STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
Santa Fe, New Mexico

18 March 1987

EXAMINER HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico. — CASE 9111

BEFORE: David R. Catanach, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division: Jeff Taylor
Legal Counsel to the Division
Oil Conservation Division
State Land Office Bldg.
Santa Fe, New Mexico

For the applicant:

MR. CATANACH: Call next Case Number 9111.

MR. TAYLOR: Case Number 9111, application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico.

MR. CATANACH: At the request of the applicant this case will be continued to the Commission Hearing March 30, 1987.

(Hearing concluded.)

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9111, heard by me on March 18 1987.

David R. Catanach, Examiner
Oil Conservation Division

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

3 April 1987

COMMISSION HEARING

IN THE MATTER OF:

| | |
|---|---|
| Application of Benson-Montin-Greer for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico, and | CASE 9111 |
| Application of Benson-Montin-Greer Drilling Corporation for the amendment of Division Order No. R-8124, Rio Arriba County, New Mexico. | CASE 8951 |

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

MR. CARR: May it please the Commission, at this time I'd request that the next two cases on the docket be continued and readvertised and scheduled at a later date. They're applications for Benson-Montin-Greer, and we would request that they be rescheduled following the entry of an order in this matter.

MR. LEMAY: Thank you. Is there any objection to that request?

If none, then that request is noted and it will be followed.

(Hearing concluded.)

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true, and correct record prepared by me to the best of my ability.

Sally W. Boyd CSR

BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
MAY 21, 1987

COMMISSION HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico.

CASE 9111

BEFORE: William J. LeMay, Director

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the New Mexico Oil Conservation Commission:

Jeff Taylor
Legal Counsel for the Commission
State Land Office Building
Santa Fe, New Mexico

MR. LEMAY: The hearing will come to order. Call Case 9111.

MR. TAYLOR: Case 9111, the application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico.

MR. LEMAY: At the request of the applicant this case will be continued to June 18, 1987. The hearing adjourned.

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
Santa Fe, New Mexico

18 June 1987

COMMISSION HEARING

IN THE MATTER OF:

| | |
|---|---|
| Application of Mallon Oil Company for the reinstatement of oil production allowables and an exception to the provisions of Division General Rule 502 for certain wells located in the Gavilan-Mancos Oil Pool, Rio Arriba County, New Mexico | CASE 9073 |
| and | |
| Application of Benson-Montin-Greer Drilling Corporation for the amendment of Division Order No. R-8124, Rio Arriba County, New Mexico | CASE 8951 |
| and | |
| Application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico. | CASE 9111 |

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 Division: Charles E. Roybal
Counsel to the Commission
Energy and Minerals Department
525 Camino de Los Marquez
Santa Fe, New Mexico 87501

For the Applicant:

MR. LEMAY: The remaining three cases, we won't have to read them because they've been on the docket for awhile, but Cases 9073, Cases 8951, Case 9111 all involved the West Puerto Chiquito Gavilan Area, and at the request of counsel these cases will be continued to July 16th hearing.

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

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

16 July 1987

COMMISSION HEARING

IN THE MATTER OF:

Disposition of Cases 9134, 9068, 9073, 8951, and 9111

Transcript in case 9134

BEFORE: William J. Lemay, Chairman
Erling Brostuen, Commissioner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Commission:

For the Applicant:

BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
SEPTEMBER 24, 1987

COMMISSION HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico.

CASE 9111

BEFORE: William J. LeMay, Director

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the New Mexico Oil Conservation Commission:

Jeff Taylor
Legal Counsel for the Commission
State Land Office Building
Santa Fe, New Mexico

MR. LEMAY: Call next Case 9111.

MR. TAYLOR: Case 9111, the application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico.

MR. LEMAY: At the request of the applicant this case will be continued to the Commission hearing to be held on October 15, 1987. The hearing is adjourned.

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

15 October 1987

COMMISSION HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico. CASE 9111

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 Division: Jeff Taylor
Attorney at Law
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant: William F. Carr
Attorney at Law
CAMPBELL & BLACK P. A.
P. O. Box 2207
Santa Fe, New Mexico 87501

MR. LEMAY: Case Number 9111. Application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMC West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico.

MR. CARR: May it please the Commission, Benson-Montin-Greer Drilling Corporation requests that this case be continued to the Commission hearing to be held in December of this year, if there is one; if not, then to the next scheduled Commission hearing.

MR. LEMAY: Thank you, Mr. Carr.

Without objection Case Number 9111 will be continued to the December docket of the Commission.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

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

18 February 1988

COMMISSION HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico.

CASE 9111

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

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division: No attorney appearing.

MR. LEMAY: Case Number 9111, the application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, will be extended -- continued to March 17th, at the request of applicants, as will Case No. 9073, de novo hearing, application of Mallon Oil Company for the reinstatement of oil production allowables.

Both of those cases will be extended to the Commission Hearing on March 17th.

(Hearing concluded.)

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

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

17 March 1988

COMMISSION HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico. CASE 9111

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

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division: No attorney appearing.

For the Applicant: William F. Carr
Attorney at Law
CAMPBELL & BLACK, P.A.
Post Office Box 2208
Santa Fe, New Mexico 87501

For Sun Exploration & Production: W. Thomas Kellahin
Attorney at Law
KELLAHIN, KELLAHIN & AUBREY
P.O. Box 2265
Santa Fe, New Mexico 87501

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date MARCH 17, 1988 Time: 9:00 A.M.

| NAME | REPRESENTING | LOCATION |
| --- | --- | --- |
| William F. Carr | Benson-Montin-Greer | Santa Fe |
| W T Kellahin | Sun Exploration & Prod. | Santa Fe |
| [illegible] | [illegible] | Santa Fe |
| R.D. Buettner | Koch Exploration Company | Wichita, KS |
| C.F. Pomeroy | | |
| [illegible] & Becky Miller | Mallon Oil Co. | Denver |
| M.A. Stallworth | Mobil Oil | Denver |
| Bruce Petitt | Reading + Bates Petroleum Co. | Tulsa, Ok. |
| [illegible] | Hooper, Kimball & Williams Inc. | Tulsa, Ok |
| James Bruce | Hinkle Law Firm (Mesa Grande et al.) | S F |
| L G Zambrano | Mobil | Denver |
| [illegible] | OCD | Aztec |
| Greg Hueni | Bergeson & Assoc. | Denver |
| Kevin M. Fitzgerald | Mallon Oil Co. | Denver |
| George Mallon | | |
| [illegible] | Mesa Grande, Ltd. | Tulsa |
| [illegible] | Benson-Montin-Greer | Farmington |
| Victor Lyon | OCD | Santa Fe |

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date MARCH 17, 1988 Time: 9:00 A.M.

| NAME | REPRESENTING | LOCATION |
| --- | --- | --- |
| Frank Sylvan | Sun E&P | Denver |
| Warren Cadwell | Sun E&P | Denver |
| Carl Pomeroy | Koch Exploration | Wichita, Ks |
| John Roe | Dugan Prod. Corp. | Farmington |

# I N D E X

VOLUME ____ OF ____ VOLUMES

A P P E A R A N C E S

| | |
|---|---|
| For Mallon, Mobil and Kodiak | W. Perry Pearce<br>Attorney at Law<br>MONTGOMERY & ANDREWS<br>P. O. Box 2307<br>Santa Fe, New Mexico 87501<br><br>Frank Douglass and Becky Miller<br>Attorneys at Law<br>SCOTT, DOUGLASS & LUTON<br>Twelfth Floor<br>First City Bank Bldg.<br>Austin, Texas 78701 |
| For Mesa Grande Ltd., Mesa Grande Resources, Reading & Bates, Hooper, Kimball & Williams, and Limestone Investments: | James G. Bruce<br>Attorney at Law<br>HINKLE LAW FIRM<br>P. O. Box 2068<br>Santa Fe, New Mexico 87504 |
| For Koch Exploration: | Robert D. Buettner<br>General Counsel & Secretary<br>Koch Exploration Company<br>P. O. Box 2256<br>Wichita, Kansas 67201 |

I N D E X CONT'D

VOLUME 2 OF 2 VOLUMES

INDEX CONT'D



EXHIBITS

E X H I B I T S CONT'D

MR. LEMAY: And I'll call Case 9111, the application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito Mancos Pressure Maintenance Project, Rio Arriba County, New Mexico.

I shall call for appearances in Case 9111.

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.

We represent Benson-Montin-Greer Drilling Corporation.

MR. LEMAY: Thank you. Additional appearances? Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin, Kellahin & Aubrey. I'm appearing on behalf of Sun Exploration and Production Company.

MR. LEMAY: Thank you. Additional appearances? Mr. Pearce.

MR. PEARCE: May it please the Commission, I am W. Perry Pearce appearing in this matter on behalf of Mobil Exploration and Producing, U.S., as well as on behalf of Mallon Oil Company.

Mr. Chairman, I would like to state that appearing with me on behalf of Mallon Oil Company is Mr. Frank Douglass and Miss Becky Miller of the Austin law firm of Scott, Douglass, and Luton.

MR. LEMAY: Thank you. Welcome to New Mexico, Miss Miller and Mr. Douglass.

MR. DOUGLASS: Thank you.

MR. LEMAY: You're no stranger to this court.

Yes, sir, Mr. Bruce.

MR. BRUCE: Mr. Chairman, my name is James Bruce from the Hinkle Law Firm and I'm here representing Mesa Grande Limited, Mesa Grande Resources, Inc., Reading & Bates Petroleum Company, Hooper, Kimball and Williams, Inc., and Limestone Investments Company. That's basically the City of Tulsa, Mr. Chairman.

MR. LEMAY: Thank you. We're happy to have Oklahoma represented.

Additional appearances in the case?

MR. BUETTNER: Mr. Chairman, I'm Robert Buettner representing Koch Exploration Company.

MR. LEMAY: Welcome to New Mexico.

Additional representation in

these cases?

Okay, if not, we shall begin with Mr. Carr.

MR. CARR: May it please the Commission, I have a very brief opening statement.

MR. LEMAY: Fine. Sally, let's go off the record just a little bit.

(Thereupon a discussion was had off the record.)

MR. LEMAY: Before we start with the opening statements I'll summarize for the record that we have -- we have allocated two days for the hearing; that there are some time restraints on the second day; that we have agreed to go into the second part of the testimony today if we can get there, and that we will start with opening statements.

So with that, Mr. Carr, please begin.

MR. CARR: May it please the Commission, Benson-Montin-Greer Drilling Corporation is before you here today seeking expansion of the BMG West Puerto Chiquito Mancos Pressure Maintenance Project Area.

This project was originally approved by the Oil Commission in 1968 and it has been expanded from time to time since that date.

We're now here before you seeking Commission approval for the thirteenth revision of the participating area and this case involves only that question. It involves whether or not this pressure maintenance project should be expanded, expanded so that the project area will include all the acreage within the Canada Ojitos Unit.

There are two basic things we believe we must show if we are to obtain your approval.

The first is that there is effective pressure communications, communication between the existing pressure maintenance project and the area included in the proposed expansion area.

We also have to present evidence that pressure maintenance has increased recovery of oil in the project area and can be expected to continue to do so.

This is not a case to debate where the boundary should be in the Gavilan Pool or the West Puerto Chiquito Pool. Those have been previously decided and we will stay away from that.

We will present evidence on communication and that is the first and primary focus of our presentation. We're going to demonstrate that pressure communication, effective pressure communication, exists throughout the area between the existing project and the proposed expansion.

We're going to show you this in a number of ways.

We're going to show you that in fact everytime we've looked for communication you can find the communication exists and therefor inclusion of this proposed expansion area in the project area is essential if, in fact, waste is to be prevented.

We're also going to talk about the improved recovery that we realize as a result of the pressure maintenance. This is not something new; it's been recognized repeatedly by this Commission over the years since 1968. But we will show you that pressure maintenance coupled with gravity drainage and gravity segregation will result in increased recovery of oil, recovery of oil that could not be obtained without pressure maintenance.

Now I understand at the previous hearings over the years, and particularly in the last year or so, you've heard a great deal about these reservoirs, perhaps more than you've ever wanted to know, and we're going to attempt to keep the evidence on the reservoir restricted, but it is essential for a full understanding of pressure maintenance that we do at least on occasion talk about this particular reservoir and we intend to do that and show you what will happen to the production from this reservoir if our application for expansion of the project is in fact denied, for if it is denied, we submit that waste will occur.

We also are going to address the question of correlative rights. Now, we will show you because of the communication there is not a barrier in the reservoir and having done that, we have to take a look at the pressure maintenance credit formula, credits that are given for re-injection of gas produced in the pressure maintenance project.

We will show you and compare voidage, reservoir voidage from wells within the project area with those that are outside the area, and we will show you how this formula is essential and how it works to protect correlative rights of those interest owners, not only in the unit area, but those outside, as well.

We are convinced when the evidence is in it will be clear to you that communication, effective communication, exists throughout the reservoir; that pressure maintenance is working and we expect it to continue to work, and that only by expanding the project area as we propose can you carry out your duty to prevent the waste of oil and protect the correlative rights of all interest own ers in this reservoir.

MR. LEMAY: Thank you, Mr. Carr. Mr. Douglass.

MR. DOUGLASS: Thank you, Mr. Chairman.

On behalf of Mallon Oil Company, we -- I think the -- from the sound of the opening statement, at least, that the issues have been drawn here, the main issue, and that is whether there is effective communication between these wells and that they propose to have this allowable benefit and the injection that's supposed to be taking place.

The proposal by Mr. Greer here, and Sun, will result in 991 barrels a day increase in the 2-section area that adjoins the Gavilan Pool.

It will increase an already existing 3-1/2-to-1 advantage in oil withdrawal rates to 6-to-1, and according to Mr. Greer's theory of the Gavilan Pool, we suggest that that will result in waste because gas from these wells will be produced and then injected in an area which is not in effective communication with the Greer-operated wells that will have this almost 1000 barrel a day increase in production.

One of the exhibits that we will submit is a map, a status map of the area, where we have colored in brown the current pressure maintenance area. It is showing the wells that are there and the wells that are producing there.

The wells that are in question in this proceeding will be the 2-section area between the pressure maintenance project and the boundary between the Gavilan and the West Puerto Chiquito Pool at this time. In other words, these twelve wells in here that are colored green and operated as unit wells will have their gas taken, injected four to seven miles away in three injection wells, and will receive allowable credits for that and increase their production by 1000 barrels a day immediately offsetting the Gavilan Pool.

The Commission ordered testing that has taken place, we believe has provided at least outside parties and the Commission the first oil zone pressures taken in the pressure maintenance area that we've been aware of for seventeen years. The last pressure that was presented to the Commission in this pressure maintenance area was a pressure taken in December of 1970 in the C-20 -- excuse me, the C-34 Well. We now have a pressure taken in a recent survey in that well.

The Commission ordered testing and pressure data, we think has shown that the pressure in the pressure maintenance area immediately to the east of this barrier that we show is about 1400 pounds and the pressure immediately east of it is in the range of 950 pounds, a 450-pound pressure differential across this barrier, which supports and actually confirms the existence of that barrier and taking the gas from the west side of the barrier to put it on the east side, is not an effective communication with these wells that are proposed to have a 1000 barrel a day allowable increase.

The Commission's order of June 8th, 1987, said there was limited communication between the two areas. Your testing that was ordered has confirmed that not only is it limited, but it's probably nonexistent between the areas as far as communication is concerned.

My client assumes that Mr. Greer will have the burden of proof in this hearing to prove his case and even though Mr. Greer has written your staff telling them when this Commission will act, about what date they will act. We suggest that this Commission is not going to act until it hears all the facts, until it analyzes and is satisfied with what it has been able to determine based on information in this -- in this hearing.

The pressure data will not support Mr. Greer as far as effective communication and the pressure data will show no effective communication. We would suggest to the -- to the Commission that under Mr.

Greer's theory of taking gas from this area and injecting it over here, when it's not having any effect over here, will cause waste, according to his theory of reservoir production in the Gavilan.

What he proposes is to increase that pr-duction, as I've indicated, by 1000 barrels a day. If you follow Mr. Greer's logic in this situation, then the Commission should not permit the expansion in this area if you don't want to increase gas withdrawals in this area over here, according to his theories of reservoir (unclear.)

In the previous hearings Mr. Greer has stated to this Commission, if you're going to err, err in the side of safety; err in the side of being safe, taking care of the situation if later facts should develop, and I think that's essentially what this Commission has done and it's difficult to be critical of a Commission that is trying to do the right thing and err on the side of safety.

In this proceeding if there's going to be an error made, then if you follow Mr. Greer's logic in that respect, then it should be denied to give credit in here, increase these withdrawals, when there's not effective communication, because that, according to Mr. Greer, will cause waste.

We are ready to go forwards with evidence to show lack of effective communication across here. We think the production data and pressure data that's been submitted has shown the necessity that you do not expand this area as far as the pressure maintenance project is concerned.

Thank you.

MR. LEMAY: Thank you, Mr. Douglass.

Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, on behalf of Sun Exploration and Production Company I'd like to make a brief statement so that you understand our position.

Unlike Mallon, who has interests only in Gavilan-Mancos, and unlike Mr. Greer, who has interests only in the unit, Sun Exploration and Production Company is in the unique position of being in both areas. Sun Exploration has some 40 percent interest ownership in the Canada Ojitos Unit. In addition, it has more than 50 percent of the ownership in Gavilan-Mancos, operating some 29 wells in that pool.

We have independently through our own experts analyzed both reservoirs and we are in support of Mr. Greer and his position.

We have carefully worked with him in order not to attempt to duplicate in an extensive way his presentation. We do feel that it's necessary and essential that we present ot you two of our own witnesses.

We will present to you Dr. John Lee, who testified before you back in March and April of last year when were discussing allowables in Gavilan-Mancos. Dr. Lee has conducted his own studies of the pressure maintenance project and he will present to you his conclusions on that subject.

It's my understanding and belief that I can present his direct testimony within an hour, an hour and a half. We will do our very best not to be repetitive of Mr. Greer, but we believe that his testimony is essential so that you'll understand our position.

In addition, we know the Commission has heard extensive geologic testimony; however, we would like to present our geologic witness, Mr. Dick Ellis, who also has testified before you on numerous occasions on the Gavilan-Mancos reservoir.

Mr. Ellis has prepared displays and testimony focused specifically on the question of whether or not geologically the expansion area, the 2-tier section area, is geologically suitable for inclusion in the expansion area. We will provide you his displays, conclusions, and reasoning for that decision.

We have between the two areas established by the Commission and reconfirmed by the Commission, the boundary of the two pools. The boundary between the western side of Gavilan and the eastern side of West Puerto Chiquito-Mancos is not adjusted. We are talking about taking the area that now is included in the West Puerto Chiquito Mancos Pool and simply expanding that 2-tier area including it into the existing pressure maintenance project.

Contrary to the allegations that Mr. Douglass has provided for you, we believe our experts will demonstrate to you, and the truth will be, that every time that alleged buffer is tested, it communicates; every conceivable way our engineers have tested to determine where there is a calculation or a test that can be made to establish communication between the expansion area and the existing area, in fact, proves communication.

It will be our testimony and proof that the expansion area is a necessary, viable, integral part of the project area and must be included. We believe it can be included in such a way as not to pose a risk to our interests in the Gavilan and that through a method of gas injection credits we can maintain a system where the reservoir voidage between Gavilan and the pressure maintenance project is in reasonable balance.

We believe this is a typical, traditional pressure maintenance project that ought ot be approved and the credits applied. We believe after all the proof is in, that you'll see no other course of action but to approve the application of Mr. Greer.

MR. LEMAY: Thank you, Mr. Kellahin.

Mr. Bruce.

MR. BRUCE: Mr. Chairman, very briefly, we may have one or two very, very brief witnesses and we'll wait and see about this.

I would comment that one of my clients, Reading & Bates, is also an interest owner in both pools and contrary to Sun, it opposes the application of Benson-Montin-Greer. They believe that the facts are otherwise than presented by Benson-Montin-Greer.

MR. LEMAY: Thank you, Mr. Bruce.

Additional opening comments?

MR. BUETTNER: Mr. Chairman.

MR. LEMAY: Mr. Buettner.

MR BUETTNER: Just briefly, I'd like to reiterate what counsel just pointed out, that contrary to Mr Kellahin's statement about the ownership, Koch also owns interest in both of the units, both these areas, and also opposed Mr. Greer's application.

MR. LEMAY: Thank you. Additional opening comments?

If not, we shall continue. Mr. Carr, you may proceed, and then Mr. Kellahin.

MR. CARR: I'll begin and at this time we'd call Albert R. Greer.

MR. LEMAY: At this time would all the witnesses that are going to be delivering testimony, would you please stand and raise hand and we'll swear you all at one time.

(Proposed witnesses sworn.)

MR. LEMAY: 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 Would you state your full name for the record, please?

A Albert R. Greer.

Q What is your relationship to Benson-Montin-Greer Drilling Corporation?
A I'm an engineer and officer.
Q And you are the applicant in this case?
A Yes, sir.
Q Mr. Greer, have you previously testified before this Commission?
A Yes, sir, I have.
Q And at that time were your credentials accepted and made a matter of record?
A Yes sir.
Q How were you qualified at that time, as a petroleum engineer?
A Yes, sir.
Q How long have you been involved with the development of the West Puerto Chiquito Gallup Oil Pool?
A About -- well, since its -- since the first discovery about 1962.
Q Did you also participate in the original hearing which resulted in an order approving pressure maintenance in a portion of this reservoir?
A Yes, sir.
Q And have you been involved at all relevant times since then?
A Yes, sir.

Q And you've studied the reservoir?

A Yes, sir.

Q And you're familiar with what's being sought here today?

A Yes, sir.

MR. CARR: Are the witness' qualifications acceptable?

MR. LEMAY: His qualifications are acceptable.

Q Mr. Greer, would you briefly state what Benson-Montin-Greer is seeking with this application?

A Yes, sir. If you'll look under Section A --

Q And are you referring to what has been marked Exhibit Number One?

A Yes, Exhibit Number One.

Q Okay.

MR. KELLAHIN: That's the brown book?

Q And that is the brown book?

A The brown book. A plat on the lefthand side in the first part of Section A, and it shows an outline of the existing unit, and by the dashed margin the area that we seek to have added to the pressure maintenance project.

Q Mr. Greer, this is the plat with the

green outline that is the first document behind the introductory tab?

A Yes, sir, this is the introduction tab, I'm sorry.

Q It shows not only the unit boundary but the proposed expansion.

A Yes, sir.

Q Now we're going to be working with this exhibit for some time. Before we start working through the various sections, would you identify for the Commission the general area that you plan to cover working from this exhibit?

A Yes, sir. We've divided the presentation into four parts: First, the reservoir description; Part II, benefits of pressure maintenance; and Part III, evidence of reservoir stratification; and Part IV is evidence of communication of wells in the proposed expansion area with the existing project area.

Q Would you now turn to the first document contained behind Tab A in Exhibit Number One, and first identify what this is intended to show?

A Yes, sir. The schematic fracture system shown on the lefthand side is -- is our interpretation of the geometry of the reservoir. Naturally fractured reservoirs typically are of a matrix porosity laced with fractures.

We did not find that to be the case in our investigation early on in this reservoir. Studies since that time have confirmed that indeed this is the geometry.

The wells act as though they are within little isolated reservoirs by themselves and yet those reservoirs are connected with each other. There's no other way that can be satisfied.

In addition, we found what I describe as tight blocks. That's these little, separate blocks we show on the plat, surrounded by a high capacity fracture system. That high capacity fracture system contains a large part of the reservoir oil and as such, that allows for gravity drainage and pressure maintenance to be effective.

If the reservoir were a matrix porosity type laced with fractures, only a small part of the reservoir with fractures, the pressure maintenance would not have worked.

We would not even have attempted it in the first place, but in view of the fact that a large part of the reservoir is in a high capacity fracture system, the pressure maintenance project could work.

Now we have shown in earlier exhibits in our interpretation of this reservoir, we have presented colored maps over the structure that show flexes and structural flexes as they move from the east side of the reservoir to the west side. We have interpreted that to mean that there is probably a directional permeability north/south. We've not run an interference test with enough wells to confirm that, but this is logical, we believe, that with the synclinal flexes at different points through the reservoir as it moved from east to west, that these flexes would have had a bearing on the fracture system and I think of them as -- as benches or permeability plateaus, and this has been really helpful in the pressure maintenance project.

We inject gas in the up-dip wells, even though where the injection wells are located the reservoir is relatively tight, the gas tends to move north/south first and then diffuse west into the next bench.

In that next bench it moves north/south and then diffuses again to the next bench to the west, and so on down the line.

This has been helpful in the pressure maintenance project being effective in the past. We look for it to be helpful if we install a gasoline plant, which is our -- our plan now, and as the stripped gas moves through the reservoir, we expect it to move north/south, then diffuse to the west, picking up liquids as it goes.

This reservoir geometry, then, becomes important in how we -- how we undertake the pressure maintenance project and how we propose to continue doing it.

One of the significant features in this reservoir is that it's stratified. We've (unclear) this since early on in drilling wells, drilling with air, drilling with gas, picking up oil in the different stratified zones. We've confirmed this recently with a production model and we recognize that as one of the problems that we have in dealing with this reservoir is that in time the zones, particularly the upper zones, with gravity segregation and stratification are going to carry a higher percentage of gas and when that gas reaches a producing well, and we have to recognize that as a problem and how to take care of it. Initially we took care of it by producing the lwoer zones first.

Now with this fracture system the way it is, and particularly within any one of these permeability plateaus, we have found that -- that the drainage is so effective that a well with good communication with the fracture system can drain the tract of a well completed in a tight block maybe two or three miles away better than the well in that tight block itself, and what that means is that we don't need a large number of wells to deplete the reservoir.

Q Mr. Greer, how many stratified zones are there in this reservoir?

A We recognize three zones, have identified three, but even within those zones there are layers that themselves are stratified. There can be two or three layers within the A zone and there can be gas production in the upper part of the A zone and oil production in the lower part.

Q Are these zones all present throughout the entire reservoir?

A Yes, sir, but in some areas one zone will be more productive than another and in one area the A zone may be more productive than it is in a different area and we'll look later at how to identify the zones.

Q All right, why don't we go to the next plat in behind Tab 1, which has a portion of the map shaded in yellow, and I'd ask you to identify what the shaded yellow area is intended to show.

A That yellow area shows our interpretation of the area which is predominant A and B zone production and we make that assessment by reviewing the production history of the areas around it.

To the southwest, of course, is Gavilan, which generally it's believed it's primarily A and B zone production.

Up to the northeast, the East Puerto Chiquito Mancos Unit has produced 4,000,000 barrels of oil from A and B zones only. The C zone doesn't produce there.

North of the unit on some Jicarilla lands, A and B zones only production.

The L-27, the well colored in red, produces only from the A and B zones. It produced about 1.6-million barrels of oil out of the A and B zones.

At the hearing last April there was some question raised, skepticism as to what the A and B zones -- whether the A and B zones really were the producing zones in the L-27 and since that time we've run a production log on that to confirm that, indeed, that is the source of the production in the L-27.

Q All right, now in Tab -- behind Tab A, would you please go to the next plat, part shaded in yellow, part shaded in brown, and explain what that is intended to show.

A We've added to the previous plat an area colored in brown and which we interpret to be dominant C zone production. There is also A and B zone production there but the dominant zone is the C zone.

We confirmed that with the production log on the F-30, which was reported in the hearing last April, and since that time we've run a production log in the B-32 that confirms it, and from the low gas/oil ratios of other wells in the area, we believe that this is a reasonable representation of the dominant C zone production area.

Q Would you now go to Tab B in this exhibit and I'd ask you to initially identify the basic benefits of pressure maintenance that you have observed in the unit area as a result of pressure maintenance.

A We have listed on the first schedule under Tab B some of the important features of pressure maintenance.

Number one, keeps the viscosity low and the formation volume factor high with an increase in the otherwise ultimate recovery.

In previous hearings we've spelled out how -- how we estimate the additional recovery.

And two, it keeps the productive -- the wells productivities high. That means that there are fewer wells required to deplete the reservoirs in any given amount of time and this is significant.

Number three, it provides a gas cap in which will be helpful in our cycling operations when we strip gas through a gasoline plant and reinject it, and cycle the gas in a sense in the up-dip wells while we're still maintaining pressure on the down-dip wells.

We're about to that point now.

And item number Four, the work that our associates have done, particularly Sun and Dr. Lee, it looks like we can pick up a significant amount of additional liquids by moving the stripped gas from the residue from the gasoline plant, reinjecting that, letting it pick up liquids, and we anticipate a significant increase in ultimate recovery that just could not be obtained any other way.

Number Five, it augments gravity drainage by pressure maintenance, keeping the fractures open and maintaining higher productivity and a higher rate of gravity drainage.

A significant part in the management or operation is lower operating costs. We have no rod and tubing wear; no bottom hole pumps to maintain; no risk of expenses for fishing jobs; all mechanical repairs are on the surface; can flow the wells to depletion; and in the end, any oil remaining in the tight blocks -- tighter part of the reservoir, we'll produce it during "blow-down".

Q Now, Mr. Greer, if you'd go to the green pages which follow that summary, first if you would identify the schematic drawing, and then using this, would you review the initial depletion plan you have for this reservoir?

A Yes, sir. We show on the righthand side on the up-dip part of the reservoir are injection wells.

In the middle of the reservoir are the intermediate wells, what we refer to as cycling wells, and that spacing there is roughly one well to 3, maybe 4, sections.

Then the down-dip recovery wells the spacing is roughly one well per section.

We point out that in the intermediate area there's only one well in 2 to 3 to 4 sections. The reason for that is that once we have achieved with the down-dip recovery wells a rate of reduction that is high enough to meet the gravity drainage potential, then any additional wells not only are unnecessary but they're harmful. The more wells we have and the higher the production rate, the lower is going ot be our ultimate recovery because -- for the reason that the producing mechanism slips from gravity segregation, gravity drainage, gravity displacement, into solution gas drive, and that's the reason that we've located our wells the way we have.

We can do that and produce at high rates on the down-dip wells, the recovery wells, without the intermediate wells. We just don't need them; we just sometimes use them for observation wells. And the end result is this greater recovery, higher efficiency all the way around.

The initial depletion plan is to produce the C zone wells first, Z zone first. Where we can't get production out of the C zone, then we had to come up to the A and B zones. The reason for that is in a lower zone we'd expect it to have the lowest gas/oil ratio. It did, and out plan has been as the gas moved down structure displacing oil, we would shut the wells in when the gas/oil ratio reached 2-or-3000 cubic feet a barrel and when the gas finally reaches the down-dip wells, then our plan was to come back, open up the A and B zones and at that time have a large volume of gas.

In the meantime, when we're producing only the lower zone with low gas/oil ratios, we can do that very efficiently with a very small amount of horsepower. Initially we were producing the reservoir with probably a fourth or a fifth the horsepower that's now required.

This was an essential part of our plan.

Once we reach the point that we're to cycle gas, which we are now, and install a gasoline plant, then we still continue pressure maintenance until we reach an economic limit, depending on -- on oil production and the plant liquid recovery.

Q Mr. Greer, how does the proposed expansion that we're discussing here today affect this original or initial basic depletion plan? Does it alter it at all?

A The only alteration we have is -- is the problem that we face with Gavilan, the cross boundary migration there.

Q And what is the affect of that?

A For one thing, we opened up all three

zones on the west boundary because that was the way the Gavilan wells were completed, and in order to minimize migration -- there's no way we can completely stop the migration from the unit to Gavilan but we minimize it by opening up the same zones going to higher gas handling volumes now than we otherwise would have.

And with the high rate of pressure decline in the Gavilan, the pressure difference, then, from our injection wells to Gavilan becomes greater and greater and the problem of migration gets greater. So we visualize and commnced last summer when the Commission ordered the high allowables, to market some gas where we could try to keep that pressure differential from -- from getting much worse. It's going to get worse from time to time unless Gavilan does something to hold up their rate of pressure decline, but we needed to do something to keep it from being as high as it might otherwise be.

Finally, then, if we're not able to produce the wells to depletion the way we had ordinarily planned using the injection gas as our energy to lift the oil, then we'd have to resort back to gas lifting the oil until the time of depletion.

Q Mr. Greer, how does stratification actually relate to this pressure maintenance effort?

A It relates to it in the sense that we

have recognize that we have to handle the gas one way or another when -- when it shows up. We can either shut in the wells, seal off the zone, or return the gas to the reservoir, which means more and more horsepower as gas breaks through in these stratified zones.

Q Would you now go to Tab C in Exhibit Number One and briefly review recent evidence on stratification?

A Under Tab C we show results of production logging of two of the wells, L-27 and the B-32.

Now the L-27 is the one that there was a question about where the gas and oil were coming from and the B-32 we had the same, same question.

If you turn to the first gray sheet, which shows the plat with the location of the well, the L-27 and on the lower part of the page we show our log of the well. I've identified there the A, B and C zones.

And then if you'll turn to the blue sheets, you'll see here the results of the production log. The logging company's analysis is set out on the righthand page. On the lefthand page we've shown schematically what -- what that shows.

On the lefthand column the fluids are identified principally by the densitometer in which we find water in the bottom with no flow between the B and C zones and at the very top of the B zone has oil production and in the top of the A zone and that's oil and gas.

On the little triangular shaped plots on the right we show the percentage of oil and the percentage of gas and where they're coming from. In this instance practically all the oil is coming from the B zone, as indicated by the center plot, triangle.

On the righthand side the gas is indicated. Practically all the gas is coming from -- from the A zone.

Of significance here is water over the C zone. The well does not make any water and so -- and this log was made while the well was flowing. There's no way that production can be coming up through the C zone with water -- with a water blanket on top of it, so that's just further confirmation that the C zone is not productive in this well.

Q Now, Mr. Greer, is there similar information available on the B-32 Well?

A Yes, sir. Following the blue sheet are some white sheets which show the front of the log in detail and then under Section D, if you'll pass the brown sheet and come to the gray sheets again, the well is located on the plat and the A, B and C zones are again identified by the log below it.

Q Now, if you'll go to the pink sheets --

A Yes, sir, if we look at the pink sheets we'll see the same kind of production logging analysis that we looked at on the L-27. Here, however, we find that the oil, practically all of the oil is coming from the C zone, two parts of the C zone. The major part of the gas is coming from the B zone and some additional gas coming from the A zone.

Here is a typical example of a stratified reservoir in which the gas and oil have segregated in those parts of the reservoir where there's communication, vertical communication, faults, fractures, such as that, or the upper zones, we've seen displacement of the oil by the pressure maintenance project, the injected gas.

This -- the well produced initially with a low gas/oil ratio so we know that all zones, all zones initially produced oil. Now the upper zones produce gas and the lower zone, the lower zone is producing a very low gas-oil ratio.

If we were to seal off the A and B zones, the C zone, which produces all the oil, and this is a good well, a significant part of the production, can produce 6-700 barrels a day, its gas/oil ratio would be like 6-or-700 cubic feet a barrel.

Q Now, Mr. Greer, the B-32 Well that we're talking about is a well located in the expansion area, is it not?

A It is.

Q All right. Behind that is again some supporting information?

A Yes, sir.

Q I'd like you now to go to Tab E in Exhibit Number One and have you now focus for a few minutes on the effect stratification has on pressure maintenance, and first I'd direct you to the first green pages behind Exhibit Number E and would ask you first to explain what these diagrams show.

A These sketches show one of the things that can happen with a stratified reservoir.

We show in the upper lefthand sketch a well producing from a stratified reservoir, oil from the lower zone, gas from the upper zone. Its gas/oil ratio is 10,000 cubic feet a barrel.

Then on Plat II on the righthand side we show if we just open up a well in the gas zone and say take half of the gas out of that well, and only half out of the other well, which will result if depletion takes place and we've found, of course, as we've indicated in one of our exhibits last April, everything else being the same, the gas will deplete about 8 to 15 times faster than the oil, and so you have a reduction, then, in the gas coming out of the A Well, as we show it here.

Here is a drop in gas/oil ratio, then, this well now only makes 500 MCF a day, 100 barrels of oil a day and its gas/oil ratio has declined from 10,000 to 5000 but that has no bearing on the oil production from the oil zone, and particular if that oil zone is producing by gravity drainage, then there can even be damage to the reservoir with the ower gas/oil ratio. We see that in the lower sketch where, as we have in this reservoir, places where there's vertical communication, then as the oil -- gas is produced from the upper zone, the gas/oil ratio drops, the oil migrates from the lower zone to the upper zone, and if it were gravity drainage recovery in the lower oil zone, it now deteriorates to solution gas drive as it migrates up into the upper zone.

Q Now is there any good news that comes from this situation?

A Yes, sir, the fact that the gas/oil ratios seem to change up and down, there's some good news to that, Mr. Chairman, and that good news is that that can happen only if we have some kind of gravity segregation. If we have gravity segregation then somewhere in the reservoir we can have efficient gravity drainage. All we have to do is recognize it and take advantage of it.

Q Now, Mr. Greer, would you turn to the gray pages which follow and first identify what the plat is designed to show noting the green circle and the wells in -- the green square and the wells inside that square.

A All right. Mr. Chairman, we show here something that has happened just almost exactly like the little sketches we were just looking at.

In the green outline we've shown two wells in red. That's the N-31 and E-6, two producing wells. the J-6, the orange color, was shut in. The green colored well is Tapacitos 4, a well outside the unit, and the other two wells in the southwest part of that 4-section block are wells that produced at a low rate during June and when the Commission set the high allowables, those wells then produced at high rates, high gas volumes, and they pulled out of the stratified zone a gas which then came from the offsetting wells, the well to the north, the two wells to the east, and as a consequence their gas/oil ratio was low but not because there was increase in production of those wells.

The two red circled wells, wells that are operated by the unit, it did not change the production rate in July, and the reason we didn't, we -- in order to try to satisfy the Commisison's directive to go to high rates of production for comparison, we had to change the mechanical equipment, the surface equipment of some of our wells. Two of them are capable of producing about 1000 barrels a day. We typically do not produce the wells at the -- at the allowables. We've always produced at less than the allowables. We just did not have the equipment in place to go to these high rates of production.

Now, these two wells, the N-31 and the E-6, we didn't have to do much to them and what we did was wait until we got most of the wells that we were going to increase production on equipped and then we raised the rate of production; just an arbitrary decision to do that, but as a consequence of that there was then a very good test of what was happening and we didn't know that this would happen. We just in reviewing the records since the high rate of production took place, we found that these offset wells pulling gas out of a stratified zone lowering our gas/oil ratio, but we didn't do a thing to change the rate of production.

If you'll look at the pink sheets, the next two pink sheets, we show on the top line a plot of the well production of the E-6 Well and, Mr. Chairman, we keep very close track of the production of our wells. We have daily records of the oil and gas production. We keep charts of the pressures and part of our process of accumulating information is to convert production every day to daily rates.

I know most operators don't do that but there's no way that the pumper can get around to a well at the same time every day.

We take the amount of production, the time of the production, convert it to daily rates so that we know what is going on in that well.

You can see that the oil production rate stayed very stable all the way across.

Now during this period, July and August, at the high rates of production the reservoir pressure was dropping approximately 40 pounds a month. We found that the operating pressure on our wells was dropping 40 pounds a month. Now this meant that the drawdown on the reservoir was exactly the same throughout this period. We had the same size oil chokes, the same size -- same amount of gas lift gas; oil production stayed very stable. Gas production, as we can see, dropped off.

Now this can only happen if you have a stratified -- stratified reservoir situation and that's what happened here.

If we go to the next sheets where we've shown on the lower green sheet by the dark shading the volume of gas that was being produced by the offset wells.

In June very little gas was being produced by the offset wells and in July the rate picked up at a high rate, and so there is the relation, and not the production rate of our well but the production rate of the offset well pulling gas out of the stratified zone.

Now, after mid-August we went ahead and increased our production rate. We put in bigger chokes, more gas lift gas, we got a higher rate of production. Now that higher rate of production, then, is coincident with lower gas/oil ratios, but that's not the reason for the lower gas/oil ratios.

Now we notice the same thing -- I've plotted here only the E-6; the N-31 had the same result and the Tapacitos 4, and we do not operate that well so I'm not as familiar with it, but it is shown on the statistics of the green sheets above the graph. The Tapacitos 4 appeared to have (unclear) in the gas/oil ratio but also they did not increase the production rate of that well.

So my assessment of that is that the same thing happened to the Tapacitos 4.

Q Now, Mr. Greer, if we look at the plat, the gray sheet, certain of the wells in the green block are within the proposed expansion area of the pressure maintenance project and others are outside.

A Yes, sir.

Q What sort of a crediting arrangement is authorized for the production that -- for the gas that's reinjectible in the unit?

A If we inject 50 percent of the gas we produce, then we get injection gas credits for that 50 percent, and if we don't inject anything, we get no credit.

Q What would be the effect of not allowing an operator to get this credit for the injected gas?

A Then if we cannot get credit for the injected gas, then we cannot produce our gas that's moving past us into Gavilan. We have to get that credit so that we can pick up our gas, at least slow it down, we're not going to stop all of it, but we can slow it down and return it to the reservoir. Then two things happen.

Number one, it's inequitable that our gas move over to Gavilan and they take it and sell it. That's an inequity. That would tend to offset that inequity.

Another inequity is that when that gas moves across to Gavilan it gives those operators a higher gas/oil ratio than they otherwise would have and they get a lower oil allowable, and that's an inequity.

We solve both inequities, or at least we move in the direction of solving both inequities by letting us have our gas injection credit and we take our gas and put it back in our reservoir and continue with the pressure maintenance project.

Q All right. Now I'd like to have you turn your attention to communication between the proposed expansion area and the existing project area.

Will you turn to Exhibit F and first just identify the first plat again that's contained behind Exhibit F on the gray sheet?

A The plat, again the plat shows the unit and the proposed expansion unit.

Q And what does the first Section F show, what -- what type of communication; what evidence of communication is present?

A The evidence of communication that we address here is overinjection. We overinjected in the existing project area and by overinjecting with no pressure increase in the project area means that the gas had to go somewhere, or gas and oil.

The only logical place for it to go is to the west into the proposed expansion area, and we show here that for the period of July to November that we overinjected at the rate of an average of 3300 reservoir barrels a day; from November to February, nearly 2000 barrels a day.

Q Will you go to the tan sheets that are next in the exhibit book and identify those?

A Well, these show the -- the upper -- the upper sheet shows the statistics which we just discussed. The lower sheet shows the pressures in the wells in the gas cap area.

Now as we look at the pressure change from June to November we see some substantial changes there in some of the wells.

The C-5, for instance, shows a gain of 159 pounds. Now that well, we'd not injected in it for ten years and there's a fairly large interference effect as a consequence.

By the same token the A-14 has a large pressure decline.

Overall it looks to me like there might have been a 20 or 30 pound pressure decline in that period.

Then if we look at the pink sheets we show the same information on the pink sheets except this is for November to February.

Here again it looks to me like we have overall pressure decline in the area, even though we overinjected.

Now a more definitive comparison is from July to February and we show that on the next green sheet, where we cover the entire period, and there we can see a consistent pressure drop in all these wells except the C-5, the one real tight injection well shows a small increase of five pounds.

All right, now during that time the

reservoir was overinjected approximately 600,000 resevoir barrels.

Q And what does this tell you about the communication in the reservoir?

A That means to me that we have communication from the existing project area into the proposed expansion area and probably on to the west.

Q If there wasn't communication what would this overinjection -- what would be the result of the overinjection?

A The pressure would build up in the existing project area.

Q Now will you go to the information contained in Section G of Exhibit One, looking now at evidence on pressure gradients, and I'd ask you to first go to the first sheet behind that and simply summarize what's intended to be shown with this section.

A In this section, Mr. Chairman, we show a pressure gradient across the reservoir, and we determined this pressure gradient principally from surface pressures of the -- of the wells.

Now we found that where we produce the wells with gas lift and the gas/oil ratios have risen as high as they have, that we have -- on shut-in we find a gas gradient from the surface to the producing zone, whether it's the A zone, B zone, or whatever is producing oil, and so actually for these wells we can get a very accurate determination of reservoir pressure and pressure gradient by taking the surface pressures and there's another reason for doing that.

When we try to measure pressrue gradients across the reservoir with bottom hole pressures, we run into many problems. The only way it can be accurately done is to calibrate all the wirelines, calibrate all the logs with the same instruments. We have to measure the surface elevations of the wells. We have to take into account the deviation of the holes, and a myriad of problems that you don't have by dealing with surface pressures.

Now we show here on the yellow pages a comparison of a pressure increase, a surface pressure increase of two of our observation wells, along with the bottom hole pressure increase which we concurrently measured, and is shown with the theoretical pressure increase and they fit very well.

Q Now, the green sheets, are they just a --

A They're just a --

Q -- statistical comparison?

A Yes, sir. They're the information supporting the yellow graph.

Q All right.

A On the whites sheets we identify some of the problems of attempting to (unclear) bottom hole pressures to determine pressure gradients.

Then if we'll go to the blue sheet with the colored plat of the pressures opposite it, we've shown here the results of the pressures which were measured. Now these pressures were taken immediately following the November OCD order for a pressure survey and at that time we kept our wells shut in. I think the time for the test was about three days; we kept our wells shut in for another week, so we had roughly 8 or 10 days shut-in time to check the behavior of these wells. We checked them every day, checked them with dead weight testers and on a number of the wells we had two dead weight testers to compare the readings of the two.

And we see here, when we plot these pressures and study them, we recognize the permeability plateaus that we talked about earlier.

In the injection wells the pressure is around 16-1700 pounds. This is after being shut in all this time.

For instance, going from the orange to the blue area, a pressure differential there of 4-to-500 pounds. Some people interpret 4-to-500 pounds as meaning there's no communication, but we've injected in these wells for twenty years, Mr. Chairman, and there's no question we have communication from the injection wells to the lower presssured next plateau to the west.

Then if we -- if we look at the blue colored area, the pressures within about 80 pounds north and south.

We get over into the green area and here these wells are all within, oh, 10 or 15 pounds north and south, where the gas is spread north/south as it diffuses to the area to the west.

And we show one well in the pink colored area, about 860 pounds, but it carried with that pattern, Mr. Chairman, carries all the way even into the brown and the yellow areas.

Now the brown area, we only show a difference of pressure in the brown area to the yellow area of 10 or 15 pounds, but the same pattern applies north/south. We see only 3 or 4 pounds difference in the wells in the brown area.

Get into the yellow area and there's only a couple of pounds difference in the wells, and yet they're 10 pounds different from the others.

Now, this pressure gradient means to me that the overinjection in the present project area has to be moving in a direction of lower pressures and that direction is west to the proposed expansion area and over to Gavilan. Now right on the Gavilan boundary; we don't have information west of there of the same type we took of these pressures. My assessment of what we've seen before, from a (unclear) test before, is that probably the Gavilan wells nearest our yellow area would show very nearly the same pressures, that we could probably equalize.

Q Mr. Greer, could you tell me now before we go on, why should the boundary for the pressure maintenance project be on the western side of the Canada Ojitos Unit or the proposed expansion?

A Well, that's the area of the present participating area. The participating area has been from time to time expanded. The project area has been expanded right along with it up until this last time and when we made application for this last expansion, then some of the Gavilan operators had objection to it and wanted this heard at a hearing where they could voice their opinions, and so that's why it was not done at that time, and it's the only logical place for the -- for the expansion, is to go to the edge of the unit and, of course, the pressure maintenance formula is designed to provide for pressure maintenance of a part of the reservoir. That's just the way it's designed and it's -- most of the times, pressure maintenance projects cover only a part of the reservoir.

Q If there was not communication across this reservoir what would you think the pressure would -- what would that do to the pressure gradient?

A Well, if there were no communication with Gavilan, we would have a significantly higher pressure.

Q Would you now go to the Section H in Exhibit Number, which addresses pressure build-up during shut-in times and explain what the brown sheets are designed to show?

A Yes, sir. We showed in Case 9113 last April how we had interpreted the pressures in the different zones to be, that they would crossover at about 10-to-11-million barrels cumulative production from both pools, and that occurred in the fall of 1986, and at that time, then, among other things we ran a pressure interference test on a frac treatment and reported that earlier, and we show on the yellow pages then following that the rate of pressure increase in this -- these -- this particular shut-in well that was our observation well.

Now we can see on the upper yellow graph how the pressure increased following the frac treatment and how it tended to level off at a very low rate, .05 of a pound per day. Prior to that time -- and that's .05 of a pound probably still includes part of the frac (unclear).

The pressure leading up to -- or the time ahead of it was only .02 of a pound a day. Now, I interpret that to mean that when the pressure is equalized throughout the area, the only time then that we're going to see effects of pressure maintenance is when the wells are producing and there's a pressure difference and then gas moves into the producing zone from the injection area.

Now, we have by contrast then, by contrast to -- to this leveling off of pressures and staying level, and this is for a number of days, like eight days after shut-in, and it was in a time when there was a problem with the gas plant in -- taking gas from Gavilan. A number of the Gavilan wells were shut in. We had all the wells in the township this well is in shut in, so there's no extraneous effects that would change or affect this bottom hole pressure and it just stayed practically flat for 8 or 9 days.

Now, by contrast, in last November when the pressure survey was taken and we kept our wells shut in beyond the pressure at the time of 3-day shut-in, we found pressures rising in this well and the adjoining well and at that time there was 3-or-400 pounds pressure difference from the nearest well, which is even 2 or 3 miles away, wasn't near, but in terms of wells up dip from these producing wells, and then we have, with that pressure differential, we see a pressure increase then in these shut-in wells. We didn't see that when the pressures were all the same.

This means to me that pressure is from the pressure maintenance project from the gas injection is causing the pressure to rise.

We show on the blue, blue colored graph at the bottom of the graph the rate at which the pressure increased in September, 1986, and then just a year later the same well, plus the well right next to it, how the pressure is increasing.

Now these pressures were surface pressures measured with dead weight tester, two different dead weight testers, and they show a very close comparison of the pressure increase.

Now these two wells are high capacity wells. They show early on, on production or shut in, the reflection of reservoir pressure in the area in which a large amount of the oil is taken.

Q Now, Mr. Greer, the two wells that are depicted on the blue graphs are wells located in the expansion area, is that --

A Yes.

Q -- not correct?

A Yes, sir.

Q How would you expect them to perform if they were not in pressure communication with the injection wells?

A Then they would both have the same rate of pressure build-up as shown by the dashed line at the bottom of the graph.

Q In your opinion could the pressure increase depicted on the blue graph be caused by anything in the Gavilan?

A No, sir. Most of the -- some of the Gavilan wells were shut in for awhile. I don't think it would have an affect on it, but some of them actually went on production, so if those Gavilan wells went on production, then their affect would have been to pull the pressure down.

So if there's any -- any affect from the Gavilan wells it's to reduce the amount of pressure build-up that we see here and had they not been producing, then they would have had even a higher rate of pressure build-up.

Q In Section 8, Mr. Greer, there are a number of tables of figures on pink, white, and blue sheets. Would you just identify those, please?

A Yes, sir. Those are just the statistics which support the graphs we just looked at.

Q Would you now go to Section I in Exhibit Number 1, which relates to evidence of communication as shown by gas/oil ratios? Would you go to the gray sheets right behind that tab and explain what this shows?

A Yes, sir, this shows -- this is the same plat we looked at earlier. We show the injection wells in the triangles on the righthand side, the producing wells in the expansion area are colored in red, and for those wells that are producing colored in red, we show their producing gas/oil ratios on the gold colored sheet following.

Q Now you're going to the gold colored sheets?

A Yes, sir. On the gold colored sheets we show a graph. The upper gold colored sheet shows a graph of the gas/oil ratio of the wells in the proposed expansion area. That's the lower solid line.

The upper solid line for comparison is a gas/oil ratio in Gavilan.

Then the dashed line shows the net gas/oil ratio if we take into account the gas we've injected.

The -- in general, what this shows is with the lower gas/oil ratios, they just would not be that low without the effect of gravity drainage and pressure maintenance and the fact that the oil has to be drained from up-dip from these wells and if it's coming from up-dip, it has to be coming from the existing project area.

And the efficiency overall for the period of time shown by this graph, the unit used roughly 1/3 as much reservoir energy as Gavilan, disregarding the injected gas.

When we consider the gas we've injected, then the unit is only using about 10 percent as much reservoir energy for each barrel of oil that we take out of the ground as is Gavilan.

Q All right, Mr. Greer, if you'll go to the plat that follows, would you identify what this plat is intended to show?

A We know that the pressure gradient and the movement of oil has to be from east to west from what we show here now and what we showed a year ago. If so, the production from the two wells on the righthand side of the blue colored area, if we convert the amount of oil that they produce with some kind of a reasonable reservoir volume, if -- if, say, two-thirds of the ultimate recovery has been produced -- already been produced by these wells, it would have to come from an area about like the size of the blue colored area. If it's only one-third, then they have produced from an area which reaches up to the brown shaded area, well inside the existing project area.

This is just further evidence that the two areas produce from the same, same reservoir.

Q And are the remaining sheets in this section supporting statistics for that?

A Yes, sir.

Q Would you go to Tab J. This talks about communication as evidenced by pressure behavior and explain what this section is designed to show?

A Yes, sir. We realize, Mr. Chairman, that in our pressure maintenance project, that if we inject as much gas up dip as moves out of the project area down dip into the expansion area, that observation wells within the project area will show very little pressure change because there's as much gas coming toward a well as is going away from it, and that, plus the fact that we did not want the pressure difference from the unit area to Gavilan to get any worse than it absolutely had to, we decided to market some gas. By marketing gas we just -- we accomplish two things.

One is we tend to hold down the pressure difference between the unit and Gavilan and the other is that there's some action takes place in the -- in the gas cap area. If we inject for awhile, we don't inject, then presumably when we're not injecting we would expect the pressure to decline. When we're injecting, we'd expect the pressure to increase.

So the C-34, the lower righthand colored well is the one that we treated, opened up the A and B zones last spring, and we thought that might be a good well to -- to test. So we -- we made that as an observation well, and that well was shut in in May and we started taking pressures in it soon after the Commission ordered its high rate of allowable and carried that as an observation well up until the November test period.

The D-17 was a well we completed last summer. It turned out to be a low capacity well. We wouldn't lose much income by shutting it in, so we shut it in and made an observation well out of it and started taking pressures in it sometime, I think the last week in September.

And then if we turn to the tan colored sheets next (unclear), we can see how the pressure changed in the C-34 observation well depending on whether we're just producing, selling gas, or -- or injecting gas. The pressure goes up and down; appears to me overall there's probably a general pressure decline in that well.

Then if we'll turn to the next pink colored sheets, we show here what happened when wells were shut in for the pressure survey in November. The pressure was declining in the D-17, the upper graph, at about 1.3 pounds a day. That's about 40 pounds a month that we had earlier noted.

Then in the C-34 it was not quite as much, about 1.13 pounds per day.

When the wells were shut in, then the pressure tended to level off and then to increase and that's an interference effect.

And one thing that we note here is the flat, flat character of the curves at the bottom. If we had had only a one-on-one situation, one producing well, one observation well, we would expect that curve to be rounded but in both instances there's that flattening and that flattening can only be caused by multiple wells effects on the observation well.

Q All right, what do the green sheets show?

A The green sheets show the same plot. Now the ones that we looked at before on the tan sheets, they're hand -- hand plotted for a point about ten times a day.

The green sheets are mechanical plots and each one of those little dots is where the pressure bomb took a pressure, and they were about every 30 minute intervals, and you can see that only by the hand plots they might be skipping part of the plots, there's little change in character but not a lot. The mechanical plot pretty well confirms the general shape of those curves, and the fact that there had to be multiple wells affecting the observation well while shut in, and during this -- that period, Mr. Chairman, we -- we were injecting only a small part of the gas, just prior to shutting in a lot -- most of it, and in order to have a situation which we hoped that the -- that most affect that would be seen on the observation wells would be the result of the producing wells with a minimum effect of the injection wells.

Then we have a number of graphs. We might look at the first gray graph following the green.

For each of the plots that we showed earlier, a tan colored sheet of the C-34, we showed some solid lines and then there are dashed lines in between. The solid lines are duplicates of these individual surveys which we show here and I'd call your attention to what are known as "lubricator bleed". This is where a well -- I'm going to bomb a well and on going through this exercise there's some gas lost to the air and it pulls the pressure down.

On this particular observation well we had a new wireline unit on it. It was stiff and in order to get the bomb to fall to the bottom, why the men in the field backed off on the stuffing blocks (sic) and -- and we got a little more leap than we ordinarily would have and that caused the pressure to drop; takes about, oh, a day for it to recover, and then pick up the reservoir -- the true reservoir pressure decline.

And if we go to the second, third, fourth, fifth, the sixth gray graph I'd point out something else, and this is where we'd have two dashed lines intersecting. It's for the C-34 from the 11th to the 24th of September.

The bombs that we're using have an advertised accuracy of about 2 or 3 pounds. In other words, if we pull a bomb like we have on one run here, the lefthand line of circles, bring it into town and get the information out of it, reprogram it, take it back out and run it in the groung, it's only guaranteed to be within 2 or 3 pounds, and we can see that that would be a big difference.

Now many times we have found that they compare just as closely as it did here. They appear to go back in with only 2 or 3 tenths of a pound of difference from the pressure that's indicated when it came out. They are just amazing instruments, and they're not infallible and once in awhile they'll have that 2 or 3 pound drop, and if you have a problem with the battery, why, you have a complete failure.

I believe that's all we -- these are just back up graphs from which the information was taken to conduct the tan colored graph at the first part of this section.

Q The rest of the material in this section is just support data, is it not, Mr. Greer?

A Yes, sir.

Q Would you now go to Section K in which evidence of communication is shown from pressure decline in a reservoir and explain what this section is designed to show?

A Yes, sir. During February we -- we had shut in a number of our wells which turned out to the A and B zone wells primarily and we produced C zone wells.

One of our -- one of the things we felt we should -- should demonstrate, if we could, we felt we showed communication from the A and B zones, when -- when we fraced the well in the C-34, it showed up in the offset wells to the south and we'll be looking at that in just a minute -- or to the west.

We still did not have then direct communication with the C zone. Now my feeling is that with the varied communication in different places in the reservoir that if we had communication across in the A and B zone, it probably gets into the C zone. So we produced mainly C zone wells and we took pressures in them, and we show here on the yellow colored sheets, a comparison of pressure declines.

For the D-17 in October, the upper yellow colored sheet, we showed about 1.2 pounds a day for October and then from November 1 through 14, about 1.3 pounds a day; in other words, it's fairly steady. We had a little higher production rate in November than in October but the barrels per pound was about the same, around 2400-2500 barrels per pound.

Then we take a look then at the next

graph, we show here the tan colored graph, the 1.21 pounds a day that we showed back in October; the 1.31 pounds a day on the next graph in November; and then if we will go to the blue sheets following that, the first blue sheet, we show here the production from February 1st to the 20th on the producing C zone only wells, and we find here that the rate of pressure decline is only .14 of a pound a day for 1500 barrels a day, or about 10,000 barrels a pound.

We show that on these next graphs. The D-17 we had one run the first part of February; showed about 10,000 barrels a pound. And the D-17, now, as I noted earlier, is a small well, makes only a few barrels a day.

To confirm that the D-17 was showing the presssure decline of the reservoir, of the bulk of the reservoir, we decided to run a bomb also in the B-29. It's our largest well and we knew that if the -- if that confirmed the pressure decline that we had in the low capacity well, plus being closer to the area of production, that that would be a good confirmation.

So we ran a bomb in the B-29 and it's shown on the lower scale and I've shown in there 10,000 barrels per psi.

Now what that means, Mr Chairman, is that during this period of time just producing these -- a few wells in the unit, that we were realizing and we were recovering more barrels per pound, in fact, nearly twice as many barrels per pound as both Gavilan and West Puerto Chiquito together during the higher rate of production. Now this is exceptional evidence of the efficiency the gravity drainage and of the pressure maintenance project and we think should be given large consideration in this hearing.

Now to continue, if these wells are in good communication with the main reservoir, then on shut-in they should show a reaction and the wells closest to the production should show the greatest reaction and that's what happened. When the wells were shut-in then in November, the B-29, the high capacity well closest to production showed its -- its immediate and rapid rise in pressure.

The D-17 showed its (unclear.)

Q Now, Mr. Greer, what conclusions have you been able to reach concerning communication in the reservoir as a result of this reservoir pressure decline?

A Well, Mr. Chairman, I conclude that the reservoir from which these wells are producing, primarily the C zone, is under gravity drainage. The pressure maintenance is effective, and given the right opportunity, high -- high recovery can be expected from the wells.

They are sensitive to rate of withdrawal and the rate of withdrawal that has affected these wells, it's clearly the withdrawal in Gavilan.

Q Now, Mr. Greer, is it your testimony that the pressure maintenance project is maintaining the pressure in the expansion area as well as in the existing project area?

A Mr. Chairman, the pressure maintenance project is being effective. There's no way that it can maintain the pressure because of the high rate of withdrawal in Gavilan. If we just had -- and, oh, I wish we had it -- an underground fence along the boundary between Gavilan and West Puerto Chiquito -- I imagine I'm not the only one who wishes that -- then we would see pressure maintained just as we did in years past in the earlier operation of the unit.

Q What percent of the unit production is being recovered in the expansion area?

A Well, a large part of the unit's total production is in the expansion area. That's, of course, because of our method of operation. Our recovery wells are our down-dip wells, and we just don't drill in the intermediate area.

Q Is there any place other than in this expansion area that the unit and the project could effectively be protected from production to the west in the Gavilan?

A No, no, there's no other practical way to go at it.

Q And what, in your opinion, would be the effective measure to expand this project area as you are proposing?

