CASE 7075: BENSON-MONTIN-GREER DRILLING Dg. Corp.
CORPORATION FOR AMENDMENT OF POOL RULES,
RIO ARRIBA COUNTY, NEW MEXICO

CASE NO.

7075

APPLICATION,

TRANSCRIPTS,

SMALL EXHIBITS,

ETC.

Telegram western union

WU AGENT SANA

305P

AYB250(1653)(1-015923I326)PD 11/21/80 1644

TWX SUPRON DAL DLY PD

01 DLY DALLAS, TX, 11-21-80

PMS DIRECTOR

NEW MEXICO OUL CONSERVATION DIVISION

310 OLD SANTA FE TRAIL

SANTA FE, NEW MEXICO 87501

RECEIVED
NOV 24 1980
OIL CONSERVATION DIVISION
SANTA FE

SUPRON ENERGY CORPORATION CONCURS WITH THE AMENDED APPLICATION OF BENSON-MONTIN-GREER DRILLING CORP. IN NMOCD CASE NO. 7075 SCHEDULED FOR HEARING ON NOVEMBER 24, 1980, FOR CERTAIN SPACING RULES AND REGULATIONS TO BE ADOPTED BY THE DIVISION IN THE WEST PUERTO CHIQUITO-MANCOS OIL POOL AND SUPPORTS THE PROPOSAL FOR LOCATION OF WELLS IN THE WEST HALF OF EACH SECTION.

SUPRON ENERGY CORPORATION

BLDG V, FIFTH FLOOR

10300 NORTH CENTRAL EXPRESSWAY

DALLAS, TX 75231

SUPRON ENERGY CORPORATION

TWX 9108619117 SUPRON DAL

NNNN

Mountain Fuel Supply Company
180 East First South
Salt Lake City, Utah 89139

Mountain Fuel Supply Company appreciates the opportunity to present to this Commission a brief statement concerning its position.

Mountain Fuel is familiar with the proceedings in this matter as well as the previous applications which have been filed with the Commission affecting the area in question. Specifically Mountain Fuel has reviewed the application now pending before the Commission and is familiar with its contents.

Mountain Fuel holds competitive Federal leases in the affected area. Mountain Fuel has entered into agreements with Cotton Petroleum Corporation and Koch Industries Inc., for the development of some of its leased properties. In the event the application is granted, Mountain Fuel's interests will be adversely affected, particularly if it forces Cotton and Koch into an uneconomic or ungeologic position. Further, in the event development in the area is further delayed by additional applications concerning well spacing, Mountain Fuel will not have sufficient time to develop its leases in an orderly fashion.

Mountain Fuel has reviewed and is familiar with the exhibits that Cotton and Koch propose to introduce into evidence in this proceeding and is also familiar with the positions those parties will be taking. Mountain Fuel fully supports the positions of Cotton and Koch in regard to the application now under consideration.

November 24, 1980

L. Craig Metcalf
Attorney for Mountain Fuel

Mountain Fuel Supply Company
180 East First South
Salt Lake City, Utah 89139

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November 24, 1980

L. Craig Metcalf

L. Craig Metcalf
Attorney for Mountain Fuel

Mountain Fuel Supply Company
180 East First South
Salt Lake City, Utah 89139

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November 24, 1980

L. Craig Metcalf

L. Craig Metcalf
Attorney for Mountain Fuel

Patrick Petroleum Corporation has reviewed the presentation of Koch Exploration Company and Cotton Petroleum and we concur with their presentations and urge the Commission to deny the application of Benson-Montin-Greer in Case 7505.

Paul Adam

FROM TELEX ..... 6161 ..... FROM TWX 910 420 1212

OR DIAL WESTERN UNION'S INFOMASTER SYSTEM DIRECTLY:

(EXCEPT IN NEW JERSEY 800-632-2271)

MCMCOMM MCM

DIAL (TOLL FREE) 800-257-2241

OR

1S06 EST

P.O. BOX 207
FARMINGTON NM 87401

OF YOUR TELEPHONE DIRECTORY

J. GREGORY MERRION AND ROBERT L BAYLESS
WELLS IN THE WEST HALF OF SECTIONS *
DRILLING CORPORATION IN CASE NUMBER 3676 INCLUDING LAY OF LOCATION OF
MERRION AND BAYLESS SUPPORT THE APPLICATION OF BRUCE MONTEY-GREEN
THIS IS A CONFIRMATION COPY OF A PREVIOUSLY PHONE-DELIVERED TELEGRAM
IN REPLY TO MARGINAL PHONE WESTERN UNION ANY MOMENT
THEIR OR ANY OTHER

NEW MEXICO OIL CONSERVATION DIVISION, ATTN
JOE RAMEY
SANTA FE, NM 87501

P.O. BOX 207
FARMINGTON NM 87401

J G MERRION
PO BOX 507
FARMINGTON NM 87401

RECEIVED
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OIL CONSERVATION DIVISION
SANTA FE

Western Union Mailgram

U.S. POSTAL SERVICE
U.S. MAIL

4-017796S329003 11/24/80 ICS IPMMTZZ CSP ABQC
2 5053255093 MGM TDMT FARMINGTON NM 11-24 1150A EST

NEW MEXICO OIL CONSERVATION DIVISION, ATTN
JOE RAMEY
MORGAN HALL
SANTA FE NM 87501

THIS IS A CONFIRMATION COPY OF A PREVIOUSLY PHONE-DELIVERED TELEGRAM

MERRION AND BAYLESS SUPPORT THE AMPLICATION OF BENSON MONTIN-GREER DRILLING CORPORATION IN CASE NUMBER 7075 INCLUDING THE LOCATION OF WELLS IN THE WEST HALF OF SECTIONS.
J GREGORY MERRION AND ROBERT L BAYLESS
PO BOX 507
FARMINGTON NM 87401

1206 EST

MGMCOMP MGM

5241 (R1/78)

TO REPLY BY MAILGRAM, SEE REVERSE SIDE FOR WESTERN UNION'S TOLL - FREE PHONE NUMBERS

Telegram western union Telegram western union Telegram western union

Memo

From

To Telegram -
Farmington
Copy.

Merrion & Bayless
support the
application
of Benson Montin -
Greer Drilling
Case No 7075
including location
of wells on
W/2 of Section.

Merrion & Robert
L. Bayless
P.O. 507 Farmington NM

Oil Conservation Santa Fe, New Mexico

Kellahin & Verity 1
BMG
Greer

Bufford & Carr Robt D Buettner
Koch 2

~~Mt. Fuel~~

Fedrick
Mt. Fuel

George Hunker - Fedrick Craig Metzler
Cotton Petr. 2
Mt. Fuel

R-6469 Dated Sept 10

Motion for dismissal under advisement

Incorporate Case No. 6997

Richard M Luce

John Carroway

Don Paul

Docket No. 37-80

Dockets Nos. 40-80 and 41-80 are tentatively set for December 10 and 30, 1980. Applications for hearing must be filed at least 22 days in advance of hearing date.

DOCKET: COMMISSION HEARING - TUESDAY - NOVEMBER 18, 1980

OIL CONSERVATION COMMISSION - 9 A.M. - ROOM 205
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

CASE 7088: Application of Southern Union Exploration Co. for reconsideration of Division Order No. R-6175, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks (a) that Order No. R-6175 be set aside, or (b) to except the E/2 of Section 32, Township 25 South, Range 24 East, Eddy County, New Mexico, from the terms of said order, or (c) clarify said order with respect to the E/2 of Section 32, Township 25 South, Range 24 East.

****

Docket No. 38-80

DOCKET: COMMISSION HEARING - MONDAY - NOVEMBER 24, 1980

OIL CONSERVATION COMMISSION - 9 A.M. - ROOM 205
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

CASE 7075: (Continued and Readvertised)

Application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks the amendment of the Special Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool as promulgated by Order No. R-2565-B and amended by Order No. R-6469, to require that wells completed or recompleted on standard units in said pool be located in the west half of the section at least 1650 feet from the outer boundary of the spacing and proration unit, and that the drilling of wells be controlled so as to allow no more than a 330-foot horizontal deviation from the surface location. Further, that the location of wells on certain specified non-standard proration units approved by Order No. R-6469 should be no closer than 660 feet to the outer boundary of the non-standard unit nor closer than 330 feet to a quarter section line or 10 feet to a quarter-quarter section line. Said specified non-standard units are the two 640-acre units in Township 24 North, Range 1 West; the two 480-acre units in Township 24 North, Range 1 East; the four 640-acre units in Township 26 North, Range 1 West; the 640-acre unit in Township 26 North, Range 1 East; and the two 640-acre units, the three 600-acre units, and the 400-acre unit, all in Township 27 North, Range 1 West. Applicant further seeks an administrative procedure whereby unorthodox locations could be approved upon receipt of written waivers from all offsetting operators being "crowded" by the unorthodox location.

****

Docket No. 39-80

DOCKET: EXAMINER HEARING - TUESDAY - NOVEMBER 25, 1980

9 A.M. - OIL CONSERVATION DIVISION CONFERENCE ROOM,
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

The following cases will be heard before Daniel S. Nutter, Examiner, or Richard L. Stamets, Alternate Examiner:

CASE 7055: (Continued from October 29, 1980, Examiner Hearing)

Application of Union Oil Company of California for a unit agreement, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the Eaves-Lea Unit Area, comprising 2209 acres, more or less, of State and Federal lands in Township 21 South, Ranges 32 and 33 East.

CASE 7077: (Continued from November 12, 1980, Examiner Hearing)

Application of Threshold Development Company for a dual completion, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for the dual completion of its Conoco "10" State Com Well No. 1 located in Unit I of Section 10, Township 19 South, Range 29 East, Turkey Track Field, to produce oil from the Wolfcamp formation and gas from the Atoka formation through parallel strings of tubing.

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
31 October 1980

COMMISSION HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico.

CASE 7075

BEFORE: Commissioner Joe Ramey

TRANSCRIPT OF HEARING

MR. RAMEY: The hearing will come to order.

We'll call at this time Case Number 7075.

MR. PEARCE: Application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico.

MR. RAMEY: This case will be continued to the Commission Hearing scheduled to be held at this same place and time on November 24th, 1980.

(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 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 C.S.R.

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 7075, heard by me on 10/29 1980.

, Examiner
Oil Conservation Division

SALLY W. BOYD, C.S.R.
Rt. 1 Box 193-B
Santa Fe, New Mexico 87501
Phone (505) 455-7409

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
31 October 1980

COMMISSION HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico.

CASE 7075

BEFORE: Commissioner Joe Ramey

TRANSCRIPT OF HEARING

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(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 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.

_____

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_____, Examiner
Oil Conservation Division

SALLY W. BOYD, C.S.R.
Rt. 1 Box 193-B
Santa Fe, New Mexico 87501
Phone (505) 455-7409

LAW OFFICES OF
HUNKER-FEDRIC, P.A.
GEORGE H. HUNKER, JR.
DON M. FEDRIC
2TH MIRAGE BUILDING
POST OFFICE BOX 1837
ROSWELL, NEW MEXICO 88201
TELEPHONE 622-2700
AREA CODE 505

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OIL CONSERVATION DIVISION
SANTA FE

November 3, 1980

Mr. Joe D. Ramey, Secretary-Director
New Mexico Oil Conservation Division
New Mexico Department of Energy
P.O. Box 2088
Santa Fe, New Mexico 87501

Re: B-M-G Application No. 7075
West Puerto Chiquito Mancos
Pool, Rio Arriba County,
New Mexico

Dear Mr. Ramey:

Please enter our appearance in the above-styled case on behalf of Cotton Petroleum Corporation. We would appreciate it if you would keep us advised as to any changes which are contemplated in connection with hearings which are scheduled before the Division. We are sending a copy of this letter to the attorney of record for B-M-G, Mr. Thomas Kellahin.

Thank you for your attention to this matter.

Sincerely yours,

HUNKER-FEDRIC, P.A.

George H. Hunker, Jr.

GHH:dd

xc: Mr. E. Russell Koeniger
Division Landman
Cotton Petroleum Corporation
717 - 17th St. Energy Center One, #2200
Denver, Colorado 80202

xc: Mr. W. Thomas Kellahin
Kellahin & Kellahin
P.O. Box 1769
Santa Fe, New Mexico 87501

STATE OF NEW MEXICO

DEPARTMENT OF ENERGY AND MINERALS

OIL CONSERVATION DIVISION

RECEIVED
OCT 31 1980
OIL CONSERVATION DIVISION
SANTA FE

IN THE MATTER OF THE APPLICATION OF BENSON-MONTIN-GREER DRILLING CORPORATION FOR AMENDMENT OF THE SPECIAL POOL RULES AND REGULATIONS FOR THE WEST PUERTO CHIQUITO-MANCOS OIL POOL, TO PROVIDE NEW WELL LOCATIONS RULES, RIO ARRIBA COUNTY, NEW MEXICO.

Case 7075

AMENDMENT TO APPLICATION

COMES NOW BENSON-MONTIN-GREER DRILLING CORPORATION and amends its application before the New Mexico Oil Conservation Division as follows:

1. Applicant has filed an Application before the New Mexico Oil Conservation Division docketed as Case 7075, said application is incorporated herein by reference.

2. In addition, to all matters raised and requested in the original application, applicant hereby amends said application to include a request that the well location rule for the subject pool also include a provision that any well on a standard spacing and proration unit be located in the West-Half of that Section.

3. As amended the well location rule requested would read:

> RULE 3. Each well completed or recompleted in the West Puerto Chiquito-Mancos Oil Pool shall be located in the West half of a Section, at least 1650 feet from the outer boundary of a standard spacing and proration unit, and that the well be controlled so as to allow no more than a 330 foot horizontal deviation from the surface location.

4. It is requested that the application as amended be readvertised and set for Commission hearing on November 24, 1980.

Respectfully submitted,

BENSON-MONTIN-GREER DRILLING CORPORATION

By _____
W. Thomas Kellahin
Kellahin & Kellahin
P.O. Box 1769
Santa Fe, New Mexico 87501

By _____
George L. Verity
Attorney at Law
501 N.W. 13th Street
Oklahoma City, Oklahoma 73103

BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
October 31, 1980

COMMISSION HEARING

IN THE MATTER OF: Application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico.	CASE 7075

BEFORE: Joe D. Ramey, Director

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the New Mexico Oil Conservation Commission: Ernest L. Padilla
Legal Counsel for the Commission
State Land Office Building
Santa Fe, New Mexico

MR. RAMEY: Call Case 7075.

MR. PADILLA: Case 7075, application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico. The applicant requests that this case be readvertised and continued to November 24, 1980.

MR. RAMEY: The case is hereby continued to November 24, 1980. The hearing is adjourned.

BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
October 31, 1980

COMMISSION HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico.

CASE 7075

BEFORE: Joe D. Ramey, Director

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the New Mexico Oil Conservation Commission: Ernest L. Padilla
Legal Counsel for the Commission
State Land Office Building
Santa Fe, New Mexico

MR. RAMEY: Call Case 7075.

MR. PADILLA: Case 7075, application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico. The applicant requests that this case be readvertised and continued to November 24, 1980.

MR. RAMEY: The case is hereby continued to November 24, 1980. The hearing is adjourned.

RECEIVED
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OIL CONSERVATION DIVISION
SANTA FE

Jason Kellahin
W. Thomas Kellahin
Karen Aubrey

KELLAHIN and KELLAHIN
Attorneys at Law
500 Don Gaspar Avenue
Post Office Box 1769
Santa Fe, New Mexico 87501

Telephone 982-4285
Area Code 505

October 28, 1980

File
Case 7075

Mr. Joe D. Ramey
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87501

RE: Benson-Montin-Greer Drilling Corporation
Oil Commission Case 7075

Dear Mr. Ramey:

This will confirm my conversation with you yesterday concerning the above referenced Commission case.

Mr. Greer desires to continue the above referenced case from October 31, 1980 to November 24, 1980 so that the application may be readvertised to include a provision that any well on a standard spacing and proration unit be located in the West-Half of that section. This will be in addition to those requested in the original application.

Please consider this letter as an Amend of our Application.

I have notified, by telegram, all interested parties of which I am aware, that the case has been continued to the new date and that the application has been amended.

Very truly yours,

W. Thomas Kellahin

WTK:jm

cc: Mr. Al Greer
Mr. George Verity

STATE OF NEW MEXICO

DEPARTMENT OF ENERGY AND MINERALS

OIL CONSERVATION DIVISION

RECEIVED
OCT 31 1980
OIL CONSERVATION DIVISION
SANTA FE

IN THE MATTER OF THE APPLICATION OF BENSON-MONTIN-GREER DRILLING CORPORATION FOR AMENDMENT OF THE SPECIAL POOL RULES AND REGULATIONS FOR THE WEST PUERTO CHIQUITO-MANCOS OIL POOL, TO PROVIDE NEW WELL LOCATIONS RULES, RIO ARRIBA COUNTY, NEW MEXICO.

Case 7075

AMENDMENT TO APPLICATION

COMES NOW BENSON-MONTIN-GREER DRILLING CORPORATION and amends its application before the New Mexico Oil Conservation Division as follows:

1. Applicant has filed an Application before the New Mexico Oil Conservation Division docketed as Case 7075, said application is incorporated herein by reference.

2. In addition, to all matters raised and requested in the original application, applicant hereby amends said application to include a request that the well location rule for the subject pool also include a provision that any well on a standard spacing and proration unit be located in the West-Half of that Section.

3. As amended the well location rule requested would read:

> RULE 3. Each well completed or recompleted in the West Puerto Chiquito-Mancos Oil Pool shall be located in the West half of a Section, at least 1650 feet from the outer boundary of a standard spacing and proration unit, and that the well be controlled so as to allow no more than a 330 foot horizontal deviation from the surface location.

4. It is requested that the application as amended be readvertised and set for Commission hearing on November 24, 1980.

Respectfully submitted,

BENSON-MONTIN-GREER DRILLING CORPORATION

By _____
W. Thomas Kellahin
Kellahin & Kellahin
P.O. Box 1769
Santa Fe, New Mexico 87501

By _____
George L. Verity
Attorney at Law
501 N.W. 13th Street
Oklahoma City, Oklahoma 73103

RECEIVED
OCT 31 1980
OIL CONSERVATION DIVISION
SANTA FE

STATE OF NEW MEXICO

DEPARTMENT OF ENERGY AND MINERALS

OIL CONSERVATION DIVISION

IN THE MATTER OF THE APPLICATION OF BENSON-MONTIN-GREER DRILLING CORPORATION FOR AMENDMENT OF THE SPECIAL POOL RULES AND REGULATIONS FOR THE WEST PUERTO CHIQUITO-MANCOS OIL POOL, TO PROVIDE NEW WELL LOCATIONS RULES, RIO ARRIBA COUNTY, NEW MEXICO.

Case 7075

AMENDMENT TO APPLICATION

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4. It is requested that the application as amended be readvertised and set for Commission hearing on November 24, 1980.

Respectfully submitted,

BENSON-MONTIN-GREER DRILLING CORPORATION

By _____
W. Thomas Kellahin
Kellahin & Kellahin
P.O. Box 1769
Santa Fe, New Mexico 87501

By _____
George L. Verity
Attorney at Law
501 N.W. 13th Street
Oklahoma City, Oklahoma 73103

STATE OF NEW MEXICO

DEPARTMENT OF ENERGY AND MINERALS

OIL CONSERVATION DIVISION

RECEIVED
OCT 10 1980
OIL CONSERVATION DIVISION
SANTA FE

IN THE MATTER OF THE APPLICATION OF BENSON-MONTIN-GREER DRILLING CORPORATION FOR AMENDMENT OF THE SPECIAL POOL RULES AND REGULATIONS FOR THE WEST PUERTO CHIQUITO-MANCOS OIL POOL, TO PROVIDE FOR WELL LOCATIONS WITHIN 660 FEET OF THE CENTER OF EACH SPACING AND PRORATION UNIT, RIO ARRIBA COUNTY, NEW MEXICO

APPLICATION FOR
COMMISSION HEARING

COMES NOW BENSON-MONTIN-GREER DRILLING CORPORATION, and applies to the New Mexico Oil Conservation Division for amendment to the Special Pool Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, to provide that the permitted well in each spacing and proration unit shall be located not closer than 1650 feet to the outer boundary of said unit, except as provided herein, and in support thereof would show:

1. That the Applicant, Benson-Montin-Greer Drilling Corporation is the owner of leases in the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, and is the operator of the voluntary Canada Ojitos Unit which covers most of such pool.

2. That heretofore the New Mexico Oil and Gas Conservation Commission, by Order No. R-2565-B, created the West Puerto Chiquito-Mancos Oil Pool consisting of the Niobrara member of the Mancos Formation covering the following described lands:

WEST PUERTO CHIQUITO-MANCOS OIL POOL:

RIO ARRIBA COUNTY, NEW MEXICO

Township 24 North, Range 1 East, NMPM
Sections 6, 7, 18, 19 and 30: All
Section 8: W/2
Section 17: W/2
Section 20: W/2

Township 24 North, Range 1 West, NMPM
Sections 1 through 36: All

Township 25 North, Range 1 East, NMPM
Sections 5 through 8 and
Sections 17 through 20, and
Sections 30 and 31: All
Section 29: W/2

Township 25 North, Range 1 West, NMPM
Sections 1 through 36: All

Township 26 North, Range 1 East, NMPM
Section 19: All
Section 20: W/2
Sections 29 through 32: All

Township 26 North, Range 1 West, NMPM
Sections 1 through 36: All

Township 27 North, Range 1 West, NMPM
Section 1: W/2
Sections 2 through 11: All
Section 12: W/2
Section 13: W/2
Sections 14 through 23: All
Section 24: W/2
Section 25: W/2
Sections 26 through 30: All

3. That said Order, as last amended by Order No. R-6469, promulgated rules for the orderly development of the pool and provided in Rule No. 3 of Order No. R-6469 for the location of the permitted well within each spacing and proration unit as follows:

> "RULE 3. Each well completed or recompleted in the West Puerto Chiquito-Mancos Oil Pool shall be located no nearer than 660 feet to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet to a quarter-quarter section line; provided, however, that nothing contained herein shall be construed as permitting the drilling of more than one well on a spacing or proration unit."

4. That Rule 3 as presently constituted permits too wide a latitude of drilling within each spacing and proration unit

which is contrary to the general philosphy of spacing in New Mexico which requires 640 acre unit wells to be located not closer than 1650 feet from the unit boundary. That the wide latitude of such rule infringes upon the correlative rights of various producers and owners in the field will cause the drilling of unnecessary wells and such rule should be amended to require that the permitted well for each spacing and proration unit should be located not closer than 1650 feet to the outer boundary thereof and that the bottom of such hole should not be permitted to deviate toward the exterior of the unit more than 330 feet from the surface location of such well.

5. That for the following non-standard proration units previously approved by Division Order R-6469, the well location for each said non-standard proration unit shall be no nearer than 660 to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet of a quarter-quarter section line; provided, however, that nothing contained herein shall be construed as permitting the drilling of more than one well on a spacing or proration unit, to-wit:

Township 24 North, Range 1 West, NMPM

1) a 640 acre unit comprising Section 23: N/2 and Section 24: N/2

2) a 640 acre unit comprising Section 23: S/2 and Section 24: S/2

Township 24 North, Range 1 East, NMPM

1) a 480 acre unit comprising Section 19: N/2 and Section 20 NW/4

2) a 480 acre unit comprising Section 19: S/2 and Section 20: SW/4

Township 26 North, Range 1 West, NMPM

a 640-acre unit comprising	Section 5:	W/2
	Section 8:	W/2;
a 640-acre unit comprising	Section 5:	E/2
	Section 8:	E/2;
a 640-acre unit comprising	Section 17:	W/2
	Section 20:	W/2;
a 640-acre unit comprising	Section 17:	E/2
	Section 20:	E/2;

Township 26 North, Range 1 East, NMPM

a 640-acre unit comprising	Section 19:	E/2
	Section 20:	W/2;

Township 27 North, Range 1 West, NMPM

a 640-acre unit comprising	Section 1:	W/2
	Section 12:	W/2;
a 640-acre unit comprising	Section 13:	W/2
	Section 24:	W/2;
a 600-acre unit comprising	Section 25:	W/2
	Section 26:	All;
a 600-acre unit comprising	Section 27:	All
	Section 28:	E/2;
a 600-acre unit comprising	Section 28:	W/2
	Section 29:	All;
and a 400-acre unit comprising	Section 30:	All.

6. That amending such rule will prevent waste and prevent the drilling of unnecessary wells and provide for the orderly development of said pool. That it is necessary to protect the correlative rights of all parties having the right to produce hydrocarbons from such pool.

7. That if exceptions to the permitted well location are necessary under the amended rule, the Division should be permitted to administratively approve an exception without notice and hearing, provided the operator applying therefor has written approval of the proposed change in location from all operators toward whose units the excepted well is to be moved.

WHEREFORE, Applicant prays that this application be set for hearing before the Commission and that after notice and hearing as provided by law, the Commission issue an Order amending Rule 3 of Order No. R-6469 to provide that the permitted well in each spacing and proration unit shall be located not closer than 1650 feet to the outer boundary thereof and that the bottom of such hole should not be permitted to deviate toward the exterior of the unit more than 330 feet from the surface location of such well; for well locations for certain non-standard proration units set forth above; for an administrative procedure to approve without hearing those cases where the adjacent unit operators toward which any such well is being moved have given written approval of the move, and further granting Applicant such other and further relief which it might be justly entitled to receive.

Respectfully submitted,

BENSON-MONTIN-GREER DRILLING CORPORATION

By _____

W. Thomas Kellahin
Kellahin & Kellahin
P.O. Box 1769
Santa Fe, New Mexico 87501

By _____

George L. Verity
Attorney at Law
501 N.W. 13th Street
Oklahoma City, Oklahoma 73103

RECEIVED
OCT 14 1980
OIL CONSERVATION DIVISION
SANTA FE

KELLAHIN and KELLAHIN
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Post Office Box 1769
Santa Fe, New Mexico 87501

Jason Kellahin
W. Thomas Kellahin

Karen Aubrey

Telephone 982-4285
Area Code 505

October 10, 1980

Mr. Joe Ramey
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87501

Re: Benson-Montin-Greer Drilling Corporation
Application for Commission Hearing to amend
well locations for the West Puerto Chiquito-
Mancos Oil Pool, Rio Arriba County, New Mexico

Dear Mr. Ramey:

I am notifying all the parties listed on the attached mailing list of the above referenced application which has been set for a Commission Hearing in the Commission Office, Santa Fe, New Mexico on October 31, 1980, at 9:00 A.M.

In addition, I have enclosed a copy of the application for hearing and a copy of the Commission's advertisement to all parties by certified mail, return receipt requested.

Very truly yours,

W. Thomas Kellahin

WTK:jm

cc: (see attachment)

Reading & Bates Petroleum
1125 17th Street
2300 Denver National Bank Bldg.
Attn: W. E. Millikan

Mountain Fuel Supply Co.
P.O. Box 11368
Salt Lake City, Utah 84139
Attn: R. E. Pittam

M. J. Harvey
P.O. Box 860
Dallas, Texas 75205

Sun Gas Company
Unitization & Joint Operations
Box 20
Dallas, Texas 75221
Attn: Ed Stein

Albert J. Blair
Mountain States Natural Gas
P.O. Box 35426
Tulsa, Oklahoma 74135

Cotton Petroleum Corp.
Suite 2200
717 17th Street
Denver, Colorado 80202
Attn: Doug Wood

Supron Energy Corporation
Building 5, Fifth Floor
10300 N. Central Expressway
Dallas, Texas 75321
Attn: A. M. Weiderkehr

Southland Royalty Company
410 17th Street
Suite 2000
Denver, Colorado 80202
Attn: Roy Williams

Southland Royalty Company
Box 570
Farmington, New Mexico 87401
Attn: L.O. Van Ryan

Mr. Merl C. Chambers
410 17th Street
Suite 1130
Denver, Colorado 80202

Merrion & Bayless
P.O. Box 507
Farmington, New Mexico 87401

Patrick Petroleum Company
1655 Colorado National Bank
950 17th Street
Denver, Colorado 80265
Attn: Paul W. Fairchild

Jerome P. McHugh
Suite 1225
600 South Cherry
Denver, Colorado 80222

Dugan Production Company
P.O. Box 208
Farmington, New Mexico 87401

Northwest Exploration Co.
1 Park Central
Suite 1487
Denver, Colorado 80202
Attn: Ms. Betty Burnett

Northwest Pipeline Corp.
Box 1526
Salt Lake City, Utah 84110
Attn: K. J. Stracke

Barrett Pierce
1008 Bonfield Building
Amarillo, Texas 79101

Koch Exploration Inc.
P.O. Box 2256
Wichita, Kansas 67201
Attn: R. J. Walton

Koch Exploration Inc.
1 Park Central
Suite 530
1515 Arapahoe
Denver, Colorado 80202
Attn: C. B. McCormick

A. J. Hill
2500 First National Bank Bldg.
Dallas, Texas 75202
Attn: Patrick Shaw

Kenai Oil & Gas Inc.
717 17th Street
Suite 2000
Denver, Colorado 80202

Resources Investment Corp.
Suite 3500
555 17th Street
Denver, Colorado 80202

Shar-Alan Oil Company
4101 East Louisiana
Denver, Colorado 80222

M. Thomas H. Harrington
P.O. Box 4026
Albququerque, New Mexico 87106

Lynco Oil Corporation
5290 DTC Parkway
Englewood, Colorado 80111

Mobil Oil Corp.
Box 5444
Denver, Colorado 80217

A. G. Hill
P.O. Box 1919
Abilene, Texas 79604
Attn: L. A. Gilles

Monsanto
1300 Post Oak Tower
5051 Westheimer
Houston, Texas 77056

Oscar Abraham
224 First National Bank Bldg.
Albuquerque, New Mexico 87106

E. L. Fundingsland, Jr.
5602 Cedarwood Street
Farmington, New Mexico 87401

John R. Anderson
Can-Lu Apartments
Box 37
12101 Lomas N.E.
Albuquerque, New Mexico 87112

Paul E. Nation
1618 First National Bank Bldg. East
5301 Central N.E.
Albuquerque, New Mexico 87108

Tom Bolack
Route 3 Box 47
Farmington, New Mexico 87401

The Carpenter Corp.
Box 608
Sour Lake, Texas 77659

Bill L. Harbert
Box 1297
Birmingham, Alabama 35201

Jack London, Jr.
101 Park Avenue
Suite 310
Oklahoma City, Oklahoma 73102

William V. Montin
1392 First National Center
Oklahoma City, Oklahoma 73102

Sun Gas Company
Unitization & Joint Operations
Box 20
Dallas, Texas 75221

Sun Gas Company
2525 N.W. Expressway
Oklahoma City, Oklahoma 73112

Mrs. Jesse Stanley
1702 Chaco
Farmington, New Mexico 87401

Conservation Manager
U.S. Department of Interior
Geological Survey
P.O. Box 26124
Albuquerque, New Mexico 87125

U.S. Geological Survey
P.O. Box 959
Farmington, New Mexico 87401
Attn: Jim Sims

Benson-Montin-Greer Drilling
221 Petroleum Center Bldg.
Farmington, New Mexico 87401

U.S. Geological Survey
Conservation Division
P.O. Box 26124
Albuquerque, New Mexico 87125
Attn: James Southerland

Frank Chavez
New Mexico Oil Conservation Div.
1000 Rio Brazos Rd.
Aztec, New Mexico 87410

George L. Verity
501 N.W. 13th Street
Oklahoma City, Oklahoma 73103

Examiner Hearing - Wednesday - October 29, 1980 Docket No. 34-80

CASE 7074: Application of Enserch Exploration, Inc. for pool creation, an unorthodox gas well location, and non-standard proration unit, Chaves County, New Mexico. Applicant, in the above-styled cause, seeks the creation of a new Fusselman gas pool for its J. G. O'Brien Well No. 2 located at an unorthodox location 660 feet from the South and West lines of Section 30, Township 7 South, Range 29 East, to be dedicated to a 308.96-acre non-standard unit comprising the W/2 of said Section 30.

CASE 6822: (Continued from October 1, 1980, Examiner Hearing)

In the matter of Case 6822 being reopened pursuant to the provisons of Order No. R-6293 which order created the West Double X-Wolfcamp Gas Pool as a retrograde gas condensate pool and set special production limitations therein. Operator(s) may appear and present evidence to establish the true nature of the reservoir and proper rates of withdrawal therefrom.

CASE 6648: (Continued from October 1, 1980, Examiner Hearing)

In the matter of Case 6648 being reopened pursuant to the provisions of Order No. R-6124 which order promulgated temporary special rules and regulations for the North Caprock-Mississippian Pool in Lea County, New Mexico, including a provision for 160-acre spacing and a 4000 to one gas-oil ratio limitation. Operators in said pool may appear and show cause why the pool should not be developed on 40-acre spacing with a 2000 to one GOR.

CASE 7045: (Continued from October 15, 1980, Examiner Hearing)

Application of Texas Oil & Gas Corp. for downhole commingling, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for the downhole commingling of Atoka and Upper Morrow production in the wellbore of its Superior Federal Com. Well No. 1 located in Unit G of Section 8, Township 20 South, Range 29 East.

CASE 7024: (Continued from October 15, 1980, Examiner Hearing)

Application of Southland Royalty Company for compulsory pooling, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Pennsylvanian formation underlying the E/2 of Section 35, Township 18 South, Range 29 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7038: (Continued from October 15, 1980, Examiner Hearing)

Application of Natura Energy Corporation for compulsory pooling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the San Andres formation underlying the NE/4 NE/4 of Section 6, Township 19 South, Range 39 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

****

Docket No. 35-80

DOCKET: COMMISSION HEARING - FRIDAY - OCTOBER 31, 1980

OIL CONSERVATION COMMISSION - 9 A.M. - ROOM 205
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

CASE 7075: Application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks the amendment of the Special Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool as promulgated by Order No. R-2565-B and amended by Order No. R-6469, to require that the locations of wells in said pool be at least 1650 feet from the outer boundary of the spacing and proration unit, and that the drilling of wells be controlled so as to allow no more than a 330-foot horizontal deviation from the surface location. Further, that the location of wells on certain specified non-standard proration units approved by Order No. R-6469 should be no closer than 660 feet to the outer boundary of the non-standard unit nor closer than 330 feet to a quarter section line or 10 feet to a quarter-quarter section line. Said specified non-standard units are the two 640-acre units in Township 24 North, Range 1 West; the two 480-acre units in Township 24 North, Range 1 East; the four 640-acre units in Township 26 North, Range 1 West; the 640-acre unit in Township 26 North, Range 1 East; and the two 640-acre units, the three 600-acre units, and the 400-acre unit, all in Township 27 North, Range 1 West. Applicant further seeks an administrative procedure whereby unorthodox locations could be approved upon receipt of written waivers from all offsetting operators being "crowded" by the unorthodox location.

STATE OF NEW MEXICO

DEPARTMENT OF ENERGY AND MINERALS

OIL CONSERVATION DIVISION

RECEIVED
OCT 10 1980
OIL CONSERVATION DIVISION
SANTA FE

IN THE MATTER OF THE APPLICATION OF BENSON-MONTIN-GREER DRILLING CORPORATION FOR AMENDMENT OF THE SPECIAL POOL RULES AND REGULATIONS FOR THE WEST PUERTO CHIQUITO-MANCOS OIL POOL, TO PROVIDE FOR WELL LOCATIONS WITHIN 660 FEET OF THE CENTER OF EACH SPACING AND PRORATION UNIT, RIO ARRIBA COUNTY, NEW MEXICO

APPLICATION FOR
COMMISSION HEARING

COMES NOW BENSON-MONTIN-GREER DRILLING CORPORATION, and applies to the New Mexico Oil Conservation Division for amendment to the Special Pool Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, to provide that the permitted well in each spacing and proration unit shall be located not closer than 1650 feet to the outer boundary of said unit, except as provided herein, and in support thereof would show:

1. That the Applicant, Benson-Montin-Greer Drilling Corporation is the owner of leases in the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, and is the operator of the voluntary Canada Ojitos Unit which covers most of such pool.

2. That heretofore the New Mexico Oil and Gas Conservation Commission, by Order No. R-2565-B, created the West Puerto Chiquito-Mancos Oil Pool consisting of the Niobrara member of the Mancos Formation covering the following described lands:

WEST PUERTO CHIQUITO-MANCOS OIL POOL:

RIO ARRIBA COUNTY, NEW MEXICO

Township 24 North, Range 1 East, NMPM
Sections 6, 7, 18, 19 and 30: All
Section 8: W/2
Section 17: W/2
Section 20: W/2

Township 24 North, Range 1 West, NMPM
Sections 1 through 36: All

Township 25 North, Range 1 East, NMPM
Sections 5 through 8 and
Sections 17 through 20, and
Sections 30 and 31: All
Section 29: W/2

Township 25 North, Range 1 West, NMPM
Sections 1 through 36: All

Township 26 North, Range 1 East, NMPM
Section 19: All
Section 20: W/2
Sections 29 through 32: All

Township 26 North, Range 1 West, NMPM
Sections 1 through 36: All

Township 27 North, Range 1 West, NMPM
Section 1: W/2
Sections 2 through 11: All
Section 12: W/2
Section 13: W/2
Sections 14 through 23: All
Section 24: W/2
Section 25: W/2
Sections 26 through 30: All

3. That said Order, as last amended by Order No. R-6469, promulgated rules for the orderly development of the pool and provided in Rule No. 3 of Order No. R-6469 for the location of the permitted well within each spacing and proration unit as follows:

> "RULE 3. Each well completed or recompleted in the West Puerto Chiquito-Mancos Oil Pool shall be located no nearer than 660 feet to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet to a quarter-quarter section line; provided, however, that nothing contained herein shall be construed as permitting the drilling of more than one well on a spacing or proration unit."

4. That Rule 3 as presently constituted permits too wide a latitude of drilling within each spacing and proration unit

which is contrary to the general philosphy of spacing in New Mexico which requires 640 acre unit wells to be located not closer than 1650 feet from the unit boundary. That the wide latitude of such rule infringes upon the correlative rights of various producers and owners in the field will cause the drilling of unnecessary wells and such rule should be amended to require that the permitted well for each spacing and proration unit should be located not closer than 1650 feet to the outer boundary thereof and that the bottom of such hole should not be permitted to deviate toward the exterior of the unit more than 330 feet from the surface location of such well.

5. That for the following non-standard proration units previously approved by Division Order R-6469, the well location for each said non-standard proration unit shall be no nearer than 660 to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet of a quarter-quarter section line; provided, however, that nothing contained herein shall be construed as permitting the drilling of more than one well on a spacing or proration unit, to-wit:

Township 24 North, Range 1 West, NMPM

1) a 640 acre unit comprising Section 23: N/2 and Section 24: N/2

2) a 640 acre unit comprising Section 23: S/2 and Section 24: S/2

Township 24 North, Range 1 East, NMPM

1) a 480 acre unit comprising Section 19: N/2 and Section 20 NW/4

2) a 480 acre unit comprising Section 19: S/2 and Section 20: SW/4

Township 26 North, Range 1 West, NMPM

a 640-acre unit comprising	Section 5:	W/2
	Section 8:	W/2;
a 640-acre unit comprising	Section 5:	E/2
	Section 8:	E/2;
a 640-acre unit comprising	Section 17:	W/2
	Section 20:	W/2;
a 640-acre unit comprising	Section 17:	E/2
	Section 20:	E/2;

Township 26 North, Range 1 East, NMPM

a 640-acre unit comprising	Section 19:	E/2
	Section 20:	W/2;

Township 27 North, Range 1 West, NMPM

a 640-acre unit comprising	Section 1:	W/2
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a 640-acre unit comprising	Section 13:	W/2
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	Section 26:	All;
a 600-acre unit comprising	Section 27:	All
	Section 28:	E/2;
a 600-acre unit comprising	Section 28:	W/2
	Section 29:	All;
and a 400-acre unit comprising	Section 30:	All.

6. That amending such rule will prevent waste and prevent the drilling of unnecessary wells and provide for the orderly development of said pool. That it is necessary to protect the correlative rights of all parties having the right to produce hydrocarbons from such pool.

7. That if exceptions to the permitted well location are necessary under the amended rule, the Division should be permitted to administratively approve an exception without notice and hearing, provided the operator applying therefor has written approval of the proposed change in location from all operators toward whose units the excepted well is to be moved.

WHEREFORE, Applicant prays that this application be set for hearing before the Commission and that after notice and hearing as provided by law, the Commission issue an Order amending Rule 3 of Order No. R-6469 to provide that the permitted well in each spacing and proration unit shall be located not closer than 1650 feet to the outer boundary thereof and that the bottom of such hole should not be permitted to deviate toward the exterior of the unit more than 330 feet from the surface location of such well; for well locations for certain non-standard proration units set forth above; for an administrative procedure to approve without hearing those cases where the adjacent unit operators toward which any such well is being moved have given written approval of the move, and further granting Applicant such other and further relief which it might be justly entitled to receive.

Respectfully submitted,

BENSON-MONTIN-GREER DRILLING CORPORATION

By _____
W. Thomas Kellahin
Kellahin & Kellahin
P.O. Box 1769
Santa Fe, New Mexico 87501

By _____
George L. Verity
Attorney at Law
501 N.W. 13th Street
Oklahoma City, Oklahoma 73103

STATE OF NEW MEXICO

DEPARTMENT OF ENERGY AND MINERALS

OIL CONSERVATION DIVISION

RECEIVED
OCT 10 1980
OIL CONSERVATION DIVISION
SANTA FE

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APPLICATION FOR
COMMISSION HEARING

COMES NOW BENSON-MONTIN-GREER DRILLING CORPORATION, and applies to the New Mexico Oil Conservation Division for amendment to the Special Pool Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, to provide that the permitted well in each spacing and proration unit shall be located not closer than 1650 feet to the outer boundary of said unit, except as provided herein, and in support thereof would show:

1. That the Applicant, Benson-Montin-Greer Drilling Corporation is the owner of leases in the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, and is the operator of the voluntary Canada Ojitos Unit which covers most of such pool.

2. That heretofore the New Mexico Oil and Gas Conservation Commission, by Order No. R-2565-B, created the West Puerto Chiquito-Mancos Oil Pool consisting of the Niobrara member of the Mancos Formation covering the following described lands:

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RIO ARRIBA COUNTY, NEW MEXICO

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4. That Rule 3 as presently constituted permits too wide a latitude of drilling within each spacing and proration unit

which is contrary to the general philosphy of spacing in New Mexico which requires 640 acre unit wells to be located not closer than 1650 feet from the unit boundary. That the wide latitude of such rule infringes upon the correlative rights of various producers and owners in the field will cause the drilling of unnecessary wells and such rule should be amended to require that the permitted well for each spacing and proration unit should be located not closer than 1650 feet to the outer boundary thereof and that the bottom of such hole should not be permitted to deviate toward the exterior of the unit more than 330 feet from the surface location of such well.

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6. That amending such rule will prevent waste and prevent the drilling of unnecessary wells and provide for the orderly development of said pool. That it is necessary to protect the correlative rights of all parties having the right to produce hydrocarbons from such pool.

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Respectfully submitted,

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By _____
W. Thomas Kellahin
Kellahin & Kellahin
P.O. Box 1769
Santa Fe, New Mexico 87501

By _____
George L. Verity
Attorney at Law
501 N.W. 13th Street
Oklahoma City, Oklahoma 73103

STATE OF NEW MEXICO

DEPARTMENT OF ENERGY AND MINERALS

OIL CONSERVATION DIVISION

IN THE MATTER OF THE APPLICATION OF)
BENSON-MONTIN-GREER DRILLING CORPORATION)
FOR AMENDMENT OF THE SPECIAL POOL RULES)
AND REGULATIONS FOR THE WEST PUERTO)
CHIQUITO-MANCOS OIL POOL, TO PROVIDE FOR)
WELL LOCATIONS WITHIN 660 FEET OF THE)
CENTER OF EACH SPACING AND PRORATION)
UNIT, RIO ARRIBA COUNTY, NEW MEXICO)

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Sections 5 through 8 and
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Section 20: W/2
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Township 26 North, Range 1 West, NMPM
Sections 1 through 36: All

Township 27 North, Range 1 West, NMPM
Section 1: W/2
Sections 2 through 11: All
Section 12: W/2
Section 13: W/2
Sections 14 through 23: All
Section 24: W/2
Section 25: W/2
Sections 26 through 30: All

3. That said Order, as last amended by Order No. R-6469, promulgated rules for the orderly development of the pool and provided in Rule No. 3 of Order No. R-6469 for the location of the permitted well within each spacing and proration unit as follows:

> "RULE 3. Each well completed or recompleted in the West Puerto Chiquito-Mancos Oil Pool shall be located no nearer than 660 feet to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet to a quarter-quarter section line; provided, however, that nothing contained herein shall be construed as permitting the drilling of more than one well on a spacing or proration unit."

4. That Rule 3 as presently constituted permits too wide a latitude of drilling within each spacing and proration unit

which is contrary to the general philosphy of spacing in New Mexico which requires 640 acre unit wells to be located not closer than 1650 feet from the unit boundary. That the wide latitude of such rule infringes upon the correlative rights of various producers and owners in the field will cause the drilling of unnecessary wells and such rule should be amended to require that the permitted well for each spacing and proration unit should be located not closer than 1650 feet to the outer boundary thereof and that the bottom of such hole should not be permitted to deviate toward the exterior of the unit more than 330 feet from the surface location of such well.

5. That for the following non-standard proration units previously approved by Division Order R-6469, the well location for each said non-standard proration unit shall be no nearer than 660 to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet of a quarter-quarter section line; provided, however, that nothing contained herein shall be construed as permitting the drilling of more than one well on a spacing or proration unit, to-wit:

Township 24 North, Range 1 West, NMPM

1) a 640 acre unit comprising Section 23: N/2 and Section 24: N/2

2) a 640 acre unit comprising Section 23: S/2 and Section 24: S/2

Township 24 North, Range 1 East, NMPM

1) a 480 acre unit comprising Section 19: N/2 and Section 20 NW/4

2) a 480 acre unit comprising Section 19: S/2 and Section 20: SW/4

Township 26 North, Range 1 West, NMPM

a 640-acre unit comprising	Section 5:	W/2
	Section 8:	W/2;
a 640-acre unit comprising	Section 5:	E/2
	Section 8:	E/2;
a 640-acre unit comprising	Section 17:	W/2
	Section 20:	W/2;
a 640-acre unit comprising	Section 17:	E/2
	Section 20:	E/2;

Township 26 North, Range 1 East, NMPM

a 640-acre unit comprising	Section 19:	E/2
	Section 20:	W/2;

Township 27 North, Range 1 West, NMPM

a 640-acre unit comprising	Section 1:	W/2
	Section 12:	W/2;
a 640-acre unit comprising	Section 13:	W/2
	Section 24:	W/2;
a 600-acre unit comprising	Section 25:	W/2
	Section 26:	All;
a 600-acre unit comprising	Section 27:	All
	Section 28:	E/2;
a 600-acre unit comprising	Section 28:	W/2
	Section 29:	All;
and a 400-acre unit comprising	Section 30:	All.

6. That amending such rule will prevent waste and prevent the drilling of unnecessary wells and provide for the orderly development of said pool. That it is necessary to protect the correlative rights of all parties having the right to produce hydrocarbons from such pool.

7. That if exceptions to the permitted well location are necessary under the amended rule, the Division should be permitted to administratively approve an exception without notice and hearing, provided the operator applying therefor has written approval of the proposed change in location from all operators toward whose units the excepted well is to be moved.

WHEREFORE, Applicant prays that this application be set for hearing before the Commission and that after notice and hearing as provided by law, the Commission issue an Order amending Rule 3 of Order No. R-6469 to provide that the permitted well in each spacing and proration unit shall be located not closer than 1650 feet to the outer boundary thereof and that the bottom of such hole should not be permitted to deviate toward the exterior of the unit more than 330 feet from the surface location of such well; for well locations for certain non-standard proration units set forth above, for an administrative procedure to approve without hearing those cases where the adjacent unit operators toward which any such well is being moved have given written approval of the move, and further granting Applicant such other and further relief which it might be justly entitled to receive.

Respectfully submitted,

BENSON-MONTIN-GREER DRILLING CORPORATION

By _____
W. Thomas Kellahin
Kellahin & Kellahin
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By _____
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Attorney at Law
501 N.W. 13th Street
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STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
COMMISSION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE NO. 7075

Order No. R-6469-A

APPLICATION OF BENSON-MONTIN-GREER DRILLING CORPORATION FOR THE AMENDMENT OF POOL RULES, RIO ARRIBA COUNTY, NEW MEXICO

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9 o'clock a.m. on November 24, 1980, at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this _____ day of _____, 19____, the Commission, a quorum being present, having considered the testimony presented and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That by its Order No. R-6469, entered in Case No. 6997 on September 10, 1980, the New Mexico Oil Conservation Division amended Rules 2, 3, and 5 of the Special Rules and Regulations governing the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, as promulgated by Order No. R-2565-B ~~as~~ and amended by Order No. R-2565-C, to provide, among other things, that each well completed or recompleted in said pool shall be located on a standard spacing or proration unit consisting of approximately 640 acres which shall comprise a single governmental section, and to further provide that each well completed or recompleted in said pool shall be located no nearer than 660 feet to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet to a quarter-quarter section line.

(3) That the applicant in said Case No. 6469, Benson-Montin-Greer Drilling Corporation, is also the applicant in the instant case, and in this case seeks the further amendment of the Special Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool to require that wells completed or recompleted on standard units in said pool be located in the west half of the section at least 1650 feet from the outer boundary of the spacing and proration unit, and that the drilling of wells be controlled so as to allow no more than a 330-foot horizontal deviation from the surface location. Further, to provide that the location of wells on certain specified non-standard proration units approved by Order No. 6469 would be no closer than 660 feet to the outer boundary of the non-standard unit nor closer than 330 feet to a quarter section line or 10 feet to a quarter-quarter section line.

Applicant further seeks an administrative procedure whereby unorthodox locations could be approved upon receipt of written waivers from all offsetting operators being "crowded" by the unorthodox location.

(4) That at the outset of the hearing of this case, protestants moved that the case be dismissed and said motion was taken under advisement.

(5) That the motion for dismissal should be denied and the application considered on its merit, based on the evidence presented at the hearing.

(6) That the applicant is the operator of the Canada Ojitos Unit Area, and as such has conducted and is conducting a pressure maintenance program in the West Puerto Chiquito-Mancos Oil Pool by the injection of gas into the Niobrara member of the Mancos ~~shell~~ shale up-structure on the eastern flank of the pool.

(7) That said gas injection is causing the oil in place to move down-dip where it is being produced from wells mainly in the western side of the unit.

(8) That the applicant carefully monitors the production from each well in the Canada Ojitos Unit Area, tracking the gas migration downstructure, and has consistently resorted to the shutting in of any well experiencing a substantial increase in gas-oil ratio, in order to help maintain reservoir pressure.

(9) That such practices have enabled the applicant to achieve remarkably flat production decline curves, and have permitted the production of quantities of oil from several of the unit wells far beyond original expectation, while maintaining pressure in the reservoir through the gas injection program.

(10) That the producing formation into which applicant injecting gas and from which it is producing oil may extend westward beyond the western boundary of the Canada Ojitos Unit.

(11) That the applicant, in seeking to require that wells completed or recompleted in the West Puerto Chiquito-Mancos Oil Pool be located only in the west half of the dedicated section, alleges that such displacement of wells to the west is necessary to prevent uncompensated for drainage of oil from the unitized lands of the Canada Ojitos Unit Area, thereby protecting correlative rights, and to prevent the dissipation of the reservoir pressure which has been built-up and maintained by gas injection, and the subsequent loss of oil production, thereby preventing waste.

(12) That the protestants in this case object to the proposed restrictions on well locations, claiming that there may be recoverable reserves in the Niobrara member of the Mancos shale which could not be produced, and that there may be other productive formations which could not be dually completed, if locations were restricted to the west half only of the section.

(13) That the protestants in this case should have the opportunity to develop the east half of the sections immediately west of the Canada Ojitos Unit, and to deny them such an opportunity would be unreasonable and could violate their correlative rights and cause waste.

(14) ~~(13)~~ That the applicant should be protected from having the Canada Ojitos Unit Area drained by wells immediately offsetting the unit boundary as such wells could violate its correlative rights and cause waste.

(16) That wells in the west Puerto Chiquito-Mancos Oil Pool completed or recompleted on spacing and proration units of approximately standard size (640 acres) should be located a reasonable distance from the outer boundary of such unit, and a minimum of 1650 feet is a reasonable distance which should afford adequate protection to all parties and prevent waste. That such wells should be located no nearer than 330 feet to a quarter section line.

(14) That the application to permit wells to be drilled in the subject pool in the W/2 only of the dedicated section should be denied.

(17) That due to the nature of the structure and formations in the subject area, there may be a strong tendency for wells, when being drilled, to drift in an easterly direction unless carefully controlled.

(18) That such drift, unless controlled, could result in the bottom hole location of wells in the subject pool being far to the east of the surface location.

(19) That in order to protect correlative rights and prevent waste, the drift of drilling wells should be monitored and the drilling controlled in such a manner that the bottom of the producing interval ~~hole location~~ in the well be not more than 330 feet from the surface location.

(20) That provision should be made for the reporting of the drift in wells drilled in the subject pool to the Division and to offset ~~xxxxx~~ operators, if any there be, and for the bringing of any well in violation of the 330-foot drift limitation to hearing, ~~unless such hearing is waived by all offset operators,~~ subject to a possible production penalty, if it appears that such well may impair correlative rights or cause waste, unless such hearing is ~~waived by all offset operators~~.

(21) That certain of the non-standard proration units approved for the subject pool by Order No. R-6469 are of such size and shape that the surface location requirement described in Finding No. (16) above cannot be practicably applicable, and exception should be granted for wells drilled on those units.

(22) That the locations of wells on said non-standard units should be no closer than 660 feet to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line nor ~~and no~~ closer than 10 feet to an interior quarter-quarter section line, and such wells should be subject to the drift limitations described in Finding Nos. (19) and (20) above.

(23) That Rule 2 of the West Puerto Chiquito-Mancos Oil Pool Special Rules and Regulations prohibits the establishment of non-standard proration units (less than 632 acres or more

than 648 acres) without notice and hearing.

(24) That an administrative procedure should be provided in said special rules whereby non-standard units necessitated by corrections in the lands surveys could be approved without such notice and hearing.

(25) That such an administrative procedure should be provided by the addition of Rule 2A to said pool rules, reading in its entirety as follows:

"RULE 2A. An exception to the provisions of Rule 2 may be obtained administratively for a non-standard unit comprising all of a single governmental section but comprising less than 632 acres or more than 648 acres resulting from a correction in the lands survey.

"To obtain such administrative approval, the applicant shall furnish the Division Director with appropriate plats and with the written consent of all operators owning lands offsetting the proration unit.

"In lieu of furnishing such consent, the applicant may furnish proof that all of the aforesaid operators were notified by registered or certified mail of his intent to form the non-standard unit. The Division Director may approve the application upon receipt of the aforementioned written consents, or if no offset operator ~~objects~~ has objected to the non-standard unit within 30 days after the Director received the application."

(26) That an administrative procedure should be adopted whereby any unorthodox location in exception to Findings Nos. (16) and (22) above could be approved without notice and hearing upon receipt of written waivers from all offsetting operators whose lands are being "crowded" by the proposed unorthodox location.

(2) That an order embodying the above findings is in the interest of conservation, will protect and not impair correlative rights, will prevent and not cause waste, and should be approved.

IT IS THEREFORE ORDERED:

(1) That the motion for dismissal of Case No. 7075 is denied.

(2) That the Special Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool, as heretofore promulgated by Order No. R-2565-B and amended by Orders Nos. R-2565-C and R-6469, are hereby further amended by the addition of Rule 2A, reading in its entirety as follows:

"RULE 2A. An exception to the provisions of Rule 2 may be obtained administratively for a non-standard unit comprising all of a single governmental section but comprising less than 632 acres or more than 648 acres resulting from a correction in the lands survey.

"To obtain such administrative approval, the applicant shall furnish the Division Director with appropriate plats and with the written consent of all operators owning lands offsetting the proration unit.

"In lieu of furnishing such consent, the applicant may furnish proof that all of the aforesaid operators were notified by registered or certified mail of his intent to form the non-standard unit. The Division Director may approve the application upon receipt of the aforementioned written consents, or if no offset operator ~~objects~~ has objected to the non-standard unit within

(2) That the application to permit wells to be drilled in the West Puerto Chiquito-Mancos Oil Pool in the W/2 only of the dedicated section is hereby denied

30 days after the Director received the application."

(4) That Rule 3 of the Special Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool, as promulgated by Order No. R-2565-B and as amended by Orders Nos. R-2565-C and R-6469 is hereby amended to read in its entirety as follows:

"RULE 3. (a) Each well completed or recompleted in the West Puerto Chiquito-Mancos Oil Pool shall be located no nearer than 1650 feet to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line, provided however, that nothing contained herein shall be construed as permitting the drilling of more than one well on a spacing or proration unit.

"(b) The operator of each well projected to and completed in the West Puerto Chiquito-Mancos Oil Pool shall conduct deviation tests on such well to determine the deviation from the vertical at least once each 500 feet or at the first bit change succeeding 500 feet. A tabulation of all deviation tests run, sworn to and notarized, shall be filed with Form C-104, Request for Allowable and Authorization to Transport Oil and Gas.

"(c) If the total deviation, assumed in a constant direction, indicates a horizontal displacement of the ~~uppermost~~ lowermost perforation, or the ~~casing shoe~~ bottom of the hole in the case of an open-hole completion, of more than 330 feet from the surface location, no allowable shall be approved for the well unless a directional survey approved by the Division Director establishes a horizontal displacement of 330 feet or less, or unless the well has been approved for production, subject to a possible production penalty, after notice and hearing.

"Offset operators to the east of any such well which has a total deviation of more than 330 feet may waive the aforesaid hearing requirement, in which case no penalty will be imposed on the well."

(5) That Rule 4 of the Special Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool, as promulgated by Order No. R-2565-B is hereby amended to read in its entirety as follows:

"RULE 4. The Division Director may grant an exception to the surface location requirements of Rule 3 (a) without notice and hearing when an application has been filed for an unorthodox location necessitated by topographical conditions or the recompletion of a well previously drilled to another horizon. All operators offsetting the proposed unorthodox location shall be notified of the application by registered or certified mail, and the application shall state that such notice has been furnished. The Division Director may approve the application upon receipt of written waivers of objection from all operators or if no objection is received from any offsetting operator within 20 days after receipt of the application and written waivers have been received from all offset operators whose lands are being "crowded" either directly or diagonally by the proposed unorthodox location."

(6) That the unit well for each of the non-standard proration units approved by Ordering Paragraph No. (3) of Division Order No. R-6469 shall be located no nearer than 660 feet to the outer boundary of its respective proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet to any quarter-quarter section line.

(7) That the deviation tests and well drift limits prescribed by Rules 3(b) and 3(c) of the West Puerto Chiquito-Mancos

Oil Pool in Ordering Paragraph (4) above shall be applicable to wells drilled on the aforesaid non-standard proration units.

(8) That the Special Rules and Regulations governing the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, promulgated by Order No. R-2565-B, as amended by Orders Nos. R-2565-C and R-6469, and as further amended by this order, are hereby continued in full force and effect until further order of the Division.

(9) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

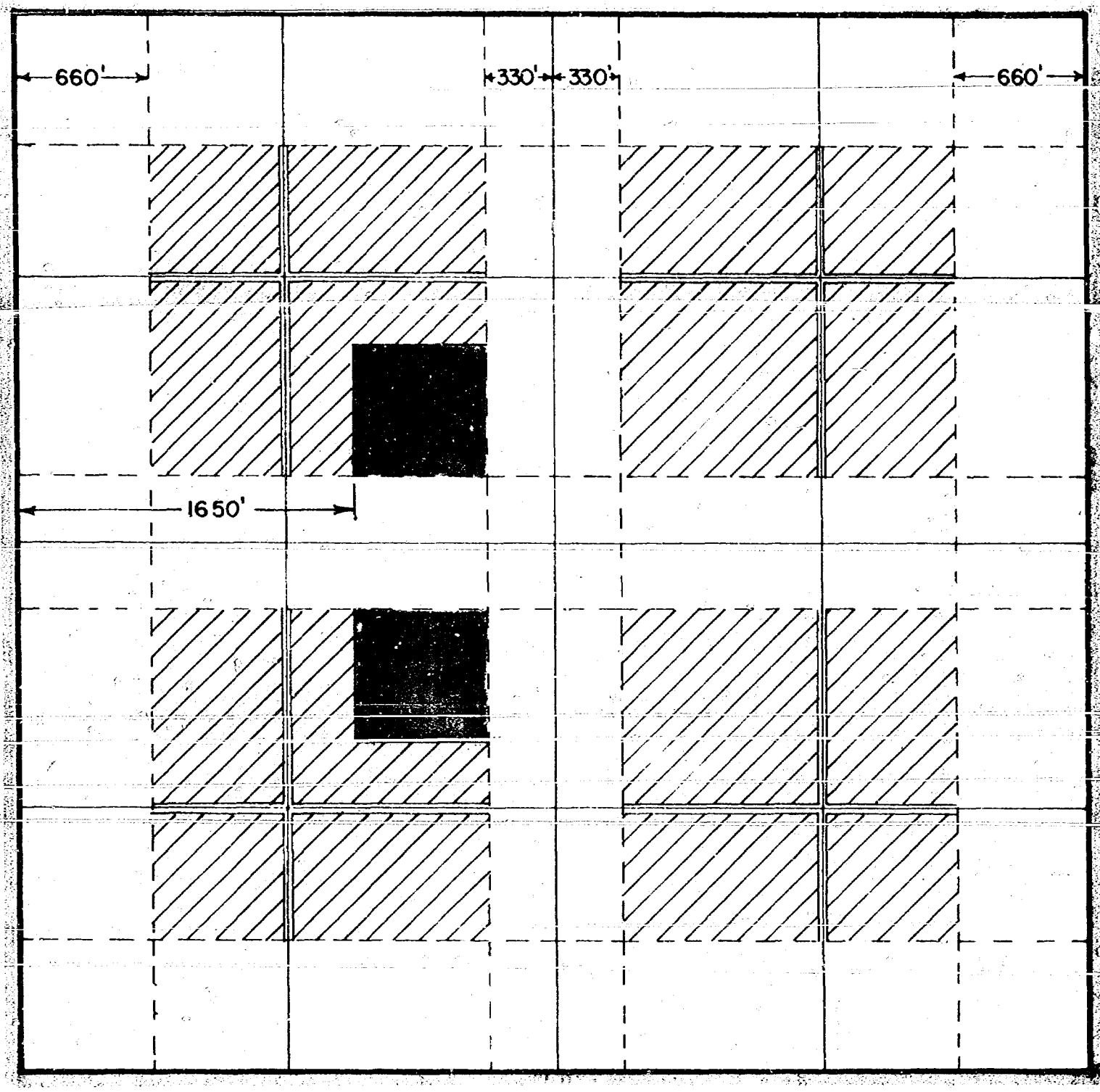
DONE at Santa Fe, New Mexico, on the day and year herein-above designated.

CURRENT RULES:

660' FROM SECTION LINE, 330' FROM QUARTER SECTION LINE, 10' FROM QUARTER-QUARTER SECTION LINE. ACREAGE DRILLABLE = 250 ACRES.

PROPOSED RULES:

1650' FROM SECTION LINE AND IN WEST HALF OF SECTION ONLY.
ACREAGE DRILLABLE = 20 ACRES.



STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
COMMISSION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE NO. 7075
Order No. R-6469-A

APPLICATION OF BENSON-MONTIN-GREER
DRILLING CORPORATION FOR THE AMENDMENT
OF POOL RULES, RIO ARRIBA COUNTY, NEW
MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9 a.m. on November 24, 1980, at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this 29th day of January, 1981, the Commission, a quorum being present, having considered the testimony presented and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That by its Order No. R-6469, entered in Case No. 6997 on September 10, 1980, the New Mexico Oil Conservation Division amended Rules 2, 3, and 5 of the Special Rules and Regulations governing the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, as promulgated by Order No. R-2565-B and amended by Order No. R-2565-C, to provide, among other things, that each well completed or recompleted in said pool shall be located on a standard spacing or proration unit consisting of approximately 640 acres which shall comprise a single governmental section, and to further provide that each well completed or recompleted in said pool shall be located no nearer than 660 feet to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet to a quarter-quarter section line.

(3) That the applicant in said Case No. 6469, Benson-Montin-Greer Drilling Corporation, is also the applicant in the instant case, and in this case seeks the further amendment of the Special Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool to require that wells completed or recompleted on standard units in said pool be located in the west half of the section at least 1650 feet from the outer boundary of the spacing and proration unit, and that the drilling of wells be controlled so as to allow no more than a 330-foot horizontal deviation from the surface location. Further, to provide that the location of wells on certain specified non-standard proration units approved by Order No. R-6469 would be no closer than 660 feet to the outer boundary of the non-standard unit nor closer than 330 feet to a quarter section line or 10 feet to a quarter-quarter section line. Applicant further seeks an administrative procedure whereby unorthodox locations could be approved upon receipt of written waivers from all offsetting operators being "crowded" by the unorthodox location.

(4) That at the outset of the hearing of this case, protestants moved that the case be dismissed and said motion was taken under advisement.

(5) That the motion for dismissal should be denied and the application considered on its merit, based on the evidence presented at the hearing.

(6) That the applicant is the operator of the Canada Ojitos Unit Area, and as such has conducted and is conducting a pressure maintenance program in the West Puerto Chiquito-Mancos Oil Pool by the injection of gas into the Niobrara member of the Mancos shale up-structure on the eastern flank of the pool.

(7) That said gas injection is causing the oil in place to move down-dip where it is being produced from wells mainly in the western side of the unit.

(8) That the applicant carefully monitors the production from each well in the Canada Ojitos Unit Area, tracking the gas migration downstructure, and has consistently resorted to the shutting in of any well experiencing a substantial increase in gas-oil ratio, in order to help maintain reservoir pressure.

(9) That such practices have enabled the applicant to achieve remarkably flat production decline curves, and have permitted the production of quantities of oil from several of the unit wells far beyond original expectation, while maintaining pressure in the reservoir through the gas injection program.

(10) That the producing formation into which applicant is injecting gas and from which it is producing oil may extend westward beyond the western boundary of the Canada Ojitos Unit.

(11) That the applicant, in seeking to require that wells completed or recompleted in the West Puerto Chiquito-Mancos Oil Pool be located only in the west half of the dedicated section, alleges that such displacement of wells to the west is necessary to prevent uncompensated-for drainage of oil from the unitized lands of the Canada Ojitos Unit Area, thereby protecting correlative rights, and to prevent the dissipation of the reservoir pressure which has been built-up and maintained by gas injection, and the subsequent loss of oil production, thereby preventing waste.

(12) That the protestants in this case object to the proposed restrictions on well locations, claiming that there may be recoverable reserves in the Niobrara member of the Mancos shale which could not be produced, and that there may be other productive formations which could not be dually completed, if locations were restricted to the west half only of the section.

(13) That the protestants in this case should have the opportunity to develop the east half of the sections immediately west of the Canada Ojitos Unit, and to deny them such an opportunity would be unreasonable and could violate their correlative rights and cause waste.

(14) That the application to permit wells to be drilled in the subject pool in the W/2 only of the dedicated section should be denied.

(15) That the applicant should be protected from having the Canada Ojitos Unit Area drained by wells immediately offsetting the unit boundary as such wells could violate its correlative rights and cause waste.

(16) That wells in the West Puerto Chiquito-Mancos Oil Pool completed or recompleted on spacing and proration units of approximately standard size (640 acres) should be located a reasonable distance from the outer boundary of such unit, and a minimum of 1650 feet is a reasonable distance which should afford adequate protection to all parties and prevent waste. That such wells should be located no nearer than 330 feet to a quarter section line.

(17) That due to the nature of the structure and formations in the subject area, there may be a strong tendency for wells, when being drilled, to drift in an easterly direction unless carefully controlled.

(18) That such drift, unless controlled, could result in the bottom hole location of wells in the subject pool being far to the east of the surface location.

(19) That in order to protect correlative rights and prevent waste, the drift of drilling wells should be monitored and the drilling controlled in such a manner that the bottom of the producing interval in the well be not more than 330 feet from the surface location.

(20) That provision should be made for the reporting of the drift in wells drilled in the subject pool to the Division and to offset operators, if any there be, and for the bringing of any well in violation of the 330-foot drift limitation to hearing, subject to a possible production penalty, if it appears that such well may impair correlative rights or cause waste, unless such hearing is waived by all offset operators.

(21) That certain of the non-standard proration units approved for the subject pool by Order No. R-6469 are of such size and shape that the surface location requirement described in Finding No. (16) above cannot be practicably applicable, and exception should be granted for wells drilled on those units.

(22) That the locations of wells on said non-standard units should be no closer than 660 feet to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet to an interior quarter-quarter section line, and such wells should be subject to the drift limitations described in Finding Nos. (19) and (20) above.

(23) That Rule 2 of the West Puerto Chiquito-Mancos Oil Pool Special Rules and Regulations prohibits the establishment of non-standard proration units (less then 632 acres or more than 648 acres) without notice and hearing.

(24) That an administrative procedure should be provided in said special rules whereby non-standard units necessitated by corrections in the lands surveys could be approved without such notice and hearing.

(25) That such an administrative procedure should be provided by the addition of Rule 2A to said pool rules, reading in its entirety as follows:

"RULE 2A. An exception to the provisions of Rule 2 may be obtained administratively for a non-standard unit comprising all of a single governmental section but comprising less than 632 acres or more than 648 acres resulting from a correction in the lands survey.

"To obtain such administrative approval, the applicant shall furnish the Division Director with appropriate plats and with the written consent of all operators owning lands offsetting the proration unit.

"In lieu of furnishing such consent, the applicant may furnish proof that all of the aforesaid operators were notified by registered or certified mail of his intent to form the non-standard unit. The Division Director may approve the application upon receipt of the aforementioned written consents, or if no offset operator has objected to the non-standard unit within 30 days after the Director received the application."

(26) That an administrative procedure should be adopted whereby any unorthodox location in exception to Findings Nos. (16) and (22) above could be approved without notice and hearing upon receipt of written waivers from all offsetting operators whose lands are being "crowded" by the proposed unorthodox location.

(27) That an order embodying the above findings is in the interest of conservation, will protect and not impair correlative rights, will prevent and not cause waste, and should be approved.

IT IS THEREFORE ORDERED:

(1) That the motion for dismissal of Case No. 7075 is denied.

(2) That the application to permit wells to be drilled in the West Puerto Chiquite-Mancos Oil Pool in the W/2 only of the dedicated section is hereby denied.

(3) That the Special Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool, as heretofore promulgated by Order No. R-2565-B and amended by Orders Nos. R-2565-C and

R-6469, are hereby further amended by the addition of Rule 2A, reading in its entirety as follows:

"RULE 2A. An exception to the provisions of Rule 2 may be obtained administratively for a non-standard unit comprising all of a single governmental section but comprising less than 632 acres or more than 648 acres resulting from a correction in the lands survey.

"To obtain such administrative approval, the applicant shall furnish the Division Director with appropriate plats and with the written consent of all operators owning lands offsetting the proration unit.

"In lieu of furnishing such consent, the applicant may furnish proof that all of the aforesaid operators were notified by registered or certified mail of his intent to form the non-standard unit. The Division Director may approve the application upon receipt of the aforementioned written consents, or if no offset operator has objected to the non-standard unit within 30 days after the Director received the application."

(4) That Rule 3 of the Special Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool, as promulgated by Order No. R-2565-B and as amended by Orders Nos. R-2565-C and R-6469 is hereby amended to read in its entirety as follows:

"RULE 3. (a) Each well completed or recompleted in the West Puerto Chiquito-Mancos Oil Pool shall be located no nearer than 1650 feet to the outer boundary of the proration unit nor closer than 330 feet to a quarter section line, provided however, that nothing contained herein shall be construed as permitting the drilling of more than one well on a spacing or proration unit.

"(b) The operator of each well projected to and completed in the West Puerto Chiquito-Mancos Oil Pool shall conduct deviation tests on such well to determine the deviation from the vertical at least once each 500 feet or at the first bit change succeeding 500 feet. A tabulation of all deviation tests run, sworn to and notarized, shall be filed with Form C-104, Request for Allowable and Authorization to Transport Oil and Gas.

"(c) If the total deviation, assumed in a constant direction, indicates a horizontal displacement of the lowermost perforation, or the bottom of the hole in the case of an open-hole completion, of more than 330 feet from the surface location, no allowable shall be approved for the well unless a directional survey approved by the Division Director establishes a horizontal displacement of 330 feet or less, or unless the well has been approved for production, subject to a possible production penalty, after notice and hearing.

"Offset operators to the east of any such well which has a total deviation of more than 330 feet may waive the aforesaid hearing requirement, in which case no penalty will be imposed on the well."

(5) That Rule 4 of the Special Rules and Regulations for the West Puerto Chiquito-Mancos Oil Pool, as promulgated by Order No. R-2565-B is hereby amended to read in its entirety as follows:

"RULE 4. The Division Director may grant an exception to the surface location requirements of Rule 3 (a) without notice and hearing when an application has been filed for an unorthodox location necessitated by topographical conditions or the recompletion of a well previously drilled to another horizon. All operators offsetting the proposed unorthodox location shall be notified of the application by registered or certified mail, and the application shall state that such notice has been furnished. The Division Director may approve the application upon receipt of written waivers of objection from all operators or if no objection is received from any offsetting operator within 20 days after receipt of the application and written waivers have been received from all offset operators whose lands are being "crowded" either directly or diagonally by the proposed unorthodox location."

(6) That the unit well for each of the non-standard proration units approved by Ordering Paragraph No. (3) of Division Order No. R-6469 shall be located no nearer than 660 feet to the outer boundary of its respective proration unit nor closer than 330 feet to a quarter section line nor closer than 10 feet to any quarter-quarter section line.

(7) That the deviation tests and well drift limits prescribed by Rules 3 (b) and 3 (c) of the West Puerto Chiquito-Mancos Oil Pool in Ordering Paragraph (4) above shall be

applicable to wells drilled on the aforesaid non-standard proration units.

(8) That the Special Rules and Regulations governing the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, promulgated by Order No. R-2565-B, as amended by Orders Nos. R-2565-C and R-6469, and as further amended by this order, are hereby continued in full force and effect until further order of the Commission.

(9) That jurisdiction of this cause is retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

ALEX J. ARMIJO, Member

EMERY C. ARNOLD, Member

JOE D. RAMEY, Member & Secretary

S E A L

fd/

CHRONOLOGY OF EVENTS LEADING TO APPROVAL OF FORM OF WEST CANADA OJITOS UNIT AGREEMENT AND DESIGNATION BY U.S.G.S. AS LOGICAL UNIT AREA

3- 5-80	Discuss with U.S.G.S. representatives issues of West Canada Ojitos Unit or Northwest Canada Ojitos Unit, with a second Southwest Canada Ojitos Unit. U.S.G.S. prefers one unit.
3-12-80	Obtained verbal approval from U.S.G.S. to eliminate DOE stipulation regarding competitive bidding.
3-12-80	Submitted proposed form of Unit Agreement to Oil Conservation Division of New Mexico Department of Energy and Minerals.
3-19-80	Meeting with Forest Service representatives in Albuquerque regarding tolling of time during winter weather.
3-20-80	Received Oil Conservation Division changes.
3-25-80	Submitted to U.S.G.S. form of agreement with Oil Conservation Division changes incorporated, to obtain approval of form.
3-26-80	Letter to Forest Service.
3-31-80	Another letter to Forest Service following discussion.
4-25-80	Forest Service advises working on proposal.
5- 1-80	Reading & Bates advised by phone of lack of manpower to pursue unitization. Benson-Montin-Greer agrees to assume Reading & Bates role.
5- 6-80	Meeting in field with Forest Service District Ranger. Ranger will add his recommendation.
5- 8-80	Filed application for designation of unit area with U.S.G.S.
5- 8-80	Filed copy of application for designation with Forest Service. Request Forest Service approval of special provision.
6-10-80	U.S.G.S. ready to approve designation. Waiting on Forest Service.
6-26-80	Joint meeting B-M-G, Forest Service and U.S.G.S. representatives in Albuquerque re "tolling of time" provision.
7- 7-80	District Ranger delayed because of forest fire. Sent recommendation to Santa Fe 7-7-80.

7-23-80	Field trip to Canada Ojitos Unit area with Ranger and five other Forest Service people. Appear to have the support of all for the proposal.
8- 1-80	First recommendation from Forest Service Santa Fe office to Albuquerque office not complete. Returned to be rewritten.
8-11-80	Santa Fe Forest Service office rewriting recommendation to Albuquerque office.
8-22-80	Forest Service approval mailed to U.S.G.S.
9- 8-80	Area designated by U.S.G.S. as logical unit area.

Sungas

RECEIVED
OCT 27 1980
OIL CONSERVATION DIVISION
SANTA FE

October 23, 1980

Oil Conservation Commission
P. O. Box 2088
Santa Fe, New Mexico 87501

Attention: Mr. Joe D. Ramey
Secretary-Director and Chief Administrative Officer

Re: Case No. 7075
Benson-Montin-Greer Drilling Corporation
Application to amend pool rules for the
West Puerto Chiquito-Mancos Oil Pool,
Rio Arriba County, New Mexico

Gentlemen:

Sun Oil Company, being an interest owner in the Canada Ojitos Unit, respectfully submits to the commission its notice of approval and support for Benson-Montin-Greer Drilling Corporation's application to amend the spacing provisions of the West Puerto Chiquito-Mancos Oil Pool, as promulgated by Order No. R-2565-B and amended by Order No. R-6469.

Sun is also in support of the adoption of an administrative procedure whereby unorthodox locations could be approved upon receipt of written waivers.

Yours very truly,

Charles Gray
Area Manager of Conservation

CG:lw

cc: Kellahin and Kellahin
500 Don Gaspar Ave.
P. O. Box 1769
Santa Fe, New Mexico 87501

Benson-Montin-Greer Drilling Corporation
221 Petroleum Center Building
Farmington, New Mexico 87401

CHRONOLOGY OF EVENTS LEADING TO APPROVAL OF FORM OF WEST CANADA OJITOS UNIT AGREEMENT AND DESIGNATION BY U.S.G.S. AS LOGICAL UNIT AREA

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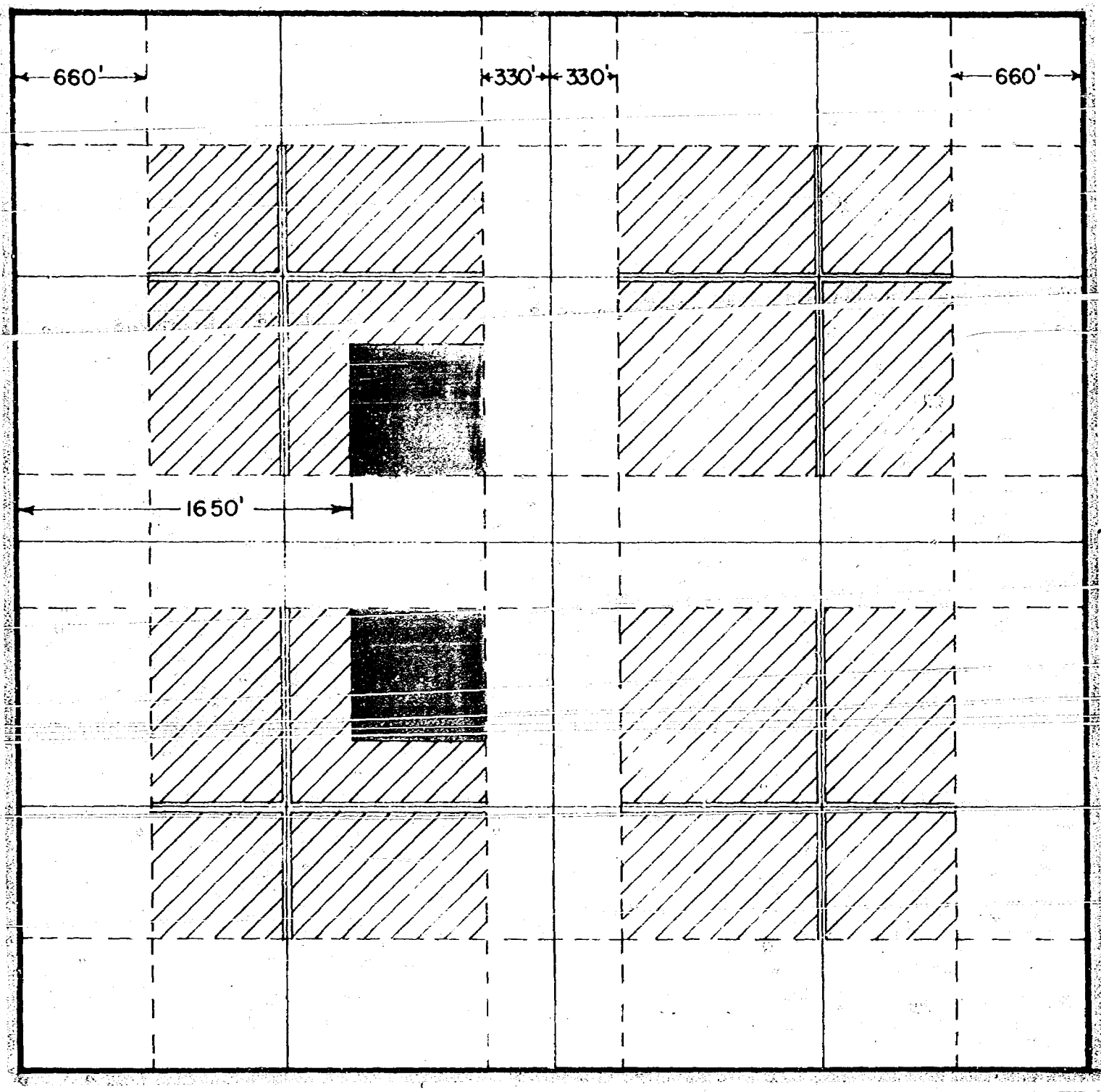
PROPOSED WEST CANADA OJITOS UNIT
CHRONOLOGY OF EVENTS

CURRENT RULES:

660' FROM SECTION LINE, 330' FROM QUARTER SECTION LINE, 10' FROM QUARTER-QUARTER SECTION LINE. ACREAGE DRILLABLE = 250 ACRES.

PROPOSED RULES:

1650' FROM SECTION LINE AND IN WEST HALF OF SECTION ONLY. ACREAGE DRILLABLE = 20 ACRES.



STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
6 August 1980

EXAMINER HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for amendment of pool rules, Rio Arriba County, New Mexico.

CASE 6997

BEFORE: Daniel S. Nutter
(On 7 August 1980)

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division: Ernest L. Padilla, Esq.
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant: George L. Verity, Esq.
BAY, HAMILTON, LEES, SPEARS & VERITY
501 Northwest Thirteenth
Oklahoma City, Oklahoma

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7075 Exhibit No. 4
Submitted by Koch
Hearing Date 11/24/80

SALLY W. BOYD, C.S.R.
Rt. 1 Box 193-B
Santa Fe, New Mexico 87501
Phone (505) 455-7409

and I want to say now, that I hope Your Honor will interrupt for questioning any time there's something that you don't quite understand or you would like to explore more fully, and as a matter of fact, I also would like to invite Mr. Friend, I believe it is, and Ms. Unshler, who are here from Koch and from USGS, to interrupt with questions as we proceed with this testimony, because I want everybody to understand it and I think that that would save time and be the best way to do it, Your Honor, and we invite that.

All right, Mr. Kellahin, now directing your attention to the second part of Section A of Exhibit One. Will you explain that exhibit to us?

A. Yes, sir. Here we'd like to go a little bit beyond, or outside the scope of engineering, perhaps, to talk a little bit about the reasons why this pool might be where it is, and some of the geological concepts as to why we find oil in these places, and as a result, then, where the probable boundaries of the pool, the reservoir, are, and then from that to draw some conclusions about the expansion of the area with additional development.

And I might say at the outset that just as all the engineering features have been interesting in this pool, one of the most interesting ones I've ever studied, so are some of the geological concepts.

The theory that I like best, the one to

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which I subscribe, as to why this oil reservoir exists where it is, has to do with the fracturing of the formation and creating of reservoir void space by fracturing, and this is brought about by flexing of the formation.

Since our 1969 hearing one of the geologists who work for us made a study based on the fracturing characteristics of dolomite and calcite and he came up with the theory that where you have a high percent of dolomite, that the formation is more brittle, more apt to fracture than if it's calcite, and he found a high percent of dolomite in wells in this area, and when we add those two things together, it makes sense to me.

Now there are some other theories, one of which we have the old "creekology" theory that, we've had some of the geologists come to us and say, well, we can trace the canyons here and where the good wells are and it's old "creekology", and of course, the answer to that is that where this pool lies in Santa Fe National Forest, a really beautiful forest, topography is rugged. Differences in elevation of 1000 or 1500 feet in just a short horizontal distance, the net result of it all being that from a standpoint of not destroying the forest, doing our best to operate here and to protect it, and also drill wells at minimum cost, we just keep them in the canyons where it's easy to get to them.

So that kind of answers the "creekology"

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theory, but pursuing the "creekology" theory, we've had some of the geologists that subscribe to the fault theory, that here are faults and where you have faults is where the production is, and they give us an east/west fault down through some of the better wells, and of course that sounded fine until we -- until we drilled a well 3 or 4 miles north of their fault system and got another good well, and then we drilled 3 or 4 miles south and we got another one, and then they have to go back to their areal photo maps and try to find some more lines they didn't see at first.

So the end result of all of it is that the one theory or concept that seems to best fit this reservoir is the one where the formation flexes, you have fracturing, and where you have fracturing you have, over a fairly wide area, reservoir with enough porosity and permeability to give production, allow production.

And when we ran an interference test that pretty well confirmed it, in that there's just no way that we have a high concentration of oil in any one area. It has to be small volume of oil per acre over a large area.

Briefly, the flexing features that we recognize here, first I might say that the boundaries of the pool on this map, the more or less north/south orange colored line is one that separates the East and West Puerto Chiquito Pools. The north boundary is the north part of the map. The

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west boundary of the pool is the west part of the map, and the south part of the pool is the south part of the map.

We can look about the center of the map on the east side near the C-5 injection well, and the color coding and symbols of these wells, the triangular ones are injection wells; the blue are wells -- are shut-in observation wells; those colored in red are the ones that are currently producing.

Near the C-5 Well in the blue shaded area is the first flex from the outcrop, and moving a couple miles to the east, the dashed line is the outcrop of the formation that produces here. And the dip of the formation from the outcrop into the blue shaded area runs from like 2 to 3000 feet per mile. It's a steep dip, fairly uniform dip, and in areas, not here, but on the west side of the basin, where we cored wells in this part of the formation, we'd always find a hard, tight, compact, no transmissibility.

MR. NUTTER: As I understand it, Mr. Green, now you've got 200 foot contours, right, like right there where the C-5 is?

A Right, and to the --

MR. NUTTER: And to the east those are all 1000 foot contours.

A Those are 1000 foot, right, and at that point at the blue coloring to the west, we start with 200 foot

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contours. And there in the blue shaded area in Section 5, why, instead of 2-to-3000 feet per mile, we're down to about 1000 feet per mile, so there's the first real flex.

Then the green shaded area, we're looking in round numbers at 4-to-500 feet per mile, so there's another flex.

Then in the brown shaded area we drop down to about 200 feet a mile.

And then when we get over into the gray shaded area, why, it's less than 200 feet a mile, maybe 100 feet a mile, and on farther west within the pool, we're looking then at a fairly flat dip of less than 100 feet per mile.

The best wells have been those right up and down the center in and near the brown and green shaded areas. To the north there's a deterioration of -- of the production, and the zones we can see a little bit on some of the cross sections we'll look at later, the four wells clustered at the end of the coloring, the brown coloring to the north of those four, two of the wells have capacities like 30 to maybe 50 barrels a day. Two of them have capacities less than 10 barrels a day.

Then on the very south part of the pool, in that blue shaded area, the contours spread again and we feel that not only is there a shallow dip there, that probably will be unproductive, but also this is sort of a re-

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entrance. We can see that the, moving from right to left across the blue colored area, you're just moving up a little valley, in a sense. Where we've had the same kind of a re-entrance in East Puerto Chiquito on the very north part of the pool, we've also had low capacity or nonproductive wells.

Now we don't know that the south part of the pool south of the unit will be nonproductive and we think it should not be taken out of the pool until somebody wants to drill a well there and determine for certain, but our feeling is it probably will not produce.

On the east boundary we believe we've pretty well defined that by the change in the flexing of the formation as it falls generally, that east side of the blue shaded area and our orange boundary between the two pools.

To the north, between the orange colored boundary and the green and blue shading, where we have no coloring at all, is an area of fairly uniform dip, and my feeling is that it probably will be a very low capacity wells, if any at all, in there, and the only value we can see of that probably would be for location of an injection well or two to take care of the wells in the proposed North Canada Ojitos Unit.

MR. NUTTER: Mr. Greer, is this change in dip and flexing evident from the surface or is it too mountainous to see it?

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A. It's pretty hard to see. Right at the outcrop you can get a good dip of the formation there.

MR. NUTTER: At that point.

A. At that point, and that then fits pretty well the subsurface control in that area. And from there on we're limited pretty much to the -- to the subsurface work.

Q. Mr. Greer, would you explain briefly for us the plan of your Canada Ojitos Unit?

A. Yes, sir. After we ran the interference test in 1965, and it confirmed some of our earlier suspicions, you might say, of the character of the formation, we concluded a couple of things.

One was that we had to have wide spacing. We had to have control rates of production in order to try to achieve gravity drainage efficiency, and this was an instance where pressure maintenance could have a most dramatic effect. Most pressure maintenance projects, we look at increases in production of something comparable to primary production. If, for instance, the primary production from a field is like a million barrels, why, in round numbers and rule of thumb, you ordinarily can say, well, by waterflooding we might get another million barrels, and by tertiary methods, perhaps, you can get up to that amount again.

But you're looking at only, ordinarily, something like doubling what you might otherwise get.

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RECD SEP 3 1980

BENSON-MONTIN-GREER DRILLING CORP.
221 PETROLEUM CENTER BUILDING
FARMINGTON, NEW MEXICO 87401
PHONE: 325-8874

August 28, 1980

Mr. Dick Bick
Koch Exploration Co.
P.O. Box 2256
Wichita, Kansas 67220

Re: PENDING DEVELOPMENT:
WEST CANADA OJITOS AREA,
RIO ARRIBA COUNTY, NEW MEXICO

Dear Mr. Bick:

We were disappointed to learn, when your Mr. Delvin Echard called earlier this month to inquire about drilling procedures in this area, that you were planning competitive drilling and were staking a location in the southeast quarter of Section 8, Township 25 North, Range 1 West. We have made a lot of progress in securing a satisfactory form of unit agreement for this area. Copy of our letter of August 28 to working interest owners in the area is enclosed for your information in this regard.

As you know, we attended a couple of meetings with your people earlier this year to discuss unitization, and although we acknowledge that there are problems in development under unitized operation, we also recognize the far more serious problems of development under competitive conditions. Both issues are covered in some detail in our letter of April 30 this year to our working interest owners, copy of which is also enclosed for your information.

Through our efforts we are developing a healthy economic climate for drilling in this area if it is unitized, and it can only be a shortsighted policy that refuses to recognize this. We urge that you review the consequences of competitive development and view with an open mind development under unitization.

Yours very truly,

BENSON-MONTIN-GREER DRILLING CORP.

BY: Albert R. Greer, President

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7025 Exhibit No. 5
Submitted by Koch
Hearing Date 11/24/80

ARG:ney

BENSON-MONTIN-GREER DRILLING CORP.
221 PETROLEUM CENTER BUILDING
FARMINGTON, NEW MEXICO 87401
PHONE: 325-8874

April 30, 1980

WORKING INTEREST OWNERS
CANADA OJITOS UNIT

RE: CONSIDERATION OF EXPLORATORY DRILLING ON LANDS ADJOINING WEST BOUNDARY OF CANADA OJITOS UNIT, RIO ARRIBA COUNTY, NEW MEXICO

We call to your attention that the Canada Ojitos Unit working interest owners jointly own oil and gas leases outside the unit area near its west boundary, and that four or five thousand acres of these leases will expire in the summer and fall of 1981 unless they are preserved by some type of development. We believe that drilling in this area will yield production only marginally profitable: even so, under the right conditions - particularly that of cooperative effort of lessees - it could be beneficial to all concerned to develop this area; and we ask that each working interest owner review this situation and advise if you would like to participate in the drilling of exploratory wells in this area - and under what conditions. We have some thoughts in this regard which we pass on to you now; and it may be that some of you will concur with the unit operator's assessment of the situation. But, concur or not, we would appreciate hearing from each of you as to ideas or suggestions as to any of the issues bearing on the prudent exploration and production of our jointly owned lands.

The area which we think should now be considered is the 1½ to 2 miles wide strip running north-south along the unit's west border (outlined on small scale plat enclosed). It is nearly all federal land, the surface of which is in the Santa Fe National Forest and under the jurisdiction of the U. S. Geological Survey, Bureau of Land Management and Forest Service. Some of the lands are open and some are leased (see large scale land plat enclosed).

Our feeling at this time is that if there is to be any drilling in this (west) area that in the interest of realizing maximum ultimate oil recovery from it as well as from presently producing (unitized) lands, that consideration should be given to the formation of a new unit comprising those lands immediately to the west of the present unit and the drilling of two or three exploratory wells in this new unit along the Canada Ojitos Unit west border. Failing to unitize all of these lands we would urge that we unitize the north part of the west area (in which all of our jointly owned lands lie) to avoid the problems of "competitive" drilling as discussed in attachments herein in some detail.

In the last two months we have discussed these - and other - plans for exploration with other affected lessees (in fact the

...

first of these meetings resulted from a proposal by Reading and Bates for a farmout of some of our lands); and although it is too early to expect firm commitments - since plans at this stage are still too nebulous - the owners of the larger tracts have expressed a willingness to consider some form of unitization and cooperative development.

Development of this area under either competitive or unitized conditions poses a number of problems; and at "first blush" they may seem too cumbersome to worry with, however a consideration of the alternatives leads one to the conclusion that, problems or not, drilling under a new "exploratory" unit is the best way to proceed. Descriptions of some of the issues are enclosed herein for your review, categorized by attachments as follows:

1. Economics of development of the new (west) area.

2. Economics of west unit dependent on existing Canada Ojitos Unit.

3. Main issues of development under a new unit and "cooperative plan" with existing unit.

4. Assurance of efficient depletion of the existing Canada Ojitos Unit Participating Area (presently developed) reservoir.

5. Orientation of spacing units.

Although the present lessees of lands adjoining the Canada Ojitos Unit to the west are cognizant of the hazards of overdrilling and need for cooperation and at this time we believe unitization may come about, it is not yet a fact. In the meantime there are open lands which may be acquired by not-so-knowledgeable "strangers" (and in view of the marginal appearing economics and other problems the possibility exists that some of the present lessees might even farmout their interests to other "strangers"); and should either of these things happen, then - despite present good intentions to consider unitization - it is possible that drilling under competitive conditions could result; and in view of this possibility we believe an effort should now be made to prevent "abuse" of the existing 320-acre well spacing order. To mitigate abuse of this order we propose to make application for orientation of spacing units within the next few weeks (item 5 above) unless we receive objection from working interest owners in the meantime. Absent objection we will undertake this as a unit effort. (Although the unit can be afforded "relief" to a certain extent from the problems caused by wells drilled offsetting the unit - see item 4 above - the greater the number of unnecessary wells the greater the problems and unpleasantness of the final results for both the present unit owners and the new drilling parties; and it is in everyone's interest to avoid such situations.)

...

As to timing of a development program, it is our thought that several months will be required to work out the unitization and cooperative agreements, with next winter being the earliest this could be accomplished; so next summer (1981) would be the earliest that drilling should be planned. We note here that a drilling and testing program running from July through October would preserve all of next year's otherwise expiring leases. There is still unresolved a problem with one of the companies which we hope can be addressed soon, in that they have indicated they didn't want to do "anything" until some of the remaining open lands had been leased. This, of course, is exactly "backwards" from what should be done: it is far better if the lands are unitized prior to the sale; so that we are assured the subject lands will be committed to the unit agreement regardless of the purchaser. Hopefully we can soon get this message across and be ready to commence working with these "outside" parties on the many issues as soon as we have response from the Canada Ojitos owners, inasmuch as we would like to have all of the owners of larger interests involved in the discussions from the beginning.

Since profitable development of the subject area west of the existing unit is dependent not only on the reservoir quality underlying these lands, but also on the production from, and reservoir control of, the existing unit (see item 2 above) the initial - and rather critical - decision which the unit owners now need make, is what ownership share of the west unit do we require to be persuaded to lend the existing unit's "good offices" and benefits to the new unit? We would appreciate your addressing this, along with the other issues and advising your thoughts and position.

In closing, we emphasize that we are not recommending the area as one in which we think can be developed oil reserves with desirable economics and at low risk: rather we think drilling here will be quite risky (of the westernmost unit wells only one - the L-27 in the north township - showed any oil production before frac treatment); and it's only that if commercial production rates should be established that we think it would be desirable for all concerned if the present unit owners were represented in the newly developed area.

Yours truly,

BENSON-MONTIN-GREER DRILLING CORP.

BY: Albert R. Greer, President

ARG/tlp

Attachments

ATTACHMENT NO. 1
ECONOMICS OF DEVELOPMENT OF THE NEW (WEST) AREA

These lands all lie within an area whose potential for production we classified ten to fifteen years ago as being marginal: productivities of the westernmost unit wells and our interpretation of the controlling geology indicated to us that it would be unusual if wells drilled on the subject lands showed initial productivities - after frac - greater than twenty to forty barrels per day, along with ultimate recoveries of 15,000 barrels per well on 320 acre spacing up to a probable maximum of 60,000 barrels per well for spacing of two sections per well.

Under the conditions of drilling costs and oil prices of ten years ago the resulting economics were just not interesting; and even two years ago when the price of oil had increased by three or four to one, the drilling costs had also escalated, so the economics were still unfavorable. Now, however, although the drilling costs are approximately three times what they were ten years ago, the price of oil - even after the windfall profits tax - is about ten times what it was then, so it now appears to us that there may be a possibility of drilling wells whose production will show a profit if the benefit of the pressure maintenance program is allowed to extend into this area. There is no way that this west area can, in itself, support a pressure maintenance program; but in conjunction with the existing project we can see some possibilities if the development and production are properly controlled.

The recovery figures of 15,000 barrels per 320 acre-spaced well derive from an estimate of a maximum of 1000 barrels per acre in place and a recovery factor of 5% of the oil in place. The 1000 barrels per acre results from "scaled down" maximum amounts of 2000 barrels per acre measured by interference tests for the area surrounding the higher capacity wells drilled in the best part of the reservoir. The 5% recovery factor comes from that calculated for solution gas drive performance of a fractured formation with reservoir oil characteristics of Canada Ojitos oil; and is further supported by the material balance calculations for the Gallegos Gallup pool - the one pool in the San Juan Basin whose characteristics are most nearly similar to that of the West Canada Ojitos Area.

Further regarding estimated oil recoveries from this area it should be noted that although the degree of fracturing - and resulting productivities - cannot be accurately forecast, the dip of the formation can: and it is too shallow to allow efficient gravity drainage depletion; so even if high capacity wells could be drilled in this area and the resulting oil in place figures were twice as high as herein estimated, the ultimate recoveries would still be limited to twice that shown above, or 30,000 barrels for a 320 acre spaced well - still not an attractive amount.

A significant income factor can be the value of the gas:

although the fraction of oil in place that can be produced will vary markedly with the effective depletion mechanism which reuslts, we would anticipate that under any method most of the gas will be produced. If there is as much as 1000 barrels per acre of oil in place there will be dissolved in it nearly 500 MCF, of which about 300 MCF should be recoverable, or about 200 MMCF per section.

The questionable feature about this potential value is how to save it - it would be very difficult under any situation other than unitization (see Attachment No. 2).

Well costs are estimated to be in the range of $700,000 to $1,000,000; the main variables being cost of frac treatment; whether drilled with mud, air and nitrogen or gas; and cost of oil and gas gathering lines. (These are also discussed further in Attachment No. 2).

ATTACHMENT NO. 2
ECONOMICS OF WEST UNIT DEPENDENT
ON EXISTING CANADA OJITOS UNIT

The west area's physical reservoir characteristics and geometry are such that it cannot support its own independent pressure maintenance program (either by gas or water); hence it is dependent on the main unit's reservoir and communication with it for any kind of depletion mechanism other than solution gas drive.

With well costs so high and solution gas drive recoveries so low, favorable economics, then, can come about for this west area only if benefit is derived from the existing unit's pressure maintenance program.

These thoughts are discussed below in a little more detail. First, in view of the flat dip and the probably low transmissibility it will be impossible to effectively conduct a pressure maintenance project on the lands themselves; so it follows that if updip migration from the presently unitized lands be cut off, the west area is doomed to solution gas drive recovery.

Even so, wells drilled in this area could serve a useful purpose if there be a cooperative plan with the main unit and if the existing unit's pressure maintenance benefits be allowed to expand to this west area. For example, a row of wells just west of the existing unit's boundary could increase the share of the reservoir oil subject to gravity drainage depletion (good recovery efficiency) in the area a mile or so inside the present unit's west boundary which lies structurally below the present high capacity wells; for oil in this area can be recovered by existing wells only by updip flow (solution gas drive depletion - poor recovery efficiency).

Most of this additional recovery, of course, will be produced through the wells outside the present unit; however if there is a cooperative agreement between the west and east units as to support of the pressure maintenance program, it is conceivable that pressure maintenance could be continued for a longer time prior to "blow down", with resulting increased recovery to the existing unit and its royalty and working interest owners. The working interest owners within the present unit, for their own "insurance" that they do indeed benefit from wells drilled outside this unit, will undoubtedly want some participation in the wells outside of it; and since the working interest owners bear a larger share of the risk than the royalty owners it would seem that such "insurance" is appropriate.

All of the foregoing favorable economic factors however are dependent on the existing unit's continuing the pressure maintenance program and (necessarily) the willingness of the owners of this unit to cooperate with such a plan, for without it the economics of the west area must be poor indeed: not only will oil recoveries be

low, but the problems of marketing this oil and gas are such that marketing costs of oil would be high and those for gas so formidable that the gas might not be saved. The marketing problems are briefly described below.

Because of the terrain and climate conditions - the subject properties lie in a mountainous area along the continental divide - there are times during the winter and spring that moving oil by truck is expensive, if not practically impossible. Oil marketing by pipeline is highly desirable, but probably cannot be achieved except through cooperation and use of the existing unit's gathering system. The terrain just does not lend itself to an oil gathering system located only on the (proposed) new unit's lands. Lost production due to inability to move oil could "make the difference" in whether profitable production would be realized.

As to gas, the problem is to have available gas production rates justifying all the costs of marketing early enough in the producing life that marketing will be undertaken. Initial volumes for 20 to 40 BOPD wells would probably be in the range of 7 to 15 MCFD; and by the time the rates will have increased to the point that marketing costs are warranted, a large part of the reserve will have been lost.

Some of these problems are:

1. Most of the wells will be east of the continental divide;

2. The existing gas pipelines are mostly west of the continental divide;

3. The volumes will not warrant the purchaser's laying the connecting lines; and

4. Even after gathering lines are laid there is the problem of compressing this gas to get it into the pipeline.

All of the above are obstacles difficult enough under any circumstances to overcome; but under competitive conditions they would be practically impossible. However, if unitized and under a cooperative agreement with the existing unit, the present gas lift and gas gathering lines could be extended; the gas lift (input gas) line could first have been used for drilling gas - and with duplicate use of this line (assuming production is obtained), and all of the lines then being buried at one time in one ditch, the marketing costs begin to be more reasonable. The oil would have a dependable market and the unused gas would be "stored" in the gas cap to be marketed at a time when (hopefully) there would be a minimum of price restrictions.

ATTACHMENT NO. 3
MAIN ISSUES OF DEVELOPMENT UNDER A NEW UNIT &
"COOPERATIVE PLAN" WITH EXISTING UNIT

From the standpoint of proper location of new wells and reservoir control the simplest development procedure would be to expand the present unit prior to drilling; and if commercial production results to bring the productive lands into participation and conduct the operations under one participating area. However, oil price controls and the recently passed windfall profits tax both make this course unattractive; and since drilling under competitive conditions cannot be profitable (not unusual for this formation), we suggest a new unit.

Probably one of the more difficult issues to resolve will be the share of participation in the west area that should be owned by the present Canada Ojitos Unit Participating Area working interest owners. Just what this participation should be as well as the other terms of a cooperative agreement between the two units will of course be subjects of prime concern, study and negotiation; and although at times they may seem too difficult to solve, one need only look to the alternatives to conclude that a determined effort to do so must be made.

We recommend that efforts be directed first toward formation of a single unit comprising all of the subject lands west of the present unit; but failing that to form a unit covering the north part of the area in which lie all of the lands of the present Canada Ojitos Unit Participating Area working interest owners.

For either of the above units a fundamental feature would be a cooperative agreement with the present unit with provisions as described later herein. First, it might be well to note some of the problems we would anticipate for unitization without a cooperative agreement. Although one might devise a geological hypothesis justifying a "stand alone" unit, we would anticipate under such a plan that the issue of drainage across boundaries would be a difficult problem to solve; and, among other things, probably a USGS requirement that wells in each unit be located some minimum distance from unit boundaries. Also, as to the new unit there would not exist the justification for establishment of large participating areas as has been occasioned by the widespread influence of the pressure maintenance project in the main unit; and we think the USGS would be hard pressed to consider large participating areas for a "stand alone" unit which has no such pressure maintenance feature. Small participating areas could lead to overdrilling and poor economics.

Whether we form a unit comprising all of the subject lands or one with just the north part of them (and treat the remainder as being under competitive development), we recommend a cooperative agreement between whichever of the two units results which provides:

1. For a method of allocating to each unit a fair share of the costs of the pressure maintenance program (perhaps on the basis of ratio of production of the two areas);

2. For extension of the present gas lift and gas gathering system, and method of accounting for gas used in gas lift;

3. For a method of accounting for gas originating from each area but "stored" in the "common" gas cap of the main area;

4. For extension of the existing oil gathering system and accounting for oil produced;

5. For a plan that satisfies the USGS as to protection of unitized lands from drainage, which plan should eliminate the need to drill any unnecessary wells just to satisfy offset drainage requirements; and

6. For a tentative plan for ultimately joining the two units into one at such time as oil prices and the windfall profits tax for the two areas is the same. (The critical time for bringing the two units into one will not arrive until free gas has channelled across the border to the wells in the west unit - and even then not until it is time to market the gas; and we do not anticipate this to occur in less than ten or fifteen years, and hopefully at that time Congress will not have extended the windfall profits tax beyond its presently defined termination date, and the merger of the two units can take place on "even terms".)

One option of unitization provision which perhaps we will want to consider is that the USGS has permitted "segregation" of the working interests under federal units; and for the last several years we have included in our unit operating agreements (BMG 1968 - revision 2) as a standard feature this provision to cover certain specific lands and wells which are treated separately.

This approach might allow (through a royalty pooling of the two areas) the royalty to be determined by a formula such that it would be exactly the same as if the new unit were a part of the existing unit - and segregate completely for different treatment the working interest share of production.

We have discussed informally with USGS representatives unitization and a cooperative plan; and have asked them to advise us what will be required in the way of protection of each unit from offset drainage; suggesting that one criteron might be rates of oil withdrawal per acre - or whatever - that can be utilized to make such a determination, other than the drilling of unnecessary wells just to meet offsets. As of now we do not have their answers; but we are hopeful that something practical can be worked out.

ATTACHMENT NO. 4

ASSURANCE OF EFFICIENT DEPLETION OF THE EXISTING CANADA OJITOS UNIT PARTICIPATING AREA (PRESENTLY DEVELOPED) RESERVOIR

In order to bring files up to date, and to refresh memories, we remind the participants of the options we earlier determined we held - along with the positions and measures we took regarding adequate control - to insure efficient depletion of, and maximum ultimate recovery from, the main reservoir. This review follows.

In the mid-1960's we made a study of the production behavior of the fractured shale reservoirs of the Mancos formation in this Northwest New Mexico area. It showed, among other things, a range of recoveries of oil in place from about 5% (Gallegos-Gallup) to 30% (Boulder); the difference in recovery apparently being due to the amount of gravity drainage realized in the depletion process. Although the West Puerto Chiquito Pool was geographically nearer Boulder (with 30% recovery), it was more like Gallegos-Gallup (5% recovery) from the standpoint of reservoir conditions; and we realized that if developed the same as that of other fractured Mancos pools that West Puerto Chiquito would be limited to a rather low recovery of oil in place. Profitable production would require more efficient depletion than "uncontrolled" exploitation would allow; so we took the unusual measures ("unusual" in the sense of having never been tried before in this formation) of pressure maintenance and restricted production rates in order to maximize the gravity drainage depletion mechanism. Further, to insure there be no external influence in the pressure maintenance program and that we could exercise proper control over the production from wells completed in the reservoir we undertook particular measures as to certain areas:

1. To the south & east (of the main reservoir) we expanded the unit area to cover all of the potentially productive lands in these directions;

2. To the north (where Indian land probably precluded unitization with the main area - but where there appeared to be continuation of the commercially productive part of the reservoir outside of the unit) we developed production - and held leases accordingly - with most of the same working interest owners in such a fashion that should development bring the two producing areas together a boundary agreement could be reached with a minimum of difficulty (pending now in this area is a separate "North Canada Ojitos Unit"); and

3. To the west we maintained a strong leasehold position until development of the westernmost wells confirmed our geological hypothesis that this area would

probably be marginally productive; at which time we either dropped leases or let them expire as their terms ran out (except for those lands lying in and north of Sections 5 and 6, T-25N, R-1W, which lands we felt held the most promise - if any there be - for this west area).

The only "indefinite" area was the one to the southwest and the situation as we saw it then with regard to control of production to protect the reservoir was this: if development here by other parties resulted in small wells, then the production would not affect the reservoir performance and could be ignored; if however enough wells were drilled - or if by some phenomenon gas would channel to wells outside the unit boundary, such that proper control of the reservoir would be lost - then we would ask that the critical wells outside the unit be brought into unitization. We would expect to accomplish this by first requesting the working interest owners of the subject wells to voluntarily join the unit; but failing in this course we would then apply to the appropriate regulatory agencies for these wells to be brought into the unit through statutory unitization; which under New Mexico law would probably be just a routine exercise.

If however, the unitization law were changed, or if for some other reason we failed to achieve unitization (or stop the drainage by drilling offset wells inside the unit) and the pressure maintenance project was in jeopardy because of drainage of oil or gas, or both, across the west boundary, then as a last resort we would reduce the pressure in the main reservoir by marketing gas from the gas cap. One characteristic which these fractured shale reservoirs in this area have shown is a greatly magnified drop in oil productivity with decrease in reservoir pressure (i.e. a 50% drop in productivity with a 5% drop in reservoir pressure). A drop in reservoir pressure of 25% to 30% would probably cause all the 20 to 40 barrel-per-day wells in the reservoir - including those within the present Canada Ojitos Unit - to drop to productivities below their economic limits, at which time it would be reasonable to presume they would be plugged and abandoned and any threat of reservoir mismanagement through production of non-unit wells would be mitigated. (Reduction in productivity of the remaining unit wells and decrease in unit ultimate recovery from that which would have otherwise occurred could be expected; and it would be necessary to weigh one set of conditions against the other to determine at what point such action should be taken).

These same conditions prevail today: so we see no real threat of serious reservoir damage that could be caused by wells drilled outside and to the west of the unit area. About the only differences now as compared to earlier when we first made the above assessment are the advent of price controls and the passage of the Windfall Profits Tax Act of 1980: these could increase the economic "pain" of bringing an outside well into unitization; but do not change the legal aspects of so doing. An owner seeking to keep his well out of the unit could offer the argument of economic hardship because of

the Windfall Profits Tax, but just as these arguments fell on deaf ears when the Congress passed this act, it is probable that such a plea appealed from an OCD ruling would probably bring "short shrift" from the courts.

The problems of competitive drilling and bringing outside wells into the unit are not limited to the "outside" parties; the income tax consequences to the existing Canada Ojitos Unit Participating Area owners of the resulting investment adjustment would also be much less desirable than that of drilling the well initially - so although there is "protection" afforded present unit owners as discussed above, it does not come without a price.

(Additional remarks regarding the problems of competitive drilling are set out in Attachment 5 herein).

ATTACHMENT NO. 5
ORIENTATION OF SPACING UNITS

The unit operator suggests that the present 320 acre spacing order be amended to provide for orientation of well spacing units by dividing each section into an East and a West half. There are a number of reasons supporting this recommendation, three of which - protection of correlative rights, avoidance of drilling unnecessary wells and relations between unit owners and outside parties - are discussed below.

Spacing of wells in the West Puerto Chiquito Pool is currently under Order No. R-2565-C established by the New Mexico Oil Conservation Commission in 1970, following a three year temporary spacing order set in 1966. Both the temporary and the final orders provide for 320 acres per well, being any two contiguous quarters within a governmental section (which are not otherwise allocated to a well).

At the time of establishing the initial temporary order there was no reason to consider orientation of the spacing units; and even when the hearing for the final order was held the pressure maintenance program in the Canada Ojitos Unit had been in operation only a little over a year, and it was not definitely known that it would continue successfully.

Now, however, this project is nearly twelve years old; and its presence has added a new dimension to reservoir behavior just as identifiable and as important as other physical characteristics of pressure, temperature, viscosity, transmissibility and etc; and orderly future development requires recognition of this new dimension.

Although it should be noted that the existing unit area occupies about 62% of the surface area of the presently designated West Puerto Chiquito Mancos pool and overlies a share of the ultimately recoverable reserves therefrom of 80% to 90%, the significant element which the unit adds - through the pressure maintenance project - is the migration of gas along the geological strike of the producing formation and the resulting downdip flow of reservoir fluids (from updip injection wells to downdip recovery wells). This, plus the formation's unusual -- but nevertheless demonstrated and effective - long distance drainage characteristics nullify, as to any area in communication with the main reservoir, the equal opportunity of wells located therein to recover oil from an equivalent spacing area - as propounded by the theory of compensatory drainage (for wells on "non-square" tracts); and consequently it could be difficult to achieve protection of correlative rights between wells inside and those downdip (to the west) outside the unit if those outside are drilled under "competitive" conditions.

We believe this to be a unique situation - not to be found elsewhere in New Mexico - and so a unique solution is warranted.

Orientation of spacing units will not completely solve this problem of protection of correlative rights - but it could reduce by one-half the otherwise resulting inequity, and accordingly is, in our opinion, justified.

Under competitive drilling not only is protection of correlative rights a problem without orientation of spacing units, but also there would exist an unwarranted potential for overdrilling: two wells in the east half of sections offsetting the unit's west boundary could require two "inside" wells to "legally" prevent drainage - the consequence being twice as many wells along the boundary as otherwise necessary; all of which would violate the intent of order R-2565-C, entered following case no. 3455 in which one of the findings was that 320 acre spacing was required "...in order to prevent the economic loss caused by the drilling of unnecessary wells...".

It may not be possible to eliminate all inequity in the protection of correlative rights nor to eliminate all economic waste through prevention of drilling of some unnecessary wells; but certainly the rules should be so written as to prevent their "abuse" and to reduce to a minimum the unnecessary wells with which the parties must contend.

This potential abuse could take place only in the area just west of the present unit: to the south and east the unitized lands probably overlap the productive area; and to the north we anticipate another unit with a "boundary agreement" eliminating any inequity. Also, if unitization of the west area as recommended elsewhere herein can be accomplished, there should be no problem even here; and consequently no need anywhere in the pool for such an order.

However, except for the northwest area where unit owners' lands lie, unitization is not yet assured, and should drilling under competitive conditions be undertaken, efforts might be made to "abuse" the existing order as indicated above by the drilling of two wells in the east half of sections adjoining the Canada Ojitos Unit Participating Area west boundary. Such abuse, if allowed, not only would complicate the protection of correlative rights and perhaps result in overdrilling but would adversely affect the unit operation and its relations with outside parties. These other problems resulting from competitive drilling should only occur if commercial production rates are established - and this alone is a rather large if ; but we cannot rely on it to assure us of trouble-free development. Some of these issues and problems are discussed next.

If commercial production offsetting the unit is established by drilling on a competitive basis then the unit owners would expect to follow one of the three following courses:

1. Pay compensatory royalty; or

2. Drill offset wells inside the unit to meet the outside

wells; or

3. Bring the outside wells into the unit.

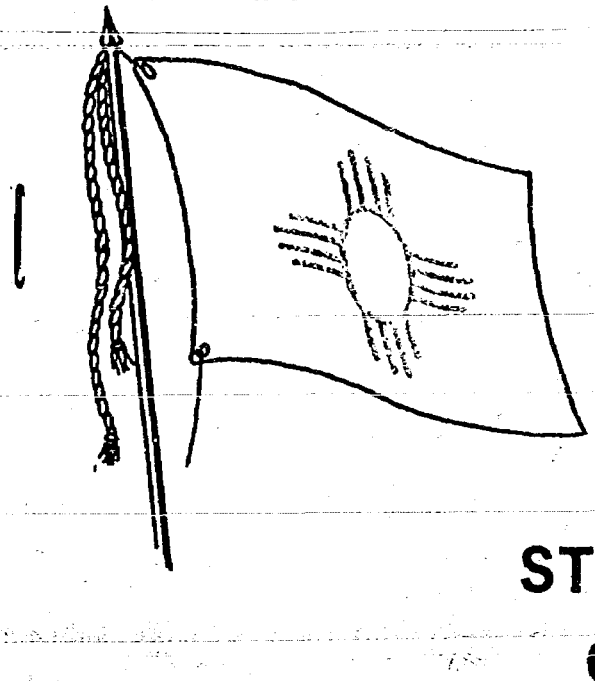
Since paying compensatory royalty is usually unsatisfactory and offset wells inside the unit would be "unnecessary wells" from standpoint of reservoir depletion, the unit owners would probably opt to bring any outside well into the unit. The cost to unit owners would be about the same: paying 100% of the cost of an "inside" well to meet the offset; or approximately a "net" of 60% (after investment adjustment) of the cost of an outside well by reason of bringing it into participation (if about one section were brought in with the well) plus the burden of greater income tax liability.

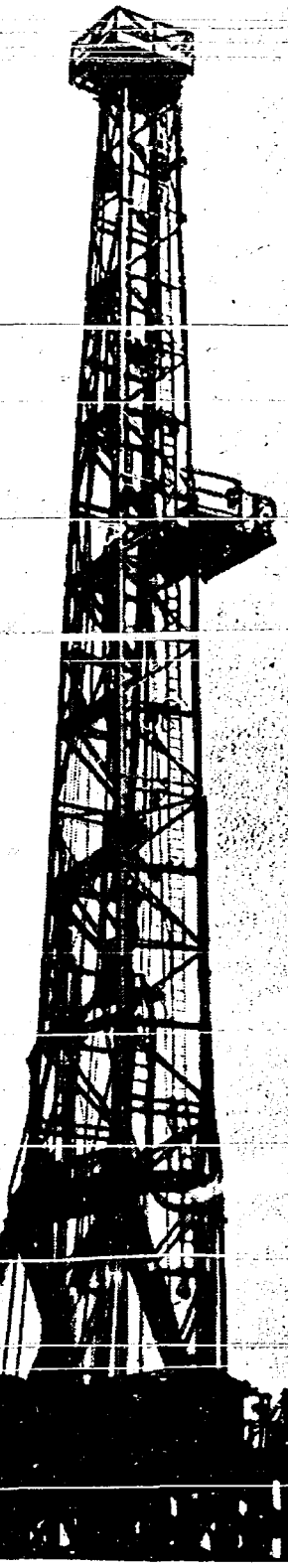
The "outside" owner could be expected to be unhappy: he took the drilling risk, and if unsuccessful he has nothing; and if successful - a commercial well - the unit reimburses him 60% of his cost and he is left with about 2% of unit production (or 1% for each of two 320-acre wells).

His situation is bad enough if oil prices and taxes were the same: but they're not; outside the unit his oil price approaches $40.00 per barrel with a 30% Windfall Profit Tax, whereas after coming into the unit the price (currently) would approximate $6.00 per barrel for his share of the oil and Windfall Profits Tax rate would be 50% to 70% depending on his category. Some relief in price will occur in the next 1½ years, but the Windfall Profits Tax burden will be with him for at least ten years.

As indicated in Attachment No. 4 herein, the bringing in of outside competitively-drilled wells would be economically "painful" - and it's doubtful that relief could be expected through legal action; and although orientation of spacing units won't completely solve this problem for either party, it could cut in half the economic misery of the "outside" party, while at the same time reducing the investment and income tax liabilities of the "inside" parties by minimizing the number of unnecessary wells and their associated costs.

Unitization of the "outside" lands and proper planning can eliminate all of the above described problems of drilling under competitive conditions, but as pointed out earlier unitization is not yet assured; and, absent unitization, the herein recommended change in pool rules is desirable.





STATE
OF
NEW MEXICO

ENERGY AND MINERALS DEPARTMENT

OIL CONSERVATION DIVISION

RULES AND REGULATIONS

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7075 Exhibit No. 6
Submitted by Koch
Hearing Date 11/24/80

(2) Casing strings in wells drilled with cable tools may be tested as outlined in sub-paragraph (e) (1) above, or by bailing the well dry in which case the hole must remain satisfactorily dry for a period of at least one (1) hour before commencing any further operations on the well.

(d) Requirements for tubing of wells are as follows:

(1) All flowing oil wells equipped with casing larger in size than 2 7/8-inch OD shall be tubed.

(2) All gas wells equipped with casing larger in size than 2 7/8-inch OD shall be tubed.

(3) Tubing shall be set as near the bottom as practical and tubing Perforations shall not be more than 250 feet above the top of the pay.

(4) The Division Director may, upon proper application, grant administrative exceptions to the provisions of sub-paragraphs (2) and (3) above, without notice and hearing, provided waste will not be caused thereby.

(e) The Division's District Supervisors or their representatives shall have authority to approve tubingless completions without the necessity of administrative approval or notice and hearing when the following conditions exist:

(1) The well is to be completed with a total depth of 5,000 feet or less,

(2) The well is not a wildcat (it is not more than one mile from an existing well producing from the same common source of supply to which it is projected).

(3) No known corrosive or pressure problems exist which might make the tubingless method of completion undesirable,

(4) The well will not be a dual completion,

(5) The tubing used as a substitute for casing will be either 2 3/8-inch OD or 2 7/8-inch OD.

RULE 108. DEFECTIVE CASING OR CEMENTING

In any well that appears to have a defective casing program or faultily cemented or corroded casing which will permit or may create underground waste, the operator shall proceed with diligence to use the appropriate method and means to eliminate such hazard of underground waste. If such hazard of waste cannot be eliminated, the well shall be properly plugged and abandoned.

RULE 109. BLOWOUT PREVENTION (See Rule 114 (b) also)

(a) Blowout preventers shall be installed and maintained in good working order on all drilling rigs operating in areas of known high pressure at or above the projected depth of the well and in all areas where pressures which will be encountered are unknown, and on all workover rigs working on wells in which high pressures are known to exist

(b) Blowout preventers shall be installed and maintained in good working order on all drilling rigs and workover rigs operating within the corporate limits of any city, town, or village, or within 1320 feet of a habitation, school, or church, wherever located.

(c) All operators, when filing Form C-101, Application for Permit to Drill, Deepen, or Plug Back, or Form C-103, Sundry Notices, for any operation requiring blowout prevention equipment in accordance with Sections (a) and (b) above, shall submit a proposed blowout prevention program for the well. The program as submitted may be modified by the District Supervisor if, in his judgment, such modification is necessary.

RULE 110. PULLING OUTSIDE STRINGS OF CASING

In pulling outside strings of casing from any oil or gas well, the space outside the casing left in the hole shall be kept and left full of mud-laden fluid or cement of adequate specific gravity to seal off all fresh and salt water strata and any strata bearing oil or gas not producing.

RULE 111. DEVIATION TESTS AND DIRECTIONAL DRILLING

(a) Any well which is drilled or deepened with rotary tools shall be tested at reasonably frequent intervals to determine the deviation from the vertical. Such tests shall be made at least once each 500 feet or at the first bit change succeeding 500 feet. A tabulation of all deviation tests run, sworn to and notarized, shall be filed with Form C-104, Request for Allowable and Authorization to Transport Oil and Natural Gas. When the deviation averages more than five degrees in any 500-foot interval, the Division Director may require that a directional survey be run to establish the location of the producing interval(s).

The Division Director, at the request of an offset operator, may require any operator to make a directional survey of any well. Said directional survey and all associated costs shall be at the expense of the requesting party and shall be secured in advance by a $5,000.00 indemnity bond posted with and approved by the Division. The requesting party may designate the well survey company, and said survey shall be witnessed by the Division.

(b) No well shall be intentionally deviated without special permission from the Division. Permission to deviate toward the vertical to straighten a crooked hole, to deviate toward the vertical or in an indeterminate direction to sidetrack junk in the hole, or to drill a relief well to control a blow-out shall be obtained from the appropriate District Office of the Division on Division Form C-103 with copies of said Form C-103 being furnished to all offset operators. Permission to deviate a well in any other manner or for any other reason will be granted only after notice and hearing. Upon request from the Division Director, any well which was deviated in an indeterminate direction or toward the vertical shall be directionally surveyed. In addition, a directional survey of the entire well bore must be made on any well which was deviated in a predetermined direction, except toward the vertical. The District Office of the Division shall be notified of the approximate time all directional surveys are to be conducted. All directional surveys run on any well which was intentionally deviated in any manner for any reason must be filed with the Division upon completion of the well. The Division will not assign an allowable to a well until the operator has submitted an affidavit that all such directional surveys have been filed.

RULE 112-A. MULTIPLE COMPLETIONS

I. The multiple completion of any well may be permitted only by order of the Division after notice and hearing, except as hereinafter provided. Multiple completion of any well without prior approval by the Division shall be solely at the operator's risk and shall be no way commit the Division to subsequent approval thereof.

II. MULTIPLE COMPLETIONS (CONVENTIONAL)

The Division Director shall have the authority to grant an exception to the requirements of Rule 112-A (I) and approve the dual or triple completion of a well to produce from more than one common source of supply without notice and hearing when application for such approval has been filed on Form C-107; and

(a) The Division has previously authorized the similar multiple completion of a well in the same common sources of supply as proposed, after notice and hearing; provided however, that in Rio Arriba, San Juan, Sandoval, and McKinley Counties, a proposed multiple completion may be approved if the Division has previously authorized the similar multiple completion of a well in the same formations as proposed, after notice and hearing; and

(b) The applicant proposes to utilize one of the mechanical installations described below:

(1) The well is to be completed as a gas-gas dual or as a gas-gas-gas triple and the hydrocarbons from each of the zones can be safely and efficiently produced through parallel strings of tubing or a combination of tubing string(s) and the tubing-casing annulus.

(2) The well is to be completed as an oil-oil dual or as an oil-oil-oil triple and the hydrocarbons from each of the zones can be safely and efficiently produced through parallel strings of tubing.

(3) The well is to be completed as a combination oil and gas multiple completion and the hydrocarbons from each oil zone can be safely and efficiently produced through parallel strings of tubing and the hydrocarbons from each gas zone can be safely and efficiently produced through parallel string(s) of tubing or through a combination of tubing and the tubing-casing annulus; and

(c) All strings of tubing used for the production of oil in the proposed multiple completion will have a nominal inside diameter of not less than 1.670 inches nor greater than 2.50 inches; and

(d) The packer(s) used to segregate the separate zones of the multiple completion will be production-type packer(s) and shall effectively prevent communication between all producing zones.

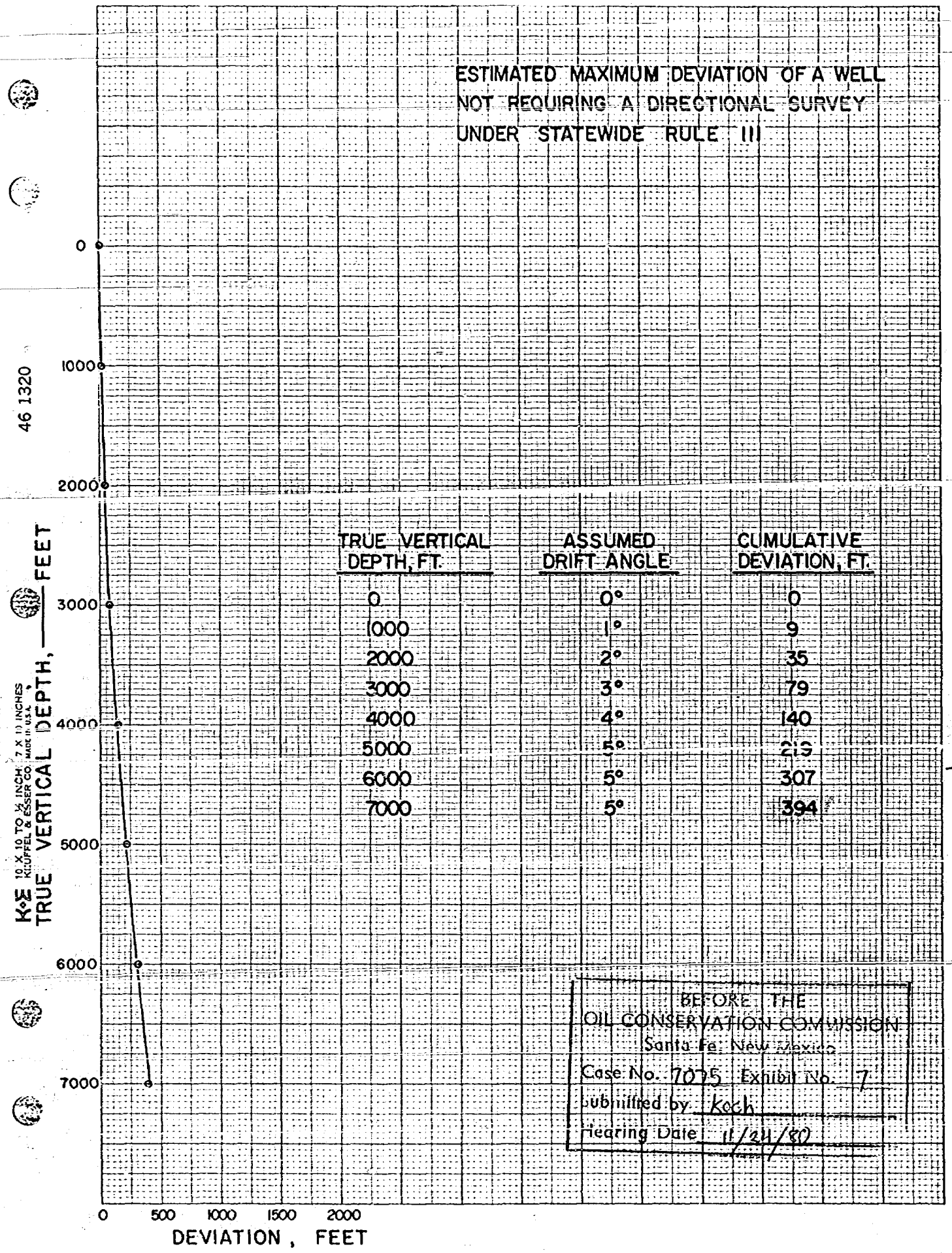
III. MULTIPLE COMPLETIONS (TUBINGLESS AND COMBINATION)

The Division Director shall have the authority to grant an exception to the requirements of Rule 112-A (I) and approve the multiple completion of a well without notice and hearing where application has been filed on Form C-107; and

(a) The Division has previously authorized the similar multiple completion of a well in the same common sources or supply as proposed, after notice and hearing; provided however, that in Rio Arriba, San Juan, Sandoval, and McKinley Counties, a proposed multiple completion may be approved if the Division has previously authorized the similar multiple completion or a well in the same formations after notice and hearing; and

ESTIMATED MAXIMUM DEVIATION OF A WELL NOT REQUIRING A DIRECTIONAL SURVEY UNDER STATEWIDE RULE III

TRUE VERTICAL DEPTH, FT.	ASSUMED DRIFT ANGLE	CUMULATIVE DEVIATION, FT.
0	0°	0
1000	1°	9
2000	2°	35
3000	3°	79
4000	4°	140
5000	5°	219
6000	5°	307
7000	5°	394



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BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7075 Exhibit No. 7
Submitted by Koch
Hearing Date 11/24/80

SUMMARY

I. Mr. Greer's proposed 1650' spacing rule is far too inflexible for the rugged terrain and sensitive environment. The present rule provides the flexibility needed.

II. Mr. Greer's proposed rules were devised to deal specifically with a possible, but unlikely, drainage situation along the west unit boundary. Our testimony, and that of Mr. Greer on previous occasions, has shown that the play to the west is far more exploratory than development in nature. The proposed rules are totally inappropriate to the exploratory nature of the play.

III. Mr. Greer and the unit interests have shown no desire during the past 15 years to extend the limits of Niobrara production westward. They consider the area uneconomic. We and others are willing to take the necessary risks, and we believe we should be allowed to do so without further delays from Mr. Greer.

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7075 Exhibit No. 8
Submitted by Koch
Hearing Date 11/24/80

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

LARRY KEHOE
SECRETARY

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-2434

January 30, 1981

Mr. Thomas Kellahin
Kellahin & Kellahin
Attorneys at Law
Post Office Box 1789
Santa Fe, New Mexico

Re: CASE NO. 7075
ORDER NO R-6469-A

Applicant:

Benson-Montin-Greer Drilling Corporation

Dear Sir:

Enclosed herewith are two copies of the above-referenced Commission order recently entered in the subject case.

Yours very truly,

JOE D. RAMEY
Director

JDR/fd

Copy of order also sent to:

Hobbs OCC x
Artesia OCC x
Aztec OCC x

Other George Verity, William F. Carr, Robert Buettner, George Hunker, Don Fedric, Craig Metcalf

CHRONOLOGY OF EVENTS LEADING TO APPROVAL OF FORM OF WEST CANADA OJITOS UNIT AGREEMENT AND DESIGNATION BY U.S.G.S. AS LOGICAL UNIT AREA

3- 5-80	Discuss with U.S.G.S. representatives issues of West Canada Ojitos Unit or Northwest Canada Ojitos Unit, with a second Southwest Canada Ojitos Unit. U.S.G.S. prefers one unit.
3-12-80	Obtained verbal approval from U.S.G.S. to eliminate DOE stipulation regarding competitive bidding.
3-12-80	Submitted proposed form of Unit Agreement to Oil Conservation Division of New Mexico Department of Energy and Minerals.
3-19-80	Meeting with Forest Service representatives in Albuquerque regarding tolling of time during winter weather.
3-20-80	Received Oil Conservation Division changes.
3-25-80	Submitted to U.S.G.S. form of agreement with Oil Conservation Division changes incorporated, to obtain approval of form.
3-26-80	Letter to Forest Service.
3-31-80	Another letter to Forest Service following discussion.
4-25-80	Forest Service advises working on proposal.
5- 1-80	Reading & Bates advised by phone of lack of manpower to pursue unitization. Benson-Montin-Greer agrees to assume Reading & Bates role.
5- 6-80	Meeting in field with Forest Service District Ranger. Ranger will add his recommendation.
5- 8-80	Filed application for designation of unit area with U.S.G.S.
5- 8-80	Filed copy of application for designation with Forest Service. Request Forest Service approval of special provision.
6-10-80	U.S.G.S. ready to approve designation. Waiting on Forest Service.
6-26-80	Joint meeting B-M-G, Forest Service and U.S.G.S. representatives in Albuquerque re "tolling of time" provision.
7- 7-80	District Ranger delayed because of forest fire. Sent recommendation to Santa Fe 7-7-80.

7-23-80	Field trip to Canada Ojitos Unit area with Ranger and five other Forest Service people. Appear to have the support of all for the proposal.
8- 1-80	First recommendation from Forest Service Santa Fe office to Albuquerque office not complete. Returned to be rewritten.
8-11-80	Santa Fe Forest Service office rewriting recommendation to Albuquerque office.
8-22-80	Forest Service approval mailed to U.S.G.S.
9- 8-80	Area designated by U.S.G.S. as logical unit area.

SUMMARY

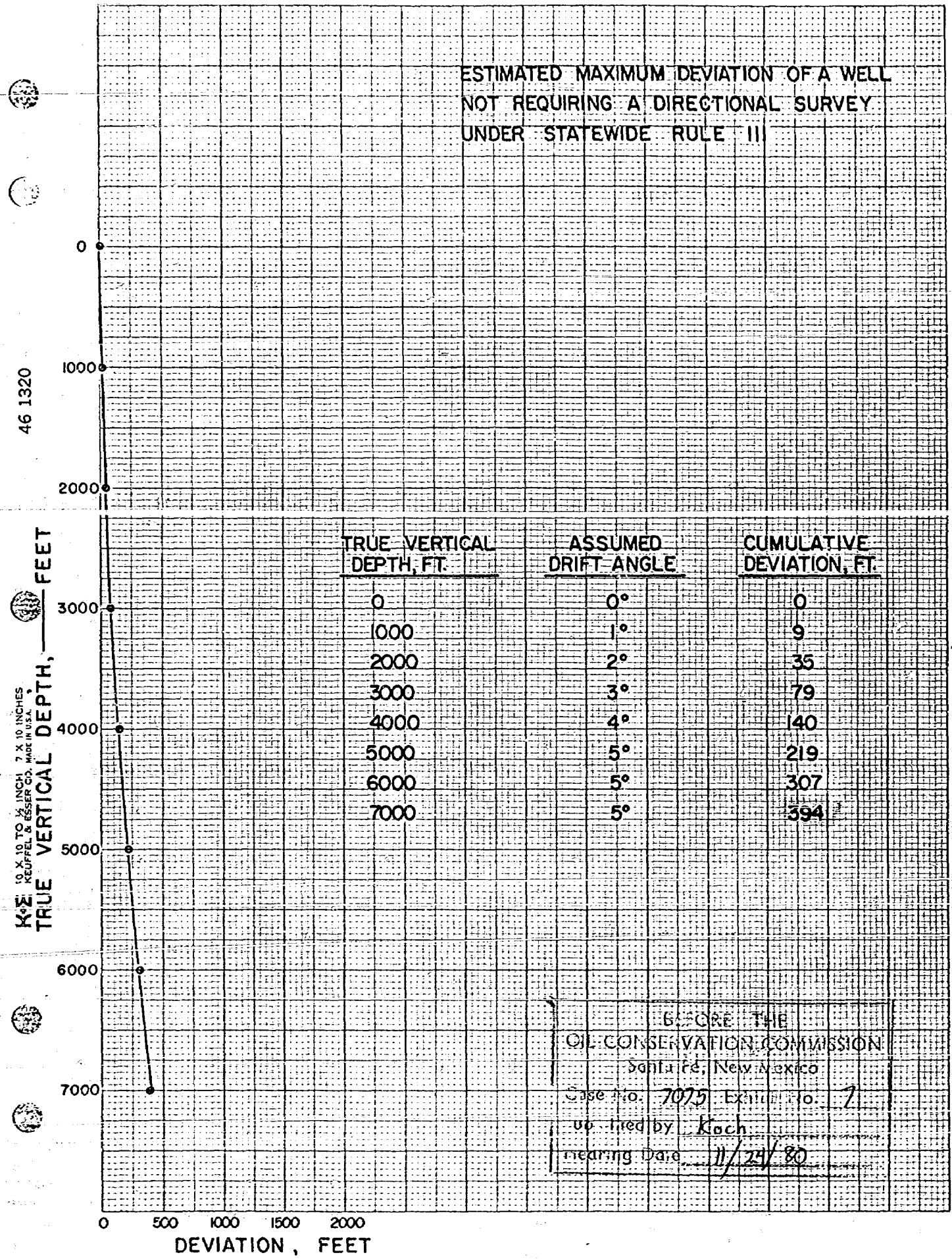
I. Mr. Greer's proposed 1650' spacing rule is far too inflexible for the rugged terrain and sensitive environment. The present rule provides the flexibility needed.

