STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 10547

APPLICATION OF BENSON-MONTIN-GREER DRILING CORPORATION FOR A HIGH ANGLE/HORIZONTAL DIRECTIONAL DRILLING PILOT PROJECT, RIO ARRIBA COUNTY, NEW MEXICO

PRE-HEARING STATEMENT

This pre-hearing statement is submitted by BENSON-MONTIN-GREER DRILLING CORPORATION as required by the Oil Conservation Division.

APPEARANCE OF PARTIES

PARTICIPANT	ATTORNEY
BENSON-MONTIN-GREER DRILLING CO. 501 Airport Drive Farmington, NM 87401 ATTN: Al Greer	W. Thomas Kellahin KELLAHIN & KELLAHIN P.O. Box 2265 Santa Fe, NM 87504 (505) 982-4285

OPPOSITION OR OTHER PARTY	ATTORNEY
SEE OPPOSITION FILING, IF ANY	

STATEMENT OF CASE

APPLICANT

Benson-Montin-Greer Drilling Corporation seeks to initiate a high angle/horizontal directional drilling pilot project within a standard 640-acre oil spacing and proration unit in the West Puerto Chiquito-Mancos Oil Pool comprising all of Section 9, Township 27 North, Range 1 West. Applicant proposes to drill vertically from a well to be located on the surface at an unorthodox surface oil well location 1050 feet from the North line and 2300 feet from the West line (Unit C) of said Section 9 to a depth sufficient to penetrate the base of Mesaverde formation and kick-off in a southerly direction, build angle and continue to drill horizontally in the Mancos formation. The applicant proposes to keep the horizontal displacement of said well's producing interval within the allowed 1650 foot offsetting provisions for said pool.

OPPOSITION OR OTHER PARTY

SEE OPPOSITION FILING

PROPOSED EVIDENCE

APPLICANT

WITNESSES	EST. TIME	EXHIBITS
John D. Roe	30 Min.	7-9 Exhibits

OPPOSITION

WITNESSES	EST. TIME	EXHIBITS

SEE OPPOSITION FILING

PROCEDURAL MATTERS

None.

KELLAHIN and KELLAHIN

By: ______________________
W. Thomas Kellahin
P.O. Box 2265
Santa Fe, New Mexico 87504
(505) 982-4285
ATTORNEYS FOR BENSON-MONTIN-
GREER DRILLING CORPORATION

PHST828.625

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY, MINERALS AND NATURAL RESOURCES

RECEIVED

AUG 28 1992

OIL CONSERVATION DIV.
SANTA FE

APPLICATION OF BENSON-MONTIN-GREER
CORPORATION FOR A HIGH ANGLE/HORIZONTAL
DIRECTIONAL DRILLING PILOT PROJECT,
RIO ARRIBA COUNTY, NEW MEXICO.

CASE NO. 10547

ENTRY OF APPEARANCE

COMES NOW CAMPBELL, CARR, BERGE & SHERIDAN, P.A., and hereby enters its appearance in the above referenced case on behalf of American Hunter Exploration, Ltd.

Respectfully submitted,

CAMPBELL, CARR, BERGE
& SHERIDAN, P.A.,

By: William F. Carr
WILLIAM F. CARR
Post Office Box 2208
Santa Fe, New Mexico 87504
Telephone: (505) 988-4421

ATTORNEYS FOR AMERICAN
HUNTER EXPLORATION, LTD.

CERTIFICATE OF MAILING

I hereby certify that I have caused to be mailed a true and correct copy of our foregoing Entry of Appearance to W. Thomas Kellahin, Esq., Kellahin & Kellahin, Post Office Box 2265, Santa Fe, New Mexico 87504-2265 on this 28th day of August, 1992.

William F. Carr

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY, MINERALS AND NATURAL RESOURCES

RECEIVED

AUG 28 1992

OIL CONSERVATION DIV.
SANTA FE

APPLICATION OF BENSON-MONTIN-GREER
CORPORATION FOR A HIGH ANGLE/HORIZONTAL
DIRECTIONAL DRILLING PILOT PROJECT,
RIO ARRIBA COUNTY, NEW MEXICO.

CASE NO. 10547

ENTRY OF APPEARANCE

COMES NOW CAMPBELL, CARR, BERGE & SHERIDAN, P.A., and hereby enters its appearance in the above referenced case on behalf of American Hunter Exploration, Ltd.

Respectfully submitted,

CAMPBELL, CARR, BERGE
& SHERIDAN, P.A.,

By: William F. Carr

WILLIAM F. CARR
Post Office Box 2208
Santa Fe, New Mexico 87504
Telephone: (505) 988-4421

ATTORNEYS FOR AMERICAN
HUNTER EXPLORATION, LTD.

CERTIFICATE OF MAILING

I hereby certify that I have caused to be mailed a true and correct copy of our foregoing Entry of Appearance to W. Thomas Kellahin, Esq., Kellahin & Kellahin, Post Office Box 2265, Santa Fe, New Mexico 87504-2265 on this 28th day of August, 1992.

William F. Carr

William F. Carr

NMOCD, Santa Fe

BENSON-MONTIN-GREER DRILLING CORP.

221 PETROLEUM CENTER BUILDING, FARMINGTON, NM 87401 505-325-8874 FAX: 505-327-9207

OIL CONSERVATION DIVISION RECEIVED '92 SEP 4 AM 8 47

August 31, 1992

U.S. Department of the Interior
Bureau of Land Management
Farmington Resource Area
1235 La Plata Highway
Farmington, NM 87401

Attention: Mr. Mike Pool

Dear Mr. Pool:

This letter is in partial response to your letter of August 13 regarding well spacing in a part of the West Puerto Chiquito Mancos oil pool in Rio Arriba County, copy with designated CFR attached enclosed for reference. We are responding to your request with respect to geological and engineering data by letter of even date directed to the attention of Brian Davis.

Involved, however, are other matters which I would like to bring to your attention. They are addressed herein.

In the discharge of its duties administering Indian leases the BLM is biased. The BLM representatives have advised that this bias stems from its trust responsibilities to the Tribes. Our perception is that it has been foisted on the BLM by its charges. Although we understand this bias, we disagree with the philosophy that says you can't approach these duties "even-handed" - as you do with federal leases. Further we think there are limits to which the BLM can lawfully go as it exercises this bias.

Also, I am wondering if you have had time to assess all of the ramifications of complying with this most recent request of the Tribe? In these respects I set out below some comments and questions.

FIRST COMMENT

You state that until the study has been completed, no further drilling will be allowed in Township 27 North, Range 1 West. We presume your office is aware - but if not we now so advise you - that a well is now being produced offsetting one of our leases in

Township 27 North, Range 1 West at reported rates of 600 to 800 BOPD. Unless allowed to drill protective well(s) we are being denied the protection of our correlative rights.

We think none of the lease terms nor any of the Department of the Interior regulations - particularly CFR 3162.2 to which you refer - gives the Department of the Interior the authority to discriminate or to deny us these rights. We presume you were not aware of the inequity your order creates, or surely, you would not knowingly have issued it. Time is of the essence here - particularly now that winter is approaching. If we are delayed by your actions until winter to drill, a further hardship will be forced on us.

SECOND COMMENT

If you feel strongly that no additional wells should be drilled until you have completed your study, then we think you are obliged to shut in the well that is draining our lease: either you should allow us the opportunity to protect our interests; or in the alternative you should stop the offense.

FIRST QUESTION

We have a question: does your office really want to get involved in setting spacing? I point out that there's no land classification in the state of New Mexico which does not at some point join land of another classification. As you know we have four main classifications: federal, Indian, state and fee. Unless there's an unbiased authority responsible for setting spacing overall, the problems of protection of correlative rights of parties in the different classifications can be insurmountable.

If, for example, the BLM sets spacing on Federal and Indian lands and the New Mexico State Land Office sets spacing on state lands and each attorney representing a fee royalty owner would set the spacing on his land, I think you can understand the problems that would develop.

SECOND QUESTION

The matter of allowables goes hand-in-hand with spacing. Is your office prepared to take over from the Oil Conservation Commission the responsibility of setting, tracking, and reporting allowables? I think wells on Federal and Indian lands in this area are measured in tens of thousands.

THIRD COMMENT AND MORE QUESTIONS

The Tribe has presented this matter to you as a narrowly-focused issue in which they seek to deny us the right to develop our lease, and you are attempting to comply (we note your file number in this case is not a general information file - but is the file of the lease which the Tribe wants to prevent us from drilling).

We think you cannot - in the approach you have taken - treat this simply as a narrowly-focused issue: there are broader implications. The subject lands are part of a larger pool that includes federal, state and fee leases. How would your spacing and allowable orders affect the other lands in the pool? Are you going to rescind the orders of the New Mexico Oil Conservation Commission? We note these orders are the culmination of 30 years of cases and hearings. The last series of hearings covered two years and many days of testimony at an estimated cost to participants for expert witnesses and attorneys of two million dollars. Are you prepared to launch a more thorough investigation? How can you equitably approach spacing other than by the procedures adopted by the New Mexico Oil Conservation Commission: allowing presentation of testimony and cross-examination of witnesses? How can you sit in impartial judgment when you have assumed the role of representative of one of the parties in interest?

I submit that spacing is such a basic issue in the orderly development of an oil reservoir and protection of correlative rights that it should only be addressed in an unbiased forum which allows - as the Oil Conservation Commission does - presentation of testimony and cross-examination of witnesses.

If the BLM chooses to represent a party, the BLM should be a participant in such a forum so that its witnesses can be cross-examined. Under the traditional method of handling these things in New Mexico the unbiased forum is the Oil Conservation Commission. If you think a spacing change is in order it seems to me you should make an application to the Oil Conservation Commission asking to change the spacing, and then follow established procedures.

SOLUTION OF YOUR PROBLEM: UNITIZATION

There is however, a lawful way in which the Department of the Interior can approve spacing patterns different from the basic ones set by the Oil Conservation Commission: through unitization of the affected lands. Our lease provides that the Tribe's lands will be committed to a unitization plan approved by the Department of the Interior. There are only three entities involved: two operators and one royalty owner, and all have expressed an interest in unitization. The problem appears to be getting the parties to meet and work on it.

American Hunter's people say they will work on it if the Tribe gives its approval for them to join in discussion. The Tribe, through its Oil and Gas Administrator, has said the Tribe is interested in pursuing unitization. I appeal to you to get this process moving.

If the Department of State can get the Israelis and the Arabs to talk peace, surely the Department of the Interior can get the Jicarilla Tribe and B-M-G to talk unitization. Although the BLM doesn't like to get involved in Tribal trades, the BLM is obliged to review - if not actively participate in - the determination of the Tribe's equities in a unit. I submit efforts of the BLM to bring about unitization would be far more fruitful than any that can come by pursuing the course you have chosen.

Yours truly,

BENSON-MONTIN-GREER DRILLING CORP.

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

ARG/tlp

Enclosure

Copies to:

1. Bureau of Indian Affairs, Energy and Minerals Resource Assistance Office, Golden, CO.
2. Bureau of Indian Affairs, Dulce, NM.
3. New Mexico Oil Conservation Division, Aztec, NM.
4. New Mexico Oil Conservation Division, Santa Fe, NM.
5. American Hunter Exploration Ltd., Denver, CO.
6. W. Thomas Kellahin, Kellahin & Kellahin.
7. Celia Kilgore, Anson, Maloney & Hill, L.L.P.

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Farmington Resource Area
1235 Laplata Highway
Farmington, New Mexico 87401

TAKE PRIDE IN AMERICA

IN REPLY REFER TO
Jicarilla Contract 404 (DL)
3162.2 (019)

AUG. 1 3 1992

CERTIFIED--RETURN RECEIPT REQUESTED
P 794 523 429

AUG 1 7 1992

Mr. Al Greer
Benson-Montin-Greer Drilling Corporation
221 Petroleum Center Building
Farmington, NM 87401

Dear Mr. Greer,

The Farmington Resource Area (FRA) of the Bureau of Land Management is conducting a reservoir analysis of T. 27 N., R. 1 W., Rio Arriba County, New Mexico to determine if the current 640-acre spacing in the Mancos formation is appropriate for this area. We have been requested to conduct this study by the Jicarilla Tribe. Until the reservoir analysis is complete, no further drilling shall be allowed in T. 27 N., R. 1 W., Rio Arriba County, New Mexico in accordance with CFR 3162.2.

We are requesting any supporting reservoir or geological data that your agency or company may have that pertains to spacing requirements in the Mancos Formation. We feel that the additional data would facilitate a more effective spacing determination for this acreage. If you wish to submit any data, please do so by October 1, 1992.

This letter is being sent to the following agencies and companies:

1. Bureau of Indian Affairs, Energy and Minerals Resource Assistance Office, Golden, CO.
2. Bureau of Indian Affairs, Dulce, NM.
3. New Mexico Oil and Gas Conservation Division, Aztec, NM.
4. New Mexico Oil and Gas Conservation Division, Santa Fe, NM.
5. Benson-Montin-Greer Drilling Corporation, Farmington, NM.
6. American Hunter Exploration Limited, Denver, CO.

If you have any questions regarding this request, please call Brian Davis at (505) 599-8994 or (505) 327-5344.

Sincerely,

M Pool

Mike Pool
Area Manager

the operator has acquired by purchase, condemnation or otherwise

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583-36586, Aug. 12, 1983; 49 FR 37364, Sept. 21, 1984; 53 FR 17363, May 16, 1988]

§ 3162.2 Drilling and producing obligations.

(a) The operating rights owner shall drill diligently and produce continuously from such wells as are necessary to protect the lessor from loss of royalty by reason of drainage. The authorized officer may assess compensatory royalty under which the operating rights owner shall pay a sum determined by the authorized officer as adequate to compensate the lessor for operating rights owner's failure to drill and produce wells required to protect the lessor from loss through drainage by wells on adjacent lands. Any such assessment will be made after a review of available information relating to development of the leased lands. Such assessment is subject to termination or modification based upon the authorized officer's continuing review of such information.

(b) The operator, at its election, may drill and produce other wells in conformity with any system of well spacing or production allotments affecting the field or area in which the leased lands are situated, and which is authorized and sanctioned by applicable law or by the authorized officer.

(c) After notice in writing, the operating rights owner shall promptly drill and produce such other wells as the authorized officer may reasonably require in order that the lease may be properly and timely developed and produced in accordance with good economic operating practices.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583-36586, Aug. 12, 1983, further amended at 53 FR 17363, May 16, 1988]

§ 3162.3 Conduct of operations.

(a) Whenever a change in operator occurs, the authorized officer shall be notified promptly in writing, and the new operator shall furnish evidence of sufficient bond coverage in accordance with § 3106.6 and subpart 3104 of this title.

(b) A contractor on a leasehold shall be considered the agent of the operator for such operations with full responsibility for acting on behalf of the operator for purposes of complying with applicable laws, regulations, the lease terms, NTL's, Onshore Oil and Gas Orders, and other orders and instructions of the authorized officer.

[53 FR 17363, May 16, 1988; 53 FR 31959, Aug. 22, 1988]

§ 3162.3-1 Drilling applications and plans.

(a) Each well shall be drilled in conformity with an acceptable well-spacing program at a surveyed well location approved or prescribed by the authorized officer after appropriate environmental and technical reviews (see § 3162.5-1 of this title). An acceptable well-spacing program may be either (1) one which conforms with a spacing order or field rule issued by a State Commission or Board and accepted by the authorized officer, or (2) one which is located on a lease committed to a communitized or unitized tract at a location approved by the authorized officer, or (3) any other program established by the authorized officer.

(b) Any well drilled on restricted Indian land shall be subject to the location restrictions specified in the lease and/or Title 25 of the CFR.

(c) The operator shall submit to the authorized officer for approval an Application for Permit to Drill for each well. No drilling operations, nor surface disturbance preliminary thereto, may be commenced prior to the authorized officer's approval of the permit.

(d) The Application for Permit to Drill process shall be initiated at least 30 days before commencement of operations is desired. Prior to approval, the application shall be administratively and technically complete. A complete application consists of Form 3160-3 and the following attachments:

(1) A drilling plan, which may already be on file, containing information required by paragraph (e) of this section and appropriate orders and notices.

(2) A surface use plan of operations containing information required by

NMOCD, Santa Fe

BENSON-MONTIN-GREER DRILLING CORP.

221 PETROLEUM CENTER BUILDING, FARMINGTON, NM 87401 505-325-8874 FAX: 505-327-9207

August 31, 1992

U.S. Department of the Interior
Bureau of Land Management
Farmington Resource Area
1235 La Plata Highway
Farmington, NM 87401

Attention: Mr. Brian Davis

Re: WELL SPACING
MANCOS FORMATION WELLS
WEST PUERTO CHIQUITO MANCOS POOL
TOWNSHIP 27 NORTH, RANGE 1 WEST
RIO ARRIBA COUNTY, NEW MEXICO
YOUR FILE JICARILLA CONTRACT
404 (DL) 3162.2 (019)

Gentlemen:

This is in response to your letter of August 13 requesting reservoir or geological data pertaining to spacing of Mancos formation wells in Township 27 North, Range 1 West.

The subject township is within the West Puerto Chiquito Mancos oil pool as designated by the New Mexico Oil Conservation Commission. A very large amount of reservoir data has been accumulated and presented to the authorities regarding this subject. As to the Department of the Interior's own records, we refer you to the applications for expansions of participating areas in the Canada Ojitos Unit which lies within the West Puerto Chiquito Mancos oil pool. In addition we refer you to hearing held by the Department of the Interior June 5, 1981 in connection with the third expansion of the Canada Ojitos Unit.

For thirty years spacing has been set in this pool by the New Mexico Oil Conservation Commission all pursuant to appropriate hearings before this body. A chronology of the orders and resulting decisions as to spacing are set out on the attached list.

Following the hearings for the cases leading to the last orders on the chronology list, Frank Chavez of the New Mexico Oil

Conservation Division formed a study committee comprising representatives of operators recently involved in drilling Mancos formation wells on the east side of the San Juan Basin, in order to devise a spacing plan to cover initial drilling in areas outside designated pools. The outcome of these meetings was, among other things, a basic spacing of 640 acres per well with an option to drill a second well on the proration unit if the first well was a small (less than 50 BOPD) producer.

The Commission has not yet acted on this proposal but the New Mexico Oil Conservation Division did recently set spacing for an exploratory area in the Mancos covered by the proposed Rock Mesa Unit in Sandoval County which contains basic 640-acre spacing with option for a second well if the first well is a small well (as recommended by the study committee).

The most recent published review of geological and engineering data for the West Puerto Chiquito Mancos pool was that which appeared in the 1991 AAPG Treatise of Petroleum Geology Atlas of Oil and Gas Fields, Structural Traps V, a paper by Greer and Ellis, copy enclosed.

A review of all of the available data shows that there are areas on the east side of the San Juan Basin in which Mancos formation wells can drain large areas; and that under unitization and pressure maintenance, benefits from this characteristic can be realized in the form of additional ultimate recovery.

However because of the extreme variation in reservoir character over short distances, it is only under unitization that these benefits can equitably derive. Absent unitization, correlative rights cannot be protected on spacing wider than 640 acres per well, and may even require the study committee provision that a second well be allowed on a 640-acre proration unit if the first well is a small well.

Yours truly,

BENSON-MONTIN-GREER DRILLING CORP.

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

ARG/tlp

Copies of letter being sent to:

1. Bureau of Indian Affairs, Energy and Minerals Resource Assistance Office, Golden, CO.
2. Bureau of Indian Affairs, Dulce, NM.
3. New Mexico Oil Conservation Division, Aztec, NM.
4. New Mexico Oil Conservation Division, Santa Fe, NM.
5. American Hunter Exploration Ltd., Denver, CO.

CHRONOLOGY
OF WELL SPACING ORDERS
ISSUED BY THE NEW MEXICO OIL CONSERVATION COMMISSION
FOR THE WEST PUERTO CHIQUITO MANCOS POOL
RIO ARRIBA COUNTY, NEW MEXICO

1962 Statewide spacing: 40 acres per well.

1963 Order R-2565: Sets temporary 160 acre spacing for East and West Puerto Chiquito Mancos pools.

1966 Order R-2565-B: Separate rules established for East and West Puerto Chiquito Mancos pools. West Puerto Mancos pool set at temporary (3-year) 320 acres per well. Provides for interference tests and transfer of allowables.

1969 Order R-2565-C: Makes permanent spacing of 320 acres per well and assigns proportional factor of 8 for allowable purposes (40 acre spacing has factor of 1).

1980 Order R-6469:

a) Sets permanent 640 acre spacing for West Puerto Chiquito Mancos pool, wells no closer than 660 feet to section line.

b) Identifies special non-standard proration units.

1981 Order R-6469-A:

a) Amends well locations for standard proration units to be no closer than 1650 feet to outer boundary, with administrative approval for exceptions because of topography and no objection from offset operators.

b) Continues location for non-standard proration units at 660 feet from proration unit boundary.

1986 Order R-6469-B: (Following application by Canada Ojitos Unit operator to equalize allowables along West Puerto Chiquito Mancos and Gavilan boundary):

a) Permits drilling of two wells in a 640 acre proration unit in west two rows of sections in West Puerto Chiquito adjoining Gavilan; but not more than one well in west half of section on Gavilan boundary.

b) Permits full 640 acre proration unit allowable when only one well on a section adjoining Gavilan if not closer than 2310 feet from Gavilan boundary.

1987	Order R-6469-D:	Permits temporary increase in allowable of West Puerto Chiquito Mancos pool to equalize with temporary increase in allowable of offsetting Gavilan pool - no change in spacing.
1988	Order R-6469-F:	Change in allowable - no change in spacing.

West Puerto Chiquito—U.S.A.
San Juan Basin, New Mexico

ALBERT R. GREER
Benson-Montin-Greer Drilling Corp.
Farmington, New Mexico

RICHARD K. ELLIS
Leede Exploration
Englewood, Colorado

FIELD CLASSIFICATION

BASIN: San Juan
BASIN TYPE: Cratonic Sag
RESERVOIR ROCK TYPE: Shale (Fractured)
RESERVOIR AGE: Cretaceous
PETROLEUM TYPE: Oil
TRAP TYPE: Fractured Reservoir
RESERVOIR ENVIRONMENT OF DEPOSITION: Marine
TRAP DESCRIPTION: Fracture system isolated from outcrop by calcite vein-filling and without connection to water

LOCATION

The West Puerto Chiquito field is located in Rio Arriba County, New Mexico, approximately 80 mi (130 km) southeast of the town of Farmington. The field is situated on the southeast flank of the San Juan basin (Figure 1). Surface use is administered by the Santa Fe National Forest, Bureau of Land Management, Jicarilla Indian Reservation, and various fee interests. Elevations range from 7000 to 8600 ft (2134-2621 m) in rugged canyon and mesa topography.

Immediately to the west lie Gavilan Mancos (oil), Gavilan Pictured Cliffs (gas), and West Lindrith Gallup-Dakota (oil) fields, while Boulder Mancos (oil) and East Puerto Chiquito Mancos (oil) fields are located north and northeast, respectively (Figure 2).

Depending on the future method of depletion, particularly as to the degree that pressure maintenance can continue to be utilized, ultimate recovery of West Puerto Chiquito is expected to be 15 to 20 million bbl of oil and 15 to 20 bcf of gas.

HISTORY

Early Exploration

Early exploration for fractured Niobrara oil reservoirs in the San Juan basin focused on the Hogback monocline, which forms the basin margin on the west, north, and east sides. Verde field, discovered by C. M. Carroll in October 1955, is located on the monocline on the west side of the basin. The pool was initially developed on 80 ac spacing and later partially infilled to 40 ac spacing with no apparent increase in recovery. Verde produced approximately 7.5 million bbl of oil from fractures formed in the Niobrara shale at depths ranging from 2000 to 4500 ft (609-1372 m). East Puerto Chiquito field (Figure 2), discovered by Intex Oil in February 1960, was developed by Benson-Montin-Greer Drilling Corp. on 160 ac spacing and has produced approximately 4 million bbl of oil at depths ranging from 1500 to 4000 ft (457-1219 m). East Puerto Chiquito produces from fractures developed in the Niobrara on a northwest-plunging nose crossing the monocline on the east side of the basin. Boulder field (Figure 2) was discovered by P-M Drilling Co. in May 1961 and has produced approximately 1.7 million bbl of oil on 80 ac spacing at depths ranging from 3400 to 4500 ft (1036-1372 m). Boulder produces from the fractured Niobrara interval along the monocline bounding the east side of the basin.

All three fields benefited from gravity drainage, which significantly increased recovery. Gravity drainage occurred because of shallow depths and the resulting low volume of gas in solution, steep dips, and low withdrawal rates (prorated allowables at Verde and Boulder and voluntary restrictions at East Puerto Chiquito).

Despite efficient recovery under gravity drainage, Boulder was overdrilled on 80 ac spacing, resulting in poor economics. As a consequence, major oil companies discontinued Niobrara exploration on the east side of the San Juan basin.

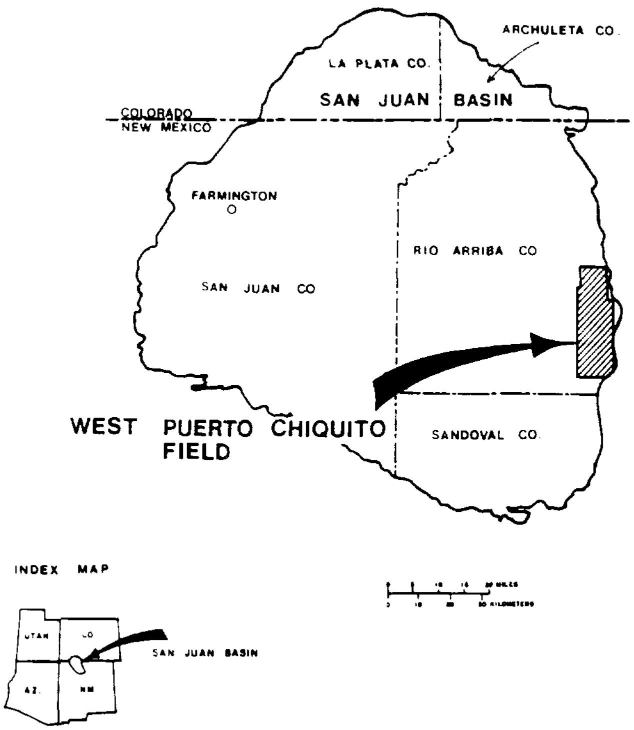

Figure 1. Location map of the San Juan basin showing the West Puerto Chiquito field.

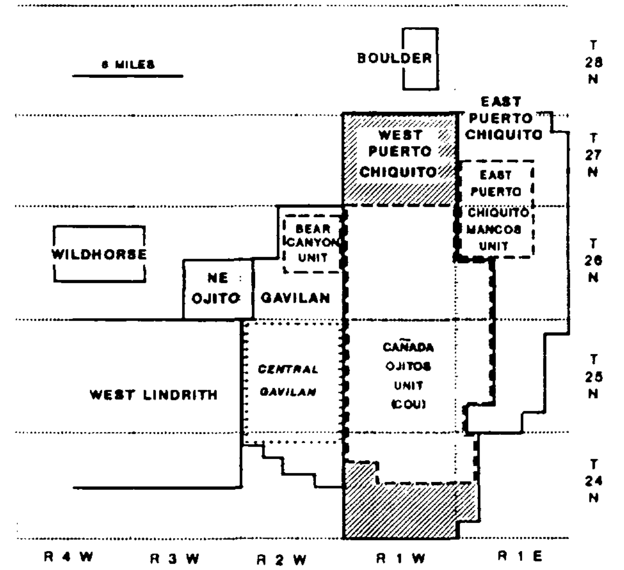

Figure 2. Map showing the locations of fractured Niobrara pools on the east side of the San Juan basin.

Field Discovery

West Puerto Chiquito field was discovered by Bolack and Greer in July 1963 at the Canada Ojitos Unit (COU) No. 2 (K-13; NE SW Sec. 13, T25N, R1W). Drilled to a total depth of 6022 ft (1835 m), the "C" zone of the Niobrara (Figure 3) was hydraulically fractured with 111,000 lb of sand and 85,620 gal. of oil in an open-hole interval from 5976 to 6022 ft (1821-1835 m). The well was completed on pump for 95 BOPD. The initial reservoir pressure was 1620 psig at a datum of +1195 ft (364 m). The discovery well was drilled to evaluate a large acreage block and test fractured reservoir development along a synclinal flexure parallel to the Hogback monocline.