A Well, if we cannot expand it, then that means that we do not get pressure maintenance credit. That means that we cannot produce our gas and return it to the reservoir, and if we can't do that, then it's not feasible to install a gasoline plant. It's not even feasible to continue the pressure maintenance project, so we'd just have two Gavilans instead of one good operation and one Gavilan.

MR. CARR: At this time we are planning to move to Exhibit Number Two. If the Commission plans to take a break this morning, this would be an appropriate time.

I will warn you, it looks a lot like Exhibit Number One if you look at in on the binding. It does not take as long to present, however.

MR. LEMAY: We'll take a fifteen minute break.

(Thereupon a fifteen minute recess was taken.)

MR. LEMAY: Let's continue. Mr. Carr?

Q Mr. Greer, would you briefly identify what Exhibit Number Two is?

A Well, yes, sir, Mr. Chairman, in establishing communication, one way we can do it is during a frac treatement where a well is given a frac treatment, a large volume of fluid is injected in a reservoir in a short time and sends a pressure pulse through the reservoir and observation wells then can pick up that pulse and that's evidence of communication.

Q And Exhibit Two reviews that kind of test information.

A Yes, sir.

Q Would you turn --

A Excuse me, it's mostly information that we obtained since the last hearing, although there -- I believe there may be one or two tests that we have referred to earlier.

Q All right, would you turn to the first plat behind the introduction tab and identify that, please?

A Yes, sir, we show here in the orange colored lines the areas of communication where we have identified communication before in -- in earlier cases, and the green, the upper green area shows comunication which we had determined earlier, reported earlier to the Commission. The lower green lines show communication which we had earlier reported in Case 9113.

I might point out, we still show the same little plat that we had in Case 9113 with the area with the question marks in the shaded area of postulated low permeability.

Q What is the table behind that plat?

A The table behind the plat identifies some of the tests that we made and some of the statistics for them.

Q All right, would you go to Section A and identify what is contained in Section A?

This is the frac treatment on the F-30.

A The F-30 we reported earlier, the upper graph shows a plot of the pressure increase against log time. The reason we do that is for comparison with some of the other tests that we've made here in case the Commission staff might like to go back and make comparisons on the same basis.

Q All right, Mr. Greer, is there anything else behind this particular tab you'd like to address?

A That's all statistics.

Q All right. If you would go to Tab B now and refer to the first plat on the yellow sheet behind that tab and identify what this is and how this relates to the prior information?

A Yes, sir. This is a reproduction of an earlier plat and added to it are two blue lines showing on the righthand side the C-34 well. We fraced the C-34 well in April, 1987, with observation wells being the B-32 and B-29. We had instruments in those wells, approximately 2-to-2-1/2 miles from the treated well.

Now, the treated well, the C-34, is one of the wells that produced from the C zone earlier. We've now opened up the A and B zones and fraced at that time with only the A and B zones open.

All right, if we turn to the next -- skip over the two green sheets and go to the gray colored sheets that have the log and the graph.

The log shows -- identifies the A, B and C zones. We introduced the bridge plug between the B zone and C zone. The gray shaded area shows a response to radioactive sand tracer used in the frac treatment, so we know from that that the frac did go into the A and B zones.

There's a little bit of an indication of the tracer down on top of the bridge plug, which we think is some radioactive sand settled on top of it.

The two lines shown on the lower graph are plots of pressure decline versus time following the frac treatment. It just happened in this particular well that they had a problem after we had about 70 percent of the frac away and we shut down for awhile and we kept track of the pressure decline and then compared it with the pressure decline following the frac treatment, but what this means is that the frac treatment was -- was in a sense getting out into a reservoir. If -- if we were just fracing into a zone that was not in communication with anything else, that second line would have been higher where the pressure just builds up as a consequence of introducing the frac fluid in the formation.

That's our first indication that the -- that the frac treatment did indeed get into the main reservoir.

Q All right, now go to the blue sheets.

A The blue sheets show the pressure response to the frac treatment in the B-32 Well.

Now the lower line of circles sloping up to the right shows the pressure buildup or the pressure survey in the B-32 run the last of January, '87, and we can see that the relation of pressure through log time is a straight line all the way up to about the fifth day, at which time that test was ended.

Now, when we -- when we fraced the C-34 and then we have a similar parallel line, we see that soon following the frac treatment of the C-34, the pressure in the B-32 begins to deviate from that line and that's a consequence of the frac. We call that a frac response.

Then under Tab C the graph is a similar

graph plotted from information taken from the B-29 Well and if you'll recall the B-32 and B-29 are both 2/2-1/2 miles west of C-34; one nearly due west, the other about northwest, and here we see the frac response, a similar kind of a response to what we saw in the B-32.

Q Now this is evidence of communication across that area?

A Yes, sir, that's evidence.

Q Could you now go -- and the remaining information behind these Tabs B and C is the supporting information, --

A Yes, sir.

Q Is that not correct?

A Yes, sir.

Q Will you go to Tab D now, to the pink sheets immediately following that tab and explain what additional information is placed on the plat?

A Yes, sir. This is the same plat we looked at before with another set of blue lines imposed on it.

These upper blue lines, the junction of them is at the A-16 well. The A-16, we treated the A and B zones in it in the same fashion we did the C-34. We had bombs then and observation wells at A-20 and the B-32, and again, we saw pressure response. And I'll note here that in narrating a description of each of these tests we've included the previous information simply so that someone studying this could pick up at any point and understand what we're trying to describe.

Q Could you now proceed to your Tab E?

A Tab E shows the pressure response to the A-16 frac treatment and the A-20 Well and here we don't see quite as much pressure response but we see a strange up and down behavior of the pressure, which I interpret that to indicate cross flow.

When we fraced that well we had indication of cross flow as the pressure was dropping off and I feel that that is what happened on the A-20.

Q All right, Mr. Greer, now we've seen the pressure response for all the blue lines in the plat behind Tab D.

Could you go to Tab F and I'd ask you to go to the blue plat immediately behind Tab F and show what additional pressure response you're showing here.

A Under Tab F we show the frac treatment along the pink colored line and that's where we fraced the D-17, the northwest end of the pink line, and saw a response in the A-20, and I might note that in this test as well as all of the other tests we've just looked at, we shut in all of our wells in Township 25 North, Range 1 West, and that, I might point out, is a significant -- significant cost. If we're shut in 2000 barrels a day for a week it is a substantial reduction in income. In order to support this test we -- we have undertaken it with that understanding.

Q Mr. Greer, how quickly was the response to the fracture treatment noted?

A Well, I don't show the time exactly here. We've got it plotted against log time on the -- on the next sheet, but it's within a matter of a few hours after the frac treatment that we begin to see the frac response.

Q And how far apart are the wells?

A These two wells are about a mile apart, under a mile.

Q Would you now refer to the information contained behind Tab G?

A Tab G we show again the same -- same plat as before and in addition we have some purple lines and two dashed red lines.

The dashed red lines one of the tests that we recorded in Case 9113, BMG Exhibit One, Section M.

The purple colored lines are those that identify the wells when the F-7 Well was given a frac treatment in November, '87. We had bombs to the north in the E-6, to the northeast in the J-6, and to the southeast in the D-17.

Q Now, Mr. Greer, you again have seen a quick response to the frac treatment?

A Yes, sir.

Q What does that show other than just communication?

A Well, we -- we have found, which we'll look at later, that's it's possible to analyze these tests and determine something about the pore volume of the reservoir as well as the transmissibility.

Q Will you now to the information contained behind Tab, I believe it's H in the exhibit book?

A Well, under G I'd like to note --

Q Okay.

A -- the blue graph, first, which shows the response in the J-6. The J-6 is a (unclear) well which shows a sharp spike and this particular well, the pressure was building up fairly fast as a consequence of us having to cut paraffin in the well later than we had intended, but it's pretty clear that the pressure was beginning to follow a pretty general path, identified path, prior to the frac treatment. There's no question that this sharp increase in presssure was a consequence of the frac treatment.

Q Are you now ready to go to Tab H?

A Yes, sir.

Q Would you go to the graph immediately behind Tab H and identify that?

A This is the -- shows the frac response in the E-6. It was the next farthest removed well.

We can see there the plots of the pressure and the frac response, the shaded area.

Q All right, Mr. Greer, would you now go to Tab I and review the graph immediately behind that tab?

A This shows, Tab I, the graph here shows the frac response to the D -- in the D-17 Well, and here I note that the plot of the pressures prior to the frac treatment was approximately 5.3 pounds per log cycle; after the frac response, approximately 11 pounds per cycle.

Now, that 2-to-1 slope can occur as a -- as a consequence of the -- an indication of a boundary or lower permeability and so I can't tell from this whether that is a frac response or a response from a boundary.

Just generally, though, that seems strange to me that it would be nine days after the well was shut in that change in slope occurs; that just by happenstance we would -- the pressure response to the well would be a consequence of a boundary when just immediately following the frac treatment a response is shown.

So my feeling is that it's probably the result of the frac treatment that causes that (unclear).

Q Mr. Greer, what conclusions can you draw from the information contained in Exhibit Two concerning these fracture treatments?

A That we have demonstrated communication throughout the area.

Q Have you attempted to analyze this test information in terms of reservoir properties?

A Yes, sir.

Q And how have you gone about making this analysis?

A Mr. Chairman, the -- we'll be looking at three -- three frac/pulse tests and an analysis of them and -- or four. Three of the -- three of the tests were recommended by the Gavilan Engineering Committee and -- and of those three tests we reported information to -- to the Gavilan Engineering Committee and we noted there that there appeared to be what we could describe as an empirical relation between the pump volume, the pump rate, and the distance between wells, and then as such, it might be susceptible to analysis.

It was my thought that that would be one project the Engineering Committee could undertake would be the analysis of these frac/pulse tests to determine something about the reservoir properties.

Unfortunately, when we took the information for the third test that was at the time when the work of the committee was discontinued.

So, we did not do this as a -- as a committee, and I initially felt that it would probably, to properly analyze this would be a very difficult, complicated process. We'd have to get into (not clearly understood).

When discussing it with Dr. Lee after our hearing last spring, he said that he felt that from a -- just a practical standpoint an analysis of these tests could be done by use of the EI formula, the EI formula by difference, and we need to take just a minute to -- to understand what -- what Dr. Lee was talking about and why we think it's a suitable and practical way to go about trying to analyze this test.

And to do that, we look at how engineers analyze pressure build-up tests and how they determine reservoir properties from that.

And the way they go about it, let's say, for instance, that we have a well that produces for ten days and is shut in for ten days. There is a -- in a sense a pressure wave moves through the reservoir whenever there's a pressure disturbance within it, and for example, after a well had been producing ten days and the pressure is dropping at the wellbore, it's dropping throughout the reservoir as far as it has its communication, you shut the well in and immediately the pressure starts building up in the wellbore, let's say 1000, 2000 feet away it's still dropping.

And so what the engineer does in a sense is he takes the previous rate of pressure decline and then he calculates how that pressure would continue dropping, how it would continue dropping, because it does drop out at different distances, if the well were to continue to produce.

And then to simulate what happens on shut-in he imposes an injection well right next to it of exactly the same capacity and then he takes the difference in the amount of build-up caused by the injection well, amount of drawdown that he calculates would be, if the well continued to produce, and then by difference he determines what the pressure build-up is.

Now, that's kind of complicated and -- and an engineer working on this found that he could make some general assumptions that would simplify this.

He could assume, for instance that the reservoir characteristics were the same on the pressure decline as they are on pressure build-up and also, -- and incidentally, now, he calculates both the pressure decline and the pressure build-up by the EI formula, and he noted, among other things, that after a certan length of time, that the -- the EI function can be expressed as a function of log, of logarithm.

So, when he shook it all out, he found

that he could come up with a relation between the pressure change and logarithm of ratio of time, the ratio of time is the shut-in time divided by the sum of the producing time and the shut-in time, and -- and that he could make a plot of that; just plot that -- just plot that ratio, the logarithm of that ratio against the pressure and then there's a relation that he can use to calculate the characteristics.

Now that engineer's name was Horner and wehnever we make a plot like that we call it a Horner plot, and the point of this is that if you can use a Horner plot to analyze this reservoir, you can use the EI formula by inference with interference tests and for analysis of these frac/pulse tests.

So that's how -- how we made this -- the analysis.

I think, Mr. Chairman, we ought --

Q Yeah, if we can take a minute, we'll pass out a book that shows how this was done, and while we're doing that, Mr. Greer, would you explain how the information you get taking this approach is different from this interference information you got a result of these tests, this straight pressure response?

A Oh, well, the -- the interference tests themselves show the pressure response, the time of the response, and we take that information, then, and analyze it.

Now, what we looked at in the black book, we just showed the pressure response without any analysis to it. We just showed that.

MR. CARR: The red book is Exhibit Three.

Q Now, Mr. Greer, could you turn to Tab A in Exhibit Number Three and identify that plat and what is shown on that plat?

A Okay, the plat is at the -- at the end of Section A, and we show here the four tests, the area of the four tests that we conducted.

Now, the colored area shows the area of influence of the particular tests; like for instance, the yellow colored area covered only a short period of time and covered only a short, small area.

The upper lefthand circle and the lower righthand circle in the yellow area are the test well and the observation well for the yellow area. And then the upper righthand red circle and the lower lefthand one, the lower one is the one for the red colored area.

It's important to recognize that in an interference test the properties shown by the test are not necessarily those between the wells, rather the bulk of the effect of the influence comes from outside that area and that's one of the virtue's of an interference test that covers such a big area, you know, we need to realize, of course, that -- that we can't tell from the test itself whether the entire area is productive or not, but one of the virtues of this type of a test is that -- let's take, for instance, one of the areas that we assume is productive, let's say that only half of it is productive, then the calculated transmissibility that we get, the calculated pore volume that we get, then, is half as much as it really is.

But we have calculated over the entire area, and so if we take our calculated pore volume in the area we get exactly the same answer, even though part of the area is not productive. So this is useful in that sense.

Now, we just can't tell exactly where the area is productive, where there's tight spots, but what happens is we get an average. Doesn't have to be a homogeneous reservoir, doesn't have to be uniform properties, what we get are average properties and we're looking at the results on that.

Now, we've summarized these tests on -- by the tabulation on the white sheet.

I would come down to line 9, in which we show the pore volume in terms of stock tank barrels per acre. On the first test, the first column, we show about 1500 barrels an acre; the next barrel about 2800 barrels an acre, and the next one, 1800, and the next one, 1100.

Now, the one on the righthand side, the C-34 and B-32 tests, there only the A and B zones were open, and the other tests all three zones were open.

The shortest test, the one with the least reliability would be Tapacitos 4, the second column, which shows the highest volume of stock tank barrels per acre.

My assessment is that for the areas that we've tested, that the probable pore volume in terms of stock tank barrels per acre, lies between 1500 and 1800, and I should point out at this point that at the last hearing Mr. Brostuen asked where the 3000 barrel per acre figure came from, and I did not take the stand after that to be able to answer it, but where it came from was in the course of the Gavilan Engineering Study Committee, I volunteered that we had found from interference tests of one zone what we thought was about 1600 barrels an acre. Looked like in Gavilan they're -- at that time they thought maybe all three zones might be productive. I didn't think the three zones would have three times as much the volume as one zone, but it might have twice as much.

And so just kind of as a horseback starter, we talked about 3000 barrels per acre. We used that figure in our -- one of our exhibits in last April, although we pointed out then that we felt that that was high, and we think that in time it will be shown that with Gavilan and this area here generally has about that volume, somewhere in the range of 1500-1800 barrels per acre of pore volume.

Now, we come down to the bottom line, we find -- first, let's see, we should look at the tenth line. By injecting a frac fluid, of course, we can't tell what's in the reservoir; what we can determine is transmissibility in terms of Kh/u, which we've shown in Line 10.

Now, if we know the gas/oil ratio of the area in question, then we can convert Kh/u to Koh or transmissibility in terms of (unclear), and -- which, incidentally, we show that in one of the appendix to this -- to this report. It's not generally set out in the technical literature and so we included it here.

Then we come down to Line 13 and we show transmissibility in terms of Koh runs from 12 to 50 darcy feet. Again we note that the one with the highest transmissibility is the one with the shortest test, probably not as accurate as the others, but it would appear that the range of 12 to 20 darcy feet is a pretty reasonable figure.

Now, when we first performed our interference tests 20 years ago, we came up with an average Kh for the areas tested of about 6-to-8 darcy feet, and that included both the high capacity system and the tight blocks, an average of those. At that time we estimated that the high capacity system would probably have transmissibilities on the order of 10 to 20 darcy feet and we reported that to you 20 years ago.

We had no way then of testing that high capacity system. We think now that these frac pulse tests probably show the transmissibility of the high capacity system. As time goes on and the frac fluid diffuses into the reservoir and the reservoir itself responds and the oil diffuses into the tight blocks, that then we get closer to an average, and so early -- in each of these tests, we take early time, we show always some higher transmissibility than the later, and my feeling is that that is what that means.

Now, the significant thing, the really significant thing in these tests, is that associated with the high transmissibility is a very substantial part of the reservoir volume. Now, this -- this is important.

If a large part of the reservoir volume has a high transmissibility, then it's susceptible to -- will respond to -- to reservoir management, which allows the gravity drainage to operate and will let the pressure maintenance project operate.

So this confirms what we had earlier found from earlier tests and could be a really rather practical tool that we think, if the industry wants to study it further, they may find that it's quite useful.

Q All right, Mr. Greer, will you turn now to Tab B and to the blue sheets behind Tab B, and explain the graph that's shown here?

A What we show here, the average characteristics that we found from these tests, we have calculated what the shape of the curve might be for a frac pulse for observation wells at different distances from the -- from the treated well.

The -- the upper curve, the squares, is for a 3000 foot radius; and then the next one, 4000, then 6, 8 and 10, and what's of interest here is how does this frac pulse behave as it moves through the reservoir. Should we expect a little spike at each well and at different distances? Will it be a little spike or what will happen?

And we see here that for wells close enough with reservoir characteristics of the kind that we have here, that at 3000 feet we do indeed get a fairly sharp increase and a fairly sharp dropoff.

We get as far out as 10,000 feet, we see no spike but in fact the pressure keeps increasing and at the end of four days at 10,000 feet it's still increasing.

Q Now will you go to the yellow graph and explain the difference in this yellow graph as opposed to the first one?

A The yellow graph is the same, just a continuation of the blue graph, except we've carried it out to nine days and we see there that at nine days the pressures begin to draw together regardless of the distance from the well.

Q Now the blue sheets contain statistics that were used in making these computations?

A Yes, sir, we -- we show generally here what -- how -- how we analyzed the tests.

The first column we show the time after the frac treatment. The second column is a pressure response.

Then the third column is one that we include just to be able to -- to study the test and how the accuracy of the EI formula is required under this method of using the EI formula by difference.

If we had continuous pumping, then the third column shows what the pressure would be in the well at the different times. Like, for instance, on the bottom line it would be 314 pounds, whereas by difference it's only .75 of a pound, so we see we have to have the EI solution fairly accurate in order to come up with the difference that gives us the right answer.

Then the other columns, we note that the EI formula is a point source for solution. Wells are not point sources. They have physical dimensions and wells after fracing, they have the large rw. Now, that doesn't stop the engineer from using the principal of the EI formula Horner plot. They go ahead and use it. It has some -- some limitations. We recognize the limitations here, that the EI formula, if the diffusivity constant times time divided by the wellbore radius squared is greater than -- or less than 100, less than 100, then the EI formula will not be exactly correct.

We've shown here, for instance, like for an rw, the next to last column, of 250 feet, an effective rw of 250 feet is generally recognized as a frac length of about 1000 feet, so if we frac the well at about 1000 foot fracture, induced fracture, the calculations for an effective rw about 250 feet will apply.

Okay, we see here in the next to last column that up to about one day our guideline is less than 100. That means the EI formula will not be perfect. Okay, to determine how far off the EI formula is, we go to the far righthand column and by taking the diffusivity constant times time and dividing it by the distance squared, that's between the observation well and the treated well, then we can go to some information that's in the appendix here that shows how far off the -- the calculation is.

Now we have shown on the plats as we come to them, 2 percent errors and 10 percent errors, so that we would -- so we'll have an idea of the -- how far the -- just the solution itself might be off, and whether it's far enough off the required (unclear) that we go to -- to an exact solution to solve our problem or if we can feel comfortable with where we are.

Q All right, Mr. Greer, what is shown on the yellow table?

A On the yellow page we have shown an example here if we look at the lefthand column, after nine days we find that the pressure has increased in the second column up to about a half a pound and then begin to slowly fall off; quite different from the sharp spike that we get for a well close to it.

Q Okay, Mr. Greer, let's now take a look at the individual tests. Let's go to the first test and the data on that after Tab C.

A This shows the test between the E-6, Canada Ojitos E-6, and Canada Ojitos N-31, and we've looked at the summary of the statistics that we calculated for that earlier.

Now if we'd go to the gold colored sheets we'll see how we analyze the field data to come up with the amount of the -- of the frac response. Now these -- these gold colored sheets were provided the Engineering Committee.

We show here the production on the little schedule on the graph on the left of nearby wells, which appears that they would produce fairly constantly during the time just prior to the test and during the test.

The nearest well, we plotted it's production, the Howard 1-8, on the bottom, where it would appear that its average production over the time would not have actually affected the well.

We see how the pressure increased, fell back off. Then the treated well was put on production and where the arrow shows N-31 on production, then withina short time after that the pressure began to respond to the N-31 pressure.

Q Now what's shown on the pink sheets?

A On the pink sheets we show the calculation for that particular test.

The orange colored line shows where the EI formula could be -- not be expected to be more accurate than within 10 percent.

On the blue colored line, as far as the calculation formula itself then would be about 2 percent.

The x's show the field data and then the other two lines show the calculated information for -- calculated curves, depending upon the assumed values of Kh and diffusivity (unclear) and then we have calculated the pore space which these two curves would show. In this particular instance the pore volume would be the same with a little difference in Kh, and we've chosen curves that (unclear) back at the (unclear).

Q All right, let's go to Tab D and look at the information on the E-6 and the Tapacitos 4.

A Here we have the same type of information.

Now, the Tapacitos 4 was -- had to be put on production shortly after the test started and so the area covered, the area of influence, is smaller than any of the other tests.

The plot of the field data is shown on the yellow sheets following the next (unclear).

You can see how -- how we estimated the pressure increase by extrapolating the rate of pressure decline. That's on the yellow sheets.

Then for the same well, the Tapacitos 4, still under Tab D, the last graph under Tab D shows again the (unclear) of the field data and my calculations for the pore volume and (unclear).

Q All right, let's go to Tab E and the Unit B-32 Well.

A This the B-32 and F-30. This is test that was reported last -- in the last hearing with no calculations made on it. The calculations appear here.

First, we show again the response in

terms of pressure versus log time. We looked at thes curves earlier.

And we pass on over to the tan colored sheets and here again we show with the orange and blue lines the 10 percent and the 2 percent lines for accuracy of the EI formula.

My feeling is that as far as a practical method of determining what these frac pulse tests mean, the EI solution is a very practical way to do that.

Q All right, Mr. Greer, go to Tab F and the last test.

A This shows the C-34 and the B-32, the calculation for that area, and this graph is shown on the green sheets that follow.

Now, this -- these wells are separated, I believe, the greatest distance of any of the tests, about two miles, 10,400 feet, and of course, have the smallest pressure response, but here again the results appear to be about the same as we've found before, a little smaller amount of stock tank barrels per acre in place, but again the treated well had only the A and B zones open and that may have had an effect on it. I think it might.

Q Would you now to go to -- I'm sorry, to Tab G and explain the variation of the curves that may result from various input parameters in this frac treatment?

A Yes, sir. We wanted to show here about how the sensitivity of the -- of the information and our testing in order to determine do we really have a pretty good analysis or would we, if we used entirely differnt characteristics, would we still get a match of the curves, and so we show some comparisons of that, and indeed there is a big difference from the -- from the measured field data if we use arbitratily selected values that are substantially different from the matches that we got.

If we look a the tan colored sheets we see that the upper one is a reproduction of the match that we made on the E-6 and N-31 and the comparison we make is if Kh/u is only one darcy feet instead of what we had earlier estimated, like 50 to 80, and if we match the peak pressure and then determine the diffusivity constant in the curve shape, why, we see that the curve nowhere near matches the field data, the field data as being shown by the x's, and so there is a very -- a distinction, clear distinction, if we choose properties that are substantially different from that, which gives a good match.

By the same token, the next sheet -- well, I guess this one is more tan and the other one's more orange than this, but this shows the match at the time of the two pressures and then compares the pressures.

Well, again the field data is shown down at the bottom with the x's and we see that instead of a 6 pound increase there would be a 660 pounds and this is for again, kh/u is equal to 1 darcy feet.

Q Will you to the blue sheet --

A One darcy feet, Mr. Chairman, is higher than some of the engineers have felt is representative of this reservoir.

Q All right, Mr. Greer, now would you go to the blue sheets and review those, please?

A Okay, here the question arises, we addressed the question if instead of a large part of the reservoir is in the high capacity fracture system, if it's only a small part, say 10 percent, we make a comparison here of how would the match be, and we see on the blue sheets that it doesn't match at all.

Q All right, what is contained behind Tabs H and I in this booklet, Mr. Greer? Is this reference material?

A Oh, these are just references, yes, sir, references and an appendix where we've done -- show some of the calculations, how we -- how we go from Kh/u to Koh, and such as that.

Q What conclusions can you draw from the analysis you've made of the pressure pulses generated by these fracture treatments?

A Well, the consistency of the -- of the information that they show, the calculated information, leads me to believe that they're a reasonable way to -- to add to our store of knowledge about this reservoir and that particularly the high capacity fracture system is associated with a large part of the reservoir volume.

MR. CARR: May it please the Commission, we are now going to pass out Exhibit Number Four, this additional booklet, and you will see when you receive it that the bulk of it are copies of an appendix and previous orders related to this pressure maintenance project.

The last section contains an explanation of how the crediting arrangement works.

I think we can present it very quickly. This is our last exhibit we'll present.

MR. LEMAY: The lightest, too. Please proceed.

Q Mr. Greer, would you identify what is contained in Exhibit Number Four?

A Yes, sir, we thought it would be good to collect the orders that affect the spacing in West Puerto Chiquito and the orders which set out the regulations for the prssure maintenance project, and we have them presented here in case there's any question comes up, that we can readily refer to them and there's a chronology of how -- how the orders originated and whether they'll be useful at our hearing today or not, we don't know, but we wanted to have the information available in case it was needed.

Q Now what is contained behind Tab A in this exhibit, Mr. Greer?

A Under Tab A are the orders relating to spacing.

Q And Tab B?

A Orders relating to the pressure maintenance project.

Q I'd like to direct your attention to Tab C in this exhibit.

A Okay, in Tab C we show how the pressure maintenance credit formula works. It's really a very simple formula, just based on net gas/oil ratio, and that means produced gas less injected gas, and that's how basically allowables are determined.

In order to make a comparison of reservoir space voided I've used some approximations here to show, for instance, for this example, about 3 barrels per MCF of free gas, reservoir space voided, and we use that in some of these next comparisons.

Q Okay, would you like to go to what is marked Case 1 on the green sheets and review that?

A Yes, sir, on Case 1, if you'll look at line 1, we show here for the conditions under which we are ow operating, which is 400 barrel per day allowable and 600 cubic feet per barrel, for a 320-acre spaced well.

This particular well we assign a gas/oil ratio of 1200 cubic feet per barrel, that means -- and its limiting gas volume is 240 MCF a day, that means it has an allowable of 200 barrels a day.

Coming further over to the right we see what reservoir space it voids: By oil, 250 barrels, by gas, 510, total of about 760 barrels of reservoir space voided.

Now, a unit well, say, offsetting that non-unit well, with the same gas/oil ratio, same limiting volume, if there's no gas injected, we show that in the third column, zero percent gas injected, then its net gas/oil ratio is the same as its produced gas/oil ratio, 1200-to-1. Its allowable is 200 barrels a day, voids the same reservoir space as a well outside the unit.

Now, if some of the gas is injected and the production is held the same, then the unit well voids much less space than the non-unit well. We show that by statistics in the rest of the table; graphically be the sketch below.

For instance, is 90 percent of the gas is re-injected, then the unit well only voids about 100 barrels of reservoir space a day, whereas its offset outside the unit voids seven times as much.

Q All right, if you'll go to the second table and show how this differs from the first?

A Here we show the variable gas/oil ratio and how a unit well can produce then at a higher gas/oil ratio if its gas is -- is re-injected and gets credit for it.

In this instance we used 100 barrels a day for the basic case.

Under line one, we show the non-unit well voiding on the righthand side 740 barrels of space per day.

The unit well, under the same conditions, then, line 2, with zero percent gas injected voids the same amount of space.

And so on down for lines 3 and 4 and 5, and then that information is shown by the lower line on the graph below similar to the one we just looked at before.

Now we take the case where the unit well, now, produces twice as much gas as the non-unit well, 480 MCF a day, in the second column, sixth line. It's gas/oil ratio is 4800 cubic feet a barrel.

Now, for the non-unit -- or for the unit well to continue to produce at that rate, it's necessary that 50 percent of the gas be injected. If less than 50 percent is injected, then the well is overproduced and has to be cut back.

And that is shown graphically by the middle line below.

If more than 50 percent is injected, then the unit well with twice as high a gas/oil ratio as the non-unit well, producing twice as much gas and the non-unit well, nevertheless only voids a fraction of the space of the non-unit well.

By the same token we go to 9600 cubic feet a barrel, and so on. But at 9600 cubic feet a barrel gas/oil ratio, then it's necessary to inject or re-inject at least 75 percent of the produced gas.

Q Mr. Greer, how does this injection formula affect correlative rights in the area?

A It protects correlative rights in a sense that it is really, despite the fact it's a very simple formula, it's very equitable, very practical, and easy to use and to monitor, and the unit is given the option to inject more than is necessary to -- to get the allowable. In other words, if it's necessary to inject 50 percent to get the allowable up the well as we just looked at with the 4800 cubic feet per barrel gas/oil ratio.

And the unit, the operator and the unit owners believe that it's beneficial to inject more than 50 percent. Then the operator has the option to that, to inject more than 50 percent, void considerably less space, less reservoir space than the offsetting well outside the unit, but if he thinks it's beneficial to do that, he has the option to do it.

If for some reason, the pressures break down, or whatever, the gas is not injected, then there is no gas injection credit, and the allowable, then, becomes the same as the non-unit well.

It's a very fair and equitable formula.

Q Is this kind of an injection formula unique to this pressure maintenance project?

A Oh, no, it's the standard formula and similar ones apply to water injection.

Q Mr. Greer, based on your study of the reservoir and your knowledge of this particular pressure maintenance project, do you have an opininon on whether or not there's effective pressure communication between the project area and the expansion area?

A Yes, sir, I believe there is.

Q In your opinion has pressure maintenance been working in this reservoir?

A Yes, sir.

Q Do you believe it will continue to work in the future?

A Yes, sir.

Q In your opinion is the credit -- the injection credit formula working effectively to protect correlative rights?

A Yes, sir.

Q What would be the effect, in your opinion, of failure to expand the pressure maintenance project as you are recommending here?

A Well, as I noted earlier, the -- we would have to forego our plans to construct a gasoline plant, inject the residue, and probably would have to phase out the pressure maintenance project rapidly.

Q In your opinion will expansion of this pressure maintenance project that you propose result in increased recovery of oil from this reservoir?

A Oh, I think substantially increased.

Q Would denial of this application result in waste?

A Yes, sir.

Q Are you aware of any other logical boundary at this time for this pressure maintenance project than the one you're proposing after the project is expanded as you're recommending?

A Oh, no, it's a very logical boundary. The recovery wells are on the very lowest part of the structure where they need to be. It's -- it's practical.

The only better solution would be to, of course, include Gavilan in the unit.

Q Mr. Greer, were Exhibits One through Four prepared by you?

A Yes, sir.

MR. CARR: May it please the Commission, at this time we'd move the admission of Benson-Montin-Greer Exhibits One through Four.

MR. LEMAY: Without objection Exhibits One through Four will be admitted into evidence.

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

MR. LEMAY: Thank you, Mr. Carr. I think we'll take a break for lunch and we'll return at 1:15.

(Thereupon the noon recess was taken.)

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

You've concluded the direct, Mr. Carr?

MR. CARR: Yes, I have.

MR. LEMAY: At this time we'll

conduct cross examination of the witness.

MR. DOUGLASS: Mr. Chairman, I'm ready to go forward but I thought maybe Mr. Kellahin, if he has any questions, I don't know whether they're really cross examination or not, but perhaps I could cover both. If he's going to question Mr. Greer, then that could take place and I can cover both areas.

MR. LEMAY: Have you got some questions, Mr. Kellahin?

MR. KELLAHIN: For economy of time, Mr. Chairman, I don't propose to ask Mr. Greer any questions on direct.

MR. LEMAY: Please proceed, Mr. Douglass.

CROSS EXAMINATION

BY MR. DOUGLASS:

Q Mr. Greer, if the proposed expansion area is not in effective communication with your injection wells, then would you agree that your proposed expansion area should not get the benefit of the net ratio for gas injection?

A Sir, we don't want credit if we're not entitled to it and I would say that there's no way that we can get credit for the gas injection if there's no communication.

Q Well, is the answer to my question, yes, that you should not get injection credit unless there's effective communication between your injection wells and your proposed expansion area?

A Yes, sir.

Q Turning to your Exhibit One, the structure map, I believe that's under Tab -- the first page under Tab Intro.

A Yes, sir.

Q Do I understand this -- what's this a structure map on, please? Is it on the Mancos or what is it?

A It's on the contour marker, top of the Niobrara Zone A.

Q Niobrara Zone A, all right. Does it reflect that on the east side of your unit here that you have a elevation or structural dip of about 800 feet per mile?

A Yes, sir.

Q And then when you get in the -- about the middle of your unit, you have about 400 feet per mile?

A Yes, sir.

Q And when you get, right before you get to the expansion area over here you have about 200 feet per mile?

A Yes, sir.

Q Now, the contour lines from -- let's see how high they do go. They go up to 3000 feet, +3000 feet?

A Just about, yes, sir.

Q All right, sir, and from 3000 feet to 600 feet, those are 200 foot contours on this structure map, is that correct?

A Yes, sir, the dashed line is a 100 foot contour.

Q So you change the contour interval when your -- the contour interval on your structure map when you got down to 600 feet, is that correct?

A Yes, sir, we did that in order to show the lower part of the area on the lefthand side.

Q All right, sir. In the expansion area, which is the dashed area, I take it, on this map, is that correct?

A Yes, sir.

Q In the expansion area would you consider the structural elevation of that area to be relatively flat?

A Yes, sir.

Q And then, as I understand it, when you come into Gavilan to the -- to the west over here, there's only a slight structural increase in that area, is that correct?

A Yes, sir.

Q You would consider the Gavilan to be relatively flat, the entire Gavilan area to be relatively flat with reference to the unit area from 600 to 3000 feet, wouldn't you?

A Well, on the south part of Gavilan the structure rises again. It's what we refer to as the Gavilan nose or dome.

Q But other than that the rest of Gavilan you'd consider relatively flat to your unit?

A I believe it drops off to -- to the west.

Q You had an exhibit under Tab B. It's a schematic drawing -- diagram, cross section?

A Yes, sir.

Q Showing an arrangement of your unit wells?

A Yes, sir.

Q I wonder -- I'd like to keep that green tab and the diagrammatic sketch, or schematic diagram under B, and also look at your structure map --

A Okay.

Q -- to see if we can identify the wells that you're talking about.

A Okay. The down dip recovery wells are essentially those in the expansion area.

Q All right, so it would be -- the dashed green line on your structure map would be about where the dotted line is that separates the down dip recovery wells from the intermediate cycling wells on your green schematic diagram, is that correct?

A Yes, uh-huh, to the extent that that sketch is not to scale, yes.

Q Approximately. Then what would be your intermediate cycling wells?

A They run over there from that point to -- to the injection wells.

Q Now, wait a minute, you've got up dip injection wells. I see K-13 at a minus -- at a +13 is that -- I don't know whether that's 50 or 30.

A Yes, sir.

Q Would that be an intermediate cycling well?

A Probably. We initially intended for the K-13 and just to the west of it the P-11 and the A-14 and A-23 to be cycling wells but as we -- as we worked over and opened up the A and B zone in some of the other wells, it looks to me like there's a good possibility that we may not need those wells, and so they would be cyclins wells with the exception of whether it's unnecessary to just -- to go to the expense of putting them in the production system. In other words, we might do the cycling we want to do without those wells.

Q Well, I just want to know what -- what area within your unit would be considered the intermediate cycling wells with reference to the structure position that you have.

A Everything down dip from the injection wells to the -- just about to the boundary.

Q Okay, and then your up dip injection wells, would that be your five injection wells that you have?

A Yes, sir, but we only have --

Q You had five; I think there are just four shown on your exhibit, is that right?

A Well, yeah. At one time the first well we used for injection was the K-13. That was to initially test our theory as to whether the reservoir might be susceptible to injection. Once we found that out, then we moved the injection wells back farther away from it.

Q So there would be the four, on your structure map it would be the four wells that show triangles, the injection wells, wouldn't it?

A Yes, sir.

Q Now, isn't it -- isn't it a fact that you could construct this gas plant, cycle the gas, and have sufficient volume that you don't need any additional gas from the down dip recovery wells?

A No, sir, I would not recommend that.

Q Let me show you what I'm going to ask to be identified -- I'll bring you a copy of Mallon Exhibit One, I haven't stamped it, but it's a letter dated March 12, 1988.

Do you recognize that letter?

A Yes, sir. Worked Saturday afternoon to get it out.

Q You signed it, didn't you?

A Yes, sir.

Q All right, sir. On the -- on the second page of that letter don't you say in the 1, 2, 3, third new paragraph, at the bottom of the -- the last sentence of that paragraph, you say, "All in all, we expect to have a capacity from all of these cycling wells of 15,000 MCF per day or more."

A Yes.

Q And those cycling wells do not include any of the wells in the expansion area, do they?

A No, no cycling wells.

Q And the plant capacity that you do your economics on is 10,000 MCF a day.

A That's correct.

Q So even from the cycling wells, according to your letter, you expect to have 5000 MCF a day more than the necessary deliverability to operate this plant.

A Yes, sir. Could I respond to that a little more fully?

Q Anything you want to, Mr. Greer.

A Okay. The economics, Mr. Chairman, on the gasoline plant hinges not only on the total volume which you have to put in the plant, but the total reserves, and one of the concerns that we have is to -- to optimize whatever we can in the way of oil and gas from this reservoir, and we want to take all the gas that we possibly can through the plant and reinject it and with the cost of the plant and the plans that we have for it, I would be concerned that there is not enough total gas in just the cycling wells alone to be an economically sound venture.

Perhaps I should go into a little bit of detail about that.

The thing that we want to accomplish, Mr. Chairman, is to pick up as much additional reservoir liquids as we possibly can. Now to do that means getting the treated gas as lean as is reasonable to do. Now this means that we have to -- to recover a substantial portion of the ethanes. We can't quit, as a number of plants sometimes do, with just butanes, propanes. We have to go to ethanes.

When we go to ethanes, the vapor pressure of the mixture that we'd have will be too high for the products to be economically trucked. That means the only way, the only feasible way that we can -- can go forward with this plant is to construct a pipeline from the plant to the nearest pipeline that we can get into to -- to market the products.

The nearest point is at Lybrook. That's, I think 40, we can see here, 44-some odd miles, 44.6 miles. The cost of that pipeline alone approaches Two Million Dollars, One Million Six-or-Seven Hundred Thousand Dollars.

By the time we add that to the cost of the plant we're up to about a Four Million Dollar expenditure and I just would not recommend to our partners that they take the risk of this big an expenditure and only plan on treating a part of the gas that we have available.

Q You don't condition this AFE on any amount of reserves, do you?

A I don't put it in the letter. I asked in a sense in I think it's the last paragraph that -- well, somewhere I asked that they trust our judgment. That's, perhaps, asking a lot of some participants but most of them we've had for a long time and they do trust our judgment.

Q Mr. Greer, there's nothing to keep you from putting through this plant the gas that you're currently producing in the expansion area, isn't that right?

A There's nothing to keep us from doing it?

Q That's right.

A Well, as I indicated this morning, if we don't have approval of the expansion of the pressure maintenance project then we can't pick up the gas, we can't return it to the reservoir, we can't run it through a pipeline, so we'd have to phase out the injection project and forego the plant. I just would not recommend that at all.

Q Well, I don't understand why you can't -- you're now picking up the gas from the wells in the expansion area.

A Yes, sir.

Q You run it in a gathering system to some point.

A Uh-huh.

Q Why can't you run the gas that you're now picking up through a plant?

A If we don't get this expansion we probably will cease doing that.

Q Well, you say you probably will, but won't -- wouldn't the economics be there?

A No, sir, the economics would not be there.

Q How much gas are you producing today from the expansion area?

A Well, it varies from time to time; about 4-or-5,000,000.

Q 4-or-5,000,000 currently?

A Yes, sir. The rough figures that I had in mind, Mr. Chairman, is that we'd pick up about half the gas, 4-or-5,000,000 cubic feet a day from the down dip recovery wells. Then we would make up the cycling wells with -- and with this capacity, 15,000,000 feet a day or more, then the cycling wells could pick up the difference, whatever it takes to balance out the load, and we would want to first take the gas from down dip wells because in time, as we inject, or re-inject the residue, then that dry gas, although we expect it to pick up liquids, is not going up as much as is currently being produced from the wells.

This means that the cycling wells will lean out and so in order to have a viable operation, we need to treat all the gas.

Q Mr. Greer, do I understand that you're currently producing under the current allowable, restricted allowable, 4-to-5,000,000 cubic feet a day from the wells in the expansion area?

A I'd like to go back and take a look and see. Let's see, let's start with the F-7, it's a full allowable. It will have 480,000 feet a day.

Then the section to the north of that 480, that would be about a million.

N-31 a quarter, that's a million and a quarter.

The F-18, about a quarter of a million, that's a million and a half.

The F-19 will be allowed about a quarter, that's 2-million.

The F-30, I believe is about, let's see, close to a half million.

Then starting back up from the bottom, the G-5, that will be a half a million, that's up to 3.

The B-32 would have another, that would be 3-1/2.

The B-29, about 4-million.

Q Yes, sir, about 4-million. Now, how much increase are you going to get if you're able to produce your expansion area wells at current restricted rates as far as oil is concerned but not with reference to gas?

A Let's see, let's see if I understand your question.

Q All right, how much gas increase really are you going to get from this application?

A Oh, it may vary from time to time. Initially, if we start out as I just indicated, about half the gas from -- from the down dip recovery wells and half from the others, we will go 4-million to 5-million, perhaps a million feet a day.

Q So you're saying the economics of this gas plant project are hinging on 1-million cubic feet a day coming from these pressure expansion area wells.

A No, sir. What I said is if we don't get the expansion we probably will not have a gasoline plant or a pressure maintenance project.

Q Well, I know you say that, but the economics are there even without the increased gas production.

A No, sir, not the way I analyze it, sir.

Q Now, let me ask you with reference to the schematic fracture system. I believe it's also under the Intro, is that correct?

A I show it under exhibit -- under Section A.

Q Oh, do you? I'm sorry, excuse me, you're right. Thank you. That's the one that has the --

A Yes, sir.

Q Let's see if I understand what your concept of the reservoir is.

This applies to the Gavilan as well as it does to West Puerto Chiquito, is that right?

A Well, we have good tests on wells in West

Puerto Chiquito and good information. We have that good information all the way up to the boundary of Gavilan.

I've had a lot of concern about the tests that were taken in the Gavilan, that they've been conducted as carefully as they should be and I can't say that the same thing exactly applies, but I do know that in general there is a high capacity fracture system in the Gavilan and I can tell you why I know that.

Q That's all right. I'm just asking you what your concept of the reservoir is and does this apply both to Gavilan and to West Puerto Chiquito.

A More to West Puerto Chiquito than to Gavilan.

Q In Gavilan, you say you think there are the high -- high capacity fractures there, is that correct?

A Yes, sir, there are some; may not be as much as in West Puerto Chiquito but there are some.

Q And I believe you also said that actually in what you call the tight blocks you can complete a well and it won't drain that tight block as well as a good well two or three miles away. Is that --

A That's correct.

Q Let's see, for instance, if there's a well over here and it's a poor oil well and it's in Gavilan, and let's say that it -- there's another section here and then here's the current pool boundary here, and over in the next section down here let's say there's a good oil well, one of these good Greer oil wells down there and it's in one of these high fracture systems.

A Yes, sir, there's just not enough of them to do it all.

Q I understand. I think that's what this fight's been about for the last several years, is that there's some good oil wells over in Gavilan that you want to be -- make good Greer oil wells.

Let me -- and what you're saying is that this -- this tight well in this tight block might have some good fracture systems that that well is not even in connection with and that fracture system may come down where it's in good communication with the Greer oil well.

A Yes, sir.

Q And so if I were to measure pressure in this poor well up here of 750 pounds, that's not the pressure of that section there. The pressure may be 1200 pounds out there in that high fracture system but it's not connected to it, isn't that right?

A That's a possibility, but we have found there are no instances of that in West Puerto Chiquito, which, of course, as I understand that's the hearing that we've got here today, is West Puerto Chiquito.

Q Well, I just want to understand what your wells are capable of doing in this area here.

Are you saying that pressure wouldn't be higher out here in this high fracture system?

A What we found in West Puerto Chiquito, Mr. Chairman, is that the pressure in that tight block is going to be about the same as the pressure in the high capacity fracture system.

The rates of diffusion that we -- we came up with as a consequence of the individual well tests and the interference tests show that we're looking at something like a matter of days for the pressures to equalize.

If there was a situation such as is shown on the board here now, it would be different from what we have found in West Puerto Chiquito.

Q Okay, when you -- when you say tight blocks, then, are you saying that that pressure in the -- in the tight well is going to be 1200 pounds and it reflects the pressure in the entire section?

A Yes, sir, if you get a good pressure on that well, that's what it will show.

Q What do you mean by a good pressure, Mr. Greer?

A Well, it's accurately taken.

Q Well, you can take an accurate pressure in one day, can't you?

A Okay, a pressure that accurately reflects the pressure in the block.

Q Well, you mean if it's allowed to build up long enough that that tight well would reflect the pressure of the block.

A Exactly.

Q And are you saying that that is done in a day or two over here in West Puerto Chiquito?

A Yes, sir, we've found, oh, three or four days -- in three or four days we've found equalization in most instances.

Q So --

A Every one of the permeability plateaus that I mentioned earlier.

Q So over here in the West Puerto Chiquito this high fracture system is not going reflect a big pressure differential between any well drilled on that section at any point.

A I think that's right.

Q But it is possible in the Gavilan where you have tight -- if there are tight sections over there, where you can actually have a pressure that's different in the well on a section than in these high pressure -- excuse me, high -- big fracs, isn't that right?

A Well, our Gavilan Engineering Committee, Mr. Chairman, when we were studying it we found two or three wells, I think the Mallon Johnson Well was one, that showed roughly 100 pounds higher pressure than the other wells. The consensus, I believe, of the members, at least it was my opinion, that that well was in a little tighter section than the others.

By and large, though, they came fairly close. The closer they are, the wells are to West Puerto Chiquito, apparently a better fracture system; the farther they get away from it, the more it appears to deviate.

MR. DOUGLASS: Could we have -- could we offere Mallon Exhibit One, the letter dated March 12th, 1988?

If we need to stamp it, I'm not familiar with your procedure here.

MR. LEMAY: Without objection, Mallon's Exhibit Number One will be admitted into evidence.

Q Mr. Greer, do you think that you've had -- or have cycled all the gas in the pressure maintenance area or is there still additional gas reserves to be produced there that hasn't been injected?

A Oh, yes. Yes. There's a substantial gas yet to be -- come out of solution.

Q Do you have an estimate, approximately you've got in the -- in the pressure maintenance area?

A Well, we can make a minimum estimate.

Q That will be fine.

A In the gas cap area generally, I'm going to refer now to gas cap and cycling wells.

Q I call it the pressure maintenance area now and the other the expansion area now.

A Okay, the existing pressure maintenance area, I'll have to kind of guess but it's something like, I think, maybe 8-million barrels, in that area and a formation volume factor of 1.3 would put you up to about 11 or 12-million barrels (unclear). For the oil in the rest of the resevoir, oh, we might get up to 12-15 million barrels of the space that we know hasn't been voided by oil and so that's roughly about 100 atmospheres, so that would be 3-million barrels, about 100-million feet. 100 atmospheres would be something like, oh, about 10 BCF, and 10 BCF is where we'd run, say, 10-million feet a day through the gasoline plant, would be -- would be about 3.6 BCF a year. We might have three years of -- of plant volume in the gas cap, as we would feel now is a secure volume. Of course, that's not enough to support the plant.

Q Well, I thought, Mr. Greer, that you've already injected 11.1 BCF.

A We recycled a lot of that.

Q Well, that's what I asked you to begin with, whether you had thought you had cycled the volume of gas that was there.

A Oh, I'm sorry, sir, I just didn't understand your question.

Q Yes.

A Oh, yeah, I'm sure that we'd cycled some. The C-34, we ran an experiment on it, you know, to -- to estimate the gravity drainage from the tight blocks (unclear).

Q Well, I thought you were calculating remaining gas that was in the oil that was in the well that was in the -- in the injection area.

A No, I just counted a figure, a secure figure that I feel that when we recommend a gasoline plant, that we would be looking at three years of its cycling course. That would be at 100 percent sweep efficiency. If we don't have 100 percent sweep efficiency, why, the gas will lean out quicker than that.

So there's no question, you know, that we have to have additional gas to have a viable, economic project at the plant.

Q How many volumes of gas do you think you have cycled now out of 11.1?

A Oh, I'd just have to dig into it and see. I doubt that we've cycled that amount.

We've cycled a substantial amount through the C-34, some through L-27, and some through the E-10. We'd just have to look at those figures and see.

Q You don't have an opinion on that?

A No, not without looking into it.

Q Did I also understand your testimony to be that you found a directional permeability over in the pressure maintenance area?

A That's my -- my belief. We have --

Q North and south.

A -- we have not really run any interference test to show that but I think it's reasonable to assume.

Q North and south directional permeability.

A Right. Yes.

Q That means the east and west permeability you can see less than north and south.

A Yes, I believe that's true.

Q And I believe in the past you have shown an area that you called today as the postulated low permeability area in the eastern, excuse me, in the western part of your overall unit. Is that correct?

A Yes, sir, but that's a carry-over from two or three years ago when we first talked about it. More than anything else, I think we were thinking that there would be a separation between our unit and the Gavilan but it didn't turn out.

Q In your booklet in the -- under Tab -- Exhibit One, Tab B, the benefits of pressure maintenance, those will only be experienced by wells that are in effective communication with your pressure maintenance project, isn't that correct?

A Yes, sir.

Q Under Tab C you've run some production logs on a couple of wells that show where they're producing from, is that correct?

A Yes, it is, and evidence of stratification.

Q Evidence of stratification. Let me ask you, is L-27 one of those logs?

A Yes, sir.

Q And I believe that you show there that gas is coming out of the A zone and oil out of the B zone, is that right?

A Yes, sir.

Q I notice on the -- on your exhibit there, you show oil plus gas in the A zone but only gas is coming out?

A Yes, sir. The column on the left that shows oil plus gas, is -- that information comes from the densitometer and all it can tell is the density of the fluids, and so it can distinguish, for instance, water in the bottom, oil up higher, and the oil plus gas, and so the -- where it shows oil plus gas, why, it's the gas coming out of the A zone and the oil coming out of the B zone that gives it the total of oil plus gas.

Q Was this well fraced when it was initially completed?

A Yes, sir.

Q Big frac?

A I'd have to look at the records. That was pretty early; in those days I think we were fracing with 2-to-4000 barrels.

Q Are there areas where the A and the B zone are in natural communication?

A Oh, yes, I think that all three zones, that there is no question they're in communication.

Q Natural, vertical communication.

A Natural, vertical communication. I think not frequently but enough to -- to give a lot of pressure equalization.

Q If this were -- if the L-27, if it were producing from a reservoir, you're normally supposed to find water on the bottom, then oil, and then gas, is that correct?

A Well, we never found any oil in this -- I mean water in this formation.

Q Well, I see some water right here on this. Is that wrong?

A Yes, sir, but that's not water in the sense that it was indigenous to the formation. I have an idea that was either condensation or (unclear) coming out of the gas, maybe. You know, over a -- well, close to fifteen years, just a very small amount of water would find its way here.

Q So in a reservoir you'd expect to find oil and then gas above it, is that correct?

A Well, we found in this reservoir with these stratified zones, the upper zones are more gassy than the lower zones but not -- not oil-free. They're -- this well, for instance, that you're looking at, the L-27, produced with an initial gas/oil ratio right at solution ratio and so it was known that initially the two zones that are producing there now produced oil and produced oil without any free gas.

Q What I'm saying is, if this AB zone was a common reservoir you would, after this long period of time, you would expect to find oil on the bottom and gas on the top.

A If we have gravity segregation; gravitation segregation.

Q If it's in a common reservoir nature takes care of gravity, does't it?

A Over -- over geologic time, yes. At the time we produced this reservoir that would not happen.

Q And you've got structural height on -- in the pressure maintenance area you're dealing with here that lends itself to gravity drainage, don't you?

A Yes, sir, and that's an asset.

Q Is it your testimony that the gas in this L-27 is gas from injection where it's gassed out this A zone only and not the B zone?

A That's my opinion, yes, sir.

Q And I believe what you're telling this Commission is that when you have that kind of situation you need to be aware of it in order to properly complete and produce your well.

A Well, we recognized then when we first started operating the area, that that would be a problem if you opened all zones up at once, and so you make a judgment decision as to how is the best way to proceed.

Q Well, you opened the A and B in this well at once, didn't you?

A Yes. We tried first the C zone and were unsuccessful in establishing production so then we came back to the A and B zones.

Q Now, the B-32 Well is another well that you've run a production log on, is that correct?

A Yes, sir, that's -- we ran two in 1986 and two in 1987; the B-32 and L-27 were run in 1987.

Q Is this the only -- you said you ran two. Did you run the same wells both years or --

A No, sir. We ran -- in 1986 we tested the N-31 and the F-30 and we reported those tests in the hearing last April, Case 9113.

Q And then you ran the L-27 and the B-32.

A This year -- or in 1987.

I believe you'll find, sir, on our AFE that we sent out for approval to test these wells that one of our objectives was to determine if these zones were stratified as we had thought they were in these down dip recovery wells so that we would be prepared when gas broke through as to how to handle it. We needed to know if there was a situation in which we might, number one, seal off a zone, or number two, it was best to just pick up the gas, provide the extra horsepower and put it back in the ground.

Q Let me ask you on B-32, you got gas only in the A and B zone in that well, is that correct?

A Yes, sir, for all practical purposes. There might be a little bit of oil there to the A and B zones but it is primarily gas.

Q Are you saying that the B-32 has been gassed out in the A and B zones from your injection?

A That's what I would -- that would be my assessment.

Q Even though the C-34, which is a nearby well, it's about a mile or two miles to the west -- to the east. I believe it's two miles, the C-34 is two miles to the east.

A Yes, sir.

Q And it's produced over 4 BCF of gas, hasn't it?

A Yes.

Q And you would say that this B-32 because it's gassed out has this good pressure communication that exists in the West Puerto Chiquito that we were talking about earlier.

A Well, it has communication, yes, sir. It doesn't take as good a communication as would be normal for gas as it does for oil.

Q Yes. This is a good oil well, this B-32.

A Yes, sir, out of the C zone.

Q But it does have that good pressure communication that we've been talking about in West Puerto Chiquito, nor these good --

A It has -- it has communication. We need to make a distinction between the pressure and the pressure maintenance project opened up pressure in the expansion area; it can't hold up pressure there because Gavilan pulls it down, but it can move gas and oil from the existing project area into the expansion area and once it gets there, then it's up for grabs; one way or another, Gavilan gets it.

Q Well, what you're saying then on this well here is that the gas is communicating -- in a good communication in this AB gas zone because you've already gassed out the AB zone in this B-32, is that --

A That's my opinion.

Q The -- have you looked at the bottom hole pressures that were taken in November and February in this -- in this pressure expansion area?

A Yes, sir.

Q Did you find that the pressures in your -- is one of the wells that you -- that was measured on both the November and February surveys, the B-32 Well?

A Yes, sir.

Q Did you find that its bottom hole pressure was approximately 450 pounds lower than the C-34 Well?

A Yes, sir.

Q And the C-34 Well is completed in the AB?

A Yes, sir, It's like 400 pounds less than the pressures (not clearly understood.)

Q Wouldn't that indicate to you separation between this good C-34 Well and this good B-32 Well when you've got within a 2-mile distance 450 pounds of bottom hole pressure difference?

A Well, sir, I would refer you to Section G, the next to the last plat and note there that from the C-34 back up to the injection area, that there is a 500 pound differential, and we know that for twenty years there's been communication across there. It's pretty difficult to say just on the strength of the pressure differences whether there is communication. That's why we prepared the exhibits we did, to show the different ways that we've analyzed it.

Q Well, let me -- you referred me to that exhibit. You're saying that 450 pounds difference, accurate pressure, two miles apart do not indicate to you that there is separation between those two pressures, as far as the resevoir is concerned.

A Obviously the communication is not as good in this area as in areas where they're equalized; it doesn't mean that there is no communication.

Q I thought you told me, though, earlier, that the AB zone had gassed out in the B-32 Well from the injection that you carried on four to six miles away.

A Okay.

Q That would indicate that for the AB zone to gas out there would have to be good communication in the gas zone, isn't that what you told me?

A I believe I said it takes less permeability in the gas zone than it does in the oil zone and once you get into the lower pressure area, then a small volume of gas expands to (not clearly understood.)

Q Let me ask you about your colored map, since you referred to it. The pressures that you show in the orange there are in what you call the gas cap or the injection area, is that correct?

A In the gas cap area.

Q Isn't it a fact that the 1678 pressure is not a shut-in pressure, it's just, apparently just measured it on the day of shut-in?

A I believe it was shut-in about 8 days.

Q Well, is that B-18 -- is that the B-18 injection well that says 1678?

A I'll have to look at my statistics to see what it is.

Q Well, I don't know whether you'd need to look at the statistics to tell me whether B-18 is the well with 1678, there.

A Oh, yeah, that 1678. I wanted to look at my statistics to see if it was one of the wells that --

Q Well, I'm just -- I'm reading from the blue sheet now, above it, that information above it there.

It says B-18 in Township 25 North, Range 1 East. Is that the same well we're talking about?

A It says the pressures for these wells was measured November 19th. Okay, so that would been a 3-day shut-on pressure on that one.

I believe, it's my recollection that the November pressure survey --

Q Starting on November the 16th it was shut-in?

A 16th to the 19th.

Q I think I recall that, too.

A Yes, sir.

Q I talked -- was reading in the upper part up there it says November the 19th. You extended it on, you said, three days, is that correct?

A Yes, sir, that well was shut-in -- that's a 3-day pressure.

These others in the pink, the brown, and the yellow, we had 8-day pressures on them.

Q And the 1726 pressure you show, you'd actually put some gas injection in during the period of time that it was shut in and when you measured the pressure, is that right?

A I believe, let's see, that's the November pressure. I'd have to look the records up. I think it received injection in that -- well, probably about the same time.

Q Well, I'm sorry, I --

A Is that the other one that I say was shut-in and measured on the 19th?

Q No, I think I confused you. I believe the B-18 you actually injected some gas in, also, is that right?

A Well, my recollection is that before the shut-in period of November 16th that we were marketing most of the gas and we were injecting a small volume in the B-18, but I'm sure that the -- all injection wells and all producing wells were shut-in before the pressure survey.

Q Is the bottom hole pressure going to be greater or less if you have a surface pressure of 1678?

A The bottom hole pressure is greater.

Q Do you know what the original pressure was in the B-18 Well to the reservoir?

A I'd have to estimate approximately. Our initial pressure, as I recall, was about 1600 pounds.

Q Well, doesn't that, excuse me, doesn't that reflect then that what you're doing in these two injection wells here, where you got pressures of 1726 and 1678, that you've actually created a greater pressure at the base of the injection surface that you had originally in the reservoir?

A Oh, yes, sir.

Q And what keeps the reservoir from fracing with that gas going --

A It's -- it's considerably below a fracing pressure. We calculated the fracing pressure -- we bought one compressor that we could use for injecting at fracing pressure if we needed to and I think it was about, we figured, 3000 to 3500 pounds surface pressure would be required to reach fracing pressure. So we -- we stay like 1000 pounds below that.

Q For these up-dip injection wells, do you find them generally to be a little tighter than your producing wells?

A Yes, sir. Yes, sir.

Q And you're not suggesting that 1678 or the 1726 really represents an average reservoir pressure for what the pressure would be in that area, are you?

A I think I made a note there that it is very difficult to tell the weighted average pressure in the gas cap because of the large amount of interference effect where we have no injection and shutting the wells in.

Q Do I also read your colored map to show that, for instance, in the yellow and the brown areas, those pressures essentially are very close together?

A Oh, yes, sir.

Q You indicate good communication through that pressure expansion area.

A Yes, sir.

Q And then your green pressures, they appear to be relatively close together, is that correct?

A Yes, sir, that's one of the permeability plateaus I mentioned.

Q Indicating good pressure communication through that area.

A Yes, sir.

Q And do I see that in the red area here you only have one pressure and that's the G-5?

A Yes, sir, that's the only one I had available.

Are you in the black book now?

Q No, I think I'm in the same one, aren't I, Exhibit One?

You mention that you made some calculations that looked like you had overinjected. Do you recall that?

A Yes, sir.

Q Do you remember that tab?

A Perhaps I can help you find it. Yes,

sir, Tab F.

