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

31 March, 1987

COMMISSION HEARING

VOLUME 2 of 5 VOLUMES

IN THE MATTER OF:

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

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

TRANSCRIPT OF HEARING

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E X H I B I T S

E X H I B I T S CONT'D

(Thereafter, at the hour of 8:30 a. m. on the 31st day of March, 1987, the hearing was reconvened, at which time the proceedings were continued as follows, to-wit:

MR. LEMAY: The meeting will come to order.

We will resume Cases 7980, 8946, 8960, 9113, and 9114, with Mr. Kellahin and -- yes, sir, Mr. Carr.

MR. CARR: Before you begin this morning, yesterday during the cross examination of Mr. Greer by Mr. Pearce, he requested certain information concerning a Delta T figure and some build-up tests.

We have that information. We have marked it as Exhibit Three. I've provided a copy to Mr. Pearce and we would move the admission of Benson-Montin-Greer Exhbiit Number Three at this time.

MR. PEARCE: Okay.

MR. LEMAY; If there is no objection the exhibits will be entered into the record.

Is there anything additional this morning before we resume with Mr. Dillon?

If not, Mr. Kellahin, please

proceed.

MR. KELLAHIN: Thank you, Mr. Chairman.

RICHARD G. DILLON,

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

DIRECT EXAMINATION

BY MR. KELLAHIN

Q Mr. Dillon, yesterday we were at the point of your testimony where we were discussing the various parameters that you were placing into what you characterized as a top of the line computer model to simulate this reservoir.

I wonder, Mr. Dillon, if you would take a few minutes and help us understand the degree of sophistication of this model in comparison to the more simple material balance calculations that we see very frequently before the Commission?

A The model to which we referred and which we have used for this study is again a 3-dimensional 3-phase relatively complex model that is really the only proper way to introduce rate and other effects, such as drainage, gravity drainage or other processes into recovery calculations.

The result obtained from material balance, which is a very simple tank type of calculation which has no areal definition, has no vertical definition, does not allow for the relative permeability effects or any gravity effects, there's no rate that can be introduced into a material balance, it's essentially a hand calculation.

The essence of a reservoir simulation model is to reproduce the fluid flow as it actually occurs in the reservoir to the best of our ability.

The model, when it's in a prediction phase will allow movement of fluid as forced by different pressure forces, gravity forces, et cetera, such that it -- it should behave identically to what the fluid actually does in the reservoir, and again, it's the only way that rate can be introduced into a recovery calculation.

Q Yesterday we were discussing the parameters that went into the model and we'd gotten to the point where you were ready to discuss how you defined the area by which the commuter -- the computer woud then simulate the reservoir.

Let me direct your attention now to that subject and to Exhibit Number Six in the Sun package of exhibits.

A Exhibit Six is a structure map on the top of the Niobrara 'A' Member. This map is the interpretation by Dick Ellis of McHugh and Associates.

The purpose of this map, which again the data was taken from Dick Ellis for Sun's purposes, was to determine the magnitude, quantify the dip in the various areas of the -- particularly the Gavilan area.

We, from study of previous testimony, et cetera, realize that dip is a critical question here and wanted to quantify for ourselves what -- what type of magnitude we were looking at.

In order to determine that we needed a data base, a structure map, in order to calculate those figures.

Q Having obtained a structure map, what then is it that you have done in order to utilize that structure map in the reseervoir simulation?

A The structure map was digitized and using Sun's geologic work station, and converted into a data base, based on a finely gridded array over the mapped area. This data base was then run through another set of software that was able to calculate the dip at each of these individual points in the reservoir. Again this was a fairly fine grid over the reservoir.

The, again, we wanted to know rather than what the regional dip was or what the dip was between any two given wells, this would enable us to produce a map, a continuous depiction of what the dip magnitude is, again particularly over the Gavilan area.

Q Are you satisfied, Mr. Dillon, that the study you have made has accurately and reliably digitalized the known structural mapping that Mr. Ellis provided to you?

A Yes.

Q All right, would you turn now to Exhibit Number Seven and identify that for us?

A Exhibit Seven is the result of the calculations there were performed on the data obtained from the structure map. It is a formation dip on the top of the, again, the Niobrara 'A' Formation.

The scale in, for example, here, I apologize for the fact that some of the contours are a little hard to read, we had a scaling problem here, but looking in the Gavilan Area, which is in the Range 2 West, Township 25 North area, taking that township for example, the solid, thin lines in that area represent, I think you can probably read that number, a value of 100 feet per mile of dip.

You can see there's several contours there that extend over a fairly significant portion of that area.

The dashed, excuse me, the dotten contour is the 50-foot per mile contour and as you can see, there's a fair number of those with, again, a larger area lying between that 50-foot contour and the 100-foot contour.

The other contour that shows up in that area, particularly up in the northwest portion of that township, you see a rather bold line that varies in width somewhat, that is the 150-foot dip contour. Again, this is measured in feet per mile.

As you can see as we get farther over into the eastern area in the Canada Ojitos Unit, dips increase significantly, as we've already learned.

The area of the present Gavilan Pool was taken along with an area that approximated to be buffer zone of the West Puerto Chiquito Unit and an average was taken over that, again using the computer software, and it was found that the average in this area approximates 50 feet per mile of dip.

Q Are you satisfied, Mr. Dillon, that the computer simulation of the reservoir has been done in such a way as to accurately reflect the structure map that Mr. Dillon -- that you were provided, Mr. Dillon, by Mr. Ellis?

A Yes.

Q All right. What then, now, having selected the model, made the selection of parameters, I assume now that you're prepared to run the model?

A That's correct.

Q And you did that.

A Yes.

Q Having run the model, are you satisfied that it has simulated the performance of the Mancos Reservoir under certain producing ratess?

A Yes, I am.

Q Would you give us a general outline of the various rates or alternatives you selected for running the model?

A The model was run under tradition conditions, specifically for oil. We used values of 200, 800, up to 1404 barrels per day per 640 acres.

The 1404 represents the depth bracket allowable set by the state. That was our maximum and we went down to a minimum of 200 barrels a day from the 640 acres.

We also utilized gas constraints in the form of GOR limits, these limits of 600, 1000, and 2000 standard cubic feet per stock tank barrel.

The combination of the oil and gas limits resulted in limiting gas rates of 200, 480, 800, up to 2808 MCF per day.

Also varied, besides the producing rate, was the spacing. As we looked before on Exhibit Five, I believe, we had two different (not understood) configurations.

We investigated the 320-acre spacing versus 640-acre spacing, and, as we just looked at, the formation dip, in order to get a range of the possible recoveries from the area of interest, we used formation dips of both 50 feet per mile, which represents an average, and 100 feet per mile, which represents a significant portion of the Gavilan and certain areas in the western part of the present West Puerto Chiquito Unit.

Q Do you have an opinion, Mr. Dillon, as to whether the Mancos reservoir is or is not rate sensitive?

A Yes.

Q And what is that opinion?

A My opinion is that the reservoir is very rate sensitive. It can produce a variety of ultimate recoveries and I've found that a large amount of waste will occur under current producing rates.

Q Do you have an opinion as to what is the most efficient rate and spacing that will result in the greatest ultimate recovery from the Mancos Reservoir?

A Yes.

Q Have you presented your conclusions in the form of a graphic display by which you can use to illustrate your opinions and conclusions?

A Yes, I have.

Q And is that shown on Exhibit Number Eight?

A Yes, it is.

Q Do you also have a larger copy of Exhibit Number Eight and you've displayed on the chalkboard?

A Yes.

Q All right, let me have you go to the larger display, if you will, please. Would you take a moment and first of all identify the exhibit for us, explain for us how to understand and read the exhibit and then show us the conclusions and opinions you've reached from the reservoir simulation by illustrating with this exhibit?

A Okay. The exibit is simply a plot of measure of recovery versus the constraints of production rates.

This particular plot is for the set of model runs that was made with a formation dip of 50 feet per mile.

Q When you say Mancos Pool, Mr. Dillon, what are you meaning by Mancos Pool?

A The Mancos Pool in this sense is the reservoir that underlays the present West Puerto Chiquito and the Gavilan Pool.

Q You're not -- you don't have a microphone with you, so you have to speak up as best you can, please.

A Yes, sir. The scales, I'll point out initially, along the vertical scale we have again our measure of recovery factor.

Along the horizontal scales we have at the top our limiting gas rate, which I discussed before, the combination of various gas/oil ratio limits and oil allowables resulted in these rates.

You can see this is a logarithmic scale that extends from a value of 100 MCF per day to a value of 6000 MCF per day.

We found in the course of modeling the reservoir that more important than the oil allowble was the constraining or limiting gas rate. We found that without exception, no matter what the initial oil allowable was, as we started our simulation at the bubble point, the GORs quickly decreased, thus limiting the production based on the GOR, thus the gas rate rather than the oil rate; however, we've included three scales along the bottom so that we can convert our limiting gas rate to different total allowable oil rates.

The first scale, for example, for an oil rate is based on a 600-to-1 gas/oil ratio limit. You can see this is scaled again logarithmically from 167 barrels per day to 10,000 barrels per day. This is again stated in barrels per day for 640 acres. This is the total production whether it be from one well on 640 acres or be from both of the wells on the 320 acres, again this is total from the

640-acre area that we're looking at.

We have a second scale that's based on a 1000-to-1 gas/oil ratio and a third one that's based on a 2000-to-1 gas/oil ratio, and you can see the corresponding changes in the equivalent oil rate that is comparable to the limiting gas rate of the pool.

We, turning now to the vertical scale again, what we have plotted here is our relative recovery factors. This scale, as you can see, is a rectangular Cartisian scale; it is not logarithmic.

The plot starts at a value of 1.0, extends to a value of 3.0.

In order to compare the results from all the various model runs that were made, each of the output, each of the results from the -- each run were converted to a relative recovery factor which is normalized or adjusted to a base case which was selected.

This base case was specifically the run that was made at a limiting gas/oil ratio of 2000-to-1 and oil rate of 1404 barrels per day, again from 640 acres.

The specific case that was run against all other cases that we normalized was the 320-acre spacing case. This was chosen because this case, this particular set of parameters of this model with any further increase in flow rate, as you can see, showed no further senstitivity to recovery from the model; that is, the 320-acre spacing case at these rates produced the least amount of oil from the model.

This case was given the value of one. This is adjusted to value of one and all other cases were adjusted against this value. For example, moving back to the other side of the plot, if we were to take, for example, the 640-acre spacing case, that is one well per section, that is represented by this green line. If we look at the highest point, we see that it curves at a limiting gas rate of 200 MCF per day.

We see against that we have a relative recovery factor of 2.0. This 2.0 indicates that the reserves or the recovery from this run was a factor of two larger than our base case. Thus, by limiting our constraining gas rate, or low rate, if you will, from 2808 to 200, we are able to double recovery from the reservoir.

And accordingly, as you come back toward the left -- toward the right again, you can see as we increase the oil rate with gas rate the same rate, that is, as we approach the higher rates that we feel are more wasteful, it follows that our ultimate recovery will decrease and finally stop in the lowest, as we have experienced in the model.

I might point out also the variance between 320-acre spacing and the 640-acre spacing.

Again the red line was represented by the 320 acres. You can see over the marjority of the curve, especially at the lower producing rates, the 640-acre spacing case actually produces more than the case with two wells, or the 320-acre spacing, so not only does the addition of one more well into a 640-acre proration unit not increase the reserves, it actually has a slight reducing effect on the reserves and that any additional well would be unnecessary from, especially, an economic standpoint and also from an ultimate recovery standpoint.

Q Let me direct your attention to the top of the three horizontal scales at the bottom of the graph. Will you locate that one for me with your pointer?

A Yes, sir.

Q All right, that one is the oil schedule rate at 600-to-1 gas/oil ratio, using 640-acre spacing. Is that not correct?

A That is for, again, based on 640 acres. It applies to both the 640 and 320-acre spacing.

Q In order to utilize that scale and understand what it would be if I had 320 acres, what do I do to the producing oil rates along that line in order to make that conversion?

For example, look at 4680 barrels. That

is the rate on 640-acre spacing.

A That's correct.

Q If I want to see the corresponding rate on 320-acre spacing at a 600-to-1 gas/oil ratio, what do I do with that number?

A In order to convert this rate, which is a flow rate from one well on 640 acres to a rate that would be applicable to each of the two individual wells on 320 acres, we would simply divide that number by two and this represents the total of the two wells. This would say that our individual allowable rate for wells on 320 acres would be limited to 2340 barrels.

Q McHugh, Dugan, Sun, and Greer have applied for a limiting rate of 800 barrels a day at a 600-to-1 gas/oil ratio on 640-acre spacing.

Would you find me on that scale that point?

A That point on this scale would be right here.

Q Where we find on the top horizontal scale the number 800, that would be 800 barrels a day?

A That's correct.

Q Where would that place us on the graph, then, if we were spacing this reservoir on 320 acres on the red line; where does that take us?

A That takes us right here to this point.

Q If spacing is on 640 acres as opposed to 320, what happens to the ultimate recovery?

A It moves up, too.

Q The maximum top allowable apart from the temorary order in this reservoir would provide an operator on 320 acres to produce at a daily rate of 702 barrels a day at a 200-to-1 gas/oil ratio.

Can you find us a horizontal scale on your exhibit that will show us where the top allowable would be on 320 acres?

A That would correspond to this point here. This would be equivalent to 702 barrels.

Q You're looking at the third or the bottom horizontal scale?

A That's correct, the 2000-to-1 gas/oil ratio.

Q And you've taken the number 1404 and divided it by half?

A That's correct.

Q All right, if that is the producing rate for the pool, where does that place us on the relative recovery factor curve?

A It places us at the lowest point, the value of 1.0.

Q And as we move from right to left along that curve on 320-acre spacing, what does the reservoir simulation tell you?

A It tells us that for decreasing oil allowable or gas, limiting gas rates, that our relative recovery factor is increased.

Q And you find as you restrict the producing oil rate down to 200 barrels -- I'm sorry, 330 barrels a day on 640-acre spacing, the top scale --

A Yes.

Q -- we see that the recovery factor can be twice that of the producing rate at a top allowable?

A That is correct. Its value is essentially 2.0. It's 1.99-something but essentially yes, the recovery would be double.

Q Is there any significance to the fact that the 320 and the 640 lines appear to come together at the point, the 2.0 recovery factor on the far left of the scale?

A At the point on the far left of the limiting gas rate of 200 MCF a day, the fact that the two lines come together is simply telling us that the combination of parameters that we input into the model, that will be 50 feet per mile, the permeability, et cetera, cause the results of the model to give us very identical answers for the two different spacings for this particular case.

Q All right, sir, if you'll return to your seat, please.

Again, the large display is a reproduction of Exhibit Number Eight --

A That's correct.

Q -- that's in the exhibit package? And that represents your work product, does it, Mr. Dillon?

A Yes, it does.

Q Let's turn now to Exhibit Number Nine. Would you identify and describe for us Exhibit Number Nine?

A Exhibit Nine is another plot of recovery factor versus restricting oil and gas rate. The difference between this plot and Exhibit Eight and the large plot is that these cases were run at a dip of 100 feet per mile.

The scales for limiting gas rate and total allowable oil rate are identical to the previous plot and can be used in much the same way. The relative recovery factor again was calculated in the same manner but the scale on this plot was extended to a value of 5.0 in order to show the enhanced recovery that we see due to the extra formation dip that was present in the model for these cases.

Q If we start at the far lower end on the lower right, that is the same relative point by which you no longer increase the producing rates of the model.

A That is correct.

Q And that is the similar thing that you did to the model run depicted on Exhibit Number Eight?

A That's correct. The results from the cases that were run at 100 feet per mile were again adjusted back to our base case which again was the case with the 320-acre spacing at the maximum rate that we looked at, again 1404 barrels at a gas/oil ratio of 2000-to-1. You can see that both of these points do not quite come down to the 1.0 line due to the added effect of the formation dip. All cases were adjusted back to the one base case.

Q As we move from right to left and go up either one of those curves, we get to a maximum height on those curves in relation to the recovery, relative recovery factor number?

A Correct.

Q I notice that you've used a different scale or a different set of numbers on this exhibit for that left vertical scale than you had on Exhibit Number Eight.

A Yes.

Q Why?

A That was necessary in order to show the increased recovery that occurred from these model runs.

Q If we look at the bottom horizontal scale which would represent the maximum top allowable under state-wide rules of 702 barrels a day, 320-acre spacing, and 2000-to-1 gas/oil ratio, we find that point and then we find the ultimate recovery at the most restrictive rate that you applied into the model, what is the relationship in ultimate recoveries?

A The relationship in ultimate recoveries for both of the cases, for example, for the 640-acre spacing, again shown by the green line, is that we increase our recovery from a value of approximately 1.4 or 1.5 up to a value of 4.5 at our most restrictive rate.

Q What does that mean?

A That means that we have approximately a 200 percent increase or that our ultimate recovery would triple by constraining the rate from our highest investigated rate to our most restrictive rate.

Q Using the reservoir parameters provided for the model, using Mr. Ellis' structure map, do you have an opinion concerning the effects, if any, of dip in the reservoir and its importance to the recoveries in the Mancos Reservoir?

A Yes, I do.

Q What is that opinion?

A My opinion is that the dip plays a significant part in the ultimate recovery. With increasing dip we see generally increasing recoveries, even identical other constraining factors, and we also see that the 50 feet per mile which is the average prevalent number in the Gavilan Area is sufficient dip to see dramatic increases in ultimate recovery when the rates are constricted to rates that will allow the gravity drainage mechanism to occur.

Q Would you turn now to Exhibit Number Ten and identify that exhibit for us?

A Exhibit Ten is simply a tabulation of the points that were used to make the plot on Exhibit Eight.

Q And Exhibit Eleven?

A Exhibit Eleven again are the points that were used to make the plot for Exhibit Nine.

Q And finally included in your exhibit book is the final page that says Conclusions.

A Yes.

Q Do those represent your opinions and conclusions that you've put down in written form?

A Yes, they do.

Q All right, would you give us your conclusions, Mr. Dillon, with regards to the simulation of this reservoir that you conducted from your opinions about that reservoir?

A My first and most obvious conclusion was that the current production rate from the wells in the Gavilan Area is causing waste and that ultimately it will result in the loss of of a vast amount of otherwise recoverable oil. This is regardless of the spacing. For a given spacing there will be more waste with increasing rate.

This is also regardless of whether there is widespread communication from over several townships, or whether the pool is confined to one township. The results of the model apply to any area within the Cavilan or the Canada Ojitos as long as there is a situation such as depicted in the model, where there's at least one square mile of continuity or transmissibility in the reservoir.

The recovery of oil from gravity drainage is significant and, as I just said, at formation dips at 50 feet per mile. By reducing the gas and oil restrictive rates, by producing -- the producing rates will allow the more efficient gravity drainage mechanism to overcome and to dominate the present mechanism, which is the less efficient solution gas drive mechanism. And this restriction would result in ultimately recovering far more reserves from the reservoir than we currently were.

In my opinion the -- from a strictly reservoir management standpoint the production constraints should be as low as possible in order to maximize oil recovery. Realizing that there are other economic constraints, and other physical reasons that perhaps the minimum rate should not be imposed, I've approximated that, a recommendation of 400 stock tank barrels of oil per day and a gas/oil ratio of 600 standard cubic feet per barrel, which is a gas rate of 240 MCF per day from a 640 acre proration unit would be the proper constraint to maximize oil recovery.

Again, this applies whether there is one or two wells producing from this 640-acre area.

As far as spacing is concerned, the -- of the two that were investigated, the 640-acre spacing is the most efficient of the two. Our results show that the recovery from the additional well is not sufficient to make the well economic and in some cases can ultimately reduce the ultimate recovery.

And in general, the statement can be made that with increasing reservoir dip, the ultimate recovery will be increased.

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

A Yes, they were.

MR. KELLAHIN: That concludes my examination of Mr. Dillon, Mr. Chairman.

We would move the introduction of Sun's Exhibits One through Eleven, including the written summary of Mr. Dillon's conclusions.

MR. LEMAY: Without objection Exhibits One through Eleven will be admitted in evidence.

Are there any questions of Mr. Dillon, friendly or unfriendly?

MR. HUMPHRIES: I'd like to ask Mr. Dillon some questions.

MR. LEMAY: Yes, please do.

QUESTIONS BY MR. HUMPHRIES:

Q How many variables can you put in your model?

A The number of variables in the model are essentially infinite. The, I believe it was Exhibit Two which showed the basic parameters that would be used in most any calculation. These were basic and again these were used and -- however, when it comes to confining the model areally, as far as a grid is concerned, you can vary it, just like I say, almost an infinite number of ways.

I know that may not be a satisfactory answer to what you were asking but it -- the reservoir is -- the reservoir model is very flexible and can be described such that it will perform the correct calculations for almost any reservoir configuration that you might encounter.

Q If you change signficantly any or all of those variables, you change significantly the model, would you not?

A That's correct.

Q Okay. How old is this technology?

A Reservoir simulation has been in existence in a crude form for probably in excess of twenty years. The technology that we utilized here, this particular generation of program, is approximately five to six years old for this generation or this particular level of technology.

Q On a scale from one to ten, with one being a guess and ten being actual historical knowledge, when you create one of these models, what do you rate it?

A A properly constructed reservoir model will approach a value of ten. That is the hope. There are, you know, inherent things that prevent it from being a- a perfect representation as a model. It is as close as we can come using known technology.

I will say again that it approaches a ten.

Q So it's essentiallyl 100 percent reliable.

A Yes.

Q How many times have you correlated a model to actual history of production? That's what I was trying to get at when I asked you how long the model had been available.

A This particular model has been used in --

just within Sun's simulation group for approximately four years, I believe, and we have done, I would say, in tens of studies, and in the vast majority of those studies the model has been calibrated or history matched against previous history and used for predictive type of modes.

We have taken a few instances where we have partially history matched a model and let it predict what will happen in the future; however, the biggest unknown in the performance of any reservoir is what we do to the reservoir in terms of voidage rates and operations. Given that we know the correct assumptions as to what the producing operations will be in the future, we have a very good record of being able to match those recoveries as exhibited in actuality from the reservoir, but management decisions are made, wells are shut in, things happen that we're not anticipating in models, but knowing the exact future events that will occur, the model, if properly calibrated, will predict within engineering accuracy the actual response from the reservoir.

Q So your personal experience is over the last four or five years that you're approaching something close to 100 percent with the exception of some changes such as shut-ins and --

A That's correct.

Q -- that kind of thing.

A It can approach 100 percent.

Q You're approaching 100 percent reliability of your model to the actual result four or five years later.

A That's correct.

MR. HUMPHRIES: Thank you, I have no further questions.

QUESTIONS BY MR. BROSTUEN:

Q Mr. Dillon, in your discussion of Exhibit Eight and Exhibit Nine, and your ultimate recovery factor, obviously you have utilized some economic limit in determining what the ultimate production would be?

A Yes.

Q What were the -- what was the economic limit and were they the same for 320 as they were for 640?

A Yes, the economic limit was set on a per well economic limit of 10 barrels of oil per day production.

Also there was a minimum bottom hole pressure of 200 pounds set, so essentially the statement could be made that the reservoir would be abandoned at 200 pounds if that occurred before the oil rate dropped to 10 barrels of oil per day.

MR. BROSTUEN: That's all I have right now. Thank you.

QUESTIONS BY MR. LEMAY:

Q I do have a question of clarity.

In terms of Exhibit Eight and Nine, if you had half your wells -- we'll take the top part of the graph -- half your wells at 800 and half your wells at 200 MCF per day, are you going to average those wells out to 400 on your graph or is your -- in other words, is your graph an average or is it predicated on all wells doing the same thing?

A It is -- the model was run on all wells doing the same thing. So could not rigorously apply an average between two points.

You could generally make that statement, but it was rate specific.

Q Well, in the real world we don't have all the wells capable of doing the same thing, so how would that -- is that kind of input, is it possible to input that into your model where you do vary the quality of wells or is that too much for your model to handle?

A No. It can -- it can handle any variance in quality of the wells, any producing conditions, any different types of lift mechanisms. For purposes of this study those numbers were held constant but, yes, it could be done.

