NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date MARCH 30, 1987 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION
William F. Carr	Campbell and Black, P.A.	Santa Fe
KENT LUND	AMOCO PROD. CO.	DENVER, CO
Bob Huber	Byram	Santa Fe
Carl Pomeroy	Koch Exploration	Wichita, Ks
KENT JOHNSON	KODIAK PETROLEUM, INC.	DENVER, Co.
Alan Emmendorfer	Mesa Grande Resources, Inc	Tulsa, OK
GREG D. Owens	Hooper, Kimball & Williams	Tulsa, OK
W. Perry Pearce	Montgomery & Andrews, PA	Santa Fe
KEVIN M. FITZGERALD	MALLON OIL COMPANY	DENVER
JOHN FAULHABER	MOBIL	MIDLAND
Lloyd Strange	Mobil	Dallas
T. L. Hill	MOBIL	Midland, Tx
E. L. Padilla	Padilla + Snyder	SF
R. W. Wilson	BLM	Farmington
JACK HAMMER	Mobil Producing	Midland, Tx
STEVE STRUNA	TENNECO Oil Company	DENVER
F. Chavez	OCD	Aztec
V. T. LYON	OCD	Santa Fe
DICK ELLIS	McHUGH	DENVER
L. Smit	MGL.	Tulsa.

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NAME	REPRESENTING	LOCATION
Owen Lopez	Hinkle Law Firm	Santa Fe
R. Frasley	Meridian Oil	Farmington
Virgil L. Stoabs	Benson - Montin - Greer	Fmn
Bruce Petitt	Reading & Bates Petr. Co	Tulsa, OK.
W. T. Kellahin	Kellahin Kellahin & Aubrey	Santa Fe
Don Howard	Rancher	Lindrith
FRANK E. SYFAN	Sun Expl & Production	DENVER
Ernest Baca	Land Office	Santa Fe
Nicholas G. Kaufy	Lloyd + Gunnell Edwards	Albuq, NM.
Jane Clancy	B.L.M	Albuq. N.M
Robert Kent	B. L. M.	Albuq. NM
Kent Craig	McHugh & Assc.	Denver, CO
GREG HUENI	BERGESON Assoc.	DENVER
JACK LONDON	LONDON - MONTIN - HARBERT	OKLA. CITY
A. L. Kuchera	Hixon Dev Co	Farmington
Barbara L. Williams	Dugan Production Corp	Farmington
Robert Buettner	Koch Exploration Co.	Wichita KS
Tom Dugan	Dugan Prod Corp.	Farmington
Red Walsh	Walsh Engineering & Prod Corp	Farmington

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NAME	REPRESENTING	LOCATION
Mike Rivera	Great Western Petroleum 4-1-87	Denver, CO
Alan Wood	Amoco 4-1-87	Denver, Co
DAVE MARTIN	PETROLEUM RECOVERY RESEARCH CENTER	SOCORRO, NM
Ann Howard	Rancher (landowner)	Lindrith NM 87029
Bill Weiss	PRRC	Socorro NM
Joe Stevens	Giant Refining Co.	Farmington, NM
Mark Adams	Rodey Law Firm	Albuquerque
ROBERT G. Mock	Phelps Dodge Corporation	Phoenix, AZ
John Roe	Dugan Production Corp	Farmington, NM

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NAME	REPRESENTING	LOCATION

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

30 March, 1987

COMMISSION HEARING

VOLUME I of 5 VOLUMES

IN THE MATTER OF:

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

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

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Commission:	Jeff Taylor Legal Counsel for the Division Oil Conservation Division State Land Office Bldg. Santa Fe, New Mexico 87501
For Benson-Montin-Greer:	William F. Carr Attorney at Law CAMPBELL & BLACK P.A. P. O. Box 2208 Santa Fe, New Mexico 87501
For Sun Exploration, Dugan Production, & Jerome P. McHugh:	W. Thomas Kellahin Attorney at Law KELLAHIN, KELLAHIN & AUBREY P. O. Box 2265 Santa Fe, New Mexico 87501 and Mr. Robert Stovall and Mr. Alan R. Tubb
For Mesa Grande Resources:	Owen M. Lopez Paul Kelly Attorneys at Law HINKLE LAW FIRM P. O. Box 2068 Santa Fe, New Mexico 87501
For Mallon Oil Co. & Mobil Producing Texas & New Mexico:	W. Perry Pearce Attorney at Law MONTGOMERY & ANDREWS P.A. P. O. Box 2307 Santa Fe, New Mexico 87504
For Amoco:	Kent J. Lund Attorney at Law Amoco Production Company P. O. Box 800 Denver, Colorado 80201

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

For Floyd and Emma Edwards:	Ernest L. Padilla Attorney at Law PADILLA & SNYDER P. O. Box 2523 Santa Fe, New Mexico and Nicholas R. Gentry Attorney at Law OMAN, GENTRY & YNTEMA P. O. Box 1748 Albuquerque, New Mexico 87102
For Meridian Oil Co.:	Paul A. Cooter Attorney at Law RODEY LAW FIRM P. O. Box 1357 Santa Fe, New Mexico 87504
For Don Howard:	William O. Jordan Attorney at Law Santa Fe, New Mexico 87501
For Koch Ex. Co.:	Robert D. Buettner Attorney at Law Koch Exploration Co. P. O. Box 2256 Wichita, Kansas 67201
For Phelps Dodge Corp.:	Mark K. Adams Attorney at Law RODEY LAW FIRM P. O. Box 1888 Albuquerque, New Mexico 87103

I N D E X

EXHIBITS

MR. LEMAY: We'll now go on to Case 7980 and subsequent cases.

MR. TAYLOR: In the matter of Case 7980 being reopened pursuant to the provisions of Commission Order No. R-7407, which order promulgated temporary special rules and regulations for the Gavilan-Mancos Oil Pool in Rio Arriba County, including a provision for 320-acre spacing units.

Operators in said pool may appear and show cause why said pool should not be developed on 40-acre spacing units.

MR. LEMAY; For purposes of these five days of hearing, we shall consolidate all five cases and accept testiony concerning all five cases, so if you would read the other cases, also.

MR. TAYLOR: Case 8946, in the matter of Case 8946 being reopened pursuant to the provisions of Commission Order No. R-7407-D, which order promulgated a temporary limiting gas/oil ratio and depth bracket allowable for the Gavilan-Mancos Oil Pool in Rio Arriba County.

This case is being reopened in consolidation with the reconsideration of the temporary special rules established by Order No. R-7407 for the Gavilan-Mancos Oil Pool.

Case 8950. In the matter of Case 8950 being reopened pursuant to the provisions of Commission Order No. R-2565-E, R-6469-C, and R-3401-A, as amended, which order promulgated a temporary limiting gas/oil ratio for the West Puerto Chiquito-Mancos Oil Pool in Rio Arriba County.

This case is being reopened in consolidation with the reconsideration of the temporary special rules established by Order No. R-7407 for the Gavilan-Mancos Oil Pool.

Case 9113, the application of Benson-Montin-Greer Drilling Corporation, Jerome P. McHugh and 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 Oil Pool, Rio Arriba County, New Mexico.

Case 9114, the application of Mesa Grande Resources, Inc., for the extension of the Gavilan-Mancos Oil Pool and the contraction of West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico.

MR. LEMAY: Thank you. We're going to call for appearances in all cases.

MR. KELLAHIN: Mr. Chairman, I'm

Tom Kellahin of Santa Fe, New Mexico.

I'm appearing on behalf of Jerome P. McHugh and Associates, they are one of the applicants along with Mr. Greer, Dugan Petroleum, and Sun.

In addition, I'm appearing in association with Mr. Robert Stovall on behald of Dugan Production Corporation, and finally, in association with Mr. Alan R. Tubb on behalf of Sun Exploration and Production Company.

The notice for Case 9113 has omitted Dugan Production Corporation as an applicant and so that it is clear, we would request that you note that Dugan Production Corporation is an applicant along with the other three companies in that case.

MR. LEMAY: So noted. Mr. Carr.

MR. CARR: May it please the Commission, my name is William F. Carr with the law firm Campbell & Black, P. A., of Santa Fe, New Mexico.

I represent Benson-Montin-Greer Drilling Corporation, one of the applicants in Case 9113, and I have one witness.

MR. LEMAY; Thank you. Are there other appearances?

MR PEARCE: May it please the

Commission, I am W. Perry Pearce of the Santa Fe law firm of Montgomery & Andrews.

I appear in these cases representing Mobil Producing Texas & New Mexico, Inc., and Mallon, M-A-L-L-O-N, Oil Company.

MR. LEMAY: Thank you, Mr. Pearce.

Additional appearances?

MR. LOPEZ: Mr. Chairman, Members of the Commission, my name is Owen Lopez of the Hinkle Law Firm of Santa Fe, New Mexico, appearing together with my partner, Paul Kelly, representing Mesa Grande, Inc. and Mesa Grande Resources, Inc.

MR. LEMAY: Thank you, Mr. Lopez. Additional appearances?

MR. LUND: Mr. Chairman, Kent Lund, Amoco Production Company, Denver.

We don't have any witnesses.

MR. LEMAY: Thank you, Mr. Lund. Additional witnesses or additional appearances?

MR. GENTRY: Mr. Chairman, my name is Nicholas R. Gentry with the Albuquerque firm of Oman, Gentry and Yntema, and I am here with Mr. E. L. Padilla of Padilla and Snyder, a Santa Fe firm representing Floyd and Emma Edwards.

MR. LEMAY Mr. Gentry, do you plan to have any witnesses to present testimony at this time?

MR. GENTRY: Well, at this point we don't, Mr. Chairman. I believe initially we had requested two hours of time from the Commission to present a case in chief.

At this time it doesn't appear that we will present that case.

MR. LEMAY: Okay, thank you, Mr. Gentry.

MR. JORDAN: I'm William O. Jordan, Santa Fe, New Mexico, and I'm appearing on behalf of Mr. and Mrs. Don Howard.

There will probably be others and I'll let you know later.

MR. LEMAY: All right, Mr. Jordan. Will you have any witnesses to present testimony?

MR. JORDAN: At this time I don't anticipate having any witnesses.

MR. LEMAY; Any additional appearances?

MR. LOPEZ: Mr. Chairman, I misspoke, it's Mesa Grande Resources, Inc., and I can also correct the record, we are also appearing in association with Koch Exploration Company with General Counsel, Mr. Bob Buettner, who's not here right now but will be here this afternoon.

MR. LEMAY: Thank you, Mr. Lopez.

Additional appearances?

At this time I think we can swear in all the witnesses that will be giving testimony for the 5-day period.

(Witnesses sworn.)

I think we'll start with Mr. Carr.

MR. CARR: May it please the Commission, Benson-Montin-Greer Drilling Corporation is before you today seeking an order abolishing the Gavilan-Mancos Oil Pool, extending the West Puerto Chiquito-Mancos Pool to the west including the acreage also currently within the Gavilan-Mancos Pool, and is also seeking the promulgation of special pool rules and regulations for the pool.

We are seeking rules that will provide for 640-acre spacing with an optional second well on each of the units.

We also are requesting that you

continue present rules which restrict production from the pool and we are requesting that the production from this pool be restricted to 800 barrels of oil per day and further limited by a gas/oil ratio of 600-to-1.

What we have here is that the historic development of this area has resulted in one reservoir being produced as two pools under separate and different pool rules.

One pool, the West Puerto Chiquito-Mancos Pool, has been developed and produced with limited withdrawals, wells on a wide spacing pattern, and experience, we believe, shows that this method of producing the pool has resulted in an increase of ultimate recovery of oil from the reservoir.

On the other hand we have the Gavilan-Mancos Oil Pool. It is developed under rules which provide for denser spacing patterns. There have been higher rates of withdrawal from this pool and these withdrawal rates have reduced the ultimate recovery from the pool. They are resulting in underground waste and they are impairing the correlative rights of the interest owners in the pool for they are denying to these interest owners with these withdrawal rates, the opportunity for the interest owners to produce without waste their just and fair share of the reserves from the pool.

This is not a new problem. A year ago the Oil Conservation Commission's office in Aztec called operators together to discuss what should be done with this reservoir. Meetings were held; nothing was resolved, and in August, 1986, we came before the Commission and after a lengthy hearing obtained an order which reduced production rates from the pool for a temporary period and directed the operators in the pool to form such technical committees as were necessary to address the problems in the pool and hopefully come back to you with some recommendations.

As you know, this effort did not work and we now must come back to you and seek your assistance in determining how this pool must be produced.

We will present evidence that will show that we are talking about one reservoir. We will show that there is geologic continuity of the rock, that the zones correlate, that there is pressure communication throughout, and we are talking about one common source of supply.

The pool, however, is stratified, and we will show you that production is from individual, separate zones. The production in the pool, we will show, is from an extensive fracture system, a multi-directional fracture system, and that there is little or no production coming from the matrix in this reservoir.

The reservoir drive mechanism is solution gas drive, but there is substantial, additional quantities of oil that can and have been recovered through gravity drainage; gravity drainage which results from the dip of the formation, both in the Gavilan and in the West Puerto Chiquito area, and also results because there is sufficient permeability throughout the reservoir.

We will show you that reduced recovery rates will in fact result in increased ultimate recovery but that these rates must be well below the solution gas/oil ratio if in fact the benefits of gravity drainage are to be realized.

At the end of our presentation we will make recommendations to you on what should be done and we believe that you will see at the conclusion of our case that although it is a complex case, it's an engineering case, and it is technical, that it is not going to be a case that will be difficult to decide, for when you look at all the technical presentations, we are convinced that what Benson-Montin-Greer, Sun, Dugan, and McHugh will show you is a presentation which more closely approximates actual reservoir performance.

When the evidence is before you, we are convinced that you will be able to enter an order restricting production rates, merging the pools, promulgating new rules, and carrying out your statutory duty to prevent waste and protect correlative rights.

Thank you.

MR. LEMAY: Thank you, Mr. Carr.

Mr. Kellahin, opening remarks?

MR. KELLAHIN: Thank you, Mr. Chairman.

I represent Jerome McHugh and Mr. Tom Dugan. They are operators and working interest owners in the Gavilan portion of this reservoir, which lies to the west of Mr. Greer's pool.

In addition, I represent Sun Exploration and Production Company. They are a working interest owner in Mr. Greer's unit, in the Canada Ojitos Unit.

It is our position, and we share the same points that Mr. Carr has raised with you, that we have, in fact, one reservoir. The Mancos reservoir should be treated as one reservoir. It is our position, and the evidence will demonstrate to you, that we must remove the artificial fiction of maintaining these two entities or areas as separate pools because there's no justification to do so.

We have in the past established a buffer zone and you'll hear discussions about this buffer zone.

It was a great hope of Mr. Greer's, and he's told this Commission before, it was a great hope that that buffer zone would provide an adequate barrier, if you would, to ensure that the production in Gavilan-Mancos to the west of Puerto Chiquito was going to be effective. The evidence will show you that every time that buffer is tested it communicates with the other side of the reservoir; convincing, compelling, actual evidence of communication between the two pools.

The evidence will demonstrate to you that the Mancos reservoir is in fact three distinct producing zones. You are going to hear discussion about the A Zone, which is the upper zone. You're going to hear discussion about the B, which is the next zone down in the formation, and finally the C Zone. You will see compelling, convincing evidence that each of those zones is produced in both sides of this same reservoir.

You're going ot find that there is significant interference between wells of tremendous extent. We're going to conclusively establish for you that the spacing must be wider than it is now. We're requesting 640-acre spacing in order to avoid the drilling of unnecessary wells.

We're going to show you that

this reservoir is unusual. It is not the typical sand matrix producing reservoir that you may be familiar with. This is an unusual fractured, stratified reservoir in which the matrix contribution is virtually nonexistent. The production comes from the fractures and that's the way the oil is recovered.

We're going to demonstrate to you that this is primarily a solution gas drive reservoir but with a significant, significant opportunity to increase ultimate recovery by restricting and controlling the gas withdrawals from this reservoir. It is rate sensitive. You will hear a lot of discussions about whether this reservoir is rate sensitive. We maintain and conclude that the rate must be controlled.

This is a continuing saga that we're into chapter three or four or five, I've lost track, but back in August we had five days of hearings in which we came before this very Commission and told you you had an emergency on your hands. We saw and proved to you that that emergency existed, that the producing rates established by statewide rules for this pool prior to the restrictions would have allowed operators to produce at a statewide maximum daily allowable of 702 barrels a day at a gas/oil ratio of 2000-to-1.

It was established then in

August, and we will reconfirm it for you today and tomorrow and the rest of this week, that those rates constitute waste. They are too high; they must be reduced; and in fact this very Commission reduced those rates in August. They reduced them down to a significant level which we maintain aids and allows this reservoir to obtian additional gravity recovery, and we're back before you today to show you that the rates need to be further restricted.

It is our position that the action taken by the Commission in August was the appropriate first step in order to put some sense and structure to this reservoir that the operators are unable or unwilling to do collectively under some concensus for themselves. We need the conservation help of the Commission to maximize the recovery of the reservoir.

The former Commission asked us in August, and it's set forth in the order, and they asked the operators to get together in this reservoir and do a reservoir study so that we would have specific, technical data to come back and demonstrate that the August action was appropriate.

We've been unable to get together and do that collective study; however, this group of applicants have done that study. We are going to give you that study in the course of this hearing, so at the conclusion the evidence will justify the further restrictions to allow this reservoir to obtain the maximum ultimate recovery of oil from a tremendous resource in this state.

We have summarized our principal points of our presentation and submitted them to the Commission last Monday, I believe. I have additional copies of that summary which I'd like to make available to you so that as you can see us go through the presentation of the technical evidence, I would like you to simply check them off the list and you can show the principal points that we're trying to establish for you that will be the benchmark upon which we believe that you can grant the relief we've requested.

MR. LEMAY; Thank you, Mr. Kellahin.

Mr. Lopez.

MR. LOPEZ: Mr. Chairman, in the spirit of accommodating a judicial economy required in these hearings, Mr. Pearce and I have coordinated our efforts to the maximum extent possible and we have decided that we will reserve our opening statement till we can give our direct testimony.

Needless to say, we are in complete disagreement with the position taken by the proponents.

MR. LEMAY: Thank you, Mr. Lopez.

Mr. Pearce?

MR. PEARCE: Nothing at this time. Thank you.

MR. LEMAY: Do you agree with Mr. Lopez?

MR. PEARCE: I do, sir.

MR. LEMAY: Okay. Amoco, Mr. Lund, do you have any opening statement?

MR. LUND: Nothing at this time, just our statement previously filed.

MR. LEMAY: Mr. Gentry or Jordan?

MR. GENTRY: Nothing at this time, Mr. Chairman.

MR. JORDAN: No, sir.

MR. LEMAY; Are there any additional opening statement people I might have missed?

Mr. Kelly, you're in agreement?

We plan to allocate two days to each side and then recognizing that there may be people like Amoco or Meridian, who I haven't heard from, that may want to make testimony or may want to support one side in a limited way, so we will accommodate those people on Friday.

But we'll start with Mr. Carr.

MR. KELLAHIN: Point of information --

MR. LEMAY: Mr. Kellahin.

MR. KELLAHIN: -- Mr. Chairman.

MR. LEMAY: Yes.

MR. KELLAHIN: In order to organize our time, we have talked with Mr. Pearce about whether or not our position in the case will be charged with cross examination time.

We would request the Commission follow the procedure back in August that was esatablished for this hearing, whereby each party keeps track in a way, a general way, of their specific use of time so that direct examination time would be charged to us; cross examination time of our witnesses charged to the opposition, and when their witnesses come on just the reserves occurs, we are charged with the time that we utilize for the hearing purpose to examine their witnesses.

We believe that system worked effectively in August and we'd request that we do the same today.

MR. PEARCE: I believe that's --

MR. LEMAY: Is that agreeable

to all the -- everyone involved in the case?

Are there any other questions on procedure? This was a general understanding that we were, without keeping a time clock keeping exact time, that we'd leave it up to the attorneys generally to confine their -- both their testimony and their cross examination to the two-day limit.

In most cases I think you've allocated less than two days, so you can have some time for cross examination.

Any questions at all on the procedures that we're going to follow over these five day -- this five day period?

MR. GENTRY: As far as the way time is allocated on Friday, when I anticipate we will want to reserve some time for presenting our position, are you going to wait until Friday to do that?

MR. LEMAY: Yes, I think I will. Generally, we want to wrap up the two sides Monday through Thursday and Friday I will call for appearances at that time and allocate the time on Friday morning; however, if you have a general idea, that would be helpful to know that before Friday.

MR. GENTRY: Okay.

MR. LEMAY; Thank you, Mr. Gentry.

Anything else? Mr. Lopez.

MR. LOPEZ: Mr. Chairman, as I understand it, closing on the proponents' side will take place on Friday, as well.

MR. LEMAY; We plan ot have closing arguments on Friday, as well, that's correct.

Any other questions or comments concerning the procedure?

If not, we'll begin with Mr. Carr.

MR. CARR: At this time we call Mr. Greer.

ALBERT R. GREER,

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

DIRECT EXAMINATION

BY MR. CARR:

Q Will you state your full name for the record, please?

A Albert R. Greer.

Q Mr. Greer, what is your relationship to Benson-Montin-Greer Drilling Corporation?

A I'm an officer and an engineer.

Q How long have you been an officer and an engineer in that corporation?

A About 35 years.

Q And what is your present position?

A President.

Q Now, Mr. Greer, Benson-Montin-Greer Drilling Corporation is an applicant in Case 9113. Would you briefly state for the Commission what is being sought in that case?

A Yes, sir. We seek to make the pool rules the same throughout the entire reservoir. The changes which come about by virtue of our application if it's granted, would permit in the Gavilan area an operator to form a 640-acre proration unit and drill a well on 640 acres, if he so chooses.

It does not require that he do that; it just gives an option.

That's the only change as to Gavilan area, is to give an option to an operator to drill on a wider spacing.

In West Puerto Chiquito an option is now given to allow operators to drill two wells on one 640-acre proration unit, whereas the existing rules will permit only one well.

Those are the basic changes to the rules. Other than that we're just asking that the temporary allowable rules be continued.

Q And this would be accomplished by abolishing the Gavilan and making -- extending the West Puerto Chiquito to include the entire area which is -- encompasses this reservoir?

A Yes, sir, that's the mechanics.

Q What interest does Benson-Montin-Greer have in the West Puerto Chiquito Mancos Pool?

A Benson-Montin-Greer is operator of the Canada Ojitos Unit, which forms the large, largest part of the West Puerto Chiquito Pool.

Q And how long have you operated that unit?

A About twenty-five years.

Q Would you briefly summarize your educational background for the Commission?

A Yes, sir. I was graduated in 1943 from New Mexico School of Mines, now New Mexico Tech, with a Bachelor of Science degree in petroleum engineering.

After a few years in the Navy in World War II, I worked for Western Natural Gas Company, a subsidiary of El Paso Gas Company, out of Jal, New Mexico, and then for a time with Anderson-Pritchard Oil Corporation as production engineer and reservoir engineer in both Hobbs, New Mexico, and Oklahoma City.

In Oklahoma City as reservoir engineer my experience was with pools in Kansas, Oklahoma, primarily; some experience with units and secondary recovery.

In early 1950 I went to work for an independent in Dallas, Leland Fikes (sic) as production engineer and reservoir engineer.

At that time I had an arrangement where I worked part time for him and part time on my own, at which time I formed one of the first units in -- Federal units in San Juan County, the Gallegos Canyon Unit, and spent most of my time since 1950 working in the San Juan Basin. For a period of ten years we had some operations in Canada, in which we were involved in secondary recovery and unitization, and then in the mid -- the mid-sixties I perceived an opportunity for independents to develop the fractured Mancos formation. The majors had sort of given up on it. Just north of West Puerto Chiquito there's a pool, the Boulder Pool, operated primarily or the main owners in the pool are Standard of Texa$ and Mobil, and they -- they found production a very -- very high rates of production. One well, which they drilled with air, flowed 4000 barrels of oil, natural, and yet in this pool, because of the structure, the permeability, they had very good gravity drainage, excellent recoveries, and yet the operation was essentially not -- not profitable, and that along with some other bad experiences, why, the majors pretty well gave up at that time on the fractured Mancos.

From my study of it, it appeared to me that their problem in having a commercial operation was overdrilling the reservoir. Standard of Texas asked for an application to increae the spacing from 40 acres to 80 acres. Mobil went along with it, but the truth of the matter is the major companies just overdrilled and overdeveloped the reservoir and they didn't make a profit, or reasonable profit.

Q Now, Mr. Greer, how long have you personally been involved with the Canda Ojitos Unit and the Mancos formation in this area?

A About twenty-five years. We intensified our efforts then and our studies in order to try to understand the reservoir and one needs to remember that back in those days the price of oil was like $3.00 a barrel, transportation cost $1.00 a barrel. It was difficult to operate a pool at a profit.

Q Have you personally been responsible for the development and the operations and the engineering work for the Canada Ojitos Unit since its creation?

A Yes, sir.

Q Are you familiar with the application

filed on behalf of Benson-Montin-Greer Drilling Corporation and others in Case 9113?

A Yes, sir.

Q Are you familiar with the applications that have been consolidated with that case for purposes of hearing here today?

A Yes, sir.

MR. CARR: At this time, may it please the Commission, we tender Albert R. Greer as an expert witness in petroleum engineering.

MR. LEMAY: Mr. Greer is so qualified.

Q Mr. Greer, have you made an engineering study of the area involved in these consolidated applications in particular focused this study on the Mancos formation?

A Yes, sir.

Q Based on this study have you reached certain conclusions about this reservoir?

A Yes, sir.

Q Have you prepared exhibits which support the conclusions that you are going to present here today?

A Yes, sir.

Q And to assist us in this presentation, and our understanding of it, could you briefly state what those general conclusions are that you have reached concerning this reservoir?

A Yes, sir. The reservoir is -- has been produced in an excessive rate to enjoy the benefits of gravity drainage and the simple conclusion that I reach is that rates need to be restricted and operate the pool as one -- one reservoir and provide an opportunity for the gravity drainage mechanism to work along at the same time with other operators to let them produce as they wish as long as they produce at not too high a rate.

Q Now, Mr. Greer, if you would refer to what has been marked for identification os Benson-Montin-Greer Drilling Corp. Exhibit Number One, the brown booklet, and at this time I would ask you to refer to the first sheet behind the index tab and ask you if you could more specifically summarize the conclusions to which you will testify here today?

A Yes, sir. The Commission has asked that we attempt to avoid redundancy of information which had been presented last August to try to identify points of difference and, if possible, points of agreement.

The sheet that we're looking at is a tan colored sheet, the first one under Section Index.

So we've attempted to do that and have divided the presentation up into nine parts.

The first is simply orientation.

Part II is notes on perceptions of reservoir mechanics, and we try to identify the differences which we have in our perceptions as to the others.

Part III, we go into stratification of producing zones.

Part IV, we discuss in a little bit more detail our disagreement with Mr. Hueni's hypothesis of the reservoir mechanics, which he presented in the last hearing.

Part V, we look athe pressurization among Niobrara reservoirs on the east side of the San Juan Basin, and evidence of presssure communication of wells within West Puerto Chiquito, as evidenced by their initial maximum pressures.

Part VI, we look at development and communication within the common source of supply for both West Puerto Chiquito and Gavilan, showing that it's one common source of supply.

Part VII is just a note on matrix porosity. We feel that it's rapidly becoming a moot issue.

Part VIII, we have some notes on gravity drainage and efficiency of recovery by depletion of high pressure.

And Part IX, we have some allowable recommendations.

Q Mr. Greer, would you identify the documents behind that sheet of paper and behind index tab one, or the index tab in Exhibit one?

A The white sheets are the index showing the different parts I just identified and the sections within the booklet which apply to those parts, and there's a listing of each sheet of paper in the booklet.

MR. CARR: May it please the Commission, we have labeled this as Benson-Montin-Greer Exhibit One in Case 9113. The information contained in this exhibit does, however, apply to all of the consolidated cases that are before you.

MR. LEMAY: So noted.

MR. CARR: Thank you, sir.

Q Mr. Greer, would you now refer to Tab A and identify the first document behind that tab in Exhibit One?

A That document is simply our application.

Q And this application specifically sets out the proposal you are making for the special rules for the -- what you propose to be one new, consolidated reservoir?

A Yes, sir, it has all the detailed specifics which, if the application is approved, should be included in the order.

Q Would you now go to the plat immediately behind the application, identify this and review this information for the Commission?

A This plat is simply an orientation plat. The West Puerto Chiquito Pool is outlined in a solid green highlighting. The area that we propose be added to West Puerto Chiquito is a dashed green highlighting.

The area shaded in grey is the area which Mesa Grande proposes be added to the Gavilan Pool.

The blue blocks, or rectangles, identify the nonstandard proration units. They're the same ones in West Puerto Chiquito as now exist. In the Gavilan area those are ones that we understand pretty well have been established by the Division now as nonstandard proration units.

We've identified generally the -- the operators and the wells. I note that Southland Royalty has not been changed to Meridian. SRC means Meridian now.

I note, too, that in Section 16 in 25, 2, that our draftsman has -- has given one of Mesa Grande's tracts to McHugh and I think that location in Section 16 has not been drilled, and another drafting error, I believe, in Section 5 of 25, 2, Mesa Grande's Guardian, I believe, is a Pictured Cliffs Well, not a Mancos well.

Q Now, Mr. Greer, there's a green dashed line around the Gavilan area that encompasses more than the current Gavilan Pool.

What's the purpose of that line?

A Well, the current Gavilan Pool, as we understand it from the orders, is outlined in red and has a rather odd shape and we just simply smoothed out the boundary.

We feel very strongly in this area that -- that the pool should be -- if an error exists in a pool boundary, it should be on the side of having more acreage in the pool than to have lands near a pool that would come under pool rules of 40 acres per well. That's caused difficulty in the past, particularly right here in Gavilan, and we would seek to avoid some of those problems now by -- by smoothing out the boundary.

Q Are you recommending that the nonstandard units depicted on this exhibit be grandfathered in by any order that results from this hearing?

A Yes, sir.

Q Would you now, by using this plat if you need to, provide a brief history of the development of this area?

A Yes, sir. The Puerto Chiquito Pool, pool, singular, was established in 1963 as a result of an application by Benson-Montin-Greer and to cover, as you can see, a rather large area. We feel that the Commission, for such a large area, based on the bad experience of wells being drilled too close together in other pools, and that there needed to be some way in which wider spacing could be accomplished. We asked for 640 -- for 160-acre spacing on a temporary basis, 3-year basis.

In 1966 when it came time for the hearing, we found in the meantime in drilling of wells that there was a fault existed between East and West Puerto Chiquito; one well cut a fault of about 300 feet of throw, and conformed general with the surface geology. We found water on the down dip side of the East Puerto Chiquito reservoir, whereas farther, deeper into the basn we were finding water-free oil.

So we separated East and West Puerto Chiquito in 1966, established 160-acre permanent spacing for East Puerto Chiquito. West Puerto Chiquito had -- we then asked for temporary 320-acre spacing.

Q When did that become permanent spacing?

A And that order became permanent in 1969 and this was as a result of -- we had commenced pressure maintenance in 1968. We wanted an opportunity on a fairly wide spacing to -- to prove, or to test our ideas about gravity drainage and pressure maintenance being effective in this reservoir and that was granted.

Then by 1980 we had established that, yes, indeed, our theories were correct. We were enjoying good gravity drainage recoveries and the wells were on rather wide spacing; a density of two to three to four sections per well.

At that time we asked for 640-acre spacing and 640-acre spacing was granted then.

In 1982 the first well in the Gavilan part of the reservoir was drilled. That was in Section 26 of 25 North, 2 West, and some development followed that and in 1983 a temporary 3-year order of 320-acre spacing was established for Gavilan, and the problem we faced at that time was a well in Gavilan drilled within about a mile of West Puerto Chiquito, just about a direct offset on 640-acre spacing, to the west of Gavilan; however, the West Lindrith-Gallup-Dakota Pool was developed on 160-acre spacing, and the the Ojito Pool, nothing had been done there and it was on a 40-acre spacing, although the operators were at a density of 160-acre per well.

So we tried to figure out a compromise and we recognized that there might be across boundary migration problems. At that time the first well in Gavilan had all the earmarks of producing from a fractured reservoir.

A few miles to the north the Dugan Tapacitos 2, although a small well, had the same earmarks and flat decline, and we felt that, of course, it was one reservoir, but how do we solve the problem of operators in Gavilan wanting denser spacing, some of these even asked for 160-acre spacing.

The Gavilan people didn't want to be part of West Puerto Chiquito and West Puerto Chiquito didn't want any part of Gavilan and so we tried to draw a line, did draw a line between what was the existing boundary for West Puerto Chiquito, made special provisions for the wells along hte boundary, hoping that there'd be a way the two pools could be operated together in harmony.

Q Now in 1986 there were some hearings. What happened at that time?

A Well, we found in 1986, as was noted earlier, the Oil Conservation Division asked the opertors to get together and take a look at the Gavilan area and was there anything that should be done or should the Commission do or should the operators do to improve the recovery and economics.

And as a consequence of that, engineering, geological, and land committees were set up and studies conducted and to a certain extent we found agreement. We did get some cooperation with operators to take pressures in wells and found discouraging results, and it was my understanding as a member of the engineering committee that the members were agreed that production rates should be restricted while further studies were made, but they couldn't agree on the amoaunt of restriction.

So two of the operators made application to reduce allowables in Gavilan and to compliment that in West Puerto Chiquito we asked for a similar reduction in allowables for West Puerto Chiquito.

Q In essence, you're seeking a continuation of those reduced allowables at this time, is that not correct?

A Yes, sir.

Q Would you now go to the next document behind Tab A, which is a structure map, and briefly review that?

A Yes, sir. This is a duplicate of one of the maps we introduced in the 1986 hearing. Since that time additional wells have been drilled. There is some more information available, and we are using this map not so much to show the exact structure at this time but simply for continuity of our case from -- from last August.

The detailed geology with up to date revisions and interpretations will be presented later by McHugh's geologist, Dick Ellis.

The purpose in showing this now is to move as rapidly as we can through some of the evidence we want to present by showing copies of sections of the reservoir where it's only on a little 8-1/2 by 11 plat we can move rapidly from one section to another.

Q All right, Mr. Greer, if you'll now go to the information in Exhibit Number One contained behind Tab B, which discusses reservoir mechanics, and I'd first ask you to go the first white sheet behind that tab and identify these.

A The first -- the first sheet shows our interpretation of -- or our perception of the reservoir mechanics as perceive them and as we believe the opponents perceive them.

Of course, Mesa Grande, Mobil and perhaps Amoco will, of course, present their own interpretations, but the Commission asked that we try to identify points of difference. We've tried to do this here.

On the lefthand side of the sketch we show a stratified reservoir in which we think the zones are occasionally connected by faults, wellbores, or fracture treatments.

There are three main producing zones, A, B, and C Zone. Above the A zone is a minor producer; we sometimes call it the Gray zone. It, too, is stratified and not in communication with the main zones.

There are two noncommercial zones at the base of the section, sometimes identified as the Sonostee. We believe that the reservoir comprises a fracture system and the high capacity fracture system surrounds tighter blocks of lower permeability. The tighter blocks are still fracture, not matrix porosity, but fracture blocks that have low capacity.

When a well is fraced sometimes the frac treatment puts the well up to a high capacity fracture system, a good connection, and sometimes it does not. We feel that the producing mechanism is a combination of solution gas drive and gravity drainage and in the Canada Ojitos Unit this is augmented by pressure maintenance by gas injection.

We believe that the gravity drainage potential is rate sensitive.

Q Now, Mr. Greer, would you review what you understand to be the position of Mesa Grande, Mallon, and those who are opposing us?

A From the information or the testimony they presented last August, Mesa Grande and Mallon apparently feel that the entire 6-or-800 foot section is a single, highly communicated reservoir fractured vertically throughout.

MR. PEARCE: If I may, Mr. Chairman, let me just inject to make clear that what we are gettng now from Mr. Greer is Mr. Greer's recollection and interpretation of what other parties' positions were at a previous hearing. And as I said that, I just want -- want everybody to understand that what he represents to be the position of other parties may not be the position of those parties.

MR. LEMAY: We understand that, Mr. Pearce.

Mr. Carr.

MR. CARR: Mr. Lemay, the question was, we asked Mr. Greer to give his understanding of their position and it is simply based on their sworn testimony.

MR. LEMAY: We understand that. You may continue, Mr. Greer.

A Mobil, we understand, thinks the reservoir is primarily of matrix porosity and completion technique Mobil uses suggests to us that Mobil believes that production is limited to zones, which would be in contradiction to -- to their other -- our other opponents.

Mobil's drainage calculation shows wide spacing of vertical fractures and that implies that the fractures that Mobil is relying on to drain the matrix may be those induced by fracture treatments.

Q Mr. Greer, would you go to the next sheet behind Tab B, the tan sheet, and explain what that depicts?

A This is a tan colored sheet; shows a fracture system from what -- the way we think the reservoir exists; tight blocks surrounded by a high capacity fracture system, and we need to realize that the reservoir is extremely variable in transmissibility. Wells drilled close together can have extemely different productivities, and I would like to give one example. I mentioned it last August. I hate to be redundant, but I think we should mention it again.

One of the first wells that we drilled in this pool was drilled with air. On reaching production we had a downhole fire, which is not too unusual in drilling with air but you hope when you drill with air that -- that you'll drill through the zone without encountering fractures and you can run the pipe and frac into the fracture system. But sometimes you'll encounter some of the fractures when you drill and if you hit oil and everything else is the same, you have a fire.

Well, that downhole fire melted the drill pipe, drill collars in two. We to got about 1100 feet of drill pipe and drill collars in the hole. We produced the well then in that condition for about a year; made about 60 barrels a day.

Then we wanted to -- just about a 40-acre offset from this well was one that had a capacity of 1-to-

2000 barrels a day. We wanted to frac this well and get into that same system and get the same high capacity well, and of course we knew that it would mechanically be disastrous to try to frac down around the drill pipe and drill collars and try to complete in that fashion, so we sidetracked the hole. We sidetracked it, a whipstock, managed to bottom the hole approximately 150 feet from the first location, but we found in drilling with air again, we were brave enough to try it again, the hole was empty. We had no oil and no gas, nothing, just 150 feet away from the first borehole.

We ran liner and fraced the well and we got our 60 barrels a day back but we didn't get the 1000 barrels a day potential of the well just a 40-acre offset away.

This shows how variable the permeability is in the reservoir.

Now some people, some people have misinterpreted this kind of a situation to mean that it's necessary to have a large number of wells to drain the reservoir; that where you have a tight formation, that the wells will not drain the reservoir.

Not true, Mr. Chairman, not true. We've found that the other wells in the reservoir could drain that well's tract better than that well itself. We shut the well in, took pressures in it, measured fluid levels, and the other wells were draining that well's tract better than that well could drain itself.

Now this is -- this is a concept that -- that we just really need to understand to understand this reservoir. A well in a high capacity system with a good hook-up with the system, a capacity of 2-or-3000 barrels a day, that well can drain that high capacity system. That high capacity system stretches for miles. It can drain the tight block around a well two or three miles away better than the well in that block itself.

And so there's no need for large numbers of wells in this reservoir to recover the oil. The only need for -- for large numbers of wells is to try to get each party his proportionate share of the oil, a very wasteful, impractical way to do it.

The only practical, logical thing to do, of course, is to unitize, take care of these problems. Absent unitization we have to do the best we can with spacing, gas/oil ratio limitations, such as that.

Q Now, Mr. Greer, would you please go to the next sheet behing Tab B, the green sheet, the pressure versus cumulative production curve, and explain this to -- explain to the Commission what this shows?

A This curve shows the relation of pressure and production in the Canada Ojitos Unit, wells completed primarily in the C Zone, and we note the change in slope as the pressure falls through the bubble point from an initial 2650 barrels a pound to about 7000 barrels a pound at which time we commenced gas injection.

The purpose we wanted to show this -- with this exhibit, is that when we commenced gas injection we stopped the pressure decline, or we slowed it down considerably from 7000 barrels a pound to 38,000 barrels a pound.

And we show this to point out the difference in pressure maintenance in this kind of a reservoir as, say, for instance, a waterflood. In a waterflood, ordinarily, if the reservoir typically is depleted pretty well, injection wells or producing wells may be converted to injection wells, and you commence gas or water injection and soon you see a kick in the offset wells, the nearby wells, and it's considered a response and that the pressure maintenance or the secondary recovery is working.

You don't see that in pressure maintenance in this reservoir. All we do is slow down the rate of pressure decline. There's no such thing as a direct injection and production response.

Q Does this graph also tend to support the position of drainage over a wide area?

A Yes, sir.

Q Will you now go to the next graph and review that?

A I just want to show here an interpretation which sometimes this production history of this well has been misinterpreted by others. This is one of the wells that was, oh, a couple of miles from -- or three miles from an injection well. Injection was commenced in 1968. It was, oh, six years or so before the injected gas reached -- reached this producer.

It would appear from this curve that when the injected gas reached the producer that the production rate dropped sharply, the production ability of the well. Now that's not the case. The reason that the production dropped sharply is because in order to get the most information we could from the wells in this reservoir, we would shut the casing in, let all the gas and oil be produced through the co-pump (sic) up the tubing. That way we had a solid column of gas from surface to the producing formation.

By taking dead weight tests on the casing we could have a very good record of what was happening to the reservoir in working bottom hole pressure.

It was unimportant to us that once the gas, injected gas hit this well that we continue producing it. The option we had was to produce the gas, go ahead and open the casing up, produce at a higher rate, and cycle the gas. That made more compressor capacity and the question was, was this really a good, efficient way to do it, or perhaps, perhaps we should delay until the gas reached all the down dip wells and then, knowing the amount of gas handling facilities that we would need, we would then get into a gas cycling process and after all, all we had to do what shut this well in and oil would flow down by gravity down dip to the next well.

And so, when the gas/oil ratio in these first wells reached about 2-or-3000 cubic feet a barrel we just shut them in and let the oil go down to the next well, feeling that in time we would come back. We would open up the A and B Zones, which in some wells it appeared to have higher gas/oil ratios than the C Zone, and at that time we would do our cycling process.

Q All right, would you now go to the last two pages behind Tab B, identify those, and review them for the Commission?

A The brown circles and the yellow injected gas shows a typical breakthrough of injected gas to a producing well, and we see here from just a visual inspection of this little diagram as to why when injected gas first hits a well it does not necessarily cut off its oil production entirely. There's -- if we visual that as a circle around the well and the injected gas coming from up dip and it channels to that well, then there's only a small part of the area immediately surrounding the well that's affected by the injected gas.

So the well still has a high capacity to produce. An example of that is the E-10 Well, which we show by the blue graph. Pressure maintenance was started in 1968, in August, 1968, and here again we have had many people ask us when the production rate increased from about 10-to-12,000 barrels a month to 20,000 a month in early 1969, was that the consequence of our pressure maintenance and gas injection. Of course the answer is no, it's not. We just simply changed the producing method from a pump to gas lift. The well had a capacity of about 3000 barrels a day. We calculated that a good gravity drainage rate might be about 700 barrels a day, so we installed gas lift equipment and produce at about 700 barrels a day.

Then in about -- in 1973 we began to see a slight increase in the gas/oil ratio and we felt that probably was injected gas and we started cutting the production back. Now production didn't just fall off. We choked the well back to those lower rates. We continued to do that until about 1977 and we had a sharper increase in gas/oil ratio. We restricted the production rate more severely and let it follow the sharp decline until about 1969 -- 79.

At that time the gas/oil ratio came back down with the restricted production rates. Then we produced the well at approximately a level rate there for the rest of the years on that graph with a slight, gentle increase in gas/oil ratio.

Q All right, Mr. Greer, will you now proceed to the information on stratification of the reservoir and start with the data contained behind Tab C first going to the cross section and the log section.

A This cross section is a duplicate of one of the exhibits which we presented in the 1983 hearing establishing temporary 320-acre spacing units in the Gavilan.

We note here the similarity of the two central logs, two wells in the center of the cross section. One of them on the left is the well, the discovery well in the -- first well in the Gavilan. Just to the right of it is a Canada Ojitos Well in West Puerto Chiquito, and the striking similarity of the lithology of these two wells is apparent. We start with the A Zone and then follow the resistivity kicks. In the B Zone the four resistivity kicks are typical throughout Gavilan and West Puerto Chiquito. The C Zone, the zone colored in brown, we can see how closely it tracks within the pool. When we get outside the pool on the righthand side, we can see how the lithology has changed in the well just outside the -- of West Puerto Chiquito.

To the west, and this well is several miles away, you can see a difference in the lithology; just where it changes we think is not significant at this time. What is significant is that the lithology is so closely the same in Gavilan and West Puerto Chiquito.

The zones at the bottom, the two red zones, are the Sonostee and clearly have tested the Sonostee individually in East Puerto Chiquito and West Puerto Chiquito; we found it to be a very poor producer, and the only reason it's been included in this reservoir for the purpose of Commission rules is that the production is so -- so low, so small, that if any production at all is obtained from it, there's no way that wells could be drilled to that -- to those zones and lower. So if the operator wants to take a chance and perforate the zones and stimulate them and try to get a little oil, he has the opportunity to do that, but they really have no bearing on the A, B, and C Zones.

And in my interpretation they're not connected by the -- by the vertical fracture system.

Q Now, Mr. Greer, would you go to the last two pages behind Tab C and using those two exhibits will you tell the Commission your drilling experience in the area and the data on stratification you've acquired in drilling?

A Yes, sir. I would point out to the Commission that Benson-Montin-Greer drilled or operated 89 wells in the East and West Puerto Chiquito Pools. And tbe reason we mention that is to give an idea of the experience that we've had. Now it doesn't take -- one doesn't just gain experience just by drilling a large number of wells but the time that we were drilling and exploring and trying to understand this reservoir, we drilled wells with cable tools, with air, and did our best to try to understand the reservoir mechanics.

And we've been charged recently, that other operators in Gavilan spend a lot of money trying to develop the field and that we haven't done anything, haven't spent any money, so I had our engineer go back and -- and convert to 1986 dollars the investment that Benson-Montin-Greer and its participants have made in this area in developing and testing and attempting to understand the reservoir. It approximates in 1986 dollars about $20,000,000.

The wells that we didn't drill with cable tools or air we learned that we needed to drill with gas in order to avoid the downhole fires. Sometimes we couldn't, didn't have gas available, so we drilled with nitrogen.

In no instance, in no instance, Mr. Chairman, in drilling with cable tools, in drilling with air, drilling with gas, drilling with nitrogen, did we ever find a continuous increase in production as we drilled through the sections. Always, and without exception, we found that the production came in abruptly as we penetrated one of the zones. No doubt from drilling the wells with cable tools, with air, gas, nitrogen, we found stratified sections.

Q How were the wells drilled in the Gavilan area?

A In Gavilan with the exception, I think, of the first well, I believe they all were drilled with mud; casing run through all zones, and then the zones perforated and either fraced together or in some instances fraced separately, and as a consequence because of the -- how close the perforations are together in many of the wells, the size of the frac treatments, it's just logical to conclude that the perforations are tied together behind the pipe and the frac treatments. Undoubtedly there are vertical fractures induced by frac treatment, the frac treatments, and that being the case, it's practically impossible unless we have an unusual situation in Gavilan to go in now and try to attempt by production logging or whatever, to determine stratification, because they have been tied together.

The overriding matter with respect to the stratification issue is -- is not whether the zones are tied together by frac treatments behind the pipe, but whether back away from the wellbore the zones are stratified such that the oil has to flow down or along through these stratified zones in reaching a wellbore, which is what I think they do.

Q Now do you have any comments to make on the log section which is attached to this?

A Yes, I would point out that the -- what we call the gray zone, which comes and goes and has far less continuity than the other zones is not shown on this log but it's just -- it would be just above the A Zone.

The stippled area in the different zones, the A Zone and the B Zone and C Zone, are parts of the zones where we found natural production in drilling either with the cable tool, with air, or with gas.

One of the strange things about the -- this reservoir, if you look at the C Zone, the brown zone at the bottom, a relatively high gamma ray kick on the left, a high resistivity on the right, one would think that this is the -- the productive part of the C Zone, but we never found that so in drilling with air and cable tools and nitrogen. Always the dust that came up with the cuttings were very dry; didn't have any wet, damp feel that we found in the other zones that were productive.

We produced, oh, several million barrels of oil from wells completed only in the stippled areas shown on the C Zone.

Another thing which we think, or which I would infer, means that at least some of the geologists felt like that the zone just above the C Zone is not productive is from the fact that on a jointly cored well, the Mallon Davis 315, which cored through that section, the geologist did not even have analyzed that 30-foot section above the C Zone. If it's a very good communicative reservoir with a connection throughout, why didn't they have it analyzed?

Q Now, Mr. Greer, I'd like you to address the gray zone for a few minutes and in so doing would you refer to the first document contained behind Tab D in Exhibit Number One?

A Yes, sir. In looking at the two green sheets under Tab D, the well that's circled in red on the righthand side of the plat, this is a well in East Puerto Chiquito. The reason we've selected it is because it shows not only the lower productivity in the gray zone, which we can compare with productivity in the other zones, but actually they experienced depletion in testing this well.

I realize that it's not in the pool that we're talking about, but it was laid down in the same geological conditions and separated only by a fault which later on I developed and so we feel that it's a good, reasonable sample of -- of how the gray zone produces and how the zones are stratified.

You might look at the next two white pages. We have a copy of the log and the gray zone colored in gray, the A Zone colored in yellow and the B Zone colored in green, and in drilling this well with cable tools, we picked up about 30 barrels of oil a day natural, and 30 barrels a day is often a good show in this reservoir. Often if you can get a well with 30 barrels a day natural, it can be fraced into a very decent well.

But to test this well we stopped drilling, stopped drilling while we were in the gray zone, put the well on a pump; we tested for three months. The production fell off from about 30 barrels a day to about 10 barrels a day. We concluded it was in a limited reservoir and so we continued then drilling on down to the A and B Zones.

Upon completion of the drilling and running casing and a liner, we set a bridge plug at 32 -- 3300 feet, below the B Zone, base of the B Zone, and with perforations in only the A and the B Zones, those two zones are fraced together with about 2700 barrels of oil and a little over 100,000 pounds of sand.

We then set the bridge plug at 3100 feet and we treated the gray zone, again with about 75,000 pounds of sand, 1700 barrels of oil, and both -- and in both instances we had an injection rate of about 53 barrels a minute.

We then put the gray zone on production with a bridge plug still in place and we found a rapid decline in productivity, and that's shown on the next graph, the next two sheets.

These -- the green points are 11-day averages of the production after recovery of frac oil from the gray zone. The natural production that was found in the gray zone was about 30 barrels a day and declined rapidly to 10. Here we found 60 barrels a day after the frac treatment, rapidly declining to 20 barrels a day, at which time we concluded that the gray zone was of a limited reservoir and as can be seen by extrapolating that curve, aobut 2000 barrels of oil would be about all we could expect from the gray zone.

So then we drilled the bridge plug and opened up the A and B Zones and the production rate increased to over 200 barrels a day and over the years the well has produced about 800,000 barrels of oil.

There's no question, Mr. Chairman, that the gray zone is not in communication with the other zones.

Q Now, Mr. Greer, how does this compare with your understanding of the testimony presented last August by our opponents?

A The -- it's our understanding that the opposition considers the entire 6-or-800 foot section one communicated reservoir.

If that was the case, in this instance, even though by drilling the bridge plug we could pick up additional production, this well that has ultimately produced 800,000 barrels of oil, would have had a flat decline, whether it was 60 barrels a day or whatever, the production of the 1-1/2 or 1000 barrels of oil just would not cause this kind of a pressure decline.

Q Is it your testimony that the gray zone is a separate zone from the A and B Zones in this area?

A Yes, sir.

Q Would you now address the stratification of the A and B Zones, and in so doing, I direct your attention to the first two sheets, the pink sheets behind Tab E?

A Yes, sir, we show here on the pink sheets the location plat of this well. This was the first well in the north part of the West Puerto Chiquito and we determined separation of the A and B Zones in this well by three separate happenings.

The first was the initial drilling with air.

The second was swabbing tests of the zones jointly and separately.

And third was production history of the

well with the zones separately and jointly produced.

Now this is not a large well by West Puerto Chiquito standards but it has produced over 150,000 barrels of oil and we consider it an adequate sample to assess reservoir behavior.

Q All right, will you now go to the blue sheets that follow and review the information you acquired upon drilling the well?

A Yes, sir. The reason we picked this well is to show stratification over a very short interval.

We can see on the log where the perforations are in the A Zone and in the top of the B Zone and they're separated only by about 30 feet.

In completing this well we perforated the -- all three sets of perforations. The two bottom ones are in the B Zone and the upper one is in the A Zone.

We swabbed the well and we found a rate of about 3 barrels of fluid an hour.

We set a bridge plug between the A and B Zones that we show there at 7050 feet and the swab rate dropped immediately to about 1-1/4 barrels an hour, a loss of nearly 2 barrels an hour in production.

Then with the bridge plug in place we fraced the A Zone with about 3000 barrels of oil and 100,000 pounds of sand.

And after two years of production we see the productivity of about 31 barrels a day and that's shown on the white sheets next following the blue sheets.

On this graph we show production in terms of barrels of oil per producing day, the upper solid line, and barrels of oil per calendar day with the dashed line on the bottom. The well is a long ways from our other operations and we just could not physically produce the well as steadily as we'd like.

But in 1969, mid-1969, we produced it long enough that -- continuously -- for the barrels per producing day, barrels per calendar day draw together, by the red circle, under the red circle, had a productivity of about 31 barrels a day.

Then in May, 1970, we drilled a bridge plug and got immediate increase in production. It was hard to assess exactly what that increase in production was because we just couldn't produce the well as continuously as we'd like. In fact, in 1971 we produced it only intermittently, and the problem we had here, Mr. Chairman, was that this well is located on Jicarilla Indian lands and I think this was the year that someone shot the prize stallion of the President of the Tribal Council and he closed the roads into the reservation. We managed to get a key to one of the locked gates but instead of about an eight mile travel from our northernmost well to this well, we had about eighty miles we had to -- we had to go to get to the well.

Things eased up in time and we managed to change our operations and take care that the well produced a little more continuously in 1972. The two green circles showed six months of production tests that I consider a good test. A lot of people consider a two or three day test a good test, but a 6-month test will undoubtedly have an increase in productivity of about 31 barrels a day to something over 60 barrels a day, and --

Q Could that increase in productivity have been attributed just to opening up more section?

A Well, this was one of the wells that I referred to in my testimony last August in that we had found this kind of stratification simply by drilling a bridge plug between the two zones, and Mr. Hueni's response was that, well, you open up more section, you get more production.

So the question here is, is that the reason that we got more production, simply because we opened up more section, or were the zones stratified, and we investigate that in the next two pages.

Q Now go to the two tan sheets and explain what they're designed to show.

A What we want to investigate here is whether it's reasonable to assume that that increase in production was from a stratified zone or was it simply by just opening up more section in the well.

And so we looked at the case of another partially penetrating well and note on the upper sketch that for a small wellbore radius and, say, a 30 percent penetration, which is what I would compare this to, out of 100 foot section, we would expect about 45 percent of the production from a partially penetrating well as compared to one that would penetrate the entire section. That's if nothing is done, but the well is produced naturally, and say that both -- or the entire section were the same, uniform throughout, and we had penetrated or, in this instance, just had the upper part open and a bridge plug there, and we drilled the bridge plug, then true, sure enough we would expect about that increase in production.

But what happens when we frac, when we frac the upper zone? And the first example I've chosen here is if the frac affected only the upper part of a reservoir we expect or consider to be a continuous communicated reservoir, and on the graphs at the bottom I've shown how production would increase with fracing of a partially penetrating well, but the frac treatment or the increase in effective wellbore radius is limited only to the upper 30 percent of the -- of the formation.

We see here following the pink horizontal line that all that's necessary is to increase the effective wellbore radius by approximately up to 5 to 10 feet and there will then be enough productivity by the part of the well exposed to the upper section, and flow coming around the bottom, as we show by the arrows, that there's enough capacity, then, that if one then opened up the lower zones, drilled a bridge plug, or whatever, one would not expect an increase in production because you already have all the productivity that the well can take.

So for that example, then, that the tract only covers the upper part of this zone, we find that it's reasonable to believe that the zones are stratified, because otherwise we did not get any -- any increase in production.

Q All right, will you now go to the last two pages behind Tab E and review this example?

A Now here we look at the situation of the partially penetrating well that was fraced and assume that the frac, even though the frac was induced into the upper part of the reservoir, that it affects the entire reservoir, all the way up and down the 400 feet.

Then assume that it increased the effective wellbore radius to 100 feet and, Mr. Chairman, I probably should pause right here to point out some of the things that we -- we have felt about this reservoir and our tests, studies have shown.

We just can't feel comfortable with the conventional analysis of a frac treatment in this -- in this reservoir. The conventional thinking is that induce a fracture and it travels many hundreds of feet throughout the reservoir.

I'm just not sure that that's what happens. When the frac treatment reaches these fractures I think there's a good possibility it will divert in any number of directions and as it does, the frac length is not nearly as long as the conventional analyses would show.

But in any event the volume that we have used here, around 3000 barrels, and in general throughout the reservoir we find that something on the order of 3000 barrels an acre is a -- is probably a reasonable figure for the hydrocarbon pore space. The if we frac with 3000 barrels it just fills up the reservoir around the well, doesn't go out along a fracture, then we still have to build up the reservoir for somewhere around 100 feet, maybe a little bit more.

If on the other hand the fracture has moved out to, say, 400 feet, then the response that we can expect or the effect in the flow characteristics of the well have -- have been demonstrated a number of times that the effect can be approximated by taking one-fourth of the length of the fracture. If the fracture went out to 400 feet, you take a fourth of that, and your effective wellbore radius has been increased to about 100 feet.

Looking at it either way, I feel like that the wellbore radius, the effective wellbore radius following the frac treatment, would have gone out to at least 100 feet.

And so now here we examine the effect of the partially penetrating well in which the wellbore radius has increased and we find that -- that when it's increased out to a bout 100 feet, that the partially penetrating well will have about 90 or even perhaps more than 90 percent of the total production of a fully penetrating well, and so here again, if this is the situation, if the frac treatment affected the entire reservoir, it's a communicated reservoir, then by drilling a bridge plug we would expect only an increase of about 10 percent, from 31 barrels a day to 33 or 4. Instead we got an increase from 31 barrels a day to about 60 barrels a day.

My assessment of this, Mr. Chairman, is that in this area those two zones are stratified and they're separated only by about 30 feet. Many analyses of frac treatments would say that the frac treatment had to go up and down, and -- and if so, then we should not have got an increase when we drilled the bridge plug.

So we look at two wells now, definitely

stratified sections.

Q Now, Mr. Greer, will you to the information behind Tab F and review for the Commission the information you accumulated for --

MR. LEMAY: We'll take a short recess at this time and we'll come back with that in about ten minutes.

(Thereupon a short recess was taken.)

MR. LEMAY: All right, Mr. Carr, please continue.

Q Mr. Greer, you've testified about the stratified nature of the A and B Zones and the gray zone. I'd now like to have you focus your testimony on production below the C Zone and in so doing refer to Tab F and the first yellow sheets behind Tab F.

A We have here the completion plat of the particular well, the Canada Ojitos Unit F-30 on which a production log was run earlier this month. It's located along the Gavilan-West Puerto Chiquito boundary and we show here on the schedule how we conditioned the well and the rates at which it was flowed prior to making this production survey.

And, Mr. Chairman, I'd like to point out that the we think it's very important to properly condition a well flowing at a steady rate prior to running a production survey. We feel that in this area if a well is shut in that -- and so many zones have been fraced, that all of the zones whether they're productive or not will be pressured up, and when we first open the well, then you can get a flow back from any and all of the zones even if they really are not contributing to production.

So we think it's important to properly condition a well and we list here how we conditioned this one prior to this test.

The well was flowing at about 435 barrels a day during the test; 1000 cubic feet per barrel gas/oil ratio, and the well has shown no water production since November of 1986.

Q All right, will you now go to the log section on the following page and review that?

A Yes, sir. On the next page we have a section of the production log and this particular log was run with a spinner survey and a fluid density measurement and also a radioactive tracer.

We show the spinner survey, the approximate zero line for the "spinner" is the vertical pink line on the left and increases in production as indicated by the spinner is shown by the red shading.

Starting at the bottom at about 7450 feet the first red shaded area shows an increase in the spinner rate and going back up to 7400, another increase, and then on up to the top of the A Zone, another increase.

On the righthand side the vertical green line is specific gravity of 1 and a specific gravity of zero and .5 are shown by the short vertical lines at the bottom of the graph. We can see, for instance, that below the bottom perforations in the C Zone at approximately 7465 feet, from there on down the hole shows to have water in it.

Now, in this well the bottom zones, the Sanostee, we perforated and separately -- perforations separately acidized to make certain they were open, and fraced with a limited entry frac that we feel a frac entered all the zones, and yet here we find when we run this production survey that there's nothing but water in the hole below the C Zone and we think that's conclusive evidence that the Sanostee is not producing in this well.

The -- and incidentally, this is one of the wells which Mesa Grande's geologist, Mr. Emmendorfer, pointed out in the August hearing that fracture logs had been run and showed vertical communication throughout the entire 600-foot interval.

Now, Mr. Chairman, we run these fracture logs like other people do in trying to obtain as much information as we can about the reservoir, but just the fact that

that fracture log as its run down the hole and the pads show different resistivities at different depths does not necessarily mean always that those are fractures and that it's vertically communicated throughout. In this instance it's not. There's no production from the Sanostee where it would show up.

We point out another thing, approximately two-thirds of the production is coming from the C Zone and the rest of it from the A Zone. Approximately a third or a fourth of the free gas is coming from the C Zone, and there are enough perforations, a high enough frac treatment, to be expected that those perforations might all be tied together behind the pipe. We fraced this well at 107 barrels a minute and yet there appears a possibility that the zones are not completed tied together. As a matter of fact, it looks like the C Zone is stratified and separated from the A Zone.

Not only that, but a fourth to a third of the free gas is -- is coming in the C Zone as evidenced by the density. If the production -- or if the reservoir were vertically communicative throughout and the gas would move up through the reservoir as had been postulated by Mr. Hueni, then I don't see why there would be gas still down here in the C Zone coming into the well.

So this log shows not only definitely

that the Sanostee is not productive, not communicative with the upper zones, but it also appears that the C Zone is separated at least a certain extent from the A Zone, even after the frac treatment.

Q Mr. Greer, would you go to the green exhibits behind the one you've just been discussing in Section E and identify those, please?

A If I might just point out one more thing. Since the spinner is not a sensitive instrument, then we also ran a radioactive tracer to determine production from the lower zone. So not only to determine from the spinner the minimum amount of production, if any, could be coming from the lower zone by the radioactive tracer we think we confirmed that there was none.

The green sheets, then following the yellow sheets are simply the logger's interpretation of his survey and I think we need not dwell on them. The information is there for anybody to study.

Q All right, let's go on with the evidence you've accumulated concerning stratification of the reservoir.

Will you now go to Tab G and explain what the first blue sheets behind that tab show?

A This is another well in the boundary of Gavilan -- oh, Mr. Chairman, I overlooked one thing. Could we go back?

Q How far back would you like to go?

A We need to go back to this well we just looked at, this F-30. I should point out here that this well is in the area which Mesa Grande has asked for be added to Gavilan and I need to point out that one of the opponents to our application, Amoco, has written a letter to the Commission, sent us a copy, in which Amoco says that it appears that only the A and B Zones produce in Gavilan and only the C Zone produces in the Unit.

Here is a well obviously most of the production coming from the C Zone and it's in the area in which they say there's only A and B Zone production. So we realize Amoco hasn't had an opportunity to study the reservoir like we have, but clearly they have misinterpreted the reservoir in this area.

Q All right, now let's go to the first exhibit behind Tab G.

A Tab G we show another production survey of a well on the Gavilan boundary. This is a smaller well, only about 125 barrels a day, located as shown on the plats.

The production log is the white sheet next following. Here we have the same color coding as before. We can see here that the spinner is quite insensitive to this small flow rate, but once again we have a positive indication of water below the C Zone and that the lower Sanostee is not -- not productive.

Again, to confirm no production from the Sanostee, we ran a radioactive tracer and here it appears that there might be some fluid entry in the C Zone, but I would -- it appears to me that most of the production is from probably that A and the B Zones, where they're tied together with a frac treatment. Just from the location of the upper perfs in the A zone where all of the big increase or decrease in density appears, the green shading, I doubt very much that oil production is coming from that one perforation there at 60 -- or 7190 feet; probably tied together with frac treatment down in the (unclear) zone.

Q Now, Mr. Greer, this concludes the portion of your testimony that focuses on stratification of the reservoir. What conclusions have you reached?

A Well, we have determined in every test that we've made over the last twenty-five years of good tests with respect to stratification, there's just no question in my mind that the zones are stratified.

Q Now, would you go to the documents contained behind Tab H and would you first review for us your understanding of the testimony that was presented last August concerning reservoir mechanics?

A Yes, sir. Mr. Hueni presented a model

which presumes a 600 foot section communicative vertically and shows oil and gas to segregate by gravity; oil vertically down and gas vertically up, but no lateral movement of oil or gas.

And we disagree with -- with that --

MR. LEMAY: Yes, Mr. Pearce.

MR. PEARCE: Thank you, Mr. Greer.

Mr. Chairman, this time I think I need to raise the level to a level of ojection to this testimony. As we all know, as opposing counsel pointed out in their opening statement, the last set of hearings in this matter too five days. Mr. Greer is purporting to cast the other parties' positions in that matter in the form of one or two sentences, which he can then disagree with and apparently bolster his position in this matter.

I don't think that's appropriate. The record of the previous proceeding speaks for itself, not only for Mr. Greer's opponent's positions of record in that proceeding, Mr. Greer's testimony was under oath in that proceeding. If Mr. Greer wants to clarify his position, I think that's appropriate. I do not believe it is appropriate for Mr. Greer to try to clarify that previous testimony in this way.

If his counsel wishes to ask

questions of his opponents' witnesses when they are on the stand, I assume he will do so. If Mr. Greer wants to read portions of testimony from those proceedings into this record, I think that is appropriate. I do not believe that one or two sentences summaries of positions of other parties to proceedings is appropriate and I do not think, contrary to what is being indicated, that he clarified anything for this record by not clearly stating positions.

Thank you.

MR. LEMAY: Mr. Carr.

MR. CARR: May it please the Commission, it's entirely appropriate for Mr. Greer, Mr. Hueni, or any other witness here today to testify on prior testimony, to comment on prior testimony that was provided under oath.

I'd remind you this is a re-opening of a case that was heard before. It isn't a case that we're trying to hear in a vacuum. It's entirely appropriate for Mr. Hueni to correct anything that Mr. Greer says if it's incorrect at a later time when they will have that opportunity.

But we're going forward with our burden of proof first. It's appropriate for Mr. Greer to testify on the sworn testimony of other witnesses in the cases -- in these cases when they were heard before, and we submit that the objection is inappropriate and should be denied.

MR. LEMAY: Thank you, Mr. Carr.

In order for us to crystallize the disagreement between the two parties, we will duly note that what Mr. Greer says is certainly not -- may or may not be the position of Mallon, et al, but we did ask for -- because he's on first, we have to have something to compare it to.

So without -- with taking that in note, we shall allow the testimony, recognizing it may or may not be what comes on later for the Mallon side. We shall note that it will be the opposing viewpoint, no matter how we want to label that opposing viewpoint.

Pleae continue.

A Well, we disagree that the reservoir is 600 feet vertically communicated section but even if it were, and what would migrate vertically down, as Mr. Hueni postulates, the reservoir mechanics cannot end here. It is necessary for the oil to move to the wellbore and to do this it must move laterally, with this well being essentially solution gas drive as shown on the following pages.

Q All right, would you now go to those two tan pages and review each of the four figures on those pages?

A In the upper sketch, Diagram Number I, we show oil moving down and gas moving up and forming a free gas space at the top of the reservoir. But to reach the wellbore the oil and gas must flow laterally, as we show in Diagram Number II.

Number III we note, then, that the oil in flowing to the wellbore would -- laterally, would necessarily have to be by solution gas drive. The gas, the free flow of the gas would be in the upper part of the reservoir. It would have to be either like Number III or perhaps the Number IV. Since gas will displace or void the reservoir faster than the oil, the presssure in the gas zone would drop faster and then the oil might expand up into the -- into the gas part and again we're back to solution gas drive.

Q All right, will you now go to the next page in this -- behind Section H, a set of green pages, and review the next two pages for the Commission.

A We note that the foregoing basic solution gas drive will be suplemented with gravity drainage down structure plus a component of gravity drainage down pay thickness. We believe these gravity drainage contributions are rate sensitive and we show here an example on 320-acre spacing of the distance, of a vertical distance which provides a head which would allow some gravity flow, depending on the pay thickness. It varies significantly, of course, if the pay really is vertically communicative to a long vertical section, but not so significant if it's a thin, stratified zones that are producing and are limited, primarily, to the down structure flow.

Q What does the table show that's at the bottom?

A That's what the table shows. It's the thicker the communicative pay section, the greater the head, the pressure head, that would be available for gravity flow down, what I call down pay thickness.

Q Now, Mr. Greer, would you just identify the calculations (not understood).

A Well, before we go to that, I should point out one other thing about Mr. Hueni's model that I feel like he overlooked, the necessary fact that oil has to flow to the wellbore, and that's because if we take the parameters that Mr. Hueni used, and I agree that -- that if the -- the reservoir were vertically communicative, that the oil could drain vertically down, as Mr. Hueni shows, to the bottom of the reservoir.

The problem is the oil at the bottom of the reservoir has got to get to the wellbore, or somewhere it has to move to the wellbore.

If we use the parameters that Mr. Hueni

has used to demonstrate this vertical amount of flow, this gravity drainage down, and he comes up with several hundred barrels a day allowable that the opponents are asking for, using those parameters and then translating that into flow to the wellbore, we find that the reservoir can produce at rates only like 15 or 20 or 25 barrels a day.

True, the oil can go down vertically through the section but to be marketed and sold it has to get to the wellbore and that is all that the reservoir can do is 15 or 20 or 25 barrels a day.

So Mr. Hueni has underestimated, has grossly underestimated the transimissibility of this fractured formation.

Q All right, Mr. Greer, will you now identify the documents behind the green sheet in in Section H?

A I noted that if -- if gas moves to the top of the reservoir that it would move sort of free flow to the wellbore and would dissipate the reservoir pressure faster than the -- that the oil will, and all that I show on the next few pages is the elementary calculations that support that.

On page three of the yellow sheets I conclude that under -- well, I have three horizontal lines showing figures. On the righthand side on the bottom is 13.1 and above that is 10.6 and above that 8.5. For the various wellbore producing pressures of the well those are the rates at which the pressure would drop faster in the oil zone than in the -- or in the gas zone than in the oil zone.

That's all that this is for.

Q Now let's go to the green graph that follows and identify that.

A They just show the average reservoir pressure as a function of the wellbore radius, the external radius, and the flowing pressure to the pressure at the external boundary that I used in order to come up with those other figures.

Q The blue graph, is that what --

A The blue graph is similar. It's for compressible liquid, whereas the other one was for gas.

The yellow present the characteristics for the -- for the gas that I used in making the calculations.

The pink sheets have the oil characteristics that I used.

Q Now, Mr. Greer, I'd like to have you look now into the portion of your testimony concerning pressure communication throughout the reservoir, and in so doing I'd like you to move to the documents contained in Section I and direct your attention to the first graph behind that Section I tab, the graph with the green line cutting across it, and ask you to review that for the Commission.

A This first green graph, or graph with a green line on it, shows the relation of presssures, virgin pressures, in pools completed in reservoirs in the Mancos formation on the east side of the San Juan Basin, and we find a very definite relation there and what it amounts to is simply that there's an oil gradient between or among the pools.

On the right hand page the white sheet with the brown coloring shows the reservoir schematically or the formation schematically, in which there appears to be a barren zone down to about 6100 feet, and then one can calcu- late the virgin pressure in any of the reservoirs in the east side of the basin with the 6100 feet as a basis and using a one well gradient down to the reservoir depth.

And what this means is that over geologic time the -- there's been an equalization of pressures among these reservoirs. It also means that if within a reservoir you find a pressure substantially less than this, then that well has suffered drainage from some other wells in that reservoir.

Q Will you now go to the yellow sheets and discuss the pressure build-up test information that you have?

A In view of this we, and by "this" I mean the fact that the initial pressure of the well can tell us whether or not its in communication with other wells in the rservoir, simply by determining what its -- what its initial maximum pressure really is, and we found out early on that it was very unreliable to attempt to determine this maximum build-up pressure from build-up pressure curves and we just show a couple of examples here as to why that's true if one attempted to extrapolate the build-up curve of the well shown on the yellow sheet. By the first period of time the tests were ended before the slope changed to the next slope, one might forecast a grossly wrong maximum pressure.

In this instance on this well the maximum pressure is finally indicated by the horizontal green line, but there's just no way in which in this fractured reservoir with the tight blocks and the high capacity fracture system to project reservoir pressures from build-up surveys. It's just very unreliable.

Q All right, will you now go to the orange sheet and explain that?

A It shows the same thing. In this instance it's a pressure fall-off test on a well put on production. Again it's -- if we had a uniform reservoir throughout the decline in pressure, the operating pressure of the wellbore should have followed the pink dashed line but it didn't. It abruptly leveled off along the green line, showing that we're dealing with a small reservoir with constant pressure at the boundary, in this instance probably 40 to 80 acres, something like that.

The green sheet shows another similar graph. This is a pressure fall-off curve of an injection well when it was shut in and the pressure fell off, and again we can see that if we attempted to extrapolate the pink line that we would have a very wrong answer.

Q All right, would you now go to the tan or orange sheets and review the presure fall-off information on the Canada Ojitos O-33 Well?

A In line with our determination that the best way to know what the maximum pressure is in a newly drilled well, is to take not a pressure build-up but a pressure fall-off curve following a frac treatment. Here is an example on the O-33 Well drilled in 1966. The virgin pressure in the particular -- this reservoir, which is the West Puerto Chiquito, was 1620 pounds at the datum shown.

This well was a couple of miles away from any other producers when it was drilled and then we can see there that its pressure fell off, oh, perhaps within 50 pounds of the pressure of the other wells, but some 150 pounds less than virgin pressure, and that could only have happened by production from the other wells draining this well.

I would point out that this was a fairly small well, 70 barrels a day in initial productivity, and the -- we note that the start of the curves here, the flattening of the curve to where it levels off to meet its ultimate pressure is like 100 to 150 pounds above its final level off point, and that means to me that for a well of this charactertistic, this permeability, that one could safely say if you're still -- if the well is still dropping on the straight line part of the curve and is still straight, it's probably 100 to 150 pounds above its pressure.

Q All right, will you now go to the curve for the L-27 Well?

A The L-27 is a curve that's shown on the pink sheet and in this instance we find that this well pressure only got down to within, oh, maybe 75 pounds of pressure in the other wells. It took about five months to do it, and this is a higher capacity well. It should have leveled off much quicker than that.

So why do we suppose that that happened? Well, this well completed in the C Zone and the pressure reaction to get from the wells producing out of the C Zone back up into the B Zone, has to follow some kind of a tortuous path, presumably through faults or something, perhaps, a long distance from the well.

So this is why I think it's different in that respect.

Even so, it shows definitely that it was in communication with the main reservoir.

Q All right, now go to the green graphs for the C-34 Well.

A There's the C-34. Now this well has a productivity quite comparable to one that we just looked at before. We notice that it's level dropped not in five months but in about ten days. This well is completed in the C Zone, same as the other well.

So we see the communication between A and B Zones is not as good as directly in the C Zone.

Q All right, now would you go to the blue sheets and address the curve that you have for the G No. 1?

A This is another fall-off curve which shows that the pressure in this well initially was substantially lower than the virgin pressure, and this one well, this is one well that we made an injection well out of.

So it, too, had been affected by production from other wells and it's located like two miles from the nearest producing well.

Q All right, go to the last set of -- the last graph in this section for the L-3.

A We show the information for the L-3 on these tan sheets and this is a small well; had initial productivity about 30 barrels a day. It had been fraced one month and about a month later we went in and cleaned out the sand; made this pressure fall-off curve.

This is one well that we did not leave shut-in long enough to -- to either reach the virgin pressure or find the beginning of the hook on the bottom which would indicate leveling off of the pressure fall-off curve.

It was within about 50 pounds of the virgin pressure at the time we ended the test. My interpretation of it was that since the curvature had not started and its a small well, that that indicated that it, too, was in communication with the reservoir from the other wells several miles away.

We confirmed that later as we'll see when we examine its production history.

Q All right, Mr. Greer, now I'd like you to direct your attention to the material you've accumulated which shows we have one common reservoir that we're talking about here.

I'd ask you to go to the material behind Tab J and identify the first plat and what the colored lines on that plat indicate.

A The pink lines indicate wells in the 1965 interference test.

The green line shows from the K-13 Well, when we injected gas in it we ran an interference test with the well to the southwest of it, the L-23, and also within a few hours of injecting gas in the K-13 Well we found gas coming out the B-18, the second well from the top on the orange colored line, indicating extremely rapid communication with that well.

Since that time we've made injection wells out of the four wells shown on the orange colored line and we know that the gas that we've injected in those wells has gone into the reservoir and maintained pressure on it because if not, the pressure would have had to build up to a very high point in those wells and it didn't do that.

Q All right, will you go to the next plat and explain the reason for the highlighting of two wells on this plat?

A We show the injection well, the B-18, on the right and on the left we show the first well in the Gavilan portion of the reservoir, which showed, as we indicated in the 1983 hearing, it had -- it showed a pressure of less than virgin pressure, which interpreted to mean that it was in communication with the -- with the main reservoir to the east.

Q Will you now go to the sketch that is two pages behind that plat or is the next page behind that plat, and review that information for the Commission and then relate it to the graph or the sketches following?

A Here we show schematically my interpretation of how the stratification of these zones might affect the pressure in the zone. We think that the , on the up-dip side of the reservoir, just as we found between East and West Puerto Chiquito, a fault, that there could be, and probably are, faults that may connect the zones, not very good but some kind of connection, and we've schematically shown that by the yellow coloring on the two pipes where pressure at the top of the pipes is the same as the gas cap pressure of the two zones but more water is being drawn out of the pipe on the right and so it has less water head and so on the righthand side down at the valves we have less pressure in the one pipe than we do in the other pipe, even though the pressures at the top of the reservoir are about the same.

Then comparing that to what I think the situation was initially, virgin conditions in this reservoir, surface pressure, all zones, would have been about 1300 pounds; a datum pressure of +1600, which is about where we think the gas/oil contact was, would be about 1500 pounds. These zones have roughly the same oil column weight so that a well with a datum of +370 feet, which is the datum used in the Gavilan area, would be 1900 pounds in both areas, namely the east and west.

Q All right, that depicts virgin conditions, is that correct?

A Yes, sir.

Q Okay, would you go to the next diagram, please?

A Then in 1982, when the first well was drilled in the Gavilan, we'd taken a substantial amount of oil out of the C Zone, not so much out of the B Zone, so my opinion is there probably was a difference in pressures in the two zones at the +370, pressures approximately on the order of those shown at the lower righthand side of this diagram.

On the next diagram on the righthand side, we show a situation which I believe existed the fall of 1986 when some more tests were run and it appears to me that the pressures in the A, B, and C Zones were beginning to pull together, the high rate of production of Gavilan, and although we don't agree that in Gavilan the only zones producing are the A and B Zones, I felt quite strongly that the A and B Zones are producing in Gavilan, and making a heavy draw on the A and B Zones, as compared to what had been in the past.

Q Will you now go to the graph that follows on graph paper and review the pressure and production information contained thereon?

A This shows my interpretation of the pressures in the different zones.

The older unit wells are shown on the bottom line, the solid bottom line being those where we had active measurements before all of the wells were put on production with gas lift plunger strings in the wells where we couldn't run bottom hole pressures again, but I imagine that that dashed extension of the older C Zone wells is a fairly reasonable projection of the pressure in the C Zone, and the same for the A and B Zones. That cross hatching shows measured pressures that we've been picking up in the Gavilan area for whatever zones they're producing there.

It appears to me that at this time on the righthand side that not only the A and B Zones will have higher pressures in West Puerto Chiquito than Gavilan but that probably the C Zone also is going to have higher pressures than the C Zone in Gavilan, with all of them drawing very close together now.

Q All right, Mr. Greer, will you go now to the information contained behind Tab K in Exhibit Number One and review now the performance of the C Zone for the Commission?

A This is, as shown here in gray, that part of the reservoir that we think was initially gas cap. The area colored in brown is the area principally oil saturated. The area colored in yellow is that part of the C Zone that has been -- oil has been replaced -- displaced by gas injection and it's our feeling that gas injected in injection wells sort of spreads out, diffuses throughout the gas cap and then that gradually moves down as oil is produced and in some instances the gas will channel the wells and in some instances it doesn't.

Q Will you now go to the pressure fall-off curve on the Unit Well O-33 and the accompanying plat and review that information?

A We looked at this curve a little earlier. This is the same well, the O-33, that had the pressure fall-off curve and we note here that this was a small well. It only got 70 barrels a day and we note further that in an informal hearing that the Commission called in January that Mr. Mallon noted that he had drilled a well that only made 85 barrels a day and he was speaking in defense, then, of close spacing, that he couldn't afford to drill an 85-barrel a day wells, and of course, in Gavilan a well that only makes 85 barrels a day initially, if that's its productivity, it probably will not produce an awful lot of oil.

We note here that this well with a lower capacity, 70 barrels a day, produced -- has produced over 250,000 barrels of oil. It could only have done that, Mr. Chairman, with the effect of the pressure maintenance, and this confirms the fact that we have a widespread communication, and we've noted that just schematically, the distance from the injection wells to the O-33. We have on occasion maintained pressure over an entire reservoir with only one injection well and that injection well is some six miles from the O-33.

Now we don't mean to imply again the waterflood type of direct injection and response. Gas simply diffuses throughout the reservoir and it maintains pressure throughout the reservoir on these down-dip wells.

We also show here in the green coloring the interference test area that we ran between the Mallon well, the Dugan Tapacitos 4, and two of the unit wells early in 1986. The two circled wells show two more of the Mallon wells in which the initial pressure showed substantial drainage from the area before the wells were completed.

Q Mr. Greer, the orange lines on this plat simply show the O-33 and the distance it is from the injection wells, is that correct?

A Yes, sir, that's right.

Q Will you now go to the next graph and plat and discuss the information on it?

A Here we have a similar sketch. This for the E-10 Well. We looked at it a little bit earlier. It's a well that has produced over 2-million barrels of oil with a low gas/oil ratio and continued high productivity and it too undoubtedly was in communication with the gas injection well several miles away.

Q Will you now go to the information on the A-16 Well on the green sheets that follow?

A The A-16 is one well that we did not have a pressure fall-off curve on, but we can tell from its production history that it has been affected by the pressure maintenance of wells several miles away. The well had an initial capacity of about 25 barrels a day and it had an initial decline rate of about one and a half percent per year.

Then in 1976 it picked up a steeper rate of decline and that, we think, was a consequence of our lowering our pressure maintenance gas injection.

Prior to 1976 the price of oil or gas was low enough that we over-injected in the reservoir, and by over-injected I mean we injected more gas than was necessary to just replace the oil. To maintain the pressure, of course, we had to over-inject as the oil falls down the structural dip, then it's necessary to increase the pressure in the gas cap in order to maintain the pressure in the producing wells. So even though we over-injected we still did not quite keep up with the pressure but it's very interesting with a well this small, 25 barrels a day capacity, several miles from the injection wells, would have that response to the pressure maintenance established.

25 barrels a day initially produced a cumulative of 120,000 barrels of oil and the very interesting part of all this is that there probably is, at the end of this graph, 95 percent of the oil still in place around that well that was there when it was it was first drilled, and what happens is that the oil by gravity is draining down through the high capacity system to the well's tight block and continually feeding that tight block and all of this because of the pressure maintenance and communication over several miles.

Q All right, Mr. Greer, will you please go to the information on the L No. 3 on the brown sheets that follow?

A Here we have another small well. This is one that I mentioned earlier that we did not continue the pressure fall-off test down below the virgin pressure, but my interpretation of it was that since it had not reached the curve, the typical curve for a small oil well on pressure fall-off, that it too was in communication with the main reservoir, and it's not as far from some of the injection wells but it's clear from its production decline curve it's pressure has been maintained by the -- by the pressure maintenance project.

For comparison I've shown here a decline curve of the wells in the Boulder Pool when their production reached a point at which they could not make their allowables. One interesting point in the Boulder Pool I forgot to mention awhile ago was that it enjoyed good gravity drainage, not by design but by happenstance. That was in the days when the oil was prorated and so operators couldn't produce as high a rate as they'd like to produce but by being prorated and the other characteristics, they managed to achieve a high recovery from the reservoir.

Q All right, Mr. Greer, what conclusions can you draw about the communication in the C Zone?

A There's no question that the communication throughout the C zone covers the areas that we've shown here several miles from injection wells to producing wells and from producing well to producing well.

Q All right. Now let's talk about the B Zone for a minute, and I'd ask you to go to the first document behind Tab L concerning the Dugan Tapacitos No. 2 Well.

A Here we show on the location plat the Dugan Tapacitos 2. It's up in the red. We also show that part of the 13th expansion area which was added to the participating area in the Canada Ojitos Unit as a consequence of the 13th expansion.

Now we made application for the 13th expansion on the basis that we felt that it was in the same reservoir as the main producing reservoir that we'd been producing for a number of years in the -- in Canada Ojitos Unit.

We based our interpretation on the -- the drilling of some of the wells in the 3rd expansion area to the south, the B-32 and B-29 in Sections 32 and 29, Township 25 North, Range 1 West; also the flat decline curve of the Dugan Tapacitos No. 2 clearly evidences the fracture system up in that area.

The green circled well on the plat is the L-27, completed in the B Zone, and our feeling was that the B Zone was a primary producer in the Dugan Tapacitos 2, simply by comparing the logs of the two wells.

And on the strength of that we asked for and received approval to expand the -- the participating area for this 13th expansion.

Q All right, Mr. Greer, let's now talk about the evidence of communication found in the Mallon area, and I direct you to the documents behind Tab M in Exhibit Number One and ask you first to refer to the plat and generally provide us with some orientation (inaudible due to opening of plats.)

A Wells on which Mallon is operator, I believe we've properly located their proration units and they're identified by the gray shading. I think Mallon's first well was the lower lefthand open circle, and we note that in both formal hearings and informal meetings of the Oil Conservation Division both Mallon and Koch have emphasized their exploratory efforts and the discovery of new reserves in the Gavilan area and the consequent importance of these efforts to the State of New Mexico.

However, analysis of the communication data of the Mallon area reveals something else: Namely, Mallon's first wells are drilled in a partially depleted reservoir discovered some 25 years earlier.

Mallon's first well was hardly more than a direct offset to the 13th expansion of the Canada Ojitos Unit participating area, an expansion approved before Mallon started drilling this well, and for which expansion area the Canada Ojitos Unit owners had earlier approved a $7,000,000 development program.

Q Now which well was the first Mallon well drilled?

A It was the lower of the open circles in gray.

Q In Section 2?

A In Section 2, yes, sir, just about a location away from the established participating area of the Canada Ojitos Unit where we drill wells on 640-acre spacing.

Q Would you now go to the green sheet that follows, which is an estimate of bottom hole pressures in the area, and review that, please?

A Yes, sir, the green sheet will show pressure measured in our interference test well, the Canada Ojitos Unit E-6, which direct offsets Mallon's well which was part of the interference test conducted a year ago, and we've attempted to estimate the initial pressure in the Mallon area when Mallon's first well was drilled.

Mallon's engineer advised us that Mallon took no bottom hole pressures prior to the surveys in 1986.

But by plotting the cumulative production from the Mallon wells against the pressures, we found an extremely good communication across this area. We can back the pressure up and it appears that the pressure probably was in the range of 1670 pounds in the Mallon area when the first Mallon well was drilled, and that point is plotted on the pink graph just below -- the first well I believe was completed in July of 1985, and the period of time covered by the green graph is shown by the dashed red line coming out of the Canada Ojitos E-6 and from there on down.

Q What conclusion can you draw about the communication between the Mallon area and the remainder of the reservoir?

A There's no question in my mind that the Mallon area was in communication, had been partially depleted by other wells, either the Gavilan well or Canada Ojito Unit well, or more than likely, both wells.

Q Mr. Greer, have you run interference tests in the area that Mallon and Mesa Grande are suggesting be deleted from the West Puerto Chiquito Pool?

A Yes, sir.

Q Is that information set forth following Tab N in Exhibit Number One?

A Yes, sir.

Q Would you please refer to the plat and the summary statement and review that interference test information, please?

A On the plat colored in yellow is the area which Mesa Grande recommends be added to Gavilan and taken out of West Puerto Chiquito.

At the junction of the green lines on this plat is the Canada Ojitos F-30, a well which we fraced last September and at the time the well was fraced we had bottom hole recording pressure instruments in wells at the extensions of the green lines. On the left was Meridian's Hill 2-Y; on the right the Canada Ojitos Unit B-29 and B-32.

This test had been suggested by Meridian's engineer, Richard Fraley at one of the engineering committee meetings of whichhe was Vice Chairman, and we agreed I think early in July to attempt to do that.

It was September before before all the arrangements could be made, the well shut in and arrangements made to frac the F-30 Well at a time when the Hill 2-Y was shut-in and our other well shut-in.

So the test was run early September.

What we found from that test was a reaction time of 10 to 15 hours from the time of starting the pumping of the frac treatment in the central well, the F-30, till we got pressure response in all three of the wells shown on the extension of the green lines, and I believe that distance is like a mile and a half, perhaps, to the southernmost well.

Later, then, in February of this year another frac treatment at the junction of the pink lines in our A-20 Well, we had again recording pressure instruments in the B-29 and B-32, and this time we found the pressure response within minutes from the time we started pumping in the A-20, the -- a pressure response in both of the other wells. One of them is two miles away from the well that's being fraced.

The conclusion that I draw from this is that, yes, we found a permeability restriction or -- I really should mention about that permeability restriction, Mr. Chairman, that's something that we all had hoped for. The Gavilan people wanted there to be a restriction to keep Gavilan out of West Puerto Chiquito; West Puerto Chiquito wanted there to be a restriction there so that we could operate separately and not have the problems of cross boundary migration.

And we postulated a permeability restriction in the bottom of the syncline between the two areas. Very difficult formation, Mr. Chairman, to forecast its characteristics like that strictly from geology. We think, for instance, at the flex point where the formation flexes into the syncline that very likely is a good place for fracturing and we might get high capacity wells there, and we did. The B-29 and B-32 are very high capacity wells. On the other side we have 30, it's not a large well but it's a good well, 400 barrels a day they produced the first six months. But perhaps in the middle, you know, right where it flattens out, if it flattens out, perhaps there'd be a permeability restriction there.

Well, I think we found a permeability restriction. The problem is it's just not a very good restriction. Time measured in 10 to 15 hours for a pressure pulse to move a mile and a half is just not very good restriction. It is more restrictive, of course, than the wells shown on the pink lines. The difference is pressure response in minutes compared to pressure response in hours.

Q All right, Mr. Greer, would you now go to the yellow graph that follows that plat?

A These graphs simply detail what I just discussed. The first yellow graph shows the pressure recorded in the B-32 and noted on there is when the frac treatment in F-30 started. The B-32 and B-29 were practically identical.

Then Meridian's Hill Federal 2-Y Well is shown on the next graph. Three different surveys ran at different times and again Meridian's engineer, Richard Fraley, made quite a study of this, this particular interference test, and presented all the information to the engineering committee along with his interpretations and I think he properly interpreted the -- what happened, both as to the difference in the wireline measurements showing the different pressures and the affect of other wells coming on in Gavilan. We were lucky when this test was run that most of the wells in Gavilan were shut-in as a consequence of a fire in a compressor plant. I don't mean lucky as that's, of course, an unlucky event, but lucky in a sense that the wells were shut-in and there were not a lot of pressure pulses running through the reservoir at the time of this test.

Q Will you now go to the pink graph and explain what those two curves show?

A Here we have the standard scale of the pressure showing the Hill 2-Y and the B-32, and one of the striking things of this graph is the amazing sensitivity and apparent accuracy of these -- these modern pressure gauges.

This scale covers approximately 1-1/2 pounds from top to bottom. The lines are in ten divisions, represents a tenth of a pound, and yet the printout of the pressures that the recorder showed just fall within 1/100th of a pound all the way in a very continuous and clear signature of what -- what was taking place in that reservoir.

You can see that the Hill 2-Y built up to slightly more of (not understood) the B-32, and I would agree, as I noted, with Richard Fraley that that's probably the consequence of the wells coming in Gavilan since its typical to have an S-type curve, just as we see here, the S-type curve for the interference effect, and the other direction where it starts out at a small rate and then increases rapidly, so there is no question we properly interpreted this interference test.

One other thing I would point out, one might say, well, one pound, that's not very much to show interference, but at this particular time the reservoir had what I would call a coefficient of about 10-to-20,000 barrels per pound of reservoir voidage. The reservoir would be voided somewhere in the rate of 10-to-20,000 barrels a day. This is -- was presented in the last August hearing by Dugan's engineer, Mr. Roe, and at the same time the pressure was dropping like at a rate of about a pound a day, so in round numbers, 10,000 pounds or 10,000 barrels in a pound Now if you take oil and gas our of the reservoir and the pressure drops one pound and you take out 10-or-20,000 barrels, if you put fluids back into the reservoir, like we did in this frac treatment, about 9000 barrels, then you would expect about a one pound increase. Actually we got a little bit more than one pound. It would also, it would be unlikely that the pressure would diffuse throughout the entire reservoir some five or six miles west and the same distance east or north in that length of time.

So there's not much doubt that the frac treatment got into the reservoir, it's being produced by the other wells, that we've established communication across the so-called permeability restriction.

Q All right, Mr. Greer, would you now just quickly identify the last exhibit in this section on the blue sheet, the graph?

A On this graph we see the pressure response in the B-32 Well following the frac treatment in the A-20 in February of this year.

We show here the time in days on the bottom scale and by reading the printout it seems to me like it was like 25 or 30 minutes after the pumping started on the frac treatment that the response began to show up.

Q All right. Now continuing your testimony on communication in the reservoir, would you go to the plat which is the second document behind Tab O and review that in conjunction with the graph that's in front of it?

A We show several things here. It's kind of a busy plot but I've repeated with the orange lines the ones that we looked at earlier on individual wells.

Up to the north we show by the green X the interference test area with the Mallon Well, the E-6, and the Dugan Tapacitos 4.

To the south by the solid green lines we show the interference test of the frac treatment of the F-30 and the dashed lines show the interference of other wells upon the Hill 2-Y.

The solid pink line shows the interference test of the A-20 on the B-29 and B-32, which you just looked at.

And then the little dashed pink lines show lines in which we have not made a direct cause and effect interference test and one might wonder why -- why we have not drilled wells in between along those dashed lines, like for instance on the south line we'll make 2-or-3000 barrels a day on the left and nearly the same on the right, and our feeling, Mr. Chairman, is that there should not be any wells in that area. We've found that all we need are up-dip wells for injection and down-dip wells located at the proper point down-dip for recovery wells. We don't need wells in between.

It's our plan of development, which we advised our participants when we started the drilling in the 3rd expansion area was that we would attempt to develop adequate production to recover the available gravity drainage production by drilling wells first in the 3rd expansion area and if we didn't get good enough -- provide enough productivity, then we would have to begin to move up-dip to obtain those wells.

Well, what's happened, we found adeqwate production in the 3rd expansion area and have not needed to move back up into the other area.

Q Will you now go to the white sheets that follow and explain what the plat shows and what the table reflects concerning the direction of flow?

A Here we show by the red circles the B-29 and B-32 Wells where we just noted the interference effect.

The green circle is the Hill Federal 2-Y and colored in blue on the right shows the area in which we've had the direct pressure response of showing communication in the blue area.

And the gray area we found, all throughout Gavilan, pressure communication.

The only area that's left that we don't have the direct cause and effect presssure communication is the -- is the yellow area, and once this was colored the blue on the right and the gray on the left, my secretary asked me if the yellow area was the Mason-Dixon line. It may not be quite that serious but that's the only area that you might say doesn't have a direct cause and effect pressure communication.

Now, but in any case we studied this area a little bit to see if there isn't something more that we know about it that might -- might lead us to conclude whether or not there is communication across that yellow area.

So first on the white sheet and about the fifth column over we show the apparent direction of reservoir flow. Initially, when the first well drilled in Gavilan it was probably flowing from Gavilan to the east.

1983 it was probably just about a toss-up.

In January, 1985, when pressure was measured in the B-32 Well, the flow was apparently to the west; the pressure higher in the B-32 than in the well indicated to the west, the Native Son 1.

On February 9th, 1986, pressure measurement in the B-29 when it was first completed again shows that the flow was probably east to west.

In September of '86 when the interference test was run pressure measurements at exactly the same time show again a pressure difference across the so-called permeability restriction flow from east to west.

My assessment of this is that most of the production in the B-29 and B-32 Wells came from up-dip. Not only that, there's probably oil moved past those wells flowing west toward Gavilan, and we'll look at that a little bit closer on the next graph.

Q All right, will you go to that production plot and review that, please?

A On the orange colored graph, the gold colored graph, the first two points on the solid line show accumulated production from the B-32 Well against pressure.

Then when the B-29 was completed and its producton added to it, we would have anticipated that if the B-32 and the B-29 were flowing oil only from -- from their reservoir east of the permeability restriction, then the plot of pressure versus production should have followed along the dashed line, but it didn't do that. Instead the pressure fell off more rapidly and that means to me that these wells are not being able to keep up with the migration to the west.

These points are plotted on the green -- the blue colored graph. The red circles show the same three points and how the pressure in these wells east of the permeability restriction follow the Gavilan in pressures, undoubtedly all closely connected.

Q Will you now refer to the drainage area that you're depicting on the white sheet immediately following the graph?

A As I indicated earlier, I believe the production from the B-32 and B-29 came from up-dip and we take a look at how much area might have been drained by these wells.

And on our first line we show that if 100 percent of the ultimate recovery had been produced by the first of this year, January 1, 1987, at a cumulative production 633,000 barrels of oil, then the area being drained by the wells would be about 900 acres and that area is colored in blue on the map.

If on the other hand the wells have only produced 50 percent of their ultimate recovery, then they would have drained an area as indicated by the blue and tan color.

Or if only 25 percent, and I hope that it's really they produced less than 25 percent of their ultimate recovery, well then the blue, tan, and green area would be the area drained and that gets us up to the next well in which we have communication to the east.

So I would -- my assessment of this information is that it confirms that we have communication all the way across the reservoir.

Q Would you now refer to the cross section, the last exhibit in Section O and review that?

A Here we look at the lithology again to see if there's some reason, if there's some geologic reason perhaps, why those two wells might be in different reservoirs, and I cannot find it.

The lefthand well is the B-32. The second well from the left is the C-34 and the area, the yellow area that we're looking at is between those two wells.

Now if we look further to the right we see a definite change in lithology when we find a well outside the field, and we don't find that difference between the two lefthand wells, and I would note again that the B-32 has a capacity to produce several thousand barrels a day. The C-34 would be on the order of 1-or-2000 barrels a day. I doubt if there's a geologist in this room who would hesitate to drill a well between those two wells if we were to offer them a farmout.

And the reason, as I've indicated before, that we haven't drilled in there is we think it's not necessary to recover the oil. The only reason we may have to drill there sometime would be to attempt to stop migration to the west.

MR. CARR: May it please the Commission, we have approximately thirty more minutes of direct testimony from Mr. Greer. We're prepared to go forward a this time. If, however, you'd like to break for lunch, this pause would be appropriate.

MR. LEMAY: I appreciate that. I think we will break for lunch.

We will continue with P, is that where we are?

MR. CARR: We'll just be starting Section P after the recess.

MR. LEMAY: I think we will take a break.

Let's return at 1:10.

(Thereupon the noon recess was taken.)

MR. LEMAY: We'll call the meeting to order.

MR. LOPEZ: Mr. Chairman, at this time I'd like to have the Hinkle law firm enter an appearance on behalf of Hooper, Kimball, and Williams, Inc., and Reading and Bates Petroleum Company, who may or may not be making a statement on Friday but want their appearance on behalf of the opponents entered and made of record.

MR. LEMAY: Thank you. So noted.

Are there any other appearances that we might have missed early on?

If not, we'll continue the examination, direct examination.

ALBERT R. GREER,

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

DIRECT EXAMINATION CONT'D

BY MR. CARR:

Q Mr. Greer, we've been talking about communication in the reservoir.

I would now ask that you focus your testimony on communication in the A and B Zones and in so doing I direct you to the first document behind Tab P in Exhibit Number One and ask you to identify the plat and review it.

A This, Mr. Chairman, this plat shows schematically the way I believe the fluids appear in the -- in the A and B Zones, principally oil productive, or oil saturated over the brown shaded area.

The area colored in yellow represents the area which I believe has had the oil been displaced with gas with production from wells completed in the A and B Zones.

And I would point out that -- that if the zones are stratified as I think they are, and with the rapid pressure decline in the A and B Zones, as a consequence of Gavilan production, then we might anticipate that the production histories, then, of these older A and B Zone wells in the unit might be affected, and on the following pages we examine two of these and the Tapacitos No. 2.

Q Will you now refer to the blue pages and review the information on the Unit Well L-27?

A The Canada Ojitos Unit L-27 is a B Zone producer and I would note again that Amoco in its letter of objection or opposition to our application stated all the unit wells produced from the C Zone and that is, of course, not true. This well produces from the B Zone and it has produced a substantial volume of oil, approximately 1.5-million barrels, and in perspective, 1.5-million barrels is about half as much as all the wells in Gavilan have produced as of this time. So it's a substantial amount of production out of the A and B Zones.

One might -- might ask how do I know that this well produces primarily from the B Zone?

All three zones have been perforated. The A, B, and C Zones have been perforated in this well. All three zones have been exposed to fracture treatments or attempts, and I've seen, Mr. Chairman, things that happened 15-20 years ago, sometimes one has to look at the records to refresh his memory as to what the facts are. This one well I don't have to look back to the records to know that it's producing from the B Zone. It's etched in my memory in a manner that I'll never forget.

The drilling report as we show here for August 6th, 1969, states rather tersely: While drilling with gas andhaving reached a depth of 7040 feet the drilling report shows the well "surfaced fluid with gas pressure which cleared hole at 7040 feet."

Later on we tested that rate at about 6 to 8 barrels an hour.

The reason, Mr. Chairman, that that sticks in my mind so well, and if we were to drill a well like this in this day and time, a drilling report would have to be more complete. In those days, now this well was drilled in the Santa Fe National Forest under the control of forest rangers, and we've had a good relation with the forest ranger; we've tried to conduct our operation in such a way it's compatible with their -- with their objectives and their obligations.

What happened, we were drilling this well with gas and, of course, when we drill with gas we flare the gas to prevent accumulation of gas on the surface and possible explosion if it all gets ignited, so it's necessary, of course, to keep the gas burning that we're drilling. Our engineer, Virgil Stoabs, was concerned that we had drilled quite a bit of hole and the hole had not started dusting. That means that the formation is damp either with either oil or water that the cuttings don't come to surface as dust; they tend to accumulate in the hole. If you accumulate enough of them you get stuck, and so this is a concern when you're first starting out to drill with gas out from under your intermediate string.

What happened here is that, sure enough, the -- when we reached 7040 feet they surfaced fluids with gas pressure which cleaned the hole.

Now what happened, Mr. Chairman, when we struck oil in the B Zone and it came to the surface along with the gas and hit the flare, the consequence was a large -- a large flare and it set the forest on fire, and that, when that report was called in to me on the radio, I'll never forget it. You know, that's one of the things that I'll always know, this well picked up the oil in the B Zone.

Okay, later on we drilled the well on down to the C Zone. We ran a liner through it, and typical of our practice in that time we perforated the C Zone and we attempted to frac it. We started the frac treatment with a quarter of a pound of sand per gallon but the well streamed (sic) out. We could not frac the C Zone.

So we perforated, then, the A and the B Zone and we fraced the well and got a good producer. We increased the rate of roughly 150 barrels a day out of the B Zone to a production rate of about 400 to 500 barrels a day.

So this is one more instance in which Amoco opposing our application has misinterpreted the facts.

Q Will you now review the production history that's contained on the next two pages in this exhibit?

A The next graph shows the production history of this particular well; very flat decline curve over the period of time shown on the first green graph, up to 1982.

Then the rest of the production up to the end of 1987 -- first of 1987 is shown on the second graph, and here we see a decline in productivity and in increase in gas/oil ratio in this well beginning in the end of 1985.

Mr. Chairman, this is one of the wells that the gas/oil ratio increased (not understood clearly). This is not a typical situation of the injected gas reaching the well and the productivity staying high and you choke the well back to hold the production down. This well just lost productivity; lost productivity at the same time that the Gavilan voidage rate was increasing dramatically. We show that the voidage rate in Gavilan, as calculated by the engineering committee in the upper cross-hatched area there, I think that this well's production is evidently affected by the Gavilan -- Gavilan production and as one of the engineers noted, well, it's only fair that Gavilan now gets back oil that the Unit has earlier drained from the other direction and perhaps that might be true. One thing we're not so sure about, although apparently we're going ot lose production to Gavilan, I'm not so sure that Gavilan will gain any.

On the way to Gavilan it's possible that the completion mechanism may change from gravity drainage to the inefficient solution gas drive, and so although, yes, we may lose production in the unit, Gavilan may not gain it. Nobody may gain it.

Q All right, Mr. Greer, will you now go to the information on the C-2 Well, contained on the orange sheets?

A The C-2 Well is located as shown on the plat. It also completed and produces from the A and B Zones and again this is a small well and if you'll look at the flat rate of decline that it has up until 1976 or 1977 when the gas injection rate is reduced, again that flat decline was abruptly changed with the increase in production and voidage of the Gavilan reservoir. I think there's a very good possibility that that's the cause and effect of that production decline.

Q Now will you go on the data on the Tapacitos No. 2|

A This is the well that we showed had the extremely flat decline indicating it was connected to a fracture system and one of the wells be based our recommendation on that the 13th expansion area of the Canada Ojitos Unit was -- covered the area up to the Dugan Tapacitos 2.

It shows the same kind of happening in its production decline and increasing gas/oil ratio as we found in the other three B Zone wells.

Now all three of these wells produce in the fashion that would make them sensitive to a drop in reservoir pressure. The L-27 and the C-2 produce with relatively high back pressures. The Tapacitos No. 2 produces with a pump under a packer, in such a configuration it would be sensitive to a drop in reservoir pressure.

I feel that all three of these wells have been affected by the Gavilan production.

Q All right, Mr. Greer, would you now go to the last plat in this section, the yellow plat that has four wells spotted on it, and explain why those wells are shown here?

A The solid -- the wells shown in solid red circles are the three wells we just looked at. The one in the open circle is the N-31, the well that we looked at the production log earlier this morning, and that well, I think, produces primarily from the B Zone and perhaps A Zone.

This is the location of all four wells that appear to be drastically affected by the Gavilan production.

The N-31 has shown an increase in gas/oil ratio from 600 cubic feet a barrel to over 2000 in less than two months.

Q Mr. Greer, would you now go to the documents behind Tab Q in Exhibit Number One and review the information compiled on communication in the Krystina area in the Gavilan Pool?

A Mr. Chairman, the Krystina area is an area of low productivity wells on the south side of Gavilan. I believe that the Krystina and perhaps another well was subject to a hearing earlier this year about the problem of the well being shut in and losing reserves while it was shut in and could not be connected to a gas market.

And when our engineering committee first took a look at this area we noted the low pressures and low well productivities and in a sense we concluded that this area was not significant in our analysis of Gavilan; they might not be connected.

I think now the engineering committee may have been a little hasty in making its initial assessment.

The production behavior now indicates the wells should be drawing from the same common source of supply as Gavilan is and a high rate of depletion in Gavilan will deny these wells the opportunity to produce their shares of the reservoir oil.

The white graph, the next graph, this is a plot of the production of the wells within the red, large, red circle plotted against the pressure in the Krystina wells.

The solid line starting in the upper lefthand corner of the graph, proceeding down to the -- to the intersection of the red and green lines and on further to the righthand side of the shaded area, is the production of all wells versus Krystina's pressure.

A new well came on production, the Greener Grass, had a cumulated production of about 26,000 barrels for these wells, that's at the junction of the green and red lines. Now if in an area where the wells are not in communication, and a new well is brought on production and it's production added to that of the other wells, one would expect a flattening of the decline curve as along that red line, but that didn't happen. Instead of the curve flattening, it steepened and it followed, then the green line, if we take out the production of the Greener Grass, then the production from all other wells plotted against the Krystina's pressure, follows that green line.

It's very clear, Mr. Chairman, that the Krystina's reserves, presssure in that area, is being directly affected by the Greener Grass Well, the well circled in green and inside the big red circle, over a mile away from it in an area of really small wells, low productivity.

The Greener Grass is only a mile or so from one of McHugh's wells in Section 3, one of the Moter Lode wells. These wells produce at fairly respectable rates and it's only practical, logical conclusion that these wells are all tied together some way.

The fact that the pressure in the Krystina area, even though it's less than pressure in Gavilan, is dropping at about the same rate and seems to track the Gavilan pressure.

That plot of pressures showing the Krystina pressure along with the Gavilan wells will be shown in detail by John Roe when he puts on his testimony.

Q Mr. Greer, based on your study of communication in this reservoir, what conclusions can you reach?

A It's a common source of supply and all the wells should be subject to the same pool rules.

Q Have you an opinion as to whether or not the matrix is contributing oil in the subject area?

A It's my opinion that it's -- it either contributes nothing or an extremely minimal amount.

Q Is the study that you made of this question, reflected by the exhibits contained in Section R, Exhibit One?

A Yes, sir.

Q Would you please refer to the first document behind that, the plat and the accompanying comparison, and review the core analysis information that you have accumulated?

A The two wells that we'll be discussing is a Mobil well in the south part of Gavilan, where the red circle shows, and Mallon's well, the 3-15, the well which was jointly supported by operators in the Gavilan Pool for the cost of coring and analyzing the cores.

In Case 8950 last August, we addressed the question of the validiy of the oil and water saturation shown by the core analysis in the Mobil Lindrith B Unit No. 38.

I was concerned about that, Mr. Chairman, because of the way the core was analyzed. They retorted the core, obviously cooked out the water of hydration and the kerogen, and it makes it very difficult to determine what the true oil and water saturations are.

I made a lot of detailed calculations foot by foot that showed why I was concerned and why there was a reason to doubt the validity of the oil and water saturations in that core.

When -- when the 3-15 was cored, and it was analyzed in a manner more appropriate to this particular formation, to determine water saturation and sure enough, it revealed a much higher water saturation than was shown by the Mobil core, supporting my concerns and supporting the fact that the matrix probably contributes nothing to the production.

Q Would you now refer to the next two documents called plot of water saturation and review those?

A The gold colored sheet is a reproduction of one of the exhibits which I presented last August. It showed the water saturation which appears to be low for the kind of permeability shown and if anything there's a reverse trend in the water saturation versus permeability. By reverse trend I mean that the water saturation really should increase with decreasing permeability, whereas it's difficult to determine that from Mobil's data. If anything, it trends in the wrong direction.

The -- incidentally, we were not invited to participate in the cost of the Mallon core, but the operators are kind enough to present us a copy of their core analyses and we plotted them with water saturation versus permeability for the Mallon 3-15 Well, and that's shown on the blue plat.

The 3-15's data are shown in solid red circles for cores that show no dehydration cracks. The X marks are cores that showed -- that had dehydration cracks. The average water saturation is obviously much higher than shown by the normal core. It would appear to be in the order of 70 percent, and supports my earlier concern that the matrix in this area is of very limited value.

Q Mr. Greer, will you now go to the documents contained behind Tab S and review the conclusions you've reached concerning the effects of gravity drainage on recovery in the reservoir?

A We show here again a plot of the Canada Ojitos Unit Well E-10, which we looked at earlier and I'd point out a couple of things that we've not noted before.

One is that a large volume of oil, about 1.2-million barrels, was produced from this well at solution gas-oil ratio while the area was under pressure maintenance by gas injection, meaning most of this production was by gravity drainage.

And again to put that volume in perspective, that's about 40 percent of the cumulative volume of all the oil from all the wells in Gavilan as of January 1.

Then an even larger volume of production was obtained, about 1.7-million barrels, before a significant breakthrough of injected gas occurred.

Now what this means, Mr. Chairman, is that the high capacity fracture system, which permitted this gravity drainage, constitutes a signficant volume of the total reservoir oil. This is important to realize that. If this were not so, if the high capacity fractures only constituted a very small part of the reservoir volume, and this is the conventional thinking of matrix reservoirs laced with fractures, is that the fracture volume is very small compared to the matrix volume. In this instance you don't have a matrix porosity and the fracture volume and the high capacity system is a very large part of the whole -- the whole reservoir.

Another thing we note is that the reservoir up-dip from this well is only about 200 to 400 feet per mile, the area supplying gravity drainage to this well.

The transmissibilities in this area, as measured by individual wells, shows low transmissibilities, too low to indicate the possibility of gravity potential, just as in Gavilan individual well transmissibilities are relatively low. They don't necessarily reflect the reservoir overall system transmissibility. We found that only by running an interference test that showed the high transmissibility and gave me the courage to go ahead and attempt the pressure maintenance project.

Q Now, Mr. Greer, would you review the graph on that page?

A Well, in general, it shows just what I've noted.

Q And then the documents behind that graph?

A Before we go to the next thing, I'd like to back up, if we might, to Section H for just a moment to talk a little bit about gravity drainage there.

If we go to Section H, the one, two, third, third and fourth sheets, the green sheets, we note here some things about gravity drainage and, for instance, where we show the midpoint distance on the lower sheet of 1867 feet, compare that with the midpoint distance of 2640 feet, we see that for a shorter distance that the resulting fluid head down in the pay thickness is greater, which would mean, perhaps, then, that the closer the wells are drilled, the higher will be this potential head and then, of course, the factor would be the gravity drainage potential and perhaps the greater gravity drainage might result. One might infer that just from a review of this or similar information.

What we need to realize is that in a practical sense that will not happen. It would happen if we drilled wells closer together and at the same time reduced their production rates, but the practicality of the thing is that that won't happen.

Each operator, of course, would probably have his own standards or own criteria for what is required in terms of payout time or time to recover the cost of drilling the well, to determine whether he wants to drill or not. Some people, some operators are satisfied with a three year payout. Some operators would like a three month payout, and in the instance of some of the opposition to our application here today, they would like a three weeks payout. But whatever, whatever that standard, whatever that criteria, an operator is going to want that kind of payout. So what that means is on 320-acre spacing if you have whatever the allowable is determined to be, whatever the operator would decide he can live with, if you move down to 160-acre spacing, he's going to want that same rate of income, and so the net result is that on the denser spacing there's a higher rate of reservoir withdrawal such that the rate will be too high to permit gravity drainage and so as we indicated in the hearing three years ago, and I say again today, that for most of the spacing ranges from 320-acres down, and we don't know, Mr. Chairman, what the opposition is going to ask for in this hearing today for spacing. We were unable to discuss this in an objective fashion in the engineering committee. Whenever you talked about what would be proper spacing for this hearing coming up in March, the opposition would refuse to discuss it. So we don't know. They may ask for 160-acre spacing. I did not prepare a lot of information about 160-acre spacing, I don't know what they'll do, but I would want to point out now, if we move down from 320 to 160 or to 80 or 40, that the closer the spacing, the less will be recovered.

Q All right, Mr. Greer, are you ready now to go back to the documents in Section S?

A Pursuing again the information with respect to gravity drainage, we have to have a -- there needs to be in the reservoir a high enough transmissibility, of course, to permit gravity drainage. We've found that the reservoir does have this high, high transmissibility, which will permit the gravity drainage, if the reservoir is not produced at too high a rate.

On the first blue sheet, the third sheet under this section, we have a pressure build-up test which shows the transmissibility in the area of the Canada Ojitos Unit B-32. It shows about 28 Darcy feet. This well concurrently had a productivity index of about 6.2 barrels of oil per day per pound of drawdown.

Perhaps I should point out here, you see the little dots starting in the lower lefthand corner and proceeding up to the top and then horizontally, those are pressure points which the pressure increased slightly above the point at which we start our analyses down at the bottom of the page and, page and what happens here is something that, Mr. Chairman, that we never used to notice in -- when we had less sensitive pressure equipment. This bomb was in the hole while the -- while the well was flowing and when we shut the well in, then the gas and the oil that's flowing up the tubing immediately stops flowing and begins to segregate. The oil runs down the tubing and the gas tends to move up, and what happens is that for a short period of time following shut-in of the well that oil flowing -- running back down the tubing will give a falsely high presssure, and that's what is shown by these dots here.

Then then the pressure comes back down when that equalizes and then we pick up the character of the build-up curve which reflects the transmissibility. So in this instance we have 28 Darcy feet. Now 28 Darcy feet is a very high transmissibility. Back in the main part of the unit, in the C Zone, we have transmissibilities on the order of 8 to 10 Darcy feet, so this is some three times as much as we found over there.

Q All right now will you review the information on the B-29?

A On the B-29 another build-up test is shown here and in this instance the bomb was set above the string, the plunger string, the gas head plunger string in the bottom of the well, about 1000 feet above bottom, and so in this instance when the well is shut-in and the oil flows down the tubing, it just flows right by the bomb and on down toward the bottom. So here the pressure builds up and you can see the little dots from a Delta T of about 1.2, up to join the sloping line of dots that are to the upper right.

This well showed a transmissibility of 49 Darcy feet and a productivity index of 20.3 barrels per day per pound.

The productivity index, Mr. Chairman, of 20 barrels per pound for a 1500 pound reservoir pressure would extrapolate out to 30,000 barrels per day, which if you had big enough casing and equipment, there would be, of course, some additional reduction in the relative permeability to oil as the pressure is drawn down but it indicates a very high capacity well, very high transmissibility.

On the next, on the white sheet, we look at the semi-build-up test for the Canada Ojitos Unit E-6. This is the well that was involved in the interference test with some of the Mallon wells a year ago.

Here again we can see the pressure build up and the little hump where the oil segregates in the tubing and gives a little false pressure hump.

One might choose one of two lines, either the A or B line, in estimating reservoir pressure. The offset well, the one that causes so much interference in the test a year ago, was shut-in. The Mallon well was shut-in during this time.

The two unit wells nearby were produced at a constant, fairly constant rate. So I believe we have a fairly, fairly good test but there's always a possibility that you can do something different and get a little more accurate reading, but I would think that the B curve in this instance is probably fairly well representative of the transmissibility in this area. If it is, then it has a transmissibility of about 13 Darcy feet at a P.I. of 1.5. This P. I. had dropped off dramatically from about 8 about a year ago, typical of what happens in this reservoir when the pressure dropped off.

Q Would you now review the calculations on the pink sheet and the accompanying plat?

A Mr. Chairman, here we arrive at an empirical way to approach the estimate of transmissibility from productivity index.

What happens, Mr. Chairman, when a well produces and the pressure drops near the wellbore, gas comes out of solution and forms a free gas phase and that greatly restricts the production. The relative permeability information that we so far have indicates for this formation a very rapid drop in relative permeability to oil with a small amount of free gas saturation.

One can approach, then, this determination of transmissibility from productivity index by a couple of ways.

One would be to estimate the relative permeability to oil from relative permeability versus saturation curves, or in this instance I've just empirically determined it by taking two wells that I feel confident of their productivity indices, confident of the transmissibility that's indicated and then calculate from that the factor which would be applied to recognize relative permeability effect.

Those calculations are shown here. On the upper righthand schedule I show that this factor would be 6.7 for the Canada Ojitos Unit B-29 and 12.5 for the B-32.

The relative permeability ratio would be the reciprocal of those, like about .12 or .06.

The average of the two is 9.6 but I've

suggested that the four wells that have roughly the same reservoir pressure, roughly the same drawdown, that one could use as an approximation a figure of 10.

Then using that figure we come down and estimate some transmissibilities from productivity indices.

The first one is for the McHugh Homestead Ranch No. 2. That well, a production log was recently run on it and at that time a productivity index taken which would be 3.3. Multiplying that by the 3.6 that we determined emperically is a good factor, we come up with 12 Darcy feet.

Mallon's Howard 1-11, we made just an estimate from that. Mallon's engineer estimated the capacity of that well at about 3000 barrels a day and I have assumeed that a well that would do that would have a drawdown probably of not more than 600 pounds. If that's true, it would have a P.I. of 5 and a transmissibility of 18.

Now that 18, and I've shown the 18 in a circle in the Mallon area, that compares with the measured transmissibility we just saw in the E-6 of about 13 or 14, or maybe even 17.

Then the BMG Canada Ojitos Unit F-30, the well that we looked at a production log on earlier this morning, during that test it showed a P.I. of 2.1. That would be a Kh of 7.4 and we show -- well, we don't show it. The

F-30 is just to the west of the transmissibility shown as 28.

Then the BMG L-27 Well, about 2.5. That's shown in a square box and the C-34, about 4, in a square box. The square boxes show transmissibilities where one zone is producing. The oblong circles show transmissibilities where three zones, if not producing are at least open to production or subject ot frac treatment.

It shows relatively high transmissibility. If anything, the transmissibility appears to be increasing to the west and I don't know why that would be. It's just that that appears to be the case, adequate transmissibility for gravity drainage.

Q All right, sir, will you go to the two yellow sheets and discuss the potential for gravity drainage from tight blocks?

A This is the only well that -- we've looked at the C-34 before. You may remember, it's on the south side of the unit. This is the only well that we produced, continued to produce, after the injected gas hits -- hit the well, and whereas we shut the other wells in when the gas/oil ratio reached 2-to-3000 or 4000 cubic feet a barrel. We just let this well continue to produce. The gas/oil ratio increased and when it got up to about 10,000 cubic feet per barrel, tended to level off and since that time that well has produced about 300,000 barrels of oil, and it produced it at a time when the pressure drop was very small, but in no way that there could have been solution gas drive providing oil to the reservoir because you have to have a drop in pressure for solution gas drive to work.

My conclusion is that the oil is draining from the tight blocks into a high capacity fracture system, being swept from there to the wellbore, one of the potential benefits that we have and perhaps it may apply to a number of wells throughout the reservoirs with pressure maintenance.

Pressure maintenance, of course, can be conducted only with unitization.

Q Now, Mr. Greer, in your opinion will oil recovery in the reservoir be increased and improved by reduction of the gas/oil ratio?

A It will be improved by the reduction of the limiting gas/oil ratio.

Q Will you refer to the brown sheets that are the next documents behind Tab S and review those, please?

A Here we review a policy or a tenet of the Oil Conservation Division of limiting gas/oil ratios. Traditionally the Division has done this and there's a reason for it. It improves the overall efficiency. The energy of the reservoir is better utilized and ultimate recovery is increased.

It's possible to quantify the increase in the ultimate recovery as a consequence of restricting the gas/oil ratios requiring oil to be produced by the ore efficient wells.

For this reservoir here is one calculation that -- or one set of calculations that shows the amount of increase that might be expected depending upon the reservoir pressure at which any given gas saturation occurs as a consequence of producing the oil.

I've shown here a sample beginning with 1500 pounds reservoir pressure and dropping 125 pounds and shows the increase of about 10 percent and then all the way on up to a fairly high -- high increases in recoveries.

The actual amount would depend, of course, upon the initial pressure as compared with the second pressure and that's why I showed the pressure drops, or approximately that for any given initial pressure in that pressure drop.

I think it is important not only in a reservoir generally, but in this reservoir, and even though a good part of the reservoir would be reacting under solution gas drive, we have two wells in a solution gas drive, one with a low gas/oil ratio and one with a high gas/oil ratio, in this reservoir the gas is going to so be utilized as to result in a higher recovery if most of the production is taken from the low gas/oil ratio well.

Q Now, Mr. Greer, I'd like you to go to Section T of Exhibit One and discuss the effect of high allowables on correlative rights in the area and I'd ask you to refer to the graph and accompanying summary paragraph on the first document behind that tab.

A All right. This is a copy of one of our exhibits in Case 8950 and we've repeated it here simply to show that at high allowables the recovery that the large wells enjoy deprives the other wells the opportunity to produce fair shares of the oil.

The oil in place is nowhere near a direct relation to the productivities of the wells, rather it's more like -- varies more like the cube root of the productivities and we show here that 200 barrels a day would be a reasonable allowable and what we asked for in Case 8950, for 320-acre spacing or 400 barrels a day for 640-acre spacing.

That still would be a better allowable than what we have asked for. We've asked for 800 barrels a day. We've asked for that simply because of the practicality of trying to compromise with people that would like to produce all the oil immediately and with those who would like to see a little higher ultimate recovery.

Q Would you now review your recomended

method for setting allowables for this pool?

A Mr. Chairman, in this pool we believe that a basic method to -- again, to get to set the allowable should be a gas limit rather than an oil limit and we make that recommendation for two or three reasons.

One in particular is that the operators do not agree among themselves as to proper allowables and recover factors, and so -- so we don't know, we can't agree among ourselves as to what percent of oil in place might be recovered.

I think there's no question about the amount of gas that would be recovered whether the pool was produced at solution gas drive, gravity drainage, gas cap expansion, whatever. When the pressure is finally pulled down to abandonment pressure all the gas down to that point will have come out of solution and will have been produced. And so if we view the situation on a basis of total gas that's present and the a gas allowable, we eliminate at least one of the points of difference in analyzing the reservoir.

Another benefit is that it makes little difference which gas sample or oil sample we use; the gas in place is going to be approximately the same. I've shown over on the righthand side a calculation of gas in place using the two different samples. The Loddy sample we've not adjusted. Mr. Hueni would, we presume, want to use his formation volume factors, which would add another perhaps five percent, but in round figures there's about a million cubic feet per acre of gas in place. That's based on 3500 barrels of stock tank -- or 3500 barrels of hydrocarbon pore space, which seems to be a reasonable estimate for the area at this time.

If we -- if we adopt this figure, a million cubic feet per acre, on 640-acre spacing then there would be 640-million cubic feet under a well. On 320-acre spacing, half of that.

If we produce all of that gas in no less than four years it would be 480 MCF a day on 640-acre spacing, 240 MCF a day on 320-acre spacing.

Corresponding oil allowables, then, at 600-to-1 limiting gas/oil ratio would be 800 and 400.

We think it makes sense to approach the situation in this way and also we note that that's a fairly rapid rate of depletion of a reservoir.

Q Mr. Greer, will you now go to the last two documents in Exhibit Number One concerning time required to recover drilling costs, and briefly review those for the Commission?

A We show here that if we went back to the allowable as it existed before the current temporary allowable, which for West Puerto Chiquito was 1342 barrels a day, gas/oil ratio limit 2000-to-1, and in the upper horizontal line we show a different actual produced gas/oil ratios for a particular well, and from that we work back down to line number seven, in which we show the time it would take to payout the cost of a $500,000 well on a 640-acre proration unit.

For 600 cubic feet per barrel that the well would produce at that gas/oil ratio, it would payout in about 0.9 of a month; 1200 cubic feet would be about 0.8 of a month, a little over three weeks; and on up to where a well with 4000 cubic feet per barrel -- the average gas/oil ratio in the pool right now is around 3000, a little over -- would be 1.7 months.

For 320-acre spacing and the allowable for it, the corresponding times would run from 1.7 months or 1.5 months up to 3.2 months.

Mr. Chairman, the -- this Commission has been told that New Mexico needs to return to these high allowables in order to provide an incentive for operators to drill and I submit, Mr. Chairman, New Mexico does not need to provide 3-week payouts for half million dollar wells to provide incentive for operators to -- to drill wells in New Mexico.

On the tan sheet we show what the payout times would be for similar gas/oil ratios under our application.

Again looking at column seven, the payout time runs from 1.5 months to 9 months for a 640-acre spaced well; 3 months to 18 months for a 320-acre spaced well.

Q Now, Mr. Greer, in addition to requesting abolishment of the Gavilan, extension of the West Puerto Chiquito, and special pool rules which address production limitations and spacing, you've asked for several other things in your application that I would like you to briefly comment on.

You're proposing a change in location requirements from 1650 feet from an outer boundary to 790 feet from the outer boundary unless otherwise provided for in the order.

What is the reason for that change?

A That would apply, that would be a change only in West Puerto Chiquito. That's the existing spacing now in Gavilan. We are suggesting that there be an option in West Puerto Chiquito to go to 320-acre spacing and if so, then this would be the well footages compatible with that spacing.

Q How do you recommend that wells previously approved for downhole commingling be handled?

A Just like they are now.

Q Now along the Canada Ojitos Unit boundary you're proposing only one well to each optional 320-acre unit along that boundary with a setback of 1650. Would you explain that proposed change?

A We have suggested that the -- any wells along the unit boundary, either inside or outside, be 1650 feet from the boundary, and that's to provide as practicably as we can some kind of a buffer zone around the unit.

Q You're also recommending a restriction of production along the unit boundary and you provide in your proposal that if the well is closer than 2310 feet to the boundary, then it should be permitted to produce only 50 percent of the top allowable. Why is that?

A Yes, sir, the reason for that is that we have provision for 640-acre spacing and a well would get -- one well on 640-acres would get that top allowable, but on a boundary where other wells that are drilled on closer spacing and lower allowables, then this would make the wells facing each other across the boundary to have exactly the same allowable.

Q If your proposal is adopted, in your opinion will it result in the prevention of waste of oil and protection of correlative rights in the subject reservoir?

A Mr. Chairman, it would be a step in the right direction. The only way that that can really be satisfied is with unitization.

Q Can you recommend to the Commission an effective date for the changes you're proposing here today?

A Yes, it should be March 1st.

Q Was Benson-Montin-Greer Exhibit Number One prepared by you or compiled under your direction and supervision?

A Yes, sir.

Q At this time I'd like to hand you what has been marked Benson-Montin-Greer Exhibit Number Two and ask you to identify that, please.

A Exhibit Number Two is an affidavit setting out that the parties in interest have been notified of this hearing.

MR. CARR: At this time, may it please the Commission, we would offer into evidence Benson-Montin-Greer Exhibits One and Two.

MR. LEMAY: Without exception they'll be admitted.

MR. CARR: That concludes my direct examination of Mr. Greer.

MR. LEMAY: Thank you, Mr. Carr.

Is there cross examination of Mr. Greer?

MR. PEARCE: Mr. Lemay, if I may suggest, if we could have a few minutes I think we'll be shorter in the long run.

MR. LEMAY: Fine. How much time do you think you need to spend?

MR. PEARCE: Five minutes will do it. It you want to take a ten minute break, that's fine with us.

MR. LEMAY; Let's take our ten minute break now and we'll convene in ten minutes -- reconvene.

(Thereupon a ten minute recess was taken.)

MR. LEMAY: We'll resume the hearing with cross examination.

Mr. Pearce, are you going to do it?

MR. PEARCE: Thank you. Yes, I am, Mr. Chairman. I appreciate it.

CROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Greer, for the record, I am Perry Pearce, representing Mallon and Mobil in this proceeding.

I'm sure that your lawyers have talked to you a great deal about the time problem that we're all facing. I've talked to myself a lot about it and I've talked to my clients a lot about it. Since we're operating on my nickel now, I'd like for you to just answer my question and if your lawyers want you to explain something to me, I'm sure they'll give you the opportunity.

I would like to refer you first, if I could, please, sir, to Tab B, as in boy, of Exhibit One, the first green sheet, and I want to see if I understand that correctly. As I look at that graphic representation, in September of 1962 that provides that the Canada Ojitos Unit pressure was about 1640 pounds, is that correct, sir?

A Yes, sir.

Q And then the last pressure I see annotated is a pressure in December of 1970 and that's a pressure of about 1280 pounds?

A I believe that's about right.

Q Do you know what that pressure is now?

A Not exactly, but the pressures that we've maintained over the years at the instruction of the Oil Conservation Division, was the gas cap pressures. We discussed the problem of getting pressures in the oil zone and if the oil migrated or was displaced down dip, and so the only pressures that we're certain of are the gas cap pressures and I believe they approximate, oh, 1350, around 1350 pounds, I believe.

Q That then is above the pressure in 1970, is that correct? The 1970 pressure I show is reflected as being about 1208.

A Well, it would not be far from that. There was a time when we overinjected and the pressure increased and then when the price of gas went up, then we reduced our injection rate. I believe it's probably fairly close to 1350 pounds.

Q I thought I recalled from your presentation this morning, sir, that during that period of over-injection prior to 1986 you were indicating that you were able to reduce the rate of pressure reduction but that we did not repressure that reservoir.

A Well, I guess I failed to clearly state myself. The -- what I was trying to say was that in order to maintain the pressure in the oil zone it is necessary to do you might say a cumulative pressure addition.

One is, as we take oil out of the reservoir, a certain volume of it, then we can replace that oil with the exact same volume of gas and the gas cap pressure will remain the same. The pressure in the oil zone will drop off a little bit depending upon how far down dip the gas/oil contact moves. This is just one of the -- what sort of complications that we have in this -- in this reservoir that is -- that the reservoir is not flat, and that's what I was trying to convey, that we can -- we can exactly replace the volume of oil that's produced but that won't quite keep up with the reservoir pressure in the (not clearly understood.)

Q And I judge that since you believe that the pressure between 1970 and the present may have climbed from 1280 to around 1350, that you have at least been able to accomplish that replacement, is that correct?

A Well, we tried to and I'm not sure that we accomplished it, but we made a reasonable effort to do that.

Q At any rate you do not have a current presssure measurement which would allow us to complete the graph that we're looking at up to the present. It appears to show a decline after that 1970 date and you do not have information to complete that graph, isn't that correct?

A Yeah. The problem, Mr. Chairman, the very close and accurate measurements that we kept of the pressure at that time was in an observation well that we -- our A-23 Well, and as long as the oil column was above that well, there was no problem in gettng and keeping pressures.

Once the oil -- gas/oil contact fell below the depth of that well, then we have no idea of knowing how far down below that well it is the gas/oil contact and not knowing that, then we can't calculate pressure down in the oil zone and the only other way to do that is to -- to pull the tubing and remove the (not understood) strings and all that, which I just hesitate to do in these expensive wells, and so we did not keep exact reservoir pressures in the C Zone wells after the gas/oil contact dropped below the -- this observation well's depth.

Q Okay. I would ask you now, sir, if you would, to turn to Tab J as in John, and I want to take a few minutes to look at the schematics which show two parallel red lines. I believe there are three of them. They're three or four pages back in Tab J. Do you have those in front of you, sir?

A Yes, sir.

Q The first one shows 1900 pound pressures for both the A and B and the C Zones. What's the source of those pressure numbers?

A The -- I'll have to refer to the index to try and find the exhibit.

It's in Section I, Item One. At a +370 foot datum we show there the virgin pressures on the east side of the San Juan Basin to be approximately 1900 pounds and that just happened to be the approximate depth at which we found the reservoir in the E-10, which was that pressure also.

Q And that's the virgin condition pressure in that well.

A That would be my interpretation, yes.

Q Okay, if we could turn to the second of those graphic displays, the column for the C Zone shows a pressure ranging between 600 -- 1650 pounds and 1750 pounds. Once again I'd ask you for the source of that number.

A Let's see. You're on the lefthand side of --

Q I'm on the lefthand side, that's correct, the 1982 display.

A Okay.

Q And the righhand C Zone column. column.

A Okay. The -- we see there the surface pressure we show in the upper righthand side of that graph ran from 1100, or runs from 1100 to 1200 pounds up and down. It approximates an average of about 1150, and then the +1600 foot datum for that surface pressure is about 1350 pounds. I think our production curve, I think we even figured 1356 or something like that in our reports.

Then if we have an oil column from that point down in the A and B Zones, it would then result in the figures that we've shown in the A and B Zones, and the C

Zone will show some of the -- a substantial amount of the oil has been removed from the C Zone; therefore its pressure, it has a shorter oil column and a lower pressure, and that's just my estimate of what the pressure would be at -- in the C Zone at that datum +370 feet.

Q And what -- where did you take the surface pressure measurement that was 1100 pounds when you started that calculation?

A In our observation well in the gas cap.

Q All right, sir. Let's switch over to the lefthand column to the A and B Zones. That shows A and B Zone pressure plus or minus 1800 pounds. Would you explain to me the source of that pressure number?

A I think that's about the pressure, approximate pressure at which the first well in Gavilan may have showed. As I recall, it was between 1750 and 1800 pounds, something like that.

Q Okay. Do you have a pressure test on the A and B Zones in the West Puerto Chiquito?

A No, sir. On West Puerto Chiquito, just as in Gavilan, when the Gavilan wells are all completed and are completed in all three zones, then in order to meet the offset requirements and hopefully minimize migration, why, we completed all of our wells in all three zones, but I would prefer to work with the C Zone a little bit longer, but I didn't have a preference.

Q You may have just addressed this. Let's turn back up to the front, if we could, please, to the plat of east/west in the Gavilan. I believe it is --

A Is that the orientation --

Q -- behind Tab A.

A -- the orientation plat?

Q Yes, and could you tell me, please, which wells in the West Puerto Chiquito Mancos Pool are completed only in the A and B Zones?

A Well, starting at the north, the L-27 in Section 27 of 26 North, Range 1 West is completed -- my interpretation it is producing primarily from the B Zone.

Coming down to the C-2 in Section 2 in 25 North, Range 1 West, is principally a B Zone producer.

Q I'm sorry, is that completed just in the B?

A I believe it has A, B, and C Zones open but the -- the A and B Zones are the only ones productive right now.

Q Okay.

A The O-33 in Section 33 has all three zones open.

Q I'm sorry, let me just go a little bit slower. I missed which well we're talking about.

A The O-33. And I feel that production from that -- from that well is coming from all three zones.

Q I do not -- I'm just not able --

A Okay, that's Section 33, Township 26 North, Range 1 West.

Q Okay, there's a --

A There's a little dot down there.

Q -- well spot almost right on the section line?

A Yes, but it's --

Q Is that that well?

A -- mis-plotted, I believe.

Q But anyway, you believe that's open in the A, B, and C, but you believe it produces primarily from --

A I think -- I think production from it comes from all three zones.

Q Okay. All right, sir.

A I believe that's about the size of it. The wells on the west side are completed in all three zones. Other wells are principally C Zone producers.

Q Okay, now, as I understand it, the L-27 Well is only A and B and the O-33 and the C-2 Wells are completed in all three --

A Yes.

Q -- is that a correct statement?

A Yes. I think very little production is coming out of the C Zone in the C-2 and I just don't have a feel for the proportion in O-33, but there's some production from both the C and the B and, perhaps, the A.

Q Okay. How -- can you give me some rough indication of how good each of those wells are?

A Well, yes, sir. The L-27 has produced about 1.5-million barrels of oil.

Q When was it drilled, please, excuse me for interrupting.

A I'd have to look it up again. I believe it was '68 or '69. It's one of the wells in the exhibits.

Q And what's the current rate on that well, if you know?

A About 150 barrels a day.

Q All right, sir, how about the O-33? Do you have that same sort of information?

A I believe it's produced about 250,000 barrels of oil; current production about 20 to 30 barrels a day.

Q And do you know about when that well was completed?

A I was looking at that graph just a little earlier. Seems to me it was '66.

Q All right, sir, and let's switch down to the C-2, if you would.

A I believe it was completed around 1965 or '66. Let's see, the cumulative on the C-2 is 245,000 barrels and its production runs about 20 barrels a day following a rapid decline last year.

Q Okay. Thank you, sir. I was unclear this morning, Mr. Greer, what you were indicating about the -- your expectations of productivity in the A and B when you said that most of the wells in West Puerto Chiquito were completed in the C Zone only.

Could you run back over that for me, please?

A Yes, we're talking about the older wells, the wells that we produced about, oh, seems to me around 6-or-7-million barrels of oil from.

You want me to name the wells?

Q No, that's all right, just indicate to me generally your expectation of the A and B in this area, please.

A Oh, the expectations of the A and B in this, say, Township 25 North, 1 West, is that your question?

Q Yes.

A Mr. Chairman, we always hope for the best, you know. I would hope that they have good productivities, and our plan, as I indicated earlier, was when we start on our gas cycling operation, to open up the A and B zones and we have, I believe, approval from our participants to work over either two or three, perhaps four, wells in the A and B Zones to commence that part of the depletion process.

The thing we don't know now is how much oil has been drained from the A and B Zones to the Gavilan area and whether we will find these wells to still have good productivities or if we're going to find that the oil has already moved out.

Our hope is that it hasn't moved out but it's a possibility.

Q Am I correct, Mr. Greer, that several years ago you were not completing in the A and B because you did not believe it was productive of oil?

A Well, we've always had our plan to open up the A and B Zones in 25 North, 1 West, when we reached the cycling phase.

Q When did you formulate those plans, sir?

A Oh, about -- our initial plans were in about 1970.

Q And I had reference to a hearing before the Commission in 1966 in which I believe you indicated that the A and B Zones were not oil productive in the West Puerto

Chiquito. Do you recall that, sir?

A In 1966? In 1966 we had completed all the wells at that time in the C Zone and I believe that one that I just mentioned to you, the L-27 completed in the B Zone, I believe, it was '68 or '69, we can look it up here and see just when that was.

Q If I may, Mr. Greer, just to make sure I understood your answer, looking at Tab J, the schematic for 1982, that we looked at a few moments ago.

A Okay, sir.

Q Do I understand that you do not have measured A and B Zone pressures in the West Puerto Chiquito?

A That's right. This is estimate of what they probably were.

Q That's 1982. Would the answer be the same in 1986, that you do not have pressure measurements?

A The wells in the south part of the unit are the ones I just mentioned that we're -- we have approvals from our participants to open up those zones and test them and we have the frac tanks on one location and I believe archaeologic clearance on another one, and I would judge it's still going to be several months before we get those tests completed.

Q So you do not have that pressure data at this time.

A No, sir.

Q Okay. Turn to, if you would, please, sir, turn to the page behind those schematics. It's a brown sheet. We're still in J.

A Yes, sir.

Q The bottom line is labeled estimate older unit wells "C" Zone.

A Yes, sir.

Q What's the source of that estimate, that data?

A The solid line is measured information. The dashed line is a continuation of that. The pressure would be the same if that is level, if it not had dropped any. If the oil level had not dropped down structure, the pressure in the gas cap had been maintained at approximately the same and that drop in pressure represents about, oh, 100 pounds, it would be about 300 feet of drop in the fluid level down the structure.

That's just a guesstimate on my part but it's probably reasonable.

Q Okay. Nomenclature explanation, please. The estimate of undrilled south unit A and B?

A Yes, sir.

Q What is south?

A That's the south part in Township 25

North, Range 1 West, offsetting the south part of Gavilan.

Q And you have, since that line is all dashed, you have no actual data on that, is that correct?

A No, sir.

Q That's "no, sir" you don't have it, not "no, sir, you're wrong.

A No, sir, I don't have the data.

Q Thank you.

A Well, let's see, Mr. Chairman, I might qualify that a little bit. On the west part of the south township we have pressures in the B-32 and B-29 and those wells pretty well are in that area

Q Okay, if we could look at that for a moment, the estimate of older unit C Zone wells, at January of '86, or so, that pressure appears to be about 1500, a little under that?

A Yes, sir, that's what I would estimate.

Q And it started out at about 1900 pounds, is that correct?

A Yes, sir.

Q Okay, that's about a 400+ pound drop. Once again I'm having trouble -- I'm not sure that I'm having trouble, but I'm having trouble understanding, because that appears to be a larger pressure drop than is reflected between the schematics for virgin conditions in the fall of

'86, isn't it?

A Well, I show on your righthand schematic the C Zone, I'm estimating 1400 and 1450 pounds. I believe this shows about 14 -- are you looking at 1-1-86 or 1-1-87?

A Well, as long as we're looking, I was looking at the wrong place.

Let's look back at what would be 1-1-82, if you can tell me about where that is and about what that estimate would show that pressure to be?

A Okay, 1-1-82 would be a little ahead of 1-1-83 on the sketch here.

Q Yes, sir.

A Just about the point where the shading meets, comes to a point, and right in there would be about -- about 1500 pounds.

Q And comparing that with the schematic, the schematic is showing 1650 to 1750.

A Well, I believe I have on the second line the 200-to-300 pounds. That would be, maybe, 1500 pounds to 1550, and then the pressure drop, which I made an estimate of there, of about 100 pounds would then bring the C Zone pressure up to 1650 to 1750 over in the Gavilan area.

Q Which, as I understand it, would be considerably above the line shown on the brown sheet?

A A little bit higher, yes, sir.

Q Okay, I'm looking, Mr. Greer, at Tab O, the first orange sheet.

A Okay.

Q A plot of cumulative production versus reservoir pressure for 29 and 32.

A Are you under Section O?

Q Yes, the first orange sheet. It's four or five sheets back.

A Okay.

Q A plot of cumulative production versus pressure.

Could you tell me what zones those pressures represent?

A Well, it's a combination of the A, B, and C Zones; just like in Gavilan, those wells are completed with all three zones open. Which is a predominant zone, if there is one, we don't know.

Q And the pressures, looking at the schematics that we were looking at a few minutes ago, the pressures between those zones may be the same. You showed a difference in pressure.

A I think it's possible, yes, sir.

Q All right, sir. Looking at the next page, which is also open, Gavilan Mancos Pool, pressure versus time, voidage versus time?

A Yes, sir.

Q Once again that's all A, B, and C, is that correct?

A Yes, sir.

Q And as I recall your testimony this morning, Mr. Greer, you indicated, I think, that in your opinion the A, B, and C Zones were -- what you said, I believe, was stratified away from a wellbore, that they might be connected at wellbores by frac jobs, is that correct?

A Yes, sir, I believe that's entirely possible.

Q All right, let's flip if we could behind Tab P, as in Paul, the second page of that exhibit, we discussed earlier the zones in which you believe at this time you have A and B production, and you named the L-27, O-33, and C-2 wells, I believe.

A Yes, sir.

Q You have drawn the -- colored the A and B in this brown color covering a good deal of the West Puerto Chiquito Pool. I was wondering if you have other data available to you which indicated to you that the A and B would be productive as you've drawn it here?

A Oh, this -- this just shows the saturations. I've not even attempted to put on here the productivities. This just shows the area where I think oil is being produced out of the A and B Zone and displaced by gas the yellow coloring, and unfortunately, the L-27 doesn't show on this plat, but you can see the -- the curvature of the -- of the yellow zone pointing to the upper left just above Section 34, where I assume that it's getting closer to the L-27.

Q Okay. I didn't understand that. If you could state for me again what the brown coloration represents.

A The brown coloration represents my interpretation of the areas in the A and B Zones that would be oil saturated. It has not yet been invaded by the gas injection.

Q Is there gas injection occurring in the A and B?

A Yes, sir.

Q In which well?

A The B-18.

Q Is that reflected on this map?

A Well, I don't know whether I reflected it anywhere, but it -- gas injection in the B-18 goes to all three zones.

Q Have you been able to determine how much of the gas you inject into the B-18 Well is taken by the A, B, and C Zones individually?

A No, sir, we gave an awful lot of thought to that early on when we started the pressure maintenance, and whaat we concluded was that the gas would go where it needed to go. If we pull oil out of the C Zone, the gas will go into the C Zone and hold pressure there.

If, on the other hand, we slow down production in the C Zone and take oil out of the B Zone, then the pressure will build up in the B Zone and go to -- and the C Zone and then to the A Zone, where it needs to go.

So I felt pretty comfortable with having all three zones open in that injection well.

Q Okay, and once again tell me, please, the basis of your interpretation of where that brown coloration is shown. I am correct, am I not, that the C-2, the O-33, and the L-27 are the only wells in which you have A and B production open, is that correct?

A Yes, sir, and because of that I have -- I have estimated that we've only pulled oil out of the A and B Zone about like is shown by the yellow coloring.

Q Thank you, sir. Looking, sir, I am still behind Tab P and I am looking at the -- I believe it is the fourth blue sheet, it is a production history graph on the L-27 Well.

A Yes, sir.

Q First of all, once again let me confirm, you do not have pressure data on these wells, is that correct?

A Current pressure data?

Q Yes, sir.

A No, sir.

Q What information do you have which indicates to you that the rapid increase in GOR reflected on that exhibit is not gas breakthrough from the injection or do you believe it is gas breakthrough?

A The principal reason is one that I mentioned this morning, the productivity of the well has dropped off. We've had breakthrough in the other wells and productivity of the wells didn't drop off so much. We had to choke them back in order for the production to drop.

This well is -- that acted differently. Its productivity just went.

Q And this well, as I recall, is not completed in the C Zone, is that correct?

A I think all the production is coming from primarily the B Zone, maybe a little bit from the A.

Q It's not open in the C Zone, is that correct?

A Yes, sir, it's open, as I indicated this morning. We tried to frac it and it just didn't frac.

Q And the other wells in which you have

seen a continued production from gas breakthrough have been open in the C and you believe that you are getting contribution from the C in those wells, is that correct?

A The ones that we've identified as C Zone wells, yes, sir.

Q Looking -- I am still behind Tab P and I'm looking at the first orange sheet, which is a rate graph on the C-2 Well.

A Okay.

Q I don't know whether I didn't understand or wasn't listening carefully enough this morning, will you explain to me again the different -- why the decline rate changed to 3-1/2 percent from something like one percent previously? What event, in your opinion, caused that?

A It's my feeling that that's where we reduced our gas injection when the price of gas went up.

It's really kind of amazing to see that from an injection well several miles away.

Q And once again you do not have any current pressure data on that well, is that correct?

A No, sir.

Q I apologize for the delay, Mr. Greer. I'm looking behind Tab S and I'm looking at the first blue sheet.

A Yes, sir, I have it.

Q The horizontal scale on that Log (Delta T).

A Yes, sir.

Q What kind of a time period are we talking about on that? What is the time unit that we're dealing with when this was done? Minutes, hours, days, weeks?

A I believe this plot, let me think just a minute, is -- well, I'd have to look the test up. It might have been in hours. That would be 100 hours out to a Delta T of 2. It might have been 100 hours and I say that would be a log Delta T of 2 would be 100 hours, and that might be what that is, but I would have to get the -- the survey itself to confirm that, and, you know, we could check with our office and get it if that's a material factor.

Q We would like to know and the same information on the orange and pink sheets that follow that, they show -- they all show the log Delta T horizontal axis and we'd just like to know what -- what that time was.

On any of the three wells reflected on those three sheets, blue, orange, and pink, did you do Horner plots?

A No, sir. A Horner plot wouldn't be on any help here. A Horner plot, of course, is useful if a well has been shut in and produced a short time and then shut in again. These wells have been produced for such a long period of time that a Horner plot would be no different from (not clearly understood.)

Q I am looking now, sir, I am still behind Tab S, and I've got two yellow sheets, one entitled Gravity Drainage from Tight Blocks. It has a couple of short paragraphs and then there's a graph below that.

A Yes, yes, I believe I'm with you.

Q The first yellow sheet is a sheet entitled Gravity Drainage from Tight Blocks.

A Yes, sir.

Q Could you tell me what you mean when you use the phrase "tight blocks"?

A Yes, sir. The initial tests that we made, both build-up tests and drawdown tests, showed that the only kind of reservoir geometry that can satisfy those -- the information that we developed, is a series or a combination of little reservoirs with a common pressure at the boundary, and by little reservoirs I mean like 20, 40, 100 acres, something like that.

A well drilled in one of those, and I call them tight blocks, their transmissibility would run from, oh, .01 Darcy feet to, perhaps, 0.2 Darcy feet, and those transmissibilities are tight compared to the overall high capacity system, the overall system of about 6 to 10 Darcy feet.

Q Do you have an opinion on the nature of what transmissibility there is in those tight blocks, the

A Yes, sir, that's what we measured with pressure build-up and pressure drawdown.

They're very typical curves. You can use any method you want to to analyze them and the end result is that they're small reservoirs with constant pressure at the boundary and the constant pressure is a high pressure, a high capacity fracture system.

Q Mr. Greer, could you give me some indication of the rock characteristics you would expect to encounter within one of these tight blocks?

A Yes, sir. The characteristics, I think, are simply fractured shale, where the fractures are tighter and closer together than a high capacity fracture system.

Q Mr. Greer, in your study of either of these two areas, have you done any studies of rock compressibility?

A Yes, sir.

Q You have?

A Yes, sir.

Q Could you indicate to me what you've done and which wells you've done such studies on ?

A The rock compressibility was of extreme importance inanalyzing the first 1965 interference test. At that time the oil was under-saturated and under-saturated oil has a compressibility on the order of 10 to 12 times 10 to the -6.

Compressibilities of the formation, from what I could get from literature, might run in the order of 6 times 10 to the -6, to perhaps, up to around, oh, 10 or 15.

If the compressibility of the shale was significantly higher, then it would materially affect the calculation. I made the calculations and presented them to this Commission in 1966, I believe it was, and I based my interpretations on two rock compressibilities.

One was in the low range, which would give a total system compressibility, I think, of around 15 or 20 times 10 to the -6, and then with a higher rock compressibility maybe up to 50.

With the lower rock compressibilities oil in place calculated to be somewhere in the range of 2000, 2500 barrels an acre.

If the rock compressibility had been higher, and I'm recalling from memory now, but I think that the high figure I used was around 20 or 25, then the oil in place would only have been like 1000 barrels a day. Actually I was hopeful that the rock compressibility was on the low side because otherwise we certainly would not have much oil in place.

Then in 1968 when we ran another interference test, the oil was then saturated. Saturated oil has a compressibility on the order of 275 to 300 times 10 to the -6. So it was like 10 to 20 times the compressibility of the rock. This meant then that the rock compressibility had very little effect, you could practically ignore it, with calculations where the oil was saturated.

The results were about the same. I came up with about 1800 barrels per acre, as I recall, when we had eliminated the indefinite value of the rock compressibility. This meant to me that then for the first analysis to compare with the second analysis, that the rock compressibility would be on the order of, I think 10 to 12 to maybe 15 times 10 to the -6.

That, I think, is the best check we have on rock compressibility.

Q Okay, I understood from '66 your estimates were 15 to 20 times 10 to the -6 and 50 times 10 to the -6 and at the 50 times 10 to the -6 you were estimating about 1000 barrels an acre, is that about it?

A Just the 50 times 10 to the -6 I believe was the total system compressibilities. That included the -- the compressibilities of oil and compressibility of the rock, compressibility of the connate water, and all that.

Q Okay.

A And again I'm callling this from memory. I'd have to dig out the figures but it's something in that order.

Q Okay, do you recall how you arrived at that range of values? Did you core a well?

A No, I just tried to cover what I thought was the waterfront. From the literature I would estimate that the compressibility might be somewhere in that range of 6 times 10 to the -6 to maybe as high as 25, and so when presenting my information to this Commission, I used both the high and the low figures so that the Commission would -- would know with the ranges that I was estimating at that time.

Q And that was an engineering estimate rather than a measurement.

A Oh, yes, sir.

MR. PEARCE: All we have, Mr. Chairman. Thank you, Mr. Greer, we appreciate it.

MR. LEMAY: Thank you, Mr. Pearce.

Are there any other questions of Mr. Greer?

Mr. Kellahin.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Greer, when we talk or you describe for us a gas cap expansion drive reservoir, would you give us a summary definition of what that type of reservoir is and how it acts?

A Gas cap expansion can, of course, occur with -- with different types of -- other types of drive, can be in conjunction with a water drive, can be in conjunction with a formation that's primarily a solution gas drive, if the formation is such that gas can migrate to the secondary gas cap, and if there's an initial gas cap it can act just like a pressure maintenance project.

Q If I understand correctly --

MR. LOPEZ: Excuse me, Mr. Chairman. Just a matter of procedure. I'm curious as to whether Mr. Kellahin is crossing or redirecting the witness to determine future procedure in these proceedings we know whether we're going to recross. If he is crossing, I think that it's only appropriate that the members of the same team proceed in advance.

MR. LEMAY; I understand. It's certainly going to be chalked up on his time, to his side.

MR. KELLAHIN: Mr. Chairman.

MR LEMAY: You needn't address

it, Mr. Kellahin, just --

MR. KELLAHIN: For clarification, I represent three distinct companies separate and apart from Mr. Greer. I consider this cross examination time chargeable as part of the time of the applicants. It may lead to some further cross examination by the opponents. I certainly don't know, but I think I'm entitled to exhaust my rights of cross examination.

MR. LEMAY: Is that part of the ground rules? Is that acceptable, Mr. Lopez?

MR. LOPEZ: (Not understood.)

MR. PEARCE: If I could rise and get into the middle of this, Mr. Chairman. It does appear to me that we have two camps involved in this thing. I don't think it is appropriate for either than camp or ours to take what is in effect examination by a friendly attorney and call half of it direct and half of it cross and I would just like to recommend that in the future if two attorneys from the same side want to question a witness who has been directed, that he do so before the other side begins cross, I think it will facilitate the process. They can come back and obviously redirect if they think that's appropriate.

MR. LEMAY: Is there any problem with that, gentlemen?

MR. KELLAHIN: I certainly

don't mind.

MR. LEMAY: We should have friendly attorneys do the direct and unfriendly attorneys do the cross examination.

Q Mr. Greer, I am told I am friendly. Am I correct in understanding that if you have a reservoir that produces principally by a secondary gas cap expansion, what that means to a layman is as the oil is withdrawn from the reservoir, the reservoir mechanics are such that gas will migrate to the top of that formation; not being produced initially, it will therefore be captured at the top of the reservoir and expand as further oil is withdrawn, providing a drive mechanism by which additional oil is recovered?

A Yes, sir, and it ordinarily takes the help of the operators in controlling the wells in order to take advantage of maintaining the pressure and all the good things that come with that, lower viscosity, and such.

Q In order to take advantage of that type of reservoir, am I correct in understanding that the operators would want to look at the gas withdrawal rates per barrel of oil so that they keep that rate of withdrawal at a point that you engineers call the solution gas/oil ratio?

A Well, as low a ratio as is practicable.

Q What would the solution gas/oil ratio mean? What does that term mean?

A That's the amount of oil that's dissolved -- or amount of gas that's dissolved in the oil and ordinarily considered at the time of the discovery or at the bubble point.

Q Applying that type of reservoir to the fact situations of the Mancos reservoir, now when I say Mancos reservoir, I am collectively meaning both the Gavilan area and the West Puerto Chiquito area. In applying that concept or that reservoir drive mechanism to the Mancos reservoir, if we produce at a top allowable of 702 barrels a day on 320-acre spacing, with a statewide 2000-to-1 gas/oil ratio, are we producing that reservoir above or below the solution gas/oil ratio?

A Well the solution gas/oil ratio, we've had some arguments about it, but it's somewhere in the range of 500 to 6-or-700 cubic feet a barrel.

A limiting gas/oil ratio of 2000-to-1 would be four or five times -- three to five times the solution ratio.

Q If we were going to tie to the limiting gas/oil ratio in that type of reservoir to the solution gas/oil ratio, is that approximately what the Commission did in the August hearing?

A Yes, sir.

Q What data and evidence have you examined that has caused you to conclude that this reservoir, the Mancos reservoir, is in fact not a gas cap expansion drive reservoir?

A Well, on the Canada Ojitos side we have injected gas and in effect have caused a gas cap there.

In Gavilan there was initially high gas/oil ratio wells. We don't know whether there's a gas cap there or not; there might have been. There is enough permeability, I think, for gas to migrate to the top of the Gavilan Nose, to migrate up-dip on West Puerto Chiquito, but to take advantage of that, as we discussed earlier, you have to control the wells and the production and take oil from the low gas/oil ratio level.

Q You have concluded that the primary drive mechanism in the Mancos area is a solution gas drive mechanism?

A Well, I feel it's a combination solution gas drive and gravity drainage. The amount of whichever one is predominant depends on how fast or how -- what the rate of withdrawal is from the reservoir.

Q Would you describe for a layman what a solution gas drive reservoir is, Mr. Greer?

A Yes, sir. The -- as oil is produced and the pressure drops, gas comes out of solution and expands and helps drive the oil to the wellbore and as the pressure drops and the gas/oil ratio increases, the pressure drops faster, and it's a vicious cycle in which -- and is a very inefficient mechanism, the least efficient, I guess, we have of producing a reservoir.

Q In terms of recovering a percentage of the original oil in place, then, a solution gas drive reservoir would be the least effective type reservoir?

A Yes, sir.

Q Is production in that type of reservoir sensitive to the rate at which you produce that reservoir?

A Well, it is only to the extent that gravity drainage is possible. If there's no gravity drainage possible, then it is not sensitive to rate.

Q You've indicated in your opinion the Mancos reservoir has a significant opportunity for a gravity drive mechanism?

A Yes, sir.

Q What is the approximate average of the structural dip for the Mancos reservoir?

A Where we've experienced gravity drainage in West Puerto Chiquito, the dips amount from 200 to 400 feet per mile in the oil zone.

In Gavilan the dips run from approximately 50 to 100 feet, adequate dip for gravity drainage.

Q Do you have an opinion, sir, as to

whether that rate of dip in the structure, both in the Gavilan area and the West Puerto Chiquito area is a sufficient enough dip to allow a gravity drainage mechanism to contribute to increasing ultimate recovery over that that you would see with a solution gas drive reservoir alone?

A Yes, sir. With the high transmissibility that we have, it's possible.

If the transmissibility were not that high, then the dips would be too low to permit gravity drainage, but in a combination, the high transmissibility. a number of 10 Darcy feet, and greater, then those dips are enough to permit gravity -- some gravity drainage.

Q Do you have an opinion, sir, as a reservoir engineer, whether or not utilization of an averge of 10 Darcy feet of permeability for the Mancos reservoir is a reasonable, realistic average?

A I believe it is.

Q And a combination with that average and the degree of dip you find in the Mancos reservoir, those two factors taken together, cause you to conclude that gravity drainage is a significant enhancement to the ultimate recovery?

A Yes, sir.

Q What happens, sir, if the pool is operated and the producing rates are such that they are set higher than would allow gravity drainage mechanism to take place?

A Well, if a reservoir is produced to too high a rate, and the pressure drops too fast, the only mechanism then that's effective is solution gas drive. Gravity drainage is a rate sensitive mechanism.

Q If it ultimately comes about that there is not enough reservoir characteristics to make gravity drainage a reasonable probability, have we caused waste by reducing the producing rates if in fact the only drive mechanism is a solution gas drive mechanism?

A No, sir, there would be no waste created.

Q What have we done?

A We have delayed the production (inaudible).

Q If on the other hand there is gravity drainage available for this reservoir, and if we do not act now in keeping those rates reduced to the optimum rate necessary for the operators to produce and pay for their wells, what have we done?

A Well, we've destroyed forever the possibility of getting to gravity drainage, and in this -- in this reservoir you cannot deplete it first and then look for gravity drainage. By that time the gas saturation is too high, the permeability of the oil too low, and it's either a question of do it now or never, never get it.

Q And therein lies the emergency that you described this morning.

A Yes, sir.

Q Let me direct your attention to your exhibit book, if you please, Mr. Greer, and if you'll look to Tab O. Following Tab O the first or the second yellow page is a display that demonstrates the wells involved in the various interference tests, is that correct?

A Well, it shows that the green -- the green lines show direct interference test. The pink lines show direct interference test. The orange lines show other evidence of communication.

Q If we look at the boundary between the Gavilan area and the West Puerto Chiquito area as they exist now, that is the darker black line running vertically that crosses througb the first green area and then the second green area?

A Yes, sir.

Q Have you found that line for me?

A Yes, sir, that's the joint boundary, common boundary.

Q In the top green area, that was an interference test conducted by -- among wells on both -- in both pool areas.

A Yes, sir.

Q Across that common boundary.

A Yes, sir.

Q And in those tests were not the A and the B and the C zones open in all those wells?

A Yes, sir.

Q When we look to the interference tests farther south along that same boundary, in that green area, again, was that interference test one conducted among wells that were perforated in not only the A but the B and the C Zones?

A Yes, sir.

Q And as we move across to the east and see the pink area, that pink area represents an interference test that was conducted among wells that were completed and open in the A and the B and the C Zones, were they not?

A Yes, sir, they were.

Q All right, sir, if we take Mr. Lopez' application on behalf of Mesa Grande and move the boundary of the two pools one row of sections to the east, and that in fact becomes the boundary between the two areas, do we now have effectively separted out the producing zones in those two areas so that we can treat them as two separate pools?

A No, sir. There is communication right straight across that boundary.

Q If we leave the boundary there can we separate out the C Zone so the C Zone which is from your testimony open and producing on both sides of that boundary, can we leave that as one common reservoir and then treat the A and the B as separate reservoirs?

A No, sir, they're tied together either by faults or by -- by fracture treatments, or whatever. We have to treat them as one reservoir.

Q If the boundary stays where it is, Mr. Greer, and you continue to operate your side of the reservoir as a solution gas drive with gravity drainage, and the west side of that boundary in the Gavilan is operated as a solution gas drive reservoir, which is not rate restrictive, what happens?

A Well, if the rate is too high in Gavilan, which it is right now, then the reservoir withdrawal rate will be so high that we cannot produce our area in Canada Ojitos Unit by gravity drainage, we will lose that ultimate recovery.

Q Let's turn to the Tab S, Mr. Greer, and direct you back to the tight blocks and the discussion you had with Mr. Pearce just a few minutes ago.

Am I correct in understanding when you refer to tight blocks you're talking about the ability of the matrix to contribute oil for production?

A No, sir, I'm thinking about blocks geometry-wise that might be 20, 40, 60, or 100 acres in size, surrounded by a high capacity fracture system, and within that tight block is fractures shale reservoir, but of tighter fractures, lower permeability than the high capacity system. That's what I mean by tight blocks.

Q So we're not talking about the ability of the matrix to contribute?

A Not matrix as is ordinarily considered in a sand reservoir such as the matrix that Mobil talks about, no, sir.

Q When we talk about the type of matrix Mobil was discussing at the past hearing, am I correct in understanding it is your opinion that there will be little, if any, contribution of that matrix to the recoveries in this reservoir?

A Yes, sir.

Q Mr. Greer, I'd like to show you what we have prepared as a summary of conclusions with regard to my three clients, Dugan Production, Jerome P. McHugh Associates, and Sun Exploration and Production Company, and it is the same position paper I handed to the Commission earlier this morning, and I'll ask you to go through that list, sir, with me and ask you if you have an opinion that is different or in agreement with each of those statements, starting off, first of all, whether or not you agree with the statement that the Gavilan Mancos Pool and the West Puerto Chiquito Mancos are in fact one single, common source of supply?

A Yes, sir, I agree with that.

Q Do you see any engineering justification for treating any of the three zones as separate reservoirs insofar as setting them up as different areas within the Mancos reservoir?

A No, sir.

Q Do you agree or disagree with the conclusion as an engineer that the pool is a highly fractured, stratified reservoir which produces from a combination of solution gas drive and gravity drainage supplemented by gas injection pressure maintenance?

A I agree with that.

Q Are you also of the opinion that the majority of oil is contained within natural fractures and the formation matrix will have little or no contribution to ultimate recoveries?

A Yes, sir.

Q Third, do you have an opinion, sir, as to whether or not there is effective pressure communication between the two areas of the reservoir?

A Yes, sir, we've -- we've demonstrated

that, I believe.

Q Again, four, I believe you've already concluded for us that there is good evidence of pressure interference based upon the interference tests?

A Yes, sir, under number four, the 640 acres that we're asking for is an option.

Q And number five, do you believe it's necessary to minimize the unnecessary dissipation of the natural reservoir energy by restricting the gas/oil ratios, as requested in that paragraph?

A Yes, sir.

Q And number six, do you believe that the current pool allowables of 702 barrels a day on a 320-acre spacing unit, as derived from the statewide depth bracket allowable, prior to the temporary order the Commission entered on September 1st, is too high for this reservoir?

A Yes, sir, it's too high.

Q I'll ask you to look at paragraph seven with regards to the pool reservoir pressures are dclining and the gas/oil ratios are increasing. Do you have an opinion as to whether those rates are excessive?

A Yes, sir, they are excessive. Unfortunately, as a practical matter, that's about all we can (not clearly understood).

Q Do you have an opinion, sir, as to whether the production completion techniques in the Gavilan area are sufficiently different whereby the operators have in effect isolated out that portion of the Mancos in their side of the reservoir so they can be treated differently from your side of that reservoir?

A No, sir, they cannot be treated differently.

Q Mr. Pearce talked to you awhile ago about some of the reservoir characteristics, fluid properties, rock compressibility, some of the other parameters that you felt applied to the Mancos reservoir.

MR. KELLAHIN: With the Commission's permission, I would like to distribute to the participants some Sun Production -- Exploration and Production Company exhibits so that I might direct Mr. Greer's attention to Exhibit Number Two. May I take a moment to do that?

Q Mr. Greer, I believe have distributed the Sun Exploration and Production Company exhibits and I'd ask you to turn your attention to Exhibit Number Two --

MR. LOPEZ: Mr. Chairman, as a point of clarification, I'd just like to know whether we're going to have any Sun witnesses to establish the basis or foundation of this exhibit before we have Mr. Greer testify as to (inaudible).

MR. LEMAY: Mr. Kellahin, would

you address that?

MR. KELLAHIN: Point of clarification, the reservoir simulation study is based upon parameters which have been reviewed by Mr. Greer and in order to lay a proper foundation for the Sun reservoir simulator engineer to discuss the simulation of the reservoir, as a predicate to that I'm laying a foundation with Mr. Greer that the reservoir parameters used by the Sun witness are fair and reasonable and realistic to apply in that simulation, and that's the purpose of asking him these questions.

MR. LEMAY: Okay.

MR. LOPEZ: So it seems clearly that we've gone from cross examination to direct examination, is that right?

MR. LEMAY: That's no problem. We'll consider this direct, friendly certainly, friendly and non-friendly can be used as good criteria for direct and cross. For the purposes of this hearing they'll all be considered the same.

You may proceed, Mr. Kellahin.

Q Mr. Greer, I'll ask you to review with me, if you will, sir, the reservoir conditions and properties set forth on Exhibit Number Two, and if you'll take a moment and go through those and let me know if you see any of those parameters that in your opinion are unrealistic, inaccurate, or in some way inappropriate to use with regards to doing reservoir calculations, whether they be volumetric calculations, material balance calculations, or some type of modeling of the reservoir conditions by simulation by computer analysis?

A They all look reasonable to me, Mr. Chairman.

Q When you talked about rock compressibility with Mr. Pearce awhile ago, you gave us 10 times 10 to the -6 as the rock compressibility.

A My estimate would be that it ranges somewhere like 10, maybe 12, or even 15, but the best figure I had was 10.

Q When we talk about the pemeability, the display shows 10 Darcy feet and I've discussed with you earlier whether or not in your engineering opinion that represented a reasonably accurate average to apply to the Mancos reservoir?

A Yes, sir.

Q Is that still your opinion?

A Yes, sir.

Q You talked to Mr. Pearce awhile ago with regards to some of the reservoir pressure numbers being used within the reservoir. Would you identify for us, Mr. Greer, what in your opinion is the bubble point of the reservoir?

A Well, it was 1534 pounds by our analyses at the temperature shown here. I might add, though, that that will have very little affect on the reservoir simulation since most of the pressure will be below the bubble point, so it's really not a material factor.

Q With regards to the initial reservoir pressure, what is your opinion with regards to the initial pressures in the reservoir?

A Well, for this simulation it really makes little difference. As I indicated before, the majority of the simulation will be at pressures below the bubble point and so it really doesn't' make much difference.

Q Mr. Greer, do you have an opinion as an engineer whether or not in using a reservoir simulation it would be reasonable and accurate applied to this reservoir to use an average dip per mile of 50 feet?

A Yeah, 50 feet per mile is a minimum dip for most of the -- for most of the reservoir. There's a little bit of it that's flatter than that, but by and large 50 would be a minimum.

Q And as we move from west to the east and move farther into the eastern edge of the West Puerto Chiquito Mancos we have dip per mile that's greater than that.

A Yes, sir, dipping down into the syncline between the two areas. The syncline, by the way, is an excellent place to locate recovery wells for gravity drainage.

MR. KELLAHIN: Thank you, Mr. Chairman. That concludes my questions for Mr. Greer.

MR. LEMAY: Are there any more questions of Mr. Greer?

MR. PEARCE: Just a few, if I may, Mr. Chairman.

MR. LEMAY: Mr. Pearce.

RECROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Greer, none of the -- none of the maps which I've looked at in this proceeding show much of the East Puerto Chiquito. Could you give me some indication of the relative rates of dip between the East Puerto Chiquito and the Gavilan Mancos Pool?

A Are you talking, sir, about East Puerto Chiquito Pool or West Puerto Chiquito Pool? East Puerto Chiquito Pool?

Q Yes, sir.

A Under Tab A the last structure map, we can determine some of the dips.

As I indicated earlier, Mr. Chairman, the detailed geologic study in structure will be presented by Dick Ellis.

If you'll tell me what part of the area that you're interested in, generally along the boundary between East and West Puerto Chiquito the dip is like 1000 feet per mile, going up as high as 3000 feet per mile, and we've found in other areas of this -- we've cored wells in this same formation and even the steep dips that the formation is hard and tight, the fractures apparently squeezed together, no communication, and that is one of the separation -- separations that we have between East and West Puerto Chiquito, that long fault to the north.

Q Now, as I recall your summary this morning of the history of the pool, you indicated, I think, that there used to be only a single Puerto Chiquito Pool, is that correct?

A Yes, sir, that was initial.

Q And when was that broken out into two separate pools?

A In 1966.

Q Do you recall a hearing before the New Mexico Oil Conservation Division in August of 1980 on the application of Benson-Montin-Greer for amendment of pool rules?

A Yes, sir, I recall that hearing.

Q Which pool and what rules, if I may?

A Oh, well, the one in August of 1980, and then I think it was continued or either another hearing in November of that year, was West Puerto Chiquito, where we went from 320-acre spacing to 640-acre spacing.

Q And do you recall a discussion of the East Puerto Chiquito Pool during that hearing in which Mr. Nutter asked you the question:

"Well, Mr. Greer, is the oil over in the west side better than the oil in the east side?"

Part of your response after discussion -- you were having a discussion of pricing -- was that:

"The dip in the formation," and I believe you were referring to the East Puerto Chiquito, "is too shallow and if it had the permeability, the transmissibility, that I think it will have, injection wells there would just result in channeling in a matter of days."

Do you call that testimony?

A Yes, sir. I believe I recall that now. And of course we have to remember that this was before any wells were drilled in there. I was estimating that the transmissibility would be similar to wells some twenty miles to the west in which well productivities were like 15 to 20 barrels a day and transmissibility would be low.

This is one of those formations that I wish I could see underground and tell ahead of time what the rock characteristics would be. After drilling the wells, of course, we've now found that by measuring the transmissibility rather than estimating what it might be when somebody drilled well, I would have found that I was wrong and nice that I was wrong.

Q Do you have a gas injection project in the East Puerto Chiquito?

A We've commenced. We've got most of the system into place; the -- part of the gas system, part of the water system. We plan on both water and gas injection in the East Puerto Chiquito.

Q Will that be part of the Canada Ojitos Pressure Maintenance Project or is that a separate project?

A That's a separate project.

Q If your application in this case to abolish the Gavilan Pool and extend the West Puerto Chiquito Mancos Pool, will you make an application to make the Gavilan part of the Canada Ojitos Pressure Maintenance Project?

A Oh, I would hesitate to forecast something like that. What I hope will happn after this hearing is that the operators will get together and will voluntarily want to do something cooperative to try to overcome these problems that we've identified.

Q We've hoped for that before, sir. If that does not happen do you intend to bring a statutory unitization case before the Commission?

MR. KELLAHIN; Objection, Mr. Chairman. It's irrelevant.

MR. LEMAY: Mr. Kellahin -- go ahead, Mr. Pearce.

MR. PEARCE: Mr. Commmissioner, I do not believe it is irrelevant. We are going through the proper way to operate a pool Mr. Greer has indicated that believes is one pool. Almost all of the present West Puerto Chiquito Mancos Pool is in a pressure maintenance project.

I think I am entitled to know whether he believes that all of the Gavilan, if it is consolidated is going to be forced, if he is successful, into the same pressure maintenance project.

MR. KELLAHIN: That asks for this witness to speculate. Mr. Pearce has asked him to speculate whether in the future if the parties fail to agree (not understood clearly) such things happen we're going to have to resort to statutory unitization --

MR. PEARCE: Mr. Chairman, I believe my question was a question of the present intention of the witness. If it was not specified, I will certainly specify it at this time.

I would like to know if at this time this witness intends to bring a statutory unitization case, if these pools are consolidated, and if he is not successful in getting a voluntary unit.

MR. LEMAY: I think we'll allow the question rephrased that way, the current situation to-day, without speculation.

Q Mr. Greer, Mr. Chairman, what I would like to do after this -- an order's been entered following this hearing, would be to try once more to get the operators together to talk about some kind of cooperative method to operate this reservoir.

We know that when the Commission entered a temporary order last August that was the hope of the Divi-sion at that time, that the operators would be able to get together.

The problem that we had then was that soon after that last hearing people began to think about this hearing and a permanent order, and it's very clear to me that the operators just would not sit down and look at the problem seriously as long as they were under a temporary order.

So if we had a temporary order -- permanent order, then, and perhaps I'm being naive, Mr. Chairman, but I would hope that the operators would voluntarily get together.

The last thing that I would want to do is to force statutory unitization on people that don't want it, and surely, surely they can begin to see the problems that we've identified and try to do something about it.

MR. PEARCE: Mr. Chairman, that was an interesting history of this point. It was not, in my opinion, responsive to my question.

I asked this witness if he was not successful in getting a voluntary unit if he had a present intention, and I think I'm entitled to an answer to that question.

MR. KELLAHIN: He got an answer, Mr. Chairman, clear and articulated. He said if all else fails, if reasonable people will not reason together, as the last resort, and it's the one he would hope did not occur, we would have statutory unitization.

It was just as clear as night and day. He had his answer.

MR. PEARCE: Mr. Greer, did you say that? There was a part of that that I did not hear.

MR. LEMAY: I didn't exactly get that answer myself.

Would you like to clarify what you told us before, Mr. Greer?

A Those things, Mr. Chairman, as a last resort, and that would be the last thing we'd want to do, to be forcing statutory unitization on people that didnt' want it.

Now we have employed the statutory unitization regulations in the statute in this pool but we have employed it only where there was an operator in the pool that we couldn't even communicate with. He wouldn't answer his telephone. He wouldn't answer his mail. There was no way that we could communicate with him.

In order to bring that party into the unit, we had to resort to statutory unitization. That's the only time we've employed it. I just hope we won't be -- feel it necessary to ever do it again.

MR. LEMAY: I think that answers the question.

MR. PEARCE: I think in the interest of time I would save something for closing.

I believe that's all have at this time, Mr. Chairman.

MR. LEMAY: Are there any other questions of Mr. Greer?

Yes.

MR. LUND: Mr. Chairman, Kent Lund with Amoco. May I ask just a couple quick questions?

MR. LEMAY: Yes, you may.

CROSS EXAMINATION

BY MR. LUND:

Q Mr. Greer, I think my engineers and my geologist would be angry at me if I didn't ask you a couple of questions.

A I don't want you to get in trouble with them.

Q Yeah. Let me ask you real quickly about the three wells that you indicated in the West Puerto Chiquito area that are productive from either the A or the B Zones, and I believe those were -- let's take them one by one. First was the L-27.

A Yes, sir.

Q Is that correct? I think you said that's from the B Zone only?

A My feeling is it's primarily from the B Zone.

Q All right.

A And the A Zone is perforated. The A Zone is the zone that we were drilling that our engineer was concerned about that he couldn't get the well to dust and that's typical of that A Zone, so there could be some production there. But it was the B Zone, when we penetrated the B Zone, that the oil came to the surface in a large enough volume to set the forest on fire.

Q So the L-27 is completed in all three zones?

A Has all three zones open but it's my feeling that the B Zone is the producer.

Q All right, and partially from the A and none from the C?

A I sure doubt there's any from the C.

Q All right. Now, with the C-2 Well, is that completed in all three zones also?

A Yes, sir.

Q And that's productive only from the B Zone?

A My feeling is that it's primarily the B Zone. As I recall, I'd have to look the records up, but I think we fraced the C Zone and it didn't do very good, and we then came back and fraced the A and B Zones separately from the C Zone. That's my recollection.

Q All right, you don't recall for sure whether there's contribution from the C Zone?

A I think there's very little from the C Zone.

Q All right. And then the last one was the O-33, I believe? That's completed in all three zones?

A Yes, sir.

Q And that's productive from all three.

A Yes. I think principally from the C Zone, but some the B and perhaps some from the A.

Q And was I correct in response to a question from Mr. Pearce, I think you said that the rest of the wells, other than these three wells we've just discussed, are productive in the West Puerto Chiquito area, are only productive from the C Zone, is that correct?

A The wells on the east side. Those on the west side are completed in all three zones, where -- where we're getting close to Gavilan, and those are completed in all three zones.

Q Okay, and the rest of the wells are completed only in the C and productive only from the C?

A I believe so.

Q Okay. And then the last question I have, I think you testified that if there's no gravity drainage contribution to this reservoir in both areas, Gavilan and West Puerto Chiquito, if there's no gravity drainage, then the reservoir would not be rate sensitive?

A That's right.

Q Is that what you testified?

A Yes, sir, that's correct.

Q Thank you very much.

MR. LEMAY: Mr. Carr?

MR. CARR: One question.

REDIRECT EXAMINATION

BY MR. CARR:

Q Mr. Greer, in response to the last question from Amoco, you testified that you had three wells in the West Puerto Chiquito portion of the pool that you believe produce from the A and B Zones.

A Yes, sir.

Q But the other wells were producing from the C Zone.

A Most of them except those on (not clearly understood.)

Q Is it fair to conclude from this that there isn't oil in the A and B Zones throughout this area that could be produced on your side of the line that's now arbitrarily run through the reservoir?

A I hope it is. That's my feeling.

Q You hope there is oil available on your side in the A and B Zones, is that your answer?

A Yes, sir.

Q Do you believe that to be the case?

A Well, it will have to be tested, you know; the two wells that are in production all the time, one of them appears to be principally the A and B Zone, and the other one appears to have some from the A Zone, and I would think tied together with the B Zone, and so I think all three zones are producing (not understood), yes, sir.

Q Nothing further.

MR. LEMAY: Mr. Greer -- yes, go ahead Frank.

MR. CHAVEZ: Frank Chavez, Oil Conservation Division, Aztec.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Greer, how much oil do you think has been derived from gravity drainage in the West Puerto Chiquito Mancos Pool that would not have otherwise been produced?

A I would say a substantial part of the 8-or-9-million barrels that we've produced. I believe it's about 8-or-9-million barrels now. A very large percent of that has been produced by gravity drainage.

Q Could you put a number on that, three, four, five million or --

A I would think at least half of that is as a result of gravity drainage. We might have gotten half of that much from solution gas drive, but I kind of doubt it.

Q Mr. Greer, how much lower than what should have been virgin pressure was the Gavilan Mancos Pool in when it was first produced?

A In my estimate it was something like 100 pounds, 80 to 120, some thing like that.

Q Given your estimate of 10,000 to 20,000 barrels per pound of drop, doesn't that estimate to close to 2-million barrels of oil that may not have been in the Gavilan Mancos Pool that would otherwise have been had it been at virgin pressure?

A The -- I'm not sure that we can apply that -- that figure all the way back.

I feel like the bubble point was around 1534 pounds and oil produced above that would not take a big volume, a large volume of oil to pull that pressure down, so I believe it would be pretty hard to make that kind of a calculation.

Q But there could be an estimate made that might be in the ballpark using that pressure drawdown?

A I suppose, yes, sir.

Q Mr. Greer, where did you think that oil migrated to?

A I presume it migrated to the east into the Canada Ojitos Unit.

Q Given that there's a large volume of of oil that may have migrated east to the Canada Ojitos Unit, couldn't part of that that would otherwise have been considered gravity drainage actually be the oil that migrated from the Gavilan area?

A As I said before, I don't think a large volume moved. I feel if pressure is above the bubble point it doesn't take much oil to move to do that.

Q Mr. Greer, in your Section O in your exhibits, where you have the table and map on the minimum area being drained by the B-32 and B-29 Wells, you testified and showed examples that those wells had communication to the east and west; however, you show only drainage from the east in your map. Is there a reason for that?

A Yes, sir, if you'll look to the previous page, the third page under Section O, the fifth column, I show my estimate of the direction of flow.

Q Well, Mr. Greer, if the pressure had been low in the Gavilan area, wouldn't there have been some flow from the west to the east to these wells?

A That's what I show here in January, 19 -- January 17th, 1985, when the B-32 was completed, then the flow appears to be -- had changed, turned around and went from west to east -- I mean east to west.

In 1982 I show the flow direction east; 1983, both directions; 1985, to the west. So all of the production which we show on the graph which you were just looking at would be while the flow was from west -- east to west.

Q Thank you.

MR. CHAVEZ: That's all I have.

MR. LEMAY: Thank you, Mr. Chavez.

Any other questions? Mr. Padilla.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Greer, would you explain what the difference in your application is, difference between 320-acre spacing as you propose and 640-acre spacing with an option to drill a second well on the 640-acre unit?

A Yes, sir, I'd be glad to -- to explain that.

Mr. Chairman, when Gavilan's temporary order was established three years ago, as I indicated before, Gavilan didn't want to be a part of our pool and we didn't want to be a part of Gavilan. We were still hoping that there could be enough restriction between the two that Gavilan could be operated however they wanted to and we could do our thing, whether we wanted to do without interference, and one of the concerns that we had at that time was that most of the operators in Gavilan who favored wide spacing favored only 320-acres (not understood).

Now in West Puerto Chiquito we had some

problem tracts and one of them is the one that I mentioned just a little earlier that we finally brought into unitization by the statutory unitization method. Accordingly, we needed in West Puerto Chiquito 640-acre spacing absolute. The only way it could be changed was through a hearing. That was to prevent the drilling of unnecessary wells by some of these small tracts that might come in on the forced pooling hearing and ask for the drilling of a well, an unnecessary well.

So we needed that 640-acre spacing fixed with no qualifications to it; it would take a hearing to drill any closer than that.

Now we don't have that problem. We had statutory unitization. We do not now have the problem of a tract that's not unitized being able to come in and force us to drill on any spacing at all. It takes a vote of the operators to bring about the drilling of a well at any kind of a spacing.

So that being the case, now that we have the statutory unitization, we no longer need the provision that wells can be drilled only on 640, so we can now make the rules the same, both Gavilan portion and West Puerto Chiquito, where wells can be drilled either on 640's or at the operator's option, on 320's, and that's the change that we're asking.

The Gavilan, all it does to the existing Gavilan rules is give an option for operators to go to 640-acre spacing. In West Puerto Chiquito it gives them an option to go to 320.

And that's the story on the spacing.

Q Mr. Greer, given that explanation, would you agree with me that typically you can still drill two wells per section basically, correct, under either option, either alternative?

A That's right. It's strictly an option, up to the operator, and we would hope as many operators as possible would take advantage of the wider spacing and avoid that much waste in drilling unnecessary wells.

Q But an operator is not precluded from drilling that second well.

A Oh, no, sir, it's strictly an option that he can drill a second well if he wants to, if our application is granted.

Q Now, with respect to the allowable, how do you propose that the allowable can be calculated? Is that on a 640-acre unit?

A Yes, sir, with the exception, of course, that there the wells that are already on 320 acres, why, they would stay on 320 acres, unless an operator wanted to pool his two 320-acre tracts together in one 640-acre proration unit.

New wells on new sections would be on 640-acre proration units and then they could drill either one or two wells on that proration unit.

Q Assuming that there are now two wells in the Gavilan area in one section, how would the production be allocated to that 640-acre unit?

A We have identified, I believe, all of those tracts in the application, and they would either continue as they are now or, at the operator's option, they could be combined into one proration unit.

Let's take, for example, that there is a high capacity well in the -- in half of the section and a low capacity well in the other part, if they want to go together to from one 640-acre proration unit, shut the little well in and allocate oil to the big well, they can do that and save the cost of operating that well.

Q Do your rules propose or presume, or take into consideration the deliverability in your example as to that high capacity well and the low capacity well in the same section?

A I don't believe I understand your question.

Q Well, do you give credit for more unit allowable to the high capacity well under your system or can the operator do whatever he feels like doing in there?

A I believe the Commission's basic proration rules permit the allocation of production to whichever of the wells in whatever proportion an operator wishes to do it, with the exception of those on the boundary to the Canada Ojitos Unit.

Q In other words, your proposal doesn't allocate or give credit to the deliverability of a particular well in a 640-acre unit.

A Well, the allowables for the oil wells, Mr. Chairman, are not at this time based on deliverabilities, like some of the gas wells are. The net of it is, there's a gas allowable and wells are permitted to produce as much as oil as they can up to that maximum gas limit, and the proportion that would be allocated to the wells on a 640-acre proration unit would be up to the operator, however he wanted to do it. As I indicated before, he might even shut one in to save the operating cost of that well.

But it allows more flexibility by far than what the current rules permit, but it's all on the direction of avoiding waste.

Q Mr. Greer, in that situation if you have two different operators, do you foresee a conflict between the two operatos as to allocation of the allowable?

A No, sir. If the two operators don't want to get together and form a single proration unit, then they just go on just like they are right now.

Q How would you split the allowable as you propose between the high capacity well and the low capacity well in a situation where you have two different operators who can't agree?

A If you have two different operators who can't agree, then they live with the situation just like it is right now, each one produces his own well and stays under the regulations.

Q In any event, you can not exceed your 640-acre daily allowable in both wells, right?

A Well, unless they form a 640-acre proration unit, then they're treated just exactly like they're treated now. It's only if they form a 640-acre proration unit that you would have any kind of consideration to -- as to division of production among the wells, between the wells.

Q Now, as I recall your testimony, there is production limitation on wells offsetting the unit, Canada Ojitos Unit, is that correct?

A Yes, sir. I believe we made provision for wells inside the unit that are located closer than 2310 feet to the line can produce only one-half of a 640-acre proration unit allowable.

Q How would a well, sir, offsetting the unit protect itself against the well further west that does not have the production limitation?

A Well, I don't believe I understand your problem. A well offsetting the unit will have -- do you want to take an example, a 320-acre well, it has a 320-acre allowable. The well offsetting it to the west would have another 320-acre allowable, unless it's on a 640-are proration unit.

Q In other words, what you're saying is that all the wells are treated equally across the -- across the pool, assuming your application is granted?

A Well, all the proration units will be treated equally or proportionately. A 640-acre unit gets twice as much allowable as a 320-acre unit.

Q Let me ask you, sir, is the East Puerto Chiquito unit or pool contiguous with the West Puerto Chiquito Pool?

A Yes, sir, the boundary is contiguous.

Q I believe it was your testimony that there's communication between these two pools.

A No, sir, I believe in 1963 we presumed that it was all one pool but as we drilled additional wells, just as we found otherwise in the area, it is pretty hard to forecast well are drilled exactly what -- what the situation is.

We found separation then in drilling wells, so in 1966 we asked the pools be divided.

Q How many wells offset each other in the -- in these two pools, the East Puerto Chiquito and West Puewrto Chiquito?

A Direct offsets?

Q Yes, sir.

A I don't believe we have any.

Q How far apart are the two closest wells in the two different pools?

A In East and West Puerto Chiquito?

Q Yes, sir.

A I'll have to look at a map.

Q Okay.

A Mr. Chairman, I guess we're on the opponents' time now?

MR. LEMAY: I wondered, Mr. Padilla. Would you identify yourself as friendly or unfriendly?

MR PADILLA: I'm neither.

MR. LEMAY: The time allocation for this will be -- I guess we have neutral time, and you can claim neutral.

MR. PADILLA: Fine, we'll claim

neutral time. I believe we had time on Friday.

MR. LEMAY: That's true. We'll subtract that from your Friday time.

A Mr. Chairman, in answer to Mr. Padilla's question, it appears to me that the closest wells might be in the East Puerto Chiquito Mancos Unit and the Jicarilla wells to the west; look like about three miles, something like that.

MR. PADILLA: Mr. Chairman, I believe that's all I have.

MR. LEMAY: Thank you, Mr. Padilla.

Additional questions of Mr. Greer?

One point, Mr. -- yes?

MR. LYON: You go ahead and make your point.

QUESTIONS BY MR. LEMAY:

Q Well, it was just a point of clarification, if I could, Mr. Greer.

Concerning your three zones, I understand that these are perfectly pressure -- in pressure communication but yet they're treated separately within a wellbore because you do not see any migration of fluids locally but regionally you do?

A Yes, sir. Regionally we see communication among the three zones but locally they appear to be separated, so -- and by locally I mean --

Q How local?

A We tested them in wells prior to a frac treatment that ties the three zones together.

Q So wells that are fractured in essence have communication between A, B, and C Zones?

A In some instances. In some instances, you know, as we indicated this morning, we fraced wells and did not tie them together. Very clearly there the zones are separated.

In Gavilan, with the tracts and the perforations as close together as they are, the chances are very good that most of the perfs are tied together behind the pipe. But --

Q Would you consider that a local variable situation, then?

A Well, it -- it's a local situation in which the zones are tied together, but -- and you have vertical communication between them, but it's nothing that will give the mass migration down through the main part of the reservoir that's away from the wellbore as was postulated by the opposition last August.

Of course, we don't know if that's a concern now or if, perhaps, the opposition has changed their position about the reservoir or if they still think it's a 600-foot communicative reservoir or whether they, perhaps, now they think it's stratified. We don't know. We won't know whether that's an issue now or whether that's a point of agreement or a point of difference, we don't know right now.

MR. LEMAY: That's all I have. Mr. Lyon?

MR. LYON: V. C. Lyon, Chief Engineer for the Commission.

QUESTIONS BY MR. LYON:

Q Mr. Greer, I'd like to visit with you a little bit about some exhibits in Section Q.

A Looks like the Krystina that you're looking at, Vic.

Q Yes. The pink sheet showing the Krystina in red? Have you found it?

A I've found it.

Q You show the Krystina circled in red and then a larger red circle within which the Krystina well is located.

Are those wells producing, the wells inside the larger red circle?

A The -- the figure typed in by the wells show the approximate 1987 production rate. For instance, the top one is 9 barrels and the next one, 10 barrels, then 3 and 2 and those that show zero are shut-in apparently most of the year. And I believe the Krystina was shut-in all year, most of the year.

Q Most of the year, I believe. The well that's circled in green, what is the status of that well?

A It averaged about 70 barrels a day for the time it produced last year. I believe it came on production, seems to me it was in May or June, which, incidentally, John Roe will be putting on the statistics of all the wells in both pools, and those wells are identified and all of the -- the exact statistics for each month for each well, and that information will be available to the Commission.

Q All right. I was unclear in your testimony whether the data shown opposite on the white page indicated that the Krystina Well was being drained by production from wells within that larger red circle or from outside the red circle.

A Well, what I've plotted is just wells that -- the production from wells within that circle. I've plotted them against the Krystina's pressure. Then the shaded area represents the deduction from the production of the Greener Grass Well and that shows clearly to me that the Greener Grass Well is draining the Krystina area.

Now how far around the Krystina beside the well itself, we don't know, but the fact that it's over a mile from the Krystina to the Greener Grass Well and the circle that I've drawn is maybe a 2-mile radius, it would seem possible that there is some kind of drainage affecting all of the wells in that circle.

Q Do you have an opinion as to whether or not that area is being drained by the wells outside the red circle?

A My feeling is that -- that they're both draining from the same common source of supply and the reason I say that is because the pressures are dropping comparably the same, about the same.

It's seemed very difficult for wells with a higher pressure than those in the Krystina area to be draining the Krystina area, and that ws the first thought that our committee had, the engineering committee, when we looked at that, that those low pressures mean it's just not communication with anything but one of the things we can't be sure about is the producing pressures in some of the wells to the north and what the pressures are there.

For instance, the wells in Section 3, we don't have much information on their pressures. They may be in communication with both Gavilan to the north, the Krystina to the south, and somehow they're kind of tied together so that the faster the Gavilan area is drawn down, the faster the Krystina area drops in pressure.

Q Do you happen to know if any of those wells are connected to a gas gathering facility?

A All I know is that -- I know that Merrion has had difficulty getting his well, his Krystina Well connected and since the Greener Grass Well is producing, I would presume that they have arranged for a gas connection for that well. I don't know about the others. Well, the others that are producing, they probably have a gas connection.

Q For those wells which don't have gas connections, in reference to your proposed amendments to the rules, the amendment of allocating oil and gas, what do you consider to be the reliability of gas measurement from a well that doesn't produce into a pipeline?

A Well, it's my undertanding that the wells that do not produce into the pipeline, let's see, I believe they're -- the OCD has given them an allowable of a certain number of MCF a day. Seems to me like it was 30 MCF a day, or something like that. That might still be -- still produce.

All we would know there would be an operator's -- the accuracy of his equipment to go by and occasionally measure that gas/oil ratio. Certainly he would not have a daily measurement like you do where it's going to a pipeline, so I would think just offhand it would not be as accurate as the wells connected to a pipeline.

Q Do you think we might be back on the honor system?

A I think it's a possibility.

Q Thank you, that's all I have.

MR. LEMAY: Any additional questions?

If not, the witness will be excused.

MR. BROSTUEN: I have some.

MR. LEMAY; Oh, yes. Just go ahead, Mr. Brostuen.

QUESTIONS BY MR. BROSTUEN:

Q Okay. Mr. Greer, I'm looking at your exhibit in Section A. It's your plat showing the location of the wells in the unit and whose testimony you want to believe, I guess, noticing that you have your wells L-11 and P-11, they were drilled essentially on, what, 160-acre offsets to each other. When were they drilled?

A They were -- I believe the P-11 was the second well in that area. K-13 was the first one, P-11 was next, and then I believe the A-14, and that was, when we drilled the L-11, that we had, I think, the A-14 Well shut-in and when we were producing the L-11 and, my gracious, we found a drop in the fluid level with the well shut-in and not producing, and I remember one of our partners said that, good night, that's just like the drawing oil out of a tank and gauge it and you can see the oil going out of the tank and the gauge line showing the lower level of oil, just like we did with our fluid levels. And that was when we decided that we needed to run an interference test. And so that interference test was run in 1965, so without looking up the records I would judge the L-11 was drilled in the fall of '64.

And I think that was the last time that we drilled any wells that close together.

Q This was when you had that 320-acre spacing in effect, is that correct?

A Yes, sir. Temporary 320-acre spacing at that time.

Q And, of course, prior to your unitization.

A No, sir, the unit was formed earlier.

Q The unit had been formed earlier?

A Yes, sir, we formed the unit before we started to drill.

Q That was a proration unit rather than a secondary recovery unit, is that correct?

A It was an exploration unit.

Q Exploration unit. Your -- could you give me any idea as to what the current producing rates are for those three wells, the L-11, the P-11, and the A-14, or will that be presented tomorrow by your geologist?

A Oh, no, I can tell you. We shut those wells in when their gas/oil ratios reached about 2-to-3000 cubic feet a barrel and they were then shut-in, oh, like in the seventies.

Q So they are continuing to be shut-in today?

A Yes, sir, they're shut-in. We'll open them up when we get into our cycling operation.

Q I see. The -- the Canada Ojitos Unit, is that now a statutory unit? Is that --

A Yes, sir, it's now a statutory unit.

Q I'm noticing that you have a considerable acreage here included. You have at least two townships, probably 2-1/2 or maybe 2-2/3rds townships here with a limited amount of drilling. How did you determine participation for a unit that big? (Not clearly understood) participation. I'm not fully aware of everything about your unit here, of course.

A Okay, what we did, we just used the same participation factor that we had for the -- the exploratory unit for the participating area. We just used that, that formula.

Q And do you have diverse mineral ownership then in this area or is this strictly --

A There's -- there's fee land and federal land and state land and then to the north there's Jicarilla land on the north boundary of the unit.

Q Inside the unit?

A Beg pardon?

Q Inside the unit, Mr. Greer?

A No, it's outside the unit --

Q Okay.

A -- now. We have plans and have been working for a fourth expansion of the unit to include most of those Jicarilla lands.

Q I see.

A We're just in the process of working on that now; been in the process for eight years.

MR. BROSTUEN; That's all I have.

MR. LEMAY: Any additional questions?

We will excuse the witness. Do you want to put your next witness on; take a five minute break first?

MR. KELLAHIN: Let's take a five minute break.

MR. LEMAY: Let's take a five minute break and come back and we'll start the next witness.

(Thereupon a five minute recess was taken.)

MR. LEMAY: We'll continue on. I might say at this point we will reconvene tomorrow at 8:30 after we get about 20 or 30 minutes from the next witness. This is to keep things on schedule, so tomorrow morning we'll reconvene the hearing at 8:30 and continue at this point.

MR. KELLAHIN: Thank you, Mr. Chairman.

Call at this time our next witness for the applicants in the Case 9113, Mr. Richard Dillon, D-I-L-L-O-N. Mr. Dillon is a petroleum engineer with Sun Exploration and Production Company.

RICHARD G. DILLON,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q For the record, Mr. Dillon, would you please state your name, sir?

A My name is Richard G. Dillon.

Q Mr. Dillon, were you previously sworn this morning as one of the expert witnesses before the Commission?

A Yes.

Q By whom are you employed, Mr. Dillon?

A I'm employed by Sun Exploration and Production Company.

Q What is it that you do for Sun Exploration and Production Company?

A I'm employed as a reservoir engineer in Sun's headquarters office in Dallas, Texas. As a reservoir engineer in this capacity, I've performed various reservoir studies. Various other functions come under my responsibility. I have spent several years in a reservoir simulation group. During that time I've done a number of studies on different fields of various types, including different materials, including sandstone, limestone, dolomite, both of clastic and reef-type structures. These had matrix, vugular and fracture porosity. Also these reservoirs had different processes, such as primary depletion; secondary processes, waterflooding, gas injection; tertiary processes, CO_2 miscible flooding.

Q Have you previously testified before the Oil Conservation Commission of New Mexico?

A No, I have not.

Q Have you testified before other oil and gas regulatory bodies of other states?

A Yes, I have.

Q When and where did you obtain your degree in engineering, Mr. Dillon?

A I obtained my degree, which is a Bachelor of Science degree in petroleum engineering, from the Colorado School of Mines in 1978.

Q And what professional associations are you a member of?

A I'm a member of the Society of Petroleum Engineers and I'm a Registered Professional Engineer in Texas.

Q As a reservoir engineer that works with Sun's Reservoir Simulation Group, what significance does that type of work have for Sun in the case that we have before the Commission today?

A That experience is significant in that I was able to rely on this past experience in order to utilize a computer model in order ot analyze the behavior of the Mancos Reservoir.

Q When we talk about the Mancos Reservoir, are you including what is defined as the Gavilan Area as well as the West Puerto Chiquito Mancos Area?

A That's correct.

Q What have you done with regards to studying the Mancos Area, Mr. Dillon?

A With regards to the Mancos Area we have taken the objective of performing a simulation study in order to determine the sensitivity of recovery from the reservoir, primarily through rates. We've also investigated other parameters which mignt affect the ultimate recovery.

Q Have you completed that study?

A That's -- yes, I have.

Q And based upon your study of the Mancos reservir, Mr. Dillon, have you reached certain conclusions and opinions as a petroleum engineer about the Mancos Reservoir?

A Yes, I have.

Q And do your opinions include opinions

concerning the optimum producing rates for the pool as well as the well spacing for that pool?

A Yes.

Q When you as a petroleum engineer with this specific experience and expertise with reservoir simulation, what is it that you are generally doing?

A With this experience I will take the parameters which we have in the Gavilan Area and the West Puerto Chiquiito Areas and use that data in a model in order to determine the various behaviors under different conditions imposed on that model.

Q When you conduct a reservoir simulation, would you describe for us what are the basic elements or parts of that type of reservoir simulation and the study that goes on with it?

What are the parts or factors that constitute the study that you made?

A The first part of any study would probably be to -- would be to choose the proper model in order to -- that is the proper computer program in order to -- which would be appropriate for the reservoir that is -- is under study.

Q After you've selected the model, what then is the next step you conduct?

A At that point the next step would be to gather interpret and to basically collect the input data to input into the model.

Q After you have collected the reservoir characteristics and parameters that you put into the model you've selected, what then is the next thing you do?

A At that point you do any manipulation if need be in order to get that data into the proper format for the particular model, and then you submit the model to the computer board -- run.

Q After the computer runs and simulates the reservir, what then is the next step, Mr. Dillon?

A The next step at that point is to take the results from the model in whatever form they may be, and analyze those results.

Q And have you followed that procedure with regards to studying and simulating the Mancos Reservoir?

A Yes, I have.

MR. KELLAHIN: At this point, Mr. Chairman, we tender Mr. Dillon as an expert petroleum engineer.

MR. LEMAY: So qualified.

Q Mr. Dillon, do you have an opinion concerning the effect, if any, of the structure or dip and it's importance to the recoveries in the Mancos Reservoir?

A Yes, I do.

Q What is that opinion?

A My opinion is that the Mancos Reservoir is very sensitive to rates in terms of ultimate oil recovery. That ultimate recovery is also affected by the reservoir dip that is present.

Q Is reservoir simulation by computer modeling something that you do on a regular basis?

A At this point in time it is not a day to day function that I perform, but it is something that happens during the process of my responsibilities, yes.

Q In your past experience involving reservoir simulations have you modeled reservoirs similar to the Mancos in terms of including a fractured reservoir?

A I have studies fractured reservoirs, yes.

Q In making your study you've said the first element of that study is to select a model. In deciding on which model to apply to a certain reservoir, what are the general types or categories of models from which you make a selection?

A The model, or models that you may choose from for any particular selection are of very different types depending on what type of fluid behavior you might expect, the different rock properties that might be present, whether or not a particular recovery process that would be unique, such as a tertiary recovery process, and you would have to take into consideration the number dimensions you want to model in, whether it be a linear model or a two-dimensional cross section, or a regular model with perhaps a 3-dimensional aerial type model.

Q When we talk about the model, are you telling us it is the computer program that you put into the computer and it's that computer program that you're selecting off the shelf?

A That's correct. The selection would be to -- for the program that is the set of computer code that would run the data that you have input to it, would perform the equations, and would give you the results. That is what I'm referring to as a model.

Q I assume that computer models and programs come in all varying levels of simplicity to very sophisticated, complex models.

A That's correct.

Q Would you describe for us in making your selection of the model that you picked for the Mancos Area, what was the type of model you selected?

A The model that we selected was a publicly available model, one that we had purchased. Specifically it's terms the VIP Model, that is -- that stands for Vectorized Implicit Program. This is a product put out by J. S. Nolen and Associates. It is a 3-dimensional black oil model and -- in other words, a conventional type of model.

It has, specifically interesting to Sun is the fact that it is written, it is designed to run on a high speed computer such as the Cray that we have, in which this work was done.

Q I can't run this program on my Apple computer in my bedroom, can I?

A No, you con't.

Q It's not something that I get from Computerland and just plug it in and run and get a simulation of this reservoir.

A No, sir.

Q When we talk about one phase and one dimenstional models what are we talking about there?

A One phase would imply that only one type of fluid would exist in the reservoir. That could be a gas or a liquid, either water or oil. One dimensional would imply that the model could only form -- excuse me, perform calculations going in one direction. That would be a -- the ost simlistic type of model from the dimension standpoint.

Q You said the VIP model you selected is one that will be 3-dimensional and 3-phase?

A Correct.

Q Would you describe what that means?

A 3-dimensional indicates that the model can simulate any configuration of the reservoir no matter what its extent is vertically, horizontally, that is areally.

The black oil 3-phase implies that it will perform calculations for having all three phases of gas, oil, and water present in the reservor simultaneously.

Q Why did you pick this particular model for the Mancos Reservoir?

A This model was chosen because it was in our judgment the best model that we could pick for it. It is a state of the art model. It's, again, it fits our physical constraints. We tested it thoroughly against other models and have deemed it a very good product.

Q Has Sun used this model to a degree that you have developed an opinion about its reliability and proven accuracy?

A Yes.

Q And what is that opinion?

A The opinion is that it's very reliable, very accurate for the type of model that it is.

Q Has Sun relied upon this model to perform sophisticated modeling of complex reservoirs other than the Mancos?

A Yes.

Q And you've selected it to apply to this

Mancos Reservoir.

A That's correct.

Q Let me direct your attention to the exhibit book. When we look at Sun Exploration and Production Company exhibit book, is this a book that you have caused to be prepared under your supervision and direction?

A Yes.

Q Do the exhibits that are in this book represent your opinions and your work product --

A Yes, sir.

Q -- as well as the input of other individuals upon which you have relied?

A Yes, it does.

Q Let's turn to Exhibit Number One, Mr. Dillon, and have you simply identify that exhibit for us.

A Exhibit Number One is a description of the program that was selected. It gives some statistics for it.

I might point out that this program is used by several other major oil companies. It essentially qualifies the programs.

Q Is this program or model one that is suitable for instances in which there is evidence of dip or structural distances in the reservoir that Mr. Greer has described earlier today?

A Yes.

Q Is this model adequate and sufficient to model a segregated reservoir?

A Yes.

Q Is this model one that is suitable for use in a fractured reservoir?

A This model is suitable for a single porosity system, such as would exist in the Mancos where there is no contribution from the matrix porosity.

Q Is model also suitable, if in fact there was matrix contribution from the sand in this reservoir?

A This model could be configured to account for that contribution, yes.

Q Let's turn to Exhibit Number Two. Having selected the appropriate model for this reservoir, Mr. Dillon, what then is the next thing that you do?

A Again, as I stated before, the next thing to do would be to gather the data and determine what input parameters to use in the model.

Q And what is depicted on Exhibit Number Two?

A Exhibit Two are the assumptions and parameters, the values thereof that were used in the model. Most of these came, as mentioned before, from -- from other sources, primarily previous testimony, calculations by Sun, and the operator of the Canada Ojitos Unit.

Q Are the parameters and assumptions that you have set forth on this exhibit all the parameters and assumptions that you need to make as an engineer in order to model this reservoir?

A The parameters that are outlined here are the basic parameters that are required, yes, to go into the model. There are other considerations, but these parameters would make the thicker configuration of the model unique for the Mancos situation.

Q Having done that, then, Mr. Dillon, would you direct your attention now to Exhibit Number Three, which, if you'll take a moment, you'll see that on Exhibit Number Two, under "relative permeability" you have put a reference and it says "Exhibit Number Three"?

A Correct.

Q Let's turn to Exhibit Number Three and have you discuss for us what you have done with regards to the relative permeability parameter that you've selected for the model.

A Exhibit Three is a plot of the relative permeability. This data was originally introduced into testimony by the operator of the Canada Ojitos Unit.

The dashed line, which is labeled "Curve used in calculation", is the data that was used in the model.

I might point out that the bottom axis, the horizontal axis indicates the total liquid saturation. The vertical axis, which is logarithmic, indicates the relative permeability ratio of gas to oil.

This data is used in the model in that it calculates -- is used to calculate the fractional flow of the fluids within the reservoir.

Q In describing the functional flow in the reservoir you've referenced this exhibit as representing the relative permeability of fractured formations prepared by, and utilized by Mr. Greer?

A That's correct.

Q This came from one of his exhibits?

A That is correct.

Q How does this compare to the relative permeability curve that Mr. Hueni used in his prior testimony before the Commission?

A According to the testimony, this is also the same curve that Mr. Hueni used.

Q Okay. Let's turn now to Exhibit Number Four. When we look at Exhbiit Number Two under "Fluid Properties", under the "Oil" portion, you've referenced us to Exhibit Number Four. What is Exhibit Number Four?

A Exhibit Four is simply the Core Lab report of the PVT analysis from the Canada Ojitos Unit Well No. L-11. It's labeled 12-11 there.

Q It is in fact the L-11 Well in the unit, is it not?

A That is correct.

Q Okay. What do we do with this?

A The next twelve pages, which constitute this report, contain the data that describes the PVT behavior of the fluids in the reservoir. This was used in the model study because we felt it was a representative sampling in a reservoir. Again this was our input data that we utilized.

Q This is part of the data that I think you said earlier you have to calibrate or recompute in order to make it suitable for use in the model?

A That's correct.

Q I forgot the magic word. What do you do?

A Manipulate, perhaps.

Q By manipulate you don't mean that you have fudged to make this do something unusual.

A No.

Q All right, manipulate is a word or art for you simulators and it simply means that you've taken this data and made it, converted it in somefashion to make it work in the model.

A That's correct.
Q That's a mechanical task that you performed.
A It has been converted into a form that is acceptable for input into this particular model, yes.
Q Having selected the model, having inputed (sic) the parameters, what then is the next thing that you need to do?
A Having selected all of the parameters and having set up the entire configuration of the model, the next thing would be to run the model.
Q Well, I didn't ask you the right question.
A That's correct.
Q Exhibit Number Five has something to do with grid size on the model.
A That's correct.
Q All right. Before you run the model you've told me you have to select a grid size. Now what in the world is that and why do you do it?
A The grid, and looking at Exhibit Five, this is simply a graphical depiction of the gridding that was used in the model. The grid is the means by which the reservoir simulator, if you will, accounts for the flow of oil and gas and/or water through the reservoir. Each of the

grid cells, which is represented by one of the squares in either the upper or lower depiction, is the smallest entity within the simulation, simulator, which has a unique pressure and saturation for each of the phases by which the model is able to reproduce the flow in the reservoir, thus accounting for the -- its relative movements.

This particular size was selected because it is an optimum combination of areal definition which eliminates errors in the model due to what we call grid effects, or numerical dispersion.

The vertical definition as you see there is five layers. This was also again an optimum value for this particular application.

Q In selecting the appropriate grid size, would you describe for us what it means when you say "7x7x5 layers", as shown on Exhibit Five?

A That simply means that as you can see here, we have seven cells in the X direction, if you will, and Y direction, in the horizontal plane, and we have five layers in the vertical plane, thus we have forty-nine cells areally and five layers vertically.

As you can see from the -- the plot for the 640-acre spacing symmetry element, as this would be called, as this is a minimum element that can be taken out of the reservoir that is representative of each incidence of a 640-acre spacing situation. You can see, as labeled, the model is 5,280 feet on a side. This represents a square mile, and we have four wells producing out of each of the corner cells, each of which was scaled in the model to be a one-quarter well. This is an acceptable simulation practice in order to reduce computer run time and avoid excessive computer cost, but at the same time not losing any accuracy or continuity of the results.

Q Do you have an opinion as an expert petroleum engineer, as to whether the model or grid size you've selected for the model is the most appropriate one to select for this purpose?

A I believe it is the most appropriate for this purpose.

Q Having selected the model, having inputed the reservoir parameters, having selected an appropriate grid size, what then is the next thing you do?

A At that point with the model entirely constructed to that point, then you would run the model.

MR. KELLAHIN: Mr. Chairman, what's your pleasure?

MR. LEMAY: Well, I think, just like any good soap opera, we should, just when we get to the interesting part, we should continue tomorrow (inaudible).

We'll reconvene at 8:30 in the

morning.

CERTIFICATE OF PARTIAL TRANSCRIPT

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing pages numbered 1 through 238, inclusive, constitute a full, true, and correct record of the portion of the hearing conducted on 30 March, 1987, prepared by me to the best of my ability.

Sally W. Boyd CSR