II. Mr. Greer's proposed rules were devised to deal specifically with a possible, but unlikely, drainage situation along the west unit boundary. Our testimony, and that of Mr. Greer on previous occasions, has shown that the play to the west is far more exploratory than development in nature. The proposed rules are totally inappropriate to the exploratory nature of the play.

III. Mr. Greer and the unit interests have shown no desire during the past 15 years to extend the limits of Niobrara production westward. They consider the area uneconomic. We and others are willing to take the necessary risks, and we believe we should be allowed to do so without further delays from Mr. Greer.

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 2075 Exhibit No. 8
Submitted by Kosh
Hearing Date 11/24/80

ESTIMATED MAXIMUM DEVIATION OF A WELL NOT REQUIRING A DIRECTIONAL SURVEY UNDER STATEWIDE RULE II



TRUE VERTICAL DEPTH, FT.	ASSUMED DRIFT ANGLE	CUMULATIVE DEVIATION, FT.
0	0°	0
1000	1°	9
2000	2°	35
3000	3°	79
4000	4°	140
5000	5°	219
6000	5°	307
7000	5°	394

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fé, New Mexico
Case No. 7075 Exhibit No. 7
Submitted by Koch
Hearing Date 11/24/80

46 1320

KEUFFEL & ESSER CO. 10 X 10 TO ½ INCH 7 X 10 INCHES MADE IN U.S.A.

RECD SEP 3 1980

BENSON-MONTIN-GREER DRILLING CORP.
221 PETROLEUM CENTER BUILDING
FARMINGTON, NEW MEXICO 87401
PHONE: 325-8874

August 28, 1980

Mr. Dick Bick
Koch Exploration Co.
P.O. Box 2256
Wichita, Kansas 67220

Re: PENDING DEVELOPMENT:
WEST CANADA OJITOS AREA,
RIO ARRIBA COUNTY, NEW MEXICO

Dear Mr. Bick:

We were disappointed to learn, when your Mr. Delvin Echard called earlier this month to inquire about drilling procedures in this area, that you were planning competitive drilling and were staking a location in the southeast quarter of Section 8, Township 25 North, Range 1 West. We have made a lot of progress in securing a satisfactory form of unit agreement for this area. Copy of our letter of August 28 to working interest owners in the area is enclosed for your information in this regard.

As you know, we attended a couple of meetings with your people earlier this year to discuss unitization, and although we acknowledge that there are problems in development under unitized operation, we also recognize the far more serious problems of development under competitive conditions. Both issues are covered in some detail in our letter of April 30 this year to our working interest owners, copy of which is also enclosed for your information.

Through our efforts we are developing a healthy economic climate for drilling in this area if it is unitized, and it can only be a shortsighted policy that refuses to recognize this. We urge that you review the consequences of competitive development and view with an open mind development under unitization.

Yours very truly,

BENSON-MONTIN-GREER DRILLING CORP.

BY: Albert R. Greer
Albert R. Greer, President

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7075 Exhibit No. 5
Submitted by Koch
Hearing Date 11/24/80

ARG:ney

BENSON-MONTIN-GREER DRILLING CORP.
221 PETROLEUM CENTER BUILDING
FARMINGTON, NEW MEXICO 87401
PHONE: 325-8874

April 30, 1980

WORKING INTEREST OWNERS
CANADA OJITOS UNIT

RE: CONSIDERATION OF EXPLORATORY DRILLING ON LANDS ADJOINING WEST BOUNDARY OF CANADA OJITOS UNIT, RIO ARRIBA COUNTY, NEW MEXICO

We call to your attention that the Canada Ojitos Unit working interest owners jointly own oil and gas leases outside the unit area near its west boundary, and that four or five thousand acres of these leases will expire in the summer and fall of 1981 unless they are preserved by some type of development. We believe that drilling in this area will yield production only marginally profitable: even so, under the right conditions - particularly that of cooperative effort of lessees - it could be beneficial to all concerned to develop this area, and we ask that each working interest owner review this situation and advise if you would like to participate in the drilling of exploratory wells in this area - and under what conditions. We have some thoughts in this regard which we pass on to you now; and it may be that some of you will concur with the unit operator's assessment of the situation. But, concur or not, we would appreciate hearing from each of you as to ideas or suggestions as to any of the issues bearing on the prudent exploration and production of our jointly owned lands.

The area which we think should now be considered is the 1½ to 2 miles wide strip running north-south along the unit's west border (outlined on small scale plat enclosed). It is nearly all federal land, the surface of which is in the Santa Fe National Forest and under the jurisdiction of the U. S. Geological Survey, Bureau of Land Management and Forest Service. Some of the lands are open and some are leased (see large scale land plat enclosed).

Our feeling at this time is that <u>if</u> there is to be any drilling in this (west) area that in the interest of realizing maximum ultimate oil recovery from it as well as from presently producing (unitized) lands, that consideration should be given to the formation of a new unit comprising those lands immediately to the west of the present unit and the drilling of two or three exploratory wells in this new unit along the Canada Ojitos Unit west border. Failing to unitize all of these lands we would urge that we unitize the north part of the west area (in which all of our jointly owned lands lie) to avoid the problems of "competitive" drilling as discussed in attachments herein in some detail.

In the last two months we have discussed these - and other - plans for exploration with other affected lessees (in fact the

...

first of these meetings resulted from a proposal by Reading and Bates for a farmout of some of our lands); and although it is too early to expect firm commitments - since plans at this stage are still too nebulous - the owners of the larger tracts have expressed a willingness to consider some form of unitization and cooperative development.

Development of this area under either competitive or unitized conditions poses a number of problems; and at "first blush" they may seem too cumbersome to worry with; however a consideration of the alternatives leads one to the conclusion that, problems or not, drilling under a new "exploratory" unit is the best way to proceed. Descriptions of some of the issues are enclosed herein for your review, categorized by attachments as follows:

1. Economics of development of the new (west) area.

2. Economics of west unit dependent on existing Canada Ojitos Unit.

3. Main issues of development under a new unit and "cooperative plan" with existing unit.

4. Assurance of efficient depletion of the existing Canada Ojitos Unit Participating Area (presently developed) reservoir.

5. Orientation of spacing units.

Although the present lessees of lands adjoining the Canada Ojitos Unit to the west are cognizant of the hazards of overdrilling and need for cooperation and at this time we believe unitization may come about, it is not yet a fact. In the meantime there are open lands which may be acquired by not-so-knowledgeable "strangers" (and in view of the marginal appearing economics and other problems the possibility exists that some of the present lessees might even farmout their interests to other "strangers"): and should either of these things happen, then - despite present good intentions to consider unitization - it is possible that drilling under competitive conditions could result; and in view of this possibility we believe an effort should now be made to prevent "abuse" of the existing 320-acre well spacing order. To mitigate abuse of this order we propose to make application for orientation of spacing units within the next few weeks (item 5 above) unless we receive objection from working interest owners in the meantime. Absent objection we will undertake this as a unit effort. (Although the unit can be afforded "relief" to a certain extent from the problems caused by wells drilled offsetting the unit - see item 4 above - the greater the number of unnecessary wells the greater the problems and unpleasantness of the final results for both the present unit owners and the new drilling parties; and it is in everyone's interest to avoid such situations.)

...

As to timing of a development program, it is our thought that several months will be required to work out the unitization and cooperative agreements, with next winter being the earliest this could be accomplished; so next summer (1981) would be the earliest that drilling should be planned. We note here that a drilling and testing program running from July through October would preserve all of next year's otherwise expiring leases. There is still unresolved a problem with one of the companies which we hope can be addressed soon, in that they have indicated they didn't want to do "anything" until some of the remaining open lands had been leased. This, of course, is exactly "backwards" from what should be done: it is far better if the lands are unitized prior to the sale; so that we are assured the subject lands will be committed to the unit agreement regardless of the purchaser. Hopefully we can soon get this message across and be ready to commence working with these "outside" parties on the many issues as soon as we have response from the Canada Ojitos owners, inasmuch as we would like to have all of the owners of larger interests involved in the discussions from the beginning.

Since profitable development of the subject area west of the existing unit is dependent not only on the reservoir quality underlying these lands, but also on the production from, and reservoir control of, the existing unit (see item 2 above) the initial - and rather critical - decision which the unit owners now need make, is what ownership share of the west unit do we require to be persuaded to lend the existing unit's "good offices" and benefits to the new unit? We would appreciate your addressing this, along with the other issues and advising your thoughts and position.

In closing, we emphasize that we are not recommending the area as one in which we think can be developed oil reserves with desirable economics and at low risk: rather we think drilling here will be quite risky (of the westernmost unit wells only one - the L-27 in the north township - showed any oil production before frac treatment); and it's only that if commercial production rates should be established that we think it would be desirable for all concerned if the present unit owners were represented in the newly developed area.

Yours truly,

BENSON-MONTIN-GREER DRILLING CORP.

BY: Albert R. Greer, President

ARG/tlp

Attachments

ATTACHMENT NO. 1
ECONOMICS OF DEVELOPMENT OF THE NEW (WEST) AREA

These lands all lie within an area whose potential for production we classified ten to fifteen years ago as being marginal: productivities of the westernmost unit wells and our interpretation of the controlling geology indicated to us that it would be unusual if wells drilled on the subject lands showed initial productivities - after frac - greater than twenty to forty barrels per day, along with ultimate recoveries of 15,000 barrels per well on 320 acre spacing up to a probable maximum of 60,000 barrels per well for spacing of two sections per well.

Under the conditions of drilling costs and oil prices of ten years ago the resulting economics were just not interesting; and even two years ago when the price of oil had increased by three or four to one, the drilling costs had also escalated, so the economics were still unfavorable. Now, however, although the drilling costs are approximately three times what they were ten years ago, the price of oil - even after the windfall profits tax - is about ten times what it was then, so it now appears to us that there may be a possibility of drilling wells whose production will show a profit if the benefit of the pressure maintenance program is allowed to extend into this area. There is no way that this west area can, in itself, support a pressure maintenance program; but in conjunction with the existing project we can see some possibilities if the development and production are properly controlled.

The recovery figures of 15,000 barrels per 320 acre-spaced well derive from an estimate of a maximum of 1000 barrels per acre in place and a recovery factor of 5% of the oil in place. The 1000 barrels per acre results from "scaled down" maximum amounts of 2000 barrels per acre measured by interference tests for the area surrounding the higher capacity wells drilled in the best part of the reservoir. The 5% recovery factor comes from that calculated for solution gas drive performance of a fractured formation with reservoir oil characteristics of Canada Ojitos oil; and is further supported by the material balance calculations for the Gallegos Gallup pool - the one pool in the San Juan Basin whose characteristics are most nearly similar to that of the West Canada Ojitos Area.

Further regarding estimated oil recoveries from this area it should be noted that although the degree of fracturing - and resulting productivities - cannot be accurately forecast, the dip of the formation can: and it is too shallow to allow efficient gravity drainage depletion; so even if high capacity wells could be drilled in this area and the resulting oil in place figures were twice as high as herein estimated, the ultimate recoveries would still be limited to twice that shown above, or 30,000 barrels for a 320 acre spaced well - still not an attractive amount.

A significant income factor can be the value of the gas:

although the fraction of oil in place that can be produced will vary markedly with the effective depletion mechanism which results, we would anticipate that under any method most of the gas will be produced. If there is as much as 1000 barrels per acre of oil in place there will be dissolved in it nearly 500 MCF, of which about 300 MCF should be recoverable, or about 200 MMCF per section.

The questionable feature about this potential value is how to save it - it would be very difficult under any situation other than unitization (see Attachment No. 2).

Well costs are estimated to be in the range of $700,000 to $1,000,000; the main variables being cost of frac treatment; whether drilled with mud, air and nitrogen or gas; and cost of oil and gas gathering lines. (These are also discussed further in Attachment No. 2).

ATTACHMENT NO. 2
ECONOMICS OF WEST UNIT DEPENDENT
ON EXISTING CANADA OJITOS UNIT

The west area's physical reservoir characteristics and geometry are such that it cannot support its own independent pressure maintenance program (either by gas or water); hence it is dependent on the main unit's reservoir and communication with it for any kind of depletion mechanism other than solution gas drive.

With well costs so high and solution gas drive recoveries so low, favorable economics, then, can come about for this west area only if benefit is derived from the existing unit's pressure maintenance program.

These thoughts are discussed below in a little more detail. First, in view of the flat dip and the probably low transmissibility it will be impossible to effectively conduct a pressure maintenance project on the lands themselves; so it follows that if updip migration from the presently unitized lands be cut off, the west area is doomed to solution gas drive recovery.

Even so, wells drilled in this area could serve a useful purpose if there be a cooperative plan with the main unit and if the existing unit's pressure maintenance benefits be allowed to expand to this west area. For example, a row of wells just west of the existing unit's boundary could increase the share of the reservoir oil subject to gravity drainage depletion (good recovery efficiency) in the area a mile or so inside the present unit's west boundary which lies structurally below the present high capacity wells; for oil in this area can be recovered by existing wells only by updip flow (solution gas drive depletion - poor recovery efficiency).

Most of this additional recovery, of course, will be produced through the wells outside the present unit; however if there is a cooperative agreement between the west and east units as to support of the pressure maintenance program, it is conceivable that pressure maintenance could be continued for a longer time prior to "blow down", with resulting increased recovery to the existing unit and its royalty and working interest owners. The working interest owners within the present unit, for their own "insurance" that they do indeed benefit from wells drilled outside this unit, will undoubtedly want some participation in the wells outside of it; and since the working interest owners bear a larger share of the risk than the royalty owners it would seem that such "insurance" is appropriate.

All of the foregoing favorable economic factors however are dependent on the existing unit's continuing the pressure maintenance program and (necessarily) the willingness of the owners of this unit to cooperate with such a plan, for without it the economics of the west area must be poor indeed: not only will oil recoveries be

low, but the problems of marketing this oil and gas are such that marketing costs of oil would be high and those for gas so formidable that the gas might not be saved. The marketing problems are briefly described below.

Because of the terrain and climate conditions - the subject properties lie in a mountainous area along the continental divide - there are times during the winter and spring that moving oil by truck is expensive, if not practically impossible. Oil marketing by pipeline is highly desirable, but probably cannot be achieved except through cooperation and use of the existing unit's gathering system. The terrain just does not lend itself to an oil gathering system located only on the (proposed) new unit's lands. Lost production due to inability to move oil could "make the difference" in whether profitable production would be realized.

As to gas, the problem is to have available gas production rates justifying all the costs of marketing early enough in the producing life that marketing will be undertaken. Initial volumes for 20 to 40 BOPD wells would probably be in the range of 7 to 15 MCFD; and by the time the rates will have increased to the point that marketing costs are warranted, a large part of the reserve will have been lost.

Some of these problems are:

1. Most of the wells will be east of the continental divide;

2. The existing gas pipelines are mostly west of the continental divide;

3. The volumes will not warrant the purchaser's laying the connecting lines; and

4. Even after gathering lines are laid there is the problem of compressing this gas to get it into the pipeline.

All of the above are obstacles difficult enough under any circumstances to overcome; but under competitive conditions they would be practically impossible. However, if unitized and under a cooperative agreement with the existing unit, the present gas lift and gas gathering lines could be extended; the gas lift (input gas) line could first have been used for drilling gas - and with duplicate use of this line (assuming production is obtained), and all of the lines then being buried at one time in one ditch, the marketing costs begin to be more reasonable. The oil would have a dependable market and the unused gas would be "stored" in the gas cap to be marketed at a time when (hopefully) there would be a minimum of price restrictions.

ATTACHMENT NO. 3
MAIN ISSUES OF DEVELOPMENT UNDER A NEW UNIT & "COOPERATIVE PLAN" WITH EXISTING UNIT

From the standpoint of proper location of new wells and reservoir control the simplest development procedure would be to expand the present unit prior to drilling; and if commercial production results to bring the productive lands into participation and conduct the operations under one participating area. However, oil price controls and the recently passed windfall profits tax both make this course unattractive; and since drilling under competitive conditions cannot be profitable (not unusual for this formation), we suggest a new unit.

Probably one of the more difficult issues to resolve will be the share of participation in the west area that should be owned by the present Canada Ojitos Unit Participating Area working interest owners. Just what this participation should be as well as the other terms of a cooperative agreement between the two units will of course be subjects of prime concern, study and negotiation; and although at times they may seem too difficult to solve, one need only look to the alternatives to conclude that a determined effort to do so must be made.

We recommend that efforts be directed first toward formation of a single unit comprising all of the subject lands west of the present unit; but failing that to form a unit covering the north part of the area in which lie all of the lands of the present Canada Ojitos Unit Participating Area working interest owners.

For either of the above units a fundamental feature would be a cooperative agreement with the present unit with provisions as described later herein. First, it might be well to note some of the problems we would anticipate for unitization without a cooperative agreement. Although one might devise a geological hypothesis justifying a "stand alone" unit, we would anticipate under such a plan that the issue of drainage across boundaries would be a difficult problem to solve; and, among other things, probably a USGS requirement that wells in each unit be located some minimum distance from unit boundaries. Also, as to the new unit there would not exist the justification for establishment of large participating areas as has been occasioned by the widespread influence of the pressure maintenance project in the main unit; and we think the USGS would be hard pressed to consider large participating areas for a "stand alone" unit which has no such pressure maintenance feature. Small participating areas could lead to overdrilling and poor economics.

Whether we form a unit comprising all of the subject lands or one with just the north part of them (and treat the remainder as being under competitive development), we recommend a cooperative agreement between whichever of the two units results which provides:

1. For a method of allocating to each unit a fair share of the costs of the pressure maintenance program (perhaps on the basis of ratio of production of the two areas);

2. For extension of the present gas lift and gas gathering system, and method of accounting for gas used in gas lift;

3. For a method of accounting for gas originating from each area but "stored" in the "common" gas cap of the main area;

4. For extension of the existing oil gathering system and accounting for oil produced;

5. For a plan that satisfies the USGS as to protection of unitized lands from drainage, which plan should eliminate the need to drill any unnecessary wells just to satisfy offset drainage requirements; and

6. For a tentative plan for ultimately joining the two units into one at such time as oil prices and the windfall profits tax for the two areas is the same. (The critical time for bringing the two units into one will not arrive until free gas has channelled across the border to the wells in the west unit - and even then not until it is time to market the gas; and we do not anticipate this to occur in less than ten or fifteen years, and hopefully at that time Congress will not have extended the windfall profits tax beyond its presently defined termination date, and the merger of the two units can take place on "even terms".)

One option of unitization provision which perhaps we will want to consider is that the USGS has permitted "segregation" of the working interests under federal units; and for the last several years we have included in our unit operating agreements (BMG 1968 - revision 2) as a standard feature this provision to cover certain specific lands and wells which are treated separately.

This approach might allow (through a royalty pooling of the two areas) the royalty to be determined by a formula such that it would be exactly the same as if the new unit were a part of the existing unit - and segregate completely for different treatment the working interest share of production.

We have discussed informally with USGS representatives unitization and a cooperative plan; and have asked them to advise us what will be required in the way of protection of each unit from offset drainage; suggesting that one criteron might be rates of oil withdrawal per acre - or whatever - that can be utilized to make such a determination, other than the drilling of unnecessary wells just to meet offsets. As of now we do not have their answers; but we are hopeful that something practical can be worked out.

ATTACHMENT NO. 4

ASSURANCE OF EFFICIENT DEPLETION OF THE EXISTING CANADA OJITOS UNIT PARTICIPATING AREA (PRESENTLY DEVELOPED) RESERVOIR

In order to bring files up to date, and to refresh memories, we remind the participants of the options we earlier determined we held - along with the positions and measures we took regarding adequate control - to insure efficient depletion of, and maximum ultimate recovery from, the main reservoir. This review follows.

In the mid-1960's we made a study of the production behavior of the fractured shale reservoirs of the Mancos formation in this Northwest New Mexico area. It showed, among other things, a range of recoveries of oil in place from about 5% (Gallegos-Gallup) to 30% (Boulder); the difference in recovery apparently being due to the amount of gravity drainage realized in the depletion process. Although the West Puerto Chiquito Pool was geographically nearer Boulder (with 30% recovery), it was more like Gallegos-Gallup (5% recovery) from the standpoint of reservoir conditions; and we realized that if developed the same as that of other fractured Mancos pools that West Puerto Chiquito would be limited to a rather low recovery of oil in place. Profitable production would require more efficient depletion than "uncontrolled" exploitation would allow; so we took the unusual measures ("unusual" in the sense of having never been tried before in this formation) of pressure maintenance and restricted production rates in order to maximize the gravity drainage depletion mechanism. Further, to insure there be no external influence in the pressure maintenance program and that we could exercise proper control over the production from wells completed in the reservoir we undertook particular measures as to certain areas:

1. To the south & east (of the main reservoir) we expanded the unit area to cover all of the potentially productive lands in these directions;

2. To the north (where Indian land probably precluded unitization with the main area - but where there appeared to be continuation of the commercially productive part of the reservoir outside of the unit) we developed production - and held leases accordingly - with most of the same working interest owners in such a fashion that should development bring the two producing areas together a boundary agreement could be reached with a minimum of difficulty (pending now in this area is a separate "North Canada Ojitos Unit"); and

3. To the west we maintained a strong leasehold position until development of the westernmost wells confirmed our geological hypothesis that this area would

probably be marginally productive; at which time we either dropped leases or let them expire as their terms ran out (except for those lands lying in and north of Sections 5 and 6, T-25N, R-1W, which lands we felt held the most promise - if any there be - for this west area).

The only "indefinite" area was the one to the southwest and the situation as we saw it then with regard to control of production to protect the reservoir was this: if development here by other parties resulted in small wells, then the production would not affect the reservoir performance and could be ignored; if however enough wells were drilled - or if by some phenomenon gas would channel to wells outside the unit boundary, such that proper control of the reservoir would be lost - then we would ask that the critical wells outside the unit be brought into unitization. We would expect to accomplish this by first requesting the working interest owners of the subject wells to voluntarily join the unit; but failing in this course we would then apply to the appropriate regulatory agencies for these wells to be brought into the unit through statutory unitization; which under New Mexico law would probably be just a routine exercise.

If however, the unitization law were changed, or if for some other reason we failed to achieve unitization (or stop the drainage by drilling offset wells inside the unit) and the pressure maintenance project was in jeopardy because of drainage of oil or gas, or both, across the west boundary, then as a last resort we would reduce the pressure in the main reservoir by marketing gas from the gas cap. One characteristic which these fractured shale reservoirs in this area have shown is a greatly magnified drop in oil productivity with decrease in reservoir pressure (i.e. a 50% drop in productivity with a 5% drop in reservoir pressure). A drop in reservoir pressure of 25% to 30% would probably cause all the 20 to 40 barrel-per-day wells in the reservoir - including those within the present Canada Ojitos Unit - to drop to productivities below their economic limits, at which time it would be reasonable to presume they would be plugged and abandoned and any threat of reservoir mismanagement through production of non-unit wells would be mitigated. (Reduction in productivity of the remaining unit wells and decrease in unit ultimate recovery from that which would have otherwise occurred could be expected; and it would be necessary to weigh one set of conditions against the other to determine at what point such action should be taken).

These same conditions prevail today: so we see no real threat of serious reservoir damage that could be caused by wells drilled outside and to the west of the unit area. About the only differences now as compared to earlier when we first made the above assessment are the advent of price controls and the passage of the Windfall Profits Tax Act of 1980: these could increase the economic "pain" of bringing an outside well into unitization; but do not change the legal aspects of so doing. An owner seeking to keep his well out of the unit could offer the argument of economic hardship because of

the Windfall Profits Tax, but just as these arguments fell on deaf ears when the Congress passed this act, it is probable that such a plea appealed from an OCD ruling would probably bring "short shrift" from the courts.

The problems of competitive drilling and bringing outside wells into the unit are not limited to the "outside" parties; the income tax consequences to the existing Canada Ojitos Unit Participating Area owners of the resulting investment adjustment would also be much less desirable than that of drilling the well initially - so although there is "protection" afforded present unit owners as discussed above, it does not come without a price.

(Additional remarks regarding the problems of competitive drilling are set out in Attachment 5 herein).

ATTACHMENT NO. 5
ORIENTATION OF SPACING UNITS

The unit operator suggests that the present 320 acre spacing order be amended to provide for orientation of well spacing units by dividing each section into an East and a West half. There are a number of reasons supporting this recommendation, three of which - protection of correlative rights, avoidance of drilling unnecessary wells and relations between unit owners and outside parties - are discussed below.

Spacing of wells in the West Puerto Chiquito Pool is currently under order no. R-2565-C established by the New Mexico Oil Conservation Commission in 1970, following a three year temporary spacing order set in 1966. Both the temporary and the final orders provide for 320 acres per well, being any two contiguous quarters within a governmental section (which are not otherwise allocated to a well).

At the time of establishing the initial temporary order there was no reason to consider orientation of the spacing units; and even when the hearing for the final order was held the pressure maintenance program in the Canada Ojitos Unit had been in operation only a little over a year, and it was not definitely known that it would continue successfully.

Now, however, this project is nearly twelve years old; and its presence has added a new dimension to reservoir behavior just as identifiable and as important as other physical characteristics of pressure, temperature, viscosity, transmissibility and etc; and orderly future development requires recognition of this new dimension.

Although it should be noted that the existing unit area occupies about 62% of the surface area of the presently designated West Puerto Chiquito Mancos pool and overlies a share of the ultimately recoverable reserves therefrom of 80% to 90%, the significant element which the unit adds - through the pressure maintenance project - is the migration of gas along the geological strike of the producing formation and the resulting downdip flow of reservoir fluids (from updip injection wells to downdip recovery wells). This, plus the formation's unusual - but nevertheless demonstrated and effective - long distance drainage characteristics nullify, as to any area in communication with the main reservoir, the equal opportunity of wells located therein to recover oil from an equivalent spacing area - as propounded by the theory of compensatory drainage (for wells on "non-square" tracts); and consequently it could be difficult to achieve protection of correlative rights between wells inside and those downdip (to the west) outside the unit if those outside are drilled under "competitive" conditions.

We believe this to be a unique situation - not to be found elsewhere in New Mexico - and so a unique solution is warranted.

Orientation of spacing units will not completely solve this problem of protection of correlative rights - but it could reduce by one-half the otherwise resulting inequity, and accordingly is, in our opinion, justified.

Under competitive drilling not only is protection of correlative rights a problem without orientation of spacing units, but also there would exist an unwarranted potential for overdrilling: two wells in the east half of sections offsetting the unit's west boundary could require two "inside" wells to "legally" prevent drainage - the consequence being twice as many wells along the boundary as otherwise necessary; all of which would violate the intent of order R-2565-C, entered following case no. 3455 in which one of the findings was that 320 acre spacing was required "...in order to prevent the economic loss caused by the drilling of unnecessary wells...".

It may not be possible to eliminate all inequity in the protection of correlative rights nor to eliminate all economic waste through prevention of drilling of some unnecessary wells; but certainly the rules should be so written as to prevent their "abuse" and to reduce to a minimum the unnecessary wells with which the parties must contend.

This potential abuse could take place only in the area just west of the present unit: to the south and east the unitized lands probably overlap the productive area; and to the north we anticipate another unit with a "boundary agreement" eliminating any inequity. Also, if unitization of the west area as recommended elsewhere herein can be accomplished, there should be no problem even here; and consequently no need anywhere in the pool for such an order.

However, except for the northwest area where unit owners' lands lie, unitization is not yet assured, and should drilling under competitive conditions be undertaken, efforts might be made to "abuse" the existing order as indicated above by the drilling of two wells in the east half of sections adjoining the Canada Ojitos Unit Participating Area west boundary. Such abuse, if allowed, not only would complicate the protection of correlative rights and perhaps result in overdrilling but would adversely affect the unit operation and its relations with outside parties. These other problems resulting from competitive drilling should only occur if commercial production rates are established - and this alone is a rather large if ; but we cannot rely on it to assure us of trouble-free development. Some of these issues and problems are discussed next.

If commercial production offsetting the unit is established by drilling on a competitive basis then the unit owners would expect to follow one of the three following courses:

1. Pay compensatory royalty; or

2. Drill offset wells inside the unit to meet the outside

wells; or

3. Bring the outside wells into the unit.

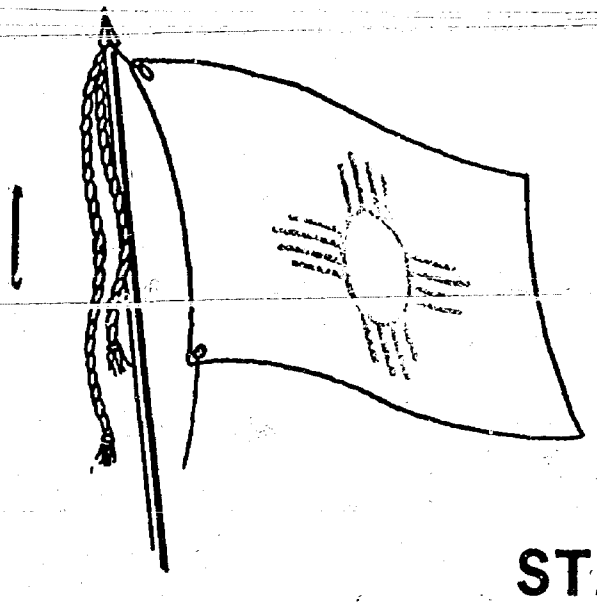
Since paying compensatory royalty is usually unsatisfactory and offset wells inside the unit would be "unnecessary wells" from standpoint of reservoir depletion, the unit owners would probably opt to bring any outside well into the unit. The cost to unit owners would be about the same: paying 100% of the cost of an "inside" well to meet the offset; or approximately a "net" of 60% (after investment adjustment) of the cost of an outside well by reason of bringing it into participation (if about one section were brought in with the well) plus the burden of greater income tax liability.

The "outside" owner could be expected to be unhappy: he took the drilling risk, and if unsuccessful he has nothing; and if successful - a commercial well - the unit reimburses him 60% of his cost and he is left with about 2% of unit production (or 1% for each of two 320-acre wells).

His situation is bad enough if oil prices and taxes were the same: but they're not; outside the unit his oil price approaches $40.00 per barrel with a 30% Windfall Profit Tax, whereas after coming into the unit the price (currently) would approximate $[illegible] per barrel for his share of the oil and Windfall Profits Tax rate would be 50% to 70% depending on his category. Some relief in price will occur in the next 1½ years, but the Windfall Profits Tax burden will be with him for at least ten years.

As indicated in Attachment No. 4 herein, the bringing in of outside competitively-drilled wells would be economically "painful" - and it's doubtful that relief could be expected through legal action; and although orientation of spacing units won't completely solve this problem for either party, it could cut in half the economic misery of the "outside" party, while at the same time reducing the investment and income tax liabilities of the "inside" parties by minimizing the number of unnecessary wells and their associated costs.

Unitization of the "outside" lands and proper planning can eliminate all of the above described problems of drilling under competitive conditions, but as pointed out earlier unitization is not yet assured; and, absent unitization, the herein recommended change in pool rules is desirable.



STATE
OF
NEW MEXICO

ENERGY AND MINERALS DEPARTMENT

OIL CONSERVATION DIVISION

RULES AND REGULATIONS

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7075 Exhibit No. 6
Submitted by Koch
Hearing Date 11/24/80

(2) Casing strings in wells drilled with cable tools may be tested as outlined in sub-paragraph (c) (1) above, or by bailing the well dry in which case the hole must remain satisfactorily dry for a period of at least one (1) hour before commencing any further operations on the well.

(d) Requirements for tubing of wells are as follows:

(1) All flowing oil wells equipped with casing larger in size than 2 7/8-inch OD shall be tubed.

(2) All gas wells equipped with casing larger in size than 2 7/8-inch OD shall be tubed.

(3) Tubing shall be set as near the bottom as practical and tubing Perforations shall not be more than 250 feet above the top of the pay.

(4) The Division Director may, upon proper application, grant administrative exceptions to the provisions of sub-paragraphs (2) and (3) above, without notice and hearing, provided waste will not be caused thereby.

(e) The Division's District Supervisors or their representatives shall have authority to approve tubingless completions without the necessity of administrative approval or notice and hearing when the following conditions exist:

(1) The well is to be completed with a total depth of 5,000 feet or less,

(2) The well is not a wildcat (it is not more than one mile from an existing well producing from the same common source of supply to which it is projected),

(3) No known corrosive or pressure problems exist which might make the tubingless method of completion undesirable,

(4) The well will not be a dual completion,

(5) The tubing used as a substitute for casing will be either 2 3/8-inch OD or 2 7/8-inch OD.

RULE 108. DEFECTIVE CASING OR CEMENTING

In any well that appears to have a defective casing program or faultily cemented or corroded casing which will permit or may create underground waste, the operator shall proceed with diligence to use the appropriate method and means to eliminate such hazard of underground waste. If such hazard of waste cannot be eliminated, the well shall be properly plugged and abandoned.

RULE 109. BLOWOUT PREVENTION (See Rule 114 (b) also)

(a) Blowout preventers shall be installed and maintained in good working order on all drilling rigs operating in areas of known high pressures at or above the projected depth of the well and in all areas where pressures which will be encountered are unknown, and on all workover rigs working on wells in which high pressures are known to exist.

(b) Blowout preventers shall be installed and maintained in good working order on all drilling rigs and workover rigs operating within the corporate limits of any city, town, or village, or within 1320 feet of a habitation, school, or church, wherever located.

(c) All operators, when filing Form C-101, Application for Permit to Drill, Deepen, or Plug Back, or Form C-103, Sundry Notices, for any operation requiring blowout prevention equipment in accordance with Sections (a) and (b) above, shall submit a proposed blowout prevention program for the well. The program so submitted may be modified by the District Supervisor if, in his judgment, such modification is necessary.

RULE 110. PULLING OUTSIDE STRINGS OF CASING

In pulling outside strings of casing from any oil or gas well, the space outside the casing left in the hole shall be kept and left full of mud-laden fluid or cement of adequate specific gravity to seal off all fresh and salt water strata and any strata bearing oil or gas not producing.

RULE 111. DEVIATION TESTS AND DIRECTIONAL DRILLING

(a) Any well which is drilled or deepened with rotary tools shall be tested at reasonably frequent intervals to determine the deviation from the vertical. Such tests shall be made at least once each 500 feet or at the first bit change succeeding 500 feet. A tabulation of all deviation tests run, sworn to and notarized, shall be filed with Form C-104, Request for Allowable and Authorization to Transport Oil and Natural Gas. When the deviation averages more than five degrees in any 500-foot interval, the Division Director may require that a directional survey be run to establish the location of the producing interval(s).

The Division Director, at the request of an offset operator, may require any operator to make a directional survey of any well. Said directional survey and all associated costs shall be at the expense of the requesting party and shall be secured in advance by a $5,000.00 indemnity bond posted with and approved by the Division. The requesting party may designate the well survey company, and said survey shall be witnessed by the Division.

(b) No well shall be intentionally deviated without special permission from the Division. Permission to deviate toward the vertical to straighten a crooked hole, to deviate toward the vertical or in an indeterminate direction to sidetrack junk in the hole, or to drill a relief well to control a blow-out shall be obtained from the appropriate District Office of the Division on Division Form C-103 with copies of said Form C-103 being furnished to all offset operators. Permission to deviate a well in any other manner or for any other reason will be granted only after notice and hearing. Upon request from the Division Director, any well which was deviated in an indeterminate direction or toward the vertical shall be directionally surveyed. In addition, a directional survey of the entire well bore must be made on any well which was deviated in a predetermined direction, except toward the vertical. The District Office of the Division shall be notified of the approximate time all directional surveys are to be conducted. All directional surveys run on any well which was intentionally deviated in any manner for any reason must be filed with the Division upon completion of the well. The Division will not assign an allowable to a well until the operator has submitted an affidavit that all such directional surveys have been filed.

RULE 112-A. MULTIPLE COMPLETIONS

I. The multiple completion of any well may be permitted only by order of the Division after notice and hearing, except as hereinafter provided. Multiple completion of any well without prior approval by the Division shall be solely at the operator's risk and shall be no way commit the Division to subsequent approval thereof.

II. MULTIPLE COMPLETIONS (CONVENTIONAL)

The Division Director shall have the authority to grant an exception to the requirements of Rule 112-A (I) and approve the dual or triple completion of a well to produce from more than one common source of supply without notice and hearing when application for such approval has been filed on Form C-107; and

(a) The Division has previously authorized the similar multiple completion of a well in the same common sources of supply as proposed, after notice and hearing; provided however, that in Rio Arriba, San Juan, Sandoval, and McKinley Counties, a proposed multiple completion may be approved if the Division has previously authorized the similar multiple completion of a well in the same formations as proposed, after notice and hearing; and

(b) The applicant proposes to utilize one of the mechanical installations described below:

(1) The well is to be completed as a gas-gas dual or as a gas-gas-gas triple and the hydrocarbons from each of the zones can be safely and efficiently produced through parallel strings of tubing or a combination of tubing string(s) and the tubing-casing annulus.

(2) The well is to be completed as an oil-oil dual or as an Oil-oil-oil triple and the hydrocarbons from each of the zones can be safely and efficiently produced through parallel strings of tubing.

(3) The well is to be completed as a combination oil and gas multiple completion and the hydrocarbons from each oil zone can be safely and efficiently produced through parallel strings of tubing and the hydrocarbons from each gas zone can be safely and efficiently produced through parallel string(s) of tubing or through a combination of tubing and the tubing-casing annulus; and

(c) All strings of tubing used for the production of oil in the proposed multiple completion will have a nominal inside diameter of not less than 1.670 inches nor greater than 2.50 inches; and

(d) The packer(s) used to segregate the separate zones of the multiple completion will be production-type packer(s) and shall effectively prevent communication between all producing zones.

III. MULTIPLE COMPLETIONS (TUBINGLESS AND COMBINATION)

The Division Director shall have the authority to grant an exception to the requirements of Rule 112-A (I) and approve the multiple completion of a well without notice and hearing where application has been filed on Form C-107; and

(a) The Division has previously authorized the similar multiple completion of a well in the same common sources or supply as proposed, after notice and hearing; provided however, that in Rio Arriba, San Juan, Sandoval, and McKinley Counties, a proposed multiple completion may be approved if the Division has previously authorized the similar multiple completion or a well in the same formations after notice and hearing; and

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
6 August 1980

EXAMINER HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for amendment of pool rules, Rio Arriba County, New Mexico.

CASE 6997

BEFORE: Daniel S. Nutter
(On 7 August 1980)

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division: Ernest L. Padilla, Esq.
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant: George L. Verity, Esq.
BAY, HAMILTON, LEES, SPEARS & VERITY
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BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7025 Exhibit No. 4
Submitted by Koch
Hearing Date 11/24/80

and I want to say now, that I hope Your Honor will interrupt for questioning any time there's something that you don't quite understand or you would like to explore more fully, and as a matter of fact, I also would like to invite Mr. Friend, I believe it is, and Ms. Umshler, who are here from Koch and from USGS, to interrupt with questions as we proceed with this testimony, because I want everybody to understand it and I think that that would save time and be the best way to do it, Your Honor, and we invite that.

All right, Mr. Greer, now directing your attention to the second part of Section A of Exhibit One. Will you explain that exhibit to us?

A. Yes, sir. Here we'd like to go a little bit beyond, or outside the scope of engineering, perhaps, to talk a little bit about the reasons why this pool might be where it is, and some of the geological concepts as to why we find oil in these places, and as a result, then, where the probable boundaries of the pool, the reservoir, are, and then from that to draw some conclusions about the expansion of the area with additional development.

And I might say at the outset that just as all the engineering features have been interesting in this pool, one of the most interesting ones I've ever studied, so are some of the geological concepts.

The theory that I like best, the one to

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which I subscribe, as to why this oil reservoir exists where it is, has to do with the fracturing of the formation and creating of reservoir void space by fracturing, and this is brought about by flexing of the formation.

Since our 1969 hearing one of the geologists who work for us made a study based on the fracturing characteristics of dolomite and calcite and he came up with the theory that where you have a high percent of dolomite, that the formation is more brittle, more apt to fracture than if it's calcite, and he found a high percent of dolomite in wells in this area, and when we add those two things together, it makes sense to me.

Now there are some other theories, one of which we have the old "creekology" theory that, we've had some of the geologists come to us and say, well, we can trace the canyons here and where the good wells are and it's old "creekology", and of course, the answer to that is that where this pool lies in Santa Fe National Forest, a really beautiful forest, topography is rugged. Differences in elevation of 1000 or 1500 feet in just a short horizontal distance, the net result of it all being that from a standpoint of not destrying the forest, doing our best to operate here and to protect it, and also drill wells at minimum cost, we just keep them in the canyons where it's easy to get to them.

So that kind of answers the "creekology"

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theory, but pursuing the "creekology" theory, we've had some of the geologists that subscribe to the fault theory, that here are faults and where you have faults is where the production is, and they give us an east/west fault down through some of the better wells, and of course that sounded fine until we -- until we drilled a well 3 or 4 miles north of their fault system and got another good well, and then we drilled 3 or 4 miles south and we got another one, and then they have to go back to their areal photo maps and try to find some more lines they didn't see at first.

So the end result of all of it is that the one theory or concept that seems to best fit this reservoir is the one where the formation flexes, you have fracturing, and where you have fracturing you have, over a fairly wide area, reservoir with enough porosity and permeability to give production, allow production.

And when we ran an interference test that pretty well confirmed it, in that there's just no way that we have a high concentration of oil in any one area. It has to be small volume of oil per acre over a large area.

Briefly, the flexing features that we recognize here, first I might say that the boundaries of the pool on this map, the more or less north/south orange colored line is one that separates the East and West Puerto Chiquito Pools. The north boundary is the north part of the map. The

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west boundary of the pool is the west part of the map, and the south part of the pool is the south part of the map.

We can look about the center of the map on the east side near the C-5 injection well, and the color coding and symbols of these wells, the triangular ones are injection wells; the blue are wells -- are shut-in observation wells; those colored in red are the ones that are currently producing.

Near the C-5 Well in the blue shaded area is the first flex from the outcrop, and maybe a couple miles to the east, the dashed line is the outcrop of the formation that produces here. And the dip of the formation from the outcrop into the blue shaded area runs from like 2 to 3000 feet per mile. It's a steep dip, fairly uniform dip, and in areas, not here, but on the west side of the basin, where we cored wells in this part of the formation, we'd always find a hard, tight, compact, no transmissibility.

MR. HUTTER: As I understand it, Mr. Green, now you've got 200 foot contours, right, like right there where the C-5 is?

A Right, and to the --

MR. HUTTER: And to the east those are all 1000 foot contours.

A Those are 1000 foot, right, and at that point at the blue coloring to the west, we start with 200 foot

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contours. And there in the blue shaded area in Section 5, why, instead of 2-to-3000 feet per mile, we're down to about 1000 feet per mile, so there's the first real flex.

Then the green shaded area, we're looking in round numbers at 4-to-500 feet per mile, so there's another flex.

Then in the brown shaded area we drop down to about 200 feet a mile.

And then when we get over into the grey shaded area, why, it's less than 200 feet a mile, maybe 100 feet a mile, and on farther west within the pool, we're looking then at a fairly flat dip of less than 100 feet per mile.

The best wells have been those right up and down the center in and near the brown and green shaded areas. To the north there's a deterioration of -- of the production, and the zones we can see a little bit on some of the cross sections we'll look at later, the four wells clustered at the end of the coloring, the brown coloring to the north of those four, two of the wells have capacities like 30 to maybe 50 barrels a day. Two of them have capacities less than 10 barrels a day.

Then on the very south part of the pool, in that blue shaded area, the contours spread again and we feel that not only is there a shallow dip there, that probably will be unproductive, but also this is sort of a re-

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entrance. We can see that the, moving from right to left across the blue colored area, you're just moving up a little valley, in a sense. Where we've had the same kind of a re-entrance in East Puerto Chiquito on the very north part of the pool, we've also had low capacity or nonproductive wells.

Now we don't know that the south part of the pool south of the unit will be nonproductive and we think it should not be taken out of the pool until somebody wants to drill a well there and determine for certain, but our feeling is it probably will not produce.

On the east boundary we believe we've pretty well defined that by the change in the flexing of the formation as it falls generally, that east side of the blue shaded area and our orange boundary between the two pools.

To the north, between the orange colored boundary and the green and blue shading, where we have no coloring at all, is an area of fairly uniform dip, and my feeling is that it probably will be a very low capacity wells, if any at all, in there, and the only value we can see of that probably would be for location of an injection well or two to take care of the wells in the proposed North Canada Ojitos Unit.

MR. NUTTER: Mr. Grear, is this change in dip and flexing evident from the surface or is it too mountainous to see it?

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A. It's pretty hard to see. Right at the outcrop you can get a good dip of the formation there.

MR. NUTTER: At that point.

A. At that point, and that then fits pretty well the subsurface control in that area. And from there on we're limited pretty much to the -- to the subsurface work.

Q. Mr. Greer, would you explain briefly for us the plan of your Canada Ojitos Unit?

A. Yes, sir. After we ran the interference test in 1965, and it confirmed some of our earlier suspicions, you might say, of the character of the formation, we concluded a couple of things.

One was that we had to have wide spacing. We had to have control rates of production in order to try to achieve gravity drainage efficiency, and this was an instance where pressure maintenance could have a most dramatic effect. Most pressure maintenance projects, we look at increases in production of something comparable to primary production. If, for instance, the primary production from a field is like a million barrels, why, in round numbers and rule of thumb, you ordinarily can say, well, by waterflooding we might get another million barrels, and by tertiary methods, perhaps, you can get up to that amount again.

But you're looking at only, ordinarily, something like doubling what you might otherwise get.

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BENSON-MONTIN-GREER DRILLING CORP.
221 PETROLEUM CENTER BUILDING
FARMINGTON, NEW MEXICO 87401
PHONE: 325-8874

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OIL CONSERVATION DIVISION
SANTA FE

November 12, 1980

Mr. Dan Nutter
New Mexico Oil Conservation Division
Box 2088
Santa Fe, NM 87501

Re: CASE 7075

Dear Mr. Nutter:

As part of our presentation in Case 7075, we will be referring to our estimate of total reservoir oil in place and future recoverable volumes of oil for the Canada Ojitos Unit. Since we are quite limited in methods available to determine oil in place because it is a fractured reservoir, we have felt the best information is pressure - production history. This however, is complicated by the fact that the oil was initially undersaturated and also the fact that as the bubble point moves down-dip, the compressibility of the overall system changes markedly until the bubble point reaches the bottom of the structure. In our instance, we commenced gas injection before the bubble point reached the down-dip limits, so this poses an additional difficulty in estimating oil in place.

Because the calculations, although not particularly complex, do involve some procedures not ordinarily encountered; and accordingly it could require an otherwise unnecessarily long amount of time to explain in a hearing; and in view of this I am sending you now some information with regard to reserves which we will present at the hearing in this case. We have already given to the protestants in our application this method of calculation; and it may be that they will accept it, and that it will not be necessary to go into detail about it. Hopefully this will be the case so that we can at the hearing simply identify the exhibits and go on.

If however, they should elect to make an issue of it, it could be helpful if you have had an opportunity for a review of the method used prior to the hearing.

I believe the notes included with the exhibits are self-explanatory, however I will point out here that in the example calculation shown on Plate IV-10 the resulting point (1.9% free gas saturation) found at the juncture of 70% fraction of undersaturated oil on the horizontal scale and 90% on the vertical scale is shown with a red circle on the enclosed Plate IV-8 (also oil in place of 38.4 MMbbls appears at the same spot).

...

Also with respect to the volume of oil which is undersaturated at any one particular time and the relative per acre volumes of oil shown on Plate IV-7, our interference tests showed 1500 to 2000 barrels an acre average for a rather large part of the reservoir and 1600 barrels an acre for the up-dip area (blue color on Plate IV-7). One possible interpretation of the distribution of the per acre volume of oil is shown on this Plate IV-7 in which the blue area represents 1500 barrels an acre and the combination of the green and the brown areas would approximate 1800 to 1900 barrels an acre, for an overall average of about 1600 or 1700 barrels an acre.

The further assumption must be made that these relative values of per-acre oil in place extend north and south of the colored area to whatever distances are required to cover the reservoir (pressure - production can only tell us volume of course, not where it is located).

The information used for these calculations was obtained in 1965 and 1966. It is my opinion that information gathered since that time would be of little additional help in estimating total oil in place because of the complexities arising from the gas injection, amount of this injected gas that is absorbed in the undersaturated oil, gas lost to other formations, and the overall problem of accurate measurement of net injected gas where we are dealing with differences in measured volumes.

If you have any questions, of course I will be pleased to supply additional information now or be prepared to bring it to the hearing.

Yours truly,

BENSON-MONTIN-GREER DRILLING CORP.

BY: Albert R. Greer
Albert R. Greer, President

ARG/tlp

Enclosures

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CANADA OJITOS UNIT

OIL RECOVERY ESTIMATE

November, 1980

	ESTIMATE RANGE From (MM bbls)	To (MM bbls)
Total Initial Oil in place	30	50
In high capacity fracture system (1/2)	15	25
In "tight blocks" (1/2)	15	25
Recovery from high capacity system 55%	8.2	13.8
Recovery from tight blocks 25%	3.8	6.2
Total recovery	12.0	19.0
Produced to 1981	6.6	6.6
Remaining future from 1981	5.4	12.4
	(Use 5	to 10)

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DESCRIPTION OF METHOD OF CALCULATING OIL IN PLACE

CANADA OJITOS UNIT

Initial oil in place in the Canada Ojitos Unit was estimated from compressibilities of the various reservoir characteristics and the production-pressure relation of 3,000 barrels per pound which was observed from October, 1964 to July, 1965, and for the production-pressure coefficient of 6,000 barrels per pound which occurred during the time period May, 1966 to October, 1966.

For the time when the coefficient was 3,000 barrels per pound it is believed that the amount of oil that was undersaturated would be in the range of .8 to .95 of total reservoir volume. The oil in place for this coefficient is shown on the plat next following identified as Plate IV-3. This is for formation compressibility (C_f) ranging from 7×10^{-6} to 23×10^{-6} and free gas saturation ranging from zero to 5 percent of pore space. The relation for .8 to .95 fraction of the oil that was undersaturated is shown by the area colored in green.

The same information is shown on Plate IV-4 for the time period when the coefficient was 6,000 barrels per pound and the fraction of total oil assumed to be undersaturated is in the range of .4 to .8.

The main indefinite factors in estimating the oil in place are the unknown compressibility of the formation and the unknown fraction of the reservoir which initially contained free gas. In order to narrow the range of estimates, calculations were made taking advantage of the fact that compressibilities changed from one period to the next yet presumably the compressibility of the formation and the volume of the gas cap were the same. This allows a calculation

in which the effect of the gas cap and the formation compressibility are combined; and since, for the purpose of determining total oil in place it makes no difference what the individual compressibilities are, it then becomes possible, by assuming a compressibility for the formation, to calculate the amount of free gas initially existing.

This is accomplished by first determining the relation of compressibility of saturated oil and gas released from it as pressure drops. This is shown on Plate IV-5 herein.

The location of the bubble point pressure (1520 psig) as it moves downdip on the structure is shown herein on Plate IV-6.

Statistics resulting from location of the bubble point pressure are shown herein on Plate IV-9.

By assuming various combinations of fraction of undersaturated oil for the first condition and the second condition one can calculate the amount of free gas; and from this to calculate compressibility - and from this the volume of oil in place. A sample calculation is shown herein on Plate IV-10. A series of these calculations permits the construction of the relations shown on the graph IV-8.

Estimates of oil in place were made under six separate assumed situations. These are described below by number and shown by colored circles on the Plate IV-8:

Situation No. 1:

This assumes 87% of oil was undersaturated under Condition No. 1 and 72% under Condition No. 2. This results if the per acre oil in place to varies with structural position as shown herein on Plate IV-7.

Situation No. 2:

This assumes reservoir oil in place was as shown on Plate IV-7 except that the downdip boundary of the reservoir is assumed to be the west side of the green-colored area. The area colored in brown is assumed to be non-productive. This results in fraction of undersaturated oil under the first condition to be 85% and under the second condition to be 67%.

Situation No. 3:

This assumes the reservoir to extend across the colored area with an equal per-acre volume of oil in place throughout. This results in fraction of oil undersaturated in the first condition of 84% and under the second condition 66%.

Situation No. 4:

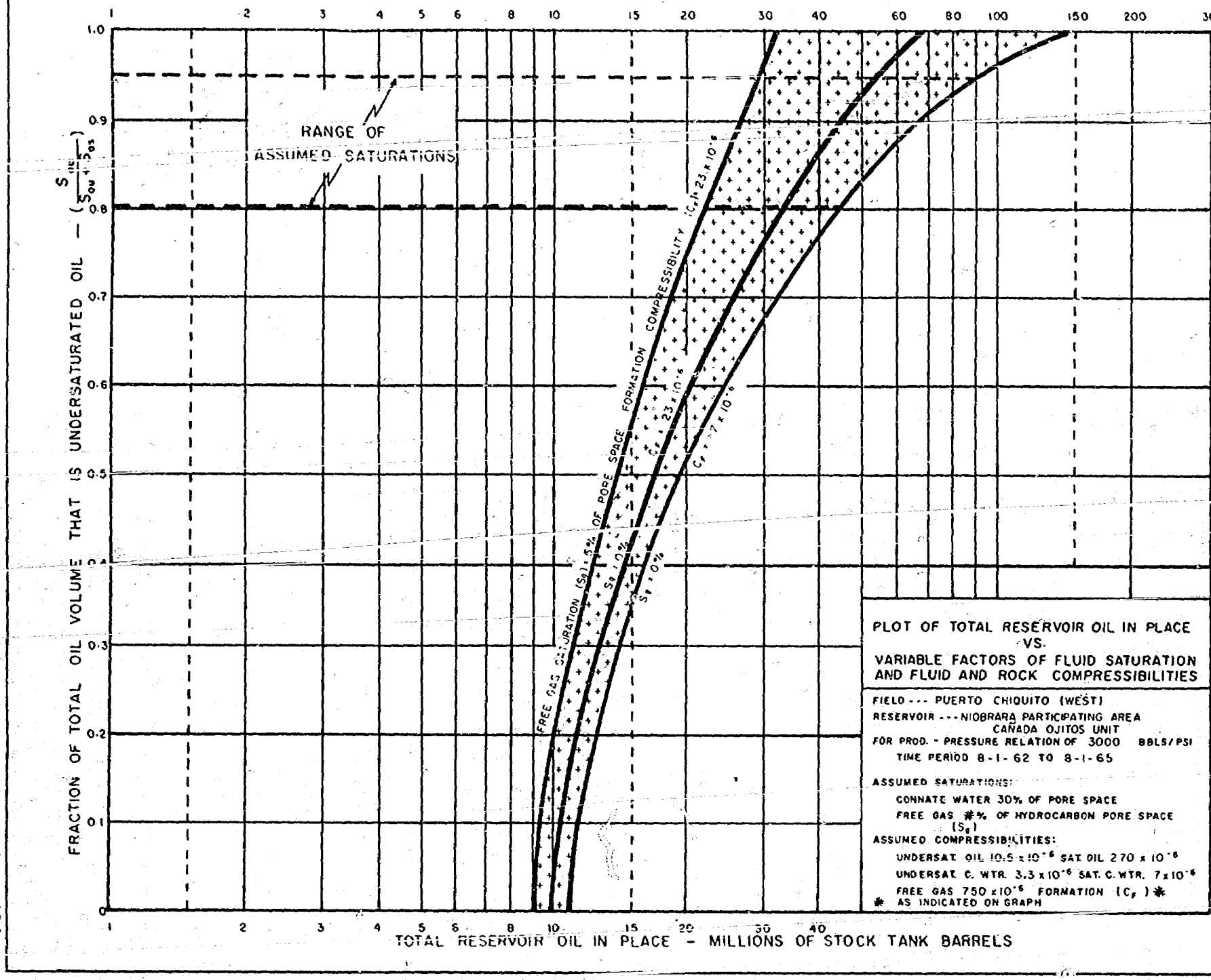
This assumes equal per-acre volume of oil in place with the downdip boundary being the west side of the green-colored area on Figure IV-7 and extending up to the 1600-foot contour interval. This results in fraction of the oil undersaturated under the first condition to be 80% and under the second condition 56%.

Situation No. 5:

This assumes the downdip limit of the reservoir to be the west boundary of the green-colored area on Plate IV-7 and the updip limit of the reservoir to be at the 1500-foot contour interval (rather than 1600-foot), with oil in place values as shown on Figure IV-7 and assuming the 1500 barrels per acre extends from the 1600-foot contour interval to the 1500-foot contour interval. This results in fraction of oil undersaturated under the first condition to be 91% and under the second to be 73%.

Situation No. 6:

This assumes east and west reservoir limits the same as in Situation No. 5 above, but with equal per-acre volumes of oil in place. This results in fraction of oil undersaturated under the first condition of 88% and under the second condition of 61%.

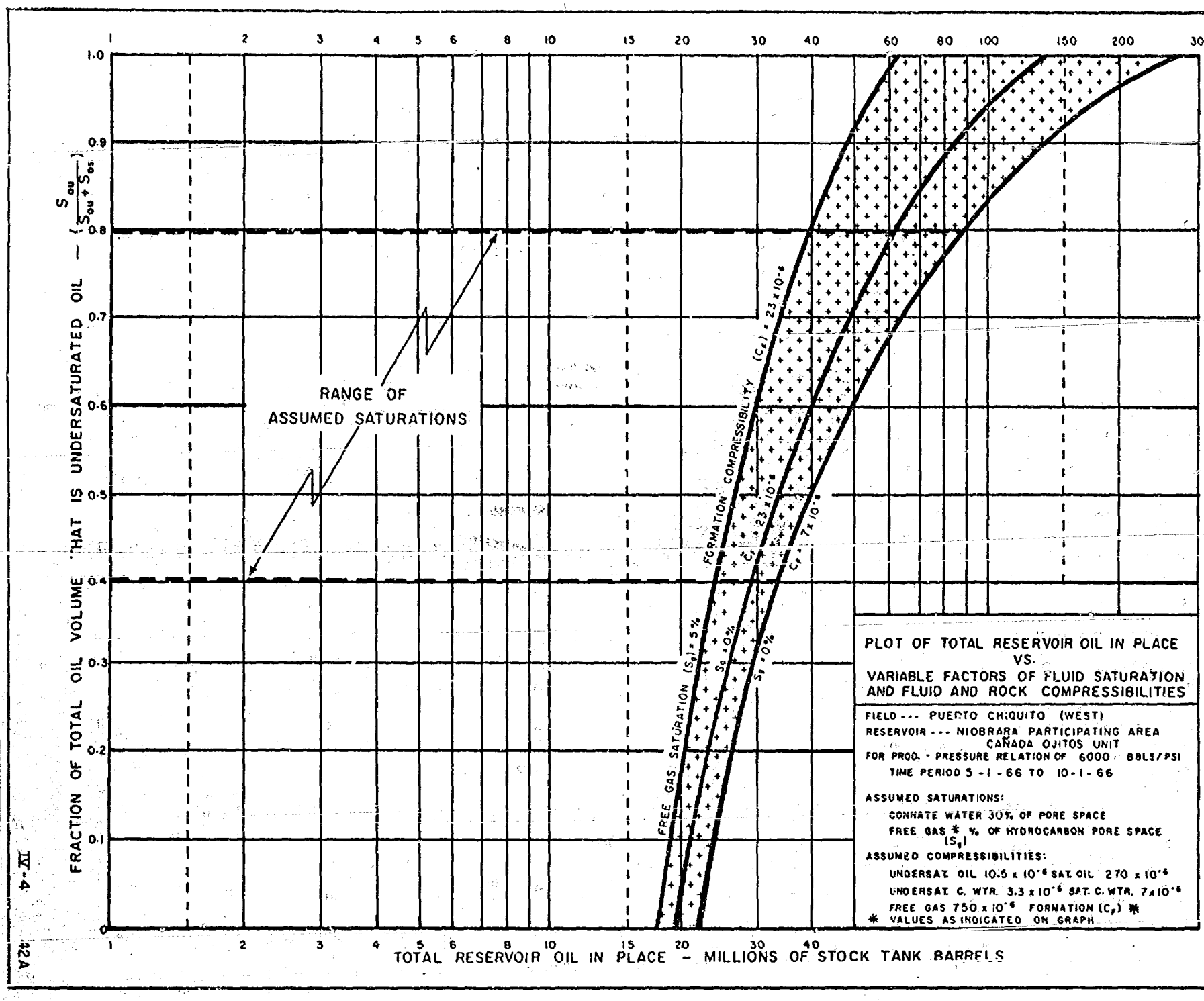


PLOT OF TOTAL RESERVOIR OIL IN PLACE
VS.
VARIABLE FACTORS OF FLUID SATURATION
AND FLUID AND ROCK COMPRESSIBILITIES

FIELD --- PUERTO CHIQUITO (WEST)
RESERVOIR --- NIOBRARA PARTICIPATING AREA
CAÑADA OJITOS UNIT
FOR PROD. - PRESSURE RELATION OF 3000 BBLS/PSI
TIME PERIOD 8-1-62 TO 8-1-65

ASSUMED SATURATIONS:
CONNATE WATER 30% OF PORE SPACE
FREE GAS #% OF HYDROCARBON PORE SPACE (S_g)

ASSUMED COMPRESSIBILITIES:
UNDERSAT OIL 10.5×10^{-6} SAT OIL 270×10^{-6}
UNDERSAT C. WTR. 3.3×10^{-6} SAT. C. WTR. 7×10^{-6}
FREE GAS 750×10^{-6} FORMATION (C_f) *
* AS INDICATED ON GRAPH

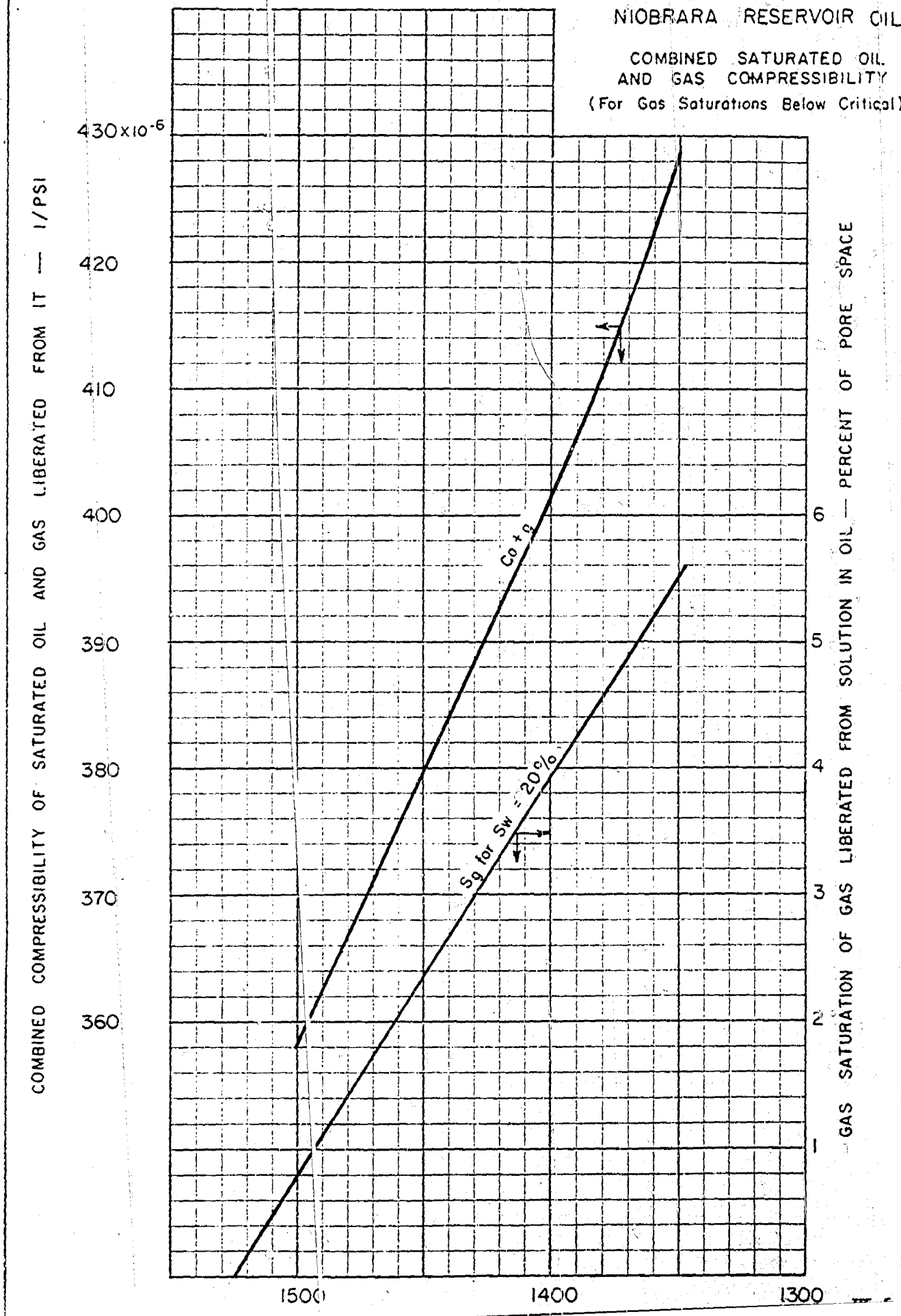

1
2
3
4
5
6
8
10
15
20
30
40
60
80
100
150
200
300
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
FRACTION OF TOTAL OIL VOLUME THAT IS UNDERSATURATED OIL — $\left(\frac{S_{ou}}{S_{ou}+S_{os}}\right)$
RANGE OF ASSUMED SATURATIONS
FREE GAS SATURATION (S_g) = 5%
S_g = 10%
S_g = 10%
FORMATION COMPRESSIBILITY (C_f) = 23 x 10⁻⁶
C_f = 23 x 10⁻⁶
C_f = 7 x 10⁻⁶
PLOT OF TOTAL RESERVOIR OIL IN PLACE
VS.
VARIABLE FACTORS OF FLUID SATURATION AND FLUID AND ROCK COMPRESSIBILITIES
FIELD --- PUERTO CHIQUITO (WEST)
RESERVOIR --- NIOBRARA PARTICIPATING AREA CANADA OJITOS UNIT
FOR PROD. - PRESSURE RELATION OF 6000 BBLS/PSI
TIME PERIOD 5 - 1 - 66 TO 10 - 1 - 66
ASSUMED SATURATIONS:
CONNATE WATER 30% OF PORE SPACE
FREE GAS * % OF HYDROCARBON PORE SPACE (S_g)
ASSUMED COMPRESSIBILITIES:
UNDERSAT. OIL 10.5 x 10⁻⁶ SAT. OIL 270 x 10⁻⁶
UNDERSAT. C. WTR. 3.3 x 10⁻⁶ SAT. C. WTR. 7 x 10⁻⁶
FREE GAS 750 x 10⁻⁶ FORMATION (C_f) *
* VALUES AS INDICATED ON GRAPH
1
2
3
4
5
6
8
10
15
20
30
40
TOTAL RESERVOIR OIL IN PLACE — MILLIONS OF STOCK TANK BARRELS

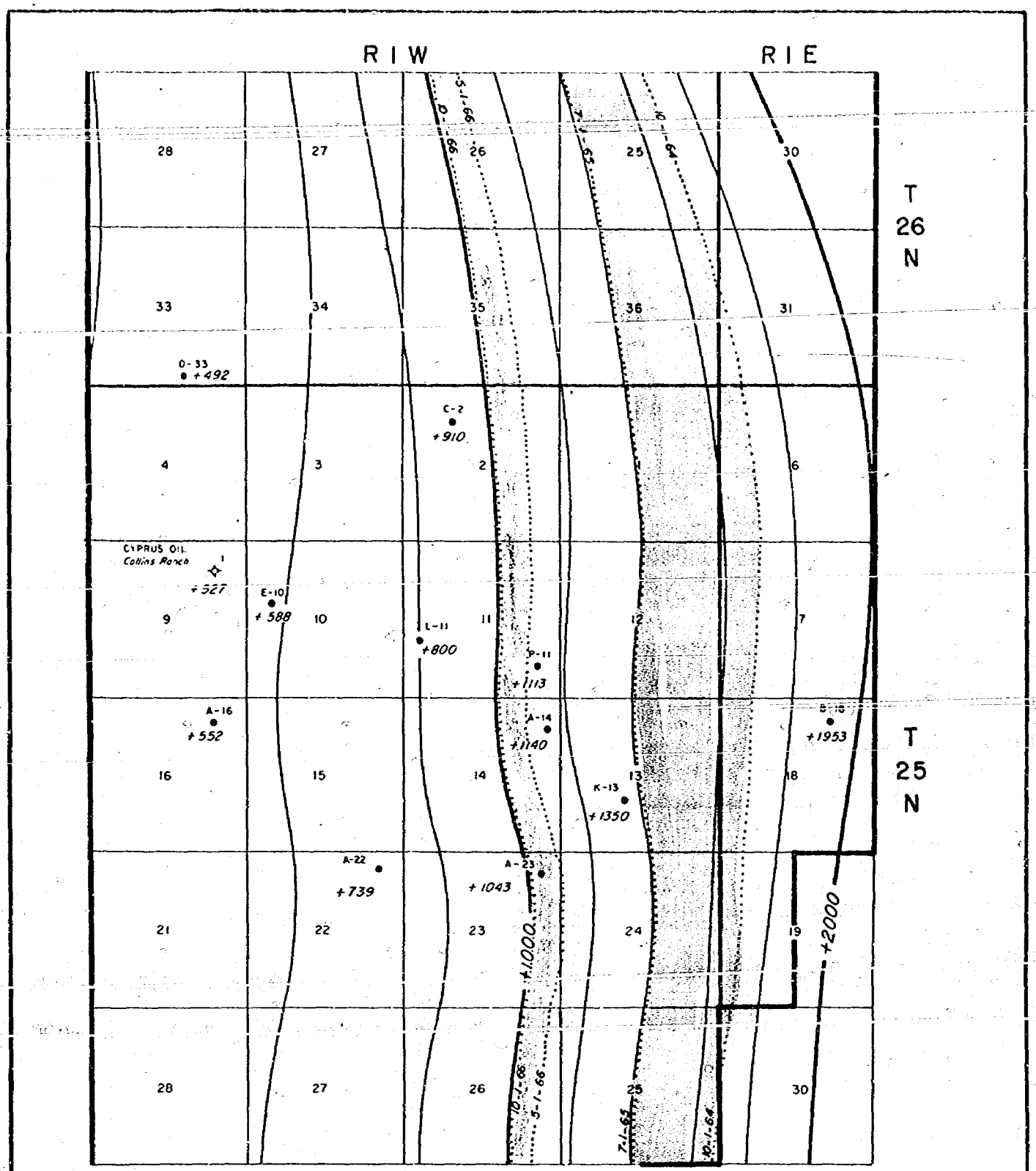
IX-4

42A

CAÑADA OJITOS UNIT
NIOBRARA RESERVOIR OIL

COMBINED SATURATED OIL AND GAS COMPRESSIBILITY
(For Gas Saturations Below Critical)





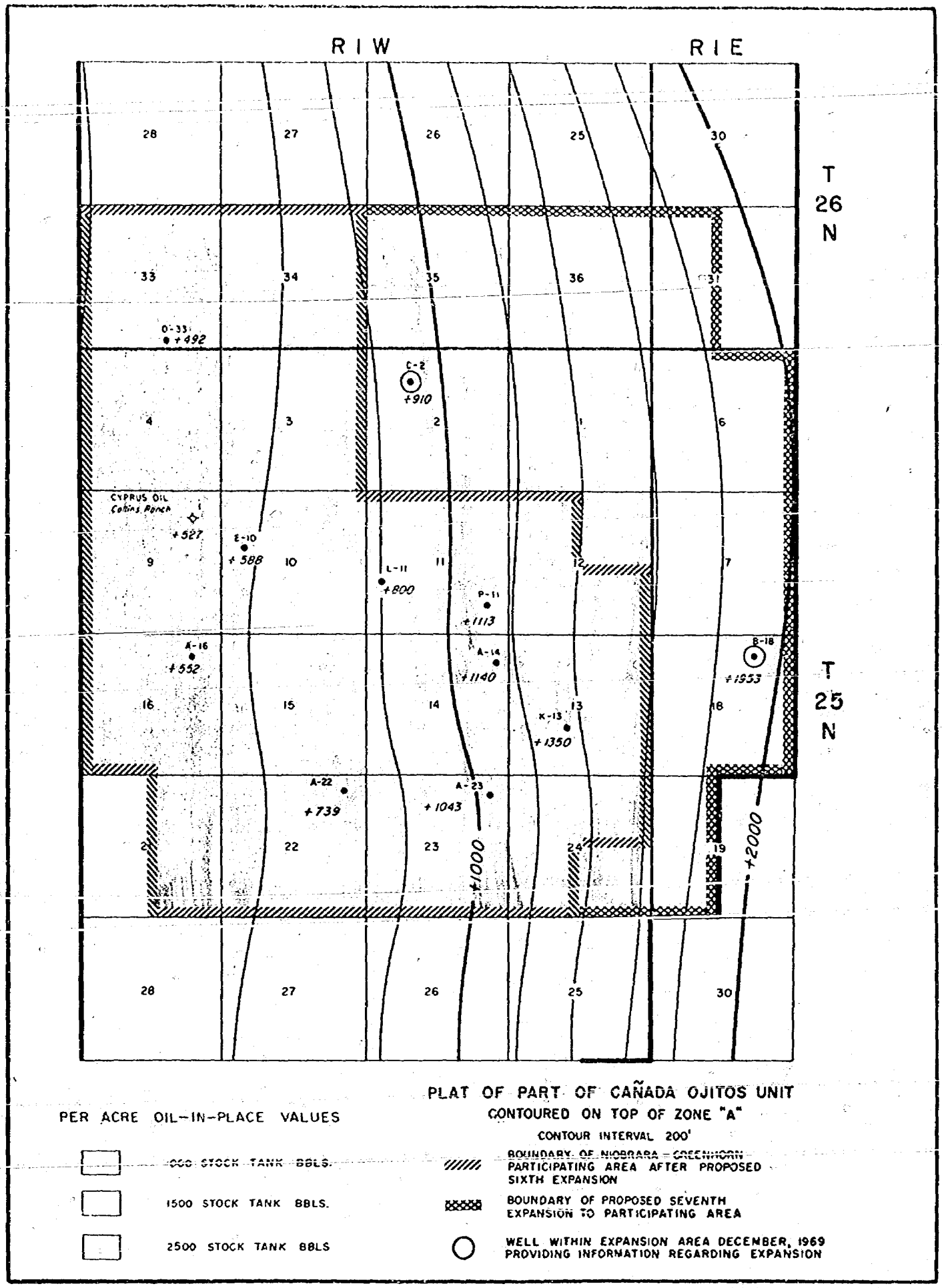
PLAT OF PART OF CAÑADA OJITOS UNIT

SHOWING MOVEMENT OF BUBBLE POINT PRESSURE
CONTOURED ON TOP OF ZONE "A"

CONTOUR INTERVAL 200'

..... LOCATION OF BUBBLE POINT PRESSURE AT DATE INDICATED

(TIME PERIOD: Oct. 1, 1964 To Oct. 1, 1966



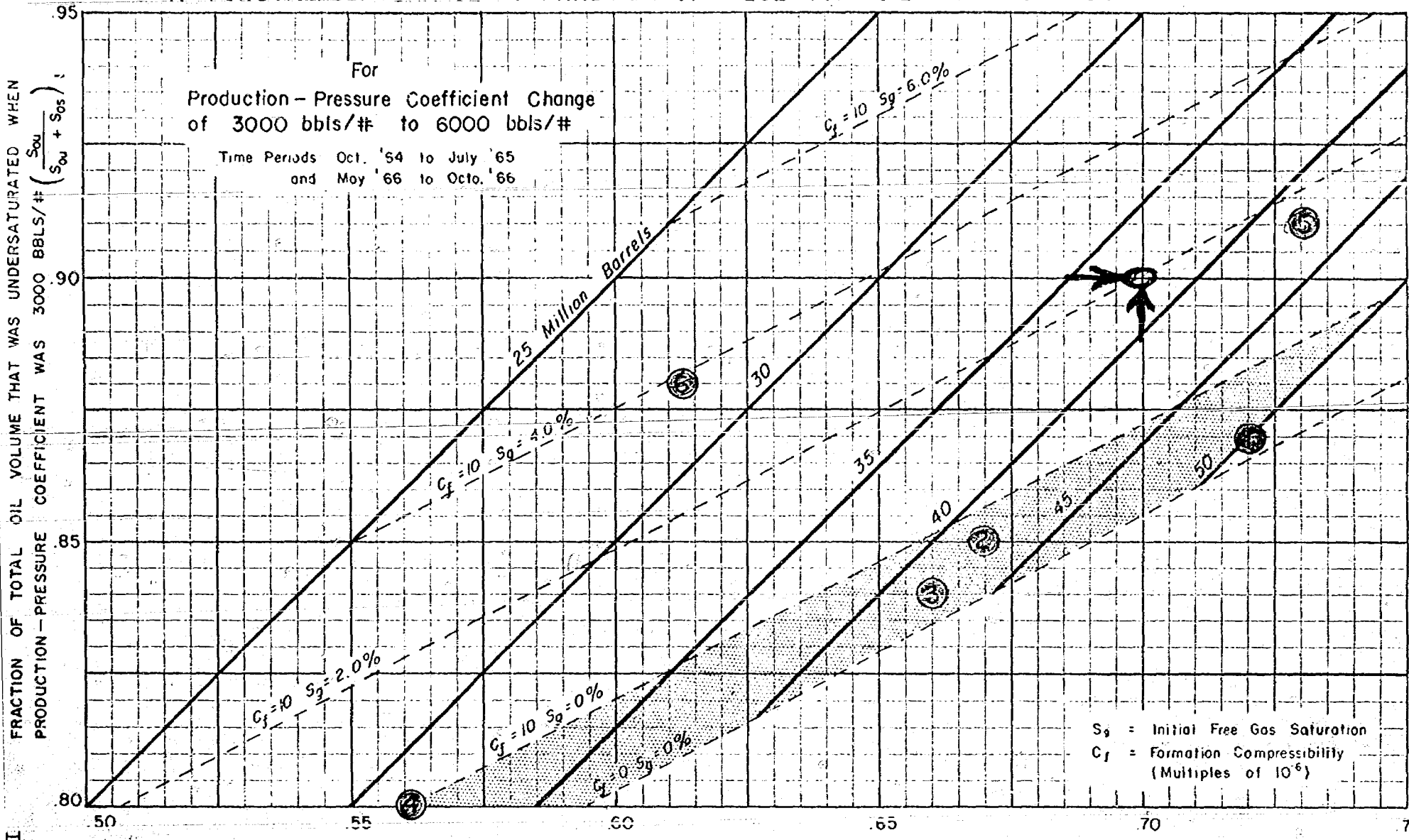
PER ACRE OIL-IN-PLACE VALUES

- 1000 STOCK TANK BBLS.
- 1500 STOCK TANK BBLS.
- 2500 STOCK TANK BBLS

PLAT OF PART OF CAÑADA OJITOS UNIT
CONTOURED ON TOP OF ZONE "A"
CONTOUR INTERVAL 200'

- BOUNDARY OF NIOBRARA - GREENHORN PARTICIPATING AREA AFTER PROPOSED SIXTH EXPANSION
- BOUNDARY OF PROPOSED SEVENTH EXPANSION TO PARTICIPATING AREA
- WELL WITHIN EXPANSION AREA DECEMBER, 1969 PROVIDING INFORMATION REGARDING EXPANSION

CAÑADA OJITOS UNIT
NIOBRARA RESERVOIR OIL IN PLACE
AS
A FUNCTION OF CHANGE IN FRACTION OF RESERVOIR OIL THAT IS UNDERSATURATED



INFORMATION USED IN ESTIMATING CANADA OJITOS UNIT OIL IN PLACE

		FIRST CONDITION	SECOND CONDITION
	Time period	October '64 to July '65	May '66 to October '66
	Pressure productivity coefficient	3000 bbl/#	6000 bbl/#
1)	Average reservoir pressure at 1195' datum	1530 psig	1422 psig
2)	Reservoir pressure at 1600' contour point (reservoir datum at 1600' contour point is 1650 - 150 = 1450 and 1450 - 1195 = ± 250) (1st) 1530 - (250) (.312) = 1452 (2nd) 1422 - (250) (.312) = 1344	1452 psig	1344 psig
3)	Contour point datum of bubble point pressure (1st) $\frac{1530 - 1520}{.312} + 1350 = 1382$ (2nd) $1350 - \frac{1520 - 1422}{.312} = 1036$	1382'	1036'
4)	Average pressure saturated oil	$\frac{1520 + 1452}{2}$ = 1486 psig = 1498 psia	$\frac{1520 + 1344}{2}$ = 1432 psig = 1444 psig
5)	Compressibility of combined saturated oil and gas liberated from it for average pressures of 1498 and 1444 (figure IV-5)	359×10^{-6}	383×10^{-6}
6)	Approximate average reservoir pressure of undersaturated oil (500' contour interval to bubble point contour)	1610 psig	1590 psig
7)	Compressibility of undersaturated oil	11.25×10^{-6}	11.35×10^{-6}

Example calculation on next page (pencilled notes) assumes that under first condition 90% of the oil was undersaturated and under the second condition that 70% was undersaturated:

Reservoir Characteristics	FIRST CONDITION Compressibility	FIRST CONDITION Saturation	SECOND CONDITION Compressibility	SECOND CONDITION Saturation
Undersaturated Oil	11.25×10^{-6}	90% of oil	11.35×10^{-6}	70% of oil
Saturated Oil	359×10^{-6}	10% of oil	383×10^{-6}	30% of oil
Connate Water	3.8×10^{-6}	20% of pore space	4.4×10^{-6}	20% of pore space
Free Gas	765×10^{-6}	Unknown	817×10^{-6}	Unknown
Formation	10×10^{-6}	-	10×10^{-6}	-

EXAMPLE CALCULATION

EQUATION 5 of EXHIBIT (1) of the 1966 hearing in case 3455 applies:

$$C_e = \frac{S_{o1}C_{o1} + S_{o2}C_{o2} + S_g C_g + S_w C_w + C_f}{S_{o1} + S_{o2}}$$

$1 - cw = 1 - .2 = .8$ ↓

x = unknown sat. of free gas

S_{o1} = 90% of oil $= .9(.8 - x) = .72 - .9x$

S_{o2} = 10% of oil $= .1(.8 - x) = .08 - .1x$

S_{o2} = 70% of oil $= .7(.8 - x) = .56 - .7x$

S_{o2} = 30% of oil $= .3(.8 - x) = .24 - .3x$

$$C_{e_1} = \left[\frac{(.72 - .9x)(11.25) + (.08 - .1x)(35.7) + 765x + (.2)(3.5) + 1.0}{(.8 - x)}\right] \times 10^{-6}$$

$$= \frac{(47.6 + 719.0x)}{(.8 - x)} \times 10^{-6}$$

$$C_{e_2} = \left[\frac{(.56 - .7x)(11.35) + (.24 - .3x)(35.3) + 817x + (.2)(4.7) + 1.0}{(.8 - x)}\right] \times 10^{-6}$$

$$= \frac{(109.2 + 694.1x)}{(.8 - x)} \times 10^{-6}$$

$$C_{e_2} = \left(\frac{6000}{3000}\right)(C_{e_1}) = 2\,C_{e_1}$$

$109.2 + 694.1x = 2(47.6 + 719x)$ $\quad x = 1.79$

$C_{e_1} = (47.6 + 719 \times .019)\left(\frac{1}{.5 - .019}\right)10^{-6} = 78.1 \times 10^{-6}$

$N = N_p / C_e = 9000 \div (78.1 \times 10^{-6}) = 38.4$ MM bbls

BENSON-MONTIN-GREER DRILLING CORP.
APPLICATION - WEST PUERTO CHIQUITO MANCOS OIL POOL

CASE 7075
NOVEMBER 24, 1980

OPENING STATEMENT

The application of Benson-Montin-Greer Drilling Corp. here before the Commission requests a change in the spacing pattern now established for the West Puerto Chiquito Mancos Oil Pool. In order for this application to be properly considered, it is necessary that we review the history of the development of the pool and the facts regarding its reservoir characteristics.

Back in 1963, after only a well or two were drilled, Benson-Montin-Greer came before the Commission and requested 160-acre temporary spacing. At that time both East and West Puerto Chiquito were thought to be one pool. Shortly after that, or a few years after that, it was realized that there was a barrier between East and West Puerto Chiquito. Thereupon an application was filed and an order entered to establish two pools - East and West Puerto Chiquito.

After 1963, when only five wells had been drilled in a cluster with approximately two miles distance between them, Benson-Montin-Greer had the courage (and it takes quite a lot), to interrupt all of the production from all five of those wells for a period of sixty days so that they could conduct one of the most remarkable interference tests that I've heard of in many years of oil and gas practice in Texas, New Mexico and Oklahoma.

This multiple interference test was conducted in 1965 and in 1966 and the results of it were presented to this Commission in Cause No. 3455. (The same cause number as in the 1963 hearing.)

At that time it was established that the pool was a fractured shale, being the Niobrara member of the Mancos; that it was a pool with a minimum amount of oil per acre in place and that it would support wells capable of very wide drainage; and the communication was so great that every one of those five wells was affected by anything that happened in any one of them.

At that time 320-acre temporary spacing was requested and granted.

At that time BMG expressed comprehensive opinions with regard to the pool and how it should be developed. Today, after seventeen years of history of the West Puerto Chiquito Mancos Oil Pool, all of the theories and opinions that were expressed to the Commission back at that time have been definitely established as engineering facts and are now a matter of history.

It is a rare instance in the oil industry that management will permit the remarkable engineering that has been achieved in this pool. Pools like the Boulder Pool, just a few miles to the north of West Puerto Chiquito where 80-acre spacing was employed and there was no pressure maintenance instituted, reflect a tragic disparity of conservation when compared to West Puerto Chiquito.

Shortly after the dramatic interference tests and the establishment of 320-acre spacing, BMG as the operator of the Canada Ojitos Unit established a pressure maintenance system by injecting gas in the upper edge of the pool. Then they carefully monitored production and voluntarily restricted production rates so as not to exceed the gravity drainage ability of the field. Without this pressure maintenance and controlled development of the pool, we would only have been able to recover approximately 5-1/2 percent of the oil in place under West Puerto Chiquito; whereas, as it has been developed we expect to recover between 50 and 60 percent of most of the oil in place. I say that we expect to. We expect to if we are able to continue the program of conservation established over the 17-year history of the field.

Our evidence will show that there are high and low capacity wells and that even the low capacity wells have maintained their initial production rates over a period of years and we will show that not only the high capacity but the low

capacity wells also drain wide areas.

We have two production wells which we will be talking about along with the others, one, the well in Section 10, has produced 2-million barrels of oil and we will show that this well has already drained an area of between 4000 and 8000 acres and is still producing oil.

The initial five well interference test enabled us to establish that the oil in place in this area was between 1000 and 2500 barrels per acre. Then after such interference tests BMG left one of those wells off production and never put it back but used it as an observation test well.

Then when the Canada Ojitos Unit operator started injecting gas in the upper side of the pool, they were able to run an additional interference test. By that further interference test they confirmed and refined their previous conclusions regarding oil in place.

Preliminary to unitizing additional areas in West Puerto Chiquito recently BMG requested of the Division and was granted 640-acre spacing. This was necessary preliminary to and as an adjunct to unitizing North Canada Ojitos and West Canada Ojitos, and as we indicated in the hearing last August held on such application, we anticipated that these areas would be unitized in a compatible program with the Canada Ojitos Unit so that the conservation program heretofore established could be continued for the greater recovery of oil. The Division granted the application for 640-acre spacing and established a spacing pattern of permitting a well to be drilled up to within 660 feet of the section line. BMG at that time paid little or no attention to the spacing pattern for the reason that unitization of the area would make it a moot point. However, since that time BMG was shocked to discover that the protestants here today would not agree to unitizing West Canada Ojitos. As a matter of fact, without advising BMG that they were terminating negotiations regarding formation of West Canada

Ojitos Unit, they proceeded to stake a location for the drilling of a well in the area 660 feet on the surface from the Canada Ojitos Unit; which well, if drilled, will most probably be considerably closer at the bottom of the hole.

If such a drilling program is to be carried on to production by the protestants, then the highly efficient gravity drainage and pressure maintenance processes established and practiced by the applicant will be destroyed and there will be serious degradation of recoveries from the reservoir. This will result in a tremendous underground waste of oil and a destruction of the correlative rights of the applicant.

In this regard, our proof will show that if protestants are permitted to drill where they desire, then the section under which they drill will not be drained as to a large amount of the western portion thereof, while on the other hand, protestants' well or wells will drain a large area under the Canada Ojitos Unit to the east of such wells. Such drilling would require that unit operator drill off-sets only 660 feet from the protestants' section line in order to partially protect the unit; but our proof will show that such off-setting wells cannot protect the unit from severe drainage by the protestants' wells.

Applicant's proof will further show that not only will the drilling pattern desired by protestants cause a great amount of oil never to be recovered from the reservoir and wasted, but in addition thereto will cause drilling of unnecessary wells. Our proof will show that close off-sets are unnecessary wells; are not only costly and wasteful, but that in addition thereto they will create much unnecessary damage to the National Forest.

Damage to the National Forest may not be strictly a matter of oil and gas conservation. However, this area is a part of the Santa Fe National Forest. It is a beautiful wooded area. Minimizing damage and maintaining its beauty has been

a significant consideration to the managers of the Canada Ojitos Unit.

After Applicant learned that the protestants would not agree to form a unit but desired to proceed with a drilling program that would prevent the greatest recovery of oil from the pool, it became apparent to BMG that they needed a different spacing pattern than that established by this Commission after the August hearing. Therefore, BMG filed the initial application in this cause. In that application we requested that the spacing pattern follow or conform to the customary 640-acre spacing regulation in New Mexico which requires that wells be located not closer than 1650 feet from the spacing unit section line. However, when BMG began to project the inevitable consequences of an application of the standard spacing pattern, it realized that wells drilled in the east half of the western tier of Sections, 1650 feet from the east line not only grossly fail to protect the applicant's correlative rights but also fail to adequately drain the western portion of their section. Thereupon, applicant amended its application to request that wells in the pool be spaced uniformly in the west half of each spacing unit.

In an ordinary reservoir where 640-acre spacing is established a well at any place 1650 feet from the line of the section adequately protects the correlative rights of the parties where there is an opportunity for compensating drainage. However, West Puerto Chiquito is no ordinary reservoir. To the contrary, it is a reservoir where the ratio of the ability of a well to produce the oil from the reservoir in relation to the amount of oil in place is much greater than the average. In other words, in this reservoir the capacity of the wells in relation to the amount of oil in place is far greater than the ordinary situation. Also, it is a pool tilted downward from east to west and where a unit was formed at an early date in the development of the pool and a pressure maintenance program

installed. These facts, together with the careful spacing of wells and production, drastically separate this pool from the ordinary oil and gas conservation situation. Oil not only drains from east to west but in addition thereto it is further moved from east to west by virtue of the fact that the Canada Ojitos Unit installed four injection wells on the eastern extremity of the pool and have been injecting gas into the formation almost from the inception of production. These conditions cause the oil to move from east to west and wells to the West of the Canada Ojitos Unit will drain the oil from the Unit. These are the reasons that a well in the sections immediately west of the Canada Ojitos Unit which is located in the east part of the spacing unit will not be efficiently draining such spacing unit. To the contrary, most of the oil produced by such well will be drained from land to the East. Applicant's evidence will show that such oil will be produced not just from the adjoining sections to the East but from large areas of the unit lands.

Even more unfortunate, such well will produce only a small amount of oil from the western part of the section upon which it is located. It will, therefore, be an improperly located well; it not only will not serve conservation but it will destroy correlative rights and may result in a tragically reduced ultimate recovery of oil from West Puerto Chiquito.

This was the reason that although the applicant initially asked for spacing 1650 feet from the line, after applying this standard pattern to the unusual charasteristics of the reservoir, it became apparent that applicant's correlative rights were going to be destroyed and the applicant realized that it must ask for a rule which would allow a more equitable recovery of the hydrocarbons in the reservoir and would come closer to preserving the energy of the pool. The only way to better protect the correlative rights of the applicant was by requiring that all wells be drilled in the west half of the section.

Our evidence will show that wells located in the western half of the sections will come much closer to producing the oil from under their own sections and that they will be far less an infringement upon the correlative rights of the owners of the Canada Ojitos Unit. Further, our proof will show that it will save the cost of the drilling of unnecessary wells and greatly diminish the overall damage to the reservoir. Also, that by eliminating the drilling of unnecessary wells it will greatly protect the surface and beauty of the National Forest.

It is difficult to fully appreciate the tremendous danger that is presented by the specter of wells being drilled 660 feet immediately west of the Canada Ojitos Unit bondary. Therefore, in order that the Division can understand the gravity of our application, we will present evidence which will show that if competitive drilling is permitted to proceed in West Puerto Chiquito in accord with the present order, that the established efficienty of the Canada Ojitos Unit will be destroyed and it may lose as much as 90 percent of its future recoveries. We will further show that this would mean a loss not only to the Canada Ojitos Unit owenrs but also a loss to the State of New Mexico of between 18 and 36 million dollars in royalty revenues and gross production taxes and a further loss to the Federal Government of between 6 and 12 million dollars in royalties and between 67 and 134 million dollars in Windfall Profits tax, meaning losses to both State and Federal governments of between 90 and 180 million dollars.

The applicant is aware of the fact that without the acreage on the west being unitized waste cannot be prevented, but absent such compatible unitization our proof will show that conservation and protection of correlative rights make it mandatory that our application be granted.

BENSON-MONTIN-GREER DRILLING CORP.
APPLICATION - WEST PUERTO CHIQUITO MANCOS OIL POOL

CASE 7075
NOVEMBER 24, 1980

OPENING STATEMENT

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In an ordinary reservoir where 640-acre spacing is established a well at any place 1650 feet from the line of the section adequately protects the correlative rights of the parties where there is an opportunity for compensating drainage. However, West Puerto Chiquito is no ordinary reservoir. To the contrary, it is a reservoir where the ratio of the ability of a well to produce the oil from the reservoir in relation to the amount of oil in place is much greater than the average. In other words, in this reservoir the capacity of the wells in relation to the amount of oil in place is far greater than the ordinary situation. Also, it is a pool tilted downward from east to west and where a unit was formed at an early date in the development of the pool and a pressure maintenance program

installed. These facts, together with the careful spacing of wells and production, drastically separate this pool from the ordinary oil and gas conservation situation. Oil not only drains from east to west but in addition thereto it is further moved from east to west by virtue of the fact that the Canada Ojitos Unit installed four injection wells on the eastern extremity of the pool and have been injecting gas into the formation almost from the inception of production. These conditions cause the oil to move from east to west and wells to the West of the Canada Ojitos Unit will drain the oil from the Unit. These are the reasons that a well in the sections immediately west of the Canada Ojitos Unit which is located in the east part of the spacing unit will not be efficiently draining such spacing unit. To the contrary, most of the oil produced by such well will be drained from land to the East. Applicant's evidence will show that such oil will be produced not just from the adjoining sections to the East but from large areas of the unit lands.

Even more unfortunate, such well will produce only a small amount of oil from the western part of the section upon which it is located. It will, therefore, be an improperly located well; it not only will not serve conservation but it will destroy correlative rights and may result in a tragically reduced ultimate recovery of oil from West Puerto Chiquito.

This was the reason that although the applicant initially asked for spacing 1650 feet from the line, after applying this standard pattern to the unusual charasteristics of the reservoir, it became apparent that applicant's correlative rights were going to be destroyed and the applicant realized that it must ask for a rule which would allow a more equitable recovery of the hydrocarbons in the reservoir and would come closer to preserving the energy of the pool. The only way to better protect the correlative rights of the applicant was by requiring that all wells be drilled in the west half of the section.

Our evidence will show that wells located in the western half of the sections will come much closer to producing the oil from under their own sections and that they will be far less an infringement upon the correlative rights of the owners of the Canada Ojitos Unit. Further, our proof will show that it will save the cost of the drilling of unnecessary wells and greatly diminish the overall damage to the reservoir. Also, that by eliminating the drilling of unnecessary wells it will greatly protect the surface and beauty of the National Forest.

It is difficult to fully appreciate the tremendous danger that is presented by the specter of wells being drilled 660 feet immediately west of the Canada Ojitos Unit bondary. Therefore, in order that the Division can understand the gravity of our application, we will present evidence which will show that if competitive drilling is permitted to proceed in West Puerto Chiquito in accord with the present order, that the established efficienty of the Canada Ojitos Unit will be destroyed and it may lose as much as 90 percent of its future recoveries. We will further show that this would mean a loss not only to the Canada Ojitos Unit owenrs but also a loss to the State of New Mexico of between 18 and 36 million dollars in royalty revenues and gross production taxes and a further loss to the Federal Government of between 6 and 12 million dollars in royalties and between 67 and 134 million dollars in Windfall Profits tax, meaning losses to both State and Federal governments of between 90 and 180 million dollars.

The applicant is aware of the fact that without the acreage on the west being unitized waste cannot be prevented, but absent such compatible unitization our proof will show that conservation and protection of correlative rights make it mandatory that our application be granted.

BENSON-MONTIN-GREER DRILLING CORP.
APPLICATION - WEST PUERTO CHIQUITO MANCOS OIL POOL

CASE 7075
NOVEMBER 24, 1980

OPENING STATEMENT

The application of Benson-Montin-Greer Drilling Corp. here before the Commission requests a change in the spacing pattern now established for the West Puerto Chiquito Mancos Oil Pool. In order for this application to be properly considered, it is necessary that we review the history of the development of the pool and the facts regarding its reservoir characteristics.

Back in 1963, after only a well or two were drilled, Benson-Montin-Greer came before the Commission and requested 160-acre temporary spacing. At that time both East and West Puerto Chiquito were thought to be one pool. Shortly after that, or a few years after that, it was realized that there was a barrier between East and West Puerto Chiquito. Thereupon an application was filed and an order entered to establish two pools - East and West Puerto Chiquito.

After 1963, when only five wells had been drilled in a cluster with approximately two miles distance between them, Benson-Montin-Greer had the courage (and it takes quite a lot), to interrupt all of the production from all five of those wells for a period of sixty days so that they could conduct one of the most remarkable interference tests that I've heard of in many years of oil and gas practice in Texas, New Mexico and Oklahoma.

This multiple interference test was conducted in 1965 and in 1966 and the results of it were presented to this Commission in Cause No. 3455. (The same cause number as in the 1963 hearing.)

At that time it was established that the pool was a fractured shale, being the Niobrara member of the Mancos; that it was a pool with a minimum amount of oil per acre in place and that it would support wells capable of very wide drainage; and the communication was so great that every one of those five wells was affected by anything that happened in any one of them.

At that time 320-acre temporary spacing was requested and granted.

At that time BMG expressed comprehensive opinions with regard to the pool and how it should be developed. Today, after seventeen years of history of the West Puerto Chiquito Mancos Oil Pool, all of the theories and opinions that were expressed to the Commission back at that time have been definitely established as engineering facts and are now a matter of history.

It is a rare instance in the oil industry that management will permit the remarkable engineering that has been achieved in this pool. Pools like the Boulder Pool, just a few miles to the north of West Puerto Chiquito where 80-acre spacing was employed and there was no pressure maintenance instituted, reflect a tragic disparity of conservation when compared to West Puerto Chiquito.

Shortly after the dramatic interference tests and the establishment of 320-acre spacing, BMG as the operator of the Canada Ojitos Unit established a pressure maintenance system by injecting gas in the upper edge of the pool. Then they carefully monitored production and voluntarily restricted production rates so as not to exceed the gravity drainage ability of the field. Without this pressure maintenance and controlled development of the pool, we would only have been able to recover approximately 5-1/2 percent of the oil in place under West Puerto Chiquito; whereas, as it has been developed we expect to recover between 50 and 60 percent of most of the oil in place. I say that we expect to. We expect to if we are able to continue the program of conservation established over the 17-year history of the field.

Our evidence will show that there are high and low capacity wells and that even the low capacity wells have maintained their initial production rates over a period of years and we will show that not only the high capacity but the low

capacity wells also drain wide areas.

We have two production wells which we will be talking about along with the others, one, the well in Section 10, has produced 2-million barrels of oil and we will show that this well has already drained an area of between 4000 and 8000 acres and is still producing oil.

The initial five well interference test enabled us to establish that the oil in place in this area was between 1000 and 2500 barrels per acre. Then after such interference tests BMG left one of those wells off production and never put it back but used it as an observation test well.

Then when the Canada Ojitos Unit operator started injecting gas in the upper side of the pool, they were able to run an additional interference test. By that further interference test they confirmed and refined their previous conclusions regarding oil in place.

Preliminary to unitizing additional areas in West Puerto Chiquito recently BMG requested of the Division and was granted 640-acre spacing. This was necessary preliminary to and as an adjunct to unitizing North Canada Ojitos and West Canada Ojitos, and as we indicated in the hearing last August held on such application, we anticipated that these areas would be unitized in a compatible program with the Canada Ojitos Unit so that the conservation program heretofore established could be continued for the greater recovery of oil. The Division granted the application for 640-acre spacing and established a spacing pattern of permitting a well to be drilled up to within 660 feet of the section line. BMG at that time paid little or no attention to the spacing pattern for the reason that unitization of the area would make it a moot point. However, since that time BMG was shocked to discover that the protestants here today would not agree to unitizing West Canada Ojitos. As a matter of fact, without advising BMG that they were terminating negotiations regarding formation of West Canada

Ojitos Unit, they proceeded to stake a location for the drilling of a well in the area 660 feet on the surface from the Canada Ojitos Unit; which well, if drilled, will most probably be considerably closer at the bottom of the hole.

If such a drilling program is to be carried on to production by the protestants, then the highly efficient gravity drainage and pressure maintenance processes established and practiced by the applicant will be destroyed and there will be serious degradation of recoveries from the reservoir. This will result in a tremendous underground waste of oil and a destruction of the correlative rights of the applicant.

In this regard, our proof will show that if protestants are permitted to drill where they desire, then the section under which they drill will not be drained as to a large amount of the western portion thereof, while on the other hand, protestants' well or wells will drain a large area under the Canada Ojitos Unit to the east of such wells. Such drilling would require that unit operator drill off-sets only 660 feet from the protestants' section line in order to partially protect the unit; but our proof will show that such off-setting wells cannot protect the unit from severe drainage by the protestants' wells.

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INDEX OF
BENSON-MONTIN-GREER DRILLING CORP. EXHIBITS
IN CASE NO. 6997
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

AUGUST 6, 1980

PART I GENERAL INFORMATION

SECTION A:

1. Location map showing pool and unit boundaries and identification of irregular spacing units requested.
2. Colored contour map showing interpreted areas of varying reservoir characteristics.
3. Typical electrical log of productive intervals.
4. North-south cross-section of well logs. (Section F of Exhibit 3, Case 3455, 11-16-66)

PART II INFORMATION RELATIVE TO RESERVOIR DRAINAGE CHARACTERISTICS AND PER-ACRE OIL-IN-PLACE DETERMINATIONS

SECTION B: Summary of 1965 interference test

1. Plat showing the four phases of the test (Section J-1 of Exhibit 3, Case 3455, 11-16-66)
2. Graph (1965) showing fluid levels and production data (Section J-7 of Exhibit 3, Case 3455, 11-16-66)
3. Plat of portion of graph (2) used in calculating oil in place (Section M-2 of Exhibit 3 of Case 3455, 11-16-66)
4. Schedule of results of calculations (Section M-1 of Exhibit 3, Case 3455, 11-16-66)

SECTION C: Summary of 1968 Interference Test

1. Plat of fluid levels, production and injection rates, August and September, 1968 (Figure I-8 of Appendix I of Exhibit 2, Case 3455, 12-17-69)

2. Graph of fluid levels and calculated interference curves (Figure I-9 of Appendix I of Exhibit 2, Case 3455, 12-17-69)

3. Ditto including boundary effects (Figure I-10 of Appendix I of Exhibit 2, Case 3455, 12-17-69)

4. Plat showing transmissibilities and areal coverage of tests (Figure I-16 of Appendix I, Case 3455, 12-17-69).

SECTION D: Variation of Oil in Place as Function of Transmissibility

1. Comparison of ratio of permeability to porosity for sandstone reservoirs with that for fractured reservoirs (Figure 9 of Exhibit 1 in Case 3455, 11-16-66)

2. Ditto for selected relations of K/o (A, B, C) (Figure III-4 of Appendix III of Exhibit 2, Case 3455, 12-17-69)

3. Relation of per-acre oil-in-place to transmissibility for selected relations of K/o and pay thickness (Figure III-5 of Appendix III of Exhibit 2, Case 3455, 12-17-69)

4. Sketch showing "jigsaw-puzzle" concept of high capacity fracture system and tight blocks.

5. Comparison of drainage of tight fracture block by well located within it and drainage of same block by high capacity fracture system.

PART III — REVIEW OF PRODUCTION HISTORY, CANADA OJITOS UNIT

SECTION E:

1. Structural contour map showing gas injection pattern and oil displacement areas.

2. Colored contour map showing interpreted areas of varying reservoir characteristics (same as Section A (2) but small scale) with high capacity wells identified with red circles, low capacity wells identified with blue circles.

3. Production history graphs (pink graphs are for wells circled in red, blue graphs for wells circled in blue on plat E (2) above.

SECTION F: Information relative to Pressure Maintenance by Gas Injection and Note on Gravity Drainage

1. Sketch showing relative pressure in gas cap and oil zone under complete pressure maintenance.

2. Pressure maintenance volumes required for gas cap pressure of 1400 psig and dipping reservoir and oil produced by gravity drainage.

3. Relative cost of "make-up" gas as function of oil price for complete pressure maintenance.

4. Graph, surface pressures of K-13 observation well.

5. Approximate equivalent volumes of make-up gas expressed as cubic feet per barrel of oil produced.

6. Approximate reservoir pressure decline from vertical drop in gas-oil contact face and horizontal displacement of oil in high capacity fracture system.

7. Graph of gravity drainage rates (Figure 5 of Exhibit 2, Case 3455, 12-17-69)

PART IV — INFORMATION REGARDING PRODUCTION BEHAVIOR OF LOW CAPACITY WELLS AND ABILITY OF LOW CAPACITY WELLS TO DRAIN LARGE AREAS

SECTION G: Apparent influence of pressure maintenance on production behavior of low capacity wells

1. Boulder Mancos Pool production history.
2. Graph of production history, Canada Ojitos Unit C-2
3. Remarks regarding production behavior and drainage areas.
4. Graph of production history, Canada Ojitos Unit A-16
5. Remarks

PART V — ECONOMICS OF MARGINAL WELLS IN AREA OF SMALL STRUCTURAL DIP

SECTION H: Information relative to Solution-Gas Drive Performance

1. Graph of relative permeability of fractured formations (Fig. IV-2 of Appendix IV of Exhibit 2, Case 3455, 12-17-69)
2. Graph of solution-gas drive production performance (Fig. IV-3 of Appendix IV of Exhibit 2, Case 3455, 12-17-69)
3. Relation of per-acre oil in place to transmissibility (repeat of Section D (3) above)

SECTION I

1. Schedule of oil values.
2. Graph of example production performance required to provide 15% return on investment on $23.30 per barrel.

3. Schedule of statistics regarding example production performance required to provide 15% return on investment at $23.30 per barrel.

4. Graph of example performance required to provide 15% return on investment at $15.90 per barrel.

5. Schedule of statistics regarding example production performance required to provide 15% return on investment at $15.90 per barrel.

PLAT OF THE FOUR PHASES

OF THE

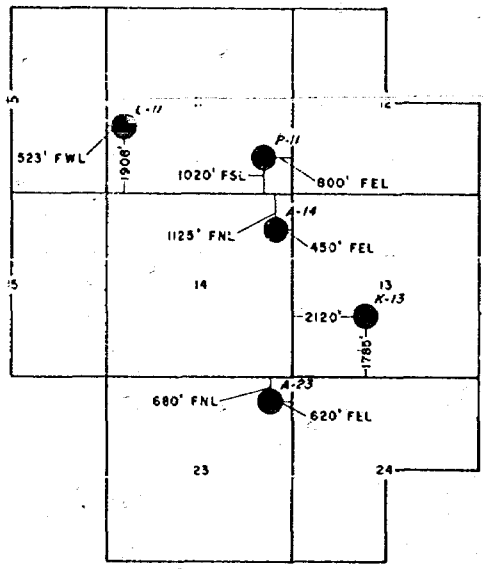
1965 - 66 INTERFERENCE TEST

NIOBRARA - GREENHORN PARTICIPATING AREA

CANADA OJITOS UNIT

1966 1824

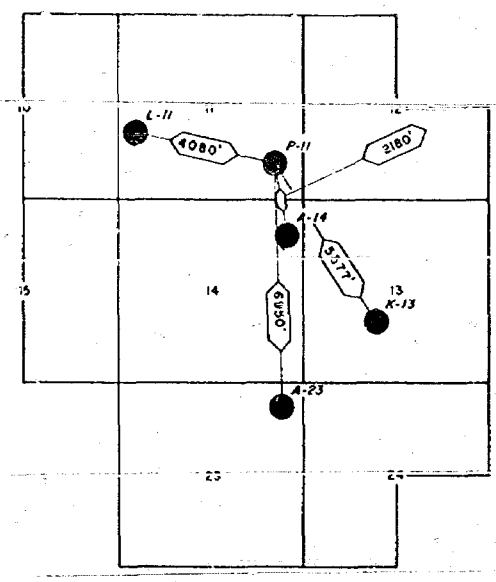
FOOTAGE LOCATIONS OF WELLS



ALL WELLS SHUT-IN

PHASE I

DISTANCES FROM P-11 TO SHUT-IN WELLS

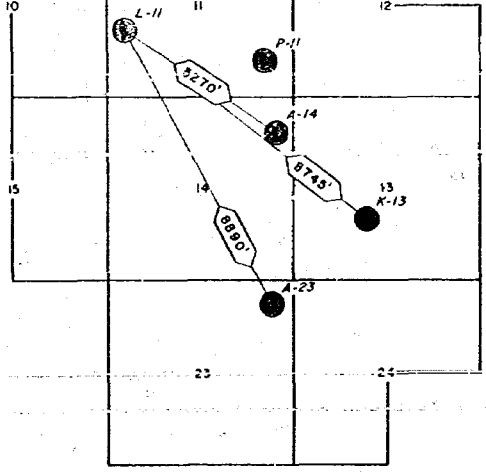


PRODUCING WELL

SHUT-IN WELL

PHASE II

DISTANCES FROM L-11 TO SHUT-IN WELLS

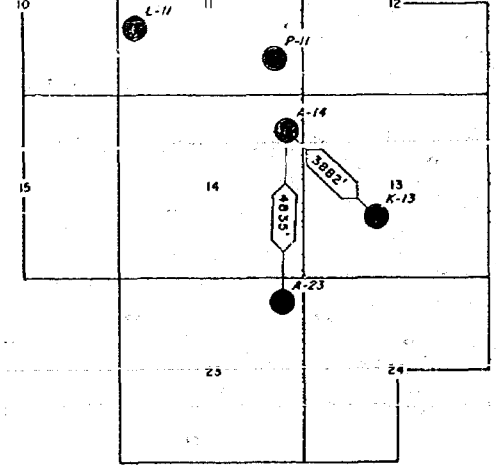


PRODUCING WELL

SHUT-IN WELL

PHASE III

DISTANCES FROM A-14 TO SHUT-IN WELLS



PRODUCING WELL

SHUT-IN WELL

PHASE IV

From 66 Rpt

PER-ACRE OIL IN PLACE
CANADA OJITOS UNIT NIOBRARA PARTICIPATING AREA
DETERMINED FROM INTERFERENCE TEST
SEPTEMBER-OCTOBER, 1965
L-11 PRODUCING, A-14 OBSERVATION WELL

TIME AFTER START OF TEST AT WHICH INTERFERENCE PRESSURE DROP MEASURED	OIL IN PLACE (STOCK TANK BARRELS/ACRE FOR ASSUMED EFFECTIVE COMPRESSIBILITY INDICATED) For $C_e \equiv 20 \times 10^{-6}$	For $C_e \equiv 50 \times 10^{-6}$
1 day	2250	890
2 days	2520	1010
3 days	2670	1070
4 days	2740	1090
5 days	2660	1050
6 days	2600	1030
8 days	2520	1010
10 days	2460	980
12 days	2420	960
14 days	2440	970

NOTE: (1) $C_e = 20 \times 10^{-6}$ results from assumed undersaturated compressibility of 10.5×10^{-6}, connate water 3.3×10^{-6}, formation compressibility of 6.7×10^{-6} and saturation as follows:

Undersaturated oil 75% of pore space
Saturated oil - 0
Connate water 25% of pore space

(2) $C_e = 50 \times 10^{-6}$ results from same values of fluid compressibilities but with formation compressibility of 23×10^{-6} and connate water saturation of 40% (assumed also no saturated oil in reservoir)

CAÑADA OJITOS UNIT
NIOBRARA PARTICIPATING AREA

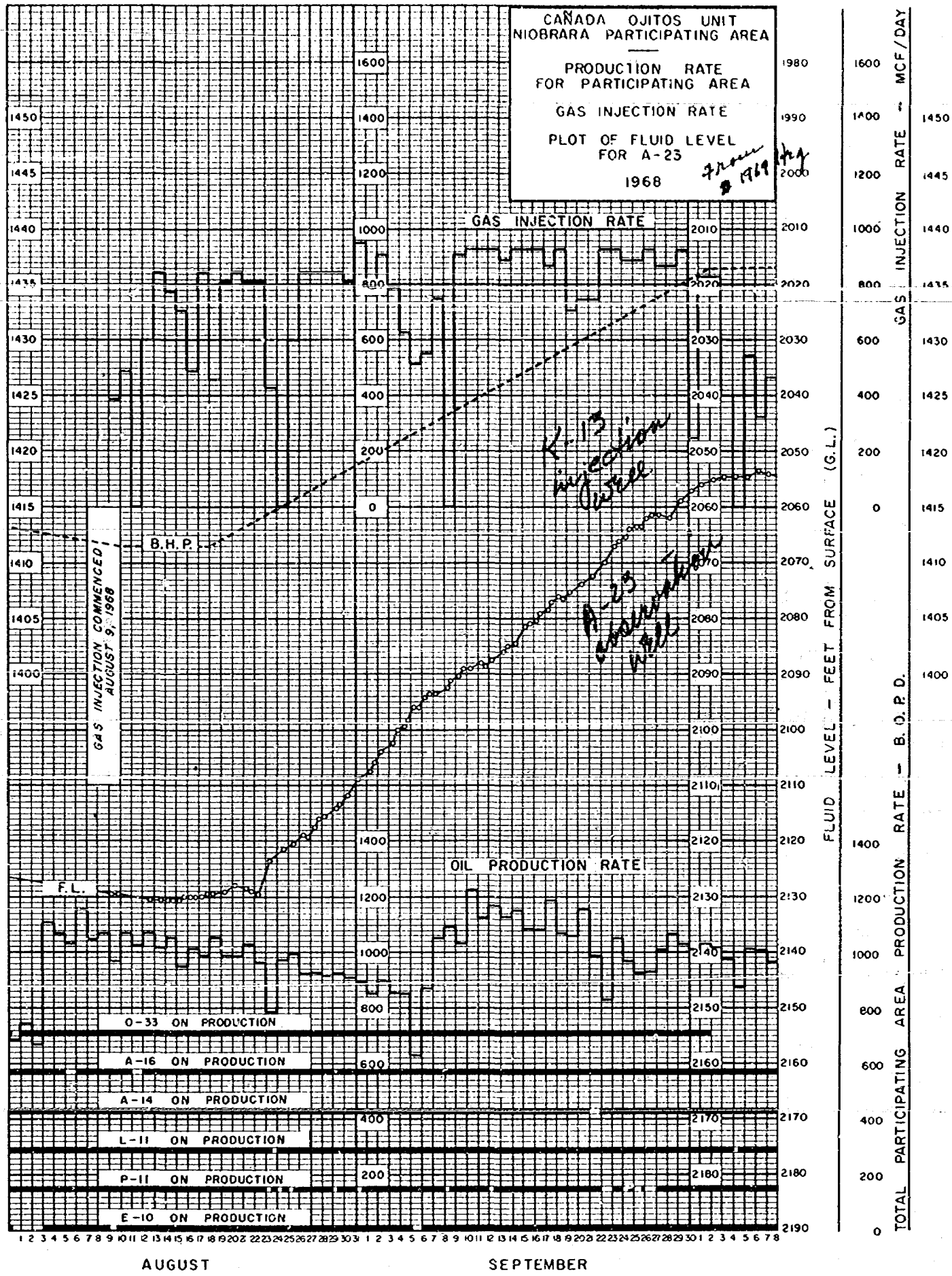
PRODUCTION RATE
FOR PARTICIPATING AREA

GAS INJECTION RATE

PLOT OF FLUID LEVEL
FOR A-23

1968

From 1969

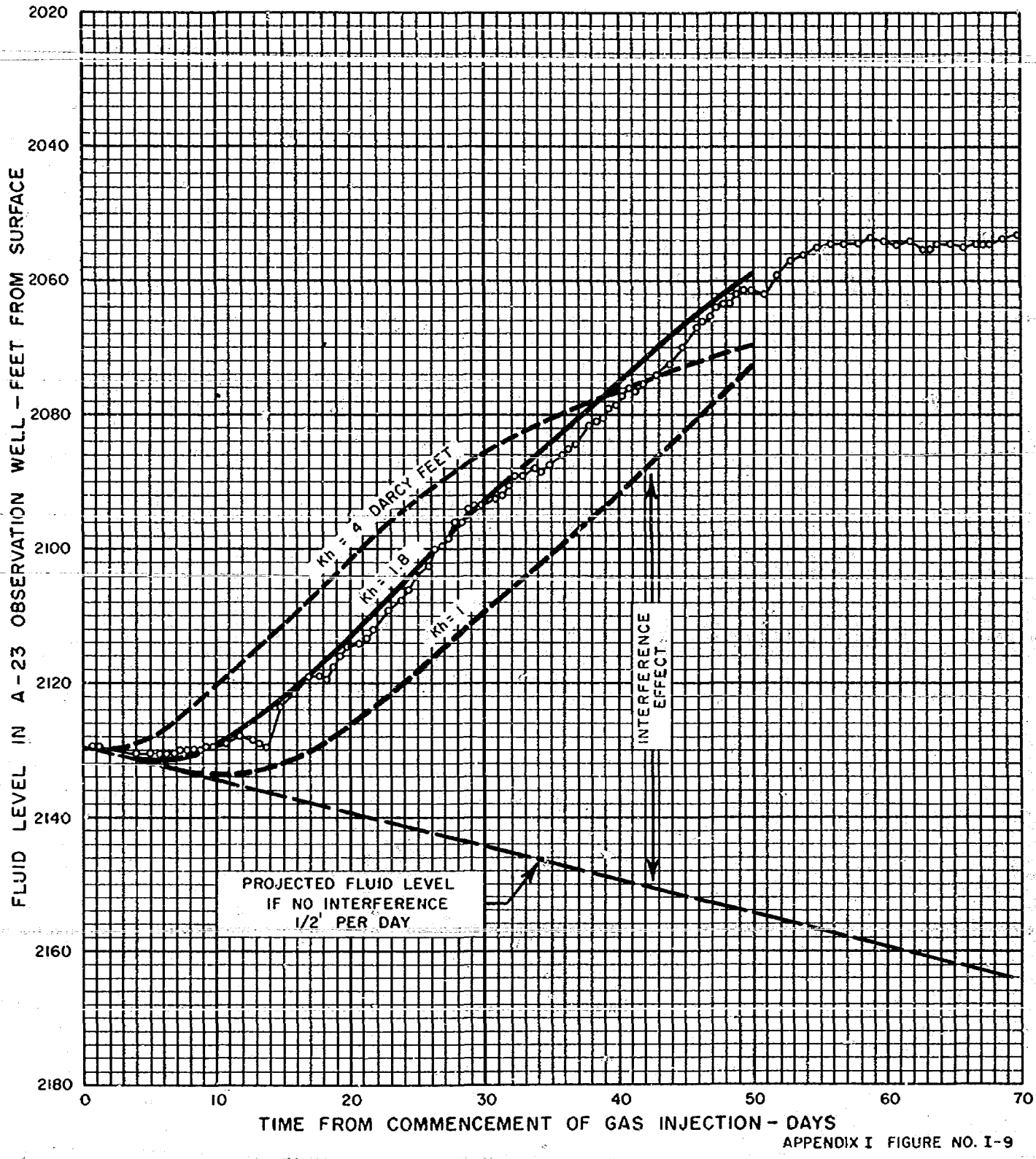


APPENDIX I FIGURE NO. I-8

COMPARISON OF
ACTUAL INTERFERENCE EFFECT
OF INITIAL GAS INJECTION
ON FLUID LEVEL OF A-23 OBSERVATION WELL
WITH CALCULATED EFFECTS

FOR CONDITIONS OF:
C_e = 415 x 10^{-6} F.V.F. = 1.28
ϕh = 1600 BBLS/ACRE STOCK TANK OIL
AND TRANSMISSIBILITIES AS SHOWN
o – MEASURED FLUID LEVELS

From 69 Hrg

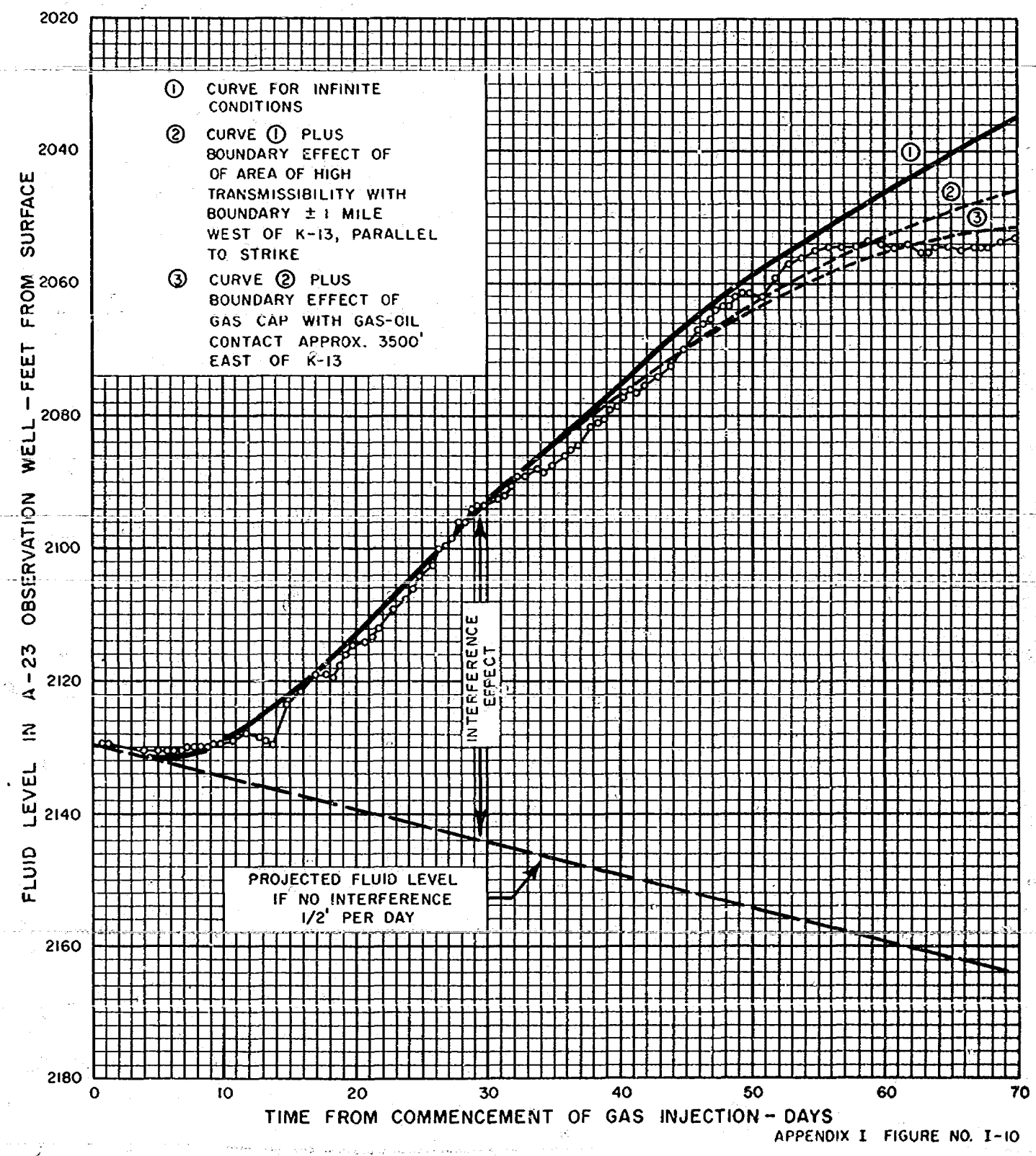


APPENDIX I FIGURE NO. I-9

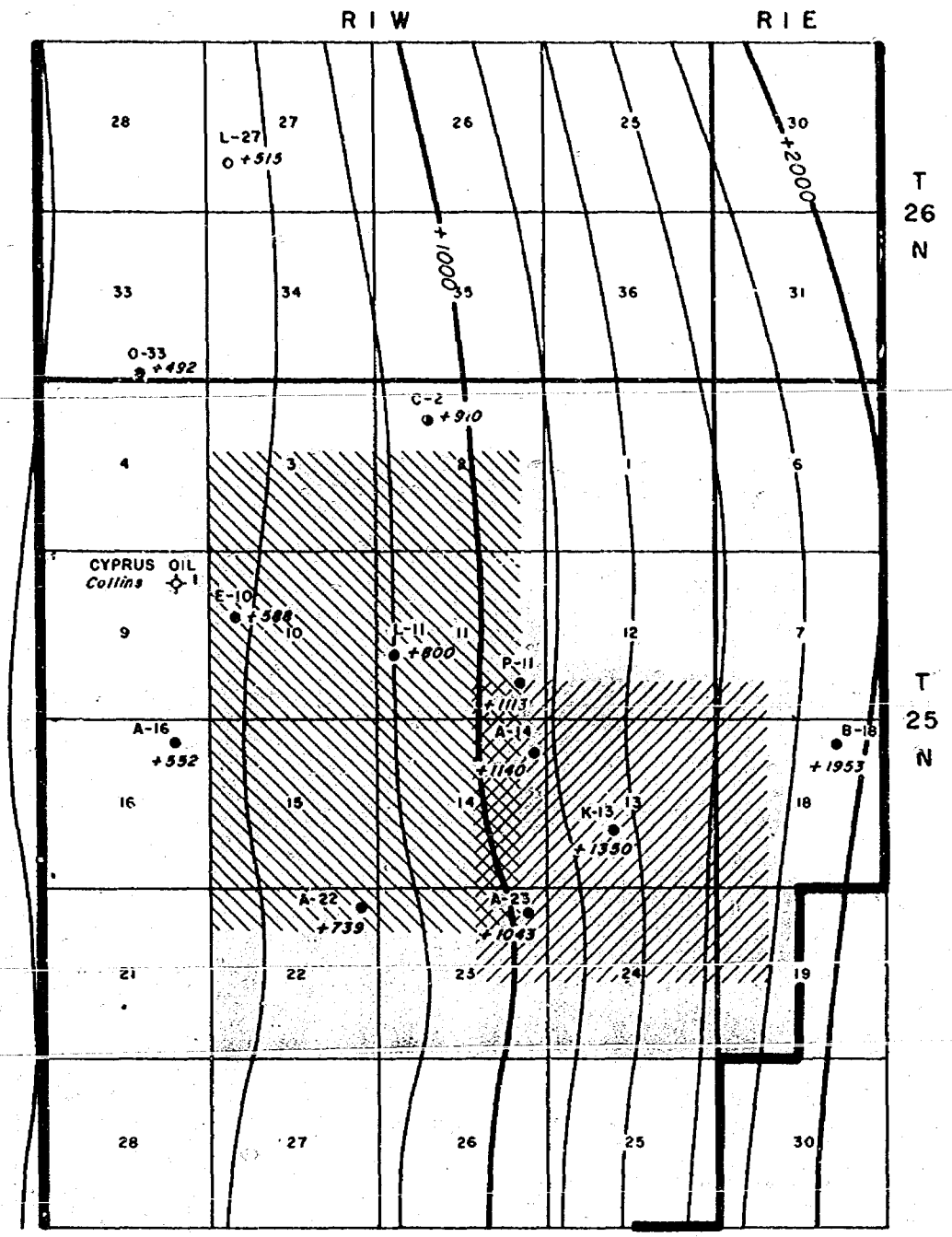
COMPARISON OF ACTUAL INTERFERENCE EFFECT OF INITIAL GAS INJECTION ON FLUID LEVEL OF A-23 OBSERVATION WELL WITH CALCULATED EFFECTS

From 69 Hrg

FOR CONDITIONS OF:
$C_e = 415 \times 10^{-6}$ F.V.F. = 1.28
ϕh = 1600 BBLS/ACRE STOCK TANK OIL
TRANSMISSIBILITY = 1.8 DARCY FEET
o - MEASURED FLUID LEVELS



APPENDIX I FIGURE NO. I-10



PLAT OF PART
OF
CAÑADA OJITOS UNIT
SHOWING ESTIMATED
RESERVOIR TRANSMISSIBILITY
BY AREAS OF TESTS

- 2.5 TO 3.5 DARCY FEET
- 10 TO 12 DARCY FEET
- 5 TO 10 DARCY FEET – (about 4.3 – 6.8)

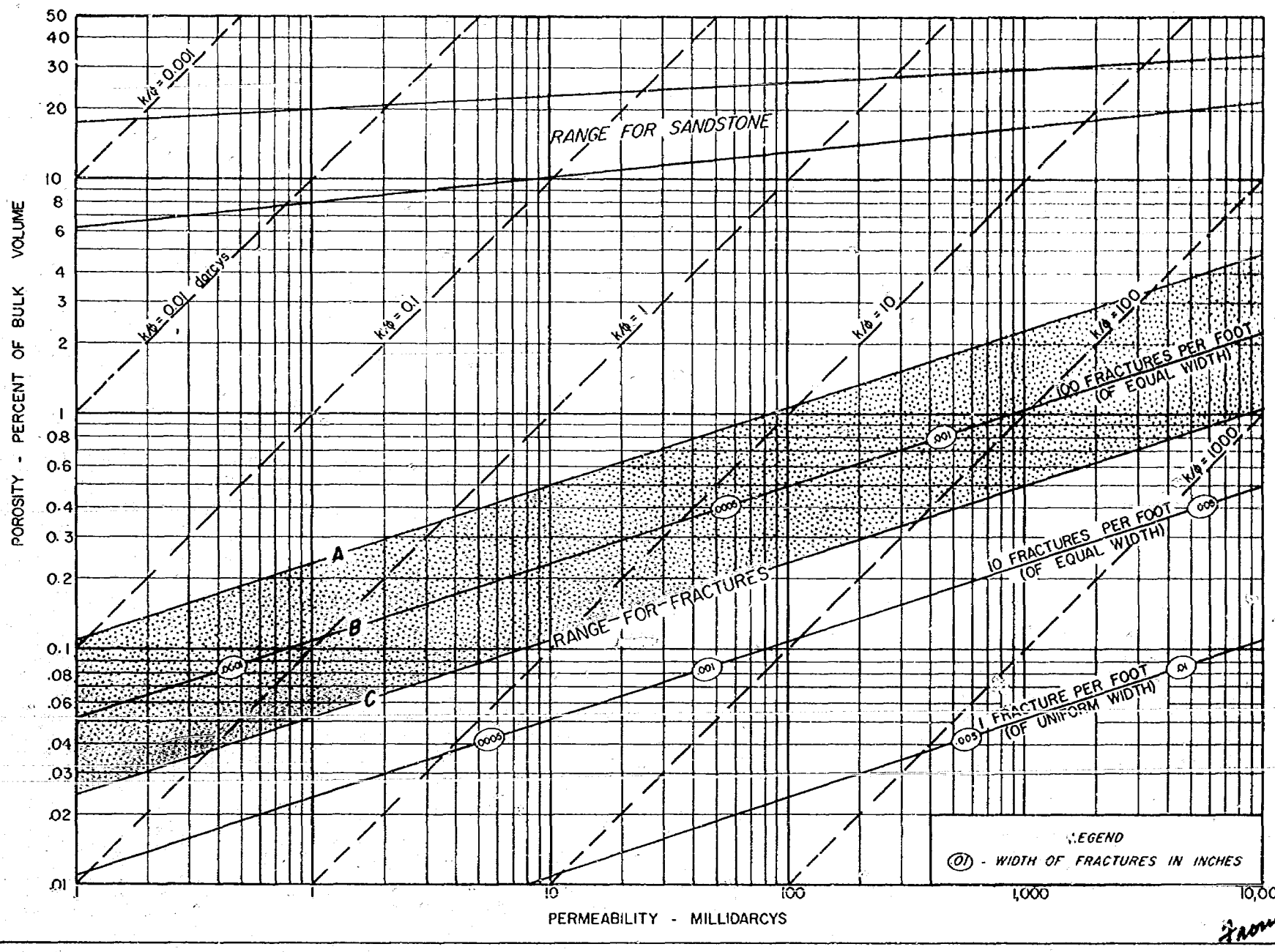
CONTOURED ON TOP OF "A" MARKER
C. I. 200'
NOVEMBER, 1969
BOUNDARY OF CAÑADA OJITOS UNIT

From 69 Hay

APPENDIX I FIGURE NO. I-16

VALUES OF Kϕ FOR SANDSTONE RESERVOIRS AND FOR FLOW SYSTEMS OF FRACTURES IN AN IMPERMEABLE MATRIX

FRACTURES PARALLEL TO DIRECTION OF FLOW

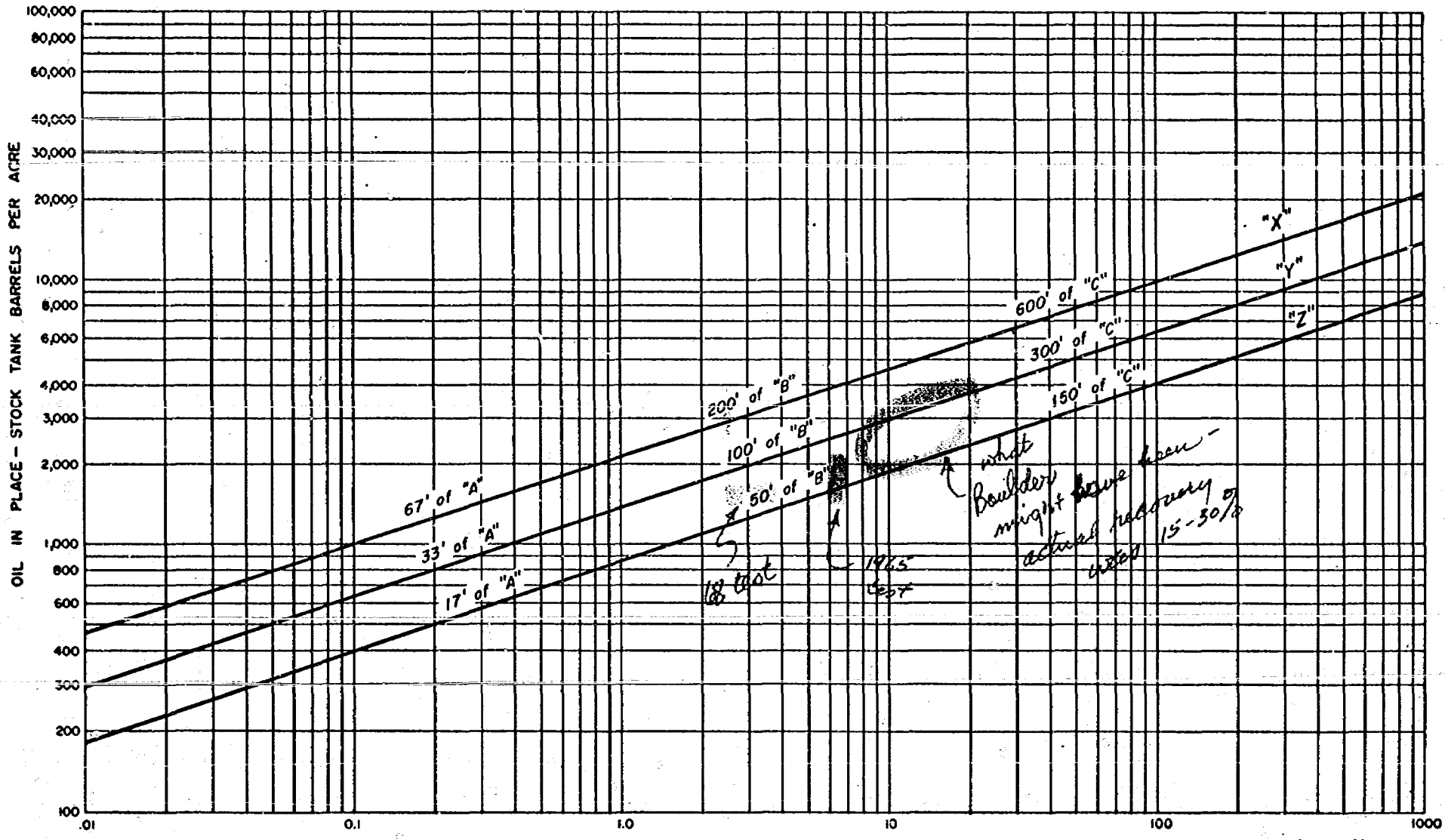


69

from Hg

APPENDIX III FIGURE NO. III-4

RELATION OF OIL IN PLACE
TO
TRANSMISSIBILITY
FOR
POROSITY–PERMEABILITY RELATIONS
"A", "B" & "C"
AND FOR
RESERVOIR THICKNESSES SHOWN
F.V.F.=1.29



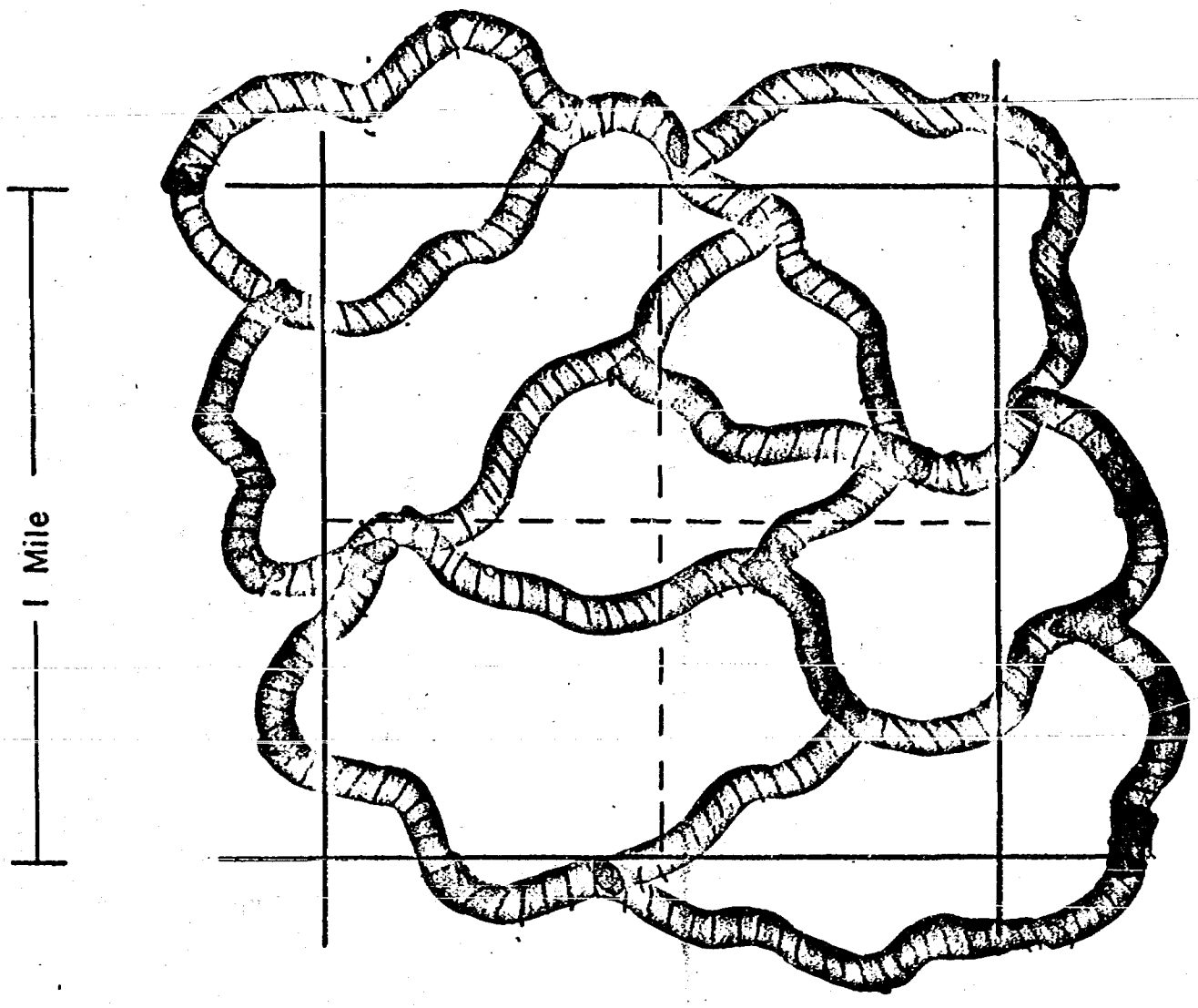
TRANSMISSIBILITY – (Kh) – DARCY FEET

From 69 Hdq

FILE: 12A

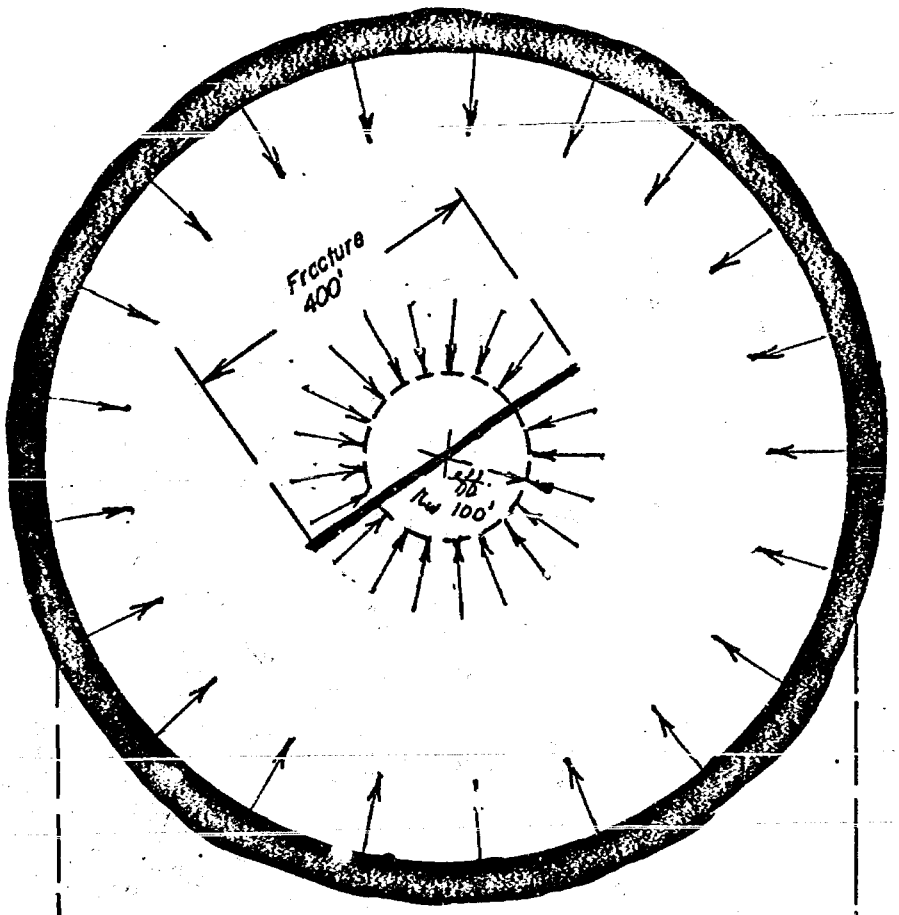
APPENDIX III FIGURE NO. III-5

SCHEMATIC DIAGRAM
OF
"JIG-SAW PUZZLE" CONCEPT
OF
TIGHT BLOCKS & HIGH CAPACITY
FRACTURE SYSTEM



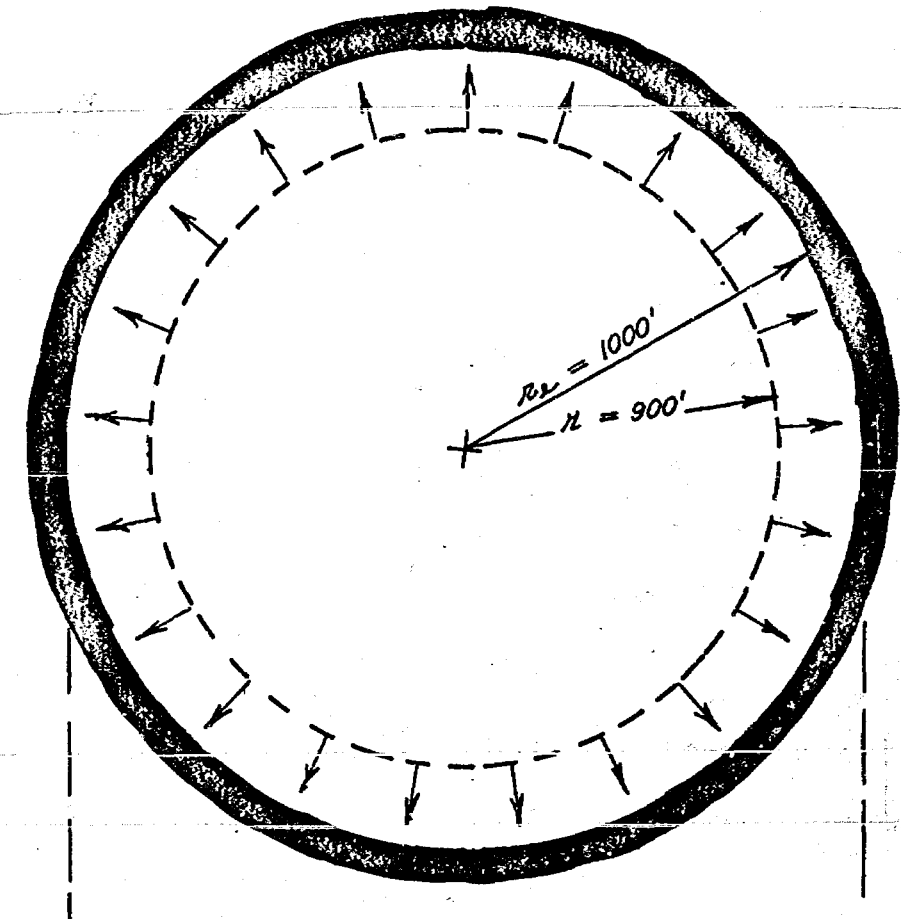
TIGHT BLOCK DRAINED
BY
INTERNAL WELL

(Not To Scale)



TIGHT BLOCK DRAINED
BY
HIGH CAPACITY FRACTURES SYSTEM

(Not To Scale)



TIGHT BLOCK DRAINED BY
CENTRALLY LOCATED WELL
Initial Production Rate
(flow system steady state)

For: r_e = 1000'

eff. r_w = 100' (1/4 of 400' fracture)

ΔP = 1500#

μ = .68 cp

B = 1.29

K_o/K = .3

Kh = .0635 darcy feet

$$Q = \frac{(3.07)(kh)(\Delta P)}{\mu B \log_{10}(r_e/r_w)} \times (K_o/K)$$

= 100 BOPD

TIGHT BLOCK DRAINED BY
HIGH CAPACITY FRACTURE SYSTEM

(Flow system unsteady state)

Instantaneous initial flow rate from 900' to 1000' radius
(per steady state relation)

A. for same pressure drawdown as for centrally located well (1500#)

$$Q = \frac{(3.07)(.0635)(1500)(.3)}{(.68)(1.29)\log_{10}(1000/900)}$$

= 2200 BOPD

B. Pressure differential required to allow 100 BOPD at K_o/K = .1

$$= \frac{(100)(.68)(1.29)\log_{10}(1000/900)}{(3.07)(.0635)(1)}$$

= 20#

MAXIMUM TIME REQUIRED TO REACH STATE CONDITIONS
IN EXAMPLE B FOR TIGHT BLOCK DRAINED BY HIGH CAPACITY FRACTURE SYSTEM

1. At pressures just above bubble point

$(C_e = \pm 40 \times 10^{-6})$

$$\eta = \frac{(6.328)(K)}{C_e \mu \phi}$$

$$= \frac{(6.325)(.91)}{(40 \times 10^{-6})(.68)} = 2.1 \times 10^5$$

$$t = \frac{r^2}{4\eta} = \frac{(1000)^2}{(4)(2.1 \times 10^5)}$$

= 1.2 days

Kh = .0635 darcy feet

ϕh = (from graph D-3 herein)

BOPA for .0635 Kh is 420 BOPA

$$\frac{(420)(1.29)}{7750} = .0699$$

$$\frac{Kh}{\phi h} = \frac{K}{\phi} = \frac{.0635}{.0699} = .91$$

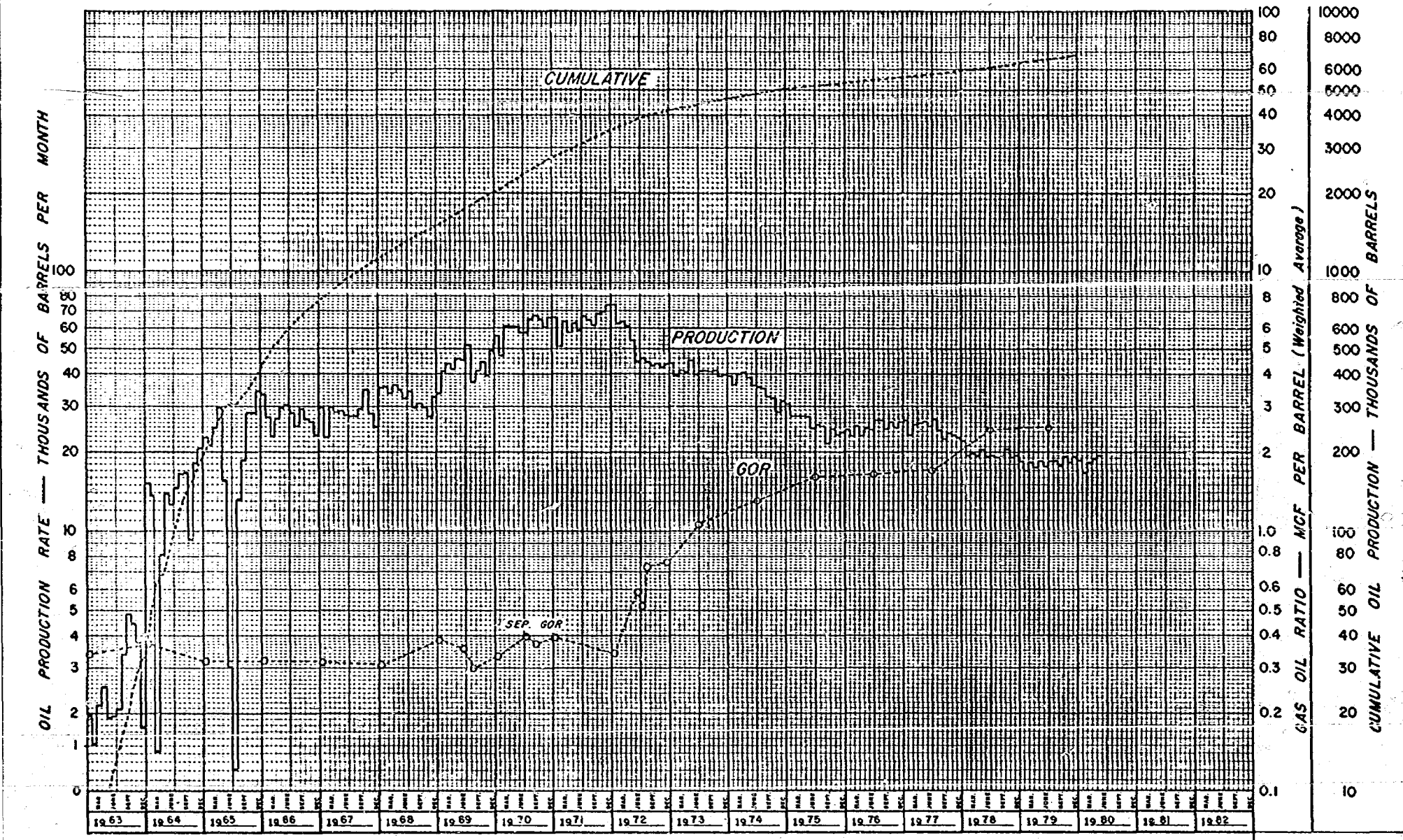
---

2. At pressure just below the bubble point

$(C_e = \pm 400 \times 10^{-6})$

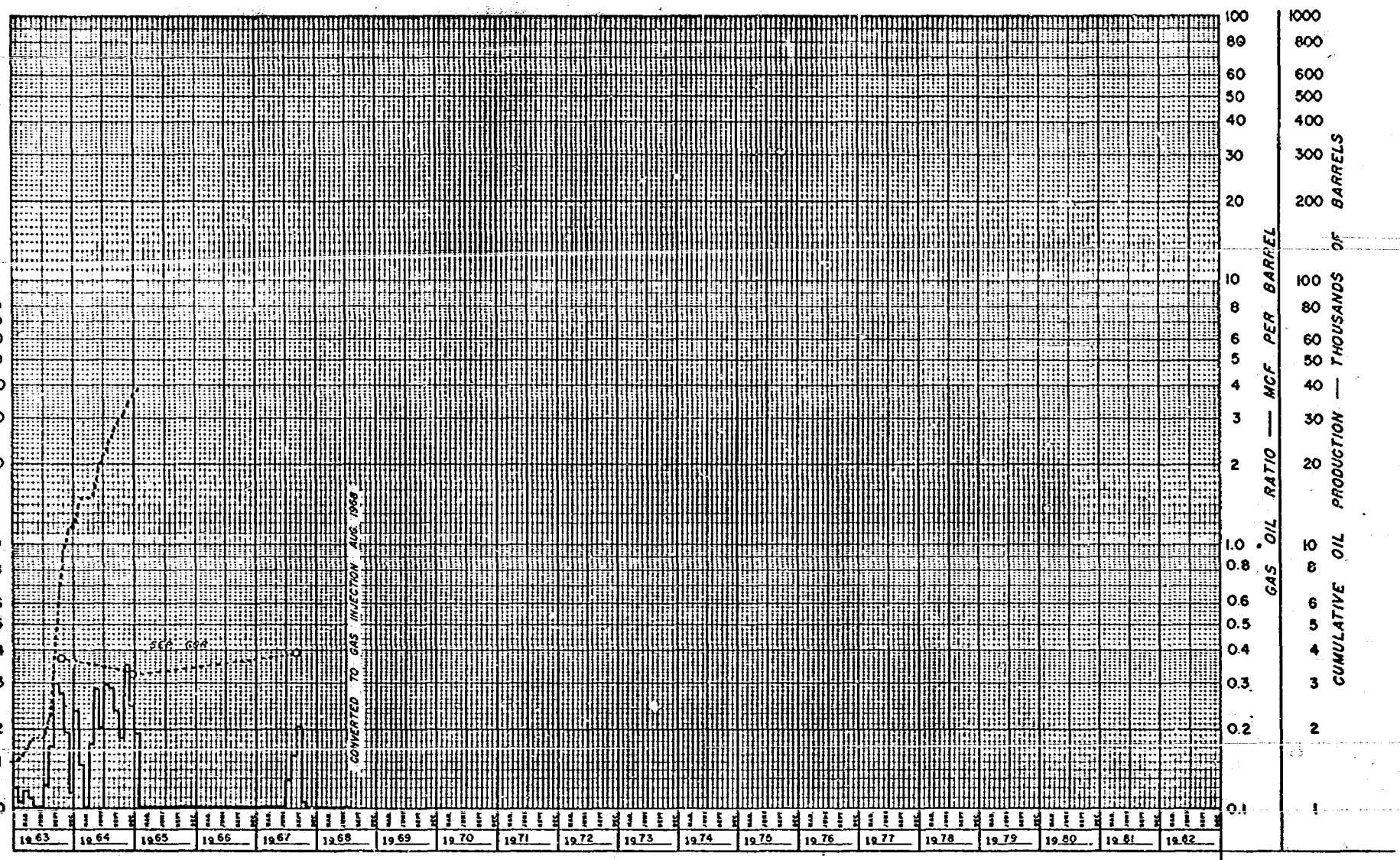
η = 10 x above

t = 10 x above ($\pm$ 12 days)



PRODUCTION HISTORY
CAÑADA OJITOS UNIT
NIOBRARA—GREENHORN PARTICIPATING AREA

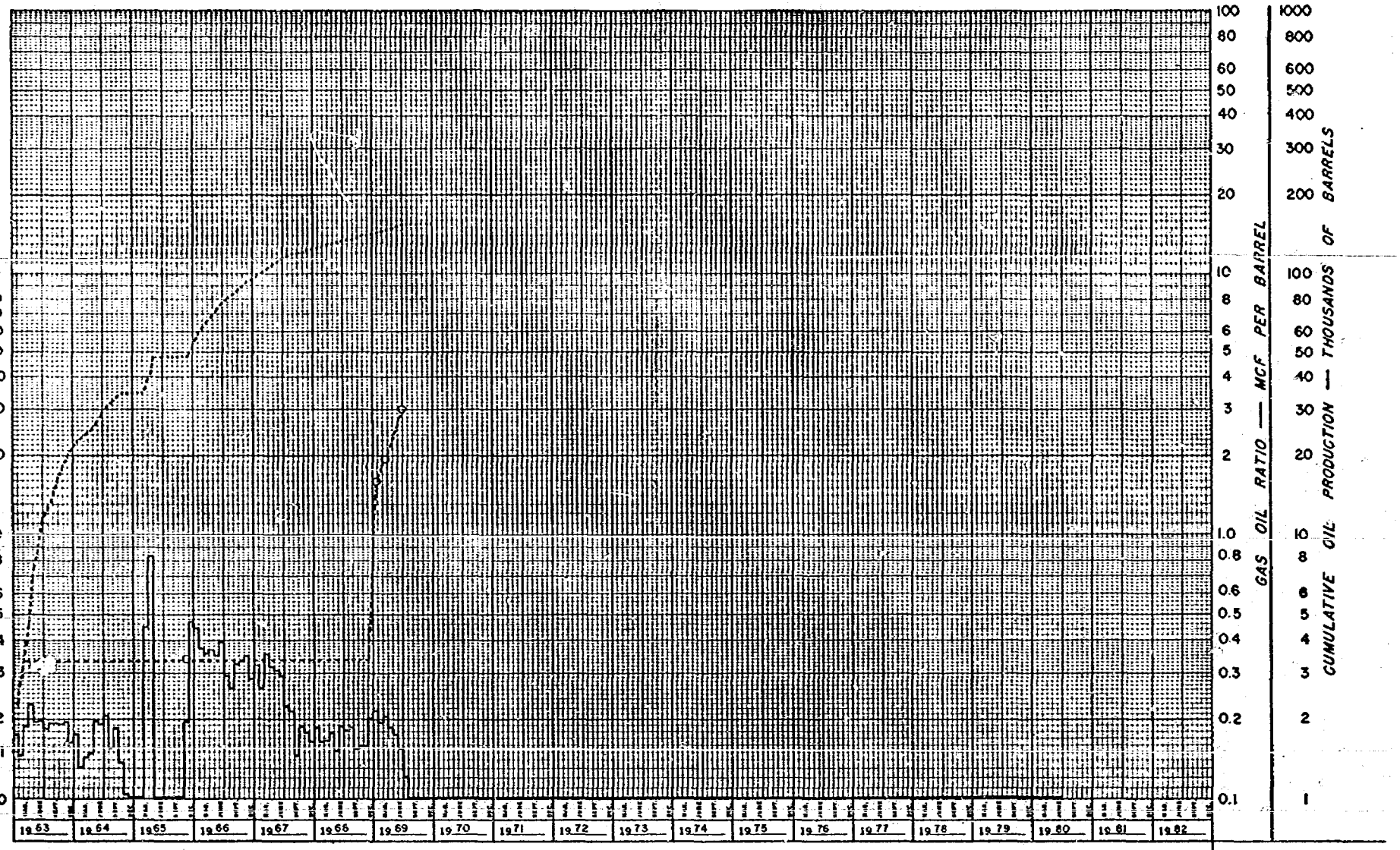
C.O.U.
PRODUCTION
HISTORY



PRODUCTION HISTORY
CANADA OJITOS UNIT WELL K-13

S-13-26N-1W

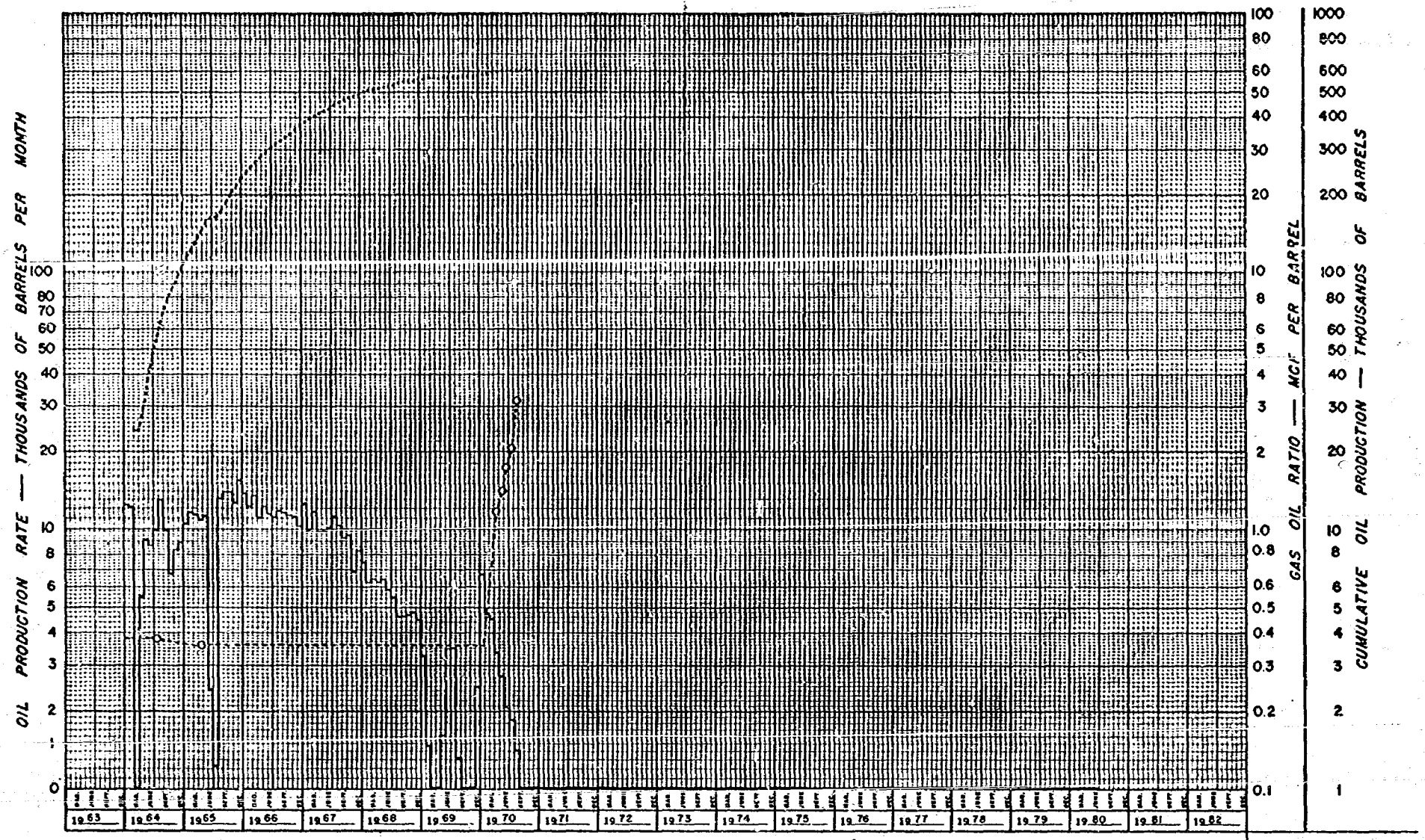
C.O.U. K-13
PRODUCTION
HISTORY



PRODUCTION HISTORY
CANADA OJITOS UNIT WELL A-14

C.O.U. A-14
PRODUCTION
HISTORY

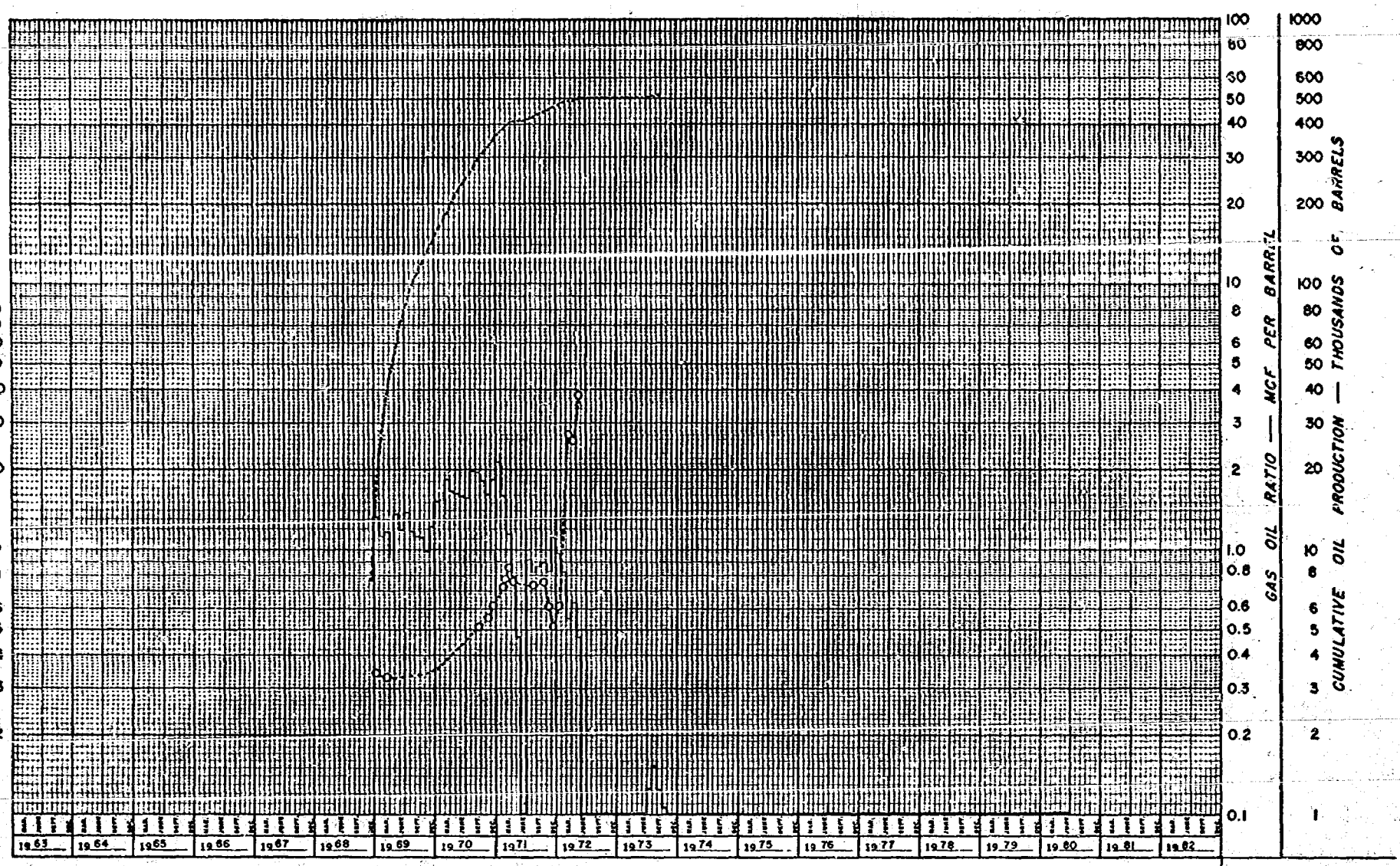
S-14 - 25N-1W



PRODUCTION HISTORY
CANADA OJITOS UNIT WELL P-11

C.O.U. P-11
PRODUCTION
HISTORY

S.9-26N.-1W

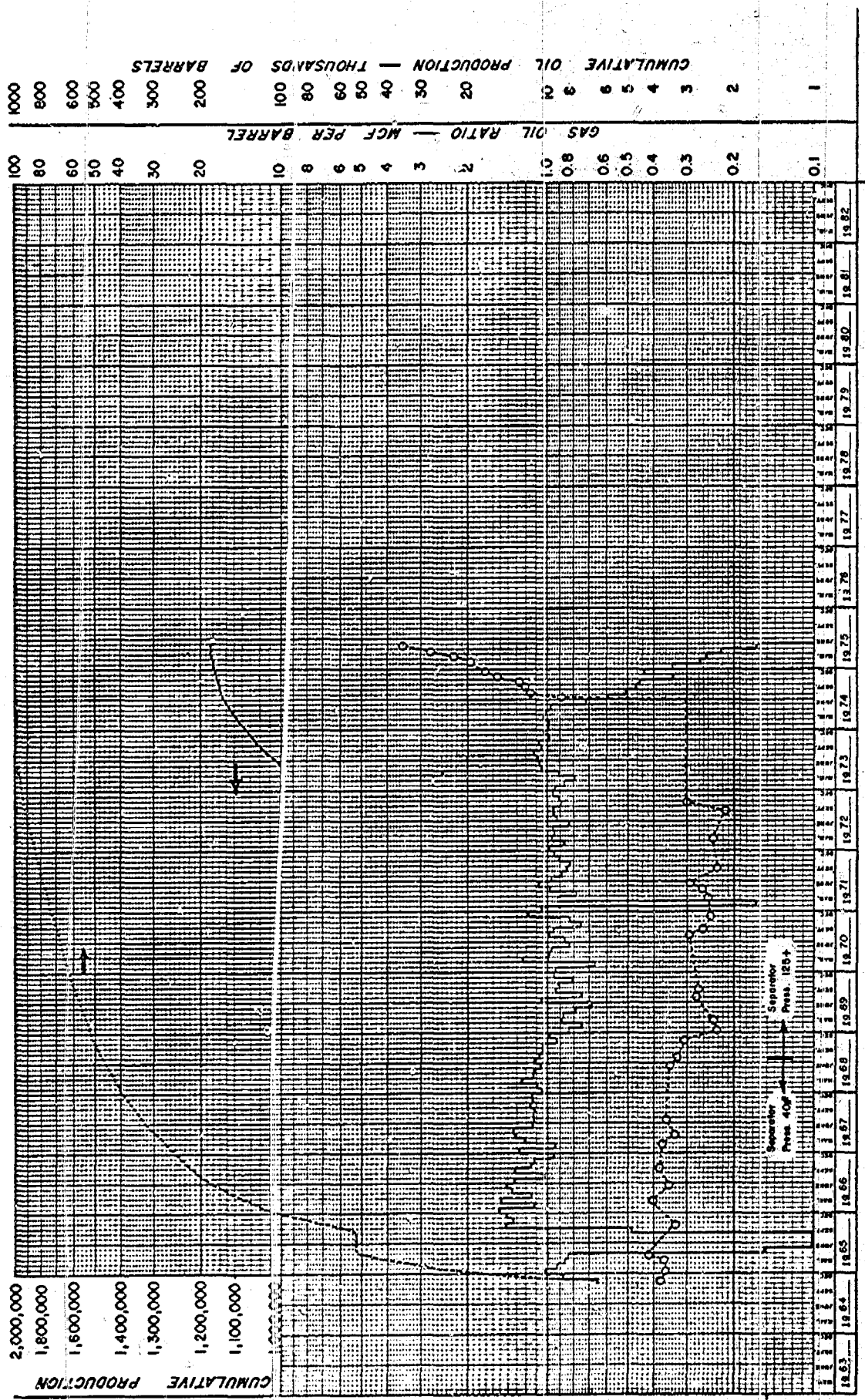


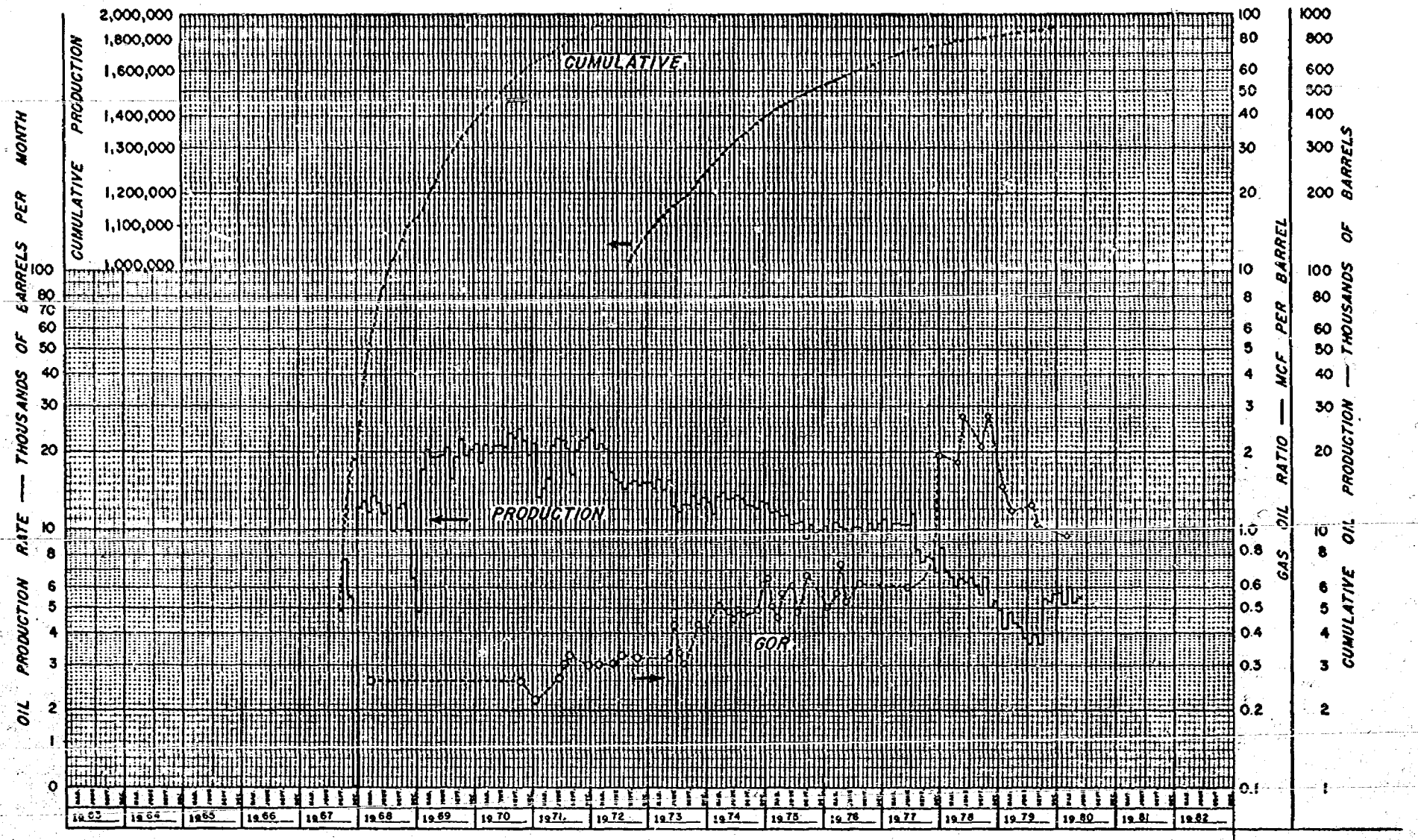
PRODUCTION HISTORY
CANADA OJITOS UNIT WELL A-22

C.O.U. A-22
PRODUCTION
HISTORY

S.22 - 23N - 1W

PRODUCTION HISTORY
CANADA OJITOS UNIT WELL L-11





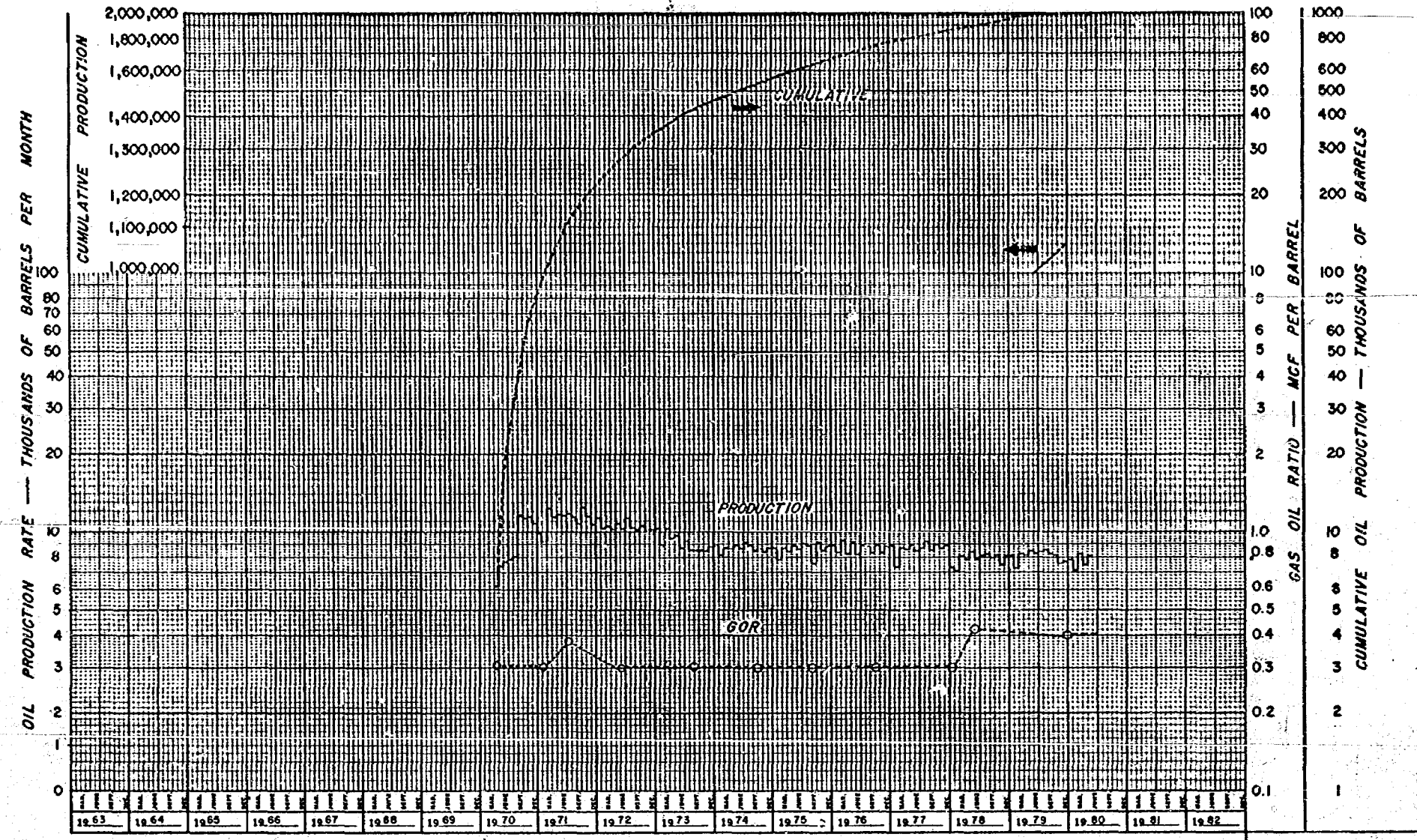
PRODUCTION HISTORY
CANADA OJITOS UNIT WELL E-10

has drained 4-8000 acres

S.10-282-4W

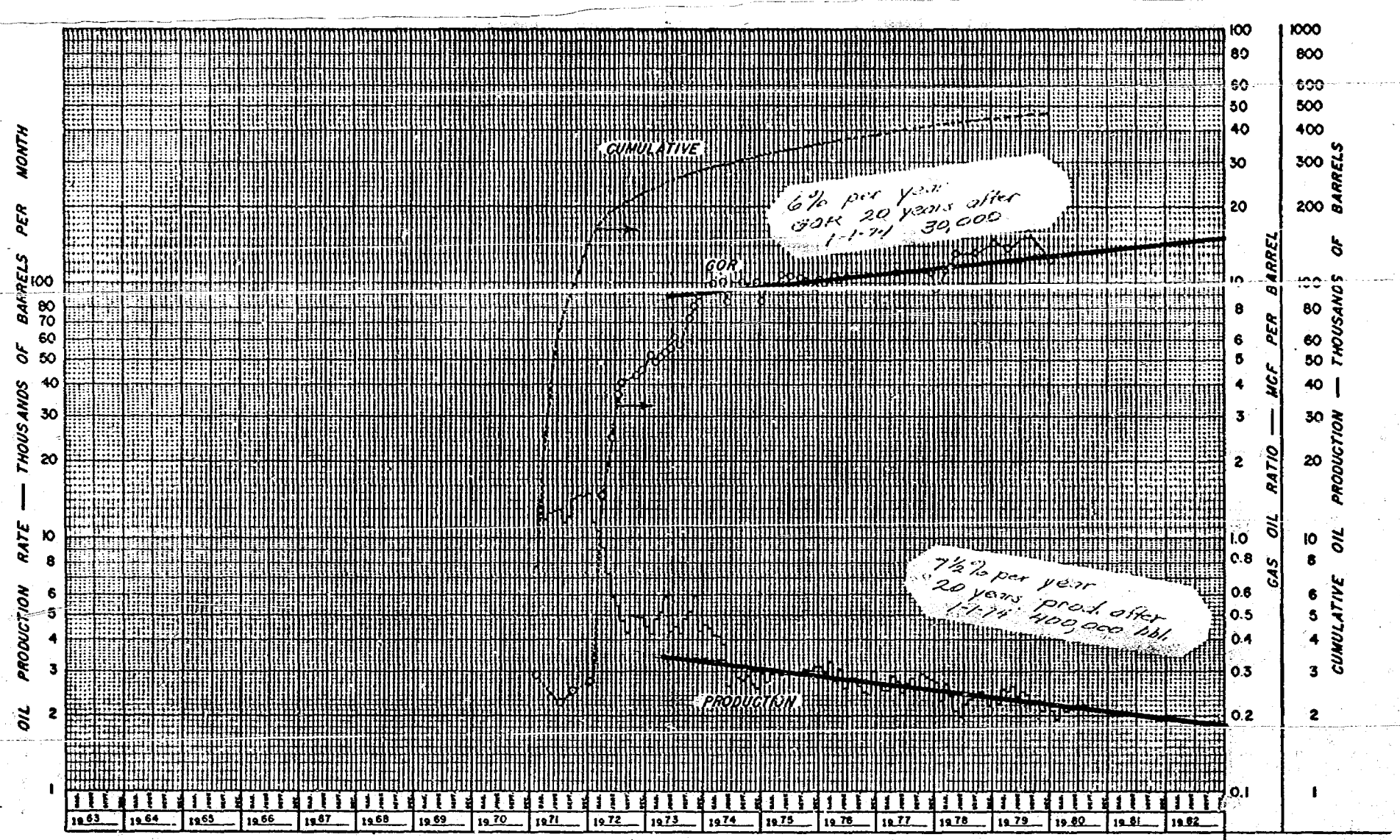
C.O.U. E-10
PRODUCTION
HISTORY

PRODUCTION HISTORY
CANADA OJITOS UNIT WELL L-27



C.O.U. L-27
PRODUCTION
HISTORY

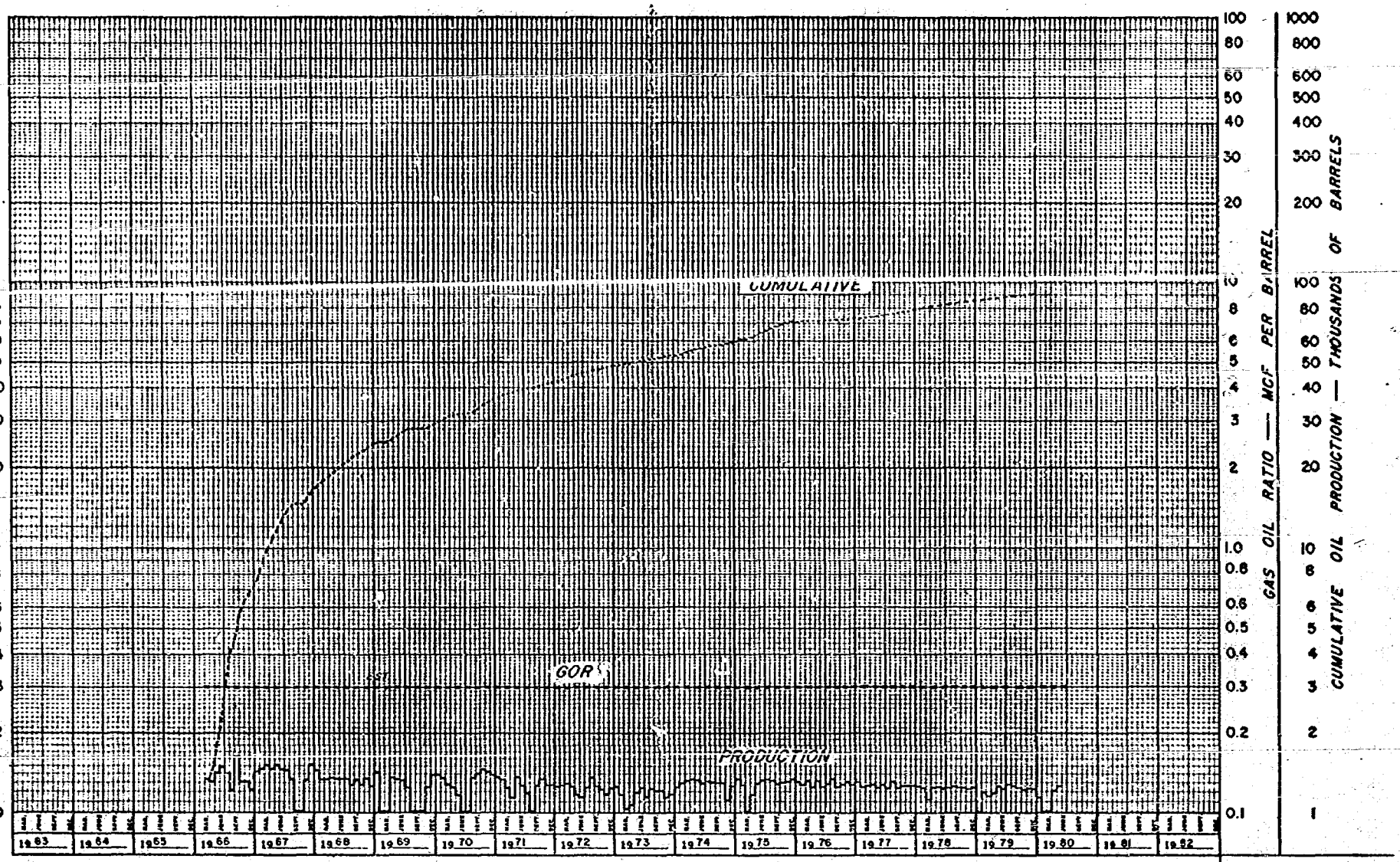
S.27-28N-1W



PRODUCTION HISTORY
CANADA OJITOS UNIT WELL C-34

C.O.U. C-34
PRODUCTION
HISTORY

S. 34 - 25N - 1W

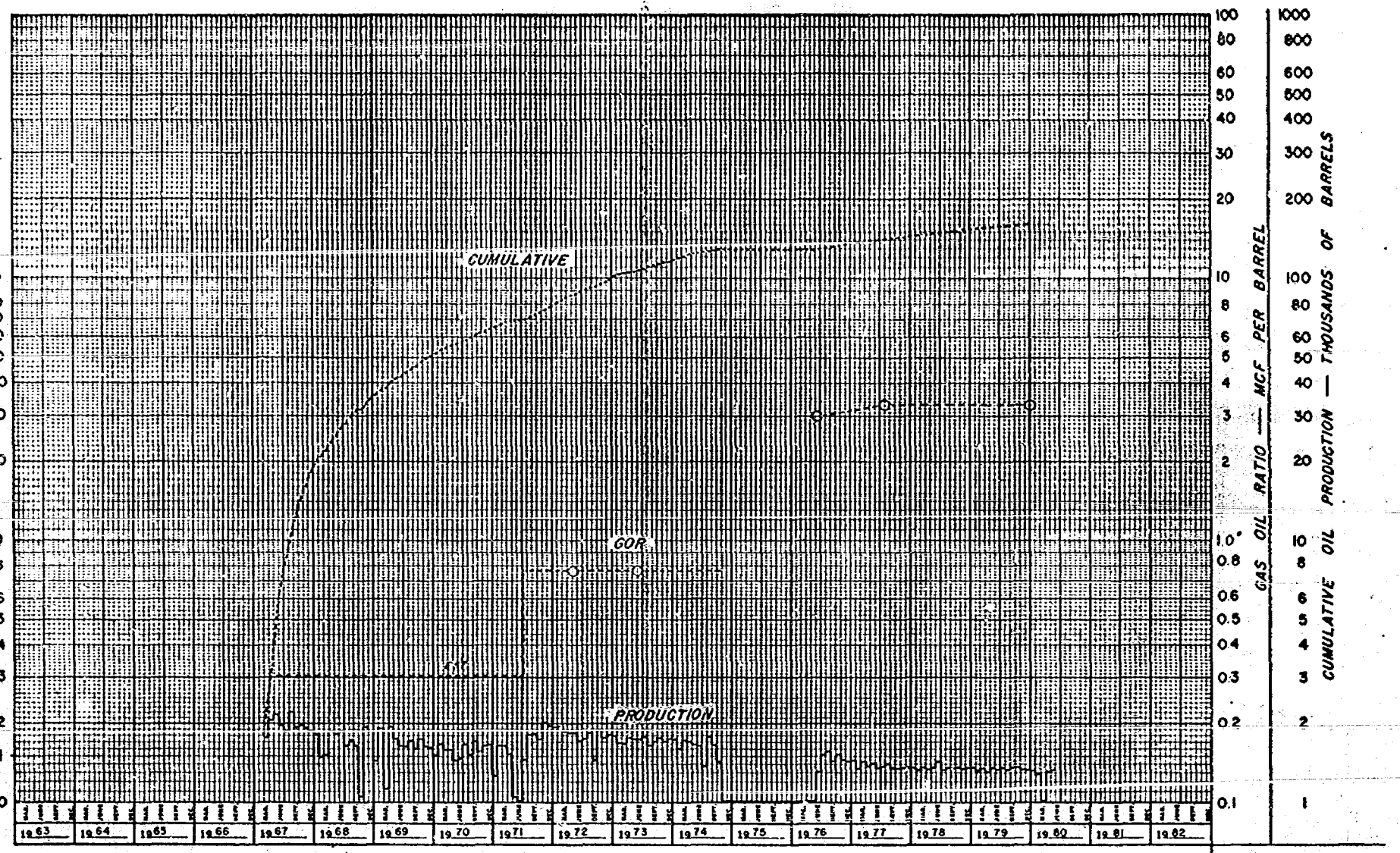


PRODUCTION HISTORY

CANADA OJITOS UNIT WELL A-16

C.O.U. A-16
PRODUCTION
HISTORY

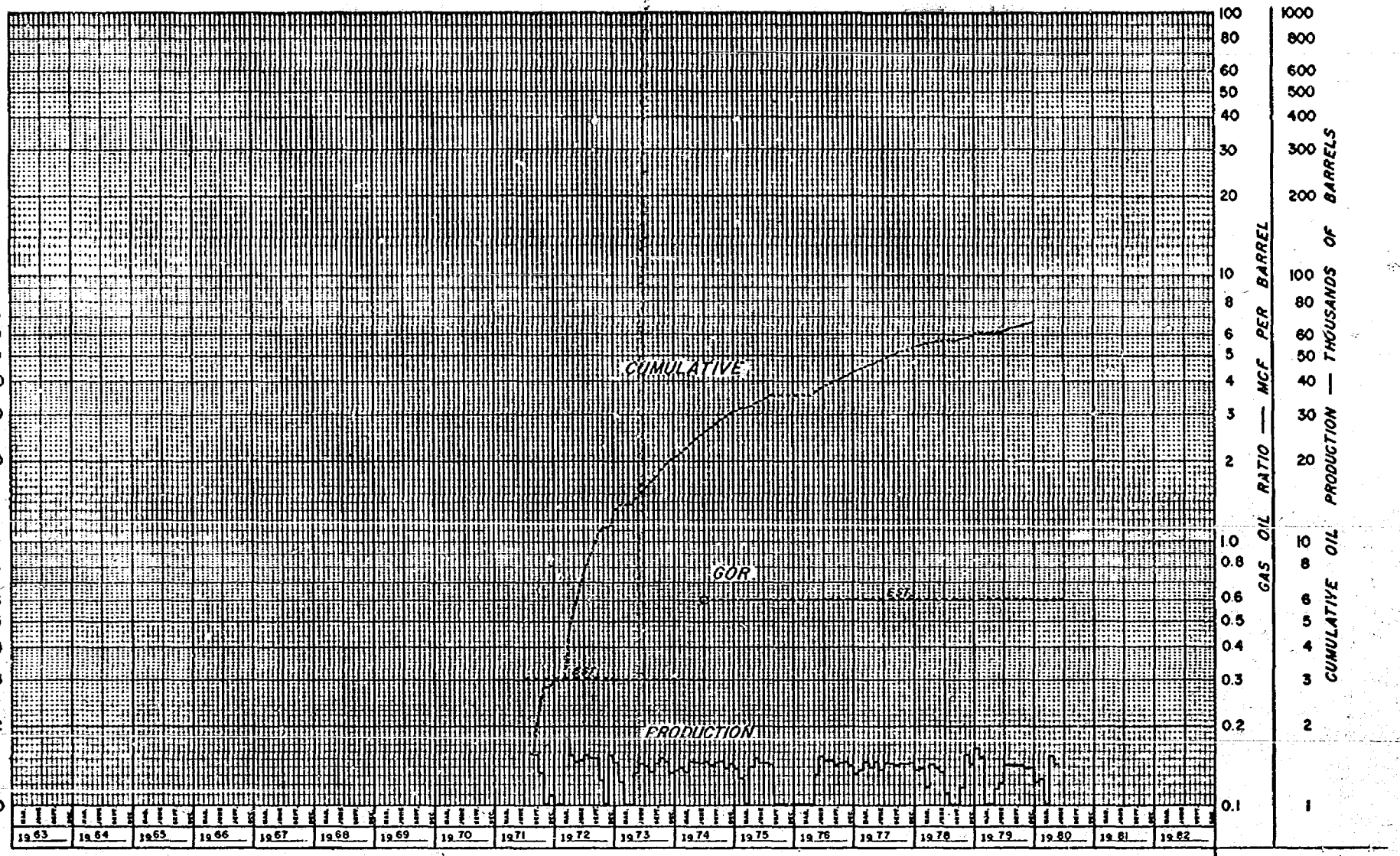
S. 19 - R9N - 1W



PRODUCTION HISTORY
CANADA OJITOS UNIT WELL O-33

S. 33 - 26N - 1W

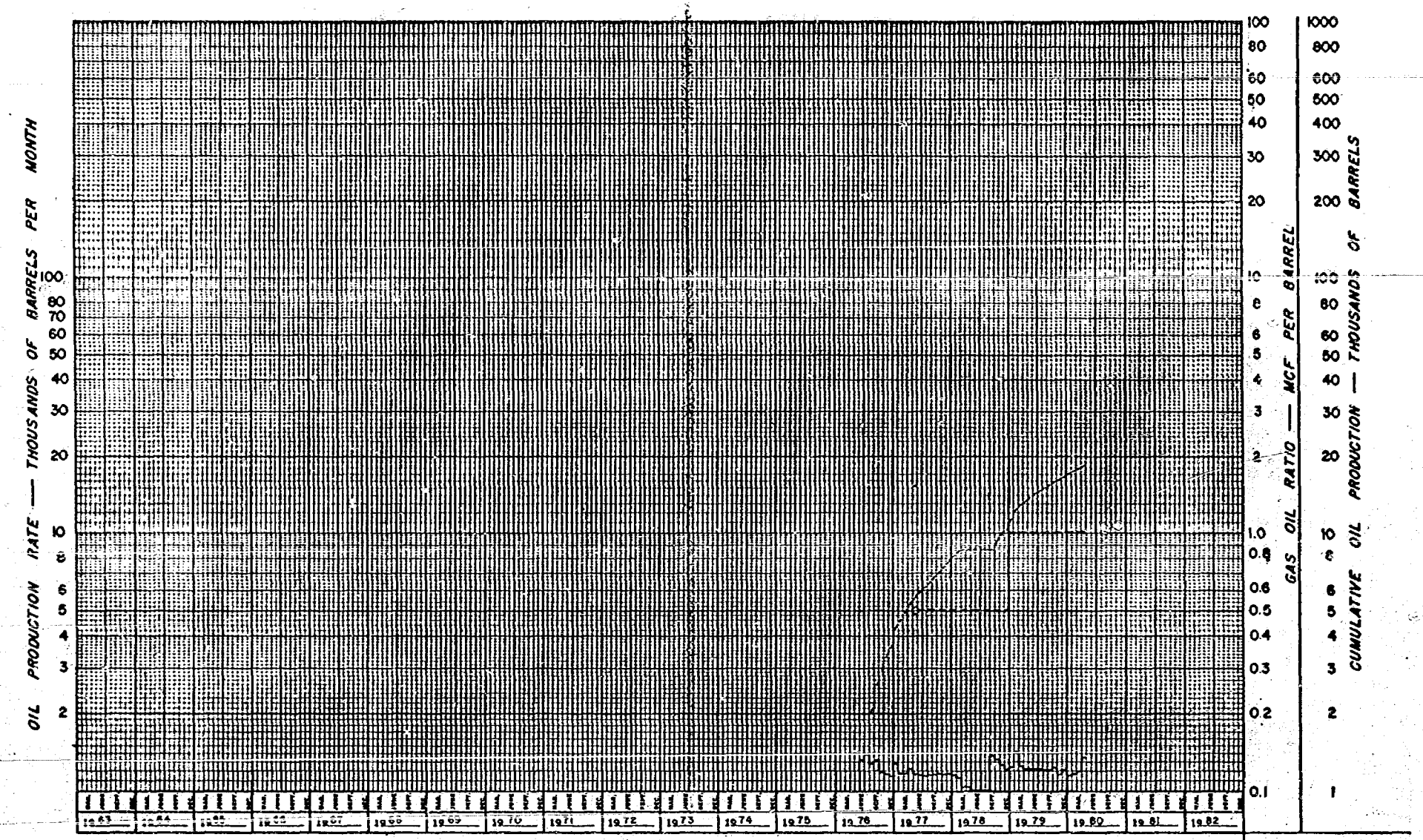
C.O.U. O-33
PRODUCTION
HISTORY



PRODUCTION HISTORY
CANADA OJITOS UNIT WELL L-3

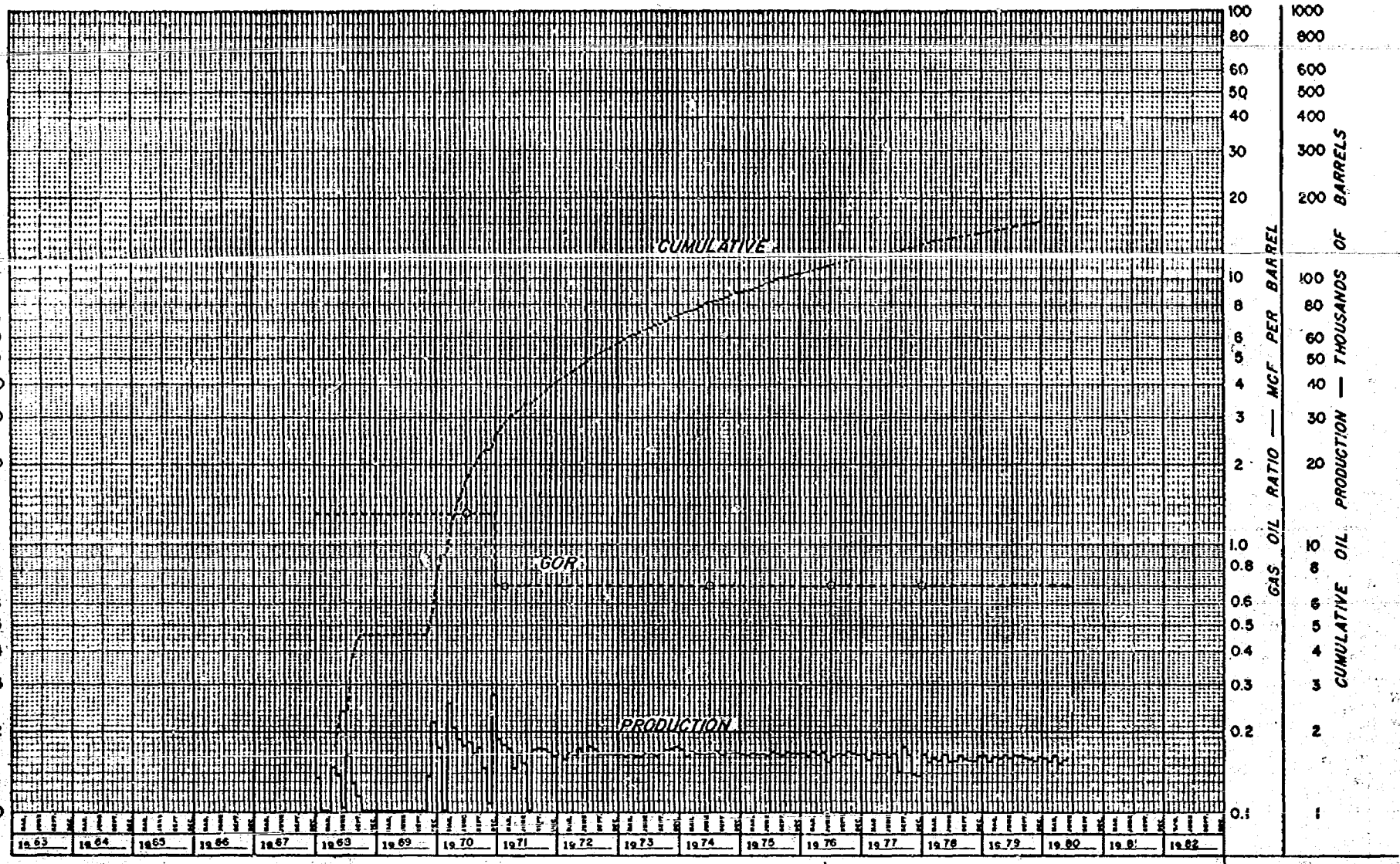
C.O.U. L-3
PRODUCTION
HISTORY

S. 3-24N.-1W



PRODUCTION HISTORY
CANADA OJITOS UNIT WELL O-9

C.O.U. O-9
PRODUCTION
HISTORY

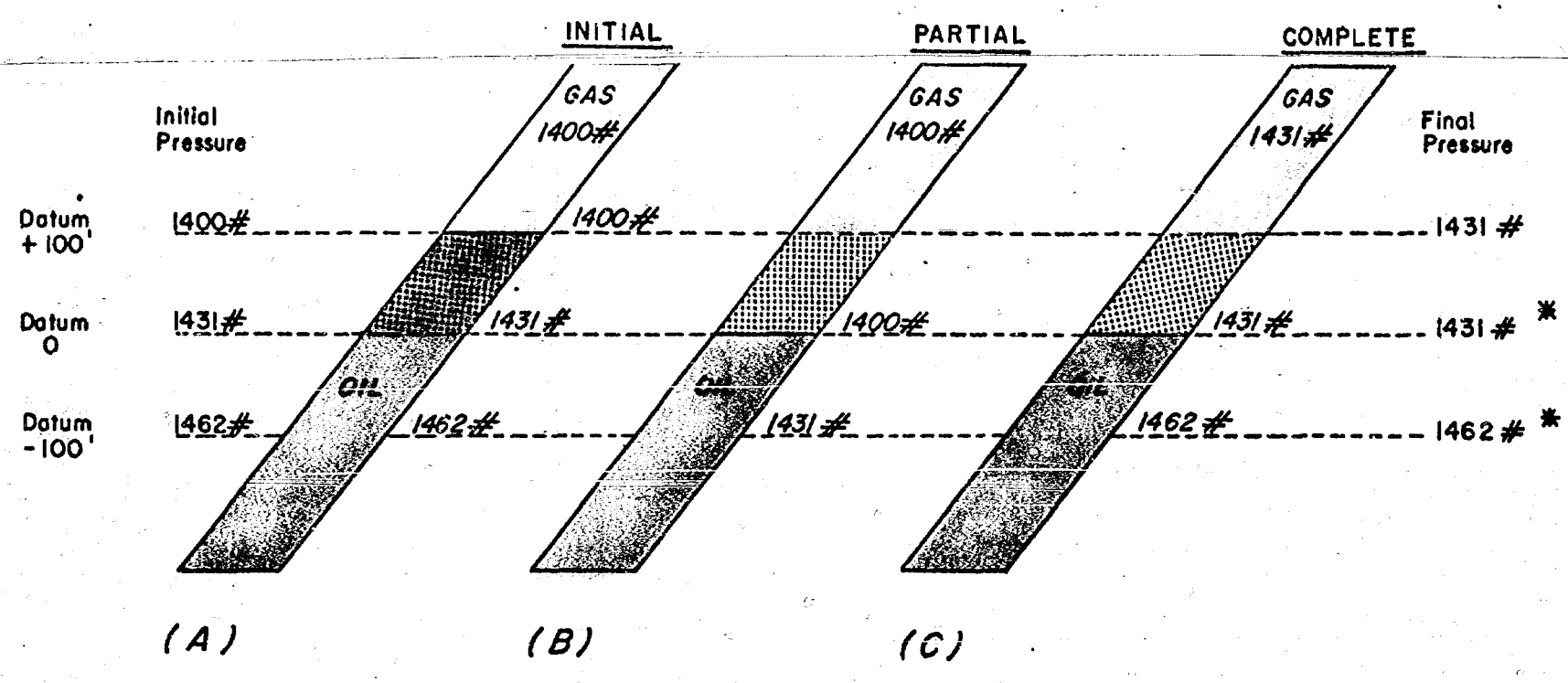


PRODUCTION HISTORY
CANADA OJITOS UNIT WELL C-2

C.O.U. C-2
PRODUCTION
HISTORY

S. 2 - 25N - 1W

SKETCH SHOWING RELATIVE PRESSURE IN GAS CAP AND OIL ZONE UNDER COMPLETE PRESSURE MAINTENANCE



* Disregard Weight Of Gas Column (± 10% Of Oil)

PRESSURE MAINTENANCE VOLUMES REQUIRED
FOR GAS CAP PRESSURE OF 1400 PSIG* AND DIPPING RESERVOIR AND OIL PRODUCED BY GRAVITY DRAINAGE

1. Effective atmospheres: $\frac{V_2}{V_1} = \frac{P_1}{P_2}\left/\frac{Z_2}{Z_1}\right/\frac{T_2}{T_1} = \frac{1412}{15.025}\ \frac{1}{.85}\ \frac{520}{615} = 93.5$

2. For every barrel of oil produced, reservoir space voided is (5.615 cf)(1.29) = 7.24 cf

3. Gas volume required to replace 1 S.T. barrel of oil produced and maintain gas cap pressure: (7.24)(93.5) = 677 SCF

4. Gas cap volume at time 6,500,000 barrels oil produced:

   a. (6,500 M bbls)(7.24)(93.5) = 4.4 BCF plus
   b. Shrinkage of oil left in reservoir .7 BCF to 1 BCF depending on oil volume = Total $\pm$ 5.2 BCF

5. Additional gas volume required to increase gas cap pressure to overcome the decrease in oil zone pressure caused by downdip displacement of gas-oil contact. Assume average recovery at gas-oil contact in high capacity system to be at rate of 250 barrels/acre and that structure dips at 200′ and 400′ per mile:
   (Consider a one-mile wide segment of the reservoir running downdip and that it contains 1/10 (one mile out of 10 along the strike) of the gas cap gas of + .5 BCF for the segment)

   a. At 400′/mile
      Recoverable oil volume per section: (250 BOPA)(540 acres) = 160,000 BO
      Drop in gas-oil contact with production of 1 barrel:
      $\frac{1 \text{ bbl}}{160{,}000 \text{ bbls/mile}}$ (400′/mile) = .0025 ft = (.0025 ft)(.312 psi/ft) = .00078 psi, which translates to:

      $\frac{.00078}{1412}$ (.52 BCF) = 287 cf/bbl

   b. At 200′/mile: 1/2 x 287 = 143 cf/bbl

   Note: If bulk of gas cap volume is concentrated in 5 mile area along strike and bulk of oil produced here, volumes required to raise gas cap pressure could be twice those shown above ("high" estimate in following table).

6. Summary:

	For 250 BOPA reservoir voidage and structure of:			
	400′/Mile		200′/Mile	
	High Est. (cf/bbl)	Low Est. (cf/bbl)	High Est. (cf/bbl)	Low Est. (cf/bbl)
a. Per barrel volume of gas required to replace oil and maintain existing gas cap pressure	677	677	677	677
b. Additional per barrel volume of gas required to raise pressure to equivalent initial oil zone pressure	574	287	286	143
c. Totals (for "complete" pressure maintenance)	1251	964	963	820
d. "Makeup" gas required if 300 cf/bbl saved from produced oil and reinjected (for "complete" pressure maintenance)	950	660	960	520

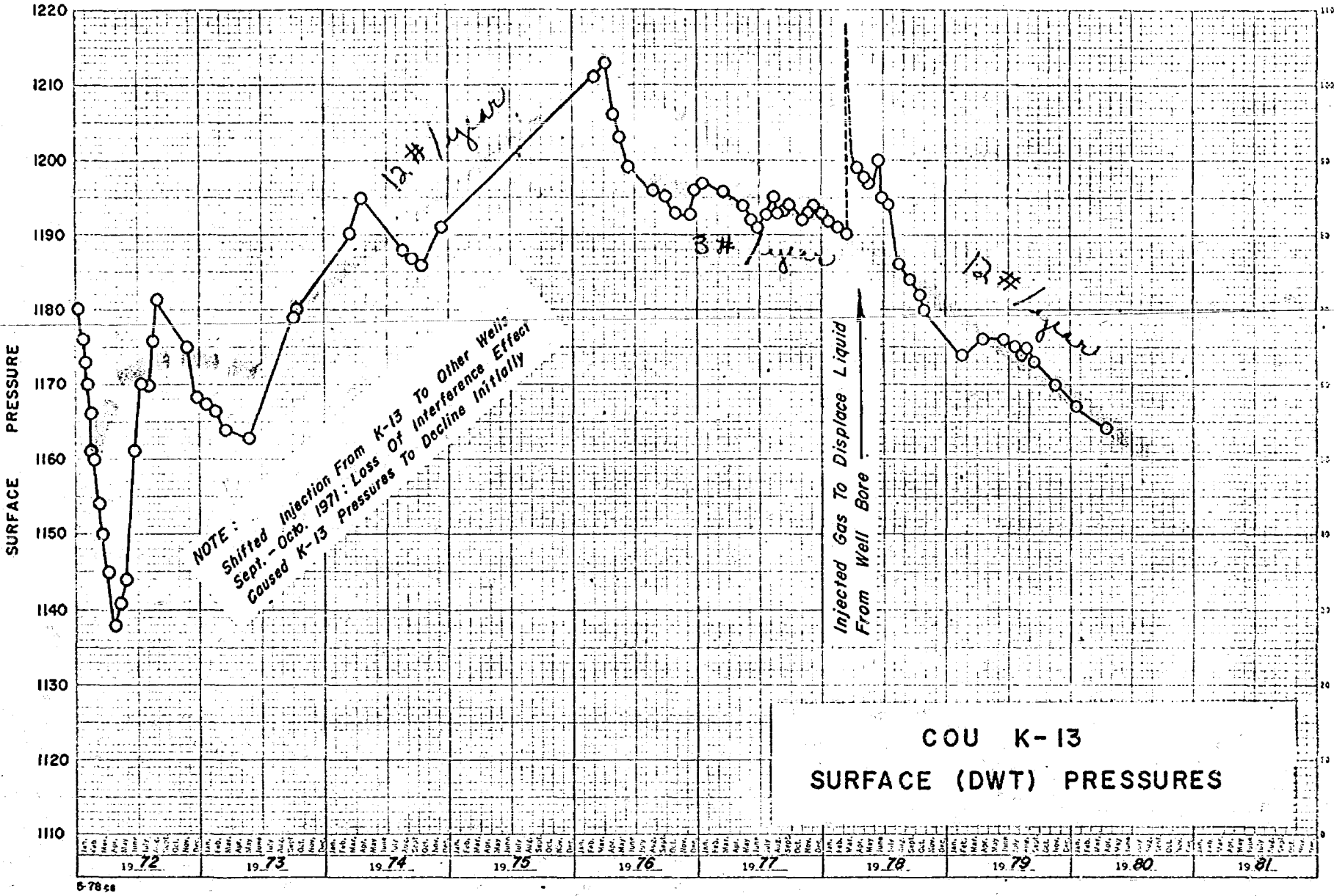
* For surface pressure of 1165# gauge and 6000′ average depth of gas cap.

NOTE: All of above applies to the simplified systems indicated to arrive at volumes for complete pressure maintenance. For less than complete pressure maintenance determination of actual pressures is more complicated.

RELATIVE COST OF "MAKEUP" GAS AS FUNCTION OF OIL PRICE *

Average oil price after windfall taxes ($/bbl)	$6.25	$10.00	$20.00	$30.00
Less 20% royalty and lease burdens ($/bbl)	5.00	8.00	16.00	24.00
Less 7 1/2% production taxes ($/bbl)	4.62	7.40	14.80	22.20
Less $2.00/bbl Operating expenses (including fuel for compressors) ($/bbl)	2.62	5.40	12.80	20.20
(Net operating income except for makeup gas) ($/bbl)	2.62	5.40	12.80	20.20
Makeup gas @ .7 MCF/bbl and $2.00/MCF ($/bbl)	1.40	1.40	1.40	1.40
Net income ($/bbl)	1.22	4.00	11.40	18.80
Cost of makeup gas as % of income before makeup gas cost	53%	26%	11%	7%

* For "complete" pressure maintenance


SURFACE PRESSURE
1220
1210
1200
1190
1180
1170
1160
1150
1140
1130
1120
1110
NOTE: Shifted Injection From K-13 To Other Wells Sept. - Octo. 1971: Loss Of Interference Effect Caused K-13 Pressures To Decline Initially
Injected Gas To Displace Liquid From Well Bore
12 # 1/4 jar
3 # jar
12 # 1/4 jar
19 72
19 73
19 74
19 75
19 76
19 77
19 78
19 79
19 80
19 81
COU K-13
SURFACE (DWT) PRESSURES
10 YEARS BY MONTHS 359-200L
5-78 ss

CANADA OJITOS UNIT

APPROXIMATE EQUIVALENT VOLUMES OF MAKEUP GAS
EXPRESSED AS CUBIC FEET PER BARREL OF OIL PRODUCED

Year	Makeup Gas Purchased (MCF)	Estimated Consumption for Fuel * (MCF)	Makeup Volume less Consumption (2) - (3) (MCF)	Oil Production (M bbl)	Makeup Volume less Consumption per Barrel of Production (4) (5) (cf/bbl)
(1)	(2)	(3)	(4)	(5)	(6)
1972	264,267	70,000	194,267	620.8	313
1973	306,197	70,000	236,197	494.5	478
1974	385,615	70,000	315,615	427.0	740
1975	346,449	70,000	276,449	308.0	897
1976	194,737	70,000	124,737	300.1	416
1977	177,850	70,000	107,850	295.1	365
1978	113,765	70,000	43,765	236.9	185
1979	98,353	60,000	28,353	218.9	130

NOTE: Above are only equivalent volumes. Operator considers all purchased gas to be injected in reservoir. Fuel used is deemed to derive from gas produced with the oil.

* Fuel consumption estimated at

(1) 19 MCF/day/compressor for 8 compressors until 1979 when changed from carburetors to fuel injection, for last 3/4 yr: 14 MCF/day/compressor.

(2) 1% of 1,000 MCF/day for 1st dehydrator 10 MCF/day
&.1% of 2,000 MCF/day for 2nd dehydrator 20 MCF/day
TOTAL 30 MCF/day

(3) Camp fuel 4 MMCF/year.

APPROXIMATE RESERVOIR PRESSURE DECLINE
RESULTING FROM VERTICAL DROP IN GAS-OIL CONTACT "SURFACE"

and

HORIZONTAL DISPLACEMENT OF OIL IN "HIGH CAPACITY FRACTURE SYSTEM"

BO/ACRE IN PLACE (AVERAGE) (1)	BO/ACRE IN HIGH CAP. SYSTEM * (2)	BO/ACRE RECOVERY AT 50% EFFICIENCY (3)	FOR RESERVOIR 10 MI LONG x 1 MI WIDE		DROP OF GAS-OIL CONTACT (FT/YR) FOR STRUCTURE		EQUIVALENT PRESSURE DROP (#/YR) FOR STRUCTURE		PRESSURE DROP AS % OF 1400# FOR STRUCTURE		TOTAL DOWN-DIP LINEAR MILES DISPLACED FOR 6500 M BBLS CUM. (12)
			TOTAL VOL. IN PLACE (M BBLS) (4)	PRODUCTION FRACTION AT 230M BBLS/YR (5)	400'/MI (6)	200'/MI (7)	400'/MI (8)	200'/MI (9)	400'/MI (10)	200'/MI (11)	
2000	1000	500	3200	.0718	28.7	14.3	9#	4.5#	0.6%	0.3%	2.0 **
1000	500	250	1600	.1436	57.0	28.6	18#	9.0#	1.2%	0.6%	4.0 **

* Assuming 50% of total initial oil in place to be in high capacity fracture system.

** For reservoir 10 miles long, this is the down-dip length of the reservoir from which oil has been displaced from the high capacity fracture system.

GRAVITY DRAINAGE RATES
WEST PUERTO CHIQUITO
FOR CONDITIONS OF:
OIL DENSITY 44.9#/cubic foot
GAS DENSITY 5.35#/cubic foot
OIL VISCOSITY .62 centipoises
FORMATION DIP 400 feet per mile

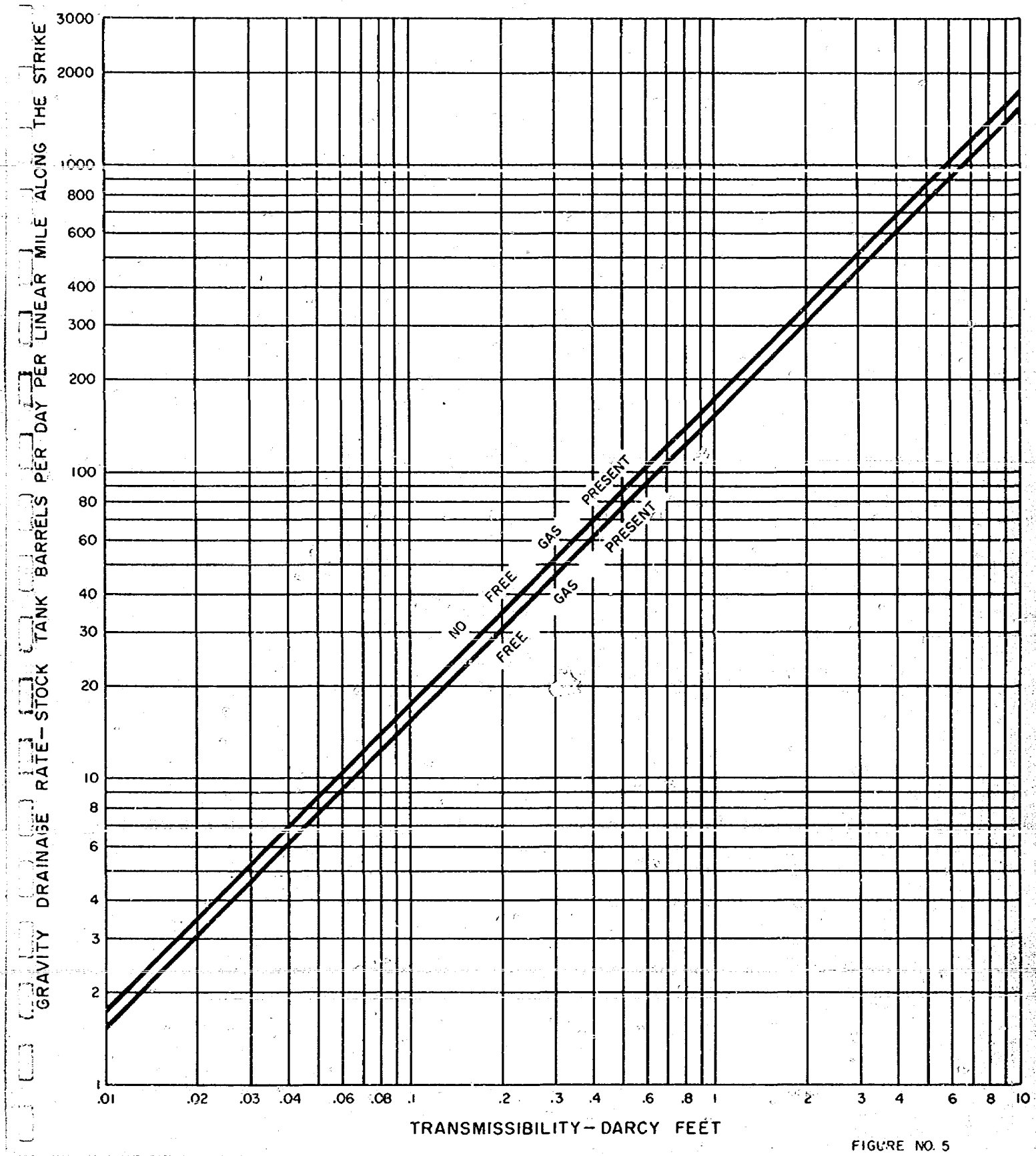


FIGURE NO. 5

NOTES REGARDING PRODUCTION BEHAVIOR OF
CANADA OJITOS UNIT A-16
AND AREA DRAINED BY WELL

1. For comparison a 70% decline rate (as was experienced by the Boulder Field wells) is indicated. For this well, A-16, produced to an economic limit of 3 BOPD, this 70% rate of decline would have resulted in a cumulative production of 10,000 bbls. (Actual cumulative to 1-1-80 is 90,000 bbls.)

2. Gravity Drainage Consideration: With the well's low initial stabilized production rate (approximately 25 BOPD) its immediate drainage area is too tight to permit substantial gravity drainage. The gravity drainage rate for a transmissibility supporting 25 BOPD and the dip of the formation of approximately 100' per mile would be approximately 2 BOPD per linear mile along the strike. For 640-acre spacing the maximum gravity drainage rate would then be about 2 BOPD.

3. Since approximately 90% of the well's production must come from something other than gravity drainage of its own immediate area, one must conclude that:

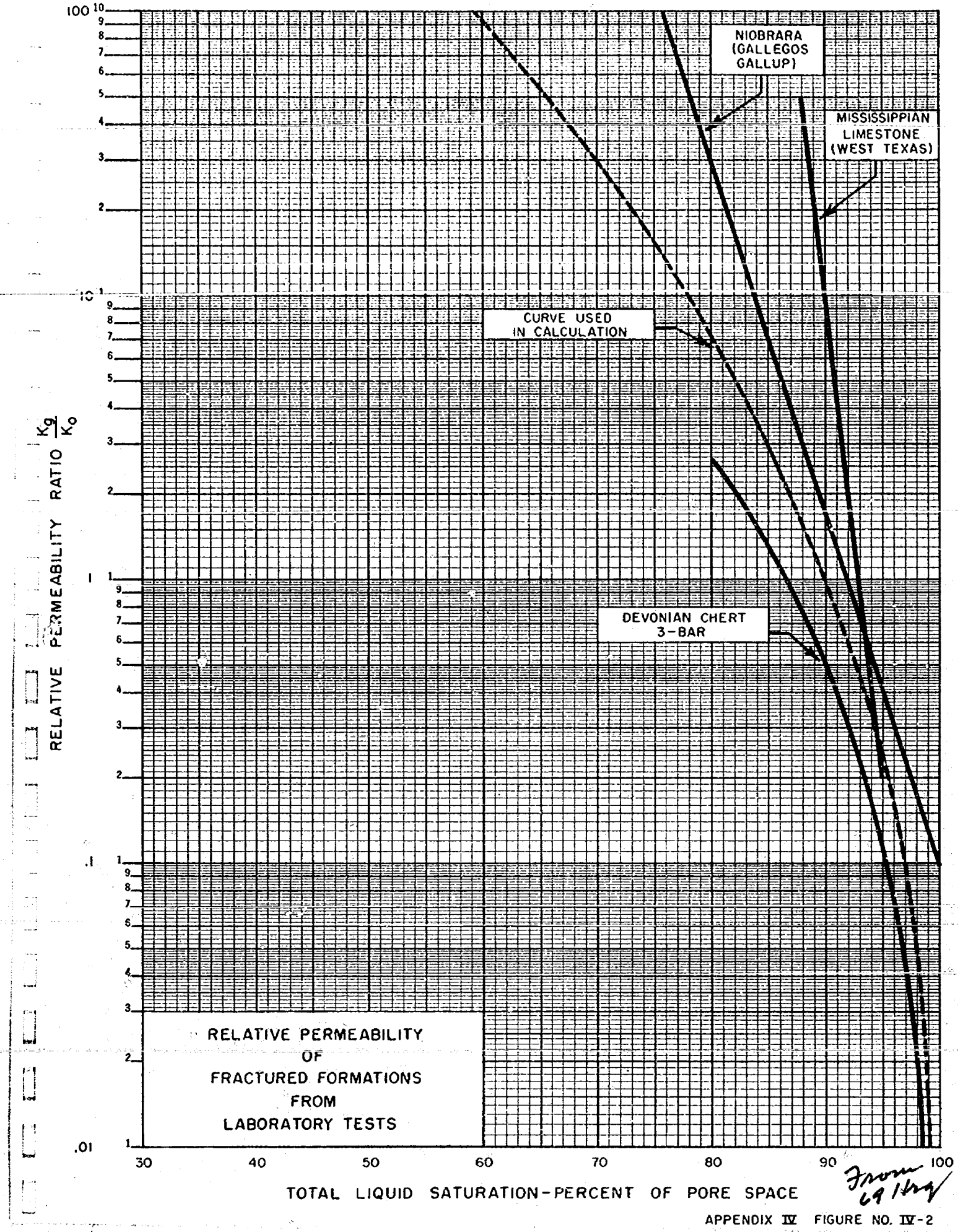
   (1) the well's production has resulted from its participation in the overall reservoir system as described by the "jigsaw" makeup of tight blocks and high capacity fracture system; and that the pressure and production in its immediate area has been maintained by the pressure maintenance system (nearest injection well approximately 4 miles away);

   or

   (2) if production is not supported by the system as described in 3(1) above and since 90% of the production must come from something other than gravity drainage, it would then have to be from solution-gas drive; and if we assume the reservoir it is draining would be of the same character as that in the vicinity of the well, and that the well would continue along its present 7% maximum rate of decline, then the ultimate recovery would be about 190,000 bbls. If 90% is from solution-gas drive this would mean 170,000 bbls. from this. At 50 bbls/acre (5% of 1,000 BOPA in place maximum estimate for tight reservoirs) this would indicate 3,400 acres being drained by the well.

4. Of the two possibilities, the most logical one is that the well is part of the overall drainage system as earlier described and is draining its share of several thousand acres. The fact that the well produced until 1976 with minimal rate of decline coincides with the pressure maintenance which was rather "complete" for the period 1972 to 1976. In 1976 the well took on an increased rate of decline which is estimated to be about 7% per year. The pressure decline in the gas cap (Section F-4 herein) of approximately 1% per year, along with possible additional decline in pressure as indicated in F-6 herein, would account for only 1% to 2% rate of reservoir pressure decline. The additional production decline rate could be the result of unknown mechanical inefficiency, but is believed not to be the result of reduction in relative permeability to oil since pressure in the vicinity of the well is now probably still above the bubble point. On the other hand, it has been observed in other wells in this area, and in other fractured Niobrara reservoirs, that productivity often drops at a much faster rate than can be accounted for by either or both pressure decline and decline in relative permeability to oil. It has been postulated that this could be the result of fractures squeezing together following pressure decline; and this could be a factor here.

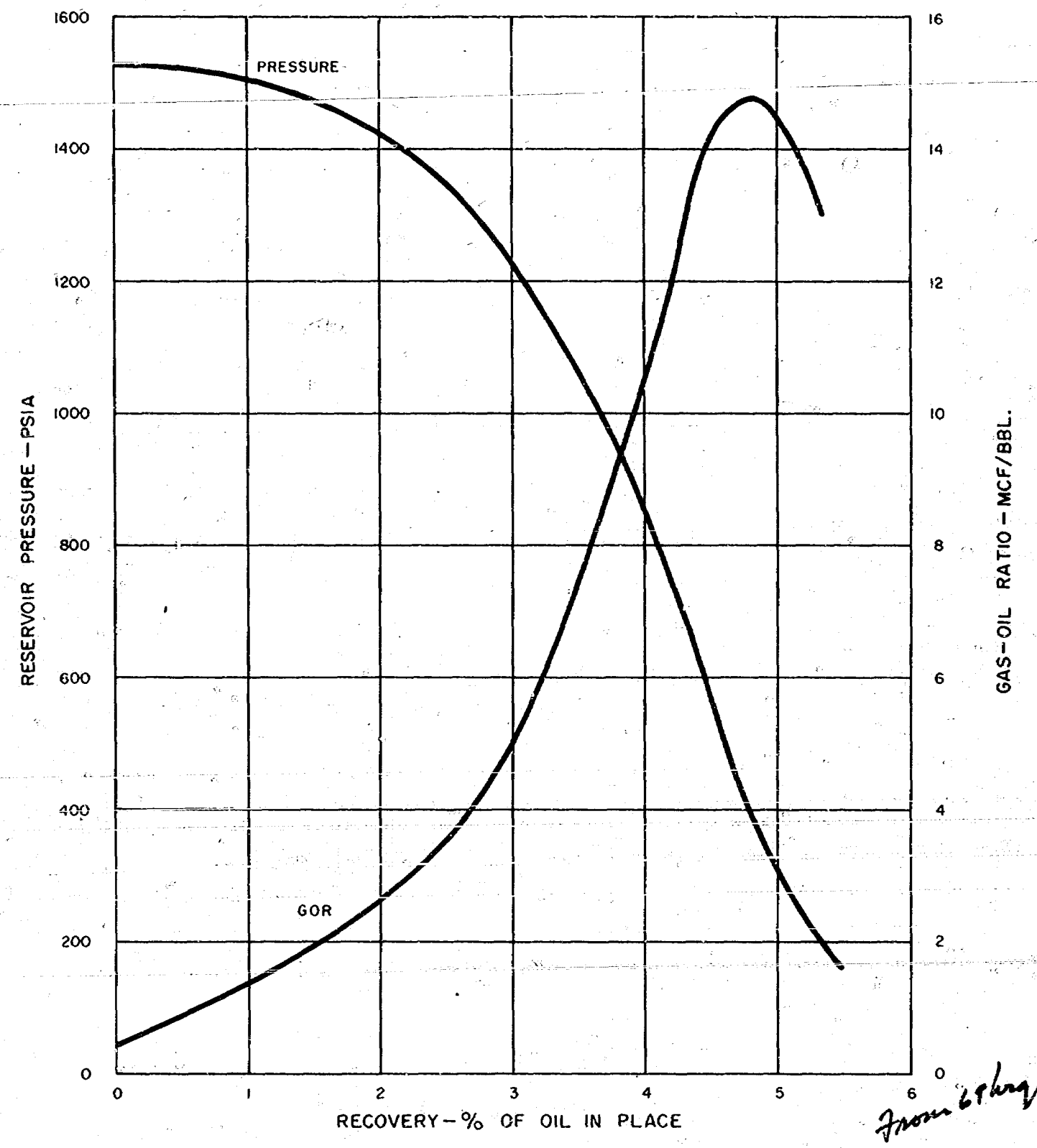
5. Under any rational interpretation, however, the well must be draining several thousand acres.



From 69 Hrg

APPENDIX IV FIGURE NO. IV-2

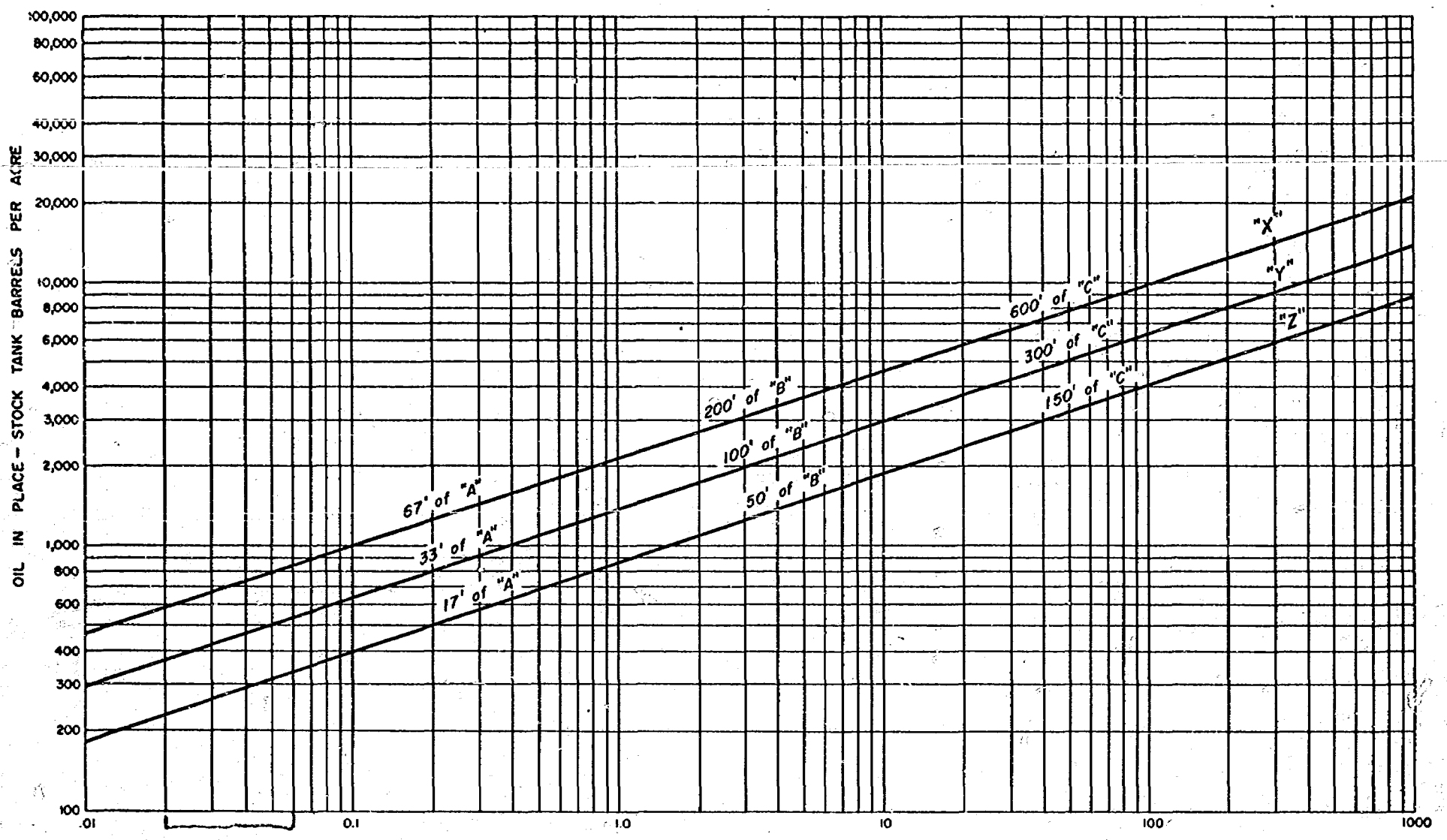
SOLUTION GAS DRIVE
PRODUCTION HISTORY
CALCULATED FOR CONDITIONS OF:
WEST PUERTO CHIQUITO
PVT DATA
AND
K_g/K_o ESTIMATED FROM LABORATORY
DATA FOR FRACTURED FORMATIONS



From Craig

APPENDIX IV FIGURE NO. IV-3

RELATION OF OIL IN PLACE
TO
TRANSMISSIBILITY
FOR
POROSITY–PERMEABILITY RELATIONS
"A", "B" & "C"
AND FOR
RESERVOIR THICKNESSES SHOWN
F.V.F.=1.29



FILE : 13A

APPENDIX III FIGURE NO. III-5

EXAMPLE PRODUCTION PERFORMANCE REQUIRED TO PROVIDE 15% ROR ON INVESTMENT
FOR INDIVIDUAL WELLS IN THE WEST PUERTO CHIQUITO POOL COMPLETED IN "LOW CAPACITY" AREAS
FOR OIL VALUE OF $15.90 PER BARREL BEFORE OPERATING EXPENSE

Curve	Initial Production Rate (BOPD)	Decline Rate Percent/Year	Cumulative Production (M bbls)	Cumulative Operating Expense at 3 BOPD (M Bbls)	Cumulative Production After Operating Expense (M bbls)	VALUE: Undiscounted Cumulative After Operating Expense ($M)	VALUE: Average Discount	VALUE: Present Worth at 15% ($M) after discounting
A	63.4	70	31.5	4.8	26.7	425	.78	330
B	123.0	70	62.6	5.8	56.8	903	.83	750
C	24.5	0	134.4	16.4	118.0	1875	.40	750

A (1) Solution gas drive performance: 50 BO/acre recovery
(2) 640-acre spacing and 70%/year production decline rate (Note: PW of production less than well cost)

B (1) Solution gas drive performance, 50 BO/acre recovery
(2) Spacing and initial productivity required (1,250 acres and 123 BOPD) at 70%/year decline rate to permit 15% ROR on $750M well cost

C Minimum production rate (24.5 BOPD) required for 0% decline and 15 yuears production to yield 15% ROR on $750M well cost

* Cost of pressure maintenance by gas injection and cost of make-up gas not included. These costs are anticipated to be recovered at a later date when gas is sold.

NOTE 1. Minimum well cost of $750M used here. Costs could be as high as $1,000M/well

2. For wells capable of producing 15% ROR on cost of $750M, the initial productivity (123 BOPD) required means that the reservoir transmissibility must be high enough to support such a well; which in turn means a transmissibility high enough to support 640 acre (plus) per well drainage.

INDEX OF
BENSON-MONTIN-GREER DRILLING CORP. EXHIBITS
IN CASE NO. 7075
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

NOVEMBER 24, 1980

PART I — INFORMATION RELATIVE TO RESERVOIR DRAINAGE CHARACTERISTICS

SECTION A: Communication tests L-27, C-34 and E-10

1. Production statistics (yellow pages)
2. A-23 observation well schedule of pressures
3. L-27 record of bottom hole pressures (green page) & graph (white page)
4. C-34 record of bottom hole pressures (blue page) & graph (white page)
5. Location plat (L-27, C-34, E-10, and A-23)
6. Graph, production vs. pressure
7. 1967 production graph by days showing E-10 frac interference

SECTION B: Oil in Place Data and Recovery Factor

1. Boulder: graph of lst 7 years production rate, 1965
2. Boulder: pressure vs. production
3. Boulder: oil in place vs. percent undersaturated oil for production pressure coefficient of 1200 bbl/#.
4. Boulder: oil in place vs. percent undersaturated oil for production pressure coefficient of 3000 bbl/#.
5. Boulder: oil in place from combination of 3 and 4 above

SECTION C: Canada Ojitos Unit: Oil in place estimate

1. Summary
2. Reference to earlier filing of estimate and Description of method of calculating oil in place (2 pages)
3. Graph, oil-in-place for pressure-production coefficient of 3000 bbl/# (Plate marked IV-3)
4. Graph, oil-in-place for pressure-production coefficient of 6000 bbl/# (Plate marked IV-4)
5. Graph: Compressibility of combined saturated oil and gas released (Plate marked IV-5)
6. Plat of location of bubble point (Plate marked IV-6)
7. Plat of per-acre oil in place estimates (Plate marked IV-7)
8. Graph, oil in place as function of change in amount of undersaturated oil (Plate marked IV-8)
9. Statistics used in estimate (Plate Marked IV-9)
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PART II INFORMATION REGARDING STRAIGHT HOLE DRILLING

SECTION D: Surveys of B-M-G COU Wells

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2. Individual well surveys

PART III FOREST LANDS

SECTION E:

PART IV DRAINAGE PATTERNS

SECTION F:

1. Sketch of water flood drainage patterns.
2. Sketch of COU drainage parterns.
3. Sketch of drainage patterns COU after impressing competitive drilling.
4. Schedule of impact on state and federal revenues of competitive drilled wells.

SECTION G:

1. Plat showing location of oil recovery wells
2. Sketch showing extended radius of drainage for close offsets
3. Sketch showing extended radius of drainage for close offsets with boundary shifted
4. Sketch showing east to west drainage patterns

4a. Schedule showing comparison of some of the problems of first drilling and then unitizing (either voluntary or statutory)

5. Sketch showing portion of spacing unit proven
6. Sketch showing principle of compensating drainage
7. Sketch of relative offset distances for wells in W/2 of sections
8. Sketch of relative offset distances for wells in E/2 of sections
9. Sketch of uniform spacing of wells on rectangular tracts with overlay of square tracts of same spacing unit area.

PART V OPERATORS FAVORING AND OPPOSING APPLICATION

SECTION H: Plat showing owners facoring and opposing applicatrion.

CANADA OJITOS UNIT
NIOBRARA-GREENHORN PARTICIPATING AREA
OIL PRODUCTION BY WELLS BY MONTHS

	K-13	A-14	P-11	L-11	A-23	TOTAL	CUMULATIVE
1962							
December	689	737				1,426	
1963							
January	380	1,538				1,918	3,344
February	129	882				1,011	4,355
March	347	1,795				2,142	6,497
April	187	2,333				2,520	9,017
May	-	1,888				1,888	10,905
June	-	1,892				1,892	12,797
July	441	1,709				2,150	14,947
August	1,610	1,848				3,458	18,405
September	2,991	1,838				4,829	23,234
October	2,720	1,813				4,533	27,767
November	1,881	1,843				3,724	31,491
December	274	1,262				1,536	33,027
TOTAL FOR YEAR	10,960	20,641				31,601	
1964							
January	2,319	1,505	12,422			16,246	49,273
February	1,098	620	12,081			13,799	63,072
March	-	873	-			873	63,945
April	1,669	963	5,514			8,146	72,091
May	2,825	1,960	9,194			13,979	86,070
June	2,089	1,888	8,619			12,596	98,666
July	2,912	2,090	9,974			14,976	113,642
August	2,870	1,122	12,967			16,959	130,601
September	2,325	1,694	9,802			13,821	144,422
October	1,723	752	6,773			9,248	153,670
November	3,514	60	8,310	6,465		18,349	172,019
December	2,459	-	8,887	8,797		20,143	192,162
TOTAL FOR YEAR	25,803	13,527	104,543	15,262		159,135	

	K-13	A-14	P-11	L-11	*A-23	A-16	TOTAL	CUMULATIVE
1965								
January	1,850	-	10,519	10,181			22,550	214,712
February	-	-	11,762	9,240			21,002	235,714
March	-	4,482	11,462	8,735			24,679	260,393
April	-	8,396	10,990	8,390	1,445		29,221	289,614
May	-	-	11,380	1,012	3,100		15,492	305,106
June	-	-	2,420	-	600		3,020	308,126
July	-	-	413	-	-		413	308,539
August	-	-	13,067	-	-		13,067	321,606
September	-	-	13,901	4,817	-		18,718	340,324
October	-	-	13,962	14,259	-		28,221	368,545
November	-	1,923	12,732	13,415	-		28,070	396,615
December	-	4,710	15,481	14,298	-		34,489	431,104
TOTAL FOR YEAR	1,850	19,511	128,089	84,347	5,145		238,942	
1966								
January	-	4,445	13,858	15,104	-		33,407	464,511
February	-	3,730	12,192	11,091	-		27,013	491,524
March	-	3,562	13,717	14,964	-	703	32,946	524,470
April	-	3,704	11,086	11,473	-	610	26,873	551,343
May	-	3,506	12,272	13,441	-	823	30,042	581,385
June	-	3,990	11,505	14,069	-	995	30,559	611,944
July	-	2,954	11,096	13,380	-	841	28,271	640,215
August	-	2,658	11,775	10,152	-	415	25,000	665,215
September	-	3,266	11,645	13,064	-	1,256	29,231	694,446
October	-	3,350	11,570	11,491	-	618	27,029	721,475
November	-	3,504	11,421	11,032	-	608	26,565	748,040
December	-	2,872	10,286	9,590		457	23,205	771,245
TOTAL FOR YEAR	-	41,541	142,423	148,851	-	7,326	340,141	

*A-23 Dropped from Schedule-Observation Well

CAÑADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	*K-13	A-14	P-11	L-11	A-16	O-33	E-10	A-22	C-2	TOTAL	CUMULATIVE
1967											
Jan.		3,218	12,519	12,802	869					29,408	800,653
Feb.		2,648	9,931	9,489	921					22,989	823,642
March		3,555	11,760	12,034	1,030	1,542				29,921	853,563
April		3,194	9,198	13,159	958	2,055				28,564	882,127
May		3,086	9,258	13,373	1,013	2,147				28,877	911,004
June		2,983	10,190	11,682	947	1,893				27,695	938,699
July		2,241	11,205	11,454	924	1,766				27,590	966,289
Aug.	581	2,166	10,348	11,552	697	2,205				27,549	993,838
Sept.	1,136	909	9,316	11,361	-	1,870	4,869			29,461	1,023,299
Oct.	2,007	1,756	9,533	11,792	-	1,915	7,763			34,766	1,058,065
Nov.	78	1,596	6,983	11,373	630	1,806	5,556			28,022	1,086,087
Dec.		1,279	8,316	11,729	1,005	1,784	859			24,972	1,111,059
TOTAL FOR YEAR	3,802	28,631	118,557	141,800	8,994	18,983	19,047			339,814	
1968											
Jan.		1,775	7,496	10,456	875	1,640	12,368		672	35,282	1,146,341
Feb.		1,326	6,300	10,941	663	995	12,931		-	35,156	1,179,497
March		1,348	6,404	12,472	674	1,011	11,798		-	33,707	1,213,204
April		1,587	6,349	11,287	705	1,764	13,580		945	36,217	1,249,421
May		1,015	6,431	11,169	677	1,692	12,862		785	34,631	1,284,052
June		1,790	5,810	10,652	646	1,760	11,620		45	32,323	1,316,375
July		1,644	5,589	11,179	658	1,315	12,493		1,239	34,117	1,350,492
Aug.		1,743	4,649	10,751	582	1,453	9,879		587	29,644	1,380,136
Sept.		1,118	4,673	10,423	663	1,305	12,199		306	30,687	1,410,823
Oct.		1,190	4,760	10,412	588	105	12,694			29,749	1,440,572
Nov.		1,183	4,800	9,252	706	1,833	9,861			27,635	1,468,207
Dec.		2,013	4,529	9,812	503	1,761	6,541	7,634		32,793	1,501,000
TOTAL FOR YEAR		17,732	67,790	128,806	7,940	16,634	138,826	7,634	4,579	389,941	

*K-13 Dropped from Schedule - Gas Injection Well

CANADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	A-14	P-11	L-11	A-16	O-33	B-10	A-22	C-2	TOTAL	CUMULATIVE
1969										
January	2,169	3,263	8,364	828	863	4,816	13,080		33,383	1,534,383
February	1,922	1,166	7,543	-	1,812	17,029	11,130		40,602	1,574,985
March	2,058	-	8,924	-	253	20,412	11,744		43,391	1,618,376
April	1,727	-	8,749	783	1,936	19,160	9,193		41,548	1,659,924
May	1,510	1,401	7,855	732	1,491	19,189	13,690		45,868	1,705,792
June	1,049	3,491	6,993	690	1,282	19,547	11,950		45,002	1,750,794
July	420	3,520	10,227	535	1,227	20,894	13,863		50,686	1,801,480
August	-	807	7,498	-	1,441	15,845	11,764		37,355	1,838,835
September	-	-	9,488	-	1,204	19,023	11,359		41,074	1,879,909
October	-	-	9,204	-	1,487	22,408	11,226		44,325	1,924,234
November	-	-	8,107	476	1,273	19,489	9,845	756	39,946	1,964,180
December	-	2,495	9,423	790	1,233	20,381	12,136	2,360	48,818	2,012,998
TOTAL FOR YEAR	10,855	16,143	102,375	4,834	15,502	218,193	140,980	3,116	511,998	

CAÑADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	P-11	L-11	A-16	O-33	E-10	A-22	C-2	L-27	TOTAL	CUMULATIVE
1970										
January	6,697	9,360	794	1,077	21,379	15,070	1,548		55,925	2,068,923
February	4,752	6,624	713	1,361	18,330	15,122	3		46,905	2,115,828
March	4,525	12,326	580	1,198	21,286	18,313	2,554		60,782	2,176,610
April	3,395	9,994	480	1,198	19,985	16,684	2,090	6,190	60,016	2,236,626
May	2,752	9,653	356	886	21,074	16,324	1,708	7,443	60,196	2,296,822
June	2,081	8,323	-	942	21,174	15,936	1,583	7,767	57,806	2,354,628
July	1,701	8,633	-	1,374	20,914	15,731	1,615	7,915	57,883	2,412,511
August	1,010	9,958	703	1,049	23,623	19,703	1,052	8,054	65,452	2,477,963
September	-	9,470	803	1,410	22,892	19,671	1,593	11,660	67,499	2,545,462
October	-	7,590	903	1,142	24,502	18,246	969	11,290	64,642	2,610,104
November	-	8,261	842	1,286	22,079	16,205	181	11,470	60,324	2,670,428
December	-	11,935	794	1,291	19,374	18,404	2,753	10,838	65,389	2,735,817
TOTAL FOR YEAR	26,913	112,127	6,968	14,214	256,612	205,409	17,949	82,627	722,819	

CANADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	L-11	A-16	O-33	B-10	A-22	C-2	L-27	C-34	L-3	TOTAL	CUMULATIVE
1971											
January	10,520	767	540	21,446	21,285	1,772	9,962			66,292	2,802,109
February	1,376	675	1,269	13,338	15,988	1,593	9,196	7,745		51,180	2,853,289
March	9,217	464	1,267	14,360	11,574	1,488	12,177	13,140		63,687	2,916,976
April	7,842	260	1,056	15,890	7,862	911	11,475	11,914		57,210	2,974,186
May	9,805	761	95	21,321	4,745	1,340	11,861	12,545		62,473	3,036,659
June	10,773	539	0	22,516	0	1,016	11,778	12,734		59,356	3,096,015
July	9,631	391	911	22,036	9,172	0	11,844	12,826		66,811	3,162,826
August	8,818	0	1,804	20,555	8,309	1,394	11,380	11,454	1,082	64,796	3,227,622
September	8,543	544	1,816	16,316	8,630	1,465	10,821	12.083	1,063	61,281	3,288,903
October	8,240	648	1,467	20,185	8,927	1,436	12,427	14,214	657	68,201	3,357,104
November	9,095	584	2,037	22,082	8,262	1,374	11,583	14,726	0	69,743	3,426,847
December	9,685	583	1,926	22,851	11,048	1,234	10,816	14,574	201	72,918	3,499,765
TOTALS FOR Y EAR	103,545	6,216	14,188	232,896	115,802	15,023	135,320	137,955	3,003	763,948	
1972											
January	9,942	548	1,870	24,240	9,712	1,339	11,300	14,834	0	73,785	3,573,550
February	8,756	587	1,899	20,510	8,229	1,196	10,245	11,469	8	62,899	3,636,449
March	9,744	596	1,754	21,519	5,496	1,347	10,585	10,776	1,599	63,416	3,699,865
April	9.481	553	1,735	20,336	6,281	1,296	10,165	9,142	1,073	60,062	3,759,927
May	9,598	363	1,718	16,708	4,637	1,503	10,884	7,214	958	53,583	3,813,510
June	8,345	330	1,453	15,880	0	1,346	10,263	5,860	973	44,450	3,857,960
July	9,258	523	1,514	15,173	0	1,494	11,316	5,400	1,060	45,738	3,903,698
August	9,506	720	1,691	14,532	0	1,415	10,471	4,781	1,008	44,124	3,947,822
September	9,527	533	885	15,057	0	1,339	10,118	4,246	1,018	42,723	3,990,545
October	8,969	446	1,792	15,408	0	1,356	10,478	4,960	533	43,942	4,034,487
November	9,075	377	1,560	14,986	0	1,307	10,060	4,839	0	42,204	4,076,691
December	9,608	482	1,626	15,108	0	1,323	10,008	4,721	1,069	43,945	4,120,636
TOTALS FOR YEAR	111,809	6,058	19,497	209,457	34,355	16,261	125,893	88,242	9,299	620,871	

CAÑADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	L-11	A-16	O-33	E-10	A-22	C-2	L-27	C-34	L-3	TOTAL	CUMULATIVE
1973											
January	9,475	560	1,598	15,024	0	1,336	10,189	4,479	937	43,598	4,164,234
February	8,689	384	1,369	14,521	0	1,108	8,981	4,219	421	39,692	4,203,926
March	7,990	82	1,374	15,775	0	1,387	10,220	4,836	0	41,664	4,245,590
April	9,002	164	1,552	14,033	0	1,212	9,470	5,182	0	40,615	4,286,205
May	10,559	397	1,499	15,561	0	1,277	9,695	5,958	660	45,606	4,331,811
June	10,793	461	1,499	12,250	0	1,294	8,738	4,280	911	40,226	4,372,037
July	10,914	325	1,535	11,796	507	1,330	9,220	4,588	830	41,045	4,413,082
August	11,308	437	1,287	12,266	1,025	1,258	8,574	4,433	689	41,277	4,454,359
September	10,564	418	1,417	12,456	502	1,315	8,689	4,179	877	40,417	4,494,776
October	10,776	414	1,496	13,502	140	1,414	8,508	4,133	1,018	41,401	4,536,177
November	9,975	284	1,416	12,759	0	1,299	8,538	3,827	946	39,044	4,575,221
December	10,261	363	1,491	13,176	0	1,395	8,786	3,764	640	39,876	4,615,097
TOTALS FOR YEAR	120,306	4,289	17,533	163,119	2,174	15,625	109,608	53,878	7,929	494,461	

CANADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	L-11	A-16	O-33	E-10	C-2	L-27	C-34	L-3	O-9	TOTAL	CUMULATIVE
1974											
January	9,960	483	1,513	12,719	1,412	8,854	3,518	706		39,165	4,654,262
February	9,332	580	1,205	11,684	1,226	8,193	3,055	781		36,056	4,690,318
March	10,367	624	1,467	13,459	1,355	8,698	3,291	678		39,939	4,730,257
April	10,156	635	1,408	13,998	1,342	8,649	3,325	979		40,492	4,770,749
May	9,702	626	1,349	13,092	1,342	8,942	2,703	922	314	38,992	4,809,741
June	7,185	579	1,303	13,133	1,314	8,591	2,608	892	696	36,301	4,846,042
July	5,884	625	755	13,695	1,354	9,013	3,000	948	619	35,893	4,881,935
August	5,151	603	1,558	13,163	1,370	8,906	2,865	825	537	34,978	4,916,913
September	4,670	593	1,306	12,462	1,261	8,541	2,785	932	343	32,893	4,949,806
October	4,493	595	842	12,375	1,353	8,786	2,878	959	0	32,281	4,982,087
November	3,382	231	0	12,008	1,340	8,389	2,685	756	0	28,791	5,010,878
December	4,169	565	0	12,929	1,342	8,677	2,587	934	0	31,203	5.042.081
TOTALS FOR YEAR	84,451	6,739	12,706	154,717	16,011	104,239	35,300	10,312	2,509	426,984	
1975											
January	3,431	644	0	12,681	1,278	8,669	2,974	780	0	30,457	5,071,428
February	2,661	557	0	11,724	1,240	7,814	2,721	560	0	27,277	5,098,915
March	2,547	0	0	11,809	1,344	8,635	2,924	0	0	27,259	5,127,074
April	2,203	379	0	11,217	1,306	8,429	2,994	802	0	27,330	5,154,404
May	1,346	590	0	11,245	1,333	8,828	2,903	1,019	0	27,264	5,181,668
June	0	628	0	10,486	1,273	8,593	2,926	935	0	24,841	5,206,509
July	0	621	0	10,650	1,342	8,981	2,928	935	0	25,457	5,231,966
August	0	610	0	10,676	1,310	8,762	2,912	857	0	25,127	5,257,093
September	0	581	0	9,259	1,233	7,612	2,976	0	0	21,661	5,278,754
October	0	598	0	10,363	1,377	9,077	3,042	0	0	24,457	5,303,211
November	0	599	0	9,698	1,365	8,566	2,993	0	0	23,221	5,326,432
December	0	634	0	9,937	1,345	8,801	3,134	0	0	23,851	5,350,283
TOTALS FOR YEAR	12,188	6,441	0	129,745	15,746	102,767	35,427	5,888	0	308,202	

CANADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	A-16	O-33	E-10	C-2	L-27	C-34	L-3	O-9	TOTAL	CUMULATIVE
1976										
January	612	0	10,281	1,360	8,970	3,107	0	0	24,330	5,574,613
February	584	0	9,682	1,262	8,409	2,954	0	0	22,891	5,397,504
March	623	0	10,701	1,387	9,318	3,274	0	0	25,303	5,422,807
April	512	0	10,276	1,288	8,340	2,789	0	0	23,205	5,446,012
May	627	0	10,079	1,355	9,085	3,053	604	0	24,803	5,470,815
June	518	610	9,707	1,090	8,259	2,574	1,041	629	24,428	5,495,243
July	590	1,034	10,183	1,209	8,919	2,816	955	791	26,497	5,521,740
August	641	1,136	10,218	1,335	8,846	2,818	948	585	26,527	5,548,267
September	542	881	9,637	1,271	8,307	2,598	843	635	24,714	5,572,981
October	567	1,029	10,617	1,373	8,858	2,467	878	385	26,174	5,599,155
November	606	920	10,003	1,319	8,377	2,438	937	355	24,955	5,624,110
December	572	887	10,621	1,283	8,804	3,000	849	293	26,309	5,650,419
TOTALS FOR YEAR	6,994	6,497	122,005	15,532	104,492	33,888	7,055	3,673	300,136	
1977										
January	601	871	11,006	1,319	8,830	2,661	609	578	26,475	5,676,894
February	530	707	9,767	1,148	7,380	2,538	697	362	23,129	5,700,023
March	533	820	10,557	1,335	8,685	2,521	867	364	25,682	5,725,705
April	558	784	10,556	1,276	8,611	2,888	799	424	25,895	5,751,600
May	502	807	10,543	1,279	8,884	2,739	928	328	26,010	5,777,610
June	575	735	10,498	1,219	8,503	2,473	767	313	25,083	5,802,693
July	483	784	11,540	1,284	8,756	2,691	903	289	26,730	5,829,423
August	611	799	8,179	1,346	9,216	2,792	891	328	24,162	5,853,585
September	500	753	7,292	1,536	8,561	2,590	817	333	22,383	5,875,968
October	541	764	7,846	1,288	8,977	2,980	857	339	23,592	5,899,560
November	538	755	7,872	1,268	8,640	2,817	865	323	23,078	5,922,638
December	541	774	7,434	1,277	8,814	2,792	878	340	22,850	5,945,488
TOTALS FOR YEAR	6,513	9,354	113,090	15,575	103,857	32,482	9,878	4,320	293,069	

CANADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	A-16	O-33	E-10	C-2	L-27	C-34	L-3	O-9	TOTAL	CUMULATIVE
1978										
January	525	745	8553	1265	7313	2717	749	319	22,186	5,967,674
February	482	665	6854	1085	7082	2281	764	252	19,465	5,987,139
March	227	704	6556	1184	8035	2651	376	72	19,805	6,006,944
April	520	653	6020	1142	7814	2391	850	71	19,461	6,026,405
May	527	720	6545	1297	8415	2087	788	0	20,379	6,046,784
June	490	856	6287	1080	7919	1979	656	0	19,267	6,066,051
July	501	653	6478	1171	8168	2206	208	0	19,385	6,085,436
August	509	681	6111	1215	8212	2315	6	0	19,049	6,104,485
September	494	676	5590	1171	7979	2364	0	763	19,037	6,123,522
October	496	689	6596	1162	8165	2477	348	638	20,571	6,144,093
November	477	676	5054	1154	7549	2389	1156	549	19,004	6,163,097
December	480	697	5293	1217	8122	2201	870	423	19,303	6,182,400
TOTALS FOR YEAR	5728	8415	75937	14143	94773	28058	6771	3087	236,912	
1979										
January	2	688	4903	1221	8150	2323	642	472	18,401	6,200,801
February	394	603	4163	1048	7218	2223	513	819	16,981	6,217,782
March	331	682	4805	1215	8230	2546	0	502	18,311	6,236,093
April	384	672	4357	1178	8051	2497	0	470	17,609	6,253,702
May	523	684	4213	1232	8362	2636	292	470	18,412	6,272,114
June	478	673	3852	1192	8324	2384	411	448	17,762	6,289,876
July	549	712	3669	1242	8481	2495	832	446	18,426	6,308,302
August	516	696	3992	1223	8528	2405	834	407	18,601	6,326,903
September	508	662	3644	1199	8224	2267	821	408	17,733	6,344,636
October	468	657	5407	1137	8107	2239	817	462	19,294	6,363,930
November	476	631	5253	1117	7585	2078	782	359	18,281	6,382,211
December	460	610	5625	1208	7722	2212	800	405	19,042	6,401,253
TOTALS FOR YEAR	5089	79	53883	14212	96982	28305	6744	5668	218,853	

CANADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS
PAGE 10

	A-16	D-33	E-10	C-2	L-27	C-34	L-3	D-9	TOTAL	CUMULATIVE
1980										
January	289	678	5708	1180	7810	2170	442	317	18,594	6,419,847
February	0	590	5195	1083	7151	1967	518	366	16,870	6,436,717
March	0	0	6005	1247	8272	2358	0	394	18,276	6,454,993
April	425	525	5264	1064	7463	2188	1072	728	18,829	6,473,822
May	514	652	5517	1150	8012	2220	875	344	19,284	6,493,106
June	495	650	5186	1153	7860	2145	800	232	18,522	6,511,628
July	493	662	4703	1238	8072	2232	792	268	18,460	6,530,088
August	447	676	5020	1250	8399	2296	836	278	19,202	6,549,290
September	503	632	4617	1139	7972	2155	765	340	18,123	6,567,413

CANADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS
PAGE 11

BOTTOM HOLE PRESSURE SUMMARY
CANADA OJITOS UNIT A-23
ELEVATION 7158' RKB
(HOLE DEPTH CORRECTION -4' AT 6300')

SURVEY DATE	PRESSURE (PSIG) AT 6300' (RKB) FOR PRESSURE GAUGE INDICATED AMERADA #42	AMERADA #43	AVERAGE	AVERAGE PRESSURE ADJUSTED TO DATUM OF + 1195'	FLUID LEVEL	FLUID COLUMN ABOVE 6300'	AVERAGE DENSITY OF FLUID COLUMN #/in²/ft	CUMULATIVE PRODUCTION M BBLS.
6-17-65		1585.8 (Run 1) 1587.5 (Run 2)	1596.7	1482.7				
6-25-65		1598.7	1598.7	1494.7				
7- 2-65	1600.4		1600.4	1496.4				
7- 8-65		1606.0	1606.0	1502.0				
7-19-65	1608.3	1607.3	1607.8	1503.8				
8-11-65	1611.2	1609.4	1610.3	1506.3	1481	4819	.3342	309
8-27-65	1606.3	1604.9	1605.6	1501.6	1497	4803	.3343	
9-13-65	1601.5	1600.2	1600.9	1496.9	1517	4783	.3347	
9-29-65	1598.1	1597.4	1597.8	1493.8	1529	4771	.3349	
10-14-65	1588.3	1585.9	1587.1	1483.1	1558	4742	.3347	
10-26-65	1585.5	1583.9	1584.7	1480.7	1575	4725	.3354	
11- 8-65	1580.8	1577.6	1579.2	1475.2	1592	4708	.3354	365
12- 5-65	1566.0	1569.9	1567.9	1463.9	1637	4663	.3362	
12-21-65	1559.6	1559.0	1559.3	1455.3	1663	4637	.3363	420
2-15-66	1541.0	1542.6	1541.8	1437.8	1725	4575	.3370	480
5-13-66	1522.8	1524.1	1523.5	1419.5	1768	4532	.3362	562

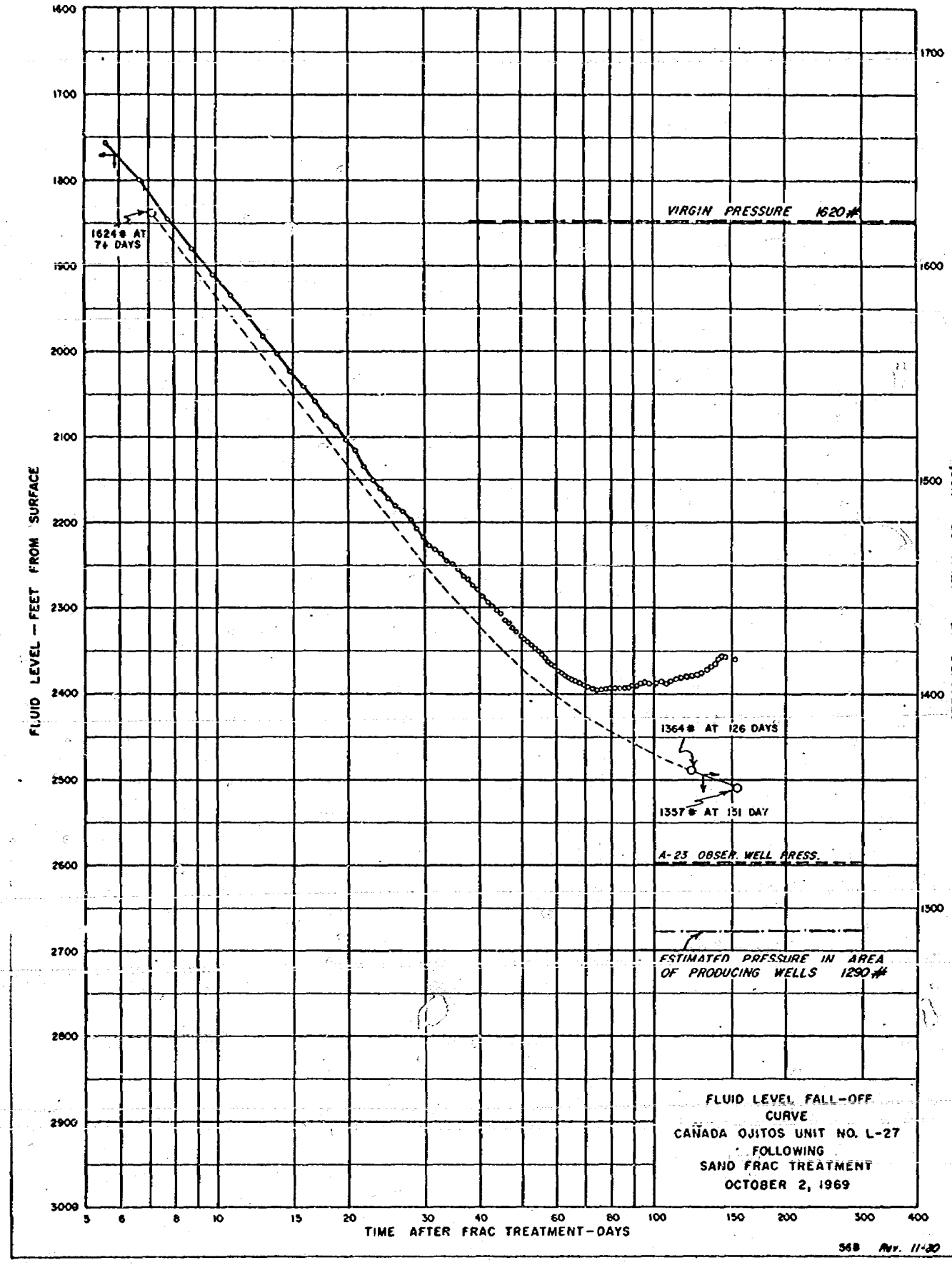
SURVEY DATE	PRESSURE (PSIG) AT 6300' (RKB) FOR PRESSURE GAUGE INDICATED AMERADA #42	AMERADA #43	AVERAGE	AVERAGE PRESSURE ADJUSTED TO DATUM OF + 1195'	FLUID LEVEL	FLUID COLUMN ABOVE 6300'	AVERAGE DENSITY OF FLUID COLUMN #/in²/ft	CUMULATIVE PRODUCTION M BBLS.
8-30-66	1509.9	1510.2	1510.2	1406.0	1812	4488	.3364	660
3-28-67	1484.4	1482.8	1483.6	1379.6	1895	4405	.3368	880
3-20-68	1434.0	1435.5	1434.8	1330.8	2058	4242	.3382	1,203
8-10-68	Estimated from fluid level		1409	1305	2130	4170	.3380	1,360
3-27-69	1446.0	1445.1	1445.6	1341.6	1992	4308	.3356	1,615
6-18-69	1434.6	1434.3	1434.4	1330.4	2009	4291	.3343	1,733
10- 9-69	1429.5	1426.6	1428.0	1324.0	2031	4269	.3345	1,893
11- 4-69	1426.9	1428.5	1427.7	1323.7	2017	4283	.3333	1,929
12- 1-69	No good	1423.7	1423.7	1319.7	2003½	4296	.3314	1,964
2- 5-70	1426.4	1424.0	1425.2	1321.2	2004	4296	.3318	2,076
3- 2-70	1427.0	1422.6	1424.8	1320.8	1995	4305	.3310	2,120
5- 2-70	No good	1423.1	1423.1	1319.1	2027½	4272.5	.3331	2,240
7- 8-70	Not run	1415.2	1415.2	1311.2	2046½	4253.5	.3327	2,370
8-28-70	1412.2	1410.8	1411.5	1307.5	2058	4242	.3327	2,472
10-12-70	1412.8	1410.6	1411.7	1307.7	2063	4237	.3332	2,570
3-29-71	1404.2	1406.2	1405.2	1301.2	2083	4217	.3332	2,914
6- 1-71	1403.6	1401.6	1402.6	1298.6	2082½	4217.5	.3326	2,997
8- 9-71	1401.2	1403.2	1402.2	1298.4	2087½	4222.5	.3321	3,147
11-24-71	1394.2	1399.0	1396.6	1292.6	2122½	4177.5	.3343	3,385
4- 3-72	1362.8	1359.4	1361.1	1257.1	2241	4059	.3353	3,676

BOTTOM HOLE PRESSURE SUMMARY
CANADA OJITOS UNIT L-27

(following frac treatment October 2, 1969 and prior to production April, 1970)

ELEVATION 7465' RKB

	10-9-69	2-5-70	3-2-70
Days after frac	7	126	151
Pressure at measured depth of 6900':			
Amerada #42 (psig)	1817.4	1560.3	1554.4
Amerada #43 (psig)	1813.0	1558.5	1551.2
Average (psig)	1815.2	1559.4	1552.8
Estimated average gradient to depth of 7030' (#/Sq.in./ft)	.351	.321	.317
Pressure differential 6900' to 7030'	45.8	41.7	41.3
Pressure at 7030'	1861.0	1601.1	1594.1
Pressure differential to datum of + 1195 (760' x .312)	- 237.1	- 237.1	- 237.1
Datum (+ 1195) pressure	1623.9	1364.0	1357.0
Pressure differential from virgin pressure of 1620 psig	+ 3.9	- 256.0	- 263.0
Pressure difference from static pressure in A-23 of approximately 1325#	+ 299	+ 39	+ 32

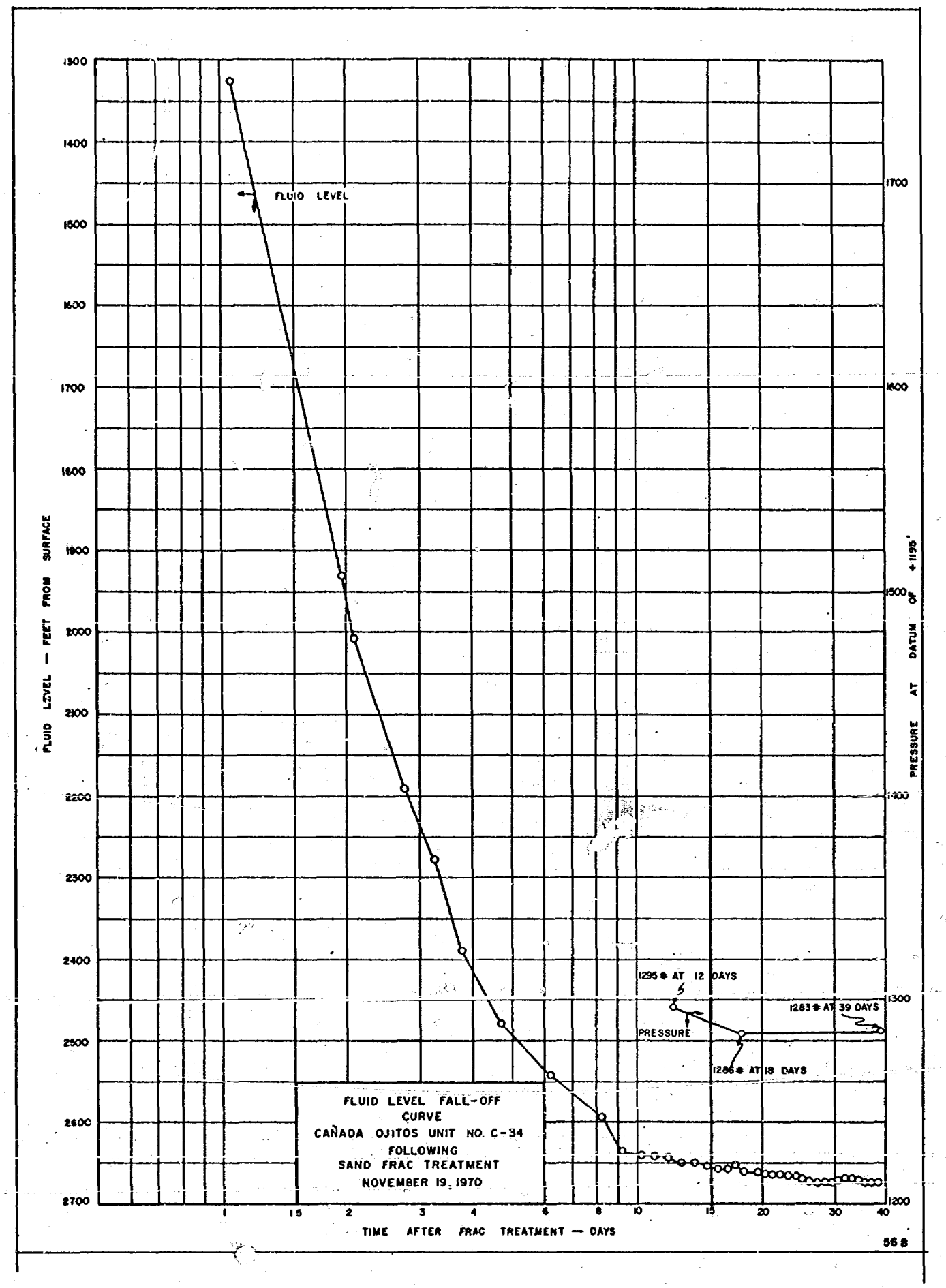

FLUID LEVEL — FEET FROM SURFACE
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
2600
2700
2800
2900
3000
PRESSURE AT DATUM OF +1195'
1700
1600
1500
1400
1300
VIRGIN PRESSURE 1620#
1624# AT 7½ DAYS
1364# AT 126 DAYS
1357# AT 151 DAY
A-23 OBSER. WELL PRESS.
ESTIMATED PRESSURE IN AREA OF PRODUCING WELLS 1290#
FLUID LEVEL FALL-OFF CURVE
CANADA OJITOS UNIT NO. L-27
FOLLOWING
SAND FRAC TREATMENT
OCTOBER 2, 1969
5
6
8
10
15
20
30
40
60
80
100
150
200
300
400
TIME AFTER FRAC TREATMENT-DAYS
568 Rev. 11-60

BOTTOM HOLE PRESSURE SUMMARY
CANADA OJITOS UNIT C-34

(following frac treatment November 19, 70 and prior to production)

ELEVATION 7427' RKB

	12-1-70	12-7-70	12-28-70
Days after frac	12	18	39
Pressure at measured depth of 6800' RKB:			
Amerada #42 (psig)	1469.3	1460.9	1457.3
Amerada #43 (psig)	1468.2	1458.8	1456.4
Average (psig)	1468.7	1459.8	1456.8
Estimated average gradient to depth of 6900' (#/in^2/ft)	.344	.343	.342
Pressure differential 6800' to 6900' (psig)	34.4	34.3	34.2
Pressure at 6900' RKB (datum + 527')	1503.1	1494.1	1491.0
Pressure differential to datum of + 1195 (668' x .312#/in^2/ft)	208.4	208.4	208.4
Datum (+ 1195) pressure	1294.7	1285.7	1282.6
Pressure differential from virgin pressure of 1620 psig	325.3	334.3	337.4
Pressure differential from static pressure in A-23 observation well of approximately 1325#	- 10.3	- 19.3	- 22.4


FLUID LEVEL
FLUID LEVEL — FEET FROM SURFACE
PRESSURE AT DATUM OF +1195'
1295# AT 12 DAYS
1283# AT 39 DAYS
PRESSURE
1286# AT 18 DAYS
FLUID LEVEL FALL-OFF CURVE
CAÑADA OJITOS UNIT NO. C-34
FOLLOWING
SAND FRAC TREATMENT
NOVEMBER 19, 1970
TIME AFTER FRAC TREATMENT — DAYS
1500
1400
1500
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
2600
2700
1700
1600
1500
1400
1300
1200
1
1.5
2
3
4
6
8
10
15
20
30
40

56 B

R I W

R I E

PLAT OF
CAÑADA OJITOS UNIT

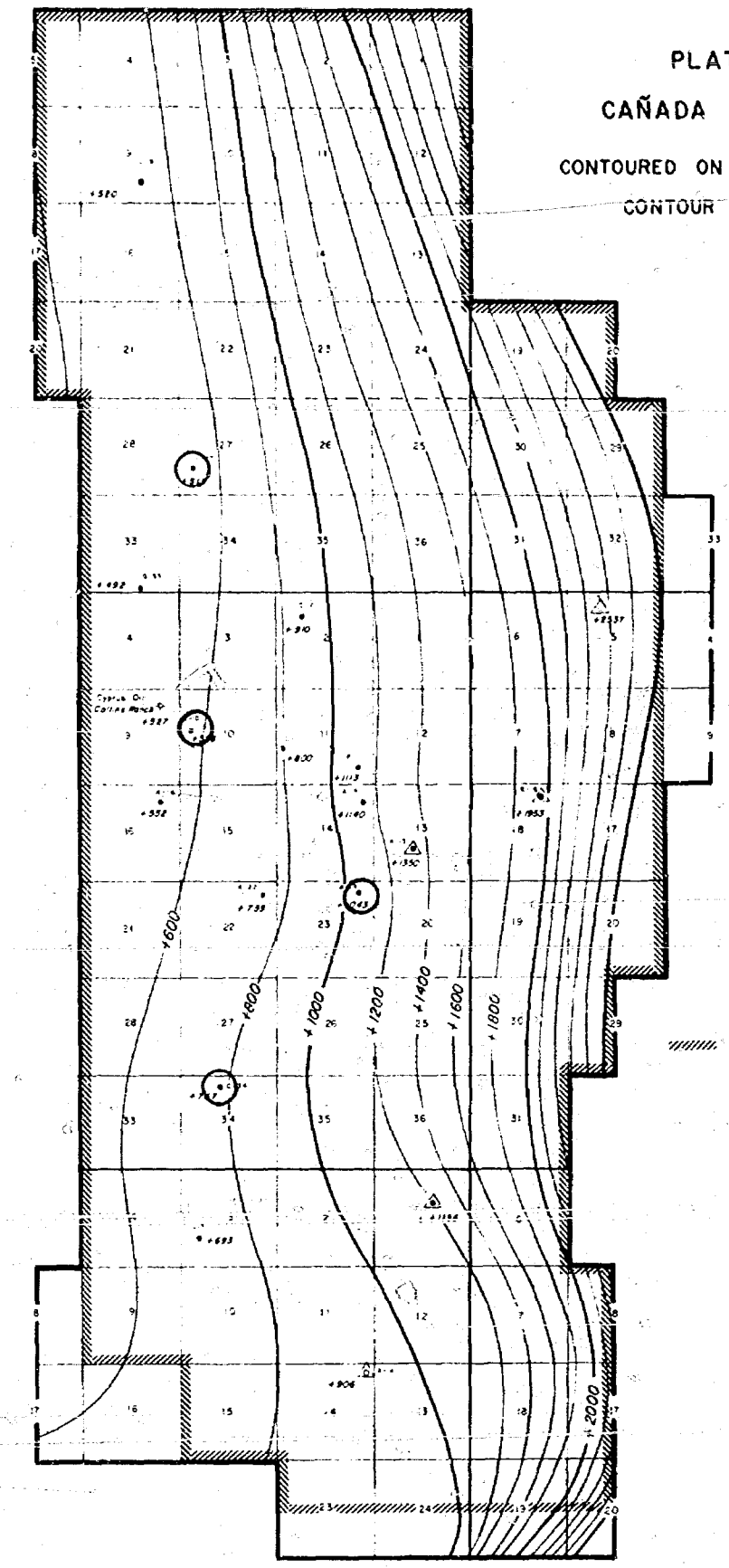
CONTOURED ON TOP OF ZONE "A"

CONTOUR INTERVAL 200'

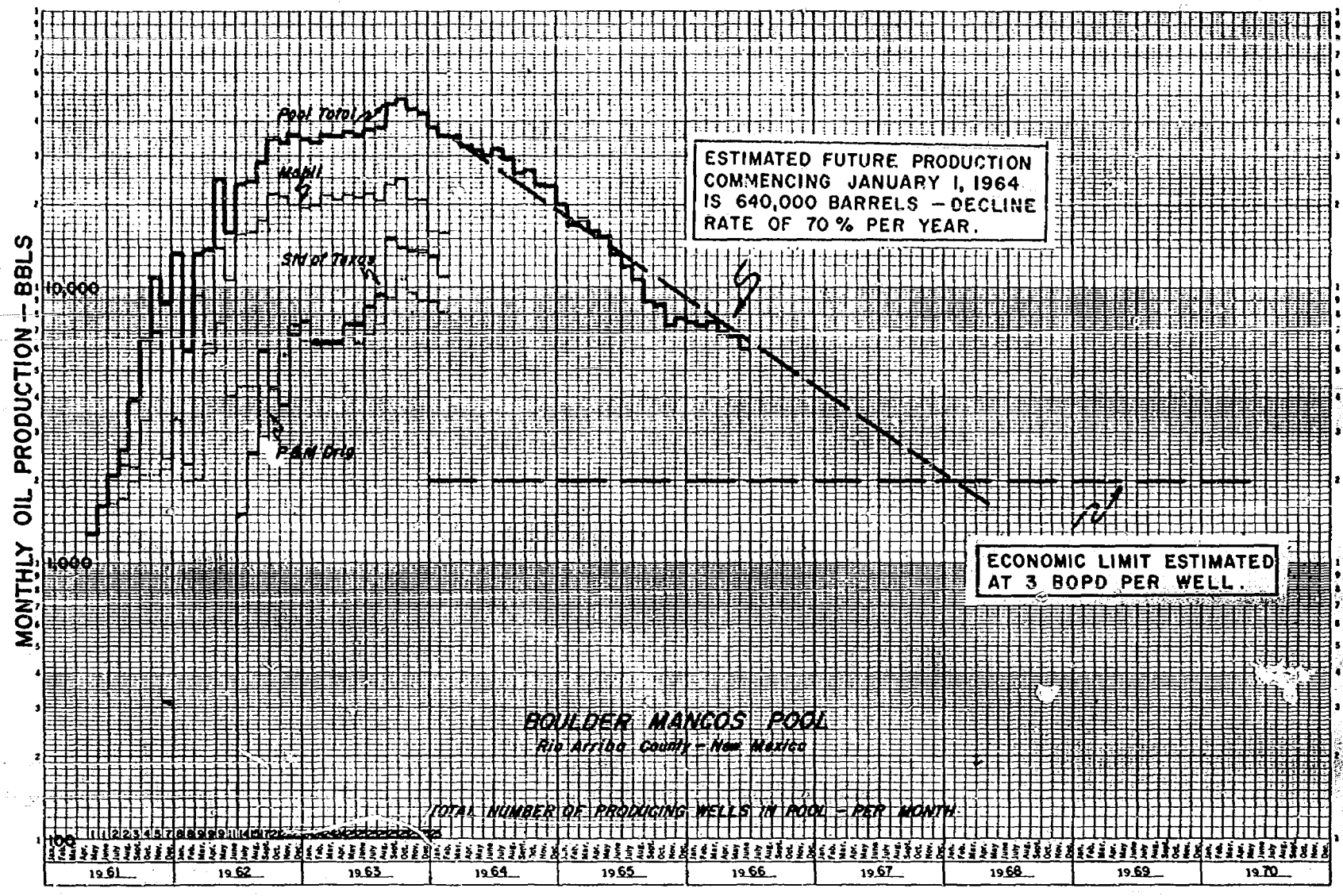
T
26
N

T
25
N

T
24
N



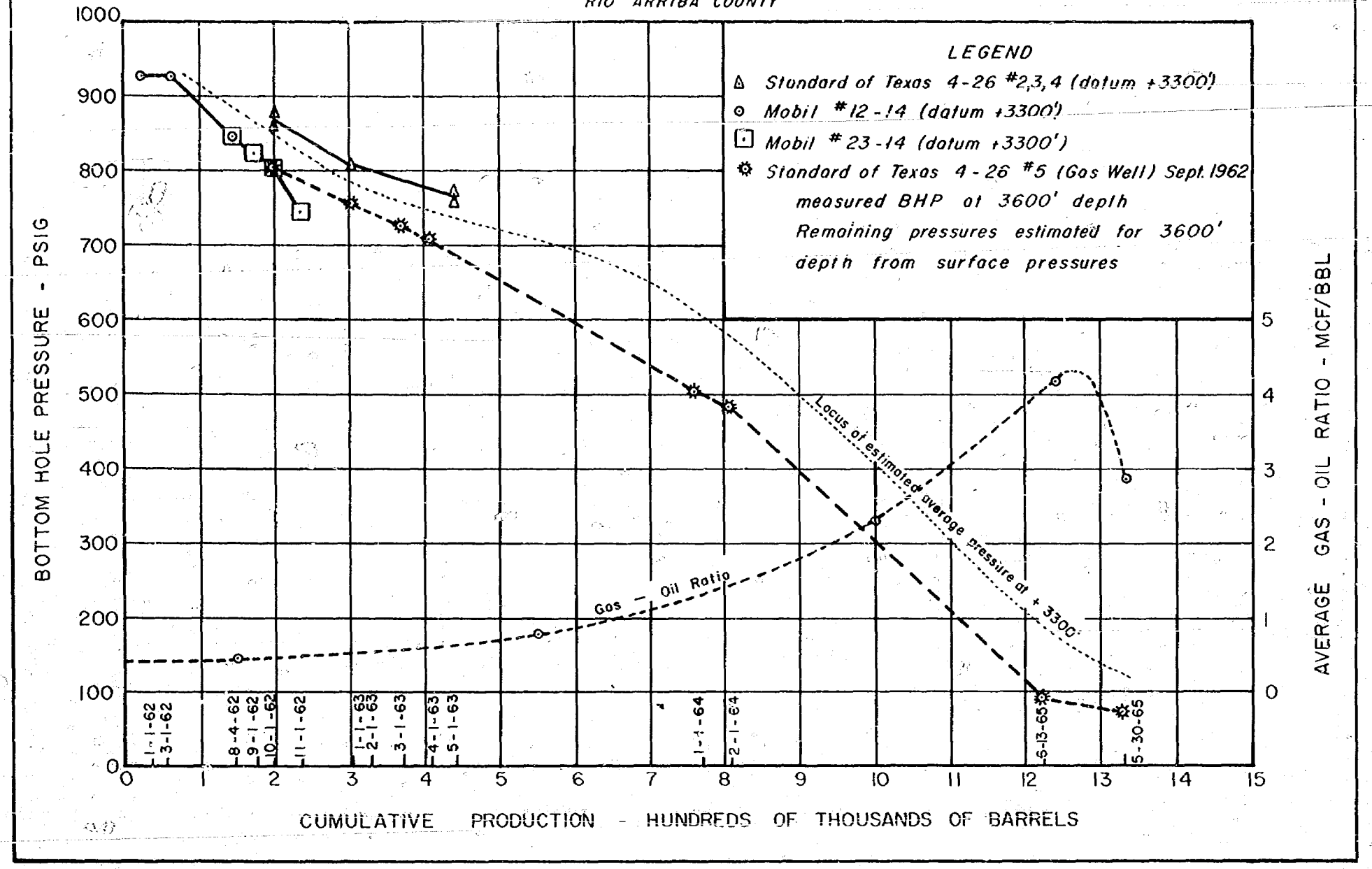
BOUNDARY OF NIOBRARA - GREENHORN PARTICIPATING AREA AFTER PROPOSED 12 TH EXPANSION

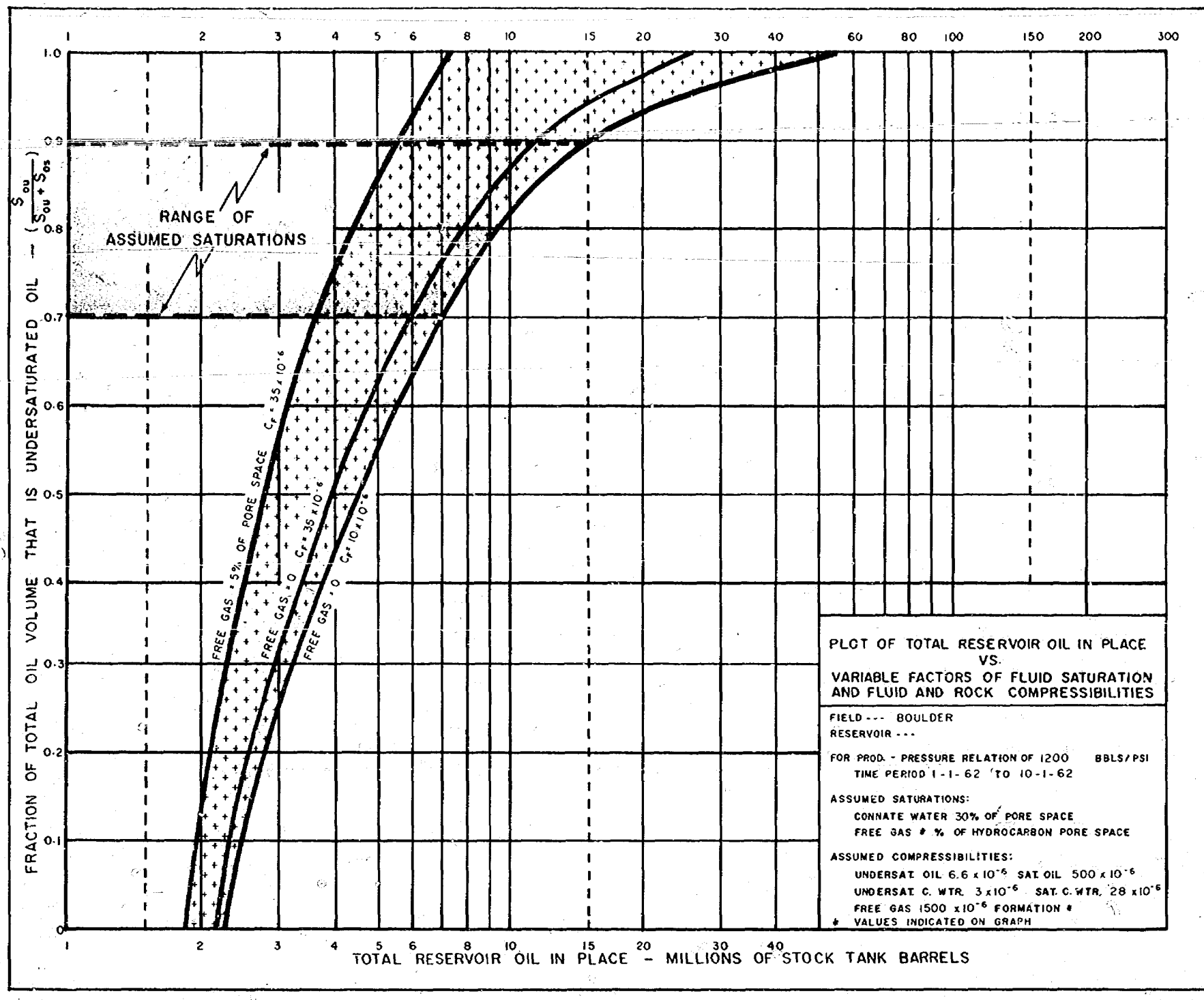

MONTHLY OIL PRODUCTION -- BBLS
10,000
1,000
100
Pool Total
Mobil
Shell of Texas
P&M Orig
ESTIMATED FUTURE PRODUCTION COMMENCING JANUARY 1, 1964 IS 640,000 BARRELS - DECLINE RATE OF 70 % PER YEAR.
ECONOMIC LIMIT ESTIMATED AT 3 BOPD PER WELL.
BOULDER MANCOS POOL
Rio Arriba County - New Mexico
TOTAL NUMBER OF PRODUCING WELLS IN POOL - PER MONTH
1961
1962
1963
1964
1965
1966
1967
1968
1969
1970

PRESSURE PRODUCTION HISTORY

BOULDER MANCOS POOL

RIO ARRIBA COUNTY





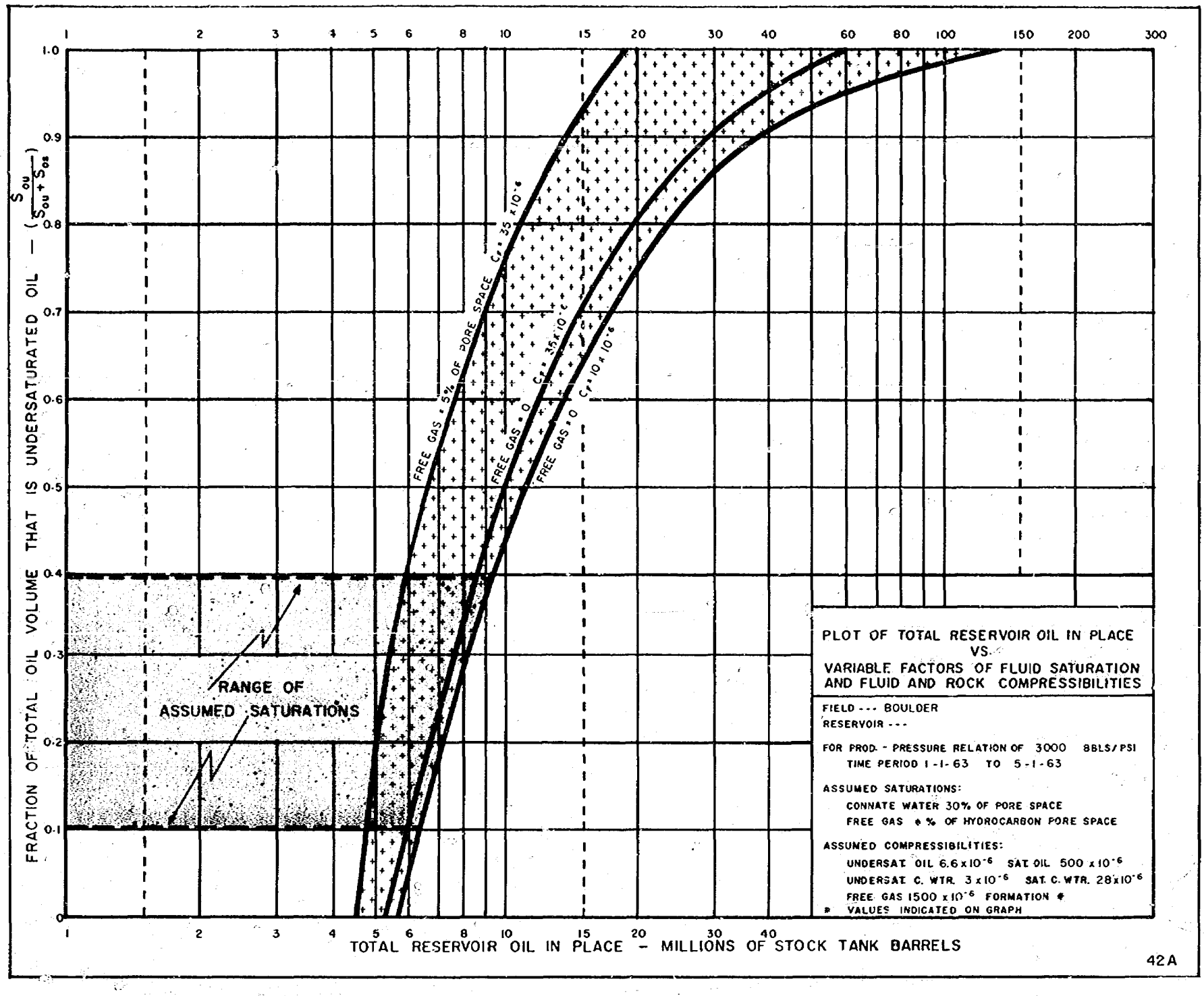
PLOT OF TOTAL RESERVOIR OIL IN PLACE
VS.
VARIABLE FACTORS OF FLUID SATURATION
AND FLUID AND ROCK COMPRESSIBILITIES

FIELD --- BOULDER
RESERVOIR ---

FOR PROD. - PRESSURE RELATION OF 1200 BBLS/PSI
TIME PERIOD 1-1-62 TO 10-1-62

ASSUMED SATURATIONS:
CONNATE WATER 30% OF PORE SPACE
FREE GAS # % OF HYDROCARBON PORE SPACE

ASSUMED COMPRESSIBILITIES:
UNDERSAT. OIL 6.6×10^{-6} SAT. OIL 500×10^{-6}
UNDERSAT. C. WTR. 3×10^{-6} SAT. C. WTR. 28×10^{-6}
FREE GAS 1500×10^{-6} FORMATION #
VALUES INDICATED ON GRAPH



PLOT OF TOTAL RESERVOIR OIL IN PLACE
VS.
VARIABLE FACTORS OF FLUID SATURATION AND FLUID AND ROCK COMPRESSIBILITIES

FIELD --- BOULDER
RESERVOIR ---

FOR PROD. - PRESSURE RELATION OF 3000 BBLS/PSI
TIME PERIOD 1-1-63 TO 5-1-63

ASSUMED SATURATIONS:
CONNATE WATER 30% OF PORE SPACE
FREE GAS ϕ % OF HYDROCARBON PORE SPACE

ASSUMED COMPRESSIBILITIES:
UNDERSAT. OIL 6.6×10^{-6} SAT. OIL 500×10^{-6}
UNDERSAT. C. WTR. 3×10^{-6} SAT. C. WTR. 28×10^{-6}
FREE GAS 1500×10^{-6} FORMATION *
* VALUES INDICATED ON GRAPH

42A

CANADA QUITOS UNIT
OIL RECOVERY ESTIMATE
ASSUMING CONTINUED OPERATION OF PRESSURE MAINTENANCE PROGRAM
AND GRAVITY DRAINAGE DEPLETION

November, 1980

	ESTIMATE RANGE	
	From	To
	(MM bbls)	(MM bbls)
Total Initial Oil in place	30	50
In high capacity fracture system (1/2)	15	25
In "tight blocks" (1/2)	15	25
Recovery from high capacity system 55%	8.2	13.8
Recovery from tight blocks 25%	3.8	6.2
Total recovery	12.0	19.0
Produced to 1981	6.6	6.6
Remaining future from 1981	5.4	12.4
	(Use 5	to 10)

CALCULATION OF OIL IN PLACE

NIOBRARA RESERVOIR

CANADA OJITOS UNIT

The following described method of calculating oil in place in the Canada Ojitos Unit was used in applications to the United States Geological Survey regarding enlargement of the participating areas for the 7th, 8th and 9th expansions. From the calculations of total oil in place as shown here, and from the volumes of per-acre oil in place determined from interference tests, it was estimated at that time that the reservoir probably covered an area of 40,000 to 50,000 acres, even though at that time the drilled area (cf. Plate IV-7 herein) outlined only about 15,000 acres.

Subsequent development confirmed the larger area. The participating area now covers approximately 53,000 acres.

DESCRIPTION OF METHOD OF CALCULATING OIL IN PLACE

CANADA OJITOS UNIT

Initial oil in place in the Canada Ojitos Unit was estimated from compressibilities of the various reservoir characteristics and the production-pressure relation of 3,000 barrels per pound which was observed from October, 1964 to July, 1965, and for the production-pressure coefficient of 6,000 barrels per pound which occurred during the time period May, 1966 to October, 1966.

For the time when the coefficient was 3,000 barrels per pound it is believed that the amount of oil that was undersaturated would be in the range of .8 to .95 of total reservoir volume. The oil in place for this coefficient is shown on the plat next following identified as Plate IV-3. This is for formation compressibility (C_f) ranging from 7×10^{-6} to 23×10^{-6} and free gas saturation ranging from zero to 5 percent of pore space. The relation for .8 to .95 fraction of the oil that was undersaturated is shown by the area colored in green.

The same information is shown on Plate IV-4 for the time period when the coefficient was 6,000 barrels per pound and the fraction of total oil assumed to be undersaturated is in the range of .4 to .8.

The main indefinite factors in estimating the oil in place are the unknown compressibility of the formation and the unknown fraction of the reservoir which initially contained free gas. In order to narrow the range of estimates, calculations were made taking advantage of the fact that compressibilities changed from one period to the next yet presumably the compressibility of the formation and the volume of the gas cap were the same. This allows a calculation

in which the effect of the gas cap and the formation compressibility are combined; and since, for the purpose of determining total oil in place it makes no difference what the individual compressibilities are, it then becomes possible, by assuming a compressibility for the formation, to calculate the amount of free gas initially existing.

This is accomplished by first determining the relation of compressibility of saturated oil and gas released from it as pressure drops. This is shown on Plate IV-5 herein.

The location of the bubble point pressure (1520 psig) as it moves downdip on the structure is shown herein on Plate IV-6.

Statistics resulting from location of the bubble point pressure are shown herein on Plate IV-9.

By assuming various combinations of fraction of undersaturated oil for the first condition and the second condition one can calculate the amount of free gas; and from this to calculate compressibility - and from this the volume of oil in place. A sample calculation is shown herein on Plate IV-10. A series of these calculations permits the construction of the relations shown on the graph IV-8.

Estimates of oil in place were made under six separate assumed situations. These are described below by number and shown by colored circles on the Plate IV-8:

Situation No. 1:

This assumes 87% of oil was undersaturated under Condition No. 1 and 72% under Condition No. 2. This results if the per acre oil in place to varies with structural position as shown herein on Plate IV-7.

Situation No. 2:

This assumes reservoir oil in place was as shown on Plate IV-7 except that the downdip boundary of the reservoir is assumed to be the west side of the green-colored area. The area colored in brown is assumed to be non-productive. This results in fraction of undersaturated oil under the first condition to be 85% and under the second condition to be 67%.

Situation No. 3:

This assumes the reservoir to extend across the colored area with an equal per-acre volume of oil in place throughout. This results in fraction of oil undersaturated in the first condition of 84% and under the second condition 66%.

Situation No. 4:

This assumes equal per-acre volume of oil in place with the downdip boundary being the west side of the green-colored area on Figure IV-7 and extending up to the 1600-foot contour interval. This results in fraction of the oil undersaturated under the first condition to be 80% and under the second condition 56%.

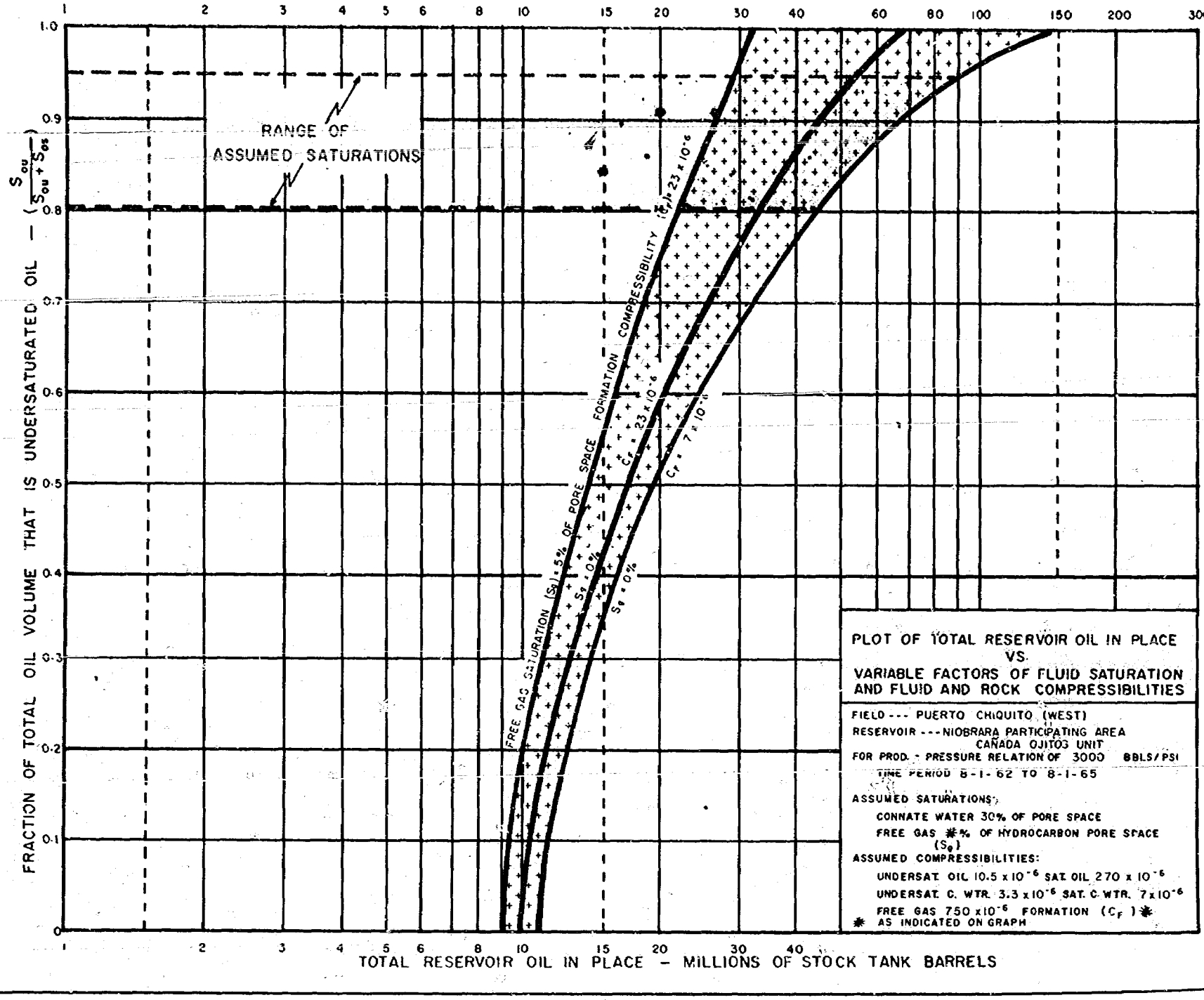
Situation No. 5:

This assumes the downdip limit of the reservoir to be the west boundary of the green-colored area on Plate IV-7 and the updip limit of the reservoir to be at the 1500-foot contour interval (rather than 1600-foot), with oil in place values as shown on Figure IV-7 and assuming the 1500 barrels per acre extends from the 1600-foot contour interval to the 1500-foot contour interval. This results in fraction of oil undersaturated under the first condition to be 91% and under the second to be 73%.

Situation No. 6:

This assumes east and west reservoir limits the same as in Situation No. 5 above, but with equal per-acre volumes of oil in place. This results in fraction of oil undersaturated under the first condition of 88% and under the second condition of 61%.

IV-3

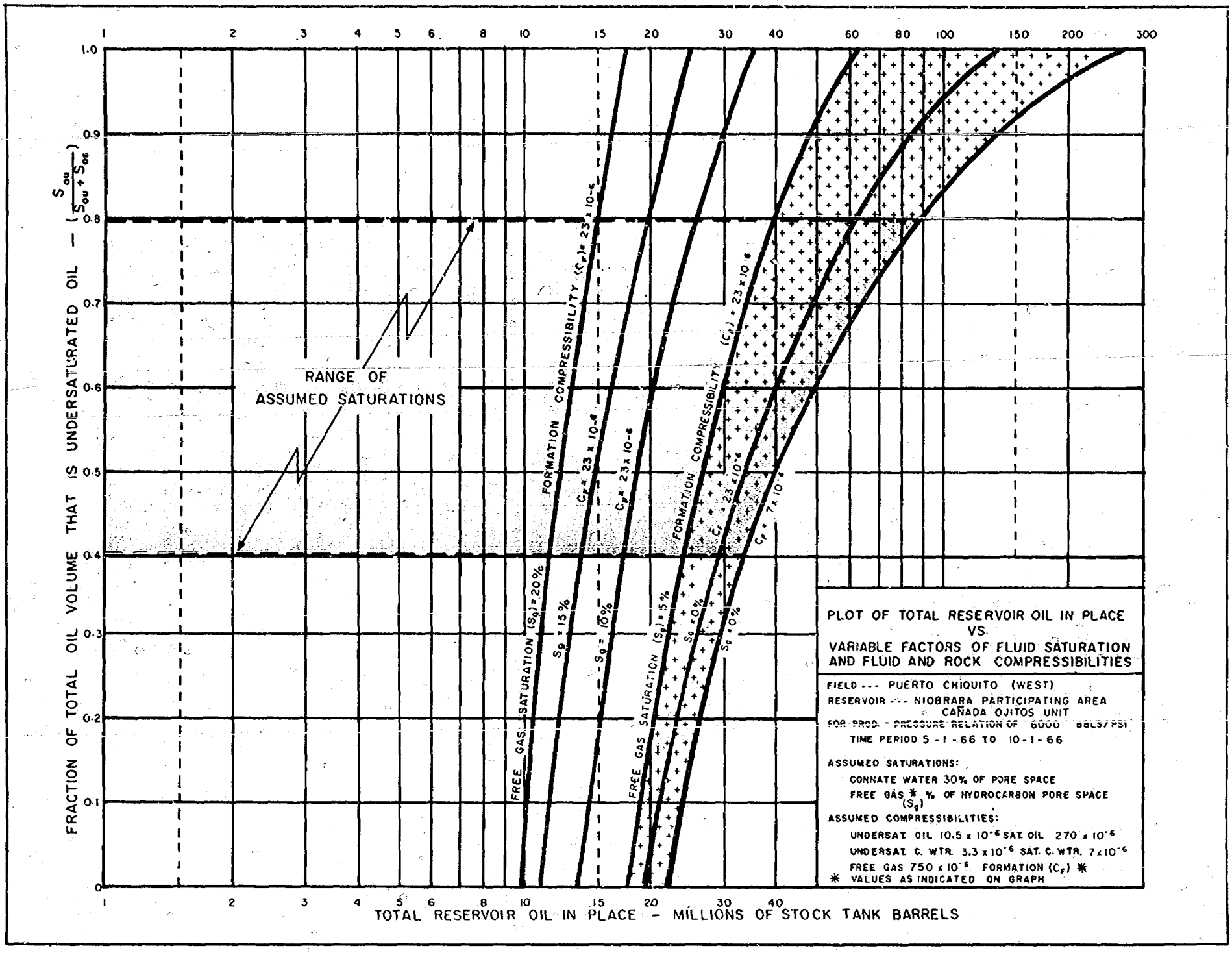


PLOT OF TOTAL RESERVOIR OIL IN PLACE
VS.
VARIABLE FACTORS OF FLUID SATURATION AND FLUID AND ROCK COMPRESSIBILITIES

FIELD --- PUERTO CHIQUITO (WEST)
RESERVOIR ---NIOBRARA PARTICIPATING AREA
CANADA OJITOS UNIT
FOR PROD. - PRESSURE RELATION OF 3000 BBLS/PSI
TIME PERIOD 8-1-62 TO 8-1-65

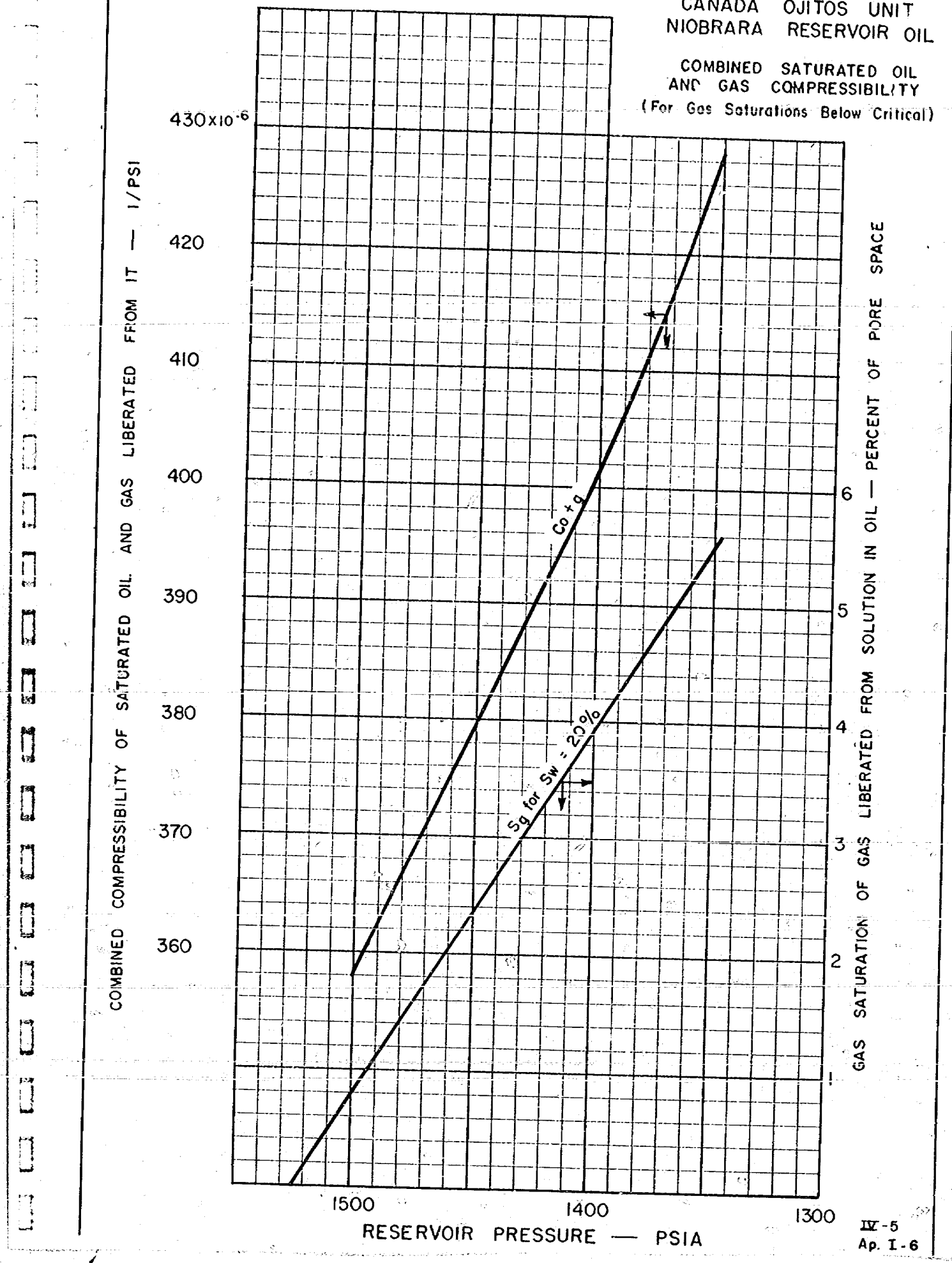
ASSUMED SATURATIONS:
CONNATE WATER 30% OF PORE SPACE
FREE GAS *% OF HYDROCARBON PORE SPACE (S_g)

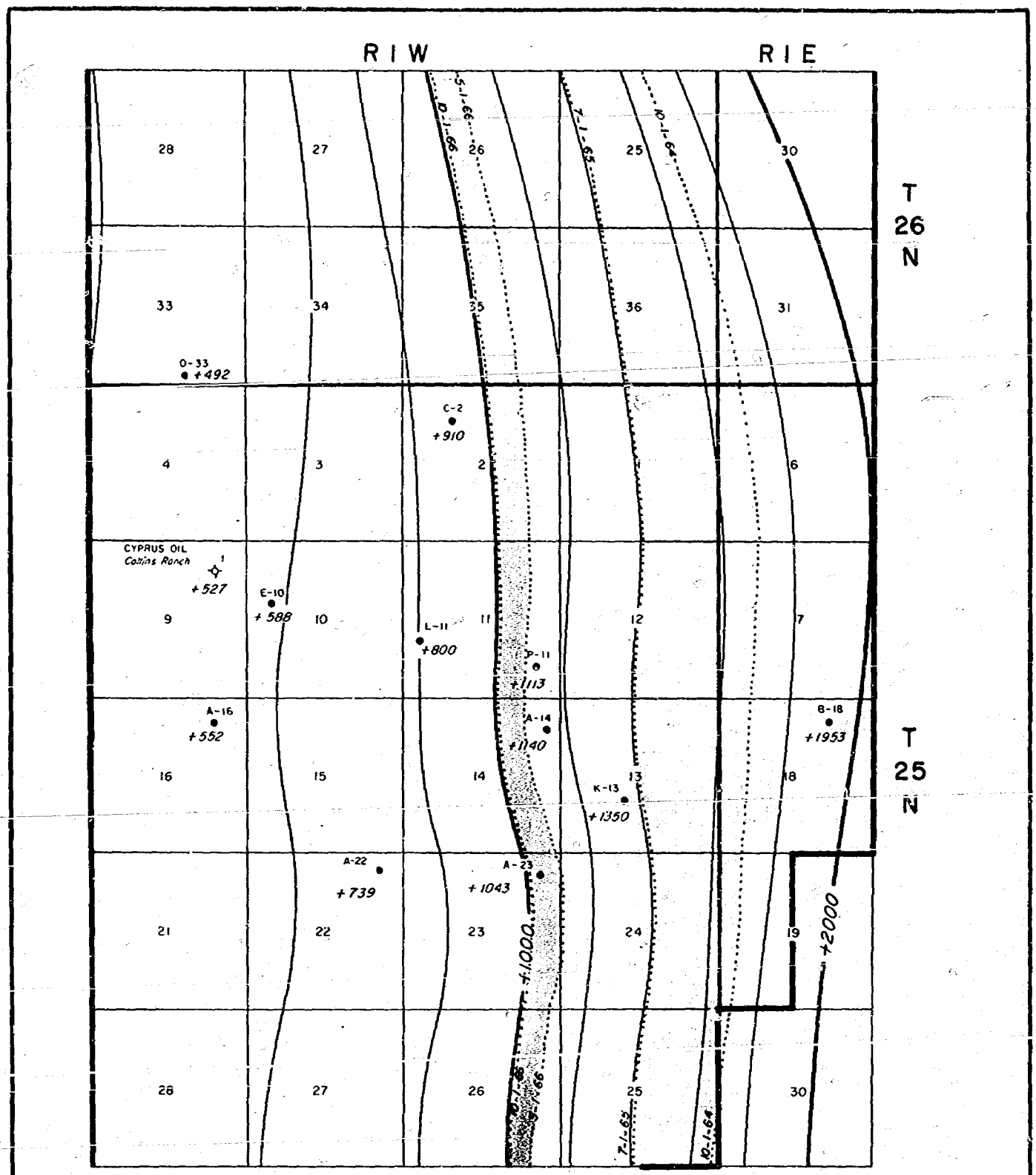
ASSUMED COMPRESSIBILITIES:
UNDERSAT. OIL 10.5×10^{-6} SAT. OIL 270×10^{-6}
UNDERSAT. C. WTR. 3.3×10^{-6} SAT. C. WTR. 7×10^{-6}
FREE GAS 750×10^{-6} FORMATION (C_f) *
* AS INDICATED ON GRAPH


FRACTION OF TOTAL OIL VOLUME THAT IS UNDERSATURATED OIL — $\left(\frac{S_{ou}}{S_{ou}+S_{oi}}\right)$
RANGE OF ASSUMED SATURATIONS
FREE GAS SATURATION (S_g) = 20%
FREE GAS SATURATION (S_g) = 15%
FREE GAS SATURATION (S_g) = 10%
FREE GAS SATURATION (S_g) = 5%
S_g = 0%
S_g = 0%
FORMATION COMPRESSIBILITY (C_f) = 23 x 10⁻⁶
C_f = 23 x 10⁻⁶
C_f = 23 x 10⁻⁶
FORMATION COMPRESSIBILITY (C_f) = 23 x 10⁻⁶
C_f = 23 x 10⁻⁶
C_f = 7 x 10⁻⁶
PLOT OF TOTAL RESERVOIR OIL IN PLACE VS. VARIABLE FACTORS OF FLUID SATURATION AND FLUID AND ROCK COMPRESSIBILITIES
FIELD --- PUERTO CHIQUITO (WEST)
RESERVOIR --- NIOBRARA PARTICIPATING AREA CAÑADA OJITOS UNIT
FOR PROD. - PRESSURE RELATION OF 6000 BBLS/PSI
TIME PERIOD 5 - 1 - 66 TO 10 - 1 - 66
ASSUMED SATURATIONS:
CONNATE WATER 30% OF PORE SPACE
FREE GAS * % OF HYDROCARBON PORE SPACE (S_g)
ASSUMED COMPRESSIBILITIES:
UNDERSAT. OIL 10.5 x 10⁻⁶ SAT. OIL 270 x 10⁻⁶
UNDERSAT. C. WTR. 3.3 x 10⁻⁶ SAT. C. WTR. 7 x 10⁻⁶
FREE GAS 750 x 10⁻⁶ FORMATION (C_f) *
* VALUES AS INDICATED ON GRAPH
TOTAL RESERVOIR OIL IN PLACE - MILLIONS OF STOCK TANK BARRELS

CAÑADA OJITOS UNIT
NIOBRARA RESERVOIR OIL

COMBINED SATURATED OIL AND GAS COMPRESSIBILITY
(For Gas Saturations Below Critical)





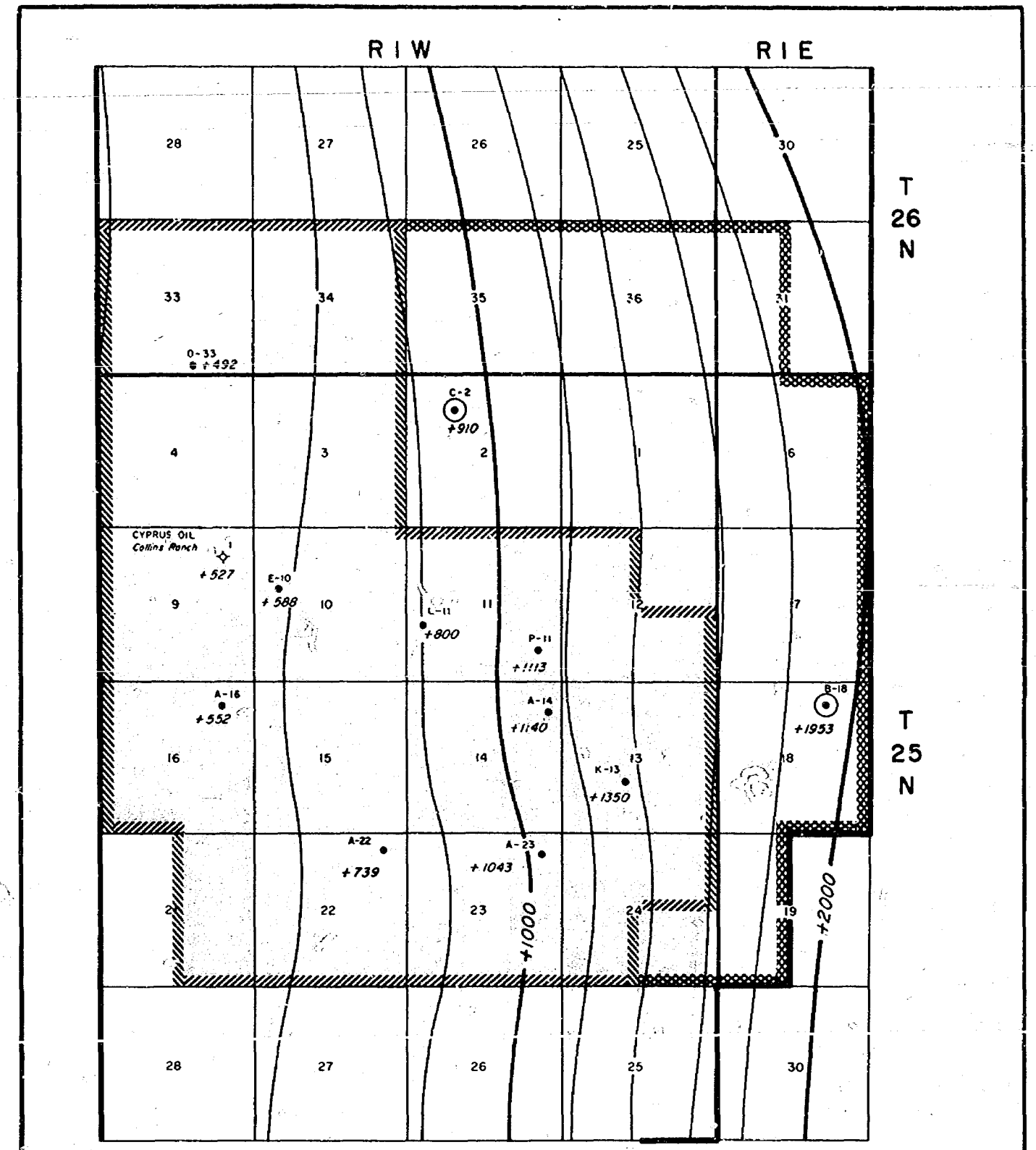
PLAT OF PART OF CAÑADA OJITOS UNIT

SHOWING MOVEMENT OF BUBBLE POINT PRESSURE
CONTOURED ON TOP OF ZONE "A"

CONTOUR INTERVAL 200'

..... LOCATION OF BUBBLE POINT PRESSURE AT DATE INDICATED

(TIME PERIOD: Oct. 1, 1964 To Oct. 1, 1966



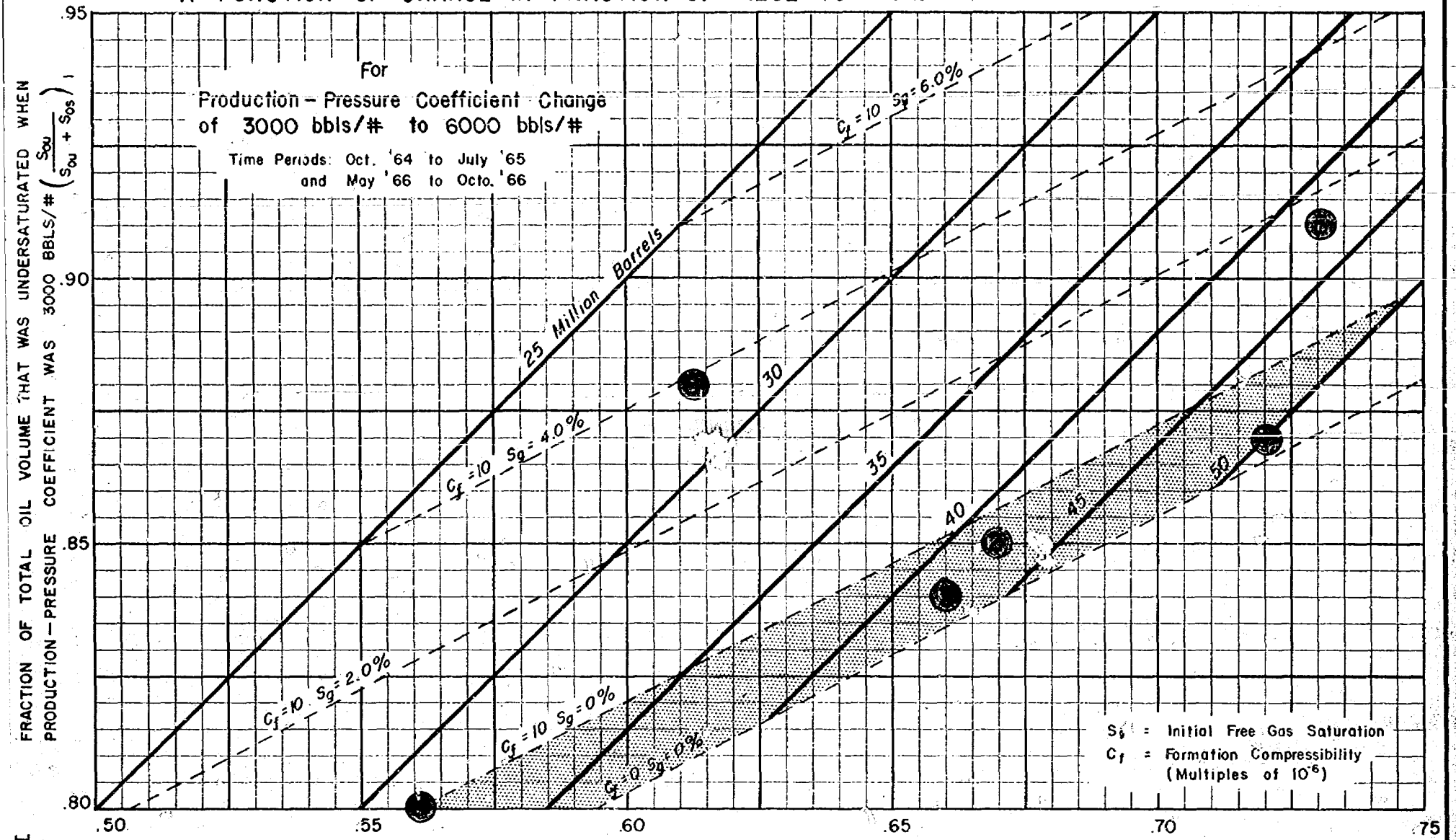
PER ACRE OIL–IN–PLACE VALUES

- 000 STOCK TANK BBLS.
- 1500 STOCK TANK BBLS.
- 2500 STOCK TANK BBLS

PLAT OF PART OF CAÑADA OJITOS UNIT
CONTOURED ON TOP OF ZONE "A"
CONTOUR INTERVAL 200'

- BOUNDARY OF NIOBRARA – GREENHORN PARTICIPATING AREA AFTER PROPOSED SIXTH EXPANSION
- BOUNDARY OF PROPOSED SEVENTH EXPANSION TO PARTICIPATING AREA
- WELL WITHIN EXPANSION AREA DECEMBER, 1969 PROVIDING INFORMATION REGARDING EXPANSION

CAÑADA OJITOS UNIT
NIOBRARA RESERVOIR OIL IN PLACE
AS
A FUNCTION OF CHANGE IN FRACTION OF RESERVOIR OIL THAT IS UNDERSATURATED



INFORMATION USED IN ESTIMATING CANADA OJITOS UNIT OIL IN PLACE

		FIRST CONDITION	SECOND CONDITION
	Time period	October '64 to July '65	May '66 to October '66
	Pressure productivity coefficient	3000 bbl/#	6000 bbl/#
1)	Average reservoir pressure at 1195' datum	1530 psig	1422 psig
2)	Reservoir pressure at 1600' contour point (reservoir datum at 1600' contour point is 1650 - 150 = 1450 and 1450 - 1195 = ± 250) (1st) 1530 - (250) (.312) = 1452 (2nd) 1422 - (250) (.312) = 1344	1452 psig	1344 psig
3)	Contour point datum of bubble point pressure (1st) $\frac{1530 - 1520}{.312} + 1350 = 1382$ (2nd) $1350 - \frac{1520 - 1422}{.312} = 1036$	1382'	1036'
4)	Average pressure saturated oil	$\frac{1520 + 1452}{2}$ = 1486 psig = 1498 psia	$\frac{1520 + 1344}{2}$ = 1432 psig = 1444 psig
5)	Compressibility of combined saturated oil and gas liberated from it for average pressures of 1498 and 1444 (figure IV-5)	359×10^{-6}	383×10^{-6}
6)	Approximate average reservoir pressure of undersaturated oil (500' contour interval to bubble point contour)	1610 psig	1590 psig
7)	Compressibility of undersaturated oil	11.25×10^{-6}	11.35×10^{-6}

Example calculation on next page (pencilled notes) assumes that under first condition 90% of the oil was undersaturated and under the second condition that 70% was undersaturated:

Reservoir Characteristics	FIRST CONDITION Compressibility	Saturation	SECOND CONDITION Compressibility	Saturation
Undersaturated Oil	11.25×10^{-6}	90% of oil	11.35×10^{-6}	70% of oil
Saturated Oil	359×10^{-6}	10% of oil	383×10^{-6}	30% of oil
Connate Water	3.8×10^{-6}	20% of pore space	4.4×10^{-6}	20% of pore space
Free Gas	765×10^{-6}	Unknown	817×10^{-6}	Unknown
Formation	10×10^{-6}	-	10×10^{-6}	-

EXAMPLE CALCULATION

EQUATION 5 of EXHIBIT (1) of the 1966 hearing in case 3455 applies:

$$C_e = \frac{S_{ou}C_{ou} + S_{os}C_{os} + S_g C_g + S_{we}C_w + C_f}{S_{ou} + S_{os}}$$

$1 - S_w = 1 - .2 = .8$ ↓ x = unknown sat. of free gas

S_{ou_1} = 90% of oil $= .9(.8 - x) = .72 - .9x$

S_{os_1} = 10% of oil $= .1(.8 - x) = .08 - .1x$

S_{ou_2} = 70% of oil $= .7(.8 - x) = .56 - .7x$

S_{os_2} = 30% of oil $= .3(.8 - x) = .24 - .3x$

$$C_{e_1} = \left[\frac{(.72 - .9x)(11.25) + (.08 - .1x)(354) + 765x + (.2)(3.5) + 10}{(.8 - x)}\right] \times 10^{-6}$$

$$= \frac{(47.6 + 719.0x)}{(.8 - x)} \times 10^{-6}$$

$$C_{e_2} = \left[\frac{(.56 - .7x)(11.35) + (.24 - .3x)(383) + 817x + (.2)(4.4) + 10}{(.8 - x)}\right] \times 10^{-6}$$

$$= \frac{(109.2 + 694.1x)}{(.8 - x)} \times 10^{-6}$$

$C_{e_2} = \left(\frac{6000}{3000}\right)(C_{e_1}) = 2C_{e_1}$

$109.2 + 694.1x = 2(47.6 + 719x)$ $\quad x = 1.9\%$

$C_{e_1} = (47.6 + 719 \times .019)\left(\frac{1}{.8 - .019}\right)10^{-6} = 78.1 \times 10^{-6}$

$N = N_p / C_e = 3000 \div (78.1 \times 10^{-6}) = 38.4$ MM bbls

AMOUNT OF HORIZONTAL DEVIATION OF WELLS

SURFACE TO TOTAL DEPTH (NIOBRARA)

FOR

WELLS IN WEST PORTION OF CANADA OJITOS UNIT

WELL	LOCATION	MEASURED DATA LOWEST SURVEY		ESTIMATED	
		DEPTH (ft)	HORIZONTAL DISPLACEMENT (ft)	FOR T.D. OF (ft)	HORIZONTAL DISPLACEMENT (ft)
O-9	SE 9-26N-1W	7820	196.8	(below Niobrara)	
L-27	SW 27-26N-1W	6945	124.2	7248	134.5
O-33	SE 33-26N-1W	7360	189.6	7371	189.6
E-10	NW 10-25N-1W	6930	133.7	7064	138.4
A-16	NE 16-25N-1W	7500	183.5	7521	185.3
C-34	NW 34-25N-1W	6767	200.9	6990	218.4
L-3	NW 3-24N-1W	7120	120.0	7148	121.0

6-9

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. He is Vice-President of Benson-Montin-Greer Drilling Corp.

2. He supervised the drilling of the Benson-Montin-Greer Drilling Corp. No. 1 (0-9) Canada Ojitos Unit, located in the southwest quarter of Section 9, Township 26 North, Range 1 West, Rio Arriba County, New Mexico.

3. During the drilling of this well, the following deviation surveys were made:

½°	at 310'	
1°	at 1150'	
1½°	at 2860'	
2°	at 2981'	
2½°	at 3458'	
3°	at 3714'	
2°	at 4580'	
1½°	at 5822'	
1°	at 6350'	HOR. DEV.
1°	at 7281'	196.8'
1¼°	at 7820'	
1¼°	at 7860'	(below Niobrara)
2°	at 8522'	

Virgil L. Stoabs

Subscribed and sworn to before me, a Notary Public in and for the State of New Mexico, this 12th day of March, 1973.;

My Commission Expires
August 4, 1974

STATE OF NEW MEXICO }
COUNTY OF SAN JUAN } SS.

AFFIDAVIT

L-27

VIRGIL L. STOABS, of legal age, after first being sworn on oath, deposes and states:

1. That he is Vice-President of Benson-Montin-Greer Drilling Corp., operator of the Canada Ojitos Unit Well No. 13 (L-27) located in Section 27, Twp. 26N, Rge. 1W, Rio Arriba County, New Mexico.

2. That he supervised operations for the drilling of the subject well.

3. That during drilling operations the following deviation surveys were run:

200'	1°
1138'	1
2043	1/2
2931'	1/2
3684'	3/4
4448'	1
5164'	2
5322'	1-1/4
5480'	1-1/4
6111'	1-1/4
6393'	3/4
6654'	3
6945'	2

HOR. DEV. @ 4345 / 24.2'

Est. 134.8' @ 7248 T.D.

Virgil L. Stoabs

Subscribed and sworn to before me, a Notary Public in and for said county and state, this 7th day of April, 1970.

Notary Public

My Commission Expires
August 20, 1970

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

O-33

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. That he is engineer for Benson-Montin-Greer Drilling Corp., operator of the Canada Ojitos Unit Well NP No. 10, located 175' from the south line and 2090' from the east line of Section 33, Twp. 26N, Rge. 1W, Rio Arriba County, New Mexico.

2. That he supervised operations for the drilling of the subject well.

3. That during drilling operations the following deviation tests were taken:

At	420'	2°
	1070'	1
	1700'	2-1/2
	2320'	2
	2840'	1
	3550'	1-1/2
	4414'	1
	4800'	3/4
	5142'	1
	5412'	1-1/2
	5590'	2
	5998'	1/2
	6397'	1
	6688'	2
	6850'	2-1/4
	6923'	2
	7019'	3
	7235'	2-1/2
	7360'	3-1/4

Hor. Dev. 189.6' T.D. 7371'

Virgil L. Stoabs

Subscribed and sworn to before me this _____ day of March, 1967.

Notary Public in and for
San Juan County, New Mexico

My Commission Expires
August 20, 1970

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

E-10

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. That he is Vice-President of Benson-Montin-Greer Drilling Corp., operator of the Canada Ojitos Unit Well No. 11 (E-10) in Section 10, Twp. 25N, Rge. 1W, Rio Arriba County, New Mexico.

2. That he was in charge of operations for the drilling of the subject well.

3. That during drilling operations the following deviation surveys were run:

At 567'	2°
687'	1-1/4
1533'	1
1733'	1
2381'	1-1/4
3009'	1-1/2
3823'	3/4
4009'	1
4970'	1/2
5715'	1-1/2
6500'	1-1/4
6611'	1-1/4
6800'	2-1/4
6930'	2

DEV. @ 6730 1337

Est. 1384 @ 7064 T.D.

Virgil L. Stoabs

SUBSCRIBED AND SWORN to before me, a Notary Public in and for said county and state, this 21st day of September, 1967.

Notary Public

My Commission Expires
August 20, 1970

A-16

STATE OF NEW MEXICO }
COUNTY OF SAN JUAN } SS.

AFFIDAVIT

75:1

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. That he is the engineer for Bolack-Greer, Inc., operator of the Canada Ojitos Unit Well No. 8 (A-16), located in the northeast quarter of Section 16, Twp. 25N, Rge. 1W, Rio Arriba County, New Mexico.

2. That he supervised operations for the drilling of this well.

3. That during the drilling sof this well, the following deviation surveys were run:

At 200'	3/4°
1109'	1
1620'	2-3/4
2100'	2
2385'	1
3240'	3/4
3905'	1/2
5150'	3/4
5650'	1/4
6098'	3/4
6545'	2
6725'	3-1/4
6817'	3-3/4
6880'	4-1/4
7044'	4-3/4
7280'	5-1/4
7500'	5

Hor. Dev.
(183.5' @ 7500'
Est 185.3 @ 7521
T.D.

Virgil L. Stoabs

Subscribed and sworn to before me, a Notary Public in and for said county and state, this ____ day of _____, 1966.

Notary Public

My Commission Expires
August 20. 1966

C-34

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. He is Vice-President of Benson-Montin-Greer Drilling Corp., operator of the Canada Ojitos Unit Well No. 14 (C-34) located in the northwest quarter of Section 34, Twp. 25N, Rge. 1W, Rio Arriba County, New Mexico.

2. That he was in charge of operations for the drilling of the subject well.

3. That during such drilling operations the following deviation tests were made:

1/2°	at	368'
1-3/4°	at	1000'
3/4°	at	1724'
1°	at	2165'
1°	at	2573'
2-1/2°	at	2833'
3/4°	at	2894'
1/4°	at	3129'
1/2°	at	3632'
3/4°	at	3865'
3-1/4°	at	4350'
3-3/4°	at	4645'
2-1/2°	at	5095'
1-3/4°	at	6110'
4°	at	6323'
4°	at	6430'
4°	at	6564'
4-1/2°	at	6767'

HOR DEV.
200.9' @ 6767

EST 218.4 @ 6990 T.D.

Virgil L. Stoabs

Subscribed and sworn to before me, a Notary Public in and for said county and state, this 15th day of February, 1971.

Notary Public

My Commission Expires
August 4, 1974

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

L-3
7148

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. That he is Vice-President of Benson-Montin-Greer Drilling Corp., a corporation organized under the laws sof the State of Delaware.

2. That he was in charge of operations for the drilling of Benson-Montin-Greer Drilling Corp. Canada Ojitos Unit Well No. 16 (L-3), in the SW¼ of Section 3, Twp. 24N, Rge. 1W, Rio Arriba County, New Mexico.

3. That during the drilling of this well the following deviation surveys were made:

At 210'	1/4°
404'	1/4
1447	3/4
2437'	1/2
3400'	1/2
4250'	3/4
4673'	1-1/4
5240'	1-1/2
5851'	2
6705'	1-3/4
7120'	2

HOR DEV. 120.0' @ 7120'
EST 121.0' @ 7145' T.D.

Virgil L. Stoabs

Subscribed and sworn to before me, a Notary Public in and for said county and state, this 24th day of August, 1971.

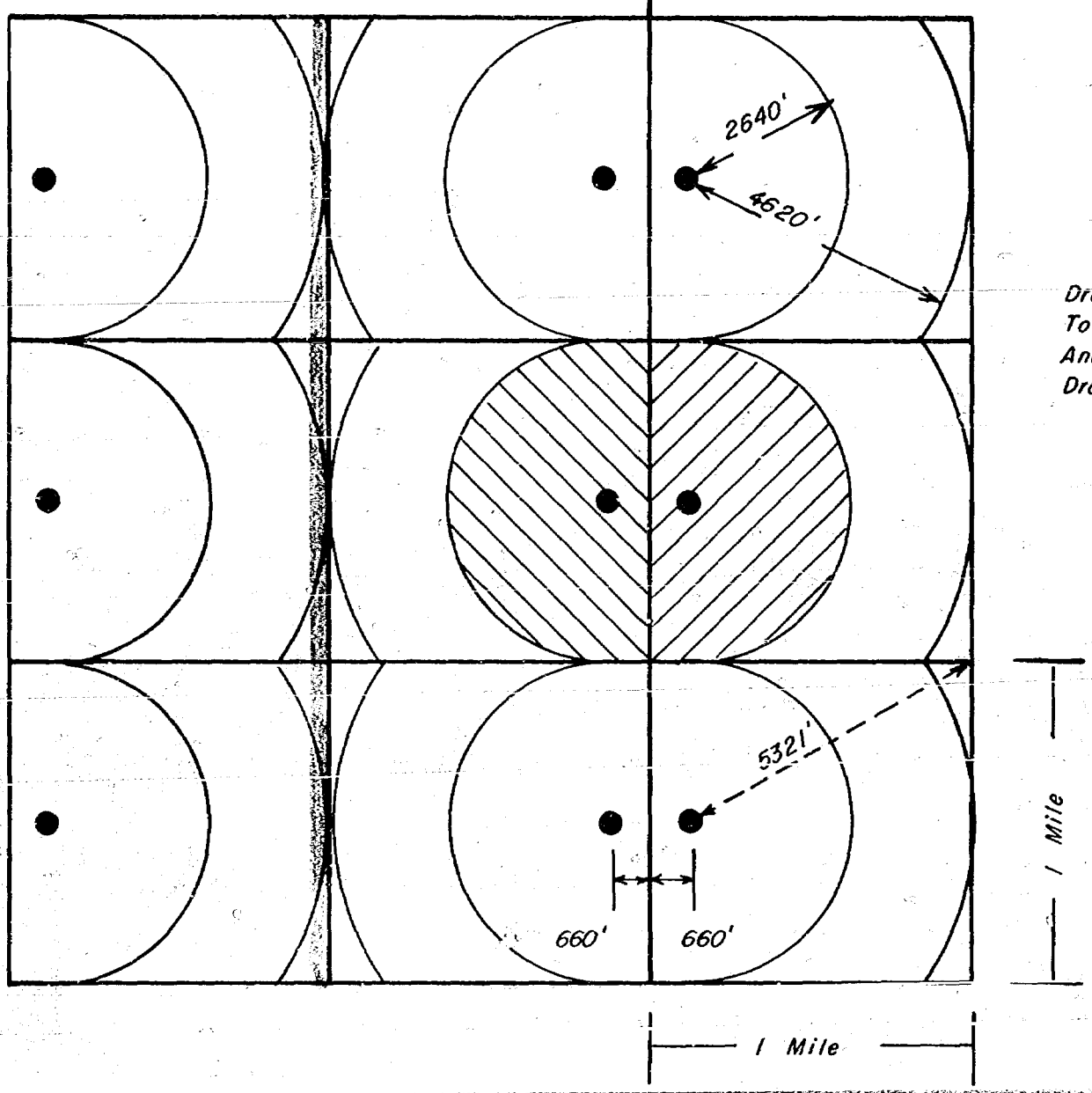
Notary Public in and for
San Juan County, New Mexico

My Commission E xpires:
August 4, 1974

IMPACT ON STATE AND FEDERAL REVENUES
OF
DEGRADATION OF OIL RECOVERY EFFICIENCY
FOR THE CANADA CUITOS UNIT
RESULTING FROM
PRODUCTION OF COMPETITIVELY DRILLED WELLS
(based on assumed free market value of oil of $40.00/barrel as of 10-1-81)

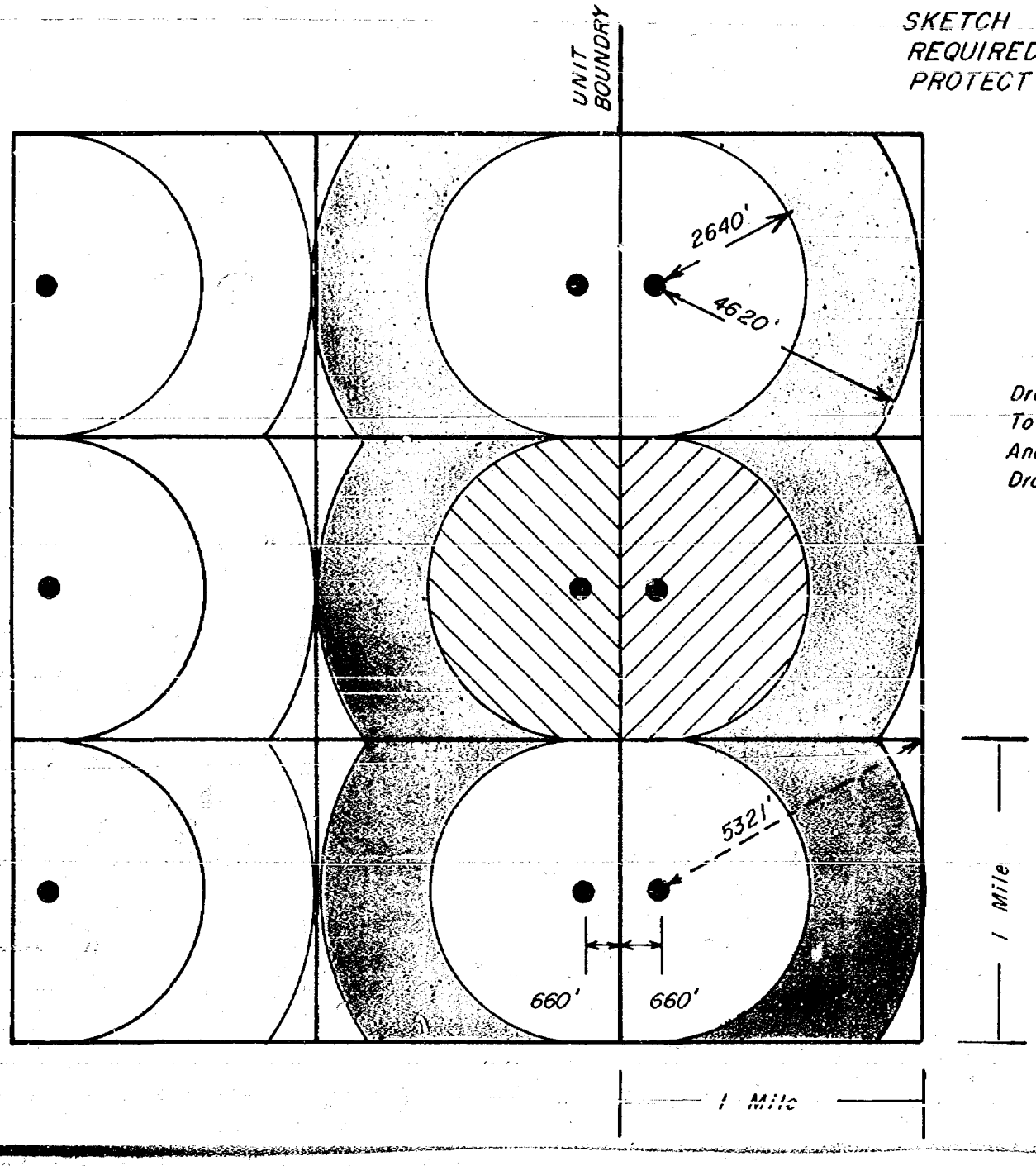
Future gross production	5 MM bbls. ($MM)	5 MM bbls. ($MM)	10 MM bbls. ($MM)	10 MM bbls. ($MM)
Gross value at $40.00/bbl.		200		400
90% of gross		180		360
State share of federal royalty				
1/2 of 1/8 of 95% (gross)	10.7		21.4	
Less approximate WFPT (bp 14.00)	(4.5)		(9.0)	
Net		6.2		12.4
State royalty				
1/8 of 1.6t		0.4		0.8
State severance tax				
3.75% of 3.5% +				
3.75% of 7/8 of 96.5% of gross		5.9		11.8
State school tax				
2.55% of 3.5% +				
2.55% of 7/8 of 96.5% of gross		4.0		8.0
State consevation tax				
.19% of 3.5% +				
.19% of 7/8 of 96.5% of gross		0.3		0.6
State ad valorem tax				
1.1% of 3.5% +				
1.1% of 7/8 of 96.5% of gross		1.2		2.4
Federal royalty				
Gross (same as state)	10.7		21.4	
Less WFPT (same as state)	(4.5)	6.2	(9.0)	12.4
Federal WFPT				
On federal royalty and state share of federal royalty	9.0		18.0	
On fee royalty ORR and integrated oil companies				
24% x 7/8 x 17 WFPT	18.0		36.0	
On independent producers				
76% x 7/8 x 12 WFPT	40.0		80.0	
Total WFPT		67.0		134.0
Total federal royalty and WFPT		73.2		146.4
Total state tax and royalty		18.0		36.0
TOTAL BOTH FEDERAL AND STATE ROYALTY AND TAXES		91.2		182.4

SKETCH SHOWING EXTENDED RADIUS REQUIRED FOR WELLS LOCATED TO PROTECT FROM OFFSET DRAINAGE



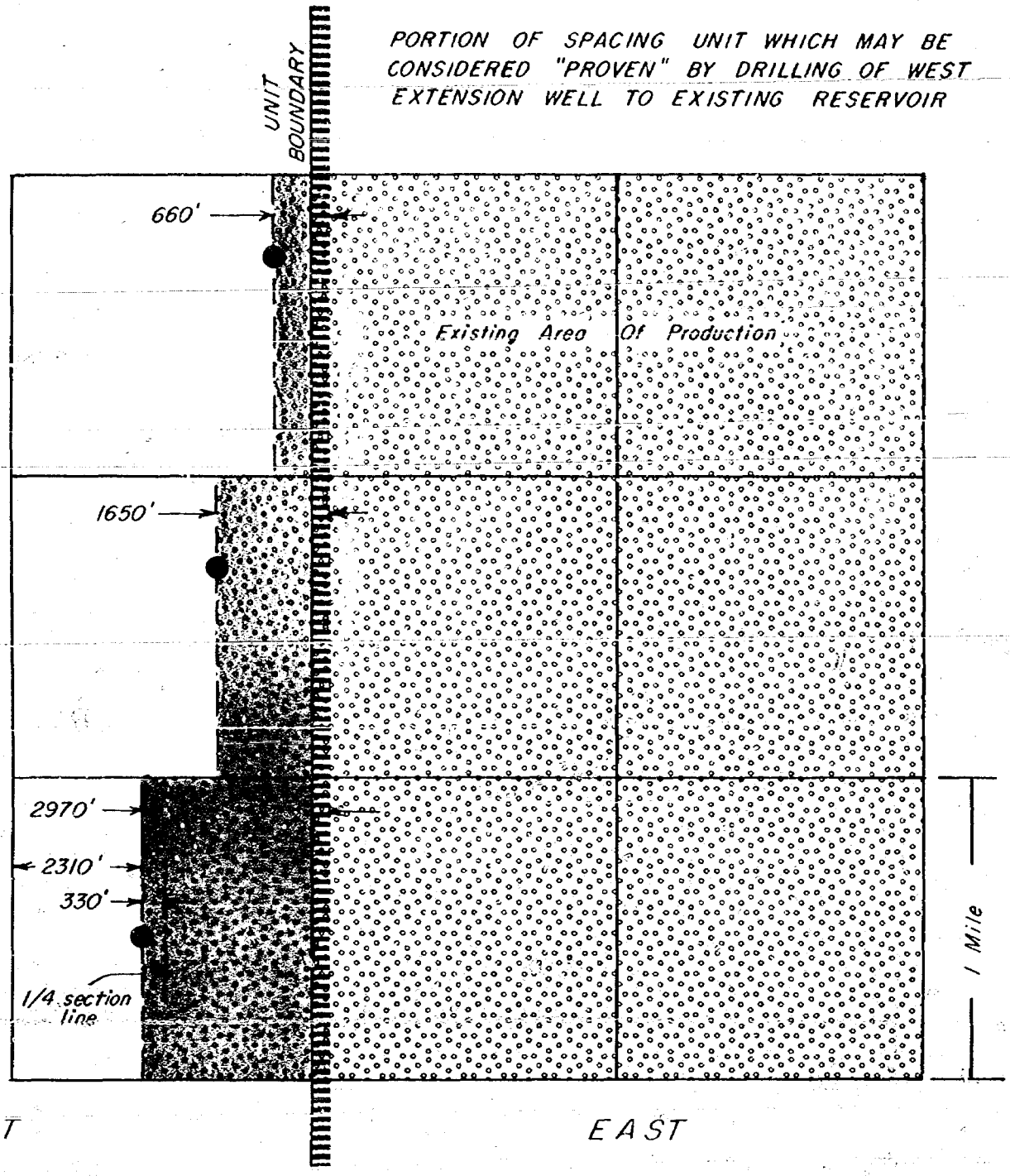
Drainage Radius Of 4620' Is Equivalent To Circular Drainage Area Of 1540 Acres And 5321' Is Equivalent To Circular Drainage Area Of 2040 Acres

SKETCH SHOWING EXTENDED RADIUS REQUIRED FOR WELLS LOCATED TO PROTECT FROM OFFSET DRAINAGE



Drainage Radius Of 4620' Is Equivalent To Circular Drainage Area Of 1540 Acres And 5321' Is Equivalent To Circular Drainage Area Of 2040 Acres

PORTION OF SPACING UNIT WHICH MAY BE CONSIDERED "PROVEN" BY DRILLING OF WEST EXTENSION WELL TO EXISTING RESERVOIR

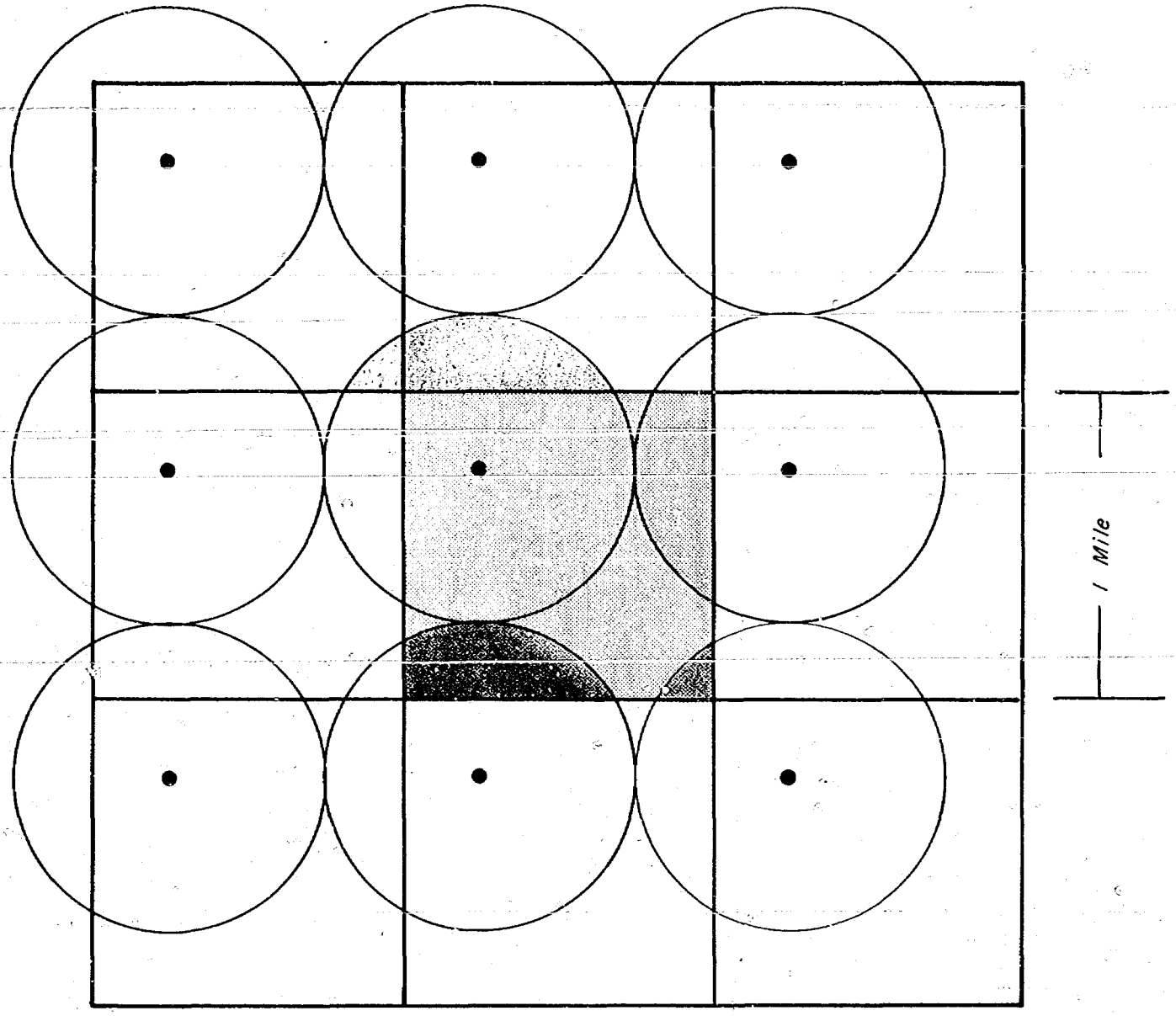


$\frac{660}{5280}$ = 12.50%

$\frac{1650}{5280}$ = 31.25%

$\frac{2970}{5280}$ = 56.25%

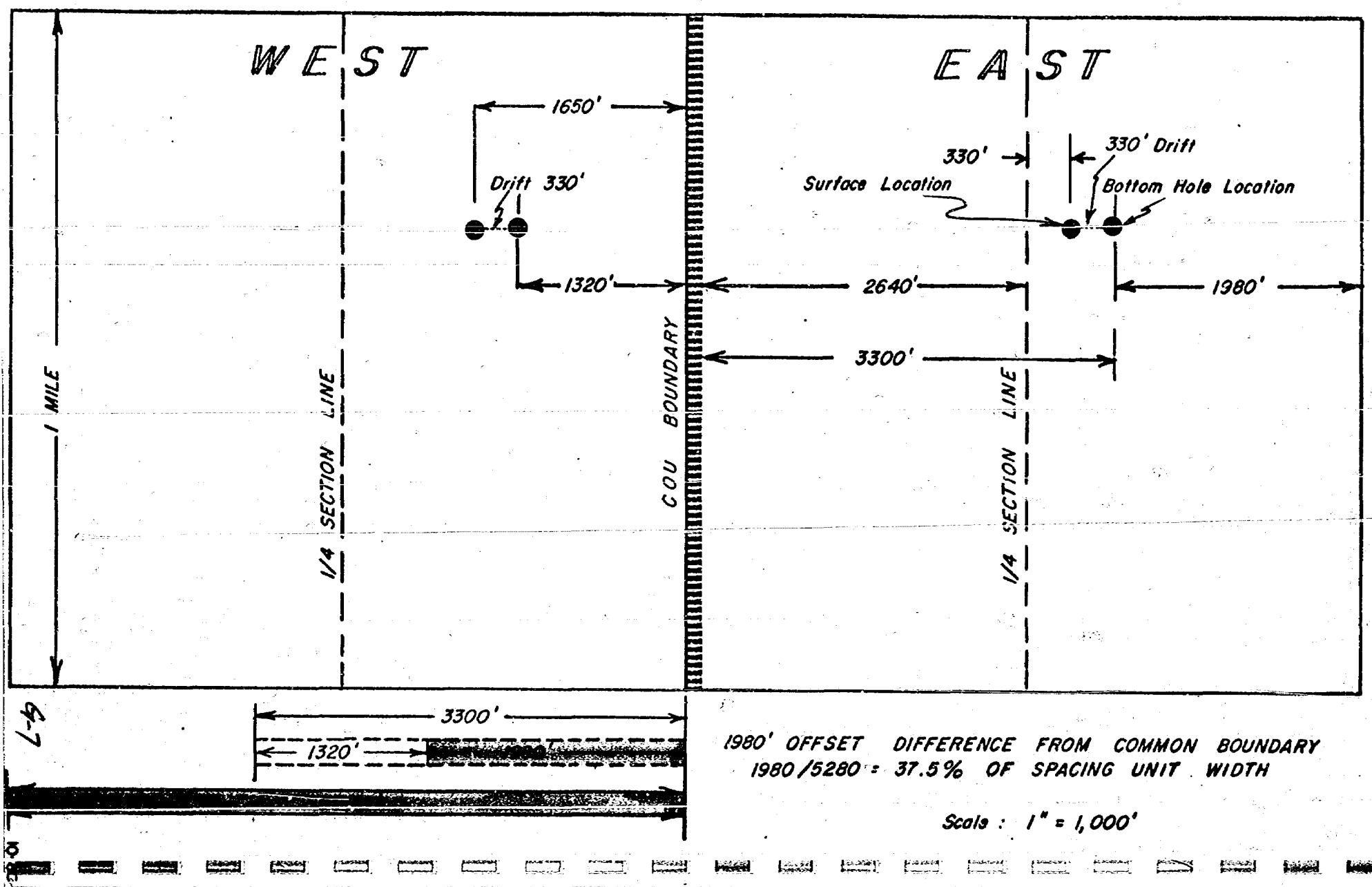
10-80



G-6

SKETCH SHOWING PRINCIPLE OF COMPENSATING DRAINAGE
FOR
OFF-CENTERED WELLS UNIFORMLY SPACED

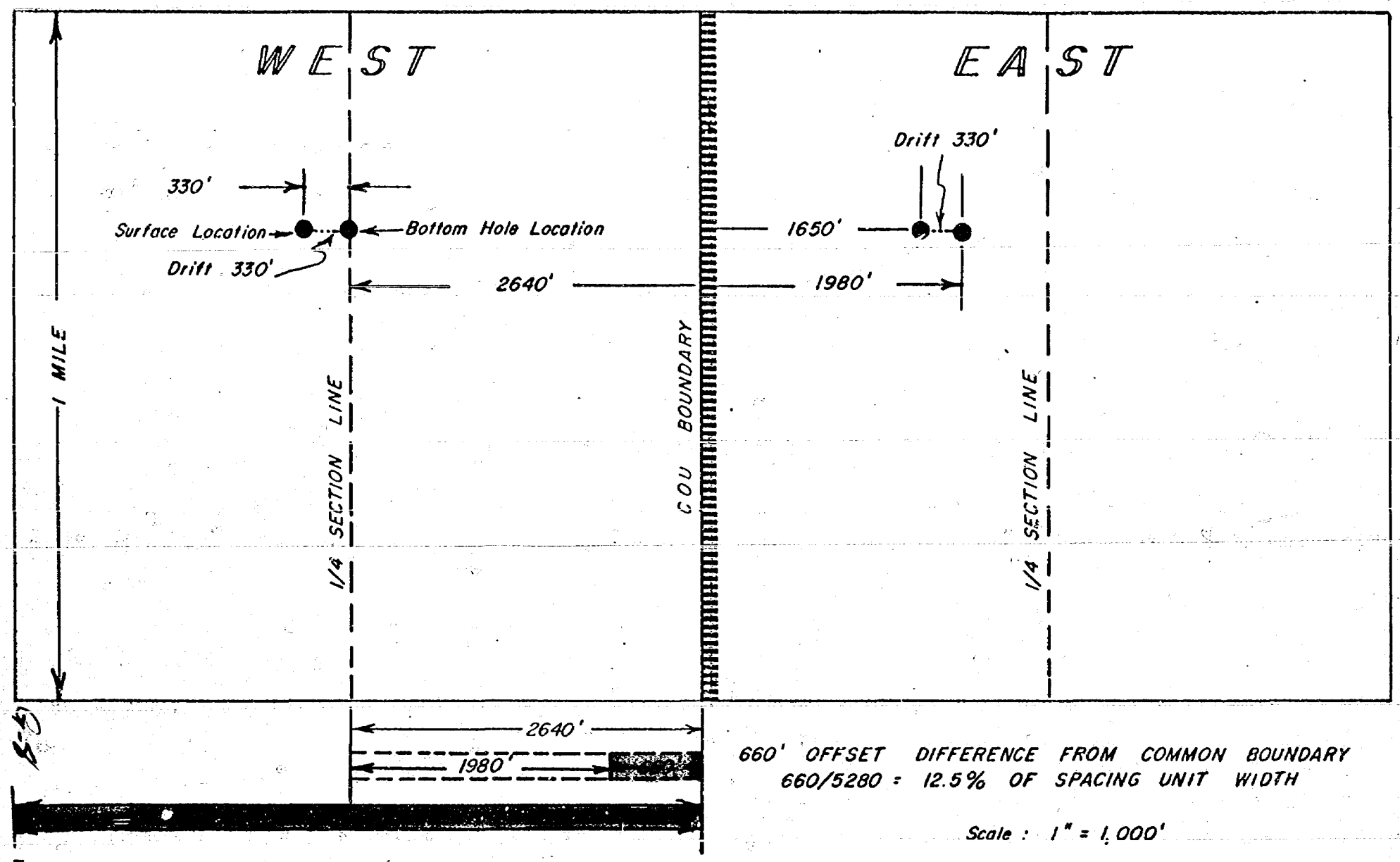
COMPARISON OF OFFSET DISTANCES FOR WELLS 1650' FROM SECTION LINES AND LOCATED IN E/2 OF SECTIONS



1980' OFFSET DIFFERENCE FROM COMMON BOUNDARY
1980/5280 = 37.5% OF SPACING UNIT WIDTH

Scale : 1" = 1,000'

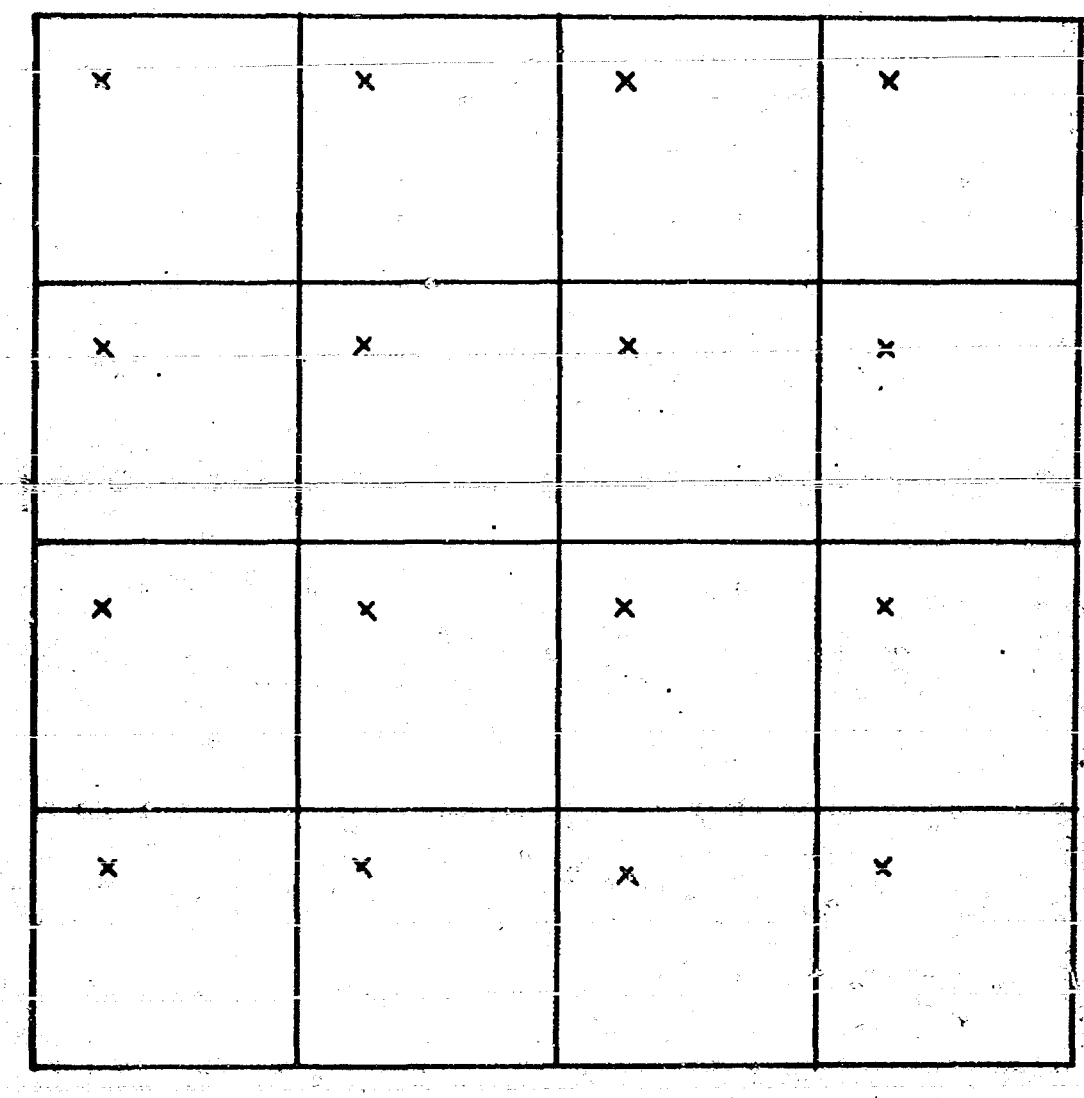
COMPARISON OF OFFSET DISTANCES FOR WELLS 1650' FROM SECTION LINES AND LOCATED IN W/2 OF SECTIONS

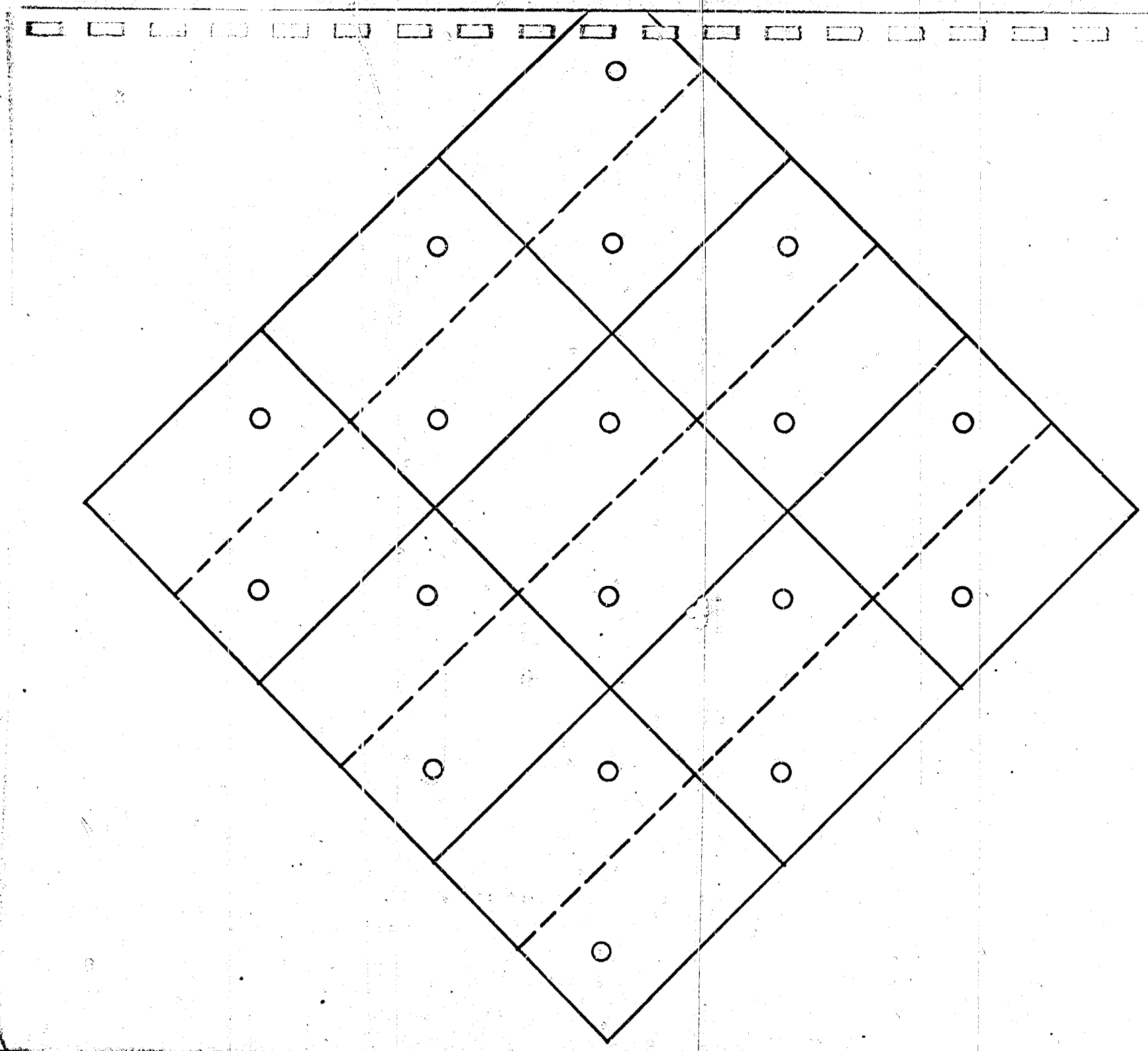


660' OFFSET DIFFERENCE FROM COMMON BOUNDARY
660/5280 = 12.5% OF SPACING UNIT WIDTH

Scale : 1" = 1,000'

CB-01





BENSON-MONTIN-GREER DRILLING CORP.
APPLICATION - WEST PUERTO CHIQUITO MANCOS OIL POOL

CASE 7075
NOVEMBER 24, 1980

OPENING STATEMENT

The application of Benson-Montin-Greer Drilling Corp. here before the Commission requests a change in the spacing pattern now established for the West Puerto Chiquito Mancos Oil Pool. In order for this application to be properly considered, it is necessary that we review the history of the development of the pool and the facts regarding its reservoir characteristics.

Back in 1963, after only a well or two were drilled, Benson-Montin-Greer came before the Commission and requested 160-acre temporary spacing. At that time both East and West Puerto Chiquito were thought to be one pool. Shortly after that, or a few years after that, it was realized that there was a barrier between East and West Puerto Chiquito. Thereupon an application was filed and an order entered to establish two pools - East and West Puerto Chiquito.

After 1963, when only five wells had been drilled in a cluster with approximately two miles distance between them, Benson-Montin-Greer had the courage (and it takes quite a lot), to interrupt all of the production from all five of those wells for a period of sixty days so that they could conduct one of the most remarkable interference tests that I've heard of in many years of oil and gas practice in Texas, New Mexico and Oklahoma.

This multiple interference test was conducted in 1965 and in 1966 and the results of it were presented to this Commission in Cause No. 3455. (The same cause number as in the 1963 hearing.)

At that time it was established that the pool was a fractured shale, being the Niobrara member of the Mancos; that it was a pool with a minimum amount of oil per acre in place and that it would support wells capable of very wide drainage; and the communication was so great that every one of those five wells was affected by anything that happened in any one of them.

At that time 320-acre temporary spacing was requested and granted.

At that time BMG expressed comprehensive opinions with regard to the pool and how it should be developed. Today, after seventeen years of history of the West Puerto Chiquito Mancos Oil Pool, all of the theories and opinions that were expressed to the Commission back at that time have been definitely established as engineering facts and are now a matter of history.

It is a rare instance in the oil industry that management will permit the remarkable engineering that has been achieved in this pool. Pools like the Boulder Pool, just a few miles to the north of West Puerto Chiquito where 80-acre spacing was employed and there was no pressure maintenance instituted, reflect a tragic disparity of conservation when compared to West Puerto Chiquito.

Shortly after the dramatic interference tests and the establishment of 320-acre spacing, BMG as the operator of the Canada Ojitos Unit established a pressure maintenance system by injecting gas in the upper edge of the pool. Then they carefully monitored production and voluntarily restricted production rates so as not to exceed the gravity drainage ability of the field. Without this pressure maintenance and controlled development of the pool, we would only have been able to recover approximately 5-1/2 percent of the oil in place under West Puerto Chiquito; whereas, as it has been developed we expect to recover between 50 and 60 percent of most of the oil in place. I say that we expect to. We expect to if we are able to continue the program of conservation established over the 17-year history of the field.

Our evidence will show that there are high and low capacity wells and that even the low capacity wells have maintained their initial production rates over a period of years and we will show that not only the high capacity but the low

capacity wells also drain wide areas.

We have two production wells which we will be talking about along with the others, one, the well in Section 10, has produced 2-million barrels of oil and we will show that this well has already drained an area of between 4000 and 8000 acres and is still producing oil.

The initial five well interference test enabled us to establish that the oil in place in this area was between 1000 and 2500 barrels per acre. Then after such interference tests BMG left one of those wells off production and never put it back but used it as an observation test well.

Then when the Canada Ojitos Unit operator started injecting gas in the upper side of the pool, they were able to run an additional interference test. By that further interference test they confirmed and refined their previous conclusions regarding oil in place.

Preliminary to unitizing additional areas in West Puerto Chiquito recently BMG requested of the Division and was granted 640-acre spacing. This was necessary preliminary to and as an adjunct to unitizing North Canada Ojitos and West Canada Ojitos, and as we indicated in the hearing last August held on such application, we anticipated that these areas would be unitized in a compatible program with the Canada Ojitos Unit so that the conservation program heretofore established could be continued for the greater recovery of oil. The Division granted the application for 640-acre spacing and established a spacing pattern of permitting a well to be drilled up to within 660 feet of the section line. BMG at that time paid little or no attention to the spacing pattern for the reason that unitization of the area would make it a moot point. However, since that time BMG was shocked to discover that the protestants here today would not agree to unitizing West Canada Ojitos. As a matter of fact, without advising BMG that they were terminating negotiations regarding formation of West Canada

Ojitos Unit, they proceeded to stake a location for the drilling of a well in the area 660 feet on the surface from the Canada Ojitos Unit; which well, if drilled, will most probably be considerably closer at the bottom of the hole.

If such a drilling program is to be carried on to production by the protestants, then the highly efficient gravity drainage and pressure maintenance processes established and practiced by the applicant will be destroyed and there will be serious degradation of recoveries from the reservoir. This will result in a tremendous underground waste of oil and a destruction of the correlative rights of the applicant.

In this regard, our proof will show that if protestants are permitted to drill where they desire, then the section under which they drill will not be drained as to a large amount of the western portion thereof, while on the other hand, protestants' well or wells will drain a large area under the Canada Ojitos Unit to the east of such wells. Such drilling would require that unit operator drill off-sets only 660 feet from the protestants' section line in order to partially protect the unit; but our proof will show that such off-setting wells cannot protect the unit from severe drainage by the protestants' wells.

Applicant's proof will further show that not only will the drilling pattern desired by protestants cause a great amount of oil never to be recovered from the reservoir and wasted, but in addition thereto will cause drilling of unnecessary wells. Our proof will show that close off-sets are unnecessary wells; are not only costly and wasteful, but that in addition thereto they will create much unnecessary damage to the National Forest.

Damage to the National Forest may not be strictly a matter of oil and gas conservation. However, this area is a part of the Santa Fe National Forest. It is a beautiful wooded area. Minimizing damage and maintaining its beauty has been

a significant consideration to the managers of the Canada Ojitos Unit.

After Applicant learned that the protestants would not agree to form a unit but desired to proceed with a drilling program that would prevent the greatest recovery of oil from the pool, it became apparent to BMG that they needed a different spacing pattern than that established by this Commission after the August hearing. Therefore, BMG filed the initial application in this cause. In that application we requested that the spacing pattern follow or conform to the customary 640-acre spacing regulation in New Mexico which requires that wells be located not closer than 1650 feet from the spacing unit section line. However, when BMG began to project the inevitable consequences of an application of the standard spacing pattern, it realized that wells drilled in the east half of the western tier of Sections, 1650 feet from the east line not only grossly fail to protect the applicant's correlative rights but also fail to adequately drain the western portion of their section. Thereupon, applicant amended its application to request that wells in the pool be spaced uniformly in the west half of each spacing unit.

In an ordinary reservoir where 640-acre spacing is established a well at any place 1650 feet from the line of the section adequately protects the correlative rights of the parties where there is an opportunity for compensating drainage. However, West Puerto Chiquito is no ordinary reservoir. To the contrary, it is a reservoir where the ratio of the ability of a well to produce the oil from the reservoir in relation to the amount of oil in place is much greater than the average. In other words, in this reservoir the capacity of the wells in relation to the amount of oil in place is far greater than the ordinary situation. Also, it is a pool tilted downward from east to west and where a unit was formed at an early date in the development of the pool and a pressure maintenance program

installed. These facts, together with the careful spacing of wells and production, drastically separate this pool from the ordinary oil and gas conservation situation. Oil not only drains from east to west but in addition thereto it is further moved from east to west by virtue of the fact that the Canada Ojitos Unit installed four injection wells on the eastern extremity of the pool and have been injecting gas into the formation almost from the inception of production. These conditions cause the oil to move from east to west and wells to the West of the Canada Ojitos Unit will drain the oil from the Unit. These are the reasons that a well in the sections immediately west of the Canada Ojitos Unit which is located in the east part of the spacing unit will not be efficiently draining such spacing unit. To the contrary, most of the oil produced by such well will be drained from land to the East. Applicant's evidence will show that such oil will be produced not just from the adjoining sections to the East but from large areas of the unit lands.

Even more unfortunate, such well will produce only a small amount of oil from the western part of the section upon which it is located. It will, therefore, be an improperly located well; it not only will not serve conservation but it will destroy correlative rights and may result in a tragically reduced ultimate recovery of oil from West Puerto Chiquito.

This was the reason that although the applicant initially asked for spacing 1650 feet from the line, after applying this standard pattern to the unusual charasteristics of the reservoir, it became apparent that applicant's correlative rights were going to be destroyed and the applicant realized that it must ask for a rule which would allow a more equitable recovery of the hydrocarbons in the reservoir and would come closer to preserving the energy of the pool. The only way to better protect the correlative rights of the applicant was by requiring that all wells be drilled in the west half of the section.

Our evidence will show that wells located in the western half of the sections will come much closer to producing the oil from under their own sections and that they will be far less an infringement upon the correlative rights of the owners of the Canada Ojitos Unit. Further, our proof will show that it will save the cost of the drilling of unnecessary wells and greatly diminish the overall damage to the reservoir. Also, that by eliminating the drilling of unnecessary wells it will greatly protect the surface and beauty of the National Forest.

It is difficult to fully appreciate the tremendous danger that is presented by the specter of wells being drilled 660 feet immediately west of the Canada Ojitos Unit bondary. Therefore, in order that the Division can understand the gravity of our application, we will present evidence which will show that if competitive drilling is permitted to proceed in West Puerto Chiquito in accord with the present order, that the established efficienty of the Canada Ojitos Unit will be destroyed and it may lose as much as 90 percent of its future recoveries. We will further show that this would mean a loss not only to the Canada Ojitos Unit owenrs but also a loss to the State of New Mexico of between 18 and 36 million dollars in royalty revenues and gross production taxes and a further loss to the Federal Government of between 6 and 12 million dollars in royalties and between 67 and 134 million dollars in Windfall Profits tax, meaning losses to both State and Federal governments of between 90 and 180 million dollars.

The applicant is aware of the fact that without the acreage on the west being unitized waste cannot be prevented, but absent such compatible unitization our proof will show that conservation and protection of correlative rights make it mandatory that our application be granted.

BENSON-MONTIN-GREER DRILLING CORP.
EXHIBITS IN CASE NO. 7075
BEFORE THE OIL CONSERVATION DIVISION
OF THE NEW MEXICO DEPARTMENT OF
ENERGY AND MINERALS
WEST PUERTO CHIQUITO POOL
RIO ARRIBA COUNTY, NEW MEXICO
NOVEMBER 24, 1980

INDEX OF

BENSON-MONTIN-GREER DRILLING CORP. EXHIBITS
IN CASE NO. 7075
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

NOVEMBER 24, 1980

PART I — INFORMATION RELATIVE TO RESERVOIR DRAINAGE CHARACTERISTICS

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2. A-23 observation well schedule of pressures
3. L-27 record of bottom hole pressures (green page) & graph (white page)
4. C-34 record of bottom hole pressures (blue page) & graph (white page)
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6. Graph, production vs. pressure
7. 1967 production graph by days showing E-10 frac interference

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2. Boulder: pressure vs. production
3. Boulder: oil in place vs. percent undersaturated oil for production pressure coefficient of 1200 bbl/#.
4. Boulder: oil in place vs. percent undersaturated oil for production pressure coefficient of 3000 bbl/#.
5. Boulder: oil in place from combination of 3 and 4 above

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2. Reference to earlier filing of estimate and Description of method of calculating oil in place (2 pages)
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4. Graph, oil-in-place for pressure-production coefficient of 6000 bbl/# (Plate marked IV-4)
5. Graph: Compressibility of combined saturated oil and gas released (Plate marked IV-5)
6. Plat of location of bubble point (Plate marked IV-6)
7. Plat of per-acre oil in place estimates (Plate marked IV-7)
8. Graph, oil in place as function of change in amount of undersaturated oil (Plate marked IV-8)
9. Statistics used in estimate (Plate Marked IV-9)
10. Sample calculation (Plate marked IV-10)

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2. Individual well surveys

PART III FOREST LANDS

SECTION E:

PART IV DRAINAGE PATTERNS

SECTION F:

1. Sketch of water flood drainage patterns.
2. Sketch of COU drainage parterns.
3. Sketch of drainage patterns COU after impressing competitive drilling.
4. Schedule of impact on state and federal revenues of competitive drilled wells.

SECTION G:

1. Plat showing location of oil recovery wells
2. Sketch showing extended radius of drainage for close offsets
3. Sketch showing extended radius of drainage for close offsets with boundary shifted
4. Sketch showing east to west drainage patterns

4a. Schedule showing comparison of some of the problems of first drilling and then unitizing (either voluntary or statutory)

5. Sketch showing portion of spacing unit proven
6. Sketch showing principle of compensating drainage
7. Sketch of relative offset distances for wells in W/2 of sections
8. Sketch of relative offset distances for wells in E/2 of sections
9. Sketch of uniform spacing of wells on rectangular tracts with overlay of square tracts of same spacing unit area.

PART V OPERATORS FAVORING AND OPPOSING APPLICATION

SECTION H: Plat showing owners favoring and opposing application.

CANADA OJITOS UNIT
NIOBRARA-GREENHORN PARTICIPATING AREA
OIL PRODUCTION BY WELLS BY MONTHS

	K-13	A-14	P-11	L-11	A-23	TOTAL	CUMULATIVE
1962							
December	689	737				1,426	
1963							
January	380	1,538				1,918	3,344
February	129	882				1,011	4,355
March	347	1,795				2,142	6,497
April	187	2,333				2,520	9,017
May	-	1,888				1,888	10,905
June	-	1,892				1,892	12,797
July	441	1,709				2,150	14,947
August	1,610	1,848				3,458	18,405
September	2,991	1,838				4,829	23,234
October	2,720	1,813				4,533	27,767
November	1,881	1,843				3,724	31,491
December	274	1,262				1,536	33,027
TOTAL FOR YEAR	10,960	20,641				31,601	
1964							
January	2,319	1,505	12,422			16,246	49,273
February	1,098	620	12,081			13,799	63,072
March	-	873	-			873	63,945
April	1,669	963	5,514			8,146	72,091
May	2,825	1,960	9,194			13,979	86,070
June	2,089	1,888	8,619			12,596	98,666
July	2,912	2,090	9,974			14,976	113,642
August	2,870	1,122	12,967			16,959	130,601
September	2,325	1,694	9,802			13,821	144,422
October	1,723	752	6,773			9,248	153,670
November	3,514	60	8,310	6,465		18,349	172,019
December	2,459	-	8,887	8,797		20,143	192,162
TOTAL FOR YEAR	25,803	13,527	104,543	15,262		159,135	

	K-13	A-14	P-11	L-11	*A-23	A-16	TOTAL	CUMULATIVE
1965								
January	1,850	-	10,519	10,181			22,550	214,712
February	-	-	11,762	9,240			21,002	235,714
March	-	4,482	11,462	8,735			24,679	260,393
April	-	8,396	10,990	8,390	1,445		29,221	289,614
May	-	-	11,380	1,012	3,100		15,492	305,106
June	-	-	2,420	-	600		3,020	308,126
July	-	-	413	-	-		413	308,539
August	-	-	13,067	-	-		13,067	321,606
September	-	-	13,901	4,817	-		18,718	340,324
October	-	-	13,962	14,259	-		28,221	368,545
November	-	1,923	12,732	13,415	-		28,070	396,615
December	-	4,710	15,481	14,298	-		34,489	431,104
TOTAL FOR YEAR	1,850	19,511	128,089	84,347	5,145		238,942	
1966								
January	-	4,445	13,858	15,104	-		33,407	464,511
February	-	3,730	12,192	11,091	-		27,013	491,524
March	-	3,562	13,717	14,964	-	703	32,946	524,470
April	-	3,704	11,086	11,473	-	610	26,873	551,343
May	-	3,506	12,272	13,441	-	823	30,042	581,385
June	-	3,990	11,505	14,069	-	995	30,559	611,944
July	-	2,954	11,096	13,380	-	841	28,271	640,215
August	-	2,658	11,775	10,152	-	415	25,000	665,215
September	-	3,266	11,645	13,064	-	1,256	29,231	694,446
October	-	3,350	11,570	11,491	-	618	27,029	721,475
November	-	3,504	11,421	11,032	-	608	26,565	748,040
December	-	2,872	10,286	9,590		457	23,205	771,245
TOTAL FOR YEAR	-	41,541	142,423	148,851	-	7,326	340,141	

*A-23 Dropped from Schedule-Observation Well

CAÑADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	*K-13	A-14	P-11	L-11	A-16	O-33	E-10	A-22	C-2	TOTAL	CUMULATIVE
1967											
Jan.		3,218	12,519	12,802	869					29,408	800,653
Feb.		2,648	9,931	9,489	921					22,989	823,642
March		3,555	11,760	12,034	1,030	1,542				29,921	853,563
April		3,194	9,198	13,159	958	2,055				28,564	882,127
May		3,086	9,258	13,373	1,013	2,147				28,877	911,004
June		2,983	10,190	11,682	947	1,893				27,695	938,699
July		2,241	11,205	11,454	924	1,766				27,590	966,289
Aug.	581	2,166	10,348	11,552	697	2,205				27,549	993,838
Sept.	1,136	909	9,316	11,361	-	1,870	4,869			29,461	1,023,299
Oct.	2,007	1,756	9,533	11,792	-	1,915	7,763			34,766	1,058,065
Nov.	78	1,596	6,983	11,373	630	1,806	5,556			28,022	1,086,087
Dec.		1,279	8,316	11,729	1,005	1,784	859			24,972	1,111,059
TOTAL FOR YEAR	3,802	28,631	118,557	141,800	8,994	18,983	19,047			339,814	
1968											
Jan.		1,775	7,496	10,456	875	1,640	12,368		672	35,282	1,146,341
Feb.		1,326	6,300	10,941	663	995	12,931		-	35,156	1,179,497
March		1,348	6,404	12,472	674	1,011	11,798		-	33,707	1,213,204
April		1,587	6,349	11,287	705	1,764	13,580		945	36,217	1,249,421
May		1,015	6,431	11,169	677	1,692	12,862		785	34,631	1,284,052
June		1,790	5,810	10,652	646	1,760	11,620		45	32,323	1,316,375
July		1,644	5,589	11,179	658	1,315	12,493		1,239	34,117	1,350,492
Aug.		1,743	4,649	10,751	582	1,453	9,879		587	29,644	1,380,136
Sept.		1,118	4,673	10,423	663	1,305	12,199		306	30,687	1,410,823
Oct.		1,190	4,760	10,412	588	105	12,694			29,749	1,440,572
Nov.		1,183	4,800	9,252	706	1,833	9,861			27,635	1,468,207
Dec.		2,013	4,529	9,812	503	1,761	6,541	7,634		32,793	1,501,000
TOTAL FOR YEAR		17,732	67,790	128,806	7,940	16,634	138,826	7,634	4,579	389,941	

*K-13 Dropped from Schedule - Gas Injection Well

CAÑADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	A-14	P-11	L-11	A-16	O-33	E-10	A-22	C-2	TOTAL	CUMULATIVE
1969										
January	2,169	3,263	8,364	828	863	4,816	13,080		33,383	1,534,383
February	1,922	1,166	7,543	-	1,812	17,029	11,130		40,602	1,574,985
March	2,058	-	8,924	-	253	20,412	11,744		43,391	1,618,376
April	1,727	-	8,749	783	1,936	19,160	9,193		41,548	1,659,924
May	1,510	1,401	7,855	732	1,491	19,189	13,690		45,868	1,705,792
June	1,049	3,491	6,993	690	1,282	19,547	11,950		45,002	1,750,794
July	420	3,520	10,227	535	1,227	20,894	13,863		50,686	1,801,480
August	-	807	7,498	-	1,441	15,845	11,764		37,355	1,838,835
September	-	-	9,488	-	1,204	19,023	11,359		41,074	1,879,909
October	-	-	9,204	-	1,487	22,408	11,226		44,325	1,924,234
November	-	-	8,107	476	1,273	19,489	9,845	756	39,946	1,964,180
December	-	2,495	9,423	790	1,233	20,381	12,136	2,360	48,818	2,012,998
TOTAL FOR YEAR	10,855	16,143	102,375	4,834	15,502	218,193	140,980	3,116	511,998	

CAÑADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

PAGE NO. 4

	P-11	L-11	A-16	O-33	E-10	A-22	C-2	L-27	TOTAL	CUMULATIVE
1970										
January	6,697	9,360	794	1,077	21,379	15,070	1,548		55,925	2,068,923
February	4,752	6,624	713	1,361	18,330	15,122	3		46,905	2,115,828
March	4,525	12,326	580	1,198	21,286	18,313	2,554		60,782	2,176,610
April	3,395	9,994	480	1,198	19,985	16,684	2,090	6,190	60,016	2,236,626
May	2,752	9,653	356	886	21,074	16,324	1,708	7,443	60,196	2,296,822
June	2,081	8,323	-	942	21,174	15,936	1,583	7,767	57,806	2,354,628
July	1,701	8,633	-	1,374	20,914	15,731	1,615	7,915	57,883	2,412,511
August	1,010	9,958	703	1,049	23,623	19,703	1,352	8,054	65,452	2,477,963
September	-	9,470	803	1,410	22,892	19,671	1,593	11,660	67,499	2,545,462
October	-	7,590	903	1,142	24,502	18,246	969	11,290	64,642	2,610,104
November	-	8,261	842	1,286	22,079	16,205	181	11,470	60,324	2,670,428
December	-	11,935	794	1,291	19,374	18,404	2,753	10,838	65,389	2,735,817
TOTAL FOR YEAR	26,913	112,127	6,968	14,214	256,612	205,409	17,949	82,627	722,819	

CAÑADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	L-11	A-16	O-33	E-10	A-22	C-2	L-27	C-34	L-3	TOTAL	CUMULATIVE
1971											
January	10,520	767	540	21,446	21,285	1,772	9,962			66,292	2,802,109
February	1,376	675	1,269	13,338	15,988	1,593	9,196	7,745		51,180	2,853,289
March	9,217	464	1,267	14,360	11,574	1,488	12,177	13,140		63,687	2,916,976
April	7,842	260	1,056	15,890	7,862	911	11,475	11,914		57,210	2,974,186
May	9,805	761	95	21,321	4,745	1,340	11,861	12,545		62,473	3,036,659
June	10,773	539	0	22,516	0	1,016	11,778	12,734		59,356	3,096,015
July	9,631	391	911	22,036	9,172	0	11,844	12,826		66,811	3,162,826
August	8,818	0	1,804	20,555	8,309	1,394	11,380	11,454	1,082	64,796	3,227,622
September	8,543	544	1,816	16,316	8,630	1,465	10,821	12.083	1,063	61,281	3,288,903
October	8,240	648	1,467	20,185	8,927	1,436	12,427	14,214	657	68,201	3,357,104
November	9,095	584	2,037	22,082	8,262	1,374	11,583	14,726	0	69,743	3,426,847
December	9,685	583	1,926	22,851	11,048	1,234	10,816	14,574	201	72,918	3,499,765
TOTALS FOR Y EAR	103,545	6,216	14,188	232,896	115,802	15,023	135,320	137,955	3,003	763,948	
1972											
January	9,942	548	1,870	24,240	9,712	1,339	11,300	14,834	0	73,785	3,573,550
February	8,756	587	1,899	20,510	8,229	1,196	10,245	11,469	8	62,899	3,636,449
March	9,744	596	1,754	21,519	5,496	1,347	10,585	10,776	1,599	63,416	3,699,865
April	9,461	553	1,735	20,336	6,281	1,296	10,165	9,142	1,073	60,062	3,759,927
May	9,598	363	1,718	16,708	4,637	1,503	10,884	7,214	958	53,583	3,813,510
June	8,345	330	1,453	15,880	0	1,346	10,263	5,860	973	44,450	3,857,960
July	9,258	523	1,514	15,173	0	1,494	11,316	5,400	1,060	45,738	3,903,698
August	9,506	720	1,691	14,532	0	1,415	10,471	4,781	1,008	44,124	3,947,822
September	9,527	533	885	15,057	0	1,339	10,118	4,246	1,018	42,723	3,990,545
October	8,969	446	1,792	15,408	0	1,356	10,478	4,960	533	43,942	4,034,487
November	9,075	377	1,560	14,986	0	1,307	10,060	4,839	0	42,204	4,076,691
December	9,608	482	1,626	15,108	0	1,323	10,008	4,721	1,069	43,945	4,120,636
TOTALS FOR YEAR	111,809	6,058	19,497	209,457	34,355	16,261	125,893	88,242	9,299	620,871	

CAÑADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	L-11	A-16	O-33	E-10	A-22	C-2	L-27	C-34	L-3	TOTAL	CUMULATIVE
1973											
January	9,475	560	1,598	15,024	0	1,336	10,189	4,479	937	43,598	4,164,234
February	8,689	384	1,369	14,521	0	1,108	8,981	4,219	421	39,692	4,203,926
March	7,990	82	1,374	15,775	0	1,387	10,220	4,836	0	41,664	4,245,590
April	9,002	164	1,552	14,033	0	1,212	9,470	5,182	0	40,615	4,286,205
May	10,559	397	1,499	15,561	0	1,277	9,695	5,958	660	45,606	4,331,811
June	10,793	461	1,499	12,250	0	1,294	8,738	4,280	911	40,226	4,372,037
July	10,914	325	1,535	11,796	507	1,330	9,220	4,588	830	41,045	4,413,082
August	11,308	437	1,287	12,266	1,025	1,258	8,574	4,433	689	41,277	4,454,359
September	10,564	418	1,417	12,456	502	1,315	8,689	4,179	877	40,417	4,494,776
October	10,776	414	1,496	13,502	140	1,414	8,508	4,133	1,018	41,401	4,536,177
November	9,975	284	1,416	12,759	0	1,299	8,538	3,827	946	39,044	4,575,221
December	10,261	363	1,491	13,176	0	1,395	8,786	3,764	640	39,876	4,615,097
TOTALS FOR YEAR	120,306	4,289	17,533	163,119	2,174	15,625	109,608	53,878	7,929	494,461	

CANADA O.IITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

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	L-11	A-16	O-33	E-10	C-2	L-27	C-34	L-3	O-9	TOTAL	CUMULATIVE
1974											
January	9,960	483	1,513	12,719	1,412	8,854	3,518	706		39,165	4,654,262
February	9,332	580	1,205	11,684	1,226	8,193	3,055	781		36,056	4,690,318
March	10,367	624	1,467	13,459	1,355	8,698	3,291	678		39,939	4,730,257
April	10,156	635	1,408	13,998	1,342	8,649	3,325	979		40,492	4,770,749
May	9,702	626	1,349	13,092	1,342	8,942	2,703	922	314	38,992	4,809,741
June	7,185	579	1,303	13,133	1,314	8,591	2,608	892	696	36,301	4,846,042
July	5,884	625	755	13,695	1,354	9,013	3,000	948	619	35,893	4,881,935
August	5,151	603	1,558	13,163	1,370	8,906	2,853	825	537	34,978	4,916,913
September	4,670	593	1,306	12,462	1,261	8,541	2,785	932	343	32,893	4,949,806
October	4,493	595	842	12,375	1,353	8,786	2,878	959	0	32,281	4,982,087
November	3,382	231	0	12,008	1,340	8,389	2,685	756	0	28,791	5,010,878
December	4,169	565	0	12,929	1,342	8,677	2,587	934	0	31,203	5,042,081
TOTALS FOR YEAR	84,451	6,739	12,706	154,717	16,011	104,239	35,300	10,312	2,509	426,984	
1975											
January	3,431	644	0	12,681	1,278	8,669	2,974	780	0	30,457	5,071,428
February	2,661	557	0	11,724	1,240	7,814	2,721	560	0	27,277	5,099,815
March	2,547	0	0	11,809	1,344	8,635	2,924	0	0	27,259	5,127,074
April	2,203	379	0	11,217	1,306	8,429	2,994	802	0	27,330	5,154,404
May	1,346	590	0	11,245	1,333	8,828	2,903	1,019	0	27,264	5,181,668
June	0	628	0	10,486	1,273	8,593	2,926	935	0	24,841	5,206,509
July	0	621	0	10,650	1,342	8,981	2,928	935	0	25,457	5,231,966
August	0	610	0	10,676	1,310	8,762	2,912	857	0	25,127	5,257,093
September	0	581	0	9,259	1,233	7,612	2,976	0	0	21,661	5,278,754
October	0	598	0	10,363	1,377	9,077	3,042	0	0	24,457	5,303,211
November	0	599	0	9,698	1,365	8,566	2,993	0	0	23,221	5,326,432
December	0	634	0	9,937	1,345	8,801	3,134	0	0	23,851	5,350,283
TOTALS FOR YEAR	12,188	6,441	0	129.745	15,746	102,767	35,427	5,888	0	308,202	

CANADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	A-16	O-33	E-10	C-2	L-27	C-34	L-3	O-9	TOTAL	CUMULATIVE
1976										
January	612	0	10,281	1,360	8,970	3,107	0	0	24,330	5,174,613
February	584	0	9,682	1,262	8,409	2,954	0	0	22,891	5,397,504
March	623	0	10,701	1,387	9,318	3,274	0	0	25,303	5,422,807
April	512	0	10,276	1,288	8,340	2,789	0	0	23,205	5,446,012
May	627	0	10,079	1,355	9,085	3,053	604	0	24,803	5,470,815
June	518	610	9,707	1,090	8,259	2,574	1,041	629	24,428	5,495,243
July	590	1,034	10,183	1,209	8,919	2,816	955	791	26,497	5,521,740
August	641	1,136	10,218	1,335	8,846	2,818	948	585	26,527	5,548,267
September	542	881	9,637	1,271	8,307	2,598	843	635	24,714	5,572,981
October	567	1,029	10,617	1,373	8,858	2,467	878	385	26,174	5,599,155
November	606	920	10,003	1,319	8,377	2,438	937	355	24,955	5,624,110
December	572	887	10,621	1,283	8,804	3,000	849	293	26,309	5,650,419
TOTALS FOR YEAR	6,994	6,497	122,005	15,532	104,492	33,888	7,055	3,673	300,136	
1977										
January	601	871	11,006	1,319	8,830	2,661	609	578	26,475	5,676,894
February	530	707	9,767	1,148	7,380	2,538	697	362	23,129	5,700,023
March	533	820	10,557	1,335	8,685	2,521	867	364	25,682	5,725,705
April	558	784	10,556	1,276	8,611	2,888	799	424	25,895	5,751,600
May	502	807	10,543	1,279	8,884	2,739	928	328	26,010	5,777,610
June	575	735	10,498	1,219	8,503	2,473	767	313	25,083	5,802,693
July	483	784	11,540	1,284	8,756	2,691	903	289	26,730	5,829,423
August	611	799	8,179	1,346	9,216	2,792	891	328	24,162	5,853,585
September	500	753	7,292	1,536	8,561	2,590	817	333	22,383	5,875,968
October	541	764	7,846	1,288	8,977	2,980	857	339	23,592	5,899,560
November	538	755	7,872	1,268	8,640	2,817	865	323	23,078	5,922,638
December	541	774	7,434	1,277	8,814	2,792	878	340	22,850	5,945,488
TOTALS FOR YEAR	6,513	9,354	113,090	15,575	103,857	32,482	9,878	4,320	295,069	

CANADA QUITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS

	A-16	O-33	E-10	C-2	L-27	C-34	L-3	O-9	TOTAL	CUMULATIVE
1978										
January	525	745	8553	1265	7313	2717	749	319	22,186	5,967,674
February	482	665	6854	1085	7082	2281	764	252	19,465	5,987,139
March	227	704	6556	1184	8035	2651	376	72	19,805	6,006,944
April	520	653	6020	1142	7814	2391	850	71	19,461	6,026,405
May	527	720	6545	1297	8415	2087	788	0	20,379	6,046,784
June	490	856	6287	1080	7919	1979	656	0	19,267	6,066,051
July	501	653	6478	1171	8168	2206	208	0	19,385	6,085,436
August	509	681	6111	1215	8212	2315	6	0	19,049	6,104,485
September	494	676	5590	1171	7979	2364	0	763	19,037	6,123,522
October	496	689	6596	1162	8165	2477	348	638	20,571	6,144,093
November	477	676	5054	1154	7549	2389	1156	549	19,004	6,163,097
December	480	697	5293	1217	8122	2201	870	423	19,303	6,182,400
TOTALS FOR YEAR	5728	8415	75937	14143	94773	28058	6771	3087	236,912	
1979										
January	2	688	4903	1221	8150	2323	642	472	18,401	6,200,801
February	394	603	4163	1048	7218	2223	513	819	16,981	6,217,782
March	331	682	4805	1215	8230	2546	0	502	18,311	6,236,093
April	384	672	4357	1178	8051	2497	0	470	17,609	6,253,702
May	523	684	4213	1232	8362	2636	292	470	18,412	6,272,114
June	478	673	3852	1192	8324	2384	411	448	17,762	6,289,876
July	549	712	3669	1242	8481	2495	832	446	18,426	6,308,302
August	516	696	3992	1223	8528	2405	834	407	18,601	6,326,903
September	508	662	3644	1199	8224	2267	821	408	17,733	6,344,636
October	468	657	5407	1137	8107	2239	817	462	19,294	6,363,930
November	476	631	5253	1117	7585	2078	782	359	18,281	6,382,211
December	460	610	5625	1208	7722	2212	800	405	19,042	6,401,253
TOTALS FOR YEAR	5089	7970	53883	14212	96982	28305	6744	5668	218,853	

CANADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS
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	A-16	D-33	E-10	C-2	L-27	C-34	L-3	D-8	TOTAL	CUMULATIVE
1980										
January	289	678	5708	1180	7810	2170	442	317	18,594	6,419,847
February	0	590	5195	1083	7151	1967	518	366	16,870	6,436,717
March	0	0	6005	1247	8272	2358	0	394	18,276	6,454,993
April	425	525	5264	1064	7463	2188	1072	728	18,829	6,473,822
May	514	652	5517	1150	8012	2220	875	344	19,284	6,493,106
June	495	650	5186	1153	7860	2145	800	232	18,522	6,511,628
July	493	662	4703	1238	8072	2232	792	268	18,460	6,530,088
August	447	676	5020	1250	8399	2296	836	278	19,202	6,549,290
September	503	632	4617	1139	7972	2155	765	340	18,123	6,567,413

CANADA OJITOS UNIT
OIL PRODUCTION BY WELLS BY MONTHS
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BOTTOM HOLE PRESSURE SUMMARY
CANADA OJITOS UNIT A-23
ELEVATION 7158' RKB
(HOLE DEPTH CORRECTION -4' AT 6300')

SURVEY DATE	PRESSURE (PSIG) AT 6300' (RKB) FOR PRESSURE GAUGE INDICATED AMERADA #42	AMERADA #43	AVERAGE	AVERAGE PRESSURE ADJUSTED TO DATUM OF + 1195'	FLUID LEVEL	FLUID COLUMN ABOVE 6300'	AVERAGE DENSITY OF FLUID COLUMN #/in²/ft	CUMULATIVE PRODUCTION M BBLS.
6-17-65		1585.8 (Run 1) 1587.5 (Run 2)	1596.7	1482.7				
6-25-65		1598.7	1598.7	1494.7				
7- 2-65	1600.4		1600.4	1496.4				
7- 8-65		1606.0	1606.0	1502.0				
7-19-65	1608.3	1607.3	1607.8	1503.8				
8-11-65	1611.2	1609.4	1610.3	1506.3	1481	4819	.3342	309
8-27-65	1606.3	1604.9	1605.6	1501.6	1497	4803	.3343	
9-13-65	1601.5	1600.2	1600.9	1496.9	1517	4783	.3347	
9-29-65	1598.1	1597.4	1597.8	1493.8	1529	4771	.3349	
10-14-65	1588.3	1585.9	1587.1	1483.1	1558	4742	.3347	
10-26-65	1585.5	1583.9	1584.7	1480.7	1575	4725	.3354	
11- 8-65	1580.8	1577.6	1579.2	1475.2	1592	4708	.3354	365
12- 5-65	1566.0	1569.9	1567.9	1463.9	1637	4663	.3362	
12-21-65	1559.6	1559.0	1559.3	1455.3	1663	4637	.3363	420
2-15-66	1541.0	1542.6	1541.8	1437.8	1725	4575	.3370	480
5-13-66	1522.8	1524.1	1523.5	1419.5	1768	4532	.3362	562

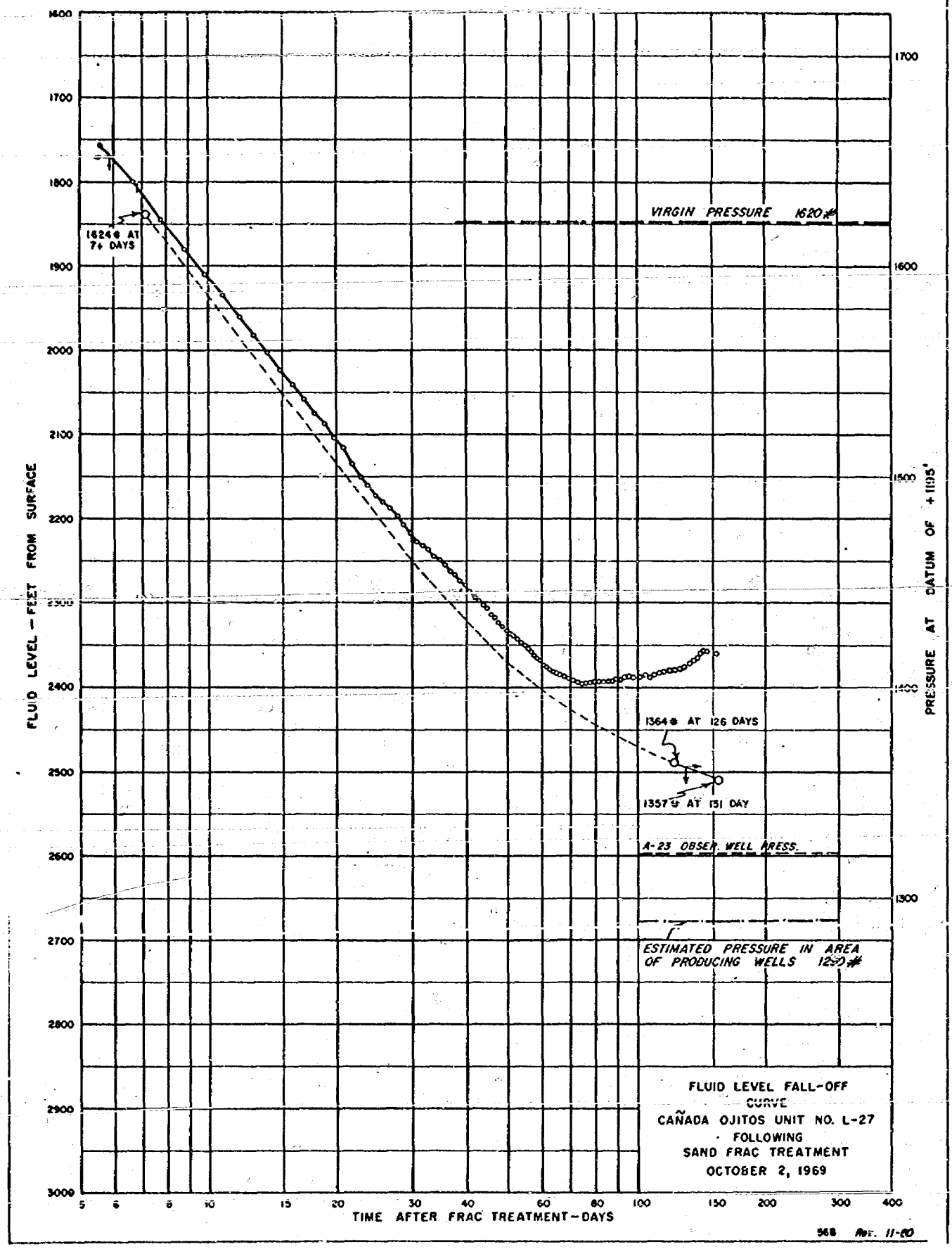
SURVEY DATE	PRESSURE (PSIG) AT 6300' (RKB) FOR PRESSURE GAUGE INDICATED AMERADA #42	AMERADA #43	AVERAGE	AVERAGE PRESSURE ADJUSTED TO DATUM OF + 1195'	FLUID LEVEL	FLUID COLUMN ABOVE 6300'	AVERAGE DENSITY OF FLUID COLUMN #/in²/ft	CUMULATIVE PRODUCTION M BBLS.
8-30-66	1509.9	1510.2	1510.2	1406.0	1812	4488	.3364	660
3-28-67	1484.4	1482.8	1483.6	1379.6	1895	4405	.3368	880
3-20-68	1434.0	1435.5	1434.8	1330.8	2058	4242	.3382	1,203
8-10-68	Estimated from fluid level		1409	1305	2130	4170	.3380	1,360
3-27-69	1446.0	1445.1	1445.6	1341.6	1992	4308	.3356	1,615
6-18-69	1434.6	1434.3	1434.4	1330.4	2009	4291	.3343	1,755
10- 9-69	1429.5	1426.6	1428.0	1324.0	2031	4269	.3345	1,893
11- 4-69	1426.9	1428.5	1427.7	1323.7	2017	4283	.3333	1,929
12- 1-69	No good	1423.7	1423.7	1319.7	2003½	4296	.3314	1,964
2- 5-70	1426.4	1424.0	1425.2	1321.2	2004	4296	.3318	2,076
3- 2-70	1427.0	1422.6	1424.8	1320.8	1995	4305	.3310	2,120
5- 2-70	No good	1423.1	1423.1	1319.1	2027½	4272.5	.3331	2,240
7- 8-70	Not run	1415.2	1415.2	1311.2	2046½	4253.5	.3327	2,370
8-28-70	1412.2	1410.8	1411.5	1307.5	2058	4242	.3327	2,472
10-12-70	1412.8	1410.6	1411.7	1307.7	2063	4237	.3332	2,570
3-29-71	1404.2	1406.2	1405.2	1301.2	2083	4217	.3332	2,914
6- 1-71	1403.6	1401.6	1402.6	1298.6	2082½	4217.5	.3326	2,997
8- 9-71	1401.2	1403.2	1402.2	1298.4	2087½	4222.5	.3321	3,147
11-24-71	1394.2	1399.0	1396.6	1292.6	2122½	4177.5	.3343	3,385
4- 3-72	1362.8	1359.4	1361.1	1257.1	2241	4059	.3353	3,676

BOTTOM HOLE PRESSURE SUMMARY
CANALA OJITOS UNIT L-27

(following frac treatment October 2, 1969 and prior to production April, 1970)

ELEVATION 7465' RKB

	10-9-69	2-5-70	3-2-70
Days after frac	7	126	151
Pressure at measured depth of 6900':			
Amerada #42 (psig)	1817.4	1560.3	1554.4
Amerada #43 (psig)	1813.0	1558.5	1551.2
Average (psig)	1815.2	1559.4	1552.8
Estimated average gradient to depth of 7030' (#/Sq.in./ft)	.351	.321	.317
Pressure differential 6900' to 7030'	45.8	41.7	41.3
Pressure at 7030'	1861.0	1601.1	1594.1
Pressure differential to datum of + 1195 (760' x .312)	- 237.1	- 237.1	- 237.1
Datum (+ 1195) pressure	1623.9	1364.0	1357.0
Pressure differential from virgin pressure of 1620 psig	+ 3.9	- 256.0	- 263.0
Pressure difference from static pressure in A-23 of approximately 1325#	+ 299	+ 39	+ 32

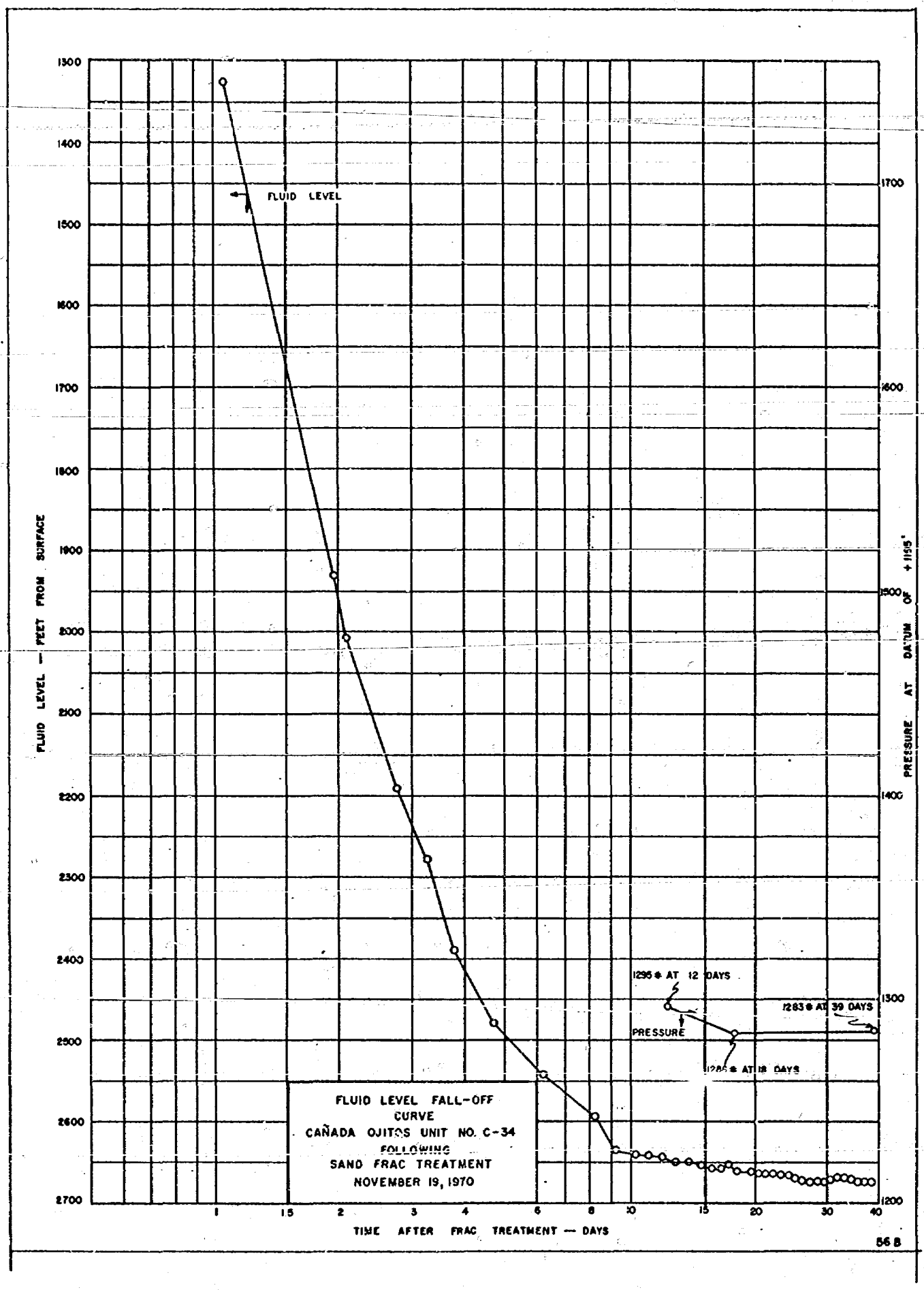

FLUID LEVEL – FEET FROM SURFACE
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
2600
2700
2800
2900
3000
PRESSURE AT DATUM OF +1195'
1700
1600
1500
1400
1300
VIRGIN PRESSURE 1620#
1624# AT 7½ DAYS
1364# AT 126 DAYS
1357# AT 151 DAY
A-23 OBSER. WELL PRESS.
ESTIMATED PRESSURE IN AREA OF PRODUCING WELLS 1250#
5 6 8 10 15 20 30 40 60 80 100 150 200 300 400
TIME AFTER FRAC TREATMENT – DAYS
FLUID LEVEL FALL-OFF CURVE
CAÑADA OJITOS UNIT NO. L-27
FOLLOWING
SAND FRAC TREATMENT
OCTOBER 2, 1969
568 REV. 11-60

BOTTOM HOLE PRESSURE SUMMARY
CANADA OJITOS UNIT C-34

(following frac treatment November 19, 70 and prior to production)

ELEVATION 7427' RKB

	12-1-70	12-7-70	12-28-70
Days after frac	12	18	39
Pressure at measured depth of 6800' RKB:			
Amerada #42 (psig)	1469.3	1460.9	1457.3
Amerada #43 (psig)	1468.2	1458.8	1456.4
Average (psig)	1468.7	1459.8	1456.8
Estimated average gradient to depth of 6900' (#/in^2/ft)	.344	.343	.342
Pressure differential 6800' to 6900' (psig)	34.4	34.3	34.2
Pressure at 6900' RKB (datum + 527')	1503.1	1494.1	1491.0
Pressure differential to datum of + 1195 (668' x .312#/in^2/ft)	208.4	208.4	208.4
Datum (+ 1195) pressure	1294.7	1285.7	1282.6
Pressure differential from virgin pressure of 1620 psig	325.3	334.3	337.4
Pressure differential from static pressure in A-23 observation well of approximately 1325#	- 10.3	- 19.3	- 22.4


FLUID LEVEL — FEET FROM SURFACE
1300
1400
1500
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
2600
2700
FLUID LEVEL
1296 # AT 12 DAYS
1283 # AT 39 DAYS
PRESSURE
1285 # AT 18 DAYS
PRESSURE AT DATUM OF +1151'
1700
1600
1500
1400
1300
1200
1
1.5
2
3
4
6
8
10
15
20
30
40
TIME AFTER FRAC TREATMENT — DAYS
FLUID LEVEL FALL-OFF CURVE
CAÑADA OJITOS UNIT NO. C-34
FOLLOWING
SAND FRAC TREATMENT
NOVEMBER 19, 1970
56 B

R I W

R I E

PLAT OF
CAÑADA OJITOS UNIT

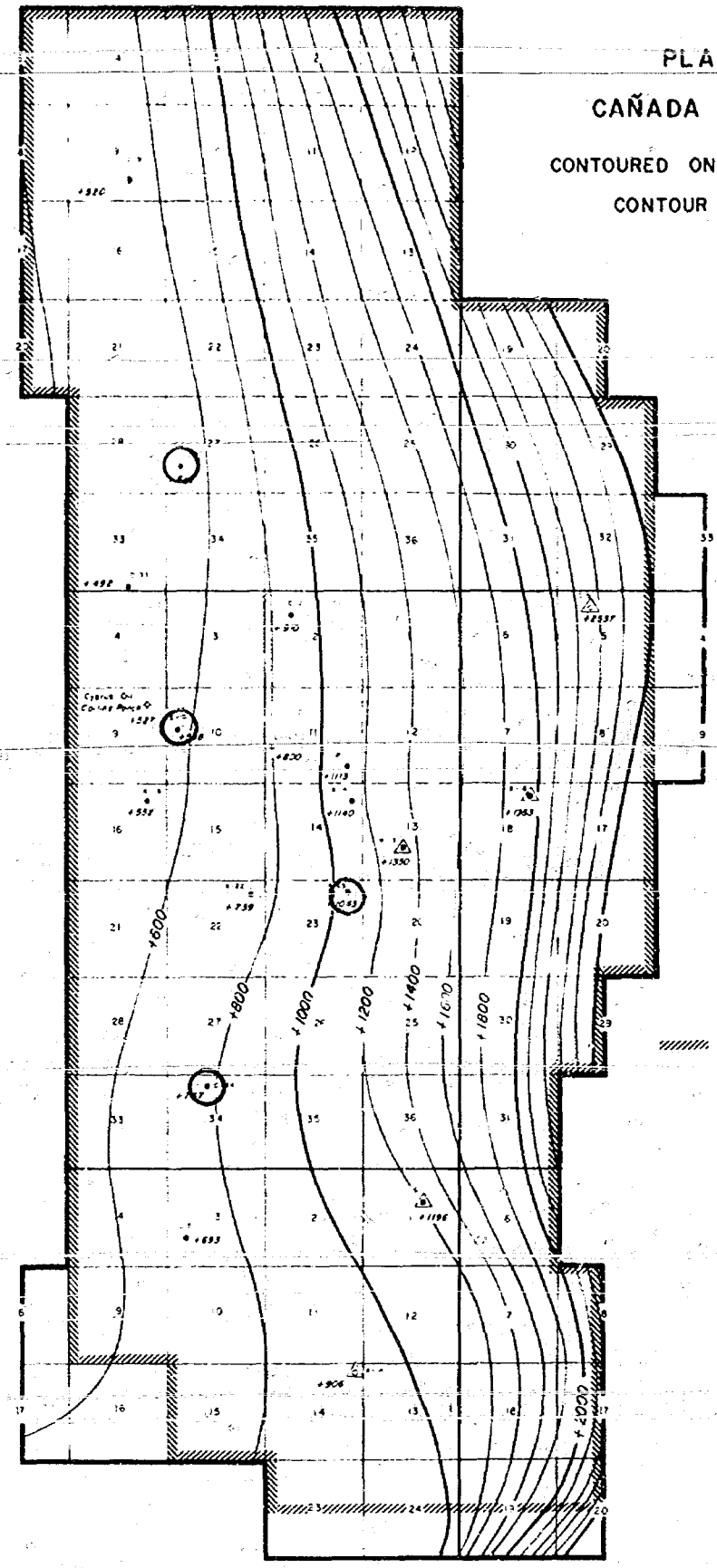
CONTOURED ON TOP OF ZONE "A"

CONTOUR INTERVAL 200'

T
26
N

T
25
N

T
24
N



BOUNDARY OF NIOBRARA - GREENHORN PARTICIPATING AREA AFTER PROPOSED 12 TH EXPANSION

CANADA QUITOS UNIT
OIL RECOVERY ESTIMATE
ASSUMING CONTINUED OPERATION OF PRESSURE MAINTENANCE PROGRAM AND GRAVITY DRAINAGE DEPLETION

November, 1980

	ESTIMATE RANGE From (MM bbls)	To (MM bbls)
Total Initial Oil in place	30	50
In high capacity fracture system (1/2)	15	25
In "tight blocks" (1/2)	15	25
Recovery from high capacity system 55%	8.2	13.8
Recovery from tight blocks 25%	3.8	6.2
Total recovery	12.0	19.0
Produced to 1981	6.6	6.6
Remaining future from 1981	5.4	12.4
	(Use 5	to 10)

CALCULATION OF OIL IN PLACE

NIOBRARA RESERVOIR

CANADA OJITOS UNIT

The following described method of calculating oil in place in the Canada Ojitos Unit was used in applications to the United States Geological Survey regarding enlargement of the participating areas for the 7th, 8th and 9th expansions. From the calculations of total oil in place as shown here, and from the volumes of per-acre oil in place determined from interference tests, it was estimated at that time that the reservoir probably covered an area of 40,000 to 50,000 acres, even though at that time the drilled area (cf. Plate IV-7 herein) outlined only about 15,000 acres.

Subsequent development confirmed the larger area. The participating area now covers approximately 53,000 acres.

DESCRIPTION OF METHOD OF CALCULATING OIL IN PLACE

CANADA OJITOS UNIT

Initial oil in place in the Canada Ojitos Unit was estimated from compressibilities of the various reservoir characteristics and the production-pressure relation of 3,000 barrels per pound which was observed from October, 1964 to July, 1965, and for the production-pressure coefficient of 6,000 barrels per pound which occurred during the time period May, 1966 to October, 1966.

For the time when the coefficient was 3,000 barrels per pound it is believed that the amount of oil that was undersaturated would be in the range of .8 to .95 of total reservoir volume. The oil in place for this coefficient is shown on the plat next following identified as Plate IV-3. This is for formation compressibility (C_f) ranging from 7×10^{-6} to 23×10^{-6} and free gas saturation ranging from zero to 5 percent of pore space. The relation for .8 to .95 fraction of the oil that was undersaturated is shown by the area colored in green.

The same information is shown on Plate IV-4 for the time period when the coefficient was 6,000 barrels per pound and the fraction of total oil assumed to be undersaturated is in the range of .4 to .8.

The main indefinite factors in estimating the oil in place are the unknown compressibility of the formation and the unknown fraction of the reservoir which initially contained free gas. In order to narrow the range of estimates, calculations were made taking advantage of the fact that compressibilities changed from one period to the next yet presumably the compressibility of the formation and the volume of the gas cap were the same. This allows a calculation

in which the effect of the gas cap and the formation compressibility are combined; and since, for the purpose of determining total oil in place it makes no difference what the individual compressibilities are, it then becomes possible, by assuming a compressibility for the formation, to calculate the amount of free gas initially existing.

This is accomplished by first determining the relation of compressibility of saturated oil and gas released from it as pressure drops. This is shown on Plate IV-5 herein.

The location of the bubble point pressure (1520 psig) as it moves downdip on the structure is shown herein on Plate IV-6.

Statistics resulting from location of the bubble point pressure are shown herein on Plate IV-9.

By assuming various combinations of fraction of undersaturated oil for the first condition and the second condition one can calculate the amount of free gas; and from this to calculate compressibility - and from this the volume of oil in place. A sample calculation is shown herein on Plate IV-10. A series of these calculations permits the construction of the relations shown on the graph IV-8.

Estimates of oil in place were made under six separate assumed situations. These are described below by number and shown by colored circles on the Plate IV-8:

Situation No. 1:

This assumes 87% of oil was undersaturated under Condition No. 1 and 72% under Condition No. 2. This results if the per acre oil in place to varies with structural position as shown herein on Plate IV-7.

Situation No. 2:

This assumes reservoir oil in place was as shown on Plate IV-7 except that the downdip boundary of the reservoir is assumed to be the west side of the green-colored area. The area colored in brown is assumed to be non-productive. This results in fraction of undersaturated oil under the first condition to be 85% and under the second condition to be 67%.

Situation No. 3:

This assumes the reservoir to extend across the colored area with an equal per-acre volume of oil in place throughout. This results in fraction of oil undersaturated in the first condition of 64% and under the second condition 66%.

Situation No. 4:

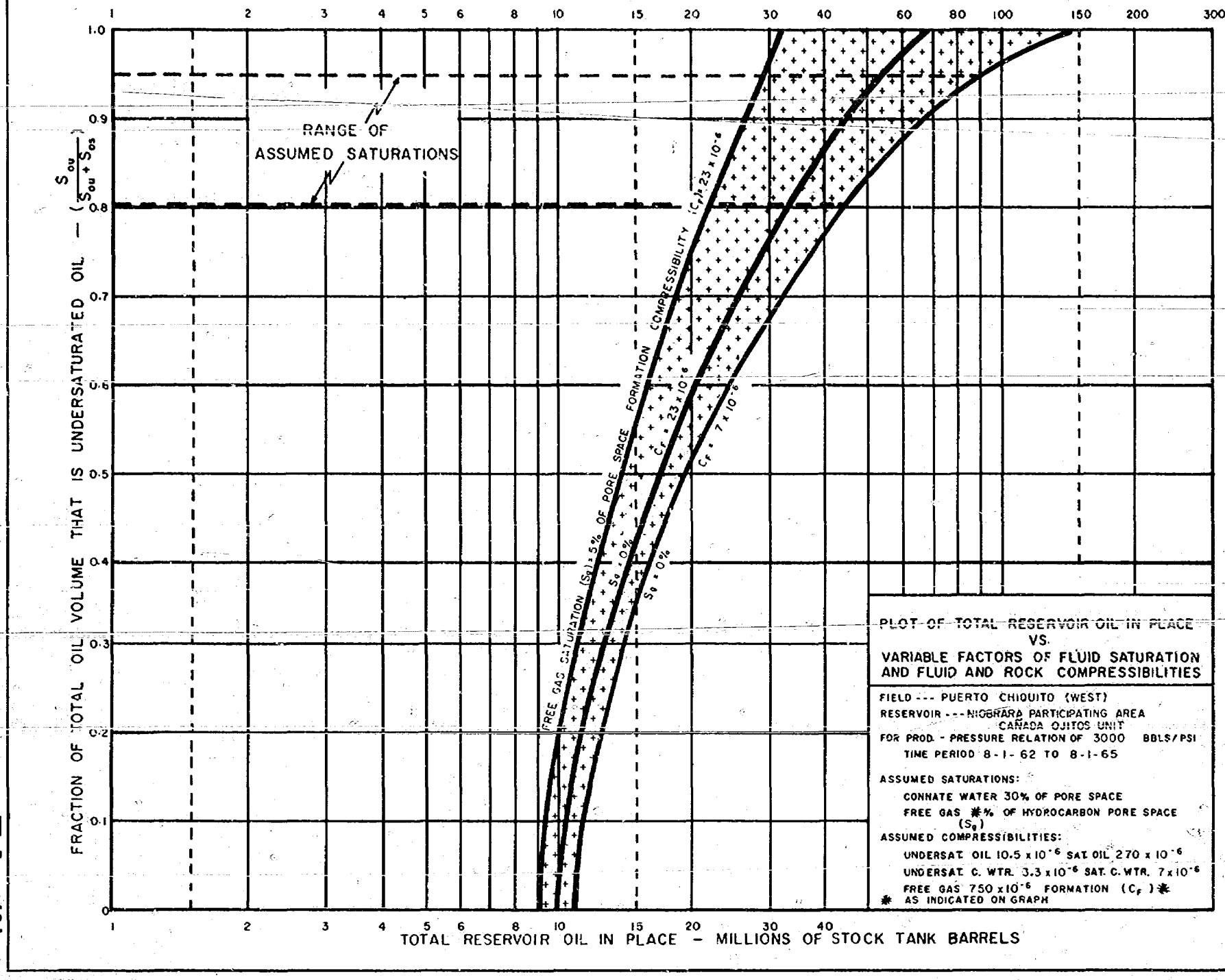
This assumes equal per-acre volume of oil in place with the downdip boundary being the west side of the green-colored area on Figure IV-7 and extending up to the 1600-foot contour interval. This results in fraction of the oil undersaturated under the first condition to be 80% and under the second condition 56%.

Situation No. 5:

This assumes the downdip limit of the reservoir to be the west boundary of the green-colored area on Plate IV-7 and the updip limit of the reservoir to be at the 1500-foot contour interval (rather than 1600-foot), with oil in place values as shown on Figure IV-7 and assuming the 1500 barrels per acre extends from the 1600-foot contour interval to the 1500-foot contour interval. This results in fraction of oil undersaturated under the first condition to be 91% and under the second to be 73%.

Situation No. 6:

This assumes east and west reservoir limits the same as in Situation No. 5 above, but with equal per-acre volumes of oil in place. This results in fraction of oil undersaturated under the first condition of 88% and under the second condition of 61%.



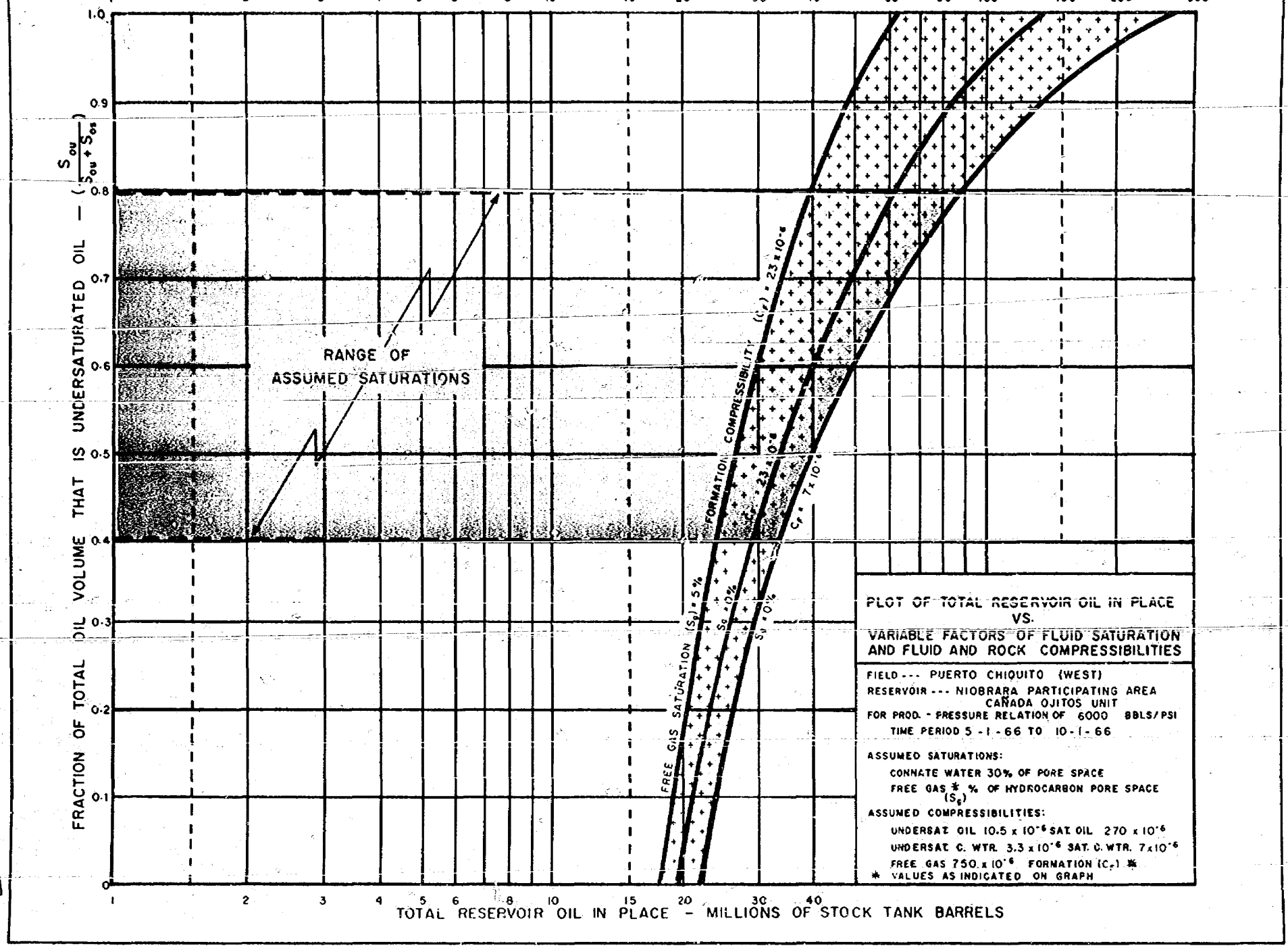
PLOT OF TOTAL RESERVOIR OIL IN PLACE
VS.
VARIABLE FACTORS OF FLUID SATURATION AND FLUID AND ROCK COMPRESSIBILITIES

FIELD --- PUERTO CHIQUITO (WEST)
RESERVOIR --- NIOBRARA PARTICIPATING AREA
CAÑADA OJITOS UNIT
FOR PROD. - PRESSURE RELATION OF 3000 BBLS/PSI
TIME PERIOD 8-1-62 TO 8-1-65

ASSUMED SATURATIONS:
CONNATE WATER 30% OF PORE SPACE
FREE GAS ✱% OF HYDROCARBON PORE SPACE (S_g)

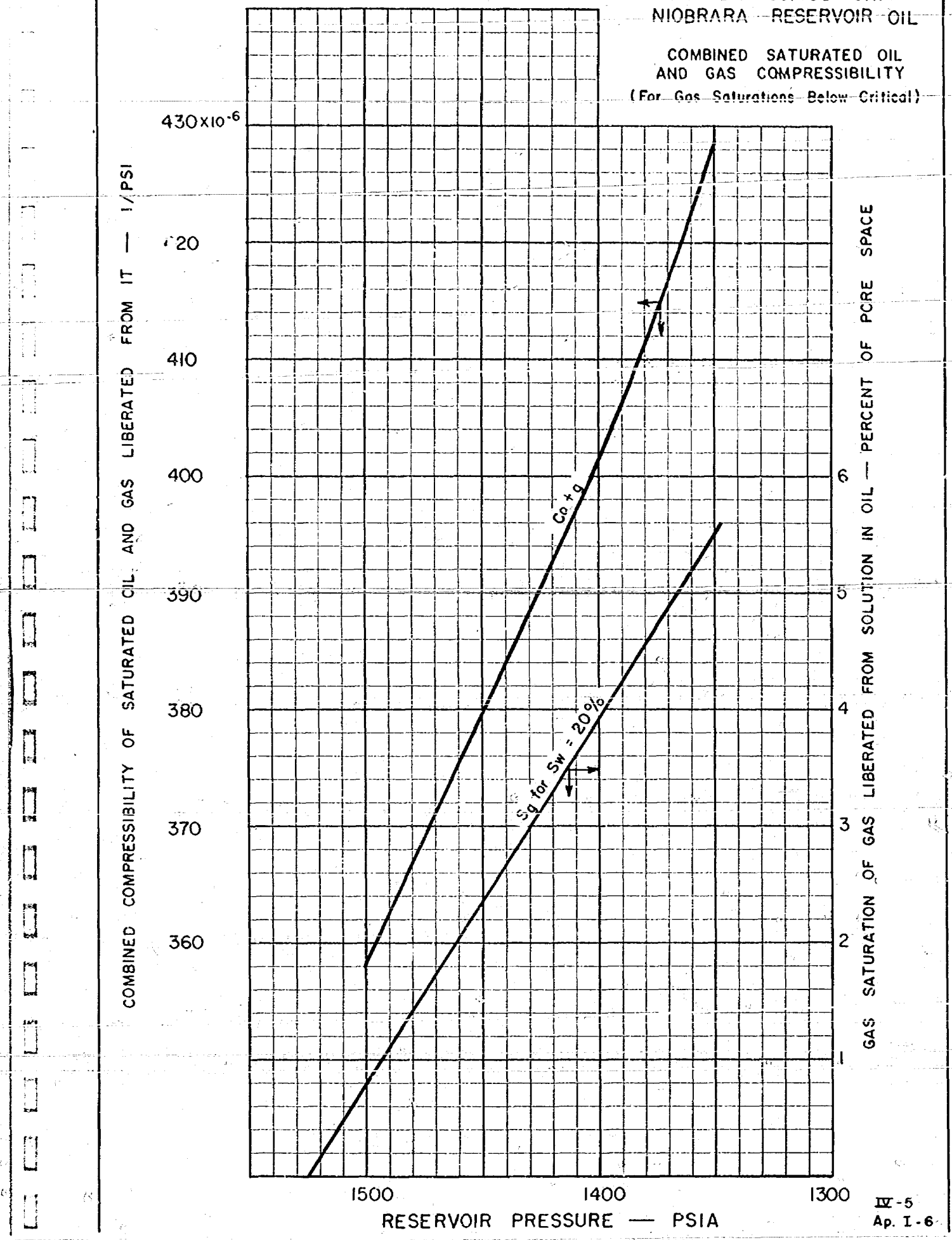
ASSUMED COMPRESSIBILITIES:
UNDERSAT. OIL 10.5×10^{-6} SAT. OIL 270×10^{-6}
UNDERSAT. C. WTR. 3.3×10^{-6} SAT. C. WTR. 7×10^{-6}
FREE GAS 750×10^{-6} FORMATION (C_f) ✱
✱ AS INDICATED ON GRAPH

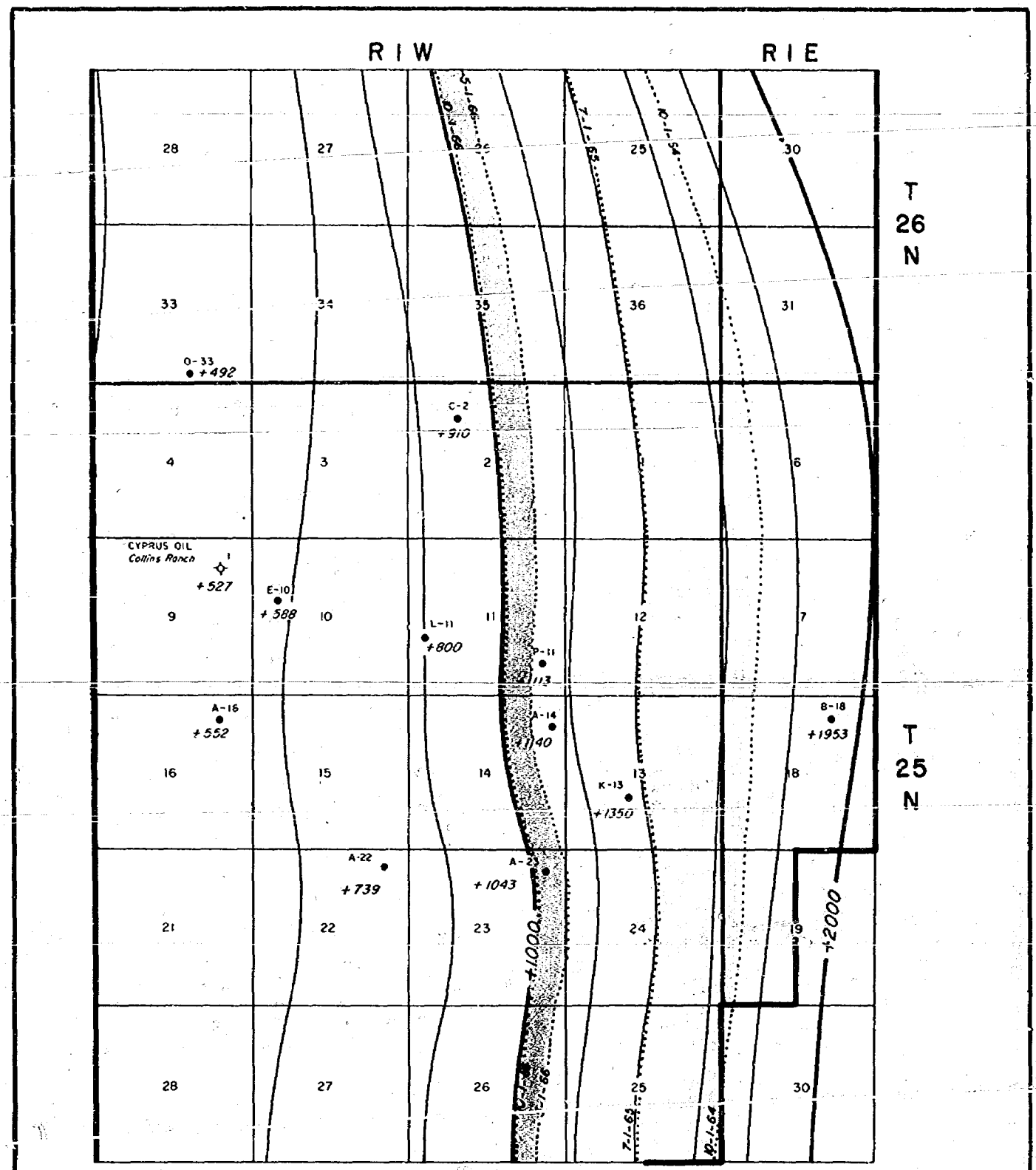
IV-3
42A


FRACTION OF TOTAL OIL VOLUME THAT IS UNDERSATURATED OIL — $(\frac{S_{ou}}{S_{ou}+S_{os}})$
TOTAL RESERVOIR OIL IN PLACE - MILLIONS OF STOCK TANK BARRELS
RANGE OF ASSUMED SATURATIONS
FREE GAS SATURATION (S_g) = 5%
S_g = 2%
S_g = 0%
FORMATION COMPRESSIBILITY (C_f) = 23 x 10⁻⁶
C_f = 23 x 10⁻⁶
C_f = 7 x 10⁻⁶
PLOT OF TOTAL RESERVOIR OIL IN PLACE VS. VARIABLE FACTORS OF FLUID SATURATION AND FLUID AND ROCK COMPRESSIBILITIES
FIELD --- PUERTO CHIQUITO (WEST)
RESERVOIR --- NIOBRARA PARTICIPATING AREA CAÑADA OJITOS UNIT
FOR PROD. - PRESSURE RELATION OF 6000 BBLS/PSI
TIME PERIOD 5 - 1 - 66 TO 10 - 1 - 66
ASSUMED SATURATIONS:
CONNATE WATER 30% OF PORE SPACE
FREE GAS * % OF HYDROCARBON PORE SPACE (S_g)
ASSUMED COMPRESSIBILITIES:
UNDERSAT OIL 10.5 x 10⁻⁶ SAT OIL 270 x 10⁻⁶
UNDERSAT C. WTR. 3.3 x 10⁻⁶ SAT. C. WTR. 7x10⁻⁶
FREE GAS 750. x 10⁻⁶ FORMATION (C_f) *
* VALUES AS INDICATED ON GRAPH

CAÑADA OJITOS UNIT
NIOBRARA RESERVOIR OIL

COMBINED SATURATED OIL AND GAS COMPRESSIBILITY
(For Gas Saturations Below Critical)





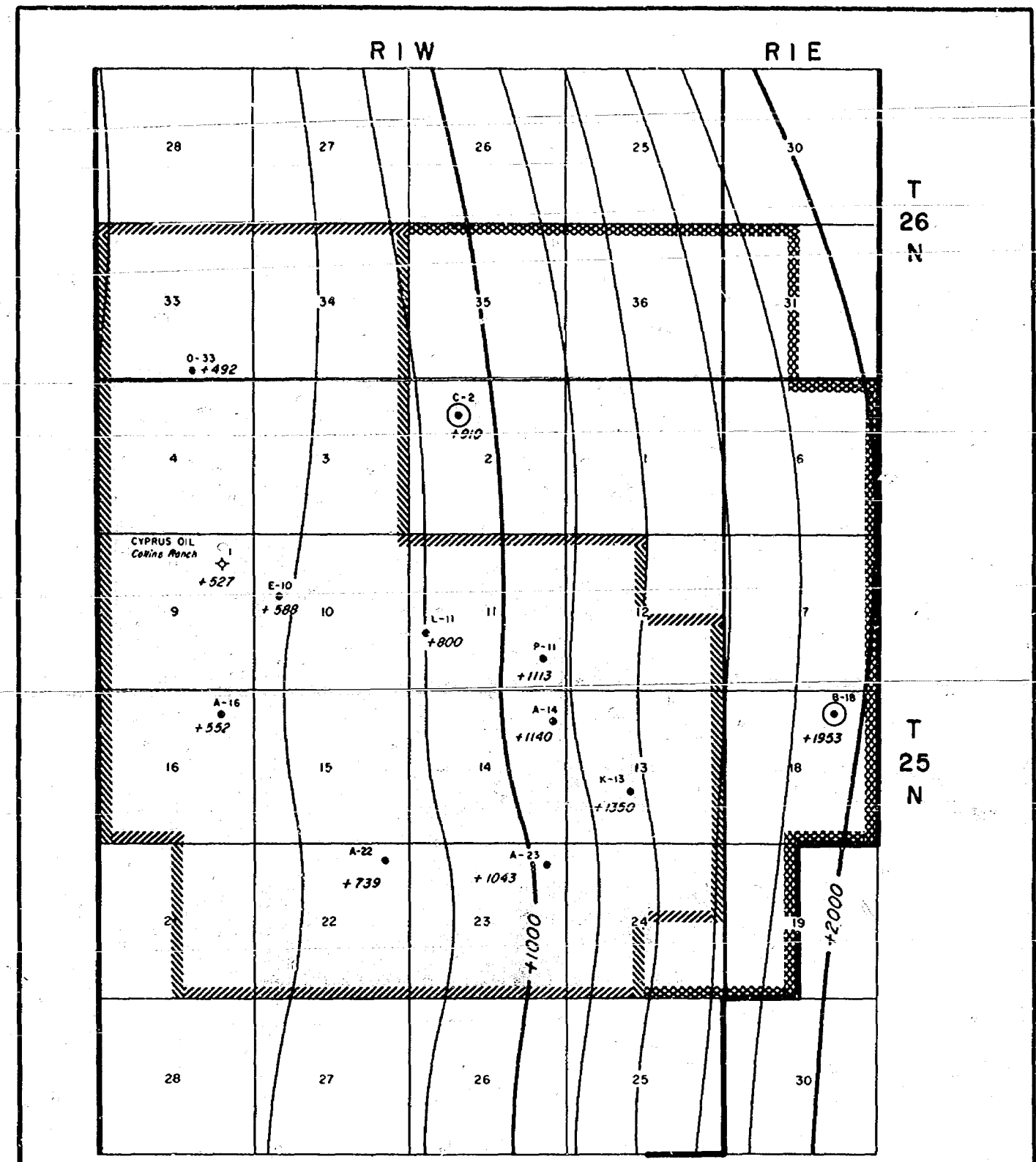
PLAT OF PART OF CAÑADA OJITOS UNIT

SHOWING MOVEMENT OF BUBBLE POINT PRESSURE
CONTOURED ON TOP OF ZONE "A"

CONTOUR INTERVAL 200'

..... LOCATION OF BUBBLE POINT PRESSURE AT DATE INDICATED

(TIME PERIOD: Oct. 1, 1964 To Oct. 1, 1966



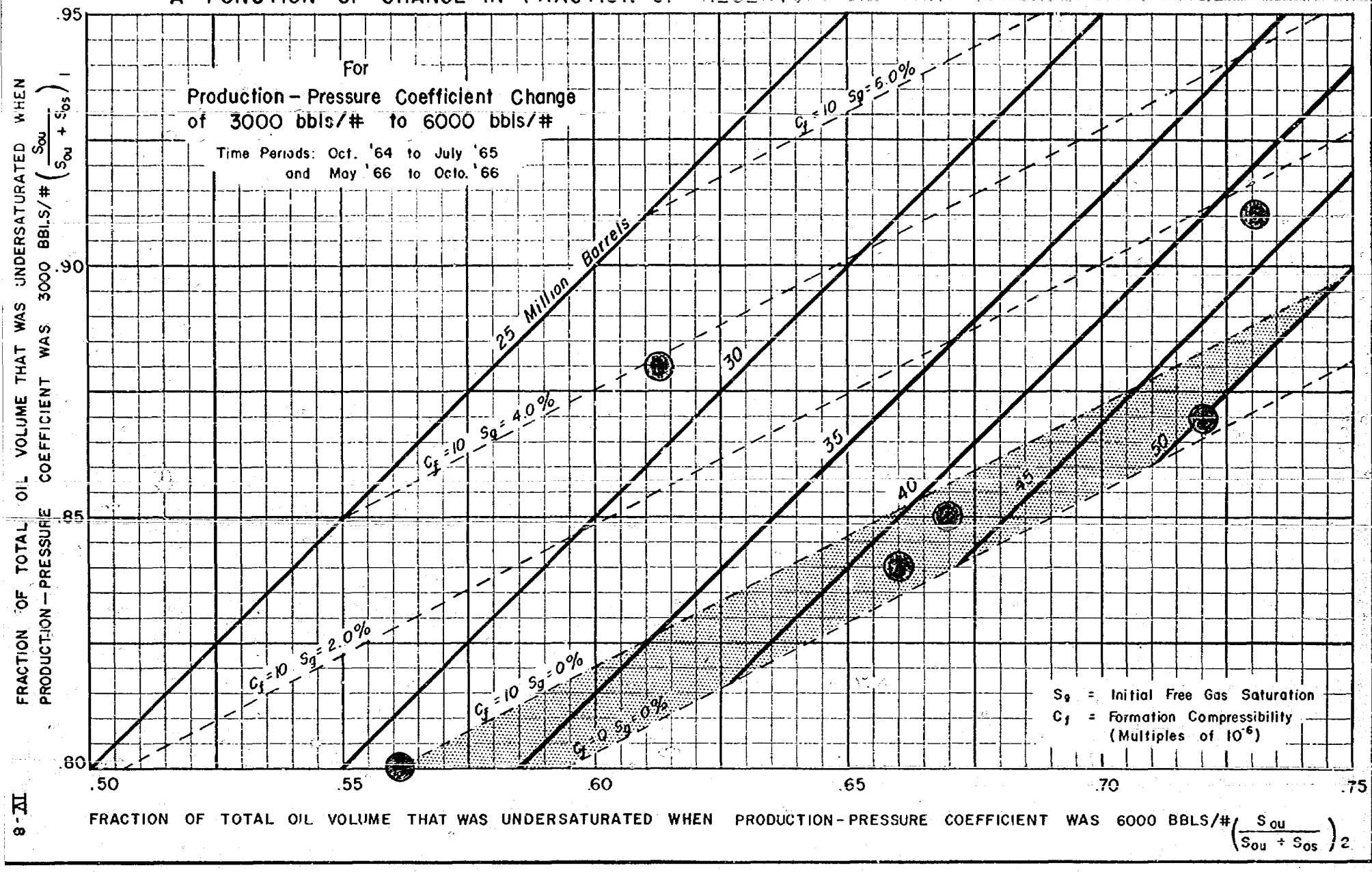
PLAT OF PART OF CAÑADA OJITOS UNIT
CONTOURED ON TOP OF ZONE "A"
CONTOUR INTERVAL 200'

PER ACRE OIL-IN-PLACE VALUES

- 1000 STOCK TANK BBLS.
- 1500 STOCK TANK BBLS.
- 2500 STOCK TANK BBLS

- BOUNDARY OF NIOBRARA - GREENHORN PARTICIPATING AREA AFTER PROPOSED SIXTH EXPANSION
- BOUNDARY OF PROPOSED SEVENTH EXPANSION TO PARTICIPATING AREA
- WELL WITHIN EXPANSION AREA DECEMBER, 1969 PROVIDING INFORMATION REGARDING EXPANSION

CAÑADA OJITOS UNIT
NIOBRARA RESERVOIR OIL IN PLACE
AS
A FUNCTION OF CHANGE IN FRACTION OF RESERVOIR OIL THAT IS UNDERSATURATED



IX-8

INFORMATION USED IN ESTIMATING CANADA OJITOS UNIT OIL IN PLACE

		FIRST CONDITION	SECOND CONDITION
	Time period	October '64 to July '65	May '66 to October '66
	Pressure productivity coefficient	3000 bbl/#	6000 bbl/#
1)	Average reservoir pressure at 1195' datum	1530 psig	1422 psig
2)	Reservoir pressure at 1600' contour point (reservoir datum at 1600' contour point is 1650 - 150 = 1450 and 1450 - 1195 = ± 250) (1st) 1530 - (250) (.312) = 1452 (2nd) 1422 - (250) (.312) = 1344	1452 psig	1344 psig
3)	Contour point datum of bubble point pressure (1st) $\frac{1530 - 1520}{.312} + 1350 = 1382$ (2nd) $1350 - \frac{1520 - 1422}{.312} = 1036$	1382'	1036'
4)	Average pressure saturated oil	$\frac{1520 + 1452}{2}$ = 1486 psig = 1498 psia	$\frac{1520 + 1344}{2}$ = 1432 psig = 1444 psig
5)	Compressibility of combined saturated oil and gas liberated from it for average pressures of 1490 and 1444 (figure IV-5)	359×10^{-6}	383×10^{-6}
6)	Approximate average reservoir pressure of undersaturated oil (500' contour interval to bubble point contour)	1610 psig	1590 psig
7)	Compressibility of undersaturated oil	11.25×10^{-6}	11.35×10^{-6}

Example calculation on next page (pencilled notes) assumes that under first condition 90% of the oil was undersaturated and under the second condition that 70% was undersaturated:

Reservoir Characteristics	FIRST CONDITION Compressibility	Saturation	SECOND CONDITION Compressibility	Saturation
Undersaturated Oil	11.25×10^{-6}	90% of oil	11.35×10^{-6}	70% of oil
Saturated Oil	359×10^{-6}	10% of oil	383×10^{-6}	30% of oil
Connate Water	3.8×10^{-6}	20% of pore space	4.4×10^{-6}	20% of pore space
Free Gas	765×10^{-6}	Unknown	817×10^{-6}	Unknown
Formation	10×10^{-6}	-	10×10^{-6}	-

EXAMPLE CALCULATION
EQUATION 5 of EXHIBIT (1) of
the 1964 hearing in case 3455
applies:

$$C_e = \frac{S_{ow} C_{ow} + S_{os} C_{os} + S_g C_g + S_w C_w + C_f}{S_{ow} + S_{os}}$$

$1 - cw = 1 - .2 = .8$; x = unknown sat. of free gas

S_{o4_1} = 90% of oil $= .9(.8 - x) = .72 - .9x$

S_{os_1} = 10% of oil $= .1(.8 - x) = .08 - .1x$

S_{o4_2} = 70% of oil $= .7(.8 - x) = .56 - .7x$

S_{os_2} = 30% of oil $= .3(.8 - x) = .24 - .3x$

$$C_{e_1} = \left[\frac{(.72 - .9x)(11.25) + (.08 - .1x)(359) + 765x + (.2)(3.5) + 10}{(.8 - x)}\right] \times 10^{-6}$$

$$= \frac{(47.6 + 719.0x)}{(.8 - x)} \times 10^{-6}$$

$$C_{e_2} = \left[\frac{(.56 - .7x)(11.35) + (.24 - .3x)(383) + 817x + (.2)(4.4) + 10}{(.8 - x)}\right] \times 10^{-6}$$

$$= \frac{(109.2 + 694.1x)}{(.8 - x)} \times 10^{-6}$$

$C_{e_2} = \left(\frac{6000}{3000}\right)(C_{e_1}) = 2\,C_{e_1}$

$109.2 + 694.1x = 2(47.6 + 719x)$ $\quad x = 1.9\%$

$C_{e_1} = (47.6 + 719 \times .019)\left(\frac{1}{8 - .019}\right) 10^{-6} = 78.1 \times 10^{-6}$

$N = N_p / C_e = 3000 \div (78.1 \times 10^{-6}) = 38.4$ MM bbls

TV-12

AMOUNT OF HORIZONTAL DEVIATION OF WELLS

SURFACE TO TOTAL DEPTH (NIOBRARA)

FOR

WELLS IN WEST PORTION OF CANADA OJITOS UNIT

WELL	LOCATION	MEASURED DATA LOWEST SURVEY DEPTH, (ft)	MEASURED DATA LOWEST SURVEY HORIZONTAL DISPLACEMENT (ft)	ESTIMATED FOR T.D. OF (ft)	ESTIMATED HORIZONTAL DISPLACEMENT (ft)
O-9	SE 9-26N-1W	7820	196.8	(below Niobrara)	
L-27	SW 27-26N-1W	6945	124.2	7248	134.5
O-33	SE 33-26N-1W	7360	189.6	7371	189.6
E-10	NW 10-25N-1W	6930	133.7	7064	138.4
A-16	NE 16-25N-1W	7500	183.5	7521	185.3
C-34	NW 34-25N-1W	6767	200.9	6990	218.4
L-3	NW 3-24N-1W	7120	120.0	7148	121.0

6-9

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. He is Vice-President of Benson-Montin-Greer Drilling Corp.

2. He supervised the drilling of the Benson-Montin-Greer Drilling Corp. No. 1 (0-9) Canada Ojitos Unit, located in the southwest quarter of Section 9, Township 26 North, Range 1 West, Rio Arriba County, New Mexico.

3. During the drilling of this well, the following deviation surveys were made:

½°	at 310'	
1°	at 1150'	
1½°	at 2860'	
2°	at 2981'	
2¼°	at 3458'	
3°	at 3714'	
2°	at 4580'	
1½°	at 5822'	
1°	at 6350'	Hor. Dev.
1°	at 7281'	196.8'
1¼°	at 7820'	
1¼°	at 7860'	(below Niobrara)
2°	at 8522'	

Virgil L. Stoabs

Subscribed and sworn to before me, a Notary Public in and for the State of New Mexico, this 12th day of March, 1973.;

My Commission Expires
August 4, 1974

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

L-27

VIRGIL L. STOABS, of legal age, after first being sworn on oath, deposes and states:

1. That he is Vice-President of Benson-Montin-Greer Drilling Corp., operator of the Canada Ojitos Unit Well No. 13 (L-27) located in Section 27, Twp. 26N, Rge. 1W, Rio Arriba County, New Mexico.

2. That he supervised operations for the drilling of the subject well.

3. That during drilling operations the following deviation surveys were run:

200'	1°
1138'	1
2043	1/2
2931'	1/2
3684'	3/4
4448'	1
5164'	2
5322'	1-1/4
5480'	1-1/4
6111'	1-1/4
6393'	3/4
6654'	3
6945'	2

DEV. HOR. 6.45 @ 124.2'

Est. 134.8'
@ 7248
T.D.

Virgil L. Stoabs

Subscribed and sworn to before me, a Notary Public in and for said county and state, this 7th day of April, 1970.

Notary Public

My Commission Expires
August 20, 1970

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

0-33

1. That he is engineer for Benson-Montin-Greer Drilling Corp., operator of the Canada Ojitos Unit Well NP No. 10, located 175' from the south line and 2090' from the east line of Section 33, Twp. 26N, Rge. 1W, Rio Arriba County, New Mexico.

2. That he supervised operations for the drilling of the subject well.

3. That during drilling operations the following deviation tests were taken:

At	420'	2°
	1070'	1
	1700'	2-1/2
	2320'	2
	2840'	1
	3550'	1-1/2
	4414'	1
	4800'	3/4
	5142'	1
	5412'	1-1/2
	5590'	2
	5998'	1/2
	6397'	1
	6688'	2
	6850'	2-1/4
	6923'	2
	7019'	3
	7235'	2-1/2
	7360'	3-1/4

Hor. Dev. 189.6' T.D. 7371'

Virgil L. Stoabs

Subscribed and sworn to before me this _____ day of March, 1967.

Notary Public in and for
San Juan County, New Mexico

My Commission Expires
August 20, 1970

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

E-10
T-25-N

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. That he is Vice-President of Benson-Montin-Greer Drilling Corp., operator of the Canada Ojitos Unit Well No. 11 (E-10) in Section 10, Twp. 25N, Rge. 1W, Rio Arriba County, New Mexico.

2. That he was in charge of operations for the drilling of the subject well.

3. That during drilling operations the following deviation surveys were run:

At 567'	2°
687'	1-1/4
1533'	1
1733'	1
2381'	1-1/4
3009'	1-1/2
3823'	3/4
4009'	1
4970'	1/2
5715'	1-1/2
6500'	1-1/4
6611'	1-1/4
6800'	2-1/4
6930'	2

Hole P/U 133.67

Est. 1384 @ 7064 T.D.

Virgil L. Stoabs

SUBSCRIBED AND SWORN to before me, a Notary Public in and for said county and state, this 21st day of September, 1967.

Notary Public

My Commission Expires
August 20, 1970

A-16

STATE OF NEW MEXICO }
} SS.
COUNTY OF SAN JUAN }

AFFIDAVIT

7521

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. That he is the engineer for Bolack-Greer, Inc., operator of the Canada Ojitos Unit Well No. 8 (A-16), located in the northeast quarter of Section 16, Twp. 25N, Rge. 1W, Rio Arriba County, New Mexico.

2. That he supervised operations for the drilling of this well.

3. That during the drilling sof this well, the following deviation surveys were run:

At 200'	3/4°
1109'	1
1620'	2-3/4
2100'	2
2385'	1
3240'	3/4
3905'	1/2
5150'	3/4
5650'	1/4
6098'	3/4
6545'	2
6726'	3-1/4
6817'	3-3/4
6880'	4-1/4
7044'	4-3/4
7280'	5-1/4
7500'	5

Hor. Dev.
(183.5' @ 7500'
Est 185.3 @ 7521
T.D.

Virgil L. Stoabs

Subscribed and sworn to before me, a Notary Public in and for said county and state, this ____ day of _____, 1966.

Notary Public

My Commission Expires
August 20. 1966

C-34

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. He is Vice-President of Benson-Montin-Greer Drilling Corp., operator of the Canada Ojitos Unit Well No. 14 (C-34) located in the northwest quarter of Section 34, Twp. 25N, Rge. 1W, Rio Arriba County, New Mexico.

2. That he was in charge of operations for the drilling of the subject well.

3. That during such drilling operations the following deviation tests were made:

1/2°	at	368'
1-3/4°	at	1000'
3/4°	at	1724'
1°	at	2165'
1°	at	2573'
2-1/2°	at	2833'
3/4°	at	2894'
1/4°	at	3129'
1/2°	at	3632'
3/4°	at	3865'
3-1/4°	at	4350'
3-3/4°	at	4645'
2-1/2°	at	5095'
1-3/4°	at	6110'
4°	at	6323'
4°	at	6430'
4°	at	6564'
4-1/2°	at	6767'

HOR DEV.
200.9' @ 6767

EST. 218.4 @ 6990 T.D.

Virgil L. Stoabs

Subscribed and sworn to before me, a Notary Public in and for said county and state, this 15th day of February, 1971.

Notary Public

My Commission Expires
August 4, 1974

STATE OF NEW MEXICO)
) SS.
COUNTY OF SAN JUAN)

AFFIDAVIT

L-3

VIRGIL L. STOABS, of legal age, being first duly sworn on oath, deposes and states:

1. That he is Vice-President of Benson-Montin-Greer Drilling Corp., a corporation organized under the laws sof the State of Delaware.

2. That he was in charge of operations for the drilling of Benson-Montin-Greer Drilling Corp. Canada Ojitos Unit Well No. 16 (L-3), in the SW¼ of Section 3, Twp. 24N, Rge. 1W, Rio Arriba County, New Mexico.

3. That during the drilling of this well the following deviation surveys were made:

At 210'	1/4°
404'	1/4
1447	3/4
2437'	1/2
3400'	1/2
4250'	3/4
4673'	1-1/4
5240'	1-1/2
5851'	2
6705'	1-3/4
7120'	2

H&R Dev. 120.0' @ 7120'
Est 121.0' @ 7145' T.D.

Virgil L. Stoabs

Subscribed and sworn to before me, a Notary Public in and for said county and state, this 24th day of August, 1971.

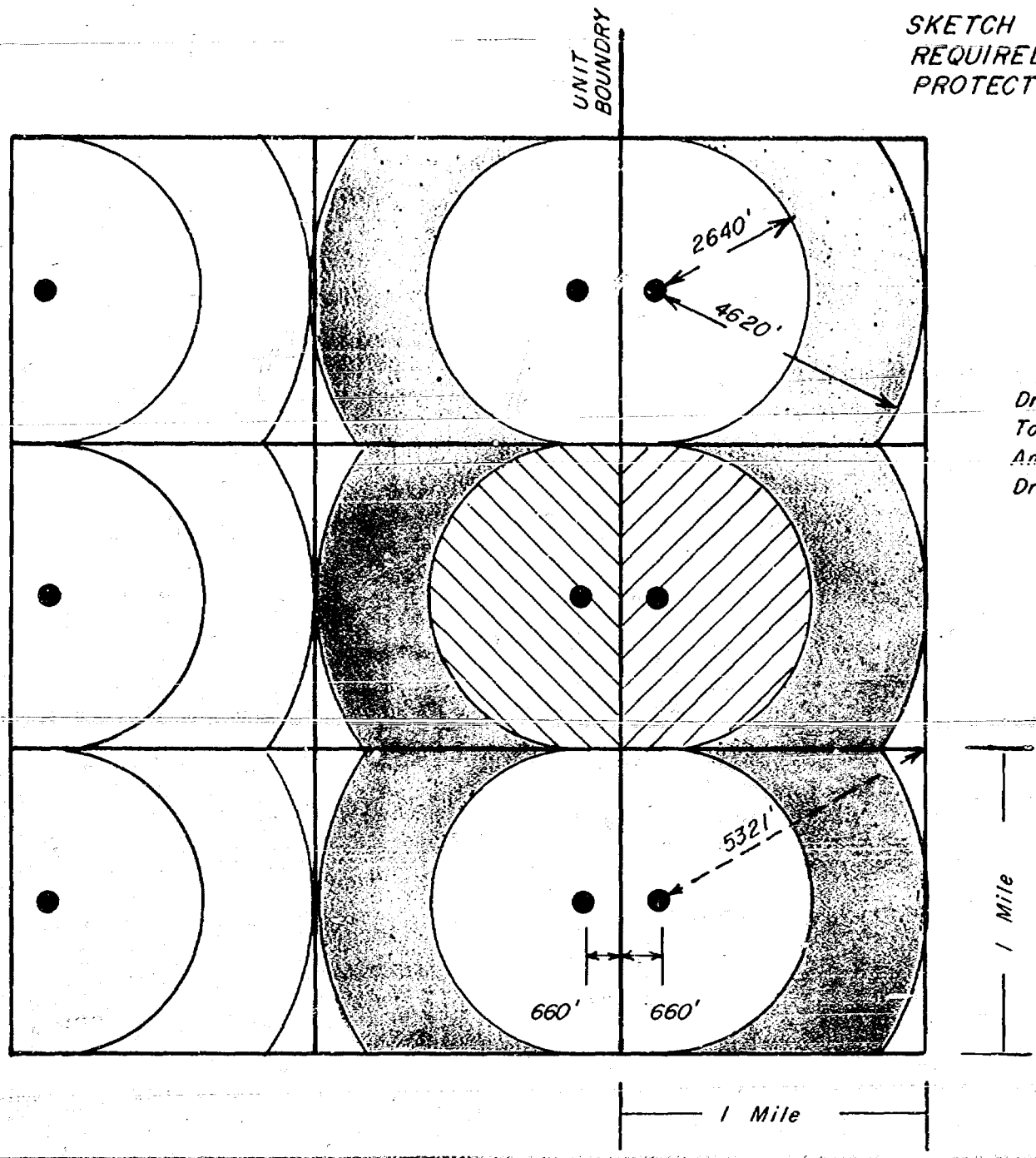
Notary Public in and for
San Juan County, New Mexico

My Commission E xpires:
August 4, 1974

IMPACT ON STATE AND FEDERAL REVENUES
OF
DEGRADATION OF OIL RECOVERY EFFICIENCY
FOR THE CANADA OJITOS UNIT
RESULTING FROM
PRODUCTION OF COMPETITIVELY DRILLED WELLS
(based on assumed free market value of oil of $40.00/barrel as of 10-1-81)

Future gross production	5 MM bbls. ($MM)	5 MM bbls. ($MM)	10 MM bbls. ($MM)	10 MM bbls. ($MM)
Gross value at $40.00/bbl.		200		400
90% of gross		180		360
State share of federal royalty				
1/2 of 1/8 of 95% (gross)	10.7		21.4	
Less approximate WFPT (bp 14.00)	(4.5)		(9.0)	
Net		6.2		12.4
State royalty				
1/8 of 1.6%		0.4		0.8
State severance tax				
3.75% of 3.5% +				
3.75% of 7/8 of 96.5% of gross		5.9		11.8
State school tax				
2.55% of 3.5% +				
2.55% of 7/8 of 96.5% of gross		4.0		8.0
State consevation tax				
.19% of 3.5% +				
.19% of 7/8 of 96.5% of gross		0.3		0.6
State ad valorem tax				
1.1% of 3.5% +				
1.1% of 7/8 of 96.5% of gross		1.2		2.4
Federal royalty				
Gross (same as state)	10.7		21.4	
Less WFPT (same as state)	(4.5)	6.2	(9.0)	12.4
Federal WFPT				
On federal royalty and state share of federal royalty	9.0		18.0	
On fee royalty ORR and integrated oil companies				
24% x 7/8 x 17 WFPT	18.0		36.0	
On independent producers				
76% x 7/8 x 12 WFPT	40.0		80.0	
Total WFPT		67.0		134.0
Total federal royalty and WFPT		73.2		146.4
Total state tax and royalty		18.0		36.0
TOTAL BOTH FEDERAL AND STATE ROYALTY AND TAXES		91.2		182.4

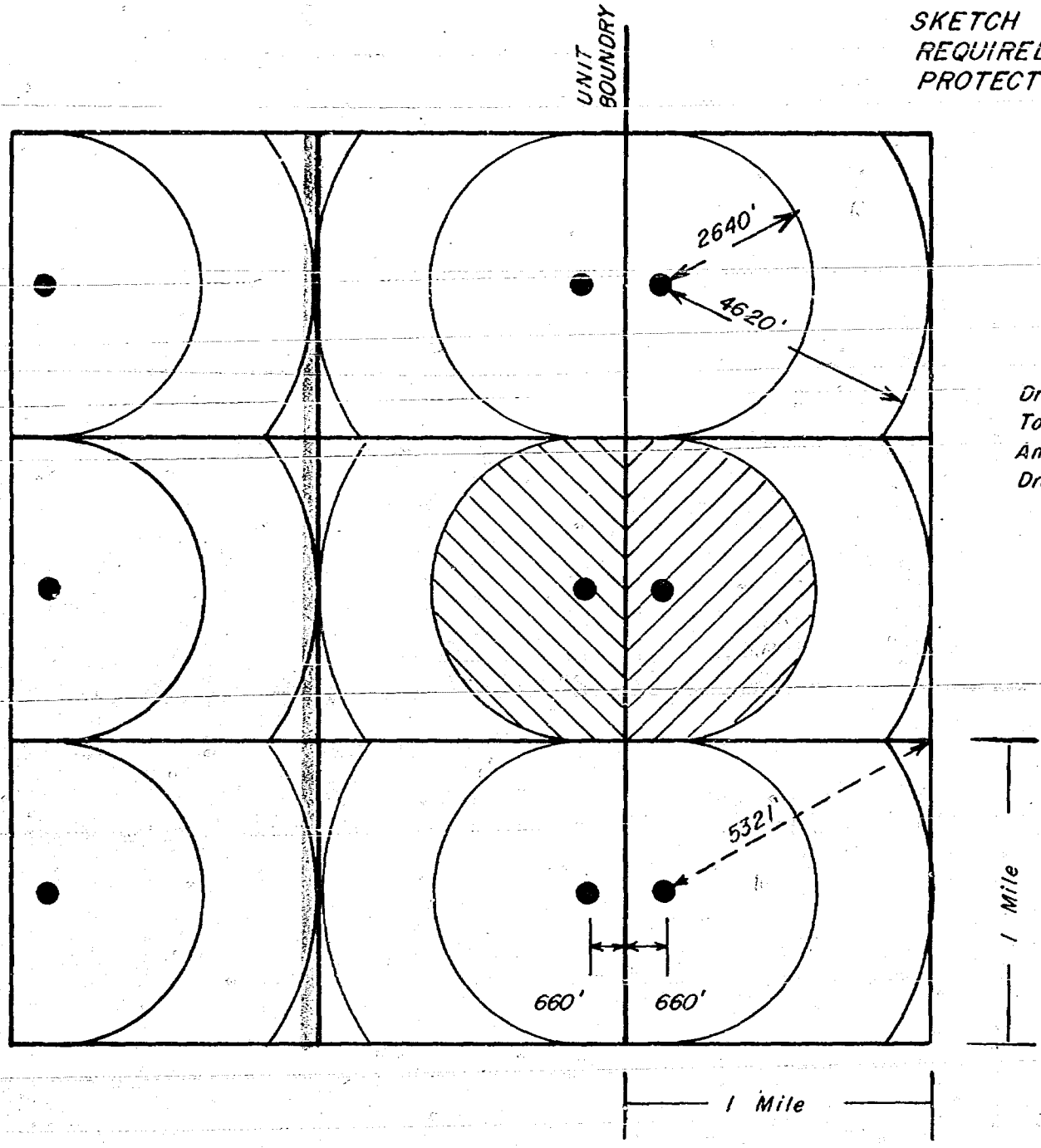
SKETCH SHOWING EXTENDED RADIUS REQUIRED FOR WELLS LOCATED TO PROTECT FROM OFFSET DRAINAGE



Drainage Radius Of 4620' Is Equivalent To Circular Drainage Area Of 1540 Acres And 5321' Is Equivalent To Circular Drainage Area Of 2040 Acres

C8

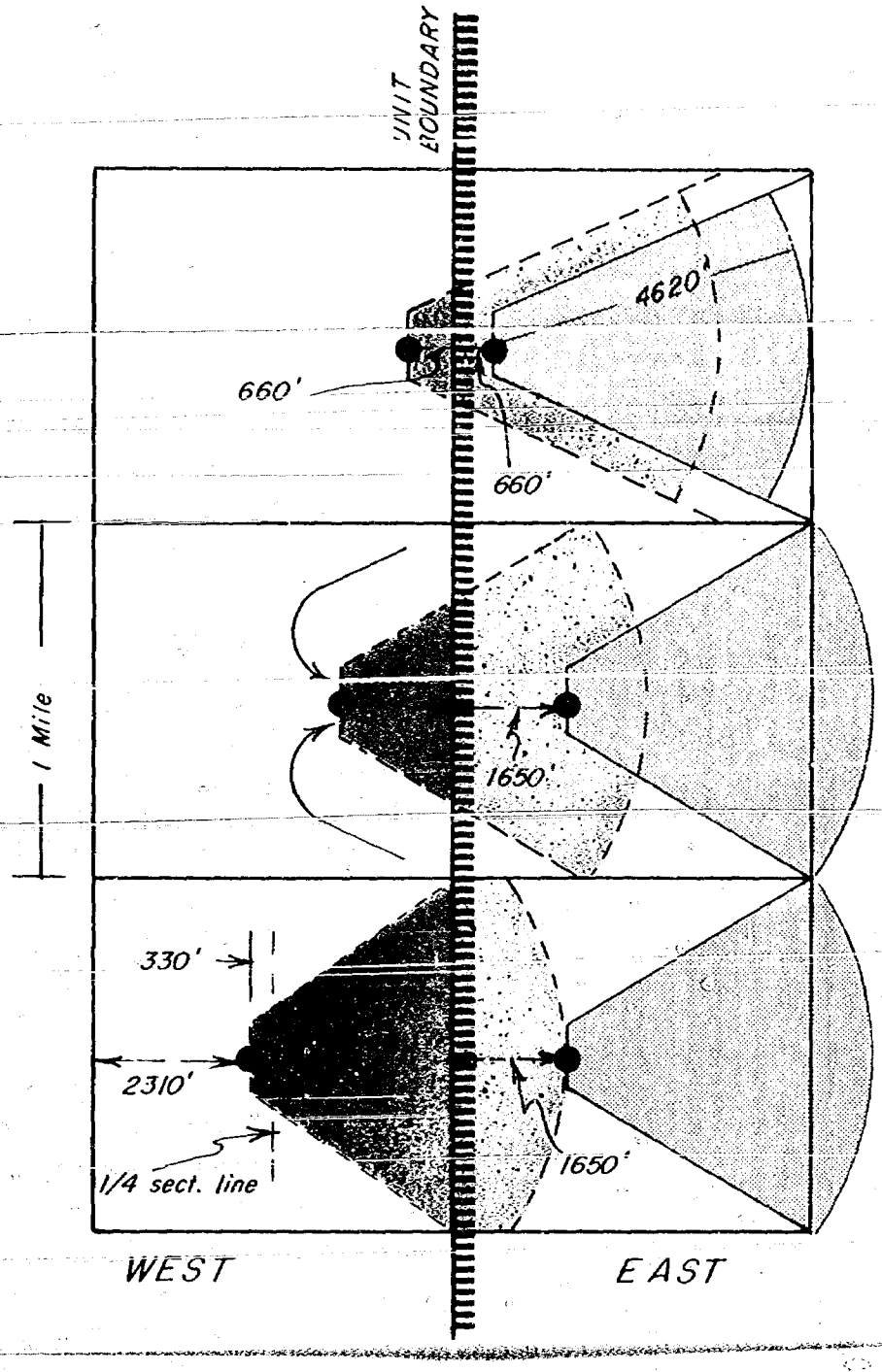
SKETCH SHOWING EXTENDED RADIUS REQUIRED FOR WELLS LOCATED TO PROTECT FROM OFFSET DRAINAGE



Drainage Radius Of 4620' Is Equivalent To Circular Drainage Area Of 1540 Acres And 5321' Is Equivalent To Circular Drainage Area Of 2040 Acres

C-3

SCHEMATIC DIAGRAM
OF
EAST TO WEST
DRAINAGE PATTERNS



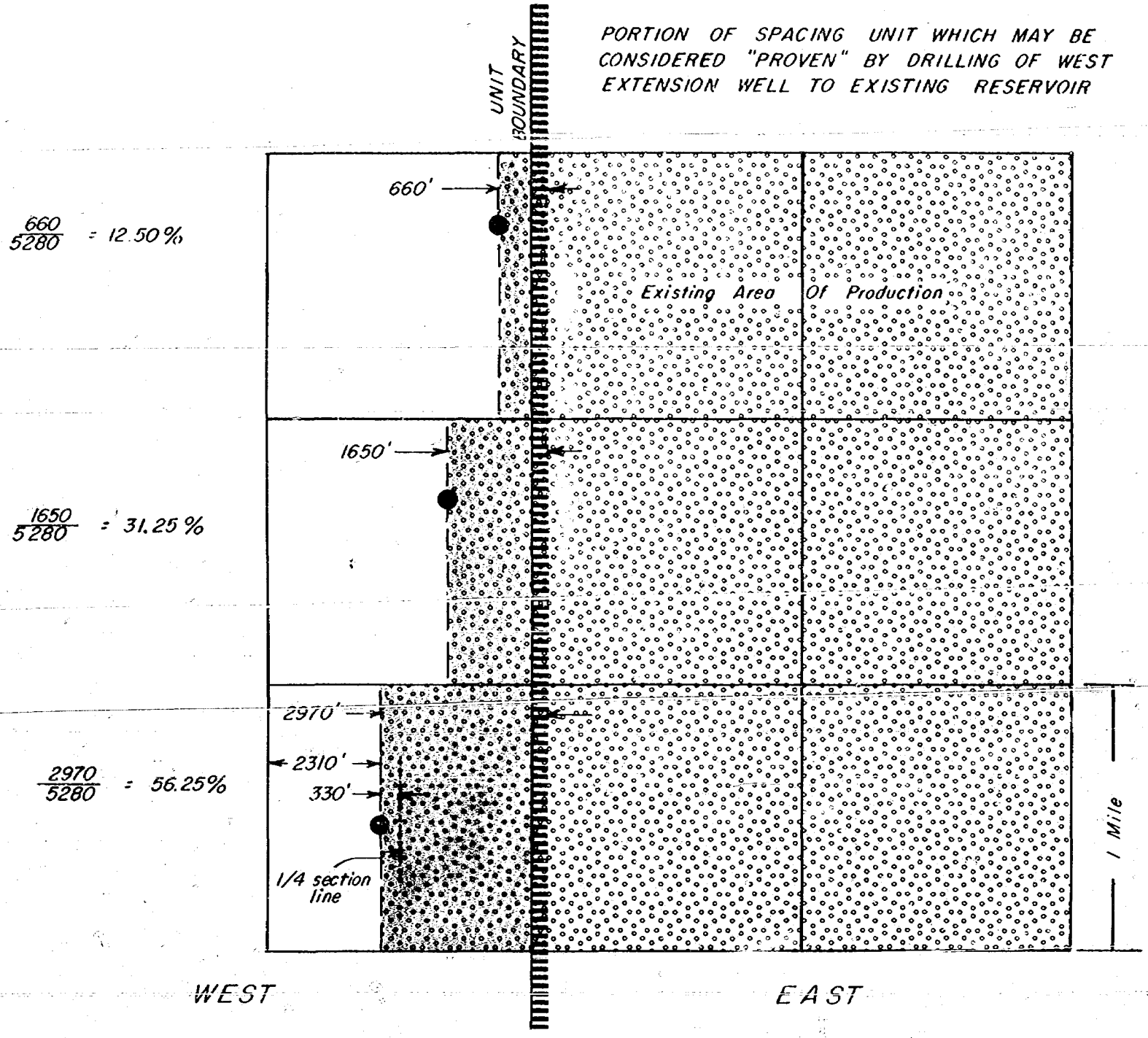
COMPARISON OF SOME OF THE PROBLEMS
OF FIRST DRILLING AND THEN UNITIZING
(either voluntary or statutory)

"ORDINARY" WATERFLOOD UNIT VERSUS CANADA OJITOS UNIT

(assume competitively-drilled well has average producing ability of unit wells)

	FUNDAMENTAL STATISTICS		RATIO OF COMPETITIVELY DRILLED WELL'S SHARE OF PRODUCTION TO ITS SHARE OF "PROVEN" ACREAGE	
	"Ordinary" Waterflood Unit	Comparative Canada Ojitos Unit	Ordinary Waterflood Unit	Comparative Canada Ojitos Unit
1. Reservoir size (omitting gas cap)	4 miles x 12 miles	4 miles x 12 miles		
2. Reservoir area (acres)	30,700	30,700		
3. Approximate spacing of oil recovery wells (acres/well)	40	3,000		
4. Approximate spacing of injection wells (of oil recovery area) (acres/well)	40	7,500		
5. Approximate number of oil recovery wells	768	10		
6. Ratio of competitive well's production to unit prod.	1/768	1/10		
7. Ratio of surface acres of competitive well's spacing unit to unit total for oil recovery wells	1/768	640/38,700 = $\frac{1}{50}$	A. Assume all of competitively drilled well's spacing unit is "proven"	$\frac{1}{768} \div \frac{1}{768} = 1$; $\frac{1}{10} \div \frac{1}{5} = 5$
8. Ratio of competitive well's "proven" acreage to unit total proven acreage for well drilled 660' from line	1/1536	1/8 x 640/30,700 = $\frac{1}{400}$	B. Assume competitively drilled well's spacing unit is proven to extent of 660' ÷ width of spacing unit side	$\frac{1}{768} \div \frac{1}{1536} = 2$; $\frac{1}{10} \div \frac{1}{400} = 40$

PORTION OF SPACING UNIT WHICH MAY BE CONSIDERED "PROVEN" BY DRILLING OF WEST EXTENSION WELL TO EXISTING RESERVOIR



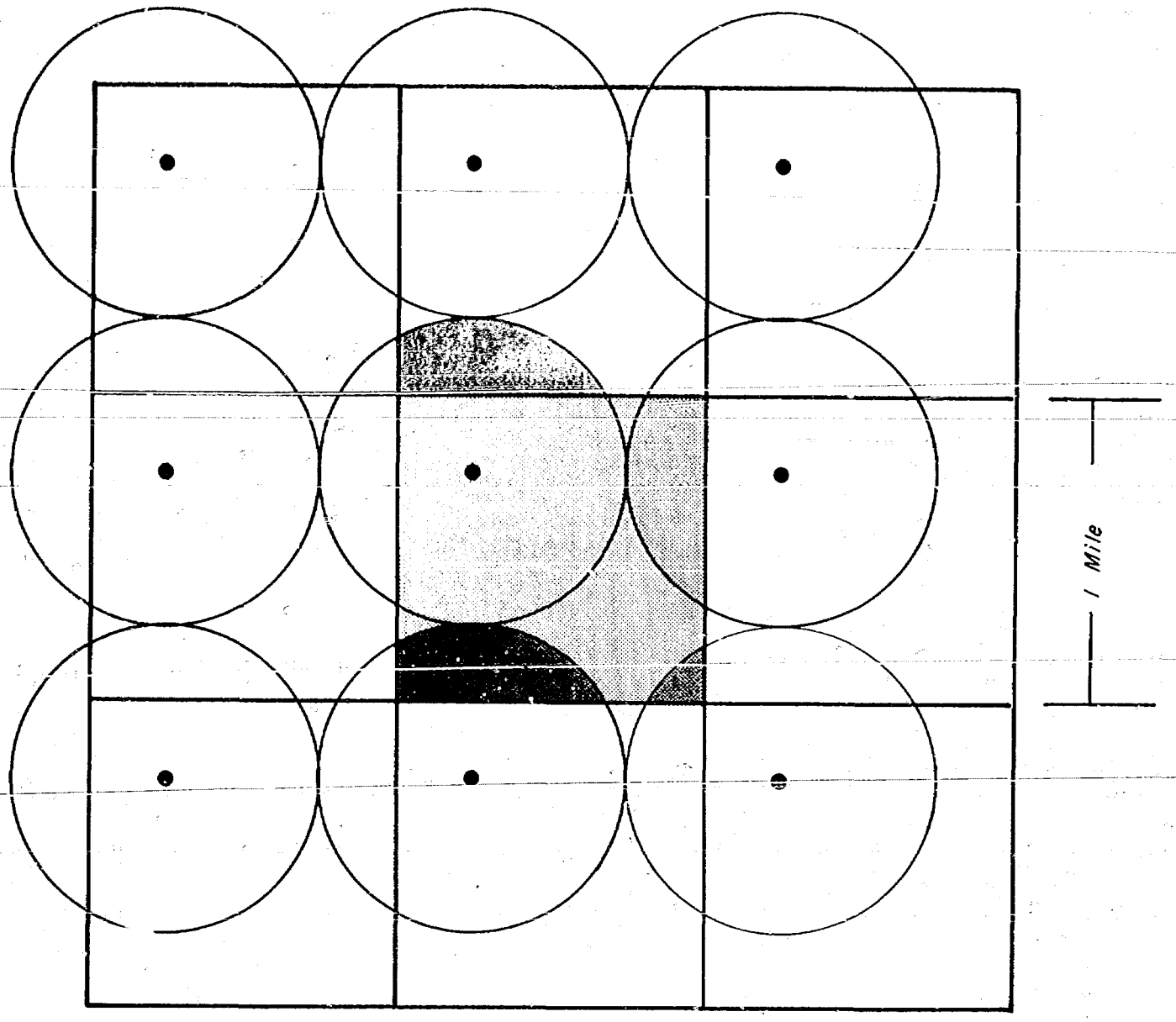
$\frac{660}{5280}$ = 12.50%

$\frac{1650}{5280}$ = 31.25%

$\frac{2970}{5280}$ = 56.25%

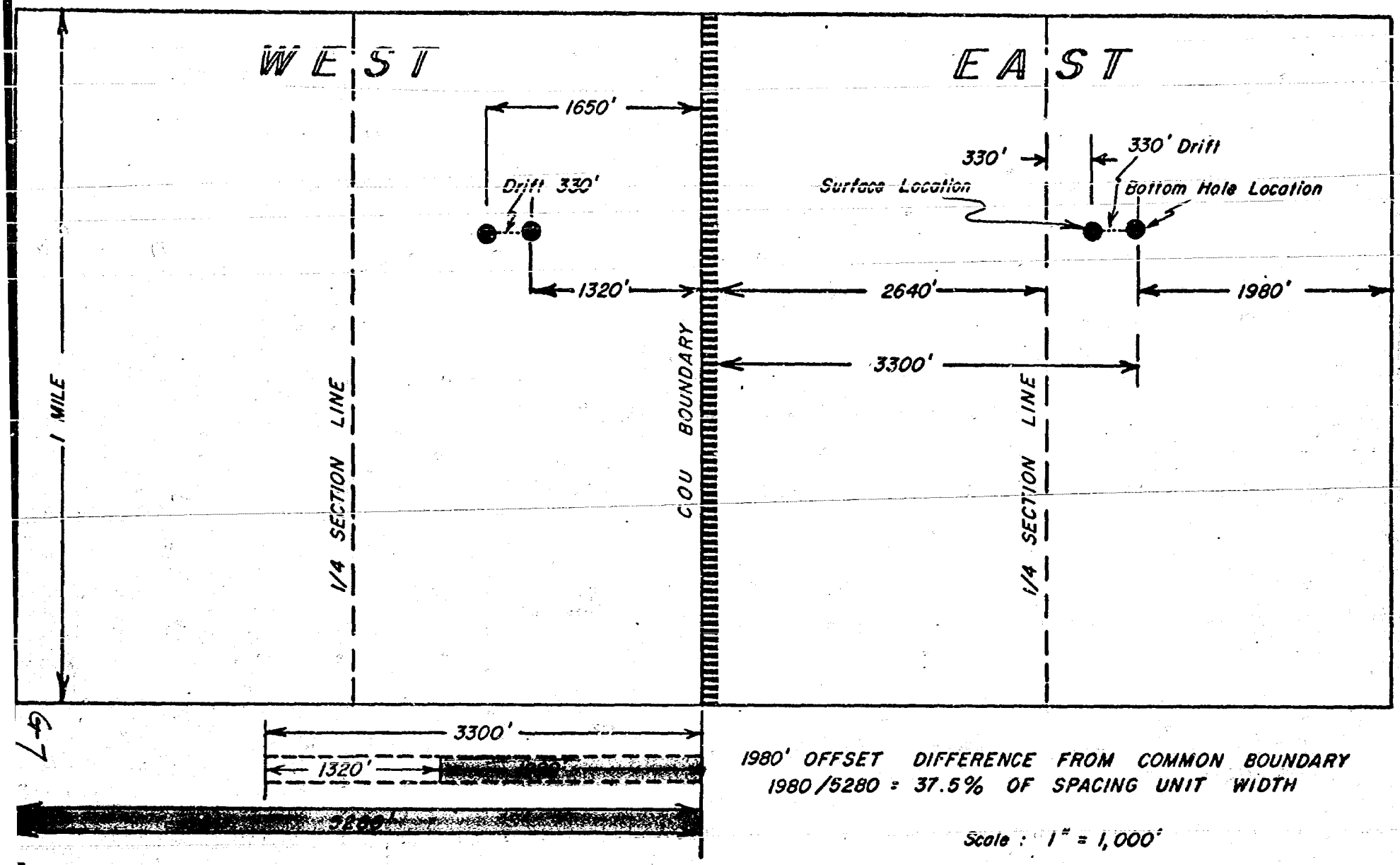
G-5

08-01-80

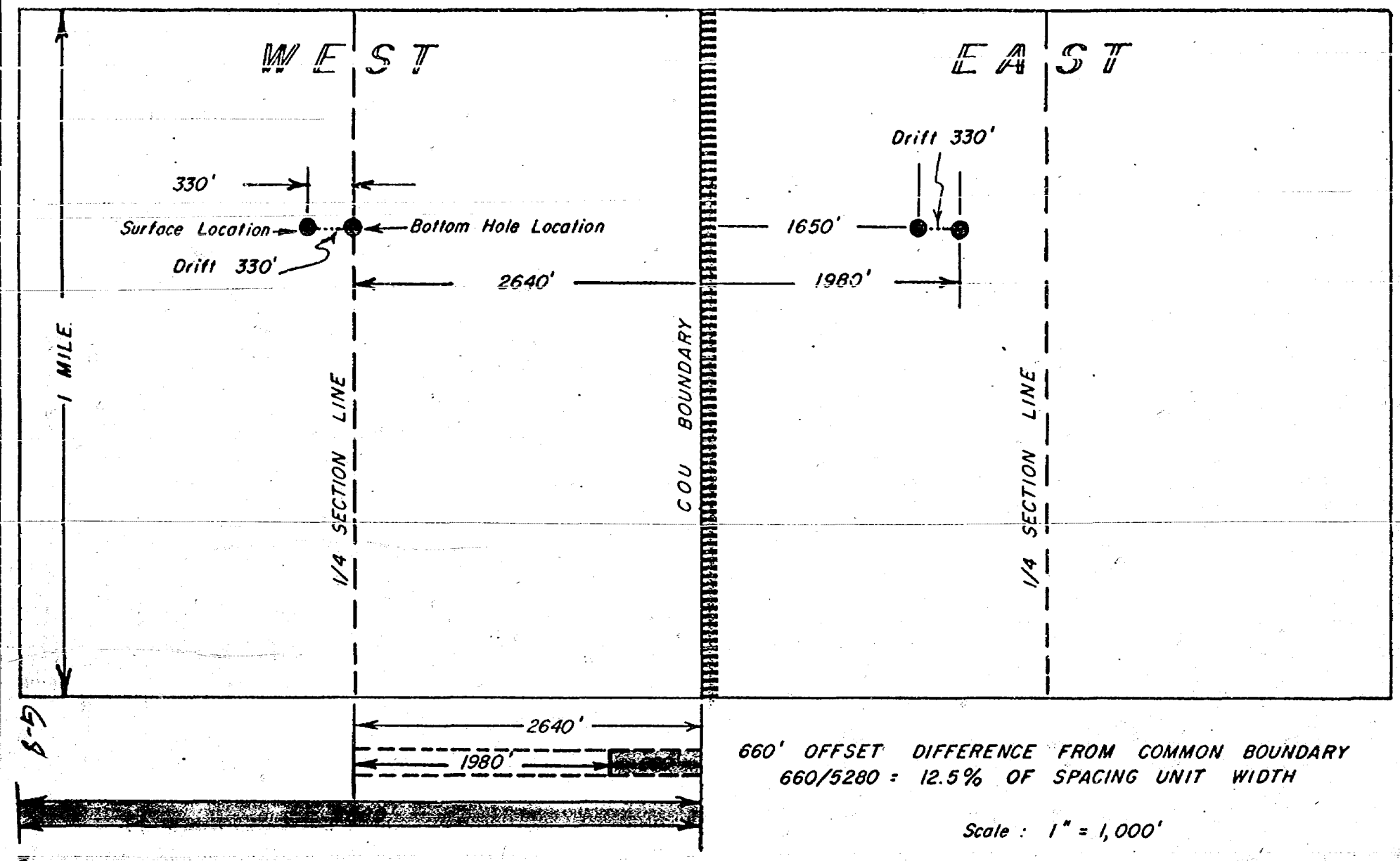


SKETCH SHOWING PRINCIPLE OF COMPENSATING DRAINAGE FOR OFF-CENTERED WELLS UNIFORMLY SPACED

COMPARISON OF OFFSET DISTANCES FOR WELLS 1650' FROM SECTION LINES AND LOCATED IN E/2 OF SECTIONS



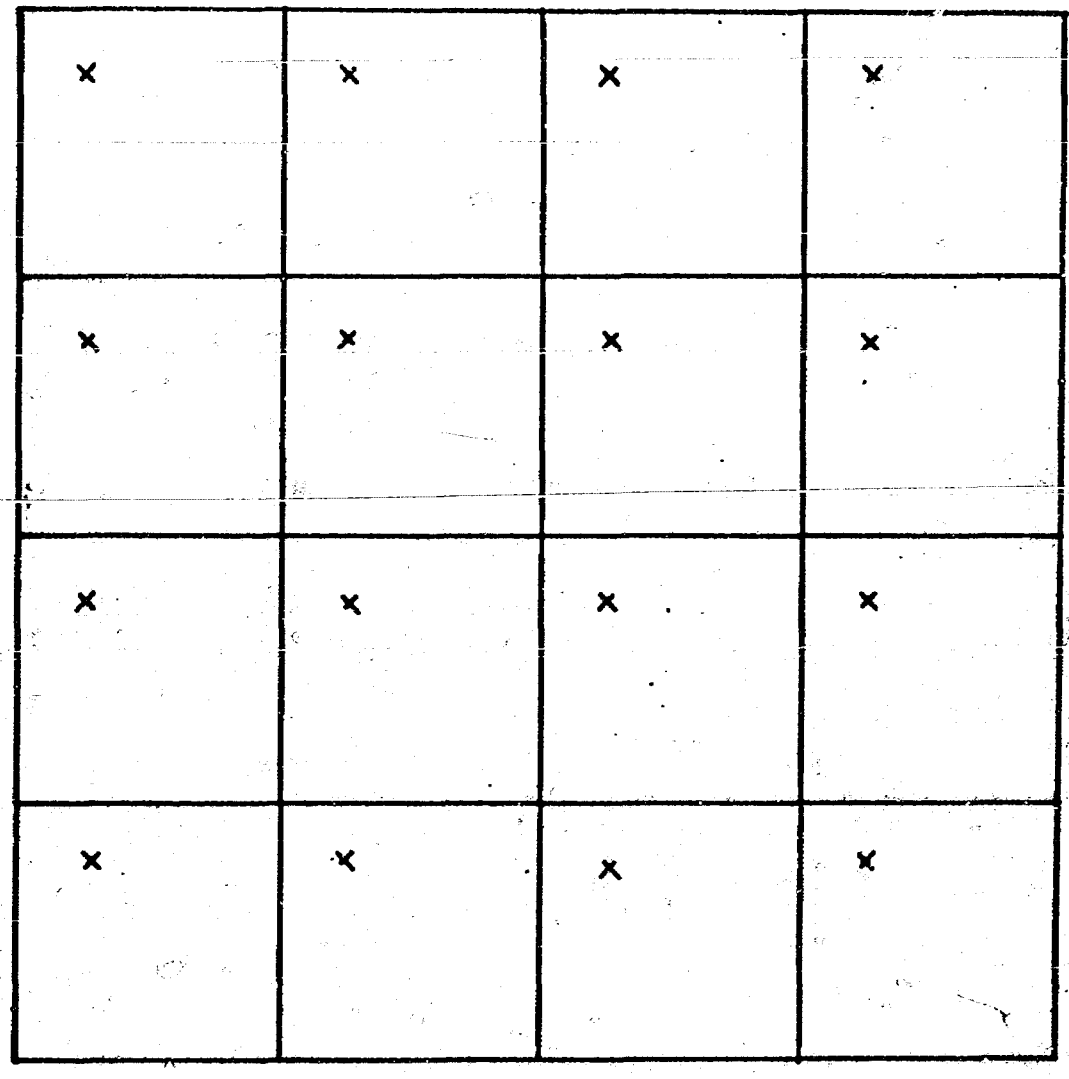
COMPARISON OF OFFSET DISTANCES FOR WELLS 1650' FROM SECTION LINES AND LOCATED IN W/2 OF SECTIONS

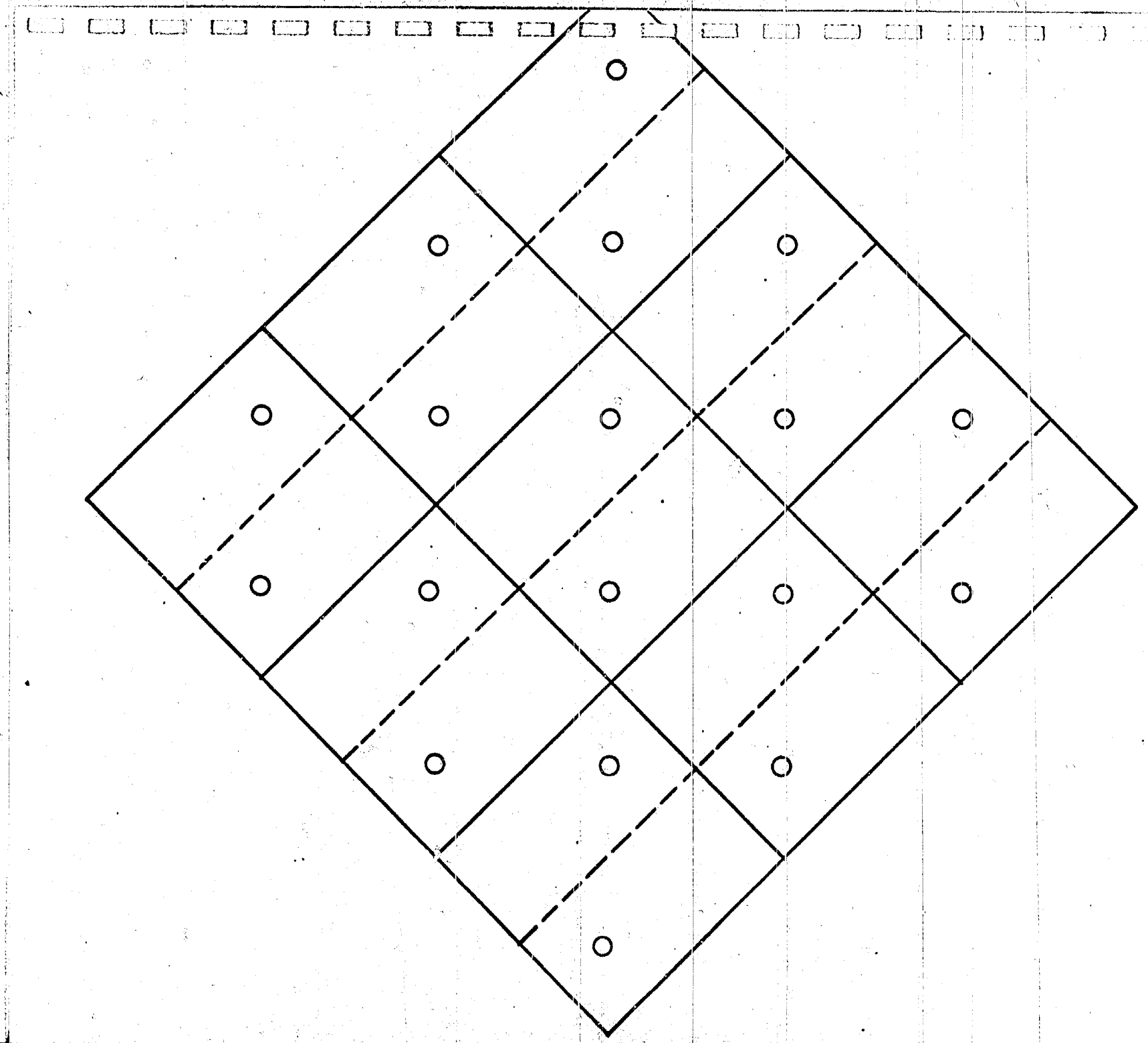


660' OFFSET DIFFERENCE FROM COMMON BOUNDARY
660/5280 = 12.5% OF SPACING UNIT WIDTH

Scale : 1" = 1,000'

8-5
10-80





BENSON-MONTIN-GREER DRILLING CORP.
APPLICATION - WEST PUERTO CHIQUITO MANCOS OIL POOL

CASE 7075
NOVEMBER 24, 1980

OPENING STATEMENT

The application of Benson-Montin-Greer Drilling Corp. here before the Commission requests a change in the spacing pattern now established for the West Puerto Chiquito Mancos Oil Pool. In order for this application to be properly considered, it is necessary that we review the history of the development of the pool and the facts regarding its reservoir characteristics.

Back in 1963, after only a well or two were drilled, Benson-Montin-Greer came before the Commission and requested 160-acre temporary spacing. At that time both East and West Puerto Chiquito were thought to be one pool. Shortly after that, or a few years after that, it was realized that there was a barrier between East and West Puerto Chiquito. Thereupon an application was filed and an order entered to establish two pools - East and West Puerto Chiquito.

After 1963, when only five wells had been drilled in a cluster with approximately two miles distance between them, Benson-Montin-Greer had the courage (and it takes quite a lot), to interrupt all of the production from all five of those wells for a period of sixty days so that they could conduct one of the most remarkable interference tests that I've heard of in many years of oil and gas practice in Texas, New Mexico and Oklahoma.

This multiple interference test was conducted in 1965 and in 1966 and the results of it were presented to this Commission in Cause No. 3455. (The same cause number as in the 1963 hearing.)

At that time it was established that the pool was a fractured shale, being the Niobrara member of the Mancos; that it was a pool with a minimum amount of oil per acre in place and that it would support wells capable of very wide drainage; and the communication was so great that every one of those five wells was affected by anything that happened in any one of them.

At that time 320-acre temporary spacing was requested and granted.

At that time BMG expressed comprehensive opinions with regard to the pool and how it should be developed. Today, after seventeen years of history of the West Puerto Chiquito Mancos Oil Pool, all of the theories and opinions that were expressed to the Commission back at that time have been definitely established as engineering facts and are now a matter of history.

It is a rare instance in the oil industry that management will permit the remarkable engineering that has been achieved in this pool. Pools like the Boulder Pool, just a few miles to the north of West Puerto Chiquito where 80-acre spacing was employed and there was no pressure maintenance instituted, reflect a tragic disparity of conservation when compared to West Puerto Chiquito.

Shortly after the dramatic interference tests and the establishment of 320-acre spacing, BMG as the operator of the Canada Ojitos Unit established a pressure maintenance system by injecting gas in the upper edge of the pool. Then they carefully monitored production and voluntarily restricted production rates so as not to exceed the gravity drainage ability of the field. Without this pressure maintenance and controlled development of the pool, we would only have been able to recover approximately 5-1/2 percent of the oil in place under West Puerto Chiquito; whereas, as it has been developed we expect to recover between 50 and 60 percent of most of the oil in place. I say that we expect to. We expect to if we are able to continue the program of conservation established over the 17-year history of the field.

Our evidence will show that there are high and low capacity wells and that even the low capacity wells have maintained their initial production rates over a period of years and we will show that not only the high capacity but the low

capacity wells also drain wide areas.

We have two production wells which we will be talking about along with the others, one, the well in Section 10. has produced 2-million barrels of oil and we will show that this well has already drained an area of between 4000 and 8000 acres and is still producing oil.

The initial five well interference test enabled us to establish that the oil in place in this area was between 1000 and 2500 barrels per acre. Then after such interference tests BMG left one of those wells off production and never put it back but used it as an observation test well.

Then when the Canada Ojitos Unit operator started injecting gas in the upper side of the pool, they were able to run an additional interference test. By that further interference test they confirmed and refined their previous conclusions regarding oil in place.

Preliminary to unitizing additional areas in West Puerto Chiquito recently BMG requested of the Division and was granted 640-acre spacing. This was necessary preliminary to and as an adjunct to unitizing North Canada Ojitos and West Canada Ojitos, and as we indicated in the hearing last August held on such application, we anticipated that these areas would be unitized in a compatible program with the Canada Ojitos Unit so that the conservation program heretofore established could be continued for the greater recovery of oil. The Division granted the application for 640-acre spacing and established a spacing pattern of permitting a well to be drilled up to within 660 feet of the section line. BMG at that time paid little or no attention to the spacing pattern for the reason that unitization of the area would make it a moot point. However, since that time BMG was shocked to discover that the protestants here today would not agree to unitizing West Canada Ojitos. As a matter of fact, without advising BMG that they were terminating negotiations regarding formation of West Canada

Ojitos Unit, they proceeded to stake a location for the drilling of a well in the area 660 feet on the surface from the Canada Ojitos Unit; which well, if drilled, will most probably be considerably closer at the bottom of the hole.

If such a drilling program is to be carried on to production by the protestants, then the highly efficient gravity drainage and pressure maintenance processes established and practiced by the applicant will be destroyed and there will be serious degradation of recoveries from the reservoir. This will result in a tremendous underground waste of oil and a destruction of the correlative rights of the applicant.

In this regard, our proof will show that if protestants are permitted to drill where they desire, then the section under which they drill will not be drained as to a large amount of the western portion thereof, while on the other hand, protestants' well or wells will drain a large area under the Canada Ojitos Unit to the east of such wells. Such drilling would require that unit operator drill off-sets only 660 feet from the protestants' section line in order to partially protect the unit; but our proof will show that such off-setting wells cannot protect the unit from severe drainage by the protestants' wells.

Applicant's proof will further show that not only will the drilling pattern desired by protestants cause a great amount of oil never to be recovered from the reservoir and wasted, but in addition thereto will cause drilling of unnecessary wells. Our proof will show that close off-sets are unnecessary wells; are not only costly and wasteful, but that in addition thereto they will create much unnecessary damage to the National Forest.

Damage to the National Forest may not be strictly a matter of oil and gas conservation. However, this area is a part of the Santa Fe National Forest. It is a beautiful wooded area. Minimizing damage and maintaining its beauty has been

a significant consideration to the managers of the Canada Ojitos Unit.

After Applicant learned that the protestants would not agree to form a unit but desired to proceed with a drilling program that would prevent the greatest recovery of oil from the pool, it became apparent to BMG that they needed a different spacing pattern than that established by this Commission after the August hearing. Therefore, BMG filed the initial application in this cause. In that application we requested that the spacing pattern follow or conform to the customary 640-acre spacing regulation in New Mexico which requires that wells be located not closer than 1650 feet from the spacing unit section line. However, when BMG began to project the inevitable consequences of an application of the standard spacing pattern, it realized that wells drilled in the east half of the western tier of Sections, 1650 feet from the east line not only grossly fail to protect the applicant's correlative rights but also fail to adequately drain the western portion of their section. Thereupon, applicant amended its application to request that wells in the pool be spaced uniformly in the west half of each spacing unit.

In an ordinary reservoir where 640-acre spacing is established a well at any place 1650 feet from the line of the section adequately protects the correlative rights of the parties where there is an opportunity for compensating drainage. However, West Puerto Chiquito is no ordinary reservoir. To the contrary, it is a reservoir where the ratio of the ability of a well to produce the oil from the reservoir in relation to the amount of oil in place is much greater than the average. In other words, in this reservoir the capacity of the wells in relation to the amount of oil in place is far greater than the ordinary situation. Also, it is a pool tilted downward from east to west and where a unit was formed at an early date in the development of the pool and a pressure maintenance program

installed. These facts, together with the careful spacing of wells and production, drastically separate this pool from the ordinary oil and gas conservation situation. Oil not only drains from east to west but in addition thereto it is further moved from east to west by virtue of the fact that the Canada Ojitos Unit installed four injection wells on the eastern extremity of the pool and have been injecting gas into the formation almost from the inception of production. These conditions cause the oil to move from east to west and wells to the West of the Canada Ojitos Unit will drain the oil from the Unit. These are the reasons that a well in the sections immediately west of the Canada Ojitos Unit which is located in the east part of the spacing unit will not be efficiently draining such spacing unit. To the contrary, most of the oil produced by such well will be drained from land to the East. Applicant's evidence will show that such oil will be produced not just from the adjoining sections to the East but from large areas of the unit lands.

Even more unfortunate, such well will produce only a small amount of oil from the western part of the section upon which it is located. It will, therefore, be an improperly located well; it not only will not serve conservation but it will destroy correlative rights and may result in a tragically reduced ultimate recovery of oil from West Puerto Chiquito.

This was the reason that although the applicant initially asked for spacing 1650 feet from the line, after applying this standard pattern to the unusual charasteristics of the reservoir, it became apparent that applicant's correlative rights were going to be destroyed and the applicant realized that it must ask for a rule which would allow a more equitable recovery of the hydrocarbons in the reservoir and would come closer to preserving the energy of the pool. The only way to better protect the correlative rights of the applicant was by requiring that all wells be drilled in the west half of the section.

Our evidence will show that wells located in the western half of the sections will come much closer to producing the oil from under their own sections and that they will be far less an infringement upon the correlative rights of the owners of the Canada Ojitos Unit. Further, our proof will show that it will save the cost of the drilling of unnecessary wells and greatly diminish the overall damage to the reservoir. Also, that by eliminating the drilling of unnecessary wells it will greatly protect the surface and beauty of the National Forest.

It is difficult to fully appreciate the tremendous danger that is presented by the specter of wells being drilled 660 feet immediately west of the Canada Ojitos Unit bondary. Therefore, in order that the Division can understand the gravity of our application, we will present evidence which will show that if competitive drilling is permitted to proceed in West Puerto Chiquito in accord with the present order, that the established efficienty of the Canada Ojitos Unit will be destroyed and it may lose as much as 90 percent of its future recoveries. We will further show that this would mean a loss not only to the Canada Ojitos Unit owenrs but also a loss to the State of New Mexico of between 18 and 36 million dollars in royalty revenues and gross production taxes and a further loss to the Federal Government of between 6 and 12 million dollars in royalties and between 67 and 134 million dollars in Windfall Profits tax, meaning losses to both State and Federal governments of between 90 and 180 million dollars.

The applicant is aware of the fact that without the acreage on the west being unitized waste cannot be prevented, but absent such compatible unitization our proof will show that conservation and protection of correlative rights make it mandatory that our application be granted.

INDEX OF
BENSON-MONTIN-GREER DRILLING CORP. EXHIBITS
IN CASE NO. 7075
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

NOVEMBER 24, 1980

PART I — INFORMATION RELATIVE TO EFFICIENCY OF RECOVERY FOR DEPLETION METHOD OF GRAVITY DRAINAGE ASSISTED BY PRESSURE MAINTENANCE BY GAS INJECTION

SECTION A: Factors affecting increased gravity drainage recovery conducted under high pressure as compared to low pressure

1. Graph

SECTION B: Bahrain Field: Limestone B reservoir

Article from December, 1979 Journal of Petroleum Technology

SECTION C: Empire Abo Field

1. Graph of porosity vs. permeability
2. Graph of gravity drainage potential
3. Graph of oil in place per acre vs. transmissibility

SECTION D: Canada Ojitos Unit

1. Graph, COU C-34
2. Schedule, COU C-34

PART II — COMPARISON OF PRODUCING CAPACITIES AND GRAVITY DRAINAGE RATES FOR WELLS IN THE WEST PART OF THE WEST PUERTO CHIQUITO POOL

SECTION E:

1. Schedule
2. Graph

INCREASE IN RECOVERY
BY DEPLETION AT HIGH PRESSURE
AS COMPARED TO
DEPLETION AT LOW PRESSURE
FOR VARIOUS FINAL OIL SATURATIONS

CONDITIONS: HIGH PRESSURE 1500#
F.V.F. = 1.29
LOW PRESSURE 50#
F.V.F. = 1.11
CONNATE WATER SATURATION = 10%

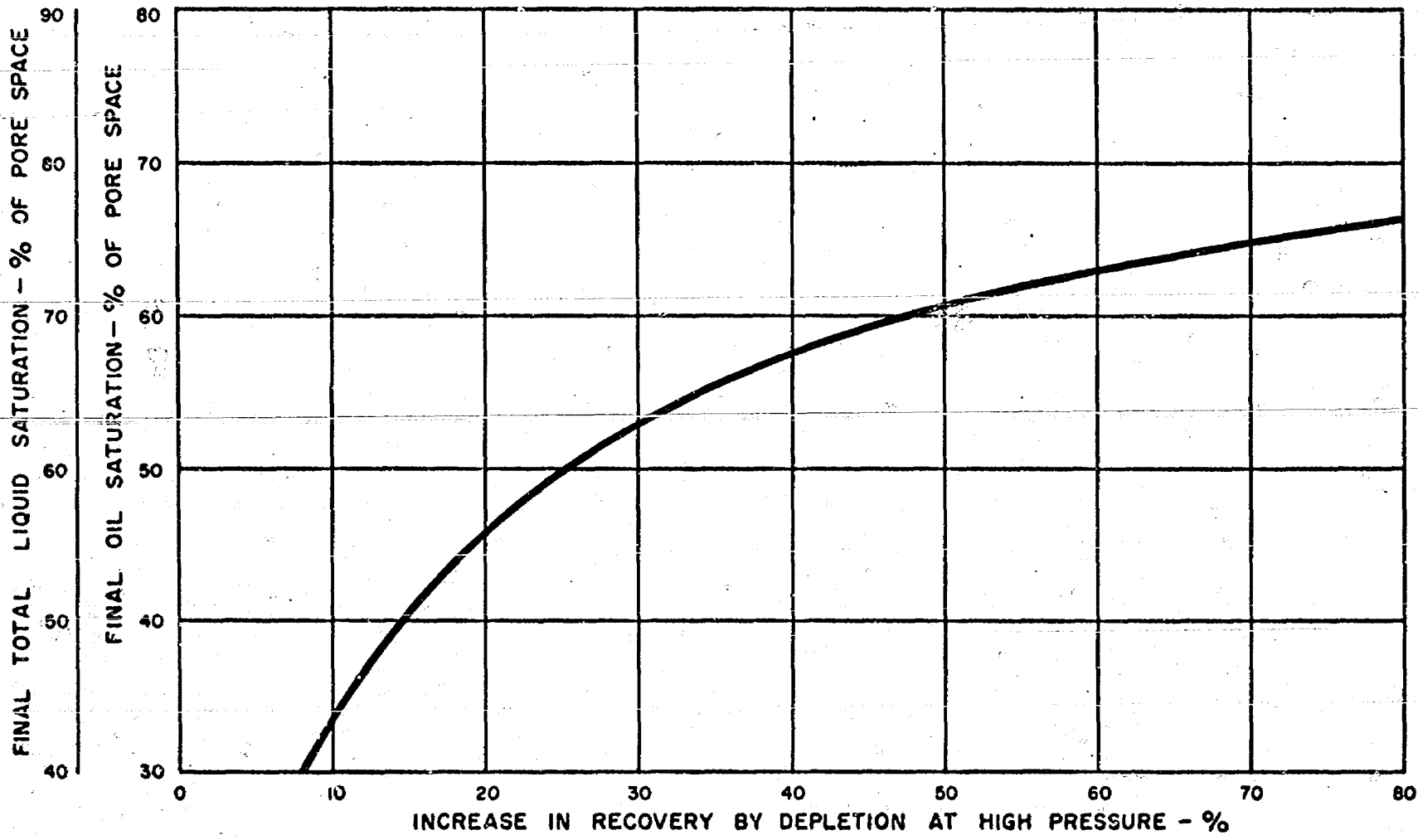


FIGURE NO. 12

Effective Displacement of Oil by Gas Injection in a Preferentially Oil-Wet, Low-Dip Reservoir

Jaffar A.N. Shehabi, SPE-AIME, The Bahrain National Oil Co.

Introduction

Gas injection as a means of maintaining pressure and improving oil recovery has been employed in the Bahrain field Second Pay Limestone B reservoir for the last 39 years. This reservoir is oil-wet. Maintaining reservoir pressure was the primary objective in the beginning. The pressure response was almost immediate and probably conformed very closely to a simple material balance, because all producing zones on the highly faulted Bahrain structure were still close to virgin conditions.

Early gas breakthrough became a matter of concern with respect to total field productivity and ultimate recovery. However, wells in the gas area were kept on production, at an optimum rate governed by tubing submergence. It gradually was realized that even with early breakthrough, a satisfactory oil recovery factor was being obtained. Attention then focused on determining actual recovery and explaining the mechanism involved.

The most recent reservoir study showed a 50% recovery factor in the gas-invaded volume, as compared to 20 to 25% in the water-invaded volume. It also was found that because of fluid transfer to other zones, the required injection rate for the Limestone B is 70,000 Mcf/D (1.98×10^6 m^3/d) instead of the 40,000 Mcf/D (1.13×10^6 m^3/d) calculated for the Limestone B alone.

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This paper describes some pertinent aspects of the reservoir, the gas injection program, and the methods used to calculate the recovery factor.

Reservoir Description

The Bahrain field structure is a highly faulted, elongated anticline (Fig. 1). Structural dips in the oil-producing horizons are in the order of 5°. The Bahrain zones, of middle Cretaceous age, are the most important oil-producing group found in this field. They are divided into eight separate zones, with zonal separation varying from 7 to 50 ft (2.13 to 15.24 m). Three types of lithology are present: limestone, siltstone, and sandstone. At the crest of the structure, the gross productive interval was 525 ft (160 m) and original net oil pay thickness was 325 ft (99 m).

The most important zone within this group, and the subject of this paper, is the Second Pay Limestone B. The reservoir rock is a soft, porous, chalky limestone with limited fractures and vugs. Gross thickness varies slightly from [illegible] (31 to 35.4 m), all of which is considered net pay. Average porosity and permeability are [illegible] and [illegible] respectively. There are no impermeable streaks to affect vertical permeability. The middle 50 ft (15.24 m) has the highest porosity and permeability. The basal 30 to 40 ft (9.14 to 12.19 m) is slightly different in character and appears to have a lower specific productivity index. Fig. 2 shows the porosity

Gas injection as a means of pressure maintenance has been employed in the Bahrain field Second Pay Limestone B reservoir for the last 39 years. This paper describes aspects of the gas injection program and the method used to calculate recovery of oil by gas, which has been found to be much greater than that by water drive.

109' x 62.8 md → 6.8 darcy feet

profile, and Fig. 3 shows type log. Average initial water saturation was 6% in the upper section and 11% in the basal section. Previous laboratory work led to the conclusion that the reservoir rock was preferentially oil-wet. For wettability determination, two plugs were cut from preserved core samples: one sample was flooded with brine until a minimum oil saturation was obtained; the other sample was flooded with oil until a minimum water saturation was obtained. The sample with minimum oil content was allowed to imbibe oil spontaneously; the sample with minimum water content was allowed to imbibe water spontaneously. The two volumes of imbibed fluids were measured periodically.

The reservoir oil was highly undersaturated, having a saturation pressure of 358 psig (2468 kPa) as compared to the original reservoir pressure of 1,236 psig (8522 kPa) at 1,900 ft (579 m) subsea. The oil has a solution gas/oil ratio (GOR) of 128 scf/STB (22.8 std m^3/stock-tank m^3) and a density of 0.8556 g/cm^3. Since this is an old reservoir, very limited information is available on virgin parameters, such as viscosity.

The productive limits of the Limestone B reservoir, approximately 8.5 miles (13.7 km) long × 3 miles (4.8 km) wide, encompassed 13,750 acres (55.640 × 10^6 m^2) and contained almost 2 billion STB (318 × 10^6 stock-tank m^3) original oil in place (OOIP). Cumulative production as of Jan. 1, 1972, was 283 million STB (45 × 10^6 stock-tank m^3) oil and 79 million STB (12.6 × 10^6 stock-tank m^3) water. Cumulative gas injected up to Jan. 1, 1972, was 206,433 MMcf (5.8 × 10^9 m^3).

Gas-Injection History

The first well tapped oil from this zone at 1,236 psig (8522 kPa) in 1932. By Feb. 1938, after only 14 million STB (2.22 × 10^6 stock-tank m^3) or 0.7% OOIP had been produced, reservoir pressure had declined by 118 psig (813 kPa). High-pressure nonassociated Arab zone gas was readily available for injection into the Limestone B without requiring compression. Thus, the gas injection program to maintain pressure was initiated in April 1938. The Arab gas was relatively rich and was injected without prior processing for liquid recovery. A total of 189,000 MMcf (5.4 × 10^9 m^3) Arab gas had been injected by April 1974, at which time it was totally replaced by the much leaner and more abundant Khuff zone gas. Up until the discontinuation of Arab gas injection, some 74,383 MMcf (2.1 × 10^9 m^3) Khuff gas also had been injected.

Limestone B injection was suspended temporarily from May 1962 to Jan. 1965 while continuing to inject the lower siltstone zones. The purpose was to observe reservoir pressure behavior of the lower zones in the absence of injection into the Limestone B. The reservoir pressure of both the siltstone zones and the Limestone B declined rapidly at about the same rate, proving fairly conclusively that reservoir communication existed. As a result, continued gas injection into the Bahrain zones was solely into the Limestone B.

Transfer of fluids from the Limestone B to the underlying and overlying formations prior to 1962 is believed to have been minimal or nonexistent,

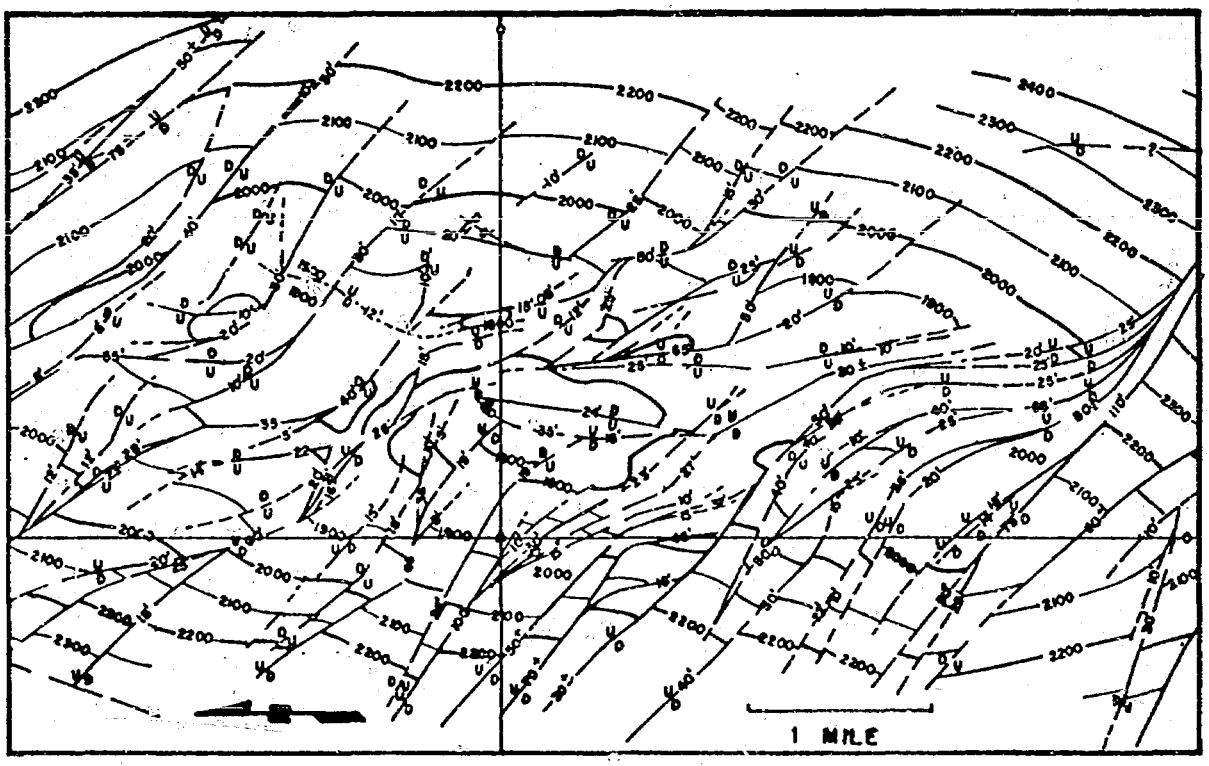


Fig. 1 – Structure map of Second Pay Limestone B.

because pressures were compatible. In subsequent material balance studies, it was found that recovery efficiency by gas was more than 50%. This indicates fluid transfer due to the decline in pressure in the underlying and overlying formations.

Subsequent production behavior of the individual zones has conclusively proved that the Limestone B is only one part of a unit that also includes the overlying sandstone and the underlying siltstones. This conclusion is important from the standpoint of determining injection rate requirements and explaining anomalously high recovery factors that could be calculated for any of these zones if they were treated as an entity. Examples are given later in the text. Overall recovery factor on a unit basis is probably in line with industry published data.

Another interesting aspect of the injection suspension period is the appearance of water cuts in the higher structural row of Limestone B wells and the regression of this water shortly after gas injection was resumed. Fig. 4 shows the fieldwide extent of this occurrence. Fig. 5 shows the recent pressure and production history of the Limestone B. In this figure as well as in subsequent figures, early history was not included, because very few recovery calculations were made before 1960.

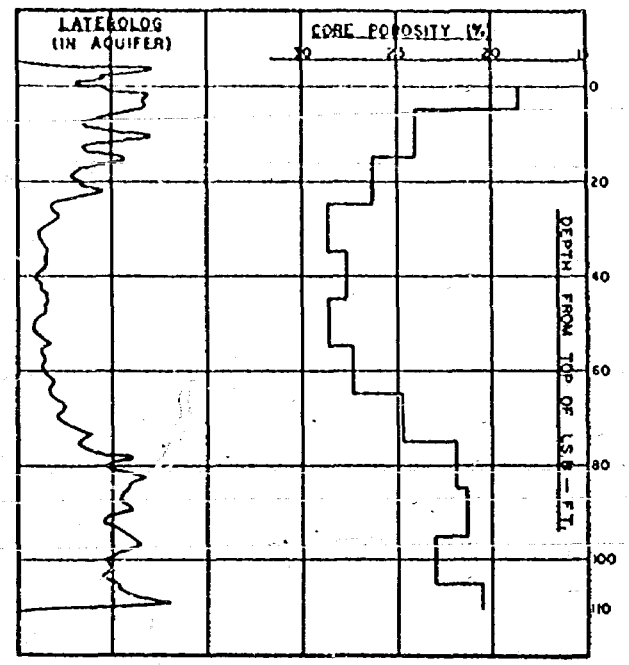


Fig. 2 – Porosity distribution in Second Pay Limestone B.

Recovery Mechanism

In order to analyze the recovery mechanism and calculate reserves, the Limestone B was subdivided into north, central, and south areas. Major faults that would prevent further expansion of the gas cap in a north-south direction helped to define the individual areas (Fig. 4). The north and south areas have been under the influence of an active water drive, whereas the central area has a combination of gas-cap drive, gravity drainage, and water drive.

The material balance calculations made in 1954 and 1959 following neutron surveys indicated a 50% recovery efficiency. In 1972, Laterolog surveys behind the water front indicated a 20% displacement efficiency by water.

In the 1972 study, a cutoff had to be chosen in order to calculate the fluid transfer to other zones. Thus, 50% and 20% recovery efficiencies by gas and water, respectively, were chosen. Gravity drainage was not quantified and was assumed to be an integral part of the 50% recovery factor.

Central Area

Ultimate recovery in the central area is estimated to be 29.7%, resulting from a combination of gas displacement, gravity drainage, and displacement by water. Recovery efficiency in the gas-invaded volume is 50% as compared to 20 to 25% in the water-invaded volume. Therefore, the objective is to continue gas injection at an optimum rate until a practical maximum growth of the gas cap is reached. The optimum rate is defined as the rate that will maintain reservoir pressure with zero net water influx. Because of fluid transfer from the Limestone B to other zones, the current optimum injection rate actually required is much higher than theoretically required – 66,000 to 70,000 Mcf/d (1.87 to 1.98 ×

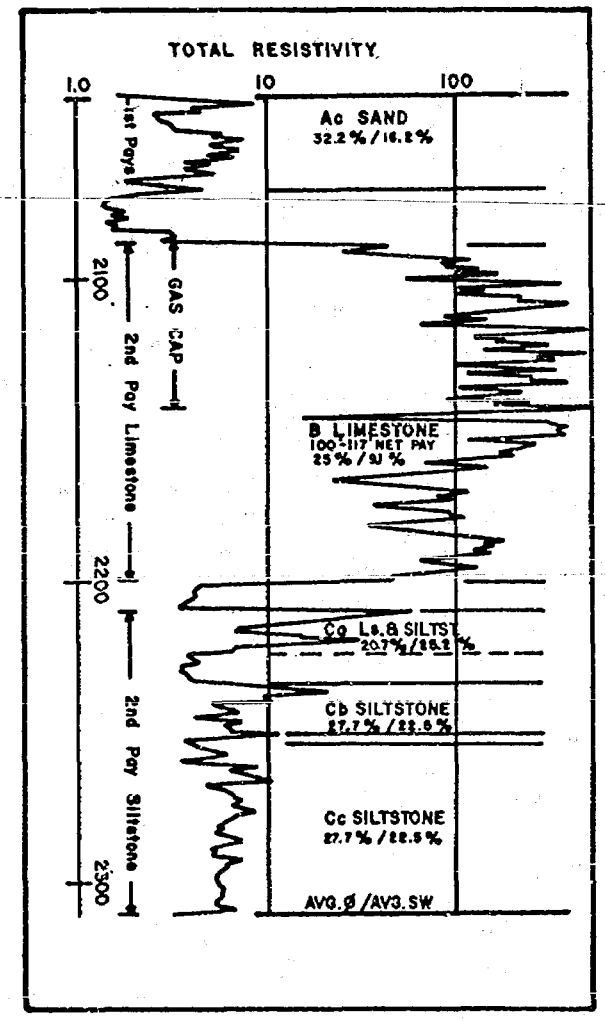


Fig. 3 – Type log showing Second Pay Limestone B with the overlying and underlying zones.

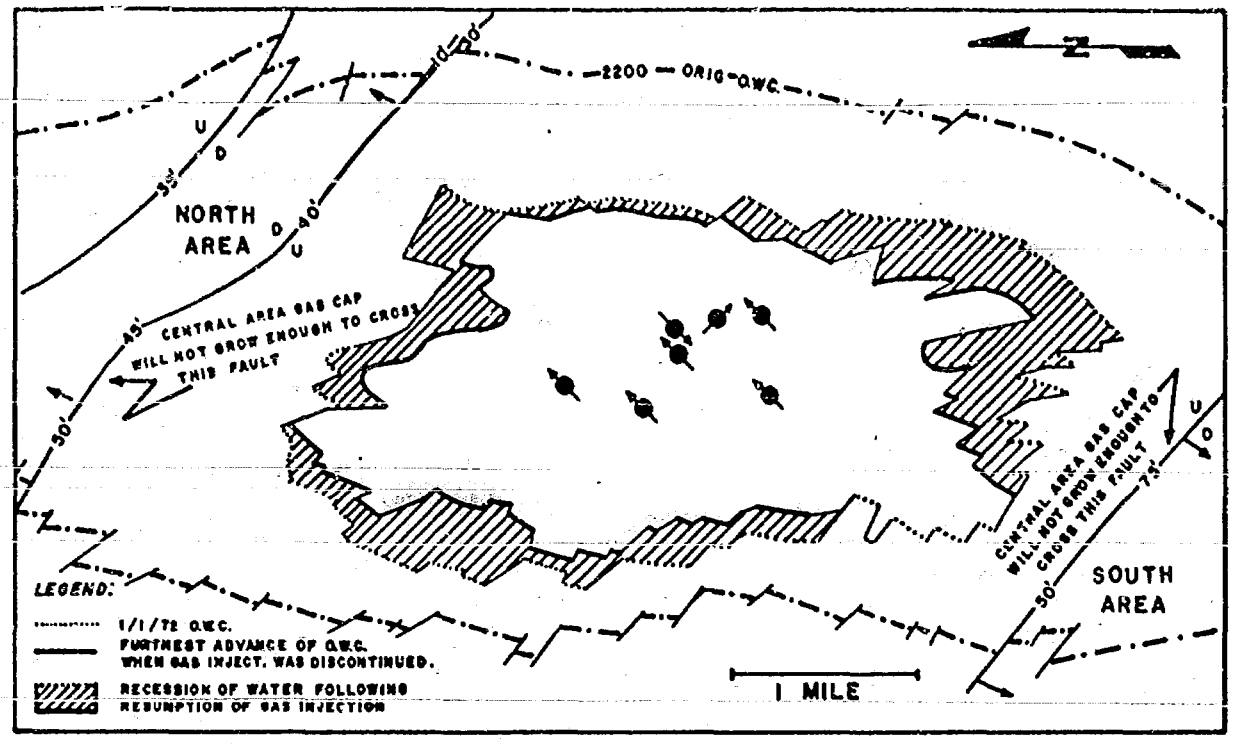


Fig. 4 – Effect of resumption of gas injection.

10^6 m^3/d) vs approximately 37,000 to 40,000 Mcf/D (1.05 to 1.13 × 10^6 m^3/d).

A study of actual experience shows that excessive gas injection rates into this particular pore geometry and rock wettability can displace encroached water back toward the aquifer, thus reducing water cuts to some extent. This unique effect was used to temporarily increase Limestone B oil production rates.

A strong gravity override influence, mainly in the direction of the east and west flanks, will limit the ultimate volume contacted by gas. After 33 years of injection, 63% of original HCPV actually had been "contacted" by gas. Gravity underride also is evident in the water-encroached volume. Approximately 25% of original HCPV has been contacted by water.

Qualitatively speaking, production data suggest that the critical rate with gas displacement is very low compared with that in the case of water displacement. This is because of the higher mobility of the gas. Because of the low dip and high vertical permeability, even with water the critical rate is low.

Fig. 6 may be useful in the case of gas displacement. However, note that very little theoretical work was done to predict such rates; the performance of the reservoir was relied upon greatly.

The water influx into the Limestone B central area has been greatest at the north and south ends because of long distances from gas injection wells at the crest of the formation. It seems overall effectiveness of gas injection can be improved by providing gas injection points closer to the north and south ends of the central area. Dispersion of the gas injection has been started in a southerly and northerly direction.

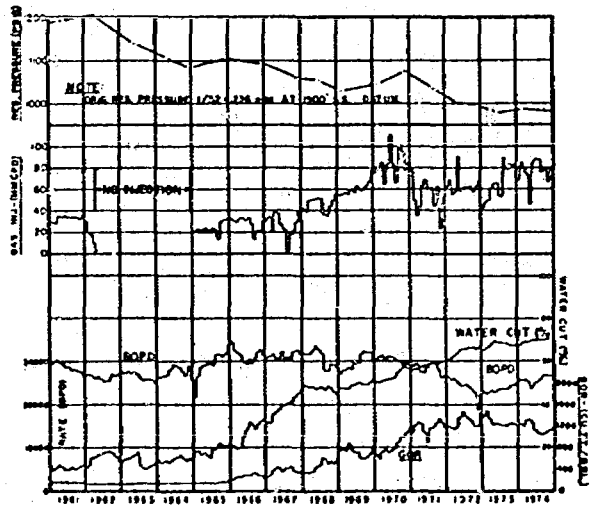


Fig. 5 – Pressure production curves – total reservoir.

Areal Pressure Distribution

Gas injection for pressure maintenance in this anticlinal reservoir has been used successfully, and the rates of injection have been increased from time to time with planned increments of oil withdrawal (Fig. 5). As the injected gas front receded from the crest, the off-take points gradually concentrated downstructure between the gas- and water-drive influences. As the gas-injection program progressed, completions in the Limestone B either were shut in or abandoned to prevent excessive production of gas. Such completions had been produced as long as possible by submerging the tubing below the liquid level in the wells and reducing the production rates.

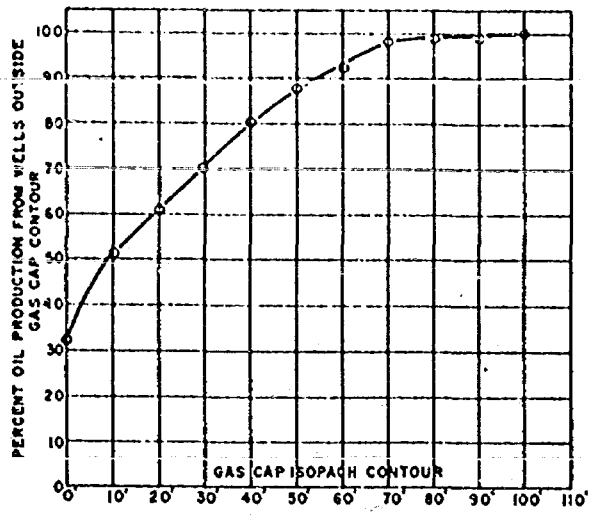


Fig. 6 – Distribution of oil production with respect to gas-cap thickness.

By the end of 1956, as a result of this action, very little oil was being produced from below the gas cap, the main withdrawal having been established around the lateral perimeter of the cap. As of Jan. 1, 1973, over 60% of the central area production came from the area having 20 ft (6 m) or less gas-cap thickness (Fig. 6). A further consequence of this change in oil-withdrawal pattern was a change in the pressure pattern of the reservoir. Before the commencement of gas injection, the lowest pressures were found in the central portion of the reservoir, but as withdrawal moved out with the expansion of the gas cap, the lowest pressures were transferred to the line of greatest production. This resulted in the formation of a "pressure trough" between the gas-invaded area and the aquifer perimeter (Fig. 7). The circumference of the pressure trough increased with the expansion of the gas cap and the resultant outer movement of oil withdrawal from the center of the reservoir. The effect of this low-pressure ring on the gas-cap shape will be considered at a later stage.

North and South Areas

With the present gas injection pattern, there is no chance of creating gas caps in the north and south areas. Water drive, with low recovery efficiency, is the predominant displacement mechanism in these areas. As of Jan. 1, 1972, there were 69 million STB (11×10^6 stock-tank m^3) in place above the oil/water contacts in these areas.

Recent production history is shown in Fig. 8 (north area) and in Fig. 9 (south area). Current production in the north area is 2,950 BOPD (469 m^3/d oil) with 87% water cut. Current production in the south area is 3,050 BOPD (485 m^3/d oil) with 81% water cut.

Plots of water cut vs cumulative oil production were used to determine ultimate oil recovery in each area. The ultimate recovery factors were determined to be 7% in the north area and 9.4% in the south area. These appeared reasonable when compared with breakthrough recovery factors determined by volumetric balance.

The low recovery factors result from a combination of inherently low recovery efficiency by water displacement (20%) and movement of oil from these downstructure to upstructure areas. Movement

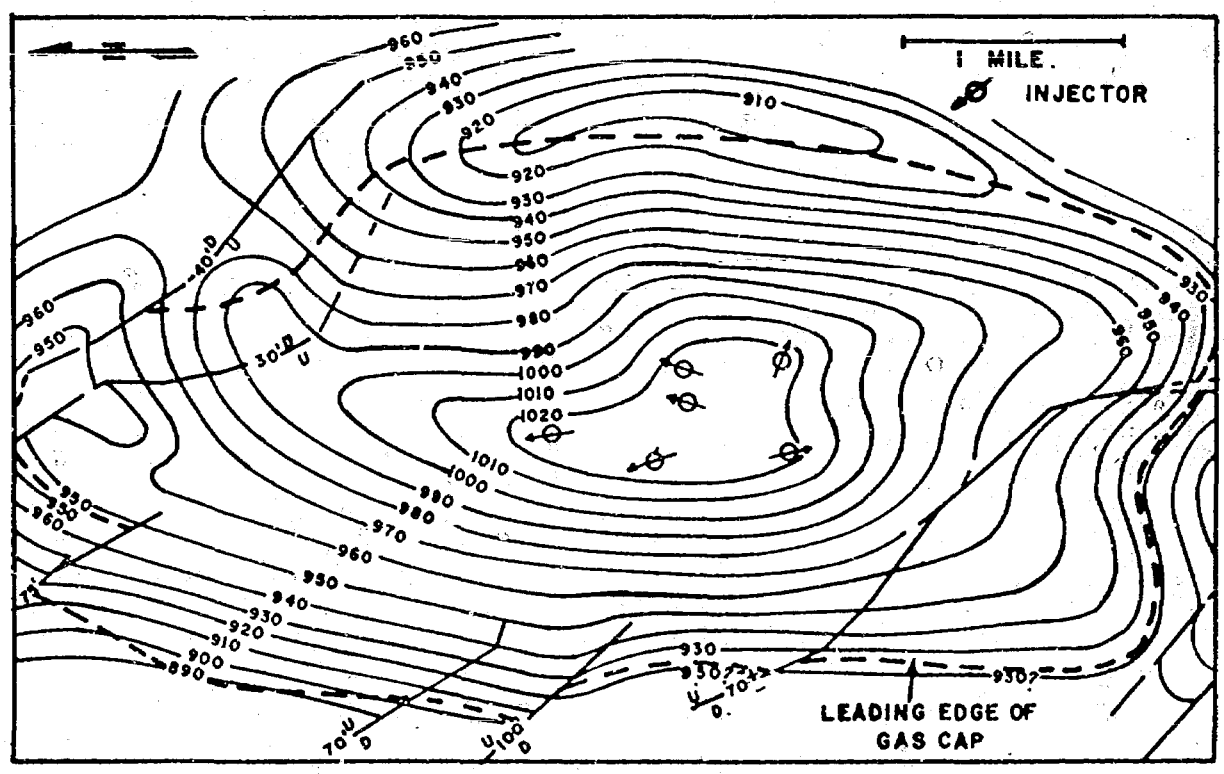


Fig. 7 – Isobaric map (psi).

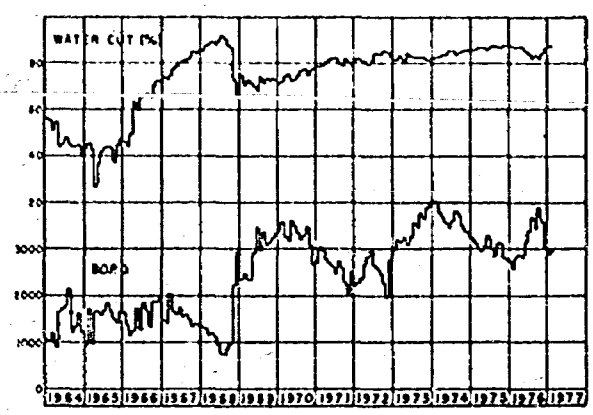


Fig. 8 – Production history of north area.

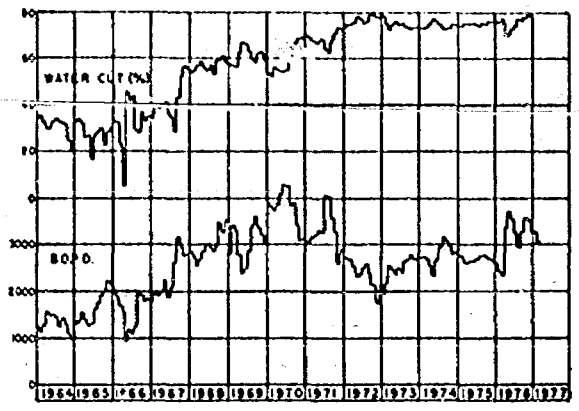


Fig. 9 – Production history of south area.

of oil from the south area is more restricted because of the larger faults present in the south. This is reflected in the slightly higher recovery factor.

With increased gas injection rates, it appears that flow across the faults separating north and south areas from the central area has been reversed. The right-hand portion of Fig. 10 indicates that oil is being transferred to the north and south areas.

Recovery Factor Calculation in the Central Area

The neutron log proved a very useful tool in the recovery factor calculations, with the complex structure and production history of the Limestone B and with the attendant gas override and water underride. A horizontal oil/gas interface need not be assumed, because a carefully designed neutron survey of selected wells would make it possible to generate a gas-cap isopach map (Fig. 11). A volumetric material balance approach then is used to compute the recovery factor in the gas cap. A sample recovery calculation appears as Table 1.

Several neutron surveys were run in the gas-cap area, and each time a recovery factor in the gas cap was calculated. The average recovery for these surveys was 50% (Fig. 12). These calculations proved beyond any doubt that oil recovery by gas is much better than by water in the Limestone B reservoir. This is thought to result from a combination of more than one of the following:

1. Recovery by gas was enhanced by the miscible action of liquids entrained in the injected gas.
2. Arab gas going into solution enhanced the oil mobility.
3. The Limestone B reservoir rock may be oil wet because: (1) laboratory analysis showed a high degree of oil wettability in cores taken from the reservoir; (2) the Laterolog shows the upper portion of the section to have extremely high resistivity, which indicates calculated water saturations of less than 6% (Fig. 13); and (3) excessive gas injection rates can displace encroached water back toward the aquifer

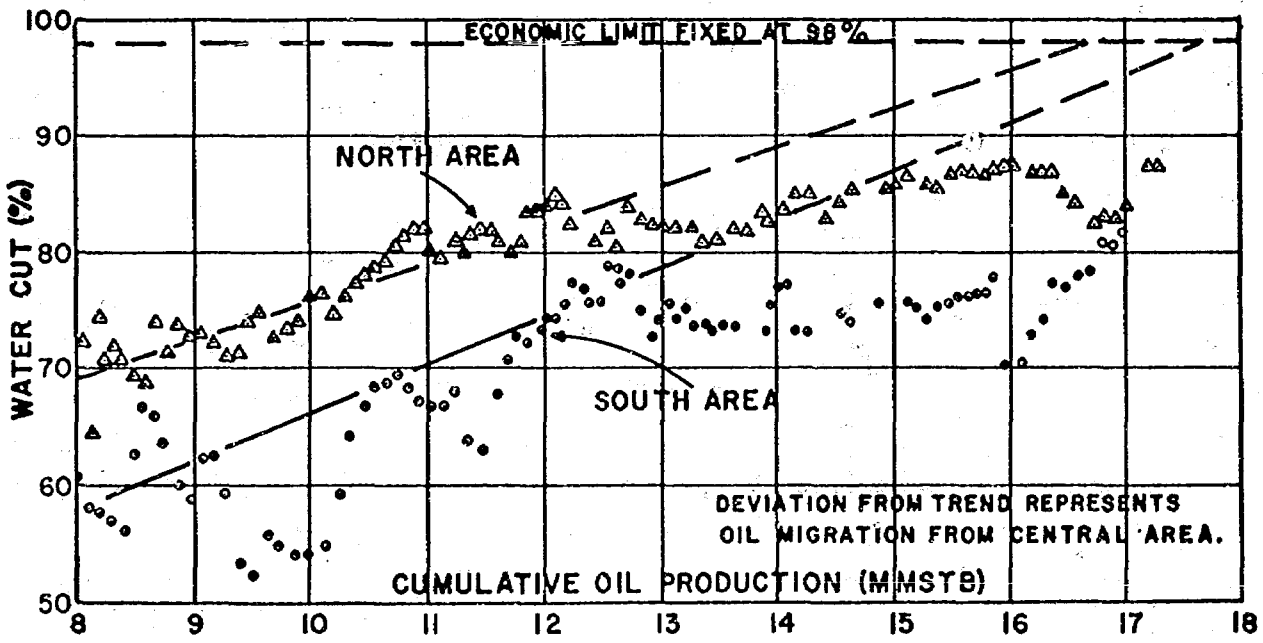


Fig. 10 – Cumulative oil production vs water cut.

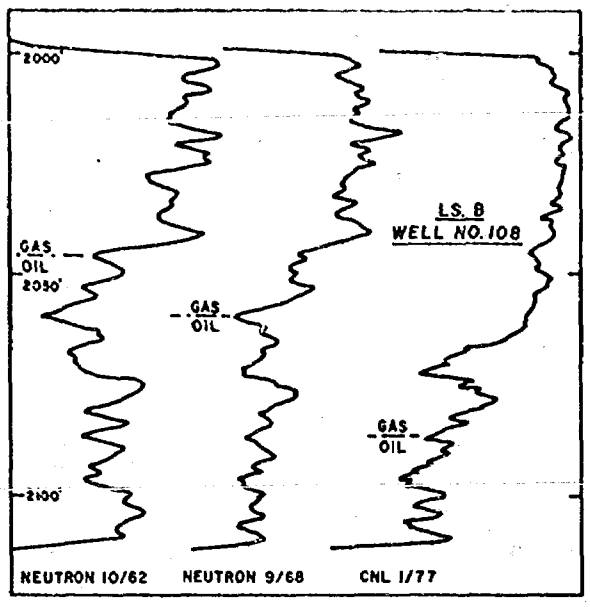


Fig. 11 – Monitoring gas-cap advance by neutron logs.

and reduce or even eliminate water cuts (a case in point is Well 253 where the water cut was as high as 50% and is now zero).

4. Gravity drainage also enhanced the recovery in spite of the low dips in the reservoir rock. The structure is highly faulted and allows Limestone B oil to drain further into underlying pay zones, especially because the pressure in these zones is lower.

Hence, the homogeneous characteristics of the zone, the pressure differential that exists between this zone and the underlying zones, and the communication between these zones by virtue of juxtaposition all contribute to a very effective gravity drainage from the Limestone B (Fig. 14).

Recent Investigations

Injected Gas Quality

Up to 1974, rich unstripped gas [15 to 20 bbl condensate/MMcf gas (84 to 112 m^3 condensate/10^6 m^3 gas)] had been injected into the Limestone B. Subsequently, leaner Khuff gas has been used for injection.

One may wonder what effect this leaner gas has on recovery. The problem was approached as if phase equilibria were the only factor affecting recovery.

The tool used in this investigation has been a flash computer program. Starting with the analyses of both the Arab gas and the crude oil, the composition of the gaseous and liquid phases in the gas cap was computed. The computation then was repeated using Khuff gas. Then the reservoir pressure was altered to see whether the Khuff gas displacement efficiency could match that of Arab gas. This investigation revealed that: (1) Khuff gas causes 8.5% less initial oil swelling than Arab gas; (2) further injection of 1 PV Khuff gas causes a 2.2% shrinkage whereas 1 PV Arab gas causes an additional 4.9% swelling; (3) the oil phase is stripped of much of its light ends when Khuff gas is used, thus becoming less mobile; and (4) a reservoir pressure increase of some 200 psi (1378 kPa) is necessary to offset the drawbacks resulting from use of a leaner gas.

One asset of Khuff gas is its high CO_2 content (6%), since CO_2 is known to enhance recovery by improving microscopic displacement efficiency of oil. However, this factor was not considered here.

In fact, the results of such investigation will be used only qualitatively, since miscible displacement/phase equilibria is not the sole factor affecting recovery and its relative contribution to recovery is not known.

Most of the PVT data available is for reservoir oil being displaced by Arab gas. No PVT data with Khuff gas is available. However, viscosity was not measured when the reservoir fluid was contacted by Arab gas. Whenever such viscosity is required, Beal's correlation tables are used, the reservoir fluid having these properties: viscosity = 2.08 cp at 136°F (2.08 kPa·s at 58°C), bubble-point pressure = 358 psig (2468 kPa), density = 33.5°API (847 mg/cm^3), and formation volume factor = 1.13. Viscosity of reservoir fluid in contact with Arab gas is computed to be 1.1 cp (1.1 kPa·s). Thus, the lowering of viscosity has been helpful in increasing the rate of gravity drainage.

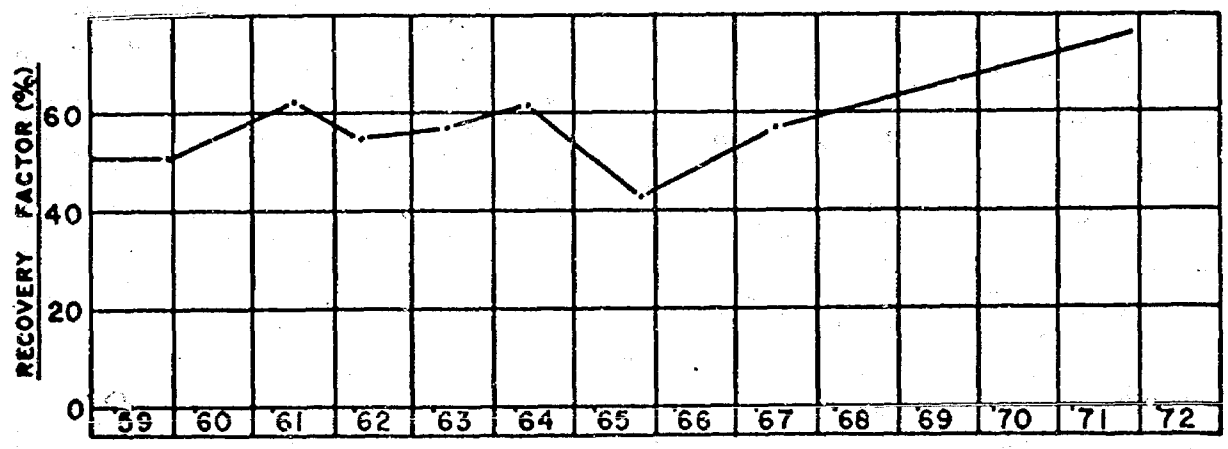


Fig. 12 – Oil recovery factors by gas displacement (based on data obtained from neutron and pressure surveys).

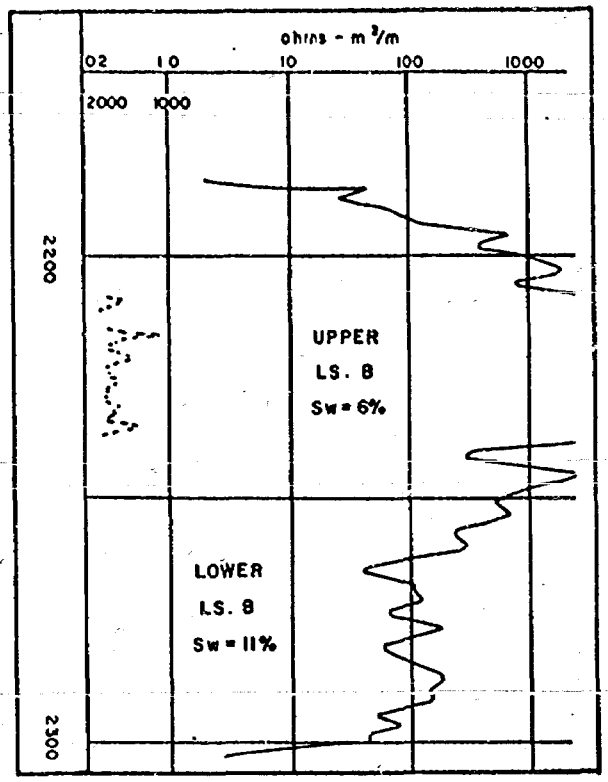


Fig. 13 – Typical Laterolog of Limestone B original oil column.

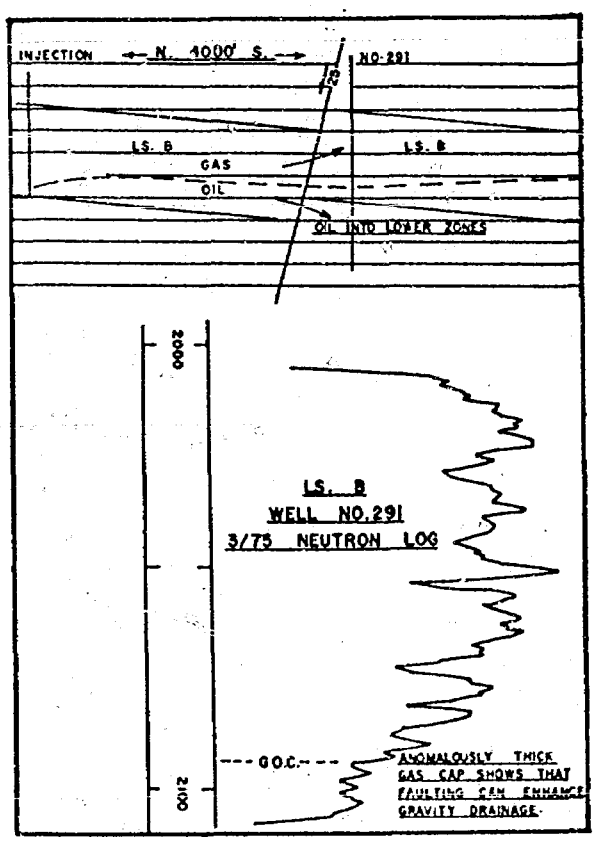


Fig. 14 – Schematic diagram showing enhancement by gravity drainage.

Residual Oil Saturation Profile

It was envisaged that gravity drainage would cause a saturation profile extending from a very low oil saturation at the crest of the structure, where the oil has been contacted by a large number of pore volumes of gas, to a high oil saturation near the gas/oil contact, where the oil has been contacted by only a few pore volumes of gas. Thus, what is calculated as 50% recovery efficiency is merely a reflection of this saturation profile. There is no theoretical reason that, in this highly oil-wet reservoir, residual oil saturation cannot be reduced to a very low figure.

It also appears that gravity drainage may lead to a vertical saturation profile in any well in the gas cap. The logging company has been asked to use its computer program to split the hydrocarbon saturation into gas and oil saturations so that the displacement efficiency can be calculated. To do that, the lithology and gas and oil densities at reservoir conditions had to be provided. It might be possible to extend this analytical approach to older neutron logs if the computer program also was provided with the porosity profile.

So far, the results have been received for only one

TABLE 1 – RECOVERY FACTOR CALCULATION IN THE GAS CAP (May 1, 1962)

Size of Gas Cap: (Based on Neutron Survey 4/62)	
Acres	4,663
Acre-ft	133,541
Avg. gas cap thickness, ft	28.6
HCPV, res bbl	239,165,000
Reservoir Parameters for Gas Cap:	
Porosity (volume weighted), %	24.56
Water saturation, %	6.01
Gas-cap pressure 5/62, psig	1218
Gas-cap temperature, °F	150
Gas formation volume factor at 1,218 psig, 150°F	2.1723
Net Gas Injected: (May 1, 1962)	
Cumulative gas injected, Mcf	88,229,000
Cumulative free gas produced, Mcf	8,203,000
Cumulative net gas injected, Mcf	80,026,000
Cumulative net gas injected, res bbl	173,840,000

Gas Going Into Solution at 1,218 psig: (PVT data)

$$\frac{386 - 128}{1.103} = 234 \text{ cu ft/RB.}$$

Oil Swelling Factor:

$$\frac{1.226}{1.103} = 1.1115.$$

Recovery Factor Calculation:

G_F = Volume of free gas in gas cap, res bbl;
V_{or} = Volume of residual oil in gas cap, res bbl, of original undersaturated crude;
$\therefore G_F + 1.1115\, V_{or} = 239{,}165{,}000$ res bbl,
and $G_F = 173{,}840{,}000 - V_{or}(0.234)(2.1723)$.

$V_{or} = 108{,}297{,}000$ res bbl;

$$\therefore \text{Recovery factor} = \frac{239{,}165{,}000 - 108{,}297{,}000}{239{,}165{,}000} = 0.547.$$

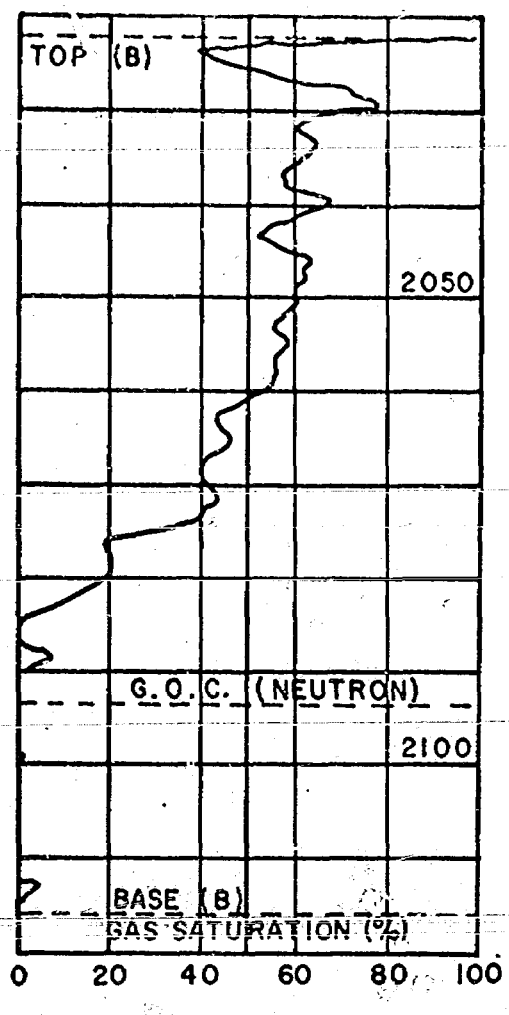


Fig. 15 – Gas saturation.

well (Fig. 15). It is obvious that, as expected, a vertical saturation profile does exist and that the displacement efficiency is in excess of 50%, giving credibility to the calculated 50% recovery efficiency. The recovery efficiency should not be much less than the displacement efficiency, due to the narrow spacing of the wells.

Conclusions

1. Neutron surveys in conjunction with pressure surveys have been used satisfactorily to determine the percentage of oil recovery by gas displacement.
2. Gravity drainage as well as the oil wettability characteristics of the rock have been conducive to a higher oil recovery by gas than by water.
3. Material balance calculations and log analysis have shown that recovery in the gas cap is 50%.
4. The possibility of reduced recovery because of changing from rich Arab gas to lean Khuff gas is recognized. This potential loss will be offset partially because Khuff gas contains significant CO_2.

Acknowledgments

I acknowledge the assistance rendered by the Bahrain Petroleum Co. Ltd. while compiling this paper.

Reference

1. Cotter, W.T.: "Twenty-Three Years of Gas Injection Into A Highly Undersaturated Crude Reservoir," *J. Pet. Tech.* (April 1962) 361-365.

SI Metric Conversion Factors

acre	× 4.046 873	E+03	=	m^2
bbl	× 1.589 873	E−01	=	m^3
cu ft	× 2.831 685	E−02	=	m^3
°F	(°F−32)/1.8		=	°C
ft	× 3.048*	E−01	=	m
mile	× 1.609 347	E+00	=	km
psi	× 6.894 757	E+00	=	kPa
sq ft	× 9.290 304*	E−02	=	m^2

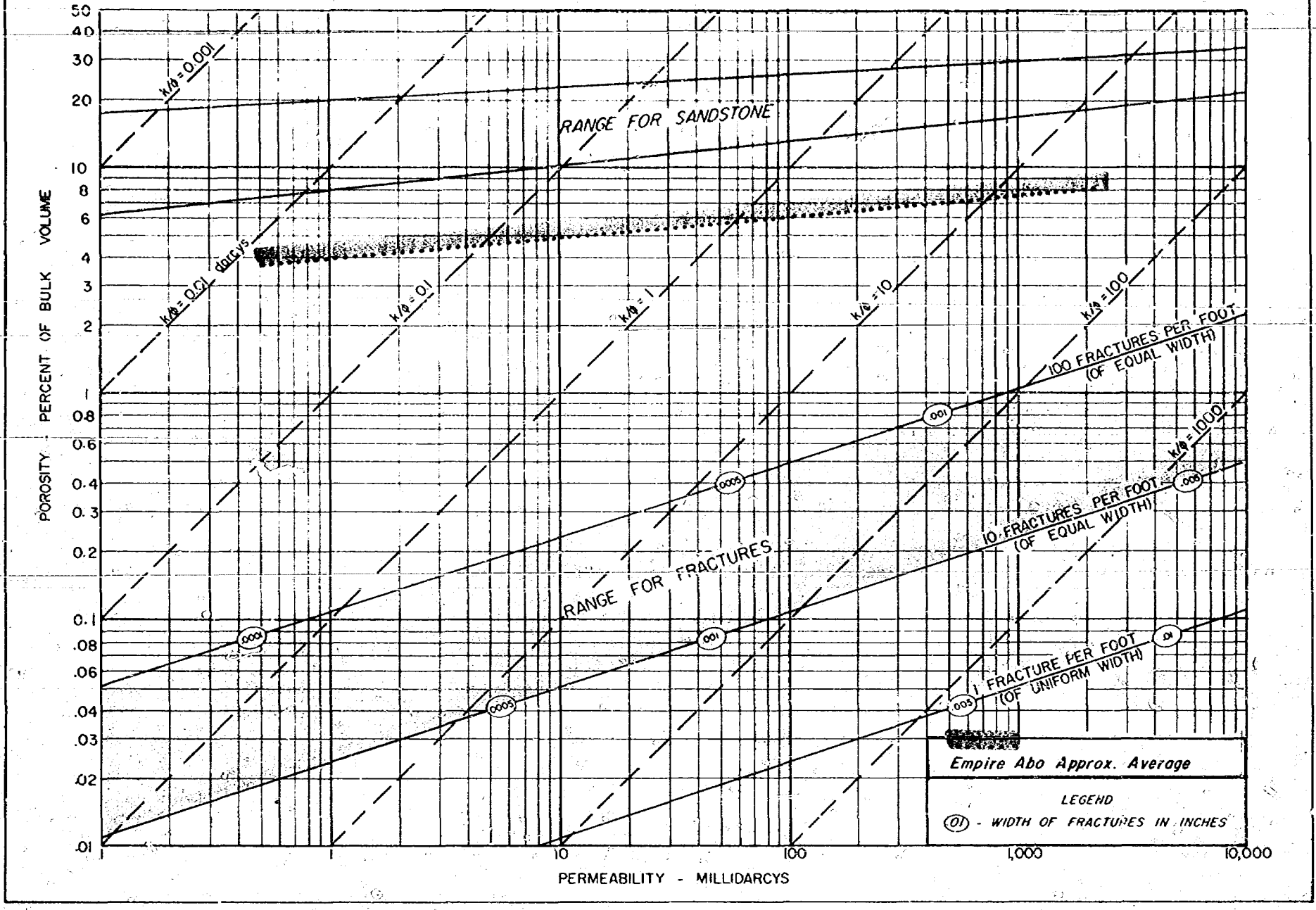
*Conversion factor is exact.

JPT

Original manuscript received in Society of Petroleum Engineers office May 24, 1978. Paper (SPE 7652) accepted for publication March 14, 1979. Revised manuscript received Aug. 24, 1979.

VALUES OF KΦ FOR SANDSTONE RESERVOIRS AND FOR FLOW SYSTEMS OF FRACTURES IN AN IMPERMEABLE MATRIX

FRACTURES PARALLEL TO DIRECTION OF FLOW



H-80

APPENDIX III FIGURE NO. III-3

GRAVITY DRAINAGE RATES
WEST PUERTO CHIQUITO
FOR CONDITIONS OF:
OIL DENSITY 44.9#/cubic foot
GAS DENSITY 5.35#/cubic foot
OIL VISCOSITY .62 centipoises
FORMATION DIP 400 feet per mile

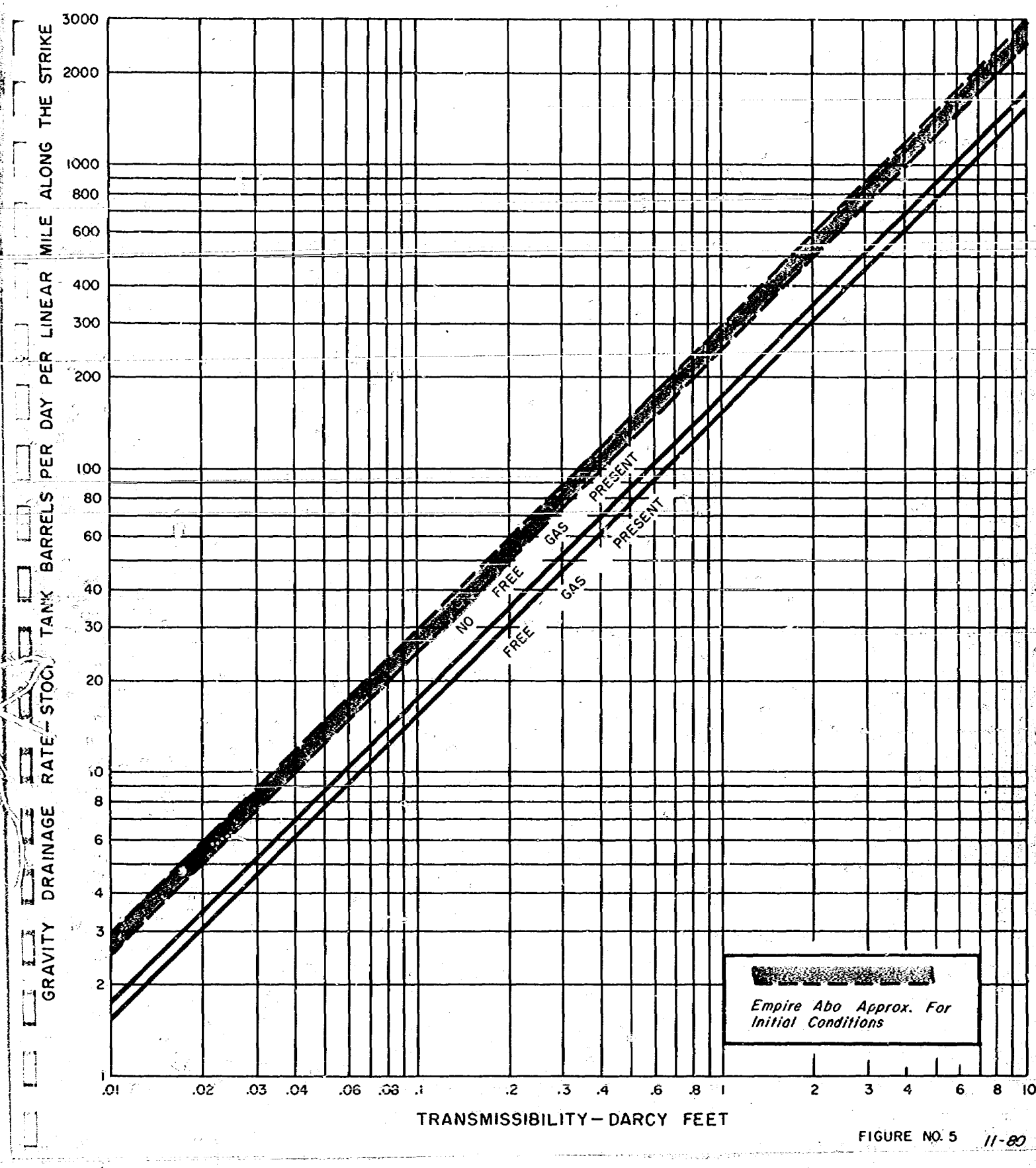
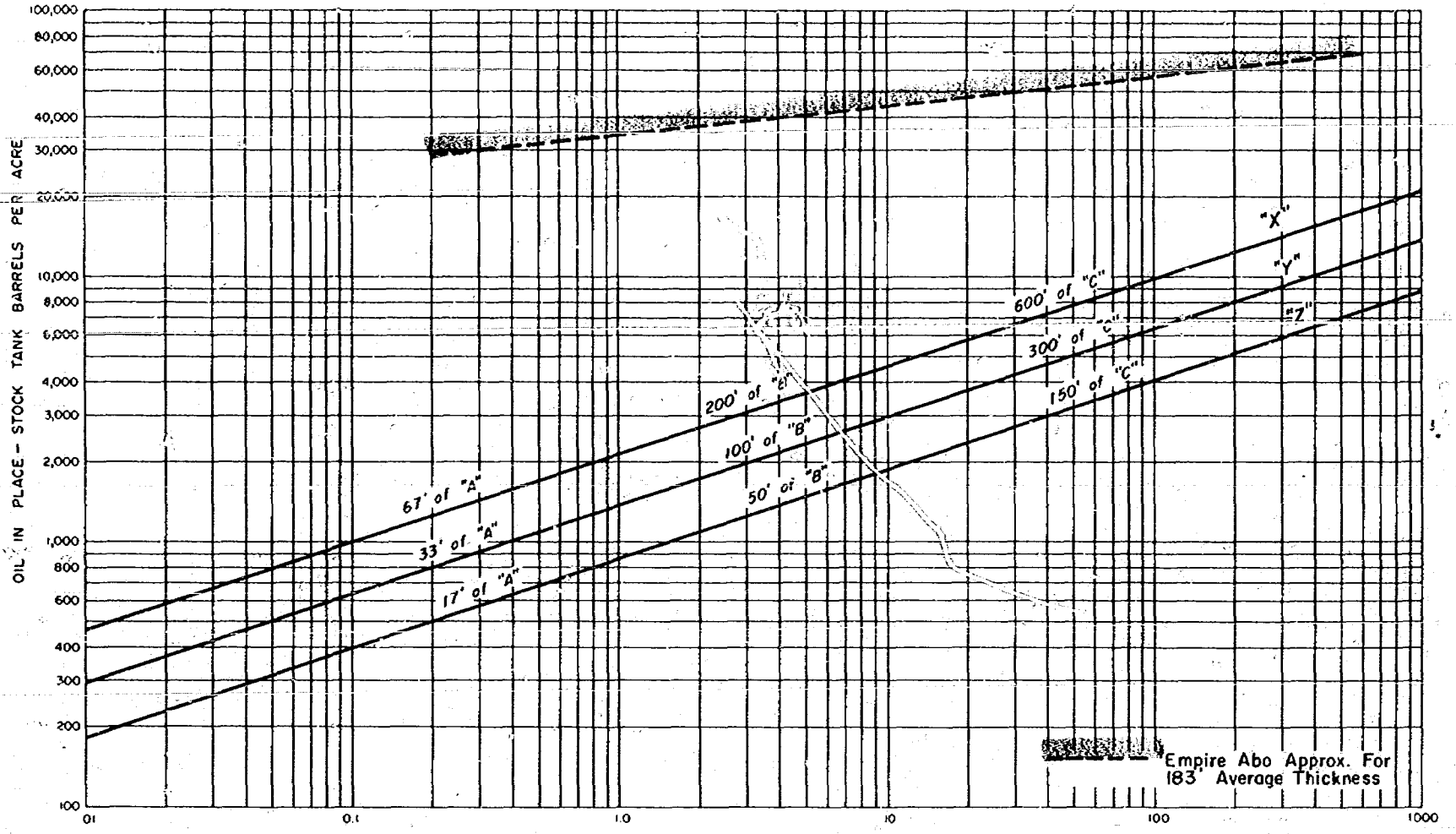


FIGURE NO. 5 11-80

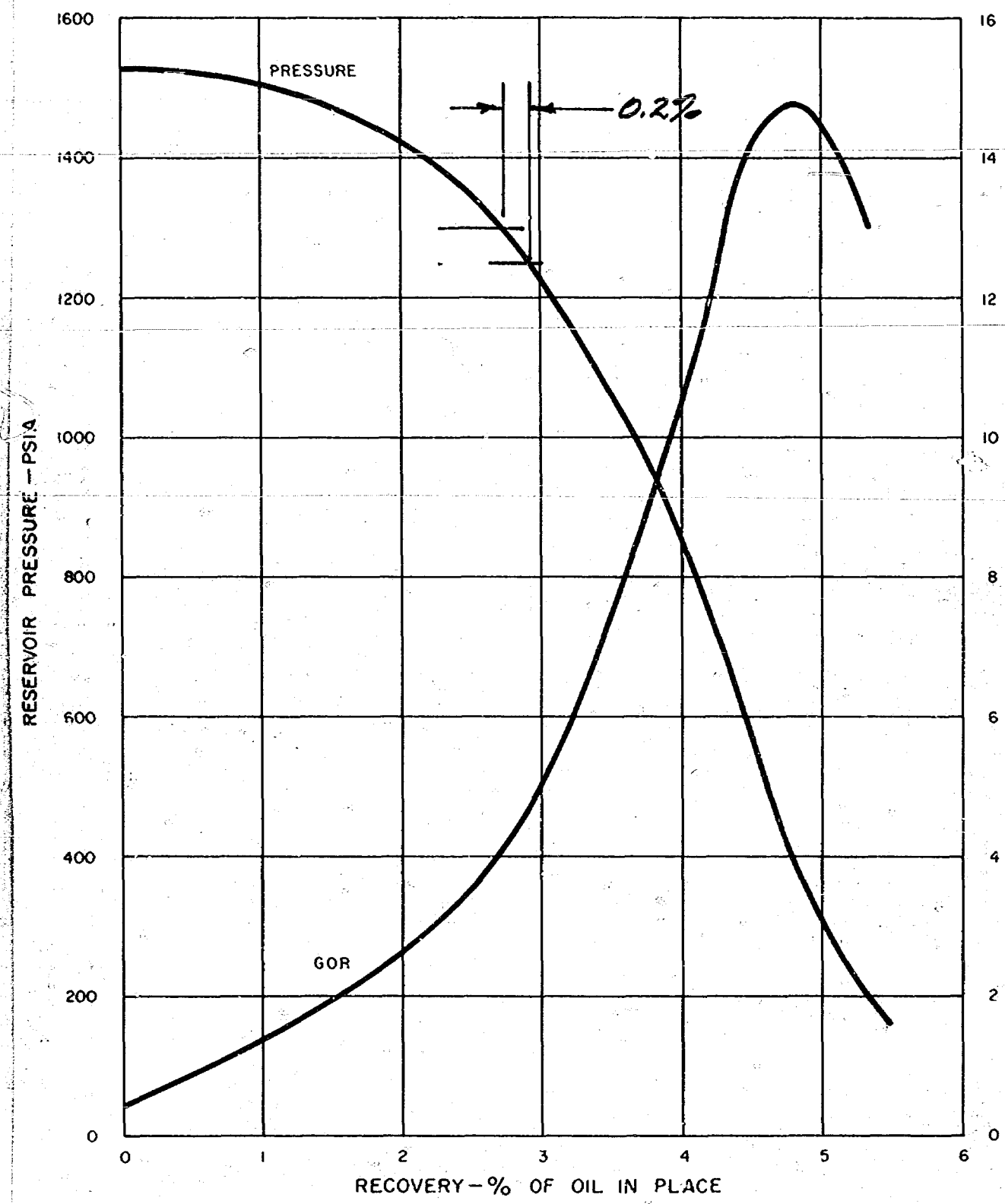
OCI-11

RELATION OF OIL IN PLACE
TO
TRANSMISSIBILITY
FOR
POROSITY-PERMEABILITY RELATIONS
"A", "B" & "C"
AND FOR
RESERVOIR THICKNESSES SHOWN
F.V.F.=1.29



APPENDIX III FIGURE NO. III-5

SOLUTION GAS DRIVE
PRODUCTION HISTORY
CALCULATED FOR CONDITIONS OF:
WEST PUERTO CHIQUITO
PVT DATA
AND
K_g/K_o ESTIMATED FROM LABORATORY
DATA FOR FRACTURED FORMATIONS



APPENDIX IV FIGURE NO. IV-3

NOTE ON DEPLETION PROCESS

CANADA OJITOS UNIT C-34

1. From 1-1-74 to 10-1-80 COU C-34 produced 213,000 barrels of oil.

2. Pressure drop at observation well location during this time was approximately 50#; now (November, 1980) it is ± 1350.

3. Pressure drop in area structurally above the C-34 and draining to it would be from about 1300# to 1250#.

4. For this pressure drop (see graph) the solution-gas drive recovery would be 0.2% of oil in place.

5. For 213,000 barrels to be 0.2% of oil in place, the oil in place would have to be over 100 million barrels.

6. At 100 million barrels in place and 10 sections being drained by this well, oil in place would have to be 10 million barrels per section or 16,000 barrels per acre, which is 10 times the reasonably accurage figure of 1,600 barrels shown by interference tests. (If 5 sections drained - the average for recovery wells - the figures would be twice the above).

7. Conclusion: The depletion process must be something other than solution-gas drive - which means gravity drainage and/or gas drive by pressure maintenance.

COMPARISON OF PRODUCING CAPACITY AND GRAVITY DRAINAGE RATES FOR WELLS ON WEST SIDE OF WEST PUERTO CHIQUITO POOL

TRANSMISSIBILITY (Kh) (Darcy feet)	GRAVITY DRAINAGE RATE: BOPD/MILE ALONG STRIKE FOR DIP OF: 100'/MILE (BOPD/MILE)	200'/MILE (BOPD/MILE)	PER WELL APPROX. PRODUCING CAPACITY FROM* TO* (BOPD)
.01	.35	.7	5 - 35
.1	3.5	7	50 - 350

* for range of ratios of re/rw of 1 to 3 and Ko/K of .3 to .7

GRAVITY DRAINAGE RATES
WEST PUERTO CHIQUITO

FOR CONDITIONS OF:
OIL DENSITY 44.9#/cubic foot
GAS DENSITY 5.35#/cubic foot
OIL VISCOSITY .62 centipoises

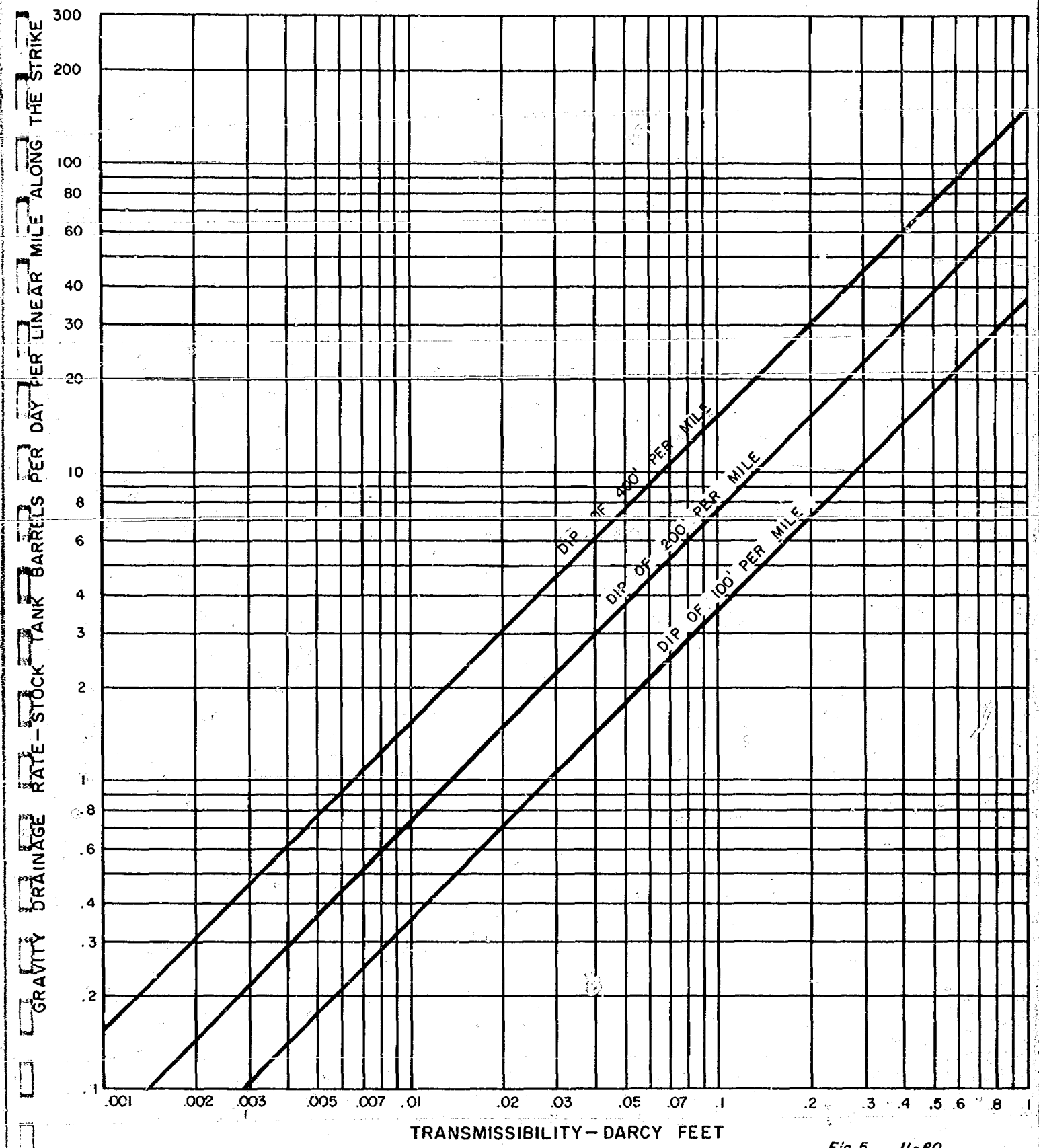


Fig. 5 11-80

INDEX OF
BENSON-MONTIN-GREER DRILLING CORP. EXHIBITS
IN CASE NO. 7075
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

NOVEMBER 24, 1980

PART I — INFORMATION RELATIVE TO EFFICIENCY OF RECOVERY FOR DEPLETION METHOD OF GRAVITY DRAINAGE ASSISTED BY PRESSURE MAINTENANCE BY GAS INJECTION

SECTION A: Factors affecting increased gravity drainage recovery conducted under high pressure as compared to low pressure

1. Graph

SECTION B: Bahrain Field: Limestone B reservoir

Article from December, 1979 Journal of Petroleum Technology

SECTION C: Empire Abo Field

1. Graph of porosity vs. permeability
2. Graph of gravity drainage potential
3. Graph of oil in place per acre vs. transmissibility

SECTION D: Canada Ojitos Unit

1. Graph, COU C-34
2. Schedule, COU C-34

PART II — COMPARISON OF PRODUCING CAPACITIES AND GRAVITY DRAINAGE RATES FOR WELLS IN THE WEST PART OF THE WEST PUERTO CHIQUITO POOL

SECTION E:

1. Schedule
2. Graph

INCREASE IN RECOVERY
BY DEPLETION AT HIGH PRESSURE
AS COMPARED TO
DEPLETION AT LOW PRESSURE
FOR VARIOUS FINAL OIL SATURATIONS

CONDITIONS: HIGH PRESSURE 1500#
F.V.F. = 1.29
LOW PRESSURE 50#
F.V.F. = 1.11
CONNATE WATER SATURATION = 10%

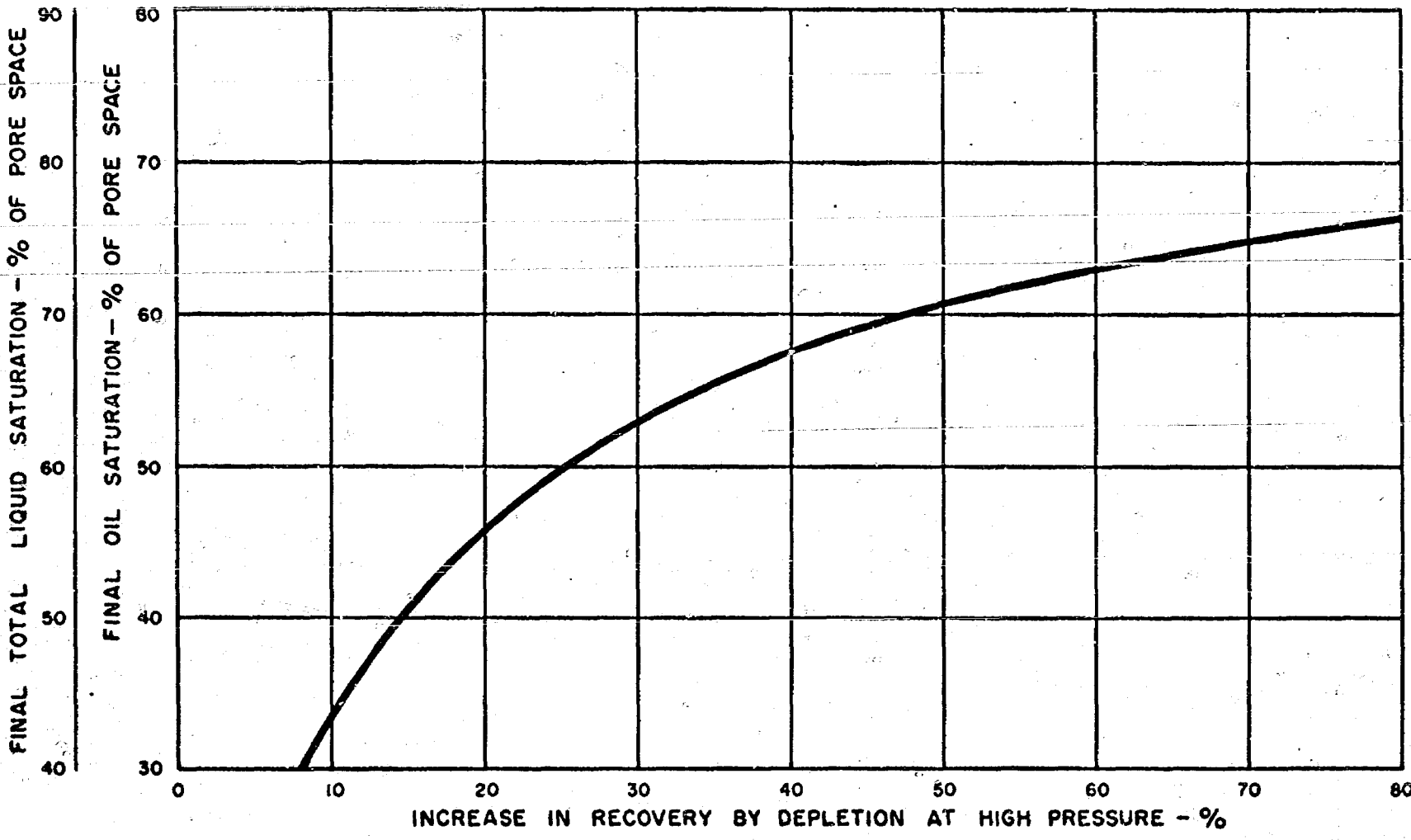


FIGURE NO. 12

Effective Displacement of Oil by Gas Injection in a Preferentially Oil-Wet, Low-Dip Reservoir

Jaffar A.N. Shehabi, SPE-AIME, The Bahrain National Oil Co.

Introduction

Gas injection as a means of maintaining pressure and improving oil recovery has been employed in the Bahrain field Second Pay Limestone B reservoir for the last 39 years. This reservoir is oil-wet. Maintaining reservoir pressure was the primary objective in the beginning. The pressure response was almost immediate and probably conformed very closely to a simple material balance, because all producing zones on the highly faulted Bahrain structure were still close to virgin conditions.

Early gas breakthrough became a matter of concern with respect to total field productivity and ultimate recovery. However, wells in the gas area were kept on production, at an optimum rate governed by tubing submergence. It gradually was realized that even with early breakthrough, a satisfactory oil recovery factor was being obtained. Attention then focused on determining actual recovery and explaining the mechanism involved.

The most recent reservoir study showed a 50% recovery factor in the gas-invaded volume, as compared to 20 to 25% in the water-invaded volume. It also was found that because of fluid transfer to other zones, the required injection rate for the Limestone B is 70,000 Mcf/D (1.98×10^6 m^3/d) instead of the 40,000 Mcf/D (1.13×10^6 m^3/d) calculated for the Limestone B alone.

0149-2136/79/0012-7652$00.25
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This paper describes some pertinent aspects of the reservoir, the gas injection program, and the methods used to calculate the recovery factor.

Reservoir Description

The Bahrain field structure is a highly faulted, elongated anticline (Fig. 1). Structural dips in the oil-producing horizons are in the order of 5°. The Bahrain zones, of middle Cretaceous age, are the most important oil-producing group found in this field. They are divided into eight separate zones, with zonal separation varying from 7 to 50 ft (2.13 to 15.24 m). Three types of lithology are present: limestone, siltstone, and sandstone. At the crest of the structure, the gross productive interval was 525 ft (160 m) and original net oil pay thickness was 325 ft (99 m).

The most important zone within this group, and the subject of this paper, is the Second Pay Limestone B. The reservoir rock is a soft, porous, stary limestone with limited fractures and vugs. Gross thickness varies slightly from [illegible] ft (31 to 35.4 m), all of which is considered net pay. Average porosity and permeability are [illegible] md, respectively. There are no impermeable streaks to affect vertical permeability. The middle 50 ft (15.24 m) has the highest porosity and permeability. The basal 30 to 40 ft (9.14 to 12.19 m) is slightly different in character and appears to have a lower specific productivity index. Fig. 2 shows the porosity

Gas injection as a means of pressure maintenance has been employed in the Bahrain field Second Pay Limestone B reservoir for the last 39 years. This paper describes aspects of the gas injection program and the method used to calculate recovery of oil by gas, which has been found to be much greater than that by water drive.

profile, and Fig. 3 shows type log. Average initial water saturation was 6% in the upper section and 11% in the basal section. Previous laboratory work led to the conclusion that the reservoir rock was preferentially oil-wet. For wettability determination, two plugs were cut from preserved core samples: one sample was flooded with brine until a minimum oil saturation was obtained; the other sample was flooded with oil until a minimum water saturation was obtained. The sample with minimum oil content was allowed to imbibe oil spontaneously; the sample with minimum water content was allowed to imbibe water spontaneously. The two volumes of imbibed fluids were measured periodically.

The reservoir oil was highly undersaturated, having a saturation pressure of 358 psig (2468 kPa) as compared to the original reservoir pressure of 1,236 psig (8522 kPa) at 1,900 ft (579 m) subsea. The oil has a solution gas/oil ratio (GOR) of 128 scf/STB (22.8 std m^3/stock-tank m^3) and a density of 0.8556 g/cm^3. Since this is an old reservoir, very limited information is available on virgin parameters, such as viscosity.

The productive limits of the Limestone B reservoir, approximately 8.5 miles (13.7 km) long × 3 miles (4.8 km) wide, encompassed 13,750 acres ($55.640 \times 10^6 m^2$) and contained almost 2 billion STB (318×10^6 stock-tank m^3) original oil in place (OOIP). Cumulative production as of Jan. 1, 1972, was 283 million STB (45×10^6 stock-tank m^3) oil and 79 million STB (12.6×10^6 stock-tank m^3) water. Cumulative gas injected up to Jan. 1, 1972, was 206,433 MMcf (5.8×10^9 m^3).

Gas-Injection History

The first well tapped oil from this zone at 1,236 psig (8522 kPa) in 1932. By Feb. 1938, after only 14 million STB (2.22×10^6 stock-tank m^3) or 0.7% OOIP had been produced, reservoir pressure had declined by 118 psig (813 kPa). High-pressure nonassociated Arab zone gas was readily available for injection into the Limestone B without requiring compression. Thus, the gas injection program to maintain pressure was initiated in April 1938. The Arab gas was relatively rich and was injected without prior processing for liquid recovery. A total of 189,000 MMcf (5.4×10^9 m^3) Arab gas had been injected by April 1974, at which time it was totally replaced by the much leaner and more abundant Khuff zone gas. Up until the discontinuation of Arab gas injection, some 74,383 MMcf (2.1×10^9 m^3) Khuff gas also had been injected.

Limestone B injection was suspended temporarily from May 1962 to Jan. 1965 while continuing to inject the lower siltstone zones. The purpose was to observe reservoir pressure behavior of the lower zones in the absence of injection into the Limestone B. The reservoir pressure of both the siltstone zones and the Limestone B declined rapidly at about the same rate, proving fairly conclusively that reservoir communication existed. As a result, continued gas injection into the Bahrain zones was solely into the Limestone B.

Transfer of fluids from the Limestone B to the underlying and overlying formations prior to 1962 is believed to have been minimal or nonexistent,

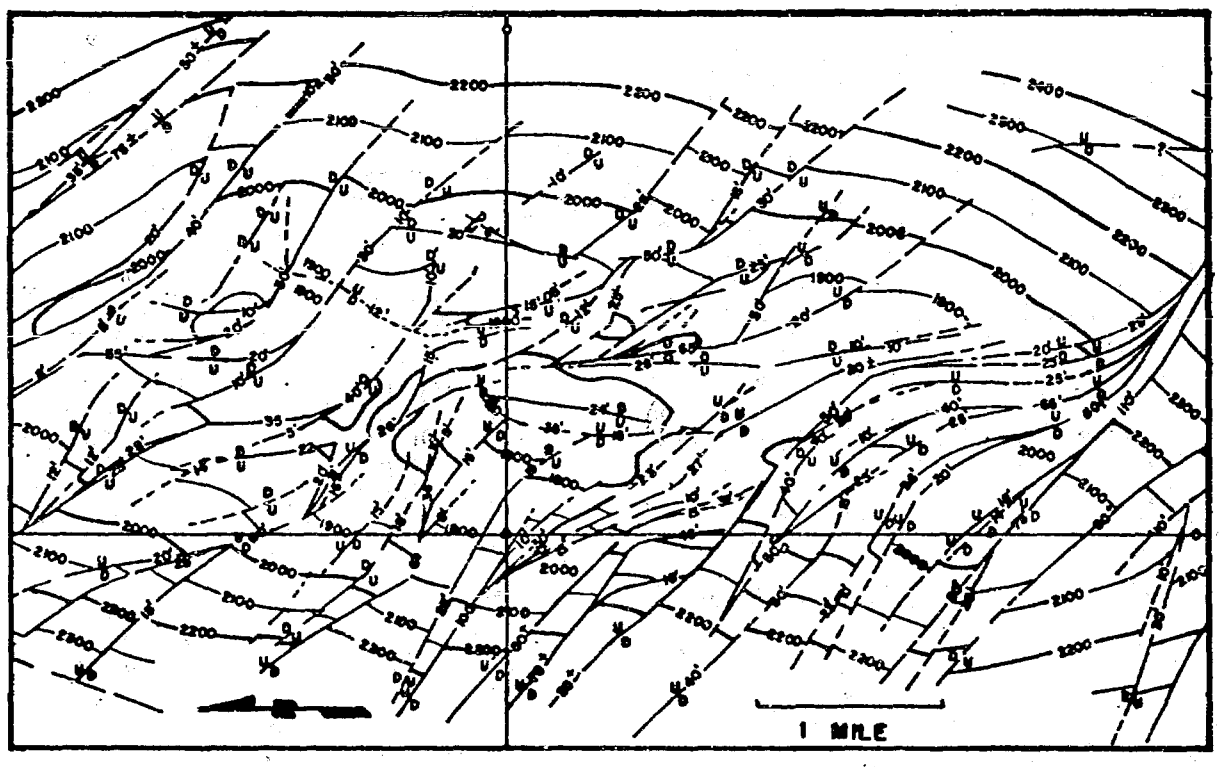


Fig. 1 – Structure map of Second Pay Limestone B.

because pressures were compatible. In subsequent material balance studies, it was found that recovery efficiency by gas was more than 50%. This indicates fluid transfer due to the decline in pressure in the underlying and overlying formations.

Subsequent production behavior of the individual zones has conclusively proved that the Limestone B is only one part of a unit that also includes the overlying sandstone and the underlying siltstones. This conclusion is important from the standpoint of determining injection rate requirements and explaining anomalously high recovery factors that could be calculated for any of these zones if they were treated as an entity. Examples are given later in the text. Overall recovery factor on a unit basis is probably in line with industry published data.

Another interesting aspect of the injection suspension period is the appearance of water cuts in the higher structural row of Limestone B wells and the regression of this water shortly after gas injection was resumed. Fig. 4 shows the fieldwide extent of this occurrence. Fig. 5 shows the recent pressure and production history of the Limestone B. In this figure as well as in subsequent figures, early history was not included, because very few recovery calculations were made before 1960.

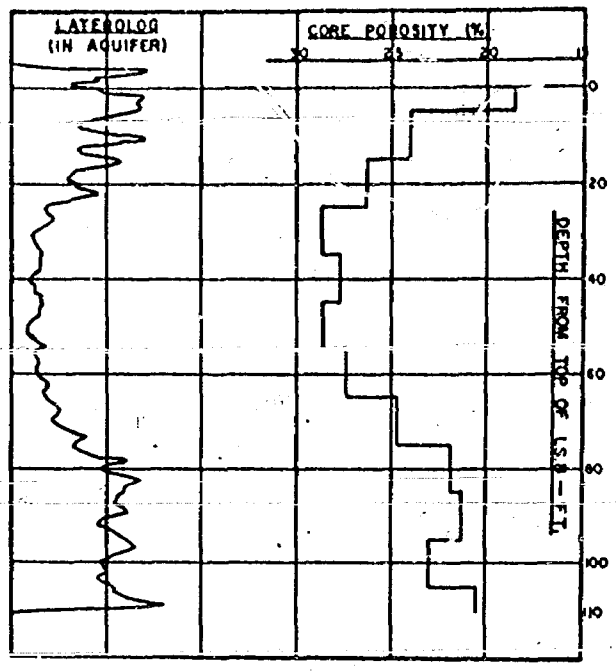


Fig. 2 – Porosity distribution in Second Pay Limestone B.

Recovery Mechanism

In order to analyze the recovery mechanism and calculate reserves, the Limestone B was subdivided into north, central, and south areas. Major faults that would prevent further expansion of the gas cap in a north-south direction helped to define the individual areas (Fig. 4). The north and south areas have been under the influence of an active water drive, whereas the central area has a combination of gas-cap drive, gravity drainage, and water drive.

The material balance calculations made in 1954 and 1959 following neutron surveys indicated a 50% recovery efficiency. In 1972, Laterolog surveys behind the water front indicated a 20% displacement efficiency by water.

In the 1972 study, a cutoff had to be chosen in order to calculate the fluid transfer to other zones. Thus, 50% and 20% recovery efficiencies by gas and water, respectively, were chosen. Gravity drainage was not quantified and was assumed to be an integral part of the 50% recovery factor.

Central Area

Ultimate recovery in the central area is estimated to be 29.7%, resulting from a combination of gas displacement, gravity drainage, and displacement by water. Recovery efficiency in the gas-invaded volume is 50% as compared to 20 to 25% in the water-invaded volume. Therefore, the objective is to continue gas injection at an optimum rate until a practical maximum growth of the gas cap is reached. The optimum rate is defined as the rate that will maintain reservoir pressure with zero net water influx. Because of fluid transfer from the Limestone B to other zones, the current optimum injection rate actually required is much higher than theoretically required – 66,000 to 70,000 Mcf/d (1.87 to 1.98 ×

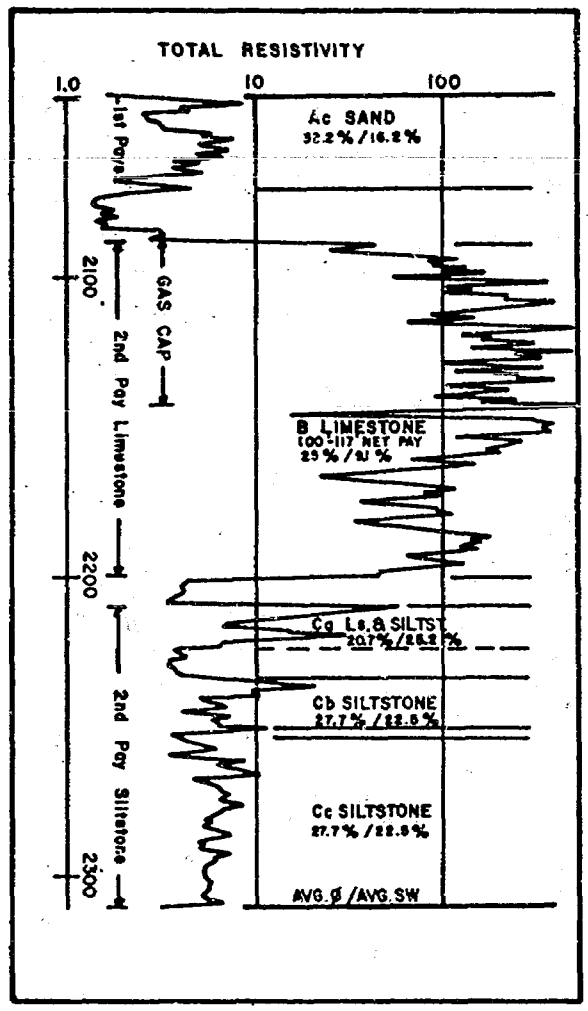


Fig. 3 – Type log showing Second Pay Limestone B with the overlying and underlying zones.

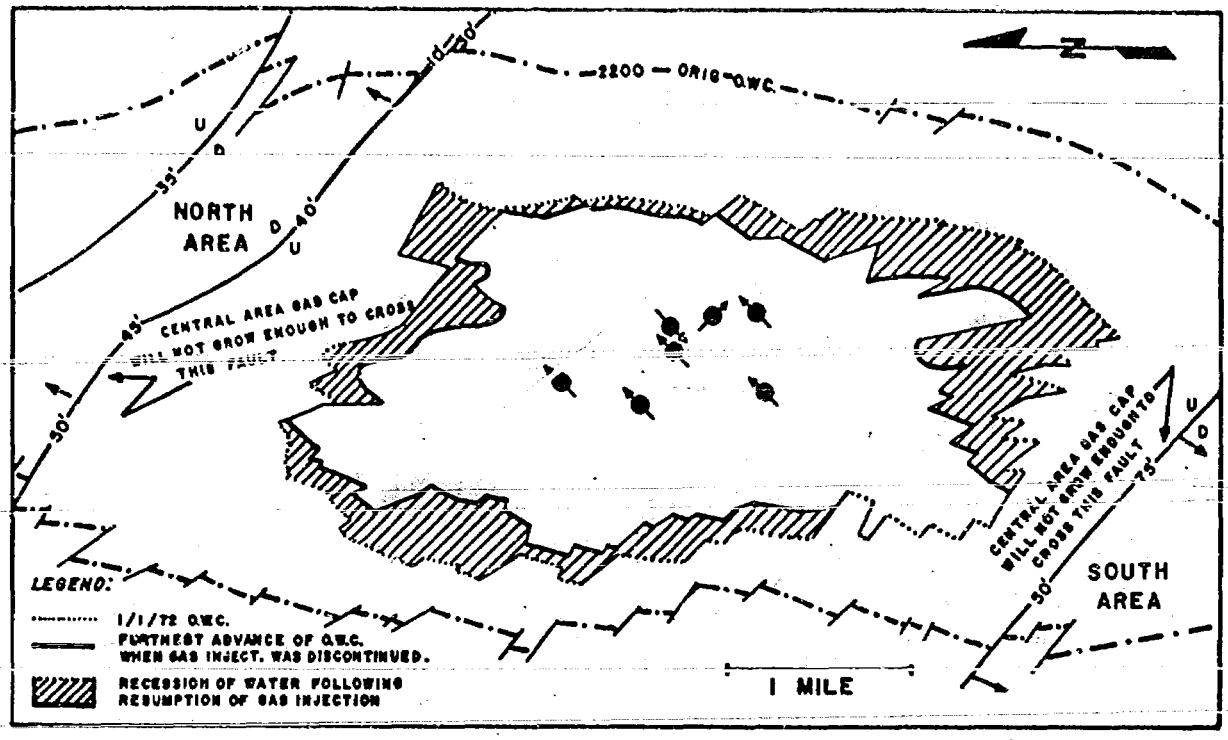


Fig. 4 – Effect of resumption of gas injection.

10^6 m^3/d) vs approximately 37,000 to 40,000 Mcf/D (1.05 to 1.13 × 10^6 m^3/d).

A study of actual experience shows that excessive gas injection rates into this particular pore geometry and rock wettability can displace encroached water back toward the aquifer, thus reducing water cuts to some extent. This unique effect was used to temporarily increase Limestone B oil production rates.

A strong gravity override influence, mainly in the direction of the east and west flanks, will limit the ultimate volume contacted by gas. After 33 years of injection, 63% of original HCPV actually had been "contacted" by gas. Gravity underride also is evident in the water-encroached volume. Approximately 25% of original HCPV has been contacted by water.

Qualitatively speaking, production data suggest that the critical rate with gas displacement is very low, compared with that in the case of water displacement. This is because of the higher mobility of the gas. Because of the low dip and high vertical permeability, even with water the critical rate is low.

Fig. 6 may be useful in the case of gas displacement. However, note that very little theoretical work was done to predict such rates; the performance of the reservoir was relied upon greatly.

The water influx into the Limestone B central area has been greatest at the north and south ends because of long distances from gas injection wells at the crest of the formation. It seems overall effectiveness of gas injection can be improved by providing gas injection points closer to the north and south ends of the central area. Dispersion of the gas injection has been started in a southerly and northerly direction.

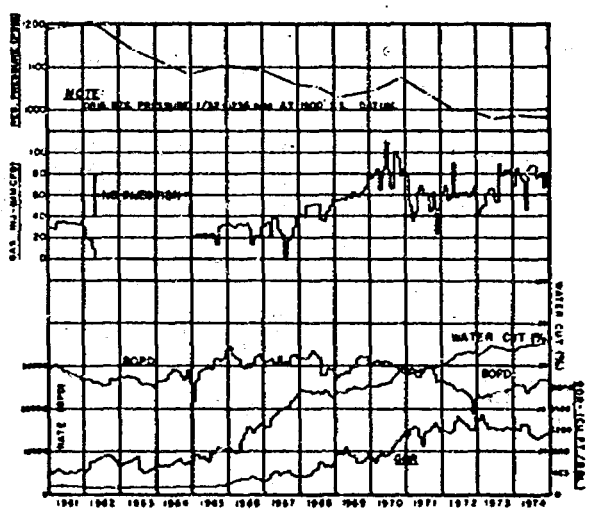


Fig. 5 – Pressure production curves – total reservoir.

Areal Pressure Distribution

Gas injection for pressure maintenance in this anticlinal reservoir has been used successfully, and the rates of injection have been increased from time to time with planned increments of oil withdrawal (Fig. 5). As the injected gas front receded from the crest, the off-take points gradually concentrated downstructure between the gas- and water-drive influences. As the gas-injection program progressed, completions in the Limestone B either were shut in or abandoned to prevent excessive production of gas. Such completions had been produced as long as possible by submerging the tubing below the liquid level in the wells and reducing the production rates.

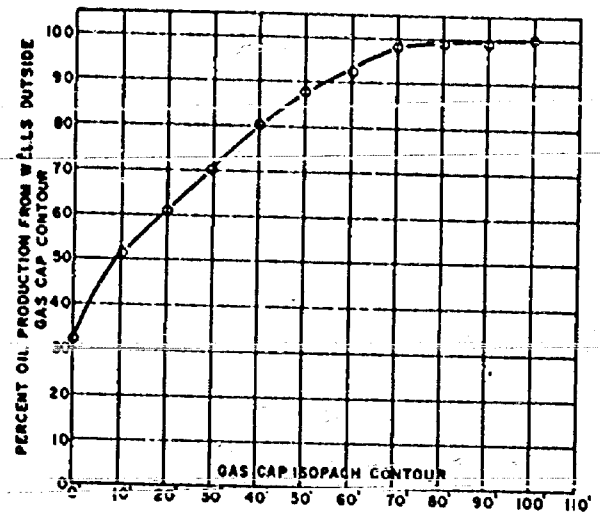


Fig. 6 – Distribution of oil production with respect to gas-cap thickness.

By the end of 1956, as a result of this action, very little oil was being produced from below the gas cap, the main withdrawal having been established around the lateral perimeter of the cap. As of Jan. 1, 1973, over 60% of the central area production came from the area having 20 ft (6 m) or less gas-cap thickness (Fig. 6). A further consequence of this change in oil-withdrawal pattern was a change in the pressure pattern of the reservoir. Before the commencement of gas injection, the lowest pressures were found in the central portion of the reservoir, but as withdrawal moved out with the expansion of the gas cap, the lowest pressures were transferred to the line of greatest production. This resulted in the formation of a "pressure trough" between the gas-invaded area and the aquifer perimeter (Fig. 7). The circumference of the pressure trough increased with the expansion of the gas cap and the resultant outer movement of oil withdrawal from the center of the reservoir. The effect of this low-pressure ring on the gas-cap shape will be considered at a later stage.

North and South Areas

With the present gas injection pattern, there is no chance of creating gas caps in the north and south areas. Water drive, with low recovery efficiency, is the predominant displacement mechanism in these areas. As of Jan. 1, 1972, there were 69 million STB (11×10^6 stock-tank m^3) in place above the oil/water contacts in these areas.

Recent production history is shown in Fig. 8 (north area) and in Fig. 9 (south area). Current production in the north area is 2,950 BOPD (469 m^3/d oil) with 87% water cut. Current production in the south area is 3,050 BOPD (485 m^3/d oil) with 81% water cut.

Plots of water cut vs cumulative oil production were used to determine ultimate oil recovery in each area. The ultimate recovery factors were determined to be 7% in the north area and 9.4% in the south area. These appeared reasonable when compared with breakthrough recovery factors determined by volumetric balance.

The low recovery factors result from a combination of inherently low recovery efficiency by water displacement (20%) and movement of oil from these downstructure to upstructure areas. Movement

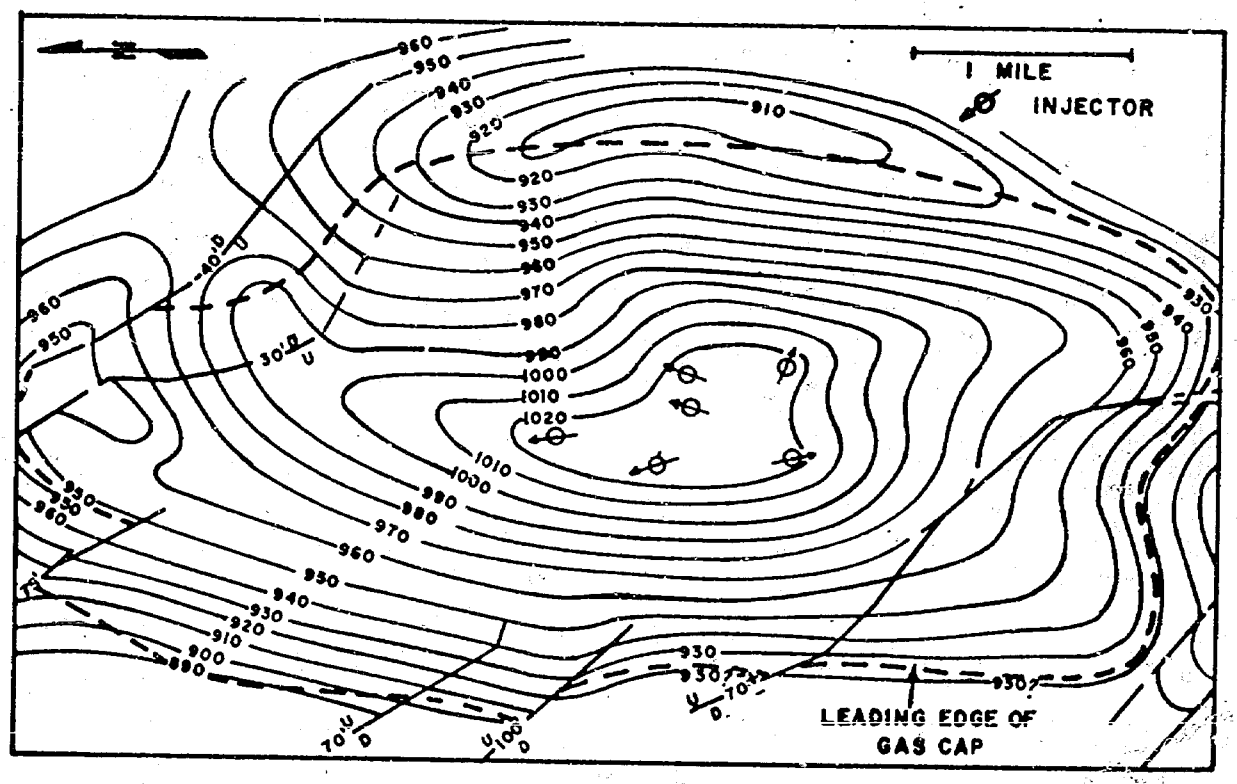


Fig. 7 – Isobaric map (psi).

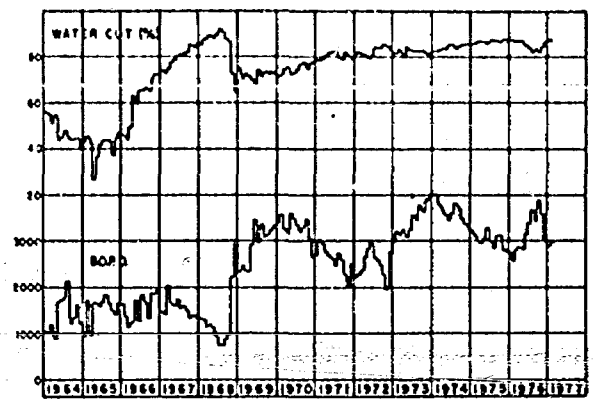


Fig. 8 – Production history of north area.

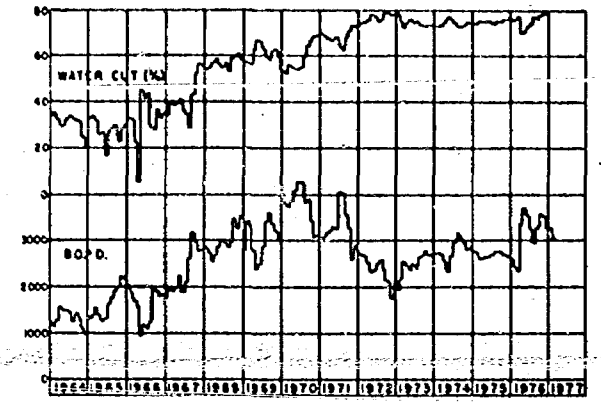


Fig. 9 – Production history of south area.

of oil from the south area is more restricted because of the larger faults present in the south. This is reflected in the slightly higher recovery factor.

With increased gas injection rates, it appears that flow across the faults separating north and south areas from the central area has been reversed. The right-hand portion of Fig. 10 indicates that oil is being transferred to the north and south areas.

Recovery Factor Calculation in the Central Area

The neutron log proved a very useful tool in the recovery factor calculations, with the complex structure and production history of the Limestone B and with the attendant gas override and water underride. A horizontal oil/gas interface need not be assumed, because a carefully designed neutron survey of selected wells would make it possible to generate a gas-cap isopach map (Fig. 11). A volumetric material balance approach then is used to compute the recovery factor in the gas cap. A sample recovery calculation appears as Table 1.

Several neutron surveys were run in the gas-cap area, and each time a recovery factor in the gas cap was calculated. The average recovery for these surveys was 50% (Fig. 12). These calculations proved beyond any doubt that oil recovery by gas is much better than by water in the Limestone B reservoir. This is thought to result from a combination of more than one of the following:

1. Recovery by gas was enhanced by the miscible action of liquids entrained in the injected gas.
2. Arab gas going into solution enhanced the oil mobility.
3. The Limestone B reservoir rock may be oil wet because: (1) laboratory analysis showed a high degree of oil wettability in cores taken from the reservoir; (2) the Laterolog shows the upper portion of the section to have extremely high resistivity, which indicates calculated water saturations of less than 6% (Fig. 13); and (3) excessive gas injection rates can displace encroached water back toward the aquifer

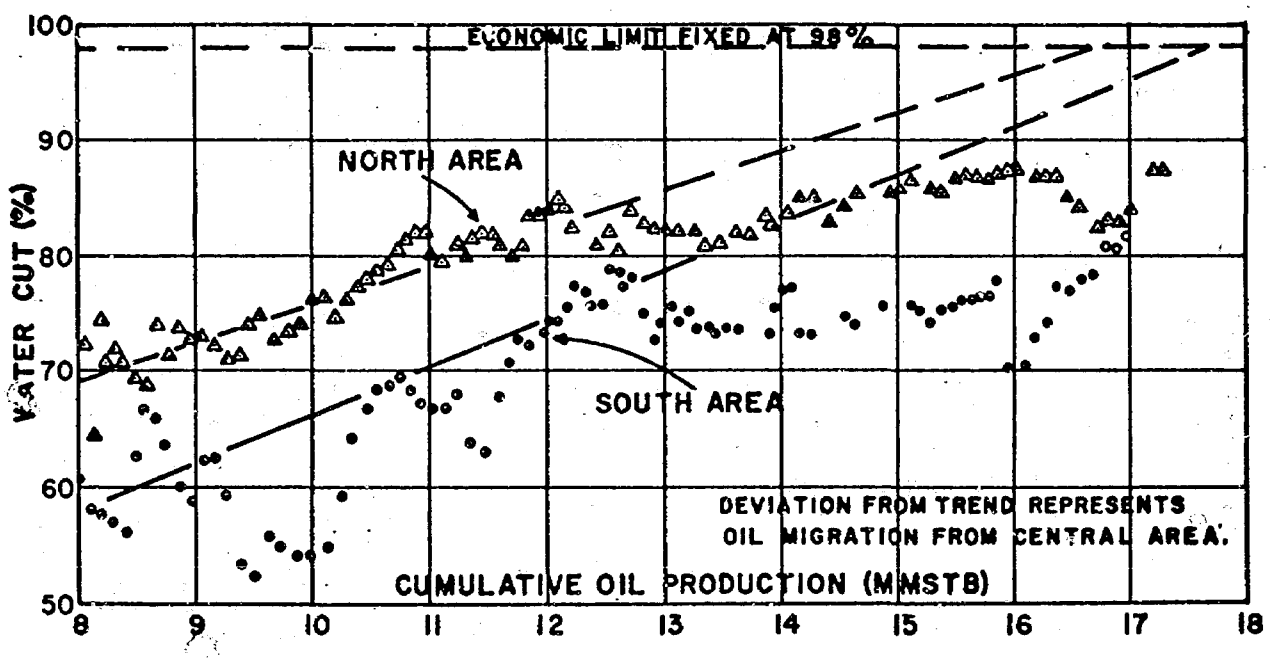


Fig. 10 – Cumulative oil production vs water cut.

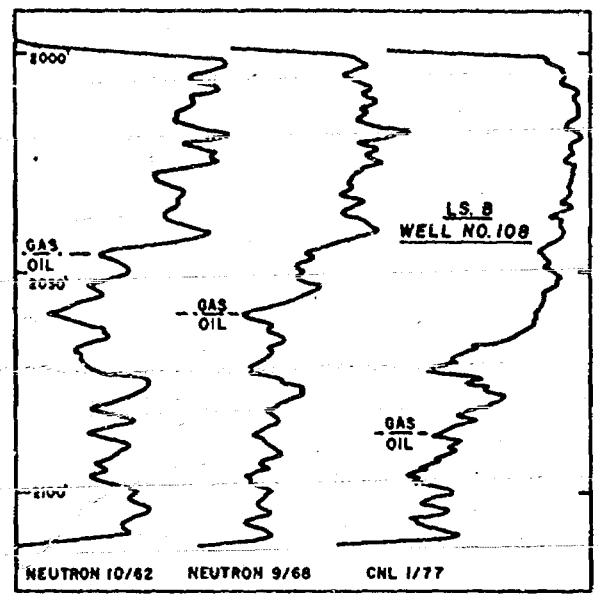


Fig. 11 – Monitoring gas-cap advance by neutron logs.

and reduce or even eliminate water cuts (a case in point is Well 253 where the water cut was as high as 50% and is now zero).

4. Gravity drainage also enhanced the recovery in spite of the low dips in the reservoir rock. The structure is highly faulted and allows Limestone B oil to drain further into underlying pay zones, especially because the pressure in these zones is lower.

Hence, the homogeneous characteristics of the zone, the pressure differential that exists between this zone and the underlying zones, and the communication between these zones by virtue of juxtaposition all contribute to a very effective gravity drainage from the Limestone B (Fig. 14).

Recent Investigations

Injected Gas Quality

Up to 1974, rich unstripped gas [15 to 20 bbl condensate/MMcf gas (84 to 112 m^3 condensate/10^6 m^3 gas)] had been injected into the Limestone B. Subsequently, leaner Khuff gas has been used for injection.

One may wonder what effect this leaner gas has on recovery. The problem was approached as if phase equilibria were the only factor affecting recovery.

The tool used in this investigation has been a flash computer program. Starting with the analyses of both the Arab gas and the crude oil, the composition of the gaseous and liquid phases in the gas cap was computed. The computation then was repeated using Khuff gas. Then the reservoir pressure was altered to see whether the Khuff gas displacement efficiency could match that of Arab gas. This investigation revealed that: (1) Khuff gas causes 8.5% less initial oil swelling than Arab gas; (2) further injection of 1 PV Khuff gas causes a 2.2% shrinkage whereas 1 PV Arab gas causes an additional 4.9% swelling; (3) the oil phase is stripped of much of its light ends when Khuff gas is used, thus becoming less mobile; and (4) a reservoir pressure increase of some 200 psi (1378 kPa) is necessary to offset the drawbacks resulting from use of a leaner gas.

One asset of Khuff gas is its high CO_2 content (6%), since CO_2 is known to enhance recovery by improving microscopic displacement efficiency of oil. However, this factor was not considered here.

In fact, the results of such investigation will be used only qualitatively, since miscible displacement/phase equilibria is not the sole factor affecting recovery and its relative contribution to recovery is not known.

Most of the PVT data available is for reservoir oil being displaced by Arab gas. No PVT data with Khuff gas is available. However, viscosity was not measured when the reservoir fluid was contacted by Arab gas. Whenever such viscosity is required, Beal's correlation tables are used, the reservoir fluid having these properties: viscosity = 2.08 cp at 136°F (2.08 kPa·s at 58°C), bubble-point pressure = 358 psig (2468 kPa), density = 33.5°API (847 mg/cm^3), and formation volume factor = 1.13. Viscosity of reservoir fluid in contact with Arab gas is computed to be 1.1 cp (1.1 kPa·s). Thus, the lowering of viscosity has been helpful in increasing the rate of gravity drainage.

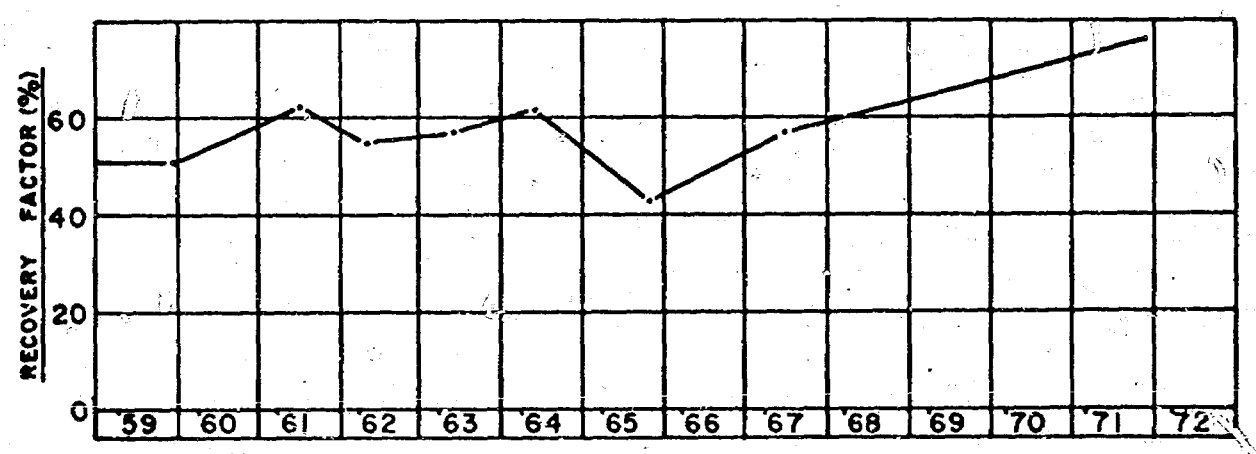


Fig. 12 – Oil recovery factors by gas displacement (based on data obtained from neutron and pressure surveys).

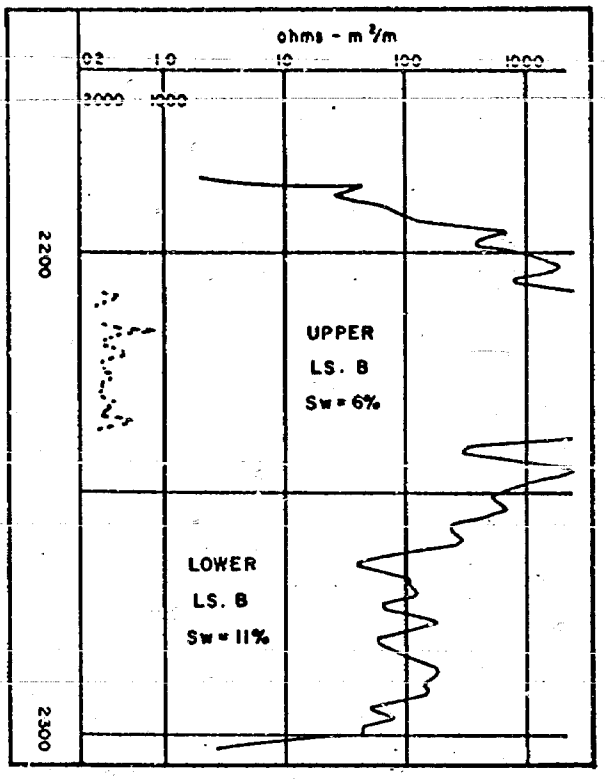


Fig. 13 – Typical Laterolog of Limestone B original oil column.

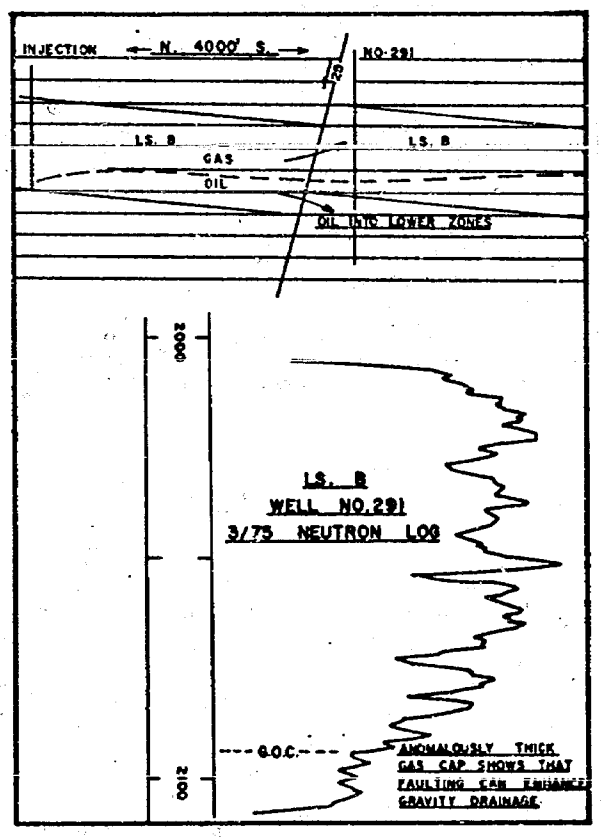


Fig. 14 – Schematic diagram showing enhancement by gravity drainage.

Residual Oil Saturation Profile

It was envisaged that gravity drainage would cause a saturation profile extending from a very low oil saturation at the crest of the structure, where the oil has been contacted by a large number of pore volumes of gas, to a high oil saturation near the gas/oil contact, where the oil has been contacted by only a few pore volumes of gas. Thus, what is calculated as 50% recovery efficiency is merely a reflection of this saturation profile. There is no theoretical reason that, in this highly oil-wet reservoir, residual oil saturation cannot be reduced to a very low figure.

It also appears that gravity drainage may lead to a vertical saturation profile in any well in the gas cap. The logging company has been asked to use its computer program to split the hydrocarbon saturation into gas and oil saturations so that the displacement efficiency can be calculated. To do that, the lithology and gas and oil densities at reservoir conditions had to be provided. It might be possible to extend this analytical approach to older neutron logs if the computer program also was provided with the porosity profile.

So far, the results have been received for only one

TABLE 1 – RECOVERY FACTOR CALCULATION IN THE GAS CAP (May 1, 1962)

Size of Gas Cap: (Based on Neutron Survey 4/62)	
Acres	4,663
Acre-ft	133,541
Avg. gas cap thickness, ft	28.6
HCPV, res bbl	239,165,000
Reservoir Parameters for Gas Cap:	
Porosity (volume weighted), %	24.56
Water saturation, %	0.01
Gas-cap pressure 5/62, psig	1218
Gas-cap temperature, °F	150
Gas formation volume factor at 1,218 psig, 150°F	2.1723
Net Gas Injected: (May 1, 1962)	
Cumulative gas injected, Mcf	88,229,000
Cumulative free gas produced, Mcf	8,203,000
Cumulative net gas injected, Mcf	80,026,000
Cumulative net gas injected, res bbl	173,840,000

Gas Going Into Solution at 1,218 psig: (PVT data)

$$\frac{386 - 123}{1.103} = 234 \text{ cu ft/RB.}$$

Oil Swelling Factor:

$$\frac{1.226}{1.103} = 1.1115.$$

Recovery Factor Calculation:

G_F = Volume of free gas in gas cap, res bbl;
V_{or} = Volume of residual oil in gas cap, res bbl, of original undersaturated crude;
$\therefore G_F + 1.1115\, V_{or} = 239{,}165{,}000$ res bbl,
and $G_F = 173{,}840{,}000 - V_{or}(0.234)(2.1723)$.

$V_{or} = 108{,}297{,}000$ res bbl;

$$\therefore \text{Recovery factor} = \frac{239{,}165{,}000 - 108{,}297{,}000}{239{,}165{,}000} = 0.547.$$

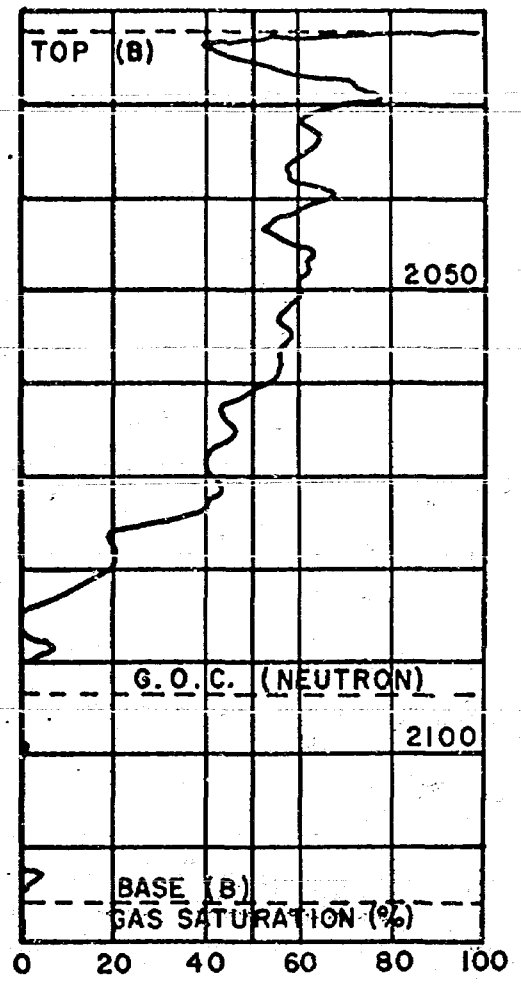


Fig. 15 -- Gas saturation.

well (Fig. 15). It is obvious that, as expected, a vertical saturation profile does exist and that the displacement efficiency is in excess of 50%, giving credibility to the calculated 50% recovery efficiency. The recovery efficiency should not be much less than the displacement efficiency, due to the narrow spacing of the wells.

Conclusions

1. Neutron surveys in conjunction with pressure surveys have been used satisfactorily to determine the percentage of oil recovery by gas displacement.
2. Gravity drainage as well as the oil wettability characteristics of the rock have been conducive to a higher oil recovery by gas than by water.
3. Material balance calculations and log analysis have shown that recovery in the gas cap is 50%.
4. The possibility of reduced recovery because of changing from rich Arab gas to lean Khuff gas is recognized. This potential loss will be offset partially because Khuff gas contains significant CO_2.

Acknowledgments

I acknowledge the assistance rendered by the Bahrain Petroleum Co. Ltd. while compiling this paper.

Reference

1. Cotter, W.T.: "Twenty-Three Years of Gas Injection Into A Highly Undersaturated Crude Reservoir," *J. Pet. Tech.* (April 1962) 361-365.

SI Metric Conversion Factors

acre	× 4.046 873	E+03	=	m^2
bbl	× 1.589 873	E−01	=	m^3
cu ft	× 2.831 685	E−02	=	m^3
°F	(°F−32)/1.8		=	°C
ft	× 3.048*	E−01	=	m
mile	× 1.609 347	E+00	=	km
psi	× 6.894 757	E+00	=	kPa
sq ft	× 9.290 304*	E−02	=	m^2

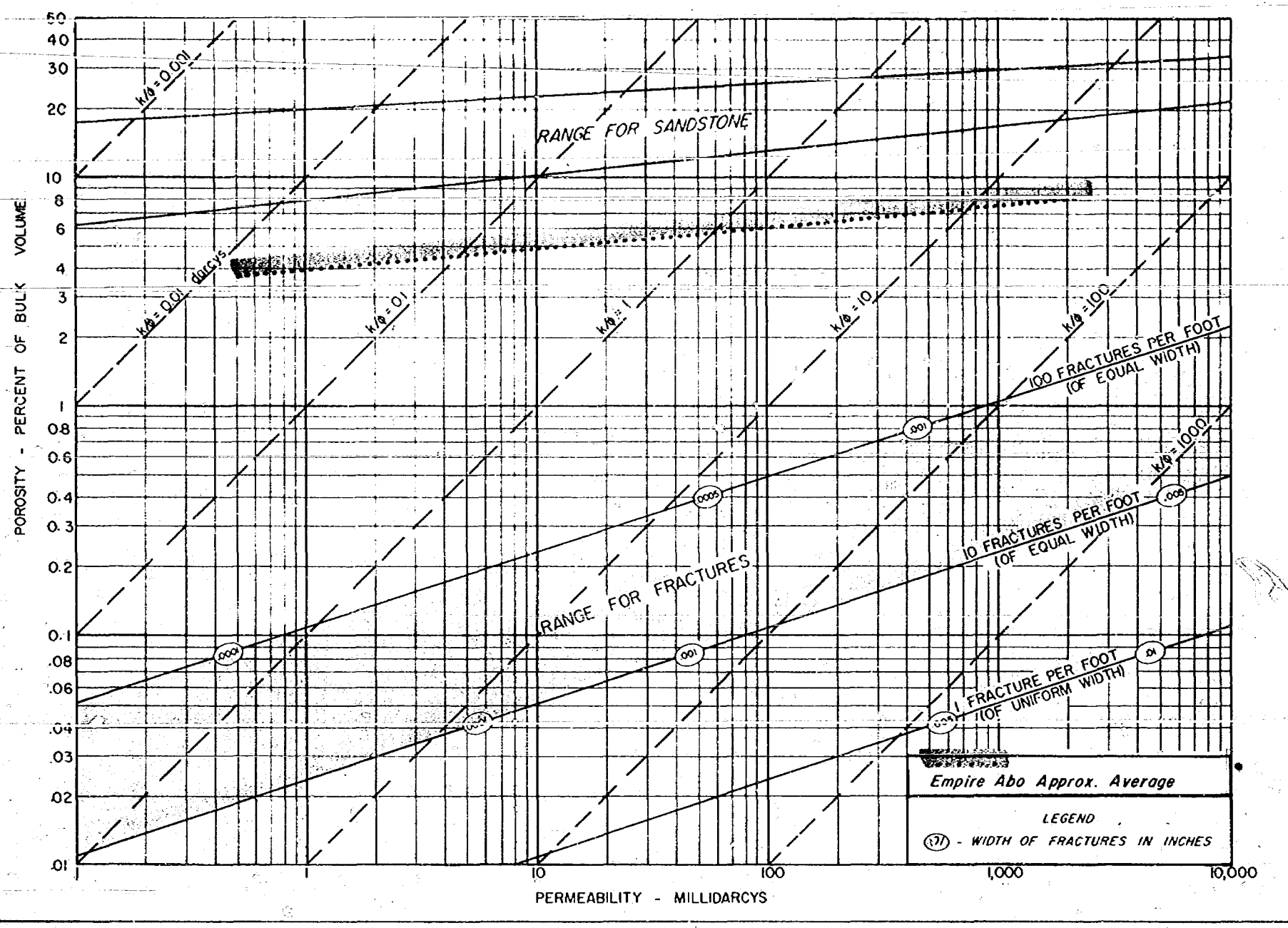
*Conversion factor is exact

JPT

Original manuscript received in Society of Petroleum Engineers office May 24, 1978. Paper (SPE 7652) accepted for publication March 14, 1979. Revised manuscript received Aug. 24, 1979.

VALUES OF K/φ FOR SANDSTONE RESERVOIRS AND FOR FLOW SYSTEMS OF FRACTURES IN AN IMPERMEABLE MATRIX

FRACTURES PARALLEL TO DIRECTION OF FLOW



OR-11

APPENDIX III FIGURE NO. III-3

GRAVITY DRAINAGE RATES
WEST PUERTO CHIQUITO
FOR CONDITIONS OF:
OIL DENSITY 44.9#/cubic foot
GAS DENSITY 5.35#/cubic foot
OIL VISCOSITY .62 centipoises
FORMATION DIP 400 feet per mile

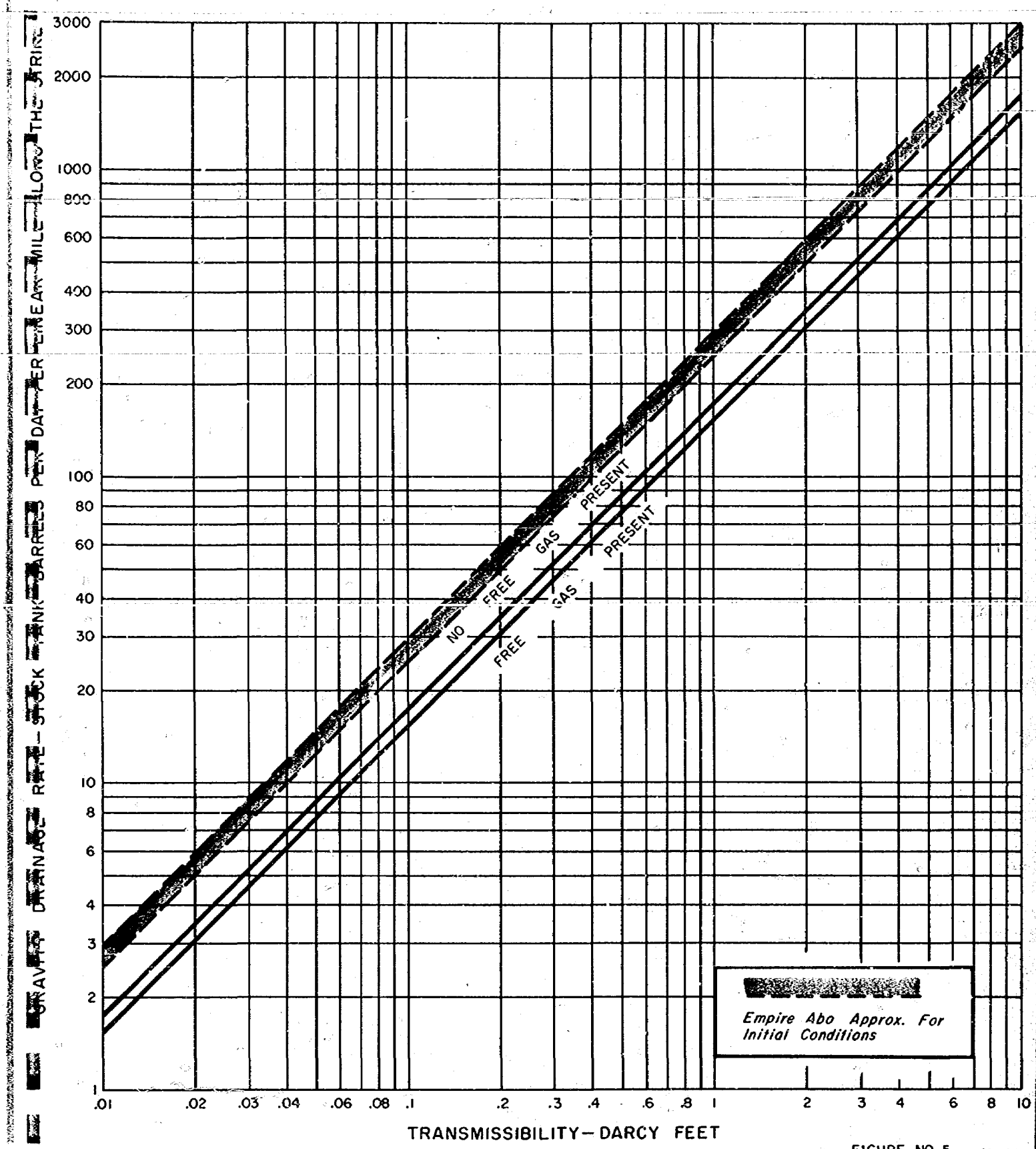
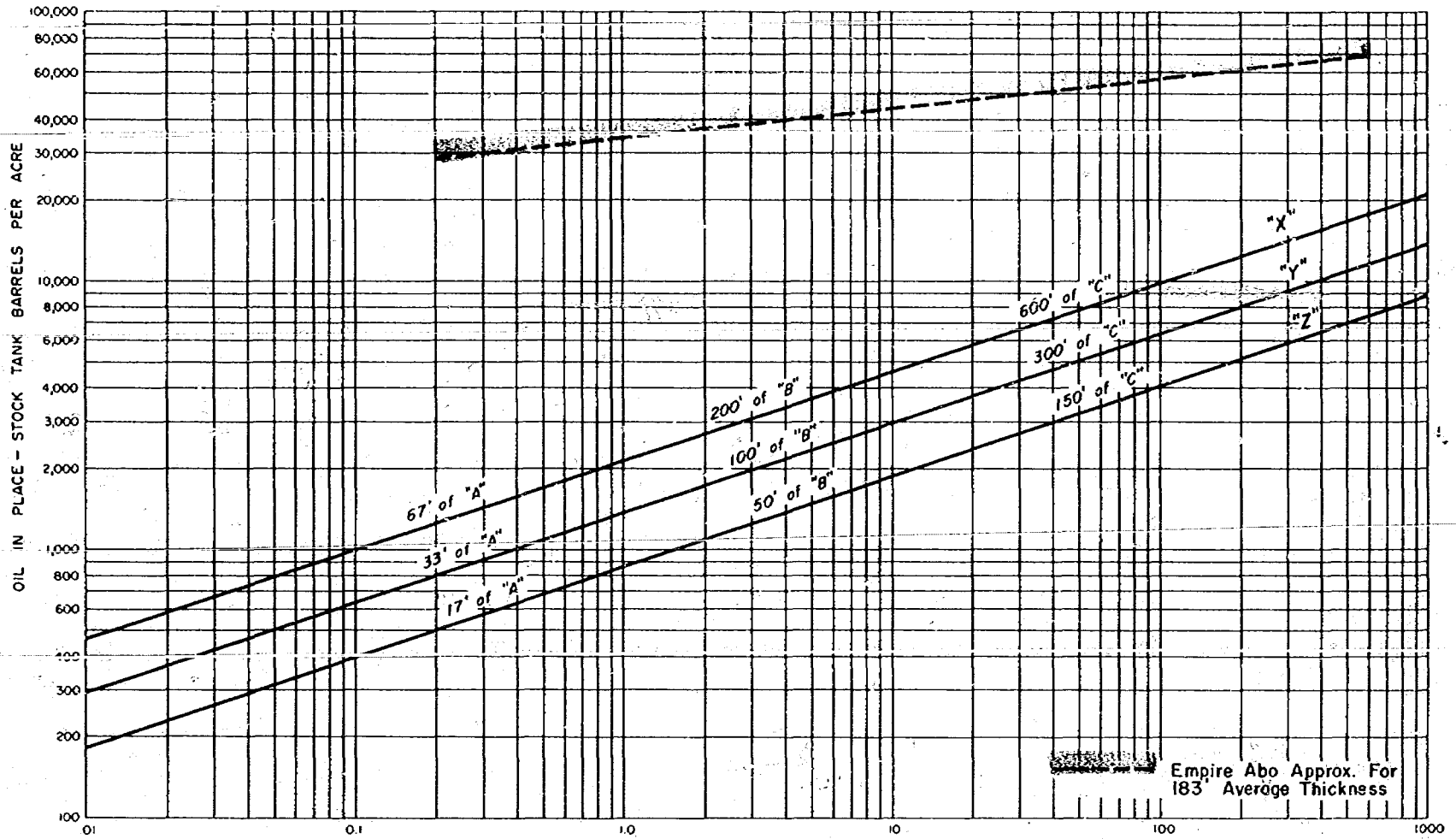


FIGURE NO. 5

08-11

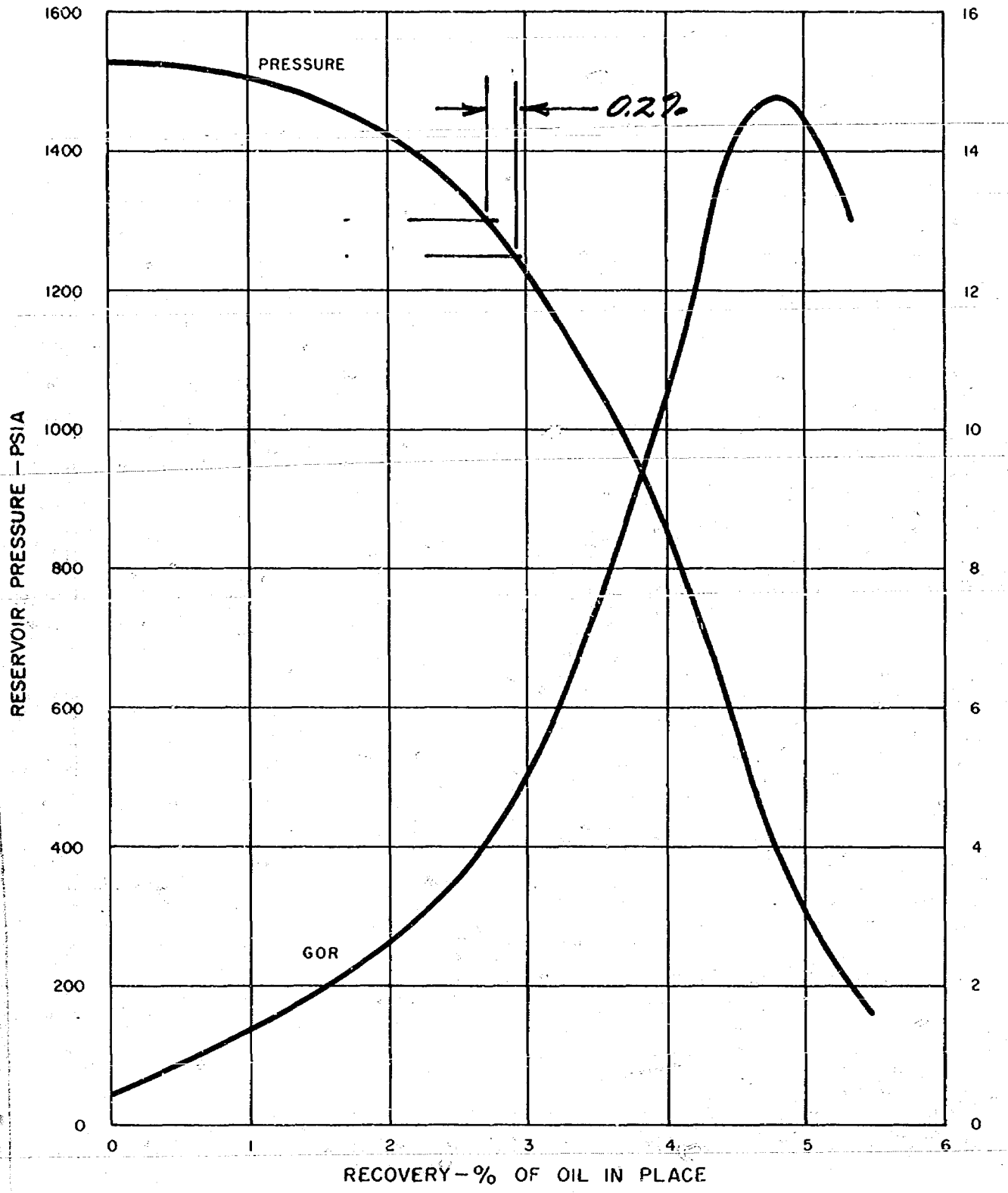
RELATION OF OIL IN PLACE
TO
TRANSMISSIBILITY
FOR
POROSITY-PERMEABILITY RELATIONS
"A", "B" & "C"
AND FOR
RESERVOIR THICKNESSES SHOWN
F.V.F.=1.29



APPENDIX III FIGURE NO III-5

SOLUTION GAS DRIVE
PRODUCTION HISTORY

CALCULATED FOR CONDITIONS OF:
WEST PUERTO CHIQUITO
PVT DATA
AND
K_g/K_o ESTIMATED FROM LABORATORY
DATA FOR FRACTURED FORMATIONS



APPENDIX IV FIGURE NO. IV-3

NOTE ON DEPLETION PROCESS

CANADA OJITOS UNIT C-34

1. From 1-1-74 to 10-1-80 COU C-34 produced 213,000 barrels of oil.

2. Pressure drop at observation well location during this time was approximately 50#; now (November, 1980) it is ± 1350.

3. Pressure drop in area structurally above the C-34 and draining to it would be from about 1300# to 1250#.

4. For this pressure drop (see graph) the solution-gas drive recovery would be 0.2% of oil in place.

5. For 213,000 barrels to be 0.2% of oil in place, the oil in place would have to be over 100 million barrels.

6. At 100 million barrels in place and 10 sections being drained by this well, oil in place would have to be 10 million barrels per section or 16,000 barrels per acre, which is 10 times the reasonably accurage figure of 1,600 barrels shown by interference tests. (If 5 sections drained - the average for recovery wells - the figures would be twice the above).

7. Conclusion: The depletion process must be something other than solution-gas drive - which means gravity drainage and/or gas drive by pressure maintenance.

COMPARISON OF PRODUCING CAPACITY AND GRAVITY DRAINAGE RATES FOR WELLS ON WEST SIDE OF WEST PUERTO CHIQUITO POOL

TRANSMISSIBILITY (Kh) (Darcy feet)	GRAVITY DRAINAGE RATE: BOPD/MILE ALONG STRIKE FOR DIP OF: 100'/MILE (BOPD/MILE)	200'/MILE (BOPD/MILE)	PER WELL APPROX. PRODUCING CAPACITY FROM*	TO* (BOPD)
.01	.35	.7	5	35
.1	3.5	7	50	350

* for range of ratios of re/rw of 1 to 3 and Ko/K of .3 to .7

GRAVITY DRAINAGE RATES
WEST PUERTO CHIQUITO
FOR CONDITIONS OF:
OIL DENSITY 44.9#/cubic foot
GAS DENSITY 5.35#/cubic foot
OIL VISCOSITY .62 centipoises

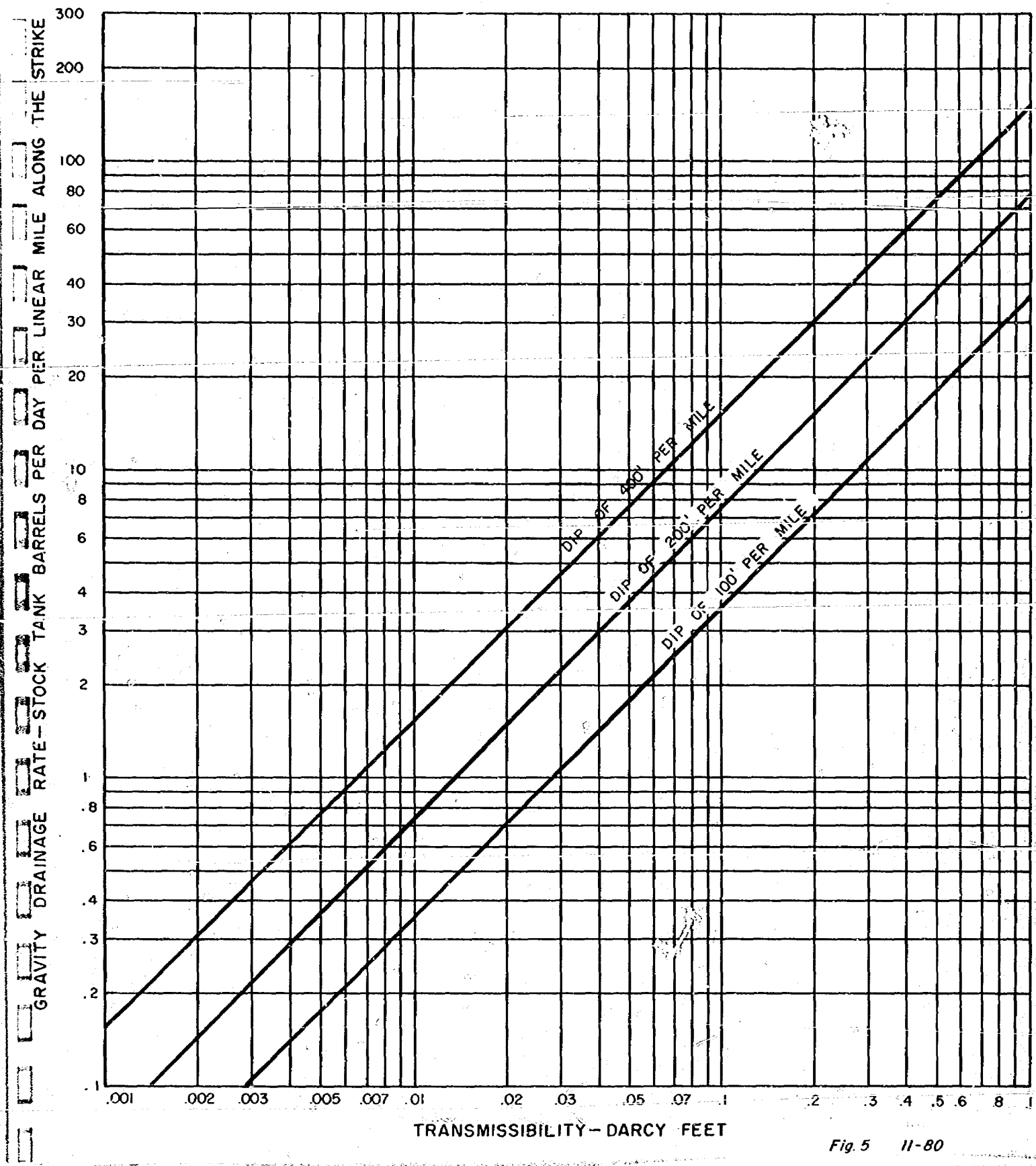


Fig. 5 11-80

INDEX OF
BENSON-MONTIN-GREER DRILLING CORP. EXHIBITS
IN CASE NO. 7075
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

NOVEMBER 24, 1980

PART I — INFORMATION RELATIVE TO EFFICIENCY OF RECOVERY FOR DEPLETION METHOD OF GRAVITY DRAINAGE ASSISTED BY PRESSURE MAINTENANCE BY GAS INJECTION

SECTION A: Factors affecting increased gravity drainage recovery conducted under high pressure as compared to low pressure

1. Graph

SECTION B: Bahrain Field: Limestone B reservoir

Article from December, 1979 Journal of Petroleum Technology

SECTION C: Empire Abo Field

1. Graph of porosity vs. permeability
2. Graph of gravity drainage potential
3. Graph of oil in place per acre vs. transmissibility

SECTION D: Canada Ojitos Unit

1. Graph, COU C-34
2. Schedule, COU C-34

PART II — COMPARISON OF PRODUCING CAPACITIES AND GRAVITY DRAINAGE RATES FOR WELLS IN THE WEST PART OF THE WEST PUERTO CHIQUITO POOL

SECTION E: 1. Schedule

2. Graph

INCREASE IN RECOVERY
BY DEPLETION AT HIGH PRESSURE
AS COMPARED TO
DEPLETION AT LOW PRESSURE
FOR VARIOUS FINAL OIL SATURATIONS

CONDITIONS: HIGH PRESSURE 1500#
F.V.F. = 1.29
LOW PRESSURE 50#
F.V.F. = 1.11
CONNATE WATER SATURATION = 10%

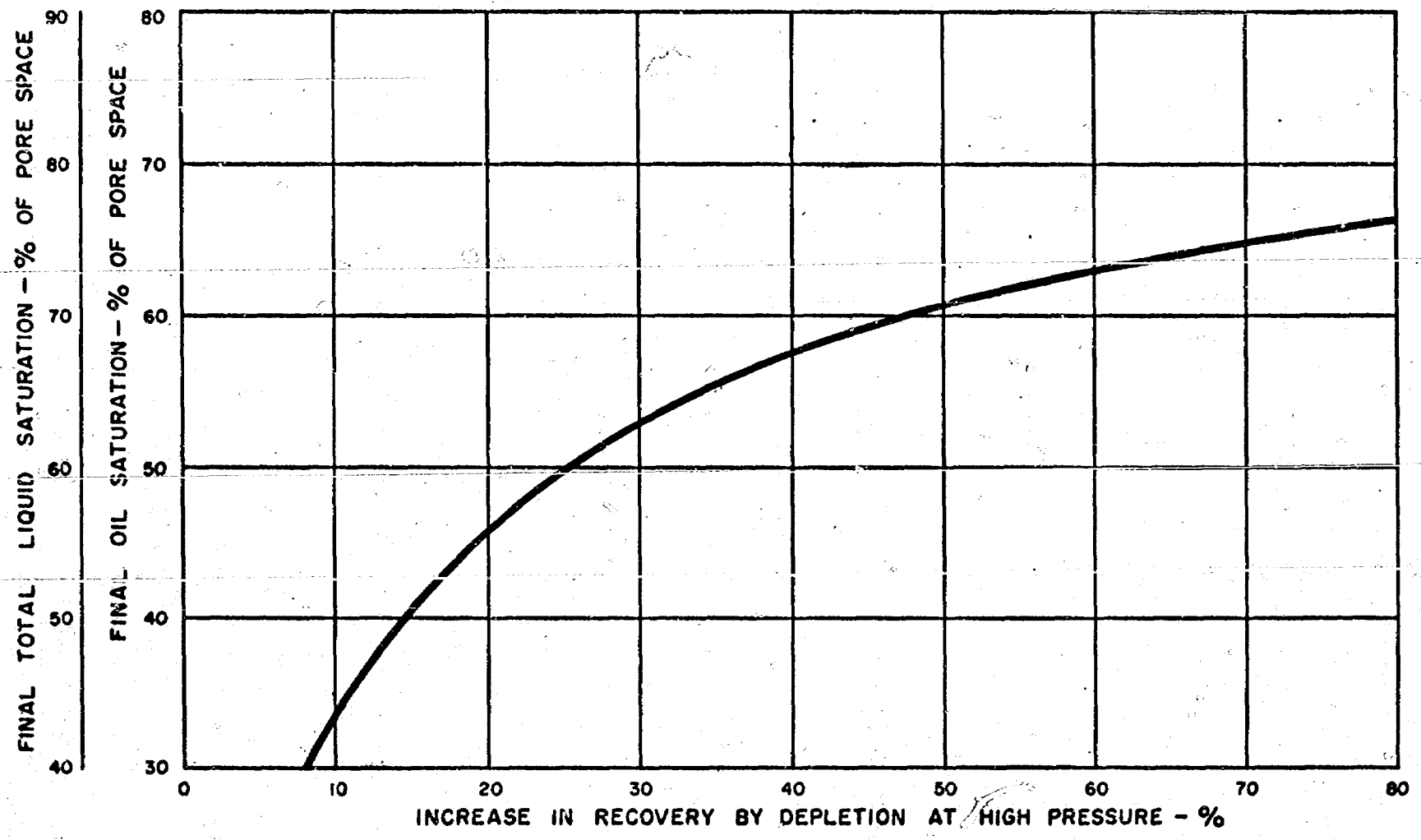


FIGURE NO. 12

Effective Displacement of Oil by Gas Injection in a Preferentially Oil-Wet, Low-Dip Reservoir

Jaffar A.N. Shehabi, SPE-AIME, The Bahrain National Oil Co.

Gas injection as a means of pressure maintenance has been employed in the Bahrain field Second Pay Limestone B reservoir for the last 39 years. This paper describes aspects of the gas injection program and the method used to calculate recovery of oil by gas, which has been found to be much greater than that by water drive.

Introduction

Gas injection as a means of maintaining pressure and improving oil recovery has been employed in the Bahrain field Second Pay Limestone B reservoir for the last 39 years. This reservoir is oil-wet. Maintaining reservoir pressure was the primary objective in the beginning. The pressure response was almost immediate and probably conformed very closely to a simple material balance, because all producing zones on the highly faulted Bahrain structure were still close to virgin conditions.

Early gas breakthrough became a matter of concern with respect to total field productivity and ultimate recovery. However, wells in the gas area were kept on production, at an optimum rate governed by tubing submergence. It gradually was realized that even with early breakthrough, a satisfactory oil recovery factor was being obtained. Attention then focused on determining actual recovery and explaining the mechanism involved.

The most recent reservoir study showed a 50% recovery factor in the gas-invaded volume, as compared to 20 to 25% in the water-invaded volume. It also was found that because of fluid transfer to other zones, the required injection rate for the Limestone B is 70,000 Mcf/D (1.98×10^6 m^3/d) instead of the 40,000 Mcf/D (1.13×10^6 m^3/d) calculated for the Limestone B alone.

0149-2136/79/0012-7652$00.25
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This paper describes some pertinent aspects of the reservoir, the gas injection program, and the methods used to calculate the recovery factor.

Reservoir Description

The Bahrain field structure is a highly faulted, elongated anticline (Fig. 1). Structural dips in the oil-producing horizons are in the order of 5°. The Bahrain zones, of middle Cretaceous age, are the most important oil-producing group found in this field. They are divided into eight separate zones, with zonal separation varying from 7 to 50 ft (2.13 to 15.24 m). Three types of lithology are present: limestone, siltstone, and sandstone. At the crest of the structure, the gross productive interval was 525 ft (160 m) and original net oil pay thickness was 325 ft (99 m).

[redacted] Gross thickness varies slightly from [redacted] (31 to 35.4 m), all of which is considered net pay. Average porosity and permeability are [redacted] There are no impermeable streaks to affect vertical permeability. The middle 50 ft (15.24 m) has the highest porosity and permeability. The basal 30 to 40 ft (9.14 to 12.19 m) is slightly different in character and appears to have a lower specific productivity index. Fig. 2 shows the porosity

profile, and Fig. 3 shows type log. Average initial water saturation was 6% in the upper section and 11% in the basal section. Previous laboratory work led to the conclusion that the reservoir rock was preferentially oil-wet. For wettability determination, two plugs were cut from preserved core samples: one sample was flooded with brine until a minimum oil saturation was obtained; the other sample was flooded with oil until a minimum water saturation was obtained. The sample with minimum oil content was allowed to imbibe oil spontaneously; the sample with minimum water content was allowed to imbibe water spontaneously. The two volumes of imbibed fluids were measured periodically.

The reservoir oil was highly undersaturated, having a saturation pressure of 358 psig (2468 kPa) as compared to the original reservoir pressure of 1,236 psig (8522 kPa) at 1,900 ft (579 m) subsea. The oil has a solution gas/oil ratio (GOR) of 128 scf/STB (22.8 std m^3/stock-tank m^3) and a density of 0.8556 g/cm^3. Since this is an old reservoir, very limited information is available on virgin parameters, such as viscosity.

The productive limits of the Limestone B reservoir, approximately 8.5 miles (13.7 km) long × 3 miles (4.8 km) wide, encompassed 13,750 acres ($55.640 \times 10^6 m^2$) and contained almost 2 billion STB (318×10^6 stock-tank m^3) original oil in place (OOIP). Cumulative production as of Jan. 1, 1972, was 283 million STB (45×10^6 stock-tank m^3) oil and 79 million STB (12.6×10^6 stock-tank m^3) water. Cumulative gas injected up to Jan. 1, 1972, was 206,433 MMcf (5.8×10^9 m^3).

Gas-Injection History

The first well tapped oil from this zone at 1,236 psig (8522 kPa) in 1932. By Feb. 1938, after only 14 million STB (2.22×10^6 stock-tank m^3) or 0.7% OOIP had been produced, reservoir pressure had declined by 118 psig (813 kPa). High-pressure nonassociated Arab zone gas was readily available for injection into the Limestone B without requiring compression. Thus, the gas injection program to maintain pressure was initiated in April 1938. The Arab gas was relatively rich and was injected without prior processing for liquid recovery. A total of 189,000 MMcf (5.4×10^9 m^3) Arab gas had been injected by April 1974, at which time it was totally replaced by the much leaner and more abundant Khuff zone gas. Up until the discontinuation of Arab gas injection, some 74,383 MMcf (2.1×10^9 m^3) Khuff gas also had been injected.

Limestone B injection was suspended temporarily from May 1962 to Jan. 1965 while continuing to inject the lower siltstone zones. The purpose was to observe reservoir pressure behavior of the lower zones in the absence of injection into the Limestone B. The reservoir pressure of both the siltstone zones and the Limestone B declined rapidly at about the same rate, proving fairly conclusively that reservoir communication existed. As a result, continued gas injection into the Bahrain zones was solely into the Limestone B.

Transfer of fluids from the Limestone B to the underlying and overlying formations prior to 1962 is believed to have been minimal or nonexistent,

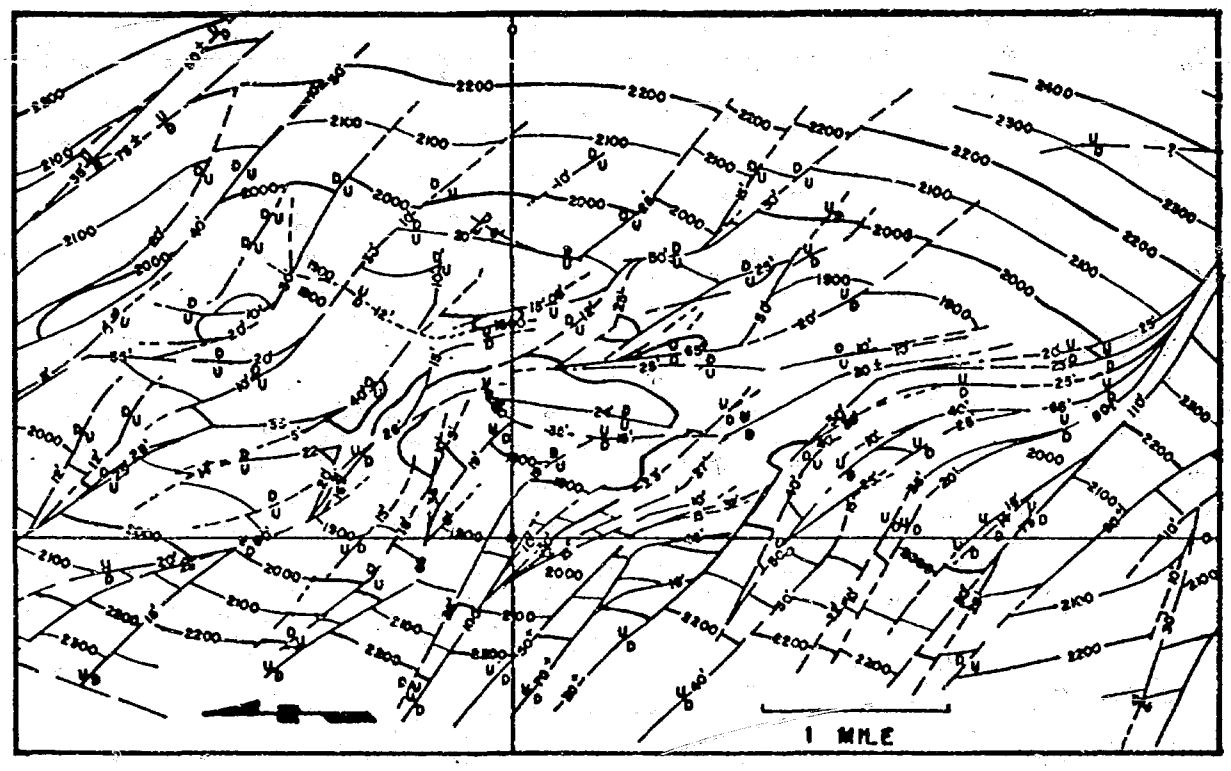


Fig. 1 – Structure map of Second Pay Limestone B.

because pressures were compatible. In subsequent material balance studies, it was found that recovery efficiency by gas was more than 50%. This indicates fluid transfer due to the decline in pressure in the underlying and overlying formations.

Subsequent production behavior of the individual zones has conclusively proved that the Limestone B is only one part of a unit that also includes the overlying sandstone and the underlying siltstones. This conclusion is important from the standpoint of determining injection rate requirements and explaining anomalously high recovery factors that could be calculated for any of these zones if they were treated as an entity. Examples are given later in the text. Overall recovery factor on a unit basis is probably in line with industry published data.

Another interesting aspect of the injection suspension period is the appearance of water cuts in the higher structural row of Limestone B wells and the regression of this water shortly after gas injection was resumed. Fig. 4 shows the fieldwide extent of this occurrence. Fig. 5 shows the recent pressure and production history of the Limestone B. In this figure as well as in subsequent figures, early history was not included, because very few recovery calculations were made before 1960.

Recovery Mechanism

In order to analyze the recovery mechanism and calculate reserves, the Limestone B was subdivided into north, central, and south areas. Major faults that would prevent further expansion of the gas cap in a north-south direction helped to define the individual areas (Fig. 4). The north and south areas have been under the influence of an active water drive, whereas the central area has a combination of gas-cap drive, gravity drainage, and water drive.

The material balance calculations made in 1954 and 1959 following neutron surveys indicated a 50% recovery efficiency. In 1972, Laterolog surveys behind the water front indicated a 20% displacement efficiency by water.

In the 1972 study, a cutoff had to be chosen in order to calculate the fluid transfer to other zones. Thus, 50% and 20% recovery efficiencies by gas and water, respectively, were chosen. Gravity drainage was not quantified and was assumed to be an integral part of the 50% recovery factor.

Central Area

Ultimate recovery in the central area is estimated to be 29.7%, resulting from a combination of gas displacement, gravity drainage, and displacement by water. Recovery efficiency in the gas-invaded volume is 50% as compared to 20 to 25% in the water-invaded volume. Therefore, the objective is to continue gas injection at an optimum rate until a practical maximum growth of the gas cap is reached. The optimum rate is defined as the rate that will maintain reservoir pressure with zero net water influx. Because of fluid transfer from the Limestone B to other zones, the current optimum injection rate actually required is much higher than theoretically required – 66,000 to 70,000 Mcf/d (1.87 to 1.98 ×

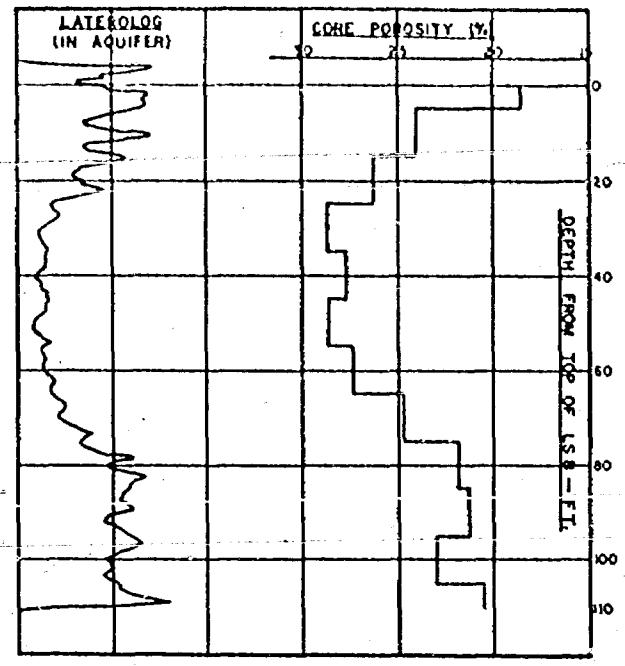


Fig. 2 – Porosity distribution in Second Pay Limestone B.

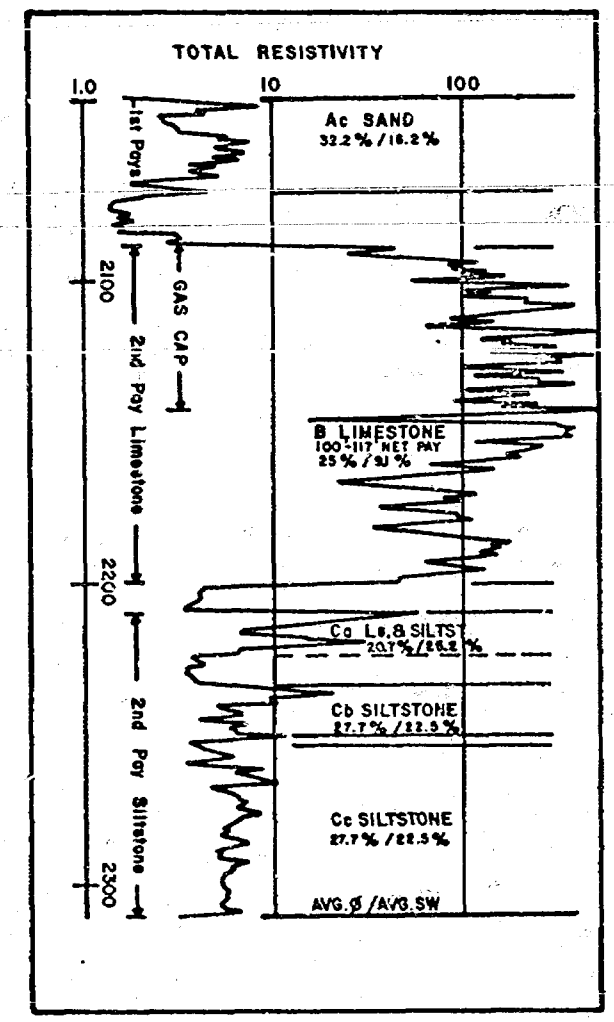


Fig. 3 – Type log showing Second Pay Limestone B with the overlying and underlying zones.

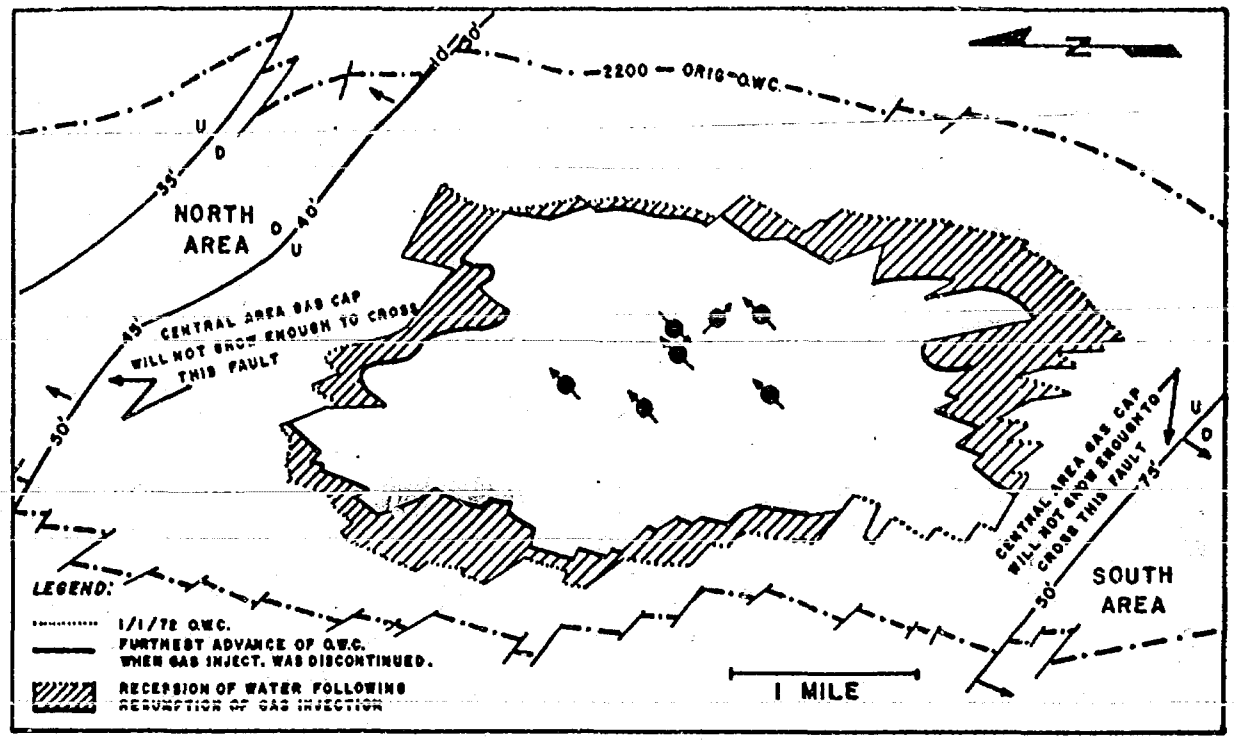


Fig. 4 – Effect of resumption of gas injection.

10^6 m^3/d) vs approximately 37,000 to 40,000 Mcf/D (1.05 to 1.13 × 10^6 m^3/d).

A study of actual experience shows that excessive gas injection rates into this particular pore geometry and rock wettability can displace encroached water back toward the aquifer, thus reducing water cuts to some extent. This unique effect was used to temporarily increase Limestone B oil production rates.

A strong gravity override influence, mainly in the direction of the east and west flanks, will limit the ultimate volume contacted by gas. After 33 years of injection, 63% of original HCPV actually had been "contacted" by gas. Gravity underride also is evident in the water-encroached volume. Approximately 25% of original HCPV has been contacted by water.

Qualitatively speaking, production data suggest that the critical rate with gas displacement is very low compared with that in the case of water displacement. This is because of the higher mobility of the gas. Because of the low dip and high vertical permeability, even with water the critical rate is low.

Fig. 6 may be useful in the case of gas displacement. However, note that very little theoretical work was done to predict such rates; the performance of the reservoir was relied upon greatly.

The water influx into the Limestone B central area has been greatest at the north and south ends because of long distances from gas injection wells at the crest of the formation. It seems overall effectiveness of gas injection can be improved by providing gas injection points closer to the north and south ends of the central area. Dispersion of the gas injection has been started in a southerly and northerly direction.

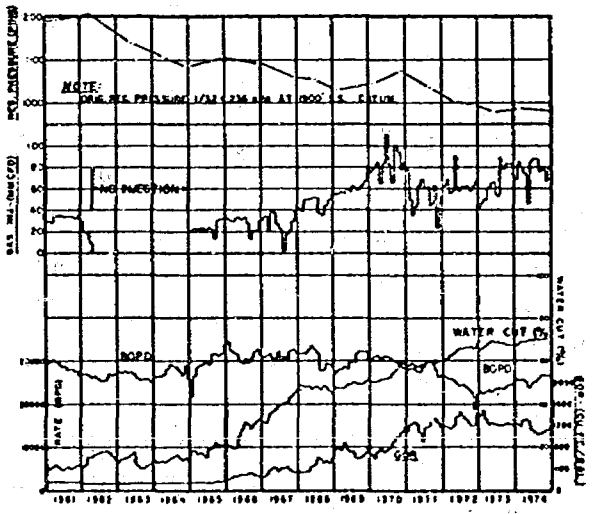


Fig. 5 – Pressure production curves – total reservoir.

Areal Pressure Distribution

Gas injection for pressure maintenance in this anticlinal reservoir has been used successfully, and the rates of injection have been increased from time to time with planned increments of oil withdrawal (Fig. 5). As the injected gas front receded from the crest, the off-take points gradually concentrated downstructure between the gas- and water-drive influences. As the gas-injection program progressed, completions in the Limestone B either were shut in or abandoned to prevent excessive production of gas. Such completions had been produced as long as possible by submerging the tubing below the liquid level in the wells and reducing the production rates.

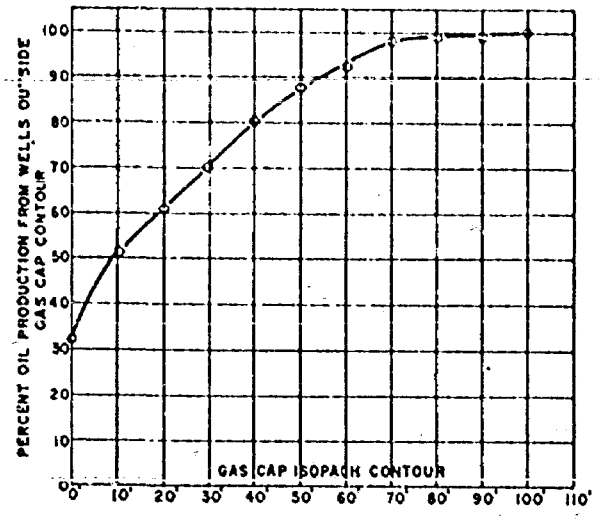


Fig. 6– Distribution of oil production with respect to gas-cap thickness.

By the end of 1956, as a result of this action, very little oil was being produced from below the gas cap, the main withdrawal having been established around the lateral perimeter of the cap. As of Jan. 1, 1973, over 60% of the central area production came from the area having 20 ft (6 m) or less gas-cap thickness (Fig. 6). A further consequence of this change in oil-withdrawal pattern was a change in the pressure pattern of the reservoir. Before the commencement of gas injection, the lowest pressures were found in the central portion of the reservoir, but as withdrawal moved out with the expansion of the gas cap, the lowest pressures were transferred to the line of greatest production. This resulted in the formation of a "pressure trough" between the gas-invaded area and the aquifer perimeter (Fig. 7). The circumference of the pressure trough increased with the expansion of the gas cap and the resultant outer movement of oil withdrawal from the center of the reservoir. The effect of this low-pressure ring on the gas-cap shape will be considered at a later stage.

North and South Areas

With the present gas injection pattern, there is no chance of creating gas caps in the north and south areas. Water drive, with low recovery efficiency, is the predominant displacement mechanism in these areas. As of Jan. 1, 1972, there were 69 million STB (11×10^6 stock-tank m^3) in place above the oil/water contacts in these areas.

Recent production history is shown in Fig. 8 (north area) and in Fig. 9 (south area). Current production in the north area is 2,950 BOPD (469 m^3/d oil) with 87% water cut. Current production in the south area is 3,050 BOPD (485 m^3/d oil) with 81% water cut.

Plots of water cut vs cumulative oil production were used to determine ultimate oil recovery in each area. The ultimate recovery factors were determined to be 7% in the north area and 9.4% in the south area. These appeared reasonable when compared with breakthrough recovery factors determined by volumetric balance.

The low recovery factors result from a combination of inherently low recovery efficiency by water displacement (20%) and movement of oil from these downstructure to upstructure areas. Movement

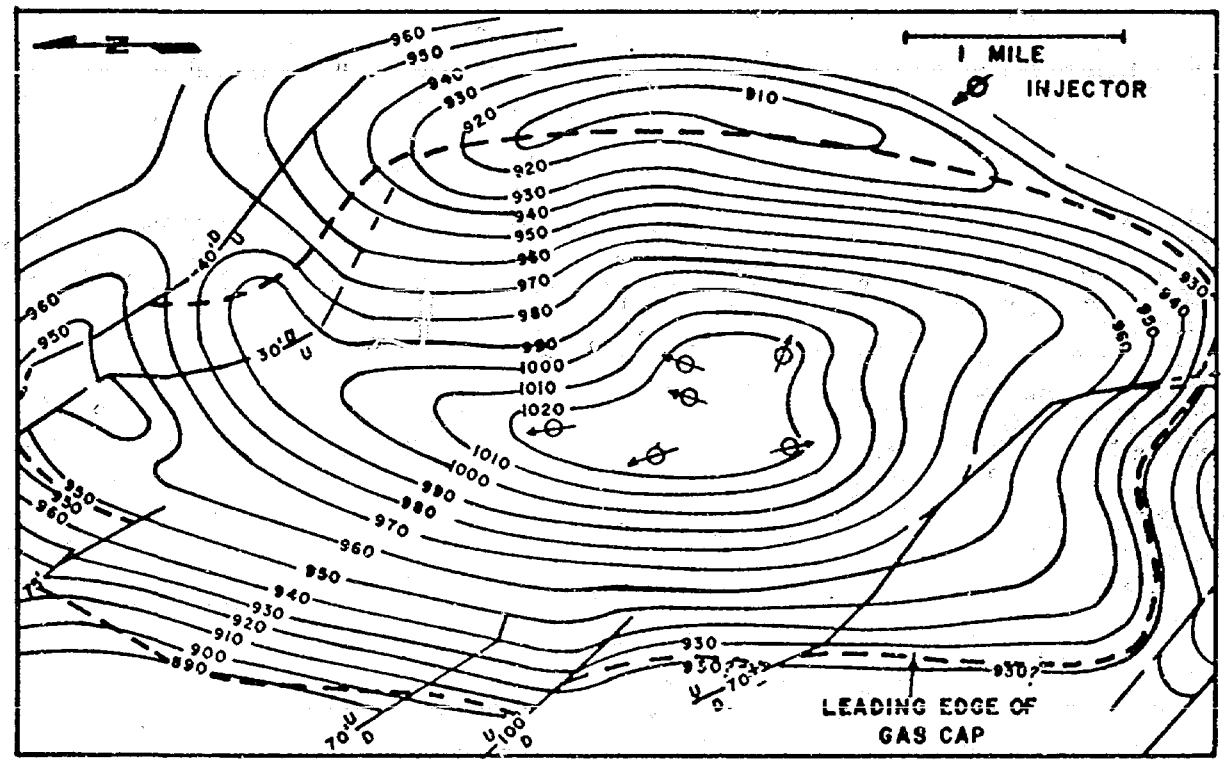


Fig. 7– Isobaric map (psi).

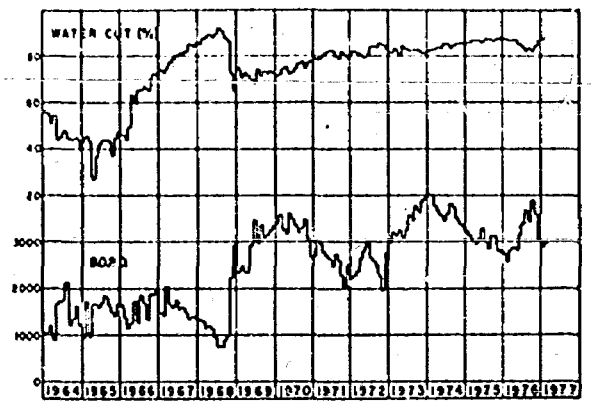


Fig. 8– Production history of north area.

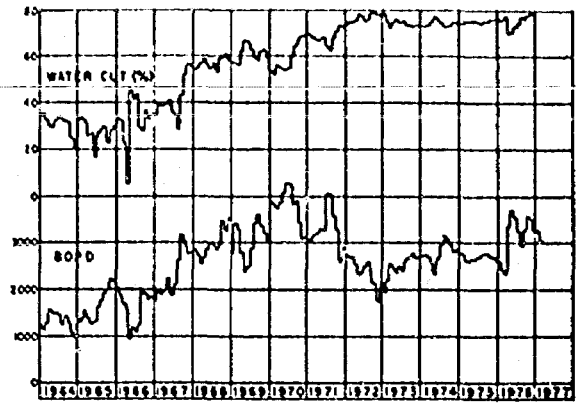


Fig. 9– Production history of south area.

of oil from the south area is more restricted because of the larger faults present in the south. This is reflected in the slightly higher recovery factor.

With increased gas injection rates, it appears that flow across the faults separating north and south areas from the central area has been reversed. The right-hand portion of Fig. 10 indicates that oil is being transferred to the north and south areas.

Recovery Factor Calculation in the Central Area

The neutron log proved a very useful tool in the recovery factor calculations, with the complex structure and production history of the Limestone B and with the attendant gas override and water underride. A horizontal oil/gas interface need not be assumed, because a carefully designed neutron survey of selected wells would make it possible to generate a gas-cap isopach map (Fig. 11). A volumetric material balance approach then is used to compute the recovery factor in the gas cap. A sample recovery calculation appears as Table 1.

Several neutron surveys were run in the gas-cap area, and each time a recovery factor in the gas cap was calculated. The average recovery for these surveys was 50% (Fig. 12). These calculations proved beyond any doubt that oil recovery by gas is much better than by water in the Limestone B reservoir. This is thought to result from a combination of more than one of the following:

1. Recovery by gas was enhanced by the miscible action of liquids entrained in the injected gas.
2. Arab gas going into solution enhanced the oil mobility.
3. The Limestone B reservoir rock may be oil wet because: (1) laboratory analysis showed a high degree of oil wettability in cores taken from the reservoir; (2) the Laterolog shows the upper portion of the section to have extremely high resistivity, which indicates calculated water saturations of less than 6% (Fig. 13); and (3) excessive gas injection rates can displace encroached water back toward the aquifer

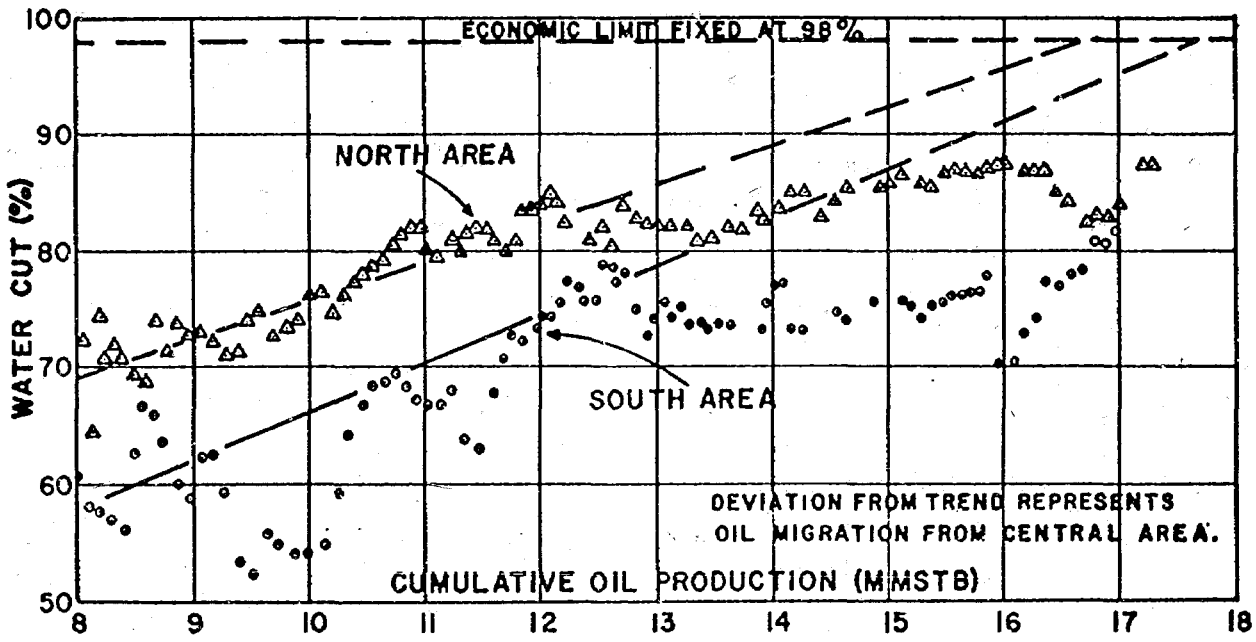


Fig. 10– Cumulative oil production vs water cut.

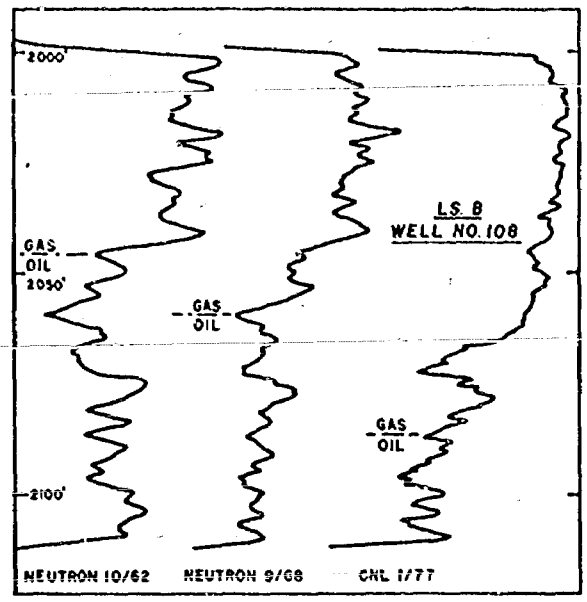


Fig. 11 – Monitoring gas-cap advance by neutron logs.

and reduce or even eliminate water cuts (a case in point is Well 253 where the water cut was as high as 50% and is now zero).

4. Gravity drainage also enhanced the recovery in spite of the low dips in the reservoir rock. The structure is highly faulted and allows Limestone B oil to drain further into underlying pay zones, especially because the pressure in these zones is lower.

Hence, the homogeneous characteristics of the zone, the pressure differential that exists between this zone and the underlying zones, and the communication between these zones by virtue of juxtaposition all contribute to a very effective gravity drainage from the Limestone B (Fig. 14).

Recent Investigations

Injected Gas Quality

Up to 1974, rich unstripped gas [15 to 20 bbl condensate/MMcf gas (84 to 112 m^3 condensate/10^6 m^3 gas)] had been injected into the Limestone B. Subsequently, leaner Khuff gas has been used for injection.

One may wonder what effect this leaner gas has on recovery. The problem was approached as if phase equilibria were the only factor affecting recovery.

The tool used in this investigation has been a flash computer program. Starting with the analyses of both the Arab gas and the crude oil, the composition of the gaseous and liquid phases in the gas cap was computed. The computation then was repeated using Khuff gas. Then the reservoir pressure was altered to see whether the Khuff gas displacement efficiency could match that of Arab gas. This investigation revealed that: (1) Khuff gas causes 8.5% less initial oil swelling than Arab gas; (2) further injection of 1 PV Khuff gas causes a 2.2% shrinkage whereas 1 PV Arab gas causes an additional 4.9% swelling; (3) the oil phase is stripped of much of its light ends when Khuff gas is used, thus becoming less mobile; and (4) a reservoir pressure increase of some 200 psi (1378 kPa) is necessary to offset the drawbacks resulting from use of a leaner gas.

One asset of Khuff gas is its high CO_2 content (6%), since CO_2 is known to enhance recovery by improving microscopic displacement efficiency of oil. However, this factor was not considered here.

In fact, the results of such investigation will be used only qualitatively, since miscible displacement/phase equilibria is not the sole factor affecting recovery and its relative contribution to recovery is not known.

Most of the PVT data available is for reservoir oil being displaced by Arab gas. No PVT data with Khuff gas is available. However, viscosity was not measured when the reservoir fluid was contacted by Arab gas. Whenever such viscosity is required, Beal's correlation tables are used, the reservoir fluid having these properties: viscosity = 2.08 cp at 136°F (2.08 kPa·s at 58°C), bubble-point pressure = 358 psig (2468 kPa), density = 33.5°API (847 mg/cm^3), and formation volume factor = 1.13. Viscosity of reservoir fluid in contact with Arab gas is computed to be 1.1 cp (1.1 kPa·s). Thus, the lowering of viscosity has been helpful in increasing the rate of gravity drainage.

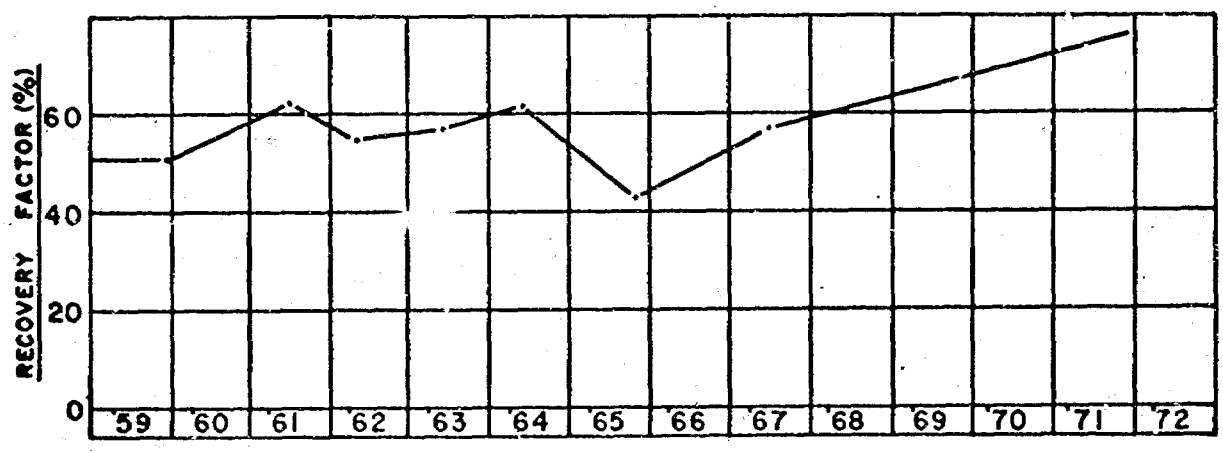


Fig. 12 – Oil recovery factors by gas displacement (based on data obtained from neutron and pressure surveys).

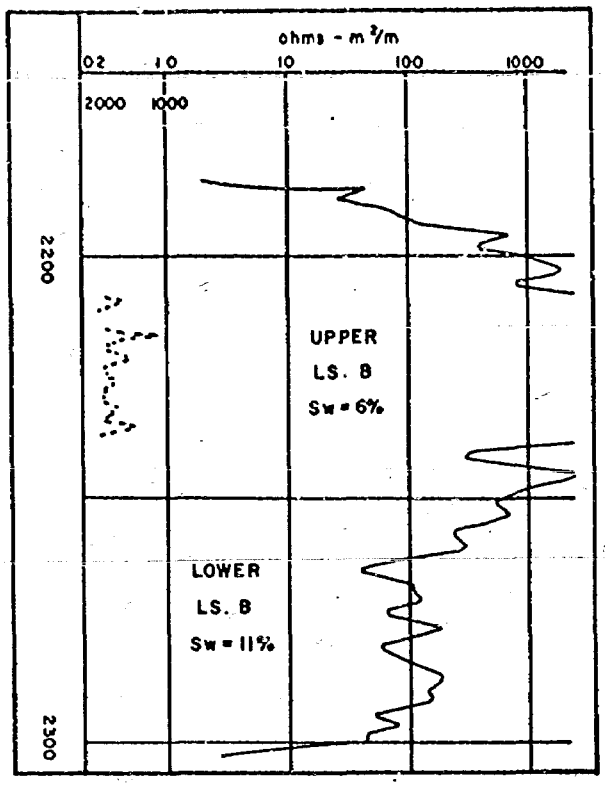


Fig. 13 – Typical Laterolog of Limestone B original oil column.

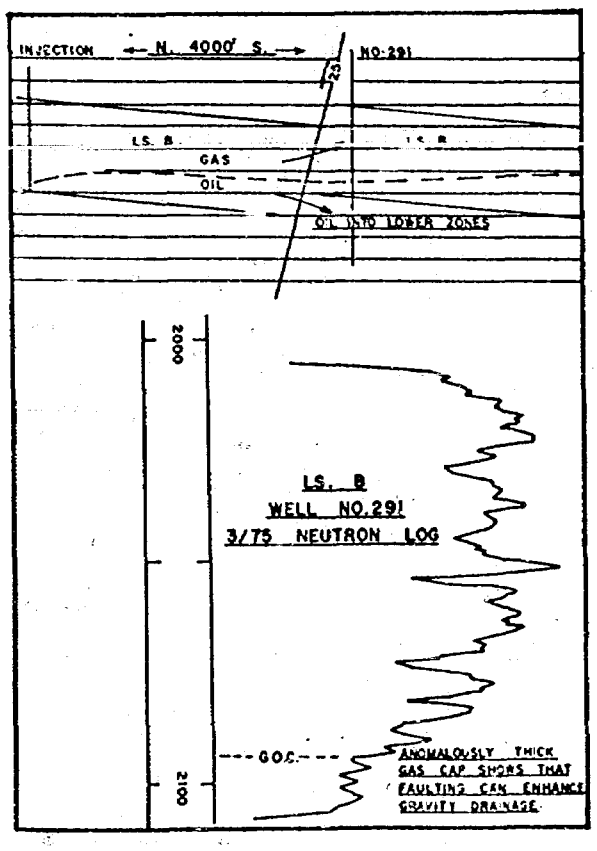


Fig. 14 – Schematic diagram showing enhancement by gravity drainage.

Residual Oil Saturation Profile

It was envisaged that gravity drainage would cause a saturation profile extending from a very low oil saturation at the crest of the structure, where the oil has been contacted by a large number of pore volumes of gas, to a high oil saturation near the gas/oil contact, where the oil has been contacted by only a few pore volumes of gas. Thus, what is calculated as 50% recovery efficiency is merely a reflection of this saturation profile. There is no theoretical reason that, in this highly oil-wet reservoir, residual oil saturation cannot be reduced to a very low figure.

It also appears that gravity drainage may lead to a vertical saturation profile in any well in the gas cap. The logging company has been asked to use its computer program to split the hydrocarbon saturation into gas and oil saturations so that the displacement efficiency can be calculated. To do that, the lithology and gas and oil densities at reservoir conditions had to be provided. It might be possible to extend this analytical approach to older neutron logs if the computer program also was provided with the porosity profile.

So far, the results have been received for only one

TABLE 1 – RECOVERY FACTOR CALCULATION IN THE GAS CAP (May 1, 1962)

Size of Gas Cap: (Based on Neutron Survey 4/62)	
Acres	4,663
Acre-ft	133,541
Avg. gas cap thickness, ft	28.6
HCPV, res bbl	239,165,000
Reservoir Parameters for Gas Cap:	
Porosity (volume weighted), %	24.56
Water saturation, %	6.01
Gas-cap pressure 5/62, psig	1218
Gas-cap temperature, °F	150
Gas formation volume factor at 1,218 psig, 150°F	2.1723
Net Gas Injected: (May 1, 1962)	
Cumulative gas injected, Mcf	88,229,000
Cumulative free gas produced, Mcf	8,203,000
Cumulative net gas injected, Mcf	80,026,000
Cumulative net gas injected, res bbl	173,840,000

Gas Going Into Solution at 1,218 psig: (PVT data)

$$\frac{386 - 128}{1.103} = 234 \text{ cu ft/RB.}$$

Oil Swelling Factor:

$$\frac{1.226}{1.103} = 1.1115.$$

Recovery Factor Calculation:

G_F = Volume of free gas in gas cap, res bbl;
V_{or} = Volume of residual oil in gas cap, res bbl, of original undersaturated crude;
$\therefore G_F + 1.1115\ V_{or} = 239{,}165{,}000$ res bbl,
and $G_F = 173{,}840{,}000 - V_{or}(0.231)(2.1723)$.

$V_{or} = 108{,}297{,}000$ res bbl;

$$\therefore \text{Recovery factor} = \frac{239{,}165{,}000 - 108{,}297{,}000}{239{,}165{,}000} = 0.547.$$

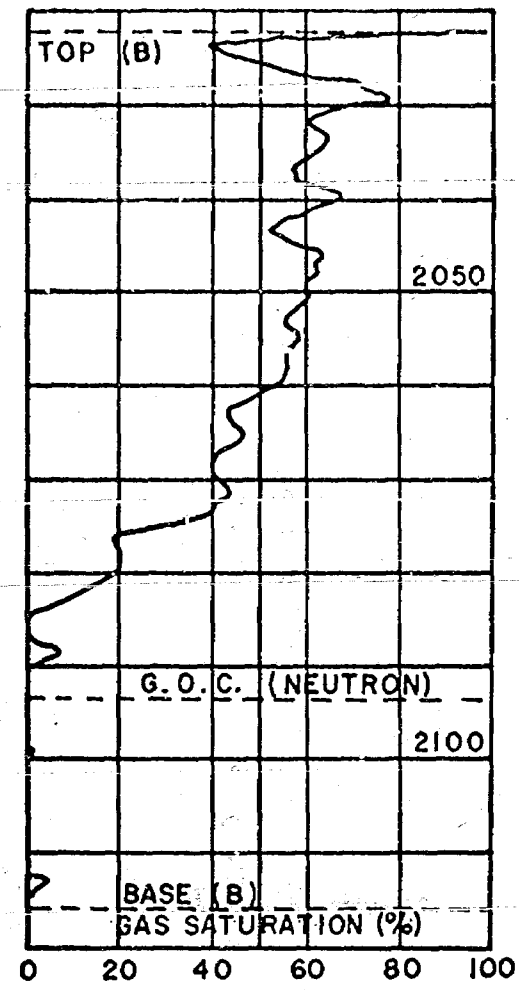


Fig. 15– Gas saturation.

well (Fig. 15). It is obvious that, as expected, a vertical saturation profile does exist and that the displacement efficiency is in excess of 50%, giving credibility to the calculated 50% recovery efficiency. The recovery efficiency should not be much less than the displacement efficiency, due to the narrow spacing of the wells.

Conclusions

1. Neutron surveys in conjunction with pressure surveys have been used satisfactorily to determine the percentage of oil recovery by gas displacement.
2. Gravity drainage as well as the oil wettability characteristics of the rock have been conducive to a higher oil recovery by gas than by water.
3. Material balance calculations and log analysis have shown that recovery in the gas cap is 50%.
4. The possibility of reduced recovery because of changing from rich Arab gas to lean Khuff gas is recognized. This potential loss will be offset partially because Khuff gas contains significant CO_2.

Acknowledgments

I acknowledge the assistance rendered by the Bahrain Petroleum Co. Ltd. while compiling this paper.

Reference

1. Cotter, W.T.: "Twenty-Three Years of Gas Injection Into A Highly Undersaturated Crude Reservoir," *J. Pet. Tech.* (April 1962) 361-365.

SI Metric Conversion Factors

acre	× 4.046 873	E+03	=	m^2
bbl	× 1.589 873	E−01	=	m^3
cu ft	× 2.831 685	E−02	=	m^3
°F	(°F−32)/1.8		=	°C
ft	× 3.048*	E−01	=	m
mile	× 1.609 347	E+00	=	km
psi	× 6.894 757	E+00	=	kPa
sq ft	× 9.290 304*	E−02	=	m^2

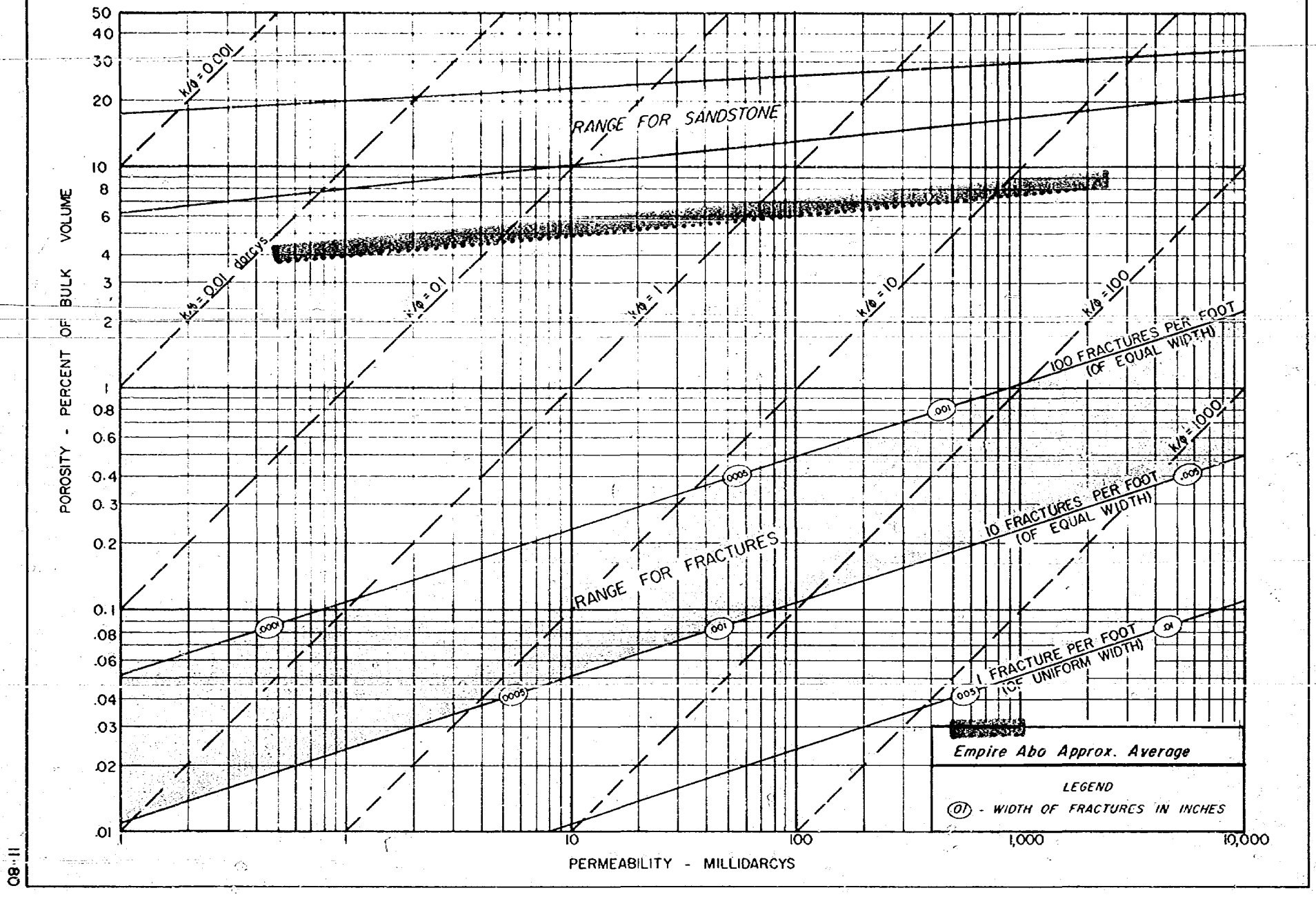
*Conversion factor is exact.

JPT

Original manuscript received in Society of Petroleum Engineers office May 24, 1978. Paper (SPE 7652) accepted for publication March 14, 1979. Revised manuscript received Aug. 24, 1979.

VALUES OF Kϕ FOR SANDSTONE RESERVOIRS AND FOR FLOW SYSTEMS OF FRACTURES IN AN IMPERMEABLE MATRIX

FRACTURES PARALLEL TO DIRECTION OF FLOW



APPENDIX III FIGURE NO. III-3

GRAVITY DRAINAGE RATES
WEST PUERTO CHIQUITO
FOR CONDITIONS OF:
OIL DENSITY 44.9#/cubic foot
GAS DENSITY 5.35#/cubic foot
OIL VISCOSITY .62 centipoises
FORMATION DIP 400 feet per mile

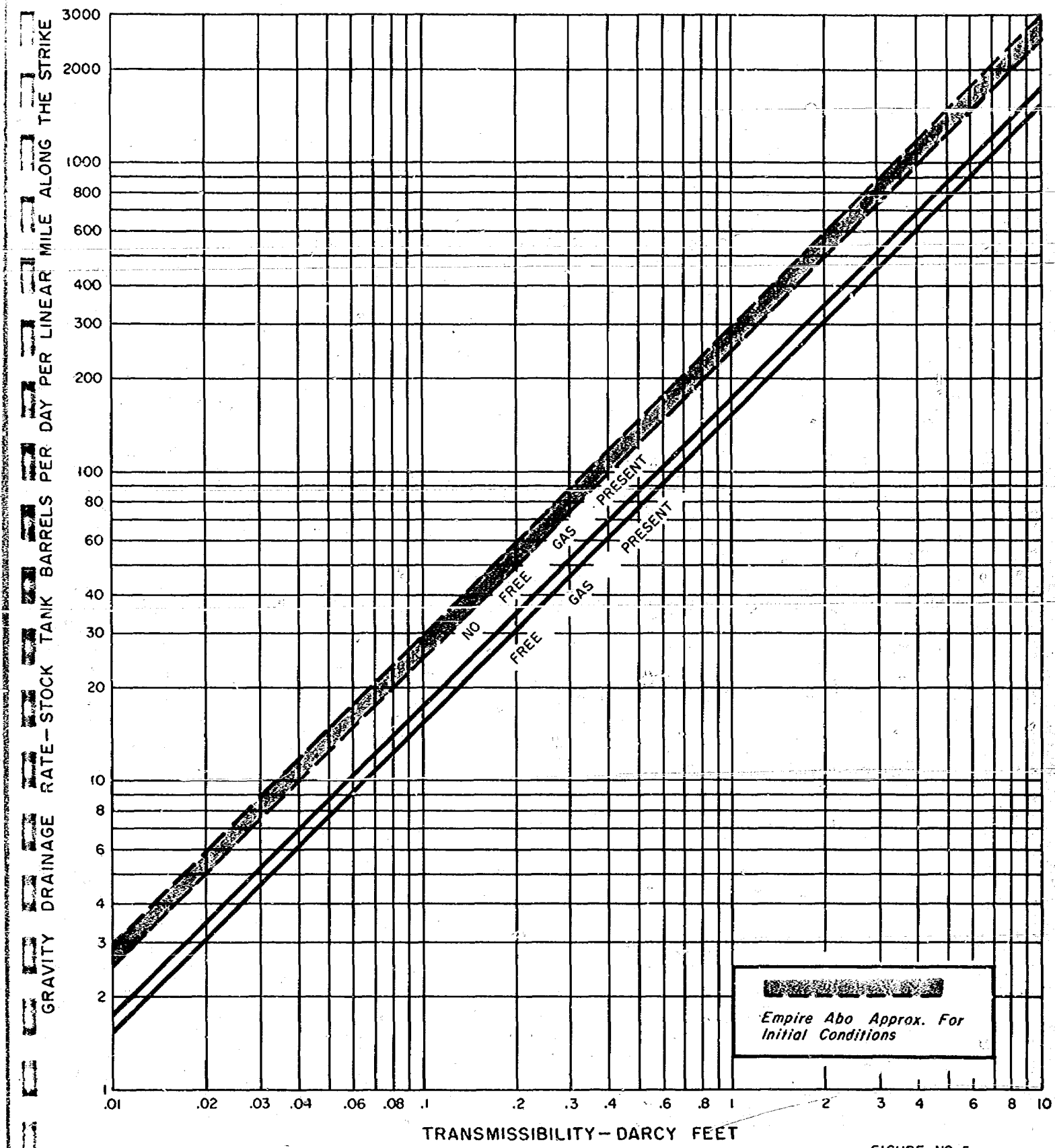
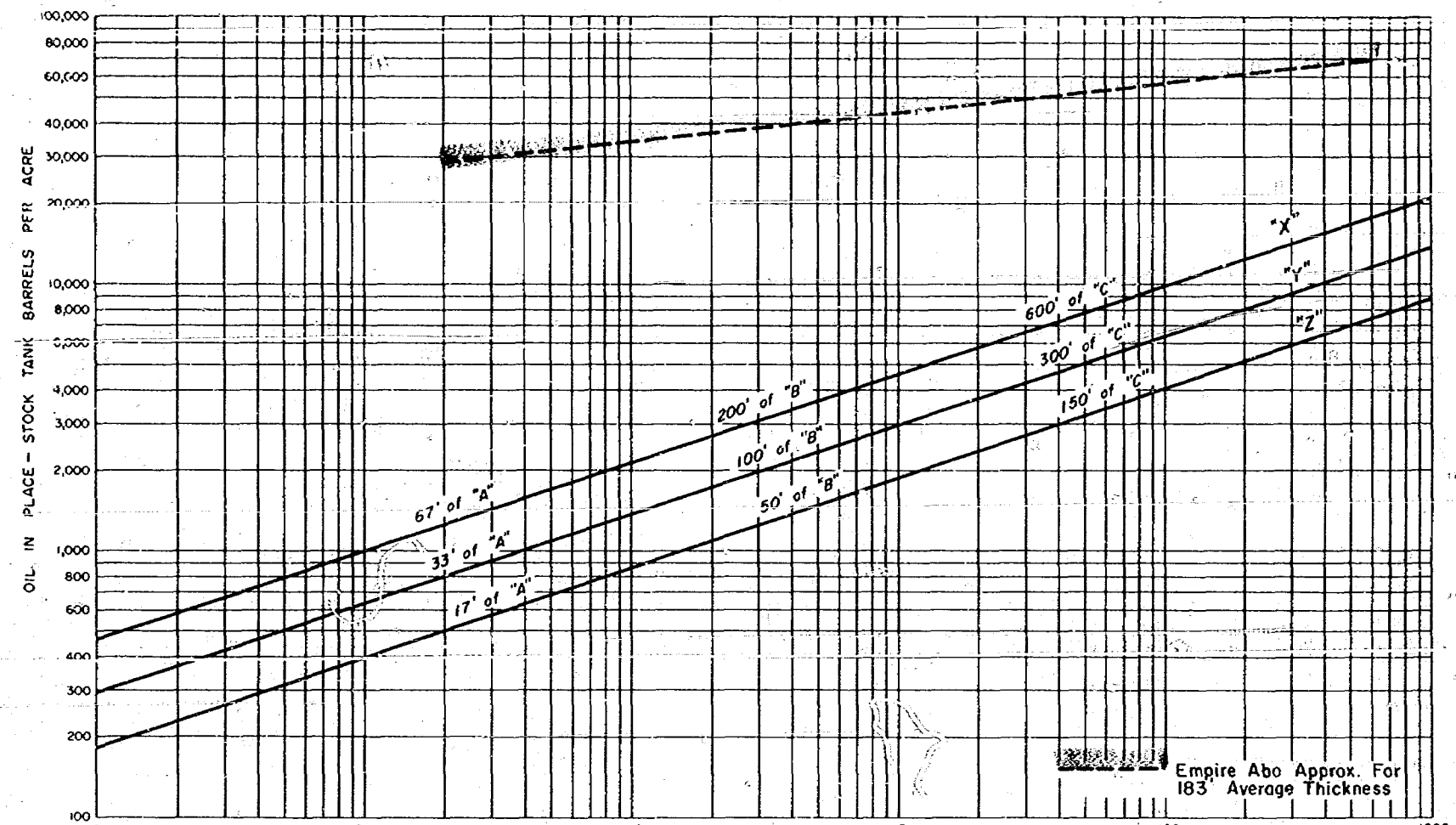


FIGURE NO. 5 11-80

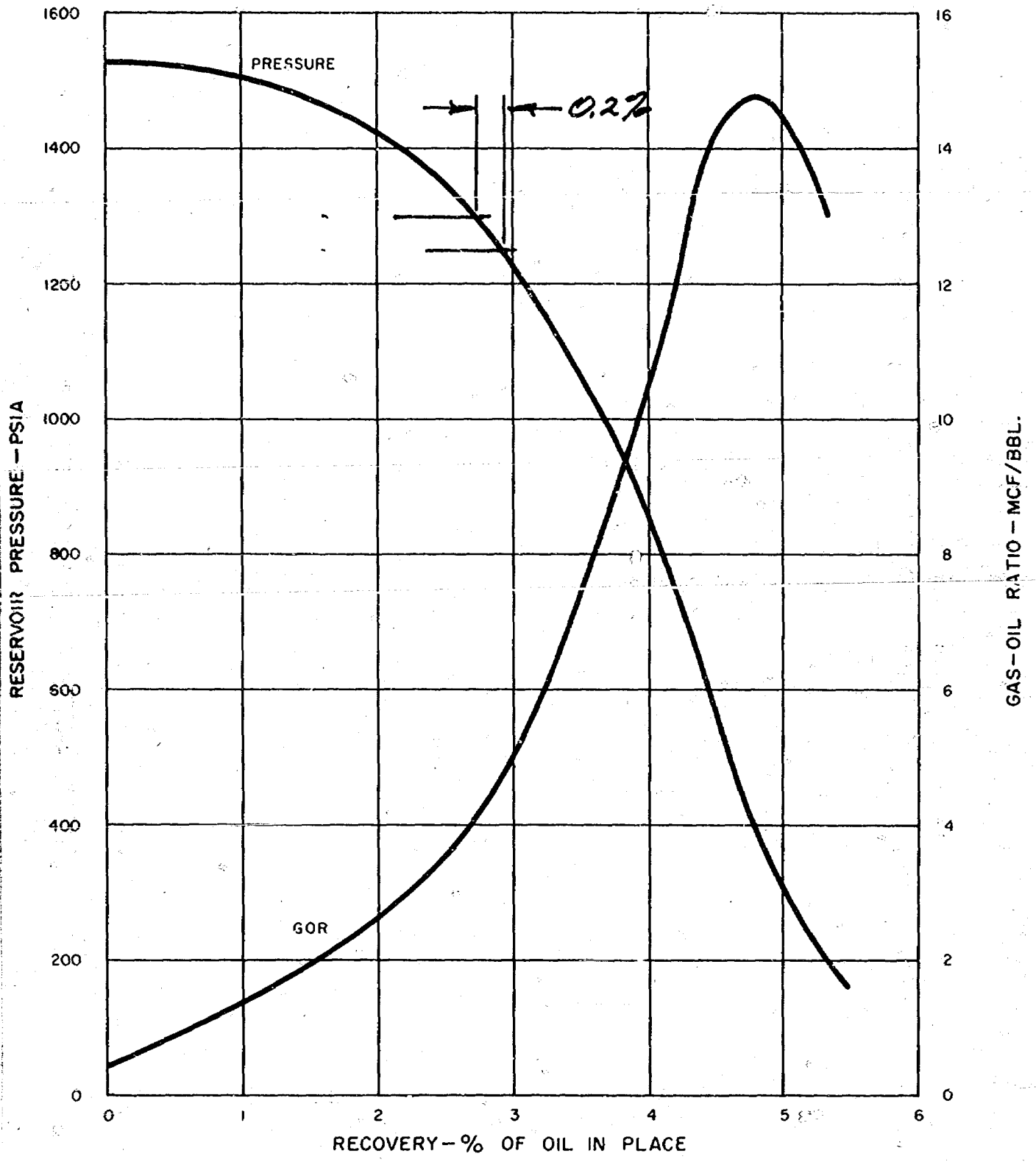
03-11

RELATION OF OIL IN PLACE
TO
TRANSMISSIBILITY
FOR
POROSITY-PERMEABILITY RELATIONS
"A", "B" & "C"
AND FOR
RESERVOIR THICKNESSES SHOWN
F.V.F = 1.29



APPENDIX III FIGURE NO III-5

SOLUTION GAS DRIVE
PRODUCTION HISTORY
CALCULATED FOR CONDITIONS OF:
WEST PUERTO CHIQUITO
PVT DATA
AND
K_g/K_o ESTIMATED FROM LABORATORY
DATA FOR FRACTURED FORMATIONS



APPENDIX IV FIGURE NO. IV-3

NOTE ON DEPLETION PROCESS

CANADA OJITOS UNIT C-34

1. From 1-1-74 to 10-1-80 COU C-34 produced 213,000 barrels of oil.

2. Pressure drop at observation well location during this time was approximately 50#; now (November, 1980) it is ± 1350.

3. Pressure drop in area structurally above the C-34 and draining to it would be from about 1300# to 1250#.

4. For this pressure drop (see graph) the solution-gas drive recovery would be 0.2% of oil in place.

5. For 213,000 barrels to be 0.2% of oil in place, the oil in place would have to be over 100 million barrels.

6. At 100 million barrels in place and 10 sections being drained by this well, oil in place would have to be 10 million barrels per section or 16,000 barrels per acre, which is 10 times the reasonably accurage figure of 1,600 barrels shown by interference tests. (If 5 sections drained - the average for recovery wells - the figures would be twice the above).

7. Conclusion: The depletion process must be something other than solution-gas drive - which means gravity drainage and/or gas drive by pressure maintenance.

COMPARISON OF PRODUCING CAPACITY AND GRAVITY DRAINAGE RATES FOR WELLS ON WEST SIDE OF WEST PUERTO CHIQUITO POOL

TRANSMISSIBILITY (Kh) (Darcy feet)	GRAVITY DRAINAGE RATE: BOPD/MILE ALONG STRIKE FOR DIP OF: 100'/MILE (BOPD/MILE)	200'/MILE (BOPD/MILE)	PER WELL APPROX. PRODUCING CAPACITY FROM*	TO* (BOPD)
.01	.35	.7	5	35
.1	3.5	7	50	350

* for range of ratios of re/rw of 1 to 3 and Ko/K of .3 to .7

GRAVITY DRAINAGE RATES
WEST PUERTO CHIQUITO

FOR CONDITIONS OF:
OIL DENSITY 44.9#/cubic foot
GAS DENSITY 5.35#/cubic foot
OIL VISCOSITY .62 centipoises

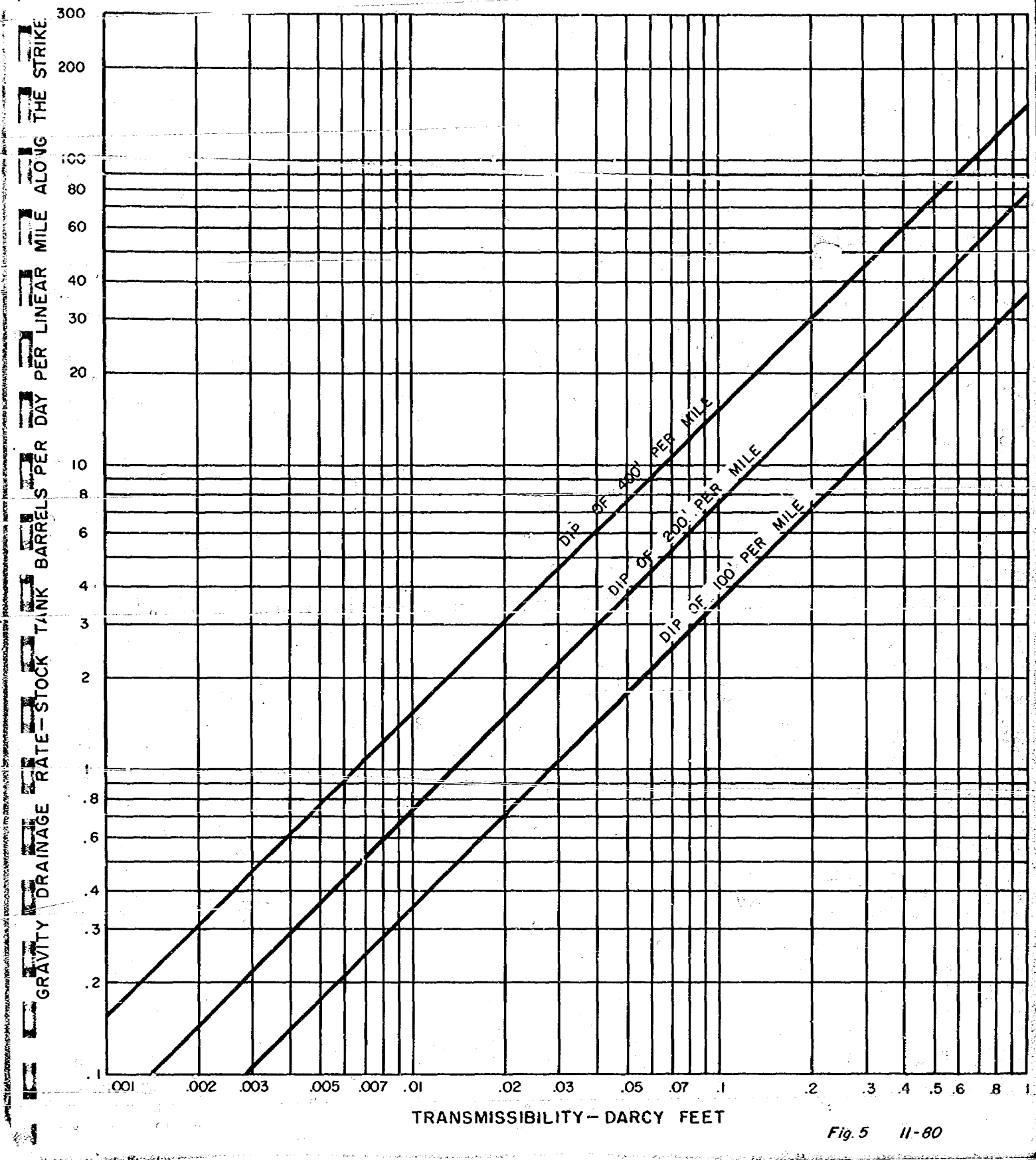


Fig. 5 11-80

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date NOVEMBER 24, 1980 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION
William F. Carr	Campbell & Black P.A.	Santa Fe
Robert O. Buettner	Koch Industries, Inc.	Wichita, KS
Richard M Lucas	Koch Exploration	Denver
W. John Carraway	Koch Exploration	Wichita KS
R. G. Walton	Koch Expl	Wichita, Ks
Jon M. Fedor	Hunker - Folan P.A.	Roswell
George H. Hunker, Jr.	Cotton Pet. Corp & Mountain Fuel Supply Co	Roswell, N.M.
Glenn A. Garvey	Cotton Petroleum Corp.	Denver
N.T. Kellahin	Kellahin & Kellahin	Santa Fe
Amanda A. Rogers	USGS	Albuq. N.M.
C.C. Kennedy	Fed	Albuq. N.M.
Earl Haught	U.S.F.S. (A.M. only)	Santa Fe, N.M.
Paul W. Adam	Patrick Petroleum	Denver, Colo.
Robert L. Pittman	Mountain Fuel Supply Co.	Salt Lake City, UT
L. Craig Metcalf	Mountain Fuel Supply Co.	Salt Lake City, Utah
Don Paull	Cotton Pet	Denver Colo
Virgil C. Stoats	Beacon - Montoya Group	Farmington

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date NOVEMBER 24, 1980 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
24 November 1980

COMMISSION HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico.

CASE 7075

BEFORE: Commissioner Ramey, Chairman
Commissioner Arnold

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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Legal Counsel to the Commission
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Santa Fe, New Mexico 87501

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	George L. Verity, Esq. BAY, HAMILTON, LEES, SPEARS & VERITY 501 Northwest Thirteenth Oklahoma City, Oklahoma
For Koch Industries, Inc.:	William F. Carr, Esq. CAMPBELL & BLACK P. A. Jefferson Place Santa Fe, New Mexico 87501
	and
	Robert D. Buettner, Esq. Koch Industries, Inc. P. O. Box 2256 Wichita, Kansas 67201
For Mountain Fuel Supply Co.:	L. Craig Metcalf, Esq. Mountain Fuel Supply Co. 180 East First South Salt Lake City, Utah 84139
	and
For Cotton Petroleum:	George H. Hunker, Esq. Don M. Fedric, Esq. HUNKER, FEDRIC, P. A. P. O. Box 1837 Roswell, New Mexico 88201

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MR. RAMEY: The hearing will come to order. We have one case on the docket this morning, Case 7075.

MR. PADILLA: Application of Benson-Montin-Greer Drilling Corporation for the amendment of pool rules, Rio Arriba County, New Mexico.

MR. RAMEY: Ask for appearances at this time.

MR. VERITY: Your Honor, George L. Verity and Tom Kellahin for the Applicant.

MR. RAMEY: How many witnesses do you have, Mr. Verity?

MR. VERITY: I have just one, Your Honor.

MR. CARR: May it please the Commission, I am William F. Carr, with the law firm of Campbell and Black, P. A., Santa Fe, appearing on behalf of Koch Industries, Inc., and we will have two witnesses, and we will have a preliminary motion we would like to make following all appearances.

MR. RAMEY: All right.

MR. HUNKER: George H. Hunker, Junior, Hunker, Fedric, P. A., Roswell, New Mexico. I'll be assisted by Don M. Fedric, my partner. We're appearing on behalf of Cotton Petroleum Corporation, Denver, Colorado, and Mountain

Fuel Supply Company of Salt Lake City, and Mr. Craig Metcalf of the Utah Bar is here to ask questions if he should care to.

MR. RAMEY: Do you have any witnesses?

MR. HUNKER: I have two witnesses and three exhibits.

MR. METCALF: I would like to make a short statement on behalf of Mountain Fuel at the outset of the hearing.

MR. CARR: Mr. Ramey, I would also like the record to reflect that I am appearing in association with Robert D. Buettner, an attorney for Koch Industries, who is a member of the Michigan, Illinois, and Ohio Bar.

MR. RAMEY: Butner?

MR. BUETTNER: B-U-E-T-T-N-E-R.

MR. CARR: Double T.

MR. RAMEY: You wanted to make a statement, Mr. Carr? Did you have a statement, Mr. Kellahin?

MR. KELLAHIN: We have an opening statement.

MR. CARR: We have a motion that I think might even be appropriate ahead of opening statements.

MR. RAMEY: Do you have any objection to Mr. Carr making his statement, Mr. Kellahin?

MR. KELLAHIN: No, sir, I'll be interested to hear what he has to say.

MR. RAMEY: All right, Mr. Carr, why don't you?

MR. CARR: Koch Industries moves that the application of Benson-Montin-Greer in this case be dismissed on the grounds that it constitutes a collateral attack on the Commission order, which by its own terms became final in accordance with the rules of the Commission.

A hearing was held on August 6th before Examiner Nutter. The subject of that hearing was amendment of the special pool rules for the West Puerto Chiquito Oil Pool.

The original rules for this pool provided that wells should be drilled within a 165 feet of the center of the quarter quarter section. At that hearing Koch Industries appeared in support of Benson-Montin-Greer and proposed that special pool rules provide for a 330-foot setback from the quarter quarter section line. A discussion was held before the end of the hearing with Mr. Nutter at which time the parties to that case agreed that it would be appropriate for special pool rules to issue providing for a 660-foot setback from section lines, a 330-foot setback from the quarter section lines, and a 5-foot setback from quarter quarter section lines.

All parties agreed, including the applicant here today. Their agreement appears on page 93 of the transcript.

The Commission then entered an order, R-6469, and with one exception incorporated this agreement, the exception being a 10-foot setback from quarter quarter section lines instead of a 5-foot. That order was dated September 105h. It could have been appealed for 30 days.

On October 10th, 30 days later, application was filed by the applicant in this case, which resulted in the hearing today. It was not an appeal but it was a new case to review the spacing and asking for a hearing before the full Commission.

The posturing of this case has two effects. One, if we wanted to come before you to challenge the 640-acre spacing, challenge the irregular spacing units that were created by the September 10 order, we would be barred from doing so, having failed to perfect our appeal.

Since this was a new application, and not a requeste for a hearing de novo, we submit that what we have is a collateral attack on an order which they permitted to become final, and it is final because they didn't exhaust their administrative remedies.

And we submit that it is improper now

for this Commission to permit them to come forward and selectively review matters about which they've apparently changed their mind. We think permitting them to come forward and to reopen this case as to certain matters, and at the same time finding ourselves in a position where we couldn't come forward and have the Commission review other matters that were considered in the prior case, would be an unreasonable act by the Commission and would arbitrarily give advantage to the applicant here today.

If the applicant is prepared to come forward and present new evidence, then we have a different situation, but this evidence would have to be evidence which became available after the original hearing, and we submit that it's highly unlikely they can present such evidence, since there have been no new wells drilled in that area since 1972.

Absent a showing that new data exists on which they can bring a new case, we submit that their application should be dismissed. We think that would be a proper ruling for the Commission. We think that if you don't dismiss this application, we're put in a position of wondering when this sort of procedure is going to stop. Maybe three months from now we can come back and have another hearing to say we have to have four wells, or four exceptions in each spacing

unit, if we never can rely on a Commission order becoming final.

We think the Commission should dismiss this application because failure to do so will set a dangerous precedent. I can assure you that we would seriously consider using this approach in lieu of ever seeking a de novo hearing for any of our clients because we would look upon it as an opportunity to review only those parts of Commission orders that we disagree with, and not having the whole matter re-opened for a true hearing de novo.

We submit that failure to dismiss this application is departure from well established Commission procedures. Failure to dismiss the application would be an arbitrary action letting one party take unfair advantage of another; that it would create an unreasonable situation where we could never rely on the finality of an Oil Conservation Commission order.

We therefor pray that the motion be granted and that the application of Benson-Montin-Greer be dismissed.

MR. RAMEY: Mr. Kellahin, would you like to respond to that? Okay, Mr. Verity?

MR. VERITY: Yes, Your Honor. We believe the field rules are not a matter of being res judi-

cata, that the Commission, Division retains jurisdiction of field rules at all times. Jurisdiction in this cause was retained for the entry of such further orders as the Division might deem necessary, in the order that he refers to. It is extremely necessary in this situation because if the conservation that has been established in this pool is to be destroyed, which it certainly will be destroyed if competitive drilling is permitted up and down the west line of Canada Ojitos, and a great waste will occur. There will be tremendous waste of oil left in the reservoir. We're prepared to prove all of this and we believe that's why the Commission retained jurisdiction and that's why the rules are changed from time to time.

MR. CARR: In response to that, Mr. Ramey, we wouldstate that retaining jurisdiction of the Commission is not tantamount to creating a situation whereby Oil Conservation Division orders do not ever become final and no one can therefor rely on them.

You retain jurisdiction so if there is a change in circumstance, if there is new data available, then you have the authority to reopen the matter.

There is not -- that is not what you have before you here today. You have a situation where all the data has been known for a number of years and the only

reason that it's come back here today is certain parties in the area, in the case, and certain people with interests in the area have elected to start developing acreage which for some reason those who have been active in the area have failed to develop for a number of years, and we submit that you do not have a situation which triggers your reopening this hearing because you do not have new facts; you do not have a new situation; you do not have a changed situation from that which was before you in August of this year.

MR. VERITY: Of course, Your Honor, with a change of condition you can reopen any matter whether there is any contention of the jurisdiction by the Commission or not, where you specifically retained jurisdiction of the cause as you did in this one, for the specific purpose of entering further orders which you may deem necessary. You did retain it exactly in this situation where if it's necessary in order to prevent waste and protect correlative rights of the parties you may go into it.

In this case, of course, at the hearing last August, BMG anticipated that we would be able to unitize the western area. Since that time we've been amazed to learn that it cannot be done and that we're going to enter competitive drilling, and it becomes critically necessary that the Commission protect this reservoir from drastic waste. That's

what our proof will show.

MR. CARR: We would make one other point and that is that if this case is reopened here today, we would understand such a ruling to permit us to bring an application with no additional data than what we've had all along; to drill wells only located in, say, the north half of the section or the east half of the section, for the change of spacing, or to attack anything else that became a matter of record in that case, was established in the prior case.

We're just asking to be treated fairly. We think if an order becomes final for us, it also becomes final for Benson-Montin-Greer.

MR. RAMEY: Mr. Metcalf?

MR. METCALF: Yes.

MR. RAMEY: Did you have something you wanted to submit?

MR. METCALF: I just have a short statement.

MR. HUNKER: He has a statement supporting Cotton's position and Mountain Fuel's position. I don't know whether it's appropriate now or not.

Well, go ahead and make your comment.

MR. METCALF: Well, Mountain Fuel appreciates the opportunity to present to this Commission a

brief statement.

Mountain Fuel is familiar with the proceedings in this matter, as well as the previous applications which have been filed with the Commission, affecting the area in question.

Specifically, Mountain Fuel has reviewed the application now pending before the Commission and is familiar with its contents.

Mountain Fuel holds competitive Federal leases in the affected area. Mountain Fuel has entered into agreements with Cotton Petroleum Corporation and Koch Industries for the development of its leased properties.

In the event the application is granted, Mountain Fuel's interests will be adversely affected, particularly if it forces Cotton and Koch into an uneconomic or ungeologic position.

Further, in the event that development in the area is further delayed by additional applications concerning well spacing, Mountain Fuel will not have sufficient time to develop its leases in an orderly fashion.

Mountain Fuel has reviewed and is familiar with the exhibits that Cotton and Koch propose to introduce into evidence in this proceeding, and is also familiar with the positions those parties are taking.

Mountain Fuel fully supports those positions of Cotton and Koch in regard to the application now under consideration.

MR. CARR: May it please the Commission, I have a motion pending and request a ruling.

MR. RAMEY: We're going to recess about fifteen minutes.

(Thereupon a recess was taken.)

MR. RAMEY: The hearing will come to order.

Mr. Verity, will your testimony show that there is a change in circumstances?

MR. VERITY: Our testimony, Your Honor, will show that at the hearing last summer there was no objection, and that that hearing was preliminary to the formation of a unit for the western tier of sections, as well as a later unit for the north tier of sections, and we'll show that without the proper conservation this pool is going to deteriorate to the extent 90 percent of our future reserves.

It's also going to show that not only will this affect reserves of the owners of the Canada Ojitos

Unit to the extent of 90 percent derogation of their future reserves, but that in addition thereto the State of New Mexico is going to lose between $18 and $36-million in royalty and gross production taxes; that the Federal government is going to lose between $67 and $134-million in windfall profits taxes; and as well as $12-million in royalties.

To think that the conservation that has been established in this pool would be destroyed by competitive drilling and the economic consequences, certainly shows that this Commission not only should but must hear this matter at this time if great waste is not to be encountered.

I think the prime duty of this Commission is to prevent waste of reservoir energy, especially in times like this, when hydrocarbons are at such a premium in this country.

There isn't any question but what the Commission has the right to hear this. A change of condition is a matter that occurs if the entire order is to be set aside and changed; not whether we have field rules, and not whether the Commission has retained jurisdiction, as they did in this case for the purpose of considering further matters, just as we have.

If we had had unitization, which we indeed anticipated that we would have in this area at the time

that that 640-acre case was heard, and as a matter of fact, in that hearing we explained to the Commission that it was as a preliminary -- was preliminary to and as an adjunct to making ready for -- for unitization.

There isn't any question but what the Commission has the authority to hear this at this time and to enter an order that changes the rules.

MR. RAMEY: Thank you, Mr. Verity.

Mr. Carr, I'm going to take your motion under advisement and we'll rule on it later. I think we need to hear at least a portion of the case.

So you may proceed, Mr. Verity.

MR. VERITY: We feel that an opening statement would be helpful to you before we present our evidence, and at this time I would like to make one.

The application of Benson-Montin-Greer Drilling Corporation here before the Commission requests a change in the spacing pattern established for the West Puerto Chiquito Mancos Oil Pool.

In order for this application to be properly considered, it is necessary that we review the history of the development of the pool and the facts regarding its reservoir characteristics.

Back in 1963 after only a well or two

were drilled in the pool, Benson-Montin-Greer came before the Commission and requested 160-acre temporary spacing.

At that time both East and West Puerto Chiquito were thought to be one pool. Shortly after that, or a few years after that, it was realized that there was a barrier between East and West Puerto Chiquito, whereupon an application was filed and an order entered establishing two pools, East and West Puerto Chiquito.

After 1963, when only five wells had been drilled in a cluster with approximately two miles distance between them, Benson-Montin-Greer had the courage, and it takes a lot, to interrupt all of the production from all five of those wells for a period of sixty days so that they could conduct one of the most remarkable interference tests that I've heard of in many years of oil and gas practice in Texas, New Mexico, and Oklahoma.

This multiple interference test was conducted in 1965, and in 1966 the results of it were presented to this Commission in Cause Number 3455, the same case as here before this Commission.

At that time it was established that the pool was a fractured shale, being the Niobrara member of the Mancos; that it was a pool with a minimum amount of oil in place,per acre in place, and that it would support wells

capable of very wide drainage, and that the communication was so great that every one of those wells were affected by anything that happened in any one of them, and at that time 320-acre temporary spacing was requested and granted.

Also at that time, BMG expressed comprehensive opinions with regard to the characteristics of the pool and how it should be developed.

Today, after seventeen years of history of the West Puerto Chiquito Pool, all of the theories and opinions that were expressed to the Commission back at that time have been definitely established as engineering facts, and are now a matter of history.

It is a rare instance in the oil industry that management will permit the remarkable engineering that has been achieved in this pool. Pools like the Boulder Pool, just a few miles to the north of West Puerto Chiquito, where 80-acre spacing was employed and where there was no pressure maintenance installed, reflect a tragic disparity of conservation compared to West Puerto Chiquito.

Shortly after the dramatic interference tests and establishment of 320-acre spacing BMG as the operator of Canada Ojitos established a pressure maintenance system by injecting gas in the upper edge of the pool. Then they carefully monitored production and voluntarily restricted

production rates so as not to exceed gravity drainage ability of the field. Without this pressure maintenance and controlled development of the pool we would have only been able to recover 5-1/2 percent of the oil in place; whereas, as it has been developed, we expect to recover between 50 and 60 percent of most of the oil in place.

I say that we expect to. We expect to if we're able to continue the program of conservation established over the 17 years history of the field.

Our evidence will show that there are high and low capacity wells and that even the low capacity wells have maintained their initial production rates over a period of years, and we will show that not only the high capacity but the low capacity wells also drain wide areas.

We have two production wells which we will be talking about along with the others, one well in Section 10 has produced 2-million barrels of oil, and we will show that this well has already drained an area of between 4000 and 8000 acres and is still producing.

The initial five well interference test enabled us to establish that the oil in place in this area was between 1000 to 2500 barrels an acre. Then after such interference tests, BMG left one of those wells off production and never put it back but used it as an observation well.

Then when the Canada Ojitos operator started injecting gas in the upper side of the pool, they were able to run an additional interference test. By that further interference test they confirmed and refined their previous conclusions regarding oil in place.

Preliminary to unitizing additional areas in West Puerto Chiquito BMG requested the Commission and was granted 640-acre spacing. This was necessary preliminary to, and as an adjunct to, unitizing North Canada Ojitos and West Canada Ojitos, and as we indicated in the hearing held on such application last August, we anticipated that these areas would be unitized in a compatible program with the Canada Ojitos Unit so that the conservation program heretofore established could be continued for the greater recovery of oil.

The Division granted the application for 640-acre spacing and established a pattern of permitting a well to be drilled up to within 660 feet of the line. BMG at that time paid little or no attention to the spacing pattern for the reason that the unitization of the area would make the point moot.

However, since that time BMG has been shocked to discover that the protestants here today would not agree to unitizing West Canada Ojitos. As a matter of fact, without advising BMG that they were terminating negotiations

regarding the formation of West Canada Ojitos Unit, they proceeded to stake a location for the drilling of a well in the area 660 feet on the surface from the Canada Ojitos Unit, which well, if drilled, will most probably be considerably closer at the bottom of the hole.

If such a drilling program is to be carried on to production by the protestants, then the highly efficient gravity drainage and pressure maintenance processes established and practiced by the applicant will be destroyed and there will be serious degradation of recoveries from the reservoir. This will result in a tremendous underground waste of oil and a destruction of the correlative rights of the applicant.

In this regard our proof will show that if protestants are permitted to drill where they desire, then the section under which they drill will not be drained as to a large portion of the western part thereof, while on the other hand, protestants' well, or wells, will drain a large area under the Canada Ojitos Unit to the east of such wells. Such drilling would require that unit operator offset -- only offsets only 660 feet from the protestants' section line in order to partially protect the unit, but our proof will show that offsetting wells cannot protect the unit from severe drainage by the protestants' wells.

Applicant's proof will further show that not only will the drilling pattern desired by the protestants cause a great amount of oil to never be recovered from the reservoir and wasted, but in addition thereto, will cause the drilling of unnecessary wells. Our proof will show that close offsets are unnecessary wells, are not only costly and wasteful, but in addition thereto will create much unnecessary damage to the National Forest.

Damage to the National Forest may not be strictly a matter of oil and gas conservation. However, this area is a part of the Santa Fe National Forest. It is a beautiful wooded area and minimizing damage and maintaining its beauty has been a significant consideration to the managers of the Canada Ojitos Unit.

After applicant learned that the protestants would not agree to form a unit, but desired to proceed with a drilling program that would prevent the greatest recovery of oil from the pool, it became apparent to BMG that they needed a different spacing pattern than that established by this Commission after the August hearing.

Therefor, BMG filed the initial application in this cause. In that application we requested that the spacing pattern follow or conform to the customary 640-acre spacing regulation in New Mexico, which requires that

wells be located not closer than 1650 feet from the spacing unit section line; however, when BMG began to project the inevitable consequences of an application of the standard spacing pattern, it realized that wells drilled in the east half of the western tier of sections, 1650 feet from the east line, not only grossly fail to protect the applicant's correlative rights, but also fail to adequately drain the western half of their sections.

Thereupon, applicant amended its application to request that wells in the pool be spaced uniformly in the west half of each spacing unit.

In an ordinary reservoir where 640-acre spacing is established, a well placed at any place 1650 feet from the line of the section adequately protects the correlative rights of the parties where there is an opportunity for compensating drainage; however, WEst Puerto Chiquito is no ordinary reservoir. To the contrary, it is a reservoir where the ratio of the ability of the wells to produce the oil from the reservoir in relation to the amount of oil in place is much greater than the average. In other words, in this reservoir the capacity of the wells in relation to the amount of oil in place is far greater than in the average situation. Also it is a pool tilted downward from the east to the west and where a unit was formed at an early date in

the development of the pool and a pressure maintenance system installed.

These facts, together with the careful spacing of wells and production, drastically segregate this pool from the ordinary oil and gas conservation situation. Oil not only drains from east to west but in addition thereto, it is further moved from east to west by virtue of the fact that the Canada Ojitos Unit installed four injection wells on the eastern extremity of the pool and has been injecting gas into the formation almost from the inception of production.

These conditions cause the oil to move from east to west and wells to the west of the Canada Ojitos Unit will drain oil from under the unit.

These are the reasons that a well in the sections immediately west of the Canada Ojitos Unit, which is located in the east part of the spacing unit, will not be efficiently draining such spacing unit. To the contrary, most of the oil produced by such well will be draining from lands to the east. Applicant's evidence will show that such oil will be produced not just from the adjoining sections to the east, but from large areas of the unit lands.

Even more unfortunate, such well will produce only a small part of the oil from the western part of the section upon which it's located. It will, therefor, be

an improperly located well. It not only will not serve conservation, but it will destroy correlative rights, and may result in a tragically reduced ultimate recovery of oil from West Puerto Chiquito.

This was the reason that although the applicant intitially asked for spacing 1650 feet from the line, after applying this standard pattern to the unusual characteristics of the reservoir, it became apparent that applicant's correlative rights were going to be destroyed, and the applicant realized that it must ask for a rule which would allow a more equitable recovery of the hydrocarbons in the reservoir and would come closer to preserving the energy of the pool.

The only way to better protect the correlative rights of the applicant was by requiring that all wells be drilled in the west half of the section.

Our evidence will show that wells located in the western half of the sections will come closer to producing the oil from under their sections, and that they will be far less an infringement upon the correlative rights of owners of the Canada Ojitos Unit.

Further, our proof will show that it will save the cost of drilling of unnecessary wells and greatly diminish the overall damage to the reservoir; also, that by

eliminating the drilling of unnecessary wells, it will greatly protect the surface and the beauty of the National Forest.

It is difficult to fully appreciate the tremendous danger that is presented by the specter of wells being drilled 660 feet immediately west of the Canada Ojitos Unit boundary; therefor, in order that the Division understand the gravity of our application, we will present evidence which will show that if competitive drilling is permitted to proceed in West Puerto Chiquito in accord with the present order, that the established efficiency of the Canada Ojitos Unit will be destroyed and it may lose as much as 90 percent of its future recovery.

We will further show that this would mean a loss, not only to the Canada Ojitos owners, but also a loss to the State of New Mexico of between $18 and $36-million in royalty revenues and gross production taxes, and a further loss to the Federal government of between $6 and $12-million in royalties, and between $67 and $134-million in windfall profit taxes, meaning losses to both State and Federal government between $90 and $180-million.

The applicant is aware of the fact that without the acreage on the west being unitized, waste cannot be prevented, but absent such compatible unitization, our proof will show that conservation and protection of correla-

tive rights make it mandatory our application be granted.

And I'd like to call Mr. Al Greer.

MR. RAMEY: Just a minute. We'd like for all the witnesses to stand and be sworn at this time.

(Witnesses sworn.)

MR. CARR: May it please the Commission, before Mr. Greer starts to testify, one other short matter.

Mr. Verity made reference to the prior hearing, and it will shorten the time it will take us ultimately to present our case, if we could have the record of the prior case incorporated into this record.

MR. FEDRIC: Mr. Chairman, Cotton and Mountain Fuel would support that. If we have the prior record incorporated, we know from the opening statement made by Mr. Verity that much of what he's talking about now is history because it is in the prior record. Possibly by incorporating that and moving forward to the subject matter at hand, which is the basis for the application, we could save some time and get right to what we're talking about.

MR. VERITY: We concur in this motion and believe that it can save time because there is a lot of detail that we have to go into and that hearing will support

it, and therefor we can cover the exhibits that were presented at that time which need to be presented here in a lot shorter order. So we concur in the motion.

MR. RAMEY: Does anyone have the case number?

MR. KELLAHIN: Case 6997.

MR. RAMEY: Case 6997. Okay, we will incorporate Case 6997 into the record today.

MR. ADAN: Patrick Petroleum is here in support of Koch and Cotton, and should we have to leave early, we'd like to leave a written statement showing support.

MR. RAMEY: All right, thank you.

ALBERT R. GREER

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

DIRECT EXAMINATION

BY MR. VERITY:

Q. Mr. Greer, if you will, please, explain to us why it's necessary to go into the history of the West Puerto Chiquito Pool and its reservoir characteristics preliminary to setting a proper pattern for the proper development, present development of the pool.

A. All right, sir, as you indicated earlier, and agreed to by the protestants, we'll move through this just as fast as we can, but it is important that the Commissioners have in mind some of the unusual facts and characteristics that just must be considered in entering an order in this application.

As I understand the Commission's responsibility here, they'll probably make their decision based principally on the protection of correlative rights and prevention of underground waste. There are side issues, such as the protection of damage to the forest, which under the plan that we recommend this pool be developed, concurrently is aided and the forest protected.

The real problem that I see is in the prevention of underground waste. This is probably, if not the most unusual pool, it's got to be one of the most unusual pools on which this Commission has ever entered any orders, in regard to the fact that just depending on how the pool is produced, how the wells are controlled, pressure maintenance installed, the range of recoveries possible from this pool is in the order of 10 to 1. Now this is most unusual.

In fields where pressure maintenance by gas injection is installed, ordinarily one can look at 10, 20, 30, or maybe 50 percent additional recovery; a ratio

of 1.3 and 1.4 to one.

Waterflood, in round numbers 2-to-one. Here we're looking at 10-to-one, a very unusual situation. Being unusual, it requires unusual rules.

Q. Mr. Greer, why did you ask for 640-acre spacing last August?

A. If I might, I'd like to continue a little bit more --

Q. All right, excuse me, sir, I thought you were through.

A. There's a little difference that the Commission has now in reviewing our application compared to ten or fifteen years ago. At that time we pointed out that if we could do these things, wide spacing, controlled production, pressure maintenance, then we would be looking at 10-to one increase in ultimate recovery.

Since that time we have intalled pressure maintenance, we have controlled the production, we are now realizing this high rate of recovery. And so what the Commission is looking at now is not an increase of 10-to-one, but a destruction of 10-to-one if your application is denied.

We already have it going. It's already in place. We've already proven the things we postulated ten to fifteen years ago. So this gives the Commission a little

different position than might otherwise they have.

Now the problem is prevention of waste and is that in order to control production, in order to carry on pressure maintenance, requires unitization. Protestants here have refused to unitize voluntarily before drilling. The characteristics of this pool are such that to drill first is to sound the death knell to voluntarily unitization. There is no way that it can be brought about after the wells are drilled.

The problems of unitizing first and then drilling are simple for the reasons that can be easily resolved. To drill first, even reasonable people will not be able to get together on acreage factors. So what this means is that if protestants drill and develop production, there's going to be a statutory unitization hearing. We can say that for certain because we'll make the application. We'll have to. We can't stand by and see 90 percent of the future potential recoveries wasted. So we'll ask for statutory unitization.

So the issue, then, of can this Commission prevent waste in this pool under the situation we're talking about now, is will the statutory unitization order be upheld in court, and that's what it amounts to. Will it be upheld in court?

If it is upheld in court, then we can continue with what we're doing, but if it's not, we're back to -- to competitive drilling and losses of production, and whether it's upheld in court can turn, the judge's decision can turn on whether in that statutory unitization order he regards the equities of the parties have been properly determined.

Now the equities of the parties can very well hinge on where the wells are located. That's how this Commission in viewing unitization will make its -- one of the things it will consider.

And so as we go around in this daisy-chain, we're back to where the wells should be located, what we're talking about here today, and the prevention of waste, and really, as we unfold our testimony I think you'll agree with me that rather than comparing it to a daisy-chain, it would be better compared to a string of dominoes. Once they start to fall, there's no stopping them. That's why we must review and get in the Commission's mind these facts and mechanics of the reservoir, how is has performed and how it will perform.

Q. Mr. Greer, why was the 640-acre spacing application necessary in August?

A. We asked for this primarily, well, there

are about three or four reasons, but the principal reason, preliminary to the formation of either a new West Canada Ojitos Unit, or the expansion of the existing unit. Now the reason that's necessary is that at this point we don't know where exactly we should locate the down dip row of wells. There should be an additional row of recovery wells drilled on the down dip side of the Canada Ojitos Unit reservoir.

To attempt to locate those wells now is an impossibility to do it properly. One thing that we know for certain, we only need one row of wells; we don't need two or three or four rows of wells; we only need one. And the best way to achieve this, we form a unit. Let's say for example, we expand the present unit and we drill two or three wells along the west boundary. For each well that's productive we bring into participation a maximum amount of acreage reasonably considered proven for production. If we have 640-acre spacing, compared to 320-acre spacing, everything else being the same, we can bring in twice as much acreage with the drilling of one well.

It's necessary to bring in undrilled acreage, which you can do in a voluntary unit and we can't do in a statutory unit or otherwise.

So, if we approach it that way, drill three or four wells along the west boundary and then we have

included the two tiers of sections, hopefully, west of the present unit. Then in a logical and reasonable fashion with locations chosen by the engineers and geologists on the basis of engineering and geology, additional locations are chosen. They're not chosen where the drilling of a well increases some company's equity. This is the only way that you can proceed in a field like this in which the oil in place per acre is so small, yet responds so well to gravity drainage and pressure maintenance, in which there's no way to have a spacing plan or program of so many acres per well, 640 sounds large, perhaps, but the wells actually drain far greater amounts of acres than that. There's no way to have a reasonable spacing order set by this Commission greater than that.

In the final analysis we'll want to drill wells probably a mile apart on that bottom row, but up and down dip, perhaps only -- only one well to three or four sections.

So, preliminary to unitizing West Canada Ojitos Unit, 640-acre spacing, and in addition there's the little issue of windows in the unit, a 40-acre tract here, or an 80 there, perhaps it's a State, or some problem in determining the title, or sometimes it's from just a purely administrative standpoint, it would be simplier to have a forced pooling of a spacing unit rather than statutory uniti-

zation to bring in a small tract. That's another reason.

One other reason is that there has been a tendency recently to require the development by basic royalty owners of leases to the full extent of their spacing unit. Here, where wells drain far greater than the spacing unit established, it just makes sense to set as large as practicable spacing unit as -- as the regulations will permit. So those are the reasons.

Q. One other thing, how did it happen that initially in this application we requested for 650 feet from the line rather than the west half of the section unit?

A. 1650 feet?

Q. 1650 feet.

A. I first thought -- as you indicated earlier, we were shocked when we found that the protestants refused to unitize a field like this. It's incomprehensible to me that -- that oil companies with engineers and geologists that can understand the reservoir mechanics would permit their managements to go ahead without unitizing. We were shocked to understand that -- that they refused to unitize; refused to even talk about it.

So we thought the best thing to do, perhaps, was to ask for the standard spacing for -- which New Mexico has, for 640-acres, which is this 1650 feet from the

line. We made that application, and then as we worked on the application of that spacing to the peculiar characteristics of this pool, we realized that that just would not protect our correlative rights, would not result in the kind of spacing of wells that in the future under statutory unitization, if it comes about, could really provide equities or reasons or grounds that the Commission could set equities.

So we found it necessary to amend our application.

Q. Turning now to what we'll ask the court reporter to mark as Exhibit One, the grey exhibit. I believe everyone has a copy of it.

At the start of that you have an index, which we will turn over to Section A. This Exhibit One is -- has Sections A through I in it, and referring to Section A, Mr. Greer, at the start will you explain the first part of that exhibit?

A. Yes, sir. The first --

Q. That section?

A. This part is a plat, an orientation plat, which is outlined in orange the West Puerto Chiquito Pool and within it the Canada Ojitos Unit. To the northeast of it is the East Puerto Chiquito Mancos Unit, which is currently being formed. In the north part is the proposed North

Canada Ojitos Unit, and on the west side you can see what in August we thought would be the West Canada Ojitos Unit.

Q. And your next part of Section A?

A. Under A, the second map under A shows our interpretation --

Q. Excuse me, hold it just a minute.

MR. RAMEY: We don't seem to have that.

MR. VERITY: Oh, I'm sorry, that's going to be Exhibit Two that you have.

This Exhibit One is the Exhibit One from the August hearing.

Turning now, if you will, to the second part of Section A.

A. Did you want to identify this exhibit?

Q. I believe I did, that this is the same -- this is Exhibit One from the August hearing.

Explain the second part of Section A, Mr. Greer.

A. This shows in color our interpretation of the areas of flexing which, in our opinion, is the controlling factor in the amount of fracturing and from that the location of the reservoir. The formation outcrops on the east on the righthand side. The initial dip is 2 or 3000 feet a mile; it's steep; it's uniform; it's hard; it's compact; there

is no permeability. As we get to the colored areas, the formation is flexed. It's a synclinal flex. The blue area is roughly 1000 feet a mile; the green area, about 400 feet per mile.

Q. And there's a fairly sudden change of that -- that amount of --

A. Yes. There appears to be different flexes and it is our interpretation that -- that this is where the fracturing occurs.

On the west side we show a grey area. It's colored grey because I think it is grey as to whether it will produce, produce in commercial quantities. Certainly it's on the edge of the reservoir. And from there, for the next two miles is an area that we had proposed for the West Canada Ojitos Unit.

Q. Directing your attention now to the next part of Section A. Will you explain that log as well as the cross section logs which follow?

A. This simply is a log to show the intervals we found to be productive within the Niobrara member of the Mancos. We designated them arbitrarily zones A, B, and C. The bulk of the production in the south part of the unit has been from zone C; in the north part of the unit and north of the unit from zones A and B.

Q. And your cross section?

A. The cross section merely shows that the zones are consistent throughout the area and there's no striking difference from one well to another. In other words, you can tell from this that even though we have large recoveries from one well, say, as compared to another, it's not the result of a large amount of oil in place around that one well, because the formation is fairly uniform throughout.

Q. What is it that causes one well to produce greater than another?

A. Just has better communication with the fracture system, just a bigger straw in the tank.

Q. Now turning, if you will, please, to Section B of Exhibit One.

A. Section B we show the -- in summary, the interference test that we ran in 1965 in which we shut all of the wells in the pool in and then started producing them one at a time, and from this interference effect we could determine communication over wide areas and also calculate oil in place per acre from one of the tests.

Q. As I understand, after you shut all five of the wells in, then you opened them one at a time and measured the interference in the other wells.

A. Yes, sir.

Q. And that's indicated on that.

A. Yes, sir.

Q. Turning to the next part of Section B, will you explain that, please?

A. Yes, sir. That graph shows fluid levels that were measured in the observation wells. The area shaded in blue shows the production from the producing wells. The little circles show the individual measurements of fluid level taken. At the same time we also measured pressures. We don't show those here but that has been reported to this Commission at an earlier hearing.

I would point out that where the little square flags are, are shown on the graph as where the points were witnessed by either Oil Conservation Commission engineers or USGS engineers, or both. It was a very dramatic test showing communication within 24 hours over distance as great as 9000 feet.

Q. Do you have -- is there a particular point of observation with regard to the A-22 Well, being -- what did you do with the A-22 Well?

A. The A-23 Well?

Q. Yes.

A. The A-23 Well had produced about a month prior to the time this intereference test was taken. It had

a capacity of about 150 barrels a day and once this test was completed we realized that it was an unnecessary well; we didn't need it to produce the oil, so we just shut it in and used it as an observation well from then on.

Q. Did that give you added control of the reservoir?

A. Yes, sir.

Q. Then your next page of this Section B.

A. The page marked B-3 shows the particular part of the interference test that we used to calculate oil in place. We used that based on the L-11 and its effect on the A-23 observation well, because it was the only one that had the characteristics suitable for calculating oil in place per acre.

The results of that calculations are shown on page B-4, in which we arrive at a range of oil in place per acre from 1000 to 2500 barrels, stock tank barrels per acre.

The reason for the wide range in estimated oil in place per acre is because of the indefinite value of the compressibility of the fractured shale, and we just didn't know what that was. We assumed a rather broad range. I felt, and I think reported in the 1966 hearing, that although we had an outside range of 1000 to 2500 barrels an acre, we

felt that it probably would fall in the range of 1500 to 2000 barrels an acre.

Q. And the diffusivity theories and you arrived at the oil in place are explained in detail in that August record?

A. Yes, sir, one of the common engineering formulas that we used.

Q. Turning now to Section C.

A. One reason --

Q. Something further?

A. No.

Q. Turning now to Section C, will you explain the first part of that exhibit?

A. When we commenced injecting gas in 1968, some three years after we ran the initial interference test, we were able to run another interference test based on the influence on the observation well of the injection of gas. That effect is shown on -- on the first graph, marked C-1, and from that we were able again to calculate oil in place per acre and transmissibility.

In the first test in 1965 we estimated transmissibility on an average for the area covered by the test, which we assumed to be several thousand acres, of about 6.3 Darcy feet. Here we come up with approximately 1.8 Darcy

feet and about 1600 barrels per acre.

At this time we had eliminated the problem of the indefinite value of the compressibility of the fractured shale because it now is insignificant compared with the compressibility of the oil. The oil is now saturated and has a higher compressibility and so we have eliminated that indefinite part of our calculations. Accordingly, we can refine our calculations of oil in place with the use of this interference test, but by the same token, we are limited to a smaller area because of the boundary effects of the gascap up dip and a higher area of transmissibility down dip and the fact that at that point we reach into the under-saturated part of the oil, so at this point, although it's accurate, it covers a smaller area than the initial -- I feel it's accurate -- it covers a smaller area than the first test.

Q. And you come up with 1600 barrels per acre?

A. Yes, sir.

Q. Then the next part of Section C.

A. C-3 just simply shows the possible effects of boundary conditions, which we indicate there under the dashed lines two and three whether these are the causes for the pressure behavior, not we don't know that they're pretty reasonable ones.

Q. And C-4?

A. C-4 shows the -- kind of in summary, the area that I believe is covered by the individual tests. The entire blue-shaded area would represent, I think, an area that the first test would be indicative of. The cross hatched area from northwest to southeast would be the second interference test, and then the cross hatched area -- no, from northeast to southwest, around the K-13 well, would be the one resulting from the test that we ran when we commenced gas injection, and the other cross hatched area, northwest to southeast cross hatching, shows the area of transmissibility that we measured by comparing the pressure in the observation well, the A-23, with the pressure in the E-10.

That western area shows to be in the range of 5 to 10 Darcy feet -- or 10 to 12. The overall shows 5 to 10 and the east part about 2-1/2 to 3-1/2 Darcy feet.

Q. Now, if you will, please, Mr. Greer, I'd like to introduce this as Exhibit Two, which we can refer to as the blue exhibit, and will you please go to Section A in the blue exhibit, skipping the index, which is at the front of it, and go to Section A and explain this to us, please?

A. Under Section A the yellow colored sheets are simply the statistics of production, of oil production, from the wells. There's eleven pages of those

statistics followed by two pages of white -- white pages of statistics that show the pressures measured in the A-23 observation well.

And then we come to the two green -- or the one green sheet, which has statistics regarding the L-27 Well, and perhaps I should say at this time that material in the blue book, our Exhibit Number Two, is information which we have never presented to this Commission before.

A large part of what's in Exhibit One, the grey book, has been presented either in the August hearing or a previous hearing.

Everything in this blue book is something that was not presented before.

The information we have here is a continuation --

Q. This is the first green page.

A. The first green page, is a continuation of the evidence of the high degree of communication in the reservoir. This shows bottom hole pressures measured on the L-27 Well following frac treatment after it was completed. It's pressure is shown by the righthand column, the lower two figures, at the time that we quit measuring the pressures in it was some 260 pounds below virgin pressure and only about 30 pounds above the static pressure in the -- in the observa-

tion well. These statistics are graphed on the next white sheet. It says fluid level fall-off curve. The small dots connected by solid line show the fluid levels measured in this well. Incidentally, it was shut-in some five months following the frac treatment while we measured this pressure decline in the well. We felt it was important to get an idea as to whether communication did extend that far north, and as indicated here, it did.

The fluid level, as you can see from the graph of the little circles, after some ninety days the dead oil in the hole began to trade out with live oil in the formation, and then we lost the drop in fluid level which we had before, but we had bottom hole pressure measurements, which, incidentally, we've taken extreme care in measuring those bottom hole pressures and we'd always use two bombs, always run each bomb twice. We would make several stops on each run. We would add the differential or the weight of the fluid below the stop to the bottom and we'd come up with an average of four or five points for each stop.

So what it means where we have each one of these points that shows to be one pressure point, there's probably forty or fifty observations that have gone into that and averaged it out in order to get that point.

Q. Mr. Greer, this is unusual for an oil

field, is it not, to have this phenomenal communication?

A. Yes, sir, this well was several miles north of any of the other wells that have been produced.

Q. You just don't have that in the average pool.

A. No, sir.

Q. Turning to your --

A. Next sheet --

Q. -- next sheet.

A. -- the blue sheet, we have here the same kind of information for the C-34 and the important thing here again, we measured pressure following the frac treatment. Where we measure a pressure fall-off test following frac treatment, we are certain that the pressure that we get is a maximum pressure. When one produces a well and then has a buildup in pressure, there's always a question in one's mind as to whether you've ever reached the maximum pressure or not, or if you waited a few more days or weeks whether it might show higher.

By taking a pressure fall-off test following the frac treatment there is no such question. The final pressure that you measure has to be the highest possible pressure in the vicinity of the well.

In this instance it's about 330 pounds

below virgin pressure on the righthand column, measured December 28th, 1970, and was about 22 pounds less than the pressure in the A-23 observation well.

It's graphed on the next sheet, the white sheet.

And then if we'll turn over to the graph which has the plat, location plat on the lefthand side and the graph on the righthand side, the graph shows 5-B at the bottom of the graph to identify it, we can see why the C-34 had a pressure less than the pressure in the observation well.

This graph on the righthand side shows pressure versus production and initially, for the first 2 or 3000 barrels of production the rate of decline in pressure was something like 3000 barrels per pound. At about the 300,000 barrel mark is when we ran the 1965 interference test where on the graph it says all wells shut-in plus or minus 50 days. From that point forward, as we produced wells and the pressure in the observation well declined, then the pressure in the observation well is somewhat less than the static reservoir pressure, simply due to the interference effect.

Down at about 1,400,000 barrels of production we commence gas injection for pressure maintenance. By that time the -- as the pressure declined and the bubble point moved down the dip in the reservoir, more and more of

the oil became saturated and so we have a higher -- higher production coefficient, we're up to 7000 barrels a pound at the point that we started gas injection.

Q. Compared to 3000 barrels previously.

A. Compared to 3000 previously, yes. Then when we started gas injection, why that slowed down to about 38,000 barrels per pound.

The upper red line shows the trend of the drop in pressure in the observation well, the A-23. The C-34 is too far from the observation -- from the injection well to have a pressure interference effect from the injection well, and so it's probably very close to the true static reservoir pressure. It's some two miles south of the observation well.

The parallel line from the C-34, which is that lower red line, connects with the point that I estimated to be the static reservoir pressure on October 15th, 1968. You see, that static pressure has to be at a lower point than the pressure in the observation well because of the interference effect of the injection well.

Prior to that time the pressure in the observation well was less, again because of interference effect.

Q. Now on the left side of that page you

have a plat there. Does that show these wells?

A. Yes, sir, the farthest north well is the L-27; the farthest south is the C-34; and the cluster of wells in the center are the wells that produced to cause these pressure drops some several miles from the producing wells.

The two wells marked in green, the right-hand one is the A-23 observation well and the lefthand one is the E-10 producing well.

And we'd now like to look at the next graph which shows a rather dramatic interference effect. We fracd the E-10 and it built up in the observation well 2-1/2 miles away in about 24 to 48 hours.

Q. That's at the normal communication in and oil and gas -- an oil reservoir, is it not?

A. Yes, sir. The production from the -- all the wells in the unit is shown by the little dashed lines at the bottom of the graph. The small circles show the -- the fluid level in the observation well measured twice a day, and the diagonal slanting dashed lines show the indicated trend of the drop in fluid level. The vertical red line shows the day, July 19th, on which we fracd the E-10 well, 2-1/2 miles from this observation well, and you can see that the drop in fluid level slowed down in about 24 to 48 hours, and then it actually -- fluid level actually picked back up.

And when the E-10 on production at about the end of the red mark, there was some 15 feet or so difference in fluid level.

Q. Now, if you will, please, Mr. Greer, would you go back to Exhibit One, the grey book, and turn to Section D, where you left off awhile ago, and explain to us the first two pages of Exhibit D -- of Section D of that exhibit?

A. Okay. D, on the graph marked D-1, shows the comparison of oil in place and transmissibility, I say oil in place, porosity and permeability for average sandstone reservoir as compared to a fractured reservoir, and the significant thing here is that for the same permeability there is far less oil in place in a fracture system than in a sand system, and this means a couple of things: That the reserves can be produced in very short time in terms of oil in place per acre, you talk -- you can have wells that are completed in a fracture system, you can produce acres per day compared to a sandstone reservoir that's very difficult to find wells that can deplete reservoirs that fast.

But it means one other thing. If you have a reservoir whose characteristics fall below the brown shaded area, below that, colored tan for sandstones, you begin to pick up characteristics of the reservoir that is amenable

to gravity drainage. Its oil in place is such, and its productivity such, that given proper care and control, if it has any dip at all you have a good chance for gravity drainage. We get all the way down to a fractured system, as we've indicated here, it's possible to have a gravity drainage system with wide spacing, and you can tell that just by looking, plotting the information on this map.

If we go into the second graph, marked D-2, and we've made some assumptions. The first yellow color on the upper graph is for horizontal fractures, horizontal fracture system.

In the lower graph we've assumed that we could have, if you had both horizontal and vertical fractures, there will be a higher porosity for the same transmissibility. We've arbitrarily just doubled those figures to arrive at the grey-shaded area.

Then from that --

Q. Mr. Greer, have you -- did you core any of these wells?

A. Yes, sir.

Q. What one did you core? Did you only -- how many did you core?

A. Well, we cored the L-11 and we could find nothing that would indicate anything different from --

Q. Does a core help you very much in determining the characteristics of this reservoir?

A. Not this reservoir.

Q. Turning to the next page of --

A. Next page --

Q. -- Section D?

A. -- we've taken the grey-shaded area and assumed 17 feet of the characteristic we've marked A on the first graph, which is equivalent to 50 feet of B, or 150 feet of the C characteristic, and have arrived at somewhat of an arbitrary possible relation between oil in place and transmissibility. We've compared that with the information that we found from our tests. The blue mark indicates that indicated by the first interference test. The pink mark is the one for the second interference test. These two are in the range of 2 to 6 Darcy feet transmissibility and the range of 1500/2000 barrels per acre in place. The green circled area is an area which represents what I would estimate for Boulder to be somewhere in that range.

So, although this is somewhat theoretical a relation of oil in place per acre to transmissibility, it seems to fit pretty well what we know about these reservoirs so far.

Q. Your next Number 4, I believe it is,

of this Section D?

A. This is a fairly important concept. The Commission needs to realize that we found, as we studied this reservoir and measured pressures, interference tests, draw-down tests, pressure build-up tests, there's only one kind of a reservoir that can fit all the information that we have, and that is a reservoir that must be comprised of tight blocks with an interconnecting fracture system, and I call it a kind of a jigsaw puzzle sort of thing; probably the bulk of the reservoir is tight blocks; the interconnecting fracture system I would imagine is small in volume compared to the tight blocks.

As to the amount of oil in place in the high capacity system and the tight blocks we don't know, but my estimate would be about half and half from the work that we've done.

What this means is that among other things, that as long and whatever part of the reservoir has this high capacity system, that a well located a distance away from one of these tight blocks can drain that tight block better than a well drilled within the block. This is something that the Commission needs to -- to grasp and to understand. It's an unusual situation. We explain it a little bit on the next page.

Q. Turn to that page, then, and go through it, 5 and 6.

A. On D-5 we show a tight block drained by an internal well on the lefthand side. We've assumed some arbitrary figures which are shown just below that, which for the characteristics that we've chosen, the well would produce 100 barrels a day, and this is a well that we assume has been given a frac treatment with a fracture length of 400 feet and effective wellbore radius of 100 feet.

And then we compare that to a like tight block but which is drained by a high capacity system all around its perimeter, and it's kind of like having a well with a 2000-foot internal diameter. It has a tremendous drainage ability.

Now the scheme pictured here on the left is -- is unquestionably a steady state kind of flow system; the one on the right is definitely an unsteady state. I've shown for a rate of flow from the 900-foot radius to the 1000-foot radius comparable to the one for the same pressure differential we show for the well located within the center of the block, and instead of 100 barrels a day, we'd be looking at a flow rate of 2000 barrels a day. This gives one the perception of the relative drainage ability of the high capacity system on the perimeter of these tight blocks.

Q. It's a factor of 0.1?

A. Yes.

So that the end result of this is that a well that's completed such that it has good communication with the high capacity system can drain a tremendous area and it can drain tight blocks within that area, can drain them better than a well drilled within them.

Q. And in this case more is not better?

A. More wells is not better, yes, sir.

Q. I'd like to direct your attention now, if you would please, turn to Section H in this Exhibit One, the grey book.

A. In addition to oil in place we need to have a little understanding as to how much of the oil in place we might reasonably expect to recover from this reservoir.

The best information we have for solution gas drive performance comes from the permeability relation we show under H-1, a graph in which we have taken information from the technical literature on different fields, and included in that is the Gallegos-Gallup Field. The relation that I used in making my calculations is the dashed line which sort of averages the information that we have here for fractured formations.

If you take that information, that rela-

tive permeability relation and kind of oil that we have in West Puerto Chiquito Pool, we find on the next graph the kind of production history that we can look toward for solution gas drive. We wind up with something like 5-1/2 percent of the oil in place is all that we can anticipate from a solution gas drive depletion mechanism.

Now the only way to compare this with -- in a field, this is, of course, a theoretical estimate -- the best way to determine that in the field is to try to find a fractured reservoir that has a little dip. They're hard to find. You don't find very many. If the fractured reservoir has a high degree of dip, then the field information you get can be camouflaged by the gravity drainage that's going on.

We have one such field, however, and it happens to be the same formation, the Gallegos-Gallup Field, in which a consulting firm prepared for the operators of the Gallegos-Gallup Pool, and they wanted to unitize and waterflood it, and the result that he came up with was five -- I think was 5.3 percent of the oil in place could be expected by primary recovery. I notice that he estimated an ultimate recovery from Gallegos-Gallup of 2.2-million barrels, and I think the last report I read was just about 2.2-million barrels, and of course, the field may produce a little bit more, but it's not going to miss the estimate very far.

So here we have the theoretical estimate, 5-1/2 percent of oil in place. We have a comparable pool, 5.3 percent of oil in place. I think that pretty well pins down what we can expect from solution gas drive.

Q. Or in other words, production without proper pressure maintenance.

A. Yes, sir.

Q. All right. Then turn to Part 3 of Section H. You didn't finish Section H, did you?

A. Oh, we don't need to.

Q. All right. Then get back to Exhibit Two, the blue book, if you will please, and refer to Section B.

A. Section B has to do with the oil in place in Boulder and the recovery factor at Boulder, and this is -- this becomes important now. We have seen what we can expect in the way of solution gas drive. And in Boulder, even back in 1965 and '66, when we first were looking at -- at how we should produce West Puerto Chiquito, we could tell from the pressure decline in -- and production decline in Boulder that it was soon to reach its -- its final amount of oil to be produced, and we could estimate it in the range of 1-1/2 to 2-million barrels. It was that far along.

And so the question that we had at that

time, did Boulder have in place fifteen times 1-1/2 to 2-million barrels? Was there 25 to 30-million barrels of oil in place in Boulder, and were they -- was the production in Boulder the result of solution gas drive, or perhaps, in view of the steep dip and the high transmissibility, did Boulder have some gravity drainage.

If Boulder realized gravity drainage and we have high, fairly high dips, not as steep as Boulder, but fairly high, we have a lower viscosity than Boulder in West Puerto Chiquito, perhaps in West Puerto Chiquito we could look to for gravity drainage by analogy with Boulder.

The issue then is how much oil was in place in Boulder. Was it 30-million barrels? Did they get five percent of the oil in place? Was it 6-million barrels? Did they get half of the oil in place? What did they get?

So we tried to calculate oil in place. Now we didn't have as much information in Boulder as we would like to have, but there was information referred to this Commission in hearings held on the Boulder Pool, and Standard of Texas reported some; Mobil reported some. When we put it together we come up with a pressure versus cumulative production graph, as shown on the second graph under this Section B.

From that -- and Boulder, incidentally,

the same as WEst Puerto Chiquito, the same as East Puerto Chiquito, as best we know the same as Verde Gallup, as we do know for La Plata, everyone of these reservoirs had undersaturated oil, and as near as we can tell, they all had gascaps, which is an unusual situation to have undersaturated oil and a gascap, too. Nevertheless, they had it.

So we found here in Boulder an initial fairly steep decline in pressure and then a leveling off, like we did in Canada Ojitos, although at that time we did not have the leveling off in Canada Ojitos, but we could anticipate it. And from the first drop in pressure compared to production we show in the graph that has the green shading at the upper part of the graph the relation of oil in place for the various factors that are shown here, for the initial pressure/production coefficient of 1200 barrels per pound. That runs all the way from 1.8-million barrels to 55-million barrels, depending on much of the oil was undersaturated, what the compressibility of the formation is, and how much free gas was in the reservoir.

My estimate of the fraction of the reservoir oil that was undersaturated is shown by the green shaded area, which runs from about 3-1/2-million to 15-million barrels.

Then after the pressure dropped some

more and its coefficient jumped up to 3000 barrels a pound, we show on the next graph the range of oil in place compared to the amount of oil that's undersaturated and now my estimate of the green shaded area, we're in the range of 4-1/2 to 9-1/2 million barrels. We're beginning to get pulled down where I'm convinced that it certainly is not 25 or 30-million barrels.

Now, the difficult thing, the problem in trying to calculate oil in place in a reservoir such as this is complicated not only by the dip of the formation, the fact that as the pressure drops the bubble point drops down dip, but also how much free gas was in the reservoir. How much was there initially and how much is there now? And how can we estimate that?

Well, we find that as we examined the relations, that we have one set of conditions at 1200 barrels a pound and then another set of conditions at 3000 barrels a pound, but the gascap should be the same. Now gas has come out of solution as the pressure dropped, but we can estimate that, and we've shown the next -- no, we didn't show it on this graph -- but we can calculate that and use that as part of our method of calculation, and we then can compare the two situations.

And we've done that on this last graph in Section B. We compared the amount of oil that was under-

saturated initially, the amount of oil that was undersaturated finally, and our range of oil in place gets narrowed down even further. The shaded area at the bottom would be an absolute maximum that we would estimate, with a formation compressibility of 15, 15 times 10 to the -6, and a gas saturation of zero percent.

My feeling is the green shaded area again is closer to what the true situation was, which looks like on the upper righthand corner somewhere in the range of 5-1/2 million, maybe 6-million barrels in place, would be -- be my estimate of the maximum that was in place in Boulder.

If there was 6-million barrels in place and they recovered 1-1/2 to 2-million barrels, then they recovered 25 to 30 percent of the oil in place.

If only 5 percent is from solution gas drive, then ... about 2/3rds or 3/4ths of what they got in Boulder had to be from gravity drainage, and this was most important because we need to then produce our reservoir in West Puerto Chiquito in order to enjoy gravity drainage.

Now, we looked at Boulder, is at a higher dip; it was a long reservoir along the strike, narrow down dip; it had a transmissibility much higher than West Puerto Chiquito; and so we realized that almost anything the operators did in the way of producing the well, they couldn't stop some

gravity drainage. They're going to get it almost regardless of what they did.

Now, if we look back at the first graph under Section B here at the production versus time graph, we see that Boulder was prorated the first two or three years of production, and although they probably didn't realize it, that also probably contributed to -- strongly to the -- or greatly to the amount of recovery that they got at Boulder. They were prorated along approximately the gravity drainage potential, and so whether they wanted it or not, they enjoyed the benefits of proration and a higher recovery than they probably otherwise would have realized.

Q. Anything further on Section B?

A. No, sir.

Q. Then let's proceed to Section C of this blue book.

MR. RAMEY: Mr. Verity, are you at a spot where we could take a fifteen minute break?

MR. VERITY: Certainly, it would be a good place, Your Honor.

(Thereupon a recess was taken.)

Q. Mr. Greer, I believe we had come to Section C of Exhibit Two, the blue book, when the recess was taken. Would you explain Exhibit -- the first page of Exhibit C?

A. Yes, sir. On the first page of Exhibit C we show my estimate of initial oil in place. The range is 30 to 50-million barrels. The shares of the oil in place depend on whether the oil is in a high capacity system or in a tight block, but I anticipate in my recovery, which shows a total recovery ranging from 12 to 19-million barrels; produced to 1981 about 6.6-million barrels, leaving the remaining future from 1981 of 5.4 to 12.4-million barrels, and in our estimates we've just used a range of 5 to 10-million barrels estimated future recovery from the Canada Ojitos Unit.

Q. That's provided that you can continue conservation in the future that's been practiced in the past.

A. Yes, sir.

Q. All right. Is this -- then the balance of Exhibit -- of Section C.

A. The second page has a description of when we earlier referred to this type of calculation, these estimates, it was reported to the USGS regarding expansion of participating areas. And the next three pages, or four pages, was a written discussion of how we make the calculation

which I won't need to go into now, which incidentally, I've reviewed this, I believe, with some of the protestants' engineers. I think that they're familiar with it, and I believe the Commission has had an opportunity to review this type of calculation.

MR. VERITY: If you think it's necessary, Your Honor, we'll go into it now.

A. On the graph marked IV-3 we have the same kind of a relationship which we showed for Boulder for the time when the oil was mostly undersaturated, and this shows the range for the green shaded area of about 22 to 90-million barrels in place.

Then on the next graph marked IV-4, when a larger part of the oil was undersaturated, we reduced the -- where again we have the range of something like 12 to 90-million barrels.

Comparing the two, and on the graph IV-5, we show the combined compressibility of the saturated oil and gas released from it. It helps us in calculating the total oil in place and then isolating from that the amount of free gas that was in the reservoir initially.

On the next graph, not marked, perhaps, it shows the yellow and the brown stripe, on the structural contour map this shows how we traced the movement of the bubble

point pressure down dip as oil was produced under these two different time periods that we used to estimate the oil in place.

Q. And page seven?

A. Page seven, I show one estimate of how the oil in place pressure might vary across the unit, depending on the flexing and mesaurements of oil in place and transmissibility. I believe this is a reasonable estimate of how that part of the reservoir, the oil might be distributed.

The blue area on the right represents about 1500 barrels per acre; the green about 2500 barrels an acre; then the brown about 1000. This was part of our application that we made for expansion of the participating area to the USGS, I believe, about 1969 or '70.

The overall average for the entire area, then, would be something like the 1500 to 2000 barrels per acre which we arrived at from our interference test.

If we use this kind of a distribution and go to the next graph, marked IV-8, we have here the same kind of a relation we have showed for Boulder, where we're comparing undersaturated oil, the tract or the reservoir that was undersaturated at the time, the coefficient was 3000 barrels a pound as compared to the amount that was -- when it was 6000 barrels a pound. Those different situations, numbered

1, 2, 3, 4, 5, and 6, are the situations described in the -- in the four page discussion at the front of this section, and depends, among other things, upon whether we assume that there was a uniform distribution of oil all the way up and down dip, or if we assume the 1500 barrels per acre up dip, 2500 down dip, or if we assume that the entire reservoir lies within, say, the blue area and the green area, or if, perhaps, the up dip side of the reservoir was actually higher than we initially estimated, we take all those different situations into account and come up with the different ranges, then, of -- of oil in place, and that runs from about 30 to 50-million barrels.

The factors, of course, that affect that in contrast to Boulder, now in Boulder we didn't have as much information on pressures, but Boulder was a smaller field, higher transmissibility, and the pressures that were measured were probably representative of the entire reservoir.

Here we're dealing with pressures in one well that is in a reservoir ten or twelve miles long, and there could be some lag in the pressure response, and undoubtedly was, and so that would, as the pressure dropped through the bubble point, the oil became saturated and it takes longer for pressure responses to move across the field, we then have a lag in the pressure response and that makes it a little more difficult, then, to come up with an exact number. I

Think that's the reason that points 1, 2, and 3 fall down in the area of -- which would indicate a zero compressibility for the formation and zero gas saturation. Actually, we know there was some free gas. We know that the formation had some compressibility.

Even so, I would still place the range of oil in place in that -- those limits, 30 to 50-million barrels.

Now since that time, of course, we have information after injecting gas, and such as that, that one might make additional calculations, but because of all the complications and the measurement of the gas, whether the gas that's injected is all confined to this reservoir, or whether some of it strays to other formations, perhaps a little bit goes to the outcrop, it's pretty difficult to, I think, to choose any other information to arrive at a more accurate estimate. I think this is about the best we can do.

Q. The IV-9 part of that Section C?

A. This is some of the statistics we've used in making these calculations and they're in here for completeness.

Q. And 10?

A. Is just an example calculation. What we wind up with, of course, is two simultaneous equations with

two unknowns, where we have the -- compare the amount, or the pressure drop in terms of barrels per pound at one set of conditions, one set of oil in place that's undersaturated as compared to the other.

It's really kind of a simple calculation but it's probably one of -- that's not generally found in literature.

Q. Directing your attention now, Mr. Greer, back to Exhibit One, the grey book, will you please refer to or turn to Section E?

A. Yes, sir. I'd like to talk now a little bit about our pressure maintenance and how -- how we interpret the program as we've instituted it.

In this first graph under Section -- Section E, we show in grey color the area we think initially had free gas saturation. The boundary between the grey and the yellow area is -- is where I think the initial gas/oil contact was. The yellow coloring shows, along with the grey, the area that now is -- has a high degree of gas saturation, and of course this is just rather schematic, but I think generally shows the situation.

On the south part of the pool I imagine the area that we have shown to be solid gas is probably -- still has a considerable amount of oil in it. It's tighter

down in that area.

The green triangles represent injection wells. The red circled wells are the primary producers at this time. The blue colored wells are either shut-in wells or observation wells.

Q. Did you make an observation in this development with regard to productive -- productivity index dropping?

A. We found that as the pressure drops in these fractured shale reservoirs, that the productivity index seems to drop at a much higher rate than one would otherwise expect. It can't be explained by relative permeability effects or anything else. I frankly don't know, but I presume or think it could be the fracture squeezing together. In any event, as pressure drops, the productivity drops at a far greater rate.

Q. Then the next portion of that, pages two and three, of this section?

A. We have a small plat here that shows the location of the wells and then we have the graphs of the production of the -- of the various wells.

The first graph shows the unit production overall and its gas/oil ratio and cumulative production.

The next sheet for the K-13, I'd simply

point out that in 1965 when the well was shut-in prior to the interference test, we realized that we did not need to produce that well again, so we would make it our first injection well, and so we didn't produce it except for two or three months to test it just before we put it on injection.

Next graph of the A-14 shows the rate at which the productivity fell off and gas/oil ratio increased as gas reached this well. It was close to the injection well. We anticipated this and sure enough within a year, why, gas had reached this well.

Next graph for the P-11 shows the same, about the same thing, and here again you can see the rapid decline in productivity as the pressure fell off prior to 1968 before we started the gas injection.

Q. And, Mr. Greer, you shut these wells in in spite of the fact that they're producing a lot of oil.

A. Yes, sir. The indicated production here is not really the well's capacities at that time. We were producing these wells with a pump with the casing shut in, all the gas and the oil coming up through the pump, and this well probably had a capacity of 100 or so barrels a day at the time we shut it in when its gas/oil ratio reached 3000-to-1.

Q. And without a unit and with competitive

drilling, is it possible to do those things?

A. No, it's not.

Q. Is it possible to control production and shut in wells?

A. No, no way you could do it if we wanted to --

Q. Without controlling these wells and shutting them in when -- when it's proper to do so, can you get the ultimate recovery of oil out of this pool?

A. Not without pressure maintenance and control of production.

Q. Well, you can't control production unless you can shut in the wells that need to be shut in.

A. No, sir.

Q. And the antithesis of this is competitive drilling.

A. Yes, sir.

Q. All right. I believe you were at the pink sheet, page seven of this section?

A. Yes, sir.

Q. Explain that, please.

A. We produced this well only about three years and produced a half million barrels of oil, and at 500 barrels an acre in the high capacity system, which is what I

would estimate in round numbers might be recovered, 4 to 500 barrels, it had produced the equivalent of 1000 acres of -- of all the oil in the high capacity system.

Next one, the L-11, we shut this well in in 1975, some seven years after gas injection was commenced. It had produced about 1,200,000 barrels and, again, at 500 barrels an acre in a high capacity system, that would be about 2400 acres, equivalent, that this well had depleted before we shut it in. On an average of 250 barrels an acre, that could even be 4800 acres.

Q. So the well actually drained -- when you shut it in had drained between 24 and 4800 acres?

A. The equivalent amount, yes.

Q. Yes. And nine?

A. On the E-10, it's produced about 2-million barrels of oil and on the same comparison it has drained all of the oil in the high capacity system for 4000 to 8000 acres.

Q. And page ten?

A. The L-27 on the same comparison, it's produced over a million barrels of oil, and again, looking at 2400 to 4800 acres that the well has depleted.

Q. And turning to eleven, the C-34?

A. The C-34, this is an interesting well. In the -- this is the only well that we have produced after

the gas/oil ratio started to increase, and we decided to test this well as an experiment to see if possibly the tight blocks were draining by gravity and contributing something to the recovery.

We've estimated in round numbers that half of the oil might be in the high capacity system and half of it in the tight blocks. A very key qeustion to the final depletion and efficient production of this reservoir is ---is how much oil can we get out of the tight blocks; can we get it at the gravity drainage efficiency? Are we going to limited only to the solution gas drive efficiency?

So we thought we'd test this one well and see if the gas/oil ratio would go completely out of sight or if it might level off. And so rather than shutting this well in when the ratio reached 3000-to-1 we -- we continued to produce it, and sure enough, when it got up to about 10,000-to-1 it leveled off. And we've had a very low decline in pressure over these last several years. There's no way that the oil that is being produced by this well is from solution gas drive. It's got to be one of two things, gas drive from the pressure mainenance system or gravity drainage. From the time the gas/oil ratio had reached 2000-to-1 the well had produced -- I mean 10,000-to-1, the well had produced nearly 300,000 barrels. It looks like it might produce another 3 or 400,000 barrels,

and if so, that's about half out of the high capacity system and half out of the tight blocks, which again we don't know if that really confirms it overall, that that's the distribution of the oil in place or not, but it does tend to confirm it.

Q. That brings you to your green sheet, page twelve of this section.

A. Yes, I believe we have these in a little more detail in another part of the section. I think we can skip them here.

Q. All right. And that brings us to Section F of this Exhibit One.

A. Here we point out one of the -- one of the little problems in maintaining pressure in a reservoir. As the oil drains down dip we have to not only replace the oil volume that we've taken out, but we have to increase the pressure in the entire gascap in order to make up for the drop in -- for the loss in pressure caused by the oil dropping down dip. We show this schematically here with the little colored sections at the top of this page, and we've also pointed out --

Q. Mr. Green, why is it, explain to us again or in different terms, if you will, please, why you have to keep increasing the amount of gas as you produce oil and

the oil column goes down dip.

A. Well, the oil has a heavy -- higher density than the gas and on this example that we've shown here, for instance, at the datum of zero, on the lefthand sketch we show 1431 pounds at that datum, 100 feet higher would only be 1400 pounds, and of course, 100 feet lower, 1462 pounds. The gas is at 1400 pounds.

If we produce the barrel of oil that's indicated by the stippled area under the middle sketch and replace it with gas at 1400 pounds, we will have lost to wells down dip from that the difference in density of the oil and gas for that 100 feet, and that's about 30 pounds, and that's why I show on the lower line the datum of -100, that we're down to 1431 pounds in the center sketch.

In order to get that back up to 1462 pounds, we have to raise the pressure of the gas, not only for the oil we just withdrew, but the entire gascap. So that means that we have to buy a little more gas than -- than if the reservoir were, for instance, a horizontal reservoir.

Q. Yes.

A. The burden of that, what that amounts to is shown on the -- the green sheet just following that.

Q. Page three?

A. Page three. Initially we start injecting

gas, the cost of makeup gas was insignificant. We were buying gas at 15 to 20 cents a thousand, and it only takes about 2/3rds to 3/4ths of an Mcf, like 10 or 15 cents a barrel was all it took to make -- of makeup gas to keep the pressure up. As the price of gas went up and the oil stayed down, this became a more significant factor. And this first column on the green sheet shows that we were up to like 50 percent of our net income in the cost of makeup gas.

Now, as the price of oil goes up, this will change and of course despite the fact that it was a burden to keep the pressure up, we did continue to buy makeup gas. Now, we didn't buy as much; we didn't keep the pressure up completely. When the price of gas started up, why, we started dropping off, which we'll look at here in just a minute.

That's shown on the white graph just following the green sheet.

Q Page four of this section?

A Yes, sir, four under F. You see in 1976 where we sharply reduced the amount of makeup gas and the pressure then started declining in this observation well, the K-13, at the rate of about 12 pounds a year, and of course, 12 pounds a year still is not a bad pressure decline. There's about -- we're dealing with about 1200 pounds surface pressure, that would take 100 years to deplete the pressure, but even

so, everything else permitting, it would be our plan to commence injecting higher volumes of gas and maintaining the pressure as soon as the price of oil makes it practicable to do so, which is within the next few months.

Q. The yellow sheet's just your information on that?

A. Yes, sir, I think we could move on now to Section G.

Q. All right, turn to Section G. That's still in Exhibit One --

A. Yes, sir.

Q. -- and explain that.

A. Well, we'll pass the white graph, G-1, and go to the graph G-2. Here we show the production from the C-2 Well. This is a small well, made about, oh, 40-50 barrels a day. The first two or three years the well was on a pump, I think first on a beam pump, then on a Kobe pump, and in 1971, where the production levels off, we put the well on gas lift. And you can see there for several years that we had a very stable production rate from this well.

Then in the beginning of 1976, when we reduced the amount of injected gas, the well picked up a decline rate of about 3-1/2 percent a year. Now you need to bear in mind this was a small well, only 40-50 barrels a day.

It's responding to injection of gas in a well four miles away from it.

Q. What would the total production of this well have been under Boulder?

A. Well, the comparative 70 percent decline rate we show in the red line, would be about 22,000 barrels and it's actually made about 8 times that much.

Q. So without injection, you not only wouldn't have got the 22,000 barrels, it would long ago have been depleted and abandoned?

A. Yes, sir.

Q. Before it was ever paid for?

A. Probably.

Then the next graph, marked G-4, we have the same kind of information for the A-16 Well. This well was on the pump initially, still is on the pump, and you can see some of the problems there in maintaining uniform production rates. Even so, we had a good run in 1968. We can see a year there in which the production is fairly level. 1974, another year in which the production is fairly stable. I believe those indicate the well's productivity, which is fairly flat, about a one percent decline per year. Then again in 1976 the well picked up rather a sharp decline, about 7 percent a year, and this appears to me to be one of those situations in which

the productivity declines at a higher rate than the pressure decline. This is significant in this case because this is the westernmost well closest to the area in which the protestants propose to drill. This is indicative of what's going to happen with pressure decline, and it has been as slow as it has, I mean like one percent a year with our pressure maintenance, and without any pressure maintenance, we're going to be again looking at these high rates of decline, this 70 percent sort of thing experienced in Boulder.

Q. Whereas under your present program and after all this time, you're still only seven percent a year.

A. Yes, sir.

Q. Let's come back to the blue book, now, to Section D, Exhibit Two, Section D.

Will you explain the first page of that section?

A. Let's see, before we talk about that, there's one other thing maybe we should point out.

Q. All right. Now you're still referring to Section G --

A. Yes, sir.

Q. -- in Exhibit One.

A. Exhibit One.

Q. All right.

A. If you'll look under Section I, the first graph, we show -- we show some typical production decline rates, and again I've used 70 percent because that's what was experienced at Boulder without pressure maintenance. The curve A shows for a 640-acre spaced well and 50 barrels an acre in place -- we're under Section I.

MR. VERITY: In the grey book.

A. In the grey book. If you have 640 barrels an acre -- I mean 640 acres and 50 barrels an acre recovery, and this is what we're looking at for solution gas drive in this area, it would take a well with an initial productivity of 63 barrels a day at that 70 percent decline to produce the oil under 640 acres, and the present worth, using in this instance an oil value of $23 a barrel after windfall profit tax and the other deductions, you'd have $475,000 present worth. It's my estimate that these wells probably could not be drilled for less than about $750,000, perhaps as much as a million. It just depends on how expensive the frac treatment is and some of the other controls.

If we take curve B at a 70 percent decline, draining 860 acres, and as shown in the line B on the schedule on sheet I-3 to come up with $750,000 present worth, and these are based on 15 percent, discounting 15 percent.

On the other hand, if we got a flat de-

cline, then it only takes a well that makes 17 barrels a day with a zero decline to return $750,000 and a 15 percent -- at a 15 percent rate. This points up to me the importance of maintaining the pressure, maintaining productivity, and the only way that can be done is with pressure maintenance by gas injection and unitization.

Q. Now turning to Section D of Exhibit Two, the blue book.

A. Here we'd like to talk a little bit about horizontal deviation in the wells. One of the parts of our application is that the wells be not allowed to be more than 330 feet at the bottom of the hole from the surface location, and the issues here, of course, are that this is the whole subject of our application, is distance of wells from lines, and the surface location is one thing, if the bottom hole location is substantially different, then the order, if there is an order, will be twarted.

There simply must be some kind of control, and of course one of the questions, one of the issues is, do the present regulations provide adequate protection, and the other issue is what causes deviation, what are the pressures, what are the factors now at this day and time that's going to result in a deviated hole, and then do they have a bearing on this -- on this issue. And they do.

We have an all time high demand for rigs right now. This means that whenever you get a rig you drill as many holes as you can, as fast as you can, and one of the ways to drill fast is to add more weight, and when you add more weight and drill fast, the hole goes crooked.

And it depends on the area that you're in. Some areas we call crooked hole country and others you don't seem to have problems. In this area there can be a problem.

What else can cause the hole to deviate? Well, along with the rig shortage there's equipment shortages. If you should run in the hole short of drill collars you can experience deviation. If you try to keep the hole straight and an inexperienced crew puts the stabilizer in the wrong place, instead of keeping the hole straight, it will go more crooked. And inexperienced crews are a problem now with the rig shortage. And it can be as simple as the morning tower driller going to sleep and you're off.

And what is the protection, what's the practical application of our rules? Well, the rules now say that you can't exceed a five degree deviation. Well, five degrees at this depth is like 6 or 700 feet. If the wells are located 660 feet from the line and it deviates 600 feet, the bottom of the bit is on the boundary and the frac treatment

will probably get across the boundary.

It becomes important, then, to control the deviation. Now there's -- or control the bottom of the hole, the location of the bottom of the hole.

If companies want to drill fast, want to take the risk of a crooked hole, then of course, perhaps, they should back off a little further and maybe the best way to write the order is to just simply say that the well has to be bottomed in the west half of the section to allow that flexibility.

But without some kind of control deviation, and big deviations can occur. And even though it's against the Commission's rules to deviate more than five degrees, as a practical matter what's going to be done if it deviates ten degrees? What if the hole is 1000 feet off at the bottom? Is the Commission going to require this company to drill another million dollar hole? Are they going to shut that first well in? As a practical matter, that probably would not happen.

And what's the relief? Well, we can say that they're closer to the line than it should be and it would be penalized, the well production be penalized, but the penalty regulations no where near protect the correlative rights.

So, we need some kind of control on the bottom -- the location of the bottom of the hole and one way is to require that it not be more than 330 feet from the surface. Now, whether that can be done practicably or not, we show here the wells in the west part of the unit, which are the wells closest to the area which the protestants plan to drill. WE show the deviations which we experienced, and the greatest one is 218 feet. It can be done. Perhaps other people wouldn't want to control it as close as we do. If not, then we need to take that into account. We certainly should not permit a hole deviation to thwart an order that otherwise takes care of correlative rights.

Individual wells and affidavits are shown following the schedule, which you don't need to look at, but the information is here for anyone to study.

Q. Then coming to exhibit -- to Section E of Exhibit Two, the blue book.

A. Under Section E we have a plat, a topographic map on which we've outlined the southern part of the West Puerto Chiquito Pool. That's outlined in blue color. In the red line we show the Canada Ojitos Unit. The solid, heavy green line shows the boundary of the Santa Fe National Forest. It's all Santa Fe forest land except the pie-shaped piece in the middle. The little square with sixteen black

dots in it represents the approximate spacing of wells on 40 acres, which was the spacing when we first started to drill in this area. The wells we've actually drilled are shown in black circles. The diagonal surrounded wells are the -- or the triangular indicated wells are the gas injection wells. The two red circles show the location, a 660-foot location in Section 8, 25, 1, which one of the protestants staked on the unit boundary, and offsetting that is the location we staked to meet it.

One of the first things that comes to mind here, of course, is of those two red circled wells, at least one of them has got to be an unnecessary well from the standpoint of recovery of oil from the reservoir.

We say they're unnecessary, we can look at the wells circled by the red dashed oblong. All of those wells are unnecessary from the standpoint of recovery of oil from the reservoir. The K-13, for instance, the one that does not -- does not have a solid black center, was our first injection well. We produced it only a short while before it was put on injection and then after we moved the injection wells farther east, we simply shut it in and made an observation well out of it.

The A-23 just southeast of it has been our continual observation well from the beginning of its history.

The P-11 and the A-14 Wells are the ones that we shut-in within a year or so after we started injection.

So if those wells are unnecessary, for certain one of those two red circles is an unnecessary well. If it's unnecessary, it means the drilling of it is going to create waste. The drilling of it is going to cause unnecessary damage to the forest.

And we'd like to talk just a minute about the protection of the forest. It's one of the most beautiful forests in New Mexico and it's been a significant concern to us in operating this unit to protect the forest land and although we started development in this unit long before environmental movement got started, we were so impressed with this forest that we did everything we could to protect it and still carry on our operations.

In order to do that, we kept most of our wells in the bottoms of the canyons where there would be a minimum of dirt work. And we show -- and also we would locate the wells back behind a screen of trees or behind a knoll, so that a traveler through the forest, it would not be conspicuous. And so right now you can follow the dashed green line from the south part of the unit up that main forest road to the A-23 well, then you go through part of our operations. You pick up the dashed line again and go past the C-2

and clear up to the north end of the unit, and on that trip you'll see one oil well. You'll see one tank battery. And that's all. And underneath that is occurring one of the most efficient oil depletion processes in the State of New Mexico.

This is remarkable. It can be accomplished, and has been accomplished, only because of unitization, and only because of the Federal type of unitization, voluntary unitization that's permitted that way. There's no way we could have drilled first and then unitized. A Federal voluntary unit system lets you first unitize and then drill, and that is -- only for that have we been able to accomplish this depletion of a reservoir and protection of forest at the same time.

To show a little more dramatically how we have protected the forest, we can look at the next graph. It has marked at the bottom of the page 152-A, a file number, and this is the Canada Ojitos Unit as it now exists, and the shaded area within it shows the Rare II area, which the Forest Service designated in its inventory two years ago.

Up dip on the righthand side of this area are injection wells; on the down dip side, on the left side of the map, are recovery wells, and within this unit, 9000 acres, that the Forest Service found qualified to be on the RARE II inventory some fifteen years after we started de-

velopment, of course we objected to this being on the RARE II inventory and we pointed out that with our operations it wasn't necessary that it be defined as a wilderness and we be prohibited from operating there, that the way we operated we did protect the forest. And so they took it off the inventory. But I think it shows very dramatically how we have preserved the forest to this day.

Q. And you were recovering all of the hydrocarbons from under that area?

A. Very efficiently.

Q. Without any surface locations.

A. Very efficiently.

Q. That brings us to Section F of Exhibit Two, the blue book.

A. Section F, the lefthand map or plat shows a comparison that we would like to make. One of the -- one of the questions that has come up in all of this difference of opinion as to how this area should be developed is that, so what, we want to drill a well offsetting your unit. That happens all the time. And this is the "so what".

In the shaded area in the center of the map we show what might be a typical waterflood and as we've shown here a scale of -- in which there are about sixteen wells per square, which would be sixteen wells to a section,

40-acre section, of the solid dots, solid colored dots. It's infilled to a 5-spot pattern and if, for instance, this were a waterflood, we would find the oil and the water moving kind of in the direction that the arrows show in the center colored section, which is namely all directions. The water from an injection well moves northeast and northwest and southeast and southwest. The oil as it moves to the wellbores is moving in all directions. There is no general migration of oil across this unit.

If a well is drilled outside the unit on the west boundary, we show by the red circle, that well if it's not unitized could affect the injection wells, the two injection wells nearest it, and what kind of an effect is that on this whole unit? Well, if we compare it to a unit about the size of Canada Ojitos, it would be some 2-1/2 times as long as this map we've shown, it would be 768 oil wells, 768 injection wells, one well offsetting that boundary would be one well out of about 800. If that well siphoned off the injection of water from the two offsetting injection wells, we're talking about maybe half of the water from the wells, again about 1/800th of the unit's energy would be perhaps wasted or gone to the offsetting well, and sure, a unit operator would attempt to bring that well into unitization, but if he didn't, so what, 1/10th of 1 percent, or 15/100ths of

1 percent of the unit's energy is gone, unless there is a back-up injection well behind it. The water will move over, flood out that well, and it's even a short time thing.

So it's not a serious matter in an ordinary waterflood or unit situation for an offset well to be drilled. It happens all the time.

But what's the situation in our case? We look at that, then, on this other plat and we see an entirely different kind of a situation.

Q. Yes, turn to the next page, if you will, please, and proceed, Mr. Greer.

MR. RAMEY: Mr. Greer, I think we need to break for lunch. Are you at a stopping place?

A. I think it's a good place to stop.

MR. RAMEY: Let's be back by 1:15.

(Thereupon the noon recess was taken.)

MR. RAMEY: The hearing will come to order and Mr. Verity, you may proceed.

MR. VERITY: Thank you, Your Honor.

Q. I believe, Mr. Greer, that when we interrupted for lunch you had just finished explaining the first

exhibit in Section F -- of the first sheet in Section F of Exhibit Two, the blue book, and you explained the minimal effects of an offset well with waterflooding, and now, if you will, please, direct your attention to the second page of Section F of the blue book, and explain that to us.

A. Yes, sir, this shows schematically the gravity drainage and pressure maintenance system that's underway now in Canada Ojitos. The blue shaded area represents the gas invaded area. The brown area schematically shows the area that's still -- still mostly oil, and the little red circle on the left side of the map represents the 660-foot offset well, and in round figures these are the dimensions that we're looking at. The unit recovery wells are about a mile a little over from the unit boundary, the better recovery wells.

And so when an offset well is now drilled under competitive conditions, as indicated by this red dot, that's just another well in the recovery system and it's going to produce not its own oil, but oil from underneath the unit. And here is the really significant thing that needs to be bourne in mind about the effect of a well, and it only takes one well, to destroy the pressure maintenance project.

This difference is that to waterflood a well drilled outside the unit might take 1/800ths of the

energy of the waterflood injection system and as such it's minimal; it can be drilled and there's no really significant change in the ···· in operation of the unit. The waterflood process is going to go on. Wells a quarter of a mile, a half a mile, a mile, and two miles away are just not affected.

But in this instance a well offsetting the Canada Ojitos unit, just a well producing one well's gas allowable -- now this you need to understand -- the allowable is 640 barrels a day, the limiting gas/oil ratio is 2000-to-1, and I see nothing wrong with either of these figures, that's a gas allowable of 1,280,000 cubic feet a day that any well in the pool can produce and the oil that comes along with it.

Now, one well, producing one well's gas allowable, will produce three times as much gas as we're now buying for make-up gas to maintain pressure on the entire unit. Now this is a situation that just is entirely different from any other pressure maintenance project in New Mexico, particularly a waterflood project.

What does this mean? It means one well, one well, is all it takes offsetting this unit and producing its gas allowable, and the pressure maintenance project is ended. There's no way we can afford to buy gas and let it be sold through somebody else's well. It can produce three times as much as what we're buying now to maintain pressure in the

whole unit.

So the first thing that happens when a producing well is drilled in this reservoir, the pressure maintenance project ceases. We're through. That's the end of it.

What else happens? Well, what happens, we look at the next exhibit.

It's a little bit hard to see from this exhibit, but the -- the blue shaded area, which represents the gas invaded part of the reservoir, has a little boundary of a pink coloring, which also is the gas invaded area, and just as gas had coned down to the well a mile or so from the unit boundary, once the offsetting well is drilled, the unit drills a well to meet that offset, when gas cones down to the furthermost unit well, then it's just a little skip for it to jump across the boundary.

Now the capacity of those wells, of course, may depend somewhat on the fracture system in the area around them, but it only takes one fracture on one of those wells over to the high capacity well, the area of the high capacity well a mile east of it, to establish communication and very high production rates, and that fracture can, of course, be an indigenous fracture, it's, perhaps, in the reservoir, I think the primary direction of fracturing is north and south,

but you can always have cross fracturing, but you don't need that. The frac treatments that are designed today often have fracture lengths calculated in 1000 to 2000 foot range. We're only talking about 1200 feet between these two wells across the line. So we don't have to have a fracture system. It can simply be a frac treatment that's connected the wells.

And then what happens? If that happens and this is a high capacity well and offsetting the unit, they're going to produce it. Our well, the nearest well here has a capacity -- initially had a capacity of 8 or 10,000 barrels a day. We restricted it to a maximum 700 barrels a day. Presently it could probably produce 1000, 2000 barrels a day if we opened it up. We're producing it at about 150 barrels a day because I believe that that's the most efficient rate to produce the well.

Does anyone think that the protestants here, if they get a well that will produce 1000, 2000 barrels a day, that they'll restrict it to 150 barrels a day? No, they're going to produce it.

When they produce it and the oil and the gas that comes with it, they may be satisfied with the 640 barrels a day allowable. They may ask for -- that the proration be limited, or be lifted. There's no reason to prorate the field if there is no longer a pressure maintenance project.

The recovery from the reservoir under solution gas drive will be just the same whether you produce it at a high rate or a low rate; might as well produce it at a high rate. The -- the country needs the oil. They'll have a good argument. Engineering will be on their side. There's no need to restrict production. You might as well open the wells up.

And when they're opened up, what will they make? What will these wells make? They have tremendous capacity if you get hooked up with a high capacity fracture system. We measured about 6 to 10 Darcy feet transmissibility of the reservoir. That supports oil wells of high capacity, but what about the gas invaded zone now; tremendous potentials. Absolute open flow was on the order of 2-billion cubic feet a day. Now that's not 2-million like "M"; that's 2-billion, like "B". That's the kind of capacity that this reservoir could show.

Now, you're not going to produce any 2-billion cubic feet a day out of a well. There are going to be restrictions to it; restrictions to flow, the size of the casing, the size of the tubing, whether it's in a tight block, how tight it is, but open flow capacity is on the order of 100-million cubic feet a day, are entirely possible and probable, and the wells actually will be able to deliver gas measured in terms of tens of millions of cubic feet a day.

And what does this mean? Well, in a short time these two wells down here bumping heads. They start off with 1000 - 2000 barrels a day; not too high a gas/oil ratio, but soon the ratio will be up to 10,000-to-1, and what it is, what are we looking at?

Well, 2000 barrels of oil a day and 20-million feet of gas a day, today's price is $100,000 a day income per well. Wells that cost $750,000 to $1,000,000, you're talking about a week to 10-day payout.

What's going to happen? Well, they're going to produce their well and they're going to think about drilling some more. In a situation like this, there's no need to worry about where the oil comes from that's coming to that well. The important thing is to get some more wells in the ground and get some more oil out. The farther you get away from that well, the farther -- the greater the risk you take of getting away from whatever the communication system is that is bringing the oil to that area. So before they drill another well, they'd better think about 320-acre spacing, or maybe 160-acre spacing; that would be the best thing.

So, in any event, the race is on. We have a gas pipeline into that area now. It's only a small line. We do have the right-of-way, but of course, it's only a 4-inch line and if we're selling 20, 30, 40, 50-million feet

a day, we need a bigger pipeline. It shouldn't be any difficulty to get that right-of-way, since we already have it, get the authority to get the bigger pipeline on it.

And what we do, naturally, we have no choice, we put our wells on production. We've got to get the oil out as fast as the neighbors, and we can get it out awful fast, but there is -- what will come under solution gas drive, about 1/10th of what we'd otherwise get. We can get it and get it in a hurry.

When we do, the pressure drops up here in the gascap area first because that's where we're pulling the pressure down fastest. These little circles that we've shown in the brown area represent gas bubbles. When the pressure is pulled down the gas breaks out of solution, the oil area expands. It expands in a band, say, like this schematically shown here, the red band.

The oil has now moved back up into the gascap, the area in which we produced the oil by gravity drainage and probably reduced the liquid saturation to 50 or 40 percent. Under solution gas drive now the oil will go back up there but won't come back out. So we lose it.

We're not talking about a matter of years; we're talking about a matter of months that this depletion is going to take place. This is the only thing that can

happen, the only result, the inevitable consequence of drilling competitively and getting a fracture connected up with a high capacity system.

When this happens we lose 90 percent of the otherwise recoverable reserves, and the impact, then, on the State and Federal revenues are shown on the next schedule.

Q. That will be irretrievable loss; there is no way you can regain it once the bubble point has been reached and these bubbles have trapped that oil.

A. Well, no, once the oil has expanded into the gascap and you pull the pressure down, the viscosity is gone, the fractures are squeezed together, the system, it's a complete loss; there's no way to protect it.

And directing your attention to the next page, this shows the impact on State and Federal revenues from the loss of recovery which will result in the event the dominoes start to fall and it happens as I've just described.

Q. Actually, your previous exhibit showed this 5 to 10 million --

A. Yes, it showed the 5 to 10 million barrels estimated future recovery, and based on that range, we've broken the figures down for the different categories, tax and royalty, to totals are shown at the bottom of the page; in round numbers, $90 to $100-million will be lost if

this takes place.

Q. Now that's just the loss to the State and Federal governments.

A. Yes, sir.

Q. It says nothing about the loss to the royalty owners and the owners of the other mineral interests in West Puerto Chiquito.

A. The working interests are not there.

In the next section --

Q. That's G of Exhibit Two in the blue book.

A. The first plat shows in color wells drilled in the east half of the section. Now these are the oil recovery wells. The wells drilled in the east half of the section are colored in blue; wells drilled in the west half of the sections are colored in red, and we note at the bottom there that 87 percent of the unit's 1980 first nine months production is from wells in the west half of the sections.

The one thing that we should point out here, which again is unique, it's different from most units, in that all of the spacing units have not been drilled, particularly along the boundary. This means that when an offset well is drilled to the unit, it's going to require another

well inside the unit. This is something that ordinarily is not the case; and something which I don't understand, when the protestants first began to think about drilling in this area, if I were in their place and saw this situation, I would have come to the unit owner and said, well, we want to drill a well offsetting the unit but when we do, you're going to have to drill a well to meet us. It's going to be an unnecessary well and there's a better way to do this. They didn't do it. We went to them and we still haven't got together.

So, we need to look now at what kind of patterns are going to -- going to result if protestants are allowed to drill close to our boundary.

The first one we show here under this plat with the doughnut colored rings is that if they drill 660 feet from our boundary, we drill 660 feet to meet them, those two wells in order to drain their respective units will have extended radiuses of drainage that they must draw from. For instance, 4620 feet in the upper row of sections. In the lower row, if you're going to go all the way to the -- to the unit corner, 5300 feet, and those distances are equivalent to circular drainage areas of 1500 - 2000 acres per well.

Now we've found wide drainage in this unit and a lot of the wells will have the ability to drain

that big an area, but one of the problems that we reach here is these wells don't have the equal opportunity to drain that other wells that have only to drain their own sections, and so right at the outset we'd have a problem of correlative rights.

In addition, let's say that the left two rows of sections are owned by the same companies. They drill the first wells offsetting our unit boundary, we drill wells to meet them. Then maybe the sections just off the plat, maybe those leases are about to expire, so they drill next, and when they drill, they're going to drill on the east side because it's close to the unit. Well, when they do, if they get production, then the owners of the leases in the left row of sections here are going to find it more profitable to meet that offset and save that oil in between for their two wells, even though they have extended radiuses of drainage.

And so what do you have? You have an area there of 9000 feet between wells and first, of course, this seems like a big distance. It is, of course, for 640-acre spacing. But also I'd point out that 9000 feet is about the distance between the two furthermost wells on our 1965 interference test in which we measured interference in less than 24 hours.

Whether that kind of communication will carry on out this far or not, we don't know, but it is possible

that we would wind up with this kind of a pattern. When we do, and if these wells are drilled under the order the way it was set in August, what are some of the consequences?

One of them is that the people have drilled these wells with the 4600 feet of extended drainage radius that's required of their wells, they have a valid case to come before this Commission and say these wells just have too big an area to drain; too far a distance; too long a distance. There's only one solution, 320-acre spacing.

And so this is one of the potential problems we face with this kind of a pattern.

The one thing that begins to look -- come out clear as we think about the problem of -- of the competitively drilled well and the destruction of the unit's pressure maintenance system, is that whatever plan this Commission decides on, it should be on that puts the maximum practicable distance between the unit wells and the non-unit wells. Certainly this is something that this Commission needs to do. What would that be?

Well, in this 660-acre foot plan, it would be for the unit boundary not to be where we've shown it here but a mile from the west side, and we show that on the next sketch.

Q. That's page three of this Section G.

A. Yes, sir. The green line there shows if that were the east boundary, then we've got a no-man's land of about 9000 feet between wells. This would give the maximum protection of interference between the non-unit wells and the unit wells, and this might be a pretty good plan. It's got a couple of problems to it. One is that the unit will lose the gravity drainage potential from the wells down dip to the boundary, but that would be a good trade-off, to lose that, give that to the outside wells in order to preserve the unit's pressure maintenance system.

We seriously considered asking for this plan before this Commission. This might give us a longer time in which we could preserve the operation of the unit before we reached the disastrous competitively producing situation that's going to otherwise occur.

But then we decided that this -- that the other problem that this has, and one that I really hoped would in time come about, is the unit boundary might change, and if the unit boundary changes, then of course we've lost the no man's land here. If we have statutory unitization and it's successful and upheld in the court, there will be a change of the unit boundary, and so really we wouldn't have gained as much as we would otherwise think we might.

So then what do we come to? Well, we

take another look at the drainage pattern and that's on the next exhibit, G-4. If, for instance, the competitively drilled wells don't reach a high capacity fracture, if they are small wells, then we have a situation somewhat like this shown here on the plat under part 4 of Section G.

The oil to these wells, both of them, the competitively drilled well, the unit well, coming from the unit and its energy, its pressure maintenance project and gravity drainage from the east, the flow pattern will be sort of as shown in the center sections where the arrows show the oil moving from the corners of the section down around behind the well and back to it. That's as far as the drainage from the outside well's tract is going to be. Most of the oil is going to come from across the line, and what happens is, of course, we have a flat decline curve, just like the A-16 Well, one of the nearest wells to this unit boundary that we looked at earlier. The pressure doesn't drop in this section. It's maintained by the injection wells four miles away, and so there's no depletion of the -- of the section to the west of the unit. It just takes it all out from under the unit.

Well, under that situation it would seem that it's only fair that -- that the competitively drilled well back off and produce a little bit of oil out from under its own section rather than take it all from out from under the

unit.

Now one of the problems that we're looking at is it's not just one well that's going to be drilled here. There's a boundary about fourteen miles long; there will be at least ten or twelve wells that would have to be drilled, unnecessary wells, to meet the offsets. If that turns into 320-acre spacing, you're not looking at twenty unnecessary wells, there may be thirty, and $30,000,000 is a lot of unnecessary money to be spent in a reservoir like this.

Well, then you look at the next pattern under section -- or part 5 of Section G, and here we take a look at down the road at some of the problems this Commission's going to be facing when we ask for statutory unitization. How much area has this competitive well proven when it was drilled? If it's drilled 660 feet from the line it's proven up about 1/8th of the spacing unit; 1650, about 31 percent; or, if as we suggest, the well be drilled in the west half of the section, and we presume that there would be a 330-foot requirement that the well be offset back from the quarter section line, then that means the well would be 2310 feet from the west line and it would prove up 56 percent of its spacing unit.

Now the problem the Commission is going to be facing under this statutory unitization we can show by

the figures on the schedule opposite this plat.

In line 7 an ordinary waterflood, you've got one well out of about 800, 1 out of 768. If it's an average well, produces the average amount of oil, then it will produce the same as is shown in line six, 1/768th of the total unit production.

If it's drilled 660 feet from the line on 40-acre spacing, it's proven up half of its unit, which would be 1/1500ths.

So then the ratio that we have shown over here on the righthand side opposite lines A and B, the ratio of a well's production to its spacing unit compared to the whole of the unit is 1-to-1. That's a real simple -- we can see at the outset, a simple kind of an equity problem to work down, and even if it proves up only half of its acreage, then it's only a 2 to-1 ratio. But what about in Canada Ojitos here?

One well out of 10, if it's an average well, is going to produce 1/10th -- have a productivity of 1/10th of the unit's production. But its spacing unit is only like 1/50th, so already we have a 5-to-1 discrepancy in productivity and spacing unit, if the entire spacing unit is proven.

If this is drilled 660 feet from the

line, then we prove up 1/8th of their spacing unit, and that's 1/400ths. That means that their production, compared to the unit, they have 10 percent, you only have 1/400th of the proven acreage. You have a ratio there of 40-to-1.

There's no way that the parties are going to be able to voluntarily determine equities, and this Commission is going to have a very difficult time determining the equities themselves, and the smaller that proven area, the more difficult the problem.

So it's clear that the bigger the tracts, proven acreage, when the well is drilled, the simplier it would be to -- the unitization problems when they're before this Commission asking for statutory unitization.

So after reviewing all those problems, we concluded that the only reasonable pattern for this pool is to pick spots and require that the well be drilled a uniform distance apart. That's the only way that fairly we can settle this. And picking spots is really not too unusual in the oil industry. You see it more frequently in 80-acre spacing and 320-acre spacing, but there's nothing wrong with doing it in 640.

So we show here on the plat under 6, plat 6 under G, the principle of compensating drainage of off-centered wells that are uniformly spaced, and for instance,

we discussed the shaded area in the center, the well directly south of it has an opportunity to produce the oil out from under the red shaded area better than does the well on each tract.

But by the same token, that well has the same opportunity to produce from the tract just north of it.

The same is true for the yellow colored areas, east and west, and the blue colored areas, northwest and southeast. And so we can have, as long as the wells are uniformly spaced, we can pick a spot, and this is the most fair and equitable way to locate the wells.

The question is, what should the spot be. Should it be northwest, southeast, southwest. Well, there are some reasons why one should be chosen as compared to another, and do we have to fix it exactly to a spot. Can it be the west half, for instance, and give more flexibility; the east half. We think it can because the issues are primarily east-west issues, not north-south issues. We'll look at it just a little more in detail.

Under the next plats, G-7 and G-8, under G-7 we look at picking spots in the east half of the section. On the west side, on the well on the left, we'll say that this well is 1650 feet from the line, that that's as close as we will allow, that we'd have a plan that required wells drilled

in the east half of sections; wells 1650 feet minimum distances from a line.

The black dot shows the surface location, if it has a drift of 330 feet, then the well on the west section will end up 1320 feet from the line.

The well on the east section, if it's drilled and crowds as close to the west as the regulation would permit, then it would drill 330 feet on the surface from a quarter section line. It's bottom hole location, assuming a 330 foot drift, would be 1980 feet from the east line, or 3300 feet from the common boundary. Now that's a comparative distance of 3300 feet for the well on the right to 1300 feet for the well on the left, a difference of 2000 feet.

We show on the lower righthand part of that diagram that that actually is 1980 feet. It's 37-1/2 percent of the spacing unit's width.

Now if the wells are drilled in the west half of the section, if we look at that on the bottom plats, the farthest east that the well on the lefthand side can be located would be again 330 feet from the quarter section line. If it drifts 330 feet it will end up on the quarter section line, 2640 feet from the boundary. The one on the righthand side, the closest it can crowd to the west boundary is 1650

feet; it drifts 330, and it bottoms 1980 feet.

We now have a comparison of 2640 feet against 1980, a difference of only 660 feet; whereas, if they were located in the east half of sections that distance is 2000 feet. That 660 foot difference out of the spacing width of a mile is 12-1/2 percent of spacing unit width.

We have just seen, if for no other reason than the fact that the formation dips from east to west, that if we have decided that there should be uniform spacing, that a spot should be picked, that there's more merit in it being in the west half than in the east half, and of course, in addition to that, we have the migration of oil from east to west. We add the two together and our conclusion is that the best location for the wells is in the west half of the section.

In this plat we show just a comparison of the diagonal spacing that we often see in 80 acres, 320 acre spacing, and in the overlay it shows units of the same area with spots chosen. In this instance if we're facing -- we look the same direction that we have been, they're in northeast spots, but you can turn the book sideways and it's northwest spots; upside-down and it's southeast spots; whichever you want. But the point is that the location of wells and fixing of spots is just as reasonable on a square unit

as it is on a rectangular unit.

Q. That's all on Exhibit G. Turn to Section H of Exhibit Two.

A. Section H, we simply show again the leases owned by people who favor our application and leases owned by operators who are opposed to it.

Those in favor of the application, their leases are colored in brown; those that oppose it are colored in grey. Those that are white are either unleased tracts or we were unable to contact them, or they don't care.

Q. Here today you represent -- we represent all of these people that are in the brown -- in the brown. That includes all the various non-operators of the Canada Ojitos Unit.

A. Yes, sir.

Q. Can you name some of those for us?

A. Well, there's Bill Montin out of Oklahoma City; Jack London; Sun Gas Company; Virgil Stobes, Stobes Oil Corp.; former governor Tom Bolack; Supron Energy Corp. out of Dallas; some of the others that's colored in have advised us that they support us, Tom Dugan, with Dugan Production Company: Reading and Bates; Merrion and Bayless; Southland says they don't care.

That's most of them.

MR. VERITY: We offer Exhibits One and Two, and you may cross examine.

MR. RAMEY: Any questions of Mr. Greer?

MR. FEDRIC: I'd like to, if I may, sir.

MR. RAMEY: Mr. Fedric.

CROSS EXAMINATION

BY MR. FEDRIC:

Q. Mr. Greer, my name is Don Fedric. I'm one of the attorneys representing Cotton and Mountain Fuels.

In the opening statement by your counsel, and some of your remarks, you've mentioned having approached Mountain Fuels and Cotton to discuss unitization. Do you recall when you first contacted Mountain Fuels?

A. I believe our first contact was last spring around -- it was probably the month of March; maybe April.

Q. Did you contact them before you contacted the unit participants in your unit?

A. Yes, sir.

Q. And did you discuss over this period of time from April to a recent period of time unitizing over on the west side?

A. With who?

Q. With Mountain Fuels?

A. Yes, sir.

Q. And now you wrote Mountain Fuels a letter about the 12th of September, is that correct, actually offering to have them join in the unit which you'd had designated as logical by USGS?

A. Right, that was the same unit.

Q. And then they replies to you, did they not, in a very short period of time that they were not --

A. They were not.

Q. -- interested in participating.

A. Right.

Q. They said they were not interested in participating because they had reached a farmout agreement for a different type of plan with Cotton Petroleu, is that correct?

A. I believe that's right.

Q. Thereafter you contacted Cotton Petroleum and talked with them, is that correct?

A. That's correct.

Q. And they said they were not interested because they had formulated their own plans and going forward, isn't that correct?

A. Okay, yes, sir.

Q. So then, in October 10th you filed the application in this instance to have the setback being 1650 feet, is that correct?

A. Yes, sir.

Q. Okay, so we had really from the point in time that you contacted Mountain States, September 12th --

A. Mountain Fuel.

Q. -- when you offered to have them join the unit, isn't that correct, up until October 10th, wasn't that the time frame in which you really talked to them about how to form the unit and how you were going to have them participate, and this sort of thing?

A. Oh, no, sir, we talked -- we had a meeting in Denver last April or May. Mountain Fuel was present, Patrick was present, Koch was present, and -- and we discussed at that time, and we were surprised at Mountain Fuel's position. Mountain Fuel usually farms out in these situations and at that time they told us it was their intention to join the unit and pay their own way, and this is the discussion that we had with them.

And I remember that because that's unusual for Mountain Fuel.

Q. And then you're saying that when you got the letter back in late September saying they did not want to

join the unit, this came as a total surprise to you?

A. It sure did.

Q. And then you went to talk with Cotton. You didn't have any surprise from them. They simply said they had their own plans, isn't that correct?

A. Right. When I discussed it with Mountain Fuel, and the gentleman is here today that can confirm our conversation, we knew that Cotton had one 320-acre tract, a farmout. They didn't own any acreage in the area but they had a farmout of this one tract. Cotton had made a deal with Mountain Fuel to farmout some of Mountain Fuel's acreage and some of Patrick's. I discussed with both Mountain Fuel and with Patrick the issue of unitization. The answer I got from Patrick was that we've already made a deal with Koch; we've already made a deal with Mountain Fuel; but if Koch and Mountain Fuel want to unitize, they can earn under our agreement with them under a unit.

Now this was our conversation with Patrick and that is why I went back to discuss -- I went to Cotton to discuss that with them.

Now my conversation with Mountain Fuel, with Mr. Pittam, was this: If Koch and Cotton would agree to unitize, would you also join the unit or would you agree that they could earn under the unit? And Mr. Pittam said that

our first answer from management is that we don't want to unitize but if Koch and Cotton want to unitize, we will go back to our management with that.

Now what that means is that there's two companies out of about twenty who are opposed to unitization, and I'll grant that I made a misjudgement earlier when I thought that there would be no problem in unitizing, and I misjudged to the extent of about 10 percent. Two of the companies out of twenty; if they would go with the unit, it would be --we'd have it formed right now.

Q. Okay, let me ask you, I had the impression from your -- your very early testimony, that you were leaving the idea with the Commission that these people dealt with you in bad faith. Now that's not what occurred, is it? You simply talked to them about joining the unit and they declined to do so.

A. No, sir.

Q. Isn't that correct?

A. No, sir. I talked to them about joining the unit. They considered joining the unit. The last time that I talked to Mr. Paul (sic) with Cotton, was we'll go back and take a look at it under this new application that you've made. They were considering it, as far as I knew, all the time, and when they jumped out and staked a location it was a

shock to me.

Q. Are you saying that you had not received any notice at all from these companies that they did not desire to join in the unit with you?

A. Right. When we -- when -- they were still considering, as far as I knew, when Koch staked its 660 foot location.

Q. Okay. Let's go back to your unit, now. As I understand --

A. Excuse me, might I add to that?

Q. Go right ahead.

A. And not only that, after Koch wrote us a letter and turned us down, they said we're not opposed to unitization; we just want to drill first.

Q. Well, let me go on to your unit. As I understand, the last well drilled for production in your unit was drilled approximately eight years ago in '72, is that correct?

A. No, I think it was ten years ago, probably, 1970, and maybe by '72 when we finally completed the last one.

Q. Okay. I'd like you to look, if you would, Mr. Greer, in your Exhibit Number One.

A. Okay.

Q. Under Section A, second plat.

A. Okay.

Q. And I simply use this map for reference purposes, no other particular reason.

A. Okay.

Q. Am I correct, Mr. Greer, that previously there were some lands that are out of the unit right now that were inside of the unit and those lands included the east half of Section 8, the east half of Section 17, and all of Section 16, in 24 North, 1 West.

A. Well, I'd have to refer to some other maps, but I have an idea that that's about right.

The east half of 8, east half of 17, and all of 16.

Q. And so those lands that I mentioned, those were all at one time located within the exterior boundary of the unit area, is that correct?

A. Yes, sir.

Q. Presently existing unit area.

A. Yes, sir.

Q. And I mentioned the east half of Section 8, and you're aware of the fact that Cotton's location for a well is in the east half of Section 5, which is immediately adjacent just to the north of the east half of 8, correct?

A. Yes, sir.

Q. I assume that the east half of 8 and the east half of 17 and all of 16 were subsequently kicked out or excluded from the unit because they were deemed to be nonproductive lands, is this correct?

A. Well, not necessarily. What we keep in the unit is lands reasonably proven to be productive, and any other lands, which of course might be productive, but are not reasonably proven to be productive, have to be excluded, and that's just one of the principles of the Federal unit.

Q. And in other words, if they're not, for example, reasonably proved to be productive, they'd be kicked out.

A. We don't know whether they'd produce or not; they just at that time have not proven to be productive.

Q. Okay, and they're assumed, I guess, not to be communicative with any other nearby well. You talk about these mass areas that you draw from, so it didn't draw from these areas, is that correct?

A. No, sir, you can't say that at all.

Q. If you'd had these areas included in a participating area of the USGS, they'd still be in the unit, isn't that correct?

A. If they were in a participating area.

Q. And if they were in a participating area, you would ask for that to be designated on the basis of communication, is that correct?

A. That's correct.

Q. So I assume you did not feel that communication was taking place as to 8, 17, and 16, from any presently then-existing wells in the unit.

A. We didn't have the information to either prove or disprove that, and in the absence of proving it, you have to leave it out. That doesn't mean anything at all with regard to whether it will produce now, whether it would be in communication if it's productive, that has nothing to do with that.

Q. All right, in 1970 you expanded the unit to include about 20,000 more acres, is that correct?

A. I forget how many acres it was, but we expanded it to include quite a bit of the gascap area on the east.

Q. All right. Why did you not at that time attempt to expand the area to include this west area of which you're now concerned?

A. Because at that time, with the price of oil and drilling costs, even though we felt then, and I feel now, that that area, the grey-shaded area, has an opportunity

to produce, and I feel should be drilled and tested, and I did -- I felt so then. But economically it wasn't justified.

Q. Now, your -- your company has some leases in the area outside of the unit, I believe, up in the northwest particularly.

A. Yes, sir.

Q. Other areas down here I guess you've let go. You haven't staked any wells up in this northwest -- north area, northwest, have you?

A. No, sir, we never staked any out here.

Q. You've not drilled any out in that area?

A. No, sir.

Q. Not filed any notice of intention to drill that you've abandoned, or anything like that?

A. No, sir.

Q. Now I'm still having a problem in fully understanding how a well outside of the unit area is going to definitely affect your unit activities. I recall from looking at some information that you provided to your people, your unit people, do you recall the letter of April 30 that you --

A. Yes, sir.

Q. -- wrote to your people in the unit?

A. Uh-huh.

Q. In attachment number four, page two,

you talked about conditions that prevail and all the different varying factors, and you said, "We see no real threat of serious reservoir damage that could be caused by wells drilled outside and to the west of the unit area."

A. I believe the sentence goes on, doesn't it?

Q. Oh, it does go on. You talk about various ifs and --

A. Right.

Q. And maybes.

A. But if -- and if you're talking about my letter, I think perhaps I should be allowed to explain.

Q. Oh, go right ahead.

A. If the wells are small, then we arrive at the situation which we describe under Section G, part 4, where we show those drainage patterns, if the wells are small wells, and that's what we're talking about there, if they're small wells, don't produce much gas, then they cannot seriously damage the unit production, and in a sense this is the parasites, and we can support parasites to a certain extent without serious damage. But that's if they're small wells, which we anticipate.

The issue and the problem which I pointed out earlier is if they're by an indigenous fracture, or an

artificially induced fracture, they are -- those wells are connected with the high capacity system.

Q. Okay, I think maybe this is what I'm trying to get at. You really don't know till a well's drilled, do you? It may be a small well; it may be a large well and not communicated with your unit, isn't that true?

A. I think that would be very unlikely.

Q. Impossible.

A. Well, out of 50,000 acres and twenty some odd wells that's been drilled, everyone of them is in communication with the other, so I'd think that the odds of any future wells drilled into the reservoir not being in communication --

Q. I wanted to ask you about that. Up here this 09 well up in Section 9, is that in communication with these other wells down here in the unit?

A. I believe so, yes, sir.

Q. Have you ever run an interference test to show that?

A. The -- it's a small well. There's no way to run an interference test, but its pressure build-up test indicates that it is being drained by the other wells.

Q. But this is more opinion than technical fact, isn't that correct?

A. Well, I think it's most unusual within a reservoir that if a -- in an area like this, that if north of the well, north of the area we're talking about, south of the area we're talking about, the virgin pressure is some given amount, and in between you drill another well and its stabilized pressure is 100 or 150 pounds less than the virgin pressure. It's a pretty good indication that it's in communication.

Q. I think what I'm still trying to get at is that you don't seem to object to a small well on the west side, and apparently, am I correct that you don't object to a well if it gets far enough away from the unit, is that correct?

A. I don't say I don't object to it, but our whole point, all of what we've done in this -- in this area is to produce efficiently and to avoid drilling unnecessary wells.

Q. I won't argue that and I'm not saying that Cotton isn't maybe going to throw its money down the hole, but I sort of think maybe that's their prerogative to do so, and is -- am I correct that really what your position is that nobody should drill to the west until you've drained the unit? Is that your position?

A. Oh, no, not at all. We've suggested -- we've suggested to Cotton, your client, that they join this unit, be a part of it, and that we together drill wells up

and down this boundary to try to find the down-dip side the best place to locate the producing wells.

Q. It would be your position if they wanted to form their own unit over here, you don't have any acreage in this southwest part, is that correct?

A. Not in the south part.

Q. Not in the part that either Koch or Cotton are in.

A. Right.

Q. Is that correct?

A. That's right.

Q. If they wanted to form their own unit over there, what would be your position then?

A. Well, we've discussed this with the -- with the USGS about forming a unit, and -- and what that turns on and whether it's practical is if there is a compatible boundary agreement between the two areas. If so, then it's possible to have a separate unit outside. This is one of the things, in fact, in our August hearing we drew the outline of the area we thought should be unitized. It's shown on our plats. I have a list, if you'd like to see it of the chronology of events that went toward forming that unit. We believe that either a unit should be formed in the west or that the present unit should be expanded to include that acreage, and

the issues are that if you form a new unit the boundary agreement becomes somewhat complicated. I think it can be done.

What's probably better is to expand the main unit and eliminate all or the problem agreements.

Q. Assuming they weren't going to unitize here, how far west would they have to go before you're satisfied?

A. If they don't form a unit all that can be done is to set some kind of a reasonable spacing pattern so that when we have a statutory unitization hearing, that these people will have something reasonable to deal with in setting acreage. That's kind of what it gets down to.

If we're going to prevent underground damage in this reservoir, that's what it's going to require.

Q. Now the reason I asked the question is we started off by agreement between everybody at 660, and then it went to 1650, and now it's to the west side. What assurances do these people have that a month from now you won't be saying let's have a boundary as sort of a bumper zone, a jump over.

A. I suppose you have the same assurance that we have that you won't be back asking for 320-acre spacing. There's nothing that I know of in the regulations or the law that will prevent you coming back and asking for 320-acre

spacing, and when you do, we'll just have to meet the issues when they arise

Q. It's my understanding that your position is that if someone drills in the area just adjacent to the unit on the west side, that you feel now that drainage will occur, is that correct?

A. Well, as I indicated earlier, and as we discussed ten and fifteen years ago and as related in that letter in front of you, we felt that this area might support low capacity wells, 20 to 40 barrels a day. They were not commercial to be drilled at that time and so we couldn't include them in the unit. We had to include lands reasonably proven to be productive in paying quantities, and the unit agreement describes what paying quantities means, and in general it's a well that will pay for its operation and retire the cost, the investment cost of drilling it in a reasonable length of time. With the price of oil as it was ten or fifteen years ago when these decisions were made, it didn't look economically practical to drill it, didn't look like it could be, in the terms of the unit agreement, reasonably proven to be productive.

Well now with the price of oil, has increased like ten or twelve to one, the drilling cost has increased three to four to one, the ratio now is such that it might be profitable. As we've shown on our exhibits, an eighteen

or twenty barrel a day well might now pay out a $750,000 investment at a 15 percent rate.

Q. And that wouldn't bother your unit at all, would it, because it wouldn't drain. Isn't that correct?

A. No, sir. As I described earlier, a typical well would be the A-16 well, the closest well to the unit boundary, the one with the flat decline, the one whose pressure is upheld, the production is upheld by injection wells , the closest one four miles away from it, and that's what I would expect to the west.

Q. All right, this is low capacity wells to the west, isn't that correct?

A. It shows the A-16 --

Q. 18 to 20 or something like that, and you say that's going to drain from you over here? Small wells like that?

A. That's why we put that exhibit on, sir, to show that small wells not only will drain but have drained for the last ten or fifteen years.

Q. And you say that's going to -- that one well, 18 to 20 barrel well, is going to ruin your pressure maintenance system?

A. Perhaps you weren't --

Q. Is this your testimony?

A. Perhaps you weren't here when we reviewed this --

Q. I just want to know, Mr. Greer, is this your testimony?

A. As I said earlier, the small wells will have drainage patterns which we showed on -- I just reviewed a few minutes ago; simply become parasites, and it's just a question, then, of how many parasites can the unit support before it has to call a halt to the -- to this kind of support and quit buying gas for somebody else's wells, and start pulling pressure down and then start the race off on depletion of an inefficient sort.

Q. With great hesitation, Mr. Greer, I'll ask you one last question.

In connection with the location that you're talking about, wouldn't it be better to give these people flexibility as to location rather than try to restrict them to one side of the unit because of topography and the geology and economics of the deal? You're talking about the beautiful forest. What if you get over there and you can't put it over there on the west side? Then you've condemned that section, isn't that true?

A. Yes, sir.

Q. What if the only place you can put it

is right in the middle of the most beautiful spot in the section?

MR. VERITY: We object to that, Your Honor, if we might. It assumes facts that are not here in evidence, that there would not be a place to drill that well in the west half. We think that is not only not in evidence, it's not the facts.

MR. FEDRIC: Mr. Chairman, as we have talked about this broad expanse of forest out there, which may or may not have a location, Mr. Greer assumes it does. I can assume it doesn't.

MR. RAMEY: I'll overrule the objection.

A. I don't mind answering him, sir. The -- if the flexibility, and during the August hearing Mr. Nutter worked out the area that would be available to drill wells in a large part of the section, which ostensibly would give flexibility to do exactly what you're saying. The point is, and the problem is, they're not going to use that; they've not used it. Instead of using this 30 percent of the area, or 40 percent, whatever it calculates that they could drill a well on, what have they used? About a fraction of one acre. How wide is a one foot line a mile long? They got 660 feet from the line and that's the line, that's the area that they were looking at. They don't look at the whole section, and

so the answer to that is, that's fine if they'll use it, but that's not what they're going to use. They're going to get up -- if it's 660, it will be 660. If it's 1650, it will be 1650. If it's 2910, they'll be 2910.

And so although it sounds great, makes a good speech to say that give us more area and we have more room to protect the forest, that's not what happens at all. That's not what happens at all.

And if, I would say this, if in the west half of the section, that a location is staked and surveyed and the forest ranger says we've looked at the west half of the section and there's no suitable location in the west half of the section, then we'd be the first to -- to agree that a well could be drilled somewhere else.

But this will be -- we've studied the area. We've lived with it twenty years. This will be an exception. There might be two or three like that, but you'll find that the rest of them, there are places to be drilled.

MR. FEDRIC: That's all I have.

MR. RAMEY: Are there any other questions? Mr. Carr?

MR. CARR: Mr. Ramey, I don't have any questions. I'd like to again move that the application of Benson-Montin-Greer be dismissed because it is nothing more than

a collateral attack on an order of this Commission that became final under Commission rules.

Contrary to representations of Mr. Verity, we have not had one single solitary bit of evidence that is new. We have had not one single thing admitted into evidence or one bit of testimony that could not have been given last August or perhaps five years ago.

The fact remains that they did not -- they were here in August based on exactly this evidence. They agreed with Mr. Nutter to how this thing could and should be spaced. That order became final because they elected not to appeal it. They now are selectively attacking parts of that order and we submit that the application should be dismissed.

MR. HUNKER: Cotton and Mountain Fuel will join in that motion.

MR. VERITY: Counsel misunderstood my statement. I did not say that there was any addition. What I said was that you do not need a change of condition to change rules. Counsel is talking about where you want to set aside an order. We're not asking to set aside an order, but as the order itself anticipated, we have a situation where for protection of correlative rights and prevention of a great amount of waste, requires change of the rules, not setting aside the order, and it does not require change of condition.

We do have the circumstance where at that time, and this is what he's referring to, we thoughtthat we had unitization, and we do not have it. That's why we at this juncture have to have a proper pattern, whereas at that time it seemed insignificant.

MR. CARR: The only thing different here today that wasn't obvious in August was that somebody else would like to develop their acreage and they're not willing to let one individual tell everyone else how it's to be developed.

MR. KELLAHIN: Can I be heard? I think everyone else has been heard on this matter?

Mr. Carr misunderstands what is intended by the pool rules and what has historically been done by the Commission for a great many years.

The Commission is not bound to adhere to any existing pool rules when it is established that the continuance would cause waste, and in fact, you can go to your statute and I can find you on 70-2-17, in paragraph (e), it says the very same thing. It says, whenever it appears that the parties have agreed to some well spacing that does not bind the Division to adhere to those well spacing rules.

It says, the Division, upon hearing and after notice, may subsequently modify any such plan to the extent necessary to prevent waste as prohibited by this act.

And that's been the whole thrust of our testimony today, that without the implementation of more finely tuned spacing patterns for this area, that substantial waste is going to occur. The Commission realized that when they entered their order on this. The very order itself maintains that the Commission continues to have jurisdiction over this subject matter and that it can modify the order as needed.

We maintain that the need has arisen and that the application is perfectly permitted and ought to be granted.

MR. CARR: Since Mr. Kellahin has elected to decide whether I am understanding or whether I'm not, I'd like to make one brief response.

He has stated that I fail to understand that parties may agree to some spacing and that isn't binding on the Commission. There's no confusion in my mind on that point whatsoever.

The fact is that when the Commission does enter an order establishing a spacing pattern, we do believe that we ought to be able to rely upon that order and absent some change in circumstance that would warrent the Commission re-opening and entering a different order, that absent that kind of change and circumstance, we should be able to rely on the original order.

MR. RAMEY: We feel it's the Commission's duty to prevent waste and protect correlative rights, and we think if it takes the change of an order to do that, it should be done, and so the motion for dismissal is denied.

MR. CARR: And I'd like to ask that the record reflect my exception to your ruling.

MR. RAMEY: Let the record so show.

MR. HUNKER: Note our exception as well for Cotton and Mountain Fuel.

MR. VERITY: Is there further cross on these exhibits?

MR. RAMEY: I think Mr. Stamets had a question.

QUESTIONS BY MR. STAMETS:

Q When you -- back to the map which is in Exhibit Number One with the multi-colors on it. I'm not sure what --

MR. VERITY: That's the one we were just looking at, I believe, A-2, I think.

Q Yes, sir. When you originally were discussing this exhibit today you showed the grey zone and you referred to that as being perhaps not productive or marginal, and I think that the exhibit itself calls that marginal.

Then you get a white area beyond that that's not colored in at all. I wish you'd talk about this a little bit more. Why do you call this marginal? What chances do you see for any development across the unit boundary?

A. Well, the two rows of sections just outside the unit, which are the western two rows on the map, are the western two rows of sections in the pool, and --

MR. VERITY: The previous -- excuse me, the previous map shows that.

A. And so the pool boundary does extend that far and in our initial -- of course the pool boundaries were set years ago, but they pretty well cover what seemed to us at that time, and still seem to me, to be areas that could be productive. The question is, is it commercially productive, and my feeling is that wells of some character will probably be -- can be drilled in that area, and we just didn't color the grey area all the way out to the white. That does not mean that we think it ends right there.

There are wells producing from this formation back over here, oh, ten miles or so away, small wells, 2, 3, 5, 10 to 15 barrels a day.

Q. Ten miles to the west?

A. Yes, I think something like that, 8 to 10 miles. I would think the whole area between those wells

and the unit will have some kind of productivity, and the issues that you run into is how far west you go before you run out of the high capacity system and at what point do you reach wells that are not commercially productive of the -- out of this zone alone.

Q. I see a dry hole over there, several dry holes. One in Section 7 of 25 North, 1 West; a couple more in Section 18; and then another well in 24 North, 1 West, Section 9. Were those wells attempted to be completed in this --

A. No, sir, they did not penetrate the formation. The problem -- perhaps it was a mistake to show them on there.

Where we've shown a well and a datum in parentheses, that means a datum that we've projected from a shallower formation, and I would say that we can only -- only approximate the structure from those shallow wells. They're generally conformable but not strictly conformable.

The only way we really can tell a structure is to drill additional wells, but those -- all these other wells that show on the map are from some other formation.

There has been one well drilled about a mile off the map. I think it shows +300 in the southwest quarter of 25, Section 25, up in Section 30 of 26 North, 1 West, we have that notation.

That's the nearest absolute control that we have.

Q. Now you were discussing the potential for compulsory unitization of this area to the west. I believe you indicated that you felt that lacking any development of those sections it would be impossible to develop what you would need to bring an application before the Commission or the Division, is that correct?

A. Yes, as we understand it, we can't ask for statutory unitization until there's something to -- some wells to talk about. Perhaps I'm misunderstanding the law.

Q. Well, assuming that you're correct, then, how quickly after an operator drilled a well outside the unit area do you think you would have the data that you would need to ask for compulsory unitization?

A. Well, in this regard we've written a letter to -- to the USGS, since it's mostly Federal land, we sent a copy, I believe, to the Commission, setting out our thoughts in this matter, and that is that if a well is drilled on the unit boundary that's productive, that certain tests be made to determine whether the well is in communication or not. One of the tests would be, of course, a shut-in bottom hole pressure test, and of course we went beyond that to suggest that in the event a well is drilled and found to be in commun-

ication with the unit, that the USGS require it to be shut in until the statutory unitization has taken place.

Of course, whether they would grant that or not we don't know, but we've asked for it.

Q. Okay. Getting back to the question now.

A. I'm sorry.

Q. How -- how long after a well is drilled and completed across the unit line do you think it would take you to develop the information you would need to bring a statutory unitization case relative to that well --

A. Okay, sir.

Q. -- and proration unit?

A. Okay, sir, what we've done is to ask that the USGS get this information. We put that information in writing. We ask that they get a productivity test and a shut-in bottom hole pressure test, and we've indicated that it could take two or three months to get that information from that well. But the instant that we know that it's in communication with this reservoir, then we would apply for statutory unitization.

Q. So what are we discussing, three or four months?

A. I would hope that that's all that we're talking about.

Q. And assuming it would take another couple of months, or maybe three months, to process the application and get an order out, you're looking then at six to seven months after completion before that well would be in the unit.

A. Yes, sir.

Q. Do you anticipate that your unit could be harmed to the degree that you discussed earlier in your testimony?

A. It depends, of course, on particularly how much gas the well is making, but in that regard and for that reason we've asked that the well just be shut-in until it's unitized.

Q. Assuming that the Geological Survey would not cause the well to be shut-in and expecting, too, the types of wells that you're anticipating in here, marginal wells, do you believe that in that six to seven months we were talking about, that your unit could be harmed to the extent that you described?

A. If they get a small well, 10 to 20 barrels a day, 30 barrels a day, a small volume of gas, then we've indicated earlier, it's just a parasite. We could support a parasite for, and a number of parasites for quite awhile

and probably not be disastrous.

It's just a question --

Q. And assume they get a top allowable well in this area, 600 and some barrels a day, in six months, seven months, would that irreparably harm the unit?

A. Yes, sir, it would, it would harm it. It would not harm it, perhaps, to the extent of the 90 percent that we've discussed is going to happen all the wells up, but a top allowable well making its volume of gas, which is three times what we're buying now, the make-up gas, would seriously drop the reservoir pressure, would seriously affect the production and waste, yes, sir.

Q. And I believe the thrust of your testimony was if they got one of these good wells it would pay off rapidly and the well would be paid off before the six or seven month period was up.

A. If they get one of those high capacity wells that produces at high capacity, it will pay out in 10 days.

Q. And under those conditions, even facing compulsory unitization, would there be any impetus for the operator to hold back on his operations even expecting you to pool him?

A. We've got a real problem there when

somebody's taking $100,000 of your production out of the ground every day, sitting back and being calm and relaxed and waiting for -- for orders and times, if the USGS would refuse to shut it -- I just don't believe that the USGS would refuse to shut it in. I don't know.

We've -- in this present case, if these people stake wells 660 feet from our line and -- and there's no restriction as far as the Commission's concerned in their drilling, we've asked the USGS not to approve their location until this hearing was held, and I don't know what's been the outcome of that, whether they've tried to go ahead and the USGS has denied that or not, I don't know, but I presume that that's the case.

And I would also presume that they would not allow a well of that type to produce. I just don't believe they would.

MR. STAMETS: That's all I have.

CROSS EXAMINATION

BY MR. RAMEY:

Q. Mr. Greer, as I understand now, you want a 1650 location from the west line of the section.

A. Oh, no, sir, our application is that the wells would be drilling in the west half of sections and

no closer than 1650 feet from a line. My thought was there would be about a 660 foot window, about a 10-acre window, to drill in.

MR. HUNKER: From the line, you mean a section line.

A. From a section line, uh-huh.

Q. 330 feet from --

A. From a quarter section line.

Q. And what were the restrictions on the bottom hole locations?

A. We were suggesting that they be not more than 330 feet from the surface location. Again, if -- this is something that we're perfectly flexible on. As long as they keep the well in the west half of the section we don't care if it deviates 1000 feet, if they'd just back off that 1000 feet before they start to drill. As a practical matter I think they can keep the wells within 330 feet by using reasonable care, but the problem we're concerned with is if, by happenstance or whatever, we try to live under the Commission's standard rules, that we just might not be protected.

Q. Do you have any -- did you take any directional surveys on any of your wells?

A. We've run directional surveys in this formation, not in these particular wells, but we do, of course,

have all of the deviations that were taken and where we have run directional surveys in this formation, they've always been if the dip is to the west, the wells have always deviated generally to the east, perhaps a little bit north of the east or south of the east, but they've been to the east.

Q. So in effect you would require the drilling of any wells to maintain some -- something under a two to three degree deflection?

A. Overall average, but if they're diligent, you know, they can start out at the top of the hole with a fairly straight minimum deviation, gradually increase to the bottom, so they could be out five degrees at the bottom and still be within a 330-foot distance easily.

MR. RAMEY: Mr. Nutter?

QUESTIONS BY MR. NUTTER:

Q. Well, Mr. Greer, how would you propose the situation be handled where someone drilled at your proposed orthodox location but the well drifted more than 330 feet to the east?

A. Well, they're in violation. Of course, if they have tried to keep the hole straight and if the deviation is not much beyond the 330 feet, why, we're not going to be unreasonable about that.

Q. Well, supposing they file a drilling, a completion report and we find that the well was drilled in the west half of the section, 1650 feet from the west boundary, and it had drifted 660 feet east instead of the 330, what would be the procedure for approving the well for production?

Have you given any thought to that?

A. Yes, sir, I have. If there's a requirement to be 330 feet from the surface location, I believe that they would -- I assume they would attempt to keep the hole straight a far greater -- there would be a more defenite pressure on them to keep the hole straight than if they're just looking at the standard five degree maximum deviation that's in the regulations now, and what should take place if they go ahead and violate that, I don't know. I guess that's up to the Commission. The standard procedure of reducing the allowable of wells if they drill closer to a line than the regulations call for just does not protect correlative rights.

Q. So the penalty --

A. The penalty --

Q. -- the penalty would not do you any good.

A. The penalty would be no good. If the allowable is 640 barrels a day, what if you penalize them 90 percent, down to 60 barrels a day, that's the average production rate of wells in the pool now, so there is no penalty; even

a ninety percent penalty is no penalty.

Q. Well, if it was penalized to where it would produce ten percent of 60 barrels, that would be a penalty.

A. Right, if it -- if it were penalized in that respect it would. If the penalty could be so written that it's -- that it penalizes the well based on its productivity, yes.

Q. But you haven't formulated or made any recommendation as to the mechanics of handling this thing?

A. No, sir, I would just hope that the operators would drill straight holes.

MR. NUTTER: That's all, thank you.

MR. RAMEY: Any other questions of Mr. Greer?

MR. VERITY: Just a minute, Mr. Examiner. Would you please mark that as Exhibit Three?

(The reporter marked Exhibit Three for identification.)

REDIRECT EXAMINATION

BY MR. VERITY:

Q. Mr. Greer, I direct your attention to what the reporter has marked Exhibit Three and skipping the

index at the front of it, would you turn to Section A?

This exhibit is in part -- in Section A through E, and I direct your attention to Section A. Would you please explain the first page?

A. Yes, sir.Now we'd like to talk a little bit about efficiency of -- in a gravity drainage depletion process in conjunction with pressure maintenance, and point out just a couple of fields that exemplify this. We realize that there are not a lot of them that have this kind of production, and the first thing we'd like to look at is the little graph under Section A,marked Figure 12.

This shows the increase in recovery by depletion at high pressure compared to depletion at low pressure, and this just simply shows that when a reservoir is depleted, we will find at the end of production that there's a certain liquid saturation in that particular kind of a reservoir.

Now that liquid saturation is going to depend on a number of things, but one of them is the viscosity and at higher pressures you have lower viscosity and there'll be less liquid left in the reservoir which means you produce more.

It's a little bit hard to measure that but we do know that it is a factor and a significant factor.

Another factor is just the fact that under depletion at high pressure the oil that's left in the ground is swelled with gas that's dissolved in it, and so if at the end of a depletion cycle in a reservoir 50 percent of the pore space is saturated with liquid in that solid oil as compared to the same reservoir at depletion with 50 percent liquid saturation but the oil is swelled with gas, then that means that you -- there is less oil left in the reservoir, which means you have produced more, and the approximate amounts here are shown depending on what the final liquid saturation is. If it's only 30 or 40 percent then the increase in recovery is only like 10 or 15, 20 percent.

If, however, you're looking at 60 or 70 percent at depletion, then perhaps as much as 50 percent more can be recovered by depletion at high pressures compared to low pressures.

The significant thing here is that particularly for the tight blocks where we may not recover the same -- or be able to deplete to the same liquid saturation that we do in the high capacity system, there could be 60 or 70 percent oil saturation that -- at depletion, and if so, if that 60 percent of oil that's left is swelled with gas still in there kept under because we depleted at high pressure, we have recovered maybe 50 or 60 percent more oil than we

otherwise would have.

Now this is -- this compares, for instance, with gravity drainage under low pressure and gravity drainage at high pressure. And so this gives one of the reasons why it's important to maintain pressure and get as much oil as we can out of the ground at high pressure initially.

Q. Proceeding then to the Section B of this Exhibit Three?

A. This is a paper that was published in the Journal of Petroleum Technology just ago. The thing that caught my eye was this part that's highlighted in green on page 1605, the first page. 102 to 116 feet of pay, which is an average of 109 feet of pay, with 62 millidarcies permeability, and as we show in the figures in red on the side, that's 6.8 Darcy feet. Now that's very close to the transmissibility that we have in Canada Ojitos; that caught my eye.

Also it's noted that although it's sugary limestone, it has limited fractures.

If you'll turn to page 1607, highlighted in green at the bottom of th page, "Recovery efficiency in the gas-invaded volume is 50 percent as compared to 20 to 25 percent in the water-invaded volume. Now this is a field that has a water drive but they imposed a pressure maintenance by gas injection in the crest of the structure.

And strangely enough, they have found that they're getting a higher recovery with the gravity drainage and the gas injecton than they did through the water-invaded part of it. In fact it's so significant they've shown it in the next page, 1608, and the plat at the top shows where they're now expanding the gas cap back in and pushing the water, which had already invaded part of the structure. They're now injecting gas and forcing that water back out because of getting higher recovery of gravity drainage with gas by pressure maintenance than they did by the water drive.

Now this being true, the highlighted part that's marked in green "that the critical rate with gas displacement is very low compared with that in the case of water...". This compares to what I've referred to as channeling potential in that you have less channeling potential where you have gas injection as compared to water injection.

Q. Proceeding now to Section C.

A. Section C is information on the Empire Abo Pool, and I would point out that in New Mexico now about half of our production comes from secondary recovery projects and of that half approximately 1/3rd comes from gravity drainage fields with gas pressure maintenance, and of course most of that is Empire Abo Pool.

We show here the characteristics of

permeability versus porosity for the Empire Abo Pool on this figure marked 3-3. As we indicated earlier, if you have a reservoir with characteristics which fall below the range for sandstone, you have possibly a candidate for gravity drainage and the reason is, as indicated here, in round numbers for the same transmissibility there's -- same permeability -- there's 1/4th as much oil in place in the Empire Abo type reservoir as in an ordinary sand for the same pay thickness.

And what that means is, for instance, if it would take 160 years to get the oil out of a sandstone by gravity drainage, well, the Empire Abo type reservoir with the same dip and same oil, you could get the oil out in 40 years, and that's about what they're doing.

So just at first blush when we look only at permeability and porosity we realize that Empire Abo is a good candidate for gravity drainage.

Then we look at the next graph and we can compare the Empire Abo rate of gravity drainage in terms of barrels per day per linear mile along the strike, it's very nearly the same as Canada Ojitos. And we see for instance that about 10 Darcy feet, which is about what you have in the Empire Abo, something like 3000, maybe 4000, barrels per day per linear mile along the strike is the gravity drainage potential. It's about 12 miles long so they've got 30 to

40,000 barrels a day gravity drainage potential.

Now what that means and without even studying or knowing very much about Empire Abo, we know that if the production rate is restricted to less than 30 to 40,000 barrels a day, and it was initially by proration, substantially less than that, that there's going to be a lot of gravity drainage in Empire Abo, bound to be, and there's so much oil in place there, there's such a high -- high volume of oil that they don't even need pressure maintenance to get a high recovery. All that Empire Abo needed was a reasonable rate of production, a reasonable limiting gas/oil ratio and Empire Abo would have a good recovery, 40 or 50 percent of the oil in place.

Now despite the fact that they really didn't need unitization and pressure maintenance, nevertheless the Empire Abo people got together, did unitize, did inject the gas and are injecting the gas, and they've increased their efficiency. It's my understanding they expect 57 percent recovery, and what they're doing there is the same thing we're doing in Canada Ojitos. It's just that they have a lot more to work with than we have.

The comparison of that, of oil in place, is shown on the next graph, which we looked at earlier for oil in place versus transmissibility, and in round numbers

we can see that the Empire Abo Pool is up around 40 to 50,000 barrels per acre in place compared with our 1 to 2000 barrels per acre in place in Canada Ojitos.

Q. Proceeding now, Mr. Greer, to Section D of Exhibit Three.

A. Section D, we're still dealing with efficiency of this method of production that we're carrying on in Canada Ojitos.

We refer now to the C-34 Well, the one whose gas/oil ratio increased to 10,000-to-1 and then we continued to produce it at a high gas/oil ratio.

Since its gas/oil ratio increased in 1974 the well has produced about 213,000 barrels of oil but the pressure drop during this time is about 50 pounds and in a range of about 1300 pounds to 1250 pounds. We show on the graph on the left with that pressure drop of about 50 pounds that about 0.2 percent of the oil could have come from solution gas drive. So if that well is receiving production from solution gas drive, then it would have to be as shown in line five, 100-million barrels in place, about the most that this well can be draining because we have pressure up-dip from it forcing the oil and gas down-dip, it might be 10 sections, which would be 10-million barrels an acre or 16 -- I mean per section, or 16,000 barrels an acre, which is about 10 times

as much as the reasonable estimate.

So the only thing we can conclude from this is that the depletion process is something other than solution gas drive. It has to be either gas drive by pressure maintenance or gravity drainage, and it's a substantial amount of oil.

Q. Next Section F of Exhibit Three, will you explain it?

A. Yes, sir. We show here one of the problems with this area to the west of Canada Ojitos, that if it has low transmissibility, like I think the information now suggests, whereas we're looking at high gravity drainage rates in Canada Ojitos, this area to the west probably will have pretty low rates. The rates are shown for 100 and 200 feet, 400 feet, per mile, with the various transmissibilities.

In the center of the graph the transmissibility is 0.1 of a Darcy foot would give a productivity of 50 to 350 barrels a day, a well would make somewhere in that range, but its gravity drainage potential is only 3 to 7 barrels per day per linear mile along the strike.

And what this means is that the wells to the west of the Canada Ojitos, all they can do if they're productive is to help deplete Canada Ojitos more efficiently. They're not going to contribute much of their own from their

own section. There's no way they can. All they can do is contribute solution gas drive recoveries.

MR. VERITY: We offer Exhibit Three.

MR. RAMEY: Exhibit Three will be admitted.

MR. VERITY: You may cross.

MR. RAMEY: Any questions? Mr. Greer, you may be excused.

Let's take about a fifteen minute recess.

(Thereupon a recess was taken.)

MR. RAMEY: The hearing will come to order. Mr. Carr?

MR. CARR: At this time I would call Richard M. Luce.

RICHARD M. LUCE

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Will you state your name, please?

A. Richard M. Luce.

Q. Where do you reside?

A. Denver, Colorado.

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

A. I'm employed by Koch Exploration Company, a division of Koch Industries, as a geologist.

Q. Have you previously testified before this Commission and had your credentials accepted and made a matter of record?

A. No, I have not.

Q. Will you briefly summarize for the Commission your educational background and work experience?

A. I graduated from Michigan Technological University in 1976 with a Bachelor of Science degree in geological engineering.

I went to work for Tenneco Oil Company in Denver, Colorado, in June, 1976, as a geological engineer. I worked with Tenneco for two and a half years; the majority of that time was spent as a development geologist, working in the San Juan Basin area. For approximately the last two

years I've been employed by Koch Exploration Company as an exploration geologist in a number of areas, among which include the West Puerto Chiquito area.

Q. Are you familiar with the area which is the subject of the Benson-Montin-Greer application in this case?

A. Yes, I am.

MR. CARR: Are the witness' qualifications acceptable?

MR. RAMEY: Yes, they are.

Q. Have you prepared for introduction in this case certain exhibits?

A. Yes, I have.

Q. Will you please refer to what has been marked for identification as Koch Exhibit Number One, identify it for the Commission, and explain what it shows?

A. This is a structural contour map on the top of the Niobrara formation in the area that we're interested in. It shows the Niobrara penetrations in this area, shown by green dots, and is contoured on 100-foot intervals.

Q. Is Koch's acreage indicated?

A. Yes. The Koch acreage is indicated by the -- the various patterns here in the western portion of Township 25 North, Range 1 West, and Township 25 North, Range

2 West.

Q. Has Koch staked a location in this area?

A. Yes. Koch staked a location in the southeast quarter of Section 8, 25 North, 1 West, at 660 feet by 660 feet from the south and east lines.

Q. Now in contouring the Niobrara, how much control have you had?

A. Well, to the eastern area there's quite a bit of control. As you go outside of the Canada Ojitos Unit to the west control becomes fairly limited. The structure that we've indicated here, there's a synclinal nose trending north-northwest down through this area, and with a possible structural -- possible structure and structural closure anticlinal to the west of our area with -- with our location possibly showing an eastward dip.

Q. Now where you have staked, in your opinion would this be a development well?

A. No. Koch considers this a high risk area and a step out of a mile or a mile and a half in this type of a play we feel is a wildcat situation. As I said before, it's a high risk area. We feel that this is in a different structural setting by matter of degree than -- than the Canada Ojitos Unit. In the area that we're looking at we probably have dips of less than 100 feet per mile, whereas

the western part of -- or the western tier of wells there has dips of anywhere from 200 to 400 feet per mile in -- within the unit.

MR. VERITY: To which we object, Your Honor. If I understand,counsel, he's now endeavoring -- the witness is now endeavoring to say this is not in the Canada Ojitos common source of supply?

A. No, sir, I'm not saying that. I'm just saying that the structural setting by matter of degree -- the amount of flexure that is involved, that we suspect is involved in the area that we're concerned with, that is, the area where our acreage is, is probably less than the amount of flexure, and probably the density of fracturing, that Mr. Greer feels the unit has seen to the east.

MR. VERITY: All right, we'll let you off; we'll withdraw our objection.

Q. In drilling the well which you have staked, which is indicated by the red dot, what would the primary objective be in drilling that well, the Niobrara?

A. The Niobrara is the primary objective that Koch's concerned with at this time, although within the area there are three other secondary objectives that are productive within this general area. Most significant of those is the Pictured Cliffs formation which produces, oh, about

three miles to the west and southwest in the Gavilan Pictured Cliffs Field.

Additionally, we feel that potential horizons would include the Mesaverde and Point Lookout formations, which produce approximately eight to ten miles up to the northwest, and the Dakota formation, which lies -- from which there is production to the west, seven or ten miles, something like that.

Q. Is there anything else you'd like to testify to from this exhibit?

A. Not at this time, I guess.

Q. Would you now refer to what has been marked for identification as Koch Exhibit Number Two and explain to the Commission what this is and what it shows?

A. This is just a type log from an area well. Specifically the well is the Cyprus (sic) Bolack No. 1, which was drilled in 1952 in Section 9 of 25 North, 1 West. It was completed as a dry hole at the time.

Basically what we want to show with this well -- with this type log are the other potential producing horizons on the left half of this exhibit, the Pictured Cliffs formation. Also on the left, the Mesaverde and Point Lookout formations. On the right side of the exhibit the Niobrara zones that we're interested in and that the Canada Ojitos Unit

is productive from. The Juana Lopez, which has been completed in a number of wells, although I'm uncertain as to its productivity, and the Dakota formation, which is also productive, like I say, within this general area, and I use that in kind of a gross sense.

Q. And what conclusions can you reach from the two exhibits you've presented?

A. Well, one of the things that Koch is definitely concerned about is being able to develop an area that we feel -- or go about development such that we can complete multiple objectives within a single wellbore, if we're so inclined, and if we, you know, have those potentials.

Q. And in so doing do you need the greatest flexibility possible within reasonable Commission rules?

A. Yes. We -- we feel because this is a wildcat area we need to maintain as much flexibility as far as where we can place our locations as possible until we're able to determine what potential lies within this area.

Q. Were Exhibits One and Two prepared by you or under your direction --

A. Yes.

Q. -- and supervision?

A. Yes, they were.

MR. CARR: At this time we would offer

Koch Exhibits One and Two.

MR. RAMEY: Koch Exhibits One and Two will be admitted.

MR. CARR: I have nothing further on direct.

MR. RAMEY: Any questions of Mr. Luce? Mr. Verity?

MR. VERITY: Yes, please, Your Honor.

CROSS EXAMINATION

BY MR. VERITY:

Q. Mr. Luce, if I understand your Exhibit One, and I don't believe mine has the colors on it yours did, but let me ask you, what were your contours on?

A. On the type log the purpose was to identify the Niobrara A zone.

Q. We're talking about Exhibit One, right, your Exhibit One?

A. Yes. Yes, sir. My Exhibit One is contoured on the horizon that's shown on Exhibit Two as the mapped horizon, the Niobrara A -- the top of the Niobrara A zone.

Q. And then where -- where do you get your contours over in 2 West under 5, 6, and 7?

A. That is inferred from the existing contours, or the existing data points to the north and to the south. And also then we went ahead and used some Isopach values from an exhibit that we had -- or from the map that we have now submitted as an exhibit to give us some estimation for the 25 North, 2 West area, since there are no data points.

Q. You have no -- you have no data points whatsoever on the Niobrara, do you, to swell this 400 foot contour way back up north and out to the west and down, and putting that 500 foot closure in there?

A. Well --

Q. There are no Niobrara points in there, are there?

A. No, sir, there are not, but as any geologist will attest, a given set of data points can be contoured in any number of different ways, and we feel that this is a possible representation of what exists.

Q. You said you needed flexibility because you might be looking at another zone. What other zone do you think you will encounter, or are you anticipating you might encounter, in the drilling of the well that you have staked in the east half of Section 8?

A. Well, sir, we don't, as I say, these are -- these other objectives that we have listed are secondary

objectives, although we feel that there is some fair potential by proximity in the Pictured Cliffs formation.

Q. Well, those zones could be just as well encountered in the west half of that section, could they not?

A. Well, that's true, but subsequent -- subsequent wells, we might not have the option to drill the Niobrara, and we do feel the Niobrara is the major objective in this area.

Q. Well, but you said you need flexibility because there were other zones that you might -- you might like to drill to, and my question is, those zones are just as likely in the west half of the section as they are in the east, are they not?

A. I'm sorry, could you repeat that, sir?

Q. You say you not only -- you say you want to drill this well where maybe you can find something other than the Niobrara well, right?

A. Well, we want to -- we want to be able have that option, yes, sir.

Q. Okay, and in Section 8 you have just as good an option in the west half, or maybe better, if I understand your contours, than you would in the east half of Section 8, isn't that true?

A. Well, I don't know that there's enough

data to discriminate between the two, so ....

Q. So it really wouldn't make any difference, east half or west half, would it, from that standpoint?

A. Not on a single well basis, but overall we feel that undue restrictions in the long term will probably hurt our potential for being able to evaluate multiple objectives.

Q. Now, you also said that you felt maybe this was going to turn back up and be going back uphill instead of being from east to west dip. What is there in the data that you've got on the Niobrara that leads you to believe that the dip here is going to reverse itself and go from west to east instead of continue from east to west?

A. Well, sir, if -- if we accept the -- the idea that this map is reasonably accurate, then to go from say, Section -- say Section 13 in 25 North, 2 West, to the east, and we're not really, you know, the data is not so closely controlled that we couldn't -- we couldn't expect that to shift with the addition of a data point. We do indeed show east dip.

Q. So what you're saying is there's a great amount of conjecture in that you really don't have any kind of a firm opinion about reversing the dip.

A. Well, sir, we feel that this is the best

representation of the data that is available. I might add that a structure map of the Pictured Cliffs area in this -- the Pictured Cliffs in this area does indeed show a structure in this general area, and we feel that it's quite reasonable that this may carry through to the Niobrara level.

Q. The relationship between the Pictured Cliffs and Niobrara is only general and not specific, is it not?

A. Well, across the area in the wells that have penetrations you can determine the interval -- thickness of an interval, and that is reasonably consistent throughout the area.

MR. VERITY: That's all.

MR. RAMEY: Any other questions? The witness may be excused.

MR. CARR: At this time I would call John Carraway.

JOHN CARRAWAY

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Will you state your name and place of residence?

A. John Carraway, Wichita, Kansas.

Q. Mr. Carraway, by whom are you employed and in what capacity?

A. I'm employed by Koch Exploration Company. I am the Engineering Manager for the Rocky Mountain Division and Off-Shore Division.

Q. Will you briefly summarize for the Commission your educational background and your work experience?

A. I was graduated from the University of Virginia in 1965 with a degree in electrical engineering.

I went to work for Exxon Company, U.S.A., and worked for them for approximately ten years as a petroleum reservoir engineer. Part of that time I spent in New Mexico and I have testified before the Commission in 1969. I've also testified before the Railroad Commission in Texas.

After about ten years with Exxon I was employed by Koch Exploration Company and I've worked for them for five years now as a petroleum reservoir engineer.

Q. Are you familiar with the area which is the subject of the Benson-Montin-Greer application?

A. Yes, I am.

MR. CARR: Are the witness' qualifications accepted?

MR. RAMEY: Yes, they are.

Q. Mr. Carraway, will you please refer to what has been marked for identification as Koch Exhibit Number Three, identify this, and explain what it shows?

A. This exhibit shows acreage which would be drillable in a given section under the current rules and also under Mr. Greer's proposed rules.

Under the current rules we can drill 660 feet from the section line, 330 feet from a quarter section line, and 10 feet from a quarter quarter section line, which gives us roughly 250 acres within a section that is drillable.

Under Mr. Greer's proposed rules we are limited to the red area there, which is 1650 feet from the section line and in the west half of the section only. That's only 20 acres out of a 640 that would be available for drilling under his proposed rule.

The cross hatched area on there, of course, is the area that represents that 250 acres under the current rules.

Mr. Greer has devised his proposed rules to deal with what he purports to be a development situ-

ation along the west unit boundary. Mr. Luce has testified that this is not the case; that drilling west of the unit entails substantial risk and is far more exploratory in nature than developmental.

I will show in exhibits to follow that Mr. Greer has also considered this area very risky and the restrictive spacing rules that Mr. Greer now proposes are not in keeping with the exploratory nature of the play.

And that's all with regard to that exhibit.

Q. All right. Will you now refer to the topographical map? This is marked for identification as Koch Exhibit Three-A, and identify this and explain what it shows?

A. This is a reproduction of the USGS topographical map of the area on which I've indicated the Canada Ojitos Unit boundary and also the existing wells within the unit. I would ask that you ignore the orange shading on the area to the west of the unit there for the time being. I'll be referring back to that later in my testimony.

The entire area lies within the Santa Fe National Forest, and as Mr. Greer has previously testified, the area is extremely rugged and it's also environmentally sensitive.

As you can see, most the existing unit

wells were drilled within the canyons and along existing roadways in order to minimize the impact of drilling on the forest.

Mr. Greer's proposed rules would deprive us of the flexibility he enjoyed in drilling the existing wells and would require that almost every well drilled be an exception location for topographical reasons.

Every existing well in the unit, save one, which is the K-13, I believe, would be an exception location under Mr. Greer's proposed rules. The flexibility of the current rules is urgently needed in order to develop this well with minimum damage to the forest.

That's all with regard to that.

Q. If you are required to develop this acreage under Mr. Greer's proposed rules and are unable to get the unorthodox well locations that you might need for topographical reasons, what impact would this have on the cost of development?

A. Well, it would greatly increase the cost involved and also greatly increase the damage to the forest.

Q. Will you now refer to what has been marked for identification as Applicant's Exhibit Number Four, identify this, and explain what it is?

A. I think this next exhibit is probably

becoming fairly familiar at this point. It's a reproduction of an exhibit which was offered by Mr. Greer in Case Number 6997, heard August the 7th, 1980, before Mr. Nutter. That's the hearing that led to the current 660-foot spacing rule.

I have reproduced all of Mr. Greer's testimony at that time which dealt with this exhibit for your convenient reference. I do not propose to read his testimony as it is somewhat lengthy, but the gist of his remarks was that the Niobrara is probably most heavily fractured in the areas of flexure where the dip of the formation east to west changes abruptly.

Where the dip rate is uniform there is little fracturing, little porosity, and little permeability. Mr. Greer pointed out that the best wells are those that are drilled in the green and the brown areas and then went on to point out that the area shaded grey and westward is an area of minimum flexing and little potential for porosity and permeability development.

My purpose in introducing Mr. Greer's testimony is not to disagree with the geological hypothesis that he describes, for we buy it ourselves, but to show that he as unit operator has regarded the area west of the unit as having little economic value, and to show why he so regards it. In fact, at no time during the past fifteen years of unit oper-

ations has the unit operator indicated any interest at all in trying to extend the limits of production westward.

Q. Will you now refer to Applicant's Exhibit Number Five -- or to Koch Exhibit Number Five.

MR. VERITY: I thought that was Exhibit Number Five.

MR. CARR: No, sir, that was -- that was Number Four and Number Five is the letter. Do you have those, Mr. Verity?

MR. VERITY: Well, I've got four -- I've got five exhibits that you've put on.

MR. CARR: We said that the topographical map was Three-A.

MR. VERITY: Oh, I beg your pardon. Thank you.

MR. CARR: Okay?

MR. VERITY: Yes, go ahead.

Q. Will you now refer to Exhibit Number Five, which consists of certain letters and review this for the Commission?

A. This exhibit is a copy of a letter written by Mr. Greer on August the 28th, 1980, to Koch Exploration Company. Mr. Greer transmitted with this letter the letter dated April 30th, 1980, which he sent to the working

interest owners of the Canada Ojitos Unit.

In this April 30th letter he sets out, among other things, the policy of the unit over the years regarding the area west of the unit. I'd like to direct your attention to page one of attachment four, which I've highlighted. It's a page about halfway through the letter. Page one of attachment four, and I'd like to read a portion of that for you, the part that I have highlighted.

This attachment four is entitled Assurance of Efficient Depletion of the Existing Canada Ojitos Unit Participating Area Presently Developed Reservoir.

"Further, to insure that there be no external influence in the pressure maintenance program and that we could exercise proper control over the production from wells completed in the reservoir, we undertook particular measures as to certain areas."

He then talks about the area to the south and east, the area to the north, and then under item three, the area to the west, which I would like to read again.

"To the west we maintained a strong leasehold position until development of the westernmost wells confirmed our geological hypothesis that this area would probably be marginally productive, at which time we either dropped leases or let them expire as their terms ran out, except for

those lands lying in and north of Sections 5 and 6, 25 North, 1 West, which lands we felt held the most promise, if any there be, for this west area."

So if you'll refer back to the topographical map you will note that the sections 5 and 6 that he refers to in this letter are north of the acreage that Koch has an interest in, and that's an area where he still retains a leasehold interest.

My point again is that Mr. Greer and the unit had never been interested in the west area and have in fact dropped leases in the area over the years.

Further, Mr. Greer's feeling about the area has not changed recently with the advent of higher oil prices.

Directing your attention again back to the topographical map, I have shaded those areas west of the unit which have been offered in recent KGS sales and in Township 25 North those areas west of the unit which have been offered -- those areas which have been offered west of the unit since 1978 in which we have indicated -- we have bought our interest and Benson-Montin-Greer has indicated no interest. They have bid -- they have not bid at all on any of those KGS sales. There's been three of them, I believe.

There has been additional acreage which

has been up south of Township 25 but I have not colored that in because Koch has no interest in that area.

So I think it's significant that Mr. Greer is still not indicating an interest in the west area and that he did not bid on any of these leases which came up in the recent sales.

Q. Will you now refer to Exhibit Number Six and review this for the Commission?

A. The following remarks deal with Mr. Greer's proposal that the bottom hole location of future wells needs to be held within 330 feet of the surface location.

The exhibit before you is just for your convenient reference, a copy of statewide Rule 111, which deals with deviation tests and with directional drilling.

The rule provides that the Division director may require directional survey whenever a well deviates more than 5 degrees from vertical in any 500-foot interval.

The next exhibit --

Q. That's Koch Exhibit Number Seven.

A. The next exhibit is a wellbore sketch which I made to show what I estimate to be the maximum deviation of a well which would not be subject to the requirement of a directional survey under statewide Rule 111. In other

words, I believe that any well which deviates more than this will necessarily exceed five degrees and be subject to the directional survey requirement. The maximum deviation of this well is 394 feet, or roughly on the same order of magnitude of Mr. Greer's 330-foot proposal. Aware that much more than Mr. Greer's 330-foot deviation cannot be drilled without the Commission and Mr. Greer's knowledge, Mr. Greer and the Commission could then take whatever steps they deemed appropriate. To require that wells be held within 330 feet is simply unnecessary, as the statewide rule is fully adequate to protect offset interests and the proposed rule, obviously, could result in substantial increased well costs.

Q. Mr. Carraway, would you now refer to Exhibit Number Eight and explain what it is and what it shows?

A. This is my final exhibit, which simply summarizes my argument so far.

Mr. Greer's proposed 1650-foot spacing rule is far too inflexible for the rugged terrain and sensitive environment. The present rule provides the flexibility which is needed.

Mr. Greer's proposed rules were devised to deal specifically with a possible but unlikely drainage situation along the west unit boundary. Our testimony, and that of Mr. Greer on previous occasions, has shown that the

play to the west is far more exploratory than development in nature. The proposed rules are totally inappropriate to the exploratory nature of the play.

Mr. Greer and the unit interests have shown no desire during the past fifteen years to extend the limits of Niobrara production westward. They consider the area uneconomic and still so consider it. We, and others, are willing to take the necessary risk and we believe that we should be allowed to do so without further delays from Mr. Greer.

We respectfully request that the Commission not rule in favor of Mr. Greer's proposal and that the pool rules be left as they now stand.

Q. Mr. Carraway, in your opinion would granting the application of Mr. Greer impair your correlative rights by denying you necessary flexibility to develop your leases in an efficient fashion?

A. I believe they would.

Q. Would denying the application in your opinion promote development of the area?

A. Would denying it promote development?

Q. Yes.

A. Yes, I believe it would.

Q. In your opinion would denying the appli-

cation be in the best interest of conservation?

A. Yes, I believe it would.

Q. Were Exhibits Three, Three-A, Four through Eight prepared by you or under your supervision and direction?

A. They were.

MR. CARR: At this time we would offer Koch Exhibits Three, Three-A, Four through Eight into evidence.

MR. RAMEY: Those exhibits, whatever you said, will be admitted; Three, Three-A, Four, Five, Six, Seven, and Eight.

MR. CARR: That's correct.

MR. RAMEY: Any questions of Mr. Carraway?

MR. VERITY: Yes, Your Honor, we have a few.

CROSS EXAMINATION

BY MR. VERITY:

Q. How much does Koch -- do you know what your company has invested in leases in the area to the west of the Canada Ojitos Unit?

A. I don't know.

Q. Would it be fair to say it's been a

considerable amount of money?

A. Yes, it would.

Q. Do you know how much it will cost to drill a well where you propose to drill it in Section 8?

A. Approximately, I think.

Q. Approximately how much?

A. I would say $700-to-$800,000.

Q. Well, obviously you folks don't mean to drill that without the hope of making money on it, do you?

A. Obviously.

Q. And so irrespective of what someone else thinks, you think it's a good place to drill a well and that it will be productive or you wouldn't be drilling it.

A. We think it's worthy of the risk, yes.

Q. And you're willing to spend $800,000, or possibly a lot more, to do that.

A. Well, some more, yes.

Q. Okay. In addition to that, you think it might be a good well, don't you?

A. We would hope so.

Q. And you would hope that you would hit a point of flexure. You said you didn't disagree with Mr. Greer's concept that the Niobrara produces the greatest at the points of flexure.

A. Well, we would hope to find a point -- we would hope to find fracturing, obviously.

Q. That's right, and you --

A. We are somewhat concerned, just as Mr. Greer is concerned, that it's going to be tight, also.

Q. Everybody can drill a dry hole, can't they?

A. Yes.

Q. And you might drill one here, but what you plan to do and what you hope to do, is to reach a point of flexure where you find a fracture system to enlarge it.

A. We hope to drill an economic well.

Q. That's right, and you hope that you drill a large well, don't you?

A. Obviously.

Q. Now, if you get a large well and you're in the fractures, you are going to drain oil from the east, are you not?

A. I don't think that follows, no.

Q. You don't?

A. No.

Q. Why do you differ? Why do you want to locate it on the east 660 feet of your section?

A. Well, I'm not a geologist, but that's

the direction that the production is. There's no control off to the west. We would like to stay as close to control as we can stay.

Q. And that's where the oil -- that's where the known oil is, isn't that correct?

A. That's right.

Q. And you want to get as close to that as you can, right?

A. That's right.

Q. And if you get into one of the flexure systems, you don't deny that you're going to drain oil from the east, do you?

A. I certainly deny that. I don't think it follows necessarily, no. You have to buy Mr. Greer's theory of gravity drainage, and everything, which just doesn't hold water in some cases.

Q. And you don't buy that.

A. Not no but --

Q. Do you have any facts to rely upon which deny the fact that we have a slope from the east to the west in this pool?

A. We have a very limited slope in the area on the west, and Mr. Greer himself has testified, or maybe not testified, but I have it written down, anyway, that because of

the limited dip the gravity drainage is very much less and probably insignificant to the west.

Q. It isn't as great to the west --

A. It isn't as great to the west.

Q. -- but you haven't heard any testimony that it is insignificant, have you?

A. Less than significant.

Q. All right, less significant, and what you're saying is that the slope on the west is not as great as it is on the east, right?

A. That's true.

Q. You do not deny, do you, that gas is being injected on the east?

A. No, I don't deny that.

Q. You do not deny, do you, that that gas moves the oil from east to the west?

A. Within his unit, yeah, it does.

Q. And do you think that there's going to be some kind of a -- of a barrier at the edge of your section that's going to prevent that oil from flowing into your well?

A. Well, he drew the barrier; it's the grey area on this map.

Q. And also at the end of that grey area is another point of flexture, isn't that correct?

A. I'm not sure about that. Mr. Greer drew the map.

Q. Now, in one of your exhibits you showed deviation where you calculated, I believe, 385-90 feet drift of a well and you said that 5 degrees was -- that this was 5 degrees, right?

A. That's correct, 5 degrees maximum.

Q. But you don't get 5 degrees on this -- on this Exhibit Seven until you get to 5000 feet depth, right?

A. That's correct.

Q. So if you take an average of what your -- of what your deviation is, you're going to come up with an average of what, 2-1/2 percent? Of 2-1/2 degrees?

A. Well, I don't think you need to take an average. The calculation is shown there.

Q. All right, but what you're saying is that you start out with a one degree deviation, you get to a -- at 1000 feet; at 2000 feet you've got two degrees; 3000 feet you're only 3 degrees; 4000, 4; and you don't get to 5 degrees until you get to 5000 feet. Are you suggesting that the Commission make the rule rather than what it is of permitting 5 degrees deviation at any point, that you limit deviation to 3 degrees until you're 3000 feet deep and to 4 degrees until you're 4000 to 5000, rather than the rule you're talking about

of 5 degrees deviation at any point?

A. I simply propose that the statewide rule is adequate.

Q. All right, let me ask you this. If you got 5 degrees deviation when you're 1000 feet deep and you maintain that 5 degrees deviation until you get to 7000 feet, is that 394-foot figure going to be correct?

A. Well, obviously not.

Q. Obviously, all right, it's going to be --

A. We also submit that it's going to be very unlikely that you could drill a well that would deviate 5 degrees at 1000 feet. You typically build up the angle as you drill deeper.

Q. All right, but you've suggested that the rule should permit you to deviate 5 degrees at 1000 feet and this is crooked hole country out here, is it not?

A. You have no evidence to show that the wells tend to drill that fast, and you know that.

Q. All right, but you are asking permission to deviate 5 degrees from the top of the hole, isn't that correct?

A. I simply submit that the statewide rule is adequate.

Q. And the statewide rule permits 5 degrees

deviation at any point, isn't that correct?

A. That's right.

Q. Now, then, you might refer to the topographical map and I believe you said you needed flexibility in locating a well and that your acreage is in orange, is that correct?

A. No, that's -- that's all of the acreage which has been offered in KGS sales since about the middle of 1978. Our acreage was purchased at the KGS sales, so our acreage is included within the orange.

Q. All right, let's look at the orange acreage and start down at the lefthand corner. If I understand this topographical map, you've got plenty of area in the west, in the center of the west half of that section that is in the lower areas to drill on, do you not?

A. It would appear so, yes.

Q. And moving then to the section to the east of that one, again you've got flat area, low area in there to drill a well in the west half of the center.

A. I'm not sure where you're pointing to but I think your point is probably correct.

Q. All right. Let's go the section to the north. We ought to be able to identify these.

MR. NUTTER: That's Section 29.

Q. Yes, move north one section, now, to Section 29, and again there's a plentiful area there in the west half of the section where you're in the bottom of the canyon, level area, is there not?

A. There would appear to be so.

Q. And moving one north in Section 20, again plenty of area in the west half in the center of the section. right?

A. Yes.

Q. Now we move one more north and we've still got area in the west half of the section. We've got one point that comes almost -- where it's low, where it comes almost up to the center, do we not?

A. Yes, and you also see another one down where the location is staked.

Q. That's right, down where you'll get in the flexure system and destroy the correlative rights and damage the reservoir.

MR. CARR: I'm going to object to that question as being entirely out of line.

MR. VERITY: We will draw it.

MR. RAMEY: You will stick to asking questions.

MR. CARR: Well, if he's going to testify

I want him put under oath.

MR. RAMEY: Let's --

Q. Refer --

MR. RAMEY: -- strike that from the record, if you would, Sally.

Q. Referring -- moving now to the next section to the west of your Section 8, there's ample room there in the west half of the middle of the section, right?

A. Yes.

Q. And to the east of that, isn't that correct?

A. Yes, it would appear to be so.

Q. The truth of the matter is from the topographical standpoint, there's no reason for not drilling in the west half of the section.

A. You're talking about the west half, but you're talking about 20 acres, you know. I can't -- I can't look at this map and say that there are 20 acres that will make a good, drillable location here, better than you would find on the east half or some other part of the section.

We're talking about 20 out of 640 acres.

Q. We're talking about the location. As I understood your testimony, you were saying, or at least implying, that there weren't drillable locations in the west

half of the section and near the center of the section.

A. I was speaking in generalaties and I believe that to be true with regard to 20 out of 640 acres in a given section.

Q. Well, in each of those sections you admitted there was a place to drill in the middle of the section, right?

A. In the west half, yeah.

Q. In the west half.

A. But not on those 20 acres necessarily.

MR. VERITY: Well, that's all.

MR. RAMEY: Any other questions for Mr. Carraway? Mr. Stamets?

QUESTIONS BY MR. STAMETS:

Q. Mr. Carraway, you heard Mr. Greer's testimony relative to the effect that completing of a high productivity well 660 feet from the unit boundary, did you not?

A. Yes.

Q. And he indicated that it could have a very disastrous effect on the -- on the unit.

A. A high capacity well, I think, could, yes.

Q. Do you disagree with his conclusion in that case?

A. Well, he made a lot of conclusions and I guess I'm not sure which you're referring to. If he was -- if we were to drill a high capacity well there that was obviously in communication with the unit, then I think it would follow that the well could damage the unit pressure maintenance project.

Q. Can you think of any way that this Commission should control such a situation so as to prevent the waste of oil and gas that Mr. Greer theorized?

A. Well, Mr. Greer assumes that Koch has absolutely no scruples at all in producing a well like that. I don't think that's necessarily the case. I don't believe that we would want to produce a well that would obviously destroy a pressure maintenance project. We would expect to cooperate with the unit in some manner, some equitable manner, I should think.

Q. Can you think of any way that we -- that this group can assure that that would happen?

A. No, I'm afraid I couldn't suggest any.

Q. Do you think a 660-foot location from the outer boundary of the unit is really a good location for drainage in a 640-acre spacing unit?

A. Well, I think I explained to you how -- or Mr. Luce did, how -- how the location resulted.

Q. Well, I'm not interested in how it resulted. I'm interested in your opinion as to whether you think that's a good idea.

A. I don't think there's anything wrong with it. As I pointed out in my testimony several times, Mr. Greer has indicated no interest in the area at all. Now he obviously doesn't think it's worth anything. He has fifteen years and more knowledge than anybody to -- to base his opinion on. We're willing to take a risk. Obviously we don't want to take any more risk than we have to. We can minimize the risk by drilling along the east side and that's where we want to drill.

Q. I'm not certain that you answered my question.

A. Rephrase it, then.

Q. Perhaps you did. Speaking strictly as a petroleum engineer, do you feel that a location 660 feet from the boundary of a dedicated section is a good location for the most efficient drainage of that proration unit?

Or would it be better to have a location which was more centrally located within the 640-acre tract?

A. Oh, I think that depends on all kinds

of things, you know, what kind of mechanism you've got, what kind of reservoir, everything. I don't see anything wrong with the location that we have staked.

Q. I don't -- I still don't think that that was your response to the question. I can appreciate it that --

A. It's not the response that you're looking for, perhaps, but I think it's an adequate response.

Q. Are you saying then that as a petroleum engineer you feel that the 640-acre unit will be just as effectively drained from a well located 660 feet from the line as a well located more centrally in the proration unit?

A. Well, again, I think it would depend a lot on the situation.

Q. Well, let's just make an assumption for the moment that you have the reservoir identical throughout the proration unit.

A. I think normally you would expect to drill the center of the section if you thought everything was exactly the same throughout, yeah.

Q. Okay.

MR. STAMETS: That's all the questions I have.

MR. RAMEY: Any other questions?

MR. VERITY: Yes, Your Honor, just one

or two more.

MR. RAMEY: Mr. Verity.

RECROSS EXAMINATION

BY MR. VERITY:

Q. Mr. Carraway, do you know of any 640-acre spacing where a location is permitted 660 feet from a line?

A. I don't believe I can think of one off the top of my head, no.

Q. You don't mean to tell this Commission, do you, that you think that the well 660 feet from the line where you've staked it will drain the west half of this section?

A. Well, it would depend on what the reservoir mechanism is. We don't know that and you don't know it either. Mr. Greer doesn't know it.

Q. And you're not telling this Commission you think that that well will drain the west half of this section, are you?

A. Well, it would depend. Our geologists think the dip is from west to east. If that be the case, then certainly it --

Q. But you're not testifying that it will drain the west half of the section, are you?

A. Well, I'm not going to make any kind of

statement like that, no.

MR. VERITY: All right, that's all.

MR. RAMEY: Any other questions? The witness is excused.

Anything further, Mr. Carr?

MR. CARR: Nothing further.

MR. HUNKER: I'd like to call Mr. Don Paull at this time. You've been sworn, Mr. Paull?

MR. PAULL: Yes.

DONALD PAULL

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

DIRECT EXAMINATION

BY MR. HUNKER:

Q. Will you state your name and address?

A. Donald Paull, 717 - 17th Street, Denver, Colorado.

Q. By whom are you employed?

A. Cotton Petroleum Corporation.

Q. In what capacity?

A. I'm Division Exploration Manager.

Q. I'd like for you to give the Commission,

if you will, please, your educational and experience background qualifying you as a -- as a geologist in this matter.

A. I am a graduate from the University of Wisconsin. I graduated in 1957 with a degree in geology. I immediately went to work for Amoco Production Company. I was with Amoco for a period of 20 years as an exploration geologist and supervisor. I left Amoco in 1977 and joined Cotton Petroleum in my present capacity as Exploration Manager.

MR. HUNKER: Are the qualifications of the witness acceptable?

MR. RAMEY: Yes, he's qualified.

Q. Are you familiar with the application that's been filed in this matter by Benson-Montin-Greer?

A. Yes, sir, I am.

Q. Are you also familiar with the amended application?

A. Yes, sir.

Q. Does Cotton propose to drill a well in the area west of the Canada Ojitos area?

A. Yes, sir, we do. We propose to drill a well in the southeast quarter of Section 5 of 24 North, 2 West.

Q. Have you prepared --

A. Excuse me, that would 1 West.

Q. 1 West. Have you prepared a plat of your

Gavilan prospect?

A. Yes, sir.

Q. Has it been marked for identification as Cotton Exhibit Number One?

A. Yes, it has.

Q. Will you tell the Commission what objective depths you plan to drill to and what formations you hope to encounter that might be productive?

A. If I may, I would like to refer to some of the previous testimony and show how it has applied to our thought process before I get to the specific --

Q. All right.

A. -- Cotton location.

Q. If you'll go into the matter of your having first located the well in accordance with the rules as promulgated and then explain why you changed the location. I'd like for you to go into that and then you may proceed.

A. All right. Originally on the basis of acreage, obviously, and a geologic interpretation of the subject area, Cotton Petroleum Corporation with a farm-in agreement with Mountain Fuels selected a location in the approximate center of the southeast quarter of Section 5 of 24 North, 1 West.

We notified the Forest Service of this

location. The initial location was approximately 1310 feet from the east line and 1310 feet from the south line.

When we learned of Mr. Greer's application calling for a location no closer than 1650 from a section line, we -- we moved our location so that it would be a qualifying location. We moved the location for two primary reasons. One, it was compatible with our structural interpretation; and we were working under an agreement with Mountain Fuel that expires in December and we have a rig scheduled to drill a prospect in December.

So without knowing the outcome of that hearing we felt that we would be protected with that location if Mr. Greer's application were approved, we would be legal. If his application were disapproved our location would be legal under the existing regulations.

Q. Will you identify the Cotton acreage on this map and also identify the Mountain Fuel Supply Company acreage?

A. Yes, sir.

Cotton Petroleum owns the west half of Section 5, 24 North, 1 WEst. We have a drilling obligation from Mountain Fuel to drill and earn acreage on the east side of Section 5 of 24 North, 1 West. We have the continuing option to drill an additional well in Section 8 of 24, 1 West, again

earning from Mountain Fuel.

Q. Are you familiar with the expiration dates of these leases?

A. Yes, sir.

Q. Are they competitive leases that were sold by the United States at public auction?

A. Yes. Cotton's lease is a competitive Federal lease that we purchased in 1979 and the Mountain Fuel lease is a competitive Federal lease that expires, I believe, in November of 1981.

So they are -- they are short term leases that demand exploration activity.

Q. Speaking of exploration activity, what is your company's philosoply with regard to the acquisition of leases and the development of leases?

MR. VERITY: Your Honor, we're going to object to that. We don't think that the philosophy that Cotton Petroleum regarding the acquisition and development of leases has anything to do with the issue here before the Commission at this time.

MR. HUNKER: We'd like to show, Mr. Ramey, that this is a company that's interested in developing the energy resources of our nation and I think that he's perfectly entitled to express the view of his management as to

what he expects to do.

MR. VERTIY: I think you can take judicial notice that everybody's patriotic and everybody likes to have a lot of oil, but I just don't see where it anywise has anything to do with the issues here before the Commission.

MR. RAMEY: Objection overruled. Go ahead and answer the question.

A Cotton Petroleum has been a very aggressive exploration company in North America. The company, as presently structured, will be four years old in December. But to speak specifically to the State of New Mexico, which is of interest to us here today, we started our exploration activities in June of 1977 in the State of New Mexico. There has been some three and a half years of exploration and in that period of time we have grown to be the 38th largest producer in the state. These are 1979 records. I think that's a pretty admirable approach for a young company, and our approach is one of buying leases, and we acquire leases wherever we can throughout the state that we can put an exploration prospect to, and I think that is the key to our exploration. We are a prospect oriented company.

We buy acreage only if we can show management that if we can acquire the acreage we will drill the acreage. We don't buy random acreage and sit on it.

And that was the posture that we took when we acquired the 320 acres that we have in this prospect. It was bought as a drillable prospect, and then we negotiated our way into the additional acreage.

In addition, we have taken a very, very aggressive attitude towards acreage in the subject area. A case in point would be the KGS sale that was held in September of this year. At that sale Cotton Petroleum exposed 1.9-million dollars. We spent 1.45-million dollars at that sale, and I think it is also very significant that one of our highest bids was in Section 31 of 25 North, 1 West, where we bid $580 per acre. We were beaten out by a competitive company that paid something on the order of $620 per acre, but it was a competitive situation and I think it's also notable that Benson-Montin-Greer were not involved in this acreage sale whatsoever.

Q. In connection with the location that you have made in the southeast quarter of Section 5, Mr. Paull, will you explain the geology that was attendant in making the decision to locate the well at that location?

A. Yes, sir. In answering that, I would like to refer to the grey copy we've seen so often in Section 8 and Mr. Greer's map.

MR. RAMEY: Which section are you in, Mr.

Paull?

A. My book's different. I think yours is in "A", the blue-green --

MR. VERITY: This is the same plat that the last witness referred to, is it not?

A. Yes, sir.

There are several things that I'd like to point to on this exhibit. Number one, there are three producing wells that are located on the eastern flank of the exhibit; one producing well in Section 32 of 25 North, 1 East, and two producing wells in Section 5 of 24 North, 1 East, and Mr. Greer states that, and I quote, "These wells drilled an area of uniform steep dip, minimum flexing, production marginal, 150,000 barrels of oil from three wells, are not in communication with the COU Unit."

Now those production that is in one gradient of dip that he states is separate from production from other areas in the field. If we move over to the -- to the Cotton location in Section 5, which is moving exactly six miles due west --

MR. VERITY: Excuse me a minute, if I might interrupt. I believe, Your Honor, I understand what he's coming at. He's endeavoring to say we're not -- that area, that is an area of West Puerto Chiquito by this order,

is not in the area. Is that -- is that what you're leading up to?

A. No, sir, I am trying to show that by Mr. Greer's own map, there are separate and distinct fields within the overall reservoir, and I think that Cotton Petroleum is -- has the prospect potential of being in a separate and distinct field from the field in the COU Unit, and it affects our geologic interpretation.

MR. VERITY: To which we object, Your Honor. We can't have before this Commission, or we have the West Puerto Chiquito Pool defined by this Commission, and a witness come in and testify, now, we don't think that our part of this, although it's in the declared unit, ought to be taken into these rules and should be considered separate because we think it's not in that reservoir. I just don't think that at this hearing on this application this witness can be heard to say that part of this area that is within the unit is not within the unit, within the -- excuse me, within the field is not within the field, and we suggest that it's improper testimony and we move that it be stricken.

I object to any further testimony along this line.

MR. RAMEY: Mr. Paull, what were the wells you were referring to first?

A. The wells in Sections 32 and Section 5.

MR. RAMEY: I think the witness is going to testify to his opinion and I think we all have opinions, so I'm going to overrule the objection.

MR. VERITY: Note our exception.

MR. RAMEY: Yes, sir.

MR. VERITY: And particularly to the extent that he's presenting testimony that a part of the area that is defined by this Commission's previous order as being in the West Puerto Chiquito Mancos Oil Field is not within it.

MR. RAMEY: So noted, Mr. Verity.

A. The established production within the COU Unit is in dip rates that range from 3 on up to, oh, probably 8 degrees. Cotton Petroleum's location is in one degree dip. Once again, a 100 to 300 degree deviation in dip from the fields that are productive and the dip rate can separate a pool to the east, gentlemen, a dip rate can separate a pool to the west by the same nature.

I call your attention to the East Puerto Chiquito Pool to the north, located in 26 and 27 North of 1 East, and I think this is even more pertinent to our case and our testimony. Mr. Greer shows a water-leg on that particular pool. The dry holes are noted on the map. He has publications that clearly show that this reservoir is separate from any

reservoir that he has within the unit.

Of significance here is the structural nosing that is shown up on that feature. One last point on this exhibit is the -- is the wiggly line to the north, where Mr. Greer shows an approximate north limit of Zone C, therein cutting off the production of Zone C from producing wells to the north and further, from the Boulder Mancos Field to the north.

Gentlemen, what I'm saying is that in this area Mr. Greer recognizes four different pools, and in his testimony I would agree that within this seven-section of control, where he has done a tremendous amount of reservoir analysis, that he has established communication data within that particular area. I also point out that in that seven sections many of those wells are drilled on 160-acre spacing. Others are drilled on 220-acre spacing, and on a straight reservoir basis 70 percent of the oil has been produced from seven sections of land within this unit. That's 4,500 acres out of a 53,000-acre unit, have produced 70 percent of the oil.

I also would like to point out that the well in Section 3 of 24 North, 1 West, I have heard no data today, and I find none in the -- in the publications, that demonstrates any communication or any pressure data that shows

communication in that particular well, and that particular well is pertinent to our reservoir in that it is some mile and a half to two miles away from our well.

My point is, is that we have a rank wildcat location that is a high risk venture.

With that I would like to return to Cotton Petroleum's Exhibit Number One. This map is a structure map contoured at a 100-foot interval on the top of the Niobrara formation. The Niobrara control wells within the area are shown by the green triangles. The Pictured Cliffs control wells and producing wells on the map are shown by the red triangles.

Now, Cotton Petroleum used a standard exploration practice in here and we projected the Pictured Cliffs datums down to a Niobrara horizon in order to make an interpretive structural map. The way we did this is if you will notice within the Canada Ojitos Unit there are four wells that have -- that have datums with square boxes around them, the first one being in Section 22 and the datum being 3565. And continuing on down in 34, datum being 3532; in Section 3 datum being 3530; and in Section 14, datum being 3525. In very consisten Isopachous interval from the Pictured Cliffs to the top of the Niobrara. We used in our projections in our area of interest 3530 as our Isopach interval.

I also think that it's extremely interesting that -- that Cotton Petroleum's map and Koch Exploration's map are very, very similar in the structural definition of a significant structural feature on the Gavilan-Pictured Cliffs Field, and I have never seen the Koch Exploration map before the -- this meeting.

By using this contour, structural contour approach, we have a strong structural nose that runs through the Gavilan-Pictured Cliffs Field and across Section 5 and through the Cotton Petroleum location. We feel very strongly that one of our major exploratory reservoirs is the Niobrara formation of the Mancos Shale. In order to produce economically from the Niobrara, we absolutely need fracture enhancement, and that's why we think that the structural nose will give us that fracture enhancement.

Fracture patterns are going to develop along areas of maximum structure and there is where we can anticipate the greatest amount of fracturing within the reservoir, and I feel across this nose that the fracture systems will in all probability run linear to the nose. In other words, they will run east/west to northwest/southeast. They will run parallel to the folding as you roll across the structure, and I also think that it's interesting that -- that Mr. Greer, in his testimony, feels that the majority of the fractures run

north/south. If we could get that direction we will be draining a large concentric pattern; we will be draining from all directions, in my opinion.

The immediate section to the south of the Cotton Petroleum location, the east half of that section has previously been excluded from the unit as not reasonably shown to be productive, was the testimony. In addition, Mr. Greer pointed out that he has no information to prove or disprove whether these lands are any part of the reservoir, and that is as close to a direct quote as I can come.

I agree. I think that Cotton Petroleum is setting off on a new exploration venture; that we have a potential of a significant reservoir and that we have the potential of a significant reservoir that is in no way going to interfere with the existing unit.

MR. VERITY: To which we renew our objection, Your Honor. Counsel -- the witness is now endeavoring to say that his land is completely separated from West Puerto Chiquito. We have no application to set aside the unit boundary of the West Puerto Chiquito, but he is saying that he's out of it, and we submit that this is improper and incompetent testimony in this hearing; that the only way he could come with that type of a hearing is to ask that the unit be reformed and that the part he's talking about be deleted from it, and

it's just not a proper -- proper thing that can be said at this hearing, where we have the declaration of this Commission that this is within the unit.

MR. HUNKER: We disagree, Mr. Ramey, with his contention.

MR. ARNOLD: Mr. Verity, were you thinking about the unit or the pool?

MR. VERITY: I'm sorry, I mean the pool where you have -- you entered an order that declared the boundary of West Puerto Chiquito Field. He's now endeavoring to -- has testified over my objection, that he's not in that field. He's in something totally different so they shouldn't be subject to these rules. Well, if that is true, he has a remedy, and that is to come before this Commission and ask that this unit be reformed, but that isn't -- that this field be reformed, but that's not the issue here today, and nobody has suggested in any pleading whatsoever that we should reform this unit.

We're talking about pattern and he -- he just can't say we're not West Puerto Chiquito; not in this hearing.

MR. RAMEY: Mr. Hunker, did you want to say something?

MR. HUNKER: We disagree with the position

of Mr. Verity, that he's taken.

One of the objectives of the test well that Cotton proposes to drill is the Niobrara, which is the admitted formation out of which Mr. Greer is producing his wells. We don't know until a well is drilled whether there's going to be any communication between the Cotton well and the wells to the east of it or not. We'd like to have an opportunity to spend our money and -- and see is what we're trying to say, and if necessary, we'd like the Commission to make an exception insofar as Cotton is concerned, granting them permission to drill a well at the location that they have selected, to save the acreage and protect their investment.

MR. VERITY: You see, Your Honor, on the one hand he's saying -- on the one hand the witness is saying we're not in West Puerto Chiquito Field, therefor we shouldn't be subject to its rules. But his counsel now says we don't know what it is but we're going to drill a well and find out.

Well, this Commission has determined that it's within West Puerto Chiquito Field, and we can't just come in without any credence, without foundation --

MR. HUNKER: I don't think there's any testimony on that at all.

MR. VERITY: We've got an order that was based on proper testimony before this Commission. It has never

been up until this moment questioned, and that order stands here today and no one has asked that it be changed, but we have a witness that says, oh, we're not in that formation, even though the order says we are; therefor, we don't want to be subject to the rules.

Now counsel says, we really don't know whether we're in it or not and we want to drill and find out, and the testimony is improper in this hearing on these issues they're bringing under this application.

MR. HUNKER: I'd like to call the Commission's attention to the fact that the location of the wells is also a part of the rules and we -- we objected this morning to having the hearing at a time when the rule had already become final. I think that they're mistaken in the position that they're taking. I think we're entitled to testify as to the formations that we expect to encounter and we think we have a nosing feature and that it's -- that it may be separated from the rest of the area.

MR. VERITY: We're not saying, Your Honor, that under an application to reform the Puerto Chiquito Pool and Unit they wouldn't have the right to make testimony under -- under proper application. That is not the application here. That's why it's improper.

MR. RAMEY: Gentlemen, I think we have

three different contour maps prepared by three different people and they all have their opinion, and I think we should hear their opinion. I'm going to overrule the objection and we'll take the testimony for what it's worth.

MR. VERITY: Note our exception.

Q. I'd like for you to continue with your testimony, Mr. Paull.

A. As Mr. Hunker pointed out, Cotton's objectives here are multifold. You can clearly see the proximity by location to the Pictured Cliffs production in the Gavilan-Pictured Cliffs Field, and as an added incentive, you can see the Pictured Cliffs well that's located in Section 12 of 24 North, 1 West, that illustrates that the production potential does carry significantly to the east. So this is a significant zone for us.

The Mesaverde is an additional zone that we feel will have potential, if we can catch the Mesaverde sand draped across the nose.

So this is a multiple pay potential. The Pictured Cliffs is spaced on 160-acre spacing. The existing location would allow us this flexibility.

I also would like to point out that this location is staked. We do have archeological approvals for this location. Everything was set in motion for the drilling

of this well long before I heard from Mr. Greer in any fashion whatsoever. We had our negotiations with Mountain Fuel and we had the location before we ever had any discussions with Mr. Greer.

The Forest Service has looked at the location and is considering it for approval. There is a road that goes right into the location.

I think with that I'd like to fall back a little bit on -- on Mr. Greer's introductory statement, and I quote as best I can, that he requests protection of correlative rights, prevention of underground waste, and protection of our natural resources.

Cotton Petroleum requests the same consideration. We've come a long way down the road on this location, gentlemen. We have an agreement with a time fuse running with Mountain Fuel. Mountain Fuel's acreage is running in term. We have a rig scheduled for December. We have the contract in our office. We cannot sign the contract until we know that we have a location, and that contract, with rig availability being what it is today, is going to find somebody that will sign it and that rig will be gone.

In addition, I think I must say that I have heard words here today such as "shocked" and "incomprehensible". I am shocked and I think it's incomprehensible

when an individual that controls a Federal unit of 53,000 acres hasn't drilled a well in 8 years. I am shocked to find an individual that holds a considerable amount of Federal lands outside of this unit that are in the 9th year of their term and absolutely nothing has happened. I think that there is a significant amount of oil and gas to be found out here, and I think it can be found without rape of existing pools or existing regulations, and I resent the inference, I guess, of Cotton and others being that kind of an operator.

Are you going to talk about Boulder-Mancos, or shall I?

Q. I'd like to have your comments about the Boulder-Mancos.

A. All right. Comments and references have been made throughout the day on Boulder-Mancos being such a terrible waste, and gentlemen, I am not for one moment going to talk in terms of 80-acre spacing. I don't want it and I'm not -- I'm not professing that, but in strictly looking at numbers, and I must admit I'm a little bit -- I'm a little bit confused by numbers because today Mr. Greer has used numbers of recoverable oil that range from 250 barrels per acre to 2500 barrels per acre in different parts of his testimony and in support of different things.

I think that I'm being fair to Mr. Greer

if I settle on a number somewhere in the 1500 per acre range as recoverable from a fracture system in the Niobrara member. And it's very interesting that the Boulder-Mancos Pool covers 1700 acres and has recovered 1.8 million barrels of oil to date. That is a recovery of 1058 barrels per acre, and depending on what number you use, if you use this 1500 barrels, to date 66 percent of the oil has been recovered in that field and today at those depths and at that kind of recovery of 75,000 barrels of oil, that individually is a very, very economic field, gentlemen.

Q. Will the granting of the application in this matter affect Cotton's correlative rights?

A. Yes, sir, it will. We have no assurances that Mountain Fuels will give us a continuance and if not, Cotton Petroleum does not have a prospect; we're strictly out in the cold on a situation that we've worked on for some nine months now.

MR. HUNKER: That's all the questions that I have at this time.

MR. RAMEY: Any questions of Mr. Paull?

MR. VERITY: Yes, Your Honor, we want to ask some questions.

CROSS EXAMINATION

BY MR. VERITY:

Q. Mr. Paull, you don't contend, do you, that your company, because it is aggressive and successful, that it should not be subject to the rules of this Commission?

A. No, sir, I do not contend that.

Q. All right.

A. For one moment.

Q. Okay, and you don't contend, do you, that a land situation means that rules should be set aside in order that your company can have an advantage from a land development standing?

A. No, sir, we're not asking for an advantage, either. The lands that we have were bought and negotiated for under competitive terms and we moved ahead in our operation under existing regulations.

Q. And the Legislature in its wisdom has determined that we shall have conservation practices and conservation law in the state, and you operate under that, do you not?

A. Yes, sir.

Q. And merely because you go buy a lease that happens to have one type of an expiration on it and some other lease might have another type, doesn't mean that you're

not subject to the rules and regulations of this Commission, does it?

A. No, sir, it does not.

Q. Now I notice on your map, if I understand your testimony, you're -- you're wanting to, and you did testify that -- that your area here has nothing to do with West Puerto Chiquito as far as geology is concerned, that you're totally separated.

A. I have seen no evidence submitted today that tells me that our prospect area will be in any way related to the existing producing reservoirs.

Q. Have you filed any applications or asked that it be deleted from the West Puerto Chiquito Pool?

A. No, sir.

Q. Do you think -- do you think that it should be deleted from West Puerto Chiquito Pool?

A. I think that the well should be drilled under a competitive basis, on the basis of our prospect, and when drilled, we will have reservoir data to direct that question to.

Q. All right, before the time that you drill that well, do you think that you should not be subject to the rules and regulations of West Puerto Chiquito until you know what you're going to get in that well?

A. Yes, sir, I -- I staked the well under the existing rules of West Puerto Chiquito.

Q. Looking at your Exhibit One, we have contoured here, and you've got it contoured on what, the "A" member of the Niobrara?

A. It's the top of the Niobrara. It is the approximate top that Mr. Greer used and refers to as "A".

Q. And you have projected insofar as the high place on there, from Pictured Cliffs datum, right?

A. That is correct, sir.

Q. And you don't suggest that it always conforms, other than generally, do you?

A. It conforms very well on the basis of the available data in this area.

Q. All right.

A. It's a very standard, accepted geologic practice.

Q. And if I understand your map, you show a nosing, in fact a closure on the 400-foot interval, and that extends from just north of the section where you want to drill to the northwest.

A. The closure that you refer to is a low -- is a low that sneaks on in through there. It's a saddle. The high point is the structural axis shown on our map.

Q. All right, and you told us that -- that moving the location from 660 from the east line and 660 from the west line to where you have it located, that is moving it to the northwest, was compatible with your geology, correct?

A. We have never staked a location at 660, sir. The road runs -- runs --

Q. But you said you thought of it.

A. No, sir, I did not say that. Our original location --

Q. I beg your pardon.

A. -- was 1310.

Q. 1310.

A. Yes, sir.

Q. I stand corrected. Thank you. But that 1310 from east and from the south, you said it was compatable to move northwest --

A. Yes --

Q. -- to your present location.

A. -- because it moves -- it moves right along the structural axis, yes, sir.

Q. And you could move it further into the west half and have it right along the structural axis, could you not?

A. Yes, sir.

Q. And geologically it would be just as well to put it there, would it not?

A. No, sir. As we move -- as we move in that direction two things happen. We move away from a location that -- that we have gone a long way towards getting approved. We will not be able to use the rig that we have a handle on at this point in time, and we will be moving structurally deeper into the basin and our well expenses will go up, and I do not know what the forest implications or the road implications would be. We are running on -- we are operating this well on a thin positive economic. If it wasn't positive economically, we wouldn't do it. We would have to re-do our economic analysis due to the increase in depth and whatever road costs that we might entail by moving trying to hit two 10-acre targets.

Q. I gather that you don't agree with the Koch witness that said he thought it was going to turn around and go back up. You think it's going down, it's going to continue to go down to the west.

A. Well, we have a feature in there that shows a reversal, too. As I say, I'm amazed that our -- that our nosing is as similar to the Koch well as it is.

Q. How much do you think you're going to go down to move from where you have your location along that

line of strike that you've drawn there into the west half of the section?

A. Well, those are 100-foot contours and on the basis of that spacing you're going to drop off, probably, 60 feet.

Q. Well then I must not understand your contour. You say that your -- now, you do think that you are going to -- to find at this location a point of flexure?

A. Yes, sir.

Q. And that means you think that you will find one of the larger communication fractures.

A. We hope so.

Q. And those fractures not only run north and south but they have cross fractures that communicate with those north/south ones, or if you will prefer, are you saying they go northwest/southeast?

A. Yes, sir.

Q. So that point of fracture will put you into the system to the east, will it not?

A. I cannot say that. I do not know.

Q. But you cannot say that it won't.

A. Nope. But I --

Q. And you can't suggest to this Commission can you, that you won't put the fracture into the system of

the Canada Ojitos Unit?

A. Sir, I absolutely do not know what the radius of drainage of the prospect location will be.

Q. And you're not -- and you're -- what do you think the radius of drainage of the wells have been?

A. Well, I -- you asked what I thought. Well, I'm not a reservoir engineer, that's equipped to get into that, but you asked for my opinion, and I suspect it is probably not a whole lot more than 640 acres, and I think that I direct your attention back to the fact that the heart of the existing Canada Ojitos Field in seven sections of land, one of the sections has two wells on it, it's drilled on 220 acres of spacing, and 70 percent of the oil from that unit comes from 4000 acres. It's an inescapable situation from a geologic point of view.

Q. You don't -- you don't disagree with that testimony, do you? With regard to its wide drainage?

A. Yes, I do.

Q. Well, do you have any information that would show that those conclusions are wrong? Have you done any studies on this Canada Ojitos area?

A. The -- the testimony that was given was full of -- of inconsistent numbers, and recovery factors.

Q. Give us an example of where there was

an inconsistency in that testimony here or the exhibit.

A. Well, I wrote them down through the testimony but I know that -- that at varying times in the testimony recovery factors were given from a range, I think the low was 50 barrels to a high of 25,000 barrels --

Q. 2500.

A. 2500 barrels per acre. I don't know which one to grab out of the hat with that kind of number.

Q. Actually, you're talking about high and low limits, are you not?

A. I'm talking about numbers that were given in testimony in support of various points that Mr. Greer was trying to make. Now --

Q. 2500, your 25 -- your -- do you recall specifically what the 2500 barrel figure was?

A. Well, I don't know whether I can pull that out or not, but it will be in the transcript.

Q. Let me assist you. That referred to the maximum amount of oil that could be in place per acre, did it not?

A. I believe he was talking about recoverable oil at the time.

Q. Well, then we'll have to refer to the record. The exhibits and that will show very clearly that the

testimony was that initially after the 5-well interference test, that we knew that there was a minimum of 1500 barrels per acre in place and a maximum of 2500 barrels per acre in place. Is there any conflict with that information?

A. No, sir.

Q. Do you recall then that after another interference test was made by one of the wells that was taken off of production as an observation well, and after gas was injected at the top of the -- of the field on the east, that we had another interference test that refined that and we brought it down to 1500 -- to 1600 acres per acre -- 1600 barrels per acre in place?

Do you find those in conflict?

A. Not within that area, no, sir.

Q. All right, where do you find the conflict with those figures?

A. Insofar -- insofar as the area of study, I do not find a conflict.

Q. All right. The truth of the matter is, Mr. Paull, as you've told us, you're not an engineer, are you?

A. No, sir.

Q. And you do not follow the figures of engineering, the calculations of engineering.

A. Well, I follow them, yes, sir.

Q. WEll, you're not telling us that you're an expert in that field.

A. I am not an expert reservoir engineer.

Q. And you have told us that the calculations and the engineering calculations that were done are beyond your field of expertise.

A. That is correct.

Q. Now let's refer to Boulder for a minute. You're not suggesting to us, are you, that the fact that they produced 1,800,000 barrels means that that field was most efficiently produced?

A. No, sir, I prefaced my statements by saying that was not the most efficient --

Q. Oh, all you said was that it was economic.

A. I said it was economic, yes, sir.

Q. And you wouldn't suggest to anyone that more oil would not have been recovered if they had maintained a proper injection of gas in the top of the field.

A. I don't know that you can make that statement.

Q. Well, you can't make that statement --

A. Well, you can't make that statement either.

Q. -- and you don't have information or facts or expertise to suggest that that's not a true conclusion, one Mr. Greer made.

A. Well, Mr. Greer can't make that statement, either, and that's been part of the testimony.

Q. Well, I can argue -- will you tell us why he can't make that statement with the information that he furnished?

A. Because he does not, and he admitted that he does not have the pressure data to support it, either.

Q. But he did have pressure data and from that he did make a conclusion, and you or your counsel did not object to the basis of it at the time, did you?

A. No.

Q. And it stands in this record as evidence based on information submitted. Right?

A. Right.

Q. And you don't have any contrary evidence to deny it, do you?

A. No, sir.

MR. VERITY: That's all.

MR. RAMEY: Any other questions of Mr. Paull? Mr. Stamets.

QUESTIONS BY MR. STAMETS:

Q. Mr. Paull, if you don't feel that you can answer this question, please feel free to tell me that.

You recall that I questioned Mr. Carraway as to whether he disagreed with Mr. Greer as to the effect of the completion of a high potential well along the border of the unit and in communication with the unit, and I'll ask you now if you disagree with Mr. Greer in that regard.

A. I don't think we know. Until we've drilled a well and run a reservoir analysis on that well, I don't think we have any way of knowing whether we are in communication with the existing pool or in a totally separate pool, and that's why I feel that we should be allowed to go ahead and explore acreage under existing spacing regulations and determine what, really, the reservoir and the pool that we have out here is.

I would restate that nothing has been entered in testimony that -- that I recall, that shows communication with the L-3 Well, which is the closest well to ours. I don't know whether it's in the existing unit or not.

Does that answer your question?

Q. No, it didn't answer my question, because the question is, if Mr. Greer is correct, and you do complete

a high productivity well that is in communication, Mr. Greer, under those conditions has stated that there will be a substantial loss to the unit because of that communication because of the gas that will be produced, and it could cause the unit to be prematurely abandoned with a resultant waste of oil in the ground.

So I'm asking if you disagree with that, and then the next question will be, why do you disagree with it.

A. If reservoir data were to indicate that we are in the same pool, then I cannot disagree with it. I can question why Mr. Greer waited until a company such as Cotton came out here to stake a location after eight long years, and then all of a sudden becomes very demanding of operators of how they operate.

Q. Going on, then, my next question is, can you see any way that this Commission under the circumstances we've talked about with a hig productivity well in communication, can you see any way that the Commission could act to prevent the waste that Mr. Greer has talked about?

A. Well, assuming he -- that the well should be drilled on a competitive basis, and if the reservoir data, you know, clearly illustrates that they are in communication, then he has the recourse of expanding this unit, as

he has threatened time and time again, and if he can support that unit expansion, then it's an all-win situation, I guess, for Mr. Greer, and a no-win situation against Cotton, but I think that that is -- is the recourse and the chain of events that I would expect to see occur out here.

If we can illustrate that there is not reservoir communication and that we have a new pool discovery, that that also should be the right of Cotton Petroleum Corporation.

Q. So the only thing that you're able to offer is something which is theoretically going to take six or seven months.

A. Yes, sir.

Q. Okay.

A. In six to seven months I think that also an operator should have the opportunity to -- to do his own pressure data and recoup his investment in this situation.

MR. HUNKER: Mr. Ramey, I'd like to offer into evidence Cotton's Exhibit Number One.

MR. RAMEY: Exhibit Number One will be admitted. Any other questions of Mr. Paull? He may be excused.

MR. HUNKER: At this time I'd like to call Mr. Glen Garvey.

GLEN GARVEY

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

DIRECT EXAMINATION

BY MR. HUNKER:

Q. For the record will you state your name and address?

A. Glen Garvey, Denver, Colorado.

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

A. Cotton Petroleum as Senior Engineer.

Q. And as Senior Engineer what is the scope of your activity and your duty?

A. With Cotton we have divided the areas of the Rockies between two of us and it is more or less all engineering functions for our particular areas of responsibility; everything from applications for permits to drill, completions, any production problems through any reservoir engineering that has to be performed.

Q. Have you testified as a petroleum engineer before the Commission?

A. Yes, sir, I have.

Q. Within the last several weeks?

A. Yes, sir, on their last Examiner Hearing date.

Q. Were your qualifications found to be acceptable?

A. Yes, sir, they were.

MR. HUNKER: Is he qualified?

MR. RAMEY: Yes, he's qualified.

Q. I'd like for you to refer to what's been marked Cotton's Exhibit Number Two and tell the Commission what this is that it shows.

A. This is just a blowup of the USGS topographic map surrounding our acreage in Section 5, Township 24 North, Range 1 West, Rio Arriba County, New Mexico.

Q. Is the road to the wellsite shown in red on that topo?

A. Yes, sir, it is. There is one slight deviation on here from the USGS topo. There is an actual road to within 30 feet of the presently staked location that was not shown on the USGS topo, but it is in fact there.

Q. Have you been to this well location, Mr. Garvey?

A. Yes, sir, I was to the well location on November 5th of this year.

Q. And is the topographic map in your opinion accurate?

A. No, sir, it is not entirely accurate. This USGS topo is made off of aerial photographs that were made in 1952, and in 28 years there can be a lot of regrowth and revegetation of roads that are shown on that map, and some, you know, naturally new ones added.

Q. It is an appropriate depiction, though, of your location, is that correct?

A. That is correct.

Q. Was this map prepared by you or under your direction?

A. Yes, sir, it was.

Q. Referring to what's been marked Cotton's Exhibit Number Two -- I mean Three, will you tell the Commission what this plat represents?

A. All I'm trying to depict in this map, again it's a topographic blowup of the area surrounding our acreage in Section 5, which shows the targetable areas under the presently existing field rules.

Q. If the application of Benson-Montin-Greer is approved, would you be restricted in the drilling of your test well?

A. Yes. In that it will involve building

some road. On this topo map we show a road that kind of goes to the northwest quarter of the section, and we were not able to locate that road when we were out there. At that time we had the information from BMG that they wanted to change the hearing again, so we did look at that. It would therefor require us to build that much additional road that we would not have to build right now.

Q. In connection with the location that you made, have you prepared an AFE for your management?

A. Yes, sir, I have.

Q. What does that AFE reflect with regard to well costs and the cost of building the road?

A. We have discussed at length with the Forest Service the cost to build the road and the location. It is their opinion, or Mr. Ferlin Brown, I believe, the District Ranger, that it would be in the order of $10-to-$12,000 per mile to build this road. Let me correct that, to upgrade the existing road that goes to the staked location. I do not have a number of what it would cost to build a new road through the forest.

The well cost that we have estimated is a dry hole cost of approximately $333,000; completion cost, approximately $288,000, for a total well cost of $620,000.

Q. Has your management accepted the recom-

mendation that this well be drilled and that you take this risk?

A. Yes, sir, they have.

Q. Did you hear Mr. Carraway's testimony with regard to the deviation of the hole?

A. Yes, sir, I have.

Q. Do you agree with his testimony? Do you think that the state rules are adequate under the circumstances?

A. I believe that the state rules are adequate under the circumstances on the basis that Cotton Petroleum has a large block of acreage about 15 miles from here that is under a similar dip and similar geologic depth, and we have not incurred any significant problems in deviation.

Q. Will you explain to the Commission what the economics of this prospect are as related to the product that you'll recover?

A. When we evaluated this well we decided to take a low recovery factor for the area and we set upon a number of approximately 250 barrels of oil recoverable per acre, which is well below Mr. Greer's estimates of 500 to 2500 barrels. This works out to 160,000 barrels of oil for a 640-acre section. So we applied that much recovery to this well.

Associated gas we put in the 1600 GOR

range, which came up with a quarter of a BCF.

We ran our economics just strictly on the oil; we ignored the amount of gas. We came up with the fact that it would be an economic venture based on these recoveries.

Q. What did you anticipate that the well would produce by way of oil production? How much daily?

A. I believe that we set up with initial IP of approximately 80 barrels per day and I do not remember what we used for a decline on that to come up to match the 160,000 barrels.

Q. Do you have any other comments to make with regard to Exhibits Two and Three?

A. No, I do not.

Q. Do you have anything else to offer the Commission in connection with this -- this hearing today?

A. Not that I can think of at the -- at the moment.

Q. At the late hour?

A. Right.

MR. HUNKER: We offer in evidence Cotton's Exhibits Two and Three.

MR. RAMEY: Cotton's Exhibits Two and Three will be admitted.

MR. HUNKER: I have no further questions

on direct.

MR. RAMEY: Any questions of the witness? Mr. Verity.

MR. VERITY: Just a few, Your Honor.

CROSS EXAMINATION

BY MR. VERITY:

Q. I believe this is your Exhibit Three, am I correct?

A. Yes, sir.

Q. Referring to your Exhibit Three, as I understand it, it shows accessability to the west half of the section in the northwest quarter of either a present road or previous road across there.

A. Yes, sir, I believe it is a previous road, as we were not able to locate it. It's probably been revegetated during the past 28 years.

Q. But if there was a road there, it certainly was an accessible area and it would remain an accessible area.

A. I cannot argue with that. It just costs substantially a greater amount of money to build a new road, which is essentially what it would be, as we would have to cut timber or remove anything that has grown over that road.

Q. And as a matter of fact, your contours indicate that it's level and accessible.

A. That is correct.

Q. Have you been onto the northwest quarter of this section?

A. I have been around there, yes. I can't say a particular because I'm not a land surveyor and I'm not exactly sure if I made it that far.

Q. So you don't know whether anything needs to be cut there or not, if you haven't been on it and seen it, do you?

A. That area is fairly heavily forested. I can't imagine that it changes just up there in the northwest quarter.

Q. Some place you got forest and some place you have timber and some places it's open, isn't that true?

A. That is correct, down in the bottom of the valleys it is mostly open, and this is working its way up a ridge.

Q. But you have, if I'm -- this plat indicates that -- that it's a -- that it is not a ridge, but a drainage, does it not?

A. Well, that's correct.

Q. And that road went up a drainage, did it

not?

A. That is correct.

Q. So isn't it probable that there is not any timber on it at this time?

A. Well, having not been there, I can't speak to that being yes or no.

Q. So you don't know, do you?

A. I do not know.

MR. VERITY: That's all.

A. I'd like to know if you know.

MR. VERITY: That's all.

MR. RAMEY: Any other questions? The witness may be excused.

Anything further, Mr. Hunker?

MR. HUNKER: Nothing further at this time.

MR. RAMEY: Does anyone have anything further to add to this case?

MR. VERITY: We have a small amount of rebuttal, Your Honor, it will be brief.

MR. RAMEY: Okay.

MR. VERITY: I'm recalling Mr. Greer to the stand.

ALBERT GREER

being recalled as a witness, testified as follows, to-wit:

REDIRECT EXAMINATION

BY MR. VERITY:

Q. Mr. Greer, you've testified previously in this hearing?

A. Yes, sir.

Q. You are the applicant -- for the applicant?

A. Yes, sir.

Q. I believe you have in front of you Koch's Exhibit One?

A. Yes, sir.

Q. Do you have any comments to make about it?

A. Well, I'd just like to point out that dispite all the geological postulations, that generally they show the same thing that our maps show. The formation dips to the west gently in this area just west of the unit boundaries. It may be flat. They indicated it's slightly from level to slight dip to the west over most of the area; a little bit, perhaps, up-dip, but this is so small it's insignificant as

compared to anything that we discussed and has no bearing on whether our earlier analyses were right or wrong. It just doesn't affect it.

Q. Mr. Greer, you have a great deal of experience in drilling in just not this Niobrara but other Niobrara crooked hole country, have you not?

A. Yes, sir.

Q. Can you tell us what happens to you normally when you drill in that kind of area if you don't make a special precaution to prevent it?

A. Yes, sir, the deviation can be greater than what you otherwise would expect. And if Cotton has drilled 15 miles west of here, they don't expect to find deviation problems, but they can occur, and we've found just as we've discussed the Niobrara and we've spent quite a bit of time in the last 20 years drilling wells, producing them, and just as we have shown here how the Niobrara can be produced, how high recoveries can be realized, other operators come along and they look at the recoveries but they don't pay any attention as to how they were managed, how we managed to get those recoveries. They just assume they can go drill a well and get the same high recovery.

By the same token they think they can drill a straight hole and no problem.

We're presently participating in a well in northwest Colorado now drilled to this same formation, the dip of the formation about 10 degrees, and the operator, despite our admonitions to be careful, went by the old wife's tail that, well, it's only 10 degree dip, the maximum deviation we can get is 10 degrees, we don't have anything to worry about. But after the deviation got out to 30 degrees they began to worry about it and they brought it back to 18 degrees with a dog-leg and it's a real problem. It can happen. It happened there, it can happen here. So deviation can be a problem.

It certainly can be a problem and we certainly think there needs to be some protection.

Q. As a matter of fact, you really expect it to occur here if you don't take precautions against it, don't you?

A. If you're not careful, yes. Can I make a comment on that?

Q. You are now referring to --

A. Koch's Exhibit --

Q. Koch's --

A. -- Four, I believe, it has the --

MR. VERITY: Is this your Exhibit Four? Or which number is it? It is your exhibit, isn't it?

MR. CARR: That's Exhibit Number Four.

That's correct.

MR. VERITY: Number Four. That's also found in -- in Exhibit One of the applicant, it's a copy of that exhibit? In Section A?

A. Yes, sir.

Q. Go ahead. You have some comments to make about this?

A. Yes, sir. Mr. Paull was talking and commenting on this, that we had defined four pools in this area, and so far we've only defined three. One is West Puerto Chiquito. One is the East Puerto Chiquito. And the little reservoir to the south just east of the unit boundary, and these pools have been determined to be separate, but we have down-dip water in Northeast Puerto Chiquito. These wells in the southeast quarter of the unit in this area of steep dip, they just don't have a wide -- high degree of communication; they're not in communication with the unit, but that's an entirely different situation from the area to the west, and as we indicated earlier, we can't tell capacities of wells that may be drilled here, but there'll be no difficulty once a well is drilled and its pressure taken to determine whether it's in communication or not. For this reason we've written a letter to the USGS requesting that they require the operators that they take these tests, and nothing would please me more

than to find that Cotton has drilled and found a new reservoir not in communication with Canada Ojitos. That would be a great relief to us; perhaps to Cotton, too.

But right now the chances are more likely that it will be in communication than out.

Q. If it's in communication it needs to apply to the rules that will protect conservation that's been established in the field.

A. Yes, sir.

Reference was made -- I don't know which exhibit this is of Koch's.

MR. CARR: That's Five.

A. Is it Koch's Exhibit Five, a letter of August 28th which I wrote to Mr. Bick (sic) of Koch, and referred to a letter of April 30th, which we'd written to our working interest owners, and some points are highlighted in here, which again simply shows that we were concerned about protection of the unit and how to protect it. That's all that amounts to, a situation entirely consistent with everything else that we've done.

It's been stated that we've taken no interest in the area west of the unit regarding its development. I would point out that the price of oil just started to go up in April a year ago; it's been a little over 15, 16 months.

That was the first indication that we've had that this area might be commercially productive to develop.

Within a year after that we had made our -- made plans as to one approach to develop this area, and contrary to remarks that have been made that we would not support development, we have suggested that three wells be drilled on the west boundary of the unit, of the existing unit, just outside its boundary, and we have here, I think we should introduce --

Q. This is all one?

A. Uh-huh.

MR. VERITY: Will you mark that as Applicant's Exhibit Four, please?

MR. HUNKER: May I see that?

MR. VERITY: Yes, you may.

(The reporter marked Applicant's Exhibit Four for identification.)

Q. I direct your attention to what the court reporter has marked Exhibit Four, Applicant's Exhibit Four, and will you please tell us what it is and explain it to us?

A. It's just a chronology of significant

events leading up to the approval of the West Canada Ojitos Unit as an area designated by the USGS as a logical unit area. You can see that from March of this year until September the 8th, when it was designated by the USGS, and this is not all of the things that we did. This is just a sketch, a summary of some of the things.

I think it's misleading to say that we've had no interest in the development of this area west of Canada Ojitos Unit.

MR. VERITY: We offer Exhibit Four in evidence.

MR. RAMEY: Exhibit Four will be admitted.

Q. Do you have anything further, Mr. Greer?

A. Well, just to make a point. Mr. Paull, who doesn't know anything about reservoir engineering, has made a reservoir engineering analysis of the Boulder-Mancos Field; mixed up considerably on the figures which we've reported, but we should straighten them out just a little bit.

Boulder covered about 2000 acres, the drilled area, and just exactly how much more than that is productive, we don't know, but the recovery is something less than 1000 barrels an acre, 6-or-800 barrels an acre, and does not approach 1000 or 1500 barrels an acre, as he referred to.

The recovery of 66 percent of the oil in

place at Boulder is -- there's no way that we can arrive at that kind of a figure. I believe he grabbed that 1500 barrels an acre as what we indicated was the average recovery. Of course it's not the average recovery but the average amount of oil in place in Canada Ojitos and doesn't have anything to do really directly with Boulder.

Q. Anything further?

A. No, sir.

MR. VERITY: With that we rest, Your Honor.

MR. HUNKER: I'd like to ask a few questions of Mr. Greer, if I may.

A. Yes, sir.

CROSS EXAMINATION

BY MR. HUNKER:

Q. Mr. Greer, did you have an Eastman survey done on the wells that you drilled in the Canada Ojitos area?

A. We did not have directional surveys on these wells. I believe as I indicated earlier in response to a similar question, everywhere that we have run directional surveys on wells drilled to this formation, we've found that they drifted up-dip.

Q. Would you have the operators outside of

this unit go to the expense of having these surveys done? Do you think it's absolutely essential? You're familiar with the Eastman survey, deviation survey?

A. Yes.

Q. Would you compel the operators, Koch and Cotton, to have Eastman --

A. Not in the least; just take their normal deviation surveys and add them up and if they're less than 330 feet, they comply.

Q. Are you familiar with Mr. C. N. Needham of the Mobil Oil Corporation?

A. I've heard of him, yes, sir.

Q. Have you read his analysis of the Boulder-Mancos Field?

A. I believe I have.

Q. Would it surprise you to know that he has said that the area covers 1700 proven acres and that the estimated primary recovery has been 1000 barrels per acre up to July of 1977?

A. Well, there's 24 wells, I believe, on 80 acres, which adds up to about 2000. 24 wells on 80-acre spacing adds up to about 2000 acres. You can say, you know, I presume he has the privilege of saying well, none of the -- that some of the spacing units were not completely productive.

My view is that more than the spacing units were productive, but we're down now to 800 to 1000 barrels an acre. That's, you know, that's not a lot to quarrel about.

MR. HUNKER: I have no further questions here.

MR. RAMEY: Any other questions of Mr. Greer? He may be excused.

Is there anything further in this case?

MR. VERITY: We have nothing further in the way of evidence, Your Honor. I would like about two or three minutes to offer a very, very brief summary.

MR. RAMEY: You may proceed, Mr. Verity.

MR. VERITY: I would like to point out to Your Honors that there is not one iota of evidence presented here today that in any way controverts the testimony and evidence presented by the Applicant.

We did have one witness who admitted he was not an engineer and didn't know anything about it, who said he found the figures confused in it. We suggest that that is not in any-wise controverting that evidence.

This evidence shows that the pool produces that West Puerto Chiquito. It proves it produces through a fracture system; that there has been 17 years of very

assiduous care in the production of the oil from West Puerto Chiquito and that by reason of that instead of getting 5-1/2 percent of the oil in place and long ago having abandoned the field, we are in the process of getting between 50 and 60 percent of the oil in place from the major portion of the field, and that if that is interrupted by competitive drilling, which will destroy that conservation program, that we will lose possibly as much as 90 percent of the future recoveries; we will strike the 70 percent decline curve that was experienced in Boulder; and it will be experienced here as soon as we have uncontrolled competitive drilling and can no longer inject oil into the top of the reservoir.

We've had people say that they -- they would like to take the position now that their acreage really isn't in the West Puerto Chiquito Field and they're going to drill a well and they hope to prove that and then they'll come back and ask that it be out, and therefor, they don't want to have rules that would protect the field at this time.

All we could say to those people is that if after they drill their well they find that they're not in the pool, in the pool, then I'm sure that this Commission will hear them and if that evidence is shown, then this Commission, I'm sure, would delete it.

But at the present time they are in the

pool. They have -- in the field and in the pool -- they haven't asked that that acreage be deleted from the field and they do have to comply with the rules and regulations of this Commission for West Puerto Chiquito Oil Pool.

We don't think there's any question that what our evidence has shown, that it will be a catastrophe if this pool is not protected and the conservation program that has been established allowed to continue the best method possible. There's no way you can protect it completely with the protestants here refusing to enter into proper unit agreements, compatible with Canada Ojitos; but the best protection, and the best protection that the Commission can grant, is to require the spacing pattern that the applicant has requested, and confine drilling to the west half of the field -- west half of each section unit, and to adopt a rule that will require that the bottom of their holes not deviate out of the west half of the section.

I suggest to this Commission that it's a rare instance when you have a case presented to you with the factual basis and backup that has here been presented. It's a rare instance in the practice of oil and gas law when you have this accurate data that can be presented in support of an application. Not only has it been accurate and comprehensive, it is -- it stands uncontroverted.

We've talked about the fact that we're an aggressive company and we've talked about lease expiration, we've talked about a great deal of things, none of which comes right down to the meat of the coconut, are we going to destroy the conservation that has been -- has enabled a dramatic production and percentage of recovery of oil here. Is that going to be destroyed or is it going to be protected?

We think that the law of correlative rights, and with the statutes of New Mexico which require that this Commission prevent waste, demand that an order be entered that will best protect this field from waste, and that is as applicant has requested, to confine the drilling in the west half of each section unit, and protection that the bottom of the hole will not deviate from it.

MR. RAMEY: Thank you, Mr. Verity. Mr. Carr?

MR. CARR: May it please the Commission, no matter how this case is actually styled, what in fact we have here is the first case of this nature ever to come before this Commission, for it is -- it appears to be a case to force voluntary unitization.

We've had a lot of talk today about statutory unitization, but Mr. Greer and I both recognize that there are substantial impediments, substantial problems, that

would have to be overcome before statutory unitization could actually be brought in this area.

And so what we have here is an application which will impose such rigid requirements on the development of interest owners west of the Canada Ojitos Unit that they will be given substantial incentive to voluntarily unitize to avoid your rules, and enable themselves to operate and produce the acreage in that area in a prudent fashion.

Now, there are several things about the evidence that need to be pointed out. There's been a substantial amount of evidence offered. We certainly would concur with Mr. Verity on that score, but there's no hard data on the area west of the Canada Ojitos Unit.

Now the operator has been actively involved in the area for 17 years and he has not drilled over there. Whatever his reasons may be, he now comes in and is objecting to those who have paid valuable consideration for leases and are in the area west of the unit proposing to drill.

The interesting thing about the case is that we have all of this data on the unit but the rules that they are proposing impact on an area on which there has been no data other than conjecture. What we have is substantial concern expressed by Benson-Montin-Greer about what the impact might be on their unit. We represent those who propose

to go out there, invest their money, and provide you with the kind of data from which you can base a clear and rational determination as to how the area should be developed. We submit that's a better approach than simply barring any development whatsoever.

What Koch Exploration is proposing is that they -- they ask that as they go out and attempt to develop their acreage, that the Oil Conservation Commission not build into its rules additional tests, additional location requirements, and lock them into additional problems with the Forest Service and other agencies, which will only increase their costs and make it more difficult for them to prudently develop their leases.

We submit the application should be denied.

MR. RAMEY: Thank you, Mr. Carr.

Anything else? If not, we will take the case under advisement.

MR. VERITY: If I might, Your Honor, just a word or two of rebuttal. I'm entitled to that, the applicant is entitled to open and close.

MR. RAMEY: Mr. Verity.

MR. VERITY: Counsel says that we want to force them into unitization. That's not what this hearing

is about today at all. It's to establish a rule that will protect the conservation system that will bring about the greatest recovery of oil and will protect the correlative rights.

Counsel says that we want to restrict them so that they can't drill and develop their acreage. That's not true at all. What we've asked is a reasonable spacing pattern that requires them to drill on the west half of their section.

What they really want is to get up close to the unit so that they can put a fracture straw into the oil to the east that's being pushed from east to west onto their units. That's exactly why they want to get close to the line. Their witnesses admitted, yes, what they were looking for and what they hope to find was a fracture system. That fracture system will put them into the gas at the top of the unit four miles away, will give them large recoveries, and will destroy the conservation of the unit.

That's what this case is all about.

MR. RAMEY: We have some correspondence. One is from Patrick Petroleum and they urge the denial of the Benson-Montin-Greer application.

We have two telegrams, one from Supron and one from Merrion and Bayless, who support Benson-Montin-

Greer.

And with that, we'll take the case under advisement and the hearing is adjourned.

(Hearing concluded.)

REPORTER'S CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY THAT the foregoing Transcript of Hearing before the Oil Conservation 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 C.S.R.

Sally W. Boyd, C.S.R.