Post-Discovery Activity

Cores from wells drilled early in the life of the West Puerto Chiquito Pool indicated the producing interval to contain no effective matrix porosity (Appendix 1). Production and interference testing (Appendices 2 and 3) confirmed that all porosity was fracture porosity and that per-acre volumes of oil in place were low: 1500 to 2000 bbl/ac. Although production capacities of some of the wells were high (1000 to 3000 BOPD per well), the solution gas drive recovery of this fractured reservoir was expected to be low. This coupled with the small volume of oil in place would result in very low primary recoveries, in the range of 100 to 150 bbl of oil/acre. In contrast, Boulder field recovery, supplemented by gravity

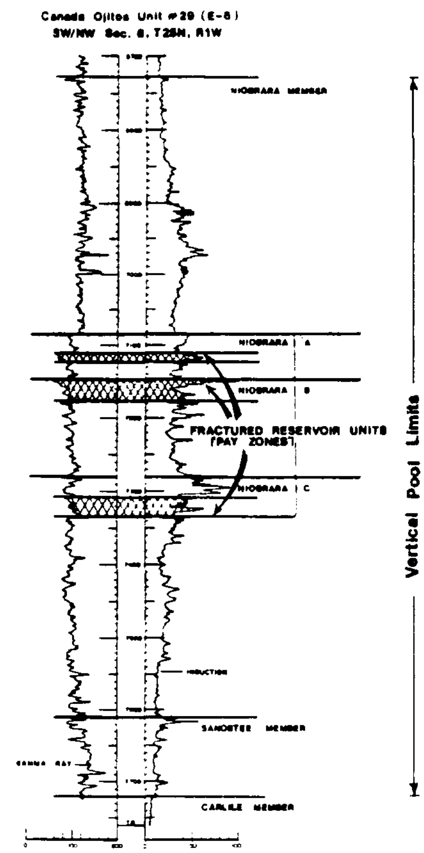

Figure 3. Type log showing units within the Niobrara. Fractured reservoir units, or "pay zones," are found in the "A," upper "B," and lower "C" submembers. The gross reservoir thickness is approximately 250 ft, while "net pay" is in the range of 30 to 100 ft.

drainage, was 600 to 800 bbl of oil/acre (NMOCC, 1988).

Given the lower dips, greater depths, greater volume of gas in solution, and higher shrinkage, "conventional" exploitation at West Puerto Chiquito would yield only solution gas drive recovery: No significant gravity drainage would occur here, despite its contribution in other fields. Furthermore, a reservoir of this type does not lend itself to efficient and economic development under competitive operations: Overdrilling and excessive production rates are a constant threat. Such conventional development would maximize current income but would leave large volumes of oil unrecovered, and the discounted present worth of the recoverable resource would be far less than its potential.

Therefore, a unique plan of development was implemented to achieve gravity drainage recoveries through pressure maintenance, wide spacing, and reservoir management. Reservoir management could only be accomplished through control of spacing and production—objectives that could not reasonably be achieved through conventional pool rules and spacing regulations under competitive operations.

In an unprecedented action, the New Mexico Oil Conservation Commission (NMOCC) approved Benson-Montin-Greer Drilling Corp.'s application to establish an oil pool covering four townships after only a few wells were drilled. To achieve adequate reservoir management, the operator formed a large federal exploratory unit (Canada Ojitos) covering most of the pool. Through a series of hearings before the NMOCC, and as reservoir information was developed, spacing was increased from 40 ac/well to 160, from 160 to 320, and finally from 320 to 640 ac. Development within the unit, however, proceeded on much wider spacing. The initial density of recovery wells approximated one well per four "downstructure" sections such that the drainage geometry for a particular wellbore was approximately 1 mi (1.6 km) in the strike direction and 4 mi (6.4 km) in the dip direction.

Development updip revealed a gas cap area of apparent low porosity and permeability. The Unit Agreement was modified to allow into participation noncommercial lands for gas injection purposes and the unit was expanded to include these lands. Low productivity wells (5 to 10 BOPD and 5 to 10 MCFG/day) were converted to useful gas injectors with injection rates of 1 to 3 million ft^3/day/well.

Productivity of recovery wells remained high because of the pressure maintenance and wide spacing. Efficient recoveries of large volumes of oil resulted—as much as 2.3 million bbl/well. Low capacity wells also maintained producing rates at proportionately high levels and accumulated relatively high recoveries: 120,000 bbl from wells with initial productivities of 25 BOPD and 250,000 bbl for wells with initial rates of 50 to 70 BOPD.

Expansion of the initially developed unit area was deterred in the 1970s by government-mandated oil price controls. Any new wells drilled in the unit would receive "old" oil prices while new wells outside a designated unit qualified for "new" oil prices. A special order sought from the Department of Energy permitting upper tier prices for wells drilled on expansion lands of this particular unit was entered in January 1981. Westward expansion of the unit was then undertaken through an initial five-well program.

Overdrilling offsetting the west boundary of the unit occurred in the 1980s and required the drilling of additional wells to protect against drainage. Most of these wells are unnecessary for the recovery of reserves in West Puerto Chiquito. As a consequence of drilling in the 1980s there was an increase in production rate and acceleration of depletion (Table 1). Spacing of wells in West Puerto Chiquito on the west boundary is approximately 640 ac/well.

New Fields

The Gavilan Mancos Pool, offsetting West Puerto Chiquito (Figure 2), was developed in the mid-1980s. Spacing was initially on temporary 320 ac/well but was later changed to 640 ac with an optional second well. Because of the close spacing and high allowables, central Gavilan was essentially oil depleted

Table 1. West Puerto Chiquito production. Note that from August 1968 through August 1987, all Canada Ojitos Unit produced gas was reinjected and 3.1 bcf of nonunit supplemental gas was acquired and injected. Gas has occasionally been marketed since 1 August 1987.

Year	Oil Production Barrels	Gas Production (Mcf)
1962	1,426	0
1963	31,601	7,268
1964	159,135	52,146
1965	238,942	80,158
1966	340,141	127,269
1967	347,789	189,291
1968	396,511	192,896
1969	519,922	230,108
1970	732,118	230,025
1971	769,573	290,146
1972	638,160	306,136
1973	511,566	487,041
1974	438,692	554,186
1975	321,875	525,000
1976	309,652	501,981
1977	315,158	519,816
1978	262,117	602,288
1979	239,031	550,477
1980	236,599	466,252
1981	237,877	535,511
1982	227,295	525,400
1983	222,455	495,013
1984	220,750	481,476
1985	379,405	449,841
1986	849,776	697,710
1987	851,195	1,499,595
1988	852,058	2,327,924
	10,650,819	12,924,954

five years after initial development (two years after substantial development). At that time and with few exceptions, all wells were in stripper oil status.

Tests of Other Zones

Pictured Cliffs Sandstone—Wells drilled to the Pictured Cliffs Sandstone (Figure 6) generally have high water saturations and produced low volumes of gas.

Mesa Verde—Cores of the Mesa Verde Formation indicate that it is probably water saturated.

Dakota Formation—Three wells have tested the Dakota Formation: one showed only water; a second approximately 100 MCFG/day with about 10 BOPD distillate and 10 BWPD; the third about 2 BOPD distillate and 2 BWPD and 40 to 50 MCFG/day.

DISCOVERY METHOD

The West Puerto Chiquito discovery well was drilled to test fractured reservoir development on a large synclinal flexure parallel to the Hogback monocline. Previous activity showed that commercial oil production could be developed in certain zones in the Niobrara in places where the monocline was tectonically fractured. Development to the west in the Lindrith Gallup-Dakota Pool, to the northeast in the East Puerto Chiquito Pool, and in an untested well drilled in 1952 3 mi (4.8 km) northwest of the discovery well indicated the Niobrara reservoir interval was present. In spite of the favorable geologic indications, the initial well and subsequent development wells were high risk, since economic success in the Niobrara play is dependent on wellbore communication with a high conductivity (tectonic) fracture system.

STRUCTURAL CHARACTERIZATION

The San Juan basin is located in the Colorado Plateau structural province. The basin is an asymmetric synclinal depression with a steep northern rim and a gently dipping southern flank. The basin is bounded by several major structural elements: to the east by the Archuleta anticlinorium and Nacimiento uplift, to the south and southwest by the Puerco fault zone and Chaco slope, to the southwest and west by the Zuni and Defiance uplifts, to the northwest by the Four Corners platform, and to the northeast by the San Juan Mountains. The central portion of the basin is bounded by the Hogback monocline on the west, north, and east sides (Figure 5).

Tectonic History

Although regional stratigraphic relations indicate present-day positive features such as the Archuleta anticlinorium, Nacimiento uplift, and Zuni uplift have an ancestral (pre-Laramide) component of structural development, Laramide tectonic forces operative in the Colorado Plateau are primarily responsible for the present configuration of the San Juan basin and its bounding structural elements. Subsidence began in Late Cretaceous time, prior to deposition of the Ojo Alamo Sandstone. The Archuleta anticlinorium and Hogback monocline on the east side of the basin were positive elements. During the Paleocene, the Ojo Alamo, Nacimiento, and Animas formations (Figure 6) were deposited in a depositional basin including the present-day San Juan and Chama basins and the Nacimiento and Archuleta uplifts (Baltz, 1967).

Laramide compressional forces operative in the Cordilleran structural province were transmitted into the Colorado Plateau, resulting in northeastward shift (Woodward and Callendar, 1977). Structural intensity peaked during late Paleocene–early Eocene: Subsidence of the central basin was at a maximum, the Nacimiento uplift was folded sharply, the Hogback monocline formed along the basin margins, and en echelon, northwest-trending folds developed on the eastern edge of the basin.

Deposition of the synorogenic San Jose Formation on the flanks of bounding uplifts preceded further northeastward shift of the Colorado Plateau. This post-San Jose (Eocene or Oligocene) deformational event resulted in wrench faulting along the Nacimiento and Gallina uplifts and uplift and tilting of all San Jose and older rocks along the eastern margin (Baltz, 1967). Late Cenozoic (Miocene or Pliocene) extensional faulting observed in the Puerco fault zone and along the Archuleta anticlinorium is thought to have reactivated earlier Laramide faulting and to be related to the development of the Rio Grande rift (Woodward and Callendar, 1977).

Regional Structure

West Puerto Chiquito field is located on the southeast basin flank, immediately north of the synclinal axis of the basin and along the west-dipping monocline. Crossing the monocline are several northwest-trending folds. Notable among these are the East Puerto Chiquito anticlinal nose, which is the locus for the East Puerto Chiquito field, and a prominent nose formed at the intersection of the Nacimiento and Gallina faults, which is the location of recent drilling activity in the southeastern portion of the West Puerto Chiquito field.

Field Structure

The structural geometry of the West Puerto Chiquito reservoir includes three genetically related structural elements: from east to west, the west-dipping monocline, a north-trending syncline, and a north-plunging anticlinal nose (Plate 1). Subsurface and outcrop data reveal no significant faulting or vertical displacement is present at reservoir level. Dips at the outcrop of the Niobrara, approximately 1 to 3 mi (1.6-4.8 km) east of the limits of the pool, range from 53 to 59°. Dips decrease rapidly to the west, varying from 6° in the gas injection (updip) portion of the reservoir to essentially flat in the synclinal trough marking the west boundary of the pool (Figure 7). The average dip in the reservoir is approximately 2° or 185 ft/mi. The prominent, north-plunging fold immediately west of the pool boundary—the "Gavilan nose"—exhibits low relief and dips in the range of 1° and is the locus for fractured Niobrara production at Gavilan field.

A map constructed on the top of the Niobrara reservoir interval reveals a clearly defined synclinal trough at the base of a monoclinal panel of dip (Plate 1). In general, the highest capacity wells are located at points of synclinal flexure (Gorham et al., 1979) along the monocline, and along major fracture trends.

Tectonic and Regional Fracture Orientation

Landsat, aerial photography, and geophysical methods provide evidence of large-scale fracture orientations at West Puerto Chiquito. The dominant (surface) fracture trends comprise a conjugate set oriented approximately northwest-southeast and northeast-southwest (Figure 8). Fracture orientations and overall "fabric" change dramatically across the (west northwest-east southeast) Lleguas fracture zone (northern portion of T25N), implying the presence of a rotational component. Several prominent northeast fracture trends are truncated by the Lleguas zone, and trends north of the zone undergo a pronounced northward shift in azimuth. Surface analysis indicates tectonic fracturing is present to some degree over all three structural elements—monocline, syncline, and anticlinal nose—localizing production in West Puerto Chiquito and Gavilan fields, a total area of approximately 150,000 ac. Electromagnetic surveys conducted in specific areas of the field indicate fractures are vertical to near-vertical in inclination.

The extrapolation of the surface fracture interpretation to reservoir depths involves difficult assumptions concerning timing of fracture development and mechanical response of rock units of varying composition and thickness. For example, the fractures cannot be throughgoing in any effective sense, since the vertical limits of production are confined to a few tens of feet. Pressure transient analyses reveal a reservoir geometry of "fracture blocks" bounded by high conductivity fractures (Appendix 3), which is confirmed by surface data and electromagnetic surveys. Therefore, Landsat-photo analysis is a useful exploratory tool.

STRATIGRAPHY

Regional Reservoir Considerations

The San Juan basin produces commercial volumes of oil and gas from structural and stratigraphic accumulations in reservoirs of Pennsylvanian, Jurassic, Tertiary, and, most important, Cretaceous age. A time-stratigraphic nomenclature chart for the San Juan basin is shown by Figure 6. The Pennsylvanian Paradox Formation produces oil and gas from cyclic sequences of restricted marine carbonates on the Four Corners platform in the northwest portion of the basin. Low-energy algal bank complexes in the shelf carbonate sequences form excellent stratigraphic traps. The Jurassic Entrada Sandstone produces oil from sand reservoirs of eolian origin occupying paleotopographic "highs" developed beneath the sealing organic limestones of the Todilto Formation.

The Upper Cretaceous formations represent a classic cyclical sequence typical of deposition in the Late Cretaceous western interior. The northwest-southeast depositional trends of the major units, and the existence of a prominent stratigraphic "rise" during the major transgressions and regressions, are the result of complex interplay between a shallow seaway to the northeast and a clastic sediment supply source to the southwest. Five major transgressions and regressions of the shoreline, and many minor ones, left a stratigraphic sequence that created ideal trapping mechanisms for large oil and gas reserves (Figure 4).

The Upper Cretaceous Dakota Formation represents the initial transgressive sand in the sequence depicted in Figure 4. Sandstone reservoirs in the Dakota produce gas and oil and are subdivided into four members. Basal units in the Dakota are generally fluvial in origin and therefore of erratic reservoir quality. Progressively younger sand units in the Dakota become more marine, with correspondingly better reservoir characteristics.

The Gallup sandstone, of Carlile age, produces oil on the Chaco slope, is the first regressive wedge in the basin, and is unique, having no equivalents elsewhere. The regressive Gallup sands are to be clearly distinguished from the transgressive, Niobrara-age sands ("transgressive Gallup," "Tocito," "Stray," or "Bisti") that are elongate, northwest-trending offshore bars. The bar sands, which are younger and seaward of the regressive Gallup, produce oil in several large fields in the central portion of the basin.

The Niobrara Member represents a major transgressive event that has equivalents throughout the western interior. Substantial dolomite contents,

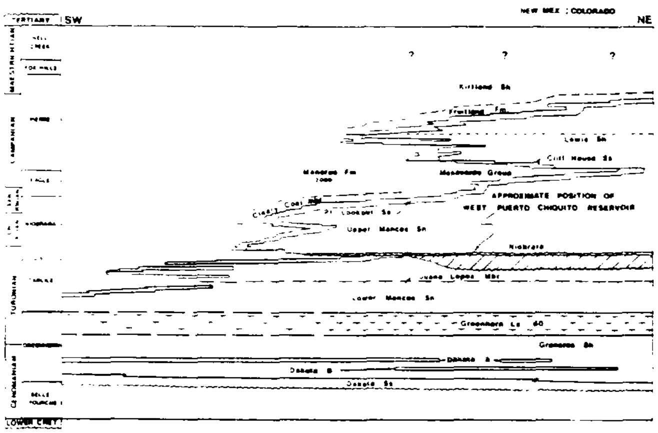

Figure 4. Upper Cretaceous time/stratigraphic section of the San Juan basin showing the stratigraphic position of the Niobrara reservoir interval at West Puerto Chiquito. (After Molenaar, 1977a.)

particularly in the highly laminated siltstone-carbonate sequences, give rise to the resistive character noted on logs (Figure 3) and impart the brittle nature responsible for fractured reservoir development on the basin flanks (London, 1972).

The Mesaverde Group consists of the Point Lookout, Menefee, and Cliffhouse formations. The Point Lookout is a regressive, coastal barrier sandstone that exhibits total northeast stratigraphic rise, over 130 mi (210 km), of approximately 1200 ft (365 m). The rise is responsible for the large, northwest-trending stratigraphic traps that produce gas throughout the central part of the basin. The Menefee is a lagoonal, back-barrier sequence of shale, coal, and fluvial sands that were deposited landward of the Point Lookout and Cliffhouse shorelines. The Cliffhouse is a transgressive sandstone developed during the overall Lewis transgression. The sands clearly intertongue with the marine Lewis shale to the northeast and the nonmarine Menefee to the southwest. A total stratigraphic rise, from northeast to southwest, of approximately 1300 ft (396 m) formed stratigraphic traps that are gas-productive throughout the basin.

The Upper Cretaceous Pictured Cliffs is a marine sandstone deposited in a variety of nearshore environments during the final regression of the Late Cretaceous sea. Prominent stratigraphic rise of approximately 1100 ft (335 m) is in large part responsible for the northwest-trending stratigraphic accumulations of gas in the central portion of the basin.

The Fruitland Formation is a sequence of nonmarine swamp and alluvial plain deposits laid down shoreward of the sea as it retreated from the basin for the last time. Fruitland Formation coalbeds and sandstones produce gas over a large percentage of the northern and central portions of the basin.

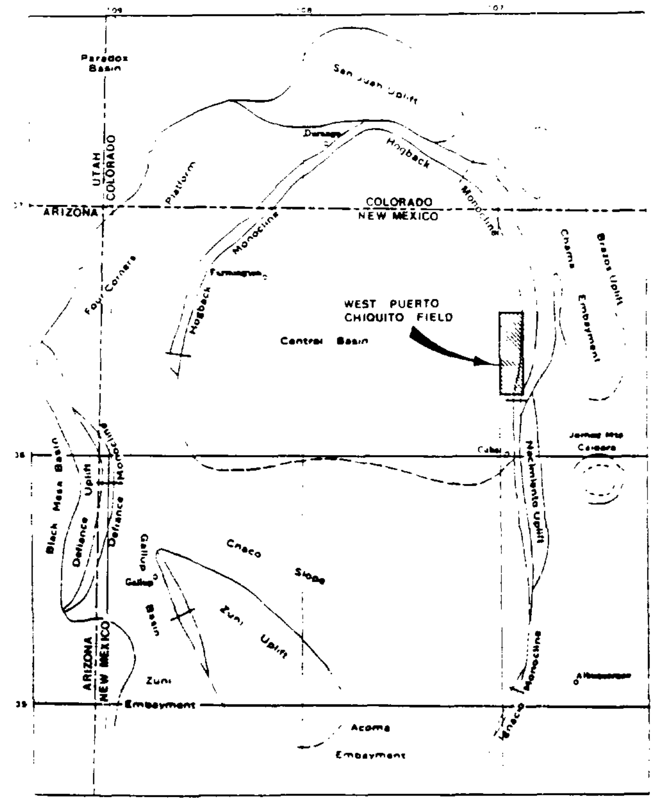

Figure 5. Map showing the location of the major tectonic features in the San Juan basin and surrounding areas.

Potential Source Rocks

Source-reservoir mechanisms have been postulated for the principal reservoirs in the San Juan basin. The Pennsylvanian Paradox carbonate reservoirs produce oils derived from the sapropelic, oil-generative shale units in the carbonate-evaporite sequence. Jurassic Entrada oils are thought to be sourced by organic limestones of the overlying Todilto Formation, which also provide the critical reservoir seal (Vincelette and Chittum, 1981).

Hydrocarbons produced from the upper Cretaceous Dakota sands are sourced by the intertonguing shales. Oil-generative marine shales in the Carlile and Niobrara members provide the source for oil produced in the regressive Gallup sand and younger basal Niobrara bar sands. Fractured reservoirs in the Niobrara shale section above the bar sands are sourced by indigenous organic-rich marine shales (see below).

Mesaverde sand reservoirs produce hydrocarbons sourced by shales of the Mancos and Lewis formations, as well as shale and coal units within the interval. Gas in the Pictured Cliffs and Fruitland reservoirs is derived from substantial volumes of methane expelled from coalbeds and shales in the Fruitland Formation.

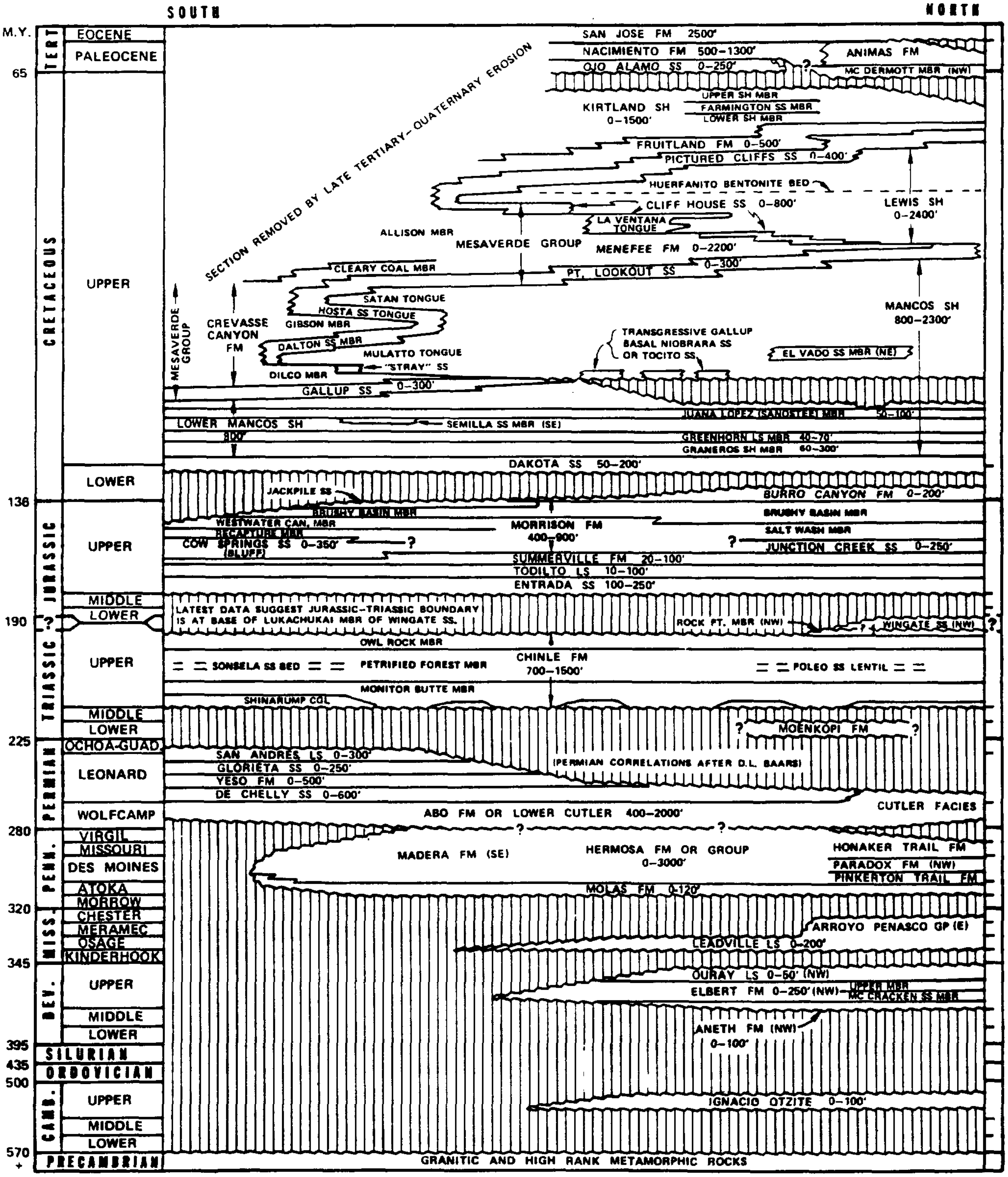

Figure 6. San Juan basin time-stratigraphic nomenclature chart. (From Molenaar, 1977b.)

TRAP

West Puerto Chiquito field is an areally extensive fracture trap of essentially indeterminate extent. Trapping of hydrocarbons at West Puerto Chiquito is provided by a loss of fracture permeability, both in the lateral and vertical directions. Although brittle reservoir units within the Niobrara interval are fractured to some extent over a large part of the basin flank, commercial production rates are dependent on

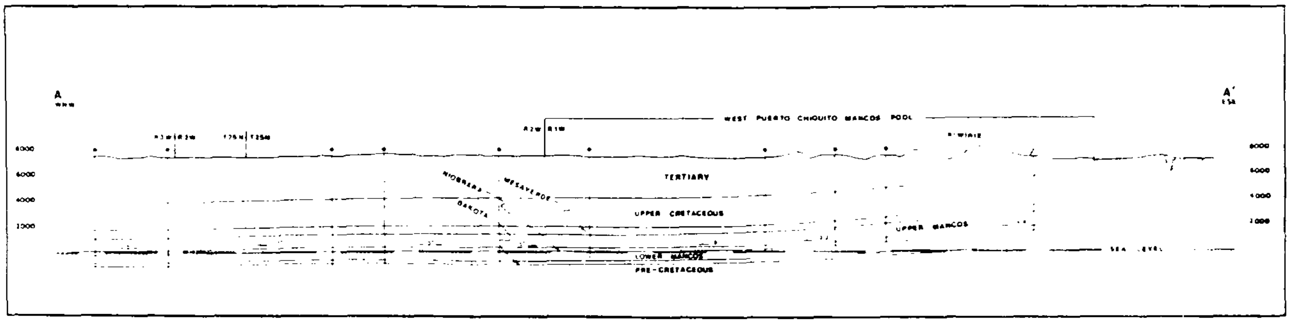

Figure 7. Structural cross section through West Puerto Chiquito field. Location of section is shown on Plate 1. No vertical exaggeration.

wellbore communication with a high-conductivity tectonic fracture system. The tectonic fracture system has been found to diminish in intensity and capacity away from the monocline (i.e., to the west), so that the "trap" is essentially a loss of commercial reservoir quality. Loss of commercial reservoir quality is known, through development and extensive reservoir study, to occur at approximately the current pool boundaries.

Vertical sealing of the reservoir is provided by massive shales of the upper and lower Mancos Shale above and below the Niobrara reservoir interval, respectively. These more ductile lithologies, though certainly fractured to some extent, are effectively "healed" and prevent the escape of significant hydrocarbons. Within the Niobrara reservoir interval, the brittle reservoir units are separated by more massive (and therefore ductile) lithologies. Vertical communication between reservoir units is limited to the area around some wellbores and along major fractures.

The West Puerto Chiquito "trap" exhibits no structural closure (Plate 1) and produces oil and gas over a vertical column of approximately 2100 ft (640 m). The reservoir has produced no water during its producing history. Trap integrity is attested to by the fact that the updip limits of the reservoir are within 1 to 3 mi (1.6–4.8 km) of the outcrop (Plate 1 and Figure 7) with no apparent hydrocarbon leakage or water incursion. Furthermore, elevation of the updip limit of the reservoir is approximately 1200 ft (366 m) structurally low to the oil-water contact in the East Puerto Chiquito field.

Although no communication has been observed between widely separated Niobrara reservoirs on the east flank during the history of production, there is nevertheless sufficient permeability in the fracture system to have equalized pressures on the east flank over geologic time (Figure 9). Thus, the original pressure observed in the West Puerto Chiquito reservoir, 1620 psig at a datum of +1195 ft (364 m), corresponds to a pressure gradient of approximately 0.33 psi/ft and reflects an "oil static" pressure differential from the datum elevation of the well to an elevation approximately 900 ft below the outcrop, or approximately 6100 ft (1859 m) above sea level (Figure 10).

Wells in a newly developed area that show stabilized reservoir pressures less than the above gradient are indications that regional migration has taken place as a consequence of fluid withdrawal from the area.

Little or no vertical displacement has been noted along major fractures in the reservoir. The major component of movement is horizontal shear associated with the tectonic forces responsible for basin subsidence. Fractures constitute a conduit rather than a barrier for subsurface fluid flow. Minor displacement faulting (50 to 100 ft [15–30 m] of throw) has been observed in the Niobrara reservoir interval in the outcrop and subsurface (using seismic data) in the southeastern portion of the West Puerto Chiquito Pool (Plate 1).

Reservoir

Stratigraphy, Lithology, and Depths

The West Puerto Chiquito reservoir consists of a highly interconnected fracture network developed in discrete reservoir units in the Niobrara Member of the Mancos Shale. The Upper Cretaceous Niobrara Member represents a major transgressive event with equivalents throughout the western interior and was deposited on an open marine shelf under low energy conditions (Cole et al., 1989).

The Niobrara reservoir interval, in local nomenclature the "A," "B," and "C" units (Figure 3), consists of a laminated sequence of shale, siltstone, mudstone, and carbonate. X-ray diffraction, petrographic, and SEM analyses suggest the reservoir lithology is predominantly a calcareous silty claystone, with percentages of quartz and carbonate (predominantly calcite and dolomite cements) ranging from 30 to 49% of the bulk volume (Cole et al., 1989). Log data suggest a high degree of stratigraphic continuity for individual units in the Niobrara throughout the southeast portion of the San

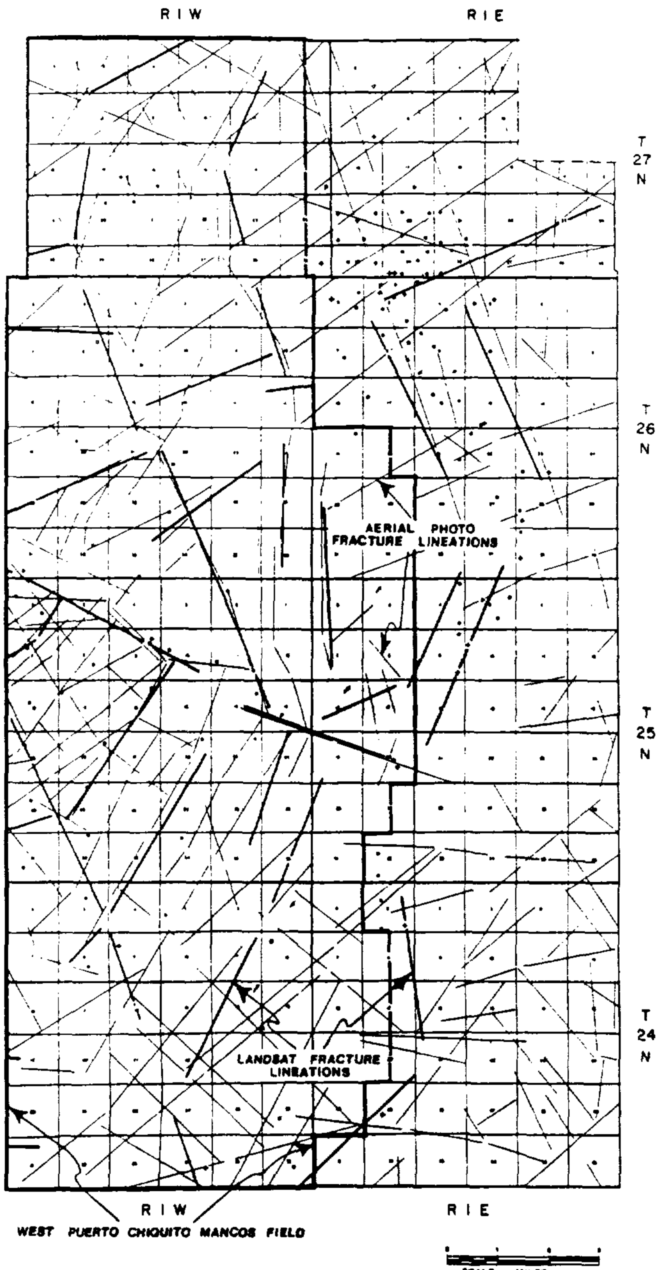

Figure 8. Map showing surface fracture interpretation of West Puerto Chiquito field. Dominant fracture "fabric" has orientations of northwest-southeast and northeast-southwest. Constructed from aerial plats and Landsat images.

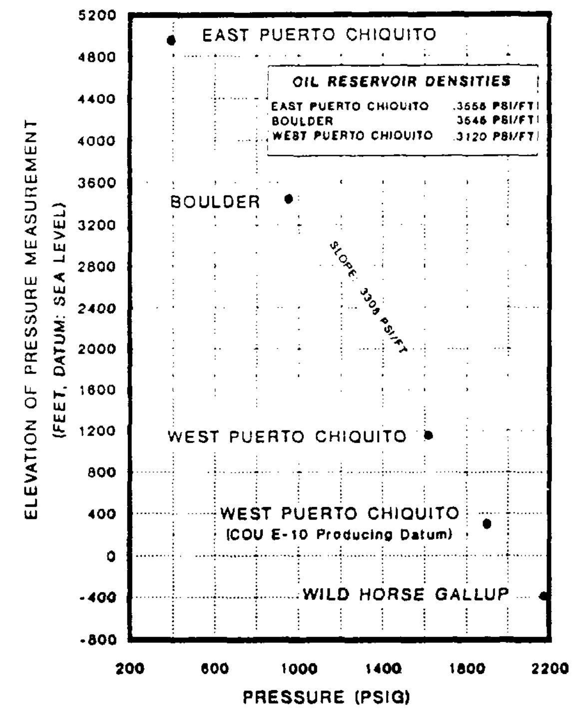

Figure 9. Plot showing initial pressures of Niobrara pools, southeast flank of San Juan basin, related by oil pressure gradient.

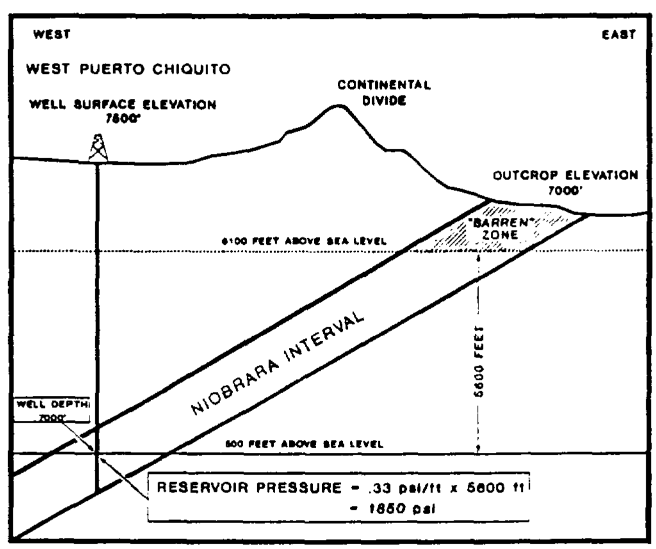

Figure 10. Sketch showing "oil static" equilibrium of pressures in the Niobrara from a "base-level" of 6100 ft above sea level. (See Figure 9.)

Juan basin. Detailed visual examination of cores, however, reveals pronounced horizontal and vertical heterogeneity, particularly in the highly laminated siltstone-carbonate sequences. Individual laminae are quite discontinuous on a scale of millimeters to centimeters, both vertically and horizontally. The laminated sequences range in thickness from 10 to 30 ft (3-10 m), and are characterized by the high resistivity response noted on logs of the Niobrara.

Certain compositional and textural aspects of the reservoir interval restrict the development of fractures to discrete zones. High dolomite contents and the thin-bedded nature of the laminated sequences result in a more brittle, fracture-prone rock unit. Examination of core shows the discrete "brittle zones" are encased in more massive shale sequences—"ductile zones." Preferentially fractured "brittle zones" have been identified in the lower "A," upper "B," and lower "C" units (Figure 3). All are laterally continuous within the pool area, have similar mechanical properties, and behave as reservoir response units. Essentially all of the hydrocarbons produced to date in West Puerto Chiquito and adjacent producing areas issue from fractures developed in these units.

The reservoir units occur in a gross interval of 250 to 300 ft (76-91 m) at depths ranging from approximately 5300 ft (1615 m) at the updip limits of the pool to 7600 ft (2316 m) at the base of the monocline.

The Niobrara "Matrix"

A key element in fractured reservoir characterization and performance prediction is the potential for matrix contribution to production. The interaction between matrix and fracture components is often the most poorly understood reservoir mechanism and yet is most critical for performance projections, particularly in a reservoir such as West Puerto Chiquito. Comprehensive analysis of core data from wells in West Puerto Chiquito and adjacent fields leads to the conclusion that "matrix porosity" is ineffective and will not contribute to production at any point in the reservoir history (Appendix 1). Therefore, effective porosity must necessarily be fracture porosity. The fractures at West Puerto Chiquito, in other words, provide essentially all of the storage capacity and permeability.

Thus, we differ with those who propose a reservoir system (NMOCC, 1987, 1988) that is controlled by dual porosity and/or imbibition—hypotheses that require the presence of a physical characteristic, effective matrix porosity, that our work indicates does not exist.

Reservoir Physical Properties

Fracture Development. Fractures contributing to reservoir fluid flow derive from two different processes: oil generation and tectonic forces. The process of oil generation involves the conversion of solid kerogen to liquid hydrocarbons and results in a net volume expansion and the development of microscopic "expulsion" fractures. Because microfractures derive from internal body forces, they are generally pervasive and randomly oriented, with extremely small aperture widths at reservoir depths. Fracture lengths, the degree of interconnection, and aperture widths are such that the permeability of the microfracture system, to the extent it could be measured, would most likely be isotropic and quite low. The degree of interconnection between microfractures and the tectonic fracture system will control the contribution of the microfractures to fluid flow and storage. Degree of interconnection of the microfracturing cannot be determined using petrographic techniques.

Tectonic fractures associated with Laramide and younger basin subsidence and east flank folding resulted in an extensive system of high conductivity fractures with orientations approximately northwest, northeast, and north. Spacing and aperture widths of the high conductivity fractures are unknown. Production and pressure information reveal exceptionally high permeabilities and a strong directional anisotropy in the high conductivity system. Petrographic and visual core analyses indicate the naturally occurring high conductivity fractures are vertical to near-vertical while the microfractures may occur in any orientation.

Proper characterization of any reservoir is dependent on the sampling of a representative reservoir volume. In a complex, heterogeneous fracture system such as exists at West Puerto Chiquito, the conventional methods of analysis using data from individual wells or groups of wells are inadequate. Core, log, and individual well pressure tests sample extremely limited reservoir volumes. Similarly, the averages derived from large amounts of such data acquired in multiple wells in a reservoir of this type will be intrinsically flawed. Pressure build-up tests, for example, sample reservoir areas measured in terms of tens of acres (and, in places, are further constrained by the bounds of the individual fracture block within which the well is completed) whereas interference tests reveal average properties of reservoir areas measured in thousands of acres. It is because of the reservoir geometry, that of a highly interconnected, high-conductivity, tectonic fracture system bounding blocks of lower conductivity fractures, that true average reservoir properties can only be determined through the use of interference testing (Appendix 3).

Pay Thickness. An accurate determination of "pay thickness," in this case fracture height, is difficult in a reservoir of this type. The average fracture height is never known independently. The porosity-thickness product, or unit pore volume, however, can be determined through the use of interference tests. Production logs and tests indicate virtually all significant hydrocarbon volumes issue from the lower "A," upper "B," and lower "C" zones (Figure 3). None of the reservoir units produce uniformly throughout the pool: The "C" unit has historically been the principal producing unit in the southern portion of the reservoir, and the "A" and "B" units are primary contributors in the northern portion of the reservoir. The average total "net pay thickness" would be in the range of 30 to 100 ft (9-30 m).

Porosity. Effective hydrocarbon pore volume for West Puerto Chiquito is wholly contained within fracture porosity (Appendices 1 and 2). Total effective hydrocarbon porosity is approximately 0.3 to 0.4% of bulk volume, with a maximum upper limit of 1%. While Nelson (1985) and others have developed methods of estimating reservoir pore volume of fractures from width and frequency data derived from cores and outcrops, others (Aguilera, 1980) suggest this method will not apply in all cases. The method certainly does not apply at West Puerto Chiquito. The only reliable method of estimating effective hydrocarbon pore volume is interference (or frac pulse) testing of producing wells. Such testing shows a pore volume (ϕh) of 0.25 to 0.30 porosity-feet, which for 30 to 100 ft (9-30 m) of net pay corresponds to a porosity of 0.3 to 1% (Appendix 2).

Hydrocarbon Characteristics

The oil produced from the West Puerto Chiquito Pool is a sweet, 39 to 40° API hydrocarbon. The solution GOR, from undersaturated fluid samples recovered from the Canada Ojitos Unit L-11 (NW/SW Sec. 11, T25N, R1W), a carefully conditioned well sampled early in the life of the reservoir, was 480 scf/bbl. West Puerto Chiquito fluid properties are discussed in Appendix 4.

Formation Compressibility and Relative Permeability

Formation compressibility and relative permeability data are important in performance predictions at West Puerto Chiquito. Although the relative permeabilities of oil and gas per se are not addressed here, some insight is offered as to the ratio of relative permeabilities, k_{rg}/k_{ro} (referred to herein as k_g/k_o). This is presented in Appendix 5. We also present in Appendix 5 analysis of available data concerning formation compressibility, C_f. Some of the salient points concerning formation compressibility in general are noted below:

1. Reservoir storage is contained in fractures of low total pore volume. Typically formation compressibility, C_f, increases with decrease in porosity. It is reasonable to expect compressibility of this formation to be higher than that normally found in oil reservoirs. The question, of course, is how much higher.
2. The value of C_f was found to approximate 15×10^{-6} ($\Delta v/v$/psi) from interference testing of Canada Ojitos Unit wells at pressures both above and below the bubble point (v = the rock volume).
3. Reported laboratory data from cores taken from nearby wells are not definitive, covering a wide range from 6×10^{-6}/psi to 150×10^{-6}/psi (Appendix 5). Moreover, compressibility from laboratory measurements of cores suffers from the same limitations inherent in all core analyses of the fractured Niobrara: Samples, individually or in the aggregate, are not representative of the reservoir.
4. Also countering the high compressibility concept is the fact that the reservoir is underpressured (less than 2000 psia at depths of 7500 ft [2286 m] or greater), indicating possible vertical support that protects from overburden pressures. Typically, the reservoir rock's horizontal stress is much less than the vertical (Nelson, 1985). Thus, it is impossible to determine C_f by analogy with formations of higher porosity or directly from laboratory data. The conventional wisdom, that a low porosity formation has exceptionally high compressibility, may not apply here. Furthermore, shearing, nonparallel separation, and natural propping of fracture faces will reduce closure effects and prevent high formation compressibility from developing.

Reservoir Fluid Flow

Fluid flow occurs only in fractures, with very high rates of diffusion as a consequence of the high conductivity fracture system. Values of k_oh, a measure of reservoir conductivity, are typically 1 to 20 darcy-feet over large parts of the reservoir. Using sensitive pressure gauges, interference effects are routinely observed between some wells over a distance of 4 mi (6.4 km) in a period of 10 hours.

It is important to note that the "tight fracture" low-conductivity networks constitute ***restrictions to flow*** rather than barriers to flow, since wells completed in the tight fracture blocks routinely observe transients from neighboring wells and rates of pressure decline similar to area-wide figures. In fact, there are no areas of the reservoir that are not *in communication* to some degree, attesting to the pervasive and highly interconnected nature of the system.

Extensive interference testing and production data indicate a strong directional anisotropy in reservoir fluid flow. Permeabilities are preferentially higher in the north-south direction. Note that this preference direction is parallel to structural strike and perpendicular to the direction of basin subsidence (Plate 1).

Given the nature of the fracture system, regional migration is to be expected and in fact has been observed throughout the southeast flank of the basin. A notable example is the Bear Canyon Unit 4 to 6 mi (6.4-9.6 km) northeast of the central Gavilan area (Figure 2), where initial pressures were 1000 psi less than virgin pressure but within a few pounds of central Gavilan's pressure at that time.

Development Considerations

Variations in Recovery. Wells producing in fractured Niobrara pools on the east flank of the basin exhibit a range of cumulative oil recoveries over two orders of magnitude: per well recoveries of 15,000 to 20,000 bbl in certain areas, and 1,500,000 to 2,000,000 bbl in others. Recoveries on a per-acre basis show a narrower range, over one order of magnitude, of 80 to 800 bbl/ac. The apparent paradox is further highlighted by the range of pore volume in commercially productive areas: approximately 1500 to 3000 bbl/ac. The differences between areas are only partially accounted for by intensity of fracturing; differences are primarily attributable to drainage area of the wells and extent to which gravity drainage recovery is achieved. Since the reservoir pore volume and fluid flow derive from fractures, production is characterized by poor relative permeability (k_g/k_o) characteristics. However, this phenomenon, namely high early permeability to gas, results in good gravity segregation and therefore good gravity drainage characteristics. Some gravity drainage will occur throughout, but the recovery will be more significant in areas of greater structural dip and conductivity and when production is controlled to optimize this important depletion process.

Misleading Nature of Reservoir's Characteristics. Methods of development are dependent on interpreted values of reservoir properties. The physical properties of fractured reservoirs are difficult to determine. Furthermore, the properties are of lower quality than the production issuing from them implies.

Example 1: Unit (per-acre) Recoverable Reserves—The high productivity and large drainage areas of individual wells are misleading as to the per-acre volume of oil in place and recoverable reserves. This feature results from the high conductivity fracture systems found throughout large areas. During early development of a field adjoining West Puerto Chiquito (Gavilan, Figure 2), individual wells located on 320 ac spacing units accumulated production volumes of hundreds of thousands of barrels, implying large per-acre recoveries. In fact, however, the wells were simply draining large areas (a township or more).

As an example of this phenomenon, the first high capacity well in Gavilan, the Native Son #2 (Sec. 27, T25N, R2W), produced large volumes of oil with small pressure declines, suggesting large per-acre reserves. This well had produced 240,000 bbl more than its south offset, the Homestead Ranch #2 (Sec. 34, T25N, R2W) when this south offset went on permanent production in 1986. By 1989, both wells were essentially oil depleted. Despite the fact that the Homestead Ranch #2 had a higher productivity, its cumulative production at near depletion of about 170,000 bbl was still 240,000 bbl less than the previously completed Native Son #2. Although both wells had drained far greater areas than their spacing units, by the time the Homestead Ranch #2 went on permanent production, additional wells in the area had dramatically reduced the thousands of acres initially available to these wells. Thus, it was impossible for the Homestead Ranch #2 to achieve a recovery comparable to the first well.

Some have proposed that the difference in recoveries of examples such as this merely reflect the time at which the wells went on production: The longer the producing time, the greater the recovery. Such an explanation is untenable here, however, since both wells are approaching oil depletion at the same time.

Example 2: Stratified Reservoir—As another example of the reservoir's misleading character, the reservoir is stratified and not all zones deplete uniformly. Gravity segregation causes upper zones to have higher gas saturations than the lower ones. Numerous field examples of such segregation have been observed. An oil and gas zone with a high gas saturation will produce in a fashion similar to a gas zone, with volumes proportional to the difference of squares of pressures, whereas zones with high oil saturation will produce more in proportion to the difference of pressures. The consequence is lower gas-oil ratios at higher rates of production, falsely suggesting greater efficiency. In fact, however, high production rates favor only certain individual wells and exacerbate problems of migration and protection of correlative rights. In a reservoir sense, however, lower rates of production permit more efficient gravity drainage and greater ultimate recovery. Greater reservoir efficiency can be achieved, of course, by first producing the lower zones. This practice was utilized in West Puerto Chiquito (see the section titled *Canada Ojitos Unit Pressure Maintenance Project* under *Recovery Efficiency*, below). Under competitive conditions, however, this conservation method can be accomplished only under strict pool regulations.

Example 3: Declining Reservoir Productivity—A further example of the reservoir's misleading character is declining reservoir productivity that is not apparent. Once production in an area is such that a group of wells capable of producing at high rates is not draining reservoir substantially outside its developed area, and the wells are produced at capacity, exceptionally high decline rates will occur.

The relatively small volume of oil in place for a given productivity of this fractured reservoir (Appendix 2) causes extremely high production decline rates. Constant percentage ($P_o/P = e^{dt}$) decline rates in excess of 100% can be expected (see *Symbols and Basic Equations* preceding Appendices). However, if the production rates are limited by equipment capacity (or proration), the decline may not be evident from the wells' performance.

Wells produced by pumping will sometimes flow intermittently. When gas-oil ratios rise with depletion, a pumping well's production is augmented by an increasing amount of flow. As a consequence, a well's true productivity may be declining but its daily oil production stays relatively the same (or in some cases increases) until a critical point is reached, when oil production rates drop abruptly.

Examples of this occurred in 1987 when the New Mexico Oil Conservation Commission ordered for both West Puerto Chiquito and Gavilan a period of high-rate allowables: 1280 BOPD and 2000:1 GOR for 640-ac proration units. Some of the higher productivity wells were located in the boundary area of the two pools in T25N. Average developed well density in the immediate area of these wells was approximately one well to 640 ac. Average production rates were in the range of 300 to 400 BOPD. Though not apparent in the pumping wells limited by equipment capacity, reservoir productivity was declining rapidly as a result of the high rate of depletion. The production of the Howard 1-8 well (NE/4 Sec. 1, T25N, R1W) offsetting the Canada Ojitos Unit is a notable example of this phenomenon (Figure 11). Although the apparent decline rate of the Howard 1-8 is high, the true decline rate for this area is more accurately reflected by the production performance of the offsetting well, the Canada Ojitos Unit E-6 (Sec. 6, T25N, R1W), a well produced by continuous gas lift (Figure 12). Earlier interference tests showed the wells in this area to have a high degree of communication.

As shown on Figure 12, once all wells in the local area were on production at rates limited primarily by equipment capacity (mid-September 1987), the constant percentage rate of production decline ($P_0/P = e^{dt}$) was 300%/year for this well, despite at least some pressure maintenance support. This decline rate extrapolates, for example, from 300 BOPD to 15 BOPD in one year.

Confirming this implication, one year later when unrestricted allowables were ordered for a two-month period (winter 1988-1989), wells in the boundary area not receiving pressure support from other areas had production rates of 1 to 15 BOPD. In the interim, increasing production rates of north Gavilan wells had essentially stopped migration from that direction. Productivity of wells receiving pressure

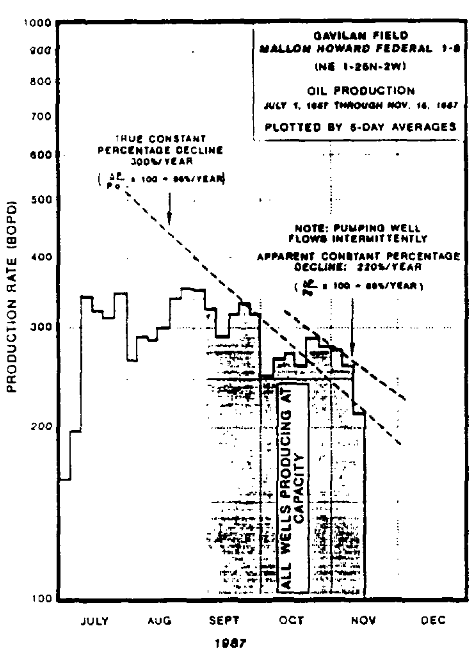

Figure 11. Production rate plot showing the masking of the Niobrara's exceptionally high decline rate when migration is reduced and production is limited by equipment capacity. *True* reservoir decline rate (see Figure 12) is greater than the apparent decline.

Analysis Type	Decline Rate, Percent per Year	
	Apparent	True
$\Delta P/P$	220	300
$\Delta P/P_0$	89	95

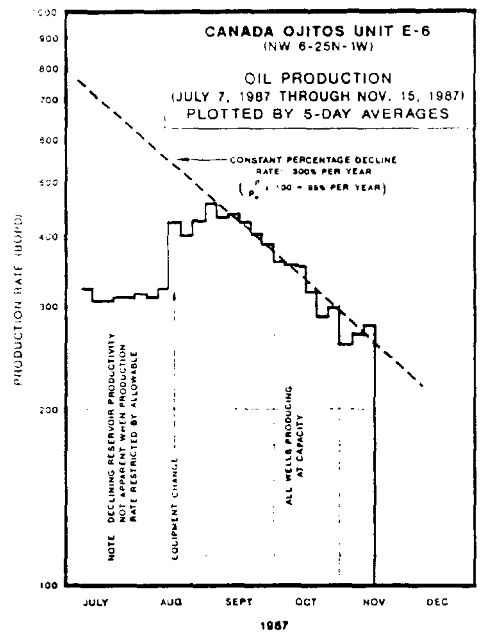

Figure 12. Production rate plot showing reservoir's true decline rate for the area of the well (Figure 11) on west boundary of the Canada Ojitos Unit in West Puerto Chiquito.

Analysis Type	Decline Rate, Percent per Year
$\Delta P/P$	300
$\Delta P/P_0$	95

maintenance support had declined, but not as dramatically as the others (Figure 13).

In summary, note that the high depletion rates depicted here are not to be considered exceptional: They are the norm for fractured Niobrara wells produced at high rates. Since well productivity varies as a function of its capacity (*Kh*), but the reservoir storage varies as only the cube root of *Kh* (Appendix 3 Figure 3-2), the higher the producing ability of wells, the greater will be the rate of depletion if produced at the high rates.

Forecasting Well Quality. Although a certain degree of communication exists throughout West Puerto Chiquito and surrounding areas, there are discrete subareas containing high conductivity fracture systems that are not directly connected to other high conductivity subareas. The exceptional conductivity of these fracture systems permits early evaluation of the development potential of a subarea. An example is southeast West Puerto Chiquito. At this writing (January 1989), activity has recently centered here where initial wells had high productivities. With the exception of a few wells that might receive pressure maintenance support from the unit, however, we anticipate there will be no future wells with the high ultimate recoveries experienced in West

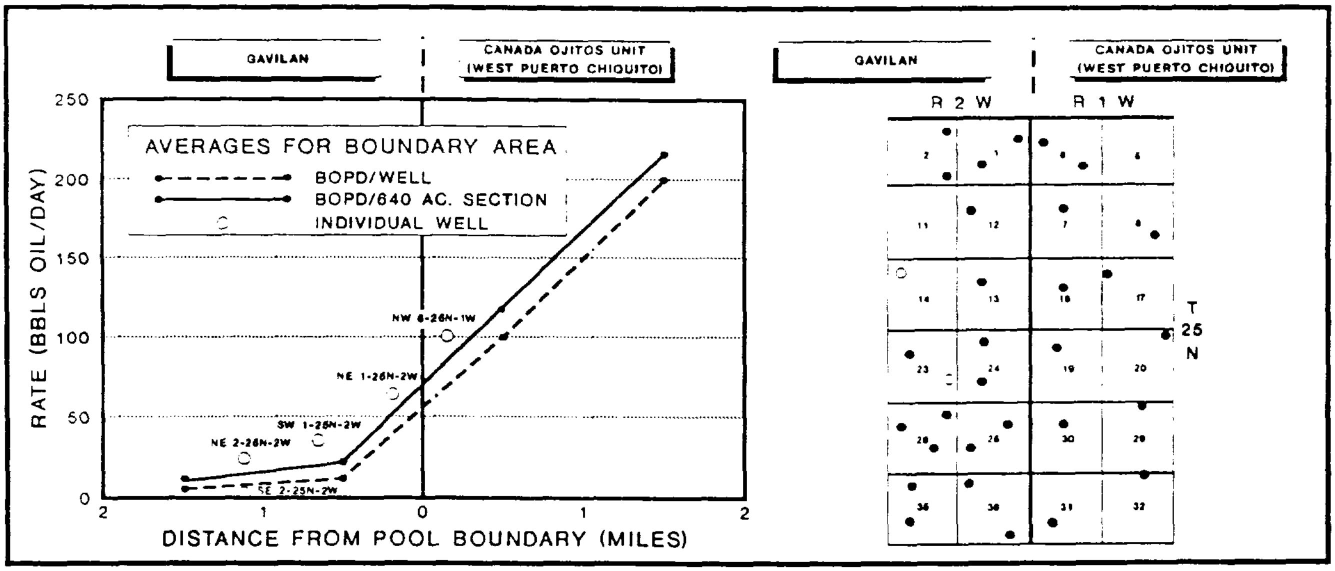

Figure 13. Map of the boundary area between West Puerto Chiquito (Canada Ojitos Unit) and Gavilan fields showing the location of producing wells. Plot of rate versus distance from the boundary shows amount of pressure maintenance support depends on well location. Averages plotted are for each of the four tiers (each tier is 1 mi east-west and 6 mi north-south).

Puerto Chiquito and in a few of the early Gavilan wells.

Two of the initial three wells in southeast West Puerto Chiquito produced at initial rates of 500 to 600 BOPD. Wells with equivalent initial rates in West Puerto Chiquito recovered up to 2.3 million bbl. Early wells of similar productivity in Gavilan produced hundreds of thousands of barrels. It is unlikely, however, that the analogy of high capacity wells and large ultimate cumulative recoveries will apply here. Rather, it is expected that future wells in southeast West Puerto Chiquito will realize ultimate recoveries of only 60,000 to 90,000 bbl/well if the existing 640 ac spacing is maintained. Closer spacing, of course, would result in proportionately lower per-well recoveries.

The method of analysis leading to this conclusion (Appendix 6) has general application to any newly drilled subarea that has a high conductivity fracture system.

Allowables and Producing Life. A development consideration for fractured Mancos formation wells is the allowable to be expected if a new pool is discovered. We anticipate that it will be similar to the allowable set in 1988 for the West Puerto Chiquito and Gavilan Pools of 800 BOPD and 2000:1 GOR for 640 ac spaced wells, an allowable inordinately high given the recoverable reserves.

Presumably the high allowable encourages exploration and development. In the fractured Niobrara, however, high allowables create problems of protection of correlative rights. Except for controls governing spacing, the pools are for practical purposes producing under the "law of capture" (see, for example, how high capacity wells can affect productivity of smaller wells—Appendix 6, Figure 6-5).

Expected producing life is a development consideration of some importance. In the absence of pressure maintenance and/or control of production to optimize gravity drainage, the depletion process will be solution gas drive, with ultimate recoveries in the range of 5 to 10% of oil in place, or 100 to 150 bbl/ac (60,000 to 100,000 bbl/well for 640 ac spacing).

To illustrate the effect of high allowables on the producing life of fractured Niobrara reservoirs, consider the development on 640 ac spacing of a subarea with 150 bbl of recoverable reserves per acre, simultaneous onset of production in all wells, and a 10 BOPD economic limit:

Per Well Average Initial Productivity (BOPD)	Producing Life (Years)
800	1.5
400	2.5
200	4.0
100	6.5

Controls Governing Well Spacing. Given the high conductivity throughout most of West Puerto Chiquito, oil recovery is essentially independent of well spacing. Of course, the greater the number of wells, the higher the total rate of reservoir withdrawal and the lower the ultimate recovery once the gravity drainage rate is exceeded.

In the Canada Ojitos Unit the initial density of recovery wells was approximately four sections per well with a drainage geometry of 1 mi (1.6 km) in the strike direction and 4 mi (6.4 km) in the dip direction. Pressure maintenance augmented the high transmissibility such that high productivities were maintained for a significant proportion of the depletion cycle and large per-well recoveries resulted. In contrast, when pressure and production are allowed to decline, additional wells are required to recover a given amount of oil in the same length of time. In summary for West Puerto Chiquito, its spacing since 1980 has been 640 ac per well. The drilled density is far less.

In contrast, the offsetting pool to the west, Gavilan, was initially spaced on 320 ac per well over the objection of operators requesting 160 ac spacing. During the latter stages of depletion, Gavilan spacing was changed to 640 ac with an option for a second well. A substantial part of southern Gavilan was developed on 320 ac spacing. The northeast part of the pool was developed later with a drilled density of approximately 1000 ac per well. At this writing (January 1989), lack of infill drilling suggests the operators are moving in the direction of wider spacing. In our opinion, the trend toward wider spacing will become generally accepted practice as additional production data become available.

Recovery Efficiency

As noted under *Development Considerations*, the large differences in per-well recoveries for oil wells producing from the Niobrara in the eastern San Juan basin are due primarily to the different drainage areas supporting the wells, along with the amount of gravity drainage realized.

Gravity drainage recovery, estimated at 55 to 60% of oil in place, is some ten times greater than the 5 to 6% expected from depletion by solution gas drive (Appendix 5). Given the reservoir geometry of a high-conductivity fracture network bounding lower-conductivity fracture blocks (Appendix 3), only parts of the reservoir can be depleted by gravity drainage. Except for certain areas of the reservoir with adequate structural dip (NMOCC, 1969), the lower conductivity fracture blocks will be depleted by solution gas drive.

That part of the reservoir occupied by high-conductivity fracture system(s) will provide some gravity drainage, even in areas of low dip angle, if production rates are not excessive. The high differential pressures that exist from the wellbore to the edge of the fracture blocks disappear in the surrounding fracture network, such that gravity segregation can take place here. In the high-conductivity system, vertical fractures apparently penetrate all producing zones, such that where the formation dip is low, the fracture height of 30 to 100 ft (9–30 m) can provide "dip" along portions of the fracture channels. In the low-conductivity fracture blocks, fractures are confined to the brittle zones and generally have insufficient conductivity to provide significant gravity drainage.

Obviously, the lower the per-acre withdrawal rate, the greater the opportunity for gravity drainage. In any newly developed area where high-conductivity fracture systems exist, production from the first few wells derives from an area encompassing a large number of undrilled spacing units. Thus, for the early part of the depletion cycle, the resulting low per-acre withdrawal and low differential pressures will facilitate gravity drainage. In areas of low dip angle, gravity drainage can yield a significant incremental recovery over that due to solution gas drive, albeit only a small proportion of the total gravity drainage potential.

Pressure maintenance greatly improves the opportunity to achieve gravity drainage recoveries (Muskat, 1945). Succinctly summarized by Muskat, "The effect of the gas injection is largely that of maintaining reservoir pressure while the gravity drainage is taking place."

Muskat notes further, "It seems likely that the case of complete gas segregation will in general require such low production rates, or pressure differentials over the pay, that it will seldom be practicable to operate a field in this manner." This constraint does not apply to the fractured Niobrara, however, where the reservoir storage is in fractures. Here the ratio of permeability to porosity is such as to make it uniquely suited to exploitation under gravity drainage depletion. As shown in Appendix 2 (Figure 2-1), for any given permeability, the porosity of a fracture system is at least an order of magnitude less than that of typical sandstone reservoirs. Consider a sandstone reservoir with permeability that would require 200 years to deplete at rates restricted to provide complete gravity segregation. The same permeability in a reservoir where fractures provide the storage would coincide with a volume of one-tenth as much oil in place. Accordingly, the same production rate would allow depletion in 20 years or less of the gravity drainage recoverable oil from the reservoir containing only fracture porosity.

Canada Ojitos Unit Pressure Maintenance Project. Significant gravity drainage recoveries have been achieved in the Canada Ojitos Unit. One method of identifying that gravity drainage took place in the Canada Ojitos Unit pressure maintenance project is through comparison of GORs versus accumulated recovery of certain wells (Figure 14). Since pressure decline for the histories shown was limited to a level approximately 100 psi below the bubble point, little solution gas drive recovery could have occurred. Continuous and extensive monitoring of pressures over three decades provides the facts with respect to reservoir pressure decline. Note the large proportion of ultimate recovery before significant increase in GOR. In addition, the COU E-10 well (Sec. 10, T25N, R1W) has the largest ultimate recovery and is also at the lowest structural datum (Plate 1). As the gas-oil contact moved downdip and GORs increased, the wells were shut in. One exception was the COU C-34 well (Sec. 34, T25N, R1W), which was maintained on production as an experiment to determine gravity drainage following gas breakthrough. The well produced 300,000 bbl at GORs in excess of 10,000 ft^3/bbl. Since the solution gas drive process cannot operate without a pressure decline and pressure decline in the C-34 well was minimal, the recovery was necessarily a consequence of gravity drainage aided in small part by gas drive moving the oil thus accumulated to the wellbore. Comparison is made with the GOR history of the average of Gavilan's 40 best wells (Figure 14).

Although of relatively small amounts, some gas drive depletion has taken place in the gas cap area. If large volumes of gas continue to be "cycled," this process is expected to yield additional recovery from increasingly larger parts of the reservoir. That gas drive has taken place near the injection wells is evident from increasing permeability to gas reflected by injection pressures and volumes (NMOCC, 1989). These gas drive recoveries from the low capacity gas cap area, albeit small volumes compared to the total, are amounts that could not otherwise be recovered, as the gas cap area cannot be economically developed by recovery wells.

In order to produce the reservoir most efficiently (at minimum GOR), the lowest producing zones were opened to production first ("C" zone in the south part of the unit), with the intention of opening the upper zones in the latter stages of depletion when cycling operations were planned. Later upon testing the "A" and "B" zones where the "C" zone had originally been produced, productivity of gas was increased but not oil. Apparently the "A" and "B" zones were oil depleted by wells completed only in the "C" zone. Therefore, efficient recovery was realized without handling large volumes of gas.

There are large areas with low-conductivity fracture blocks, whose interconnecting high-conductivity fracture system is of a lower capacity than the better areas, as for example of some of the injection wells in the gas cap. Because of the orientation (along the strike) of some of the low capacity areas, they serve a useful purpose in dividing the reservoir into subareas permitting the pressure maintenance to be more effective and therefore increasing efficiency of recovery from the better areas. The dominance of north-south directional permeability causes minimum pressure differentials in a north-south direction (along strike) and significant pressure differentials (because of the intervening lower capacity systems) east-to-west (perpendicular to strike). The consequence is a series of areas that reflect "pressure plateaus." Insofar as the pressure maintenance project is concerned, this characteristic aids in efficient oil recoveries: Injected gas moves north-south along the strike and then diffuses downdip across the intervening lower conductivity system, first into one pressure plateau where it again moves north-south and then diffuses into the next. Note that if the preferential permeability were directed vice versa, there would be a greater tendency for the injected gas to channel directly downdip to recovery wells. Since the gas cap is in a low-conductivity portion of the reservoir with associated low storage volume, the gas cap pressures have increased with rising GORs as greater volumes of gas are produced and higher pressures are required to move the injected gas out of the gas cap (Figure 15).

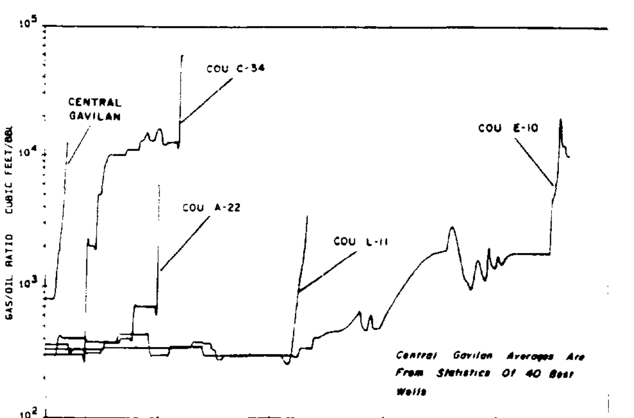

Figure 14. Plot of GOR versus cumulative oil production for four Canada Ojitos Unit wells. Note large recoveries prior to GOR increase, reflecting gravity drainage. Note well with largest recovery, COU E-10, Sec. 10, T25N, R1W, is at the lowest structural datum. Note large recovery of C-34 after gas breakthrough which, in view of minimal pressure decline, is mostly from gravity drainage. Comparison is made with average of Gavilan's 40 best wells.

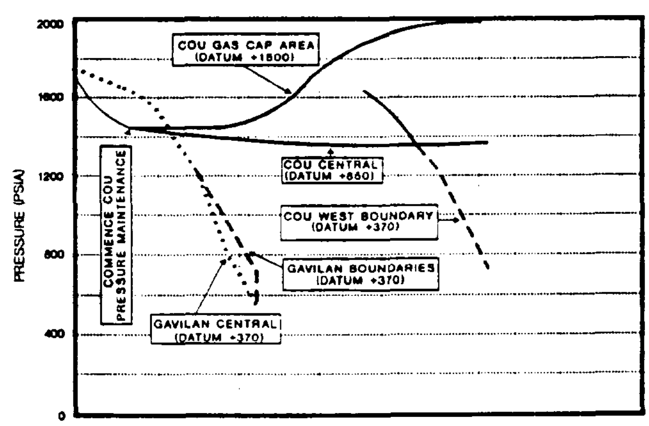

Figure 15. Plot of COU reservoir pressure versus cumulative production. Note the increase in gas cap pressures as larger volumes of gas are handled following GOR increases. Note the leveling of pressures associated with the onset and continued pressure maintenance in the Canada Ojitos Unit. Note also the rapid pressure declines in the Gavilan Pool and the concurrent effect on the Canada Ojitos Unit area adjacent to the pool boundary.

Finally, we note that management of the Niobrara through pressure maintenance and controlled production will yield efficient recoveries on wide spacing (NMOCC, 1969). This is evidenced by the remarkable performance of certain Canada Ojitos Unit wells. For example, the Canada Ojitos Unit E-10 well (Sec. 10, T25N, R1W) produced 2.3 million bbl of oil while the reservoir pressure declined approximately 100 psi. The depletion process clearly was not solution gas drive. The process of solution gas drive operating over that pressure decline would result in a recovery of 40 to 50 bbl/ac (equivalent to a drainage area of 45,000 to 60,000 ac). The higher estimated gravity drainage recovery for this area, 30 to 40% of oil in place, resulted in a recovery of 600 to 800 barrels per acre and *efficient* depletion of a reservoir area of 3000 to 4000 ac for this well.

In summary, a substantial area within the Canada Ojitos Unit reservoir is estimated to recover 30 to 40% of the oil in place (NMOCC, 1969, 1980, 1988). The amount attributable to recovery by gravity drainage will be 25 to 35%, five times the amount that would have resulted from "conventional" development on close spacing and at high production rates.

Field Comparison. To illustrate the difference in recovery efficiency between fractured Niobrara pools developed under different operating conditions, comparison is made between West Puerto Chiquito and central Gavilan, an offsetting pool (Figure 2) developed under competitive conditions.

Close spacing and high allowables caused a high rate of depletion in central Gavilan that prevented the field-wide segregation of oil and gas that must occur to permit significant gravity drainage recovery (as it did in West Puerto Chiquito). High conductivity fracture systems are known to exist in Gavilan: Values of $K_o h$ of 10 to 20 darcy-feet have been measured through both interference and frac pulse testing (NMOCC, 1988). This conductivity along with Gavilan's low dip angles provided gravity drainage recoveries of 2 to 4% of oil in place which, when combined with the solution gas drive recovery of about 6%, provides a total recovery of 8 to 10% of oil in place, one-quarter to one-third of that realized for the Canada Ojitos Unit.

This estimate of the efficiency of Gavilan's recovery is arrived at as follows: Central Gavilan is estimated to produce approximately 5 million bbl of oil, 1 million bbl of which was recovered while pressures were above the maximum assumed bubble point of 1660 psi. Of the remaining 4 million bbl produced below bubble point pressure, approximately 1 million bbl resulted from regional migration, leaving 3 million bbl produced below the bubble point that originated under central Gavilan lands. Solution gas drive recovery is estimated at 6% of the oil in place (Appendix 5). Central Gavilan's initial oil in place is estimated at 30 to 40 million bbl (NMOCC, 1988), which therefore provides a solution gas drive recovery of 1.8 to 2.4 million bbl. The remaining 0.6 to 1.2 million bbl results from gravity drainage. Of the ultimate production (from pressure below the bubble point and after migration) this approximates one-sixth to one-third—a volume large compared to the total, but only 3 to 6% of the gravity drainage potential.

Further insight into the comparison of recoveries under gravity drainage and pressure maintenance versus development under competitive conditions comes from data of pressures and cumulative production. Because of cross-boundary migration, it is not possible to compare directly pressures and cumulative production of the two areas. A generalization of relative efficiencies of recovery, however, is evident from a comparison of plots of pressure versus cumulative production (Figure 15). The Canada Ojitos Unit initial pressure decline below bubble point was less than Gavilan's. Ultimate recovery, however, for the Canada Ojitos Unit is estimated to be greater.

As can be seen from the above review of the issues affecting recovery, it is impossible to acquire the information necessary to make precise analyses of efficiency. The foregoing, however, provides insight that can be used as a base for understanding recovery processes of the fractured Niobrara reservoir. The database will improve with time and production. When north Gavilan is depleted, for example, and its reservoir volume better known, a refined estimate can be made of migration prior to first production.

Source

The most likely source of the hydrocarbons produced at West Puerto Chiquito is the organic-rich marine shale of the Niobrara. Total organic carbon (TOC) contents reported from wells northwest of West Puerto Chiquito range from 1 to 3% (Cole et al., 1989). A reconstruction of the time and temperature history of the reservoir interval using the method of Lopatin (1971) gives a preliminary estimate of source rock maturity and the timing of generation and entrapment of hydrocarbons at West Puerto Chiquito (Figure 16). Of particular importance to the accuracy of the method are the burial and thermal histories of the Niobrara at the selected well, in this case the Canada Ojitos Unit 29 (E-6; SW NW Sec. 6, T25N, R1W). Successive periods of deposition, erosion, and uplift brought the Niobrara to its present burial depth of approximately 7100 to 7700 ft (2164–2347 m). Evidence exists, however, to place the unit at a maximum burial depth nearly 1000 ft (305 m) deeper during the Eocene and early Oligocene as a result of increased original thicknesses of Nacimiento and San Jose sediments (Baltz, 1967; Fassett and Hinds, 1971). Furthermore, although the present-day geothermal gradient is approximately 1.6°F/100 ft, higher heat flows associated with the development of the San Juan volcanic field most likely elevated the geothermal gradient during the early to mid-Tertiary (Bond, 1984; Reiter and Clarkson, 1983; Reiter and Mansure, 1983).

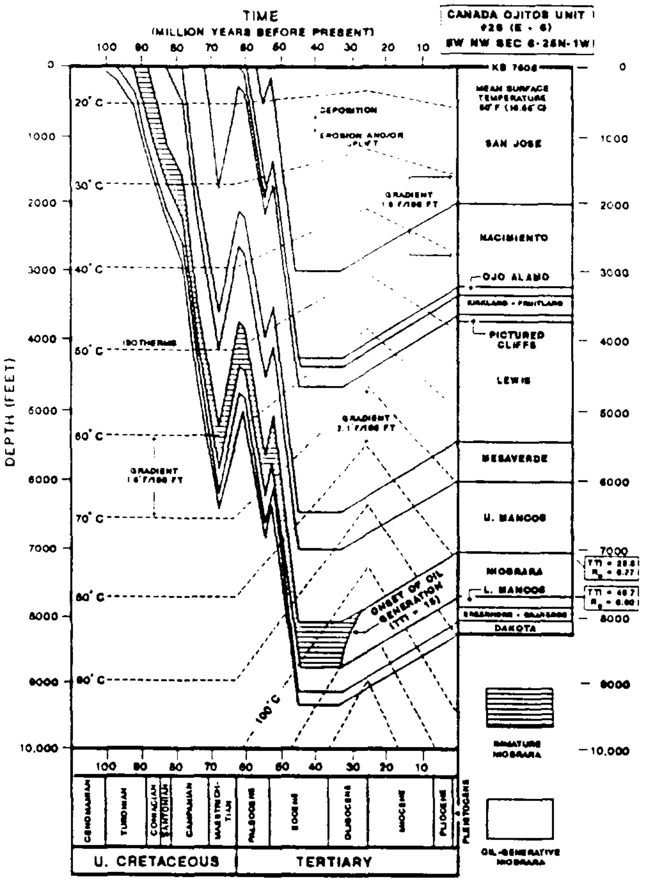

Figure 16. Burial and thermal history reconstruction at the Canada Ojitos Unit 29 well (E-6; SW NW Sec. 6, T25N, R1W) showing onset of oil generation in the Niobrara and estimate of present-day maturity level.

The thermal history of the Niobrara interval prior to the end of the Cretaceous (Maastrichtian) is assumed constant at 1.5°F/100 ft (Tissot and Welte, 1978), followed by an increase in the gradient to a maximum (at West Puerto Chiquito) of 2.1°F/100 ft at the end of the Oligocene, at which time volcanism and intrusive activity associated with the San Juan volcanic field had peaked (Steven, 1975). From the end of Oligocene to the present, gradients are assumed to decline at a constant rate to the present 1.6°F/100 ft.

In spite of the inherent uncertainty in the burial and thermal history data, the reconstruction is considered a reasonable preliminary estimate of the thermal maturity of the Niobrara at West Puerto Chiquito. As a further check on the accuracy of the method as applied here, the calculated thermal maturities (as measured by the "TTI," or "Time-Temperature Index") were compared to the maturities derived from vitrinite reflectance (R_0) data using the relationship established by Waples (1980).

Timing of Generation and Entrapment

Development of the Hogback monocline and associated tectonic fractures at West Puerto Chiquito occurred in late Paleocene-early Eocene, approximately 48 to 54 Ma (Baltz, 1967) and prior to hydrocarbon generation. The Niobrara interval entered the oil-generative phase, corresponding to a TTI of 15.0 (Waples, 1980), approximately 28 to 33 Ma during the mid- to late Oligocene (Figure 16). The presence of open fractures at the time of hydrocarbon generation may have facilitated the expulsion of oil from the shales to the fracture system, preventing the build-up of abnormal pressures frequently associated with generation in a closed system (e.g., the Bakken system in the Williston basin or the Green River-Wasatch system in the deep Uinta basin). Present-day maturities calculated for the Niobrara at West Puerto Chiquito range from TTI values of 29.5 at the top of the interval to 49.7 at the bottom, corresponding to vitrinite reflectance values ranging from 0.77 to 0.90%, respectively. Vitrinite reflectance values obtained from laboratory analyses of samples from the top and bottom of the Niobrara reservoir interval in the Canada Ojitos Unit #29 (E-6) well were 0.86 and 0.90%, respectively, in good agreement with values predicted by the Lopatin (1971) method. Both the burial history and laboratory methods indicate the Niobrara interval is thermally mature and probably still within the oil-generative phase at West Puerto Chiquito.

The East Puerto Chiquito "Problem"

Migration of hydrocarbons appears to have occurred to a limited extent in and adjacent to West Puerto Chiquito. Fractures in the Niobrara produced nearly 4 million bbl of oil at East Puerto Chiquito field on the northeast boundary of West Puerto Chiquito but at structural elevations ranging from 1200 to 5000 ft (366-1524 m) higher (Plate 1). Reconstruction of the burial and thermal history at East Puerto Chiquito indicate the Niobrara is below the threshold maturity level for oil generation. Hydrocarbons apparently migrated into East Puerto Chiquito from the deeper, oil-generative Niobrara to the west at some point prior to the late Tertiary (Miocene-Pliocene?) normal faulting that separated the two reservoirs.

EXPLORATION AND DEVELOPMENT CONCEPTS

Regional Play

Exploration for fractured Niobrara oil reservoirs has been pursued on the flanks of the San Juan basin, in northwest Colorado, and along the Front Range of eastern Colorado. Development of a Niobrara fracture play involves, at a minimum, recognition of the following fundamental criteria:

1. Presence of intense folding, faulting, and/or fracturing of the type normally associated with the flanks of foreland basins.

2. The concept that fracture systems form in networks with a specific spatial relationship to folds and generally over the entire structural feature.
3. The presence of brittle, fracture-prone lithologies, usually with high dolomite contents, isolated vertically by more ductile lithologies.
4. The presence of a fracture-prone texture, characterized by a thin-bedded, highly laminated sequence of brittle lithologies.
5. Sufficient source rock quality and thermal history to place the Niobrara interval within the generative phase during or after fracture formation.
6. Little or no later tectonism to destroy trap integrity.

Lessons Learned

Modern exploratory techniques, such as seismic data, could provide important data concerning fold geometry and extent but would be unlikely to locate major fracture trends with small vertical displacements. The application of seismic techniques, even at a point prior to the discovery of West Puerto Chiquito, would be unlikely to enhance the structural interpretation of the area due to the abundant subsurface and outcrop control. Seismic data in faulted portions of the reservoir, however, may assist in location of wells. Landsat and aerial photographic techniques appear to provide a cost-effective preliminary interpretation of the orientation and relative intensity of tectonic and regional fracturing in a prospective area. Certain electrical techniques are likely to provide data complementary to surface techniques, identifying subsurface locations of fracture trends to assist in well location.

Perhaps the most important lesson learned is that successful exploration and development of fractured Niobrara reservoirs can only be accomplished through use of large exploratory units. The Niobrara cannot be efficiently, economically, and equitably developed under competitive conditions. For example, West Puerto Chiquito wells separated by 40 ac spacing distances and draining from the same large reservoir area have shown differences in productivity of two orders of magnitude (the equivalent of 40 BOPD versus 4000 BOPD). It is therefore impossible in a practical sense to unitize fractured Niobrara reservoirs after discovery of a new field. Furthermore, competitive operations lead to adversarial positions and defeat the cooperative efforts needed for acquisition of test data, joint studies, and the free flow of information.

Had West Puerto Chiquito been developed under competitive conditions, for example, the result would have been more wells, less ultimate recovery, and a discounted net operating income of only a fraction of that realized.

REFERENCES CITED

Aguilera, R., 1980, Naturally fractured reservoirs: Petroleum Publishing Company, 703 p.

Arps, J. J., 1945, Analysis of decline curves: Trans. AIME 1945, v. 160, p. 228-247.

Baltz, E. H., 1967, Stratigraphy and regional tectonic implications of part of Upper Cretaceous and Tertiary rocks, east-central San Juan Basin, New Mexico: U.S. Geological Survey Professional Paper 552, 101 p.

Bond, W. A., 1984, Application of Lopatin's method to determine burial history, evolution of the geothermal gradient, and timing of hydrocarbon generation in Cretaceous source rocks in the San Juan Basin, northwestern New Mexico and Southwestern Colorado, *in* F. F. Meissner, et al., eds., Hydrocarbon source rocks of the greater Rocky Mountain region: RMAG, p. 433-447.

Bulnes, A. C., and R. U. Fitting, Jr., 1945, An introductory discussion of the reservoir performance of limestone formations: Trans. AIME 1945, v. 160, p. 179-201.

Cole, R. D., J. M. Allmaras, J. P. Zager, and G. E. Moore, 1989, Sedimentology, petrology, and X-ray mineralogy of the Coniacian-Santonian Niobrara shale, northeastern San Juan basin, New Mexico: American Association of Petroleum Geologists Section Meeting, Albuquerque, New Mexico.

Economides, M. J., and K. G. Nolte, 1987, Reservoir stimulation: Schlumberger Educational Services.

Fassett, J. E., and J. S. Hinds, 1971, Geology and fuel resources of the Fruitland Formation and Kirtland Shale of the San Juan Basin, New Mexico and Colorado: U.S. Geological Survey Professional Paper 676, 76 p.

Fatt, I., 1953, The effect of overburden pressure on relative permeability: Trans. AIME 1953, v. 198, p. 325-326. (*Technical Notes* Journal of Petroleum Technology, October 1953.)

Gorham, F. D., Jr., L. A. Woodward, J. F. Callendar, and A. R. Greer, 1979, Fractures in Cretaceous rocks from selected areas of San Juan basin, New Mexico—Exploration implications: American Association of Petroleum Geologists Bulletin, v. 63, n. 4.

Jones, F. O., 1975, A laboratory study of the effects of confining pressure on fracture flow and storage capacity in carbonate rocks: Journal of Petroleum Technology, January, 1975.

Keeling et al., 1964, 1969, Laboratory analyses of cores for relative permeability, El Paso Natural Gas Company 1964, Keeling engineering study for Gallegos Gallup Unit, Pan American Laboratories 1969, fractured Devonian chert and Ellenburger.

London, W. W., 1972, Dolomite in flexure-fractured petroleum reservoirs in New Mexico and Colorado: American Association of Petroleum Geologists Bulletin, v. 56, p. 815-821.

Lopatin, N. V., 1971, Temperature and geologic time as factors in coalification: Akademiya Nauk SSR Isvestiya Seriya Geologicheskikh, n. 3, p. 95-106.

Molenaar, C. M., 1977a, Stratigraphy and depositional history of Upper Cretaceous rocks of the San Juan Basin area, New Mexico and Colorado, with a note on economic resources: New Mexico Geological Society Guidebook, 28th Field Conference, p. 159-166.

Molenaar, C. M., 1977b, San Juan basin time-stratigraphic nomenclature chart: New Mexico Geological Society Guidebook, 28th Field Conference, p. xii.

Muskat, M., 1945, The production histories of oil-producing gas-drive reservoirs: Journal of Applied Physics, v. 16, p. 147-159.

Muskat, M., 1949, Physical principles of oil production: New York, McGraw-Hill Book Company, Inc., 922 p.

Nelson, R. A., 1985, Geologic analysis of naturally fractured reservoirs: Houston, Gulf Publishing Co., 410 p.

New Mexico Oil Conservation Commission, spacing hearing for the Boulder Pool, July 10, 1963.

New Mexico Oil Conservation Commission Case No. 3455, November 1966 and December 1969.

New Mexico Oil Conservation Commission Case No. 7075, November 1980.

New Mexico Oil Conservation Commission Case Nos. 7980, 8946, 8950, 9113, and 9114, March 1987.

New Mexico Oil Conservation Commission Case Nos. 7980, 8946, 8950, and 9111, June 1988.

New Mexico Oil Conservation Commission Case No. 9525, February 1989.

Ramey, J. H., Jr., 1964, Rapid methods for estimating reservoir compressibilities: Trans. AIME, v. 231, p. 447-454, Journal of Petroleum Technology, April 1964.
Reiter, M., and G. Clarkson, 1983, Relationships between heat flow, paleotemperatures, coalification and petroleum maturation in the San Juan Basin, northwestern New Mexico and southwestern Colorado: Geothermics, v. 12, p. 323-339.
Reiter, M., and A. J. Mansure, 1983, Geothermal studies in the San Juan basin and the Four Corners area of the Colorado Plateau: I. Terrestrial heat-flow mesurements: Tectonophysics, v. 91, p. 233-251.
Steven, T. A., 1975, Middle Tertiary volcanic field in the southern Rocky Mountains, *in* B. F. Curtis, ed., Cenozoic history of the southern Rocky Mountains: GSA Memoir 144, p. 75-94.
Thomas, R. D., and D. C. Ward, 1972, Effect of overburden pressures and water saturation on gas permeability of tight sandstone cores: U.S. Bureau of Mines, Journal of Petroleum Technology, February, 1972.
Tissot, B. P., and D. H. Welte, 1978, Petroleum formation and occurrence—a new approach to oil and gas exploration: New York, Springer-Verlag, 538 p.
Van Golf-Racht, T. D., 1982, Fundamentals of fractured reservoir engineering: Amsterdam, Elsevier, 710 p.
Vincelette, R. R., and W. E. Chittum, 1981, Exploration for oil accumulations in Entrada sandstone, San Juan basin, New Mexico: American Association of Petroleum Geologists Bulletin, v. 65, p. 2546-2570.
Waples, D. W., 1980, Time and temperature in petroleum formation, application of Lopatin's method to petroleum exploration: American Association of Petroleum Geologists Bulletin, v. 64, p. 916-926.
Woodward, L. A., and J. F. Callendar, 1977, Tectonic framework of the San Juan Basin, *in* San Juan Basin III: New Mexico Geological Society 28th Field Conference Guidebook, p. 209-212.

APPENDICES

Symbols and Basic Equations

BOPD = barrels oil per day

STB = stock tank barrels

MCF/D = thousands of standard cubic feet per day

GOR = gas-oil ratio, cubic feet per barrel

C_f = formation compressibility

h = thickness

ϕ = porosity, fraction of pore volume

K, k = permeability

k_o = permeability to oil

k_g = permeability to gas

k_{ro} = relative permeability to oil

k_{rg} = relative permeability to gas

k_g/k_o = ratio of relative permeability

μ = viscosity as in Kh/μ

μ_o = viscosity of oil

μ_g = viscosity of gas

Symbols for constant percentage decline curve (also known as "constant rate," "exponential," "semi-log") (Arps, 1945; Muskat, 1949):

$$P = P_o e^{-dt} \text{ or } P_o/P = e^{dt} \quad (1)$$

where P_o = initial production rate, any units

P = production rate at time t, same units as for P_o

e = base natural logarithms

d, t = decline rate (fraction or decimal) and time in any consistent units

Also $C = (P_o - P)/d$

where C = cumulative recovery between production rates P_o and P

d = decline rate in units consistent with P_o and P

(Accordingly, a plot of P versus C is straight line on coordinate paper.)

Symbols for a variation of analysis of these decline curves sometimes used:

$\Delta P/P_1 = D$

Where ΔP = production rate decline from P_1 to P_2

D = decline rate in consistent units (fraction or decimal per month, per year, etc.)

Also $C = (P_1 - P_2)/(-(\ln 1 - D))$

Where C = cumulative recovery between production rates P_1 and P_2

D = decline rate in units consistent with P_1 and P_2

ln = natural logarithm

Appendix 1. Matrix Porosity Ineffective

The conclusion that matrix porosity is ineffective is based on the following observations from core data in West Puerto Chiquito and adjacent areas:

1. *Porosities and permeabilities are extremely low.*

Significant reductions occur in porosity and permeability measurements made at ambient conditions upon restoration to reservoir conditions (Nelson, 1985).

Analyses at ambient conditions of recent cores indicate average porosities in the range of 1.2 to 2.1% and (geometric) mean permeabilities of 0.015 to 0.024 md. At reservoir confining stress, these porosity values reduce to approximately 0.8 to 1.5%; and the corresponding permeabilities are estimated to reduce to 0.000046 md to 0.00011 md, respectively, using the method of Thomas and Ward (1972). Note that this method recognizes the inherent increase in formation compressibility with decreasing overburden stress that occurs when cores are brought to the surface and tested at ambient conditions. Review of all available sources forces the conclusion that there are no known sandstone reservoirs in which a "matrix" of this quality contributes commercial oil volumes, with or without fracture enhancement.

Capillary pressures are likely to be very high, such that drainage of oil from tight pores is not likely to occur over the range of pressure encountered in depletion. More fundamental, however, is the question whether the microporosity *ever* contained hydrocarbons. Displacement of water by hydrocarbons from microporosity in the shale and siltstone during oil generation would be unlikely.

2. *Petrographic analyses indicate ineffective porosity.*

Microporosity in the siltstone laminae and carbonate laminae, low originally because of grain size, has been effectively destroyed by secondary diagenetic effects: Intergranular porosity is occluded by abundant carbonate cement and authigenic clay minerals throughout the reservoir interval. Photomicrographs and SEM analyses provide clear evidence that "matrix porosity" is essentially ineffective waterfilled microporosity.

3. *Visual examination indicates no oil saturation.*

Cores taken in the reservoir section in a well adjacent to West Puerto Chiquito were examined under ultraviolet light in the field immediately upon removal to the surface, and again in the lab. No saturation, staining, or fluorescence of the "matrix" was observed (Kurt Fagrelius, 1987, personal communication). However, fluorescence and staining were observed along fracture and bedding planes.

4. *Laboratory oil saturations are very low to nonexistent.*

Laboratory measurement and calculation of fluid saturations in reservoir lithologies of this type are fraught with uncertainty. For example, using conventional retort methods, oil saturations as high as 30 to 50% were reported for a recent core from a well adjacent to West Puerto Chiquito. The data from this analysis are unreliable because of the possibility of kerogen "cracking" and loss of bound water due to exposure to the elevated temperatures encountered in the retort process.

To achieve more reliable results, the Dean-Stark extraction method was used to analyze plugs from a subsequent well adjacent to West Puerto Chiquito field, resulting in low indicated oil saturation. This analysis revealed geometric mean oil saturation for 49 samples of 10.6%, highlighting the error in results associated with the application of conventional analysis methods to a rock of this character. Even this more reliable method is subject to significant analytical errors (see below), which when combined with such low oil saturations in a rock of extremely low permeability, argue for *no* effective oil saturation in the matrix.

5. *Water saturation supports minimal oil saturation.*

The average water saturation of cores analyzed by the Dean-Stark method at ambient conditions was 62.5%. At reservoir confining stress, the samples experienced porosity reductions in the range of 25 to 30%. Thus, a core of 90 to 100% water saturation in the reservoir becomes, at surface conditions, a core with water saturations in the 60 to 70% range. Furthermore, since connate waters are commonly gas saturated, the reduction to surface pressures may cause minor water expulsion due to solution gas drive, resulting in measured water saturations lower than actually exist in the reservoir.

In any case, pressure of the gas evolving from the formation water would likely be sufficient to prevent filtrate invasion of the microporosity. Thus, any water saturation measured must be formation water, is most likely too low, and is *not* representative of reservoir conditions. The customary assumption that at ambient conditions the difference between 100% of pore volume and that occupied by water represents hydrocarbon saturation is not valid here. The 60 to 65% water saturation measured at ambient conditions probably reflects actual water saturation of 100% at reservoir conditions.

6. *Low oil saturation not caused by flushing.*

Flushing of oil from a core sometimes occurs in the coring process, resulting in low measured oil saturation.

Such an explanation for the low oil saturation of the Niobrara cores is untenable: Rock of 0.02 md is not likely to be flushed, and oil staining and fluorescence were observed on some fractures and bedding planes (Kurt Fagrelius, 1987, personal communication). If flushing occurred, the first to be flushed would be the fractures; since the fractures were not flushed, it follows that the matrix of 0.02 md permeability was not flushed.

7. *Laboratory oil saturations are of questionable accuracy.*

The Dean-Stark procedure, while more reliable than the retort method, does not measure oil volumes directly; rather, the oil saturation is calculated by weight difference using a measured water volume (weight) recovered. Given the low porosities and apparent low oil saturations in an extremely low sample pore volume, the weight difference attributed to oil saturation is vanishingly small and subject to large measurement errors. Whatever the actual oil volume measured in the cores, it almost certainly originated in the fractures, which themselves occupy an extremely small proportion of the total sample volume analyzed.

Appendix 2. Fracture Porosity: The Reservoir Storage

The effective hydrocarbon pore volume in the West Puerto Chiquito field is wholly contained in fractures. This fundamental conclusion derives from both assessment of core analyses (Appendix 1), which effectively preclude any "matrix" contribution, and from extensive interference and production testing, which provide direct evidence that the storage volume, as well as the permeability, most likely is of fracture porosity.

To understand the storage system in West Puerto Chiquito, we begin with a comparison of porosity (ϕ) and permeability (K) for matrix (sandstone) and fracture systems, and then relate well test information to these relationships.

The permeability versus porosity relationships for 2200 sandstone specimens (Bulnes and Fitting, 1945) and a fracture system with fractures parallel to the direction of flow are presented in Figure 2-1 (NMOCC, 1966). Note that for any given fracture density (or spacing) and a given permeability, the fractures are of equal aperture width. The graph provides an overview of the relation of fracture width and spacing to fracture porosity and permeability.

This particular fracture flow system is defined analytically for fracture spacing in centimeters (Jones, 1975) as:

$$\phi f = 4.93 \times 10^{-3} \left(\frac{K}{S^2}\right)^{1/3} \qquad (1)$$

ϕf = fracture porosity (%)

K = flow test permeability (darcys)

S = fracture spacing or average distance between fractures (centimeters)

If fracture "density" (as opposed to "spacing") is given in fractures per foot, F (NMOCC, 1965), the equation is:

$$\phi f = 5.05 \times 10^{-4} (KF^2)^{1/3} \qquad (2)$$

To understand fracture flow it is instructive to examine the relation of fracture spacing (or density) and aperture width to permeability from equation (1) or (2) or Figure 2-1.

For any given permeability, the porosity becomes a function of fracture spacing: As spacing decreases (density increases), the porosity increases. Furthermore, for any given permeability, the porosity is essentially independent of aperture width—a concept not easy to grasp at first introduction. Note that aperture width does not appear (directly) in equations (1) or (2). Porosity is simply a function of permeability multiplied by the $^2/_3$ power of fracture density, a concept useful in estimating maximum fracture porosity (see below).

For fracture systems with nonuniform aperture widths, the permeability increases as the cube of the porosity. For a given permeability, therefore, increasing aperture width results in decreasing density (and fracture porosity). Thus, the maximum ratio of porosity to permeability will occur for fractures of uniform width rather than for mixed widths.

Clearly, in a naturally fractured reservoir, fractures are not uniformly parallel to the direction of the flow, and therefore, porosity is expected to be greater than that for an idealized system of parallel flow. It has been suggested (Van Golf-Racht, 1982) that for a fracture system in which the fractures are not parallel to the direction of flow but at random distribution, the porosity would be increased by the value of the cube root of pi squared, an increase in porosity values (for a given permeability) over those shown by equations (1) and (2) and Figure 2-1 of 35%.

In natural (nonideal) systems, fractures have flow restrictions and are not perfectly interconnected such that the porosity will be higher for any given permeability than that shown by the (ideal) parallel flow system.

Whatever the true relation of porosity to permeability for a system, changes in fracture aperture width—as with changes in overburden pressure—will cause porosity to vary as the cube root of the permeability (Jones, 1975). Furthermore, in comparing one area of a reservoir with another, if the fracture density is the same, but the fracture width is different, then the ratio of porosities for the two areas will be proportional to the cube root of the ratio of the permeabilities.

In defining an approximate upper limit of ratio of porosity to permeability for fracture systems, we

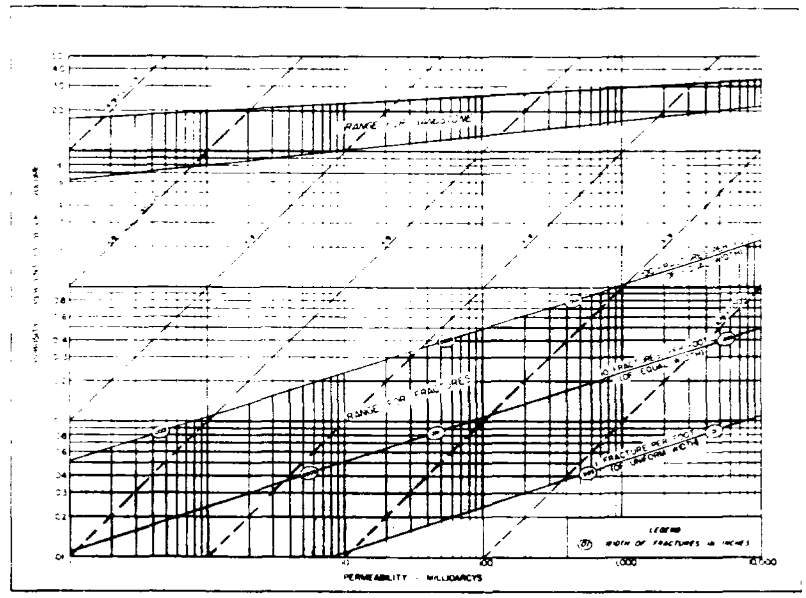

Figure 2-1. Relation of porosity to permeability for typical sandstone reservoirs compared with that for a fracture system in which the fractures are parallel to the direction of flow.

have arbitrarily selected a relation that provides porosities equivalent to approximately twice that shown for the parallel system of 100 fractures/ft (NMOCC, 1969) and is the upper line on the field identified as "most fracture systems" on Figure 2-2. Figure 2-2 is an expansion of Figure 2-1 except that the above maximum limits line and a lower (not limiting) line have been added in lieu of the basic parallel fracture system of Figure 2-1. The purpose of Figure 2-2 is to aid in distinguishing fracture porosity from typical sandstone matrix porosity through production and interference testing. Central to this effort is identification of a maximum upper porosity limit for fracture systems of a given permeability.

The selected upper limit is equivalent to a system of fractures parallel to flow of 282 fractures/ft (24 fractures/in.). It is also equivalent to randomly distributed fractures of 180 fractures/ft (15/in.) using Van Golf-Racht's adjustment. It is difficult to conceive of a fracture system of any description having a porosity greater than that shown by a system of parallel fractures with a density of 24 fractures/in. (or randomly distributed fractures of 15 fractures/in.). For the system of parallel flow and 282 fractures/ft, the fracture widths for 10, 100, and 1000 md are, respectively: 0.0002 in., 0.0004 in., and 0.0009 in. (0.005, 0.01 and 0.02 mm).

The lower limit of ratio of porosity to permeability for a fracture system approximates the lower range of values determined for West Puerto Chiquito and Boulder fields, and may represent reasonable values for other commercial fractured reservoirs. It is not, however, intended to be a lower limit in the same context that the upper line is probably close to a true maximum upper limit for any fractured reservoir.

The curves of Figure 2-2 have been expanded both directions from the range of Figure 2-1 in order to examine the porosity-permeability relationships in "tight" reservoir rock and the hypothetical relations of the curves at a pore volume of 100% of the bulk volume.

The convergence of the upper and lower bounding lines for sandstone samples at 100% of pore volume results from the selection of the approximate boundaries of the Bulnes and Fitting (1945) sample population. There appears to be some analytical justification for this to occur because at pore volumes of 100% of bulk volume permeabilities of all systems of whatever nature will have to coincide.

On the other hand, the junction at 100% pore volume of the lower line for fracture systems is purely coincidence, and although of a certain amount of interest, it has no analytical significance. This line represents a fracture density of about 28 fractures/ft for a parallel flow system or about 18 fractures/ft for randomly distributed fractures; and at a permeability of 10^7 darcys the porosity of such fracture systems is projected to occupy 100% of the bulk volume (with the fractures apparently separated by infinitely small layers).

It is apparent from Figure 2-2, except for sandstone with unusual characteristics, if the production and interference testing shows total porosity values which fall below the sandstone relation for the corresponding permeability then at least some fracturing is present. Also if the total porosity falls above the maximum line for fractures of the corresponding permeability, there has to be some matrix contribution. Further, if the total porosity falls below the maximum fracture line, then the fracture porosity is probably a large part of the total porosity—and may even be 100% of it.

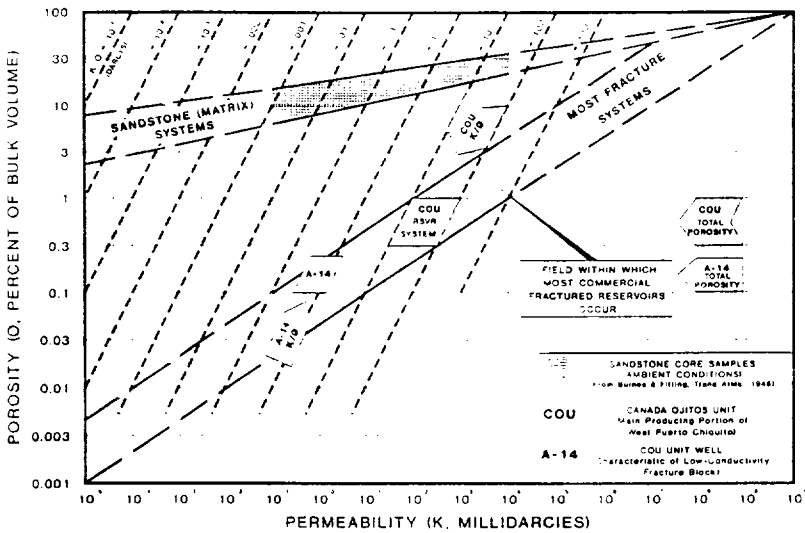

Figure 2-2. Data of Figure 2-1 expanded with fracture system replaced with upper (limiting) and lower (nonlimiting) definition of field for "most fracture systems." Reservoir properties from interference and production testing for Canada Ojitos Unit (COU) areas within West Puerto Chiquito are identified.

To locate the West Puerto Chiquito characteristics, we note that it is impossible from interference and production testing (or by any other method for that matter) to determine directly the values of porosity or permeability. Such testing, however, will reveal values for kh/μ, k_oh, ϕh, and k/ϕ. If k_{ro} is known or can be closely approximated as, for example, in tests at pressures above or slightly below the bubble point, then Kh can be determined. By "sampling" several thousand acres under such conditions, the bounds of the K/ϕ directing arrow for the "COU reservoir" field of Figure 2-2 were determined.

The bounds for the porosity field cannot be directly calculated but can be approximated as follows:

From the same interference testing, the average unit pore volume approximates 0.25 porosity-feet. Identifying the porosity requires estimating the pay thickness. It is impossible to measure exactly the pay thickness in West Puerto Chiquito wells. It is probable, however, that the pay thickness is confined to the identified resistive zones on electric logs. A reasonable assessment of this suggests a range of 30 to 100 ft (9-30 m) for pay thickness.

These thicknesses and 0.25 porosity-feet pore volume translate to a porosity of 0.3% to 1.0%. These bounds are plotted on Figure 2-2 identified as "COU total porosity." The "COU total porosity" relation intersects that for K/ϕ at the field identified as "COU reservoir system." By the same method Kh can be reduced to K and the field identified from ϕ and K. From visual inspection of Figure 2-2, however, the effect of varying thicknesses, and resultant ϕ, is more readily seen by interconnection of K/ϕ lines with those of ϕ.

The location of the "COU reservoir system" field lying in the graph's "most fracture systems" area means that it is possible—we believe probable—that all of the porosity is fracture porosity. For it to be otherwise, i.e., containing a matrix porosity, the porosity of the matrix after allowing a minimal amount for fractures, would have to be substantially less than 1%. We think this unlikely (see Appendix 1).

Note that for a typical fractured dual porosity (sandstone matrix) system, essentially all of the permeability will be from fractures. In this case the share of the total porosity that is from fractures plotted against (total) permeability will fall in the field "most fracture systems"; whereas the same permeability compared with total porosity will fall high above (in the sandstone field). Valhall field (Nelson, 1985), for example, produces from a highly porous chalk. Well test analyses here indicated a total permeability of 66 to 100 md and corresponding fracture porosity of 0.3 to 0.4% (Nelson, 1985), which falls in the same field as the "COU reservoir system," whereas Valhall total porosity falls far above this field. In contrast, the independent determination of total porosity at West Puerto Chiquito places it entirely in the field for fracture systems.

The "average" determined for the Canada Ojitos Unit results from the influence of the combined properties of both the low capacity fracture blocks and the high capacity fracture system. It is virtually impossible to determine the values of the high capacity system alone. In some cases, however, reasonably accurate determinations can be made of the characteristics of an individual fracture block, as, for example, the block containing the A-14 injection well (Sec. 14, T25N, R1W) described in Appendix 3 and plotted as Figure 2-2.

Note here the extremely low porosity (0.1 to 0.2%) of the A-14 fracture block and the fact that the permeability and total porosity fall within the field for fracture systems. As before, if independent knowledge showed the total porosity for the fracture block to be significantly greater than that for fracture porosity then it would indicate some matrix porosity. Clearly this is not the case here.

The A-14 fracture block porosity is an order of magnitude lower than the "COU reservoir system." This significantly lower porosity, typical of fracture systems, is markedly different from that for matrix porosity systems. Changes in permeability from one area to another in a matrix reservoir typically show relatively small porosity changes. If, for example, the West Puerto Chiquito reservoir contained effective matrix porosity, the change in porosity for a permeability change similar to the difference between the COU average value and that of the A-14 fracture block would be by a factor of less than two rather than the factor of ten shown by the tests. Furthermore, a matrix porosity of 0.1 to 0.2% is outside the bounds of any known producible matrix porosity reservoir.

In summary, this analysis supports the conclusion reached from interpretations of core data that the reservoir contains no effective matrix porosity.

Appendix 3. Geometry of the Niobrara Fractured Shale Oil-Producing Reservoir of West Puerto Chiquito

The main producing reservoir of the West Puerto Chiquito Pool lies within the Canada Ojitos Unit. It comprises a system of lower capacity fracture blocks joined by an interconnecting, high-capacity fracture system. In the main part of the reservoir, the size of the individual fracture blocks is in the range of 20 to 200 ac. The less productive parts of the reservoir may have fracture blocks of larger sizes.

That this is the geometry of the system is supported by the fact that many individual well build-up, drawdown, or pressure fall-off tests show capacities (*Kh*) in the range of 0.02 to 0.5 darcy-feet; whereas the overall average reservoir capacity is from one to three orders of magnitude higher than that of the individual blocks. The overall average physical properties can only be determined from interference and frac pulse tests. A frac pulse test is analysis of the pressure pulse generated by hydraulic fracture treatment (NMOCC, 1988).

Although some have suggested that the reservoir might be of dual porosity type, the production and pressure data do not support this premise. If the reservoir were of the typical dual porosity type (matrix porosity laced with fractures), then the reservoir average transmissibility determined from interference tests would be in the same general range as that shown by testing of individual wells. The difference—up to three orders of magnitude—indicates the individual well fracture blocks are linked together by a high capacity fracture system with exceptionally high transmissibility in order to bring the overall average up by such a degree.

Individual well pressure tests reflect a flow regime covering small areas, generally 100 ac or less. The only reservoir geometry that can be satisfied by pressure and production testing is the fracture block system described above and shown in idealized form on Figure 3-1. Note that this basic geometry is corroborated by Landsat and aerial photography (Figure 8). Although most of the reservoir area is occupied by the lower capacity fracture blocks, at least half of the in-place reservoir volume lies in the high-capacity fracture system bounding the fracture blocks. In some areas, as much as 80 to 85% of the total recoverable oil comes from the high-capacity system, depending upon the degree of operation of the gravity displacement producing mechanism.

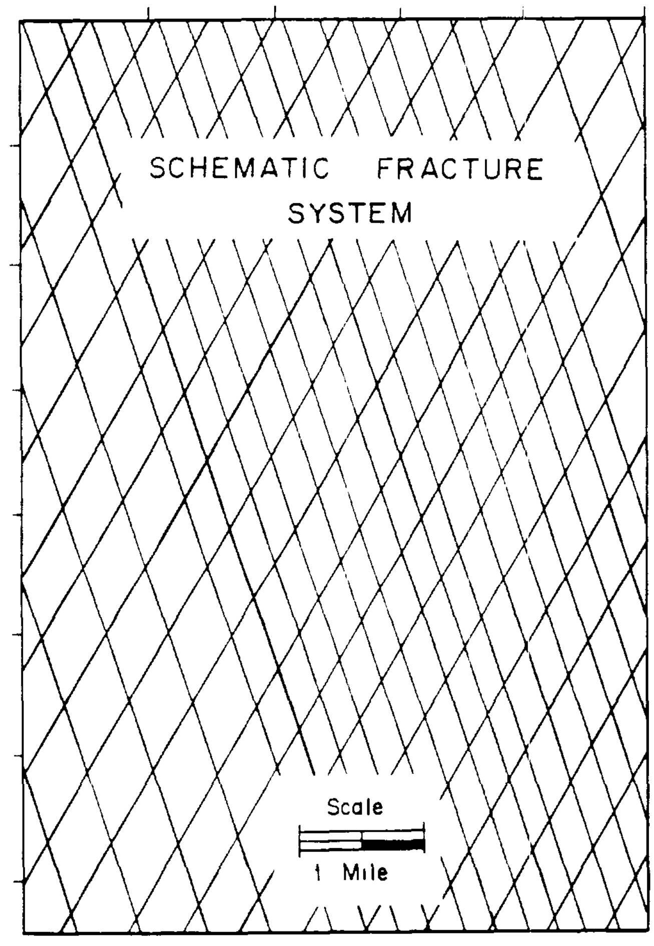

Figure 3-1. Sketch showing idealized fracture network of low capacity fracture blocks bounded by interconnecting high capacity fracture system.

It is impossible, of course, to determine the exact shape of a fracture block. However, it is not essential to the understanding of the reservoir flow system and its bearing on reservoir management to know the exact shapes or sizes of the fracture blocks. What is important is to recognize that the reservoir comprises a network of low-capacity fracture blocks linked by a high-capacity fracture system.

A well produced from a low-capacity fracture block has a relatively low transmissibility compared to that of the high-capacity fracture system such that the flow regime within the block is *essentially* that of "constant pressure at the boundary" for any time in its depletion history. For those parts of the reservoir where pressure is maintained by gas injection, the system is *exactly* that of constant pressure at the boundary. This is a fundamental distinction to make in analyzing data to determine reservoir properties.

The reservoir overall (the low-capacity fracture blocks and high-capacity fracture system taken together) average physical properties—Kh/μ, K_oh, and ϕh—can be determined from interference and frac pulse tests. Complete understanding of the reservoir and its behavior, however, requires a knowledge of these properties for the individual fracture blocks as well, particularly with respect to the type of porosity contained therein.

We make the observation that the unit pore volumes of the fracture blocks vary with their permeabilities, but in general these volumes are small compared to the overall reservoir average pore volume. For the individual fracture block, the value of Kh/μ, K_oh and K_gh can be approximated from build-up and drawdown or pressure fall-off tests. The value of unit pore volume, ϕh, for an individual fracture block, however, is more difficult to determine.

The calculation for an individual fracture block of its total pore volume, estimated unit pore volume (ϕh, in terms of stock tank barrels per acre, STB/ac, of hydrocarbon pore space) and its area are presented here. Estimates of Kh and porosity are included, as well. In making such analyses it is preferable to use tests in which there is a minimum influence of wellbore storage and afterflow. The best wells for such testing, therefore, are gas injection wells. Furthermore, to minimize the effects of stratification, it is preferable to use wells with only one zone open to the wellbore. One such test is shown by the type curve, Figure 3-2, of a pressure fall-off test made in 1987 on the Canada Ojitos Unit A-14 injection well (Sec. 14, T25N, R1W) (NMOCC, 1989). The system is that of constant pressure at the boundary as determined from the leveling of pressures at t_{DX_f} values above 2 (if it were a closed system the plotted points would fall to the left of the infinite line, or if a boundary had not been reached, the points would follow the infinite line) (see SPE Paper 6015, Transactions AIME 1978, v. 265, p. 139).

The fact that the measured points depart from the theoretical line at values between t_{DX_f} of 0.4 to 1 may indicate that the fracture block is not of exactly uniform dimensions. In addition it is unlikely that the well is exactly centered on the induced fracture. This phenomenon would affect the shape of the curve to some extent, but since the conductivity of the fracture is so much higher than that of the surrounding rock, there would not be a significant difference if the well were located at one end of the fracture rather than in the middle.

The same reasoning applies regarding the location of the fracture within the fracture block. The leveling of the pressures will occur as a function of the shorter distances to the edge of the block such that any estimate of the block's volume or size will be on the minimum side.

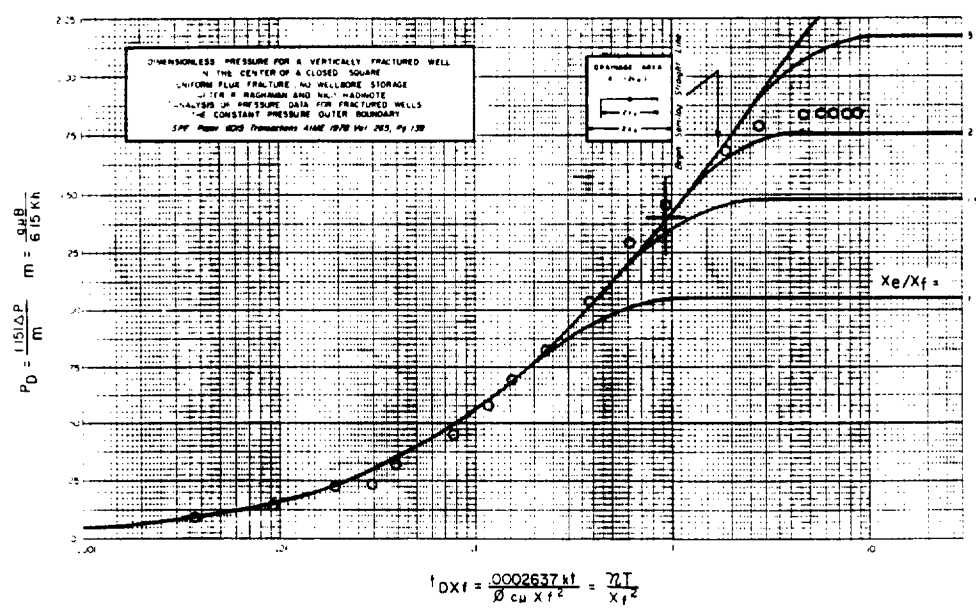

Figure 3-2. Plot of measured points of pressure fall-off test COU injection well A-14 (Sec. 14, T25N, R1W) in COU within the West Puerto Chiquito field. Plotted points are against background type curve for "constant pressure at the boundary."

Once a curve match has been obtained, then the total pore volume can be calculated. In the above example, $K_g h/\mu$ is 0.46 darcy-feet/cp and for C_T equal to 370×10^{-6} and the ratio of t to t_{DX_f} equal to 1/0.94, the total pore volume in the fracture block is calculated to be 28,000 bbl of hydrocarbon pore space (equivalent to 22,000 STB).

Although it is impossible to determine fracture length or unit pore volume from this information alone, it is possible to determine how the value of one is dependent on the other. Furthermore, the relation of the total fracture length, $2x_f$, to unit pore volume can be described. Figure 3-3 shows this limit of definition in determining fracture length or unit pore volume. If one knows the fracture length, the unit pore volume can be determined, or vice versa. In the absence of independent information as to one or the other, however, this relation—one variable dependent on the other—is the limit of definition that can result from analysis only of a build-up or fall-off test.

To make an independent determination of the length of the induced fracture, we analyze the frac treatment causing the induced fracture. Although aided by analysis of the frac treatment, the unknown quantities are such that it is impossible to construct a mathematically exact solution that will provide unit pore volume. Given the fact that maximum average pore volume is probably less than 2000 bbl per acre (from interference tests in West Puerto Chiquito), it is possible to combine information from the two sets of data to arrive at an approximate solution.

With respect to analysis of the frac treatment, we note that in other wells tested by radioactive tracer surveys following frac treatment, and by production testing with zones individually fractured, the results show that there is very little build-up of frac height during frac treatments using low viscosity fluids in the Niobrara. Rather, the frac appears to be confined to, if not the perforated interval, the particular zone (A, B, or C). For the subject well the perforated interval was 30 ft (9 m), and it is believed that the total frac treated interval could not exceed 50 ft (15 m).

The main variable in the instant case in estimating the length of the induced fracture is the leak-off of the frac fluid, or frac efficiency. Using frac efficiency as the variable, the fracture lengths were computed by the KGD model (Economides and Nolte, 1987) and the results for 30 ft (9 m) and 50 ft (15 m) fracture lengths displayed graphically (Figure 3-4).

These curves show the limit of definition in estimating frac length (one variable dependent on the other). Amount of leak-off, and efficiency, is next to impossible to determine. The relation does, however, provide an entirely independent method of estimating frac length. In calculating the curves by the KGD model, an oil viscosity of 3 cp, Young's Modulus of 5.6×10^{-6}/psi, frac treatment rate of 67½ BPM, and total volume of 3600 bbl were used.

With the knowledge that overall reservoir unit pore volume will probably not exceed the equivalent of 2000 STB/ac, this is used as the highest point on the ordinate of the plot in Figure 3-3. Using this information from Figure 3-3 and combining it with that of Figure 3-4 provides a method of estimating frac length as shown by reproducing the curves of Figures 3-3 and 3-4 on Figure 3-5. Although the maximum ordinate for the pressure fall-off test is only an estimate for the reservoir, it is a reasonable estimate. The result is not particularly sensitive to this estimated figure: If the correct figure were 1000 instead of 2000 bbl/ac, the consequence would be a reduction in pore volume of 50 to 100 bbl/ac.

From Figure 3-5, we determine the total frac length to be in the range of 700 to 800 ft (213-244 m), and the corresponding hydrocarbon pore volume to be 300 to 400 STB/ac. From this and the fracture block's

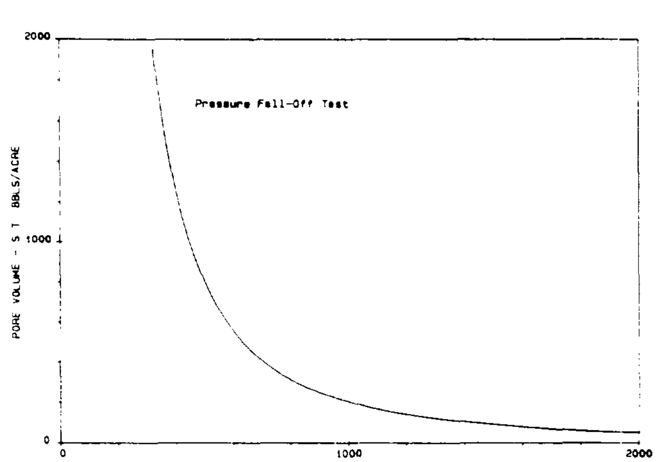

Figure 3-3. Relation of unit pore volume (stock tank barrels per acre) to fracture length of hydraulically induced fracture of the COU A-14 well determined from pressure fall-off test shown in Figure 3-2.

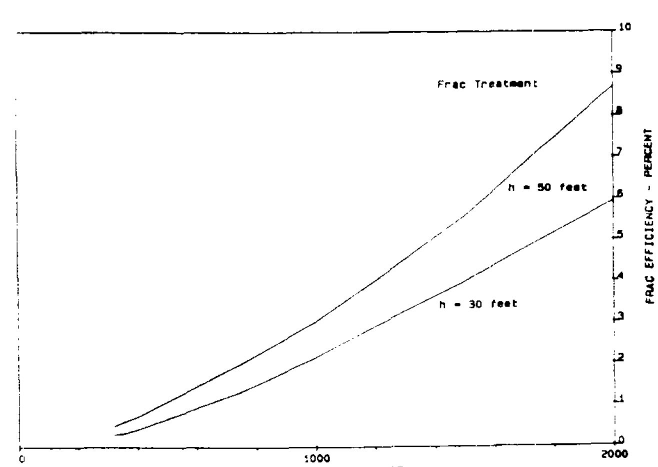

Figure 3-4. Relation of frac efficiency to total induced fracture length for hydraulic fracture treatment of the COU A-14 injection well calculated by the KGD and PKN methods.

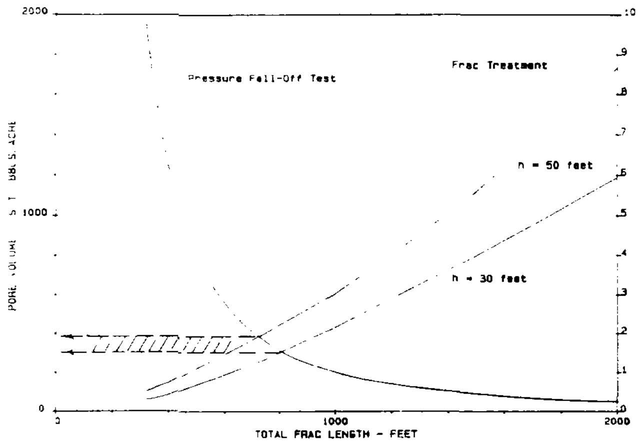

Figure 3-5. Combination of Figures 3-3 and 3-4 using arbitrarily selected maximum ordinate of 2000 stock tank barrels per acre for location of data of pressure fall-off test. Interpreted frac length 700 to 800 ft. Pore volume of well's low capacity fracture block approximately 300 to 400 barrels per acre using KGD method of hydraulic fracture analysis.

total pore volume, the minimum area occupied by the fracture block can be calculated; in this case, 55 to 75 ac.

Fracture lengths versus the frac efficiency were also calculated by the PKN method (Economides and Nolte, 1987). Using this method and a similar combination of data, the unit pore volumes are indicated to be in the range of 200 to 270 STB/ac with a fracture block size of 80 to 110 ac.

The 30 ft frac "height" line intersects the other at a fracture length of 800 ft (244 m) (Figure 3-5). For this fracture length, the fracture width is 0.19 in. This amounts to an effective sand volume supporting the propped fracture of ±44% of the 147,000 lb of frac sand used.

For the 50 ft (15 m) frac height line intersection at 730 ft fracture length, the average fracture width is 0.16 in., which indicates 58% of the sand volume is effective in propping the fracture.

As gas continues to be injected in this well, permeability to gas is increasing. The maximum value so far shown is a $K_g h$ of 0.015 darcy-feet. Since permeability to gas has increased approximately sevenfold since initial injection, it is reasonable to believe that K_{rg} is approaching a value of 0.5. Kh for this block would be 0.025 to 0.035 darcy-feet using a range of 0.4 to 0.6 for K. As noted above, the corresponding unit hydrocarbon pore volume is 200 to 400 STB/ac. From this ϕh = 0.033 to 0.067 and the resulting K/ϕ values range from 0.4 to 1.1. The corresponding average porosity values for the estimated 30 to 50 ft (9–15 m) of pay (and the 200 to 400 STB/ac determined above) range from 0.1 to 0.2%. These values (covering the ranges for both KGD and PKN models) are plotted in Figure 2-2 of Appendix 2 (example identified therein as A-14).

These porosity and corresponding permeability values for the A-14 fracture block converted to hydrocarbon pore volume (bbl/acre) are compared with those obtained in interference tests sampling large areas of the reservoir by displaying its field on a graph of capacity (Kh) versus unit pore volume in STB/ac (Figure 3-6).

On Figure 3-6, the basic X, Y, and Z lines derive from the porosity and permeability relations for the field identified as "some fracture systems" on Figure 2-2 of Appendix 2. The "probable upper limit for fracture porosity" is identified as the "A" relation, the lower part of the field as the "C" relation, and halfway in between, the "B" relation. Using these values and the number of feet of pay as shown on Figure 3-6, lines X, Y, and Z have been computed.

Figure 3-6 was prepared in 1969 (NMOCC, 1969) as a basis to work from in comparing unit pore volume as it might be dependent on Kh. Most of the test data were acquired by the operator of the Canada Ojitos Unit. Kh data for Boulder were from tests made by Standard of Texas (NMOCC, 1963). Location of the X, Y, and Z lines of **Figure** 3-6 is based on the premise that the thicknesses of the "pay zones," in this case the fractured reservoir units, are relatively uniform throughout the reservoir. Increases in pore volume between areas are caused by greater curvature (or bending stress) applied to the reservoir units, resulting in increased aperture width but relatively similar fracture density throughout. Thus, the ratio of oil in place of two areas varies as the cube root of the ratio of their respective capacities (Kh). Clearly we cannot expect this to be the case throughout; but it is surprising the number of tests that fall in the projected ranges.

The character of the fracture network makes unreliable such analyses as Horner plots where extrapolated to estimate reservoir pressure. One can be assured only that the reservoir pressure is as high as the last pressure measured. Extrapolation can be reliable only in the sense that it marks the maximum possible. Because of this infirmity, the Canada Ojitos Unit operator uses pressure fall-off tests following fracture treatment to estimate maximum reservoir pressure indicated by a well.

Numerous examples corroborate the existence of "tight" fracture blocks and nearby high capacity fracture systems. The Canada Ojitos Unit E-10, for example, was drilled through the pay zones with air. The flow stream analysis showed no hydrocarbons above that of the background overlying shales, and the well produced no oil or gas "natural." After frac treatment, however, it produced at high rates and has accumulated 2.3 million bbl. Clearly, the character of the formation in the bore-hole was not representative of the reservoir.

In conclusion, the reservoir geometry underscores the difficulty of attempting to analyze the reservoir through core analyses. The bulk of the recoverable reserves are probably located in open fractures of the high capacity fracture system. Reservoir property

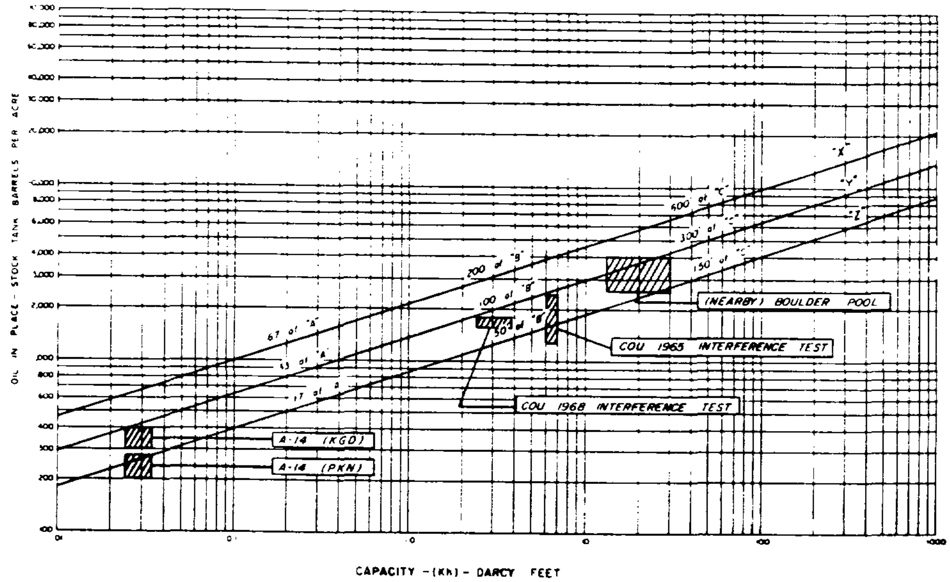

Figure 3-6. Plot of pore volume (stock tank barrels per acre) as dependent on capacity, *Kh*, determined from interference and pressure testing.

determination through core analyses of the low capacity "tight" block must be considered suspect. The properties of the high capacity system, from which the bulk of the reserves will come, are even more difficult to determine. Average characteristics reflected by interference and frac pulse testing, however, yield data useful in development planning and reservoir management.

Appendix 4. West Puerto Chiquito Fluid Property Data

Although in most solution gas drive reservoirs the process involves a mix of flash and liberation processes, in making our analyses we have used differential liberation fluid property data (Figure 4-1) since this more nearly represents the entire depletion process here. In support of this position, we offer the following observations.

With early free gas movement in a fractured solution gas drive reservoir, the free gas is removed from the system as soon as it reaches the wellbore. With early high GORs, this commences with first production, and the reservoir process is clearly one approaching strict differential liberation. Although liberated gas as it moves through the reservoir to the wellbore stays in contact with reservoir oil until it reaches the wellbore, so does gas liberated in the laboratory stay in contact with some oil for the length of the pressure "step" during the laboratory analysis. The laboratory simulation of the reservoir process may not be perfect, but values obtained from it are probably as accurate as the values determined for the other factors influencing a reservoir analysis. Most of the production in West Puerto Chiquito has been the consequence of gravity displacement: Here the liberated gas moves—not to the wellbore—but updip to form a gas cap, and the result is the same, differential liberation.

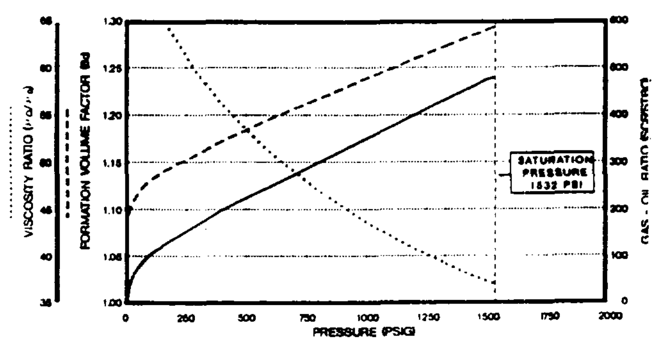

Figure 4-1. Fluid property data from COU K-13 well, Sec. 13, T25N, R1W, in West Puerto Chiquito field.

Since part of the recovery in West Puerto Chiquito will be by solution gas drive and most of the recovery in nearby fields will be by solution gas drive, we now review in more detail the influence of both differential and flash liberation characteristics for solution gas drive.

In estimating the portion of the overall depletion process that is influenced by differential and flash characteristics, it is instructive to review the mathematical relation of the various factors influencing solution gas drive depletion. This is most clearly accomplished by inspection of Muskat's method summarized in Appendix 5 (Muskat, 1945). The first step of equation (1) in Appendix 5 defines change in reservoir oil saturation with pressure decline. This step, as noted above, is clearly independent of flash data. Simply expressed, the gas and oil arrive at the wellbore by the differential depletion process, what happens thereafter will not have a retroactive effect on the reservoir's oil saturation.

The only effect of flash data lies in the determination of its share of the process which relates the volume of produced oil to the volume it occupied in the reservoir. Note that this produced volume is small (5 to 10% of oil-in-place for solution gas drive) compared to the remaining reservoir volume controlled by differential data. Furthermore, note that the fraction of the total stream that reaches the stock tank as oil depends on the "path" the mixture takes from the bottom hole of the well bore up the production string(s) to the stock tank. The paths taken by the production in the different wells may be different; but field-wide for the various operators the overall effect of the flash process modifying reservoir performance calculated by differential data will be small. In summary, it amounts only to the differences in amount of gas dissolved in oil at the stock tank for the different paths taken by the oil up the production strings. These different paths are defined by the production method used.

In our analyses, we use differential data all the way through. Not only is the reservoir process differential; but also we note that a substantial amount of a field's production as it moves from the bottom of the wellbore to the surface is differential liberation:

1. A large volume of oil has been produced in West Puerto Chiquito with submersible hydraulic pumps. Here as the produced oil moves to the surface, it is in continual contact with the power oil, and as gas comes out of solution from the produced oil, it immediately goes into solution in the power oil in a strictly differential liberation process. On flashing into the separator, the gas still in solution in the power oil prevents it from contacting the produced oil; so here again the process is still largely differential liberation.
2. Sometimes pumping wells are produced such that the gas is separated from the oil in the bottom of the well and moves up the annulus separate from the oil. Here the process is differential liberation until the two streams are combined in the separator.
3. In some of the wells that flow by gas lift by heads, the gas and oil are separated in the bottom of the wellbore and stay separated all the way to the stock tank—a form of the differential liberation process.

In summary, fluid sample data determined by the differential liberation process is appropriate for reservoir analyses at West Puerto Chiquito.

Appendix 5. Relative Permeability and Formation Compressibility

Fluid withdrawal from a closed reservoir causes pressures to decline and net overburden pressures to increase, resulting in a reduction in pore volume. Change in overburden pressure causing a reduction of as much as 50% of the pore space has been determined not to affect the ratio of relative permeabilities (gas to oil) in a sandstone (Fatt, 1953). In the absence of information to the contrary, we think it probable that the same will hold for a fractured reservoir.

Although this characteristic does not change, as pressure declines formation compressibility (C_f) causes a reduction in pore volume and, as a consequence, reduces the free gas saturation. Accordingly, the corresponding relative permeability ratio (k_g/k_o) will be smaller than that had the pore volume not been reduced. If the formation compressibility were of the same order of magnitude as system compressibility, it would have a marked effect on reservoir performance.

At West Puerto Chiquito and vicinity, neither the value of C_f nor that of k_g/k_o is precisely known. Since each property operates to influence the same factors controlling reservoir performance, we examine these two characteristics together.

Reported Formation Compressibilities

Three separate analyses for formation compressibility have been reported for West Puerto Chiquito and the offsetting pool, Gavilan:

1. Comparison of interference tests in West Puerto Chiquito at pressures above and below the bubble point.
2. Brine squeeze test of core samples from a Gavilan field well.
3. Special test to estimate fracture compressibility from cores of another Gavilan field well.

Remarks with respect to these tests follow.

1. An interference test that "sampled" several thousand acres in the Canada Ojitos Unit in West Puerto Chiquito in 1965 (NMOCC, 1966) when the oil was undersaturated and the formation compressibility was significant (with respect to system compressibility) showed reservoir volume of oil in place ranging from 1000 to 2500 STB/ac for the assumed range of formation compressibilities of 26×10^{-6}/psi to 6×10^{-6}/psi. Another interference test run in 1968 (NMOCC, 1969) in part of the area covered by the 1965 test showed stock tank oil-in-place volume approximating 1700 bbl/ac. This test was run when pressures were below the bubble point and the formation compressibility was believed to be relatively insignificant. A pore volume of 1700 bbl/ac shown by the second interference test approximates the average estimated from the first test. The formation compressibility would then be the average of 6×10^{-6}/psi and 26×10^{-6}/psi; or approximately 15 to 16×10^{-6}/psi.
2. Brine squeeze tests were run using cores from the Mobil B-38 well, Sec. 4, T24N, R2W (personal communication, Mobil to Gavilan Engineering Committee, 1986). From the plot of volume change versus applied pressure, the calculated compressibilities were determined to range from 6×10^{-6}/psi to 16×10^{-6}/psi.
3. Information from the special tests directed at estimating fracture compressibility from cores of the Mallon Davis Federal 3-15, Sec. 3, T25N, R2W, was reported for three samples (NMOCC, 1987). They were approximately 50×10^{-6}/psi, 100×10^{-6}/psi, and 150×10^{-6}/psi, a spread of 100×10^{-6}/psi. The laboratory qualified its results because of the difficulty in supporting the samples in such a fashion as to properly simulate reservoir conditions.

We believe the best information as to value of formation compressibility is the comparison of the interference tests. The brine squeeze tests, while yielding values approximating those of the interference tests, are subject to the same limitations inherent in all core analyses of this reservoir: Core samples are not representative of the producing reservoir (Appendices 2 and 3).

It is to be expected that compressibility will vary somewhat from one area to another. It is unlikely, however, that it will vary over the extreme ranges indicated in item 3 above. Even so, the study was expanded to include analyses involving the reported high compressibilities in order to cover completely the effect of such phenomena should they in fact exist.

"Critical Formation Compressibility"

For an overview of the effect of formation compressibility on solution gas drive performance, we inspect Muskat's basic formula (Muskat, 1945) equation (1) below. Note that the left-hand member of equation (1) is actually value *per unit pore volume* and has the same dimensions as formation compressibility. Note, also, early in the depletion cycle when free gas saturation and k_g/k_o are low, that $\Delta S_o/\Delta P$ approaches the value of lambda. Lambda is the dominant member of the two terms defining saturated oil compressibility (Ramey, 1964), which for the subject reservoirs is 200 to 300×10^{-6} (Figure 5-1). This is the same order of magnitude as the high values (100 to 150×10^{-6}/psi) of formation compressibility indicated by the tests of item 3 above. Thus, without analyses, but simply from inspection of the formula, it is clear that if formation compressibilities were in fact this high, they would modify significantly the otherwise normal reservoir performance.

For instance, if the initial value of $\Delta S_o/\Delta P$ were the same as that of formation compressibility, then the volume change of the oil saturation would be balanced by the pore volume change due to the formation compressibility and little free gas would evolve as oil is withdrawn. Gas oil ratios would decline initially and never reach high values with depletion. The fractures would contract such that the porosity would be significantly reduced from its original value. If the initial GORs were low, a very large part of the initial oil in place would have been expelled at depletion.

We refer here to the formation compressibility that initially balances $\Delta S_o/\Delta P$ as the "critical" formation compressibility. If, initially, formation compressibilities are above "critical," reservoir pressures will not decline on withdrawal of oil, and the solution gas drive process cannot take place. We have not included production behavior for such a situation, as we think

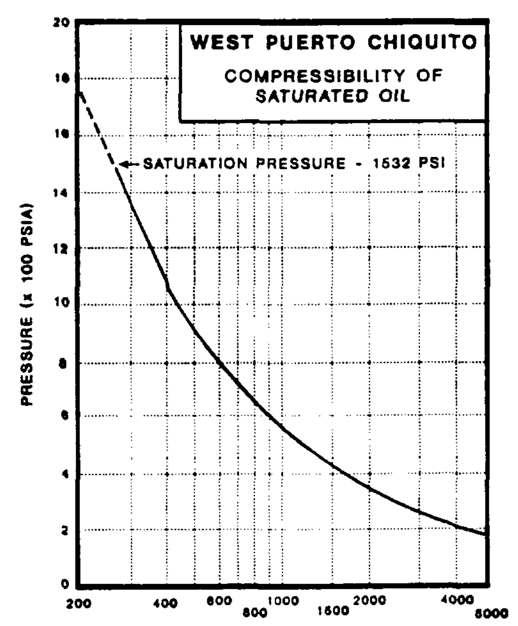

Figure 5-1. Compressibility of saturated oil from West Puerto Chiquito fluid property data.

it unlikely that it would actually occur. We make this note, however, since for one of the k_g/k_o curves studied herein, the critical formation compressibility approximates 100×10^{-6}/psi—well within the range of the 50 to 150×10^{-6}/psi reported for the special compressibility tests.

To illustrate production behavior where the value of formation compressibility approximates, but is slightly less than, "critical," as well as sensitivity of the production histories to different values of C_f, we present GOR histories utilizing three relative permeability ratio curves (curves I, II, and III of Figure 5-2). These three curves lie in the range indicated by laboratory measurements of relative permeability of fractured formations (Keeling et al., 1964, 1969). Curves I and II will "bracket" the characteristics on the high and low sides; and curve III lies in between these extremes.

Only GOR histories are displayed, since this provides a means of comparison with field performance from a minimum of data; namely, oil and gas production. In all of our determinations of sensitivity to formation compressibility, certain precautions were taken to insure that the differences in curves were indeed the consequence of changing C_f and not caused by mathematical inaccuracies. Straight line curves (saturation varies as the logarithm of k_g/k_o) were chosen since they permit precise calculation of k_g/k_o for any given saturation. Also the Muskat method, with formation compressibility recognized (equations 5, 6, and 7 below), was used. Once composite functions have been determined for the average pressure of each step, there remain only two unknowns: oil (or free gas) saturation and the corresponding relative permeability ratio. Although in developing production histories of typical reservoirs it is possible to obtain acceptable results with this method by the direct calculation at each step from a reasonable projection of the average saturation for each preceding step, greater precision is reached by converging the saturation and relative permeability ratio values to exact matches. An integral part of the computer program used performs this convergence. Approximately 40 precise points were used to define each curve up to a free gas saturation of 20%. The program identifies and then makes a straight line interpolation between the relevant points to determine the convergence. Thus, although the k_g/k_o relations used do not exactly follow the curves, being instead a series of points on the curve with interconnecting straight lines, they are precisely the same for each set of C_f comparisons.

Fluid property data for West Puerto Chiquito (Appendix 4) were used along with 10% connate water saturation and an abandonment pressure of 125 psia. With these parameters the "critical formation compressibility" approximates the values in Table 5-1. (Higher water saturations would result in lower values for critical formation compressibilities.

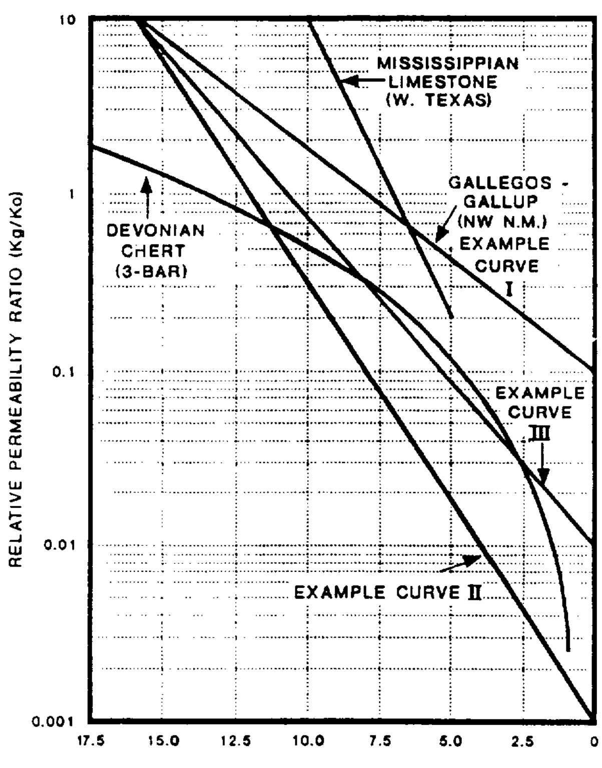

Figure 5-2. Ratio of relative permeability characteristics for some fractured reservoirs and example curves used in analyses.

Table 5-1

For curve (of Figure 5-2)	Initial k_g/k_o	Approximate "Critical" Formation Compressibility
I	0.1	100×10^{-6}/psi
II	0.001	300×10^{-6}/psi
III	0.01	230×10^{-6}/psi

Plots of GOR versus oil recovery in percent of oil in place are shown on Figure 5-3 for these three relative permeability curves and associated "critical" formation compressibility. Note the relatively high recoveries for curves II and III and the overall shape of the GOR curves: an initial decrease with only a slight increase over the depletion history. The curve shapes bear little resemblance to those of typical solution gas drive reservoirs.

Overview: Sensitivity of Oil Recovery to Formation Compressibility

An example of variation in oil recovery with C_f is demonstrated using relative permeability curve II of Figure 5-2. Here k_g/k_o and all parameters other than C_f are held constant. The results are displayed on Figure 5-4 where the GOR histories are plotted against cumulative recoveries in percent of oil in place for the several formation compressibilities shown.

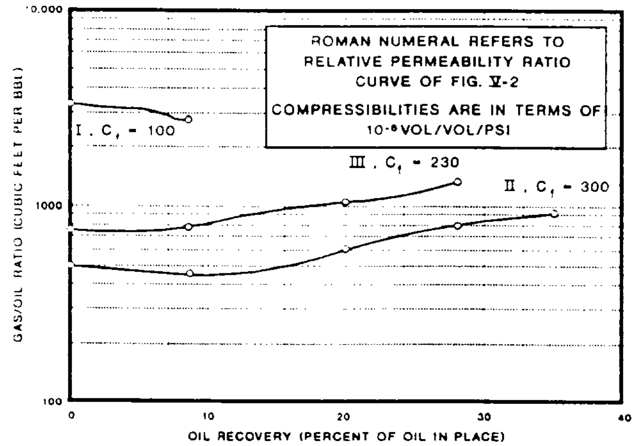

Figure 5-3. Solution gas drive GOR histories using "critical" formation compressibility. Note high recoveries for k_g/k_o curves II and III and that shape of all GOR curves bears no resemblance to that of typical solution gas drive reservoirs.

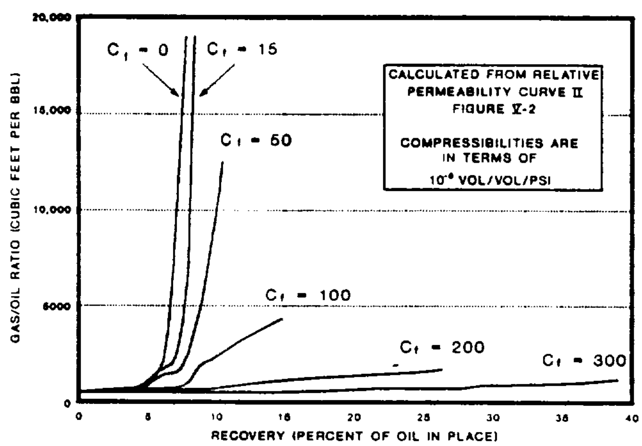

Figure 5-4. Solution gas drive recovery using relative permeability curve II and various formation compressibilities. Note extreme range of recoveries for the different compressibilities.

Here the ultimate recovery is identified by the end point of each GOR line. They show a range of recovery of five to one (confirming the observation that high C_f's would indeed be significant) for C_f ranging from the "critical" to zero (Table 5-2).

Estimate of Relative Permeability and Formation Compressibility through Comparison with Field Data

For purposes of comparison with calculated performance using the k_g/k_o curves and several values of C_f, we use the field performance of central Gavilan offsetting West Puerto Chiquito. Note that West

Table 5-2

C_f (10^{-6}/psi)	Ultimate Recovery of Oil in Place
0	8.8
15	9.2
50	11.0
100	15.7
200	28.0
300	41.6

Puerto Chiquito's pressure maintenance and relatively large amounts of gravity drainage preclude accurate determination of k_g/k_o from its production data. Although central Gavilan (Figure 2) has received substantial gravity drainage and support from migration, its dominant recovery mechanism, at least for the latter part of the depletion cycle, is solution gas drive. Analysis of solution gas drive provides k_g/k_o data.

In estimating relative permeability characteristics from central Gavilan production data, we note the following:

1. Because of the high conductivity of the fracture systems, significant gravity drainage has occurred (see "efficiency" above), even in areas of low dip. The result is lower GORs initially and apparently lower relative permeability ratio (k_g/k_o) than the reservoir's true character. In the latter stages of depletion, however, an effect of the earlier gravity drainage is to cause lower oil saturations than would be the case for pure solution gas drive. Therefore, the GORs and apparent relative permeability ratios will appear higher than had the process been pure solution gas drive. Gravity drainage, in other words, renders the determination of oil saturation associated with a given relative permeability ratio quite difficult.
2. Different areas of the reservoir will have different degrees of fracturing and may cause actual relative permeability ratios to be different in the different areas. The principal effect of the varying degrees of fracturing, however, will be reflected in the gravity drainage effects rather than difference in relative permeability ratios.
3. Even if reservoir pressures are reasonably well known and k_g/k_o can be calculated from GORs and estimated reservoir pressures, determination of the corresponding true oil saturation is more difficult, and sometimes the procedure cannot be completed. In Gavilan, where indefinite amounts of gravity drainage and regional migration have occurred, it is impossible to determine precisely the concurrent oil saturation. Regional migration precludes estimation of free gas saturation from the elementary relation of oil produced below the bubble point and an estimate of oil in place, along with formation volume factors. To enlarge the study area to include lands providing regional

migration in the analyses brings in complications more difficult to deal with: The Bear Canyon Unit (Figure 2) is downdip, with a lower well density, more efficient gravity drainage (a depletion process significantly different from Gavilan's), and migration from the east, where pressure maintenance support is involved. In spite of the problems of dealing with production above the bubble point, gravity drainage, and migration, the GOR history of Gavilan nevertheless provides some insight with respect to ratio of relative permeability and formation compressibility.

Since central Gavilan is essentially oil depleted (Figure 5-5), it is possible to make a reasonable projection of (economic) ultimate recovery: 5 million bbl. Any economically recoverable oil beyond that amount will be from stripper wells supported by gas sales or from "protected" wells still receiving gravity drainage. With an estimate of central Gavilan's ultimate recovery, it is possible to relate its GOR history to recovery in percent of ultimate. This provides one method of estimating C_f and k_g/k_o from a minimum of required field data; namely, oil and gas production.

Central Gavilan encompasses approximately 24,000 ac and has produced largely by solution gas drive from both high and low capacity wells with a high degree of communication. Although by no means a "perfect laboratory" for determining C_f and k_g/k_o, the overall production with appropriate adjustments should reveal nearly average formation properties.

k_g/k_o characteristics influence, and can be determined from, reservoir performance at pressures below the bubble point. Analysts have not agreed on Gavilan's bubble point pressure, but the highest reported (NMOCC, 1987) is 1660 psi. Approximately 1 million bbl were produced prior to the reservoir reaching this pressure.

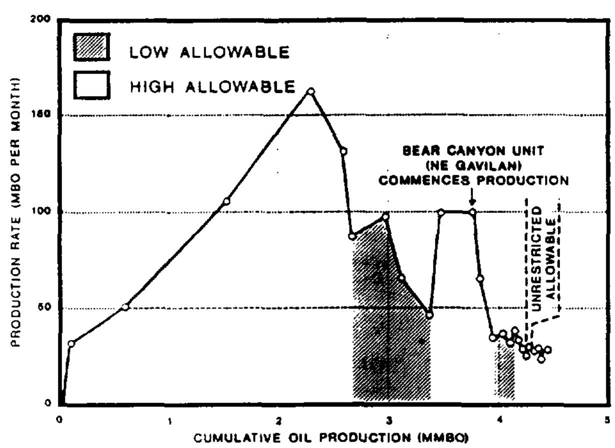

Figure 5-5. Plot of production rate versus cumulative recovery for central Gavilan. Periods of high and low allowables are identified along with one period of unrestricted allowable. Economic ultimate recovery of 5 million bbl estimated from this plot.

Statistics for central Gavilan's GOR history for production below this bubble point pressure are set out in Table 5-3. A plot of GOR versus ultimate recovery is shown in Figure 5-6. The first 65% of ultimate recovery reflects a smoothed curve of the published data (NMOCC, 1988) for production below the bubble point. Data for the rest of the curves come from monthly reports to the New Mexico Oil Conservation Commission.

The lower curve extending from this base ("all wells," Figure 5-6) derives from reported data for all wells in central Gavilan, while the upper curve ("all wells except two," Figure 5-6) excludes two wells (Hill Trust #1, Sec. 5, and High Adventure #1, Sec. 8; both in T25N, R2W). These two wells are still receiving substantial gravity drainage and do not reflect the relative permeability characteristics shown by the other approximately 60 wells. If the production of these wells were to be included in determining average GOR (and k_g/k_o values), the result would be values lower than the true average reservoir characteristics.

Similarly, other wells initially receiving gravity drainage and indicating k_g/k_o values lower than the true reservoir character will, in the later stages, exhibit higher gas saturations and k_g/k_o values than the true reservoir average. As a consequence, the curve for "all wells less 2" (Figure 5-6) shows higher GORs than would be the case in the absence of gravity drainage. We have therefore selected the GOR history between these two extremes ("average" curve of Figure 5-6) as more nearly representative of the actual relative permeability character for this part of the depletion cycle.

GOR histories for various formation compressibilities were calculated for the (straight line) k_g/k_o curves I, II, and III (Figure 5-2) and compared to the central Gavilan GOR history on Figures 5-7, 5-8, and 5-9. Clearly, the calculated curve forms for compressibilities exceeding 15×10^{-6}/psi bear no resemblance to the curve of field performance, forcing the preliminary conclusion that the value of C_f is probably low.

GOR histories using relative permeability ratio curves I and II (Figures 5-7 and 5-8) "bracket" the field data on both the high and low sides. As k_g/k_o characteristics move in the direction of a curve "match" (from curve II to curve III on Figures 5-8 and 5-9), the curves with higher C_f's show greater divergence at the latter part of the depletion cycle. Clearly, as convergence is approached between calculated and observed curves, values of C_f decrease, making it unlikely C_f will be greater than 15×10^{-6}.

Finally, use of k_g/k_o curve IV (Figure 5-10) with $C_f = 15 \times 10^{-6}$/psi results in an approximate match with field performance (Figure 5-11). Use of higher C_f values (not plotted) show greater divergence from field performance as the match improves. Moreover, for the reasons noted below, the true k_g/k_o relation is probably one that would shift the curves farther left (past a "match"), reducing even further the

Table 5-3. Central Gavilan gas-oil ratios and cumulative production

		Prod. below Bubble Point		Gas-Oil Ratios *		
Date	Cumulative Oil Prod. (M Bbl)	Cumulative Less 1000 (M Bbl)	Ultimate Recovery (%)	Central Gavilan (cf/bbl)	Central Gavilan Less Two Wells ** (cf/bbl)	Average (cf/bbl)
	0			550	550	550
07/85	1,000	0	0	850	850	850
12/85	1,500	500	12.5	1,100	1,100	1,100
06/86	2,000	1,000	25.0	1,400	1,400	1,400
08/86	2,500	1,500	37.5	2,000	2,000	2,000
01/87	3,000	2,000	50.0	3,150	3,150	3,150
08/87	3,500	2,500	62.5	4,600	4,600	4,600
05/88	4,050	3,050	76.3	8,000	9,600	8,800
07/88	4,100	3,100	77.5	9,000	11,600	10,300
10/88	4,200	3,200	80.0	10,800	15,200	13,000
01/89	4,300	3,300	82.5	13,000	18,800	16,000
		(4,000) ***	(100.0) ***			

* GORs are smoothed averages.
** Hill Trust #1 and High Adventure #1, Sec. 5 and 8, T25N, R2W.
*** Ultimate recovery for production below bubble point estimated at 4000 M bbl.

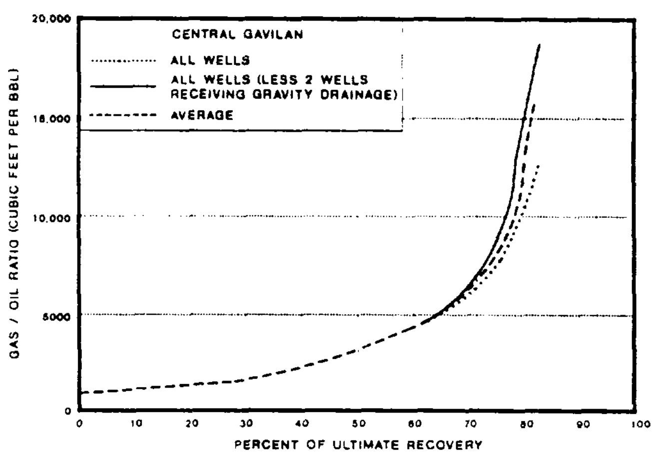

Figure 5-6. GOR history of central Gavilan from field data. Average curve is used in making comparisons of calculated histories with field performance. Percent of ultimate recovery is based on cumulative recovery of production below maximum assumed bubble point pressure of 1660 psi.

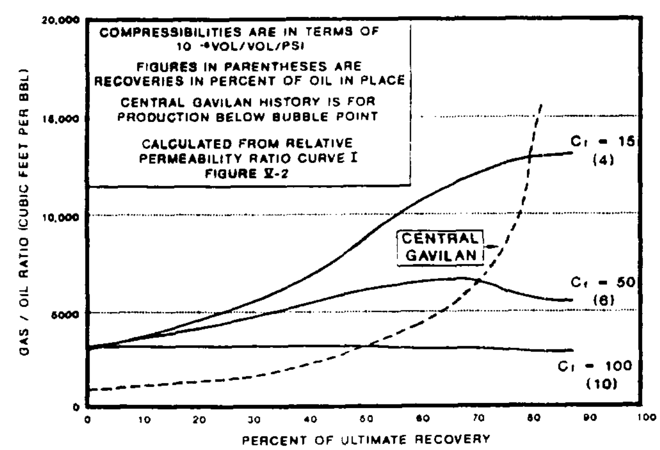

Figure 5-7. Calculated solution gas drive recoveries using k_g/k_o curve I of Figure 5-2 and various formation compressibilities. Histories are GOR versus ultimate recovery. Note failure of calculated curves to "match" field performance.

possibility that high formation compressibilities exist.

Gavilan's greater depths and higher temperatures would result in a higher bubble point than that determined for West Puerto Chiquito oil. Solution gas drive recoveries, however, are not sensitive to small differences in initial bubble point pressures; recognition of a different bubble point would not materially affect such analyses. Furthermore, a higher bubble point than that used would result in lower values of the composite function lambda and cause even greater divergence between the calculated curves using high formation compressibilities and the field data.

The foregoing analysis, while not completely definitive, clearly eliminates formation compressibilities in the range of 100 to 150 × 10^{-6}/psi. In fact, it is unlikely that C_f is higher than 15 × 10^{-6}/psi.

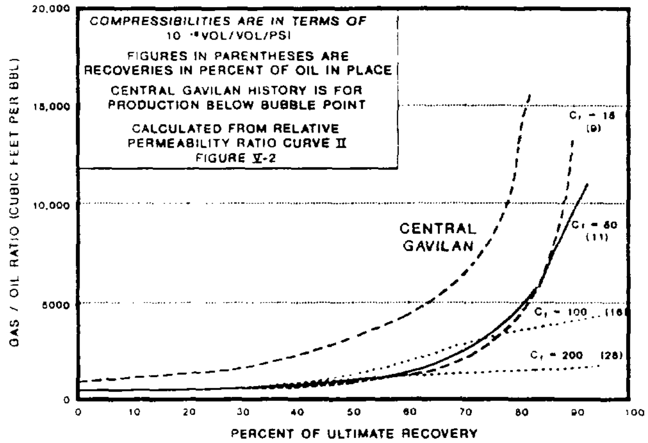

Figure 5-8. Calculated solution gas drive recoveries using k_g/k_o curve II of Figure 5-2 and various formation compressibilities. Note these curves fall below that of field performance. Note divergence from field data of curves for $C_f = 100$ and 200×10^{-6}.

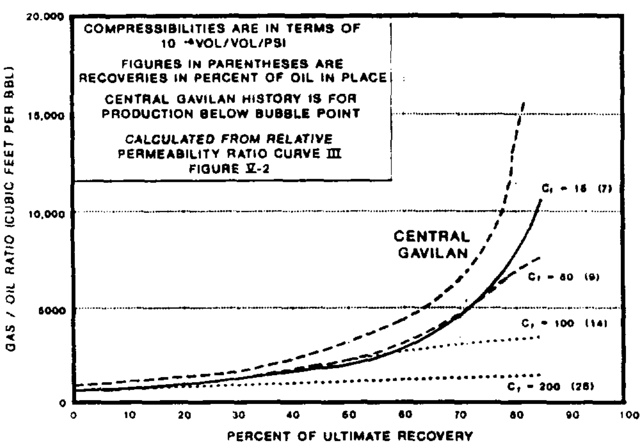

Figure 5-9. Calculated solution gas drive recoveries using k_g/k_o curve III of Figure 5-2 and various formation compressibilities. Note low value of maximum GORs for curves with C_f of 50×10^{-6} and greater.

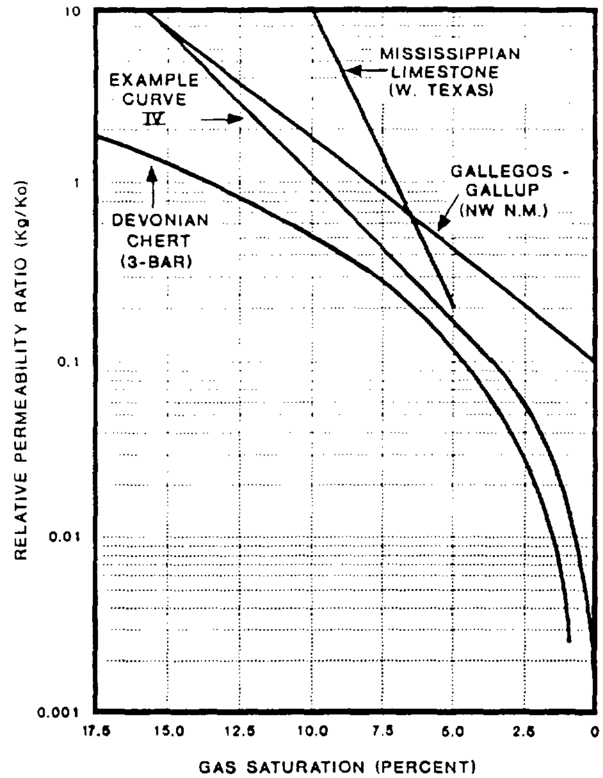

Figure 5-10. k_g/k_o example curve IV compared with those of some fractured formations.

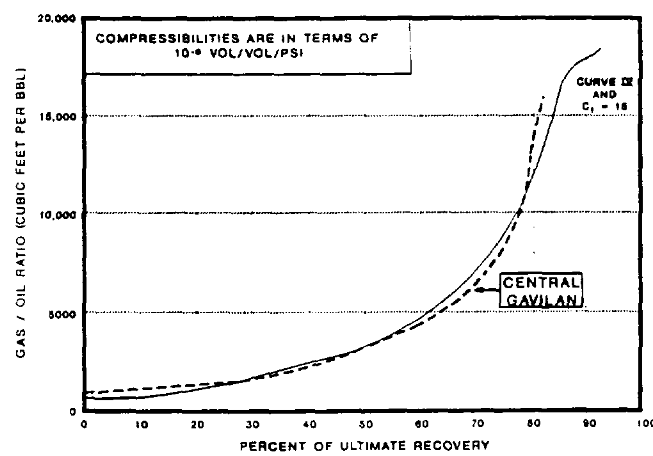

Figure 5-11. Calculated solution gas drive recoveries using k_g/k_o curve IV (Figure 5-10) and using formation compressibility of 15×10^{-6}. Despite apparent match authors believe true representation of k_g/k_o, in the absence of migration and gravity drainage, would be shifted to the left.

Data of this analysis, although adequate to eliminate high values of C_f as being appropriate, are not sufficiently precise to identify formation compressibility in the comparatively narrow ranges up to 15 or 20×10^{-6}/psi. For this definition we rely on the inherently more accurate results obtained from the interference test data.

Probable Range of "True" k_g/k_o Characteristics

An approximate match of GOR and percent ultimate recovery results from relative permeability curve IV and C_f of 15×10^{-6}/psi (Figures 5-10 and 5-11). No adjustment has been made to compensate for regional migration or gravity drainage effects early in the depletion cycle. Regional migration would have no effect on the shape of the curve if it were present *throughout* the depletion cycle. The effect in central Gavilan, however, where regional migration was substantial initially but decreased with time, is similar to that of gravity drainage when GORs are plotted against ultimate recovery: lower initial GORs than for no migration; then as migration is reduced, rising more steeply than had no migration been present.

In view of the above, curve IV, despite its apparent "match" with field performance, is somewhat optimistic for the "true" k_g/k_o relation. Curve IV represents limiting lower values of k_g/k_o; any adjustment for gravity drainage and migration would shift the k_g/k_o relation higher on the plot of Figure 5-10, at least for the early part of the curve. The latter part of the k_g/k_o curve (at higher gas saturations) would most likely "flatten" such that the probable range of "true" k_g/k_o values would assume a form within the shaded area shown on Figure 5-12.

The effect on ultimate solution gas drive recoveries of the different curves is shown by example:

At 175 psi abandonment pressure and $C_f = 15 \times 10^{-6}$/psi, curve IV yields a solution gas drive recovery of 5.94% of oil in place, while the curve represented by the extended shading results in a recovery of 5.65%. Apparently the k_g/k_o values for gas saturations greater than 10% have a minor effect on recovery. At a free gas saturation of 10%, the solution gas drive recovery using curve IV is 90% of ultimate recovery (recovery using the extended shading curve is 80% of its ultimate).

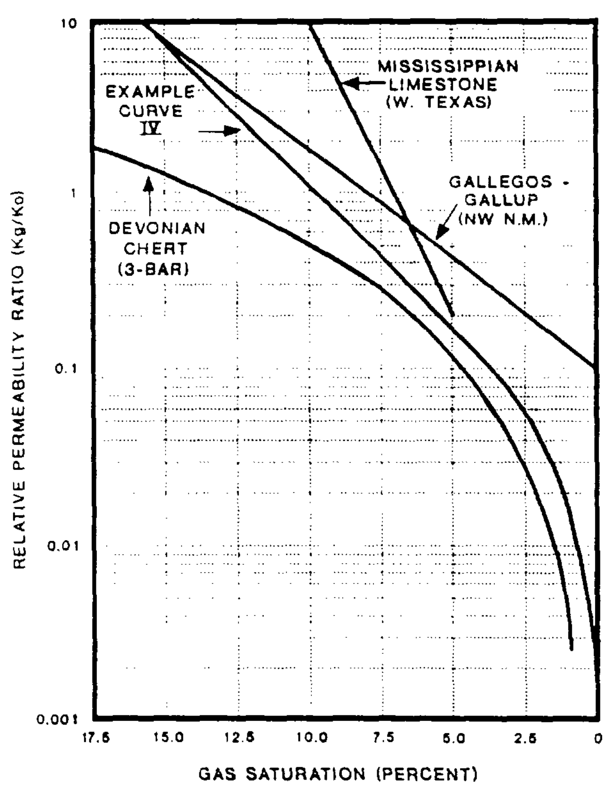

Figure 5-12. k_g/k_o curve IV showing adjustment (shaded area) in which true k_g/k_o relation should lie (after accounting for migration and gravity drainage).

In summary, we conclude that formation compressibility is that shown by the interference tests: approximately 15×10^{-6}. The exact shape of the k_g/k_o relation will turn on the indefinite amount of migration and gravity drainage of central Gavilan, with minimum values represented by curve IV (Figures 5-11 and 5-12). It is probable that true k_g/k_o fits in the shaded area of Figure 5-12. Whatever its exact shape, it appears that the resulting solution gas drive recovery will not exceed 6% of oil in place.

Muskat Method of Calculating Solution Gas Drive Performance

The Muskat method (Muskat, 1945), after substituting S for p, and R_s for S, can be described, in incremental form, as follows:

$$\Delta S_o/\Delta P = \frac{S_o\,\lambda + (1 - S_o - S_w)\,\varepsilon + S_o\,\eta\,(\psi)}{1 + (\mu_o/\mu_g)} \qquad (1)$$

$$\text{Gas Oil Ratio, } R = \alpha\,\psi + R_s \qquad (2)$$

Oil Recovery (fraction of initial pore space) =

$$(S_{oi}/B_{oi}) - (S_o/B_o) \qquad (3)$$

Oil Recovery (fraction of initial oil in place) =

$$(S_{oi}/B_{oi} - S_o/B_o)/(S_{oi}/B_{oi}) \qquad (4)$$

where $\lambda(p) = (1/B_o\gamma)\,(dR_s/dp)$

$\varepsilon(p) = (1/\gamma)(d\gamma/dp)$

$\eta(p) = (1/B_o)(\mu_o/\mu_g)(dB_o/dp)$

$\alpha = (\gamma B_o)(\mu_o/\mu_g)$

S_o = oil saturation, fraction of pore space

S_w = water saturation, fraction of pore space

μ_o/μ_g = ratio of viscosity of oil to gas

ψ = relative permeability ratio

B_o = reservoir barrels of oil per stock tank barrel

γ = standard cubic feet of gas per reservoir barrel of oil

R_s = gas in solution in the oil at the subject pressure, cubic feet per barrel

i means initial conditions

(The derivatives dR_s/dp, $d\gamma/dP$, and dB_o/dP in the composite functions λ, ε, and η are determined by graphical, or numerical, integration.)

Recognition of Formation Compressibility Using the Muskat Method

Muskat treated formation compressibility as negligible. Recognition of formation compressibility is accomplished as follows:

Although the left-hand term of equation (1) shows $\Delta S_o/\Delta P$, actually it is change in oil saturation *per pore volume* per pressure differential, and as such, it has the same dimensions as formation compressibility, which in English units is $\Delta V/V$/psi. Accordingly, equation (1) becomes:

$$\Delta S_o/\Delta P = \frac{S_o\,\lambda + (1 - S_o - S_w)\,\varepsilon + S_o\,(\psi) - C_f}{1 + (\mu_o/\mu_g)(\psi)} \quad (5)$$

where C_f = formation compressibility, $\frac{1}{\Delta}(\frac{\Delta V}{\Delta P})$

And since at the end of a pressure step, the pore volume has shrunk by an amount equal to formation compressibility times pressure change, $C_f \times (P_i - P_2)$, then the volume of oil remaining at the end of a pressure step (P_2) has likewise been decreased by formation compressibility in the same proportion, so equation (3) above becomes:

Oil Recovery, fraction of initial pore space:

$$S_{oi}/B_{oi} - (S_o/B_o)\,((1 - C_f\,(P_i - P_2)) \quad (6)$$

where P_i = initial pressure

P_2 = pressure at end of a ΔP step

And accordingly, equation (4) above becomes:

Oil Recovery, fraction of initial oil in place:

$$\frac{S_{oi}/B_{oi} - (S_o/B_o)\,((1 - C_f\,(P_i - P_2))}{S_{oi}/B_{oi}} \quad (7)$$

Appendix 6. Example of Development Forecast through Recognition of High Conductivity in a Reservoir Subarea (Recent Development South Part of West Puerto Chiquito)

The reservoir geometry that exists in the main West Puerto Chiquito reservoir (Appendix 3) has been found in nearby "subareas" of the field. The subareas may be in communication with each other through low permeability fractures, but the internal high capacity fracture network of one subarea may not be in close communication with other subareas. Within a subarea the interconnected fracture system can be revealed by interference, frac pulse, and occasionally shut-in pressure testing.

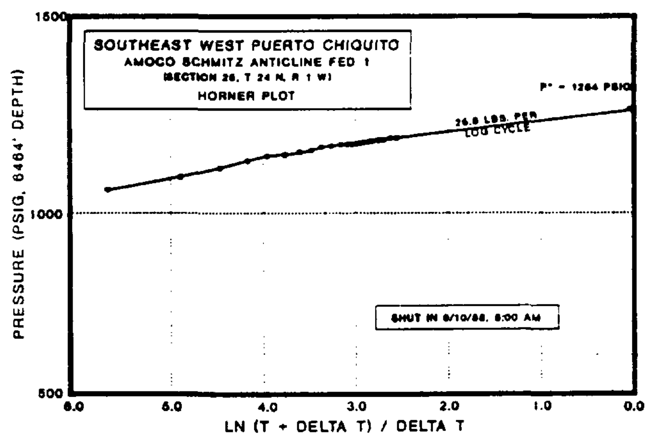

Figure 6-1. Plot of pressure buildup test of a well in southeast West Puerto Chiquito, a reservoir "subarea" first produced in 1985.

The pressure behavior of an individual well will often be defined by flow systems of "constant pressure at the boundary" (Appendix 3). Some will show influence of a nearby fault or fracture of high capacity. Typically, engineers do not attempt to analyze the "late time" portion of a pressure build-up. In the fractured Niobrara, however, with properly conducted tests, analysis of the late-time period of pressure build-up can be distinctive in assessing such reservoir character. Sensitive pressure gauges are desirable in acquiring late-time data.

An example of pressure build-up revealing presence of a high capacity fault or fracture in southeast West Puerto Chiquito (NMOCC, 1989) occurs in the Amoco Schmitz Anticline No. 1 well, Sec. 25, T24N, R1W from tests conducted in September 1988 (Figures 6-1, 6-2, and 6-3). Figures 6-2 and 6-3 are expanded scale sections of Figure 6-1. Significant are the pressures from the 60th to the 116th hours of shut-in shown on the greatly expanded plat of Figure 6-3 and comparison with those just preceding. Although the pressures were not taken with a sensitive instrument, it is possible to average the points of equal pressure (scanner reads several points identically) and determine, as shown in Figure 6-3, that the pressures fall in a straight line, not at all like the "rounding" of pressures that occurs in a closed reservoir. Rather, the well test data indicate the presence of a linear high capacity fault or fracture.

Note that a straight line sealing fault will cause the slope of a pressure build-up curve to double. It can also be shown by the same type of analysis (method of images) that a linear fault or fracture of infinite capacity will cause the slope to decrease by one-half.

For the Schmitz well the slope of the build-up curve decreases by somewhat less than half (40.5 to 25.8

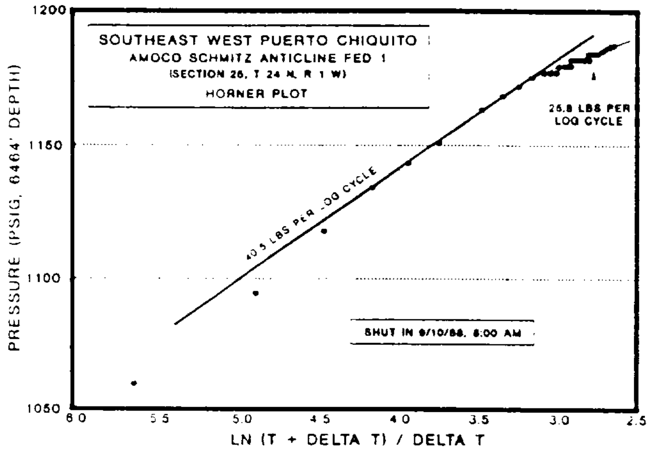

Figure 6-2. Plot of portion of pressure build-up (Figure 6-1) expanded to show that part of curve with a slope of 40.5 lb per log cycle.

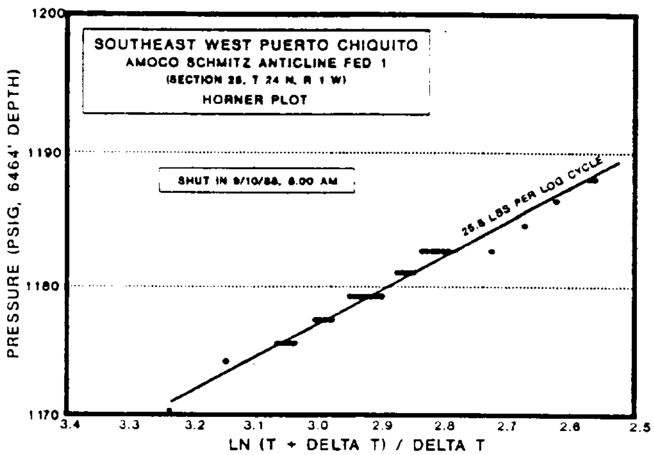

Figure 6-3. Plot of portion of build-up of Figure 6-1 greatly expanded to show "late-time" straight line slope of approximately 26 lb per log cycle, evidencing presence of high capacity fracture in well's immediate drainage area.

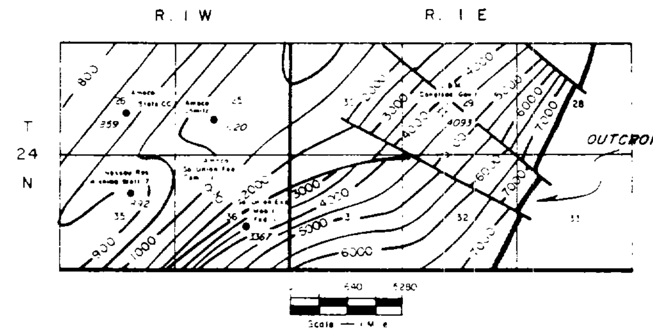

Figure 6-4. Plat showing structural contours and surface identified faults part of southeast West Puerto Chiquito "subarea" with northwest-southeast orientation.

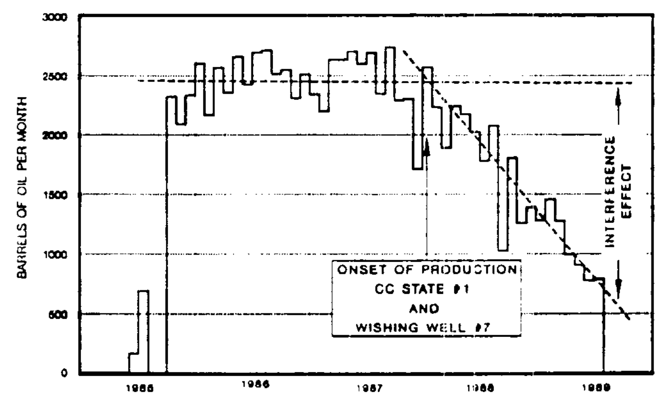

Figure 6-5. Production rate plot showing interference effect of new wells producing at high rates on stabilized production of existing wells.

psi/log cycle), indicating a high capacity fault or fracture (but not one of infinite capacity). Surface fault orientations (Figure 6-4) suggest that the possible extension of the high capacity fracture system observed in the Schmitz well would extend to the vicinity of the second well drilled in this area, the Amoco C.C. State No. 1 (Sec. 26, T24N, R1W). Confirmation that an interconnected fracture system exists between the wells was observed in the production interference effects on the Schmitz well when the C.C. State went on production in February 1988 (Figure 6-5).

Thus, although no interference testing was available in southeast West Puerto Chiquito, the existence of a high capacity fracture system was established using:

1. The late-time straight line slope of pressure build-up.
2. Production interference effects.
3. Equalized pressure of high capacity and low capacity wells.

Knowledge of the existence of the interconnecting fracture system permits forecast of the prospects of extension drilling as follows:

From pressure decline and production volumes for approximately four months, the indicated subarea reservoir volume is 2,500,000 STB. Pressure build-up showed a value of $kh/\mu = 1$ for the better wells.

In the absence of interference (or frac pulse) testing, pore volume per acre cannot be determined directly, nor can diffusivity, which depends on it. By assuming a series of reservoir per-acre volumes, calculating the diffusivity constant from these and Kh/μ, however, a plot can be made of reservoir unit pore volume versus two indicated areas: the area of the total reservoir oil volume; and the area that could be reached by steady state conditions (Figure 6-6).

The curve showing area that could be reached by steady state conditions in 120 days for $kh/\mu = 1$ approximates the curve for the reservoir volume area (lower two lines of Figure 6-6). If the subarea internal fracture system's diffusivity were the same as that of individual wells ($kh/\mu = 1$), then there would be no indication that the subarea reservoir was limited in size; extension drilling might provide similar wells.

If the subarea contains a high capacity fracture system, however, then the subarea's diffusivity and the area that could be reached by steady state conditions will be greater. An example is the upper curve in Figure 6-6, which results from a 3 to 1 ratio of reservoir Kh/μ to individual well Kh/μ. In West Puerto Chiquito and Gavilan, the Kh/μ for the high capacity fracture system is many multiples of that for individual wells. The same is probably true here.

Thus, for any assumed values of pore space per acre, the area that could be reached by steady state conditions is far greater than that indicated by reservoir volume. The surrounding area, therefore, must be of significantly lower permeability, and extension wells located therein will be limited in area drained to that of their own tracts. Recoveries, therefore, are expected to average 60,000 to 100,000 bbl per well. Further, since the permeability is known only to be significantly lower than for the existing wells, extension wells could very well be marginally economic, or nonpaying.

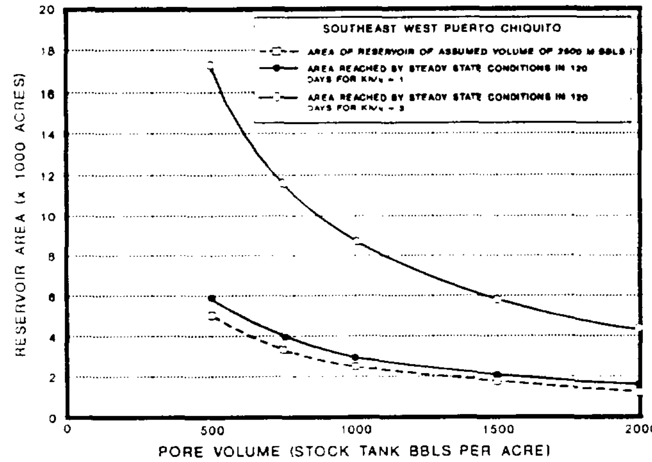

Figure 6-6. Plot showing reservoir area covering volume of 2.5 million bbl as dependent on per acre volume along with the concurrent area that could be reached by steady state conditions for the transmissibilities shown.

Another "tool" that may be of some use in evaluating a new subarea is Figure 3-6 of Appendix 3. Until information is available identifying existence of a high capacity fracture system, we suggest caution in assuming that the reservoir of a new area is of better quality than Figure 3-6 would imply.

Appendix 7. Field Description

Field name .... *West Puerto Chiquito field*

Ultimate recoverable reserves .... *15-20 million bbl (depending on future depletion method)*

Field location:

- **Country** .... *U.S.A.*
- **State** .... *New Mexico*
- **Basin/Province** .... *San Juan basin*

Field discovery:

- **Year first pay discovered** .... *Fractured Niobrara Member of U. Cretaceous Mancos Shale 1962*

Discovery well name and general location:

- **First pay** .... *No. K-13 Canada Ojitos Unit*

Discovery well operator .... *Bolack-Greer*

IP:

- **First pay** .... *15 BOPD and 6 MCF/D*

All other zones with shows of oil and gas in the field:

Age	Formation	Type of Show
Upper Cretaceous	*Mesa Verde*	*Gas*
	Pictured Cliffs	*Gas*
Lower Cretaceous	*Dakota*	*Gas*

Geologic concept leading to discovery and method or methods used to delineate prospect:
Postulated Niobrara fracture trap formed by Laramide development of basin-bounding monocline.

Structure:

Province/basin type .... *Colorado Plateau/Structural; Klemme IIB, Bally 222*

Tectonic history
Pre-Laramide faulting and uplift associated with development of Ancestral Archuleta anticlinorium rejuvenated during Eocene with vertical uplift and lateral shift, which created the Hogback monocline and a series of north-trending folds.

Regional structure
West-dipping flank of Hogback monocline and adjacent north-plunging structural "nose."

Local structure
5° homoclinal dip to west flattening to 0° at base to form synclinal flexure on west side.

Trap:

Trap type(s)
Fracture system isolated from outcrop by calcite vein-filling, and without connection to water.

Basin stratigraphy (major stratigraphic intervals from surface to deepest penetration in field):

Chronostratigraphy	Formation	Depth to Top in ft*
Tertiary	*Nacimiento, San Jose*	*Surface*
Upper Cretaceous	*Ojo Alamo*	*3000*
	Kirtland-Fruitland-PC	*3300*
	Lewis	*3700*
	Mesa Verde: Cliff House, Menefee, Pt. Lookout	*5200*
	Mancos	*6000*
	Niobrara	*7000*
	Sanostee, Carlile, Greenhorn, Graneros, Dakota	*7500*
	Entrada	*8300*

**Varies from 2000 ft shallower to 500 ft deeper than schedule depending on structural position and topography.*

Reservoir characteristics:

- Number of reservoirs *1*
- Formations .... *Niobrara Member of Mancos Shale; A, B, C lithologic units*
- Ages .... *Upper Cretaceous*
- Depths to tops of reservoirs .... *5000-7500 ft depending on structural position and topography*
- Gross thickness (top to bottom of producing interval) .... *250 ft*
- Net thickness—total thickness of producing zones
  - Average .... *50-100 ft*
  - Maximum .... *100-150 ft*
- Lithology .... *Highly laminated shale, siltstone, and minor limestone and dolomite sequence*
- Porosity type .... *Fracture*
- Average porosity *0.5-1.0%*
- Average transmissibility .... *Varies 1-50 darcy-feet*

Seals:

- Upper
  - Formation, fault, or other feature .... *Massive shale (Mancos) and loss of fractures*
  - Lithology .... *Shale*
- Lateral
  - Formation, fault, or other feature .... *Niobrara—loss of fractures*
  - Lithology .... *Shale*

Source:

- Formation and age .... *Niobrara (Upper Cretaceous)*
- Lithology .... *Shale*
- Average total organic carbon (TOC) *1-3%*
- Maximum TOC .... *NA*
- Kerogen type (I, II, or III) .... *NA*
- Vitrinite reflectance (maturation) .... $R_o = 0.77\text{-}0.90\%$
- Time of hydrocarbon expulsion .... *Tertiary*
- Present depth to top of source .... *5000-7000 ft*
- Thickness .... *300 ft*
- Potential yield .... *NA*

Appendix 8. Production Data

Field name .... *West Puerto Chiquito field*

Field size:

- Proved acres *80,000*
- Number of wells all years *40*
- Current number of wells *40*
- Well spacing .... *640 ac*
- Ultimate recoverable .... *15-25 million bbl*
- Cumulative production .... *10 million bbl*
- Annual production .... *0.5 to 1.0 million bbl*
- Present decline rate .... *
  - Initial decline rate .... *
  - Overall decline rate .... *

**Rates not meaningful because of pressure maintenance project, continuous development, gravity drainage.*

- Annual water production .... *Nil*
- In place, total reserves .... *50-100 million bbl*
- In place, per acre foot .... *NA*

Primary recovery .... *NA; pressure maintenance started early in life*
Secondary recovery .... *NA; see above*
Cumulative water production .... *Nil*

Drilling and casing practices:

Amount of surface casing set .... *500 ft*
Casing program
Early wells: 7⅝-in. intermediate through Mesa Verde, set from 100 ft to 500 ft above A zone, 5½-in. liner through pay
Later wells: 5½-in. intermediate from surface through pay
Drilling mud .... *Fresh water, viscosity 35 seconds shallow, 50-70 deep; water loss 4.8 though producing zones*
Bit program .... *Recent wells: 12¼-in. surface hole, 8¾-in. through Lewis shale, 7⅞-in. to TD*
High pressure zones .... *None*

Completion practices:

Interval(s) perforated .... *Primarily A, B, and C zones*
Well treatment .... *Sand frac*

Formation evaluation:

Logging suites .... *Induction-gamma ray, neutron density, some frac logs*
Testing practices .... *Open-hole: none; all testing done after running production casing*
Mud logging techniques .... *Sample logging, observation of lost circulation zones, occasionally gas monitoring*

Oil characteristics:

Type .... *NA*
API gravity .... *38-40°*
Base .... *Paraffin*
Initial GOR .... *480 ft³/bbl (gas in solution)*
Sulfur, wt% *0*
Viscosity, SUS .... *0.62 cp at initial reservoir conditions*
Pour point .... *NA (low)*
Gas-oil distillate .... *NA*

Field characteristics:

Average elevation .... *Surface 7000-8000 ft*
Initial pressure .... *1620 psig at datum +1195*
Present pressure .... *2000 psi near injection wells, 1000 psi most remote wells*
Pressure gradient .... *0.313 psi/ft (initial reservoir conditions)*
Temperature .... *155-170°F*
Geothermal gradient .... *0.015-0.018°F/ft*
Drive .... *Solution gas*
Oil column thickness .... *Indeterminate*
Oil-water contact .... *None*
Connate water .... *Indeterminate*
Water salinity, TDS .... *NA*
Resistivity of water .... *NA*
Bulk volume water (%) .... *NA*

Transportation method and market for oil and gas:

90% moves through pipelines, remainder trucked.

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Farmington Resource Area
1235 Laplata Highway
Farmington, New Mexico 87401

RECEIVED
PM 8 57

IN REPLY REFER TO:
Jicarilla Contract 404 (DL)
3162.2 (019)

OCT. 1 3 1992

CERTIFIED--RETURN RECEIPT REQUESTED
P 081 574 963

Mr. Bob Stovall
New Mexico Oil and Gas
Conservation Division
P. O. Box 2088
Santa Fe, NM 87504-2088

Dear Mr. Stovall:

The Farmington Resource Area (FRA) of the Bureau of Land Management has completed an analysis of 640-acre spacing in the Mancos formation in T. 27 N., R. 1 W., Rio Arriba County, New Mexico. The Mancos formation is a fractured shale with production from a gravity drainage mechanism. In this type of reservoir, an adequate size proration unit is necessary for economical production without waste.

Through numerous hearings before the New Mexico Oil Conservation Division, it has been determined that 640-acre spacing in the Mancos formation is necessary to economically produce this formation without waste of resources. After reviewing all of the data pertinent to these hearings, we found nothing to support a change in the current spacing.

The suspension of drilling in T. 27 N., R. 1 W., Rio Arriba County, New Mexico is hereby lifted and operations can resume in this area.

This letter has been sent to the following:

1. Jicarilla Indian Tribe, Oil & Gas Administration, Dulce, NM.
2. Bureau of Indian Affairs, Energy and Minerals Resource Assistance Office, Golden, CO.
3. Bureau of Indian Affairs, Jicarilla Agency, Dulce, NM.
4. New Mexico Oil and Gas Conservation Division, Aztec, NM.
5. Benson-Montin-Greer Drilling Corporation, Farmington, NM.
6. American Hunter Exploration Limited, Denver, CO.

Under provisions of 43 CFR 3165.3, you may request an Administrative Review of the order described above. Such request, including all supporting documents, must be filed in writing within 20 business days of receipt of this notice and must be filed with the State Director, Bureau of Land Management, P. O. Box 27115, Santa Fe, New Mexico 87502-0115. Such request shall not result in a suspension of the order unless the reviewing official so determines. Procedures governing appeals from instructions, orders or decisions are contained in 43 CFR 3165.4 and 43 CFR 4.400 *et seq.*

If you have any questions regarding this decision, please call Brian Davis at (505) 599-8994.

Sincerely,

Mike Pool
Area Manager

NORDHAUS HALTOM TAYLOR
TARADASH & FRYE

ATTORNEYS AT LAW

A PARTNERSHIP INCLUDING A PROFESSIONAL CORPORATION

B. REID HALTOM
LESTER K. TAYLOR
ALAN R. TARADASH
PAUL E. FRYE
WAYNE H BLADH
MARCIA L. GREEN, P.C.

LEE BERGEN
TERESA ISABEL LEGER
LISA M. ENFIELD
CYNTHIA A. KIERSNOWSKI
KATHARINE S. MILLER

ALBUQUERQUE OFFICE
SUITE 1050
500 MARQUETTE AVENUE, N.W.
ALBUQUERQUE, NEW MEXICO 87102

TELEPHONE (505) 243-4275
TELEFAX (505) 243-4464

SANTA FE OFFICE
SUITE 9
200 W. DE VARGAS STREET
SANTA FE, NEW MEXICO 87501

TELEPHONE (505) 982-3622
TELEFAX (505) 982-1827

Reply to Santa Fe Office

September 2, 1992

HAND-DELIVERED

Mr. William J. LeMay
Oil Conservation Division
State Land Office Building
310 Old Santa Fe Trail, Room 219
Santa Fe, NM 87501

Re: Jicarilla 404 #3 (F-9) Well and Jicarilla 404 #2 (K-10) Well Applications of Benson-Montin-Greer Drilling Corp. for High Angle/Horizontal Direction Drilling Pilot Project, etc.

Hearing Date: September 3, 1992

Dear Mr. LeMay:

This firm represents the Jicarilla Apache Tribe, which is the landowner, lessor, royalty owner and governmental entity potentially affected by the applications identified above. This letter is submitted on behalf of the Jicarilla Apache Tribe on the conditions and for the purposes stated below. This letter should not be considered to be an entry of appearance by the Tribe in this proceeding, nor as an indication that the Tribe in any way submits itself to the jurisdiction of the Oil Conservation Division, nor as an indication that the Tribe will in any manner be bound by any decision to be rendered by the Division in this proceeding. The Tribe submits this letter solely for the purpose of providing the Division and all interested parties in this proceeding certain information directly relevant to the applications submitted by Benson-Montin-Greer Drilling Corp. (BMG). The Tribe provides this information solely as a courtesy to the Division and to carry out the government to government relationship existing between the State of New Mexico and the Jicarilla Apache Tribe.

The Tribe submits the following for the Division's consideration:

1. The State of New Mexico and its agencies do not have jurisdiction to authorize BMG to drill any well on the Jicarilla Apache Reservation over the objection of the Tribe or of the Federal Government. Any such interference in the management of the oil and gas

resources of the Tribe, held in trust by the United States, would be an infringement on tribal self-government and would be preempted by federal law. See, eg., Assiniboine and Sioux Tribes v. Board of Oil and Gas Conservation, 792 F.2d 782 (9th Cir. 1986) and Assiniboine and Sioux Tribes v. Calvert Exploration Co., 223 F.Supp. 909 (D.Mont. 1963), rev'd on jurisdictional grounds sub nom. Yoder v. Assiniboine and Sioux Tribes, 339 F.2d 360 (9th Cir. 1964).

2. The Tribe objects to the specific well locations proposed by BMG on the grounds that the locations are too close to the north boundary of Sections 9 and 10 and too close to the existing Tribal/American Hunter well located on Section 3. The proposed wells could result in drainage of the Jicarilla/American Hunter property and thereby cause economic injury to the Tribe, in violation of the Indian Mineral Leasing Act.

3. The Tribe objects to the wells proposed by BMG on the grounds that these additional wells should not be drilled until more information is available concerning formation pressure, gas-oil ratios, and optimal production rates to maximize long-term recovery of oil and gas from this reservoir. Any well in Section 9 or 10 would be premature and could result in permanent damage to the reservoir and waste of the Tribe's mineral resources.

4. The Tribe has requested two agencies of the Federal Government, the Bureau of Indian Affairs and the Bureau of Land Management, to conduct reservoir studies for the Tribe on an area including the 404 Lease held by BMG. The Farmington Resource Area Manager has informed the Tribe (by letter dated August 12, 1992) that the BLM will not approve any APD in the area included in the reservoir study until the study is completed. That study has not been completed and the BLM has not informed the Tribe of the date by which BLM expects to complete its study. Until the BLM and BIA reservoir studies are complete and the Tribe and the relevant federal agencies have reviewed those studies and determined appropriate spacing for this area (among other issues), there is no "acceptable well-spacing program" in effect for this area and no APD can be approved by BLM. See 43 CFR § 3162.3-1.

5. For the reasons stated above, any action taken by the Division at this time (before the BLM, BIA and Tribe have completed their reservoir studies) which purports to authorize BMG to drill the proposed wells, would have no legal effect and would amount to a futile act. Any action by the Division to authorize drilling of these wells at this time would precipitate an unnecessary and avoidable conflict between the State of New Mexico on the one hand and the Tribe and the Federal Government on the other.

6. On or about July 30, 1992 BMG applied to the Tribe for a permit to conduct a seismic survey on Sections 9 and 10 designed to locate potential well sites. The Tribe is

still reviewing that application and has not acted on it. If the seismic permit is granted, either as requested or with amendments, BMG has stated its intention to conduct the seismic survey and use the results to locate potential well sites. The proposed well locations identified in the pending applications with the Division will in all probability need to be altered based on the seismic surveys. BMG's attempt to obtain the Division's approval of the tentative well locations identified in its applications is premature and will probably waste the time and resources of the Division.

For the reasons stated above, the Jicarilla Apache Tribe respectfully suggests that the Division take no action on the BMG applications until the Tribe and the relevant federal agencies have resolved these issues related to the management of the Tribe's mineral resources. Only the Tribe and the Federal Government can, in the end, decide whether the proposed wells may be drilled and produced as BMG has proposed. In a case such as this, where the Division is informed that the Federal Government and the Tribe have asserted their authority to decide the very issues presented by an operator's application to the Division, the Division should decline to act on the application. The Division should decline BMG's invitation to involve the State of New Mexico in a jurisdictional dispute with the Jicarilla Apache Tribe and the United States.

Sincerely,

NORDHAUS HALTOM TAYLOR
TARADASH & FRYE

Wayne H. Bladh

cc: Bureau of Land Management
1235 La Plata Hwy.
Farmington, NM 87401
Attn: John Keller

Jicarilla Agency
Bureau of Indian Affairs
P.O. Box 167
Dulce, NM 87528

American Hunter Exploration, Ltd.
c/o Jim Lister
410 17th Street, Suite 1220
Denver, CO 80202

William F. Carr, Esq. (Hand-Delivered)
Campbell, Carr, Berge & Sheridan
P.O. Box 2208
Santa Fe, NM 87504

W. Thomas Kellahin (Hand-Delivered)
Kellahin & Kellahin
P.O. Box 2265
Santa Fe, NM 87504

whb:\txtlib\jat\bmg\ocd8-27