Q Other examples in a period of time, we'll say if you had wells producing at high rates and then they were cut back at a -- after payout, we'll say, after a month or so of production, they were cut back in half. Then do you take your -- your model and bring it back to the recovery factors you show. In other words, at any particular point in time you're dealing with this chart and when the wells vary you will have varying recoveries?

A That's -- that's correct. The model had to make the assumption, or in the model we had to make the assumption that not knowing all of the varieties of producing features of the wells that the limits that I've shown here were composed from the very beginning, so if a well, for example, in the field were, say, to be produced at the top bracket allwoable for a period of time and then reduced, this would not be a rigorous explanation of the ultimate recovery from that -- from that well. It would an approximation of -- the model given the varying historical rate could predict what the ultimate recovery would be, but again, that was, that assumption was made in here that that did not change through the life of the well.

Q But there again is it fair to say that if you're dealing with variables that you could take an average and come pretty close to the projections on your graph?

A I think that's correct, yes.

Q Thank you.

MR. LEMAY: Any additional -- any questions of --

MR. BROSTUEN: I have an additional question or two here.

MR. LEMAY: Yes.

QUESTIONS BY MR. BROSTUEN:

Q Mr. Dillon, on your Exhibit Two you're showing your net pay, two 30-foot zones, and you're saying one zone modeled.

Are you contending you modeled those 2 30-foot zones as one zone or are you just taking one zone and utilize the data for one zone?

A In the model, in order to reduce the number of cells and reduce the computer time and other considerations, the model is scaled to one zone. It would behave identically whether there were two zones or three zones, but for terms of economy one zone was actually modeled in the reservoir. It had five individual layers within it. We scaled it up assuming that the real world consisted of roughly two layers each of which had 30 feet of net pay.

Q So would you be utilizing, say, 60 feet of net pay in your calculations?

A That's correct.

Q As one zone. Your porosity you're giving here is one percent plus or minus. Is that -- you're talking about matrix porosity, is that correct?

A No, that would be a fracture porosity.

Q Fracture porosity of one percent?

A Yes.

Q Do you have any -- any porosity data for the matrix porosity or any cores that were analyzed or that you have data from logs utilizing any of that information?

A The data that was utilized in this study, the one percent explanation for the fracture porosity, was arrived at by taking the -- if you go down about four lines, the original oil in place of 3000 barrels per acre, which was calculated from various sources, was taken as the input data to the model.

By backing out the calculations of the saturations, the net pay, et cetera, we arrived at a porosity of 1.0 percent, plus or minus, it was approximately in that area.

We did not start out with the assumption that the porosity was one percent and go from there. We started out with the -- the 3000 barrels per acre and calculated what the porosity would have to be in order to obtain that.

To answer the rest of your question, yes, there's core data available and -- which shows some results from the matrix porosity; however, in this model we were modeling strictly the fracture porosity which we feel is the -- essentially the sole contribution of the oil to the pro ducing wells. The fracture -- excuse me, the matrix poros ity was assumed to be negligible and insignificant for these purposes.

Q So what you're saying is your original oil in place you assumed was 3000 stock tank barrels per acre?

A That's correct.

Q How did you arrive at a 3000 barrels fig ure?

A Again, this information was supplied by -- primarily from the operator of the Canada Ojitos Unit. There were also some calculations, some information that came up at the last hearing that indicated that perhaps the total oil in place was somewhere on the order of 60 to 100-million barrels. By simply dividing that by the area over which we're looking, you arrive at numbers in the area of 3000 barrels per acre.

Q So this -- this is an assumption based on other assumptions about the recoverable oil in the -- origi- nal oil in place in the two pools or the single pool, whatever you want to believe, is that correct?

A That's correct.

Q So if this -- this number is incorrect, this assumption is incorrect, your entire model would be thrown off, is that correct?

A That is correct, yes. If this number, for example, is optimistic, if there's less oil in place, then the results that we saw from the model would be even more dramatic in that we would have less of a source of oil to pull from; pulling at higher rates would deplete it even faster. Again, if the -- if the number is on the low side, and I don't believe it is, I believe it's somewhat optimistic, then the results from the model would be somewhat offset by that -- by that assumption.

Q Thank you.

MR. LEMAY: Any questions of Mr. Dillon?

Mr. Pearce.

CROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Dillon, to begin, what other commercially available or in-house created models does Sun use in modeling reservoirs, besides VIP?

A Besides the VIP we have a number of other models produced by J. S. Nolen and Associates. They are different variants of this that have specialized purposes, such as thermal models or compositional models.

We also have softwear available from Core Laboratories, their data model which we've utilized in the past, which is an older generation of of models.

We have not purchased but we lease various models from Scientific Softwear, InterComp Group. There is a group from London that has a new group who program those Eclipse that we've used.

I think that we've tested in some form essentially every product that has come on the market.

Q All right, thank you, sir.

Let's look at Exhibit Two for a moment, if we could.

I want to see if I understand your part of the work here. Am I correct in understanding that the values shown on Exhibit Two were provided to you and you do not have an independent verification of those values?

A The values here, most of which show the origin or documentation, were for the most part obtained from some other source, yes.

I did not myself make an in depth study of the particular variables from this reservoir. That's been done a number of times and the -- most of that data is public. We relied on the operator of the Canada Ojitos Unit for part of this, based on his experience from the area.

To answer your question, most of it, yes, did come from other sources.

Q Looking down at the last item in the first section of that under Reservoir Conditions and Properties, that's really a transmissibility number, not a permeability number, isn't it, Darcy feet?

A That is correct. Transmissibility sometimes doesn't have meaning to non-engineering types. It is labeled permeability for those purposes. Transmissibility can have various units which may or may not be Darcy feet.

Q Until we started this proceeding, transmissibility didn't mean anything to me.

Did I understand your answer to several previous questions that really the validity of not only this model but other models depends upon the validity of the parameters that you put into that model?

A That's correct.

Q You had some questions earlier, sir, about the preferability of modeling over material balance.

A Yes.

Q Can you briefly explain to me, a layman, what the difference is? What is a material balance calculation versus what the model does?

A A mataerial balance calculation essentially gives one answer and that is the original oil in place. It can give another answer with an assumed oil in place of influx into the reservoir or some other single variable, but the answer from any material balance calculation which, however, maybe fairly complex in that it assumed a number of different conditions, rock compressibility, et cetera, the end result is not rate dependent and is simply a measure of the original fluids in the reservoir.

Q Some of the same items appear to show up in the model that show up in material balance, except it is a -- has a lot more complicated factors that it can consider with some of the same underlying principles, is that fair?

A That's fair, yes.

Q Thank you. Okay, in looking at -- I'm looking at Exhibit Five. For the 640-acre spacing symmetry, as I understand it, if you're assuming a 640 section and 3000 stock tank barrels per acre, you're assuming that the -- multiply those out and that's the amount of oil to be considered, is that --

A That's correct, yes.

Q And your model assumes that all of -- all of the horizon in the reservoir is uniform, that there is no variability in your model. It assumes that, for instance, in the 640-acre tract shown on the top of Exhibit Five --

A Yes.

Q -- that each bit of that has the same characteristics.

A That's correct.

Q Do you believe that's generally true from what you know of the Gavilan Pool?

A It -- the Gavilan Pool is a somewhat heterogeneous reservoir; however, for my purposes in developing this process model, if you will, which is describing the processes going on in that area, we took the smallest sampling that we could from there and assumed constant properties due to the fact that there's an infinite combination should we assume to vary any one property over that group.

Q Have you looked at any directional permeability information?

A In constructing this grid we did not utilize any and at this point have not come to any conclusions on directional permeability, no.

Q I gather from that answer that you have looked at some information and have not reached a conclusion, is that --

A That's correct.

Q If you concluded that there was directional permeability present, would that affect the model?

A Yes, it would.

Q Okay, in working the model, and I'm still looking at the top diagram on Exhibit Five, you show four wells, one at each quarter -- each corner of the 640 and I understand you keep telling me that, but a quarter well in the model, how are those wells produced? Were they produced wide open and shut in? Were they produced continuously to reach the production level?

A The wells, each of which were scaled to one quarter of whatever the assumed producing rate was for that particular run. For example, if we were assuming a constraining rate of 200 barrels of oil per day, each of these quarter wells would be forced to initially produce 50 barrels of oil per day, thus the summation of those four quarters would add up to 200 barrels, thus giving us our one full well at 200 barrels per day.

Q Okay, so that if looking at this 640-acre depiction, if there is some dip in there, then you're producing both in the model, both the up-dip quarter well and the down-dip quarter well at the same rate.

A That's correct.

Q Did you inject any gas into the up-dip wells as we understand is done in the Canada Ojitos portion of what you are calling the Mancos Pool?

A In this particular configuration, no, we did not inject any gas into this model scheme.

Q And therefore any recoveries shown by

this modeling would be from primary recovery.

A That's correct.

Q Okay, let's turn now, if you would, please, to Exhibit Eight.

If we could start, sir, could you explain to me the relative recovery factor, the vertical axis on this diagram?

A Again the relative recovery factor is a measure of the ultimate recovery obtained from each run, which is normalized or compared against our standard base case, which is the 320 acres at the maximum rate.

Q Okay, and what was that base case recovery factor?

A That was assigned a value of 1.0 --

Q Yes, and in terms of percentage of oil in place recovered?

A In terms of original oil in place, that particular run recovered -- excuse me, I'll have to recall that from memory -- if I recall, that was about 11 percent of the original oil in place.

Q And that, as I understand it, is the far right -- one of the (not understood) on the far right of your line.

A That's correct.

Q So that's the lowest recovery you would expect.

A Yes, under these conditions.

Q And you have not in your modeling process studied gas injection, is that correct?

A For this particular configuration that we're showing you today, no, we have not studied that. We have in the past made sensitivity runs but we don't have any exhibits here today to show you on that, no.

Q Yes, I was only addressing these exhibits.

Mr. Dillon, what's your understanding of Sun and other parties requests for maximum oil allowable for a 640-acre unit?

A I don't believe I understand your question. I'm sorry.

Q In your -- when you were being questioned by Mr. Kellahin I think he asked you about the set of points above the number 800 on the uppermost lower scale.

A Right.

Q Do I understand that from his questioning that the request is for a 600-to-1 GOR, an 800-barrel a day allowable, and 640-acre spacing?

A That is what we requested at the time of application, yes.

Q Goodness, that answer makes me nervous, Mr. Dillon.

Do I gather from that answer that you're asking for something different now?

A My results, as you can see, show that there is further sensitivity with reduced producing rate; however, again, this is a strictly reservoir management question that I'm addressing. There are other factors involved.

Again, again the application does state, yes, 800 barrels of oil per day. If I were alone in this matter and had television with nothing but the results of models to look at, it would indicate to me that some lower rate would probably be the optimum.

Q I'm looking at your conclusions, the last sheet of your package of exhibits, Item Number 4, and I see rates of approximately 400 stock tank barrels of oil per day and a GOR of 600 from a 640 proration unit.

Should that be 800?

A No. The results of the model indicate that it should be more on the order of 400.

Q That -- the difference is a difference between your modeling results and the application rather than in the (not understood).

A That's correct.

Q In your model you used the 10 Darcy feet transmissibility number. If the transmissibility were lower than that, what affect would that have on the model? If you lower transmissibility, what happens in the model?

A If the transmissibility is lowered in the model, then, of course, fluid flow becomes more difficult from cell to cell as it would in the reservoir.

Q And how does -- I'm still looking at Exhibit Eight. What effect would you expect that to have on the way Exhibit Eight looks?

A Exhibit Eight, with a decrease in transmissibility, the red and green curves would essentially have the same characteristics as we see here but the end point of the curve would be reduced somewhat, depending on what the reduction in transmissibility was.

Q The whole curve would shift down or would the slope shift so that the end points were lower?

A The whole curve would shift down and essentially retain the same character. Of course there would be a change in the scale of recovery factor, but the essential character would stay the same in that it would increase with decrease in constraining rates.

Q As I understood your opening presentation, you were asked by Mr. Kellahin if this model could be used for dual porosity reservoirs and I believe you answered that it could be configured to do that.

A That's correct.

Q Did you do that in the course of preparation for this hearing?

A No. In the course of preparation for this hearing we concluded that there was only a one porosity, one permeability system present and effective in the reservoir, thus it did not necessitate making changes to the model that would accommodate two different types of porosity; it would accommodate a matrix porosity. It was set up for a fracture porosity system.

Q How -- how does this model take into account what Mr. Greer refers to as tight blocks?

A The tight blocks that Mr. Greer referred to are an integral part of the reservoir. They contribute to the production through the fractures that exist in those tight blocks and it was assumed for our modeling purposes that the porosity and the permeability was all of one type; that is, fracture porosity, for our purposes.

Q And you assumed in constructing this model that the transmissibility within those tight blocks was 10 Darcy feet?

A We assumed that the equivalent transmissibility in the reservoir was 10 millidarcy feet -- 10 Darcy feet, excuse me, as shown by interference tests and other calculations.

Q What were your assumptions about vertical permeability versus horizontal permeability in this reservoir?

A We assumed that within the layers that we are investigating that the horizontal and vertical permeabilities were equal.

Q Now I'm still not clear up towards the front, and I believe you had a -- yes, you had a question or two about it and I'm still not clear, I'm looking at Exhibit Two, the net pay, it says there are two 30-foot zones, one zone was modeled and now you've just indicated that within zones the model assumed that the vertical and horizontal permeabilities were equal.

A That's correct.

Q Okay, can you help me understand what I've just said to you?

A The individual zones or members of the Niobrara, the A, B, and C, for example, are assumed for our purposes to be a zone. We assume those to have an average of 30 feet of net pay.

For purposes of modeling, in order to obtain the simplest model that would still give us the same results as the more complex description, that as we scale the model, within that layer, as we show on Exhibit Five, there were five individual layers, model layers; that is, individual cell blocks, if you will, within that layer. These were done. These were divided such to give us vertical definition within each layer such that changes in saturation and pressure could occur within each layer, rather than making the simplifying assumption that all saturations would be the same for any given area in the model, vertically within that 40-foot layer -- 30 foot layer.

Q Looking back for a moment, if you would, sir, at Exhibit Number Eight, you indicated that the base case showed about 11 percent recovery. What's the recovery mechanism for that 11 percent?

A The recovery mechanism from that, although it's not a result that is obtained from the model, it's not an answer that is printed out on the output, in my assumption is essentially a solution gas drive mechanism.

Q When we were discussing the zone a few moments ago, you were indicating that the model, you broke it down into five vertical strata within each of those 30-foot zones.

Does the model assume equal gas -- does the model calculate an equal gas percentage in each of those layers or does it differentiate gas/oil percentages between layers?

A It differentiates different saturations in each layer. It does assume anything. It calculates those saturations as they occur as a result of the parameters that we give the model.

If we had simply used one gross block for our vertical definition and did not have our five layers, one saturation would be assumed up and down within that -- that zone.

The five layers give a more detailed, more accurate answer to the problem.

Q And what is the recovery mechanism in your opinion for those recoveries above the 11 percent if the production rates were reduced?

A If the rates are reduced, the mechanism becomes, I believe, increasingly dominated by gravity drainage.

Q So that if I look at Exhibit Eight, it is possible to have a 50 percent gravity contribution and a 50 percent solution gas drive contribution? I mean I'm looking at the relative recovery factors and I --

A Right.

Q -- want to understand if that's what that means, that one --

A At some point along that curve, I cannot tell you where it is, the contributions may be equal, yes.

Q Okay. What would the results of the model be if the transmissibilities vertically were, let's say, one tenth of the transmissibility horizontally?

What impact would that have on results?

A That would, and I'm speculating here to a certain extent, would affect the model such that the oil and gas would not be able to communicate vertically as rapidly. The effect of that would probably be to reduce the overall recovery from the model from a solution gas drive standpoint in that that gas would not be able to escape from the oil and your relative permeability oil would be affected adversely. However, with the higher number still retained in the hoizontal direction, the gravity drainage mechanism would still be able to be effective. So my answer to that is that the curves would be, for example, on Exhibit Eight, the curves would be shifted downward but would still exhibit their curvature upward as we go to the left. That is, they would still be rate dependent and show higher recoveries.

Q Okay, let's switch that around and have the higher transmissibilities vertically rather than horizontally, what impact would you expect on the model from that change of circumstance?

A If the transmissibilities were higher in the vertical direction, that would allow the oil and gas to flow up and down within a reservoir, so to speak, easier. Production to the well would be inhibited. That combination of effects would complicate the results of the model. It would, depending on what those ratios were, and I can't answer at what point, the curve again would be reduced, I feel, downward, and again depending on what that ratio was, at some point in time you might see a decrease in one of the mechanisms. Solution gas would perhaps become more of a -- convert to more of a -- perhaps a gas cap mechanism, except for the fact that the gas is being produced out of the up-dip wells.

I just have to have an estimate of what those numbers would be in put them in the model. I really can't answer that. That's a little bit more complex than I can answer off the top of my head.

Q And additionally, am I correct that it would complicate things if the transmissibility in one direction horizontally were greater than the ransmissibility in another direction horizontally, east versus west.

A That's correct. That could, depending on which direction in relation to the dip that that occurred, it could enhance the recovery from the drainage mechanism, the gravity drainage mechanism, or it could perhaps reduce it somewhat. It would still be effective unless there was some total lack of communication in some direction.

Q Then, as I understand the last few answers, the graph, the shape of the graph, the placement of the graph lines on the grid are dependent upon a number of things and this model has assumed a transmissibility number, has assumed it radially, is that correct?

A I'm not sure radially is the correct term.

Q Homogeneous?

A That's a proper term, yes.

Q And you have not modeled the different set of assumptions, if I understand it, than this homogenetic (sic) --

A That is correct, no.

MR. PEARCE: That's all I have. Thank you, sir.

MR. LEMAY: Any additional questions of Mr. Dillon?

Yes, Frank Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Dillon, does you model take into account interference?

A Interference between the wells?

Q Yes.

A Yes, it takes into account any relationship between production that you would see in the field. The wells are all connected in the model via the grid. So, yes, interference would be seen.

Q So the spacing is not just determined whether the -- you didn't assume that a well would drain 320 or a well would drain 350, it was just a model overall of the production from the pool, is that correct?

A That's correct. The model does not pre-assume any spacing or any recovery mechanism. It simply calculates to the best of our ability, to the best of its ability, what would happen in the reservoir given these spacings, given these dips, et cetera.

Q Is this program capable of calculating optimum spacing and optimum production rates?

A Given the constraining rates for all of the other variables, yes, an optimum spacing or any other parameter, since (not clearly understood) is a parameter, can be established, yes.

Q Given the model results you showed on the chart, I guess in Exhibit Nine, would you presume then those results that denser spacing, say, at 160 or even 80 acres, would be even more wasteful?

A It is my conclusion that, yes, the chart that's hanging, which I believe is Exhibit Eight, from extrapolation of the data that we have would show that that is very likely. Until that run is made I can't make that positive statement, but, yes, my opinion is that tighter spacing would further decrease the recovery from the reservoir.

Q Then in your opinion based on your (not understood) would even greater spacing than 640 accomplish even more efficient production?

A Again, speculating somewhat, I would say that it is very possible that perhaps a wider spacing could be more efficient; however, at some point you reach a limit that some of the oil does not get produced because it is not able to travel to the producing wellbores, and I cannot tell you what that spacing would be from my results.

Q In the use of your computer models, do you often when you practice with your company's policy, given the accuracy of the model, proceed with what the models might direct you to do and not given some greater political or economic consideration?

A Within the structure, management structure at Sun, typically the results of the model are taken and usually economics are applied to those results. Usually we have the opportunity to interact with those people making the econmic assessment, such that we can optimize from an economic standpoint.

Not having that luxury in this case, we essentially were limited to optimizing from strictly a reservoir standpoint.

Q So economics could not be used in this model (not clearly understood.)

A Economics could be used to optimize. They were not for terms of coming up with my conclusions.

Q Thank you.

QUESTIONS BY MR. LEMAY:

Q Mr. Dillon, I have a question. Your model shows certainly that this reservoir is rate sensitive, especially to the rate of dip as exhibited by Exhibits Eight and Nine. Double the dip and you go from two to four times the base level.

What other factors on Exhibit Two can you tell us that would be important or critical in judging the degree of rate sensitivity to this reservoir?

Which are the critical elements in the assumptions on Exhibit Two?

A On Exhibit Two the other parameters would be the initial oil in place, as I mentioned before. With any reduction in that number it would become probably more rate sensitive, as with higher numbers it would become less, generally.

It is fairly insensitive to rock compressibility. That really wouldn't affect the rate sensitivity. The model has been found to be relatively insensitive to relative permeability. The permeability would have an affect on the ultimate recovery but for the -- all of the cases that we ran it was found that it was still rate dependent no matter what the permeability or transmissibility that we -- that we ran.

The PVT, the fluid properties would have some minor affect on that. I don't believe they would -- they would enter into any determination of whether or not the reservoir was rate sensitive.

Q So far we've just got oil in place. How about porosity, temperature, any of those items, do they affect rate sensitivity?

A Well, no, the temperature would not. The initial pressures would not. The, again it would be the oil in place which -- which is directly related to the porosity.

Q Okay, that's all I have.

MR. LEMAY: Any additional questions?

MR. HUMPHRIES: I have one.

MR. LEMAY: Yes.

QUESTIONS BY MR. HUMPHRIES:

Q I guess it's two questions. Either I misunderstood something or I made an incorrect conclusion yesterday.

Did you tell -- did you say in your testimony just a few minutes ago that you did not consider tight blocks as a part of this formation or this field?

A The tight blocks were considered to be an integral part of the average reservoir properties and those average properties were applied to the model.

We do not have tight blocks set up within the model, no, per se.

Q Describe to me how you averaged, because I think I heard you say in the same testimony that you considered this to be homogenous fractured throughout this entire production area, is that right, or this entire formation, and in order to arrive at that you took -- you averaged the tight blocks in with the rest of the fracture system. Is that I understood you to say?

A We --

Q Or is that what you said, I guess.

A No, I don't believe that's really -- really what I said.

The -- let me approach your question from a different way and I hope I can answer it better for you.

The permeability number, the transmissibility that was used was not averaged from any -- any sources other than the fact that it is within the range of direct measurements from pressure build-up and interference tests directly on the in situ permeability in the reservoir;

that is the -- the result of calculations such as those that Mr. Greer showed us yeesterday, show that 10 Darcy feet is a representative number for the reservoir, and yes, for the question that we assumed again that we had a constant permeability or a homogeneous reservoir, as you said.

Q Well, I don't mean to ask you to speculate, my understanding about Mr. Greer's testimony yesterday in Section B, I believe, there were basic reservoir mechanics as perceived from prior OCD Cases 8946 and 8950.

One of the unique characteristics that we're asked to decide upon about this particular question is that the field is indirectly draining the tight blocks it surrounds, so that becomes in my mind a crucial part of this testimony and your model and it also says that that pressure maintenance by gas injection is combined -- a combination to (not understood) the formation, and if I understand it right, you average -- you did not include any consideration for gas pressure maintenance and you did average the blocks based on your assumptions.

A That's correct, for purposes of presentation at this hearing, no, we did not run any specific cases with this particular set up for gas injection. We've done that in the past and have come to some intermediate conclusions, but -- and to answer your other question, again, the mechanism that the model is being

-- that it is using is the fluid flow within a type of porosity, type of permeability in the model. We have it constructed such that that represents the fracture porosity, the fracture permeability, no matter what the -- whether we say that it's a fracture within a tight block or it's a large fracture. We have essentially made the assumption that one number can represent the combination of those two effects.

Q And that would then, as far as you're concerned, average out in your model existence and consideration of this uniqueness of the tight blocks in this formation.

A To a certain extent, yes.

Q I have one other question. On Exhibit Two, I think you've been over the assumptions you made, but one of the inputs or the variables, I presume that you used in fluid properties, was under Exhibit Four.

Would the age of that information have anything to do with its particular application today or its value today?

A The age of the information is critical in that the older the information, that is the sooner that this information is obtained to the time of discovery of the reservoir, in all likelihood the higher probability that this is a representative sample of the reservoir fluids.

Q So the fact that this is 1962 information is more valuable not less valuable --

A That's correct.

Q -- in your model. Thank you. I have no further questions.

MR. LEMAY: Any additional questions? Mr. Lyon.