A The second page of Tab F, there is a tabulation there, is that correct?

A Yes, sir.

Q I'm not sure I understand, it says test period July 1987 to November 1987.

A Yes, sir.

Q And it says, withdrawals for test period M, is that thousands of reservoir barrels --

A Yes, sir.

Q -- a day?

A Yes, sir, that's what I mean by that M.

Q That means that there were 515,000 reservoir barrels withdrawn per day over that July to November, '87 period.

A Yes, sir.

Q And then the injection for that period of time you say is 954,000 reservoir barrels, is that right?

A Yes, sir.

Q And then the injection less withdrawals is 490 -- 439,000 barrels.

A Yes, sir.

Q Reservoir barrels.

A Yes, sir.

Q And it says test days, 135.

A Yes, sir.

Q And then it says average rate of overinjection in the thousands of reservoir barrels a day, which is the same measure as above, and it's 3300.

A Yes, it would be 3.3 M barrels, or 3300.

Q Well, I don't understand, if there's -- if there's only been 954,000 barrels a day injected, how could 3.3-million reservoir barrels be the average rate of overinjection?

A It's only 3300 barrels.

Q Well, that's not what it says. It says 3300 thousand reservoir barrels.

A Oh, I'm sorry, that's a -- that's a mistake.

Q Should it just be 3300 barrels?

A Yes, sir. That's in the clerical. I didn't check that for typographical errors.

Q And then during the test period November, '87 to February, '88, there's 1900 barrels overinjection?

A Yes, sir, essentially.

Q Did you find that the reservoir pressure in the pressure maintenance area increased between November of '87 and February of '88?

A No, sir, I believe when we reviewed that this morning what I said was that the pressure dropped probably both times, from July to November and November to February, and then we looked at the overall from July to February as being more definitive of the total pressure drop.

Q How about your measured bottom hole pressure? Did it show an increase or decrease between November of '87 and February of '88 in your pressure maintenance area?

A I'd have to look that up. I don't --

Q Well, subject to check, according to the information we have your L-27 and your E-10 had pressures of 1389 and 1391 in November of '87.

A Yes, sir, they were about the same.

Q And then in February of '87 -- '88, in those same two wells the pressure was 1387 in the L-27, which is about the same.

A Yes, sir.

Q And it was 1403 in the E-10, or about 12 pounds greater.

A Yes, sir.

Q When you overinject do you expect to get some pressure increase?

A Well, perhaps whoever is involved in the pressure survey will recall, we decided to - to estimate the pressures of those two wells in February, and the L-27 -- or the E-10 in November, by taking (unclear) surface pressure and estimating the bottom hole pressure.

You'd think, of course, those would have been within 10 or 15 pounds but I wouldn't want to guess that they would be any closer than that.

There are two other things to consider. The L-27, is one of the closest wells to the C-5 injection well and if we'll look at the pink sheets following, about the second or third sheet following that schedule that you're looking at, we'll see that the C-5 lost 154 pounds in February and so it's not very far from the C-2 but the weighted average pressure would be far from the L-27, but the weighted average pressure would be a pressure change and again, as I stated earlier, it's very difficult to tell.

As far as the E-10 is concerned, the E-10 was pulled pretty hard in November just prior to shut-in and was produced only a small amount between November and February.

So we have to take all these things into account in order to try to arrive at what's happening in the reservoir, and the best way, I felt, was to look from July to February, the entire period, and that's shown on the green sheet and (not clearly understood) overall to the gas cap area lost pressure.

Q Well, the only measured bottom hole pressure you have in the -- in July, the -- strike that, because, first of all, you haven't given Mallon all the bottom hole pressure data you have, have you?

A Well, we've given them all that we've used for this hearing.

Q I understand, but that's not all you have, is it?

A Well, no.

Q In fact, even for this hearing, for instance, on some of the graphs you gave us you left out pressures in between, didn't you?

A If you'll refer to what graphs you're talking about, I'll be able to tell you.

Q Yeah. Like on the COU-34.

A Okay.

Q You gave us 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13 periods of bottom hole pressure, is that right? I have a list here you can use.

A Okay. Let's see, I asked my secretary to make copies of everything that we had on our graphs.

MR. DOUGLASS: I'd like to have that identified as Exhibit Two, a copy of a printout of the bottom hole pressure survey given to Mallon, March 9, 1988.

Q Is that a list of the pressures that you supplied?

A I believe that's the list, yes, sir.

Q Well, I'm asking you on the CU -- COU C-34, that's not all the bottom hole pressures you've measured from June 30th to November the 21st, is it?

A Well, it should be. It is our intention that that would be.

Q Is that --

A Yes, sir, because there -- looking at the dashed lines between the pressure surveys?

Q Beg pardon?

A I'm looking at the pressure plat on this C-34 under Section J, the third -- it was my instructions to the person preparing the pressure surveys to be sure that every one that is being used here was copied for you.

Q Well, I understood that. Now, looking at that graph, were there any pressure surveys made in between these points that you've not supplied us?

A We tried to take some. Now, July, I think you'll find some plats in July.

Q Right.

A August, and in September, the early part of September. That's when we were having problems with the batteries. The supplier, manufacturer, of the bottom hole pressure equipment somehow or other got a supply of bad batteries, and we didnt' know what the problem was, just that we got failed runs. We would run them down in the hole, come back out with it, and we had no information.

We had earlier, when we first started using these GRC instruments, found that if -- if the battery -- it's a battery pack is what it is, and it's got, I think, six cells C size cells, and altogether they've got 1-1/2 volts apiece, gives you about 9 volts.

We had found in the first part of (not clearly understood) in 1986 that we needed to check the overall voltage of this gravity pack and when it was less than 9 volts, why we found that we would get bad runs, and so in the -- from that time on we checked every, every battery pack before we ran it and they all checked out fine.

And so we had no idea until we finally had a -- testing every possible way that we could, we found that an individual cell within a 6-cell battery pack, if it was weak, that that would cause a failure, and so in about mid-September, then, we adopted the system of checking the -- each individual cell.

Mr. Chairman, we had to devise in our own way. We think that the manufacturer could tell us how to be sure that we were going to have batteries that would properly operate their equipment, but they didn't. We had to sit down and figure out how to put a load on each of these little 1-1/2 volt cells, test it, we tested for six minutes, then we'd take about one percent of the cell's total ampere hours out of it and then if it does show substantial drop in voltage or in temperature, we found a bad cell would get so hot you couldn't hold it in your hand for the six minutes.

So, we just had to do that and the result was that we had to discard about half of the battery packs that we bought.

We have since that time worked out an arrangement where we buy ourselves directly from the manufacturer, test them, then have them put in the battery pack.

And so here during July, August and September we had battery failures, I remember that. I don't know about the one in October, that dashed line.

Q Would you say the pressures from these failures were inaccurate?

A (Unclear) not accurate. They just didn't record. (Unclear) Then the man takes them out to the field, runs them in the lubricator, hold them there for fifteen minutes, or so, gets a check on a lubricated pressure, writes that down, and goes ahead and runs the bomb in the hole.

Then we pull the bomb, I'll say, a week later. We don't know whether we get a run or not until that bomb gets out of the hole and what we found was the bomb had registered every thirty minutes like it's supposed to, registering atmospheric pressures and it might only run for two hours. It would fail, completely fail, before a man ever got back out to the field, and yet there was no way, we had no way of telling that until after we'd run it in the ground, left it there for a week, pulled it out and brought it back and we'd take it out and the printout shows pressures for two or there hours and then it's just blank.

Q Did you have any bottom hole pressures on this C-34 well prior to July, excuse me, June 30th of 1987?

A I think we had some, oh, two or three scattered ones when we treated that well.

Q We have a -- we have a pressure you provided us that says in December of 1970, that that pressure was about 1555 in that well.

A In 1970?

Q Yes, sir. Do you have any since 1970 to 1987?

A Oh, I doubt it.

Q What -- over in your injection area, what seals off the north end and the south end of the gas cap area that you've described?

A Well, to -- to the north there's not much production up there. The -- we have plans, and I hope that sometime we do have production up there, but unless we figure something out, there's no -- hardly any place for the gas to go, so --

Q Is this -- is there some of this formation production farther to the north than other places?

A Yes, sir, but not very much.

Q How about to the south? Is there production to the south in this area?

A There's two -- two wells beginning to be drilled south of us. We have our fingers crossed it won't be a south Gavilan.

Q But right now you don't know of any separation between the north area that's producing a little bit and the south area, which you now say is producing a little bit.

A Well, I feel like the gas is not escaping, if that's your point. There's no place for it to go.

Q Well. Let me turn you to Tab E. I believe you skipped it going to a later one.

A Tab E, you want?

Q Tab E, yeah.

A All right, sir.

Q The green sheet, you show three plates there, is that right?

A Yes, sir.

Q In the bottom plate, you show a dimension for the oil to get up to another area up there, is that correct?

A Yes, sir.

Q Well, if -- if that -- that same connection could exist in Plate I and Plate II, also, couldn't it?

A Oh, yes, sir. I just took them in sequence in order to make it a little bit simpler to try to make my point.

Q And do I understand in this section that what you're -- what you're talking about here is that you're saying that the E-6 Well, since its oil production didn't go up and its gas/oil ratio went down, that was caused by some other well rather than the E-6, is that right?

A Yes, sir.

Q And you say that's bad, that the E-6 gas/oil ratio going down is bad.

A Yes, sir.

Q All right, so as I understand your theory in the Gavilan, if the gas/oil ratios go up, that's bad, if it's in the Gavilan wells, but if it the gas/oil ratio goes down in your well, that's good, that's bad also.

A It's bad when the gas moves out of our area over to another one. It's bad when gas depletes a stratified zone and our oil migrates up into it, and I think that's what's happening.

Q Let me look with you on the third sheet. I think in that section there's two sets of green sheets but the one I want, it says page 3.

A All right, sir.

Q Do you see that one? Do I see on the E-6 Well that in June, when it produced 7128 barrels it has a ratio of 4376?

A Yes, sir.

Q And when the production went up by about 50 percent the gas/oil ratio went down from 4376 to 2509.

A No, sir, the gas volume went down first and then (unclear) the oil.

MR. LEMAY: Excuse me, Mr. Douglass, where are you?

MR. DOUGLASS: I'm sorry, on this page right here, Page 3 under Tab F -- D.

MR. PEARCE: The second set of green sheets behind Tab E, Mr. Chairman.

MR. DOUGLASS: Tab E, two sets of green sheets there, Tab E.

Right there, there you are.

MR. LEMAY: Thank you.

MR. DOUGLASS: I apologize.

MR. LEMAY: That's all right.

Q My question was, in June your oil production was 7128 barrels, is that correct?
A Yes, sir.
Q And your gas/oil ratio was 4376.
A Yes, sir.
Q You increased your oil production by 50 percent, approximately, from 7128 to 11,180.
A But that's not the sequence. The gas volume went down first and then you raised the oil volume.
Q Well, --
A That's why we -- we give this explained in more detail than that simplistic approach.
Q Well, it is -- I'm sorry I'm so simplistic, Mr. Greer, but is the answer to my question yes, that when you went from an oil production 7128 to an oil production of 11,180, or about 50 percent increase, the gas/oil ratio went down from 4376 to 2509?
A No, sir, the gas/oil ratio went down first as is shown on the green graph just below the statistics that you're looking at.
First the gas/oil ratio went down. The E-6 oil production was quite high at about 320, 15, 20, 30 barrels a day.
Q Well, the gas production for June is 31-million, is that right?

A Uh-huh.

Q The gas production for July is slightly higher than that, is that correct?

A Right.

Q And then the gas production in August goes down about 4-million, is tht right?

A Yes, sir.

Q Now, there's a gas/oil ratio. Did it go down from June to August when the production went up 50 percent?

A As I said before, sir, the ga/oil ratio went down first and then we raised the oil rate in the last part of August. That's when the oil rate went up.

The first part of August we show here. the oil rate is still 330 (unclaar) barrels a day.

It was the last approximately three weeks in August that we raised the oil rate.

Q On the N-31 the April production is 1967 barrels?

A Yes.

Q With a gas/oil ratio of 2710?

A Okay.

Q Is the oil production in August 5912, or about three times the April rate?

A Yes. The same thing happened to the N-31 that happened to E-6.

Q Yes, sir.

A The gas column went down first. Then we changed the producing equipment to pick up the oil rate in the last half of August.

Q Does the gas/oil ratio from April go from 2710 down to 1346?

A Yes, sir.

Q On the Tapacitos 4 Well, May production, 4548 with a gas/oil ratio of 1003?

A Yes, sir.

Q August production rate gone down slightly, gone down about 300 barrels a day and the gas/oil ratio went from 1000 cubic feet per barrel down to 709, is that correct?

A Well, it looks to me like the oil rate, if anything, dropped off a little bit on Tapacitos 4.

Q Well, that's what I said, it went down about -- it went down about 300 barrels and the gas/oil ratio went down 1000 to 700, right?

A Right, so it increased the production but I did not affect its gas/oil ratio because it had increased.

Q Well, if you look at June, the last month it produced 24 days, it produced 3320 barrels at 918 ratio, didn't it?

A Yes, sir, only 24 days, it's a little hard to compare that.

Q Well, I don't know what's hard about it. The others are dated -- were those 31-day rates on the rest of them?

A (Unclear).

Q Those 31? The gas/oil ratio, though, went down as production went up between June and July and August, is that correct?

A No, sir, the whole production stated about the same, 4548 in May, 4350 in July, 4240, it dropped in August, so it's production, oil production did not go up.

Q Well, I asked you in June, the oil production was 3320 --

A In June it only produced 24 days and you can't really compare it by days.

Q The -- on the Howard 1-8, the April production was 363 barrels, is that correct?

A Yes, sir.

Q And the gas/oil ratio was 6171?

A Yes, sir.

Q The August production was 8596?

A Yes, sir.

Q And its gas/oil ratio was 3233, is that right?

A Yes, sir.

Q And the Howard 1-11, the April production was 815 barrels that month, GOR of 7240, is that right?

A Yes, sir.

Q And its oil production in August was 5400 barrels and its gas/oil ratio was 5881?

A Yes, sir.

Q And your testimony is that when the -- when this shows the gas/oil ratio is going down with oil production going up, that's bad, and when this shows that gas/oil ratios are going up as production goes up, that's bad.

A Well, that's not quite what I said.

Q Okay. Was there any reason in putting in this blue sheet here on the Mallon wells, showing the uncorrected daily field readings and the corrected daily field readings?

A Oh, yeah, They corrected each of our daily rates by the final total volumes for the month. We tried to do the same thing for Mallon's. We didn't have the figures exactly for them but we used what information we had that was reported by days and then by the month and we recognize that that may not be an absolutely correct adjustment for the Mallon wells; however, I think it's insignificant insofar as this particular exhibit is concerned that one uses the exact amount of gas production (unclear).

Q You're not suggesting that Mallon was doing anything improper as far as these figures --

A Oh, no, no. We have to make those corrections on anybody's report.

Q Okay.

MR. DOUGLASS: Mr. Chairman, I will continue on but any time anyone needs or wants a break, I lose track of time sometimes.

MR. LEMAY: Continue on, Mr. Douglass.

Q A number of times when you were referring in your exhibit here to high allowables and high production rates, were you referring to the production that occurred under the normal statewide allowables that were applicable to this field?

A I was referring to the high allowables that the Commission set last -- last spring over the three or four month period in the fall.

Q When you refer ot those high allowables what you're really referring to is the normal statewide allowables for those wells, isn't that correct?

A No, sir, that's a high allowable but the normal allowable for this pool is what we're producing at right now. That's what was set by the Commission last (unclear). The existing allowable is the allowable.

Q Well, the existing allowable is actually a restricted allowable by virtue of an application that you made to the Commission or a request you made to the Commission, you've reduced it below statwide allowables, is that right?

A Well, it's the allowable that's in effect and I believe the order that set the high allowable said that would be a temporary allowable.

Q Well --

MR. LEMAY: I don't know if there's much to be gained by arguing relative high, low. I think the Commission knows what the allowables were and by charactizing them as statewide, high, low, average, I don't see any -- any -- where you're going on that subject.

MR. DOUGLASS: I just wanted to find what allowables are --

MR. LEMAY: I think we understand high and low and I think it's the same as your reference to statewide versus restricted; however you want to characterize them, they're -- they're numbers assigned to the wells and we know which ones they are.

MR. DOUGLASS: That's -- I wanted to make sure what (not clearly understood.)

Q Did I understand that you changed some equipment on your wells in order to produce at the test rates that were set forth in the Commission's order?

A Yes, sir, that's correct.

Q Do you find that -- that it's important to an operator to know what the allowable is going to be for the field in order that he can set the necessary equipment to produce that allowable?

A Well, yes.

Q Were you, by installation of this equipment, able to produce the higher volume than you had previously?

A Yes, sir.

Q Referrng to your surface pressures that you've used, is it your testimony that surface pressures are more accurate than measured bottom hole pressures?

A Under the circumstances of what we were -- made a survey, and particularly where the formation dips from -- from east to west, the only real significant area that would come about for these particular wells that were tested and have a gas column from the surface to the oil pay, would be the density and the pressure difference that would be a consequence of the fluids in the reservoir at different structural positions, and moving from east to west the structure drops to the west, and so if we made any correction at all there, for that part of an analysis, why then the -- the pressure gradient would be greater, and so what -- what we're saying here is that the way we took the pressures would show a minimum pressure gradient across this area. And for the reasons stated, it would be more accurate for pressure differences than the problems you get into trying to get bottom hole pressures.

Q Well, has it been your usual experience that bottom hole pressures are more accurate than surface pressures?

A It depends on what you're trying to determine.

Q If you're trying to determine the pressure differential between an area would you normally find the bottom hole pressures more accurate than the surface measured pressures?

A Not where we're dealing with 15 to 20 pound pressure differences; not -- not the kind of surveys there were conducted for these -- these surveys the Commission ordered.

You see, none of the wirelines are calibrated, the bombs weren't calibrated at the same equivalent (sic); no hole deviation taken into account; no surface elevation differences taken into account; the Amerada RKG-3 bombs that are typically used, we found that just the temperature correction itself at different times that we've had the bombs calibrated can be as much as 5 pounds difference. We subtracted 7 pounds from each of our measurements, approximately, to take care of the -- the effect of the pressure or temperature on the equipment, which is as accurate as we could do. But other operators, how they corrected theirs, we don't know.

But unless you have some kind of a standard, there's no way to take bottom hole pressures and expect to get pressure differences within 15 to 20 pounds when the bombs themselves are only supposed to be accurate within 8 or 10 pounds, and some not even that much.

Q Well, the bottom hole pressure bombs, this Amerada gauge type are 1/4 of a pound per 1000 feet.

A They're 1/4 -- some of them are 1/4th of 1 percent and some of them are a 1/2 a percent. I believe the ones that -- that were used here primarily were 1/2 a percent.

One percent on a 3000 pound element, see, is 30 pounds, and 1/4 percent is 8 pounds; that's the kind that was used on one well, so there's no just no way to tell pressure differences within a few pounds the way these surveys were conducted.

Q Let me ask you, I think the next section here is H, Did you have the -- this is a graph showing the pressure maintenance effects on shut-in wells B-32 and B-29. Is that is depicted?

A Yes, that's correct, the blue graphs.

Q That's the blue graphs?

A Yes, sir.

Q Well, now, let me ask, do I understand that the bottom graph there is the rate of pressure increase in September of '86 in the B-32?

A Yes, sir, that's the very bottom dashed line.

Q That well was shut in for 12 days?

A Yes, sir.

Q And was -- during that period of time was the rest of the field shut in?

A Yes, sir.

Q All of the rest of the field was shut in for those 12 days?

A Well, in our area. Now I think I mentioned that a gas plant was down for a substantial period at that time and a lot of Gavilan wells were down, so there was a minimum of pressure disturbances in the reservoir in September of '86.

Q Well, was this pressure only 806 pounds, then? That surface pressure was only 806 pounds?

A No, sir, the -- what I've shown on the bottom scale is simply the rate the pressure increased, not the pressure itself.

Q The pressure was substantially higher than --

A Oh, yeah, it was around 1400 pounds.

Q And the -- you show in November of '87, you show two lines of pressure increase --

A Yes.

Q -- for the B-32 and the B-29.

A Yes, sir.

Q And is that -- was that during the period of time that the entire field was shut down?

A Yes, the entire field was shut down for three days and we kept our wells shut in for another, oh, 8 or 9 days, as I recall.

Q Were there other wells producing from the field during that period of time?

A Well, some of the wells in Gavilan were producing and we had our wells shut in.

Q Isn't another explanation of the increase in pressure in November of '87 that the B-32 and the B-29, that they've drawn down to the point where they were building up from a pressure influx from an area west of what I've called the barrier or west of the pressure maintenance area?

came from the pressure maintenance project where we had like way up to 1700 pounds.

Q Well, I understand that's your feeling but my question is, couldn't that also represent an increase in pressure from the surrounding area?

A I think it's very unlikely. We found all the evidence so far that we studied is pressure drainage from east to west.

Q Well, you had the higher pressures in November of '87 on the Mallon acreage and higher pressure on the B-17 than you did at the B-32 or the B-29, didn't you?

A The Mallon acreage, I think, felt the pressure that time as significantly higher than the (unclear).

The Johnson well, which as I indicated earlier today, we found during studies in the Gavilan Engineering Committee, that it's an entire are and typically runs about 100 pounds higher than the rest.

Q Well, the pressure was higher in the B-17 area, also, wasn't it, in November?

A I don't remember. It would not be very much higher.

Q Well, if it's any higher in this real good rock that you're talking about here, it's going to cause an increase in the B-29 and the B-32, isn't it?

A And if it's higher it got its pressure from the pressure mainenance project (not clearly understood.)

Q The B-17 had been shut-in, hadn't it, hadn't been producing it?

A Yes, sir. It still reflects the pressure in the area.

Q But it's going to have a higher pressure if it's shut in if other wells around it are producing, isn't it?

A Well, it just reflects the reservoir pressure.

Q And I say, if it hadn't been produced, then it can reflect a higher reservoir pressure than the wells around it.

A But that would have no bearing, whether it's producing or not on the build-up of these wells here.

Q Let' me see if I understand what you're saying.

Out in the reservoir here, where I'm not producing and I have a well that is producing, normally the pressure is going to be lower where the well is than out in the reservoir where I'm not producing.

A Until the pressure builds up, yes, sir.

Q You mean until it equalizes?

A Till it equalizes.

Q So if I don't produce an area and I measure the pressure, then normally it's going to be higher than the producing wells in the area.

A Sure.

Q And the way it equalizes is the pressure goes down in the area that I'm not producing and comes up in the area I have been producing.

A The -- I would have to look at the B-17 pressure and compare it with the B-32. My recollection is that there was not any substantial difference in pressure.

Q Well, it doesn't take much pressure at all in this good rock that you're talking about to cause a slight pressure increase, does it?

A No, but, Mr. Chairman, in order to determine if there is a pressure difference, a small amount, we'd have to go at it in some other way than the way these pressures were taken.

Q Well, on the blue graph here, you're talking about small pressure increases, aren't you, 6, 7, 8 pounds?

A Right, and I show how to determine small pressure differences. We can determine it but not by bottom hole pressures, which was what you were preparing to do.

Q I know, you've used the more accurate

surface pressure.

Q For this purpose, yes, sir.

Q Let me go to Tab I. Now, as I understand the heading you say here is that this is evidence that because of the gas/oil ratios in the expansion area, because they're lower than the Gavilan pressures -- excuse me, Gavilan gas/oil ratios, that's evidence that your pressure maintenance expansion area is in communication with your present pressure maintenance area.

A No, sir, not that they're lower than Gavilan; just that the low level that they are would be associated with something other than a solution gas drive and that something other would have to be gravity drainage or pressure maintenance, or both.

The comparison with Gavilan was simply to show the efficiency of recovery by comparing one area against another.

Q Well, what -- the area you're comparing on this exhibit, as I understood, the statement, you say on the average, these wells, you're -- are you talking about your pressure expansion area wells?

A Yes, sir.

Q These pressure expansion area wells show substantially lower GOR's than the adjoining Gavilan wells. Do you mean the entire field, entire Gavilan field, or pool?

A On the average, yes, sir, I think that's what we plotted.

Q You haven't compared it with the wells that are adjoining, in the two sections adjoining this area, have you ?

A I took the average of Gavilan and the average of each well.

Q And then you're saying bacause the GOR on the F-18 is slightly above the solution ratio, that that indicates that it's in the pressure maintenance area as opposed to being in an area out here by -- in the -- in an area connected with Gavilan and not connected with the injection area?

A No, sir, I'm not saying that at all. Mr. Chairman, there is a high degree of communication between Gavilan and West Puerto Chiquito. There -- there's just no question about that, and I do not intend to imply that.

What the lower gas/oil ratio shows, so far, and we've only found that low gas/oil ratio in the C zone in this area, and that low gas/oil ratio means to me that it's not in the C zone; it means to me that this is showing gravity drainage; it means to me that it's getting help from the pressure maintenance project.

Q Did you measure pressure in the F-18 Well?

A I don't believe we did.

Q In this area of pressure maintenance -- excuse me, in the expansion area, have you never measured a pressure in the C zone versus a pressure in the AB zone?

A As near as we can tell in that area, very little; they're probably the same.

Q My question was have you ever measured, wasn't it, between the C zone and the AB?

A No.

Q Were you requested during this pressure survey area to make that kind of pressure survey to see in the C zone and AB and see what -- if there was a pressure difference?

A Yes, sir. I think it would be an exercise in futility since each of these wells are fraced in all three zones and the odds are that they probably are tied together in some way with the fracture system, and even though they're segregated, it's very unlikely that we should run a pressure and find a difference. But not only that, we know that reservoir wide that the zones are tied together and so it's only reasonable to assume that the pressures are about the same.

Q Are the -- are the wells in the proposed expansion area generally lower structurally than the Gavilan wells?

A Yes, sir.

Q Under a solution gas/oil ratio producing mechanism you would expect the lower structural wells to have the lowest gas/oil ratio relative to any time in the producing life of the reservoir.

A No, sir.

Q Why not?

A No, sir, a solution gas drive, you expect the gas/oil ratio to be the same regardless of structural position.

Q When this gas comes out of solution in this reservoir, where does it go, Mr. Greer?

A There is -- we're non-solution gas drive and it segregates by gravity, which I contend it does segregate by gravity and the others contend that it does not segregate.

If you have segregation, then you have the wherewithal to have gravity drainage and efficient gravity drainage recovery, and I'm convinced that in Gavilan there is some gravity drainage recovery. There's no way, no matter how bad the reservoir is abused, there's going to be some gravity drainage, and that's evidenced by -- by gravity segregation.

Q In a solution gas drive reservoir with the pressure below bubble point, would gas come out of solution in the reservoir?

A Yes, sir.

Q Where does that gas go when it comes out of solution in the reservoir?

A To goes to the wellbore.

Q All of it goes to the wellbore?

A Yes, sir, that's typical of a solution gas drive reservoir, Mr. Chairman. It makes no difference the rate at which you produce it, how you produce it, a solution gas drive reservoir will give you the same gas/oil ratio and if -- if the gas segregates and goes to the top of the reservoir (not clearly understood), then again you have gravity segregation and potential for gravity drainage recovery, not solution gas drive.

Q Well, of course the gas moving structurally high in a solution gas drive reservoir is a natural phenomenon in a solution gas drive reservoir, isn't it?

A No, sir, not unless you have gravity segregation, it is not.

Q Well, when you say gravity segregation, oil versus gas is gravity drive, isn't it gravity segregation?

A No, sir. Mr. Chairman, the engineers have a clear understanding of solution gas drive and a solution gas drive means that the gas and oil mixed together move to the wellbore and there is no way for gas to segregate and to move up structure or to move down structure, unless you have gravity segregation.

If you have gravity segregation, you can have gravity drainage, and to whatever extent that happens, then you moved from solution gas drive to gravity drainage.

This is the thing that we've seen in this reservoir and we'd like to take advantage of it and have tried to operate over these twenty years.

Q I just want to make sure that your testimony is that in a solution gas drive reservoir if you get below the bubble point and the gas comes out of solution, it all moves to the wellbore and none of it moves structurally higher than its current position.

A That is right. The permeability is so low, Mr. Chairman, that the gas and the oil can only move one direction and that's to low pressure.

If it segregates and goes up structure, then you have gravity segregation. It's just that simple.

Q The permeability of 10 darcy feet to 50 darcy feet is not going to be much of an impediment to fluids moving, oil or gas.

A No, that's our position, that this reservoir has high enough transmissibility for gravity drainage, gravity segregation.

Q Well, if you have that in a solution gas drive reservoir, structurally you expect the lower structure wells to have the lower gas/oil ratios.

A No, sir, we've been over this two or three times. That's not the way a solution gas drive operates.

Q In -- I believe we're in Tab I and I see here a plat with a sideways pyramid, brown and blue.

A Trapezoid, is what I call it.

Q Trapezoid, all right. Tell me what that trapezoid is.

A Well, Mr. Chairman, I'm sorry that I can't -- have not properly explained these exhibits when we went through them.

Q Well, I think the chairman is smarter than I am. That's why I'm asking; I want to make sure I underestood what you said.

A Okay. My assessment, Mr. Chairman, is that the movement in this area, underground movement, moves from east to west.

When we take the amount of oil that the B-29 and B-32 have produced and recognize that it's coming from the east, and then make just an approximate assumption as to percentage recovery and oil in place per acre, and gravity drainage, approximate, and put that oil back in the reservoir, I recognize whether it's either 2/3rds depleted or 1/3 depleted in that area, we come up with a substantial area that has had to supply oil to those two wells and that substantial area is back up into the existing project area, and the point of the exhibit was to show that the production from these wells is not coming just from the wellbore or just from the 40 acres around it, but very probably is coming from, it's coming from the present expansion -- or present project area and doing just exactly the way we expect recovery wells to do, to pickup oil from the intermediate area where we have only one well for three or four sections.

Q Mr. Greer, you show no drainage from the west to the east in the B-29 and B-32 wells, is that correct?

A Yes, sir. From east to west I show drainage.

Q I was going to say, you show no drainage from the west to the east --

A No.

Q -- of the B-29 and B-32.

A No, most of it's coming from up-dip.

Q I see, I understand you say -- feel that way, but what keeps the B-29 and the B-32, these very good wells, from draining from the west?

A Gavilan.

Q Unless the pressure is lower in the B-29 and the B-32 than it is to the west, it will be draining the area to the west, is that right?

A I don't think the pressure is higher to the west.

Q And it --

A Not in any, excuse me, not to any -- any significant part of the reservoir. There are isolated wells and tight, tight spacing units that will show a higher pressure but that doesn't mean that the area as a whole is draining to the east.

Q And as I understand it, what you're really saying here is essentially all of the drainage that's occurred in the B-29 and B-32 well, all of the oil that is produced has come from the east of those two wells?

A Well, of course (not clearly understood) I guess, my opinion is that most of it, you know, there's 10 percent or 20 percent coming from the wells fraced west of it, but by and large the source of build up is just like we had planned with this pressure maintenance project, it's up-dip from the recovery wells.

Q If there is a barrier to flow to the east of the B-29 and the B-32, that would mean that the drainage area that you show here would have to be west rather than to the east, wouldn't it?

A If it was an effective barrier, and if there were no other indications of directional flow.

Q Let me turn to the next tab, J, I believe you've already mentioned the 34 well, anyway, in the pressure data. Do you have a graph on that?

A Yes, sir.

Q Is it your conclusion that the C-34 represents a reflection of the injection and pressure maintenance areas?

A Well, I think this graph shows the reflection of both production and injection.

Q It does not show -- this graph, pressure graph of the C-34, does not show communication with wells to the -- to the west, does it?

A Well, it's not a one-on-one test like we had with the -- with the frac pulse tests. The fact that the pressure drops, it appears to me it has to come from -- from production or from withdrawals from the reservoir and as I indicated earlier, the reason that we market some gas is in order to get some kind of reaction in the reservoir that otherwise would not show if we were just putting as much gas in as we're taking out.

Q Well, is the answer to my question that this pressure graph alone does not show any communication with wells to the east -- excuse me, wells to the west?

A It shows communication with the wells; we just can't identify which wells and it appears to me that production or withdrawals is from the expansion area and that that almost has to be the cause of it.

Q I'm sorry, would you repeat that answer?

A Well, like 3/4 to 90 percent of the production that we have taken from the wells has been from the expansion area and so I would assume that the -- the pressure decline in this well is a consequence of withdrawals since most of the producing wells, or most of the production is in the expansion area, it would just be my assessment that that's probably the cause.

Q Well, in the -- in the August and September period that you have here, didn't you have a very relatively small amount of injection in the --

A Yes, sir.

Q -- injection wells?

A Yes, sir.

Q And your pressure was going down.

A Yes, sir.

Q Let me go over to D-17. Is the -- is the time that the pressure starts -- first of all, the pressure is declining in the D-17 prior to the beginning of this test, is that right?

A Yes, sir, we're looking at the green

sheets under Tab J.

Q Yes, sir.

A The wells are producing on the down slope there.

Q And that means that the wells in the pressure maintenance -- excuse me, in the expansion area, or the Gavilan area, were causing the pressure to decline in the B-17, is that correct?

A Well, that would be my assessment, yes, sir.

Q Now, when the pressure starts increasing, is that when all the wells in the field were shut in?

A Yes, sir.

Q And it continued to increase until when? I get November, about November the 21st?

A I think (not clearly understood). I forget how long (not clearly understood) but something like that.

Q And was that -- when were --

A Pardon me?

Q When were the wells returned to production, do you recall?

A Yes, sir. That's a -- I would consider a typical interference effect.

Q And that interference affect -- the expan sion area wells and the Gavilan wells.

A Yes, sir. I think I made some rough -- rough calculations that (not clearly understood) -- that I believe part of the -- that pressure decline very well was caused by Gavilan --

Q The D-17 pressure alone does not show communication of that well with the pressure maintenance area, does it?

A Not in itself, no, sir. Now those, those -- those curves, I think, tend to reflect more just interference of production and shutting in. That's what our analysis showed.

Q Did the bottom hole pressure survey on the C-34, as you described it, that was a bottom hole pressure bomb you were describing that you called "an amazing instrument", wasn't it?

A Yes, sir. Yes, sir, if we had all of the bombs like that for our survey, we might be able to show up some pressure differences across the reservoir.

Q Let me ask you about Item K here in Exhibit One.

A Yes, sir.

Q If the -- if your application -- first of all, do you know about what your oil production is per day under the restrictive allowable in this pressure maintenance expansion area?

A It seems to me it's in the range of 1500 and 2000 barrels a day. I'd just have to get, you know, the records out and look at that.

Q That -- I think that our calculation of one month is around 1732 barrels. Does that sounds in the range of what you're talking about.

And on the -- on this Exhibit K, or Tab K here on the gold sheets --

A Okay.

Q -- it may be an appropriate color; does that show the daily rates you could produce those wells in the pressure maintenance -- in the proposed expansion area if this application is granted?

A I believe so. The -- there might be some pressure declines since November; a more realistic figure is probably 2500 barrels of oil per day.

Q It shows about 3176 barrels a day, is that right?

A Yes, sir. I'm not sure that it still has that capability.

Q And, for instance, the B-29 well, it's 1066 barrels, it, if this pressure maintenance expansion area is granted, even though its normal allowable would be 800 barrels a day, under the rules that you have in effect for your unit, you could actually produced 1066, couldn't you?

A Yes, sir, we could. Our practice, however, is again not to do that. The only time we got to produce wells at that high a rate was in cooperation with the Commission here in trying to analyze the reservoir, high and low rates of production.

We have never produced these wells at their full allowable. I just don't believe in that.

So the answer is we would not produce at 3000 barrels a day.

We would not produce the B-29 at 1100 barrels a day for a 30-day period. We might produce it for half the month and average maybe 5-or-6-or-700 barrels a day, but we would not pull it that hard.

Unless, there's only one (not clearly understood) and unless, that's unless we're -- we're losing oil to Gavilan and we have to do that to protect from drainage. That would be the balancing thing that I hope we don't have to get into.

Q Well, if you, have you made a study to determine what the relative producing rates are between the first two rows of sections on the Gavilan side versus two in the proposed expansion area?

A No, sir. Of course it depends on whether we continue with the existing allowable or not, and if we do, why, then our threat to drainage is minimized as compared to high rates of production and, if so, then we can slow, slow our producing rates down.

Q But you're going to be the one to make that decision.

A Well, --

Q You, Mr. Greer.

A -- I'll probably get some help from some of the working interest owners.

Q But you have no -- under your proposal you have no allowable limitation to keep you from producing 3176 barrels of oil a day.

A If we injected all the gas.

Q Is it -- is it a requirement that you inject all the gas or that you inject all the gas above 600-to-1?

A To get the full allowable we have to inject everything above 600-to-1, yes, sir.

MR. DOUGLASS: I'm going to holler uncle this time, if that's (not clearly understood).

MR. LEMAY: Are you suggesting that we take a break so you can analyze the other two books here, Mr. Douglass?

MR. DOUGLASS: Well, I'd like

to do it for two purposes but that's one of them.

MR. LEMAY: We'll break for twenty minutes.

(Thereupon a twenty minute recess was taken.)

MR. LEMAY: Shall we resume?

Mr. Douglass?

MR. DOUGLASS: Thank you, Mr. Chairman.

Q Let me ask you to go to Exhibit Two, if you would, Mr. Greer, and the first page I see in there, I believe is a structure map under Tab Intro, and I believe that you -- this is a previous exhibit that you have.

A Yes, sir.

Q Before I believe you connected up some of these wells in the green here to the wells in orange or gold, is that right?

A Well, in Exhibit Two we show some of the connections, yes.

Q Not on this one.

A No, sir. That represents what we had earlier provided to the Commission.

Q Well, for most of the communication that you show in the gold area here, or orange lines, are those shut-in type interference tests where you produce one well and shut-in another, and that type of thing?

A Well, as I recall, they were -- they were different. I'd have to go back to our earlier exhibit to identify any one issue or points. The O-33, let's see --

Q Well, I didn't want to go to each one and identify each one.

When I read the transcript of the two previous hearings and looked at the exhibits, I thought that what you indicated here, that these were not frac type interferences but these were --

A Oh, I -- yes, sir.

Q -- pressure, what we call normal or usual pressure interference tests where you shut in one well or all the others and produce another and see if you get pressure effects.

A I believe most of these, let's see, the interference tests that we ran are not shown on here. They were in addition to what's shown here.

The tests that are indicated here, all right, for instance, the C-34, the well that I believe we've said produced 3-or-4 BCF, we felt like there was no way that that C-34 well has produced that volume of the gas with no more pressure decline than it had, and it took at different times the amount of pressure decline and the amount of gas produced and there's no way that that could come about without that well receiving support from the gas injection wells.

Q All right, maybe I can approach it this way. Are there any of the wells that are connected by the orange or gold here that represent frac type tests, interference tests?

A Not -- no, none of these are frac pulse tests.

Q Now, as we go to the green wells on this same --

A Okay.

Q -- thing, are any of those interference tests that are shown here the frac type tests?

A Yes, certainly. The lower set of green solid lines are one of the frac pulse tests and they're -- and that particular test is covered in the red book.

Q Okay, that -- that's an old test, one that you had put on at the last hearing.

A Yes, sir.

Q And it was a frac type test?

A It was a frac type test.

Q Now, in the earlier exhibit that you put on, didn't you have a dashed pink line between the green B-32 and the orange C-34 wells, do you recall?

A I believe we have that in one of the exhibits and I think we showed the exhibit following that or it was probably done in one of those trapezoids, but I don't recall for sure.

Q All right. Now in your Exhibit Two here under Tab B, is the communication which you say occurs there from a fracture treatment?

A Yes, sir, that's a sand fracture.

Q It's not -- it's not what you engineers would normally call an interference test.

A No, no, sir. No, sir. This is what we call a frac pulse test, the kind of test the Gavilan Engineering Committee recommends we could look into, and did do, in cooperation with Meridian on one test and Dugan on another and two of the unit wells on another ( not clearly understood.)

Q This test, the C-34, the B-29 and the B-32 would be across what my client has indicated is a barrier.

A Yes.

Q I want to visit with you about what's happening in this area.

As I understand what you've done here is, on the blue graphs here, you've shown on the B-32 and B-29 when you thought the frac responses were present, is that right?

A Yes, sir.

Q Now, wells can have responses as far as pressure build-ups or drawdowns are concerned because of things other than the well being fraced, can't they?

A Oh, yes.

Q Could be other wells going on production.

A Yes, sir.

Q Other wells going off production.

A Yes, sir.

Q Faults.

A Sure.

Q Permeability barriers.

A Yes, sir.

Q Any type of reservoir limit that might restrict the pressure.

A Yes, sir.

Q Going to the first graph --

A Oh, excuse me, sir, there has to be communication between two wells to -- for that to occur.

A I understand. Now, let's see if I understand the blue graph here. When do you show the first response that you call frac response?

A In time in terms of days we might ought to look at the next book. This frac is in logarithm, logarithmic scale.

Q Do you want to --

A It may be easier --

Q Do you want to refer to another book now?

A Well, in order to get away from the logarithmic scale it might be simpler.

Q Well, I didn't know that I needed to be that precise.

You show a line here and then you show a separation of circles. Did it appear that it occurs within --

A Well, it's about a fourth of a day.

Q About a fourth of a day. Okay, that's good enough for me.

And timewise it occurs in about, what, roughly 3-1/3, 3-1/2 days from the shut-in?

A Yes, sir, a little better than three days.

Q Three days plus. Now, if I were to look back on that B-17 pressure build-up, would it have -- would it's curve look something like this that you have with the pressure build-up on that B-17 that we had back in Exhibit One?

A Well, the B-17, if I recall was not drilled at the time of this -- this test.

Q I'm saying it may not have been drilled but I was talking about the shape of the -- of the pressure increase, there's a curve, build-up at the end there, didn't it?

A Are you going to talk about another one of the frac pulse tests that the --

Q Nope.

A -- B-17 was in?

Q Nope. Not -- just a normal -- as I recall you ran a shut-in pressure in that well in November, a bottom hole pressure.

A Yes, sir.

Q And you have it build up at the end .

A Yes, sir.

Q And the curve at the end was building up higher than it was to begin with.

A Yes, sir.

Q Isn't that what's generally happening here as far as the B-32 is concerned?

A Well, we show now how the response happened in the B-17 in the frac treatment and in this instance, you know, we had all the wells in the township shut in.

Q Well, the pressure survey we discussed on the B-17 in Exhibit One was not from a frac response, was it?

A The -- the comparison, Mr Chairman, that needs to be made for the point under discussion here now, is the difference in the pressure build-up as a consequence of the frac pulse and for comparison we have a build-up not necessarily on another well; we have a build-up this well and it's the one on -- the lower graph on this page. Let's see, the blue graph, it says a Response to Frac Treatment of the blue graph. It says Response to Frac Treatment of the C-34. As a consequence of the frac treatment in the C-34 and we can see a build-up curve and the B-32 was shut-in in January of 1987. It has a very straight line.

Let's see, have you found the graph?

MR. LEMAY: We're on the C-34 now or the --

A Yes, it says Response to Frac Treatment on COU C-34 on the bottom graph, and Bottom Hole Pressure Build Up Survey Well COU B-32.

Did you have the right graph?

MR. LEMAY: Okay, we had that, yes.

A On the lower -- the lower line shows how a pressure build-up in this particular well as a consequence of shut-in following production, and it's very clearly a straight line and for the same -- it was shut-in for about five days. We can see that at the point where the frac response starts on the C-34, on a similar test just about a few weeks later, it does not follow that same straight line. It deviates and it deviates because of the interference from the frac treatment.

So, Mr. Chairman, we'll have to go to another well to see what would have been the pressure build-up we had (unclear).

Q Let me ask you, Mr. Greer, you haven't prepared what the producing rates were in January of '87 or the producing rates in April of '87 on the B-32 well, have you?

A I don't show it here but I did check it out and they were approximately the same.

Q And did you check the production in the rest of the Gavilan and the proposed expansion area to see what the production in that area was over both periods of time?

A We had all of our wells shut-in, the whole township.

Q In what periods of time?

A Through the period of the test.

Q Each time?

A Yes, sir.

Q Is this the -- is the -- is the time sequence the same here on the B-32 in January of '87 or is it --

A Yes, sir, the bottom scale while we're in the Delta T is the same; same, so we have comparable graphs.

Q All right. Then with reference to the frac response that you had, is this the fracture treatment that was done on the C-34, you actually fractured the reservoir over a substantial distance, is that right?

A Well, the service companies, Mr. Chairman, will -- will tell you that they can get a frac out 1000 feet, 1500 feet, or whatever. We don't know what happens in this fractured reservoir, just how far it goes.

The assumptions that we've made so far is that I feel like in general they probably do not exceed 1000 feet and that's where we come up with 1/4th of that distance or a 250-foot effective wellbore radius. But just how far they go, it's a little difficult to -- to tell.

The classical theory on it apparently just doesn't fit this reservoir.

Q If you've got a well two miles away that was fraced you could see the response in approximately a quarter of a day, is that right?

A Yes, sir.

Q (Not clearly understood.) Now the next well is also a frac response, you say, from the same fracture treatment, is that right

A Yes, sir. We had a bomb in both wells, when the well was treated and the C-34 was treated.

Q Is this B-29 well farther or closer to your --

A This was a little bit farther.

Q And the pressure response there is about, what, about a half a day, roughly?

A Yes, sir, something like that, yes, sir.

Q Again you get a -- a well's been shut-in about two and a half days when you get a response, as you call it.

A Well, we -- we deliberately plan it that way. You see, Mr. Chairman, these bombs with the (unclear) they have, have about a six-day maximum that we can rely on getting pressures, so in designing a test like this we have to -- have to figure approximately how to allocate that six days and the way I've done it so far, it should take two or three days prior to the -- to the frac treatment that we shut the well in and run the bomb, and then we do the frac treatment and then that gives us maybe three and a half, four days, after the frac treatment to pick up the response.

That's really a tricky situation if we have bad weather and we have a problem, maybe, gettng a frac job off exactly when you plan it.

In this instance, as I recall, we -- we managed to do it about -- well, about that procedure, so in round numbers that's how and why we do it the way we did it.

Q Do you have the pressure information prior to the bomb time of 51 hours, for instance, on this B-29 well?

A Well, I think so. I imagine we provided it to you people along with everything else.

Q You think we already have it after you provided it to us?

A I think so.

Q And the same would be true on the data on the C -- on the B-32 well --

A Yes, sir.

Q -- prior to the time of 20.8 (sic) hours?

A Yes, sir.

Q Was there any change in the curve in the early period of time on these two shut-in wells?

A Oh, I don't remember. The -- what we tried to do is fit the information on our graph here and it's a question of whether you start on one end or the other, and we -- I think we balanced it out with the last pressure on the righthand side of the scale and we ran it as far back as the graph would go.

Q Did the pressure response that you say here, frac response, have been from a permeability barrier in the reservoir?

A I don't -- I don't see it that way here. Ordinarily you have a 2-to-1 slope in a case like that and I haven't measured that and just looking at it, it's not a 2-to-1 slope, so I don't think that's --.

Q How about a well being shut-in in the reservoir? It doesn't give you a 2-to-1 slope or increased well communication, does it?

A I don't know what you're saying.

Q Well A is producing and Well B is shut-in for a pressure --

A Okay.

Q -- test, when you shut in Well A, through communication you should see an effect --

A Yeah, right.

Q -- on the pressure.

A Yes, sir.

Q And it's not a 2-to-1, is it?

A Well, we're not talking about a boundary there.

Q Let's -- let's go to -- D is the A-16 frac and you measured it in B-32 and A-20, is that correct?

A Let's see, under which tab now?

Q D.

A D, like dicker?
Q D, as in dog.
A D, as in dog. Yes, sir, that's the A-16 frac. We observed it in the A-20 and the B-32.
Q Now, there, on your -- on your graph comparing it to the B-32, how quickly did you see the frac response according to what you indicate there and timewise?
A Well, it's like another, oh, a fraction of a day.
Q Quarter of a day?
A Something like that.
Q Now that -- that well is about, almost three miles away whereas the C-34 is approximately, what, a mile and a half to a mile and a quarter?
A The C-31 is about two miles, maybe --
Q Two miles?
A -- two and a half to the B-29.
Q I thought we were talking about the 32, I'm sorry.
Am I off a well?
A Well, I was comparing the C-34 and the B-29 frac with the A-16 and the B-32.
Q Well, that wasn't what I was comparing.
A Oh, okay, two different things there.
Q All right, I thought you -- I thought we

were comparing A-16 with B-32.

A Okay.

Q And that distance is about three miles.

A Okay, yes, sir.

Q And the B-32 to the C-34, according to what I see here, is about a mile and a half to a mile and three-quarters.

A Well, it's 10,400 feet. That's very close to two miles there.

Q It's about two miles. All right, and when the -- and you got a response in about the same period of time, about a quarter of a day, is that right?

A I was thinking we got a quicker response on the north/south line than we did the east/west line, but I'm not -- I'd have to look at the information to be sure.

Q Well, I thought you looked back at the -- I guess it's D, isn't it?

A Yeah, I think we're just kind of guessing at a quarter a day. There's probably not that much difference.

Q All right, sir. And then the -- timewise what are we looking at from the time of shut-in? Again about three plus days?

A Okay, now are you looking at the A-16 and the B-32?

Q Yes, sir.

A Yes, sir, shut-in about a little over three days at the time of the frac, and ran it out to again about six days, the same method as before.

Q All right, under Tab E would be the A-20, is that right?

A Yes, sir, the A-20.

Q When you fraced the A-16 this is the pressure graph in the A-20.

A Yes, sir.

Q Again this time the A-16 is closer, excuse me, the A-20 is closer to the A-16, isn't it?

A Yes, sir.

Q And what is its time to get the frac reaction according to your frac response?

A I'd have to run a -- it might be a little bit longer than the other one; looks like, oh, maybe half a day. It's a little hard for me to see it on this small scale.

Q Okay, closer but it took longer.

A Yes, sir. I think that's typical of our north/south running probably higher than the east/west.

Q Okay, and you show here some cross flow.

A Yes, that's my interpretation, yes, sir.

Q You mean cross flow in the A-20 well?

A That would be cross flowing between the A, B and C zones within the A-20 well itself. That -- we found that to be the case when we fraced the well and the pressure bleeding off during the frac. It kind of looked like we had cross flow in it then and that's why I've observed it here, because of the erratic pressure behavior here after it leaves that upper dashed line.

Q The rest of the pressure tests, or the rest of these still are frac tests and they're between wells that would all be in the pressure maintenance -- excuse me, in the expansion area, is that correct? In other words, starting with --

A Yes, sir, the F-7 frac and the B-17 and the A-20; the A-20 to the B-32 and B-29, yes, sir.

Those two wells, the C-34 and A-16 are the only ones we had available for workover in the AB zone, so they're the only wells in the unit we could use to make such a test.

Q Turn to Tab I, if you would, please, sir.

A Okay.

Q As I understand how you deterined whether it's been frac response, or any kind of a response is a slope change, is that correct?

A Yes, sir.

Q Looking at the beginning of this graph that you have here, it says 4.3 over there.

A Yes, sir.

Q Isn't there a slope change from about 4.3 as you go to a little over 4.42, I guess it is, from there compared ot the, oh, from about 4.43 to roughly 4.8?

A Yes, sir.

Q All right, sir. And you haven't identified that as what that slope change was, is thqt correct?

A No, sir, it's not very much of a change. It would be -- whether that was just the well leveling off or what, we didn't feel that was signficant.

Q Do I see at the -- where you say the frac of the F-7 started, isn't there a slope change prior to the time that that -- you started pumping F-7 frac there?

A Well, I'm not sure. You can see how that pressure ranges around there. It appears to me, and my analysis of it is that a straight line from the lower lefthand set of circles up through that part, it just makes sense to me is that that's the -- what we're looking at there, of course, is 2-or-3/10s of a pound difference in those points that are relatively below the -- that dashed line. I think it's just a question of the first pressure that we measure there appears to be like, probably, within minutes of the frac treatment it's pretty hard to follow that in a graph.

I imagine if we go back to the particular pressure survey and we have noticed frac responses within -- within minutes rather than hours, I think that could very well be the case here.

Q The pressure that you're measuring here is in the B-17, is that right?

A Yes, sir.

Q And do we have the pressure data prior to 146.5 hours, did you furnish that to us?

A Okay, that's bomb run number 1 and it shows to be, well, it's the D-17 for -- let me see if I can find the schedule.

We show a run from November 7th to November the 12th; then we have another one from 11-13 to 11-21, so you have that bomb run.

Q The bomb run that's shown here like 1009 and the bomb run 1008, does that mean that's the total number of bomb runs that you've made for the unit or is that the total number of bomb runs in this well?

A No, it's not really very significant of anything. I thought at one time that we would try to keep the bombs identified by bomb runs and then I decided it was better to start out again by the wells, and so it's kind of mixed up. About all it is, is the identification of them so we can go to our files and find a particular run if we need to.

Q And then it wasn't -- do you have a tabulation that shows the previous bombs (unclear) what well they were run in or --

A We can -- we have like, here we see 1009, we can go to our files and pick out 1009. You see, that's what we had to do to provide you with copies of the runs. The blame things, Mr. Chairman, are a bit of a problem to file. They come of on this perforated computer paper and that's the way our girl files them. To take that out and make xeroxed copies of them is really time consuming and so what we did when they asked for our pressure surveys, we just went back and pulled the disks out and run them through the computer again and just run out an original print for them and then from that, from that print we cut off the tails and all that and stick that into a Xerox and without having to tear up our files.

And so what I'm saying is that if we need another run or we find a run that's incomplete, why, we can reproduce it, but my feeling is that you probably got complete runs.

Q Well, I was just asking about your system, Mr. Greer.

A Yeah, I'm afraid it's not a very good system.

Q Let me go to Exhibit Three, Mr. Greer, and let me get you to turn to the Summary of Four Frac Pulse Tests.

MR. LEMAY: Will you identify that for us?

A Yes, it's the last two pages under Section A.

Q All right. Excuse me, it was Tab A, that's right, I'm sorry.

I'm sorry, Mr. Chairman, I didn't get the right tab.

MR. LEMAY: It's all right, we got it.

Q Mr. Greer, if I understand Item 10, that's the average transmissibility between those two wells, is that -- each of the two wells at the top of the hearing there?

A No, sir, this is where we have a difference in interpretation.

The interference test was (unclear) we say that transmissibility represents the characteristis of the formation in the colored area, not between the two wells.

Mr. Chairman, we put on an exhibit the first time in 1969 that in which we showed that you could completely excavate the material of the formation between the observation well and the treated well, or the test well, and there will be very little difference in the pressure in the observation well if you take as much oil out as an interference test, typical interference test where you're producing the well as it would be with the formation in place and the reason for that is that the area of the formation that influences this test, as the time of the test goes on gets larger, and it's a substantial area as we have colored in here for these different tests.

Q Maybe I can get at it this way, Mr. Greer.

Would that be a minimum average transmissibility between the two wells?

A No, sir. What that represents is an average of the characteristics of the area. Between the two wells you might have a high capacity, you might have a low capacity, but the area in general -- and that's not homogeneous, not necessarily homogeneous, not necessarily uniform, it represents the average and, of course, you know, you can have some niceties of what's the shape of the area and how that affects it, but in general, as I discussed this morning, if part of the area is not productive, there turns out to be again another averaging in which if you use the calculated oil in place per acre and the area that you've estimated, then, your total volume would be the same, even if half the area is completely nonproductive.

It's just one of the characteristics of EI formula that the interference test (unclear.)

Q Well, between the C-34 and the B-32, which is about two miles.

A Yes, sir.

Q Between those two wells there is an average transmissibility of 48 darcy feet on the average for whatever area those wells are draining.

A That's right. Kh/u 48 and you come up with Koh of about 14 darcy feet.

Q Does that necessarily tell you that those two wells, though, were in communication with each other?

A Oh, yes, sir, they're in communication but it does not tell us that there's 14 darcy feet in a direct line between the two, in fact I don't think there are.

As I indicated earlier, I think we have directional permeability. There is directional permeability north/south and my own feeling is that it's probably higher north/south than it is east/west.

So it should be substantially less in an east/west direction.

Q And each, and the C-34 and the B-32 have both been hydraulically fraced.

A Yes, sir. The C-34 was hydraulically fractured in the C zone years ago; just recently for this test in the A and B zones and the B-32 was fractured in all three zones, and so there's that little bit of a difference, the treated well in the two zones and the observation well in three zones.

Q Let me ask you under Tab F --

A Okay.

Q -- the green sheets.

A All right, sir.

Q This is the Ei function here, is that right?

A Yes, sir.

Q Up at the top there it says the value of q, barrels of fluid a day, 95,040, barrels -- BFPD, is that barrels of per day?

A Yes, sir, and that's -- that derives from the injection rate of 66 barrels a, which is the first -- the first line and so in this frac pulse the injection rate is 66 barrels a minute and we show how we modified one of our other programs to come up with this frac pulse program.

And the third line from the bottom of the information up at the upper righthand side, it says the days shut in, .071.

Okay, that's not the day the well was

shut-in, that's the day that -- or the time that the frac ended. The frac lasted for 7/100ths of a day, It would be an hour and a half, or something like that, and so rather than deal in barrels per minute, why we're dealing in barrels a day. Our pulse then lasts for (not clearly understood) into calculation.

Q Mr. Greer, the 95,040 isn't reflective of what's being produced from any well in any of these areas, is it?

A Oh, no, Mr. Chairman, I hope I didn't mislead anybody when we first talked about frac pulse test.

When a well is fraced we know that the formation opens up when it's fractured and we pump into it at a much higher rate than we could with just pumping without fracing the formation.

Now that last (unclear) as indicated here 7/100ths of a day, and once you're finished pumping, then almost instantaneously the fracture closes and the pulse that moves through the reservoir is then back to a normal type of -- by normal I mean comparable to a normal pulse test and in a way it moves in the same fashion as it would had the injection been at a lower rate for a longer period of time without fracturing.

Q What you've just described is not the flow of fluid through a forced medium is it, the fracture opens and closes?

A Right, the fracture opens, the pulse starts, the fracture closes, and then the pulse continues after that 7-or-8/100ths or a 1/10th of a day, whatever otherwise had been induced by a normal test. And for that reason, Mr. Chairman, I should point out that in each one of these tests we show the frac response in the observation well quicker that we would have calculated it, and we think that that's one of the reasons that this pulse gets out into the reservoir a little quicker in the high capacity system than it would be if it was just an ordinary interference test, and we found that in each one of the tests. That's why we dont' try to match the curves in the early part of the test, for that reason because we think that does not validate the rest of that pressure flow through the reservoir. It's not in balance.

MR. DOUGLASS: I don't have any further questions. We do offer Mallon's Two.

MR. CARR: We have no objection.

MR. LEMAY: Without objection Mallon's Exhibits One and Two will be admitted into evidence.

Additional questions of the witness?

Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Greer, in your Exhibit Number One under Tab G, we have the multi-colored Isopach.

You started quoting the pressures from the east side of the unit to the west side of the unit. Did you also take a look at the pressures as they continued through the Gavilan further west?

A Oh, no, sir, we just had our man measure wells every day from our wells.

We do not try to make a -- to get over in Gavilan. We might have lost a little of the validity of the test to go back up dip. By confining our surveys to the area in which the formation dips from east to west, then we have a minimum pressure gradient.

We come back up dip then to the west, why, you might have another slightly different situation. I think not much different, and it probably would have been good to (not understood) than to carry the thing on across.

Anyway, we did not.

Q Did you examine the pressures that were taken during the Commission required testing procedure and compare them as to how they would appear in the Gavilan Mancos Pool as part of the continuation of this map?

A Yes, sir, just in general and they were pretty close. I remember the surface pressure at the Mallon (not clearly understood) was within 8 pounds; probably the same is true of the Meridian well, but I have not tried to make an exact comparison for the reason that those pressures were taken with different pressure gauges and so there would be a difference there.

One of the main things perhaps I should point out, Mr. Chairman, that we inferred from what we have done here, I know there has been a suggestion that the drainage is not from east to west but from Gavilan to -- to the expansion area, and I would point out that the B-29 and B-32, the wells showing 1814 pounds in the brown colored area is the center of highest withdrawals. We produce some of the wells around 1000 barrels a day down to around 7-or-800 barrels a day, and -- and given the pressure gradient was from east -- or from west to east from Gavilan to those wells, it would have to be -- into the expansion area, it would have to be across the yellow area into the brown area and so highly significant, I think, to our analysis here is that there is a pressure gradient, although small, from the brown area into the yellow area, and from the yellow area west my feeling, as I indicated earlier, is that they probably would be very nearly the same.

Q Mr. Greer, if the application is granted, and you're allowed to produce your wells in the expansion at the highest rate under the rules of the pressure maintenance project, would your producing bottom hole pressures be significantly lower than perhaps the producing bottom hole pressures of the wells in the Gavilan Pool?

A I think not. Mr. Chairman, our -- our plan always has been to produce at the -- at the minimum reasonable rate and the only reason we produce at higher rates is in order to minimize as much as possible, from a practical standpoint, migration.

If Gavilan is not produced at a high rate and the pressure is not pulled down in Gavilan, then we're not going to pull the pressure down in our area.

Q Would you be opposed to the operators in Gavilan being allowed to produce at a rate that would give an equivalent bottom hole producing pressure to what you would be producing in your expansion area?

A If we had some way of measuring or accurately determining that, I would have no objection to it.

There's a bit of a problem, as you probably know, where the transmissibility is as high as it is, Section 1, for instance, would produce at a higher rate and on shut-in would equalize the entire Section 6 even though it isn't producing, and vice versa, and so it's a very difficult problem to actually measure.

Q But if some allowance could be made other than looking at actual volumes but looking at pressures, you would not be opposed to that?

A I said if there were a way to do it in a fair, in a fair fashion, but as I see it, the Gavilan operators have -- have a lot of security. The pressure gradient has been from the Unit toward Gavilan for some time now and there's no way that -- that we can take gas out of the area, take gas from Gavilan and put in the gas cap if we're not getting a reaction and a pressure maintenance affect, and the reason for that, Mr. Chairman, is that the system offers a balance or an adjustment.

If we take too much gas out of the boundary area, drain Gavilan, and put that gas in our gas cap and find communication with the expansion area, then the pressure builds up in the gas cap and we're already at pressures as high as I want to go and we have no other recourse other than to sell gas.

When we sell gas, then we don't get the pressure maintenance credit, so they're balancing, a safety valve, so to speak as far as Gavilan is concerned, where there's just no way that we can take more than our fair share out of the reservoir.

Q How significant are producing bottom hole pressures on either side of this dividing line between the pools, even though the shut-in pressures seem to be equivalent?

Would there be a difference in fluid movement because of different bottom hole producing pressures?

A Yes, sir, you could have fluid movement from one area to the other during production, shut the wells in , and the pressures, I feel, will equalize rapidly across that boundary because of the high -- high transmissibility.

MR. CHAVEZ: That's all I have.

MR. LEMAY: Thank you, Mr. Chavez.

Additional questions of the witness?

MR. BROSTUEN: I've got a few questions here.

MR. LEMAY: Commissioner Brostuen.

QUESTIONS BY MR. BROSTUEN:

Q Mr. Greer, I'd like to refer to one of your plats that you show in the -- the -- if I can put my hands on one here, the -- that show the wells drilled and completed in West Puerto Chiquito. Perhaps you can help me

Here's one in under -- this would be Tab -- Tab A in Exhibit One.

A Okay.

Q One of the things that was mentioned here today was to protect the correlative rights and what we're proposing to do here, or you're proposing to do, is to expand West Puerto Chiquito Unit, pardon me, the Canada Ojitos Unit into the expansion area that you're showing on this -- this plat, is that correct?

A No, no, sir. The Unit already covers the expansion area, not only the Unit but the participating area. Expansion, that comes about by application from the operator to the Department of Interior, the State Land Office, and the Conservation Commission, and all three of those agencies have approved the expansion the expansion of the participating area to cover the entire Unit area, and so the only thing that's left that we need is just expansion of the pressure maintenance project, and that, the control for that expansion, lies solely with the Conservation Commission; the State Land Office, and the Department of Interior do not have a voice in that.

Q The, Mr. Greer, in the expansion area, then, is that covered by any of the orders that were included in I believe it's your Exhibit Number Four?

A Yes, sir. Yes, sir, all of the -- all of the orders, and they read as only three.

Q Could you direct me to the -- to the unitization? I'm assuming there was a compulsory unitization, then, of -- of the -- of a portion of this -- of the Canada Ojitos Unit?

A I believe it was two years ago -- was it two years ago -- two years ago we had a few outstanding tracts within the unit. Now the participating area had already been expanded to cover the whole unit, and we asked for statutory unitization to pick up a few tracts that we just did not communicate with people and they were a problem and we had to come to the Commission every time we wanted to drill a well, and ask for a forced pooling order to get started and then later on all the adjustments had to be made. So we asked for statutory unitization of the entire area.

It was our understanding at that time that -- that that covered the pressure maintenance project expansion. The way we read the statute is that there's no way to have a statutory unitization without pressure maintenance, and so we felt that -- two years ago, that this really had been legally covered.

That's sort of the history of that.

Q So finally what you're saying is that two years ago there were some tracts that were brought into the

Canada Ojitos Unit by the compulsory -- by utilizing the compulsory unitization --

A Yes, sir, there were --

Q -- statute?

A -- I forget, two or three tracts.

Q Can you -- could you indicate those tracts to me on this map?

A No. Let's see, I'm sure that by tomorrow morning we could dig out the exhibits for that.

Q Fine, fine. In the, and as I say, I haven't -- I haven't reviewed the orders that -- order or orders that may have been issued regarding compulsory unitization in this matter. One of the requirements for compulsory unit -- to utilize that statute, it's under, I think, Section 70-7-5, and it's pargraph B, a statement that the reservoir or portion thereof involved in the application has been reasonably defined by development, and one of the questions I have in reviewing the entire unit here, is the large number of tracts which apparently have had no wells on them and how -- how this -- how the justification was for saying that these tracts had been reasonably defined by development.

I'm looking up in, say, in the corner, in this particular map there's a lot of writing on it, or printing on it, it's difficult to tell, but say up in the northeast corner of the map there, you have a number of tracts up there, no wells, how was -- how was that justified?

A That was by geological inference and the -- in a sense all of the pattern of the participating area expansions themselves, the unit agreement calls for expansion of participating area, that lands be brought into participation which are either, number one, proved to be productive in paying quantities; or number two, are necessary for unit operations.

The analysis that we've made, the beliefs that we have, is that those lands are necessary for unit operations; the reason is that if someone came along and drilled a well in that northeast part of the unit, got on the gas cap, a gas well, then they could go to market with the Unit's gas, and then by geological inference we believe that that land is needed in the Unit.

Q And you were able to convince the Commission or the Division at that point in time that such was the -- such were the geologic conditions.

A Yes, sir. We brought that to the Department of Interior, to the State Land Office, to the Conservation Commission.

Q Thank you, that's all I have. Oh, excuse me, I have one more question, Mr. Greer.

This is on another matter. On Tab -- under Tab E, on page three, Exhibit One, I just want a little information. Page three, yes, and I'm sure you've presented this information already, and it's probably somewhere in here if I could dig it out, but I thought you could get to it more rapidly.

On page three you list a number of wells, Canada Ojitos Unit E-6 through -- well, there are some other wells not in the unit.

Could you tell me which -- which intervals they are producing from, A, B or C?

A I believe all of these wells on that schedule -- I'm looking at the schedule, a green sheet says Page III.

Q That's correct.

A Yes, sir. The E-6 is all three zones; N-31 is all three zones; I'm reasonably certain that the Tapacitos 4, the Howard 1-8 and Howard 1-11 are -- all three zones are open.

Q Thank you.

MR. BROSTUEN: That's all I have.

MR. LEMAY: Additional questions of the witness?

Any redirect, Mr. Carr?

MR. CARR: No redirect.

MR. LEMAY: If not, the witness may be excused.

Call your next witness.

MR. CARR: I have one witness and Mr. Kellahin has a couple of them.

MR. KELLAHIN: Mr. Chairman, what's the pleasure on time this evening?

MR. LEMAY: I think we've agreed pretty much we can stay till six. We'd like to continue this on till six today, picking up at nine in the morning, because I think we are running a little behind and we need to utilize the time.

MR. KELLAHIN: Perhaps if I could call Mr. Ellis at this time, there's a chance we might be able to finish his presentation this evening.

MR. LEMAY: Yes.

MR. KELLAHIN: Mr. Chairman, at this time I'd like to call Mr. Dick Ellis to the stand as our geologic witness.

MR. LEMAY: Fine.

MR. KELLAHIN: Mr. Ellis has already been sworn.

RICHARD K. ELLIS,,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A My name is Richard K. Ellis. I'm a geologic consultant.

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

A I have.

Q And have you been retained by Sun Exploration and Production Company to continue with your geologic evaluation and studies of the Gavilan Mancos Area, as well as the West Puerto Chiquito Mancos Pool?

A I have.

Q And pursuant to that employment have you made a further geologic study with regards to the expansion area that Mr. Greer proposes to include within the pressure maintenance project that now exists for the Canada Ojitos Unit?

A I have.

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

MR. LEMAY: His qualifications are accepted.

Q Mr. Ellis, the package of exhibits which I have marked as Sun Exhibit Number Two, I believe, is this a package of exhibits, the displays and the information and conclusions depicted in this booklet, those -- do those represent your personal opinions and conclusions?

A They are.

Q Did you prepare these displays or were they prepared under your direction and supervision?

A They were.

Q Let me direct your attention to the first page of the exhibit booklet that you prepared and ask you first of all, sir, to identify the first display.

A The first display is a structure map on top of what we call the Niobrara "A" Unit within the Niobrara member of the Mancos formation.

Q Is the top of the Niobrara "A" Member the structural point at which you and other geologists that have worked this area and participated in the various operators and working interest owners study groups have used as the marker or the method by which to develop the structure?

A It is.

Q All right. What does it show you, sir?

A Very simply and directly, it shows a varying amount of dip from the outcrop to the western boundary of the pool, which is also coincident with the western boundary of the proposed expansion area.

It also shows the strike is generally north/south. There is a synclinal face at what we would call a monocline which extends from the outcrop to the west boundary of the pool. That syncline is approximately within one mile of the western boundary of the pool.

Q How have you identified the area of the thirteenth revision to the unit participation area?

A It's outlined in red.

Q And for purposes of this hearing, we have called that the expansion area, have we not?

A That's correct.

Q And the existing pressure maintenance project area is identified in what color?

A In the green outline.

Q So let's go on to the next page. What have you prepared here, sir?

A This is a true scale section view, structural section view of the reservoir from the outcrop of the west boundary of the pool.

Q What do you mean by a true scale?

A Basically, a horizontal and vertical scale are the same, one inch equals in this case, I think, one inch equals 8000 feet. That's incorrectly marked at the bottom.

Q Describe for us how we know where each of the cross sections are displayed within the project area and the expansion area.

A From the previous exhibit we have marked the locations of Sections A, B and C. They're oriented approximately perpendicular to structural strike, which in this case is slightly east of north, and that's all.

Q Let's start with the northernmost structural cross section, which is the top display on the second page of the exhibit book and have you describe what -- what it shows you.

A It shows a varying progression of dips from the outcrop to the west boundary of the pool beginning at about 53 degrees dip at the outcrop.

In the up-dip gas injection portion of the project area we're approximately 5 degrees. At the Unit No. 5 Well the measured dip, at least from the section itself, was approximately 5 degrees.

Down in the withdrawal portion of the

reservoir near the left boundary of the section I've presented, we're talking about dips, essentially flat to approximately 2 degrees.

That same relationship applies for both Sections B and C. We're beginning to see approximately 55 to 60 degree dips after the outcrop, rapidly decreasing into the gas injection and withdrawal portions of the reservoir.

Q What do your structural exhibits show you concerning the proposed expansion area?

A Both of the structural exhibits show that the project area and the expansion area, as proposed, are integral parts of -- of the structural entity, that being the modified syncline that we've identified on the structure map, that defines the West Puerto Chiquito Mancos reservoir.

Q Do you have a geologic opinion as to whether the three zones of production in this interval, the A, the B and C, each one individually is a continuous zone or formation within this interval as we go across the existing area through the expansion area?

A I do, and they are continuous across the pool as represented in the next exhibit, which is just an induction log cross section across West Puerto Chiquito. There's no horizontal scale implied here. The vertical scale is as indicated at the bottom of the section.

We're showing the stratigraphic consistency, again at this scale, we're showing the stratigraphic consistency in the Upper Niobrara member specifically, across the reservoir from the gas injection into Gavilan.

There are no significant thickness changes involved and lithologic changes from core examination and also log examination don't appear to occur in any significant fashion.

It also shows that the reservoir interval we'll discuss in just a second consists of basically three discrete units that we all the A, B and C units of the Niobrara. These units we know now from production tests, fracs, and surveys, and core data, are responsible for all the observed hydrocarbon production to date in both reservoirs, Gavilan and West Puerto Chiquito.

Q Turn to the next display. I believe that's a type log, and which well have you used as a type log.

A I used one of the gas injection wells, which is the Unit No. B-18.

Q What does it show you?

A This is an induction log again kind of an expanded scale with the typical reservoir section in the pool. As I mentioned, this is in the gas injection area but this log is typical of all the logs we've observed in the area.

The colored and hachured area within the A, B and C units are the discrete reservoir units that we've identified in previous hearings, and as I mentioned just a second ago, they're known through cores and production tests and spinner surveys to have produced all the hydrocarbons, significant hydrocarbons in both the project and expansion programs.

These reservoir units, the ones that are hachured, we've used observational data from the core to learn a little bit about these sequences. Basically what they are are highly laminated shales, siltstones, and carbonates that are dolomitized in places. This, the fact of having dolomite in the reservoir is very significant, particularly for this reservoir. It creates a highly brittle and fracture-prone lithology.

We think in the presence of the pronounced structural change along the monocline that we have developed a high fractured reservoir as a result of that.

Q Now would you turn to the next page in the exhibit book? Would you identify that for us, please?

A This is a compilation of data that's been derived from an interpretation of surface fracture trends, using both Landsat and aerial photography. This study was conducted by the Canada Ojitos Unit.

It shows a series of regional and tectonic fractures that are present in the area. As you can see, the most -- other most significant part of this is that there is a multi-directional orientation. No particular direction appears to be dominant.

We feel that, you know, even though these are surface indications, they do give us some clue as to the distribution of fractures in the subsurface. They cannot be be exactly coincident at the surface all the way down to the reservoir at 7000 feet, but they do give us a pretty good idea of what the tectonic and regional fracture distribution is.

Q Is that an acceptable method of analysis displayed by individuals of your profession to take surface indications like this and project them as subsurface orientations of fractures?

A It has been done, you know. It's certainly -- certainly is a method that can be used; a good first order approximation of the distribution in the subsurface.

It also shows, if I can continue, it also shows a couple of the more significant trends that we feel have appeared to localize some high capacity, high volume production in the reservoir, one of those being the fracture orientation at approximately north 60 degrees west, in the north half of Township 25 North, 1 West. Everybody (not clearly understood) difficult to identify. We could have highlighted it but it's a pretty prominant trend along which most of the high volume Canada Ojitos Unit wells occur.

There's also another trend pointed at about 20 degrees West in the west half of Township 25 North, 1 West, along which the highest volume of wells in the unit occur. Both of these fracture trends cross the expansion area and at least a portion, if not all, of the existing project area.

We feel that the fracture study at least indicates a good chance for connection across all of the expansion and project area.

Along these same lines, one of the early conclusions that was reached in conjunction with the court-ordered interpretation study, where was also a electromagnetic study done in a 4-section area in the northwest corner of 25 North, 1 West. Both sets of data appear to support the theory proposed by Mr. Greer concerning the presence of fracture blocks. the orientation and presence of fracture blocks in the reservoir.

Q When you said that the existing project area and the expansion area are connected, describe for me what you're meaning by connected.

A Connected at least in a vertical and -- connected in a vertical sense by fractures which in the subsurface are probably cutting the reservoir units.

I don't know if that answered your question.

Q My question was whether or not there is sufficient information from which you as a geologist can conclude that there is natural flexion to the extent that the A, the B, and the C zones at various points in the expansion area and in the existing area are connected.

A That's a reasonable conclusion from the frac distribution we've observed on the surface.

Q When you're looking at the surface, describe for me whether or not the mechanism that displays the fracturing as depicted on the surface is also the same mechanism that would have operated to fracture the Mancos itself?

A Most geologists and people that study this type of thing are convinced that the existence of surface fracture trends are indicative of the tectonic forces that were operative in the area. This particular distribution that you see here is exactly what we would predict would occur in a situation where you have compressional forces operating at approximately a right angle to the structural strike; in this case, north/south.

These resulting fracture trends that are oriented north and southwest and northwest/southeast are an expected outgrowth of those compressional forces in the northeast flank of the basin.

Q Do you see any geologic event or feature, either structural or stratigraphic, that would preclude geologically the expansion area from being connected to the existing project area?

A I do not.

Q Let's turn now to the last page of the exhibit book, Mr. Ellis. Would you identify this for me?

A This is a -- this is a schematic of the reservoir by which I think we may present a geologic characterization of West Puerto Chiquito and -- and Gavilan. It's not meant to imply any scale. There's no vertical or horizontal scale to apply here. We are qualitatively showing the steep dips on each side of the reservoir flattening out to a syncline at approximately the west boundary of the West Puerto Chiquito and the proposed expansion area, and then also what's been referred to as the Gavilan over to the west of that.

What I've done here is depict the reservoir as a series of three discrete, vertically separated, reservoir units, the red being the diagrammatic indication of the A unit; yellow, the B unit; and C, within the blue unit.

They're essentially constant in lithology throughout the pool and also the adjoining pool, Gavilan; and in fact, pretty much all over the southeast flank of the basin they're consistent in lithology.

These vertically stratified units are connected vertically, we feel, along faults and large fractures and in conjunction are next to the wellbores.

We've also observed from both production data and observations, visual observations in the core, local areas where you can have tight intervals that appear not to have any apparent link to the high capacity fracture system required for commercial production.

Q Did you find any agreement or correlation between the good wells and the fracture system versus pool wells and their location to a fracture?

A There's a rough correlation. I think that I mentioned those two prominent fracture trends, the Gallegos trend and the trend to the southwest of that. Most of the high volume wells, apparently, do fall within proximity to those -- those established trends. There is a rough correlation, yes.

Q When we look at this display, approximate for me where you have located the western boundary of the West Puerto Chiquito Pool and the eastern boundary of the Gavilan Mancos Pool/

A Okay, although not depicted on the

sketch, it would be approximately the low point just as we roll out of the low point in the syncline.

Q Based upon your studies of the geology, Mr. Ellis, what are your geologic conclusions and observations about the reservoir, particularly with regards to the expansion area and the existing project area?

A I feel based on a study I've conducted in conjunction with many of the other people who work this reservoir, that the geologic data, that's structural, stratigraphic, and lithologic, is conclusive on the issue of connection and I feel pervasive communication between the project area and the expansion area.

In other words, you know, the success of the existing project area, I think, is inextricably linked to the operations in the proposed expansion area from a geologic standpoint.

Q When you talk about in a geologic sense the comunication of the expansion area with the existing project area, how are you defining that word?

A Basically that conclusion is reached by the information gathered from the fracture examination, the surface fracture examination, you know, observed from pressure data in the (unclear) interference data.

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

We would move the introduction of Sun Exhibit Number Two.

MR. LEMAY: Without objection, Sun Exhibit Number -- is that Two --

MR. KELLAHIN: Yes, sir.

MR. LEMAY: -- will be entered into evidence.

Mr. Douglass, any questions of the witness?

MR. DOUGLASS: (Mr. Douglass responded but could not be clearly heard by the reporter.)

MR. LYON: I'm ready.

MR. LEMAY: Go ahead.

MR. DOUGLASS: Does Mr. Carr have any questions?

MR. CARR: No, I do not.

QUESTIONS BY MR. DOOUGLASS:

Q Mr. Ellis, with reference to your structure map, the first item in the brochure here, do you show any geological separation from north to the south from this structure?

A No, we do not.

Q You also don't show any geological separation to the west, is that correct?

A No, we do not.

Q You also don't show any geological separation from the west, is that correct?

A That's correct.

Q This structure map, is it very similar to the one Mr. Greer has that we visited with him about this morning?

A Somewhat different. There's a few additional data on it.

Q But essentially you have, relative to the structure itself, steeply dipping on the east and then you get to the flat area, which is in this case almost exactly coincidental with the proposed expansion area, is that correct?

A That's correct. The steeply dipping part of that structure map you alluded to there is not, perhaps, as (unclear) as it might be, but I'd just make a quick comment that we used three different contour intervals in here. It's very unusual to have dips varying from 60 degrees to flat in a single structure map, so that's one of the reasons why the structure (unclear) wouldn't work.

Q And Exhibit Two, are those the structural sections?

A That's correct.

Q Moving across it? And starting from west to east, does the Niobrara section -- am I pronouncing that correct, Niobrara?

A Niobrara.

Q Niobrara, is it -- is the -- does that section on the logs appear to be roughly the same in each one of the wells as you go from west to east, shown on these structural cross sections?

A That's correct.

Q And so looking at those particular log sections, on each of the wells shown on your structural cross section you don't see any separation or any geological division, is that correct?

A If you mean by separation, fault separation, no, we don't.

Q Or any other kind of geological separations.

A Well, as indicated, there's no lithologic change, no apparent stratigraphic thickness change. So.

Q On each of these do I see that the easternmost well that you have on your structural cross section is a dry hole?

A Yes, they are. There -- you'll also note the number right next to the dry hole symbol indicates they've been projected into the last section. If you'll look at the structure map previous to that, there's an indentation which reflects some previous production developed by Sotex (sic) back in the late fifties. That would hinder a well (unclear) of its performance never has appeared to be connected in any fashion in the Canada Ojitos Unit, so in a projection of those wells versus control points for my cross section back to the outcrop, although they appear within the unit boundary, they're not.

Q If I understand what you just said is basically one well and maybe more that appear to have the same section, you actually couldn't divide it from the producing wells but they appear to be separated.

A Well, no, in a log sense, yeah, they apparently have no -- no difference from the producing wells, and that's typical all over the southeast part of the field.

Q The fourth sheet, I believe, is a -- you can skip the third one, I don't have anything on it to ask him.

Well, the third one, you show the A, B and C intervals. That's the first time you show them, I believe, on the -- in the exhibit here, is that correct?

A That's correct.

Q And do I understand your testimony to be from a geological standpoint you believe those, A, B and C, are in natural communication with each other because of natural fracing, natural fractures.

A And also wellbore communication along wellbores.

Q But that's not considered natural communication, is it?

A No.

Q My question is do you consider the A, B and C in this producing area that we're involved with here, to be in communication with each other due to natural fracturing?

A Natural fracturing in the reservoir.

Q In the reservoir, right.

A Limited, limited communication vertically, yes.

Q Limited communication.

A Enough to be an equalization of pressures vertically.

Q And in geological time or over producing time?

A Well, probably both.

Q Well, obviously, if it's over producing time it's going to be over geological time.

A I was concerned about more than over a man's history of producing the reservoir. That's what I indicated.

Q You say there's effective comunication between A, B and C in natural fractures in the producing area through (unclear) years.

A Yes, I do.

Q Then the fourth sheet, there's areas that have little pluses in them. I didn't undertand what those areas mean --

A Okay, the --

Q -- in the A, B and C zones.

A -- combination of coloring and hachuring, not one without the other, would indicate the zones within which we have production survey data, production testing data, and also visual observation of core data would indicate all fo the significant hydrocarbons produced to date in both reservoirs have issued from those hachured zones.

Q Are you saying that the other part that doesn't have a hachured part is not productive?

A No, they are productive. There's minor production observed in many spots.

Q The second question on this B-18 Well, I believe this is an injection well, is that correct?

A That's correct.

Q All right, then I believe Mr. Greer's already indicated that he thought it was tight. Do you agree with that, that it's in the tight area?

A Yeah, most of the injection portion of the reservoir is fairly tight.

Q You can't tell from the logs, though, whether it's tight or not, can you?

A Not on an injection log, that's true.

Q And then the fifth sheet, I believe, is your -- it says fracture interpretation. That's surface fracture interpretation, is that correct?

A That's correct.

Q It is not being projected to the reservoir.

A No. It may not be an accurate means of showing distribution in the -- in the subsurface.

Q And I take it from what you indicated that this is certainly better than voodoo but it's not yet perfected. Would you agree with that?

A Oh, I think it's a whole lot better than voodoo. It's a -- it's certainly, as I indicated, a good, first order approximation of the fracture distribution in the subsurface at reservoir depth.

Q Doesn't -- doesn't tell you whether you have one or more reservoirs underneath the ground, does it?

A No.

Q And then the -- the last sheet, as I understand it, is just a schematic drawing with reference to your interpretation of the Gavilan and West Puerto Chiquito, is that right?

A That's correct.

Q The -- you do show some tight zones in the A, B and C, is that right?

A They appear in various parts throughout there.

Q And when you say tight zones you mean that fluids can't even flow through those areas?

A Oh, I think there's probably a fluid flow and certainly pressure transient movement through that portion of the reservoir. They're not meant to imply that, either, that they extend for any distance out of the plane of the actual sheet in which they're presented.

Q When you say -- when you say tight, you're just talking about relative?

A Relatively tight, right.

Q Have you made any studies to determine the amount of fluid that can move through these tight zones?

A Oh, I'm not an engineer.

Q As a geologist, when you're trying to determine whether there's effective communication in a reservoir, do you normally rely on the pressure data and interpretation of that by reservoir engineers to tell you whether there is effective communication in the a reservoir?

A Oh, no. First of all, I'd certainly use whatever geologic tools are available to -- to establish that fact.

That would be supportive data and just as the (unclear) supports the engineering data.

Q I understand, but there's nothing in geology that tells you how effective communication is between two wells, is there?

A Not, not in any quantities, yes, that's true.

MR. DOUGLASS: Pass the witness.

MR. LEMAY; Thank you, Mr. Douglass.

Additional questions of the witness?

Mr. Lyon.

QUESTIONS BY MR. LYON:

Q Vic Lyon, Chief Engineer for the Commission.

I'd like to ask you a couple questions about your exhibit on the Landsat fractures.

The traces of the fractures that you've shown here are, I assume, the occurrence of a fracture at the surface.

A As observed on photos, yes.

Q Do you have any information or do you have any opinion as to whether or not those fractures extend truly vertically from the -- from the surface or are oriented in any particular direction as they progress down from the surface?

A Well, we -- we think the orientation of the fracture distribution in the subsurface will be very similar to this because of the -- you know, the expected distribution based on tectonic forces that are out there.

In this case we know, for example, that the north/south strike along the monocline would have indicated prior tectonic forces (unclear) that are operating perpendicular in that area.

As a result of that you get a distribution, the orientation northwest/southeast and a complimentary direct, northeast/southwest, and we would expect that distribution, that particular orientation to be present in the subsurface.

As to the vertical or near vertical nature of these fractures, we don't make that determination based on our examination of photos. In this particular case it was wisely decided by the unit to support the fracture study using a (not understood) magnetic study that was able to determine that the fractures vary anywhere from an inclination of 20 degrees off vertical to essentially vertical. So they are near vertical in every case.

Now, they wouldn't necessarily be through-going to reservoir depth, is the point I think I was making.

Q Well, for instance, there are places in here where the fractures have enclosures, where there is a discrete block shown here.

If these -- if these fractures were parallel, then you would expect a block of the same size at reservoir depth, same shape.

Q Yes, they will be approximately the same size. The block size will be approximately the same or similar to that.

Now, there's also a scale of observation problem in here. We're obviously not going to pick up particular -- we can get all the mechanics to do an interpretation but particularly in an area where you have no other indication and you do (not clearly understood) has been established for us, and you also have a problem of having (unclear) around the surface in the area, and those, the combination of those two things and also the steep (not clearly understood) makes it very difficult to see a lot of fractures. I mean, some of the fractures that aren't, you know, obvious on the photos, you just kind of miss a lot, is what I mean to say.

But we have picked up a distribution here that I think is accurate in terms of, you know, what we'd expect in the subsurface.

Q And are you talking about the frequency of occurrence or are you talking about a rigorous projection of reservoir data of the same type, same orientation of fractures as you see here on the surface?

A The frequency of occurrence is probably going to be very similar to what we observe on the surface.

What I just tried to explain was that there could, in fact, be many more fractures that we were not able to pick up because of the conditions on the surface, but the frequency that we observed here we'd certainly expect in the subsurface, and as far as any kind of rigorous block size that we could apply using this interpretation, I sure wouldn't want to hang my hat on a rigorous block size.

It does indicate that you've got a bottom hole set that creates fracture blocks.

MR. LYON: That's all I have.

QUESTIONS BY MR. LEMAY:

Q Mr. Ellis, I have two quick questions.

One, did you extend your correlations in- the Gavilan area, and also maybe a little bit to the west of that when you were analyzing the productive interval, the reservoir interval?

A Yes, we've done quite extensive work on that in Gavilan.

Q Is that interval correlative with the Gallup interval as you get into the basin?

A Probably not. If what you're referring to are the Gallup sands, why, that is definitely a different stratigraphic interval and also a different stratigraphic age.

What's commonly referred to as Gallup sand production (not understood.)

Q Did you take that reservoir interval and project it into any known formation name into the interior of the basin or just into the Mancos interval?

A It is actually under the Gallup in the basin. This highly resistive character you observe in the Niobrara over here on the east flank is -- is still present as you work your way, particularly northwest along the gross paleo (not understood) that direction.

But the Gallup itself, you know, that -- that particular nomenclature is probably misleading in the sense that, you know, it should refer specifically to that sand interval that develops below what we call the Niobrara on the east flank.

This does exist out in the basin, though. It's a very persistent unit. In fact the same thing, producing interval produces in the fractured Niobrara fields on the northwest hogback.

Q One other question. Is there geologic evidence you see to limit production either to the north or to the south in the Canada Ojitos Unit?

A No, there isn't.

Q Is there any evidence to suggest the field does go further north or further south than the current confines of the unit?

A You can certainly have reservoir capacity all along this monocline bearing north and south. There is going be some definite sweet spots which are going to related to the presence to tectonic fractures, I think.

Just about anywhere on the southeast flank, as we've observed in West Lindrith and parts of the Gavilan, you're going to run into areas that are just not commercial production; but as far as pressure development, commercial reservoir development, I think your proximity to the monocline is going to control the, you know, possible existence of commercial production.

Q With your analysis of the fracture pattern, have you looked at horizontal fractures at all?

A Well, I just don't really know how to go about addressing that problem. We, you know, of course looked at the core with that in mind, but I don't think we were convinced that, you know, any fractures moving in approximately all directions would be anything to look at.

MR. LEMAY: Additional questions of the witness?

If not, he may be excused.

Mr. Kellahin, do you want to put someone else on or not?

MR. KELLAHIN: I'm about ready for a break, Mr. Chairman.

MR. LEMAY: Let's take ten minutes.

(Thereupon a recess was taken.)

MR. LEMAY: We're just going to go on the record here to -- to adjourn the meeting till tomorrow.

We'll reconvene tomorrow at 9:00 o'clock and at that time, I think, I have one more witness, Dr. Lee, and then do you plan to have one witness, Mr. Douglass?

MR. DOUGLASS: Yes, sir.

MR. LEMAY: Were there any

other witnesses that were going to be called tomorrow?

Okay, so adjourned to 9:00 tomorrow.

(Hearing adjourned at 5:45 p.m. until 9:00 o'clock a.m. on the 18th day of March, 1988.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing pages numbered 1 through 245, inclusive, constitute a full, true and correct transcript of the portion of the hearing in New Mexico Oil Conservation Commission Case 9111 heard on 17 March 1988, and continued until 18 March 1988, reported by me to the best of my ability.

Sally W. Boyd CSR

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

17 March 1988

COMMISSION HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the expansion of the BMG West Puerto Chiquito-Mancos Pressure Maintenance Project Area, Rio Arriba County, New Mexico.

CASE 9111

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

TRANSCRIPT OF HEARING

VOLUME II OF THE TRANSCRIPT IN NMOCC HEARING IN CASE NUMBER 9111 AS CONTINUED ON 18 MARCH 1988.

A P P E A R A N C E S

SAME AS VOLUME I.

REPORTER'S NOTE: Thereafter on the 18th day of March, 1988, the hearing in NMOCC Case Number 9111 before the Oil Conservation Commission was reconvened at 9:00 o'clock a.m. and commenced at 9:30 o'clock a.m., at which time the following proceedings were had, to-wit:

MR. LEMAY: We shall resume, excuse the delay, unavoidable. Resume with Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman, at this time we will call Dr. John Lee.

W. JOHN LEE,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Dr. Lee, for the record would you please state your name, sir?

A My name is John Lee.

Q And what is your occupation, Dr. Lee?

A I'm a consultant for S. A. Holdedge and Associates, a petroleum engineering consulting company in College Station, Texas.

I'm also a professor of petroleum engineering in Texas A & M University.

Q Have you previously testified before the New Mexico Oil Conservation Commission as a professional petroleum engineer?

A Yes, I have.

Q You testified before the Commission back in March and April of 1987 with regards to the Gavilan Mancos hearings conducted during that period of time?

A That's correct.

Q And since that period of time you've continued to study and be involved in the evolution of information and the analysis of that information in the Gavilan Mancos Pool?

A That's right.

Q And have you reviewed and studied information from the Canada Ojitos Unit?

A Yes, I have.

Q And in addition, have you reviewed and studied information from the West Puerto Chiquito Mancos Pool?

A Yes, I have.

Q In addition, Dr. Lee, have you prepared a study of the major requirements for the expansion of the pressure maintenance project into what we've identified yesterday as the expansion area?

A Yes, I have prepared such a study.

MR. KELLAHIN: At this time, Mr. Chairman, we would tender Dr. Lee as an expert petroleum engineer.

MR. LEMAY: His qualifications are accepted.

Q Dr. Lee, let me have you identify what is marked as Sun Exhibit Number One. What is that, sir?

A That's an exhibit in which I've presented my conclusions in this study and the evidence on which those conclusions are based.

Q What, in your opinion, are the major requirements that must be satisfied for the expansion of the existing pressure maintenance project to include the expansion area that we've identified?

A Well, in my opinion there are two major requirements which must be satisfied and these are: First, we need to establish that there's effective pressure communication between the existing pressure maintenance project area and the expansion area; and secondly, we need to establish that the pressure maintenance - gas injection program in the on-going unit has increased recovery in the project area, and can be expected to continue to do so in the expanded project area in the future.

Q Apart from the two major requirements for the expansion area approval, have you made a study to determine whether there were any additional benefits to expanding the project area into the expansion area?

A Yes. In addition, I've found that there is an additional benefit and that would come from installation of a gas plant and additional hydrocarbon recovery which would result from gas cycling in that plant.

Q In pursuing your study, Dr. Lee, have you utilized the available field data in making your study?

A Yes, I have.

Q And have you been able to reach any conclusions?

A Yes, I have.

Q What are those conclusions, sir?

A Well, to summarize the major conclusions, first, on the issue of pressure communication, my conclusion is that the existing pressure maintenance project area and the expansion area are in effective pressure communication. That's as evidenced by interference tests and other data.

In fact, in pursuing the study I found that no interference test run between wells in the unit has ever failed to show communication in the sense of a prssure response.

Then on the second issue, improved recovery attributable to pressure maintenance - gas injection, what I found is that gravity drainage, and by that I mean migration of gas up-structure and oil down-structure, is occurring in the Canada Ojitos Unit, and evidence of this is provided by production of oil at low gas/oil ratios in the C zone completions despite the fact that the reservoir pressure has dropped below even 1000 psi, which is substantially below the original bubble point pressure in the reservoir, and if gravity segregation were not occurring, if instead, solution gas drive were the dominant drive mechanism, the gas/oil ratios would be increasing at this lower pressure level.

The second conclusion in this area is that some computer reservoir simulation calculations, which I have made, these calculations show greater recovery at a given production rate with pressure maintenance than without pressure maintenance, except at very high rates at which so lution gas drive would become more dominant.

The third conclusion is that simulator calculations show that recovery increases in the Unit decrease at a rate -- excuse me, recovery increases in the Unit, as rate decreases these recoveries increase because and oil can segregate efficiently under the influence of gravity flow rates but it can't segregate efficiently at high rates.

And then the final conclusion has to do with gas cycling, and what we found here was that additional liquid recovery due to the gas plant could be increased by about 700,000 barrels with this process.

Q In dealing with your opinions and fulfilling the requirements you've set forth for the approval of the expansion area, Dr. Lee, the first step that you've analyzed is pressure communication, is that not true?

A That's correct.

Q The reason to examine the extent and the effectiveness of pressure communication between the expansion area and the existing project area is for what purpose?

A Well, if the two areas are not in pressure communication, then it serves little point to establish that there is a very efficient gravity drainage process going on with the existing unit. We must show that the two areas are in communication in order for this efficient recovery to have some meaning as evidence to support expansion of the pressure maintenance area.

Q So as a predicate for the balance of your study, you needed to first determine and satisfy for yourself that there was pressure communication between the two areas?

A That's correct.

Q And what did you conclude?

A My conclusion is that the existing pressure maintenance project area and the expansion area are in effective pressure communication.

Q What is the basis upon which you have evaluated and determined that conclusion is fair and appropriate?

A Well, the basis -- there are really several bases. To itemize these, first I would mention, as I did in my summary, that interference tests show pressure communication over widespread areas within the expansion area and between wells in the existing unit, and the proposed expansion area.

The map from Mr. Greer's black exhibit book, Section G, summarize those tests in which pressure communication has been established. I've simply made a copy of that map to re-focus on the results of these interference tests, and that map is the figure that I have labeled Figure PC-1, which is found on page eight of this exhibit booklet.

Q It's the figure immediately after the written narrative, after page seven?

A Yes, that's correct, and this -- this figure simply shows lines between those well pairs in which a pressure response has been seen due to either a fracture treatment or some sustained production or injection in another well.

The second basis for my conclusion is that not only did we see pressure response in wells offsetting wells being fractured hydraulically in the fracture pulse testing work, but I want to emphasize that these responses were seen very rapidly and over large distances.

The reason I want to emphasize that is because that indicates high formation permeability. We might get different estimates of what that permeability is, depending on how we approach the analysis, but the inescapable conclusion is that the permeability is very high, and the reason that I emphasize that is that high permeability is the key to effective gravity drainage.

Again, just to bring focus on this key point, I've reproduced a figure I've entitled Figure PC-2, which is on page nine of my exhibit booklet.

This is the response to a fracture treatment of COU D-17 in Well A-20, and the point I want to emphasize is that in this example, which is typical of our frac pulse tests, a response was seen in something like four or five hours. It's a little hard to read the time scale exactly because it's a logarithmic scale, but just reading on the scale we see that somewhere near four days the fracture treatment occurred and four or five hours later a response was seen.

These two wells happen to be about a mile apart, thus emphasizing the point that we see rapid response over large distances, indicating high permeability.

Q The D-17 well and the A-20 well are both wells in the expansion area?

A They're -- these are -- these particular wells, D-17, let's see, I think we'd probably need to look at a pay zone map.

The D-17 well is located about midway north and south in the expansion area and A-20, about a mile below, or south, of the D-17, on the edge of the expansion area.

I think you can find this on any of the several maps that we have. The one that I'm referring to now specifically is in the brown exhibit book, Section C, a map on the second page of that booklet.

Q In addition to the interference test and the pressure response observed in these wells, what other evidence can you cite that supports your conclusion about the effective pressure communication between the expansion area and the existing project area?

A Well, I would again emphasize that in no case in which an interference test has been run, either in the existing unit, or between wells in the existing unit and the expansion area, or between wells in the expansion area itself, have we failed to see communication in the sense of a pressure increase due to, say, injection of fracture fluid.

Other evidence has been presented by Mr. Greer and I don't want to spend a lot of time restating what he has stated, so I simply summarized here the other evidence that he has cited supporting pressure communication.

The first of these items, quickly, was over-injection and the basic point here was that injection into the reservoir between July '87 and November '87 and November '87 to February, 1988, there has been over-injection; that is, there's been more injection than there has been withdrawals in the existing project area and yet the bottom hole pressures have not increased, even though this over-injection has occurred.

The second point to summarize quickly from Mr. Greer's work, which is work on pressure gradients, and the essential point here was that pressures near individual wells decrease in a regular fashion, starting at the gas injection wells to the rest of the unit, going on down through the existing pressure maintenance project area and on into the proposed expansion area.

The third point that Mr. Greer made was a pressure increase in shut-in wells and the main issue here was that pressures continued to build up in observation wells, specifically wells B-29 and B-32, which are in the proposed expansion area, following a 3-day shut-in period, November 16th to 19th, 1987, and for ten further days, and the source of this continued increase in pressure, in my judgment, was the higher pressures in the existing project area, which show communication between the existing area and that expansion area.

The next point from Mr. Greer's evidence, gas/oil ratios, here Mr. Greer simply shows that the producing gas/oil ratios in the proposed pressure maintenance project area were substantially lower than those in Gavilan, and I've used the word "adjoining" Gavilan wells here and, as we clarified yesterday, we're really talking about all of Gavilan here, the gas/oil ratio is substantially lower in the pressure maintenance area than in Gavilan.

This implies to me that the -- that the wells in the Canada Ojitos are being fed oil by gravity drainage from unit wells to the east and up-structure, which, of course, will require pressure communication.

Finally, Mr. Greer mentioned the pressure history of observation well C-34 and also of observation well B-17, and the main point here was that increases and decreases in pressure in these wells could be correlated to changes in induction -- injection and production rates within the unit, which again implies pressure communication.

And then the final point, the pressure decline in the expansion area found in Section K of the brown book, the essential point here was that the pressure maintenance project is maintaining pressure in the proposed expansion area. This is reflected particularly in the observation well D-17 in the expansion area at times of reduced withdrawals from Gavilan, and what the evidence showed there, was that the rate the pressures decline is -- is not steep at all despite withdrawals from the fields generally, which implies there is pressure support to those wells, again implying pressure communication.

Q Do you have an opinion, Dr. Lee, as to whether or not there is sufficient field data that you have studied establishing adequate and sufficient pressure communication between the two areas, that you then could continue on with the balance of your study?

A That's correct. I have concluded that.

Q Your second major requirement for the expansion of the pressure maintenance project into the expansion area was to determine, first of all, whether or not you could project or see the improved recovery caused by pressure maintenance?

A That's correct.

Q And what did you conclude?
A Well, I summarize my conclusions here on page ten of my exhibit booklet.

The first of these conclusions is that gravity drainage, or gravity segregation, pseudonyms for the same phenomenon, which means migration of gas up-structure under the influence of gravity and migration of oil down-structure, I've concluded that this segregation is occurring within the Canada Ojitos Unit.

The second conclusion is based on some reservoir simulator calculations. These calculations show greater recovery at a given production rate with pressure maintenance than without pressure maintenance, and I want to emphasize greater recovery at a given production rate if you maintain the pressure than if you don't.

And the third conclusion, also based on simulator calculations, here we show that recovery increases in the unit as rate decreases because gas and oil can segregate efficiently under the influence of gravity at low rates but it can't segregate efficiently at high withdrawal rates.
Q Do you find, sir, that there is field evidence that pressure maintenance is improving recovery?
A Yes, I have found field evidence that pressure maintenance is improving recovery, and I have summarized this evidence on the page that I've labeled IR-2

and IR-3 and IR-4. These are on pages 17, 19, and 20 of the exhibit book.

All right, turning first to Figure IR-2 on page 17, This is our field evidence, and basically it's this:

We have noted that the A and B zones have been invaded by injected gas. Production logs, which Mr. Greer presented yesterday, from the Unit wells L-27 and B-32 indicate this invasion of injected gas.

Production logs in the Unit Wells F-30 and B-32, though specifically indicated that in the C zone, which has not yet been invaded by injected gas in the down-structure wells, in these wells these production logs provide direct evidence that production is still at low gas/oil ratio.

Now, there are two other wells that I want to comment on, Wells F-18 and B-29.

These two wells have not had production logs run but, by analogy, that is, by proximity to F-30 and B-32, and by comparable producing gas/oil ratios, we infer that also they are producing only modest amounts of free gas from the C zone, producing gas at something close to the current solution gas/oil ratio.

Now, to be more specific, I've tabulated in this figure for each of these wells that I mentioned, two with production logs and two wells which are close analogs of these wells, their approximate current productivity; their current producing gas/oil ratio; and the C zone gas-oil ratio, which either was measured in a production log or which is inferred by analogy, and the essential point is that the C zone gas/oil ratio is in the range of 600-to-700 cubic feet per barrel for each of these four wells, two of these based on direct measurements, and these are probably the -- the (not clearly understood.)

Our point is that if we have low ratio production from the C zone wells, then gravity drainage must be effective because the -- the pressure in this area has dropped to the range of 1000 pounds, or less, and if we did not have effective gravitational segregation of these fluids, then we would have solution gas drive dominating and the gas/oil ratio would be growing substantially by this time.

All right, the second bit of field evidence that we have is based on a look at other wells in the Canada Ojitos Unit which produce at low gas/oil ratios for long periods of time, at which periods of time they had substantial volumes of production.

These, the two wells that I'm going to cite as examples are not in the expansion area as the title of this figure might imply, so let me clarify the record on that point, but they are wells within the unit.

What we'll see when we look at these figures is that they produce low gas/oil ratios for long periods of time and then there is a rather sudden increase in gas/oil ratios spread out over a limited period of time, and this particular behavior is characteristic of wells that are operating under the gravity drainage mechanism. This increase in gas/oil ratio would indicate the approach to the well of a gas/oil contact as injected gas is displacing the oil down toward these wells.

All right, the specific figures that we show are, first, in Figure IR-3, which is on page 19 of our exhibit, this is the porduction history from well L-27. There are two pages to this figure; the first page takes the history through 1982.

On this figure what we see plotted is gas/oil ratio and through 1970, through 1982, the gas/oil ratio has been in the 300-to-400 standard cubic feet per barrel range.

The production has been -- was held reasonably constant in that era and we'll see the cumulative production, with the top line we went off scale in 1979. The cumulative production went over a million barrels by that time.

Then if we continue to look at the pro

duction history, in 1983, '84, '85, and '86 and '7, what we'll note first, continuing the gas/oil ratio, is production at a ratio on the order of 400 cubic feet per barrel, and then in 1986 the gas/oil ratio began to increase rapidly and by the end of 1986 had gone to 2000-to-1 gas/oil ratio.

This is characteristic of a well producing under a gravity drainage mechanism. This particular well is a little bit complicated in that the A zone probably gassed out completely. There's continuing production of oil from the B zone but, nevertheless, a contact, in my judgment, moved into the vicinity of this well causing this increase in gas/oil ratio, but there was no significant solution gas drive component to production through this -- from this well for these many years through 1985.

The second well history on Figure IR-4 is even more dramatic. This is also a well in the unit but outside the expansion area, production history of the well L-11, and here we see, starting in 1964, a gas/oil ratio in the range of, generally, 4 -- say, 200-to-400 standard cubic feet per stock tank barrel, and then suddenly, in 1974, at which time the cumulative production had gone over a milion barrels, the gas/oil ratio increased very sharply and within a matter of a few months the gas/oil ratio was quite high.

Again, this indicates to me, approach in this well of a gas/oil contact with the gas efficiently being segregated above the oil for the time prior to the appraoch of this contact, and no significant solution gas drive component prior to this time.

In this well the perforations are in the C zone only.

So that summarizes my field evidence.

Q Is that evidence consistent with calculations an engineer might make to check field data?

A Yes, it is. I think to understand the calculations and to further understand what's going on in the field, we might take a look at a hypothetical or schematic illustration of mechanics of gravity drainage, and that's illustrated in Figure IR-1, which is on page 16 of the exhibit booklet.

This is simply again intended to be an exhibit, schematic in nature, which illustrates why gravity drainage can be effective when it's allowed to operate and the conditions under which it may not be particularly effective.

In the schematic what we've shown is a cross section of an oil column, say, with an injector up-structure and a producer down-structure.

There are two figures shown here, one showing what might happen at low oil withdrawal rates and the other showing what might happen at high oil withdrawal rates.

And let's look first at low oil withdrawal rates.

In our schematic here, at low oil withdrawal rates, the gas continues to encroach into the oil column. If the gas is invading relatively slowly, the oil has an opportunity to drain down and rejoin or continue to stay up with the oil column and drain down to quite a low oil saturation at abandonment conditions. The longer we let the oil drain, the lower that abandonment condition of oil saturation will be.

At the same time, near the producing well on the lefthand side of our diagram, (unclear) are drawn into the producing well, we are necessarily going to have some gas coming out of solution of that oil.

Now, there are competing forces near the producing wells. There are pressure forces; there's low pressure in the well and higher pressure in the formation, so one force wants to make the gas flow into the producing well. So I've shown an arrow there with some gas moving in toward our producing well.

But other forces active in the reservoir, gravity forces, specifically, want to let the gas move up to the top of the oil column, and I show an arrow with forces in that direction.

Now, obviously, what we're looking at here is the force balance. If the rates are quite low, these pressure forces causing the gas releases from solution to move into the well will be relatively small and, of course, the gravitational force is fixed, but if the pressure forces are small, small relative to the gravity forces, then a lot of the gas that's released from solution can migrate upwards, perhaps forming a gas layer above the oil zone, but again the forces of gravity will tend to have that gas migrate back up and rejoin the oil column and further displace some of the oil -- or rejoin the gas column and further displace some of the oil that remains in that gas column.

So if we produce slowly, and slowly means relative to the rate at which oil can drain under the influence of gravity, we'll have a little free gas saturation, basically, in our oil zone, and that will be confined mostly to an area around the producing well.

All right. The schematic on the bottom illustrates the difference that we'll have if we produce at high rates.

Here again we've shown our injector and producer but now at high withdrawal rates, with a given amount of injection we don't maintain the pressure in the reservoir as high, so the pressure drops more, more gas comes out of solution, and in particular at high rates, we have higher drawdowns near the individual producing well.

All right, now the dominant forces will be the pressure forces which will cause gas that comes out of solution to predominantly go into the producing wells.

In addition, another thing happens at high withdrawal rates, and that is that the gas in the remaining gas column will tend to override that oil column. The gas and oil are always competing for going toward that pressure sink in the producing well, and the gas is a laot more mobile than the oil.

The only thing tending to hold the gas back is the influence of gravity, but if we produce at high rates, gravity can't win so the gas will tend to override the oil column and break through down into the producing well, resulting in production at relatively high gas/oil ratios.

Also, because we're moving relatively rapidly, the oil doesn't have time to drain to as low a saturation by the time we're reached an economic limit gas/oil ratio in our producing well.

So when we go slow, in summary, slow meaning slow enough that gravity drainage can occur, then we can continue to produce for long periods of time at low gas-oil ratios.

When we produce rapidly, meaning rapidly relative to the rate at which oil can drain naturally under the influence of gravity, then we'll produce at high gas/oil ratios and really we'll have solution gas drive dominating the recovery.

All right, that's -- that's a background for the computer studies that we did and my intent is to present here the results of the computer simulation, which is really our way of quantifying how high a -- how high a high rate is and how low a low rate is in order for gravity drainage to be effective.

So given that background, we can look at the results of this computer simulation. I'll be following the notes that I have on page 13 of my exhibit booklet, in which I say that we are now going to be looking at a comparison of simulated recovery with and without pressure maintenance.

Q While we're looking at that section, we also find on pages 22 and I believe 23 a description of the gravity drainage model?

A Yes, and I'll -- I'll refer to that as I -- as I go through this section of my discussion. Of course it was a computer simulation and a computer simulation means that there are certain characteristics of the reservoir which we have to input into our computer simulator, and those are described in the Figures IR-5 and IR-6 on pages 22 and 24 of our exhibit booklet.

I'm not going to go into a lot of detail in this description of our model. It's -- it's there for a complete reference should we need to clarify any questions, but I do want to point out some highlights of the simulation.

What was simulated was a one-mile wide slice through the reservoir, and this was a cross section through the reservoir, a cross section similar to the schematic cross section that we've been looking at in the last few minutes.

This particular cross section was eight miles long. It went from the top of the structure down to the edge of the expansion area.

It was 40 feet thick. We tried to simulate only the production from one zone, say, the C zone, in the unit.

The other noteworthy points, or most noteworthy points in our simulation, I think, include the absolute permeability; we assumed a horizontal permeability of 100 millidarcies with -- to go along with our 40 feet of thickness for this one zone.

And then on the second page of this discussion of the model, on page 23 I describe our producing well conditions and our pressure maintenance conditions.

We had one production well in this section. We're simply trying to illustrate a principle and we're not trying to capture in detail what would go on in the actual reservoir. Of course, in the actual reservoir we would have three or four producing wells along this milewide slice starting at the gas cap and going down to the edge of the unit, but we put all our production down-structure.

This production well we located one-half mile east of the western edge of the unit. This production well was produced at constant rate, and we're looking at several different rates, but it was maintained at that rate until the pressure in the reservoir -- until the flowing bottom hole pressure reached 500 pounds, and at that point the well was then produced at a constant bottom hole pressure of 500 pounds from that point forward.

Now we didn't take this depletion of the reservoir all the way to an economic limit. We terminated these runs at a gas/oil ratio of 2000 standard cubic feet per stock tank barrel. By that point, in our judgment, it was time to have seen the relative effects of solution gas drive versus gravity drainage.

Also, we would terminate an individual run if the flow rate in our one producing wel' dropped below

10 stock tank barrels per day.

But the major point I want to emphasize, and it will be important when we look at some of our recovery numbers later, is this was not taken to depletion at a much higher producing gas/oil ratio.

Next I want to summarize what we did in our injection well to maintain pressure. We had a single injection well near the top of the structure. It's a half mile west of the eastern edge of the unit. And here, to simulate partial pressure maintenance, we injected gas at a constant bottom hole pressure of 1600 pounds, and the actual injection rate varied as the depletion process continued. If it increased, tended to increase as the gas saturation around this well increased; but in the pressure maintenance cases it was not sufficient for complete pressure maintenance but at least for partial pressure maintenance, somewhat such as is going on in the unit today.

All right. I think of major interest is what did the simulator study show; what were the results.

Well, Figure IR-7, which is on page 25, I think summarizes well the results of the study.

In this figure we have a couple of comparisons but the first one that I want to mention is the comparison of recovery efficiency with pressure maintenance with recovery efficiency without pressure maintenance.

In the Figure IR-7 we've plotted recovery efficiency as a percent of oil in place within this milewide section as a function of the production rate from the single producing well that we had.

The top curve, the dotted line, shows the recovery efficiency when we had pressure maintenance with our injection at a constant bottom hole pressure of 1600 pounds.

The lower curve shows the recovery without pressure maintenance and the first thing that I hope is pretty obvious in this figure, is that there's -- given production rate, let's say 1000 barrels of oil per day, there's really quite a substantial difference in the recovery, at least up to this 2000-to-1 gas/oil ratio, between the pressure maintenance case and the no pressure maintenance case, on the order of 3 or 4 percent of the oil in place if no pressure was maintained, and on the order of 23-to-24 percent if pressure was maintained.

So the simulator said that maintaining pressure makes quite a difference at a particular withdrawal rate.

Q What is the main reason for the improved recovery with pressure maintenance?

A The reason for improved recovery with pressure maintenance is that if we maintain pressure we have less gas coming out of solution, less of a solution gas drive component, and therefore, this gas not coming out of solution means that that gas is not produced and we don't lose this reservoir energy. It's basically a difference between a gravity drainage drive mechanism dominating and a solution gas drive mechanism dominating.

Pressure maintenance gives gravity drainage more chance to operate.

Q Did you continue with your studies and determine what is the effective rate on recovery? At what rate should be produce the reservoir to have the most efficient recovery?

A Yes, I did. I won't say that this study quantified the rate at which the reservoir ought to be produced most efficiently, because it was not an attempt to capture all the exact detail of the reservoir, as I mentioned earlier. It was a -- it was a study in which we used properties typical of the reservoir but without trying to include all the details of the reservoir; however, what it did show, I think, can first be summarized on this same Figure IR-7, when we not only compare recovery with and without pressure maintenance but look at a given case, let's say, with pressure maintenance at what the recovery is at various rates. We know that at rates above approximately 1000, perhaps 1100, barrels per day there's a sharp increase in recovery; that tends to improve as the rates get lower and the lowest rate that we studied was on the order of 500 barrels per day.

So somewhere in the range of 500 to 1000 barrels per day for the properties used in this cross section, we have improved recoveries.

As rates get higher, let's say, dropping to 1100 barrels per day and moving on upward to extremely high rates, the recovery drops off sharp -- sharply, and the essential point to be made here is that if you produce too fast in a reservoir which has an opportunity to have gravity drainage (unclear) dominating, you lose the benefits that that gravity drainage can provide to you. The reservoir essentially operates completely under a solution gas drive mechanism.

The next figure, Figure IR-8, is intended to give further insight into this phenomenon.

In Figure IR-8 what we show is producing gas/oil ratio at our single producer as a function of cumulative oil recovery from the reservoir.

We show here the cumulative gas/oil ratio at three different rates. The lowest that's shown here is 633 cubic feet -- excuse me, at 633 stock tank barrels per day.

Here we see that up until the time approximately 20 percent of the oil in place has been recovered from the reservoir, that the gas, producing gas/oil ratio remains quite low or comparable to solution gas oil ratio.

At that point the contact is sufficiently closed to the producing well, the reservoir pressure is also dropping because we're not claiming any reservoir pressure (unclear) in the simulation, at that point the gas/oil ratio begins to increase sharply.

At the other extreme, at a production rate twice that 633, the gas/oil ratio begins to increase after only a small percentage of the oil in place has been produced.

There is one intermediate case and it's -- it's a complicated-looking case, but it illustrates some of the mechanics of gravity drainage. Here we show recovery at a producing rate of 950 barrels per day. At this rate, too, at first the gas/oil ratio was beginning to increase from early times due to the drawdown near the well, and of course, this was caused by gas coming out of solution and being produced in that producing well, but some other gas was also coming out of solution but migrating to the top of the structure, as I illustrated in my schematic.

When the gas saturation had developed throughout the oil column at the top of the structure and that gas had sufficient permeability to flow, that that gas could then begin to flow away from the vicinity of the well and up to the top of the structure and rejoin the gas cap which was growing and because that gas could now flow away readily, rather than be produced, the gas/oil ratio actually dropped back but couldn't stay low forever, eventually began to rise as the contact approached nearer and nearer the well.

The -- that -- that figure showed the behavior with pressure maintenance.

Figure IR-9 shows the gas/oil ratio versus cumulative recovery for the case where there is no pressure maintenance. Herein we see that with a greater -- that with a given amount of recovery the gas/oil ratio doesn't rise as rapidly if the rate is low but -- but here we see in all cases the producing gas/oil ratio rising to the point at which we terminated our runs much sooner than was the case with pressure maintenance.

The Figure IR-10, page 28, summarizes the recovery efficiencies. These are not meant to be indicative of what's to be expected in the field except directional. They are not forecasts of field recovery.

The essential, most essential qualifier is that these recoveries are recoveries up to producing gas-oil ratio 2000 cubic feet per barrel, and, of course, we would produce a well to an economic limit ratio much higher than that.

However, directionally what these recovery efficiencies show is that for the case of no pressure maintenance, at an extremely high rate we reach this limiting ratio when only 1-plus percent of the oil has been produced and at a much lower rate of 633 cubic feet barrel we reached this limiting gas/oil ratio when only about 7 percent of the oil in place had been produced.

For the case of a partial pressure maintenance at a very high rate, the recovery is essentially the same as with no pressure maintenance, but at the low rate the recovery efficiency has approached 30 percent because gravity drainage has been allowed to do its thing.

Q You've satisfied your first major requirement with regards to the project and have satisfied yourself that there substantial evidence of pressure communication between the expansion area and the project area?

A That's correct.

Q And under the second major point you have satisfied yourself that there is substantial evidence that improved recovery in the existing project area is caused by pressure maintenance.

A That's correct.

Q Then you also conclude that improved recovery can also be applied to the expansion area and that recovery attkributable to pressure maintenance.

A Yes, I am.

Q In addition to those two major requirements and your opinions on those areas, you mentioned in the beginning of your presentation that you had made a study to determine if the expansion of the project area into the expansion area would have additional benefits.

A That's correct.

Q And what did you find?

A What I found was that expansion of the Canada Ojitos Unit would provide the opportunity to build a gas plant with attractive economics. This plant would allow the unit operator to replace the reservoir gas - gas cap, cycle it out, send it through a gas plant and reinject the residue gas from the gas plant back into the reservoir to maintain pressure and this cycling of gas we estimate could increase the hydrocarbon liquid recovery by over 700,000 barrels during the life of the project.

Q To make sure I understand, you're including the cycling of gas from the expansion area and the existing area?

A That's correct.

Q What happens if we don't have the expansion area included in the project and you're simply cycling the gas in the existing area?

A If we're simply cycling the gas in the existing area, we really don't have enough gas to send through the plant long enough to have attractive plant economics.

As Mr. Greer pointed out yesterday, his estimate of current gas in place in the gas cap, is in the area of about 10-billion cubic feet.

All right, with that 10-billion cubic feet being the target if the cycling were confined to the existing area, the plant needs to be able to process about 10-million cubic feet of gas per day to have attractive economics because (not clearly understood) and some quick mental arithmetic indicates that if you process 10-million cubic feet per day, and have about 10-billion cubic feet to process, we'd only have about a 3-year life for that gas plant, and the economics of that don't look very attractive.

Q What evidence do you find to support your conclusion that the expansion area hydrocarbons are necessary in order to make a gas plant economical?

A Well, the evidence is based on, again, some reservoir simulation.

In this case we used a so-called compositional reservoir simulator.

The compositional reservoir simulator is different from the usual simulator in that it allows us to look at vaporization of liquids within the reservoir, vaporization of those liquids into the gas phase, or vice versa, if that's the way the fluids want to transfer, and this is essential in looking at this gas plant because a lot of the additional hydrocarbons liquid recovery is going to come from taking the cap gas out, which is saturated with intermediate molecular hydrocarbons, sending those liquids into the gas plant and in the gas plant removing a major fraction of the ethane and heavier hydrocarbons and then re-injecting a gas which is mostly methane back to the reservoir.

Now, when we re-inject methane, the oil in the reservoir will tend to vaporize its lighter components and this re-injected gas will pick up vaporized hydrocarbons from the oil remaining in the reservoir.

To be able to study this process of vaporization of oil and a pick up of hydrocarbons which will ultimately become plant liquids, we needed this compositional type simulator which can model this change of phase of hydrocarbons within the reservoir.

Specifically we looked at two cases. First, continued re-injection of reservoir gas, that is, no cycling, continue the current operations; and secondly, recovery of liquid hydrocarbons in a gas plant, the cycling operation.

The results, I think, are brought into focus in Figure GC-1, which is following the two written pages of this part of my testimony.

This is output from the compositional reservoir simulator. Here we have the cumulative production in millions of barrels versus time. This simulation assumed as a starting date for a gas cycling operation, 1-1-88. I realize that the operation did not begin 1-1-88, but what we're really trying to do here, is look at -- at 10 years following known history of cycling operations.

Shown on this graph on the top line are the total liquid hydrocarbons recovery with the cycling operation on a cumulative basis.

Under that we show the total hydrocarbons recovery without cycling, and, of course, the difference in these two curves is the additional recovery that we could attribute to this gas plant.

You'll notice in 1997 that there's a kink in the curve. What we did to compare cycling to noncycling was to assume that the cycling operation would -- would continue for 10 years and then we would follow that cycling operation by blowdown in both cases.

In the blowdown phase, of course, with the cycling we assumed we would continue to send to reservoir gas through the plant.

To be fair to the noncycling case, we assume that at that point there would be some hypothetical recovery process installed; that may or may not be a realistic assumption and if it's wrong, of course, no recovery process being installed, then we wouldn't recover the hydrocarbon liquids from -- from the produce (not clearly understood), so this -- this, if anything, would penalize the cycling case when we compare it to the noncycling case.

The additional recovery at the end of the 10-year operating phase, you'll note on the graph, at the end of 1997 approximated 2-million barrels.

After that the -- some of the benefit of the cycling operation actually began to match.

If we install this hypothetical recovery process for the noncycling case starting at blowdown, that blowdown phase itself would vaporize some of the lighter hydrocarbons in the reservoir oil; however, I would note that even if those plant liquids would be recovered, they would be recovered more than 10 years from the start of cycling operation and so if you discount them to their present worth, they would be much less valuable than hydrocarbon liquids which would occur in the first 10 years after the plant was installed.

The bottom line, I think, is brought into even sharper focus on the next figure, GC-2. It's a bar graph and here we show production with and without cycling.

We show the plant natural gas liquids, PGNL, in the two cases and, obviously, with cycling there's a lot more plant natural gas liquids.

We show the crude oil next to the plant natural gas liquids. As you can see from the bar graph, there's more crude oil recovered without cycling; however, there's a very logical explanation for that. With cycling what might have been produced later as crude oil will be vaporized and produced as plant liquids, so we just change the form in which the liquifiable hydrocarbons are recovered.

The important point is that the sum of the plant liquids and crude oil is greater by about 700,000 barrels in the cycling case than in the noncycling case, and to give some more specific numbers to look at, on the next page, Figure GC-3, we summarize the plant natural gas liquids. crude oil, and total recoveries with cycling, without cycling, to the difference, and ultimately, the difference is approximately 700,000 additional barrels of hydrocarbon liquids being recovered with the gas plant.

The remaining pages in this exhibit simply give details of the model that was used for simulation and again I don't want to spend a lot of time on these details, but I think some of the -- some of the details are important.

The model dimensions, here, while we were not trying to simulate the reservoir exactly, we were at least trying to capture the essential features of the reservoir, so this simulation was also a cross section, a 2-dimensional cross section; however, this cross section was 8 miles wide, which is a reasonable average for the total width of the Canada Ojitos Unit.

It was about 7 miles long and although the unit is longer in some places, we used 8 miles in our earlier gravity drainage study, 7 miles again is a reasonable average for length of the unit.

Here we looked at 3 layers, which are intended to be representative of the A, B and C zones, and these layers were 30, 30 and 40 feet in thickness.

The permeability that was used I think is the next number of essential importance. We used 100 millidarcies, horizontal permeability.

We had some vertical permeability. Remember, in simulating these zones with -- with single layers, the vertical communication between these zones is necessarily going to be limited, although it does exist. If nothing else, it exists in wellbores, through hydraulic fractures, but also, probably, through some natural fractures in some areas of the reservoir, and so we had a modest amount of vertical permeability between these layers.

In a model of this size and with the porosity that was used, the original oil in place was about 47-million stock tank barrels, which I think is a reasonable approximation to the oil in place in the Canada Ojitos Unit.

We summarized the plant recovery factors. We believe that the plant can recover 70 percent of the ethane; 90 percent of the propane; and 100 percent of the butane and heavier hydrocarbons.

And the way the model actually worked, the unit production is from four wells located in alternate cells in the model. By cells in the model, I think that might be best explained by looking at perspective and areal view of the model, which is a couple of pages later in the exhibit.

Basically in alternate cells we had production and we had our injection in one of these cells.

The furthest up-dip well was converted to gas injection and historically the time at which injection began, which was 1968.

Of course, with only four wells in our model, and many more wells in the unit, we have to allocate actual production to the nearest well in the model and that's what we did.

The model ends at the Canada Ojitos Unit-

Gavilan Pool boundary on the west, but we found that in order to be able to match observed historical gas/oil ratios and pressure performances in this area, that we had to have migration out of the Canada Ojitos Unit, and we did this simply by puttig an additional well in the most western cell of our model, and the so-called "Gavilan Migration" was simply represented by the production from this well.

Well, that, I think, describes the essential features of the model. We might take a brief look at the history match.

When we -- when we model a reservoir, it's important, even though we're trying -- not trying to capture every detail, at least to brief these important details.

Figure GC-7 shows the production in the model versus observed production of oil and the model gas/oil -- the model MCF per day of gas versus the observed MCF per day of gas.

The oil production was forced; that is, we forced the wells to produce what had been observed historically and what we matched on was the gas/oil ratio, and basically this is a reasonable match. We seem to have captured the essential characteristics of the reservoir and, of course, doing historically gives us more confidence that if we project forward in the future, that the future performance projection will be realistic.

The remainder here is simply more detail information about the model.

Q In your opinion, Dr. Lee, is there substantial evidence of the ability of the project to function and recover liquid hydrocarbons that would not otherwise be recovered if the expansion area is included into the project area and gas cycling is implemented as proposed with the inclusion of the installation of a gas plant?

A Yes.

Q The idea of a pressure maintenance project is an accepted method of enhanced recovery, is it not, sir?

A Yes, it is.

Q And what is the basic concept by which that is an accepted method of recovery?

A Well, the basic concept is that to provide outside sources of energy, such as gas injection in this case, we can improve oil recovery by maintaining pressure at a higher level and in this case, minimizing the contribution of solution gas drive, which will improve recovery.

Q Is it an integral part of pressure maintenance projects such as this to have an injection gas credit apply for that operation?

A Yes, it is.

Q What is the necessity for an injection gas credit in terms of the effect it has on the net voidage of the reservoir?

A Well, in terms of net voidage of the reservoir, if we -- if we re-inject the produced gas, of course, we minimize the amount of the reservoir voidage; however, that re-injection has an expense and therefor I think it's logical to give credit for that because that re-injected gas is doing good for recovery from the reservoir as a whole.

Q In your studies, Dr. Lee, have you seen any data, evidence, or have you made any calculations or simulations that cause you to believe that the expansion area is not appropriately included in the existing project area?

A I have seen no evidence that would lead me that conclusion.

Q Do you have an opinion, sir, as to whether the inclusion of the expansion area into the existing project area will prevent waste of hydrocarbons?

A Yes, I believe that it will prevent waste of hydrocarbons.

Q Do you have an opinion as to whether it will result in recovery of hydrocarbons that would not otherwise be recovered?

A Yes, I believe it will result in additional recovery of hydrocarbons.

MR. KELLAHIN: Mr. Chairman, at this point that concludes my direct examination of Dr. Lee.

We would move the introduction of Sun Exhibit Number One.

MR. LEMAY: Without objection, Sun Exhibit Number One will be admitted into evidence.

Are you having any questions?

MR. CARR: I have just a couple of questions, yes, sir.

MR. LEMAY: Fine. Why don't you do that at this time, if you would, Mr. Carr.

CROSS EXAMINATION

BY MR. CARR:

Q Dr. Lee, would you refer to what is identified as Figure IR-7? Page 25.

A Yes.

Q If we look at this, if I understand the purpose of this exhibit, it shows that there was greater efficiency and greater recovery obtained by producing wells at lower rates, is that correct?

A That's correct.

Q You are not attempting here to suggest that an appropriate allowable is 1000 or 1100 per day per well, are you?

A Oh, goodness, no. In fact, what we've -- what we've simulated here is production from a number of wells along each mile of section. We simply, for simplicity in modeling, allocated all that production to a single well, so actually, in practice, each individual well along that milewide section might be producing, say, 3-or-400 barrels per day. We're just looking at a total because we're trying to model the rate at which the gas/oil contact moves, given a total amount of production.

Q And you're modeling the rate of withdrawal from a certain area within the reservoir.

A Yes.

Q Not an allowable or a rate --

A No.

Q -- that should be assigned to any well?

A No.

MR. CARR: That's all I have.

MR. LEMAY: Fine.

MR. KELLAHIN: May we have a short break?

MR. LEMAY: I think I was going to recommend it at this point.

Let's take a fifteen minute break and then we'll proceed with cross examination.

(Thereupon a recess was taken.)

MR. LEMAY: We will continue. Are you ready, Mr. Douglass?

MR. DOUGLASS: Yes.

CROSS EXAMINATION

BY MR. DOUGLASS:

Q John, I hope you don't mind if I call you John, I think we've known each other long enough where you can call me Frank.

John, as I understand your -- your study here, first of all you looked at the situation to see whether you thought there was effective pressure communication, and then in addition, you made a study to see whether the pressure maintenance project had been effective. That's generally what you did.

A That's right.

Q All right, now if the -- if the proposed expansion area is not in effective communication with the pressure maintenance project, would that in any way detract or change the conclusion that you had with reference to the second part of your study; that is, that the pressure maintenance project appears to have been successful?

A It wouldn't change the conclusion that the pressure maintenance project appears to have been successful; that wouldn't change at all.

Q So, really, these are two separate items that we've got here. In other words, you could have made the study with reference to whether the pressure maintenance project was effective or not, and there could have been a barrier, actually, in the reservoir between the pressure maintenance area and the propose expansion area, and your study on the effect of this pressure maintenance area would essentially have been the same.

A Except that part of my evidence, Frank, was the fact that we appear to have gravity drainage was evidenced by a low GOR well, low GOR production in the expansion area, so I think, really, the conclusion is based on evidence from the expansion area directly.

Q On the GOR, we'll get to that.

Well, other than that, then, your -- still your study on the effectiveness of the pressure maintenance area, the effectiveness of that would not be affected by whether it was connected to the expansion area.

A I'll agree with that.

Q Now, let's look at your -- your proof of effective pressure communication.

Are essentially all of your opinions based on the work that was done by Mr. Greer?

A That's correct.

Q And I believe on page 4 is where you start with your discussion of the pressure communication aspect, is that correct?

A That's correct.

Q Do you have gravity segregation or gravity drive when you have a reservoir that essentially has no dip in it?

A You can have if you have high vertical permeabilities.

Q So you can have a solution gas drive reservoir that has relatively little or no dip and still get, as you say, the benefits or the effect of gravity segregation, is that correct?

A We're talking about a matter of definition here. By definition, pure solution gas drive has no gravity drainage benefit. When you can't have gravitational segregation then you have solution gas drive. That's simply a definition of what that means.

When the gas and oil can segregate, then you have a contribution, at least a small contribution, from gravity drainage, but you can't call it a solution gas drive reservoir.

Q Well, do you -- let me ask this. When you get below the bubble point in a reservoir that's fairly flat and gas starts coming out of solution, as it comes out of solution does all of it go to the wellbore?

A It depends on the -- it depends on the peremeability in the reservoir, and in particular how the well, well away from the wellbore, it depends on the vertical permeability.

Q Let's assume that you have good vertical permeability.

A All right.

Q In fact you've got fractures in this reservoir, where you had some (unclear).

Under those circumstances would all the gas move to the wellbore?

A No, then the gas, given that vertical permeability, could migrate upward.

Q Upward. The first item that you talk about here is the interference test, I believe, and you show a map that Mr. Greer put on previously, is that correct?

A That's correct.

Q Under G, I believe, in Exhibit One. No, that's --

A It's from the black exhibit book, though.

Q Right, Exhibit Two. Is this the map?

A Yes, it is.

Q When you say interference test are you talking about the two fracture response tests, that is, the fracture on the C-34 well to the fracture on the A-16 well?

A I include those, yes.

Q Those are the only fracture response tests that were done between the pressure maintenance area and the proposed expansion area.

A I believe that's correct.

Q And it's your -- you say those interference -- you think of those as the interference test between those two areas.

A Yes.

Q Do you have any other interference tests between the proposed expansion area and the pressure maintenance area?

A No, all those tests are shown on this map.

Q Well, when you say no, you mean that there are no other interference tests that you know of between the pressure maintenance -- expansion area and the pressure maintenance area.

A That's correct.

Q Now have you looked at the bottom hole pressures that were run as a result of the Commission's order during the last six to eight months?

A I've seen those. I don't have a copy of those, but I'm generally aware of them.

Q Assume with me, then, -- with me, John, that the pressures in the pressure maintenance area that were measured, were about 1400 pounds, and -- in both surveys -- and assume with me in both surveys that the pressures measured in the expansion area were approximately 950 pounds.

A All right.

Q 450-pound difference. Does that indicate a highly transmissibility rock, or a highly permeability rock, existing between the proposed expansion area and the pressure maintenance area?

A Well, just taking it as an isolated fact, it might appear that you're not having good flow; however, that was one of the reasons for Mr. Greer's pressure contour map throughout the entire reservoir, where he showed smoothly changing pressures throughout the entire reservoir, cause by -- caused in particular by continued, substantial over-injection.

Q You describe those pressures as shown on Mr. Greer's, what I call, rainbow map, being smooth --

A Yes, I do.

Q -- through the transition. All right, we'll get that in a second.

Have you observed the calculations that Mr. Greer did using, apparently, a formula that you confirmed would be helpful to him, and I believe it's Exhibit Two. I'm sorry, it's Three, Exhibit Three.

A Yes, I've looked at his results.

Q Yes. His results, where he shows Koh in darcy feet, Item 13 there, for instance, between the -- in the area of the COU -- the 34 well, which is in the pressure maintenance area, and the 32, which is in the expansion area, he says 14 darcy feet Koh.

A Could you refer me to the section that --

Q Yes, I believe it's after Section A and maybe the last page of Section A, right before Tab B.

A All right, sir, the well pair again?

Q COU 34 and COU B-32.

A Yes.

Q 14 darcy feet, is that correct?

A Yes, that's correct.

Q Do I recall in the -- in reading the transcript of the March and April '87 hearing that you indicated that you made some calculations or thought that the 10 darcy feet was a representative figure for the reservoir rock that you were dealing with here?

A Yes.

Q Would that be -- would the 14 be comparable to that?

A Yes, it would.

Q Do you recall Mr. Chavez asking you a question about if you had 10, I think he said millidarcy feet and you corrected him to 10 darcy feet, do you recall him asking you if you had, in effect, 10 darcy feet, would you expect there to be a pressure differential that would exist at around 400 psi when the wells are about 4 miles apart? Do you recall that question?

A I don't recall the question but --

Q Well, he asked you that, let me read back your answer --

A All right.

Q -- and I'll read the whole question and answer to you. I don't have an extra copy.

Dr. Lee -- this is Mr. Chavez.

"QUESTION: Dr. Lee, at a reservoir permeability, an average of 10 millidarcy feet, would you expect there to be pressure differential that would exist around 400 psi when the wells are about 4 miles apart?

ANSWER: I think you meant to ask me at

10 darcy feet, and I'm going to respond to that, Mr. Chavez.

QUESTION: Yes, that's right, yes.

ANSWER: Not if there is a -- not if there is continuous communication at that transmissibility level but we would need to -- we need to compare permeabilities within the communicating strata and I need to qualify my answer to that extent, specifically, if you don't want to compare a pressure measurement in the C to a pressure measurement in the A some distance away; if we believe that the A and C are basically in very poor communication."

Do you recall that?

A Yes, sir.

Q The first part of your answer is "not if there is continuous communication at that trasmissibility level", is that right?

A That's correct, but again, in the context of this field, remember that we have this substantial over-injection in the gas cap causing these pressure gradients, and we're not talking about simply production from offset wells without the over-injection into one area.

Q Well, even if you've got over-injection, if you've got this good transmissibility, it's just going to move just as fast with over-injection as it is without any injection, isn't it?

A Well, apparently it's not.

Q And apparently one of the reasons is that there may be a barrier between the C-30 -- the B-32 and the C-34.

A Well, but we -- we see -- we see pressure drops from the cap to the -- to the east of this supposed barrier. It's not a sudden drop, based on the data that I remember. It's a continuous drop starting at the cap on down to the edge of the expansion area.

Q The pressure that you're talking about was in these injection wells right after they were shut-in after having been injecting for some period of time.

A Well, pressures, pressures in shut-in wells, generally, yes, wells in the cycling area, but including some in the expansion area, those in which Mr. Greer used surface pressure measurements to get a large number of well pressures at the same time.

Q On your -- turning to page 5, on that over-injection aspect, we see there was no pressure increase. It says, "Despite the over-injection, the average reservoir pressure did not increase during either period of time." Is that correct?

A That's correct.

Q Have you looked at the bottom hole pressures to see if it indicated that the bottom hole pressure in the pressure maintenance area actually did show some increase --

A Well --

Q -- in November to -- November to February time?

A Well, I've looked at the bottom hole pressures and the surface measured pressures all together, and taken as a collection I don't see any pressure increase.

Q Let me ask you with reference to the rainbow map, the one that you said has a smooth -- I believe it's in Exhibit One, Tab G, is that right?

A Yes, sir.

Q Down in the yellow and brown area, you would consider that a smooth gradient, wouldn't you? You talked about a lot of pressures at about 803 or 804, and then it looks like it's about a 10 pounds increase in the surface pressures there.

A Yes, that's correct.

Q All right, sir. When you get up here in the pressure injection area up here, you've got real high pressures, 16-1700 pounds, is that correct?

A Yes, sir.

Q In a mile or a mile and a half those pressures just -- there's not a smooth there, that's a precipitous drop from that injection area to the next row of pressures, isn't it?

A Well, yes.

Q And then the -- from about -- from the blue area to the green area you have fairly smooth area of pressures, isn't that correct?

A Yes.

Q And then you have another precipitous drop from about 1140 pounds ot about 800 pounds or even 340 pounds difference on Mr. Greer's exhibit, is that correct?

A Yes. As you move into an area of very concentrated withdrawals, I would note. The precipitous drop that you are referring to, 800 pounds to, say, 1100 pounds, is into an area of high withdrawals. The precipitous drop near the injection area is in an area of very high injection.

Q The -- but you would still describe that as a smooth pressure gradient.

A Continuous, smooth, yes.

Q Any pressure gradient is going to continuous if it's going down, isn't it?

A Yes, sir.

Q All right, sir. Now, next you talk about the gas/oil ratios, I believe, is that correct?

A Yes, sir.

Q And I believe later in your exhibit you talk about the -- comparing the B-32 well that has a production log on it, is that correct, --

A Yes, sir.

Q -- on page 17?

A Yes.

Q Would you refer to Exhibit One, Tab D? Is that the production log on the B-32?

A Yes, it is.

Q Is the -- is the pressure in the area of the B-32 some 4-or-5-600 pounds below the bubble point pressure?

A Yes, it is.

Q And do I understand that on this production log here, that it shows essentially solution oil or no gas coming out of the oil at the lower level in the C, is that right?

A Well, yeah. I would say the producing GOR is probably in the 600-700 standard cubic feet per barrel range.

Q Essentially solution ratios?

A Somewhat above but close to solution

ratio.

Q Why -- why isn't this gas coming out of solution because it's being below the bubble point, coming out with this oil down in the C zone?

A Because of gravitational segregation.

Q Oh, do you mean that the gas in that area is moving up in this wellbore?

A It's moving up in the wellbore or, if there's not communication with the other zones in this well, up, back up to the gas cap.

Q In other words, this could be fracture communication from the hydraulic fracturing in this well where the gas that you're talking about that ought to be coming out of the C, that could be coming out in the A and the B up here.

A Could be.

Q Right in that immediate area.

A That would -- that would mean gravitational segregation, right.

Q And if you have a -- in the area we're dealing with here, in the pressure -- excuse me, in the expansion area, that's essentially a very flat, almost no structural relief in that area as far as the well is concerned, isn't it?

A That's correct.

Q Then another logical explanation for the gas in the B-32 coming out of the A and the B zone could be that the solutoin gas that's coming out of solution in that area is accumulating around the wellbore and moving up and coming out of the A and B zone.

A Yeah, under the influence of gravity moving up, which is exactly what I described in my description of gravity drainage.

Q Well, you're going to have that kind of gravity segregation even in the reservoir. We've already established that.

A Yes.

Q John, if the, if you have this -- this good pressure communication between the pressure maintenance area and the proposed expansion area, has that communication always existed there since the time that nature essentially finished moving the rocks around in this area?

A Yeah, I would say if it's there now it has to have always been there.

Q So the fluids that we're talking about that you and Mr. Greer think, you know, think move the pressure maintenance area into the expansion area, those fluids could move in the other direction just as easy.

A They will move in the direction of the pressure gradient, that's correct.

Q All right, and if you're producing only the pressure maintenance area, then fluids are going to move just as easily from the expansion area into the pressure maintenance area.

A Given, given a pressure difference, they will move in the direction of that pressure difference.

Q And with these transmissibility figures and calculations that Mr. Greer's made here, you can actually calculate how much movement that could be over a period of time with reference to that, couldn't you?

A You could make calculations, yes.

Q You haven't made those.

A No, I haven't.

Q You don't know how much oil would have moved from Gavilan to the pressure maintenance area -- excuse me, the expansion area, into the -- into the pressure maintenance area in the twenty years that it produced before Gavilan and the expansion area started producing.

A I made no -- no projections about it.

Q Would that be -- in making those calculations, would that be a pretty good test to see if this -- the transmissibility in darcy feet calculations appear to be accurate?

A If you took into account everything that's going on.

Q Let's talk just a little bit about your -- your pressure maintenance -- your effective pressure maintenance here.

Is it fair to say whether the -- whether the pressure -- whether the expansion area wells are in or out of the reservoir that you're looking at, you would have arrived at the same conclusion on pressure maintenance? It looks like it's a benefit to the area that you're dealing with.

A Yes.

Q Is the model that you made in -- you made two models, I believe, used two models.

A Yes, correct.

Q Is -- on page 16, is that a depiction or an observation that -- schematically of the model that you're talking about?

A Oh, the phenomena that we observe here, we observe in modeling at different rates.

Q Let -- let me ask you, one of the things that I see, I believe, is that you use a significant factor dip, is that correct?

A That's correct.

Q Is the angle of the dip important to whether you have what you call gravity drive, gravity segregation?

A Well, the steeper the dip, the more effective gravitational segregation can be, yes.

Q All right, have you made any studies about just the -- how effective gravity is without pressure maintenance? Is that part of your study?

A Yes, that's part of this study.

Q And I assume that you get about 5 percent, or so, recovery?

A Yeah, at a limiting gas/oil ratio, it's pretty low, but yes.

Q So even with just gravity and this high angle dip, you're only going to get about 5 or 6 percent recovery.

A Without pressure maintenance?

Q Without pressure maintenance.

A Right.

Q What if you have essentially flat or just very little dip, what type of -- of recovery would you get from gravity with those conditions?

A It depends o withdrawal rate. If you produce slowly enough you could -- you could get good recovery.

An example of where that happens is the Oklahoma City Pool, which is flat, which is producing a high percentage of oil in place under gravity drainage.

Incidentally, this model near our producing well, we put it in the flat area of the reservoir honoring the structure that we have here.

Q That's the second model.

A No, the first model, also. Let's look at page 24, Figure IR-6. That's the elevation above sea level versus horizontal distance from the western edge of the unit. Our producing well was right in the middle of that first mile, so it was in the flat part of the reservoir.

Q So that -- that particular well gets the benefit of the -- of the dip or the gravitational forces for the rest of the model, is that correct?

A Right, but gas that migrates away from -- from the oil near that well has to go up.

Q You didn't make a study of where -- the 500 foot level there, you just closed it off there to see what effect it would have at that well and the bottom of that area where the top of the reservoir was essentially 500 feet.

A No, I did not.

Q But you say that you could produce that well slow enough where you'd even get some effect then of gravitational --

A Yes, and I will speculate that that rate would be so slow that it would be uneconomic; it would never pay the well out.

Q And that's one of the problems that you have with trying in almost every reservoir, in trying to get some benefit from gravity segregation, or gravity drive, as you describe this, that your rates may be so low that you can't economically produce your well.

A That's true in most reservoirs. It's the rare reservoirs with high permeability in which you have this opportunity that we have here.

Q High permeability and large dip.

A Some dip. Again there are reservoirs on record with two or three degree angle dips that -- in which gravity segregation is quite effective.

Q What -- at 335 feet per mile, what -- what gravity is -- I mean what angle dip is --

A I don't know. That's -- that's steep. It's steep here. That's an average for this reservoir, but I will agree with the point you're making, that that's steep.

Q Well, it is about 3.6 degrees?

A I don't remember. Yeah, sure, yes, but that's an average. It's much steeper in parts.

Q Let me also ask you on page 16 with reference to your IR-1 that you have there. I know that this is (unclear) schematic, but as I understand the forces that are here, in each of them you show the gas above the oil column.

A That's correct.

Q Now, we're talking about in the reservoir that distance being only about 100 feet, 30 feet as far as net pay is concerned.

A That's correct.

Q And if it's got some shale in between maybe another 50 or 100 feet, is that right?

A Correct.

Q But the distance from, say, the producer that you're talking about and injection, you're talking about 3 or 4 miles, aren't you?

A In our model study.

Q Yes.

A 8 miles, well, 7 miles.

Q All right, 7 miles.

A Yes.

Q So you're talking about 100-200 feet versus maybe 25,000 to 35,000 feet.

A Correct.

Q So if you were drawing this true scale, the reservoir would look more like just a line, just a line here, versus the distance between the lowest producer you've got and the injector, wouldn't it?

A That's correct.

Q So the -- the effect of gravity within that -- that little area, the gas is not going to have to move very far to get to the top of that -- the top of that area.

A That's right.

Q Do I -- is the -- when you said that your model that you prepared went to the edge of the expansion area, were you talking about the western edge?

A Yes.

Q The fracture response that you say that you see in such a short time, you say it's got to be attributable to the inescapable conclusion of a high permeability formation.

A I think the fact that we see it continuously in case after case a short time after fracture leads us to the logical conclusion that that high transmissibility formation must be the cause.

Q And that high transmissibility formation is between C-34 and the B-29 and the B-32.

A Well, in those areas where these tests have been conducted.

Q Well, that's in the area that's been compared on that interference test, isn't it?

A Right.

Q Do I also see that -- that in your study of the pressure maintenance area that it appears that what has been taking place there is the normal effect of a gas injection project where the gas is taken from the wells that are producing relatively low structure, inject it back into the -- to higher structural positions and that gas, pluse the normal gravity drive that you have because of the angle of the formation, is pushing the oil down and you're producing it from the relatively low structural position, is that correct?

A That's correct.

Q And as that happens you, -- one of the normal consequences of that is that you have oil wells to gas out.

A Correct.

Q It's just like in a waterflood project, if you have a successful waterflood, you're going to have oil producing wells to water out. Is that correct?

A Yes.

Q So in a successful gas injection program you're going to have gas wells -- I mean, excuse me, oil wells to gas out as the gas moves down in the formation.

A That's correct.

Q Did you find that that appeared to be exactly what was happening in the pressure maintenance area, that you were having a successful gas injection project and the wells were gassing out because of the gas being injected and moving down in a normal or expected pattern as far as the reservoir was concerned.

A Correct.

Q Now, let me talk about the gas plant.

A Okay.

Q Did you hear Mr. Greer's testimony yesterday?

A Yes, I did.

Q Do you think the difference of 1000 MCF a day producing ability is going affect, adversely affect, the economics of this gas (inaudible)?

A Depending on where that 1000 barrels per day is.

Q 1000 MCF.

A 1000 MCF. Yes. If I might elaborate, we don't have the ability to produce gas from the wells in the remaining oil column. We don't have the opportunity with the reinjected gas to strip out the liquifiable hydrocarbons, or the vaporizable hydrocarbons from that oil column, so the loss of 1000 barrels per day in the proposed expansion area would be crucial.

So it's not so much, you know, it's part-

Q Well, that's 1000 MCF a day. The gas that's being produced in the expansion area now, it doesn't know how far it is from the gas plant, whether it's in the expansion area with a net ratio or without, does it?

A Right.

Q And so if there's 4-or-5-million cubic feet a day in the expansion area, then that would be a significant volume to a gas plant operation, wouldn't it?

A Yes.

Q Are there other operators in the Gavilan Field that are actually taking their gas and processing it through a gas plant now?

A I don't know.

Q You're not aware that the Mallon wells have their gas processed in a gas plant.

A No, I'm not aware.

Q You're not -- there's not any gas cycling project or gas injection project in Gavilan, is there?

A No.

Q If the -- if there is effective separation between the pressure maintenance area and the expansion area, that's not going to detract from the attractiveness of the field trying to cycle the gas that's available in the pressure maintenance area, is it?

A Well, that was the point I was trying to make earlier. I think, yes, it will, because, you know, if we cycle out the existing cap and reinject methane, we've got to be able to contact oil with that methane.

If we can't contact the most down structure wells continuously and continue to strip out the vaporizable hydrocarbons from that, then the plant economics don't look attractive.

Q Well, if there is effective separation between the pressure maintenance area and the pressure expansion area, you're saying that if that, if there is that kind of separation, then it's really not going to be economical to put in a gas plant in the pressure maintenance area --

A That's what I'm saying.

Q The only -- the only way this would make it economical is that if you were to take the rich gas out of the separated area and inject it and run it through the plant, you'd either have to inject it or sell it, wouldn't you?

A Right.

Q You still would have, even if these are two separate areas pressurewise, you'd still have the gas that's available from the pressure expansion area out of those oil wells to run to a gas plant with.

A Once.

Q Well, that's all the gas is being run through -- to the gas plant that's being produced out of Gavilan now, isn't it?
A Well, but here a look at the economics of the operations, says the plant is not a going operation if that's the way it has to be operated.
Q Let me ask you about both of your models here.
Do you -- do you assume a homogeneous type of system throughout these models?
A Yes.
Q You don't model in over in the pressure maintenance area these tight blocks that Mr. Greer has talked about?
A No.
Q Let me ask you with reference to GC-7, I don't have the page number on it, I think it's page 6 or 7 (not clearly audible), which is your --
A Yes, sir, the history match?
Q -- history match. This is a production history match on the -- on the unit production, is that correct?
A Yes.
Q Did you -- did you attempt to match pressure?

A There aren't enough pressures to match. What we tried to do was come close to matching at the end of history, at the end of '87.

Q You didn't -- didn't see -- didn't try to match any pressures from 1963 on?

A No.

Q Would this type of model give you some pressures now if you wanted to find out what the pressure was in 1963 or '65 or '67?

A Yes.

Q Where are those pressures?

A I can provide them to you. We have the computer output.

Q We -- do you have them?

A Yes. I could get it in just a moment and --

Q All right.

A -- tell me specifically the numbers you would like for me to read for you and I think we can be efficient.

Q Well, if we could just look at your computer output maybe that would help us (inaudible).

A All right.

Q Do I -- do I also see that as far as within the area you studied, that the additional recovery of the cyclings is just a little bit over 8 percent of the total recovery?

A I haven't put it on a percentage basis but if you're taking the 700,000 barrels and comparing the total recovery, and that turns out to be 8 percent, I would agree with you.

Q Well, I was looking at GC-3. It says without cycling it's 8482 on your -- in your model study, and with cycling it's 9183.

A Yes, that looks like about 8 percent.

Q About an 8 percent (unclear). John, did -- did you study the gas/oil ratios in the Gavilan and the expansion area during the production test periods that occurred since July of this -- this last year?

A No, I haven't.

Q You didn't observe that at the test rates that the test rates produced by the Commission hearing in July, August, September, October, and the first half of November, the gas/oil ratios in the Gavilan and in the proposed expansion area were lower than they were in the previous producing periods or in the subsequent producing periods?

A I just haven't studied it.

Q Assume with me that they were. Let's assume these factors.

Assume first of all that there's effective separation or noneffective communication between the expansion area and the pressure maintenance area, first assumption.

The seocnd assumption, assume with me that when the Gavilan and the expansion area wells produce at the rates from July through the first part of November, that their gas/oil ratios were less than they were previous and less than they were from November and December and January of this year.

Have you got the two assumptions?

A I think so.

Q What is your explanation of that occurrence as far as Gavilan and the expansion area is concerned?

A Well, I guess I don't have an explanation because I know that yesterday Mr. Greer tried to explain that, and he didn't hold with those assumptions and in particular his explanation was gas being drawn off the expansion area in a sequence of diagrams.

So, you know, I -- I have no explanation. I think the best explanation is the one that Mr. Greer had, which is that there is no barrier.

Q That removes one of my assumptions.

A Yes, sir, I understand it.

Q Do you have that computer printout? May we look at it for just a second?

MR. DOUGLASS: My computer experts tell me it will take a little while to look at this and get the data that we want. What I was going to suggest is I don't have any further cross examination of Mr. Lee other than this, what information we might obtain from this.

I was wondering if -- I'm willing to close out my cross examination and let anyone else here have questions and then we would be ready to start our case before the lunch hour and then perhaps use the lunch hour -- I do like to let my people at least have a little lunch, but in addition I'll get them to look at this computer printout here during the lunch hour period and that might speed up the time and not leave a time period now where we don't have anything -- where there's nobody doing anything but us looking at this computer printout, if that would be an acceptable thing.

MR. KELLAHIN: I understand Mr. Douglass wants his people to look at the printout and then we'll go ahead while they're doing that with the rest of the presentation?

MR. DOUGLASS: That would fine.

MR. KELLAHIN: I'll consent ot do that, yes, sir.

MR. LEMAY: Okay. Are there any other questions of the witness at this time?

MR. PEARCE: I have a few, Mr. Chairman.

MR. LEMAY: We'll go ahead, you're part of the cross examination, Perry, I think.

MR. PEARCE: Yeah.

MR. LEMAY: So why don't you continue?

MR. PEARCE: All right.

CROSS EXAMINATION

BY MR. PEARCE:

Q Dr. Lee, I think I'll be brief. Most of my questions deal with me trying to make sure I understand a couple of things that you've talked about.

Let's look first, if you would, please sir, at page 22 of your exhibit, which is the description of the gravity drainage model.

Now, did I understand your response to one of Mr. Douglass' questions just a moment ago to be that this model takes no account of any kind of dual porosity system?

A That's correct.

Q Does not discriminate between fractures and the tight blocks, as they have been described.

A That's correct.

Q How did that assumption relate to the area covered? Does it then assume that then assume that the whole area is one fracture with this permeability?

A It assumes that there's a fracture system with this permeability, with the fractures having, you know, spacing, but it -- it's not one fracture. It's a system of fractures.

Q And the input, as I understand it, into the model had an absolute permeability of 100 millidarcy feet, which is 12 or 13 -- millidarcies, which is 12 or 13 darcy feet, is that about right?

A The input to this model had 100 millidarcies and 40 feet --

Q Right.

A 4 darcy feet.

Q Right. And this is a model of one of three pay sections?

A That's correct.

Q And therefor, you would indicate to us that you think this model reflects the West Puerto Chiquito Mancos Pool because we have the three zones, each assumed to have 4 darcy feet; therefor, we have the -- close to the 14 that you discussed earlier with Mr. Douglass, is that --

A Well --

Q Am I going the right direction?

A Well, directionally, but in detail my as sumption is there's 10 darcy feet and there are two other layers which might be 30 feet each, the A and B, and I'm really trying to model something like the C. 40 feet there, 30 in each of two other layers, 100 feet total, 100 milli- darcies, 10 darcy feet.

Q Looking at the average dip put into the model, 335 feet per mile, is that simple division of the numbers which you can pick up off of page 24?

A It should be, but what actually went into the model is what is on page 24, and this 335 -- no 335 went into the model.

Q I'm sorry.

A 335 did not go into the model. What went into the model is what is on page 24.

Q Okay.

A The depth varying with distance.

Q That will be average depth over the en- tire pool.

Looking, sir, at page 14 of your exhibit, I'm looking specifically at paragraph 4-b, as in boy, read- ing: At rates below 1100 stock tank barrels per day, total withdrawals from one zone in a mile-wide section, the rate at which oil drained down from the gas invaded region equals or exceeds withdrawal rate... now, walk me through that slowly so I understand what that part of that sentence means, please, sir.

It's total withdrawals from the one -- from the one zone in the mile-wide section. Does that mean one of the three zones, A, B and C?

A Yes. Remember that in this model, we put only one zone in the model, so we're saying recovery from this single zone, that's what I mean by one zone.

Mile-wide, our model, call it a slice of the reservoir one mile wide.

Total withdrawals, we -- actually, there might be three or four producing wells in this one mile wide area, and what we're really trying to model is the effect of that total withdrawal rate from these three or four wells because it's that oil withdrawal rate that causes the gasoil contact to move down at some specified rate.

Q All right, sir, in -- in this case we're dealing with whether or not the Commission should include an area that is two miles wide within a pressure maintenance project.

A I think I understand your problem. Our one mile wide area is one mile wide going from the western edge of the expansion area up to the crest of the structure.

It's a one mile wide strip; starting at the gas injection area, continuing down through the unit, that's the mile in width.

The length would include that 2-mile length of the expansion area plus 6 additional miles in the existing pressure maintenance project area.

Q Let's go back and help me understand something that I thought I understood you to say earlier this morning, that at some point you were attempting to model the rate at which the gas/oil contact moves.

A Correct.

Q All right, when are you trying to model that?

A I'm trying to model that in all these studies of the effective rate on recovery.

We have a gas cap which is growing in size due to injection. There will be some sort of gas/oil contact. The faster we withdraw oil the faster that gas cap will move down structure.

That's what I mean by modeling the movement of the gas/oil contact. At high rates of withdrawal the contact is moving down rapidly; at low rates of withdrawal it will move down slowly.

Q With regard to the operation of a gas plant, does the efficiency of gas cycling depend at all upon whether or not a pressure maintenance operation is in effect? Does the simple fact of a pressure being maintained either improve or damage cycling efficiency?

A Would you define cycling efficiency for me? Do you mean the amount of ethane and heavier that can be removed from the gas that gets to that plant?

Q Yes.

A No.

Q Does it have any effect on the amount of ethane and heavier hydrocarbons that are picked up as the lean stream goes through the cycling area?

A Yes.

Q How is that improved? Can you explain that to me?

A With pressure maintenance, I guess it wouldn't, wouldn't depend on the -- what the lean stream picks up as it goes through. It would simply reflect the -- if we have a pressure maintenance project and continue reinjecting gas, it means that the lean stream would be able to go through more and more times as opposed to a blowdown operation in which the gas would move through only once and then there would be no more gas to move through.

So, again, the benefit of the pressure maintenance would be the opportunity to continue to move gas through the oil zone and pick up more liquid hydrocarbons.

Q Let's look back at page 14 again. Understanding that the one mile wide section in the one zone runs west to east, that's what you told me it did.

A Yes, right.

Q All right, if those -- if that assumption and your ideal rate of between 500 and 1100 stock tank barrels a day renders the most efficient operation, what is the efficient withdrawal rate from the present Canada Ojitos Unit?

A I don't know.

Q To maximize the recovery?

A I don't know. It would be -- it would be on the order of the width, the total width of the unit; let's say 8 miles times a per section withdrawal rate, somewhere in the 500-to-1000 barrel a day range.

Q Dr. Lee, several times during your direct examination this morning, you discussed your conclusion that there was effective communication between the present pressure maintenance project area and the proposed expansion of that area, is that correct?

A That's correct.

Q And several times I thought I heard you qualify that by saying words to the effect of "at least to the extent of pressure effects". Do I recall that correctly?

A If I said that, I misspoke.

Q All right. You -- you are convinced and persuaded that there is effective flow of fluid communication between the two areas.

A Yes.

Q And you believe that somewhere in the vicinity of transmissibilities of 10 to 15 darcy feet accurately reflect that flow communication?

A In at least parts of the area. There are known tight areas, too, but at least in the areas which have been tested with interference tests, yes, I believe that.

MR. PEARCE: I don't think I have anything further, Mr. Chairman.

MR. LEMAY: Thank you, Mr. Pearce.

Additional cross examination from anyone on this side?

Additional questions of the witness?

Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Dr. Lee, on page 16 of your exhibit you have a schematic of gravity drainage. Would this be somewhat of a model of the production you would expect in the expansion area?

A In the expansion area alone or in the expansion area connected to the rest of the unit?

Q Well, in the proposed expansion area.

A Well, in the expansion area alone, of course, the area there is flat whereas in this schematic we have dip, but connected with the unit as a whole, I think the principles would apply here, with the area flattening out.

Q Would it be more representative if we were to continue the reservoir on that -- on that top schematic horizontally to the left of what's shown on the -- on your schematic? Would that be representative of the proposed expansion area?

A Yes, it would, and, of course, that's what we did in our computer simulator model studies; we flattened it out (unclear).

Q Okay. Could you describe the direction of fluid movement, then, towards the producing wellbore from the flat area going towards the wellbore as it would be described by your computer simulator?

A It would be basically the same as we show in this schematic; that is, some -- some gas would -- would move in towards the well. Some gas would migrate straight up to the top of the structure, and that's what we saw in the computer simulation.

Q In your gas plant simulator is the economics of the gas plant based on the 700,000 barrels extra hydrocarbons recovered?

A It's truly based not only on the extra recovery but when that recovery occurs and I think fundamentally important is that there was a net gain of something like 2-million barrels in the first ten years, which really dominates the economics.

And then some of that 2-million in theory vanishes during later years because you pick up some of that during -- you would pick up some of that during blowdown of an operation which (unclear) you would then vaporize some of the hydrocarbons and produce those; however, to do that would still require installation of a plant and if there were no plant, the additional recovery due to the cycling operation would probably remain in the 2-million barrel range.

Q Did your simulator take into account the different BTU of the gas sold, say, to a pipeline either with or without the plant?

A Yes. The economics includes the value of the gas.

Q Dr. Lee, if the application is approved, the wells in the proposed expansion area will be allowed to produce at a higher rate than they're producing at now, won't they?

A That's correct.

Q If that higher rate causes flow from the Gavilan area into the expansion area, would that disturb the efficiency of the pressure maintenance project?

A It wouldn't disturb the efficiency.

Q Would you be oppoeed to the Gavilan operators producing at rates that would offset any flow that might occur from from Gavilan into the pressure maintenance project area?

A Well, I can't make regulations. I think certainly correlative rights need to be protected in some way.

MR. CHAVEZ: That's all I have.

MR. LEMAY: Thank you, Mr. Chavez.

Additional questions of the witness?

MR. DOUGLASS: Just one additional information question.

RECROSS EXAMINATION

BY MR. DOUGLASS:

Q On your oil in place, original oil in place on page 34, John.

A Yes, sir.

Q Would that, if you took off the first two miles to the west over there, would that reduce it by -- since it's 8 miles long, would it reduce it by one-quarter, or is that oil in place proportional to the reservoir, or non-proportional to the reservoir?

A It's only 7 miles unless I've messed up my arithmetic.

Q Or 7 miles.

A It was 8 miles in the other model against a specific section, but directionally I think you're correct, about, approximately, 2/7ths of (unclear) or however, or the top cell also has some gas in it, so maybe closer to 1/3 of the oil.

Q Do you have an estimate of the original oil in place in what you call the pressure maintenance area, as far as that entire area is concerned?

A No, I don't.

MR. DOUGLASS: No further questions.

MR. LEMAY: Is it my understanding, Mr. Douglass, you wanted to bring the witness back after lunch to ask some questions?

MR. DOUGLASS: I'm not sure. Since it's just about lunch time, my folks are looking at the computer printout. That would be the only thing we'd have and we may just cover that in our direct.

MR. LEMAY: Let's take a lunch break now and we can make that decision when we come back.

MR. KELLAHIN: May Dr. Lee be excused but for the questions about the pressure data in the model?

MR. LEMAY: Yes, that's --

MR. PEARCE: Oh, something else might occur to us, Tom.

MR. DOUGLASS: I don't think I'm going to have any questions except about it.

MR. LEMAY: We'd like to finish up the questions of the witness if we can --

QUESTIONS BY MR. BROSTUEN:

Q Mr. Lee, Dr. Lee, --

MR. LEMAY: -- before we take the lunch hour.

Q -- on page 36-B of your exhibit you give a reservoir gas composition. It's obviously an analysis of

-- well, is this an analysis of gas produced from the West Puerto Chiquito?

A Yes, it is.

Q And then going to your Figure GC-2, you're showing -- this is your graph showing the -- the production of produced natural gas liquids, crude, and total liquid without cycling.

You're showing that with -- with cycling you are recovering a higher percentage of natural gas liquids.

Without cycling you're showing a lower amount of that.

How much are you -- how much are you producing at the present at the time? How much is being produced? How much natural gas liquids are being produced at the present time?

A None.

Q So where does the -- where does the -- the without cycling portion of your graph come from? Where does that come from?

A That would come from the blowdown period. After 10 years of production in the future without cycling, then --

Q Going back --

A -- we say we might put in a hypothetical gas plant and recover plant liquids there at that time.

Q Then you're showing that -- perhaps you can explain to me the process of recycling, what's happening in the reservoir, you've produced your gas. You've stripped off your liquid, recycled the gas, essentially methane, and it goes back into the reservoir and picks up additional natural gas liquids.

A That's right.

Q What is the make-up of those liquids and where are they coming from?

A Those liquids are coming from the oil that remains in the reservoir. As that methane contacts oil which still has some intermediate (unclear) carbons in it, let's say ethane, propane, some butanes, and so forth, when you mix methane with that crude oil at reservoir pressure and temperature, some of that crude oil will vaporize or, yeah, will vaporize, and those lighter hydrocarbons will go into gas phase and so when you produce that gas back out it will no longer be pure methane. It will be methane with some ethane and propane and butane, and so forth, in it.

Q Okay, I understand. You're saying, then, that you're simply extracting more of the natural gas but you're not extracting more crude.

A Right.

Q And so you're -- how do you -- how do you relate that to the graphs you're showing? You're showing more additional crude being extracted without cycling than you did with cycling.

A That's because some crude oil was vaporized when -- was in contact with that injection (unclear).

Q You're actually -- you're actually taking off the natural gas liquid still retained in the -- in the crude that were not -- did not come off with the gas, first of all, from the crude in the reservoir.

A Yes.

Q I think that's all I have, Doctor, thank you very much.

A Yes, sir.

MR. BROSTUEN: That's all I have now.

MR. LEMAY: Are there any other questions of the witness with the exception of questions after lunch pertaining to, I think, computer modeling?

MR. DOUGLASS: The computer printout?

MR. LEMAY: If not, the witness may be excused to be recalled after lunch for the sole purpose of computer modeling or any redirect which will go on from there.

Let's -- hold on a second.

Let's reconvene at 1:00 o'clock so we can --

MR. KELLAHIN: Mr. Chairman, is there an opportunity either on the record or off the record to discuss the afternoon in terms of forecasting our time?

MR. LEMAY: Let's go off the record just for a second and we can summarize.

(Thereupon the noon recess was taken.)

MR. LEMAY: At this time we shall reconvene.

I want to summarize the record. We, in essence, said we're pretty much on schedule; we plan to wind it up today.

In terms of -- Mr. Douglass, did you have some questions for the previous witness?

MR. DOUGLASS: I do not, Mr. Chairman. What we -- counsel have consulted. What we would like to have identified as Mallon Exhibit Three is the computer printout that Mr. Lee conducted and had with reference to his model study and we'd like to introduce that for the limited purposes of showing his work papers. We'll refer to some of this data, we think, later in our testimony and we would like to offer it at that time. We only have one copy, obviously, and we discussed with counsel, and with your permission we'll withdraw it from here and go over and make copies, however many copies the Commission would like to have and sufficient copies for counsel.

MR. LEMAY: That's fine. Is that acceptable? We'll proceed that way.

Do you have any -- any redirect on the -- on the witness, Mr. Kellahin?

MR. KELLAHIN: No, sir.

MR. LEMAY: Fine. He may be excused.

I think we're ready for the other side. We're ready.

MR. DOUGLASS: Call Mr. Hueni.

MR. LEMAY: You may proceed.

GREGORY B. HUENI,

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

DIRECT EXAMINATION

BY MR. DOUGLASS:

Q Would you state your name for the record, please, sir?

A Yes. My name is Gregory B. Hueni.

Q I think you might get closer to your mike.

A Okay. My name is Gregory B. Hueni.

Q All right, sir, and what's your occupation?

A My occupation is a consulting petroleum engineer and Vice President of Jerry R. Bergeson and Associates.

Q Where are you stationed?

A I'm -- I reside at 11420 West 27th Place in Lakewood, Colorado.

Q Have you testified before this Commission as a petroleum engineer previously?

A Yes, I have.

Q And have you actually testified with reference to the areas that we're going to be concerned with here today in the August '86 hearing and the April '87 hearing, and one additional hearing, I believe, that concerned this area, is that correct?

A Yes, I have.

Q And have you made a study of the -- the area that we've been concerned with the last day and a half and prepared or had prepared under your supervision certain exhibits and testimony for presentation here today?

A Yes, I have.

MR. DOUGLASS: We tender him as an expert in the area under question.

MR. LEMAY: His qualifications are accepted.

Q I believe we're at Mallon Exhibit Four.

MR. DOUGLASS: Mr. Chairman, what we've done is that we have our exhibits and for a selected number, including the Commission, the staff, and opposing counsel we've placed them in folders that have -- that can be put in a notebook and you should have near you, I hope, a notebook that -- for that purpose, and we would like to then have identified for the -- for the record as Mallon Exhibit Four the distance from current injection wells to map, and each of those exhibits that you have will have a place where that exhibit number can be inserted.

Q All right, Mr. Hueni, I've placed on the board here what's been identified as Mallon Exhibit Number Four. Could you tell us what you've shown in that exhibit, please?

A Exhibit Number Four is a map of the western -- or eastern two tiers of sections in the Gavilan Mancos Pool which are located in Range 2 West, and then the majority of the West Puerto Chiquito Pool, which is located in Range 1 West and Range 1 East.

On this particular map we've outlined the boundaries of the Canada Ojitos Unit Pressure Maintenance Project and shaded the interior of those boundaries in the brown color, to indicate the area that's currently considered as part of the pressure maintenance project.

Q I believe that's consistent with the questioning and answering that's been going on previously, and that's been the area that we refer to as the pressure maintenance area.

A Yes, that's correct.

Q Or project area. Right?

A That's correct.

Q All right, sir.

A We have located on this particular map those wells that have been used as gas injection wells in the Canada Ojitos Unit Pressure Maintenance Map and indicated those wells by a triangle.

Next to those wells we have indicated the amount of gas that had been injected into each well prior to the start of 1988.

From the north end of the injection wells we see the Canada Ojitos Unit No. 18, which has injected a cumulative volume of about .2 BCF of gas.

We noted on this exhibit that injection ceased 1972, but that's not quite correct. In the middle of 1987 that well was again used as an injection well and a volume of gas was injected into that well specifically and then that well was shut in and the pressure was measured in that well.

Subsequent to that, that's one of the pressures that's reported in the November pressure map presented by Mr. Greer.

Q Was the volume so small that you didn't even have to change the amount injected because of the round off that had occurred?

A That's right, there was not a great deal of gas injected in that period of time in 1987.

The next well to the south is the well, the Canada Ojitos Unit No. 5. It is the primary injection well in the project, injecting into the A, B and C zones and it's injected a cumulative volume of about 6.8-billion cubic feet of gas into that particular well.

The next well is Well K-13 that's injected 1.1 BCF of gas. According to our records injection ceased in April of '87.

Moving further to the south we have Canada Ojitos Unit No. 17 Well, which has injected 2.3-billion cubic feet of gas. That well has until 1988 been a C zone injection well with the 2.3 BCF of gas going into that well.

And then, finally, there is the COU No. 19 Well at the far south end of the unit, which has injected a 0.7 BCF of gas.

From each of these individual injection wells we've drawn in arrows to producing wells in the proposed expansion area.

Q All right, how did you identify the expansion area on Exhibit Four?

A The expansion area is the white area that is located in the western portion of Range 1 West within the boundary of what's designated as the Canada Ojitos Unit, which is the dashed line surrounding that area.

Q Is that -- is that western line also the pool boundary as it now stands between Gavilan and West Puerto Chiquito?

A Yes, it is.

Q All right, I believe you were talking about the arrows and the lines drawn from the injection wells?

A Yes. Each of the individual arrows is drawn and the arrows are drawn specifically to those wells in the proposed expansion area that will benefit from gas injection credit. All of those wells are currently limited by their gas/oil ratios.

There are a total of 11 lines with arrows drawn from the gas injection wells to those wells that would receive benefit through the proposed gas injection credit.

Q And how have those distances -- what's the ranges of distances from injection well to recipient well and the net ratio?

A The range of distances range from a minimum of about 20,200 feet to a maximum of about -- which is about 4 miles -- to a maximum of about 36,000 feet, which is approximately 7 miles.

Q All right, sir. One of the -- I believe in Mr. Greer's testimony he testified that he thought the B-32 had gassed out in the A and B, as I recall. Can you show us the relationship of the B-32 with reference to these injection wells and any other wells that are producing in the pressure maintenance area?

A Yes. The B-32 Well is located in Section 32 of Township 25 North, Range 1 West. That particular well is commingled in the A, B and C zones. You can see that it's located approximately 23,000 feet from the Canada Ojitos Unit No. 17 Well; however, we need to remember that the Canada Ojitos Unit No. 1 7 Well is a well that has injected gas strictly into the C zone since it's -- since it's been on injection until very recently when it was recompleted as an AB well, AB injection well, as well.

In the intermediate, between the B-32 Well and the Canada Ojitos 17 Well, is located the C-34 Well in Section 34. That particular well has individually from the C zone accumulated -- has a cumulative production of gas 4.3-billion cubic feet, of gas, so if that gas that has -- that was measured in the production log in B-32, has come from the injection -- from the injection program, it would have had to come a distance -- well, it would have had to come most likely from the area of the Canada Ojitos Unit No. 5 Well, which is many miles away.

We would note also that the No. 5 Well is as close to another AB zone producer, the Canada Ojitos Unit No. 13 Well, located in Section 27 of Township 26 North, Range 1 West, which also produces from the AB zone. That well is not gassed out in the AB zone, we have a production log on that. That well is actually up-structure to the B-32 Well.

So it seems very unlikely to me that that gas that is reported to be produced from the AB zone, that the source of that is indeed a gas injection project.

Q With reference to generally the location of the wells that are supposed to receive this injection credit to the injection wells, how would you describe those distances for us, whether they appear to be close distances, medium distances, or far -- far removed distances?

A Well, they see -- they seem to me to be a fairly removed distance or a far distance, and it would seem to me that basically the wells that are going to receive the credit are either in a syncline area or on the opposite side of the syncline area that runs through that particular region of the -- of the Mancos Pool, and also that these wells are located on the -- on opposite sides of a -- of a permeability barrier that we believe exists in between the injection wells and the proposed expansion wells.

Q Anything else you want to add on Mallon Exhibit Four?

A No.

MR. DOUGLASS: Offer Mallon Exhibit Four.

MR. CARR: No objection.

MR. LEMAY: Without exception Mallon Exhibits Three and Four will be admitted into evidence.

MR. DOUGLASS: Thank you, Mr. Chairman.

Q I'd like to have identified for the record as Mallon's Exhibit Five, Area of Non-Communication -- a map entitled Area of Non-Communication.

Would you tell us what you've shown on Mallon Exhibit Five?

A Yes. Mallon Exhibit Five is a map of the same area that we showed on the preceding exhibit.

Once again the area that is part of the Canada Ojitos Unit Pressure Maintenance Project is shaded in

-- shaded in brown and the proposed expansion area is shaded in white.

What we have located on this particular map are wells within the West Puerto Chiquito Pool that are shut-in with the reasons they're shut-in generally being that they are low productivity wells or, perhaps, a well that is gassed out.

Beginning at the north end of the -- of the map, we have shown a well that's shut-in. This is the Canada Ojitos Unit No. 22 Well, which had a reported initial potential, I believe, of 1 barrel of oil per day.

The next well to the south is the Canada Ojitos Unit Number 21 Well, which in October of 1986, I believe, had an initial potential of 15 barrels a day and has recorded a cumulative production of about 6000 barrels of oil.

Moving further to the south we have the Canada Ojitos Unit No. 24 Well. That particular well in September of 1987 was reported to produce 2 barrels of oil per day, and has registered a cumulative production of less than 1000 barrels, I believe 600 barrels of oil.

And then moving basically to the southwest from that, we have the well B-17, which is the Canada Ojitos Unit 35 Well.

This well was drilled recently in July

31st of 1987. It completed ultimately as an observation well after having an initial potential of 10 barrels a day.

All of these wells, incidentally, have been massively -- or have been hydraulically fractured, and we're quoting our pulse frac rates.

Moving then to the eastern -- to the east a little bit into the pressure maintenance project, we have the A-16 Well, which is the Canada Ojitos Unit No. 8, which had an initial potential of about 40 barrels a day. That well, by 1986, was being produced intermittently and actually in 1987 was recording flow rates in the order of 4 to 5 barrels a day with not an exceptionally high gas/oil ratio. That well has produced a long period of time. It has accumulated production of about 120,000 barrels of oil.

And then the final well that is shown as a shut-in well is the A-22 Well, located in Section 22, which was shut-in in June of 1972. This is a well that really has been a fairly good well. It has cumulative production of 500,000 barrels of oil. It was shut-in when the gas/oil ratio reached 6000 standard cubic feet per stock tank barrel. Once again this was back in 1972 itself.

We have connected the wells that are shown as shut-in wells by a red line. We believe that the productivity information demonstrated by these wells and perhaps more importantly later on, the pressure information that we have available to us demonstrates that there is a region of low productivity that separates, basically, the pressure maintenance area from the proposed expansion area.

Q I notice there are a couple more wells you have information by in Section 34 and in Section 3 to the south here, is that correct?

A Yes, that's correct. Those two wells are both -- are both producing wells. The southernmost of those wells is the Canada Ojitos Unit 16. In October of '87 we have shown on there that it had a production capacity of 12 barrels of oil per day. This is a sustained productive capacity as indicated by the monthly production statistics.

Q In other words, October of '87 it produced the entire month and averaged 12 barrels a day?

A That's correct. So once again, that is -- is really a relatively low productivity well in that particular area, as well.

Q And 10 MCF a day, is that correct?

A That's correct. That's correct.

Q The C-34, I believe you already mentioned it, but what is that?

A Yeah. The C-34 well is a well that produced basically from the C zone in the earlyu 1970's.

In 1973 that well went high gas/oil ratio and went to approximately a 10,000-to-1 gas/oil ratio.

It was produced continuously until 1985. It was shut-in in '85, at which time it was producing 48 barrels of oil per day with a 12,000 gas/oil ratio from -- from the C zone.

It was worked over in 1987 to add in the A and B zones, as well. The test rate in December of 1987 of 48 barrels of oil per day and 488 MCF per day, which is a 10,000 GOR, would indicate to us that this well -- that the production from the C zone, that by adding the AB zone, that we really didn't gain anything from the AB and that it was probably communicating with the C zone from -- from early on in its productive life, because when it was recompleted in the AB it produced essentially the same types of quantities that had previously been produced out of the C zone.

Q How do those last two wells you described compare with the producing wells in the expansion area immediately across the area that you have designated "barrier"?

A Obviously, there is a considerable difference in productive quality between the C-34, for example, and the Canada Ojitos Unit 25, which is the B-32 Well, which, in October of '87 produced at a rate of 770 barrels a day and almost a million cubic feet of gas.

To the north of that we have the B-29 Well which in October produced at a rate of 992 barrels of oil per day with approximately 2-million cubic feet of gas.

Q What about the G-5 or the Unit 37 Well?

A The Unit 37 Well in December of '87 produced 147 barrels of oil per day with 390 MCF per day. All of those wells appear to be of a different quality than the wells on the -- on the -- to the east.

Q Anything else you want to add with reference to Exhibit Five?

A I'd like -- once again we've connected the wells that were shut-in, low productivity, using a red line to indicate where -- information where we do have low productivity well deliverabilities. We've extended that line and indicated in there a barrier to indicate the area that we think is, basically, that is noneffective in communicating with the proposed expansion area. The southern part of that barrier we believe is supported not only by differences in well quality but also differences in pressure.

Q You'll have those on later exhibits, is that correct?

A That's correct.

MR. DOUGLASS: Offer Mallon Exhibit Five.

MR. CARR: No objection.

MR. LEMAY: Without objection Mallon Exhibit Five will be admitted into evidence.

Q I'd like to have identified for the record as Mallon Exhibit Six a map entitled Initial Reported Well Pressures. Could you tell us what's shown on Exhibit -- Mallon Exhibit Six?

A Mallon Exhibit Six is a -- is the same map, or the same type of map, that we've shown in preceding exhibits. Once again the same area is described. The pressure maintenance area is shown in brown once again. We've overlain on this map the barrier that we believe is supported by production and pressure information.

We have now added onto this information some initial pressure information that we -- we had available to us on either side of this barrier.

The pressure information we have in the pressure maintenance project, the last reported pressure in the C-34 Well until a very recent pressure was provided to us approximately two weeks ago, was a pressure that was measured in December 28th of 1970. It was the last, to our knowledge, the last oil zone pressure maintenance pressure that was taken in the unit some 17 years ago. That pressure corrected to a common datum of plus 370 feet results in a bottom hole pressure of 1555 psi.

In early 1985 the Canada Ojitos Unit No. 25, otherwise known as Well B-32, was drilled and a pressure taken in that well.

Q 14 years later.

A This is 14 years later. The pressure in that well corrected to the exact same datum was 1720 psi.

In between these two wells, it's interesting to note, is the calculated transmissibility, the effective oil transmissibility reported by Mr. Greer in his exhibits of 14 darcy feet.

Q Anything else you want to add with reference to Mallon Exhibit Six?

A No.

MR. DOUGLASS: Offer Mallon Exhibit Six.

MR. LEMAY: Without objection Exhibit Six will be admitted into evidence.

Q I'd like to have identified for the record as Mallon's Exhibit Seven November 1987 Static Pressure Information.

Will you tell us what you've shown on Exhibit Seven, please, sir.

A Exhibit Seven is a map showing the November, 1987 static pressure information. These -- these pressures are -- represent shut-in pressures. They represent pressures converted to a common subsea datum as opposed to any kind of surface measured pressures.

In general the conversion process was not significant to the final numbers that are shown here, so these numbers that are shown, we would consider to be very accurate representations of pressures in the reservoir itself.

Q Were these pressures taken as a result of the Commission's order of June 8, 1987, and the testing and pressure requirements of that particular order?

A Yes, they were the result of those testing requirements. Yes, that is correct.

Q All right, sir. What do the -- what do the pressures show?

A The pressures show a considerable amount of pressure continuity in a north/south direction but a substantial lack of pressure continuity in the east/west direction.

Once again we've shown on this map our interpreted barrier that separates the pressure maintenance project from the proposed expansion area. In the pressure maintenance project area we have the L-27 Well, which is, from the production log, an AB producer with a measured pressure of 1389 psi.

We then go the south to the E-10 Well, which is a C zone well, which has a pressure of 1391 psi.

And we move then further to the south to the C-34 Well, which at that time had pressure of approximately 1395 psi. All of these, once again, reported at a common subsea datum of plus 370 feet.

On the west side of the barrier we have values reported for the Canada Ojitos Unit No. 29, which is the E-6 Well to the north, of 954 psi.

We have the D-17 Well, which is a well that is strictly an observation well, not used as a producer. This observation well pressure was 994 psi in November of 1987.

Then further to the south we have the Canada Ojitos Unit 36, which is the A-20 Well, with a pressure of 943 psi.

And further to the south we have the Canada Ojitos Unit B-32, or No. 25 Well, which had a pressure of 953 psi at that time.

I might add that there were other pressures that were taken as part of the November survey. For example, in Section 1 of Township 25 North, Range 2 West, we have -- I'm sorry, that should be in the Section 2, we have the Mallon Fisher Federal 2-1 in Section 2 of Township 26 North, which had at that time a reported pressure of 982 psi.

Q 982?

A 982.

Q All right.

A And then to the south of that well in Section 12 we have the Johnson Federal Well, which had a reported pressure of 1093 psi.

Q 1,093.

A And then, finally, further to the south in Section 24 we have Meridian's Hill Federal Well, which had a pressure of 908 psi.

Q 9-0-8, is that correct?

A That's correct. Once again we see a great deal of uniformity in pressures on the west side of the barrier. We see a great deal of uniformity of pressures on the east side of the barrier, and we see in November a pressure gradient of approximately 450 psi across the barrier.

Now one comment I might make with respect to measuring these kinds of pressure gradients using surface pressure measurements and the difficulties involved in that, is that we can compare, for example, from one of Mr. Greer's exhibits, his shut-in surface pressure values, we can compare the pressure drops that he reports from shut-in surface pressures to the pressure drops that we actually measured using -- using bottom hole pressure measurements.

The -- on the Greer exhibit that showed the pressure gradients through the reservoir, the E-10 Well in November of 1987 was reported to have a pressure of 1144 psi.

At that same time the E-6 Well was reported to have a pressure of 804 psi.

Now, if you compare the true difference in bottom hole pressures across this barrier using actual bottom hole pressure information, you would see that the comparison of our lettered numbers, 954 to 1391, is a pressure gradient of 437 psi pressure -- pressure difference; whereas, if we make the comparison of Mr. Greer's reported surface pressures and we compare the difference there, we have a pressure difference instead of 437, we have a pressure difference of only 340.

So the effect of using these shut-in surface measurement pressures across this barrier is to understate the actual magnitude of the pressure discontinuity that exists at that point in the reservoir.

Q Let me ask you, with reference to the Mallon Exhibit Seven, what's your opinion as to whether that pressure data taken in November of '87 indicates effective communication from the pressure maintenance area to the expansion area?

A That data, together with other data we'll be presenting, indicates to me that there is no effective pressure communication between the two different areas.

Q Let me refer you back to Mallon Exhibit

Six, if I could. With reference to the initial pressures, do these initial pressures indicate to you there is effective communication across the barrier as indicated on Mallon Exhibit Six?

A That information, once again, indicates a lack of effective pressure communication across the barrier.

Q Anything else you want to add with reference to Exhibit Seven?

A No, I don't believe so.

MR. DOUGLASS: Offer Mallon Exhibit Seven.

MR. LEMAY: Exhibit Seven will be admitted into evidence without objection.

Q I'd like to have identified for the record as Mallon Exhibit Eight a map entitled February 1988 Static Pressure Information.

Would you tell us what you've shown on Mallon Exhibit Eight, please, sir?

A Mallon Exhibit Eight is a presentation of a map of the same area as the preceding exhibits. Recorded on this map are pressures taken in February, 1988, a survey that was done in conjunction with the state testing requirements.

Once again, these tests have all been corrected to a common subsea elevation of plus 370 feet above sea level.

Once again we have shown on this map the barrier that exists between the pressure maintenance area and the proposed expansion area.

To the east of this barrier in the pressure maintenance area we have on the far north the L-27 Well with a measured pressure of 1387 psi, essentially unchanged from the 1389 psi that had been measured in November of 1988 at that same well location.

Then going to the south we have the E-10 Well, which has -- is a C zone producing well. It had a recorded pressure 1403 psi, up approximately 12 psi from the 1391 psi pressure reported in November of 1987.

Q Let me ask you about that E-10 Well. Does that indicate that there was actually a pressure increase from November '87 to February '88 in that particular well?

A That's what the measurements tell us.

Q All right, sir.

A Then to the south we have repeated the number that we had for the C-34 Well. There was not a measurement taken in February of 1988. The November pressure, however, was 1395.

The available pressure data on the east side in the pressure maintenance area indicates certainly no decline in pressures and, on the other hand, even an increase in pressure, particularly on the E-10 Well.

We look, then, to the area that is west of the barrier.

We begin on the north end with, once again, the Canada Ojitos 29 Well, which is the E-6, which had a measured pressure of 912, which represents, then, a drop of 42 psi from the -- from the November, 1987 pressure.

Moving to the south we see the D-17 Well, which had previously recorded a pressure of 994 has now declined to a pressure of 961.

Moving further to the south, the A-20 Well, which had reported a pressure of 943, has now declined to 924.

Q Let me stop you right there. I think from a distance there appears to be an error underneath that well, underneath pressure 943 and 924, is that correct?

A That -- that's correct. That should be -- that's just an underscore under the 943 number and happens to then kind of line up with the "A" in "barrier", makes it look like an arrow that points from west to east.

Q It's not really an arrow, it's just the design of the map happened to come where the "A" was in the "barrier", is that right?

A That's correct. Okay, and then the final well where we have a recorded pressure is the B-32 Well, where the pressure previously had been reported at 953, it's now declined down to 936.

Now, we also have pressures -- we might -- well, we also have pressures in February of 1988 for the Mallon well, the Mallon Fisher Federal Well, which had a recorded pressure of 1,005 psi.

Q 1,005?

A Psi, that's correct.

Q All right.

A And then further to the south we have the Johnson Federal Well in Section 12, which had a reported pressure of 1,058.

Q 1,058?

A That's correct.

Q All right.

A Once again we have declining pressures in -- on the west side of the barrier in the proposed expansion area. We have pressures that have remained the same or gone up to the east side of the barrier, and we have uniformity of pressures north/south on the east side of the barrier, and now, instead of having a 450-pound pressure difference, we have a slightly greater pressure gradient across the -- across -- or pressure discontinuity across this barrier region.

Q With reference to Exhibit Eight, what's your opinion as to whether those pressures taken approximately three months later indicate effective communication from the pressure maintenance area to the expansion area?

A Given that this reservoir is reported to have permeability thicknesses in terms of darcy feet, I would say that there is no effective communication between the pressure maintenance area and the proposed expansion area.

Q Anything else you want to add with reference to Mallon Exhibit Eight?

A No.

MR. DOUGLASS: Offer Mallon's Exhibit Eight.

MR. LEMAY: Exhibit Eight will be admitted into evidence without objection.

Q Let us have identified for the record Mallon Exhibit Nine, a graph entitled Comparison of COU Pressure Maintenance Area Field Pressure and Gavilan Field Pressure.

Tell us, if you would, what you've shown on Mallon Exhibit Nine.

A Yes. May I approach this exhibit?

Q That would be fine. I'll be your pointer.

A Thank you. Mallon Exhibit Nine is a composite of pressure information that has been recorded for the Canada Ojitos Unit Pressure Maintenance Area, the Gavilan Mancos Pool, together with the proposed expansion area in the Canada Ojitos Unit, and then we put both -- both sets of information together.

Looking first to the panel that's in the upper lefthand portion of the graph, the very upper lefthand portion of that is data that was taken directly from the exhibit presented by Mr. Greer showing the pressure, the early pressure history of the pressure maintenance project.

Q That was in the March '87 hearing, is that correct?

A That's correct, and all of the --

Q You actually reproduced that exhibit and placed it on your Exhibit Nine, is that right?

A Yes, that's -- that's correct. That's what that -- that portion of the exhibit is.

Q We have shifted the scale in order to have the pressures presented at a common subsea elevation of plus 370 feet above sea level, so that all data will be presented at a common elevation.

Once again the pressure information that was available for the pressure maintenance area ceased in December 28th of 1970, with a final measured in the C-34

Well, which is the final pressure, right, it's that very last pressure point measured in the C-34 well.

Q Is that the same -- same pressure that you had on Exhibit Six which you showed for the Unit 34 Well?

A Right. That is the pressure of 1555 psi. Since that time, obviously, in 17 years or so that's transpired since then, the pressure maintenance area has continued to produce although we haven't had any pressures to include on this chart.

We've plotted -- we plotted the pressure history against the cumulative production taken from the pressure maintenance area, so the pressure maintenance area itself has gone to a cumulative production of approximately 7.8-million barrels by the start of 1988.

At that point in time as a result of the testing requirements, pressures were taken in the -- in the Canada Ojitos Unit and one of the pressures we've shown here is the E-10 pressure measured in February of 1988.

Q And you have shown that on Exhibit Eight here, is that correct?

A Yes, that's correct. That's the 1403 pressure. Now, you can see we took that and a couple other pressures at about that same point in time because we also had pressures on the L-27 Well of 1387 and in November of

1987 we had a pressure on the C-34 Well of 1395. You can see the net impact is -- that all the pressures would fall essentially at the same point.

So for the pressure maintenance area all three of those pressures fall along the trend that was established early in the life of the pressure maintenance project.

Now, the -- the upper righthand panel of this same exhibit shows the recorded pressure history taken from wells in the Gavilan Mancos Pool, as well as some of the wells that are in the proposed expansion area, Canada Ojitos Unit.

Once again, we have plotted on the lefthand side of the graph well pressures, and these pressures have been corrected to a common sea level datum of plus 370 feet.

We have plotted this information versus the total cumulative production coming from both the Gavilan Mancos Pool as well as the proposed expansion area, and you can see that the -- that those two areas together have produced and I should note that the final pressures that you see in -- on this particular exhibit and in November of 1987, because we didn't necessarily have all the production to carry -- to put the February, 1988 pressures on.

So these pressures end in 1987 and what

you can see, then, is the pressure history for wells in the -- in the Gavilan Mancos Pool proposed expansion area.

You can see that there is a good deal of pressure communication between those wells that are located in that area.

The wells that are shown by the large symbols, the large triangle, the large square, the large hexagon, and the large hourglass, are all wells in the proposed expansion area.

Q That -- that's in this area you mentioned earlier that's west of the pressure maintenance area.

A That is correct.

Q And then you have additional Gavilan --

A Then we have some additional Gavilan pressures shown in there, as well.

We can see --

Q You list all the wells with the pressures over on the --

A Yes, we list the wells. Unfortunately, in the original there is some color coding here so it's very difficult to -- on the Gavilan wells, necessarily to connect a symbol back to a -- back to a specific well, because more than one symbol shows up in this colored in black.

The --

Q Now the scale that this is done to is

pressure and -- versus cumulative production.

A Yes, and it is the same scale. In other words, we've shifted it by 100 psi starting off with 900 psi in the Gavilan, going up to 1850 psi, whereas, on the other scale it went from 1000 psi up to 1950.

So it's the exact same scale. It's just shifted a little bit.

We can see from the pressure expansion area well measurements that those well measurements follow the trend in Gavilan, of the Gavilan wells, as well.

Q What's the heavy black line you show in the upper --

A The heavy black line is, I guess, what we can refer to maybe as just an eyeball trend of the -- of the pressure history, how it's declined as production has come from the field.

The 5.2-million barrels that's been taken out of the Gavilan Mancos Pool has occurred really since 1982. That 5.8 -- or 5.2-million barrels taken out in that time frame, once again in contrast to the 7.8-million barrels taken out in the period from 19-, I believe, 1962 or '63, out through 1987, which is a period of about 24 years, for the Canada Ojitos Unit.

The final panel is the one that we consider the most significant. It is the combination of data from the pressure maintenance area combined with data from the Gavilan Mancos and proposed expansion areas.

We have plotted this on a time scale beginning in 1962, extending out to 1988.

Q Let's see if I understand. You've now converted the pressures and the cumulative production, you've put the same pressures but converted the cumulative production to time when that particular cumulative production occurred. Is that correct?

A That's correct.

Q And in order to make a comparison between these two, the two upper panels, which are on cumulative production, the only comparisons you can make to those would be on a time basis, isn't that correct, as far as -- as where their pressures were at that particular time.

A That is correct. That's correct.

The early -- on the lefthand side of the chart, the solid black line represents the early pressure - time history for the Canada Ojitos Unit Pressure Maintenance Area.

Q That would be off the graph that's been presented as a Greer exhibit up to the point of -- of about 30 -- of about 3-million barrels of recovery within the period of roughly 1970, or thereabouts, is that right?

A That's -- yes, that's correct.

And then we have extended that period of time where no pressures were taken out until 1988, where we have recorded pressures in the C-14, which is the C-34 Well, taken in November; the E-10 Well, and we both similar pressures taken in both November as well as February for the E-10 Well; and the L-27 Well, where we have similar pressures taken in both November and February for that well, as well.

All three of those wells are in the pressure maintenance area.

Q And all three of those pressures are shown here in the course of the late 1987 or early 1988 on the time scale.

A That is correct.

Q The pressure history from the Gavilan Mancos Pool together with the pressures for wells in the proposed expansion area is shown by the solid line on the righthand side. It begins in 1982 at which time the Gavilan Pool was discovered. It's apparent that the Gavilan area had in 1982 approximately, I guess, looks to be about 20 years, 19 or 20 years, after development of the Canada Ojitos Unit Pressure Maintenance Area, the Gavilan area had not suffered any signficant amount of pressure depletion, such that the pressure was close to original pressure and we don't really have really good initial pressure information in the Gavilan area, so that pressure could be a little bit on the -- on the low side.

We see, then, the completely different behavior of the Gavilan Mancos Pool and the pressure expansion area from the pressure maintenance area. The expansion area, as well as the Gavilan Mancos Pool, as it's depleted has had a considerable drop in pressure, as would be expected when you -- when you deplete a reservoir such as this.

We note, we've noted on this particular exhibit several individual wells in the pressure expansion area, once again follow the trend of the Gavilan Mancos Pool and, in fact, all the wells in the proposed expansion area follow this trend.

Q Have you put some of those pressures on Exhibit Nine on the bottom panel here, like the No. 32 Well, you put the pressure -- that's Unit 25, you put that pressure on? And you put a 28, Unit 28, B-29 pressure, another well -- pressure out of the B-32 up here to show where those particular pressures fell with relationship to that general pressure decline, is that right?

A Yes, we have. I, and I might note that the early -- the performance of the pressure maintenance area had very little impact on Gavilan. In a similar sense, it appears the performance of Gavilan is having very little impact on -- if any, in fact I can't see any kind of impact, on the pressure maintenance area.

Q Do the -- does this pressure versus tubing and production data comparison indicate that -- that there is effective comunication between the Gavilan and expansion area versus the pressure maintenance area?

A It indicates that there is -- it's -- I see no communication whatsoever between those two areas. They appear to be performing completely independently. Once again, this -- this kind of presentation is not just simply a presentation of pressure gradient with -- of pressure gradient across the field, it is a representation of the pressure gradient with time, how that's actually changed.

Initially there was a pressure gradient going in the direction from the Gavilan Pool into the pressure maintenance area. That existed for 20, approximately 20 years. It's only been in the last year that that pressure gradient has changes such that it is now going in the direction of Gavilan to the west from the pressure maintenance area, but once again, there's been no noticeable impact on the pressure performance of either area by what happens in the first area.

Q Well, you said gradient. Does that pressure difference, then, really represent a gradient between the two areas or does it actually represent the performance of two separate reservoirs?

A I interpret it as a pressure discontinuity, two separate reservoirs. They have no impact one on the other.

MR. DOUGLASS: I offer Mallon Exhibit Nine.

MR. LEMAY Exhibit Nine will be admitted into evidence without objection.

Q We could identify for the record Mallon Exhibit Ten, as set of calculations entitled Flow Calculations from Gavailan-Proposed Expansion Area for Reservoir Rock Described by Mr. Greer in Exhibit 3, Tab A, page 7, 3/17/88.

We don't have a large one of these because we just got the information yesterday, is that correct?

A That's correct.

Q All right, what have you -- what have you shown here on Mallon Exhibit Ten?

A Mallon Exhibit Ten shows an estimate of how much fluid would have migrated from the Gavilan area to the Canada Ojitos Unit Pressure Maintenance Area over the period of time that the pressure maintenance unit was -- was producing prior to the discovery of the Gavilan Pool.

The calculation is based on this permeability thickness value that was identified through these interference tests that Mr. Greer described previously.

Before we go through the calculations, I might simply, if I could move to the second sheet, I might note on the second sheet that the data that we have used in this calculation, as you'll see, the critical piece of data that we have used is for the interference test pair, Canada Ojitos Unit C-34, Canada Ojitos Unit B-32, the two wells that we say are on the opposite side of the barrier. That is the far righthand column and then if we go to the very bottom line, line number 13, in the lower righthand corner, we see K (unclear). which represents oil transmissibility measured in darcy feet, not millidarcy feet but darcy feet, a value of 14.

We are going to perform a calculation here, or we will form a calculation that is taken -- the equation is taken from one of the classical texts in reservoir engineering, a text by Craft and Hawkins, and we have included the cover sheet from that particular -- that particular textbook as the next page we reference equation 6.14. That is the equation that we'll be using. It describes linear flow of incompressible fluid, which basically a liquid system is going to be of small compressibility, and we're talking about steady state flow under an enclosed pressure differential. We're going to calculate a flow rate and from that we'll calculate how much fluid has migrated across the boundary between the proposed expansion area towards the pressure maintenance area, assuming the value of permeability thickness is a correct value.

Q Let's get those two wells, then, C-34 and the B-32 Wells.

A That is correct. That is the two wells on either side of the barrier located approximately 10,000 feet apart.

Q And wells in -- those wells in November had a 442 pound pressure differential as a result of shut-in bottom hole pressure measurements, as shown on Mallon Exhibit Seven, is that right?

A That is correct.

Q All right. You're now going to calculate using Mr. Greer's millidarcy -- or his darcy feet here, what kind of flow we would have during -- from west to east if they were a common reservoir, is that correct?

A That is correct. We have repeated at the very top of the front sheet the formula. This is straight of Craft and Hawkins. There is nothing complex about this in the least.

The value q represents the oil rate in barrels of oil per day.

The value Kh is permeability thickness measured in darcy feet.

We have a value that should be a large W, it looks like a symbol mu on this -- on my sheet, right under Kh; that should be a large W.

Q You want everybody to make that a large W?

A That is the flow width of the -- that's the flow width, basically the length between the pressure expansion area and pressure maintenance area, the common boundary flank.

The pressure differential that we're going to analyze is the pressure differential in the direction from the Gavilan Pool in the direction of the Canada Ojitos Unit Pressure Maintenance Pool.

Okay. I'll tell you the values we used in a second. The capital M value is the viscosity if the fluid is flowing in centipoise. B is an oil formation volume factor and delta L is the linear flow length that the pressure gradient exists across.

Now the values that we are using, we are using a flow width of 8 miles. That -- that basically corresponds to the common barrier or the common boundary between the proposed expansion area and the pressure maintenance area.

The pressure differential of 350 psi can be seen from the preceding exhibit and it is the 350 pounds betwen the initial Gavilan pressure and the dashed line.

That's 350 pounds imposed across that.

The mobility of the fluid is .6 centipoise. That's the viscosity -- I'm sorry, I said mobility, that's the viscosity of the oil.

The formation volume factor is 1.3 reservoir barrels per stock tank barrel.

The length across which this 350 pound pressure gradient has existed is -- 10,560 feet is the distance between the B-32 Well, which fell along the trend of initial pressures in the Gavilan area, and the C-34 Well, which is the well along the dashed line for the pressure maintenance area.

And now what we're going to do is calculate how much fluid would have flowed -- would have gone across that barrier in the 17-year period, yeah, moving from west to east in the 17-year period from the time the Canada Ojitos Unit Pressure Maintenance Project started up until Gavilan was discovered.

The next line is simply substituting in those values that are not dependent on permeability thickness and coming up with a flow rate then is equal to 2039 times whatever the permeability thickness value is. We take Greer's value of 28,000 barrels a day across this boundary, which over a 17 year period would result in the flow of 177,000,000 barrels of oil across that boundary.

Obviously, that amount of oil hasn't -- hasn't gone across the boundary. What that tells us is that that permeability thickness product just can't be realistic; it just can't be anywhere close to realistic.

If it were that high, basically we would have found Gavilan had the same pressure as the Canada Ojitos Unit Pressure Maintenance Project, and we didn't.

If we went through and calculated what might be reasonable values for that kind of pressure differential, we might come down to a value of, say, .01, which is 10 millidarcy feet, a lot more consistent with the kinds of wells that we've seen in that area between the -- between the pressure maintenance area and the proposed expansion area, and in the case of -- in that case we would have seen over that 17-year period a flow of maybe 127,000 barrels of oil.

Q Would you consider 127,000 barrels of oil flowing over a period of 17 years to be effective communication between the two areas?

A No, I would not.

Q Anything else you want ot add with reference to Mallon Exhibit Ten?

A No.

MR. DOUGLASS: I offer Mallon Exhibit Ten.

MR. LEMAY: Exhibit Ten will be admitted without objection.

Q Let us have identified as Mallon Exhibit Eleven a set of graphs that were taken out of Mr. Greer's exhibits with additional calculations made with reference to such.

We don't have large copies of these, either, Mr. Chairman. These were just made from the data that we obtained yesterday.

All right, Mr. Hueni, what have you shown on Mallon's Exhibit Eleven?

A Mallon Exhibit Eleven is a review of several of the fracture stimulation flow tests that have been referred to as the basis for indicating that there is substantial pressure communication across this barrier area.

Interference tests, interference testing in general can be done one of many different ways.

I think the way that we believe to be the most correct, what we know is the most correct, is basically the way as shown on our last exhibit where you plot up the bottom hole pressures, the measured bottom hole pressures versus time and you see, then, if the performance of one area affects the performance of the other area, and the data clearly indicates that there is no effective communication between the pressure maintenance area and the proposed expansion area.

Q You said last exhibit. I believe our last exhibit was Exhibit Ten. Are you referring to Exhibit Nine?

A That is correct, I'm sorry, Exhibit Nine.

Q And also Exhibit Eight and Exhibit Seven show that same type of interference test that you're talking about.

A That -- that is correct, just the spot pressure measurements to get a point in time also show that, but even more meaningful is this trend in pressures that we've observed.

A second type of interference test is the type that is classically run where a well is -- is turned on or shut-in or injected into and then an observation well is used to monitor pressures and they're observed then if there is any kind of pressure response.

Q Let me ask you about that. Was that any type of those conventional type interference tests across the barrier as you've shown it on Exhibit Eight?

A We have looked in detail at the information that was provided to us about two weeks ago by Mr. Greer. During those tests there were several periods where Mr. Greer had run pressure bombs in the hole. They were in the hole and during those periods of time significant changes were made on one or the other side of this barrier with a pressure bomb on the opposite side of the barrier.

Unfortunately, in all cases the battery failed and we have no test that represents the conventional test.

To give you specific examples of this, we have pressure measurements for the C-34 Well. We are, however, missing the data between August 18th and September 11th of 1987. The expansion area at that time -- well, the C-34 Well had a pressure bomb in the well at that time. The expansion area production at that time was producing approximately 3000 barrels a day.

On the 19th Well B-29, F-30, and J-6 were shut-in. Production was reduced to 1600 barrels a day and for the period 8-20, August 20th to August 22nd, those wells remained shut-in.

After August 20 those wells were returned to production, increasing the rate to 3300 barrels a day. In the -- well -- and then on the 27th B-32 was shut-in, reducing the rate down to 2500 barrels a day.

Pressure changes monitored in C-34, if pressure changes had been monitored successfully in Well C-34, and they had demonstrated any kind of variation in pressure was directly responsive to the turning on and shutting in of these wells on the opposite side of the barrier, we could have considered that as a conventional interference test. Unfortunately, once again, all of that data was -- was not available as a result of mechanical malfunctioning of the pressure gauges.

We had a similar situation to that exist in -- in the period of about November 1st, '87, at which point in time there was a pressure gauge in the B-17 Well, as well as in the C-34 Well, I believe. The E-10 at that time, which is in the pressure maintenance area, was placed back -- was placed back on production and injection was reduced.

The expansion area during that time produced at a constant rate. Once again, a measurement of pressure change fluctuations in the D-17 Well resulting from these changes in the E-10 and the change in injection in the pressure maintenance area would have been indicative of interference effects in a conventional sense.

Once again this data is not available because of mechanical malfunctioning of the gauges.

So unfortunately, the only type of interference information that we have available to work with is interference information information that was derived from fracture stimulation treatments.

Q Would you say that's the interference across this barrier as opposed to conventional interference tests? In other words, you're talking about fracs across the barrier or wells that are on either -- either side of the barrier trying to see if those have an effect across the barrier, is that right?

A That is correct.

Q Okay. What about Exhibit Eleven, then, what's the first sheet on it?

A The first sheet on Exhibit Eleven is a plot taken from Mr. Greer's Exhibit Number Two, Tab G, presented yesterday, of the response to frac treatment of the Canada Ojitos Unit F-7 Well, or frac treatment in that well to the bottom hole pressure survey build-up on Well Canada Ojitos Unit J-6.

These are two wells which are accepted to be in the pressure expansion area to the west of the boundary.

The plot is expressed in terms of pressure on the lefthand scale versus time along the X axis.

We can see that the F-7 frac began on November 25th, 1987, and immediate and significant pressure response was noted in the range of approxiately, oh, looks like about 9 psi, after which the pressure frac undoubtedly was terminated shortly thereafter, followed by a sharp pressure decline and then once again returned to the normal rate of build-up of the pressure plot for the J-6 Well.

Q Does that indicate to you that this is -- the first page of Mallon Exhibit 11 is an exact duplication of Mr. Greer's Exhibit Two, Tab G, found there, is that correct?

A That's exactly right and it indicates fracture response. It indicates communication.

Q Between two wells that we show west of the barrier, is that correct?

A That is correct.

Q In the area that you've previously testified about having good communication in light of the pressures that you've seen in that area.

A That is correct.

Q All right, sir, what's the second page?

A The second page is a similar type of fracture interference effect and it is taken from Mr. Greer's Exhibit Number Two, Tab H, same date. It is, once again, the result of fracturing in the Canada Ojitos F-7 Well and then it is the effect on the Canada Ojitos Unit E-6 Well.

Q A well a little further removed than the J-6, is that correct.

A That is correct, a little --

Q And then --

A -- further removed.

Q But in the same section west of the barrier in the area of good communication.

A That is correct. This plot, once again, is presented on the scale of pressure on the lefthand side and time along the X axis.

Once again, the starting frac is noted on 11-25-87; a pressure response is obtained; pressure increases by 1 to 1-1/2 psi over the trend; and then after termination of the fracture treatment it eventually is -- is fractured at a depth that bleeds off into the formation, the fracture fluid bleeds off into the formation, the fracture response dies out and the trend in build-up pressures continues.

Once again we've noted Mr. Greer's noted the fracture response and we agree with that one, too.

Q What's the third page? What does it cover?

A The third page now is the fracture stimulation of the well C-34 and then the pressure measurements taken in well B-32, which Mr. Greer indicated indicate fracture response and that is, in fact, is shown; he has shown that on his exhibit by a difference between the dotted lines and the dashed lines or he's written in fracture response.

Once again this is taken from Greer Exhibit Number Two, Tab B.

I have added onto that in my handwriting that the upper set of dotted -- of dots represent Gavilan -- a period of time when Gavilan was producing and all wells that were in Township 25 North, Range 1 West, were shut-in.

The lower curve, which was presented for the comparison on B-32 which showed no inflection, at that point in time, that same point in time, Gavilan wells were on production and we aren't exactly sure what the status of individual wells in the Canada Ojitos Unit pressure expansion area were at that point in time.

So we're not sure about possible interference effects. What we have here is what is shown as fracture response on this (unclear) could just as easily be referred to as non-homogeneous reservoir behavior.

I'd like to -- to note that on this particular exhibit, contrary to the other two exhibits, we now have pressure plotted versus a logarithm of time, not time versus a logarithm of time.

Q Does that make an effect on what the pressure -- pressures look like as far as this goes?

A It makes a great effect on that.

Q What is shown on the fourth page?

A Okay, the fourth page, now, is that exact same data converted to the same scale as Mr. Greer presented his -- his exhibits on the other two wells for. This is a plot of pressure versus time. It is for exact -- it is for the exact same well here, the C-34, B-32, pressure versus time, and I have a feeling if we had put in there the point at which they started pumping the C-34 frac, that nobody would be able to see any change in trend in pressures.

Q Let me see if I understand. The first two pages, you indicate that data on that shows frac response between the wells west of the -- of the barrier and in the good communication area, is that correct?

A That is correct.

Q And it's done on a time basis.

A That's right, it's done on a time basis.

Q Then, the exhibit that Mr. Greer shows on the supposedly interference across the barrier, he uses a delta, delta versus time, logarithmic time, is that correct?

A That is correct.

Q All right, sir, and you have on the next sheet, page 4, converted that pressure to actual time on the same scale basis, and the same time basis, as the first two exhibits, is that correct?

A That is correct.

Q Did you see a frac response on the B-32 from the work done on C-34?

A I see no response and certainly no imme- diate response and nothing that would indicate a high permeability connection between the two.

Q All right, sir, what's the fifth page? Do you have a fifth page? Take my fifth page.

A The fifth page is a page taken also from Mr. Greer's Exhibit Number Two. It is the results of the -- of the pressure run in the well B-29 well, which is in the proposed expansion area, at the same time that the well C-34 was stimulated, the well C-34 in the pressure maintenance area was stimulated.

Q Again across the barrier?

A Once again across the barrier.

Q This is Greer Exhibit Two, Tab C, where it shows this graph, reproduction of it.

A That is correct.

Q All right, sir. What's the scale on this one?

A Once again the scale, as was the case for the last well, is pressure versus the logarithm of shut-in time. Once again, the deviation from the straight line is shown as fracture response where it could be just as easily attributed to a non-homogeneous formation or under -- under effect such as that.

Q What have you shown on page 6, then?

A Page 6 is the exact same data taken on the pressure survey on the B-29 well taken at the same point in time, plotted on the same scale that Mr. Greer presented his first two wells on, that is just on a straight time basis, pressure versus time.

Q Wait a minute, now, I don't see any frac indication on that -- on that page 6. When --

A Well, I --

Q -- was the well fraced?

A -- I unfortunately left it off. I assume that it was maybe not particularly obvious that that well was fraced at about some time between 70 and 80 hours of shut-in.

Q So if the -- if the Commission wanted to put on that exhibit when the well was fraced, it was between 70 and 80 hours, is that correct?

A That's when I interpret it. I know it's right in that time frame.

Q Do you see any frac response in -- in that period of time or any other period of time from about 50 hours on?

A No, I don't.

Q All right. What's the page 7?

A Page 7 is another frac response, response to frac treatment. Now it is using the fracture treatment in the F-7 and using the D-17 Well as -- as a pressure monitoring well.

And once again this well has been plotted pressure versus logarithm of shut-in time. This is taken also from Greer's Exhibit Number Two, Tab I, presented yesterday.

Q All right, have you actually added some additional information on this from that original exhibit?

A Yes. We have added, for example, if you would look on the lower lefthand portion of the graph, we've drawn a line through what appears to be an early time, or I won't say early time, it appears to be a slope that was in effect up to a log delta T value of about 4.4, of about 3.6 pounds per cycle.

We then see a change in slope of 5.3 pounds per cycle, which could, once again, reflect -- it's possible that it would reflect a barrier in that particular well; could -- it might simply reflect some sort of non-homogeneous behavior in that particular well.

We move further up, we've added the value of 5.3 pounds per cycle, I believe, as I remember his -- Mr. Greer's exhibit. We move further up and we have added, there was an 11 pound per cycle trend that was drawn and then frac response was associated with it.

Well, we noted that that 11 pound per cycle actually began almost a day before the second 11 pound per cycle value is then used to identify frac response.

I think our point is simply that it is very difficult to use this kind of information to identify interference effects because it can be confused with so many other effects, and, in fact, we would have a hard time accepting fracture interference as a standard by itself because it represents, basically it is not fluid flow through a porous media, it is parting of the rock and pushing fluid throught that rock at a high rate, and the fact that you can do it demonstrates that, well, that is just not fluid flow through porous media and shouldn't be analyzed as such.

Q All right, the next -- the next to the last page, what is shown in Mallon Exhibit Eleven?

A The final page in Mallon Exhibit Eleven is the same information, the pressure maintenance on the D-17 plotted as a function of time versus pressure, once again noting where the -- they started pumping the F-7 frac, noting the irregular shape of the build-up and certainly it is difficult for us to ascribe any of that behavior, particularly the frac response, although we do believe that the F-7 and D-17 wells are in an area that is in pressure communication.

Q All right. Is there any other comments you'd like to make with reference to the interference tests, use of the various pressures, surface pressures versus the bottom hole pressures, items of that sort, with regard to trying to determine whether there's effective communication across this barrier?

A We believe that the information that is the most valid is the long term pressure trends monitored and recorded in a bottom hole -- through bottom hole measurements.

We believe that those pressure measurements give valid results where you can have results that are misinterpreted using surface measured pressures.

We believe that interference tests that are run in a conventional sense where we have wells that are produced and then pressure changes measured as a result of production or injection, but not in such high rates as occur during fracturing, are valid measures of interference, and in this particular case all of our analysis indicates that there is no interference that has occurred across that area, even as a result of fracture treatments.

MR. DOUGLASS: Offer Mallon Exhibit Eleven.

MR. LEMAY: Exhibit Eleven into evidence without objection.

MR. DOUGLASS: Mr. Chairman, we'd like to have identified for the record the next two exhibits since they will be referred to in tandem. It's Mallon Exhibit Twelve, a map entitled December, 1987 Well Status. You may recall yesterday morning that was a map that I referred to in my opening statement.

We'd like to have identified as Mallon Exhibit Thirteen a tabulation entitled COU Unit Production Data.

We don't have a large blow-up of Exhibit Thirteen but we do on Exhibit Twelve.

Q Can you tell us what you've shown on Exhibit Twelve and Thirteen, please, sir?

A Yes, sir. Exhibit Twelve is a status map showing the current status of wells producing in the pressure maintenance area and then the status of wells producing in the proposed expansion area and Gavilan area.

We've color coded this exhibit to show basically the wells that are current active injection wells as of December '87 in blue. Wells that are shut-in, inactive, are shown in yellow. Wells that are producing from the pressure maintenance area are shown in the pinkish color. We've once again shown the barrier. We have then shown the wells that are producing in the pressure expansion area, or the proposed expansion area, in green.

Q Plus you've shown the wells in green producing from the --

A Yes, from the Gavilan Mancos --

Q -- Gavilan.

A -- area from the western -- from the eastern two tiers of sections.

We have shown on each of these, we've shown relative rates of production of the various wells. If we were to review this information and look first at the wells that are producing in the pressure maintenance area, we would note that in December the E-10 Well, which is located in Section 10 of 25 North, 1 West, produced only one day during that month. It produced at a rate of 227 barrels of oil per day and 1.8-million per day.

Q I'm sorry, 1. --

A 1.8-million cubic feet of gas per day for one day, and 227 barrels of oil for that one day.

There are six other wells that are located in the pressure maintenance area that produce. In total, those six wells produce a total of 380 barrels a day for an average of 63 barrels a day. These wells represent wells that are up-dip of the barrier, up-dip of the permeability barrier. They represent the last row of producers in the pressure maintenance project.

Several of these wells have higher GOR's than you might expect of solution GOR's. This is not a result of Gavilan production, Gavilan depletion. Those wells, as you have noted, or as we have noted, have pressures in line with the pressures they've always had, 1400 pounds. We had a pressure in the E-10 Well and the L-27 Well. Both of those are higher than solution GOR wells. They have not had any kind of severe pressure decline. Their GOR increase is not a result of Gavilan withdrawals.

We believe this is the last row of pressure maintenance producers that will be able to produce.

Q Unless some additional wells are drilled to the west and on the east of the barrier, is that right?

A Well, that's -- that's always possible. There could be several additional wells drilled in the pressure maintenance area.

In the proposed expansion area the wells shown in green, in that area there are 11 wells. Those 11 wells produce 2800 barrels a day for an average of 246 barrels of oil per day.

Q I believe there's actually 12, I believe there's --

A Well, there's one that at that time was recovering frac oil.

Q Oh, I see, I'm sorry, it's that one.

A Yeah.

Q Continue.

A These wells are producing at a much higher rate in spite of the pressure being lower. Their performance is not -- has not had any impact on the performance of the -- of the pressure maintenance wells.

If we -- I'm sorry, if we look, then, at Exhibit Thirteen that summarizes the production data, we would note what we've shown on this is we've shown a 3-year period, 1985, 1986 and 1987.

We have recorded the production from the existing pressure maintenance area, both oil and gas, the area that's shown in brown.

We've recorded the production from the proposed expansion area wells, the wells shown in green --

Q At the beginning of 1985, is that when the production in the expansion area essentially started?

A That is correct. Prior to 1985, prior to the development of Gavilan Mancos Pool, wells were not present along that proposed expansion area. Those wells have been drilled in response to the development that has occurred in the Gavilan Mancos area.

And we've also shown the total oil and gas production. We have then taken -- the next line is the percentage of total unit production represented by the oil and gas.

Now we might note that in 1986 in the proposed expansion area, that includes four months of production that's at restricted allowables resulting from the allowable restrictions.

In 1987 that production includes 7-1/2 months at restricted allowable, but 4-1/2 months of normal, statewide allowable production.

The percentage of total unit production in each year for each of the different areas is shown below.

In 1985 61 percent of the oil came from the pressure maintenance area, and 39 percent came from the proposed expansion area.

By 1987 only 15 percent of the oil is coming out of the pressure maintenance area with the 85 percent of the oil coming from the proposed expansion area.

We would conclude from this that not only is the pressure maintenance area at its, probably final stages of depletion in terms of the benefits of pressure maintenance, but we would conclude that the basic way that the operation of the West Puerto Chiquito -- West Puerto Chiquito Field has become more of an operation that is based on competition with the Gavilan Mancos Pool.

MR. DOUGLASS: Offer Mallon Exhibits Twelve and Thirteen.

MR. LEMAY: Exhibits Twelve and Thirteen are admitted into evidence without objection.

MR. DOUGLASS: I'd like to have identified for the record Mallon Exhibit Fourteen, a bar graph entitled Calculated Allowable Production Rates Using

December, 1987 GOR & Restricted Gavilan Allowable.

Q What have you shown on Mallon Exhibit Fourteen?

A Mallon Exhibit Fourteen shows the competitive position or competitive relationship of wells that are in the eastern two tiers of the Gavilan Mancos Pool, producing from that area, compared to the production that is being taken from the proposed expansion area in the Canada Ojitos Unit.

Q You show 23 active wells in the Gavilan and refer back to Mallon Exhibit Twelve, would those be the green colored wells there?

A Yes, that's correct. There are a couple wells, I believe there are a few more than that, there are a few wells that are down in Township 24 North, Range 2 West, that were extremely low volume or zero volume producers that were not included in these calculations.

Q For instance, in the -- in Section 2 there's a well, no barrels of oil per day.

A Yes.

Q I believe there's a well, Amoco well, in Section 14, it's WOPL, waiting on a pipeline, is that correct?

A Yes, that's correct.

Q There's a well down in Section 24 that says one barrel of oil a day.

A Right, and that's really not offsetting the proposed expansion area.

Q All right. So the 499 for the Gavilan wells comes from the remaining green 23 wells shown on Exhibit Twelve in the -- in the Gavilan Pool area, is that correct?

A That is correct. And then on the right-hand side we have for in the pressure or expansion area we have included a total of 12 wells, as indicated in green, and we have estimated for one well, the well that was in Section 7, that was being recovering frac oil, we included that based on its recent initial potential rate of about 140 barrels of oil a day.

The production derived from the Gavilan area, these eastern two tiers of sections in the Gavilan area, is shown in the cross hatched area by the cross hatched bars, and the production derived in the pressure expansion area is shown by the solid bars.

All of our -- these are calculated numbers. They are based on the observed gas/oil ratios measured in December. It is based on restricted Gavilan allowable that allows production from a well on 320-acre spacing of 400 barrels a day and a 600-to-1 GOR, which means that no more than 240 MCF per day of gas can be produced from one of those wells.

Under that set of circumstances we see that the Gavilan -- Gavilan Mancos, for the two tiers of sections in Gavilan can produce approximately 500 barrels of oil per day, whereas the 12 wells in the Canada Ojitos Unit area, many of which are on 640-acre spacing, can produce 1732 barrels of oil per day.

Looking then to the righthand side, righthand set of bars, we will see that if gas injection credit is applied -- is approved for the proposed expansion area, obviously it doesn't affect the Gavilan side of the fence at all, it stays at 500 barrels a day, but the Canada Ojitos Unit pressure maintenance area production will expand on the order of 2723 barrels a day.

Q That difference is approximately how many barrels?

A It's approximately 1000 barrels, 991 barrels.

Q Increase. Now if you take Mr. Greer's production figures that he showed the ability of his wells to produce in this expansion area, I believe it was something in excess of 3100 barrrels, is that correct?

A I believe that's correct, although he indicated that with the pressure decline it might not be quite that high now.

Q Do you feel, then, that the 2723 is at least a minimum type ability of those wells in the expansion area to produce?

A I think that's -- that's a minimum, yes.

Q All right, what conclusion do you draw from the Fourteen Exhibit?

A The conclusion that's immediately drawn from that is that there is a real danger -- well, the conclusion is that there is probably going to be severe drainage that would occur in the event that the pressure -- proposed expansion area is included in the pressure maintenance project and a situation where production is already 3-1/2-to-1, a production advantage of 3-1/2-to-1 will be increased to a production advantage of 6-to-1.

Q Seeing the current advantage that -- that the expansion area has over the two sections in the Gavilan area is about a 3-1/2-to-1; that is 1732 versus 5 -- 499?

A Yes, that's correct.

Q And if the application is granted here where injection credit is obtained for wells that you've indicated are not in effective communication with the pressure maintenance project, the unit could increase its production just in that area by almost 1000 barrels a day.

A That is correct.

Q With a ratio of almost 6-to-1 over the

Gavilan wells.

A That is correct, and that increase occurs not with a reduction in voidage in the Gavilan Mancos proposed expansion area, because the gas that will be taken from that area will be replaced -- will be put back in on the other side of the barrier and would not be effective in maintining the pressure.

Q What about the Gavilan wells that -- these 23 wells, do they have the ability to produce more than 499 barrels a day?

A Yes, they have the ability to produce considerably more than that amount.

Q Is the reason that they're not is that they are now being restricted by this current allowable restriction?

A That is correct. They are restricted by the current allowable restriction and in fact it's been observed that as they've been restricted by that allowable, that the gas/oil ratios have gone up and the effect of that restriction has been even more severe than would otherwise have occurred.

Q Anything else you want to add on Mallon Exhibit Fourteen?

A No.

MR. DOUGLASS: Offer Mallon Exhibit Fourteen.

MR. LEMAY: Exhibit Fourteen will be admitted into evidence without objection.

MR. DOUGLASS: I'd like to have identified as Mallon Fifteen a bar graph entitled the same, I believe, as the previous one, with reference to the Mallon Howard Federal 1-8 Well and the BMG Unit 29 Well.

Q Would you tell us what you've shown on Mallon Exhibit Fifteen, please, sir?

A The preceding exhibit compared the wells that were in the eastern two tiers of the Gavilan Pool to the wells that are in the western two tiers in the proposed expansion area in the Canada Ojitos Unit. This particular example is a comparison of how the -- how a gas injection credit for the proposed expansion area would affect two off-setting wells. The two wells that we've selected are the Howard 1-8 and the Canada Ojitos Unit No. 29.

Q Represented by the slashed bar graphs, is that right?

A That is correct. The Howard Federal 1-8 is in Section 1 in the northeastern corner of that section.

The Canada Ojitos Unit No. 29 is in the northwestern corner of Section 6 of -- of the next township.

Those wells are located approximately 2000 feet apart. They have had an interference test run between those two wells, indicating excellent pressure communication between those two wells. They are both high capacity wells.

Q Do you think they're comparable wells?

A I would consider them very comparable wells.

Now, what we've shown on this graph, we've shown the December gas/oil ratios which control the allowables, so, for example, the Howard Federal 1-8 production of 24 barrels a day is controlled by 10,199 standard cubic foot per barrel GOR, whereas the 50 barrels a day being produced from the E-6 well is controlled by 4,818 standard cubic foot per barrel GOR.

So both wells have additional capacity. In October of 1987 the 1-8 well produced 264 barrels of oil per day.

Q 264 barrels of oil per day in October?

A That's correct, and when it produced that 264 barrels of oil per day, the gas/oil ratio was measured at 3,609.

Q 3,609 in October.

A That's correct.

Q At the 264-barrel a day rate.

A That's right. The --

Q Are you telling me now that it's producing 24 barrels of oil a day its ratio is almost 3 times greater, 10,199?

A That is correct. Now, the Canada Ojitos Unit No. 29 Well in October produced 313 barrels of oil per day.

Q 313 barrels of oil per day.

A And the gas/oil ratio on that well in October was 3,312.

Q 3,312 in October.

A That is correct. We've shown then on the lefthand side, based on the December GORs, the significant reduction in production for those wells from their producing capacity, in the case of Mallon from 254 barrels a day down to 24; in the case of the Canada Ojitos well from 313 down to 50.

Now, with the gas injection credit, the competitive position between these two wells worsens considerably. The Mallon well is not going to increase in production. It stays at a low value of 24 barrels a day, whereas the Canada Ojitos Unit well increases to 155 barrels a day as a result of the gas injection credits.

Q In your opinion what is -- under those conditions, that is, going from 50 versus 24 to 155 versus 24, what's going to happen with reference to drainage between the Howard 1-8 and the E-6 well, or the Unit 29 well?

A If you remember some of the preceding pressure exhibits, the Fisher well, which is to the west of the Mallon well at a higher pressure than was present in Section 6 of the Canada Ojitos Unit, indicating there was already a pressure differential in that direction.

By increasing the production from the Canada Ojitos Unit No. 29 Well, and other wells in that area, that's just going to simply aggravate that pressure differential and drainage from the Gavilan Mancos Pool.

MR. DOUGLASS: Offer Mallon Exhibit Fifteen.

MR. LEMAY: Exhibit Fifteen into evidence without objection.

Q Let us identify for the record as Mallon Exhibit Sixteen a tabulation entitled Comparison of 1/1/88 Pressure, Gas Saturation & Pressure Change Base on Compositional Model Results.

And I'll ask you, Mr. Hueni, is this essentially data that was obtained from Mallon Exhibit, I believe, Three, the computer printout data that Dr. Lee provided?

A Yes, that's correct.

Q All right, sir, what have you shown on that sheet?

A Yes, we've shown three items. We've

shown the pressures that are capsulated in Dr. Lee's compositional model as of January 1st, 1988. We've shown those for each of the individual cells that are in the model. Models are built, they consist of a number of different grid cells.

This model consists of three layers of cells designated layer 1, 2 and 3, and I think we would think of those normally in terms of layer A, B and C in the Niobrara.

Once again, we will keep in mind that Dr. Lee restricted vertical permeability between the A, B and C, as indicated by his input data. That is not necessarily the case; we would -- we believe there would be some communication between those layers.

Then as we go from left to right across the page, we see basically cells that represent the area between the Gavilan, which we have Gavilan at the top, moving then from the west over to -- to eastern side where we would have the cells that would be representative of the up-dip area of Canada Ojitos Unit Pressure Maintenance Area.

What we've done is we've shown the pressures in pounds per square inch that is recorded in his model at that particular point in time for each of the individual cells.

We've also shown the amount of gas saturation that is present in each cell at that particular time and, finally, we've shown the pressure change that's occurred from discovery of the Canada Ojitos Unit in early 19 -- well, 1963, we have change in 1/1/1964, measured in -- as a pressure in pounds per square inch.

If we look first at gas saturation values there would be a certain -- there would be certain things that we would note.

First, that the gas saturations that are non-zero occur on the righthand side of the page and basically in layers A and B, indicating that A and B, basically, only have positive gas saturations, only have free gas saturations in the far eastern portion of the Canada Ojitos Unit Prssure Maintenance Area.

Q That would be the first three cell blocks, is that correct?

A It would be the first three cell blocks. From the way I interpret Dr. Lee's model, I don't think I'm taking too many liberties with this. It would be perhaps represented going from the C-5 injection well, going over the next, oh, three or so sections. Well, we'd be including the C-5, I'm sorry. It would be the C-5 section and then the next two sections after that, and we would not see any gas saturation in the AB zones behond that point.

Of course, once again, if we allow communication, vertical communication, perhaps induced by hydraulic fracturing, to occur, then we could actually have some gas saturation in the AB, as well.

The C zone, however, has gas saturations all the way across the field and all the way into the Gavilan area. Well, once again, we have a production survey taken on Well B-32, production log survey, which showed no gas coming out of the C zone. So we could conclude either, once again, that this -- the model in this case is not particularly accurate in describing the exact distribution of gas saturations or perhaps there is simply vertical communication that allows that gas in the C to find its way up to the AB and if then it is produced out of the AB interval.

We note also the pressure change from January 1st, 1964, that is, in effect as of January 1st, 1988, and it's difficult from this to recreate the magnitude of the gradient that exists across the field. I think what you can see, if you look in the far righthand side of those values under Canada Ojitos Unit injection, there really hasn't been much pressure drop in that area. In other words, the pressure has been maintained in that area by -- by the injection.

However, once we move, let's say, two miles further to the west, that pressure then, the pressure drop is fairly uniform from there all the way to the Gavilan area. In other words, in layer number one the pressure is 385, the pressure drop is 385 psi, layer number one, two miles away from the injection.

Over in the Gavilan area it's only 60 pounds per acre, then, 449 psi.

In other words, the significant pressure differential that's actually occurred in the Gavilan Pool where the pressure was brought from 1800 down to 950 pounds, a drop of 850 pounds, that pressure drop is not being predicted.

The gradient that occurs -- I don't -- the pressure discontinuity that occurs between the pressure maintenance area and the proposed expansion area is certainly not present in the simulation model.

Q But your conclusion is about whether this simulation work is coming anywhere accurately reflecting the -- what the real world is over here in this expansion area.

A Yes. It may represent what's going on in the pressure maintenance area, but it doesn't look to me like that's a valid history match for the -- what he referred to as the Gavilan withdrawal area.

Q Does this -- in looking at this model that Dr. Lee has prepared and then looking at the actual physical data in the field, is that another confirming fact that it appears that the expansion area is actually producing from a separate reservoir as opposed to the pressure maintenance area?

A Yes, I believe it is.

Q In your opinion if the Commission grants the -- Greer's request to increase the -- obtain ratio credit in the expansion area, will it cause drainage of oil from Gavilan area to the expansion area?

A Yes, it will.

Q In your opinion -- or is the expansion area in effective communication with the existing pressure maintenance area?

A No, it's not.

Q Does the unit presently enjoy a production advantage in the expansion area versus the comparable area in the Gavilan Pool?

A Yes, they do.

Q Let me ask you one additional question, do you know of any reason why the gas that's produced from the pressure maintenance area -- excuse me, from the expansion area -- is not available to use in a plant that could be constructed by the unit?

A I know of no reason.

Q Are you aware of whether the gas from the Mallon wells goes to a plant?

A Yes, I am aware that it does go to a

plant.

Q Anything else you want to add with reference to your testimony, Mr. Hueni?

A No, sir.

MR. DOUGLASS: Offer Mallon Exhibit Sixteen.

MR. LEMAY: Without objection Exhibit Sixteen will be admitted into evidence.

Is there any more questions on that side? I know that Perry is --

MR. PEARCE: Nothing, Mr. Chairman, thank you.

MR. LEMAY: Okay. Any other lawyers on that side want to ask Mr. Hueni questions?

If not, we'll take a break, fifteen minutes, and be back for cross examination.

(Thereupon a recess was taken.)

MR. LEMAY: Cross examination by Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Hueni, when we're talking about this barrier area that is depicted on a number of your displays, perhaps we can use Exhibit Number Twelve as a representative example of the issues I'd like to talk to you about.

When you've identified this as a barrier area between the expansion area and the existing project area, this is not what we generally call a traditional geologic barrier, is it?

A Well, I think it's as much a geologic barrier as many barriers are. We have many reservoirs of stratigraphic traps and -- and as I see it, if you have a loss of permeability in a portion in a reservoir, that is -- that's a geologic barrier. I don't know how else you could refer to it.

Q But for the instance or the definition of permeability, there is no other geologic instance in here that would constitute a barrier. It is that permeabilty that we're looking at, is it not?

A Certainly it would appear that there's no permeability so -- and that's what we focus on, so I don't recognize any faults, if that's what you're asking.

Q You were here when Mr. Ellis testified yesterday about the general geology of the area?

A Yes, I was.

Q And you don't have any disagreement with the way he's depicted the structure on his structural displays?

A No, I don't.

Q And his identification of the continuity of the reservoir across the existing project area, through the expansion, into the eastern edge of Gavilan, shows a continuous reservoir?

A No, I don't think so. You know what I heard Mr. Ellis say was the fact that -- is that he could make a cross section with all the logs and you could identify the same lithology throughout the entire area, but he indicated that there were several wells, wells that, let's say, are on the up-dip edge of the pressure maintenance area that are nonproductive that have the same log characteristics, indicate the same lithology, but they're not productive.

Q And so --

A So I don't -- I don't guess I consider it continuous.

Q Continuous in the extent that we can follow the A zone lithology across from the original area through to Gavilan.

A You can identify that lithology on logs and you can trace it across and I don't disagree with that.

Q The focus, then, of your study and investigation has been to determine to what extent the barrier area is an effective barrier as to communication between the expansion area and the existing project area.

A I guess, yes, that would be (unclear).

Q Do you have any disagreement with Mr. Greer that in the existing project area for the pressure maintenance project that that in fact is an effective project?

A I haven't studied that project the way that Dr. Lee has. I think it's a highly complex reservoir, you know, I see wells that have gassed out down structure from wells that have continued to produce up structure. I see wells that are productive in -- in let's say the AB, not productive in the C. I think it's a -- I think it's a much more complex field than I -- and we have not done a detailed engineerring study of -- of that, other than to recognize the prepssures that exist in that particular area in contrast to what exists in the Gavilan area.

Q And you have not made a study of the economics of a gas plant, gas operation, cycling project that Dr. Lee discussed for us this morning.

A No, we've not been asked to do any economic analysis on the gas plant.

Q And you've not made a study nor formed an opinion with regards to whether or not the utilization of the expansion area into the pressure maintenance project will result in the recovery of additional hydrocarbons that would not otherwise be recovered.

A Yes, I have formed that opinion in the sense that I don't believe you get any benefit in terms of additional hydrocarbon recovery from the pressure expansion area by injecting the gas taken from that area and injecting that into the pressure maintenance area.

Q And that is because we come back again to the issue of the barrier between the expansion area and the existing project area.

A That's right.

Q In your testimony back in April and March of 1987 you acknowledged, along with Mr. Greer, that there in fact is communication between the expansion area and the existing project area.

A We said there might be a small amount of communication and we indicated that if such communication did exist, that Gavilan area could be depleted without having any effect on his pressure maintenance project.

Q And the issue yesterday and today and the issue ultimately to be decided by the Commission is whether or not Dr. Lee and Mr. Greer are correct that there is effective communication between this area or if the Commission agrees with you that in fact there is not. That's the issue that we're trying to decide, is it not?

A We're certainly, yes, we're certainly trying to decide if there is a barrier to present -- prevent significant flow.

Q And Mr. Greer should be entitled to his injection gas credit for gas taken out of the expansion area and re-injected up structure in the existing project area if there in fact is effective communication across the barrier.

A Well, I don't believe there's effective communication there. If there were effective communication that would be true.

Q Nothing further.

MR. LEMAY: All right, any questions, Mr. Carr?

MR. CARR: I have no questions. I'm going to call Mr. Greer for a brief rebuttal.

MR. LEMAY: Additional questions from the audience?

Yes. Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Hueni, when the Gavilan Pool was

first developed, the initial pressures in the Gavilan Pool were lower than what would otherwise have been expected, is that correct?

A It's a little bit of a difficult question to ask. The original pressures were taken by Northwest Pipeline out there and they had reported pressures, and I'm not sure if these were corrected to a datum, but they had one pressure measurement that was 1736 and they had one that was 2100 and then they had another one which was 2100 psi. So in other words, they had -- they had a range of pressures and they actually plotted those pressures up in comparison with the trend in pressures expected through the pools that are -- that follow along, such as the West Puerto Chiquito and the other pools that are -- that have gradients along that trend, and we have always -- we've always had a difficult time knowing whether we could rely on those pressure tests or not because we don't really have any of the back-up data on those wells.

What we have done is we have taken pressure measurements that we have confidence in and plotted them up versus cumulative production and we've extrapolated it back to zero cumulative production for the Gavilan area, and that would indicate a pressure more in the range of 1800 psi, which I think your question was. That might represent a little bit of a pressure drawdown in comparison to what we might have expected, and I think we saw that on the exhibit where we overlaid the Canada Ojitos Unit production -- pressure performance versus the Gavilan pressure performance, and you saw that the Gavilan was just a little bit lower at that same datum than -- than was --

MR. DOUGLASS: You're referring to Exhibit Nine?

A -- Exhibit Nine, that the Gavilan pressure was a little bit lower than the start of the Canada Ojitos Unit pressure ran.

Q Would that indicate that a certain volume of oil had -- or gas had moved from the Gavilan area?

A If that -- if that is true, there could be a minor amount of volume that has moved and that was part of the point of our calculation of linear flow across a barrier is that basically that -- that barrier would have to be a region of very low permeability thickness product, because there is not that much that's moved because Gavilan really wasn't found to be significantly depleted.

Q In your Exhibit Ten did the calculations you did take into account that gas was being injected to the east of the producing wells perhaps causing a higher differential from one direction than from another?

A I'm sorry, the -- Exhibit Ten is the flow calculations?

Q That is correct.

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

Q In your Exhibit Ten did the calculations taken into account gas being injected to the east of the producing well, which might have caused a higher differential from one direction?

A Can I --

MR. DOUGLASS: Sure.

A The calculations are based upon pressure differential measured (not clearly understood) area, and we've said that that was representative of the B-32 Well, and the reason we say that is because when this well was first tested --

MR. DOUGLASS: The B-32.

A -- the B-32, Canada Ojitos Unit B-32 Well, it fell right on this trend of Gavilan area pressure. That's this well right here. And so we said, okay, back in time, in 1982, before Gavilan began production, we would have expected the B-32 to be right up in that same area, and then for the pressure differential, the pressure differential takes into account the fact that the C-34 pressure is influenced by any kind of gas injection that occurs up structure, so this 350 pound pressure that exists, that differential that exists across that narrow 2-mile strip is --

takes into account all the physical reality of what's happened out there.

Q In your opinion if Mr. Greer's application is approved, will waste be caused as defined by general oil industry definition?

A Well, certainly. It won't -- it won't do any good to inject gas from one reservoir basically into another reservoir. Perhaps more than waste, I would concentrate on the correlative rights, and I think the correlative rights of the parties in the Gavilan Mancos Pool would be seriously violated.

But in terms of waste, the Gavilan Mancos is being pressure depleted and what it would mean is that the proposed expansion area would deplete the pressure of the overall Gavilan area. It would have basically a production benefit, we'd be able to reap a reward in competition but I'm not sure it would change the ultimate recovery of the Gavilan Mancos Pool. I think it would just simply serve to redistribute the production with a much more significant amount going to the Canada Ojitos Unit area.

Q If Mr. Greer's application was approved and it was found out later that a barrier of some kind did exist, how long would that -- would it take to see that in pressures and production in the Canada Ojitos Unit?

A Well, you know, I've got twenty years

worth of history there, more than twenty years; we've got twenty-five years worth of history, and we haven't seen it, seen it yet, so I don't know, you know, how we should say we should look for another year, another two years, at it. It's fortunate that they've had the testing, recent testing requirements, because with -- in the absence of having some tests in the pressure maintenance area itself, we wouldn't really be able to establish this factual base, that there is a significant difference in pressures in the pressure maintenance area versus the pressure -- proposed expansion area and the Gavilan area.

So I don't know really what -- what additional information you would gain beyond what you already have available.

Q Would it be your recommendation that the operators in the Gavilan be allowed to produce at a rate that would prevent the flow of oil and gas to the Canada Ojitos Unit if Mr. Greer's application is approved?

A Yes.

MR. CHAVEZ: That's all I have.

MR. LEMAY: Thank you, Mr. Chavez.

Additional questions of the witness?

QUESTIONS BY MR. LEMAY:

Q What, just in general, Mr. Hueni, what kind of pressure differential -- now, I'm just taking the border line, now, between Gavilan and West Puerto Chiquito -- given that border line, wells on each side, what kind of pressure differential would you consider as a serious violation of correlative rights, so that you would get significant flow from one side of that line to the other?

A I'm not sure that I can completely answer that because the -- there are obviously variations in quality within the Gavilan area going over into the proposed expansion area. Some of the -- in some cases the wells, for example, Mallon wells and the offsetting Canada Ojitos Unit wells, appear to be high productivity wells.

A small pressure differential in that area could result in a significant flux of fluid in one direction or the other.

On the other hand, there are other areas where the reservoir quality is not as high and so a larger pressure differential may not result in any more oil moving -- moving across that boundary between Gavilan Mancos and -- and West Puerto Chiquito.

I know that's not a -- that's not a very satisfying answer, but we don't see a great deal of pressure differential right now out there, and yet we see rates of withdrawal that are 3-1/2-to-1 in the pressure expansion area, and we still don't see that high a pressure differential, just a couple pounds, so we're -- we're dealing with -- within the Gavilan Mancos Pool itself some fairly permeable rock, certainly not 10 darcy feet, but we're dealing with some fairly permeable rock and it's not going to take a large pressure differential to cause flow across that boundary.

So I'm -- I'm thinking we're talking in terms of 50 pounds or less.

Q I think you've helped me quantify what -- what has otherwise -- had not been quantifiable. 50 pounds, in your estimation would be a serious violation of correlative rights that should be corrected across the boundary. Is that fair to say that?

A Well, you know, once again, it's going to depend on the areas that you're looking at and there are -- that's such a -- that's such a difficult question, but in general, we just don't see that much of a pressure gradient in the Gavilan Mancos Pool.

I'm sorry, I really can't answer that very satisfactorily. I can't -- I can't feel too comfortable about it.

Q What about -- one other thing that's a little bit disturbing -- I guess not disturbing, it's hard for me to come to grips with, was your last exhibit when you were comparing two very close wells, one on the West Puerto Chiquito side, the other on the Gavilan side, and you were analyzing GOR's, I think, on those wells, they were so close, how do you account for the difference in -- in GORs, as stated, if they're 2000 feet apart, I think you mentioned? One has a GOR of something like 12,000-to-1, was it, and the other 3000?

MR. DOUGLASS: 10,000. I think it's Exhibit Fifteen, Mr. Chairman.

Q 10,000 versus roughly 5,000. I guess I'm asking how is that possible?

A Yes. How is it possible? It seems that there are many things that are possible here that (not clearly understood.)

Q One would take away from the other; I would expect them to be equal going in, but if they're not equal going in, there's something we're not seeing here.

A Well, we have noted, and we are not prepared at this point in time to give a complete explanation. Mr. Greer gave his explanation but we're not prepared at this point in time to indicate why low rates result in higher GOR's.

It's simply our observation that they do.

If we reflect back to the October period of time when these wells were both being allowed to produce at the normal statewide allowable rates, the GOR's were very comparable. They were 3600 for the Mallon well and 3300 for the BMG well.

Q I grant you that. Has anyone entertained the theory that the C zone may be the kicker in here? In other words, we see low GOR's in the C zone, where that zone has capability, potential capability, it would contribute higher volumes of oil and the GOR remains constant, and I'm not throwing out this theory, but this never had come up before that the C zone may be the one that responds to higher allowables and therefor reduced GOR's when you -- when you kick them up there.

A I think, you know, if we look back at the televiewer results in the Gavilan area as well as the production logs, and I grant the production logs can change from time to time, but thus far we have seen within the Gavilan area itself, we have not seen anything that we consider to be a considerable C zone producer, or indicating high potential out of the C zone.

There are a number of different hypotheses that could be -- could be raised as to why -- as to why this phenomenon happens. Once again, we could even go to tight fracture blocks and -- versus -- and the fact that we need higher pressure drawdowns in order to get the oil out of the tight fracture blocks. I mean that's just a hypothesis.

Q I didn't mean to get us on a tangent here.

A Yeah, I understand that.

Q We could go on for days and Sally wouldn't like that -- nor would the rest of us -- but I was just trying to look at the correlative rights issues on the two sides of that -- that line.

A That's right. I might note with respect to that particular exhibit, the way that we calculated these numbers is we took the number of -- we took the amount of production and divided it by the days on production that that well produced.

So, for example, on the righthand side, for the Canada Ojitos Unit well, 155 represents simply taking the production, dividing by the number of days it was on production and assuming that it wouldn't have any kind of GOR restriction.

That does not mean that the Canada Ojitos No. E-6 that that well, that 155 barrels is its capacity. We know that the Mallon well has a capacity of several hundred barrels a day and we are fairly confident that the E-6 has that same capacity. It just so happens that that's the only factual data base that we had and that particular well that we show 155 may be produced at several hundred barrels a day.

Q Thank you.

MR. LEMAY: Additional questions of the witness; additional cross, redirect.

Fine, you may be excused.

(Thereupon a recess was taken.)

DR. JOHN LEE,

being recalled on rebuttal, and remaining under oath, testified as follows, to-wit:

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Dr. Lee, do you have a copy of the information that Mr. Hueni was utilizing when he responded to your testimony about the gas plant simulation model performance?

A I don't have it with me but I'm familiar with what he -- what he had and it certainly is from our computer output.

Q The criticism, as I recall it, by Mr. Hueni is not that you, sir, but the model was not reflective of the real world and that that was a major flaw in the analysis that you had made with regards to the gas plant.

Would you specifically refresh our recollection as to what Mr. Hueni's specific criticism was of the modeling?

A Well, I believe I can generalize and say that his criticism was that it did not represent the distributions of pressures and gas saturations areally in accordance with certain observed facts.

Q Is it necessary for the purposes to which you utilized that model to have the model match actual field performance as to those items?

A No, I--in my judgment it was not. The -- what we really need with that model is to start with the right amount of oil in place, produce the right amount of oil and gas, inject the right amount of gas, and have essentially the correct amount of oil and gas in place in the reservoir at the time that we start our study of cycling operations, because what we're really after is to look at the ability of injected gas to strip the lighter hydrocarbons from the crude oil in the reservoir, and to do that we need to take into account the dip, the fact that we do have zones, and so forth, but we don't, and did not have the objective of trying to model the reservoir in any detail at all in space; in particular, we didn't try to match details of pressure and saturation.

In fact, we deliberately simplified the model. That was a very simplified model of the reservoir.

What it would have taken to do a rigorous model study would be a very fine grid, which we did not have; that is breaking up the model into many, many small parts; matching individual well as opposed to gross area production, and so forth, and that sort of study would simply have been prohibitively expensive; again keep in mind the objective. We're just trying to have the right amount of oil and gas in place, the correct structure, and so forth, and so we -- we did that. We did have the objective in -- in getting the right amount of oil and gas in place to match the pressure at the boundary of the unit during 1987.

So that's -- that really was our objective in the pressure match.

So to serve the purpose of the model, which is to have the oil and gas in place and look at the ability of injected gas to strip hydrocarbons from the crude oil in the reservoir, we believe the model serves that purpose quite adequately.

Q Thank you.

MR. LEMAY: Thank you. Any questions of the witness?

RECROSS EXAMINATION

BY MR. DOUGLASS:

Q John, just to make sure I understand what you've said is that your model assumes a continuous reservoir from the area of -- the expansion area all the way across to the injection wells.

A That's true.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Additional questions of the witness?

He may be excused.

Additional witnesses, Mr. Kellahin?

MR. KELLAHIN: No, sir.

MR. LEMAY: Pardon?

MR. KELLAHIN: No, sir.

MR. LEMAY: Are there any other -- yes, sir, Mr. Carr.

MR. CARR: I'm going to recall Mr. Greer.

MR. LEMAY: Fine. Mr. Greer.

ALBERT R. GREER,

being recalled on rebuttal, and remaining under oath, testified as follows, to-wit:

REDIRECT EXAMINATION

BY MR. CARR:

Q Mr. Greer, I direct your attention to Mallon's Exhibit Number Five. The red line on the exhibit is a line that Mr. Hueni indicated was indicative of a region of low productivity, and I'd like you to first look at the COU 22 Well in the north, the northernmost well on the red line, and if you'll recall, Mr. Hueni testified that well produced from -- was producing one barrel a day, is that correct?

A Yes, sir. I'll ask Mr. Stoltz to point to that well so that -- I think it will be faster to go through these exhibits just looking at their enlarged displays rather than have to dig through the pages of the pages of the book.

The F-20 well, Mr. Hueni said was capable of making one barrel a day out of the Mancos.

That well has not yet been tested in the Mancos. We've drilled it through the Mancos into the Dakota and we got one, one or two barrels a day and maybe 100 MCF of gas a day out of the Dakota.

We've not yet come back for various reasons to open up the Mancos but -- but we will.

So at this point we really don't know and certainly we cannot take that well's production at this point to be definitive of that particular area.

Q Will you look at the C-34? Are you through talking about the F-20?

A I suggest we come down the -- down the line --

Q All right.

A -- to the C-32.

Q All right.

A We were unsuccessful fracing that well. We have in mind re-fracing it once we have determined what's the best way to frac these wells, and I -- I hate to admit it, Mr. Chairman, but after all these years operating in this reservoir, we still don't know how's the best way to either locate them, drill them, frac them, and whatever. We've tried everything.

We've tried to frac them with oil; we've tried gelled oil; we've tried slick water; we tried gelled water; and we've tried carbon dioxide. We've tried locating the wells by fracture studies, by studying flex trends, structural positions, and everything we could think of. With all the assets that one has at one's disposal, the one outstanding asset is good luck.

Q Mr. Greer, are you aware of any of the wells in this area that would be capable of producing prior to some sort of a frac treatment?

A Oh. I think out of roughly 100 wells that we've drilled in that area that we've had one that was completed naturally and we hadn't fraced it (not clearly understood.)

Q Do you believe this -- do you believe the G-32 in its present state is indicative of the ability of the reservoir to produce?

A No, you can't say that for sure.

Q Would you like to move down that red line to the next well, the J-8?

A The J-8, I don't know about that. It looks to me like a small well. I have no plans to go in and try to go in and try to do any work on it.

The next well to it, the A-16, was initially completed and produced for many years in the C zone and just last summer we gave it a frac treatment in the A and B zones and we still have had some trouble with our production equipment going on and still not tested it. We just don't know what it will do in the A and B zones, so it's really indefinite at that location.

Q What about the A-22?

A The A-22 was a good well in the C zone. We have plans to open up the A and B zones in it. We'll be asking our partners for approval to do that at our operating meeting next month.

Q Will you look now at the C-34?

A The C-34, I believe Mr. Hueni mentioned that he saw no increase in production when we treated the A and B zones and he quoted the December production as being the combined production from all three zones, A, B and C zones, which is not the case.

In December the C-34 was still producing from only the A and B zones and that approximately half a million feet day and 40 barrels of oil a day is from the A and B zones.

We have since drilled out the bridge plug, opened up the C zone. The well now makes 1.2-to-1.500,000 cubic feet of gas a day. We picked up at least a half million feet of gas a day and some oil in the -- in the A and B zones.

Q In your opinion does the information on this exhibit establish a low productivity area in the reservoir?

A Oh, not -- not exactly. We feel like there is no question, Mr. Chairman, there are low productivity zones throughout the pool and there are tight streaks which we've indicated on our different displays, and in my view there's no permeability barrier. There are permeability restrictions and in our analysis they're not effective in preventing a pressure maintenance project from working.

Q Do you have anything further you'd like to address with Exhibit Number Five?

A No, sir.

Q At this time I'd like you to refer to what has been admitted as Mallon Exhibit Number Seven. This is a map that shows a pressure differential between the existing project area and the expansion area --

MR. LEMAY: Before we continue, let's take a ten minute recess here. He's got to leave. We're just going to locate the Commissioner.

(Thereupon a recess was taken.)

Q Mr. Greer, before you is Mallon's Exhibit Number Seven. If you'll recall, in testifying about this exhibit Mr. Hueni indicated that he had used bottom hole pressures to get a different result than you had.

A Yes, sir. He made the comment that the bottom hole pressures were a better way to determine pressure gradient across the reservoir and -- and that the method I used, the surface pressure, was not as accurate, and he used as an example the E-10 well in which he used bottom hole pressures in the conventional manner and what I wanted to point out is that there was no bottom hole pressure run in the E-10. The E-10's bottom hole pressure was calculated from the surface pressure, and so in a sense they are one and the same thing, taking into account the weight of the column of gas.

Now, the difference that Mr. Hueni shows is simply the difference due to the elevation of the structure and the density of the fluids in the structure, in the reservoir, for the difference in elevation points in the reservoir and I pointed that out during my discussion of the use of the surface pressure gradients in that those were minimum gradients and that to get a true reservoir pressure gradient one would have to add the density of the fluids within the reservoir for the difference in the structural positions, and that's all that particular example shows, is that, yes, there is a greater pressure gradient and that's -- that what it is, and all I was trying to show was a minimum pressure gradient. And so his comment that it's not accurate just does not apply. A surface pressure map is a very accurate representation of the pressure gradient, of the minimum pressure gradient.

Q Mr. Greer, Mallon Exhibit Number Eight contains some additional pressure information. Do you care to comment on that information?

A Yes, sir, we will need to look at that exhibit. It -- we just received the pressure information on Tuesday morning when we left our office to come over here, and we've not had time to study those pressures.

We presumed that the time that we would be using those pressures and studies for the Commission would be for the May hearing and it's our intention to be so prepared at that time.

I'm a little surprised at one of the pressures in the Fisher Federal, which I didn't report to be 100 pounds higher than our E-6. When we were measuring pressures earlier we found pressures equalized across the -- the Section 1 over to the Dugan Divide 3 Well, which is just north of the Fisher Federal, and we found never more than a few pounds difference in pressure, so I don't know why, why there would be a difference now. That seems kind of strange to me, but we'll be investigating that come the May hearing.

Q I direct your attention to Mallon Exhibit Number Eleven. This is copies of various plots that you've prepared and comments upon them as prepared by Mr. Hueni.

A Yes, sir.

Q And I'd ask you, why did you use different methods of plotting?

A Well, I hate to admit it, Mr. Chairman, but I'm just, I guess, a little lazy from time to time, but the most accurate ways I've done all these plots is by use of flowing pressures against the logarithm of time or the logarithm of the ratio of time, and there's a lot of work involved in converting time to -- the logarithm of time and individual plots.

The plots for the coordinate scales as shown by Mallon Exhibit Eleven, our Exhibit Two, Tab G, is a coordinate plot; that is, the vertical scale and the horizontal scale are coordinates rather than log plots, log scales, and the reason for it, it's a little bit simpler.

The truth of the matter is that had we used the log scale we would have shown a little deviation where we've tied the two lines together at about the 27th-28th of November, had we used a log scale there probably would have shown a small difference rather than those lines coming together and that would have been a more accurate plot.

Same is true on Tab H. We just didn't need the resolution that we get with the accuracies that we get from the log scales and the -- and the larger or smaller vertical scales on pressures.

Now, when we come to the next one, the C-34 and B-32, here we had only .5 of a pound and there's no way to tell .5 of a pound, what it means, unless you have a vertical scale with resolution that will show it, and we need the plot of time on the log scale and -- and that's the reason that we've used the build-up in January 31st for comparison and it's very clear that -- that there's a difference, something different happened after the frac treatment, a few weeks later in the pressure build-up, and that could only have been from the frac treatment.

Mr. Hueni says, well, that might be a non-homogeneous reservoir. Well, I know nothing had happened, Mr. Chairman, between January and April to make that reservoir change from homogeneous to non-homogeneous, or vice versa, and nothing happened to it.

So if it's non-homogeneous when it shows a break from a straight line at one time, it should show it at another time.

And the same, same comments apply to our Exhibit Two, Tab C and the plots shown there.

A good example of -- of trying to analyze a half pound -- a half pound difference in extrapolating a line is shown on Mallon's next page where they have the long, straight line showing our B-29 pressure build-up, 300 pounds on a vertical scale, and they're trying to look for

On our Exhibit Two, Tab I, still under Mallon's Exhibit Eleven, my interpretation of the probable, true rate of pressure increase is that which I show by .5 of a pound per cycle, which carries from the pressure survey in the lower lefthand part of the graph up to the beginning of the next one, and as I indicated yesterday, there's two or three (unclear) bobbles in the begining of that second survey, but the overall average, it's a straight line from the extrapolation of the last part of the survey, it seems to me it makes sense to continue it there, and it would just be happenstance that something else happened right when we treated the well and the response came just a very short time after the treatment of the well. It seems to me a more logical reason for that is the frac treatment.

On the last page I have the same -- the same problem as to how do you resolve something like what we're looking for here is a fraction of a pound with a large scale.

Q Mr. Greer, Mr. Hueni talked about it would be difficult to use this data to see interference effects because it wasn't measuring an ample flow of fluid through a reservoir.

A Yes, and Mr. Hueni made the comment that fracturing is not the normal flow of fluids through porous media, and I tried to explain that yesterday when we were first going over this.

When a well is first fraced a large volume of fluid is injected in the reservoir at fracturing pressures so the formation is split open and it's true at that time that is not the flow of fluids through porous media that would follow the laws, physical laws of fluid flow through porous media, but once that fracture closes down to where it was in the frac treatment, then the pressure pulse that moves out through the reservoir will follow the laws of fluid flow and, for example, at a point perhaps 2000 feet away from the wellbore, the fluid in the reservoir at that point does not know how the fluid got into the reservoir, whether it was injected through a frac treatment or any other method of getting the fluid into the reservoir and the pressure pulse started, and so at that point, and from there on, it -- the pressure pulse will follow the laws of fluid flow as we know them.

And I think it's pretty clear that that's what happened in view of the consistency of the results that we obtained.

Q Now, Mr. Greer, Mallon Exhibits Fourteen and Fifteen are bar graphs that show an advantage to the project area, or the expansion area in one case and also an advanted to certain wells.

Could you comment on that?

A Yes, sir, I would just mention briefly that those bar graphs comparing allowables did not take into account the reservoir space voided. That's the significant thing in determining equity and correlative rights.

Q I'd like to direct your attention to -- to what has been marked BMG Exhibit Number Five. This is, again, the March 12, 1988 letter prepared by you and sent to the Canada Ojitos working interest owners that has been introduced, I believe, as Mallon Exhibit Number One.

Attached to that are some calculations and I direct your attention to that and ask you to refer to this and see if you couldn't at least set the record straight on what we were talking about in this letter.

A Okay. I wonder if I might first point out what I think -- that I just feel we should put in perspective, Mr. Chairman, the importance of the gasoline plant not only to our unit operations but to -- to the State and the Federal royalties and to everyone that's interested in -- in the increased production from the reservoir that might result from installation of a gasoline plant, and to put that into perspective, Mr. Chairman, I'd like to refer a little, if we could, to Dr. Lee's Exhibit GC-1. Do you suppose we could find those?

Yes, sir, that's the one, the page. it would be page 31.

MR. LEMAY: Got it.

A The bottom triangle-identifying line shows the increase in recovery at any time by virtue of stripping the gas through the gasoline plant and -- and re-injecting that gas in the reservoir and picking up additional liquids of the reservoir.

At any time after about 6 to 10 or 12 years, there's roughly 1.8-to-2-million barrels additional recovery anticipated as a result of having this gasoline plant in operation and re-injecting the residue into the -- into the formation.

Now, the -- that volume of reservoir liquids, 2-million barrels, is on the order of all the future production we anticipated from all the Gavilan wells.

Now, this, this I believe is more to put in perspective just the increase, not the total production from the unit, just the increase resulting from the gasoline plant is on the order of the future production of all the wells in Gavilan, and to make that assessement of the future gas plant production, we can use the -- and I think we should mention it here -- the pressures by the OCD-ordered pressure surveys. Here we're not dealing with pressure gradients and small differences, we're taking the pressure de cline from July to November, approximately 200 pounds, and any errors of -- of typical errors of bottom hole pressure measurements then, and compared to 200 pounds, will ultimately be fairly small. Exactly it figures out to about 40 pounds per month, and in August Gavilan produced 102,000 barrels; September, 96,000; October, 92,000, at 2500 barrels per pound.

We can take 2500 barrels per pound and to some reasonable abandonment pressure, maybe 200 pounds, that's 800 pounds; that multiplied by 2500, 2-million barrels.

You can also take those three months and plot them on semilog paper and find that there is a definite decline of 102 to 96 to 92, I feel that's not happenstance. If you project that out, it comes out to about a million, 2-million barrels.

So that's a reasonable estimate for the future production of all of the Gavilan wells.

Now I would like to look at the plant economics. There was --

Q Those are attached to Exhibit Number Five?

A Yes, sir.

Q See, our Exhibit Number Five is Mallon's Exhibit Number One.

A We've -- we've added to it.

Q Right, we've added to it and made it our

Exhibit Five.

I'd like to point out, Mr. Chairman, first, that there was a little confusion here yesterday, that if we want to run a 10-million foot a day gasoline plant that all we need is 10 or 15-million feet a day from wells in the gas cap area, and that will support the plant and that's all there is to it.

I tried to explain yesterday and I believe Dr. Lee did again today, that there just is not enough reserves in the gas cap to -- to support the plant for an additional length of time, and so, so that's one thing that we need to realize in the econmics.

Now, another thing, if I might point on page two, I'd like to start on page one, the last -- the very bottom line on my letter I say, "When gas is marketed, it will not be marketed from the tailgate of the plant but rather will be that produced from wells without going through the plant."

Then the next paragraph, "This means that plant economics will not be based on the 'margin', as is ordinarily the case. Rather the income from the plant liquids will be over and above any income which the unit owners would otherwise realize: This will be particularly true the first two or three years during 'payout' of the facility."

Now, Mr. Chairman, our working interest

owners are sophisticated oil people. When I wrote this letter I assumed that they understood what I meant about a gasoline plant operating on the margin, so I did not go into detail to explain what I was talking about.

I've set out on the attachment here now a way that we can look at that.

Now, a gasoline plant is often built to pick up gas from the wells, the gas goes through the plant, liquid is taken from the plant, and then the residue is marketed.

Now, that is not what we intend to do. We intend to inject the residue, and if -- if we were to operate the plant on a margin, then what we have to do is to take into account the value of the gas, what it would be as it goes into the plant, compared to the value of the gas that comes out of the plant, plus the value of the liquids. The difference is the margin.

We show here one example of the margin, I've used here a shrinkage of 17 percent. It may vary from 12 to 17, somewhere in that range; that's not going to be significant in the overall analysis. And we'd have a BTU loss of approximately 10 percent. The BTU from time to time will vary but the cost will be roughly the same. In this instance I show here for an example of the gas varying $1.50 an MCF. And comparing that with the 59 cents per MCF that we get for the liquids, we show that the residue would be worth $1.09, the liquid's worth 59 cents, for $1.68.

The difference, then, is the margin, or about 18 cents an MCF.

Then if we go to the next page we see the figures in the upper righthand column as to what .18 an MCF means on the margin, and we show there for the first year, in contrast to over $2-million a year of gross income, there's only $657,000. After royalty and taxes that drops down to $504,000 and the operating expense will be the same. Net revenue, then, operating on a margin, is $200,000 and $200,000 initial income for a $4-million investment is just not practical, prudent, or anyway feasible and so we would not recommend or suggest a gasoline plant unless we were able to inject the residue and continue with the pressure maintenance project.

So that's the first point that we come to, that we'd have to -- we'd have to inject the residue and let it pick up liquids as an essential part of our -- of our plan.

So then we get to the point, can we continue the pressure maintenance project without the area expanded to include the area we now ask for and the answer is we can't. We feel that the Gavilan people's concern about drainage, all the tests, the accurate tests that we've taken, show that the pressure gradients from a high pressure area to a low pressure area to the west, and we are very much concerned about how much we've lost to Gavilan in the last year and how much we're going to lose in the future.

What this means, then, is that if we do not get the approval for the expansion of the pressure maintenance project, we will have to commence the -- some kind of a -- some kind of a dismantling of it, and how fast we go to blowdown will just depend on what happens and how much we feel that we're losing to Gavilan. It's just -- just that simple. We can't forecast that now and don't know what it will be, but it's something that we -- we have to be prepared for.

And I believe with respect to that, and respect to the blowdown, I need to point out to the -- to the Commission that as unit operator we have the responsibility to be prepared for whatever -- what we have to face.

We would hope the Commission approved our order and we can go ahead with our gasoline, but if not, we need to be prepared to market gas in large volumes. At present I believe our marketing outlet is through the El Paso system, a 6-5/8ths inch gathring line that runs through Gavilan.

We have found that when we get up to as high as 5-million feet a day, that the pressures on that line increase, tend to back the Gavilan wells off the line and there's a limit, not unless you go to 5-million feet a day, that we could sell through our present system.

So, Mr. Chairman, we have -- have acquired right-of-way over to one of El Paso's larger lines, the (not clearly understood) line, and we have right-of-way all the way now in hand and we have estimates for the cost of laying 10-inch line over to that 12-inch.

At that time we'd be able to market from 20 to 40-million feet of gas a day, in the event it's necessary to do that, go to blowdown, if it appears to us that we need to do that to minimize migration to Gavilan.

Now the gas we can sell, of course, depends on the allowable. The higher the allowable for an area, why, the more gas we can sell. We would not get, without injecting gas, will not get pressure maintenance credit, will be able to sell only the volumes of gas allocated to the wells and we'd have to open up a number of wells that we already have shut in, but we've (not clearly understood) feet a day (unclear) and that's just a back-up plan that we feel like we have to have, not knowing what's going to happen.

Now, if I might, I'd like to refer to our Exhibit One under Tab S.

We show here, Mr. Chairman, that we overinjected in the present project area from July to November about 3300 barrels day, reservoir barrels a day; November to February abaut 1900. I think the weighted average might be something like 2500 barrels a day.

And if we look at the green sheet following, about two or three more pages, and if we care to compare pressures from July to February, we find that there is a definite pressure drop in the gas cap area; just exactly how much it is, I don't know, but -- but it could be as much as four or five percent, and without trying to go to real accurate (unclear), I think it's entirely possible that we have lost as much out of the gas cap by the pressure declines as we did by over-injection, which would mean maybe a 1,200,000 reservoir barrels over that period of time, 5034 barrels a day, and that's at 1400 pounds pressure. When that gas gets into the low pressure area, which is into the expansion area, then that translates to something like 7-or-8000 barrels a day, and -- and that's a substantial amount of movement from the present project area into the expansion area.

Now, there was some mention made yesterday that maybe our injected gas gets away by moving north and south. I'd like to point out that for the all the time that we've injected gas, we've seen no -- no loss of reservoir pressure until Gavilan comes along and we now have that to contend with and that's the only time that we've seen losses in pressure.

And in connection with that, the issue of can we lose pressure north and south, I'd like to refer to our -- our pressure map, I believe our opposition calls it our rainbow map, if I can find it.

Q G of Exhibit One.

A G?

Q Yes.

A The next to the last page of Exhibit G. It shows, if you look at that, the blue colored area near the injection wells would have the highest pressures. The blue colored area is something like 1200 pounds and 1300. The blue colored area when you look at reservoir pressures there, are from 100 to 200 pounds less than virgin pressure. That means that gas cannot move either north or south from a lower pressure to a higher pressure, and that being the case, we do not anticipate and we have not experienced a pressure loss as a consequence of migration north and south.

Now, if we go further west, of course, to the green area and the red area, the pressures are less, the virgin pressures are higher, so you get up to differentials of 4-or-500 pounds. So we feel comfortable about being able to contain the gas in the gas cap.

Then if I might refer to the last section of Exhibit One, Section K, the next to the last graphs are blue sheets. There are two pressure surveys. I'd like to look at the graphs, if we might. There's a pressure survey on the bottom, two pressure surveys on the top graphs.

It's for days in February from the 6th to the 20th.

Mr. Chairman, have you found that graph yet?

MR. LEMAY: The last -- the graph?

A Yeah, the next -- there. There you have them, yes, sir.

Here we see that during this period of time our recovery was 10,000 barrels per pound. That's 10,000 stock tank barrels per pound and that's compared to everything else we've seen recently, that's fairly decent. That's four times as much as we received, or obtained during the time of high allowable price of oil.

Now, there's no way that we can keep our -- our pressure decline forever at 14/100ths of a pound when Gavilan will be declining at high rates faster than that, but this shows you what can happen, what has happened, and shows that the pressure maintenance project is effective.

Now this is not a calculation of migration across the reservoir. It's not a computer run to estimate what it might be. This is the facts, the consistent, plain, simply facts that the pressure maintenance project is doing its job.

Q Mr. Greer, in your opinion is the present gas injection crediting arrangement as provided for this particular pressure maintenance project, is it capable of protecting correlative rights once your application is granted?

A There's no question in my mind that it will protect the correlative rights and provide for a -- at a minimum, at a minimum we have to void no more reservoir space than the wells outside the unit, and if we continue to inject at higher percentages than we have over the past, we will be voiding less reservoir space than those wells outside the unit and I know concern's been expressed here about we might take gas out of Gavilan and put it in our gas cap and take it away from them. There's no way that can happen. The gas will stack up in -- near our injection wells. We couldn't inject any more. We would have to market gas. When we market gas we don't get injection credit. So it's a self-adjusting procedure with self-adjusting regulations that we'd be living under and so there just will be under any circumstances protection of correlative rights if this order is granted.

Q Mr. Greer, if the application is denied will that not, in effect, spell the end of the pressure maintenance project?

A Yes, sir.

Q If that happens, in your opinion will the recovery of oil from the area be reduced?

A Yes, sir, it will.

Q Would it also result in additional recovery of other liquid hydrocarbons?

A Yes, sir.

Q Would both of these things cause the waste of hydrocarbons?

A Yes, sir.

Q Do you have anything further to add to your testimony?

A No, sir.

Q Was Exhibit Five prepared by you?

A Yes, sir.

MR. CARR: At this time we move the admission of Benson-Montin-Greer Exhibit Number Five.

MR. LEMAY: Without objection Exhibit Five will be admitted into evidence.

Questions of the witness?

RECROSS EXAMINATION

BY MR. DOUGLASS:

Q Mr. Greer, I think you started out with referring to Mallon's Exhibit Five, is that correct?

A Yes, sir.

Q With reference to that exhibit, I believe you pointed out that F-20, you said hadn't been tested in the barrier formation.

A Not a barrier, yes, sir, that's right.

Q But other than that it is correct, it's not producing from the Niobrara, is it?

A Oh, no, sir.

Q Are each of the other wells shown on Mallon Exhibit Five shut-in?

A Well, the A-16, I do not consider it shut-in, if you want to point to that one. That's the one we worked over in the A and B zones and I think they're currently laying the gas pipeline to that.

That well, Mr. Chairman, initially made a very small amount of oil, just enough to run the pumping unit -- I mean gas, well, both oil and gas; just enough gas to run the pumping unit so we did not have it tied into our gas gathering system.

Now that we've worked it over in the A

and B zone, why, we have it shut in until we get it tied into the system.

Q But it is shut-in.

A It is shut-in, yes. Well, it's not producing. It's being worked on.

Q Now, do I understand that the -- the frac pressure difference that you say represents a response between the C-34 and the B-32 is a half of one pound?

A Yes.

Q Okay.

A I think it's a half or 65/100ths, something like that.

Q And it's based on that frac response that you say that there is communication, good communication across this barrier, is that -- that we say exists.

A Mr. Chairman, I say the area we have colored in blue on that particular test showed an average transmissibility of, I believe it was 14 darcy feet.

Q Do you disagree with the pressures shown on Mallon Exhibit Six that show in December 28, 1970, that the C-34 had a pressure of 1555 and fourteen years later that the B-32 had a pressure of 1720?

A No, sir.

Q Now that's a pressure difference there of 165 pounds.

A Yes, sir.

Q That's over this area that you got half a pound.

A Yes, sir.

Q On the frac.

A Uh-huh.

Q Are -- on Mallon Exhibit Seven that you referred to, is the pressure of 1395 an accurate bottom hole pressure measurement in the C-34 Well?

A I think it probably is. (Unclear.)

Q Is the B-32 bottom hole pressure of 953 in November accurate?

A That looks all right.

Q That's 440 pounds of pressure differential, bottom hole pressures.

A Yes, sir.

Q And even by your surface calculated pressures there is 340 pounds --

A Yes.

Q -- at least 340 pounds difference, isn't there?

A At least, yes, sir.

Q Mr. Greer, isn't that a better indication of non-interference than half a pound fracture job?

A No, sir. If I might refer to our Exhibit

Number Three, Exhibit Number Three under Section B.

Mr. Chairman, this -- this exhibit shows pressure responses to be expected from wells at different distances from the treated well. We have lines for a distance of 3000 feet; the next one 4; the next one 6, 8, and the bottom one was 10,000 feet.

These two wells were about 10,400 feet apart and so for a reservoir with transmissibility of what we've shown here, Kh over (unclear) of 80, and the treating rate at 100 barrels minute, the pressure that -- that would result in a reservoir of that character would only be about our analysis.

No, Mr. Chairman, again I would point out that -- that the difference that we have and Mr. Mallon's engineer interference tested. I say that interference testing showed average characteristics for that area. From time to time Mr. Mallon's engineer said that that means the character of the reservoir between the two wells or in a line between the wells and I disagree with that.

I feel strongly that the north/south permeability is higher than the east/west. We recognize there's tight streaks in the reservoir and I think that's entirely possible to have the high trasmissibility throughout a large area and yet the gravity drainage, which is the only way we get gravity drainage is to have that high trans missibility. It's there.

Now, if there are peremability restrictions, and I know there are and we have drawn a permeability restriction on our plats on the low part of the structure. There are other permeability restrictions. A significant thing, Mr. Chairman, is not are there permeability restrictions but are those restrictions enough to prevent the pressure maintenance project working, and we're convinced that they are not.

Q Mr. Greer, if the barrier exists as shown by the Mallon testimony, then you're approaching the blowdown stage in your pressure maintenance project, anyway, aren't you?

A If you were correct, yes, sir.

Q And from the very beginning you knew at some point you're going to have a blowdown in this pressure maintenance project, didn't you?

A Yes, sir.

Q Where do you sell the gas when you do sell it out of this pressure maintenance project?

A Well, that would be on the spot market.

Q It goes through El Paso's line?

A El Paso is the transporter, yes.

Q Does El Paso run it through their gasoline plant?

A Yes, sir.

Q Is that gasoline plant located in New Mexico?

A I forget which one; at least I'm sure it will get treated.

Q Is that the Charco or --

A Chaco?

Q Chaco?

A Oh, seems to me that the marketer has -- might be the Blanco Plant. I'm not certain which one it is.

Q When you get ready for blowdown of the pressure maintenance project are you going to have to enlarge your lines, anyway, or are you just going to use the existing lines under your plan?

A Well, it would be my hope that as long as the pressure maintenance project can be continued that we would have a small enough blowdown in the end that we could get by with our existing facility.

Q Did you do any economics on the Mallon wells versus the statewide allowables they had when the Commission cut the allowables in the area as far as the gas plant that they were going to?

A No, sir, the people who had the gas plant appeared and presented testimony at the hearing last fall.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Additional questions of the witness?

MR. CARR: No questions.

QUESTIONS BY MR. LEMAY:

Q Mr. Greer, just -- if you don't mind, just a speculation again, like Mr. Hueni. I would like to know what you consider on that line dividing Township -- or Range 1 West to 2 West, the field division between West Puerto Chiquito and Gavilan, what you consider a significant violation of correlative rights, in terms of pounds.

A In terms of pressure?

Q Yes.

A I'm afraid my answer to that would be a lot like Mr. Hueni's. It's a difficult thing to say but the higher the transmissibility, the more migration can occur with a minimum pressure difference.

I've -- I've given some thought to how it might be monitored and certainly we're willing to consider anything that's reasonable. It would be -- be pretty hard to say.

But certainly, if there is a 50 pound difference, and a true difference from the pressure in the -- in the main part of the reservoir, not small wells that have -- that are obviously tight wells, then 50 pounds would be -- would be significant.

Q Well, given your reservoir voidage concept, that you work with on the crediting, voiding the reservoir in the Gavilan area, then, of course, repressuring up in the gas cap, is there a time frame there that you could say that works to equalize once you've withdrawn, then reinject? In other words, we're looking for equality. You're voiding it, agreed, and you're -- you're re-injecting elsewhere, so you're pressuring -- how long does it take to work that down?

A Let me point out that the -- the effect of the -- of the pressure maintenance operation is continuing all the time and it's not a question of when we pick up the gas and it gets into the gas cap and works its way back down. Even if we shut down injection right now, and this is one of the real problems we have, if we shut down injection right now, that pressure maintenance effect is going to continue and yet we're not going to get credit for it; no way we'll get credit for it if we aren't injecting.

So the unit is at risk anyway that we look at it, and the time that it takes for that gas to move across is really -- is really not a significant point. The -- I believe that we can -- well, I know that we can inject in -- in our injection wells and pick up pressure responses just as we've done with our observation wells in the -- in the expansion area and it will show fairly rapid pressure response and that means the pressure will -- just the interference effect alone will build up rapidly and transmit the pressure across the reservoir in a matter of days, and so it's a short time any way that you look at it.

Q That's true. Thank you.

MR. LEMAY: Yes, sir, Mr. Lyon.

QUESTIONS BY MR. LYON:

Q Mr. Greer, looking at the exhibit on eight?

MR. DOUGLASS: Seven, Mallon Seven.

Q Mallon Exhibit Seven, your injection wells are up dip in the brown area, is that right?

A Yes, sir.

Q Do you have any producing wells or do you plan to produce any wells in the brown area?

A No, sir. Our -- well, yeah, we're producing some. The L-27 and the O-9 in Township 26 North. Occasionally we'll produce the E-10, but primarily what we have in mind for -- for those wells are to put them in operation if we get the gasoline plant going and cycle those wells. That's the reason we're opening up the A and B zones like in the C-34, and the L-11, we just recently opened up the A and B zone in it, and a short test that we ran last week, I feel, is -- it had leveled off and is obviously a good test. The well produced about 2-million feet a day with about 15 percent drawdown; has a capacity of at least 5-or-6-million feet a day.

I would expect the same thing out of the A-22 when we work it over and we will get some oil along with the gas during the cycling operation.

Our plan has been not to drill wells down dip below the ones -- existing ones we have and we recognize that there is a tight area through there, but it's -- but a barrier, and we feel that the oil by gravity and pressure maintenance is moving its way down to the tighter area and working its way through it by virtue of the pressure from the pressure maintenance project.

Once that oil is replaced by gas, then the pressure in the gas cap area will drop off fast and at that point we have to be prepared to do whatever's necessary to avoid too much migration to Gavilan.

Q Now, if -- if you were not to produce any wells in that brown area, and continued to inject in your injection wells, if the pressure did not increase, would you presume, do you think it's a reasonable presumption that the gas would be migrating through the apparent tight area into your wells in the proposed expansion area?

A That's my belief right now.

Q And if that migration was not taking place through that tight area, then the injection area, the brown area, would increase in pressure?

A Yes, sir.

Q And if you -- if you increased the pressure in the brown area and if you used your gas injection credits in the proposed expansion area, then you would probably create a larger pressure sink in that expansion area.

A Not if the gas moves into the area and -- and -- like we think it is right now, in our A-6 and A and B zones in the B-32 and B-29, we think that it's only natural to expect the to -- not to reach a well uniformly in all three zones. We think it's happening right now, otherwise, we would not see this 10,000 barrel per pound that we did in February.

If we were not getting help from the pressure maintenance project, that pressure would have dropped dropped even faster.

Q Now, in calculating your -- your barrels per pound drop in pressure, did you consider the pressure and the production from all the wells in your unit? Is that what that's based on?

A Oh, that's based on the wells producing in the expansion area.

Q Just (not clearly understood).

A Yes, and we compared that with the production from wells in the expansion area last fall.

Q Do -- do you -- do you -- let me ask you this. Have you studied the pressure data that was collected -- this would be November or February?

MR. DOUGLASS: That's November. February is Exhibit Eight.

Q Have you looked at the pressure data that was gathered in the pressure survey?

A Oh, I've looked a little bit at the July and November pressures but not even looked at all at the -- at the February pressures.

I notice in the July and November surveys there still is some information missing that we need to analyze it.

Q Are you aware of any pressure data that was gathered that isn't represented on this exhibit?

A Well, we have pressures on every well every day that we take when we're producing, so we have lots of pressures. As far as shut-in pressures are concerned, and such as that, we take pressures every once in awhile in wells.

Q Why?

A One of the things I'm concerned about, of course, is we never injected more than 4-or-5-million feet of gas a day. We build this gasoline plant, we'll be up to 8-or-9-million feet a day. We'll have a substantial interference effect and from now until, oh, probably a lot further beyond that, we will be taking pressures trying to analyze the interference effects and particularly if we're going to need to drill another injection well to handle our 8-million feet a day.

Q Now, I may -- I may not have -- you may have testified to this before but I'd like to ask you, are you injecting the gas that you're producing in the proposed expansion area at the present time?

A Yes, sir, right now we're -- we're injecting everything we're producing.

Q Well, what I was leading up to in regard to the pressure information, do you consider that the representation of pressures on the Exhibit Seven and Exhibit Eight to be fairly representative of all the pressures that were taken (unclear).

A Well, they look reasonable to me, all except the -- the 100 pounds higher pressure in the Mallon Fisher Well, all except that.

MR. LYON: That's all I have.

MR. LEMAY: Thank you, Mr.

Lyon.

Additional questions of the witness?

If not, he may be excused.

Are there any statements in the case?

MR. CARR: As the applicant, I'd like to go last.

MR. LEMAY: Pardon?

MR. CARR: May I go last as the applicant?

MR. LEMAY: Well, I was wondering if there was any besides closing arguments. I didn't know if there was anyone here who had -- had some statements they'd like to make.

MR. PEARCE: If I may, Mr. Chairman, this may be the appropriate time.

I have been asked to submit for the record in this matter letters from Mobil Exploration and Producing, U.S., Inc., and also letters from Kodiak Petroleum, Inc.

Both letters state those companies' opposition to Mr. Greer's application. If this is an appropriate time I'll pass those out and I don't know how to get them marked, even. We can certainly make them Mobil

One and Two, if that's easier for the Commission.

MR. LEMAY: Fine. They're generally statements, anyway --

MR. PEARCE: Yes, sir.

MR. LEMAY: -- subject to non-cross examination --

MR. PEARCE: Yes, sir.

MR. LEMAY: -- so I don't know if they have to be marked as exhibits.

MR. PEARCE: That's fine.

MR. LEMAY: We can --

MR. PEARCE: And for the others in attendance, I have made multiple copies and will just leave them up here on the table.

MR. LEMAY: Is -- before closing arguments, is there anyone else in the audience that would like to make a statement at this time?

Fine, we'll entertain short closing arguments, would be fine, and we'll reverse the order that we started with opening, if that's acceptable.

MR. DOUGLASS: Mr. Chairman, do you have a suggestion as to your definition of "short"?

What would you --

MR. LEMAY: I'm leaving that up to the discretion of you people since --

MR. DOUGLASS: Since I'm not completely familiar with your practice --

MR. LEMAY: We're efficient here, Mr. Douglass, and generally the testimony is in the record and this is the summation.

MR. BUETTNER: Mr. Chairman, a couple of us here may be a little bit confused about whether you'd like us to make our statements now or in conjunction with the so-called closing.

MR. LEMAY: Well, I would prefer to hear the statements prior to closing arguments in the case.

Yes, sir, Mr. Bruce.

MR. BRUCE: Mr. Chairman, this is made on behalf of my clients; I won't repeat all the names.

Benson-Montin-Greer has applied for expansion of its West Puerto Chiquito Mancos Pressure Maintenance Project.

This application should be denied by the Commission for the simple fact that the 2-section tier on the west side of the West Puerto Chiquito Pool is separated from that pool by a (unclear) permeability barrier; thus, BMG's current pressure maintenance project has no effect on the expansion area. The only effect of granting this application will be to increase the existing substantial advantage which BMG wells have over Gavilan wells and increase drainage from the Gavilan Pool and thus severely adversely affecting the correlative rights of Gavilan interest owners.

The evidence, particularly the pressure and production data shows that a barrier exists between the expansion area and the area to the east of the permeability barrier. This shows that the expansion area is part of the Gavilan Mancos Pool and not the West Puerto Chiquito Mancos Pool, thus my clients encourage the Commission on its own motion to contract the West Puerto Chiquito Mancos Pool and expand the Gavilan Mancos Pool by the addition to Gavilan of the proposed expansion area.

With respect to the gas/oil ratios, we think it's ironic that since 1986 Mr. Greer has advocated reduced allowables to prevent increasing GOR's. Now, however, Mr. Greer thinks that high and increasng GOR's, due to curtailed production are just fine.

Furthermore, he advocates greatly increased production from his own wells which will have the effect of stealing hydrocarbons from Gavilan wells, which are already suffering from curtailed allowables.

At the very least, the Gavilan wells should have normal, statewide allowables re-instituted immediately pending the Commission's next Gavilan hearing.

We think it's significant that both Koch and Reading & Bates, parties who own interest in both Gavilan Mancos and West Puerto Chiquito Mancos Pools disagree totally, not only with BMG's proposed pressure maintenance expansion, but also with the interpretation which Mr. Greer places on his data. If Mr. Greer can't convince the unit owners that they need expansion, I think that says something about the validity of the evidence submitted by BMG.

The driving force for the expansion of this pressure maintenance project seems to be the proposed gasoline plant which has an approximate cost of $4-million and which Mr. Greer states must be started with the utmost speed, yet Mr. Greer has no written plans or specifications for the plant, apparently no right-of-way for the proposed pipeline, and the only document regarding the plant is a bare bones AFE sent to working interest owners less than a week ago.

If the plant really needs to be started immediately, it seems that plans for the plant would be somewhat more advanced than the middle -- than the minimal data and design Mr. Greer has presented to the unit owners.

Furthermore, if Mr. Greer needs

extra gas for the plant, that can surely be provided by re-instituting normal statewide allowables in Gavilan Mancos and the proposed expansion area. This will allow wells to produce more gas for the plant and I'm sure that many Gavilan owners would be glad to sell gas to BMG; however, we do not think Benson-Montin-Greer should be allowed to take Gavilan hydrocarbons by Commission order.

Mr. Greer has always urged the Commission to err on the side of caution in dealing with these two pools; however, he now throws caution to the wind so that he can obtain an unfair advantage over the Gavilan owners. To do this BMG has massaged the data to conform to a desired outcome rather than fitting the data to a reasonable theory.

My clients believe that the only reasonable conclusion upon a fair examination of the data is that the expansion area is part of Gavilan Mancos and is separated from the West Puerto Chiquito Pool by a permeability barrier.

As a result, in order to protect correlative rights, BMG's application must be denied.

Thank you.

MR. LEMAY: Thank you, Mr. Bruce.

Additional comments before

closing arguments?

MR. BUETTNER: I had a little bit more I was going to say. It seems to me that I could abbreviate it.

Mr. Greer is demanding cut the other owners to 1/6th of what he can produce from his offset wells. He wants you to let them drain the -- let him drain oil from the Gavilan, give a 600 percent production advantage to protect the project that there's scant evidence really needs protection or is otherwise protected on any side except to the west.

He testified the gas goes north like gangbusters. He's testified it goes south (unclear); to the east is up, and the only place where there's an arguable, any kind of an argument about restriction, about how effective the restriction is, not whether there's a restriction, is down dip to the west, and that's the area where he wants you to impose these huge penalties on the Gavilan owners in terms of drainage.

And Koch is -- not only do we think that that's not fair, but we also urge you not to put us in the position of being obliged to participate in an uneconomic 4-million dollar gas plant.

That's about all we have to say.

MR. LEMAY: Additional statements?

We will have our closing arguments in reverse order.

MR. PEARCE: Thank you, Mr. Chairman, I will attempt to be as brief as I can.

Mr. Chairman, we are here because Mr. Greer wants to include a row of two sections in a presently existing pressure maintenance project. That's what we're here to talk about, whether or not that row of two sections ought to go into that pressure maintenance project.

Now, if we're to look at that, I want to take just a couple of minutes and tell you some of the things that you've heard in the last two days, because I think they're critical to your thinking about whether or not that ought to be done; a couple fo things which Mr. Greer calls plain and simple facts. That's all we're talking about, just plain and simple facts.

The fact is the Canada Ojitos Unit went on production about 1962.

The fact is that in 1970 the pressure in the Canada Ojitos pressure -- in the Canada Ojitos Unit was about 1555 pounds.

The fact is that 15 years later

the pressure in the Gavilan Pool adjoining the Canada Ojitos Unit was 1720 pounds.

From 1962 until 1985 something had prevented those pressures from equalizing. That is a plain and simple fact.

I don't understand Kh and I don't understand mu and I don't understand millidarcies and darcies, but I understand that from 1962 to 1985 those pressures had not equalized.

Mr. Greer tells us now that he is concerned because now the Gavilan pressure is lower than the Canada Ojitos pressure, and he is concerned about what that might do to his pressure maintenance project.

From 1962 until 1985 we know it didn't do anything. We know that. That's a plain and simple fact.

We know that when the wells in the proposed areas Mr. Greer wants to add to the pressure maintenance project came on line they came on and declined just like Gavilan wells. Those are the curves they match. That's a plain and simple fact.

The pressures which we have looked at from November and February show that the wells in the proposed expansion area match Gavilan pressures. They don't match pressure maintenance project pressures. That's a plain and simple fact.

Now, if Mr. Greer can't economically build a gasoline plant, I may be very sorry for him. That may be unfortunate, but he should not be able to utilize Gavilan type reserves and damage the Gavilan reservoir in order to build a pressure -- a gasoline plant.

That's not fair. It's not reasonable.

Mr. Greer said not half an hour ago sitting right here, Mr. Greer said, talking about permeability restriction, he said, I know there are some. he's drawn it on maps for years, the map which Dr. Lee used this morning was a copy of a Greer map and it had that hachured area on it that we've seen over and over again from everybody.

The plain and simple fact is the wells in the proposed expansion area are not in effective pressure communication with the present pressure maintenance project.

They are not. From 1962 to 1985 those pressures didn't equalize. They're not going to equalize now.

To allow Mr. Greer to take gas out of that proposed expansion area, inject it into the pressure maintenance project area, and get credit in the proposed expansion area, is unfair and will drain Gavilan reserves to his wells.

Mr. Chairman, that's not fair.

MR. LEMAY: Thank you, Mr. Pearce.

Mr. Douglass.

MR. DOUGLASS: Thank you, Mr. Chairman.

I now find out Mr. Pearce is a difficult act to follow.

When we designed this case we wanted to give you the facts that have become available as a result of the testing procedures and orders which you've set out, because I think this Commission in the March and April hearings of 1987 was concerned that they really didn't have a grip on all of the factual data that they needed to make the kinds of determination that you wanted to, and that's why in designing this case I said, let's don't do any computer modeling; let's just take what data and information shows, what the actual facts are, and see what that tells us as far as this reservoir is concerned, because I think when you look at it, it's going to tell this Commission exactly what we've seen in the last two days, and that is that irrespective of how successful the pressure maintenance project was that Mr. Greer has carried out, and I don't want to in in any way impinge (sic) that. That's fine, that's wonderful, I'm delighted that he did it. It may have resulted in substantial additional recovery in his part of the reservoir and his type of reservoir that he has there.

But what you're faced with now is undisputed, factual data that there is no effective communication across the barrier that we've shown here.

Mr. Greer has not disputed one single pressure data fact that we've shown you.

He's not disputed any of the original pressure data information that has been shown here, and that is the kind of data that this Commission can rely on. It's the kind of data reservoir engineers and geologists use all the time to make their toughest and very hardest type of determinations.

And what's happened here, the only explanation I have is that Mr. Greer really hasn't faced up to what this data shows you, what this data really shows you, that when he says he can get a frac response in this high permeability reservoir in a period of a quarter of a day and half a pound, that when you look at years and years of pressure data or when you look at shut-in data over a relatively short period of time, you come to one inescapable conclusion, is that there is a pressure barrier between these two areas and that barrier is substantial because it is now supporting a 450 pound pressure differential, and as Mr. Hueni has pointed out, the pressure maintenance project pressure has performed just as the pressure maintenance project should perform. And Mr. Lee has said that it appears to him that that pressure maintenance project is performing as it should; gas wells gassing out down structure as he has illustrated.

Mr. Lee also pointed out that the Gavilan pressure, although starting above, is now substantialy below, it has not affected that pressure maintenance project, nor has the pressure maintenance project affected Gavilan. It's just as if these two reservoirs were thirty miles apart, is what it amounts to, and someone is going to have to step up and point out to all the parties involved, yes, there is a pressure barrier in this reservoir, and yes, the two areas do perform differently, and yes, we are going to have to regulate those two areas differently.

And that's why this application should be denied, because you're taking the pressure maintenance area regulation and applying it to an area that is not in effective communication. It's not under pressure maintenance.

I guess another thing that disturbs me, is that it -- that it appears that Mr. Greer wants to hold this Commission as a hostage, just as he's been holding my client hostage since he got the allowable reduced in September, 1986.

There's not much we can do about being held hostage, other than present the facts to this Commission and request fair treatment.

But I think there's a whole lot that this Commission can do about being held hostage, and that is to look at the facts and make the determination based on that, that if Mr. Greer needs additional gas to finance a gasoline plant, then the way to handle that is to increase the allowables back to the normal state allowable rate that was in existence before, because Mr. Greer has 85 percent of his production coming from this expansion area, and I think we have shown without question the production advantage that he has.

The bar graphs that we presented here have not been disputed about it. Well versus well, Mallon well versus Unit well, or the 2-section area versus 2-section area, that what is taking place here is a pure and simple violation of Mallon's correlative rights and the Gavilan correlative rights, and this Commission should not, and I think will not, be held hostage because of a gasoline plant.

We have the later interjection

in this proceeding that, well, I'm going to blowdown the entire reservoir, by Mr. Greer, this is what he said, I'm going to blowdown the entire reservoir if I don't get what I want.

I suggest to you that Mr. Greer has already seen and he knows that his injection project is nearing the end of its life. It's coming. It happens to every reservoir when you carry out this type of injection project, and there comes a blowdown time, and that time may or may not come as far as Mr. Greer's determination in the pressure maintenance area, but Gavilan and Mallon shouldn't be held hostage because of that. That's a determination that Mr. Greer makes with reference to his working interest owners and this Commission, I assume, as far as that goes.

In short, we've presented facts, facts that are supported in this record; facts that have been supported from the stand; facts that show that there's not effective communication.

Mr. Lee's entire calculations are based on that area, expansion area being effective pressure communication. Mr. Greer, you heard him testify just a few minutes ago, that he says he recognized the tight area.

I think that this Commission has to make sure that everyone recognizes that tight area as the area that we're showing.

This application should be denied.

Thank you.

MR. LEMAY: Thank you, Mr. Douglass.

Mr. Kellahin.

MR. KELLAHIN: Gentlemen, it's always amazed me that at the end of the technical presentation before a body of experts that the lawyers are then called upon to come before you and tell you what you're supposed to do.

I guess my amazement continues as we again display that effort this afternoon.

I take comfort from the fact, though, that there is not a lawyer on the Commission. There hasn't been in God knows when and I hope there never is. We want you to decide this on the facts as presented as best you see them.

Some of the things that the prior lawyers have said bother me enough that I would like to comment on them.

I guess the first one is that Mr. Pearce says he does not understand the consequences of what the evidence has displayed in terms of the pressure differential. It's of no consequence that he doesn't understand it. That's why we come before a technical committee to help us resolve this issue.

I quite frankly, in my own simple way, don't find this to be a very complicated case.

I think Mr. Douglass had an interesting way to phrase his closing argument. He said it twice. He says, "we have designed our case." "We have designed our case."

Well, with all due respect, Mr. Chairman, Mr. Greer and the Sun people that have presented their case to you haven't designed anything. We've come forward before you with a simple projection of the facts as clearly and as carefully as we thought we could do that.

Mr. Bruce's comments concern me. He's concerned about the correlative rights of owners that are in the Gavilan and in the Unit.

I will tell you his ownership interest is 4 percent of the Unit.

As I told you yesterday when we began this discussion, Sun, and Sun alone, is in the unique position of having a substantially greater interest at risk in the Gavilan than any of these people in this room.

It was not Mr. Greer that came before you and held this Commission hostage to have you reduce the allowables in Gavilan effective (unclear). That application was made on behalf of Jerome McHugh, who was an owner in the Gavilan Mancos. The Gavilan Mancos ownership by McHugh was transferred to Sun and it was Sun and McHugh who brought forth with you for discussion those -- those cases.

I think this is a simple case. The more I listen to it, the more positive I am that it is.

The unit area that is being requested for inclusion in the pressure maintenance expansion is part of the unit itself. The unit has been consolidated. That acreage has been brought into the unit. Those interest owners in the expansion area are now participating, the royalty, the working interest owners, the overriding royalty owners, are currently participating in the success of the project.

You've approved it. The BLM has approved it. The Commissioner of Public Lands has approved it. We now come forward and ask you to approve the expansion of the pressure maintenance gas injection credit for the main project itself.

I don't think you have to take a lot of time to analyze all the intricacies of the evidence. I think I like the way Mr Lyon was approaching the solution as he asked Mr. Greer questions earlier this afternoon.

The fact of the matter is that in this highly communicated reservoir with such large permeability, Mr. Greer has told us that the gas injection into the gas cap sees a quick response in a matter of days. It seems to me that if gas withdrawn from the expansion area is injected into the gas cap and does not successfully communicate across the barrier, then you're going to get overpressurization in the gas cap and you're simply not going to be able to put the gas into the ground, and if you can't redistribute the gas into the reservoir, you don't get the credit, and what's so wrong with that? That's exactly the way pressure maintenance works in all pressure maintenance projects in this state, including this one. This one is no different.

Mr. Greer is absolutely right. This is a simple, interesting, wonderfully clear method to solve this problem. It is self-regulating. If you don't re-inject the gas, you don't get the credit. If you sell the gas, then you're in the same position that the Gavilan Mancos owners are when they sell their gas.

We do not see the concern. In fact, quite frankly, we think that the opposition has raised the emotional level of their dispute with the Canada Ojitos owners and operators to a point where it no longer is reasonable and objective.

We think you have no other choice, based upon the substantial evidence but to approve Mr. Greer's application.

We request that you do so.

MR. LEMAY: Thank you, Mr. Kellahin.

Mr. Carr.

MR. CARR: Thank you.

May it please the Commission, at the beginning of this case I speculated that you've heard more about the Gavilan than you possibly ever wanted to, and being after 5:00 on Friday, I'm going to be short.

I, like Perry, don't pretend to come in here and tell you what Kh's and mu's are, but there are certain things that I think at the end are important to look at to refocus this matter.

We're here seeking approval of an expansion of an existing pressure maintenance project.

We've come before you and we've presented a backbreaking pile of evidence. But I think it's important to recognize that what we're doing coming before you with all of this is not trying to hold you hostage, not trying to take advantage of anybody, but to give you the information you need as technical people, to make an informed decision.

And what do we get? Well, we're held up as trying to hold you hostage and take advantage of everyone in the room.

We know it's possible to take advantage the other way, too, and without pointing the finger at anyone, if you have a lease that offsets an effective pressure maintenance project, you really might like to not be restricted and not have an effective gas credit arrangement on the border, because you'd be (unclear) then, and so it's not just a simple situation where Mr. Greer is out there trying to take advantage of someone else. When that comes into your mind, I think you need to remember there are two sides to that question.

I submit what we're here seeking is an informed decision on a substantial amount of evidence; a decision we're convinced, if you review it when you think about it, will show that clearly what we are entitled to is expansion of a pressure maintenance project which is benefiting Mr. Greer, the other interest owners in this unit, and the State of New Mexico.

We're asking you, not for special treatment. We're asking you to do what's fair. We've been out there for twenty-five years. We have been running this pressure maintenance project for twenty, and we have done nothing without coming before you, as we have here, keeping you fully informed as to what we're doing.

We submit the question you must decide is whether or not there is effective communication across this reservoir. I'm not going to sit here now and talk to you again about the seven ways we have shown pressure communication, evidence that was further supplemented by analysis of the data, which established that there were large areas of the reservoir in this analysis of fracture pulse test through which communication could be seen.

We're going to leave those questions in your hands. We're going to point out, however, that when you think about these, remember we've been injecting gas in the top of that structure for a very, very long time. You don't see how it is pressured up.

We've injected gas produced in the unit and from without and you don't see the pressure building up.

We also think it's important when we talk about pressures to go back to what they call our rainbow map. There's been an awful lot of testimony about a 400-pound difference between the red area and the western boundary of the unit.

Mr. Greer talked about pressure

benches. If you'll look at it you can find a 700-pound difference between the injection interval and the one immediately offsetting it. There's nothing mysterious about what's going on here. You have the kind of pressure gradient you would expect in a reservoir of this nature with an effective pressure maintenance project going on.

Mr. Greer said there are tight areas. He didn't tell you where it was because he said they were throughout this area.

He has postulated all along a restriction, but he has told you now that restriction, although he had hoped it would work, didn't.

So what we submit we have shown is a pressure maintenance project which should be expanded, expanded as we propose. The only other thing that might ever be done is it probably should be extended some day further to the west.

We've talked about a gas plant. This isn't a carrot we're holding out. This isn't something we're doing to try and hold you hostage. This is something that has been, as Mr. Greer testified, in the plans from the very beginning and it happens to be that the time to do it is now and we're going forward with it.

Now Mr. Bruce was present throughout this case. He could have asked Mr. Greer all sorts of questions about right-of-way and things of that nature but he didn't. He drew some conclusions for you at the end.

Lawyers -- I'm not giving you testimony now and Mr. Bruce wasn't giving you testimony a few minutes ago, and without testifying I can't tell you that right now we have 90 percent of the right-of-way, but I could if I put Mr. Greer back on, or that we have 86-plus percent working interest approval to go forward with this project, but the AFE that has been approved by the 86 percent is contingent upon approval of this application by you. That's not testimony, but I don't think attorneys should come in and not ask questions and then draw conclusions from evidence they didn't produce and then expect us to sit here quietly about it.

We believe we've shown that there is an effective pressure maintenance project going on here. Look at the results we get with the reservoir energy we are using and when you look at that, keep in mind that, yes, we're taking more gas out, MCF for MCF, than the well in the unit, Mr. Mallon's well, but we're putting that gas back in and we're not using the reservoir energy needed to produce the oil that other people are, and that's how it is supposed to work; that's what you do with a pressure maintenance project that is confined to a portion of a single reservoir.

That's what we have here, an

effective pressure maintenance project that is working to the benefit of the interest owners and the State of New Mexico.

Now, Mr. Kellahin said he hoped you never had an attorney on the Commission. Well, I hope you get one on your staff because I'll tell you this: You make the technical decision but that decision is made within the context of rules and regulations and the statutes and court decisions which govern your activities, and when you look at that, that body of law and the regulations which define what you do, it says that the primary function you perform is the prevention of waste, the Supreme Court in Continental versus the Oil Commission, waste is your primary duty; correlative rights was a necessary secondary adjunct to that function.

The question of waste, then, must be addressed by you in deciding if you're going to grant this application and even when Mr. Hueni was asked by Mr. Chaves, will waste be caused in a traditional industry sense by granting this, Mr. Hueni wouldn't answer that question; he rushed off to correlative rights.

Well, I'll tell you the reason he didn't is waste cannot and will not be caused by granting this application. You will not dissipate reservoir energy. You will not leave oil in the ground. And so we have presented testimony, on the other hand, that shows you if you deny it, you are going to leave oil in the ground. You are not going to get the liquid hydrocarbons out that you other- wise would get, and so on that alone I submit to you that if you are to meet your duty to prevent waste, you have one de- cision and that is to grant this application.

If you don't, I submit you're going to be authorizing waste, and that takes you to the second leg of your -- your statutory jurisdiction, and that is the protection of correlative rights. Now that's probab- ly the harder part of the order you're going to be asked to write, because that's when you have to sit down and decide what's going to be done to equalize withdrawals on that boundary line. We submit to you the existing formula does that and it's a self-regulating system. The more we put back into the reservoir, the more we're allowed to take out. We are not going to void the reservoir. If we quit, then, then our production rates will be the same as the Gavilan.

So we submit to you that what you've got to do is look at your statutory area of responsi bility. When you do that, the application will have to be granted because in fact it will prevent waste, and you have a difficult question on correlative rights, but I'm convin ced we have shown you how that can be answered.

We now turn this matter over to you.

MR. LEMAY: Thank you, Mr. Carr.

Is there anything further in this case?

If not, we shall take it under advisement. Thank you, gentlemen, and ladies.

(Hearing adjourned.)

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing pages numbered 247 through 497, inclusive, constitute a full, true and correct transcript of the portion of the hearing in New Mexico Oil Conservation Commission Case 9111 heard on 18 March 1988, reported by me to the best of my ability.

Sally W. Boyd CSR

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

19 May 1988

COMMISSION HEARING

IN THE MATTER OF:

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| A pre-hearing conference is called by the Oil Conservation Commission to establish procedures, determine issues, and to set forth a hearing agenda for Cases Numbers 7980, 8946, 8950, and 9111, all set for an evitiary hearing to be held commencing at 9:00 a.m. on Monday, June 13th. | CASE 7980 8946 8950 9111 |

BEFORE: William J. Lemay, Chairman
Erling Brostuen, Commissioner
William M. Humphries, Commissioner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division: Charles E. Roybal
Attorney at Law
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

A P P E A R A N C E S

| | |
|---|---|
| For Sun Exploration & Development Company & Dugan Production Corp: | W. Thomas Kellahin<br>Attorney at Law<br>KELLAHIN, KELLAHIN & AUBREY<br>P. O. Box 2265<br>Santa Fe, New Mexico 87504-2265 |
| For Benson-Montin-Greer: | William F. Carr<br>Attorney at Law<br>CAMPBELL & BLACK P.A.<br>P. O. Box 2208<br>Santa Fe, New Mexico 87501-2208 |
| For Mallon Oil Company: | Frank Douglass<br>SCOTT, DOUGLASS & LUTON<br>Attorneys at Law<br>Twelfth Floor<br>First City Bank Bldg.<br>Austin, Texas 78701 |
| For Mallon Oil Company & Mobil Producing: | W. Perry Pearce<br>Attorney at Law<br>MONTGOMERY & ANDREWS P.A.<br>P. O. Box 2307<br>Santa Fe, New Mexico 87504-2307 |
| For Mesa Grande Ltd.: | Owen M. Lopez<br>Attorney at law<br>HINKLE LAW FIRM<br>P. O. Box 2068<br>Santa Fe, New Mexico 87501-2068 |
| For Amoco Production Co.: | Kent J. Lund<br>Attorney at Law<br>Amoco Production Company<br>P. O. Box 800<br>Denver, Colorado 80201 |

MR. LEMAY: Okay, we shall now open Cases Number 7980, 8946, 8950, 9111, possibly more.

MR. LOPEZ: Mr. Chairman.

MR. LEMAY: Mr. Lopez.

MR. LOPEZ: There is another case, I think, that might be included, but I haven't heard back from you. I wrote a letter with an application for the extension of the Gavilan Mancos two tiers to the east and the retraction of the West Puerto Chiquito, and I don't know what case number has been assigned as to that --

MR. LEMAY: Mr. Lopez, I certainly received that. That's why I said and possibly other cases. Part of the reason for not responding was to get some comment from the lawyers present as to how wide a spectrum you want to look at in considering your request as well as possibly other requests for consideration.

MR. LOPEZ: Well --

MR. LEMAY: We plan to handle that this morning.

MR. LOPEZ: Okay, fine. I just -- I thought it went hand in glove with Case 9111 where the order was pending.

MR. LEMAY: We read your argument and it was persuasive.

MR. LOPEZ: Thank you.

MR. LEMAY: At this point I think all of you have -- let me just for those who haven't seen this, this is a pre-hearing conference that's hereby called by the Oil Conservation Commission to establish procedures, determine issues, and to set forth a hearing agenda for Cases 7980, et cetera, concerning the Gavilan Mancos Oil Pool and/or West Puerto Chiquito Mancos Oil Pool, Rio Arriba County, New Mexico.

In regard to that, we have -- we have issued a proposed statement. Lawyers, and interested parties in the audience, if you have not received a copy of the proposed statement, hopefully we have some back there for your consideration.

Our purposes, basically, are to sit down and get the ground rules for these hearings that will take place during the week of June 13th through 17th, and hopefully we won't need to use all five days, but as you all know, we've heard quite a bit of testimony over a two-year period, concerning two oil fields in Rio Arriba County.

It's our intent not to re-hear everything that's been heard in the past but to incorporate the records of all these cases. Again, for those of you who weren't familiar with what's gone on to date, is we've -- we've heard five days of testimony last year. That followed four or five or more days of testimony the year before, which this Commission did not hear, but last year we did hear everything from the beginning up to that point.

Case 9111 was heard a couple of months ago. An order was not issued on that and we ended up incorporating consideration of that case, rolling it into the testimony, and -- rolling it into the record, I should say, of the June 13th to 17th, 1988 hearing docket.

Now we've received an application by Mr. Lopez for what I would say the consideration of field boundaries in the area. My personal preference is if we're going to consider expansion of Gavilan, we might consider contraction of Gavilan; in other words, opening up that issue of present pool boundaries between the Gavilan Mancos and the West Puerto Chiquito Mancos Oil Pools. I think consideration of that is appropriate, after consulting with the Commissioners.

We want to have this thing be pretty wide open as to what we consider but not entertain evidence that would either be cumulative in nature; be not that applicable where there's been stipulated items in the past as part of the record, let's not talk about this thing being a fractured reservoir and some of the geological evidence that's been presented in the past is good. Unless that's changed, I think we can all accept it and there doesn't seem to be much disagreement on the geology; not to excluded geologic testimony, but only to kind of streamline the procedure and narrow down what the Commission -- what's relevant to consideration of the main issues.

In that regard you'll remember that we've got our own guy now, Bill Weiss is -- is really the expert for the Commission. There's been some work done by Bill, as well as some people in the Farmington office.

We plan to -- we'd like to introduce -- some of that information is right here. We'd like to distribute that today for consideration in your own cases.

We plan to divide it up again, red/blue, good guys/bad guys, however you want to refer to that, but have the two opposing sides that have been pretty well established historically, and have -- have representation into that side, into that -- that particular viewpoint, come forth within a day and a half of testimony.

Now, this -- this can be, as indicated in our proposed statement, this can be handled rather loosely, the way you'd like to present your cases. Example, if you're given a day and a half and want very little direct but quite a bit of cross examination and rebuttal, I think, without putting (sic) a time clock involved, you are all gentlemen and have been able to abide by that pretty well in the past. We'd like to continue that process so that there is an element of equal time; we're not telling you how to use that time.

You know, with that in mind, that's our idea on how we'd like to handle it and I think the Commission would like to hear from some of you.

Yes, sir, Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, for the record, for procedure's sake this morning, I would like to suggest to you that you call for appearances and find out what attorneys are here to represent what parties and see if we can find out who the players will be for June.

MR. LEMAY: I plan to do that. At this point I -- it's properly advertised and I will call for appearances in Cases Number 7980, 8946, 8950, 9111, and any other cases that we may consider pertaining to the Gavilan and West Puerto Chiquito.

Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin, Kellahin & Aubrey.

I'm appearing in these proceedings for Sun Exploration and Production Company, and Dugan Production Corporation.

Mr. Chairman, in the past I

have represented also Jerome P. McHugh in these Gavilan proceedings. Mr. McHugh has sold his interest substantially to Sun and so Sun replaces Mr. McHugh in the proceeding.

MR, LEMAY: Thank you.

MR. CARR: May it please the Commission, my name is William F. Carr from the law firm of Campbell & Black, P. A, Santa Fe. We represent Benson-Montin-Greer Drilling Corporation.

MR. DOUGLASS: Mr. Chairman, I'm Frank Douglass of Scott, Douglass & Luten of Austin and Houston, and we'd like to be in Santa Fe, and I'm representing Mallon Oil Company.

I think we would be aligned, according to the Proposed Statement of Hearing as a proponent.

MR. PEARCE: May it please the Commission, I am W. Perry Pearce of the Santa Fe office of Montgomery and Andrews Law Firm.

I'm appearing in this matter in association with Mr. Douglass on behalf of Mallon Oil Company; also appearing on behalf of Mobil.

MR. LEMAY: Mr. Lopez?

MR. LOPEZ: Mr. Chairman, my name is Owen Lopez with the Hinkle Law Firm in the Santa Fe office, appearing on behalf of Mesa Grande Limited.

MR. LUND: Good morning, Mr.

Chairman. Kent Lund appearing on behalf of Amoco Production Company.

We're part of the proponents, too.

MR. LEMAY: Part of the proponents, Mr. Lund?

MR. LUND: Yes, Mr. Chairman.

MR. LEMAY: Additional appearances in this case?

Got all the players, okay.

Let's go through here and just get some comments. We can do this on the record or off the record. Any suggestions on that?

MR. KELLAHIN: I'd like to see it on the record, Mr. Chairman.

MR. LEMAY: Fine. I would certainly summarize on the record if we kept it off the record.

At this point I would like to bring up the possibility that -- is Mr. Bob Stovall in the audience?

MR. ROYBAL: Mr. Chairman, he had to go to Albuquerque at the last minute.

MR. LEMAY: Okay. Did you want to bring that item up, since it is a legal item --

MR. ROYBAL: Yes, Mr. Chairman.

MR. LEMAY -- that might preclude his involvement?

MR. ROYBAL: Mr. Chairman, Mr. Stovall will be the, as I understand it, the Division counsel beginning next month and Mr. Stovall previously was associated with -- with Dugan Oil Company, and I believe it has contacted all the attorneys that are -- have made appearances in this case and from what I understand there have been no objections made to Mr. Stovall becoming the Commission's attorney, but I believe it's important that we get that on the record and then ask the question whether there are in fact any objections to his functioning in that capacity for the Commission.

MR. LEMAY: Are there any problems with Mr. Stovall appearing on behalf of the Commission?

Mr. Kellahin?

MR. KELLAHIN: Mr. Chairman, I had represented Dugan Production Corporation in the Gavilan proceedings during a period of time where Mr. Stovall was their house lawyer (unclear).

To the best of my recollection Mr. Stovall never took an active participating role in any of the hearings, and on behalf of Mr. Dugan we do not raise any conflict of interest issue on behalf of that client.

On behalf of Sun Exploration

and Production Company we also see no reason to preclude Mr. Stovall from participating on behalf of the Commission or the Division in this proceeding.

MR. LEMAY: Thank you. He would be certainly staff because of his position.

How about Mr. Lopez or Mr. Douglass, any comments?

MR. LOPEZ: Yes, Mr. Chairman, Mr. Roybal's correct. Mr. Stovall did contact me and on behalf of Mesa Grande Limited we have no objection to his participating as a Commission attorney.

MR. LEMAY: Mr. Douglass? Mr. Pearce?

MR. DOUGLASS: Yes, Mr. Chairman, I believe Mr. Pearce was involved in that and I think he can make a statement on behalf of my client.

MR. PEARCE: Thank you, Mr. Chairman.

We were in fact contacted. Many of us here appearing before the Commission have dealt with Mr. Stovall and have some regard for him. We appreciate him contacting us to discuss this matter. We have discussed it among ourselves and do not have an objection.

MR. LEMAY: Mr. Carr.

MR. CARR: And Benson-Montin-

Greer also has no objection to Mr. Stovall participating.

MR. LEMAY: Thank you. Mr. Lund.

MR. LUND: If they don't have an objection, I don't either, Mr. Chairman.

MR. LEMAY: Well, we'll have a Commission lawyer, then, Mr. Stovall, on for that week. Thank you, gentlemen.

Mr. Lopez.

MR. LOPEZ: Mr. Chairman, since we're dealing with these procedural matters, I would like a determination of whether our application for the expansion and contraction of the common boundary as contained in my application will be considered along with the rest of these cases.

I think we need to determine that.

MR. LEMAY: I think we do, too. Mr. Carr.

MR. CARR: Does the Commission desire to discuss that at this time?

MR. LEMAY: Yes.

MR. CARR: As I recall, a year ago Case 9114 was an application perhaps filed by Mr. Lopez, it was filed by one of the participants in the hearing, seeking a re-determination of the boundaries between these two pools.

At the same time Case 9113 was an application that I filed. The thrust of that was to abolish the Gavilan Pool. The intent was to recognize this as one common source of supply. I guess it could abolish the West Puerto Chiquito, as well, but it was to take the boundary completely out.

Now, I think this is an important question and I think it really is a threshold question that needs to be decided because it does have impact on what all of our testimony will be. It's hard for us to come in and tell you today what we're going to say about migration between the pools if the question remains where the pool boundaries lie, obviously.

If it is your position to open the hearing and again consider the appropriateness of this boundary, and I believe both applications were denied last year, I, when I got Mr. Lopez' application, thought, well, maybe I ought to file my application again to abolish the Gavilan, and I thought maybe discretion was the better part of valor there and not to put on a black hat for you at the outset; instead defer to you. If that question is, however, raised, we would want to discuss the entire question of the boundary including the elimination of the boundary altogether, and we would be happy if procedurally it's necessary, to refile an application so it's properly before you for advertisement or we would be happy to have it incorporated into your statement, that the question will be discussed, the full question will be discussed; i.e. not only moving the boundary but eliminating the boundary.

MR. LEMAY: All right, thank you, Mr. Carr.

Additional comments on the boundary?

Mr. Lopez.

MR. LOPEZ: Mr. Chairman, in light of Mr. Carr's comments, I would have no objection to extending it to include the matters he's raised, but our boundary, as you know, in my cover letter which I think all counsel received a copy of, we felt that, as I mentioned earlier, that our most recent application goes hand in glove with Case 9111, which was the extension of the pressure maintenance project filed by Benson-Montin-Greer which is under consideration (not clearly audible). I think Mr. Carr can figure on it that if we're going to discuss what should be done, we should also discuss where the boundaries between the pools would lie, if indeed there do exist such boundaries, therefore I would have no objection to incorporating his request, as well, but I do think it has to be addressed.

MR. LEMAY: Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, I rise in opposition to the reconsideration of what I would characterize as a political boundary.

The prior orders entered by the Commission in '86, as well as the June '87 order, I thought laid that issue to rest. The Commission's orders, as I recall them, found this to be one common source of supply, but as a practical matter chose as a political boundary the current boundary between the pools.

Since that time there has been significant activity between the Unit on the east side and Gavilan on the west side with further production, development, and drilling.

We utilize and rely to some degree upon the political boundary. If we are going to once again visit that issue, it raises in my mind some questions of the legal efficacy of doing so within the scope of what I thought was to be the June hearing.

The Commission, after a week's testimony, I thought decided the issue of the boundary, and right or wrong, we're dealing with the boundary as it is now.

It's also my understanding that there has been no geologic evidence that would cause us to believe the geology is significantly different than we knew it to be in June, and wherever you put the boundary, it's going to be a political boundary. The parties have relied for the last year on the current boundary and I think to re-visit that issue simply upsets and moves backward and we haven't proceeded forward.

I guess my understanding of the order was that we would visit in the June hearing of this year the issue of whether the producing rates on the reduced basis that they were applied in the June order was to be the main topic of conversation and we were to take the high production test period and the low production test period plus the reservoir engineering, if you will, that had been developed in the last year, and focus in on the issues that are now necessary for further consideration, which is what is to be the producing rate for Gavilan, how you need to integrate those producing rates in each half of this reservoir, and determine what should happen with the producing rates.

If we're not moving ahead, I think, if we regress and now talk about where the political boundary is, we're going to need more than the week you've anticipated. Let me remind you that we spent two days in hearing before this Commission talking about adjusting the political boundary between West Lindrith and the western boundary of Gavilan. We spent two days working through that deal, and if we're going to visit again where to put the boundary between West Puerto Chiquito and Gavilan, we're going to need some more time.

I think you have a legal problem in introducing that as an issue now. I think Mr. Lopez wants a second bite of that apple and he's already been denied, as we were. We've solved that one, at least made a decision on it, and I suggest that it's not a decision that needs to be re-made.

I think you can address all the issues that are important in the context of determining whether there is a method of adjusting the equities between the two pools as they exist now. Again, they introduced some of that topic at the pressure maintenance hearing. We can about mechanical and physical ways to adjust producing rates and measure bottom hole pressures to handle that boundary.

I don't think we need to visit the boundary here.

MR. LEMAY: Thank you, Mr. Kellahin.

Mr. Douglass or Mr. Pearce?

MR. PEARCE: Thank you, Mr. Chairman.

I'm in the unusual position of

sympathizing with everybody who's talked to the issue this morning and the problem is I would like for the Commission to tell us what issues the Commission wants to consider. I agree with Mr. Kellahin that if the boundary issue is injected into this proceeding, this is a much larger, much more complicated and much more extensive hearing.

If -- if the boundary issue needs to be revisited, as Mr. Lopez suggests, and that cannot be done separate from the June hearing in the Commission's view, then I think that has to be considered, but I think the Commission has to tell us what issues they want to address and whether or not they think some issues, some separate issues can be considered later if they need to.

I, frankly, was concerned that 9111 is still with us, and I fear, having a proceeding which grows like Topsy, if we can't settle a discrete issue like 9111, I don't know how we're ever going to get out of this, Mr. Chairman, and I personally, rather than -- than stating a position for some client, would like for the Commission to tell me what you want us to talk about and if you'll let us know that, we'll try to get an accurate estimate of how much time we need and we'll try to meet schedules, but I think Mr. Kellahin may be right, a week may not do it.

We'll do what we can to help you, but if you let us talk about all of the issues or any issue we want to, you have a problem, Mr. Chairman, and I, as I say, I sympathize with everybody and I don't have an answer. Sorry.

MR. LEMAY: Mr. Douglass.

MR. DOUGLASS: Mr. Chairman, I read with interest your proposed statement of hearing. I think it is something that's much needed in this type of proceeding. It's very helpful, at least to the lawyers involved, and I read under one of these items an issue for hearing was the determination of whether there's migration between the Gavilan and the West Puerto Chiquito Mancos Pools.

The second part of that is whether -- whether the horizontal boundaries of the pool are appropriate, and whether correlative rights were being violated.

So I assume by that the boundaries of the pools were something that you were interested in.

It seems to me that -- that the main issue should be the production rate that's involved there, with reference to Gavilan. I took it from this, maybe, that the board itself wishes to hear some thing in that area, and I guess we need guidance is really what it amounts to, and I think the parties are correct here that if we go much farther than the production rate, then we may need additional time.

Maybe you may want to consider a bifurcated hearing (not clearly understood) make a decision on that, and then make a decision on the pool boundaries, as far as that is concerned, at some later time.

We certainly don't want to delay the decision on the production rate since the time is building up against us as a proponent as far as what's happening in the field.

We urge guidance from you gentlemen. I think, more than anything else. We would certainly like to go forward with the production rate part.

Perhaps after this prehearing conference the attorneys for the parties might get together and reach some sort of an agreement or a tentative understanding on the boundaries as far as what might take place in this next hearing and report back to your group as to that.

MR. CARR: I'd like to say one thing just briefly. I found myself in the awkward position of perhaps agreeing with Mr. Pearce, but perhaps agreeing with everyone that we really do need some help and because I think, and I don't want to misunderstood as saying I think the boundary issue should be reopened, because I really don't, but I think that is the threshold question because I think the whole hearing will follow that kind of a determination and we've got to know what we're talking about before we can come in here and take our positions on that, I think is what we're saying, and I would hope that the attorneys could retire and agree but I wouldn't want to raise false hopes.

MR. DOUGLASS: I think most of the attorneys, Mr. Chairman, sense the decision in 9111 would give us a lot of guidance on at least what your consideration was as far as where the effective boundary was between the areas that we were dealing with here, and it looks like you're not going to have that kind of guidance before the hearing and I think we're seeking that type of guidance now. I think all of the attorneys, as far as I sense, would be receptive to that type of guidance before planning this next hearing.

MR. LEMAY: Mr. Lopez?

MR. LOPEZ: And -- and it was in that spirit, Mr. Chairman, that I did file the application and as a follow-up to 9111, because I do think that the evidence there is before the Commission and apparently will be discussed in the June hearing without repetition of the evidence as presented, and therefore, I just felt if Mr. Greer's application in that case is denied, then the boundary is not a political one but a geological one as we've been arguing from the (unclear) and there wouldn't be a great deal of additional testimony or time required, in my opinion.

That is also the reason that I limited the application just to discussion of those western two tiers of Puerto Chiquito and did not include the entire spectrum of the Gavilan boundary.

MR. LEMAY: Mr. Lund, do you have any comments concerning this?

MR. LUND: Just a couple, Mr. Chairman, and I think that we ought to stick to the format that's in your proposed statement in which you say you don't want to consider vertical boundaries at this time, but there is going to be some overlap because of the testimony about the A and B producing zones and the C zone, and an issue that Mr. Douglass raised on (not clearly understood), and it seems to me we ought to here those issues and then any technical (not clearly audible).

MR. LEMAY: I'd like to say something in -- did you have something, Mr. Roybal?

MR. ROYBAL: Yes, Mr. Chairman. Just, I guess, a reference back to the Commission's last open meeting, where the procedures for this case were discussed, and I think at that time you heard from legal staff that in order to hear paragraph Roman Numeral 111-4. including the horizontal boundary issue, that we did need a vehicle to get that issue before the Commission, and at that time two things were -- well, one thing was suggested, and that was a reopening of 9113 and 9114, even though a decision has been rendered in those cases denying those applications.

I think we now have an alternate vehicle with Mr. Lopez' application and his willingness to consider the issues raised by Mr. Carr within that -- that application. Perhaps it's even a superior vehicle if you don't have a denial already on the record in those cases in that new case; a brand new case might be the best vehicle, but as the other attorneys have stated, the -- it is a threshold question whether horizontal boundaries are to be considered by the Commission and once that's decided we can structure it from there.

MR. LEMAY; Does anyone else have anything to say on this particular issue, whether to consider horizontal boundaries?

Yes, sir, Mr. Chavez.

MR. CHAVEZ: Mr. Chairman, I just want to ask if -- if the boundaries are changed will there be a practical difference in the way the pools are operated and if there aren't, and all we're doing is just making more administrative burden on everybody, then one should not consider the issue.

The pool rules have been adjusted such that the operating, producing rates are the same on either side of the boundary. There are already in place buffer zones to protect against cross drainage if such might occur and and there may not be a practical outcome of changing the pool boundary as far as operating the pools is concerned.

MR. LEMAY: Anyone else have anything to say in this issue?

It may be a good time to take a fifteen minute break. I think the Commissioners and I will huddle and we'll have an answer for you after that.

(Thereupon a recess was taken.)

MR. LEMAY: Well, we considered all the arguments, pro and con, on enlarging this thing.

First of all I'd just like to make a couple preliminary statements with regard to what I heard from you gentlemen.

Mr. Kellahin, I don't agree with you on the fact that -- I think we have to reconsider issues when we go to testing periods. All these things are interrelated. We're talking about really wanting to visit this thing one more time and do it in a very efficient manner, but we don't want to have the Commission hamstrung by not being able to consider certain things, which means horizontal boundaries.

So we are going to consider that and we're going to do it with a separate case that will either expand or contract the present boundary. We're doing it, not because we think we're really opening this thing up to a lot of testimony, a lot of back and forth, it's -- we don't want to be constrained by not being able to consider that issue in the event we come to an overall conclusion on the way to handle this -- this whole situation.

As far as the five days go, we cannot allow a little more time but let me state a view that we have as commissioners, that you all have employed extremely competent experts but a lot of it is overkill. We've heard a lot of stuff. We've heard a lot of cumulative stuff. We've -- we've digested things that are only marginally applicable to points you want to make.

So we feel that a lot of efficiency, now that we're going back the second time, that can be handled by you in your presentations.

Being honest, you've all testified before us and we've handled oilfields in two hours, not five days. If you take that -- we've got two oilfields, that's four hours, not five days. And, you know, there's such opposition in this thing that you're building up cumulative evidence that is very weighty but sometimes, and I think you know where we're coming from, we wonder the significance of hearing all that. What's the point? Where are you getting to? How does that really pertain to what you're trying to prove?

We've certainly seen a lot of computer models. We've been frustrated by the fact that it's very difficult for us to analyze one computer model versus another computer model.

And you've recognized that in subsequent cases, so that there are keys that you can employ that are in those models that can prove points but to try and sway the Commission based on things that we're not capable of analyzing and therefore we're only hearing witnesses, rebuttal witnesses and rebuttal on top of that, is highly questionable use of time.

So we're saying if you're looking for direction, we want to have these issues open. We want to not be hamstrung on what we can and cannot do in trying to come to grips with these fields.

If my memory serves me correctly, I think, Mr. Pearce, initially it was your consideration that Case 9111 should be part of this overall Gavilan. It wasn't? Well, then someone mentioned that. I thought it was -- Lopez, oh, yeah, didn't you say 9111 should be -- ought to be part of this roll-up?

MR. LOPEZ: I guess.

MR. LEMAY: I thought so. So, you know, we've thrown it in the roll-up and then we're hearing that it's too much to handle.

So, let's -- let's say we need to handle it, we need to handle all of it in an efficient manner and we don't want to be limited as a Commission to not be able to consider variations of that boundary whether it be political or geological or engineeringwise (sic).

That's the reason for having it in there, not to introduce a new issue. That issue has always been there. But any time you go into the possibility of a barrier, I think your -- your logical sequence takes you elsewhere and we want to be able to take the -- be taken elsewhere and come up with the proper orders that will put this -- this thing, you know, on the back burner for awhile so you can start operating under some certainty.

That's the reason for having it in here, Item Number 4, and legally it's necessary, and I guess it is, to create another case in here and that's what we're going to do.

In consideration of -- we want to give strong, clear signals as to what we're going to do. Now we've allowed a flexibility with a day and a half. We could enlarge that a little bit but I mean we'd rather keep a tight schedule and have you run a little bit over than say you've got this time and run over.

The things that we find very productive as a Commission are the opportunity to call back some witnesses like we did this morning, ask them direct questions, not have a lot of legal maneuvering involved. We're trying to at this point in time get through to the basics of these cases.

In that regard we are incorporating all the records, all the cases so you can refer to them but we don't have to go over them again. We're not, I don't think at this point we're that thick-headed and need that much education. In fact the three of us feel like we're experts like all you lawyers do on these (unclear).

And we've got lots of experts. Let's just confine the testimony to new evidence and conclusions based on that and we want the widest discretion possible in creating our orders to solve a combination of pretty tough problems in this area.

Let's see, at -- at this time, before we bring Bill Weiss on, he wants to say a few things, are there anything else -- or is there anything else in our proposed statement that you all feel should be changed or modified to accommodate the case hearings?

Yes, sir, Mr. Douglass.

MR. DOUGLASS: Thank you, Mr. Chairman.

With reference to the issues not for hearing, I was wondering if -- it might assist us if a little more definition could be set out there.

For instance, I have some suggestions. One would be gas market or gas plant capacity or gas plant construction issue with reference to increase in the production rate. If that's going to be an issue in the hearing, then I think we need to know about it now. It's not listed above but it could be one of the reasons why, and I would like to suggest that gas plant capacity, gas plant construction, gas market issues would not be an issue for this hearing that's coming up.

I think it would again reduce -- I'm seeking to reduce the areas because I want to get to the main issue, I think, just like you do.

MR. LEMAY: That's what we're trying to do. Thank you.

Mr. Carr. have you got a --

MR. DOUGLASS: I have an additional suggestion but I'll put that one out first.

MR. CARR: Well, I would just submit that that's already in the record.

We -- we're not trying to do a bunch of legal maneuvering here, at least I'm not, and the signal is clear about trying to be efficient and direct, and the questions that I raised earlier about the scope of the hearing were honest questions about how far you wanted us to go and I recognize what you're trying to do is not be constrained. Likewise, we will try to cover the subject matters that we understand that are relevant to what you're trying to do in an efficient fashion.

To the extent that the gas plant has been discussed, I can tell you today I am not aware of our planning to go back through that; that is another factor in the overall problem that you're trying to resolve. Should it become significant, I'd want to discuss it, but I can tell you now, I'm not planning to, and I will do my best to abide not by the letter only but by the spirit of what you're trying to do with this order.

MR. LEMAY: Thank you. I think that's really the essence of it. I don't, myself as a Commissioner, view the gas plant as a critical issue because it's a fallout of what we're trying to decide; therefor, I would say it should be -- well, I don't say it should be excluded, but look -- look at it this way, you're given a day and a half. If you want to spend a day on the gas plant, you're making a big mistake.

MR. DOUGLASS: Well, it became such a big issue in the last hearing, I just want to make sure it's not one in this issue -- in this hearing, and whatever you said about that, that's what we've got.

We're now dealing with another field, the Gavilan here, as far as its market and so forth, and if those are not going to be issues in this hearing, then I'm glad to hear it because I can concentrate more on the --

MR. LEMAY: Well, let's put it this way, too. Given the spirit of the thing, Mr. Douglass, if you want to make it an issue and it's of such a minor importance to the overall scheme of things, you're not using your time well. So those people that want to choose to make something an issue that -- that really isn't that important, and it's a judgment call on your part, there again I consider that an error in judgment.

MR. DOUGLASS: Well, I -- I agree with you. I thought maybe it -- my experience with lawyers has been that if you give them an open pasture they'll graze all over it and if you give them a narrow corral and you tell them that's where you want to go, and you make it clear that you're not going to tolerate them getting outside of that corral, they'll stay, I think, generally inside of that, even though some may make a mistake and forget it.

MR. LEMAY: Well, we're making kind of a corral that the horses can jump out, but if they do, they may be lost.

MR. DOUGLASS: All right.

MR. LEMAY: So --

MR. DOUGLASS: Well, let me mention a couple other issues that I think that I've seen -- I've read the records in these two previous hearings and that is the question of pressure maintenance or gas injection in the Gavilan. Is that a non-issue? In other words, it's not listed up here in the issues for the hearing and I hope it's going to be a non-issue in -- in the Gavilan, and also, the effect of what is the production rate in the Gavilan with reference to a pressure maintenance or gas injection project in the West Puerto Chiquito. I don't see that listed here, so I would hope that's going to be a non-issue, and if it's going to be an issue, then I need to know so I can prepare for it. I'm not planning on making it as part of my case, but I need to be ready to face that issue if that's going to be -- that's part of the outside the corral, I need to know about it now; if it's going to be part inside the corral, then I'll --

MR. LEMAY: Speaking of the corral, let's hear from the other side (not clearly audible). Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, I understand from the last public meeting that the Commission had and talking about issues for this June hearing, the Commission raised on its own the question of unitization of Gavilan. I think that scope of that question, if we're to address it in June is certainly broad enough to look at the prevention of waste issue, the -- the advantages of pressure maintenance in Gavilan, and I am like the other lawyers before, if that is an issue you wish us to address, we'll certainly do so.

I had understood that that was of concern to the Commission and unitization of Gavilan in that context may be an important factor for you to consider.

MR. LEMAY: Let me state that -- yes, sir, Mr. Pearce.

MR. PEARCE: I'm suddenly scared, Mr. Chairman. I don't see in any of the cases on this Commission's docket or any of the cases that we've added to the Commission's docket this morning, anything about unitization in the Gavilan and I must confess that I have a number of clients and a number of other lawyers have a number of clients who are -- would be extremely concerned if that issue were somehow coming in the back door.

The Commission has authority to compulsorily unitize in some instances. The Commission has authority to approve voluntary unitizations in some instances. Outside of that kind of application I certainly do not understand that we're going to be discussing anything having to do with unitization of the Gavilan in this proceedings.

If we are going to discuss that, then I think we need either somebody's voluntary unitization agreement on the table before us or somebody's compulsory unitization application on the table before us, because I don't think unitization is one of those things which you can just sort of (not clearly understood) mull about and say, well, gee, that's a good idea and then issue an order.

Either we're going to -- somebody's going to say let's unitize and come forward with something firm, or I don't think we ought to talk about it, and if somebody's suggesting that we have a free floating unitization discussion, I think I and my clients are certainly on record in opposition to that and I think we don't have an application before the Commission which will with-stand judicial scrutiny for any order doing anything about it.

MR. LEMAY: Co-counsel raised the issue, that's why we're discussing it, but there are some rumors around, do we want to address (not clearly understood) that conversation?

MR. KELLAHIN: Mr. Chairman, we're addressing the fundamental issue of prevention of waste in Gavilan. This case began two years ago when we sought on behalf of our clients to reduce the producing rates and that was simply to provide a conservation of the energy and drive mechanisms in the reservoir to give us a window of opportunity to look at several things. One, whether the operators could agree upon the reservoir and what was going on in the reservoir; whether or not they could agree upon a method to produce that reservoir; and whether ultimately the best and most efficient way may not in fact be unitization.

The fact that there's not a unitization application before you misses the point. To prevent waste, you may ultimately decide that the way to drive the parties to unitization is to simply shut in the reservoir. You can do that.

So if that is what we're talking about in terms of unitization, if we're talking about whether or not Gavilan is suitable for pressure maintenance, and that's something you want to talk about, we'll be happy to present it.

MR. DOUGLASS: Well, Mr. Chairman, let me make it clear. I didn't raise -- I didn't say unitization or raise the issue of unitization.

What I asked about was whether the issue of pressure maintenance or gas injection in Gavilan was going to be an issue in this hearing and whether the effect of the production rate in Gavilan was going to affect the pressure maintenance or gas injection project that was over in West Puerto Chiquito.

If that is going to be an issue, then I would like to know about it. It's not listed here and I would like to know about it.

If -- if it's going to be not in consideration, then I think that would help very much in guidance to the lawyers on how they approach and prepare their cases.

That was -- I'm not talking about unitization. I'm talking about --

MR. LEMAY: I understand, but how do you issue pressure maintenance without unitizing or --

MR. DOUGLASS: Well, I don't

know in New Mexico whether you have large enough leases to conduct your own pressure maintenance (interrupted) --

MR. LEMAY Large enough to do it, so -- that's what we're talking about, one logically leads to another, so you're asking for a narrow corral, you know, I'm not sure we can give you one.

Mr. Carr.

MR. CARR: And I may be jumping the fence and lost at this point, but to look at this whole question and try and get something done here today and deal in good faith with it, I would be remiss if I didn't stand up and say that when we talk about moving a boundary line one section, two sections, one way or the other, that underlying that is the question of communication in a common reservoir, and you can't say we can't talk about the effect of drainage on one side of this arbitrary line and not discuss what happens to wells immediately offsetting on the other.

So, as to production rates in Gavilan affecting West Puerto Chiquito, yes, and I'm going to jump the corral on that.

MR. LEMAY: Well, you're not jumping it. I think one thing leads to another.

As far as forcing unitization in Gavilan, I can tell you right now, Mr. Pearce, we don't have any authority to do that. We're not asking for a unitization agreement that's presented before us and that we have to rule on that unitization agreement. But I think if we're talking about adjusting maximum rates of recovery, that, correct me if I'm wrong, I understand Sun Oil Company, is now actively engaged in trying to get an engineering committee together in the Gavilan Field. We've heard that; if you want to comment on that, please do.

MR. DOUGLASS: Well, I think that's the kind of evidence we can present in the hearing. That's what I want to know is if that's important to you. We're going to show what's actually taking place out there while this production has been reduced out there as far as my client is concerned, and we're going to show also that a pressure maintenance project or gas injection project in this kind of reservoir is not going to be effective.

So I sense that this is something that's important to you folks and we'll be ready to meet it. I just want to make sure that it was important to you at this juncture, and I think that I sense that it is, and we're going to be ready.

MR. LEMAY: Put it on the list, we're getting a big list here.

Day and a half, so you're going to have to speed up.

MR. DOUGLASS: Right, that's

all I need to know, is what, you know, is what you're interested in because I can play round or flat, and this is very helpful to me because I think --

MR. LEMAY: Sure, and you've got a time constraint and we're not saying that you have to do something, but we'd like to know as a Commission what's going on.

We heard that Sun's called an engineering committee. The last one broke up because, as we understand it, they couldn't reach agreement. Now maybe this one's making some progress. It would certainly help us to know that -- what results have been reached on that committee.

Don't spend a lot of time with it but bring us up to date on it.

Only because -- I can't see looking at one issue and excluding others when they're interrelated, and it makes it tough on your job, I know.

Looking ahead, allocate some time there --

MR. DOUGLASS: All I need is to know what you're interested in.

MR. LEMAY: Well, I think we're learning about the reservoir and any time you tell -- when you can tell this Commission that a pressure maintenance project is in operation in West Puerto Chiquito but we don't think one would be operative in Gavilan or would be effective because of these reasons; you don't have to carry on for -- you can cover that in five minutes, I think, not five days.

MR. DOUGLASS: I think my issue is not for hearing, it's been shot down, so now let me suggest that the only other consideration I have, since I think it's clear that we're going to be a proponent, I notice in the set-up here, and I think is a good outline of the presentation, and one, at least I checked with -- with folks on our side, as proponents it looks like within the time period that's set out there for a day presentation, that the direct case is probably going to be a little less than a day, but I'm sure the cross examination would fill up that amount.

I sense that last time, although I thought I had the short end of the stick, I think it worked out very well in the last hearing, the arrangement between attorneys; I think there was very little objection over evidence and items of that sort, and let the hearing flow well, and I sense that that might be the same type of thing that we're going to experience in the next one.

I would suggest that if we're going to be proponents, we ought to have an opportunity to open and close, and I notice here that the last item is the rebuttal by opponents. I would suggest that we would have an opportunity for surrebuttal; in other words, we ought to be able to put on something to rebut whatever their rebuttal is, and obviously it can't be very much because there we wont' have much time to prepare for it, but I do think that we should have the opportunity to open and close as far as the case is concerned and that should give us an opportunity to put on evidence as to their rebuttal, and it should be limited to their rebuttal, nothing new; it should be limited to their rebuttal. I think that's the way you get hearings closed down.

MR. CARR: We have no objection to that. We plan to use our half of the time, however, we want to (not clearly understood).

MR. LEMAY: You can go on and rebut and rebut and rebut the rebuttal if you want to, but -

MR. CARR: It will be like having this talk here today.

MR. DOUGLASS: Let me suggest on the last Item VI that we are willing to proposed to provide exhibits in advance of the hearing. I would suggest --

MR. LEMAY: That was my next question.

MR. DOUGLASS: And we're certainly willing to do that. It obviously puts a time bind on everyone but the last hearing that I attended here I received four volumes of exhibits that were about five or six inches tall that I had never seen before and I don't think that that's an effective way, at least for me to represent my client, because I really didn't have an opportunity to see and review those as far as (unclear) and also, it doesn't give you an opportunity to really look at them in that short period of time.

So I would suggest -- and also I think it will limit the amount of exhibits. I think you'll have a tendency to try to get the exhibits in the corral, so to speak, if you're going to have to give them to the other side in advance.

I'm not going to put on any exhibit that you can't understand what you're looking at and so we're certain willing to try to --

MR. LEMAY: Exchange exhibits a week ahead of time?

MR. DOUGLASS: Yes, sir, I was going to suggest Tuesday, I think that's June 7th, if I recall, by, say, by noon on June 7th would be our suggestion for the exchange of exhibits.

MR. LEMAY: Mr. Kellahin, Mr. Carr, what do you think about that?

MR. KELLAHIN: Mr. Chairman, before we get into the issue of exhibits, I wonder if we have completed our discussion about the potential issues.

Are there any other issues that the Commission wants to identify for us that are not inherently clear in the notice?

MR. PEARCE: We've moved from that, Mr. Kellahin.

MR. LEMAY: We've enlarged the corral --

MR. KELLAHIN: I couldn't seem to (inaudible).

MR. LEMAY: -- it looks like here. We've got -- it's a fine line what we'll consider in it.

We're not going to consider compulsory unitization, we can't. We know that.

MR. KELLAHIN: No, I appreciate that but for the good part of a month worth of testimony, we're always talking to you, now here's a chance for you to tell us or --

MR. LEMAY: I think I've tried to do that.

MR. KELLAHIN: Yes, sir.

MR. LEMAY: All right, let's

continue that a litte bit more then, as far as the issues go, you mean?

MR. KELLAHIN: Yes, sir, are there any other specific issues that we need to address that are not listed here in this notice that we've talked about, or should talk about?

MR. LEMAY: Well, we added number 5 in there and that is -- as far as the statement, though, is it necessary to put a number 5, being an issue of possible pressure maintenance in Gavilan? Would you like to see that in there?

MR. DOUGLASS: Well, I thought it was in there. I thought -- I did think you made it clear, Mr. Chairman, that was something that you were interested in.

If you want -- if somebody else wants you to write it down for them, that's fine, but you don't have write it down for me.

MR. LEMAY: I'll put it in the statement because we plan to issue one.

MR. KELLAHIN: I meant apart from that, sir, if there was anything else among you that had not yet been discussed. We need a signal as to whether or not there is other issues.

MR. LEMAY: We're trying to

roll together a lot of things that have happened in Gavilan. Those of you that aren't familiar with that committee that's looking into area-wide spacing on the east flank of the San Juan Basin concerning wildcat locations going to fractured Mancos; that's a 640-acre, I thought, consensus with a second well.

We have 640-acres here. We're not going to entertain a lot of testimony concerning the spacing. I think that's set. I mean we're narrowing this corral now. We've established communication enough to say that 640's with an option of a second well is it.

As far as the vertical boundaries go, I think we've pretty well on cross sections defined the A, B and C zones, and the zone below, Sonestee, or whatever they call that thing, that produces a good well occasionally.

The fact that you've got some Dakota contributing here or there I don't think is a significant issue. So, you know, we don't have to spend a lot of time on that.

We've conducted a lot of hearings, I mean a lot of tests, this last year and we have some conflicting stuff there on GOR's and, you know, I think that's the reason for the tests, is to hear some of that, get into rate sensitivity in the reservoir. I mean that's the obvious stuff that we're going to hear.

I don't know what else to say

about it. Any of the other Commissioners have any ideas concerning a larger corral or maybe a narrower one?

Erling, do you have anything?

MR. BROSTUEN: I think that the -- the issue of unitization at this time, that is something that could be discussed but certainly, as you said, Bill, is not an issue before the Commission at that June hearing.

I think some things have to be resolved first before we can decide, make an interpretation as to whether pressure maintenance would be effective at all, and that's certainly not a subject for the case coming up, case coming up in June.

I think that if something is being done in the way of an engineering committee being formed and some cooperation being exhibited by the -- by the parties involved, that we do need for the Commission to be made aware of that, any progress that's being made. I think that's the -- what I would see as any discussion, limited discussion, as far as pressure maintenance or as far as unitization, if it is a matter which should be taken up at some time, if we hear evidence at the June hearing that leads us to believe that pressure maintenance or unitization would be beneficial and an engineering committee has been formed, or the Commission feels that in the interest of protection of -- or the conservation of oil and gas, prevention of waste, and protection of correlative rights that a unitization hearing should be held, the Commission on its own volition can do that. That's within the authority of the Commission to set a call for a hearing on that, and that's something that is true for any -- any pool in the State of New Mexico.

MR. LEMAY: Mr. Humphries, do you have anything to say about the corral or --

MR. HUMPHRIES: I would like to say, if there was a way the corral could be expanded or limited to accommodate the complexity of the question, I would be willing to try to lay those boundaries out, but I think we count on you as being sincere in your arguments.

If you want to do this once a month for the rest of my two and a half years, I guess I'll be glad to hear this once a month.

It seems to me an incredible amount of time and money has gone into this and that the Commission owes it to you to conclude this with some kind of concise statement that you can either disagree with or agree; therefor, we don't want to limit the issues any more than to say some of this stuff you don't you have to tell us about any more. I've told -- I've learned enough lawyer talk here in the last year to last me for the rest of my life but I'm willing to stipulate that I already understand some of this stuff. If you want to keep presenting that, you're wasting your time and ours. From a standpoint of what's new and what's important, let's try to put some conclusion to an extremely complex, interrelated thing that we can come out with a conclusive, comprehensive analysis and order that, hopefully, -- I don't -- I really do not want to split the baby. I'm not looking for a compromise, I'm looking for what the evidence would conclude, or lead us to the conclusion that a final determination can be made, and if you want to argue about it throughout the rest of this Commission's tenure and other commissions, I guess that's something you have to determine.

I think we do try to write clear, concise orders and, hopefully, we'll do that with this one. So I don't want to limit the corral to the point you can't get all of the pieces into the evidence that you want to get in before the Commission and we'll discuss it thoroughly, but I certainly don't want to hear it ad nauseam some of the things we've already heard.

I would certainly like to see this five day effort result in some kind of a Commission order that everybody can either feel free to attack or litigate, or whatever you'd like to do, but that's -- so I don't want to arbitrarily exclude or include anything.

It is a multiple issue endeavor

that we're in and the sooner we conclude it, the sooner you all can go about trying to adopt or adapt to whatever the Commission rules.

MR. LEMAY: I think that that gives you all -- you're wanting to hear from us, so that's why I thought the associate commissioners here can tell you how they feel about it, because I'm only one voice, although I am Chairman, and I wanted to get this thing out on the table in a very candid fashion so you know where we're coming from.

In essence we're saying, we don't want to be too limited on what we can consider in the way of an order.

Recognizing that we're constrained by law, we can't unitize in San Juan. We can't go in here and provide compulsory unitization.

We want to be able to know up to date what's going on. We want to be able to issue an order that the other side if they don't agree, or whatever, can take it to the courthouse and not say, well, gee whiz, we have to go through another year of -- of splitting the baby or I don't know or more tests.

There was a reason for that a year ago. A year ago we had three green commissioners that weren't familiar with the Gavilan and West Puerto Chiquito situation, so you started at point zero and brought us up to date. We've heard cases in the meantime. I think we're ready to settle the issue now. We'll never get all the facts but we've got enough out there that -- that we should be able to come up and analyze them and come up with an order.

We owe that to you and that's what we want to do in five days of hearing in the most efficient way possible.

That will give you an idea of where we're coming from, then I think we can go on from there.

Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, do you want the parties to declare on what they are proposing to focus on in terms of producing rates for Gavilan? It would certainly be of help to me if I know I have to share my time with Mr. Douglass or share it with Mr. Carr.

My position, sir, is that less is best in terms of the producing rates and for my clients, we propose that the producing rates in Gavilan certainly be no higher than they're currently restricted at.

So we will present testimony and witnesses that will tell you, hopefully, that the current rates may be a little excessive but we certainly don't want to see them increased.

MR. LEMAY: Not a surprising conclusion, but I'd certainly think that it would help to have that position summary paragraph, like we did last year, to that extent,

MR. CARR: And I can assure you Mr. Kellahin will be splitting his time with me based on that statement.

MR. DOUGLASS: If there's any question, we haven't decided on a specific rate. I'm sure that we would propose at least the statewide. We may split the division as far as oil and gas production. We may actually propose a gas amount than is greater than would come under the statewide rules based on the data that I've seen in the case before.

We don't have a specific amount to recommend to you now but will propose one and since my client's got six wells producing a total of 50 barrels a day right now, I can assure you we're going to request some increase.

MR. LEMAY: Fine, I assume that, too.

But if it might help to take these issues that we're -- we're definitely , at least 1 through 3, the fact that we have allowables limiting gas/oil ratios, you could have a sumamry paragraph on that prior to the hearing, so I'll make that part of -- in corporate that in the statement. We did last year and (unclear) this year. I think it would be helpful.

Let's see, where are we? On issues, are we pretty clear on those? Okay.

MR. KELLAHIN: Do you want us to declare now, today, what we propose in terms of a producing rate.

MR. LEMAY: No.

MR. PEARCE: We're not ready to, Mr. Chairman.

MR. LEMAY: No, no, I think that will be submitted prior to the hearing.

It will be part of this -- see, we're going to issue another statement. We're going to modify this statement. This is only a proposed statement.

Within that statement we will request a position paper from you prior to the hearing that is exchanged with the other side.

MR. KELLAHIN: That leads me finally into my response about the exhibits.

Until I'm able to formulate among my clients and our witnesses the exact issues we've discussed, I can't declare to you who's going to be a witness or how long it's going to take them to testify or in fact when they're going to get all their exhibits ready, and I guess I dislike hearing by ambush as much as the next lawyer, but it's -- it's the game we play around here, unfortunately, is that we have exhibits finally from the draftsman sometimes the day of the hearing.

MR. LEMAY: Well, we'll entertain some exceptions to exhibits at the last minute. I don't think we're that bullheaded by saying no one can submit an exhibit that wasn't presented before, but we're talking about a general case of either exchanging exhibits prior to the hearing or not, and I think that's the issue we're looking at. That's why I want some feedback from you as lawyers which you would prefer.

I understand Mr. Douglass would prefer to, on June 7th, was it, have the -- his exhibits submitted to us and copies to you. Are you in opposition to that?

MR. KELLAHIN: Yes, sir, I believe I will be.

MR. LEMAY: Okay.

MR. KELLAHIN: My proposal would be to submit them, or to have all exhibits exchanged among all parties the first order of business on the commencement of the hearing date on the 13th. I propose that because I know from practice in dealing with this case and many others, I won't be able to have them much before then.

So we would -- we would request an exchange of exhibits at that time.

MR. LEWAY: Shall we vote on it? How do you feel about the --

MR. CARR: The other thing is, I mean, last year I was up until 2:00 o'clock in the morning the night before the hearing spread all over my office trying to put together exhibits and I don't want to be in bad faith, but I come in here with that, and I recognize also Mr. Douglass' concern and that is why when earlier this year they requested information from us we complied and provided it.

It's -- it's a hard call. I think that if they're concerned about having time to look at the exhibits, they'll be going first. If it's the first thing exchanged, they can hit us with them and we'll get them cold and they can have a day and a half to look at ours. I could -- I think it would be wise to just go with the distribution of exhibits on the first day of the hearing.

MR. LEMAY: Mr. Lopez.

MR. LOPEZ: Well, maybe it's much ado about nothing, but it's my feeling that we can pretty much frame the issues and the principal consideration the Commission is going to be having to address is what -- who's right based on how the reservoir has performed since all the tests were ordered.

So most of the exhibits will be referred to because they've already been entered into the record in previous cases. Therefor, in this instance, if I might usually agree with Mr. Kellahin, that human nature means you don't prepare until the last minute to deal with a crisis as it faces you in the morning, but in this case it would seem that if we're going to have voluminous exhibits that we already haven't considered, that in the spirit of trying to reach some sort of informed resolution during the course of the week, that an earlier exchange would be helpful.

MR. LEMAY: Mr. Pearce.

MR. PEARCE: Mr. Chairman, we've spent a good deal of time this morning talking about expanding the issues without expanding the time and as I understand it, that's really what the Commission is asking us to do, address as many issues as we can, as we think that matter, in as little time as we can possibly use to do it.

That means, in my opinion, we do have to be a lot more efficient than we have been in the past.

I do think one of the best ways

to encourage lawyers to be efficient is to give them more time to prepare for what they're going to be confronted with and I favor an earlier exchange of exhibits because I think we will be more efficient when we are before you in the hearing if we have exchanged those exhibits.

With regard to the nights that we have all had immediately before the beginning of hearing, staying up very late and having exhibits everywhere and having draftsmen with tape and pen and that will go on the night before whatever day you say we have to have exhibits ready.

MR. LEMAY: (Not clearly understood).

MR. PEARCE: It doesn't matter. That -- that night is going to go on but you can choose when it's going to happen.

MR. LEMAY: It's been my experience that just the reverse of that might have happened the first time we visited; in other words, each exhibit, given enough time, prompts the other side, we sent you home and you come back two days later, prompts the other side to prepare counter-exhibits or develop cross examination that would exceed their cross examination had they been a little bit surprised.

I don't know. I see both sides

of that as a matter of is it efficient to have all this information so that you can -- you can prepare a lot of counter-exhibits or is it best to go with the case no matter what the other side presents.

MR. KELLAHIN: One final comment and then you need to tell us what you want to do.

MR. LEMAY: Okay.

MR. KELLAHIN: Remember at the March hearing of last year we talked about this same thing, the exchange of exhibits, and what happened is Mr. Lopez then, as he excused as a matter of style, gave us exhibits one at a time and we had an exhibit book that was empty until we put each witness with each display.

So you can carry this to any extreme you want. I'm not sure there is any way that's more efficient than the other. If you give the exhibits ahead of time the lawyers have more time to dream up questions and you go that way. And if you trade them at the first day of the hearing everybody is in this great frenzy of looking at exhibits and I'm not sure either one is right, but tell us what you want and we'll do it.

MR. LEMAY: Well, okay. The reason why I was open for questions was because we want efficiency and I thought if there was agreement on the issue that the Commission could be swayed based on hearing -- you tell us what's most efficient but since it's been the pattern of the Commission to not exchange exhibits, they will be exchanged on the first day of the hearing, only because we've done it that way in the past and that's why we'll do it this way in the future.

That's the precedent setting way to do things.

MR. HUMPHRIES: And if you want to stay up till Sunday morning at 2:00 -- or Monday morning at 2:00 o'clock, that's up to you.

MR. LEMAY: But Monday morning we'll have the exhibits from both sides be exchanged.

But we're going to do better than that, because right now we have our own witness, who's going to be exchanging exhibits with all of you today. So he's got -- at this point I'd like to introduce our expert witness, Bill Weiss, who is going to just tell you a little bit about what -- he's our guy this time and what he's come up with and what he's got in there for you.

Bill?

MR. WEISS: I think I know or have met most of you, but I do -- I work for the New Mexico Petroleum Recovery Research Center down in Socorro, and what I've done is collected all the data and compiled it; that was collected from June 30th through February 23rd of this year, and this is the static pressure data, the pressure build-up data, production data, that we've taken and Cliff Polston, who is a student down at Tech, -- incidentally, in two years if you guys want a PC expert to improve the efficiency of your operations, there's going to be a dandy -- but we've put all this together, and as I look through it, I drew some conclusions and I listed those conclusions.

So, Cliff, you can pass them out to the parties rather than everybody because I don't know if we have enough copies. There's a party back there, and here (unclear).

MR. LEMAY: Give some to the Commission now.

MR. WEISS: But at any rate, I did have a problem and I'd like your engineering folks to comment on it and one of them is -- is the tendency of the formation volume factor and an average viscosity and an average reservoir density, and these things are all dependent on pressure and the way I approached it was the volume weight, in other words, the gas base, if a well made so much gas and so much oil, I volume weighted those for reservoir conditions and then averaged, volume averaged the viscosity and formation volume factor.

So if you have comments along those lines I'd sure like to hear them earlier and how you propose it should be done and I'd be glad to -- to put them in the results. I need those comments fairly soon.

The static pressures are dependent on the reservoir density and the transients to build up pulse tests -- incidentally, there were some pulse tests submitted that were not required, and these are the frac tests that Al Greer and the responding pressure that was submitted in the other hearing.

So these are, depending on what you choose, the results (not clearly undertood) formation volume factor and the viscosity.

I might say as I went through this thing that it appeared to me that this reservoir -- this is a common pool. It's a common reservoir, and that it's very anisotropic, a lot of directional permeabilty. This has to enter into the thinking.

MR. LEMAY: Excuse me, Bill, could you sit in the witness chair then Sally can pick up what you're saying a little easier?

MR. WEISS: Sure. And that it does have to be included in the thinking of how -- what's done next, in my opinion, and then I -- and also I do an analogy to the Spraberry Trend Field in Texas, west Texas, which is quite similar to this -- to this Mancos, and you might look at it.

And of interest to all of you, the Sproberry has produced over a million barrels of oil to date, and back in '63 they predicted the primary would be about 250-million barrels.

And that's all I have to say.

If anybody needs a copy if you'd give us an address, a card or something we'll make some more up and mail them to you.

I would appreciate your comments concerning the data. The worksheets are in here. It will take some time. The rate sensitivity data is all in here. We've done the statistics on it. There's a lot of dope and if you look at the worksheets, particularly on the static pressures, you see you don't like something, I'd like to hear it pronto, as soon as possible, so then we're all talking from the same -- from the same level.

MR. LEMAY: Thank you, Bill. You're not up there for cross examination but just for distribution of some data, so you'll know what Bill's done to date.

We'll issue another statement. How about other -- other -- other parts of -- sorry, Mr. Roybal.

MR. ROYBAL: Mr. Chairman, one

more fairly minor procedural issue that's come up. We've had requests for what we've called technical conferences with Division and State Land Office staff, essentially the engineering staff, and we've talked amongst the lawyers and I think come up with a procedure that everyone finds agreeable and that is when that type of conference is requested, that the lawyer notify opposing counsel that that will occur. We'll try to make equal time available for staff -- of the staff if anyone else wants to do that, to have similar conferences and the discussion will be limited to what's the record, but the main thing would be that counsel would tell each other that they're having their -- they've both talked with -- with the engineering staff of the Division and with the State Land Office.

MR. LEMAY: Has that been agreed to by both sides?

MR. CARR: May it please the Commission, if Mr. Lopez' clients want to talk to Mr. Weiss or whoever, they don't have to notify me. I think time is too short. When we talked about that, you start thinking in the context of four weeks and the important of dialogue with Mr. Weiss, nobody has to tell me that they're talking to Mr. Weiss. If they want me to, I'll try to coordinate that for them, but I think that -- I think Sun is starting engineering committee work now. It's important to have some direct input with the people who are making some calls so that won't even be necessary as far as I'm concerned.

MR. LEMAY: Thank you, Mr. Carr. And Mr. Lopez.

MR. LOPEZ: And vice versa and I don't think (unclear) if they want to talk for sixteen hours and we only want to talk for half an hour, that's fine with me, as well. It's -- it's just a fact that I think would be helpful if our respective engineering witnesses or advisers would have a chance to talk to the Commission's advisers and (unclear) for their own benefit without the interference of lawyers, at least from our side. I don't care what the Commission wants to do on that.

MR. LEMAY: Good, let's even modify that proposal. That's a unanimous spirit of cooperation. Can we say that scientist can talk to scientist without lawyers present and not call this ex parte communication, because it's really an exchange of scientific ideas and data. It's not -- most engineers don't even know what ex parte means.

Good, we like that spirit of cooperation, at least at that level.

Anything else procedural, do you think?

MR. ROYBAL: No, Mr. Chairman.

MR. LEMAY: How about it, anything else from those present, of how we're going to conduct this case?

Okay, we'll issue a revised statement and we'll exchange exhibits Monday and we'll go from there.

I would like to request, I'm sorry, let's not go off the record yet, that one week prior -- we are going to use that June 7th date -- let's make it the 13th -- no, wait a minute, June 7th, that's a Tuesday, that both sides submit a summary of what they're going to present and distribute that to the other side and give us a copy of that at the Commission.

That I do want beforehand. Thank you.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR