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

2 April 1987

COMMISSION HEARING

VOLUME 4 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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I N D E X

I N D E X COMT'D

E X H I B I T S

MR. LEMAY: The meeting will now come to order. We shall resume where we left off with the direct testimony of Mr. Hueni by Lopez.

MR. LOPEZ: Thank you, Mr. Chairman.

GREGORY D. HUENI,

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

DIRECT EXAMINATION CONT'D

BY MR. LOPEZ:

Q Mr. Hueni, I think it would be helpful if you would summarize your testimony yesterday and in that connection relate to the summary and recommendations that were distributed at the conclusion of yesterday's hearing.

A Okay. Yesterday we discussed the first phases of our engineering study, which were the description of reservoir performance based on the observed performance data that we had in the field and then we also described the reservoir characteristics that we believe are the characteristics of Gavilan Mancos Pool.

With respect to the discussion yesterday, one of our principal conclusions was that the Gavilan Mancos

Pool produces primarily from the Niobrara A and B intervals as opposed to the C interval, and that was based on the production log surveys as well as the individual tests that were run in the C Zone as well as -- and also in conjunction with the televiewer type information.

One of the other things that we mentioned and we will prove today, is that this production from the Niobrara AB in the Gavilan Mancos Pool is only very weakly connected to the West Puerto Chiquito gas injection area, which we believe produces primarily from the Niobrara C.

We also discussed that the western tier of sections in the West Puerto Chiquito Pool are in pressure communication with the Gavilan Mancos Pool. We reviewed the pressure time and the pressure production characteristics and we noted that wells tended to have similar pressure producing characteristics, and this is one of the reasons we believe that the Gavilan Mancos Pool boundaries in the AB interval should be expanded to include these sections.

We noted that -- that what we believe is occurring in the Gavilan Mancos Pool is a dual porosity system; that we have a high capacity fracture system and we believe that this contains approximately 10 percent of the original oil in place in the pool.

In addition, we have a secondary porosity system, or a matrix porosity system, which really encompasses all the low flow capacity rock, be it the traditional matrix rock, microfractures, or just simply low permeability fractures, and we believe that this poorer quality rock contains approximately 90 percent of the oil in place.

We said that in order to properly understand reservoir performance we have to have a proper interpretation of reservoir characteristics, including fluid properties and with respect to that we said the bubble point pressure was different than what the fluid property test would suggest. We said it was a value of 1660. We said the laboratory test on rock compressibility indicated much higher rock compressibilities than had been traditionally used in the field, and we also said that -- that the transmissibility or permeability thickness product was considerably less than the 10 Darcy feet that has been quoted previously. We believe that for the majority of the field area the average transmissibility is probably less than 400 millidarcy feet.

One of the things that we've noticed, we have the high capacity fracture system, which allows for vertical segregation of gas and oil. On the other hand, the matrix is very low permeability and it is going to produce more by a solution gas drive process.

Finally, at the end of the day, we came

to the conclusion that the original oil in place, based on material balance calculations for the Gavilan Mancos Pool was on the order of 55-million stock tank barrels.

Q Would you now briefly summarize what you are going to be discussing today, and in this connection relate to the rest of the summary?

A Okay. We intend to show that in our reservoir analysis, or that our reservoir analysis indicates that there is a -- there is a weak connection between the Gavilan Mancos Pool and the West Puerto Chiquito gas injection area.

We intend to show that the depletion of the Gavilan Mancos Pool will not have a significant impact on the West Puerto Chiquito gas injection area.

We know the current primary depletion is approximately 6 percent of the oil in place. We believe that ultimate primary depletion will amount to 17 percent of the oil in place and we intend to show why we believe that to be the case.

We have run several sensitivity cases to see if this recovery is rate sensitive and we've found that it's not rate sensitive and we intend to show why that particular phenomenon is true.

We have also run cases investigating the possibility of injection into the Gavilan Mancos Pool.

We've tried two cases, a case where we would inject basically at current reservoir pressures and maintain -- maintain the pressure in the reservoir and we have determined for that case that we would actually instead of improving recovery, we would actually adversely affect current recovery.

We have run a second case where we actually deplete the reservoir to a very low pressure and then we initiate a gas injection program and we find that we do receive some additional improved recovery from -- from that type of operation. In that particular case we increased recovery from about 17 percent to about 20 percent of the oil in place.

We intend to present the economics that are associated with each of those cases.

We have also investigated the concept of correlative rights based on the density of future wells. If we could be assured that we would drill wells of top allowable quality, then we would see that it would be reasonable to drill one well per 640 rather than two wells per 320.

On the other hand, if we end up with limited capacity wells, we will see that two limited capacity wells, each drilled on 320 will significantly out perform or -- or -- well, they'll significantly out perform one well on 640.

Q All right. We're now going to refer to Section 4 in Exhibit Ten, which is entitled Reservoir Analysis.

Yesterday you discussed the reservoir performance, as you just stated, and a description of the reservoir, as well. Could you tell us how that information was used to complete the reservoir analysis that we're going to discuss?

A Okay. The, as you mentioned, Section 4, it does contain the reservoir analysis that we performed. What we have attempted to do is to basically integrate the reservoir characteristics that we previously described and using those characteristics with some modifications actually duplicate the performance that we observed to date in the Gavilan Mancos Pool.

The reservoir analysis that we have done has been done based on a computer simulation model. It's a similar type computer simulation model to the BIP model that was described by Sun. The model that we have used is one that Sun referred to. It is a model from a company called Exploration Consultants, Limited. It's a company in London. The model name is the Eclipse Model. It is a model that we have used extensively in our work in the North Sea. We have used it on dual porosity fields in the North Sea, including the Buchan Field.

Once again, it is, we believe, an appropriate model to use. It provides the reservoir definition that we believe is appropriate to describe the Gavilan Mancos Pool.

Q You indicated that you're attempting ot describe reservoir performance with your reservoir analysis. How did you describe actual field performance, and in this connection would you refer to Figures 52 and 53 under Section 4?

A When we do a modeling study or simulation study, what we are required to do is to put in characteristics for the field or a portion of the field that we're studying, characteristics such as the fluid properties and the permeability, transmissibility, and then what we do is we run the model and we receive output from the model and we then want to compare that output to what we've actually observed in the field. Now if we cannot duplicate what's actually occurred in the field, then we don't have a correct description of the field and we need to modify our understanding.

So what we have presented in Figures 52 and 53 are what we would like to consider as being the average field performance curves. This is actual data. This is data measured in the field.

We plotted it up. Normally we are used to looking at plots, I think, of a producing rate versus time or pressure history versus time, but we realize in the Gavilan Mancos Pool that over a period of time the field has been developed so if we're going to study the field, perhaps a better way of looking at it that removes to some extent the time influence, is to take at particular points in time the measured pressure for the field and the measured GOR for the field, both of which we've actually presented. We've presented a pressure history versus time and we've presented the gas/oil ratio history versus time, and then plot gas/oil ratio versus pressure.

And the curve that we look at in Figure 52 is simply performance of the Gavilan Mancos Pool. We had a period of pressure decline from initial pressures in the vicinity of 1800 psi down to average pressures in the vicinity of 1600 psi when the gas/oil ratio amounted to approximately 1000 stadard cubic feet per stock tank barrel, and, incidentally, that draws my attention, the scale on the lefthand side indicates MCF per stock tank barrel. That should be standard cubic feet per stock tank barrel, and if I forget to update this, I would say that there are going to be several plots that will have that same discrepancy. They should record instead of thousands of cubic feet per stock tank barrel, they record just standard cubic feet per stock tank barrel.

When the reservoir pressure dropped to about 1600 psi, we saw an increase in the gas/oil ratio. That increase is as we have shown on this particular -- on this particular plot. This is factual data. This was what we see for the field.

The only -- the only thing that we might note is that we believe that the pressure, the last two pressure points that are down or that have pressures less than 1400 psi, may not be representative of true average pressure, just based on a calculation of oil in place that we saw, a declining oil in place for those last two pressure points, and once again we just don't believe that we're obtaining from our pressure tests pressures that are representative of true volumetrically average pressure for the reservoir.

Now, Figure 52 is a plot of gas/oil ratio versus pressure.

Figure 53 has on the Y axis both pressure expressed in psi, and gas/oil ratio, and once again it should be expressed in terms of standard cubic feet per stock tank barrel, and those two quantities are plotted versus what we might call fraction of oil in place produced, and to get fraction of oil in place produced we've taken the cumulative oil production, recorded from the producton histories at any point, and we've divided by our estimated oil in place value of 55-milion barrels, and so what we see from the end points of our curves, we are now at a stage of depletion of recovering about 5.7 percent of the oil in place.

Now both Figures 52 and 53 are plots that we would like to believe represent average field conditions. They are based on measured field data. They're presented a little bit differently than we're sometimes used to saying, but they are -- they are what we call actual (not clearly understood.)

MR. LOPEZ: Mr. Chairman, Members of the Commission, I would encourage you, we're getting into some high tech stuff, I can for sure tell you that, and if you want to interrupt the witness to make sure you're staying with him, feel free, and I encourage you to do so.

Q Does the field average trend in GOR versus pressure match individual well trends, and in this connection I would refer you to Figures 54 through 67?

A The answer is that the field average trend represents a composite trend for all the wells, and some wells perform a bit differently; some wells perform more or less in the same manner that the field as a whole is performing. I think from our standpoint we believe that individual wells perform a bit differently because there is variability in the reservoir parameters as suggested by the second derivative map of Mr. Emmendorfer and as suggested by the actual production performance as we've alluded to in terms of variations in producing characteristics.

So what we have done to illustrate this is to take the plot that we constructed for the field average gas/oil ratio versus pressure, and we have then plotted individual plots where we've included on the individual plots individual well performance so that you can obtain a feel for how representative, perhaps, the average field is compared to the individual wells.

We feel that we are going to describe the model that matches average field performance. We believe the model is capable of describing each individual well if we had sufficient time and resources to describe each well, but it needs to pointed out that certain wells perform differently than field average, and that is a reflection once again of different contributions of these dual porosity characteristics.

In Figure 54, I don't intend to look at all of these but for example, 54 is the ET No. 1. The field actual curve is a value shown by the circles. The performance of the ET No. 1 is shown by the squares.

Initially we had gas/oil ratios less than the field average. Then we had an abrupt and sudden increase in gas/oil ratio and pressure of around 1600, and it has actually gone to a value over the value plotted on this scale as indicated by the arrow to the top of the page.

If we turn then to Figure 55, we have a case where -- which is the Fisher No. 2-1 Well, which has performed rather than coming to GOR's in excess of the field average, it's actually stayed at GOR levels under the field average, but in a way you can see that it does parallel the same type of trend in terms of its gas/oil ratio versus pressure performance.

If we turn to Figure 56, we would see then the plot of actual field performance and the plot of the performance for the McHugh Full Sail No. 1 Well, and we would see that in this particular case over a large portion of the GOR pressure history the two wells compare very favorably. So this represents more or less the average that we see in the field.

I don't believe that we necessarily need to look at the other figures. I think it would show once again that in many cases we have similar trends to the field average performance but they tend to be displaced a bit from the actual field average. Some wells deviate from the trend; some, the trends are steeper; some the trends are less steep than the field performance. Once again it indicates the variabiity of the reservoir that we are not dealing with just a simple, homogeneous type system.

Q Have you included under Appendix A the production performance of each and every well in the field?

A Yes, we have. The information that we have included in Appendix A is very similar to the information that Mr. Roe included in his exhibits, which had a detailed production history plot and tabulation for each of the wells in the field.

Q Okay, so in these previous figures that you've just discussed you indicated the GOR versus presssure trends for the field as a whole and for individual wells. Before we turn to the analysis of how the Gavilan Mancos Pool performs, is it necessary to determine its relationship to the historical West Puerto Chiquito Mancos gas injection project, and with respect to that I would ask you to discuss information reflected on Figures 68 through 71.

A Yes, it is. We believe that it is necessary that rather than simply construct a simulation model of the Gavilan Mancos Pool, we have to be sure that whatever happens in the Gavilan Mancos Pool doesn't necessarily have some close relationship to what's occuring in the West Puerto Chiquito gas injection area.

I think it's certainly not the intention of -- well, we just want to insure that we don't have an adverse -- we dont' create an adverse effect on the West Puerto Chiquito Pool.

So what we -- we did before we concluded with our analysis of the Gavilan Mancos Pool itself, we turned our attention to the relationship of Gavilan Mancos Pool to the West Puerto Chiquito Pool.

Figure 68 in our report is the figure that is very similar to one presented by Mr. Greer. It is the initial pressures recorded for various pools along the east side of the San Juan Basin.

On the lefthand scale it records the datum of the pressure measurement, measured feet above sea level, and then along the X axis we have the reported pressure measured in psi, and we have several fields specified on this exhibit. We have the Puerto Chiquito Mancos East. We have the Boulder Pool. We have the Puerto Chiquito Mancos West Pool. We have the Well Canada Ojitos E No. 10. We go now from the top left to the bottom right. We also have the Wild Horse Gallup Pool.

There were some early pressures taken in various wells in the Gavilan Pool. We show them as the Gavilan No. 1, the Rucker Lake No. 2, the Gavilan No. 1-E pressures.

For various reasons we would not necessarily expect an individual pressure survey to be representative of the pool average, so what we have done is we have taken the pressure versus cumulative production history that we looked at yesterday and we basically set an upper bound and a lower bound on that history for the point in time when Gavilan was first discovered, and if you would recall, we said the initial pressure in Gavilan was about 1800 psi, and that is represented by where we say "Gavilan initial pressure", where we show the circle. That is an 1800 psi value.

And then the upper and lower bounds are represented by the bar that goes across the -- across the page.

And what this particular graph shows is that indeed the Gavilan initial pressure is a bit lower than we would have expected it to be were the reservoir not in some sort of pressure communication with -- with other production in the area, and I think the logical place to assume that we would be likely to have pressure communication or possible pressure communication, would be the West Puerto Chiquito gas injection project area.

So having established the fact that the pressure communication may exist, the question then becomes how significant is that communication and what does it mean relative to the depletion of the two pools. And what I'd like to do, then, is to turn next to Figure 69.

Figure 69 is a plot which was presented previously by Mr. Greer in his testimony. This particular plot is the only data that we, unfortunately, have on the pressure history of the Canada Ojitos Unit pressure maintenance area, and what this pressure history is, along the lefthand scale we have the pressures measured at a datum elevation of -90 -- of 1195 feet relative to sea level, and then we have these pressures plotted versus cumulative oil production ranging from zero out to 3-million barrels on the far righthand side of the X axis.

Along this graph Mr. Greer has plotted several individual well pressures and noted the dates on which those well pressures were taken, and he records then the pressure decline initially in the Canada Ojitos Unit area.

And in I believe 1968, injection was commenced in the reservoir, then causing a leveling of pressure within the reservoir. Although the pressure has remained relatively level, I think we see at the -- on the righthand half of the graph the pressure is declining with time and we have assumed, consistent with what Mr. Roe testified, the pressure has declined has declined at a rate of about 10 psi in this pressure maintenance area in the period of time from 1970 where the graph ends until 1982, when the Canada Ojitos Unit -- or when Gavilan Mancos Pool was first discovered and tested in terms of what its pressure was.

And if you recall, that pressure indicated to be about 1800 pounds.

Now from this pressure plot we would note that the initial pressure in Canada Ojitos was about 1625. By 1970 the pressure had dropped down to what appears to be 1280 psi. This represents a pressure decline of about 340 psi that we have observed within the Canada Ojitos Unit in this -- in this time frame.

We add on approximately another 110 psi that may have occurred after 1970 prior to discovery of the Gavilan Mancos area bringing us to a decline in pressure in the Canada Ojitos Unit gas injection area of 450 psi at the time the Gavilan Mancos Pool is discovered.

We noted that the Gavilan Mancos Pool pressure, on the other hand, was drawn down by approximately 80 psi. If we had extremely high transmissibiity between the two, the Gavilan Mancos Pool pressure would have been drawn down similar to the pressure drawdown that's been experienced in the gas injection area.

Now, what that indicates to us is that there is some type of flow restriction between the west Puerto Chiquito gas injection area and the Gavilan Mancos Pool, which produces primarily from the A and B Zones.

To study how severe a flow restriction we would have to put in the area between these two pools, we constructed a simulation model, as we've shown in Figure 70. Figure 70 is the simulation model that we constructed that consisted of five cells. Now when you set out a simulation model, you set out individual cells that represent areas of the field and so we have five cells and Cells 1 and 2 are intended to depict the Gavilan area, including, perhaps, the west tier of sections in the West Puerto Chiquito Field.

Reflecting back to the fact that the production in the syncline area, many of those wells tend to appear to be lower transmissibility and a barrier present to some extent between -- in the syncline area, we have represented the syncline area by Cell No. 3, and then as we move further to the east we have Cells 4 and 5, representing the West Puerto Chiquito Mancos Pool.

The reason the cells are stacked at different heights, or different elevations, is simply that there is some structural relief between the Gavilan Nose area going down into the syncline and then coming back into the West Puerto Chiquito, the east area of West Puerto Chiquito.

Now, what the idea is in the simulation model, is to impose on Cells 4 and 5 over a period of time representing the time period from 1962 through 1982, a pressure drop of approximately 450 psi, based on the preceding observed pressure drop that we looked at in the -- in Figure 69, and then what we want to do is we want to use the transmissibility that we've assigned to the syncline area, we want to vary that until we determine a transimissibility that results in the observed pressure drawdown in the Gavilan Mancos Pool, when it was drilled in 1982, and we said that that pressure drop was about 70 psi.

We made several simulation runs attempting to define what the transmissibility would be in this restricted area, whether it is a syncline area or whether it is some -- some other area. We've used a syncline because that seems reasonable to us, but -- but basically the fact is that we see a restriction somewhere between West Puerto Chiquito gas injection area and Gavilan Mancos Pool.

And when we varied the transmissibility in Cell No. 3, we ended up reducing the transmissibility to a value of about 15 millidarcy feet in that region, and when we reduced that transmissibility in that region, we would see then a 450-pound pressure drop on the righthand side of that cell, and we would see a 70 psi pressure drop on the lefthand side.

So what we're saying is that the restriction has to be on the order of about 15 millidarcy feet in through -- in between the two pools.

Q So does that mean that we put 15 for that "kh =" in Cell 3?

A Where it says "kh = variable", the final result that we came to was a value of about 15, and I think you can see that by comparison the values that we were using for both West Puerto Chiquito area and the Gavilan area were values considerably higher, higher than that number, and in fact the values within Cells, well, 4 and 5 could be still higher than the 400 and 1000 transmissibility values that we've shown here.

It simply says that there has to be some type of restriction in between the two cells and the value that we believe is reasonable to duplicate the performances on the order of 15. We know it's considerably tighter than what's on either side of it.

Q Okay, I'd like you to refer to Figure 71 and explain what this shows.

A Okay. Figure 71 is in part this match that we achieved when we had 15 millidarcy feet in the syncline and then it also reflects how we expect then the behavior to perform in the future in terms of if we deplete the Gavilan Mancos Pool what affect that might have on the east area of West Puerto Chiquito or at least the gas injection area.

Once again we have what appear as four vertical lines on this particular graph, separating the graph up into five different areas.

The westernmost area represents Cells 1 and 2 that we've looked at before and they are intended to represent Gavilan and perhaps the western tier of sections in the West Puerto Chiquito area.

The syncline area is shown and then the next two areas to the right represent the east area of West Puerto Chiquito.

The Y axis is actually oil potential but basically we can consider that to be equivalent to a pressure measured at all points in the system at a common elevation which we've chosen as +900 feet, and at that particular elevation we start off with a pressure in 1962 in each one of the cells that is a pressure of about 1700 psi.

At that point in time the east area of West Puerto Chiquito is place on production and the pressure begins to decline and we show those pressure declines dated September, '62, April of '64, July of '65, and eventually we end up out at January of 1980, and we note, then, that the difference between the pressure in September of '62 and the January of '80 is approximately 450 psi.

And the individual lines that run more or less horizontally across the page represent the pressure in each of the individual cells for each of the individual areas in the field.

And what we see, if we took the January, 1980 pressure and we started following it across, we would see that the pressure would not increase significantly as we go across the east area of West Puerto Chiquito. It would increase quite significantly in the troubh area, or the syncline area, and then it would level off into the Gavilan Mancos Pool, resulting in approximately a 70 psi drawdown in that area.

So this is the basis on which we say we've duplicated performance. We've matched the 450 pound pressure drawdown in the east area of West Puerto Chiquito and we've matched the 70 pound pressure drawdown observed at the time Gavilan was discovered.

Now what we have done in order to study the influence that the Gavilan Mancos Pool will have on the depletion of the gas injection program in West Puerto Chiquito is basically to assume that no pressure drop would occur in the West Puerto Chiquito area. In other words, we have fixed the pressure on the righthand side. No, I don't want to say that.

We have -- we have shut it in the west -- West Puerto Chiquito area, and we have shut in that production so that it basically is not taking any fluid out, and then we continue to produce Gavilan and we see, then, what the withdrawals in Gavilan, what effect that would have on the West Puerto Chiquito pressure history, and I think then you see a whole series of pressure profiles that decline down to a very low pressure in the Gavilan area. In fact it gets down to under 100 psi, and then you see the pressure gradient back through the system, back through the syncline, and into the east -- into the east area of West Puerto Chiquito and you see basically minimal pressure effect on the gas injectin program as a result of drawing the west area of the Gavilan pressure down to a very low value.

And from this we have concluded that the operation of the Gavilan Mancos Pool will not have a significant impact on the West Puerto Chiquito gas injection area.

Q If that's the case, then, what's the best way to deplete the Gavilan Mancos Pool?

A In -- in our study, first we studied to see if there was a relationship between the Gavilan Mancos Pool and the gas injection area of West Puerto Chiquito and we determined that there -- that those two pools can operate separately of each other within the -- within this depletion history that we've studied.

So we then studied the behavior of the Gavilan Mancos Pool and what we are going to see is that after we duplicated Gavilan Mancos Field performance on the average, we studied the various methods of depletion of the pool and we determined that the optimum course of operation and particularly in an economic sense is to simply deplete the field with perhaps at a later point in time some low pressure gas injection.

Q And when you say deplete the field, does that mean under applicable statewide rules?

A Yes, that is correct. We see that -- what we'll be seeing here in a few minutes is that the recovery from this pool is not rate sensitive within the range of rates at which the pool -- the pool is capable of being produced, and therefore we see no reason to have a restricted allowable situation in this pool.

Q And how did you reach this conclusion?

A We reached this conclusion by doing a simulation model study of the Gavilan Mancos Pool.

Q And now, of course, I'd like you to explain that and in that connection would you refer to Figures 72 through 80?

A Okay. We've looked at one simulation model that we constructed relating the Gavilan area to the West Puerto Chiquito area. Now we're looking at a second simulation model that we constructed that was constructed to attempt to explain the performance in the Gavilan Mancos Pool, and similar to the type of model that Sun described, we are analyzing a portion of the reservoir and attempting to duplicate the average field performance characteristics.

Now, the portion of the reservoir that we are studying is basically a 640-acre section of the reservoir and we did not use just a simply square mile representation of the reservoir because we wanted to include wells on 320-acre spacing and so what we did is we took a picture of the reservoir that was a bit elongated and then had a -- well, had a length of about 7500 feet as shown in Figure 72, and a width of approximately 3700 feet, and this would basically model a 640-acre area developed on 320-acre spacing with wells located in northwest and southeast diagonal locations.

This is the planer view looking at the model that we set up. Now what we ran was a cross sectional model and the cross sectional model is represented by the schematic shown in Figure 73.

The cross sectional model consisted of five individual layers describing possible flow out of the Niobrara A, B, and C intervals, as we've shown on the lefthand side of the model.

We used two layers to represent the Niobrara A section. We used two layers to represent the Niobrara B section. We allowed those layers to communicate vertically based on what we saw in the televiewer logs.

We also included a third layer to represent the Niobrara C, which we believe is minimally productive in the Gavilan Mancos area, and as you'll note by the space between the layers, that is shown to indicate that we did not allow communication between the C interval and

and the upper A/B intervals.

The cross sectional model, simulation model, consists of 37 cells in the horizontal dimension and that's what we show by -- as we go across, as we have them numbered and each cell has dimension of about 202 feet.

We have included in the thickness of the model the -- more or less the gross thickness that we might see in the A and B zones as well as in the C zone or something that we would consider representative. It's possible that -- that there is less thickness in each individual zone than what we've shown. The result of that would be simply that rather than having a thick zone with a low porosity, we would have a thinner zone with a higher porosity.

The accuracy of the model is not particular dependent on so much obtaining the right thickness as it is obtaining the right transmissibility, Kh product, and the right phi H, porosity thickness values, so at any rate, this is the model that we set up and what we do with the model, then, is we produce wells at particular rates that we believe are representative of field rates, and we then attempt to match the observed performance that we looked at back in Figures 52 and 53 for the field average, and if we get a good description of the properties, such as the transmissibility, the fluid properties, the rock compressibility, the relative permeability characteristics, then we will be able to duplicate more or less what actually has occurred in the field, and this is a standard by which a model is measured. It's easy to take parameters and stick them into a model and to run the model.

It's very hard to get a model adjusted so that it actually fits actual field performance.

In performing our study we ran somewhere between 80 and 100 different runs using a model similar to this to study the performance of the field. We adjusted several of the parameters in attempting to duplicate field performance. It is not an easy process to actually duplicate the performance and it is only through that process that we feel comfortable with the reservoir properties.

Now what I'd like to show you is the effect of a couple different -- what you do is you assume the make-up of the model. You assume what the reservoir looks like and then you test to see if that make-up conforms to what you actually observed.

And what I'd like to show you is a couple different graphs that show how different types of systems behave, and the first one I'd like to show you is Figure 74.

Once again we are describing the behavior of these systems in terms of how we expect the gas/oil ratio to behave as pressure declines in the reservoir and what we've shown here are three separate model runs. None of these represet what we believe the actual field looks like at this point, but they are -- they are very comparable runs in all of their other parameters, and what I'd like to show you is that this gas/oil ratio trend that we observe versus pressure depends first on the type of porosity we have out in the area, as well as the ability of the gas to segregate within the system, segregate vertically within the system.

So what we have on the far lefthand side is the system -- one of the illustrations that we showed earlier was a fracture system with solution gas drive. We have little bubbles going along with the oil. And that type of system is shown on the far lefthand side. We see a very rapid gas/oil ratio increase with decline in pressure, and in this case the gas is not segregating vertically and this is how we would expect performance to look.

If we have a single porosity system, a fracture system, which has high capacity fractures and the gas segregates to the top of the model, then the gas/oil ratio pressure performance is as shown -- as what we show in the bottom righthand picture.

Now the dual porosity system is a mix of solutiong as drive performance from the matrix and a gas segregation drive in the high capacity fracture system, and inasmuch as that's true, we would expect a dual porosity system to basically represent the area more or less in between these two individual systems. And what we've shown, then, are the results obtained using a dual porosity description of the reservoir where we've set the fracture volume equal to the matrix volume. In other words, we have an equal volume of oil in the fractures; we have an equal volume of oil in the matrix.

Once again the reason that we're showing you this is that we have to look at in terms of actually has occurred in the field is the gas/oil ratio trends and the pressure performance, and these are the pieces of information that people have claimed constitute an emergency situation, so we are trying now to describe the reservoir such that we can match these trends.

So Figure 74 gives us some perspective of how different types of description of the reservoir affects these trends.

Now I'd like to show you one more picture that is intended just to, hopefully, give you a feeling for how these trends are influenced by another parameter and that parameter is the volume of oil that's contained in the fracture versus the volume of oil that's contained in the matrix. And what we've done is set that out as a fraction that we've designated as F. That represents the fracture oil volume compared to the total oil volume, and all of these runs are based on a dual porosity system where we have both types of porosity present.

And what we conclude from this is that the less oil that we contain in the fractures, the steeper is the gas/oil ratio versus pressure performance.

Q You're referring to Figure 75 now?

A Yes, I am. I'm sorry. I am referring to Figure 75.

Q And that fracture, F=0.1 is one-tenth?

A Right. When it's 0.1, that represents a system that has 10 percent of the oil in the fractures and 90 percent of the oil in the matrix.

Now what we're trying to do is more or less generate curves similar to these that we've looked at that we've computed from the model and have them look the same as what we saw in the field, and as I said before, we have made many runs and tried many different combinations, both single porosity systems as well as dual porosity systems, and what we come up with for our best match expressed in terms of the gas/oil ratio versus pressure behavior, is what we show in Figure 76.

In this case we have the actual historical information shown by the squares. We have the information derived from our final history match run shown the triangles.

In general we match up quite well with

the pressure, gas/oil ratio behavior actually observed. We note once again that we believe that the latest pressures are not necessarily representative of average presssure.

Unfortunately, if we have a model with a constant volume of oil in place, there is no way that we could actually match that -- that pressure behavior that actually occurred. It either -- it has to be a dual porosity system or there has to be another explanation for those last two points.

But with the exception of those two points we have a very good mactch on pressure GOR behavior.

If we turn Figure 77, which is obviously misspelled, instead of Figure it's "FUGRUE", we have the match expressed in terms of the observed pressure decline and the gas/oil ratio trends calculated versus fraction of oil in place produced, and once again we have more or less duplicated the pressure decline in the reservoir and we've duplicated the gas/oil ratio trends in the reservoir with our computed answer based on what we have in the simulation model.

Once again, there is no way -- well, there is no way that we can -- well, we've more or less matched those trends.

Now, what I'd like to do next is to show you what the reservoir would look like in terms of the gas content of the individual cells that we just looked at at different points in time, and this is shown on Figure 78. Keep in mind that what we have -- what we're describing is a high capacity fracture system surrounding a low capacity matrix system or tight fracture block system.

What we have here are three different points in time at which we output our computed results. Those times were a time of 180 days; a time of 360 days; and a time of 540 days, and what we have shown then is in the matrix system, if we focus on the very last one, which represents basically the state of depletion that we think we are close to at this point in time, we show the matrix as having approximately 4 percent gas saturation and that is uniform throughout. Each of the matrix blocks has approximately 4 percent gas saturation.

And then as we look down to the fracture blocks, the -- we see then the various layers, the A, B, and C layers on the far lefthand side, and we see the 37 cells across the top of the page. We see that the gas saturation, this is expressed in percentage, is approximately 55 to 60 percent along the top layer of the reservoir, and then the gas saturation goes down to a very low level at the -- at the base of the reservoir, and what this is indicating is that gas is segregating vertically in the fracture system and this is totally consistent with what we have observed in the field through the production control surveys.

Q Would it be helpful to refer back to Figure 28 under Tab 3?

A I think it probably would be. Figure 28 on Tab 3, which was one of the figures that we didn't -- didn't label, it was a schematic of the dual porosity system and it had both red and green coloration to it. What we're looking at here is the exact same type of system that we have now model results computed for.

The various layers, in this case we show, I guess there are six cells, or six matrix blocks in a vertical direction, well, in our model we only have --

Q Greg, I'm not sure everybody is with you yet.

A Sorry. In this schematic we show six sets of matrix blocks in the vertical direction, vertical dimension. In a way, although this is a simplification, we have -- we have five layers and I don't mean to imply that the matrix blocks are of equal dimension necessarily to the layers themselves. The matrix blocks are actually much, much smaller than the individual layers. But what we are picturing if we viewed each of these -- each of these blocks essentially as a layer, we would see that the gas saturation in each of matrix blocks at that point in time that we looked at on the computer output was about 4 percent, so we would have the presence of both the gas, the red dots and the green dots, simultaneously in each of those matrix blocks and that refers to both phases being present.

Then within the high capacity fracture system we would have seen the gas segregate up to the very upper reaches of the reservoir such that we had the gas, high gas saturation at the upper reaches of the reservoir and the low gas saturation at the base of the reservoir.

So the simulation output is basically just a restatement of what we've drawn here conceptually.

Q Okay. Now do you want to continue with Figure 79?

A Well, Figure 79 is the same type of information except instead of showing the gas saturation in the system at different points in time, we've now shown the pressure in the system at different points in time, and if we focus once again on the time period 540 days, we note the average reservoir pressure right to the right of that is stated to be 1,284 psi. If we look at each individual cell in the model, though, and we look at the pressures in those cells, we will see the cells that represent the low capacity matrix are much higher pressure, approximately 13 to 1400 psi than are the cells that represent the fracture system, which are down at 700 to 800 psi.

In other words, to have flow occur from

the matrix into the fracture system, you have to have a pressure difference driving that flow and that pressure difference is what we see on this -- on this particular figure.

Now the final figure that I would like to show with respect to the history map, we've looked at pressure versus gas/oil ratio plots. We've looked at pressure versus fractional oil in place plots, and that, perhaps, doesn't give you as much of a feel for how good the quality of history match is as if we convert this back to a time basis and in Figure 80 we have done this. And what we have done is we have put into the model what is the equivalent of the oil production schedule that you see along the top of the page. In other words, we've input basically into the model the actual historical oil production and what we are computing is the gas oil ratio that we would expect to come from the field.

So if we have the correct description of the field, then we'd get a duplication of gas/oil ratio performance. The actual performance values for gas/oil ratio are shown by the X's that are connected. Our computer values are the values that are shown by the -- by the dots.

This is -- in my experience in simulation, this is an extremely close match to actual observed behavior.

Q Okay. I guess you testified that you

think you got an excellent match.

Now that you have a match, what does this (not clearly understood) do?

A Well, that's right. We, once again, we do believe that we have an excellent match. We believe that we have a description of the reservoir that is indeed valid. It basically describes the reservoir performance. So we feel that is that is the case then we can study how the -- what the appropriate method of depletion of the reservoir is considering different alternative depletion schemes, such as just primary production for gas injection or primary production at various rates.

Q Have you studied the studied the sensitivity of recoveries and producing rates, and in that connection would you explain that with respect to Figure 81?

A Yes, I would. We've taken this model now that represents a 640-acre area, and that 640-acre area contains a volume of approximately 1.5-million barrels.

Now what we've done is we have run the model at flow rates coming from that -- that amount of oil in place that when scaled up to our 55-million barrel oil in place number will result in flow rates that are achievable in the field.

For example, we have -- we estimate there's 55-million barrels of oil in place. We have 1.5-

million barrels in the model and that tells us that we have about 1/36th of the total reservoir volume in the model. So now if we want to run -- if we want to study field depletion at a rate of 3600 barrels a day, then what we take out of our model is a rate of 100 barrels per day.

I think we need to be -- we need to be clear on that, that there is a scaling mechanism that needs to be honored in doing -- in doing this kind of analysis. If instead of taking out of the model 100 barrels a day we take out a rate of let's say 1000 barrels a day out of the model, then that would be the equivalent of withdrawing fluid from the entire reservoir at 36 times that 1000 barrels a day or at a rate of 36,000 barrels.

Now we are going to have some considerable differences with the Sun testimony in terms of the scaling factor that should be applied in studying rate sensitivity.

We have run our model at what we would consider rates that duplicate field performance rates of 3600 barrels a day, which is our current field rate. We have run a case at the equivalent of 7,200 barrels a day, which we believe is approximately the rate that could be achieved if the allowable restrictions were removed, could be achieved for a short period of time in the existing wells, and we've also run our model at twice that rate at an output from the field of 14,400 barrels a day with no gas restrictions whatsoever to determine if within that range of possible producting rates for the field, if there will be any sensitivity of recovery to those kinds of producing rates.

Our three cases which, I guess, really should be labeled on this, on this run, or our three runs, are shown on Figure 81 in terms of pressure versus gas/oil ratio production. Unfortunately we haven't labeled them as -- as nicely as we would like.

The run that is the squares represents 7200 barrels a day.

The runs that -- the run that is the circle is, I believe, 3600 barrels a day.

And the run that is the diamond or the triangle, I'm sorry, represents 14,400 barrels a day.

And what we see on Figure 81 is that we do have some variation in gas/oil ratio versus pressure performance for each of the individual cases. We will see a bit different production characteristics for each of those cases.

But as we turn to Figure 82, which plots pressure as well as gas/oil ratio versus our fractional oil recovery, we see that while we have variations in gas/oil ratio performance, that in terms of the pressure match to fractional oil recovery we end up with basically the same pressure at the same point in recovery for all three cases, indicating that there is no ultimate difference in recovery as a result of producing at these rates.

And in all cases where we terminated the computer run which was at a fairly low pressure of about 250 pounds, we were arriving at that point in the depletion -- depleting life of the reservoir at about 16+ percent recovery. We will have a little additional recovery beyond that point which we didn't include in our computer model, which we estimate might be another one percent.

Now, once again, we've looked at these things in terms of the pressure of the gas/oil ratio plotted versus fraction of oil in place.

What I'd like to do now is look at each individual case plotted on a time basis so you can see what type of flow profile we would expect from the reservoir, and Figure 83 is our first case. It reflects -- Figure 83 we show the oil production history and then we show as a dashed line expected future oil production using our model.

And what we have done in this case is remove the allowable restriction, allow the field to produce at a rate of 7,200 barrels a day, and we see the kind of performance that we have depicted on this -- on this plot.

Now, according to our estimate at this

point in time, based on our economics, the actual rate at which the oil production from a total of 55 wells would become uneconomic would be somewhere in the neighborhood of 250 barrels a day, or the equivalent of about 5 barrels of oil per day per well.

So the line is drawn down, the dashed line is drawn down to a value on the rates scale of 10 to the 2nd, as shown on the lefthand side of the Y axis but really that's a little bit, that's further out in time than we'll be able to produce based on the economics of the situation and it really needs to be terminated a little bit higher at a 250-barrel a day rate, which really eliminates production in about 1996, somewhere in that timeframe.

So what we see is under this case about a 10-year remaining life for the -- for the field as a whole.

Now, if we turn beyond that page we would like to show you what the gas saturation profile looks like at various points in time in the future.

The -- we have once again gas saturation in percentage on this plot shown at various times in the future, representing values for the individual cells that we've evaluated, the matrix, as well as fractures, and what we show, then, if we focus on the bottom portion of the graph, 2,160 days, we see that the matrix, the gas saturation in the matrix has reached a value of approximately 12 percent gas saturation that is uniformly distributed in each of the matrix blocks.

And in the fractures we see that gas segregation has occurred, allowing gas to go to extremely high saturations at the top of the reservoir and once again at the very base of the reservoir in the B zone we have very minimal gas saturations.

So we have had gas segregation occur in the -- in the fracture system, whereas we've had the solution gas drive in the matrix system.

And we do have oil, then, at the base of the reservoir in the lower portion of the fracture system. It's unfortunately a very small volume because we only have 10 percent of our volume to begin with in the fractures, and second, it's also very difficult to get out because of the high gas saturation that's above it. It's very difficult to push that oil out.

We have, then, also shown on Figure 85 the pressure values consistent with that -- that particular valuation that we looked at, the 7200 barrels a day at different points in time. That is just simply presented for documentation sake.

Figure 86 is the performance projection that we have calculated based on a field depletion rate of 3,600 barrels of oil per day, rate versus time. In other words, this is more or less our representation of the continuation of the field as it is today, no additional wells and the allowable restriction is continued. We see that we will be able to maintain on the average that productive rate for another year or two and then once again because of loss of pressure we will suffer a decline in production during that period of time, and then we will go to a production decline and we would reach the 250-barrel a day economic limit for the field somewhere around the end of 1996.

So we might end up prolonging the life of the field by another year by restricting the rate by that -- by the restricted allowable.

The gas saturation and the pressure values at various points in time for that case are presented to complete the documentation in Figures 87 and 88.

And then finally, in Figure 89, we have our final case, which is a case assuming that we allow the field to produce at a rate that really is in excess of the capacity of the field to produce. It's a rate of 14,300 barrels of oil per day. We basically would have to have more transmissibility out in the field than what we've got in the model if that -- if that field is actually going to make 14,300 barrels a day, at least assuming the imposition of a 702-barrel a day top allowable on individual wells.

The production decline that we see, it

starts with a higher rate and declines off more rapidly, and we would reach, then, the 250-barrel a day economic limit sometime at the start of 1995.

Once again the recovery under all three of these curves is essentially identical.

And then once again we completed the documentation for that case with the gas saturation and pressure, pressure tables shown in Figures 90 and 91.

Q So what is your conclusion with respect to the rate sensitivity of the Gavilan Mancos Pool?

A In our opinion there is no rate sensitivity of the Gavilan Mancos Pool within the range of rates that we can reasonably expect from -- from the field as it actually is capable of producing. The main reason from a physical standpoint that this is true is that we are dealing with most of the oil contained in the matrix and the matrix is producing by a solution gas drive and it requires a high pressure differential in order to get that flow out of the matrix and into the fracture system, and so we just don't -- we just don't have the situation where rate sensitivity would be an appropriate -- appropriate concept that we would have to worry about.

Q This opinion of yours differs significantly from that of Sun and therefore would you explain why, and I'd like you to refer back to their Exhibit Eight.

A Yes, I will. Yes, our opinion is different than Sun's opinion and there are really several reasons for this, one of which is the fact that they are using a single porosity model to describe the reservoir.

The second reason is that they are using considerably different reservoir characteristics to describe the reservoir.

We are using a dual porosity system, which we have then taken reservoir characteristics and matched performance with. So we would expect differences for those reasons but one of the other major reasons that we differ in their opinion is that we would not agree with the rate at which they -- with the manner in which they have indicated their rate sensitivity, and focusing specifically on Figure 8, on the line that is right below the X axis, we see that their base case rate at 600-to-1 represents withdrawals from the field in the range of 4,680 barrels a day, and what they have, is they have a model representing 640 acres with 3000 barrels per acre in their model. So they have about 1.9-million barrels of the total field oil production.

So now if we scale that up with 55-million barrels of oil in the reservoir, we would say that the rate at which they are representing when they plot on their -- their graph a value of 4,680, what that corresponds to in terms of the true field withdrawal rate proportional to the oil in place is 25 times that value of 4000 barrels a day for a value in excess of 100,000 barrels a day of withdrawals from the Gavilan Mancos Pool, which is certainly way beyond the ability of the reservoir to produce.

We have studied, we have looked at several single porosity systems before arriving at our dual porosity system. We see the same behavior if you go to extremely high flow rates and even though you have a very high capacity fracture system, if you go to extremely high flow rates, you can cause rate sensitivity, but the kinds of flow rates you have to go to are the equivalent of 100,000 barrels per day out of the field.

The range of rates that we believe when scaled up to actual field performance that are truly representative of the field, really fall to the left of what's shown on their graph.

Q I think you testified earlier that you think at least at the present without removing the allowable restrictions that the field could be capable of producing 7200 barrels of oil per day.

A That is our opinion. I would have to say the information is a bit sketchy on which we base that opinion because it's difficult to fully ascertain the true productive capacities of some of the wells.

We've assumed that perhaps there would be wells that would be capable of giving us more production than that, but we would say that if the 702 allowable is maintained, statewide allowable, then 7200 would be a reasonable estimate.

I believe Mr. Roe indicated that the voidage that could be taken from this resevoir actually could be twice the voidage that it's currently taking and I would offer that as perhaps a similar type opinion.

Q Okay. Mr. Hueni, have you studied the benefits of utilizing a gas injection program with respect to the Gavilan Mancos Pool, and in this connection I'd ask you to refer to Exhibits or Figures 92 ad 93?

A Yes, we have. We have taken the model that we used to match observed performance and then we have assumed that the -- that one of the alternative methods of depleting the reservoir would be to inject gas into the reservoir and in our first case, which we describe as a high pressure gas injection case, we assume that injection begins almost immediately and it maintains a pressure in the order of 1250 psi.

The effect of the gas injection is basically that gas will move through the high capacity fracture system and because we are maintaining the pressure the matrix will basically no longer flow into the high capacity fracture system because there will no longer be a gradient between the -- between the matrix and the fracture system.

The result of this is that the gas will flow very rapidly down the high capacity fracture system to the offsetting wells. We will have early gas breakthrough, and because we'll have to install some fixed amount of injection capacity out there, as we get high gas breakthroughs we either have to shut in wells or cut those wells back, and as a result of that we will -- we will have to restrict oil production, and that's what we show in the years 1988 and '89, is severe restrictions in oil production because of early gas breakthrough.

By the end of 1989 we've reached a producing gas/oil ratio in the neighborhood of 16,000 standard cubic feet per stock tank barrel and at that point in time we elected to terminate the injection project and began blowdown, so we were then able to open the wells up more or less at capacity without any type of gas restriction and so we then had, well, a jump in oil production followed by a blowdown phase of production.

That was our high pressure gas injection case. Once again we have the dashed line extending out to 100 barrels a day. It would actually be terminated somewhere in the vicinity of 250 barrels a day.

The next case is what we call a low pressure gas injection case. What we attempt to do first is get maximum contribution from the tight matrix or tight fracture blocks and to do that we go ahead, return the field to its statewide allowable spacing. We recognize that we are going to have a rapid decline in pressure. We are going to have some increase in GOR in individual wells and certainly field GOR is going to go up a bit, and as a consequence the oil production will then decline off in primary sense, out through 1991, at which point in time we begin injection at a very low reservoir pressure and what we try to do is push out some of that oil that's remaining in the lower part of the fracture system at that point and we do get a little bit of additional recovery in that fashion.

Q Have you prepared an economic evaluation of the various options with relation to the Gavilan Mancos Pool?

A Yes, I have. Before I turn to that I would like to turn to the final page of Section 4, which is Page 4.9. It immediately precedes the blue -- the blue tab.

Q Okay.

A What we have summarized on Page 4.9 are the ultimate recoveries derived from each of the four -- well, from three -- or from four of the five cases that we've just looked at; the ultimate recoveries derived from the 3600 barrel primary depletion case, which is 9.4-million barrels, or 17 percent of the oil in place; the 7200 barrel a day depletion case without -- primary depletion case, which is almost identical, once again 17 percent of the oil in place.

The 3600 barrel oil per day case where we implemented high pressure injection, we suffered a loss in productive capacity but eventually we got back and recovered about 9.6-million barrels of the oil in place, which represents 17.4 percent.

And then the 7200 barrel a day depletion case down to a low pressure followed by low pressure injection, where we recovered an oil in place of 11.1-million barrels, representing 20 percent of the oil in place in the Gavilan Mancos Pool.

That would conclude my comments as to the recoveries.

Q Okay.

MR. LEMAY: Is this a good time to break, Mr. Lopez? Are you through with these exhibits?

MR. LOPEZ: This is a fine time to break.

MR. LEMAY: The commissioner has a meeting, and we'd like to have him present and we'd like to have him present when we go on to the next set of exhibits.

So we'll break for -- let's

take a 20 minute break and be back at five minutes after ten.

(Thereupon a 20 minute recess was taken.)

MR. LEMAY: Mr. Lopez?

MR. LOPEZ: Thank you, Mr. Chairman.

Q Mr. Hueni, have you prepared an economic evaluation of the various options for depletion of the Gavilan Mancos Pool, and if so, would you explain what you did and what conclusions you reached?

A Yes. We have prepared an economic evaluation for the -- for four different depletion cases for the Gavilan Mancos Pool. These are described in Section 5, titled Economics.

As we, well, the input to each of these cases we might review as indicated in the text. On page one we considered four alternative cases. They're labeled 3600 barrel a day field rate, 7200 barrel a day field rate. Both of these are primary depletion.

We evaluated high pressure gas injection economics and low pressure gas injection economics.

In order to get the production flow streams we took the output from our simulation models and we scaled those up to total field scale and we then allowed the flow, the oil flow streams to be terminated at the economic limit of production from the field.

We used in our economic evaluation a cost, some cost numbers and prices that were furnished to us by Mallon indicating a well operating cost of approximately $2500 per well per month.

We used a total of 55 producing field wells. Injection wells, when we had those cases, had a slightly lower operating cost of $1500 per well month.

State revenue was evaluated -- well, state revenue included 4.6 percent ad valorem tax, a severance tax of 3.75 percent of oil sales, and 16 cents per MCF of gas sales, and we included the school and conservation taxes in the ad valorem tax calculation.

Oil prices we evaluated based on $16.00 per barrel. We used a constant price scenario because I think like everybody else, we really don't know what's going to happen to prices.

This -- we also used a price of $1.65 per MCF.

In terms of the interest evaluated, we evaluated 100 percent of the field interest assuming a net revenue interest of 82.5 percent.

Investment requirements for the high

pressure gas injection were about $3.2-million; for the low pressure cased, about $2.1-million.

We have the individual computer runs which were analyzed using a publicly available economics program. It's called the Garrett program, Garrett Grade II program. Those individual economic evaluations are included in Figures 94, 95, 96, and 97 for the four cases. Those individual evaluations show producing rate, both oil and gas. They show the interest factors evaluated, the prices, the revenue streams, the expense streams, the state -- well, the severance tax and ad valorem flow streams, resulting then finally in a net cash flow for each individual case.

Rather than looking at each of the individual figures, if we would refer to 5.3, Page 5.3 of the text, we would see then in summary form the results of our analysis.

We have the remaining oil production for the three cases and the remaining gas production, resulting in an oil -- when added to what we estimate the cumulative recovery to be as of about July 1st, yields the ultimate recoveries we show under each individual case.

We have then the severance tax and the ad valorem tax resulting from each -- each evaluation.

We show the operating cost and the required investment resulting in the bottom of that table in the cumulative cash flow and then reflecting the fact that money has time value, a discounted cash flow value discounted at 10 percent.

Reviewing that final number we note that at current field rates we expect to derive about $60.5-million in net present value from the field. If we return to the statewide field allowable, which is our recommendation, that that increases a bit to $64-million. If we unitize and inject in a high pressure gas situation, we will end up diminishing our cash flow down to about $49-million.

And finally, going to the low pressure case, low pressure injection case, we arrive at a $68.2-million discounted cash flow value.

Q Have you studied the proposal that future development should be based on 640-acre spacing rather than 320-acre spacing?

A Yes, we have studied that proposal.

Q Would you please comment, and in that connection I'd ask you to refer to Figures 98 through 100?

A In order to determine how the proposal relating to future development on 640 acres compared to 320 acres affects correlative rights, we used our computer model. We set it up such that we had two adjoining sections, each of which comprise 640 acres, each of which are given the exact same properties, are given the same oil in place, are given the same transmissibility.

On one 640 acres we drilled two wells spaced on 320's.

On the second 640-acre tract we drill a single well.

That Figure 98 is a schematic of the situation that we're modeling.

We've evaluated two cases. In the first case we have assumed that we drill wells that are -- have high transmissibility. They have high productivity and as a consequence, they will be subject to either the statewide allowable or whatever allowable is imposed on the field production.

We show in Figure 99 for this first case average oil flow rate versus time in days. We have two lines on this. One of -- the line that's defined by the square blocks represents the two wells, each of which were drilled on 320 acres and the third line represents a single well drilled on 640's and that's represented by the triangles.

And we see that basically the two lines are essentially identical through a good portion of the rate/time curve and they finally separate just a little bit after about 2,300 days.

We show in the tabulation on that graph

as a function of time the recovery from two wells versus the recovery from one well and the cumulative oil recovery expressed in thousands of barrels is designated by Np, the Np column, and so we have two columns that are designated in this fashion.

So after 10.5 years if we are able to drill wells that are affected by the top allowable, then we will recover 630,000 barrels compared to 611,000 barrels from the single well. So in this case where we have high capacity, top allowable type wells, we don't see a significant violation of correlative rights between those two wells.

On the other hand, if we structure a case, and there are certainly many different cases that we could envision, but in this particular case what we did is we reduced the oil in place in the given area and we reduced its transmissibility, and we ran the model again such that both wells, that the wells -- that all three wells in the model are limited capacity wells, then what we found was that after 10.5 years for the two wells that were -- that were drilled on the -- each on -- well, that were drilled on the 640-acre section, basically, with 320-acre spacing, we found, and this is shown on Figure 100, if I didn't say that before, we found under the oil production column that those two wells had recovered 248,000 barrels and one well, the one well, the single well on 640 acres, had recovered 186,000 barrels, and I think what this exhibit is trying to illustrate is that when we have capacity type wells it is certainly advantageous to an operator to have more wells on a given 640 in a competitive sense than it is -- than it is to have the neighboring section developed on 640 -- on one well per 640.

So from this we would conclude that to some extent correlative rights will be violated if one well -- if a single well is drilled on 640's versus development on 320-acre spacing.

MR. LYON: Mr. Hueni, where is time zero on these two --

A Time zero, we started our model run from, I believe, the initial conditions, just the initial conditions in the reservoir.

MR. LYON: Thank you.

A One of the reasons we did that is that there, well, there are many -- we just aren't so sure how many top allowable wells we would be able to drill out in that field at this point in time.

Q And referring to your report, Exhibit Ten, did you provide summaries with the back-up figures under each tab and -- and also attach certain appendices thereto, and if so would you explain what's contained in these?

A To document our report we have attempted to explain verbally the work that we've completed in our engineering study. We've attempted to include as many exhibits as possible to explain the conclusions we've arrived at included in -- we've attached in our various appendices.

Appendix A includes the tabulation of production information that we used in reviewing field performance.

Appendix B consists of the Terra Tek Laboratory investigations that we discussed yesterday.

Appendix C presents the fluid property information obtained from the Loddy No. 1 Well, which we subsequently adjusted in doing our engineering study.

And finally, Appendix D contains the data input that we used in our simulation model and the output from our final history match run where we feel that we duplicated actual field performance.

Q Would you now summarize your testimony and provide us with your recommendations?

A Okay. If I could ask you to turn to the summary and recommendations.

We have summarized in writing our -- the summary conclusions that we reached and the recommendations that result from those conclusions.

We've already discussed that we believe that the Gavilan Mancos Pool is primarily an A and B interval producing pool. We believe that it is only weakly connected to the east area of the West Puerto Chiquito gas injection area and we believe that that is produced primarily from the Niobrara C.

We have shown to our satisfaction the primary depletion of the Gavilan Mancos Pool, that it's not going to affect the gas injection operations in the West Puerto Chiquito Pool.

We believe that the western tier of sections in the West Puerto Chiquito Pool appear to be in good pressure communication with the Gavilan Mancos Pool and therefore should be included in the Gavilan Mancos Pool proper.

We believe that the rock characteristics of the Gavilan Mancos Pool are those of a dual porosity system. They are -- that is what's been described previously in previous descriptions of the reservoir. It is consistent with reservoir performance and it's consistent with all of the testing information that we have available, and we estimate that only about 10 percent of the oil volume actually resides in the high capacity fracture system with the low capacity fracture system containing the remaining 90 percent.

We have come to some conclusions regarding reservoir characteristics that are based on laboratory tests and which are once again consistet with actual observed field performance.

We believe that within the fracture system we are seeing gas segregation and within the matrix system we are seeing basically solution gas drive or pressure depletion.

We are depleting a volume of oil that's estimated to be about 55-million stock tank barrels. We've recovered about 6 percent of that in place volume already. We have suffered, obviously, a pressure decline and we believe that is to be expected.

We see the optimum course for operation of the field, well, we see that under primary recovery that we will recover about 17 percent of the oil in place through just primary means. We do not see this as being rate sensitive within the range of rates that is really possible to achieve in the Gavilan Mancos Field.

We would not recommend high pressure gas injection for the simple reason that we would fear that channeling would occur, very rapid channeling. Wells would go to high gas/oil ratios in a very short period of time and we would then end up with a detrimental effect on field possibility.

We see there is some potential for low pressure gas injection operations. We do not believe that those are going to be needed for another four to five years. Basically we need to go primarily through the pressure depletion stage of the Gavilan Mancos Pool.

We see correlative rights problems if future drilling is limited to 640-acre spacing since wells are not able to -- capacity wells are not able to compete equally, two wells on 640 versus one well on 640.

We would see a potential correlative rights violation in that case.

These are our summary conclusions. The recommendations that follow from that it would seem to us would be that the Gavilan Mancos Pool would be extended to include the western tier, and it shows on our recommendation "tiers" but it really should just read western tier of sections, in the western -- in the West Puerto Chiquito Pool.

We would recommend continue primary depletion of the Gavilan Mancos Pool. Specifically we would not recommend any kind of unitization and gas injection program.

We would recommend returning to -- the allowable rates to the 320-acre statewide spacing allowable of 702 barrels a day. Any type of restricted rated below that certainly are going to reduce the profitability of the field and without a doubt also redistribute remanining reserves on which there is no basis for that redistribution.

And finally, we see that the well spacing should be maintained at 320 acres in order to protect the correlative rights of all owners in the Gavilan Pool.

Q Was Exhibit Ten prepared by you and under your supervision?

A Yes, it was.

MR. LOPEZ: Mr. Chairman, at this time I would like to offer Exhibit Ten into evidence.

MR. LEMAY: The exhibits will be admitted into evidence without objection.

MR. LOPEZ: This concludes our direct testimony for Mr. Hueni.

MR. LEMAY: Thank you, Mr. Lopez.

Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Hueni, I don't even pretend to understand what you reservoir engineers do with reservoir simulation. Mr. Faulhaber yesterday characterized one of my questions as simple minded. I'm sure some of mine now are going to be simple minded.

If you'll help me, though, in understanding what you've done by giving me a short, concise answer and when you can give me a yes or no answer so that in my own particular way I can understand what you've done.

A Okay.

Q My style is certainly different from Mr. Lopez' style. I would like a simple answer that I could understand, is that all right?

A If it's possible I will give you a simple answer.

Q I'll do my best to keep it simple.

A Okay.

Q Did you review your August testimony before the Commission in preparing for your testimony this week?

A No, it did not.

Q You quoted a portion of your testimony from the August hearing yesterday when you discussed that in terms of the thickness of the reservoir that you had used in certain of your calculations and assumptions. Do you remember that testimony?

A Yes, I do.

Q In the August hearing, Mr. Hueni, was it your testimony that based upon your studies up to that point, that in the Gavilan, the Gavilan Mancos area, the solution gas/oil ratio was in the area of about 646 cubic feet of gas to one barrel of oil?

A I believe that what you're asking is was the initial solution gas/oil ratio in that range. Is that correct?

Q Yes, sir.

A I believe in the August hearing that that is what we were (unclear).

Q Am I correct in remembering that in the August hearing you testified that the bubble point pressure in the Gavilan Mancos of 1,770 pounds psia, I guess, is that right --

A That's correct.

Q All right, was the number that you felt gave you the best performance match when you testified then.

A Yes, that's correct.

Q Did I recall that correctly?

A Yes, you did.

Q Yuu have testified, I believe, yesterday about the bubble point pressure that you find in the Gavilan Mancos based upon your studies now and what is that number now?

A The number that believe is most consistent with reservoir performance is 1,660 psia.

Q In August I believe that you testified that in your opinion the reservoir is operating under a secondary gas cap drive with gas migrating only in the vertical direction. Was that not your testimony?

A Yes, that's correct.

Q And now you no longer hold that opinion.

A No, that's not correct. I think we need to explain at this point.

Q I'll give you a chance in a minute to explain that. Let me go through --

MR. LOPEZ: Mr. Chairman, I think while he's asking the question the witness has every right to explain that.

MR. LEMAY: I think he does, too. Mr. Kellahin, he can address that and you can redirect the question to get the point you want to make. The yes and no answers are difficult when you're -- there's a reason for it and I think we've always allowed some explanation.

MR. KELLAHIN: My upbringing tells me the District Court rules are different, Mr. Chairman, but I'll abide by your decision.

MR. LEMAY: We are very casual here, Mr. Kellahin, and try and get the answers from the witnesses without the strictness of the District Court.

Q Let me start over so that you and I are on the same wave length.

Based upon your studies in August, your testimony was that your opinion about the reservoir is that this was a reservoir that the drive mechanism, the primary drive mechanism, was a result of secondary gas expansion. Did I characterize that correctly?

A Not really.

Q All right. In August your material balance projections based upon a solution gas drive modeling calculated a higher gas/oil ratio than the actual gas/oil ratio for field performance, is that not correct?

A I would like to explain that. Would that be (unclear)?

Q Yes.

A The work that we did in the August hearing was based on -- was certainly not based on a simulation study of the field. It was also not based on certain detail studies that we have completed since that time.

The models that we used in the August hearing indicated to us simply that based on the observed field gas/oil ratio behavior that that field gas/oil ratio behavior was not indicative of a reservoir performing as a solution gas/drive reservoir because the actual gas/oil ratios that we observed in the field were not the sharp, sharply increasing gas/oil ratios that we would expect from a solution gas drive reservoir.

Q Having made that explanation, I believe the answer to my question is yes?

A No, I don't think that's true.

Q We'll try again. The actual gas/oil ratios for field performance were lower than the gas/oil ratios that you predicted using your material balance calculations of the reservoir.

A They were lower than what would be predicted were the reservoir operating as a solution gas drive reservoir and that is one of the reasons we indicated that the reservoir was not performing as a solution gas drive reservoir.

Q In your August testimony you testified that the interference testing that Mr. Greer conducted provides information only about the region between the wells on the interference test. Is that a correct statment?

A That's principally correct.

Q And that is still your opinion now?

A Our opinion now is that probably with the dual porosity system that the conditions that are necessary for proper interpretation of an interference test were not met so that any results coming therefrom are probably not valid.

Q Instead of the interference test data, you have put greater emphasis on the pressure build-up data?

A We have put dual emphasis on the pressure build-up data together with the actual flow capacity data.

Q The results from the different data are dissimilar, are they not?

A They are certainly not as dissimilar as the results comparing those two values to multiple Darcy feet permeability.

Q In making your calculation in August of the permeability, the average permeability in the reservoir for the Gavilan Mancos, you used a thickness of 600 feet in making your calculation, did you not?

A Yes. As we explained, we used 600 feet in order to arrive at a minimum permeability value so that when we calculated the rate of gas segregation we would have perhaps the most pessimistic case so that we wouldn't over-state the rate at which the field could be produced and pro-duced without (unclear).

Q In August you testified that in your opinion the statewide gas/oil ratio of 2000-to-1 should be reduced to the solution gas/oil ratio in the reservoir, which was approximately 646 cubic feet of gas to one barrel of oil. Was that not your testimony?

A I believe that -- that was one of the re-commendations, yes.

Q And in your August testimony you concluded that at least the reservoir was rate sensitive insofar as controlling or limiting the gas withdrawals from the reservoir to that approximate solution gas/oil ratio.

A I'm sorry, would you repeat that question?

Q Yes, sir. Today you have told us the reservoir is not rate sensitive at the rates that you have modeled. My question is that in August under your hypothesis then of the reservoir the only justification for the -- the primary justification for reducing the gas/oil ratio down to the solution gas/oil ratio is because the reservoir is rate sensitive.

A We are still -- if you were to produce that reservoir as we have it today at extremely high rates, it would demonstrate rate sensitivity as well, but one of the points that we were making, and we've confirmed that with model studies, but one of the points that we were making within the range of rates that are actually achievable within the Gavilan Mancos Pool, that is not going to be the case.

Q I'd like to discuss with you a moment the structural dip in the Gavilan Mancos. In August, am I correct in understanding that it was your opinion that due to the absence of significant structural dip gas segregates to the top of the formation but will not move laterally across the field. Was that one of your conclusions in August?

A That was one of our conclusions, yes.

Q In addition did you not also conclude in August that the pressure production data indicates a reasonable value of original oil in place of 100-million barrels?

A We indicated that using a conventional rock compressibility value that that was -- that was true. We indicated with potentially a higher rock compressibility value that number would be reduced significantly.

Q And as conclusion 11 for the August hearing, did you not conclude that comparison of predicted solution gas drive performance to actual data indicates the reservoir is not a solution gas drive reservoir but is behaving as a gas cap expansion reservoir?

A I suspect gas segregation would have been a better word for it but I don't dispute the gas cap expansion.

Q This morning when you were talking about the computer simulation of the reservoirs, in describing Exhibit 77, in which you talked about the simulation of the reservoir and the match to field performance, in response to one of Mr. Lopez' questions, you began your comment by saying, "There is no way --" and then you paused and then you said, "we can" and then you paused again and then you said, "Well, there is" and then you said, "We got a good history match." What were you trying to say, Mr. Hueni?

A I apologize for the confusion I've created there.

MR. LEMAY: Excuse me, what exhibit are we referring to?

MR. KELLAHIN: 77. Figure 77, Mr. Chairman. Perhaps not specifically that figure but it was comments directed to the history match based upon field performance.

A Yes. I appreciate your question. I hesitated to say what I was about to say for fear of confusing the entire group here, but I'll --

Q Perhaps you'll go ahead now. It won't matter.

A Okay, then that's no problem. What we are saying is that if we can match reservoir withdrawals as we feel that we have matched quite closely based on the gas/oil ratio trend, the computed versus the actual, then we are taking the correct amount of voidage out of the reservoir.

The oil in place number is a fixed value, should be a fixed value and therefore by material balance principles, which are certainly honored within a computer simulation model, as well, the pressure should be consistent throughout the entire -- in other words, if you can match the voidage exactly, or reasonably close, then you would expect the pressure match should be reasonably close throughout.

The point that I was about to make on Figure 77 was that the voidage match is close throughout and that the pressure match is close except for the last two points, and by material balance principles, that is not possible; therefore we conclude most likely that the pressure information is in error.

Now did that help? I'm sorry.

Q Yes, sir, it sure did.

Do I now finally have a complete book of all your conclusions, your study, your reservoir analysis for this reservoir, or am I missing yet something from this book?

A I don't know.

Q I can read this book the way it is presented in evidence and have a complete understanding of your hypothesis and how you've modeled and simulated the reservoir?

A The book was intended not strictly for the hearing but it was intended to report to all the people that commissioned the study the approach that we used and the results that we obtained.

Q Without leading me through the book, Mr. Hueni, can I determine from examination of the book that we have information by which we can understand and know all the reservoir parameters and assumptions that you have put into the model?

A I believe that you have the information on the case that we -- that we ended up with for our history match case.

We included as Appendix B the simulation input for that particular run and then the output resulting therefrom.

Q In reference to Appendix D, do those parameters and assumptions represent the data after the match with reservoir performance?

A They represent the data that was used in obtaining the match.

Q Do we have all the data that was used after the match so that we know what parameters you have adjusted in order to get the match?

A I'm afraid your sequence of questions is out of order. We don't adjust the parameters after the match . We adjust the parameters before the match and that's in fact how we obtained the match, and you have, by adding them to your input, you will have values then for the -- for all, for the descriptive parameters that were used in the model itself to obtain the match.

Q That is the point I want to focus on, is the parameters.

What was the matrix permeability that you used?

A The matrix permeability was assigned at a ratio to the total permeability as being 0.001th of the -- of the fracture permeability, of the high capacity fracture system permeability.

Q Was that transmissibility number held constant -- held constant, or did you vary it?

A We have made several runs with transmissibilities ranging from 30 milllidarcy feet up to 10,000 millidarcy feet.

Q I gave you the wrong question. It's for that particular run --

A Oh, yes, it's --

Q -- to simulate the performance you held that value for permeability constant.

A Permeability is normally invariable. We did attempt, we did make some runs with what we call pressure sensitive permeability and we found no substantial impact.

Q But the one we have here to understand is where you held the permeability constant for that purpose.

A Yes, that's correct.

Q When we look at the fracture permeability, what number was used?

A We have, once again, in the final run we are using a value of 400 millidarcy feet. We have analyzed several runs ranging from 30 millidarcy feet to 10,000 millidarcy feet.

Q When we look at the matrix, what was the matrix porosity value used?

A The matrix porosity value, let me explain how we did this, is that we -- we assigned -- we calculated something that we felt was a reasonable value of oil in place in a 640-acre area, and I think we were using a value of about 1.5-million barrels.

We recognize that in individual tracts, that the oil in place may be substantially higher or substantially lower; in fact, more likely substantially lower than what we show here.

By knowing the number of the volume in a 640-acre area, we can determine the porosity thickness that is appropriate to use in that area.

Now, at that point we combine those two values. If we use a thickness value of 100 feet, we use half the porosity that we would use if we used a thickness value of 50 feet. So you cannot separate in our model, even though I can tell you what the porosity in the model is, you cannot divorce the porosity value that's in the model from the thickness value that's used in the model, but I can tell you, in fact it is in the input data, what the porosity value is.

Q Let me go back to the fracture permeability value that was used. You gave me 400 millidarcies, I believe. That's a Kh value.

A 400 millidarcy feet, that's correct.

Q Yes, and what did you use for K?

A We have the same problem here, that we are not able to divorce the -- we cannot "de-couple" the transmissibility obtained from a pressure build-up test or from a flow capacity analysis without knowing accurately the thickness. So if -- for the values of thickness that we use, we could calculate a permeability. On the other hand, if we used smaller values of thickness, we would have had a higher permeability, but I can tell you -- well, once again, the permeability number is contained in the input.

Q It's in the data here and if I --

A Yes, it is.

Q -- want to find out K I can look in the book and find it.

A Right. I would assume that one of your experts could find that out.

Q Let's -- let's have you do that for me.

A Okay. You turn to Appendix D. If you would turn to Appendix D, to -- the first sheet is labeled Input Data for Final History Match Run.

Q Okay.

A Okay. Now you need to know what the thickness is first that we've used in each of our cells. The thickness values are shown just about in the middle of the page. There are some hyphens and we show dZ. Okay, the dZ values, then, 32.5 represents 32.5 feet. That is for Layer 1. The same value applied for Layer 2. The 42.5 feet applied to Layer 3 and 4, and 120 feet applied to Layer 5, which Layer 5 is representing the C Zone.

The permeability that we used, once again, has to viewed in conjunction with the thickness value and the permeability value that we used as shown there for the fracture system was 2.53 millidarcies.

So what we -- what we have to do is we have to sum up the H values, multiply them by 2.5 to arrive at the transmissibility that was again put into the model.

Now, also on that sheet you would see the porosity values shown further down. The porosity values for the -- let's see, the porosity values for the matrix are .26 percent, or no, I'm -- yeah, .26 percent .00255, and then that is -- I take that back. That .0255 represents the total porosity which is then multiplied later on by .9 to represent the matrix and then multiplied by .1 to represent the fracture system porosity.

Q Thank you very much. In understanding the information that was inputted into the model so we can simulate the reservoir, let me next ask you what initial saturations for oil, gas, and water were used?

A We, in our model, used an oil/gas model. The water phase was not included to reduce the computational time and expense inasmuch as the water phase we would consider to be basically immobile.

Q When we talked about the Sun computer model on Tuesday, we talked about dip. Did you apply any dip or structure to your model?

A The final match runs are on zero dip. We have several runs we can show or are prepared to show that show dips up to one degree with no variation in our conclusions.

Q I was interested in what the final match was.

A The final match was based on zero degree dip.

Q What matrix block size did you use, Mr. Hueni?

A Matrix block size is not specifically --

is not specifically described in the model (unclear.)

Q You would have to assume a number, then, if it's not specifically described. What number did you assume?

A You can't -- no, that's -- that is not how the dual porosity works.

You input characteristics for the model that -- that -- well --

Q All right, if you don't do it, then what is the matrix-fracture exchange transmissibility?

A Okay. We've got values in the model -- let's see, let's see if I can explain this.

I'm going to read to you so that you'll --

Q I need all the help I can get.

A -- have it directly out of the model as to how they use this.

The matrix-fracture coupling transmissibility term which exists between each cell of the matrix grid and the corresponding cell in the fracture grid are proportional to the cell block volume, being of the form transmissibility, TR is equal to a Darcy constant, which I don't have in front of me right now what that value is, times permeability of the matrix blocks, which may or may not be directional, times the volume of the cell block, which is not the pore volume having no porosity factor, and sigma is a factor of dimensionality. The value of sigma is shown in the computer output as point -- well, it's shown on the computer input data sheet as being 0004.

Now once again, you need to be careful to couple all of the values that we are using for sigma for proportionality constants and things such as that, together with the ratio of permeability, matrix permeability to fracture permeability, and it's certainly not a -- it's not a simple matter. I'm just saying that when we have a value of sigma it has to be looked at in relationship to values that we have of the relationship of matrix to fracture permeability, as well.

Q What was the pore volume in the A matrix block?

A In the A matrix block?

Q In a --

A Or in one matrix block. I don't have that number in front of me. Certainly your experts can calculate that based on the dimensions of the cells that we show on the input data sheet, the porosity, and the fluid properties, all the information is there.

Q How many phases are in this model, Mr. Hueni?

A There are two phases, oil and gas.

Q In the two-phase model that you've used, what gas/oil capillary pressure data did you use for the matrix?

A We did not have any gas/oil capillary pressure test information to use.

Q You didn't have any data. Did you make any assumptions or use any number?

A No. I don't believe that there's a great deal of guidance on gas/oil capillary pressure curves and low peremability matrix.

I would also, one of the reasons that I'd point out, also, that we didn't do that, if you would like me to, is simply that what we consider to be the matrix component is not a simple intergranular matrix such as we normally deal with.

We envision it as consisting of a low capacity fracture system. We consider it to also include microfractures. We consider it also to include intergranular porosity in the classical sense, and we do not particularly feel that we have a single system for which we would be willing to -- to use (not clear).

Q In making these judgements as an engineer and putting various parameters in the model then for -- for that particular value or number you would assume zero, I guess?

A Well, we assume that there is no capillary pressure forces.

Q Okay. Describe for me for a point of information, Mr. Hueni, how the program calculates the flow to the fracture.

Perhaps you could start off by simply -- let me help you a little bit.

What -- what type of method did you use, psuedo steady state, unsteady state? That's the kind of area I'm trying ot understand.

A The program is fully implicit in its analysis. It basically reflects, as I understand it, and I have to admit I have not looked at the code; I don't have access to the code of this model and it's a commercially available model. I would believe that it would represent a transient condition in the matrix inasmuch as we take a variety of different time steps.

Q In dealing with this model I would assume that it has to be one or the other. It either has to assume or use a pseudo steady state or it's an unsteady state. Are there any other choices for this model?

A I would be hard pressed to say one way or the other. I'm not sure. I would guess -- no, I'm not going to guess because I don't know how the model is coded internally.

I would be happy to provide the documentation, though, for the dual porosity calculations in the model.

Q That would be very helpful and I would appreciate that. Do you have that available with you here in Santa Fe?

A I think I do. I think I do.

Q Maybe at the next break you could share that with us.

A Yes.

Q Let's go back to the history match for a moment.

You've talked about, and I think Mr. Lopez characterized for you the degree to which the reservoir simulation matched field performance was excellent.

A I characterized it as excellent.

Q Is this match unique?

A That is not a yes or no answer.

Q Well, let's start with the finding unique. How was -- that's a word of art, I think, with you reservoir simulators. What does that mean?

A A match is done to a -- any match is not going to completely duplicate performance, so it's all degrees to which you duplicate performance.

Now this is an excellent match inasmuch as it does duplicate the actual performance and it is unique in the sense that we have run approximately 100 runs and did not come anywhere close to duplicating performance without -- with other systems, or we didn't come nearly as close.

Now if you ask are there other possible combinations, I think any engineer would have to admit that there are conceivably other possible combinations, but none of which appear to us to be reasonable and consistent with the reservoir characterization that we have, and that's important.

The ultimate -- perhaps one of the greatest strengths, I think, to our report is the fact that it is consistent.

Q You've anticipated my next question and I'll simply paraphrase what I think was your answer. Then this is not the only set of assumed and calculated reservoir parameters into the model by which you can history match the reservoir.

A That's right, and that's why we've presented all the parameters in our report, so that you would know exactly what we used.

Q Were there any constraining rates used in your history match?

A Yes. We attempted to keep our -- in individual runs we attempted -- well, we did keep the cross sectional model output at a particular value for at least as long as it would maintain that value.

For example, we are running at -- we have a model that contains 1.5-million barrels of oil in that model, and that represents -- that represents slightly under 3 percent of the 55-million barrels in place.

So what we do is we take 3 percent times the field rate, which is, let's say, at a particular point in time maybe around 3600 barrels a day, that gives us a 100 barrel a day rate.

So in this particular case we would run our model on a 100 barrel a day rate because we felt that was the appropriate scale down version from the actual field.

That, incidentally, is one --

Q Excuse me, let me clarify something. Did you hold thatd -- that rate constant?

A We held the rate constant for as long as it would be constant under the Kh values that we had in there, but I need to say that this is one of the reasons that we didn't plot rate versus time. That's why we've presented all of our plots as a function of fractional oil in place, because the Gavilan Pool has been developed over a period of time within those wells coming on, and the cross sectional area doesn't have any real method of representing that.

Q What was the lowest daily oil producing rates at which you held the model to -- and I forgot what the number was? You said you ran was it 100 barrels a day?

A Well, 100 barrels a day translates in our model to about 3,600 barrels a day actual field performance.

Q In making the comparison between what you've done and what Sun has done, did you run the model at a rate below the statewide allowable of 702 barrels a day, using a 2000-to-1 gas/oil ratio on 320 acres?

A By that 100 barrel a day case, the 3,600 barrel a day field case is in line with what the field actually produces under the restricted allowable situation.

Q And that assumes one well on a 320 or --

A Yes, it has one well per 320.

Q I think it's clear, the lowest rate case you used was equivalent to the top allowable that the state imposes for the Gavilan Mancos in the absence of the special reduction order.

A You're saying that the lowest field rate we evaluated was 3,600 barrels a day?

Q Yes.

A Is that what you're trying to say?

Q Yes.

A Yes, that would be correct.

Q And we didn't -- you didn't model any rates lower than that?

A I could explain to you, if you'd like, why we didn't.

Q My question is whether you did.

A Okay.

Q And you've said it's no.

A No.

Q All right. Just finally now, Mr. Hueni, during the matching, when we take the model and you've got the assumptions you've made and you've got the average of the parameters that you've taken from the Gavilan Mancos, you've put all that into the program and you have made your history match with reservoir performance.

Can you check off for me the things that you adjusted or changed in order to make the history match?

A I can check off some of the things.

Q That would be helpful.

A Okay. Things that immediately come to mind, we ran -- we ran dual porosity models and we ran single porosity models representing strictly a fractured system. Okay, so that's -- that's one of the things.

We also ran different models representing different sets of fluid properties, basically three sets of fluid properties.

First the bubble point set of pressure fluid properties ran 1500 psi. We ran the 1770 psi, and then we ended up using the 1,660 psi case, and we ran runs with those.

We ran runs that varied in terms of the transmissibility from 30 millidarcy feet up to as high as 10,000 millidarcy feet.

We ran different runs with different rock compressibility values, in the range of, I believe, I'm not sure that we ever went under 50, but I think we were -- we ended up with 100.

We ran different runs assuming different degrees of vertical communication with the ratio of vertical permeability to horizontal permeability, ranging from zero vertical communication to a value of .1 to a value of 1.0. The finally history match run has a vertical permeability to horizontal permeability ratio of .1. In other words, vertical permeability is one tenth of what the horizontal permeability is. Once again we felt that was a conservative factor.

Let's see, we ran -- we ran different cases, of course, with different rates and I can't recall any others we ran. Oh, I take that back. We did run under the dual porosity model, we evaluated various values of the fracture storage compared to the total storage in the system, and we ran various runss testing the response to various values of the matrix, the fracture transmissibility connecting coupling ratio.

Q When you ran your major model of the Gavilan Mancos reservoir, were you using your dual porosity system model?

A When we ran our major model, what do you mean by major model?

Q Well, you have identified for us the Figure 70, I think it is, where it's labeled the Gavilan Mancos/Canada Ojitos Model.

A The -- this particular model was run as a single porosity system.

Q That was not run as a dual porosity system.

A No, it was not. We did not feel that it was necessary.

Q Looking at Figure 70, which you have before you, what reservoir volumes were used in the cells?

A I don't have that information in front of me. I would have to --

Q We don't have the oil in place number for that?

A I don't.

Q Perhaps you could provide that to me at a break if it's available.

A If it's available I'll provide it to you.

Q Am I correct in understanding that the conclusions you have reached about this reservoir are based upon the results that you have seen from the reservoir simulation of the reservoir?

A It is based, it is a combination of what we have seen from the reservoir simulation in conjunction with the physical evidence that we described under reservoir performance and reservoir description.

Q The simulation of the reservoir using the model is dependent upon the parameters and assumptions you program into that model.

A That's right, you have to have something you can put into the model, yes.

Q The parameters and assumptions that you made yesterday that went into the model I understand were an averaging of those parameters among wells in the Gavilan Mancos Pool as well as the Canada Ojitos Pool?

A They represented reasonable values that we considered representative of the pool.

Q Where you and the Sun reservoir engineer disagree, then, is in primarily the selection of the parameters, the assumptions that are made, and what wells are selected or what data is selected by which you average and then input those numbers into the model.

A Well, we differ, we differ in the type of model that we use. We differ in the characteristics that we have attributed to the Gavilan Mancos Pool that we consider representative of the pool and in terms of the ultimate results that come out, we differ in terms of the method used to scale up those results to reflect total field performance.

Q Each of you has selected a different model of program software for selection. You've used your judgment about it and I assume Mr. Dillon did his, that's the difference.

A We would hope, although models do tend to give somewhat different results, different models do, we would hope that we were both using credible models, so we would end up with somewhat similar answers.

Q Am I correct, then, in understanding my simple way that the reason you can get such varying results between your position and that of the Sun expert is in the selection of the assumptions and the parameters that's put into the model?

A Well, we obviously have a totally different description of how we view the field.

Q Thank you, Mr. Hueni.

MR. LEMAY: Does that conclude your cross examination, Mr. Kellahin?

MR. KELLAHIN: Just a minute. I'm told there may be something I've just forgotten.

MR. LEMAY: Part of your cross examining?

MR. KELLAHIN: Yes.

Q Very quickly, Mr. Hueni, and I apologize, in the material balance we had, I believe, 55-million stock tank barrels of oil in place and that was the value you've used in the model.

A No, that is the value that we believe is in the field independent of the model. The model, because it only represents a portion of the field, cannot tell us the oil in place.

Q The oil in place number that you have used is 55-million barrels.

A That's correct.

Q And will that include also the oil in the matrix system?

A Yes.

Q In dividing up the zones does that also include the oil in the C Zone, then?

A I think we've indicated that we don't believe the Gavilan Mancos' AB Pool produces significantly from the C Zone.

Q So the 55-million barrels of oil in place your estimote of the oil in place for the A and the B Zones and it's your opinion that the C Zone will not contribute -- will not have oil in it.

A No, I said that it was not significant. I think we have production tests to indicate that there is oil in it but it is low productivity and what we are seeing in term of the pressure response in the Gavilan A -- in the Gavilan Mancos Pool is primarily the result of the oil that resides in the A and B Zones.

Q But it doesn't exclude that oil in the C Zone. The 55-million barrels is whatever you think is from the top of the A to the base of the C Zone.

A The 55-million barrels reflects the oil in place that is in pressure production -- that is -- production is coming from and the pressure is then reflective of, and since we believe very little production comes from the C Zone, then we believe that the majority of the material balance indicated oil in place is indicative of oil in place in the AB, although there may be some in the C.

Q And the 55-million barrels of oil in place is confined to the current boundaries of the Gavilan Mancos Pool, excluding the West Puerto Chiquito Mancos?

A The material balance calculation is done using the Gavilan Mancos pressure production history, along with the western tier of Canada Ojitos Unit section wells.

Q You say the western tier, then you have picked up outside of the Gavilan Mancos Pool boundary that row of sections immediately to the east of the existing boundary.

A That is correct. Material balance is a balance of pressure and production and the production that we've considered is that production coming from -- including the western tier of Canada Ojito Unit section wells which are in pressure communication with the remainder of the Gavilan wells.

MR. LEMAY: Does that conclude your cross examination, Mr. Kellahin?

MR. KELLAHIN: Yes, sir. Thank you.

MR. LEMAY: Do you want to take a sip of water or anything before --

A No, I'm fine.

MR. LEMAY: Okay. Additional questions of the witness?

Mr. Chavez.

MR. CHAVEZ: I've got to refer to the book for some of these.

MR. KELLAHIN: Frank, do you

want to sit at the table?

MR. CHAVEZ: If I could just use this corner it would be good.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Hueni, your Exhibit Number 34, could you turn to that, please?

MR. LEMAY: A little louder, Frank. What exhibit is it?

MR. CHAVEZ: Number 34. It's the frac pressure -- I'm osrry, the pressure build-up test of the Northwest Pipeline Corporation Rucker Lake No. 2, is that correct?

A Yes, that's correct.

Q In your testimony you said that the separation of straight line segments indicates a dual porosity system, but there could be other factors that could also cause a separation.

A I -- I indicated it may indicate, it may indicate a dual porosity system but it is not in and of itself conclusive. The deviation from one straight line trend is indicative of non-homogeneous behavior whether it is dual porosity, whether it is layered reservoir effects or those would be the principal causes that I would expect.

In our August, 1984, testimony we indicated we -- we reviewed this same information and we indicated at that time that just based on this information alone we would not be ready to conclude that this is a dual porosity system reservoir, and in fact our conclusions with respect to dual porosity, this is just one evidence out of several pieces of evidence.

I hope that will answer your question.

Q That will do, thank you. In using this type of a plot isn't it possible to extrapolate the last straight line segment to the 10 to the -1 line and estimate a reservoir pressure?

A It's going to depend on the degree of depletion that's occurred in the vicinity of this well prior to this time.

Q On your Exhibit Number 50, that's the first exhibit where it appears you indicated that the reservoir pressures, the last two pressure tests, were not average or were not representative, is that correct?

A That is -- that is our interpretation, that the last two points may be more severely affected than perhaps some of the earlier ones. We would hope that the earlier points had gone up to -- to average reservoir pressure. Even then we'd have no -- no absolute, conclusive evidence that those prior points had gone up.

Q During the period of time that these

pressures were taken, weren't the wells in the Gavilan Mancos restricted or their restriction began during this time?

A That is correct, but even with the restriction we were still maintaining a reasonably high degree of voidage, or voidage, I think Mr. Roe's numbers that showed voidage indicated that the voidage even with restrictions is still -- has sort of flattened out, so the voidage in the -- in the latter part of '86 is not really diminished. It's been relatively -- relatively constant and what happens is that we are simply, in our estimation, pulling down the fracture at a faster rate than we're pulling down the matrix pressure.

Q Could a sudden change in the voidage rate caused by restrictions reflect some unusual pressures like this?

A I don't believe so. I mean what we have been seeing out there when we run static tests or pressure build-up tests, is we will see a well build-up in pressure to a maximum value and then we will see the pressure start declining off at a rate of 1 psi per day, and so I think that the pressure we're measuring is -- in my estimation it is a pressure that is -- that is certainly -- it builds up to a point and then it feels the interference effects of general depletion by all the wells in the vicinity and that's what's causing it then to drop down to 1 psi per day and I believe that that is in part reflecting the interference effects that are -- that exist through the high capacity fracture system caused by other wells.

Q Okay. Will you turn to exhibit -- Figure 68, please?

Do you believe that the Gavilan Mancos pressure was lower than what should have been expected in the pool when it was discovered?

A I would say that the indications are that yes, it is a bit lower than would be expected, but I'm basing that pretty much just on the evidence that we see -- see before you in that particular figure.

Q Using that difference and referring ot Figure 53, could you estimate perhaps the -- a certain amount of the original oil in place has been moved from the reservoir to cause the lower pressure?

A Yes, I think that -- that can be done. I would estimate, I believe, that it may be on the order of 400,000 barrels.

MR. KELLAHIN: What? I didn't get that.

A 400,000 barrels.

Q If that 400,000-barrel estimate is correct, would you estimate that that did move to the east towards the Canada Ojitos Unit?

A Well, we would have to say that the pressure gradient appears to go in that direction, so yes, I would estimate that it has moved eastward.

Q Will you turn to Figure Number 70, please? I'm sorry, make that 71.

A Okay.

Q Referring to Figure 71 and to previous testimony from Mallon/Mesa Grande group, would you say that this shows the relationship between the A and B Zone production on the Gavilan Mancos side and the C Zone production in the West Puerto Chiquito Mancos?

A It very well could reflect the fact that the C Zone is -- is the major productive interval in the West Puerto Chiquito, the east portion of the Puerto Chiquito Pool, whereas the AB interval is the interval that contains the majority of the oil in the Gavilan area.

Unfortunately, it could also just be due to a transmissibility barrier that may exist in the synclinal area separating the two. The only factual information that we can speak to is the fact that the Canada Ojito Unit gas injection project area was drawn down by what we estimate to be about 450 psi at a time when the Gavilan Field pool was discovered and drawn down by only maybe about 70 psi.

Q Well, if the drawdown in the West Puerto

Chiquito Mancos Pool was mostly in the C Zone, why wouldn't you want to compare that with drawndown in A and B Zone of the Gavilan Mancos Pool?

A What we are looking for is the interaction between the West Puerto Chiquito gas injection program and the Gavilan Mancos Pool itself. One of the things that I -- we wanted to investigate is if the operational program that was recommended for the Gavilan area would affect the West Puerto Chiquito gas injection program that Mr. Greer is conducting, and so that's why we were comparing them, is the data on the -- that's why we're comparing the data.

Q Well, wouldn't the data be more desribed then on that basis as a comparison between the -- or the description of the vertical permeability between the A and B Zones and the C Zone, then, in that area?

A That is possible but it is also possible that it is simply a restriction that exists in the synclinal area. We, in our model, we set up simply a permeability restriction and whether that permeability restriction reflects the difference between the A and B being productive in one area in the C or whether it reflects some sort of permeability restriction in the AB, which Mr. Greer has indicated he believes he has some production from, we -- we aren't sure. We can't really identify that. The only thing that we can really speak to is the presence of the -- of the pressure differences.

Q If Mr. Greer were to further develop the A and B Zones just to the east of the syncline, would it be more appropriate then to redo a chart like this using actual pressures?

A What it would appear to us is -- it appears to us that the Gavilan Mancos Pool is minimally connected to the West Puerto Chiquito gas injection area.

Now, if development occurs on the east side of the syncline in the Gavilan -- or in the A and B Zones, and that has a relationship to the Gavilan Mancos A and B Zones, then it would appear to us that we have a situation where we have A and B production depleting in one fashion and C Zone production depleting in a completely separate fashion.

Q Thank you. That's all I have.

MR. LEMAY: Thank you, Mr. Chavez.

Additional questions of the witness. Yes, Mr. Stockton.

QUESTIONS BY MR. STOCKTON:

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

When you do a modeling exercise or simulation such as you've done here and you use software that you've purchased, do you go through any type of procedure to validate that software as far as its structural components and its code?

A We did not purchase the software. It's commercially available software and is installed on the (unclear) Cray System out of Washington, the State of Washington.

We have used this model in conjunction with studies we've performed on behalf of a large international company over in the North Sea, who has this model available to them, who have used it on low permeability reservoirs and their exercise, they have gone through an exercise of validation and comparison to some other dual porosity system models and they feel satisfied that the answers are reasonable.

Q But you've not done any yourself?

A No, we have not done any personally.

Q Okay. You mentioned that this -- that you had used this model before in some North Sea calculations. Do you happen to know what the lithology of that field it's been used in before is?

A Well, primarily it is an extremely tight sand matrix with extreme fracture, extremely highly fractured.

Q But it's a sandstone.

A Yes, it is a sandstone.

Q Okay. Now, I'm somewhat confused here. During Mr. Kellahin's cross examination there was a -- you made mention that you had used an assumption of -- in the model that, if I understood right, 1.5-million barrels per section was an oil in place assumption. Is that right?

A We constructed a model that by necessity had to have a certain amount of oil in place in the model and that oil in place value, well, we just -- the model obviously does have to have some oil in place in it and the value that we specified in the model was a value of 1.5-million barrels. This, we're only studying a portion of the field as opposed to the entire field, so we specified the 1.5-million barrels as being perhaps representative of what we'd have in the 640-acre area. The important thing is that we then scale up our results proportionately to what we think the oil in place number is, the true oil in place number in the field is.

Q So you scaled that up to match the -- your material balance oil in place, is that right?

A That -- that's correct. We determined the oil in place, we felt the best estimate for oil in place, the 55-million barrel number, came from our pressure production history that we had available to us. That represented 55-million barrels.

Our oil in place in our model is 1.5-million barrel, so roughly we have 35 times as much oil in place in the field as we did in our model, so we scale up the withdrawal rates and the voidage rates from our model by that same factor of 35 to apply to total field components.

Q On your Figures 74 and 75, as I recall you mentioned when you were referring to these that these are characteristics of reservoirs -- these curves are characteristic of reservoirs of the different types you have labeled on them here.

A That is correct.

Q Do you have anything to compare these with? Is there any secondary literature that addresses this -- this subject? Or is this just --

A This -- this is, well, the solution gas drive curve that we show gas/oil ratio versus pressure, I think if you would take some of the preceding testimony that's been heard previously in this case where we have gas/oil ratios and pressure plotted versus oil in place, exhibits of Mr. Greer's presented previously, and we presented a similar exhibit in the last hearing, that the gas/oil ratio performance increases dramatically in a solution gas drive.

If you would re-plot that I think you

would see the same type of shape that you see for the single porosity system when expressed in terms of gas/oil ratio versus pressure.

For the gas segregation drive case, this is sort of a unique situation, I believe, in this field in that we have high capacity fractures that allow gas to move to the top in the formation. Unfortunately, we say "top of the formation" we don't necessarily mean laterally across the field. We mean just vertically up to the top of the localized producing interval.

Now when it gets up to that point, the gas forms this -- we called it perhaps inappropriately in the August hearing, we called it a gas cap, and really maybe it's just this layer of gas that's on top of the reservoir.

Unfortunately, with wells perforated through the entire section, provided all the perforations are open, which we know in many cases they aren't, that for those kinds of wells they will produce gas and oil and this is the trend that you see that you compute and all I can say is that this is computed for the schematic that we showed you before of a fracture system filling with gas at the top and oil in the bottom, for those types of conditions.

Q Now, if you'll turn to your Appendix E that Mr. Kellahin was questioning you about earlier --

A Appendix D?

Q I'm sorry, Appendix D, yes, would you -- I didn't follow the discussion on porosity.
A Well, the first point that I want to -- I'm sorry, did you have a question that you wanted me to --
Q Well, just explain to me on this page what represents porosity and which of the two porosities you're assuming it represents.
A Okay. Porosity values are represented by -- in the lower half of the page, the values that are indicated PORO.

If you look at the first one of those values you see a value of .00255; the value of 1 37 represents that that applies to cells along the top layer, the 37 cells along the top layer. The next two values of 1 indicate that that is the top layer itself. Or, no, it's in the Y direction, because we have a cross sectional model we only have one cell wide, and then the final values 1 through 4 indicate that those values apply to what we are assigning to the matrix.

Okay, now, the value 6 through 9 apply to cells that are attached to those matrix cells that represent fracture and you note they're given the same porosity number. It's the line right below it, and that's 6 through 9.

Now, what we have done in our model is we have started with that and we've varied the split of porosity between the matrix portion of the reservoir and the fracture portion of the reservoir and if you look down right below some of those -- some of the data we just looked at, you'll see something that says multiply, and it will say PORO and then it says .9, and then that is the factor we've multiplied the porosities that are quoted above, we've multiplied those by .9 to reflect the porosity in the matrix system, and we've multiplied the next values down by .1 to represent the volume -- the porosities in the fracture system.

So when we -- when we make our runs we want to study various values of the distribution of porosity between matrix and fracture, all we have to do is change those multiplication factors at the bottom to obtain that.

Once again I caution you that porosity is a number that is derived with using a particular model thickness. We have used in our model a thickness that is consistent with the intervals thickness based on the fact that we have identified from the fracture logs that that entire interval is fractured.

If we wanted to use a lower thickness value for -- for a given zone, then what we would have to do is proportionally increase the porosity number, maintaining the same oil in place.

We are not necessarily saying that the

Gavilan Mancos Pool has .2 percent porosity.

Q Okay. What -- what are the porosity numbers that are below the two you just discussed there?

A Those two values of porosity that are to the C Zone. We have specified in our model, we have five layers, two represent the A and two represent the B and then one layer represents the C, and it is isolated from the A and B Zones.

The C Zone, we have assigned, and this is more or less an arbitrary assignment, we have assigned one, 1/20th of 5 percent of the oil that's residing in the C Zone and once again I would indicate to you that that is a more or less arbitrary assignment based on our observation that we don't see much C Zone production.

Q Finally, as I understood you, you have assumed this is just a two-phase system.

A We have excluded the water from the system because the water is in a mobile phase in the system.

Q Okay. Thank you.

MR. LEMAY: Thank you, Mr. Stockton.

Additional questions of the witness. Mr. Lyon.

QUESTIONS BY MR. LYON:

Q Mr. Hueni, referring back to Exhibit 34 that Mr. Chavez asked you about.

A Yes, sir.

Q Is the shape of this curve not sometimes indication introduced as evidence in this -- in the earlier hearing, has this shaped curve not been shown to result in interference between wells?

A I -- that was not the normal interpretation and I don't believe that it would be probably in this case. This is a relatively early test. If you -- I apologize for the quality of the reproduction, but the test date was in December of 1983, so we certainly didn't have the degree of interference between wells at that date that we have currently. So --

Q That is true, but there were two wells that were completed at the same time that this well, that this test was conducted. Have you checked to see whether those wells might have -- one or both of those wells might have been on at the time that this pressure anomaly --

A To answer your question in sort of a dual fashion, no, we have not checked and second, the -- if it were an interference test affect, or an interference affect, then what it might reflect to get the second build-up that we observe on this pressure test, we would have to check to see if perhaps the well was -- the offsetting well was shut in such that then pressures began to build-up faster.

Q Is that right?

A That's right, we would have to check to see if that --

Q And it would appear that the slope of this assumes after it makes this little excursion is essentially the same slope that was building up on the (inaudible).

A Yes, but that's what we would expect out of a dual porosity system.

Let me tell you one other evidence that we would probably speculate on as being indicative of a dual porosity system as opposed to interference, and that is the fact that in the segment in between the two straight lines we expect to arrive at a half slope, not a (not understood) slope but a half slope if it is a dual porosity system.

Certainly, once again, it could be interference but I think, you know, what you might want to look at in this regard is if it is a dual porosity system we would expect this half slope behavior to occur, and it appears to occur but we haven't tried to confirm that.

Q Right there at the end of it, it looks like there might be another breakthrough at the very end.

A It's possible. It's possible. I mean

we, in the last hearing, and even in this hearing, we have not tried to say that dual porosity dependent on a simple indicator such as what we have here on the Rucker Lake No. 2. We're saying that it is indicated by a variety of different types of situations that we've observed.

Q Okay, that's fine for that.

I'm a little puzzled in your statement, correct me if I'm wrong, that you have used the vertical permeability as opposed to your horizontal permeability of

A That's correct.

Q I can understand why that occurs in reservoirs that are bedded and so why would that happen in a fracture system?

A Well, let me -- let me back up and explain.

We -- we -- we used a value of .1 and I think in several of our exhibits you noted that the gas saturation occurred at the top of the formation, so obviously, even with a .1 ratio we achieved effective segregation of gas and oil in the fracture system.

Now, if we had used a value of 1, a ratio of 1, we would have achieved the exact same result. What we are trying to say is one of the things that we have tried to do in the study is not to put forth anything that appears to be an optimistic position with respect to the behavior of the reservoir and we realize that a value of 1 will really give the same answer as the value of .1 has, because high capacity fractures by definition have a lot of permeability, so .1 times a lot of permeability is still a lot of permeability and it's enough to cause gas to segregate in the fractures. That is not a -- the .1 value is not -- is essentially equivalent to a value of 1. The model is not sensitive to that value within -- within the range of the types of permeabilities we're talking about in the fracture system, and incidentally, I hate to expand on some of these things, but that is one of the reasons that the Sun model, we feel, grossly overstates the rate at which the reservoir will become rate sensitive. If you have a great deal of permeability, particularly in just a 30-foot thick zone, the rate of segregation is going to be extremely fast. Gas is going to move very quickly to the top of the formation and oil is going to stay at the bottom, and in part the result of -- you have to produce at very, very high rates in a horizontal sense ot be able to produce the oil the gas before it has a chance to split out.

So we just don't feel that those kinds of rates are the kinds of rates that -- that actually will occur in a high capacity vertical fracture system.

Q It just seems strange that you would use something that would be that conservative.

A Well, it gives the exact same answer as the value of 1 and it indicates that we have -- because we have vertical segregation.

Q Mr. Hueni, would you agree that before you could begin a gas injection for a vertical matrix program that you would need to unitize?

A Yes.

Q I noticed on your comparison, your economic comparison, that you have assumed that you would begin gas injection probably before this hearing.

A We, on all of our runs, we began our runs at a point in time where a cumulative oil production of 3.8-million barrels had been achieved and to the best of our knowledge, if the field continues to produce at about a 3,600 barrel a day rate, that would occur in the vicinity of July 1st, 1987.

Q Well, it seems to me that that's an unrealistic comparison when you haven't even started talking about unitization. As a matter of fact, that's a -- kind of a dirty word around here right now.

A That's what I understand. That, I'm not prepared to comment on any kind of past discussions that have been held in technical committee meetings with respect to unitization. That's not why I'm here.

Q Okay. Also you've modeled a producing

rate that you admit was not - not within the capacity of the wells in the reservoir.

A No, I'm sorry, that's not the case.

Q 14,400 barrels per day.

A Well, we modeled the reservoir that would pull out 14,400 barrels a day with the intention of showing that were the wells capable of producing that volume, they would still end up with the exact same recovery.

The fact that the wells are not capable of in some producing 14,400 barrels is strictly a reflection that we do not have 10 Darcy feet of permeability in the Gavilan Mancos Pool.

If we did have that, then we would have plenty of wells producing 70 barrels a day or 700 barrels a day and we could achieve that, but I think most people would agree that the Gavilan Mancos Pool is not under a 702 barrel a day allowable system going to produce 14,400 barrels a day.

So if our results yield the same recovery at that high rate, I think we would have to say that within the reasonable rates of reservoir performance that we have -- that we have determined that there's no sensitivity of recovery to rate.

Q Well, it seems to me that it does not present a great deal of valuable information to the

Commission for you to model things which are not practiced in making your comparison.

MR. LOPEZ: Mr. Chairman, is Mr. Lyon going to testify or --

MR. LEMAY: No, I think Mr. Lyon can rephrase the question, possibly, so he's not testifying.

Q Well, I -- you could tell me whether you agreed or not but it seems to me it would be a lot more informative to this Commission if you had modeled a pressure maintenance program which we could feasibly put in within a period of time from the present so we could evaluate that rather than a performance which we have already passed.

A Well, I disagree that we've already passed it. We have modeled two cases, one of which is based on current reservoir pressure; one is based on a second reservoir pressure.

I guess we could model any combination thereof in between. We have modeled rates of 14,000 barrels a day, which the field is not capable of. The Sun study, when extrapolated to field rates, they only presented it for a 300 -- for a 640-acre section, extrapolate back to the field and get 100,000 barrel a day rate, and I question whether that is reasonable either.

Q Good point. Mr. Hueni, how uniform do

you consider the fracture system, major fracture system in the reservoir to be?

A I do not consider it uniform and the reason I do not consider it uniform is that we see many different -- many wells with varying well capacities. We looked at the capacity rate. So we see a great variability in well producing characteristics, which we think is a reflection in part of the intensity of fracturing.

We also refer back to Mr. Emmendorfer's second derivative map, which I think also indicates that we would expect a variability in degree of fracturing in this -- in this field.

I would not consider the fracture system very uniform but there are high capacity fractures present in different areas and it is the -- we made, we tried to make the point about the variability of individual well performance and we talked about trying to match the field average performance, and our -- we have gone through and tried to look at individual wells and interpret in light of our dual porosity model how those wells would perform, and with the kinds of things that we see, is that individual well performance is probably affected by localized variations of fracture intensity, as well as localized variation in the ratio of fracture storage volume to matrix storage volume.

So we think that -- I would personally think it would be very variable.

Q Do you have an opinion as to whether or not fracture porosity and matrix porosity are distributed in approximately the same -- to the same extent in the same parts of the field? Are they closely related or are they separate distributions?

A Well, our description of the total field is based on a ratio of fracture oil in place of 10 percent of the total. So the matrix contains 90 percent. But now that is on a total basis and we've just talked about the variability of individual wells and that that may indeed relate to differences in fracture intensities in this ratio, localized ratio of fracture volume to -- to matrix volume.

And, you know, I think what we're trying to picture is a reservoir that is indeed very complex, very heterogeneous, and we would not expect to see oil in place uniformly distributed across this -- across this area, because we have variations in these parameters.

Q I think you would agree with me, though, that in order for the matrix porosity, the oil contained therein to get to a wellbore, it needs to get into the fracture system.

A Absolutely. Absolutely. That's why when we look at the televiewer logs when we see intervals that do not have a significant degree of fracturing, and these are the larger fractures that we see on the televiewer, we do see low productivities for those wells.

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

MR. LEMAY: Thank you, Mr. Lyon. I think we have additional questions, the Commissioners and I do of this witness, so we'll probably break for lunch.

Before we do, however, I'd like to go off the record just a minute and talk about some timing that we have left in the hearing.

(Thereupon a discussion was had off the record.)

(Thereafter the noon recess was taken.)

MR. LEMAY: We shall resume at this time. Again let's stay off the record for awhile, Sally.

(Thereupon a discussion was had off the record.)

GREGORY D. HUENI,

resuming the witness stand, testified as follows, to-wit:

QUESTIONS BY COMMISSIONER HUMPHRIES:

Q I'll start since I'm not particularly encumbered with any professional knowledge.

I always thought that lawyers and (unclear) did strange and mystical things. Now I gather petroleum people do too.

Is it fair to say that you made certain assumptions that would change the variables?

A We -- the only assumptions that we made, well, we evaluated the field. We came up with what we consider to be the appropriate reservoir description of the field, parameters such as permeability, parameters such as fluid properties. Those are not necessarily assumptions. Those are characteristics on which we have a certain amount of engineering data. The engineering data is not always accurate so to the extent that it's not always accurate you end up assuming a value, but it has to be within a certain range of engineering reasonableness --

Q Okay.

A -- and that's what I meant, if we talked about assumptions, I was attempting to -- to obtain the most reasonable set of descriptive parameters but they're certainly within -- in fact I'd say they're the most likely set of values that we have to describe the reservoir.

Q Well, what we see in these very sophisticated models that your computer programs create are a very sophisticated, three dimensional, complex model that's many dimensions times the spread sheet but essentially, if you change the variables you change the output to some extent.

A That is correct. Some variables have a greater impact on the output than other variables. That's one of the reasons that you do it, is that you then obtain an understanding about what are the critical variables that determine performance for a given field. If it's permeability or is it ratio of vertical permeability to horizontal, so it's a tool that allows you to imagine how the reservoir performs and then to check that against -- to calculate it arithmetically and then compare that to actual performance.

Q So it gives a close resemblance of what was actually there.

A Well, we believe that that's a close resemblance.

Q Would it be fair to assume, for somebody like myself, that history of the opertion of a field or pool or a particular formation would tend to give better or more defined variables or input?

A This is the conventional wisdom that when you don't have any -- when you first discover a field and you apply one of these simulation models without any production experience on which to compare your model output to, then you don't have as accurate a model as you would have, as if you have several years of production history that then you can use to judge if your model gives you the same type of performance as that production history.

Q And it might not be particularly germane but it seems to me that if -- what's the source of the hydrocarbons in this particular brittle rock that we're talking about, besides dead dinosaurs?

A Or whatever that skeleton was.

Q Well, what --

A I believe thats really more appropriately a geological question but I believe there would be some evidence that it is generated more or less in place, that the rock is what you call self-sourcing but I would prefer you ask that of one of our geologic experts.

Q I thought that's what you might say but I wasn't sure. You talked a lot about matrix content of fluids in this particular formation, and previous testimony talked about tight blocks as being something that was also, or perhaps not in agreement with you, but a container of the gas and oil in this particular formation. Is there a similarity between your matrix and their tight blocks?

A I think conceptually there is a similarity. The difference is that, and I hope I don't misstate their position, so they'll have a chance to correct it, they believe, I think, that there is a high capacity fracture system that is very high capacity and it surrounds tight matrix blocks that they would say are maybe 100 to 400 millidarcy feet in transmissibility.

We would say that there is a high capacity fracture system represented by the extensive and very closely spaced vertical fractures that is relatively high capacity. We do not believe that in some it is 10 Darcy feet, and it surrounds a matrix that is much tighter than what they -- than what they describe and our matrix is many times less permeable than -- than what they consider to be their tight fracture blocks.

Our matrix is once again not the classical type of matrix where you just have intergranular porosity but it includes other factors, as well.

Q So you say they're similar but not the same.

A They're similar but I think they differ in the degree of transmissibilities they're trying to describe.

Q Okay. If I misquote you, correct me, because I was taking notes as fast as I could but A and B, you claim that the A and B Zones in this particular formation either are meeting or so close that they vertically communicate in the Gavilan Mancos Field.

A We would believe that they are -- that they probably communicate and the evidence, one of the principal pieces of evidence that we have with respect to that issue is the televiewer logs that show vertical fractures extending between the two. That is as opposed to the C Zone, where -- where we know it's separate. But, I mean, I hate to talk in generalities, but -- but even within individual zones, say the C Zone was 40, or the A Zone was 50 feet thick and it was fractured and it was separate from the B Zone, even within the A Zone the gas will segregate within that 50-foot thickness. That's a very -- that's a substantial thickness.

So we have -- we have interpreted the reservoir as having communication between the A and B Zones. That may not be perfect communication. That's one of the reasons we put in a vertical permeability to horizontal permeability ratio that was less than one.

Q Are -- are you comfortable to say that that case does not exist in -- east of this barrier?

A I'm sorry, which case?

Q That we don't have the A and B that close together?

A Well, actually the A and B is close together and is equally close together on the east side of the syncline. Once again I think we would believe that what is -- what has been testified to is accurate and that the C Zone is really functioning as a separate unit than the A and B Zone, and I would say that that is true on the east side of the syncline.

Q So you don't see a whole lot of difference in these zones in the formation going from east to west.

A Well, that's -- that's not entirely true. We, because of the geological evidence, believe, and the production evidence, believe that the C Zone is not, even though it's present and can be correlated from east to west or west to east, that the C Zone, which is reasonably productive in the -- in the Canada Ojitos Unit, or highly productive, is not in the Gavilan Mancos area, in the Gavilan Mancos Pool, and that's based on the televiewer logs and the production surveys.

Similarly, as we go the other direction in the A and B, we see the Gavilan Mancos Pool being primarily an AB producing pool. When we move over to the Canada Ojitos Unit we see some production from the AB. We would believe if that were the case that it would not be related to the C Zone production in the Canada Ojitos Unit; that -- and that it probably is not as good a production just on the basis that it's been -- been there for 25 years and not developed.

Q You're testifying that the earlier testimony has demonstrated that there is communication back and forth between the area east of this barrier and west of the barrier, so in the Gavilan Mancos Pool and in the West Puerto Chiquito Pool.

A Yes, we said there was limited communication between the gas injection area of the West Puerto Chiquito Pool and the Gavilan Mancos Pool. Keep in mind that the gas injection area of the West Puerto Chiquito Pool has -- it apparently is primarily seasonal, based on this performance (inaudible).

Q But you recognize some movement in the --

A We -- we recognize a minor amount of movement between the two areas.

Q Did I understand you right then this morning when you said that the initial pressures that you found in the Gavilan Mancos field or pool were lower than what you would have expected and that by some calculations or some results of your model, that you predicted that maybe some 400,000 barrels of fluid may have been lost across the barrier?

A That --

Q Going east into the West Puerto Chiquito?

A That is -- that is correct. The information indicates that there is some minor amount of communication and it indicates that there was over a twenty year period a pressure gradient established across the boundary and some flow would have occurred as a result of that.

Q Okay, and that's across the syncline.

A Well --

Q Or through the area.

A Well, it's from one area to the other and whether the barrier is represented geologically by the syncline area or whether it's represented by the fact of the difference between the Gavilan being primarily AB and the Canado Ojitos Unit, or West Puerto Chiquito Unit being primarily C Zone gas injection.

Q Okay. My understanding of it, and when I get into geology and away from engineering I'll ask one of the geologists, but we talked about the production bearing zones being a highly brittle formation that fracture and with separating zones between those being relatively fluid, soft, thick, apparently moves, and it does not allow, if there's a great distance of it, does not allow for vertical transmission, is that right?

A Yes, yes, that's the way I understand it.

Q Okay, this is simplistic, I understand, but this is a formation like a barrier formation. That's what creates cracks and fissures.

A At this point I'll defer to the geologist.

Q Okay.

A That's in line more or less with my understanding, as well.

Q Well, I'll wait for one of the geologists to come along.

A Okay.

Q Then maybe I shouldn't, I'm not sure, but what I'm getting at is this depiction of what's West Puerto Chiquito, even though we're talking about different zones, we've talked about an impervious, not impervious but restricted layer that's somewhere along, perhaps, the syncline, right?

A It's a low, low transmissibility barrier of some sort that is -- the reason we've always associated it with the syncline is because, well, because of some of the geologic considerations, but also because we've seen several wells in the syncline area that have been very minimally productive, and I think we reviewed those wells in our testimony.

Q Is, I think this is probably a geologic question, too, but if the syncline is in fact representative of what's apparently being identified as a restrictive area, we know it communicates some, but if that formation was bolted up like that and created that syncline, is it not possible to move the more fluid lithologies from between the formations? From between the zones?

A You mean between the A, B, and C Zones?

Q Yes, sir.

A I don't believe we have any data to indicate that the C Zone communicates with the AB Zone anywhere.

Q We don't know where the -- how close they are together at that restrictive area, is that --

A Well, I --

Q -- correct?

A -- think I should defer that to the geologist.

Q Okay. All I understand you to be saying is Mr. Greer's been injecting gas at the far east end of the West Puerto Chiquito for some long period of time to maintain pressure and assuming that most of those things are right, with some geologic questions that I have about the syncline, is it then possible that in fact his gas matrix is producing a result at the -- I guess that's the nose of the Gavilan Mancos Field at the --

A No.

Q -- top of the --

A It's not possible.

Q You don't think that there's anything that's helping sustain by maintaining pressure at the east end of this whole --

A I believe in my own mind that the benefit of the gas injection program is limited to the east area of the West Puerto Chiquito Unit, although there is a -- there is a very minor amount of communication, as indicated by pressure, pressure behavior between that east area and the west area, and in fact in the first twenty years of, as we said before, in the first twenty years of production from West Puerto Chiquito a 450 pound drop in that area tended to result in a 70 pound drop in the other area.

Now that we have Gavilan on production, Gavilan is certainly withdrawing its -- the volume of oil from its area and the pressure is declining and that's -- and we don't expect that in turn to have much impact on the other side as it depletes, and that's what the purpose of our model exhibit was.

Q From a production standpoint, is there something that indicates to you that you have closure or loss of structural integrity or some significant change at the west end of the Gavilan Mancos, somewhere out there between Range 3 and 4 West?

A We have -- we have not studied beyond the field boundaries of the Gavilan Mancos Pool. To the edge of field boundaries we see nothing other than just the fact that there is a variability in well quality, and I guess maybe just referring to my maximum oil producing rate map, although some of those wells have not produced for a long period of time, there are several of those wells that may be out in that area that are not as highly productive as some of the other higher capacity wells in the Gavilan Mancos Pool, but there's nothing that I see, see from an engineering standpoint that indicates that termination.

Q So you think that Gavilan Mancos has an unknown west boundary, is that -- or did I misunderstand you?

A Well, we have producing wells up to the western edge of the boundary and I believe that's how far it extends at this point in time.

I'm not prepared to say if there's a geologic reason or not why people should be drilling beyond those boundaries. We focused once again on the pool itself, the wells that are currently drilled.

Q And from a production standpoint, in understanding models and things, don't we have to make some assumptions that the pool or pools or a combination thereof is closed, that it is --

A Well, it must be closed because we calculate a specific volume of oil in place, 55-million barrels, but if you'll note, we've been a little bit careful not to say there's so many million barrels in this area and so many million barrels in that area, because we really don't know how to distribute that oil and so we have maybe a rough area of the field boundaries based on the number of wells that have been drilled out there, but we once again have a difficult time saying that that 55-million barrels occurs in any one specific area.

Q Thank you. I'll ask the geologist for that.

A Yes.

MR. HUMPHRIES: That's all.

QUESTIONS BY MR. BROSTUEN:

Q I have a few questions, Mr. Hueni.

There's been considerable discussion about the drive mechanisms in the West Puerto Chiquito Pool and the Gavilan Pool. It's my understanding, and I hope Mr. Greer will correct me if I'm wrong, that his contention is that in the West Puerto Chiquito Pool gravity is a primary energy, you might say, drive mechanism; however, in your interpretqtion of the Gavilan Pool you apparently discount gravity and refer to this drive mechanism as solution gas and gas drive and gas segregation drive.

You discount gravity. Gravity is a force which acts upon all of us, each and every one of us and everything, you might say. Why, why do you discount it?

A Actually we don't discount it. The effect the gravity has is it causes the fluids, the -- when the fluids enter the fracturs system, the oil and gas, that is the force that causes the gas to rise to the top and the oil to fall to the lower section of the reservoir in a vertical sense. That is the effect gravity is having.

In Mr. Greer's area, as I interpret it, when I believe -- I believe that probably, well, if Mr. Greer has some matrix contribution, he claims in his area he has all fracture contribution, I would have to say that I would think that he might have some matrix contribution in that area as well, but when his oil moves out of the tight fracture blocks or the matrix blocks, moves into the high capacity fracture system, the effect of gravity there is to cause it to move not just to the bottom of the vertical interval, but it causes it to move laterally across the field, because he has quite a high degree of closure and quite a high degree of dip, so his oil runs down structure. Ours just falls to the bottom of -- of the producing.

Q Do you consider the porosity in the West Puerto Chiquito Pool in the C Zone to be similar to the porosity, the dual porosity that you've identified in the A and B Zones in the Gavilan Pool?

A Our study was directed to the Gavilan Mancos Pool. It is a pool on which we have producing history, where we know the variation of gas/oil ratio performance and pressure performance over a range, and based on that performance we're able to support the dual porosity concept.

Unfortunately, well, unfortunately we don't have the data to study West Puerto Chiquito much and we have not been able to do that and therefore I really can't express a conclusion with respect to that.

Q I see. So you don't want to express any opinion or conclusion as far as West Puerto Chiquito is concerned.

A Well, my feeling is that if it is a dual porosity system in West Puerto Chiquito, there would very definitely be a possibility that the fracture volume relative to the total volume in West Puerto Chiquito in the C Zone might be more substantial than the 10 percent value that we attribute to Gavilan, and I say that strictly because I see some very high capacity wells in the West Puerto Chiquito area. somewhat higher than the capacity wells we see in the Gavilan area.

Q In your discussion of possible pressure maintenance or gas injection in the Gavilan Pool you state that the -- perhaps the best way to -- to get involved in this would be upon the depletion of the -- the depletion of the primary reserves, is that correct?

A That's correct.

Q And I won't ask again about the West Puerto Chiquito Pool but it appears that Mr. Greer's gas injection program has been -- has had considerable effect upon the production rates in that -- in that pool, is that correct?

A Well, I think we ought to keep in perspective that we've produced in excess of 3-million barrels in 3 years out of the Gavilan Mancos Pool where the West Puerto Chiquito area has produced 8-million barrels in 25 years.

Now the production has stayed relatively constant but I suspect that in the Gavilan Mancos Pool had we restricted rates down to fairly low values that -- that we could have maintained them at a constant, constant level for quite some time as well.

So what I'm saying is that the evidence of constant production is not necessarily evidence of -- that the -- of the optimum plan of depletion.

Q It appears from exhibits that Mr. Greer presented that the gas injection has had an affect on the recovery. Do you -- I guess I'm asking for an opinion and you don't have to answer if you don't want to, but do you believe that that reservoir was near depletion as far as primary term is concerned when gas injection was --

A No, I don't. I don't believe that. I -- it -- in fact we know what the production pressure history was for that reservoir is what we showed on Figure 69, so we know it wasn't near depletion.

There are substantial differences in the structural characteristics of the Gavilan Field and the West Puerto Chiquito east area and I think we recognize those.

Also, the benefit that we see of gas injection is to sweep out -- is to sweep out the oil out of the high capacity fracture system. It's not going to displace oil out of the tighter matrix blocks. In fact that is the same statement that Mr. Greer makes about his tight -- his tight fracture blocks, is he says they don't -- they aren't displaced. They drain out.

So if we inject gas and we sweep down a high capacity fracture system and that's all the oil that we're going to get out, then we need to know the percentage of oil that's in that high capacity fracture system relative to the amount that's in the matrix, and if there is a relatively small amount in the high capacity fracture system, we're going to sweep through there very rapidly and have early gas breakthrough.

Now Mr. Greer has the advantage -- he may have, I'm going to speculate again, in my opinion he probably has -- he does have a dual porosity system. He probably has a higher proportion of fracture porosity to total porosity. So he has more oil to sweep out with his gas injection program.

A second benefit that he has is that the gas will naturally stay at the top of the reservoir, the crest of the reservoir, and the oil at the base, because of the vast difference in structural characteristics that occur in the West Puerto Chiquito Pool.

So I consider it comparing apples and oranges to compare what will happen in Gavilan with what's going -- with what may have happened in West Puerto Chiquito.

Q Thank you very much. That's all I have.

QUESTIONS BY MR. LEMAY:

Q Mr. Hueni, I've got a tough time trying to understand and maybe accept this dual porosity, only because I visualize a reservoir that's fractured having all gradations of fractures from some that are high capacity to some that are very tight. I can visualize a system between and therefore being in my mind one system but with these great variations between maybe 10 Darcys and 1/10th of a millidarcy. For my own clarification, how does this concept fit mathematically in a model with what you're doing? Are you dealing with two distinct types of -- of behavior and therefore segregating them or is it gradational behavior? Can you --

A Well --

Q -- call it gradational behavior?

A -- that is the -- that is what we're trying to represent. We recognize that reservoirs are not, you know, this or that. They are gradational in nature and what we're recognizing is that there is substantial volume of oil stored in what has to be a low flow capacity system, and there is a substantial volume of oil -- or there may be a minor volume of oil that is stored in a high capacity flow system but which is the primary factor that allows the oil to flow through the system.

People have proposed triple porosity systems and maybe they'll end up with even more than that to try and more fully explain all the different gradational behavior that we (unclear) but we believe the dual porosity system, that what we're doing is we are just recognizing that there is a large amount of oil stored in a very low capacity system and it is gradational and there is a small -- and we think there's a small amount stored in the high capacity system.

Now the -- one of the things we might say with respect to fractures is that the permeability in a fracture is proportional to the width squared of the fracture, so if I have a fracture that's twice as wide as an adjacent fracture, I have four times the permeability there, so when I go from a fracture that is .001 inch wide to .01 inch wide, I increase my permeability through that -- that part of the reservoir by a hundredfold and that is what we're trying to recognize, is that there are -- it is gradational in nature but in general we can separate the entire volume into something that's lower capacity and something that's higher capacity, and that is, that's the essence of a dual porosity system.

Q In terms of computer modeling I was wondering in visualizing the gradational system, would that fit better into a one phase or a two phase or a three or four or five phase, or how does that affect your modeling if you're dealing in a gradational system?

A Well, models are always approximations to reality. The advantage of having a model is that you can put in variations in reservoir parameters and variations that we've put in are we've, by setting out a model, this cross sectional model, we've taken into account the height factors. By setting out something that has length we've taken into account the horizontal factors. By putting in a dual porosity system we've tried to take into account that there is some portion of the rock that has high flow capacity and then there is also a portion of the rock that has low flow capacity.

So we're trying to put in all these -- these gradational factors and lump them into as complete a description as possible.

Now, with respect to the different number of phases that are present, when we talk about phases present, we're talking about oil, gas, or water generally, and normally you consider most oilfield systems to be comprised of three phases.

What we have done is we have included only the oil and gas in the model because the water, which resides, let's say, in the matrix, whatever would be interstitial in the matrix, is basically, as we see it, immobile. It is not going to move substantially from -- from where it's currently at, at least we think there is good evidence that that will not occur.

Now the presence of water in the -- in that matrix porosity undoubtedly has an impact on that matrix porosity. In fact what it does is it causes a permeability in the matrix porosity that was already low to be lower because of the presence of water. We're well aware of that and we believe that even with these low values that we have for permeability, that we will still get sufficient flow out of the low permeability rock.

Q Now I think I understand, but trying to crystallize just a little bit, there is a disagreement --

A Yes, sir.

Q -- mainly with Mr. Dillon. He -- he has assumptions and you have assumptions and I think in general these assumptions, many of them appear to be the same, or at least any variation, like in the bubble point, would not affect whether your conclusions would be rate sensitive or non-rate sensitive in a reservoir or correct me if I'm wrong, I'm trying to find those areas of disagreement that would impact the sensitivity of that reservoir to a great extent, so that you could say it was either rate sensitive or non-rate sensitive, and I take it permeability or transmissibility would be one. If you go from 10 Darcys to 400 millidarcies, that's going to be a factor that would greatly swing that thing to rate sensitive or non-rate sensitive.

A I believe that it would be fair to say within the rates at which the field can practicably be produced the tighter the permeability, the lower the transmissibility value, the more rate sensitive the reservoir would be.

Q So that it works reversed. If you tighten up the rock, you're going to get a more rate sensitive reservoir.

A That's absolutely right.

Q So in that case the assumptions of Sun would tend to support the conclusions of -- of your study. From that, at least from that figure. I don't know. I don't want to put words in your mouth, but --

A No, I --

Q -- we have -- we have the 400 millidarcy transmissibility figure that you used as an average and the, I think, the 10 Darcy feet that was an average from Mr. Dillon's assumptions.

A Well, if we -- if we had 10 Darcy feet in the reservoir, we would end up with a less rate sensitive phenomenon in the rate sensitive than whatever we have, within the range, now I -- I testified already that I believe that the way that the Sun study was scaled up ended up showing rate sensitivity at such high rates that they are not rates that are going to be realized in the field.

Q The other elements that I find, of course, rock compressibility, you testified that that factor they were -- well, more conservative than in initial figures and you believe that the compressibility is greater than --

A It will not affect the rate sensitivity but it does affect the interpretation of the reservoir in terms of how much is there, what the storage capacity is, and calculations such as those are sensitive to the compressibility, as is the -- well, the calculation of oil in place in material balance. So --

Q Okay, so that would affect it from that point of view.

The other thing was this -- you mentioned, and I hope I understood you, the dual porosity system again versus a single porosity system, that the dual porosity system would tend to favor less sensitivity in the reservoir as compared to a single porosity system?

A That is correct, because the only way the oil can get from the low, low matrix porosity blocks or if you want to talk about tight matrix blocks, tight fracture blocks, the only way the oil gets out of one and into the other is by a pressure differential. You have to have a lower pressure in the high capacity fracture system to cause oil to flow out of that, that system.

Q Okay.

A And so, so you actually want a high pressure differential to get the -- get the flow out of the system, so -- and since 90 percent of your oil is contained in those -- those types of -- that type of porosity, then you actually are not hurt particularly by going to higher rates.

Q That's -- that's the question I wondered how -- go back to that statement, 90 percent matrix, 10 percent fracs, do you have any proof of that or is that an assumption?

A No, it was not an assumption. We, as I said before, we ran approximately 80 to 100 individual simulation runs to try and duplicate field performance and we've heard already people question about the uniqueness of the runs.

Well, we are much, much closer using the set of parameters that we ended up with, the description that you've heard us provide, than we were able to arrive at using alternative descriptions. In fact we used a description very similar to what Sun did, and we find that that is not anywhere close to representing field performance on the average.

So we believe that, you know, we believe that we have a fairly unique description.

Q But -- but the proof of that was mainly in the computer modeling? There was no core studying or anything that would, to your knowledge, that would divide up the tight rock and say, okay, that's -- out of this unit volume 10 percent comes from the -- this high -- this big fracture here; the other 90 percent from this tight rock?

A Well, the core studies, as we've testified before, indicate that there is matrix porosity, and deciding that a ratio of 90 percent to 10 percent value, if we had, for example, 50 percent fracture volume compared to --

well, maybe -- could I refer to one of the exhibits?

Q Sure, please do.

A If we would look at Exhibit 75, we presented several -- we presented a dual porosity system with different ratios of this -- this fracture volume to total volume, and you can see three cases here, one for a 50 percent ratio of fracture volume to total volume; one for a 20 percent and one for a 10 percent. You can see what they do is they affect the GOR performance.

Now if we had 50 percent of the fracture volume, if the rock was -- had porosity of which 50 percent was represented by the fracture volume, then we would have expected the gas/oil ratio increases to be less substantial than they actually have been and the procedure in matching up the observed gas/oil ratio performance has allowed us to vary, we varied this ratio of fracture volume to total volume and the value that we find that provides us with the correct match of gas/oil ratio performance is not a 50/50 mix, it's a 10/90 mix.

Q It looks like at least in the lefthand side of that curve those lines aren't that far apart. They seem to spread out as you get more history on it.

A That's right, you need to look what the scale is pressure on the X axis --

Q Right.

A -- not time --

Q Uh-huh.

A -- and the pressure that we're at right now is a pressure of --

Q 1250, somewhere in there?

A Yeah, 1250, 1300, 1400, somwhere in there, and I think that you'll see that there is a substantial difference at those kinds of pressure levels, and there -- it becomes a very recognizable difference when you compare actual performance to the calculated performance, and we've included and would be prepared to show later on that there -- that the 10 percent number is much more reasonable than say a 50/50 mix.

Q In that same regard, again trying to understand the reservoir, did I understand you correctly when you mentioned something about interference tests, you didn't beieve them or you didn't place any value in them?

A No, I believe them. The way interference tests normally are run is -- or one of the purposes they're normally run, is to identify properties between adjacent wells. They -- and what oftentimes you're looking for, if you have three wells, you're looking to see if the permeability is different in one direction than it is in the other direction, and so you run your interference test and you perform your calculations on those interference tests.

There are certain sets of assumptions, and this is true not only for interference tests but for pressure build-up tests, you cannot just run a test and then take it and arbitrarily put a line on a curve and calculate out what you think is the transmissibility indicated by that test. You have to assure that the formulas that you are using to make those calculations with are not -- or that they are actually valid for the type of tests that you ran and what my comment was with respect to interference tests, dealing with a fractured reservoir, a dual porosity system reservoir, as we see it is that the equations that would apply in the interference test analysis may not be valid at the -- for the conditions the tests were run at out in this -- this particular field. I realize that was a bit of a roundabout answer, but --

Q We just wondered what kind of value you placed interference tests as an indication --

A Well, in certain reservoirs under the right conditions we place a great deal of value on them. We just don't believe in this particular reservoir that the interference test could be properly interpreted to get 5 to 10 Darcy feet of permeability, although once again, this was a test run back in the '65 to '68 timeframe for which we have very little information -- on which we have very little information.

Q I guess I wasn't so much concerned about it as a measurement of permeability but as a function of drainage. Another way to phrase that in terms of a question would be do you believe these high capacity wells are draining low capacity areas beyond the proration unit?

A That would imply that we would have to be able to assign a certain amount of oil in place to each proration unit. In a dual porosity system we've said that we have -- we have fracture porosity and we have matrix porosity. Fracture porosity in turn is a function of fracture width and fracture intensity, so we have to know what the width and the intensity is in a given area.

If we have essentially constant width and a -- just a variation in intensity, then fracture porosity varies almost directly as the productivity of the well.

On the other hand, if we have no change in intensity, but simply a change in the fracture width, then the porosity varies as the cube root of permeability.

Well, that's -- that's quite a difference in assigning porosity on the basis of productivities to given areas, and what we're saying is that you have to know both width and you have to know fracture spacing, and unfortunately, we'd like to say that we know a lot about this reservoir, but as several people have cited before, we have just very, very limited samples out of that reservoir.

Q Well, maybe in a specific example I can get your opinion of this.

A Okay.

Q I think it was the previous testimony they talked about the Merrion Krystina, that area in the south end of Gavilan, without having any production from those wells there was a drop in pressure.

With just my briefing I would assume there's some drainage there without any production. It could not be from that proration unit so some other well would have to be draining that.

A Absolutely. Absolutely. The -- there is pressure communication throughout the field. We've seen that in the terms of pressure plots, and we believe that the recoveries that individual wells will achieve will be proportional to the rates at which they're allowed to produce, so if you have two wells, each of which you're allowed to produce at 100 barrels a day, they are probably going to split the reserves pretty much.

On the other hand, if one has the capability of -- of producing two times what the first one is, then it will get twice the recovery.

The problem that we have, we recognize that. The problem we have is how do we determine that the one that's getting two times the recovery doesn't have two times the oil in place to begin with.

Q This is what I was trying to get around to. If we assume that 90 percent of the reserves are in the low capacity system and 10 percent are in the high fractures, and for hypothetical cases let's take a well that can produce 1000 barrels a day and one that can produce 10 barrels a day. Let's say we have an allowable that will allow that well to produce 1000 barrels a day. The 10 barrel a day well certainly can't come close to in my way of thinking draining its reserves, and would be drained quicker by the 1000 barrel a day well if it was connected to the porosity system, or the -- yeah, connected, compared to, say, 500 barrel a day allowable, which would draw less from this well making 10 barrels a day.

Does that -- does that in your mind make sense or is there any reason that that would be a correlative rights issue?

A Well, it certainly is possible and in the extreme it appears as such, but once again, when we get to actual field variations between wells, you know, that was one of the reasons we went through and showed the variations of individual well performance, and we looked at it in terms of gas/oil ratio versus pressure plots for individual wells, and we noted that they differ from the field average, and we are -- we have matched the entire -- we have matched the average trend in gas/oil ratio and pressure performance using the computer model. That's the average for the field and we've said 10 percent of the oil is in the -- in the fracture system and 90 percent, as an average for the field, but if we looked at each individual well we might conclude that in the localized area around each individual well, that that ratio would vary.

So once again we're back to the problem of having this really complex interaction of parameters that determine well performance and we have a great deal of variability out here, so we, you know, we calculated the 55-million barrel oil in place number, which undoubtedly somebody's already going to take issue with, and if we had extended that to calculating individual well oil in place values, I think we've -- we're really jumping from the frying pan into the fire.

Q If you were going to inject gas, say next year, and the field was unitized, where would you inject, at the top of the Gavilan Dome?

A I suspect that that is where we would inject it, yes, and, well, part of the reason that we would inject it up there is that's a lower pressure, that area is lower pressure just because it's a little bit higher structurally, and as a result of being a little bit lower pressure, it has somewhat higher gas/oil ratios.

On the other hand, we also have some poorer productivity wells up there.

I don't think that you would necessarily -- I mean I can speculate on that, but I think you would obviously want to do a considerable amount more study than speculating.

Q And finally I will ask you the question that you wanted to answer.

Why -- why didn't you model the production rates less than 3600 barrels a day?

A The reason is, is that if we were to review the -- the prediction run for 3500 barrels a day, we would see that what we have is, we have the matrix depleting as a solution gas drive. We would see that the fracture has the gas already at the top of the fracture and the oil below. In fact when we looked at those -- those individual -- well, I'll tell you what, we should turn to that. If we would turn to Figure -- Figure 87. This is a plot of the gas saturations in each of the individual cells in both the matrix and a fracture system, and at the time of ultimate depletion, well, depletion down to an average pressure of 256 psi, psi in the model, the time is 2,520 days in the model and if we look at that point, we would see that we have a uniform gas saturation in the matrix and we would see that we have rates of -- or we have gas saturations that are essentially completely filling up the oil pore volume at the top of the fracture system.

Now, I hope it's apparent, it may not be, but there is really nothing that we can do to make that a better situation. We've got the gas moving to the top. We've got the matrix depleting with the uniform gas saturation and that is not rate sensitive. The matrix depletion is not rate sensitive, so there's really nothing that we can do that would cause the picture that we see here to look any better.

So we could look at 1800 barrels a day but it's going to look exactly the same as what we see here.

MR. LEMAY: I don't believe I have any more questions.

Are there any more questions of Mr. Hueni?

MR. HUMPHRIES: I have one more.

MR. LEMAY: Yes.

QUESTIONS BY MR. HUMPHRIES:

Q I think I understood you to say you went through a test to determine or at least calculate the relative pressure in the matrix and in the fractures. Did you tell us in your report?

A Well, what I said is that we believe we have a dual porosity system. A dual porosity system requires the fracture pressure to be less than the matrix pressure, and the only way that we have of identifying that difference between the two pressures is really the output form the simulation model.

So it's not a field test.

Q It was not a field test --

A No.

Q -- to determine -- that convinced you there was greater pressure in the matrix than there was in the --

A If we have a dual porosity system, we have a greater pressure in the matrix than we do in the --

Q And since we're talking about rate sensitivity, if you vacated the fracture system is there ever -- are there circumstances in which that fracture can be invaded by water or gas or any -- any other changes that would change that pressure relationship and you'd no longer have appropriate differential?

In other words, could you block by depletion of the fracture system into the matrix the remaining oil by changing the pressure significantly?

A No, I don't -- that is what we basically have modeled here. We have run several of our evaluations with what we call pressure sensitive permeability, and we've not seen any dramatic change in our results by taking the pressure off the fracture system in terms of its effect on -- the fracture system is a high capacity fracture system connected to a tight matrix, and matrix will feed in at a rate, but it's not going to feed in a high rate. I -- I would hope that everybody would see that if we're dealing with extremely low permeabilities, that that will not have a high flow rate into the fracture system. So even though we may, with a pressure sensitive permeability, lose some of the permeability in the high capacity fractures, we're still going to have more than sufficient permeability to produce at pretty much whatever rate we are able to support with the matrix.

Q But if you depleted the large fracture system for all practical purposes to the point the field was no longer economic, would you continue to have that kind of pressure differential? It would seem to me that that would have a great deal to do with rate sensitivity.

A Well, as long as you start to deplete, initially as you start to deplete, the sequence that happens, we produce the reservoir at a high rate. A fracture system depletes faster than the matrix system. You create a large pressure differential. A large pressure differential causes the matrix to flow in at as high a rate as it possibly can. That helps support the pressure in the fracture system. As the pressure in the entire system starts to be drawn down, the rates at which oil will feed into the fracture system diminish. The rates at which they'll be taken out from the wells will diminish, and basically what we have is a leveling off of the production curve. And so eventually we reach a point in time where we reach depleting -- depletion conditions for the reservoir. We have a low pressure in the fracture system and almost as low a pressure in the matrix system, as well, at that point in time. and it's not rate sensitive.

Q Okay. Thank you.

QUESTIONS BY MR. BROSTUEN:

Q Mr. Hueni, in your response to a question by the chairman, you were discussing a three phase or two phase reservoir system whereby you can use a two phase oil and gas and not include water because the water's immovable, and then if I heard you correctly, and this is where I want some clarification, you stated that the water in the micro-fracture matrix porosity also diminished the ability of the oil to move out of that matrix porosity, is that what you said?

A Well, I think it needs to be recognized. I mean there -- there are certain -- we said that when we ran our core plug tests, those are all run on a -- on a single phase type system and when we have multiple phases in there the effect of the multiple phases is basically to reduce the permeability to each individual phase.

So if we have core plug tests that are run and they have a low permeability to a -- the flow of a single fluid, then if we put two fluids in there they're going to have a still lower flow and what I'm saying is that we recognize the fact that permeability of the matrix will be -- will be reduced from that shown in the core plug analysis due to the presence of water.

Q In a sense, though, we have a water wet reservoir, is that not correct?

A We do not know if we have a water wet reservoir or not.

Q If we did, and the water was immobilized, it would stick around the facies of the sand grains or the fracture facies, that would facilitate the (not clearly understood) -- it would facilitate the movement of oil out of the matrix porosity, I suppose, to (not clearly understood).

A Well, I think that's right, as opposed to an oil wet reservoir, but once again the presence of water reduces the pore size that the oil has to move through, so you do have a reduction in permeability --

Q Okay.

A -- when you do have water present, and we recognize that. We once again ran a two phase model with the concept being that we have a low permeability matrix and -- but even with a very low permeability matrix, we have sufficient permeability to have flow from the matrix into the fracture system.

Q Thank you very much.

MR. LEMAY: We'll let you go in a minute.

A Okay.

QUESTIONS BY MR. LEMAY:

Q Trying again, to crystallize the areas of disagreement, I think the first group testified that at present pressure depletion rates, something like 30 pounds a month or in that range, I think, that meant the field would be depleted in three years. Your graphs and all your information show at the present rate a 10 year depletion. What are the reasons for that discrepancy? Can you comment on that?

A Well, I think it would be fair to say that their rate of depletion is based on withdrawals of the current -- of the current level, but as pressure declines, productivity declines, as well, and that extends the life of the field.

Q I'm not sure again, as --

A Okay. I believe, and I hope once again I'm not misstating their position, but I believe that their very short life for the field is based on taking out as much oil next year as they're taking out today.

A I'm following you.

Q But as they take out more oil, the pressure declines, the productivity declines, and it extends the field life.

Q And you've extended that curve out more with the reduction in volumes each year.

A Well, that's -- that's right. Ours is a -- we show the decline curve as it extends out as volumes go down.

Q Okay.

MR. LEMAY: Any more questions of the witness?

MR. LYON: May I ask just one question?

MR. LEMAY: Okay.

QUESTIONS BY MR. LYON:

Q I think the answer to this is obvious but I just wanted to confirm it.

Referring to Figure 49, in your tabulation of fluid properties, MUo, the pressure of 1114, should that not be 0.5 rather than 0.1?

A You're right. That's entered incorrectly. For the oil in place calculation, that is not one of the parameters used.

MR. LEMAY: If there are no other questions of the witness, he may be excused.

MR. LOPEZ: Mr. Chairman.

MR. LEMAY: Yes, sir.

MR. LOPEZ: I still have some redirect.

MR. LEMAY: Well, sure, please redirect, Mr. Lopez. I didn't mean to cut you off.

REDIRECT EXAMINATION

BY MR. LOPEZ:

Q Mr. Hueni, I believe Mr. Kellahin stated this morning that your testimony this week in this hearing had differed from the testimony you gave at the time of the August hearing.

Would you please tell us in what respects, if any, your testimony this week has differed from your testimony in August, and if there is a difference, why there is a difference?

A Yes. In general, most of the conclusions that we reached in the August hearing are very similar to what we reached in our study here. The changes in any of our conclusions are based on the additional testing and studies that have been completedin the interim and that were recommended, that have been recommended previously by various parties in the field.

But we have not changed -- in the August hearing we indicated that we felt the fluid properties that were associated with the reservoir, with the fluid property sample that was available for the reservoir were not correct.

We still have that same opinion, although we have a slightly revised estimate of what the bubble point pressure is.

We believe that the gas was segregated in the reservoir.

We still believe the gas is segregating in the reservoir. We believe it is occurring in the high capacity fracture system and in the matrix, however, it is not segregating, and so we feel that we're consistent with that, as well.

We made a statement that increased gas saturation at the top of the formation would eventually descend to the level of perforations causing increased GORs could not be avoided in the long term, therefore high GORs should not necessarily be attributed to a solution gas drive mechanism without confirmation from production control surveys.

We've run those production control surveys and we do see gas segregation.

Pressures at that time were currently below the bubble point. Well, they still are. We agree with that.

We said pressure production data indicated a reasonable value of oil in place at 100-million barrels. This could be reduced depending on lab measurements on rock compressibility. We carried out the lab measurements and they've consequently been reduced.

We said that matrix porosity might contribute to ultimate recovery, although the magnitude of the current contribution could not be determined at that point. It says the contribution of the matrix will be more significant as the pressure is lowered. That is exactly what we're saying today, no difference.

Comparison of predicted solution gas drive performance to actual data indicates the reservoir is not a solution gas drive. That is exactly what we're saying today.

We said in order to maintain current gas segregation in the reservoir producing rates need to be limited and oil allowable of 702 barrels of oil per day per 320-acre unit, and a gas allowable of 453 MCF per day based on an initial solution gas/oil ratio of 646 is more than adequate to maintain effective segregation and we are still saying that you can produce at the statewide top allowable and not cause -- cause any kind of damage to the reservoir.

In other words, we consider that we have modified our position primarily based on the additional test information that we have seen, integrating that into a complete reservoir study.

Q I'd now like you to refer to Figure 70, Figure 70, and explain again why you used a single porosity system as a model rather than a dual porosity system.

A Figure 70 was a schematic of the model that we used to study possible communication between the Gavilan Mancos Pool and the east side of the West Puerto Chiquito Pool, and we indicated that we used a single porosity model to study this -- this behavior as opposed to the dual porosity model that we used to interpret Gavilan Mancos Field performance.

We'd like to say simply that the reason that we used a single porosity system model is that we were not attempting to match gas/oil ratio performance in the pool, as we were doing with the Gavilan Mancos Pool. All we were trying to do is establish a degree of communication between the two pools, so we do not need as sophisticated a model to achieve that purpose, and a single porosity system with a variable transmissibility barrier somewhere between the two pools is sufficient to -- to serve that particular purpose.

Q And finally I think Mr. Kellahin raised some discussion with respect to the uniqueness of the model you employed to analyze this reservoir and I think suggested that you could manipulate any number of different numbers and parameters and get the same results.

Would you care to comment?

A I think it always has to be said in fairness that there, because there are an infinite variety of different combinations of field performance parameters that you can study, that if you only study 100 of them that you may not have obtained the only match that's possible to actual field performance.

What I would like to say is that we have studied a variety of different systems within the reasonable bounds of several of the different parameters and we are not able to obtain a history match of nearly the quality that we've presented to you today with any other combination of parameters that we have found to be reasonable in describing the field performance.

Q And this match was represented on your

Figure 80, is that correct?

A That is correct. That is our match, on Figure 80.

Q In your experience do you encounter many matches that good?

A No. No, there, especially in heterogeneous reservoirs such as we have here, this is, I would consider, a very excellent match.

MR. LOPEZ: I think that's all my questions.

MR. LEMAY: Thank you, Mr. Lopez.

Any additional questions of the witness?

If not, he may be excused. Thank you very much.

At this time we'd like to call a couple witnesses if we may, just to -- for points of clarification mainly.

Mr. Richard Ellis, would you come up just for a few minutes?

MR. LEMAY: The witnesses being recalled, I just want to remind everyone that they're still under oath, so we won't have any swearing in.

Mr. Humphries has some questions about the geology of this reservoir and how it got to be what it is today.

RICHARD ELLIS,

being recalled and remaining under oath, testified as follows, to-wit:

QUESTIONS BY MR. HUMPHRIES:

Q Well, probably everybody understands it but me, but we've talked about a very brittle rock that's a zone between A, B, and C, and we have some indication that A and B, at least in the Gavilan Mancos are very, very close together. In West Puerto Chiquito are they that close together?

A In a vertical sense?

Q Uh-huh.

A Well, the entire Niobrara producing interval is -- is a net thickness of about 300 feet.

The A, well, I couldn't tell you without looking at a log just how thick the overall A Zone is, but if you don't mind me taking a guess, 60 feet; maybe the B might be 80-90 feet; and then the C would be the rest of that.

Q Is there a signficant separation between them?

A Well, I think in describing the reservoir I was -- I was placing separations between individual units that I consider to be reservoir response units. I used that terminology and I also characterized them as being highly anisotropic and brittle.

The intervening zones are what I would call the massive and more plastic lithologies, but even though they are fractured to some extent, they don't have the fracture intensity that the surrounding brittle zones do and in fact, because of the plastic nature of the lithology, they probably heal to some extent. By "heal" I mean maybe the fracs would close up, you know, because of the nature of the lithology.

So that's what I meant by the separation between those zones.

The actual brittle zones are not all of the A, for example, or all of the B, with some kind of intervening barrier between them. They would be individual units in the B and I think based on the core work, you know, I could identify, maybe, 3 or 4 significant individual brittle zones in that unit.

Q Well, in West Puerto Chiquito you have production from A, B, and C, is that correct?
A Yes, you do.
Q And do you agree that A and B are almost one zone and essentially vertically fractured to the point that they produce --
A Together.

Q -- together as one zone?

A Oh, I think every well out there is hydraulically fractured, so you're communicated vertically by virtue of hydraulic fracturing but the zone are separate in the reservoir is all I'm saying.

Q But then there's enough of the other material that you've described as being very plastic in nature separating C from A and B --

A They're discrete units.

Q -- to make a significant difference from West Puerto Chiquito --

A It prevents the vertical fluid flow --

Q From C to A and B?

A -- in the reservoir. C to B, B to A, C to A.

Q Well, okay, the --

A Right. I'm separating both the A and the C reservoir.

Q Hasn't a great deal of the testimony discussed about what's happening west of this barrier indicated that perhaps that there is almost homogenous zone, A and B together, and --

A Okay, well, that's not my interpretation, no.

Q Okay, then maybe that is what I was --

but in West Puerto Chiquito I see three distinct zones.

A Okay, I see distinct producing zones within all of the three different units in -- on both sides of the existing boundary.

Q Okay.

A That's what I've testified to.

Q What I started to ask you awhile ago is if that structure or formation or whatever you want to call it, being the brittle zones interspersed with the rather fluid ones in the Niobrara formation, if it bends is that part of what creates the fracs? I believe there was some testimony about that, that at the outside of the bend there's a greater fracture than there is at the inside of the bend?

A Yeah. Well, it's -- it's -- that's a very skill-dependent observation, you know, your radius of curvature obviously is critical in this instance, you know, if you look at the diagram that was presented, you have a false impression of the radius of curvature of the actual fold.

The radius would be on the order of miles. The actual thickness of the unit is on the order of 300 feet, and therefore you can't say that the top of the A over the crest of an anticline, for example, would fracture preferentially relative to the bottom of that C unit, for example, just because of the scale of your observation.

Q Is there something that you see or your experience tells you or your model definition or anything that we've talked about in all this, that tells you in that restrictive barrier that supposedly divides the two, West Puerto Chiquito and Gavilan Mancos Pools, that there is some structural difference there that's actually dividing them? I mean we've heard a lot of testimony of being gas communication, oil probably, or fluid moves back and forth, and yet we're talking about the distinct difference between the two pools and perhaps setting a boundary between those two pools? Is there something there that -- in this particular diagram here it appears that this syncline may contribute to the barrier. Is that your assessment?

A No --

Q Or do you believe there is a barrier there at all?

A Well, I don't believe there's a barrier there at all, you know, as I testified earlier, the structural development was the result of a single set of applied tectonic forces in the area. These are compressional features. The fractures that resulted in these individual intervals resulted from that same application of forces.

You will have zones of increased fracture intensity at zones of increased structural intensity, which would correspond to your points of maximum curvature, but they don't in any sense of the word create a situation where you have a barrier to fluid flow across that supposed boundary of the two pools.

There's nothing geologic that would lead me to believe that.

Q And you've seen enough information from both sides of the barrier from wells, known geology, to tell you that things are pretty constant, that there's no major syncline, and then I asked you yesterday --

A Oh, well --

Q -- or day before yesterday about that --

A Well, yeah. Well, you need to look a true structural representation of the reservoir, excuse me. That, you know, representation we see there, of course, gives you an exaggerated structural view, if you want to look it. It's, you know, really there's a 160 feet of relief in the top of the nose to the bottom of the syncline. It's, you know, it's not a (unclear) structure if you look at the scale of the (unclear).

Q Would that formation, if it looked like that, it wouldn't be planal, would it? It would have all kinds of -- like if you waved a blanket or something over it.

A Yeah, going over the structure I guess you could use that characterization.

Q Would that be a fair representation of -- would that affect well to well performance, or the geology surrounding the well which might create different kinds of fractures, intensify the fractures?

A Well, at first blush I think that it would, but you could see a distinct lack or correlation between the second derivative map and existing production data; in fact, no correlation.

Q I think that answers the question. Thank you.

QUESTIONS BY MR. LEMAY:

Q I have one, Mr. Ellis. Just concerning these, the fracture patterns, I think you testified that projection of what you saw at the surface or through their photogrpahs, and so forth, led you to believe there's a random fracture pattern and correct me if I'm wrong in what you said, but subsequent testimony established some north trending faults on the south end of the Gavilan Field, anyway, out of a couple wells.

After hearing that did that change your idea of maybe the fracture pattern within the field?

A Well, I think certainly after looking at the televiewer logs, you know, you could have a fracture orientation at that scale of observation that gives you that orientation, but again, you know, previous testimony last August found a single dominant fracture direction of northwest/southeast, and the critical thing again would be the nature of your observation.

If you look at the scale of the borehole you're looking at a 7-inch borehole picture of the subsurface. You're dealing with vertical, sub-vertical fractures at spacings, indicated spacings of, I believe, two to six inches. If you have a spacing of a fracture at even anything more than that, you're going to miss it, you know, in your observation of the borehole, you know, you have a distinct lack of statistical validity in trying to relate a dominant fracture direction observes in a borehole to an overall reservoir fracture pattern development. In fact, the borehole, if you want to characterize it simply-mindedly, samples less than one billionth of one percent of the total reservoir. Even if you had -- all 179 wells had dipmeter tools or televiewer logs in it, why I still wouldn't necessarily believe, you know, you were looking at a single fracture direction and I seriously doubt you could find that indication if at all.

Q That's all we have to look at, whether it's a core or logs. Of course the logs have a little greater radius of investigation --

A Yeah.

Q -- but we're limited with those data points.

A Well, I think when you're dealing with geologic observations that have some lateral continuity in the subsurface, that makes sense. If you're dealing with vertical observations, you know, it's -- actually you're looking at a line that's, you know, infinitesimally small and trying to observe that, you know, it's a different type of observation whether you're looking vertically rather than horizontally. With a borehole it's vertical, and I'm saying that's a statistically invalid way to characterize reservoir properties of that extent.

Q In trying to develop a pattern of drainage, if there were more vertical fractures aligned in a north/south direction, wouldn't you expect more communication in a north/south direction with the individual wells than in an east/west direction?

A If you had some kind of dominant fracture direction you might suppose there was some kind of directional permeability in the reservoir, that's true.

Q The only other thing, here again it was maybe hearsay or something that was -- I read somewhere, that it's possible to pick up some of these fracture orientations, areas of fractures, from seismic surveys.

Have you had any experience at all with analyzing any geophysical methods that lead you to believe that fractures can be shown on seismic?

A Well, if you're going to use the seismic tool for that, that particular purpose, then I'd want to see some kind of vertical offset on these fractures. I think we're probably dealing with shear fractures of the subsurface. If there is no vertical offset, I seriously doubt the seismic tool will help. You might see minor discontinuities if you move along this section, but that probably wouldn't be a tool we'd want to use in this particular environment.

MR. LEMAY; Did you want any redirect after we ask questions or --

MR. KELLAHIN: I understood the ground rules to be that we would not.

MR. LEMAY: Well, I would prefer that but you're always welcome to.

MR. KELLAHIN: You're doing fine without us, Mr. Chairman.

MR. LEMAY: Well, fine, I think we are, too. Thank you. We're trying to answer a few questions.

At this point we'd like to take maybe a fifteen minute break and come back with just a couple more witnesses.

(Thereupon a fifteen minute recess was taken.)

MR. LEMAY: Is Alan Emmendorfer here?

MR. EMMENDORFER: Yes, sir.

MR. LEMAY: Okay, Would you come up here for a few questions, please?

ALAN P. EMMENDORFER,

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

QUESTIONS BY MR. LEMAY:

Q Just a couple of quick ones here, if you don't mind.

A No problem.

Q You heard what Mr. Ellis said concerning fracture patterns and what was said previously concerning fracture patterns. I just wondered if you agree or disagree with what was said --

A Well --

Q -- previously.

A I disagree with him and it's probably safe to say that since we've been involved with each other since last summer that the only thing we can probably agree on is that there's oil being produced out of the wells in the Gavilan area.

Q You would characterize your relationship as one that's typical of two geologists in disagreement.

Do you believe in the vertical fractures that the predominant direction in that field is vertical fractures are aligned in a north/south direction?

A I believe that there's a multi-directional set of sheared fractures and that there's possibly an extensional fracture developed between the two that set different orientations as you go around the structural nose of the Gavilan Dome.

Q Okay.

A I believe that those orientations can be determined within the wellbore. I'm not prepared to present testimony as to which directions under which particular wells. I've done a complete study on that but I have not brought that with me. We ran fifteen of those oriented microfracture logs that I testified with yesterday and I've looked at everyone of those and I've done in depth statistical studies on those.

I think that I can tell the three principal fracture directions that are the shear fractures and the extensional fracture that's between the two, if it does exist in a particular wellbore that I've got the information from; however, I don't -- I know, and I don't think I'll ever know how I'll be able to determine which of those particular sets of fractures may be preferentially enjoying the current stress regime in the area, providing which ones of those are the dominant fracture direction, which would be the high capacity fractures. I think that I consider that these logs are very accurate in their determination of orientation within the logs, or within the wells.

We heard, I believe, Mr. Ellis and myself quoted Dr. Stearns, that has done quite a bit of fracture work. It's a very recent article himself and a graduate student completed and a summary of this article was in one of the more recent geological -- GSA Bulletins where they had GeoNotes, and in a very recent one they stated that even in a highly fractured dolomite, that to study the whole field you would have to have up to a cube on the surface of, say, or even subsurface, of 9 feet on a square side to analyze and figure out fracture density within that reservoir; however, cores which, although you cannot tell the density of fractures throughout the area, do or are accurate in their depiction of the orientation of those fractures. Fractures routinely are not random except in a few cases, such as chicken wire type fractures, dehydration type stuff, but these -- nature is very systematic in what it does and these orientations in a core will be accurate to within the reservoir itself, even though you may not be able to tell the density of fractures within the area around the wellbore.

Q You had any experience with seismic in fracture location, any geophysical tools like seismic?

A Fracture location in what respect? That there's one fracture there or a swarm of fractures or --

Q No, I mean very highly fractured compared to another area that wasn't so highly fractured?

A No, sir, I'm not.

Q Thank you very much, Mr. --

A Uh-huh.

Q -- Emmendorfer.

MR. LEMAY: Mr. Al Greer, could you step back here? We could maybe ask you a few more questions?

MR. CARR: He'll be here in just a second.

MR. LEMAY: Okay. Well, we can do that later.

How about Mr. John Roe, to answer another few questions?

Mr. Roe, basically, we want to get into an area, I think, with you that has not been covered that we think is an important part of the field and important part of the correlative rights issue, and that's the south part of the field that's been shut-in and people are losing reserves without producing them. In that regard, I'd like, maybe, Vic Lyon to ask you a couple of questions in that area because he -- he's studied it and has some points I think we need to get in the record.

MR. ROE: Sure.

JOHN ROE,

being recalled and remaining under oath, testified as follows, to-wit:

QUESTIONS BY MR. LYON:

Q Mr. Roe, I reviewed your -- your -- I think it was the first exhibit, where you tabulated the data on all of the wells.

There were a lot of wells that were shown on there just as locations but I have strong impressions that there are many wells that have been completed that are not producing because they do not have access to gas gathering lines.

Could you give us some data on that?

A I -- that tabulation, my Exhibit Number One, from that I did not have anything that you could really pick out which wells were not producing during December simply because they weren't connected to a pipeline, but most of the wells that I showed that had zero production, or several of the wells, during December were shut-in primarily at the operator's option because they either could not get permission to vent the gas that's associated with the oil or the gas venting allowable, in other words, approximately 30 MCF a day, would be produced in such a short period of time that the operator chose not to vent the gas for such a small amount of oil.

There are approximately, I don't have right here at my fingertips an exact number of wells that are shut-in without a pipeline connection but I could get that without too awful much trouble.

Q Do you know whether some of the wells that are shown as producing are venting the gas because they don't have a pipeline connection?

A I can speak for Dugan Production and Jerome P. McHugh. For the most part there had been some production prior to obtaining a pipeline connection.

Dugan Production has just recently installed a rather extensive gas gathering system in the northern part of the field, simply to have access to a market. We were not able to obtain a -- we were able to -- or we had our acreage dedicated, fortunately, and so we did have a gas contract, but we -- we basically installed about six miles of gas gathering system so that we could deliver gas to El Paso because they would not come get it.

I am aware of -- that Mallon Oil had a similar arrangement. They also had to install a fairly extensive gas gathering system, primarily for the same reason. But prior to delivering that gas through our system we did get some gas subject to an allowable restriction, or a venting restriction.

Q I think the November issue of (not understood), is the latest one that we had available, and when I was reviewing that I did notice that McHugh had a gathering system and Dugan has a gathering system. There was a system called Gavilan Joint Venture, which I think is Mallon.

A Yes, sir.

Q Where do those gathering systems deliver their gas?

A It's my understanding, and I'd like to say I probably should not speak a whole lot for Mr. Mallon's system, but it's my understanding that that's no longer -- that does gather gas from his wells and he ties into a line that belongs to the Gas Company of New Mexico.

Dugan Production's line ties into El Paso's main line in Section 32 of 26 North, 2 West, and it's their lateral 2C-50.

Mr. McHugh's lines, he operates not just one gathering system. We -- any of his wells that we've completed, as much as practical, we lay one line to gather as many wells as we can, but there is many lines that we've laid to a central point. So there's more than just one central delivery point.

But McHugh's gas pretty much goes into El Paso's system, contracted to Northwest Pipeline.

Q All right. Now, yesterday when I was visiting with you in a break in the hearing, you mentioned that your Loddy Well, which has been used as a pressure observation well --

A Yes, sir.

Q -- was denied access to the market because of flaws in your contract with Northwest Pipeline.

A It's -- that's my understanding, yes. We actually had the well connected for sales but we were not given permission to first deliver gas into the line and there are other wells that have experienced that same frustration.

I think even some of Meridian's wells, we had pressure data on them and again Meridian's engineer would probably be better to comment on them, but the last -- the Hill Federal Wells, the 1, the 2-Y, and the 3, they were quite awhile getting their wells hooked up.

Q I'll ask, as an engineer would you --

would you agree that necessity to vent that gas because of lack of a pipeline connection is a matter of waste?

A It's definitely a matter of waste but I had a very lengthy conversation with Mr. Chavez over that very same issue.

Dugan Production, in order -- because I -- because I feel the well to well communication in this reservoir is such that idle wells or undeveloped acreage is suffering drainage, I myself view what I presented as Exhibit Number Ten, which was the pressure history in the Loddy, is a direct measurement of that fact and because I do feel there is a pretty extensive well to well communication throughout the reservoir, that an operator needs to be producing his wells or his oil reserves are being drained, as evidenced by the Loddy.

And the Loddy is not the only example that we have of that. We have Meridian's wells, we have basically the same kind of pressure data in their wells, the Hawk Federal 1, 2, and 3.

Any well that's been completed and left idle for any length of time, we've been able to observe a reduction in reservoir pressure, in any well that we've measured pressure in. I'm not aware of any well that we've been able to monitor pressure that hasn't experienced a decline in reservoir pressure.

Q I realize these questions don't have any bearing on the issue that is involved here, but I think that it certainly is a question of waste and correlative rights that the Commission is aware of. Do you have any recommendation that -- of action the Commission might take that's appropriate to prevent such impairment of correlative rights and waste?

A Well, it's hard for me to -- I haven't thought that through very, very clear. I would like, you know, I think that probably, with some help from our attorneys, I might be able to give you some -- some ideas, but I don't think I probably should comment on that at this time.

I do think that there's need for something.

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

MR. LEMAY: Mr. Chavez?

QUESTIONS BY MR. CHAVEZ:

Q Mr. Roe, in conjunction with Mr. Lyon's question, we're discussing issues of violation of correlative rights, and things like that.

In your opinion as a petroleum engineer, if a well is not allowed to connect to a gas pipeline, and is therefore restricted in venting or does not produce to prevent the waste of gas to the atmosphere, (not understood) in the pool, do you think that operators' rights may be violated?

A Yes, I feel so, and that's basically what led me to produce our Tapacitos 4 and caused you to tell us to shut it in, because we were overproduced. I was unaware of the 30 MCF a day. I thought we had more production allowable than we did.

Q Thank you.

MR. LEMAY: If there are no questions, Mr. Roe, we appreciate you addressing that issue. Thank you.

Mr. Greer, could we ask you to come back up for some questions?

ALBERT R. GREER,

being recalled and remaining under oath, testified as follows, to-wit:

QUESTIONS BY MR. BROSTUEN:

Q Mr. Greer, in your discussion on the section behind Tab R in the exhibit that you presented to the Commission the other day, you discussed a comparison of core analyses between the Mobil Lindrith B Unit No. 3 and the Mallon 3-15 Davis Federal.

One of the things that I'm not -- one of my questions, I guess, is this the same core analyses that Mr. Hueni referred to? Is it the same study that Mr. Hueni refers to where he reviewed these core analyses (not understood)?

A I believe so, sir, the Mallon Davis 3-15.

Q And it's the same study that was performed by Terra Tek, is that the name of the company?

A Yes, sir.

Q In your analysis here, unless I missed it some place, you do not mention as far as the porosity values that would permit -- that may have been derived from that analyses, and you are aware of the values which Mr. Hueni has presented. Do you agree with those or do you feel that because of the manner in which the samples were -- were handled or the analysis was performed, that they are invalid numbers as far as porosity is concerned?

A Well, as far as porosity is concerned, I would think they're -- they're reasonable numbers. My main concern last year was with the saturations of oil and water.

Q I see, so that's where your difference of opinion comes in.

A That was my main concern.

Q Very good.

A Along with the fact that the permeability was so low that I felt the water saturation would be so high the (not clearly understood.)

Q Thank you, that's all I have.

QUESTIONS BY MR. LEMAY:

Q Mr. Greer, in light of the testimony since your testimony, do you feel that you are losing some gas or oil down dip to the Gavilan Field on the current situations of pressures and the way the field is being produced today?

A There's no doubt about it, Mr. Chairman.

Q If the pressures were equalized in there, would that still be the case?

A Yes, sir. Yes, sir. We're voiding the reservoir at the rate of about, oh, zero to 1000 barrels a day and Gavilan is voiding it at the rate of 10 to 20,000 barrels a day.

Q And you believe that permeability barrier in there, as it's been drawn, is an imperfect barrier, that you're losing some A and B oil down dip into Gavilan and mabe some C, also?

A Yes, sir. It's hard to tell how much from which zone but there's just no doubt that we're losing oil across the boundaries. I think that's evident, you know, from our Exhibit N, where we showed the communication across the boundary, both the existing Gavilan boundary and Mesa Grande's proposed new boundary.

Q I know we've had the computer modeling and since your testimony we've had the Sun model and then Mr. Hueni's model. Have you got anything to say concerning either rate sensitivity in the reservoir or the existance of a dual porosity system?

A Yes, sir. First let me say the -- in determining the dual porosity system and the percent of the oil that might be in the fractures and in the matrix as determined by Mr. Hueni is based primarily on his model of which, you know, you were asking some questions this morning and could see very little difference in the lines from 1/10th fracture porosity up to 5/10ths and my concern about the model, of course, is dependent on what goes into it.

One of the real critical factors that goes into the model is the relative permeability to oil. This is something that in a fractured reservoir is most difficult to determine. It's difficult to determine in a laboratory even when you can visualize, take a little block and fracture it and cut some fractures in it and stick it into something to analyze it in a laboratory and the water's going to -- or whatever fluid you're using is going to immediately drop to the bottom of the fractures and its tough, it's a tough situation to analyze.

The very best thing we can -- that we have to determine this is field performance and the field performance is dependent on how carefully you've conditioned the wells and monitoring the offet wells and this is one of the things that I had visualized would be a good project for the Engineering Committee, would be to work on this, but of course we didn't get to that point.

Absent that, the best thing we could do in our area, we chose two wells that unquestionably produce from a high capacity fracture system. That's our B-29 and our B-32, just east of the so-called permeability restriction. We made a test at a time by happenstance when the Gavilan wells were pretty much shutdown because of the fire at the compressor station. In conjunction with the interference test that we ran, which I just referred to here under Section N of our Exhibit One, we also ran productivity indices tests and transmissibility tests. This was in conjunction with the work of the Engineering Subcommittee.

Meridian had presented its work to the committee the first week in November. I had in my briefcase when we went to the November, mid-November meeting, 20 copies of the information and I'll summarize some of it for you here now. I think it's the best we have right now to tell something about relative permeability, and of course even that's not as definitive as we'd like for it to be.

I believe it's under Section -- Section S, but I'll have to look.

If you'll turn to Section S and one, two, three, four, five, about the sixth page there's a pink sheet and on the lefthand side it says Page 1, the righthand side, Page 2. I've used here a method of determining Kh from PI, and what that means is the determination of the relative permeability ratio to oil at that particular time. The key, the key figures are on a schedule on the upper righthand side under Kror divided by Krow and under that we have 6.7 and 12.5 and is an average of 9.6. It would be nice to have the figures check a little closer but that's all we had.

9.6 in this instance means that the relative permeability to oil is about 10 percent of what it would be if there were no restrictions of flow presumably by free gas saturation.

Now if we'll go to one of Mr. Hueni's exhibits, I'll show you my concern. I believe it's Figure 37.

In the test that we ran, and I don't have the exact figures now, but the free gas saturation would have probably have been in the range, I would think, the average not over 5 percent, so if we come to this graph and we see on the bottom oil saturation goes up to, well, in units of a tenth, it would be 80 percent oil saturation next to the righthand side; halfway in between would be 90 percent oil saturation, and 10 percent free gas saturation would be a line right straight up from that, and you go up from that till you reach a relative permeability of 1/10th and that's where the average fell. One would be a little bit above that and one would be a little bit below that.

Now the line that Mr. Hueni is using and put in his model, is the dashed line that starts at the upper righthand side of the graph and goes down to the lower lefthand side, so we can see that for wells that we know are producing from a high capacity fracture system, see, these are large wells, Mr. Chairman, that produce 6-or-800 barrels a day with about 100 pound drawdown. The PI that we extrapolated even with the relative permeability effects, would stretch out to about 30,000 barrels a day on one of the wells.

So there's no doubt about what they're producing and so the problem that I have with his model is when he puts something in it that is so wrong, so far wrong, and then he uses that model to determine so many things. He uses it to determine a bubble point. He uses the model to determine the percent of oil that's in the fracture system. And so I just can't have any confidence in it.

That's my concern about it.

Q Thank you, Mr. Greer. We're trying to resolve some differences and it doesn't look like we're going to resolve many of them.

Mr. Hueni, do you mind coming back for a few more questions? You've had a long two days.

GREGORY D. HUENI,

being recalled and remaining under oath, testified as follows, to-wit:

QUESTIONS BY MR. LEMAY:

Q You actually get more time than normal, not because you're the last witness, but because you're the only engineer on the MMM side where they have two of them.

The first thing, on the shut-in question, Mr. Roe's comments concerning the answers to his questions, do you have any comments on -- on that problem as we see it? We want to get some testimony in the record because we certainly view it as a serious matter.

A I'll have to be honest, at the time that Mr. Roe testified I was checking out some of the other information. I know that you -- I believe you had a concern with wells that were flaring gas, is that correct?

Q Well, that were really being deprived of their reserve because they didn't have a tie-in to the casinghead gas market and therefore the pressure was dropping. I think I mentioned one to you which was that Krystina well that Greg Merrion operates. There's others in the area, too, quite a few others.

A Well, I agree. I think there is concern and I do believe that because there is pressure communication in the field that all wells will share in proportion to the rates at which they're allowed to produce, they'll share in the remaining reserves based on that -- on that rate, and if wells are deprived of their right to produce, then there is a serious problem there.

Q Do you have any comments on your Figure 37, Mr. Greer's comment concerning that -- what he considered your erroneous assumption that went into the computer models?

A Well, the -- this, I'm sure sounds like going back and forth, but we -- the build-up test that Mr. Greer used that he ran on his Canada Ojitos Unit B-39 and B-32 Wells, we agree they're very high capacity wells and we've analyzed the build-up tests that he presented and we come up with permeability values substantially below the values that he came up with.

As a consequence, in his exhibit, when he calculates and takes permeability thickness and divides or then relates that to productivity and calculates out a relative permeability ratio, we don't -- we don't agree with what he calculates, so we don't believe that the number that he has calculated has any bearing to relative permeability at all.

We believe we have a high capacity fracture system. We believe is we looked at the Sun detailed output from the computer run we would see gas at the top of the formation, oil at the bottom of the formation.

The relative permeability characteristics that we've shown here, if you were to review the literature, you would see that the relative permeability characteristics assigned to the fracture system, and that is what those dashed lines were, were fracture system, not the matrix, I think you would see that the -- the literature would suggest, papers by Keith Coates, regarding vertical equilibrium models would suggest that those -- that those (not understood) permeability curves are consistent with gas segregating at the top of the formation and oil underlying the formation. They are what we call vertical equilibrium curves.

We didn't use those curves because that's -- for that reason. We used them primarily because the literature, and I would cite, and I have cited in our report, reference by a fellow named Fatt, F-A-T-T, and also referenced in papers by Aguilera, that when you do have high capacity fracture systems, the relative permeability characteristics that should be applied to those fractures themselves, not the entire rock, but those fractures, is represented, best represented by straight line functions, or straight line curves between the end points. That is what we have done. We have, in reference to Mr. Greer's exhibit, we don't agree with how he calculated Kh so we don't agree with how he calculated Kr, relative permeability, so we don't agree.

Q Do you believe that -- that there is significant migration at the present time between Puerto Chiquito and the Mancos Field, that there is some oil moving across the field boundaries?

A Mr. Chairman, we believe that it is a very complex question. We, I think the testimony has indicated that the A and B and the C Zones are separate pools. We believe that the C Zone in the Canada Ojitos Unit is primarily a gas injection zone. We do not believe that the A and B Zone in the West Puerto Chiquito is a gas injection zone. It seems to be related more to the Gavilan Mancos Field.

I think we've seen that from Mr. Greer's exhibits in terms of the B-29 and B-32 pressure information, that is it tracking more on the Gavilan Mancos pressure.

We have seen previously that the Canada Ojitos gas injection project does not track with the Gavilan Mancos pressure, so we have concluded that in the West Puerto Chiquito area that we are producing out of two separate zones with totally different producing mechanisms.

Mr. Greer's gas injection program is operative primarily in the C Zone. In the AB Zone it is more of a pressure depletion in line with the Gavilan -- the Gavilan Mancos Pool.

Inasmuch as there is a sharing, inasmuch as there is a competition in the Gavilan Mancos Pool, primarily in the AB Zones, we believe that that competition exists. We do not believe that there is C production, substantial C production in the Gavilan Mancos Pool that is drawing oil across the boundary of the West Puerto Chiquito Pool into the Gavilan Mancos Pool.

Q So the reservoir voidage that Mr. Greer referred to would not be significant in your thinking because you're dealing with these separate zones.

A Well, we don't believe that --

Q If you can --

A -- I'm sorry, I didn't mean to interrupt.

Q I was going to say that -- just that I didn't define the question properly. What I meant to say, that if you're -- if you're voiding more in the AB in the Gavilan, that that's not a factor with his C Zone or AB Zone in Puerto -- West Puerto Chiquito.

A Well, we unfortunately have no idea, really, the relative amounts that he's voiding out of the AB Zone in West Puerto Chiquito versus the amount that he's voiding out of the C Zone. It very well could be that the amount he's voiding out of the AB Zone is proportional to the amount of voidage that's coming out of the Gavilan Mancos Pool, so that there is no drainage between the two pools in the AB Zone.

In the C Zone, the Gavilan Mancos Pool is not voiding a substantial amount, whereas that is where we see the majority of his voidage occurring in the West Puerto Chiquito Pool, although he's also replacing his voidage with injected gas in operation.

So we're trying to draw the distinguishing fact that we're dealing with two, we call it the Niobrara -- we call it the Niobrara, or the Mancos Pool, but we're dealing with the Niobrara AB Zone that is separate and distinct from the Niobrara C Zone, and I think we have to recognize that.

Q To your knowledge is there any difference in pressures in the AB Zone and C Zone?

A In the Gavilan area, we do not have any substantial evidence of pressure differences, but once again, in the Gavilan area we also don't have highly -- we don't have any wells that are highly productive in the C Zone.

In the Canada -- or West Puerto Chiquito Pool we either have wells that are primarily C Zone wells or we have wells that are A, B, and C Zone wells, and it very well could be that there is a different pressure in the AB Zone than there is in the C Zone.

We do not have that information.

MR. LEMAY: Thank you very much, Mr. Hueni.

At this point I don't think -- Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, I have available now Dr. Lee's summary for tomorrow, as well as his bibliography, and in accordance with our statements earlier today, I'd like to distribute this after the hearing.

MR. LEMAY: Fine. These are the exhibits that you're presenting tomorrow?

MR. KELLAHIN: No, sir, they're not the exhibits.

MR. LEMAY: Oh.

MR. KELLAHIN: They're the summary of his conclusions --

MR. LEMAY: I see.

MR. KELLAHIN: -- as well as the bibliography sheet that he's provided.

MR. LEMAY: Okay. Since we are running ahead of time, at least today, is there anyone in the audience that has any statements that they'd like to make today, possibly in preference to tomorrow? We'll accept closing statements but we're also, in the interest of time, wanting to get as much in today as we can.

The schedule for tomorrow, then, would be we'll have the rebuttal witness by Mr. Lee. Then we'll cross examine. And the possibility of a rebuttal rebuttal witness. In the interest of time we hope that we'll try and limit this to the morning. We don't want to go over in the afternoon. If necessary, I'm sure we will, because we want to get all the testimony in the record.

At that time we will be accepting statements into the record and closing arguments.

So that's the schedule for tomorrow. Does anyone have anything to add or to --

MR. KELLAHIN: I don't.

MR. LEMAY: 8:15 tomorrow morning.

We'll adjourn for today and resume tomorrow at 8:15.

(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