QUESTIONS BY MR. LYON:

Q Mr. Dillon, on Exhibits Ten and Eleven you have two sets of data on each exhibit.

A Yes.

Q What is the significance of those two sets of data?

A The -- I assume you're referring to the fact that there is one table which is separated by a heading that says Relataive Recovery Factures (VS Same Spacing), and then there's another table below that?

Q Right.

A Okay. The upper table are the data points that were used in making these plots. These are the direct results from the model.

These are normalized to our base case, which I believe I've mentioned here at the top is the 320-

acre spacing; 1404 barrel of oil per day case, again at 50 feet per mile of dip.

The second set of numbers that you're looking at were adjusted similarly but they were adjusted for the same spacing; that is they were adjusted to the case that recovered the lowest amount of oil for that particular spacing. Thus you see that the 320-acre spacing numbers do not change because the same base case was used for normalizing those numbers.

In the 640-acre spacing case you see that there's a slight difference there. It was enough of a difference that it shows up in about the third decimal point out there.

This -- this was to show the sensitivity given a base case of 640 acres, if you want to compare within that case rather than comparing it to 320. If you would make the assumption that you wanted to make all your comparisons for one spacing.

That was simply done to, you know, facilitate the interpretation of the results in a different manner.

Q On the Exhibit Eleven, the differences were more pronounced.

A That's correct.

Q Is there an explanation for that?

A Again, the numbers that you see in the upper table were normalized but compared against the base case which had 50 feet per mile of formation dip.

The set of numbers in the lower table were compared again within that set of four runs. In other words, you see that the highest rate case again has a value of 1, thus this takes out the effective dip and says that given 100 feet per mile of dip, and, say, 320-acre spacing, our lowest rate produces a factor of 3 times as much oil as our base case which has, in that case, which has a value of 1.0.

Q So this is not a question of repeatability of your model.

A No. This is just a different presentation of the results in a different format that facilitates comparing each of these four runs, it breaks it down to strictly a rate parameter.

Q And all four of these are compared to your base case that's shown on Exhibit Number Four? Your base case is 320-acre spacing, 50 feet per mile dip, and 640-acre spacing as compared to that and then the two on Exhibit Eleven are also compared to that first column on Exhibit Ten.

A That's correct. For the upper table in each of those, yes.

Q All right. Would it -- would it be fair to characterize the results of your model study to say that at 50 feet dip per mile and 100 feet dip per mile gravity drainage is a viable mechanism for producing oil and that this can be enhanced by extending the amount of time that you take to exhaust the reservoir?

A That's correct.

MR. LEMAY: Additional questions?

QUESTIONS BY MR. STOCKTON:

Q Mr. Dillon, my name is Bruce Stockton. I'm with the New Mexico State Land Office.

Have you done simulations on other solution gas drive reservoirs?

A Yes, I have.

Q What -- can you generalize the shape of the curves that you usually receive from those results?

A The studies that I've seen from other solution gas drive reservoirs, those studies have been of a different nature in which we did not go in and impose different rates on those reservoirs. We history-matched or we imposed the actual rates that we had seen in the past and we predicted from that, assuming a rate.

If we were to -- I can speculate somewhat that if we were to go out and do a rate sensitivity such as this, the curves would look somewhat different. If there was strictly no mechanism active in the reservoir except for solution gas drive, the curves would look different.

Q So is what you're saying is you feel that you have accounted for in this simulation both gravity drainage and solution gas drive, is that correct?

A That's correct. Again the model does not pre-assume any dominant recovery. It essentially tells you what will happen under the conditions that you give it and I believe that, yes, the two mechanisms that we see are gravity drainage and solution gas.

Q In this simulation model that you have used, does this have the capability to (not clearly understood) functions for some of teh input parameters?

A In order to do that -- it could be utilized to do that, yes. It's not something that's inherent in the model. It would have to be something that the person making the study would have to impose on the model and make a variety of runs. But it could be done.

Q And in this case you chose not to do that, though.

A No. We picked our assumptions and made our runs based on that.

Q Okay, thank you.

MR. LEMAY: Additional questions?

Mr. Lopez?

CROSS EXAMINATION

BY MR. LOPEZ:

Q Mr. Dillon, I noticed on your Exhibit Six that you have used two different contour intervals. Would you explain the reason for that?

A Exhibit Six, which is a structure map, utilized two different contour intervals because of the wide variance in structure tops that we see in this area. In order to make it most appropriate for presentation of what the structure was, it was necessary to go to two different structural intervals, yes.

Q And is the 500-foot contour interval used on the righthand side of the exhibit as opposed to the 100-foot interval they used over in the Gavilan Mancos Area?

A That's correct.

Q And in so doing it would not show the significant difference in structural relief between the three areas of -- between the two pools, would it?

A If, I believe, if I undertand the question right, you're asking does this map depict the structural relief properly between the two areas?

Q Yes.

A I believe it does. The data are labeled on the contours as they exist by our interpretation of the reservoir.

Q If you used the same contour, though, it would show quite a different picture, wouldn't it?

A The contours, yes, would become somewhat closer over to the right area, especially in areas to the -- to the east of the, and out of the Puerto Chiquito -- West Puerto Chiquito Unit.

Q Therefore you'd see a much more significant difference in structural relief between the two areas.

A That's -- that's correct. Visually it would appear to be different, yes.

Q Also, Mr. Dillon, you've assumed that this reservoir has 10 Darcy feet transmissibility. What kind of producing rates or capacity would you expect from wells that amount of transmissibility?

A In terms of -- of absolute --

Q Barrels per day.

A Barrels per day. We essentially stopped our investigation at, I believe looking at Exhibit Eight, for example, you can see we stopped at a producing rate of 1400 barrels of oil per day from one well.

From the drawdowns that were present at

that point I believe there is a possibility that higher rates could be seen from that type of permeability.

Q In the real world what would you expect producing rates to be with that amount of transmissibility?

Well, I see on your Exhibit Eight that you have 4680 thousand barrels per day as a possibility. Would that surprise you?

MR. KELLAHIN: I'm going to object to the question, Mr. Chairman.

Mr. Lopez has phrased in terms of some abstract concept about the real world. If he could rephrase his question to apply to this particular reservoir it might be intelligible enough that this witness could understand and respond to it.

MR. LEMAY: Mr. Lopez, would you rephrase the question?

MR. LOPEZ: Okay, I'll rephrase the question.

Q Have you ever seen a well that has 10 Darcy feet transmissibility produce 4680 barrels a thousand -- 4680 barrels per day, or more?

A In my experience, no, I have ot, although that's not the purpose of the graph. More critical to the graph is the limiting gas rate which at that oil rate would be 1.8-million cubic feet per day, and that would be well within reason.

Q Do you know what the average producing rate in the Gavilan Mancos Pool is?

A Today?

Q Yes.

A No, I can't answer that question specifically.

Q Would it surprise you if it's less than 100 barrels per day?

A No, that would not surprise me.

MR. LEMAY: Additional questions of Mr. Dillon? If not, he may be excused.

Oh, I'm sorry, Mr. Kellahin.

MR. KELLAHIN: I wonder if Mr. Dillon might take a break here at this point and I have a few questions to ask him, but perhaps now is an appropriate time for a break. He's been testifying for close to two hours.

MR. LEMAY: I realize that. We're ready to excuse him, but you if you want him back, we certainly -- if he wants more direct we'll take a break now and resume after -- we'll take a ten minute break and resume at 10:30.

(Thereupon a ten minute recess was taken.)

MR. LEMAY: Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Dillon, I'm like Mr. Pearce, I know just enough reservoir engineering to be dangerous. If I ask you a question that causes you to speculate, just tell me "I can't speculate for you. I don't know."

I've asked many engineers questions that are unintelligible and if I give you one, don't be bashful to tell me it makes no sense.

What I want to do is clarify perhaps only for my own information, but I perceive some confusion, and I think I've introduced it, in terms of terminology.

We have talked about the reservoir model. We have talked about material balance calculations being a model. We have talked about reservoir simulations.

Can you give me a concise and clear way to understand how to distinguish between a model and then reservoir simulation because I think it my discussions with you I have sometimes used modeling when I meant to ask you simulation questions.

Could you tell me, for example, when we talk about a material balance calculation, is that not simply a model?

A That's correct. That's a very simply model or conception of the reservoir.

Q When we talk about reservoir models, what is the correct way to identify and describe and understand that word?

A Again a model is simply a concept of the processes in the reservoir. The term as I've used it today and I think maybe you, also, dealing with it on a daily basis, a model, as I've defined it, is a reservoir simulation model that is a complex set of computer code that uses known and proven equations to describe the exact flow of the fluids in the reervoir on an areal sense, a vertical sense, in three dimensions, as a function of time, as a function of different parameters, where at times one hears the term model that could be applied to things as simple as a simple mental concept to describe a reservoir such that knowing a few facts about the reservoir we might presume that it's a certain type of drainage. It's -- you have a concept that it's a gravity drainage reservoir or solution gas drive, but there are no facts, no computations that back up that assumption.

The range of what one considers to be a

model could vary from simply a mental conception to a sophisticated 3-dimensional simulation of the reservoir.

Q I'd like to direct your attention to Exhibit Number Eight, simply because I think it's a useful display to ask you some questions about the changing or altering certain of the parameters or assumptions that go into the model by which then the reservoir is simulated.

If I understood this correctly, -- well, let me just put the question to you, if we look at the lower righthand portion of the two curves, and as we move to the left on those curves, that shows increasing ultimate recovery as we reduce the rates and the assumption was that there was 10 Darcy feet of permeability in the reservoir.

A That's correct.

Q Now, if that permeability is reduced, what happens to the curve?

A If the permeability is reduced and the numbers from results of those calculations from the model were to be plotted on this curve and adjusted again to their -- to a base case at that transmissibility, the right handside of the curve would again be the value of 1; however, the lefthand side of the curve, that is the highest point we see would be brought down and the entire curvature of the curve would be brought down in some relation to the decreased permeability that was introduced in the model.

Q Is it a correct generalization of your testimony that as the permeability is reduced, that the slope of that curve, then, as you reduce the rates, is not as great as you would see it at a higher permeability range?

A That's correct.

Q What is the lowest permeability range that you have analyzed in your study?

A In our studies the lowest cases, the lowest transmissibility that we utilized in any of the cases was 1 Darcy foot.

Q At 1 Darcy foot do you still see any effects of gravity drainage on increasing ultimate recovery over straight solution gas drive?

A Yes, you can see a -- you can continue to see a curvature of the line. The line still slopes. Again, as I mentioned, the magnitude of the line is reduced substantially from the 2.0 value that it shows in this graph, but nonetheless it still shows a rate dependency at that transmissibility.

Q Is it a correct generalization then that the permeability can be adjusted over a very large range and you still see ultimate recoveries benefiting by reducing the producing rates?

A That's correct.

Q You gave us some percentages in response to Mr. Pearce's question awhile ago and I'm not sure i understood exactly what the percentage was. Can you give us a general range of percentages that you see are reasonable to apply to this reservoir if we assume the total absence of the influence of gravity drainage in the model; take that out altogether?

A By taking out any vertical definition in the model, forcing it to produce such that it is in a relatively pure solution gas drive mechanism, there's no segregation of the gas, it's produced with the oil, it -- and that has been done with the model, we have made early cases where we did not have the vertical definition that we saw. A pure solution gas drive or the lowest result that we've seen from this model has been reoveries on the order of 4.9, around 5 percent, using essentially the same parameters that we're using except for taking out vertical difinitions, thus eliminating any -- just about any chance of contribution by gravity drainage.

Q Within the range of your study, can you give us an approximation of the maximum percentage that gravity drainage might reasonably be expected to affect ultimate recovery in the reservoir?

A I believe that approximately, somewhere on the order of 50, perhaps approaching 60 percent, of the original oil in place could be recovered by gravity drainage if that mechanism were allowed to dominate from the time that the reservoir was discovered and produced.

Q There were some questions with regards to your understanding and application of the phrase "tight blocks". When you use that phrase, tight blocks, does that mean that you are dealing with or does that imply that you're dealing with a dual porosity type reservoir?

A No. The term "tight blocks" as I've interpreted it and using in this study, implies that there are areas of the reservoir, this being a somewhat heterogenous reservoir, that are tighter than other areas. there is a fracture system that invades all of the productive area of the reservoir, and it's through that system that the oil is produced.

It is only through that system. There, from my calculations, there are no -- there is no contribution, no significant contribution, from any other type of porosity other than matrix; that is there is no -- or excuse me, other than fracture. There is no contribution from any of the matrix porosity which may or may not exist in the reservoir.

The results as we've seen here, again, in the early calculations I did in setting up this model, indicate that the matrix contribution is negligible and that this is not to be confused with what we call "tight blocks", which are of a fracture porosity type, identical to any high conductivity fracture system that permeates throughout the reservoir; that is, we have a single type of porosity, not a dual or two-type of porosity system.

Q Is the simulation of this reservoir one whereby you can cause the simulation to distinguish between simply modeling and a homogeneous reservoir where you stick a bunch of straws in and suck out all the oil, versus a heterogeneous reservoir that has non-uniformities, areal differences, and certainly more complexity than the simple, homogeneous reservoir?

A Going back to your original question, I believe that the answer to that is yes.

Q Your simulation is one that is suitable for the Mancos Reservoir?

A Yes, I believe it is.

Q And it does not cause by the input of these parameters or assumptions, you've not caused this simulation to characterize and consider this reservoir simply to be a homogeneous reservoir?

A By the input parameters that I've used in the construction of the reservoir that I've gone through, the reservoir, although on an areal sense over the entire producing area of what we're looking at, both pools is heterogeneous. Within the reservoir model, the simulation model, we have made certain assumptions about what the effective transmissibility and other parameters are.

Q Do you have any difficulty, reservations, qualms, or argument based upon your study with the parameters and assumptions you've made in modeling this reservoir?

A No, I do not.

Q Let me ask you about the question asked earlier about the effect of pressure maintenance. I believe in response to that question you said you did not put in a factor that would take into consideration the pressure maintenance occurring in the unit.

A That's correct.

Q What will happen if you assume pressure maintenance and you have gas injection, as is occurring in the reservoir; do you have any opinions as to what that will do to the simulation of that reservoir?

A By maintaining or partially maintaining the voidage and pressure in the reservoir by injecting the produced gas, the results would indicate that the recovery, the absolute recoveries that we're looking at here, would increase substantially; that the added energy to the reservoir from the injected gas would in all cases regardless of rate increase the ultimate recovery from the reservoir by usually several factors. It could be a two or three-fold factor increase in ultimate recovery.

Q By excluding that from consideration is it fair to characterize your opinion as being one that shows a more conservative ultimate recovery from the reservoir than you might otherwise expect from pressure maintenance?

A That's correct.

Q Thank you, Mr. Dillon.

MR. LEMAY; Thank you, Mr. Kellahin.

Additional questions?

RECROSS EXAMINATION

BY MR. PEARCE:

Q Just very briefly, Mr. Dillon if I may, I thought I heard you to say during Mr. Kellahin's questioning right now that you had reached the conclusion that we had a single porosity system based upon work which you did prior to modeling this reservoir?

A That's correct.

Q Could you describe that work, please?

A The analysis that I went through prior to modeling this was somewhat quantitative with the exception that I went back through the transcripts and exhibits to see what other -- other companies had done.

Specifically I went back and looked at

some exhibits -- an exhibit that Mobil had introduced at the last hearing. They had done some recovery calculations and specifically had done some sensitivity to what type of a -- or what size of a fracture would be necessary in order to produce the rates that they were exhibiting, that they were seeing exhibited in the reservoir at the permeabilities that they assumed were there from their core data, and they were making the assumption that this was essentially a matrix contribution to a fracture system, and thus being produced into the -- into the wellbore.

The calculations they did to come up with this matrix contribution were based on core data that showed very low permeabilities but were based on data that was taken under conditions that were inappropriate for their use in these calculations. The permeabilities that they came up with were on the order of hundredths of a millidarcy and even at that they were calculating that you would have to have two fractures, each of which a mile long, in order to produce 150 barrels of oil a day at this permeability, which is a significant rate; however, the -- by correcting or by assuming what the correct permeability should be, if the cores had been tested under the correct conditions, that is, the cores were tested for permeabilities after they had had all residual fluid saturations removed and they had been tested under atmospheric conditions.

If these cores had been tested under the correct overburden conditions with the in situ saturations that we assumed exist in the reservoir, the permeabilities would have been cut by at least a factor of 10, if not 15 to perhaps 100.

If we make the assumption that they were cut by a factor of 50, for example, that would reduce this 150 barrels of oil per day number to something on the order of -- 50 would be 3 barrels of oil and in my judgment that was insignificant compared to the hundreds of barrels of oil that we were seeing exhibited by actual wells in the reservoir.

They also did not take into account any relative permeability effects that would have further reduced this calculated number from the matrix system. They assumed 100 percent oil saturation but yet their pressure calculations were done at pressures that were below the bubble point, thus gas saturation would have had to exist.

So the relative permeability of oil would have bene reduced perhaps by another factor of 10, so it was my conclusion that there was no significant contribution from the matrix at the permeabilities that we believe may exist in that matrix.

Q Your analysis of a single porosity system, then, is based on that prior testimony and those exhibits. You have done no independent study of other data, is that correct?

A Other than magnitudes of permeability that we might expect from the matrix, no, I have done no other studies.

Q In response to some of my questioning earlier and in response to Mr. Kellahin's questioning just a few moments ago, we were talking about whether or not studies had been conducted considering gas injection into this reservoir. I believe you indicated to me that you had done some preliminary work but had not concluded that, is that correct?

A That is correct.

Q And your discussion with Mr. Kellahin was your preliminary opinion not having completed that study? Is that a fair characterization?

A That's a fair characterization. We have seen the results that I gave to Mr. Kellahin, yes.

Q Just one moment, please.

Nothing further, thank you. I appreciate --

MR. LEMAY: Thank you, Mr. Pearce. Additional direct or any other questions of the witness?

If not, he may be excused.

Thank you, Mr. Dillon.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. chairman.

If we might take a moment, I will call Mr. Richard Ellis. He's a geologist with Jerome P. McHugh and Associates. We will distribute Mr. Ellis' exhibits and get on with it.

MR. LEMAY: All right, gentlemen, please continue.

RICHARD K. ELLIS,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Ellis, for the record would you please state your name, sir?

A Richard Ellis.

Q By whom are you employed, Mr. Ellis, and in what capacity?

A I'm employed by Jerome McHugh as a geologist.

Q Mr. Ellis, have you previously testified before the Oil Conservation Commission of New Mexico as a petroleum geologist?

A Yes, I have.

Q In fact you testified before the Commission last August, 1986, with regards to certain of the cases that have been consolidated for hearing today, did you not?

A Yes, I did.

Q Have you participated on behalf of your company in the work studies that were conducted subsequent to the last hearing on the Mancos Reservoir?

A Yes.

Q And pursuant to your employment have you prepared a geologic presentation for the Mancos Reservoir for today's hearing?

A I have.

Q Would you identify and describe for the Commission when and where you obtained your degree in geology?

A I obtained my Bachelor of Science degree in geology in 1975 from the University of Washington in Seattle and I --

Q Subsequent to graduation with that degree do you have any other degrees?

A Yes, I also got a Bachelor of Science in mathematics in 1975 from the University of Washington in

Seattle; a Master of Science in geology from the University of California at Berkeley in '77, a Juris Doctor degree in 1982 from the University of Denver, College of Law; been a member of the Colorado Bar since 1983.

Q Mr. Ellis, I know you're suffering from a little laryngitis. We'll bear with you.

Would you describe for us, sir, your employment experience as a petroleum geologist?

A Spent two summers, 1975 and 1976, working for Exxon in the Gulf Coast and Rocky Mountains.

I went with Chevron in Denver in 1977; spent seven and a half years with them in various capacities, geophysicist, exploration geologist, reservoir geologist, responsible for development in the Painter (sic) Reservoir Unit and the Rangeley Unit, and finally as a project supervisor responsible for exploration work in San Juan, Uinta, Piceance, Paradox Basins.

And I went with Mr. McHugh in March of 1985.

MR. KELLAHIN: At this time, Mr. Chairman, we tender Mr. Ellis as an expert petroleum geologist.

MR. LEMAY: His qualifications are acceptable.

Q Mr. Ellis, let me direct your attention, if you will, sir, to what we've marked as Exhibit Number One, and ask you to identify that exhibit.

A Exhibit Number One is a structure map on the top of the Niobrara A member. The structure top is the top of what we feel to be the producing interval in the field.

Q Did you prepare this structure map?

A I did.

Q Before we discuss the exhibit itself and the conclusions you can draw from this exhibit, would you take a moment and simply orient us as to what data is displayed?

A Okay. Basically we're looking at a portion of Rio Arriba County, New Mexico, situated in the southeast part of the San Juan Basin.

For reference I've indicated on all the structure maps an outcrop line. This is the outcrop of the Niobrara A that I used in the actual structural mapping process.

We have 215 wells that went into the construction of the map. You'll notice that there are several wells in here without structural datums. They're -- actually the number of wells that you'll see on the map will be closer to 250 but we had 215 structural datums that went into the construction of the map.

Highlighted in yellow on a few of the maps are -- is the proposed outline of the West Puerto Chiquito Pool. If you look carefully, you'll see a dotted line that indicates the boundary of the Canada Ojitos Pool wholly contained within that proposed pool outline.

I've also indicated on here a series of three structural cross sections in pink. The A, B, and C, are basically perpendicular to the axial plane of the Gavilan nose and also parallel to the strike of the monocline.

Also in blue is stratigraphic cross section X, which will be used later to talk a little bit about Niobrara stratigraphy.

Q Would it be cumbersome for you to hold the microphone, Mr. Ellis? Let's try it.

A Okay.

Q As a geologist, Mr. Ellis, what do you conclude about the structure as displayed on Exhibit Number One?

A Basically if you'll take a look at the map I think you can identify three structural elements within the pool outline. I submit that these structural elements are genetically related and therefore, because they are genetically related you have a situation where the pool is a single, unified, structural entity.

These three structural elements include, starting from the east off of the outcrop would be the mono-cline, this plane (sic) of dip here.

Immediately adjacent to it and west of it would be the syncline between the Gavilan nose and the mono-cline.

And immediately west of the syncline would be the Gavilan nose.

As I mentioned earlier, I established an attitude (sic) for the Gavilan nose of approximately 10 de-grees east -- maybe I didn't mention that, but I have a direction for the axial plane of the Gavilan Pool of approx-imately 10 degrees east of north, and it is parallel to the strike of the monocline.

Q Do we have wells in the Mancos Reservoir within the yellow shaded area that are located in each of the three elements of the reservoir, the structural elements of the reservoir?

A Well, yes, we have wells completed in the Niobrara producing interval in all three structural ele-ments, that's correct.

Q When we look at the dividing line that currently exists between the Gavilan Area and the West Puer-to Chiquito Area, do you see any structural feature that would cause you to separate the Mancos reservoir into two separate and distinct areas?

A No, I do not. In fact it becomes more clear when we look at the structural cross section, but basically the current dividing line between the Unit and the Gavilan Pool is on an eastward dipping plane (sic) off of the crest of the Gavilan nose.

Q Can you express a geologic opinion as to whether the proposed outline of the consolidated pool areas has a reasonable geologic basis?

A Yes. Basically, as I indicated a minute ago, I feel that since these three structural elements that we see encompassed within the pool outline are genetically related, you know, you're dealing with a situation where these things behave as a single structural entity. It's the same structure throughout the pool.

Q Let's go now to Exhibit Number Two and have you first of all simply identify and orient us to the exhibit. Will you take just a second and let us unfold copies of that?

A Okay. Referring to the structural map again just real briefly, again the three cross section orientations are highlighted in pink. As I mentioned, I set them up perpendicular to the axial plane direction of the Gavilan Nose and the strike of the monocline. I hoped to give us a true structural picture of what the reservoir looks like.

Now we'll move to Exhibit Number Two. This is a structural cross section.

Basically I have highlighted on this structural cross section in green the Niobrara interval, the A, B, and C zones of the Niobrara, the (not understood) of production in the pool, and I've also highlighted in yellow the proposed pool outline, the limits of the proposed pool outline; in pink, the limits of the currently existing Canada Ojitos Unit.

The method of construction for the structural cross section is pretty standard. What I've done is I've tied the sections to the outcrop. We have outcrop information, you know, in the field. Also I've taken the wells that you see on the structural cross sections and projected them into the line of section along the plunge direction of the Gavilan nose and along the strike of the monocline. I've shifted them vertically to account for the structural differences sought in the line of section.

There should be three wells, one in each section that have no projection, starting with the one at the top, A-A', the key well in the section is the Mallon 1-11 Howard Federal.

On B-B' the key well is the Mesa Grande Gavilan Howard No. 1, and the key well on C-C' would be the McHugh Homestead Ranch No. 2.

Okay, that's basically the matter of construction. There's one drafting error. If you'll look in B-B', the western limit of Range 1 West, immediately to the west of that it says Range 1 West. That should read Range 2 West.

Q What is the vertical and horizontal scale that you've selected for the three cross sections?

A I've selected the same vertical and horizontal scale of one inch equals 2000 feet. This is significant in that it gives you a true scale structural representation of the reservoir. There is no exaggeration in a vertical direction that gives you a false impression of the dip rates throughout the pool.

Q As we go from right to left on any of the three structural cross sections, will you show us how to read and understand the exhibit and identifying the degree or rate of dip that occurs?

A Beginning from the outcrop, you'll notice that we have a range of dips in the Niobrara section between 53 and 59 degrees.

Moving into the east side of the unit you're looking at an average dip rate of 2 to 6 degrees and as you move through most of the rest of the unit and all of Gavilan Pool, you're looking at dips less than 1.5 degrees. With the exception of the crest or the dip reversal at the crest of the Gavilan nose, and the dip reversal at the bottom of the syncline, there are no non -- all dips in the pool are non-zero. In other words, there is dip throughout the pool except for those two flexure points at the bottom of the syncline and the top of the Gavilan nose.

Q Using the structure map as a way to lead us across the structural cross section, if you'll pick any one of those lines on Exhibit Number One, show us the rate of dip per mile as we move from the far right going to the far left.

A I didn't calculate a foot per mile figure for the dip rate for the outcrop figures but it should be in the range of 7500 feet per mile right at the outcrop.

As you move away from the outcrop you see an immediate flattening of dip and that's represented in the contour intervals next to the outcrop which I should mention we have three different contour intervals in the map, or that go into the make-up of the map.

Let's take just a minute and look to the north, anything less than 1000 feet above sea level is a 50 foot contour interval. Within 1000 to 2000 feet above sea level is a 100 foot contour interval, and above 2000 feet above sea level is a 500 foot contour. There's an obvious reason for -- for doing that, you know, if you want to keep your 50 foot contour interval next to the outcrop, you're not going to see any well control at all. There's just going to be a black blob.

So I've, you know, deliberately done that not to create a distorted impression of what the dip rate is but just so that the map is readable and in fact you can see exactly what happens on a structural cross section.

Q As we take the structure map, then, and move from right to left, if you'll start at the eastern boundary of the proposed consolidated pool, and take the first few sections as we move to the west, and give us an indication of the dip per mile as we move in a westerly direction.

A Yes. Actually we start out at about 5000 feet, or so, per mile dip rate.

When we get into the eastern part of the unit, the gas comparative part of the unit, you're dealing with dip rates of approximately 6 degrees. That would give you a good 555 feet per mile.

Moving down the hill we get to a 4 degree figure here on C-C', that would give you approximately 359 feet per mile.

Now at 2.2 degrees further down the hill on Section A-A' you're dealing with 203 feet per mile.

At, well, at the -- on the east side of the Gavilan nose we've got a maximum dip rate of approximately a degree just to the east of the crest of the nose and that will give you approximately 92 feet per mile.

Anything less than, well, to give you an example, approximately 1/2 a degree would be from 4 to 6 feet per mile dip rate.

Q The structure map that you've identified and described, is that the same structure map that you gave Mr. Dillon for his utilization in the computer simulation of this reservoir?

A Yes.

Q In your opinion, Mr. Ellis, is it fair and reasonable to use an average dip per mile of 50 feet per mile in calculating the dip for a certain portion of this reservoir?

A Oh, a certain portion if you're talking about the portion basically on the west side of the proposed pool outline, the Gavilan Pool, in other words, would be somewhat higher than that. The average should be in excess of 50 feet.

Q And for another portion of the reservoir can you identify for us where an approximate average of a dip of 100 feet per mile is appropriate?

A Certainly the west flank of the Gavilan nose shows dip rates in excess of 100 feet per mile. The east flank of the Gavilan nose shows dip rates of around 100 feet per mile.

The oil withdrawal portion of the unit shows dip rate of approximately 100 to 150 feet per mile.

Q So with regard to the structural cross sections on Exhibit Number Two, do you see any significant changes in the thickness or faulting in the pool area?

A No, I do not. At this particular scale there is no evidence of any significant faulting or stratigraphic change that would give rise to, you know, obvious changes in the cross sectional view. This is significant in terms of the development of a structural (not understood) like the Basin. You'll note that none of the Cretaceous units show any kind of indication of thinning. I interpret this to mean that we're dealing with predominant Laramide tectonic forces that gave rise to these impressional features along the flank of the basin. And it is probably true that the same tectonic forces gave rise to all three elements, and that's the basic reason for lack of thinning, for lack of faulting, due to faulting. That's the basic reason why I believe we're dealing with kinetic (not understood) eroded from one tectonic force (not understood).

Q Based upon your studies, Mr. Ellis, and since you have told us that the three structural elements are genetically related, what conclusions can you reach with regards to the fracture system?

A Well, certainly, if you understand tectonic forces, operative and creating your structural features, they were probably also a causative mechanism for the development of a fracture system in the unit.

Q Can you describe a geologic reason, or attach a geologic reason to the western boundary of the proposed pool area?

A Yes, I can. If you'll look at the west side of the three structural cross sections, you'll notice a dip flattening at the end of all three cross sections. Basically, referring back to the structure map, you're looking at a defnite change in structural form as you move west of the range lines in 2 West and 3 West. We're looking at much wider dips. There's no, you know, real structural form that I'd want to pin on that particular part of the mapped area, so it definitely would appear that we're losing the form of the Gavilan nose as we move up the (not understood).

Q Is there anything else about Exhibit One or Two before we go on to the next exhibit?

A No, there's not.

Q All right, sir, let's go on then.

Mr. Ellis, would you identify for us Exhibit Number Three?

A Exhibit Number Three is a compilation of Landsat fracture lineation data which came from a unit study that was done last year.

Q Would you identify the source of the information that's depicted on this exhibit?

A Yes. The information came from a study that was commissioned by the Canada Ojitos Unit.

Q Would you explain to us the significance and purpose of the exhibit?

A The Landsat data is basically giving an indication of the orientation or distribution of regional fractures, at least as seen on the surface.

Both of the next two exhibits are scale dependent in that you're looking at a very large scale, you know, regional interpretation, if you will, from, you know, from satellite altitudes.

What this Landsat fracture map would show you basically are the regional fractures and maybe any large tectonic fractures that are operative in the area.

Q Let's go --

A You'll notice --

Q Let's perhaps go to Exhibit Number Four which might be helpful to look at at the same time we look at Exhibit Number Three, and then let me ask you some questions about them together.

A Would you identify this exhibit for us?

A Yes. I've referenced this map as a

photogeologic interpretation.

Q What does that mean?

A Again this is a compilation of the fracture lineation data that came from the study commissioned by the Unit.

The scale on this particular map, the scale of observation on this particular map will be somewhat different in that the data is viewed on photographs taken at an approximate elevation of 20,000 feet.

You're going to see much more detail. You're also going to see evidence of what I consider to be tectonic fracturing in the area.

Q What is the significance to you as a petroleum geologist of the information depicted on Exhibits Three and Four?

A There are a couple of significant observations we can make here. One of them, you know, issues from the photogeologic map more so than the Landsat data, and that is that we have evidence of a conjugate system of fractures in the area. This system would have an approximate orientation of northwest/southeast conjugates. That would be northeast/southwest.

If you'll look in the regional map you have those orientations in the map, as well, but if the two were overlain you'd see that the regional fracture trends are somewhat oblique to the conjugate system that exists in the photogeologic map.

I believe that the conjugate system is probably derived from the same Laramide tectonic forces that gave rise to the development of our three structural elements.

We can also --

Q Go ahead.

A We can also draw the preliminary conclusion, anyway, that fractures evidenced on the map are probably vertical to subvertical. You might expect the same general distribution of fracturing in the subsurface, and I believe that the, you know, the indication on the surface here is that, you know, at least at reservoir depths we're dealing with a multi-directional fracture orientation.

Q We spent some time at the last hearing discussing among the geologic witnesses whether or not it was reasonable to conclude that there as a specific orientation to the fractures in the Mancos reservoir.

Does this help you reach a conclusion on that subject?

A Well, I've -- I have concluded that we're dealing with a multi-directional fracture orientation at reservoir depths. Obviously, since you're dealing with, you know data that gives you a picture of actual surface frac ture distribution, there will probably be some change in the orientation at that, but I think that the fact that you have tectonic forces operative in the area is going to, you know, lead you to believe that you're going to have a conjugate system of fractures at depth, but I see no evidence that there is a dominant fracture direction based on these sets of data and there certainly doesn't appear to be a barrier to flow across the existing pool boundary on the west side of the unit, particularly if you, you know, observe the form on the photogeologic map.

Q You've told us just now that this may be some indication why -- by which you can project vertical fractures into and through the Mancos reservoir?

A Well, let me clarify that point somewhat, Mr. Kellahin. We're -- although we do have a multi-directional distribution on the surface, I believe, and this is pretty well documented in the literature, that, you know, the fracture distribution for the various different lithologic units as you move vertically down to reservoir depths, is going to change. We know, for example, that regional fractures will change strike dramatically at lithologic boundaries of the subsurface.

So I don't expect this exact fracture distribution in the map to bear any resemblance whatsoever to the fracture distribution in the subsurface, other than to say that you have a multi-directional conjugate set at reservoir depths.

Q Let's talk about the fracture system within the Mancos reservoir itself. Can you conclude based upon your studies whether or not we have vertical fracturing in the reservoir that will cause each of the three zones within the reservoir to be interconnected?

A I've an opinion on that. I think one of the later displays is more instructive on that point, you know. I definitely don't believe that we have vertical communication of fractures amongst all the Niobrara units, if you will.

Q While we're talking about the orientation of fractures, there has been previous discussion about the utilization of a dipmeter to help establish some orientation to the fractures.

Why don't yau give us your opinions and observations about the utilization of that data?

A You know, I believe that there are a number of different logs in use today that will give you evidence of the existence of fractures in the subsurface, and they're probably accurate insofar as you use them just for that purpose.

The dipmeter, however, has a number of inherent problems. I'm not, obviously not a, you know, a logging expert or anything, but the most obvious problem from just a purely scientific standpoint is you're dealing with a very scale dependent observational set of data.

You've got a tool, you've got a tool in the subsurface that's looking for vertical to sub-vertical fractures at some unknown spacing in the reservoir in a 7-inch hole, and then you're taking that data and trying to relate it, or trying to derive some kind of statistically valid fracture orientation in the reservoir, while you're sampling, at least in the case of a single borehole, less than 1-billionth of one percent of the total reservoir. So even if every hole out there had dipmeter information and had some kind of, you know, psuedo-fracture orientation established for it, you're still sampling such an infinitesimally small portion of the reservoir that that kind of data is, you know, to my way of thinking meaningless.

Now, that's one of the reasons why we at least took a look at some of the surface fracture indications, is it does have the advantage of, you know, some sort of statistical validity You know, at least you're looking at the entire reservoir and trying to characterize the -- not the entire reservoir, the entire pool, and trying to characterize the fracture distribution in the reservoir on that basis.

Q Have you made a study, Mr. Ellis, of the stratigraphic uniformity of the A, the B, and the C Zones in the Mancos reservoir?

A Yes, I have.

Q And have you reduced that to a stratigraphic cross section?

A Yeah, a stratigraphic cross section.

Q That will be Exhibit Number Five?

Will you describe Exhibit Number Five, Mr. Ellis?

A Exhibit Number Five is a stratigrahic cross section basically traversing the pool.

Q How many wells have you picked for the stratigraphic cross section?

A We've selected a 16-well cross section.

Q Is that a representative 16-well cross section to demonstrate to you the stratigraphy of the Mancos reservoir?

A Yes, because we believe the lateral homogeneity in the individual units in the Niobrara is -- is, you know, basically, without question, I think those 16 wells give a fair representation of the stratigraphic continuity.

Q Let me have you go to Exhibit Number Five and demonstrate to us the evidence you see that supports your conclusion that there is stratigraphic uniformity among wells for each of the three producing zones.

A In the construction of the cross section we're hanging, if you will, all the logs on the top of the Niobrara A, picking that as our datum, and also highlighted at the top of the Niobrara B and the top of the Niobrara C.

There's other tops of individual units in the lower part of the Mancos interval down below that I haven't highlighted.

Basically I'd like to, you know, just highlight the fact that we're dealing with very continuous units in the individual zones of the Niobrara. I've just highlighted three of them as exemplary of that point.

One of them in the Niobrara A is highlighted in blue. You can see it maintains its consistent log signature, at least with respect to the gamma ray, log across the pool.

Because the resistivity tool is sensitive to mud conditions at the time of logging, changes will occur that make that particular signature somewhat different. There is, however, a resistivity kick in each one of the little blue intervals I've highlighted there.

I've also highlighted a zone in the B in similar fashion and also one in the Niobrara C.

And also highlighted on that stratigraphic cross section are the individual perfs within the different wells on the section, and this is mainly meant to be representative of each operator's completion practices.

Q Is there anything else about Exhibit Number Five that in a preliminary way you'd like to direct our attention to?

A Yeah, there's a drafting error that ought to be pointed out and that is that several of the wells, particularly in the northern part of Gavilan are completed in what we would call the gray zone of the Niobrara and I apologize for not having a log section that will give you an indication of the log signature within that unit. It too exhibits characteristics of uniformity, at least in the northern part of the pool.

I've indicated those wells that have perforations in that gray zone here in pink, both the (not understood). It's just an unfortunate thing that there are, as I said, in the northern part of Gavilan several wells completed in the gray zone.

The other thing to point out would be that with the exception of the one unit well on the right-hand side of the section, the E-10, all of the wells in the section are open in the A, B, and C intervals of the Niobrara, and that also includes the B-18 well at the eastern edge of the unit. It's open in the A, B, and C for gas injection.

Q Is that the only well on the cross section that displays a unit well that is open for gas injection?

A That is correct.

Q And that's the last one on the far right of the cross section?

A Yes.

Q And that well is open in the A, B, and C for gas injection?

A Yes, it is.

Q Okay. How are the perforations indicated on the exhibit? I cannot see that far.

A It's a little difficult. On each one of the copies you have you'll see a black line that indicates the particular foot that was perforated. I just highlighted those particular feet with a pink highlighter is all. You can see that there are zones where you've got, you know, many, many perforations next to each other, you know, it has the appearance to be, you know, solidly perforated, but in fact there are individual peaks in there that are individually perforated. There are several zones, as you can see, particularly above the top of the C Zone in the Niobrara in the Reading & Bates Well you'll see a hiatus in the perforations between the lower part of the Niobrara B interval, or the middle part of the Niobrara B and in the top of the C.

In other words, there's zones throughout that are, uniformly not perforated because of their log signatures.

Q Do you have an opinion, Mr. Ellis, as to whether or not this is a stratified reservoir?

A Yes, I do.

Q And what is that opinion?

A I believe it's a very highly stratified reservoir.

Q What is the significance of the green, or is that blue, color?

A Oh, that's one of the what I would call a marker unit. I was trying to indicate, you know, the stratigraphic uniformity throughout the pool, but they're relatively arbitrary in their selection. There's many more within that Niobrara A, B, C interval and I think if you sat down and were very careful about your correlating (not understood) of the pool.

Q Find a point on the cross section, if you will, where we move out of the Gavilan area and move into the West Puerto Chiquito area.

A Yes, that particular point would be approximately here.

Q To the right of that point on the cross section are there wells completed in the A, B, and C Zones of the Mancos reservoir?

A Yes. In fact most of the wells in the unit are completed in those zones.

Q And as we move to the left of that line, what occurs in the Gavilan area with regards to the completions in those three intervals?

A All of the wells in the Gavilan Pool are completed in the A, B, and C. There were a couple of wells where we attempted to differentiate the productive capacity of the individual units. Those were some of the later wells. The Mallon Davis 3-15 was completed in the C initially and I believe has been recompleted in the A and B since then.

And then the McHugh High Adventure Well was completed in the A and B initially, but all of the Gavilan wells, to my knowledge, are open in the A, B, and C.

Q Let's go to Exhibit Number Six now.

MR. KELLAHIN: Mr. Chairman, we have a logistics problem here with our next exhibit.

Unfortunately we have only one set of the actual photographs that complete this exhibit and additionally it's very difficult to see without close inspection.

I wonder if you might have some

discussion about how to present this so that we can all see it in a meaningful way?

I'm happy to put it up here.

MR. LEMAY: We could come down there and that would allow --

MR. KELLAHIN: Perhaps that might be helpful if you could come down here and look at this, we'll try to explain it in a way that the opponents' technical people can also see the same information.

Q All right, Mr. Ellis, let's do this slowly, realizing that we're all trying to look at one exhibit together and in addition realizing that the court reporter has to make some sense out of what we're saying when you point to this and that and the other.

So take a moment and when you point to a portion of the exhibit, please describe where you are on the exhibit so the record will reflect it.

Let me begin first of all by asking you to simply identify what this exhibit is.

A This is a display of what I call core results and analysis in the Mallon Davis Well.

Q Take a moment and find for us where the Mallon Davis Well is within the Mancos reservoir. Where are we going to find that well?

A Well, if you can make reference to your cross section, look at Section 3 of Township 25 North, 2 West. It will be in the northern portion of the Gavilan Pool.

Q What is the purpose of making this analysis and presentation of this display? What are you trying to show?

A All I'm trying to show here is clarification on what I believe to be the salient points of the rather exhaustive analysis we've performed on the Mallon core.

Q Was the Mallon core a core that was available to the geologists at the August, 1986, hearing?

A No, it wasn't.

Q All right, this is data from the last hearing that's been developed.

A Yes, this is work we did after the hearing.

Q Go to the display itself and before you describe your conclusions, help us understand how you put this display together.

A Okay. The lefthand side of the display basically is a series of three logs. The induction log is on here more for reference than anything. It shows the characteristic signature in the Niobrara and again that would just tell us what's in the Niobrara section.

And there's no -- there is no difference whatsoever between log signature of the zone we're dealing with on this induction log and what we expect throughout the pool. So we believe it's probably, at least from a lithologic standpoint, a representative log.

Also, as I've indicated on the induction log, the zone of reservoir, that's highlighted in blue. We also have next to the induction log a composite of what I call -- or what Welex calls, a composite fracture log and basically this is a qualitative representation of the presence of fractures in a particular part of the subsurface. The composite is basically giving you a fracture index and you know, just by way of definition, their definition of a high fracture index would be what I would call a reasonable certainty that there's a fracture at that particular point in the subsurface.

Now this log is derived from a log suite that was run in the Mallon Davis Well. There were basically four sets of log data that went into the makeup of this so-called fracture index. Those are the caliper log, the SP lot, dipmeter and density log, and next to that I have what I've called a fracture frequency log and this is just an attempt to graphically depict the observational data that TerraTek, the core analysis people, gave us confirming the fractures in the core.

They made a visual inspection, foot by foot, of the 334 feet of recovered rock out of this 337-foot interval and gave us, you know, a report concerning the fracture density, type of fracture, orientation of the fracture realizing, of course, that this was not an oriented core, but that, you know, you can certainly tell general directions in the reservoir.

Q Would you take a moment and describe for us the various operators that participated and shared in the coring of this Mallon well?

A Well, I think I can give most of them. Let's see, there was my company, McHugh, Dugan, Meridian, Mallon, Mesa Grande, Mobil, and Amoco.

Q It represented a joint study, then, by various operators and you simply selected the next available well from which you could derive an accurate core.

A Correct.

Q All right. Please continue.

A Okay. Going back to the fracture treatment, I need to explain this. This is, you know, an artifact (sic) of the observational data that we got from TerraTek, an attempt to graphically depict the preferential nature of the fracturing in the reservoir.

What I've done here is really quite simple, you know. For anything -- any foot analyzed with greater than four fractures per foot indicated, I've drawn a blue line on the plot.

In fact, the report indicates that every foot had a fracture in it, but what I'm trying to do is -- is give you an idea of -- of what is significant about the work they did, and that, I feel, is that individual zones within particularly the Niobrara B Zone, from the core are preferentially fractured relative to those zones around them.

And also in a more general sense, the Niobrara B Zone is preferentially fractures relative to the C Zone below it.

Q What is the significance of the core photographs themselves as we move to the far right of the display?

A Okay. The photos are there so we can examine why this qualitative observation of certain zones of the Niobrara B have a greater propensity to fracture than other zones. We're going to take them on a smaller scale. We've been looking at a log scale observation on the left part of the display. We're going to go down to the core scale now for the photographs.

We've got two photographs; one is a plain light view; one is an ultra-violet light view of the same interval in the core. That interval was situated at the top of the B Zone of the Niobrara, and, you know, that zone that is the core interval is highlighted in yellow there.

Just a few quick observations before we get into the more significant (not understood) of this.

In the ultra-violet view you can see several zones that apparently are fluorescing. The ultra-violet light view should give you at least some indication that you have fluorescing zones within, you know, a particular core.

You can see that certain zones are fluorescing The reason why they're fluorescing is because TerraTek took their plug samples by drilling with (not clear) oil and that contamination of those plug intervals is the reason why those things look like they're fluorescing; that's nto natural hydrocarbon fluorescence.

There is indication of natural hydrocarbon fluorescence at approximately 7098 feet and I think it's related to the fracture phase that you can see behind the core material there and that would be, you know, a natural hydrocarbon fluorescence.

If you'll look at the plain light view, you'll also see that there are light and dark zones. The light zones are probably coarser grained materials than silt laminae, and possibly limestone laminae that are light colored relative to the darker shales and mudstones around them. Now those zones in the ultra-violet view are highlighted and you can definitely tell which of those things -- or which part of the core is a sand or silt laminae; however that's not natural hydrocarbon fluorescence. It's just a situation where you've got back lighting and the actual ultra-violet photographic process would be that associated with the fracture traces.

So the only natural hydrocarbon fluorescence that I would attribute to this photo would be that associated with the fracture phase which is at approximately 7098.

MR. KELLAHIN: Mr. Chairman, we're going to have a number of more minutes on this exhibit. We'd be happy to try and complete this exhibit before the lunch hour, if you'd like; whatever the pleasure of the Commission is.

MR. LEMAY: How long?

MR. KELLAHIN: Fifteen or twenty minutes.

Q Will you look now at the photographs depicted on the exhibit and have you identify for us the bottom two photographs on that exhibit. Simply tell us what they are and then we'll come back to the rest of the display.

A Can I finish up with the larger photograph first?

Q Sure, let's do that.

A Okay. Basically, let's take a quick look at the lithology of that upper B Zone in the Niobrara.

You'll note that you're dealing with a very highly laminated, thin-bedded sequence of alternating shales and mudstones and siltstones and sandstones and probably minor limestone laminae, as well.

The scale of those -- the thickness of those individual units will vary anywhere from millimeters to centimeters. There's a high degree of variability in the rock in a vertical sense and, you know, obviously, you have to consider that to have tremendous vertical (not understood).

The other significant aspect, if you'll look at approximately the depth 7089.5, you'll notice a sandy or a silty laminae which within the scale of the core pinches out in a lateral direction. Now this is quite common at the Niobrara interval and it also points up the fact that you have tremendous horizontal anisotropic reservoirs and I believe the combination of those two, since you do have such a highly anisotropic reservoir, you're probably dealing with also an extremely brittle zone relative to the ore massive lithologies around it and the more massive lithologies are going to behave plastically relative to the antisotropic, brittle units that indicates. Now the range, if you'll examine, you know, in our examination of the core, the range in thickness of these so-called "brittle" zones ranges anywhere from a couple of feet to approximately 30 feet in thickness. They are generally encased in much more massive, and therefore plastic, lithologies, and, you know, I believe based on this observational data that we're dealing with, you know, despite the tremendous vertical and horizontal heterogeneity in the reservoir, we're dealing with a homogeneous unit. These individual brittle zones behave homogeneously because they are so heterogeneous and I think, you know, they're -- and that leads me to believe that they're probably a reservoir response unit in and of themselves.

That's what I wanted to note. We have, to sum up, then, I believe the situation in the Niobrara is this: We have discrete, pervasively fractured zones because they are more brittle that are encased by the more plastic zones around them. The plastic zones in a vertical sense are certainly going to be fractured; however, they're not going to be nearly as intensively fractured as these more brittle zones, and you can certainly expect or intuitively observe that, you know, you could have healing in these more plastic zones that would prevent any kind of real time vertical communication in the reservoir, certainly with respect to fluid flow. And that leads me to believe that the Niobrara units, individual units within the Niobrara, particularly within the Niobrara B and probably within the Niobrara A, even though we don't have core data to support it, are behaving in a highly stratified and by stratified I mean stratified on the order of a few to tens of feet and highly stratified in a very compartmentalized fashion.

Now let's take this scale of observation down one more step and we're going to look at an individual laminae within that core. Now these two photos did not come from exactly the same core interval that we're observing up above. They came from these two indicated feet on the logs.

Now the lefthand photo, I think, is dramatic evidence of a phenomenon that's been noted in the Niobrara and a lot of different places. We've seen it in Rangeley. We've seen it in the San Juan Basin and now we see it here in Gavilan, as well, and it's not surprising, and that is that -- well, first, first of all, the photo itself is a thin section photograph showing a part of the rock that has been injected with a fluorescing dye at ambient pressure, and what you can see there is you've got large open fractures that are fed by an intricate system of microfractures. This, I believe, is the best characterization of the porosity and permeability of the Niobrara reservoir.

On the righthand side again, you know, we've got a large open fracture, but we've got a large open fracture that appears to be right on the contact between a muddy or a silty or a clay lithology, and, you know, a sandier, silty lamina. This large open fracture, as you can see, is fed by a series of microfractures, is particularly visible on the mudstone at the upper central part of the photo, but you can also see a series of microfractures cutting through the sandstone laminae. YOu can see them not only cutting and breaking individual grains, but you can see them separating grains, such that they go around individual grains and feed the main fracture system.

This last photo, I think, suggests the possible reason why we have noted oil saturations in some of our plug analyses in this rock, and that is it would appear that oil migrating through open fractures has contaminated, if you will, the grain boundaries, or left a residual or an oil saturation along grain boundaries that are immediately adjacent to open fractures.

Well, one other quick item before we finish this.

You know, I'm reasonably certain, based on photos and my observations with respect to the core itself, that you're dealing with essentially no storage capacity in the matrix, intrinsic storage capacity in the matrix. You get, because of tectonic forces operative in the subsurface you get this imprinting of fracture permeability and porosity. It's obviously going to include the sandstone and siltstone laminae, particularly in the permeable zones, and that, I believe, is the reason why you're going to, you know, the ability of the Niobrara to produce.

Q Okay.

MR. LEMAY: I think we'll break for lunch now and return at 1:20.

(Thereupon the noon recess was taken.)

MR. LEMAY: Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

RICHARD K. ELLIS,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Ellis, at this time I'd like to direct your attention to the Exhibit Number Seven that is in your package of exhibits and ask you you to identify that for us.

A Yes. this is an excerpt from the petrologic investigation conducted by Terra Tek on the Mallon core.

Q This is to be read in conjunction with the information you've described on Exhibit Number Six?

A Yes.

Q And what is the purpose of this exhibit, Mr. Ellis?

A I've included this exhibit as a summary statement with respect to the analysis of the core and also as evidence that it's not just the applicants in this case that believe that the matrix is -- is very unlikely to contribute to production in the reservoir.

Q Let me ask you, sir, to take this opportunity, based upon your study of the geologic characteristics in the Mancos reservoir as depicted on all your exhibits, and provide us with the geologic conclusions of the various significant factors that you think are appropriate for the Commission to understand with regards to a decision in this case.

MR. KELLAHIN; By way of assistance, Mr. Chairman, we have provided in written fashion Mr. Ellis' conclusions. I've identified that as Exhibit Number Eight. If during the break I could produce additional copies of this, I'd be happy to share my copy with Mr. Pearce and Mr. Lopez for now, there may be other copies in some of these packages; mine didn't have one.

Are there copies? All right. Let me substitute this one because it is stamped as an exhibit. It's all done.

Q All right, Mr. Ellis, would you give us your geologic conclusions about the reservoir?

A Yes. Basically referring to Exhibit Number Eight, we'll just take the more important ones in sequence.

I believe basically that we're dealing with a single unitified structural entity. As you've seen on our structural cross sections, a fairly simple, overall structural form to the pool area.

The other important conclusion I'd like to highlight is the fact that the dip rates in a majority of the pool area are quite low. It is true that on the east side of the unit you've got dips that range from 2 to 6 degrees but dips throughout most of the rest of the area are less than 1.5 degrees, and certainly within the gas injection, by the time you get ot the gas injection portion of the unit, you're down in the range of 6 degrees or less.

There is dip that exists throughout the area with the exceptions I noted earlier, the dip reversal at the crest of the Gavilan nose and at the bottom of the syncline.

I've also concluded from fracture analysis that we've got indications of a multi-directional fracture orientation. We expect this fracture distribution at the surface to be similar to but not necessarily exactly the same as what exists at reservoir levels.

I believe that the Laramide tectonic forces that were operative in the development of the three structural elements were also operative in the development of the pool-wide fracture system.

And one very important conclusion with respect to the fracture, directionality of fractures in the reservoir, would be that no one fracture direction appears to dominate and certainly doesn't appear to create any kind of areal flow.

I've concluded from the core study and the core photographs that we're dealing with several discrete, highly laminated and thin-bedded intervals in the Niobrara B, and that these brittle zones, if you will, are preferentially fractured relative to the units around them.

Because they're highly anisotropic, I believe that they've behaved as single reservoir responsive units. They appear to have the thicknesses that -- that appear to have indicated thicknesses in a range of a few feet to 20 to approximately even as much as 30 feet of thickness.

Also I am reasonably certain that we're dealing with a multi-directional fracture distribution at reservoir depths and that this fracture distribution does not extend vertically in the reservoir for any great distance, but in fact, the brittle zones on the order of a few tens of feet in thickness are very communicative throughout but that the intervening plastic zones around them, because of the more massive lithologies, and the healing nature of that particular zone, has probably created a situation where the reservoir interval, the brittle zones, are discrete, behaving separate from the -- from each other.

In other words, the reservoir is highly stratified.

Also a conclusion basically from the photomicrographs and from the actual rock data that was prepared by Terra Tek, it would appear that the reservoir storage capacity and permeability is derived from a system of large open fractures, which are fed by a network of microfractures, and that the fracture system is extensive throughout these brittle zones. In other words, they include the sand, silt, non-shale, and mudstone laminae that we saw in the photos this morning, and, as I concluded this morning, I think the presence of oil saturation in the analyses of the plug samples is -- is, to my way of thinking, probably primarily due to the fact we have oil migrating through open fractures and resulting in saturation of along boundaries and contacts that are adjacent to the fractures.

The analyzed porosities and permeabilities, I haven't included any data on that, but from the Exhibit Seven that I just gave you, the statement that Terra Tek made there, and also the fact that the average porosity in the analyzed interval ranges or is approximately 2 percent, and the arithmetic average of permeabilities, at least for the samples that are not contaminated by dehydration cracking in the sample cleaning process, appear to average about .02 millidarcies.

This is very low and I think all the reservoir storage capacity and permeability derives from the fractures.

MR. KELLAHIN: That concludes my examination of Mr. Ellis, Mr. Chairman.

We would move the introduction of McHugh Exhbiits One through Eight.

MR. LEMAY; Without objection the exhibits will be accepted.

Are there any questions of Mr. Ellis? Mr. Pearce?

CROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Ellis, as you began your presentation this morning you indicated, I believe, that there were three structural elements largely at work in this area, those being a monocline, a syncline, and the Gavilan nose, is that correct?

A That's correct.

Q Would you expect that each of those elements would cause similar fracturing patterns so that this reservoir should be -- should exhibit a homogeneity in fracturing or each of those structural elements, because of different folding rates, or something, have different fracturing effects?

A I would expect there -- there to be, certainly to be differences in the overall fracture distribution across the different elements, if you will refer to the fracture map, the photogeologic interpretation. In fact the crest of the Gavilan nose, if you'll look at it, is -- shows a distinct lack of fracturing across the crest of the nose.

When you get into the bottom of the syncline, however, you're looking at substantially increased fracture intensity.

Q Let's turn, if we can, I'm sorry I have forgotten the exhibit numbers, the Landsat interpretation and the exhibit following it. I'm not sure, were they Three and Four?

A Yes, that's correct.

Q Okay.

A Go ahead.

Q Thank you. It's my understanding that Exhibit Three, the Landsat interpretation, results from your interpretation of a Landsat photo which the Canada Ojitos Unit commissioned, is that correct?

A I reviewed the photo and verified the fracture lineation data that was presented to the unit by the expert photo interpretation and then I transposed that data, which was actually contained on topographic sheets, onto this scale base map so that it correlates with the structural.

Q Okay, and has the DHR Whitehead & Associates actually interpreted the lines from the Landsat photo rather than you?

A That's the drafting person.

Q Okay.

A He did no interpretation. He's a drafting person.

Q Okay, I'm still not clear. Who interpreted the photos to determine whether the lines on this exhibit ought to be?

A The expert involved in the interpretation was a guy named Goldsmith out of California.

Q Have you -- did you indicate that you had reviewed the Landsat photo?

A I have seen the photo and I've correlated his observations with what my observations would be on the photo, that's correct.

Q Okay. Let's take a look just real quickly at the proposed geologic interpretations. I have the same sorts of questions. Who took the photo? Who did the interpretation as to where the lines should appear?

A The BLM supplies the photo mapping sequence and Mr. Goldsmith again did the interpretation, and I have all of the photos again verified with respect to his interpretation.

Q Okay.

A And all of the data is transposed from his topographic maps again onto the base --

Q I apologize for interrupting. Could you give me an indication of what the instructions to Mr. Goldsmith were?

A I wasn't involved in commissioning the study. The Unit actually commissioned the study and since we are interest owners in the Unit we had access to the study, so I received his interpretation, had my own photos, and did my own verification of his work.

Q When you say the Unit commissioned the study, the unit operator, in your understanding is that who gave whatever instructions were given to Mr. Goldsmith?

A Yes, that's correct.

Q Okay. If we could take a look for a moment at your Exhibits One and Two, maybe I can just pull down part of this, I'd like to refer you, if I could, please, to Exhibit Number One, which is the structure map on top of the A, and ask you, if you would, to locate for us the Canada Ojitos Unit Well No. 22.

A In Section 20 of 26 North, 1 West.

Q What's the status of that well, if you know?

A I have no idea.

Q Can you locate for us the Canada Ojitos Unit Well No. 21?

A Section 32 of 26 North, 1 West.

Q Do you have any idea of what the producing status of that well is or the rates of production?

A No, I don't.

Q Canada Ojitos Unit Well No. 24.

A In Section 8 of 25 North, 1 West.

Q Same questions. Do you know historical or present production on that well?

A No, I don't.

Q And finally, a well down in 31 on this map, it appears to be marked 26 Unit.

A Yeah.

Q Do you have any information on the present or past production of that well?

A No, I don't.

Q Looking at the well in Number Eight, the Canada Ojitos Unit 24 Well, on Exhibit Number Two. If that well had been included in the A-A' cross section, where would it have fallen on that cross section?

A Approximately in this location here.

Q Between -- it looks like you're indicating about halfway between two other wells on that cross section. Could you tell me what those are?

A That would be the unit No. 32, the J-6; Unit No. 11, E-10.

Q And am I correct that you were indicating about halfway between those two wells is where that one would appear?

A Yes, approximately.

Q Okay. Similarly, looking at the 26 Well down in Section 31, if that well had been included on the C-C' cross section, can you indicate about where it would be located?

A You mean on the cross section?

Q Yes, the 26 Well.

A It is on the cross section.

Q Oh, it is on the cross section?

A Yes, that's correct.

Q Okay. That was just a misinterpretation of your --

That's all I've got on those two, thank you, sir.

I'd like for you, if you would, please sir, to turn with me to the second page of the last document you've discussed called Geologic Conclusions.

The first sentence of paragraph number 8, would you read that, to yourself is fine?

A Core micrographs show that reservoir storage capacity and permeability derives from a system of large open fractures fed by a network of microfractures.

Q Could you explain to me your opinion of that network of microfractures? Just fill in what those words mean and explain that to me, if you would?

A Okay. As we noted in the photomicrographs, basically your attention is immediately drawn to the fact that you have large open fractures which run through the rock. In one of those, well, actually in both of those pictures you appear to have fluorescing zones that feed into the large open fracture, because -- particularly on the second photo, because the fluorescing zones, the much thinner fluorescing zones cut individual grains and also separate the individual grains, you interpret those as being a tectonic related phenomenon; i.e. microfractures in this case. That's my --

Q Okay, do --

A -- analysis of it.

Q Do you have -- can you give me an indication of what sort of transmissibility one ought to expect in a microfracture?

A Oh, I have no idea. Relative to something else or on its own, I have no idea.

Q Towards the latter part of your testimony this morning, you were discussing something and I missed part of it, but let me ask you and see if you can refresh my recollection, that had 0.2 of a millidarcy permeability?

A You mean my testimony this afternoon? An arithmetic average for the core analyzed data on the Mallon core indicated a permeability of .02 milidarcies.

Q .02 millidarcies. Is that -- is that from the microfractures or is that from something else, in your opinion?

A Okay. The actual data that gave rise to that average comes from slug samples in that particular core.

And routinely, as a group, what happened was we selected particular intervals to sample with slugs. Those intervals routinely or uniformly, anyway, were in zones that had higher sand, silt laminae percentages. So we were trying to address the problem of what exactly the matrix properties were and that, because of that, I feel that that permeability is probably representative of the actual matrix permeability.

Q When you began this morning deciphering your Exhibit Number Two with the cross section, you pointed out that that had a scale of one inch equal to 2000 feet in order, I believe your phrase was "to avoid false impressions of dip rate."

A That's correct.

Q That's a danger with Exhibit One, is it not, with the three scales? I mean just looking at that without realizing the scales, some concern in there.

A Yeah. Strictly -- strictly from a, you know, from a visual viewpoint you may get the impression that up next to the outcrop you in fact have less dip than you in fact do. The main reason why the structural cross sections exist is to show exactly what's happening in a structural view in the reservoir.

As I said earlier, if continue the 100 or the 50 foot contours up to the outcrop, you'd lose all conception of what kind of well control is -- actually exists in that east part of the Mancos.

Q I believe you indicated that you hold the opinion that the fractures indicated on the surface representations should not be expected to be duplicated at reservoir depth. Is that correct?

A What I indicated was the multi-directionality of the surface fracture distribution will probably exist at depths because it exists at the surface. The fact is, however, you're looking at the tertiary units on the surface that show the kind of system of fractures. You wouldn't expect the exact same fracture identified on the surface map to exist in the exactly the same position in the subsurface, or it may not even be the same fracture in the subsurface. All I'm saying is that the tectonic forces that gave rise to the conjugate system on the surface certainly gave rise to a conjugate system in the subsurface and it may not bear a direct correlation between what you see at the surface.

MR. PEARCE: Thank you. That's all I have.

MR. LEMAY: Point of clarification on your Exhibit Seven. It's only one page, Is there a -- it stops right there. Is there a second page to that?

A No, it's one page.

MR. LEMAY: Yeah, there's one page behind the cover page. You said two pages. You just -- the title of the actual report and then the excerpt would the first sentence of that second page? "If fracturing is performed in the ..." and then it stops. Isn't there a --

A Oh, no, the first second -- the first sentence of the second page is the relevant, you know, sentence.

MR. LEMAY: I see, the rest is not relevant.

A Well, the second sentence, first and second sentence, excuse me.

MR. LEMAY: Okay. Frank?

QUESTIONS BY MR. CHAVEZ:

Q Mr. Ellis, in your first sentence on your geologic conclusions you say that structural mapping and cross sections indicate that the pools are genetically related and behave as a single, unified structural entity.

How does structurally mapping and cross sections show that the pools behave as a single unified structural entity?

A I drew the conclusions that the three structural elements, the nose, the syncline, and the monocline, are genetically related because of the absence of any kind of thinning associated with the units across the pool. In -- in routine structural geology one thing that we look to to try and establish discontinuity, at least structural discontinuity in a particular situation, would be that kind of thinning over the top of the structure, indicating some kind of older paleo-structure was operative and also any faulting.

Now the absence of both thinning and faulting let me to believe that the same tectonic forces which would be Laramide in age in this particular basin, are responsible for the development of all three structures. Since they're genetically related, therefore, I believe they behave as a single unified structural entity.

Q By "behave", I guess I don't understand what you mean by "behave".

A Well --

Q Could you explain that, please?

A Yeah. The fracture system that probably gave rise or -- let me back up.

The tectonic forces that gave rise to the development of these structures probably also gave rise to the fracture (a portion of this answer lost due to changing of tape.)

Q Did you look at any faulting outside of this study area?

actual producing gas/oil ratio, the thing that's most obvious is during the month of September through December the oil production took a pretty dramatic drop, mainly as a result of the curtailed production beginning September 1st, and also we see, which is unrelated to that drop, a fairly substantial increase in the gas/oil ratio that also leveled off during the September through December.

Q The bottom line on the plot is the gas/oil ratio; the top line is the producing rate?

A Yes, sir, that's correct. The top is the barrels of oil per month and the gas/oil ratio during December was about 5700, which would be the lower line.

Q Okay. Let's turn to another example under Mr. McHugh's wells, let's turn and look at the Native Son No. 2 Well, and if you'll find the graph that shows the tabulation of that production.

A Okay.

Q All right, sir, would you describe for us what significance this has for you?

A Here again where we're dealing with actual barrels of oil per month and gas/oil ratio, again during the month period September through December, which would be the later two divisions on the graph, there is two months per division, we see a fairly substantial reduction in the oil and we also are observing that the gas/oil ratio is continuing to incline and during the month of December it was about 3550 cubic feet per barrel.

Q All right, and finally, let's turn to the Mesa Grande Resources wells and find the Gavilan Federal No. 1.

Again describe for us what's occurring with relation to the producing oil rates and the gas/oil ratio rates.

A This again is -- it's evident that during the months September through December the oil rates have been reduced. Prior to our reduction the oil rates were declining, the gas/oil ratio was inclining. Since reduction the gas/oil ratio has continued on a general incline.

Q What significance do these three particular examples have with regards to your concerns about the production in the Gavilan Mancos area?

A The primary purpose for pointing out these specific wells is they are either large wells or wells that had a high gas/oil ratio. Even with the reduced production levels that were dictated with the allowable reduction order September through December. We are continuing experiencing increasing gas/oil ratios throughout the pool, and again in wells operated by all operators.

Q Turn to Exhibit Number Three, Mr. Roe. Would you identify Exhibit Number Three for us?

A Well, as part of my overall regional work I'm aware of the vary substantial magnitude of faults in the immediate area, yes.

Q Well, why wouldn't you include other faults in the immediate area as part of this genetically similar area that you're calling a single unified structural entity?

A Okay, the specific faulting that I'm referring to would be that associated with the Nacimiento Mountain front. That, as you know, has many thousands of feet of relief across the fault and there's probably some -- some form of high or reversed fault.

Because of the tertiary units next to the fault, we believe that that particular fault has younger movement on it; therefore, you know, and you're -- the obvious conclusion there is that you have a much younger feature that is operative.

Now there could also be a much older feature operative in there. You've got a basement high -- excuse me, a PreCambrian rock high to the east of the actual fault lines. It's just a totally different animal.

Q That's just to the east, isn't it?

A It's not directly east, no. It's south about two townships, about -- about fifteen miles.

Q Is there other faulting to the southwest and west or to the north of this area?

A Oh, there is faulting throughout the area. As may not have been clear is there's normal faulting all over the area. In fact on the structure map, if you look in the northeast part of the map area, right against the boundary of the East Puerto Chiquito Mancos Unit with the West Puerto Chiquito Pool, there's a very significant normal fault with throw approximately 300 feet and there is quite a bit of minor, normal faulting in the area, yes.

Q So as far as being genetically related, you're not excluding other areasa on the, say, on on the east side of the San Juan Basin as being part of this unified structural entity?

A Oh, no. I believe anything associated with the monocline itself is part of the same tectonic force. The monocline appears to have largely a Laramide age structural development and anything associated with the monocline on all sides of the basin I believe to be genetically related.

Q On the seocnd page of your geologic conclusions, actually starting with number 6 on the first page, you mention plastic lithologies and you mentioned that also in your testimony concerning the cores. Are you saying that the plastic lithology is what closes fractures that might otherwise communicate between the A, B, and C Zones?

A Yes, I think that's a distinct possibility.

Q What do you base that conclusion of plastic lithologies on?

A Well, a lot of -- a lot of the technical literature has given quite a bit of verbiage to the rock mechanics of different rock types and basically the massive lithologies, and particularly this lithology, which is largely shale and mudstone, you know, behaves in a plastic fashion relative to what I would call the more brittle zones, which are, as I mentioned earlier, extremely heterogeneous in both vertical and horizontal directions.

Q You say a lot of literature gives much attention to this. Is there any specific documentation that you have about plastic lithologies and brittle lithologies concerning this particular area?

A Well, I couldn't give you a title but most of the work has really been done in the A & M rock mechanics lab by a guy named Sterns, and a reference to that author would probably give you some of the information you need.

Q And he deals with these lithologies located in this particular area of the San Juan Basin?

A Oh, I doubt if he's got a Niobrara rock in his lab.

Q Is it possible, then, in your work in the San Juan Basin to trace the Niobrara from the west side to the east side on -- based on logs and all of the Niobrara lithology across the San Juan Basin?

A Okay, there is definitely a stratigraphic interval that people call the Niobrara that extends from west to east across the San Juan Basin. The lithology within the Niobrara changes dramatically depending on the orientation of your traverse across the basin. We're dealing in a very localized area here within the pool with a very consistent and uniform stratigraphic interval.

Q In your Exhibit Number Two you have shown across all three cross sections where you have -- where the application for the expansion of the existing West Puerto Chiquito Mancos Pool (inaudible) at a township line between 1 West and 2 West.

Do you fully agree with that on the basis of your study of the structure?

A Well, I believe that boundary would be between 2 West and 3 West.

Q I'm sorry, you're right.

A Yes, I do, and as I mentioned earlier, it's -- it's a mere coincidence that the proposed west boundary of the pool also happens to coincide with the current production limits in the Gavilan Pool as we know it.

There is, in fact, as I mentioned earlier, that dip flattening to zero degrees at the west side and I think the change in structural form as you move across the range line into 3 West, that supports the idea of a west boundary along the range line.

Q When you say change in structural form, what does that mean?

A If you look at the structure map, at least to the west of the range line, you're not dealing with a panel of dip, but a panel of west dip off of the Gavilan nose any more. In fact what you've done is you've rolled out at the bottom of that particular panel of dip and, you know, have had no, you know, outstanding structural form entrenched through there.

Q Okay, so the change itself from some dip to no dip itself indicates to you that you have a change in structure that would indicate a change in the common source of supply?

A That -- it's a possibility that the mechanism of production or mechanism of -- yeah, mechanism of production could change at the range line. We don't have sufficient production data west of the range line to completely divorce the production in 3 West from the production in 2 West.

It seems ot me that the change in struc

tural form is at least arguable at that point and that's one of the reasons why the application specifies the west boundary in that location.

Q Then could I interpret that as (unclear) geologic reason for ending the pool at that -- at that point?

A That's correct.

Q In studying the three cross sections you have, you also show other places where there is geologic change, specifically on the top cross section just to the right of the Range 2 West, Range 1 West line you show where you have a change in structure at that point. You're starting to get a rise in dip through the Gavilan nose, is that correct?

A To the west of -- yeah, correct.

Q But that particular geological feature itself does not indicate a change in pool (inaudible), does it?

A Basically I've related the three structural elements already and then shown that there's a continuity of multi-directional fracture distributon across that zone there would link the -- link the two or three elements together.

Q But you've already said that there were mono-directional fractures all through the area in that part of the San Juan Basin.

A That's correct.

Q Why particularly here does this create a difference when you have a change in dip?

A A difference meaning what now?

Q Well, there are fractures all over this area. I think, if I understood you correctly, but particularly here at this point they indicate you've got a common source of supply, although you do have a change in dip, where those fractures, say, between Range 2 West and 3 West, you don't show -- you say there they are different sources of supply.

A Yes. That, well, I believe, you know, what I was trying ot indicate was the structural form changes at the range line. You're no longer dealing with discrete elements that behave together as a single entity, the nose, the syncline, and the monocline interchange to the west of the range line, even though you've got indications of tectonic fractures, you just don't have the structural intensity, if you will, to the west of the range line, and therefore there's a possiblity that, you know, it's truly not part of the -- the West Puerto Chiquito mechanism of production.

Q And a change in structural intensity is a criteria?

A Yes, I believe it is.

Q Well, is there an intense -- is the structural intensity in the Gavilan different than in the West Puerto Chiquito Mancos?

A You can see that most of the pool based on the dip rates on the cross section is in == it is consistent. As you move, obviously, as you move up onto the outcrop you get a very dramatic steepening in dip and, you know, but the most, the majority of the pool is all at a very low dip rate.

MR. CHAVEZ: That's all I have.

MR. LEMAY: Mr. Brostuen.

QUESTIONS BY MR. BROSTUEN:

Q Mr. Ellis, in your resonse to Mr. Chavez' recent -- not the most recent question but did you state that there is a faulting in the Gavilan area? Is that what you were saying?

A Oh, well, at the scale on the cross sections, of the structural cross sections, that is, we don't see any significant faulting in the area. We do know, as for example on the stratigraphic cross section, that the minor changes in thickness you note in those intervals is probably due to minor normal faulting.

Q I see. So you're not saying that faulting is not --

A Oh, no.

Q -- occurring in the other area?

A Oh, no, it's very small magnitude. The throws would be on the order of, you know, less than 50 feet.

Q Then your interpretation, the lineations that you're presenting here on Exhibit Four, I believe, are the surface expression of the subsurface faults, which might be referred to as minor faults?

A I don't think there's continuity between what exists at the surface and what exists in the subsurface, but the presence of a multi-directional fracture distribution indicates that tectonic forces were active to create a conjugate system in the area and in -- at the reservoir level there is probably a conjugate system developed.

Q Yes. I'm not implying that what we're seeing on the surface, the lineations here are surface on down but they are related to -- to structural features that exist at depth.

A Well --

Q There is a relationship.

A Well, yes.

Q A cause and effect, you might say.

A Yeah.

Q Okay. Referring to your well log, or your cross section, this one here as Exhibit Five, and right now I haven't opened it up but I'm looking at your -- the Unit Well B-18 in Section 18, Township 25 North, Range 1 East.

I'm noticing that on the -- on the gamma ray curve over here it appears that most of the perforations are coincidental with the clean zones. Is that because these are the inner zones, the more brittle zones, which would be -- tend to fracture? Is that what you're saying? Or do we show some -- are we showing a sand? Are we showing limestone, or what are we showing here?

A Yeah, well, that's a big problem is trying to calibrate the log response to lithology and that's one of the reasons why the core data is so helpful. In fact, I think the reason why those zones have been perforated routinely in the cleaner intervals is because of a resistivity response in those intervals. I think it's fortuitous, though, that it appears that these cleaner zones, we'll say cleaner, but in fact you've seen the core photographs indicate that it's highly laminated. You might have a higher percentage of those individual silt and sand lands in a particular interval that will result in a gamma ray looking cleaner than the 100 percent shale line, for example, and, you know, that I think is the reason why we've perforated in this past with just the resistivity response. I mean the indications of higher resistivity in those cleaner zones.

Q Well, it appears to me that some of the, some of the clean -- what I've heard of the clean zones on these gamma ray logs look rather significant.

I've also noticed that there was in your exhibit in the E-6 there's a discrepancy between the log depth and the core depth, and I'm assuming what you've done is you have adjusted that?

A We've adjusted that.

Q You've adjusted that.

A Yeah, the actual cored interval indicated about 8 feet low to the actual log entered.

Q On that same exhibit you show the composite fracture log and the -- on the far right of the composite fracture log you have a fracture index going from low to high, and I would -- assuming that the low, on the low side of the curve we're looking at that portion of the section which would have a less fracture density than on the right, is that correct?

A Not necessarily fracture density as much as just the mere presence of fractures.

If you're looking at the low side of the frcture index all that's tellling you qualitatively is that those -- that that log suite, those four logs that go into the makeup of their composite fracture log, are not indicating fractures present at that particular interval, or at that particular foot.

Q So --

A It has no real bearing on fracture intensity per se.

Q Or fracture frequency? Does it have a bearing on fracture frequency?

A No, no, huh-uh.

Q Then I guess I fail to understand why you have included the core fracture frequency visual from the -- from the core when it appears to be that there is little re lationship. (Not clearly understood) relationship but looking at the section from, say, 7170 to 7190, perhaps, we're showing a number of fractures went through that section whereas it shows very low frequency on the other, on the fracture index curve.

A Yeah, okay. A lot of that could be related to the actual tool sensitivity, you know. Obviously, you know, it's going to see different scale effects in the borehole than the visual examination of that very rock interval, and that's the difference there, is, you know, when you're examining a core foot by foot there's a much greater likelihood, obviously, than you're going to pick up indications of fractures.

The tool operates in a very imperfect environment.

Q Thank you. Are you aware of any porosity logs that were run in these wells? Did you examine any porosity logs?

A Yeah, we've got, I guess, every well that McHugh has operated we've had a CNL/FDC log run on, yes.

Q And a sonic, perhaps, for a well or --

A Some of the later wells we've run sonic logs on.

Q I see. And what do you -- I know it's very difficult to answer inasmuch as you don't have a log before you, but what -- what have you seen on these logs that -- insofar as porosity is concerned in some of what I'll refer to as the cleaner zones on the Niobrara logs that have been presented here?

A Yeah, that would be a tough -- tough questions to answer. I --

Q You must have formulated some opinion, though.

A Yeah, yeah. Based on the core data, now the core data, I think, is much more relevant here because, you know, obviously looking at the actual rock data, you know, has some merit, we have felt and have gone on record before as indicating that we don't feel the porosity logs are giving us any held whatsoever in the clean zones.

The clean zones, in fact, are dirty. They are clean relative to the 100 percent shale line but I don't think the log suites that are available are helping us in any exact fashion to determine what the porosity is in those rocks.

I think the more relevant parameter, anyway, is permeability. You know, there's going to be a non-zero porosity in any of these rocks we analyze but unfortunately we're dealing with, you know, microporosity, which is in effective.

Q From your experience are we looking at primarily one percent, less than one percent, greater than one percent, porosity? What --

A Well, I think the rock data ranges anywhere from --

Q No, only from your log analsyses, I'm saying --

A Oh, okay.

Q -- and not looking at the core analyses.

A Yeah, well, I -- I'd have to be quite honest with you, I don't even use the CNL/FDC log.

Q I see. How many of these wells have been --

-- is it customary procedure to core these wells through the Niobrara phase?

A Well, unfortunately, no. I wish we had more core data but we've got basically one Mobil core, the Mallon core, a very limited interval cored in one of the other Mallon wells, and then I believe it's two Unit wells have some early core data.

Q So your -- your porosity data based on core analysis is very limited, would you say that?

A Yes, it is.

Q And insofar as your core data from log analyses, it's nonexistent because you don't look at those logs, is that correct?

A Well --

Q You don't have any faith in them?

A Yeah, I basically don't use the density log at this point in my reservoir analysis, based on earlier experience. I started out using them because I had come from a matrix reservoir background where logs mean something, and it's just my opinion, based on my early experience that the logs are not very helpful, so I do not use them at the present time.

Q Also in your response to Mr. Chavez, and I apparently missed part of it, I wish you'd refresh my memory or help me to understand, you said that you had taken the plug samples from the core on this (not clearly understood) that you saw where they had been extracted?

A Yes.

Q And where you'd done the tests on those plugs to determine porosity or/and permeability?

A That's correct.

Q And you said that the permeability that you saw there that was presented was essentially matrix permeability?

A Yes, I believe it was.

Q And what sort of permeability are we talking about here? I missed the numbers; you said you did present them.

A Okay, sure. Let me -- let me just preface that remark or the answer to your question with a remark.

In the actual process of cleaning the samples we -- well, let me back up.

We wished in our analysis of the core to fully address the matrix question and we felt it necessary amongst the group to do the best job we could as far as getting accurate saturation data. So we used the (not clearly understood) process for that reason. In the process of doing that, and the toluene cleaning process that follows the (not clearly understood), we ended up with the dehydration cracks in many of the plug samples and were forced to qualify the permeability numbers with respect to that data. In fact, it's probably not usable because any time you've got a horizontal crack in a plug, why, you're going to affect the horizontal permeability.

Okay, so that data needs to be thrown out. When you do that, you end up with about 63 samples that apparently don't have any dessication cracks in them and just remembering from memory, I think the average porosity for the plug analyzed samples was somewhere in the range of 2 to 2.2 percent, but when you factor out the samples that have been contaminated by cracks, the permeability numbers range from a low of .003 millidarcies, 3/1000ths of a millidarcy, to a high of .08 millidarcies, 8/100ths of a millidarcy, and the average, the arithmetic average would be

Q Okay, thank you, very much.

QUESTIONS BY MR. LEMAY:

Q I just have a quick one, Mr. Ellis.

Somewhere I guess I've read in the literature and I wonder if you could comment on it, that the frequency of fracturing is somehow related to the calcium carbonate in the rock. In other words dolomitic or limey sections will fracture easier being more brittle.

Is that fair to say that's the case in

the Gavilan area?

A Yeah, I think that's probably very likely. One of the early studies done on the B and C zones in the unit was directly on that point and they concluded that the dolomite percentage in the overall interval had a significant contribution to the brittle nature of the (unclear.)

Q And those, if you're looking at the log, would be in the more highly resistive areas and that's why those are the areas that are perforated?

A Yes, I believe that's true. The zones that are not as resistive are probably going to be the more massive lithologies, the shales and mudstones.

MR. LEMAY: Additional questions?

QUESTIONS BY DR. SZABO:

Q Are you implying a system of open fractures, the cracks that are more or less continuous in the reservoir?

What I'm looking for or fishing for is what propping agent keeps the fracs open?

A Excuse me, beg pardon?

Q What propping agent would keep the fractures open?

A Okay. I believe that the situation in

the reservoir, because you have such a tremendous amount of heterogeneity in the reservoir, that the fractures are open primarily because of heterogeneity but also because of the structural form of the reservoir.

Obviously, if you get in flexion points on the reservoir you're going to have a greater number of open fractures at that point, but you also have the, I think, fairly unique situation in the Niobrara of having very thin bedded and highly laminated lithologies that allow you because of the way the rock necessarily was braced to keep the fractures open.

Q What would have prevented the migration of the liquids down dip by gravity if these fractures were open?

A Well, nothing. Nothing within the brittle zones in the reservoir. You're not going to have any restriction, I feel, to -- along -- along the reservoir units down there.

Q Then we should expect a gas cap with liquids segregated at the bottom.

A Well, there's going to be some segregation within each individual reservoir, yes.

Q Aside from economic screams of anguish, then, is there any reason why you shouldn't prohibit the production of gas except for recycling in order to maximize the return of liquids from the reservoir?

A Well, that's an engineering question and I think you know that.

Q So essentially the fluids would migrate down if you created your gas build-up with gas recycling?

A I think there's probably going to be segregation within the individual reservoir units, that's correct.

Q Yes, lost gas that affects the loss of recovery by keeping fractures open, possibly.

A Well, I'm not sure I understand your question.

Q In other words as long as you maintain your reservoir pressure it keeps them from collapsing.

A Oh, yeah, I expect that's certainly possible, yes.

MR. LEMAY: Additional questions?

MR. HUMPHRIES: Mr. Chairman, I have a couple.

MR. LEMAY: Yes, Mr. --

QUESTIONS BY MR. HUMPRIES:

Q Mr. Ellis, for the most part you guys speak English and I understand it, and this may be a little bit more hypothetical than some people would like but, for my knowledge, if there were a restrictive barrier in between the Gavilan Mancos Pool and the West Puerto Chiquito Pool, what would I see on your structural cross section?

A Well, there's a number of examples that come to mind. If you want to see a truly definitive barrier between the two, maybe a fault with a magnitude of 500 feet would help.

Q Besides that, and since we're saying that there is apparently no fault similar to, I forget the term you used, but minor faults with 50-foot throw, or something like that, would there be other things, other geologic factors that might separate these?

A Well, if you had some laterally discontinuous stratigraphy in operation in the reservoir, it's just possible you could have, you know, some kind of a barrier at some point.

Q If I understood you right when Mr. Chavez was asking you questions about that separation in Range 3 West, you started to see some changes in the geology there and in this particular formation more specifically, but you don't have information that tells you exactly where that stops, is that --

A Well, I think I was referring to production information. We don't know that, you know, that the wells on the west side of Gavilan are not somehow similar to the production west of the line.

There is a structural discontinuity is what I was alluding to and it was --

Q Does that structural discontinuity become more pronounced at, like, Range 4, between 3 and 4, or does the information just run out as far as you're concerned, where the production knowledge is not important to you?

A Oh, well, yeah, well, obviously production information is important. I think maybe I wasn't making my point clear, but, you know, all I'm referring to as geologic justification for the placement of our proposed west boundary would be the change in structural form. You're going from a very well defined nose with fairly uniform dip panel, a west panel, to flat dips at the range line, and no structural form.

You know, sure, there's change in the contour all over that but you've contoured a 50-foot interval. If you want to look at that on the structural cross section, why, it would be expressionless, completely, you know, flat in my mind, at least at that scale.

Q Okay.

A All right, I'm, you know, talking about a change in structural --

Q At the west side of what's now the Gavilan Mancos.

A Our proposed pool, yeah.

Q If I understood you right, and the difference in the rock between the production zones A, B, and C, that we've been talking about here, you say that there are certain plastic qualities or lithography associated with that, that keep production from going back and forth between A, B, and C Zones, is that right?

A Yeah, it certainly has the potential to restrict fluid flow in a vertical sense reservoir-wide. I think you've got tremendous communicated fluid flows within these individual brittle zones that Ive alluded to , but the plastic nature of the rocks around them would, I feel, restrict the fluid flow in a vertical sense throughout the reservoir.

Q So in your Exhibits Three and Four is -- would there be some necessary association of structural cross section that might indicate a barrier between the brittle zones of West Puerto Chiquito and Gavilan Mancos at this point?

A Within the brittle zones, no. I believe there's a fair amount of established lateral continuity within the brittle zones across the pool.

Did I answer your question?

Q I think so. And then going back to Mr.

Chavez' line of questioning, out at, again, at the west end of this particular cross section that you're talking about here, are you saying that that fracturing doesn't exist at the west end of that or I thought I understood you to say it does.

A Yeah, well, at least as we see on the surface fracture maps there is a kind you could set that extends west of the range lines, yes, that's true.

I was -- in answer to Mr. Chavez' question, I made reference to structural intensity as a guide to development of sufficient reservoir permeability to give like kind production between the three structural elements.

I don't know whether I answered your question or not.

Q Just one more time for my clarification. Then at the west end the reason that the so-called fracturing that you've described as one of the reasons why there is no barrier between Gavilan Mancos and West Puerto Chiquito, along with the information that you got in these brittle zones, is that the entire formation changes for some reason somewhere between Section -- or Range 3 and Range 4, and therefore the fracturing is not particularly relevant at the west end as it is at the east end?

A Well, Range 2 and Range 3, you mean?

Q Well, yeah --

A See I'm drawing the line --

Q -- the information stops somewhere between Range 3 and Range 4, you said.

A Oh, no, no, I said my, you know, the information stops between Range 2 and Range 3. Range 4 isn't represented on the map and I was referring to production information. At least the surface fracture map indicates that there are fractures that extend across that line.

What I was saying is that the structural intensity appears to be consistent throughout the pool area, whereas when you cross the range line into 3 West, because of the structural form indicated on the structure map, you have lost that structural intensity and therefore those brittle zones in the subsurface that produce the oil in the Niobrara are going to be, you konw, a different animal, basically. There may not be the continuity, lateral continuity, of permeability in the reservoir.

Q So that gives you a geologic boundary to the west end of the present Gavilan Mancos Pool.

A That's correct.

Q Okay, I understand. Thank you.

MR. LEMAY: Any additional questions of Mr. Ellis?

If not, he may be excused.

Care to call your next witness?

MR. KELLAHIN: Yes, sir.

MR. LEMAY: Mr. Kellahin?

(There followed a brief recess.)

MR. KELLAHIN: Gentlemen, my next witness is Mr. John Roe, who's a petroleum engineer for Dugan Production Corporation.

JOHN D. ROE, JR.,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Roe, for the record would you please state your name and occupation?

A Okay. My name is John Dale Roe, Junior. I'm a petroleum engineer for Dugan Production Corporation.

Q Mr. Roe, have you previously testified before the Oil Conservation Division of New Mexico as a petroleum engineer?

A Yes, sir.

Q Did you provide testimony to this commission in the August, 1986, hearings with regards to certain of these cases?

A Yes, I did.

Q And have you continued to study the information available from the Mancos reservoir, including the Gavilan Mancos area of this reservoir?

A Yes.

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

MR. LEMAY: Qualifications are acceptable.

Q Mr. Roe, let me direct you to what we have marked as Dugan Exhibit Number One and have you identify exhibit.

A Okay. What I've marked as Exhibit Number One is four pages with -- of data that is organized by operator and then alphabetically under operator by well number, and it is an attempt to present, one, an idea of what wells are involved in the Gavilan Mancos Pool. I've given the location of each of the wells, the completion date, the actual production, that each individual well had during December, 1986, and I've presented the cumulative production of each individual well as of January 1st, 1987.

Q At this point, Mr. Roe, approximately how many operators do we have in the Gavilan Mancos Pool?

A There officially are ten operators within the Gavilan Mancos Oil Poool.

Q And as of December of '86, how many producing wells did you have in the Gavilan Mancos Pool?

A During December there were 49 wells that actually produced, that had production.

In addition to these 49 wells there were 21 additional wells that are completed, ready to produce, or being completed for production.

Q In addition to that, sir, how many staked locations were there for the pool?

A There were 15 additional locations, bringing a total of 85 potential wells within the Gavilan Mancos Pool area.

Q This can be utilized, then, as a guide or an index to helping us understand who operates what wells and shows us how to identify those wells and shows when the wells were completed and the production information.

A That is correct.

Q All right, sir.

Let's turn to Exhibit Number Two now, Mr. Roe, and have you identify that exhibit.

A Exhibit Number Two is a much more detailed compilation of the production statistics for each of the wells in the Gavilan Mancos Pool area.

It -- in the front portion of this exhibit there are some green shaded pages that present the pool production and this would be the total from the pool for all wells within the pool.

You'll note on the first page that production from the pool began in December of 1980 from a well operated by Dugan Production, and it by month lists production data through December, 1986.

Q Okay, if we turn past the green sheets and we have the pink sheets, what are those?

A All right. The pink sheets list the same type of information but for each individual operator, again from the date of first production that any individual operator had production in the pool through December, 1986.

Q I want to look up individual well production information, can I turn to the white sheets in this exhibit?

A Yes, sir, the white sheets are -- there is one sheet, or at least one sheet, for each well that's within the Gavilan Mancos Pool Area and in addition. associated with the tabular data, is a production plot for each well.

Q In looking at the individual well information for the Gavilan Mancos Pool, I would like to have you tell me how I find the individual wells by an operator. Are they listed alphabetically by operator in this portion of the exhibits?

A Yes, sir, starting with the operator is the first index of our -- our listing, and then within each operator we are alphabetically by well.

So, for instance, if we were to turn to a well operated by Jerome P. McHugh, we put it first under the section -- I have not put dividers in here to divide the operators but would look to the section that McHugh's wells are listed and then the Janet No. 2 would be alphabeticallyl within McHugh's group of well data.

Q If we turn to Mr. McHugh's Janet No. 2 Well, there will be a separate page by which you have tabulated the production and then there will be also a graph that shows the gas/oil ratio versus the oil production rates?

A Yes, sir. I have not marked this particular page in all books but in several of the books I've put a little yellow tab and it would be the first of three tabs. That would be the production curve for the janet No. 2, yes.

Q All right, let's look at the production curve for the McHugh Janet No. 2, and ask you to describe how we might use this graph to realize information about this particular well.

A Okay. The things that are most obvious on this graph, other than it does present the actual barrels of oil per month that were produced from the well and the

A Yes. Exhibit Number Three is a very similar presentation to Exhibit Number Two; however, in Exhibit Three we have the wells and production statistics for each well within the West Puerto Chiquito Pool.

Q Would you go through with us and identify the various color tabs?

A Yes. This -- the first nine pages in this exhibit are shaded green and they primarily present what would be the total pool production, if you examine the first page beginning in December, 1962, taking you through December of 1986.

Now, the difference -- the second set of pages, there's also nine of them that are shaded blue, the seocnd or the blue shaded pages reflect only the Canada Ojitos Unit production, pretty much for the same period of time.

The green pages included four wells that were -- were not actually within the Canada Ojitos Unit.

The pink shaded pages following the blue reflect the production within the West Puerto Chiquito Pool that was not included in the Canada Ojitos Unit, so it would be the balance of production in the West Puerto Chiquito Pool, an probably a fairly important page for reference would be the gold colored page. It's -- primarily the purpose for including this is in a lot of our testimony today, and the unit operator routinely refers to the wells by their unit letter and section number, the State does not recognize this numbering system. It's a matter of convenience for locating the wells within the unit area, so this could serve as a cross reference between what is the official state designated Canada Ojitos Unit well number and the conveniently unit section number that we use routinely.

Q And finally, the white pages in this exhibit.

A The white pages following the gold, as with the Gavilan Pool, is monthly production -- production statistics for each well within the Canada Ojitos Unit from the date of first production through December, 1986.

Q Let me direct your attention now to what we've marked as Dugan Exhibit Number Four, Mr. Roe. This is simply a reproduction out of Sun's exhibit book, it's their Exhibit Number Two on the reservoir parameters that were used in their computer simulation of the Mancos reservoir, Mr. Roe. The purpose of including this at this point is I would like to have you review the parameters for me and have you tell me whether or not you have an expert opinion as a petroleum engineer as to whether these parameters are representative of the information you have and know to exist for the Gavilan Mancos area?

A Would you like me to review each parameter or just --

Q No, just take a moment and look through these without reading them out loud and tell if there are any of these parameters that you feel are not reliable or do not fairly represent the characteristics you see for wells in the Gavilan Mancos area.

A I have reviewed this list and I -- it's my opinion that the information included in -- on Dugan Production Exhibit Four is representative of reservoir and fluid properties not only in the Canda Ojitos Unit, but also in Gavilan.

Q Let me direct your attention now, Mr. Roe, to Exhibit Number Five. I'd like to spend some time on this exhibit, Mr. Roe. Do you have a copy before you, sir?

A Yes, sir.

Q Is this an exhibit that you have caused to be prepared?

A Yes.

Q And have you reviewed the information on here to determine whether it has been correctly depicted and accurately represented?

A Yes, I have.

Q Would you take a moment and tell us -- or identity the exhibit?

A Yes, sir. This -- a portion of this exhibit was included in Dugan Production Exhibit Number Two at the August allowable reduction hearing, which was Case 8946. On that exhibit that we presented in August we had data through June of 1986. I have taken the data that is available production-wise and updated this exhibit through December of 1986 and I've updated it for pressure information through March of 1986.

And primarily what we're presenting on this exhibit is -- we're attempting to show the pressure information and the history of the reservoir pressure in the Gavilan Mancos Pool area and along the bottom portion of the exhibit we are presenting the voidage that we're causing in the Gavilan Mancos pool area, with the oil production and then we've got two additional curves that we're attempting to show the range of voidage that we're causing in the reservoir with the gas production.

Q Let's use the bottom horizontal scale that shows in years displayed by months per year, starting with August of 1984. Would you follow that for us on the scale and at the same time in following that scale, if you'll locate the line that has been identified as Oil Plus Maximum Gas Voidage? Do you find that block?

If you read up from July, 1985 --

A Yes, sir.

Q -- it says Oil Voidage. You go up the

next one says Oil Plus MInimum Gas Voidage.

A Yes.

Q And then finally above that it says Oil Plus Maximum Gas Voidage?

A Yes, sir.

Q Look at that line that I've last identified and tell me what that is.

A Okay. That -- that would be my estimate of what the total voidage that occurred during any one month from the number of wells that are identified immediately above that line.

So, for instance, during July of 1985 the reservoir experienced a reduction in volume by approximately 7725 or 50 barrels, reservoir barrels, and that occurred from the fact that 28 wells were producing.

Q All right, if we look at the month of July of '85; we follow over into the lefthand vertical scale where it says Reservoir Voidage?

A Yes, sir.

Q We find 8000 and just below that, then, is the reservoir voidage in barrels per day?

A Yes, that's correct.

Q All right. As we move from August of '84 through July of '85, what opinion do you have about the rate of increase in the reservoir voidage line?

A Okay. The, during the period of time that you've identified there and the time actually extends probably up into -- maybe through October of 1985, the reservoir voidage was fairly constant or did not regularly exceed about 8000 barrels a day, and the number of wells that were producing during this period of time was fairly stable. It was a period of time that we -- the reservoir was not experiencing a great increase in withdrawal.

Q If we follow the bottom horizontal scale and we look at 1986, did I correctly hear you to say that in the August '86 hearing you had data available through May 31st of 1986?

A No, I -- it was through June 30th --

Q June 30th.

A -- of 1986.

Q All right. June 30th of '86. If we find that point and we move vertically and find the Reservoir Voidage line again, am I correct in finding that at that point we had 43 wells?

A Yes, sir.

Q Are these producing wells?

A Yes. The numbers indicated are the wells that actually had production during that month.

Q Do you attach any significance to the rate at which the reservoir voidage was occurring between

October of '85 and June 30th of '86?

A Yes. It is just the -- the Total Voidage curve indicates we were experiencing a pretty substantial increase in the reservoir production and that's partially explainable by the fact that the wells producing were beginning to -- to -- or new wells were being place on production during this time and, for instance, during June of 1986 there were 43 wells that produced, which is an increase of 5 over the previous month.

Q What is the relationship with the increase in reservoir voidage insofar as it applies to your previous testimony in August of '86 that an emergency was occuring or existed in the Gavilan Mancos Pool?

A Our primary concern in August was that we had at that -- at that hearing had a sufficient amount of pressure data to -- and as the exhibit in August had indicated, the rate of pressure decline that the reservoir was experiencing had shifted from around 5 pounds per month, which would be for the period prior to, say, October, '85, and beginning in November or in that generally vicinity of November, '85, the rate of pressure decline increased to around 30 pounds per month, and our primary reason for becoming really alarmed was we could project this 30 pounds into the future and it, as an engineer, it did not allow us much time to make a modification to the method that we were producing the reservoir, if there was a method that would result in improved recoveries, and that was what we viewed as an emergency.

Q If we look now to December 31st of '86, find that line on the bottom horizontal scale and follow it, then, vertically, to the last input point where it shows 49 wells.

A Yes, sir.

Q What is your opinion about the reservoir voidage that is displayed at that point in the exhibit?

A Okay. During December, 1986, the -- as you mentioned, we had 49 and during November there had been 50 wells that had production, but there was roughly 49 wells, 50, that had -- that had established production. The reservoir voidage during December was approximately 22,100 reservoir barrels a day, of which about 4300 of that was oil and the remainder was free gas.

The real significance in that number was during December, as I had mentioned, during review of the prodution statitistics in Exhibits Two and, although I did not mention it in Exhibit One, one of the pieces of information presented in Exhibit One was the number of days that each individual well produced during December.

There are many wells that are only producing 25 to 30 percent of the time. These are generally the larger wells or the higher gas/oil ratio wells.

The real significance, knowing that during the period September through December we did have some of our bigger wells, our higher gas/oil ratio wells, shut in or producing at reduced levels, some of them as low as 6 to 8 days per month, had we not had a reduction in the permissible gas production during any one month, from prior to the allowable reduction hearing, we were able to produce approximately 1.4 million cubic feet a day.

With the allowable reduction the gas volumes restricted, were restricted to about 240 MCF a day.

So had we not had this restriction during December, I had put exact numbers on it, but knowing that the wells were producing 25 to 30 percent of the time, I feel fairly certain that the reservoir voidage during December would have been a couple of time what we're showing here and I would have had to add paper to the top of my graph in order to present that voidage.

Q In your opinion has the temporary order of September 1st, '86, caused a reduction in the rate of reservoir voidage of the reservoir?

A It did not provide the reduction that we were hoping for because there are some of our engineering group that does feel there are things we could do to improve recoveries; however, from this graph, and I've highlighted on several of the graphs, I don't think I had time to highlight everybody's copy of this exhibit, but I've highlighted three wells that are of particular interest.

Q Well, let me ask you this. In the absence of tlhe temporary order, the voidage in the reservoir would have been above the 22,000-barrel index, where it is now.

A Yes, sir.

Q December 31st.

A Yes.

Q And where would it have been approximately, if you know?

A I haven't, mainly because it was a difficult number to calculate, but I feel fairly certain it would be at least twice what we're showing during December, which would be a rate of about 44,000 barrels per day, and the rate at the top of my scale is 36,000 barrels a day. So we would have, like I say, have to either change the scale or add graph paper.

Q Do you have an opinion, Mr. Roe, as to whether or not there is a continuing need for such an order as was entered in September in order to control the rate at which the reservoir is being voided?

A Yes. I think that what this graph depicts is that we have a continuing need to at least maintain the levels of voidage that we have. It would possibly suggest even a greater -- or a need for a greater reduction than we currently are operating under.

Q What effect, if any, has the additional wells that have come on production had on the ability of the temporary orderto control reservoir voidage?

A The dramatically -- dramatic increase in reservir voidage that we see is a factor of two things. One, we have experienced a large number of new wells coming on production, and as I've indicated on Exhibit Number One, we have about 21 addtiional wells right now that will in the very near future be placed on production.

So the new wells coming on production is dramatically increasing the amount of voidage that we're seeing from the reservoir. These new wells are coming on in production in a reservoir that generally is monthly declining in reservoir pressure at about 30 pounds a month. The lower the reservoir pressure gets, the higher the gas/oil ratio within the reservoir is getting and these new wells not only in pure numbers but the fact they're coming on higher gas/oil ratios is having a dramatic effect on the reservoir withdrawal.

Q When we look at the upper half of the exhibit, those lines and the well names, those indicate pressure versus time lines?

A Yes, sir.

Q Okay. At what point in examining that display do you show that wells were declining at the rate of 5 barrels of pressure per month?

A That -- that rate of pressure decline existed before November of 1985.

Q And after November of '85 what has happened to the rate of pressure decline?

A All right, beginning sometime after the data we had in October, we -- the pressure began declining at a rate that was quite a bit more than 5 pounds per month and it averages, oh, about 30 pounds a month, and there's many wells that are depicting rates of pressure decline up to 50 pounds a month.

Q Let's find an example of a pressure decline. Perhaps we could use the Loddy Well that's identified in green on my copy, or maybe the one that has the line above that, I guess it's one of the Canada Ojito Unit wells, the E-6? Do you find one of those lines?

A Okay, I would prefer to use the Loddy for the reason that -- and this is on some of the graphs identified with a green shading -- this well during this period of time was not producing at all, so the question of whether we're looking at adequately built-up pressure or not shouldn't be a question. This well had no production until

December of 1986.

Q During the period of no production in this well, how many months are you talking about?

A Roughly ten months. The well -- we first -- the well was completed in August of 1985. We started monitoring reservoir pressure during the latter part of February, 1986.

Q During that period of time without production in the well what was the total number of pounds of lost pressure in that well?

A We'll have quite a bit more detail on this particular well in a later exhibit, but it experienced roughly a 3300 pound pressure drop during this period of time.

Q What is that an indication of to you, Mr. Roe?

A It confirms what the rest of this data is telling us, is that throughout the reservoir we are experiencing a fairly good communication well to well and throughout the reservoir. The additional wells, specifically the Loddy, the Loddy was during this period of time at the kind of the northwestern edge of the developed reservoir. There was no significant production immediately adjacent to the well. The nearest producing well that was producing under a sustained basis was approximately a mile and a half away, so whatever was causing this pressure reduction in this well was at least a mile and a half away from the Loddy.

In addition to the specific example of the Loddy, we've taken and presented pressure data from wells both in the northern part of the study area, the southern part of the study area, the east and the west. We even got some wells within the Canada Ojitos Unit presented on this exhibit.

Q If we look at the later end of the production decline -- I mean pressure decline curve, do you see any effects of having the producing rates restricted as a result of the September 1st, '86 order?

A The rate of -- the arresting of the rate of pressure decline was not as much as I had hoped it would be having reduced allowables beginning in September; however, again if we could use the Loddy as an example, the pressure data that is depicted here prior to September was declining at a rate of about 47 pounds per month and again remember this is in a well that was not producing. It was shut in and the only thing that was happening is we were monitoring reservoir pressure.

Beginning with the pressures that we have during the latter part of September and in October, the rate of pressure decline in this well slowed to about 33 pounds per month. Now I feel fairly certain that that primary rate of -- arrest in the rate of pressure decline is a direct result of the reduction in reservoir voidage that did occur beginning in September, and so this, I feel, although it's not as dramatic as I personally had hoped we would see, this is, I think, a very specific example of benefit that was derived from the reduction in allowables.

Q The rate of pressure drop in this well is projected to be about 33 pounds a month. Was I correct in hearing you?

A That was the rate that it slowed to; however, the last pressure we have in the well in the latter part of November suggests that it's -- the rate of pressure decline is increasing a little. From September to October it's back to about a rate of 39 pounds a month.

Q Do you have an approximation of the pressure decline in typical wells in the Gavilan Mancos Reservoir on a monthly basis?

A Yes, sir, I -- the rate of pressure decline throughout the reservoir is averaging about 30 pounds per month.

Q If the rate of pressure decline from the reservoir continues unarrested at about 30 pounds per month, what in your opinion is the remaining life of this pool?

A We would have approximately three years of remaining life as we know Gavilan today.

Q What is your concern about that, Mr. Roe?

A My major concern is that I believe that there is potential for improving the recoveries from the Gavilan Mancos Pool area. I think the -- knowing that it's declining at a roughly -- at a rate of 30 pounds per month, knowing that the reservoir pressure, as I've indicated on this graph is in the range of 1250 pounds currently, we are by anybody's standards significantly below the bubble point pressure. We see the increasing gas/oil ratios in individual wells and we see it on a pool total. I know as an interest owner in the Canada Ojitos Unit that what's happening in Gavilan is going to allow a very long established pressure maintenance and efficient mode of operation in the Canada Ojitos Unit to be unraveled. I -- my real concern is that what is happening and displayed on this graph is going to have a dramatic effect on the ultimate recovery from the Mancos Reservoir from the areas that we're referring to as Canada Ojitos Unit and also the Gavilan Mancos.

Q Let's turn to Exhibit Number Six, Mr. Roe.

Some of the following information is again statistical information that you tabulated on the reservoir. I'd like you to simply identify the information we have in Exhibit Number Six.

A Yes, sir. Exhibit Six is nothing more than just a tabulation, again organized alphabetically by operator and under each operator for each well that I was either able to find the information on or had time to present the information on.

But Exhibit Six consists of 16 pages of information as to where each of the wells is perforated within the zones that I've identified and for just reference purposes I've divided it up into an area that is above the A Zone, the A Zone, B Zone, C Zone. There is an area that's below what we normally refer to as the base of the C and the top of the Sanostee. It sporadically is perforated. And then there is what we -- I refer to as the Sanostee. All of these zones are within the Gavilan Mancos Pool, also the West Puerto Chiquito Mancos Pool, and I -- the purpose of presenting this is --

Q Excuse me, this also includes the Benson-Montin-Greer wells, at least a certain number of those wells in the tabulation?

A Yes, sir. I've got the data on ten of the wells that are within the unit area.

Q All right, sir. Let's go now to Exhibit Number Seven. Would you identify what you have compiled as Dugan Production Exhibit Number Seven?

A Dugan Exhibit Number Seven is basically a reproduction of the open hole resistivity log pretty much on all of the wells that the tabular data was listed on Exhibit Number Six, and the primary reason for presenting this piece of information is all wells are hopefully reduced to the same scale so that it would be an easy matter to make a correlation between any of the wells that you chose to compare.

Q Thank you. Let's turn now to Exhibit Number Eight.

You have used as Exhibit Number Eight a plat of wells in the Gavilan Mancos area and you've highlighted in yellow two wells?

A Yes, sir.

Q One of them is the Loddy well that we just discussed in Exhibit Number Five?

A That's correct.

Q All right, sir, and the next one is the Homestead Ranch No. 2 Well?

A Yes, sir.

Q Let me direct you now, and using this still as a guide, Exhibit Number Eight, let me direct you to Exhibit Number Nine and have you identify that exhibit.

A Exhibit Number Nine is a presentation of the well information and results of a production survey that we ran in the Homestead Ranch No. 2, which is located in the Southwest quarter of Section 34 of 25 North, 2 West.

Q Let's turn through Exhibit Number Nine and it might be just as easy to count the second page from the back.

My copy of that second page from the last has some colored shading on it.

A Yes, sir, everybody's should be.

Q Everybody's shaded?

A Should be.

Q All right, sir, would you identify and describe what that is?

A Okay. This is a reproduction of the actual log of information that was recorded during the production survey that we made in the Homestead Ranch No. 2 on March 13th of 1987.

Q What does this show you as an engineer, Mr. Roe?

A The information that -- the bottom line is that 100 percent of the production that we were getting from the well is coming from a 20-foot zone near the top of the B Zone and although we did not monitor production from the C Zone during this period of time, the fact that the density of the wellbore fluid opposite the C Zone is oil rather than water, we could conclude that the C Zone has at some time produced.

Q What do you conclude from looking at this production control survey with regards to whether or not this is a stratified reservoir?

A It to me confirms that we at least have a barrier between the B and the A Zone. I reviewed the completion that we had on this well initially. I reviewed the treating pressures and frac rates that existed when this well was stimulated, and it's my believe that each zone, the perforations in the A, B, and C, did receive stimulation during the frac based upon our analysis of the treating rates and pressures, and so with the knowledge that each zone did receive stimulation, the fact that the majority of the production, or all of the production is coming in near the top of the B Zone tells me that there is a barrier between the A and B.

Q Let's turn now to Exhibit Number Ten. Would you identify for us what Exhibit Number Ten is?

A Okay. Exhibit Number Ten is a presentation of the pressure data that we monitored in Jerome P. McHugh's Loddy No. 1, this well being located in the northwest quarter of Section 20 of 25 North, Range 2 West, and this is the same data that was presented on an earlier exhibit, Exhibit Number Five.

Q I want to direct your attention to the first page of Exhibit Number Ten and at the same time have you help orient us by looking at Exhibit Number Eight. I have located in Section 20 in yellow the Loddy No. 1 Well?

A Yes, sir.

Q Looking at the first page of Exhibit Ten, describe for us first of all what you are showing on that exhibit.

A Okay. The first page of Exhibit Number Ten, and Exhibit Ten consists of eleven pages, the first page presents a summary of what is attached on the next ten pages in more detail.

We have with time just the graph paper we're using presents the rate of -- or the pressure on the vertical scale as we've adjusted to a datum in the reservoir of +370 feet, and across the bottom are just the number of days so we can keep track of what happened to the reservoir pressure as time progresses.

As I've indicated at the bottom left corner, the well was completed August 30th of 1985. I had said earlier the well hadn't produced. There were three days in August that we did produce the well and a total of 225 barrels were produced on a short production test.

Q August of '86?

A Yes, sir, I'm sorry, August of '86.

Q Except for that short production test, the well did not produce from completion in August 30th of '85 up through what time? What date?

A The well was first placed on production December 11th of 1986, and I have that date indicated on the graph.

Q During that period of time, was this well used as an observation well?

A Yes, sir, it was.

Q During that total period of time in the absence of production, tell us what the total loss in pressure was in that well.

A During the period that we're talking about, we had approximately 300 pound pressure loss, beginning, like I've indicated with our pressure we measured the latter part of February, up through the latter part of November, just prior to putting the well on production.

Q Would you describe for us as we go down the pressure plot on that well and show us instances of where you think there has been communication or interference by events that are occurring in other wells?

A Sure. Starting with the first pressure information we have, and I might mention that a majority of this pressure information was recorded with a pressure bomb that we had borrowed from the Canada Ojitos Unit. It's a very sensitive pressure bomb and the data that was collected with that bomb I've identified across the very top of the page as GRC, which is the name of the company that sold the bomb, and the specific run that that bomb pressure information was recorded.

For reference, the -- attached to these sheets, for instance, the GRC Run 28 & 30, that would be the first page behind this and naturally I was not able to present the detail on the first page that does exist on the subsequent pages, so I don't plan to review subsequent pages but the tremendous accuracy of this pressure bomb and watching the pressure declline early in the life at a rate of and monitor this pressure decline, is pretty amazing to me.

Not all of our data was recorded with this bomb. We've confirmed this pressure decline with an Amerada pressure bomb on several occasions, that we leased from a contract service. As I've indicated earlier, the early part of pressure decline was about 7 -- averaged about experiencing a rate of pressure decline of 1.68 psi per day. We -- we don't have any data during August, but the first pressure we -- we collected in September, and again the specific details on any individual data is attached, but the rate of pressure decline slowed from the 1.68 psi per day to about a .96 psi per day, and this slowing of pressure was -- we monitored that for several days during September. During the latter part of November, prior to placing the well on production, we monitored pressure again and it had resumed a little steeper rate of decline now declining at 1.32

psi per day.

Each of these changes in rates of pressure decline had to have been the result of factors that were happening somewhere else in the reservoir.

Q Let's look at Exhibit Number Eight and have you relate to us, based upon your study, what wells and activities in offsetting wells have communicated or been affected or appeared in the Loddy No. 1 Well.

A Sure. During the majority of the time that we were monitoring pressure in the Loddy, the closest offset well to the Loddy is a well operated by Mesa Grande Resources, which is directly north about a half a mile. This well is the Brown No. 1. This well was placed on production during March of 1985; however, it was operated very sporadically. It did not produce continuously throughout this period and the cumulative production at the end of November of 1986 was just 25,000 barrels of oil, so we feel fairly certain that this well was not responsible for the rates of pressure decline; that removing that well has -- the primary, undoubtedly it had to have been influenced, influencing the pressure some when it was on production, but there were many months between March of '85 and November '86 that it didn't produce at all.

Q Identify for us wells on Exhibit Eight that you find have influenced the pressure on the Loddy No.

1 Well.

A Okay. We think that we've been able to correlate things that have happened in the Full Sail No. 1, which is in the southeast quarter of Section 29.

Q Moving to the south of 20 and the next section to the south, the southern well in that section?

A Yes, sir, it would be in the southeast quarter, and that's roughly a mile and a quarter away. During this period of time the Full Sail 1 was producing, as was the ET No. 1, which is in the northwest quarter of Section 28, also about a mile and a quarter away, and the Janet No. 2, which is about 2-3/4 of a mile away in the southeast quarter of Section 21. These three specific wells were producing throughout the period and we feel that we are possibly able to identify changes in the rates of decline based upon what's happening in these three wells, plus I feel very certain there were other wells in the reservoir that were affecting what's happening here, also.

Q What do you conclude about the distance by which wells are able to affect each other?

A It's my feeling this is a direct measure of the ability of any one well to drain areas that greatly exceed the existing spacing of 320 and even the 640-acre spacing we're asking for in our application.

Q Let me ask you, Mr. Roe, to summarize

your engineering opinions and conclusions with regards to the Mancos Reservoir and how you would recommend to the Commission that this pool be operated and what rules be established.

A Based upon the data that I've presented here and on a tremendous amount of information on this reservoir, I've been studying this reservoir since the very first well was completed. Dugan Production has an interest in 40 of the 70 wells. I've had access to a tremendous amount of information, not only in the 40 wells that we have an interest in but in a cooperative effort with the Engineering Study Committee I've been active in all of the meetings that we've had. I have had the benefit of working very closely with Mr. Greer and sharing in all of the knowledge he's amassed in his 25 years of experience in the Canada Ojitos Unit.

And based upon all of that, I am very concerned about the rates the pressures are declining. I am concerned about the rate at which the gas/oil ratio is increasing. I'm concerned that there is a tremendous number of operators that are becoming very interested in developing the reservoir on the existing spacing. As I've indicated, we have 15 locations that are staked, with operators planning to drill. Based upon my analysis, if the pressure continues to decline, we have roughly another three years before we get to what will be the latter stages of depletion of this reservoir. I feel fairly certain that not only in Gavilan but in the unit we have the opportunity to improve recoveries by allowing gravity drainage to work and I feel, based upon Sun's analysis, which substantiates my ideas, that the rates of pressure in production are excessive, so that gravity drainage will not have a chance to work if we continue producing the reservoir as we are now.

Therefore I think we need to initiate some efforts to slow the rate of pressure decline and -- and try to get an operation in the reservoir that will allow gravity drainage to become more of a factor in ultimate recovery from the reservoir.

Q Do you have an opinion, Mr. Roe, as to whether or not the Gavilan area and the West Puerto Chiquito Mancos area ought to be treated as one common source of supply?

A Yes, I do have.

Q And what is that opinion?

A I feel that the pressure data we have very clearly indicates that it is one common source.

Q Do you have an opinion as to whether or not this is a stratified reservoir consisting of three distinct producing zones?

A Yes.

Q And what is that opinion?

A I feel that the data we've presented today and a tremendous amount of additional data, supports that there are stratification -- there is stratification within the Mancos interval and we are dealing with three reservoirs that are isolated from each other.

Q What would you recommend to the Commission to adopt as a spacing for the Mancos Reservoir?

A We have asked that a spacing of 640 acres be established.

Q With the option for a second well on 640?

A Yes, sir, that would provide for those operators that still feel that they have a need to drill a second well on a 640 for whatever reason, they either don't believe the reservir engineers, or they did not get the results they wanted with the first well, then at their option they would be able to drill a second well. They would not be forced to drill a second well.

Q Do you have a recommendation to the Commission as to a gas/oil ratio or a limiting gas/oil ratio to apply to this reservoir?

A We've -- in our application we've asked for a limiting GOR of approximately the solution GOR, which is 600 to 1.

Q Do you have an engineering opinion as to whether that is a fair and reasonable limiting gas/oil ratio rate to apply to the reservoir?

A Yes. It is a logical rate to apply from a standpoint that that is what we believe to be close to the solution GOR.

Q And do you have a maximum daily producing oil rate that you would recommend to the Division be adopted and apply to this reservoir?

A Yes, sir, 800 barrels of oil per day per 640-acre unit.

Q If allowables are set higher than your recommended allowables for a limiting gas/oil ratio and for an oil producing rate, what effect will that have in your opinion on the ability of this reservoir to obtain additional drive mechanism for gravity drainage?

A It will definitely restrict the time period with which gravity drainage will be allowed to work and it will result in a reduction of oil recovered from the reservoir.

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

We would move the introduction of his Exhibits One through Ten.

MR. LEMAY: Without objection Exhibits One through Ten will be admitted in evidence.

I think we'll take a break now before we get to cross examination.

Take a ten minute break.

(Thereupon a ten minute recess was taken.)

MR. LEMAY: We will resume with examination of Mr. Roe.

Is there any additional direct examination --

MR. KELLAHIN: No, sir.

MR. LEMAY: -- for Mr. Roe?

Questions of Mr. Roe?

MR. CARR: No.

MR. LEMAY: No, Mr. Carr?

Mr. Pearce.

CROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Roe, would you please look at your Exhibit Number Four with me for a few minutes?

A Yes, sir.

Q I understood you to answer Mr. Kellahin that you believed that was reliable and fairly represented the wells in the Canada Ojitos Unit and the Gavilan unit.

A Yes.

Q A couple of items on there that cause me some problem with that response.

I'm looking, for instance, at the item labeled permeability, which is I understand is transmissibility, and it says 10 Darcy feet. Do you think 10 Darcy feet is representative of the wells both in the Canada Ojitos and the Gavilan Pools?

A Yes, sir, I think, although I didn't have any of that data, Mr. Greer on one of his exhibits yesterday actually presented the results from pressure build-up tests that are in our area.

Q I'm looking now, sir, at your Exhibit Number Three, and I'm looking at the Benson-Montin-Greer Canada Ojitos Unit Well No. 21.

A Yes, sir.

Q Barrels of oil per day column beginning in 1985, I find those figures to be 18.2, 17.6, 20.0, 15, 13.7. Down in July of 1986 the number is 20.5. Do you believe that those production levels are indicative of a well that has 10 Darcy feet of transmissibility within this reservoir?

A I would have to say that the 10 Darcy feet is intended to represent an average of the reservoir. I would not associate that high a transmissibility with each well; however, I might point out that there are a lot of reasons that a well might not be -- the production rate would not necessarily reflect its transmissibility.

Q Could you give me some instances?

A Well, ineffective stimulation, skin damage that was created during the stimulation, the reservoir area around the wellbore might actually exhibit a higher transmissibility than the production rate would -- would indicate, and we would be able to detect this on a pressure build-up and you wouldn't necessarily be able to infer it from the production.

Q Do you know what area of the Puerto Chiquito or Gavilan Pools this well is located in, this well in what's commonly called the trough? (sic)

A Yes, sir, also at the top of the page you have the benefit of being able to see that the well's in the northeast quarter of Section 32 of 26, 1, which is at -- I don't really refer to it as the trough, but that is adjacent to the west Gavilan Mancos area, yes.

Q Turning to the next page, there is a sheet on the Canada Ojitos Well No. 23 and once again if you skim down the barrel of oil per day column, do you believe those rates are indicative of 10 Darcy feet?

A Again, Mr. Pearce, I -- I would not

necessarily -- my comments from the previous well would stand with this well, also.

Q Do you have any information or knowledge right now about how these wells were completed and whether or not there were any completion problems with these wells which might have restricted their producing ability?

A I am familiar with the general completions, although there may have been something specific in the individual wells that I am not aware of.

I might mention that you've picked out two wells that are in the northern part of -- of what we're talking about. Both wells are in Township 26 North, and the fact that there is one or two wells in a general area that would not have 10 Darcy feet, does not mean that 10 Darcy feet is not an average for the reservoir.

As I recall, Mr. Greer had an example of a well that he TD'ed and was unsatisfied with the well and just deviated 40 feet -- a 40-acre location away and had an entirely different well.

So I think you're looking at the results, if the production truly reflects the transmissibility that exists, I think you're looking at this would be one of the -- a well that's copleted in one of the tight blocks, if you want to think of it in that manner.

Q And do I understand correctly that the transmissibility which you would expect to find within those tight blocks is substantially less than 10 Darcy feet.

A Yes. The tight blocks would have the low permeability, if you're in the middle and removed from the higher capacity fractures.

Q I notice that the same sorts of production levels also show up on the 26 Well, which is in 25 North, barrels of oil started out in May of '85 at 138 but then it dropped very rapidly to 17 and it is now down around 3, 4, or 5. Do you have any information about the completion or any prodution problems with that well?

A Yes, sir, I have a great deal of information on that well because it also sets -- offsets a well that Dugan Production operates in Section 36 of 25, 2, and we have identified an area that's fairly localized in Section 31 of 25, 1, and 36 of 25, 2. Dugan Production's biggest disappointment was drilling a well that looks just like this.

I might point out that within a -- one section away in Section 32, it's what Mr. Greer referred to as the B-32, he has a well that will produce -- it has tested at over 1000 barrels a day with a 4-pound drawdown.

Q Okay. Then looking at the 10 Darcy feet number set forth on your Exhibit Four, when you say that is an average number, could you explain to me a little more fully about what you think that is? Or is there a set of data which has been averaged to arrive at 10?

A No, we did not mathematically average a set of data. We have access to several build-ups that -- that we felt 10 to be representative of that. Now I honestly cannot say I added up all those numbers and divided by the total numbers. 10 is a number that is convenient to talk about and it's certainly in the range of transmissibilities that our build-up data did indicate, and again with reference to one of Mr. Greer's exhibits, he had this presented on a plat that shows transmissibilities more than twice, maybe three times, both in the Gavilan area and the Unit area.

The idea of what we're trying to depict is what is primarily going influence the operation of the reservoir as a whole, recognizing that there are going to be areas within the reservoir that aren't going to have 10 Darcy feet. They're going to have some lesser permeabilities because they are not as highly fractured and because they are not as highly fractured they -- they will be poorer wells.

Q Okay. Looking up that exhibit a couple of lines, the original oil in place line, 3000 stock tank barels per acre, could you give me your honest opinion of what that number is? Is that some sort of averaging? How as that number derived, if you know, and what level of confidence do you personally have in it?

A I have accepted that number because it's the number that has worked very well.

Now, in our original pool hearing three years ago, I was involved and aided Mr. Greer in putting a lot of this data together that was part of his testimony, and this number comes from not only a very detailed study of the Mancos in the Boulder, the Gallegos, Gallup, the Hogback area, there are many areas in the Boulder Mancos and the East and West Puerto Chiquito, and this is a number that primarily has been established with pressure interference data and we -- we have no reason to have anything but a fairly high confidence in that -- that number.

MR. PEARCE: I don't think I have anything further. Thank you, sir.

MR. LEMAY: Thank you , Mr. Pearce. Are there any questions of Mr. Roe?

Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Roe, on your Exhibit Number Nine, which includes a spinner survey of the Homestead Ranch No. 2 Well --

A Yes, sir.

Q You stated that you thought the A, B, and C Zones had all been fractured adequately. How did you determine that?

A Primarily, Frank, we -- I took a look, knowing that not all operators are real advocates of limited entry type stimulations but I am, and this particular well was completed with 35 perforations and knowing the diameter of those perforations and by having a copy of the rate and pressure that was actually recorded during the stimulation, I'm able to calculate how many barrels per minute were literally pumped out of each perforation and it's a fairly exact calculation. In other words, you pump the plume up so high it's go to have so many holes or the pressure is going to get higher or you're going to bust something.

So making a calculation that is fairly standard, in other words, it's not a lot of -- lot of guessing and by golly, the only uncertainty is are the perforations round and do I know the size of the hole. If I know that, and I know what the fluid properties were, which I admittedly have to assume that what I got charged for in the invoice and what the treating company said they mixed, they did mix.

But if I know that, then this is a fairly exact calculation and I was able to take that data and calculate that at least thirty holes were stimulated during the frac job, and I cannot find any one interval that I can take five holes away; in other words -- so I know that five holes may have not been treated, and if I take five holes out of any one zone, I still have to have perforations left or there are perforations left in any of the zones, A, B, or C, so based upon that calculation I know that I had to have put some stimulation out each perforation, at least a few perforations in either zone. In other words, there are more than five holes in the A Zone, and there's more than five holes in the B Zone and the C Zone.

Had there been only five holes, then I would have said, aw, maybe the A Zone didn't take the frac, but I feel fairly certain that at least thirty holes did accept frac fluid, which was, you know, we had our sand in, and based on that, they were all treated.

Q Did you drop any ball sealers during the frac to verify that?

A No, sir. I personally do not like dropping ball sealers during a frac job.

Now we did use ball sealers during -- prior to the frac job to help insure that we had a maximum number of perforations open prior to our frac job.

Q How many were open on that basis? How many did you determine were open prior to frac?

A Oh, Frank, I don't remember. I know we did not ball out. This -- this particular well is one that I was not on. Mr. McHugh's engineer was there and I am using the treating company's reports to make my calculations.

I do know they did not ball out and so I can't say that we seated all balls, but the fact you seat all balls doesn't mean that you opened all perforations, either.

So I do not have a ball count for you.

Q You mentioned that, as an earlier witness did, that perhaps the amount of allowable that you're requesting in the application may be too -- too much at this time.

Do you have a figure just -- or your own personal opinion what may be an adequate or appropriate allowable?

A Well, this -- this is something that I've done a lot of work on. In our application at the August hearing one of my exhibits, and I think, I hope some of my testimony reflected, first off, our application was for 200 barrels a day, and one of my exhibits pointed towards the fact that if economics were not a factor and all the operators weren't experienced and, you know, this is a pretty tough time for all operators, so we do have to recognize that pure reservoir mechanics are not all that we need to consider, but if I was to get the reservoir voidage back to where the rate of pressure decline was in the 5 pounds per month, it would, as I recall, now again I'm remembering, but it was in the range of 50 barrels a day.

In order to pure reservoir mechanics, now, again we did not ask for 50. Our application in the August hearing was for 200, and I'm not saying that, you know, I strongly support that, that's just a recognition that -- even that the 800 is high, but it is a number we feel will be better than returning to the 700 or 1400 on a 640-acre basis.

MR. CHAVEZ: That's all I have.

MR. LEMAY: Thank you, Mr. Chavez.

Any additional questions of Mr. Roe?

Do you want some redirect --

MR. KELLAHIN: Yes, sir.

MR. LEMAY: -- or do you want some more questions?

One question I want to ask first. Point of ignorance from the Commission, two of them.

QUESTIONS BY MR. LEMAY:

Q On your Exhibit Number Five, you show an oil plus minimum gas voidage and an oil plus maximum gas voidage.

Can you explain to us the difference in minimum and maximum?

A I'll try. When I -- in all -- the only curve we talked about was the upper curve, which would be the maximum voidage. If all other gas left in the reservoir was a free gas, and it was only free gas in the reservoir, now recognizing that we're dealing with a reservoir and there's oil throughout, and as the pressure comes down some of this gas that's being produced during December did come from a free phase but some of it came out of solution, not only with the oil we produce but from oil that's several miles away from it, or I don't have a distance, but any oil -- with the reservoir communication we've got, a pressure drop in any one well will affect large areas around the well, and so not only do you get the gas that's associated with that barrel of oil but some of the gas that's associated with oil that's adjacent to those barrels that were produced also is produced, and so dependent upon -- and if that's what happens, in other words, if the gas come out of solution, rather out of a free space, in other words, if the gas is occupying a volume and I take it out of the reservoir, that causes a voidage that I would see in the upper curve.

If the gas literally comes form solution of other oil in the reservoir, then the only real voidage that results is the change in the oil formation volume factor, because I took a small part of the gas out; in other words I went from 15 pounds to 12 pounds, so there was a small reduction in pressure and a little bit of gas left. I took that gas out of the reservoir but the real change in volume was just shrinkage in the oil that's still left in the reservoir.

So if the gas came out of solution in that manner, if all of it came out of solution in that manner, that would be the lower line.

If all of it left in a free phase, that would be the upper line. Invariably the real voidage is somewhere between -- because we are getting free gas and we are getting gas that is coming out of solution of the residual oil that's left in the reservoir.

Q So your professional opinion is you're getting both and a realistic line would be somewhere between those two.

A Yes, sir.

Q Thank you.

MR. LEMAY: Additional questions of Mr. Roe?

QUESTIONS BY MR. HUMPHRIES:

A You made a statement at the end that in approximately three years the life of the Gavilan Field as you know it today would end under present circumstances.

A Yes, sir.

Q Am I right in looking at this that the Gavilan Field's inception was 1984?

A The discovery well, which was drilled by Northwest Exploration, was completed in August of 1982, I think, or in that general area.

I have the completion dates listed on the -- my Exhibit Number One.

The actual pool that we're calling Gavilan Mancos Pool was not actually officially recognized until the pool rules were effective, which was March 1st of 1984, and they were for the three year period, which basically brings us here today as one of the cases.

Q With these assumptions that we're discussing and potential implacement of these kinds of recommendations that you made, what would be the life then?

A I'm sorry, I don't think I understood you.

Q Well, you said that as the field is being operated under the August, 1986 order, is that correct --

A Yes, sir.

Q -- that you think perhaps three years is the maximum life.

A Well, there's -- there's a couple of things that could happen that I haven't really accounted for.

The three years comes from just a pure calculation of knowing that the rate pressure is now declining at 30 pounds a month, I know that we have 1250 pounds, roughly, average in the reservoir, and I feel fairly certain that an abandonment pressure, we could argue about what is an abandonment pressure, but it will be in the range of 200 to 250 pounds, so we have roughly 1000 pounds left to produce, and if we're using that at the rate of 30 pounds a month, we've got roughly 33 months.

Q Okay, if we implement the 640-acre with one well optional spacing, 600-to-1 gas/oil ratio, 800 barrels per day per section, what do you think the life of the field would be then?

A Well, if some of the operators take advantage of the benefit of not drilling two wells in a section, which I would hope the company I work for would consider that, and I think we would, because we're high at about a half a million dollar well, and the less of those you can drill and, again, if you extrapolate this out, you're looking at roughly 3-million of additional recovery from the reservoir.

If there's going to be -- right now there's going to be 85 wells; by the end of the life there could conceivably be 100 wells, so you're talking about getting an average of 35,000 barrels of oil per well from this date forward, and you just can't spend a half a million dollars to get that.

So, hopefully, some operators would take advantage of the option to drill one well per section. That would give us -- that would minimize the impact of a lot of additional wells being placed on production.

It won't necessarily extend the life of -- in other words, it won't make this curve any better unless a lot of operators will then go together and form a 640-acre spacing unit and in the instance that the ownership is common between wells, that could happen, and if that does happen, then those operators could at their option produce only the lower gas/oil ratio and produce less of the free gas, and if that did happen, then the life would be extended, but I don't have a time that I can give you; there are so many variables that would affect that.

We're just trying to take a step that will move us towards a direction and primarily I don't like recommending to Mr. Dugan that we go out there and develop our undeveloped acreage one well per 320, knowing that I'm going to average 35,000 barrels per well.

Q If I understand you right, then, on Exhibit Number Five, under a better managed scenario, those curves, those confining curves would flatten out?

A If I had my total say-so, if we were able to -- I hate to use this word,-- but if we were able to unitize, we would be able to change that slope of that curve, yes, sir.

Q What would an optimum curve look like, if that curve flattened out and --

A Well --

Q -- you had the best of all worlds, what would that curve look like?

A For twenty years the unit maintained a rate of pressure decline of about 11 pounds per year.

Q Which unit, the --

A The Canada Ojitos Unit, with pressure maintenance, matching -- attempting to maintain reservoir pressure and produce the reservoir at a rate that approximately matched the gravity drainage rate, the rate of pressure decline, and again I said twenty years, I'm not sure how many years, but the rate of pressure decline was about 11 pounds a year.

Q So approximately a third of what exists today.

A Yes, sir. Now again, to some degree the questions you're asking are better addressed in the work that Richard Dillon did with his model study. If I had my total say-so, we would like to figure out exactly what the gravity drainage rate is and then match reservoir withdrawals to equal that, but under a competitive operation and one well every 320 acres, and the only way an individual operator has to protect his correlative rights, is to drill wells, this curve isn't going to do anything but get worse unless we at least allow the option to drill less wells, which is basically what our application asks for.

It doesn't force anybody to drill less wells; it just gives the individual operators that option.

Q Now, if I undertand right here, these wells are all in the Gavilan Mancos Pool.

A Well, the majority of them are. There are a couple of wells --

Q Yeah, I see the E-6 and the B-9.

A Yes, sir, and then there's the B-32. We -- we don't have as much Gavilan data on here -- I mean the Unit well data on here, although there is more Unit well data that we could have put.

There's quite a bit of pressure data in

Gavilan that's not on this, but it would not serve to add to the plot. It would just confuse things. It's more of the same.

In other words, I did not mean to say that this is a presentation of all of the pressure data we have. This is a representation --

Q I understood that, but there has been an intense effort to maintain pressure in the Canada Ojitos West Puerto Chiquito.

A Yes, sir, and that might explain why Mr. Greer's here today because he's very concerned about what's happened.

Q I understand, but you're talking about a 20 year life in his field and maybe, if I understand you right, a -- well, 22 years at this point --

A Yes, sir.

Q -- and some thing like 6 more years maximum with, as I understood not from your testimony, but other testimony prior to you, that there at least at this point are no plans for any kind of pressure maintenance in what's currently known as the Gavilan Mancos Pool.

A Well, yeah, what you said is right, but the reason that he's had the life, longevity and production that he's had is because he was able to control reservir voidage and he intentionally did that. In other words, for many years the Unit was produced. It -- well, when Dugan Production first became involved in the unit its average production was 600 barrels a day and not because that's all that he could produce. He could produce 30 or 40,000 barrels a day, I would guess. I don't -- have never made an effort to know what the combined productivity of the Unit would be, but there's many wells that, like I say, I know of one that I've looked at that produced 1000 barrels a day with a 4-pound drawdown. The productivity of that well is pretty high.

The controlled rates of reservoir withdrawal is what has resulted in a 22-year life so far in the unit.

Had we had a controlled rate of withdrawal in Gavilan, which we have not, in order for the operators to protect their correlative rights they have to drill their acreage and they have to produce their wells. They really don't have a choice. With the communication that this graph would indicate exists throughout the reservoir, an operator that has undeveloped acreage is -- needs the (not clearly understood.)

QUESTIONS BY MR. LEMAY:

Q I have a question mainly to understand it, since you're going to be the last witness on the first side.

As we come down dip, what's the limiting factor down dip in the Gavilan? Do they have dry holes in the west end of Gavilan?

A No. Right now -- Mr. Ellis was trying to address that a little bit. We haven't really identified the west end of Gavilan, but we know from a personal fairly extensive investigation of what is known as the West Lindrith Gallup-Dakota, we know that when you get into 3 West, Range 3 West, there are Gallup or Mancos wells. It's still Mancos but the people that call if West Lindrith Gallup-Dakota are completing the same thing we're calling the Niobrara interval in Gavilan. It's -- you can correlate it on a log. In the original spacing hearing in 1984 we presented a cross section that tied West Lindrith in to Gavilan and to the Canada Ojitos Unit, but the fractures diminish as we go west, and that's what's going to control the western boundary of our area and right now we have not really identified it, but we feel it's fairly close to where we're at.

Q Must get tight; there's no down dip water?

A No, sir, not that we've observed.

Now, the Mancos does produce water in a down dip area in East Puerto Chiquito, but again, that 's different than what we're dealing with.

Q Well, the point of the question was we're to -- assuming we're to -- we have a three year life based on this -- this current pressure drop, as you identified, but we also, I think, are assuming a fixed number of wells or a fixed amount of acreage that this pressure drop is associated with, if we enlarge the field any more, especially in the down dip side, we're talking about a lesser life, then, aren't we?

A Well, that's our real concern and the basis of our application, is we would like to hold the number of wells that are required to develop the reservoir and try to keep this curve from getting any worse.

Now one thing that I really did not bring in, and there's no way to bring it in this curve, but the lower the pressure gets in Gavilan, the more likely we are to start having an inflow of oil from the east, and so that will give us a longer life but it will also -- it is also affecting what's happening in the Canada Ojitos Unit.

Q Mr. Greer has been known to be a generous person in the past.

A Not this time.

MR. LEMAY: Are there any other questions of the witness? Mr. Kellahin.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Roe, so I understand the direct relationship between the pounds of pressure that are lost, lost on some basis in the Unit as well as Gavilan, you told us that in the Unit Mr. Greer by pressure maintenance is controlling the loss of pressure to 11 pounds per year?

A That is the rate that existed prior to Gavilan being developed, yes.

Q And if we look at your Exhibit Number Five, we see on a yearly basis then, that in Gavilan you're having a pressure loss of 360 pounds.

A Yes, sir, in fact the -- one of my exhibits, the Loddy actually in a ten month period lost 300 pounds, again remembering the Loddy was not in the center of production, it was on the edge of the development that existed at the time.

Q Mr. Pearce had selected out for you to note the miniscule amount of oil production, some three wells in the Unit. In selecting reservoir parameters, Mr. Roe, for the reservoir, would you consider it appropriate to select data from wells that produce a large portion of the oil from that reservoir versus wells that produce such small amounts of the reservoir energy?

A No. It wouldn't be appropriate. What we are trying to do was arrive at numbers that would represent what's going to happen to the reservoir as a whole, and recognizing that there would be areas that wouldn't be exactly simulated but there will also be areas of the reservoir that will have higher, much higher transmissibilities than the ten. So we're trying to look at something that would give us a representative piece of the reservoir.

Q And do you believe the parameters listed on your Exhibit Number Four are reasonable parameters to make that selection upon?

A Yes, I do.

MR. KELLAHIN: I have nothing further.

MR. LEMAY: Additional questions of Mr. Roe.

If not, he may be excused.

MR. KELLAHIN: The proponents, as we've been characterized, Mr. Carr and my clients seek to rest our direct case.

Mr. Carr is our official timekeeper. We are ready to debate the amount of time we have used and the amount of time we have kept track for the opponents and Mr. Carr, I think, has some numbers for you to consider.

MR. CARR: May it please the

Commission, at this time we submit that Greer, Dugan, McHugh, and Sun have used 7 hours and 31 minutes.

In cross examination Mallon, Mesa Grande, and Amoco have used 2 hours and 18 minutes.

Questions from the Commission and others, including Mr. Padilla, is 1 hours and 13 minutes, and we tender back to you 45 minutes today.

Based on that we submit that we are reserving 5 hours and 15 minutes for cross examination and rebuttal.

MR. LOPEZ: Mr. Chairman, that's all well and good as I see it. I concur that we've used 2 hours and 18 minutes and adding the 45 minutes left today, that gives the proponents approximately 3 hours.

We have two more days according to I think the rules of the game established early on and so as I would calculate it. We will be able to go forth with our case and stop sometime after lunch on Thursday leaving at least three hours, that giving the opponents and whoever else whatever necessary time you need to do whatever cross examination.

I think this is one sort of thing just can't be (inaudible) with a logarithmic scale and I think we're just going to have to play it by ear.

MR. LEMAY: I agree. There was

some talk earlier that the proponents or side one would like to reserve some time to recall some witnesses and for that reason they were not using all their cross examination time. Does that sound like something you would all like to do, or part of the game plan?

MR. LOPEZ: We would like to keep some time for surrebuttal (inaudible).

MR. CARR: We're not going to fight over minutes, but we were giving our briefing of where we are.

MR. LOPEZ: So it looks like -- are we going to go forward this afternoon?

MR. LEMAY: That's in your option. If you'd like to, well, we can do that. Sally's on one tape and for that reason she has some concern, but I think she could catch it on her tape.

MR. LOPEZ: Well, it would suit us just as well to start at 8:00 in the morning if it would be better for you.

MR. LEMAY: Since it's your turn at bat, we'll go by your wishes.

MR. LOPEZ: Why don't we start at 8:00, unless that's too hard a hardship on --

MR. LEMAY: I don't believe so. I think we could -- did you say 8:00 or 8:30?

MR. LOPEZ: 8:00 o'clock. 8:15.

MR. KELLAHIN: Mr. Chairman, it's only 17 after 4:00 in the afternoon and we are going to come to Friday and just as sure as God made little green apples we are going to run out of time.

We have sat anxiously waiting for days to understand the opposition's position. Maybe we could have a little clue with an opening statement or something. Don't make us suffer tonight.

MR. LEMAY: As I mentioned yesterday, Mr. Kellahin, with all good soap operas, we always leave them with the good things to happen next time, so tune in tomorrow and you'll find out.

MR. KELLAHIN: It may not be good, Mr. Chairman. There's 45 minutes, it's their nickel, Mr. Chairman, if they want to waste it.

MR. LEMAY: We're accommodating the other side at this point in time.

Since we started early and we're going to start a little earlier tomorrow, I don't see any problem with adjourning early today.

That doesn't mean that we're going to continue to adjourn early. I think once they get on we'll want to push through so we will have some reserve time on Friday, and if we do run into Friday, the way I have it figured right now, there will be some time Friday. I don't see that much direct testimony.

So besides closing arguments we can run over a little on Friday. We're trying to reserve that because we know how -- how these kind of things can keep going on and on without putting time limits.

So unless there's any other objection to the current schedule, we'll adjourn for the day.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true, and correct record of this portion of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR