07-14

STATE OF NEW MEXICO
ENERGY AND MINERALS DEP/

This was an attempt to take an appeal from the OCC to the Secretary [EMNRD]

525 Camino de los Marquez
Santa Fe, New Mexico
87501

TONEY ANAYA
GOVERNOR

October 22, 1986

J.

Owen Lopez, Esq.
Robert D. Buettner, Esq.
William F. Carr, Esq.
Robert G. Stovall, Esq.
Jeff Taylor, Esq.

Ernest L. Padilla, Esq.
Paul Cooter, Esq.
W. Thomas Kellahin, Esq.
Kent Lund, Esq.
W. Perry Pearce, Esq.

Dear Counsel:

Re: NMOCC Case No. 8946
Order R-7407-D

You have all received copies of Mr. Lopez' letter to me dated 20 October 1986 and the notice of appeal on behalf of Mallon Oil Company and Mesa Grande Resources, Inc., in the referenced matter. As I understand it, Mr. Lopez seeks that I exercise my discretion under Section 70-2-26 NMSA 1978 to hold a public hearing on whether the subject order contravenes the public interest. You may know that no public hearing under this authority has heretofore been sought and that no such hearings have ever been held. Accordingly, I am without any precedential guidance in the affair, and I think it best in the circumstances to first solicit your advice before I determine whether to exercise discretion at all. I shall appreciate your response on my concerns by Wednesday, 29 October 1986.

As noted in Mr. Lopez' letter, if I should embark upon a public hearing the time constraints involved are very short. Can they and should they be waived? Can and should all parties be bound by the statutory deadline for hearing? What kind of hearing notice is required? When should my order or decision issue? What of the ongoing settlement studies and the mid November discussions with staff?

Mr. Lopez has proposed that, in light of the time constraint, I could first address myself to the entire record before the Commission and then request additional evidence and testimony in a public hearing. Would my determination on such basis comport with the statutory <u>de novo</u> proceeding requirement? Can and should the <u>de novo</u> proceeding requirement be waived?

Finally, I would like your thoughts on the public interest jurisdiction that would be involved. What are the limits of that jurisdiction? What are the public purposes to be served by a proceeding founded on such jurisdiction? What private purposes must be accounted for? In what way, if any, would my jurisdiction and the limits of my determination or order be different from a court's direct review of the Commission's Order R-7407.

I realize that the response time I have given you is sudden and is bound to aggravate your already busy schedules. Nevertheless, I am bound to resolve these concerns in my own mind promptly if I hope to exercise my discretionary option within the allotted time. Your kind attention is gratefully appreciated.

Very truly yours,

PAUL L. BIDERMAN
Secretary

PLB:rm

CERTIFICATE OF SERVICE

I hereby certify that I caused to be mailed a true and correct copy of the foregoing Notice of Appeal to the following individuals on this 20th day of October, 1986:

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October 20, 1986

HAND DELIVERED

OCT 1986
Received
Office of Sec'y

Mr. Paul Biderman
Secretary
Energy & Minerals Department
525 Camino de Los Marquez
Santa Fe, New Mexico 87501

Dear Paul:

Enclosed is a Notice of Appeal on behalf of Mallon Oil Company and Mesa Grande Resources, Inc. which is self-explanatory. We filed our Motion for Rehearing on October 1, 1986 from the Oil Conservation Commission's Order R-7407-D and it is deemed denied since the Commission failed to act within 10 days of the filing of the Motion.

According to Section 70-2-76 N.M.S.A. 1978, we are permitted an appeal to the Secretary of Energy and Minerals Department if the Order contravenes the public interest. The hearing before the Secretary is to be held within 20 days of the denial of the rehearing. According to our calculations, this means that you should hold a hearing on or before November 3, 1986.

The statute also provides that the hearing shall be de novo. Since the original hearing before the Commission occupied 4 1/2 days, we would propose to introduce the entire record of the original hearing at your hearing. Once you had an opportunity to review the record, you could in your discretion request additional evidence or testimony as you deem necessary. However, we believe that to repeat in person what is already contained in the record would be a waste of time and human resources. By copy of this letter to opposing counsel, we invite their concurrence in our proposal as well as whatever additional comments or suggestions they may have.

Finally, you should be aware that since the close of the original hearing, all interested parties in the Gavilan Mancos Pool have continued meeting through various technical committees with the purpose of reaching a consensus as to how the pool should be operated. These parties are scheduled to meet with the Commission staff mid-November to discuss informally their progress. However, due to statutory time constraints, that process should not affect your deliberations unless an actual consensus is reached before you have an opportunity to make your ruling.

Sincerely,

Owen

Owen M. Lopez

OML/mg
cc: W. Perry Pearce
Ernest L. Padilla
Robert D. Buettner
Paul Cooter
William F. Carr
W. Thomas Kellahin
Robert G. Stovall
Kent Lund

ENERGY AND MINERALS DEPARTMENT

STATE OF NEW MEXICO

IN THE MATTER OF THE APPEAL
TO THE SECRETARY OF THE ENERGY
AND MINERALS DEPARTMENT FOR
THE PURPOSE OF CONSIDERING:

THE APPEAL OF OIL CONSERVATION COMMISSION ORDER R-7407-D AMENDING THE SPECIAL RULES AND REGULATIONS OF THE GAVILAN-MANCOS OIL POOL	Oil Conservation Commission Case No. 8946

NOTICE OF APPEAL

COME NOW MALLON OIL COMPANY and MESA GRANDE RESOURCES, INC. and pursuant to Section 70-2-26 NMSA 1978, appeal to the Secretary of the Energy and Minerals Department of the State of New Mexico for reversal of the above-captioned order as violative of the public policy of the State of New Mexico, and in support thereof applicants state:

FACTUAL BACKGROUND:

The Oil Conservation Commission, hereinafter Commission, held a hearing on the Application of Jerome P. McHugh and Associates on August 7, 8, 21, 22 and 27, 1986. The Application sought the imposition of reduced oil allowables and reduced limiting gas-oil ratios for the Gavilan-Mancos Oil Pool (Gavilan Pool), Rio Arriba County, New Mexico. This pool was created by the Commission Order R-7407 entered on December 20, 1983. This same order adopted special pool rules for the Gavilan Pool.

The Application of Jerome P. McHugh and Associates (Applicant), was opposed by Mallon Oil Company ("Mallon") and Mesa Grande Resources, Inc. ("Mesa Grande") and by several other interested parties. Both Mallon and Mesa Grande are interest owners in and operators of wells in the Gavilan Pool.

On September 11, 1986, the Commission entered Order R-7407-D which reduced the oil allowables and reduced the limiting gas-oil ratios for the Gavilan Pool. Appellants Mallon and Mesa Grande are affected by this Order.

Pursuant to Section 70-2-26 NMSA 1978, Mallon and Mesa Grande appeal the entry of Order R-7407-D filed by the Oil Conservation Commission. In support of its appeal, Appellants state:

POINT I: ORDER R-7407-D SHOULD BE REVERSED BECAUSE THE COMMISSION FAILED TO MAKE "BASIC CONCLUSIONS OF FACT"

Order R-7407-D fails to comply with applicable statutory and judicial mandates. In Continental Oil Co. v. Oil Conservation Commission, 70 N.M. 310, 373 P.2d 809 (1962) the New Mexico Supreme Court in a case dealing with a natural gas pool discussed the basic conclusions of fact that the Commission is required to find prior to changing a proration formula. The requirements are that the Commission find, as far as it is practical to do so:

(1) the amount of recoverable reserves under each producer's tract;

(2) the total amount of recoverable reserves in the pool;

(3) the proportionate relationship of (1) and (2); and

(4) what portion of the reserves can be recovered without waste.

A review of Order R-7407-D shows that the Commission failed to make any of these required findings and did not discuss any of these necessary elements. The record in this matter is clear, Dugan Exhibit # 1, that the changes adopted by the Commission constitute a change in the proration formula since these changes alter the relative proportion of production between operators in the Gavilan Pool and deviate from statewide rules. Order R-7407-D is therefore contrary to law and arbitrary and capricious.

POINT II: ORDER R-7407-D SHOULD BE REVERSED BECAUSE THE ORDER IMPAIRS THE CORRELATIVE RIGHTS OF INTEREST OWNERS IN THE POOL

A. Order R-7407-D finds, Paragraph (12)(n), that a reduction in the allowable oil production rate and lower gas-oil ratio will afford an opportunity to recover more hydrocarbons because of gravity drainage. The gravity drainage claimed by Albert Greer, based solely on information from the West Puerto Chiquito-Mancos Oil Pool is based upon the angle of dip of the formation in said pool. This theory presupposes that for there to be more oil recovered from the pool, one proration must be down-dip from another proration unit and must recover the oil from the up-dip unit. If the Commission's finding that gravity drainage will occur if production rates are slowed is correct, the correlative rights of the owners of up-dip proration units will be impaired as the reserves underlying their tracts are allowed to migrate to other proration units.

As a result, not only does the Commission's Order fail to protect the correlative rights of interest owners in the pool as is required by statutory and case law, but the Commission's Order actually acts to destroy those rights by preventing operators of up-dip proration units from recovering the reserves underlying their tracts prior to those reserves migrating to down-dip tracts. In the absence of unitization, any act by the Commission which favors gravity drainage is arbitrary and capricious and contrary to law.

B. Applying the Commission's amended gas-oil ratios and amended production allowables to the wells in the Gavilan Pool establishes that the applicant is benefitted by this order even more than requested in its application. The percentage of pool production allocated to various operators in this pool prior to these cases under the applicant's proposal and under the Commission's order are as follows:

PERCENT OF TOTAL STUDY AREA OIL PRODUCTION

Operator	6/86(1)	Applicant's Proposal(1)	Koch Proposal 702/588 (1)	Order of 400/600 (2)
Amoco	0.3	0.6	0.4	0.5
Dugan	2.5	4.2	2.9	3.6
Mallon	19.5	14.2	16.3	13.6
McHugh	39.7	37.5	41.7	41.6
Meridian	9.9	13.0	10.9	11.7
Merrion	0.4	0.6	0.4	0.5
Mesa Grande	10.7	13.2	10.9	11.8
Mobil	4.2	5.8	4.9	5.7
Reading & Bates	1.1	1.8	1.3	1.6
BMG	11.8	9.1	9.9	9.5
TOTALS	100.1	100.0	100.0	100.1

(1) Data taken from Dugan Production Company Exhibit No. 3 to the hearing of this matter.

(2) Calculated from data available in record.

This data clearly shows that the effect of the Commission's Order is to penalize certain interest owner's production in the Gavilan Pool much more severely than others, and even more than the applicant requested. It is also undisputable that the most equitable and balanced treatment of production curtailment in the Gavilan Pool was that proposed by Koch Production Company which was supported by Mallon and Mesa Grande.

For these reasons, Order R-7407-D violates the correlative rights of certain interest owners in the Gavilan Pool and is therefore contrary to law and is arbitrary and capricious.

C. Order R-7407-D also impairs the correlative rights of owners in the Gavilan Pool by allowing wells in the western section of the adjoining West Puerto Chiquito-Mancos Pool to receive credit for gas injection and produce at higher allowable rates than wells in the Gavilan Pool. Some of these wells were relied upon by the applicant to demonstrate the direct and high degree of communication between wells in the Gavilan Pool. The evidence submitted by all parties isolated these western wells from the other wells lying to the east in the West Puerto Chiquito-Mancos Oil Pool. Consequently, there is no justification for treating more favorably these western wells in the West Puerto Chiquito-Mancos Pool.

For this reason Order R-7406-D violates the correlative rights of interest owners in the Gavilan Pool, and is thereby contrary to law and is arbitrary and capricious.

POINT III. <u>ORDER R-7407-D SHOULD BE REVERSED BECAUSE THE ORDER FAILS TO CONTAIN SUFFICIENT FINDINGS</u>

Finding 12(b) of the Order states that the Gavilan Pool is primarily a solution-gas drive reservoir with potential for substantial additional ultimate oil recovery by gravity drainage. Testimony in this case is uniformly in agreement that increasing gas-oil ratios are to be expected in solution gas drive reservoirs and in fact John Roe found that the pressure decline curves and gas-oil ratio curves closely conform to the expected curve shown in Dugan Exhibit 2.

In Fasken v. Oil Conservation Commission, 87 N.M. 292, 532 P.2d 588 (1975) the New Mexico Supreme Court stated that two levels of findings were necessary in Commission orders. First, those orders must contain "ultimate findings" such as that the order operates to prevent waste or protect correlative rights. Secondly, the order must contain sufficient findings to "disclose the reasoning of the Commission".

The findings of Order R-7407-D fail to set forth the reasoning of the Commission which allows it to ignore the primary production mechanism in favor of the confiscatory mechanism of drainage or some other unspecified production mechanisms.

For this reason Order R-7407-D is contrary to law and is arbitrary and capricious.

POINT IV. ORDER R-7407-D IS CONTRARY TO LAW

Paragraph (11) of Order R-7407-D finds that the working interest owners in the Gavilan Pool are not in agreement on any method of operation of the pool other than that previously adopted by the Commission Order R-7407. During the presentation of testimony in support of the applicant's case, it became clear that the applicant brought this case with the intent of forcing other operators to agree to the unitization of the Gavilan Pool. In fact, the applicant threatened that if its application did not force the desired unitization, the applicant intended to apply for even more restrictive allowables in the future.

Consequently, it is clear that the applicant seeks to have the Commission do indirectly what the New Mexico Oil and Gas Act does not authorize it to do directly. The Oil and Gas Act does not authorize statutory unitization for primary recovery of oil and gas reserves. However, Order R-7407-D essentially operates to coerce operators to unitize involuntarily and is without statutory authority.

Order R-7407-D is therefore contrary to law and is arbitrary and capricious.

POINT V. ORDER R-7407-D IS NOT SUPPORTED BY SUBSTANTIAL EVIDENCE, IS ARBITRARY AND CAPRICIOUS AND IS CONTRARY TO LAW

The following findings made by the Commission Order R-7407-D are not supported by substantial evidence contained in the record as a whole.

1. Finding (11)
2. Finding (12)
3. Finding (13)
4. Finding (14)
5. Finding (15)

In the absence of such substantial evidence the Order is arbitrary and capricious and is contrary to law.

Subsequent to that time, Mallon and Mesa Grande have received from counsel for applicant a copy of the proposed draft order which was submitted to the Commission for its consideration. Mallon and McHugh are unaware of what further steps have been taken with regard to the drafting and preparation of the final order entered in this matter.

In Morgan v. United States, 304 U.S. 1, 58 S.Ct. 773 (1938) the United States Supreme Court considered the propriety of communications being received in administrative proceedings from only one party to that proceeding. The Court states:

> If in an equity cause, a special master or the trial judge permitted the plaintiff's attorney to formulate the findings upon the evidence, conferred ex parte with the plaintiff's attorney regarding them, and then adopted his proposal without affording an opportunity to his opponent to know their contents and present objections, there would be no hesitation in setting aside the report or decree as having been made without a fair hearing. The requirements of fairness are not exhausted in the taking or consideration of evidence, but extend to the concluding parts of the procedure as well as to the beginning and intermediate steps.

58 S.Ct. at 777.

In this case, the Commission specifically requested proposed findings and conclusions from only one party to this proceeding and applicants Mallon and Mesa Grande have therefore been denied their rights to due process of law and their rights to a full and fair hearing of this matter.

WHEREFORE, Mallon Oil Company and Mesa Grande Resources, Inc. request that the Secretary vacate and set aside Order R-7407-D.

Respectfully submitted,

MONTGOMERY & ANDREWS, P.A.

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and

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Counsel for Mesa Grande Resources, Inc.

CERTIFICATE OF SERVICE

I hereby certify that I caused to be mailed a true and correct copy of the foregoing Notice of Appeal to the following individuals on this 20th day of October, 1986:

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October 24, 1986

OCT 1986
Received
Office of Sec'y

Mr. Paul Biderman
Secretary
Energy & Minerals Department
525 Camino de Los Marquez
Santa Fe, New Mexico 87501

Dear Paul:

In response to your letter of October 22, 1986, it is our opinion that a decision by you not to consider the Commission's decision would constitute an abuse of discretion. The purpose of Section 70-2-26 NMSA 1978 is identical to that behind the provision for an OCC rehearing which was construed in Pubco Petroleum Corp. v. Oil Conservation Commission, 75 N.M. 36, 399 P.2d 932 (1965), namely, "to afford the Commission [here EMD] an opportunity to reconsider and correct an erroneous decision." Id., 75 N.M. at 38 (construing Section 70-2-25's predecessor, Section 65-3-22, 1953 Comp.). This opportunity is essential. Closely related is the vital role played by the responsible agency issuing a decision, since the courts ordinarily "give special weight and credence" to the expertise of the Commission. Fasken v. Oil Conservation Commission, 87 N.M. 292, 293, 532 P.2d 588 (1975) (reversing and remanding for failure of Commission to make sufficient findings).

The legislature in 1977 placed the OCC under the EMD, so that now the EMD must bear responsibility for OCC decisions. Coincidentally, the legislature enacted Section 70-2-26. Laws 1977, ch. 255, Sections 9, 60. The hearing before the Secretary is the only opportunity for the EMD to review a decision by the OCC prior to judicial review. This opportunity, for EMD review through a de novo hearing, became all the more important when the statute relating to judicial review of OCC decisions was amended in 1979 to delete the provision for de novo review by the district court. Section 70-2-25 (1986 Cum.Supp.) (Laws 1979, ch. 133, Section 1). Presently, the only remaining opportunity for a de novo review of the case is the one to be performed by the EMD Secretary.

With respect to my suggestion that the record before the OCC be reviewed prior to your taking any additional evidence, I believe it is sound and accords with the statutory intent. Section 70-2-26 requires that the record before the OCC be made part of the record of the hearing before the EMD Secretary. This is similar to the de novo provision in Section 70-2-25 before it was amended. I believe it makes sense for the Secretary to review the existing record before taking any additional evidence for two reasons: first, it may be that no additional evidence is necessary, and second, the Secretary can make an informed decision regarding the admission of additional evidence after benefitting from a review of the original record. It is clearly in the interest of judicial economy.

Also be aware, however, the de novo proceeding requirement should not be waived. Even though the original record will be before the Secretary, it is vitally important that the hearing remain de novo, not for the sake of necessarily receiving new evidence, but for the sake of the standard of review. In a de novo review, the Secretary is free to substitute his judgment for that of the OCC. He can make his own independent findings from the record. This is important because it permits the Secretary to discharge his duties as the person ultimately responsible for the actions of the OCC and allows him the opportunity to correct any errors or admissions prior to judicial review. Moreover, it is important in this case that the Secretary act since we claim that the OCC's findings are deficient. Whereas the district court can duly reverse and remand if it so finds, see Fasken v. Oil Conservation Commission, 87 N.M. 292, 293-94, 532 P.2d 588 (1975), the Secretary can correct the deficiencies as he chooses.

As to the concern you expressed regarding time constraints, it agains is clear that the requirement that the hearing be held within 20 days can be waived. The deadline for holding a hearing is not jurisdictional, as is the time for seeking a rehearing, for example. The timing requirement is for the benefit of the parties and they can clearly waive it.

In the event, the EMD cannot hold a public hearing within the statutory time period, the parties must continue as they would have in the absence of a hearing. See Public Service Company v. New Mexico Public Service Commission, 92 N.M. 721, 594 P.2d 1177 (1979) (commission not required to act within statutory time period); Mountain States Telephone and Telegraph Co. v. New Mexico State Corporation Commission, 90 N.M. 325, 563 P.2d 588 (1977) (commission not required to act within constitutional time period).

Regarding the question of notice raised in your letter, it is my opinion that no additional notice is required, other than to ensure that all parties to the OCC proceedings are given notice. The statutory issues to be considered at the EMD hearing cannot be raised by any new person since appeal from the EMD decision can be brought only by a party to the EMD hearing, or to the OCC hearing or rehearing. Section 70-2-26.

Finally, regarding your request for comments as to the limits of the public interest jurisdiction involved, it is apparent that the purposes of the EMD are much broader than those of the OCC. The OCC principally protects correlative rights and promotes conservation. The EMD's charge is much more comprehensive, and includes among other duties the charge to:

> "J. ensure that the state and its political subdivisions receive, from the severance of irreplaceable energy resources from the soil of this state, the maximum economic return, consistent with the good of the entire state;
>
> * * *
>
> M. provide for an economic climate in the state to foster the energy resource extractive industry;
>
> * * *
>
> O. provide that these objectives should be accomplished in a way that is primarily in the best interest of the state but also to the benefit of the rest of the nation.

Section 9-5-3. The OCC is not charged with carrying out these duties.

The EMD Secretary's jurisdiction is significantly different than that of the OCC or of a court on judicial review of the OCC's decision. The court can not raise and consider section 9-5-3 purposes, since on review it may only determine whether the OCC's decision is supported by substantial evidence or is otherwise not arbitrary, capricious or contrary to law.

As to the private interests that the EMD Secretary must consider, they are only those presented to the OCC at the original hearing. Any other interests would be aggregated within the public interest and public purposes that the EMD Secretary is to consider under Section 9-5-3. This is because the appeal remains a quasi-judicial proceeding, and is not a rule-making proceeding in which other private interests are allowed to comment. Moreover, the hearing statute, Section 70-2-26, does not permit other private interests to intervene.

In conclusion, we request that you set the matter for hearing on or before October 30 unless opposition counsel agree to a later hearing date. If they do not, we would ask that a hearing be set by October 30 at which we would propose to introduce the entire record of the OCC proceedings and suggest that the case be recessed until further notice, subject of course to suggestions of other counsel. We firmly believe that the issues raised in the Notice of Appeal occasion your reviewing the case with respect to the public interest questions involved, not the least of which are those raised under Point VI, namely the chilling effect the OCC's decision has had an out-of-state operators doing business in New Mexico and the unjustified detrimental economic impact it has on the state's income.

Naturally, if you have any further question or suggestions, please do not hesitate to contact me.

Sincerely,

Owen M. Lopez

Owen M. Lopez

OML/mg
cc: All Counsel of Record

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October 27, 1986

Mr. Paul Biderman
Secretary
Energy and Minerals Department
525 Camino de Los Marquez
Santa Fe, New Mexico 87501

"Hand Delivered"

Re: Notice of Appeal of Mallon Oil Company and Mesa Grande Resources, Inc., of Oil Conservation Commission Order R-7407-D, Case 8946

Dear Mr. Biderman:

Our firm represents Jerome P. McHugh & Associates, who sought and obtained the Commission's approval in Order R-7407 to temporarily reduce the rates at which oil and gas were being produced in the Gavilan Mancos Oil Pool.

We now seek your denial of the hearing requested by Mr. Pearce and Mr. Lopez on behalf of Mallon and Mesa Grande because they have failed to allege sufficient factual basis upon which you may have such a hearing.

While Section 70-2-6 N.M.S.A. 1978, has never been used, its purpose and procedures are simple and clear: It is to be used in those rare and unusual situations when an Oil Conservation Commission Order, based upon prevention of waste and protection of correlative rights, in fact, contravenes an established state-wide energy plan or public interest. For example, assume that the Commission, so that the operator will not drain his neighbor, enters an order precluding an operator from producing gas in excess of his gas allowable in a prorated pool. Assume that excess production is needed so that New Mexico will not lose a significant share of its market to another producing state. That would be an example under the statute of an issue which is not within the scope of the Commission hearing and on which the Secretary may have a hearing.

Neither Mallon nor Mesa Grande have provided you with anything but a routine Commission case in which the Commission has exercised its discretion based upon its unique and significant expertise.

I have received a copy of Mr. Lopez's letter to you dated October 24, 1986. With great reluctance I must tell you that Mr. Lopez's letter contains a number of statements that are absolutely wrong:

First: Mr. Lopez is wrong in his first paragraph when he tells you that the purpose of Section 70-2-26, N.M.S.A. 1978 is "identical" to that behind the provisions for an OCC rehearing. He further erroneously implies that the original Section 70-2-26 procedure for a district court DeNovo was a viable alternative which the legislature deleted in 1979. In fact, since 1962 when the New Mexico Supreme Court required the district court review to be limited to the record before the Commission, the appeal procedures have left the findings of complex and technical issues to the agency with the requisite expertise and only overrule the Commission when a review of the whole record reflects that the Commission's order is not based upon substantial evidence. See Continental Oil Company v. OCC, 70 NM 310, 373 P2 809 (1962).

Second: The purpose of Section 70-2-26 N.M.S.A. 1978 is NOT identical to that behind the provisions for an OCC rehearing NOR must the EMD bear responsibility for OCC decisions. The 1979 Legislature was not intending to substitute the Secretary for the District Court in the appeal process. As I have stated above, the Secretary's involvement is limited to two unusual situations, neither one of which occurs in the subject case.

Third: Contrary to Mr. Lopez's opinion, 70-2-26 N.M.S.A. 1978 absolutely requires a hearing within the twenty-day period. This time limit is essential to the purpose of the act which is to require the Secretary to act with utmost speed to correct a Commission order that contravenes the state wide energy plan or public interest issue before the appeal gets to district court.

The application before you is virtually identical to that filed before the Commission and denied by the Commission. Of all of the operators in the pool, only Mesa Grande and Mallon have filed for a rehearing and having been denied, have request you to grant a hearing. Nothing in Mr. Lopez's October 24, 1986 letter, nor Mr. Pearce's application for hearing, justifies a hearing. The applicants have not claimed that the Commission order violates the statewide energy plan.

You have asked us for our comments on the "public interest jurisdiction." That jurisdiction is very broad but must be made with "due regard for the conservation of the state's oil, gas and mineral resources." While it is impossible to develop a general guideline of specific public interest issues, it is obvious that this application does not contain any.

Among all of the issues raised by the applicant there are only two issues that appear to raise any possibility of being "public interest" issues: (1) an allegation that the Commission Order favors in-state operators at the expense of out-of-state operators, and (2) an allegation of "lost" revenues to the State of New Mexico.

The first issue can be disposed of by simply comparing the allegation to the information found at page 5 of the application. First, we take exception to the table and disagree with the applicant on its meaning. However, assuming the applicant's table is correct, only Dugan and BMG are in-state operators and only Dugan's share of the oil production increased under the order. With the exception of Mallon, all of the rest of the operators percentages increased, including the applicant, Jerome P. McHugh and Mesa Grande's. This is a frivolous claim unsupported by the applicant's own application and lacks a sufficient basis upon which to have a hearing.

The second issue contends that there is a loss of income to the state. Contrary to the allegation in the application, this evidence was hotly disputed. The applicant has mistated the issue to imply that the income to the state is "lost." The Koch exhibits 7, 8, and 9 relied upon by the applicant on page 9 (see transcript Vol III, Page 381-832) contended that the reduction in the production rates would defer $317,341 of State of New Mexico production taxes. The evidence that refuted the contention of the applicant was presented by Al Greer (see Transcript Volume II, page 79-87 and Greer Exhibit 4). Mr. Greer concluded that "the State could reduce the allowable.... and in two years sell the oil and be ahead financially as compared to producing the oil and getting the income now."

Thus, the issue correctly stated and in the light most favorable to the applicant is:

Does the temporary reduction in pool producing rates in the Gavilan Mancos, which will leave that oil in the reservoir to be produced at a later date, but which postpones $317,341 in production tax income to the State of New Mexico, constitute a sufficient issue for the Secretary of Energy to grant a hearing?

We have concluded and we urge you to conclude that it does not.

In response to your letter of October 22, 1986, we are of the opinion that the time constraints are intentional and jurisdictional, precluding you or any party from waiving them. We believe that telephone notification to all parties before the Commission is adequate notice, but that a hearing must be held on or before October 30th in order to comply with the statute.

We find no specific limitation on when you must enter your order. The question about the ongoing studies and mid November report to the OCD staff should tell you that this order is temporary in nature and not sufficient enough to compel you to have your own hearing.

We do not believe that you can waive the DeNovo requirement nor would we consent to such a waiver. We disagree with Mr. Lopez on his suggested procedure because your jurisdiction over this matter is significantly different from that of the Commission.

Very truly yours,

W. Thomas Kellahin

WTK:ca

cc: All Counsel of Record

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October 28, 1986

HAND DELIVERED

Mr. Paul Biderman, Secretary
New Mexico Department of
Energy and Minerals
525 Camino de Los Marquez
Santa Fe, New Mexico 87501

Re: Notice of Appeal of Mallon Oil Company and Mesa Grande Resources, Inc. of Oil Conservation Commission Order R-7407-D; Case No. 8946.

Dear Mr. Biderman:

This letter is in response to your questions of October 22, 1986, concerning the above-referenced Notice of Appeal.

Having presented their case to the Oil Conservation Commission and not having a record which could be successfully appealed to the District Court, Mallon and Mesa Grande are now attempting to utilize the provisions of Section 70-2-26 to bring a matter before you for review - a matter which neither raises questions contemplated by this section of statute nor a matter which can be effectively disposed of by the Secretary of Energy since it involves questions of reservoir damage and the waste of oil - questions which properly rest with the Oil Conservation Commission.

Section 70-2-26, N.M.S.A. 1978, was adopted at the time the Department of Energy and Minerals was created. This section of statute recognizes that there may be circumstances in which the State of New Mexico has interests which are inconsistent with the statutory duties of the Oil Conservation Commission i.e., the prevention of waste of oil and natural gas and the protection of correlative rights. This section of statute anticipated the formal promulgation by the Energy and Minerals Department of a state-wide energy plan. If an order of the Oil Conservation Commission contravenes that plan or an order has been entered contrary to the public interest, the Secretary of Energy and Minerals can call the matter before him, receive testimony on questions other than those relating to waste and correlative rights and enter an order consistent with the State Energy Plan or the public interest. No question concerning any state-wide energy plan is presented by the Notice of Appeal filed by Mallon and Mesa Grande. You, therefore, must determine whether or not predetermination Commission Order R-7407-D contravenes the public interest.

Pursuant to Section 70-2-26, the Secretary of Energy and Minerals <u>may</u> call a matter before him for hearing. This is a discretionary matter. Once the Secretary decides to call a matter before him for hearing, however, this statute is clear as to other matters which are not within the Secretary's discretion. The first non-discretionary requirement is that the hearing must be held within twenty days of the entry of the Commission's order. The twenty-day figure was not arbitrarily set by the legislature. It was designed to be consistent with the appellant procedures for Oil Conservation Commission orders set out in Section 70-2-25, N.M.S.A. 1978. Under this section of statute, any party of record adversely affected by a Commission decision, following the denial of an application for rehearing, may appeal the decision to the District Court. It was the intent of those of us who drafted this statute, and I believe the legislature, to provide that this separate appeal procedure would be available, but that it would be available only within the time frame of the OCC appeal statutes. It was our intention that a party not be allowed to file an application with the Secretary of Energy and Minerals and at the same time pursue the matter before the District Court. It, therefore, is essential that if you decide to hold a hearing on this matter, the hearing <u>must</u> be held within the twenty days provided for by statute. You must also receive testimony on <u>all</u> issues, for your order will be the only order appealed to the courts. If you decide not to hear the case, an early decision will permit Mallon and Mesa Grande to appeal pursuant to Section 70-2-25, N.M.S.A. 1978.

Another matter which is not discretionary with the Secretary, once he decides to hold a hearing under this statute, is that the hearing must be <u>de novo</u>. On this point, the statute is clear. It provides that the hearing "shall be a de novo proceeding". The reason for this is that if the Secretary of Energy reviews a matter to determine whether or not it is consistent with a state-wide energy plan or the public interest, his jurisdiction is different from that of the Commission and he is necessarily deciding different issues and looking for different facts than those which were properly before the Commission. For this reason, it is essential that any proceeding before the Secretary be de novo.[1]

In this case, the Application for Rehearing filed with the Commission and the Notice of Appeal filed with the Secretary of Energy differ only to the extent that in the Notice of Appeal, Mallon and Mesa Grande assert that the actions of the Commission are contrary to the public interest. This is the only new question presented to you by the Notice of Appeal, for all other questions simply require a review of the actions of the Oil Conservation Commission - actions which were taken squarely within its statutorily imposed duty - actions which should be reviewed only by the District Court.

It is essential that you look to the Notice of Appeal to determine the scope of the questions being presented to you for consideration. Mallon and Mesa Grande assert that Order R-7407-D is contrary to the public interest for it discriminates in favor of in-state New Mexico operators. This bald assertion, which is factually incorrect, does not create a public interest issue which warrants bringing the matter back for further hearing before the Secretary.

Mallon and Mesa Grande also assert that the Commission's order is contrary to the economic interest of the State of New Mexico. In support of this statement, the evidence presented by Koch Exploration Company is cited. This testimony was not "undisputed" but, to the contrary, was soundly refuted by testimony presented by Benson-Montin-Greer. See Benson-Montin-Greer Exhibit 4, Transcript Volume II, pages 79 through 87.

Furthermore, the questions raised by Mallon and Mesa Grande involve a determination of whether the ultimate recovery from this reservoir will be jeopardized by imprudent operating

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Mr. Lopez in his letter of October 24 states that the purpose of Section 70-2-26 is identical to that of the provision governing OCC rehearings. This misstates the purpose of this statute. This statutory appeal provision is not designed to ask the Secretary to correct errors of the Commission, but to assure that OCC actions, though correct from a waste and correlative rights point of view, do not contravene the State's energy plan or the public interest. A review of an OCC order for error is a separate matter and is properly addressed to the courts.

procedures or whether current production should be delayed while engineering and geological studies are undertaken to insure that the greatest ultimate recovery be obtained from this reservoir. These are questions that were addressed to the Oil Conservation Commission. Its decision is fully set out in Order R-7407-D in which it concluded that production from this reservoir should be delayed - production which can be made up at a later date - instead of risking total loss of a reservoir which, if properly produced, will continue to produce hydrocarbons and, therefore, revenue for the State of New Mexico over an extended period of time. We submit that the Commission's decision will prevent the waste of oil, will result in the greatest ultimate recovery of this resource, is in the best interest of all producers in the reservoir and is consistent with the public interest.

Mr. Lopez stated in his October 22 letter that your deliberations should not be affected by the fact that engineering and geological committees are currently meeting in an attempt to determine appropriate development and production rates in the Gavilan area. It is important to note, however, that those who should be best able to resolve the current problems in the Gavilan area are working on it. Additional hearings will only tend to divert these efforts - efforts which hopefully will result in real progress toward a solution whereby everyone in the reservoir, including the State, will recover their just and fair share of the reserves therefrom without waste.

As to your question concerning notice, it appears that those involved in any hearing before you would be the same parties that appeared in the hearings before the Oil Conservation Commission. I believe Mr. Pearce's service of the Notice of Appeal on October 20, 1986, would be sufficient to meet fundamental notice requirements in this situation.

I appreciate this opportunity to comment on the Notice of Appeal filed on October 20, 1986.

Very truly yours,

William F. Carr

WILLIAM F. CARR

WFC/ab
cc: Albert R. Greer
W. Perry Pearce, Esquire
Paul Cooter, Esquire
Robert D. Buettner, Esquire
Kent Lund, Esquire
Owen M. Lopez, Esquire
Ernest L. Padilla, Esquire

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
525 Camino de los Marquez
Santa Fe, New Mexico
87501

TONEY ANAYA
GOVERNOR

October 30, 1986

Mr. Jeff Taylor
Oil Conservation Division
State Land Office Building
Santa Fe, New Mexico 87503

Dear Counsel:

RE: NMOCC Case No. 8946
Order R-7407-D

After considering the Notice of Appeal of Mallon Oil Company and Mesa Grande Resources, Inc. from the above-referenced order of the Oil Conservation Commission, and after reviewing the correspondence of counsel, the state energy plan and pertinent statutes, I have determined that the appeal does not present an appropriate case for the exercise of the Secretary's discretion to convene in a de novo hearing under Section 70-2-26 NMSA 1978.

A memorandum of decision is in preparation and will be mailed as soon as possible. This letter is to provide you initial notice of my decision against holding a hearing, to spare parties or their witnesses any expense or scheduling difficulties as the deadline for convening the hearing approaches.

My thanks to all counsel for their timely and thorough responses.

Very truly yours,

Paul L. Biderman

PAUL L. BIDERMAN
Secretary

cc: All Counsel of Record

HINKLE, COX, EATON, COFFIELD & HENSLEY

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October 31, 1986

To All Counsel of Record
(List attached)

Re: The Appeal of Oil Conservation Commission Order R-7407-D Amending the Special Rules and Regulations of the Gavilan-Mancos Oil Pool
No. RA 86-2371(C)

Gentlemen:

I am enclosing a copy of the Petition for Review, in the above captioned matter, which was filed in District Court yesterday.

If the Messrs. Carr, Kellahin and Taylor will not accept service on behalf of their clients, I will arrange to have the summonses served by a process server. Please let me know your wishes in this regard.

Very truly yours,

HINKLE, COX, EATON,
COFFIELD & HENSLEY

Owen M. Lopez

Owen M. Lopez

ML:frs

enclosures

FIRST JUDICIAL DISTRICT

COUNTY OF RIO ARRIBA

STATE OF NEW MEXICO

IN THE MATTER OF THE APPEAL
TO THE DISTRICT COURT
FOR THE COUNTY OF RIO ARRIBA
STATE OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

No. RA 86-2371(C)

THE APPEAL OF OIL CONSERVATION
COMMISSION ORDER R-7407-D AMENDING
THE SPECIAL RULES AND REGULATIONS
OF THE GAVILAN-MANCOS OIL POOL

PETITION FOR REVIEW

COME NOW MALLON OIL COMPANY and MESA GRANDE RESOURCES, INC. and pursuant to Section 70-2-25 NMSA 1978, appeal to the District Court for the County of Rio Arriba, the State of New Mexico for reversal of the above-captioned order and in support thereof applicants state:

FACTUAL BACKGROUND:

The Oil Conservation Commission, hereinafter Commission, held a hearing on the Application of Jerome P. McHugh and Associates on August 7, 8, 21, 22 and 27, 1986. The Application sought the imposition of reduced oil allowables and reduced limiting gas-oil ratios for the Gavilan-Mancos Oil Pool (Gavilan Pool), Rio Arriba County, New Mexico. This pool was created by

FIRST JUDICIAL DISTRICT

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IN THE MATTER OF THE APPEAL
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FACTUAL BACKGROUND:

The Oil Conservation Commission, hereinafter Commission, held a hearing on the Application of Jerome P. McHugh and Associates on August 7, 8, 21, 22 and 27, 1986. The Application sought the imposition of reduced oil allowables and reduced limiting gas-oil ratios for the Gavilan-Mancos Oil Pool (Gavilan Pool), Rio Arriba County, New Mexico. This pool was created by the Commission Order R-7407 entered on December 20, 1983. This same order adopted special pool rules for the Gavilan Pool.

The Application of Jerome P. McHugh and Associates (Applicant), was opposed by Mallon Oil Company ("Mallon") and Mesa Grande Resources, Inc. ("Mesa Grande") and by several other interested parties. Both Mallon and Mesa Grande are interest owners in and operators of wells in the Gavilan Pool.

On September 11, 1986, the Commission entered Order R-7407-D which reduced the oil allowables and reduced the limiting gas-oil ratios for the Gavilan Pool. Appellants Mallon and Mesa Grande are affected by this Order.

Pursuant to Section 70-2-25 NMSA 1978, Mallon and Mesa Grande appeal the entry of Order R-7407-D filed by the Oil Conservation Commission attached hereto as Exhibit "A". In support of its appeal, Appellants state:

POINT I: ORDER R-7407-D SHOULD BE REVERSED BECAUSE THE COMMISSION FAILED TO MAKE "BASIC CONCLUSIONS OF FACT"

Order R-7407-D fails to comply with applicable statutory and judicial mandates. In Continental Oil Co. v. Oil Conservation Commission, 70 N.M. 310, 373 P.2d 809 (1962) the New Mexico Supreme Court in a case dealing with a natural gas pool discussed the basic conclusions of fact that the Commission is required to find prior to changing a proration formula. The requirements are that the Commission find, as far as it is practical to do so:

(1) the amount of recoverable reserves under each producer's tract;

(2) the total amount of recoverable reserves in the pool;

(3) the proportionate relationship of (1) and (2); and

(4) what portion of the reserves can be recovered without waste.

A review of Order R-7407-D shows that the Commission failed to make any of these required findings and did not discuss any of these necessary elements. The record in this matter is clear, Dugan Exhibit # 1, that the changes adopted by the Commission constitute a change in the proration formula since these changes alter the relative proportion of production between operators in the Gavilan Pool and deviate from statewide rules. Order R-7407-D is therefore contrary to law and arbitrary and capricious.

POINT II: ORDER R-7407-D SHOULD BE REVERSED BECAUSE THE ORDER IMPAIRS THE CORRELATIVE RIGHTS OF INTEREST OWNERS IN THE POOL

A. Order R-7407-D finds, Paragraph (12)(n), that a reduction in the allowable oil production rate and lower gas-oil ratio will afford an opportunity to recover more hydrocarbons because of gravity drainage. The gravity drainage claimed by Albert Greer, based solely on information from the West Puerto

Chiquito-Mancos Oil Pool is based upon the angle of dip of the formation in said pool. This theory presupposes that for there to be more oil recovered from the pool, one proration must be down-dip from another proration unit and must recover the oil from the up-dip unit. If the Commission's finding that gravity drainage will occur if production rates are slowed is correct, the correlative rights of the owners of up-dip proration units will be impaired as the reserves underlying their tracts are allowed to migrate to other proration units.

As a result, not only does the Commission's Order fail to protect the correlative rights of interest owners in the pool as is required by statutory and case law, but the Commission's Order actually acts to destroy those rights by preventing operators of up-dip proration units from recovering the reserves underlying their tracts prior to those reserves migrating to down-dip tracts. In the absence of unitization, any act by the Commission which favors gravity drainage is arbitrary and capricious and contrary to law.

B. Applying the Commission's amended gas-oil ratios and amended production allowables to the wells in the Gavilan Pool establishes that the applicant is benefitted by this order even more than requested in its application. The percentage of pool production allocated to various operators in this pool prior to these cases under the applicant's proposal and under the Commission's order are as follows:

PERCENT OF TOTAL STUDY AREA OIL PRODUCTION

Operator	6/86(1)	Applicant's Proposal(1)	Koch Proposal 702/588 (1)	Order of 400/600 (2)
Amoco	0.3	0.6	0.4	0.5
Dugan	2.5	4.2	2.9	3.6
Mallon	19.5	14.2	16.3	13.6
McHugh	39.7	37.5	41.7	41.6
Meridian	9.9	13.0	10.9	11.7
Merrion	0.4	0.6	0.4	0.5
Mesa Grande	10.7	13.2	10.9	11.8
Mobil	4.2	5.8	4.9	5.7
Reading & Bates	1.1	1.8	1.3	1.6
BMG	11.8	9.1	9.9	9.5
TOTALS	100.1	100.0	100.0	100.1

(1) Data taken from Dugan Production Company Exhibit No. 3 to the hearing of this matter.

(2) Calculated from data available in record.

This data clearly shows that the effect of the Commission's Order is to penalize certain interest owner's production in the Gavilan Pool much more severely than others, and even more than the applicant requested. It is also undisputable that the most equitable and balanced treatment of production curtailment in the Gavilan Pool was that proposed by Koch Production Company which was supported by Mallon and Mesa Grande.

For these reasons, Order R-7407-D violates the correlative rights of certain interest owners in the Gavilan Pool and is therefore contrary to law and is arbitrary and capricious.

C. Order R-7407-D also impairs the correlative rights of owners in the Gavilan Pool by allowing wells in the western section of the adjoining West Puerto Chiquito-Mancos Pool to receive credit for gas injection and produce at higher allowable rates than wells in the Gavilan Pool. Some of these wells were relied upon by the applicant to demonstrate the direct and high degree of communication between wells in the Gavilan Pool. The evidence submitted by all parties isolated these western wells from the other wells lying to the east in the West Puerto Chiquito-Mancos Oil Pool. Consequently, there is no justification for treating more favorably these western wells in the West Puerto Chiquito-Mancos Pool.

For this reason Order R-7406-D violates the correlative rights of interest owners in the Gavilan Pool, and is thereby contrary to law and is arbitrary and capricious.

POINT III. ORDER R-7407-D SHOULD BE REVERSED BECAUSE THE ORDER FAILS TO CONTAIN SUFFICIENT FINDINGS

Finding 12(b) of the Order states that the Gavilan Pool is primarily a solution-gas drive reservoir with potential for substantial additional ultimate oil recovery by gravity drainage. Testimony in this case is uniformly in agreement that increasing gas-oil ratios are to be expected in solution gas drive reservoirs and in fact John Roe found that the pressure decline curves and gas-oil ratio curves closely conform to the expected curve shown in Dugan Exhibit 2.

In Fasken v. Oil Conservation Commission, 87 N.M. 292, 532 P.2d 588 (1975) the New Mexico Supreme Court stated that two levels of findings were necessary in Commission orders. First, those orders must contain "ultimate findings" such as that the order operates to prevent waste or protect correlative rights. Secondly, the order must contain sufficient findings to "disclose the reasoning of the Commission".

The findings of Order R-7407-D fail to set forth the reasoning of the Commission ~~which~~ allows it to ignore the primary production mechanism in favor of the confiscatory mechanism of drainage or some other unspecified production mechanisms.

For this reason Order R-7407-D is contrary to law and is arbitrary and capricious.

POINT IV. ORDER R-7407-D IS CONTRARY TO LAW

Paragraph (11) of Order R-7407-D finds that the working interest owners in the Gavilan Pool are not in agreement on any method of operation of the pool other than that previously adopted by the Commission Order R-7407. During the presentation of testimony in support of the applicant's case, it became clear that the applicant brought this case with the intent of forcing other operators to agree to the unitization of the Gavilan Pool. In fact, the applicant threatened that if its application did not force the desired unitization, the applicant intended to apply for even more restrictive allowables in the future.

Consequently, it is clear that the applicant seeks to have the Commission do indirectly what the New Mexico Oil and Gas Act does not authorize it to do directly. The Oil and Gas Act does not authorize statutory unitization for primary recovery of oil and gas reserves. However, Order R-7407-D essentially operates to coerce operators to unitize involuntarily and is without statutory authority.

Order R-7407-D is therefore contrary to law and is arbitrary and capricious.

POINT V. ORDER R-7407-D IS NOT SUPPORTED BY SUBSTANTIAL EVIDENCE, IS ARBITRARY AND CAPRICIOUS AND IS CONTRARY TO LAW

The following findings made by the Commission Order R-7407-D are not supported by substantial evidence contained in the record as a whole.

1. Finding (11)

2. Finding (12)

3. Finding (13)

4. Finding (14)

5. Finding (15)

In the absence of such substantial evidence the Order is arbitrary and capricious and is contrary to law.

POINT VI. ORDER R-7407-D IS CONTRARY TO THE PUBLIC INTEREST

Order R-7407-D is contrary to the public interest for the following reasons:

A. Order R-7407-D discriminates in favor of in-state New Mexico operators and against out-of-state operators, including Mallon and Mesa Grande.

B. The undisputed evidence (Koch Exploration Company's Exhibits 7, 8 and 9) demonstrates that the result of Order R-7407-D is contrary to the economic interests of the State of New Mexico. Although the issue before the Commission was loss of reservoir energy, it is clear that the resultant loss of income to the State of New Mexico through loss of severance taxes and royalty income, not to mention the loss of income to interest owners in the Gavilan Pool, far exceeds the cost of gas required to maintain the Gavilan Pool's present reservoir energy. Consequently, there is no economic justification for the order.

Therefore, Order R-7407-D violates the correlative rights of interest owners in the Gavilan Pool, is contrary to law and is arbitrary and capricious.

POINT VII. ORDER R-7407-D SHOULD BE REVERSED BECAUSE MALLON AND MESA GRANDE HAVE BEEN DENIED DUE PROCESS OF LAW AND A FULL AND FAIR HEARING

At the close of the hearing of this matter on August 27, 1986, the Chairman of the Commission requested applicant's counsel to provide him with a draft order in this matter. Subsequent to that time, Mallon and Mesa Grande have received from counsel for applicant a copy of the proposed draft order which was submitted to the Commission for its consideration. Mallon and McHugh are unaware of what further steps have been taken with regard to the drafting and preparation of the final order entered in this matter.

In Morgan v. United States, 304 U.S. 1, 58 S.Ct. 773 (1938) the United States Supreme Court considered the propriety of communications being received in administrative proceedings from only one party to that proceeding. The Court states:

> If in an equity cause, a special master or the trial judge permitted the plaintiff's attorney to formulate the findings upon the evidence, conferred ex parte with the plaintiff's attorney regarding them, and then adopted his proposal without affording an opportunity to his opponent to know their contents and present objections, there would be no hesitation in setting aside the report or

> decree as having been made without a fair hearing. The requirements of fairness are not exhausted in the taking or consideration of evidence, but extend to the concluding parts of the procedure as well as to the beginning and intermediate steps.

58 S.Ct. at 777.

In this case, the Commission specifically requested proposed findings and conclusions from only one party to this proceeding and applicants Mallon and Mesa Grande have therefore been denied their rights to due process of law and their rights to a full and fair hearing of this matter.

WHEREFORE, Mallon Oil Company and Mesa Grande Resources, Inc. request that the District Court vacate and set aside Order R-7407-D.

Respectfully submitted,

MONTGOMERY & ANDREWS, P.A.

Edmund H Kendrick

Edmund H. Kendrick
Post Office Box 2307
Santa Fe, New Mexico 87504-2307
(505) 982-3873

Counsel for Mallon Oil Company

and

Owen M. Lopez

Owen M. Lopez
Hinkle, Cox, Eaton, Coffield & Hensley
Post Office Box 2068
Santa Fe, New Mexico 87504-2068

Counsel for Mesa Grande Resources, Inc.

CERTIFICATE OF SERVICE

I hereby certify that I caused to be mailed a true and correct copy of the foregoing Petition for Review to the following individuals on this 31st day of October, 1986.

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Owen M. Lopez

Owen M. Lopez

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION COMMISSION

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

RECEIVED-11
SEP 18 1986
Montgomery, AL

CASE NO. 8946
Order No. R-7407-D

APPLICATION OF JEROME P. McHUGH AND ASSOCIATES FOR AN AMENDMENT TO THE SPECIAL RULES AND REGULATIONS OF THE GAVILAN-MANCOS OIL POOL.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing on August 7, 8, 21, 22, and 27, 1986 at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this 11th day of September, 1986, the Commission, a quorum being present, having considered the testimony presented and the exhibits received at said hearings and being fully advised in the premises,

FINDS THAT:

(1) The applicant has made a good-faith diligent effort to find and notify all operators of wells and each appropriate interested party as required by Division Order No. R-8054.

(2) Due public notice has been given as required by law and the Commission has jurisdiction of this case, the parties, and the subject matter thereof.

(3) The applicant, Jerome P. McHugh and Associates, seeks an order amending the temporary Special Rules and Regulations of the Gavilan-Mancos Oil Pool as promulgated by Division Order No. R-7407 to establish for a period of not less than ninety days a temporary special production allowable limitation of 200 barrels of oil per day for a standard 320-acre spacing and proration unit and a special temporary gas-oil ratio limitation factor of 1,000 cubic feet of gas per barrel of oil produced.

(4) In Companion Case No. 8950, Benson-Montin-Greer Drilling Corporation seeks an order amending the Special Rules and Regulations of the West Puerto Chiquito-Mancos Oil Pool

EXHIBIT "A"

promulgated by Division Order No. R-3401 to establish a temporary special production allowable limitation of 400 barrels of oil per day for a standard 640-acre spacing and proration unit and a special temporary gas-oil ratio limitation factor (GOR) of 1,000 cubic feet of gas per barrel of oil produced.

(5) Case No. 8950 and Case No. 8946 have been consolidated for purposes of hearing.

(6) Benson-Montin-Greer Drilling Corporation, Dugan Production Corporation and Meridian Oil Company appeared in support of McHugh's application.

(7) The proponents in this case presented testimony and evidence to show that:

(a) The Gavilan Mancos Oil Pool is a highly fractured reservoir which produces primarily by solution gas drive but has potential for significant additional oil recovery by gravity drainage and reducing the dissipation of natural reservoir energy by wells with relatively high gas-oil ratios;

(b) Based upon measurements of reservoir pressure and interference testing, excellent communication exists between wells and throughout the reservoir;

(c) Based upon bottom hole pressure measurements, the reservoir pressure is declining at rates that provide little time to prepare and develop a plan for improving the future operation and development of the reservoir;

(d) Based upon bottom hole pressure measurements, the daily producing oil rate should be reduced immediately to 200 barrels and the limiting gas-oil ratio should be reduced to 1,000 to slow reservoir depletion rates, allow time to evaluate the reservoir and formulate a plan for future operations and development that will result in increased recoveries of oil and gas; and

(e) Gravity drainage will be a factor in improving ultimate recovery in the Gavilan Mancos Oil Pool.

(8) Mobil Producing Texas and New Mexico Inc. appeared in opposition to McHugh's application and presented evidence to show that the Gavilan-Mancos Pool is a typical solution gas drive reservoir with significant potential for oil recovery from matrix porosity and that, because such a reservoir is not rate sensitive, to continue to produce the wells at the current allowable of 702 barrels per day and 2,000 GOR would not result in the reduction of the ultimate recovery of oil and gas therefrom.

(9) Mallon Oil Company, Mesa Grande Resources Inc. and Koch Exploration appeared and presented evidence to show that the Gavilan-Mancos Oil Pool is an individual well gas cap drive reservoir and that the limiting GOR should be reduced to the solution gas oil ratio in order to most effectively produce the reservoir but opposed the reduction in the maximum daily oil allowable, discounting the potential for significant gravity drainage.

(10) Prior to the application in this case, the operators in the Gavilan-Mancos Oil Pool formed a working interest owners committee, including geologic and engineering technical subcommittees, in order to discuss and address the issue of the most effective and efficient methods to develop and produce the pool.

(11) The applicant presented testimony that despite numerous meetings, the working interest owners have not yet agreed to any method of operations within said pool other than that provided in its special rules and that an emergency exists requiring the Commission to act immediately to reduce the rate of reservoir voidage in the Gavilan-Mancos Oil Pool to prevent waste and preserve reservoir energy until the working interest owners can reach such an agreement or until the Commission finally determines how best the pool might be developed and produced.

(12) The evidence presented at the hearing established that:

(a) the Gavilan Mancos Oil Pool primarily produces from a fractured shale with little or no matrix contribution;

(b) the Gavilan Mancos Pool is primarily a solution gas drive reservoir with potential for substantial additional ultimate oil recovery by gravity drainage;

(c) significant pressure depletion is occurring in wells and areas of the reservoir that have produced very little oil or gas;

(d) pressure interference tests have been conducted in representative areas of the pool, all of which demonstrate almost instantaneous interference over large distances;

(e) the solution GOR is between 480 and 646 cubic feet of gas per barrel of oil and most likely approximates 600 cubic feet of gas per barrel;

(f) wells in some areas of the Pool are producing at GOR rates in excess of the solution gas-oil ratio;

(g) free gas is being liberated reservoir-wide irrespective of structural position;

(h) reduction of the limiting GOR in the Gavilan-Mancos Oil Pool to near the solution GOR will prevent the inefficient dissipation of reservoir energy and will permit the owners in the pool to utilize their share of reservoir energy;

(i) the current 702 barrel per day oil maximum allowable is based upon an extension of Oil Conservation Division (Division) Rule 505 to wells in the Gavilan-Mancos Oil Pool depth range with 320-acre dedication;

(j) such depth bracket allowable could be appropriate for a normal pool with substantial matrix contribution to production but bears no rational relationship to the most efficient rate at which to produce the subject pool;

(k) the proposed 200 barrel per day maximum allowable, if imposed, would appear to result in production from the various tracts in the pool generally in closer proportion to the reserves thereunder than the current 702 barrel maximum allowable;

(l) imposition of such a maximum allowable, at this time, would unfairly penalize the operators of newer generally higher capacity wells as opposed to those operators of older generally declining capacity wells which previously enjoyed high rates of reservoir drainage;

(m) adoption of a temporary 400 barrel of oil per day maximum allowable rather than the 200 barrel limit proposed will, at this time, better permit the operators of the newer high capacity wells to recover their share of the oil in the Gavilan-Mancos Oil Pool; and

(n) a reduction in both the daily oil production rate and the limiting GOR will reduce the rate of reservoir voidage and pressure depletion and afford an improved opportunity for gravity drainage, thereby preventing waste, and permit operators additional time to determine the most effective and efficient method to further develop and produce the Pool.

(13) The adoption of a 600 cubic feet of gas per barrel of oil limiting GOR and reduction of the oil depth bracket allowable to 400 barrels per day in the Gavilan-Mancos Oil Pool on a temporary basis, at this time, is necessary to prevent waste.

(14) The adoption of such limiting GOR and depth bracket allowable will, at this time, more nearly permit each operator to use his share of the reservoir energy and more nearly recover the oil underlying the individual tracts in the pool than the existing limiting GOR and depth bracket allowable and will, therefore, better protect correlative rights.

(15) Such limiting GOR and depth bracket allowable should be adopted effective September 1, 1986, and should be continued until further order of the Commission.

(16) The issues raised in this case should be reconsidered when temporary special pool rules for the Gavilan-Mancos Oil Pool established by Order No. R-7407 are brought up for reconsideration in March, 1987, or upon the recommendation of the pool study committee.

IT IS THEREFORE ORDERED THAT:

(1) The terms and conditions of this order shall apply to all wells completed in the Gavilan-Mancos Oil Pool or wells completed in the Mancos formation within one mile thereof effective September 1, 1986 and shall remain in effect until further order of the Commission.

(2) The limiting gas oil ratio in the Gavilan-Mancos Oil Pool, as heretofore defined and described, Rio Arriba County, New Mexico, shall be 600 cubic feet of gas for each barrel of liquid hydrocarbons produced and that the depth bracket allowable therefor shall be 400 barrels of oil per day.

(3) Both applicants and opponents shall be permitted representatives on the Gavilan Pool Technical Study Committee and this Study Committee shall submit a status report to the Commission on or before November 15, 1986.

(4) Unless reopened by the Commission based upon the report of the Study Committee, this case shall be reopened at a Commission hearing in March, 1987, to be consolidated with the reconsideration of the Temporary Special Rules established by Order No. R-7407 for the Gavilan-Mancos Oil Pool.

(5) Jurisdiction of this cause is retained for entry of such further orders as the Commission may deem necessary.

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

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

JIM BACA, Member

ED KELLEY, Member

R. L. Stamets

R. L. STAMETS, Chairman and Secretary

S E A L

KELLAHIN and KELLAHIN
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W. Thomas Kellahin
Karen Aubrey

Jason Kellahin
Of Counsel

November 5, 1986

Owen M. Lopez, Esq.
Hinkle, Cox, Eaton,
Coffield & Hensley
P. O. Box 2066
Santa Fe, New Mexico 87504

Re: Entry of Appearance and
Acceptance of Service
No. RA 86-2371(C)

Dear Mr. Lopez:

I am enclosing a copy of the Acceptance of Service and Entry of Appearance on behalf of my client, Jerome P. McHugh & Associates, which was filed in District Court today.

Very truly yours,

Tom

W. Thomas Kellahin

WTK:ca
Enc.

cc: All Counsel of Record

FIRST JUDICIAL DISTRICT
COUNTY OF RIO ARRIBA
STATE OF NEW MEXICO

IN THE MATTER OF THE APPEAL
TO THE DISTRICT COURT
FOR THE COUNTY OF RIO ARRIBA
STATE OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING

THE APPEAL OF OIL CONSERVATION COMMISSION ORDER R-7407-D AMENDING THE SPECIAL RULES AND REGULATIONS OF THE GAVILAN-MANCOS OIL POOL

NO. RA 86-2371(C)

ENTRY OF APPEARANCE

AND

ACCEPTANCE OF SERVICE

COMES NOW KELLAHIN, KELLAHIN & AUBREY, and enters their appearance and hereby accepts service of the Petition for Review as of November 4, 1986, on behalf of Jerome P. McHugh & Associates.

Respectfully submitted:

Kellahin, Kellahin & Aubrey

By W. Thomas Kellahin

W. Thomas Kellahin
P. O. Box 2265
Santa Fe, NM 87504

(505) 982-4285

CERTIFICATE OF SERVICE

I hereby certify that I caused to be mailed a true and correct copy of the foregoing Acceptance of Service and Entry of Appearance to the following individuals on this ~~5th~~ 7th day of November, 1986.

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Jeff Taylor

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
525 Camino de los Marquez
Santa Fe, New Mexico
87501

TONEY ANAYA
GOVERNOR

November 5, 1986

Dear Counsel:

RE: Appeal to Secretary of Energy and Minerals from Oil Conservation Commission Case No. 8946

Enclosed please find my Memorandum Decision in the above-referenced proceeding.

Thank you for your prompt and conscientious efforts in this matter.

Very truly yours,

Paul L. Biderman

PAUL L. BIDERMAN
Secretary

PLB:rm

ENERGY AND MINERALS DEPARTMENT
STATE OF NEW MEXICO

IN THE MATTER OF THE APPEAL
TO THE SECRETARY OF THE ENERGY
AND MINERALS DEPARTMENT FOR
THE PURPOSE OF CONSIDERING:

THE APPEAL OF OIL CONSERVATION
COMMISSION ORDER R-7407-D AMENDING
THE SPECIAL RULES AND REGULATIONS
OF THE GAVILAN-MANCOS OIL POOL

Oil Conservation
Commission Case No.8946

MEMORANDUM DECISION
BY THE SECRETARY OF ENERGY AND MINERALS

This matter has come before me on the appeal of Mallon Oil Company (Mallon) and Mesa Grande Resources, Inc. (Mesa Grande) from Order R-7407-D issued by the Oil Conservation Commission (the Commission) on September 11, 1986. The appeal is submitted to the Secretary of Energy and Minerals (the Secretary) by Section 70-2-26 NMSA 1978, which explicitly grants the Secretary discretion to convene a public de novo hearing to review orders of the Commission on specified grounds. I have considered the Commission's order, the Notice of Appeal, the correspondence of counsel, the applicable statutes and the state's energy plan. For the reasons stated below, I decline to exercise my discretion to convene the hearing requested by Mallon and Mesa Grande.

This case was initiated on the application of Jerome P. McHugh and Associates (McHugh) for an amendment to the Temporary Special Rules and Regulations of the Gavilan-Mancos Oil Pool. A similar application was filed by Benson-Montin-Greer Drilling Corporation (Benson) and the two matters were consolidated for the Commission. The amendments were sought to temporarily reduce the limitations on allowables for oil production and the gas-oil ratio limitation factor for that pool. After due public notice, a number of interested parties appeared to present various positions through counsel and testimony in hearings conducted over more than four days.

In its order R-7407-D issued September 11, 1986, the Commission ruled that it will adopt a temporary modification of the limiting-gas oil ratio and of the allowable production limitation in the Gavilan-Mancos Pool. This decision was premised on certain findings which, in essence, hold that these modifications will serve to prevent waste and better protect correlative rights in the subject pool. The Commission also found that reconsideration of the issues raised in the case should occur during or before March of 1987 through either of several designated proceedings.

Mallon and Mesa Grande filed a Motion for Rehearing with the Commission on October 1, 1986, which motion was deemed denied upon the Commission's failure to act within ten days. Mallon and Mesa Grande thereupon filed their timely appeal on a variety of grounds with the Secretary on October 20, 1986. Because of the lack of precedent or established procedures for conducting an appeal to the Secretary under Section 70-2-26, supra, I sent a letter to counsel requesting comments on certain procedural and jurisdictional issues. Timely responses addressing these questions were filed by counsel for Mallon, Mesa Grande, McHugh, Benson and Dugan Production Corp. In addition, correspondence from representatives or attorneys for Amoco Production Company and Koch Exploration Company has been reviewed. In view of the shortness of time within which the statute permits the Secretary to act, and the potential inconvenience to the parties of having attorneys and witnesses available in anticipation of a possible hearing on short notice, a letter was distributed on October 30 announcing my decision not to conduct a hearing. This memorandum decision describes the reasoning behind that decision.

ANALYSIS

The appeal to the Secretary under Section 70-2-26, supra, is actually an inference from the Secretary's discretion to review Commission orders sua sponte. "The secretary ... may hold a public hearing to determine whether an order or decision issued by the commission contravenes the department's statewide plan or the public interest," id. [emphasis added]. It is reasonable to infer therefrom that the Secretary's attention may be called to such an inconsistency through an appeal by one of the parties to the Commission case, which is the process that has occurred here. Nevertheless the Secretary's authority to conduct such a hearing or to issue a decision requiring revision of the Commission's order may only be premised on the grounds stated in the statute. Unless the secretary believes that the department's statewide plan or the public interest may be violated by the Commission's order, he cannot hold a hearing.

Any attempt to invoke the Secretary's discretion must therefore suggest how the statewide energy plan or the public interest have been contravened by the Commission. I know of no administrative or judicial precedent that addresses how broadly or narrowly this unique standard was meant to be interpreted. In particular, "public interest" is a vague term that may be interpreted in any number of ways. From my reading of the statute, however, I conclude that the standard to be applied by the secretary in this procedure is a narrow one.

A narrow interpretation of this standard would mean that the Secretary is empowered to act only insofar as the interests that he is charged with protecting are different from those within the purview either of the Commission or of the courts. I am quite confident that the statute did not intend to create an intermediate quasi-judicial tribunal with authority to review the

Commission's orders for legal adequacy or compliance with the constitutional dictates of due process of law. Nor could the intent of the statute be to provide for secretarial review of Commission orders on the same standards as those entrusted to enforcement by the Commission itself in the Oil and Gas Act, Section 70-2-1 through 36 NMSA 1978, as amended, since the standards available to the secretary are stated explicitly and are different from those that guide the commission. The only logical reading of Section 70-2-26, supra, is that the secretary is authorized to measure the Commission's decisions, based upon its statutory duties, for their consistency with the policies identified and implemented by the Secretary. The logic of this interpretation is supported by the statutory scheme which places the Oil Conservation Commission within the Energy and Minerals Department, Section 9-5-3 NMSA 1978, but assigns exclusively to the Commission the power to enforce the interests of the Oil and Gas Act, supra. The Secretary's review power is solely intended to ensure consistency between the Secretary's energy policy strategies and the Commission's decisions, so that one component of the state's energy agency could not undermine the efforts of the chief energy officer of the state, Section 9-5-3 and 9-5-5 NMSA 1978.

Proper application of the Secretary's prerogative requires review of the state's energy plan, as promulgated pursuant to Section 9-5-3 (K) and 9-5-6(A)(3), NMSA 1978; and other lawful pronouncements of the state's energy interests as found in the laws. Were it to appear likely that the Commission's order interfered with the goals or implementation strategies of either of these sources of state energy policy, I would invoke my discretion to conduct a de novo hearing to determine the extent of any such inconsistency. I find no cause to do so, however, and none has been presented to me by the appellants.

The Mallon/Mesa Grande notice of appeal cites numerous grounds for reversal. In summary, these include: the arbitrary, capricious and illegal failure by the Commission to issue findings required by law to change proration rules (Point I); or to issue findings supported by substantial evidence in the record (Points III and V); or to impact correlative rights evenly and fairly (Point II). Point IV of the appeal challenges the Commission's alleged attempt to coerce unitization indirectly without lawful authority, while Point VII claims a violation of due process requirements by the Commission's action eliciting a draft order from only one party. Without commenting on the merits of any of these claims, they all lie clearly within the jurisdiction of the reviewing courts, pursuant to Section 70-2-25B NMSA 1978 and with the Commission in the first instance. While the state laws may well contemplate that any such violation should not go unremedied, nowhere in Section 70-2-26 do I find the legislature to have entrusted that responsibility or authority to me.

Nothing in the Mallon/Mesa Grande appeal alleges any violation of the state's energy plan, but in view of the Secretary's statutory discretion to act sua sponte I have nonetheless reviewed the appropriate portions of that document, "A Policy Level Plan for the Development and Management of New Mexico's Energy and Minerals Resources," Energy and Minerals Department (9/84). I find no conflict therein to suggest that I invoke my discretion on the basis of that document.

Only Point VI of notice of appeal even attempts to assert a contradiction between Order R-7407-D and the public interest, as that term should be construed in Section 70-2-26. In that point appellants allege, first, discrimination by the Commission's order against out-of-state operators; and, second, that the order would cause the state of New Mexico to lose income from oil production taxes and royalties. On their face such allegations might well prompt concern that the state's energy policy interests could be adversely affected.

I do not, however find sufficient substance to these assertions to invoke my discretion to conduct a de novo hearing. Counsel for McHugh points out rather persuasively that appellants' own data are only partially consistent with the notion that the order discriminates against out-of-state producers. But even if the data were to reveal consistently more favorable results for in-state over out-of-state producers, a greater, initial showing of prejudice would be necessary to induce me to invoke the Secretary's discretionary review power. Results alone may suggest the possibility of discrimination, but in this case the Commission has clearly premised its action on principles that were differently motivated. So long as the chips were permitted to fall where they might, it is not discriminatory that they landed disproportionately outside the state. If the Commission had acted solely out of malice toward foreign companies, and had lacked substantial legitimate evidence or rationale for its decision, as appellants imply, then that issue may be addressed by the judiciary. It is clearly not the Secretary's function to conduct such a review under Section 70-2-26.

The other asserted violation of the public interest in the order is the economic detriment to the state from the allegedly unnecessary and arbitrary reduction in allowable oil production resulting from the order. There can be no question that the state benefits from petroleum production, and an order limiting production without justification would be a proper subject for the Secretary's review. But the Commission's order considered the reduced production and balanced that consequence against valid competing policy interests. In particular, the loss of some immediate production revenues, while undesirable in itself, may be quite tolerable if the result is to increase the total production that will ultimately derive from the pool. The Commission's order reveals that it weighed considerable technical evidence and argument presented by several parties before concluding that this long-term benefit would be precisely the result of its short-term sacrifice. Whether its judgment was right or wrong, its reasoning is certainly consistent with the state's interest "to protect and preserve the extractive resources of the state of New Mexico for present and future generations," Section 9-5-3(A), supra [emphasis added]. The statutory language authorizing the Secretary to review the commission's action explicitly requires his consideration of conservation, Section 70-2-26. To the extent that the highly experienced Commission and its staff may have lacked the expertise or judgment to weigh accurately the technical evidence that led it to its conclusion, there is little reason to believe that the Secretary could do any better.

Finally, I note that the Commission limited the duration of its decision so that by March, 1987, if not sooner, it will be reconsidered through one of several designated procedures. Even if appellants have correctly identified defects in the order, time and further measurements of reserves and flows may reveal results that relieve some of the controversy. As far as I am concerned the Commission's judgment should at least be given the deference of several trial months before being subjected to review on the accuracy of its readings of the available data.

DECISION

The Commission's order does not appear to give rise to issues requiring the Secretary to invoke a hearing to determine consistency with the state's energy plan or the public interest, as that term is contemplated in Section 70-2-26, supra, because the order already gives due consideration to some of the same energy policies that the Secretary is charged with developing and implementing. Any errors asserted by appellants are properly addressed to the process of judicial review. I see no basis for exercising the Secretary's limited authority to convene a public hearing to determine whether Oil Conservation Commission Order R-7407-D contravenes the department's statewide plan or the public interest, and accordingly dismiss the appeal.

NEW MEXICO ENERGY AND MINERALS DEPARTMENT

11/5/86
DATE

Paul L. Biderman
PAUL L. BIDERMAN
SECRETARY

ENDORSED
FILED IN MY OFFICE THIS
NOV 24 1986

FIRST JUDICIAL DISTRICT

COUNTY OF RIO ARRIBA

STATE OF NEW MEXICO

IN THE MATTER OF THE APPEAL
TO THE DISTRICT COURT FOR THE
COUNTY OF RIO ARRIBA, STATE OF
NEW MEXICO FOR CONSIDERING:

NO. RA- 86-2317(C)

OIL CONSERVATION COMMISSION
ORDER NO. R-7407-D AMENDING
THE SPECIAL RULES AND REGULATIONS
OF THE GAVILAN-MANCOS OIL POOL.

RESPONSE OF OIL CONSERVATION COMMISSION
TO PETITION FOR REVIEW

The New Mexico Oil Conservation Commission, by and through its attorney, responds to the Petition for Review on file herein as follows:

1. The allegations contained under the heading "factual background" beginning on Page One of the Petition are admitted, except that Order R-7407-D temporarily amended said special pool rules rather than adopting rules in the first instance.

2. The allegations contained under "Point 1" of the Petition are denied.

3. The allegations contained in Paragraph A of "Point II" of the Petition are denied except the first sentence thereof.

4. The allegations contained in Paragraph B of "Point II" of the Petition are denied.

5. The allegations contained in Paragraph C of Point II of the Petition are denied.

6. The allegations contained in Point III of the Petition are denied except the first sentence thereof.

7. The allegations contained in Point IV of the Petition are denied except the first sentence thereof.

8. The allegations contained in Point V of the Petition are denied.

9. The allegations contained in Point VI of the Petition are denied.

10. The allegations contained in Point VII of the Petition are denied, except those contained in the first paragraph thereof.

WHEREFORE, the Oil Conservation Commission respectfully requests that this Court enter an Order affirming the decision entered by Order No. R-7407-D and dismissing the Petition filed herein.

Respectfully submitted,

Jeffery Taylor

JEFFERY TAYLOR
Assistant Attorney General
Oil Conservation Division of the
Energy and Minerals Department
P. O. Box 2088
Santa Fe, New Mexico 87504-2088

CERTIFICATE OF SERVICE

I hereby certify that I caused to be mailed, postage prepaid, a true and correct copy of the foregoing Response of the Oil Conservation Division to all parties of record.

11-24-86

JEFFERY TAYLOR

STATE OF NEW MEXICO

COUNTY OF RIO ARRIBA FIRST JUDICIAL DISTRICT

IN THE MATTER OF THE APPEAL TO THE DISTRICT COURT FOR THE COUNTY OF RIO ARRIBA, STATE OF NEW MEXICO, FOR THE PURPOSE OF CONSIDERING:

THE APPEAL OF OIL CONSERVATION COMMISSION ORDER R-7407-D AMENDING THE SPECIAL RULES AND REGULATIONS OF THE GAVILAN-MANCOS OIL POOL.

NO. RA 86-2371 (C)

ENTRY OF APPEARANCE

AND

ACCEPTANCE OF SERVICE

COMES NOW CAMPBELL & BLACK, P.A., and enters and their appearance and hereby accepts service of the Petition for Review as of December 5, 1986, on behalf of BENSON-MONTIN-GREER DRILLING CORP.

Respectfully submitted,

CAMPBELL & BLACK, P.A.

By J. Scott Hall

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I hereby certify that I caused to be mailed a true and correct copy of the foregoing Acceptance of Service and Entry of Appearance to the following individuals on the 5th day of December, 1986.

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By J. Scott Hall
J. SCOTT HALL

ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION COMMISSION

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

CASE NO. 8946
Order No. R-7407-D

APPLICATION OF JEROME P. McHUGH AND ASSOCIATES FOR AN AMENDMENT TO THE SPECIAL RULES AND REGULATIONS OF THE GAVILAN-MANCOS OIL POOL.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing on August 7, 8, 21, 22, and 27, 1986 at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this 11th day of September, 1986, the Commission, a quorum being present, having considered the testimony presented and the exhibits received at said hearings and being fully advised in the premises,

FINDS THAT:

(1) The applicant has made a good-faith diligent effort to find and notify all operators of wells and each appropriate interested party as required by Division Order No. R-8054.

(2) Due public notice has been given as required by law and the Commission has jurisdiction of this case, the parties, and the subject matter thereof.

(3) The applicant, Jerome P. McHugh and Associates, seeks an order amending the temporary Special Rules and Regulations of the Gavilan-Mancos Oil Pool as promulgated by Division Order No. R-7407 to establish for a period of not less than ninety days a temporary special production allowable limitation of 200 barrels of oil per day for a standard 320-acre spacing and proration unit and a special temporary gas-oil ratio limitation factor of 1,000 cubic feet of gas per barrel of oil produced.

(4) In Companion Case No. 8950, Benson-Montin-Greer Drilling Corporation seeks an order amending the Special Rules and Regulations of the West Puerto Chiquito-Mancos Oil Pool

promulgated by Division Order No. R-3401 to establish a temporary special production allowable limitation of 400 barrels of oil per day for a standard 640-acre spacing and proration unit and a special temporary gas-oil ratio limitation factor (GOR) of 1,000 cubic feet of gas per barrel of oil produced.

(5) Case No. 8950 and Case No. 8946 have been consolidated for purposes of hearing.

(6) Benson-Montin-Greer Drilling Corporation, Dugan Production Corporation and Meridian Oil Company appeared in support of McHugh's application.

(7) The proponents in this case presented testimony and evidence to show that:

(a) The Gavilan Mancos Oil Pool is a highly fractured reservoir which produces primarily by solution gas drive but has potential for significant additional oil recovery by gravity drainage and reducing the dissipation of natural reservoir energy by wells with relatively high gas-oil ratios;

(b) Based upon measurements of reservoir pressure and interference testing, excellent communication exists between wells and throughout the reservoir;

(c) Based upon bottom hole pressure measurements, the reservoir pressure is declining at rates that provide little time to prepare and develop a plan for improving the future operation and development of the reservoir;

(d) Based upon bottom hole pressure measurements, the daily producing oil rate should be reduced immediately to 200 barrels and the limiting gas-oil ratio should be reduced to 1,000 to slow reservoir depletion rates, allow time to evaluate the reservoir and formulate a plan for future operations and development that will result in increased recoveries of oil and gas; and

(e) Gravity drainage will be a factor in improving ultimate recovery in the Gavilan Mancos Oil Pool.

(8) Mobil Producing Texas and New Mexico Inc. appeared in opposition to McHugh's application and presented evidence to show that the Gavilan-Mancos Pool is a typical solution gas drive reservoir with significant potential for oil recovery from matrix porosity and that, because such a reservoir is not rate sensitive, to continue to produce the wells at the current allowable of 702 barrels per day and 2,000 GOR would not result in the reduction of the ultimate recovery of oil and gas therefrom.

(9) Mallon Oil Company, Mesa Grande Resources Inc. and Koch Exploration appeared and presented evidence to show that the Gavilan-Mancos Oil Pool is an individual well gas cap drive reservoir and that the limiting GOR should be reduced to the solution gas oil ratio in order to most effectively produce the reservoir but opposed the reduction in the maximum daily oil allowable, discounting the potential for significant gravity drainage.

(10) Prior to the application in this case, the operators in the Gavilan-Mancos Oil Pool formed a working interest owners committee, including geologic and engineering technical subcommittees, in order to discuss and address the issue of the most effective and efficient methods to develop and produce the pool.

(11) The applicant presented testimony that despite numerous meetings, the working interest owners have not yet agreed to any method of operations within said pool other than that provided in its special rules and that an emergency exists requiring the Commission to act immediately to reduce the rate of reservoir voidage in the Gavilan-Mancos Oil Pool to prevent waste and preserve reservoir energy until the working interest owners can reach such an agreement or until the Commission finally determines how best the pool might be developed and produced.

(12) The evidence presented at the hearing established that:

(a) the Gavilan Mancos Oil Pool primarily produces from a fractured shale with little or no matrix contribution;

(b) the Gavilan Mancos Pool is primarily a solution gas drive reservoir with potential for substantial additional ultimate oil recovery by gravity drainage;

(c) significant pressure depletion is occurring in wells and areas of the reservoir that have produced very little oil or gas;

(d) pressure interference tests have been conducted in representative areas of the pool, all of which demonstrate almost instantaneous interference over large distances;

(e) the solution GOR is between 480 and 646 cubic feet of gas per barrel of oil and most likely approximates 600 cubic feet of gas per barrel;

(f) wells in some areas of the Pool are producing at GOR rates in excess of the solution gas-oil ratio;

(g) free gas is being liberated reservoir-wide irrespective of structural position;

(h) reduction of the limiting GOR in the Gavilan-Mancos Oil Pool to near the solution GOR will prevent the inefficient dissipation of reservoir energy and will permit the owners in the pool to utilize their share of reservoir energy;

(i) the current 702 barrel per day oil maximum allowable is based upon an extension of Oil Conservation Division (Division) Rule 505 to wells in the Gavilan-Mancos Oil Pool depth range with 320-acre dedication;

(j) such depth bracket allowable could be appropriate for a normal pool with substantial matrix contribution to production but bears no rational relationship to the most efficient rate at which to produce the subject pool;

(k) the proposed 200 barrel per day maximum allowable, if imposed, would appear to result in production from the various tracts in the pool generally in closer proportion to the reserves thereunder than the current 702 barrel maximum allowable;

(l) imposition of such a maximum allowable, at this time, would unfairly penalize the operators of newer generally higher capacity wells as opposed to those operators of older generally declining capacity wells which previously enjoyed high rates of reservoir drainage;

(m) adoption of a temporary 400 barrel of oil per day maximum allowable rather than the 200 barrel limit proposed will, at this time, better permit the operators of the newer high capacity wells to recover their share of the oil in the Gavilan-Mancos Oil Pool; and

(n) a reduction in both the daily oil production rate and the limiting GOR will reduce the rate of reservoir voidage and pressure depletion and afford an improved opportunity for gravity drainage, thereby preventing waste, and permit operators additional time to determine the most effective and efficient method to further develop and produce the Pool.

(13) The adoption of a 600 cubic feet of gas per barrel of oil limiting GOR and reduction of the oil depth bracket allowable to 400 barrels per day in the Gavilan-Mancos Oil Pool on a temporary basis, at this time, is necessary to prevent waste.

(14) The adoption of such limiting GOR and depth bracket allowable will, at this time, more nearly permit each operator to use his share of the reservoir energy and more nearly recover the oil underlying the individual tracts in the pool than the existing limiting GOR and depth bracket allowable and will, therefore, better protect correlative rights.

(15) Such limiting GOR and depth bracket allowable should be adopted effective September 1, 1986, and should be continued until further order of the Commission.

(16) The issues raised in this case should be reconsidered when temporary special pool rules for the Gavilan-Mancos Oil Pool established by Order No. R-7407 are brought up for reconsideration in March, 1987, or upon the recommendation of the pool study committee.

IT IS THEREFORE ORDERED THAT:

(1) The terms and conditions of this order shall apply to all wells completed in the Gavilan-Mancos Oil Pool or wells completed in the Mancos formation within one mile thereof effective September 1, 1986 and shall remain in effect until further order of the Commission.

(2) The limiting gas oil ratio in the Gavilan-Mancos Oil Pool, as heretofore defined and described, Rio Arriba County, New Mexico, shall be 600 cubic feet of gas for each barrel of liquid hydrocarbons produced and that the depth bracket allowable therefor shall be 400 barrels of oil per day.

(3) Both applicants and opponents shall be permitted representatives on the Gavilan Pool Technical Study Committee and this Study Committee shall submit a status report to the Commission on or before November 15, 1986.

(4) Unless reopened by the Commission based upon the report of the Study Committee, this case shall be reopened at a Commission hearing in March, 1987, to be consolidated with the reconsideration of the Temporary Special Rules established by Order No. R-7407 for the Gavilan-Mancos Oil Pool.

(5) Jurisdiction of this cause is retained for entry of such further orders as the Commission may deem necessary.

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

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

JIM BACA, Member

ED KELLEY, Member

R. L. Stamets

R. L. STAMETS, Chairman and
Secretary

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REPLY TO SANTA FE OFFICE

July 22, 1987

File

Tom C. Barr, Secretary
Energy, Minerals and
Natural Resources Department
Villagra Building
Santa Fe, New Mexico 87501

Re: Review of Oil Conservation Commission Orders
R-7407-E and R-6469-D

Dear Secretary Barr:

Enclosed please find the Application for Review of two Oil Conservation Commission orders. Under the provisions of the New Mexico Oil and Gas Act, you are authorized to hold hearings to review Commission orders, if it appears that those orders contravene the State's energy plan or the public interest. Mallon Oil Company and Mesa Grande Resources believe that such contraventions have occurred.

Because of the short time frame established by the statute, Mallon and Mesa Grande request that a hearing be opened on or before July 29, 1987 at which time we request that a future date be set for counsel for the parties to present argument after you and your staff have had an opportunity to review the record and briefs in this matter.

Thank you for your consideration of and attention to this vitally important matter.

Sincerely,

W. Perry Pearce

WPP:mp:71
#9831-86-01
Enclosures
cc w/enclosures:
Charles Roybal, Esquire
Mr. William LeMay
Jeff Taylor, Esquire
All Counsel of Record

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:	CASES NOS. 7980, 8946, 9113, AND 9114 ORDER NO. R-7407-E CASE NO. 8950 ORDER NO. R-6469-D

APPLICATION FOR REVIEW

COME NOW Mallon Oil Company and Mesa Grande Resources, Inc. ("Applicants") and file this, their Application for Review of Commission orders in the above-described matters, and state as follows:

I.

BACKGROUND

A controversy has developed between two sets of owners and operators on how to produce the Gavilan Mancos Oil Pool ("Gavilan"). Applicants and certain other allied owners[1] believe the Gavilan and the West Puerto Chiquito-Mancos Pool

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1 Mallon Oil Company
Mesa Grande Resources, Inc.
Mesa Grande, Ltd.
Mobil Oil Corporation
American Penn Energy, Inc.
Kodiak Petroleum
Hooper, Kimball & Williams
Reading & Bates Petroleum Co.
Koch Exploration
Amoco Production Company
Arriba Company, Ltd.
Smackco, Ltd.
Phelps Dodge Corp.
Floyd & Emma Edwards
Don Howard

("West Puerto"), although physically adjacent to each other, are separate and distinct pools with no effective communication and that the currently designated boundary between the pools is inaccurate and should be moved roughly one or two section lines to the east. Gavilan contains wells capable of very high rates of production and pool recovery is not rate sensitive.[2] Therefore, the standard statewide depth-bracket allowable is appropriate.

Opposition owners[3] in the pools, however, have argued that the Gavilan and West Puerto are in direct effective communication, that pool recovery from the Gavilan is rate sensitive and that production from the Gavilan Pool should be drastically reduced.

The Oil Conservation Commission of this Department ("Commission") conducted a five-day hearing held in March and April 1987, after which the the Commission agreed with

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2 "Rate sensitive" is a shorthand expression used by technical people to indicate that the amount of ultimate primary recovery is affected by the rate or level of production. There are a number of natural producing mechanisms which are not rate sensitive such as a "solution gas drive" mechanism. The Applicants have submitted convincing evidence that the primary drive mechanism for the Gavilan is a solution gas drive which demonstrates that ultimate recovery of Gavilan oil reserves is not affected by the rate or level of production.

3 Benson-Montin-Greer Drilling Corporation
Jerome P. McHugh & Associates
Dugan Production Corporation
Sun Exploration and Production Company
Meridian Oil Company

Applicants that the Gavilan is a separate pool from the West Puerto. See R-6469-D Finding of Fact, Paragraphs (5)(6)(7) & (17), Ordering Paragraph (1) and R-7407E, Finding of Fact (6)(7)(8), Ordering Paragraph (1). A dispute, however, continues between the parties concerning the proper boundary line between the Gavilan and West Puerto and whether production from the Gavilan is rate sensitive. Accordingly, the Commission orders required bottomhole pressure tests on all wells in both pools within the first week of July 1987. (R-6469-D Ordering Paragraph (3) & R-7407-E Ordering Paragraph (4)). The orders have now been effectively amended by the staff, not the Commission, to require less than all wells to be tested. Applicants object to that informal amendment.

The Commission also established a testing period for rate sensitivity purposes, allowing all wells to produce at near top allowables for 90 days and then drastically reducing production for another 90 days. At the end of the test period, wells are to remain drastically reduced for at least an additional five months pending a reopened hearing, in May 1988, to consider the test data. Applicants object to this unnecessarily extended period of restricted allowables below the standard statewide depth brackets.

II.

THE OIL CONSERVATION COMMISSION HAS ENTERED ORDERS WHICH CONTRAVENE THE DEPARTMENT'S STATEWIDE PLAN AND THE PUBLIC INTEREST

The Applicants request a review by the Secretary of the Energy, Minerals and Natural Resources Department ("Secretary") of Commission Orders R-6469-D and R-7407-E pertaining to rules governing production from the Gavilan and the West Puerto because such orders contravene this Department's Statewide Plan and the public interest of New Mexico. Applicants have prepared a brief memorandum on the authority of the Secretary to grant this Application, which brief is attached hereto as Exhibit A and incorporated herein by reference.

Applicants request the Secretary to amend the Commission orders as follows:

1. The testing requirements for five wells should be reinstated and modified to obtain necessary data.

2. The reopened hearing should be scheduled in February 1988 instead of May 1988 in light of the 83% cut in statewide depth bracket allowable imposed by the Commission at the request of the Sun Oil Co.-BMG Group.[4]

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4 Applicants believe the real intent of the Sun-BMG group is to confiscate the Applicants' property. Without a reservoir study of the Gavilan the BMG group decided the Gavilan needed to be unitized. Applicants, frustrated by BMG groups' refusal to collect and discuss technical data finally commissioned an outside study to determine feasibility of secondary recovery and thus unitization. That study concluded no secondary recovery or unit was needed. After the Commission cut the Gavilan top allowable by 83% in September 1986, at the request of the BMG group, Sun, BMG's partner, began buying properties in the Gavilan. Sun tried to buy Applicants' Gavilan oil properties at distress prices. In short, it is the intention of the Sun-BMG group to drive these Applicants out of the oil business in the Gavilan and take over operation of their properties. With this background, the Secretary can realize why the matters requested herein are of extreme urgency to the continued health of the oil industry in New Mexico.

3. If the Secretary does not advance the hearing from May 1988 to February 1988, then the Secretary should order effective January 1, 1988, the reinstatement of statewide depth bracket allowable which previously existed in the Gavilan of 702 bopd with a 2000/1 GOR for a 320-acre proration unit, (twice this amount for a 640-acre proration unit). Such reinstated statewide allowables should remain in effect until the Commission acts on the May 1988 reopened hearing.

4. The Secretary should make clear that the proper boundary between the Gavilan and West Puerto will be considered at the reopened hearing based on the test and production data ordered by the Secretary and the Commission.

5. Applicants also urge that the additional points set out in Applicants' prior Application for Rehearing be considered by the Secretary. A copy of the Applicants' Application for Rehearing before the Commission is attached as Exhibit B and incorporated herein by reference.

III.

TESTING REQUIREMENTS

These Applicants have specifically requested that bottom hole pressure data be obtained from the following BMG wells in West Puerto:

Canada Ojitos Unit (COU)

E-10
F-30
B-29
B-32
L-27

The details of this bottom hole pressure testing and the need therefore is set forth on Pages 4-6, Paragraphs 2a., 2b. and 2c. of Exhibit B.

The Commission is refusing to follow its own orders of June 8, 1987, (attached as Exhibit C and incorporated herein) to require bottom hole pressures on all wells and BMG has refused to pressure test key wells covered by the orders. This bottom hole pressure information will provide meaningful data on the proper location of the boundary line between Gavilan and West Puerto.[5] In addition, this pressure data will enhance the information available to confirm that the Gavilan wells are not rate sensitive. The Secretary should modify the above order to require well testing as requested by Applicants on the COU wells E-10, F-30, B-29, B-32 and L-27.

IV.

REOPENED HEARING DATE SHOULD BE SCHEDULED IN FEBRUARY 1988

If the reopened hearing ordered by the Commission remains scheduled for May 1988, the estimated loss in production during this five-month period alone to all interested parties due to the

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5 BMG has filed an application with the Commission to increase its allowables along the current boundary line of the Gavilan and West Puerto. This Application, scheduled for hearing on September 24, 1987, would permit the BMG wells producing from the A & B zones to obtain gas injection credit to remove allowable penalties for gas injected in the C zone. The effect would be to restore 70% of the allowable cut to the BMG wells while continuing the 83% allowable cut against the wells operated by Applicants and other parties in Gavilan.

allowable limitation imposed by these Commission orders will exceed 400,000 barrels of oil and 750,000 MCF of gas, worth $9,000,000.00. State tax revenue loss alone would exceed $800,000.00. It is estimated that the monthly tax loss in revenue to the State will be $170,000.00 per month not counting its one-half share of federal lease royalty. In other words, advancing the hearing from May 1988 to February 1988 could restore $170,000 per month in badly needed State revenues plus the State's one half of increased federal royalties.

In addition, the continuation of these unwarranted allowable restrictions below the standard statewide depth bracket allowables will shift reserves from these Applicants to the Sun-BMG group and result in a clear violation of the correlative rights of these Applicants and their royalty owners, including the BLM. The BLM royalty on Applicants' tracts because of newer leases are higher than the BMG operated BLM tracts in West Puerto. <u>The effect of these orders is to drain reserves from tracts in which the State of New Mexico would be entitled to higher royalty rates</u>.

The Applicants are not contesting another four month 83% reduction in statewide allowables (October 1987 through January 1988) to obtain the data the Commission has indicated it needs to finally settle the rate sensitivity issue in the Gavilan and to settle the proper location of the Gavilan-West Puerto boundary. It is unreasonable, however, to require these Applicants and others to continue on 83% statewide allowable cut until May 1988 and so long thereafter until an order issues, while the Commission reviews new data, some of which will have been gathered as early as July 1987. The Commission should advance the reopened hearing to February 1988, in order to stop the arbitrary and unnecessary restriction in allowables for the Gavilan.

V.

IN THE ALTERNATIVE, STATEWIDE DEPTH BRACKET ALLOWABLES SHOULD BE RESTORED PENDING THE REOPENED HEARING.

If the Secretary elects not to require an advancement of the May 1988 hearing to February 1988, then in all fairness and in order to comply with the statewide plan and in the public interest the allowables for the Gavilan should be restored to 702 bopd with a 2000/1 GOR effective January 1, 1988, for a 320-acre proration unit and twice such amount for a 640-acre proration unit. A similar restoration of allowables should be implemented in the West Puerto.

The Commission's orders contemplate a partial restoration of the Gavilan allowable effective July 1, 1987, to 640 bopd and a 2000/1 GOR for a 320-acre proration unit. (Gavilan is essentially drilled on a 320-acre pattern.) Bottomhole pressure tests were to be run on all wells in the first week of July 1987. After three months of this partially restored production rate, the allowable is then reduced on October 1, 1987, to 400 bopd with a 600/1 GOR with new bottomhole pressure tests to be conducted in the first week for October 1987. After three months of reduced production (October, November and December), additional bottomhole pressures will be conducted in the first week of January 1988. Under the existing orders, this severely restricted rate will continue, after the testing period ends, until the Commission acts on the May 1988 reopened hearing. That means a minimum of an additional five months of restricted allowables without any justification. In other words, the Gavilan receives partial restoration of its production rate for only three months and then the Gavilan rate is again restricted below the statewide depth brackets allowables for a minimum of at least eight months. The Gavilan has already suffered a ten-month 83% restriction of statewide depth bracket allowables at the 400 bopd and 600/1 GOR from September 1986 through June 1987. The net effect of the Commission orders are to require Gavilan to produce at a statewide depth bracket allowable restriction of 83% for at least 18 months out of a 21-month period.

The inequity to Applicants is clear. Therefore, the allowable for the Gavilan should be restored January 1, 1988 to the statewide depth bracket of 702 bopd with a 2000/1 GOR, for a 320-acre proration unit and twice this amount for a 640-acre proration unit continuing until the Commission acts on the May 1988 hearing.

VI.

BOUNDARY QUESTION

Because of the additional test data required by the Commission and requested by the Applicants, the Secretary should make clear that the proper boundary between Gavilan and West

Puerto should be considered at the reopened hearing based upon all data then available.

VII.

ADDITIONAL REVIEW

The other matters for which Applicants request review by the Secretary are set forth in Exhibit B. At this time, however, Applicants are willing to abide by the subject orders if the above tests, hearing advancement, allowable restoration and boundary consideration are ordered by the Secretary. Applicants will not pursue its appeal if the requests outlined above are granted by the Secretary since all parties will have sufficient data and equal footing to proceed with what Applicants hope will be a February 1988 reopened hearing.

CONCLUSION

For the foregoing reasons, Applicants request that the Commission's orders be amended to require 1) proper testing, 2) advancing the reopened hearing to February 1988, (or, in the alternative, to reinstate allowables effective January 1, 1988, pending the results of the reopened hearing,) and 3) the reopened hearing will consider the proper boundary of the Gavilan and West Puerto.

In order to grant this request, the Secretary does not need to rehear the evidence presented at the original hearing or rule on the merits of the arguments presented at the original hearing. The Secretary can grant this request based upon the previous hearing record, the Commission orders and the arguments of counsel. The requested amendments will not change the substance or direction of the Commission orders but rather will clarify those orders, provide proper test data for review, and will give all parties a fair and equal standing at the reopened hearing.

Accordingly, Applicants' request the Secretary open this hearing on or before July 29, 1987, which date is within twenty days of the denial of Applicants' Application for Rehearing. However, in light of the short time period for the hearing to be convened the Secretary could use this initial hearing to set the ground rules for a hearing to be resumed shortly after July 29, 1987.

Respectfully submitted,

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I hereby certify that I caused a true and correct copy of the foregoing Application for Review to be mailed to the following persons this 22nd day of July, 1987.

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Sarah M. Singleton
Jay R. Hone
Charles W. N. Thompson, Jr.
John M. Hickey
Mack E. With
Galen M. Buller
Katherine W. Hall
Edmund H. Kendrick
Helen C. Sturm
Richard L. Puglisi
Arturo Rodriguez
Joan M. Waters
Terri A. Mazur
Stephen R. Kotz
James C. Murphy
James R. Jurgens
Ann M. Maloney
Deborah J. Van Vleck
Anne B. Hemenway
Roger L. Prucino
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REPLY TO SANTA FE OFFICE

July 30, 1987

RECEIVED
AUG - 5 1987
OIL CONSERVATION DIVISION
SANTA FE

Mr. Jeff Taylor
Legal Counsel for the Division
Oil Conservation Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

Dear Mr. Taylor:

Enclosed please find a copy of the Appeal of Commission Orders Nos. R-7407-E and R-6469-D which has been filed in the District Court of the First Judicial District of New Mexico.

I understand that Benson-Montin-Greer and other parties have also filed an appeal of this matter.

If I can be of assistance, please do not hesitate to contact me.

Sincerely,

Perry

W. Perry Pearce

WPP:mp:123
#9831-86-01
Enclosure

Robert D. Buettner
General Counsel and Secretary

KOCH
EXPLORATION COMPANY

May 18, 1988

Mr. William J. LeMay, Chairman
Mr. William R. Humphries
Mr. Erling A. Brostuen
New Mexico Oil Conservation Commission
State Land Office Building
Santa Fe, NM 87501

Re: Cases 7980, 8946, 8950 and 9111

Gentlemen:

As requested in the Commission's Public Notice of Prehearing Conference in the referenced cases, Koch hereby enters its appearance as follows:

(a) Koch's position on the issues set forth in the Notices is that allowables in the Gavilan Pool and the westernmost two section-wide tier of the West Puerto Chiquito-Mancos Oil Pool should be restored to statewide depth-bracket allowables and GORs.

(b) Koch has no present intention to present witnesses, except possibly in rebuttal to testimony which may be adverse to Koch's positions as hereinabove set forth. Even if such rebuttal testimony should be necessary, Koch doubts that more than one hour would be required for its presentation.

(c) Koch believes the Commission's paramount objective in these hearings should be to immediately restore allowables to stop the waste which has been engendered by the experiment with restricted production. However, Koch believes that the Commission should consider, without delaying allowable restoration, the issue of redefining the Gavilan-Mancos Pool boundary to include the "western tier" of two sections currently forming the western edge of the Canada Ojitos Unit.

(d) Koch has not reviewed the proposed statement of procedure and therefore is unable to comment upon it, however, as a non-operating working interest owner in Gavilan properties operated by Mallon Oil Company, we would adopt the position of Mallon's counsel with regard to these matters.

Please keep us advised of further developments in these cases.

Yours very truly,

Robert D. Buettner

R. D. Buettner

RDB:lra

cc: Thomas Kellahin, Esq.
William F. Carr, Esq.
Owen Lopez, Esq.
W. Perry Pearce, Esq.
Frank Douglass, Esq.
Mr. Vic Lyons
Mr. Frank Chavez
Mr. Bill Weiss

Dockets Nos. 16-88 and 17-88 are tentatively set for May 25 and June 8, 1988. Applications for hearing must be filed at least 22 days in advance of hearing date.

DOCKET: EXAMINER HEARING - WEDNESDAY - MAY 11, 1988

8:15 A.M. - OIL CONSERVATION DIVISION CONFERENCE ROOM,
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

The following cases will be heard before David R. Catanach, Examiner, or Michael E. Stogner, Alternate Examiner:

ALLOWABLE: (1) Consideration of the allowable production of gas for June, 1988, from fourteen prorated gas pools in Lea, Eddy, and Chaves Counties, New Mexico.

(2) Consideration of the allowable production of gas for June, 1988, from four prorated pools in San Juan, Rio Arriba, and Sandoval Counties, New Mexico.

CASE 9356: (Readvertised)

In the matter of the hearing called by the Oil Conservation Division on its own motion to consider amending the "Special Rules For Applications For Wellhead Price Ceiling Category Determinations," pursuant to the Natural Gas Policy Act of 1978 (NGPA), as promulgated by Division Order No. R-5878-B, as amended, by revising Forms C-132 and C-132-A to reflect the Department name change.

CASE 9368: Application of Siete Oil & Gas Corporation for a waterflood project, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks authority to institute a waterflood project on its Blackhawk Federal Lease underlying the SE/4 of Section 23 and the SW/4 and SE/4 NW/4, of Section 24, both in Township 18 South, Range 31 East, by the injection of water into the Shugart Yates-Seven Rivers-Queen-Grayburg Pool in the perforated interval from approximately 3722 feet to 3747 feet in its Blackhawk Federal Well No. 3, located 2040 feet from the South line and 920 feet from the West line (Unit L) of said Section 24. Said well is located approximately one mile north of the Texas-New Mexico Pipeline Maljamar Plant No. 2 Booster Station.

CASE 9369: Application of Hixon Development Company for compulsory pooling, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Gavilan-Mancos Oil Pool underlying all of Section 36, Township 26 North, Range 2 West, forming a standard 640-acre oil spacing and proration unit for said pool. Said unit is to be dedicated to the applicant's Tapacitos Well No. 4 located at an unorthodox oil well location within the buffer zone as prescribed by Rule 2(b) of R-7407-E 1100 feet from the South line and 1600 feet from the East line (Unit O) of said Section 36 which is presently completed in and producing from the Gavilan-Mancos Oil Pool and to which the E/2 of said Section 36 is presently dedicated. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well and a charge for risk involved in drilling said well. Said unit is located approximately 3.5 miles southwest by south of Gavilan, New Mexico.

CASE 9377: Application of Hixon Development Company for compulsory pooling, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all overriding royalty interests in the Gavilan-Mancos Oil Pool underlying all of Section 25, Township 26 North, Range 2 West, to form a standard 640-acre oil spacing and proration unit for said pool. Said unit is to be dedicated to the applicant's Tapacitos Well No. 2 located at a previously approved unorthodox location (NSL-1404) 1545 feet from the South line and 790 feet from the West line (Unit L) of said Section 25 which is presently completed in and producing from the Gavilan-Mancos Oil Pool and in which the S/2 of said Section 25 is presently dedicated. Said well is located approximately 4.5 miles north-northwest of Gavilan, New Mexico.

CASE 9370: Application of Union Texas Petroleum Corporation for downhole commingling, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks approval to commingle production from the Basin-Dakota and Blanco-MesaVerde Pools in the wellbore of its Jicarilla "G" Well No. 8, located 1650 feet from the North and East lines (Unit G) of Section 2, Township 26 North, Range 5 West. Said well is located approximately 9.5 miles northwest by west of the Southern Union Gas Company Ojito Camp.

CASE 9371: Application of Reading & Bates Petroleum Company for compulsory pooling, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Gavilan Mancos Oil Pool underlying all of Section 15, Township 25 North, Range 2 West, forming a standard 640-acre oil spacing and proration unit for said pool. Said unit is to be dedicated to the applicant's Howard Federal "15" Well No. 43 located at a standard oil well location 1650 feet from the South line and 790 feet from the East line of said Section 15 which is presently completed in and producing from the Gavilan-Mancos Oil Pool and to which the E/2 of said Section 15 is presently dedicated. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well and a charge for risk involved in drilling said well. Said unit is overlaid by the community of Gavilan, New Mexico.

CASE 9376: Application of Nearburg Producing Company to amend Division Order No. R-8605 and the assignment of an oil allowable retroactive to April 1, 1988, Lea County, New Mexico. Applicant, in the above-styled cause, seeks to amend Division Order No. R-8605, dated March 8, 1988, by changing the non-standard oil proration unit to include Lots 3 and 4 of Section 19, Township 16 South, Range 37 East, to be dedicated to its Soledad "19M" Well No. 1 located at an unorthodox location 1000 feet from the South and West lines of said Section 19 thereby forming a non-standard oil spacing and proration unit consisting of 100.81 acres. Applicant also seeks the assignment of an oil allowable for said well to be made retroactive to April 1, 1988 based on the new acreage factor. Said well is located approximately 4.25 miles southeast of Lovington, New Mexico.

CASE 9350: (Continued from April 27, 1988, Examiner Hearing)

Application of Amerind Oil Company for a non-standard oil proration unit, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for an 80-acre non-standard oil proration unit for production from the Strawn and Atoka formations comprising the SE/4 NE/4 and NE/4 SE/4 of Section 2, Township 17 South, Range 37 East, Undesignated Shipp-Strawn Pool, Undesignated Humble City-Strawn Pool, and Undesignated Humble City-Atoka Pool, said unit to be dedicated to a well to be drilled at a standard oil well location thereon. Said unit is located approximately 4.5 miles north of Humble City, New Mexico.

CASE 9367: (Continued from April 27, 1988, Examiner Hearing)

Application of Marsh Operating Company for an unorthodox gas well location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for an unorthodox gas well location 660 feet from the North line and 990 feet from the East line (Unit A) of Section 34, Township 16 South, Range 34 East, to test the Undesignated South Kemnitz Atoka-Morrow Gas Pool, the N/2 of said Section 34 to be dedicated to the well. Said well is located approximately 5.5 miles North-Northwest of Buckeye, New Mexico.

CASE 9372: Application of Santa Fe Energy Operating Partners, L.P., for compulsory pooling, and a non-standard gas proration unit, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests from the surface to the base of the Morrow formation underlying the E/2 W/2 and Lots 1 through 4 of Section 30, Township 21 South, Range 28 East, forming a non-standard 313.12-acre gas spacing and proration unit for any and all formations and/or pools developed on 320-acre spacing, to be dedicated to a well to be drilled at a standard gas well location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as opertator of the well and a charge for risk involved in drilling said well. Said unit is located approximately 6 miles east-northeast of Carlsbad, New Mexico.

CASE 9374: Application of Bass Enterprises Production Company for compulsory pooling, and two non-standard gas proration units Eddy County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests from the surface to either the base of the Morrow formation or to a depth of 12,100 feet, whichever is deeper, underlying the SE/4, E/2 SW/4, and Lots 3 and 4 of Section 30, Township 21 South, Range 28 East, to form a non-standard 316.44-acre gas spacing and proration unit for any and all formations and/or pools developed on 320-acre spacing within said vertical limits and the E/2 SW/4 and Lots 3 and 4 of said Section 30 to form a non-standard 156.44-acre gas spacing and proration unit for any and all formations and or pools within said vertical limits developed on 160-acre spacing, both aforementioned units to be dedicated to a single well to be drilled at a standard gas well location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well and a charge for risk involved in drilling said well. Said units are located approximately 6 miles east-northeast of Carlsbad, New Mexico.

CASE 9373: Application of Texaco Producing Inc. for salt water disposal, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks authority to dispose of produced salt water into the Brushy Draw-Delaware Pool in the perforated interval from approximately 5417 feet to 6170 feet in its Salt Mountain "36" State Well No. 1 located 660 feet from the North and West lines (Unit D) of Section 36, Township 26 South, Range 29 East, which is located approximately 2.25 miles east by north of where the Pecos River crosses the Texas/New Mexico Stateline.

CASE 8334: (Reopened)

In the matter of Case No. 8834 being reopened pursuant to the provisions of Division Order No. R-8222, which promulgated temporary special pool rules and regulations for the Alston Ranch-Upper Pennsylvanian Pool in Lea County, New Mexico, including a provision for 160-acre spacing units. Operators in the subject pool may appear and show cause why the Alston Ranch-Upper Pennsylvanian Pool should not be developed on 40-acre proration units. The present horizontal extent of said pool consists of the W/2 of Section 25, Township 13 South, Range 34 East, which is located approximately 9 miles west by north of McDonald, New Mexico.

CASE 9357: (Readvertised)

Application of El Ran, Inc. for a unit agreement, Chaves and Roosevelt Counties, New Mexico. Applicant, in the above-styled cause, seeks approval of the Chaveroo San Andres Unit Area comprising 1,120 acres, more or less, of Federal and Fee lands underlying all or portions of Sections 34 and 35, Township 7 South, Range 32 East, and Sections 3 and 10, Township 8 South, Range 32 East. This area is located on the Chaves and Roosevelt County line and 20 miles south of Elida, New Mexico.

CASE 9358: (Readvertised)

Application of El Ran, Inc. for the reclassification of a pressure maintenance project to a waterflood project and for waterflood expansion, Chaves and Roosevelt Counties, New Mexico. Applicant, in the above-styled cause, seeks to reclassify the El Ran Chaveroo Pressure Maintenance Project (Division Order No. R-7044) to a waterflood project and to expand said project to include the area underlying the proposed Chaveroo San Andres Unit Area comprising all or portions of Sections 34 and 35, Township 7 South, Range 32 East, and Sections 3 and 10, Township 8 South, Range 32 East. Applicant also seeks to expand said project by including 13 additional injection wells into the San Andres formation. Said area is located on the Chaves and Roosevelt County line and 20 miles south of Elida, New Mexico.

CASE 9375: (a) CREATE a new pool in Lea County, New Mexico, classified as an oil pool for Devonian production and designated as the Vada-Devonian Pool. Further, assign approximately 63,160 barrels of discovery allowable to the discovery well, the Union Pacific Resources Company State 26 Well No. 1 located in Unit N of Section 26, Township 10 South, Range 33 East, NMPM. Said pool would comprise:

TOWNSHIP 10 SOUTH, RANGE 33 EAST, NMPM
Section 26: SW/4

(b) RECLASSIFY the Fowler-Upper Silurian Oil Pool in Lea County, New Mexico, to the Fowler-Upper Silurian Gas Pool as the only two wells producing from this pool are gas wells.

(c) EXTEND the Antelope Ridge-Atoka Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 22 SOUTH, RANGE 34 EAST, NMPM
Section 34: W/2
Section 35: N/2

(d) EXTEND the Blinebry Oil and Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 22 SOUTH, RANGE 37 EAST, NMPM
Section 17: NW/4

(e) EXTEND the DK-Abo Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 38 EAST, NMPM
Section 25: NE/4

(f) EXTEND the King-Wolfcamp Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 13 SOUTH, RANGE 38 EAST, NMPM
Section 19: SW/4

(g) EXTEND the Lea-Bone Spring Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 34 EAST, NMPM
Section 11: SE/4
Section 14: NE/4

(h) EXTEND the Lea-San Andres Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 34 EAST, NMPM
Section 25: S/2
Section 36: NW/4

(i) EXTEND the Lovington-Paddock Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 16 SOUTH, RANGE 37 EAST, NMPM
Section 33: SE/4
Section 34: SW/4

(j) EXTEND the West Lusk-Delaware Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM
Section 31: NW/4

(k) EXTEND the North Lusk-Seven Rivers Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM
Section 4: NE/4

(l) EXTEND the Maljamar Grayburg-San Andres Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 17 SOUTH, RANGE 33 EAST, NMPM
Section 26: NW/4

(m) EXTEND the Sanmal-Queen Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 17 SOUTH, RANGE 33 EAST, NMPM
Section 11: W/2

(n) EXTEND the Scharb-Bone Spring Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 35 EAST, NMPM
Section 20: NW/4

(o) EXTEND the West Teas Yates-Seven Rivers Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 33 EAST, NMPM
Section 9: SE/4

(p) EXTEND the West Tonto Yates-Seven Rivers Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM
Section 13: NW/4

(q) EXTEND the Tubb Oil and Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 22 SOUTH, RANGE 37 EAST, NMPM
Section 17: NW/4

(r) EXTEND the North Vacuum Atoka-Morrow Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 17 SOUTH, RANGE 35 EAST, NMPM
Section 16: W/2

(s) EXTEND the Wantz-Abo Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 21 SOUTH, RANGE 38 EAST, NMPM
Section 6: Lots 11, 12, 13, and 14

(t) EXTEND the Warren-Tubb Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 38 EAST, NMPM
Section 25: SW/4
Section 36: NW/4

(u) EXTEND the North Young-Bone Spring Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 18 SOUTH, RANGE 32 EAST, NMPM
Section 18: NE/4

DOCKET: COMMISSION HEARING - THURSDAY - MAY 19, 1988

9:00 A.M. - MORGAN HALL, STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO

CASE 9378: In the matter of the hearing called by the Oil Conservation Division on its own motion to promulgate a new Rule 711 to provide for the administrative approval and regulation of commercial surface waste disposal facilities and the requirement of a $25,000 bond for such facilities.

CASES 7980, 8946, 8950, AND 9111: (Reopened)

A pre-hearing conference is hereby called by the Oil Conservation Commission to establish procedures, determine issues, and to set forth a hearing agenda for Cases Nos. 7980, 8946, 8950, and 9111, all concerning the Gavilan-Mancos Oil Pool and/or West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico, all set for an evidentiary hearing to be held commencing at 9:00 A.M. on Monday, June 13, 1988.

The Oil Conservation Commission on June 8, 1987, entered Order No. R-7407-E adopting Permanent Special Rules and Regulations for the Gavilan-Mancos Oil Pool and also entered Order No. R-6469-D which modified the allowable and gas-oil ratio in the West Puerto Chiquito-Mancos Oil Pool so that both subject pools had the same allowables and gas-oil ratios.

These orders included provisions for production and bottomhole pressure monitoring in both pools which were conducted from June 27, 1987 to February 19, 1988.

All interested parties are hereby notified to appear with their attorneys at the regularly scheduled Commission hearing on May 19, 1988, at 9:00 A.M., Morgan Hall, State Land Office Building, Santa Fe, New Mexico, to enter their appearances and be prepared as follows:

(a) To declare their position on the issues set forth herein;

(b) Identify witnesses and substances of testimony and approximate length of time for direct presentation;

(c) Determine other issues that should be considered; and

(d) Raise any objection, amendment, or modification to proposed procedures.

Following the conclusion of the pre-hearing conference on May 19, 1988, the Commission will enter a statement of procedure binding all parties to the conduct of the June, 1988 hearing. A proposed statement of procedure is available at the Oil Conservation Division Office in Santa Fe.

CASE 9355: (Continued and Readvertised)

Application of Jack J. Grynberg to amend Commission Order No. R-6873, as amended, for simultaneous dedication and for an unorthodox gas well location, Chaves County, New Mexico. Applicant, in the above-styled cause, seeks the amendment of Commission Order No. R-6873, as amended, to: (1) allow for the drilling of a second well in the Foor Ranch-PrePermian Gas Pool to be drilled at an unorthodox gas well location 660 feet from the South and West lines (Unit M) of Section 18, Township 9 South, Range 27 East, on an established 320-acre, more or less, gas spacing and proration unit comprising the W/2 of said Section 18, which is presently dedicated to the Harvey E. Yates Company Seymour State Com Well No. 1 located at a standard gas well location in the SW/4 NW/4 (Unit E) of said Section 18; (2) declare the applicant to be the operator of the second well or, in the alternative, to be named the operator of said unit; and (3) establish a risk factor and overhead charges for the new well. Said unit is located approximately 8.75 miles south-southwest of Campbell's Switch.

New Mexico
Petroleum Recovery Research Center

A Division of
New Mexico Institute of Mining and Technology
Telephone (505) 835-5142

Socorro, NM 87801

May 19, 1988

Gavilan-West Puerto Chiquito Mancos Operators
New Mexico Oil Conservation Division Preliminary Hearing
Santa Fe, NM 87501

Gentlemen:

Enclosed are data collected during the 6/30/87 to 2/23/88 test period. Various calculations have been performed with the data to reach conclusions. Your review of the data, analytical methods, and your comments would be greatly appreciated. Please respond in a timely manner so that corrections can be made to this preliminary report prior to the June 13, 1988 Gavilan-West Puerto Chiquito Mancos hearing.

Sincerely,

Bill Weiss

William W. Weiss
Field Petroleum Engineer

WWW:jeg
enc.

Table 3

A REVIEW OF THE GAVILAN - WEST PUERTO CHIQUITO MANCOS RESERVOIR PERFORMANCE DURING THE PERIOD OF JULY, 1987 - FEBRUARY, 1988.

Background

The New Mexico OCD requested that operators of the two subject pools, Gavilan and West Puerto Chiquito, conduct pressure buildup tests on key wells. The purpose of the tests was to measure static pressures and reservoir characteristics when the quality of the data was sufficient to analyze. The commission also ordered a variation in well-producing rates via the allowables ruling. The variation in producing rates suggests that the reservoir may be rate-sensitive shown by the fact that lower GOR's were observed during periods of high production rates.

Included in the pressure study were wells Wildfire #1, High Adventure #1, Loddy #1, and Boyt & Lola #1, operated by Sun E&P; Bearcat #1 by Mesa Grande Resources; Howard Federal #43-15 by Reading and Bates; Hill Federal #2Y (later switched to Hill Federal #1) by Meridian; Johnson Federal 12#5 by Mallon; Lindrith B-#37 by Mobil, and Canada Ojita Unit (C.O.U.) wells E-6, B-32, A-20, and K-13 operated by BMG.

In addition to the thirteen wells requested by the commission, operators generously provided information from other wells which is incorporated in this review.

The two subject pools both produce from the Mancos Shale at a depth of about 6,200 to 7,800 feet. Production is from the "A", "B", and "C" zones in what is described as a tight naturally-fractured reservoir consisting of shaley siltstone and low-porosity, fine-grained sand. Some characteristics of the Mancos Reservoir are similar to the larger Spraberry Trend Field of West Texas which has been mentioned extensively in the literature.

Production from the Gavilan Pool is by primary means only, while the West Puerto Chiquito Pool has produced primary and secondary oil via a gas injection program during the past twenty years. The C.O.U. well E-10, alone has produced over 2,000,000 barrels of oil--strong evidence that gas injection is a successful secondary recovery process.

Static Pressures

Static pressures were measured on 6/30/87, 11/19/87, and 2/23/88 in the designated wells with all other pool wells shutin. Pressures which were obtained with a downhole bomb are illustrated in Figures 1-3. Notice in Figures 2 and 3 a small pressure decline during 11/19 -2/23 which indicates pressure support from C.O.U.

The method of arriving at the +370-ft pressure is outlined in Matthews and Russell's "Pressure Buildup and Flow Tests in Wells," Monograph Volume #1, pages 117 and 118, published by the SPE. Briefly, bomb pressure was corrected to the top of the "B" zone based on the tubing gradient. The pressure was then adjusted to a +370 ft datum based on the reservoir gradient. The reservoir gradient was determined from the volume-weighted, average fluid density from the Loddy #1 PVT data. The volume parameters were the gas- and oil-producing rates prior to the test, corrected to reservoir conditions. The work sheets are included in the appendix.

Examination of the pressure data illustrates the presence of a pressure gradient from east to west across the pools--the exception being the undeveloped east side of Gavilan. Pressure gradients of this nature are not uncommon in gas injection projects. For example, the isobaric lines shown in Figure 4 are taken from a CO_2 flood located in North Texas. The well density is 80 acres in this tight, heterogeneous carbonate reservoir, and the production response shown in Figure 5 clearly demonstrates that the reservoir is contiguous, even with a 300-psi pressure drop across the 80 acres. The same is true of the Gavilan-West Puerto Chiquito Pools.

Figure 6 illustrates the directional dependency of the pressure gradients resulting from gas injection in West Puerto Chiquito. Notice that the pressure drop per 1000-ft is about a factor of 10 larger in the east-west direction than in the north-south direction.

Pressure Buildup Tests

Transmissibility, kh/μ, and flow capacity, kh, were calculated from the transient buildup data whenever the data permitted. Since the GOR's were above those of solution gas, the analytical method used to find reservoir parameters included converting gas and oil flow rates to one reservoir flow rate. Formation volume factors and fluid viscosities were arrived at by volume averaging the Loddy #1 PVT data in a manner similar to that used to find reservoir fluid density.

The technique used to analyze most of the transient data consisted of using Agarwal time, T x dt/T + dt, as the time parameter to eliminate short, producing-time effects, and plotting the pressure difference vs. time on logarithmic paper along with the first derivative of the pressure difference curve in order to find the proper semi-log straight line. Most of the buildups had storage and skin effects, which were identified by a unit slope on the logarithmic plots. The middle-time (MTR) straight line began at about 50 times the end of the unit slope line. The first derivative plot confirms the unit-slope-line rule. The C.O.U well analyses were complicated by the presence of a constant pressure boundary caused by gas injection. In an effort to maintain consistency with the Gavilan analyses, the pseudo-steady state (MTR) straight line was used in all analyses. The single exception was the November data from the B-37 well which fit a dual porosity model very nicely and was so analyzed. Work sheets are included in the appendix.

Table I summarizes the analyses of the pressure buildup data. The transmissibility and capacity are mapped on Figures 7 and 8, respectively.

As mentioned earlier, the 11/19/87 buildup data from the B-37 well was of sufficient quality, and free of boundary effects, that the dual porosity analytic model described by Raghaven in the December, 1983 JPT could be applied. Using the analytical techniques presented in Raghaven's article, "New Pressure Transient Analysis Methods for Naturally Fractured Reservoirs," produced the following results:

Fracture capacity, $k_f h_f$	=	1,477 md-ft
Matrix capacity, $k_m h_m$	=	9.16 md-ft
Transfer coefficient λ'	=	1.27×10^{-7}
Fracture Storativity, $\phi_f C_f h_f$	=	1.106×10^{-5}
Dimensionless matrix storativity, ω'	=	27 (about 4% of total porosity is in the fracture system)

These results support Mobil's observation that the reservoir is a dual porosity system.

Interference Tests

BMG recorded bottomhole pressures at various observation wells while stimulating seven Canada Ojitos Unit wells. The pressure pulse generated by the hydraulic fracture treatment was recorded as a deviation from the pressure trend as seen on the attached curves included in the appendix. The pressure differential resulting from the frac job was analyzed with a type curve from Ramey's "A Drawdown and Buildup Type Curve for Interference Testing," and Kamal's "Well Interference and Pulse Tests" analytical method.

Problems with determining the proper formation volume factors, viscosities, and compressibilities, all of which are saturation dependent, were encountered. Accepting the problems in estimating saturations the Kamal method results are illustrated in Figure 9 as capacity, kh, in Darcy feet and as storage ϕh, in Figure 10. Again, the N-S major permeability trend is evident. The Ramey-type curve gave similar results but was considered more subjective than Kamel's analytical method.

Frac pulse response of F-7 at E-6 and D-17 was analyzed using the well-known method introduced by Ramey to determine direction and magnitude of the permeability trend in an anisotropic reservoir. The major trend is 33,600 md-ft north with a 370 md-ft trend normal to the major axis. The results include an estimate for $\phi \mu c_t$ of 3.5 x 10^{-7} which was observed in the frac pulse test analyses and the B-37 buildup. The results are illustrated on Figure 11 and detailed in the appendix.

The interference test data supported by static pressure measurements indicate that the permeability is much greater in the N-S direction than in the E-W direction. Similar differences in major and minor permeabilities were reported by Elkins and Skov in their "Determination of Fracture Orientation from Pressure Interference." Their data concerning the Spraberry Trend is summarized in Figure 12.

Rate Sensitivity

During the 6/30/87 to 2/23/88 test period, a GOR vs. BOPD trend developed which indicated increased recovery efficiency at high production rates. A total of 87 wells were monitored. The GOR's were based on monthly averages except where producing time was less than three months, then daily rates were utilized.

Logarithmic plots of rate vs. GOR were made for the 87 wells. A total of the 46 wells had a goodness of fit to a logarithmic straight line of 85% or better. Only one well had a positive slope indicating poor recovery efficiency at high rates, the remaining wells indicate increased recovery efficiency at high rates. The wells with their correlation coefficients are tabulated in Table II. All wells are included in the appendix.

Explanations for the favorable rate sensitivity vary. Three possibilities are:

1. Counter-current gas flow with the formation of a secondary gas cap displacing oil downward.

2. Formation of a large pressure difference between the fractures and the matrix enhancing the transfer of oil to the fracture system.

3. Formation of an unusually large number of gas bubbles in oils subject to rapid pressure decline which in turn reduces the oil saturation.

The concept of the formation of gas bubbles with resulting reduced oil saturation was proposed 25 years ago by Amoco in a paper titled "The Role of Bubble Formation in Oil Recovery by Solution Gas Drives in Limestones," which followed a paper by Kennedy and Olsen on the same subject. Since then, little has been done to advance the concept.

Increasing the pressure difference between the fractures and the matrix was suggested by Elkins as a means of improving recovery efficiency in the Spraberry Trend. If this was applied in the field, the results were not well documented in the literature. The concept does have merit in the Mancos where the surface area available for flow from the very tight matrix is largely due to the fracture system.

Normally, rate-sensitivity is associated with a displacement process and is readily described with the fractional flow equation:

$$f_g = \frac{1 - \dfrac{4.9 \times 10^{-4}\, k\, k_{ro}\, A\, (\Delta\rho) \sin\Theta}{q_t\, \mu_o}}{1 + \dfrac{kro}{krg}\,\dfrac{\mu g}{\mu o}}$$

Dake eq 10.21
Page 359

With the formation of a secondary gas cap, oil is displaced downward and the sin(-90°) becomes a minus one which allows the fraction of gas flowing, f_g, to decrease as the total rate, q_t, increases.

This equation was applied to well B-37 utilizing the parameters derived from the November pressure buildup test, 320 acres drainage, relative permeability ratios from Slider's textbook, curve #16 on page 456 which is for large fractures connected together, and Loddy #1 PVT data. Figures 13-16 depict the theoretical match to the actual data obtained, utilizing only the fractional flow equation. The trend of the theoretical curve is similar to the production trend in the B-37, E-6, and Johnson-Federal 12#5 wells; however, the Bearcat #1 does not follow suit.

The match of the theoretical to the actual shown on Figure 17 for the B-37 well was obtained by reducing the permeability-area product in the fractional flow equation from 8.75 x 10^7 md-ft^2 to 8.75 x 10^5 md-ft^2 suggesting the secondary gas cap is not continuous throughout the 320 acre drainage area.

The permeability calculated from the well B-37 buildup test was used to match the producing f_g trend in the critical rate, q_{crt}, equation

$$q_{crt} = \frac{4.9 \times 10^{-4}\, kk_{rg}\, A\, \Delta\gamma \sin\Theta}{\mu_g\ (M-1)}$$

results in a 50 STB/D critical flow rate.

Counter to the production data supporting the improvement in the recovery efficiency, is recovery efficiency as a function of pressure drop. During the period of high-production rates, the recovery efficiency averaged 98 barrels/psi for the nine wells illustrated in Figure 18. However, during the low production rate period, illustrated in Figure 19, the recovery efficiency increased to 136 barrels/psi. Results are tabulated in Table III.

This dichotomy can be explained by pressure support external to the individual well-drainage areas. Notice that the Bearcat #1 and Howard-Federal #43-15 demonstrate little variation in recovery efficiency as a function of pressure drop since they do not have external pressure support. However, wells E-6, A-20, and B-32 show improvement during the period of low production rates when gas injection was able to support withdrawals. In fact, pressure did not drop at B-32 during the low rate period, yet the well produced 42,200 barrels of oil during this period.

In a similar manner, the B-37, Loddy #1, and High Adventure #1 enjoyed external pressure support, apparently from outside the pool boundaries.

Conclusions

The Gavilan-West Puerto Chiquito Mancos Pools appear to be a common reservoir. It is clear that the reservoir fracture system is sufficient to allow fluid migration across pool boundaries.

The anisotropic nature of the reservoir should be further defined in order to investigate a secondary recovery process. Production rates in a secondary mode would be dependent on balancing injection and production rates rather than the poorly understood, currently postulated producing mechanisms.

It is worth noting that the Spraberry Trend Field has produced over a billion barrels of oil with about 25% of it as a result of primary recovery.

Table I

Transient Test Results

Well	Test Date	$\frac{kh}{\mu}$ md-ft/cp	kh md-ft	k_oh md-ft	k_gh md-ft
E-6	11/19/87	18,320	1,523	1,290	232
B-32	11/19/87	21,700	5,123	4,925	196
Fisher Federal #2-1	2/23/88	5,710	231	154	76
Johnson Federal 12#5	11/19/88	3,110	131	88	44
Hill Federal 2Y	6/30/87	1,240	141	126	15
Hill Federal #1	11/19/87	7,020	117	12.3	98
Bearcat #1	6/30/87	2,500	165	133	32
Lindrith B-37	11/19/87	19,020	1,477	1,242	235
Howard Federal 43-15	11/19/87	3,690	65	14.2	50.5
High Adventure #1	11/19/87	11,150	1,126	992	134
Loddy #1	11/19/87	2,085	140	113	27

TABLE II.

Gavilan Dome
Rate Sensitivity Correlation Coefficients

Operator	Well Name	c.c.	Slope
AMOCO	SCC	1.00	NEG
M.G.	PRO#2	1.00	NEG
B.M.G.	L-11	1.00	NEG
B.M.G.	J-6	1.00	NEG
MALLON	JF 12#5	1.00	NEG
MERIDIAN	HF 3	1.00	NEG
MERIDIAN	HF #1	0.99	NEG
SUN	JA A2	0.99	NEG
SUN	NS 2	0.98	NEG
M.G.	BC#1	0.98	NEG
M.G.	RL#3	0.98	NEG
MOBIL	B 37	0.98	NEG
SUN	FS A2	0.97	NEG
MALLON	RF 2#16	0.97	NEG
MERIDIAN	HF 2Y	0.97	NEG
MALLON	HF 1#11	0.97	NEG
MERRION	KRY 1	0.96	NEG
M.G.	HC #1	0.96	NEG
MERIDIAN	HAF 2	0.96	NEG
SUN	DRDO 1	0.96	NEG
B.M.G.	E-10	0.96	NEG
SUN	HR 1	0.95	NEG
SUN	NS 1	0.95	NEG
MOBIL	B 73	0.95	NEG
SUN	ET 1	0.93	NEG
SUN	LOD 1	0.93	NEG
M.G.	GH#1	0.92	NEG
M.G.	MAR#1	0.92	NEG
B.M.G.	N-31	0.92	NEG
MERIDIAN	HAF 3	0.92	NEG
M.G.	INV#1	0.91	NEG
SUN	FT E1	0.91	NEG
MALLON	FF 2#1	0.90	NEG
M.G.	GAV #3	0.90	NEG
B.M.G.	A-20	0.90	POS
MALLON	PF 13#6	0.89	NEG
B.M.G.	E-6	0.89	NEG
SUN	BL 2	0.89	NEG
SUN	FT 1	0.88	NEG
MOBIL	B 34	0.88	NEG
SUN	ML 2	0.87	NEG
B.M.G.	F-19	0.87	NEG
SUN	NS 3	0.86	NEG
MOBIL	B 38	0.86	NEG
MOBIL	B 74	0.86	NEG
MALLON	DF 3#15	0.85	NEG

Of the sample
with c.c. > .85

Negative Slopes	
ammount	percentage
45	97.83%

Positive Slopes	
ammount	percentage
1	2.17%

85% Correlation Coefficient Cut Off Point

TABLE II.

Gavilan Dome
Rate Sensitivity Correlation Coefficients

Operator	Well Name	c.c.	Slope
B.M.G.	C-34	0.84	POS
SUN	LL 1	0.80	NEG
SUN	GG 1	0.80	NEG
R&B	IN 34-16	0.79	NEG
B.M.G.	O-9	0.76	NEG
B.M.G.	B-29	0.76	POS
R&B	HF 43-15	0.76	NEG
DUGAN	LIND 1	0.75	NEG
M.G.	RL#2	0.73	NEG
SUN	HA 2	0.71	NEG
B.M.G.	L-3	0.68	NEG
B.M.G.	F-30	0.66	NEG
SUN	JA B3	0.66	NEG
SUN	NH 1	0.65	NEG
SUN	WW 1	0.62	NEG
B.M.G.	F-18	0.58	NEG
M.G.	BRO#1	0.54	NEG
SUN	HA 1	0.52	NEG
B.M.G.	D-17	0.52	NEG
MOBIL	B 72	0.49	NEG
SUN	FS B3	0.48	NEG
SUN	FS 1	0.46	NEG
SUN	BB 1	0.44	NEG
B.M.G.	L-27	0.43	NEG
B.M.G.	O-33	0.43	NEG
B.M.G.	B-32	0.36	POS
AMOCO	SGC 1	0.35	NEG
M.G.	GAV #1	0.32	POS
AMOCO	BCU 2	0.31	NEG
MALLON	HF 1#8	0.31	NEG
SUN	JA 1	0.29	NEG
B.M.G.	K-8	0.20	NEG
B.M.G.	F-7	0.18	POS
B.M.G.	N-22	0.17	POS
B.M.G.	A-16	0.16	NEG
MERRION	OCG 1	0.15	POS
B.M.G.	G-5	0.13	POS
SUN	ML 1	0.08	POS
HIXON	DIV 3	0.06	NEG
B.M.G.	G-32	0.05	NEG
HIXON	TAP 4	0.01	POS

TABLE III.

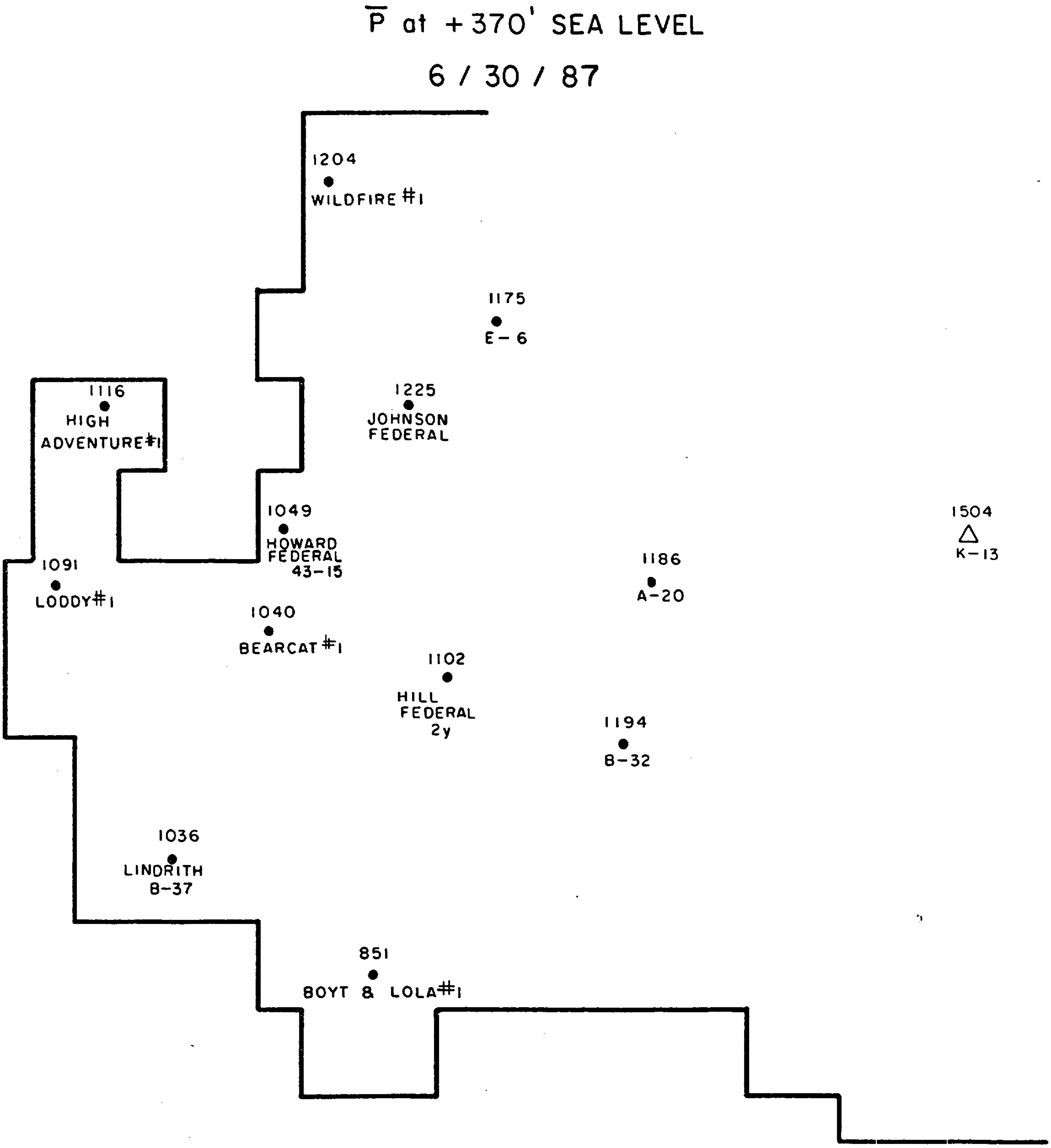
Gavilan Dome, Recovery Efficiency
Barrel per PSI Pressure Drop

6/30-11/19

Operator	Well Name	dP psia	Cum Oil bbl	Cum/dP bbl/psia
B.M.G.	E-6	208	41118	198
B.M.G.	A-20	217	2443	11
B.M.G.	B-32	237	83828	354
M.G.	Bearcat #1	271	2929	11
Mobil	Lind B 37	270	26385	98
R & B	HF 43-15	261	1020	4
Sun	High Adventure #1	291	24002	82
Sun	Loddy #1	230	7296	32

11/19-2/23

Operator	Well Name	dP psia	Cum Oil bbl	Cum/dP bbl/psia
B.M.G.	E-6	16	4424	277
B.M.G.	A-20	19	2400	126
B.M.G.	E-10	-12	2317	-193
B.M.G.	B-32	0	42177	1000+
Merridian	Hill Federal #1	4	453	113
M.G.	Bearcat #1	33	531	16
Mobil	Lind B 37	36	13011	361
R & B	HF 43-15	37	393	11
Sun	High Adventure #1	54	14052	260
Sun	Loddy #1	53	3318	63



$\overline{P}$ at +370' SEA LEVEL
6 / 30 / 87
1204
WILDFIRE #1
1175
E-6
1116
HIGH
ADVENTURE #1
1225
JOHNSON
FEDERAL
1049
HOWARD
FEDERAL
43-15
1504
K-13
1091
LODDY #1
1186
A-20
1040
BEARCAT #1
1102
HILL
FEDERAL
2y
1194
B-32
1036
LINDRITH
B-37
851
BOYT & LOLA #1

Figure 1

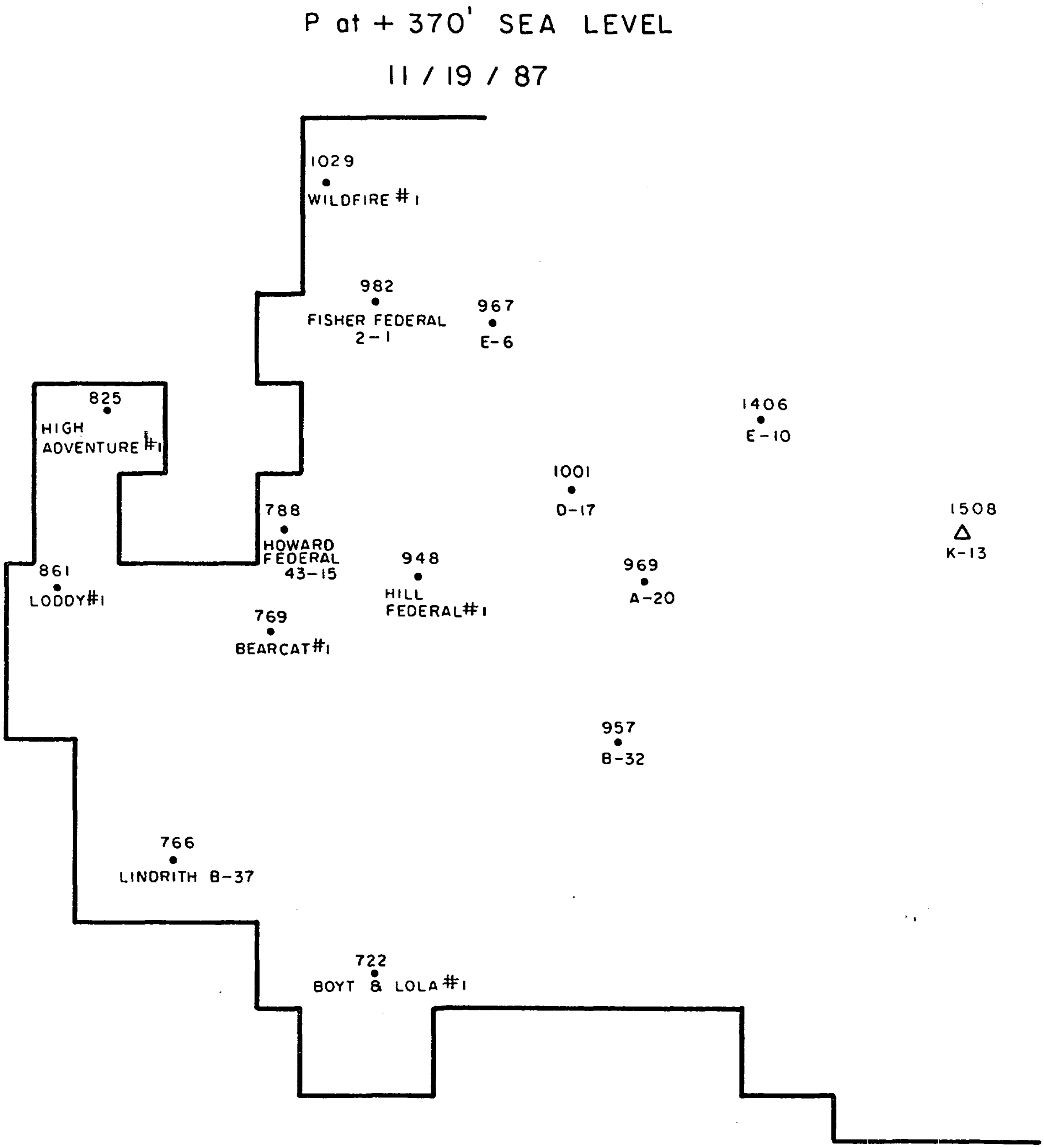

P at + 370' SEA LEVEL
11 / 19 / 87
1029
WILDFIRE #1
982
FISHER FEDERAL
2-1
967
E-6
825
HIGH
ADVENTURE #1
1406
E-10
1001
D-17
1508
K-13
788
HOWARD
FEDERAL
43-15
861
LODDY #1
948
HILL
FEDERAL #1
969
A-20
769
BEARCAT #1
957
B-32
766
LINDRITH B-37
722
BOYT & LOLA #1

Figure 2

$\overline{P}$ at +370' SEA LEVEL 2/23/88

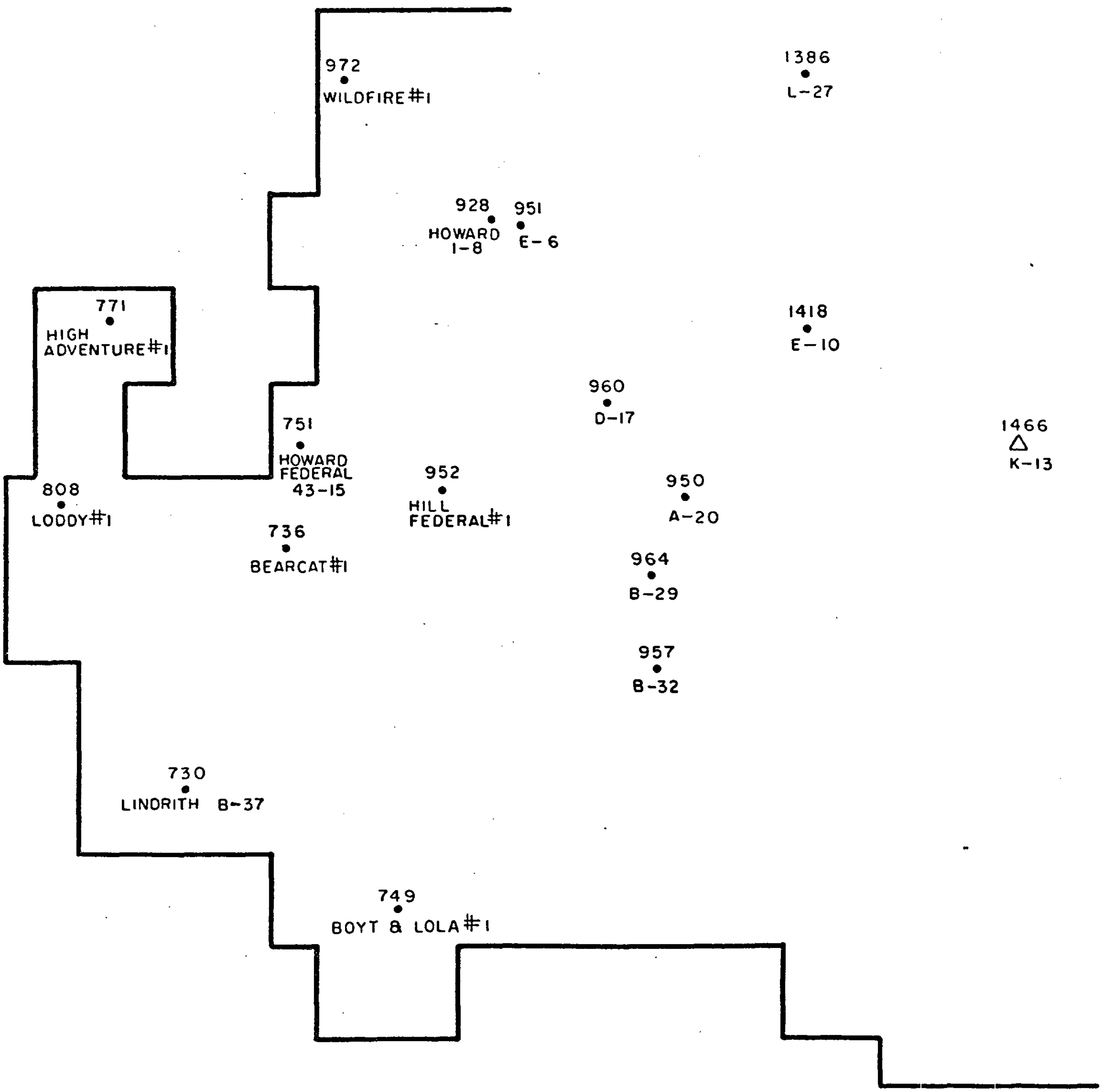


Figure 3

CO_2 FLOOD ISOBARS

SPE / DOE 17327

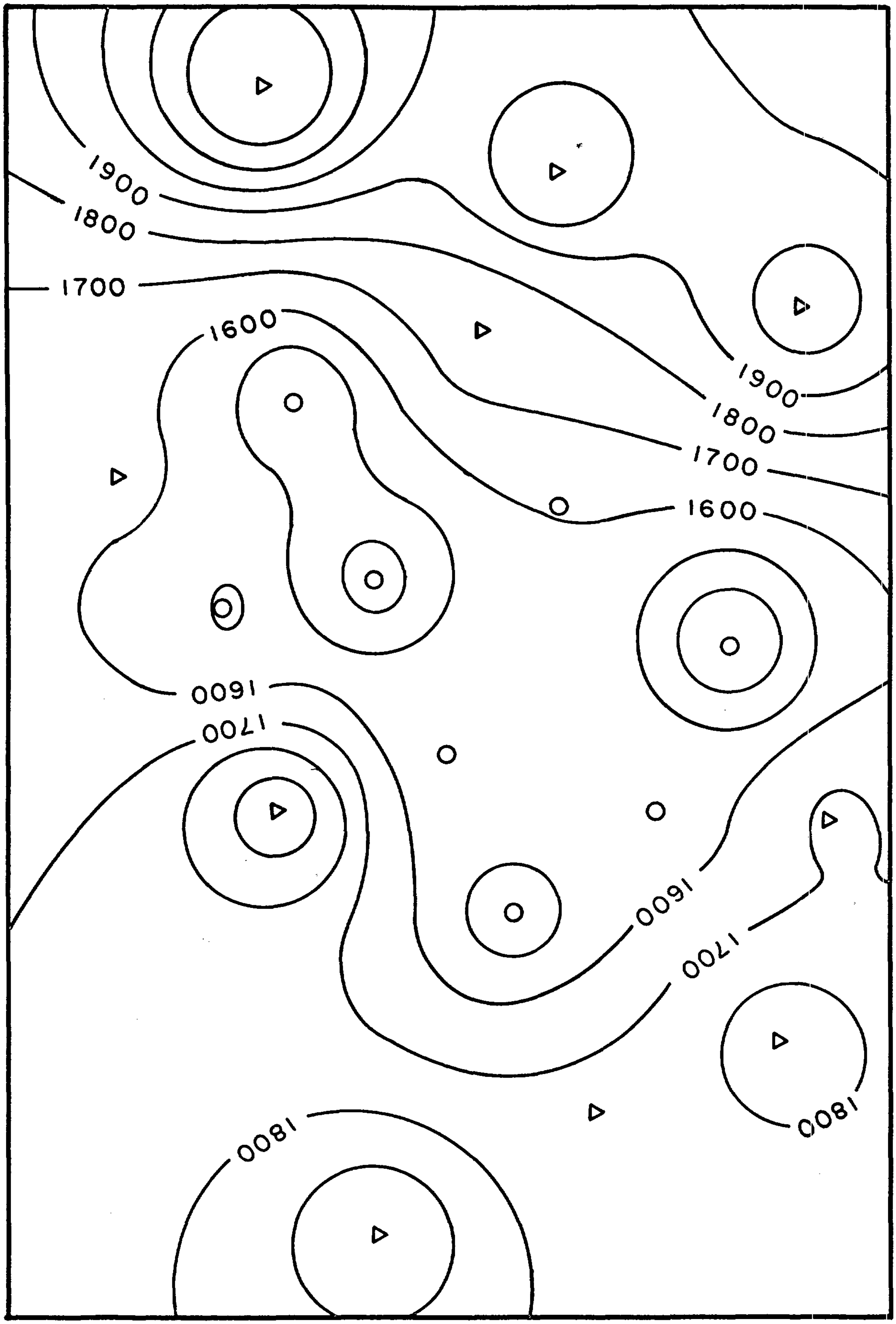
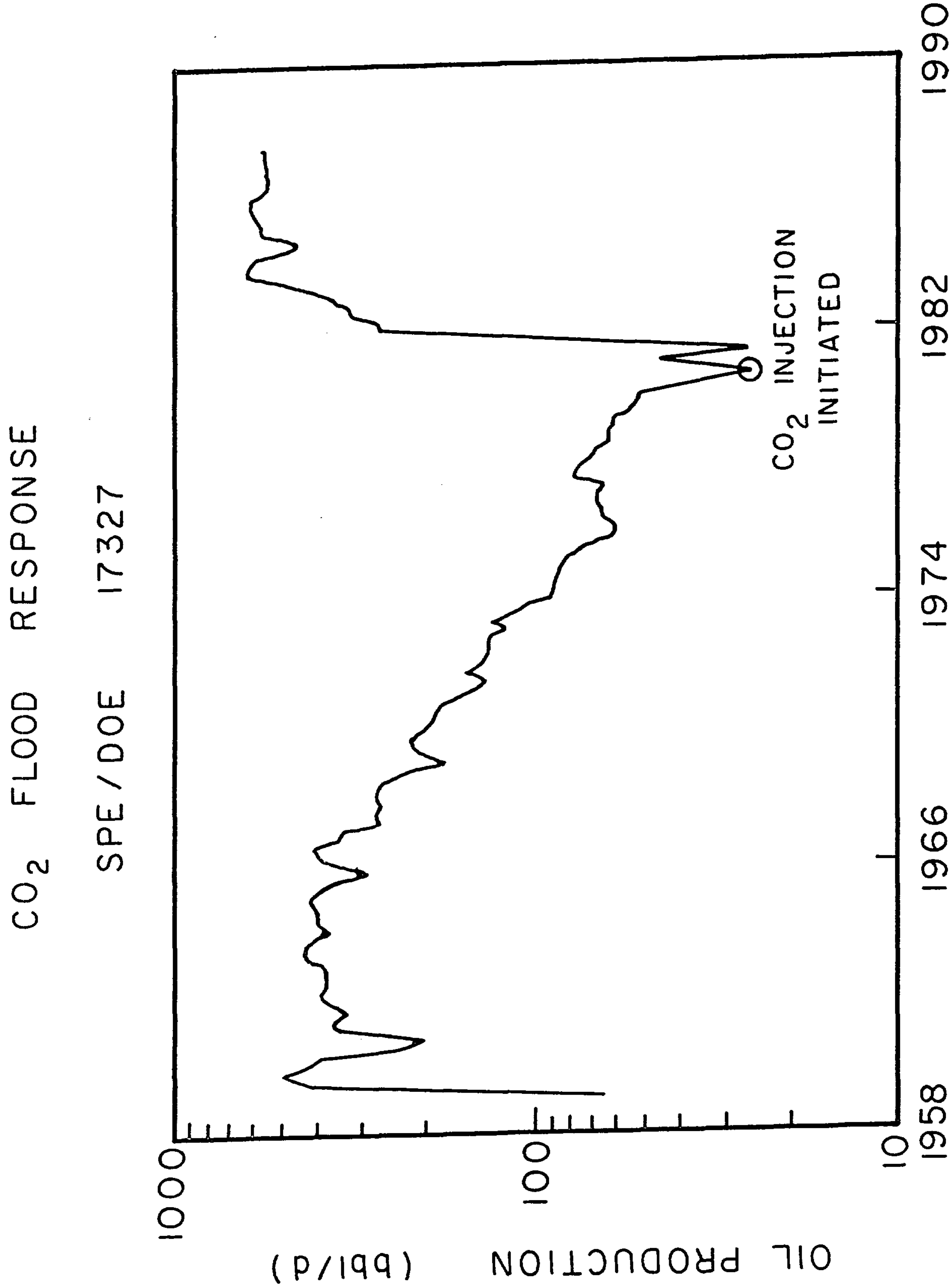


Figure 4



CO_2 FLOOD RESPONSE
SPE/DOE 17327
CO_2 INJECTION INITIATED
OIL PRODUCTION (bbl/d)
1000
100
10
1958
1966
1974
1982
1990

Figure 5

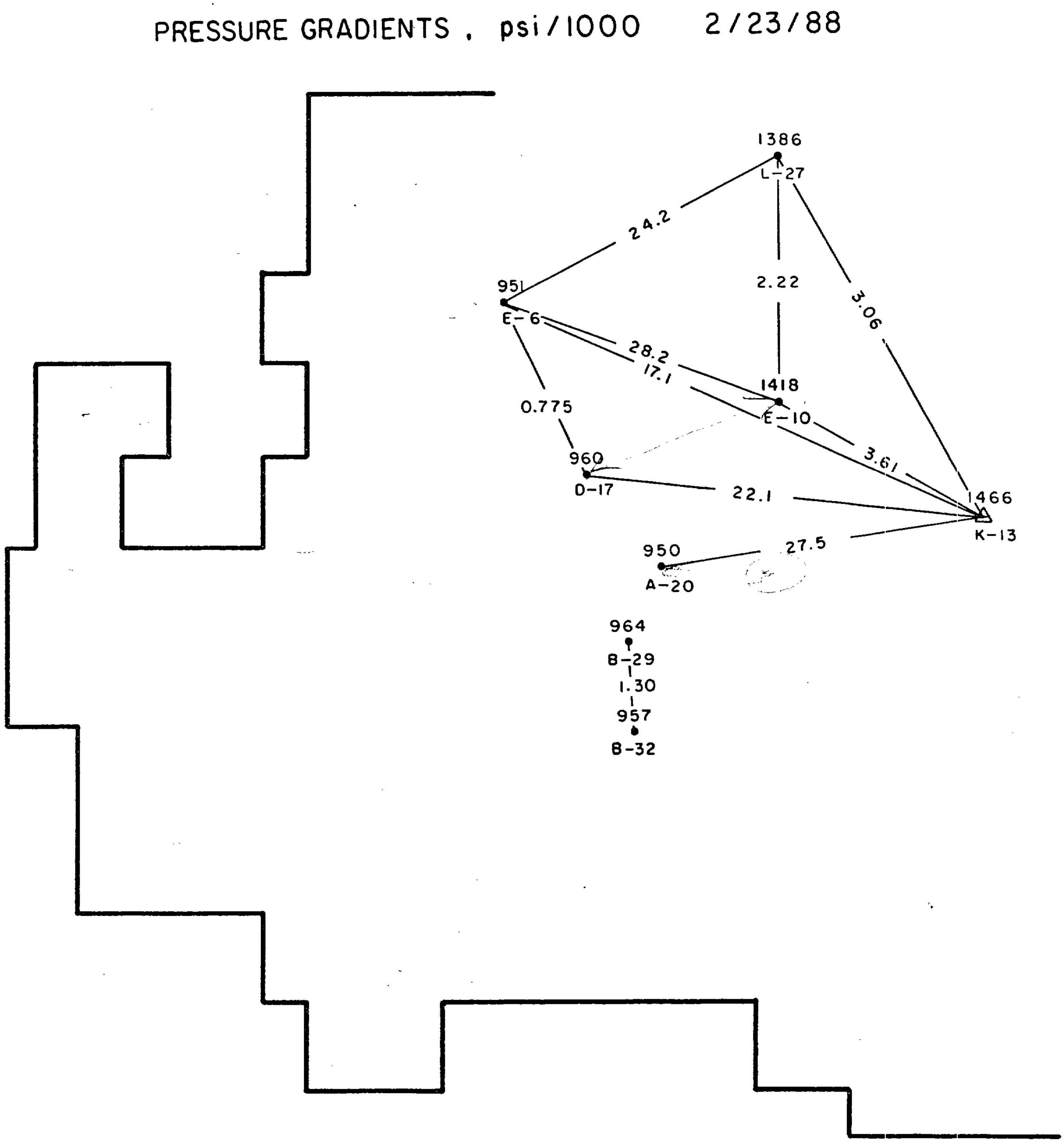

PRESSURE GRADIENTS , psi/1000 2/23/88
1386
L-27
24.2
2.22
3.06
951
E-6
28.2
17.1
1418
E-10
0.775
3.61
960
D-17
22.1
1466
K-13
950
A-20
27.5
964
B-29
1.30
957
B-32

Figure 6

TRANSMISSABILITY $\frac{Kh}{\mu}$, $\frac{md \cdot ft}{cp}$ FROM BUILDUPS

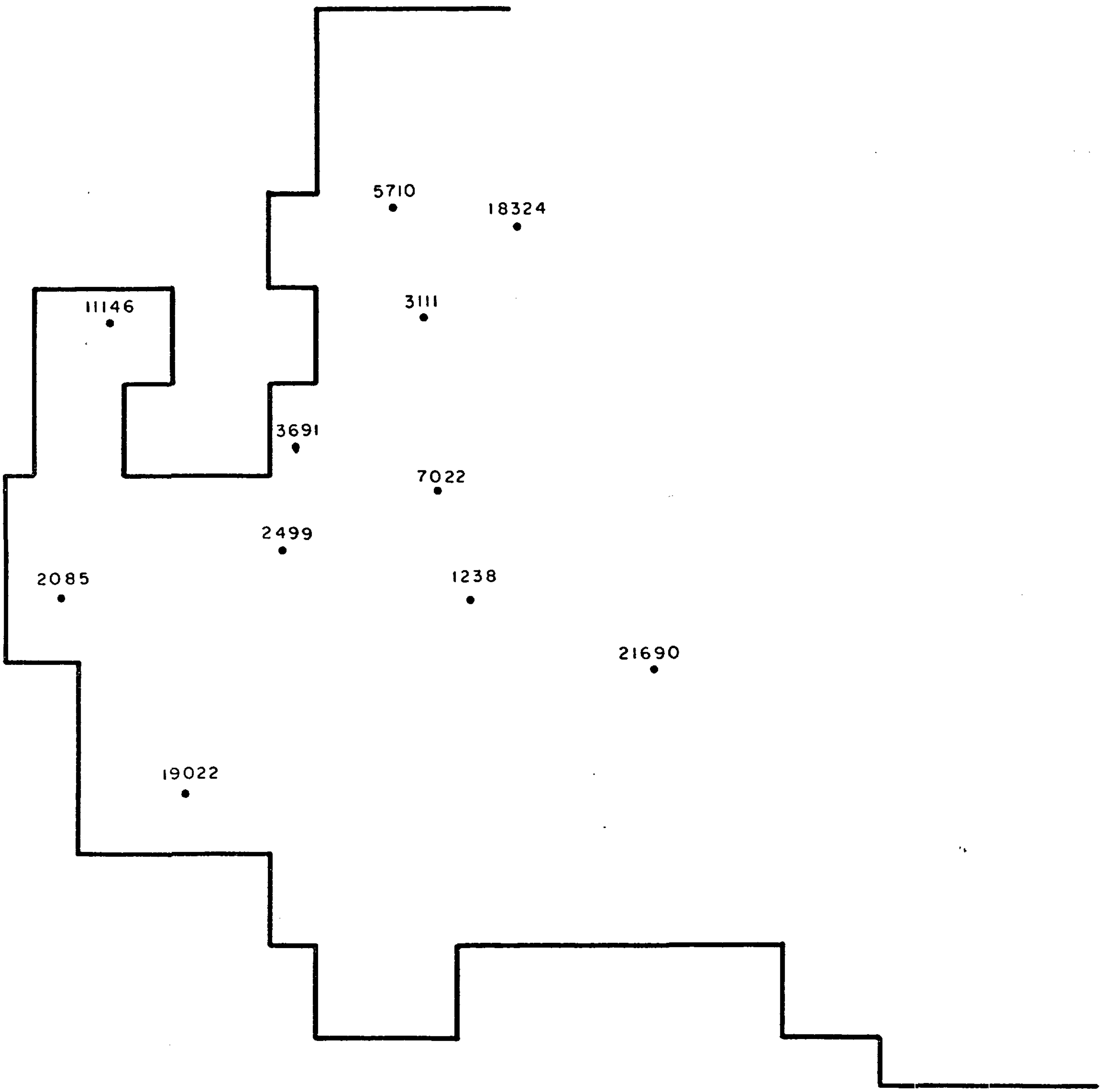


Figure 7

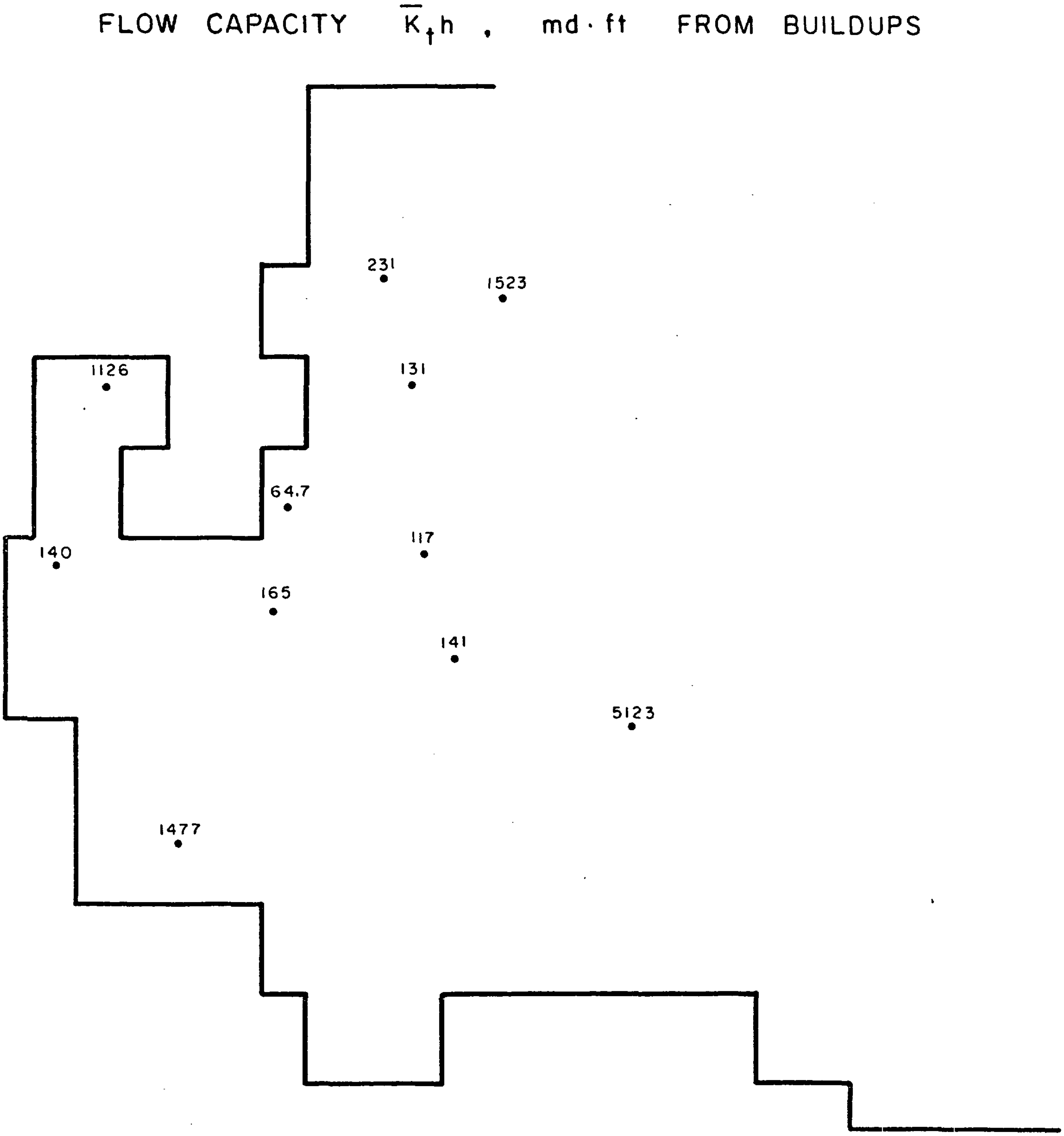

FLOW CAPACITY $\overline{K}_t h$, md·ft FROM BUILDUPS
231
1523
1126
131
64.7
117
140
165
141
5123
1477

Figure 8

Kh (Darcy - ft)

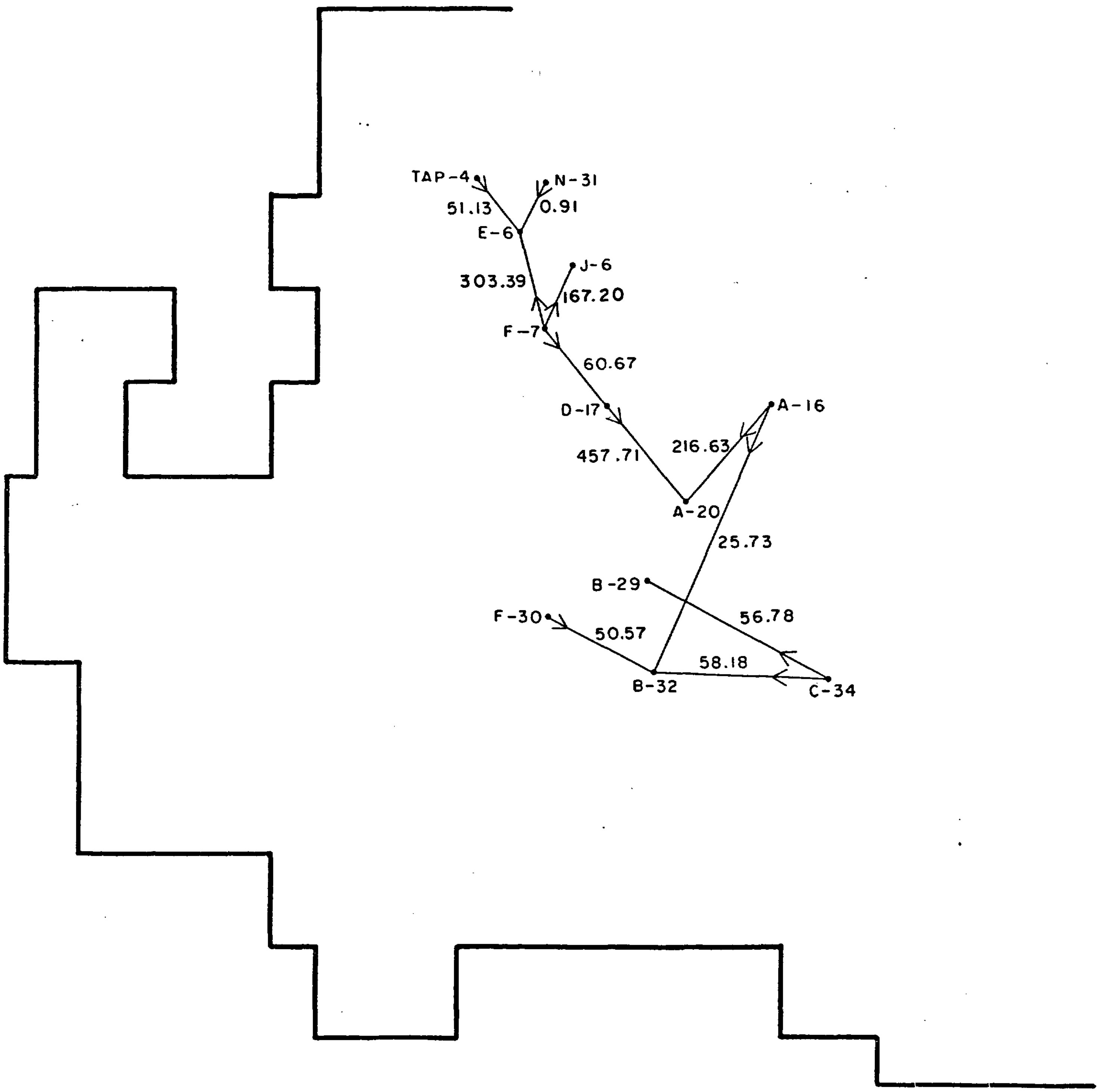


Figure 9

Φh (Fraction-ft)

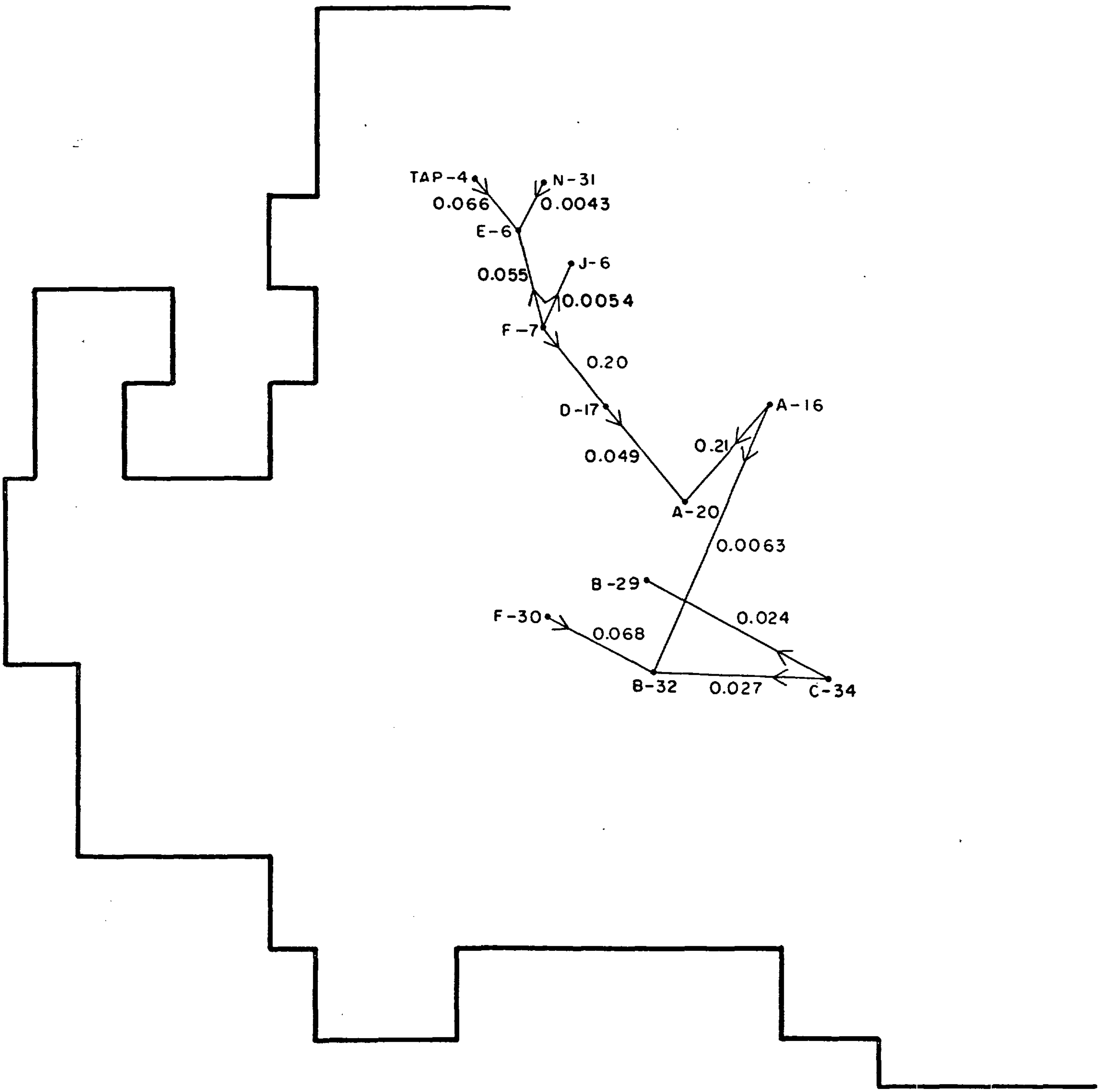


Figure 10

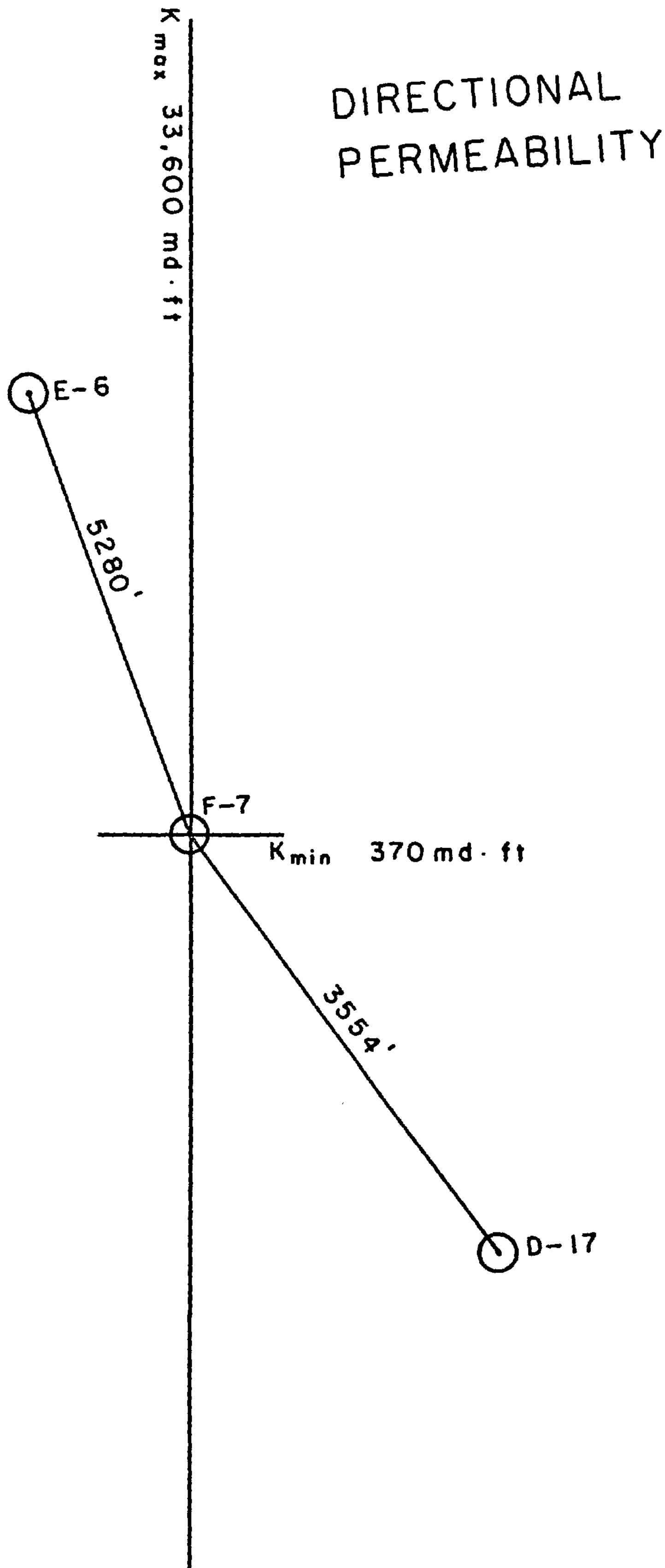

DIRECTIONAL
PERMEABILITY
K max 33,600 md·ft
E-6
5280'
F-7
K min 370 md·ft
3554'
D-17

Figure 11

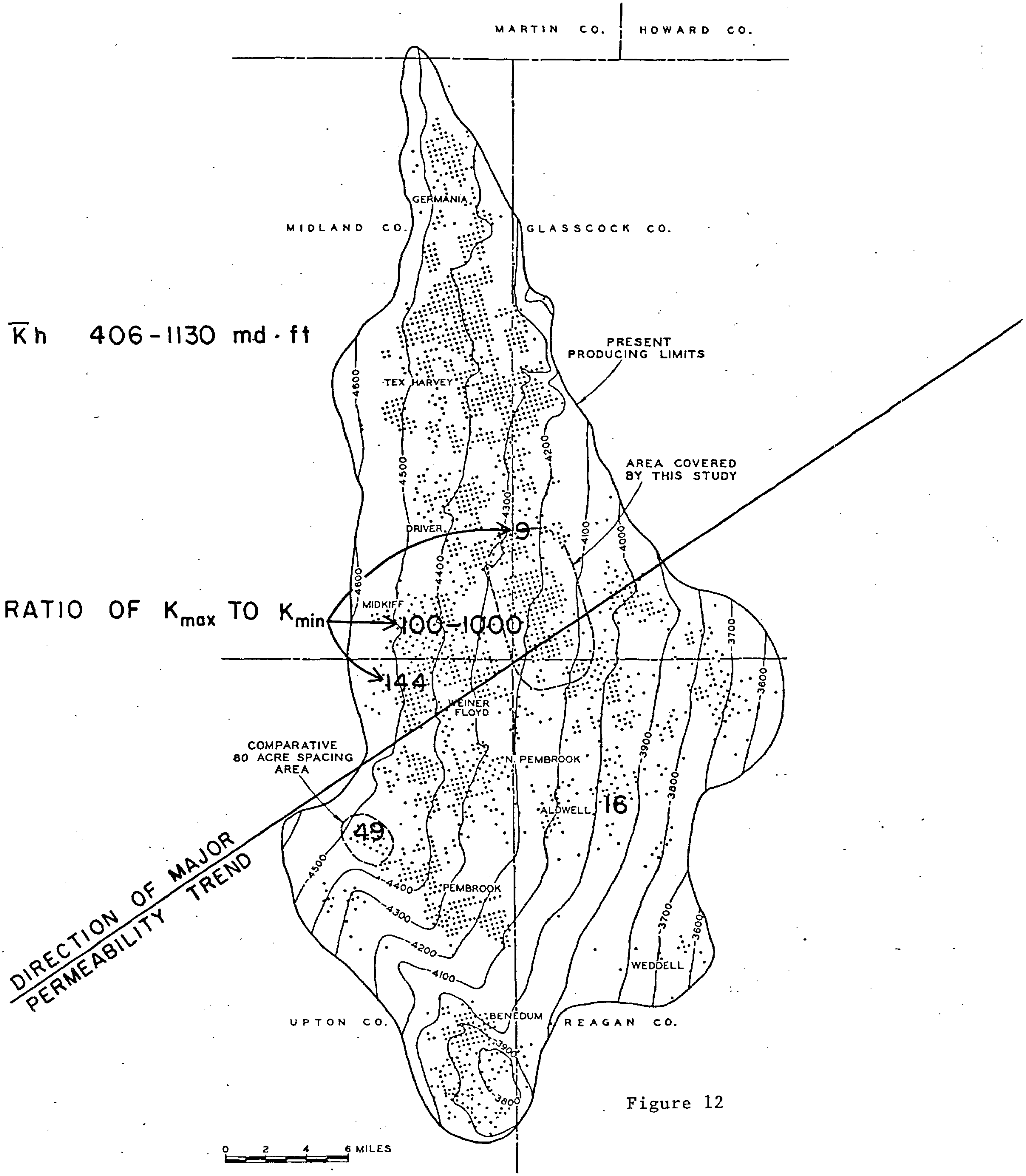


FIG. 1 — SPRABERRY TREND FIELD, CONTOURS ON TOP OF SPRABERRY FORMATION.

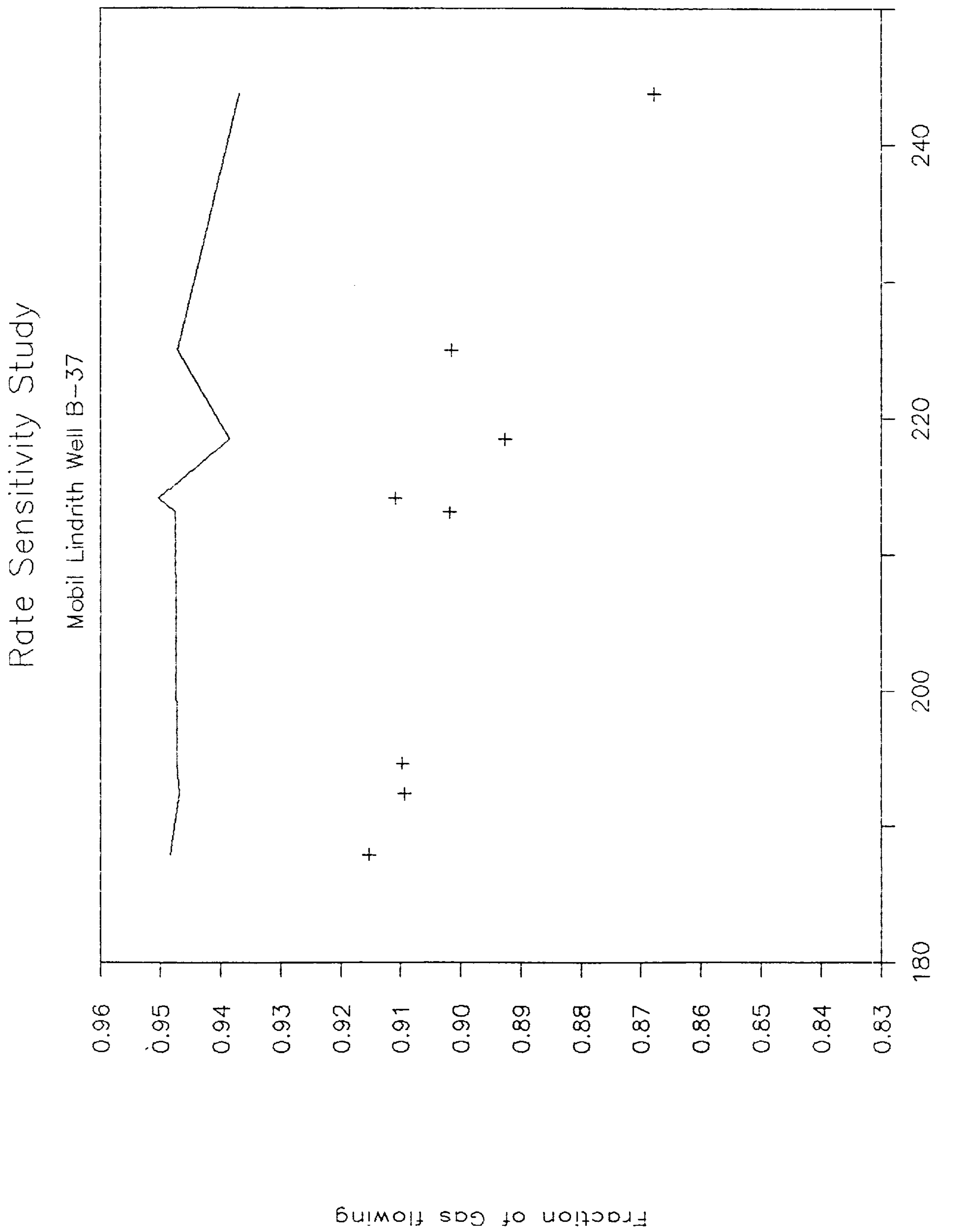

Rate Sensitivity Study
Mobil Lindrith Well B-37
Fraction of Gas flowing
0.96
0.95
0.94
0.93
0.92
0.91
0.90
0.89
0.88
0.87
0.86
0.85
0.84
0.83
180
200
220
240
Rate, BOPD
Theoretical
+ Actual

Figure 13.

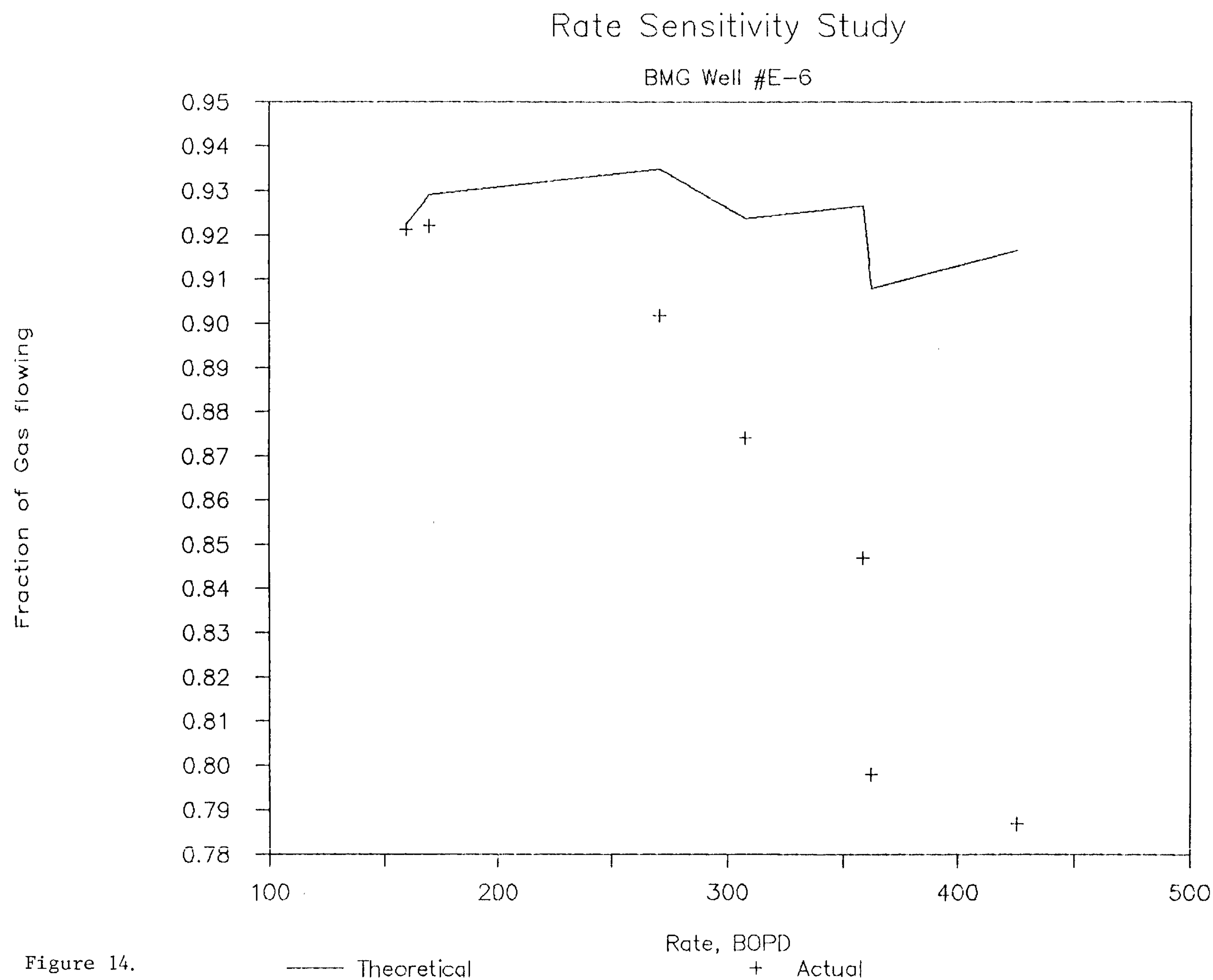
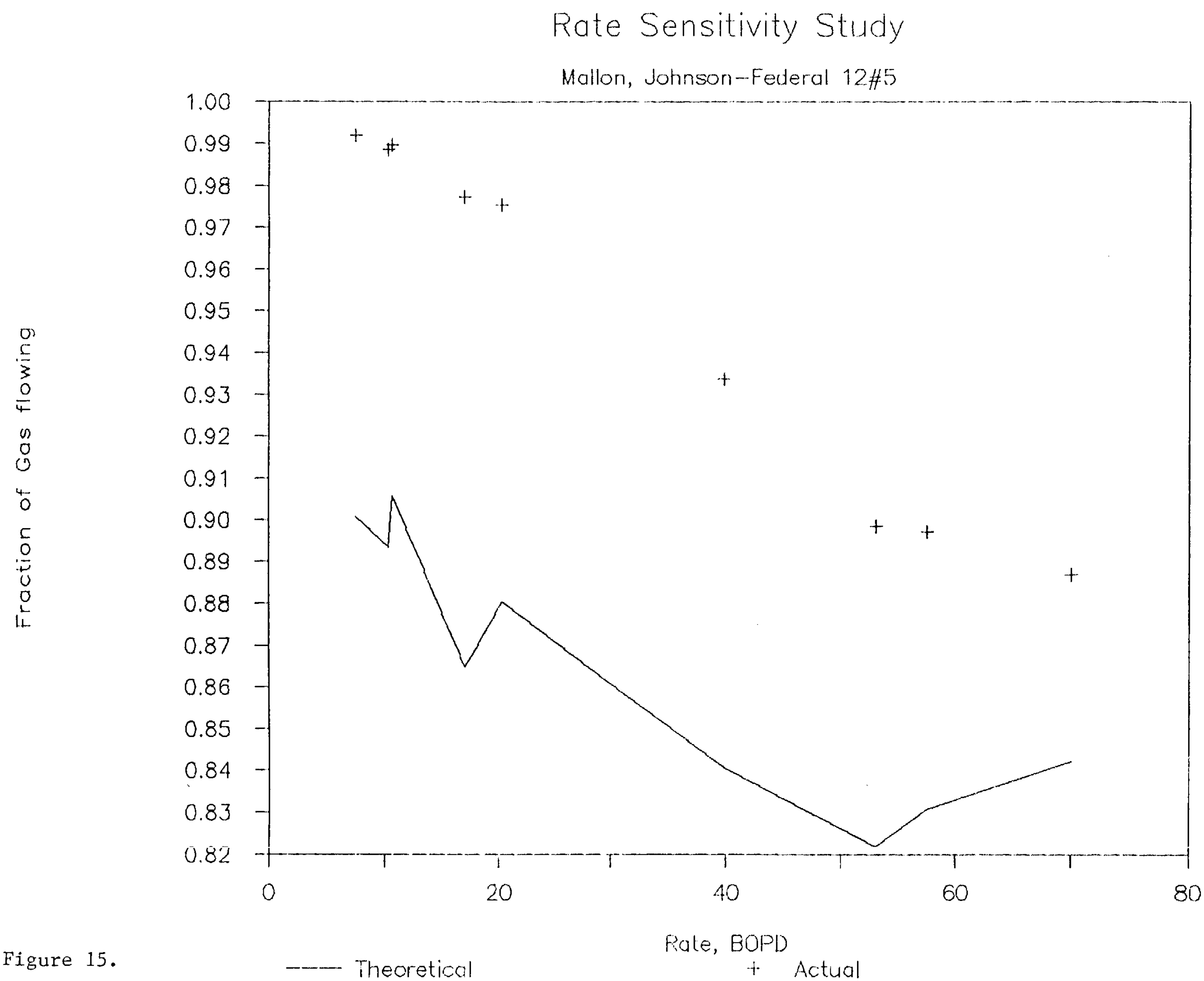
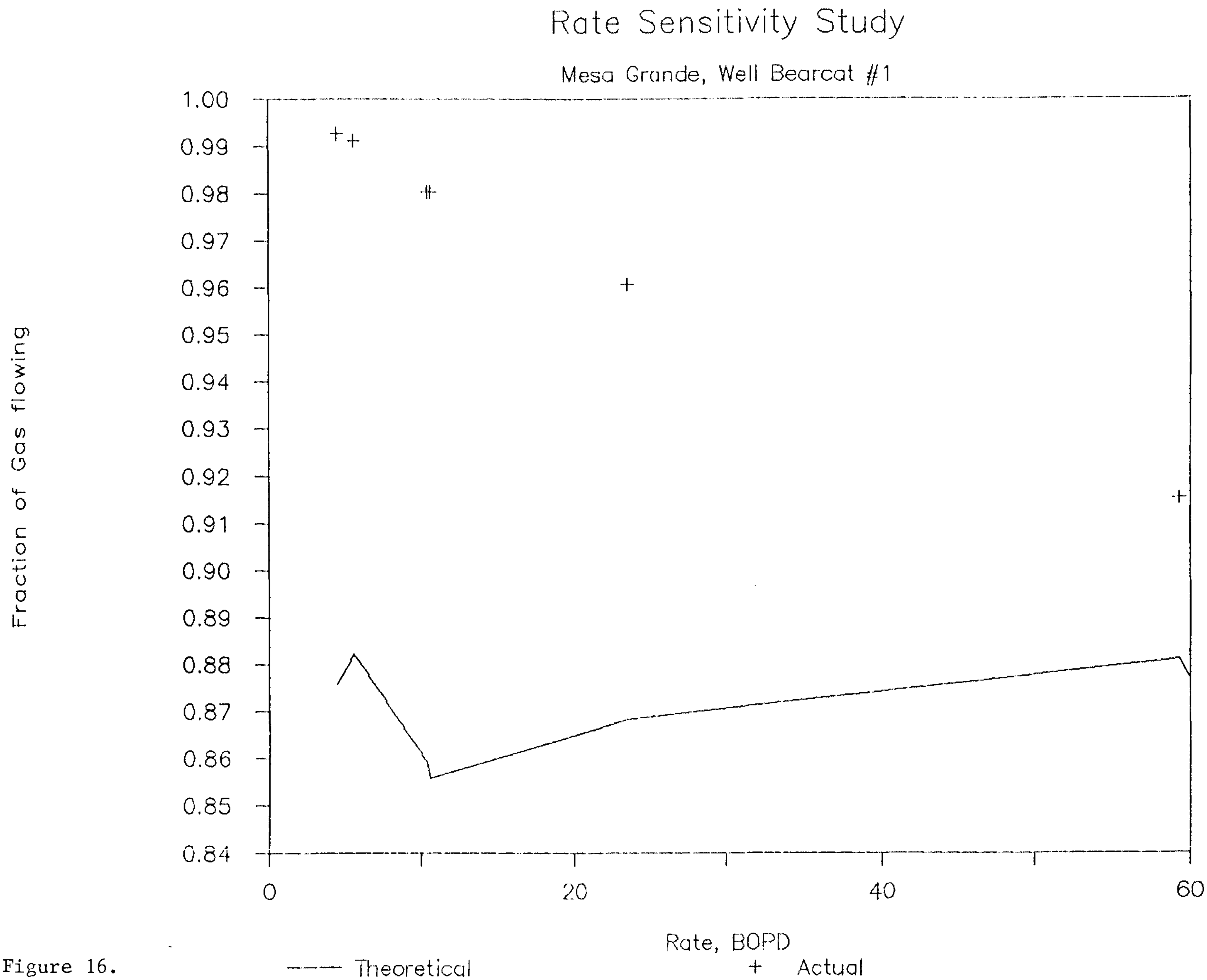

Rate Sensitivity Study
BMG Well #E-6
Fraction of Gas flowing
0.95
0.94
0.93
0.92
0.91
0.90
0.89
0.88
0.87
0.86
0.85
0.84
0.83
0.82
0.81
0.80
0.79
0.78
100
200
300
400
500
Rate, BOPD
Theoretical
+ Actual

Figure 14.



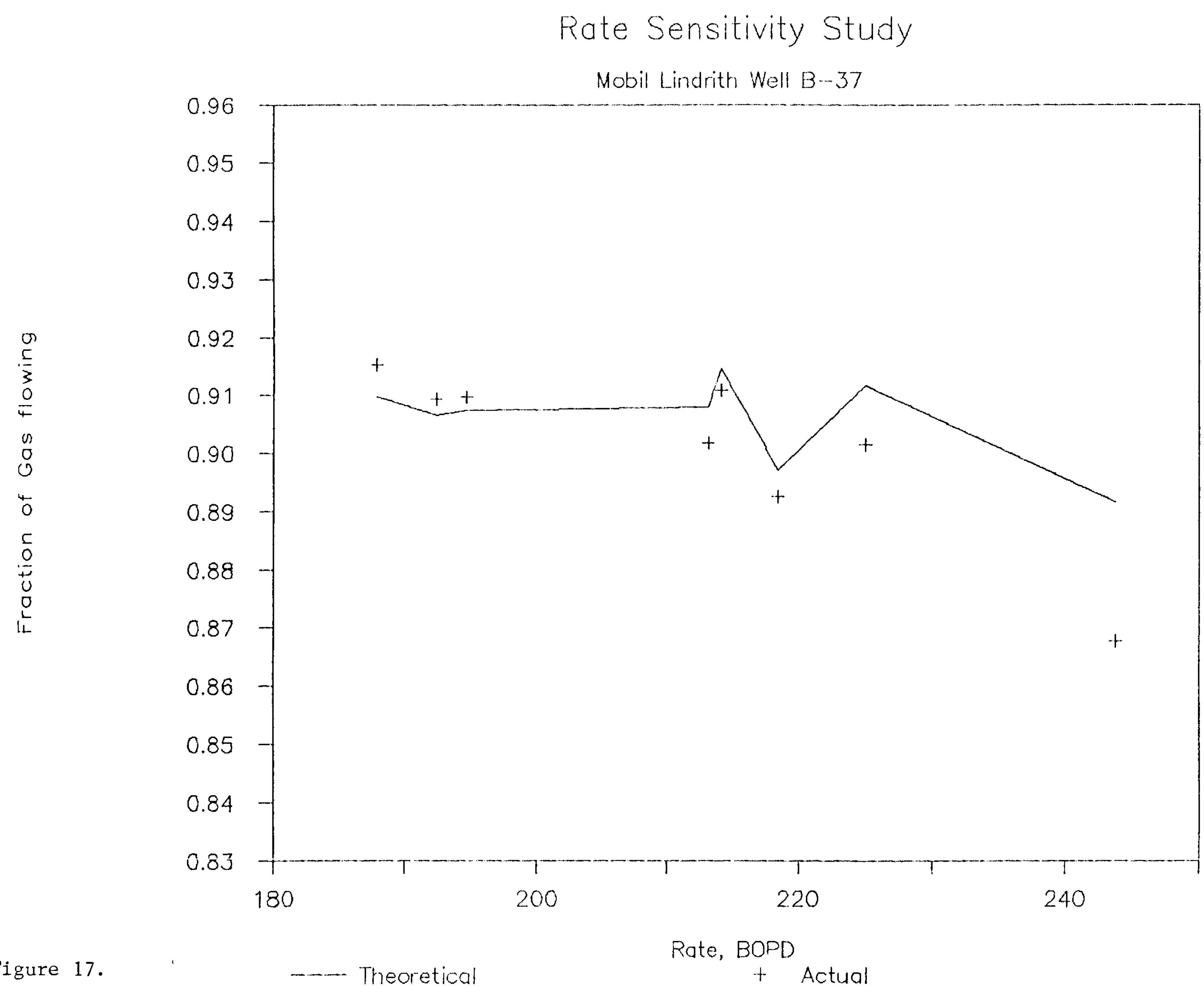
Rate Sensitivity Study
Mallon, Johnson-Federal 12#5
Fraction of Gas flowing
1.00
0.99
0.98
0.97
0.96
0.95
0.94
0.93
0.92
0.91
0.90
0.89
0.88
0.87
0.86
0.85
0.84
0.83
0.82
0
20
40
60
80
Rate, BOPD
Theoretical
Actual

Figure 15.



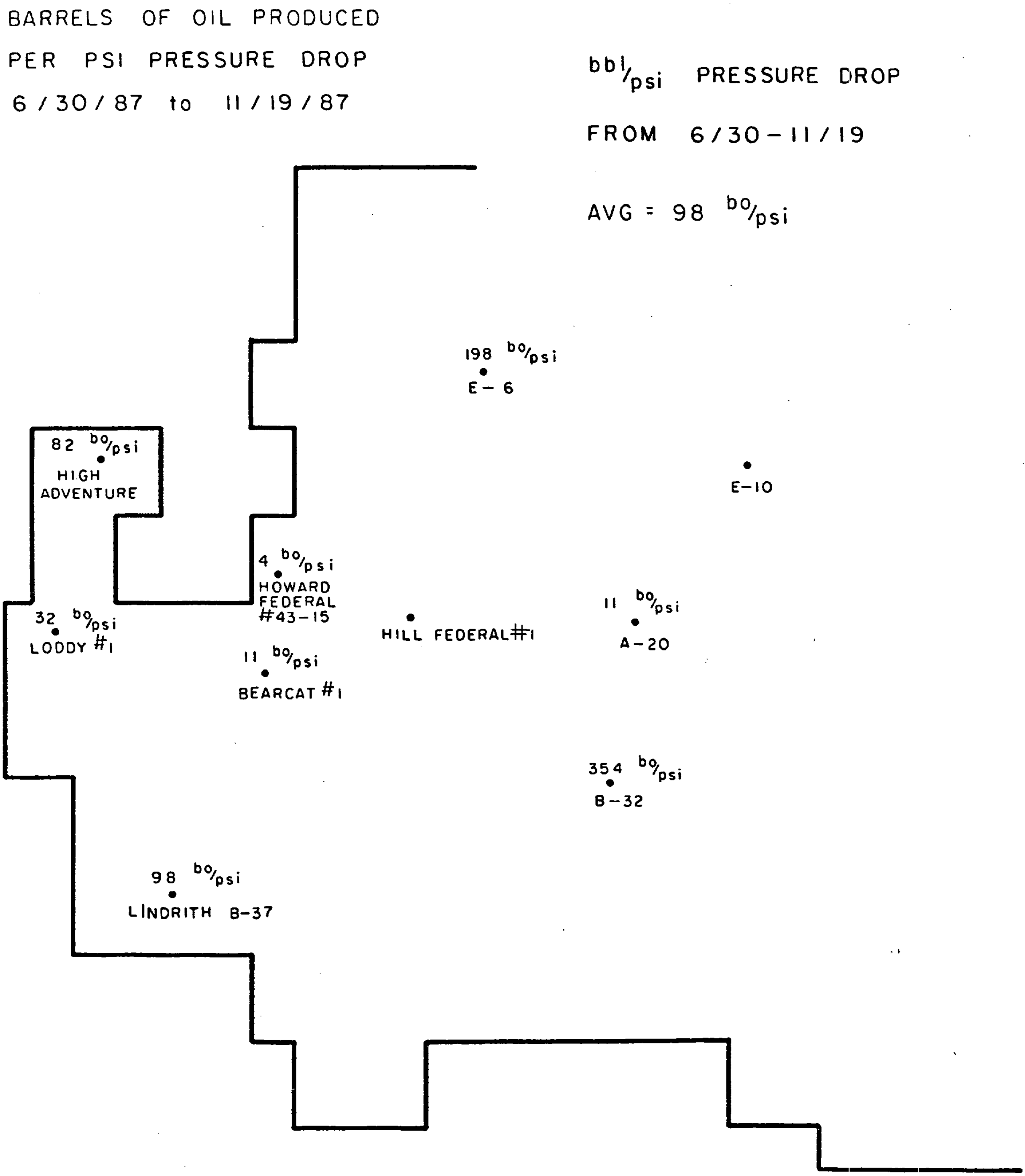
Rate Sensitivity Study
Mesa Grande, Well Bearcat #1
Fraction of Gas flowing
1.00
0.99
0.98
0.97
0.96
0.95
0.94
0.93
0.92
0.91
0.90
0.89
0.88
0.87
0.86
0.85
0.84
0
20
40
60
Rate, BOPD
Theoretical
+ Actual

Figure 16.



Rate Sensitivity Study
Mobil Lindrith Well B--37
Fraction of Gas flowing
0.96
0.95
0.94
0.93
0.92
0.91
0.90
0.89
0.88
0.87
0.86
0.85
0.84
0.83
180
200
220
240
Rate, BOPD
Theoretical
+ Actual

Figure 17.



BARRELS OF OIL PRODUCED
PER PSI PRESSURE DROP
6 / 30 / 87 to 11 / 19 / 87
bbl/psi PRESSURE DROP
FROM 6/30-11/19
AVG = 98 bo/psi
198 bo/psi
E-6
82 bo/psi
HIGH ADVENTURE
E-10
4 bo/psi
HOWARD FEDERAL #43-15
32 bo/psi
LODDY #1
HILL FEDERAL #1
11 bo/psi
A-20
11 bo/psi
BEARCAT #1
354 bo/psi
B-32
98 bo/psi
LINDRITH B-37

Figure 18

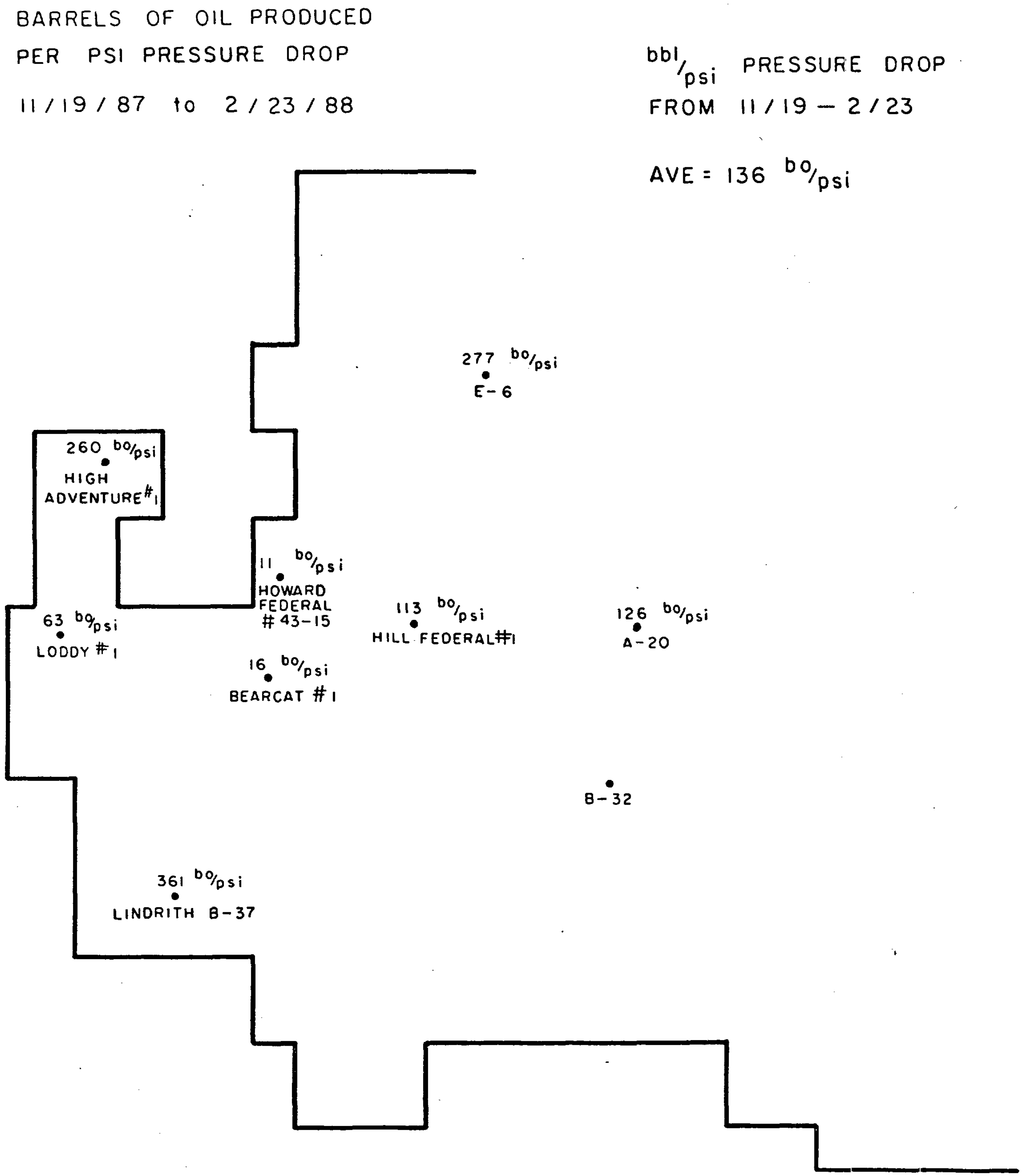

BARRELS OF OIL PRODUCED
PER PSI PRESSURE DROP
11 / 19 / 87 to 2 / 23 / 88
bbl/psi PRESSURE DROP
FROM 11 / 19 – 2 / 23
AVE = 136 bo/psi
277 bo/psi
E-6
260 bo/psi
HIGH ADVENTURE #1
11 bo/psi
HOWARD FEDERAL # 43-15
63 bo/psi
LODDY #1
113 bo/psi
HILL FEDERAL #1
126 bo/psi
A-20
16 bo/psi
BEARCAT #1
B-32
361 bo/psi
LINDRITH B-37

Figure 19

APPENDIX I

Static Pressure Worksheets

	KB		Subsea
Operator	BMG		
Well	E-6		
Elevation	7505		
Top of B Zone	7148		+357
Test Date		6/30/87	
Bomb Depth	7277		+228
Bomb Pressure, psig		1214.2	
Fluid Level	7137		+368
Wellbore Gradient			
Oil, psi/ft	(0.3)(228-357)		-38.7
Gas, psi/ft			
Pressure at Top of B Zone		1175.5	
Top of B Zone to +370 ft	13		
Production			
BO/D		321	
Mcf/D		1471	
Volume Weighted Reservoir Density, psi/ft		0.06350	
dP to +370 ft		.83	
Pressure at +370 ft datum		1174.7	

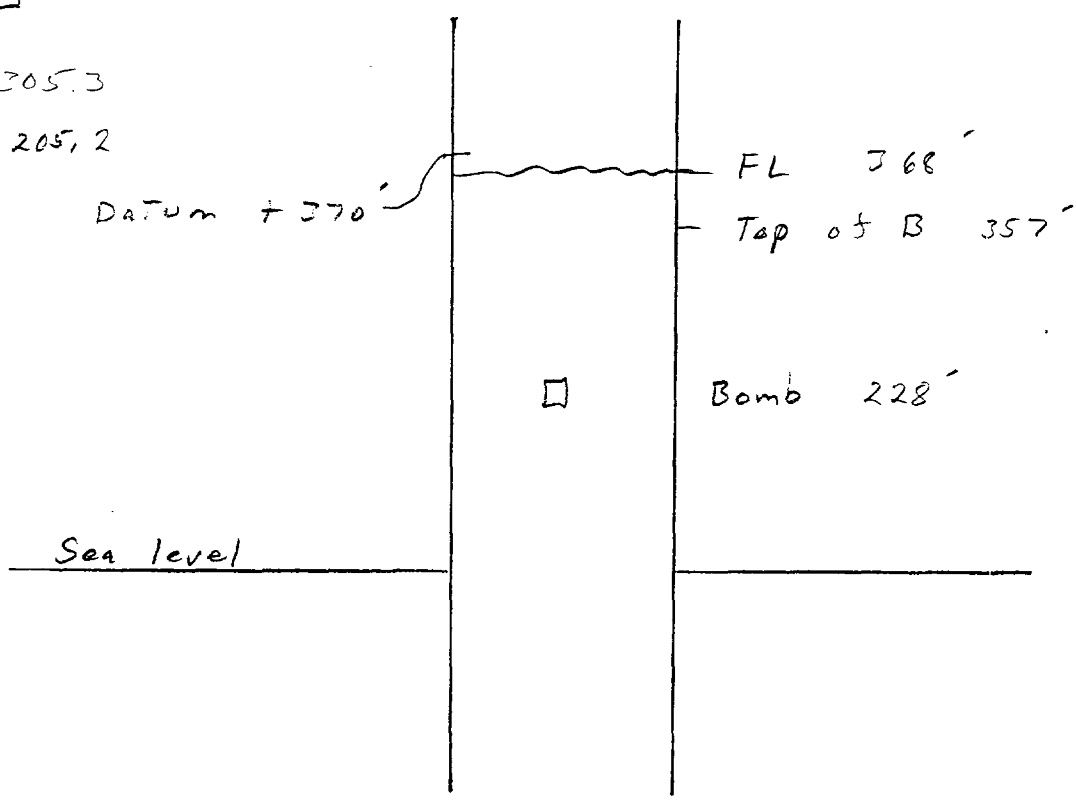
$(321)(1.342) = 430.8$

$\left[1471 - \frac{(321)(501)}{1000}\right] 2.328 = 3050.1$

$(.7088)(430.8) = 305.3$

$(.067265)(3050.1) = 205.2$

$(.433)(.1466)$



	KB		Subsea
Operator	BMG		
Well	E-6		
Elevation	7505		
Top of B Zone	7148		+357
Test Date		11/19/87	
Bomb Depth	7337		+168
Bomb Pressure, psig		1014.9	
Fluid Level	7132		+323
Wellbore Gradient			
Oil, psi/ft	0.3(168-323)		-46.5
Gas, psi/ft	0.03(323-357)		- 1.0
Pressure at Top of B Zone		967.4	
Top of B Zone to +370 ft	13		
Production			
BO/D		291	
Mcf/D		1250	
Volume Weighted Reservoir Density, psi/ft		0.05437	
dP to +370 ft		0.7	
Pressure at +370 ft datum		966.7	

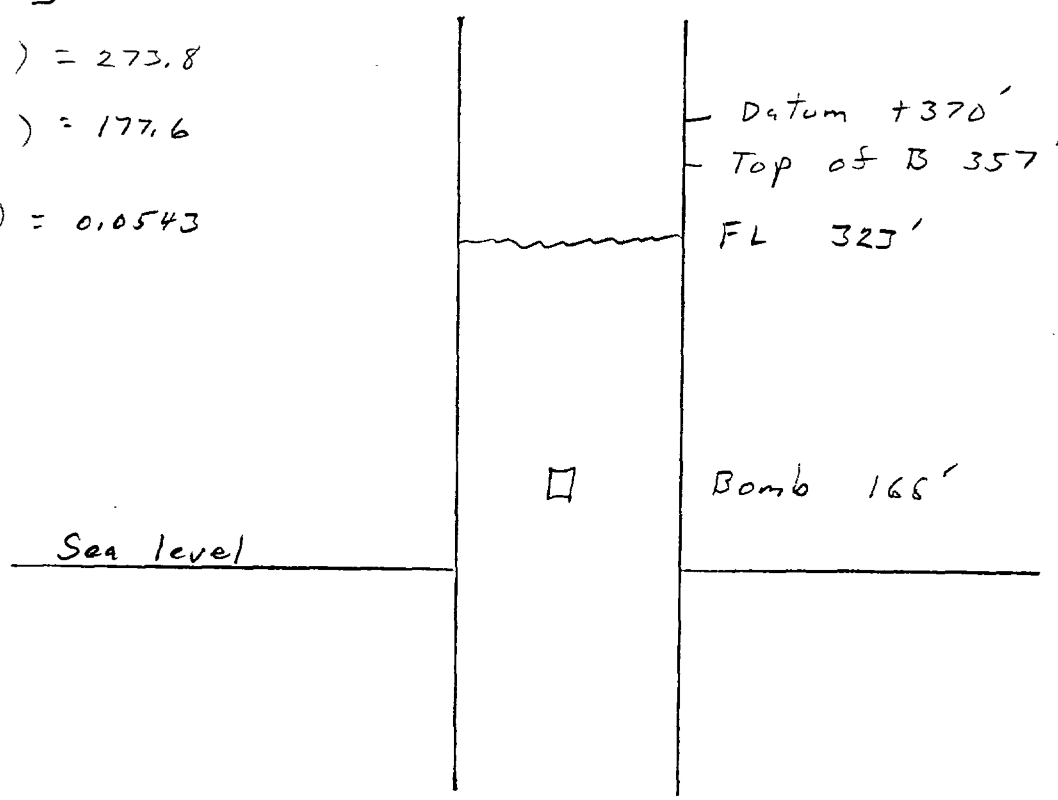
(291) (1.317) = 383.2

$$\left[1250 \quad \frac{291(443)}{1000}\right] 2.865 = 3211.9$$

(.7143) (383.2) = 273.8

(.055291)(3211.9) = 177.6

(.433)(.1256) = 0.0543



Operator	BMG		
Well	E-6		
	KB		Subsea
Elevation	7505		
Top of B Zone	7148		+357
Test Date		2/23/88	
Bomb Depth	7277		+228
Bomb Pressure, psig		955.2	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(228-357)		-3.9
Pressure at Top of B Zone		951.3	
Top of B Zone to +370 ft	13		
Production			
BO/D		160	
Mcf/D		840	
Volume Weighted Reservoir Density, psi/ft		0.04788	
dP to +370 ft		0.6	
Pressure at +370 ft datum		950.7	

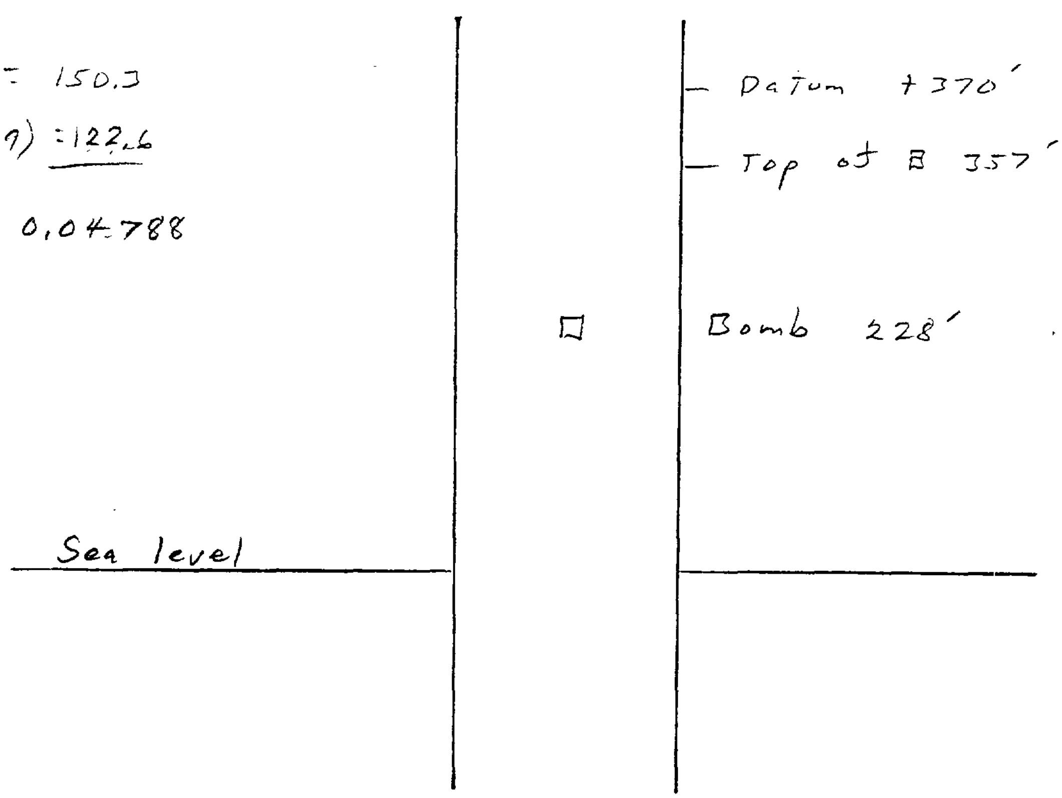
$(160)\ (1.314) = 210.24$

$\left[840 - \frac{(160)(437)}{1000}\right] 2.932 = 2257.9$

$(.7148)(210.2) = 150.3$

$(.054314)(2257.9) = 122.6$

$(.433)(.1106) = 0.04788$



	KB		Subsea
Operator	BMG		
Well	E-10		
Elevation	7341		
Top of B Zone	6820		+521
Test Date		11/19/87	
Bomb Depth	7012		+329
Bomb Pressure, psig		1403	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(329-521)		-5.8
Pressure at Top of B Zone		1397.2	
Top of B Zone to +370 ft	151'		
Production			
BO/D		234	
Mcf/D		1760	
Volume Weighted Reservoir Density, psi/ft		0.0580	
dP to +370 ft		8.8	
Pressure at +370 ft datum		1406.0	

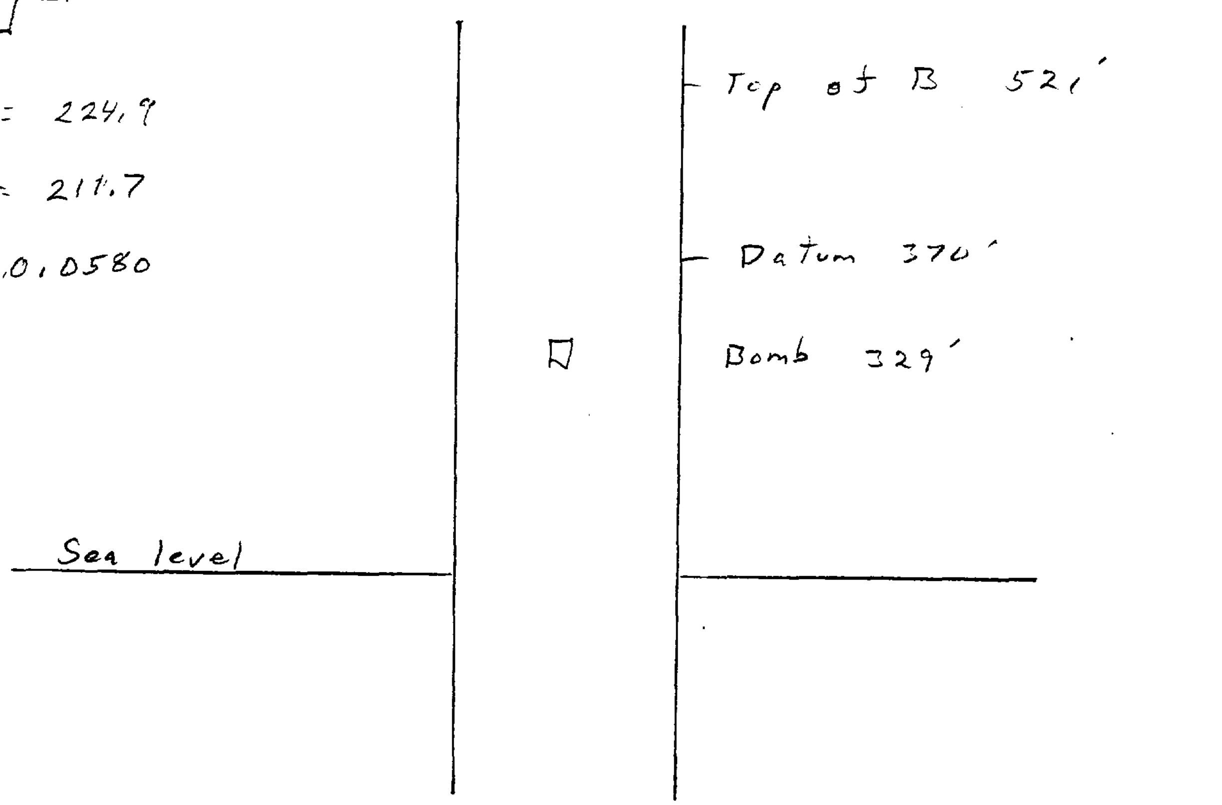
$(234)(1.370) = 320.6$

$\left[1760 - \frac{234(565)}{1000}\right] 2.081 = 3387.4$

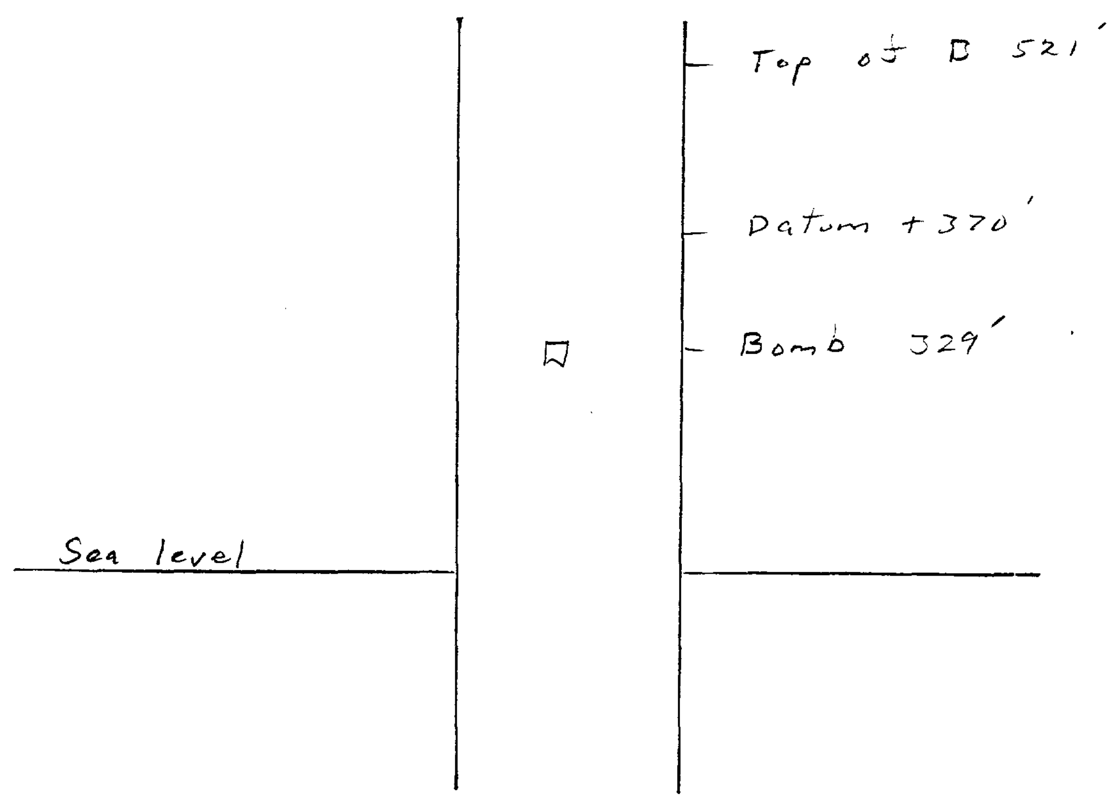
$(.7015)(320.6) = 224.9$

$(.080205)(557.4) = 211.7$

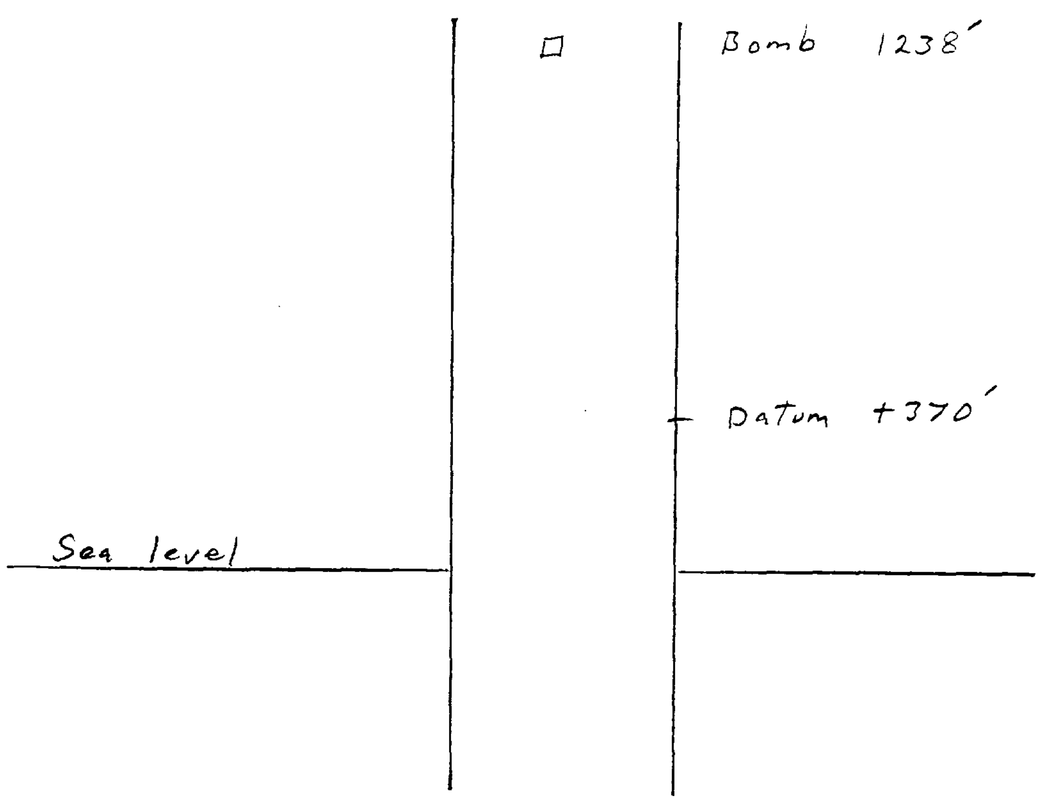
$(.433)(.1339) = 0.0580$



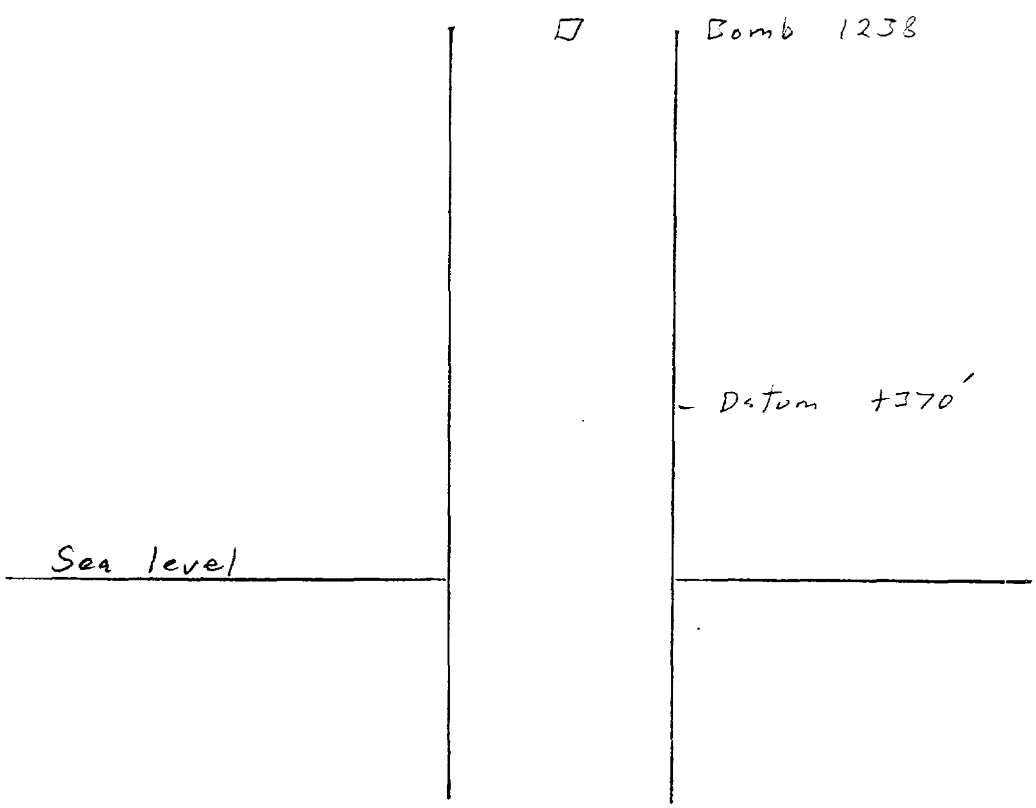
	KB		Subsea
Operator	BMG		
Well	E-10		
Elevation	7341		
Top of B Zone	6820		+521
Test Date		2/23/88	
Bomb Depth	7012		+329
Bomb Pressure, psig		1415	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(329-521)		-5.8
Pressure at Top of B Zone		1409.2	
Top of B Zone to +370 ft	151		
Production			
BO/D		23	
Mcf/D		1600	
Volume Weighted Reservoir Density, psi/ft		.058	
dP to +370 ft		8.8	
Pressure at +370 ft datum		1418.0	



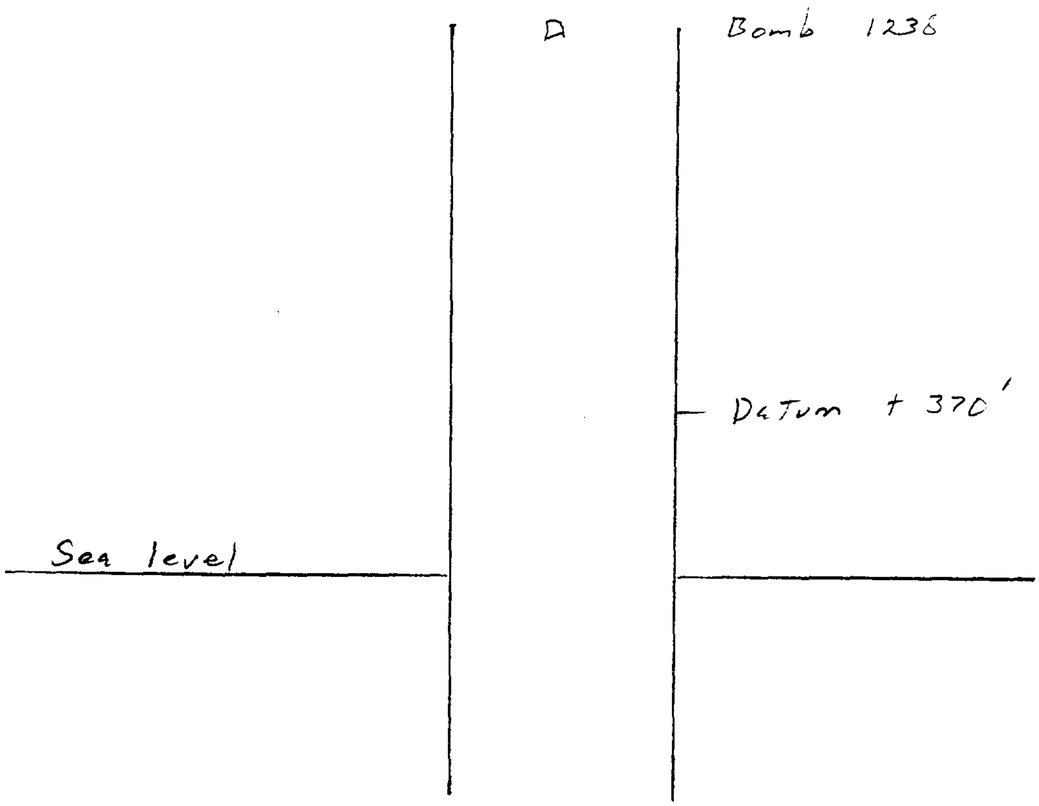
	KB		Subsea
Operator	BMG		
Well	K-13		
Elevation	7100		
Top of B Zone			
Test Date		6/30/87	
Bomb Depth	5862		+1238
Bomb Pressure, psig		1477.8	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(0.03)(1238-370)		26.04
Pressure at Top of B Zone			
Top of B Zone to +370 ft			
Production			
BO/D			
Mcf/D			
Volume Weighted Reservoir Density, psi/ft			
dP to +370 ft			
Pressure at +370 ft datum		1503.8	



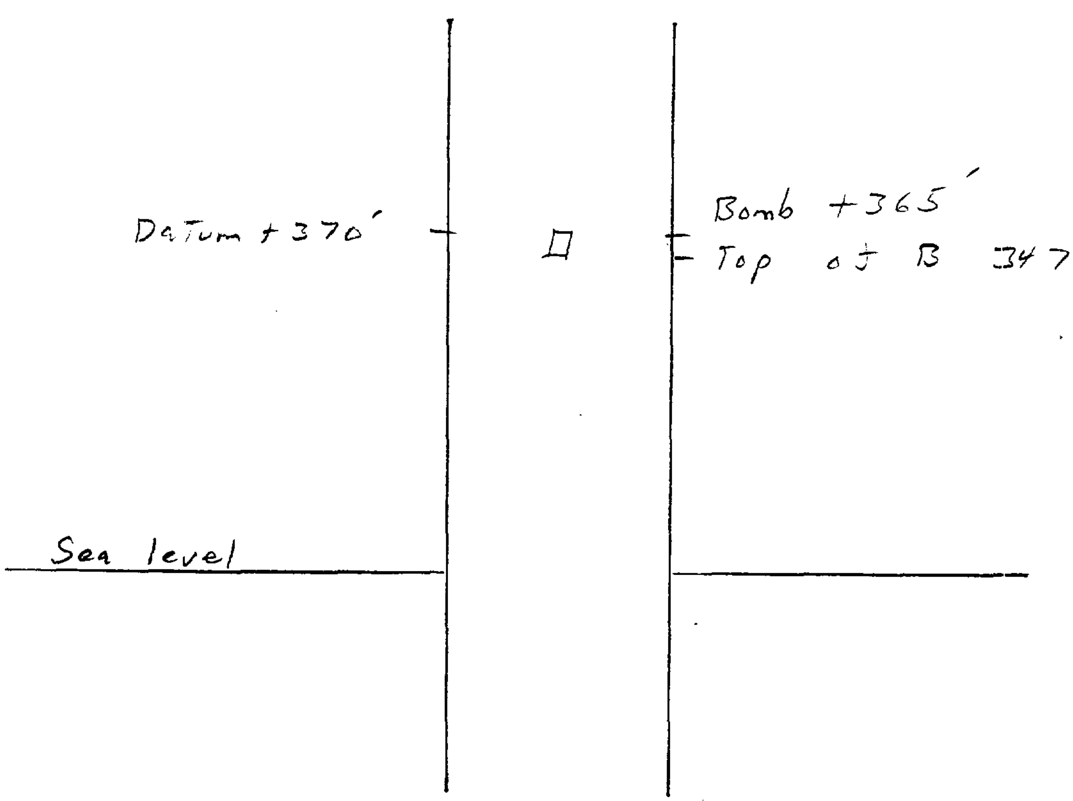
	KB		Subsea
Operator	BMG		
Well	K-13		
Elevation	7100		
Top of B Zone			
Test Date		11/19/87	
Bomb Depth	5862		+ 1238
Bomb Pressure, psig		1482	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(1238-370)		26.04
Pressure at Top of B Zone			
Top of B Zone to +370 ft			
Production			
BO/D			
Mcf/D			
Volume Weighted Reservoir Density, psi/ft			
dP to +370 ft			
Pressure at +370 ft datum		1508	



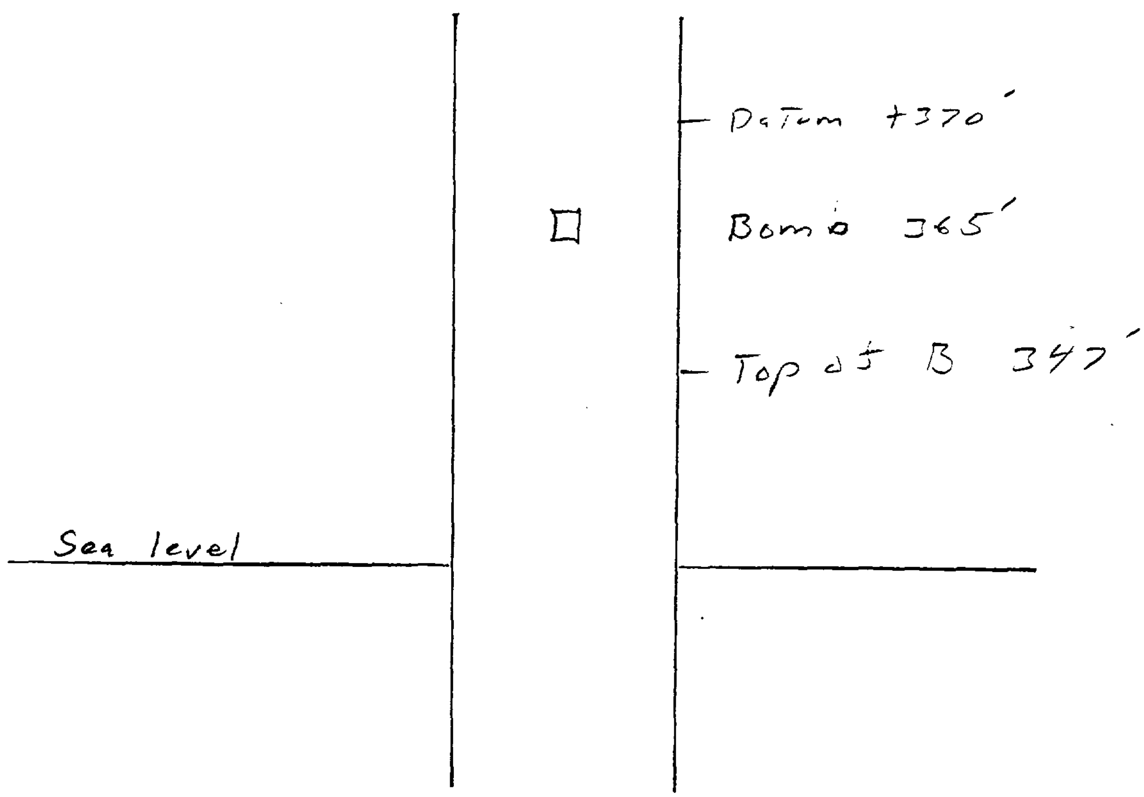
	KB		Subsea
Operator	BMG		
Well	K-13		
	KB		Subsea
Elevation	7100		
Top of B Zone			
Test Date		2/23/88	
Bomb Depth	5862		+1238
Bomb Pressure, psig		1440	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(1238-370)		26
Pressure at Top of B Zone			
Top of B Zone to +370 ft			
Production			
BO/D			
Mcf/D			
Volume Weighted Reservoir Density, psi/ft			
dP to +370 ft			
Pressure at +370 ft datum		1466	



Operator	BMG		
Well	D-17		
	KB		Subsea
Elevation	7477		
Top of B Zone	7130		+347
Test Date		11/19/87	
Bomb Depth	7112		+365
Bomb Pressure, psig		1001	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(365-347)		.5
Pressure at Top of B Zone		1001.5	
Top of B Zone to +370 ft	23		
Production			
BO/D			
Mcf/D			
Volume Weighted Reservoir Density, psi/ft		.035	
dP to +370 ft		0.8	
Pressure at +370 ft datum		1000.7	



	KB		Subsea
Operator	BMG		
Well	D-17		
Elevation	7477		
Top of B Zone	7130		+347
Test Date		2/23/88	
Bomb Depth	7112		+365
Bomb Pressure, psig		960	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(365-347)		0.5
Pressure at Top of B Zone		960.5	
Top of B Zone to +370 ft	23		
Production			
BO/D			
Mcf/D			
Volume Weighted Reservoir Density, psi/ft		.035	
dP to +370 ft		0.8	
Pressure at +370 ft datum		959.7	



	KB		Subsea
Operator	BMG		
Well	A-20		
Elevation	7444		
Top of B Zone	7038		+406
Test Date		6/30/87	
Bomb Depth	7166		+278
Bomb Pressure, psig		1224.6	
Fluid Level	6992		+454
Wellbore Gradient			
Oil, psi/ft	(0.3)(278-406)		−38.4
Gas, psi/ft			
Pressure at Top of B Zone		1186.2	
Top of B Zone to +370 ft	36		
Production			
BO/D		37	
Mcf/D		220	
Volume Weighted Reservoir Density, psi/ft		0.05628	
dP to +370 ft		2.0	
Pressure at +370 ft datum		1186.0	

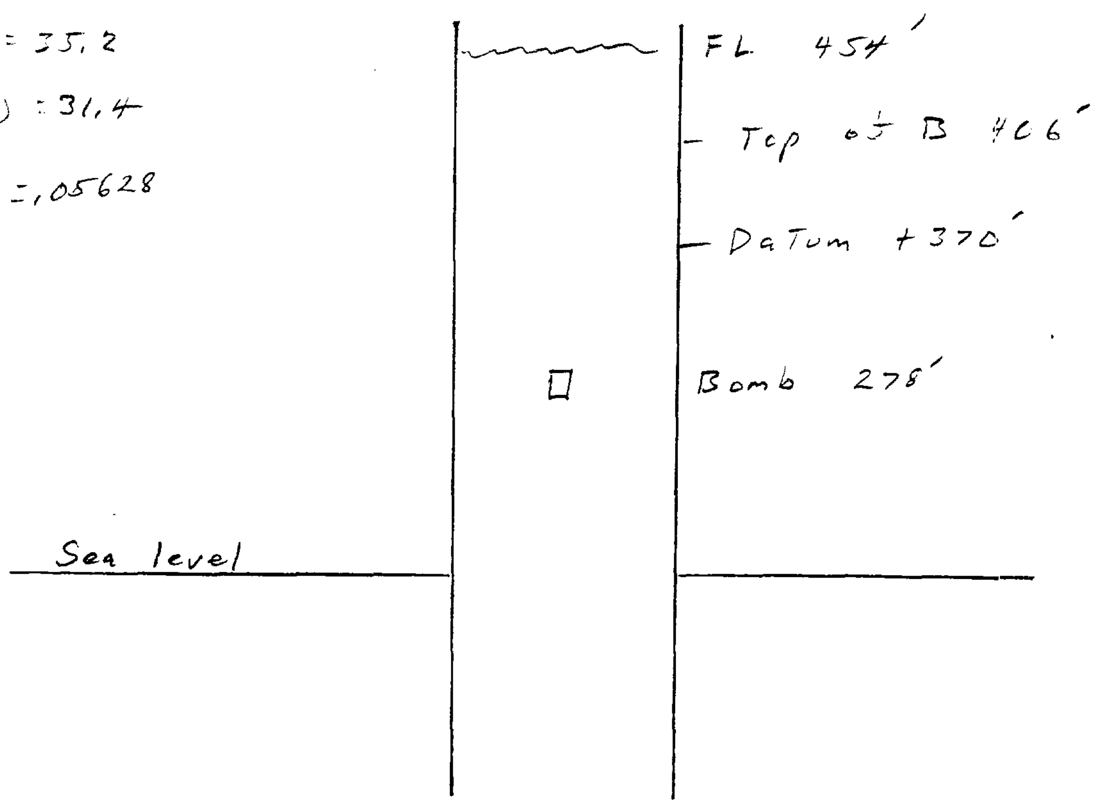
(37) (1.344) = 49.7

$\left[220 - \frac{(37)(505)}{1000}\right] 2.3 = 463$

(.7074)(49.4) = 35.2

(0.067899)(463) = 31.4

(.433)(.1300) = .05628



	KB		Subsea
Operator	BMG		
Well	A-20		
Elevation	7444		
Top of B Zone	7038		+406
Test Date		11/19/87	
Bomb Depth	7166		+278
Bomb Pressure, psig		971.1	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(0.03)(278-406)		-3.8
Pressure at Top of B Zone		967.3	
Top of B Zone to +370 ft	36		
Production			
BO/D		37	
Mcf/D		220	
Volume Weighted Reservoir Density, psi/ft		0.0458	
dP to +370 ft		1.6	
Pressure at +370 ft datum		968.9	

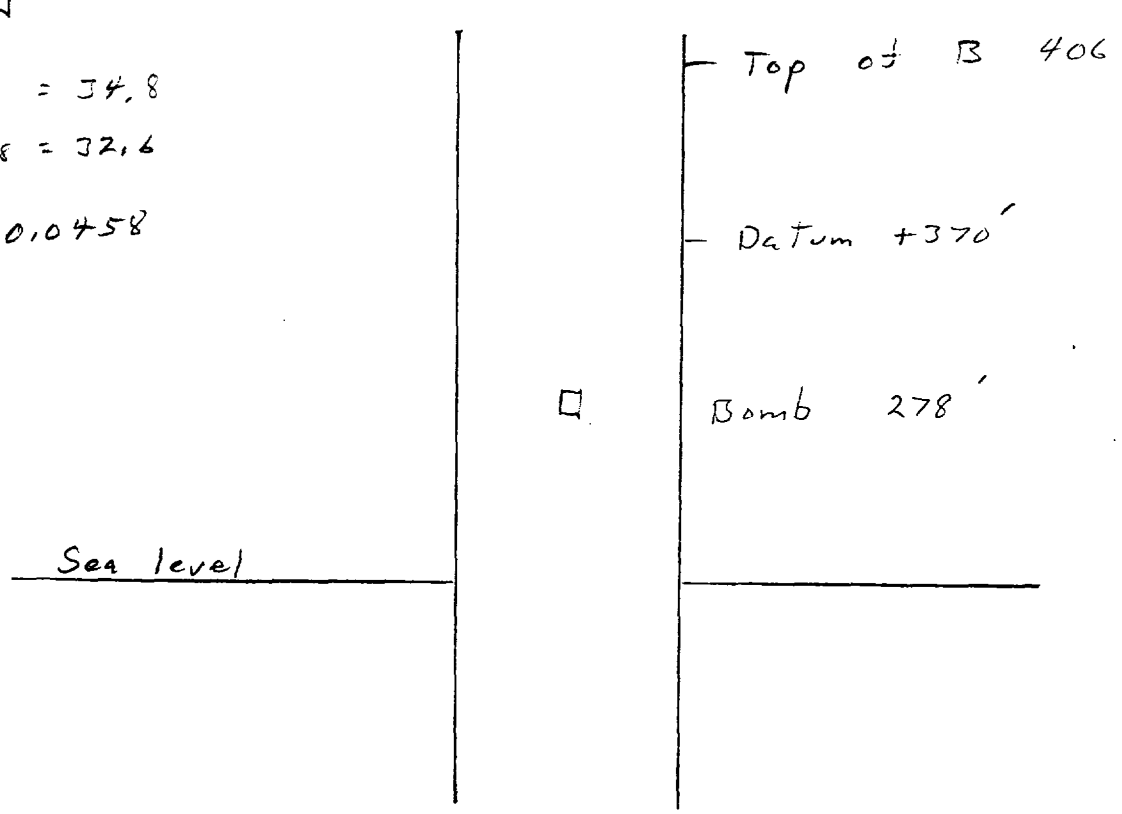
$(37)(1.316) = 48.7$

$\left[220 - \frac{(37)(441)}{1000}\right] 2.891 = 588.8$

$(.7144)\ 48.7 = 34.8$

$(.055291)\ 588.8 = 32.6$

$(.433)\ .1057 = 0.0458$



	KB		Subsea
Operator	BMG		
Well	A-20		
Elevation	7444		
Top of B Zone	7038		+ 406
Test Date		2/25/85	
Bomb Depth	7166		+ 278
Bomb Pressure, psig		952.4	
Fluid Level	None		
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(278-406)		- 3.8
Pressure at Top of B Zone		948.6	
Top of B Zone to +370 ft	36		
Production			
BO/D		45	
Mcf/D		360	
Volume Weighted Reservoir Density, psi/ft		.0395	
dP to +370 ft		1.4	
Pressure at +370 ft datum		950.0	

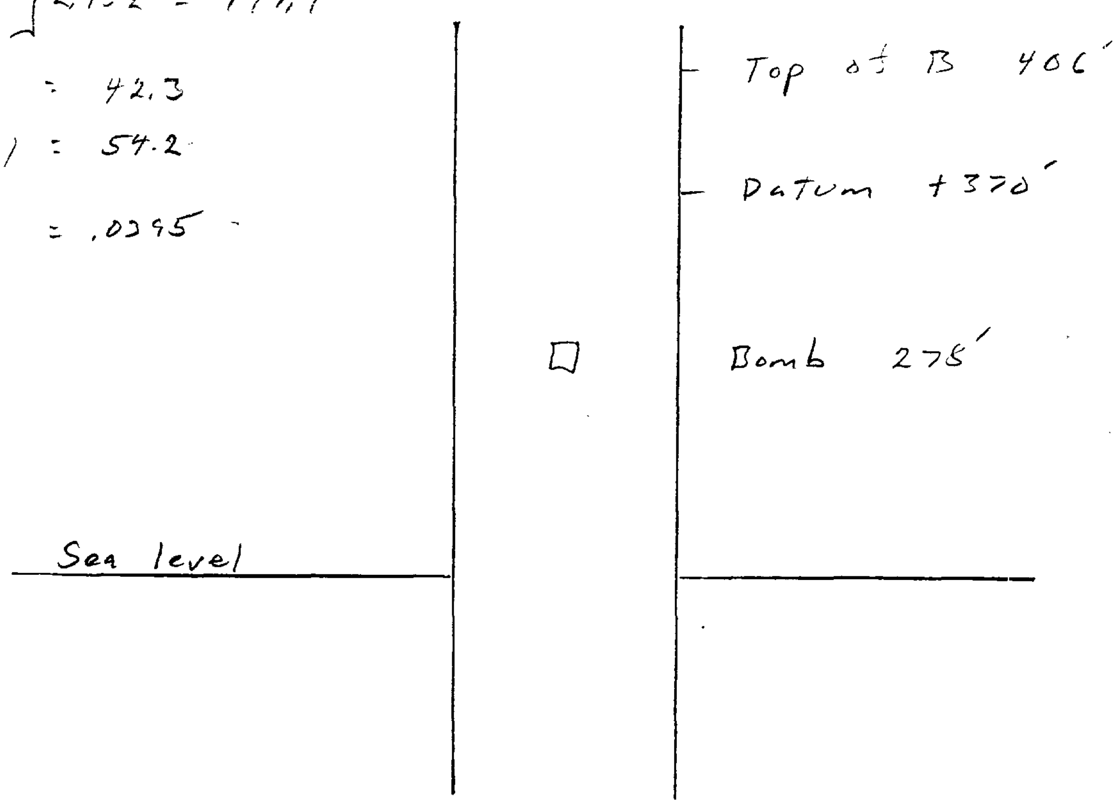
$$(45)(1.314) = 59.1$$

$$\left[360 - \frac{(45)(437)}{1000}\right]2.932 = 997.9$$

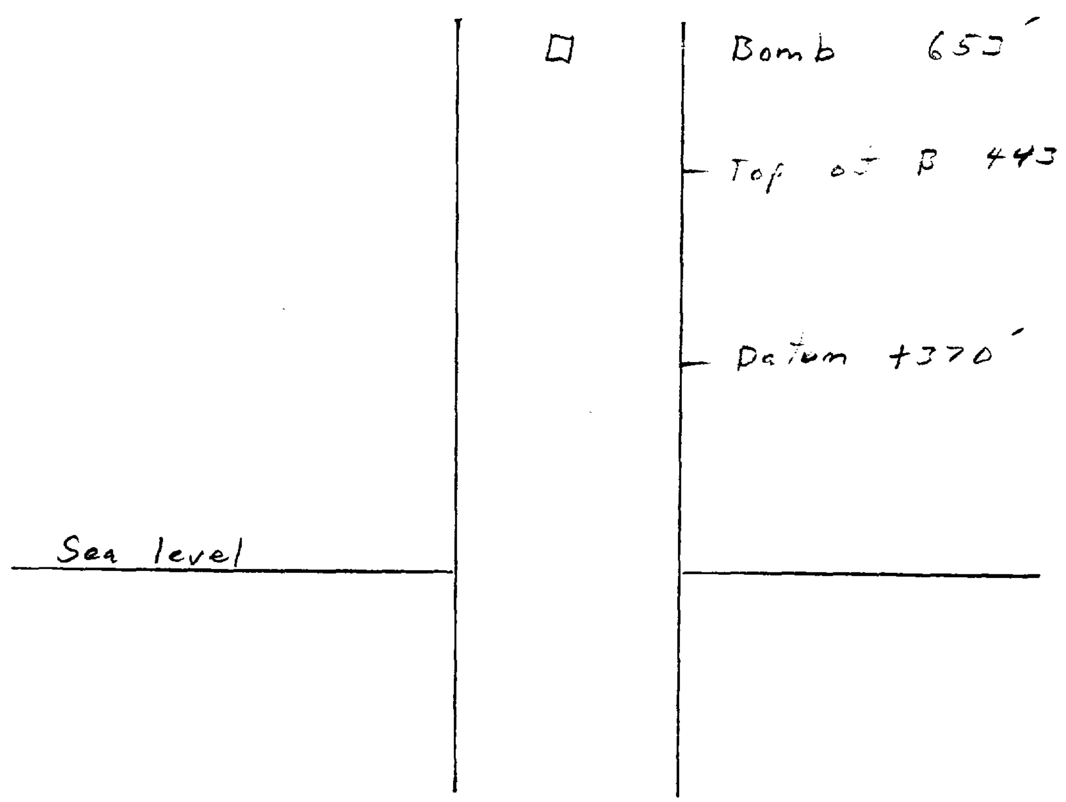
$$(.7148)(59.1) = 42.3$$

$$(.054314)(997.9) = 54.2$$

$$(.433)(.09130) = .0395$$



Operator	BMG		
Well	L-27		
	KB		Subsea
Elevation	7475		
Top of B Zone	7032		+443
Test Date		2/26/88	
Bomb Depth	6822		+653
Bomb Pressure, psig		1372	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(653-443)		6.3
Pressure at Top of B Zone		1383.3	
Top of B Zone to +370 ft	73		
Production			
BO/D			
Mcf/D			
Volume Weighted Reservoir Density, psi/ft		.035	
dP to +370 ft		2.6	
Pressure at +370 ft datum		1385.9	



	KB		Subsea
Operator	BMG		
Well	B-29		
Elevation	7508		
Top of B Zone	7085		+423
Test Date		2/23/88	
Bomb Depth	7212		+296
Bomb Pressure, psig		962	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(03)(296-423)		-3.8
Pressure at Top of B Zone		958.2	
Top of B Zone to +370 ft	53		
Production			
BO/D		1136	
Mcf/D		1590	
Volume Weighted Reservoir Density, psi/ft		0.1117	
dP to +370 ft		5.9	
Pressure at +370 ft datum		964.1	

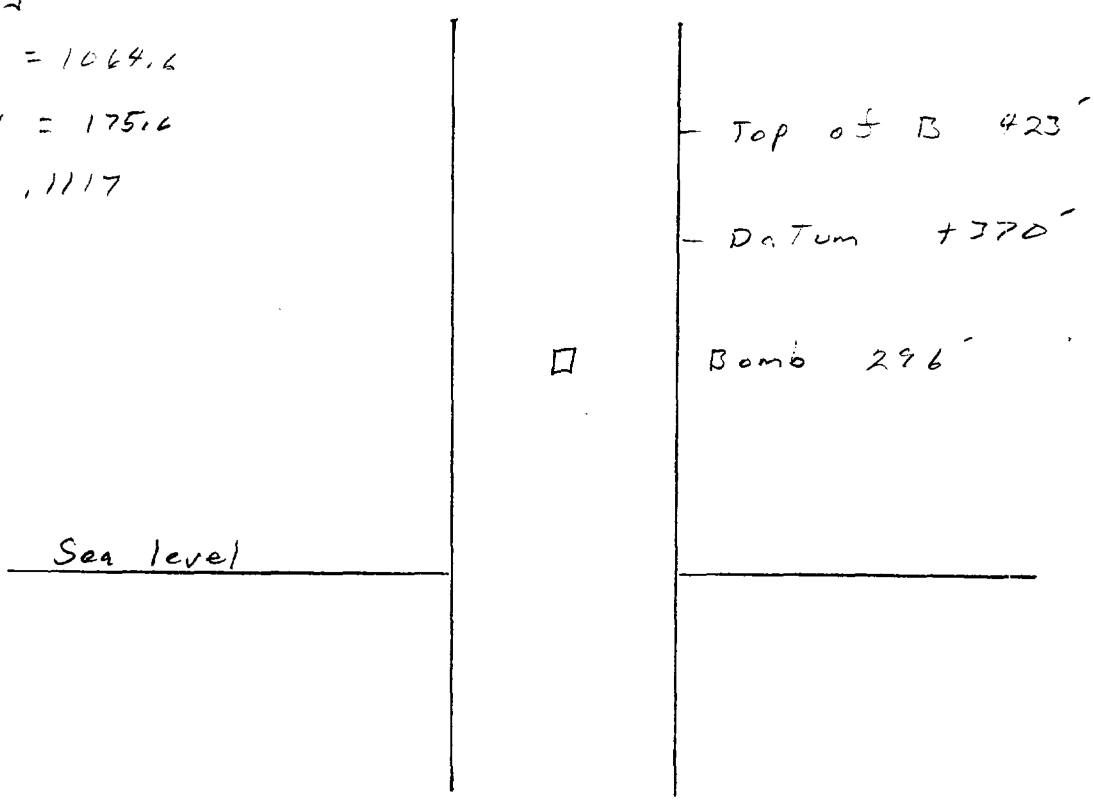
(1136) 1.316 = 1488.2

$\left[1590 - \frac{(1136)(430}{1000}\right] 3.015 = 3321.1$

(.7154) 1488.2 = 1064.6

(.052877) 3321.1 = 175.6

(.433)(.2579) = .1117



Operator	BMG		
Well	B-32		
	KB		Subsea
Elevation	7611		
Top of B Zone	7190		+421
Test Date		6/30/87	
Bomb Depth	7316		+295
Bomb Pressure, psig		1203.4	
Fluid Level	7262		+349
Wellbore Gradient			
Oil, psi/ft	(.3)(295-349)		-16.2
Gas, psi/ft	(.03)(349-421)		-2.2
Pressure at Top of B Zone		1185	
Top of B Zone to +370 ft	51		
Production			
BO/D		520	
Mcf/D		470	
Volume Weighted Reservoir Density, psi/ft		0.1832	
dP to +370 ft		+ 9.3	
Pressure at +370 ft datum		1194.3	

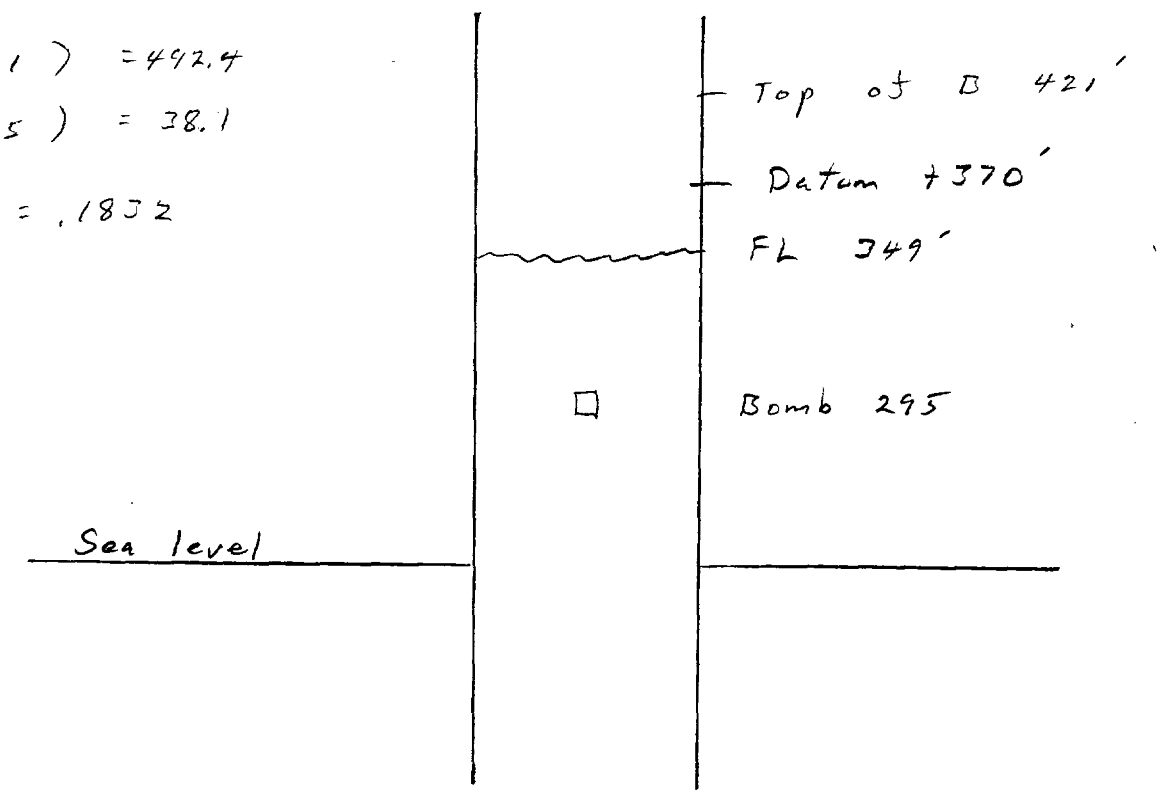
$(520)\ (1.331) = 692.1$

$\left[470 - \frac{(520)(476)}{1000}\right] 2.524 = 561.5$

$(.7115)(692.1) = 492.4$

$(.067841)(561.5) = 38.1$

$(.433)(0.4232) = .1832$



	KB		Subsea
Operator	BMG		
Well	B-32		
Elevation	7611		
Top of B Zone	7190		+421
Test Date		11/19/87	
Bomb Depth	7302		+309
Bomb Pressure, psig		970.5	
Fluid Level	None		
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(309-421)		-3.4
Pressure at Top of B Zone		967.1	
Top of B Zone to +370 ft	51		
Production			
BO/D		766	
Mcf/D		920	
Volume Weighted Reservoir Density, psi/ft		.05684	
dP to +370 ft		2.9	
Pressure at +370 ft datum		970.0	

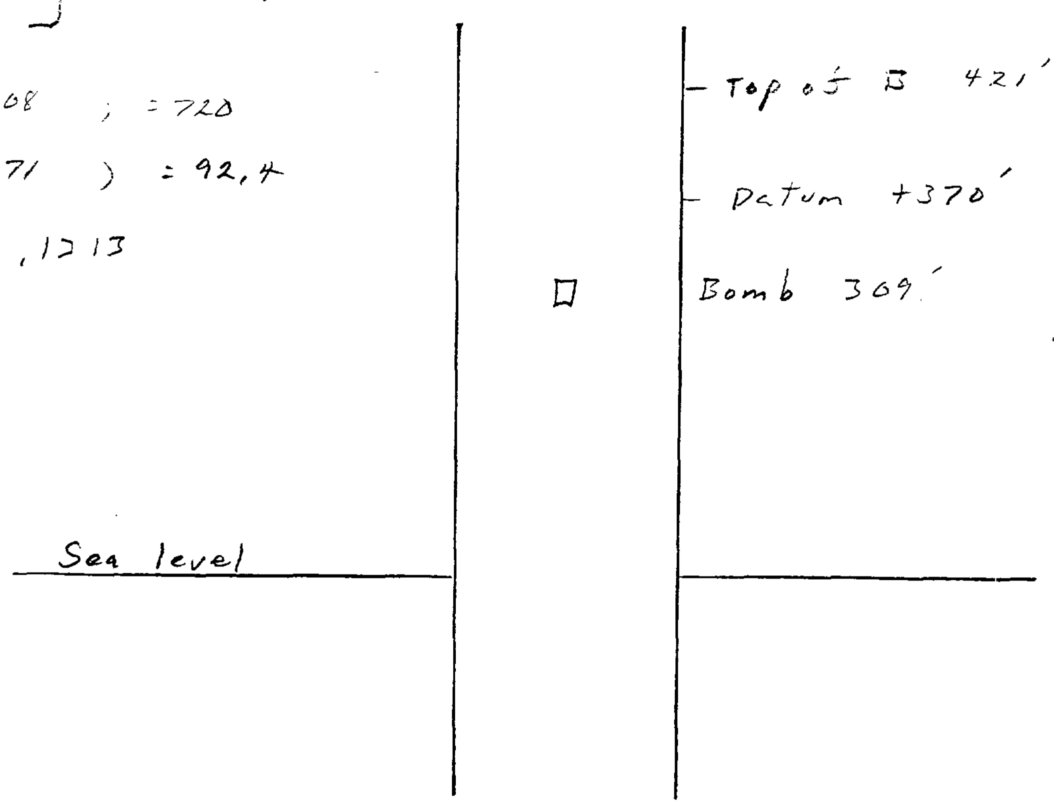
$(766)\quad(1.316) = 1008.1$

$\left[920 - \frac{(766)(442)}{1000}\right] 2.875 = 1671.6$

$(0.7143)(1008) = 720$

$(0.055291)(1671) = 92.4$

$(.433)(.3032) = .1313$



	KB		Subsea
Operator	BMG		
Well	B-32		
Elevation	7611		
Top of B Zone	7190		+421
Test Date		2/23/88	
Bomb Depth	7302		+309
Bomb Pressure, psig		953.8	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	.03(309-421)		-3.4
Pressure at Top of B Zone		950.4	
Top of B Zone to +370 ft	51		
Production			
BO/D		754	
Mcf/D		770	
Volume Weighted Reservoir Density, psi/ft		0.1238	
dP to +370 ft		+ 6.3	
Pressure at +370 ft datum		956.7	

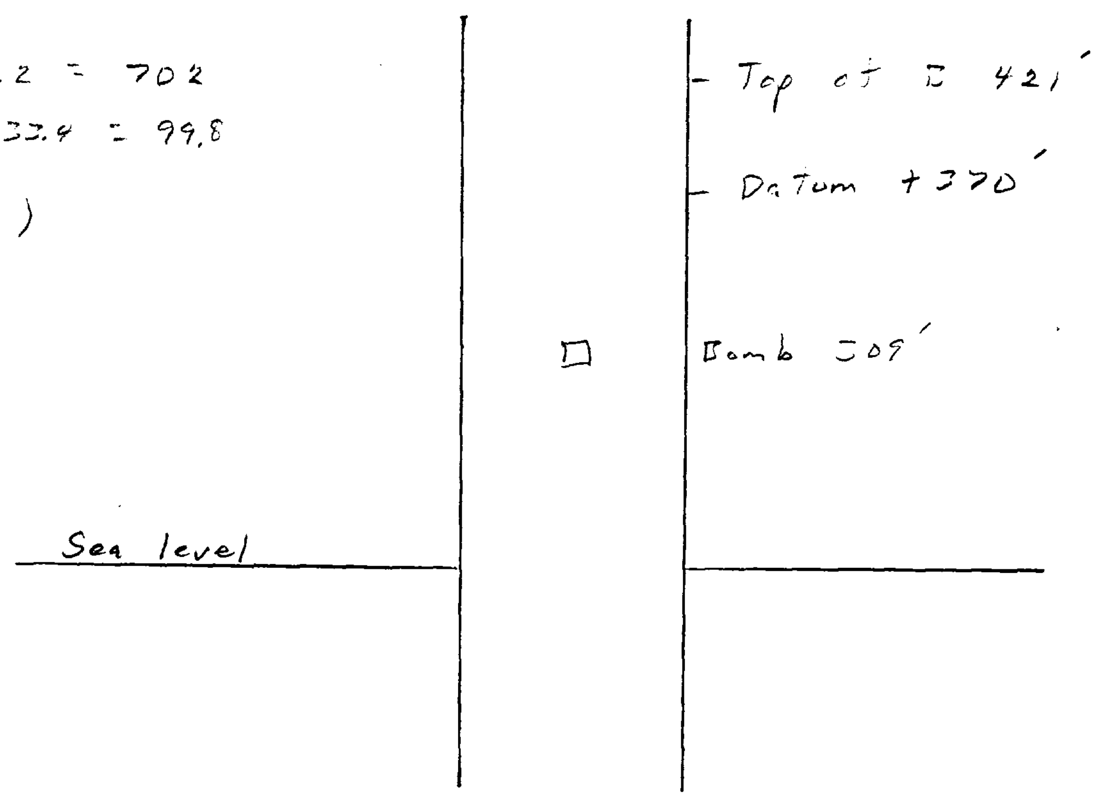
$(754)\ 1.288 = 971.2$

$\left[770 - \frac{754(280)}{1000}\right] 3.792 = 1833.4$

$(.7229)\ 971.2 = 702$

$(.054314)\ 1833.4 = 99.8$

$(.433)(0.2858\ )$



	KB		Subsea
Operator	Mallon		
Well	Johnson Federal 12-5		
Elevation	7430		
Top of B Zone	7029		+401
Test Date		6/30/87	
Bomb Depth	7611		-181
Bomb Pressure, psig		1427	
Fluid Level	5205		+2225
Wellbore Gradient			
Oil, psi/ft	(0.355)(-181-401)		-206.6
Gas, psi/ft			
Pressure at Top of B Zone		1220.4	
Top of B Zone to +370 ft	94		
Production			
BO/D		30	
Mcf/D		382	
Volume Weighted Reservoir Density, psi/ft		0.04324	
dP to +370 ft		4.1	
Pressure at +370 ft datum		1224.5	

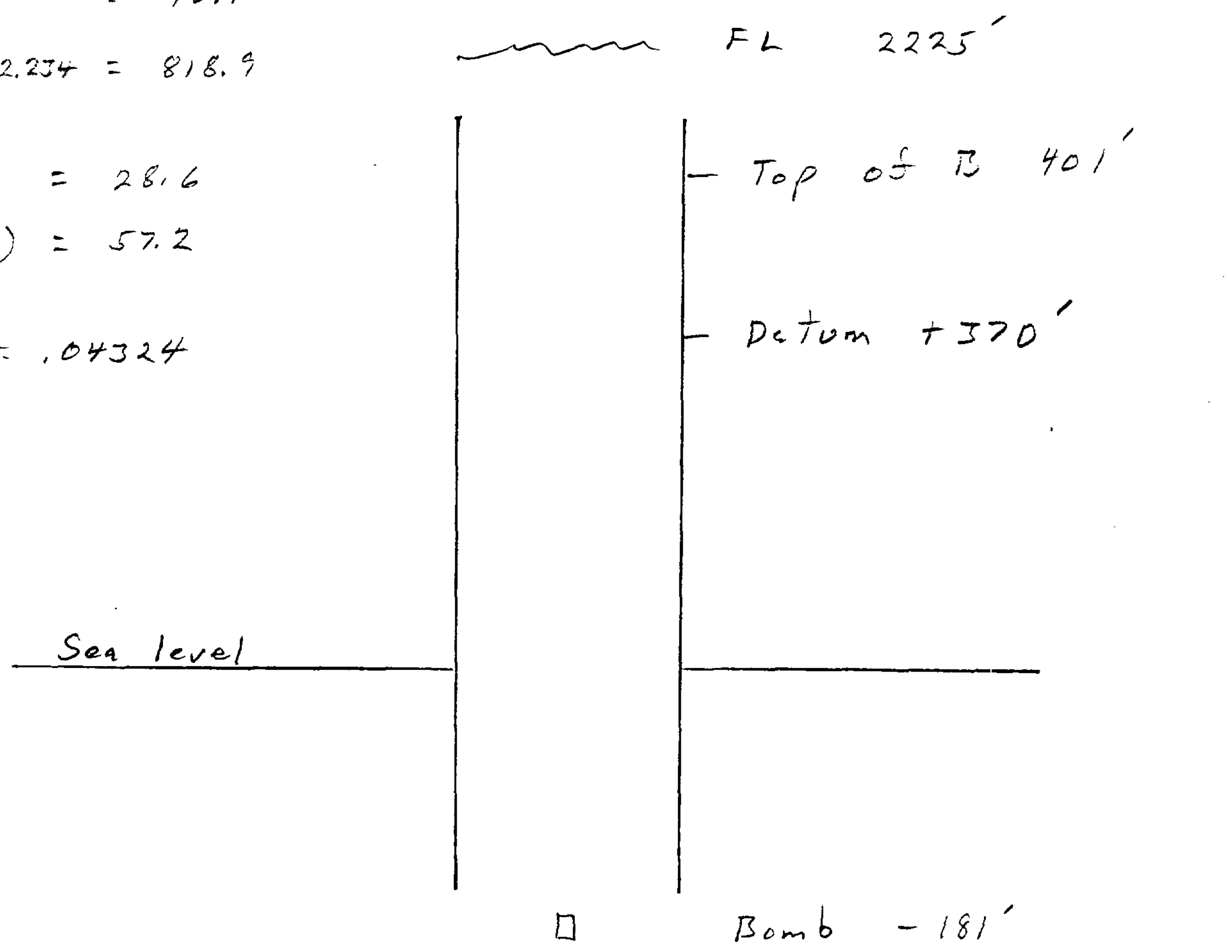
$(30)(1.348) = 40.4$

$\left[382 - \frac{(30)(515)}{1000}\right]2.234 = 818.9$

$(.7072)(40.4) = 28.6$

$(.069860)(818.9) = 57.2$

$(.433)(.09986) = .04324$



	KB		Subsea
Operator	Mallon		
Well	Fisher Federal 2-1		
Elevation	7654		
Top of B Zone	7307		+347
Test Date		11/19/87	
Bomb Depth	7875		-221
Bomb Pressure, psig		1177	
Fluid Level	7297		+357
Wellbore Gradient			
Oil, psi/ft	(0.34)(-221-347)		-193.1
Gas, psi/ft			
Pressure at Top of B Zone		983.8	
Top of B Zone to +370 ft	23		
Production			
BO/D		228	
Mcf/D		575	
Volume Weighted Reservoir Density, psi/ft		0.08429	
dP to +370 ft		1.9	
Pressure at +370 ft datum		981.9	

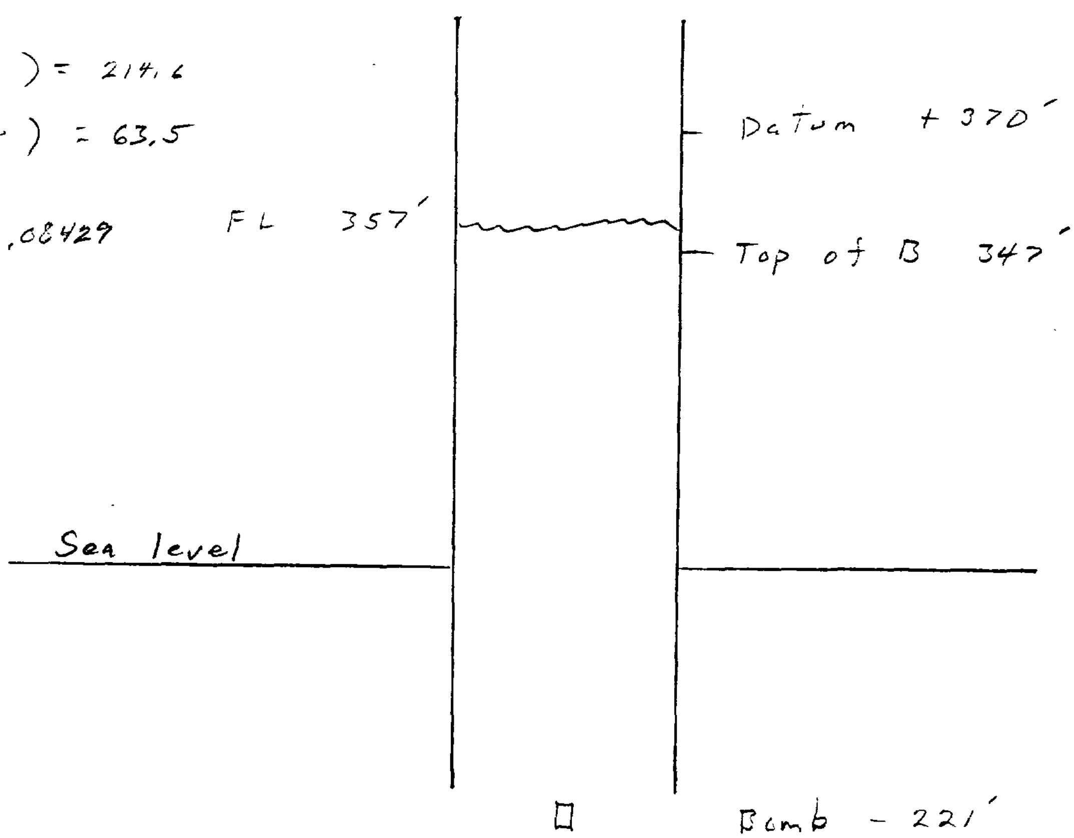
$(228)\ (1.3185) = 300.6$

$\left[575 - \frac{(228)(448)}{1000}\right] 2.808 = 1127.8$

$(.7140)(300.6) = 214.6$

$(.05627)(1127.8) = 63.5$

$(.433)(.19467) = .08429$



	KB		Subsea
Operator	Mallon		
Well	Howard 1-8		
Elevation	7522		
Top of B Zone	7150		+372
Test Date		2/23/88	
Bomb Depth	7300		+222
Bomb Pressure, psig		980	
Fluid Level	4523		+2999
Wellbore Gradient			
Oil, psi/ft	.345(222-372)		-51.8
Gas, psi/ft			
Pressure at Top of B Zone		928	
Top of B Zone to +370 ft	2		
Production			
BO/D		120	
Mcf/D		1021	
Volume Weighted Reservoir Density, psi/ft		.03754	
dP to +370 ft		0.1	
Pressure at +370 ft datum		928.1	

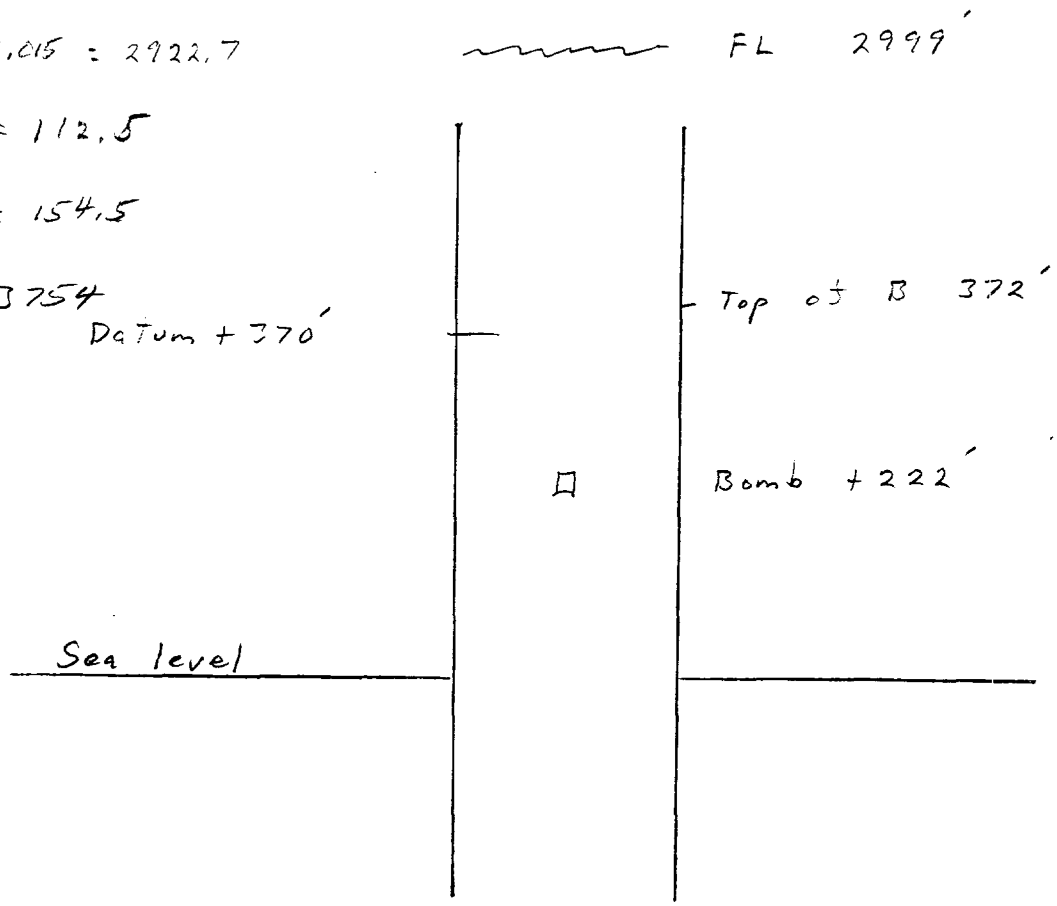
$(120)(1.310) = 157.2$

$\left[1021 - \frac{(120)(430)}{1000}\right] 3.015 = 2922.7$

$(.7154)(157.2) = 112.5$

$(.052877)(2922.7) = 154.5$

$(.433)(.08671) = .03754$



	KB		Subsea
Operator	Mesa Grande		
Well	Bearcat #1		
Elevation	7249		
Top of B Zone	6777		+472
Test Date		6/30/87	
Bomb Depth	6800		+449
Bomb Pressure, psig		1036	
Fluid Level			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft	(.03)(449-472)		-.66
Pressure at Top of B Zone		1035.4	
Top of B Zone to +370 ft	102'		
Production			
BO/D		52	
Mcf/D		347	
Volume Weighted Reservoir Density, psi/ft		0.04657	
dP to +370 ft		4.8	
Pressure at +370 ft datum		1040.2	

$(52)\ (1.325) = 68.9$

$\left[347 - \frac{(52)(463)}{1000}\right] 2.67 = 862.2$

$(.7129)\ (68.9) = 49.1$

$(.05920)(862.2) = 51.0$

$(.433)(.1076) = .04657$

Top of B 472'

Bomb 449'

Datum +370'

Sea level

By analogy to Hill Fed 24 (237') Loddy #1 (205') and High Adventure #1 (230') the FL of Bearcat #1 will be +200' to +250' therefore the gradient is gas only

	KB	Subsea
Operator	Mesa Grande	
Well	Bearcat #1	
Elevation	7249	
Top of B Zone	6777	+ 472
Test Date	11/19/87	
Bomb Depth	6770	+ 479
Bomb Pressure, psig	765	
Fluid Level	below +370'	
Wellbore Gradient		
Oil, psi/ft		
Gas, psi/ft	(.03)(479-472)	.15
Pressure at Top of B Zone	765.15	
Top of B Zone to +370 ft	102	
Production		
BO/D	10.6	
Mcf/D	192	
Volume Weighted Reservoir Density, psi/ft	.035	
dP to +370 ft	3.6	
Pressure at +370 ft datum	768.7	

$(10.6)(1.289) = 13.7$

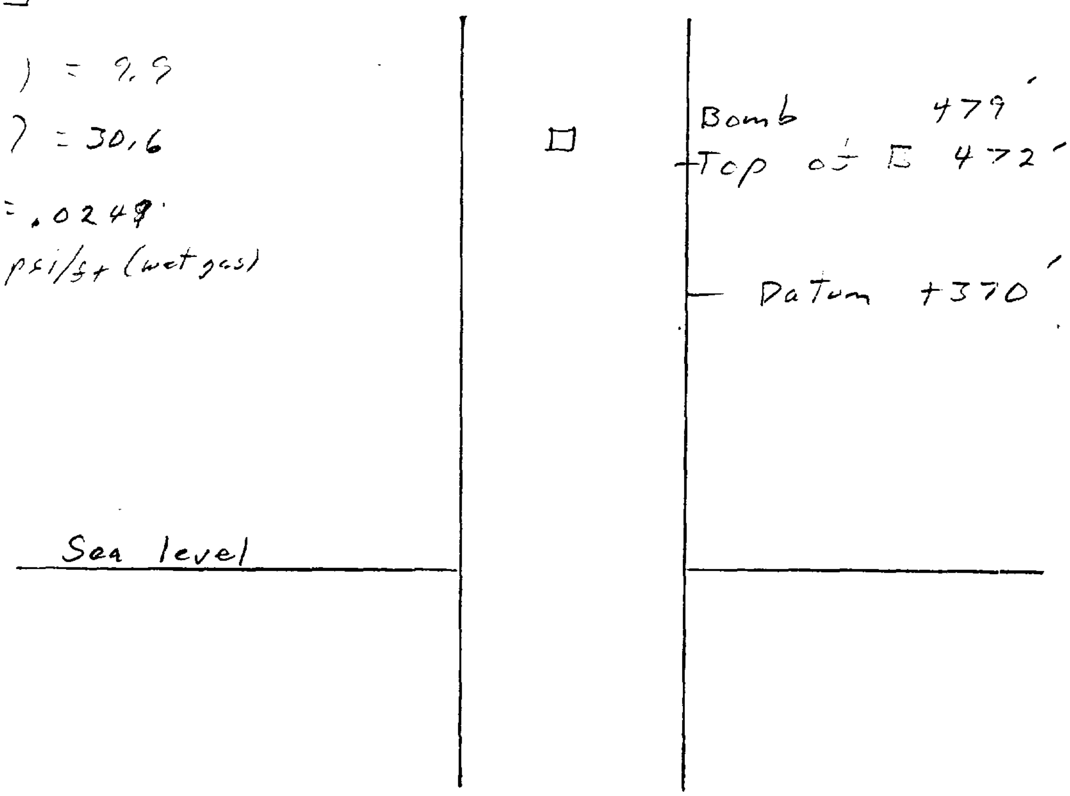
$\left[192 - \frac{(10.6)(385)}{1000}\right]3.7 = 695.3$

$(.722)(13.7) = 9.9$

$(.04414)(695.3) = 30.6$

$(.433)(.05725) = .0248$

use 0.035 psi/ft (wet gas)



Operator	Mesa Grande	
Well	BearcaT #1	
	KB	Subsea
Elevation	7249	
Top of B Zone	6777	+472
Test Date	2/23/88	
Bomb Depth	6770	+479
Bomb Pressure, psig	732	
Fluid Level	below +370'	
Wellbore Gradient		
Oil, psi/ft		
Gas, psi/ft	(.03)(479-472)	.15
Pressure at Top of B Zone	732.15	
Top of B Zone to +370 ft	102	
Production		
BO/D	5.7	
Mcf/D	213	
Volume Weighted Reservoir Density, psi/ft	0.035	
dP to +370 ft	3.6	
Pressure at +370 ft datum	735.7	

$(5.7)(1.285) = 7.3$

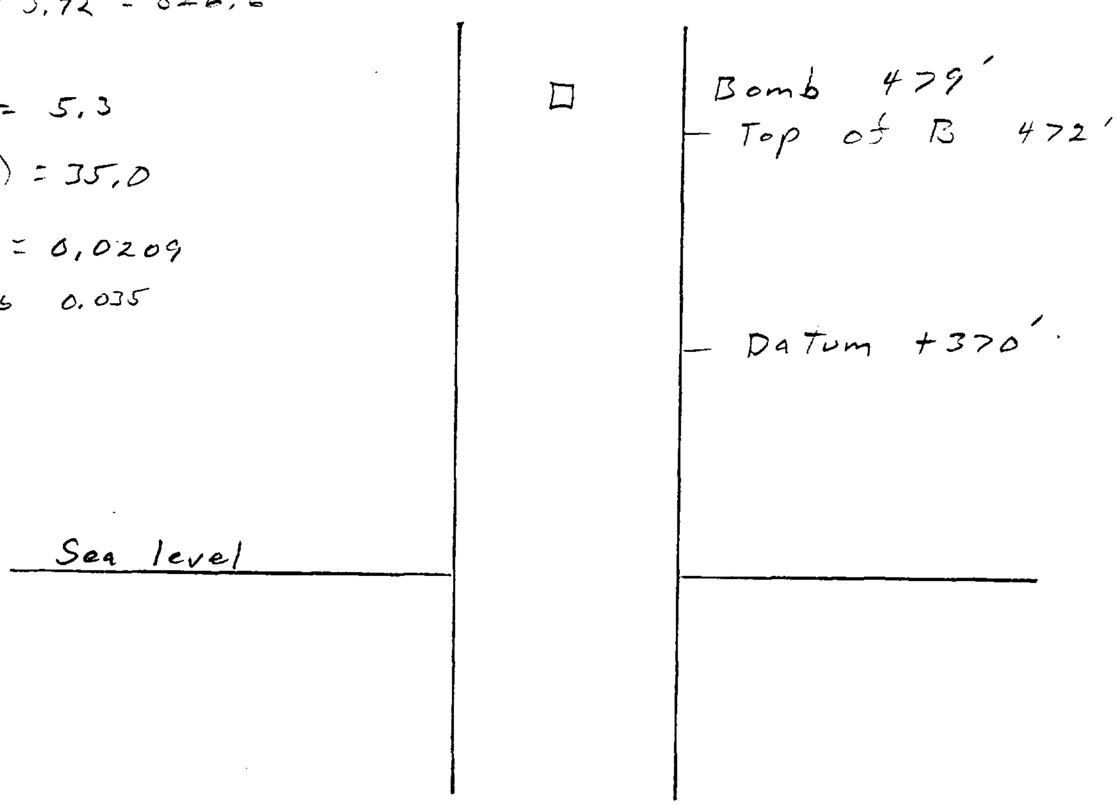
$\left[213 - \frac{5.7(373)}{1000}\right] 3.92 = 826.6$

$(.7239)(7.3) = 5.3$

$(.04239)(826.6) = 35.0$

$(.433)(.04837) = 0.0209$

use wet gas 0.035



	KB		Subsea
Operator	Meridian		
Well	Hill Federal 24		
Elevation	7467		
Top of B Zone	7013		+454
Test Date		6/30/87	
Bomb Depth	7400		+67
Bomb Pressure, psig		1165	
Fluid Level (oil)	7230		+237
	7300	water	+167
Wellbore Gradient			
Oil, psi/ft	(.3)(237-167)		21.0
Gas, psi/ft	(.03)(467-237)		6.3
H_2O, .433 psi/ft	(.433)(167-67)		43.3
Pressure at Top of B Zone		1094.4	
Top of B Zone to +370 ft	84		
Production			
BO/D		100	
Mcf/D		240	
Volume Weighted Reservoir Density, psi/ft		.08803	
dP to +370 ft		7.4	
Pressure at +370 ft datum		1101.8	

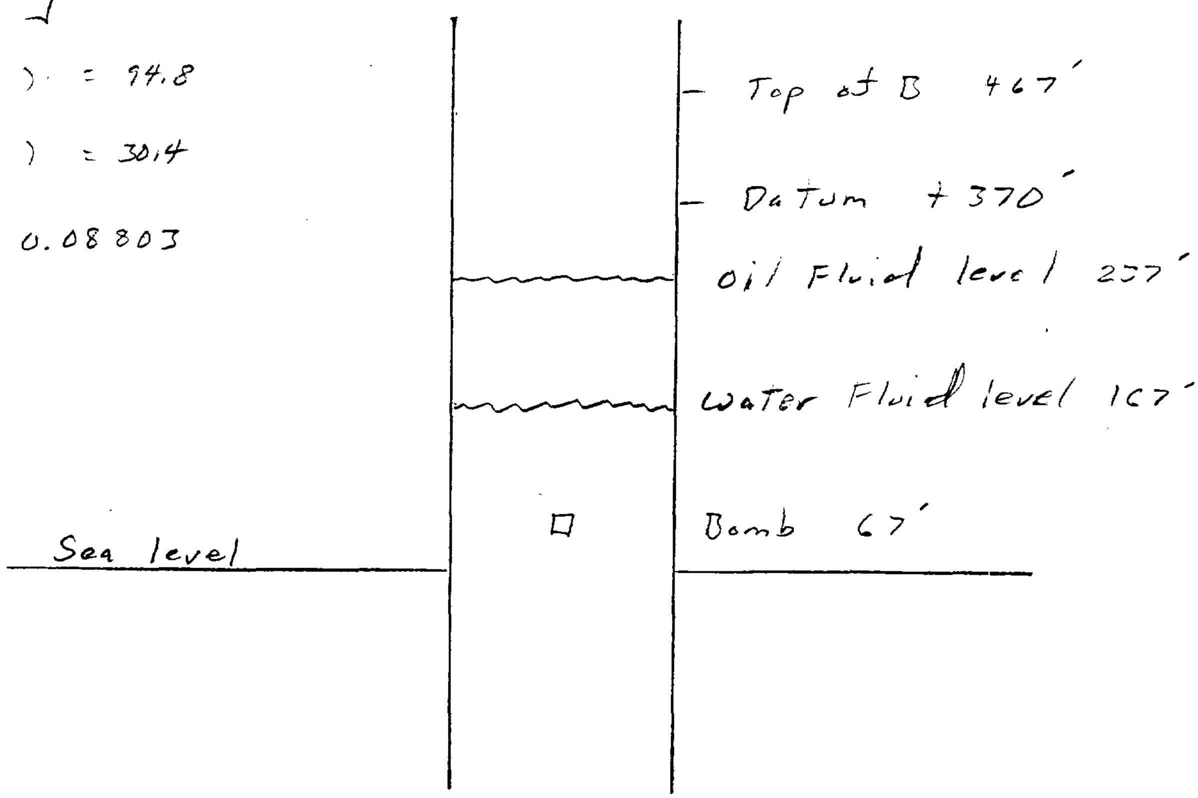
$(100)(1.333) = 133.3$

$\left[240 - \frac{(100)(479)}{1000}\right] 2.511 = 482.4$

$(.7113)(133.3) = 94.8$

$(.062944)(482.4) = 30.4$

$(.433)(0.2033) = 0.08803$



	KB		Subsea
Operator	Meridian		
Well	Hill Federal #1		
Elevation	7480		
Top of B Zone	7017		+463
Test Date		11/19/87	
Bomb Depth	7555		-75
Bomb Pressure, psig		988	
Fluid Level	7456		+24
Wellbore Gradient			
Oil, psi/ft	(.3)(-75-24)		-29.7
Gas, psi/ft	(.03)(24-463)		-13.2
Pressure at Top of B Zone		945.1	
Top of B Zone to +370 ft	93'		
Production			
BO/D		27	
Mcf/D		880	
Volume Weighted Reservoir Density, psi/ft		0.035	
dP to +370 ft		3.3	
Pressure at +370 ft datum		948.4	

$(27)(1.314) = 35.5$

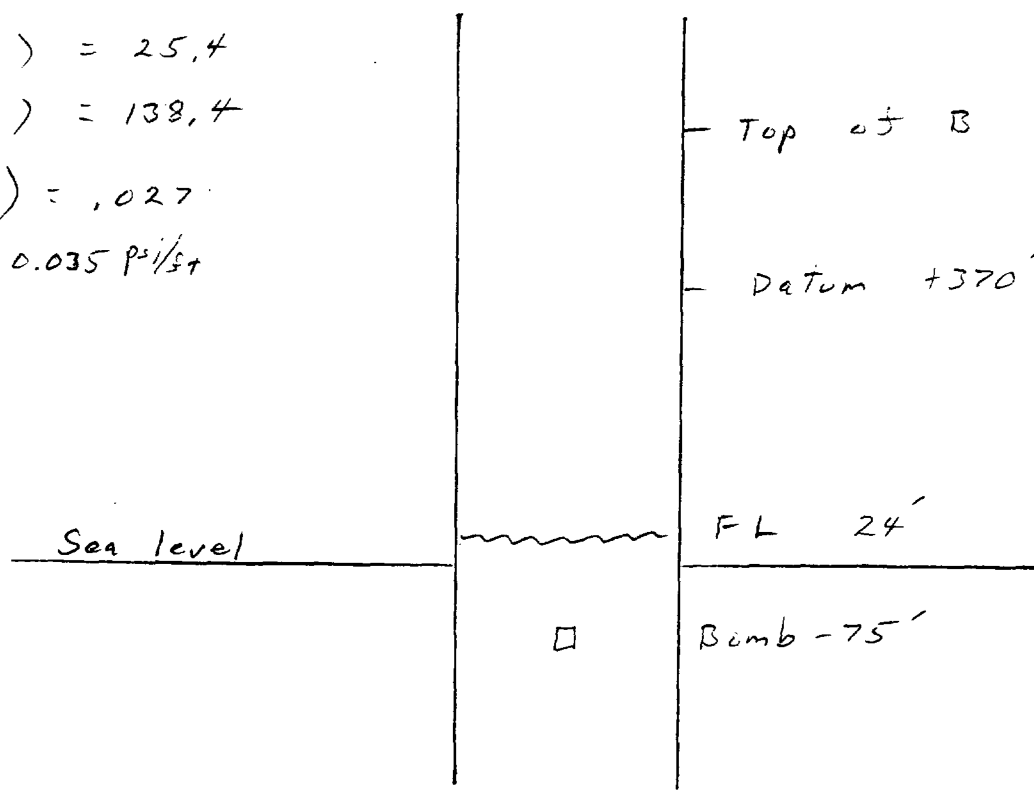
$\left[880 - \frac{(27)(436)}{1000}\right] 2.95 = 2561.3$

$(.7149)(35.5) = 25.4$

$(.05403)(2561) = 138.4$

$(.433)(.06307) = .027$

use wet gas 0.035 psi/ft



	KB		Subsea
Operator	Meridian		
Well	Hill Federal #1		
Elevation	7480		
Top of B Zone	7017		+463
Test Date		2/23/88	
Bomb Depth	7555		−75
Bomb Pressure, psig		966	
Fluid Level	7552		−72
Wellbore Gradient			
Oil, psi/ft	.3(75-72)		−0.9
Gas, psi/ft	.03(463+72)		−16.05
Pressure at Top of B Zone		949	
Top of B Zone to +370 ft	93		
Production			
BO/D		11	
Mcf/D		962	
Volume Weighted Reservoir Density, psi/ft		0.035	
dP to +370 ft		3.3	
Pressure at +370 ft datum		952.3	

$(11) \quad (1.314) = 14.5$

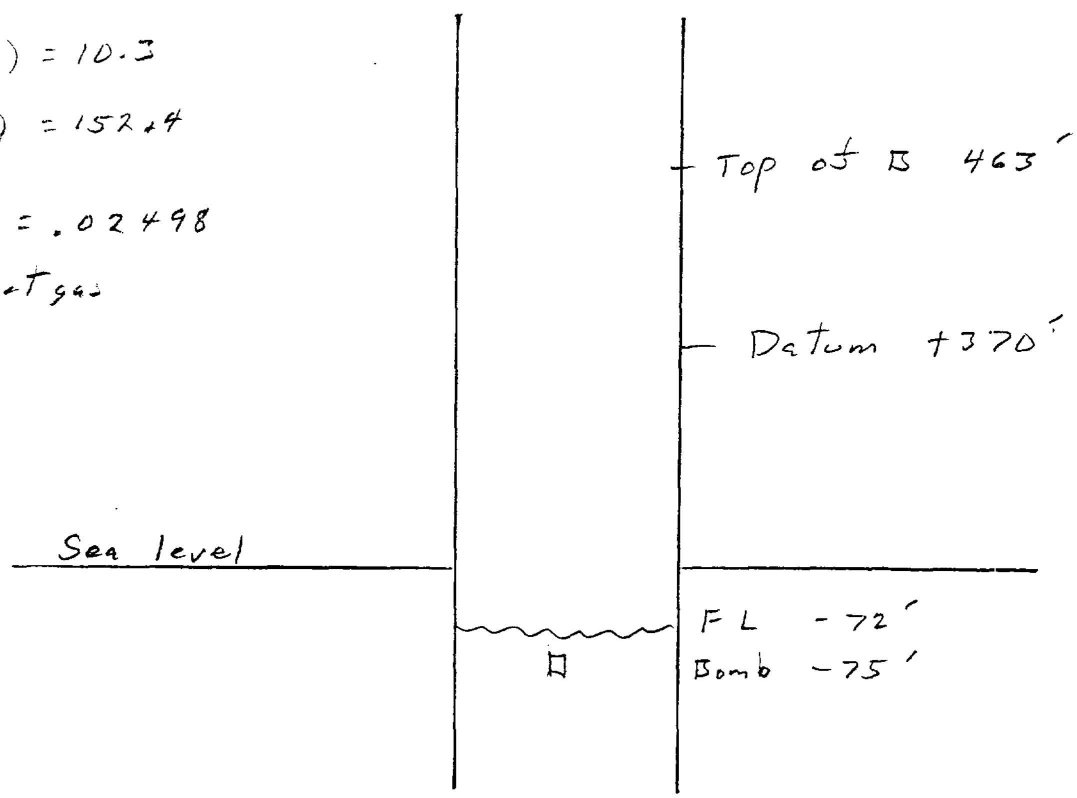
$\left[962 - \frac{(11)(437)}{1000}\right] 2.932 = 2806.5$

$(.7148)(14.5) = 10.3$

$(.054314)(2806.5) = 152.4$

$(.437)(.05769) = .02498$

use 0.035 wet gas



5/2/88

	KB		Subsea
Operator	Mobil		
Well	Lindrith B-37		
Elevation	7134		
Top of B Zone	6683		+ 451
Test Date		6/30/87	
Bomb Depth	6814		+ 334
Bomb Pressure, psig		1059	
Fluid Level			+ 419
~~Distance to Top of B Zone~~			
Wellbore Gradient			
Oil, psi/ft		0.3 (419-334)	
Gas, psi/ft		0.03 (451-419)	
Pressure at Top of B Zone		1059-26 = 1032	
Top of B Zone to +370 ft		81	
Production			
BO/D		54	
Mcf/D		435	
Volume Weighted Reservoir Density, psi/ft		0.04270	
dP to +370 ft		3.5	
Pressure at +370 ft datum		1035.5	

$(54)(1.323) = 71.4$

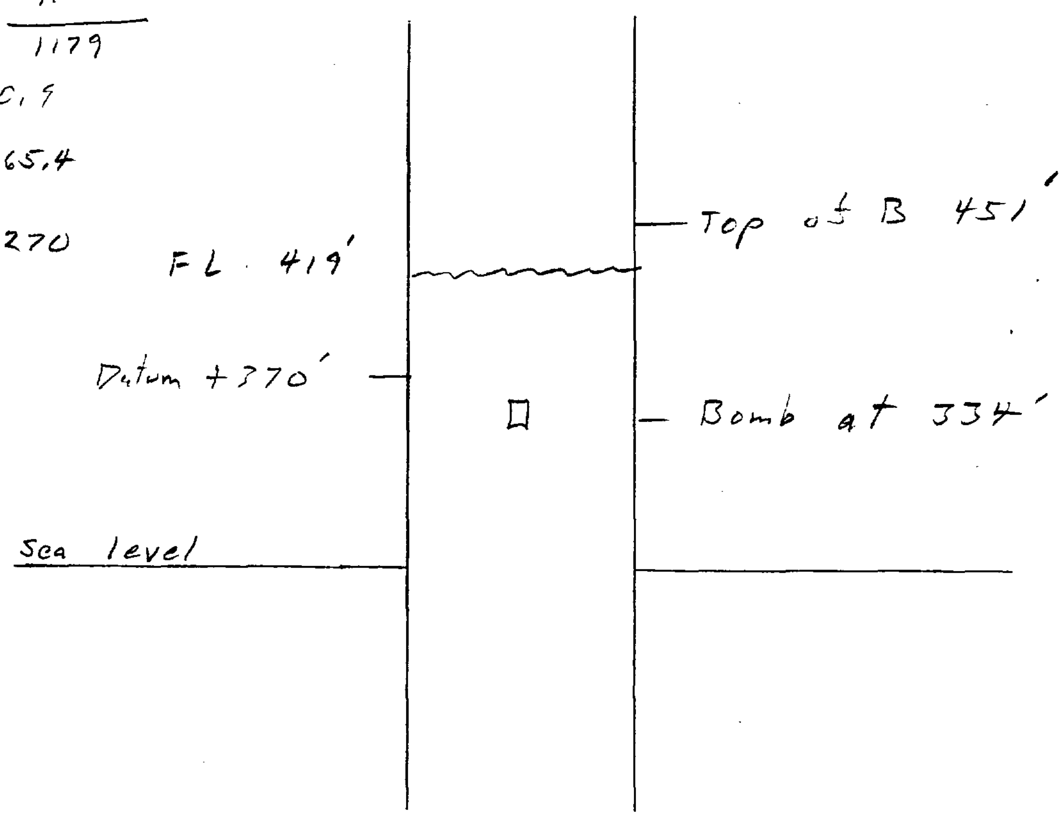
$\left[435 - \frac{(54)(459)}{1000}\right] 2.7 = 1107.6$

$\overline{1179}$

$(71.4)(.7131) = 50.9$

$(1107.6)(.05903) = 65.4$

$.433(.0986) = .04270$



	KB		Subsea
Operator	Mobil		
Well	Lindrith B-37		
Elevation	7134		
Top of B Zone	6683		+451
Test Date		11/19/87	
Bomb Depth	6814		+334
Bomb Pressure, psig		797	
Fluid Level			+522
~~Distance to Top of B Zone~~			
Wellbore Gradient			
Oil, psi/ft		0.3 (451-334)	
Gas, psi/ft		0.03	
Pressure at Top of B Zone		762	
Top of B Zone to +370 ft		81	
Production			
BO/D		214	
Mcf/D		889	
Volume Weighted Reservoir Density, psi/ft		0.04422	
dP to +370 ft		3.6	
Pressure at +370 ft datum		765.6	

$(214)(1.291) = 276.3$

$\left[889 - \frac{(214)(287)}{1000}\right]3.656 = 2947.4$

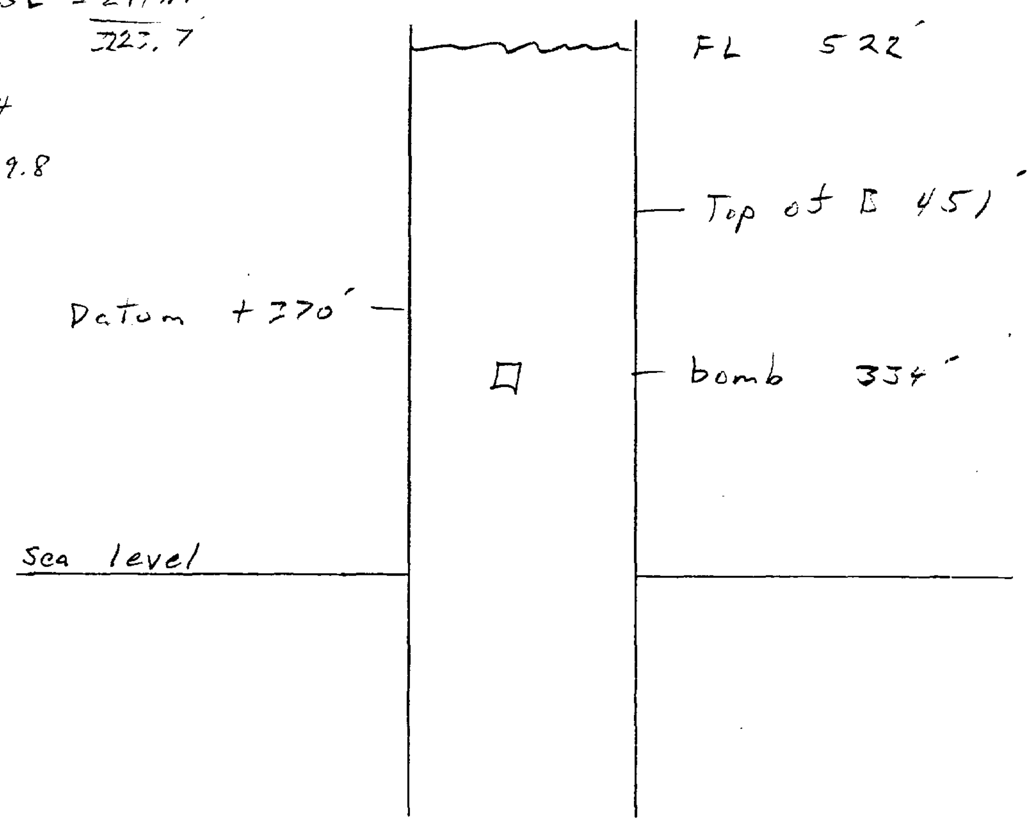
3223.7

$(276.3)(.7218) = 199.4$

$(2947.4)(.04404) = 129.8$

$\rho_{Avg} = (.10212)(.433)$

$= .04422$



	KB		Subsea
Operator	Mobil		
Well	Lindrith B-37		
Elevation	7134		
Top of B Zone	6683		+451
Test Date		2/23/88	
Bomb Depth	6894		+240
Bomb Pressure, psig		774	
Fluid Level	6744		+390
~~Distance to Top of B Zone~~			
Wellbore Gradient			
Oil, psi/ft		.3 (390-240) = 45	
Gas, psi/ft		.03 (451-390) = 1.8	
Pressure at Top of B Zone		774-47 = 727	
Top of B Zone to +370 ft		81	
Production			
BO/D		188	
Mcf/D		816	
Volume Weighted Reservoir Density, psi/ft		0.04070	
dP to +370 ft		3.3	
Pressure at +370 ft datum		730.3	

$(188)(1.284) = 241.4$

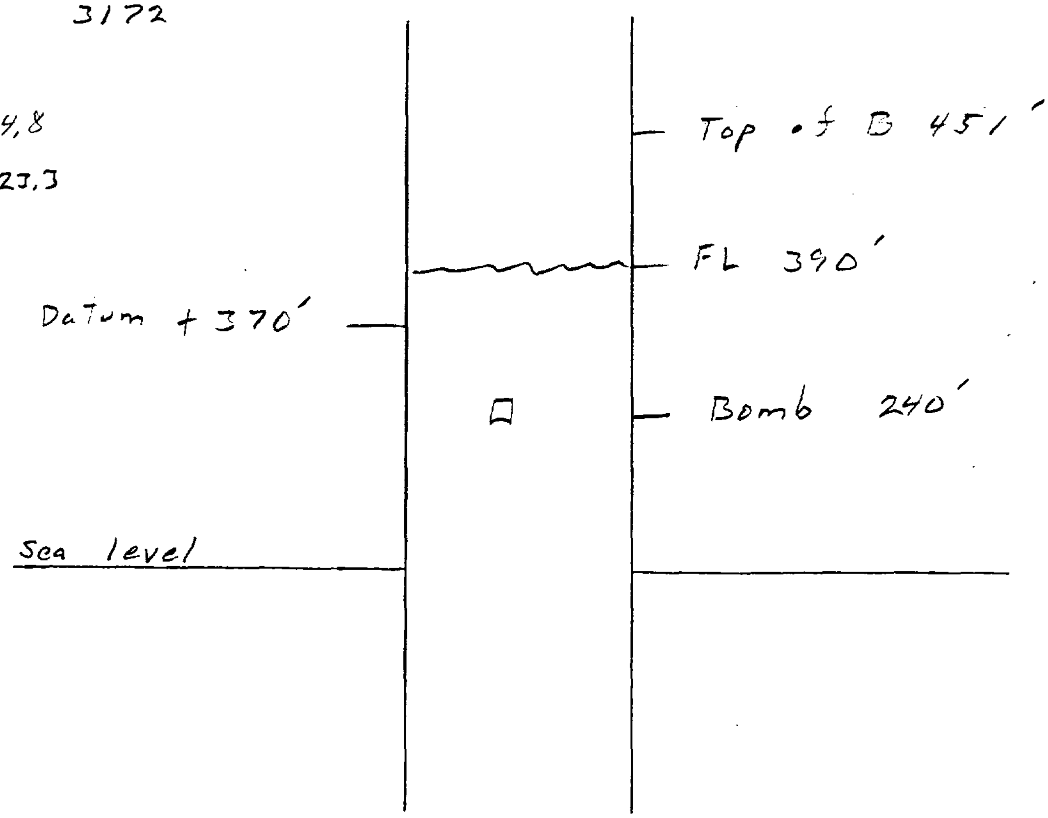
$\left[816 - \frac{(188)(372)}{1000}\right] 3.928 = 2930.5$

3172

$(.7241)(241.4) = 174.8$

$(.04209)(2930.5) = 123.3$

$\rho_{AV} = .09399\ (433)$



Operator	Reading & Bates		
Well	Howard Federal 43-15		
	KB		Subsea
Elevation	7269		
Top of B Zone	6799		+ 470
Test Date		6/30/87	
Bomb Depth	6802		+ 467
Bomb Pressure, psig		1045	
Fluid Level	None		
~~Distance to Top of B Zone~~			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft		.03	
Pressure at Top of B Zone		1045 - (.03)(2) = 1045	
Top of B Zone to +370 ft		100'	
Production			
BO/D		4.3	
Mcf/D		239	
Volume Weighted Reservoir Density, psi/ft		0.035	
dP to +370 ft		3.5	
Pressure at +370 ft datum		1048.5	

$(4.3)(1.327) = 5.7$

$\left[239 - \frac{(4.3)(446)}{1000}\right] 2.632 = 623.8$

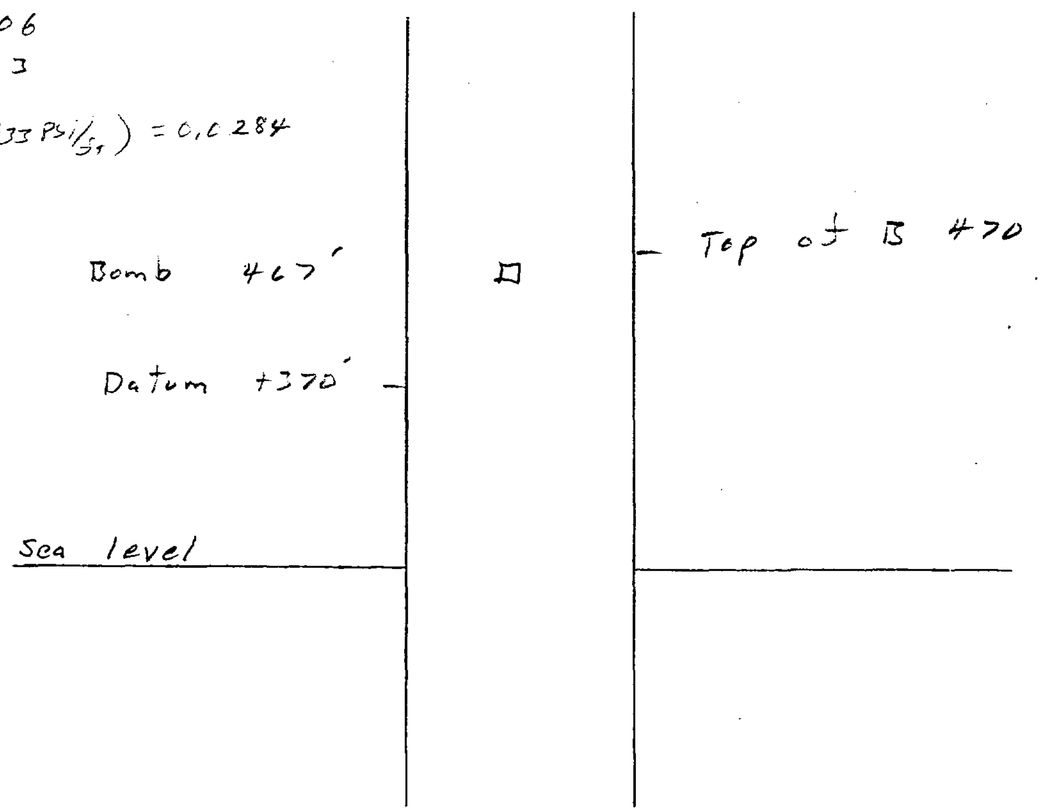
629.5

$(.7125)(5.7) = 4.06$

$(.05978)(623.8) = 37.3$

$\rho_A = (.0657\ gm/cc)(0.433\ psi/ft) = 0.0284$

use 0.035 (wet gas)



	KB		Subsea
Operator	Reading + Bates		
Well	Howard Federal #3-15		
Elevation	7269		
Top of B Zone	6799		+470
Test Date		11/19/87	
Bomb Depth	6512		+757
Bomb Pressure, psig		776	
Fluid Level			
~~Distance to Top of B Zone~~			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft		0.03 (757-470) =	
Pressure at Top of B Zone		776 + 8.6 = 784.6	
Top of B Zone to +370 ft		100	
Production			
BO/D		9.2	
Mcf/D		637	
Volume Weighted Reservoir Density, psi/ft		0.035	
dP to +370 ft		3.5	
Pressure at +370 ft datum		788.1	

(9.2) (1.292) = 11.8

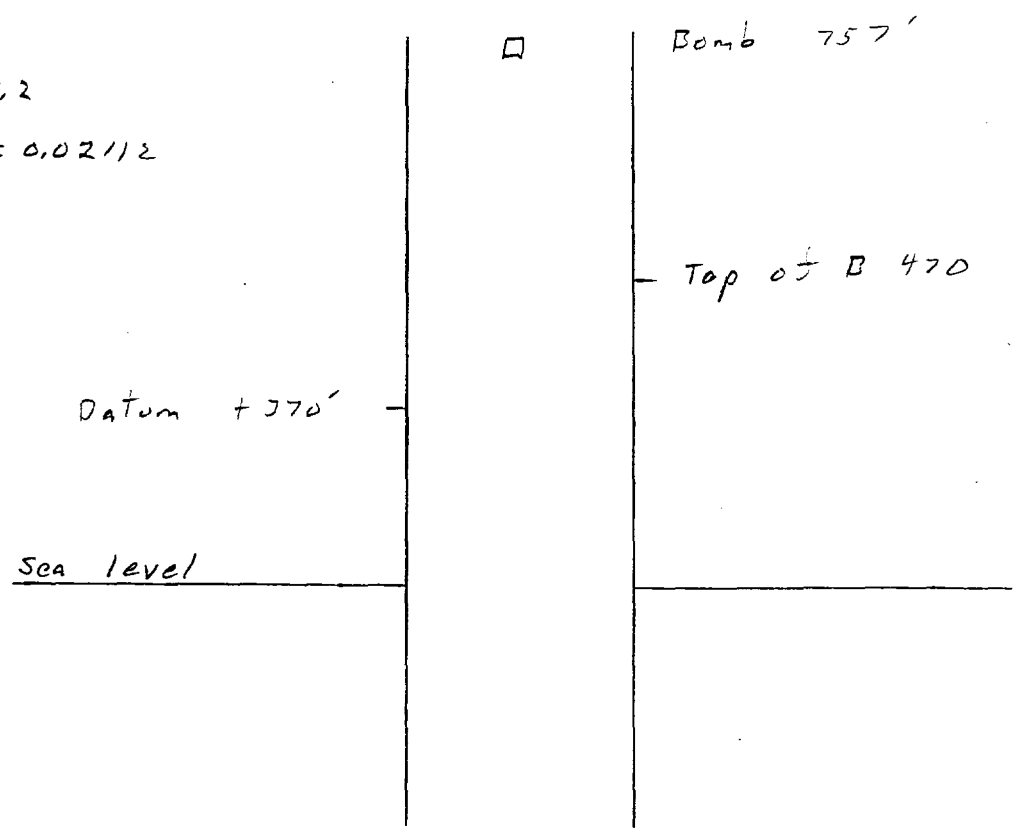
$\left[637 - \frac{(9.2)(390)}{1000}\right] 3.6 = \underline{2280}$

(.7210)(11.8) = 8.57

(.04526)(2230) = 103.2

(.433)(0.04877) = 0.02112

use 0.035



	KB		Subsea
Operator	Reading & Bates		
Well	Howard Federal 43-15		
Elevation	7269		
Top of B Zone	6799		+470
Test Date		2/23/88	
Bomb Depth	6512		+757
Bomb Pressure, psig		739	
Fluid Level	None		
~~Distance to Top of B Zone~~			
Wellbore Gradient			
Oil, psi/ft			
Gas, psi/ft		.03 (470 - 757)	
Pressure at Top of B Zone		739 + 8.6 = 747.6	
Top of B Zone to +370 ft		100	
Production			
BO/D		3.6	
Mcf/D		240	
Volume Weighted Reservoir Density, psi/ft		0.035	
dP to +370 ft		3.5	
Pressure at +370 ft datum		751.1	

$(3.6)(1.268) = 4.63$

$\left[240 - \frac{(3.6)(280)}{1000}\right] 3.792 = 904.9$

909.5

$(.7229)(4.63) = 3.35$

$(~~.043344~~)(904.9) = 39.2$

$\rho_A = (.04681)(.433) = 0.02027$

use wet gas 0.035

Bomb 757

Top of B 470'

Datum +370'

Sea level

	KB		Subsea
Operator	Sun		
Well	Boyt & Lola #1		
Elevation	7351		
Top of B Zone	6848		+503
Test Date		6/30/87	
Bomb Depth	7000		+351
Bomb Pressure, psig		853	
Fluid Level			+363
~~Distance to Top of B Zone~~			
Wellbore Gradient			
Oil, psi/ft		0.3	
Gas, psi/ft		0.03	
Pressure at Top of B Zone		845	
Top of B Zone to +370 ft	133'		
Production			
BO/D		1.8	
Mcf/D		9.7	
Volume Weighted Reservoir Density, psi/ft		.04210	
dP to +370 ft		5.6	
Pressure at +370 ft datum		850.6	

(0.3)(363-351) = 3.6
(.03)(503-363) = 4.2
7.8

853
− 8
845

(1.8)(1.301) = 2.3

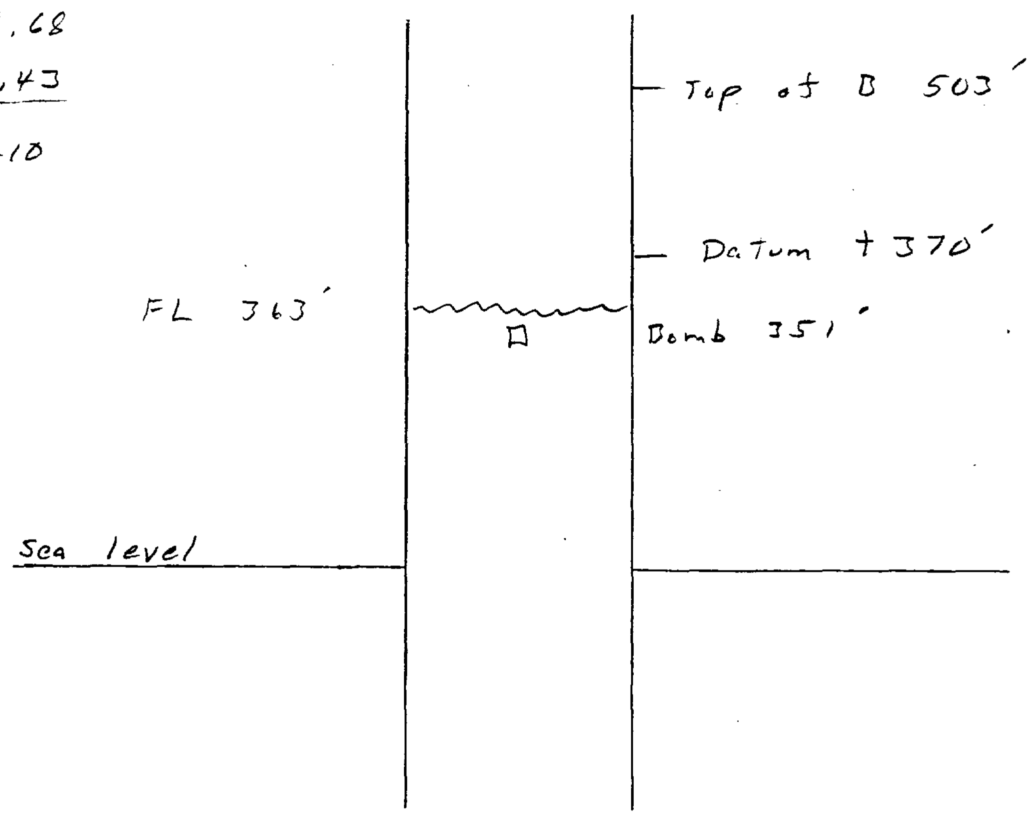
$\left[9.7 - \frac{(1.8)409}{1000}\right] 3.309 = 29.6$

32.03

(.7183)(2.3) = 1.68

(.04848)(29.6) = 1.43

(.433)(.0973) = .04210



	KB		Subsea
Operator	Sun		
Well	Boyt + Lola #1		
Elevation	7351		
Top of B Zone	6848		+503
Test Date		11/19/87	
Bomb Depth	7060		+351
Bomb Pressure, psig		762	
Fluid Level			+571
Distance to Top of B Zone			
Wellbore Gradient			
Oil, psi/ft		.3(503-351) = 45.6	
Gas, psi/ft			
Pressure at Top of B Zone	762-46	716.4	
Top of B Zone to +370 ft	133'		
Production			
BO/D		1.8	
Mcf/D		9.7	
Volume Weighted Reservoir Density, psi/ft		0.04241	
dP to +370 ft		5.6	
Pressure at +370 ft datum		722.0	

$(1.8)(1.315) = 2.4$

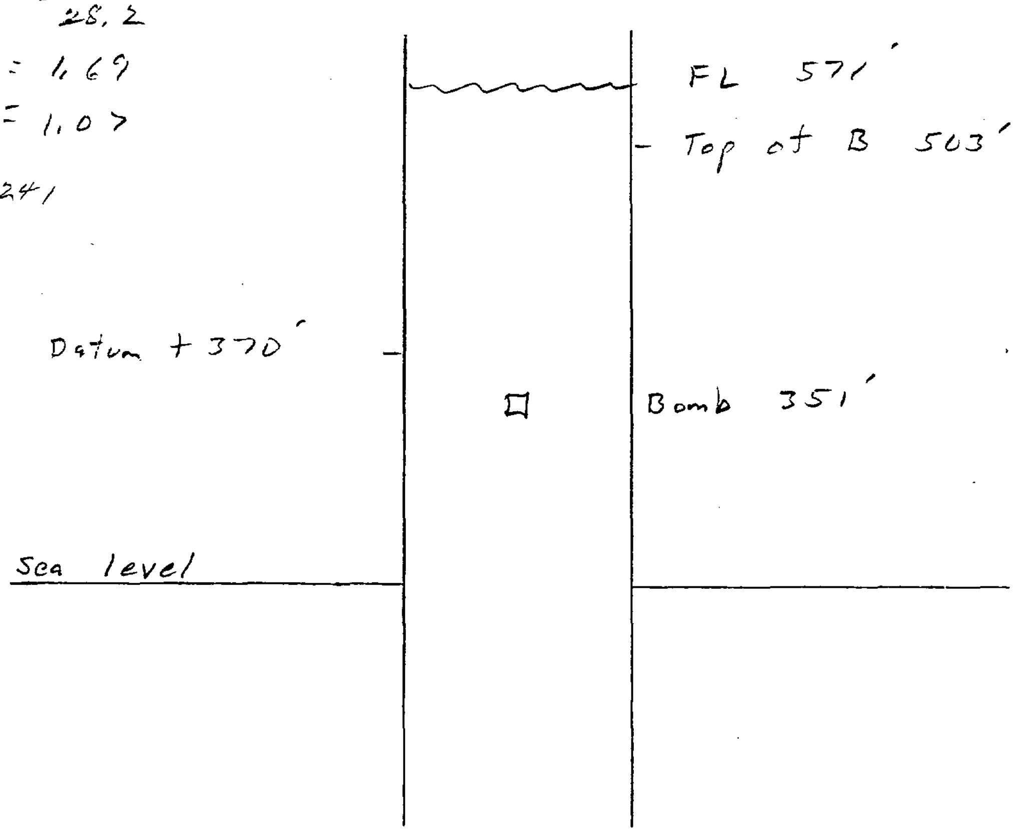
$\left[9.7 - \frac{(1.8)(440)}{1000}\right] 29 = 25.8$

$\overline{28.2}$

$(.7146)(2.4) = 1.69$

$(.04155)(25.8) = 1.07$

$(.433)(.09794) = .04241$



Operator	Sun	
Well	Bert + Lola #1	
	KB	Subsea
Elevation	7351	
Top of B Zone	6848	+503
Test Date	2/22/88	
Bomb Depth	7000	+351
Bomb Pressure, psig	790	
Fluid Level		+561
~~Distance to Top of B Zone~~		
Wellbore Gradient		
Oil, psi/ft	(0.3)(503-351) = 45.6	
Gas, psi/ft		
Pressure at Top of B Zone	790 - 45.6 = 744.4	
Top of B Zone to +370 ft	133'	
Production		
BO/D	1.8	
Mcf/D	9.7	
Volume Weighted Reservoir Density, psi/ft	.03727	
dP to +370 ft	5.0	
Pressure at +370 ft datum	749.4	

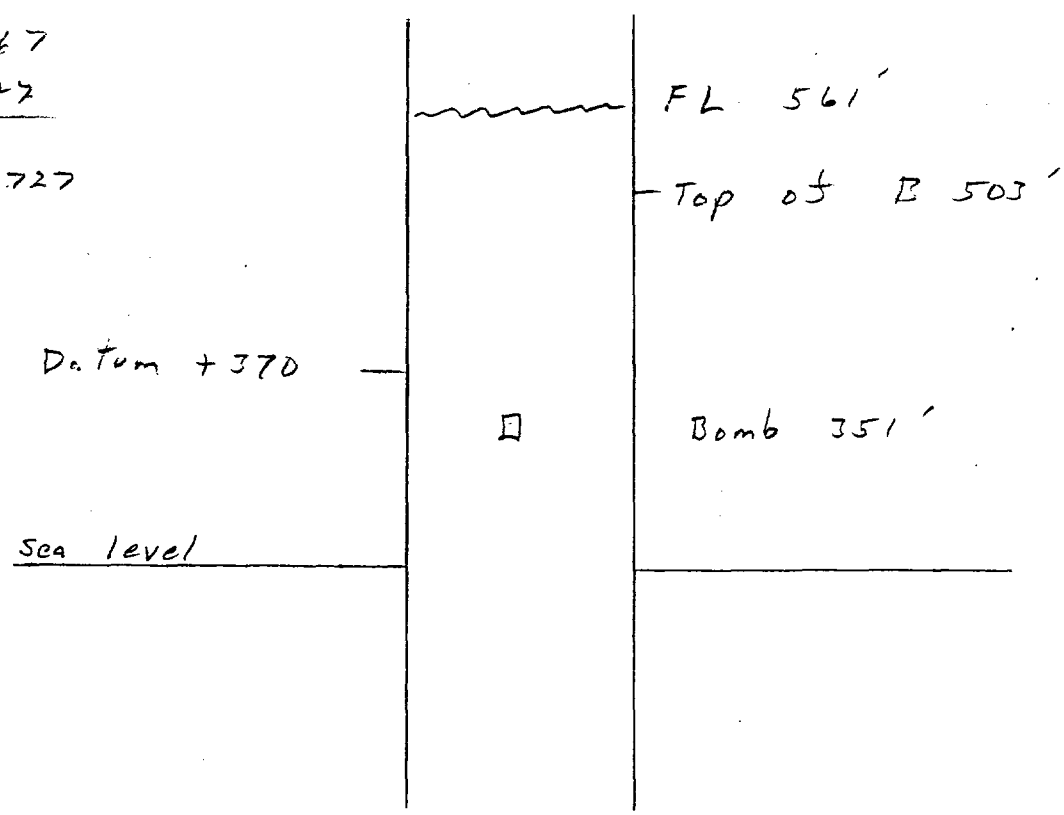
(1.8) (1.288) = 2.3

$\left[9.7 - \frac{(1.8)(380)}{1000}\right] 3.792 = 34.2$

(.7229)(2.3) = 1.67

(.04302)(34.2) = 1.47

(433)(.08606) = .03727



Operator	Sun		
Well	High Adventure #1		
	KB		Subsea
Elevation	7332		
Top of B Zone	7150		+ 182
Test Date		6/30/57	
Bomb Depth	7310		+ 22
Bomb Pressure, psig		1164	
Fluid Level	7102		+ 230
Wellbore Gradient			
Oil, psi/ft	0.3 (182-22)		48
Gas, psi/ft			
Pressure at Top of B Zone	1164-48 =	1116	
Top of B Zone to +370 ft	188'		
Production			
BO/D		225	GOR
Mcf/D		604	2684
Volume Weighted Reservoir Density, psi/ft		.07474	
dP to +370 ft		14.1	
Pressure at +370 ft datum		1101.9	

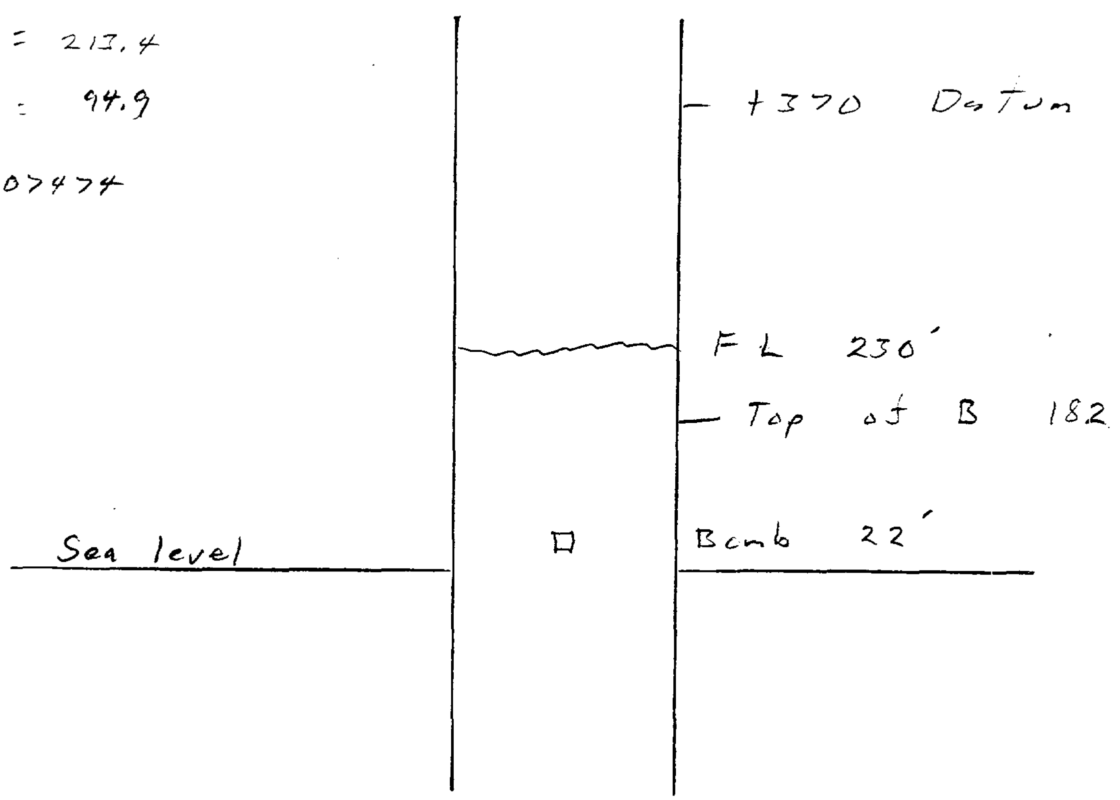
$(225)(1.334) = 300.2$

$\left[604 - \frac{(225)(482)}{1000}\right] 2.46 = \frac{1485.8}{1786}$

$(.7110)(300.2) = 213.4$

$(.063860)(1485.8) = 94.9$

$(.433)(.1720) = 0.07474$



	KB		Subsea
Operator	Sun		
Well	High Adventure #1		
Elevation	7332		
Top of B Zone	7150		+182
Test Date		11/19/87	
Bomb Depth	7400		-68
Bomb Pressure, psig		911	
Fluid Level			+210'
Wellbore Gradient			
Oil, psi/ft	(.3)(-68-182)		-75
Gas, psi/ft			
Pressure at Top of B Zone		836	
Top of B Zone to +370 ft	188		
Production			
BO/D		228	
Mcf/D		689	
Volume Weighted Reservoir Density, psi/ft		0.05798	
dP to +370 ft		10.9	
Pressure at +370 ft datum		825.1	

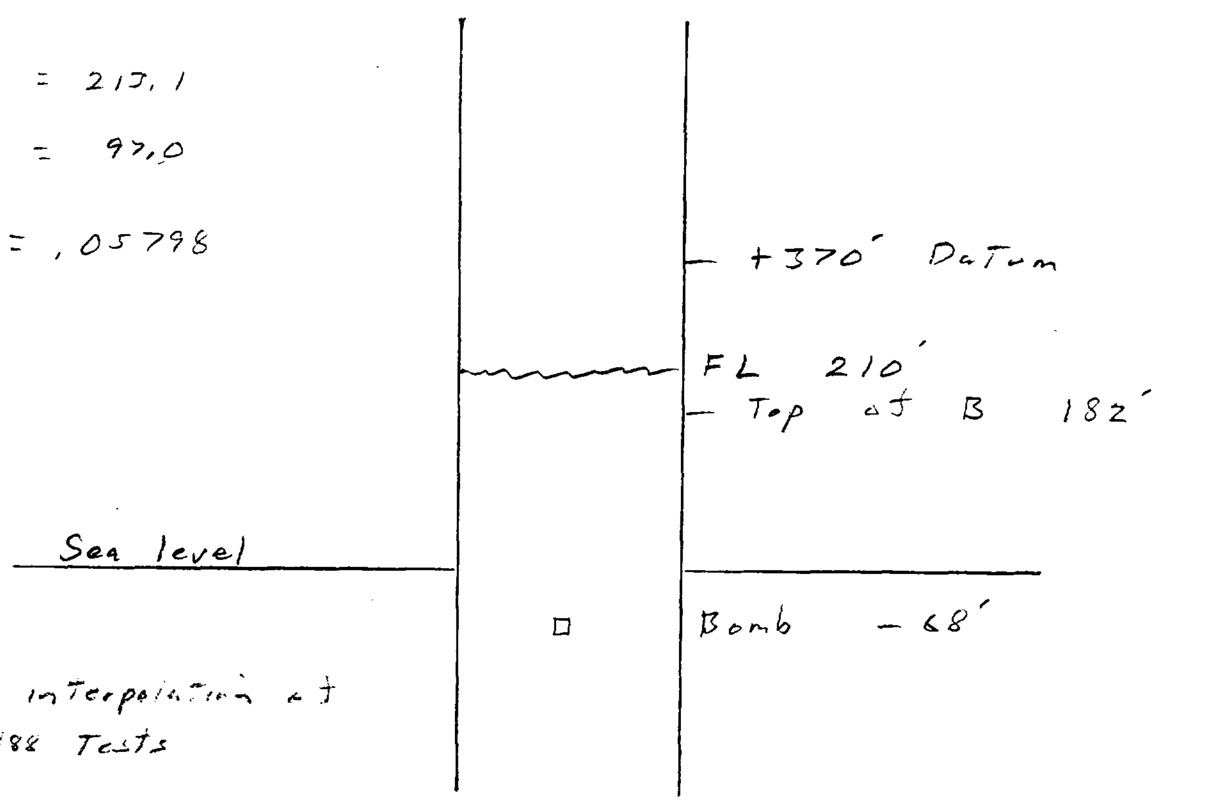
$(228)(1.30) = 296.4$

$\left[689 - \frac{228(405)}{1000}\right] 3.385 = 2019.6$

$(.719)(296.4) = 213.1$

$(.04805)(2019.6) = 97.0$

$(.433)(.1339) = .05798$



Fluid level by interpolation at 6/30/87 + 11/19/88 Tests

$$\frac{1116-785}{911-785} = \frac{230-197}{FL_{11/19}-197}$$

FL = 210'

Operator	Sun		
Well	High Adventure #1		
	KB		Subsea
Elevation	7332		
Top of B Zone	7150		+182
Test Date		2/23/88	
Bomb Depth	7400		-68
Bomb Pressure, psig		860	
Fluid Level	7135		+197
Wellbore Gradient			
Oil, psi/ft	(.3)(-68-182)		-75
Gas, psi/ft			
Pressure at Top of B Zone		785	
Top of B Zone to +370 ft	188'		
Production			
BO/D		269	GOR
Mcf/D		584	2171
Volume Weighted Reservoir Density, psi/ft		0.07269	
dP to +370 ft		13.7	
Pressure at +370 ft datum		771.3	

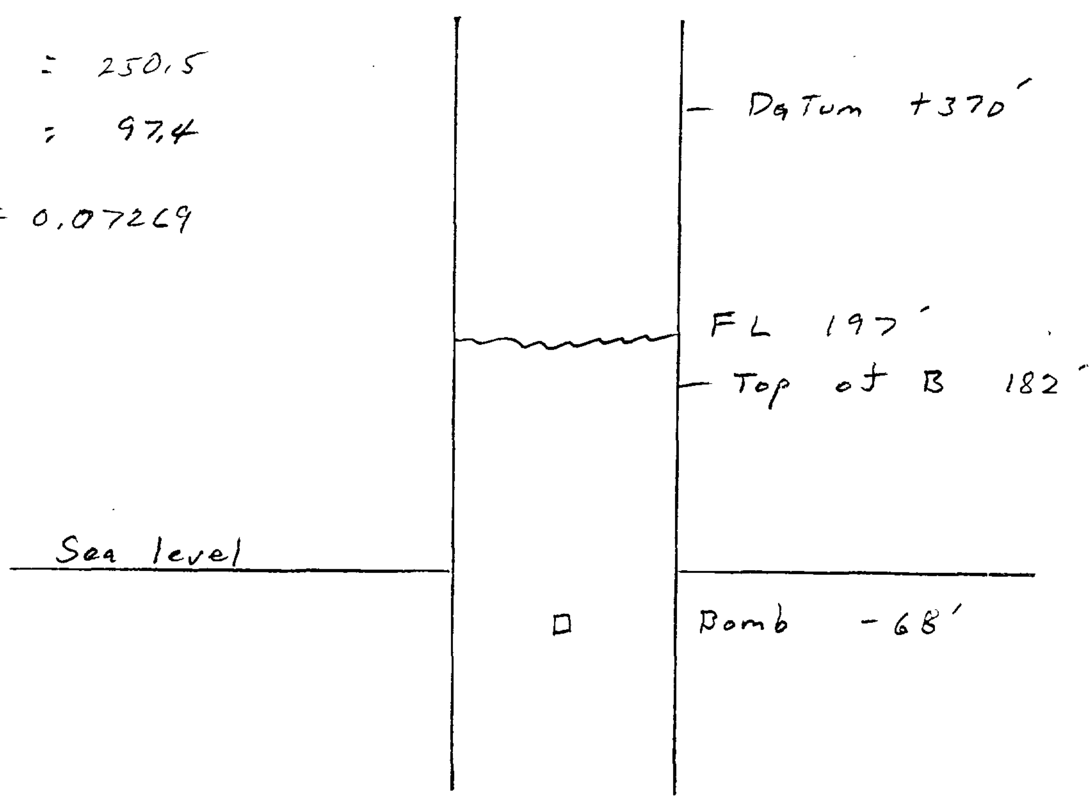
$(269)(1.292) = 347.5$

$\left[584 - \frac{269(390)}{1000}\right] 3.6 = 1724.7$

$(.7210)(347.5) = 250.5$

$(.05647)(1724.7) = 97.4$

$(.433)(.16789) = 0.07269$



	KB		Subsea
Operator	Sun		
Well	Loddy #1		
Elevation	7167		
Top of B Zone	6927		+ 240
Test Date		6/30/87	
Bomb Depth	7100		+ 67
Bomb Pressure, psig		1140	
Fluid Level	6962		+ 205
Wellbore Gradient			
Oil, psi/ft	(.3)(205-67)		41.4
Gas, psi/ft	(.03)(240-205)		1.1
Pressure at Top of B Zone		1097.5	
Top of B Zone to +370 ft	130′		
Production			
BO/D		61	
Mcf/D		433	
Volume Weighted Reservoir Density, psi/ft		.04819	
dP to +370 ft		6.3	
Pressure at +370 ft datum		1091.2	

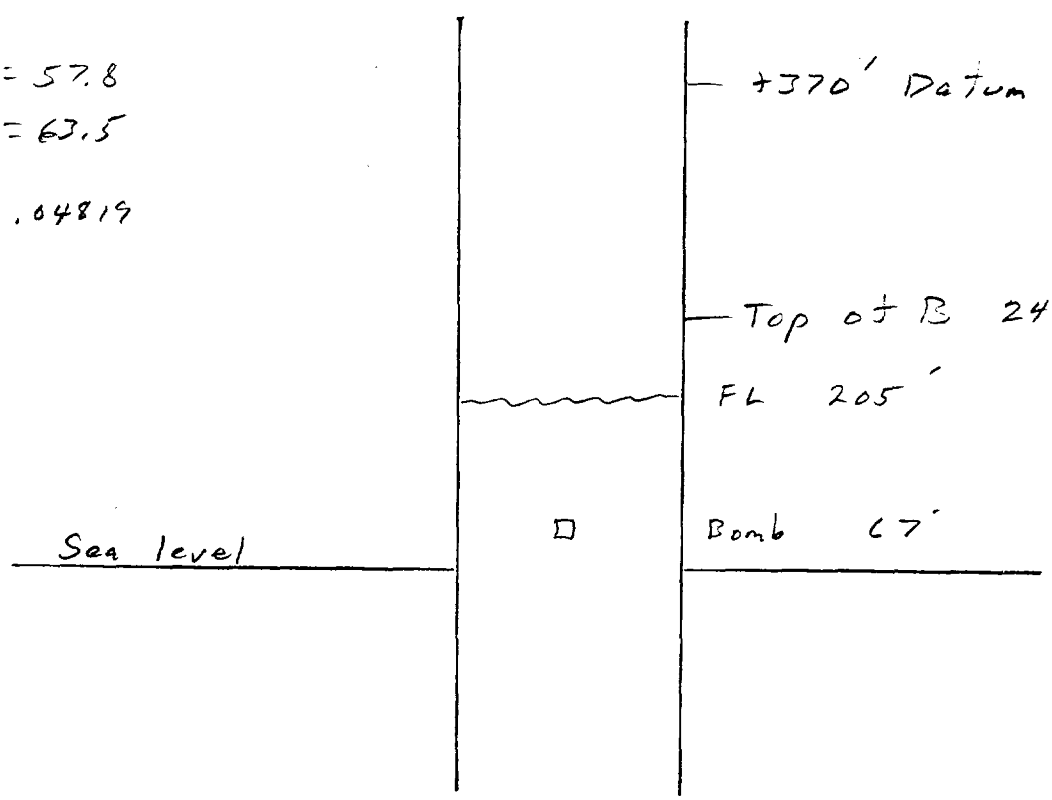
$(61)\ (1.333) = 81.3$

$\left[433 - \frac{(61)(480)}{1000}\right] 2.497 = 1008.1$

$(.7113)\ (81.3) = 57.8$

$(.062944)\ (1008.1) = 63.5$

$(.433)\ (.1113) = .04819$



	KB		Subsea
Operator	Sun		
Well	Loddy #1		
Elevation	7167		
Top of B Zone	6927		+240
Test Date		11/19/87	
Bomb Depth	7100		+67
Bomb Pressure, psig		902	
Fluid Level			+182
Wellbore Gradient			
Oil, psi/ft	(.3)(182-67)		34.5
Gas, psi/ft	(.03)(240-182)		1.7
Pressure at Top of B Zone		866.8	
Top of B Zone to +370 ft	130		
Production			
BO/D		58	
Mcf/D		338	
Volume Weighted Reservoir Density, psi/ft		0.4187	
dP to +370 ft		5.4	
Pressure at +370 ft datum		861.4	

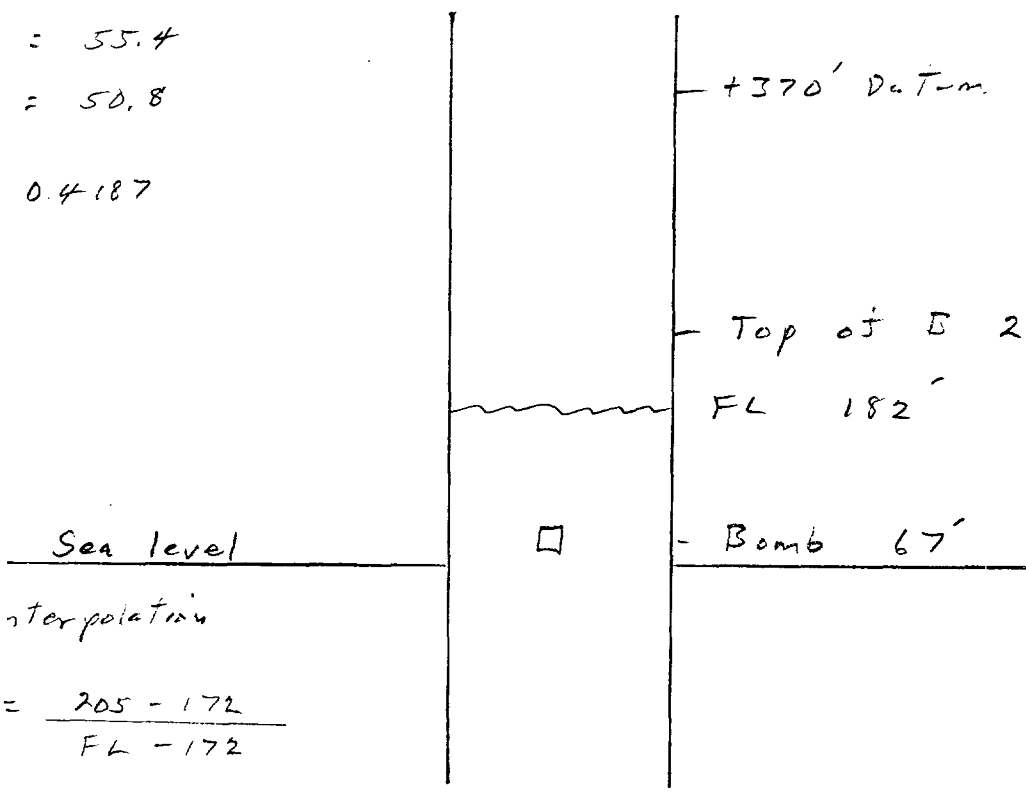
$(58)(1.303) = 77.1$

$$\left[338 - \frac{(58)(412)}{1000}\right] 3.25 = 1020.8$$

$(.7178)(77.1) = 55.4$

$(.049729)(1020.8) = 50.8$

$(.433)(.09670) = 0.4187$



Fluid level by interpolation

$$\frac{1097.5 - 812.5}{902 - 812.5} = \frac{205 - 172}{FL - 172}$$

$FL = 182$

	KB		Subsea
Operator	Sun		
Well	Loddy #1		
Elevation	7167		
Top of B Zone	6927		+240
Test Date		2/23/88	
Bomb Depth	7100		+67
Bomb Pressure, psig		846	
Fluid Level			+172
Wellbore Gradient			
Oil, psi/ft	(.3)(172-67)		31.5
Gas, psi/ft	(.03)(240-172)		2.04
Pressure at Top of B Zone		812.5	
Top of B Zone to +370 ft	130		
Production			
BO/D		52	
Mcf/D		369	
Volume Weighted Reservoir Density, psi/ft		.03569	
dP to +370 ft		4.6	
Pressure at +370 ft datum		867.8	

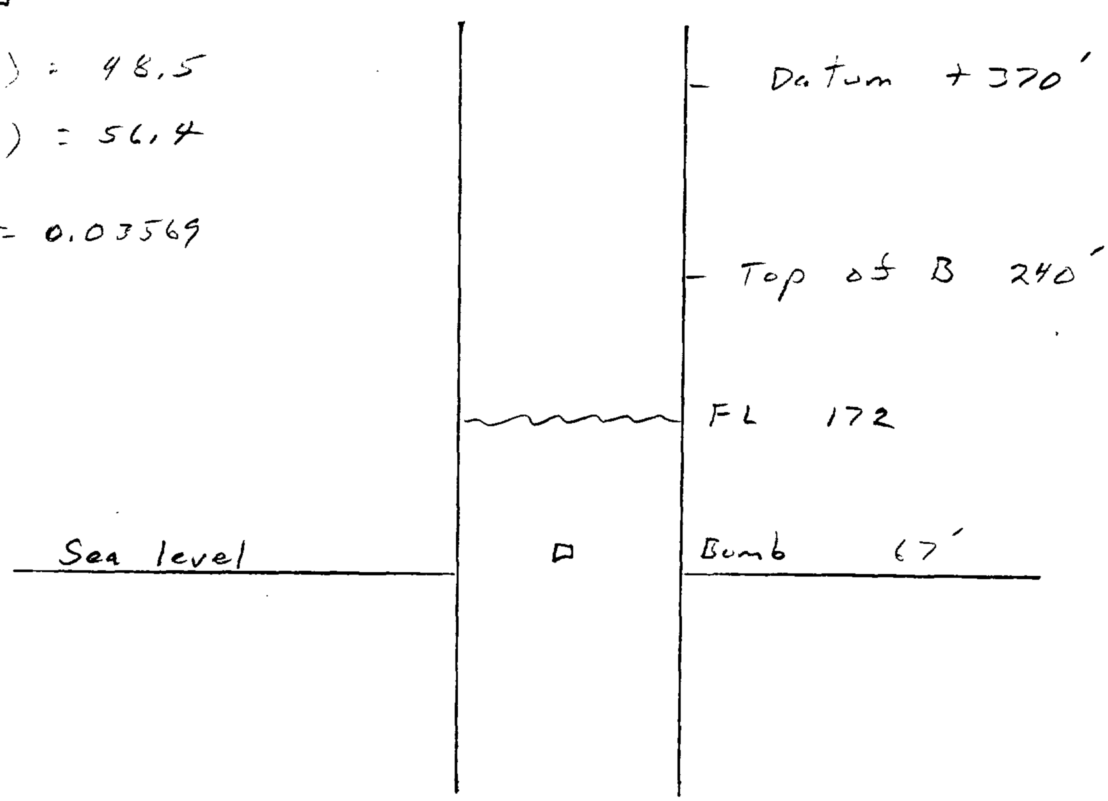
$(52)(1.295) = 67.3$

$\left[369 - \frac{(52)(399)}{1000}\right] 3.46 = 1205.0$

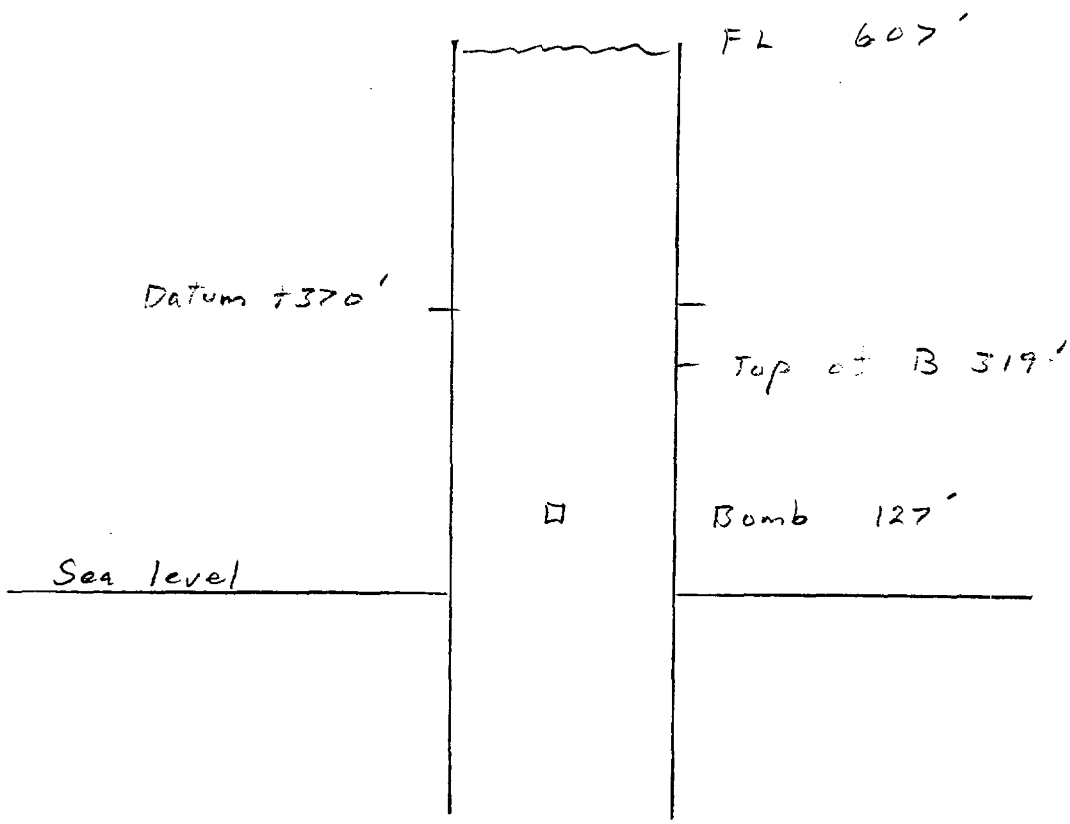
$(.7200)(67.3) = 48.5$

$(.04679)(1205) = 56.4$

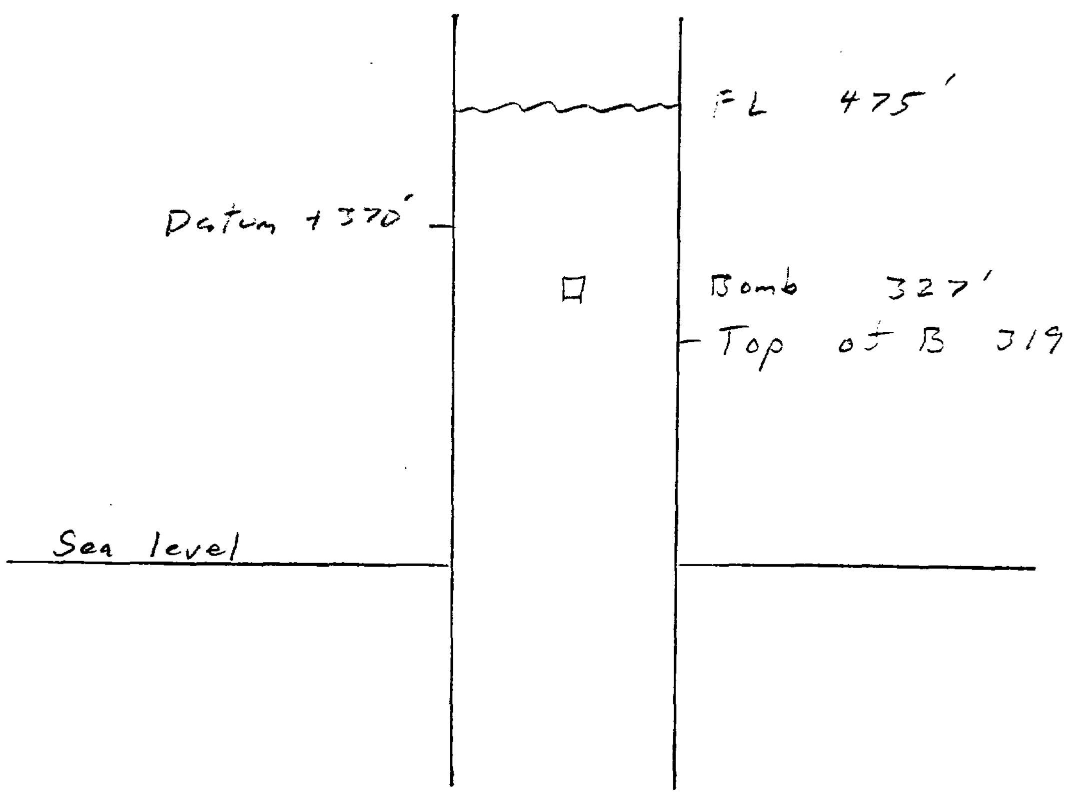
$(.433)(0.08243) = 0.03569$



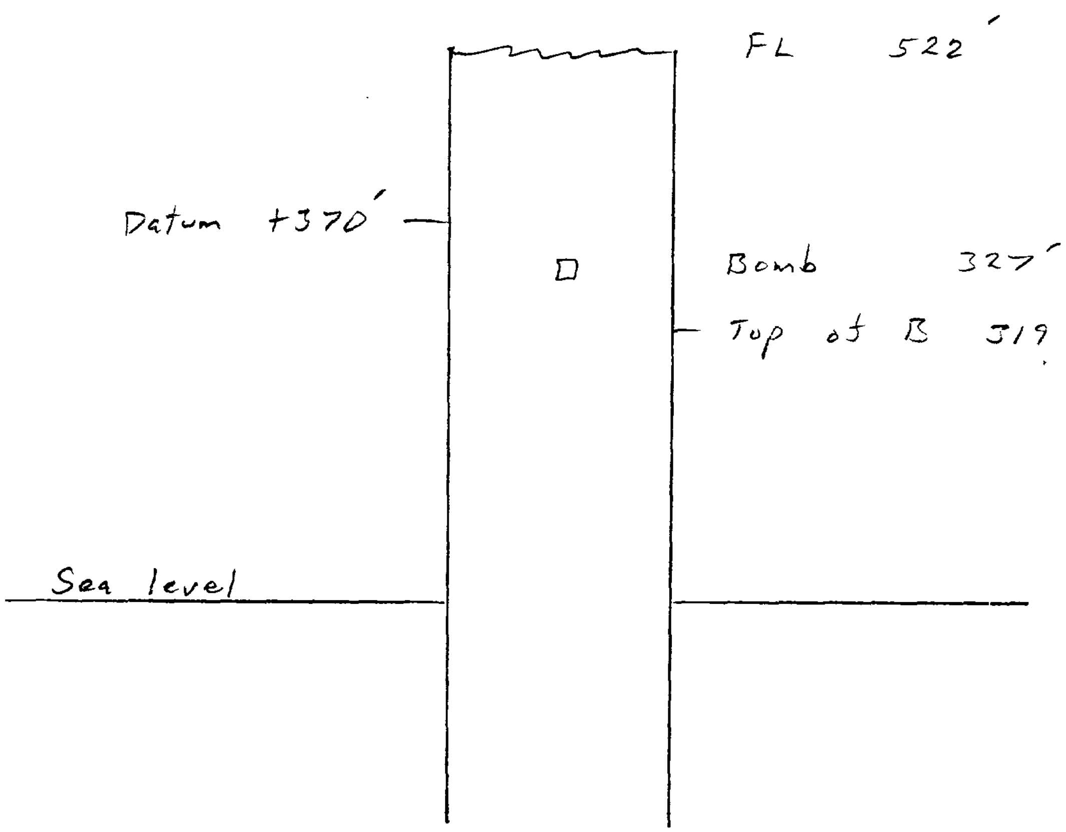
	KB		Subsea
Operator	Sun		
Well	Wildfire #1		
Elevation	7727		
Top of B Zone	7408		+ 319
Test Date		6/30/87	
Bomb Depth	7600		+ 127
Bomb Pressure, psig		1263	
Fluid Level	7120		+ 607
Wellbore Gradient			
Oil, psi/ft	(.3)(319-127)		57.6
Gas, psi/ft			
Pressure at Top of B Zone		1205.4	
Top of B Zone to +370 ft	51		
Production			
BO/D		Not Produced	
Mcf/D			
Volume Weighted Reservoir Density, psi/ft		.035	
dP to +370 ft		1.8	
Pressure at +370 ft datum		1203.6	



Operator	Sun		
Well	Wildfire #1		
	KB		Subsea
Elevation	7727		
Top of B Zone	7408		+319
Test Date		11/19/87	
Bomb Depth	7400		+327
Bomb Pressure, psig		1028	
Fluid Level	7252		+475
Wellbore Gradient			
Oil, psi/ft	(.3)(327-319)		2.4
Gas, psi/ft			
Pressure at Top of B Zone		1030.4	
Top of B Zone to +370 ft	51		
Production			
BO/D		Not Produced	
Mcf/D			
Volume Weighted Reservoir Density, psi/ft		0.035	
dP to +370 ft		1.8	
Pressure at +370 ft datum		1028.6	



	KB		Subsea
Operator	Son		
Well	Wildfire #1		
Elevation	7727		
Top of B Zone	7408		+319
Test Date		2/23/88	
Bomb Depth	7400		+327
Bomb Pressure, psig		972	
Fluid Level	7205		+522
Wellbore Gradient			
Oil, psi/ft	.3(327-319)		2.4
Gas, psi/ft			
Pressure at Top of B Zone		974	
Top of B Zone to +370 ft	51		
Production			
BO/D		Not Produced	
Mcf/D			
Volume Weighted Reservoir Density, psi/ft		0.035	
dP to +370 ft		1.8	
Pressure at +370 ft datum		972.2	

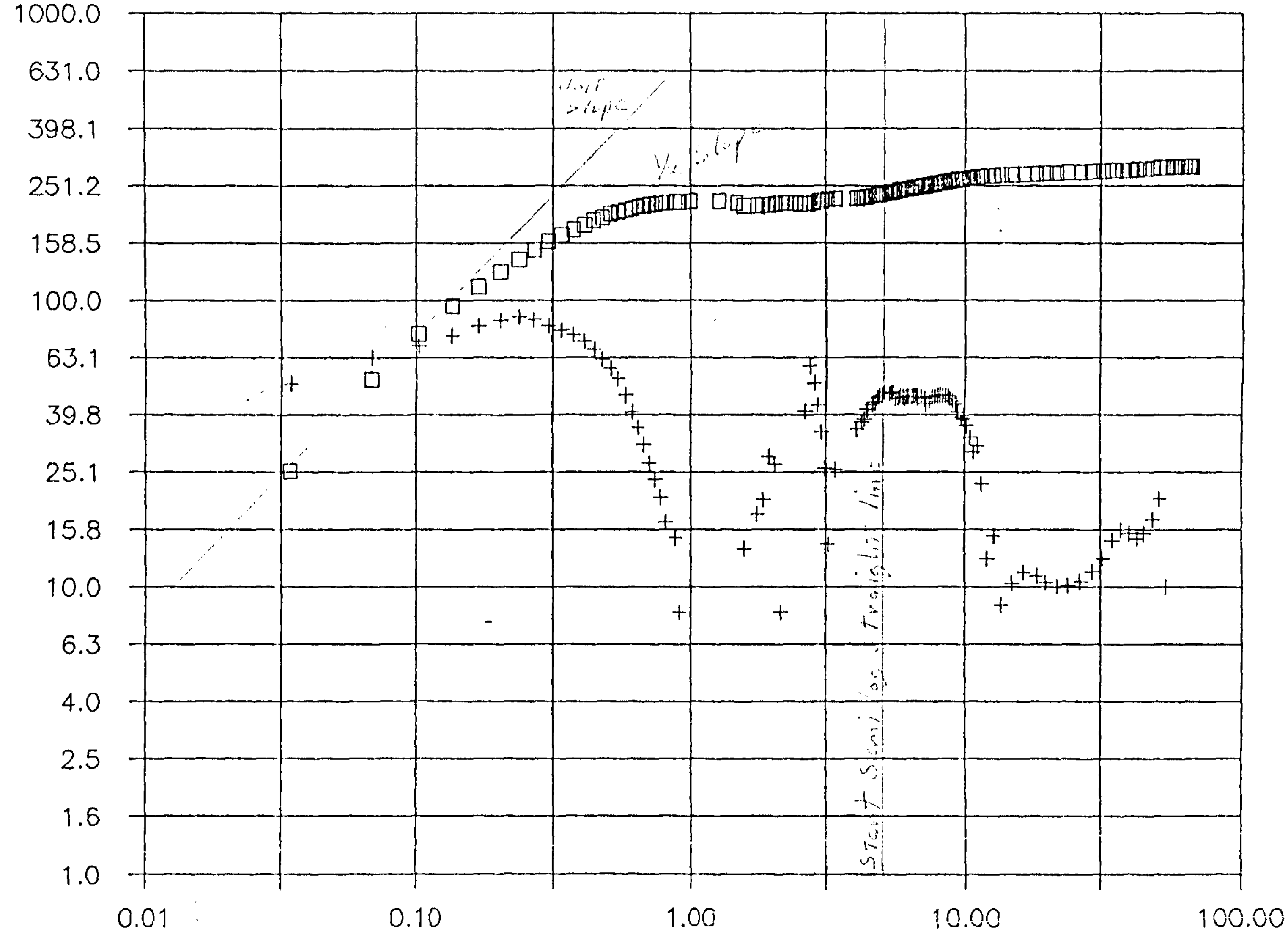


APPENDIX 2

Pressure Buildup Worksheets

Gavilan Dome

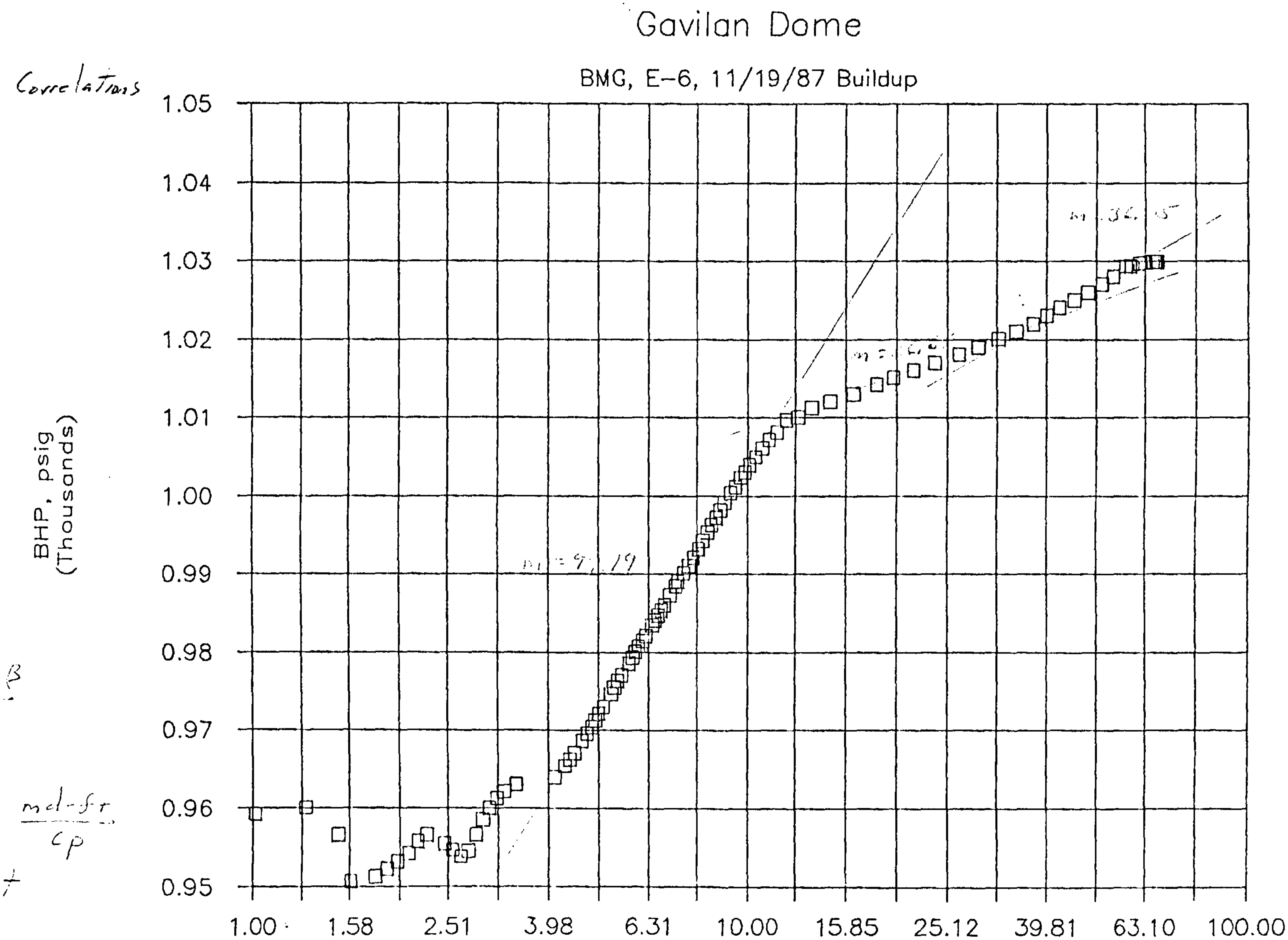
BMG #E-6, 11/19/87 Buildup



□ dP + dP'

Gavilan Dome, 11/19/87 Buildup
BMG, E-6, $q = 281$ B/D GOR = 4500

Initial work
From Standings Correlations
GOR = 4000
$B = 11.0$
$q_o = 281$
$m = 36.05$



$$\frac{kh}{\mu} = \frac{162.6\, q B}{m}$$

$$\frac{kh}{\mu} = 13{,}942 \ \frac{md\text{-}ft}{cp}$$

Using q_t concept

$$q_{Rt} = q_o B_o + \left(q_g - \frac{q_o R_s}{1000}\right) B_g + q_w B_w$$

$$\frac{kh}{\mu} = 14{,}156$$

From Lodely PVT
$B_g = 2.798$ RB/Mcf
$R_s = 452$

$B_o = 1.242$
$q_g = 4000 \times 281$

$B_g = 5.04 \times 10^{-3} \frac{TZ}{P}$
$q_{..} = 3179$ ...

11/17/87 Buildups

4/14/88

①

Initial Work

E-6 $\quad q_o = 281\ B/D \quad GOR = 4296 \quad q_g = 1207\ Mcf/D$

Boundry Dominated Flow. Therefore use Flow Regime 1 (doesn't work 4/24/…) for analyses $\quad m = 99.19 \quad$ Max pressure = 1030 psig

Transform gas flow rate to RB

$$\left(q_g - \frac{q_o R_s}{1000}\right) B_g$$

where q_g, Mscf/D
R_s; scf/bbl
B_g, RB/Mscf

$$\left[1207 - \frac{(281)(466)}{1000}\right] 2.632 = 2832\ RB/D$$

Total flowrate $= (281)(1.327) + 2832$
$= 3205$ RB/Day

Flow Regime #1

$$\lambda h_t = \frac{(162.6)\, q_{Rt}}{m} = 5254\ \frac{md \cdot ft}{cp} \quad (m = 99.19\ psi/cycle)$$

if $m = 36.05$ last slope

$$\lambda h_t = 14{,}456\ \frac{md \cdot ft}{cp} = \left(14{,}456\ \frac{md \cdot ft}{cp}\right)(.0831\ cp) = 1200\ md \cdot ft$$

Average viscosity $(1.327)(281\ BO/D)(.605) = 255.6\ \frac{RB \cdot cp}{D}$

$+ \ (2832\ RBG/D)(.0143) = 40.5\ \frac{RB \cdot cp}{D}$

$3204\ RB/D \qquad 266.1\ \frac{RB \cdot cp}{D}$

$$\frac{266.1\ \frac{RB \cdot cp}{D}}{3204\ \frac{RB}{D}} = 0.0831\ cp$$

Average Rate, STB/D
$(1{,}076)(2.632) = 2832$ STB/D
$+ \ 281\ (1.327) = 373$ STB/D
3205 STB/D

Average FVF $\frac{3205}{1076 + 281} = 2.361$

4/14/86
②

doesn't work with m = 99.19 psi/cy

$$Kh_{absolut} = \left(5254 \frac{md \cdot ft}{cp}\right)(.0831\ cp) = \cancel{1200}\ \underset{437}{}\ md \cdot ft$$

$$K_o h = \frac{(162.6)(281)(1.327)(.605)}{36.05} = 1018\ md \cdot ft$$

$$K_g h = \frac{(162.6)(2832)(\quad)(0.0143)}{36.05} = 783\ md \cdot ft$$

BMG E-6 11/19/87 Buildup Last effort

4/15/88

3

10 hr → 55 hr Agarwal Time (Averaged slope)

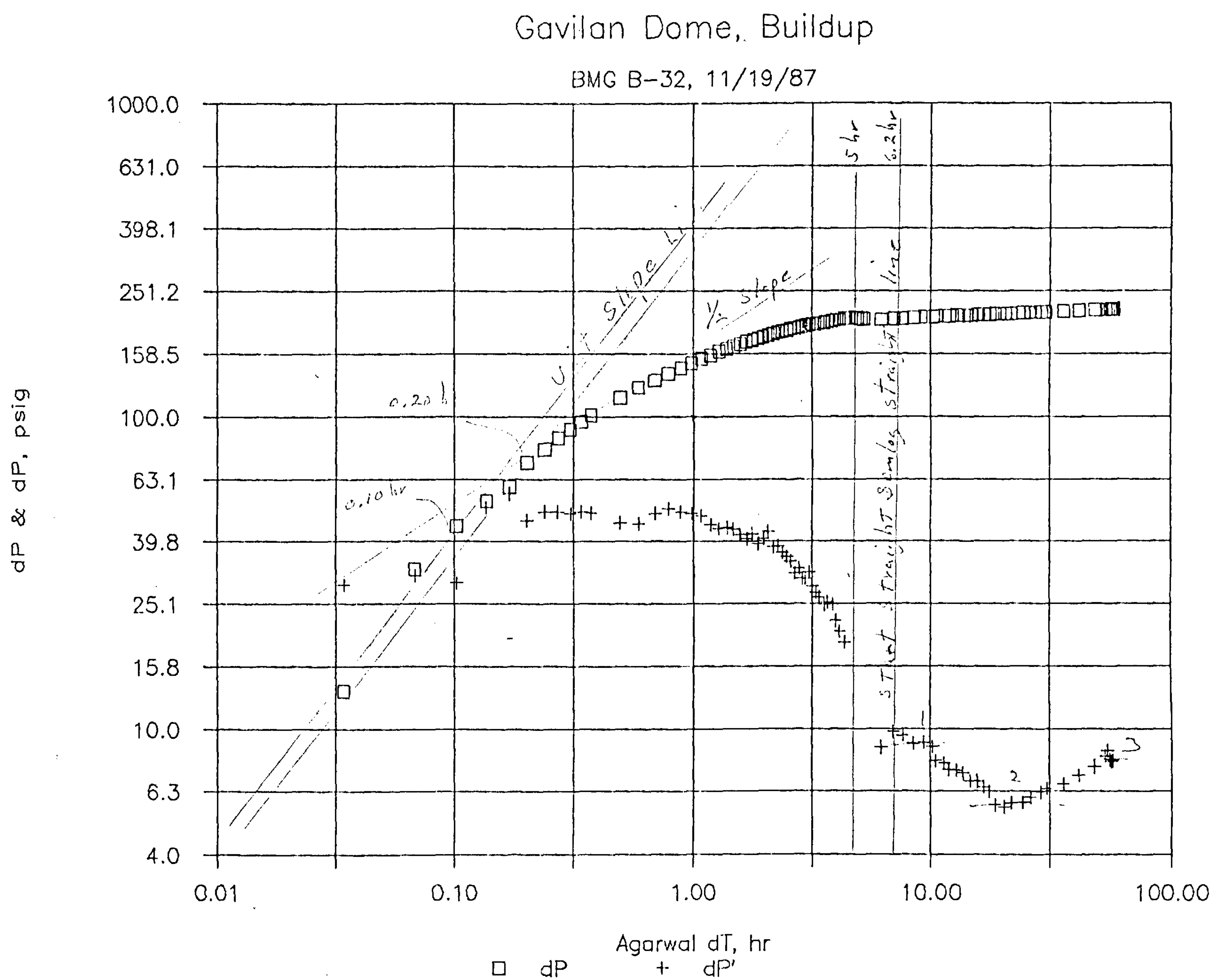
cc = 99.5 %, Intercept = 977.9 psig slope = 28.44

$$\frac{Kh}{\mu}_{absolute} = \frac{162.6\, q_{bRt}}{m} = \frac{(162.6)(3205)}{28.44} = 18324\ \frac{md \cdot ft}{cp}$$

$$Kh_{absolute} = \left(18324\ \frac{md \cdot ft}{cp}\right)(0.0831\ cp) = 1523\ md \cdot ft$$

$$K_o h = \frac{(162.6)(281)(1.327)(.605)}{28.44} = 1290\ md \cdot ft$$

$$K_g h = \frac{(162.6)(2832)(0.0143)}{28.44} = 232\ md \cdot ft$$



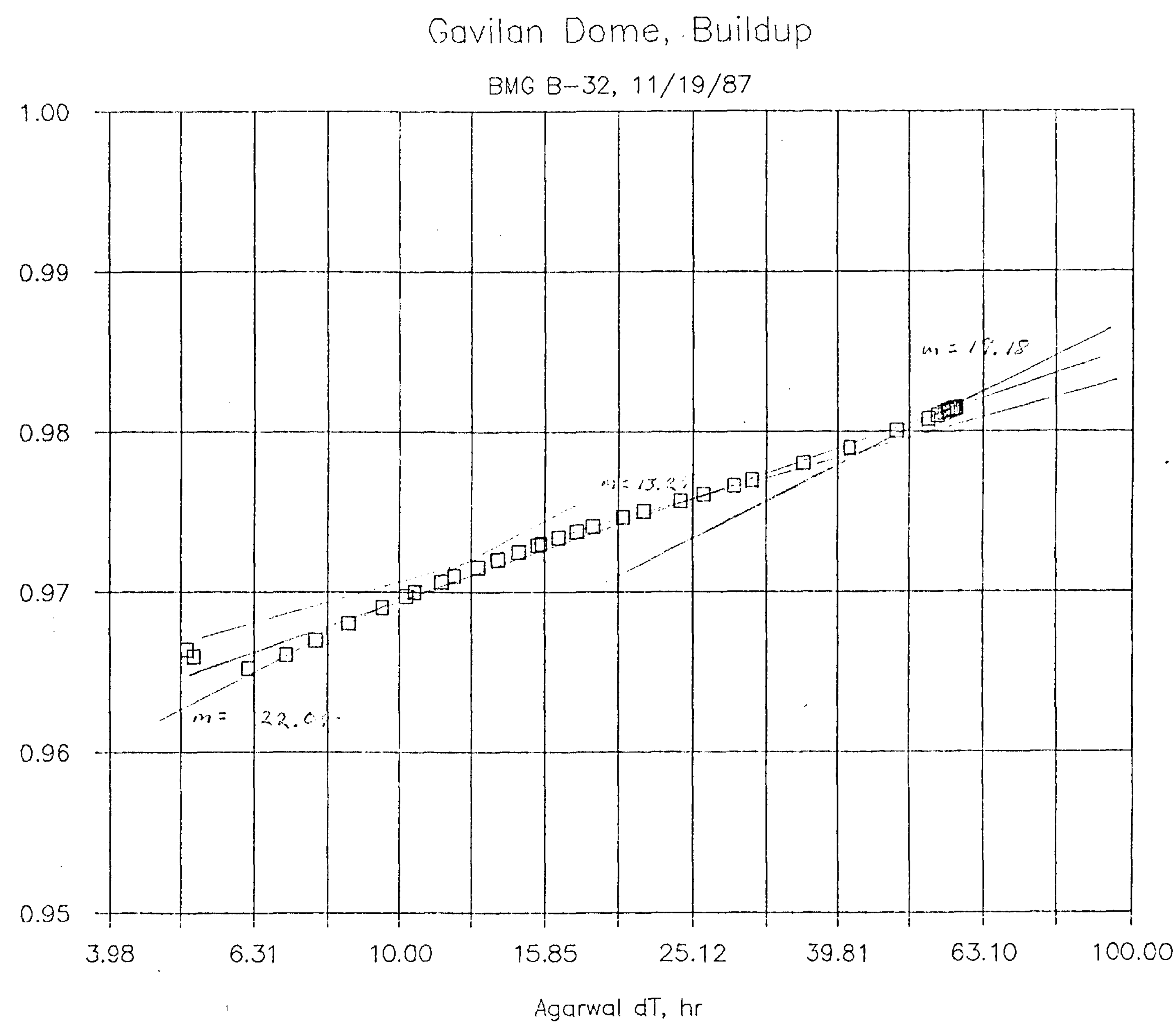
Gavilan Dome, Buildup
BMG B-32, 11/19/87
1000.0
631.0
398.1
251.2
158.5
100.0
63.1
39.8
25.1
15.8
10.0
6.3
4.0
0.01
0.10
1.00
10.00
100.00
dP & dP, psig
Agarwal dT, hr
□ dP
+ dP'
unit slope line
1/2 slope
0.20 hr
0.10 hr
5 hr
6.2 hr
start straight semilog straight line
1
2
3

4/13/88 wwc

From Loddy #1
PVT data @ 1000 psig
GOR = 1200
$\beta = 1.242$
$q = 719$ BOPD
$m = 19.18$

$\frac{kh}{\mu} = \frac{162.6\, q\, \beta}{m}$

$\frac{kh}{\mu} = 7570\ \frac{md \cdot ft}{cp}$



BMG 3-32 7/24/32

11/19/87 Buildup q_o = 719 BOPD GOR = 1,242

q_g = 893. Mcf/D Max pressure 955

B_o = 1,314 B_g = 2.932 μ_o = 0.635 μ_g = 0.01403 Rs = 437

ρ_o = .7148 ρ_g = .000891

q_o, RB = (719)(1,314) = 944.8 RB/D

q_g, RB = $\left[893 - \underbrace{\frac{(719)(437)}{1000}}_{\text{314 bbl/D equivalent}}\right]$ 2.932 = 1697 RB/D

$q_{t} = q_o + q_g$ = 2642 RB/D

Volume average viscosity + density

(944.8)(0.635) = 599.9

(1697)(0.01403) = 23.8

623.8

$\mu_{Average}$ = 0.2361 cp

(944.8)(0.7148) = 675.3

(1697)(.000891) = 1.5

676.9

$\rho_{Average}$ = 0.2562 gm/cc

$\frac{0.2562}{1} = \frac{X}{0.433 \text{ psi/ft}}$

Reservoir gradient, X = 0.1109 psi/ft

$\frac{K_t h}{\mu} = \frac{(162.6)(2642 \text{ RB/D})}{19.8}$ = 21,696 $\frac{\text{md·ft}}{\text{cp}}$, Kh = 5123 md·ft h ≈ 150'

K = 34.2 md

$K_o h = \frac{(162.6)(944.8)(.635)}{19.8}$ = 4927 md·ft

$K_g h = \frac{(162.6)(1697)(0.01403)}{19.8}$ = 196 md·ft

7/29/.3

Mallon

Fisher Federal 2-1

11/19/87 Buildup $m = 69.0$ $q_o = 39.8$ $q_g = 347.47$

$\bar{P}$ 978 $B_o = 1.317$ $B_g = 2.85$ $\mu_o = 0.628$ $\mu_g = 0.01409$ $R_s = 444$

$q_o, RB = (39.8)(1.317) = 52.4166$

$q_g, RB = \left[347.47 - \frac{(39.8)(444)}{1000}\right] 2.85 = 939.9$

$q_t, RB = 992.3$ RB/D

$(52.4)(.628) =$

$(939.9)(.01409) =$

46.15

$\mu_{Average} = 0.0465$ cp

$\lambda_t h = \frac{(162.6)(992.3)}{m} = 2338 \frac{md \cdot ft}{cp}$

$Kh = 109$ md

2/23/88 Buildup $m = 87$ $q_o = 98$ $q_g = 1013$

$\bar{P} \sim 925$ $B_o = 1.310$ $B_g = 3.015$ $\mu_o = 0.643$ μ_g 0.01396 $R_s = 430$

$q_o = (1.310)(98) = 128.4$ RB/D

$q_g = \left[1013 - \frac{(98)(430)}{1000}\right] 3.015 = 2927.1$ "

3055

$q_t = 3055$ RB/D

$(128.4)(.643) = 82.56$

$(2927.1)(0.01396) = 40.86$

123.42

$\mu_{Average} = 0.0404$

$\lambda_t h = \frac{(162.6)(3055)}{87}$

$\lambda_t h = 5710 \frac{md \cdot ft}{cp}$

$\bar{K}h = 231$ md·ft

$K_o h = \frac{(128.4)(.643)(162.6)}{87} = 154$

$K_g h = \frac{(2927.1)(.01396)(162.6)}{87} = 76.4$

Meridian

Hill Federal 2-4

6/30 87 Buildup

$m = 108.4 \quad q_{o} = 107.2 \quad q_{g} = 327.0 \quad \bar{P} = 1111$

$B_o = 1.334 \quad B_g = 2.477 \quad \mu_o = .588 \quad \mu_g = 0.01442 \quad R_s = 482$

$q_{o} = (107.2)(1.334) = 143.0$

$q_{g} = \left[327 - \frac{(107.2)(482)}{1000}\right]2.477 = 682$

$825\ RB/D$

$(143)(.588) = 84$

$(682)(0.01442) = 9.8$

93.92

$\lambda_t h = \frac{(162.6)(825)}{108.4} = 1237.5 \frac{md\text{-}ft}{cp}$

$\mu_{Average} = 0.1138$

$\bar{k} h = 141\ md$

$k_o h = \frac{(162.6)(143)(.588)}{108.4} = 126$

$k_g h = \frac{(162.6)(682)(.01442)}{108.4} = 15$

Meridian

Hill Federal #1

11/19/57 Buildup

$m = 168.9 \quad q_o = 24 \quad q_g = (820)(3) \quad \bar{P} = 943$

$B_o = 1.312 \quad B_g = 2.965 \quad \mu_g = 0.01401 \quad \mu_o = .637 \quad R_s = 435$

$$q_{bo} = (24)(1.312) = 31.5$$

$$q_{bg} = \left[(820)(3) - \frac{(24)(435)}{1000}\right]2.965 = 7262.9$$

$$q_{bt} = 7294 \text{ RB}$$

$(31.5)(0.637) = 20.06$

$(7262.9)(.01401) = 101.75$

121.81

Average μ = 0.01670

$$\lambda_t h = \frac{(162.6)(7294)}{168.9} = 7022 \ \frac{\text{md.ft}}{\text{cp}}$$

$\bar{k} h$ = 1173 md. ft

$$k_o h = \frac{(162.6)(20.06)(.637)}{168.9} = 12.3$$

$$k_g h = \frac{(162.6)(7262.9)(.01401)}{168.9} = 98.0$$

[illegible] Resources

Bear Cat #1 4/26/88

6/30/87 Buildup

q_o = 47.11 BO/D
Max BHP 1052 psig
B_o = 1.327

q_g = 268.95 Mcf/D
P_{1hr} = 950.2 psig
B_g = 2.632

h = 95' (perforated)
m = 46.36 psig/cycle
μ_o = .605

μ_g = .01428

R_s = 466

$$q_o, RB = (47.11)(1.327) = 62.5 \text{ RB/D}$$

$$q_g, RB = \left[268.95 - \frac{(47.11)(466)}{1000}\right] 2.632 = 650.1 \text{ RB/D}$$

$$q_t = q_o + q_g = 712.6 \text{ RB/D}$$

Volume average viscosity

$$(62.5)(0.605) = 37.8$$
$$(650.1)(0.01428) = \underline{9.28}$$
$$47.1$$

$$\frac{47.1}{712.6} = 0.06610 \text{ cp}$$

$$\lambda_t h = \frac{162.6\ q_t}{m} = \frac{(162.6)(712.6)}{46.36} = 2499 \frac{\text{md}\cdot\text{ft}}{\text{cp}}$$

$$k_o h = \frac{162.6\ q_o B_o \mu_o}{m} = \frac{(162.6)(62.5)(.605)}{46.36} = 132.6 \text{ md}\cdot\text{ft}$$

$$k_g h = \frac{162.6\ q_g (RB) \mu_g}{m} = \frac{(162.6)(650.1)(0.01428)}{46.36} = 32.6 \text{ md}\cdot\text{ft}$$

$$kh_{Absolute} = \left(2499 \frac{\text{md}\cdot\text{ft}}{\text{cp}}\right)(0.0661 \text{ cp}) = 165.2 \text{ md-ft}$$

$$k_{absolute} = 1.8 \text{ md}$$

end of storage
at .033 hr

Gavilan Dome, 11/16/87 Buildup

Mobil, Lindrith B-37

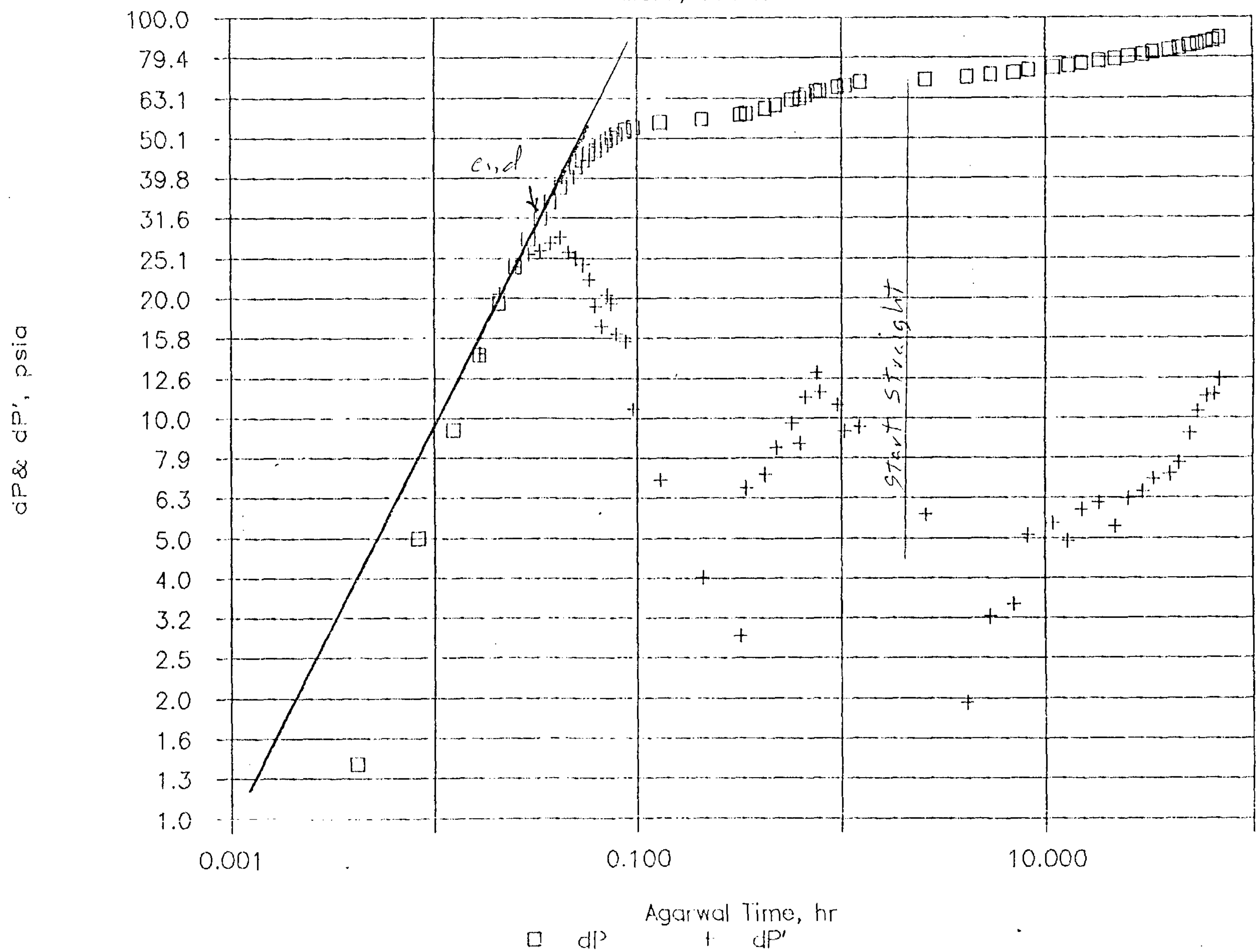
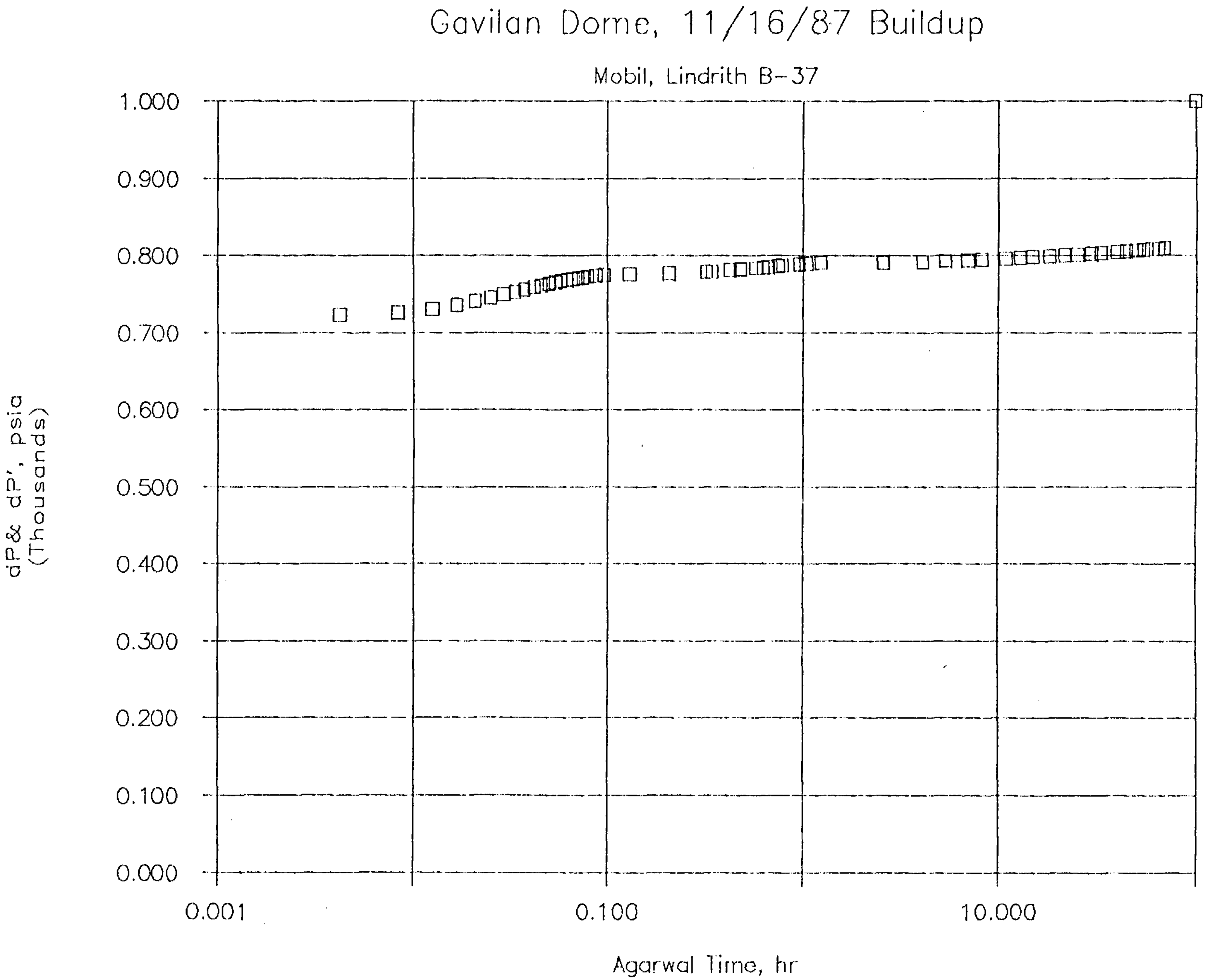
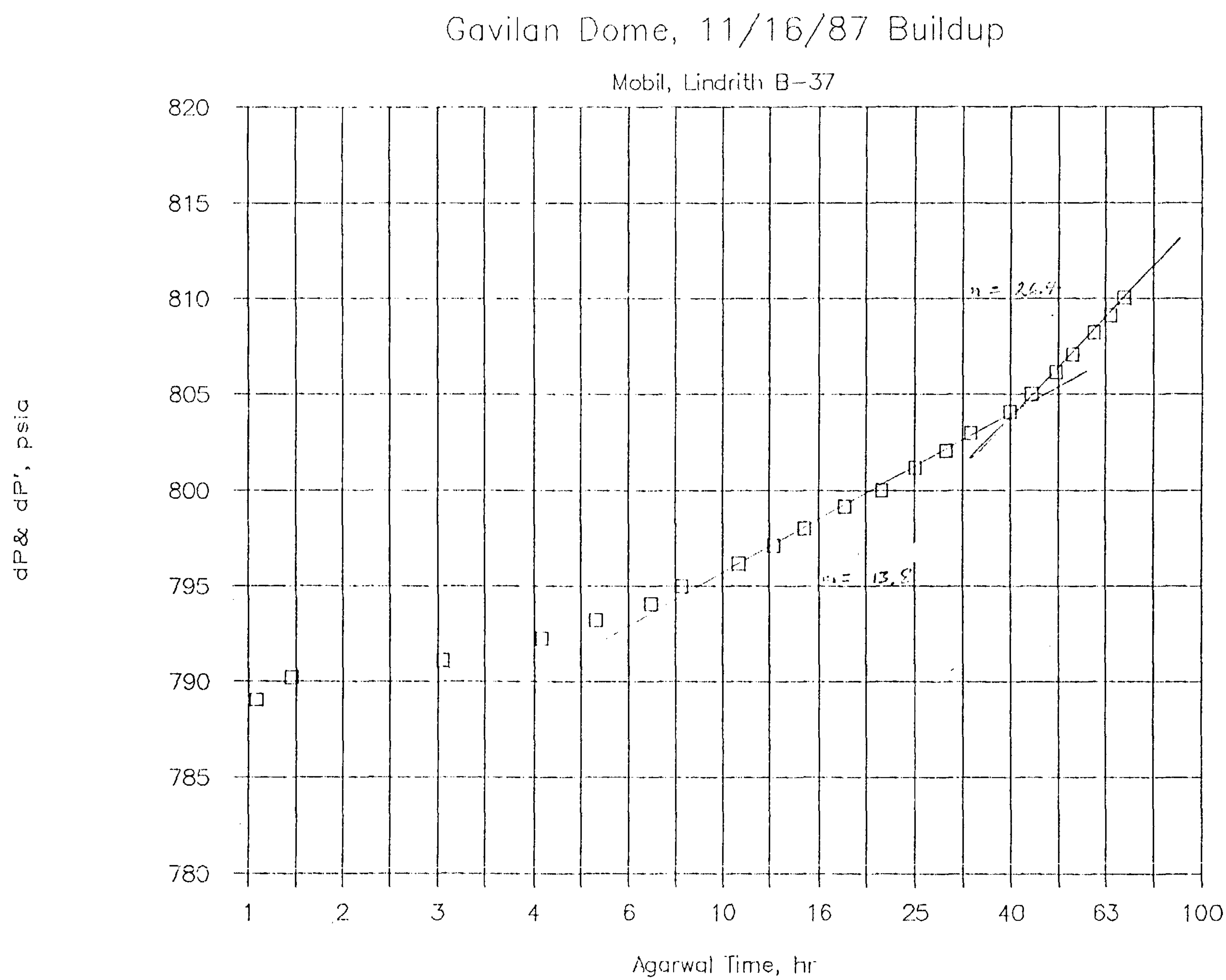


Fig 1



Gavilan Dome, 11/16/87 Buildup
Mobil, Lindrith B-37
dP& dP', psia
(Thousands)
1.000
0.900
0.800
0.700
0.600
0.500
0.400
0.300
0.200
0.100
0.000
0.001
0.100
10.000
Agarwal Time, hr

Fig 2



Gavilan Dome, 11/16/87 Buildup
Mobil, Lindrith B-37
820
815
810
805
800
795
790
785
780
dP& dP', psia
1
2
3
4
6
10
16
25
40
63
100
Agarwal Time, hr
m = 26.4
m = 13.8

Fig 3

Mobil Lindrith "B" Unit
Well #37
11/16/87 Buildup

① 4/24/88

Max Pressure 810 psig   Loddy PVT Data

Rates 221.2 BOPD, 889.1 Mcf/D   GOR = 3907 scf/bbl

m = 26.4 psig/cycle   h = 233 ft

Flow Rates, Reservoir bbl

gas $\left[889.1 - \frac{221.2(400)}{1000}\right] 3.5 = 2802$ RB/D

oil $(221.2)(1.295) = 286$ RB/D

$q_t = 3088$ RB/D

$\lambda h_t = \frac{(162.6)(3088)}{26.4} = 19{,}022 \frac{md \cdot ft}{cp}$

Average viscosity

$(2802)(.0136) = 38.11$

$(286)(.705) = 201.63$

239.7

$\frac{239.7 \text{ RB} \cdot cp}{3088 \text{ RB}} = 0.0776 \, cp$

$\left(\frac{Kh}{\mu}\right)_{absolute} = 19{,}022 \frac{md \cdot ft}{cp}$ or 1477 md·ft (6.3md)

$K_o h = \frac{(162.6)(286)(.705)}{26.4} = 1242$ md·ft (5.3md

$K_g h = \frac{(162.6)(2802)(0.0136)}{26.4} = 235$ md·ft (1.0md

2

4/24/88

Skin estimate

$$S = 1.151\left[\frac{\overset{C1}{761.4-721.2}}{26.4} - \log\frac{\overset{C2}{6.3}}{(.001)(1.265\times10^{-3})(.0776)(.229^2)} + 3.23\right]$$

$S = -5$

Then from type curve for wells with storage + skin

at $S = -5$ $\quad P_D = \dfrac{(1477)(87)}{(141.2)(3088)(.0776)} = 3.80$ $\quad \dfrac{\Delta P\, kh}{141.2\, q B \mu} = 1$

at $\Delta P = 87$ psig $\quad \Delta t = 59,523$

From Type curve at $P_D = 3.8$ & $S = -5$ $\quad t_D = 1.9\times10^7$

$$\phi = \frac{(2.637\times10^{-4})(6.3)(59,523)}{(1.9\times10^7)(0.0776)(1.265\times10^{-3})(.229^2)} \qquad t_D = \frac{2.637\times10^{-4}\, kt}{\phi \mu c_t r_w^2}$$

$\phi = 10.11\times10^{-2}$

$\phi h = 0.236$

$$k_m = \frac{(532.3)(1.011\times10^{-3})(1.265\times10^{-3})(233^2)(0.0776)}{41.6}$$

$k_m = 0.069$ md

$$\lambda' = 12\left(\frac{.069}{6.3}\right)\left(\frac{0.229^2}{233^2}\right) = 1.27\times10^{-7}$$

$$\phi_f c_f h_f = 8.33\times10^{-4}\left[\frac{(1477)(1.011\times10^{-3})(1.265\times10^{-3})(233)(1.27\times10^{-7})(12.833)}{(0.0776)(.229^2)}\right]^{1/2}$$

$\phi_f c_f h_f = 1.106\times10^{-5}$ $\qquad \phi_f = \dfrac{1.106\times10^{-5}}{(1.265\times10^{-3})(233)} = 3.75\times10^{-5}$

4/24/88

$$\omega' = \frac{\phi_m}{\phi_f} = \frac{1.011 \times 10^{-3}}{3.75 \times 10^{-5}} = 27$$

or ~ 3.7% of total porosity is in fractures

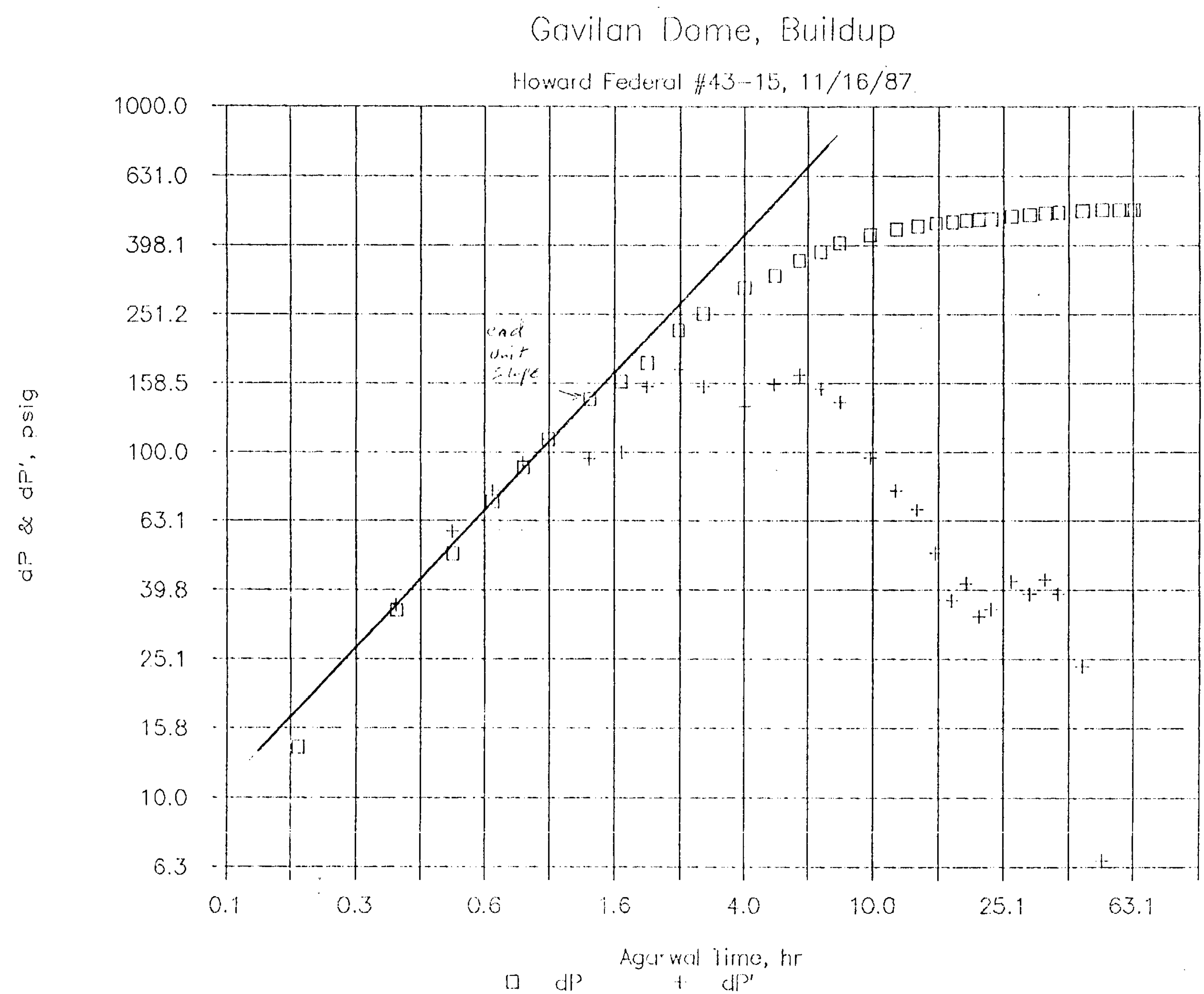

Gavilan Dome, Buildup
Howard Federal #43-15, 11/16/87
1000.0
631.0
398.1
251.2
158.5
100.0
63.1
39.8
25.1
15.8
10.0
6.3
0.1
0.3
0.6
1.6
4.0
10.0
25.1
63.1
dP & dP', psig
Agarwal Time, hr
dP
dP'
end unit slope

Fig 1

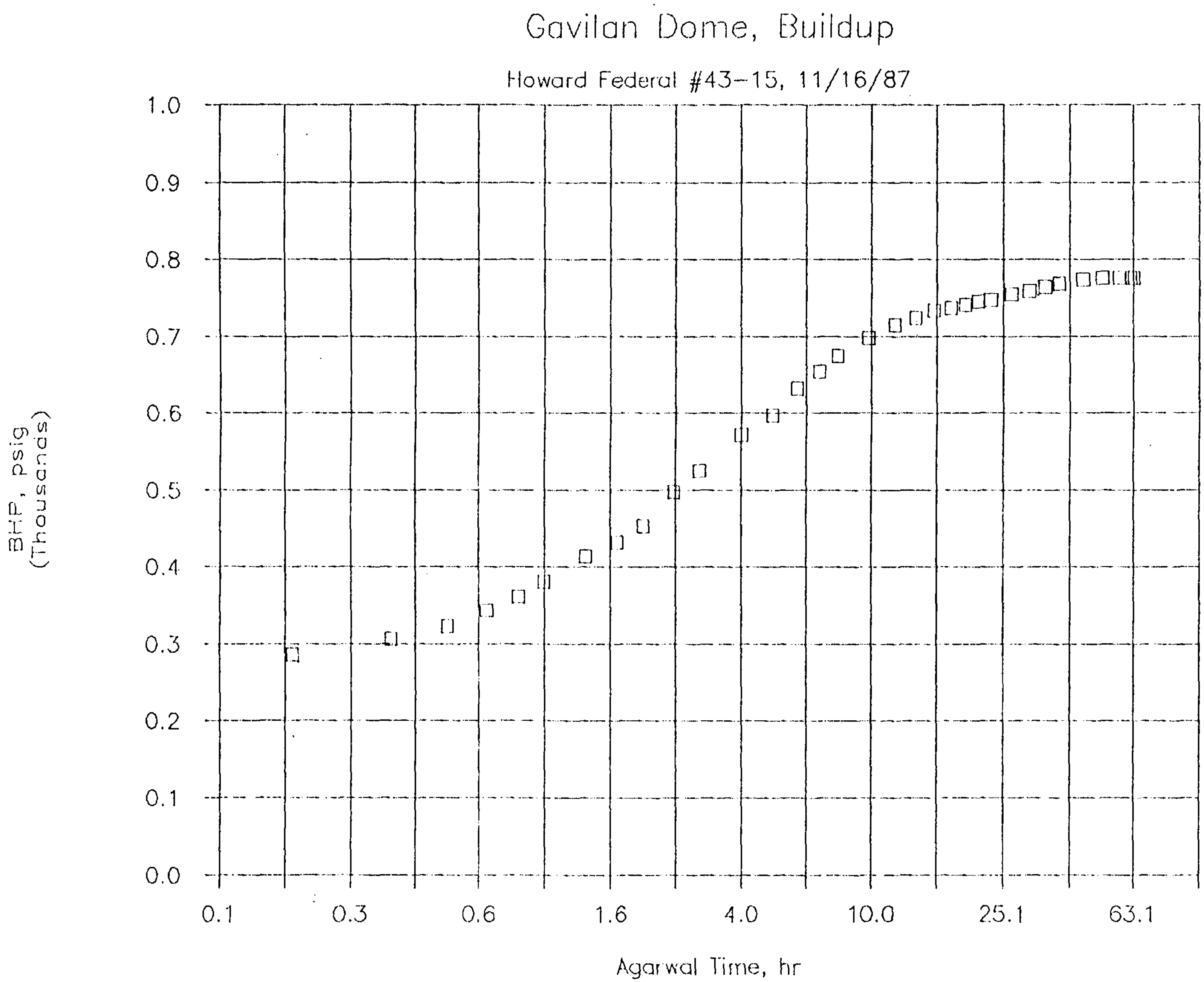

Gavilan Dome, Buildup
Howard Federal #43-15, 11/16/87
BHP, psig
(Thousands)
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0.1
0.3
0.6
1.6
4.0
10.0
25.1
63.1
Agarwal Time, hr

Fig 2

Gavilan Dome, Buildup

Howard Federal #43-15, 11/16/87

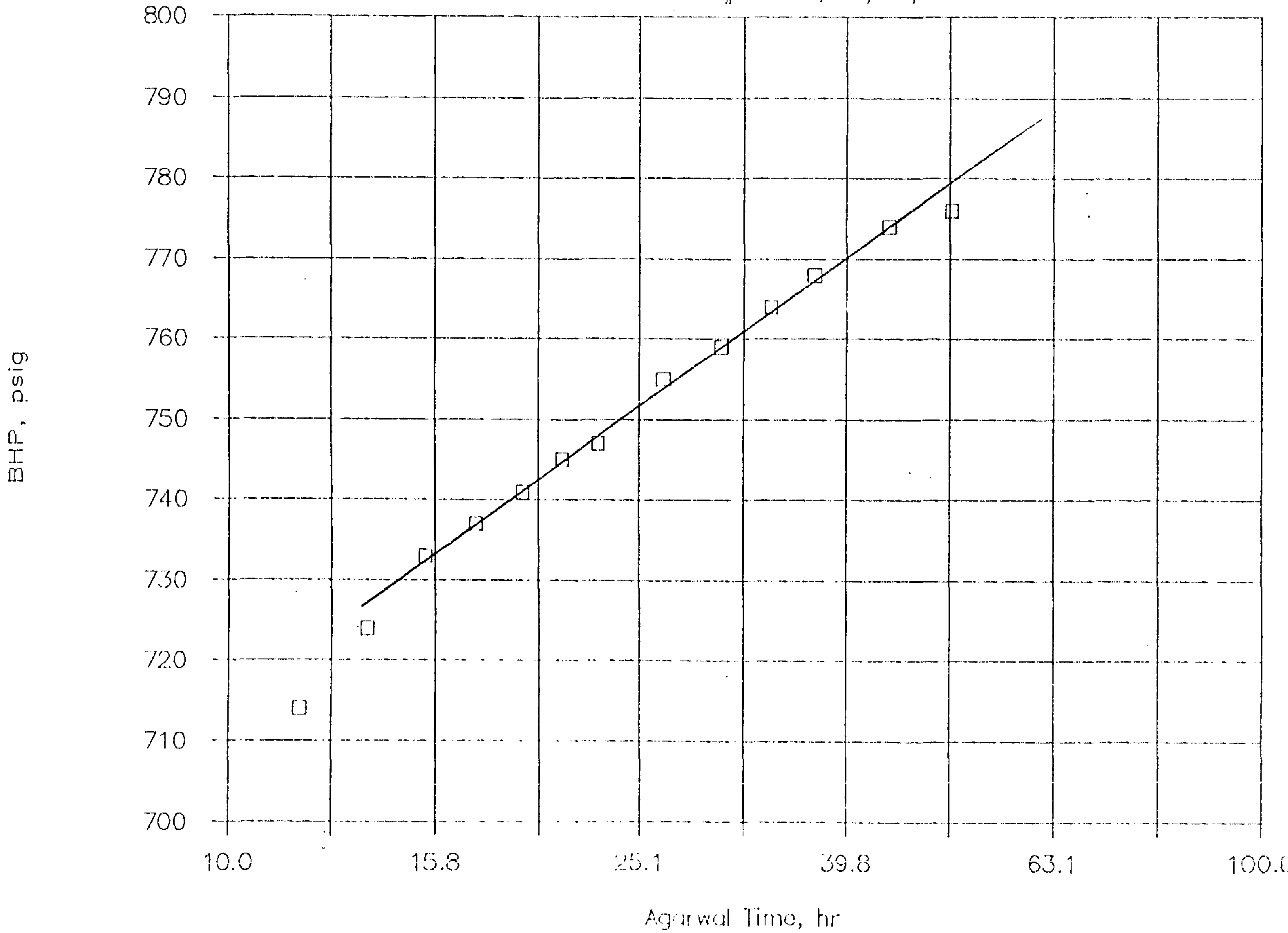


Fig 3

Reading ...

Howard Federal #43-15

11/1? Buildup

q_o = 9.19 BOPD $\qquad q_g$ = 636.63 Mcf/D $\qquad \bar{P}$ = 852 $\qquad m$ = 92.77

B_o = 1.301 $\qquad B_g$ = 3.309 $\qquad R_s$ = 409 $\qquad \mu_o$ = .680 $\qquad \mu_g$ = 0.01375

$$q_o = (9.19)(1.301) = 11.9$$

$$q_g = \left[636.63 - \frac{(9.19)(409)}{1000}\right]3.309 = 2094.2$$

$$q_t = 2106 \text{ RB/D}$$

$$(11.9)(.680) = 8.13$$

$$(2094.2)(0.01375) = 28.79$$

$$\mu_{average} = 0.01753 \text{ cp}$$

$$\lambda_t h = \frac{(162.6)(2106)}{92.77} = 3691 \ \frac{md \cdot ft}{cp}$$

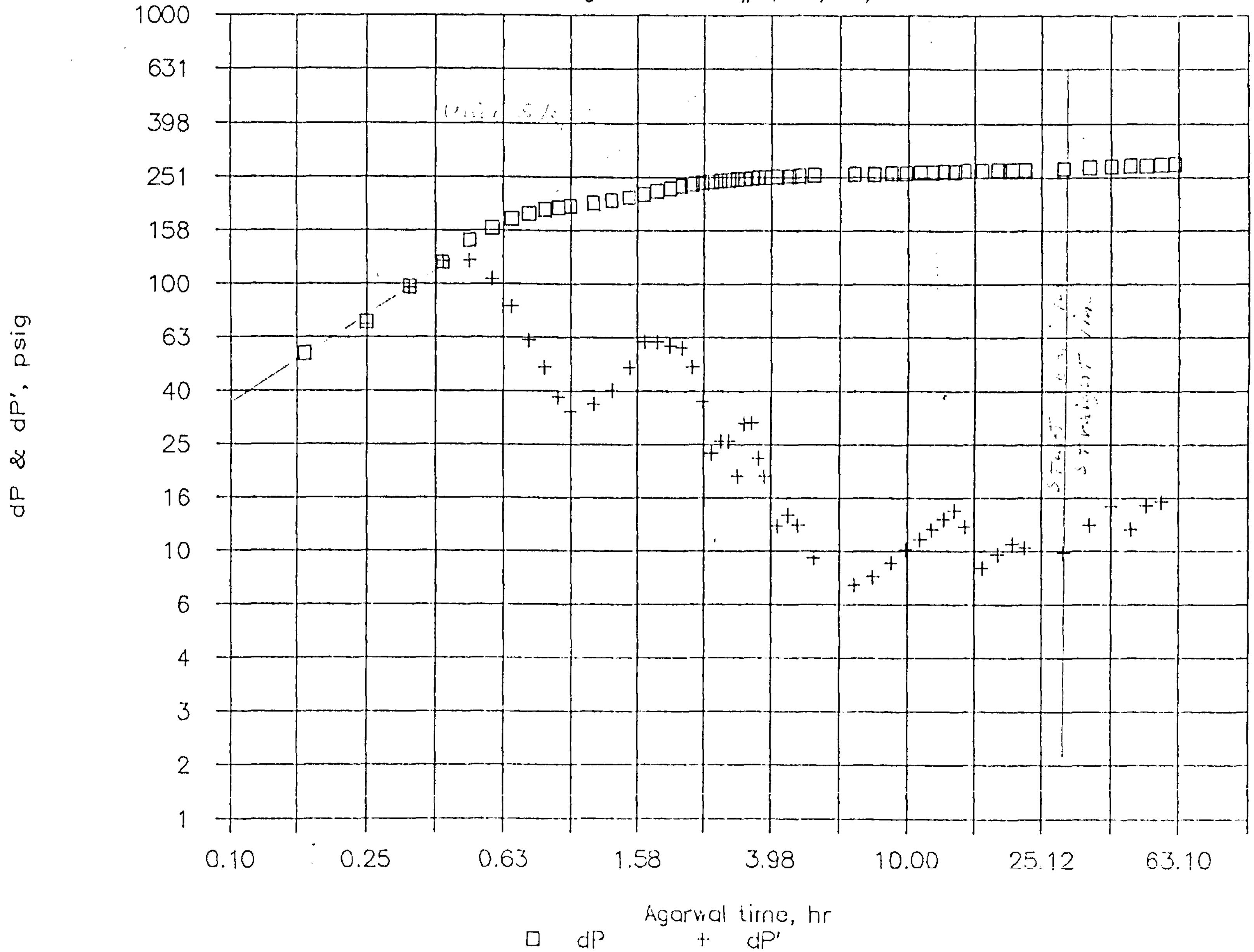
$$\bar{K} h = 64.7 \text{ md} \cdot \text{ft}$$

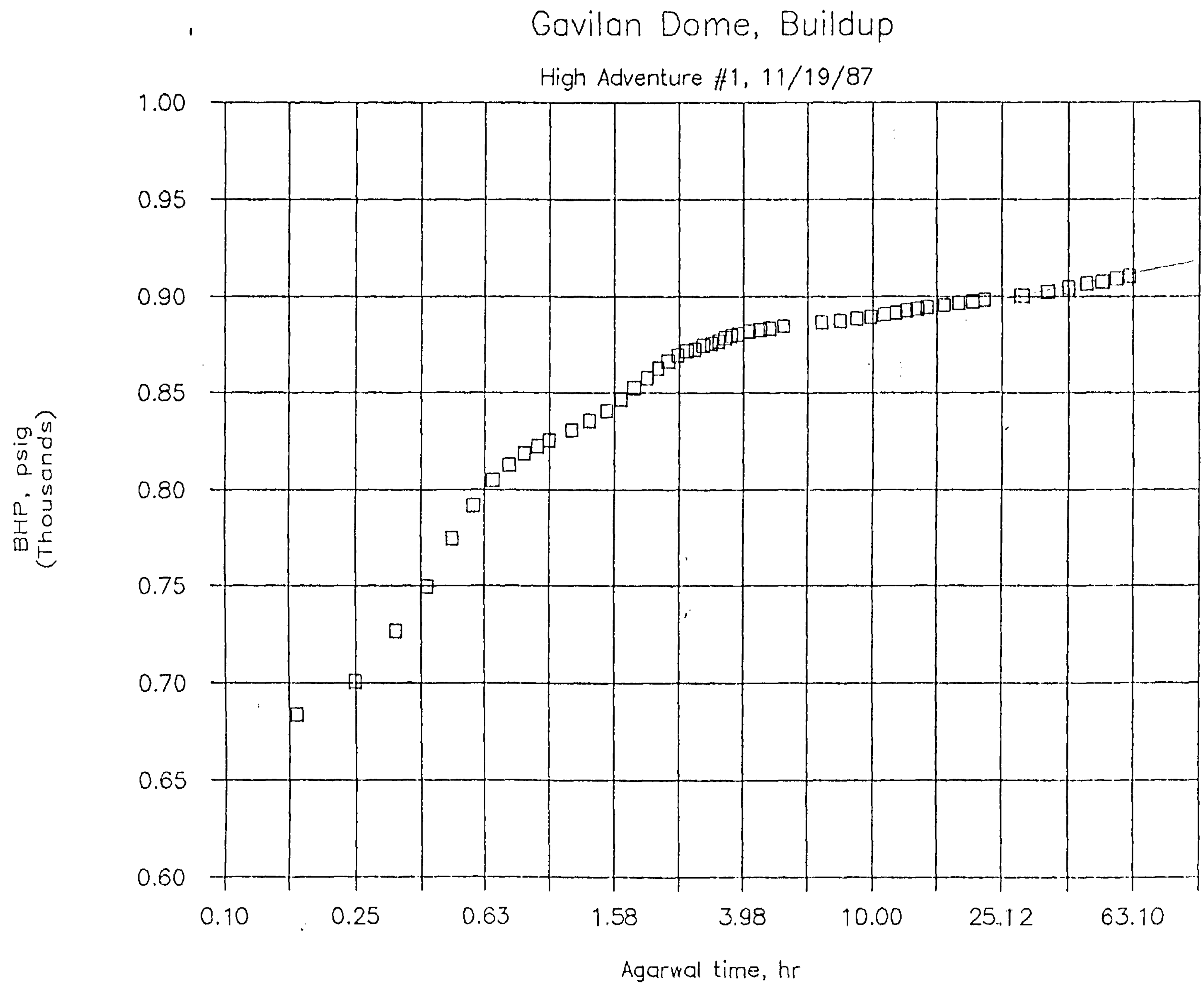
$$k_o h = \frac{(162.6)(11.9)(.68)}{92.77} = 14.2$$

$$k_g h = \frac{(162.6)\,2094.2(.01375)}{92.77} = 50.5$$

Gavilan Dome, Buildup

High Adventure #1, 11/19/87





Gavilan Dome, Buildup
High Adventure #1, 11/19/87
BHP, psig
(Thousands)
1.00
0.95
0.90
0.85
0.80
0.75
0.70
0.65
0.60
0.10
0.25
0.63
1.58
3.98
10.00
25.12
63.10
Agarwal time, hr

$b_g = 723.34$

$q_o = 233$

$T = 840\,h$

Gavilan Dome Buildup Analysis
Sun High Adventure #1, Start Test 11:23 AM, 11/16/87
Flow Time,T = 840 hours   q = 233 B/D

@ 910 Psia

$B_o = 1.308$ $B_g = 3.065$ $R_s = 426$ $\mu_o = .647$ $\mu_g = .01392$

dt hr	BHP psig	dP psig	T*dt/T+dt Agarwal	Agarwal' WMS Tech
0.00				
0.17	683.8	54.9	0.167	
0.25	700.8	71.9	0.250	70.4
0.33	726.8	97.9	0.333	97.3
0.42	749.7	120.8	0.416	121.4
0.50	774.7	145.8	0.500	122.4
0.58	791.6	162.7	0.583	104.8
0.67	805.0	176.1	0.666	82.9
0.75	813.0	184.1	0.749	62.0
0.83	818.9	190.0	0.832	49.0
0.92	822.9	194.0	0.916	38.0
1.00	825.9	197.0	0.999	33.5
1.17	830.9	202.0	1.168	35.7
1.33	835.9	207.0	1.328	40.3
1.50	840.9	212.0	1.497	49.1
1.67	846.9	218.0	1.667	61.0
1.83	852.8	223.9	1.826	60.8
2.00	857.8	228.9	1.995	58.9
2.17	862.8	233.9	2.164	58.0
2.33	866.8	237.9	2.327	49.2
2.50	869.8	240.9	2.493	36.7
hr	psig	psig	Agarwal	WMS Tech
36.00	902.7	273.8	34.521	12.6
42.00	904.7	275.8	40.000	14.7
48.00	906.7	277.8	45.405	12.1
54.00	907.7	278.8	50.738	14.9
60.00	909.7	280.8	56.000	15.5
66.00	910.7	281.8	61.192	

Reservoir bbl

$(233)(1.308) = 304.8$ RB

$\left[723 - \frac{(233)(426)}{1000}\right] 3.065$

$= 1911.8$ RBG

$q_t = 2217$ RB/D

$(304.8)(0.647) =$

$(1911.8)(.01392) =$

$\mu_{Average} = 0.1010$ cp

6 points

CL : 99.7%

P_{1hr} = 852.9 psig

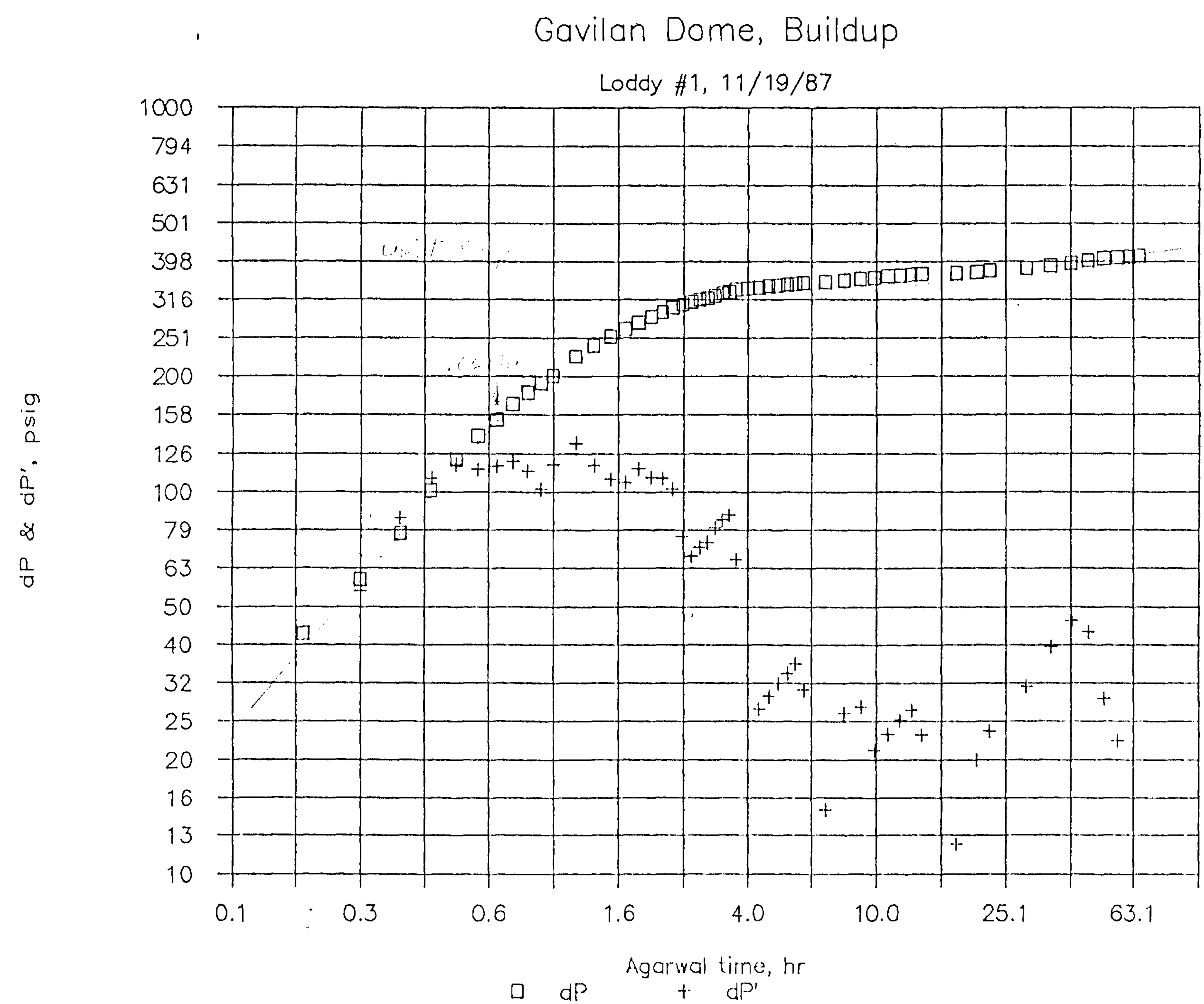
slope = 32.34 psi/cycle

$$\lambda_t h = \frac{(162.6)(2217)}{32.34} = 11,146 \ \frac{md \cdot ft}{cp}$$

$$\bar{K} h = 1126 \ md \cdot ft$$

$$K_o h = \frac{(162.6)(304.8)(.647)}{32.34} = 991.5$$

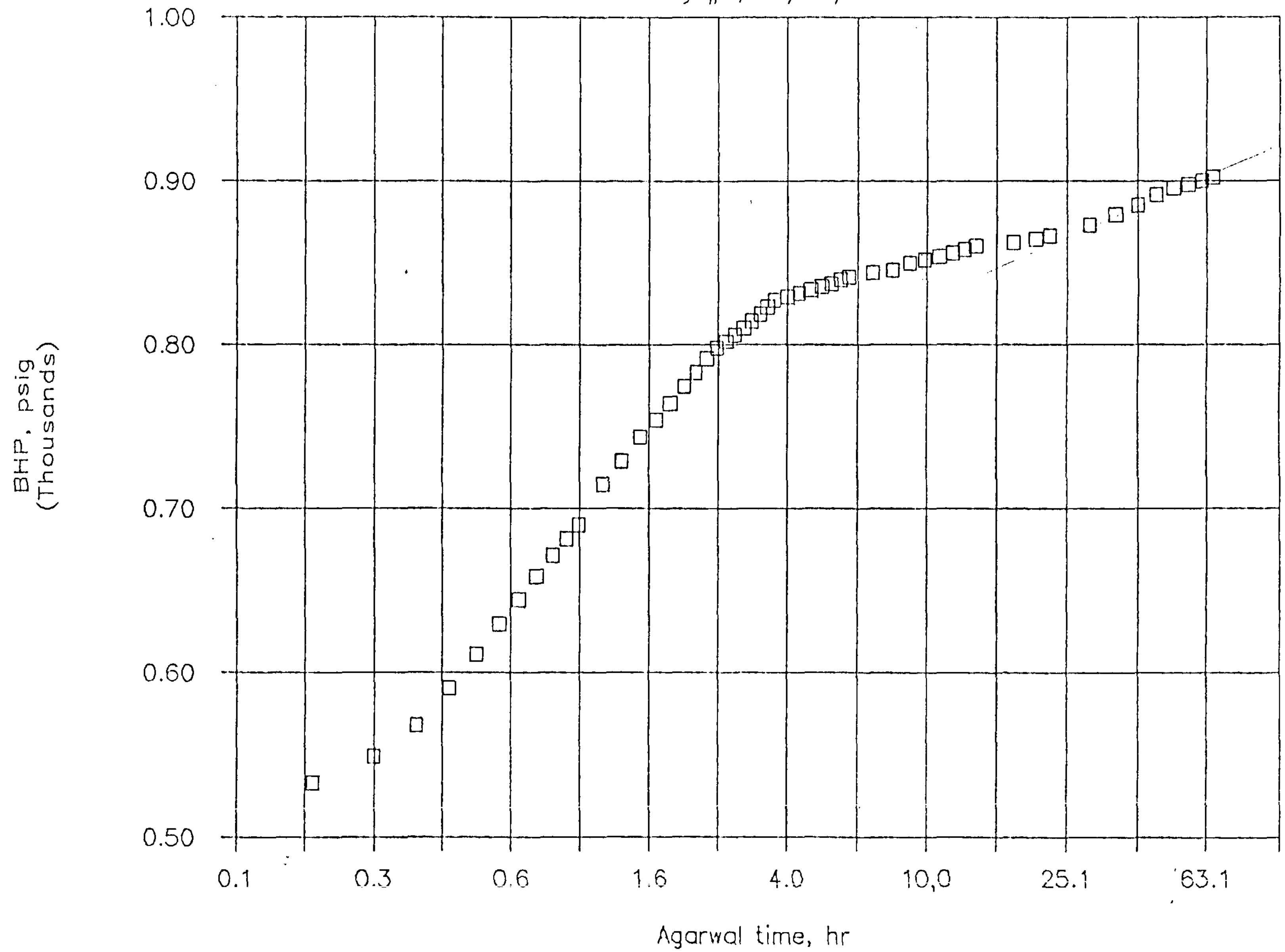
$$K_g h = \frac{(162.6)(1911.8)\,.01392}{32.34} = 133.8$$



Gavilan Dome, Buildup
Loddy #1, 11/19/87
1000
794
631
501
398
316
251
200
158
126
100
79
63
50
40
32
25
20
16
13
10
dP & dP', psig
0.1
0.3
0.6
1.6
4.0
10.0
25.1
63.1
Agarwal time, hr
dP
dP'

Gavilan Dome, Buildup

Loddy #1, 11/19/87



$q_g = 338.54$ Mcf/D

$q = 67$ BO/D

$T = 840$ hr

Gavilan Dome Buildup Analysis
Sun Loddy#1, Start Test 10:06 AM, 11/~~16~~ 19/87
Flow Time,T = ~~816~~ 840 hours q = ~~69~~ 67 B/D

$B_o = 1.307$ $B_g = 3.098$ $R_s = 423$ $\mu_o = 0.650$ $\mu_g = 0.01390$

Cartesian plot
cc = 100%
Intercept
$P_{0hr} = 490$ psig

dt hr	BHP psig	dP psig	T*dt/T+dt Agarwal	Agarwal' WMS Tech
0.00	490.0			
0.17	532.6	42.6	0.167	
0.25	549.2	59.2	0.250	55.1
0.33	567.9	77.9	0.333	85.7
0.42	590.7	100.7	0.416	108.3
0.50	611.4	121.4	0.500	117.7
0.58	630.1	140.0	0.583	114.4
0.67	644.6	154.6	0.666	116.5
0.75	659.1	169.1	0.749	120.6
0.83	671.5	181.5	0.832	113.3
0.92	681.9	191.9	0.916	101.8
1.00	690.2	200.2	0.999	117.9
1.17	715.0	225.0	1.168	133.7
1.33	729.5	239.5	1.328	117.2
1.50	744.0	254.0	1.497	108.1
1.67	754.4	264.4	1.667	105.8
1.83	764.8	274.8	1.826	115.3
2.00	775.1	285.1	1.995	109.1
2.17	783.4	293.4	2.164	108.7
2.33	791.7	301.7	2.326	102.2
2.50	797.9	307.9	2.492	76.4
hr	psig	psig	Agarwal	WMS Tech
36.00	879.2	389.2	34.479	39.4
42.00	885.4	395.4	39.944	46.2
48.00	891.7	401.7	45.333	43.1
54.00	895.8	405.8	50.648	28.9
60.00	897.9	407.9	55.890	22.4
66.00	900.0	410.0	61.061	27.7
71.00	902.1	412.1	65.317	

$(67)(1.307) = 87.57$ RB/D

$\left[338.54 - \frac{(67)(423)}{1000}\right]3.098$

$= 961.0$ RB/D

$q_t = 1049$ RB/D

$(87.57)(.650)$

$(961)(.01390)$

$\mu_{Average} = 0.0670$ cp

7 points

cc 98.9%

$P_{1hr} = 754.7$ psig

slope = 81.82 psi/cycle

$$\lambda_t h = \frac{(162.6)(1049)}{81.82} = 2085 \ \frac{md.ft}{cp}$$

$\bar{K}h = 140$ md.ft

$$K_o h = \frac{(162.6)(87.57)(.650)}{81.82} = 113.1$$

$$K_g h = \frac{(162.6)(961)(.01390)}{81.82} = 26.5$$

APPENDIX 3

Interference Test Analyses Worksheets

Frac Pulse Analyses

Kamal Method

(1) 5/13/88

Frac D-17 Response at A-20 5/27/87 $\bar{P} \sim$ 1240 psi

Pump Time 1.63 hr

Signal Time 80.0 hr

Lag Time, t_l 35.5 hr

Peak $\frac{\Delta P}{q}$ 1.41×10^{-6}

Δt_{cyc} = signal time + pump time = 80.0 + 1.63 = 81.63

$$\text{Pulse Ratio} = \frac{\text{Pump time}}{\Delta t_{cyc}} = \frac{1.63}{81.63} = 0.0200$$

$$\text{Demensionless time lag, } t_{l_D} = \frac{t_l}{\Delta t_{cyc}} = \frac{35.5}{81.63} = 0.435$$

Demensionless cycle period, $\Delta t_{cycD} = C\, t_{l_D}^{A} + D$

$$\Delta t_{cycD} = (0.337)(.435^{-.815}) - 0.325$$

$$= 0.339$$

From Fig 10-13

A = −0.815

C = 0.337

E = −1.34

F = 0.0255

D = −0.325

Demensionless response amplitude

$$\frac{\Delta P_D}{\Delta t_{cycD}} = 1 \times \left[F \exp(E\, t_{l_D}) + 0.01\right]$$

$$= -1 \left[.0255 \exp\left[(-1.34)(.435)\right] + 0.01\right]$$

$$= -0.0259$$

$$\Delta P_D = (-0.0259)(0.339) = -0.00878$$

ΔP_D = $\Delta t_{cycD} \times$ [illegible]

5/12/80

$$\Delta P_D = \frac{kh\,\Delta P}{70.6\,B\,\mu\,q} \qquad B = 1.86 \qquad \mu = 0.559$$

$$kh = \frac{70.6\,B\,\mu\,\Delta P_D}{\Delta P/q}$$

$$kh = \frac{(70.6)(1.86)(0.559)(0.00878)}{1.41\times10^{-6}}$$

$$kh = 457{,}000 \text{ md.ft}$$

$$\Delta t_{cycD} = \frac{k\,\Delta t_{cyc}}{56900\,\phi\,c_t\,\mu\,r^2} \qquad r = 12757$$

$$\phi c_t h = \frac{kh\,\Delta t_{cyc}}{56900\,\mu\,r^2\,\Delta t_{cycD}}$$

$$= \frac{(457{,}000)(81.63)}{(56{,}900)(.559)(12787^2)(.339)}$$

$$= 2.12\times10^{-5}$$

$$c_{t\,1240psi} = S_o c_o + S_w c_w + S_g c_g + c_f$$

$$(.87)(3.6\times10^{-4}) + (0.1)(3.3\times10^{-6}) + (0.1)(7\times10^{-4}) + 100\times10^{-6} = 4.8\times10^{-}$$

$$\phi h = 4.41\times10^{-2}$$

$$\phi = 2.94\times10^{-4} = 0.03\%$$

5/13/88

Determine c_t

Assume $S_w = 0.10$ $c_w = 3.3 \times 10^{-6}$ $c_f = 100 \times 10^{-6}$

$S_g = 0.03$ c_g : $S_o = 0.87$ c_o =

BHT = 170° = 630°

	1000	125
γ_o	.714	.71
γ_g	.0572	.0716
T	630°	630°
Z	.872	.85
R_s	452	523
B_o	1.32	1.35
B_g	$\frac{2.767}{1000}$	2.176
$\frac{dR_s}{dp}$	0.30	0.28
$\frac{dB_o}{dR_s}$	3.99×10^{-4}	4.67×10^{-4}

$$\underset{1000\,psi}{c_o} = \frac{1}{B_o}\frac{dR_s}{dp}\left[B_g - \frac{dB_o}{dR_s}\right]$$

$$= \left(\frac{1}{1.32}\right)(0.30)\left[2.767 \times 10^{-3} - 3.99 \times 10^{-4}\right]$$

$$\underset{1000}{c_o} = 5.38 \times 10^{-4}$$

$$\underset{1250}{c_o} = \left(\frac{1}{1.352}\right)(.28)\left[2.176 \times 10^{-3} - 4.67 \times 10^{-4}\right]$$

$$= 3.54 \times 10^{-4}$$

$$c_{o_{800}} = \left(\frac{1}{1.294}\right)(0.28)\left[3.521 \times 10^{-3} - 4.29 \times 10^{-4}\right]$$

$$c_{o_{800}} = 6.69 \times 10^{-4}$$

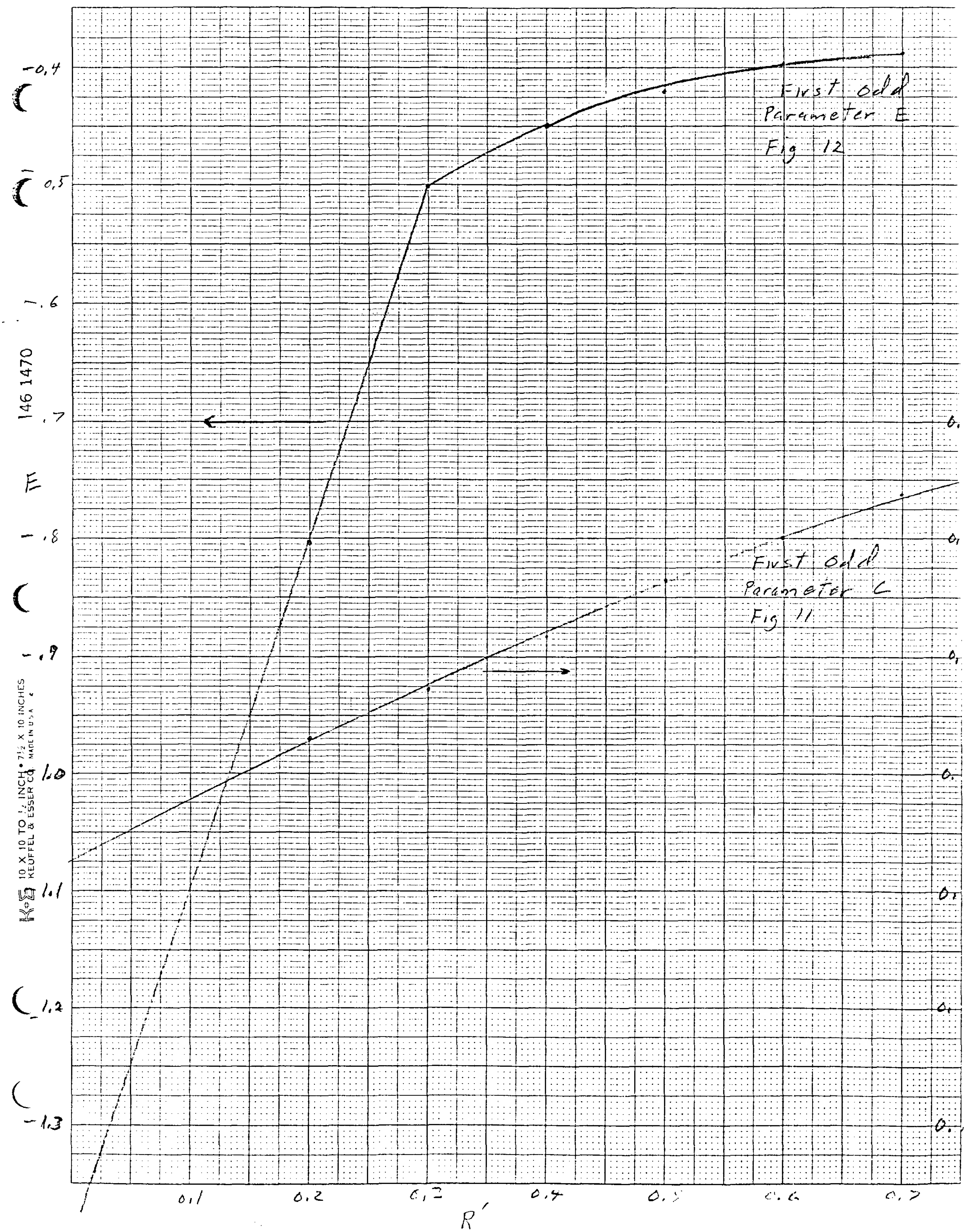
$$c_{o\,500} = \frac{1}{1.253}(0.32)\left[5.804 \times 10^{-3} - 5 \times 10^{-4}\right]$$

$$c_{o_{500}} = 1.17 \times 10^{-3}$$

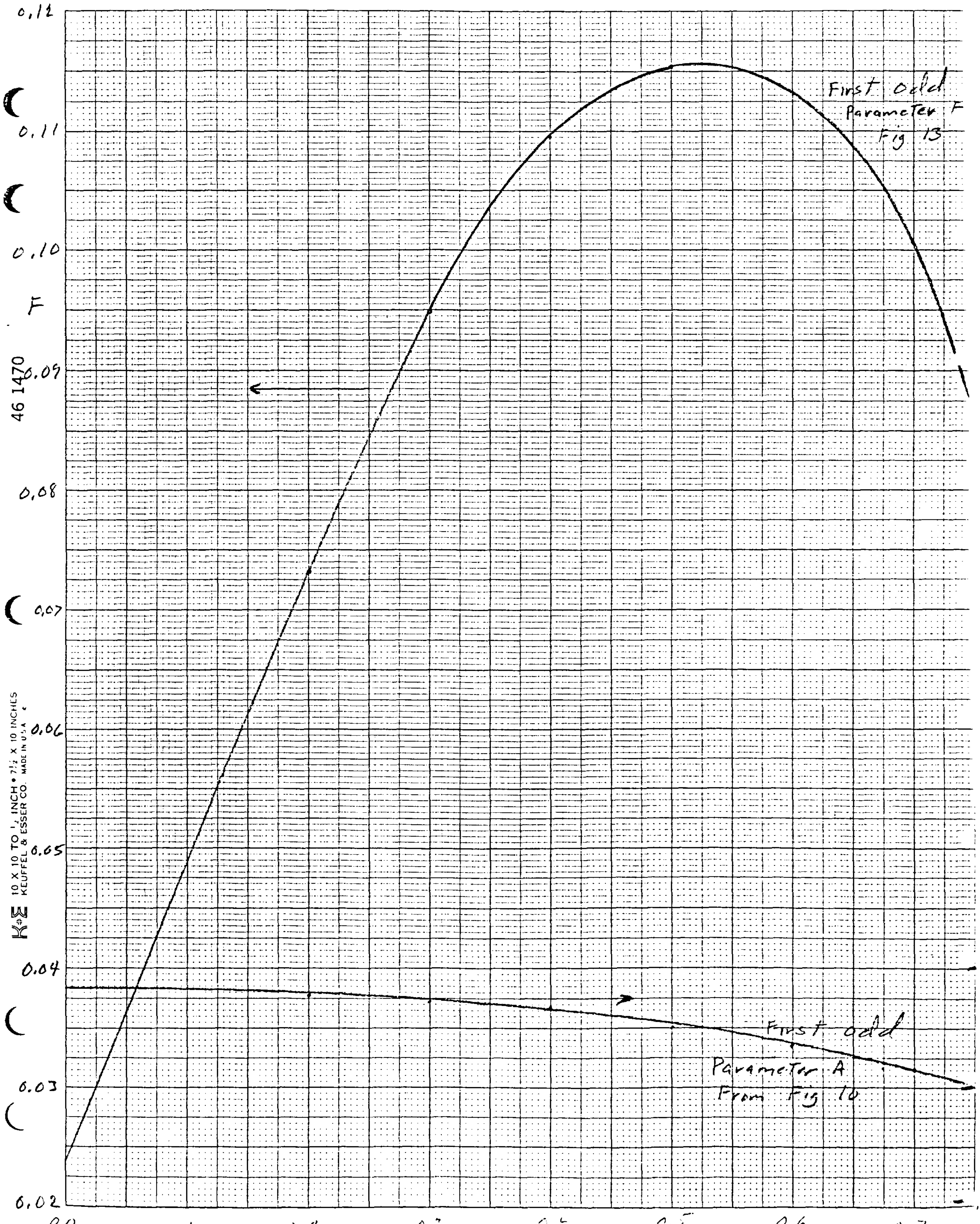
(4)
5/12/88

$$C_g = \frac{1}{P} - \left[\frac{dz}{dP} \quad \frac{1}{z}\right]$$

	Z	$\frac{dz}{dP}$	C_g
$\bar{P} = 500$	0.914	1×10^{-4}	1.89×10^{-3}
$\bar{P} = 800$	0.887	8×10^{-5}	1.16×10^{3}
$\bar{P} = 1000$	0.872	6×10^{-5}	9.31×10^{-4}
$\bar{P} = 1200$	0.859	6×10^{-5}	7.63×10^{-4}
$\bar{P}$ 1300	0.852	8×10^{-5}	6.75×10^{-4}

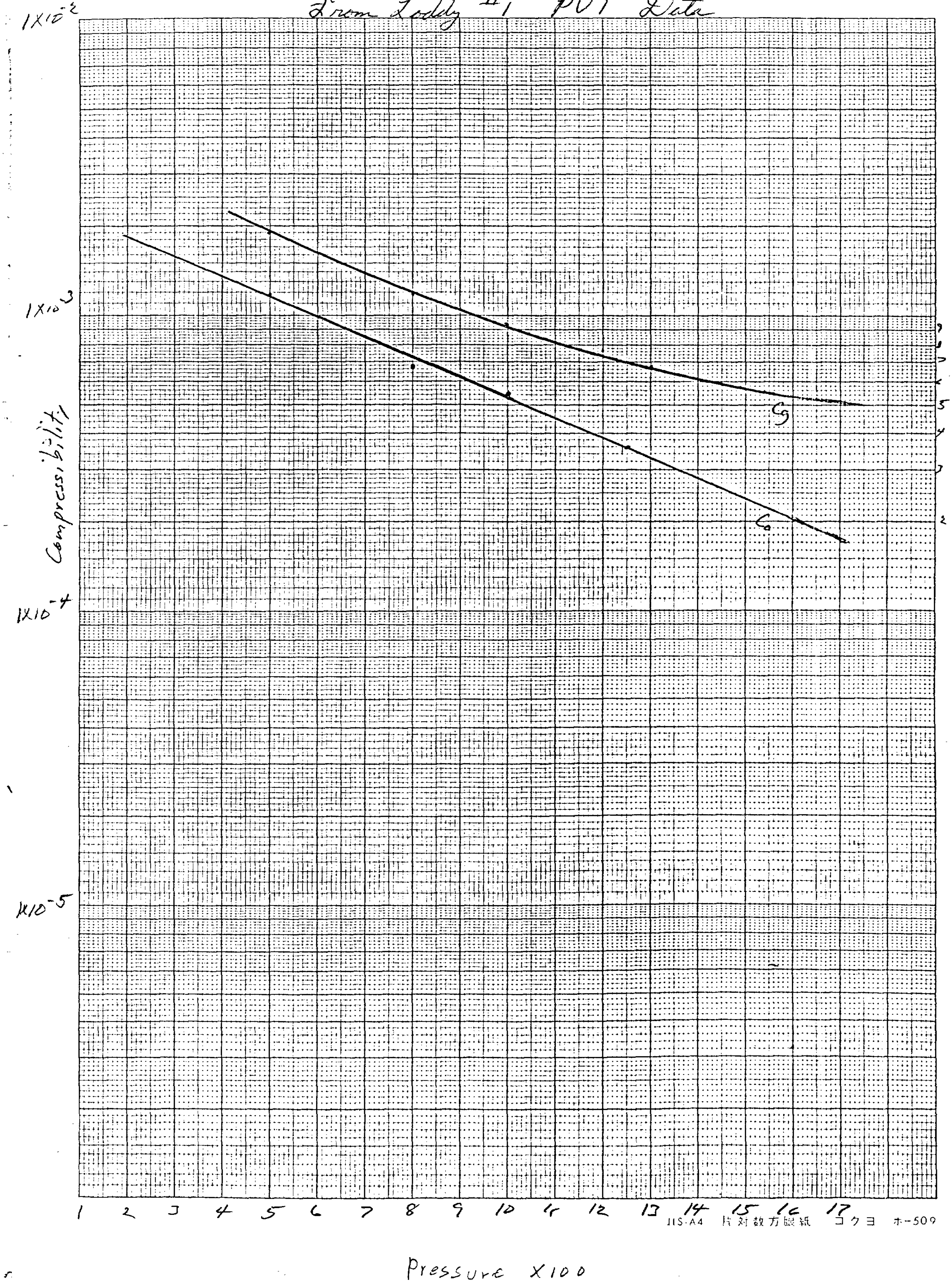


First odd
Parameter E
Fig 12
First odd
Parameter C
Fig 11
E
R′
-0.4
0.5
.6
.7
.8
.9
1.0
1.1
1.2
1.3
0.1
0.2
0.3
0.4
0.5
0.6
0.7
146 1470
10 X 10 TO ½ INCH • 7½ X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.



0.12
0.11
0.10
F
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
R'
First odd Parameter F Fig 13
First odd Parameter A From Fig 10
46 1470
K+E 10 X 10 TO 1/2 INCH • 7 1/2 X 10 INCHES KEUFFEL & ESSER CO. MADE IN U.S.A.

From Loddy #1 PVT Data



Frac Pulse Analysis
Kamal Method

Frac Well	TAP 4
Response Well	E-6
Date	2/13/86
Static Pressure, psig	1691
Pump Time, hr	0.672
Signal Time, hr	32.16
Lag Time, hr	16.08
Peak dP/q	7.09E-06
Constants from Figures 10-13	
A =	-0.815
C =	0.335
E =	-1.34
F =	0.029
D =	-0.325
Total Cycle Time, dTcyc =	32.832
Pulse Ratio, R' =	0.020467
Demensionless Time Lag, TlD =	0.489766
Demensionless Cycle Period, dTcycD =	0.274382
Demensionless Response Amplitude, dPD =	0.006871
Average Formation Volume Factor, B =	1.41
Average Viscosity, cp =	0.53
Distance Between Wells, ft	3448
kh = 70.6*B*μ*dPD/(dP/q) =	51135.35
ϕCth = kh*dTcyc/(56900*μ*r^2*dTcycD) =	1.71E-05
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	1.75E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	1.52E-04
Water Saturation, Sw =	0.1
Water Compressibility, Cw =	3.30E-06
Formation Compressibility, Cf =	1.00E-04
Total Compressibilty, Ct =	2.57E-04
ϕh =	0.066369

Frac Pulse Analysis
Kamal Method

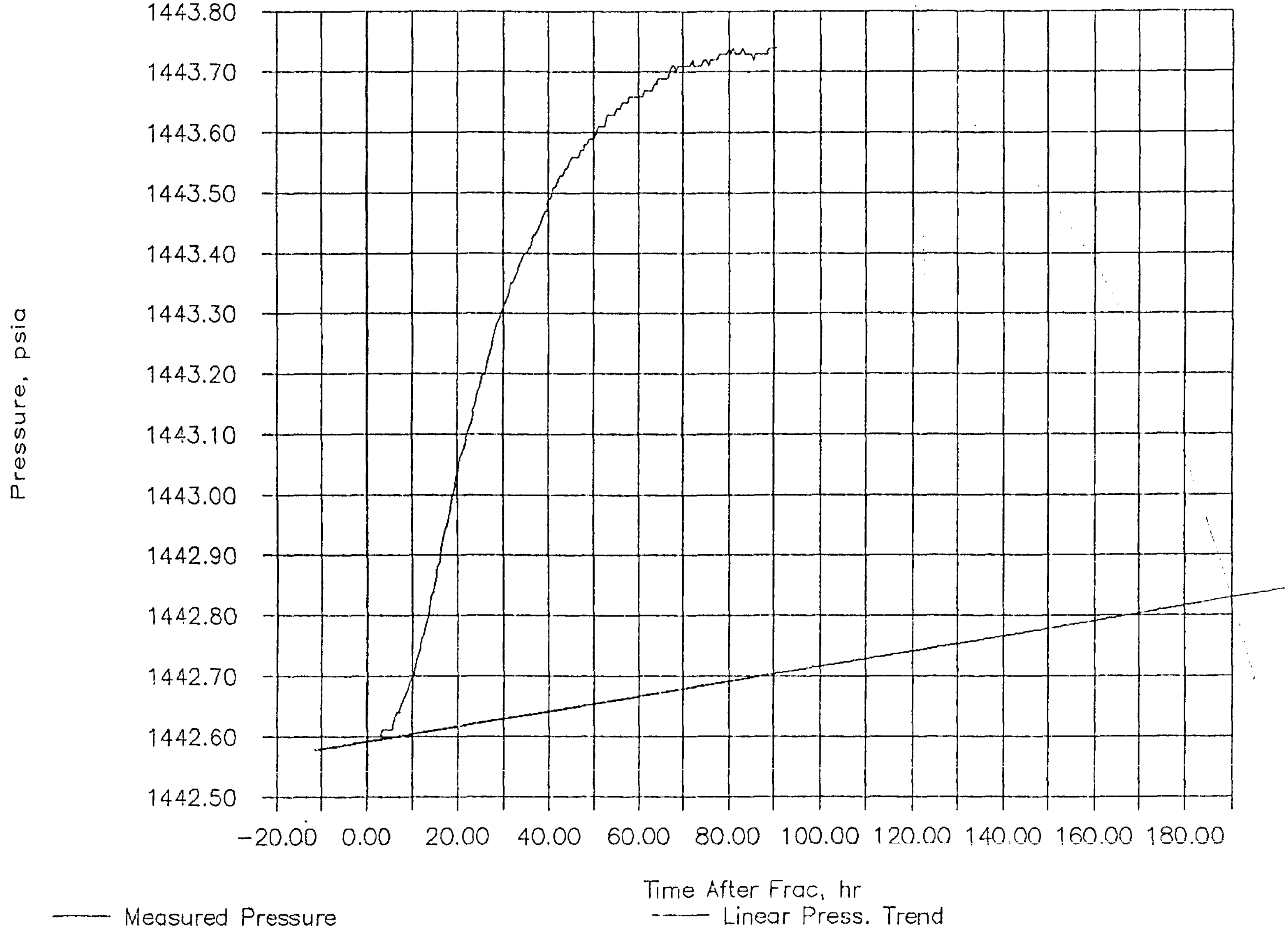
Frac Well	N-31
Response Well	E-6
Date	4/1/86
Static Pressure, psig	1660
Pump Time, hr	1.1232
Signal Time, hr	96
Lag Time, hr	42.72
Peak dP/q	4.40E-04
Constants from Figures 10-13	
A =	-0.815
C =	0.325
E =	-1.38
F =	0.0265
D =	-0.325
Total Cycle Time, dTcyc =	97.1232
Pulse Ratio, R' =	0.011564
Demensionless Time Lag, TlD =	0.439853
Demensionless Cycle Period, dTcycD =	0.309727
Demensionless Response Amplitude, dPD =	0.007570
Average Formation Volume Factor, B =	1.41
Average Viscosity, cp =	0.53
Distance Between Wells, ft	2858
kh = 70.6*B*μ*dPD/(dP/q) =	907.7466
øCth = kh*dTcyc/(56900*μ*r^2*dTcycD) =	1.16E-06
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	1.85E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	1.52E-04
Water Saturation, Sw =	0.1
Water Compressibility, Cw =	3.30E-06
Formation Compressibility, Cf =	1.00E-04
Total Compressibilty, Ct =	2.66E-04
øh =	0.004346

Frac Pulse Analysis
Kamal Method

Frac Well	F-30
Response Well	B-32
Date	9/4/86
Static Pressure, psig	1443
Pump Time, hr	1.3
Signal Time, hr	190
Lag Time, hr	90.5
Peak dP/q	6.70E-06
Constants from Figures 10-13	
A =	-0.815
C =	0.328
E =	-1.375
F =	0.025
D =	-0.325
Total Cycle Time, dTcyc =	191.3
Pulse Ratio, R' =	0.006795
Demensionless Time Lag, T1D =	0.473078
Demensionless Cycle Period, dTcycD =	0.278674
Demensionless Response Amplitude, dPD =	0.006422
Average Formation Volume Factor, B =	1.41
Average Viscosity, cp =	0.53
Distance Between Wells, ft	7000
kh = 70.6*B*μ*dPD/(dP/q) =	50570.35
øCth = kh*dTcyc/(56900*μ*r^2*dTcycD) =	2.35E-05
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	2.60E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	5.90E-04
Water Saturation, Sw =	0.1
Water Compressibility, Cw =	3.30E-06
Formation Compressibility, Cf =	1.00E-04
Total Compressibilty, Ct =	3.44E-04
øh =	0.068246

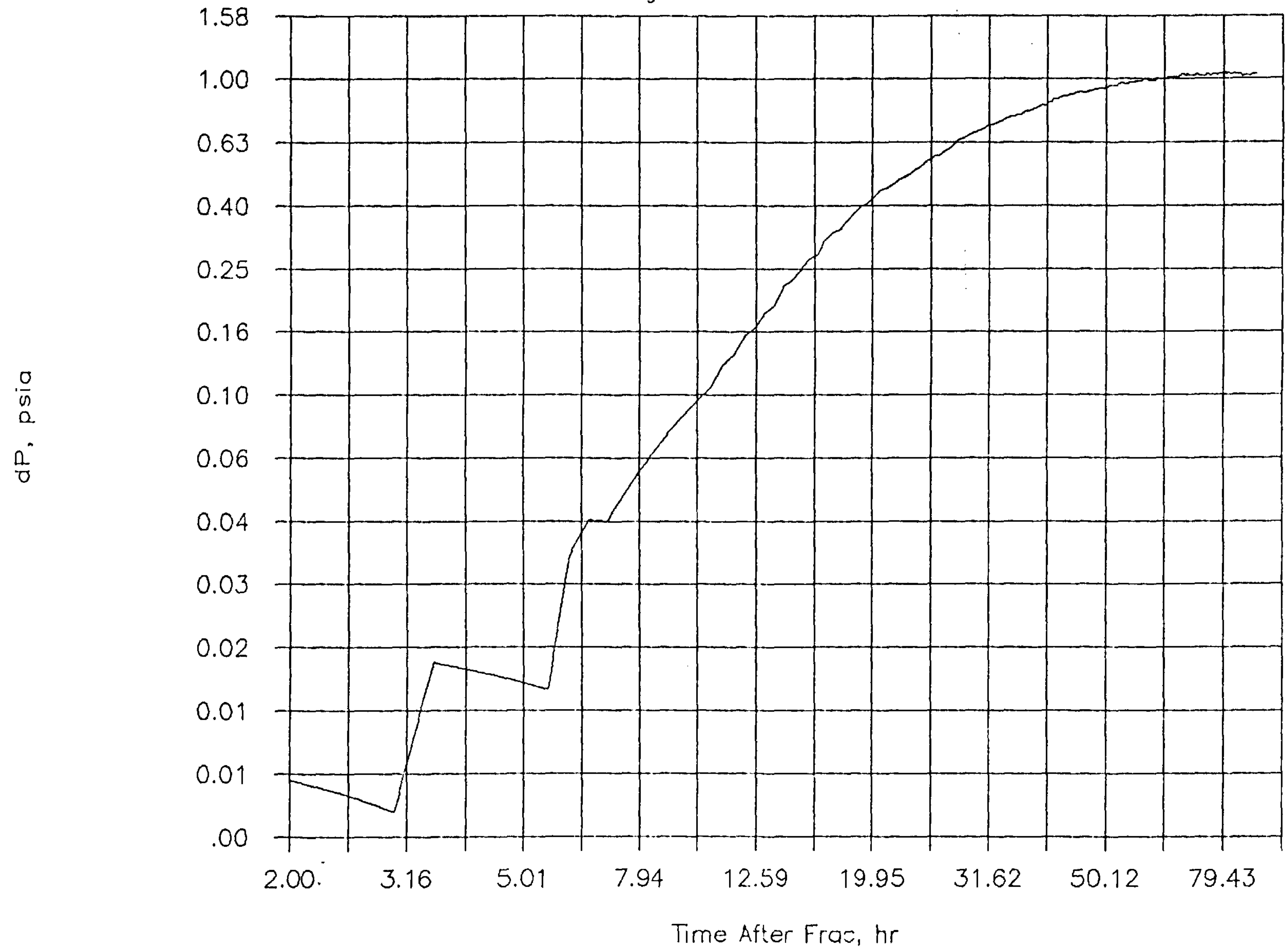
B.M.G. Interference Test

Signal From F-30 to B-32



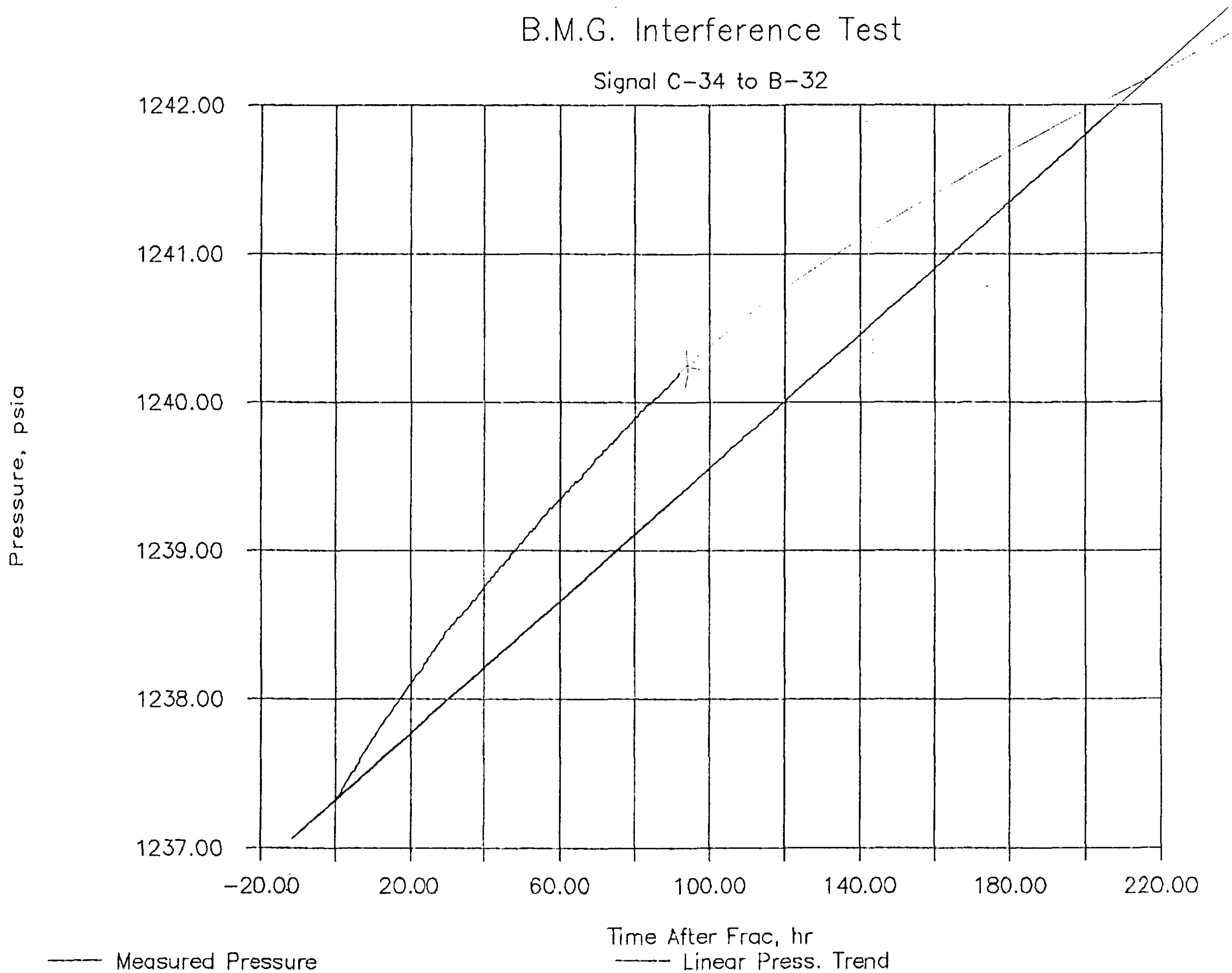
B.M.G. Interference Test

Signal From F-30 to B-32



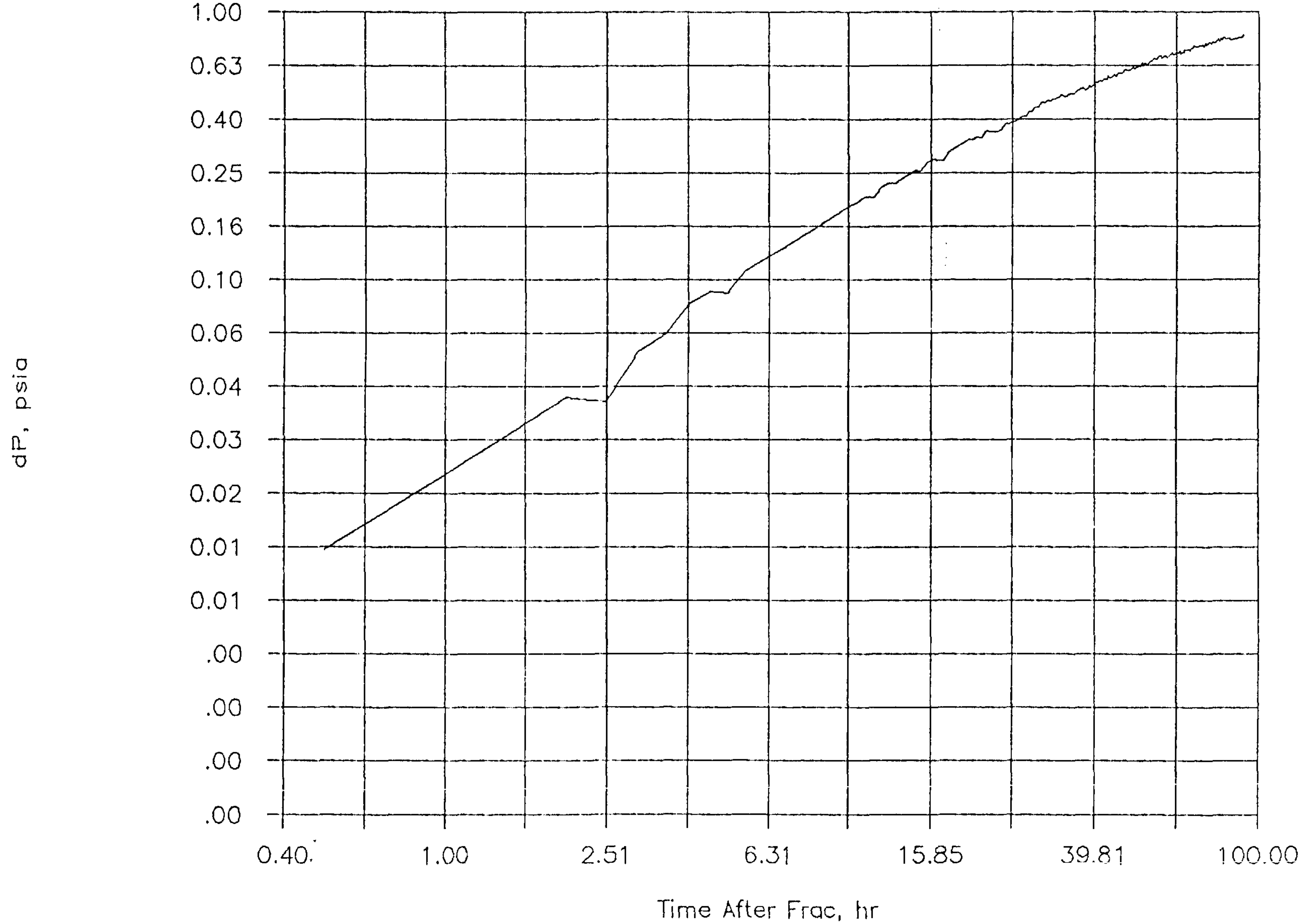
Frac Pulse Analysis
Kamal Method

Frac Well	C-34
Response Well	B-32
Date	4/23/87
Static Pressure, psig	1237
Pump Time, hr	1.7
Signal Time, hr	215
Lag Time, hr	96
Peak dP/q	8.83E-06
Constants from Figures 10-13	
A =	-0.815
C =	0.328
E =	-1.375
F =	0.025
D =	-0.325
Total Cycle Time, dTcyc =	216.7
Pulse Ratio, R' =	0.007844
Demensionless Time Lag, TlD =	0.443008
Demensionless Cycle Period, dTcycD =	0.311865
Demensionless Response Amplitude, dPD =	0.007358
Average Formation Volume Factor, B =	1.79
Average Viscosity, cp =	0.552
Distance Between Wells, ft	10411
kh = 70.6*B*µ*dPD/(dP/q) =	58134.34
ØCth = kh*dTcyc/(56900*µ*r^2*dTcycD) =	1.19E-05
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	3.60E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	7.00E-04
Water Saturation, Sw =	0.1
Water Compressibility, Cw =	3.30E-06
Formation Compressibility, Cf =	1.00E-04
Total Compressibilty, Ct =	4.35E-04
Øh =	0.027306


B.M.G. Interference Test
Signal C-34 to B-32
Pressure, psia
1242.00
1241.00
1240.00
1239.00
1238.00
1237.00
-20.00
20.00
60.00
100.00
140.00
180.00
220.00
Time After Frac, hr
Measured Pressure
Linear Press. Trend

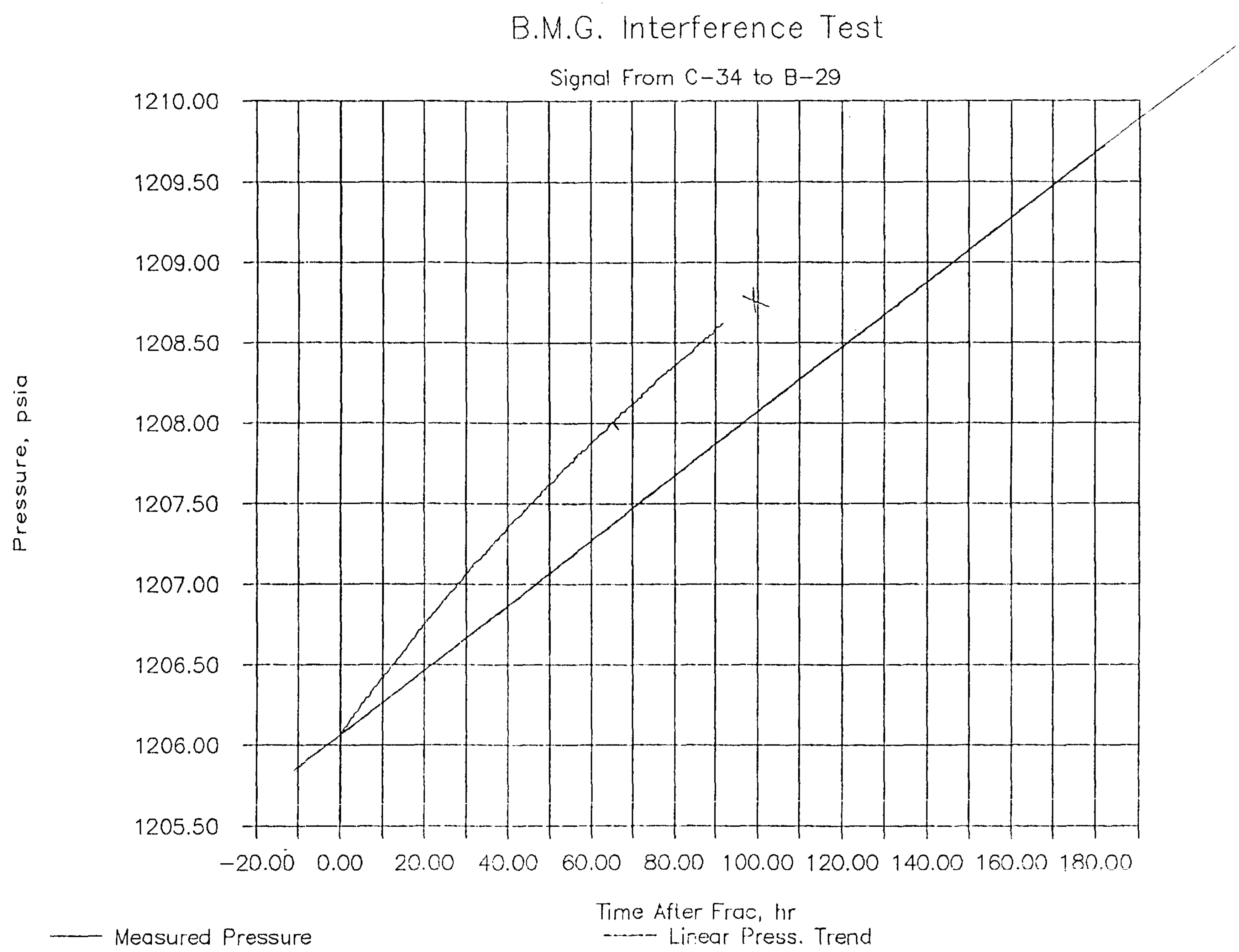
B.M.G. Interference Test

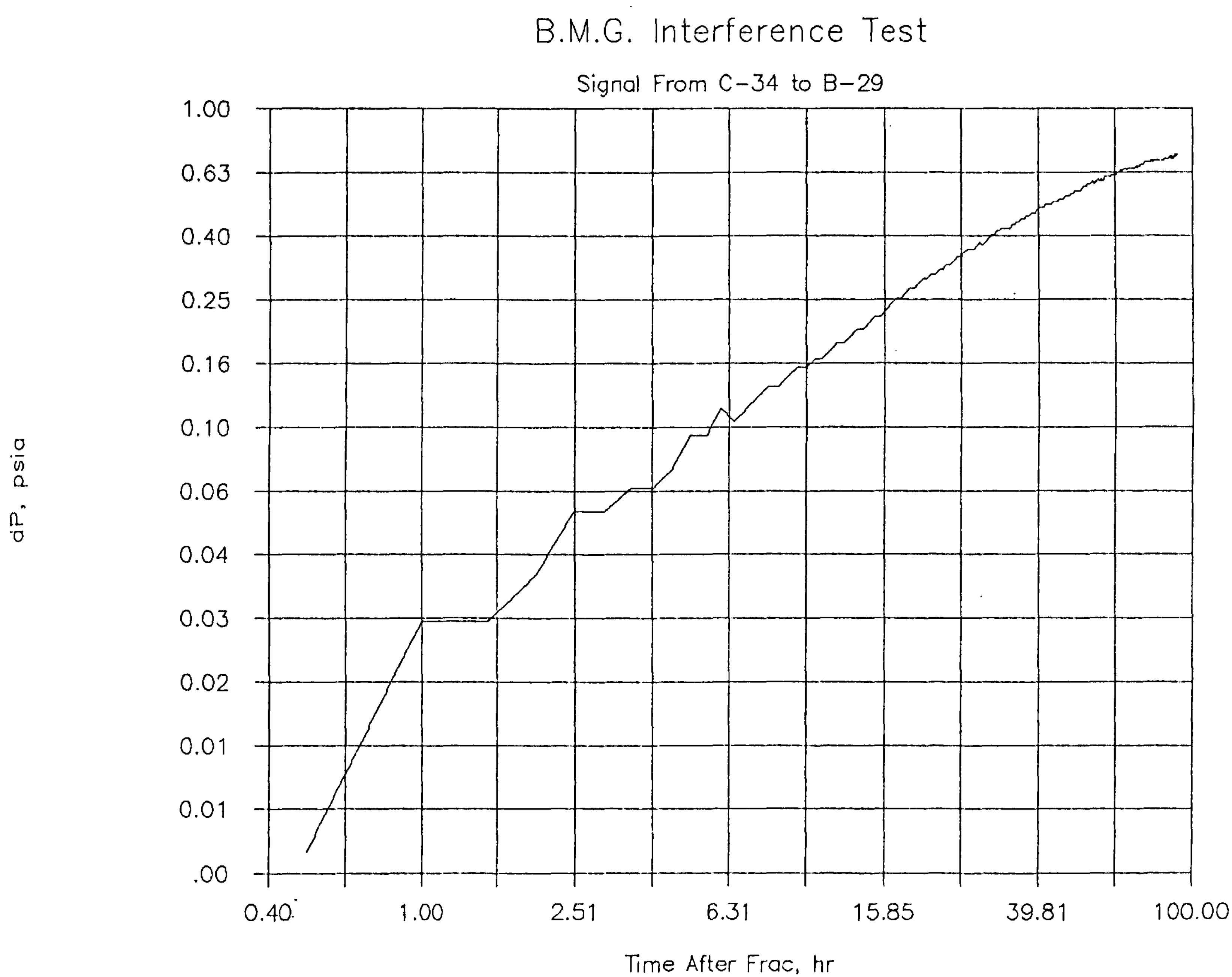
Signal C-34 to B-32



Frac Pulse Analysis
Kamal Method

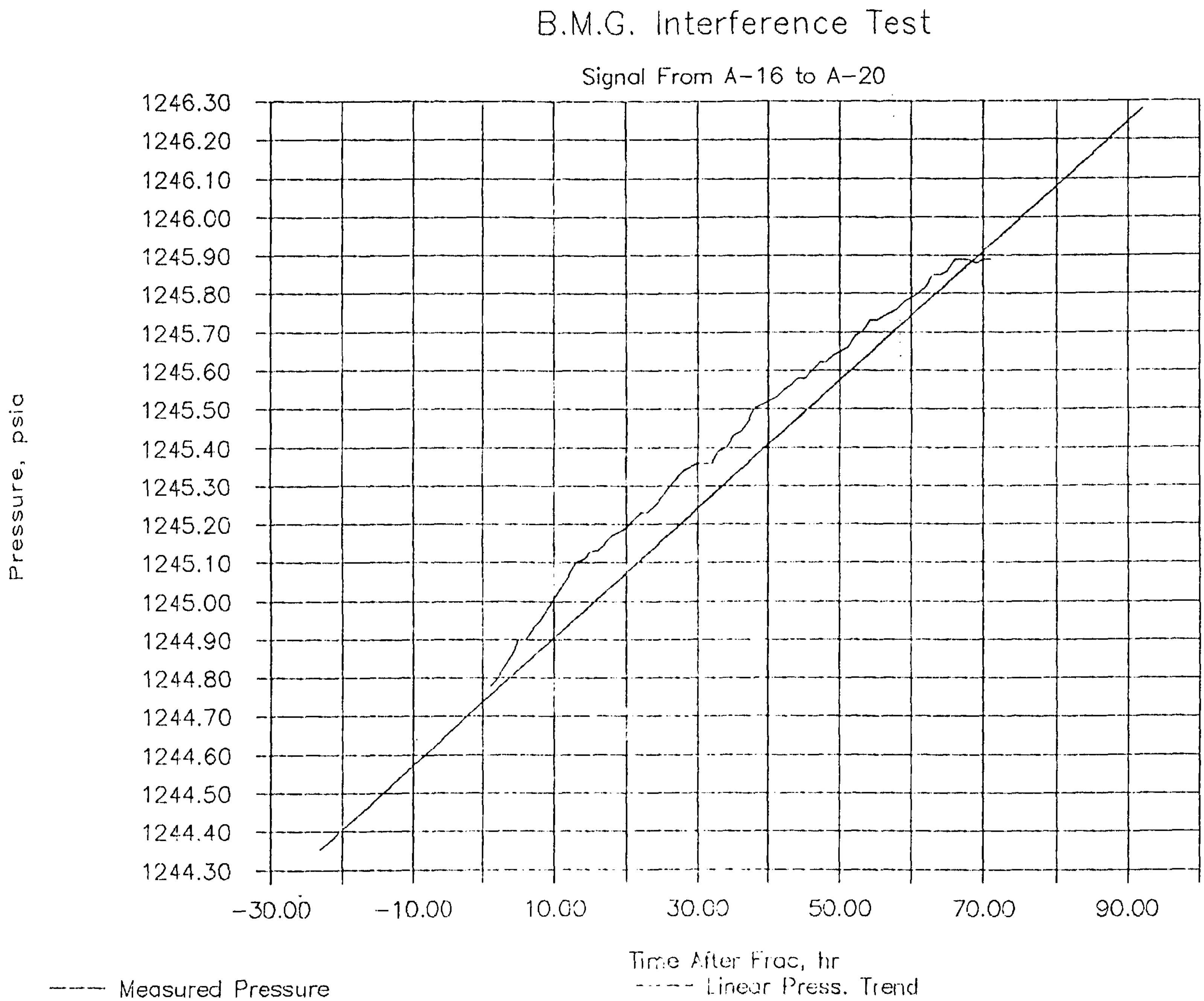
Frac Well	C-34
Response Well	B-29
Date	4/23/87
Static Pressure, psig	1207
Pump Time, hr	1.7
Signal Time, hr	200
Lag Time, hr	99
Peak dP/q	7.63E-06
Constants from Figures 10-13	
A =	-0.815
C =	0.33
E =	-1.375
F =	0.026
D =	-0.325
Total Cycle Time, dTcyc =	201.7
Pulse Ratio, R' =	0.008428
Demensionless Time Lag, TlD =	0.490827
Demensionless Cycle Period, dTcycD =	0.264395
Demensionless Response Amplitude, dPD =	0.006144
Average Formation Volume Factor, B =	1.79
Average Viscosity, cp =	0.552
Distance Between Wells, ft	11222
kh = 70.6*B*µ*dPD/(dP/q) =	56176.33
ØCth = kh*dTcyc/(56900*µ*r^2*dTcycD) =	1.08E-05
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	3.80E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	7.20E-04
Water Saturation, Sw =	0.1
Water Compressibility, Cw =	3.30E-06
Formation Compressibility, Cf =	1.00E-04
Total Compressibilty, Ct =	4.53E-04
Øh =	0.023942

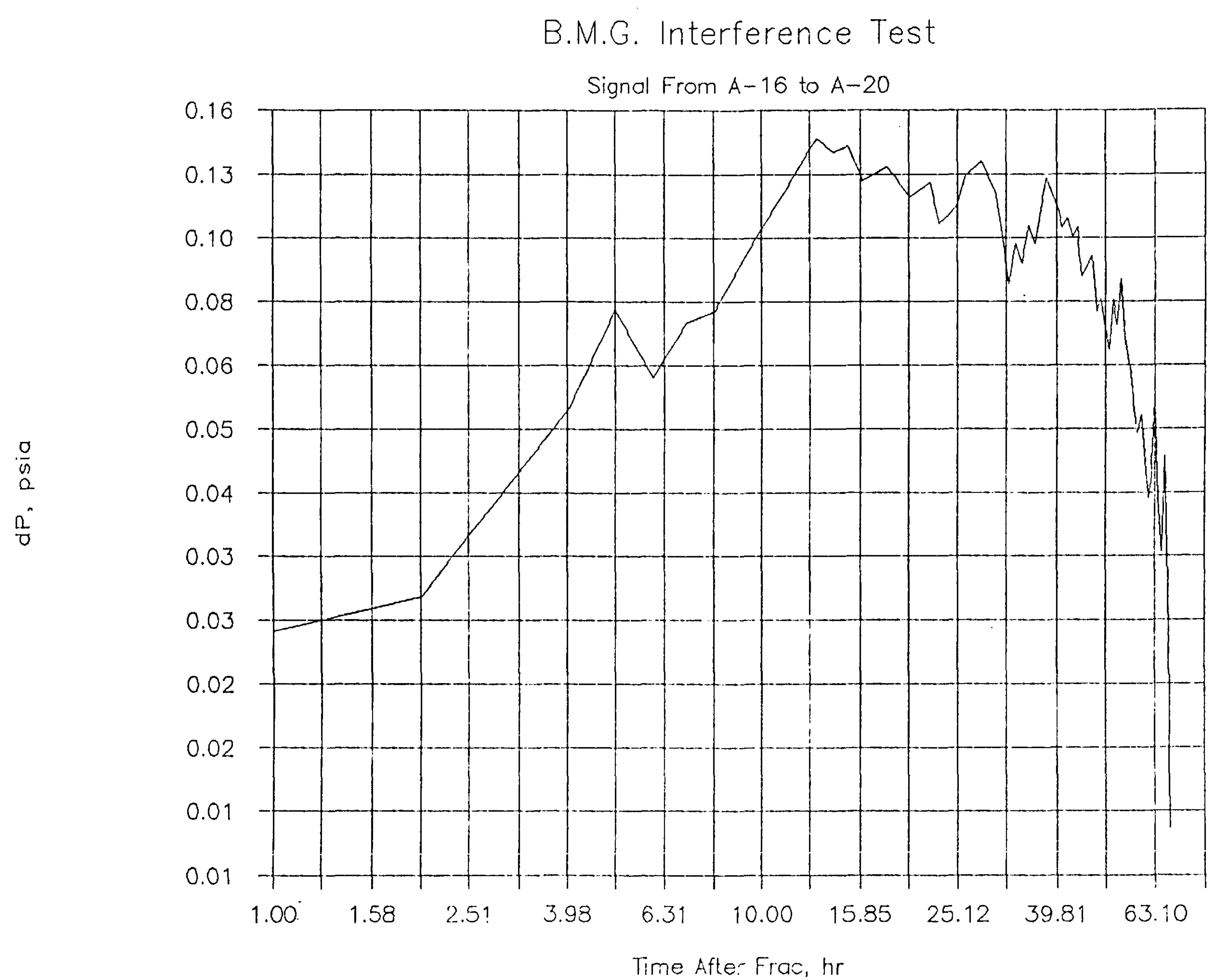

B.M.G. Interference Test
Signal From C-34 to B-29
Pressure, psia
1210.00
1209.50
1209.00
1208.50
1208.00
1207.50
1207.00
1206.50
1206.00
1205.50
-20.00
0.00
20.00
40.00
60.00
80.00
100.00
120.00
140.00
160.00
180.00
Time After Frac, hr
Measured Pressure
Linear Press. Trend


B.M.G. Interference Test
Signal From C-34 to B-29
dP, psia
1.00
0.63
0.40
0.25
0.16
0.10
0.06
0.04
0.03
0.02
0.01
0.01
.00
0.40
1.00
2.51
6.31
15.85
39.81
100.00
Time After Frac, hr

Frac Pulse Analysis
Kamal Method

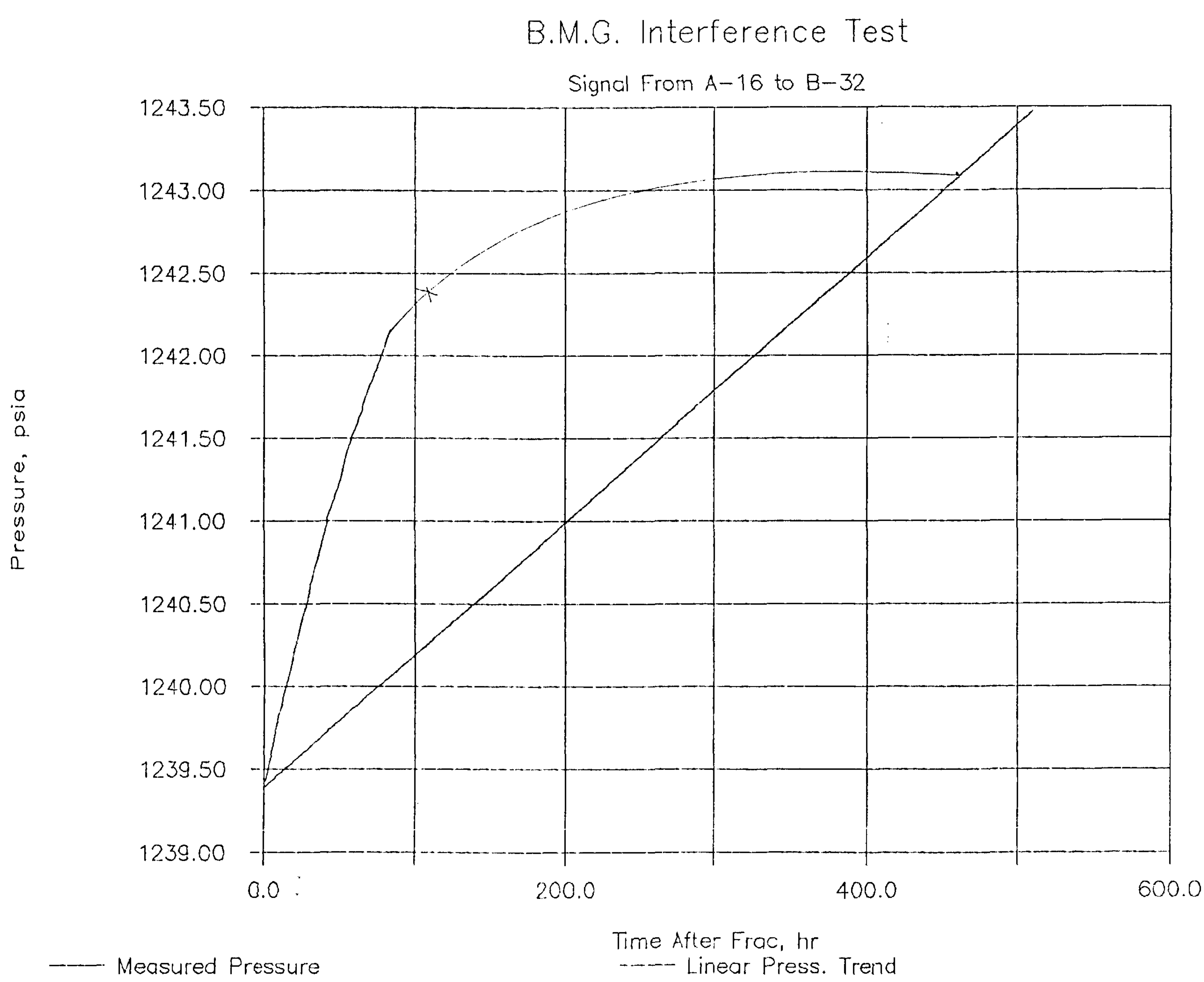
Frac Well	A-16
Response Well	A-20
Date	5/11/87
Static Pressure, psig	1234
Pump Time, hr	1.6
Signal Time, hr	68
Lag Time, hr	13
Peak dP/q	1.05E-06
Constants from Figures 10-13	
A =	-0.815
C =	0.335
E =	-1.34
F =	0.029
D =	-0.325
Total Cycle Time, dTcyc =	69.6
Pulse Ratio, R' =	0.022988
Demensionless Time Lag, TlD =	0.186781
Demensionless Cycle Period, dTcycD =	0.989944
Demensionless Response Amplitude, dPD =	0.032251
Average Formation Volume Factor, B =	1.8
Average Viscosity, cp =	0.555
Distance Between Wells, ft	7312
kh = 70.6*B*µ*dPD/(dP/q) =	2166337.
øCth = kh*dTcyc/(56900*µ*r^2*dTcycD) =	9.02E-05
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	3.60E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	7.00E-04
Water Saturation, Sw =	0.1
Water Compressibility, Cw =	3.30E-06
Formation Compressibility, Cf =	1.00E-04
Total Compressibilty, Ct =	4.35E-04
øh =	0.207599


B.M.G. Interference Test
Signal From A-16 to A-20
Pressure, psia
1246.30
1246.20
1246.10
1246.00
1245.90
1245.80
1245.70
1245.60
1245.50
1245.40
1245.30
1245.20
1245.10
1245.00
1244.90
1244.80
1244.70
1244.60
1244.50
1244.40
1244.30
-30.00
-10.00
10.00
30.00
50.00
70.00
90.00
Time After Frac, hr
Measured Pressure
Linear Press. Trend


B.M.G. Interference Test
Signal From A-16 to A-20
0.16
0.13
0.10
0.08
0.06
0.05
0.04
0.03
0.03
0.02
0.02
0.01
0.01
dP, psia
1.00
1.58
2.51
3.98
6.31
10.00
15.85
25.12
39.81
63.10
Time After Frac, hr

Frac Pulse Analysis
Kamal Method

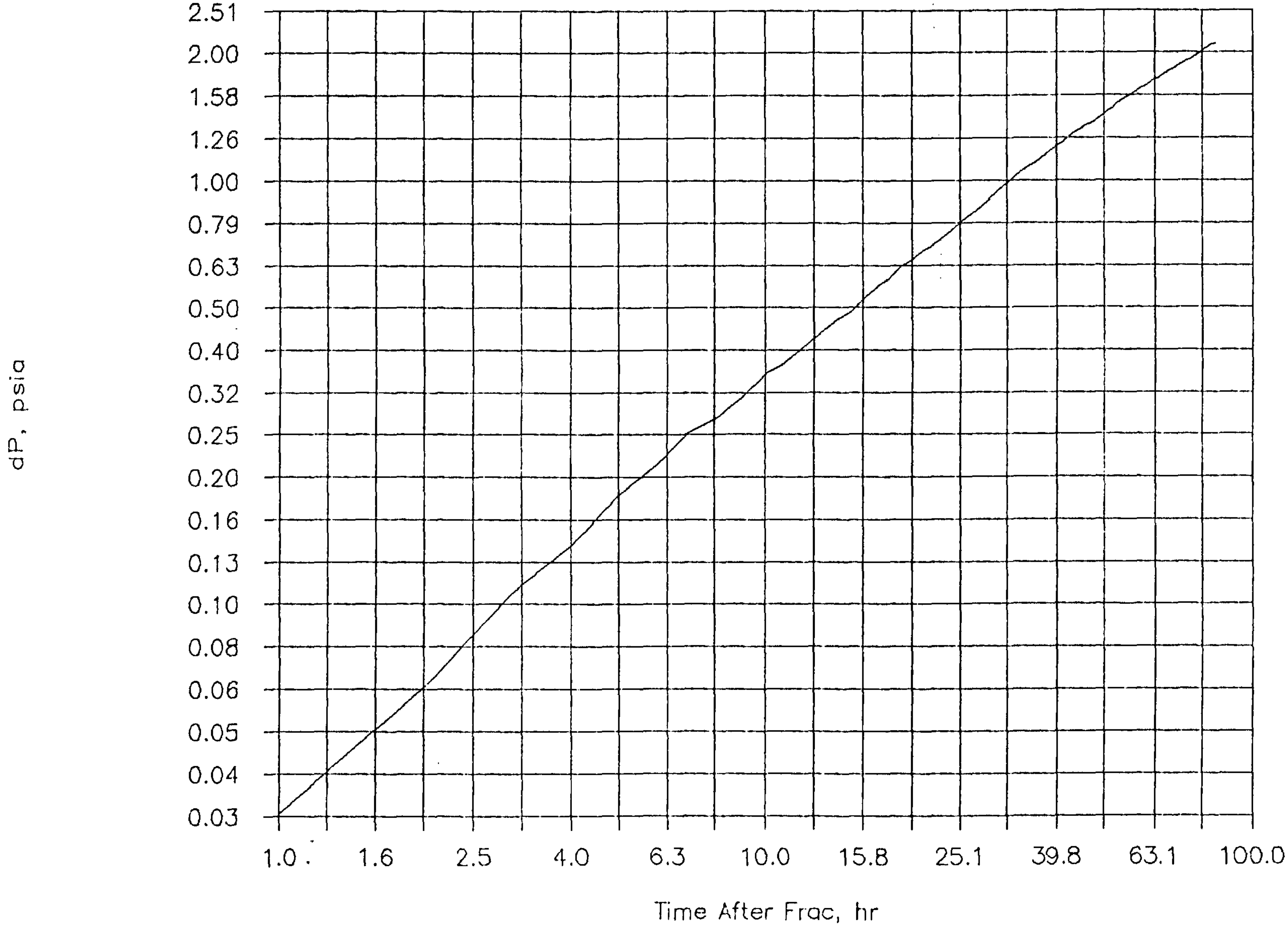
Frac Well	A-16
Response Well	B-32
Date	5/11/87
Static Pressure, psig	1240
Pump Time, hr	1.6
Signal Time, hr	470
Lag Time, hr	150
Peak dP/q	3.65E-05
Constants from Figures 10-13	
A =	-0.815
C =	0.328
E =	-1.375
F =	0.025
D =	-0.325
Total Cycle Time, dTcyc =	471.6
Pulse Ratio, R' =	0.003392
Demensionless Time Lag, TlD =	0.318066
Demensionless Cycle Period, dTcycD =	0.509299
Demensionless Response Amplitude, dPD =	0.013315
Average Formation Volume Factor, B =	1.8
Average Viscosity, cp =	0.555
Distance Between Wells, ft	16538
kh = 70.6*B*μ*dPD/(dP/q) =	25728.77
øCth = kh*dTcyc/(56900*μ*r^2*dTcycD) =	2.76E-06
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	3.60E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	7.00E-04
Water Saturation, Sw =	0.1
Water Compressibility, Cw =	3.30E-06
Formation Compressibility, Cf =	1.00E-04
Total Compressibilty, Ct =	4.35E-04
øh =	0.006347



B.M.G. Interference Test
Signal From A-16 to B-32
1243.50
1243.00
1242.50
1242.00
1241.50
1241.00
1240.50
1240.00
1239.50
1239.00
Pressure, psia
0.0
200.0
400.0
600.0
Time After Frac, hr
Measured Pressure
Linear Press. Trend

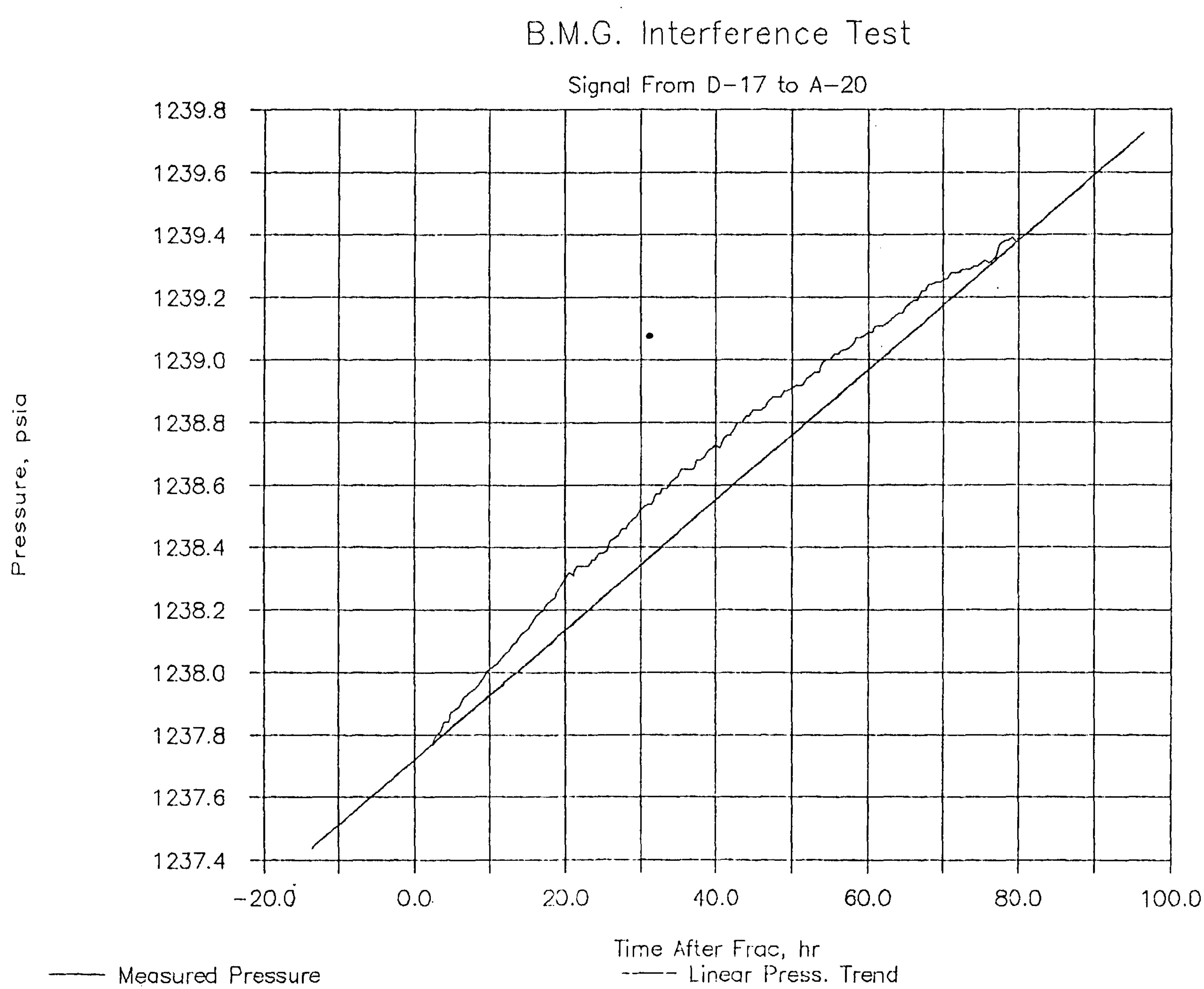
B.M.G. Interference Test

Signal From A-16 to B-32

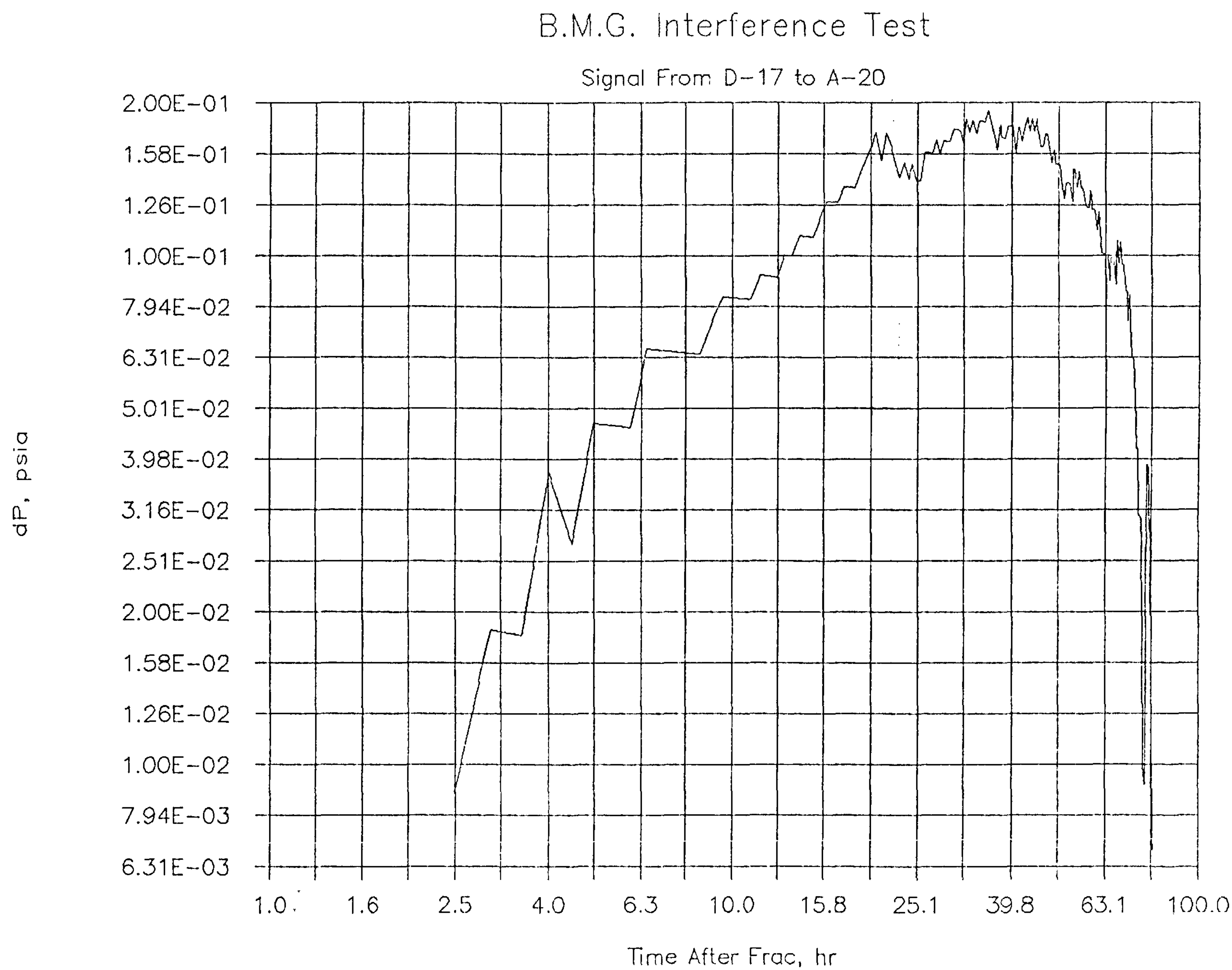


Frac Pulse Analysis
Kamal Method

Frac Well	D-17
Response Well	A-20
Date	5/27/87
Static Pressure, psig	1240
Pump Time, hr	1.63
Signal Time, hr	80
Lag Time, hr	35.5
Peak dP/q	1.41E-06
Constants from Figures 10-13	
A =	-0.815
C =	0.337
E =	-1.34
F =	0.0285
D =	-0.325
Total Cycle Time, dTcyc =	81.63
Pulse Ratio, R' =	0.019968
Demensionless Time Lag, TlD =	0.434889
Demensionless Cycle Period, dTcycD =	0.339280
Demensionless Response Amplitude, dPD =	0.008791
Average Formation Volume Factor, B =	1.86
Average Viscosity, cp =	0.559
Distance Between Wells, ft	12787
kh = 70.6*B*μ*dPD/(dP/q) =	457710.6
ϕCth = kh*dTcyc/(56900*μ*r^2*dTcycD) =	2.12E-05
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	3.60E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	7.00E-04
Water Saturation, Sw =	0.1
Water Compressibility, Cw =	3.30E-06
Formation Compressibility, Cf =	1.00E-04
Total Compressibilty, Ct =	4.35E-04
ϕh =	0.048730

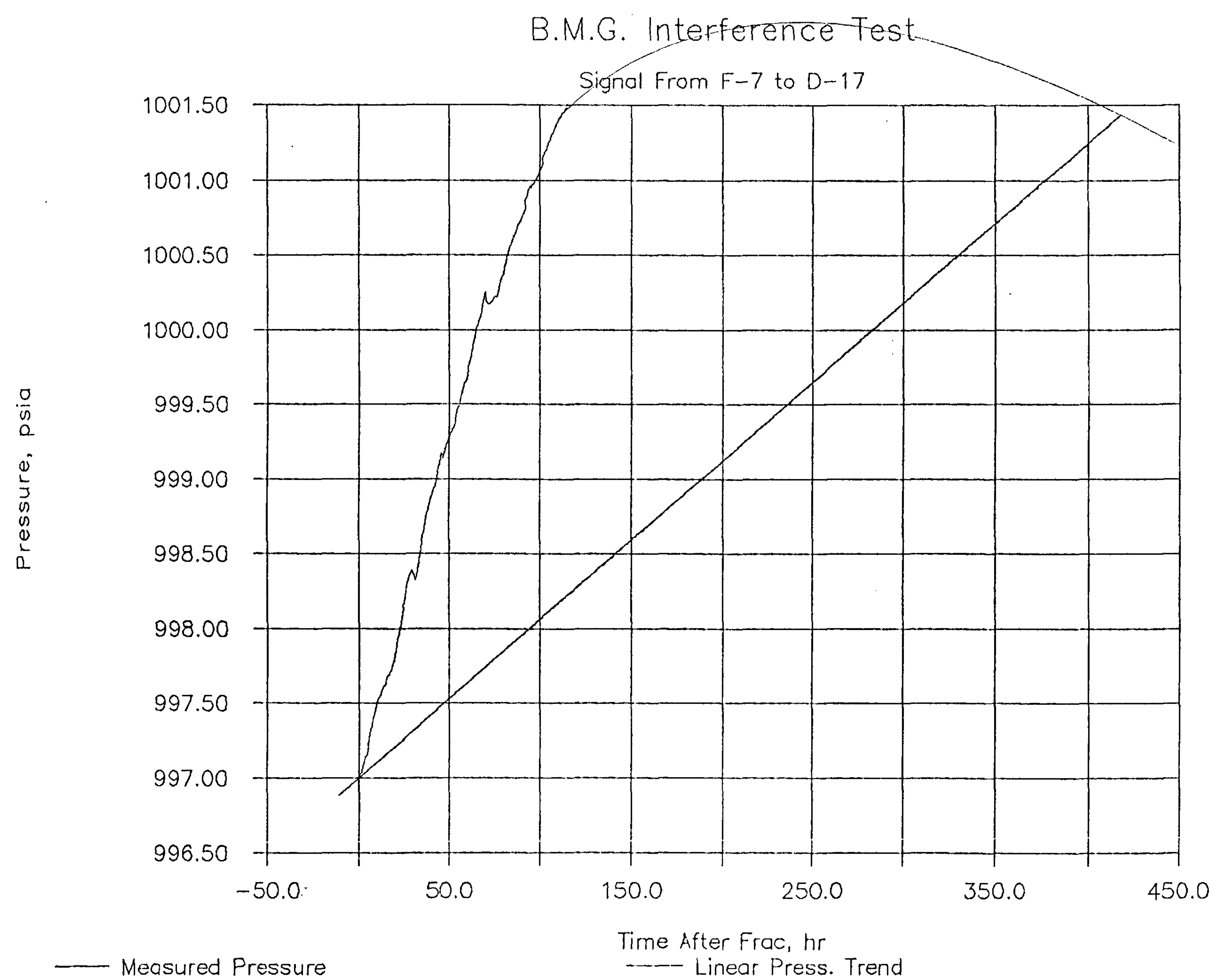


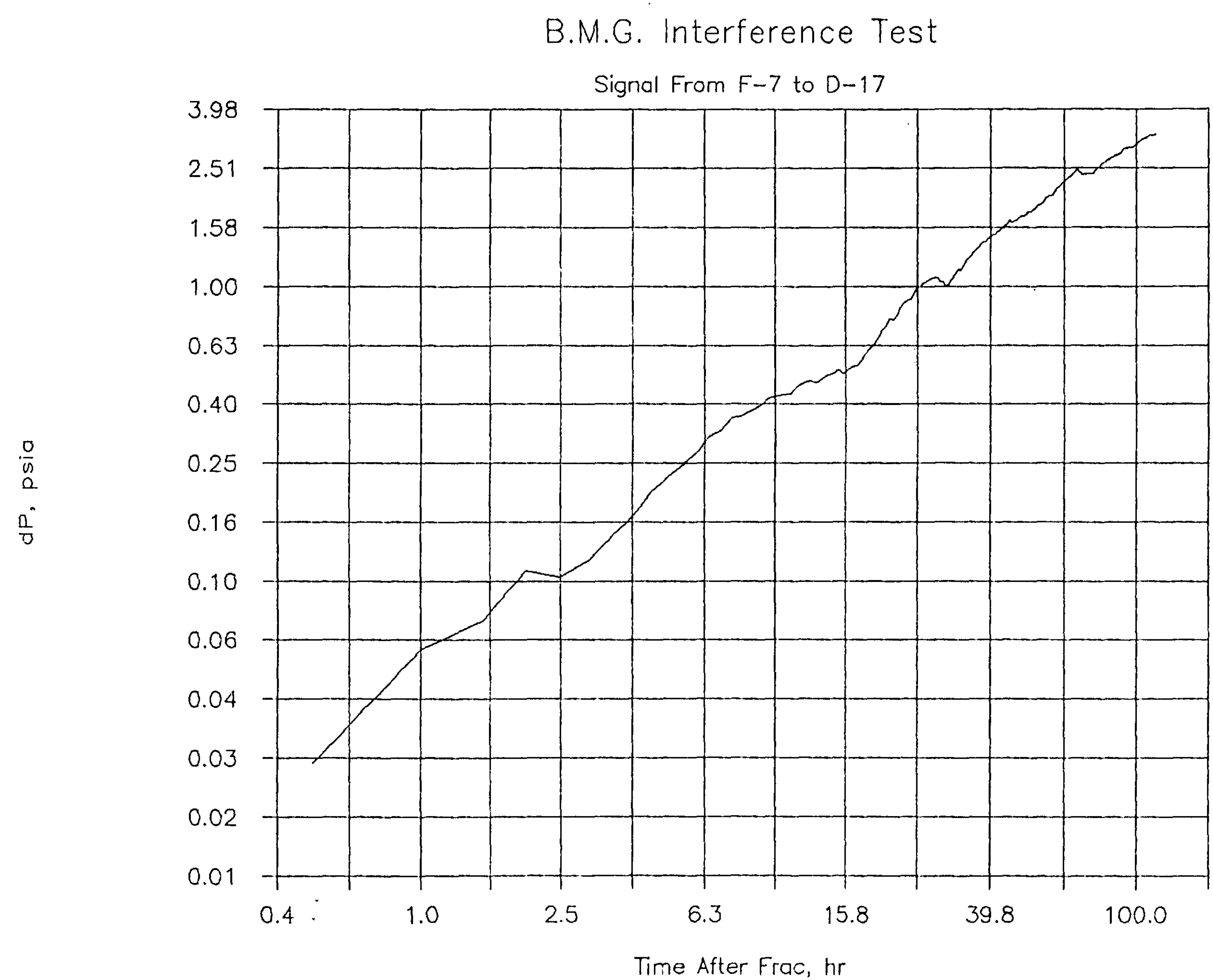
B.M.G. Interference Test
Signal From D-17 to A-20
1239.8
1239.6
1239.4
1239.2
1239.0
1238.8
1238.6
1238.4
1238.2
1238.0
1237.8
1237.6
1237.4
Pressure, psia
-20.0
0.0
20.0
40.0
60.0
80.0
100.0
Time After Frac, hr
Measured Pressure
Linear Press. Trend


B.M.G. Interference Test
Signal From D-17 to A-20
dP, psia
2.00E-01
1.58E-01
1.26E-01
1.00E-01
7.94E-02
6.31E-02
5.01E-02
3.98E-02
3.16E-02
2.51E-02
2.00E-02
1.58E-02
1.26E-02
1.00E-02
7.94E-03
6.31E-03
1.0
1.6
2.5
4.0
6.3
10.0
15.8
25.1
39.8
63.1
100.0
Time After Frac, hr

Frac Pluse Analysis
Kamal Method

Frac Well	F-7
Response Well	D-17
Date	11/25/87
Static Pressure, psig	997
Pump Time, hr	1
Signal Time, hr	420
Lag Time, hr	115
Peak dP/q	0.000026
Constants from Figures 10-13	
A =	-0.815
C =	0.33
E =	-1.375
F =	0.024
D =	-0.325
Total Cycle Time, dTcyc =	421
Pulse Ratio, R' =	0.002375
Demensionless Time Lag, TlD =	0.273159
Demensionless Cycle Period, dTcycD =	0.625243
Demensionless Response Amplitude, dPD =	0.016559
Average Formation Volume Factor, B =	2.8867
Average Viscosity, cp =	0.48
Distance Between Wells, ft	3554
kh = 70.6*B*u*dPD/(dP/q) =	60671.99
OCth = kh*dTcyc/(56900*u*r^2*dTcycD) =	1.18E-04
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	5.30E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	9.20E-04
Water Saturation, Sw =	1.00E-01
Water Compressibility, Cw =	3.30E-06
Formation Compressibilty, Cf =	1.00E-04
Total Compressibilty, Ct =	5.89E-04
Oh =	0.201045


B.M.G. Interference Test
Signal From F-7 to D-17
1001.50
1001.00
1000.50
1000.00
999.50
999.00
998.50
998.00
997.50
997.00
996.50
Pressure, psia
-50.0
50.0
150.0
250.0
350.0
450.0
Time After Frac, hr
Measured Pressure
Linear Press. Trend

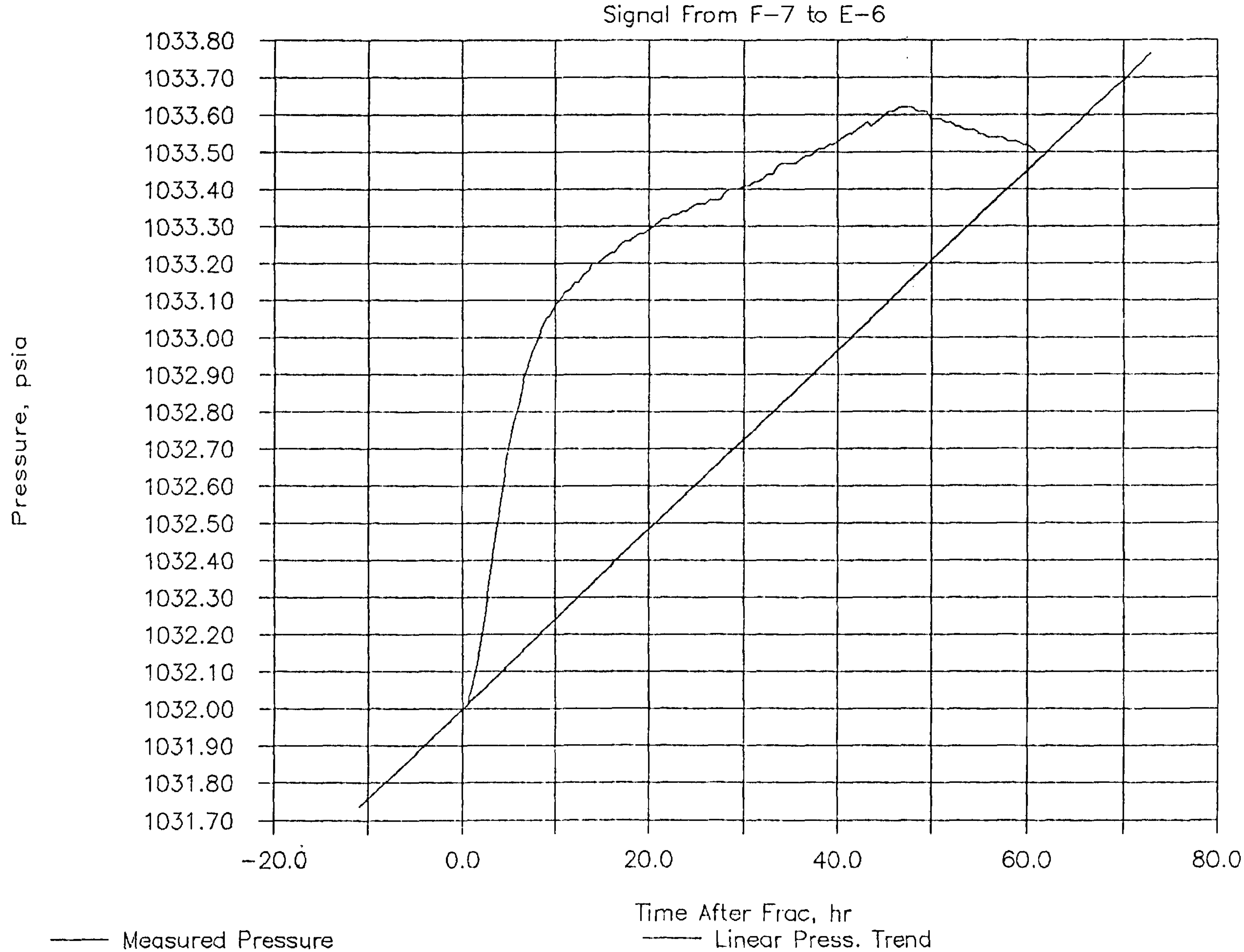


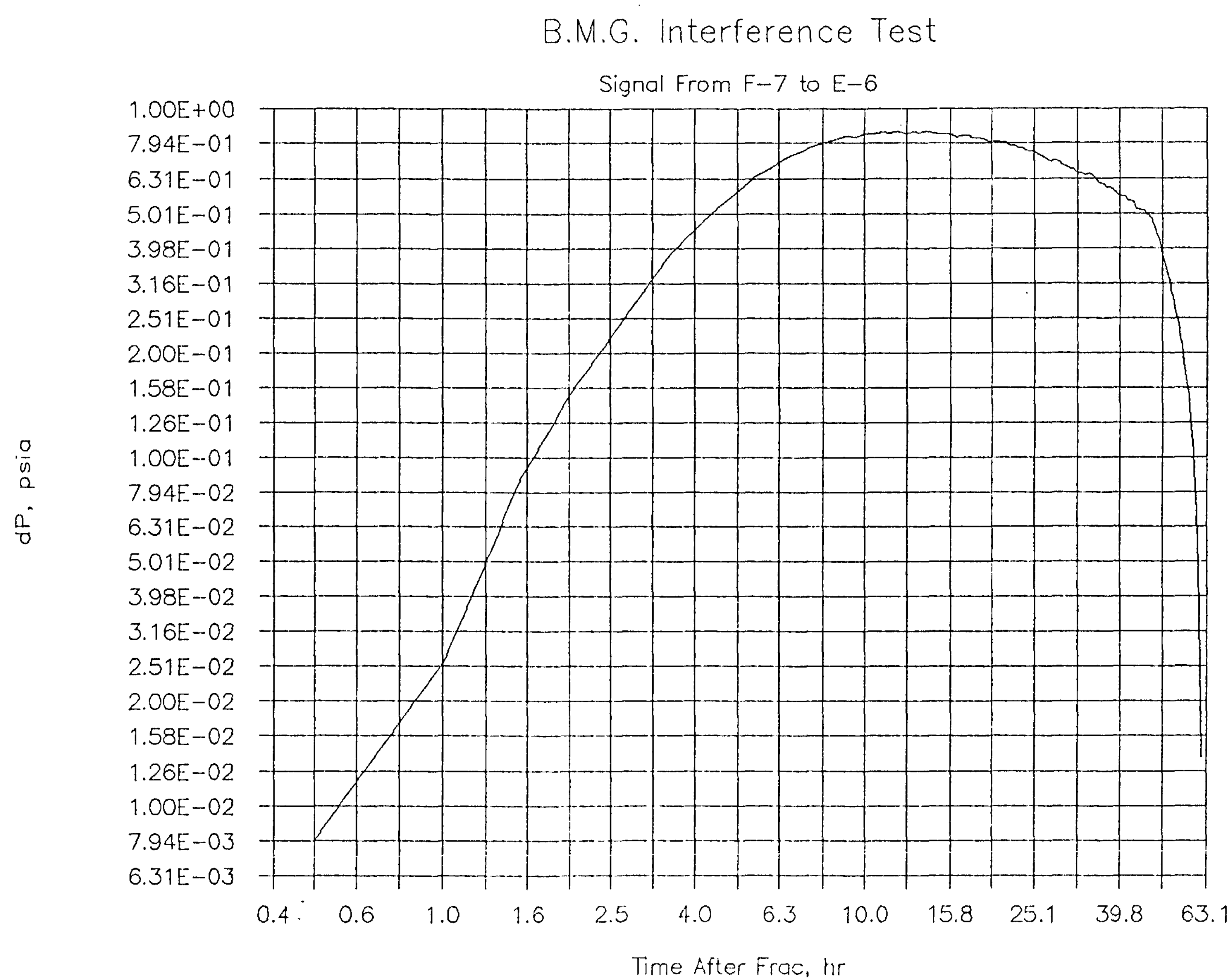
B.M.G. Interference Test
Signal From F-7 to D-17
3.98
2.51
1.58
1.00
0.63
0.40
0.25
0.16
0.10
0.06
0.04
0.03
0.02
0.01
dP, psia
0.4
1.0
2.5
6.3
15.8
39.8
100.0
Time After Frac, hr

Frac Pulse Analysis
Kamal Method

Frac Well	F-7
Response Well	E-6
Date	11/25/87
Static Pressure, psig	1032
Pump Time, hr	1
Signal Time, hr	62
Lag Time, hr	14
Peak dP/q	7.04E-06
Constants from Figures 10-13	
A =	-0.815
C =	0.335
E =	-1.35
F =	0.0225
D =	-0.325
Total Cycle Time, dTcyc =	63
Pulse Ratio, R' =	0.015873
Demensionless Time Lag, TlD =	0.222222
Demensionless Cycle Period, dTcycD =	0.816334
Demensionless Response Amplitude, dPD =	0.021770
Average Formation Volume Factor, B =	2.8867
Average Viscosity, cp =	0.4814
Distance Between Wells, ft	5280
kh = 70.6*B*µ*dPD/(dP/q) =	303392.7
øCth = kh*dTcyc/(56900*µ*r^2*dTcycD) =	3.07E-05
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	5.00E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	8.80E-04
Water Saturation, Sw =	0.1
Water Compressibility, Cw =	3.30E-06
Formation Compressibility, Cf =	1.00E-04
Total Compressibilty, Ct =	5.62E-04
øh =	0.054583

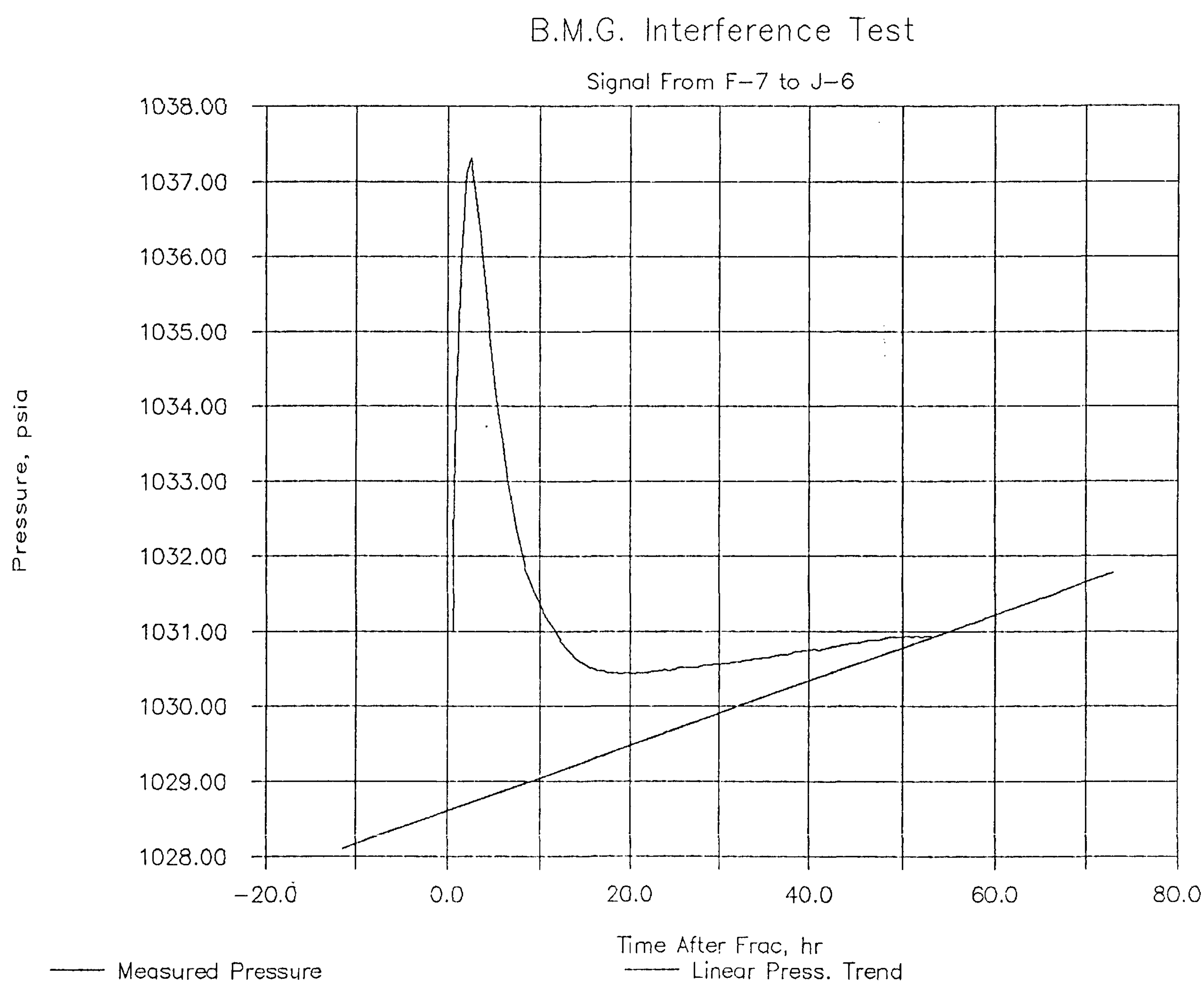
B.M.G. Interference Test




B.M.G. Interference Test
Signal From F-7 to E-6
1.00E+00
7.94E-01
6.31E-01
5.01E-01
3.98E-01
3.16E-01
2.51E-01
2.00E-01
1.58E-01
1.26E-01
1.00E-01
7.94E-02
6.31E-02
5.01E-02
3.98E-02
3.16E-02
2.51E-02
2.00E-02
1.58E-02
1.26E-02
1.00E-02
7.94E-03
6.31E-03
dP, psia
0.4
0.6
1.0
1.6
2.5
4.0
6.3
10.0
15.8
25.1
39.8
63.1
Time After Frac, hr

Frac Pulse Analysis
Kamal Method

Frac Well	F-7
Response Well	J-6
Date	11/25/87
Static Pressure, psig	1032
Pump Time, hr	1
Signal Time, hr	53.5
Lag Time, hr	3
Peak dP/q	7.01E-05
Constants from Figures 10-13	
A =	-0.815
C =	0.335
E =	-1.34
F =	0.029
D =	-0.325
Total Cycle Time, dTcyc =	54.5
Pulse Ratio, R' =	0.018348
Demensionless Time Lag, T1D =	0.055045
Demensionless Cycle Period, dTcycD =	3.234214
Demensionless Response Amplitude, dPD =	0.119465
Average Formation Volume Factor, B =	2.8867
Average Viscosity, cp =	0.4814
Distance Between Wells, ft	5830
kh = 70.6*B*μ*dPD/(dP/q) =	167199.6
ϕCth = kh*dTcyc/(56900*μ*r^2*dTcycD) =	3.03E-06
Oil Saturation, So =	0.87
Oil Compressibilty, Co =	5.00E-04
Gas Saturation, Sg =	0.03
Gas Compressibilty, Cg =	8.80E-04
Water Saturation, Sw =	0.1
Water Compressibility, Cw =	3.30E-06
Formation Compressibility, Cf =	1.00E-04
Total Compressibilty, Ct =	5.62E-04
ϕh =	0.005387


B.M.G. Interference Test
Signal From F-7 to J-6
Pressure, psia
1038.00
1037.00
1036.00
1035.00
1034.00
1033.00
1032.00
1031.00
1030.00
1029.00
1028.00
-20.0
0.0
20.0
40.0
60.0
80.0
Time After Frac, hr
Measured Pressure
Linear Press. Trend

2

Directional Perm.
Analysis of F-7 observed
at D-17 & E-6

Directional Perm. Analysis of F-7 Frac.
Observed at D-17 & E-6 on 11/25/87

$\bar{P} = 967\ psi$ $\qquad$ $R_s = 445$

$B_o = 1.3375$ $\qquad$ $\mu_g = 0.01428$

$B_g = 2.7845$ $\qquad$ $\mu_o = 0.6464$

E-6

BOPD = 270.87

MCFPD = 1144.00

$$(270.87)(1.3375) = 362.29$$

$$\left(1144 - \frac{(270.87)(445)}{1000}\right)2.7845 = \underline{3054.5}$$

$$3416.8\ RB/D$$

$$FVF = \frac{(362.29)(1.3375) + (3054.5)(2.9845)}{3416.8} = 2.81$$

$$(270.87)(.6464) = 175.09$$

$$\left(1144 - \frac{(270.87)(445)}{1000}\right)(0.01428) = \underline{14.62}$$

$$189.71$$

$$\mu = \frac{(175.09)(.6464) + (14.62)(0.01428)}{189.71} = .59$$

J-6

BOPD = 14.9

MCFPD = 523

$(14.9)(1.3375) = 19.93$

$\left(523 - \frac{(14.9)(445)}{1000}\right) 2.9845 = 1541.10$

1561.0 PE/D

$$FVF = \frac{(19.73)(1.3375) + (1541.10)(2.9845)}{1561.0} = 2.9635$$

$(14.9)(.6464) = 9.63$

$\left(523 - \frac{(14.9)(445)}{1000}\right)(.01428) = 7.37$

17.00

$$\mu = \frac{(9.63)(.6464) + (7.37)(.01428)}{17.00} = 0.37$$

$$AVG\ FVF = \frac{2.8099 + 2.9635}{2} = 2.8867$$

$$AVG\ \mu = \frac{0.59 + 0.37}{2} = 0.48$$

Match Points

	$\frac{\Delta P}{8}$	P_D	ΔT	$\frac{t_D}{r_D^2}$	$\frac{t_{PD}}{r_D^2}$
D-17	10.0×10^{-6}	.48	100	2.2	3.0
E-6	10.0×10^{-6}	.48	100	7.8	.03

$$\bar{K}h = \frac{(141.2)\,B\mu\,P_D}{\frac{\Delta P}{8}}$$

since $h = 150$

$$\bar{K} = \frac{(141.2)(.27)(2.8867)(.48)}{(100 \times 10^{-6})(150)}$$

$\bar{K} = 3521.68$ mdarcy

$\bar{K}h = 528252.24$ md-ft

$$y^2 k_x + x^2 k_y - 2xy\,k_{xy} = \frac{(0.0002637)(\bar{K}^2)\Delta t}{\phi C_T \mu \left(\frac{t_D}{r_D^2}\right)}$$

Let $W = \phi C_T \mu$

D17-

$$4880^2 k_x + 3210^2 k_y - 2(3210)(-4880)k_{xy} = \frac{.0002637(3521.68)^2(100)}{W\ (2.2)}$$

E-6

$$5090^2 k_x + 1490^2 k_y - 2(1490)(5090)k_{xy} = \frac{(.0002637)(3521.68)^2(100)}{W\,(7.8)}$$

D-17

$$-1(2.311 K_x + K_y + 3.04 K_{xy} = .0144/W)$$

E-6 $$11.67 K_x + K_y + 6.83 K_{xy} = .0189/W$$

$$9.359 K_x + 0 K_y + 3.79 K_{xy} = .0045/W$$

$$\boxed{K_x = .000481/W - .4050 K_{xy}}$$

$$K_y = \frac{.0189}{W} - 6.83 K_{xy} - 11.67\left(\frac{.000481}{W} - .4050 K_{xy}\right)$$

$$\boxed{K_y = \frac{.0133}{W} - 2.10 K_{xy}}$$

$$K_x K_y - K_{xy}^2 = \bar{K}^2$$

$$\left(\frac{.000481}{W} - .4050 K_{xy}\right)\left(\frac{.0133}{W} - 2.10 K_{xy}\right) - K_{xy}^2 = 3521.68^2$$

$$\frac{6.40\times10^{-6}}{W^2} - \frac{1.01\times10^{-3} K_{xy}}{W} - \frac{5.39\times10^{-3} K_{xy}}{W} + 0.851 K_{xy}^2 - K_{xy}^2 = 3521.68^2$$

assume $\phi C_T \mu = 3.5\times10^{-7}$ $\therefore$ $W = 3.5\times10^{-7}$

$$52244897.96 - 2885.71 K_{xy} - 15400 K_{xy} - .149 K_{xy}^2 = 12402230.02$$

$$39842667.94 - 18285.71 K_{xy} - .149 K_{xy}^2 = 0$$

$$K_{xy} = \frac{-b \pm \sqrt{b^2 - 4ac}}{2A}$$

(5)

$$K_{xy} = \frac{18285.71 - \sqrt{18285.71^2 - 4(-.149)(39841266 7.94)}}{2(-.149)}$$

$$\underline{K_{xy} = 2141.53}$$

$$K_x = \frac{.006481}{3.5\times10^{-7}} - (.4050)(2141.53)$$

$$\underline{K_x = 506.97}$$

$$K_y = \frac{.0133}{3.5\times10^{-7}} - 2.10(2141.53)$$

$$K_y = 33502.79$$

$$K_{\frac{max}{min}} = .5\left((K_x + K_y) \pm \left[(K_x - K_y)^2 + 4K_{xy}^2\right]^{1/2}\right)$$

$$K_{\frac{max}{min}} = .5\left((506.97 + 33502.79) \pm \left[(506.79 - 33502.79)^2 + 4(2141.53)^2\right]^{1/2}\right)$$

$$K_{max} = 33641.29$$

$$K_{min} = 368.47$$

$$\tan^{-1}\left(\frac{K_{max} - K_x}{K_{xy}}\right)$$

$$\Theta = \tan^{-1}\left(\frac{33641.29 - 506.97}{2141.53}\right)$$

$$\Theta = 86.30^{\circ}$$

Fracture Responce From F-7 to D-17
Q = 122400

time hr	pressure psia	dt	dp	dp/q	shut in time hr
72	997.08	2	0.240565	1.97E-06	218
75	997.22	5	0.306970	2.51E-06	221
78	997.41	8	0.424367	3.47E-06	224
81	997.54	11	0.482730	3.94E-06	227
84	997.62	14	0.492034	4.02E-06	230
87	997.7	17	0.502254	4.10E-06	233
90	997.85	20	0.583367	4.77E-06	236
93	998.04	23	0.705350	5.76E-06	239
96	998.26	26	0.858181	7.01E-06	242
99	998.38	29	0.911840	7.45E-06	245
102	998.39	32	0.856306	7.00E-06	248
105	998.58	35	0.981561	8.02E-06	251
108	998.77	38	1.107584	9.05E-06	254
111	998.92	41	1.194359	9.76E-06	257
114	999.05	44	1.261868	1.03E-05	260
117	999.16	47	1.310093	1.07E-05	263
120	999.27	50	1.359019	1.11E-05	266
123	999.38	53	1.408631	1.15E-05	269
126	999.52	56	1.488911	1.22E-05	272
129	999.65	59	1.559847	1.27E-05	275
132	999.83	62	1.681424	1.37E-05	278
135	999.99	65	1.783628	1.46E-05	281
138	1000.12	68	1.856446	1.52E-05	284
141	1000.19	71	1.869864	1.53E-05	287
144	1000.19	74	1.813871	1.48E-05	290
147	1000.24	77	1.808455	1.48E-05	293
150	1000.37	80	1.883602	1.54E-05	296
153	1000.51	83	1.969303	1.61E-05	299
156	1000.63	86	2.035546	1.66E-05	302
159	1000.73	89	2.082321	1.70E-05	305
162	1000.81	92	2.109616	1.72E-05	308
165	1000.96	95	2.207422	1.80E-05	311
168	1001	98	2.195730	1.79E-05	314

Fracture Responce From F-7 to E-6
Q = 122400 bfpd, r = 5280 ft

time hr	pressure psia	dt hrs	dp psia	dp/q	Linear Press. Trend
69.5	1032.02	0.5	0.007916	6.47E-08	1032.012
70	1032.05	1	0.025833	2.11E-07	1032.024
70.5	1032.12	1.5	0.083749	6.84E-07	1032.036
71	1032.2	2	0.151666	1.24E-06	1032.048
71.5	1032.28	2.5	0.219583	1.79E-06	1032.060
72	1032.37	3	0.297499	2.43E-06	1032.072
72.5	1032.47	3.5	0.385416	3.15E-06	1032.084
73	1032.55	4	0.453333	3.70E-06	1032.096
73.5	1032.63	4.5	0.521249	4.26E-06	1032.108
74	1032.7	5	0.579166	4.73E-06	1032.120
74.5	1032.77	5.5	0.637083	5.20E-06	1032.132
75	1032.82	6	0.674999	5.51E-06	1032.145
75.5	1032.88	6.5	0.722916	5.91E-06	1032.157
76	1032.92	7	0.750833	6.13E-06	1032.169
76.5	1032.96	7.5	0.778749	6.36E-06	1032.181
77	1032.99	8	0.796666	6.51E-06	1032.193
77.5	1033.02	8.5	0.814583	6.66E-06	1032.205
78	1033.05	9	0.832499	6.80E-06	1032.217
78.5	1033.06	9.5	0.830416	6.78E-06	1032.229
79	1033.09	10	0.848333	6.93E-06	1032.241
79.5	1033.1	10.5	0.846249	6.91E-06	1032.253
80	1033.12	11	0.854166	6.98E-06	1032.265
80.5	1033.13	11.5	0.852083	6.96E-06	1032.277
81	1033.15	12	0.859999	7.03E-06	1032.29
81.5	1033.15	12.5	0.847916	6.93E-06	1032.302
82	1033.17	13	0.855833	6.99E-06	1032.314
82.5	1033.18	13.5	0.853749	6.98E-06	1032.326
83	1033.2	14	0.861666	7.04E-06	1032.338
83.5	1033.2	14.5	0.849583	6.94E-06	1032.350
84	1033.21	15	0.847499	6.92E-06	1032.362
84.5	1033.22	15.5	0.845416	6.91E-06	1032.374
85	1033.23	16	0.843333	6.89E-06	1032.386
85.5	1033.23	16.5	0.831249	6.79E-06	1032.398
86	1033.25	17	0.839166	6.86E-06	1032.410
86.5	1033.26	17.5	0.837083	6.84E-06	1032.422
87	1033.26	18	0.824999	6.74E-06	1032.435
87.5	1033.27	18.5	0.822916	6.72E-06	1032.447
88	1033.28	19	0.820833	6.71E-06	1032.459
88.5	1033.28	19.5	0.808749	6.61E-06	1032.471
89	1033.29	20	0.806666	6.59E-06	1032.483
89.5	1033.3	20.5	0.804583	6.57E-06	1032.495
90	1033.31	21	0.802499	6.56E-06	1032.507
90.5	1033.32	21.5	0.800416	6.54E-06	1032.519
91	1033.32	22	0.788333	6.44E-06	1032.531
91.5	1033.33	22.5	0.786249	6.42E-06	1032.543
92	1033.33	23	0.774166	6.32E-06	1032.555
92.5	1033.34	23.5	0.772083	6.31E-06	1032.567
93	1033.34	24	0.759999	6.21E-06	1032.58
93.5	1033.35	24.5	0.757916	6.19E-06	1032.592

Fracture Responce From F-7 to E-6
Q = 122400 bfpd, r = 5280 ft

time hr	pressure psia	dt hrs	dp psia	dp/q	Linear Press. Trend
94	1033.36	25	0.755833	6.18E-06	1032.604
94.5	1033.36	25.5	0.743749	6.08E-06	1032.616
95	1033.36	26	0.731666	5.98E-06	1032.628
95.5	1033.37	26.5	0.729583	5.96E-06	1032.640
96	1033.37	27	0.717499	5.86E-06	1032.652
96.5	1033.37	27.5	0.705416	5.76E-06	1032.664
97	1033.39	28	0.713333	5.83E-06	1032.676
97.5	1033.4	28.5	0.711249	5.81E-06	1032.688
98	1033.4	29	0.699166	5.71E-06	1032.700
98.5	1033.4	29.5	0.687083	5.61E-06	1032.712
99	1033.41	30	0.684999	5.60E-06	1032.725
99.5	1033.41	30.5	0.672916	5.50E-06	1032.737
100	1033.42	31	0.670833	5.48E-06	1032.749
100.5	1033.42	31.5	0.658749	5.38E-06	1032.761
101	1033.43	32	0.656666	5.36E-06	1032.773
101.5	1033.44	32.5	0.654583	5.35E-06	1032.785
102	1033.44	33	0.642499	5.25E-06	1032.797
102.5	1033.46	33.5	0.650416	5.31E-06	1032.809
103	1033.469	34	0.647333	5.29E-06	1032.821
103.5	1033.47	34.5	0.636249	5.20E-06	1032.833
104	1033.47	35	0.624166	5.10E-06	1032.845
104.5	1033.47	35.5	0.612083	5.00E-06	1032.857
105	1033.48	36	0.609999	4.98E-06	1032.87
105.5	1033.49	36.5	0.607916	4.97E-06	1032.882
106	1033.49	37	0.595833	4.87E-06	1032.894
106.5	1033.5	37.5	0.593749	4.85E-06	1032.906
107	1033.51	38	0.591666	4.83E-06	1032.918
107.5	1033.51	38.5	0.579583	4.74E-06	1032.930
108	1033.52	39	0.577499	4.72E-06	1032.942
108.5	1033.52	39.5	0.565416	4.62E-06	1032.954
109	1033.53	40	0.563333	4.60E-06	1032.966
109.5	1033.54	40.5	0.561249	4.59E-06	1032.978
110	1033.55	41	0.559166	4.57E-06	1032.990
110.5	1033.55	41.5	0.547083	4.47E-06	1033.002
111	1033.56	42	0.544999	4.45E-06	1033.015
111.5	1033.57	42.5	0.542916	4.44E-06	1033.027
112	1033.58	43	0.540833	4.42E-06	1033.039
112.5	1033.57	43.5	0.518749	4.24E-06	1033.051
113	1033.58	44	0.516666	4.22E-06	1033.063
113.5	1033.59	44.5	0.514583	4.20E-06	1033.075
114	1033.6	45	0.512499	4.19E-06	1033.087
114.5	1033.61	45.5	0.510416	4.17E-06	1033.099
115	1033.61	46	0.498333	4.07E-06	1033.111
115.5	1033.62	46.5	0.496249	4.05E-06	1033.123
116	1033.62	47	0.484166	3.96E-06	1033.135
116.5	1033.62	47.5	0.472083	3.86E-06	1033.147
117	1033.62	48	0.459999	3.76E-06	1033.16
117.5	1033.61	48.5	0.437916	3.58E-06	1033.172
118	1033.61	49	0.425833	3.48E-06	1033.184

Fracture Responce From F-7 to E-6
Q = 122400 bfpd, r = 5280 ft

time hr	pressure psia	dt hrs	dp psia	dp/q	Linear Press. Trend
118.5	1033.61	49.5	0.413749	3.38E-06	1033.196
119	1033.59	50	0.381666	3.12E-06	1033.208
119.5	1033.59	50.5	0.369583	3.02E-06	1033.220
120	1033.59	51	0.357499	2.92E-06	1033.232
120.5	1033.58	51.5	0.335416	2.74E-06	1033.244
121	1033.58	52	0.323333	2.64E-06	1033.256
121.5	1033.57	52.5	0.301249	2.46E-06	1033.268
122	1033.57	53	0.289166	2.36E-06	1033.280
122.5	1033.56	53.5	0.267083	2.18E-06	1033.292
123	1033.56	54	0.254999	2.08E-06	1033.305
123.5	1033.56	54.5	0.242916	1.98E-06	1033.317
124	1033.55	55	0.220833	1.80E-06	1033.329
124.5	1033.55	55.5	0.208749	1.71E-06	1033.341
125	1033.54	56	0.186666	1.53E-06	1033.353
125.5	1033.54	56.5	0.174583	1.43E-06	1033.365
126	1033.54	57	0.162499	1.33E-06	1033.377
126.5	1033.54	57.5	0.150416	1.23E-06	1033.389
127	1033.53	58	0.128333	1.05E-06	1033.401
127.5	1033.53	58.5	0.116249	9.50E-07	1033.413
128	1033.53	59	0.104166	8.51E-07	1033.425
128.5	1033.52	59.5	0.082083	6.71E-07	1033.437
129	1033.52	60	0.069999	5.72E-07	1033.45
129.5	1033.51	60.5	0.047916	3.91E-07	1033.462
130	1033.5	61	0.025833	2.11E-07	1033.474
130.5	1033.5	61.5	0.013749	1.12E-07	1033.486

APPENDIX 4

Rate Sensitivity

$$q_{crit} = \frac{(4.9\times10^{-4})(kk'_{rg})(A)(\Delta\gamma)(\sin\theta)}{(\mu_g)(M-1)} = RB/D$$

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$kk'_{rg} = \frac{235}{235\,ft} = 1.0\,md$

$B_o = 1.293$

$A = 139400$

$\Delta\gamma = (0.7206 - 0.0136)$

$\mu_g = 0.01359$

$\mu_o = 0.710$

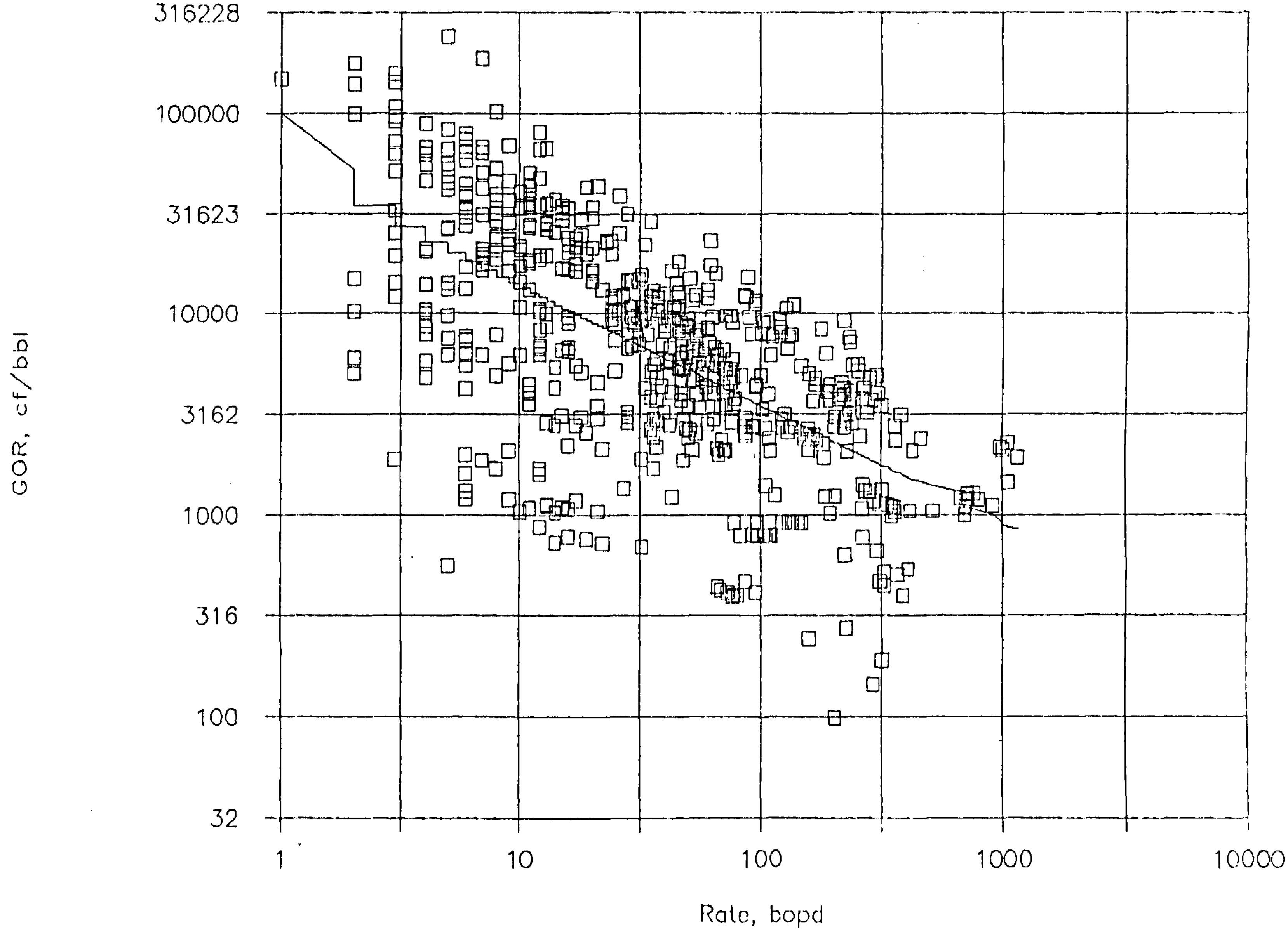
$M = \frac{k_{rg}}{k_{ro}}\frac{\mu_o}{\mu_g}$ @ 800 psi $\frac{(0.85)(0.710)}{0.01359} = 44.4$

$$q_{crit} = \frac{(4.9\times10^{-4})(1\,md)(139400)(0.7206-0.0136)(-1)}{(0.01359)(44.4-1)(1.293)}$$

$q_{crit} = 63.3\ RB/D$ or $50\ STB/D$

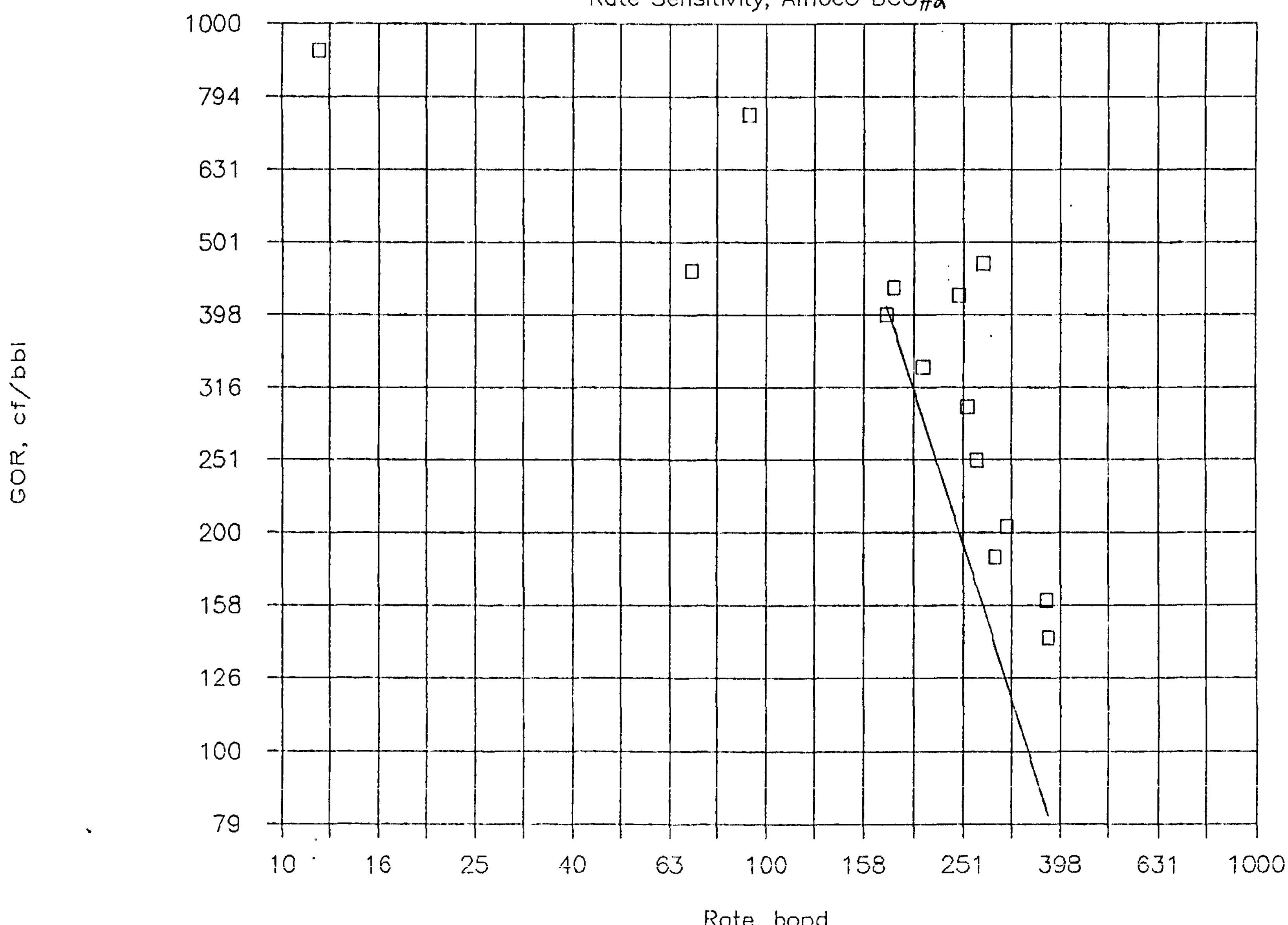
GAVILAN—W. PUERTO CHIQUITO

Rate Sensitivity, All Wells



Gavilan Dome, 2/15–2/29/88

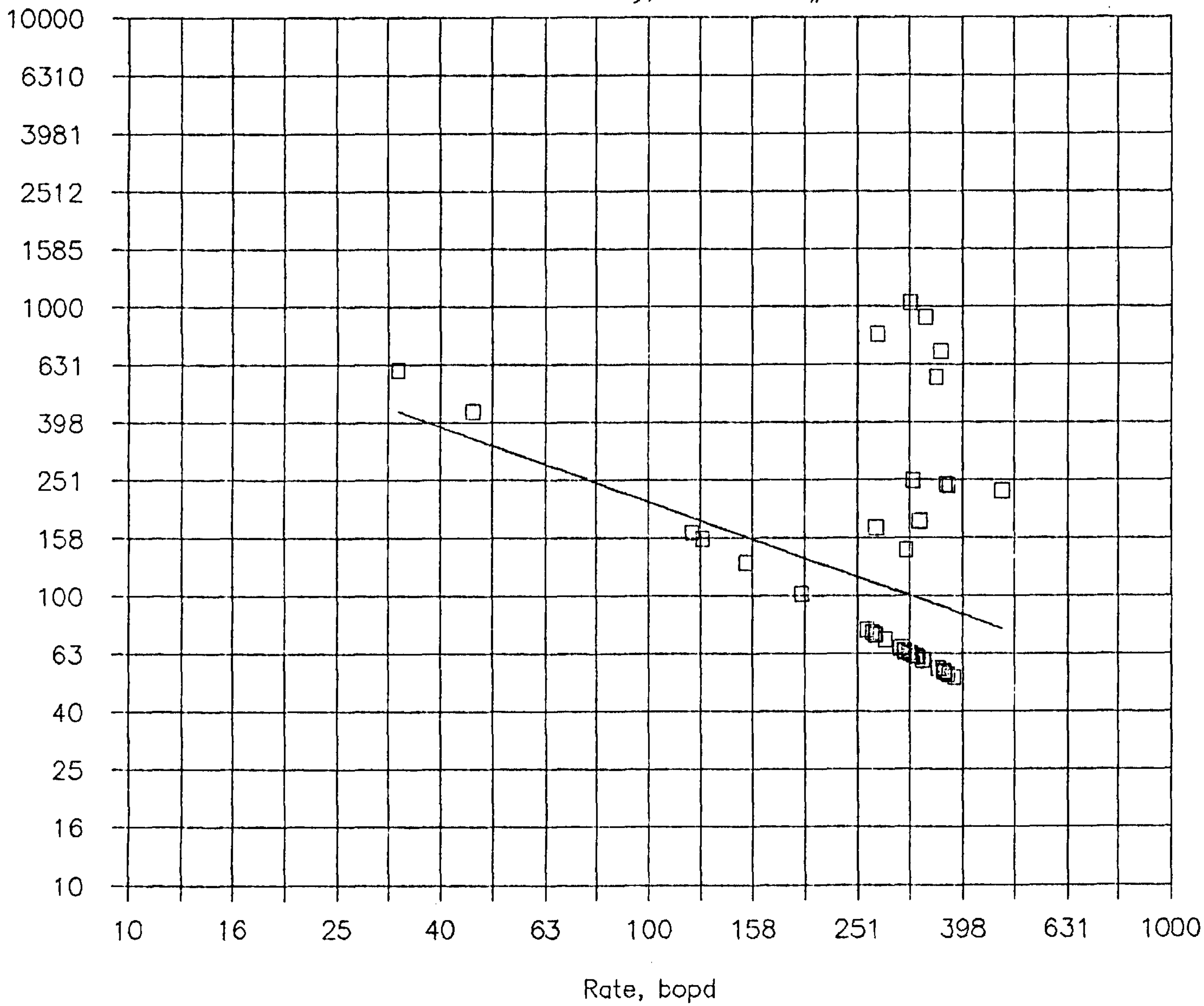
Rate Sensitivity, Amoco BCU#2



C.C. = 0.31

Gavilan Dome, 1/6–2/29/88

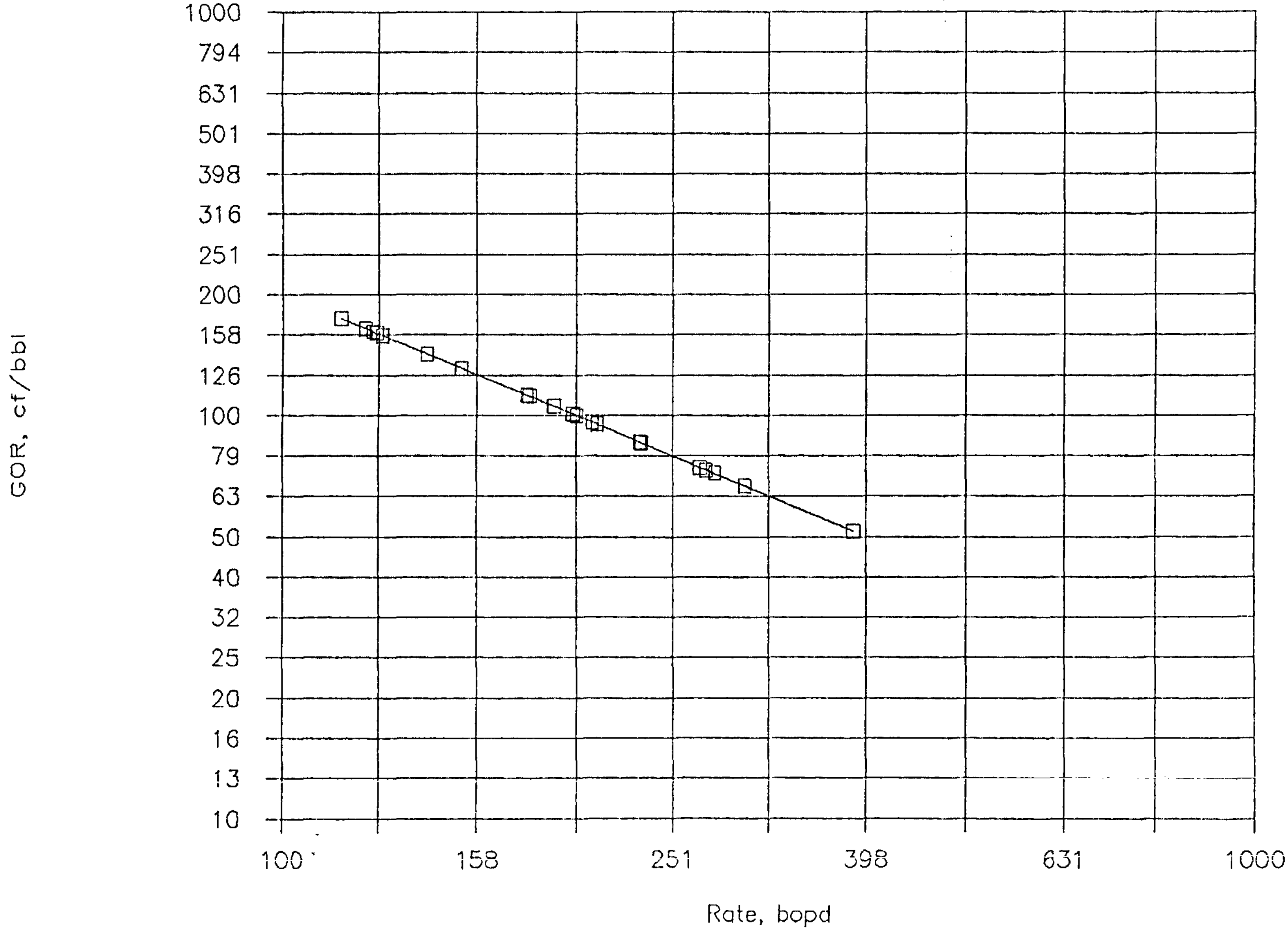
Rate Sensitivity, Amoco SGC#1



C.C.= 0.35

Gavilan Dome, 2/1–2/29/88

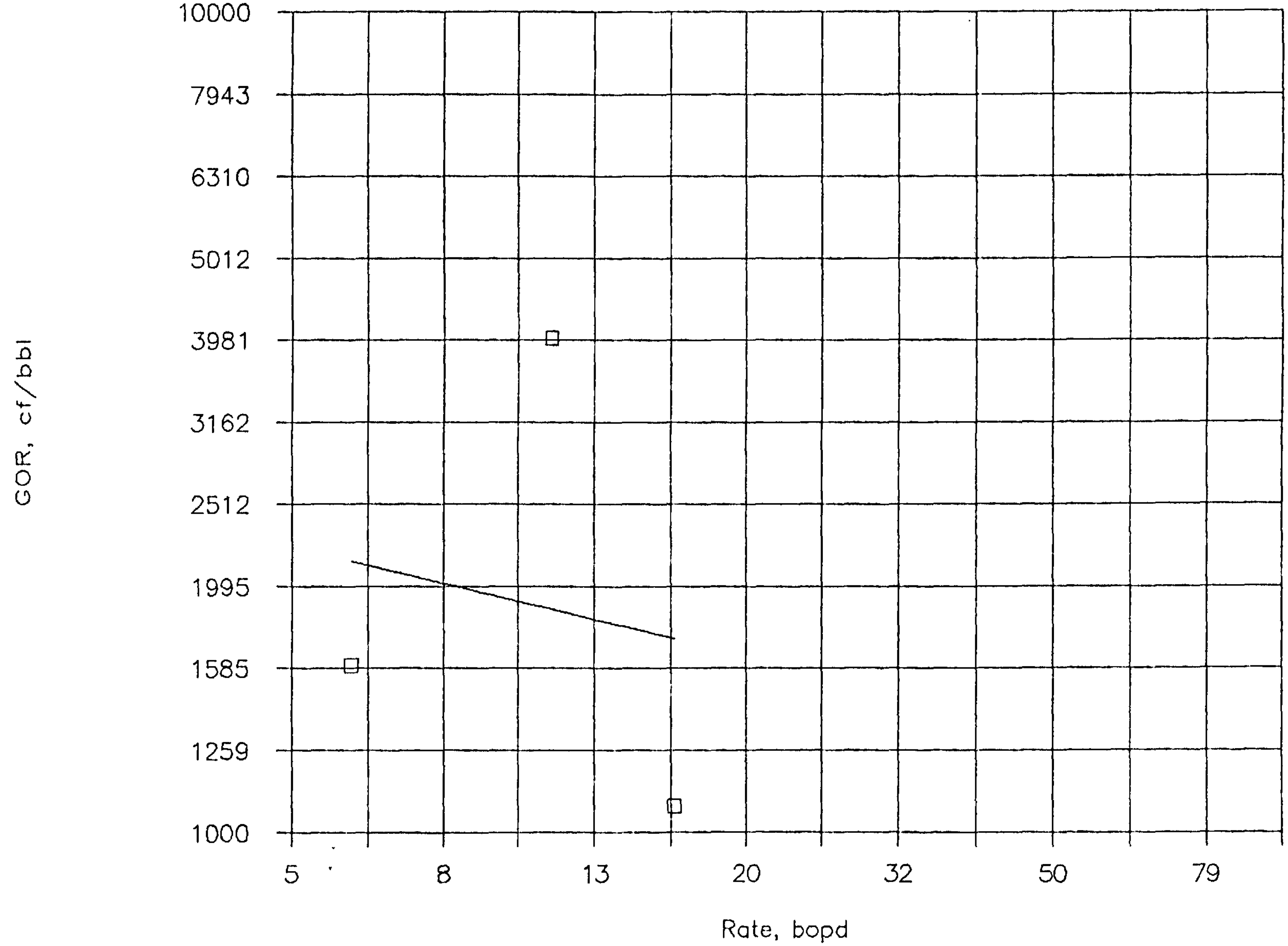
Rate Sensitivity, Amoco SCC



C.C. = 1.00

W. Puerto Chiquito, July—Sept. 87

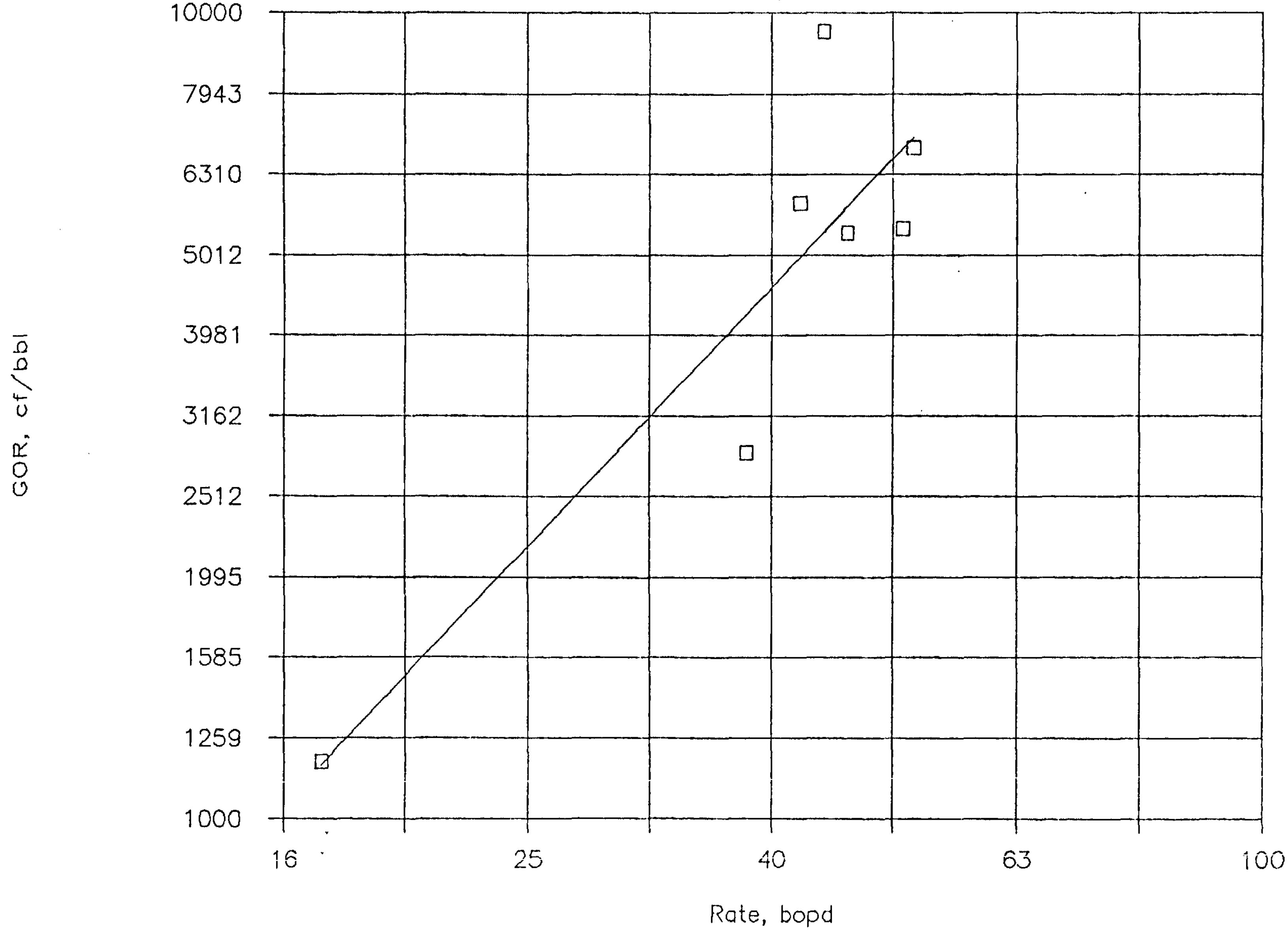
Rate Sensitivity, BMG A-16



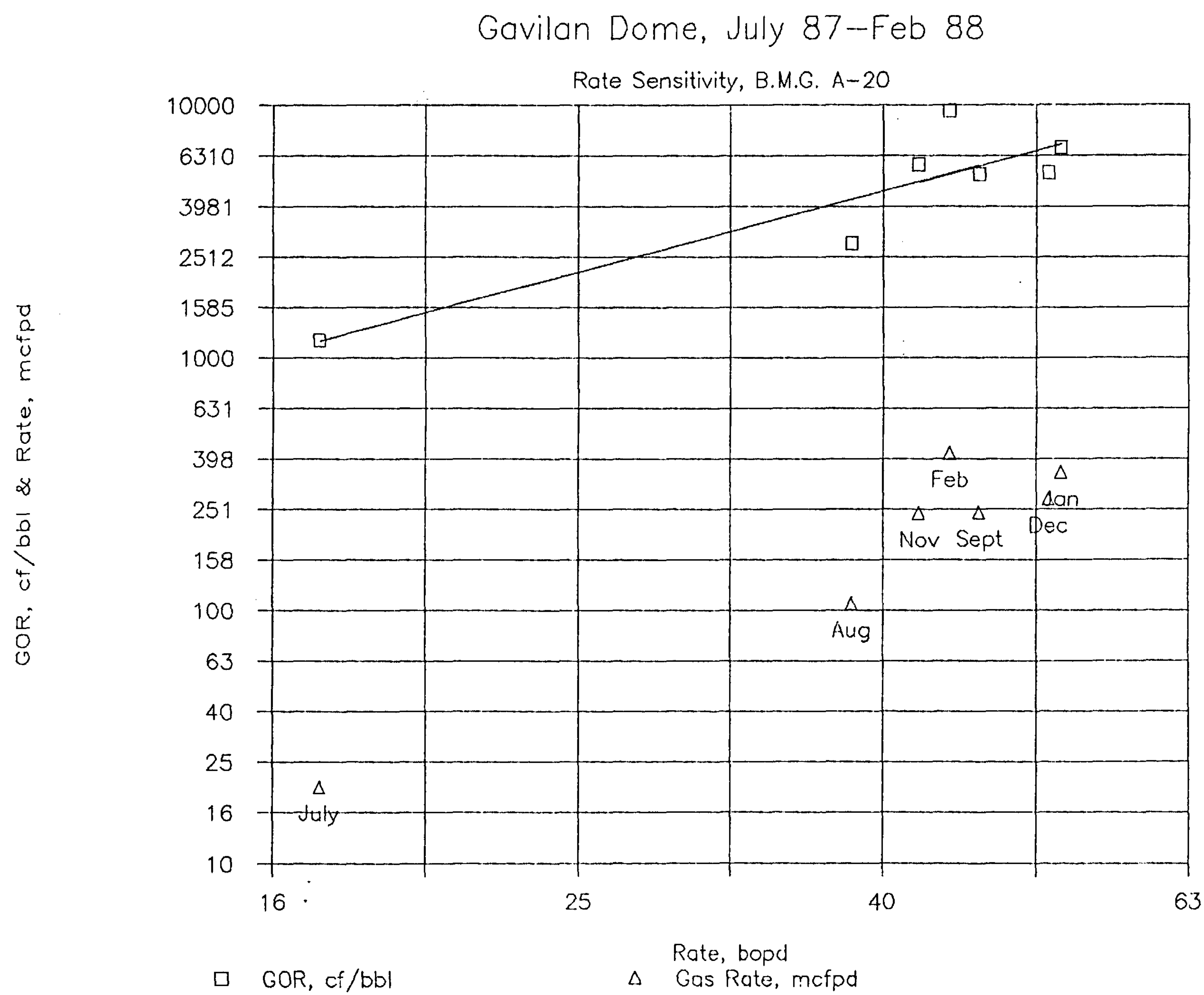
C.C. = 0.16

W. Puerto Chiquito, July 87—Feb 88

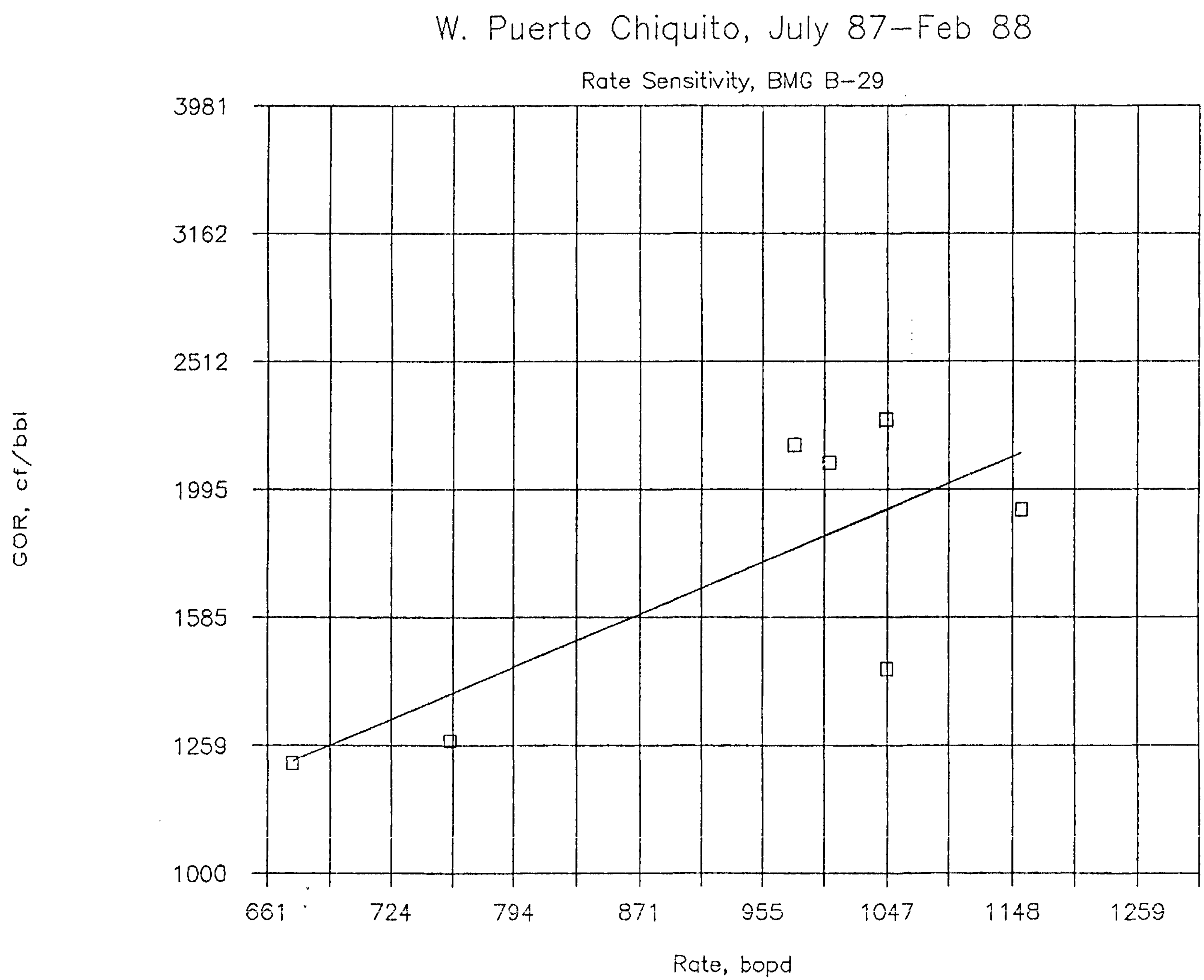
Rate Sensitivity, BMG A—20



C. C. =0.90



Gavilan Dome, July 87--Feb 88
Rate Sensitivity, B.M.G. A-20
GOR, cf/bbl & Rate, mcfpd
10000
6310
3981
2512
1585
1000
631
398
251
158
100
63
40
25
16
10
16
25
40
63
Rate, bopd
Feb
Jan
Dec
Nov
Sept
Aug
July
GOR, cf/bbl
Gas Rate, mcfpd

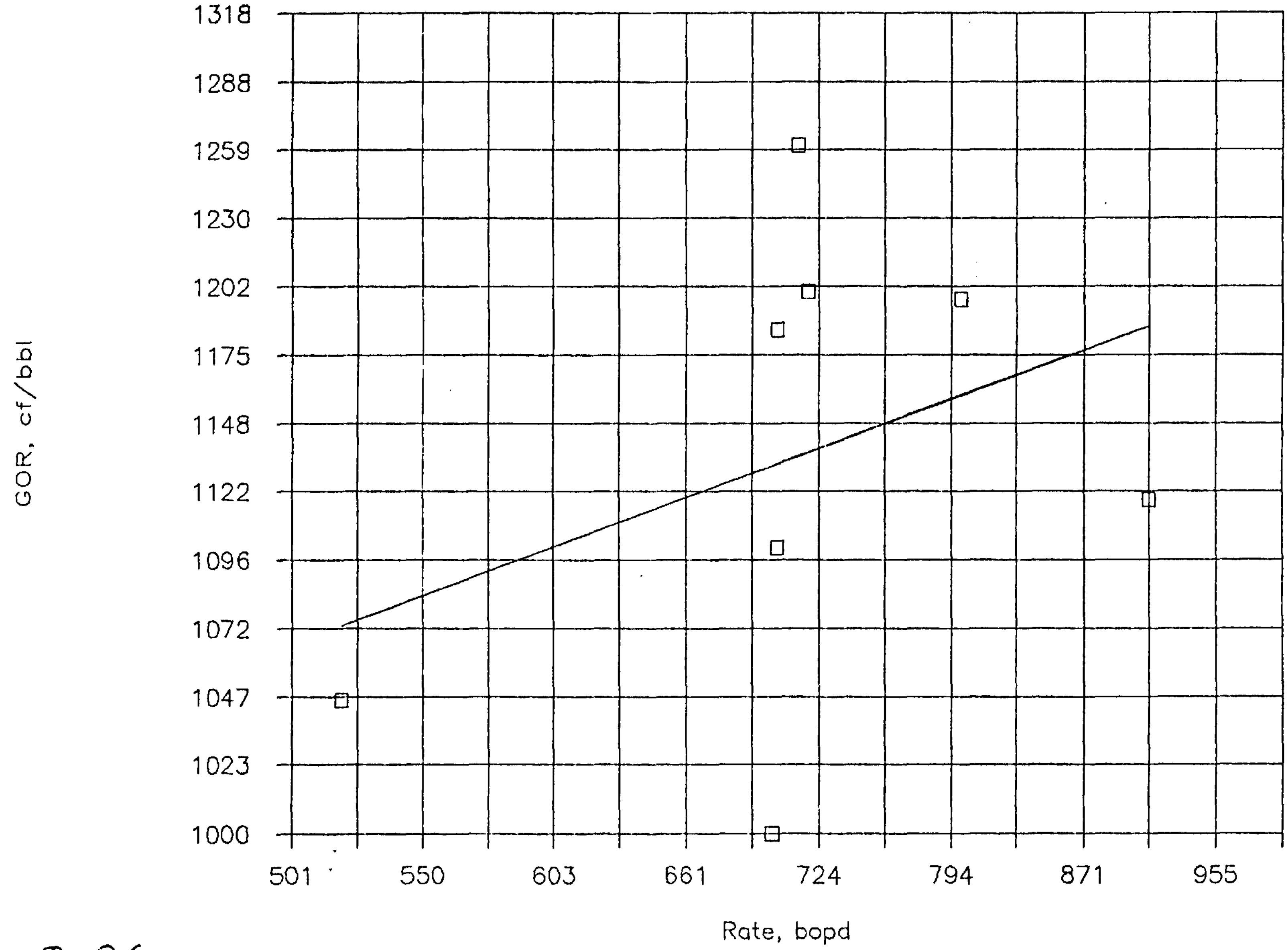


W. Puerto Chiquito, July 87—Feb 88
Rate Sensitivity, BMG B-29
GOR, cf/bbl
3981
3162
2512
1995
1585
1259
1000
661
724
794
871
955
1047
1148
1259
Rate, bopd

C. C. = 0. 76

W. Puerto Chiquito, July 87–Feb 88

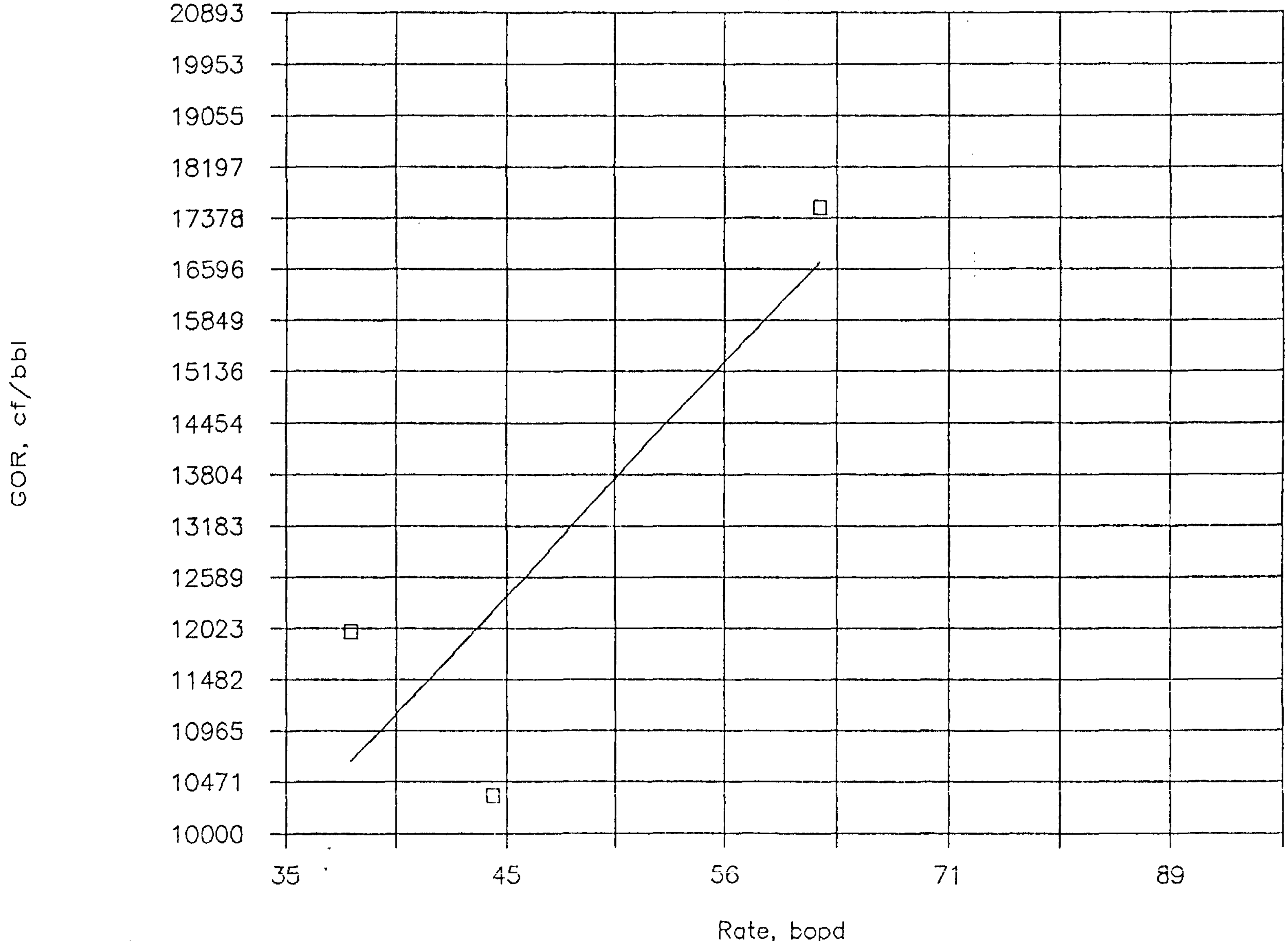
Rate Sensitivity, BMG B-32



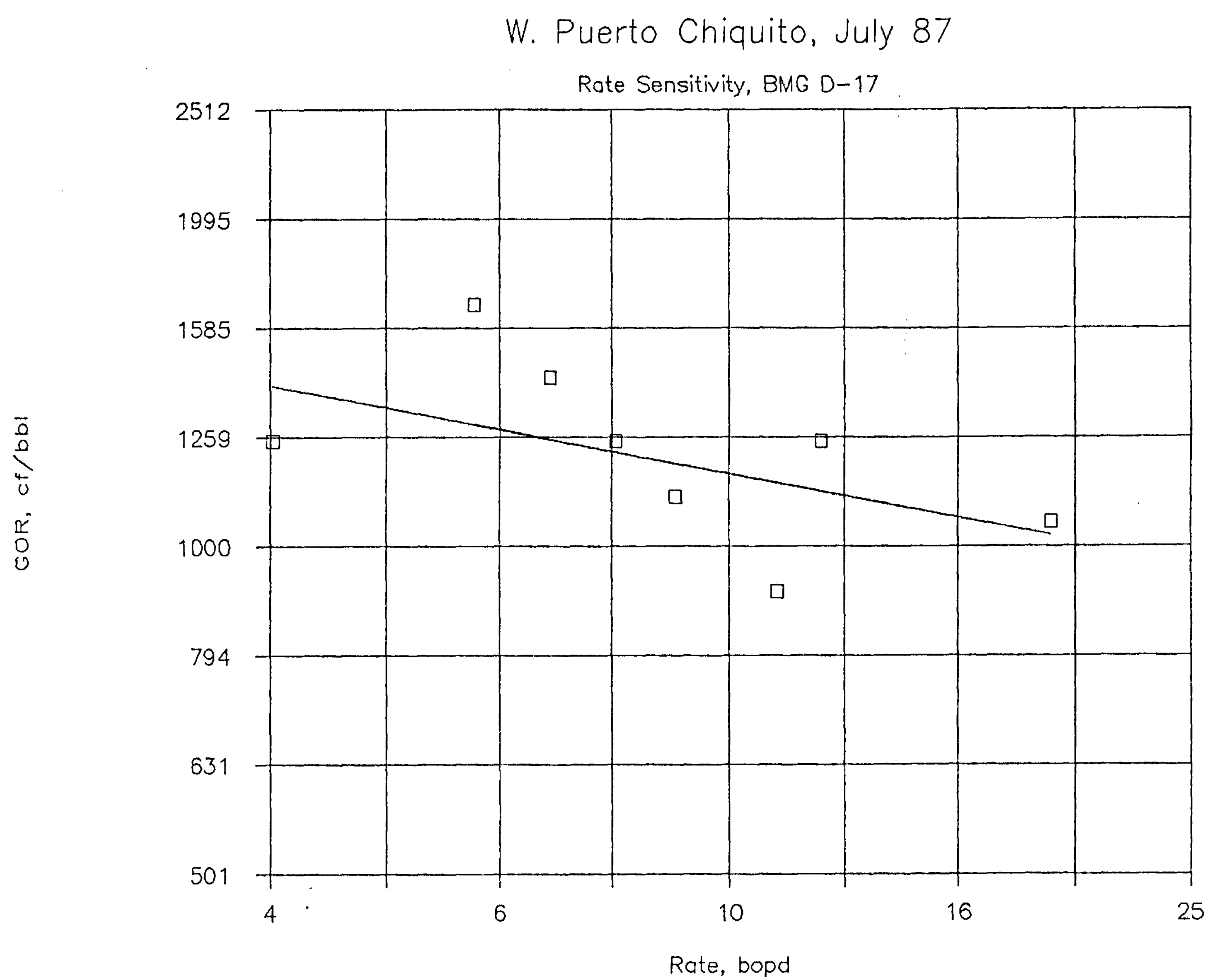
C.C. = 0.36

W. Puerto Chiquito, Dec 87—Feb 88

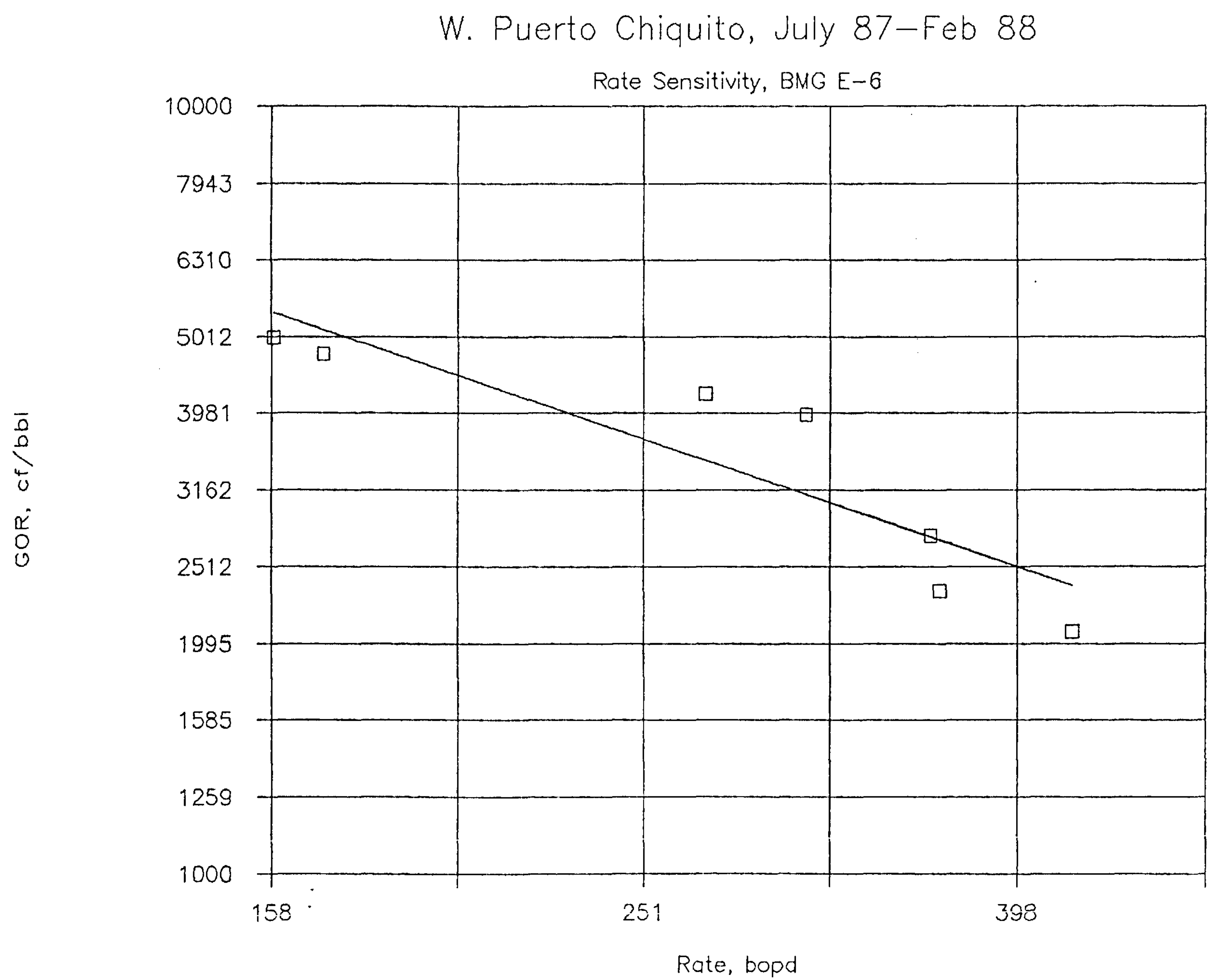
Rate Sensitivity, BMG C—34



C.C. = 0.84

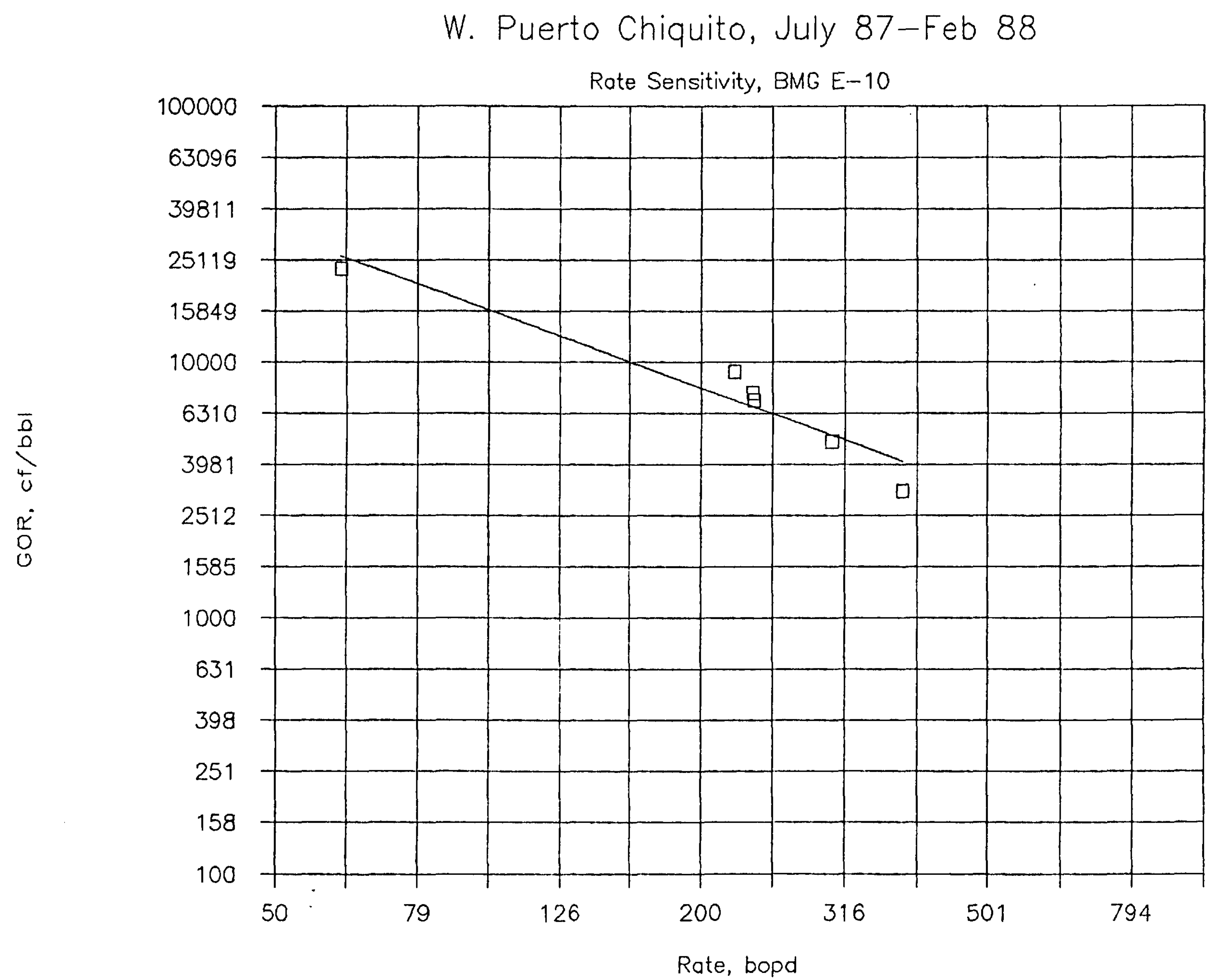

W. Puerto Chiquito, July 87
Rate Sensitivity, BMG D-17
2512
1995
1585
1259
1000
794
631
501
GOR, cf/bbl
4
6
10
16
25
Rate, bopd

C.C. = 0.52

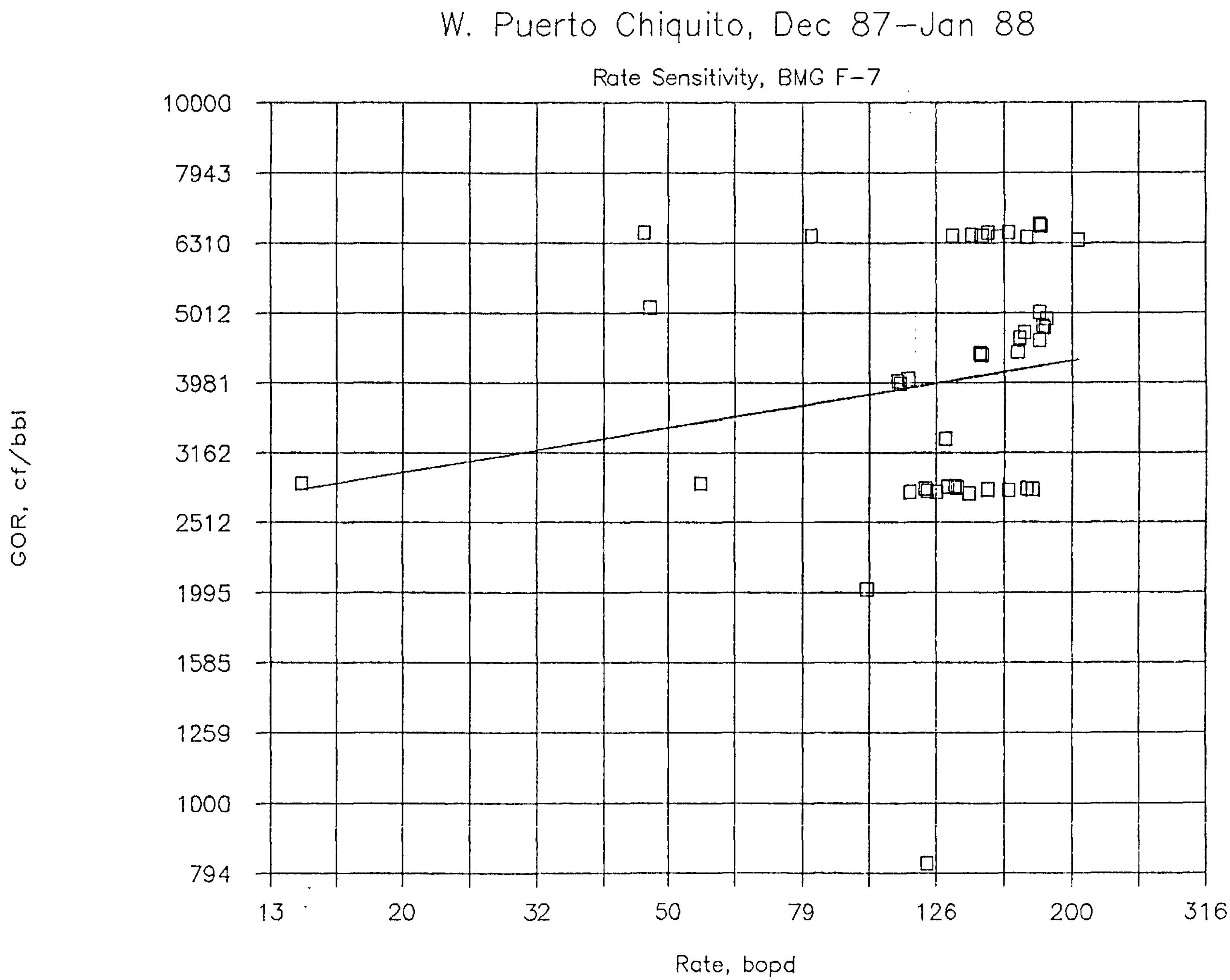


W. Puerto Chiquito, July 87—Feb 88
Rate Sensitivity, BMG E-6
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
1000
GOR, cf/bbl
158
251
398
Rate, bopd

C. C. = 0.89

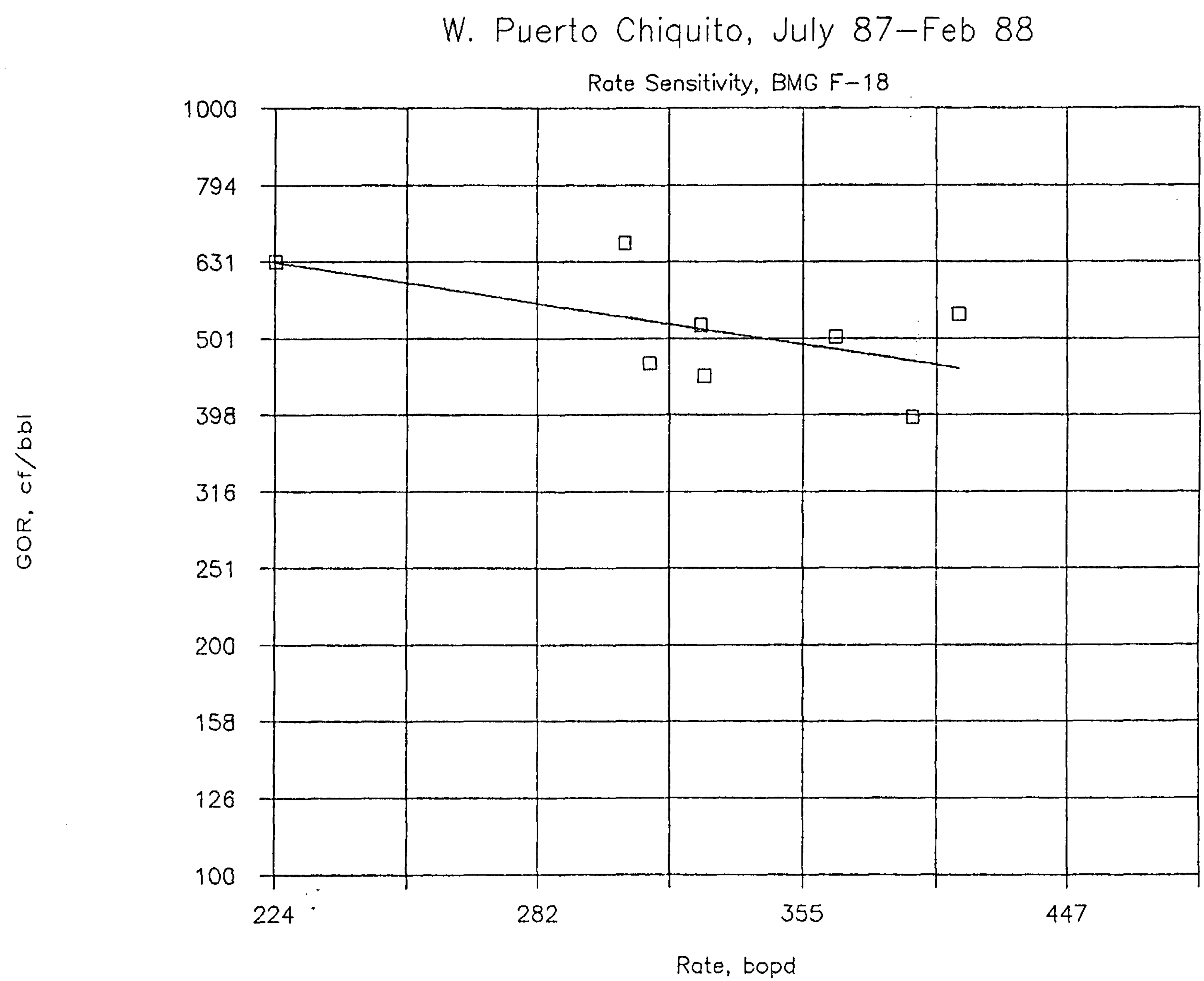

W. Puerto Chiquito, July 87–Feb 88
Rate Sensitivity, BMG E–10
GOR, cf/bbl
100000
63096
39811
25119
15849
10000
6310
3981
2512
1585
1000
631
398
251
158
100
50
79
126
200
316
501
794
Rate, bopd

C. C. = 0.96



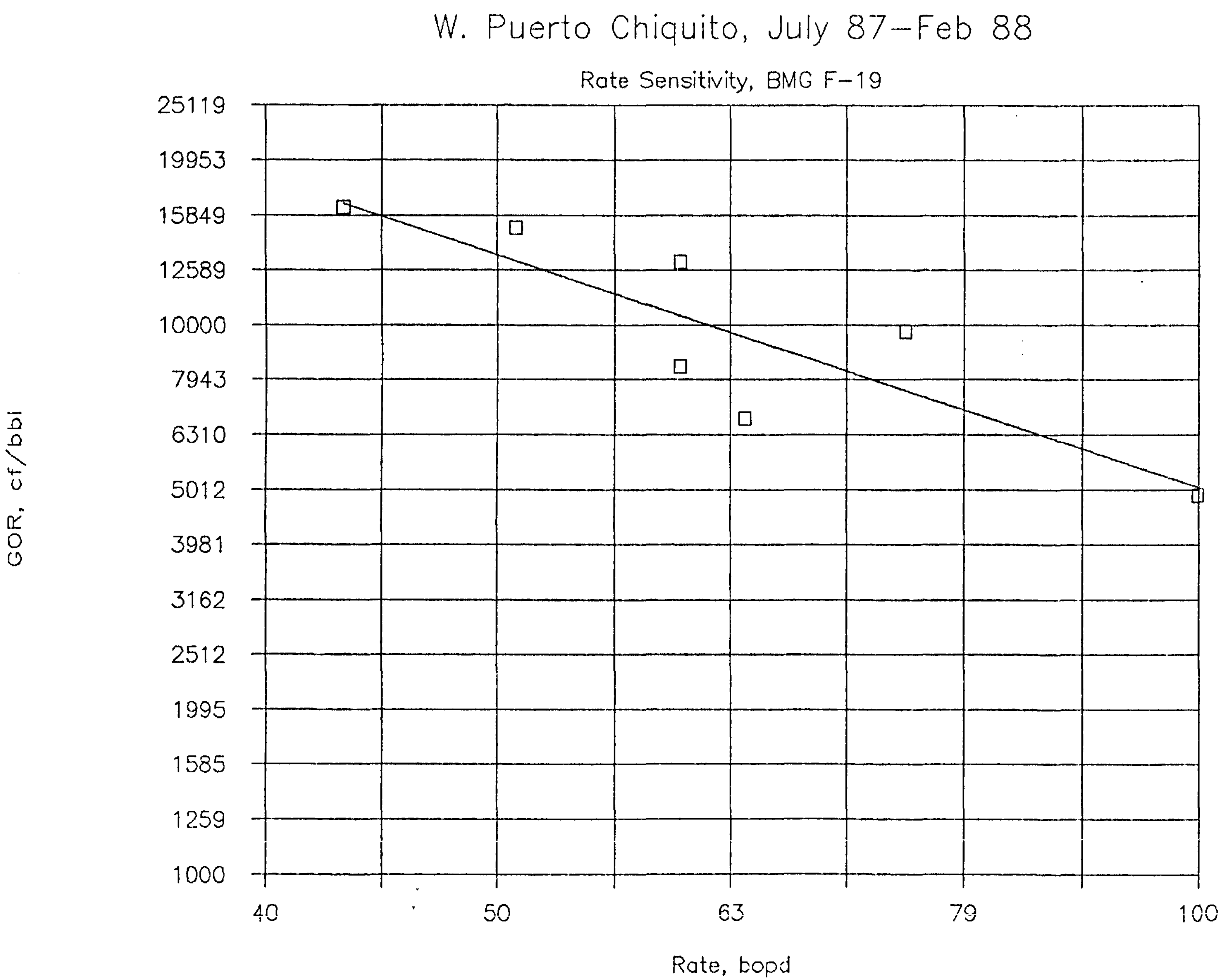
W. Puerto Chiquito, Dec 87–Jan 88
Rate Sensitivity, BMG F-7
GOR, cf/bbl
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
1000
794
13
20
32
50
79
126
200
316
Rate, bopd

C. C. = 0.18

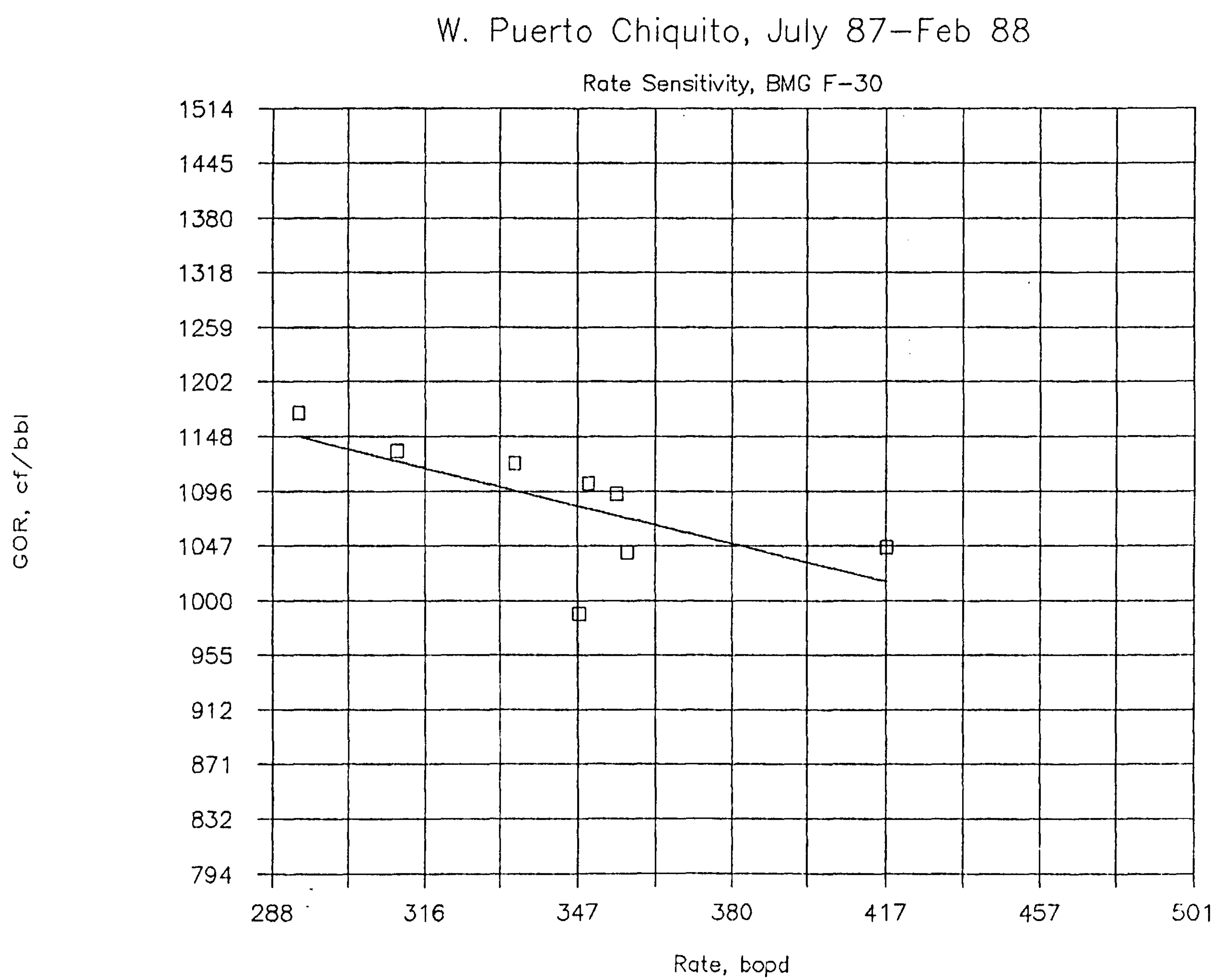


W. Puerto Chiquito, July 87—Feb 88
Rate Sensitivity, BMG F-18
1000
794
631
501
398
316
251
200
158
126
100
GOR, cf/bbl
224
282
355
447
Rate, bopd

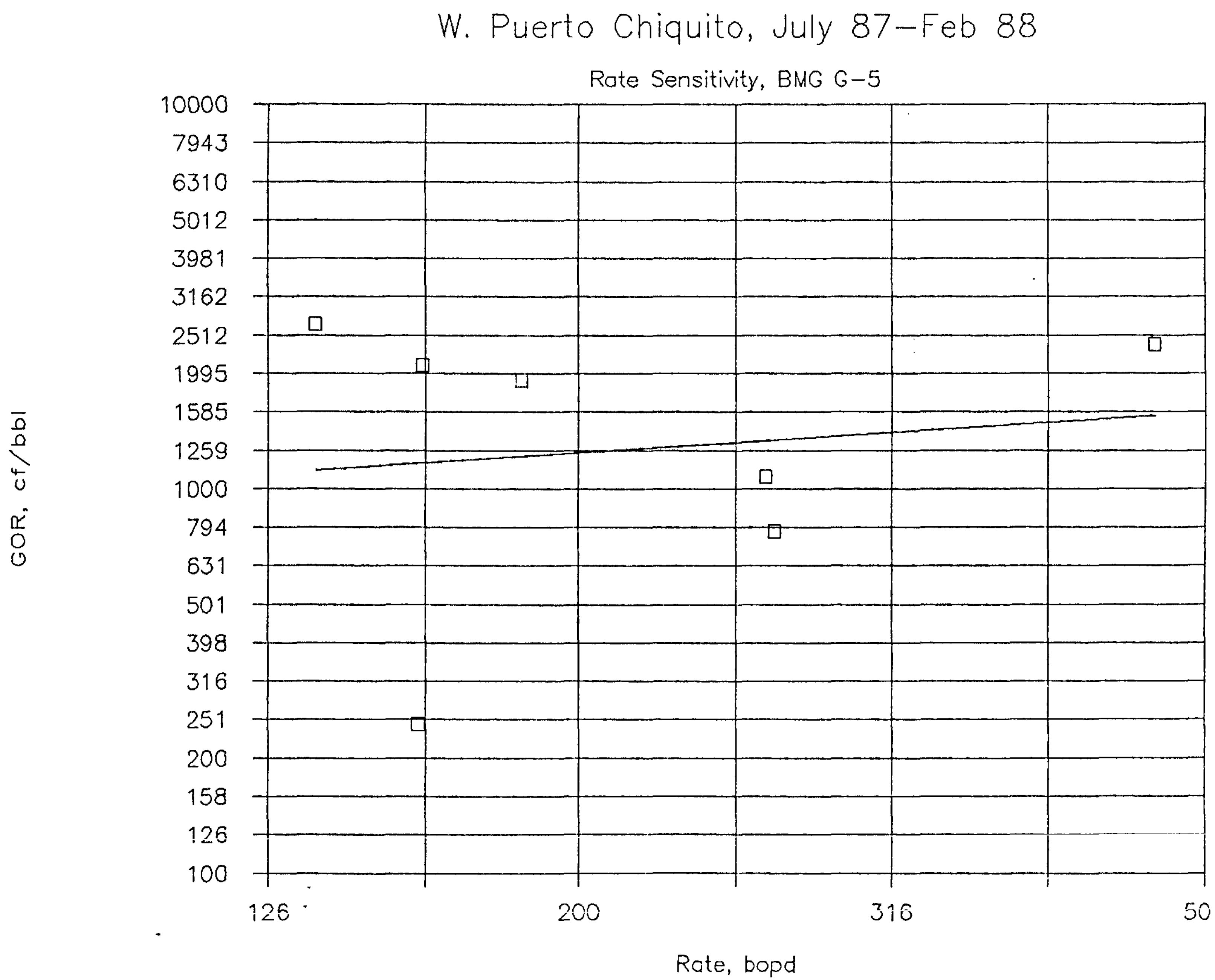
C.C. = 0.58


W. Puerto Chiquito, July 87–Feb 88
Rate Sensitivity, BMG F-19
GOR, cf/bbl
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
1000
40
50
63
79
100
Rate, bopd

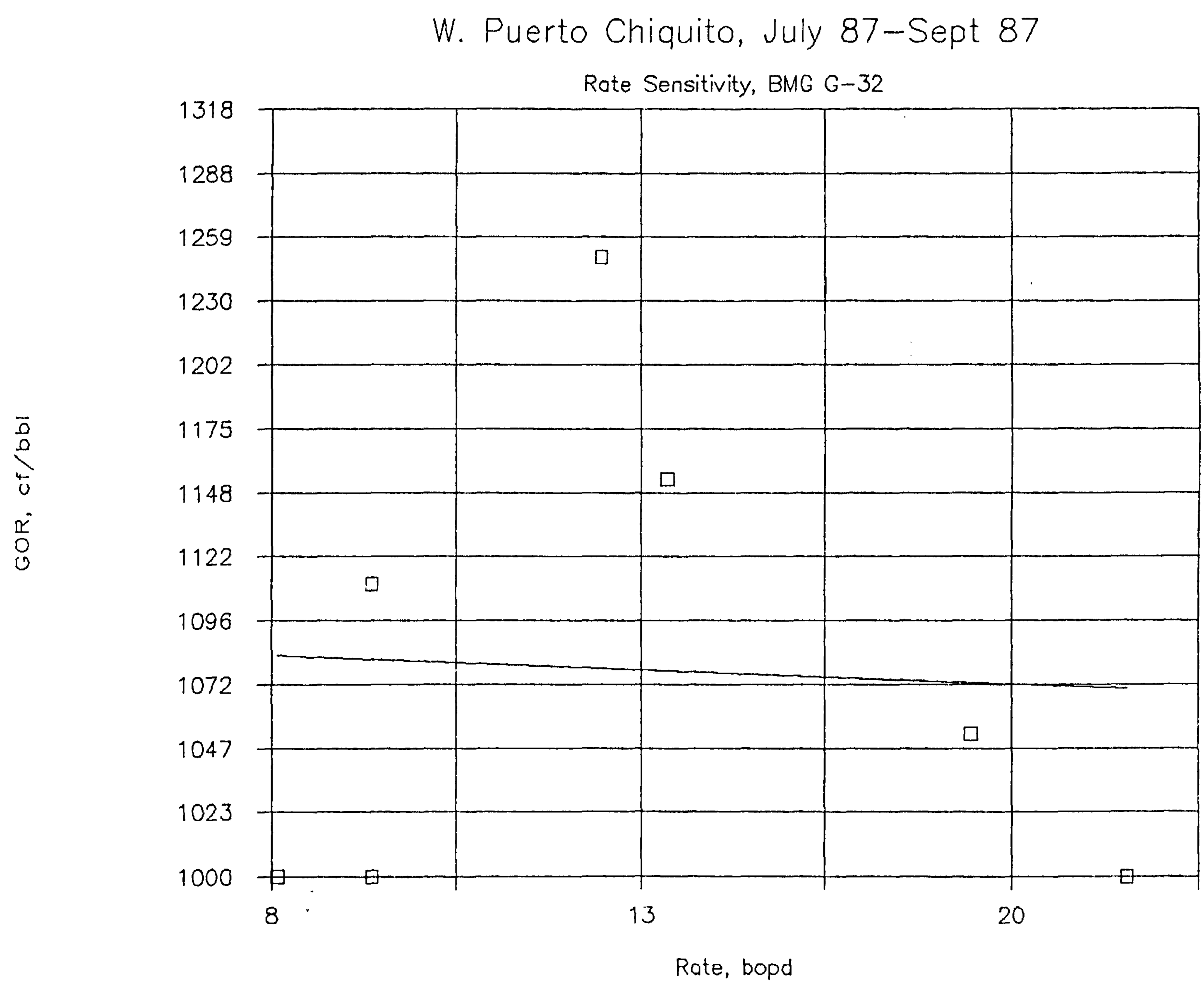
C. C. = 0.87


W. Puerto Chiquito, July 87—Feb 88
Rate Sensitivity, BMG F-30
1514
1445
1380
1318
1259
1202
1148
1096
1047
1000
955
912
871
832
794
GOR, cf/bbl
288
316
347
380
417
457
501
Rate, bopd

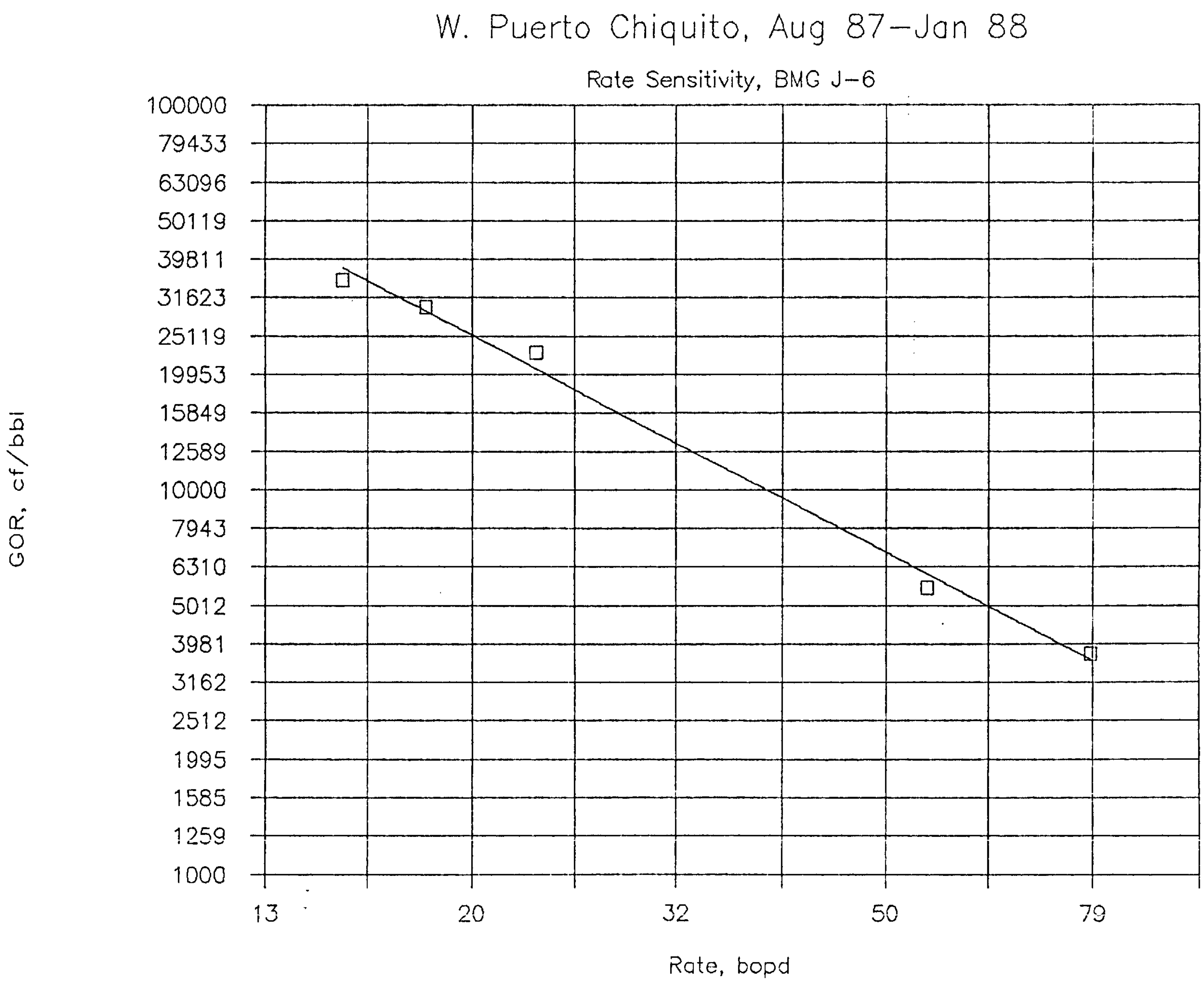
C.C. = 0.66


W. Puerto Chiquito, July 87—Feb 88
Rate Sensitivity, BMG G-5
GOR, cf/bbl
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
1000
794
631
501
398
316
251
200
158
126
100
126
200
316
501
Rate, bopd

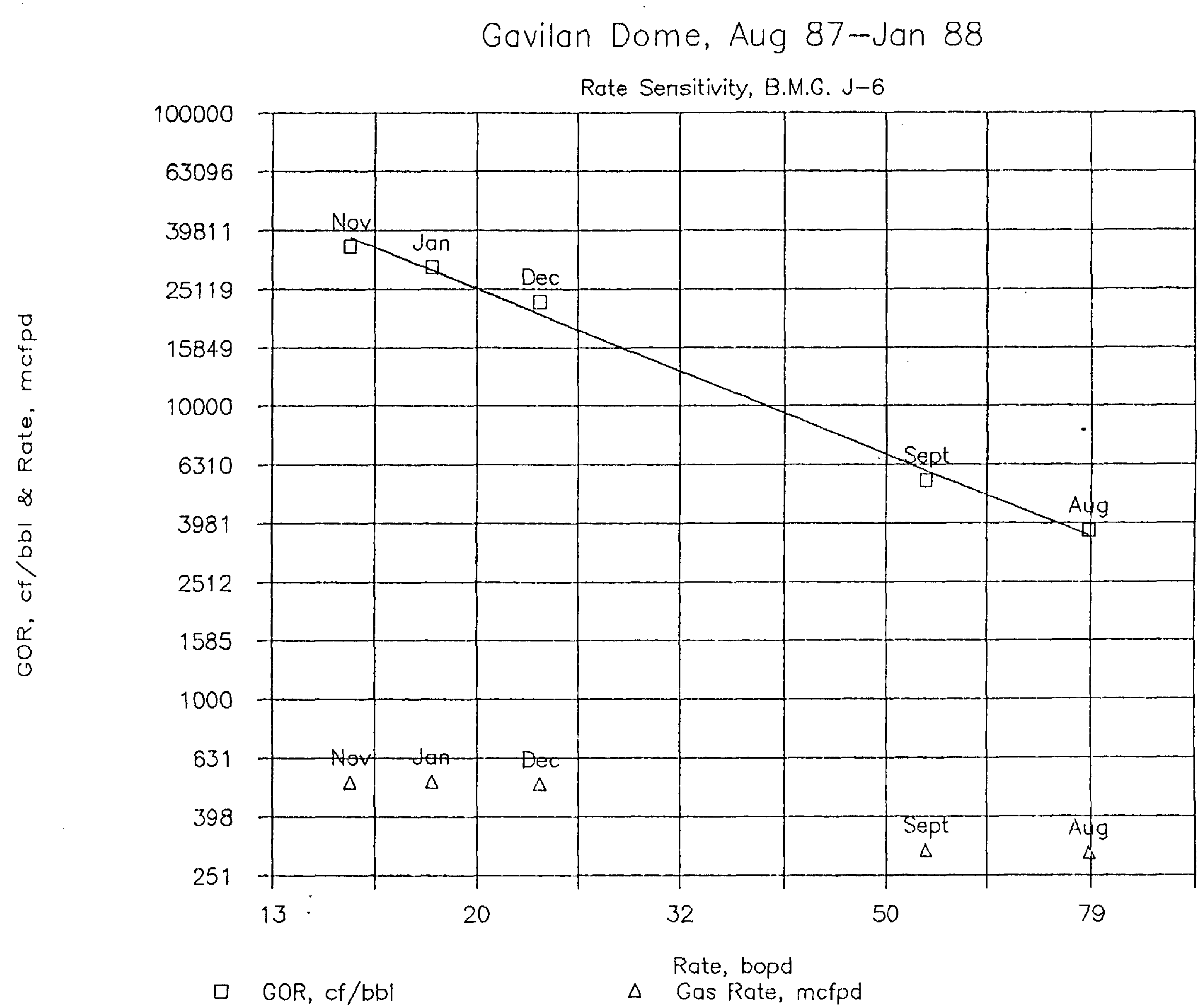
C.C. = 0.13


W. Puerto Chiquito, July 87–Sept 87
Rate Sensitivity, BMG G-32
GOR, cf/bbl
1318
1288
1259
1230
1202
1175
1148
1122
1096
1072
1047
1023
1000
8
13
20
Rate, bopd

C. C. = 0.05

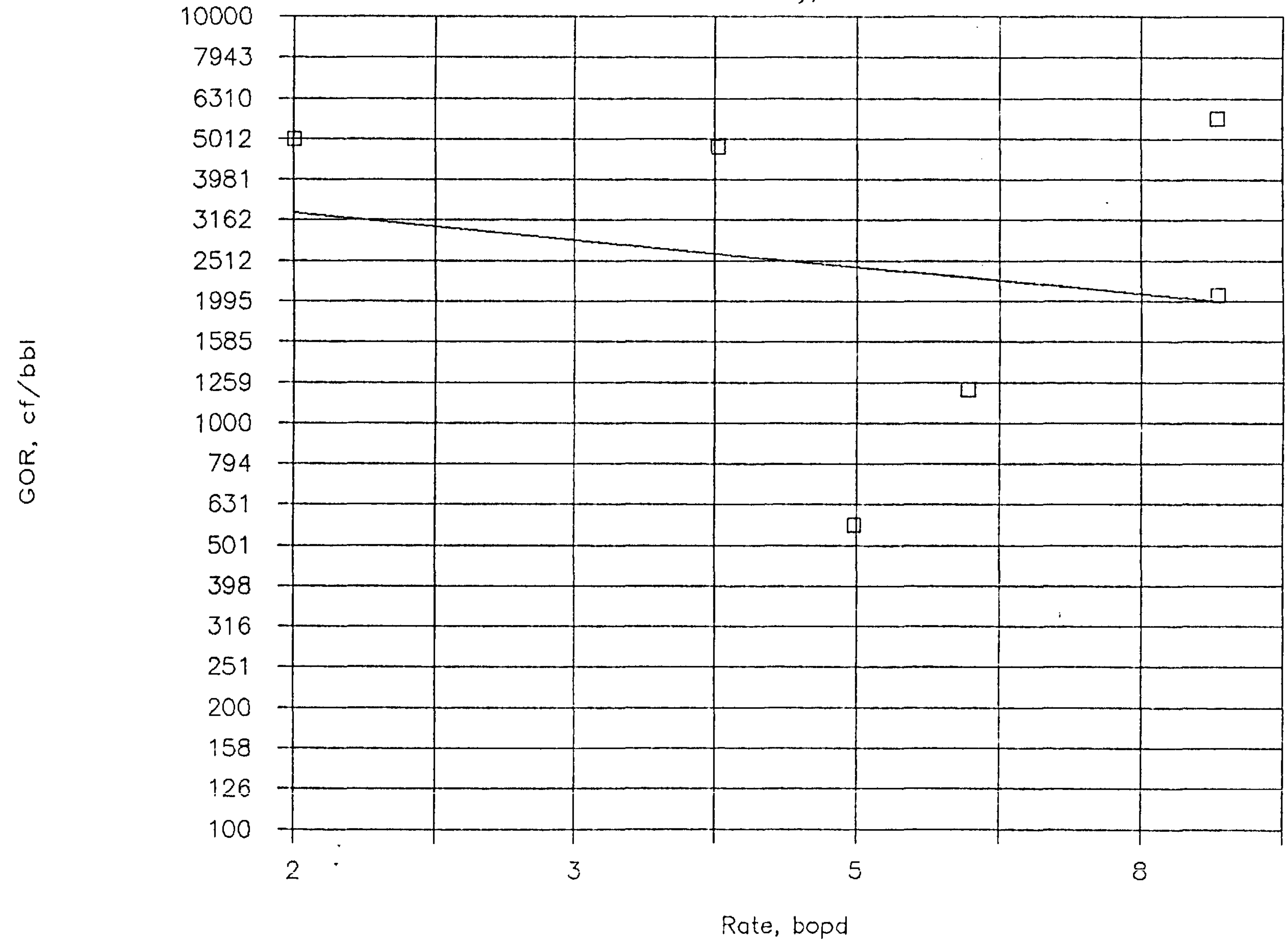

W. Puerto Chiquito, Aug 87–Jan 88
Rate Sensitivity, BMG J–6
GOR, cf/bbl
100000
79433
63096
50119
39811
31623
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
1000
13
20
32
50
79
Rate, bopd

C.C. = 1.00


Gavilan Dome, Aug 87—Jan 88
Rate Sensitivity, B.M.G. J-6
100000
63096
39811
25119
15849
10000
6310
3981
2512
1585
1000
631
398
251
13
20
32
50
79
Nov
Jan
Dec
Sept
Aug
Nov
Jan
Dec
Sept
Aug
GOR, cf/bbl & Rate, mcfpd
Rate, bopd
GOR, cf/bbl
Gas Rate, mcfpd

W. Puerto Chiquito, July 87—Feb 88

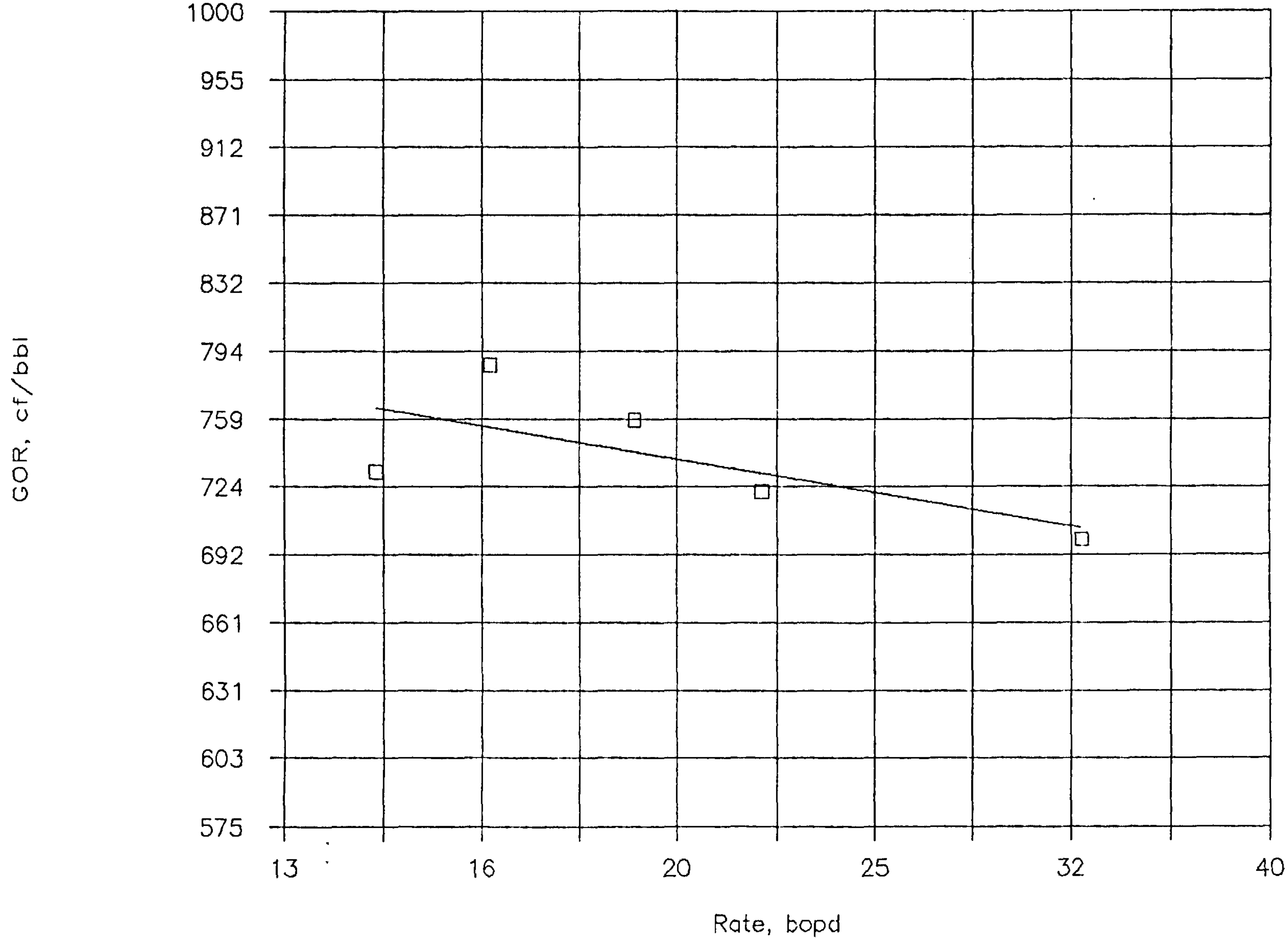
Rate Sensitivity, BMG K—8



C.C. = 0.20

W. Puerto Chiquito, Sept 87–Jan 88

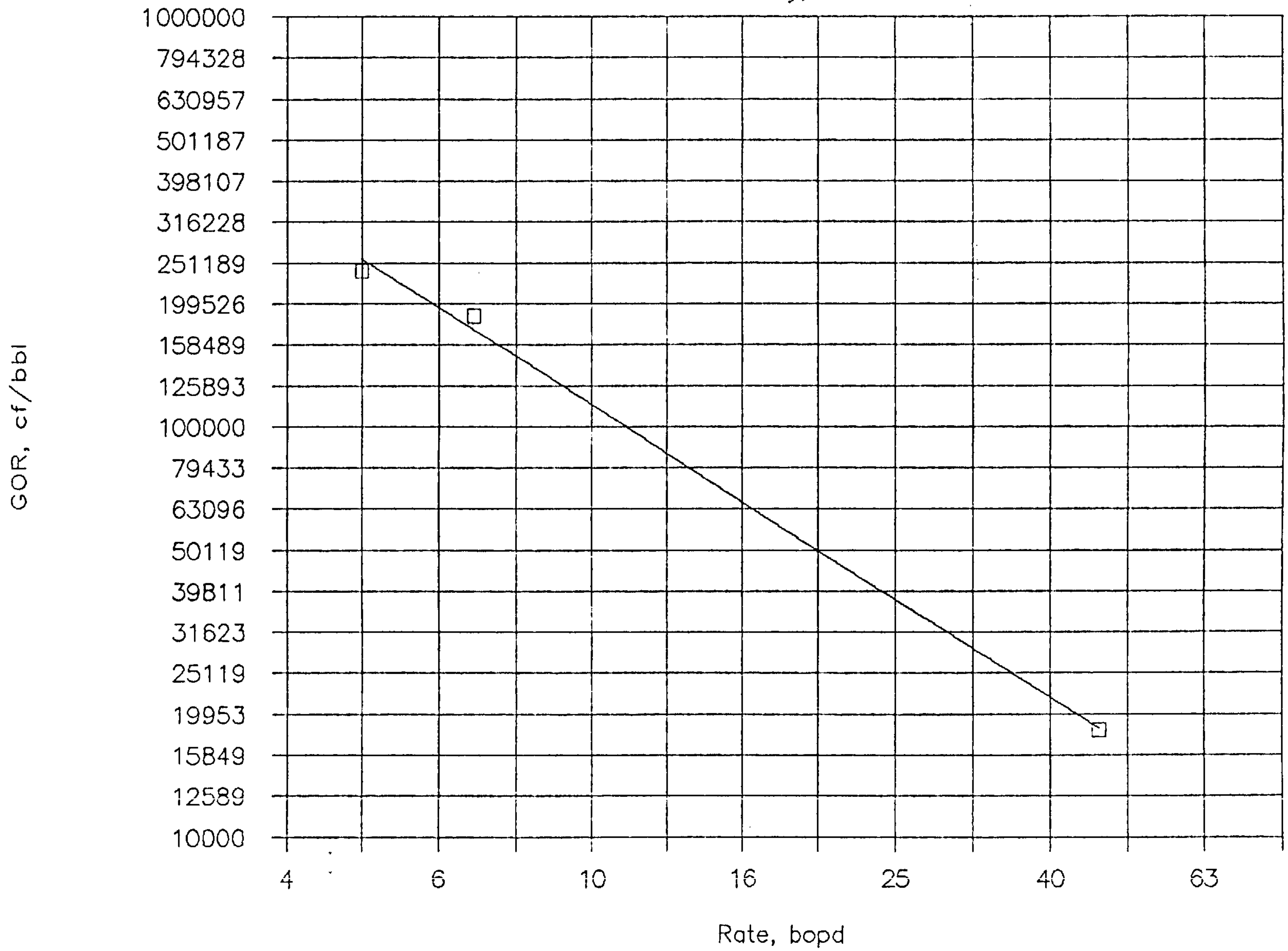
Rate Sensitivity, BMG L-3



C.C. = 0.68

W. Puerto Chiquito, Sept 87–Jan 88

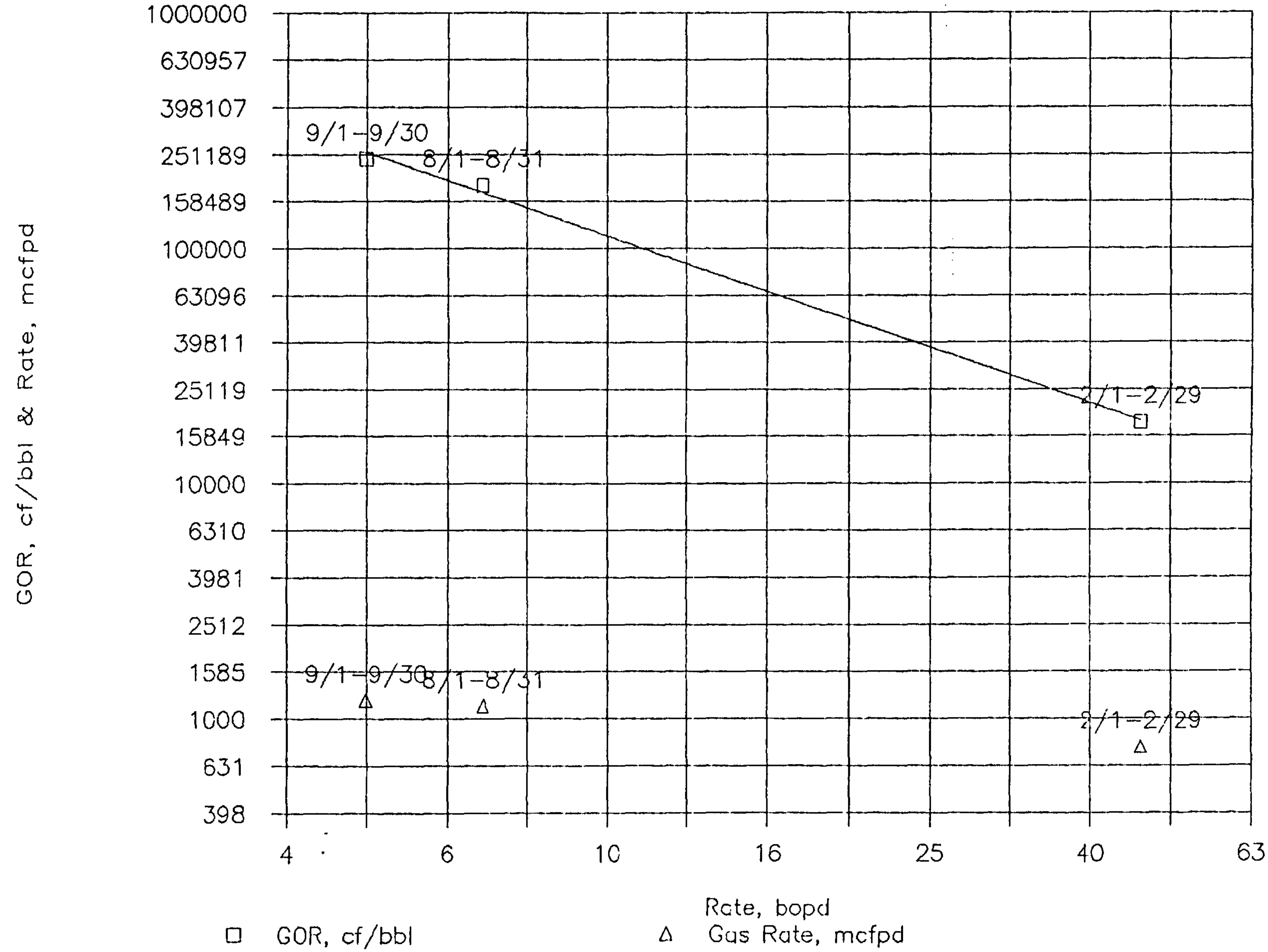
Rate Sensitivity, BMG L-11



C.C. = 1.00

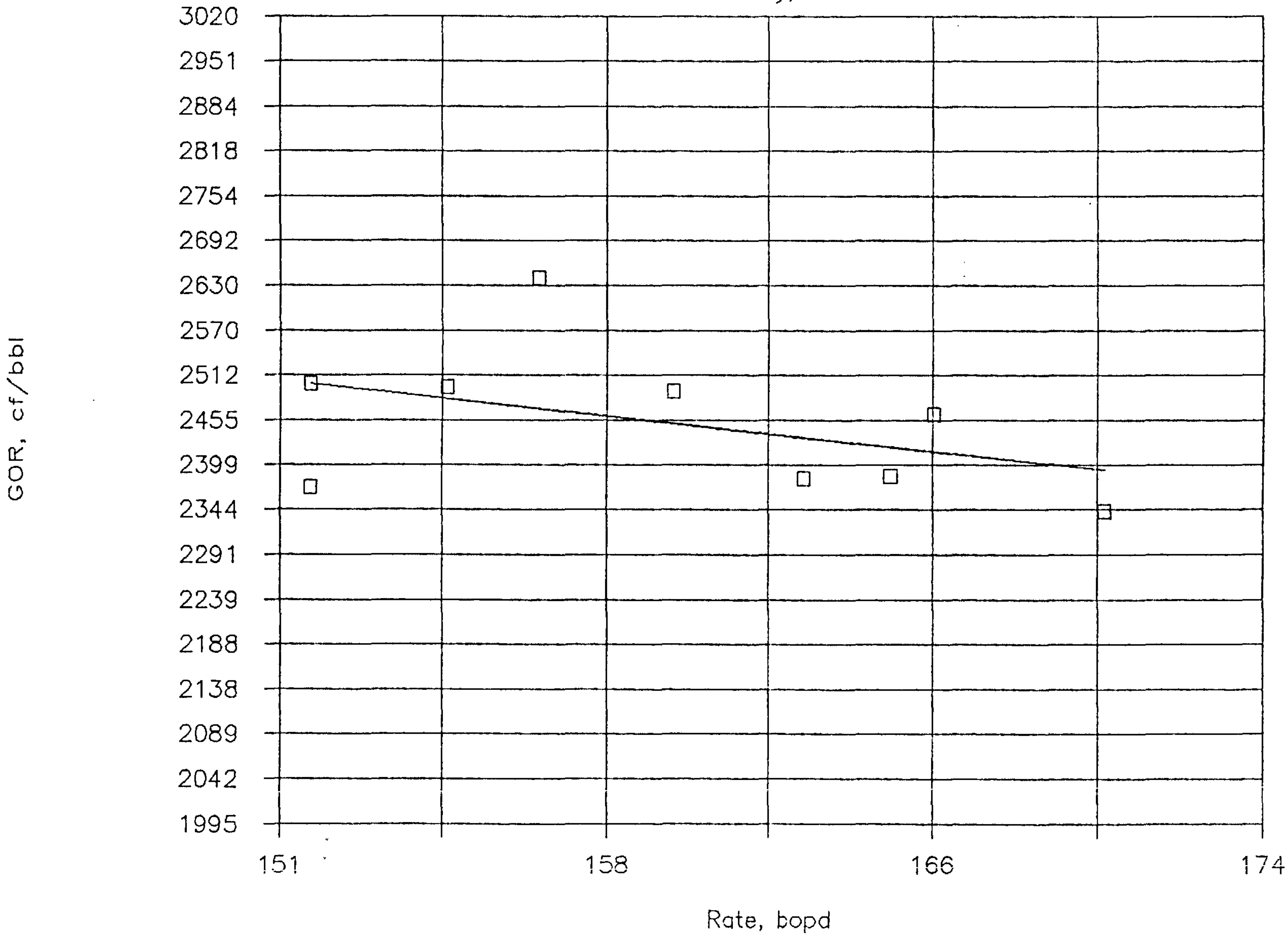
Gavilan Dome; Aug 87, Sept 87, & Feb 88

Rate Sensitivity, B.M.G. L-11

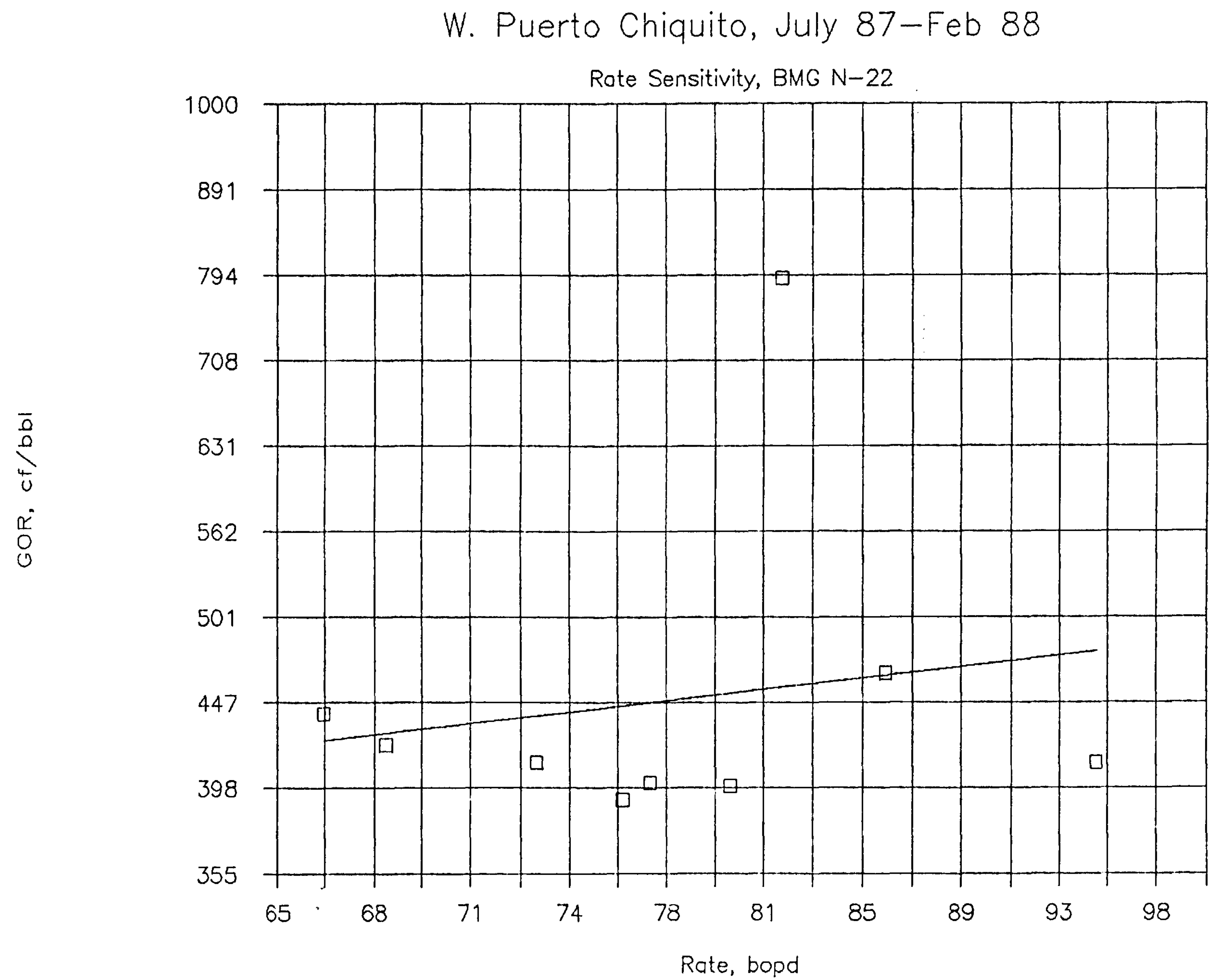


W. Puerto Chiquito, July 87—Feb 88

Rate Sensitivity, BMG L-27

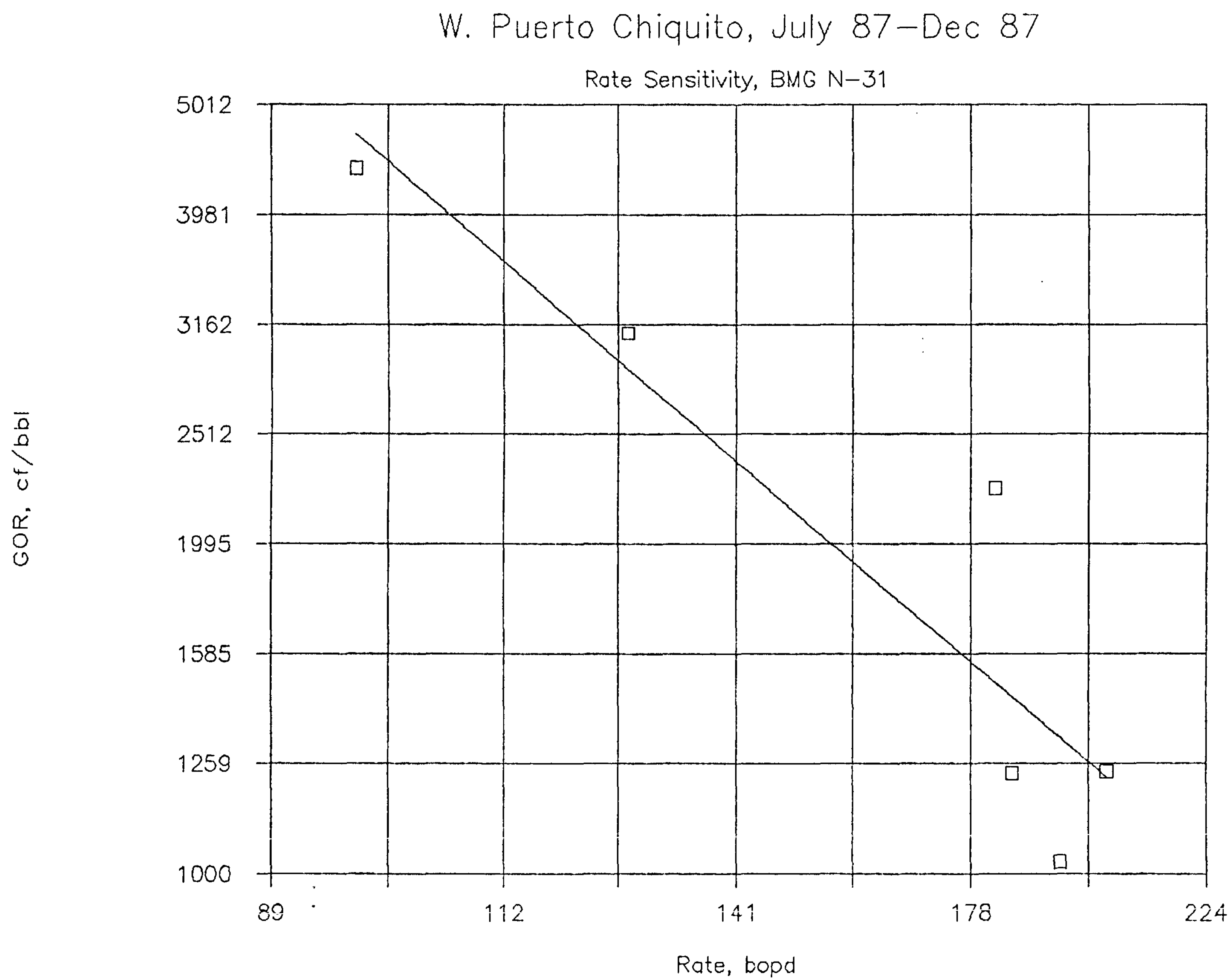


C.C. = 0.43



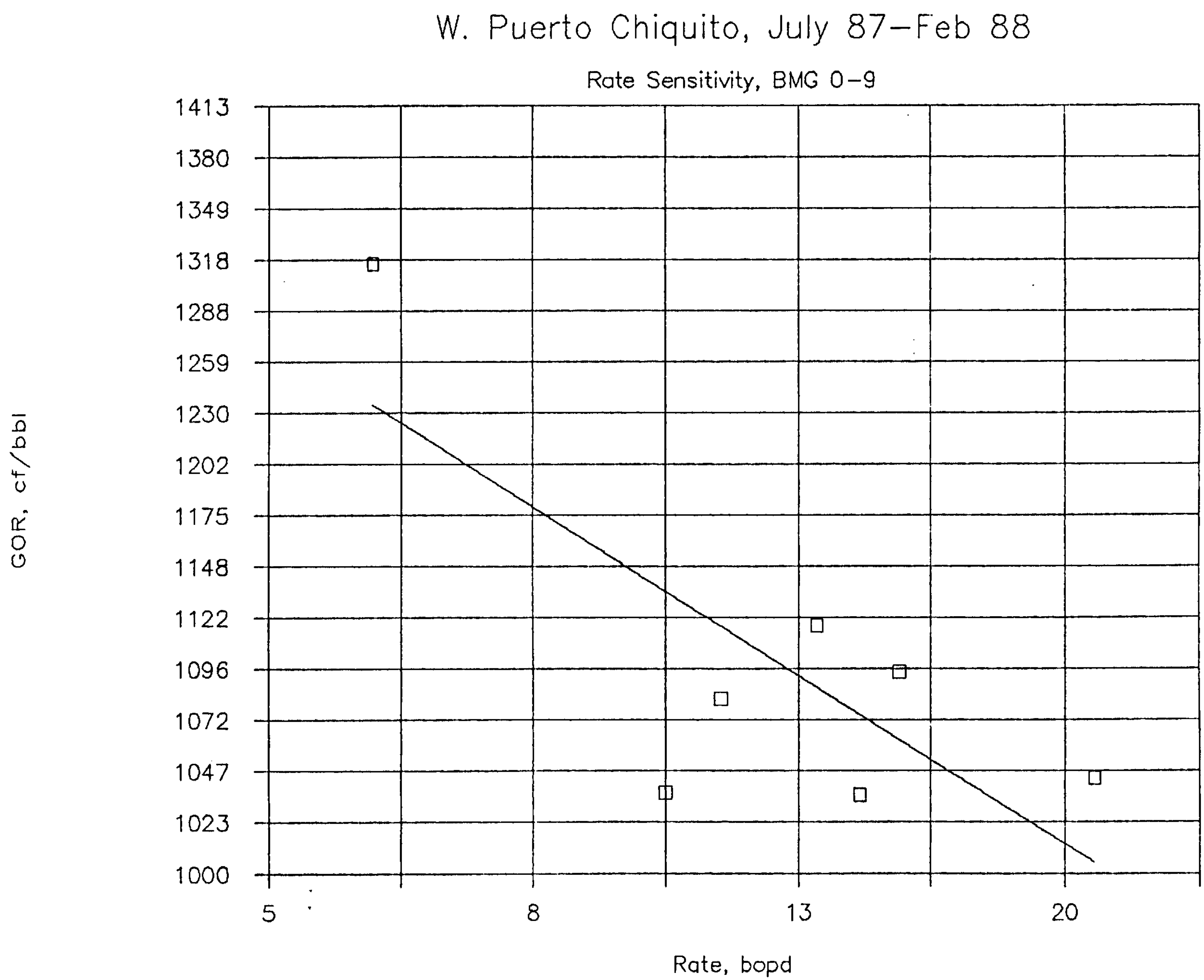
W. Puerto Chiquito, July 87—Feb 88
Rate Sensitivity, BMG N—22
1000
891
794
708
631
562
501
447
398
355
GOR, cf/bbl
65
68
71
74
78
81
85
89
93
98
Rate, bopd

C.C. = 0.17

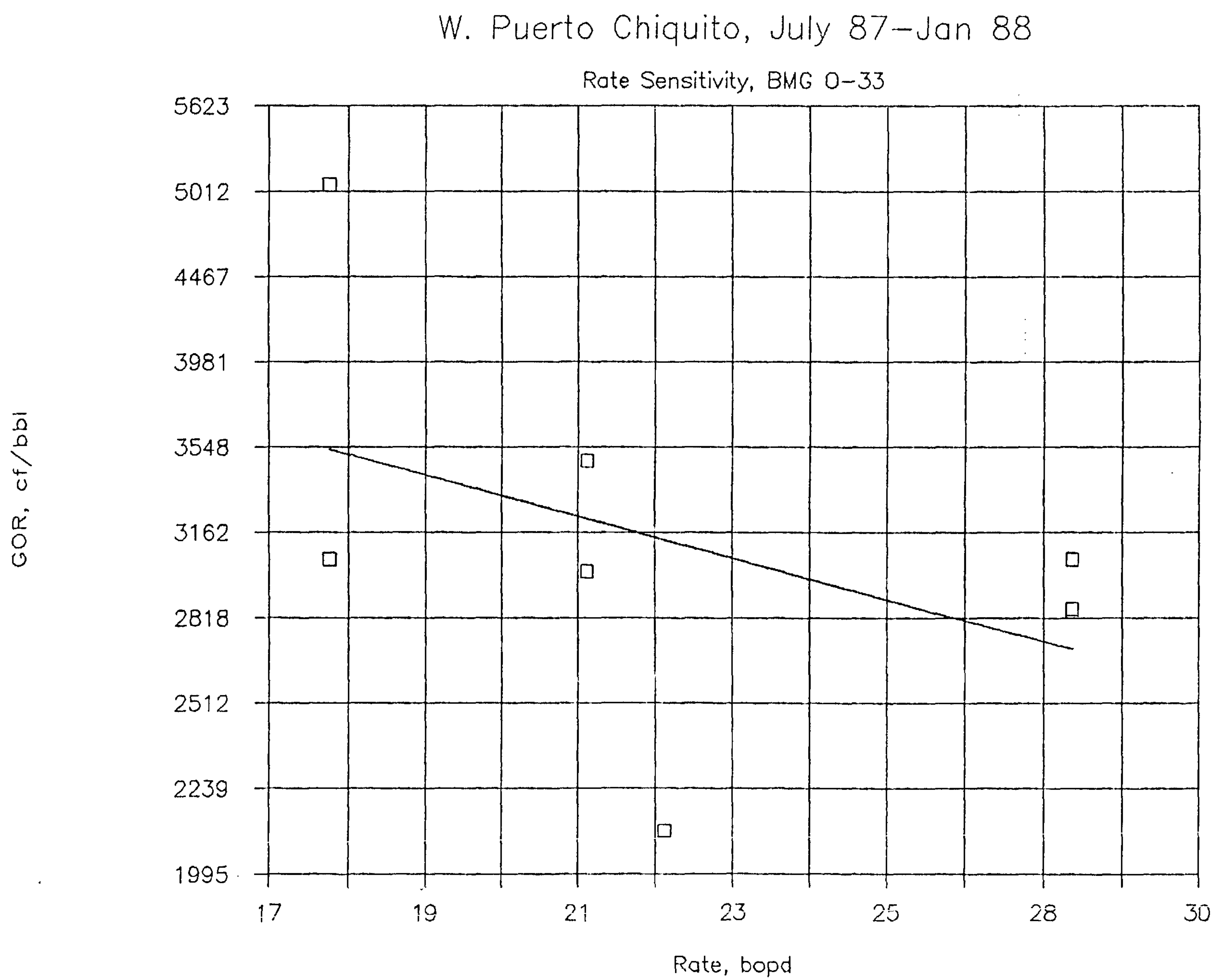


W. Puerto Chiquito, July 87–Dec 87
Rate Sensitivity, BMG N–31
GOR, cf/bbl
5012
3981
3162
2512
1995
1585
1259
1000
89
112
141
178
224
Rate, bopd

C.C. = 0.92


W. Puerto Chiquito, July 87–Feb 88
Rate Sensitivity, BMG 0–9
GOR, cf/bbl
1413
1380
1349
1318
1288
1259
1230
1202
1175
1148
1122
1096
1072
1047
1023
1000
5
8
13
20
Rate, bopd

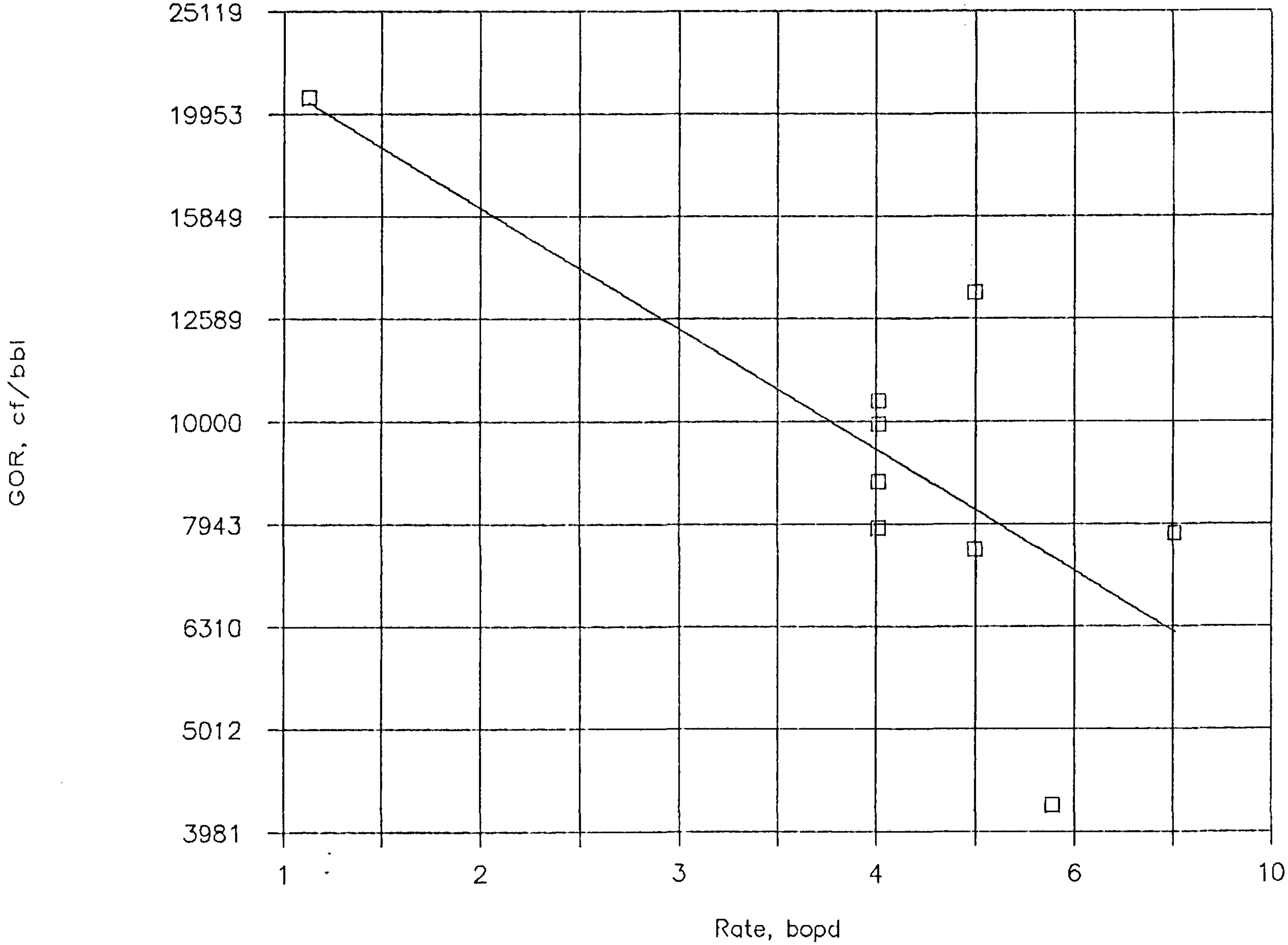
C.C. = 0.76


W. Puerto Chiquito, July 87–Jan 88
Rate Sensitivity, BMG O–33
GOR, cf/bbl
5623
5012
4467
3981
3548
3162
2818
2512
2239
1995
17
19
21
23
25
28
30
Rate, bopd

C.C. = 0.43

Gavilan Dome, July 87–Feb 88

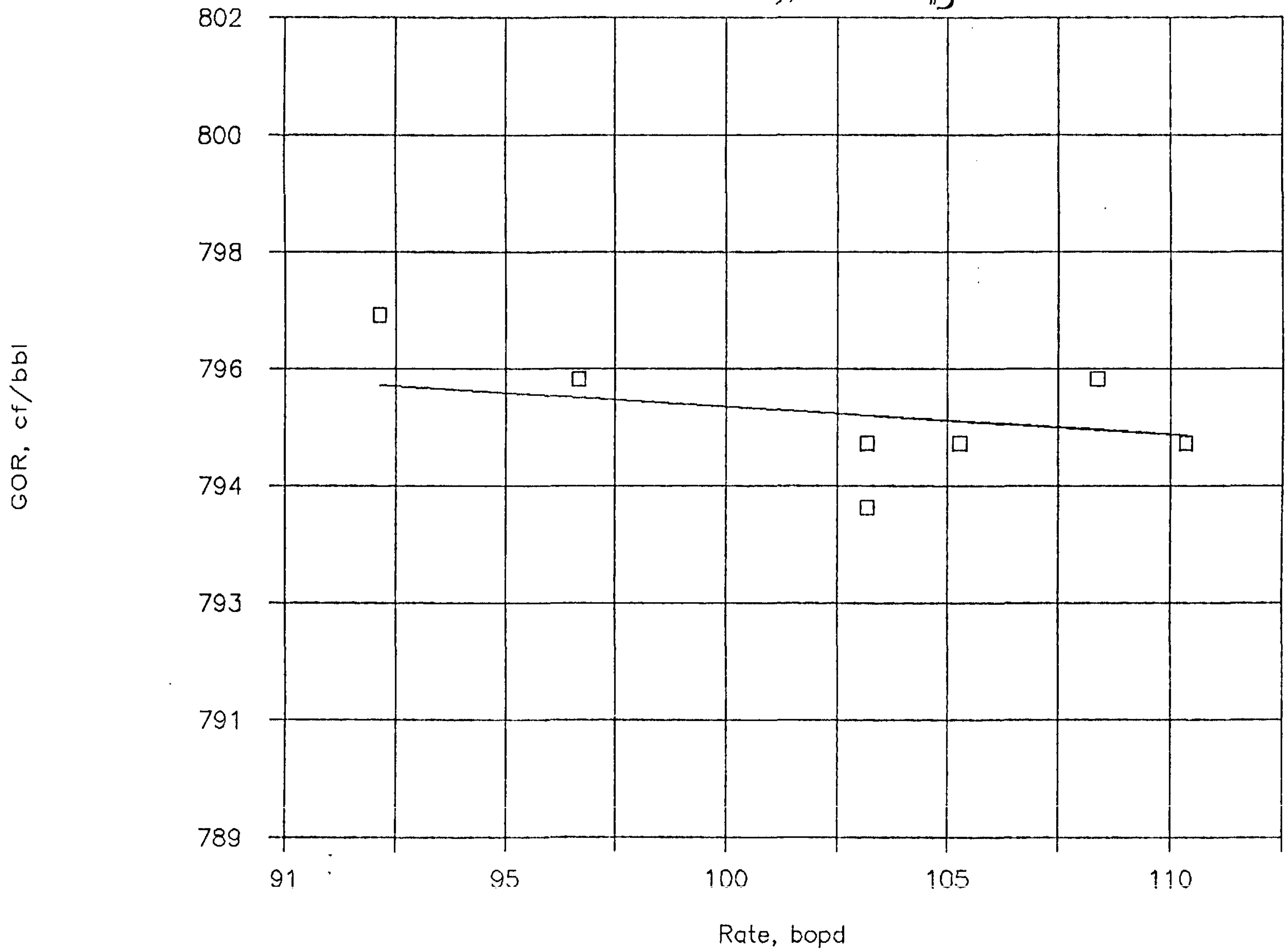
Rate Sensitivity, Dugan Lind #1



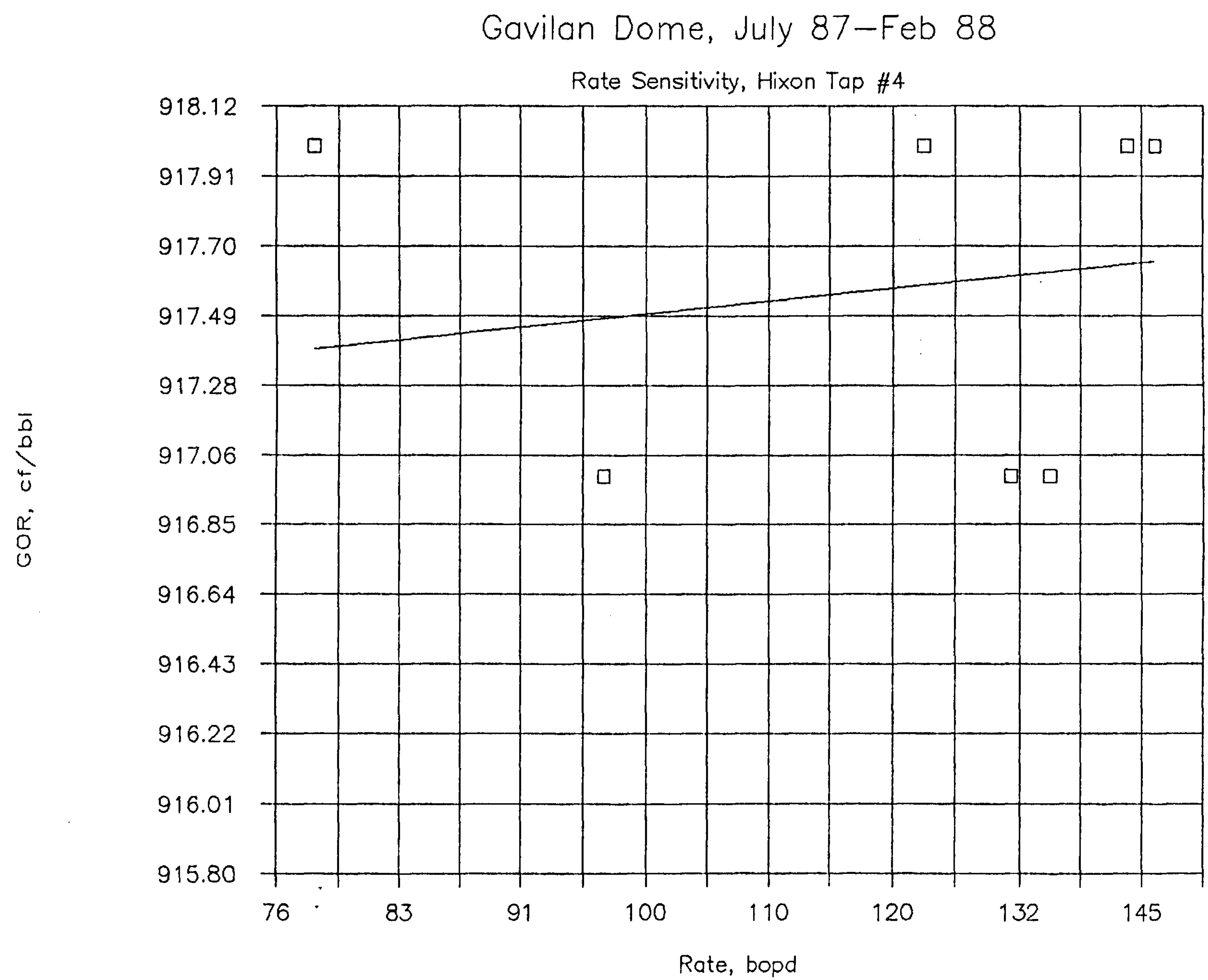
C.C. = 0.75

Gavilan Dome, July 87—Feb 88

Rate Sensitivity, Hixon Div #3

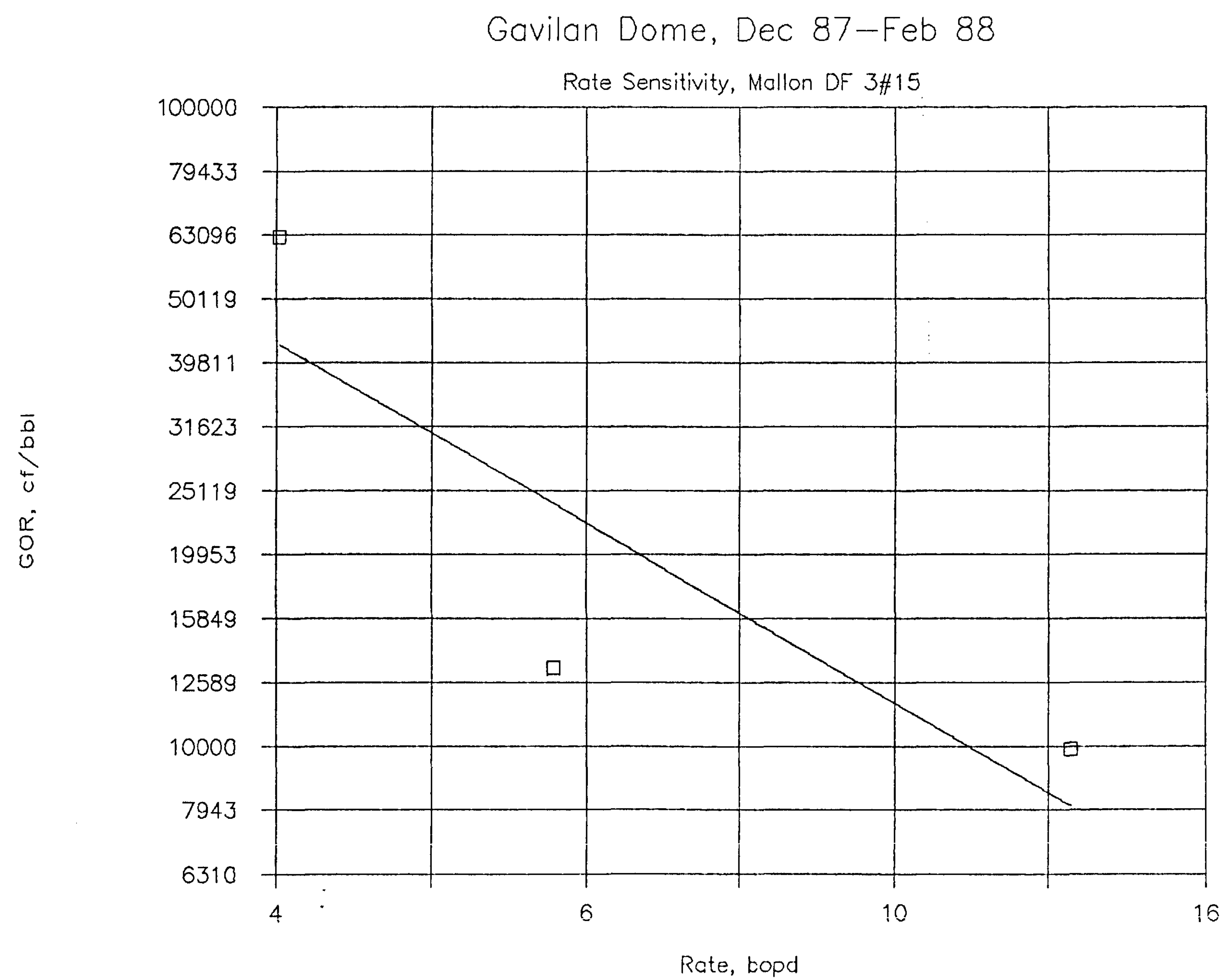


C.C. = 0.06



Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Hixon Tap #4
918.12
917.91
917.70
917.49
917.28
917.06
916.85
916.64
916.43
916.22
916.01
915.80
GOR, cf/bbl
76
83
91
100
110
120
132
145
Rate, bopd

C.C. = 0.01

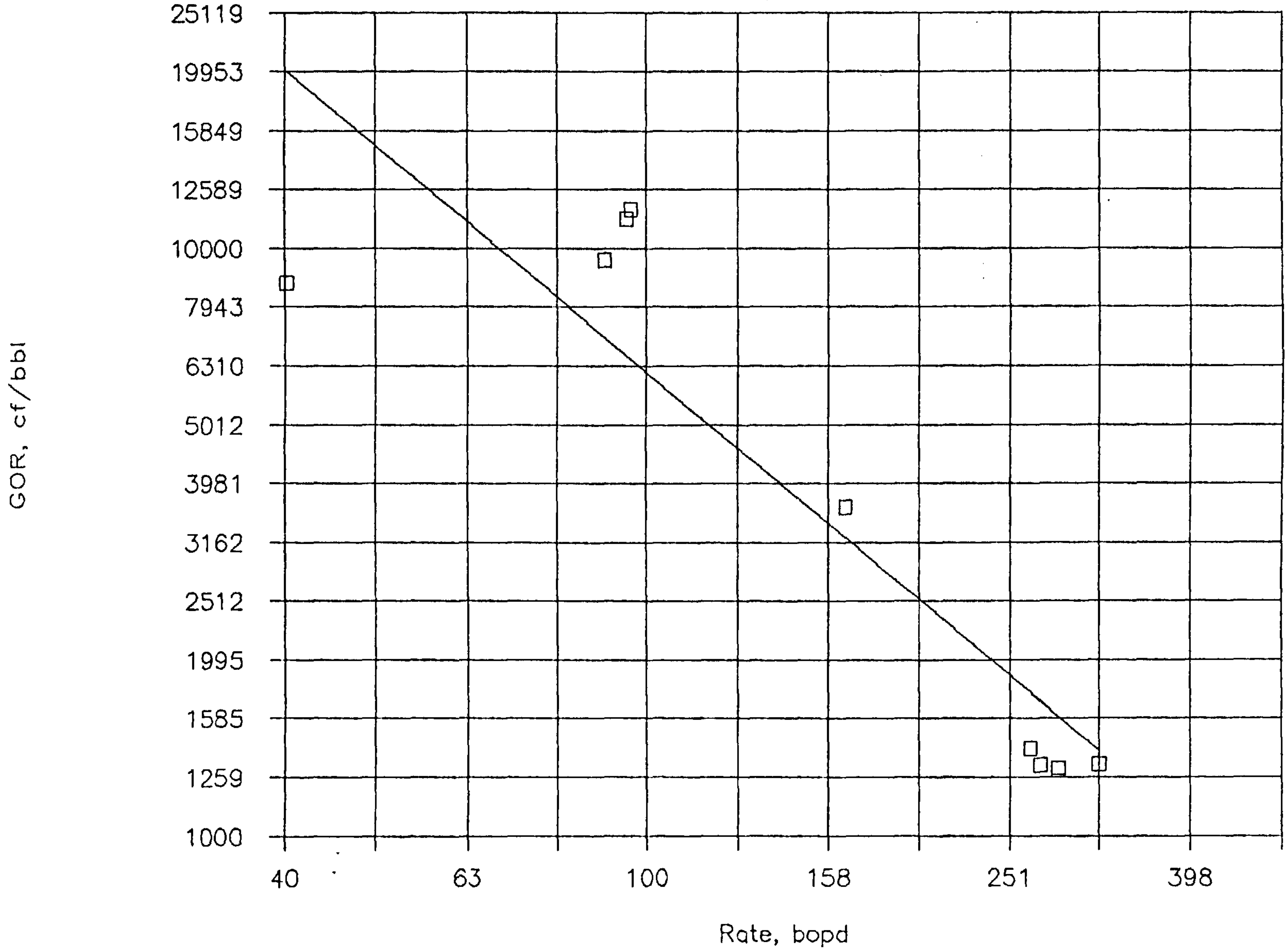


Gavilan Dome, Dec 87—Feb 88
Rate Sensitivity, Mallon DF 3#15
GOR, cf/bbl
100000
79433
63096
50119
39811
31623
25119
19953
15849
12589
10000
7943
6310
4
6
10
16
Rate, bopd

C.C.=0.85

Gavilan Dome, July 87–Feb 88

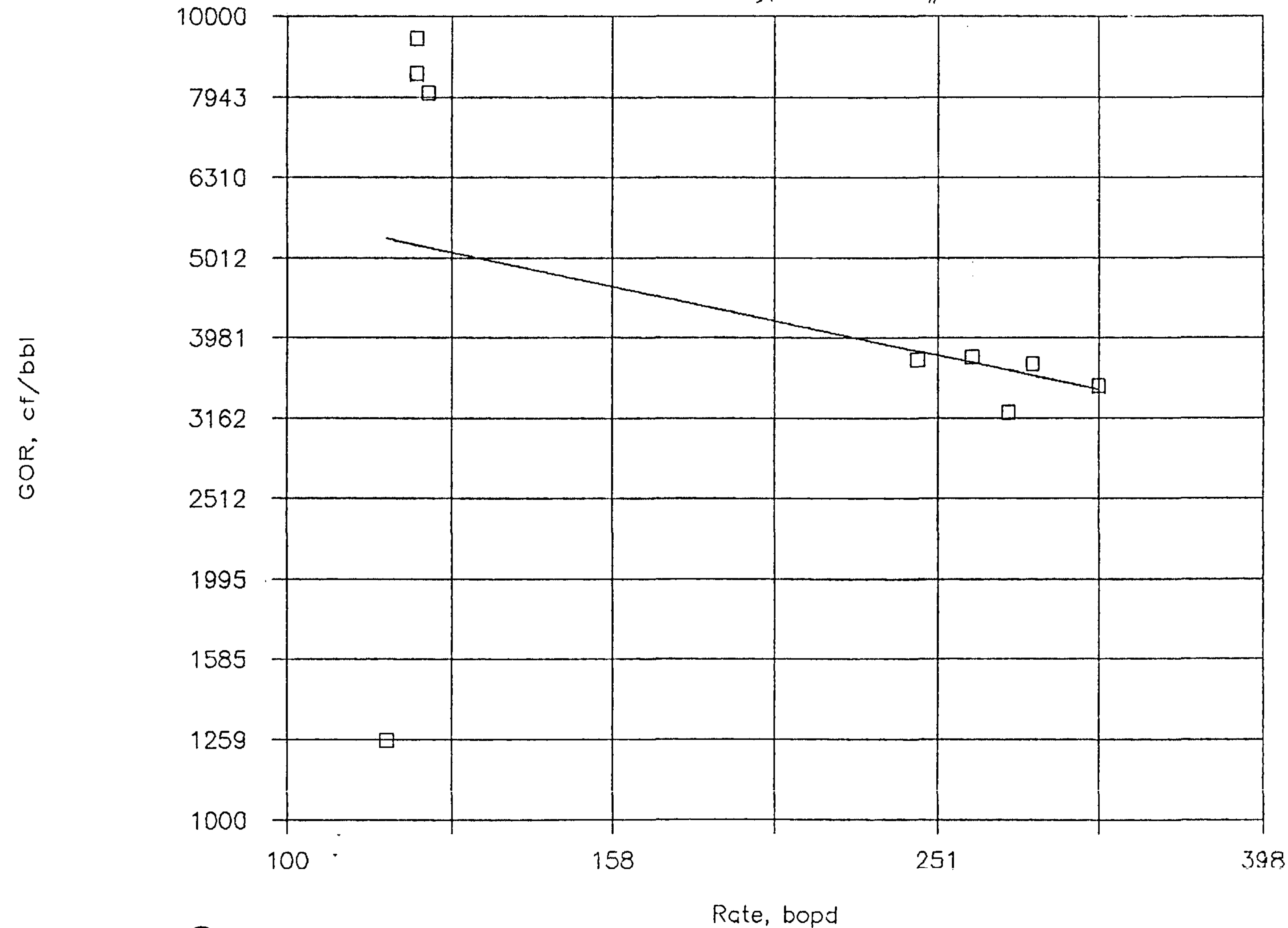
Rate Sensitivity, Mallon FF 2#1



C.C. = 0.90

Gavilan Dome, July 87–Feb 88

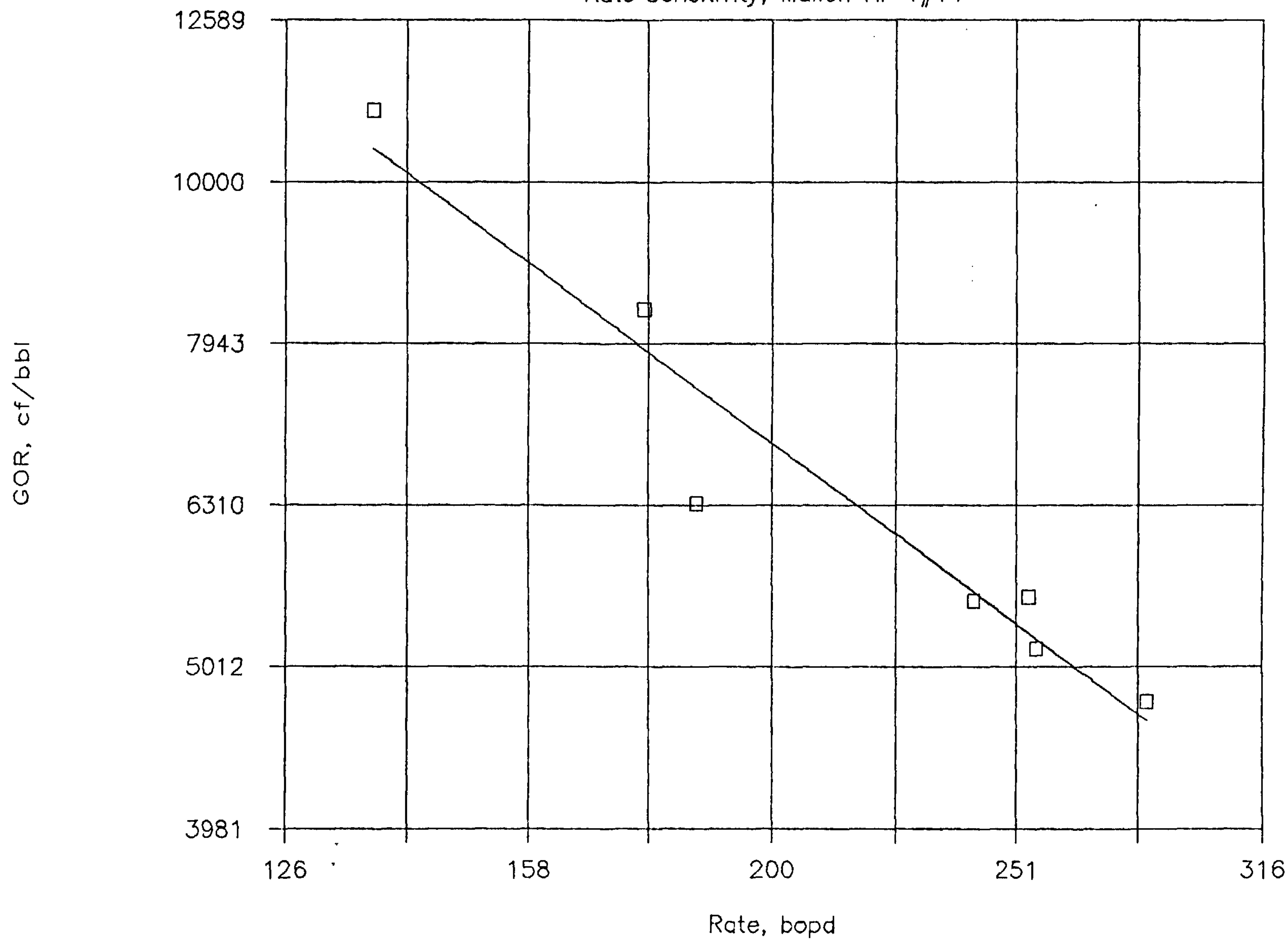
Rate Sensitivity, Mallon HF 1#8



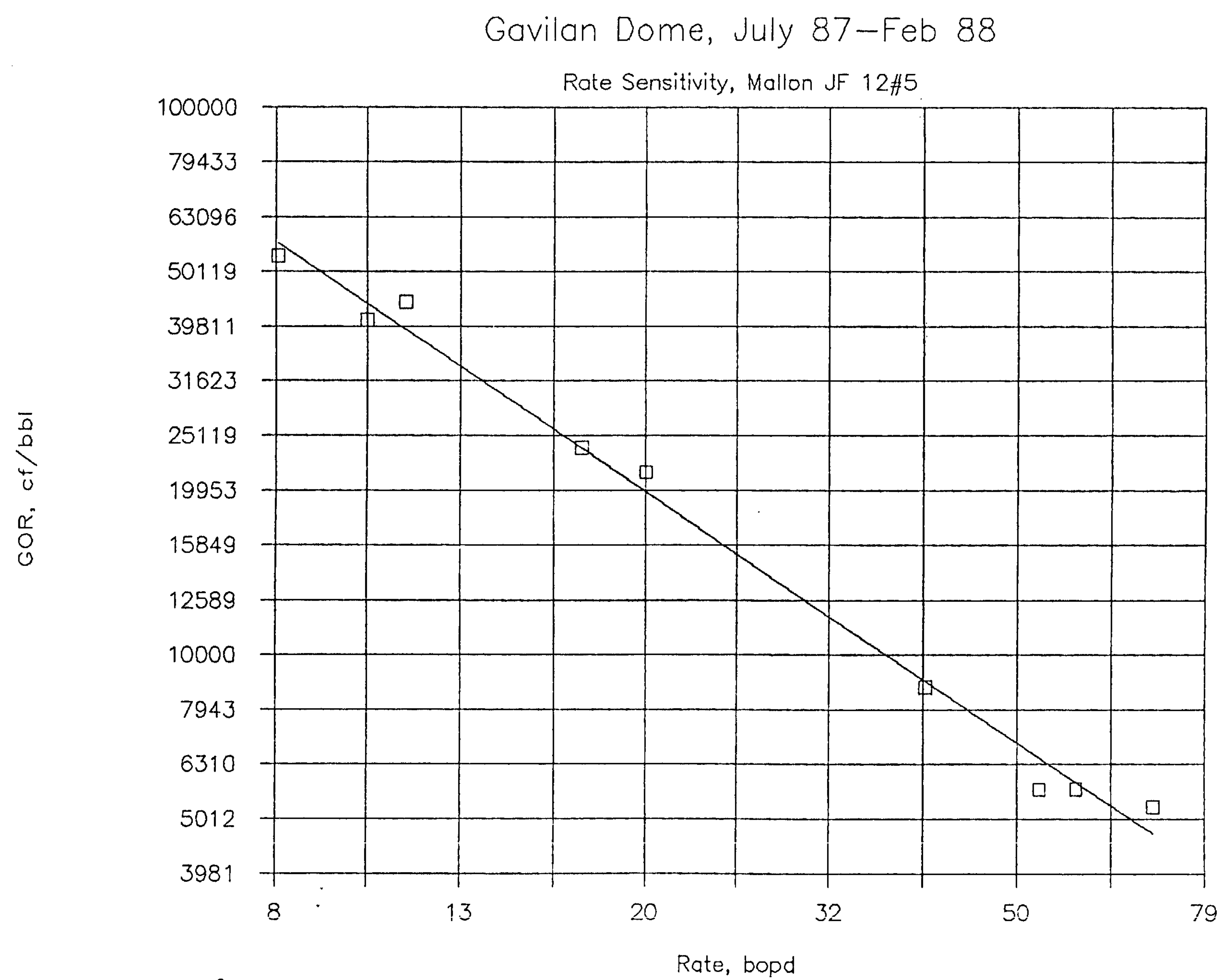
C. C. = 0.31

Gavilan Dome, July 87—Feb 88

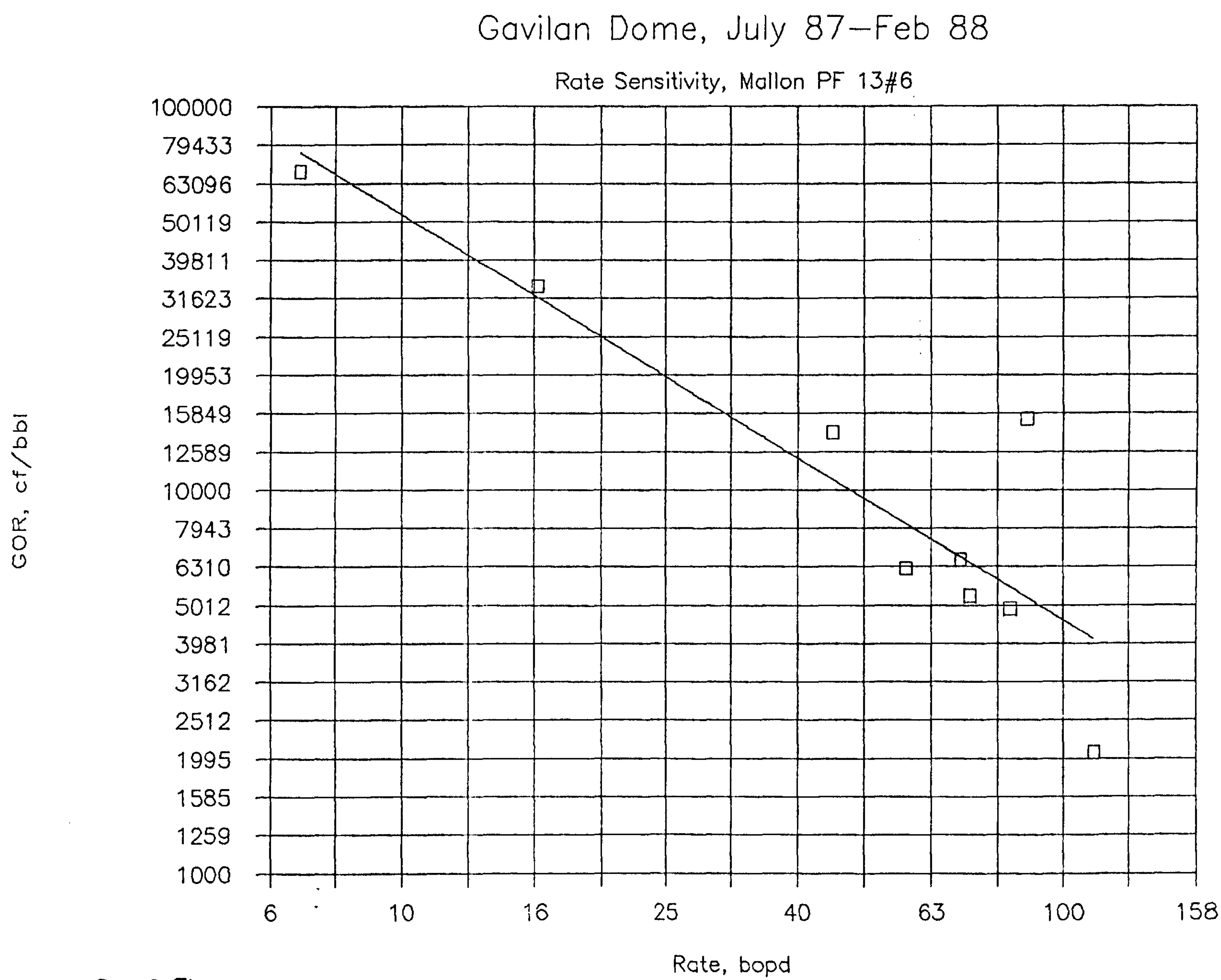
Rate Sensitivity, Mallon HF 1#11



C.C. = 0.97

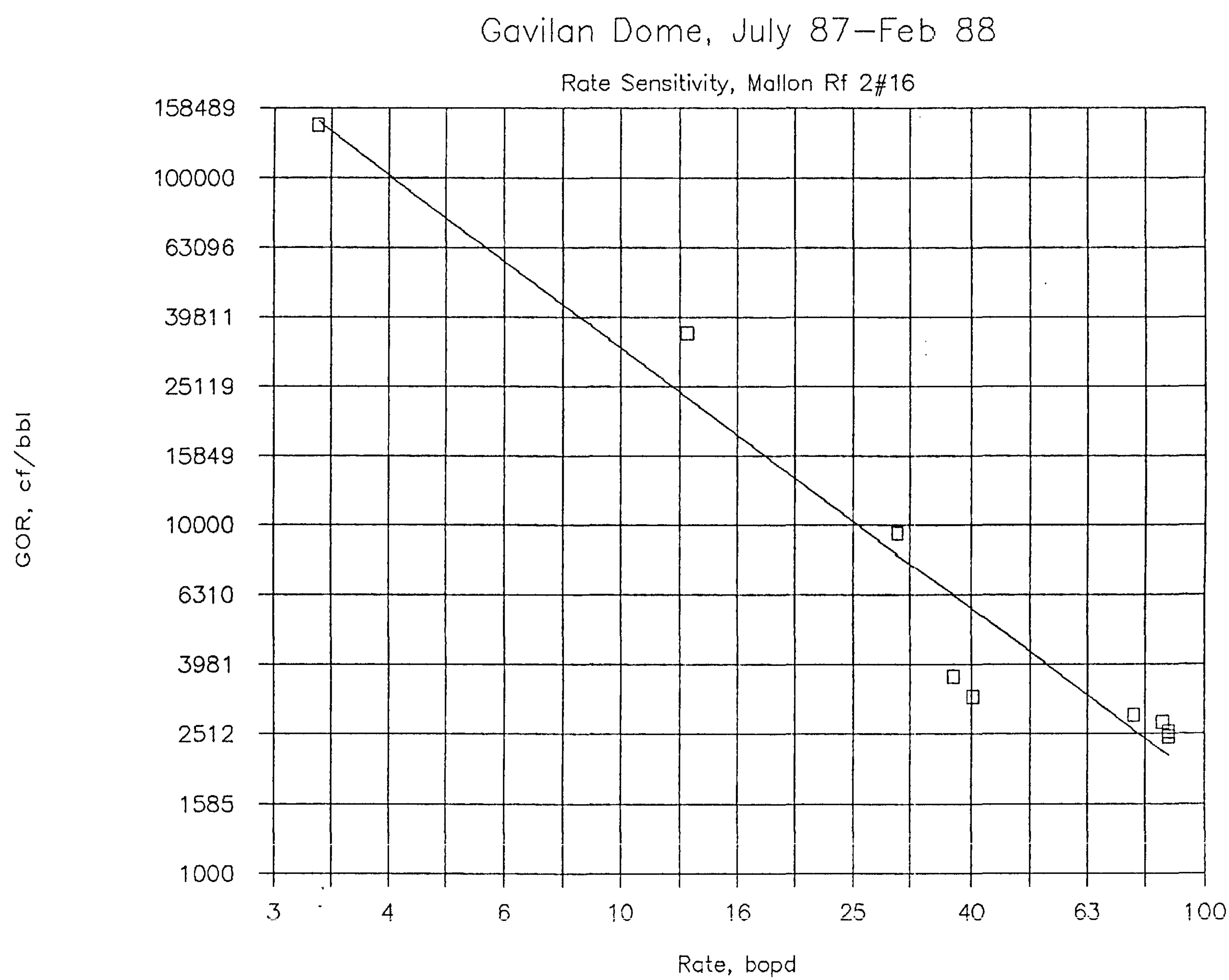

Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Mallon JF 12#5
GOR, cf/bbl
100000
79433
63096
50119
39811
31623
25119
19953
15849
12589
10000
7943
6310
5012
3981
8
13
20
32
50
79
Rate, bopd

C.C. = 1.00



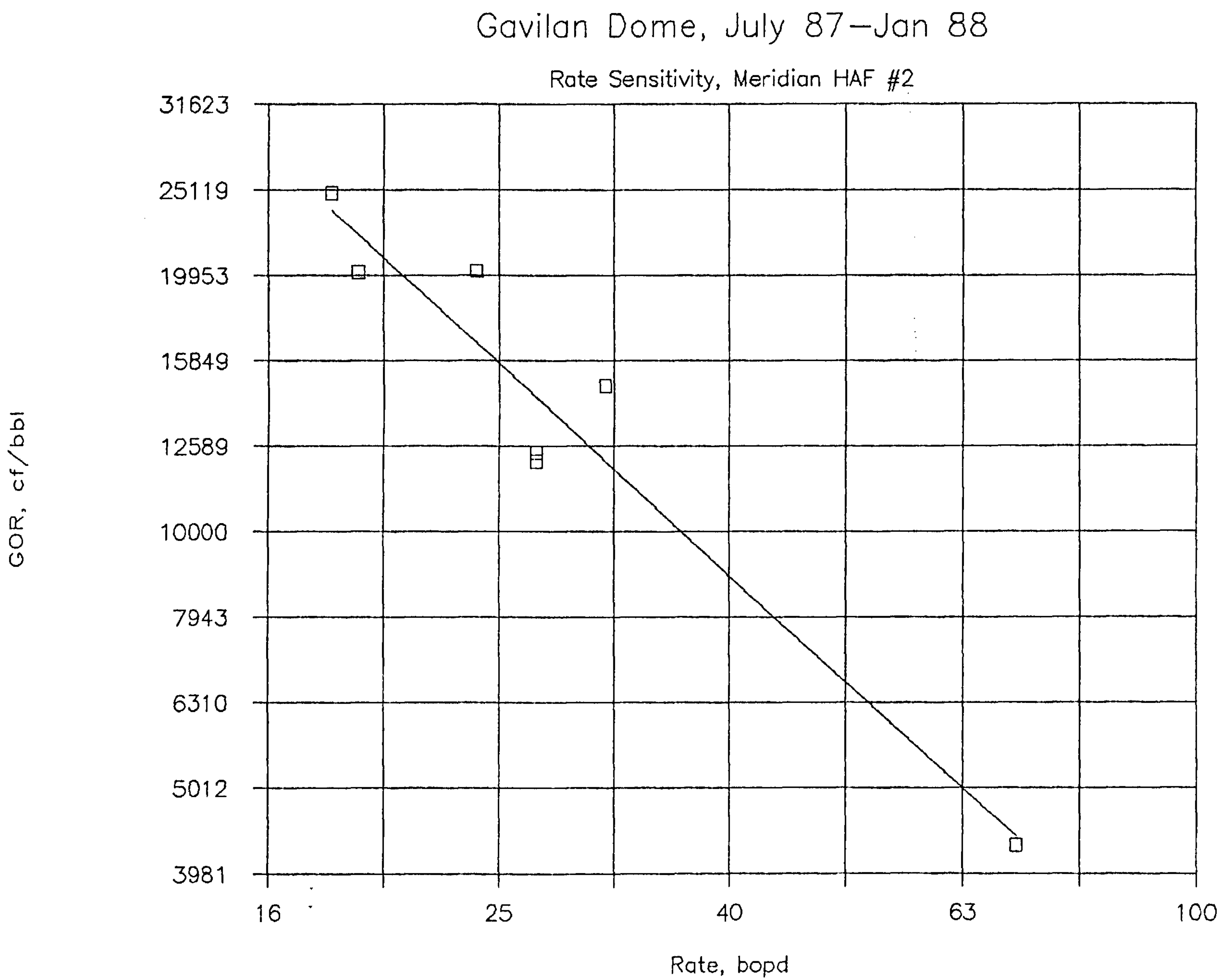
Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Mallon PF 13#6
GOR, cf/bbl
100000
79433
63096
50119
39811
31623
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
1000
6
10
16
25
40
63
100
158
Rate, bopd

C.C. = 0.89



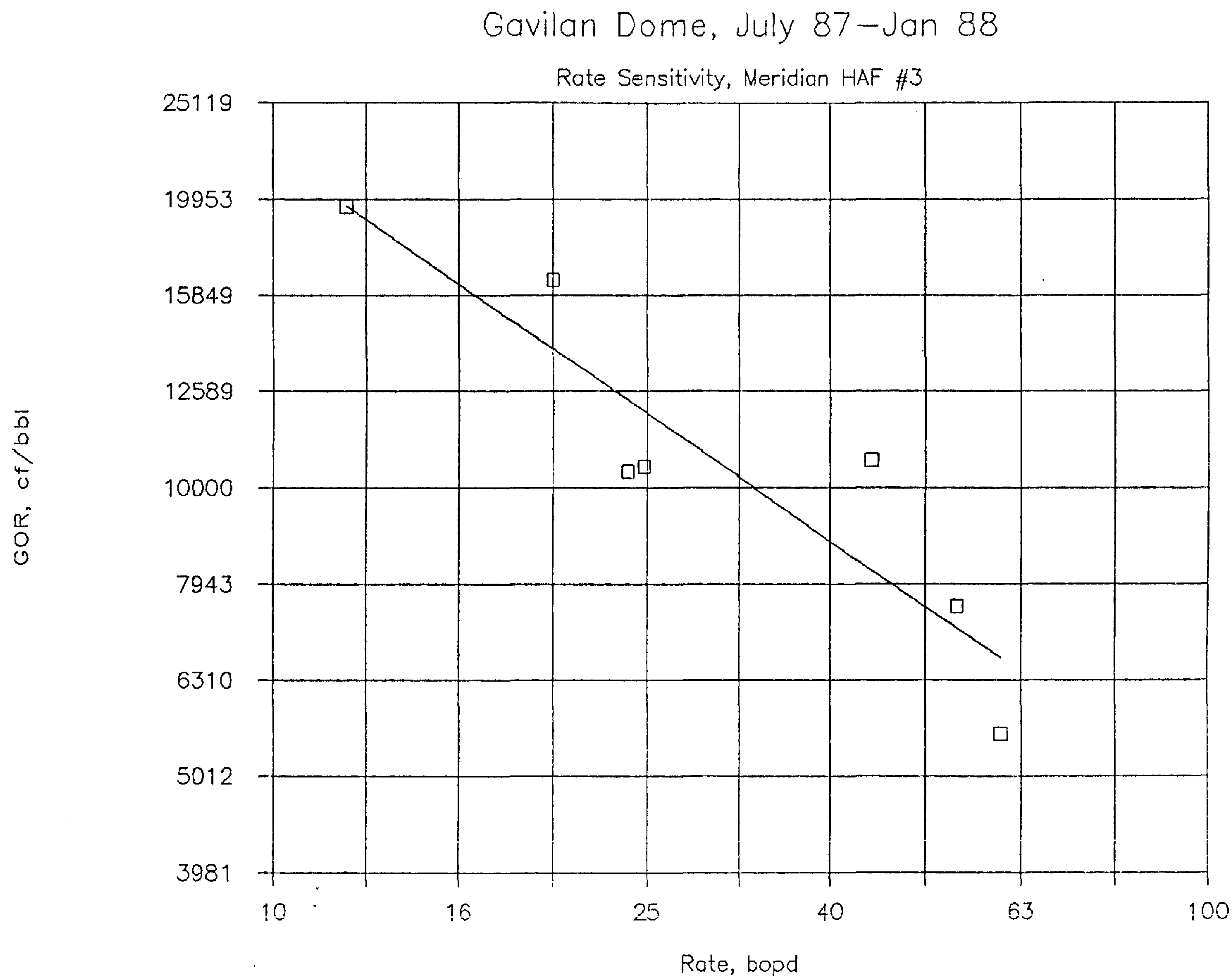
Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Mallon Rf 2#16
GOR, cf/bbl
158489
100000
63096
39811
25119
15849
10000
6310
3981
2512
1585
1000
3
4
6
10
16
25
40
63
100
Rate, bopd

C.C. = 0.97



Gavilan Dome, July 87—Jan 88
Rate Sensitivity, Meridian HAF #2
GOR, cf/bbl
31623
25119
19953
15849
12589
10000
7943
6310
5012
3981
16
25
40
63
100
Rate, bopd

C. C. = 0.96

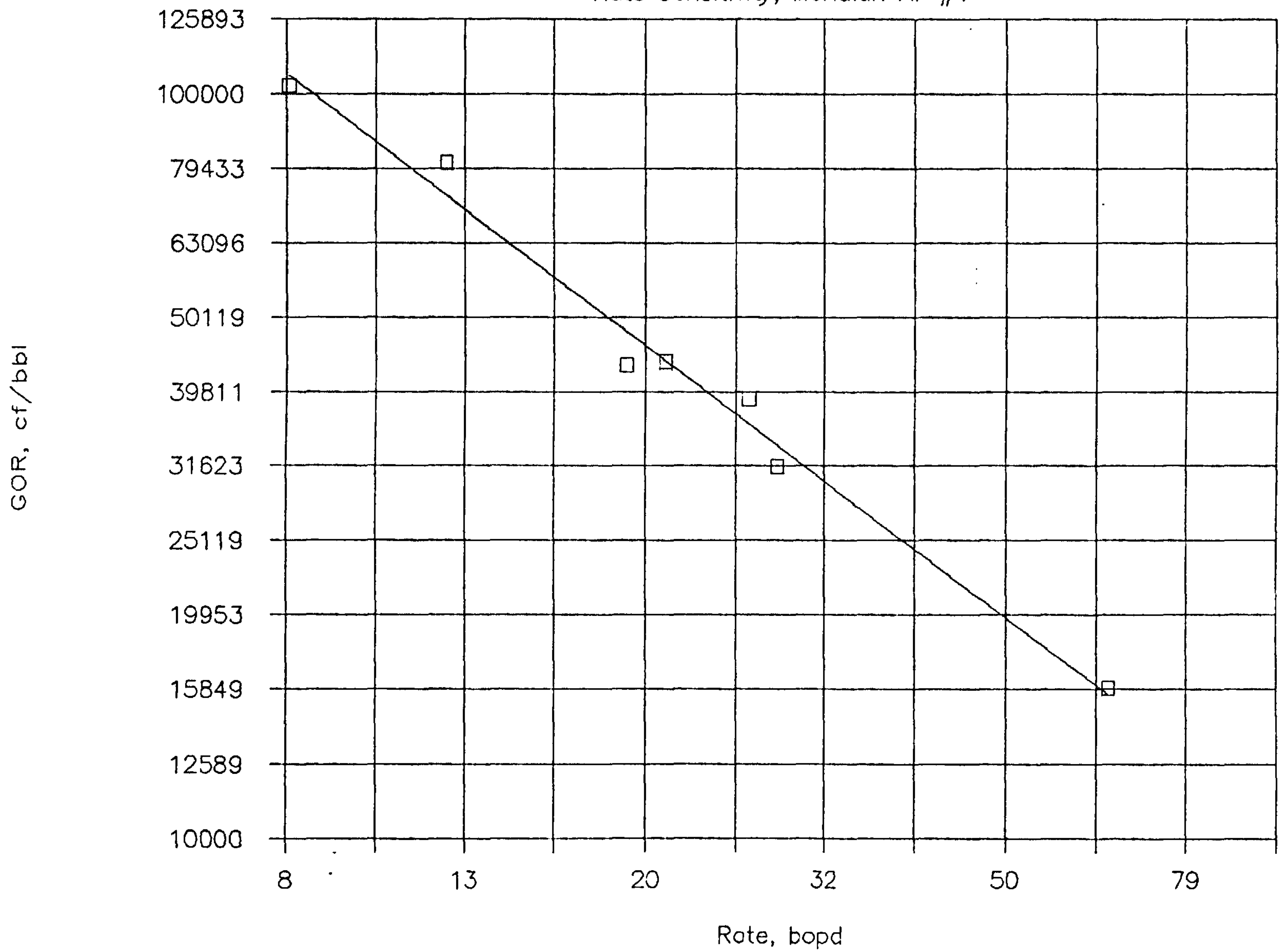


Gavilan Dome, July 87—Jan 88
Rate Sensitivity, Meridian HAF #3
GOR, cf/bbl
25119
19953
15849
12589
10000
7943
6310
5012
3981
10
16
25
40
63
100
Rate, bopd

C.C. = 0.92

Gavilan Dome, July 87–Jan 88

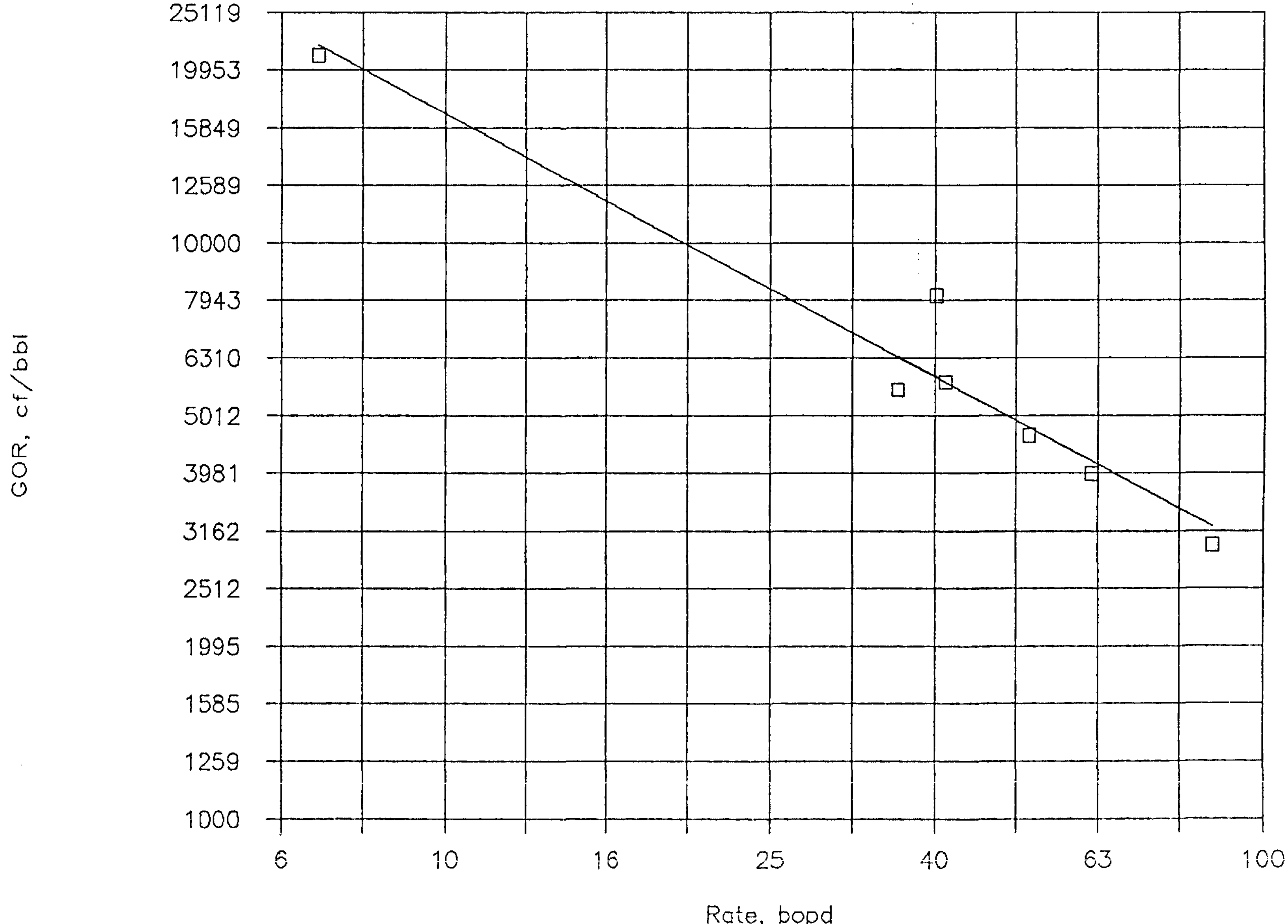
Rate Sensitivity, Meridian HF #1



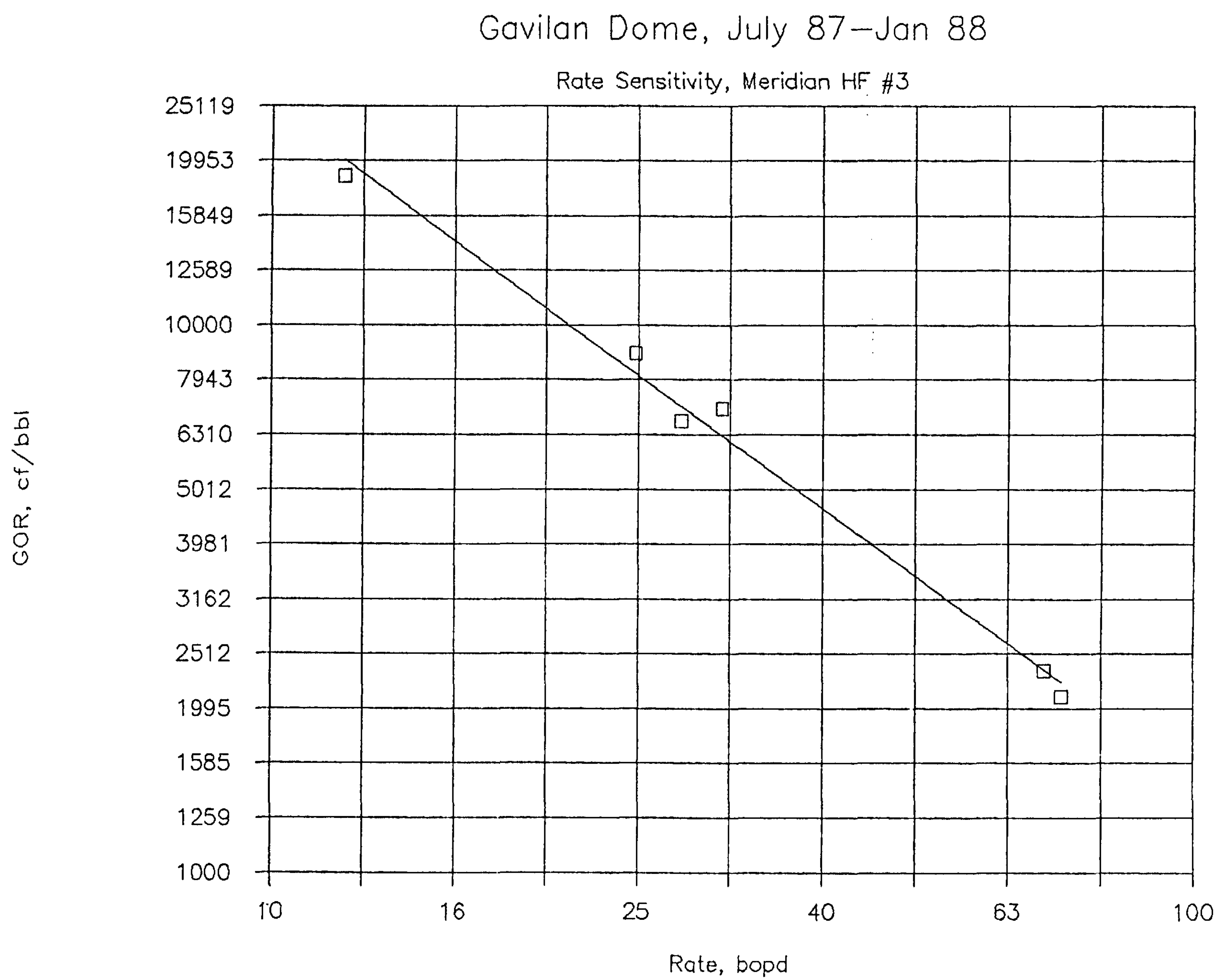
C.C. = 0.99

Gavilan Dome, June 87—Jan 88

Rate Sensitivity, Meridian HF #2Y



C.C. = 0.97

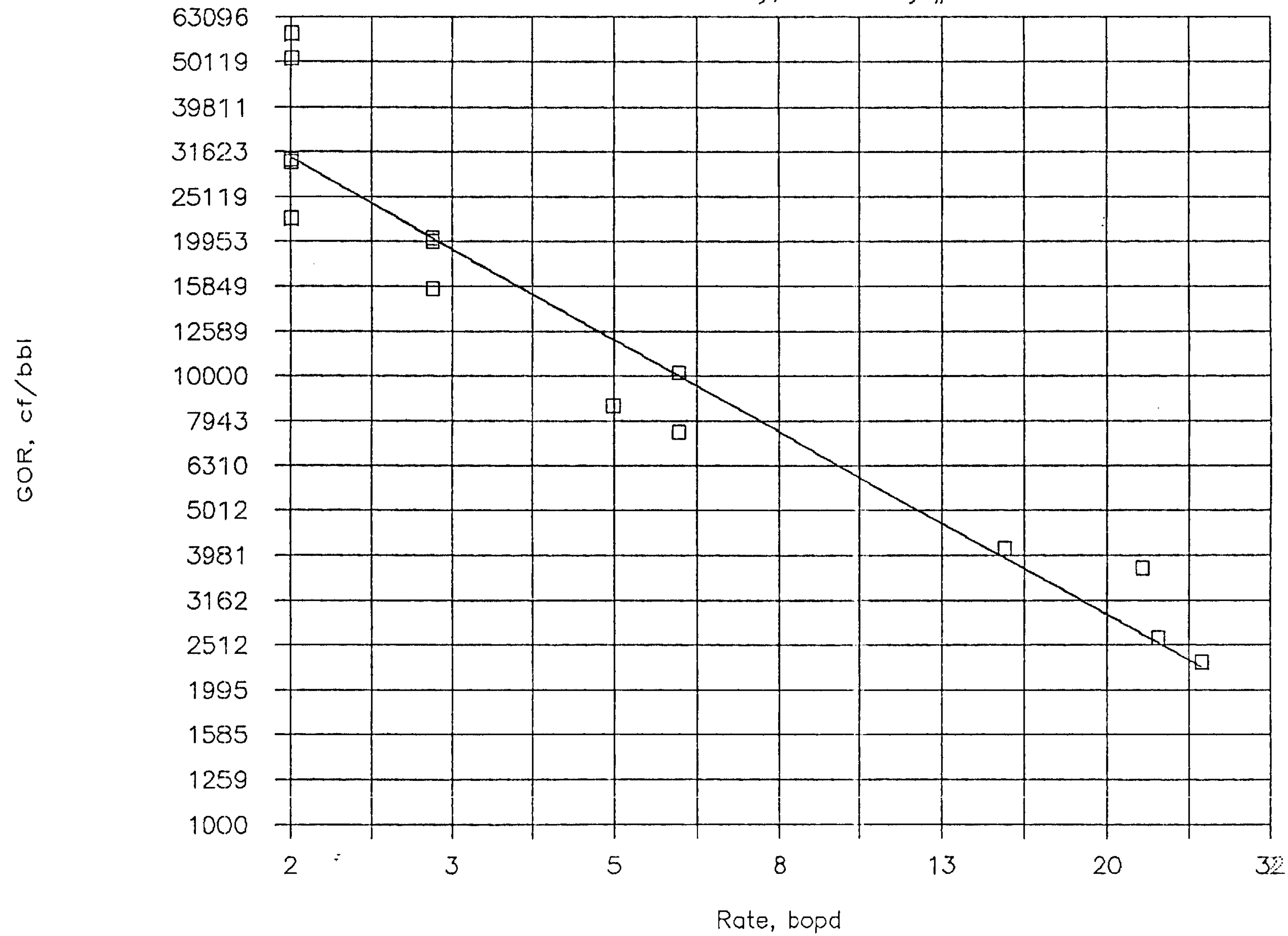


Gavilan Dome, July 87—Jan 88
Rate Sensitivity, Meridian HF #3
GOR, cf/bbl
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
1000
10
16
25
40
63
100
Rate, bopd

C. C. = 1,00

Gavilan Dome, 1/1–2/15/88

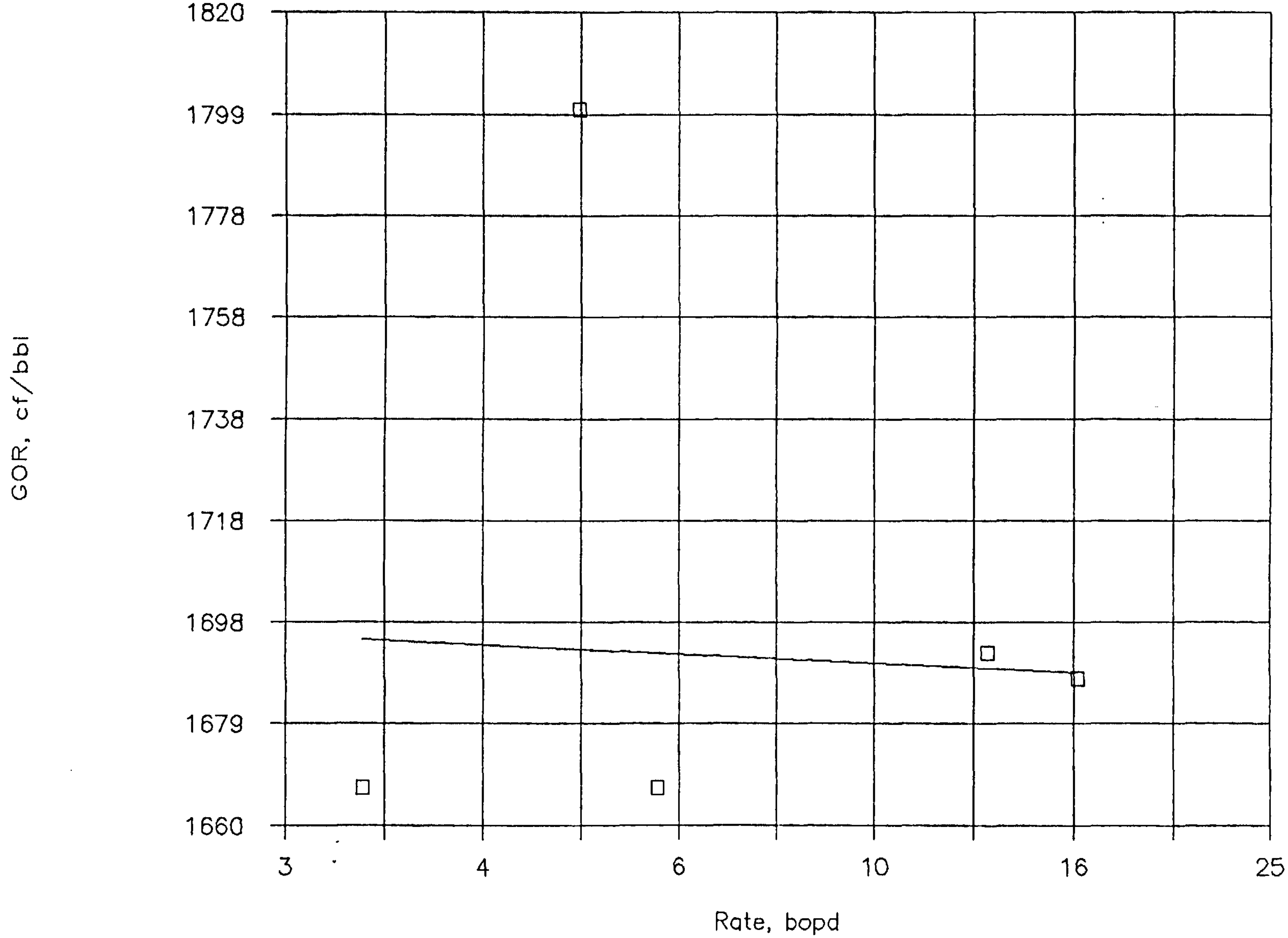
Rate Sensitivity, Merrion Kry #1



C.C. = 0.96

Gavilan Dome, July 87

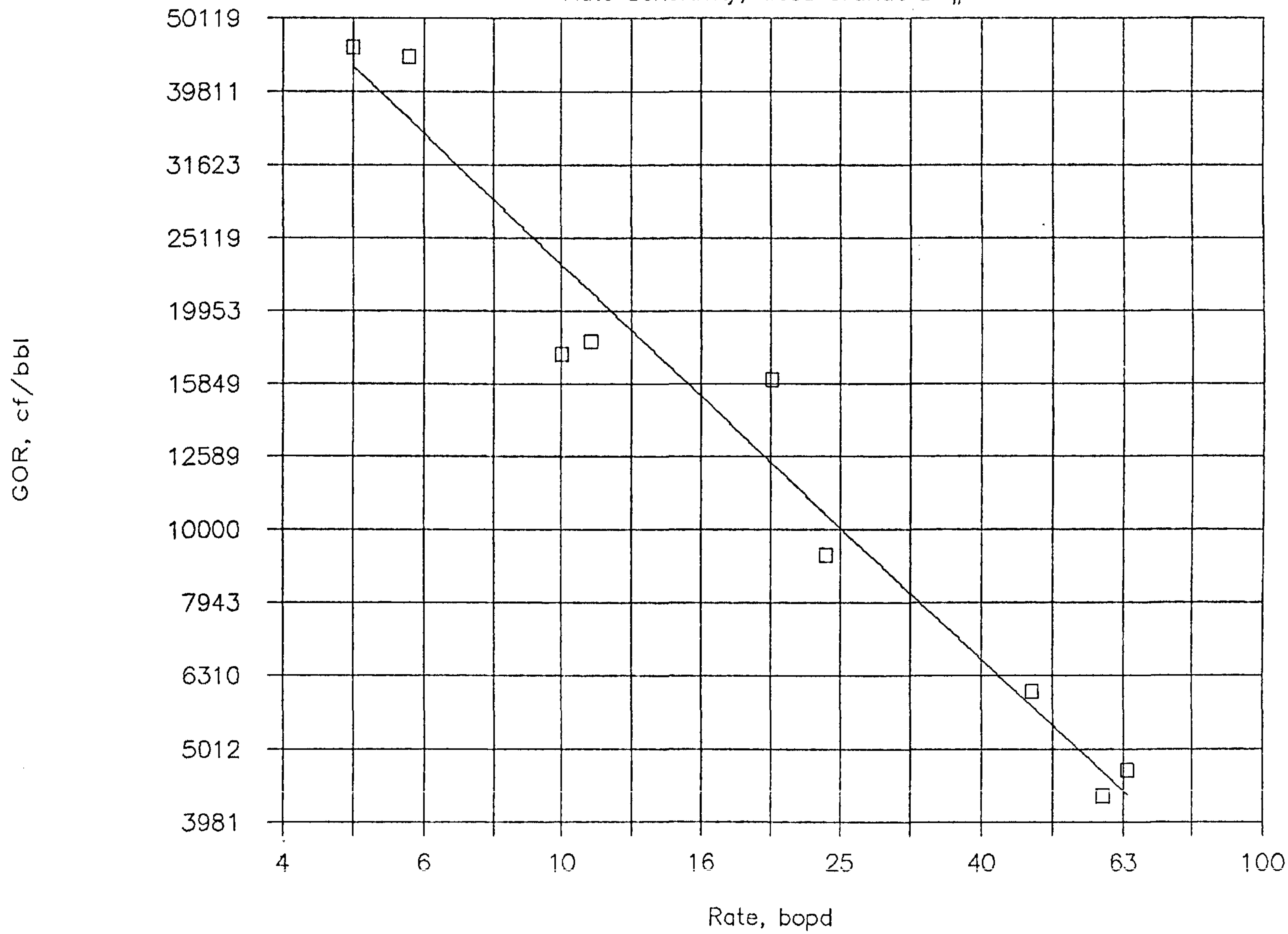
Rate Sensitivity, Merrion OCG #1



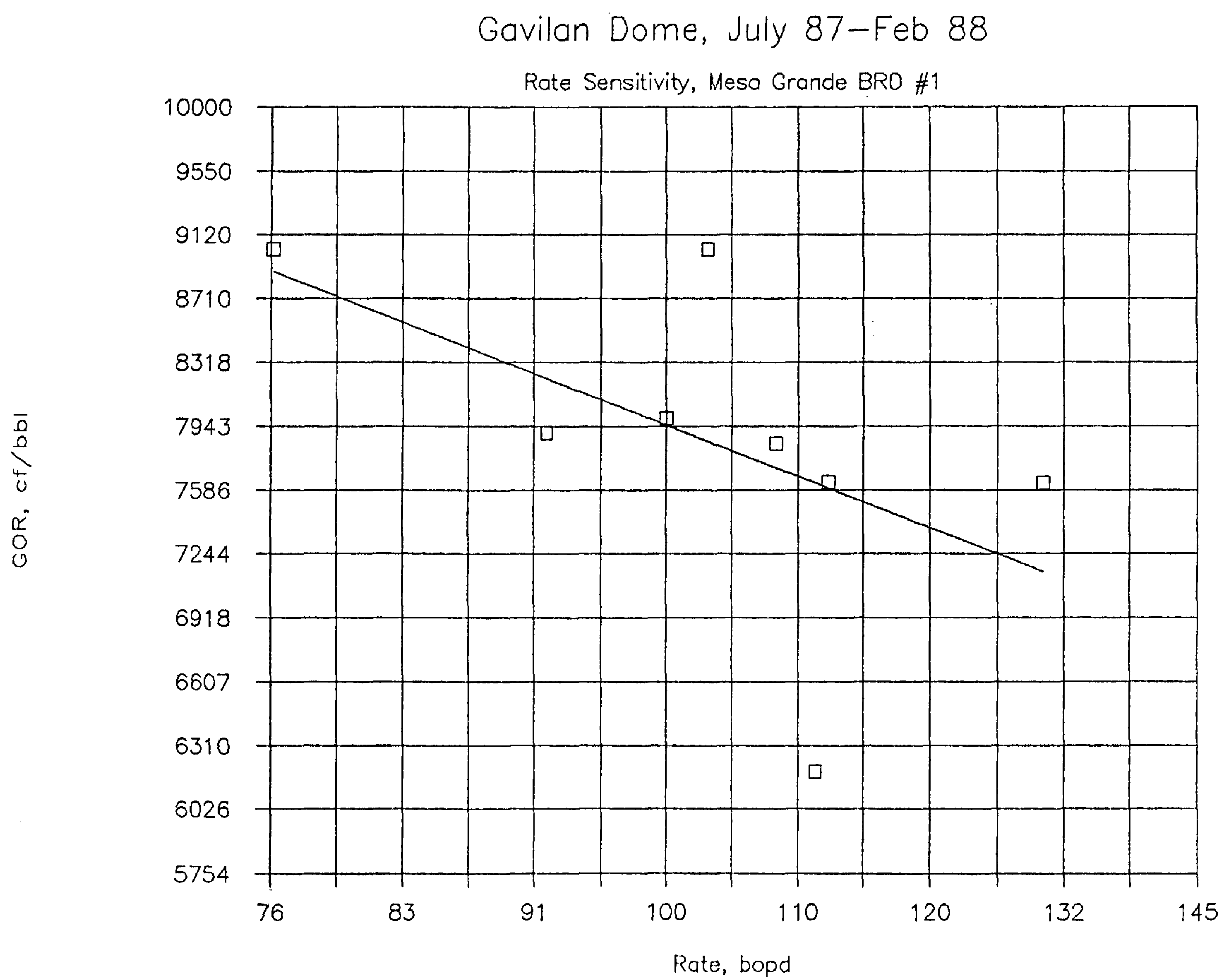
C. C. = 0.15

Gavilan Dome, July 87—Feb 88

Rate Sensitivity, Mesa Grande BC#1



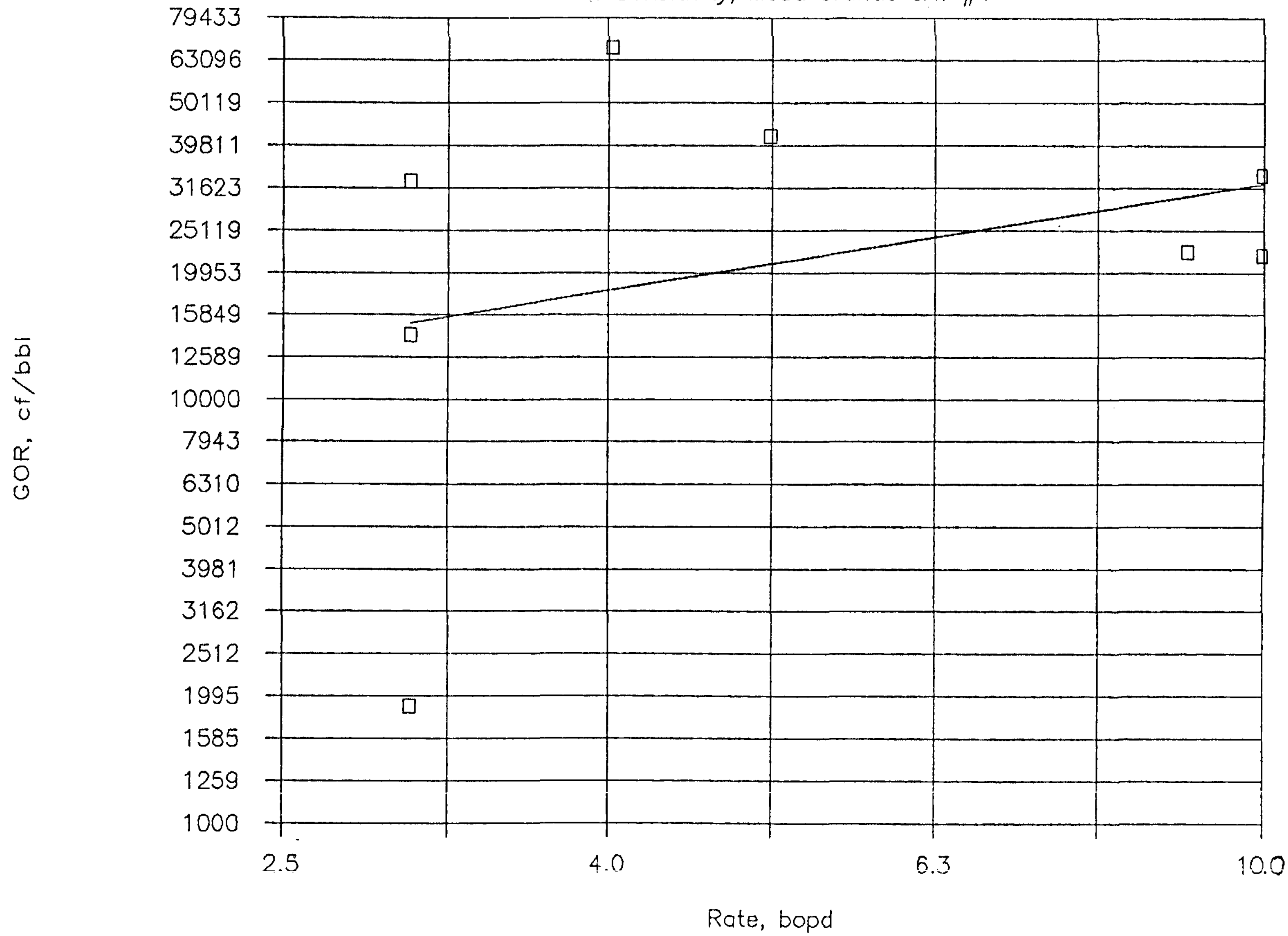
C.C. = 0.98


Gavilan Dome, July 87–Feb 88
Rate Sensitivity, Mesa Grande BRO #1
GOR, cf/bbl
10000
9550
9120
8710
8318
7943
7586
7244
6918
6607
6310
6026
5754
76
83
91
100
110
120
132
145
Rate, bopd

C.C. = 0.54

Gavilan Dome, July 87–Feb 88

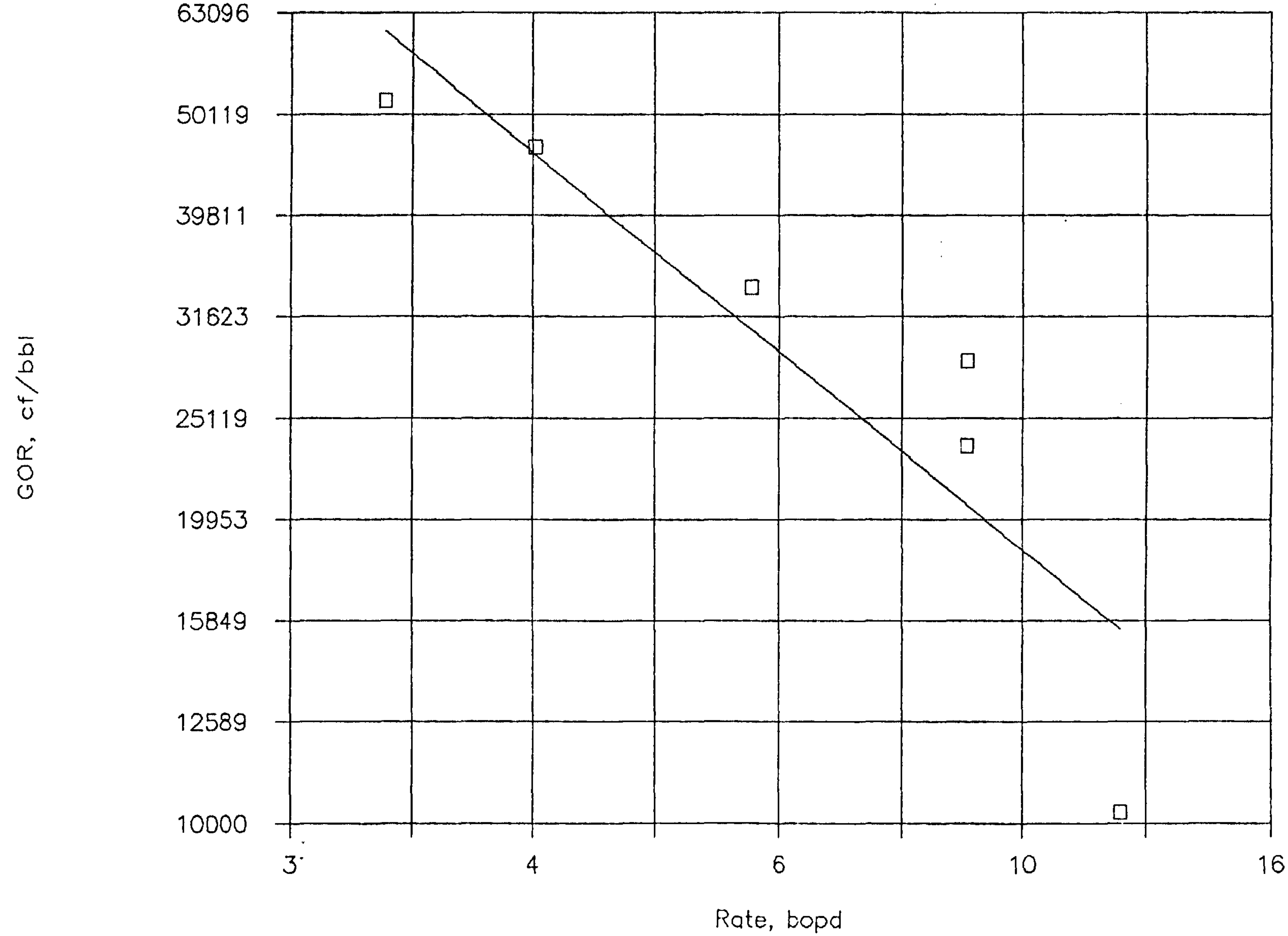
Rate Sensitivity, Mesa Grande GAV #1



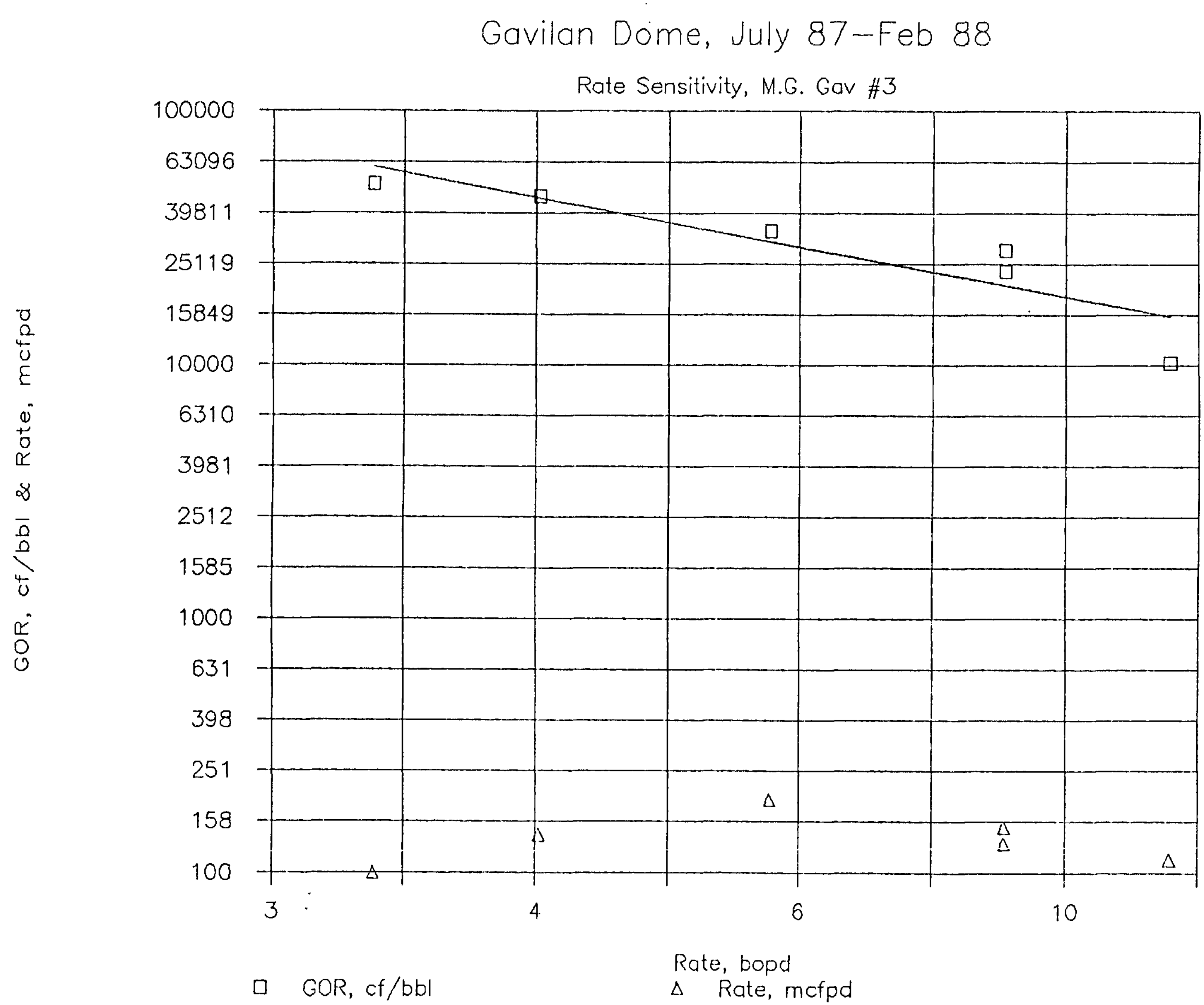
C. C. = 0.32

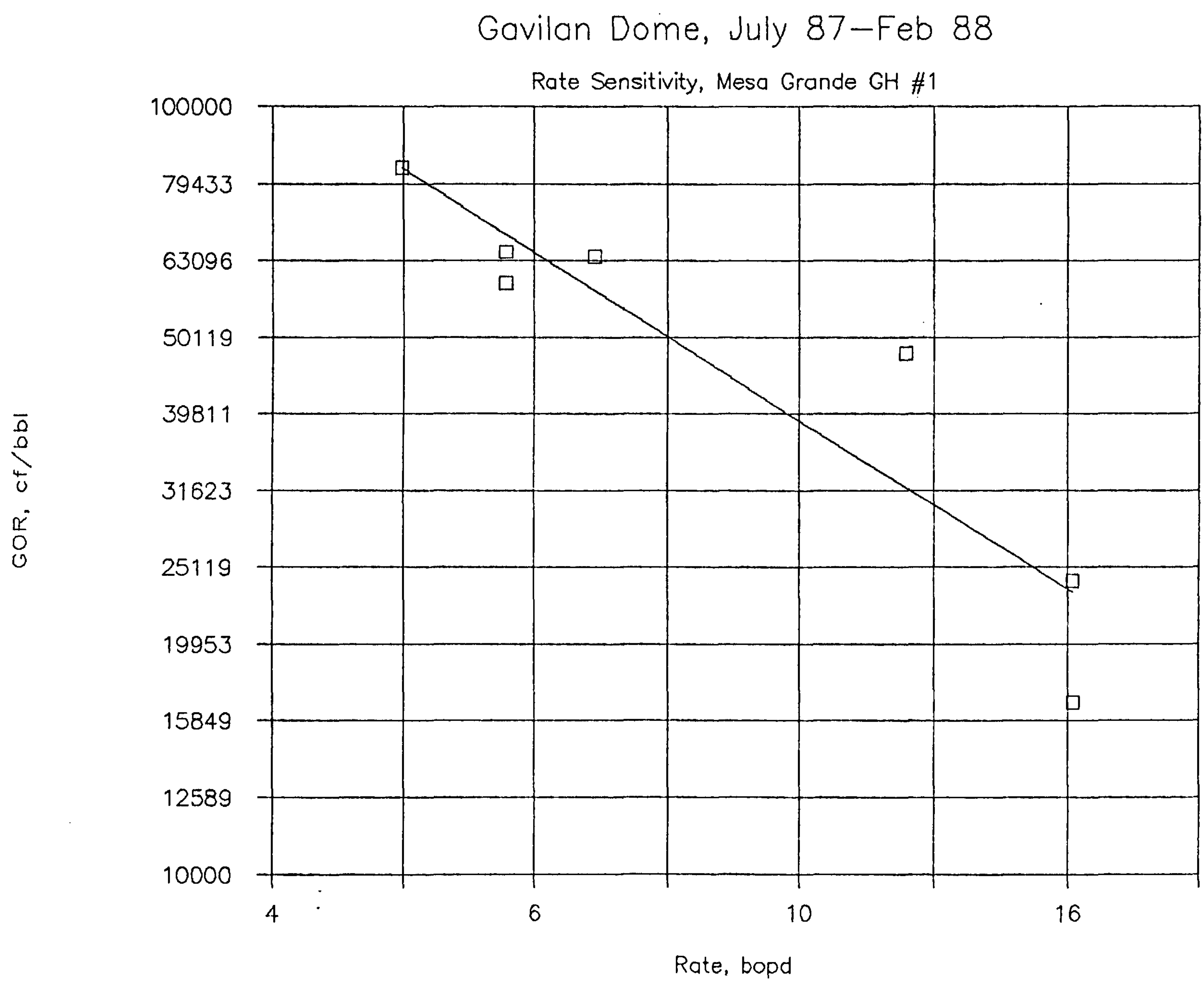
Gavilan Dome, July 87–Feb 88

Rate Sensitivity, Mesa Grande GAV #3



C.C. = 0.90

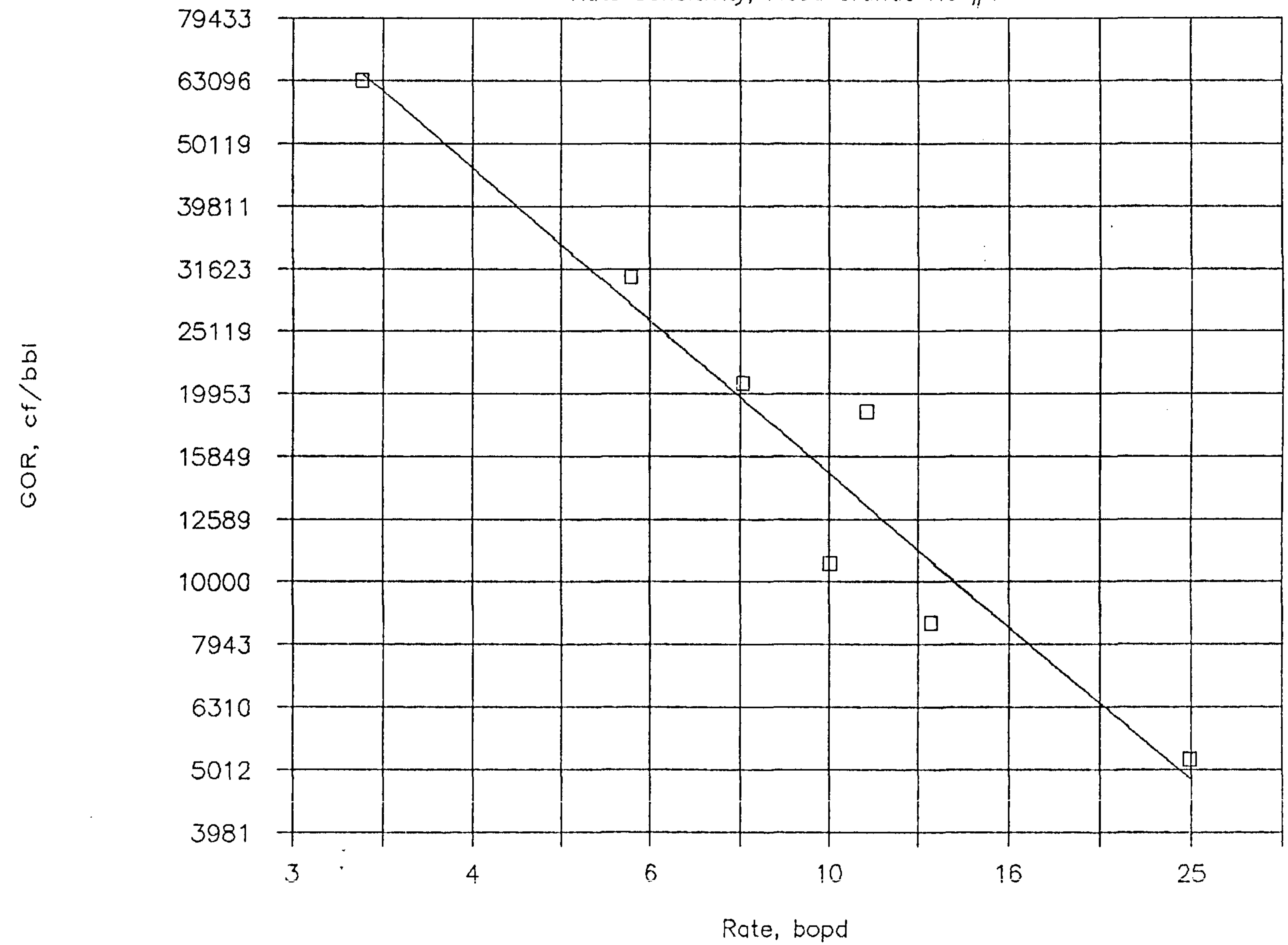

Gavilan Dome, July 87—Feb 88
Rate Sensitivity, M.G. Gav #3
100000
63096
39811
25119
15849
10000
6310
3981
2512
1585
1000
631
398
251
158
100
GOR, cf/bbl & Rate, mcfpd
3
4
6
10
Rate, bopd
GOR, cf/bbl
Rate, mcfpd


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Mesa Grande GH #1
GOR, cf/bbl
100000
79433
63096
50119
39811
31623
25119
19953
15849
12589
10000
4
6
10
16
Rate, bopd

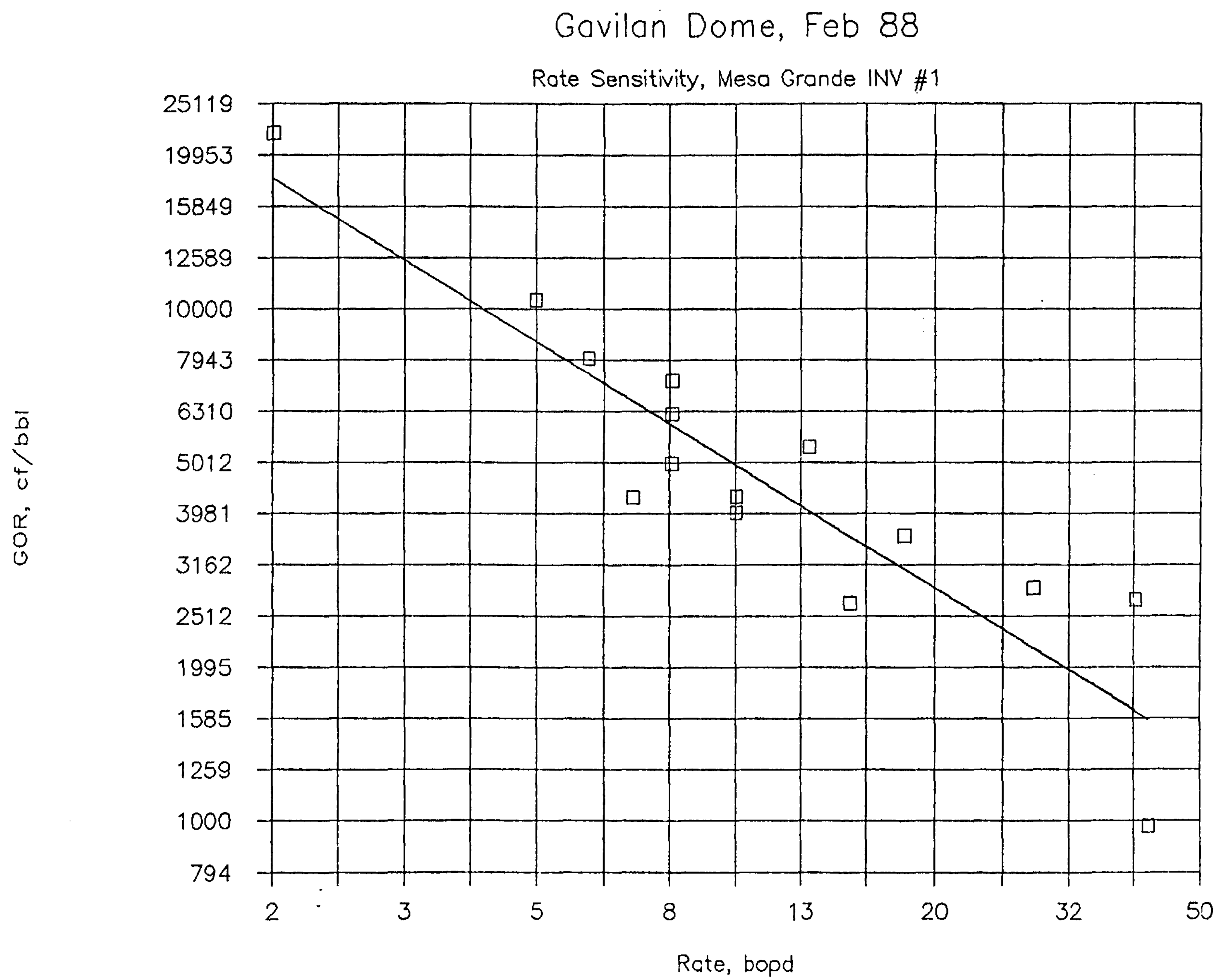
C.C. = 0.92

Gavilan Dome, Aug 87–Feb 88

Rate Sensitivity, Mesa Grande HC #1

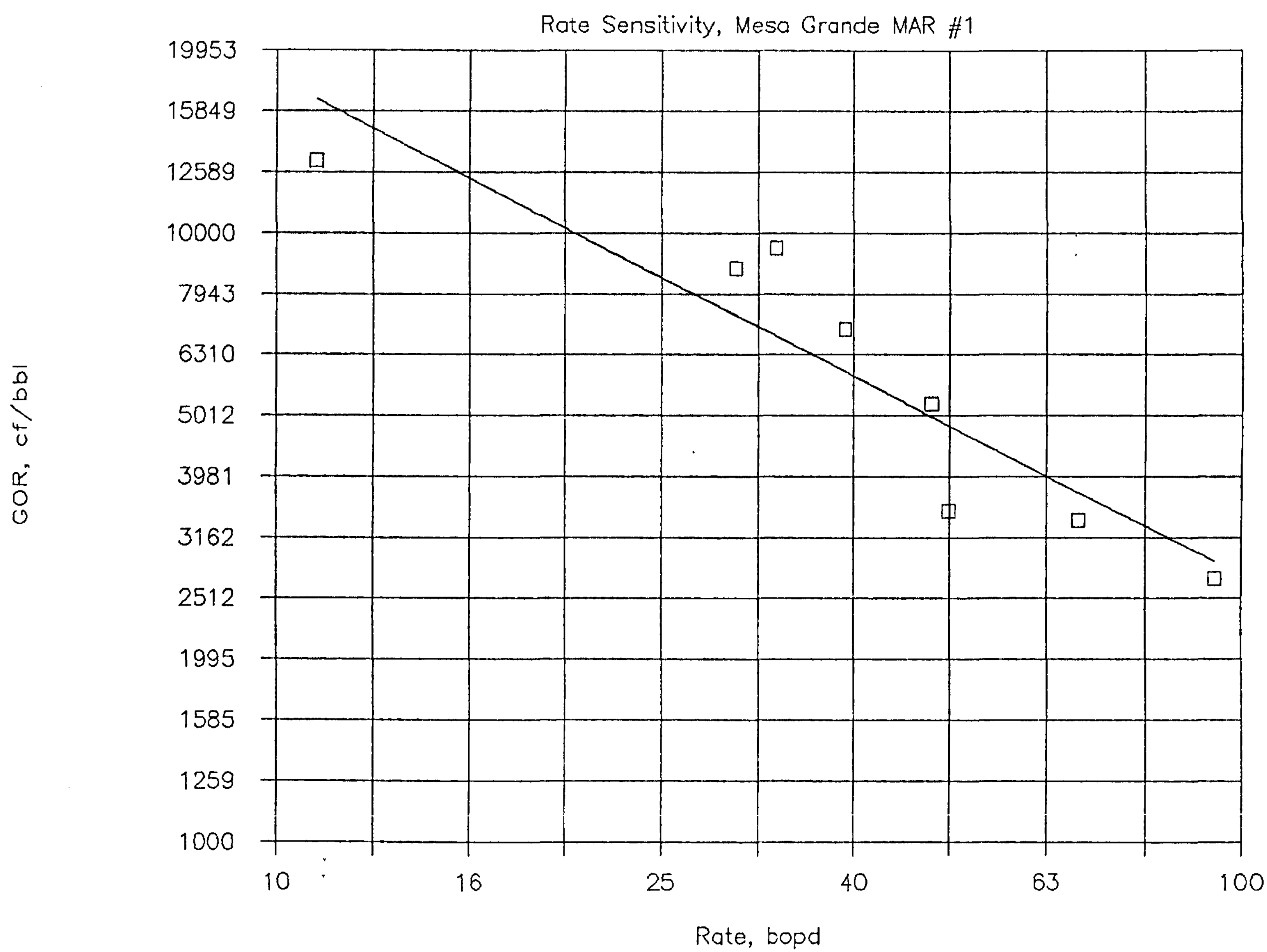


C. C. ≈ 0.96


Gavilan Dome, Feb 88
Rate Sensitivity, Mesa Grande INV #1
GOR, cf/bbl
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
1000
794
2
3
5
8
13
20
32
50
Rate, bopd

C.C. = 0.91

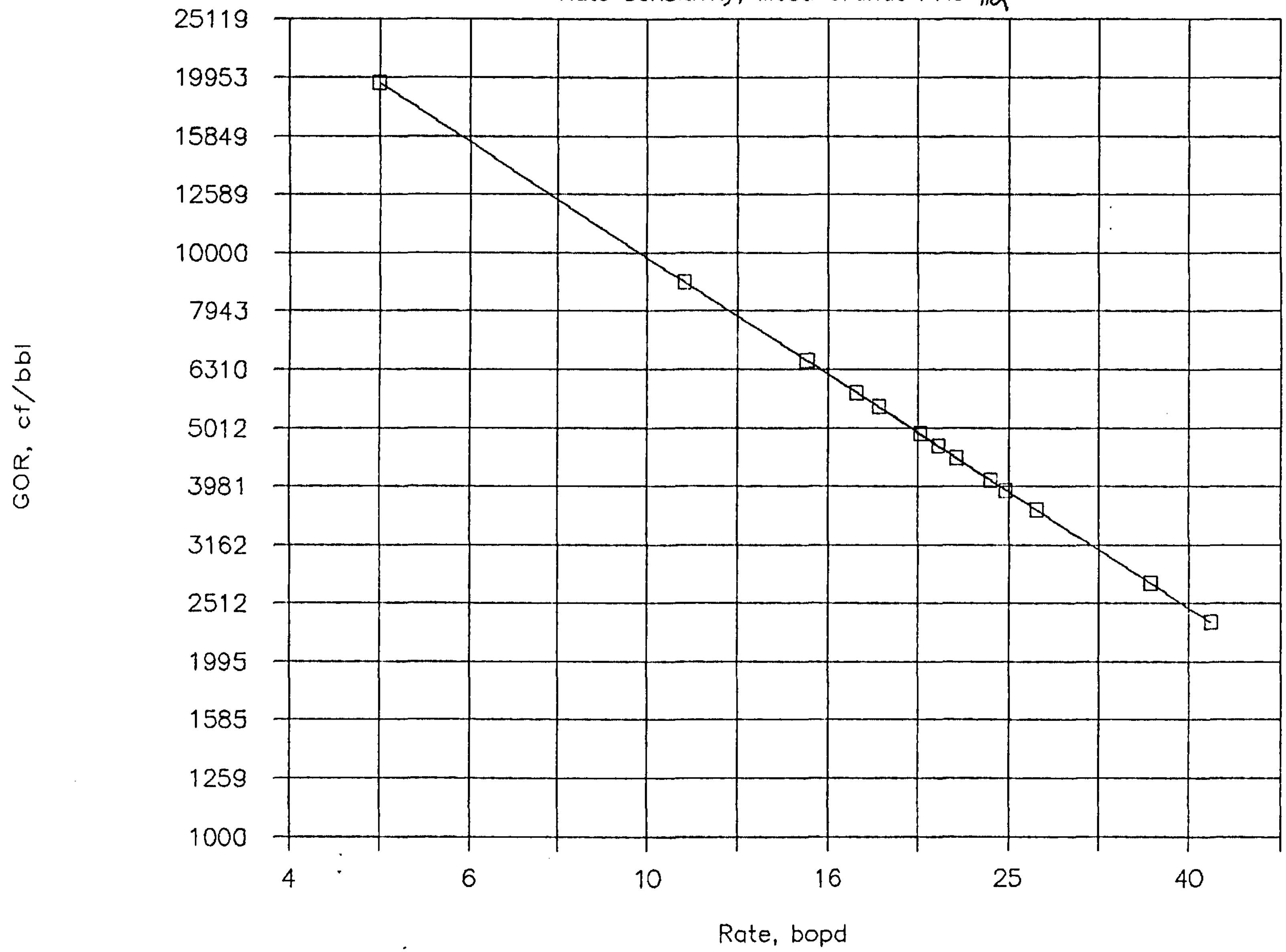
Gavilan Dome, July 87–Feb 88



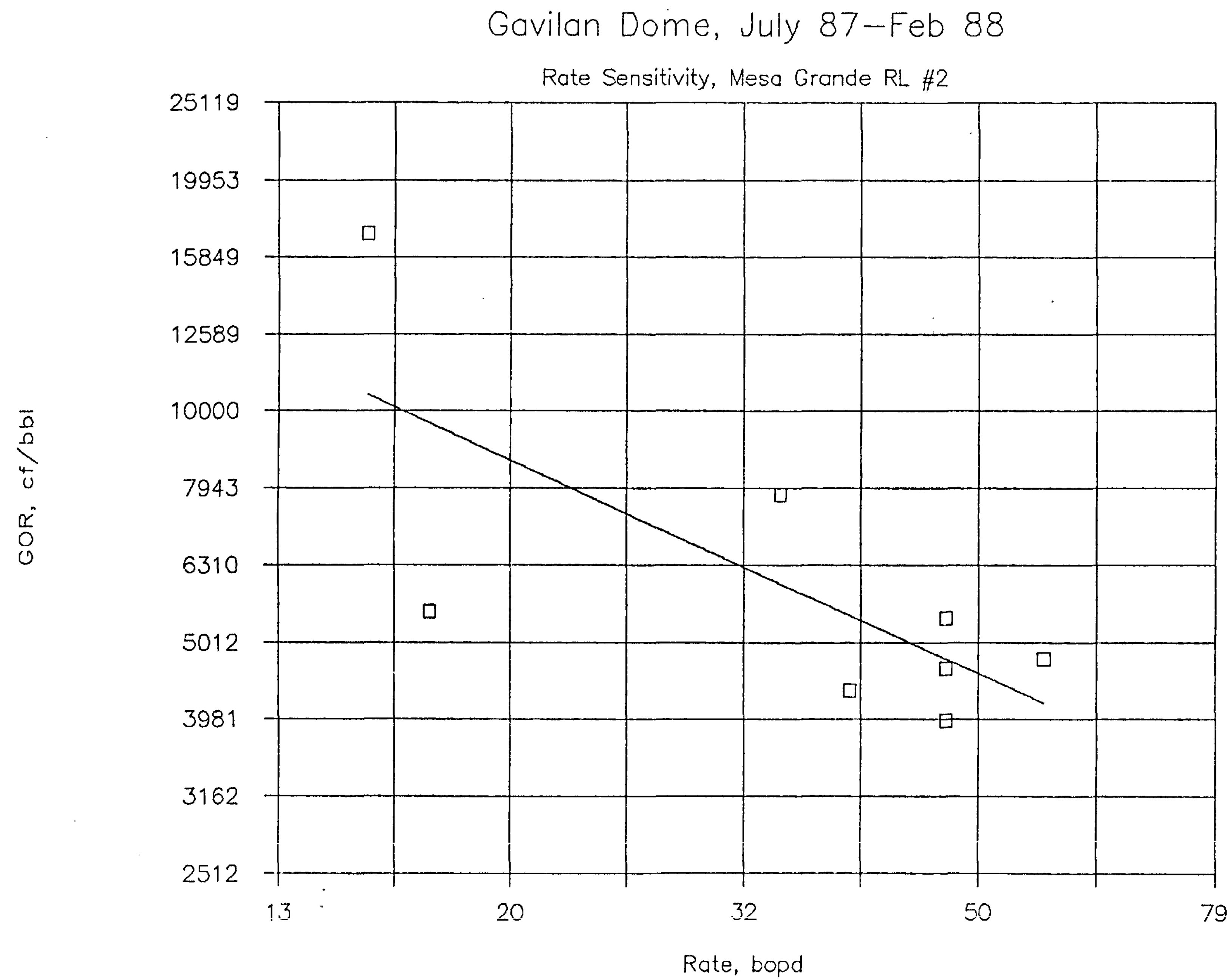
C. C. = 0.92

Gavilan Dome, Feb 88

Rate Sensitivity, Mesa Grande PRO #2

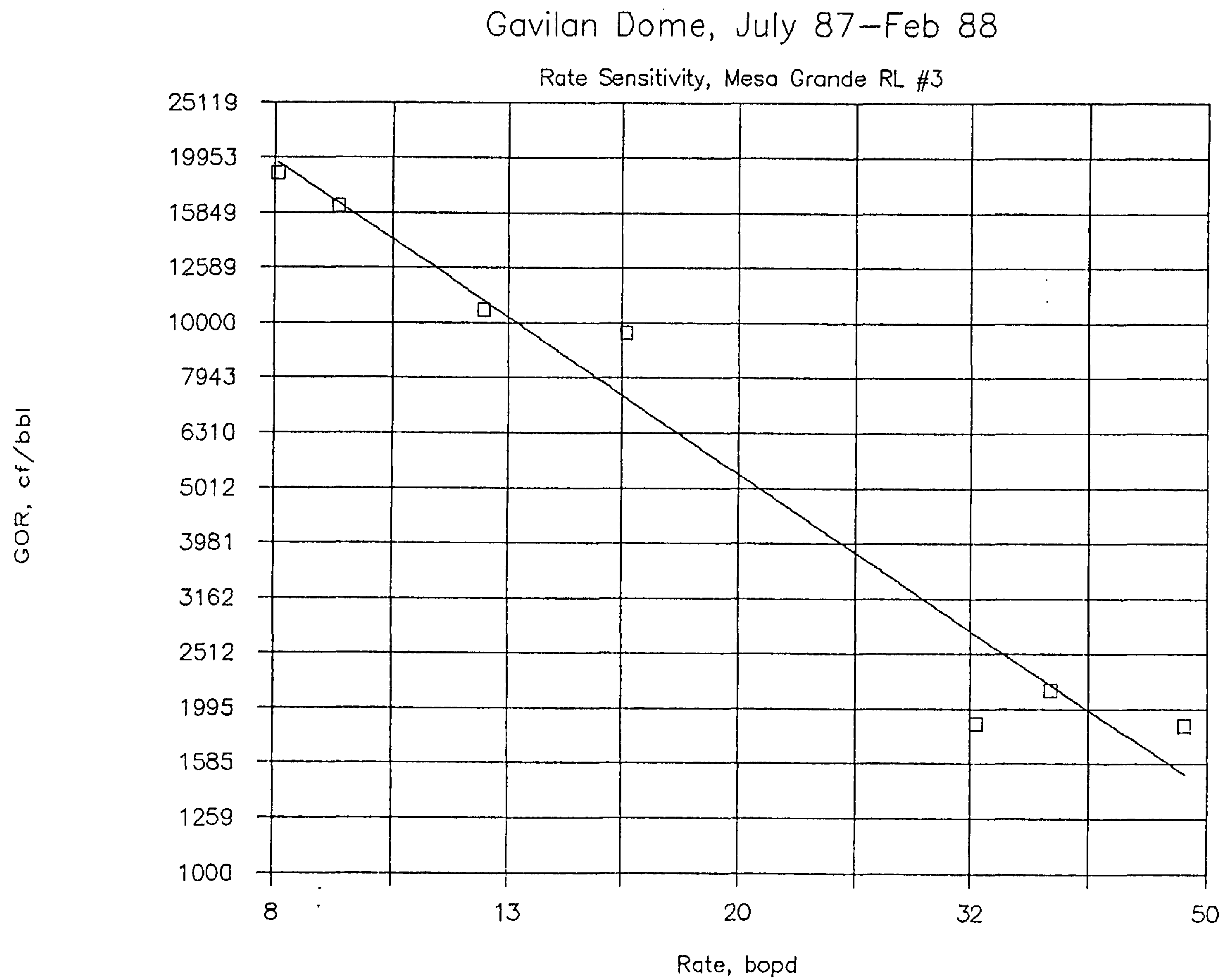


C.C. = 1.00

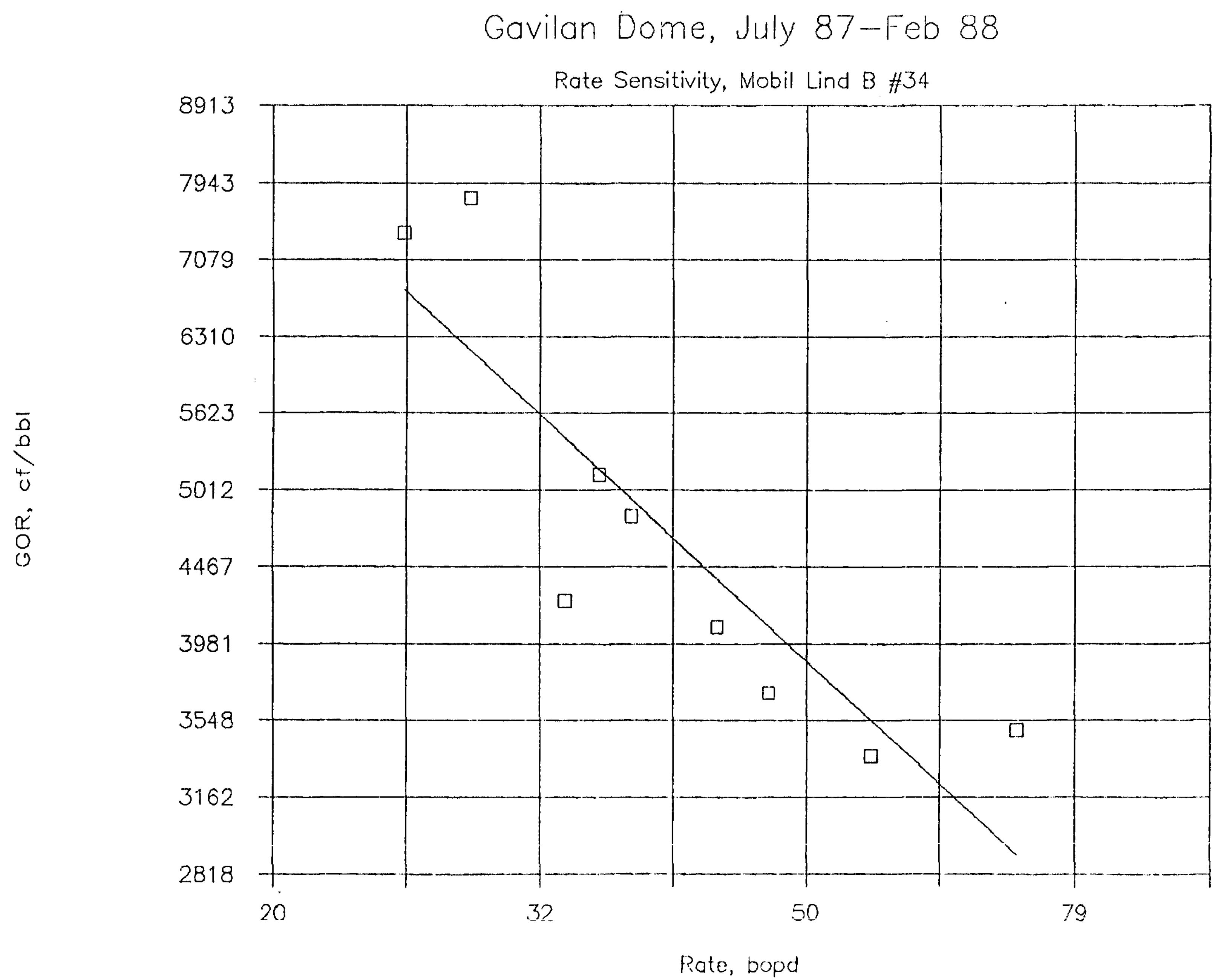


Gavilan Dome, July 87–Feb 88
Rate Sensitivity, Mesa Grande RL #2
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
GOR, cf/bbl
13
20
32
50
79
Rate, bopd

C.C. = 0.73

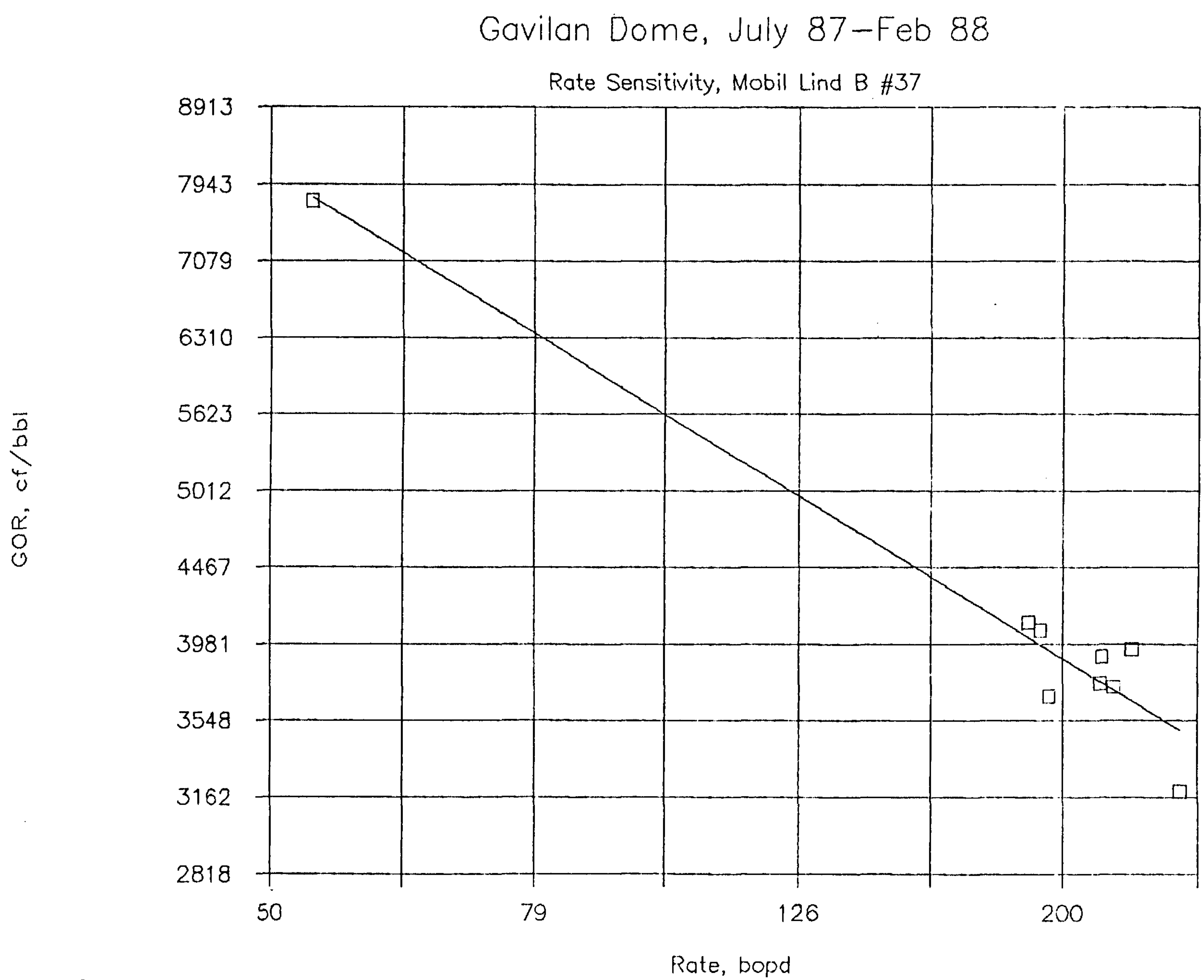

Gavilan Dome, July 87–Feb 88
Rate Sensitivity, Mesa Grande RL #3
GOR, cf/bbl
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
1000
8
13
20
32
50
Rate, bopd

C.C.= 0.98



Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Mobil Lind B #34
GOR, cf/bbl
8913
7943
7079
6310
5623
5012
4467
3981
3548
3162
2818
20
32
50
79
Rate, bopd

C.C. = 0.88

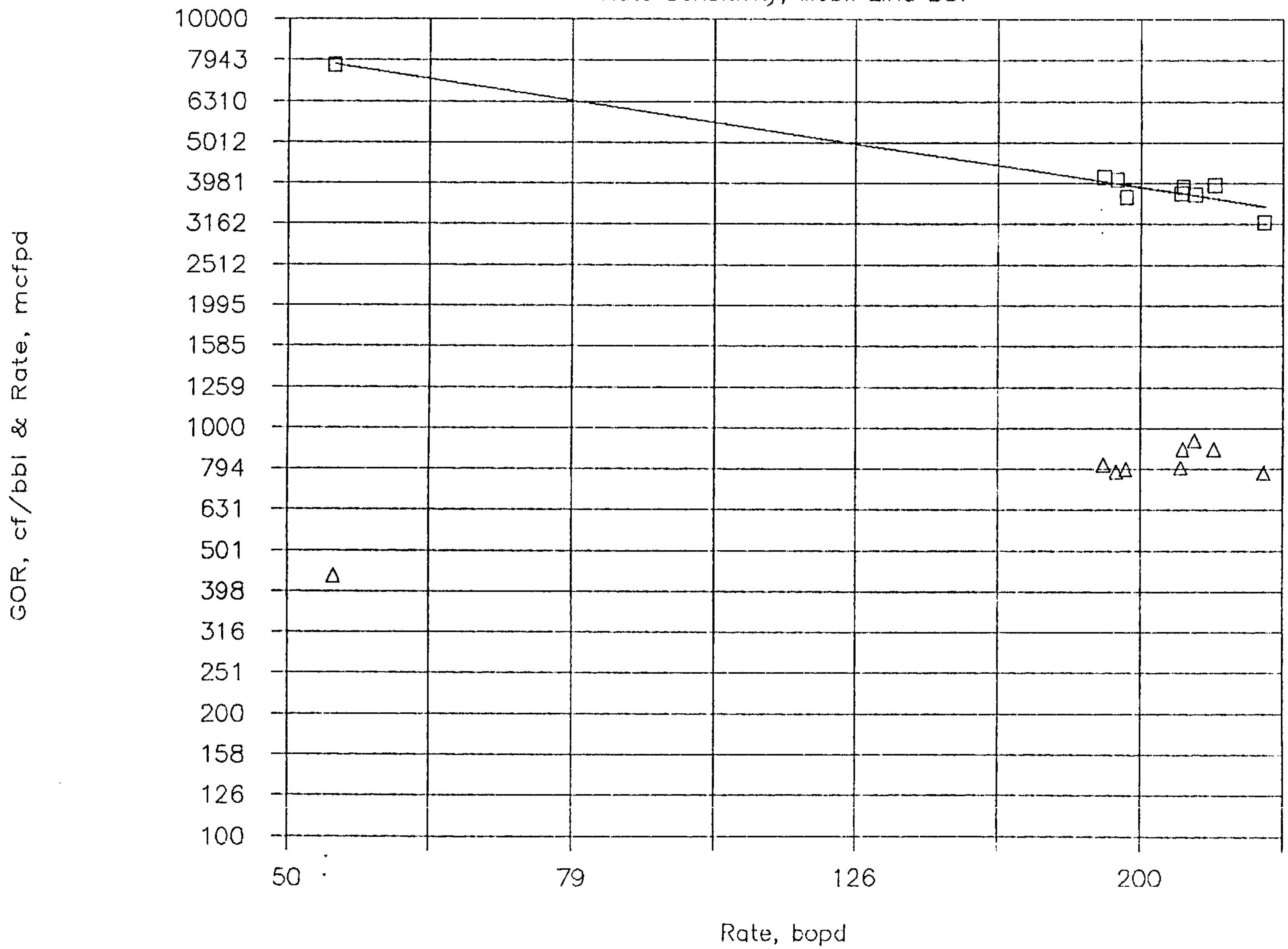


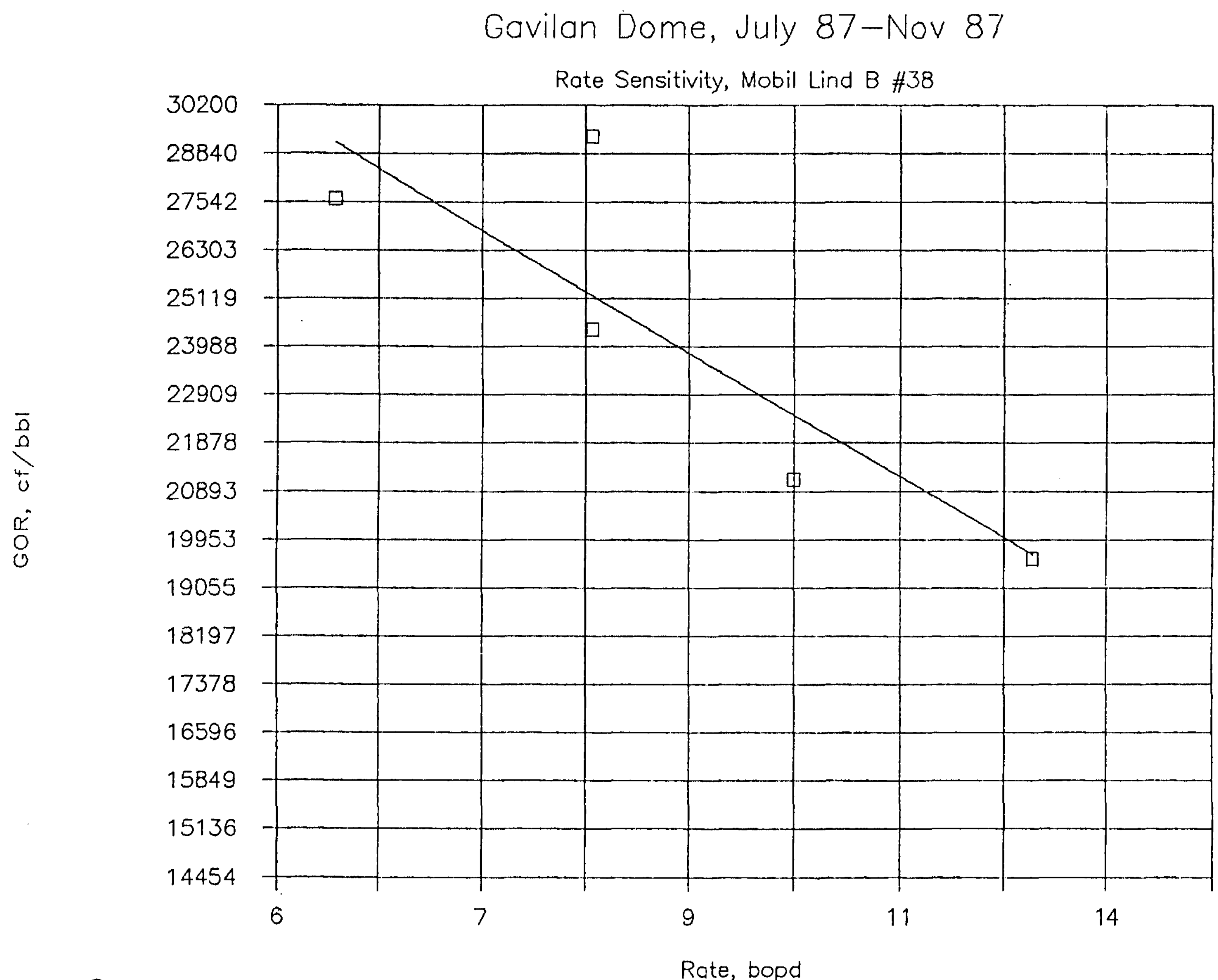
Gavilan Dome, July 87–Feb 88
Rate Sensitivity, Mobil Lind B #37
GOR, cf/bbl
8913
7943
7079
6310
5623
5012
4467
3981
3548
3162
2818
50
79
126
200
Rate, bopd

C.C. = 0.98

Gavilan Dome, July 87–Feb 88

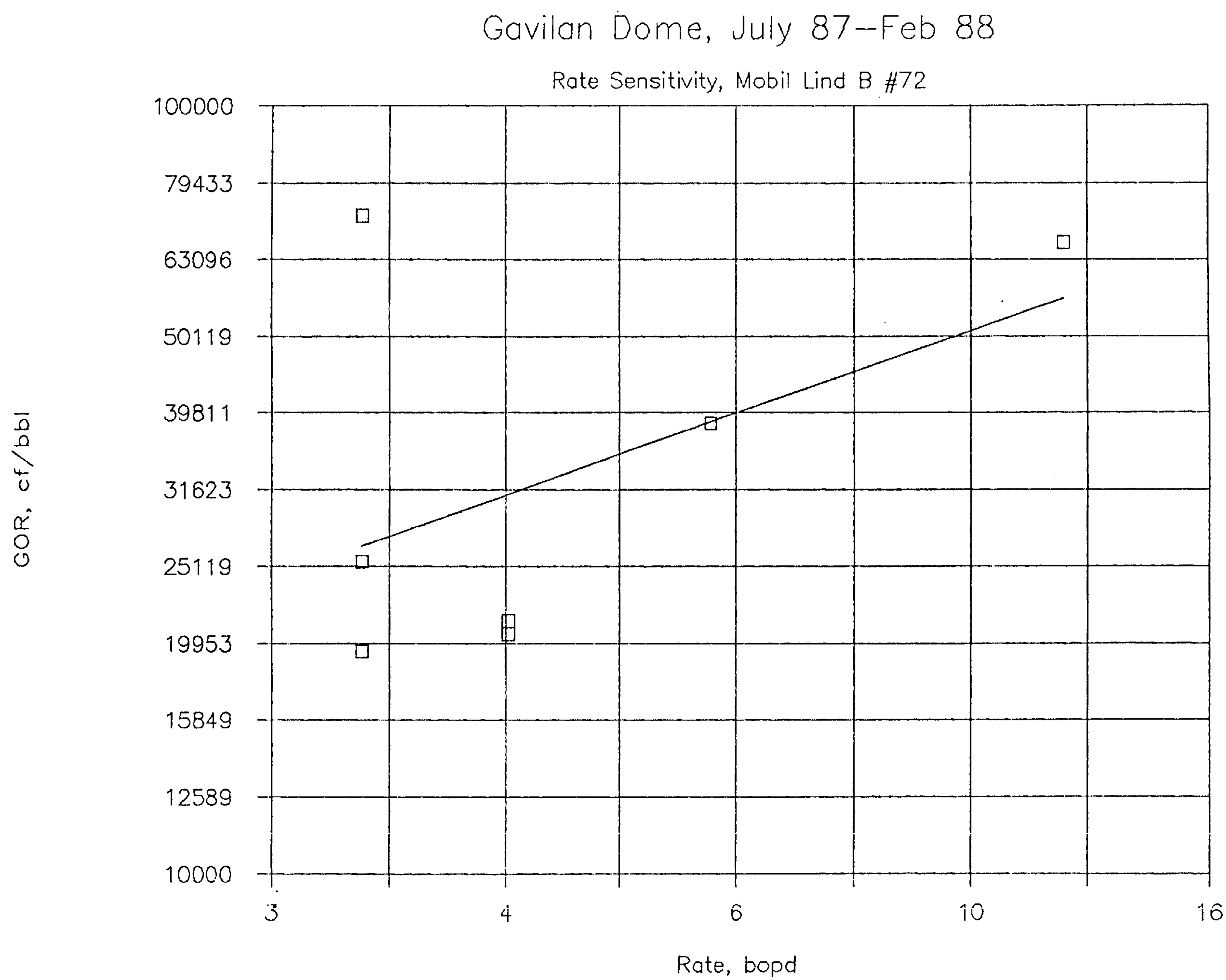
Rate Sensitivity, Mobil Lind B37



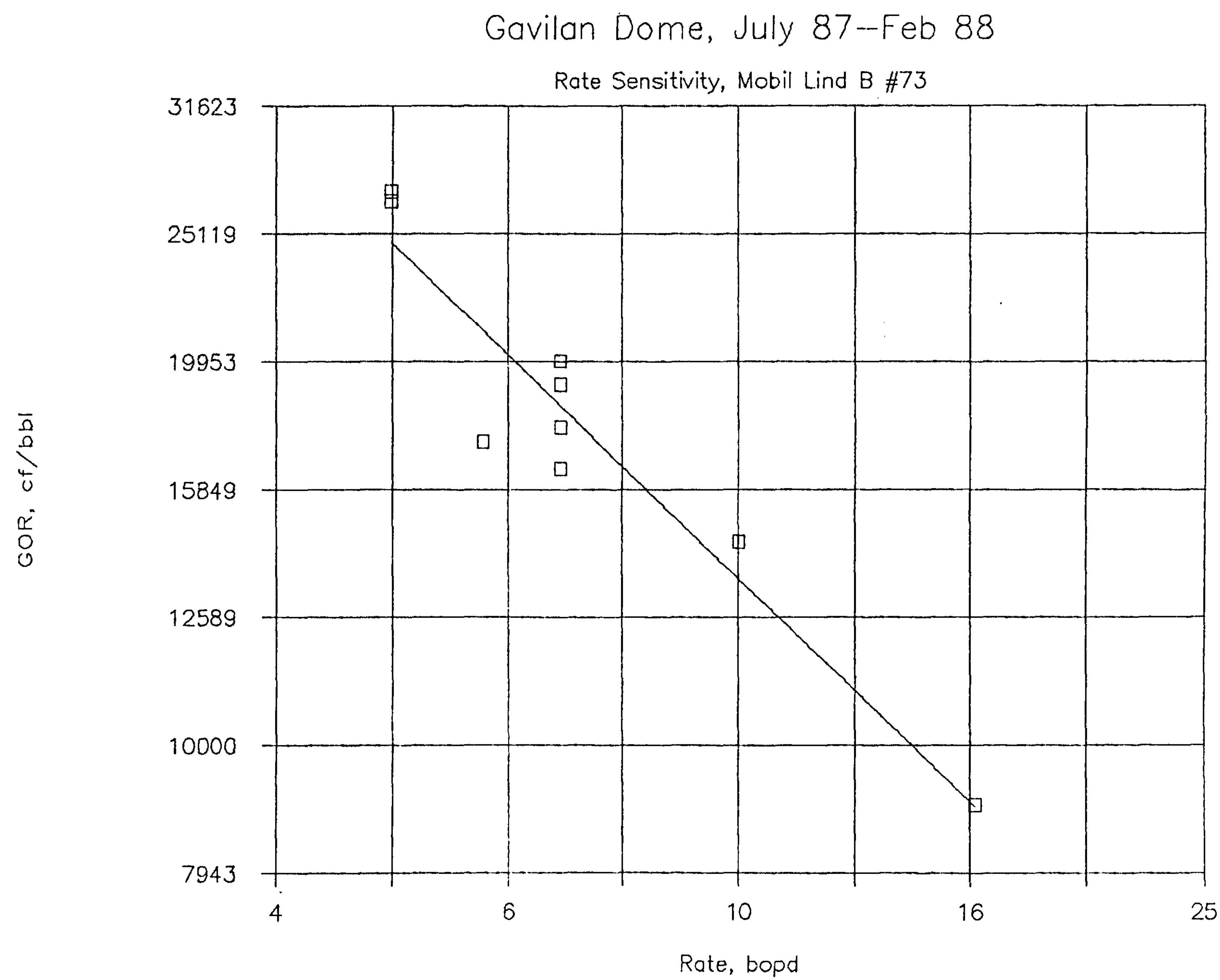


Gavilan Dome, July 87—Nov 87
Rate Sensitivity, Mobil Lind B #38
30200
28840
27542
26303
25119
23988
22909
21878
20893
19953
19055
18197
17378
16596
15849
15136
14454
GOR, cf/bbl
6
7
9
11
14
Rate, bopd

C.C. = 0.86


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Mobil Lind B #72
GOR, cf/bbl
100000
79433
63096
50119
39811
31623
25119
19953
15849
12589
10000
3
4
6
10
16
Rate, bopd

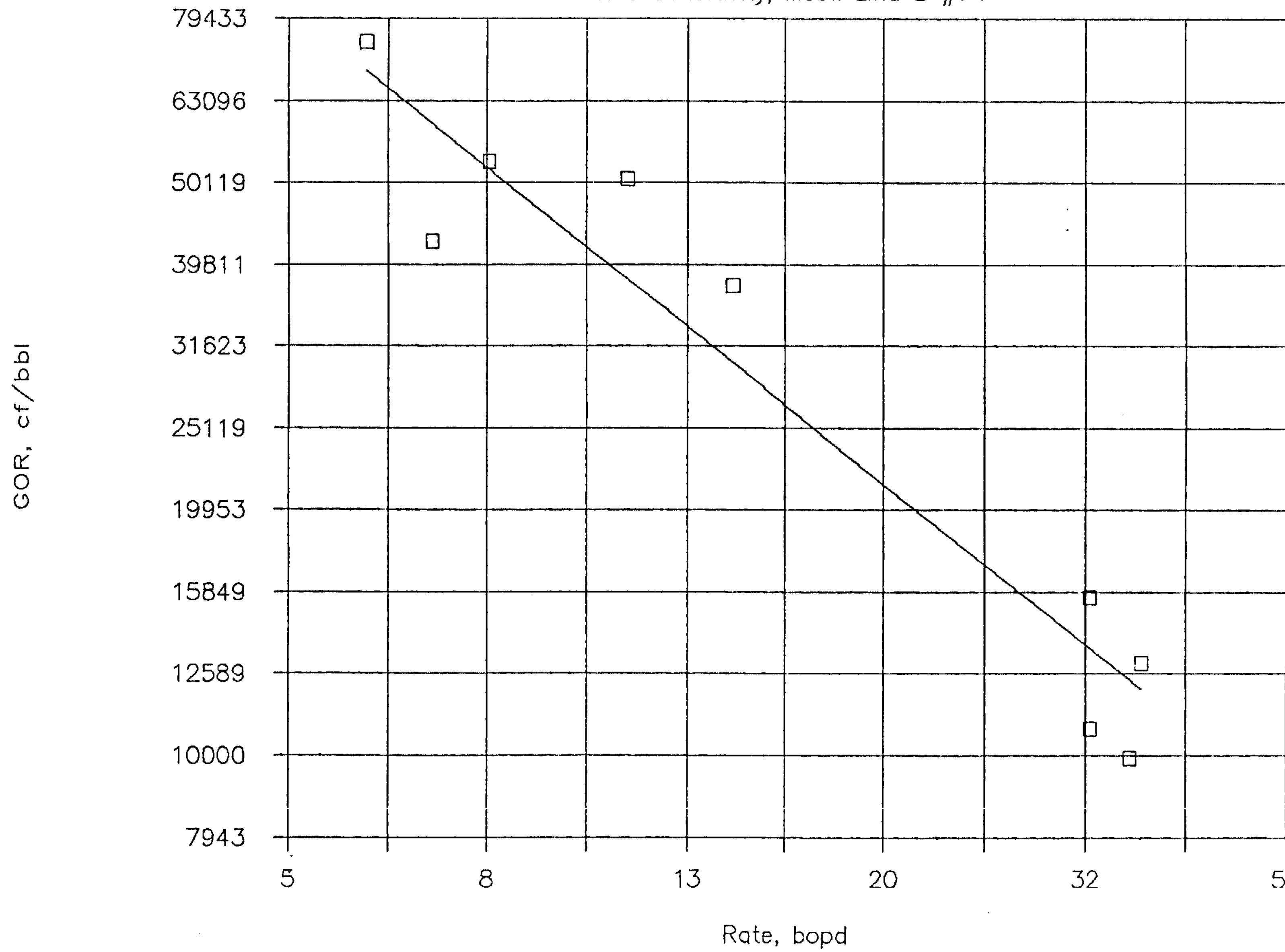
C.C.=0.49


Gavilan Dome, July 87--Feb 88
Rate Sensitivity, Mobil Lind B #73
31623
25119
19953
15849
12589
10000
7943
GOR, cf/bbl
4
6
10
16
25
Rate, bopd

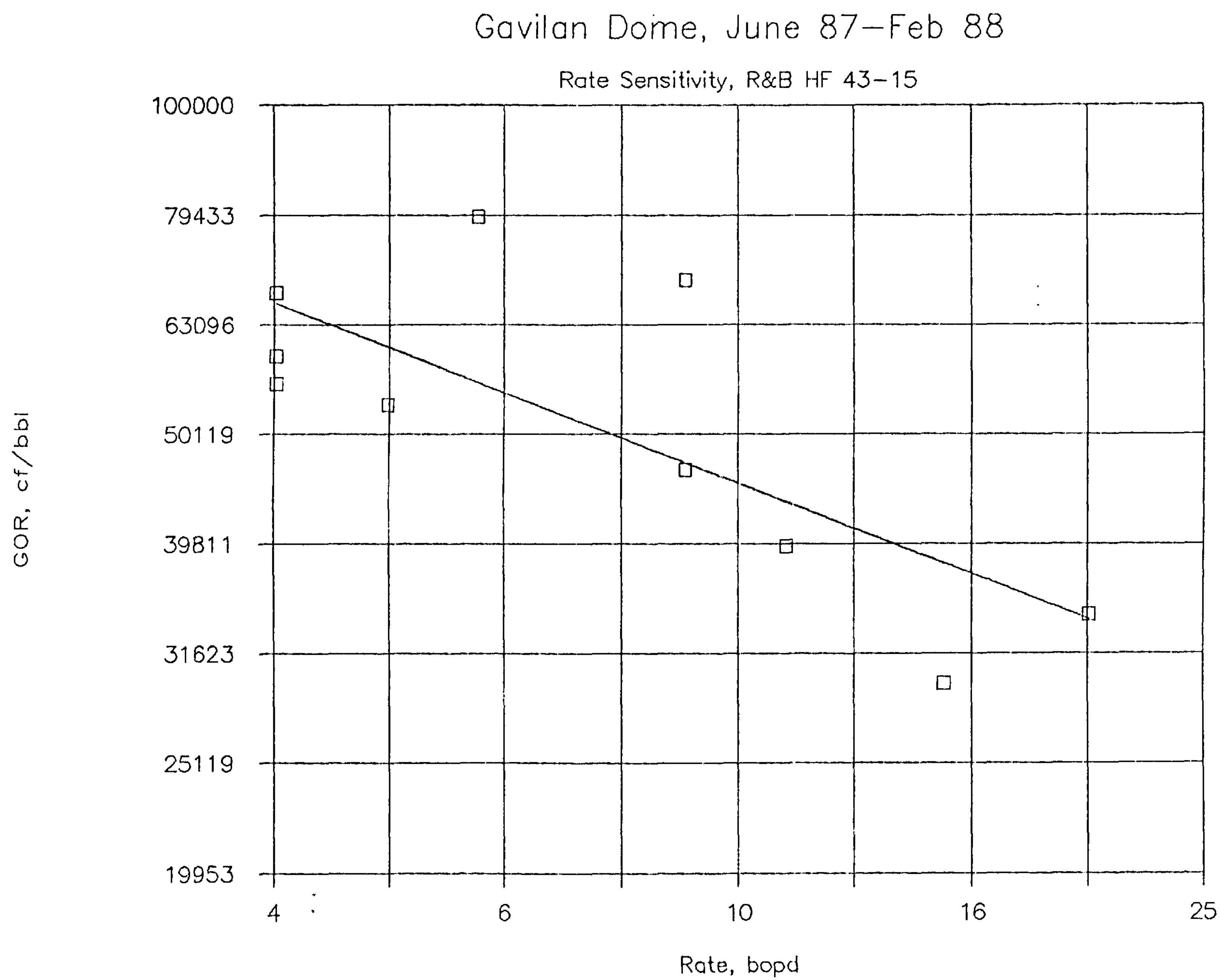
C.C. = 0.95

Gavilan Dome, July 87–Feb 88

Rate Sensitivity, Mobil Lind B #74



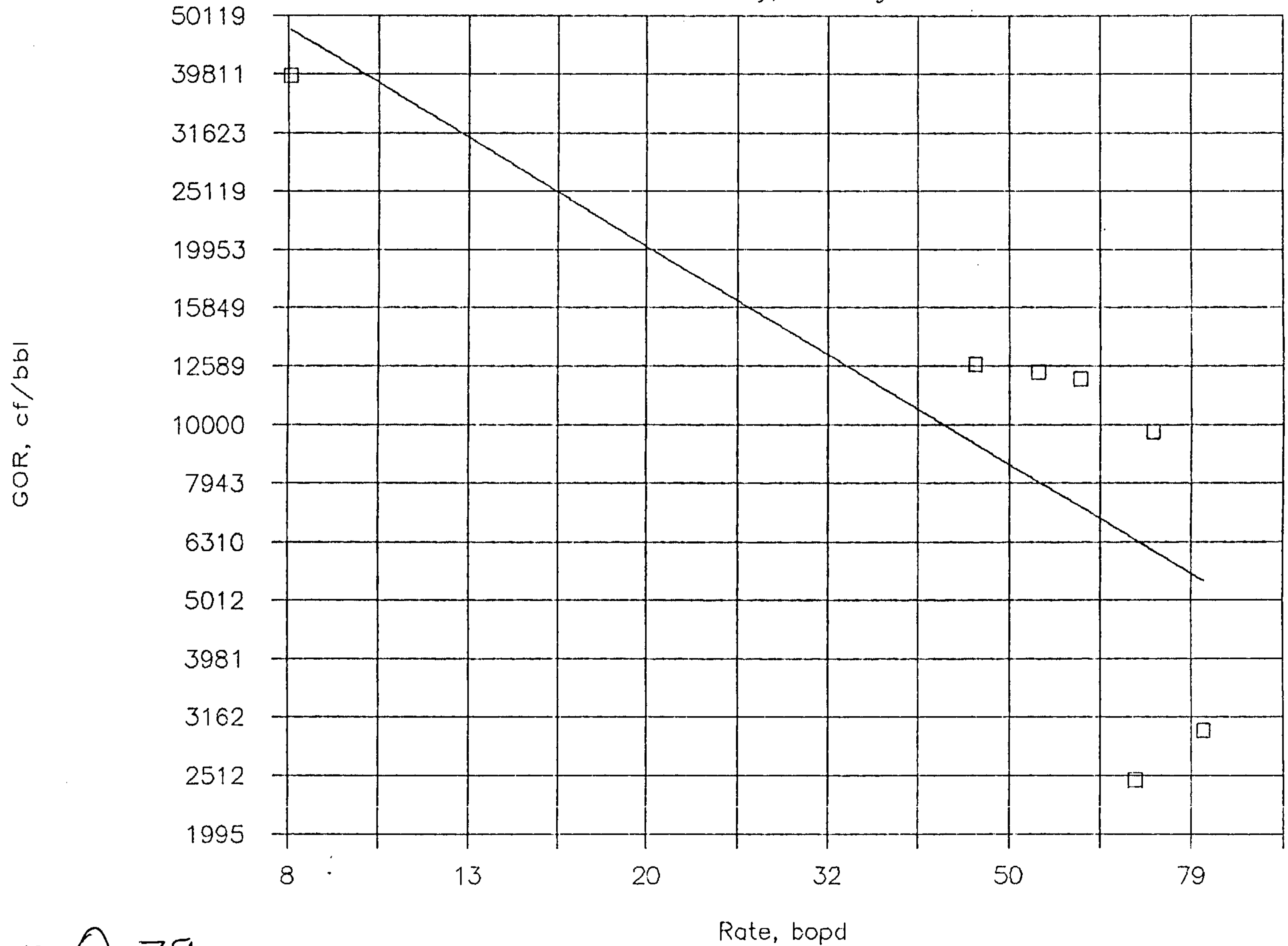
C.C. = 0.86


Gavilan Dome, June 87—Feb 88
Rate Sensitivity, R&B HF 43-15
100000
79433
63096
50119
39811
31623
25119
19953
GOR, cf/bbl
4
6
10
16
25
Rate, bopd

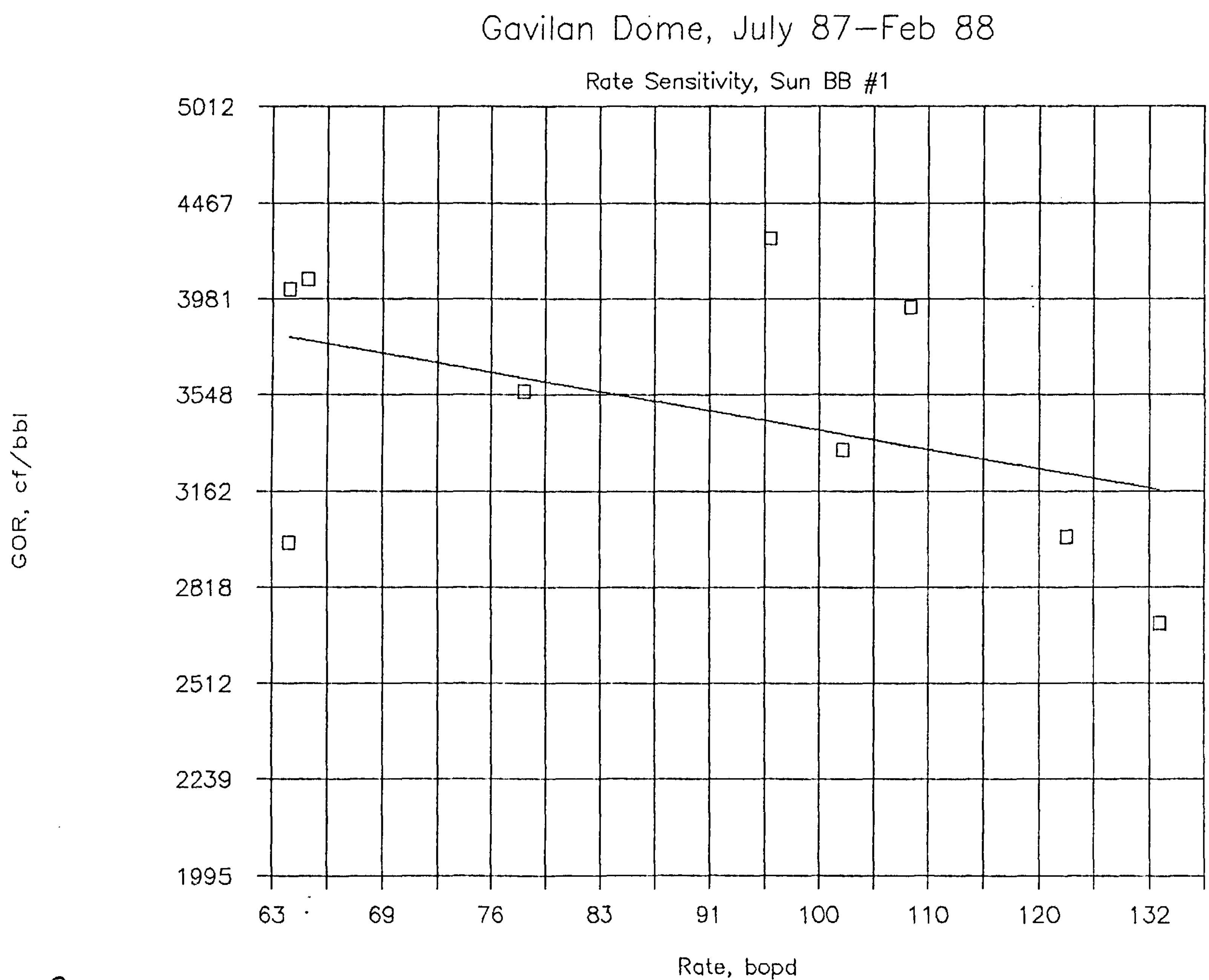
C.C. = 0.76

Gavilan Dome, Sept 87–Feb 88

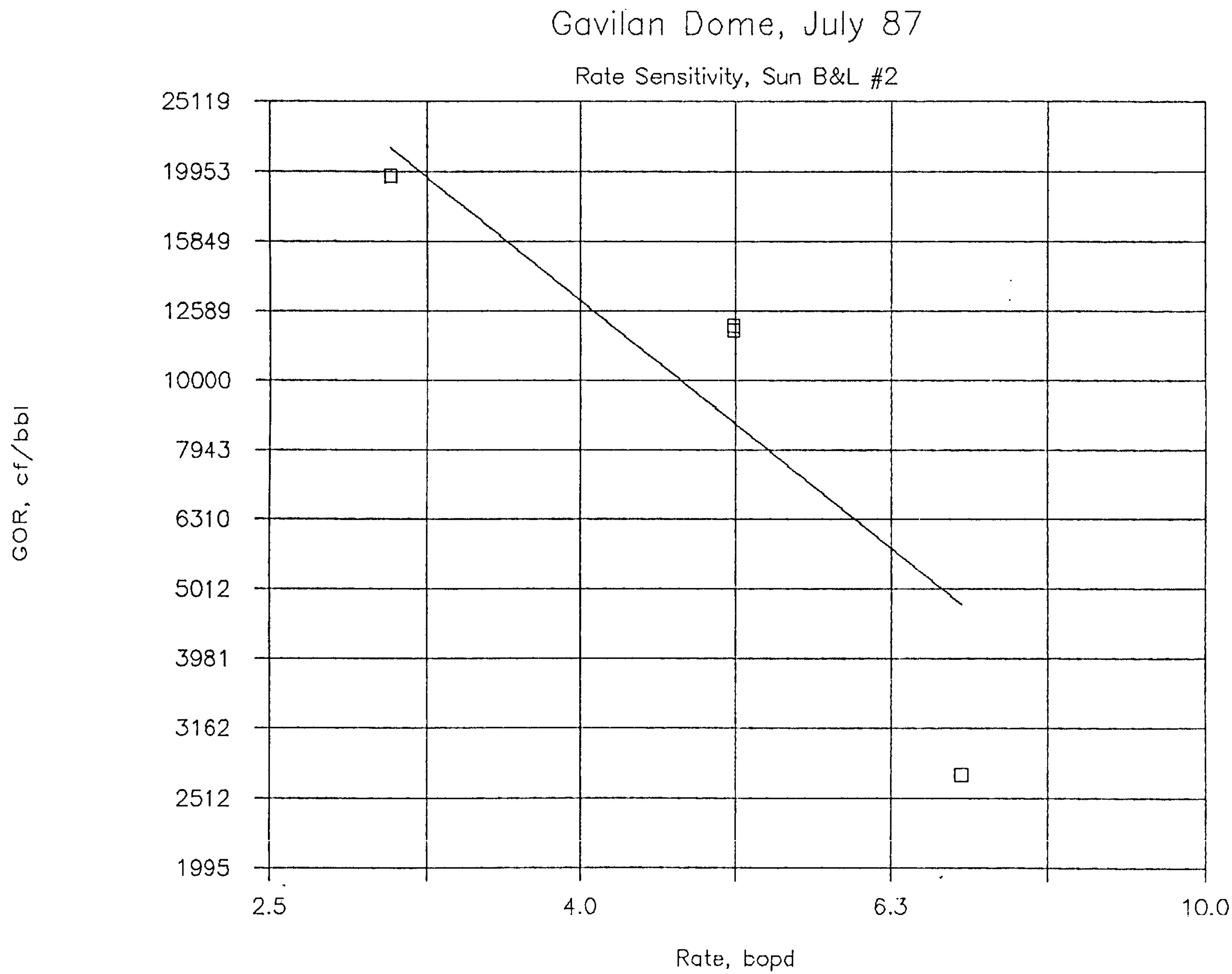
Rate Sensitivity, R&B Ing 34–16



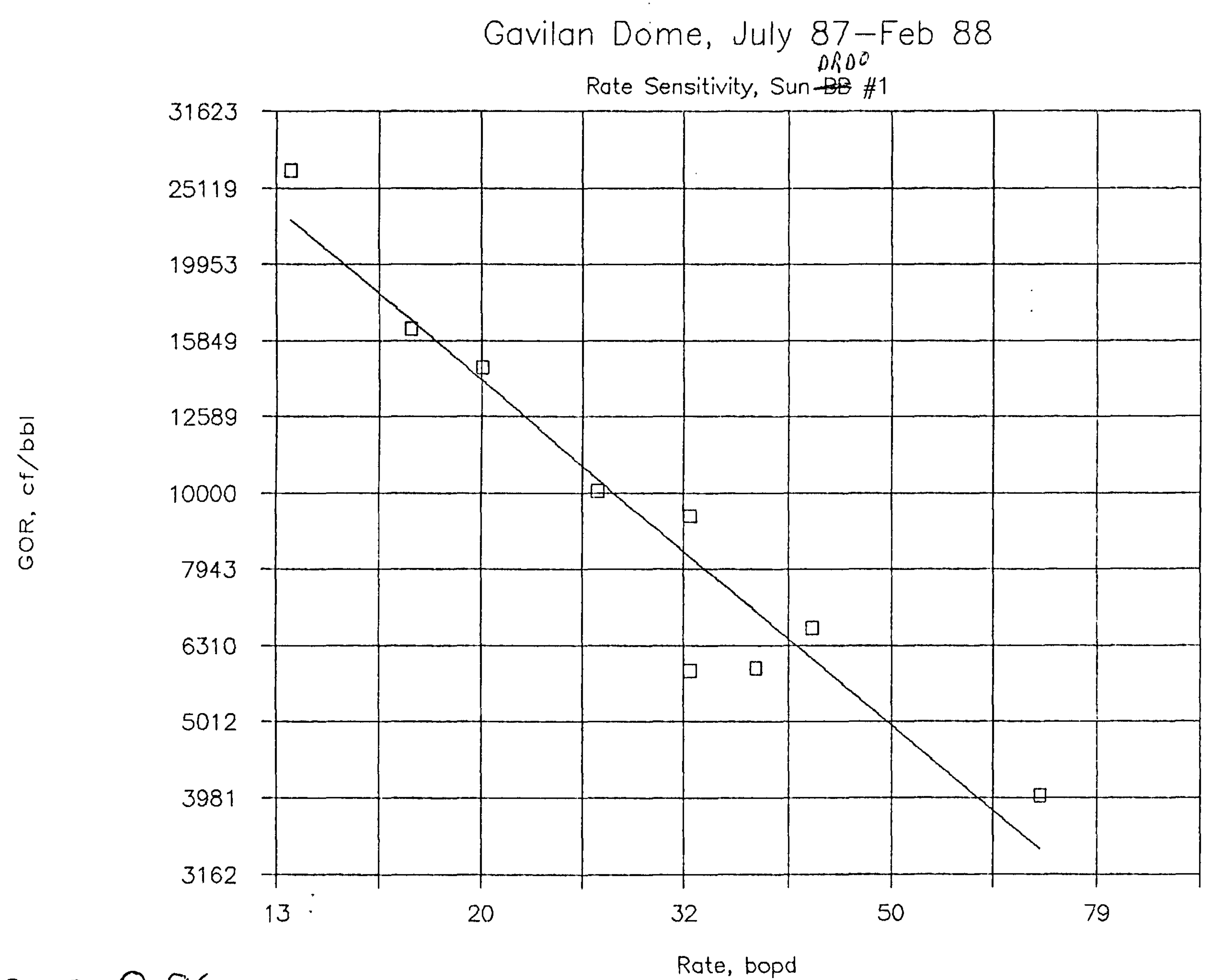
C.C. = 0.79


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun BB #1
GOR, cf/bbl
5012
4467
3981
3548
3162
2818
2512
2239
1995
63
69
76
83
91
100
110
120
132
Rate, bopd

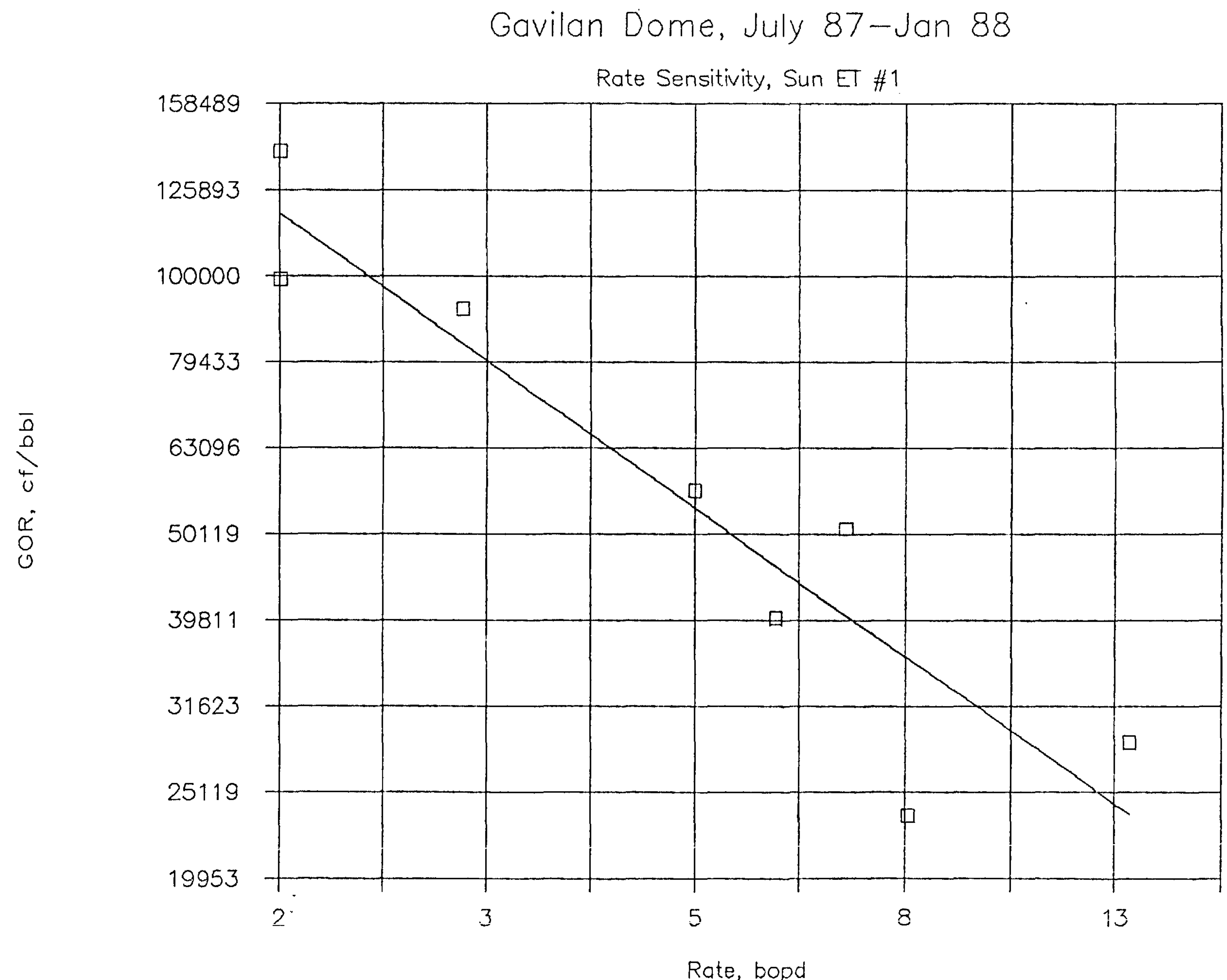
C.C. = 0.44


Gavilan Dome, July 87
Rate Sensitivity, Sun B&L #2
GOR, cf/bbl
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
2.5
4.0
6.3
10.0
Rate, bopd

C. C. = 0.89

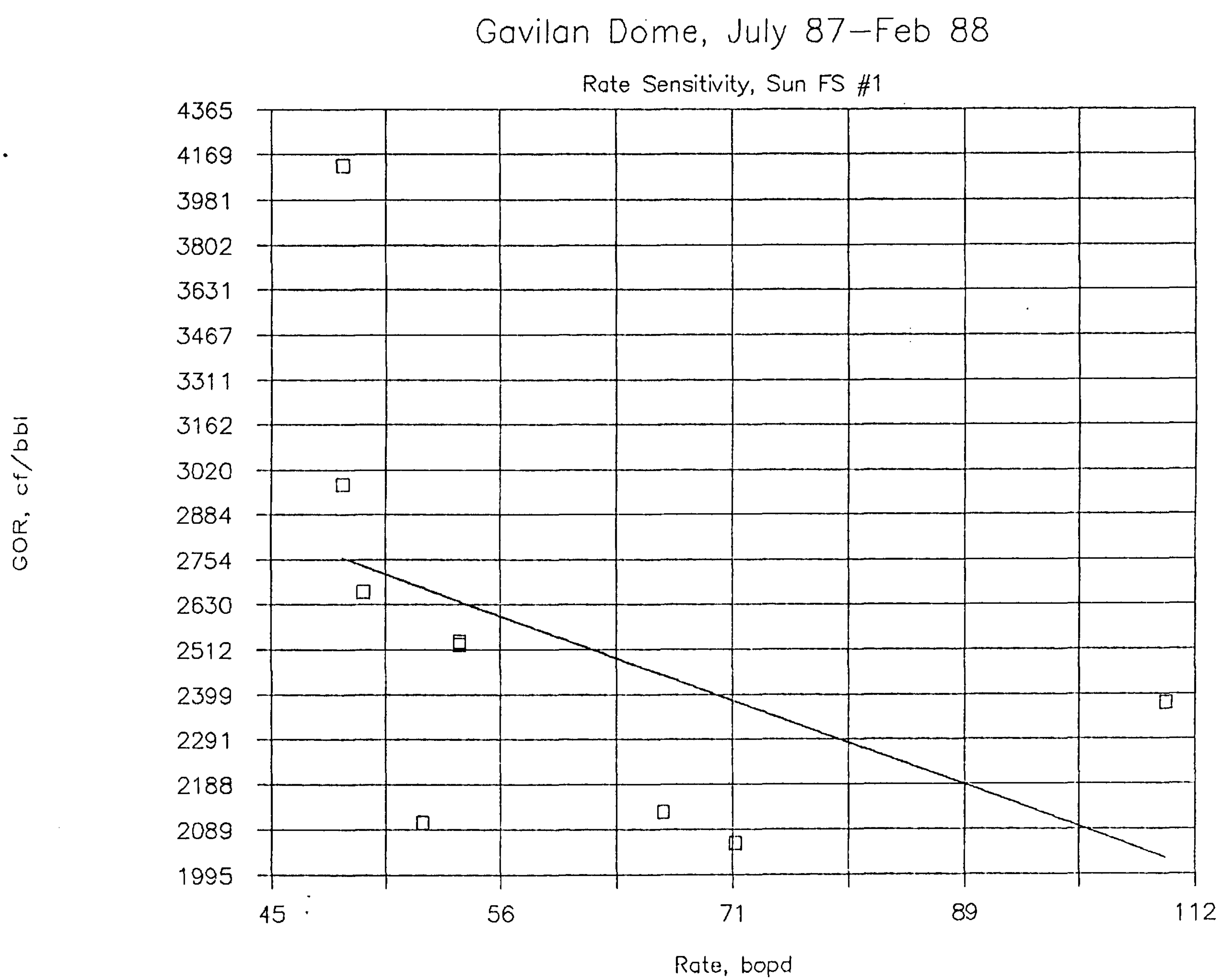

Gavilan Dome, July 87–Feb 88
Rate Sensitivity, Sun ~~BB~~ DRDO #1
31623
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
GOR, cf/bbl
13
20
32
50
79
Rate, bopd

C.C. = 0.96

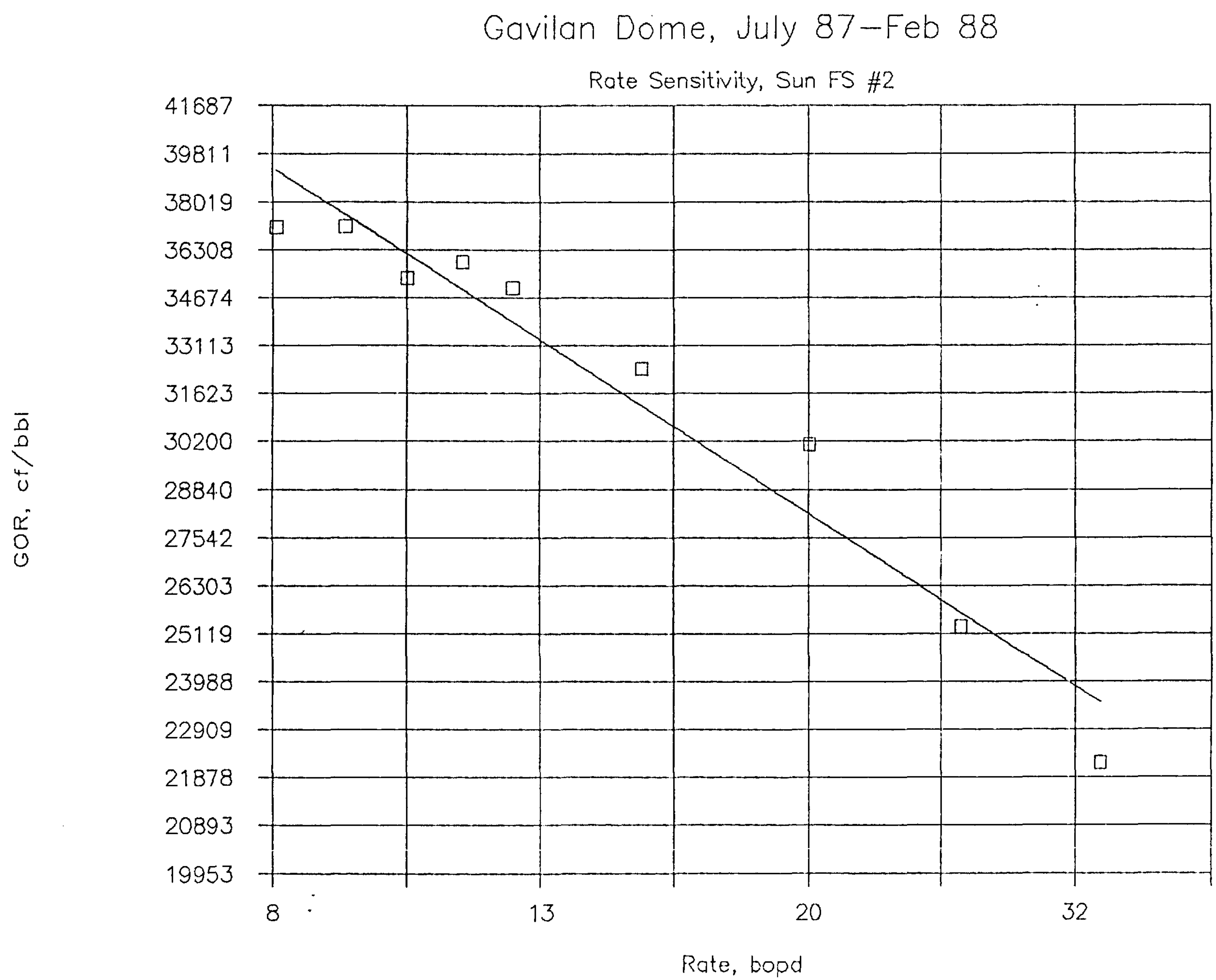


Gavilan Dome, July 87–Jan 88
Rate Sensitivity, Sun ET #1
158489
125893
100000
79433
63096
50119
39811
31623
25119
19953
GOR, cf/bbl
2
3
5
8
13
Rate, bopd

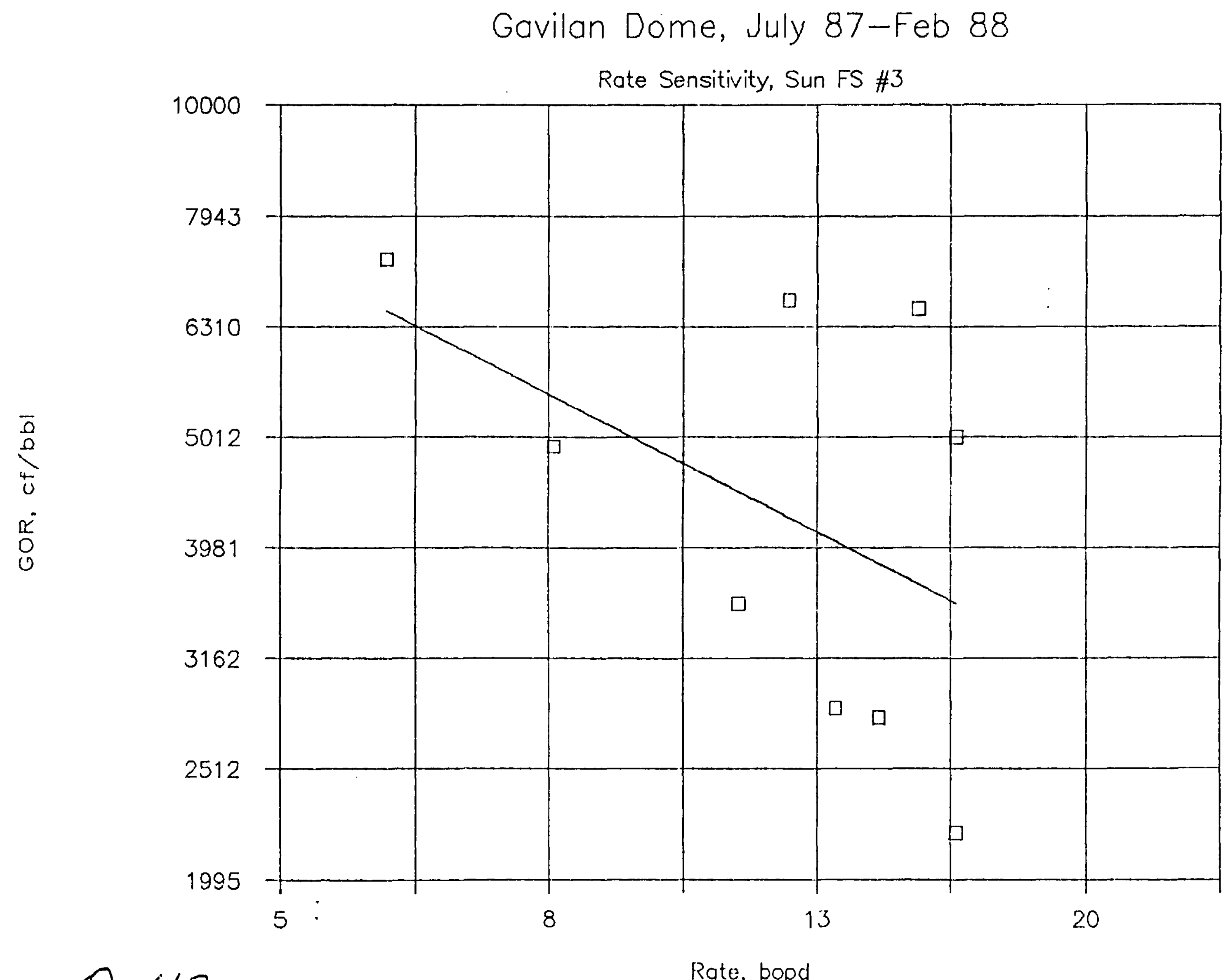
C.C. = 0.93


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun FS #1
GOR, cf/bbl
4365
4169
3981
3802
3631
3467
3311
3162
3020
2884
2754
2630
2512
2399
2291
2188
2089
1995
45
56
71
89
112
Rate, bopd

C.C. = 0.46


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun FS #2
GOR, cf/bbl
41687
39811
38019
36308
34674
33113
31623
30200
28840
27542
26303
25119
23988
22909
21878
20893
19953
8
13
20
32
Rate, bopd

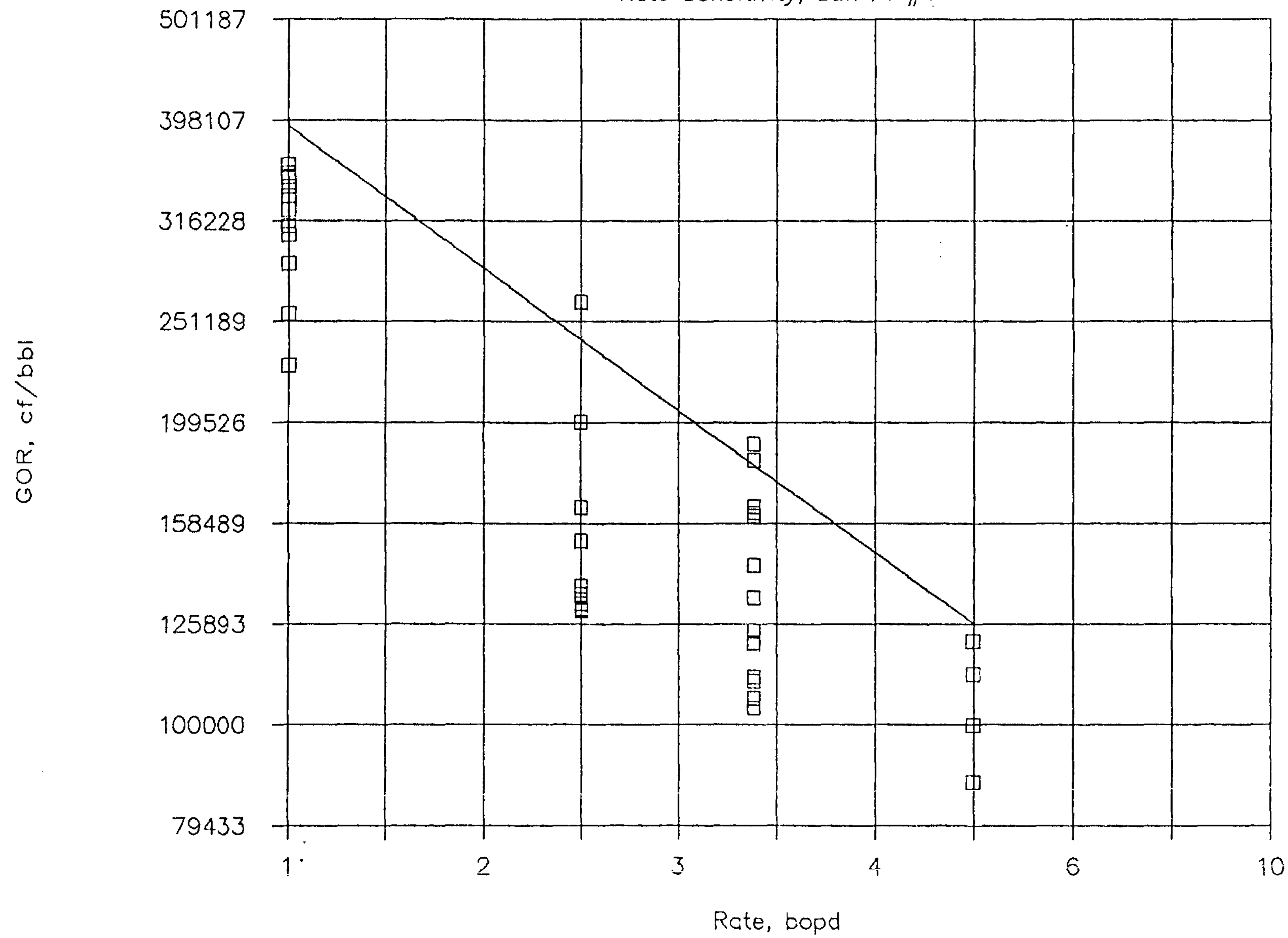
C.C. = 0.97


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun FS #3
10000
7943
6310
5012
3981
3162
2512
1995
GOR, cf/bbl
5
8
13
20
Rate, bopd

C. C. = 0.48

Gavilan Dome, July 87—Aug 87

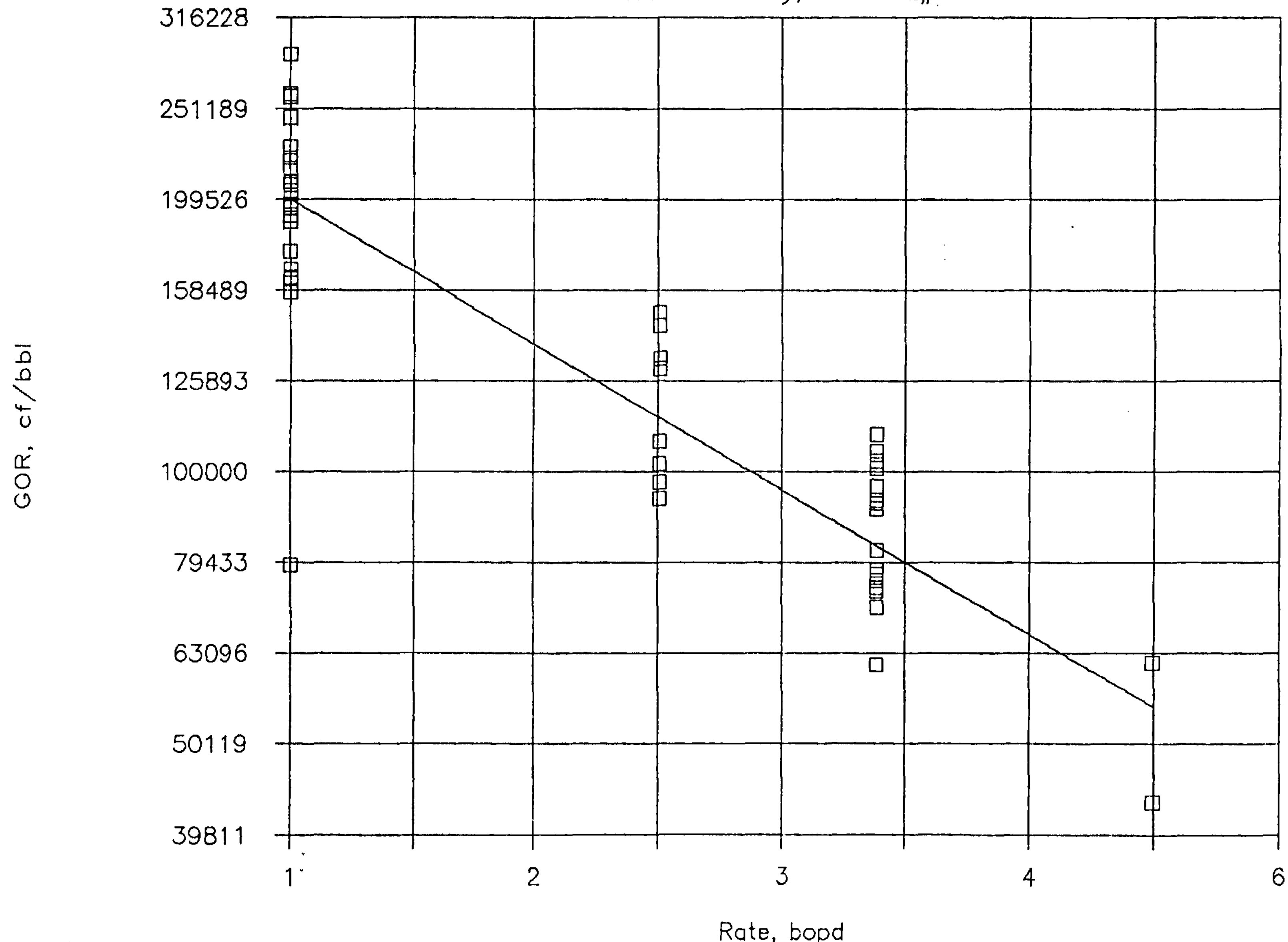
Rate Sensitivity, Sun FT #1



C. C. = 0.88

Gavilan Dome, July 87–Aug 87

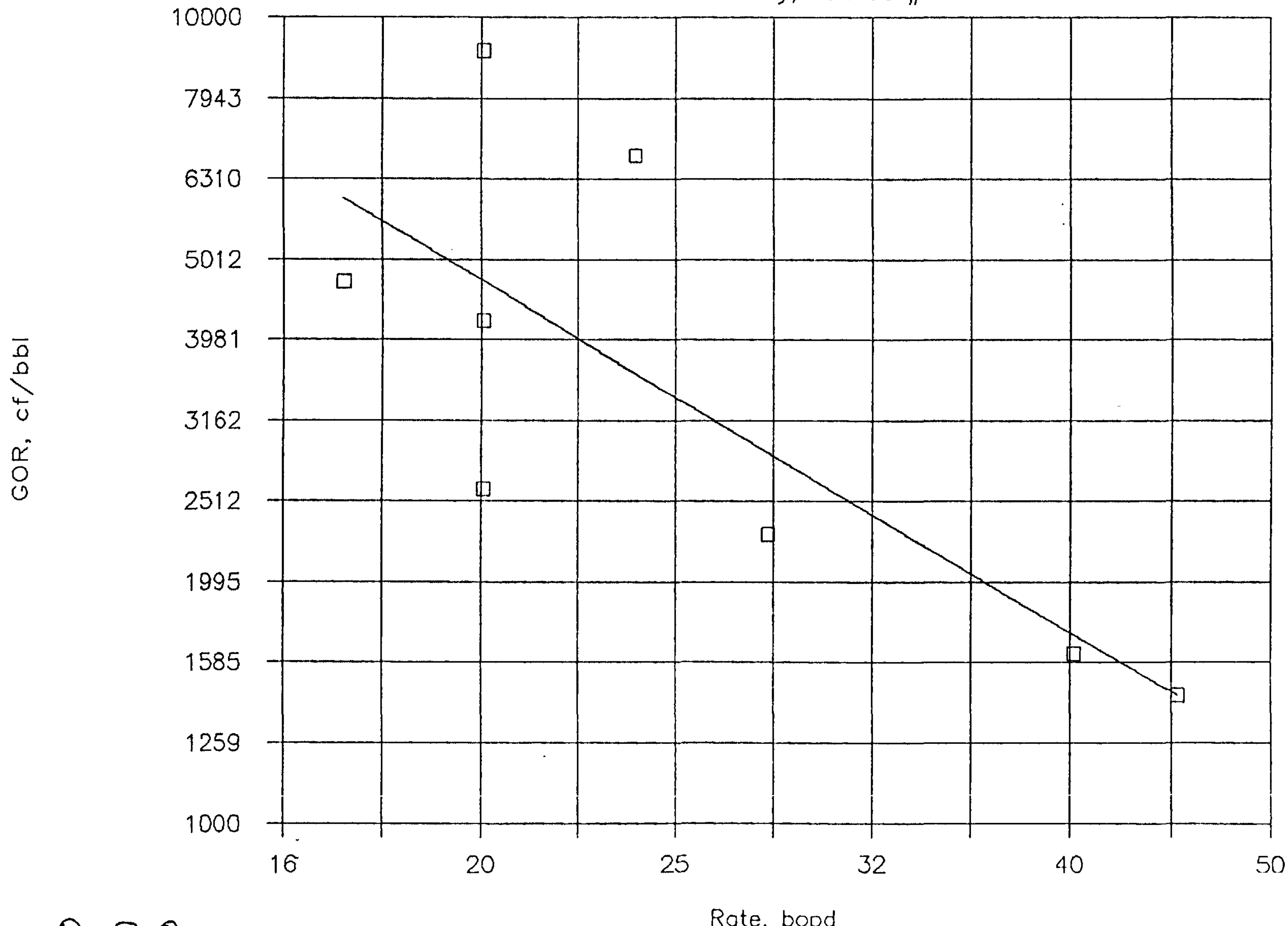
Rate Sensitivity, Sun FT E#1



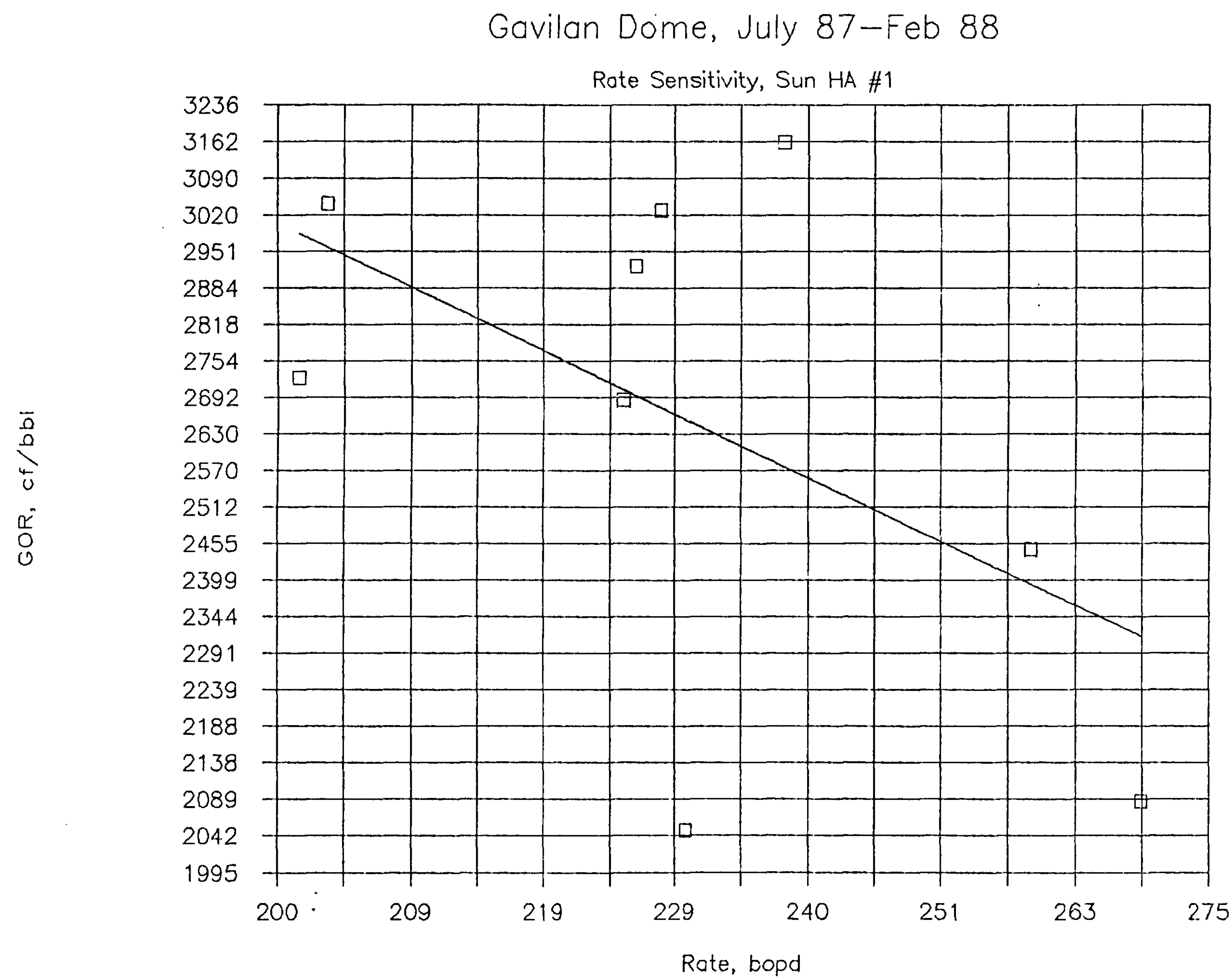
C.C. = 0.91

Gavilan Dome, July 87

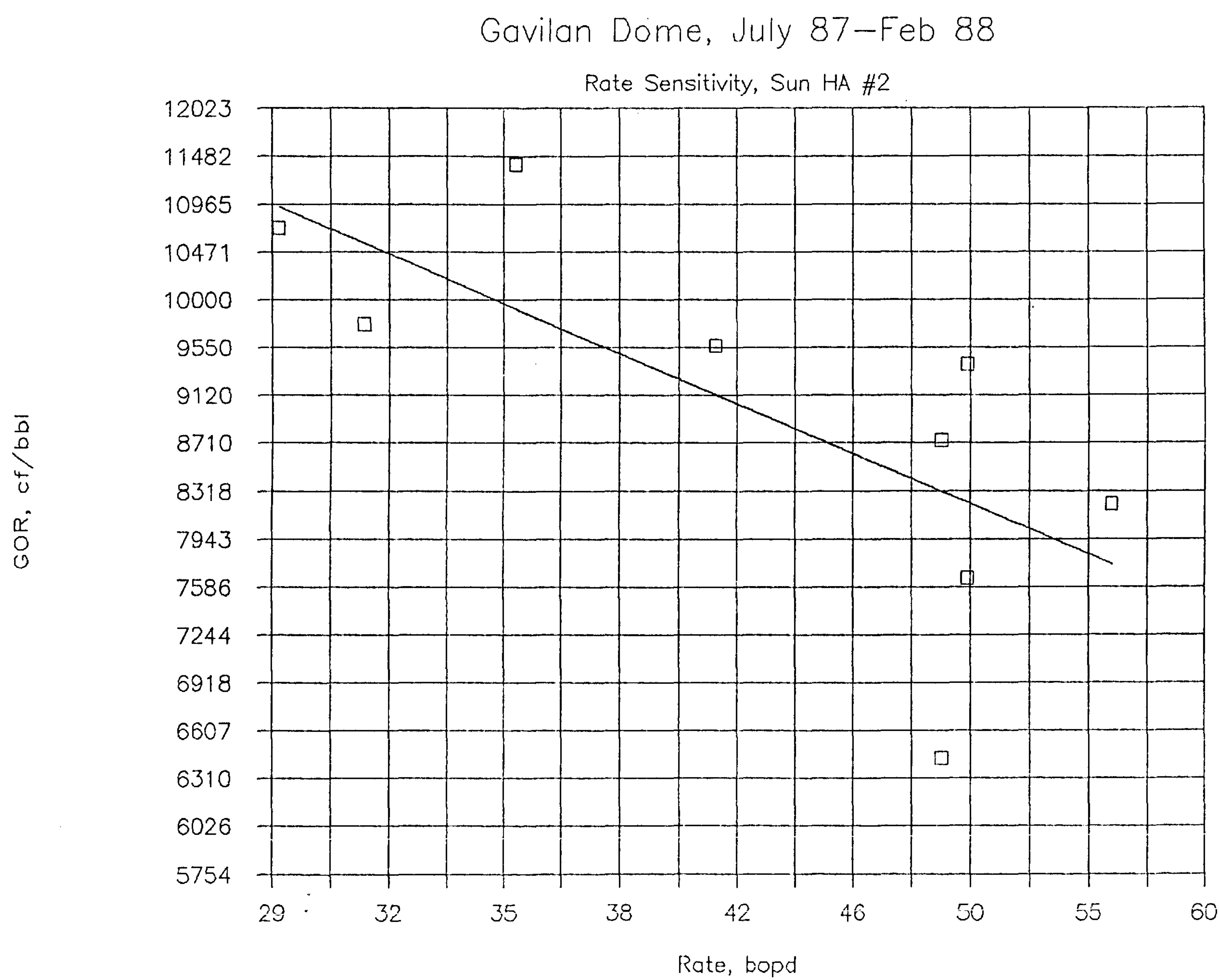
Rate Sensitivity, Sun GG #1



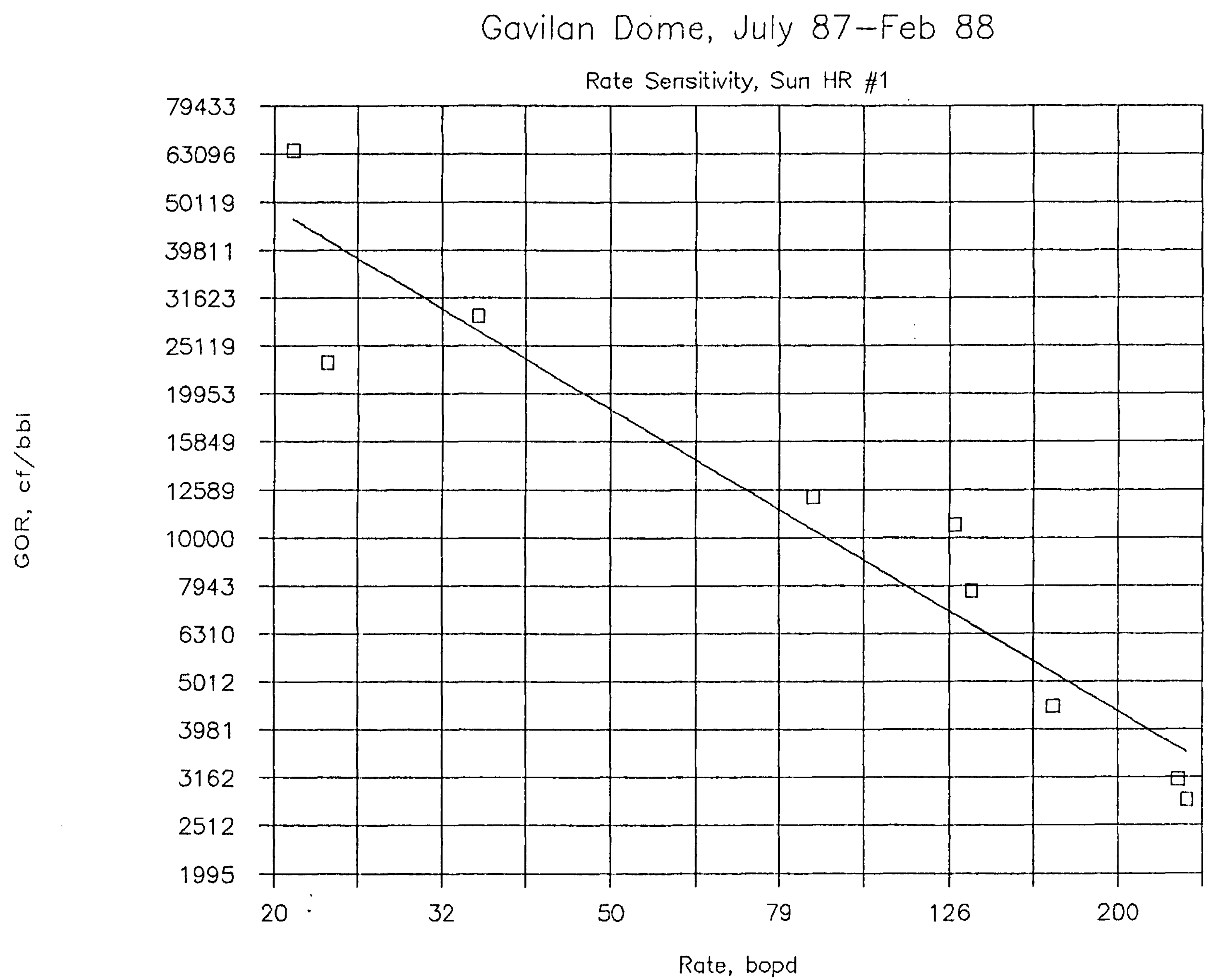
C.C. = 0.80


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun HA #1
GOR, cf/bbl
3236
3162
3090
3020
2951
2884
2818
2754
2692
2630
2570
2512
2455
2399
2344
2291
2239
2188
2138
2089
2042
1995
200
209
219
229
240
251
263
275
Rate, bopd

C.C. = 0.52

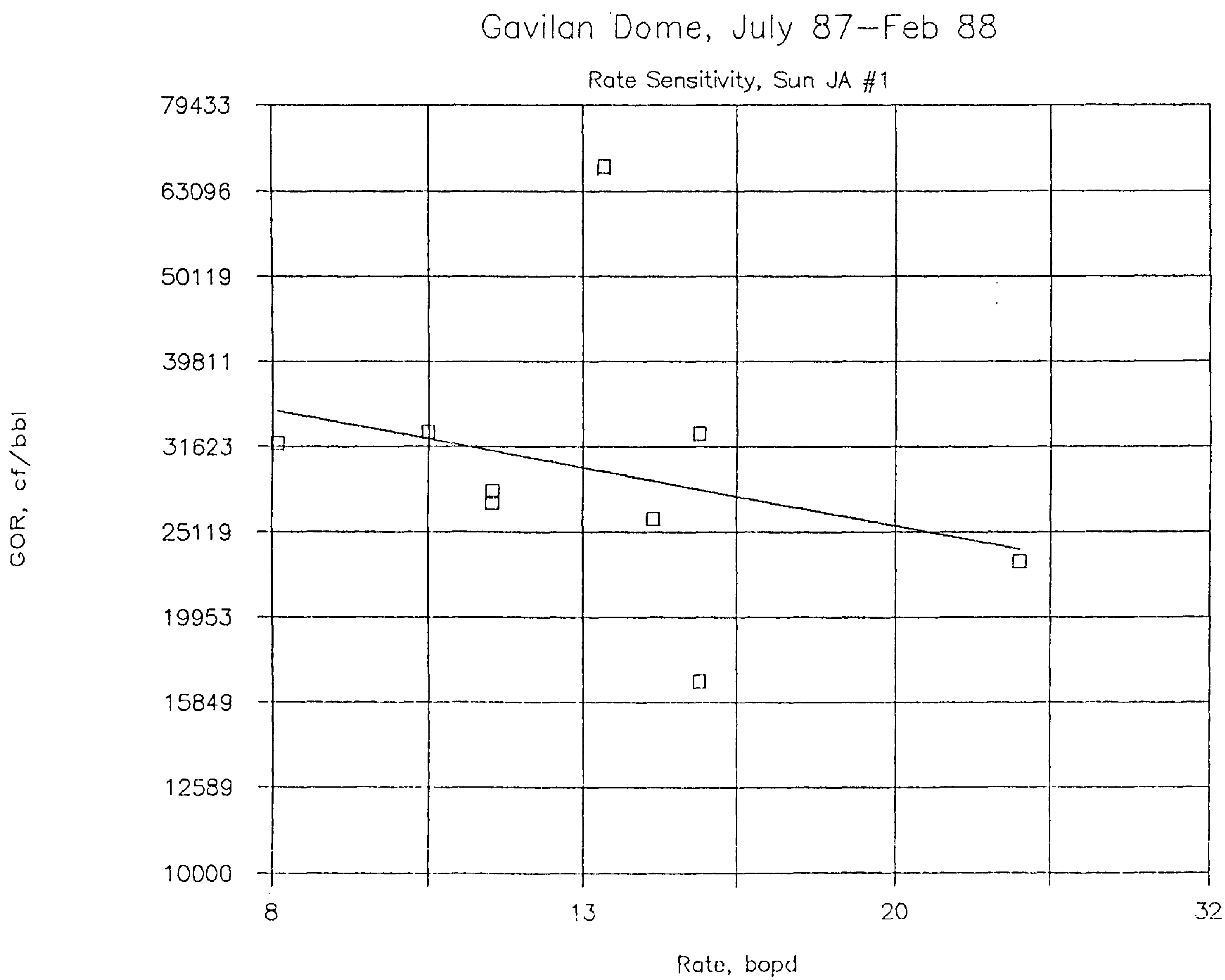

Gavilan Dome, July 87–Feb 88
Rate Sensitivity, Sun HA #2
GOR, cf/bbl
12023
11482
10965
10471
10000
9550
9120
8710
8318
7943
7586
7244
6918
6607
6310
6026
5754
29
32
35
38
42
46
50
55
60
Rate, bopd

C.C. = 0.71



Gavilan Dome, July 87–Feb 88
Rate Sensitivity, Sun HR #1
79433
63096
50119
39811
31623
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
GOR, cf/bbl
20
32
50
79
126
200
Rate, bopd

C. C. = 0.95

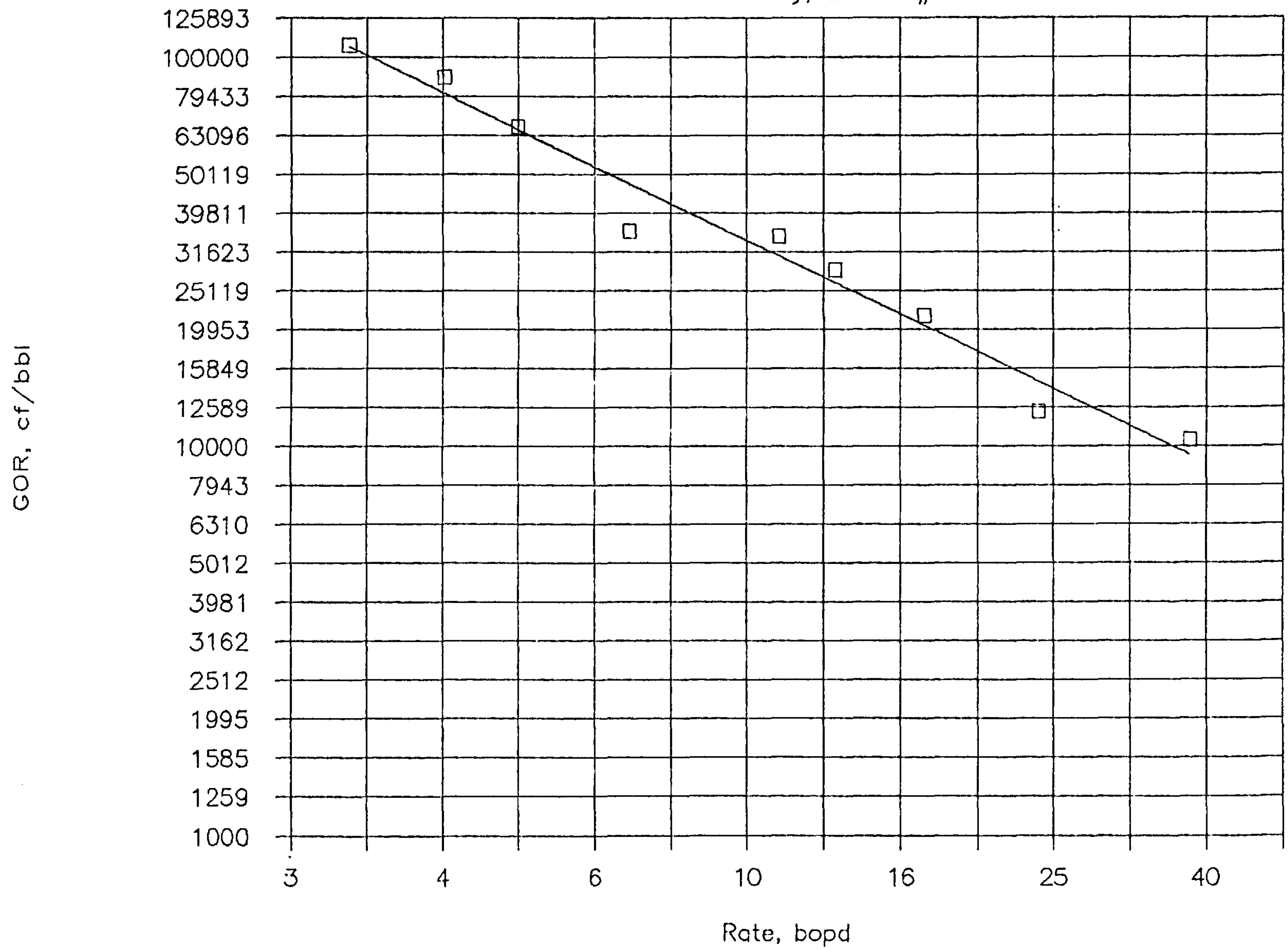


Gavilan Dome, July 87–Feb 88
Rate Sensitivity, Sun JA #1
79433
63096
50119
39811
31623
25119
19953
15849
12589
10000
GOR, cf/bbl
8
13
20
32
Rate, bopd

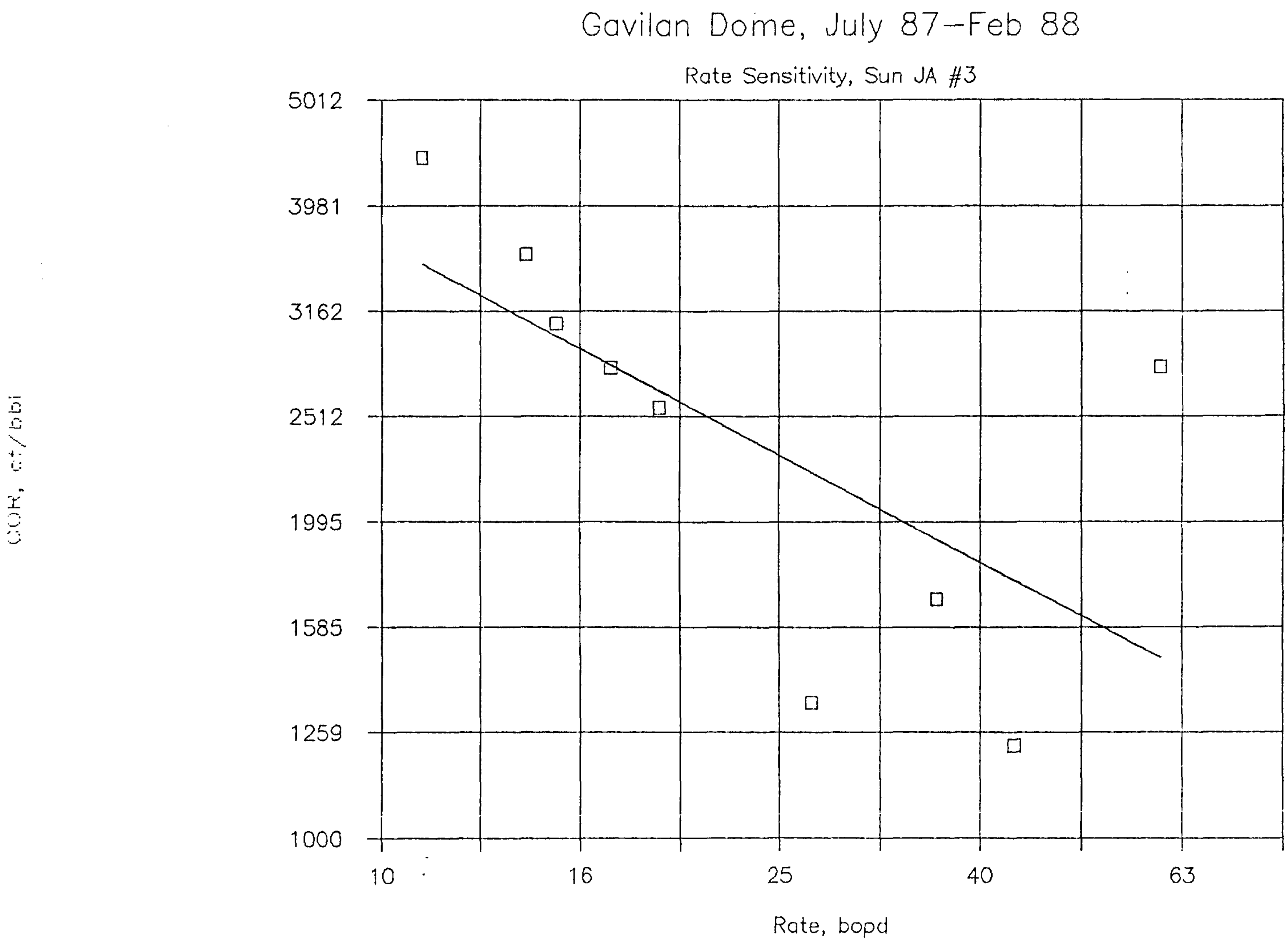
C. C. = 0.29

Gavilan Dome, July 87–Feb 88

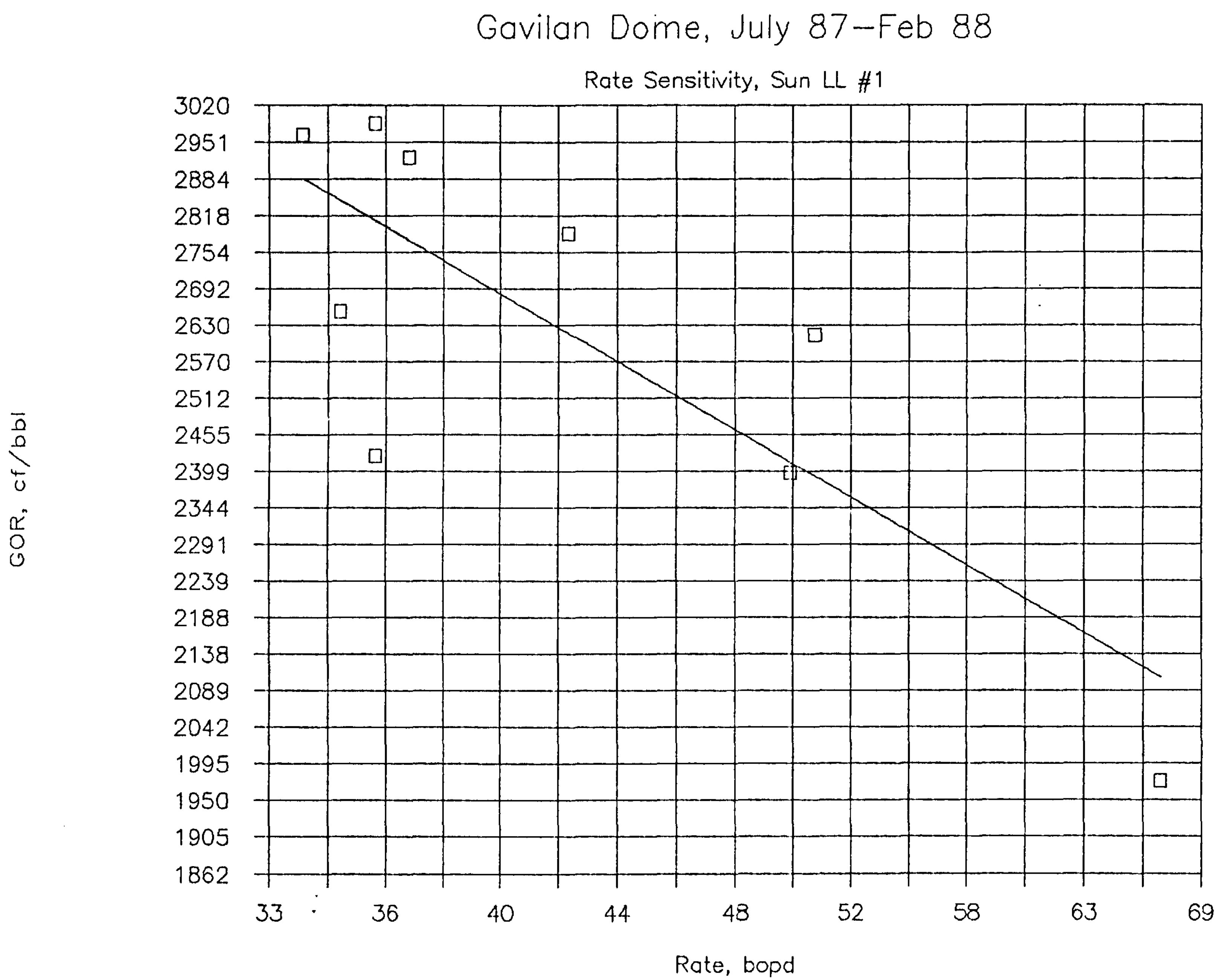
Rate Sensitivity, Sun JA #2



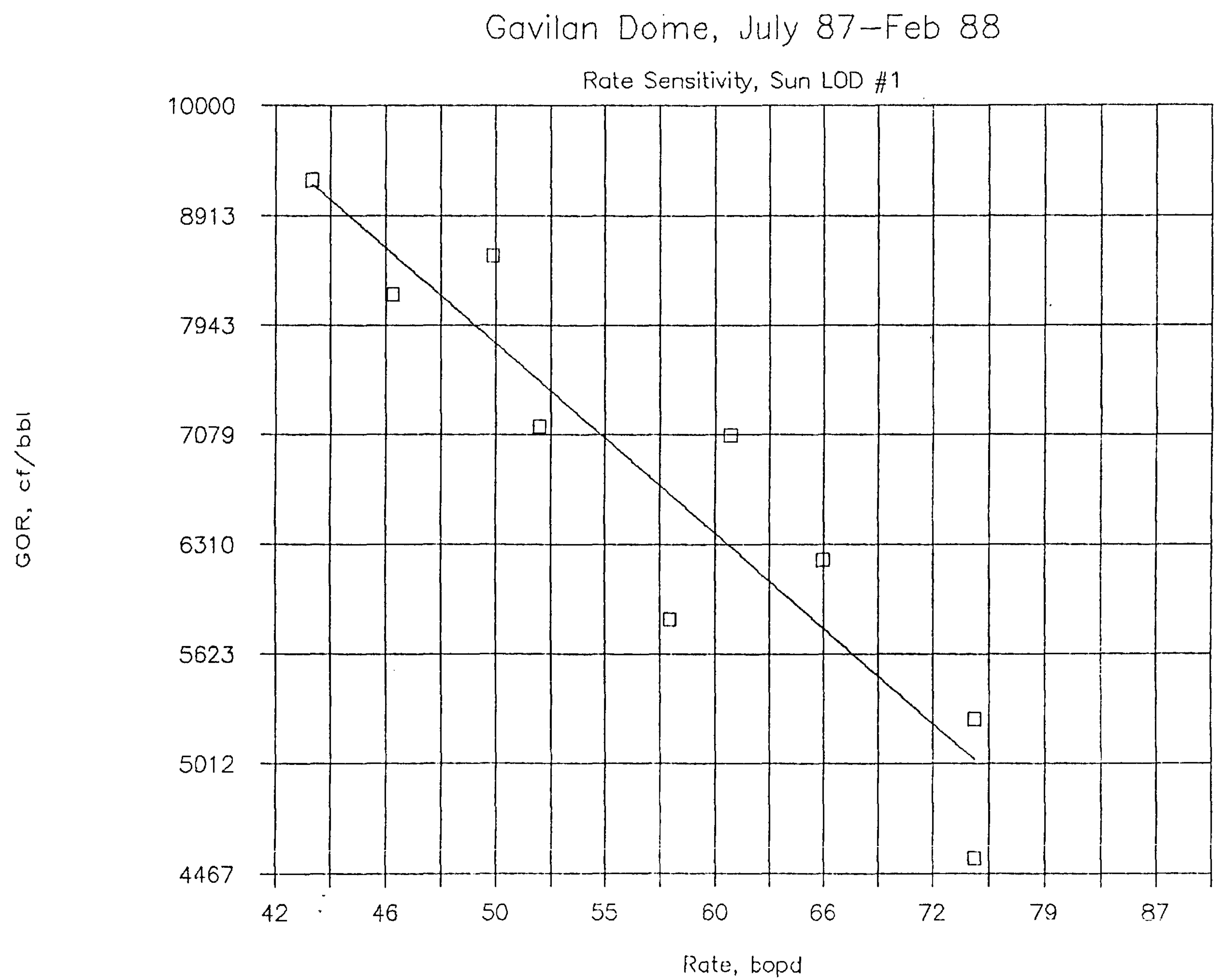
C.C. = 0.99


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun JA #3
GOR, cf/bbl
5012
3981
3162
2512
1995
1585
1259
1000
10
16
25
40
63
Rate, bopd

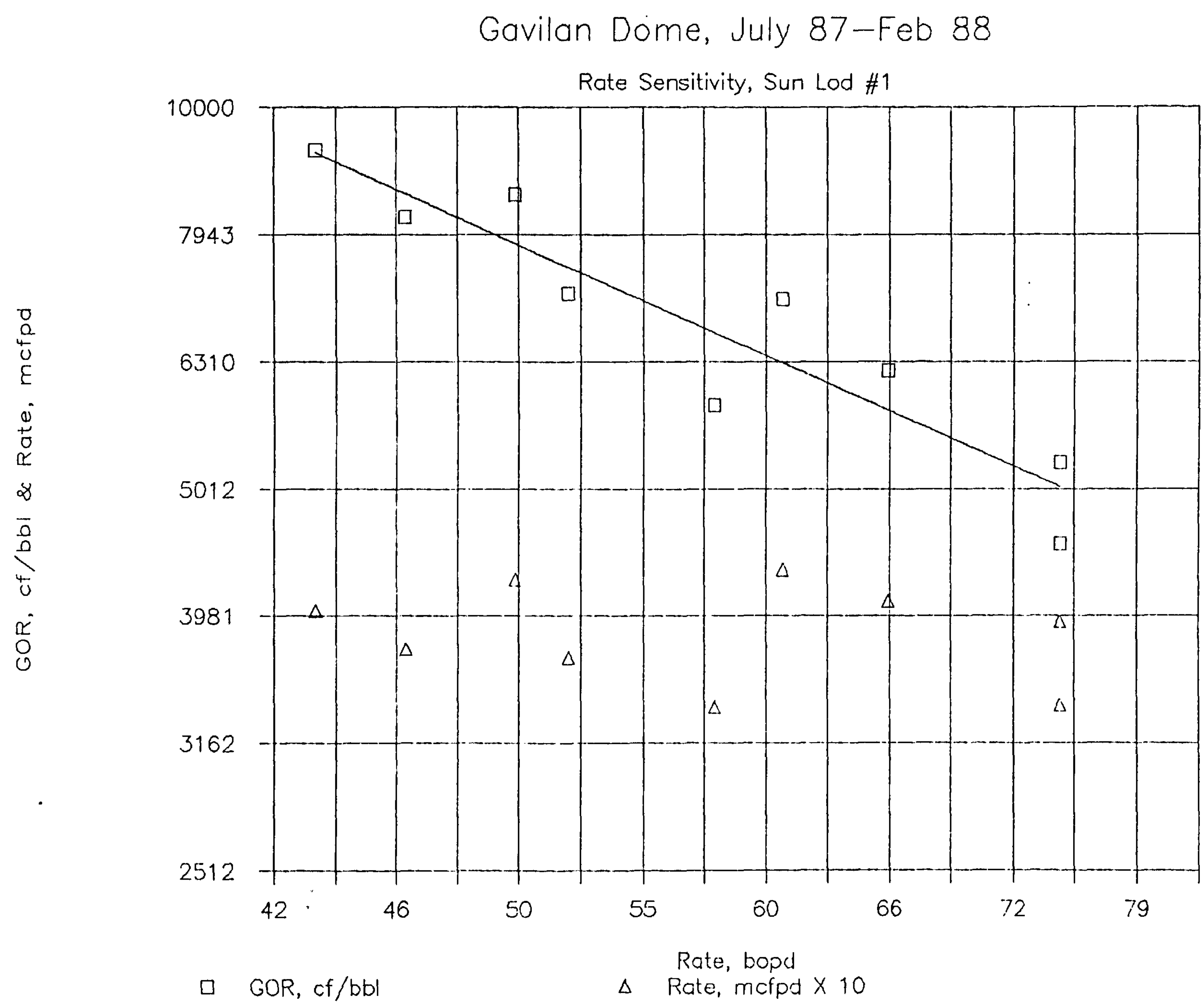
C. C. = 0.66

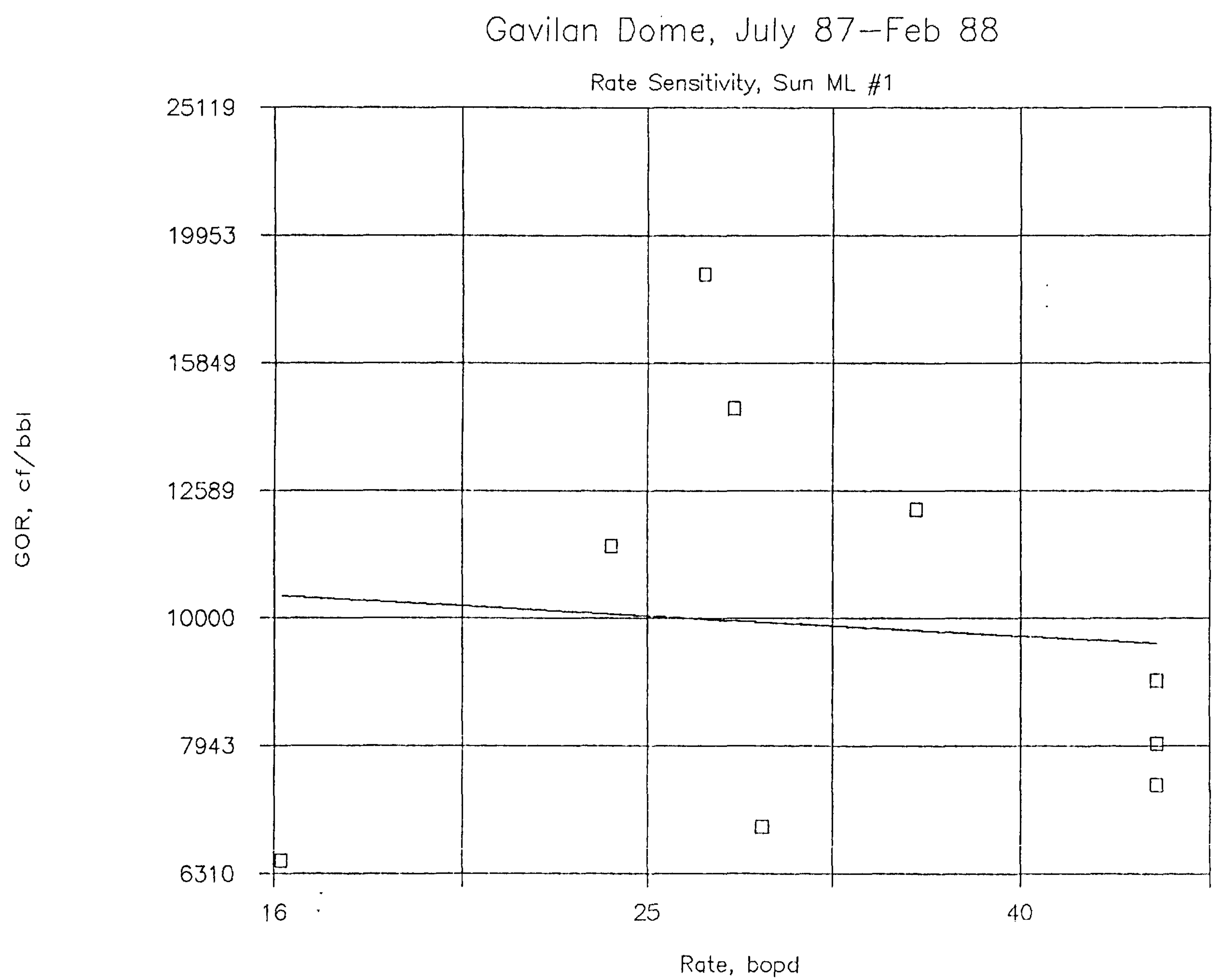

Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun LL #1
GOR, cf/bbl
3020
2951
2884
2818
2754
2692
2630
2570
2512
2455
2399
2344
2291
2239
2188
2138
2089
2042
1995
1950
1905
1862
33
36
40
44
48
52
58
63
69
Rate, bopd

C. C. = 0.80

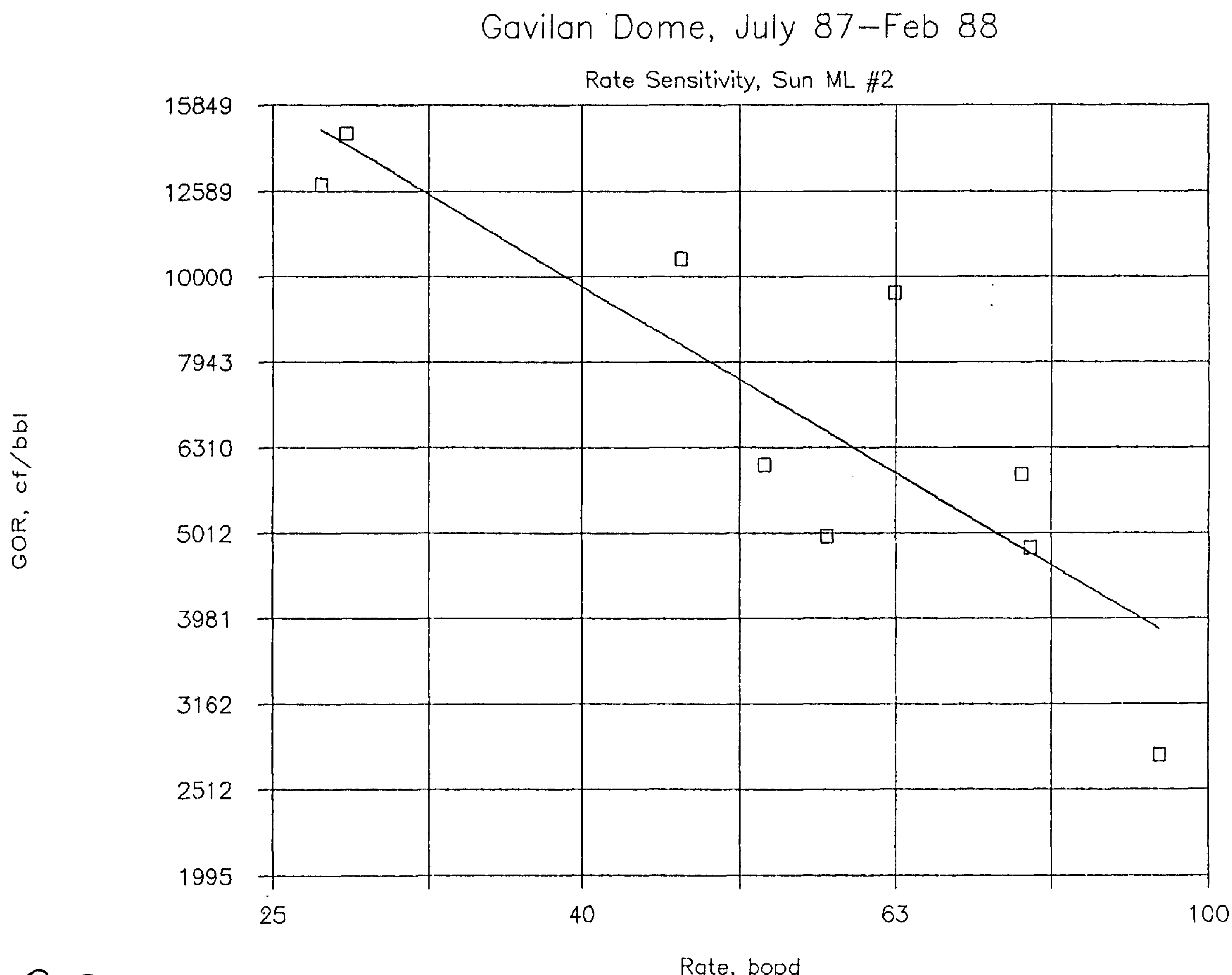

Gavilan Dome, July 87–Feb 88
Rate Sensitivity, Sun LOD #1
GOR, cf/bbl
10000
8913
7943
7079
6310
5623
5012
4467
42
46
50
55
60
66
72
79
87
Rate, bopd

C.C. = 0.93

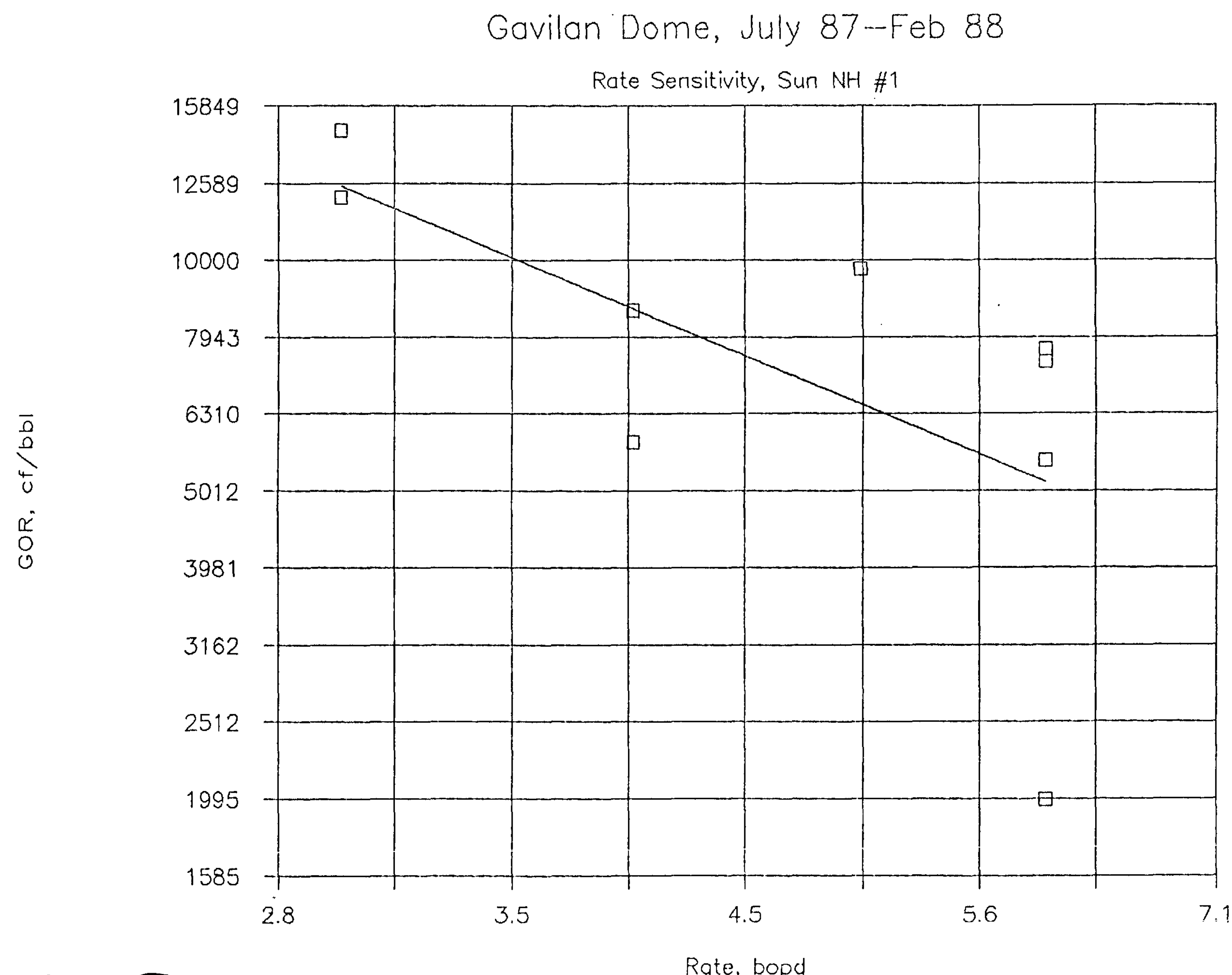

Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun Lod #1
10000
7943
6310
5012
3981
3162
2512
GOR, cf/bbl & Rate, mcfpd
42
46
50
55
60
66
72
79
Rate, bopd
GOR, cf/bbl
Rate, mcfpd X 10


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun ML #1
25119
19953
15849
12589
10000
7943
6310
GOR, cf/bbl
16
25
40
Rate, bopd

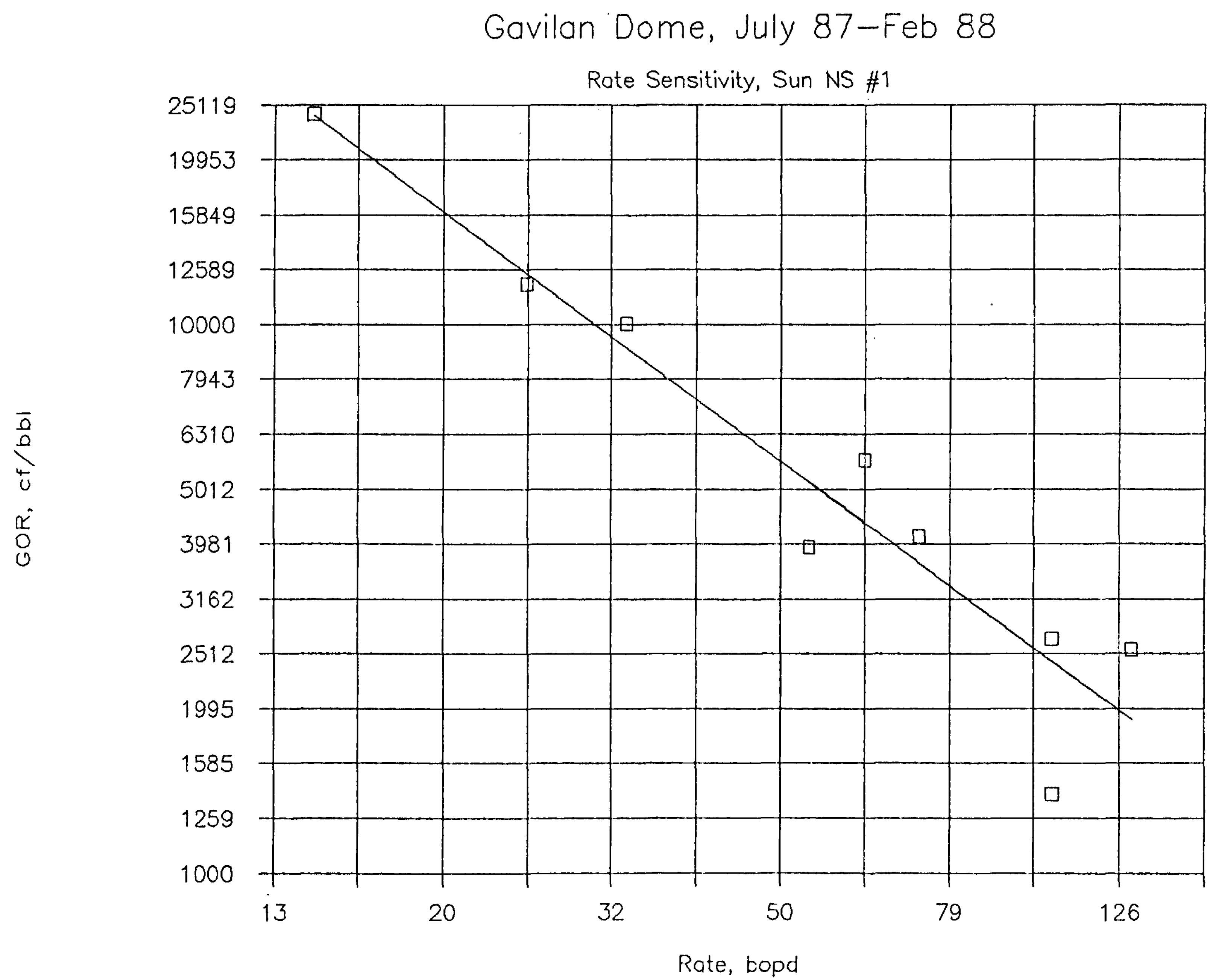
C.C. = 0.08


Gavilan Dome, July 87–Feb 88
Rate Sensitivity, Sun ML #2
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
GOR, cf/bbl
25
40
63
100
Rate, bopd

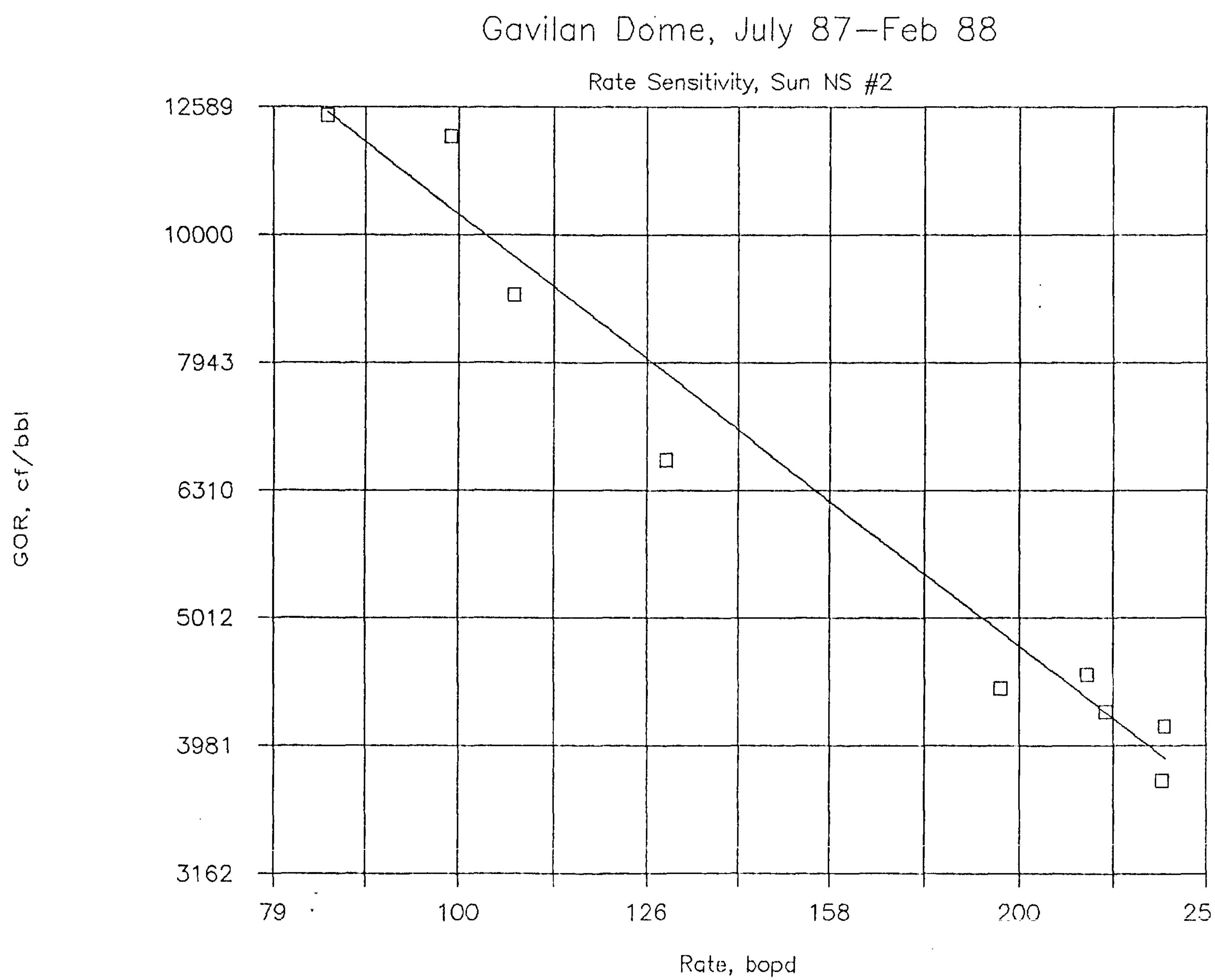
C.C. = 0.87


Gavilan Dome, July 87--Feb 88
Rate Sensitivity, Sun NH #1
GOR, cf/bbl
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
1585
2.8
3.5
4.5
5.6
7.1
Rate, bopd

C. C. = 0.65


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun NS #1
GOR, cf/bbl
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
1000
13
20
32
50
79
126
Rate, bopd

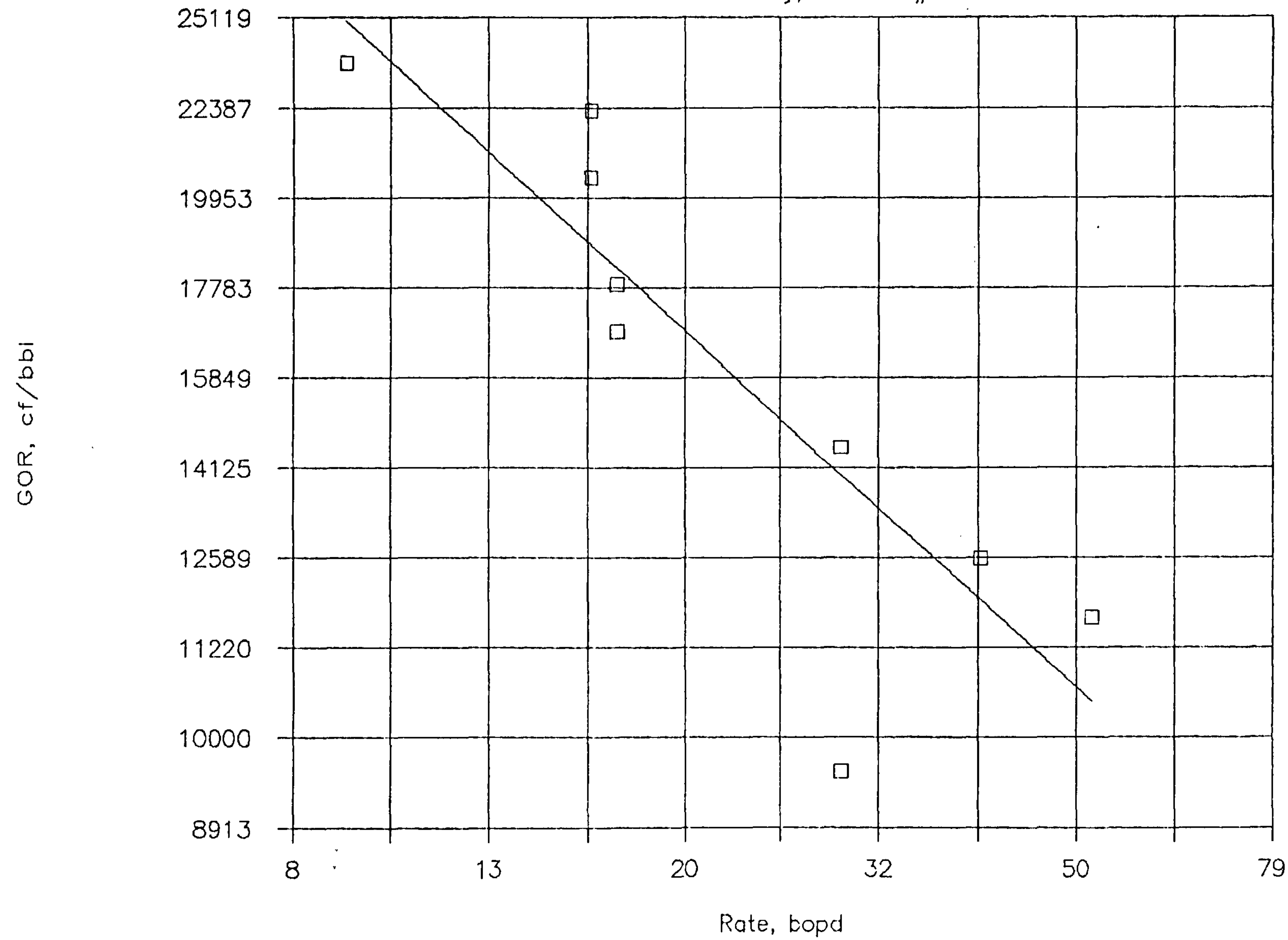
C.C. = 0.95


Gavilan Dome, July 87—Feb 88
Rate Sensitivity, Sun NS #2
12589
10000
7943
6310
5012
3981
3162
GOR, cf/bbl
79
100
126
158
200
251
Rate, bopd

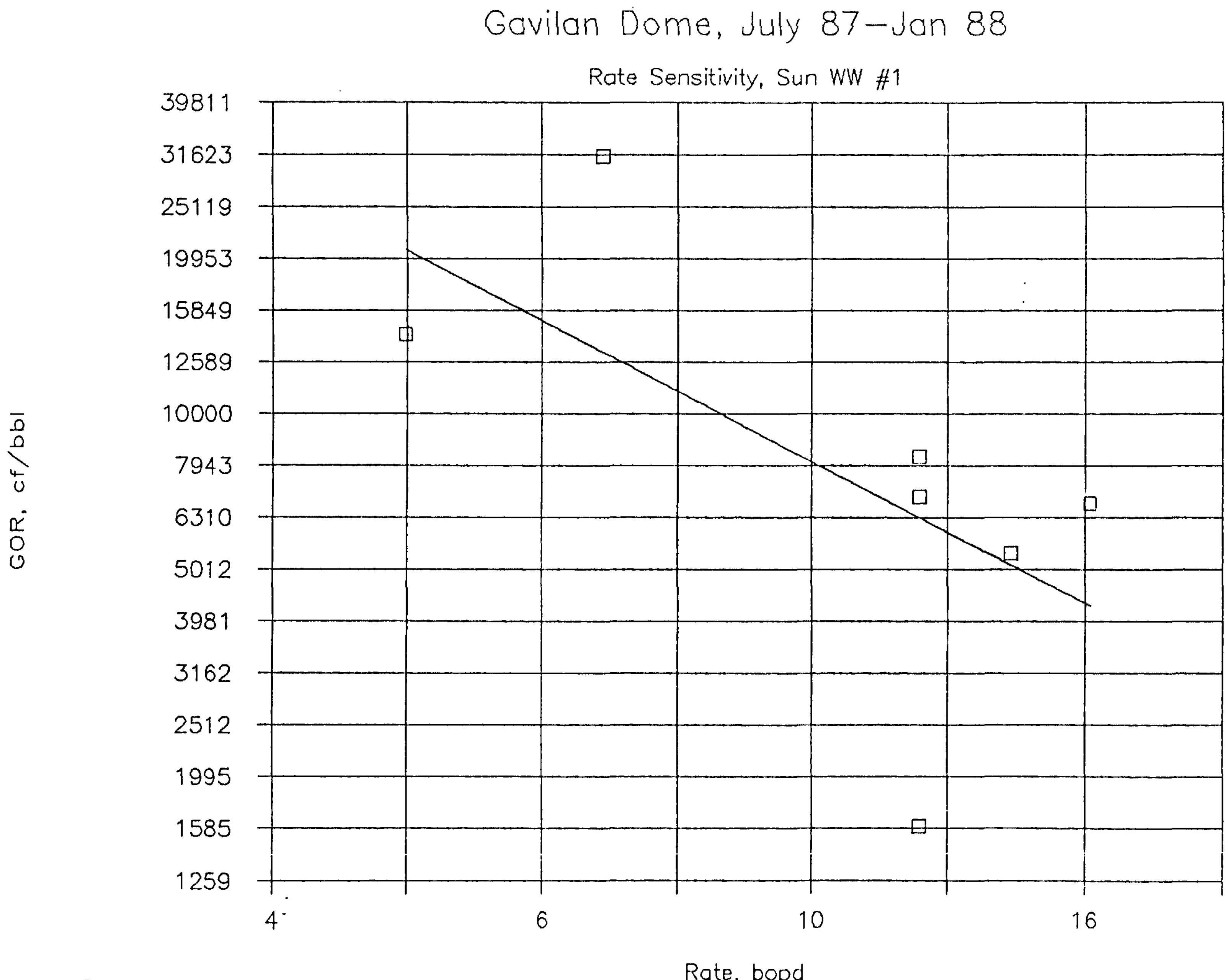
C.C. = 0.98

Gavilan Dome, July 87—Feb 88

Rate Sensitivity, Sun NS #3



C. C. = 0.86


Gavilan Dome, July 87—Jan 88
Rate Sensitivity, Sun WW #1
GOR, cf/bbl
39811
31623
25119
19953
15849
12589
10000
7943
6310
5012
3981
3162
2512
1995
1585
1259
4
6
10
16
Rate, bopd

C.C. = 0.62

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
AMOCO	BCU#1	1/1-1/31	190	314	8173	1554	60
AMOCO	BCU#1	2/1-2/29	145	292	7297	1058	42
				606			
AMOCO	BCU#2	2/1-2/29	274	228	3421	938	67
AMOCO	HTF#1	2/1-2/29	1687	12	83	140	20
AMOCO	OCFB#1	2/1-2/29	13250	22	44	583	292
AMOCO	SGC#1	1/1-1/31	8971	30	273	2449	245
AMOCO	SGC#1	2/1-2/29	3856	35	810	3123	142
				65			
AMOCO	SCC#1	2/1-2/29	99	201	4432	440	20
BMG	A-16	7/1-7/31	1075	16	214	230	18
BMG	A-16	8/1-8/31	1600	6	25	40	10
BMG	A-16	9/1-9/30	4009	11	212	850	45
				33			
BMG	A-20	7/1-7/31	1176	17	187	220	20
BMG	A-20	8/1-8/31	2843	38	568	1615	107
BMG	A-20	9/1-9/30	5331	46	1103	5880	245
BMG	A-20	11/1-11/14	5812	42	585	3400	243
BMG	A-20	12/1-12/31	5405	51	666	3600	277
BMG	A-20	1/1-1/31	6802	52	1601	10890	351
BMG	A-20	2/1-2/29	9474	44	133	1260	420
				290			
BMG	B-29	7/1-7/31	1219	673	18176	22160	821
BMG	B-29	8/1-8/31	1269	757	21187	26887	960
BMG	B-29	9/1-9/30	1922	1156	32372	62230	2223
BMG	B-29	10/1-10/31	2092	1003	15041	31460	2097
BMG	B-29	11/1-11/16	2262	1046	16738	37860	2366
BMG	B-29	11/30-12/31	2161	977	17578	37990	2111
BMG	B-29	2/1-2/29	1444	1047	8379	12100	1513
				6659			
BMG	B-32	7/1-7/31	1046	519	12984	13575	543
BMG	B-32	8/1-8/31	1261	714	19993	25210	900
BMG	B-32	9/1-9/30	1119	911	27344	30600	1020
BMG	B-32	10/1-10/31	1197	800	11998	14360	957
BMG	B-32	11/1-11/16	1200	719	11509	13810	863
BMG	B-32	11/30-12/31	1185	704	11964	14180	834
BMG	B-32	1/1-1/31	1000	701	13319	1300	700

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
BMG	B-32	2/1-2/29	1101	704	16894	18605	775
				5772			
BMG	C-34	12/1-12/31	10345	44	348	3600	450
BMG	C-34	1/1-1/31	11990	38	191	2290	458
BMG	C-34	2/1-2/29	17551	62	494	8670	1084
				144			
BMG	D-17	7/1-7/31	1195	9	135	160	1067
BMG	E-6	7/1-7/31	3966	307	7687	30490	1220
BMG	E-6	8/1-8/31	2339	362	11228	26260	847
BMG	E-6	9/1-9/30	2068	426	12765	26404	880
BMG	E-6	10/1-10/31	2757	358	5375	14820	988
BMG	E-6	11/1-11/16	4223	271	4063	17160	1144
BMG	E-6	12/1-12/31	4998	159	2391	11950	797
BMG	E-6	1/1-1/31	4752	169	2033	9660	805
				2052			
BMG	E-10	7/1-7/31	3124	380	11012	34400	1186
BMG	E-10	8/1-8/31	4896	303	9384	45940	1482
BMG	E-10	9/1-9/30	7124	236	6127	43760	1750
BMG	E-10	11/1-11/16	7589	235	3754	28490	1781
BMG	E-10	1/1-1/31	9199	222	1761	16200	1800
BMG	E-10	2/1-2/29	23201	62	556	12900	1433
				1438			
BMG	F-7	12/1-12/31	2689	124	2224	5980	332
BMG	F-7	1/1-1/31	5457	147	3832	20910	804
				271			
BMG	F-18	7/1-7/31	631	224	3362	2120	141
BMG	F-18	8/1-8/31	448	326	10096	4520	146
BMG	F-18	9/1-9/30	538	406	9751	5250	219
BMG	F-18	10/1-10/31	395	390	5846	2310	154
BMG	F-18	11/1-11/16	504	365	5469	2755	184
BMG	F-18	12/1-12/31	522	325	9753	5095	170
BMG	F-18	1/1-1/31	465	311	9643	4480	145
BMG	F-18	2/1-2/29	667	304	6982	4655	202
				2651			
BMG	F-19	7/1-7/31	6754	64	1869	12624	435
BMG	F-19	8/1-8/31	9719	75	2314	22490	725
BMG	F-19	9/1-9/30	13050	60	1436	18740	781
BMG	F-19	11/1-11/14	15035	51	712	10705	765
BMG	F-19	12/1-12/31	16392	43	693	11360	757
BMG	F-19	1/1-1/31	4899	100	398	1950	488
BMG	F-19	2/1-2/29	8417	60	120	1010	505
				453			

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
BMG	F-30	7/1-7/31	1042	357	10009	10430	373
BMG	F-30	8/1-8/31	989	347	9703	9600	343
BMG	F-30	9/1-9/30	1046	417	12506	13080	436
BMG	F-30	10/1-10/31	1094	355	5331	5830	389
BMG	F-30	11/1-11/16	1123	334	5337	5992	375
BMG	F-30	11/30-12/31	1134	311	9963	11295	353
BMG	F-30	1/1-1/31	1171	293	8491	9940	343
BMG	F-30	2/1-2/29	1104	349	8366	9240	385
				2763			
BMG	G-5	9/1-9/30	774	266	1330	1030	206
BMG	G-5	10/1-10/31	1073	263	3952	4240	283
BMG	G-5	11/1-11/16	1912	183	2924	5590	349
BMG	G-5	11/21-11/30	2093	158	473	990	330
BMG	G-5	12/1-12/31	2688	135	2697	7250	363
BMG	G-5	1/1-1/31	244	157	4860	11880	383
BMG	G-5	2/1-2/29	2374	465	3252	7720	351
				1627			
BMG	G-32	7/1-7/31	1132	13	53	60	15
BMG	G-32	9/1-9/30	870	12	46	40	10
				25			
BMG	J-6	8/1-8/31	3764	79	1905	7170	299
BMG	J-6	9/1-9/30	5556	55	1530	8500	304
BMG	J-6	11/1-11/10	35101	15	149	5230	523
BMG	J-6	12/1-12/31	22735	23	340	7730	515
BMG	J-6	1/1-1/31	29858	18	211	6300	525
				190			
BMG	J-8	9/1-9/30	1852	7	27	50	13
BMG	K-8	7/1-7/31	562	5	146	82	3
BMG	K-8	8/1-8/31	1207	6	29	35	7
BMG	K-8	9/1-9/30	2065	9	46	95	19
BMG	K-8	12/1-12/31	5618	9	89	500	50
BMG	K-8	1/1-1/31	4789	4	95	455	20
BMG	K-8	2/1-2/29	5000	2	41	205	10
				35			
BMG	L-3	9/1-9/30	722	22	486	351	16
BMG	L-3	10/1-10/31	732	14	205	150	10
BMG	L-3	11/1-11/16	758	19	211	160	16
BMG	L-3	12/1-12/31	699	32	256	179	22
BMG	L-3	1/1-1/31	787	16	305	240	13
				103			
BMG	L-11	8/1-8/31	186207	7	116	21600	1137

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
BMG	L-11	9/1-9/30	240000	5	15	3600	1200
BMG	L-11	2/1-2/29	18206	46	418	7610	761
				58			
BMG	L-27	7/1-7/31	2462	166	3980	9800	408
BMG	L-27	8/1-8/31	2641	157	4863	12845	414
BMG	L-27	9/1-9/30	2386	165	4949	11810	394
BMG	L-27	10/1-10/31	2382	163	2439	5810	387
BMG	L-27	11/1-11/16	2497	155	2479	6190	387
BMG	L-27	11/21-11/30	2491	160	1443	3595	399
BMG	L-27	12/1-12/31	2343	170	3064	7180	399
BMG	L-27	1/1-1/31	2372	152	4697	11140	359
BMG	L-27	2/1-2/29	2501	152	3351	8380	381
				1440			
BMG	N-22	7/1-7/31	791	82	2365	1870	64
BMG	N-22	8/1-8/31	465	86	1634	760	40
BMG	N-22	9/1-9/30	401	77	2317	930	31
BMG	N-22	10/1-10/31	412	73	1093	450	30
BMG	N-22	11/1-11/16	392	76	1213	475	30
BMG	N-22	11/21-11/30	412	95	947	390	39
BMG	N-22	12/1-12/31	422	68	2108	890	33
BMG	N-22	1/1-1/31	440	66	1911	840	29
BMG	N-22	2/1-2/29	399	80	1753	700	32
				703			
BMG	N-31	7/1-7/31	2240	182	5291	11850	409
BMG	N-31	8/1-8/31	1238	203	6303	7800	252
BMG	N-31	9/1-9/30	1025	194	5833	5980	199
BMG	N-31	10/1-10/31	1234	185	2771	3420	228
BMG	N-31	11/1-11/16	3106	127	2035	6320	395
BMG	N-31	12/1-12/31	4393	97	1457	6400	427
				988			
BMG	O-9	7/1-7/31	1082	11	319	345	12
BMG	O-9	8/1-8/31	1316	6	19	25	8
BMG	O-9	9/1-9/30	1044	21	297	310	22
BMG	O-9	11/21-11/30	1095	15	137	150	17
BMG	O-9	12/1-12/31	1118	13	331	370	16
BMG	O-9	1/1-1/31	1037	10	270	280	10
BMG	O-9	2/1-2/29	1036	14	304	315	15
				90			
BMG	O-33	7/1-7/31	3484	21	574	2000	74
BMG	O-33	8/1-8/31	5056	18	89	450	90
BMG	O-33	9/1-9/30	3052	28	729	2225	85
BMG	O-33	10/1-10/31	3003	21	313	940	63
BMG	O-33	11/1-11/14	2115	22	260	550	46
BMG	O-33	12/1-12/31	2853	28	333	950	95
BMG	O-33	1/1-1/31	3051	18	372	1135	54

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
				156			
DUGAN	LIND #1	7/1-7/31	7766	8	128	994	34
DUGAN	LIND #1	8/1-8/31	7504	5	121	908	36
DUGAN	LIND #1	9/1-9/30	7884	4	95	749	31
DUGAN	LIND #1	10/1-10/31	8733	4	116	1013	33
DUGAN	LIND #1	11/1-11/16	10465	4	22	225	28
DUGAN	LIND #1	11/21-11/30	9935	4	15	152	30
DUGAN	LIND #1	12/1-12/31	13367	5	60	802	29
DUGAN	LIND #1	1/1-1/31	4227	6	22	93	23
				40			
HIXON	DIV #3	7/1-7/31	794	103	2480	1969	82
HIXON	DIV #3	8/1-8/31	795	105	3147	2501	83
HIXON	DIV #3	10/1-10/31	795	110	1759	1399	87
HIXON	DIV #3	11/1-11/15	796	108	1619	1289	86
HIXON	DIV #3	12/1-12/31	795	103	3083	2452	82
HIXON	DIV #3	1/1-1/31	796	97	3019	2404	78
HIXON	DIV #3	2/2-2/29	797	93	2322	1851	74
				719			
HIXON	TAP #2	7/1-7/31	6239	12	355	2215	73
HIXON	TAP #2	8/1-8/31	6209	10	325	2018	65
HIXON	TAP #2	10/1-10/31	6202	6	99	614	38
HIXON	TAP #2	11/1-11/15	6208	7	77	478	43
HIXON	TAP #2	12/1-12/31	6220	5	127	790	32
HIXON	TAP #2	1/1-1/31	6196	5	56	347	32
HIXON	TAP #2	2/1-2/29	6220	6	41	255	36
				51			
HIXON	TAP #4	7/1-7/31	918	143	4133	3795	131
HIXON	TAP #4	8/1-8/31	918	146	4235	3889	134
HIXON	TAP #4	10/1-10/31	917	135	2154	1976	124
HIXON	TAP #4	11/1-11/15	917	131	1970	1807	120
HIXON	TAP #4	12/1-12/31	918	123	3824	3510	113
HIXON	TAP #4	1/1-1/31	917	97	2140	1962	89
HIXON	TAP #4	2/1-2/29	918	78	1944	1784	71
				853			
MALLON	DF 3#15	12/1-12/31	62591	4	44	2754	230
MALLON	DF 3#15	1/1-1/31	9908	13	141	1397	64
MALLON	DF 3#15	2/1-2/29	13295	6	95	1263	66
				23			
MALLON	FF 2#1	7/1-7/31	1326	316	9789	12979	419
MALLON	FF 2#1	8/1-8/31	1407	265	8211	11556	373
MALLON	FF 2#1	9/1-9/30	1306	285	6844	8936	372
MALLON	FF 2#1	10/1-10/31	1321	272	8426	11134	359
MALLON	FF 2#1	11/1-11/15	8730	40	597	5212	347
MALLON	FF 2#1	11/20-11/30	3636	165	1814	6596	600

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
MALLON	FF 2#1	12/1-12/31	9591	90	1077	10329	861
MALLON	FF 2#1	1/1-1/31	11649	96	479	5580	1116
MALLON	FF 2#1	2/1-2/29	11232	95	1048	11771	1070
				1624			
MALLON	HF 1#8	7/1-7/31	3212	278	8609	27649	892
MALLON	HF 1#8	8/1-8/31	3691	288	8919	32922	1062
MALLON	HF 1#8	9/1-9/30	3472	316	9471	32886	1096
MALLON	HF 1#8	10/1-10/31	3771	264	8186	30871	996
MALLON	HF 1#8	11/1-11/15	3736	244	3657	13664	911
MALLON	HF 1#8	11/21-11/30	8022	122	856	6867	981
MALLON	HF 1#8	12/1-12/31	1255	115	805	1010	144
MALLON	HF 1#8	1/1-1/31	9388	120	720	6759	1127
MALLON	HF 1#8	2/1-2/29	8498	120	841	7147	1021
				1867			
MALLON	HF 1#11	7/1-7/31	6328	186	5578	35298	1217
MALLON	HF 1#11	8/1-8/31	5147	256	5368	27628	1316
MALLON	HF 1#11	9/1-9/30	4770	284	6241	29769	1294
MALLON	HF 1#11	10/1-10/31	5503	241	7472	41119	1326
MALLON	HF 1#11	11/1-11/30	5545	254	3803	21087	1406
MALLON	HF 1#11	12/1-12/31	8339	177	1415	11800	1311
MALLON	HF 1#11	2/1-2/29	11085	137	684	7582	1516
				1535			
MALLON	JF 12#5	7/1-7/31	23870	17	322	7686	452
MALLON	JF 12#5	8/1-8/31	5281	70	1260	6654	370
MALLON	JF 12#5	9/1-9/30	5689	58	1725	9813	327
MALLON	JF 12#5	10/1-10/31	5682	53	1644	9341	301
MALLON	JF 12#5	11/1-11/15	8730	40	597	5212	347
MALLON	JF 12#5	11/20-11/30	21547	20	223	4805	437
MALLON	JF 12#5	12/1-12/31	40893	10	270	11041	425
MALLON	JF 12#5	1/1-1/31	44067	11	75	3305	472
MALLON	JF 12#5	2/1-2/29	53509	8	114	6100	407
				287			
MALLON	PF 13#6	7/1-7/31	5311	72	2235	11869	383
MALLON	PF 13#6	8/1-8/31	4897	83	2558	12526	404
MALLON	PF 13#6	9/1-9/30	2071	111	3331	6899	230
MALLON	PF 13#6	10/1-10/31	15351	88	2725	41831	1349
MALLON	PF 13#6	11/1-11/15	6241	58	872	5442	363
MALLON	PF 13#6	11/20-11/30	6573	70	769	5055	460
MALLON	PF 13#6	12/1-12/31	14096	45	178	2509	627
MALLON	PF 13#6	1/1-1/31	34024	16	252	8574	536
MALLON	PF 13#6	2/1-2/29	67677	7	96	6497	406
				550			
MALLON	RF 2#16	7/1-7/31	2849	76	2366	6741	217
MALLON	RF 2#16	8/1-8/31	2468	87	2708	6683	216
MALLON	RF 2#16	9/1-9/30	2541	87	2604	6617	221

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
MALLON	RF 2#16	10/1-10/31	2718	85	2550	6931	224
MALLON	RF 2#16	11/1-11/15	3686	37	370	1364	136
MALLON	RF 2#16	11/20-11/30	3227	40	441	1423	129
MALLON	RF 2#16	12/1-12/31	9538	30	751	7163	276
MALLON	RF 2#16	1/1-1/31	35631	13	295	10511	350
MALLON	RF 2#16	2/1-2/29	141905	3	21	2980	373
				458			
MERIDIAN	HAF #2	7/1-7/31	20207	24	386	7800	488
MERIDIAN	HAF #2	8/1-8/31	14827	31	689	10216	464
MERIDIAN	HAF #2	9/1-9/30	4296	70	1049	4506	300
MERIDIAN	HAF #2	11/1-11/16	12074	27	27	326	326
MERIDIAN	HAF #2	11/21-11/30	12384	27	190	2353	336
MERIDIAN	HAF #2	12/1-12/31	20154	19	325	6550	364
MERIDIAN	HAF #2	1/1-1/31	24918	18	306	7625	477
				216			
MERIDIAN	HAF #3	7/1-7/31	10685	44	696	7437	465
MERIDIAN	HAF #3	8/1-8/31	7537	54	1089	8208	410
MERIDIAN	HAF #3	9/1-9/30	5551	60	907	5035	336
MERIDIAN	HAF #3	11/1-11/16	10520	25	25	263	263
MERIDIAN	HAF #3	11/21-11/30	10401	24	167	1737	248
MERIDIAN	HAF #3	12/1-12/31	19618	12	280	5493	211
MERIDIAN	HAF #3	1/1-1/31	16465	20	159	2618	154
				239			
MERIDIAN	HF #1	7/1-7/31	15915	65	1037	16504	1032
MERIDIAN	HF #1	8/1-8/31	38913	26	515	20040	1002
MERIDIAN	HF #1	9/1-9/30	43723	21	314	13729	915
MERIDIAN	HF #1	11/1-11/16	102500	8	8	820	820
MERIDIAN	HF #1	11/21-11/30	31623	28	167	5281	880
MERIDIAN	HF #1	12/1-12/31	43236	19	191	8258	751
MERIDIAN	HF #1	1/1-1/31	81011	12	95	7696	962
				179			
MERIDIAN	HF #2Y	6/1-6/30	2997	87	1819	5452	260
MERIDIAN	HF #2Y	8/1-8/31	3978	62	934	3715	219
MERIDIAN	HF #2Y	9/1-9/30	4626	52	773	3576	238
MERIDIAN	HF #2Y	11/1-11/16	21143	7	7	148	148
MERIDIAN	HF #2Y	11/21-11/30	8100	40	140	1296	216
MERIDIAN	HF #2Y	12/1-12/31	5733	41	857	4913	234
MERIDIAN	HF #2Y	1/1-1/31	5554	36	1082	6009	207
				325			
MERIDIAN	HF #3	7/1-7/31	2342	69	1105	2588	162
MERIDIAN	HF #3	8/1-8/31	2101	72	1516	3185	152
MERIDIAN	HF #3	11/1-11/16	6679	28	28	187	187
MERIDIAN	HF #3	11/21-11/30	7027	31	183	1286	214
MERIDIAN	HF #3	12/1-12/31	8861	25	624	5529	213
MERIDIAN	HF #3	1/1-1/31	18724	12	199	3726	143

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
				237			
MERRION	KRY #1	1/1-1/31	19631	13	65	1276	51
MERRION	OCG #1	7/1-7/31	1691	8	55	93	13

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
MESA GR.	BC #1	6/1-6/30	6010	47	895	5379	269
MESA GR.	BC #1	7/1-7/31	4681	64	966	4522	301
MESA GR.	BC #1	8/1-8/31	4323	59	1543	6670	267
MESA GR.	BC #1	10/1-10/31	16050	20	20	321	321
MESA GR.	BC #1	11/1-11/17	9263	24	400	3705	218
MESA GR.	BC #1	11/21-11/30	18094	11	85	1538	192
MESA GR.	BC #1	12/1-12/31	17406	10	251	4369	182
MESA GR.	BC #1	1/1-1/31	45768	5	99	4531	206
MESA GR.	BC #1	2/1-2/29	44417	6	96	4264	213
MESA GR.	BRO #1	7/1-7/31	9027	76	1135	10246	683
MESA GR.	BRO #1	8/1-8/31	9027	103	2783	25123	930
MESA GR.	BRO #1	10/1-10/31	7627	130	3912	29837	962
MESA GR.	BRO #1	11/1-11/16	7848	108	1725	13538	846
MESA GR.	BRO #1	11/21-11/30	7990	100	800	6392	799
MESA GR.	BRO #1	12/1-12/31	7631	112	2234	17047	852
MESA GR.	BRO #1	1/1-1/31	6194	111	1886	11681	687
MESA GR.	BRO #1	2/1-2/29	7907	92	1661	13133	773
MESA GR.	GAV #1	7/1-7/31	21926	10	149	3267	218
MESA GR.	GAV #1	8/1-8/31	22408	9	238	5333	190
MESA GR.	GAV #1	10/1-10/31	32875	3	104	3419	110
MESA GR.	GAV #1	11/1-11/17	14220	3	41	583	34
MESA GR.	GAV #1	11/21-11/30	42027	5	37	1555	194
MESA GR.	GAV #1	12/1-12/31	1889	3	36	68	6
MESA GR.	GAV #1	1/1-1/31	33977	10	130	4417	316
MESA GR.	GAV #1	2/1-2/29	67716	4	81	5485	219
MESA GR.	GAV #3	7/1-7/31	28595	9	79	2259	151
MESA GR.	GAV #3	8/1-8/31	10247	12	299	3064	113
MESA GR.	GAV #3	10/1-10/31	33843	6	178	6024	194
MESA GR.	GAV #3	12/1-12/31	23618	9	55	1299	130
MESA GR.	GAV #3	1/1-1/31	51710	3	31	1603	100
MESA GR.	GAV #3	2/1-2/29	46578	4	45	2096	140
MESA GR.	GH #1	7/1-7/31	16749	16	239	4003	267
MESA GR.	GH #1	8/1-8/31	24102	16	372	8966	345
MESA GR.	GH #1	10/1-10/31	47667	12	12	572	572
MESA GR.	GH #1	11/1-11/17	64780	6	109	7061	392
MESA GR.	GH #1	11/21-11/30	58909	6	44	2592	324
MESA GR.	GH #1	12/1-12/31	63796	7	152	9697	359
MESA GR.	GH #1	1/1-1/31	83186	5	118	9816	393
MESA GR.	HC #1	8/1-8/31	8604	13	371	3192	110
MESA GR.	HC #1	10/1-10/31	5200	25	25	130	130

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
MESA GR.	HC #1	11/1-11/16	10727	10	161	1727	108
MESA GR.	HC #1	11/22-11/30	63267	3	15	949	136
MESA GR.	HC #1	12/1-12/31	18663	11	89	1661	151
MESA GR.	HC #1	1/1-1/31	20767	8	129	2679	128
MESA GR.	HC #1	2/1-2/29	30725	6	109	3349	146
MESA GR.	INV #1	2/1-2/29	4259	14	228	971	54
MESA GR.	MAR #1	7/1-7/31	2709	94	1416	3836	256
MESA GR.	MAR #1	8/1-8/31	3376	68	1489	5027	229
MESA GR.	MAR #1	10/1-10/31	5237	48	1394	7301	243
MESA GR.	MAR #1	11/1-11/17	6948	39	620	4308	253
MESA GR.	MAR #1	11/21-11/30	8774	30	212	1860	233
MESA GR.	MAR #1	12/1-12/31	13194	11	263	3470	129
MESA GR.	MAR #1	1/1-1/31	3494	50	451	1576	197
MESA GR.	MAR #1	2/1-2/29	9449	33	750	7087	308
MESA GR.	PRO #1	2/1-2/29	4594	21	512	2352	98
MESA GR.	RL #2	7/1-7/31	4771	57	855	4079	272
MESA GR.	RL #2	8/1-8/31	5389	47	1260	6790	251
MESA GR.	RL #2	10/1-10/31	3967	47	1456	5776	186
MESA GR.	RL #2	11/1-11/17	4336	39	664	2879	169
MESA GR.	RL #2	11/21-11/31	5500	17	120	660	83
MESA GR.	RL #2	12/1-12/31	4629	47	1088	5036	187
MESA GR.	RL #2	1/1-1/31	7791	34	506	3942	141
MESA GR.	RL #2	2/1-2/29	17015	15	336	5717	249
MESA GR.	RL #3	7/1-7/31	2156	37	556	1199	80
MESA GR.	RL #3	8/1-8/31	1860	48	1250	2325	83
MESA GR.	RL #3	10/1-10/31	1875	32	933	1749	56
MESA GR.	RL #3	11/1-11/17	9625	16	32	308	62
MESA GR.	RL #3	12/1-12/31	10554	12	177	1868	75
MESA GR.	RL #3	1/1-1/31	16365	9	192	3142	101
MESA GR.	RL #3	2/1-2/29	18720	8	175	3276	131
MOBIL	LIN B#34	7/1-7/31	3501	72	2229	7804	252
MOBIL	LIN B#34	8/1-8/31	3365	56	1733	5832	216
MOBIL	LIN B#34	9/1-9/30	3697	47	1396	5161	172
MOBIL	LIN B#34	10/1-10/31	4817	37	955	4600	170
MOBIL	LIN B#34	11/1-11/16	4246	33	532	2259	141
MOBIL	LIN B#34	11/20-11/30	4083	43	384	1568	174
MOBIL	LIN B#34	12/1-12/31	5126	35	987	5059	181
MOBIL	LIN B#34	1/1-1/31	7368	25	560	4126	179
MOBIL	LIN B#34	2/1-2/29	7766	28	691	5366	215

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
MOBIL	LIN B#37	7/1-7/31	7750	54	1683	13044	435
MOBIL	LIN B#37	8/1-8/31	3733	218	6772	25283	936
MOBIL	LIN B#37	9/1-9/30	3192	244	7314	23349	778
MOBIL	LIN B#37	10/1-10/31	3953	225	6975	27573	889
MOBIL	LIN B#37	11/1-11/17	3907	214	3641	14225	889
MOBIL	LIN B#37	11/20-11/30	3682	195	1947	7168	796
MOBIL	LIN B#37	12/1-12/31	3757	213	3837	14417	801
MOBIL	LIN B#37	1/1-1/31	4063	192	3657	14858	782
MOBIL	LIN B#37	2/1-2/29	4112	188	3570	14679	816
MOBIL	LIN B#38	7/1-7/31	19598	13	415	8133	262
MOBIL	LIN B#38	8/1-8/31	21127	10	300	6338	235
MOBIL	LIN B#38	9/1-9/30	29320	8	219	6421	199
MOBIL	LIN B#38	10/1-10/31	24403	8	238	5808	187
MOBIL	LIN B#38	11/1-11/16	27625	6	96	2652	166
MOBIL	LIN B#72	7/1-7/31	20565	4	108	2221	74
MOBIL	LIN B#72	8/1-8/31	21349	4	86	1836	68
MOBIL	LIN B#72	9/1-9/30	25473	3	74	1885	63
MOBIL	LIN B#72	11/20-11/30	38523	6	44	1695	188
MOBIL	LIN B#72	12/1-12/31	66383	12	81	5377	199
MOBIL	LIN B#72	1/1-1/31	71987	3	79	5676	183
MOBIL	LIN B#72	2/1-2/29	19500	3	58	1131	45
MOBIL	LIN B#73	7/1-7/31	19977	7	173	3456	115
MOBIL	LIN B#73	8/1-8/31	17279	6	165	2851	106
MOBIL	LIN B#73	9/1-9/30	16449	7	187	3076	103
MOBIL	LIN B#73	10/1-10/31	17724	7	192	3403	110
MOBIL	LIN B#73	11/1-11/16	26657	5	67	1786	112
MOBIL	LIN B#73	11/20-11/30	19154	7	52	996	111
MOBIL	LIN B#73	12/1-12/31	8970	16	302	2709	113
MOBIL	LIN B#73	1/1-1/31	14429	10	219	3160	117
MOBIL	LIN B#73	2/1-2/29	27143	5	98	2660	111
MOBIL	LIN B#74	7/1-7/31	53190	8	210	11170	30
MOBIL	LIN B#74	8/1-8/31	15613	32	727	11351	437
MOBIL	LIN B#74	9/1-9/30	12994	36	980	12734	424
MOBIL	LIN B#74	10/1-10/31	9931	35	1008	10010	323
MOBIL	LIN B#74	11/1-11/16	10793	32	482	5202	325
MOBIL	LIN B#74	11/20-11/30	37495	14	109	4087	454
MOBIL	LIN B#74	12/1-12/31	50631	11	141	7139	376
MOBIL	LIN B#74	1/1-1/31	74360	6	100	7436	372
MOBIL	LIN B#74	2/1-2/29	42538	7	119	5062	281

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
R&B	HF 43-15	6/1-6/30	55728	4	103	5740	239
R&B	HF 43-15	7/1-7/31	29693	15	378	11224	416
R&B	HF 43-15	8/1-8/31	39632	11	353	13990	466
R&B	HF 43-15	9/1-9/30	46545	9	44	2048	410
R&B	HF 43-15	10/1-10/31	34337	20	98	3365	673
R&B	HF 43-15	11/1-11/16	69293	9	147	10186	637
R&B	HF 43-15	11/21-11/30	79180	6	61	4830	483
R&B	HF 43-15	12/1-12/31	53333	5	117	6240	240
R&B	IN 34-16	9/1-9/30	39613	8	31	1228	205
R&B	IN 34-16	10/1-10/31	12698	46	1160	14730	526
R&B	IN 34-16	11/1-11/16	12312	54	858	10564	660
R&B	IN 34-16	11/20-11/30	11991	60	663	7950	723
R&B	IN 34-16	12/1-12/31	9708	72	1231	11950	703
SUN	BB#1	7/1-7/31	2701	133	3585	9684	372
SUN	BB#1	8/1-8/31	2995	123	3309	9909	367
SUN	BB#1	9/1-9/30	3322	102	1635	5431	362
SUN	BB#1	10/1-10/31	3944	108	2054	8100	426
SUN	BB#1	11/1-11/16	4282	96	1533	6564	410
SUN	BB#1	11/22-11/30	2973	64	451	1341	192
SUN	BB#1	12/1-12/31	3563	78	2026	7219	267
SUN	BB#1	1/1-1/31	4030	64	1538	6198	258
SUN	B&L#1	7/1-7/31	10250	2	48	492	21
SUN	B&L#1	8/1-8/31	6020	2	50	301	10
SUN	B&L#1	9/1-9/30	14909	2	11	164	15
SUN	B&L#2	7/1-7/31	13971	4	34	475	53
SUN	DRDO#1	7/1-7/31	4010	70	2106	8445	282
SUN	DRDO#1	8/1-8/31	6664	42	1038	6917	266
SUN	DRDO#1	9/1-9/30	9324	32	550	5128	302
SUN	DRDO#1	10/1-10/31	14614	20	383	5597	295
SUN	DRDO#1	11/1-11/16	16424	17	264	4336	271
SUN	DRDO#1	11/21-11/30	26475	13	101	2674	334
SUN	DRDO#1	12/1-12/31	10084	26	713	7190	257
SUN	DRDO#1	1/1-1/31	5901	37	1135	6698	216
SUN	E.T.	7/1-7/31	28740	13	404	11611	387
SUN	E.T.	8/1-8/31	50890	7	172	8753	324
SUN	E.T.	9/1-9/30	56356	5	87	4903	288
SUN	E.T.	10/1-10/31	91667	3	48	440	232
SUN	E.T.	11/1-11/16	99280	2	25	2482	155

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
SUN	E.T.	11/21-11/30	40089	6	45	1804	226
SUN	E.T.	12/1-12/31	23621	8	214	5055	181
SUN	E.T.	1/1-1/31	139615	2	13	1815	113
SUN	FS#1	7/1-7/31	2533	54	1404	3556	142
SUN	FS#1	8/1-8/31	2060	71	1918	3952	146
SUN	FS#1	9/1-9/30	2128	66	1120	2383	140
SUN	FS#1	10/1-10/31	2525	54	1027	2593	136
SUN	FS#1	11/1-11/16	2667	49	787	2099	131
SUN	FS#1	11/21-11/30	2378	109	368	875	109
SUN	FS#1	12/1-12/31	2105	52	1405	2957	106
SUN	FS#1	1/1-1/31	2976	48	1446	4303	143
SUN	FSA#2	7/1-7/31	22195	33	990	21973	732
SUN	FSA#2	8/1-8/31	25292	26	678	17148	660
SUN	FSA#2	9/1-9/30	30122	20	345	10392	611
SUN	FSA#2	10/1-10/31	32395	15	294	9524	501
SUN	FSA#2	11/1-11/16	35884	11	138	4952	354
SUN	FSA#2	11/21-11/30	37120	8	50	1856	309
SUN	FSA#2	12/1-12/31	35008	12	244	8542	427
SUN	FSA#2	1/1-1/31	37137	9	95	3528	358
SUN	FSB#3	7/1-7/31	6550	15	447	2928	98
SUN	FSB#3	8/1-8/31	2800	14	370	1036	38
SUN	FSB#3	9/1-9/30	2197	16	254	558	35
SUN	FSB#3	10/1-10/31	2851	13	255	727	38
SUN	FSB#3	11/1-11/16	3548	11	177	628	39
SUN	FSB#3	11/21-11/30	6663	12	83	553	69
SUN	FSB#3	12/1-12/31	4919	8	222	1092	39
SUN	FSB#3	1/1-1/31	7263	6	137	995	38
SUN	FTS#1	7/1-7/31	156636	3	22	3446	431
SUN	FTS#1	8/1-8/31	177222	2	45	7975	332
SUN	FTS#1-E	7/1-7/31	96712	3	73	7060	243
SUN	FTS#1-E	8/1-8/31	147825	1	40	5913	211
SUN	GG#1	7/1-7/31	3224	28	254	819	91
SUN	HA#1	7/1-7/31	2688	225	6290	16905	604
SUN	HA#1	8/1-8/31	2924	226	6098	17831	660
SUN	HA#1	9/1-9/30	3042	203	3451	10499	618
SUN	HA#1	10/1-10/31	3160	238	4522	14288	752

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
SUN	HA#1	11/1-11/16	3029	228	3641	11029	689
SUN	HA#1	11/21-11/30	2446	259	1812	4433	633
SUN	HA#1	12/1-12/31	2725	201	3422	9324	548
SUN	HA#1	1/1-1/31	2049	230	3450	7068	471
SUN	HA#2	7/1-7/31	6435	49	1455	9363	312
SUN	HA#2	8/1-8/31	9774	31	810	7917	293
SUN	HA#2	9/1-9/30	10726	29	485	5202	306
SUN	HA#2	10/1-10/31	8211	56	1057	8679	457
SUN	HA#2	11/1-11/16	8733	49	776	6777	424
SUN	HA#2	11/21-11/30	9566	41	327	3128	391
SUN	HA#2	12/1-12/31	9398	50	906	8515	473
SUN	HA#2	1/1-1/31	11391	35	741	8441	384
SUN	HR#1	7/1-7/31	2837	241	7231	20516	684
SUN	HR#1	8/1-8/31	3130	235	6347	19865	736
SUN	HR#1	9/1-9/30	10617	128	1914	20321	1195
SUN	HR#1	10/1-10/31	7768	134	2538	19714	1038
SUN	HR#1	11/1-11/16	4455	167	2671	11899	744
SUN	HR#1	11/21-11/30	12157	87	611	7428	929
SUN	HR#1	12/1-12/31	29058	35	242	7032	1005
SUN	HR#1	1/1-1/31	23162	23	68	1575	525
SUN	JA#1	7/1-7/31	26019	14	420	10928	364
SUN	JA#1	8/1-8/31	28062	11	305	8559	317
SUN	JA#1	9/1-9/30	27180	11	178	4838	285
SUN	JA#1	10/1-10/31	16785	15	293	4918	259
SUN	JA#1	11/1-11/16	67333	13	39	2626	219
SUN	JA#1	11/21-11/30	23240	24	96	2231	279
SUN	JA#1	12/1-12/31	32738	15	160	5238	249
SUN	JA#1	1/1-1/31	31906	8	212	6764	251
SUN	JAA#2	7/1-7/31	10379	38	1125	11676	389
SUN	JAA#2	8/1-8/31	12279	24	655	8043	298
SUN	JAA#2	9/1-9/30	28395	13	215	6105	359
SUN	JAA#2	10/1-10/31	34693	11	212	7355	409
SUN	JAA#2	11/1-11/16	66521	5	73	4856	208
SUN	JAA#2	11/1-11/21	21660	17	103	2231	279
SUN	JAA#2	12/1-12/31	88865	4	74	6576	329
SUN	JAA#2	1/1-1/31	107549	3	51	5485	274
SUN	JAB#3	7/1-7/31	1224	43	1283	1570	52
SUN	JAB#3	8/1-8/31	1688	36	961	1622	60
SUN	JAB#3	9/1-9/30	1344	27	453	609	36
SUN	JAB#3	10/1-10/31	2560	19	368	942	50

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
SUN	JAB#3	11/1-11/16	2795	17	268	749	47
SUN	JAB#3	11/21-11/30	3075	15	120	369	46
SUN	JAB#3	12/1-12/31	2801	60	423	1185	44
SUN	JAB#3	1/1-1/31	4416	11	334	1475	49
SUN	LL#1	7/1-7/31	1973	67	1939	3826	125
SUN	LL#1	8/1-8/31	2615	51	1374	3593	133
SUN	LL#1	9/1-9/30	2397	50	844	2023	119
SUN	LL#1	10/1-10/31	2787	42	752	2096	116
SUN	LL#1	11/1-11/16	2986	36	574	1714	107
SUN	LL#1	11/21-11/30	2922	37	294	859	107
SUN	LL#1	12/1-12/31	2653	35	992	2632	94
SUN	LL#1	1/1-1/31	2422	36	1071	2594	84
SUN	LOD #1	7/1-7/31	7072	61	1898	13422	433
SUN	LOD #1	8/1-8/31	6212	66	1776	11033	409
SUN	LOD #1	9/1-9/30	5255	75	1276	6705	394
SUN	LOD #1	10/1-10/31	4538	75	1420	6444	339
SUN	LOD #1	11/1-11/16	5837	58	926	5405	338
SUN	LOD #1	11/21-11/30	8548	50	398	3402	425
SUN	LOD #1	12/1-12/31	8206	46	1051	8625	375
SUN	LOD #1	1/1-1/31	9252	43	1043	9650	402
SUN	ML#1	7/1-7/31	11402	24	711	8107	270
SUN	ML#1	8/1-8/31	6861	29	793	5441	202
SUN	ML#1	9/1-9/30	6460	16	63	407	136
SUN	ML#1	10/1-10/31	7402	47	894	6617	389
SUN	ML#1	11/1-11/16	7984	47	745	5948	372
SUN	ML#1	11/21-11/30	8942	47	378	3380	423
SUN	ML#1	12/1-12/31	12175	35	629	7658	450
SUN	ML#1	1/1-1/31	14617	28	847	12381	442
SUN	MLA#2	7/1-7/31	9571	63	1877	17965	599
SUN	MLA#2	8/1-8/31	2756	93	2512	6924	256
SUN	MLA#2	9/1-9/30	4973	57	910	4525	266
SUN	MLA#2	10/1-10/31	6030	52	989	5964	314
SUN	MLA#2	11/1-11/16	4815	77	1239	5966	373
SUN	MLA#2	11/21-11/30	5869	76	611	3586	448
SUN	MLA#2	12/1-12/31	10493	46	836	8772	487
SUN	MLA#2	1/1-1/31	14692	28	770	11313	435
SUN	NS#1	7/1-7/31	4105	73	2181	8952	309
SUN	NS#1	8/1-8/31	2679	105	2831	7584	281
SUN	NS#1	9/1-9/30	1395	105	210	293	147
SUN	NS#1	10/1-10/31	2556	130	518	1324	331

GAVILAN DOME DATA BASE
RATE vs. GOR SENSITIVITY

OPERATOR	WELL	DATE	AVERAGE GOR	AVERAGE BOPD	CUM OIL	CUM GAS	AVERAGE MCFPD
SUN	NS#1	11/1-11/16	3932	54	862	3389	242
SUN	NS#1	11/21-11/30	5661	63	502	2842	355
SUN	NS#1	12/1-12/31	10044	33	749	7523	289
SUN	NS#1	1/1-1/31	11837	25	711	8416	301
SUN	NSA#2	7/1-7/31	4229	222	6646	28108	937
SUN	NSA#2	8/1-8/31	3739	238	6421	24005	889
SUN	NSA#2	9/1-9/30	4125	239	4066	16774	988
SUN	NSA#2	10/1-10/31	4526	217	4127	18678	983
SUN	NSA#2	11/1-11/16	4414	195	3113	13742	859
SUN	NSA#2	11/21-11/30	6669	129	900	6002	857
SUN	NSA#2	12/1-12/31	8984	107	859	7717	965
SUN	NSA#2	1/1-1/31	12412	85	677	8403	1050
SUN	NSB#3	7/1-7/31	11665	52	1360	15865	610
SUN	NSB#3	8/1-8/31	12580	40	1087	13675	506
SUN	NSB#3	9/1-9/30	14502	29	458	6642	391
SUN	NSB#3	10/1-10/31	9581	29	520	4982	293
SUN	NSB#3	11/1-11/16	17857	17	237	4232	282
SUN	NSB#3	11/21-11/30	20477	16	109	2232	319
SUN	NSB#3	12/1-12/31	22308	16	276	6157	342
SUN	NSB#3	1/1-1/31	23718	9	163	3866	276
SUN	NH#1	7/1-7/31	5802	4	121	702	24
SUN	NH#1	8/1-8/31	1989	6	176	350	11
SUN	NH#1	9/1-9/30	5484	6	95	521	31
SUN	NH#1	10/1-10/31	8600	4	85	731	38
SUN	NH#1	11/1-11/16	12059	3	51	615	38
SUN	NH#1	11/21-11/30	9750	5	32	312	39
SUN	NH#1	12/1-12/31	7653	6	121	926	39
SUN	NH#1	1/1-1/31	7371	6	159	1172	39
SUN	WW#1	7/1-7/31	6731	16	468	3150	105
SUN	WW#1	8/1-8/31	6923	12	311	2153	80
SUN	WW#1	9/1-9/30	5406	14	219	1184	70
SUN	WW#1	10/1-10/31	8290	12	207	1716	90
SUN	WW#1	11/1-11/16	1599	12	187	299	37
SUN	WW#1	11/21-11/30	14256	5	39	556	70
SUN	WW#1	12/1-12/31	31385	7	13	408	17

APPENDIX 5

Hard-to-Find References

T.P. 3622

RESERVOIR PERFORMANCE AND WELL SPACING, SPRABERRY TREND AREA FIELD OF WEST TEXAS

LINCOLN F. ELKINS, SOHIO PETROLEUM CO., OKLAHOMA CITY, OKLA., MEMBER AIME

SUMMARY

The Spraberry Trend Field of West Texas was discovered in January, 1949. Drilling of 2,234 wells and production of some 45 million bbl of oil by January, 1953, indicated this to be an important field which will ultimately cover more than 400,000 acres. In addition to being the world's largest field in areal extent, the Spraberry has presented many problems in well completion and operation and has demonstrated unique reservoir performance characteristics.

The pay section consists primarily of a few fine grained sandstone or siltstone members in a thousand-ft thick section of shale, limestone, and siltstone. Since porosity averages only 10 per cent and nearly all permeabilities are less than 1 md, conventional core analysis does not delineate the "pay" section. Mercury injection was used as a capillary pressure test adaptable to rapid routine use to select those intervals having low enough connate water saturation to contain commercially significant oil saturation. In the central area of the field this "pay" amounts to 16 ft of Upper Spraberry and 15 ft of Lower Spraberry sands.

An interconnected system of vertical fractures, observed in cores, provides the flow channels for oil to drain into the wells but most of the oil is stored in the matrix since the void volume of fractures is estimated to be less than 1 per cent of that in the sand. Initial potentials of wells range up to 1,000 B/D after fracture treatment which should be compared with estimated capacity of 5 to 10 B/D if oil had to flow into the wells through the sand itself.

Without exception initial pressures of later drilled wells were significantly lower than initial pressures of earlier drilled nearby wells in a large area some 6 miles long. This means the earlier drilled wells had drained fluids from areas much greater than their 40-acre proration units. Since most of this performance occurred while the reservoir pressure was above the saturation pressure it was analyzed by the compressible fluid flow theory. This analysis gave calculated initial pressures which agreed within $\pm$ 30 psi of measured pressures of 60 per cent of wells in the area using 16-md permeability corresponding to a fracture system substantially that indicated by cores and using combined compressibility of rock and its contained oil and water corresponding to the core analysis data. The most important feature of this analysis was the very close agreement between effective compressibility of the rock and its contained oil and water from the field performance and that from the core tests, because it meant there are no "islands" of low permeability reservoir rock left untapped in the inter-well area and thus no additional wells are necessary to insure that at least one well penetrates each "reservoir."

Twenty-five of forty-four 40-acre spaced wells on three contiguous sections were used in a four-month interference test. Six shut-in wells were tested monthly for oil production, productivity index, gas-oil ratio and pressure buildup, and seven shut-in wells were tested for decline in reservoir pressure. Tests on 12 regularly producing wells gave comparative data for interpretation of shut-in test wells. Reduction in reservoir pressure, decline in productivity index, and increase in gas-oil ratio were found to be substantially the same in the shut-in test wells as those in the comparative regularly producing wells, meaning that the producing wells were depleting the

[1]References given at end of paper.

Manuscript received in the Petroleum Branch office Feb. 2, 1953. Paper presented at the AIME Annual Meeting in Los Angeles, Calif., Feb. 14-19, 1953.

RESERVOIR PERFORMANCE AND WELL SPACING, SPRABERRY TREND AREA FIELD OF WEST TEXAS

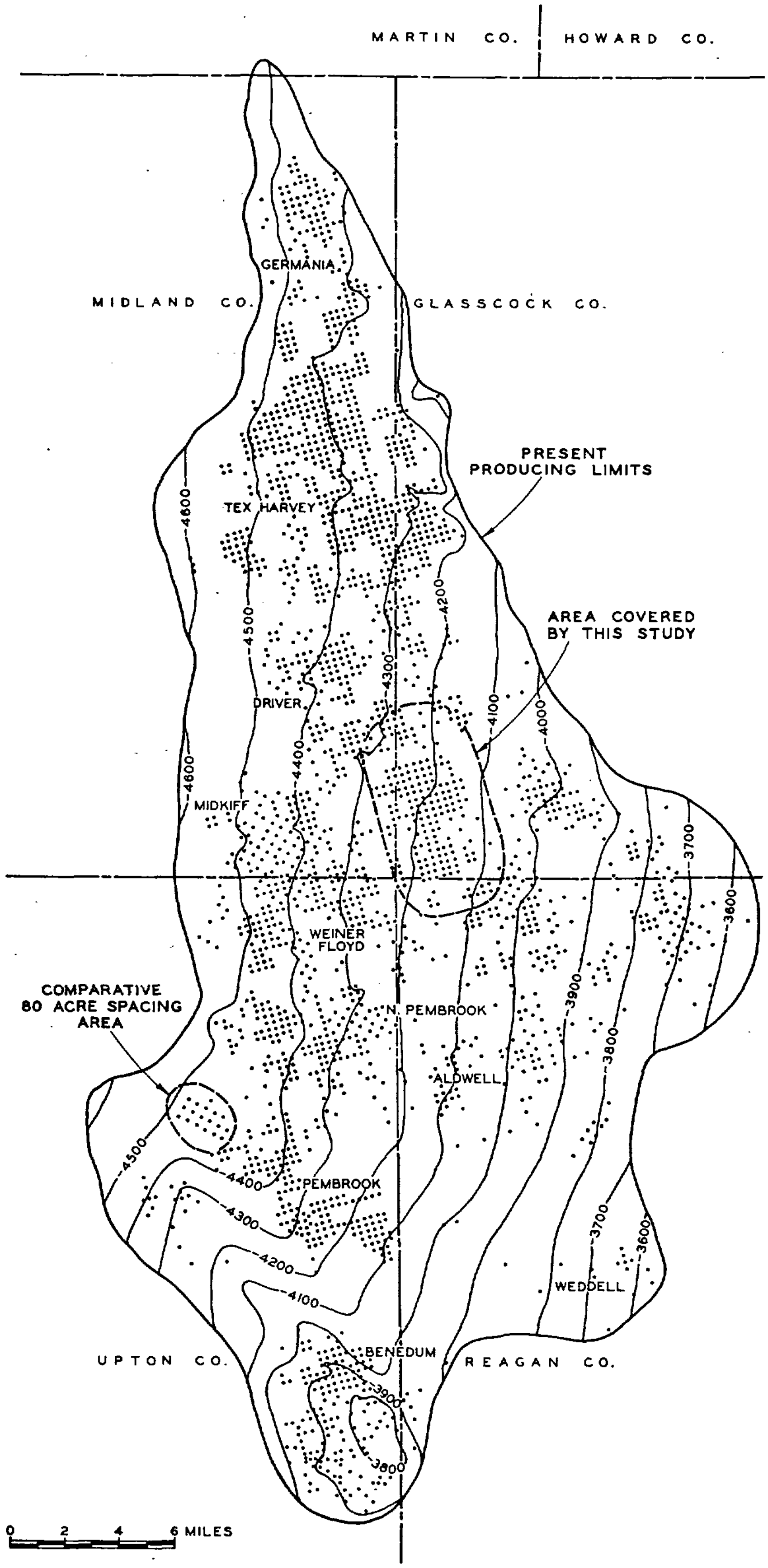


FIG. 1 — SPRABERRY TREND FIELD, CONTOURS ON TOP OF SPRABERRY FORMATION.

reservoir with the same efficiency at these points in the reservoir a quarter of a mile away as they were at points near the producing wells themselves.

Rapid decline in oil productivity and rapid increase in gas-oil ratio point to recovery of only some 7 or 8 per cent of oil in place. Laboratory tests on Spraberry cores indicate this low recovery is probably caused by capillary retention of oil due to "end effects" in the small fractured blocks of the reservoir rocks. Production rates necessary to overcome this capillary retention of oil cannot be achieved by any practicable spacing of wells.

The significance of this study is that direct experiment in the field itself demonstrates ability of a well in the Spraberry to recover oil from areas of the order of at least 160 acres as efficiently as could many wells on the same area even though the effective permeability of the reservoir including its fractures is only 16 md. It also demonstrates how modern reservoir engineering methods coupled with an enlightened management attitude can lead to an early understanding of a specific reservoir's performance and thus to proper development and operation.

HISTORY

The Spraberry sands of West Texas, named from a ranch owner on whose property they were first tested, were proved productive in January, 1949, in the Spraberry Deep Field in Dawson County. In February, 1949, the sands were proved productive in the Tex-Harvey Field in Midland County some 50 miles to the south. Development was very slow until late 1950 and early 1951 when additional fields were discovered including Germania, Driver, Midkiff, Pembrook, Benedum Spraberry, and others. Activity increased in 1951, reaching a peak at the beginning of 1952 when some 235 rotary rigs were in operation in the Trend. Thereafter drilling fell off sharply due partly to the steel shortage, but due mostly to the rapid decline in oil productivity of wells.

Development as of Jan. 1, 1953, is outlined in Fig. 1, including limits of semi-proved commercial production. More than 400,000 acres in an area nearly 40 miles in length and up to 25 miles in width are included in this one field which most likely will be proved ultimately to be continuous, making it the largest in areal extent in the world. The circled area near the center of the field indicates the area in which tests were run which are presented in this paper. History of development and production of the Spraberry Trend are shown graphically in Fig. 2.

Originally 40-acre proration units were in effect despite two concerted efforts in 1951 to obtain wider spacing. In December, 1952, however, regulations were changed to provide 80-acre proration units with 80-acre plus tolerance to each unit at the option of the operation. In addition, the various Spraberry fields covering parts of five counties were combined officially into one known as the Spraberry Trend Area Field.

GEOLOGY

The Spraberry formation is of Permian Leonard age and consists of about a thousand-ft section of sandstones, siltstones, shales and limestones with the top of the section occurring at a depth range of about 6,300 to 7,200 ft within the probable productive area. The structure is predominantly a broad regional monocline dipping westward about 50 ft per mile as illustrated in Fig. 1. Some noses are superimposed on the monocline and there is one anticline with about 200 ft of closure in the Benedum Area at the southern tip of the Spraberry Trend. Other anticlinal structures occur in Spraberry fields outside the Trend area such as Spraberry Deep in Dawson County. To the north and east the section grades primarily to a carbonate section providing the necessary seal for the stratigraphic trap. To the south and west the section becomes more shaly. Updip limits of commercial production are controlled by scarcity of vertical fracturing — the dominant feature of this unique reservoir — rather than by lack of accumulation of petroleum. Downdip production is limited both by scarcity of fractures and by water. Readers are referred to other papers for greater geological detail.[1,2,3]

DRILLING AND COMPLETION

Wells are drilled to the top of the Spraberry in about 35 days with rotary rigs using water and water-base mud. Some operators set a salt string at about 4,000 ft, followed by a liner to reduce mud costs while others set a single long oil string. Until late 1951 nearly all wells had casing set on top of the Spraberry after which the wells were drilled in with cable tools or with rotary tools using formation oil as the drilling fluid. Initially some wells were shot with nitroglycerine, but most wells have been hydrafraced to obtain satisfactory productivity. Very few wells will flow without such treatment.[4,5] Initial potentials of wells range up to 1,000 B/D and average about 250 B/D. Since late 1951 many wells have been successfully drilled through the entire Spraberry section with water-base mud, casing set through, cemented, and gun perforated. They have then been completed by hydrafrac using packers and temporary bridging plugs for selective treatment. Nearly all wells in the test area discussed in this paper were completed in the Upper Spraberry alone with casing set on top followed by cable tool and hydrafrac completion. After tests reported in this paper were completed, many of these wells were deepened to the lower Spraberry by continuous diamond drilling using oil as the drilling fluid and were completed in open hole. On new wells this same operator has changed entirely to normal rotary drilling with water-base mud and with casing set through the entire zone.

RESERVOIR CONDITIONS

Sand Properties

The Spraberry section is best illustrated by means of the composite log in Fig. 3 which includes the gamma ray and induction logs, geological description, and core analysis. Typical is the main upper pay sand about 31 ft in gross thickness productive throughout most of the field and the main lower pay sand about 27 ft in thickness productive in part of the field. In addition, numerous other thinner sands and siltstones occur distributed throughout the 900-ft section which is mostly shale. Porosity of these sands ranges up to 13 per cent and permeability ranges from less than 0.001 md to about 1 md. Shale sections also have about these same porosities and per-

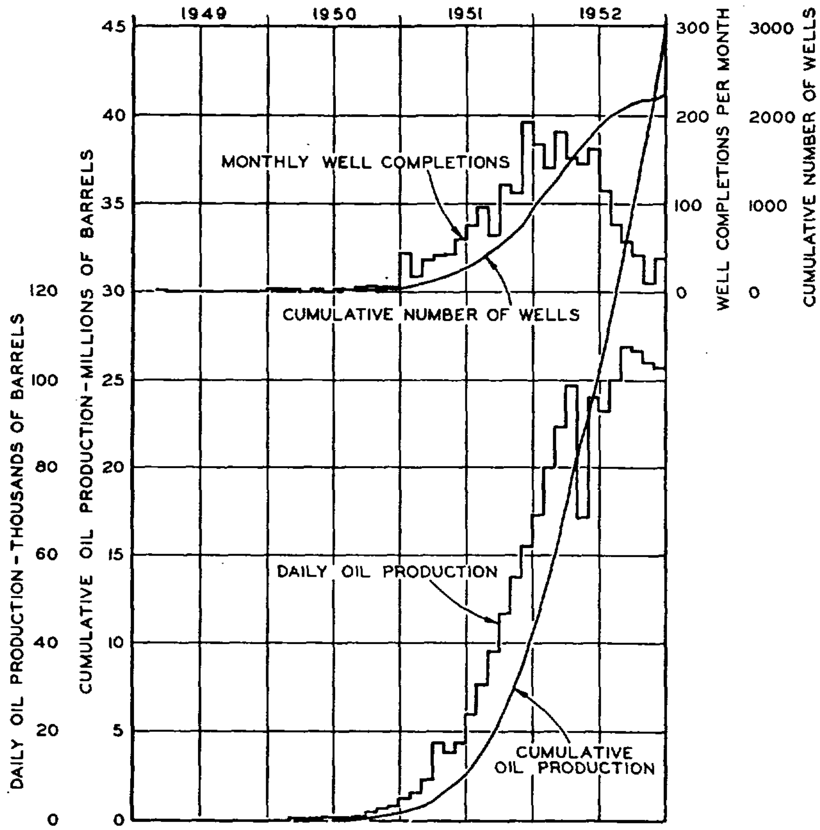


FIG. 2 — HISTORY OF DEVELOPMENT AND PRODUCTION, SPRABERRY TREND AREA FIELD.

meabilities. Residual oil saturation in water-base mud cut cores determined by both retort and extraction methods ranges from about 10 per cent to 30 per cent in both shales and sands. Thus, conventional core analysis does not delineate the "pay" section.

Retorting of Spraberry shale at 400° F under vacuum yielded no oil recovery while retorting of companion samples at 1,000° F yielded recovery equivalent of 10 to 30 per cent of pore space. Vacuum distillation of Spraberry crude at 400° F gave about 50 per cent vaporization. The hydrocarbon material in the Spraberry shale thus is not ordinary crude oil but is probably a highly viscous or even semi-solid residue. It is not a commercial deposit.

Porous diaphragm, centrifuge, and mercury injection capillary pressure methods all give similar values for irreducible water saturation for Spraberry sandstones. Single point mercury injection measurements at 1,300 psi were made to determine those portions of sand which had pores large enough to permit oil entry under conditions of capillarity which probably exist in the reservoir. Typical data are included in Fig. 3 and are labeled irreducible water saturation. Similar tests by commercial service laboratories have been reported as "productive porosity." Arbitrarily selecting "pay" as that section having less than 60 per cent irreducible water saturation limits the main upper sand to an average of 16 ft and the main lower sand to an average of 15 ft. Most other sand

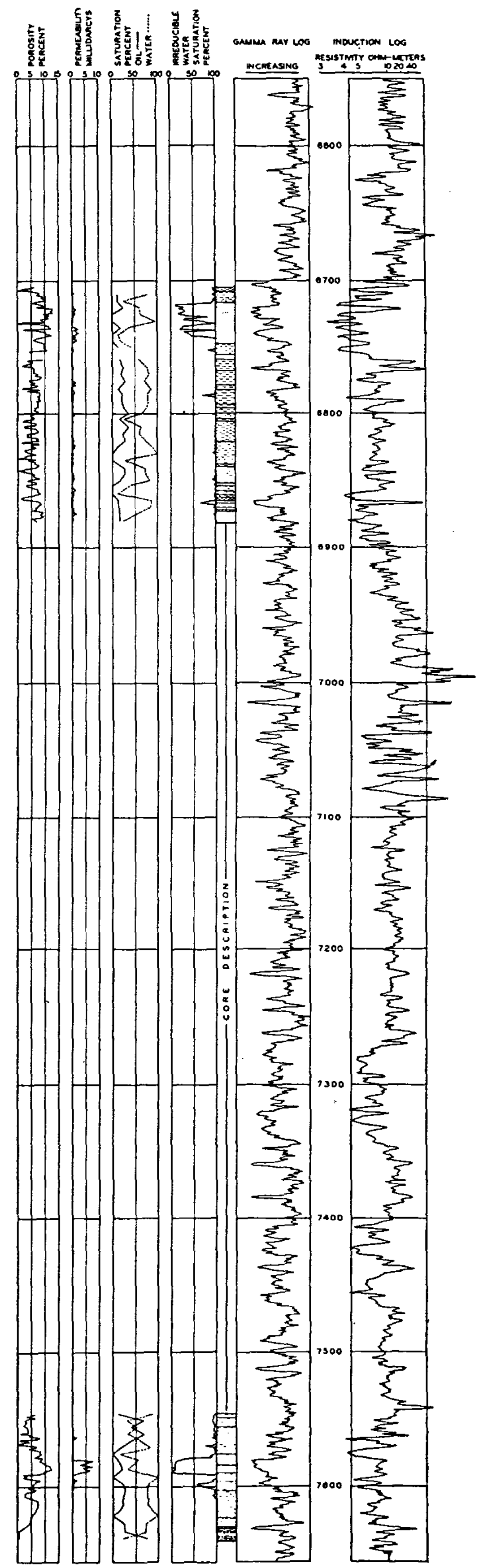


FIG. 3 — COMPOSITE LOG, SOHIO PROCTOR NO. 1, REAGAN COUNTY, TEX.

Table 1 — Spraberry Sand Properties, Driver Field, Glasscock County, Texas

Main Upper Spraberry Sand

Well	Gross* Sand Section Ft	Net** Pay Ft	Average Porosity Net Pay Per Cent	Average Irreducible Water Sat. Net Pay	Reservoir Pore Vol. Bbl/Acre Gross Sand	Hydrocarbon Pore Volume Bbl/Acre Gross Sand	Hydrocarbon Pore Volume Bbl/Acre Net Sand
A	30	18	10.6	28.4	21,650	11,650	10,630
B	36	20	9.1	28.4	24,600	11,650	10,100
C***	24	15	9.8	19.4	16,550	10,100	9,230
D	29	15	10.1	25.0	20,300	9,150	8,850
E	22	10	10.2	32.8	16,400	6,280	5,280
F***	17	11	10.4	25.0	12,700	7,530	6,360
G	41	13	9.7	32.0	27,500	8,530	6,750
H	27	17	8.5	25.7	18,250	9,080	8,300
I	28	14	8.9	30.6	18,800	8,470	6,670
J	32	23	11.1	37.8	25,800	13,800	12,400
Average	31	16	9.9	30.1	21,600	9,930	8,610
Main Lower Spraberry Sand							
A	27	14	9.4	15.2	15,850	9,310	8,700
I	36	20	9.9	24.9	23,700	11,800	11,500
J	19	10	10.6	9.5	12,100	7,680	7,450
Average	27	15	10.0	16.5	17,230	9,630	9,230

*Sandstone and siltstone section by core description.
**Section having less than 60% irreducible water saturation by Mercury Injection Method.
***Complete section not cored and analyzed. Excluded from averages.

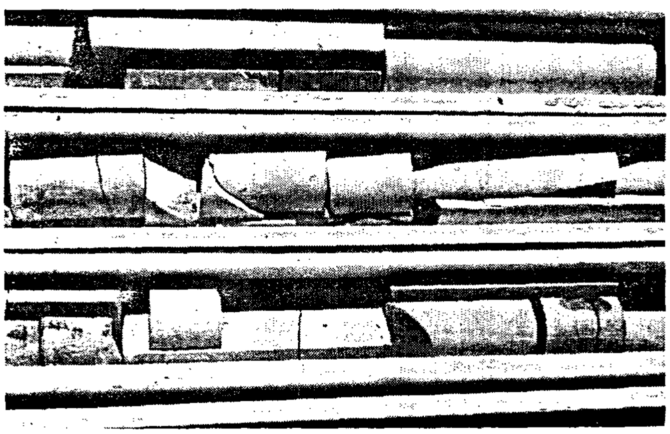


FIG. 4 — TYPICAL FRACTURES IN SPRABERRY CORES.

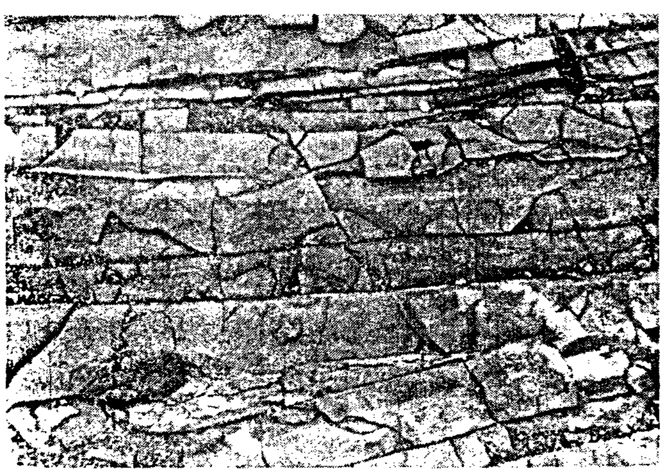


FIG. 5 — TOP VIEW OF VERTICAL FRACTURES IN OUTCROP OF BRUSHY CANYON FORMATION.

streaks are too fine grained to contain sufficient oil saturation to be productive in this area but some of these thinner streaks apparently are productive in some parts of the field. Data for ten wells cored in the test area are summarized in Table 1. Values for hydrocarbon pore space for each well on both the gross sand and net sand basis are not products of average values but are summation of values measured individually on a sample of each foot of core.

Vertical Fractures

The unique feature of the Spraberry formation is the extensive vertical fracturing observed in all productive wells cored. Sixty-two per cent of 2,058 ft of cores from five wells in this area had single fractures present and 4 per cent had multiple fractures, some parallel and some intersecting. Fracture spacing laterally is probably of the order of a few inches to a few feet estimated from frequency of fractures observed vertically in the 3.5 in. diameter cores. Typical fractures in cores are illustrated in Fig. 4. The vertical fracture pattern may very well be similar to that occurring in the outcrop of the Spraberry equivalent Brushy Canyon Formation some 70 miles south of Carlsbad, New Mexico, as illustrated in Fig. 5.

One hundred eleven measurements of fracture openings were made on these cores by comparing core diameter normal to the fracture with that parallel to the fracture after matching the core pieces by bedding planes, bit scratches, and fracture irregularities. These fracture measurements ranged up to 0.013 in. and averaged 0.002 in. Some large fractures exist as demonstrated by cement in cores cut below casing but these are infrequent. Productivity of wells indicates some of the fractures must be open because the actual initial potentials of wells often exceed the potential calculated from core analysis permeability by a factor of about 25. Fractures exist in the shales but pressure-production data discussed later indicate

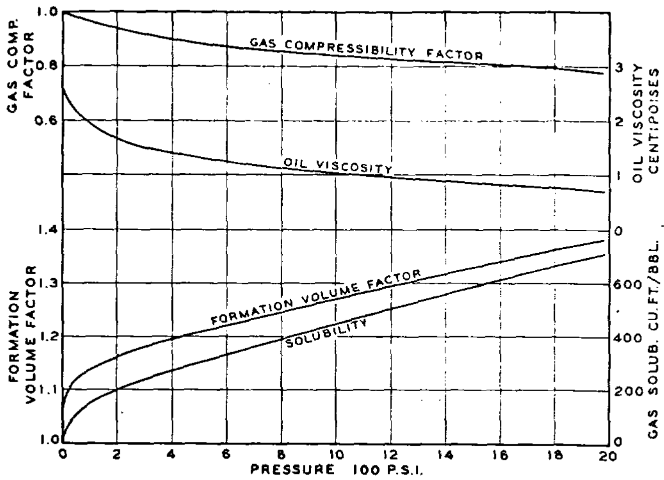


FIG. 6 — AVERAGE SUBSURFACE OIL SAMPLE, UPPER SPRABERRY SAND, DRIVER FIELD, GLASSCOCK COUNTY, TEX. TEMPERATURE, 136° F.

flow is mainly limited to the sand section and vertical communication through fractures in shale is negligible.

Fracture void volume in the main upper Spraberry sand is estimated to be about 110 bbl per acre based on fracture opening and probable fracture spacing just discussed. Fractures thus contribute little to reservoir void volume but do serve as conduits for flow of oil and gas from the reservoir to the wells.

Properties of Oil at Reservoir Conditions

Subsurface samples of oil were obtained from ten newly completed upper Spraberry wells in this area. Properties of each oil sample at saturation pressure are summarized in Table 2 and average properties at various pressures are presented graphically in Fig. 6. Of greatest significance for analysis of upper Spraberry reservoir performance observed is the approximate 300 psi undersaturation of oil initially. Formation volume factor is 1.385 and gas in solution is 713 cu ft per bbl at the 136° F reservoir temperature. Lower Spraberry oil in this area was saturated initially at a pressure of about 2,535 psi. Formation volume factor is 1.58 and gas in solution is 1.047 cu ft per bbl at the 144° F reservoir temperature.

Oil in Place Initially

Tank oil in place initially in the Upper Spraberry, estimated from these various core analysis, fracture opening, and subsurface sample data, is 7,250 bbl per acre on the gross section basis and 6,300 bbl per acre on the net section basis considering only those intervals having less than 60 per cent irreducible water saturation. Similar estimates for the main lower Spraberry sand are 6,150 bbl per acre on the gross basis and 5,900 bbl on the net basis respectively.

MEASUREMENT AND INTERPRETATION OF INITIAL PRESSURES IN WELLS

After hydrafrac treatment each well in the subject area was produced just a few hours for clean up and was then shut in for a minimum of 72 hours prior to measurement of reservoir pressure. Production during clean up ranged from 100 to 400 bbl generally. Wells so tested are identified in Fig. 7 and data obtained are presented graphically in Fig. 8 with appropriate corresponding circular symbols. Subsequent 72-hour shut in pressures of some producing wells are shown as X's, and lines connect pressures of an individual well. Within each closely associated group the later drilled wells had lower initial pressures without exception than did the earlier drilled wells, and in nearly all cases the initial pressures of later drilled wells correspond closely with 72-hour shut in pressures of nearby regularly producing wells. Each later drilled well was at least 1,320 ft from any previously producing well, and one, Davenport C-14, in Section 11, was over half a mile from any producing well. This latter well reflected some 130 psi reduction in reservoir pressure at this distance even though it was completed within about three months of the wells first drilled in the area.

This rapid equalization of pressure over such wide area means the fractures observed in cores are a sample of an

Table 2 — Properties of Reservoir Oil, Upper Spraberry Sand, Driver Field, Glasscock County, Texas

Well	Reservoir Pressure Psi (−4400′ Datum)	Reservoir Temp. °F	Pressure at Sampling Depth Psi	Sat. Press. Psi	Formation Volume Factor	Gas Sol. Cu Ft Per Bbl	Oil Visc. at Sat. Press. Cent.	Compressibility of Oil Vol/Vol/Psi	Gravity Residual Oil °API
A	2330	135	2111	1944	1.398	721	0.77	12.7×10^{-6}	37.7
B	2231	136	2110	1982	1.391	719	—	12.0×10^{-6}	37.0
C	2263	137	2185	2008	1.362	685	0.66	12.7×10^{-6}	36.6
D	2251	137	2130	2090	1.356	679	0.62	11.9×10^{-6}	37.4
E	2212	138	2109	1797	1.365	666	0.78	11.7×10^{-6}	37.3
F	2325	137	2111	1959	1.396	714	—	12.1×10^{-6}	37.1
G	2341	137	2108	2016	1.397	726	—	12.0×10^{-6}	37.3
H	2308	136	2175	2124	1.370	740	—	11.2×10^{-6}	37.3
I	2074	136	1847	1935	1.441	768	—	12.9×10^{-6}	37.5
J	2218	136	2002	1958	1.376	711	—	12.4×10^{-6}	37.0
Average		136		1981	1.385	713	.71	12.2×10^{-6}	37.2

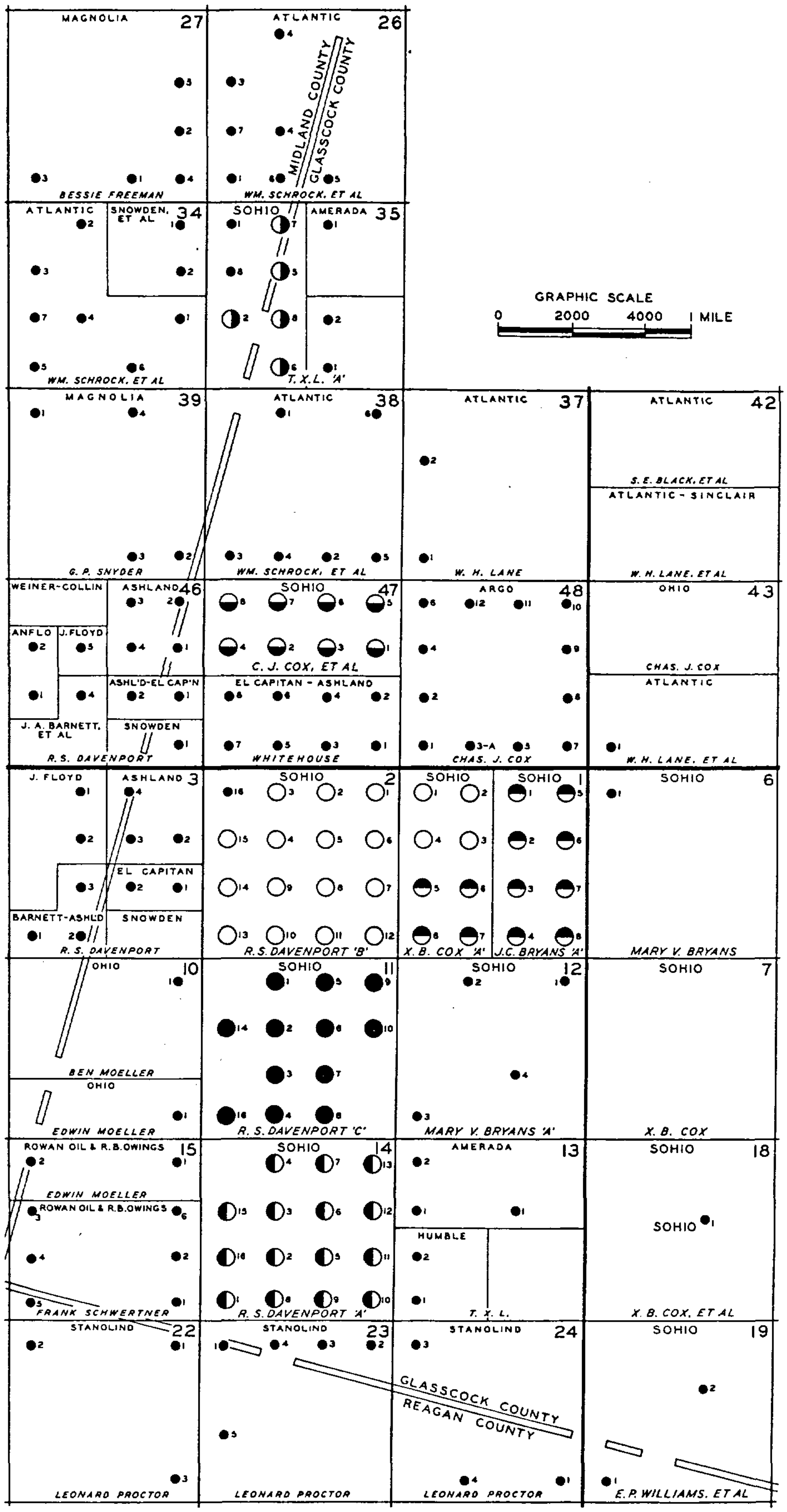


FIG. 7 — GROUPING OF WELLS FOR COMPARISON OF DECLINE OF INITIAL PRESSURE IN WELLS WITH DATE OF COMPLETION.

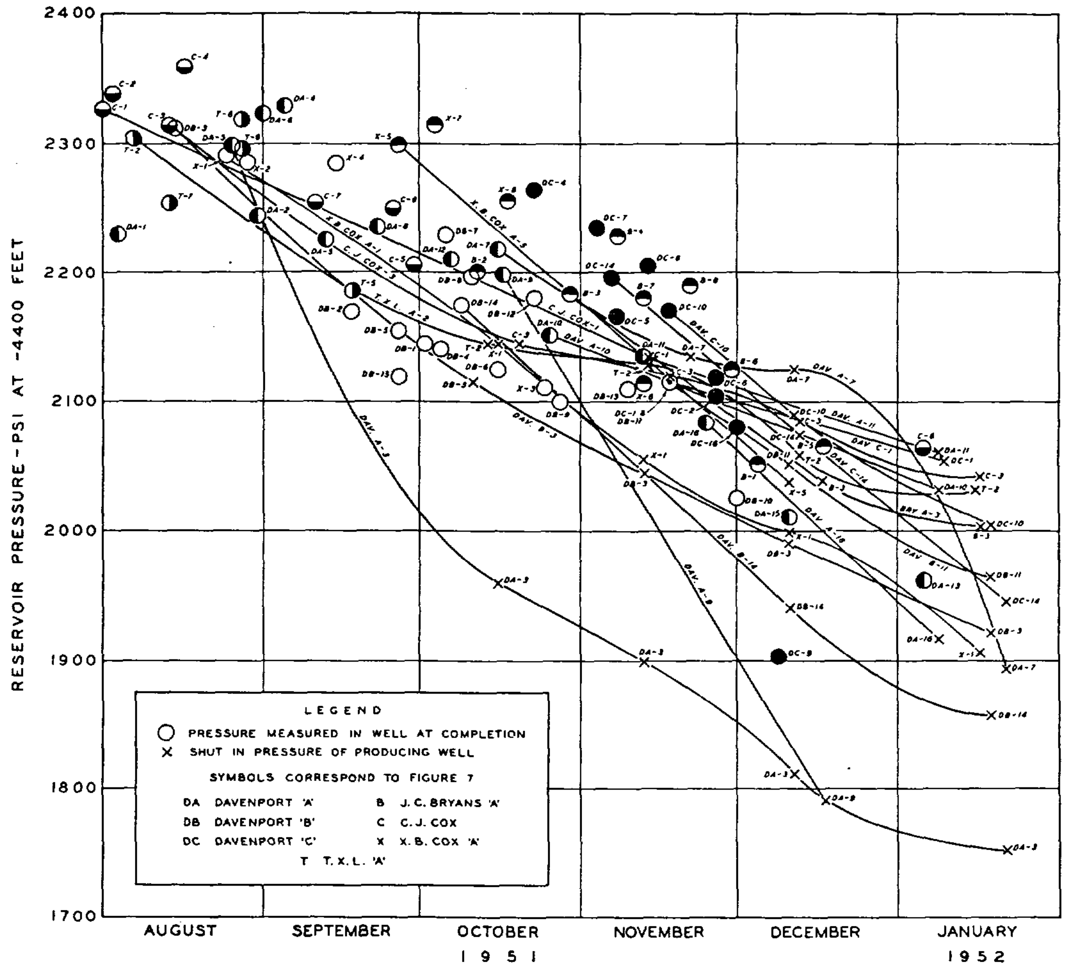


FIG. 8 — COMPARISON OF INITIAL PRESSURES IN WELLS WITH DATE OF COMPLETION.

extensive well interconnected system of fractures covering this entire area. Since without exception reduced pressures were observed in all later drilled wells in each area, many wells drilled were unnecessary because they did not connect to fractures not already being drained by previously drilled wells.

Since reservoir pressures were above the saturation pressure of the oil until about Dec. 1, 1951, the performance was analyzed by the theory of flow compressible fluids by considering each well as a point sink in an infinite reservoir of uniform thickness, porosity, and permeability, and calculating the pressure drawdown at locations of each new well by Equation (1).[6,7]

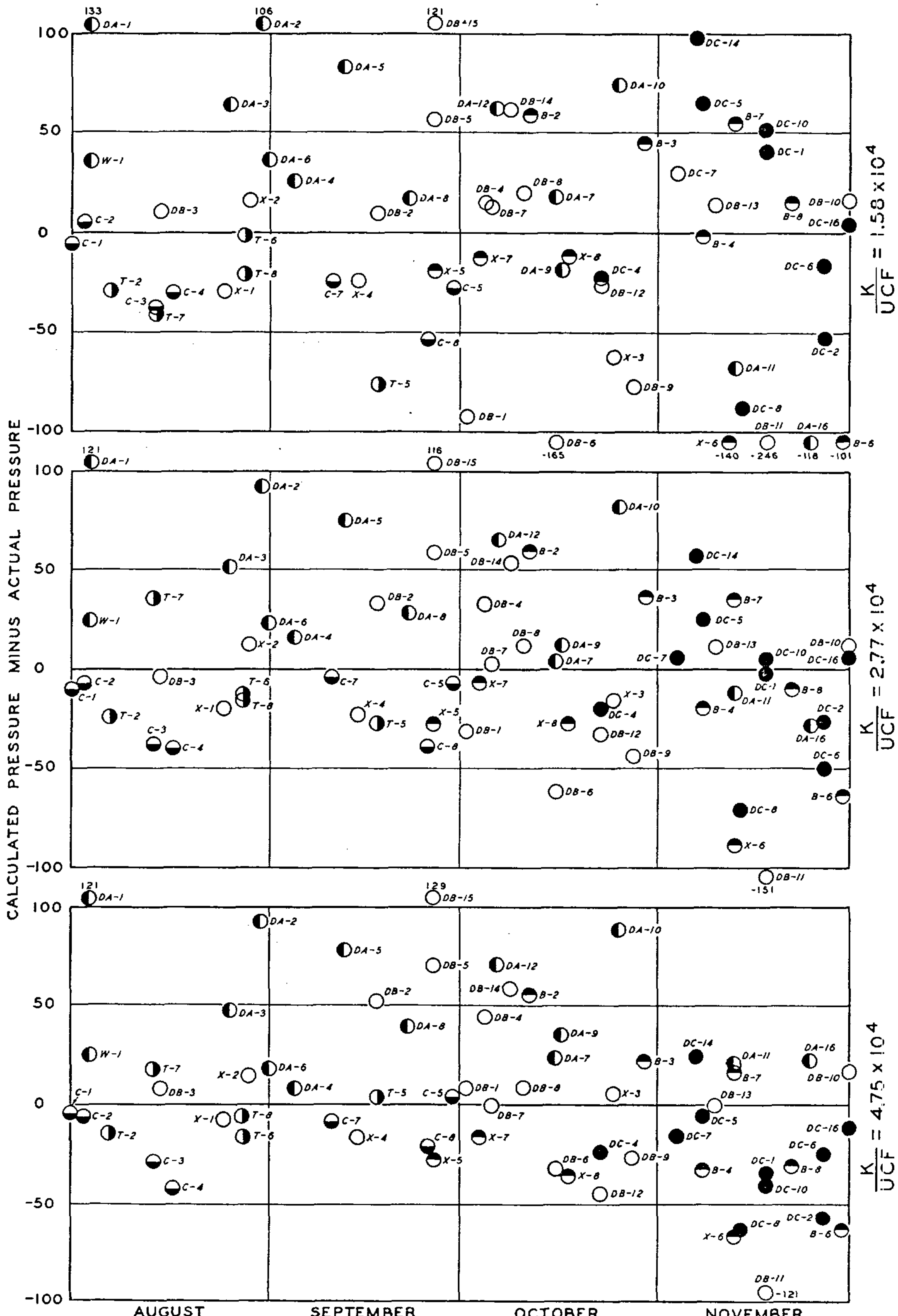
$$P_o - P = \frac{QUB}{4\pi KH\,1.127}\,Ei\left(-\frac{R^2}{\frac{4KT}{UCF}\;6.32}\right) \quad . \; . \; . \quad (1)$$

where:

P_o — Initial pressure, psi
P — Pressure at R at time T
Q — Constant production rate, B/D
U — Oil viscosity, centipoise
B — Formation volume factor
K — Effective permeability, darcys
H — Thickness, feet
R — Distance, feet
C — Weighed average compressibility of oil, connate water, and rock
F — Porosity, fraction
T — Time, days
$Ei()$ — Exponential integral
1.127, 6.32 — Conversion factors

Total pressure drawdown is the summation of effects of all producing wells using their appropriate production rates, distances, times on production, etc. Production from 143 wells within three miles of key wells indicated in Figs. 7 and 8 was used in calculation of expected initial pressures of 65 wells completed by Dec. 1, 1951.

Because the correct diffusivity factor is unknown and is in implicit form in the relation it was necessary to assume various values of $\frac{K}{UCF}$ and calculate pressures of each well. Deviations between measured and calculated pressures are shown for three values of diffusivity in Fig. 9 leading to selection of 2.77×10^4 as the "best" value of $\frac{K}{UCF}$ based on most



SYMBOLS CORRESPOND TO FIGURE 7

DA	DAVENPORT 'A'	B	J. C. BRYANS 'A'
DB	DAVENPORT 'B'	C	C. J. COX
DC	DAVENPORT 'C'	X	X. B. COX 'A'
		T	T X L. 'A'

FIG. 9 — COMPARISON OF CALCULATED INITIAL PRESSURES WITH ACTUAL INITIAL PRESSURES OF WELLS.

Table 3 — Expansibility of Rock, Oil and Water Derived from Pressure — Production Analysis Upper Spraberry Sand

Diffusivity $\frac{K}{UCF}$	Expansibility Bbl/Acre/Psi
1.58×10^4	0.186
2.77×10^4	0.204
4.75×10^4	0.197

uniform distribution of plus and minus errors on the basis of both time and geographical distribution. Sixty per cent of calculated pressures are within plus or minus 30 psi of measured initial pressures of wells, which is very excellent considering the working accuracy of pressure gauges in field application, difference in clean-up production and build-up characteristics of wells and the necessary assumption that all wells on each lease had equal production during any particular month.

Average effective permeability in this area was approximately 16 md for the 31-ft gross section as determined by this analysis, corresponding to productivity index of 0.48 B/D per psi and initial potential of 520 B/D. Actual productivity indices ranged from about 0.1 to 2.5 initially and initial potentials ranged from 31 to 960 B/D in this area. This effective permeability in millidarcy-feet is also of the same order of magnitude as that determined by build-up curve analysis in an adjacent area.[8] Considering the flow to be primarily in two sets of equally spaced mutually perpendicular uniform fractures permits calculation of average fracture opening by Equation (2).[9]

$$W = \left(\frac{12\,KS}{6.45 \times 10^8} \right)^{1/3} \quad \ldots\ldots\ldots \quad (2)$$

where

W — Fracture opening, inch
K — Effective permeability, darcys
S — Fracture spacing, inches

For average fracture spacing of 10 in. corresponding to frequency of fractures seen vertically in 3.5 in. diameter cores the fracture opening is calculated to be 0.0015 in. For 4-in. spacing the opening would be 0.0011 in., and for 2-ft spacing 0.0020 in. These calculated fracture openings compare favorably with the average opening of 0.002 in. actually observed in cores.

The factor HCF, obtained by elimination of $\frac{K}{U}$ from $\frac{KH}{U}$ and $\frac{K}{UCF}$ in Equation (1), multiplied by 7,758 is combined expansibility of rock and its contained oil and water in bbl per acre per psi. Expansibility so calculated is summarized in Table 3 for a three-fold range of diffusivity used in the analysis of the pressure-production performance.. It is significant that the calculated expansibility varies only 9 per cent for this range and thus little error is introduced even though the resolving power of the analysis is not high in selecting the most probable value of the diffusivity factor. The corresponding combined expansibility of rock, oil, and water calculated from core analyses and subsurface samples is summarized in Table 4. Certainly the almost perfect agreement between expansibility calculated from the pressure-production analysis and that from the cores is partly fortuitous because data from individual core wells have an average deviation of $\pm$ 15 per cent from the mean. But the good agreement of all factors in the analysis including calculated individual well pressures, calculated permeability and fracture opening versus well tests and core measurement, and calculated expansibility of rock, oil, and water versus core data must mean these values quite accurately represent average conditions in this area of the field. Close agreement of expansibility of oil, water and rock derived from the analysis with that from cores using only sand intervals probably means production comes only from the sand and vertical migration through fractures in shale is not significant. At least this lack of migration through large vertical intervals was confirmed by a large increase in production when nearly depleted upper Spraberry wells were deepened to the lower Spraberry.

Observation of reduced reservoir pressure initially in all later drilled wells in each area certainly leads to the conclusion that there exists an interconnected system of fractures tapped by all wells drilled. But the almost perfect agreement between combined expansibility of rock, oil and water derived

Table 4 — Expansibility of Rock, Oil and Water Derived from Cores and Subsurface Fluid Samples Upper Spraberry Sand

	Volume Bbl/Acre	Unit Expansibility Vol/Vol/Psi	Gross Expansion Bbl/Acre/Psi
Oil	10,060	12.2×10^{-6}	0.124
Water	11,650	3.2×10^{-6}	0.037
Rock	240,000	1.88×10^{-7}*	0.045
			0.206

*Pore Vol. Change/Bulk Vol/Psi.

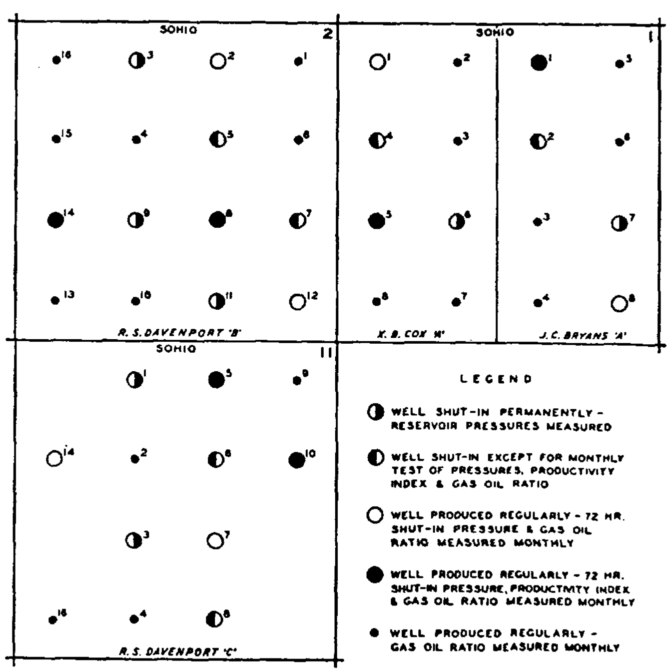


FIG. 10 — KEY TO WELLS IN LARGE SCALE INTERFERENCE TEST.

using only production and initial pressures of wells and expansibility of rock, oil, and water obtained from core analyses indicate the chance is nil that the interwell area has untapped "islands" of reservoir containing commercially significant amounts of oil. Thus additional wells, and for that matter many existing wells, are unnecessary to insure that each part of the reservoir is permeably connected to some well.

INTERFERENCE TEST

In order to continue to observe interference and other features of reservoir performance in the inter-well area, indicated initially by reduced reservoir pressure of later drilled wells, Sohio Petroleum Co. obtained permission from the Texas Railroad Commission to conduct a large scale long time interference test. The test area included three contiguous sections of land upon which 44 wells almost completed uniform 40-acre spacing development. Alternate wells in the center rows were shut in and their allowable production transferred to other wells on each lease in such manner as to protect correlative rights among all leases involved in the test area. The test area is outlined in Fig. 10.

Seven of the wells were shut in throughout the test and had reservoir pressure measurements made monthly. Six of the shut-in wells had production rate, gas-oil ratio, and flowing bottom hole pressure measured after which they were then shut in for a 72-hour pressure buildup test. Additional spot measurements of reservoir pressure were made after the wells had been shut in for one week and for one month. The wells were then returned to production for a 48-hour test period during which gas and oil production were measured and the flowing bottom hole pressure was measured in each well during the last six hours of the test period. The wells were then shut in again for 72-hour pressure buildup tests and for spot readings of reservoir pressure after shut-in periods of one week and one month, etc. Each of the six wells so tested was shut in for three successive months each followed by the 48-hour production test and pressure tests just described. Shut-in wells so tested are illustrated by appropriate symbols in Fig. 10.

To provide a basis for evaluating the observations in the shut-in wells, various tests were made in regularly producing wells. Seventy-two hour shut-in pressures were measured at monthly intervals in six regularly producing wells. Production rate, gas-oil ratio, and flowing bottom hole pressure measurements followed by 72-hour reservoir pressure buildup tests were conducted at monthly intervals in six additional regularly producing wells. Wells so tested are illustrated by appropriate symbols in Fig. 10. In addition, oil production rate and gas-oil ratio were measured on all regularly producing wells in the test area at least once each month.

Decline in Reservoir Pressure

Although the reservoir was below the saturation pressure in the area during the interference test, reservoir pressure continued to decline rapidly due to continued development and due to rapidly increasing gas-oil ratios. Pressure data of the shut-in wells and of the producing wells are presented graphically in Fig. 11 with appropriate symbols to designate test program of each well. Some of the wells shut in permanently showed build up in reservoir pressure for a short time, but soon all shut in wells demonstrated significant decline in reservoir pressure at these points 1,320 ft from any producing well. In wells shut in except for 48-hour production tests monthly, the reservoir pressure built up to a maximum and then declined within each 30-day shut-in period. Only the 30-day shut-in pressures of these wells are included in Fig. 12. These wells also demonstrated significant decline in reservoir pressures at points in the reservoir 1,320 ft from regularly producing wells. Shut-in wells had approximately the same rate of pressure decline as did the producing wells and none of the shut-in wells failed to indicate some significant decline in pressure. During March and April, 1952, the pressure declined about 3 psi per day. During May and June, 1952, the rate of decline of reservoir pressure was reduced to about 2 psi per day due to curtailed production during the oil strike.

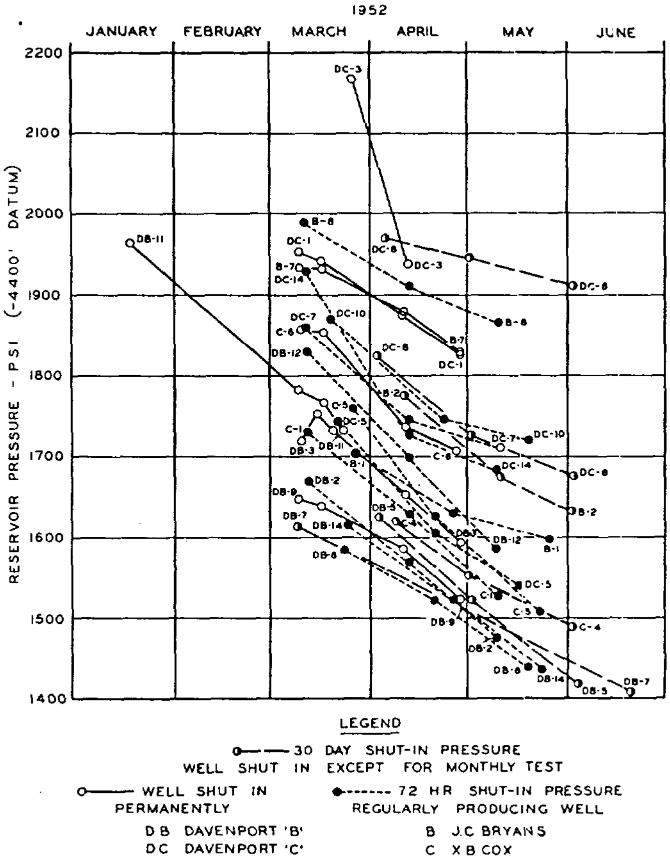


FIG. 11 — COMPARISON OF DECLINE IN RESERVOIR PRESSURE, SHUT-IN WELLS VS REGULARLY PRODUCING WELLS.

Reservoir pressures in the test area covered a range of some 500 psi due partly to difference in date of development of various areas and due partly to variations in density of drilling surrounding particular wells. Thus wells on the Davenport "B" lease drilled earlier and most completely surrounded by areas approaching complete development on a uniform 40-acre spacing pattern reflect the lowest reservoir pressure. Such regional variation in reservoir pressure makes it difficult to determine lag of pressure decline in the inter-

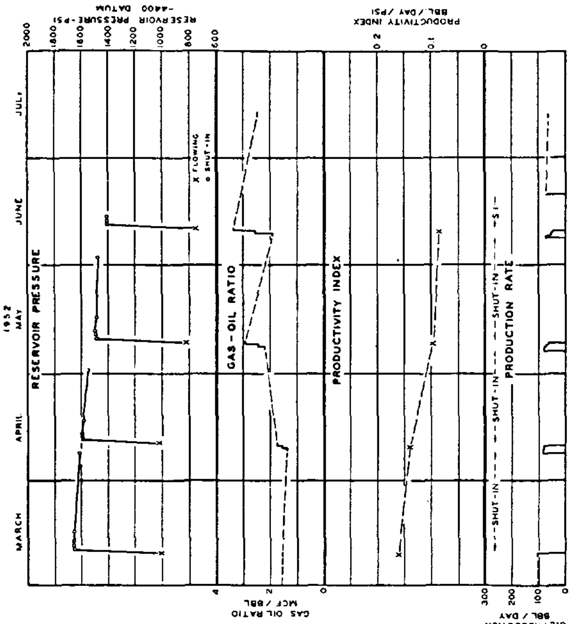


FIG. 12-E — PERFORMANCE OF X. B. COX A-4 SHUT-IN TEST WELL.

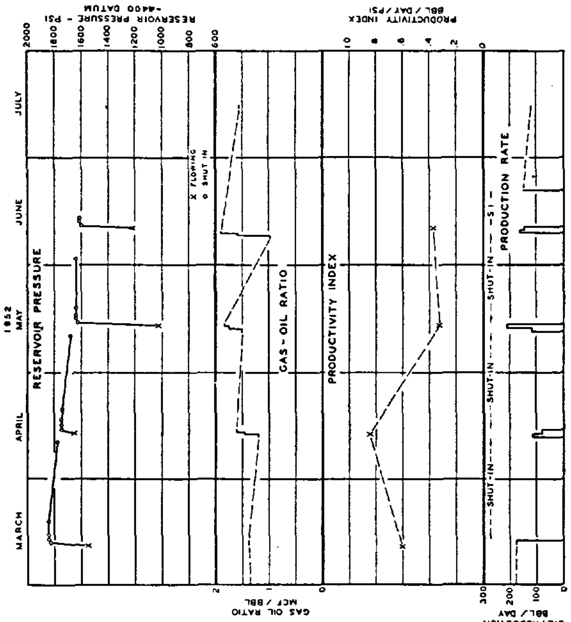


FIG. 12-F — PERFORMANCE OF J. C. BRYANS A-2 SHUT-IN TEST WELL.

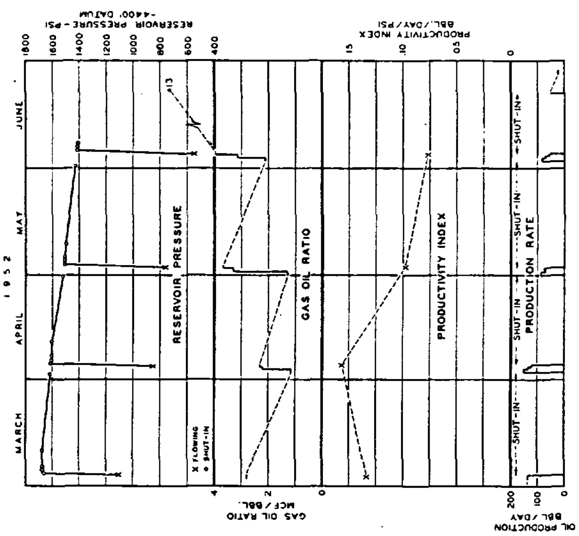


FIG. 12-C — PERFORMANCE OF DAVENPORT B-5 SHUT-IN TEST WELL.

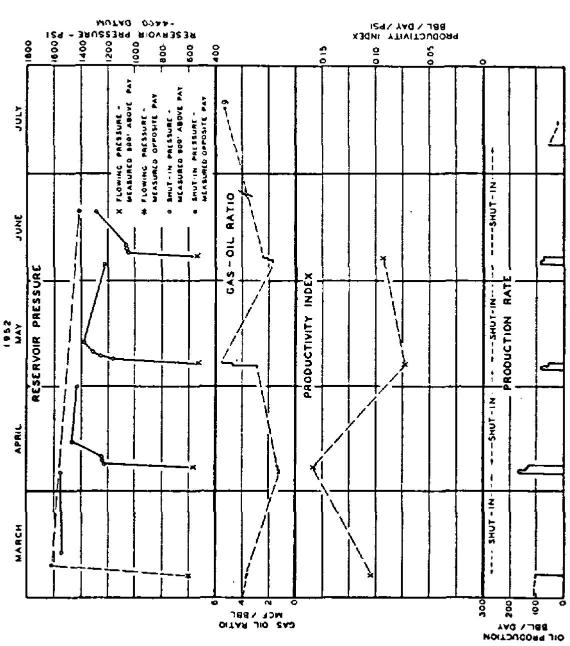


FIG. 12-D — PERFORMANCE OF DAVENPORT B-7 SHUT-IN TEST WELL.

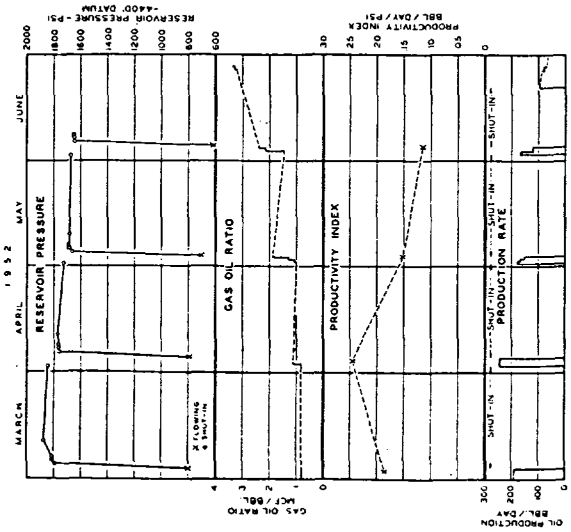


FIG. 12-A — PERFORMANCE OF DAVENPORT C-6 SHUT-IN TEST WELL.

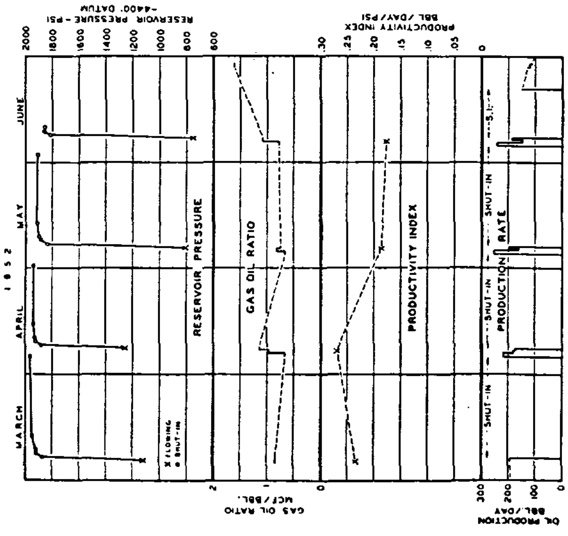


FIG. 12-B — PERFORMANCE OF DAVENPORT C-8 SHUT-IN TEST WELL.

well area behind that of the area close to the producing wells. One good example, however, is Davenport B-11 which had been shut in long before the test program started. Five of the eight surrounding wells had 72-hour shut-in pressures measured in March, 1952. Average of these pressures was 1,725 psi or about 40 psi below the 1,765 psi pressure of Davenport B-11 when all pressures were corrected to a common date.

These data show that, on the average, the pressure declined in shut-in observation wells 1,320 ft from any producing well at almost exactly the same rate as it did in the producing wells. As should be expected, the pressure in the shut-in wells was slightly higher than in the nearby producing wells but this lag which ranges at most up to 200 psi indicates depletion of the area of shut-in wells lagged only a few weeks behind the depletion of the area near the producing wells.

Most of the observations of lower initial pressures in later drilled newly completed wells were made while reservoir pressure was above or very near the saturation pressure of the formation oil. Under those conditions large pressure changes occurred with removal of quite small volumes of oil due to the expansibility of oil above the saturation pressure. These observations during the interference test have shown that without exception production from wells has continued to affect reservoir conditions at points up to at least 1,320 ft away from the producing wells while the reservoir pressure has declined hundreds of psi below the saturation pressure of the formation oil. And this occurred during a period when much larger amounts of oil and gas must be removed to effect reservoir pressure changes due to the much larger expansibility of fluids below the saturation pressure.

Gas-Oil Ratios and Productivity Indices

In previous discussions of well spacing and recovery efficiency, proponents of wider spacing have often stated that interference between wells demonstrated by changes in pressure means efficient recovery of oil over the distance pressure drawdown was observed. Opponents of wider spacing have argued that reduction of pressure did not necessarily mean recovery of oil. The proponents have had to rely on theoretical considerations involving assumptions which were not acceptable to all concerned. It would indeed be fortunate if methods were available by which a well could be drilled and the oil content of the reservoir determined accurately. The well could then be shut in while other wells are produced and later could be resampled to determine oil recovery from the reservoir by difference. However, such techniques have not yet been developed and it is necessary to rely on indirect observations of depletion such as changes in oil productivity and gas-oil ratios in shut-in wells compared with such changes as occur in regularly producing wells to judge relative recovery efficiency.

As previously mentioned, gas-oil ratios and productivity indices were measured for six wells shut in except for a 48-hour production test each month. Data obtained in the series of tests on each of the wells are presented graphically in Fig. 12A-F, inclusive. With one exception the reservoir pressure in each well reached a maximum and then declined during each 30-day shut-in test period, and all of the wells had significant decline in pressure from month to month as discussed previously. Circled pressure points represent 1, 2, 3, 7, and 30 days shut-in pressures. In three shut-in wells the gas-oil ratio decreased during the first month it was shut in and in all six shut-in wells it was higher at the end of the four-month test period than it was at the beginning. In five of the six shut-in wells the productivity index was higher following the first one-month shut-in period than it had been at the beginning of the test. In all of the six shut-in wells the productivity index was lower at the end of the three-month test period than it was at the beginning of the test.

During each 48-hour production test of the shut-in wells, oil production was gauged for the first 24 hours, the next 18 hours, and finally for each of the last six one-hour periods. Flowing bottom hole pressures were recorded during this last six-hour period just prior to shutting in the well for a pressure buildup test. Gas production was measured throughout the 48 hours by orifice meters. Production data and gas-oil ratio calculated for the first 24 hours, the next 18 hours, and the last six hour periods included in Fig. 12A-F, inclusive, show that oil production declined generally and gas-oil ratio increased generally for each of the wells such that 48 hours was insufficient for the wells to be completely stabilized. Thus actual changes in productivity and gas-oil ratios in these shut-in wells probably were more severe than the 48-hour tests indicate. Additional gas-oil ratio and oil production tests were made within one to two weeks after the wells had been returned to regular production and four of the six wells showed further significant increase in gas-oil ratio. Data of these latter tests are included in each well performance chart.

Results obtained in six regularly producing wells tested for comparison are presented in Fig. 13A-F, inclusive. These charts show the oil production rate, gas-oil ratio, and productivity index data along with the flowing pressure and static reservoir pressure measured after 24 hours, 48 hours, and 72 hours shut-in periods. These 72-hour shut-in pressures, summarized in Fig. 11, were discussed previously. Gas-oil ratios of all six of these regularly producing test wells increased during the period and productivity indices of all six of these wells declined significantly throughout the test period.

Productivity indices of all shut-in and regularly producing test wells are summarized in Table 5. The tabulation includes ratio of the last test to the first test of each well to illustrate relative decline in productivity. For the regular producing wells this ratio averaged 0.56 representing 44 per cent decline in productivity during a two month period. For the shut-in test wells this ratio averaged 0.66 representing 34 per cent decline in productivity. As mentioned in discussion of well performance records in Fig. 12A-F these shut in test wells were still declining in production at the end of the 48-hour test following each one-month shut-in period. The last three tests were not comparable to the stabilized test following regular production before the well was shut in but they should be comparable to each other since all were measured at comparable times on production. For the group of shut-in wells the ratio of last productivity index to that measured after the first one-month shut-in period averaged 0.54 representing 46 per cent decline during a two-month period during which only enough oil was produced to test the wells. Production of these six wells during the 48-hour tests totalled less than 2 per cent of production from the four leases involved and average production of each of the shut-in wells was less than 10 per cent of average production of each of the regularly producing wells during the test period.

Reservoir pressure declined about 150 to 185 psi during the test and the corresponding increase in viscosity of oil should have been about 10 per cent from 0.82 to 0.90 cp. Thus, only 10 per cent of the 45 per cent decline in productivity index is attributable to changes in oil viscosity and the remaining 35 per cent must be due to actual reduction of oil saturation in the reservoir. Since over three-fourths of the decline in productivity index observed is due to reduction in oil saturation and since the same percentage decline in productivity index occurred in shut-in wells as did in regularly producing wells, it can only be concluded that a well in the Spraberry effects recovery of oil as efficiently at points in the reservoir at least

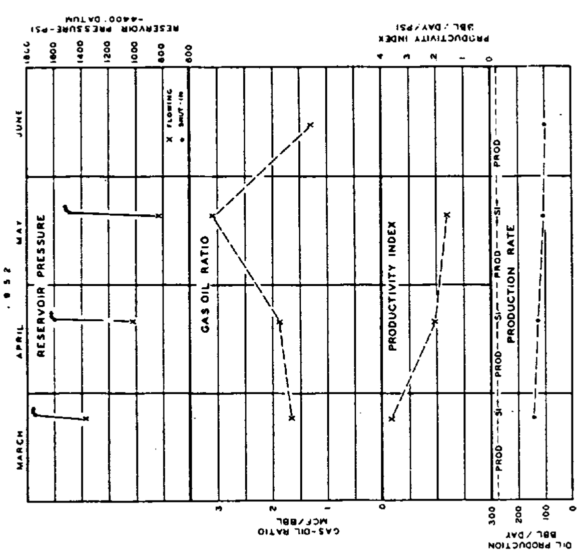


FIG. 13-E — PERFORMANCE OF X. B. COX A-5 REGULARLY PRODUCING WELL.

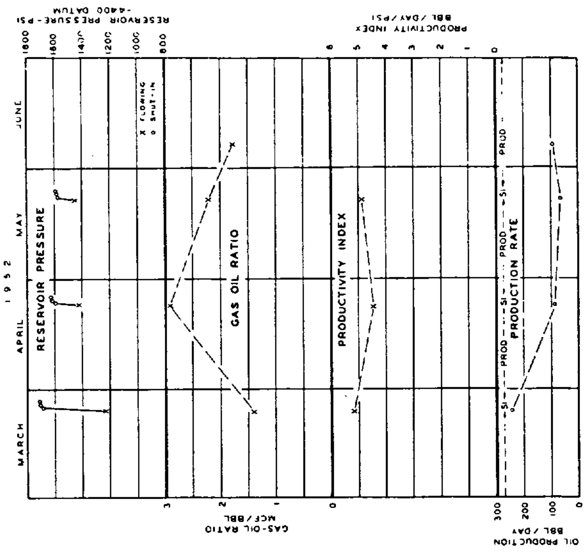


FIG. 13-F — PERFORMANCE OF J. C. BRYANS A-1 REGULARLY PRODUCING WELL.

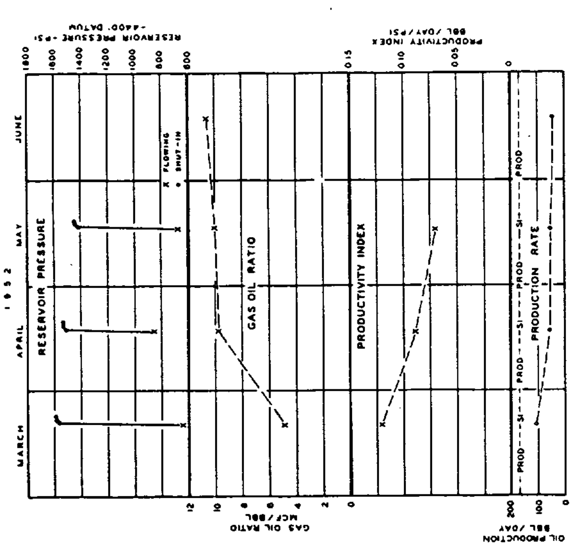


FIG. 13-C — PERFORMANCE OF DAVENPORT B-8 REGULARLY PRODUCING WELL.

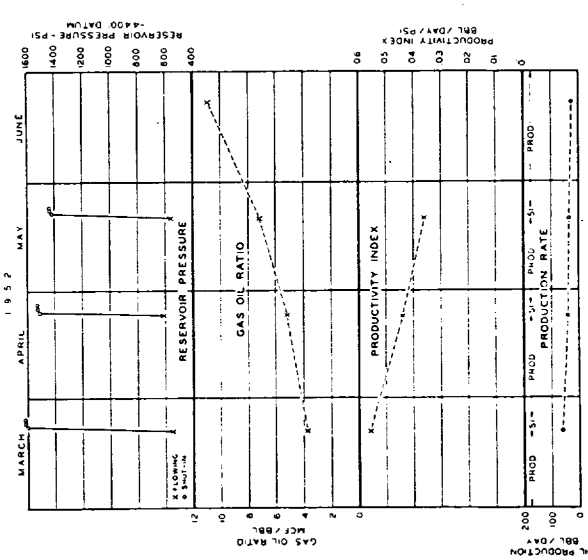


FIG. 13-D — PERFORMANCE OF DAVENPORT B-14 REGULARLY PRODUCING WELL.

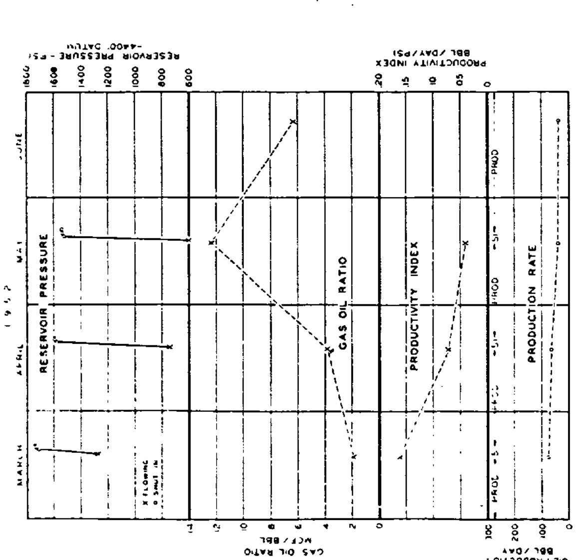


FIG. 13-A — PERFORMANCE OF DAVENPORT C-5 REGULARLY PRODUCING WELL.

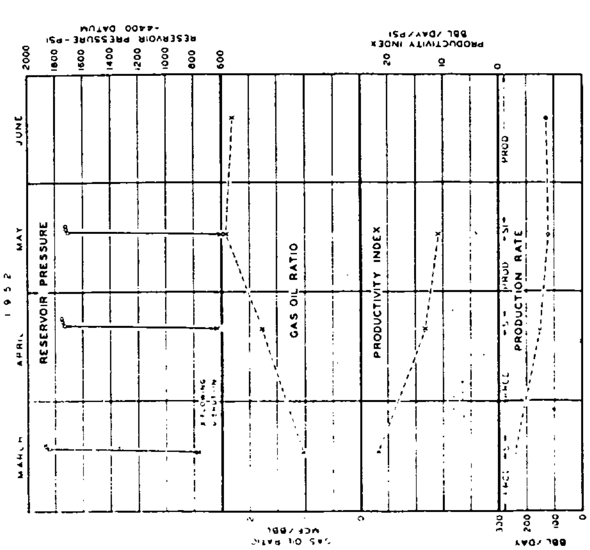


FIG. 13-B — PERFORMANCE OF DAVENPORT C-10 REGULARLY PRODUCING WELL.

Table 5 — Decline in Productivity Index

Shut-In Wells Tested Monthly

Well	Productivity Index — Bbl/Day/Psi March*	April**	May**	June**	Ratio June Test / March Test	Ratio June Test / April Test
Davenport C-6	0.187	0.248	0.150	0.114	0.61	0.46
Davenport C-8	0.235	0.269	0.185	0.176	0.75	0.65
Davenport B-5	0.134	0.157	0.098	0.077	0.57	0.49
Davenport B-7	0.105	0.158	0.073	0.093	0.88	0.59
Cox A-4	0.160	0.140	0.099	0.087	0.54	0.62
Bryans A-2	0.59	0.82	0.32	0.36	0.61	0.44
				Average	0.66	0.54

Wells Produced Regularly

Well	Productivity Index — Bbl/Day/Psi March	April	May	Ratio May Test / March Test
Davenport C-5	0.163	0.073	0.043	0.26
Davenport C-10	0.219	0.133	0.111	0.51
Davenport B-8	0.120	0.088	0.070	0.58
Davenport B-14	0.056	0.044	0.036	0.64
Cox A-5	0.365	0.202	0.152	0.42
Bryans A-1	0.52	0.45	0.49	0.94
			Average	0.56

*Test taken after regular production before well shut-in.
**Test taken last 6 hours of 48-hour production test following one month shut-in period.

1,320 ft from the well as it does from points near the well itself.

Since gas-oil ratios in the Spraberry have increased rapidly after the reservoir pressure declined below 1,600-1,700 psi, it is best to compare gas-oil ratios of the shut-in wells with those of the producing wells at common pressures rather than at common dates. Gas-oil ratios of the six regularly producing wells having productivity index tests and the gas-oil ratios of the six shut-in test wells are plotted versus 72-hour shut-in reservoir pressure in Fig. 14. The last gas-oil ratio point for each shut-in well plotted at the lowest reservoir pressure represents the test one to two weeks after the well had been returned to production. It is included because it represents more stabilized production than do the other measurements made during the 48-hour production tests following each one-month shut-in period. Similarly the last gas-oil ratio point for each of the regularly producing wells represents a test in June, 1952, most nearly corresponding in date to the last tests of the shut-in wells.

Although gas-oil ratios of individual wells varied irregularly during the test, there is good general agreement between the trend of gas-oil ratios of shut-in wells and the trend of gas-oil ratios of regularly producing wells. This is particularly true when it is recalled that shut-in wells were not stabilized within the 48-hour production test following each one-month shut-in period. This is best illustrated by Davenport B-5 and Davenport B-7 wells, whose gas-oil ratios increased from 3,364 to 13,077 cu ft per bbl and from 2,414 to 9,160 cu ft per bbl, respectively, within one to two weeks after the wells had been returned to regular production. These compare with gas-oil ratios 14,250 cu ft per bbl for Davenport B-8 and 11,130 cu ft per bbl for the Davenport B-14 at approximately the same date.

Since change in gas-oil ratio is an index of depletion of oil and since approximately the same changes in gas-oil ratios occurred in the shut-in wells as did in the regularly producing wells, it can only be concluded that oil saturation was reduced by substantially the same amount in the vicinity of the shut-in wells as it was in the vicinity of the producing wells.

These various comparisons of performance of shut-in wells with performance of nearby producing wells have shown by three indices of depletion, decline in reservoir pressure, decline in productivity index, and increase in gas-oil ratio, that substantially the same reduction in oil saturation was occurring in the vicinity of the shut-in wells as was occurring in the vicinity of the producing wells. These detailed tests were conducted in an area drilled on a uniform 40-acre spacing pattern so the tests of shut-in wells are limited to points 1,320 ft from some regularly producing well. But the previous observations of reduced pressure in newly completed wells in this same area included many step out developmental wells 1,870 ft from any producing well and one over half a mile from any

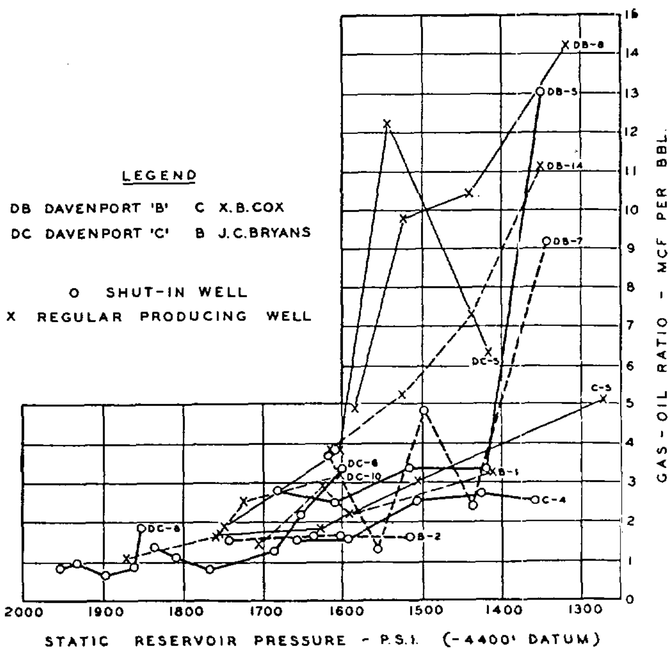


FIG. 14 — COMPARISON OF GAS-OIL RATIOS OF SHUT-IN AND PRODUCING WELLS.

producing well. There is no reason to believe reduction in productivity index and increase in gas-oil ratio would be limited to distances of 1,320 ft when reductions in reservoir pressures have occurred over much greater distances. From these various observations, it can only be concluded that one well can effect recovery of oil from an area of at least 160 acres in the Spraberry Trend as efficiently as could many wells drilled on the same tract.

GENERAL RESERVOIR PERFORMANCE

Production History

This extensive program of obtaining cores, subsurface oil samples, initial pressures of each well and the conduct of an extensive interference test in this area has yielded the most complete record of performance of any area in the Spraberry Trend. History of oil production, gas-oil ratio, and reservoir pressure of the 16-well Davenport "B" lease covering Section 2 in this area is presented in Fig. 15. Production began in August, 1951, and reached a maximum in January, 1952, when full development on a 40-acre spacing pattern had been completed. During this period average reservoir pressure declined from 2,350 psi initially to about 1,900 psi and gas-oil

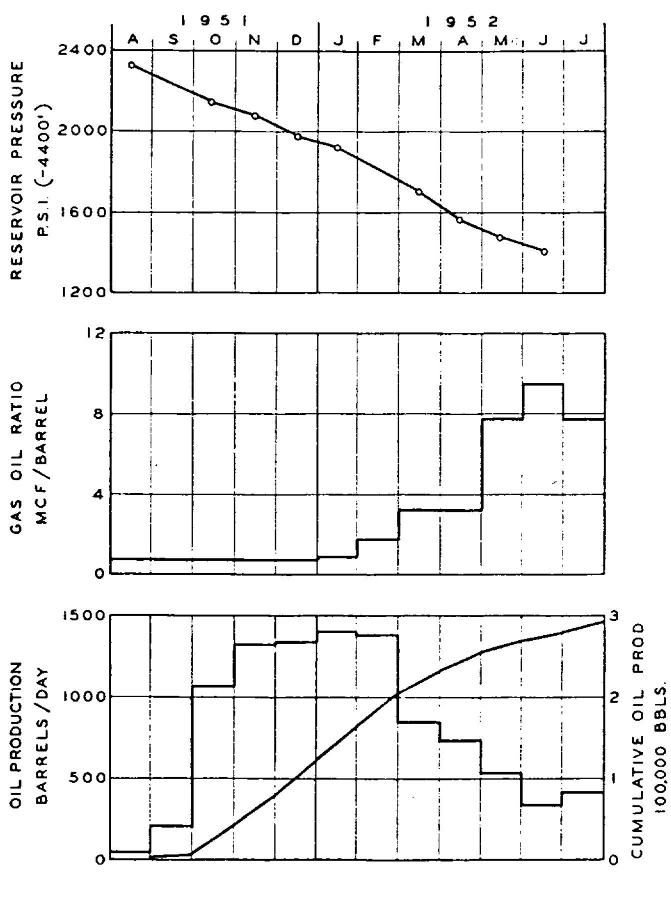


FIG. 15 — RESERVOIR PERFORMANCE, SPRABERRY SAND, DAVENPORT B LEASE (16 WELLS), DRIVER FIELD, GLASSCOCK COUNTY, TEX.

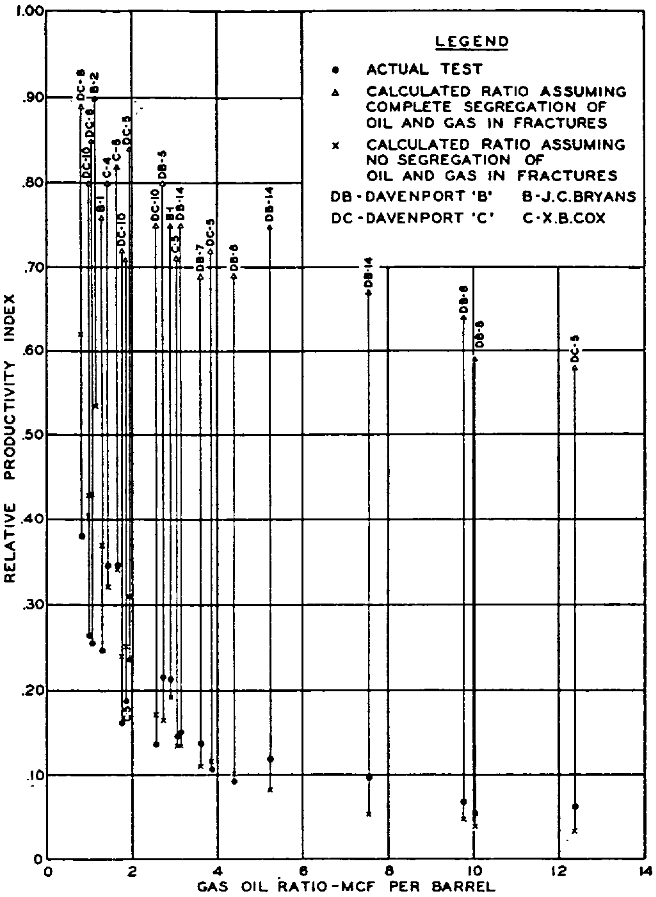


FIG. 16 — RELATION BETWEEN DECLINE IN PRODUCTIVITY INDEX AND GAS-OIL RATIO AND DEGREE OF SEGREGATION OF OIL AND GAS IN FRACTURES.

ratios remained below 1,000 cu ft per bbl at or near the solution ratio. Cumulative recovery was 170,000 bbl, or 265 bbl per acre. Production declined sharply in March due partly to some wells being shut in for the test program just described and due partly to some wells being dead and shut in for installation of gas lift equipment. Radical changes in reservoir conditions caused production to continue to decline sharply through June when it averaged only 25 bbl per well per day even though additional wells were returned to production each month. In February gas-oil ratios started to increase rapidly such that by June the average gas-oil ratio for the lease was about 9,500 cu ft per bbl and ratios for some wells were as high as 30,000 cu ft per bbl. Reservoir pressure had declined to about 1,400 psi in June and cumulative lease production was only 280,000 bbl, equivalent to 17,500 bbl per well or 440 bbl per acre. Four wells on the lease were deepened to the lower Spraberry, accounting for the increase in production and decrease in gas-oil ratio in July, 1952. Extrapolation of production decline from the upper Spraberry alone on this lease would not indicate future production to be a large percentage of past production, and this points to very low ultimate recovery in barrels per acre and in percentage of oil in place initially.

Other leases in the test area have experienced the same type decline in oil productivity and increase in gas-oil ratio, although such changes have lagged slightly behind that of the Davenport "B" lease due partly to later development and due partly to the Davenport "B" lease being most completely surrounded by areas of complete development on the 40-acre spacing pattern.

Decline in Well Productivity

Many factors affecting production change very rapidly in the Spraberry, as indicated by the decline in production of this typical lease and by the decline in productivity indices of various test wells in the interference program. For example, one well near the test area had a productivity index of 0.46 B/D per psi in a test taken within a few days after completion of the well. Two months later in a second test the productivity index declined from 0.23 to 0.09 B/D per psi in a 14-day test while the gas-oil ratio was still less than 1,000 cu ft per bbl. Such decline in productivity is much greater than that corresponding to normal relative permeability - saturation relations.

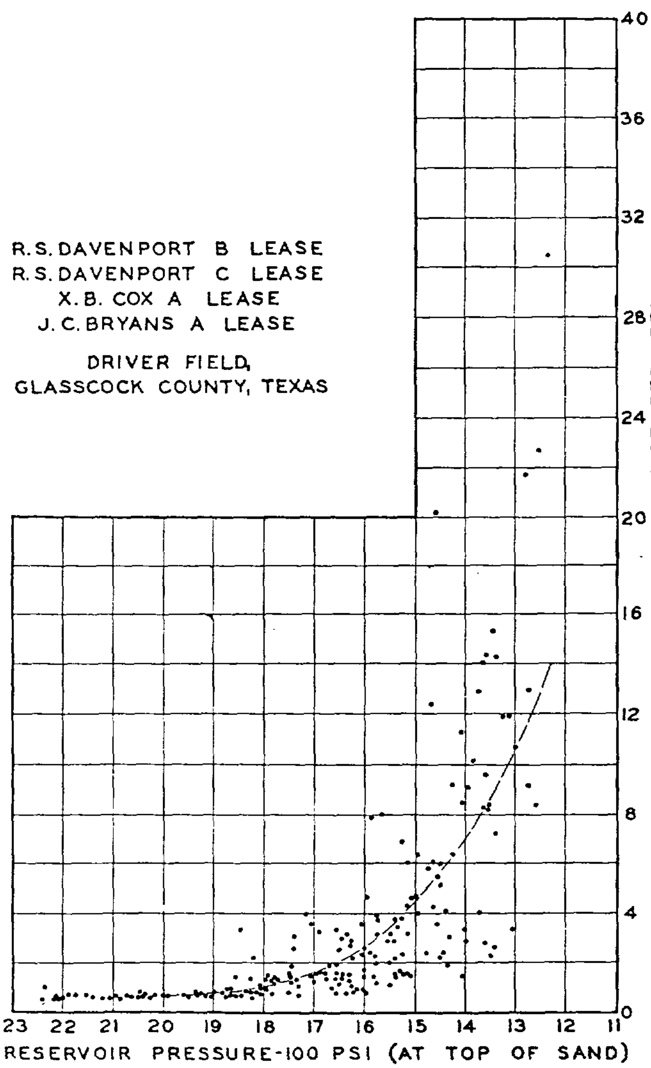


FIG. 17 — GAS-OIL RATIO VS RESERVOIR PRESSURE, PERIODIC INDIVIDUAL WELL TESTS.

Since the fracture openings are paper thin, gravity segregation of oil and gas may be very incomplete — particularly in the vicinity of the wells where velocities are highest, where considerable additional gas is being continually released from solution as the fluids flow into the area of reduced pressure. and where the converging flow concentrates pressure loss due to friction. With complete segregation of oil and gas in uniform fractures the relative permeabilities to oil and gas would correspond ideally to the relative saturations in the fractures (diagonals of a permeability - saturation plot). With no segregation in the fractures, gas would be transported as bubbles dispersed in the oil phase and the friction effects would be about the same as if only oil were present. Relative permeability to oil would correspond to the fractional composition of oil in the flowing mixture and relative permeability to gas would have no meaning in the normal concept of permeability.

Theoretical productivity index was calculated for each test of the wells in the interference test program both for the case of complete segregation of oil and gas in the fractures and for the case of no segregation of oil and gas using relative permeability - saturation relations just previously defined and using Equation (3) developed by Evinger and Muskat.[10]

$$PI = \frac{2\pi K_s H}{(P_s - P_f)\ ln\ r_e/r_w} \int_{P_f}^{P_s} \frac{K_o/K_s}{U} \frac{dP}{B} \quad . \ . \ . \ . \ . \ . \quad (3)$$

where:

PI Productivity index
K_s Specific permeability
H Thickness
K_o Effective permeability to oil
P_s Static reservoir pressure
P_f Flowing bottom hole pressure
U Oil viscosity
B Formation volume factor
r_e Drainage radius
r_w Well radius

Initial productivity indices of these test wells were calculated from initial potential tests, measured initial shut in reservoir pressures, and flowing bottom hole pressures estimated from a simple linear average of tubing pressure versus flowing bottom hole pressure from 16 tests of other new Spraberry wells. Error in flowing bottom hole pressure is estimated to have been less than 100 psi, and pressure drawdown was greater than 500 psi in all but one of the 12 test wells. Actual relative productivity indices, using these as starting points. and theoretical relative productivity indices for 23 tests of the 12 wells are plotted versus gas-oil ratio in Fig. 16. Assumption of no segregation of oil and gas in the fractures gives approximately ten times closer agreement with the actual productivity tests than does assumption of complete segregation of oil and gas in the fractures. At gas-oil ratios greater than 5,000 cu ft per bbl actual productivity is consistently greater than that calculated assuming no segregation of oil and gas in the fractures but still many fold less than that assuming complete segregation. Some deviation is not surprising because oil volume fraction of the flowing gas-oil mixture is less than 10 per cent and at least some segregation should be expected.

In addition to explaining the abnormal decline in productivity of Spraberry wells this analysis has one very practical application in considering installation of artificial lift to increase production rate of flowing wells. This theory indicates only nominal increase in production by lowering flowing bot-

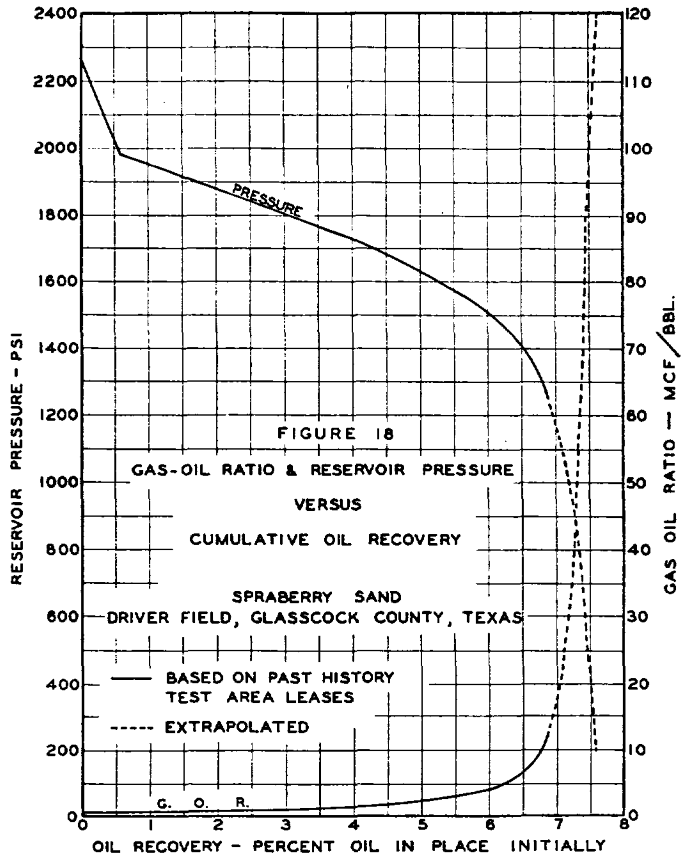


FIG. 18 — GAS-OIL RATIO AND RESERVOIR PRESSURE VS CUMULATIVE OIL RECOVERY.

tom hole pressure from say 500 psi to 100 psi when the well is capable of flowing steadily at the higher pressure. Many wells tested under these conditions have flowed at substantially the same rates as they could be pumped.

Gas-Oil Ratio, Pressure and Recovery

Individual gas-oil ratios of the various wells on the test leases are plotted versus reservoir pressure in Fig. 17. Gas-oil ratios remained at or near the solution gas-oil ratio until the pressure declined below 1,900 psi. With further reduction in pressure they then increased rapidly and averaged about 11,000 cu ft per bbl at 1,250 psi reservoir pressure. Gas-oil ratios of many wells in the test area have increased further to the range of 20,000 to 80,000 cu ft per bbl at reservoir pressure in excess of 900 psi although insufficient pressure data are available to plot the trend accurately.

Because of the rapid changes in Spraberry wells and differences in depletion of the wells, the relation between pressure decline, gas-oil ratio, and cumulative recovery cannot be accurately determined simply by averaging lease data. Such a comparison can be made, however, by material balance methods using the gas-oil ratio - pressure trend in Fig. 17, and the properties of the reservoir oil in Fig. 6. Calculations of percentage recovery of oil were made for increments of pressure decline such that gas-oil ratio corresponded to the average in that pressure range and the material balance was satisfied. Results of these calculations are presented in Fig. 18, which shows calculated gas-oil ratio and pressure versus percentage recovery of oil in place initially. The solid line corresponds with the gas-oil ratio - pressure trend in Fig. 17 and the dashed line corresponds with extrapolation of the gas-oil ratio trend.

This relation between pressure and oil recovery per cent permits an approximate indirect material balance estimate of oil in place initially in the main upper Spraberry sand in the test area. Recovery percentages corresponding to May 20, 1952, reservoir pressures of 18 wells in the three-section test area ranged from 2.45 per cent to 6.65 per cent and averaged 5.72 per cent. Combining this recovery percentage with oil in place initially in the main upper Spraberry sand indicates expected recovery of 360 to 415 bbl per acre by May 20, 1952, depending upon whether net sand oil content or gross sand oil content is applicable. Actual recovery of the four leases to that date totalled 735,000 bbl, or 418 bbl per acre on the basis of 40 acres per well.

The comparison cannot be exact because analytical methods have not yet been developed which will account for the complex flow behavior when the reservoir is below the saturation pressure and both free gas and oil are present. Equalization of pressure between the undeveloped area and the test area should be much slower than that observed in newly completed wells during development when the reservoir was above the saturation pressure. Reduction in effective permeability to oil, demonstrated by the two-fold reduction in productivity indices of wells in the interference test, and seven-fold increase in expansibility of the oil-gas mixture when the pressure declines below the saturation pressure should reduce this rate of pressure equalization.

Considering these factors, the agreement between the expected recovery and the actual recovery is good. Not only does this mean that the pressure-recovery relation in Fig. 18 reasonably represents basic performance of the Spraberry, but it also re-affirms the previous conclusion that the fracture system provides permeable contact with all reservoir blocks containing oil. Thus "islands" of reservoir rock containing commercial quantities of oil do not remain untapped by fractures in the inter-well area.

Unique Reservoir Performance

The relations between gas-oil ratio, pressure, and oil recovery percentage in Fig. 18 show that gas-oil ratios had increased significantly above the solution ratio when only 3 or 4 per cent of the oil in place had been recovered and that they had increased to about 12,000 cu ft per bbl when less than 7 per cent of oil in place had been recovered. Such trend to very high gas-oil ratio at very low percentage recovery of oil is not the performance normally expected in sandstone reservoirs where recoveries are often 15 to 25 per cent of oil in place before high average gas-oil ratios are reached. This performance of the Spraberry results from the unique properties of the reservoir, including the exceedingly fine grained low permeability matrix and the high degree of fracturing. With such conditions, retention of oil within the pores of the rock due to unbalanced capillary forces, well known as end effects in laboratory fluid-flow experiments, is important. Normally this end effect, which may be expressed as a capillary pressure difference, is at most a few psi and it is unimportant when compared with total pressure difference from a distant point in the reservoir to the well bore where the oil and gas must flow the entire length through chains of pores. In the Spraberry where the reservoir rock is divided into segments a few inches to a few feet in size, the total pressure gradient from the center of a block to the fracture face is of

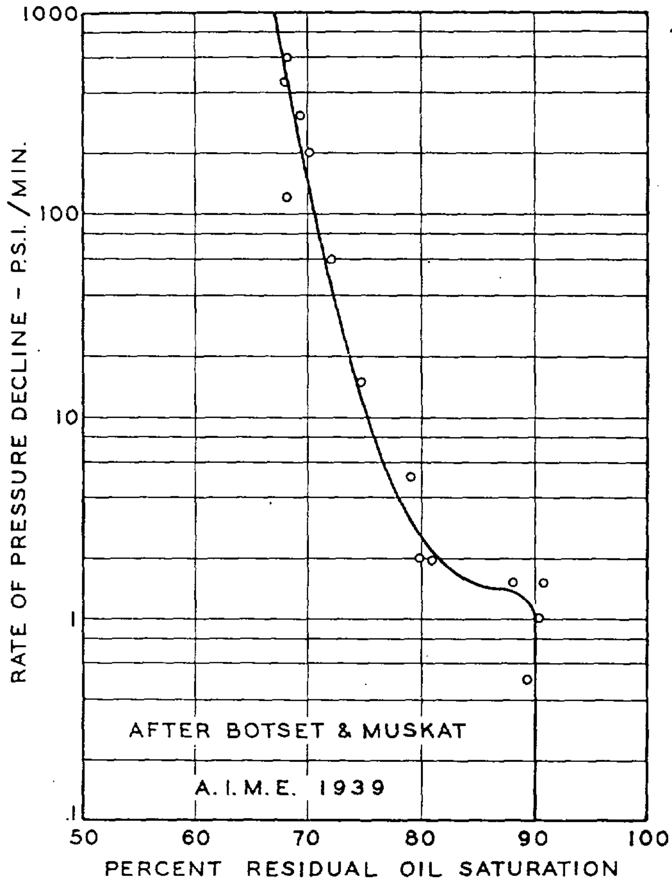


FIG. 19 — EFFECT OF RATE OF PRESSURE DECLINE ON FINAL SATURATION (SMALL CORE TESTS).

the same order of magnitude as the force of capillary retention and lower recoveries of oil result. The inter-relation between permeability, flow rate, capillary pressure, fluid properties, etc., is complex but the characteristic performance of small samples of reservoir rock is illustrated by an experiment conducted by Botset and Muskat, reported in 1939.[11] These investigators performed experiments in which a small core filled with gas-saturated oil was allowed to produce by pressure depletion at different rates in successive experiments. Results of these experiments are summarized in Fig. 19, which is a plot of residual oil saturation versus rate of pressure decline. With pressure decline of 600 psi per minute, the residual oil saturation was 67 per cent of pore space. At successively lower rates of pressure decline, the residual oil saturation was higher until the pressure decline rate reached about 1.5 psi per minute. Below this rate of production, recovery was independent of rate within experimental limits of accuracy. At high rates of production, the pressure gradient within the core was sufficient largely to overcome the capillary retention of oil. At lower rates of production, the pressure gradient was less and effects of capillarity were more pronounced. At very low rates of production, a certain minimum oil recovery was attained regardless of production rate. This latter phenomenon is due to necessity of removal of enough oil so that gas bubbles forming within individual pores could grow in size to connect with gas bubbles in adjacent pores such that it could flow readily out of the core. When this equilibrium saturation had been reached the gas flow rate was low enough that the viscous drag of gas on oil was insufficient to overcome the capillary retention and no more oil was produced.

Since the relation between the various factors involved are very complex and many of them not known quantitatively for the Spraberry, similar laboratory experiments were performed directly upon a Spraberry core sample. A core 2 in. in diameter and 6 in. in length was machined to fit closely a steel cylinder. The core containing 28.5 per cent water saturation was placed in the cell and filled with gas-saturated Spraberry oil from a subsurface sample. Gas and oil were removed from the core at such a rate to result in pressure decline of about 200 psi per minute. The core was removed and oil saturation determined to be 2 per cent by difference in weight between the core with its residual oil and water saturation and the weight of the core with its initial water saturation. Oil recovery was calculated to be 52 per cent of oil in place initially in the core.

After being cleaned, the same core containing 13.4 per cent water saturation was replaced in the cell and again filled with gas-saturated Spraberry crude oil. Withdrawal of fluids was slowed to a constant rate of pressure decline of about 100 psi per day. Residual oil similarly determined by weight difference was 57.5 per cent of pore space and the oil recovery similarly calculated to be 7 per cent of oil in place initially. Data for both tests are summarized in Table 6. Practically all production of oil occurred before pressure declined to 1,000 psi. Thereafter only gas was produced.

Pressure decline of 100 psi per day in the slower experiment reported is some 30 to 100 times faster than the reservoir pressure decline rate in presently developed areas of the Spraberry Trend, which is of the order of 1 to 3 psi per day. Recovery performance of fracture blocks of size and properties similar to that used in the laboratory experiment should certainly be no better than that of the laboratory core. In addition, recovery performance of blocks a few feet in size at pressure decline rates of the order of 1 to 3 psi should be about the same as that observed in the laboratory core test at a pressure decline rate of 100 psi per day. This is based on assumption from theory of relative permeability and capillarity that similar end effects occur in different sized blocks when production rates are such that total pressure drop from the center to the face of the block is the same in all blocks. Frequency of fractures and opening of fractures observed in cores coupled with determination of reservoir permeability from analysis of the pressure-production relation indicates

Table 6 — Results of Laboratory Experiments Pressure Depletion of Oil Saturated Spraberry Cores

CORE PROPERTIES	
Porosity	8.15%
Permeability	1.1 md
Size	2.18" diam. x 6.1" length
TEST NO. 1	
Simulated Connate Water Saturation	28.5 %
Saturation Pressure of Crude Oil	2000 Psi
Average Rate Pressure Drawdown	200 Psi/Min.
Residual Oil Saturation by Weight Difference	25 %
Calculated Oil Recovery — Per cent of Oil in Place Initially	52 %
TEST NO. 2	
Simulated Connate Water Saturation	13.4 %
Saturation Pressure of Crude Oil	1990 Psi
Average Rate of Pressure Drawdown	100 Psi/Day
Residual Oil Saturation by Weight Difference	57.5 %
Calculated Oil Recovery — Per cent of Oil in Place Initially	7 %

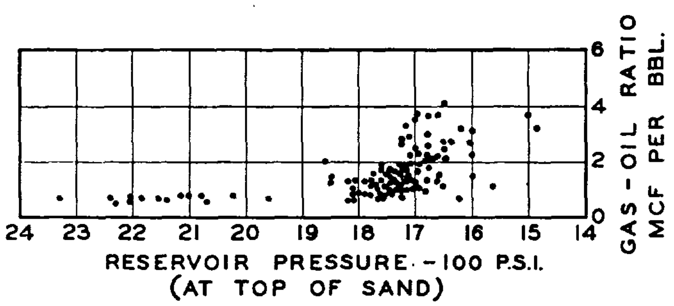


FIG. 20 — GAS-OIL RATIO VS RESERVOIR PRESSURE, PERIODIC INDIVIDUAL WELL TESTS. E. D. BERNSTEIN LEASE, R. W. CLARK LEASE, R. PEMBROOK LEASE, PEMBROOK FIELD, UPTON COUNTY, TEX.

fracture blocks are probably in this size range, and it appears that this recovery mechanism greatly influenced by capillary retention is the proper explanation of early trend to high gas-oil ratios and very low percentage recovery of oil in place indicated by performance to date in the Spraberry.

Since most Spraberry wells have been produced at near capacity and very low recovery percentage is indicated even in the areas of 40-acre spacing, no practical method exists by which the rate of pressure decline could be greatly accelerated to achieve more efficient natural recovery.

The possibility that recovery is affected by production rate in the Spraberry cannot be ruled out on the basis of the two Spraberry core tests by analogy to the Botset-Muskat experiments. However, a portion of the Pembrook Field was developed on uniform 80-acre spacing. With proration based on 40-acre units, the production rate per acre in this portion of the Pembrook Field has been half the production rate per acre of the portion of the Driver Field drilled on 40-acre spacing, which has been discussed in this paper. Relation between gas-oil ratio and reservoir pressure for this portion of the Pembrook Field is presented in Fig. 20.

Core analyses, oil characteristics including solubility, shrinkage and saturation pressure, and reservoir pressure initially in this area of the Pembrook Field were very similar to those in the Driver Field. Comparison of data in Fig. 20 with that in Fig. 17 shows the relation between gas-oil ratio and pressure — and thus recovery efficiency — are substantially the same for the 80-acre spacing area and the 40-acre spacing area. In addition oil recovery per acre attained when reservoir pressure had declined to 1,650 psi was about the same in both areas. These factors demonstrate reduced withdrawal rate per acre should have no adverse effect on ultimate recovery if the remainder of the field is developed on wider spacing.

Applicability to Entire Field

Reservoir performance data included in this paper come entirely from the two areas outlined. However, reservoir conditions and reservoir performance are qualitatively similar to this throughout the Spraberry Trend. Those readers interested in any other particular area are referred to the testimony presented by W. O. Keller at the recent hearing on the Spraberry Trend.[12] This includes summaries of core analyses, subsurface sample analyses, potentials and productivity indices of wells, examples of reduced reservoir pressure in later drilled wells, decline curve estimates of ultimate recoveries, etc., for various areas in the field.

CONCLUSIONS

1. Spraberry oil is stored primarily in pores of sand matrix of very limited section. Paper-thin vertical fractures provide flow channels for oil in this extremely low permeability reservoir.
2. That a well can deplete an area of at least 160 acres in the Spraberry as efficiently as could many wells in the same area was confirmed by direct experiment in the field.
3. Capillary "end effects" in the small fractured blocks of rock limit recovery to only a few per cent of oil in place initially.

ACKNOWLEDGMENT

Just as important as the particular facts reported here regarding reservoir performance and well spacing in the Spraberry Trend is the demonstration of co-operation that can be achieved through thorough understanding at all levels from field personnel to corporate management in solving a pressing problem. While space does not permit individual acknowledgment, the tireless efforts of pumpers, pressure unit operators, field engineers and supervisors, laboratory personnel, and others are gratefully appreciated for making the thousands of measurements accurately and on time which made this analysis possible.

The author wishes to express his appreciation to the management of Sohio Petroleum Co. for its support in the conduct of this extensive field research program and for its permission to publish the data included in this paper.

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A DRAWDOWN AND BUILD-UP TYPE CURVE FOR INTERFERENCE TESTING

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ABSTRACT

Interference testing is a powerful method for in situ measurement of transmissivity, storativity, and quantitative identification of anisotropy and system boundaries. The log-log type-curve matching procedure can be used for analysis of interference data taken during production or drawdown. Once production is terminated, observation well pressures return toward the initial pressure. This recovery, or pressure build-up, has been interpreted by differencing the extrapolated drawdown and measured build-up. This procedure extracts the "injection" well which causes the build-up. A new type curve for both the drawdown and build-up portion of the test has been prepared. Application of the new type curve shows that the older differencing procedure may obscure detection of system boundaries. The principal of the build-up type curve may be extended to other flow problems.

INTRODUCTION

The initial assessment of geothermal reservoirs usually has two main objectives. One is determination of the deliverability from the reservoir, and the other is estimation of the reserves, or the economically producible amount of steam in the system. Many geothermal reservoirs are complicated by the fact that neither the porosity-thickness product nor producible area are known, either early in the life or after extended production. One means of determining the deliverability is a pressure transient test. Pressure transient tests can be conducted in a short period of time, and early in the life of a geothermal development. However, estimation of steam reserves requires an extended period of production with observation of mean reservoir pressure at various stages of production. Material and energy balance performance matching with a detectable decline in pressure following production is the minimum information for performance matching. Thus it is necessary to produce a reservoir for an extended period of time before performance matching can be accomplished with acceptable risk.

The dilemma is that single-well pressure tests of fairly short duration are needed to provide accurate information on deliverability (permeability thickness or transmissivity) and well condition, while long-term production testing is required to establish reserves. Fortunately, an interference test is a type of pressure transient test that can be accomplished in a reasonable period of time, and yet provide important information concerning apparent reserves early in the life of a geothermal development. At least two wells are required for an interference test. More than two wells is desirable.

The main problem with single-well pressure transient tests is that distances in the reservoir are measured in units of the wellbore radius. A test of an individual well can yield important information concerning the condition of the well, the formation conductivity, and drainage boundaries of the well. However, long periods of production are required prior to pressure build-up testing for boundaries to be evident, when distances are measured in units of wellbore radius. An alternate procedure is to observe pressure effects transmitted between two or more wells. This kind of test is called an interference test. The theory of interference testing was explained by C.V. Theis (1935). A modern discussion of interference testing procedures has been presented by Earlougher (1977). There are many recent publications on this important subject in both the groundwater and the petroleum engineering literatures. An example of application of interference testing to geothermal systems has been published by Chang and Ramey (1979).

One simple basis for interference test analysis is the continuous line source solution. This model assumes that a single well is produced at a constant rate in an infinitely large slab reservoir of constant properties. The pressure effects caused by the producing well may be observed at one or more distant wells, which are not produced but used simply as pressure observation stations. The solution to this problem can be displayed on a piece of log-log coordinate paper. Figure 1 is a type-curve for this problem as used commonly in the petroleum literature. Figure 1 presents the analytical solution for the conventional line-source well (exponential integral solution).

$$p_D = -\frac{1}{2}\,\mathrm{Ei}\left(-\frac{r_D^2}{4t_D}\right), \tag{1}$$

where

$$p_D = \frac{kh}{141.2\,qB\mu}(p_i - p_{r,t}) \tag{2}$$

$$r_D = r/r_w \tag{3}$$

$$t_D = \frac{0.000264kt}{\phi\mu c r_w^2} \tag{4}$$

In Eqs. 2-4, English engineering units are used: permeability in millidarcies, lengths in feet, pressures in psi, viscosity in centipoise, flow rates in stock tank barrels per day, time in hours, porosity in fraction of bulk volume, formation volume factor in reservoir volumes per standard volume, and total system effective compressibility in reciprocal psi.

Figure 1 presents a dimensionless pressure which is directly proportional to an observed pressure drawdown versus the ratio of a dimensionless time to the dimensionless distance between the production and observation well squared. The dimensionless time is directly proportional to real time, and the dimensionless distance is directly proportional to real distance. An important characteristic of the logarithmic scale is that quantities proportional to the plotted scale are simply displaced linearly along the scale. Thus it is possible to graph the field data observed in an interference test as a pressure drop on the ordinate versus time on the abscissa, and make a direct comparison with the analytic solution represented by Fig. 1. This procedure is called log-log type-curve matching, and has been outlined in detail in many references, such as Earlougher (1977).

Once a set of field data has been matched with the line-source type curve, it is possible to equate the pressure difference point with the dimensionless pressure from the type-curve to make quantitative calculations. In the usual case, the net formation thickness (h), the flowrate (q), the formation volume factor (B), and the viscosity (μ) of the produced fluid would be known. The objective of the pressure matchpoint would be calculation of the effective permeability to the flowing phase (k). From the time matchpoint, it would be possible then to calculate the porosity-compressibility product. In the ordinary case, the porosity would be known, and thus it would be possible to obtain a check on the average compressibility of the formation and fluid. An alternative would be to determine the in-place porosity under the assumption that the average compressibility of the rock-fluid system were known. This step is frequently done in petroleum engineering work as a check upon porosity derived either from core analyses or from well logging methods. In petroleum engineering application, one frequently obtains both effective permeabilities and porosities which agree with information known from other sources. For example, the effective permeability will frequently agree with that obtained from a pressure buildup test on a single well, while the porosity obtained from an interference test will frequently agree with porosities obtained from core analyses.

In the case of interference testing of geothermal systems, analysis is often more complex. In the use of the pressure matchpoint, it is often observed that the net formation thickness for the geothermal system is not known. This may be a result of the fact that the formation has not been fully penetrated by drilling, or that the system is fractured and characteristics are not readily apparent. In this case, the product of permeability and formation thickness is obtained, a useful quantity for deliverability and well condition determination. In the case of the time matchpoint, frequently the porosity is not known. Since the thickness also is not known, there is a dilemma as to the kind of useful calculation available from the time matchpoint. Fortunately, important and useful information can be obtained from the time matchpoint. The product of porosity, compressibility, and thickness can be computed. This product is sufficient to estimate the mass of geothermal fluid in the system per unit area. An estimate of the system area and recovery factor for the fluid is then sufficient to make an initial estimate of the capacity of the system.

The result obtained by this method is definitely preliminary, and should be checked by material-energy balance performance matching as production follows. Several uncertainties have been identified which render the results of the test uncertain. The Theis line-source method depends on a single-phase fluid flow model. There may be carbon dioxide or steam caps in geothermal systems. In this case, the compressibility of the system may be close to that of gas, rather than liquid. Another problem is that geothermal systems are often fractured systems. Recently, Deruyck (1980) studied interference testing in fractured (two-porosity) systems, and Kucuk (1980) has offered a similar study. It appears that this sort of system should be studied further.

Both show that two-porosity system interference results may resemble the Theis curve for a homogeneous system, but the parameters which result from type-curve matching can be uncertain.

We have established the potential importance of an interference test in the early evaluation of geothermal steam systems. Because an interference test involves producing a geothermal system from an initially static condition for some time, it is obvious that the test must eventually be terminated. When this happens, there is an opportunity to obtain additional information as pressures return toward the initial state. Most discussions of interference testing deal mainly with the pressure drawdown period. But the ensuing shut-in period, when pressures recover toward the initial state, can provide important information concerning drainage boundaries of the system. One discussion of this kind of procedure was presented by Ramey in 1975. In general, the procedure involves extrapolating the initial drawdown portion of the test and differencing the pressure recovery from the extrapolation from the drawdown. The result is extraction of the effect of an injection well which caused the pressure shut-in. An example of this kind of differencing is given by Ramey (1975). Fortunately, it is possible to prepare a new log-log type-curve which contains both the drawdown and build-up portions of the test on a single graph.

Pressure-Build-up Type Curves

We consider that a well is produced at constant rate for a period of time, t_p, and then shut in. During the initial drawdown portion, the pressures at adjacent shut-in observation wells are represented by Fig. 1 and Eqs. 1-4. After the producing well is shut in, it is necessary to employ the principle of superposition to generate a relationship which describes the shut-in period properly. This results in:

$$\frac{kh}{141.2\ qB\mu}\left(P_i - P_{ws_{r,t+\Delta t}}\right) = P_D(r_D, t_p+\Delta t) - P_D(r_D, \Delta t) \tag{5}$$

Equation 5 can be evaluated generally by replacing the dimensionless pressures by their appropriate line-source values for a particular producing time, t_p, and a range of shut-in times, Δt. Fig. 2 presents such a graph. The format is similar to Fig. 1, except the pressure build-up lines are shown as a family of curves dropping below the line-source solution, each displaying the parameter of dimensionless producing time divided by the dimensionless distance squared.

t_{pD}/t

Figure 2 is the general solution for both pressure drawdown and pressure build-up measured at a shut-in observation well caused by a well producing at a constant rate for time, t_p. Obviously, a single type-curve match between field data and Fig. 2 can be made with the match involving both the production and the build-up data.

Field Example

In 1975 Ramey presented several sets of pressure drawdown and build-up interference data. We will select one example from this reference for purposes of discussion. The example will be the production of well 5-D with an interference effect measured in well 1-E, 700 ft away from well 5-D. This test actually involved injection rather than production, but the principle is the same. The injection into well 5-D caused a pressure rise in 1-E, and after shut-in, the pressure rise declined, approaching the initial pressure at an extended period of shut-in.

The details of the field example will not be given completely here. The results for well 1-E were selected by Ramey in 1975 to illustrate the principle of differencing pressure build-up data to extract the effect of the well causing the shut-in. As found in this study, well 1-E appeared to provide a reasonable match with the line-source solution for both the drawdown and pressure build-up data. (See Wentzel, 1942, for rate change differencing.)

Table 1 provides the field data for the example interference fall-off test at well 1-E. Fig. 3 is a log-log type curve of both the drawdown and build-up pressure drops as a function of the total test time. This sort of field data graph can be matched directly with the new drawdown-build-up line-source type-curve presented in Fig. 2. Fig. 4 is an illustration of the kind of match that can be obtained between the well 1-E example and the new drawdown-build-up type curve. In the match shown in Fig. 4, the same matchpoint found by Ramey in 1975 has been maintained. It is evident by comparing the field data with the new type-curve that although the drawdown portion matches the line-source reasonably well, the build-up portion of the curve after shut-in does not appear to match the computed buildup curves in Fig. 2 ideally. This may represent an indication of some sort of boundary effect becoming evident during the build-up portion of the test.

On the other hand, in the 1975 publication by Ramey, the differencing procedure was used to analyze the pressure build-up portion of the test. The build-up portion was found to match the line-source solution reasonably well. We suspect that the differencing procedure involves enough trial and error that data may be forced to match the line-source even when the field data are not a good match for the line-source solution. On the other hand, a number of other field cases have been found which appear to provide reasonably good matches with the new drawdown-build-up type curve shown in Fig. 2.

ACKNOWLEDGMENT

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TABLE 1--FIELD EXAMPLE INTERFERENCE FALL OFF
Well 1-E

Total Time, (hours)*	Δt, (hours)	Δp, (psi)**
27.5		3
47		5
72		11
95		13
115	14	16
125	24	16
142	41	13
192	91	10
215	114	10
240	139	6
295	194	5.8

*$t + \Delta t$ after shut-in at 101 hours.
**Actual measured pressure rise.

q = 115 b/d r = 700 ft
B = 1 res b/Stb h = 25 ft
μ = 1 cp t_p = 101 hrs

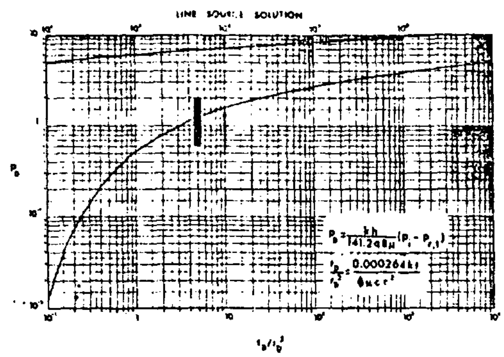

Fig. 1--The Continuous Line-Source Solution Type Curve

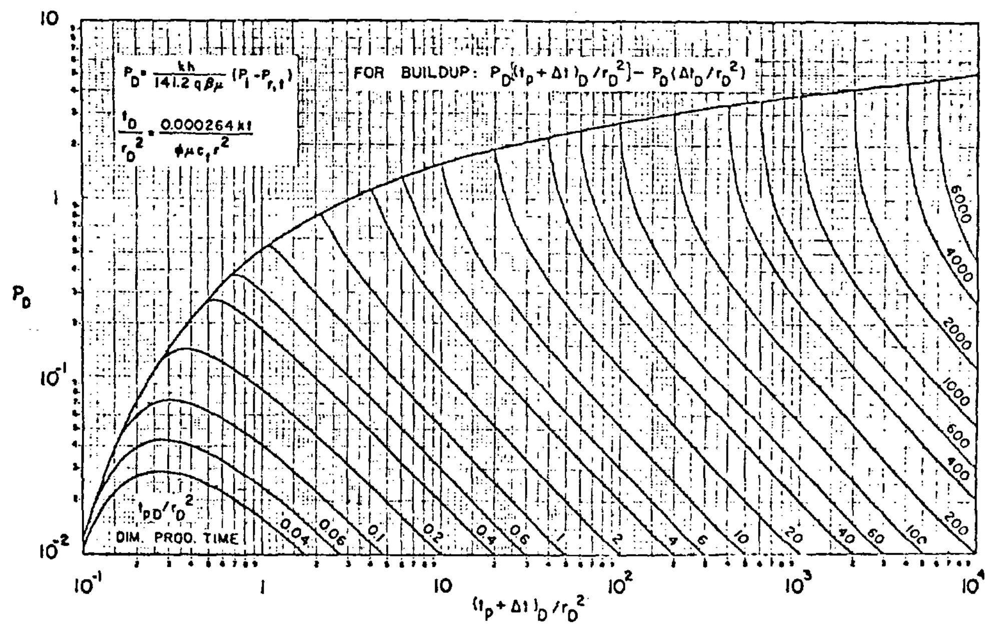

Fig. 2--Drawdown and Buildup Interference Test for a Line Source Well

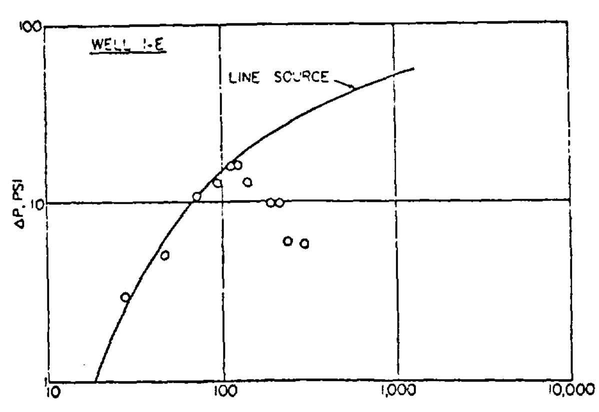

Fig. 3--Field Data Graph for Well 1-E

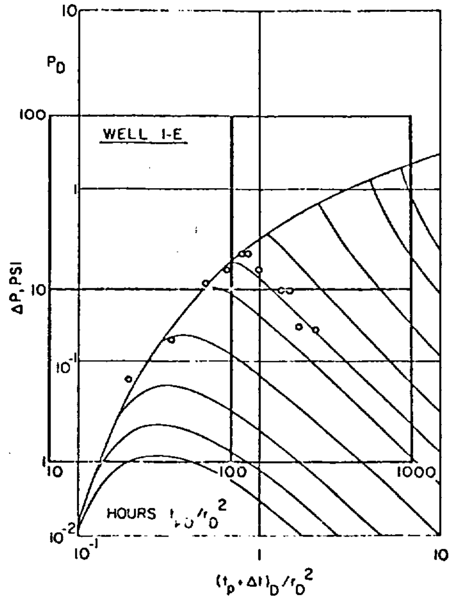

Fig. 4--Type-Curve Match for Well 1-E

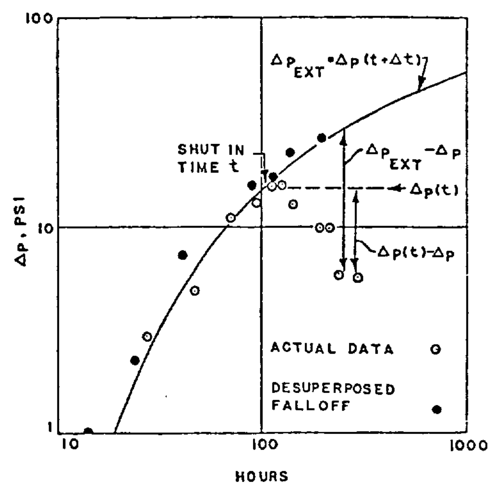

Fig. 5--Field Example Interference Falloff Analysis, Well 1-E

BUBBLE FORMATION IN SUPERSATURATED HYDRO-CARBON MIXTURES

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ABSTRACT

In many investigations of the performance of petroleum reservoirs the assumption is made that the liquid, if below its bubble-point pressure, is at all times in equilibrium with gas. On the other hand, observations by numerous investigators have indicated that gas-liquid systems including hydrocarbon systems, may exhibit supersaturation to the extent of many hundred psi in the laboratory. Up to the present, there has been no reliable data on which to judge the actual extent of supersaturation under conditions approaching those existing in petroleum reservoirs.

The work reported here deals with observations and measurements on mixtures of methane and kerosene in the presence of silica and calcite crystals. Bubbles were observed to form on crystal-hydrocarbon surfaces in preference to the glass-hydrocarbon interface or to the body of the liquid. Statistically, it was found that the number of bubbles formed per second per square centimeter of crystal surface was a function of the supersaturation only, and the function was evaluated graphically.

Supersaturations were observed up to 770 psi, under which condition bubbles formed quickly and with considerable violence. With decreasing degrees of supersaturation, the frequency of bubble formation became less, until at 30 psi supersaturation and lower, no bubbles were observed to form, even though the observation at 30 psi was continued for 138 hours. It was found that silica and calcite crystals had identical effects, within experimental error, in accelerating the formation of bubbles, and that small amounts of water and crude oil had no effect on the results.

It is shown that the maximum supersaturation that can exist in a reservoir may be calculated from the data presented and from the area of the rock surface. It is also shown that the number of bubbles formed in the reservoir, in order of magnitude, may be calculated for any rate of pressure decline imposed on the reservoir by production. The bearing of the number and distribution of bubbles on reservoir performance is discussed.

[1]References given at end of paper.

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INTRODUCTION

A liquid system is supersaturated with gas when the amount of gas dissolved exceeds that corresponding to equilibrium at the existing pressure and temperature. The degree of supersaturation may be conveniently expressed as the difference between the bubble-point of the mixture and the prevailing pressure. Thus, if a mixture having a bubble-point of 1,000 psi at a given temperature exists in single liquid phase at 700 psi at the same temperature, it is supersaturated to the extent of 300 psi.

There are many examples of high supersaturations, mostly in aqueous solutions, reported in the literature. Thus, Kenrick, Wismer and Wyatt[1] showed that water may be saturated with oxygen, nitrogen or carbon dioxide at 100 atmospheres, and the pressure reduced to one atmosphere without producing bubbles immediately. When liquids are in a state of tension, they may be considered as supersaturated at least to the extent of the tension. The tensile strength of water has been reported as 30 atmospheres by Meyer,[2] 60 atmospheres by Budgett,[3] 30 to 50 atmospheres by Temperley and Chambers,[4,5] 200 atmospheres by Dixon,[6] and 223 atmospheres by Briggs.[7]

Vincent[8,9] determined the tensile strength of a mineral oil as 45 psi. Gardescu[10] maintained pressures for short times in a model reservoir at 115 psi below the bubble-point.

It should be noted that the high supersaturations observed were obtained on systems carefully purified to remove particles or surfaces which might promote the formation of bubbles. These "nuclei" were considered as contaminants which interfered with the determination of a property of the liquid. In petroleum reservoirs, the mineral and water surfaces with which oil is in contact must be accepted as essential parts of the system under investigation. Further, the data, to be of greatest utility for engineering purposes, should deal quantitatively with the number of bubbles formed in the reservoir under prevailing conditions. It is clear that observations of the maximum supersaturations that can be maintained for unspecified short periods, cannot yield this type of information.

In the direction of developing a quantitative approach to the phenomenon of supersaturation, it was noted that bubbles are always formed on a solid surface rather than in the liquid phase. Their formation appears to be distributed at random both as regards time and location on the solid surface. It would therefore be expected that a sufficiently large number of observations would give, at a fixed supersaturation, a constant average number of bubbles formed per square centimeter of surface per second. This theory of random formation of bubbles is in accord with the wide variation of supersaturations reported in the literature on apparently identical systems, and is supported by the data obtained in this investigation.

EXPERIMENTAL METHOD

Methane used in this investigation was the commercial material, obtained in 1,500 psi cylinders and rated as 96 per cent pure, the impurities being ethane, propane, nitrogen and oxygen. The kerosene had an API gravity of 46.3°, with an average boiling point (10 per cent intervals) of 344°F. The quartz and calcite minerals used were accurately cut from large natural crystals. The crude oil used was from the East Texas Field.

The choice of test methods was complicated by the fact that at high supersaturations, glass was the only solid found which did not accelerate bubble formation. In a steel observation cell, bubbles were observed to form repeatedly at certain points on the steel surface and on the exposed surfaces of the gaskets. The slightest scum on a mercury surface would promote bubble formation at high supersaturations, although no trouble from this source was observed in the lower range of values. However, at low supersaturations, due to the longer periods of observation required, the greater effect of diffusion of gas across gas-liquid boundaries eliminated the possibility of employing such surfaces.

Two methods were therefore employed. In the first method, used at high supersaturations, the system was confined in a glass tube with a gas-liquid contact as an upper boundary. For lower supersaturations, the system was confined above carefully purified mercury. As will be shown later, diffusion was not a factor for the periods of observation required in the first method, while no bubbles were observed to form on the mercury surface in the low supersaturation tests for which the second method was used.

In both methods, filtered kerosene and methane were agitated together in an Aminco mixing bomb for several hours, at 500 psi or 1,000 psi and room temperature. An amount of gas was released that would cause a slight drop in pressure, and shaking continued. A rise in pressure to the original value indicated that saturation was complete. The gas phase was bled off from the mixture at constant pressure, and the pressure then raised to 2.000 psi, to give an unsaturated solution of accurately known bubble-point.

In the first test method, used for high supersaturation values, quartz or calcite crystals were stacked in a test tube within a Penberthy visual cell as shown in Fig. 1. The crystals had rectangular faces of accurately known areas, the total area for each crystal averaging about 4.5 sq cm. Sufficient kerosene containing no dissolved gas was introduced into the tube to cover the bottom and one-half of the sides of the lowest crystal. The pressure in the cell was then raised to the test pressure, usually 1,000 psi, by introducing methane, and enough saturated kerosene was added to raise the liquid level to the center of the next higher crystal, holding the pressure constant.

A valve, connecting the cell to a fixed and calibrated orifice, was then opened, and the pressure allowed to fall. An electric timer was started when the valve was opened, and the time at which the first bubble appeared was noted. In conjunction with the calibration curve, the time indicated the pressure, and thus the supersaturation pressure, at which the bubble formed. A typical calibration curve is shown in Fig. 2. Where warranted by temperature fluctuations, corrections based on several calibration curves made at different room temperatures, were applied.

The appearance of a bubble terminated a run, since considerable mixing and evolution of gas generally accompanied its formation. To prepare for the next run, the cell was then allowed to fall to atmospheric pressure to desaturate its contents. It was then again brought to the test pressure by the induction of gas, and live kerosene was added until the liquid level rose to the center of the next higher crystal. The pressure was allowed to fall by opening the valve to the calibrated orifice, and the observation repeated. After the glass tube containing the crystals was filled above the top crystal, the tube was emptied, and another set made. Normally, 85 observations constituted a series, which could be analyzed

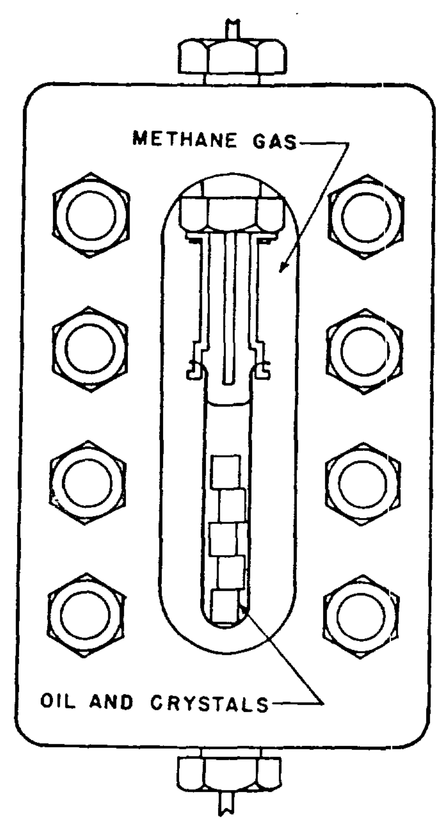

FIG. 1 — WINDOWED CELL FOR HIGH SUPERSATURATION TESTS.

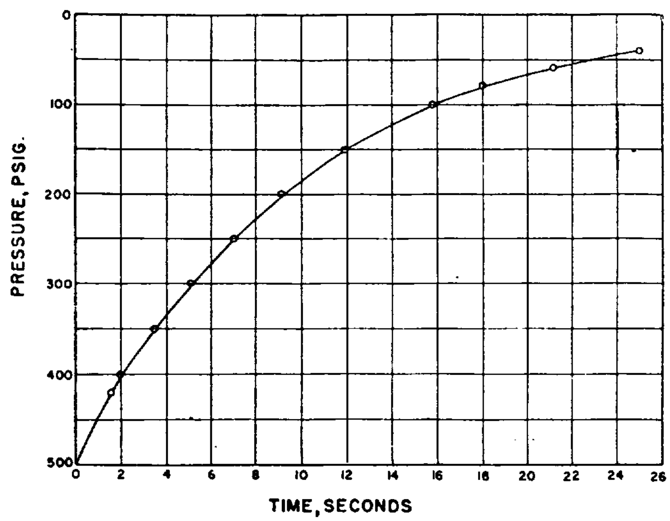

FIG. 2 — TYPICAL ORIFICE CALIBRATION CURVE.

statistically. On one series (Series E), in which the crystal area was twice the usual area, 170 observations were made to provide more points in the high supersaturation range.

The data desired from this method were (1) the number of bubbles formed in a definite narrow range of supersaturation values, (2) the total number of seconds during which the system was in this range, and (3) the area of crystal-oil interface involved. To obtain (1), the supersaturation ranges were selected to correspond to two-second intervals on the orifice calibration curve, and the number of bubbles observed in each of these intervals totaled. To obtain (2) for a given interval, two seconds for each test that went through the interval were added to the time spent in the interval by those tests terminating in the interval; (3) was determined as the average crystal-oil area for the tests terminating in the interval involved.

An example of the calculation of the number of bubbles formed per second per square centimeter (termed the frequency) by this method follows. In the interval zero to two seconds, corresponding to the supersaturation range of 0-95 psi supersaturation, no bubbles were formed and the frequency is zero. In the interval two to four seconds, corresponding to 95-165 psi supersaturation, nine bubbles were formed, and 76 tests passed through the interval without forming bubbles. The actual time spent in the interval in those tests terminated by bubble formation in the interval is shown in the first nine terms in the first bracket of the denominator below.

$$F = \frac{9}{[1.1+1.2+0.9+1.5+0.3+1.4+0.7+1.5+0.6+(76)\,2]\,[4.47]} = 0.0125$$

The term 4.47 represents an average of the crystal areas exposed to live oil. The frequency, thus determined, represents the probability that a bubble will form in one second on one square centimeter of crystal surface, at the average supersaturation in the interval.

In the second method, employed where the degree of supersaturation was so low that long times of standing were required, mixtures were confined above mercury as shown in Fig. 3. In order that no reaction products between kerosene and mercury could be formed and act as nuclei, the kerosene was distilled over sodium. After this precaution was taken no bubbles formed on the mercury surface.

In determining the frequency of bubble formation by this method the cell was assembled as shown in Fig. 3 with a single crystal inside the glass tube. The cell was then evacuated to less than 1 mm mercury pressure and purified mercury was drawn into the cell through the bottom connection until the inverted test tube was completely immersed in and filled with mercury. Water was then pumped into the top of the cell, with mercury being withdrawn from the bottom, until the test tube could be observed to a position well below the crystal, which had floated to the top of the test tube. The pressure in the cell was then adjusted to 1,000 psi which was 500 psi above the bubble-point of the mixture. A sample of kerosene-methane mixture was then introduced into the open lower end of the test tube, and then collected above the mercury.

Then the pressure on the system was lowered by bleeding off water from the top of the cell until the desired supersaturation was reached. The system was then allowed to stand until a bubble was observed to form, or in one case, until 138 hours had elapsed without bubble formation. After a bubble had been observed, the pressure was quickly raised to 1,700 psi, so as to redissolve the bubble before appreciable diffusion had taken place. One filling could thus be used for a number of tests without refilling the tube.

To correct for small variations of bubble-point with temperature, which could not be considered as negligible in this method, the magnitude of the bubble-point variation was

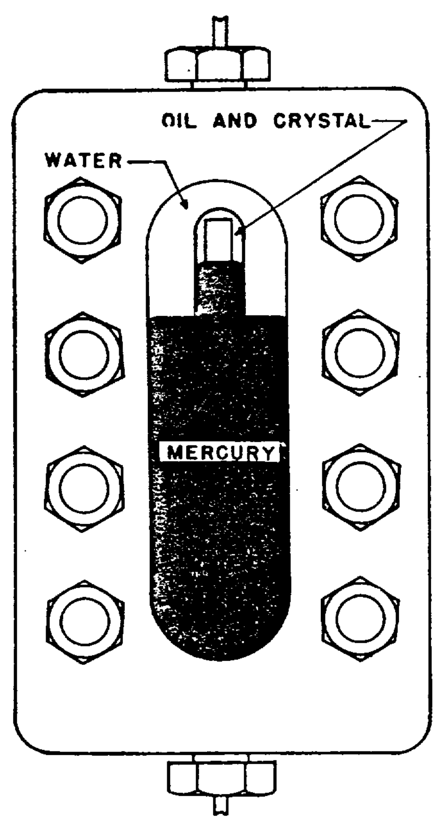

FIG. 3 — WINDOWED CELL FOR LOW SUPERSATURATION TESTS.

estimated by using available K-value charts for methane in a 200 molecular weight solvent. Correction was then applied by raising or lowering the pressure in the cell to keep the supersaturation of the liquid constant.

The frequency, as measured by this method, was simply the reciprocal the time which elapsed at a given supersaturation before a bubble was observed, divided by the crystal area.

DISCUSSION OF RESULTS

At any vapor-liquid interface in a supersaturated system vaporization is taking place. In the first method employed, such an interface existed and it was necessary to determine what influence, if any, this process exerted on the measured frequencies. To this end, two series of tests, "A" and "B," were run, the first involving an initial rate of pressure decline of 55 psi per second, while the initial pressure decline rate for Series "B" was 30 psi per second. If the loss of gas at the interface were effective in lowering the supersaturation, it should be more pronounced in the second series, and the frequency of bubble formation should be lower. Reference to Tables I and II, and to Fig. 4, in which the average frequencies for all series are plotted against the supersaturation, shows no effect in this direction. All subsequent runs by Method 1 were made with pressure decline rates higher than those used in Series "B," so as to eliminate the possibility of this source of error.

Both Series "A" and "B" were made with kerosene saturated with methane at 500 psi in the presence of quartz crystals. The temperature of saturation and testing ranged from 84°F to 86°F. As in the other series investigated, the errors introduced by this variation did not exceed others inherent in the method and no correction for temperature was applied.

Series "C" was made with a mixture of kerosene and methane with a bubble-point of 1,000 psi, to determine the effect of absolute saturation pressure on bubble frequency. The data are contained in Table III and are plotted in Fig. 4. It is seen that, within the error involved in statistical observations of this type, there is no difference between liquids of different bubble-point at the same supersaturation. The crystals used in this series were quartz, as in the two previous series.

Series "D" was made with 1,000 psi bubble-point oil, and in all respects was similar to Series "C" except that calcite crystals were substituted for quartz. The data are shown in Table IV and are plotted on Fig. 4. It is seen that the composite curve drawn fits the data of this series as well as the previous data, and that calcite must be considered as equivalent to quartz as an accelerator of bubble formation.

In Series "E," a volume of saturated oil sufficient to cover twice the area of crystal as in previous tests was introduced. In other respects the runs were identical with those of Series "D." An examination of Table V, and the points for this series plotted on Fig. 4. indicates that the frequency of bubble formation, in terms of bubbles formed per second per square centimeter of crystal surface, is comparable to that obtained in the other runs. In order that sufficient data for statistical purposes should be available, twice as many runs as usual were made under the conditions of this series.

Undiluted crude oil could not be used in the tests described, because its dark color interfered with the observation of bubbles. However, it was thought possible that nuclei might be present in crude oil and might influence the frequency data obtained. In Series "F," therefore, the maximum amount of East Texas crude oil which would still allow visibility, 1.6 per cent, was added to the system. Other conditions were the same as in Series "E," *i.e.*, 1,000 psi bubble-point oil in contact with calcite. As shown in Table VI and Fig. 4, there is no discernible effect of the addition of crude oil to the system.

Data on frequencies at supersaturations below 50 psi, where effects of diffusion at the gas-liquid interface were considered to render results by the first method of investigating unreliable, are shown in Table VII. The frequencies are also

Table I — Summary of Test Data for Series "A"

Time Interval Sec.	Average Supersaturation psi	No. Bubbles Observed	Bubble Frequency Bubbles/cm²/sec x 100
0- 2	48	0	0
2- 4	130	9	1.25
4- 6	194	13	2.08
6- 8	249	16	3.34
8-10	295	14	3.50
10-12	333	9	3.44
12-14	364	7	3.79
14-16	391	6	4.96
16-18	412	4	5.14
18-20	427	3	6.04
20-22	439	2	6.21
22-24	449	0	0
24-26	458	1	10.15

Table II — Summary of Test Data for Series "B"

Time Interval Sec.	Average Supersaturation psi	No. Bubbles Observed	Bubble Frequency Bubbles/cm²/sec x 100
0- 2	32	0	0
2- 4	86	0	0
4- 6	129	7	.962
6- 8	166	10	1.52
8-10	197	9	1.55
10-12	227	11	2.26
12-14	254	11	2.86
14-16	278	8	2.68
16-18	301	8	3.52
18-20	321	7	4.30
20-22	338	5	4.76
22-24	354	3	5.20
24-26	369	3	7.89
26-28	382	1	3.99
28-30	394	1	6.38
30-32	405	1	44.7

Table III — Summary of Test Data for Series "C"

Time Interval Sec.	Average Supersaturation psi	No. Bubbles Observed	Bubble Frequency Bubbles/cm²/sec x 100
0- 2	80	0	0
2- 4	216	10	1.39
4- 6	318	21	3.68
6- 8	406	22	5.22
8-10	484	15	7.26
10-12	550	9	7.51
12-14	609	5	12.85
14-16	663	2	15.96
16-18	709	0	0
18-20	747	1	18.61

Table IV — Summary of Test Data for Series "D"

Time Interval Sec.	Average Supersaturation psi	No. Bubbles Observed	Bubble Frequency Bubbles/cm²/sec x 100
0- 2	80	0	0
2- 4	216	14	2.01
4- 6	318	17	3.08
6- 8	406	18	4.71
8-10	484	16	6.63
10-12	550	12	9.95
12-14	609	5	10.25
14-16	663	2	12.09
16-18	709	0	0
18-20	747	0	0
20-22	778	1	76.5

Table V — Summary of Test Data for Series "E"

Time Interval Sec.	Average Supersaturation psi	No. Bubbles Observed	Bubble Frequency Bubbles/cm²/sec x 100
0- 2	81	0	0
2- 4	220	43	1.69
4- 6	322	51	2.98
6- 8	406	42	4.68
8-10	481	21	6.15
10-12	548	8	7.68
12-14	605	4	11.13
14-16	656	1	16.46

Table VI — Summary of Test Data for Series "F"

Time Interval Sec.	Average Supersaturation psi	No. Bubbles Observed	Bubble Frequency Bubbles/cm²/sec x 100
0- 2	81	0	0
2- 4	220	12	1.71
4- 6	322	18	3.13
6- 8	406	20	4.98
8-10	481	17	7.71
10-12	548	9	8.49
12-14	605	4	7.85
14-16	656	4	14.2
16-18	700	1	17.2

Table VII — Summary of Low Supersaturation Tests by Second Method

	Dry Quartz Crystal			Water-Wet Crystal		
Supersaturation psi	No. Bubbles Observed	Time Before First Bubble, Sec. Range	Average	No. Bubbles Observed	Time Before First Bubble, Sec. Range	Average
50	10	36.3-87.2	56.7	10	39.1-77.2	58.1
40	4	104-600	287.4	6	102-343	236.5
30	None in 138 hours			None in 27 hours		

plotted on Fig. 4. As indicated in the table, 14 observations on dry quartz crystals were made and 16 on quartz crystals which had been wet with water. It is seen that the presence of water has no discernible effect. It should also be noted that the data obtained by this method fit very well on the composite curve obtained by the method employed for investigation systems of high supersaturation. The conformity of the data by the two methods in the region of low supersaturation is further evidence that the error due to diffusion in the first method is not appreciable under the conditions employed.

The composite curve shown in Fig. 4 was drawn as the best curve to fit all of the data obtained. It is of interest to note, however, that this curve fits the points for each series almost as well as any that could be drawn.

SIGNIFICANCE OF DATA IN PETROLEUM RESERVOIR STUDIES

In the work described, an effort was made to duplicate the essential conditions which affect the formation of bubbles in petroleum reservoirs, insofar as these conditions are known. It is appropriate, therefore, to discuss some of the implications of the results in regard to a reservoir to which they may apply.

When oil is produced from a reservoir, the pressure normally declines, even if an effective water-drive is present. Some reservoirs, such as the East Texas reservoir, are so undersaturated, that substantially their entire recoverable contents may be produced at restricted rates without the pressure falling below the bubble-point of the oil. More commonly, however, the oil becomes supersaturated in the early stages of production, even though it may have been highly undersaturated initially.

On the basis of data presented here, bubbles would be expected to form only after the supersaturation exceeds 30 psi. Supersaturation in excess of this figure and bubbles will naturally occur first in the low-pressure regions in the immediate vicinity of the producing wells. Because of the comparatively high velocities and intimate contact between gas and oil, substantial equilibrium should exist between the two phases at this location under normal flowing conditions.

As the reservoir pressure declines, and the isobar corresponding to 30 psi supersaturation moves outward from the wells, bubble formation will follow it. If the reservoir oil is uniform in composition and subject to normal gravitational pressure distribution, the surfaces connecting the bubbles farthest from the wells will be an inverted and truncated cone, with sides of constant slope. The expanding cone will follow the isobar to the limit of the reservoir or to the region of interference with another well.

When a bubble is formed, diffusion of gas from the surrounding oil begins, decreasing the supersaturation in its immediate vicinity and expanding the bubble. Surface forces, tending to compress the bubble, become negligible when its radius exceeds about .01 mm. (If the surface tension is taken as five dynes per centimeter, and bubble radius, or the radius of the pore through which the bubbles are expanding, is .01 mm the excess pressure in the bubble is only .15 psi.) Due to the phenomenon of supersaturation, the equilibrium pressure of the gas dissolved in the oil is at least 30 psi higher than the pressure inside the bubble initially, and rapid evolution of gas occurs. This situation accounts for the observation that bubbles expand to about 1 mm in radius almost instantly after they are formed on crystal surfaces.

Aspects of reservoir behavior on which the data presented may shed some light may be listed as follows:

1. The extent to which reservoir fluids may be considered to be truly at equilibrium. This is a function of the number of bubbles formed and the rate of diffusion from the oil into the gas phase as well as the rate of pressure decline imposed by production from the reservoir.

2. The order of magnitude of the number, size and distribution of bubbles formed in reservoirs.

As a first step in estimating the departure from equilibrium, the maximum supersaturation possible in the reservoir may be estimated. It is evident that this maximum will occur in the early life of the reservoir as bubbles are forming, rather than at a later date when concentration gradients have been lowered by diffusion. As an example, consider a reservoir rock with a surface area of 450 sq cm per cu cm. (The unit area assumed corresponds to a rock made up of spheres .01 cm in diameter with rhombohedral packing.) From the slope of the frequency curve, Fig. 4, we may estimate the bubble frequency, as the curve approaches its intercept, as 10^{-4} bubbles per second per square centimeter per psi supersaturation. Thus, if a supersaturation of only 31 psi could persist for one day, more than four thousand bubbles would be formed in each cubic centimeter of rock. The aggregate volume of gas, if each bubble were the equivalent of one mm in diameter, would be more than twice the entire rock volume. It is clear, therefore, that the maximum supersaturation is less than one psi in excess of the intercept value on Fig. 4, and differs from this value by less than the uncertainty in our measurement of the intercept. The intercept value of 30 psi will therefore be taken as the maximum value of supersatuartion that can exist more than momentarily in a reservoir.

It should be noted that while 30 psi represents the maximum supersaturation in a reservoir, the reservoir as a whole will never have an average supersaturation approaching this figure. While bubbles are forming in one position, oil in contact with bubbles already formed in another position will be substantially at equilibrium with them. If the reservoir pressure remains constant for a time, the oil and gas phases will approach complete equilibrium due to diffusion. If the pressure is declining at a uniform rate, supersaturation in excess of 30 psi and bubble formation will occur only if the diffusion rate into bubbles already formed is insufficient to prevent such supersaturations at all points. We thus have a criterion and a means of determining the number of bubbles that is necessary and sufficient to provide the amount of diffusion required for a given rate of pressure decline. This requirement may be expressed

$$\frac{dp}{dt} = \frac{dp_s}{dt} = \frac{Q}{V_o}\cdot\frac{dp_s}{ds} \quad . \; . \; . \; . \; . \; . \; . \; . \quad (1)$$

where $\frac{dp}{dt}$ is the rate of pressure decline imposed by production from the reservoir;

$\frac{dp_s}{dt}$ is the rate of decline of saturation pressure due to

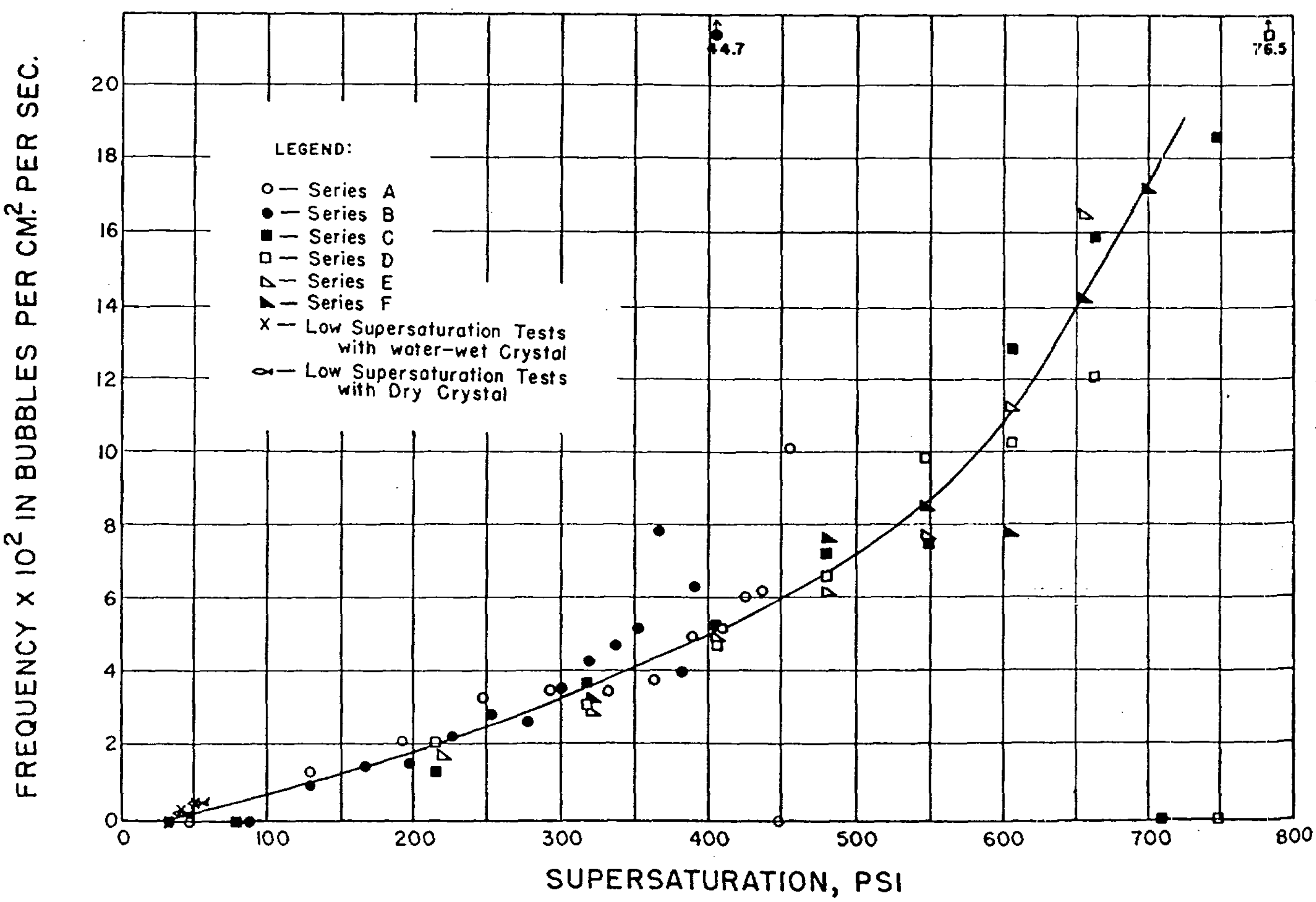

FIG. 4 — COMPOSITE BUBBLE FREQUENCY CURVE.

diffusion at the point in the region of influence of a bubble farthest removed from the bubble;

Q is the volume of gas, in surface measure, which diffuses through the volume V_o of oil in unit time;

$\frac{dp_s}{ds}$ is the decrease in equilibrium pressure due to the evolution of unit volume, in surface measure, of dissolved gas.

In determining the number of bubbles required to reduce the maximum saturation pressure at a rate equal to the reservoir pressure decline, steady state spherical flow is assumed: As shown by Bertram and Lacey,[11] the entire effect of the reservoir rock on diffusion may be expressed as a factor of about 0.8, representing the increased length of path attributable to the presence of the aggregate. (The truth of this statement is evident when it is remembered that both the amount of diffusible gas and the cross section available for diffusion are decreased by a factor representing the fractional porosity. Except for the above correction, therefore, the presence of the reservoir rock will be ignored.)

We may write, for each bubble in the reservoir,

$$Q = 0.8\frac{4\pi D(S_e - S_b)}{\frac{1}{r_b} - \frac{1}{r_e}} \quad . \; . \; . \; . \; . \; . \; . \; . \quad (2)$$

where D is the diffusion constant, and r_b and r_e are respectively the radius of the bubble and of the region of influence of the bubble, and S_b and S_e are the concentrations of gas at r_b and r_e, respectively. Each cubic foot of the reservoir may be assumed to contain N bubbles, each of which has a region of influence comprising $\frac{1}{N}$ cu ft. r_e may be expressed in terms of N as

$$r_e = \sqrt[3]{\frac{3}{4\pi N}} \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (3)$$

V_o in equation (1) is simply $\frac{1}{N} = \frac{4}{3}\pi r_e^3$.

Equations (1), (2) and (3) may then be combined to give

$$\frac{dp}{dt} = \frac{dp_s}{dt} = \frac{3.2\pi ND(S_e - S_b)}{\frac{1}{r_b} - \sqrt[3]{\frac{4\pi N}{3}}}\;\frac{dp_s}{ds} \quad . \; . \quad (4)$$

If the relation between the saturation pressure, p_s, and the gas dissolved at this pressure S, be linear, then $\frac{S}{p_s} = K_s$, and

$$S_e - S_b = K_s(p_{se} - p_{sb})$$

where K_s is the slope of the pressure-solubility curve, and p_{se} and p_{sb} are respectively, the equilibrium pressures at r_e and r_b. Further, $\frac{dp_s}{ds}$, for a linear solubility relation, may be represented by $\frac{1}{K_s}$. For a reservoir in which the maximum supersaturation is 30 psi, the maximum value of $K_s(p_{se} - p_{sb})$

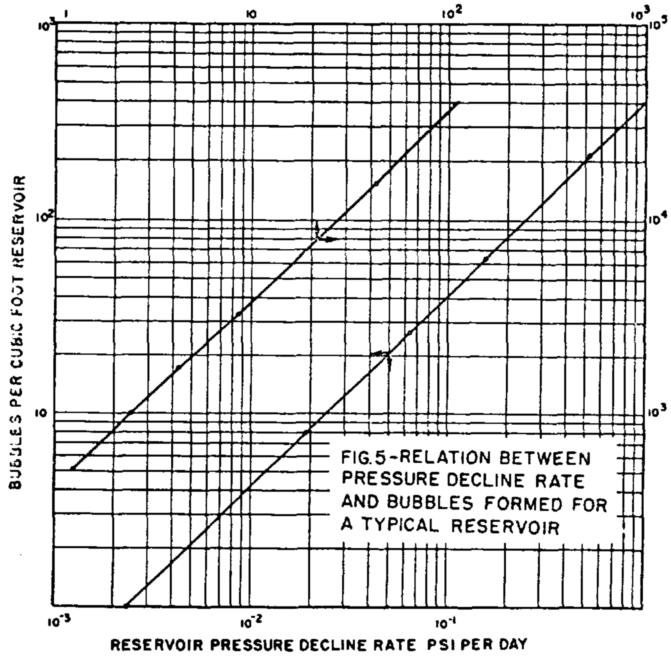

FIG. 5 — RELATION BETWEEN PRESSURE DECLINE RATE AND BUBBLES FORMED FOR A TYPICAL RESERVOIR.

must equal 30 K_s. As a final equation, relating the number of bubbles with the rate of pressure decline, we may write

$$\frac{dp}{dt} = \frac{dp_s}{dt} = \frac{96\,\pi ND}{\frac{1}{r_b} - \sqrt[3]{\frac{4\pi N}{3}}} = \frac{301\,ND}{\frac{1}{r_b} - \sqrt[3]{4.2N}} \quad . \; . \quad (5)$$

If, in accordance with our observation that bubbles almost instantly reach the radius of 1 mm we assign this value to r_b, and let D equal 10^{-4} sq ft per hour as an average value,[12] we may calculate the number N for a typical reservoir, for any value of $\frac{dp}{dt}$. Fig. 5 shows a plot of N against the right-hand term of Equation (5). For reservoir pressure declines of 0.1, 1 and 10 psi per day, we may read corresponding numbers of bubbles per cu ft of reservoir satisfying the imposed conditions 40, 400 and 4,000. Due to the assumptions made in determining the diffusion rate, particularly the assumption of the value of r_b, the calculation must be considered correct only as to order of magnitude.

For a rock consisting of grains averaging 0.1 mm in diameter, there are about 10^6 pores per centimeter cube, or some $3 \cdot 10^{10}$ pores per cu ft. It is clear that even at the most rapid reservoir pressure decline rates, only about one pore in a million will have a bubble originating in it. Where unaffected by flow, the gas will be present as a continuous enlarged bubble, encompassing many pores, surrounded by oil which is free of gas. When gradients are applied, the gas inside the continuous bubble will flow with a relative permeability characteristic of a much higher gas saturation than corresponds to the overall reservoir content, while the oil will be characterized by a relative permeability equal to the homogeneous fluid permeability of the rock. Equilibrium gas saturations, at which gas exhibits zero relative permeability, should not exist in a reservoir with gas distributed in this manner. It is noteworthy that such behavior, although detectable by a decline in gas/oil ratio in the early life of gas-drive reservoirs and generally reported in laboratory studies, has been reported absent in all field measurements.[13]

CONCLUSIONS

The data and calculations presented support the following conclusions:

1. Supersaturations as high as 770 psi are possible for short periods in a system consisting of kerosene, methane and crystals such as silica and calcite.

2. When crystals such as silica or calcite are present, bubbles invariably form on their surfaces rather than in the oil itself.

3. The tendency of bubbles to form in systems of this kind may be measured by the frequency, *i.e.*, the number of bubbles formed per second per square centimeter of crystal surface in contact with liquid.

4. Under the conditions of the tests, the frequency varied from .22 at 800 psi to zero at 30 psi saturation. No bubbles were observed to form at 30 psi supersaturation or lower, even though the test at 30 psi supersaturation was continued for 138 hours.

5. Calcite and silica surfaces are equally effective in promoting bubble formation.

6. The presence of water or crude oil, when added to the above system, had no measurable effect on bubble frequency.

7. From the bubble frequency measured, it may be calculated that maximum supersaturations in reservoirs cannot exceed 30 psi by more than a fraction of one psi, and that average supersaturations will be substantially less than this amount.

8. It is shown that the number of bubbles formed per cu ft of reservoir depends on the rate of diffusion of gas through oil and on the pressure decline rate imposed by production. For decline rates of 0.1, 1 and 10 psi per day, the number of bubbles formed will be 40, 400 and 4,000 per cu ft respectively, in order of magnitude.

9. Even at the higher rates of pressure decline, only one bubble is formed per million pores in the rock, suggesting that the increase of gas saturation in reservoirs takes place by the enlargement of gas bubbles into gas masses encompassing many rock pores.

10. Variations in the manner in which gas is distributed in permeable media may account for different relative permeabilities for the same gas saturation, and may explain discrepancies between laboratory and field data on the same type of rock.

ACKNOWLEDGMENT

It is a pleasure to acknowledge the financial support of the Tennessee Gas Transmission Co., under whose fellowship this work was done, and the encouragement given by Herman A. Otto and O. H. Moore of this company. The interest taken in this project and the advice freely given by Harold Vance, head of the petroleum engineering department, A. and M. College of Texas, is also gratefully acknowledged.

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Determination of Fracture Orientation from Pressure Interference

LINCOLN F. ELKINS
MEMBER AIME
ARLIE M. SKOV
JUNIOR MEMBER AIME

SOHIO PETROLEUM CO.
OKLAHOMA CITY, OKLA.

ABSTRACT

Inclusion of anisotropic permeability in mathematical analysis of pressure transients observed during development of the huge Spraberry field indicates a major fracture trend which is in good agreement with that observed by fluid-injection tests spread over a 12- by 17-mile area. Delineation of this trend is important in selecting a pattern of injection for the pending large-scale water flooding in this field. Determination of reservoir parameters yielding best agreement between calculated pressures and observed reservoir pressures in newly completed wells was made using an IBM 650 computer.

INTRODUCTION

The Spraberry field covering 400,000 acres is a tight sand of less than 1-md permeability cut by an extensive system of vertical fractures. Primary recovery dominated by capillary retention of oil in the fractured sand matrix blocks is less than 10 per cent of oil in place. Strong forces of capillary imbibition of water into the sand, coupled with water flow under dynamic pressure gradient, indicate considerable increase in oil recovery can be achieved through water flooding. Best results will occur if the pattern of water injection is selected to force the water flow across the grain of the major fracture system.

Existence of an oriented vertical fracture system in the Spraberry, observed first in cores, was highlighted more recently by the 144-fold contrast in permeability along and at right angles to the major fracture trend required to match relative water breakthrough times in Humble Oil & Refining Co.'s waterflood test there. Spraberry operators since have conducted two gas-injection tracer tests for further areal confirmation of the fracture trend. Re-analysis of early reservoir pressure transients for evidence of anisotropic permeability has permitted many more local determinations of major fracture trend without resort to further field tests.

This paper is limited to updating analysis of reservoir pressure transients to include anisotropic permeability as a test for orientation of the major fracture trend in the Spraberry. The reader is referred to Refs. 1 and 2 for information about general Spraberry reservoir performance and to Refs. 3 and 4 for information about significance of fracture orientation in selection of the injection-well pattern for water flooding the Spraberry.

RESERVOIR PRESSURE DATA—DRIVER AREA

During early development of the Spraberry Driver area, Sohio Petroleum Co. made the extra effort to measure the initial pressure in each of the 71 wells in a 5-mile-long area immediately after completion. Progressively greater reductions in pressure ranging up to 400 psi were observed throughout the six-month development period. Detailed data are presented in Ref. 1.

Since the reservoir oil was undersaturated some 300 psi initially, early reservoir performance involving 55 new well pressures is subject to analysis as flow of a single compressible fluid in a porous media. Assumption of uniform permeability in all directions yielded good agreement between calculated pressures and observed pressures of these wells in the earlier study,[1] but subsequent, additional, mathematical development to include anisotropic permeability in the transient pressure considerations and present availability of electronic computers to perform the much more extensive arithmetical calculations now yield even better agreement.

The previous analysis, assuming uniform permeability, consisted essentially of calculating pressure reduction expanding circularly around each producing well and summing these effects at the time and location of each newly completed well for comparison with the measured pressure reduction. Permeability, effective fluid and rock compressibility, and permeability × thickness were varied until the best match with measured pressures was obtained. The present analysis, assuming anisotropic

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Discussion of this and all following technical papers is invited. Discussion in writing (three copies) may be sent to the office of the *Journal of Petroleum Technology*. Any discussion offered after Dec. 31, 1960, should be in the form of a new paper.

[1]References given at end of paper.

permeability, is similar except that, in effect, the pressure reduction caused by production of a well expands in elliptical form with length/width varying as the square root of the ratio of permeability along and at right angles to the fracture trend. This adds fracture azimuth and permeability ratio to the other significant factors affecting performance. Values of certain of these variables were assumed and one other altered until a "best" fit was obtained. It was then "fixed" and a second one adjusted, then a third, etc., until no new combination could be found to improve the agreement between calculated and actual pressures. Seventy complete sets of calculations involving 155 producing wells and 55 new well pressure points were performed.

Results of this series of calculations with respect to the orientation of fractures and contrast in permeability — factors most pertinent to water flooding — are summarized in Figs. 2 and 3 which show average (root mean square) error in pressure vs these variables. Deviation between calculated pressures and measured pressures of individual wells are presented in Fig. 4 both for assumption of directional permeability and of uniform permeability. While the resolving power of the analysis is not high, indicated by comparison of error with and without consideration of permeability contrast, there is little doubt that orientation of the fractures so calculated has sufficient accuracy to serve as a starting point for planning Spraberry waterflood injection-well patterns. They indicate an average fracture trend of N 56° E and a thirteen-fold ratio of effective permeability along and at right angles to the main fractures. Corresponding flow capacities are 3,220 and 248 md-ft, or about 104- and 8-md effective permeabilities based on 31-ft gross Upper Spraberry sand thickness. Matrix permeability is less than 1 md.

Since these pressure data of 55 new wells cover an area 5 miles in length, they permit a determination of consistency of fracture orientation. Results of four sub-area analyses also are presented in Fig. 2, with indicated

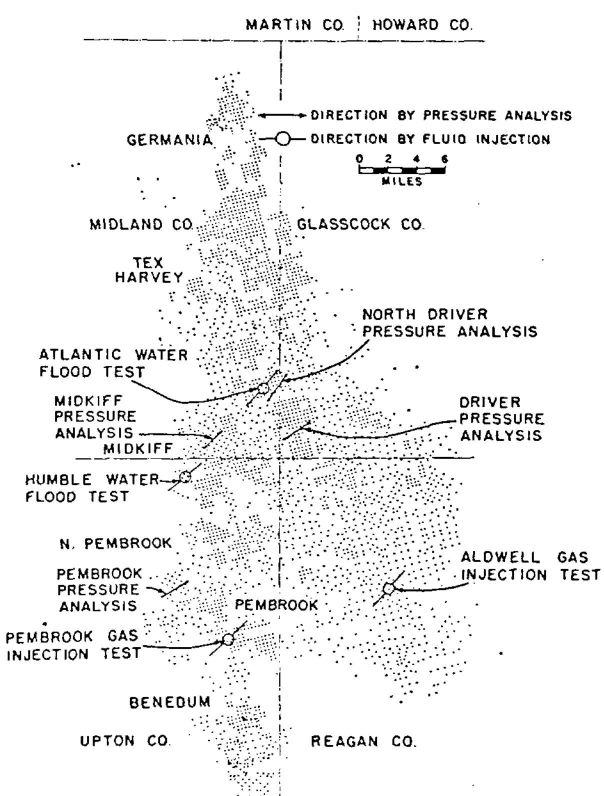

FIG. 1—FRACTURE ORIENTATION, SPRABERRY TREND.

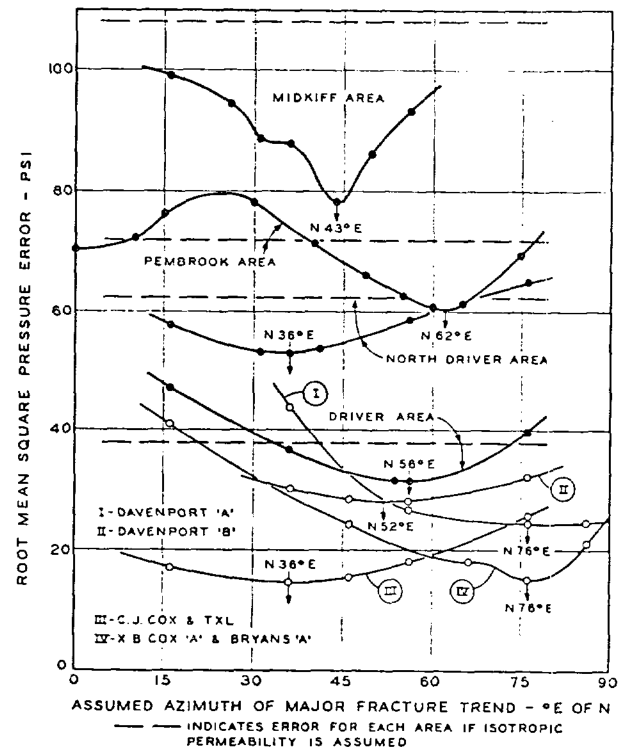

FIG. 2—FRACTURE ORIENTATION BY AREA AND BY LEASE IN THE DRIVER AREA.

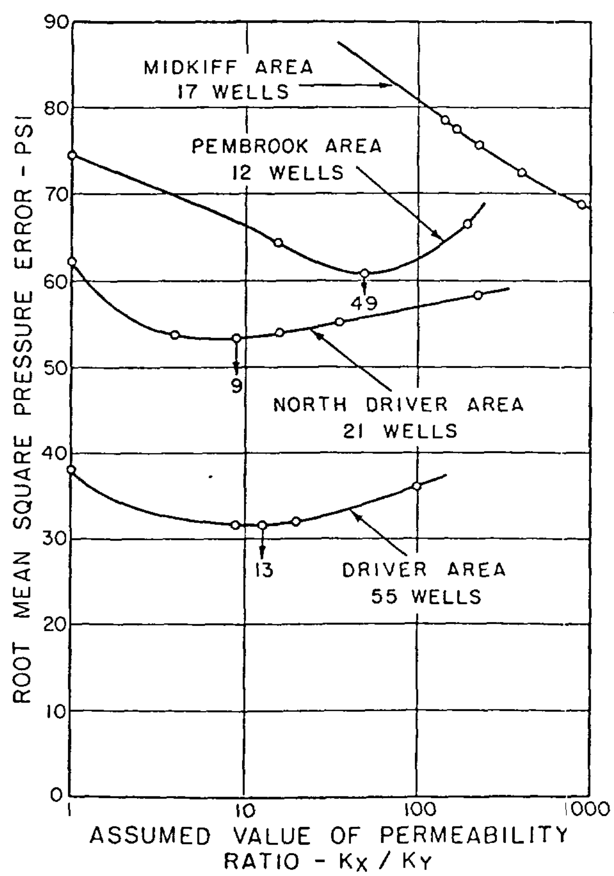

FIG. 3—EFFECTS OF CHANGING MAGNITUDE OF PERMEABILITY RATIO — k_x/k_y.

fracture orientation varying between N 36° E and N 76° E or ± 20° from the average direction determined using all 55 wells.

RESERVOIR PRESSURE STUDIES— OTHER SPRABERRY AREAS

Early pressures for four other areas in the Spraberry[2] have been analyzed similarly, and results are included in Figs. 2 and 3. Due possibly to the fact that three of these sets were not truly "initial" pressures of new wells but were pressures measured after as much as two months' production, there is significantly greater deviation between "best fit" calculated pressures and measured pressures than in the previously discussed results based on pressures measured immediately upon completion of new wells. Nevertheless, it is significant that fracture orientations calculated for the Midkiff and North Driver areas are in good agreement with those determined by the Humble[3] and Atlantic[4] waterflood tests, respectively. Similarly there is good agreement between the fracture orientation determined from one pressure analysis and that from the gas-injection test in the Pembrook area.[5] An attempt to determine fracture orientation from pressure data of another group of wells near the Pembrook gas-injection test resulted in such very large deviation between calculated pressures and measured pressures that no conclusion is warranted. Quite possibly this is due again to the fact that these pressures were not measured upon completion of the wells but were simply first tests available.

Fracture orientations determined by these various analyses of pressure interference between wells and by water injection and by gas injection are summarized in Fig. 1 and in Table 1. They show a range in direction from N 36° E to N 76° E over an area about 17 miles in length by 15 miles in width. Similarly, the ratio of permeability along the fracture trend to that perpendicular to it ranges from about 6 to 144 or higher.

CONCLUSIONS

Inclusion of anisotropic permeability in analysis of pressure transients in the Spraberry gives somewhat better agreement between calculated pressures and observed pressures of new wells than does assumption of uniform permeability. Close agreement between the many fracture orientations so determined and those indicated by field injection tests spread over a 15- by 17-mile area demonstrate the anisotropy is real — not merely a chance variation in the statistics. This evidence of wide-spread uniformity of fracture trend is helpful in planning the injection pattern for forthcoming Spraberry water floods.

ACKNOWLEDGMENTS

The authors wish to thank R. E. Collins of the U. of Houston and H. H. Rachford, Jr. of Humble Oil & Refining Co. for advice on the mathematical treatment of transient flow in anisotropic reservoirs. The original derivation of Eq. 1 is included in a book, *Flow of Fluids Through Porous Materials,* soon to be published by Collins. The authors also wish to thank the Pembrook Unit Operators Committee for permission to publish results of the Pembrook gas-injection fracture orientation test.

Ellen Kilpatrick developed the computer program and performed the calculations which serve as the basis for this paper.

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APPENDIX

The pressure drawdown at the location of a new well due to constant production of another well in an extensive reservoir of uniform thickness having aniso-

TABLE 1—FRACTURE ORIENTATION AND PERMEABILITY CONTRAST, SPRABERRY TREND AREA FIELD

	Fracture Trend	Ratio of Permeabilities*	Avg. Deviation Calculated vs Measured Pressures (psi)	Equivalent Permeability** (md-ft)
Midkiff Area				
Humble Water Flood	N 50° E	144		
Pressure Analysis (17 wells)	N 43° E	100 to 1000	78.4	443
North Driver Area				
Atlantic Water Flood***	N 42° E	—		
Pressure Analysis (21 wells)	N 36° E	9	53.3	406
Pembrook Area				
Gas Injection test	N 48° E	—		
Pressure Analysis (16 wells)	N 62° E	49	60.6	446
Aldwell Area				
Radioactive Gas Tracer[6]	N 53° E	about 16		
Driver Area†				
Pressure Analysis				
55-Well Composite	N 56° E	13	31.6	888
14-Well Davenport A Lease	N 76° E	36	24.7	1130
15-Well Davenport B Lease	N 52° E	6	28.4	968
13-Well X. B. Cox and J. C. Bryans A Leases	N 76° E	36	15.2	1020
12-Well C. J. Cox and T.X.L. Leases	N 36° E	7	14.7	481

*Ratio of permeability along major fracture trend to permeability perpendicular to fracture trend.

**$h\sqrt{k_x k_y}$

***Orientation determined by general pattern of reduction of gas-oil ratio and water breakthrough.

†See Ref. 1 for identification of leases.

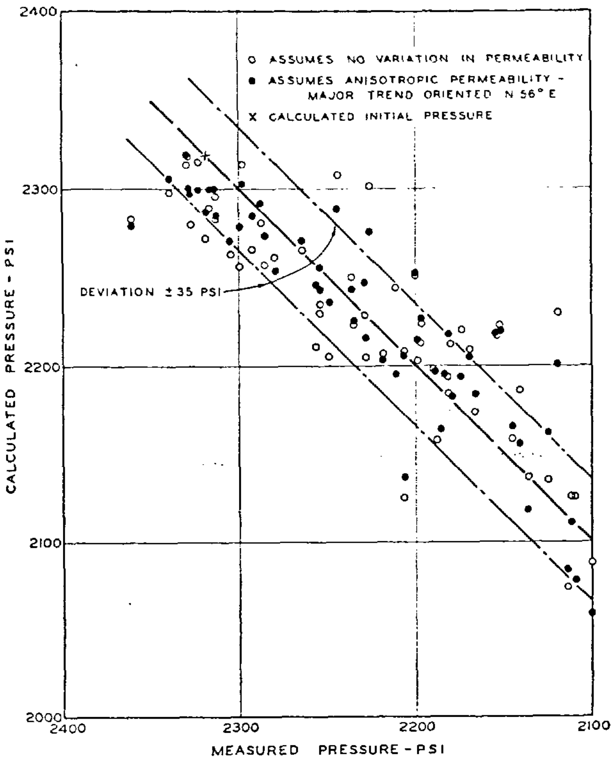

FIG. 4—CALCULATED PRESSURE VS MEASURED PRESSURES, DRIVER AREA, SPRABERRY TREND FIELD.

tropic permeability is given by Eq. 1 for conditions of single-phase flow.[7]

$$p_i - p = \frac{(-)\ q\ \mu\ B}{4\ \pi\ \sqrt{k_x\ k_y}\ h\ 1.127}$$
$$\mathrm{Ei}\left(- \frac{\dfrac{(x - x_o)^2}{k_x} + \dfrac{(y - y_o)^2}{k_y}}{\dfrac{4\ t}{\mu\ c\ \phi}\quad 6.32} \right) \quad . \ . \ . \ (1)$$

where p_i = initial pressure (psi),
p = pressure at x, y at time t (psi),
q = production rate (B/D),
μ = viscosity of oil (cp),
B = formation volume factor,
h = thickness (ft),
t = time (days),
c = effective compressibility of oil, water and rock (vol/vol/psi),
ϕ = porosity (fraction),
Ei(— —) = exponential integral,
k_x = effective permeability in x direction (darcies),
k_y = effective permeability in y direction (darcies),
$(x - x_o)$ = distance from producing well to pressure point in x direction (ft),
$(y - y_o)$ = distance from producing well to pressure point in y direction (ft), and
1.127 and 6.32 = conversion factors.

The pressure reductions at a point due to production of different wells are additive. For uniform permeability, Eq. 1 reduces to the simpler, well known form involving r^2 and k.

Since significant reservoir properties including effective compressibility of rock and its contained fluids and permeability, whether uniform or anisotropic, appear implicitly in this relation they can be determined only by trial solutions until the set of values is found which gives the best match between calculated pressures and measured pressures. Fracture orientation, diffusivity parallel to the main fractures and diffusivity perpendicular to the main fractures are related implicitly in Eq. 1, and geometric mean permeability $\sqrt{k_x\ k_y}$ and p_i are explicit. Determination of the best set of these factors requires the following sequence.

1. Determine x and y coordinates of all producing wells and pressure observation wells.

2. Rotate these coordinates to an assumed fracture orientation since axes in Eq. 1 correspond to directions of maximum and minimum permeabilities.

3. Calculate $\Sigma\ q$ Ei (— —) for each pressure observation well using assumed values of diffusivity in the new x and y directions and determine the associated values of $\sqrt{k_x k_y}$ and p_i by least-squares method.

4. Successively modify the fracture orientation and diffusivities in the x and y directions until a set of values of these factors is found such that any further modification increases the sum of squares of the difference between measured and calculated pressures of the individual observation wells. ★★★

WELL INTERFERENCE AND PULSE TESTS

MED M. KAMAL
Amoco Production Company

SPE Mid-Continent Section
Continuing Education Course
On
Well Test Analysis

April 21. 1975

5. Using some approximate known values of the formation permeability, porosity, and thickness, the viscosity of the oil and the total compressibility, together with the dimensionless cycle period, the dimensionless response amplitude, and Eqs. 30 and 32, calculate the cycle period and the response amplitude.

6. Using the pulse ratio and the cycle period, calculate the pulsing period and the shut-in period.

ANALYZING THE PULSE TEST GRAPHICALLY

After running the test and measuring the time lags and the response amplitudes, the following method may be used to determine the values of the two groups (kh/μ) and $(\phi c_t h)$.

1. Calculate the dimensionless time lag using Eq. 31.

2. Determine the dimensionless cycle period using the dimensionless time lag and the appropriate curve in Figs. 17, 18, 21, and 22.

3. Determine the dimensionless response amplitude using the dimensionless time lag and the appropriate curve in Figs. 19, 20, 23, or 24.

4. Calculate the value of (kh/μ) from Eq. 32 and the value of $(\phi c_t h)$ from Eq. 30.

DESIGNING THE PULSE TEST ANALYTICALLY

1. Select the pulse ratio as in the graphical method.

2. Calculate the dimensionless time lag using Eqs. 22 and 23.

3. Using Figs. 25 and 26, find A and C.

4. Using Figs. 27 and 28, find E and F.

5. Calculate the dimensionless cycle period using Eq. 33 and the dimensionless response amplitude using Eq. 34.

6. Using some approximate known values of the formation permeability, porosity and thickness, the viscosity of the oil, and the total compressibility, calculate the cycle period and the response amplitude using Eqs. 30 and 32.

ANALYZING THE PULSE TEST ANALYTICALLY

1. Using Eq. 31, calculate the dimensionless time lag.

2. Calculate the dimensionless cycle period using Eq. 33.

3. Calculate the dimensionless amplitude using Eq. 34.

4. Calculate the value of (kh/μ) using Eq. 32 and the value of $(\phi c_t h)$ using Eq. 30.

A WORKED EXAMPLE ON THE DESIGN AND ANALYSIS OF PULSE TESTS GRAPHICALLY AND ANALYTICALLY

The following is an example of the steps to be taken to design and analyze a pulse test:

Assume that the most convenient pulse ratio is 0.6 and that the reservoir has the following approximate properties:

MALLON OIL COMPANY

1099 18th Street, Suite 2750, Denver, Colorado 80202
(303) 293-2333

May 27, 1988

New Mexico Oil Conservation Division
Box 2088
Santa Fe, New Mexico 87504-2088

Attention: Mr. William LeMay

Dear Bill:

Just to let you know that our entire engineering committee had its last meeting yesterday prior to the hearing and everyone agreed on the interpretation of the data as will be presented by Bergeson Engineering. I, personally, along with several others strongly encouraged a straight forward and short direct, though the engineers say it will be difficult, we are going to try not to exceed five hours.

I hope this will be helpful and as you said, if the field data is clear then it should not take forever to explain it. We believe this to be the case.

Sincerely,

MALLON OIL COMPANY

George O. Mallon, Jr.
President

GOM:sss

"GLO" MEETING ATTENDANCE 5/26/88

Embassy Suites Hotel, Denver

Name	Company
Bob Buettner	Koch
Larry Sweet	Mesa Grande, Ltd.
Perry Pearce	Montgomery & Andrews, P.A.
Luis Zambrano	Mobil
MIKE STALLSWORTH	MOBIL
Jim Yaye	Mobil
JOHN FAULHABER	MOBIL
Greg D. Owens	Hopper, Kimbell & Williams, Inc.
BRUCE PETITT	READING & BATES PETROLEUM CO.
CHARLES KOHLHAAS	CONSULTANT
Frank Douglass	Scott, Douglass & Luton
KEVIN M. FITZGERALD	MALLON OIL CO.
KENT A. JOHNSON	KODIAK PETROLEUM, INC.
BETSY LOUGH	AMOCO
Michael J. Rospide	Amoco
KENT LUND	"
Lincoln F. Elkins	Consultant
Becky Miller	Scott, Douglass & Luton
RAY E. JONES	J. R. BERGESON & ASS.
Owen Lopez	Hinkle Law Firm
Alan Burzlaff	Tenneco

ENDORSED

JUN 06 1988

FIRST JUDICIAL DISTRICT COURT
SANTA FE, RIO ARRIBA & LOS ALAMOS COUNTIES
P.O. Box 2268
Santa Fe, NM 87504-2268

FIRST JUDICIAL DISTRICT COURT
COUNTIES OF SANTA FE and RIO ARRIBA
STATE OF NEW MEXICO

Sieu an Quach v. Tina Gonzales	SF 87-444	C
~~Whitfield Bus Lines v. NM State Public Ed~~	~~SF 86-1073~~	~~C~~
Manuel Ferran v. Andy M. Vigil	SF 86-235	C
Painewebber Inc. v. Roy Flynn	SF 86-568	C
Zia Mobile Home Park v. City of Santa Fe	SF 86-901	C
Eberline v. NM Employment Security	SF 86-977	C
Mallon Oil v. Oil Conservation Comm.	RA 87-1572	C

ORDER TRANSFERRING
CASES TO DIVISION III

THIS MATTER coming before the Court upon the oral motion of the Court and the Court being fully advised in the premises;

HEREBY ORDERS that the above-entitled and numbered causes be, and the same are hereby transferred to Division III.

IT IS FURTHER ORDERED that all new and re-opened causes be assigned to Division III after May 24, 1988.

Art Encinias

ART ENCINIAS
Presiding Judge

cc:
W. Thomas Kellahin, P.O. Box 2265, Santa Fe, NM 87504
Campbell & Black, P.O. Box 2208, Santa Fe, NM 87504
Montgomery & Andrews, P.O. Box 2307, Santa Fe, NM 87504
Owen Lopez, P.O. BOx 2068, Santa Fe, NM 87504
Jeffery Taylor, P.O. Box 2088, Santa Fe, NM 87504
Connie Reischman, P.O. Box 1928, Albuquerque, NM 87103
Robert Poole, P.O. Box 1769, Albuquerque, NM 87103
City Attorney, P.O. Box 909, Santa Fe, NM 87504
Ralph Montez, P.O. Box 2202, Santa Fe, NM 87504
Pete Dinelli, 5301 Central Ave., NE #1510, 1st National Bank Bldg., East, Albuquerque, NM 87108
Roy M. Flynn, Jr., Rt. 7 Box 129W, Santa Fe, NM 87501
Eloy Martinez, P.O. Box 398, Santa Fe, NM 87501
Arthur Fields, 411 Paseo de Peralta, Santa Fe, NM 87501
Attorney General's Office, P.O. Drawer 1508, Santa Fe, NM 87504
Paul Kelly, P.O. Box 2068, Santa Fe, NM 87504
Larry Maldegen, P.O. Box 669, Santa Fe, NM 87504
Dan Gonzales, 2000 E. Lohman, Suite B, Las Cruces, NM 88001
Richard Bosson, P.O. Box 1775, Santa Fe, NM 87504
Larry Smith, P.O. Box 2949, Santa Fe, NM 87504

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

GARREY CARRUTHERS
GOVERNOR

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87504
(505) 827-5800

NOTICE

The location for the State of the Industry Meeting scheduled for June 3, 1988, at 9 o'clock a.m. has been changed from Morgan Hall, State Land Office Building, to a meeting room at the Inn At Loretto, 211 Old Santa Fe Trail, Santa Fe, New Mexico.

Dockets Nos. 19-88 and 20-88 are tentatively set for June 22 and July 6, 1988. Applications for hearing must be filed at least 22 days in advance of hearing date.

DOCKET: EXAMINER HEARING - WEDNESDAY - JUNE 8, 1988

8:15 A.M. - OIL CONSERVATION DIVISION CONFERENCE ROOM,
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

The following cases will be heard before David R. Catanach, Examiner, or Michael E. Stogner, Alternate Examiner:

ALLOWABLE: (1) Consideration of the allowable production of gas for July, 1988, from fourteen prorated gas pools in Lea, Eddy, and Chaves Counties, New Mexico.

(2) Consideration of the allowable production of gas for July, 1988, from four prorated gas pools in San Juan, Rio Arriba, and Sandoval Counties, New Mexico.

CASE 9380: (Readvertised) (This case will be continued to June 22, 1988.)

Application of McKay Oil Corporation for a unit agreement, Chaves County, New Mexico. Applicant, in the above-styled cause, seeks approval of the West Fork Unit Area comprising 20,775.02 acres, more or less, of State, Federal and Fee lands in portions of Townships 4 and 5 South, Ranges 21 and 22 East. The center of said acreage is approximately 3 1/4 miles west of the intersection of U.S. Highway No. 285 and State Highway No. 20.

CASE 9395: Application of Yates Petroleum Corporation for an unorthodox gas well location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for an unorthodox gas well location 660 feet from the North and East lines (Unit A) of Section 12, Township 13 South, Range 32 East, to test all formations and/or pools to the base of the Mississippian formation, developed on 320-acre spacing, the E/2 of said Section 12 to be dedicated to said well. Said well is approximately 12.75 miles south by east of Caprock, New Mexico.

CASE 9382: (Continued from May 25, 1988, Examiner Hearing)

Application of TXO Production Corp. for a unit agreement, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval of the Phiester State Unit Area comprising 320 acres, more or less, of State lands in the E/2 of Section 36, Township 11 South, Range 37 East. Said unit is located approximately 4.5 miles north of U.S. Highway 380 on County Road 168.

CASE 9383: (Continued from May 25, 1988, Examiner Hearing)

Application of TXO Production Corp. for directional drilling and unorthodox oil well locations, Lea County, New Mexico. Applicant, in the above-styled cause, seeks authority to re-enter the plugged and abandoned Skelton Oil Company Phillips State Well No. 1 located 2310 feet from the South line and 1650 feet from the East line (Unit J) of Section 36, Township 11 South, Range 37 East, wherein the applicant proposes to deepen and deviate said well to within 50 feet of the following targeted locations (both of which are unorthodox):

1. In the Wolfcamp formation - 2570 feet from the North line and 1604 feet from the East line of said Section 36; and,
2. In the Devonian formation - 2100 feet from the North line and 1550 feet from the East line of said Section 36;

both zones to be dedicated to the SW/4 NE/4 (Unit G) of said Section 36 forming a standard 40-acre oil spacing and proration unit. IN THE ALTERNATIVE, should re-entry into the aforementioned well be found impracticable, the applicant seeks authority to re-enter the temporarily abandoned Apache Corporation Heyco "36" State Well No. 1 located 1650 feet from the North line and 990 feet from the East line (Unit H) of said Section 36, wherein the applicant proposes to deepen and deviate said well to within 50 feet of the following targeted locations (both of which are unorthodox):

1. In the Wolfcamp formation - 1890 feet from the North line and 1289 feet from the East line of said Section 36 to be dedicated to the SE/4 NE/4 (Unit H) of said Section 36 forming a standard 40-acre oil spacing and proration unit; and,
2. In the Devonian formation - 2100 feet from the North line and 1550 feet from the East line of said Section 36 to be dedicated to the SW/4 NE/4 (Unit G) of said Section 36 forming a standard 40-acre oil spacing and proration unit.

Said unit is located approximately 4.5 miles north of U.S. Highway 380 on County Road 168.

CASE 9396: Application of BCO, Inc. for a non-standard oil proration unit, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks an order modifying the standard 40-acre spacing requirements for its State "J" Well No. 1 located 540 feet from the North line and 820 feet from the East line (Unit A) of Section 16, Township 23 North, Range 7 West, which is presently completed as an oil well in both the Undesignated Lybrook-Gallup Oil Pool and Graneros formation (DHC-672) and dedicated to the NE/4 NE/4 of said Section 16, by: (a) permitting the dedication of an additional 40 acres (NW/4 NE/4) to said unit, thereby forming a non-standard 80-acre oil spacing and proration unit consisting of the N/2 NE/4 of said Section 16; and (b) said order to be made retroactive to the date of first production, October 13, 1987. Said well is located in Lybrook, New Mexico.

CASE 9397: Application of Petrus Oil Company for an unorthodox oil well location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for an unorthodox oil well location 1650 feet from the South line and 2590 feet from the West line (Unit K) of Section 11, Township 17 South, Range 33 East, to test the Queen formation, the NE/4 SW/4 of said Section 11 to be dedicated to said well. Said location is approximately 3.5 miles north-northwest of Buckeye, New Mexico.

CASE 9398: Application of Exxon Corporation for downhole commingling, simultaneous dedication, and an unorthodox gas well location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval to commingle production from the Drinkard, Tubb Oil and Gas, and Blinebry Oil and Gas Pools within the wellbore of its N. G. Penrose Wells Nos. 1 and 2 located in Unit B (660' FNL and 1980' FEL) and Unit H (1980' FNL and 660' FEL), respectively, Section 13, Township 22 South, Range 37 East, and to commingle production for the Drinkard, Wantz-Granite Wash, Blinebry Oil and Gas, and Tubb Oil and Gas Pools within the wellbore of its N. G. Penrose Well No. 4 located in Unit A (350' FNL and 660' FEL) of said Section 13. Applicant further seeks to simultaneously dedicate Tubb gas production from the three above-described wells with the N. G. Penrose Well No. 3 located in Unit G (1980' FN and EL) of said Section 13 to the NE/4 of Section 13 forming a standard 160-acre gas spacing and proration unit for said pool. Also the applicant seeks approval for an unorthodox gas well location for said N. G. Penrose Well No. 4 in the Tubb Pool. Said wells are located approximately 4 miles southeast of Eunice, New Mexico.

CASE 9399: Application of Exxon Corporation to amend Division Administrative Order DHC-195, as amended, Lea County, New Mexico. Applicant, in the above-styled cause, seeks to amend Administrative Order DHC-195, as amended April 15, 1988, which authorized downhole commingling of production from the Drinkard, Wantz-Granite Wash, and Blinebry Oil and Gas Pools in its N. G. Penrose Well No. 3 located 1980 feet from the North and East lines (Unit G) of Section 13, Township 22 South, Range 37 East, by removing from said order the testing provisions of the Blinebry zone. Said well is located approximately 4 miles southeast of Eunice, New Mexico.

CASE 9353: (Continued from May 25, 1988, Examiner Hearing)

Application of Read & Stevens, Inc. for an unorthodox gas well location, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for an unorthodox gas well location 660 feet from the North and East lines (Unit A) of Section 19, Township 19 South, Range 29 East, Undesignated Turkey Track-Morrow Gas Pool or Undesignated West Parkway-Morrow Gas Pool, the E/2 of said Section 19 to be dedicated to said well forming a standard 320-acre gas spacing and proration unit for either pool. Said location is approximately 7.5 miles southeast by east of the old Illinois Camp.

CASE 9400: Application of Wagner and Brown to amend Division Order No. R-4326, Lea County, New Mexico. Applicant, in the above-styled cause, seeks to amend Division Order No. R-4326 by expanding the existing disposal interval in its Soldier Hill "AE" State Well No. 1, located 800 feet from the North line and 1800 feet from the West line (Unit C) of Section 23, Township 12 South, Range 32 East (currently disposing into the East Caprock-Devonian Pool from 11,224 feet to 11,234 feet), to include all formations from 6,000 feet to 11,234 feet. Said well is located approximately 8.5 miles south by east of Caprock, New Mexico.

CASE 9401: Application of Northwest Pipeline Corporation for salt water disposal, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks authority to dispose of produced salt water, at a maximum injection pressure in excess of 0.2 psi/ft. of depth to the uppermost perforation, into the Blanco-Mesaverde Pool in the perforated interval from 5360 feet to 5681 feet in its Rosa Unit Well No. 94 located 1650 feet from the South line and 1820 feet from the West line (Unit K) of Section 16, Township 31 North, Range 5 West, which is located approximately 7 miles south of the point common to Colorado, New Mexico, and the western boundary of the Carson National Forest.

CASE 9402: Application of Union Texas Petroleum Corporation for an infill well finding, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks an order, pursuant to FERC Rule 271.305 of the Natural Gas Policy Act of 1978 and to Rule 16.A.5 of Division Order No. R-5878-B, as amended, showing that its State Com Well No. 1-A located 1028 feet from the North line and 1120 feet from the East line (Unit A) of Section 16, Township 28 North, Range 9 West, Basin-Dakota Pool, is needed to effectively and efficiently drain the existing 320-acre gas spacing and proration unit comprising the E/2 of said Section 16 which could not otherwise be produced by either the existing well or any other such well which has produced from the Basin-Dakota Pool within said unit. This unit is located approximately 4.75 miles southeast by south of Blanco, New Mexico.

CASE 9371: (Continued from May 11, 1988, Examiner Hearing)

Application of Reading & Bates Petroleum Company for compulsory pooling, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Gavilan-Mancos Oil Pool underlying all of Section 15, Township 25 North, Range 2 West, forming a standard 640-acre oil spacing and proration unit for said pool. Said unit is to be dedicated to the applicant's Howard Federal "15" Well No. 43 located at a standard oil well location 1650 feet from the South line and 790 feet from the East line of said Section 15 which is presently completed in and producing from the Gavilan-Mancos Oil Pool and to which the E/2 of said Section 15 is presently dedicated. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well and a charge for risk involved in drilling said well. Said unit is overlaid by the community of Gavilan, New Mexico.

CASE 9376: (Continued and Readvertised from May 25, 1988, Examiner Hearing)

Application of Nearburg Producing Company to amend Division Order No. R-8605 and the assignment of an oil allowable retroactive to April 1, 1988, Lea County, New Mexico. Applicant, in the above-styled cause, seeks to amend Division Order No. R-8605, dated March 8, 1988, by changing the non-standard oil proration unit to include Lots 3 and 4 of Section 19, Township 16 South, Range 37 East to be dedicated to its Soledad "19M" Well No. 1 located at an unorthodox location 1030 feet from the South and West lines of said Section 19 thereby forming a non-standard oil spacing and proration unit consisting of 100.81 acres. Applicant also seeks the assignment of an oil allowable for said well to be made retroactive to April 1, 1988 based on the new acreage factor. Said well is located approximately 4.25 miles southeast of Lovington, New Mexico.

CASE 9403: Application of Nearburg Producing Company for an unorthodox oil well location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for an unorthodox oil well location 400 feet from the South and East lines (Unit P) of Section 24, Township 16 South, Range 36 East, Northeast Lovington-Pennsylvanian Pool, the S/2 SE/4 of said Section 24 to be dedicated to said well. This location is approximately 4 miles southeast of Lovington, New Mexico.

CASE 9404: Application of Nearburg Producing Company for a non-standard oil proration unit and an unorthodox oil well location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for an unorthodox oil well location 330 feet from the North and West lines (Unit D) of Section 30, Township 16 South, Range 37 East, Undesignated Northeast Lovington-Pennsylvanian Pool, said well to be dedicated to Lots 1 and 2 of said Section 30 thereby forming a 100.49-acre non-standard oil proration and spacing unit for said pool. Said location is approximately 4.3 miles southeast of Lovington, New Mexico.

CASE 9405: Application of Nearburg Producing Company for an unorthodox gas well location, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for an unorthodox gas well location 1200 feet from the South line and 750 feet from the West line (Unit M) of Section 26, Township 19 South, Range 25 East, Undesignated Cemetery-Morrow Gas Pool, the S/2 of said Section 26 to be dedicated to the well. Said location is approximately 4.8 miles west by south of Lakewood, New Mexico.

CASE 9406: Application of Nearburg Producing Company for an unorthodox gas well location, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for an unorthodox gas well location 660 feet from the South line and 1650 feet from the West line (Unit N) of Section 1, Township 22 South, Range 24 East, Undesignated McKittrick Hills-Morrow Gas Pool, the S/2 of said Section 1 to be dedicated to said well. This location is approximately 13 miles west of Carlsbad, New Mexico.

CASE 9407: Application of Nearburg Producing Company for an unorthodox gas well location, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for an unorthodox gas well location 2310 feet from the South line and 960 feet from the East line (Unit I) of Section 11, Township 22 South, Range 24 East, Undesignated McKittrick Hills-Morrow Gas Pool, the S/2 of said Section 11 to be dedicated to said well. This location is approximately 14.5 miles west of Carlsbad, New Mexico.

CASE 9373: (Continued and Readvertised from May 25, 1988, Examiner Hearing)

Application of Texaco Producing Inc. for salt water disposal, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks authority to dispose of produced salt water into the Brushy Draw-Delaware Pool in the perforated interval from approximately 5417 feet to 6170 feet in its Salt Mountain "36" State Well No. 1 located 660 feet from the North and West lines (Unit D) of Section 36, Township 26 South, Range 29 East, which is located approximately 2.25 miles east by north of where the Pecos River crosses the Texas/New Mexico Stateline.

CASE 9385: (Continued from May 25, 1988, Examiner Hearing)

Application of Blackwood & Nichols Co., Ltd. for salt water disposal, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks authority to dispose of produced salt water into the Ojo Alamo or Kirtland formation in the perforated interval from approximately 2422 feet to 2531 feet in its Northeast Blanco Unit Well No. 206 located 790 feet from the South line and 1190 feet from the West line (Unit M) of Section 10, Township 31 North, Range 7 West. Said well is approximately 8 miles north-northeast of the Navajo Lake Dam.

CASE 9350: (Continued from May 25, 1988, Examiner Hearing)

Application of Amerind Oil Company for a non-standard oil proration unit, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for an 80-acre non-standard oil proration unit for production from the Strawn and Atoka formations comprising the SE/4 NE/4 and NE/4 SE/4 of Section 2, Township 17 South, Range 37 East, Undesignated Shipp-Strawn Pool, Undesignated Humble City-Strawn Pool, and Undesignated Humble City-Atoka Pool, said unit to be dedicated to a well to be drilled at a standard oil well location thereon. Said unit is located approximately 4.5 miles north of Humble City, New Mexico.

CASE 9408: Application of J. R. Cone for determination of permanent allocation of downhole commingled production and for the amendment of Division Administrative Order DHC-473, Lea County, New Mexico. Applicant, in the above-styled cause, seeks to amend Administrative Order DHC-473, dated June 27, 1984, by determining the permanent allocation of production from the Blinebry, Tubb, and Drinkard Pools and for the adjustment of said production allocation retroactive to August 16, 1984 for its J. R. Cone Eubanks Well No. 2 located 1980 feet from the South line and 660 feet from the West line (Unit L) of Section 14, Township 21 South, Range 37 East. Said well is located approximately 3 miles north-northeast of Eunice, New Mexico.

CASE 9362: (Continued from May 25, 1988, Examiner Hearing)

Application of Meridian Oil Inc. for the extension of the vertical limits of the Cedar Hill-Fruitland Basal Coal Pool and the concomitant contraction of the Mount Nebo-Fruitland Pool, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks the extension of the vertical limits of the Cedar Hill-Fruitland Basal Coal Pool to include any and all coal zones of the Fruitland formation, from approximately 2,579 feet to 2,878 feet, in Sections 3 through 6, Township 31 North, Range 10 West, and Sections 19 through 22 and 27 through 34, Township 32 North, Range 10 West. Applicant also seeks the concomitant contraction of said zones from the Mount Nebo-Fruitland Pool. Said area consists of 16 square miles in the form of a square centered approximately 5.5 miles east by north of Cedar Hill, New Mexico.

CASE 8834: (Reopened and Readvertised)

In the matter of Case No. 8834 being reopened pursuant to the provisions of Division Order No. R-8222, which promulgated temporary special pool rules and regulations for the Alston Ranch-Upper Pennsylvanian Pool in Lea County, New Mexico, including a provision for 80-acre spacing units. Operators in the subject pool may appear and show cause why the Alston Ranch-Upper Pennsylvanian Pool should not be developed on 40-acre proration units. The present horizontal extent of said pool consists of the W/2 of Section 25, Township 13 South, Range 34 East, which is located approximately 9 miles west by north of McDonald, New Mexico.

CASE 9409: Application of Conoco Inc. for an unorthodox oil well location and simultaneous dedication, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval of an unorthodox oil well location 1650 feet from the North line and 2460 feet from the West line (Unit F) of Section 19, Township 26 South, Range 37 East, Scarborough Yates-Seven Rivers Pool, to be simultaneously dedicated to the existing 40-acre proration unit consisting of the SE/4 NW/4 of said Section 19 to the above-described well and to its Eaves A. Well No. 4 located 1980 feet from the North line and 1650 feet from the West line of said Section 19. Said unit is approximately 2 miles north of Mile Corner 8 on the Texas/New Mexico State line.

CASE 9410: Application of Tipperary Oil & Gas Corporation for an unorthodox oil well location and directional drilling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval to plug back its Monsanto "30" State Well No. 2, located 1830 feet from the South line and 660 feet from the East line (Unit I) of Section 30, Township 16 South, Range 37 East, to 8,230 feet and then commence drilling directionally to penetrate the top of the Undesignated Northeast Lovington-Pennsylvanian Pool at a true vertical depth of approximately 11,050 feet and within a 150-foot radius of an unorthodox subsurface location 1200 feet from the South line and 660 feet from the East line of Section 30, Township 16 South, Range 37 East, the E/2 SE/4 of said Section 30 to be dedicated to the well forming a standard 80-acre oil spacing and proration unit for said pool. Said well is approximately 5.5 miles southeast of Lovington, New Mexico.

CASE 9391: (Continued from May 25, 1988, Examiner Hearing)

Application of Foran Oil Company for compulsory pooling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Strawn formation underlying the E/2 SE/4 of Section 7, Township 16 South, Range 37 East, forming a standard 80-acre oil spacing and proration unit for the Northeast Lovington-Pennsylvanian Pool, to be dedicated to a well to be drilled at a standard oil well location in the NE/4 SE/4 (Unit I) of said Section 7. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well and a charge for risk involved in drilling said well. Said unit is approximately 4 miles east by south of the junction of U.S. Highway 82 and New Mexico State 18 in Lovington, New Mexico.

CASE 9392: (Continued from May 25, 1988, Examiner Hearing)

Application of Foran Oil Company for compulsory pooling and non-standard gas proration unit, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests from the surface to either the base of the Morrow formation or to a depth of 13,000 feet, whichever is deeper, underlying the SE/4, E/2 SW/4, and Lots 3 and 4 of Section 30, Township 21 South, Range 35 East, forming a 312.05-acre, more or less, non-standard gas spacing and proration unit for any and all formations and/or pools within said vertical limits developed on 320-acre spacing, and the SE/4 of said Section 30 forming a standard 160-acre gas spacing and proration unit for any and all formations and/or pools within said vertical limits developed on 160-acre gas well spacing, both aforementioned units to be dedicated to a well to be drilled at a standard gas well location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well and a charge for risk involved in drilling said well. Said area is approximately 2.5 miles south of the junction of New Mexico State Road 176 and County Road 32.

CASE 9375: (Continued and Readvertised)

In the matter of the hearing called by the Oil Conservation Division on its own motion for an order creating, assigning a discovery allowable, reclassifying, and extending certain pools in Lea County, New Mexico.

(a) CREATE a new pool in Lea County, New Mexico, classified as an oil pool for Devonian production and designated as the Vada-Devonian Pool. Further, assign approximately 63,160 barrels of discovery allowable to the discovery well, the Union Pacific Resources Company State 26 Well No. 1 located in Unit N of Section 26, Township 10 South, Range 33 East, NMPM. Said pool would comprise:

TOWNSHIP 10 SOUTH, RANGE 33 EAST, NMPM
Section 26: SW/4

(b) RECLASSIFY the Fowler-Upper Silurian Oil Pool in Lea County, New Mexico, to the Fowler-Upper Silurian Gas Pool as the only two wells producing from this pool are gas wells.

(c) EXTEND the Antelope Ridge-Atoka Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 22 SOUTH, RANGE 34 EAST, NMPM
Section 34: W/2
Section 35: N/2

(d) EXTEND the Blinebry Oil and Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 22 SOUTH, RANGE 37 EAST, NMPM
Section 17: NW/4

(e) EXTEND the DK-Abo Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 38 EAST, NMPM
Section 25: NE/4

(f) EXTEND the King-Wolfcamp Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 13 SOUTH, RANGE 38 EAST, NMPM
Section 19: SW/4

(g) EXTEND the Lea-Bone Spring Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 34 EAST, NMPM
Section 11: SE/4
Section 14: NE/4

(h) EXTEND the Lea-San Andres Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 34 EAST, NMPM
Section 25: S/2
Section 36: NW/4

(i) EXTEND the Lovington-Paddock Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 16 SOUTH, RANGE 37 EAST, NMPM
Section 33: SE/4
Section 34: SW/4

(j) EXTEND the West Lusk-Delaware Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM
Section 31: NW/4

(k) EXTEND the North Lusk-Seven Rivers Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM
Section 4: NE/4

(l) EXTEND the Maljamar Grayburg-San Andres Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 17 SOUTH, RANGE 33 EAST, NMPM
Section 26: NW/4

(m) EXTEND the Sanmal-Queen Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 17 SOUTH, RANGE 33 EAST, NMPM
Section 11: W/2

(n) EXTEND the Scharb-Bone Spring Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 35 EAST, NMPM
Section 20: NW/4

(o) EXTEND the West Teas Yates-Seven Rivers Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 33 EAST, NMPM
Section 9: SE/4

(p) EXTEND the West Tonto Yates-Seven Rivers Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM
Section 13: NW/4

(q) EXTEND the Tubb Oil and Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 22 SOUTH, RANGE 37 EAST, NMPM
Section 17: NW/4

(r) EXTEND the North Vacuum Atoka-Morrow Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 17 SOUTH, RANGE 35 EAST, NMPM
Section 16: W/2

(s) EXTEND the Wantz-Abo Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 21 SOUTH, RANGE 38 EAST, NMPM
Section 6: Lots 11, 12, 13, and 14

(t) EXTEND the Warren-Tubb Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 38 EAST, NMPM
Section 25: SW/4
Section 36: NW/4

(u) EXTEND the North Young-Bone Spring Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 18 SOUTH, RANGE 32 EAST, NMPM
Section 18: NE/4

CASE 9411: In the matter of the hearing called by the Oil Conservation Division on its own motion for an order creating, assigning a discovery allowable, and extending certain pools in Lea County, New Mexico.

(a) CREATE a new pool in Lea County, New Mexico, classified as an oil pool for Bone Spring production and designated as the Southeast Buffalo-Bone Spring Pool. The discovery well is the Sun Exploration and Production Company Buffalo Fed Well No. 1 located in Unit B of Section 11, Township 19 South, Range 33 East, NMPM. Said pool would comprise:

TOWNSHIP 19 SOUTH, RANGE 33 EAST, NMPM
Section 11: NE/4

(b) CREATE a new pool in Lea County, New Mexico, classified as an oil pool for Ellenburger production and designated as the North Teague-Ellenburger Pool. Further, assign approximately 50,820 barrels of discovery allowable to the discovery well, the Texaco Producing, Inc. B. F. Harrison Well No. 1 located in Unit C of Section 9, Township 23 South, Range 37 East, NMPM. Said pool would comprise:

TOWNSHIP 23 SOUTH, RANGE 37 EAST, NMPM
Section 9: NW/4

(c) CREATE a new pool in Lea County, New Mexico, classified as an oil pool for Pennsylvanian production and designated as the West Tulk-Pennsylvanian Pool. The discovery well is the BTA Oil Producers Tulk 8801-JV-P Well No. 1 located in Unit O of Section 20, Township 14 South, Range 32 East, NMPM. Said pool would comprise:

TOWNSHIP 14 SOUTH, RANGE 32 EAST, NMPM
Section 20: SE/4

(d) EXTEND the Air Strip-Bone Spring Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 18 SOUTH, RANGE 34 EAST, NMPM
Section 34: E/2
Section 35: NW/4

(e) EXTEND the Antelope Ridge-Atoka Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 23 SOUTH, RANGE 34 EAST, NMPM
Section 11: NE/4

(f) EXTEND the South Corbin-Wolfcamp Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 18 SOUTH, RANGE 33 EAST, NMPM
Section 8: SW/4

(g) EXTEND the Gladiola-Wolfcamp Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 12 SOUTH, RANGE 38 EAST, NMPM
Section 16: NE/4

(h) EXTEND the Hardy Tubb-Drinkard Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 21 SOUTH, RANGE 36 EAST, NMPM
Section 3: Lots 9, 10, 15 and 16

(i) EXTEND the Lane-Abo Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 9 SOUTH, RANGE 33 EAST, NMPM
Section 35: N/2 and SE/4

(j) EXTEND the Moore-Permo Pennsylvanian Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 11 SOUTH, RANGE 32 EAST, NMPM
Section 14: SE/4

(k) EXTEND the Shipp-Strawn Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 16 SOUTH, RANGE 37 EAST, NMPM
Section 35: SE/4

(l) EXTEND the Skaggs-Abo Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 37 EAST, NMPM
Section 2: SE/4
Section 11: NE/4

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Docket No. 18-88

DOCKET: COMMISSION HEARING - MONDAY - JUNE 13, 1988

9:00 A.M. - MORGAN HALL, STATE LAND OFFICE BUILDING,
SANTA FE, NEW MEXICO

CASES 7980, 8946, 8950 AND 9111: (Reopened) See Attached Statement of Hearing.

CASE 9412: Application of Mesa Grande, Ltd. for consideration of the horizontal boundaries of the West Puerto Chiquito-Mancos Oil Pool and the Gavilan-Mancos Oil Pool, Rio Arriba County, New Mexico.

STATEMENT OF HEARING
PROCEDURES FOR CASES 7980, 8946, 8950 and 9111 (RE-OPENED) and 9412

I. Incorporation of prior relevant hearings before the Commission:

The Commission states that the transcripts and exhibits from the following cases will be incorporated into the hearing record in the subject cases:

(a) Case 8946 (Order R-7407-D) heard August 7, 8, 21, 22, and 27, 1986;

(b) Case 8950 (Order R-6469-C) heard August 7, 8, 21, 22, and 27, 1986;

(c) Case 8946 (Order R-7407-E) heard March 30, 31 and April 1, 2, 3, 1987;

(d) Case 8950 (Order R-6469-D) heard March 30, 31 and April 1, 2, 3, 1987;

(e) Case 9111 (Order Pending) heard March 17 and 18, 1988; and

(f) Case 9412.

II. Geological evidence, witnesses and analysis:

It is stated that:

(a) Because of the incorporation of the prior records including the geological evidence, presentation of redundant, cumulative or repetitive geologic testimony, exhibits or evidence will not be permitted; and

(b) Any engineering or geological witness may incorporate and utilize any of the existing geologic exhibit data and interpretation already in the records of the cases set forth in Paragraph I above. New interpretations based upon new geologic and engineering data are permitted.

III. Issues for Hearing:

The Commission states that the following constitute the only issues to be considered by the Commission at the hearing:

1. The current maximum producing allowable for each pool is 800 barrels of oil per day per 640 acres, limited however, by a gas-oil ratio of not more than 600 cubic feet of gas per barrel of oil. The Commission will consider at the hearing the following:

   (a) Whether the current oil allowable for each pool should be increased or decreased and if so, to what rate and why; and

   (b) Whether the current gas-oil ratio limitation should be increased or decreased and if so, to what rate and why.

2. All parties should be prepared to declare and support what is the most efficient rate of production for the subject Mancos Oil Pool(s) and whether these pools are rate sensitive.

3. An analysis and interpretation of the results of the June 27, 1987 - February 19, 1988 production and BHP testing and how the results effect other issues under consideration.

4. A determination of whether there is migration between the Gavilan and West Puerto Chiquito Mancos Pools; whether the horizontal boundaries of the pool are appropriate; and whether correlative rights are being violated?

5. Whether pressure maintenance would be economical and prevent waste in the Gavilan field.

IV. Issues not for Hearing:

It is stated that:

1. The Commission will not hear any issue not set forth in III above.

2. The Commission will not address the issue of modification of the existing 640-acre spacing for either pool.

3. The Commission will not consider a modification of the vertical boundaries of either pool.

V. Proposed schedule of proceedings:

It is stated that the proceedings shall be organized as follows:

1. That the parties shall be aligned so that all parties seeking to increase the allowables or GOR rates shall be identified as the proponents and those parties supporting an allowable based upon current rates, or lower rates, shall be identified as opponents.

2. The time shall be divided equally between both groups so that the direct and cross examination by the opponents approximately equals the time used by the proponents for direct and cross examination.

3. Brief position papers and witness lists will be sent by proponents and opponents to the OCD and each other outlining their major arguments by June 7, 1988. Exhibits will be exchanged Monday Morning, June 13, 1988 at 9:00 a.m.

4. The order of proceedings shall be:

Monday A.M.	Presentation by Oil Conservation Commission and Commissioner of Public Lands of expert witnesses and cross examination.
Monday P.M. through Tuesday A.M.	Proponents present direct case subject to cross examination.
Tuesday P.M. through Wednesday A.M.	Opponents present direct case subject to cross examination
Wednesday P.M.	Rebuttal by Proponents
Thursday A.M.	Rebuttal by Opponents
Thursday A.M.	Surrebuttal by Proponents

(Note: Monday P.M. through Thursday A.M. - 3 days - can be allocated 1 1/2 days each with each side dividing up their time according to their preference.)

Thursday P.M.	Recall of witnesses by Oil Conservation Commission
Friday A.M.	Closing arguments and statements.

State of New Mexico
ENERGY, MINERALS and NATURAL RESOURCES DEPARTMENT
Santa Fe, New Mexico 87503

GARREY CARRUTHERS
GOVERNOR

TOM BAHR
CABINET SECRETARY

ANITA LOCKWOOD
DEPUTY SECRETARY

IN THE MATTER OF THE APPEAL TO THE SECRETARY OF THE ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT FOR THE PURPOSES OF CONSIDERING:

CASES NOS. 7980
8946
8950
9111
9412

THE APPEAL OF OIL CONSERVATION COMMISSION ORDERS R-8712, R-7407-F, R-6469-F, and R-3401-B, AFFECTING THE SPECIAL RULES AND REGULATIONS OF THE GAVILAN-MANCOS OIL POOL AND THE WEST PUERTO CHIQUITO-MANCOS OIL POOL.

MEMORANDUM DECISION OF THE SECRETARY OF ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

This matter has come before the Secretary of Energy, Minerals and Natural Resources ("Secretary") on the application of Mallon Oil Company; American Penn Energy, Inc.; Hooper, Kimbell and Williams; Koch Exploration; Kodiak Petroleum, Inc.; Mesa Grande, Ltd.; Mesa Grande Resources, Inc.; Reading and Bates Petroleum Company; and Amoco Production Company ("Applicants") for review of the Commission Orders in the above described matters. The application for review was submitted to the Secretary pursuant to Section 78-2-26, NMSA 1978, which grants the Secretary discretion to convene in public De Novo hearing to review orders of the Oil Conservation Commission ("OCC") on specified grounds. I have considered the OCC's Order, the application for review, the correspondence and pleadings of counsel, the applicable of statutes and the state's energy plan and find no basis for rehearing.

The matter which is brought before me has been the subject of over 17 days of hearing before the Oil Conservation Commission in the past four years. Many hours of evaluation and study have gone into preparation for the various hearings on both sides of the issue. Renown experts in the field of geology and engineering have presented differing views in the nature of the reservoir.

The applicants for review in this case are attempting to formulate public policy and energy plan issues to argue my jurisdiction to hear this matter. However, in order for me to make public policy decisions as requested by the applicants, I would have to review or rehear much of the technical testimony which has been presented in this case, and I would have to substitute my judgement on the technical evidence for that of the Commission. The allegations of the applicants use the same allegations which they have made before the Commission.

The fact that the Commission Orders were not entered on a unanimous decision, and that the dissenting Commissioner has expressed his views in a separately stated opinion, indicates to me that the Commissioners have thoroughly and carefully examined all of the evidence in this case, and that they have each exercised their own independent analysis in entering a decision. It is not the purpose of the statute authorizing secretarial review to place the Secretary in position of overturning a majority Commission decision, unless that decision is contrary to a statewide energy plan or the public interest. The presence of the dissenting Commission opinion does not establish that the orders entered by the Commission contravene a statewide energy plan or the public interest.

The majority of the Commission made its decision based upon substantial evidence. I therefore decline to exercise my discretion to hear these cases <u>De Novo</u>.

NEW MEXICO ENERGY, MINERALS
AND NATURAL RESOURCES DEPARTMENT

Tom Bahr

TOM BAHR, Secretary

DATE 9-26-88

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date AUGUST 7, 1986 Time: 8:15 A.M.

NAME	REPRESENTING	LOCATION
Paul Thompson	Northwest Pipeline	Farmington
Paul Cooter	Rodey Law Firm	Santa Fe
W T Kellahin	Kellahin & Kellahin	Santa Fe
George Mallon	Mallon Oil Co	Denver
Greg Owens	Hooper, Kimball & Williams, Inc	Tulsa, OK
Marcia [illegible]	US BLM	ALBQ
Kirk A. Stone	Amoco Prod.	Denver
Kent Lund	" "	"
John D. Savage	Chandler & Savage	Midland
William F. Carr	Campbell and Black	Santa Fe
Ernest L. Padilla	Padilla & Snyder	SF
Jack Grynberg	Grynberg Pet.	SF
Jim Gillham	Gulram, Inc.	Roswell
Joel Carson	Losee & Carson P.A	Artesia
Bruce Petitt	Reading & Bates Petroleum Co.	Tulsa, Okla
[illegible] E. Tate	Mobil Prod Tx & N Mex	Midland, TX
R. Fuller	Byram	Santa Fe
Michael L. Klein	John H Hendrix Corp.	Midland
[illegible]	[illegible]	[illegible]

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date AUGUST 7, 1986 Time: 8:15 A.M.

NAME	REPRESENTING	LOCATION
Ernie Busch	OCD	Aztec
S. STRUNA	TENNECO OIL Company	DENVER
Tom Kelley	YATES Petroleum	Artesia
AL GREER	BENSON-MONTIN-GREER	FARMINGTON
DAN NUTTER	CONS ENGR	STA FE
KENT A. JOHNSON	KODIAK PETROLEUM, INC.	DENVER, CO.
GREG HUENI	BERGESON & ASSOCIATES	Golden, Co.
Charley Cook	Kodiak Petroleum Inc	Denver
David Mikesh	Mallon Oil Co.	Denver, Co.
RL HERMANSON	AMERICAN PENN ENERGY	DENVER CO.
[illegible]	Hinkle Law Firm	Santa Fe
T. L. Hill	Mobil Producing Tx & N.Mex., INC	Midland TX
Luis G. Zambrano	Mobil Producing Tx. & N. Mex, Inc	Midland, TX
W. Perry Pearce	Montgomery & Andrews	Santa Fe
Tom Dugan	Dugan Prod. Corp.	Farmington
Kurt Fagrelius	Dugan Prod. Corp.	Farmington
[illegible]	Mobil	Hobbs
[illegible]	[illegible] Refining Co.	Farmington
Gary Johnson	McHugh & Assoc	Denver
DICK ELLIS		
John D Roe	DUGAN PROD. Corp	Farmington
Kevin M. Fitzgerald	MALLON OIL (Dixon)	DENVER

Alan P. Emmendorfer	Mesa Grande Resources	Tulsa
Kathy Michael	Mesa Grande Resources	Tulsa
John Faulhaber	Mobil Producing Texas & New Mexico Inc.	Midland
T. L. Hill	"	Midland
Bruce Petitt	Reading & Bates Petr. Co.	Tulsa
Jerry McHugh Jr.	Jerome P. McHugh	DEN
Greg Owens	Hooper, Kimball & Williams, Inc.	Tulsa
Sherman E. Dugan	Dugan Production	Farm
Robert G. Stovall	Dugan Prod Corp	Farm.

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

7 August 1986

COMMISSION HEARING

IN THE MATTER OF:

Application of Jerome P. McHugh and Associates for an amendment to the special rules and regulations of the Gavilan-Mancos Oil Pool... CASE 8946

and

Application of Benson-Montin-Greer Drilling Corporation for the amendment to the special rules and regulations of the West Puerto Chiquito-Mancos Pool ... CASE 8950

BEFORE: Richard L. Stamets, Chairman
Ed L. Kelley, Commissioner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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Attorney at Law
Legal Counsel to the Division
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Kent Lund
Attorney at Law
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For Hooper, Kimball and Williams

Greg Owens
Tulsa, Oklahoma

I N D E X

E X H I B I T S

MR. STAMETS: The hearing will come to order.

We will call next Case 8946.

MR. TAYLOR: Application of Jerome P. McHugh and Associates for an amendment to the rules and regulations of the Gavilan-Mancos Oil Pool promulgated by Division Order Number R-7407, to establish temporary special production allowable limitations and gas/oil ratio limitations for said pool, Rio Arriba County, New Mexico.

MR. STAMETS: We'll call for appearances in this case and I will ask that everybody take enough time so that we -- so that Sally and I can both get down all the attorneys and who they're appearing for.

MR. CARR: May it please the Commission, initially I would request that you also at this time call Case 8950, the application of Benson-Montin-Greer Drilling Corporation for amendment of the rules in the West Puerto Chiquito-Mancos Pool. They're going to involve the same testimony and we'll ask that they be consolidated for the purpose of testimony.

MR. STAMETS: Is there any objection?

Well, since Mr. Carr has already read the style of the case, we will call and consolidate Case 8950 at this time.

We'll call again for appearances.

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, representing the applicant, Jerome P. McHugh and Associates.

MR. STOVALL: Robert Stovall of Farmington representing Dugan Production Corp.

MR. CARR: Willim F. Carr, Campbell and Black, P. A., of Santa Fe, representing Benson-Montin-Greer Drilling Corporation.

MR. PEARCE: W. Perry Pearce, of the Santa Fe law firm Montgomery and Andrews, appearing in this matter on behalf of Mobil Producing Texas and New Mexico, Inc.

Also I'd like the record to reflect that my firm is appearing in this matter in association with Mr. Kent Lund, L-U-N-D, of Amoco Production Company of Denver.

Mr. Lund expects to make a statement on behalf of Amoco at the close of the case.

MR. STAMETS: Thank you. Other appearances?

MR. LOPEZ: Owen Lopez with the Hinkle Law Firm in Santa Fe, New Mexico, appearing on behalf of Mallon Oil Company and Mesa Grande Resources, Inc.

MR. PADILLA: Ernest L. Padilla, Santa Fe, New Mexico, appearing on behalf of Koch Exploration.

Also appearing in association with me is Robert Buettner.

MR. STAMETS: Robert Buettner?

MR. PADILLA: He's an attorney.

MR. STAMETS: Thank you.

Are there other appearances?

MR. COOTER: Paul Cooter, with the Rodey Law Firm in Santa Fe, appearing on behalf of Meridian Oil.

MR. OWENS: Greg Owens, appearing on behalf of Hooper, Kimball, & Williams.

MR. STAMETS: Any other appearances?

MR. LOPEZ: Mr. Chairman, I think Ken Johnson is expecting to appear on behalf of Kodiak.

MR. STAMETS: If anybody sees Mr. Johnson they can advise him that we consider him appeared.

MR. LOPEZ: Mr. Chairman, my name is Owen Lopez appearing on behalf of American Penn, as well.

MR. STAMETS: American Penn.

MR. LOPEZ: Yes.

MR. STAMETS: Any other late appearances?

This is a very popular case. Okay, there being no further appearances I would ask Mr. Kellahin to proceed.

MR. KELLAHIN: Mr. Chairman, I would like to make an opening statement on behalf of my client so that you will have the opportunity to have a preview of the testimony that we will present through our expert witnesses with regards to this application.

As you can see from the attendance by those parties that are interested in this case, there's a lot of interest. You characterized this as a popular case. With all due respect, we have a very serious problem requiring emergency attention by the Commission.

This is an application involving a pool that the Commission created at the request of my client several years ago. You may recall that in this portion of Rio Arriba County, just to the west of the Puerto Chiquito-Mancos Pool the Commission established the Gavilan-

Mancos Pool. It was originally established on 320-acre spacing. Jerome P. McHugh and Associates there the original applicants for the spacing.

As the pool has operated and developed, the evidence will show you that we have a state of emergency within this pool that is beyond the scope of the current operators to agree upon a solution.

We come before you today not asking for an ultimate solution but a temporary remedy so that we all might explore what the ultimate solution will be.

It has come to the attention of my client, as well as all the operators within this pool, that this pool is in the midst of a dramatic, irreversible reservoir-wide pressure decline and production changes that are occurring.

Our testimony will show you that the accelerated pressure declines and the increasing dissipation of reservoir energies are resulting in waste. The effects of the way the pool is being operated are going to have economic effects on a great many people and that's why the interest is here today.

We are seeking, and our evidence will show you, that apart from economic concerns, however, this case involves one of the fundamental concepts of the Commission and that is the prevention of waste.

It has come to our attention that this problem exists. We have notified other operators; engineering and other technical committees are being formed, but there's a need for immediate action now.

Our application seeks an emergency order so that the Commission will reduce the gas/oil ratio for this pool and the producing rates. It is our testimony that will do nothing more than buy us some time. The time, however, is very important. The problem is complex and we simply have to have the time to get a solution.

The evidence will show you that the current top allowable for the oil wells in the Gavilan-Mancos, spaced upon 320 acres is 702 barrels a day; that these wells are also being operated at gas/oil ratios on a statewide basis at 2000 cubic feet of gas to one barrel of oil.

It will be our testimony that we will seek from you an emergency order immediately reducing those rates to a daily producing rate not in excess of 200 barrels of oil plus the requirement that those wells also be within a gas/oil ratio of 100,000 (sic) cubic feet to one barrel of oil, so they will meet the two requirements. We that action will be necessary and appropriate. Our witnesses are so convinced and will so testify and that will give us a temporary solution. We're requesting that that take place for a 90-day period to help us, if not preserve the status quo in terms of the way the reservoir enginergy is being expended, to at least help minimize the waste that we believe is occurring so that the operators and their technical people will have an opportunity within that 90-day period to continue their studies to see if we can come up with more effective answers as to how to efficiently and effectively operate the remaining reserves in this pool.

The testimony from our witnesses will be dramatic. It has convinced them beyond a reasonable doubt and we will attempt to demonstrate that to you, also.

We are not in this alone. We seek the support of a great many operators. I'm certain that there are other perspectives and points of view. Be that as it may, we think this is an unusual and unique case and our testimony is that we will seek and hope that you will feel compelled to aid us in this very serious problem.

MR. STAMETS: Any other opening statements? Mr. Carr.

MR. CARR: May it please the Commission, as you're aware, Benson-Montin-Greer Drilling Corporation operates and has operated the Canado Ojitos Unit in Rio Arriba County for approximately 25 years and they are producing oil from the West Puerto Chiquito-Mancos Oil Pool.

They're producing this pool in a fashion is keyed to the characteristics of the reservoir, that is keyed to the gravity drainage which they experience in that reservoir and they are developing the wells on a very wide spacing pattern.

You have authorized and provided in your rule for a 640-acre spacing pattern, but this particular unit is developed with a very low well density and you'll find that you have really one well to every, approximately, 2500 acres.

The problem we have today comes from what is going on in the Gavilan. The Gavilan-Mancos Oil Pool adjoins the Canado Ojitos Unit. They have a common boundary. There have been a number of hearings concerning the Gavilan Pool in the -- in recent years.

Three years ago we were here before you talking about what would be the appropriate spacing pattern in the Gavilan. At that time the highest capacity well in that Gavilan area produced something in the neighborhood of 100 barrels of oil per day.

Since that time there's been a flurry of activity; numerous wells have been drilled; many of these wells are high capacity wells, and this recent activity and recent events in this area, have shown that there is a serious problem in the area, a problem for those operators who operate in the Gavilan; also a serious problem for Benson-Montin-Greer.

The number of high capacity wells in the Gavilan, the recent development there, have created a situation where those wells can produce the reserves in the Gavilan in a very short period of time, and this is creating a problem on the western boundary of the Canada Ojitos Unit.

This boundary problem is not new. When we were here three years ago, this commission in its order recognized that that problem existed and the rules that were adopted at that time provided that, among other things, that only one well could be drilled in the east half of those sections adjoining the unit.

The reason for those wells -- for those rules is because we have one common source of supply, in essence. That's why were were here then; that's why we are here now, and we need to have compatible rules on both sides of this common boundary unit.

There are other things that are going on in the unit. We're injecting gas. We'll show you that there is a permeability restriction to the unit and that may provide some effective barrier and may be of some assistance to us, but the bottom line is we're doing things in the unit that affect what's going on in the Gavilan.

They are doing things over there which affect what's going on in the Canada Ojitos, and you see the evidence unfold, I believe you will see that we're clearly at least looking at the possibility of unitization in the Gavilan area, but what we've got to be in a position to do, whether it is the unitization in the Gavilan or just special pool rules, we've got to start from a point where we have rules that are compatible, so whatever agreements we can reach we can do so as effectively as possible because we believe it is essential that certain agreements be entered between the unit and the offsetting operators or we're going to be drilling unnecessary wells and waste is going to result.

We're here today in support of the application of Jerome McHugh. We believe what Mr. McHugh is seeking and what Mr. Greer is seeking in this companion case are desperately needed restrictions on production in this area.

We're going to ask for virtually the same rules on our side of the common boundary as Mr. McHugh is seeking in the Gavilan.

We're going to also present to you some general testimony on the nature of the reservoir, testimony that supports both McHugh's application and that of Mr. Greer, and testimony which we submit will be of general assistance to you in solving what is an extremely important, complicated problem in the San Juan Basin.

MR. STAMETS: Any other opening statements?

At this time we would like to have all those who may be witnesses in this case stand and be sworn at this time, please.

(Witnesses sworn.)

MR. STAMETS: You may proceed, Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, I'd like to correct an error I made in my opening statement. I misspoke about the gas/oil ratio. The current statewide rule on the gas/oil ratio is 2000 cubic feet of gas. We are requesting it be reduced to 1000 cubic feet.

MR. STAMETS: Mr. Kellahin, I would hope that before the day is over, I know we're not going to get done today, but I would hope that before the day is over someone might be able to supply me a couple of numbers which would represent the impact on oil production in the pool and the impact on gas production in the pool if McHugh's application were approved as is.

MR. KELLAHIN: We have those exhibits.

MR. STAMETS: Okay. If we don't get to them today, why, I still want to see those numbers.

MR. KELLAHIN: Mr. Chairman, I have a preliminary matter about complying with the notice requirements of the Commission with regards to the hearing and I'd like to take just a few moments to introduce and qualify the landman that helped me prepare the notices and to authenticate a plat that I'd simply like to use to help us keep track of the parties and the wells involved.

If I may do that, I would call Mr. Kent Craig at this time.

KENT CRAIG,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q For the record would you please state your name and occupation?

A Yes. My name is Kent Craig and I'm the landman for Jerome McHugh in Denver.

Q Mr. Craig, have you ever testified before the Oil Conservation Division as a petroleum landman?

A Yes, I have.

Q Pursuant to your employment by Jerome P. McHugh, did you prepare or have compiled the (not understood) of working interest owners and operators listed on Exhibit A attached to Exhibit Number One for this hearing?

A Yes, sir, I did.

Q Would you describe for the commission briefly how that document was prepared?

A Basically what we did, Mr. Commissioner, is we had a take-off made of the Gavilan Pool area by an independent broker that worked for us in checking records, in order to identify all the working interest owners of record in the county, as well as owners that we picked up in the BLM office here in Santa Fe, and we compiled that list by virtue of that take-off.

These include not only working interest owners, but in the event we found any unleased mineral owners, they are also listed on there.

Q In your opinion, Mr. Craig, have you made a good faith, diligent effort to notify all the operators and in the absence of an operator, the unleased mineral owners within the boundaries of the pool?

A Yes, sir, we have, as far as -- as far as any interests that are of record.

Q Have you made inquiry of other operators within the pool to determine whether or not they had additions or corrections to make to the list?

A Initially when we were talking about forming our geological and engineering committees for the study of the Gavilan Pool I inquired as to all the working -- all the operators, excuse me, in the pool to send me a listing of their working interest owners within their wells and all I've -- all but one, I believe, have done so.

Q Have you also made an effort to determine the operators within a mile of the pool boundary?

A Yes, sir, we have.

Q Are those names also located on Exhibit A to Exhibit One?

A To the best of our knowledge they are, yes, sir.

Q Let me direct your attention now to Exhibit Number Two and ask you to identify Exhibit Number Two.

A Exhibit Number Two is just a plat we prepared showing, basically, the 320-acre units within the Gavilan Pool. This -- it's color coded by operator. This by no means -- we are by no means inferring that this acreage that is solid yellow or solid green is 100 percent owned by McHugh or Dugan or whoever.

This is merely the location of the wells, the applicable 320-acre units per well and the operator of that well.

In the lower righthand corner you'll note in Section 24 of 24 North, 2 West, there are two wells located in that section which we've stippled around one of them and circle the other one. Those are out of the Gavilan Pool and I'm not sure as to what their proper spacing is. We just highlighted them in that they are on the border of the pool.

MR. KELLAHIN: That concludes my examination of Mr. Craig.

We move the introduction of Exhibits One and Two.

MR. STAMETS: Without objection the exhibits will be admitted.

MR. PEARCE: Excuse me, Mr. Stamets, just for purpose of the record, we have not checked this and have no objection to its entry subject to subsequent check for verification.

MR. STAMETS: So --

MR. PEARCE: I don't know that the information here is correct; I don't know that it's not.

MR. STAMETS: Well, what you'd like to do then, is be able to recall this witness --

MR. PEARCE: Yes, sir.

MR. STAMETS: -- will under those circumstances delay admitting these exhibits until Mr.

Pearce has had an opportunity to examine them and we would admit them later.

Any other questions of this witness?

He may be excused at this time.

MR. KELLAHIN: Mr. Chairman, at this time we'll call our geologic witness, Mr. Dick Ellis.

RICHARD K. ELLIS,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Ellis, for the record would you please state your name, sir?

A My name is Richard K. Ellis.

Q You'll have to speak up so we can can all hear you.

By whom are you employed and in what capacity?

A I'm employed by Jerome P. McHugh and Associates as a geologist.

Q Mr. Ellis, would you give us your educational background?

A I have a Bachelor of Science degree in mathematics from the University of Washington in 1975; Bachelor of Science degree in geology in 1975, University of Washington; Master of Science in geology from the University of California at Berkeley, 1977; Juris Doctor degree, 1982, from the University of Denver Law School; member of the Colorado bar since 1983.

Q Mr. Ellis, would you summarize for us what has been your general work or employment experience as a petroleum geologist?

A I began my petroleum geology work with Exxon in the summers of 1975 and 1976 while I was in graduate school.

I went to work full time for Chevron USA in Denver in 1977 and spent seven and a half years with them in the various, different capacities ending with a management position. I was a project leader in one of our exploration districts in the Denver office.

And then I went with Mr. McHugh in his firm in March of 1985. I've been a geologist with him since.

Q Have you previously testified as a petroleum geologist before the Oil Conservation Division?

A Yes, I have.

Q Have you made a geologic examination and study of the Gavilan-Mancos Pool insofar as Mr. McHugh's application before the Commission is involved?

A Yes, I have.

MR. KELLAHIN: At this time, Mr. Chairman, we would tender Mr. Ellis as an expert petroleum geologist.

MR. STAMETS: Are there any questions about Mr. Ellis' qualifications?

He is considered qualified.

Q Mr. Ellis, I'd like for you to give us some of the background from your own personal knowledge and observations of the Gavilan-Mancos Pool insofar as it concerns the questions of how the pool is operated and being produced.

A All right.

Q When did you first become involved in that project?

A Basically we've looked at the producing situation in the pool since I came with Mr. McHugh last year.

We had some information that came to light toward the end of 1985. Most of it was engineering related data, pressure -- pressure data, specifically, that gave us cause for concern.

As soon as I had cause to believe that we were dealing with a situation of rapid depletion of the reservoir, I recommended to Mr. McHugh and we initiated as a company an intensive study of the reservoir and we have as part of that study included all the major operators within the pool and we are currently involved in ta very intensive study effort trying to determine just -- just what the solution to the problem is.

Now, we basically feel that our proposal today, the emergency, temporary reduction in the allowables, is necessary to reduce the rate of current withdrawals in the pool. It, the primary reason for seeking this temporary rule, as Tom mentioned earlier, is to allow us the time to complete this reservoir study that we have done, and along those lines, if we're not prepared at the end of this proposed 90-day temporary rule to make application for a Gavilan Unit, then we will be back for a further reduction in production rates at that time.

Now, as I said, we -- we embarked on this study, including all the major operators --

Q Let me ask you some questions about the study, Mr. Ellis. What companies were invited and participated in the studies and generally when did they take place?

A We initiated the study group right after the OCD called an informational meeting in February of this year concerning operational practices in the Gavilan Pool.

There was quite a large turnout for that, indicating some interest in what was going on, and we called a meeting for May 1st of this year and notified all the operators, who in turn notified some of their working interest owners, and we had notified our working interest owners, to come to that initial, formational meeting.

We held the meeting and then determined we needed to share quite a lot of data in the pool, and we did that. We shared data amongst ourselves.

At the second meeting we determined that perhaps the study would proceed a little more rapidly if we were to break down into specific work groups, the engineers and the geologists, and we did that. We held meetings in July of this year, 8th, 9th, and 10th of July, in Farmington and had our small subcommittees working at that time toward an understanding of the problem.

Q Would you identify for us, Mr. Ellis, the areas in which data has been developed to depict or to identify the nature and scope of the problem?

A Yes. We basically three sets of data that we feel clearly depict the gravity of the problem out there now.

The first set is the geologic data and basically I'll present the structural and stratigraphic elements of the pool that we believe show that we're dealing with a reservoir-wide single, unified production entity.

We'll also show that the damaged, what we feel to be the damaged parts of the reservoir are in direct communication with all of the reservoir.

The second set of data we'll bring out on testimony will be the gas/oil ratio data. That data will show a dramatic increase basically in the last six months of production out of the pool, and you know, from my experience in other reservoirs, this GOR data is a very good yardstick of the efficiency with which that pool is being produced.

And the third, and final, set of data that we would like to bring out on testimony is the pressure data we've acquired in the pool. Basically Gary Johnson, our engineer, John Roe, Dugan's engineer, will be able to present that for us.

Q Mr. Ellis, let me turn now to the package of Mr. McHugh's exhibits.

MR. KELLAHIN: They have been identified, Mr. Chairman, as Exhibit Number Three. Within the book it's been subdivided again into Sections A, B, C, and D.

Q Mr. Ellis, let's turn to the geologic investigation of what is occurring in the Gavilan-Mancos Pool and let me, first of all, turn your attention to Sub-section C of Exhibit Number Three.

Within that, or just after that tab there is what purports to be a structure map and then there's a cross section. Are you with me? All right, sir.

Let me turn to the structure map and first of all have you identify that for me.

A Yes. The exhibit Tom's referring to is a structure map on top of the -- what I call the Niobrara A pick in the field. That's the top of the -- what we consider to be the pay interval in the pool.

Q What have you concluded from an examination of the geology that you can illustrate for us by using this structure map?

A Basically in constructing the structure map we used all the available well data in the pool; used commonly accepted practices with regard to the construction of the map, and from this map I conclude that the Gavilan nose, if you will, is a large, northeast plunging structural feature. All the pool wells completed to date in the pool have been completed from either the crest or the flank of this structural nose.

You can see that I've indicated some minor faulting in the southwest portion of the mapped area. I feel the faulting is significant only in that it probably is genetically related to the development of the fracture system in the Niobrara producing interval that is responsible for the oil production in the pool.

Let's consider for a second the minor faulting I've indicated there. You'll -- you'll see in looking at that data that we've got throw across those faults in the range of less than 100 feet. What I have concluded from the mapping I've done is that none of these faults are sealing.

We have three wells that lie along the trace of that fault, three McHugh wells in the southeast of Section 29, northwest of Section 33, and the southeast of Section 33, that are basically high capacity wells, or at least they were until we had more pervasive interference in the field.

So I've concluded from that that the faults, rather than being sealing faults in fact probably enhance vertical communication with the fracture system.

These wells, as I have them mapped, including the well in the northeast of Section 32, appear to be in one fault block. We will bring out on later testimony the pressure data that indicates that these wells are all communicative with the pool as a whole, that in fact wells in the southwest side of that fault block are in communication, as are the wells within the fault block.

I've concluded in general from this display here that we're dealing with a structurally unified entity and it's my belief that the nose that's present here in Gavilan is responsible for the pervasive fracture system in the Niobrara interval.

Q When we focus on the identified problem of how the pool is being produced and operated, how does the continuity of the geology for this producing interval affect the magnitude of that producing problem?

A In terms of the -- what I've indicated to be the structural continuity in the map, and because I do feel that it's a single entity that's responsible, and there are no indications that we have isolation due to faulting across this structure, that the net effect will be that we're going to have communication across the structure, pervasive, reservoir-wide communication.

Q Would you describe in your own words what you, as a geologist, see to be the problem that is agreed upon at least within your company involved in the Gavilan-Mancos Pool?

A Well, we -- we recognize that we're dealing with indications of a very rapid depletion in this reservoir that's ubiquitous in the reservoir.

We recognize that problem and after some preliminary study in our subcommittees at least the major operators and many of the working interst owners recognize the problem, and we agree, you know, based on the analysis we've done from a geologic and engineering standpoint, that the immediate reduction in the current allowable is essential.

Q Do you see geologically any justification for locating or separating out the problem area as being only one portion of the pool or conversely, does it encompass the whole pool?

A No, I don't see any reason for separating out any particular portion of the pool from a structural and geological standpoint.

Q Let's turn now to the cross section, Mr. Ellis. But before we leave the structure map, was that prepared by you?

A Yes, it was.

Q That's your work product and your interpretation and evaluation?

A Yes, sir.

Q All right, let's turn to the cross section. Would you identify that exhibit for us?

A That's what I would call a structural, stratigraphic cross section through the Gavilan-Mancos Pool.

Q Why was this cross section prepared, Mr. Ellis?

A I've done that to provide further evidence of the structural uniformity within the pool and also to provide some measure of stratigraphic uniformity within the producing interval in the pool.

Q What do you conclude from an examination of the cross section?

A From a structural standpoint, referring back to the structure map, we have a trace of the cross section identified on the map. I've selected this tract to be along the axial plane of the fold and made projections of wells into that axial plane.

Once you construct a structure section of this from the eighteen wells, you can conclude that you have a very low relief, gentle doming in the central portion of the fold and basically structural uniformity across the fold is what I would conclude in a structural sense.

I used the induction log in each of these eighteen wells in the structure stratigraphic cross section to depict the uniformity in the Niobrara producing interval stratigraphy throughout the pool, and if you'll look at these, the representation on the section, you'll see that except for minor character changes in this induction log, and that's related mainly to the hole conditions during logging, that the signature of this producing interval, this Niobrara stratigraphic interval, is uniform throughout, so that is also another conclusion you would draw from this section, is that it is a uniform stratigraphic interval.

You'll also notice that the thickness of these units appear to be invariant except for very small variations throughout the -- throughout the section.

This also brings -- brings up a number of other considerations in trying to establish stratigraphic uniformity in the pool. We, meaning McHugh and the technical people associated with our analysis of the field, believe that the log data is generally suspect in a pool of this types, so we have looked at some core data and, in fact, as part of our overall study efforts, we're acquiring additional core to try and address of the problem of stratigraphic uniformity, and based on the core data that I've been able to see and some of the sample descriptions, these thinly laminated shales and minor very fine-grained, silty laminae, and sandy laminae in the Niobrara are preferentially fractured relative to the more massive shales of the Mancos interval and the Carlisle above and below.

They're preferentially fractured particularly in areas like Gavilan where you have a very low relief hole like this and minor faulting, which creates a lot of internal stresses within the interval.

Now the core data, we believe, is going to be very significant for a lot of reasons, but three of the more significant reasons that I've come up with based on my analysis of the limited core data available in the field, are that the density of logged porosity that we're seeing in this particular interval through the analyzed core intervals, bears no relation to the core porosities that are analyzed.

Now, in fact, the correlation is so poor that there appears to be no way to calibrate the density porosities with the core porosities as you would expect to be able to do in a true matrix reservoir.

Based on my experience with matrix reservoirs, and this is also another conclusion from some of the core data, the amount of the effective or producable matrix in the Niobrara producing interval section is minimal and I generally use cutoffs in my work of about 0.1 millidarcy permeabilty. I consider anything greater than 0.1 millidarcy to be probably fracture permeability.

And the final conclusion I come up with the respect to the core data and how it relates to the stratigraphic uniformity question is because of the extremely thin, interbedded nature of these very fine-grained sandstone laminae, it's probably difficult in any kind of core analysis, whether it be plug or hole core, to get a statistically valid analysis of the matrix porosity in the rock. It's probably impossible to do that with respect to the fracture properties, and as a result of all this looking at the core data, I've come out believing that the so-called matrix in the Niobrara will have essentially no impact on present or future reservoir performance.

Just to kind of sum up this particular display and the previous one, I feel that based on the structure and stratigraphy I expect the Gavilan-Mancos Pool, if you will to behave as a single, unitified producing entity, and as we'll see later, the pressure data lends further credence to this conclusion.

Q Let's go on to an examination of the information that you have tabulated on the gas/oil ratios. Once we've done that we'll come back and look at the geology gain to see what conclusions you can draw about the relationship of the gas/oil ratios in certain wells to the geology.

Let's turn to the Tab A of Exhibit Three, which is in two parts, there are two displays there. If you'll describe for us, or at least identify each display.

A The first display is a plot of the producing GOR conditions in the reservoir as of January 1st of this year.

The second display is a plot of the producing GOR conditions as of July 1st of this year.

Q Were these prepared by you or compiled under your direction?

A Yes.

Q Give us an explanation of what the information shows you.

A Well, it's kind of an outgrowth of this concept of stratigraphic and structural uniformity. This data kind of falls into place with respect to that overall conclusion and I'll give you some reasons why here.

The initial display is a depiction of the producing GOR conditions on the first of this year, January 1st of this year. It's compiled from C-115 production data filed with the state.

Basically what I've done for all the wells in the pool is divided the monthly oil production into the monthly gas production and coming up with a producing GOR for a given month.

For this particular month or actually for the month immediately prior to January 1st, December, '85, we have some indicated conditions in the pool that are significant when viewed with respect to the next plot, which is actually six months later.

The nine wells with darker hachuring on this plot are wells that produce at greater than a 2000 GOR. Now there's probably a lot of different reasons why these things are indicated to be high GOR wells but we believe and have always believed that there are areas in this pool where free gas basically has -- has always existed.

The five wells to the north, the five dark hachured wells to the north, are essentially structurally high wells. One might expect that gas, free gas, to have developed in a structurally high position if it was going to develop at all.

The wells the south, the four wells to the south, again are in structural -- structurally higher positions, but they're also very low capacity wells and there could have been free gas stringers associated with this low capacity part of the reservoir.

But the real significant part of this display and what bears on the next display are the two wells that are in the lighter hachures. One is the Native Son 2, a McHugh well, and the other one is the Mother Lode 1, which is a McHugh well. At this time in the reservoir those -- those were the only two what I would call down dip or down structure wells that actually produced with GOR's greater than 1000.

Then we go to the next plot, a producing GOR plot for July 1st of '86. You'll notice immediately the dramatic change. We have fifteen additional wells that have GOR's, producing GOR's greater than 1000. What this is saying is that more and more gas is accompanying each barrel of oil to the well on a poolwide basis.

Now this GOR increase appears to be

spreading rapidly and I'll get to that in a minute with my next two displays, but this rapid spread is occurring in all parts of the reservoirs and it's not necessarily tied to structural position.

Q If they were simply tied to structural position, what then would you conclude?

A It's a pervasive, pool-wide type of effect and --

Q Because it's not tight structure it's pervasive over the pool?

A Yes. Well, the actual progression of the development of these high GOR conditions is -- appears not to be related to purely -- purely structural position in the pool.

Q To make sure I understand your testimony, we're concerned about the way the pool is being produced, the rates. Is there a reasonable geologic explanation so that if this pool was properly producing in its most efficient way, would we see the type of gas/oil ratios on the second display for July? Do those have a geologic explanation?

A You could generally say that because of the stratigraphic uniformity of the Niobrara producing interval the pervasive nature of the fracture system within the producing interval, the fact that it is reservoir-wide has allowed this kind of a very complete communication within the reservoir and that's the reason why I feel that, you know, the fact that the GOR problem has developed is really not totally related just to structural position on the field. There is a geologic explanation for that. The fact is that the fracture system is pervasive and all-encompassing (not clearly understood) pool.

Q Let's talk about your opinions of the fracture system. You talked earier about the porosity. Sometimes we see reservoirs in which matrix itself contributes, has porosity and contributes to the production.

In some areas we see a combination of matrix production and fracture production.

Give us your geologic opinion about where the porosity system lies for this pool.

A That would be an opinion, at least in my case, based primarily on my examination of analyzed core data and based on that examination, as I indicated earlier, I'm convinced that the matrix contribution in a reservoir like this is essentially minimal and that the porosity system is single and related to fracture porosity only.

Q All right, sir, are you ready to go on to the next display?

A Almost.

Q All right, sir.

A I'd like to -- I's like to point out with respect to this last display that I've got seven wells in there that are basically circled with red, and these are wells that I've indicated in the next two displays and they have their GOR histories plotted. We can go to the next two displays.

Q Those are filed after the B tab in Exhibit Three. The first one is a yellow display and the next one is the bluish green display.

A These next two graphical displays depict the data in the previous exhibits in a time sense. Basically, I've selected four wells from the south and west portions of the reservoir to display on this one. This again is data that's taken from the C-115 producing data filed with the state and again the manner in which I computed the monthly producing GOR was just the monthly gas over the monthly oil produced.

The only real significant point to be made in a display of this type is you, obviously, need to note the fact that there is a very dramatic increase in the GOR over a very specific period of time, from January to June of this year, which comports almost exactly with the two previous pool-wide displays that I prepared.

Okay, now we can move to the north and east portions of the reservoir with the next plot.

I've selected three other wells that basically indicate the same thing, a dramatic increase again occurring between that very limited period from January to June of this year.

And all of the last four exhibits indicate to me and the technical people I'm associated with that the situation is quite alarming and that we feel the -- the real solution to this problem is to control these high GOR wells; basically to preserve reservoir energy and although we've identified an interim stopgap solution to be the reduction of the allowable rates, it's my firm opinion and I have Mr. McHugh's full support on this, that even without further study, that the only solution to this problem, the developing problem as we now see it, is unitization of the Gavilan Pool.

At any rate, the conclusion is that we're looking at a reservoir-wide GOR increase that is indicating a rapid dissipation of reservoir energy.

Q Now that we've examined the gas/oil ratio plats or displays, I'd like to take you back to the structure map for a moment.

Am I correct in understanding that you are finding wells in the pool at locations lower in the structure, those wells having higher gas/oil ratios than you would expect a well at that structural position to have at this point in its life?

A Yes, that's -- that's generally true. We have seen that areas in the reservoir that have undergone extensive production over a period of time appear to have developed this -- this dramatic increase in GOR in a rather short period of time.

It does, generally in a most efficient development of the reservoir, one might expect the increase in GOR to occur down structure in a very systematic way but in this particular case, as I indicated when we went through that GOR data, it would appear that the increase in GOR's is more related to areas of higher and more extensive withdrawal and it is not necessarily tied to the structural position, although one might expect that in a normal, more efficiently produced reservoir.

MR. KELLAHIN: That concludes my examination of Mr. Ellis.

At this point in the testimony we would move the introduction of his exhibits which are Sections A, B, and C of Exhibit Three.

MR. STAMETS: Are there objections to the admittance of these exhibits?

They will be admitted.

Are there questions of this witness?

MR. PEARCE: There are going to be some. We're just trying to pick the order, Mr. Chairman.

MR. STAMETS: Okay.

(Thereupon a recess was taken.)

MR. STAMETS: The hearing will please come to order.

Mr. Pearce, have you all decided who's going to --

MR. PEARCE: I think Mr. Lopez is going to go first.

MR. STAMETS: Okay. I would hope that we can follow the same sequence in the future examinations and then I can figure out who to start with.

Mr. Lopez?

MR. LOPEZ: Thank you, Mr. Stamets.

CROSS EXAMINATION

BY MR. LOPEZ:

Q Mr. Ellis, I think you were discussing your opinion with respect to fracturing in the area of the Gavilan-Mancos Dome. What's your opinion with respect to regional fracturing in the area?

A That's something that Mr. McHugh and our organization has given some attention to. We, however, have not completed a photogeologic study per se in the immediate area of the Gavilan Dome. The fact that such a study could help bring to light some additional data that bears on the production and the performance in the reservoir doesn't escape me but at the present time I feel that the best data we have concerning the fracturing in the reservoir is production related data.

Q Do you see any evidence of vertical communication within the Gavilan Dome area?

A By inference I certainly do, and as I mentioned with respect to the structure map, the -- the three wells that lie along that northern fault that I've mapped in that fault block to the southwest portion of the map area being high capacity wells, or as I said, they were high capacity wells until all the wells started interfering, is perhaps the best inferential data I have concerning the vertical communication accorded the overall fracture system by the faulting that's in the reservoir.

MR. STAMETS: Mr. Lopez, I'd like a little clarification on your first question.

You were comparing fracturing in the area of the Gavilan Dome versus regional fracturing, and I'm not sure if when you say regional fracturing if you're talking about something that extends outside the area of what's now classified as the Gavilan-Mancos Pool or outside the plus 550 foot contour. Could you clarify that for us?

MR. LOPEZ: It was my intent to have the question have as broad a meaning as possible. By regionally I mean including the Puerto Chiquito Unit and going westward (not clearly understood.)

MR. STAMETS: So at least those townships which surround what's currently the Gavilan-Mancos Pool.

MR. LOPEZ: And the unit that we're discussing here today.

MR. STAMETS: And under those conditions does your answer remain the same?

A Yes.

MR. STAMETS: Thank you.

Q And if I put it to include the basin as a whole, that would also be the same.

A Do you want to repeat that?

Q The entire San Juan Basin as a whole with respect to any evidence you have or know about with respect to regional fracturing.

A Certain parts of the basin we've spent quite a lot of time doing photogeologic studies on. That's an exploratory tool we do use in the overall basin area.

With respect to the Gavilan-Mancos Pool, as I mentioned, most of the inferences I have made concerning the fracturing and faulting in this reservoir are production related and also related to the actual correlation of logs within the pool.

So at least it would have to be less than a basin-wide scope, in answer to your question.

Q Is it your opinion that the formation itself that we're discussing is very permeable?

A If by permeable you mean permeability related to the, what I would call the pervasive fracture system, yes, in a general sense. There are obviously zones within this particular pool that have less overall effective permeability than others. We've identified a number that are extremely tight but in general the fracture permeability in large areas of the pool is significant.

Q How about the matrix contribution and what is your opinion on its permeability?

A Based on the core data I've seen, and I've seen very limited core data to date, I believe that there are three wells within the pool that -- or excuse me, not three wells within the pool -- two wells within the pool and one well within the Canada Ojitos Unit that have done some analysis of core permeability of the matrix.

That particular analysis that I have seen indicates extremely low permeability in the matrix, less than 0.1 millidarcy.

Q Then is it your opinion that permeability does in large part depend on the fracture system?

A That's my contention and that's based on work I've done to date. I believe it is necessary to get a statistically valid sampling of the nature of the matrix with respect to the reservoir and that is why Mr. McHugh has recently signed an $80,000 AFE for some additional core data in our pool. We're doing that under the aegis of the study subcommittee that we have set up and Mr. McHugh, even though I've influenced his thinking heavily concerning the -- the lack of contribution from the matrix, has agreed that is a question we need to resolve.

But it is my firm belief, at least based on the data I've seen thus far, and I'm admittedly an open minded person, that the matrix contribution is essentially nil.

Q In both the Gavilan Dome area and in West Puerto Chiquito?

A Well, the, as I said, the limited core data we have would seem to indicate that's true, yes.

Q Do you see any difference between the two, the West Puerto Chiquito Unit and the Gavilan Dome area?

A Specific numbers?

Q Yes.

A I could pull out my numbers and run through that with you but basically from memory, the range of numbers we're dealing with permeability-wise ranges anywhere from less than .01, which is beyond the limit of resolution and measurement of permeability, up to 11 millidarcies.

Now, as I said, any -- I consider anything above 0.1 millidarcy of permeability in any of those analyses as indicative of some kind of fracture contribution.

I believe that the actual matrix permeability is probably somewhere in the range of less than .01 to possibly as high as 0.3 millidarcy.

Q But because of the fracture contribution tne highest number with respect to permeability in the Gavilan Dome area is the number you said, 11?

A Based on the data I've seen, yeah. That's from three different core analyses.

Q Do fractures in the Gavilan Dome run in all directions in your opinion?

A I believe it's generally a pervasive system. I think it's got a multi-directional orientation.

Yes, I do.

Q Have you run and analyzed fracture logs to indicate the direction of any of the fractures?

A We have not done any of that in any of the wells I've been associated with with Mr. McHugh.

Relying from experience and, you know, some of the lab research that was done at Chevron, we're not totally convinced that the fracture logs currently in use in the industry are necessarily a positive indicator of directional fracturing in a borehole.

Q What kind of reservoir producing mechanisms do you discover or find in the Gavilan Dome area?

A Well, I'm not an engineer but the attention I've given to this problem in conjunction with Gary Johnson, our engineer, and Mr. Roe, an engineer from Dugan, and Mr. Greer, the engineer from Canada Ojitos Unit, I think we have generally concluded that we're dealing, at least at this point in the reservoir life, with a solution gas drive producing mechanism.

Q Well, if that's the case, isn't it normal to see gas/oil ratios increase with the depletion of the reservoir?

A You will have -- down to the bubble point there should be very little increase in the overall GOR in the reservoir.

Below the bubble point certainly you would expect to see increasing GOR's under a solution gas drive.

Q Do you have an opinion as to what the average fieldwide GOR is?

A At the current time?

Q Yeah.

A Based on a display that will be presented by our engineer in the next section here, it looks like we're dealing with about a 1500 -- okay, a monthly average about 1450 GOR poolwide.

Q Now, referring to your exhibits under Tab A, and specifically with respect to certain wells indicated on your exhibits, were you aware that the Gavilan Howard No. 1 had experienced a casing leak between the Gallup and Dakota?

A We've had some verbiage to that effect in our study subcommittee meetings. We understand that there was contamination of the reported production data in the Gallup interval from gas leaking behind some kind of downhole plumbing to -- from the Dakota formation. So it is entirely possible that dark hachured zone in the Gavilan Howard could be incorrect, and until we have verification that that was actually the case, why, I'd like to leave that here because the reported production to the state possibly up to the point at which I made that final graph, could be above 2000.

Q Now, referring to the Gavilan No. 1, which offsets the Gavilan Howard, were you aware that it was commingled?

A Yes, I am.

Q With the Dakota?

A Uh-huh.

Q Have you been able to calculate how much gas has been introduced out of the Dakota?

A That would be extremely difficult to do. We have the reported proportions that are used in the reporting of gas and oil production to the state. We believe, however, that the majority of the production out of the Gavilan 1 is strictly from the Mancos formation. That is problematic, however. If you will notice the two wells you referred to exist on --

MR. STAMETS: Excuse me again. I need a little clarification here because we -- in the -- on this sheet, on Exhibit A, up in the northern part there's a Howard 1-11. Below that there is a Gavilan Howard and I'm not sure which well we're talking about.

MR. LOPEZ: Okay, I think, Mr. Chairman, that it's best to go to the second page of your exhibit because more wells are represented there, and my first question had to do with the Gavilan Howard in Section 23, the Gavilan Howard No. 1.

MR. STAMETS: Okay, thank you.

MR. LOPEZ: My second question was just the Gavilan No. 1, which is in Section 26.

MR. STAMETS: Okay.

MR. LOPEZ: And now along that same line of questioning I'd like to ask Mr. Ellis if he was aware that the Gavilan No. 2 in the same section we've just discussed is a severely damaged well?

A Yes, it is. I am aware of that.

Q Do you think it's representative of the producing characteristics of the reservoir being in this condition?

A That would be open to some question. The point I began to make here a second ago concerning two, and now all three of these wells, is that all three of them exist on both plots and as I pointed out in the dissertation on the initial plot, the real significant portion of what I was trying to point out is not necessarily the dark hachured wells that exist on both plots.

There are problems concerning the analysis of GOR conditions on those particular wells but the important thing is the change in the remaining wells in the pool between the two plots. That's the point I was making.

Q Now turning your attention back to the Gavilan Howard No. 1, were you aware that Mesa Grande reported 3665 barrels of produced --

THE REPORTER: I'm sorry, Mr. Lopez, I didn't understand your question. Would you mind repeating it again for me?

MR. LOPEZ: Certainly.

THE REPORTER: Thank you.

MR. LOPEZ: We're referring back to the Gavilan Howard No. 1 and I asked Mr. Ellis if he were aware that Mesa Grande recorded that well's production in June so it should correspond to his second page of his Subsection A of Exhibit Three; that there was in fact 3665 barrels of oil produced in that month and 4191 MCF. According to my calculations that would give a GOR of 1143, which was less than the 2000, so I would question how you have characterized that well on your exhibit.

A Well, that, of course, was good news to all of us. We like to see these kinds of changes occurring.

At the time we prepared these graphs we had no C-115 data shared with us by Mesa Grande and I guess the point I'd make is that I made the assumption that the well condition did not change. In fact, what we're seeing here is that that dark hachured area ought to just be a light hachured area. That's, as I said, good news.

Q And were you also aware that the Rucker Lake No. 2 GOR has declined?

A Again, for the same reason, we didn't have the production data in June on that. We have to assume under that scenario that the condition of the well remained the same.

Q Then on what basis did you prepare this exhibit we're discussing?

A All of the wells you see on here are based on actual C-115 data or data provided to us at the last engineering subcommittee meeting.

As I mentioned, the Mesa Grande production data is not yet in our hands from that meeting, so we assume under that scenario that the condition of the well remains the same, a reasonable assumption.

As you've just pointed out, we can -- we can certainly change the Rucker Lake 2 and the Gav Howard 2 to light hachured circles.

Q How do you explain the decline in GOR's?

A That, well, certainly with respect to the Gavilan Howard, if what they indicate is correct, and again we've never seen any actual data concerning a repair of that well, but basically they've corrected the communication problem behind pipe in the Gavilan Howard.

The Rucker Lake Well I'm not familiar

with any kind of production change that would give rise to that decrease in GOR and I'd certainly defer to our engineering experts concerning decreases in GOR in a depletion drive reservoir of this type.

Q Hasn't the McHugh Native Son No. 1 also experienced a decline in GOR and you should be familiar with that one. How do you explain its decline?

A Well, there could be a number of reasons why free gas may not make it to the wellbore in a high capacity well of that sort. There may be -- and again, this is engineering, really, within the realm of engineering testimony, but it is possible you could have had segregation in the area of the wellbore and because of the producing conditions in the wellbore you could have preferentially allowed through some mechanical means the oil to enter the wellbore and not -- not the free gas associated with it.

So although earlier in the life we had a much higher GOR in the Native Son 1, there could be a number of different explanations why that GOR went down.

MR. STAMETS: What's the location of the Native Son No. 1?

A That's the northeast of Section 34.

MR. STAMETS: Northeast of 34. That well isn't even circled on my exhibit.

A Yeah, that well currently produces with a

GOR of less than 1000.

MR. STAMETS: Okay, so you're -- we weren't talking about a well identified as a high GOR well.

MR. LOPEZ: No, since he didn't know about the Rucker, I just thought I would go to a well that I thought he might know about to see if we could find out the nature of the --

MR. KELLAHIN: Mr. Chairman, I don't want to deny Mr. Lopez a full opportunity to cross examine this witness but we do have Mr. Roe, a petroleum engineer, that can talk all day long with Mr. Lopez about gas/oil ratios. He has an explanation of all these questions.

MR. STAMETS: If you could defer that to the engineering witness that might speed things along.

MR. LOPEZ: I appreciate that, Mr. Chairman, I'm just trying to examine Mr. Ellis on the exhibits he introduced and I understand the Commission's concern to get on with the hearing and I will bear that in mind if I may just ask one more question along this line in this vein, with your permission.

MR. STAMETS: Certainly.

Q Mr. Ellis, I refer you on this same exhibit we've been discussing to those dark circled wells that, let's say, begin with the Lindrith 1 and go south in the pool. What quality of well -- wells are those in your opinion?

A As I mentioned earlier, that's a portion of the pool that we feel is extremely low permeability. The capacity of those wells as a result is -- is quite low. That is a problem in terms of analyzing the production associated with those wells to place them into the overall scheme of the pervasive increase in GOR pool -- poolwide, but as purely from a factual standpoint, the production reported to the state indicates that those wells are in excess of 2000 GOR and I think I may have made that particular caveat at the time I explained the displays, that we do have problems explaining why those GOR's are the way they are and we do have at least a perception that it may possibly be related to the development of free gas in that low permeability portion of the reservoir.

Q And since we agree that these are poor quality wells, what effect do you think they have on the reservoir or the GOR to begin with?

A Well, there's no question that the overall effect from those four or five wells, actually, there's many more in there that have never produced but certainly we would expect if they did produce, then to fall into the same categories as the other four or five, the overall effect, of course, is quite small in terms of any kind of effect on the overall poolwide GOR.

Q Are any of the wells which experienced large increases in GOR's McHugh wells?

A They certainly are. The first display that I presented in yellow is my depiction of the wells in the south and the west portions of the reservoir. Those are all McHugh wells.

Q Are these McHugh wells large capacity wells which have produced large quantities of oil to date?

A Yeah, there's at least one in there that is a very high capacity well. The other two -- other three wells, at least with regard to the overall pool capacity, are average capacity, and the other one well that I'm referring to, the ET No. 1, has been variable throughout its life as either a low or a high capacity well.

Q So can we reach the conclusion that the higher the withdrawals, or that higher withdrawals result in higher GOR's?

A Not necessarily. If you'll look at the next plot, we've got three other wells, and all I meant to do in selecting these wells was select the wells that cover a portion of the field and give a flavor as to what's happening poolwide. That was the whole intent of my presentation, was to indicate the overall nature of this GOR increase.

These three wells, in terms of their withdrawal, are, of course, much lower than that area in the south and west portions of the reservoir that has produced for a much longer time, and you can see the corresponding, same corresponding effect in the north and east parts of the resevoir, and we do definitely have a couple of high capacity wells, or at least one high capacity well in that blue plot. But is you're speaking with regard to the cumulative withdrawals, this portion of the reservoir has made aobut a tenth of the oil the rest of the reservoir has done.

Q If allowables are severely restricted and pressure stabilized will that result in recharging the reservoir in the vicinity of these wells?

A I believe that might be a question that would be better answered by a reservoir engineer, but, you know, maybe I'm mistaken. I'm --

MR. LOPEZ: Thank you (inaudible).

MR. STAMETS: Are there other questions of the witness?

Mr. Pearce.

MR. PEARCE: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Ellis, you mentioned at several points during your direct testimony that you had some limited core data, cores which you had examined or reviewed. Would you state to me, please, what wells you have cores available on, please?

A The well data -- or, excuse me, the core data I've been able to examine, as I mentioned, has come primarily from three cores in the area. I understand there is a fourth core available but because of apparent company policy I don't think we have access to that data at this time.

The three wells I'm referring to are the Canada Ojitos L-11 Well, the Mallon 1-11 Howard Well.

MR. STAMETS: Excuse me, could you give us section, township, and range?

A The L-11, I believe, is in Section 11 of 25 North, 1 West.

The 1-11 Howard is in the --

MR. STAMETS: I'm trying to find these on the --

A Yeah, that would be off the base map we have given you.

MR. STAMETS: Okay, thank you.

A The next one is the Howard 1-11, a Mallon well in Section 1, southwest quarter.

MR. STAMETS: Thank you.

A And then the other well is in the southwest of Section 4, Township 24 North, 2 West, the Mobil Unit B 38 Well.

MR. STAMETS: Southwest of what, please?

A Section 4, Township 24 North, 2 West.

MR. STAMETS: Thank you.

Q And just because I'm nosy, sir, what fourth well do you understand there is a core but you have not seen data?

A I believe there's an Amoco well up there in that northeast Ojito Pool for which they've cored the Niobrara producing interval.

Q And with regard to the three cores that you have information on, did you actually examine those cores or have you examined a core analysis performed by someone else?

A I've looked at the core analyses prepared by an industry -- a third party contractor in the industry, CORE Lab. I have not made a visual examination and a search of the core myself.

Q You said there in your testimony, sir, that log porosity and core porosity didn't match. I'm wondering what did you do to arrive at that conclusion?

A Basically, as part of our first study committee meeting we had a Mobil representative that shared his log information with us. We were able to share at the time all the information, all the production data from all of our 23 wells, and we appreciate the fact that Mobil was able to share their log data with us.

I took that litho-density log that was run on the Mobil B-38 Well and as was the practice when I used to analyze quite a bit of core data for a major company, I tried to calibrate the log indicated density porosities with core analyzed porosities generated by CORE Lab, and in doing so, in areas where the hole rugosity is at least -- excuse me, where there is no hole rugosity, I came up with an error (sic) curve between the density log porosity and the measured core porosity.

I can, you know, I have prepared, you know, some work on that and we could -- we could certainly go over it at some point, but I haven't made an exhibit for that.

Q Well, sir, my problem is this is probably the only discussion I'm going to have with you on the record, so if you have some information that you could share with us, I'd appreciate you sharing it with us, please.

A Just ask the questions.

Q Okay. You indicated that you had done a curve of the correlation as I understand it, between those two sets of data and you indicated to me, I believe, sir, that you had some work which we could discuss at a future time.

Could you describe for me exactly what you have done and exactly what you have available and then I will ask you the following questions?

A Basically, again, what I've done is I've annotated on the density log for the Mobil B-38 Well the analyzed core porosities for all of the points which were analyzed in the 183-foot interval that they have analyzed with CORE Lab. There's a net 81 feet that was analyzed in that core analysis, plotting each one of those core porosity points on this log, I then compared the measured core porosity to the indicated measured density porosity on the log. In all cases there is a difference between the indicated log porosity and core porosity and in some cases even in areas of the hole where there is no rugosity problem, the error can be as great as in log porosity units 24 percent.

And I did that for the entire interval that was analyzed.

Q Do you have that annotated log available, sir?

A Yes, I'm referring to it.

Q May we see it, please?

MR. PEARCE: Mr. Chairman, at this point I would like to ask that I be able to take this document from the witness, provide it to one of our experts, proceed with some other questioning that I have while they work it over. That may speed the process along, because otherwise I'm going to have to ask you for a recess while some experts look at this log.

MR. STAMETS: Is there any objection?

MR. KELLAHIN: We don't have any objection.

MR. STAMETS: Okay.

Q Thank you, Mr. Ellis.

Now, tangential to that I thought I understood during your direct testimony you indicated that borehole conditions had hampered log quality. Could you describe if that's -- first of all, is that correct? Do you recall that?

A With respect to the B-38 log, yes, there is a zone of rugosity in what I would call the lower part of the A zone of the Niobrara producing interval that effectively renders the density log indicated porosity incorrect in a normal situation.

Q Thank you. During your direct testimony, sir, I understood you to indicate that based on your core data examination you concluded matrix contribution to be minimal. During previous cross examination did I understand you to say that you -- well, could you describe for me how you define minimal in that context?

A The majority of my background in analyzing reservoir properties from a geologic standpoint is in a matrix reservoir and specifically in the sandstone reservoir that I have had some experience with, we have done quite a bit of lab related research bearing on the issue of what is a producable matrix, and in doing that our conclusion, at least with respect to that particular sandstone reservoir, was that we had no effective contribution from that reservoir, although porosities of about 4 percent, and permeabilities less than 2 millidarcies.

Now, it's certainly conceivable that these minimum limits could vary for different reservoirs, and I am of the opinion, at least based on, as I said, the limited core data we've seen here and also some of the core data I've seen from the Niobrara producing interval on the Rangely Anticline in Colorado, that we're probably talking about matrix producable or effective matrix reservoir being in excess of 0.1 millidarcy and I haven't given consideration to what a minimum porosity would be that would allow this thing to be a producable reservoir, but certainly the permeability, at least in my mind, would almost have to be greater than 0.1 millidarcy to contribute.

Q Mr. Ellis, I understood you to say that you had reached this conclusion based upon some study you had conducted in another reservoir, is that correct?

A That's correct.

Q Could you specify what reservoir that was, please, sir?

A The Nugget Sandstone Reservoir and the Painter Reservoir Field in the thrust belt in southwestern Wyoming is the sandstone reservoir I refer to.

The other reservoir that I alluded to was the Niobrara producing interval on the Rangely Anticline; essentially the same section that produces in the Gavilan Pool.

Q Are those fractured reservoirs?

A There is fracture enhancement in the Nugget Reservoir, but obviously, with the quality of matrix you have in that reservoir the contribution from the matrix overwhelms the fracture contribution. It's not a pervasive fracture system such as we have here in Gavilan Pool.

In the Niobrara reservoir at Rangely, obviously it's a thinly laminated shale, much as we have in this particular instance in the Gavilan Pool. It's our conclusion, anyway, based on core data we've had from numerous wells in the field that it is strictly a fracture-type animal; that all permeability related to oil production in the Niobrara on the Rangely Anticline is fracture related.

Q And you performed the studies during a previous employment, is that correct?

A Yeah, that's correct.

Q Is that research reported in a written paper?

A Intercompany reports, yes.

Q I think you touched upon it just now but I'd like for you to explain to me a little more fully if you could, I understood you during your direct to say that you're using a 0.1 millidarcy cutoff for the matrix. Could you go back and review for me, please, what -- what you said on the record and then try to explain to me what it means, because you've got at least twice the education as I have.

A Well, admittedly the determination of what ends up being producable from a matrix standpoint is largely hypothetical, at least from the geologic standpoint. The conclusions that we have come to looking at other, one other Niobrara instance, was that in order for that thinly laminated sandstone laminae that is ubiquitous in the Niobrara throughout the Rocky Mountains, not necessarily in the same proportions or the same percentages, but does exist, in order for that to contribute from a production standpoint, and from a storage standpoint, you would have to have permeabilities in excess of 0.1 millidarcy.

Now, I'm sure there's quite a bit of engineering theory and empirical data that could be generated to verify that figure but at least from a geologic standpoint we had to place a limit on it and that Niobrara reservoir appears to need at least 0.1 millidarcy to --

Q And did you -- I'm sorry.

A -- contribute oil.

Q In arriving at -- at that cutoff number, did you assume some permeability that needed to be --

A That is a permeability, 0.1 millidarcy.

Q Let's switch to a different part of your direct exam at this time, Mr. Ellis, please.

I understood you to indicate that you believe that there were areas in the Gavilan-Mancos Pool in which gas always existed, is that correct?

A It's certainly a possibility. I don't think anybody knows for sure.

Q As an expert in the field of geology, is that your opinion?

A As a geologist who's listened to quite a few engineers speak of the problem and -- yeah, that's my expert opinion.

Q Would -- would that gas be in the form of an initial gas cap?

A That's -- that's certainly possible, at least some of the preliminary data we looked at indicated that we had much higher gas/oil ratios near the crest of the dome; however, I don't feel that there is necessarily a gas cap per se that would have formed in this reservoir. You know, we could just as easily have had free gas zones that didn't necessarily coalesce to form a gas cap.

Q If you assume an initial gas cap or free gas zone, would that indicate to you that there were portions of the reservoir which were below bubble point?

A As a geologist listening to engineers speak about such things, yes, I think that would certainly indicate that.

MR. STAMETS: Okay, let me follow up on that, if I might, Mr. Pearce.

Are we talking about at initial conditions in the reservoir?

MR. PEARCE: That was -- that was my intention in the question. I understood that we were talking about the initial free gas or gas caps existing.

A Well, that's probabaly a question best left to the engineers to address on their testimony or cross examination, if you wish, but maybe I ought to defer to them.

Q You indicated, I believe, that you expected the bubble point to be about 1450 pounds at this time, is that --

A I think that was an average poolwide GOR that I was speaking of.

Q And do you know what the average GOR on Mr. McHugh's wells is at this time?

A I could probably come up with a breakdown on a well by well basis. I, because of my belief that we're dealing with a pervasive, totally continuous, uniform reservoir I've never really broken out Mr. McHugh's wells per se, and as indicated on those second two plots of that GOR section, again just an exposition of the production data, the upward pressure applied to the poolwide average GCR is not just a result of the increasing GOR's in the McHugh portion of the reservoir, but also the north and east portions of the reservoir, as I've indicated on the second, blue gas/oil ratio plot.

Q I understood you, Mr. Ellis, to indicate in your direct testimony that you believed that the production mechanism in this reservoir was solution gas drive, is that correct, sir?

A Yes.

Q If the production mechanism in this reservoir is solution gas drive, would you please explain to me, sir, why you believe increasing GOR's represent an emergency situation?

That's the best slow pitch you will ever have, Mr. Ellis.

MR. KELLAHIN: May I have an opportunity to inject an objection?

I believe that is, in fact, beyond the scope of the expertise of this witness and is truly an engineering question at this point and we have those available and will present them and Mr. Pearce may ask questions.

MR. PEARCE: I appreciate that and I will appreciate the opportunity to ask those sort of questions of the engineers, but I understood this witness to be indicating to me that he believed there was a problem; that he believed the evidence of that problem or that emergency situation was increase in GOR's.

A That's part of the problem.

MR. PEARCE: And I would like to know upon what basis he reached that conclusion.

MR. STAMETS: We'll allow the witness to answer the question if he feels qualified to answer.

MR. PEARCE: Even if he doesn't he can say so.

A That's certainly true and I think I would defer to the engineering experts on that matter, although I have an opinion, I feel that it's probably best explained in the portion of our direct testimony that will deal with all those questions.

Q All right, sir, and I understood you during the previous part of your response to indicate, I think in response to something that I said, that the increase in GOR's in the Gavilan-Mancos Pool were part of the problem.

A That's correct.

Q Could you please specify for me what you believe the other part of the problem to be?

A Well, again, I, basically in preparation for my direct testimony, have dealt with production data and geologic data and both of these sets of data are really data that I consider within the realm of expertise of a geologist to have dealt with. This is merely an exposition of the data. The actual underlying engineering reasoning behind the nature of the problem is something that's best left to the experts in that field, so I'm going to defer that question to our engineering portion of the testimony.

MR. PEARCE: May I have just a moment, please, Mr. Chairman?

All right. I apologize for the delay, Mr. Chairman, just a couple more.

Q One question which has been brought up, Mr. Ellis, is have you made that annotated log available to the other members in your technical committee?

A No, I have not. It was prepared yesterday.

Q Now we move into an area, sir, in which I am going to try to attempt to read you a couple of questions.

Mr. Ellis, did you use density neutron cross plot porosity or density porosity in your annotation and comparison of the core data and log data?

A I've used just the density log porosity. No cross plot was made.

Q Can you tell, Mr. Ellis, whether or not most of the areas on this log that show a large core versus log porosity divergence are in areas of bad hole condition or areas of large shale content?

A Yes, I can.

Q And are they?

A No, they're not.

Q Do any of those instances occur in areas in which there is large shale content?

A Particularly -- yes, in answer to your question, yes. The area of the lower part of what I would call the Niobrara A producing interval has been analyzed by

CORE Lab to indicate shales, or at least they didn't perform an analysis on the rock because they felt it was shale.

Q And in doing a comparison in those areas, did you attempt to make any correction for the presence of that shale?

A Without an analysis on the CORE Lab plot, you know, such a comparison was meaningless because they didn't do an analysis on the shale in that interval.

I only compared the log response in areas where they had determined that there was sand sufficient to justify a plug analysis.

Q Did you compare sonic log porosity with core data?

A No, I did not.

MR. PEARCE: I don't think I have anything further of this witness, Mr. Chairman.

MR. STAMETS: Are there other questions of the witness?

Anything on redirect, Mr. Kellahin?

MR. KELLAHIN: All these lawyers, Mr. Chairman, and no one wants to take him on?

MR. STAMETS: Oh, yes, we want to ask a question about rugosity, if you would explain that for the record, please.

A It's the -- I was referring, and again I have not shown you this particular log, I was referring to a portion of the hole that has caliper indications greatly in excess of the actual gauge of the hole during drilling and in that -- in that particular part of the hole we have a much larger hole diameter than you would normally expect just from bit penetration, and that is what I would term a rugose hole, a rugose portion of the hole.

MR. STAMETS: Okay.

MR. PEARCE: May I just jump back into this, Mr. Chairman?

MR. STAMETS: Why, certainly, Mr. Pearce.

MR. PEARCE: Thank you.

MR. STAMETS: We're always happy to hear from you.

Q Mr. Ellis, I've been requested to have you express an opinion on how isolated gas or in the form of gas caps or free gas can exist in a continuous reservoir.

A I, again, I believe that's properly within the bailiwick of engineering testimony, but it's certainly possible that in spite of the low indicated dips on the structure map here that we could have some form of segregation in this reservoir, gravity segregation allowing the less dense gas to migrate into a high structural position on the -- on the nose.

Q How could that exist if we have the kind of pervasive fracture system that you were discussing, or -- well, I don't understand.

A Gravity segregation within the fracture system?

Q Yeah, how would you not get free gas over the entire upper extent of the reservoir through the pervasive fracture system?

A Basically, all I was indicating, that there may be zones -- or I will indicate now that there may be zones within that reservoir that do not have the same transmissibility characteristics as you may have in other parts of the reservoir, and that differential may in fact create zones where, you know, you might have preferentially accumulated free gas.

Q And that is some modification to your description. I believe the phrases you have used are pervasive and ubiquitous and you may have used the phrase homogeneous in terms of the fracturing throughout this reservoir. You're now indicating that there are areas which are more or less fractured than other areas.

A Oh, that's certainly true. We can see that in all the production data. We can see that geologically, as you've indicated.

Q Thank you, sir.

MR. STAMETS: Any other questions of this witness?

Mr. Kellahin?

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q So that I understand the question from Mr. Pearce, does pervasive in your definition equate with uniformity?

A It could -- it could certainly mean that in a -- in a general sense, at least as far as I'm able to analyze the reservoir from a geologic standpoint, and again, a lot of that analysis, you know, needs to be inferential and conjectural because of the lack of integrity in -- in, say, the normal formation evaluation methods, at least, you know, it would appear to me that the reservoir is -- is in a general sense highly conductive and uniform stratigraphically and structurally throughout.

Now there is that uniformity. There may be zones within areas within the reservoir, as we've seen since day one in the production data where the fracturing may not be quite as extensive.

Or we may have just missed these zones of higher capacity in the drilling of these wells; maybe the boreholes just didnt penetrate or reach and communicate with these higher capacity zones of fracturing.

Q Let me ask you a question about the analysis of the gas/oil ratios that you plotted on one of your exhibits.

I believe you've identified for us an area in which we have higher capacity wells which have demonstrated higher gas/oil ratios in excess of 2000-to-1. We've got an area that's like that, do we not?

A We do.

Q Do we also have an area of low capacity wells which also have a high gas/oil ratio in excess of 2000-to-1?

A Yes, on a reported production basis we do have an area of that type.

Q So we don't see the gas/oil ratio problem confined to the high capacity wells in a particular portion of the reservoir?

A No, we do not.

Q Is there any geologic correlation to the gas/oil ratios whereby you can conclude geologically that the wells with the higher gas/oil ratio are confined to higher portions of the structure?

A I don't believe that's true at all. As I indicated earlier, it appears that the -- the development of this higher GOR production is not specifically tied to the structural position in the reservoir.

Q If you'll take your structure map, which was the first display after Tab C, would you locate for us the Mobil well, I think it was the B-38, on which you examined a core analysis? Let's find out where that is.

A Okay, that particular well was in the southwest quarter of Section 4 in 24 North, 2 West.

Q Down in the southwestern portion of the pool?

A That's correct.

Q Now, would you locate for us the other wells within this display from which there is core information available? Where do we find those wells?

A The other well that I'm aware of within the area represented by this display is in the southwest quarter of Section 1, the Mallon Howard 1-11.

The other core point that I referred to is just off the map to the east in Section 11 of 25 North, 1 West.

Q If I can assume for the purposes of my question, Mr. Ellis, that the Mobil geologist is going to make a different conclusion from an analysis of the Mobil core. I think we can assume that for a moment. All right, if we make that assumption, and he comes to a different conclusion from that analysis, would that persuade you as a geologist that we ought to change what we characterize as a problem to being no problem at all?

A No, that wouldn't convince me at all.

Q What would it take you in terms of additional information in order to satisfy yourself that in fact the matrix portion of this interval is going to give you significant contribution of oil production for the pool?

A Before I'd want to make a summary statement concerning the matrix contribution in the reservoir, although I have very firm opinions at least at this point in time, I'd like to see a statistically more valid sampling of the reservoir made both areally in the reservoir, and as I indicated earlier along those lines, we are participating in a core to be taken by Mallon in the drilling of his well in Section 3 of our township, which I hope will buttress the conclusion that I have, at least at this point in time, that the matrix contribution is minimal.

Q If the matrix contribution is in fact minimal, what is your concern, then, about the way the pool is currently being produced? What impact does that have?

A The field as it's currently being produced from all of the production data I've seen and structural and stratigraphic studies I've made, and all of the pressure data that we've been able to analyze, the concern I have is basically the rapid depletion of the reservoir drive mechanism, being the dissipation of the gas energy in this reservoir, and that problem needs to be addressed.

Q If the Commission approves Mr. McHugh's application and reduces the gas/oil ratio the production rates for a 90-day period, would that be a sufficient period of time to allow cores to be taken in order to provide additional testimony on this issue?

A We certainly hope that that should be much more than a sufficient time to get the core out of the Mallon well and we are prepared in the drilling of our additional pool wells, if in fact we go ahead with that, to take an additional core that should be able to address that problem in a final way.

MR. KELLAHIN: Thank you, Mr. Chairman.

RECROSS EXAMINATION

BY MR. PEARCE:

Q Just a couple more, Mr. Ellis, if I may.

I want to make sure I understand -- understood Mr. Kellahin's question and your answer when he asked you to speculate based upon certain assumptions with regard to what Mobil's witness would say and whether or not that would affect your view of the problem. That was the same problem that you deferred to the reservoir engineer previously, wasn't it?

A No, it wasn't; not as I understood the question from Mr. Kellahin.

Q Looking, sir, at the January 1st, 1986, and July 1st, 1986, plots of wells with 2000-to-1 or greater GOR's, I notice that a cluster of three of those wells, the Boyt Lola 1, 2, and the Twilight 1, appear on both of those plots, is that correct, sir?

A Correct.

Q Do you know when those were drilled, sir?

A Yes. They were, I believe, completed, and I may have to defer to our engineer for this, last year or the year before. I can't give you an exact date.

Q Do you know what the initial GOR's on those wells were?

A From memory, and again I don't have the information in front of me, those wells had high GOR's, high initial production indicated GOR's.

Q Is it possible that that indicates that those wells penetrated the zone of free gas which we discussed earlier?

MR. KELLAHIN: I'm going to object to the question. It calls for a possibility; anything is possible. We talk to our witnesses in terms of reasonable geologic probabilities. The question is inappropriate. I object to it.

MR. STAMETS: Will you rephrase the question in terms of reasonable geologic probability?

Q Is there a reasonable geologic probability that those wells encountered free gas or a gas cap, which we discussed earlier in the afternoon?

A That's certainly a possibility. I can update you as to those dates within which those wells were completed, if you wish.

Q Please.

A The Boyt Lola No. 1, 12-2-84.

The Boyt Lola No. 2, 1-10-85.

Twilight Zone No. 1, 1-21-85.

MR. STAMETS: What was the date for the Number 2 well, please?

A 1-10-85.

MR. STAMETS: Thank you.

Q And going back once again to the logs and cores on which you did the annotation of the log that we discussed earlier, did you attempt to do a shale correction on the log porosity itself?

A On the density log porosity itself?

Q Yes, sir. Understanding that --

A No, it was not.

Q In the course of your study of this reservoir, sir, have you attempted to calculate the possible storage capacity of the pervasive fracture system which you have discussed?

A No, I have not.

MR. PEARCE: That's all, Mr. Chairman.

MR STAMETS: Any other questions of the witness?

He may be excused.

I presume you do not have a short witness at this point?

MR. KELLAHIN: Mr. Chairman, that was my brief witness. That was as short as they get.

MR. STAMETS: Okay. We will recess the hearing until 8:15 tomorrow morning at the same location.

(Thereupon the hearing was in recess.)

(Thereupon at the hour of 8:15 o'clock a.m. on the 8th day of August, 1986, in Morgan Hall, State Land Office Bldg., Santa Fe, New Mexico, the hearing was again called to order, at which time the following proceedings were had, to-wit:)

MR. STAMETS: The hearing will please come to order.

Mr. Kellahin, you may call your next witness.

MR. KELLAHIN: Mr. Chairman, we'll call our next witness at this time, Mr. John Roe, a petroleum engineer with Dugan Production Company.

So that you can keep track of where we are, Mr. Roe will identify the balance of the exhibits in the package identified as McHugh Exhibit Three. There is a remaining section in that green booklet. Mr. Roe will discuss those two displays.

In addition, I'm going to hand you Exhibits Four -- I'm sorry, they're numbered Dugan Production Exhibits One and Two, so that now we will have McHugh exhibits, then have Dugan exhibits.

Exhibit Number one for Dugan is

Mr. Roe's work product showing the effect on each of the wells in the Gavilan-Mancos between current production and Mr. McHugh's proposed limitations.

The next exhibit is Exhibit Number Two, which will be a blue booklet of Mr. Roe's engineering displays.

JOHN ROE,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Roe, would you please state your name?

A Okay, I am John Roe.

Q Mr. Roe, by whom are you employed and in what capacity?

A I'm employed by Dugan Production Corporation in Farmington, New Mexico, and I'm their Engineering Manager.

Q Mr. Roe, for the record would you summarize your educational background and your work experience as a petroleum engineer?

A I attended New Mexico Tech and graduated from New Mexico Tech in 1970 with a Bachelor of Science in petroleum engineering.

Prior to graduation I worked two summers with a major oil company.

Upon graduation in 1970 I went to work for Union Oil of California and worked with Union through 1982, through August of 1982.

During my employment with Union Oil I worked at various locations throughout the United States, predominately the Rocky Mountain area. The bulk of my experience with Union was in the Reservoir Department; however, while I worked for Union I also had training in the drilling and production and actually functioned as a drilling engineer and production engineer.

At the time I left Union I was the District Engineer in their Oklahoma City District Office.

I went to work for Dugan Production in August of 1982 and have worked for Dugan production since that time, basically providing all of the engineering requirements related to the operations of Dugan Production in the production of our wells and drilling and production of our wells for Dugan Production and on a consulting basis.

Q What involvement have you had as a petroleum engineer on behalf of Dugan Production Company with the wells drilled and operated for Jerome P. McHugh?

A Early in the development of the field Mr. McHugh didn't drill the discovery well but he was the operator of the first several wells in this pool, and Dugan Production served as agent for Mr. McHugh during the permitting, drilling, and completion of the majority of the 23 wells that Mr. McHugh now operates in the Gavilan-Mancos Pool area.

Q Would you describe for us, Mr. Roe, what has been your professional experience with the Gavilan-Mancos Pool?

A As a petroleum engineer, I was involved, as I indicated, in the majority of Mr. McHugh's wells from the permitting phase through the completion and production phase.

As a working interest owner in the general area, Dugan Production has an interest in several of the wells operated by other operators, so I've had an opportunity to follow the drilling and completion of those wells. I was involved in the original spacing hearing that resulted in the pool being temporarily developed on 320 acres. I've been involved in the hearing that resulted in the first northern extension of the pool, and I've been involved in the engineering and geologic evaluation committees that have had four meetings to date studying the area and specifically related to the problem that we're here today.

MR. KELLAHIN: Mr. Chairman, at this time I'd tender Mr. Roe as an expert petroleum engineer.

MR. STAMETS: Without objection the witness is considered qualified.

Q Mr. Roe, let me ask you to direct your attention first of all to Mr. McHugh's package of exhibits marked as Exhibit Number Three for the hearing purposes and looking at those exhibits, if you'll turn to the index tab marked D, would you identify for us the first display after the tab?

A Yes. This is a plot of reservoir pressure corrected to a constant datum of plus 370 feet above ground -- above sea level, and also reflected on this plot is the pool average gas/oil ratio. Both of the pressure and the GOR are plotted against cumulative production from the pool.

Q Are you familiar with the information that went into the preparation of this exhibit and can you attest to its accuracy?

A Yes, I was involved with the preparation of this exhibit and can attest to its accuracy.

Q All right. Now that you've identified the exhibit, would you explain what significance it has to you as a petroleum engineer?

A Okay. The primary importance of this exhibit is that it relates what we believe to be the bottom hole pressure performance in the area that -- predominantly in the Gavilan-Mancos Pool area, but also in the areas immediately adjacent to the Gavilan-Mancos Pool.

It presents pressure data from 18 wells that are -- or 19 wells and from five different operators.

It presents pressure data that indicates the pool is in communication from north to south and from east to west and it indicates to me that its production is increasing and in the latter months the monthly production is increasing. The rate of pressure decline is accelerating. This is to be expected in the production of any reservoir. The fact of pressure declining is not a major concern of mine. It's the fact that we're seeing an acceleration in the rate of pressure decline accompanied by, beginning in the early part of 1986, acceleration in the pool gas/oil ratio.

Q Do you have an opinion, Mr. Roe, as to whether or not the 19 wells depicted on this display are a representative group of wells that are characteristic of all the wells in the pool?

A Yes. In fact, we excluded some of the pressure data that we have available basically because it was redundant. It just added confusion to the plot.

Q Could you identify some of the wells that you've excluded from the display in order to come up with a typical or characteristic curve or plot for the wells?

A I -- there are -- we have pressure data as of right now -- there are 43 wells that have been completed in the pool and are ready to produce. Of those 43 wells we have pressure data from 31 wells. On this plot I've presented only 19. I -- I do not have immediately available wells that we've excluded but I could prepare a list.

Q Yesterday Mr. Lopez asked Mr. Ellis some questions about certain of the wells that had been plotted with gas/oil ratios. I believe one was the Gavilan Howard No. 1 Well. Have you utilized that well in preparing this gas/oil ratio plot?

A No, sir, we did not.

Q And why not?

A Primarily as a working interest owner in that well, from the date of first completion I've been concerned that there was communication between the Dakota and the Mancos. I myself have been convinced that it exists and I think recently the operator did repair that communication, which, the GOR from this particular well from the Mancos was high from the date of first production and I was not certain whether the high GOR was -- was the result of the communicaor the fact that the Mancos actually had a high GOR from date of the first production, but because of the doubt we had, we excluded that data.

Q And what about the Gavilan No. 1 Well, that was also discussed yesterday, was that included or was that excluded from this display?

A We did not include the Gavilan No. 1 in this particular presentation, mainly because we do not fully understand the GOR performance of the Gavilan No. 1. It is clear in my mind that the high GOR, it has produced with a high GOR from the first completion. The GOR initially declined and then has later resumed an incline.

We excluded that because the Gavilan 1 is anomalous to the rest of the wells.

Q Can you identify for us, Mr. Roe, what the actual and what the adjusted gas/oil ratios are for the pool that you've utilized?

A Yes. During -- during June the pool average GOR, if you utilized the data reported by the operators on the C-115's, during June the actual production from the pool was 5436 barrels of oil per day, 8624 MCF of gas per day, for a poolwide average of 1586.

During June the Gavilan Howard No. 1 averaged 22 barrels of oil per day and 140 MCF of gas per day with an average GOR of 1148, which I might add is up from May's GOR, and may was the first month that it produced with the communication corrected.

The Gavilan No. 1 during the month of June averaged 31 barrels of oil per day with 530 MCF per day at an average GOR of 14,600. Reducing the pool average production of 5436 barrels of oil per day for these two wells, the average pool production would be 5283 barrels of oil per day and reducing the gas production for these two wells, the average production would be 7954 MCF per day, for an overall average, excluding those two wells, of 1506 standard cubic feet per barrel, and that is the number that's plotted on our graph.

Q Let's look at the plot and have you show us what the gas/oil ratio was for January 1st of '86 and what the gas/oil ratio currently is so that we can see it on the graph itself.

A Okay. During January 1st of 1986 we -- and just as a matter of information, we have identified January 1st of '85 and January 1st of '86 for time reference on this graph.

The graph has cumulative production along the bottom and each data point is a month.

Q What is the significance of the area shaded in pink?

A The significance of the area shaded in pink would be our feeling, it's our belief that this amount of gas, or the gas under this portion of the curve, is -- is -- I'm calling free gas. Now whether it was free gas in the reservoir initially or it is gas that has evolved from solution as reservoir pressure declines, we haven't made an effort to pinpoint that yet, but it is gas that would be -- result in a GOR above what we believe the solution GOR to be. We've indicated the two pieces of information that we have confidence in from fluid data in the Loddy No. 1, which is a unit well, or a pool well. We have, based upon pvt data that Mr. McHugh acquired, a GOR, a solution GOR of 588 standared cubic feet per barrel.

We also have indicated the initial solution GOR in the Canada Ojitos Unit, based upon a sample analysis provided by Mr. Greer, and that solution GOR was 488 standard cubic feet per barrel.

This would be -- show the range of solution GOR's depicted by the dark gray area.

Now, one thing that I didn't get my -- anser your question fully, Mr. Kellahin, the January GOR, that level was in the range of 1395 standard cubic feet per barrel and it's been fairly constant in that level since, oh, mid-1985. Beginning in January we see the increase in GOR up to its current level of 1500.

Q Do you as a petroleum engineer attach any significance to the increasing gas/oil ratio from approximately January '86 to the current? In other words, is this a gas/oil ratio change that you would expect in this reservoir or in your opinion is this systematic (sic) of a potential problem in the way the reservoir is being produced?

A The fact that the gas/oil ratio is increasing is something that we would expect to occur as reservoir pressure declines, given the fact that the primary producing mechanism in this reservoir is solution gas drive.

Our primary concern is not the fact that the GOR is increasing, but it does suggest as the reservoir pressure is declining as we've depicted on this plot, that we are -- that we have approached the bubble point pressure and that we are now producing below the bubble point pressure.

Q Would you turn to the second page of the exhibits after Tab D and identify what that exhibit is?

A Yes. The second page is nothing more than a base map of the general area that we are involved with. We've outlined the pool boundary, the existing pool boundary of the Gavilan-Mancos Pool in the solid or the solid cross-hatched line, and we've also identified the extensions to that pool that are in -- currently being considered by the Commission based upon the wells that have been completed, and those are identified with the lighter dashed line.

Presented on this plat, the only purose of giving this plat is that we have presented the 19 wells and the location throughout the reservoir of these 19 wells that we have plotted pressure data from, and again, our primary emphasis is to show that we're trying to depict reservoir pressure representative north to south and east to west as much as possible.

Q Mr. Roe, I've had a gentleman count for me the number of wells on this display and he says that there are 9 as opposed to 19. Is there any significance to you in dislaying only the 9 wells as opposed to all the 19 wells in which you had the pressures and the gas/oil ratios plotted?

A Yes. The -- I intended to qualify the second pages that in a later exhibit that I will present, it does have --

Q The balance of the wells, then, are going to be on one of your other exhibits?

A Yeah, they'll be on an exhibit that I have prepared and for clarity purposes, like I say, we start out with 31 wells. We are trying to present a picture of the reservoir in as clear a manner as possible. The other data is more or less redundant but the balance of the 19 wells will be on an exhibit that we'll get to in just a minute.

Q All right, sir, at this time let's turn to what is marked as Dugan Production Corporation Exhibit Number One, which is on legal paper and consists of four pages.

Does this document represent your work product, Mr. Roe?

A Yes, it does.

Q Would you identify that exhibit for us?

A Okay. On Dugan Production Exhibit One we have a tremendous amount of information that is tabulated for the 59 wells in the pool that have been drilled and completed and are either on production or ready to produce.

In addition we have information on the one well in the pool that is drilling.

We have presented information for 13 additional wells that have had locations cleared, staked, and are near the stage of being ready to start drilling operations, bringing --

Q What is the source of the information utilized, Mr. Roe?

A Predominately the records at the Oil Conservation Commission, both from the well files or production information is our -- our source.

Q How many operators have you tabulated on the exhibit?

A On the exhibit we have a total of ten different operators. I've -- in the study area that is the Gavilan-Mancos or immediately adjacent, we also have 5 wells that are tabulated that are immediately adjacent to our area but within the West Puerto Chiquito Mancos Pool.

So a total of 11 operators counting BMG.

Q All right, sir, if you'll take any one of the wells and operators you would like and start from left to right and have you explain to us how to understand the exhibit.

A Okay. For -- just for simplicity only, on page one under Mallon Oil, I'll choose the Fisher Federal 2-1. Again there's nothing to be pointed out on this well other than -- than it is a well that will provide an explanation on how this table reads.

The Fisher Federal 2-1 is located in Unit A of Section 2, Township 25 North, Range 2 West.

It was completed on June 16th of 1985, and as of July 1st, 1986, it has a cumulative production of 99,375 barrels of oil, 54,196 MCF of gas, and I've taken those two numbers and converted it to what I consider a reservoir voidage, an effective voidage from the reservoir, of 137,138 reservoir barrels of volume.

During June of 1986 this well did average

455 barrels of oil per day; however, -- well, 455 barrels of oil per day, 576 MCF per day, and did produce with a GOR averaging 1265 standard cubic feet per barrel.

The numbers presented under these three columns generally are the actual production that did occur during June. The only times that that is not the case is if June's production was anomalous, either low or high for some reason, or the well is not producing during the month of June but is completed and ready to produce.

In those instances where June's production is not actual, I've indicated those with a small letter "e" indicating that I've estimated it based upon the best information I have available, which is either production in the previous months or my estimate of the potential of that well, if it's a particular -- is one of the 16 wells that are completed but not on production.

I've taken the June production or potential production and converted it to a voidage volume in reservoir barrels per day. This particular well voided 1177 barrels of volume per day during the month of June.

The last three columns on this tabulation are an effort to present what I think the impact on each well will be if the Commission approved Mr. McHugh's application to put an allowable restriction of 200 barrels of oil per day and a GOR restriction of 1000 standard cubic feet per barrel.

This particular well would be reduced from a daily rate of 455 barrels of oil per day to 158 barrels of oil per day. The little subscript "r" indicates that it -- this particular well, because its GOR exceeds 1000, will be further restricted by the GOR to 158 rather than the 200 barrels of oil per day that we're asking for.

The 200 MCF would be the maximum permissible gas production under our requested allowable reduction.

The 158 barrels of oil per day and 200 MCF per day converts to a reservoir voidage of 409 barrels of volume per day. This basic information is presented on every well in the pool.

Q Let's turn to page two of the exhibit and look at the subtotals under Mr. McHugh's production, and if you'll look at the reservoir barrels a day under the June '86 production number, you get 10,492?

A Yes, sir.

Q And if the Commission adopts the proposed reduction, what will be the change in Mr. McHugh's reservoir barrels a day?

A His voidage would be reduced from the 10,492 to 5237 reservoir barrels of volume per day.

Q And we can find that for each of the

operators listed on the display by making the same comparison to see what the change is for each operator?

A That is correct.

Q Let's turn to the last page and look at page four about midway into the exhibit, it says "Total Gavilan Pool area". CAn you identify for us what the change will be on a barrels oil per day basis for the pool?

A Yes. During the month of June the pool did or had potential to produce 8188 barrels of oil per day. Under our proposal the pool potential production from wells, from the 59 wells that are completed and ready to produce, would be reduced to 4936 barrels of oil per day.

Q And looking at the same line, if you move over to the voidage number for the reservoir barrels a day in June of '86, will you make a comparison in that number to the voidage number if the proposed change is adopted?

A Yes. During the month of June with the production level that did exist or had the potential to exist, we had reservoir voidage of 25,993 barrels of volume per day. That, under our proposal, would be reduced to 14,143 reservoir barrels of volume per day.

Q Below that number you listed BMG Drilling Corporation and their wells in the study area.

A Yes, I have.

Q And then the total study area would

include, then, the Benson-Montin-Greer wells?

A Yes.

Q Mr. Roe, in your opinion is there a reasonable basis for the proposed reduction by Mr. McHugh in the gas/oil ratios and the producing rates?

A Yes, we are making an effort to reduce the reservoir voidage which is currently at unacceptable levels or at the levels that it is currently at it is providing a rate of pressure drop that we feel is fixing the number of days that this reservoir will continue to produce.

We have made an effort to buy some time to evaluate several possibilities of -- of improving the recovery from the reservoir and improving the overall economics from continued operations in the reservoir.

Our proposal, as evidenced by the bottom line of the total study area, would basically reduce the voidage in half from its current level, resulting in some additional time that we won't have if -- if we aren't granted a reduction in allowable.

Q Do you have an opinion as to whether or not the impact of the proposed McHugh reduction has been allocated among the operators in an equitable way?

A Yes, I do.

Q For example, let's look at the McHugh interest. What percentage of the June '86 production does Mr.

McHugh have in relation to the pool production? Have you made such a calculation?

A Yes, I have.

Q And what is that percentage?

A During June, based upon the total study area production, which does include the five Canada Ojitos wells, Mr. McHugh's oil production accounted for 39.7 percent of that total.

Q And under the proposed change what percentage of the pool production does Mr. McHugh have if the change is adopted?

A He will realize a slight reduction to 37.5 percent of the total pool production.

Q Mr. Roe, let's turn to your Exhibit Number Two, which is the package of information in the green folder -- sorry, wrong color, blue folder.

So that I don't have to ask you the same question on each display, Mr. Roe, is the information depicted in your Dugan Production Corporation Exhibit Number Two prepared by you or compiled under your direction and supervision or in the absence of that, have you examined this information and satisfied yourself that it is true and accurate to the best of your informatio and belief?

A Yes.

Q All right, sir, let's turn to the first display in the package of exhibits. It's on a bright yellow piece of paper. Would you identify that for us?

A Okay, this started out to be -- there's two pieces of information depicted on this, this particular graph.

We've taken a graph that Mr. Greer has prepared for his Canada Ojitos Unit, which is immediately adjacent to our pool to the east. Utilizing fluid data that he has accumulated during the past 25 years of production at the Canada Ojitos Unit he has confidence that if solution gas drive were to be the sole production mechanism, this graph presents the pressure performance and GOR performance that we could expect given the fluid properties, the relative permeability properties that do exist in the Canada Ojitos Unit.

We have superimposed upon this graph the actual pressure performance and the actual gas/oil ratio performance that has occurred to date with the production of approximately 2.3-million barrels of oil from the Gavilan-Mancos Pool and immediately adjacent study area.

Q What conclusions do you draw or opinions do you reach based upon an analysis of the information on this plat?

A Based upon the plat it appears to us that there is enough similarity between reservoir pressure performance and the gas/oil ratio performance that we -- we feel comfortable that it gives us some predictive guidelines as to what the future holds in the Gavilan-Mancos Pool area.

Q If production continues at its current rates and as you may anticipate by the addition of production from wells already completed, can you make any predictions as to what is the likely force of these various curves?

A Yes. As indicated on this -- this curve, now, because I believe that we initially started production above the gas -- above the bubble point pressure, the gas/oil ratio curve for the Gavilan area, even though I've plotted it as it has occurred, the production that did occur above the bubble point probably should have been excluded from our cumulative production. This would result in you actually shifting our gas/oil ratio curve to the left because this curve becomes important only after you go below the bubble point.

So what that does to our gas/oil ratio is it puts it a little more on track with the predicted GOR performance curve and if that is correct, we should expect a pretty dramatic increase in gas/oil ratio in the very near future.

Q What's the explanation, then, for why the gas/oil ratio deviates from the predicted curve?

A The -- again, we -- we're not totally positive because we're right in the midst of trying to resolve some of these matters, but any production that occurred above the bubble point pressure, if such production did occur, and I believe it did, would -- should have been excluded from our cumulative production that we used in plotting the gas/oil ratio data against and had you excluded -- had we excluded that, it would have brought our GOR curve more in line with the predicted GOR curve.

Q Let's go to the next display. Would you identify that for us?

A This is the production -- this particular graph presents the reservoir pressure information and my estimate of reservoir voidage that has occurred between the time period August, 1984, through June of 1986, and on this graph is presented the balance of the pressure data from the 19 wells that were depicted on our original map, showing the area from which we've sampled reservoir pressures.

Q This is the exhibit that you referred to earlier when I asked you about the nine wells on the prior display.

A Yes, this is.

Q All right, sir. Would you explain this exhibit for us?

A Okay. On this particular exhibit there are 19 wells; 11 of them operated by Jerome P. McHugh; 3 by Meridian; 2 by Mallon Oil Company; 2 by Mesa Grande Resources; and 1 by BMG in the Canada Ojitos Unit.

As I've indicated, we've plotted what we believe the reservoir pressure performance to be depicted by these 19 wells. Along with that I've plotted what I think the voidage from the reservoir that was created by the barrels of oil each month. This would be the bottom line that we've identified as oil voidage. The area under the curve would be the actual volume that was voided.

For instance, during May the oil voidage was 57,000 -- approximately 57,000 reservoir barrels per month -- or per daya, and the -- the -- during the month of June this voidage is estimated to be 8500 reservoir barrels per day.

In the light shaded area is an area that would represent the amount of voidage in addition to the oil production that would occur. All of the gas that we produced was not in fact a free gas phase in the reservoirs but was evolved from oil in the reservoir because we're below the solution GOR, below the bubble point pressure, all gas comes out of solution resulting in an oil shrinkage. That would be the reservoir voidage that is depicted in the light blue and during the month of May that interval was -- the reservoir voidage total was 7000 barrels and if that was the reservoir voidage during June, the voidage from the reservoir was 9900 barrels of volume per day.

Now depicted as the upper curve and shaded darker blue would be the upper limit of what the voidage would have been if we consider that all gas produced above our solution GOR that we're using for the Loddy No. 1, which was 588 standard cubic feet per barrel, if we consider all gas above that level as free gas when it left the reservoir, that would be -- result in a higher voidage than had the gas actually come out of solution resulting in an oil shrinkage.

The levels of reservoir voidage if the gas was treated as a free phase in the reservoir rather than a dissolve phase, would have been during May 11,016 reservoir barrels per day and during June that voidage would have been 17,163 barrels per day.

The other item of interest, and it's indicated right above the maximum voidage figure for each month, would be the well count that represents the number of wells during any one month that did have production and for instance, during the month of May, 1986, there were 38 wells that did have a production reported, not necessarily for the whole month but the month they did have some production.

During the month of June there were 43 wells that had reported production, and again I will stress that of the 59 wells that are completed and ready to produce, there are 16 wells that are not depicted on this graph.

Q Let's take some examples on the display, Mr. Roe, of individual wells so we can see what's occurring. Let's start off with the Loddy No. 1, Mr. Roe, and give us a moment to make sure everyone's found that on the -- on the display. It's identified, I believe, in the right margin of the display towards the middle of it.

Have you found that, sir?

A Yes, I have.

Q Would you describe for us what's occurred with its production and let's pick out some dates.

A Okay, the first month that we have data plotted for the Loddy was during the latter part of February, 1986.

Q All right, let's start right there and describe for us what's occurred with that well.

A Okay. What we've done in the Loddy, and by "we" Mr. McHugh is the operator, is we've measured pressure in a well that is currently shut in and really short of the minor amount of production that occurred during the completion and clean-up phase of that well. This well has never produced. We've utilized it as a pressure observation well and we've presented the information on this graph to show that we feel it is displaying or we are measuring a reservoir pressure that is in line with what we feel to be predominant or existing throughout the pool area and in the absence of production of the Loddy 1 being utilized as a pressure observation well, that pressure has declined and I don't want to get exact numbers off of this graph because I have some very detailed information in a later exhibit that we'll go over, but we do want to point out that this well is presented on this graph, it's declining from a pressure of approximately 1625 psia and this is at a -- all of these pressures are at the same datum that we've selected for the reservoir. It's declined from a little over 1600 psia down to a pressure that we measured in the latter part of July of approximately 1570 psia.

Again, the numbers I've given you -- or 1470, I'm sorry -- the numbers I've given you are only approximate. We have some exact and very detailed informaton we'll go over just shortly.

Q The point is I want you to identify for me some key wells and tell me generally what is occurring and then we'll get into the specifics of the pressure information.

Let's, before we leave the Loddy well, though, tell me if there's anything on the display to show me what has occurred in that well even prior to its first production.

A Okay, one of the important and probably the primary reason that we're here today is that the initial pressure in the Loddy No. 1, as I indicated, was approximately 1630 psi. This is substantially below the pressure that was, say, in the reservoir the early part of August as measured in the Native Son No. 2 at a level of 1750 psia.

Q I believe that's August of '84, is it not?

A Yes, during August of '84. We -- we again have presented the Loddy on this graph. You can see that the pressure in this well initially in the completion of the well, in other words, this well did encounter a pressure that had been reduced from higher levels that we had measured earlier in the reservoir, and you can also see in the absence of production the pressure that was measured in the Loddy has also declined in this well.

This well is located in the northwestern part of the study area and as I've indicated, we have some very detailed information on this in a later exhibit.

Q Let's turn to the Hill Federal No. 2 Well, Mr. Roe, and have you go through the same question and answer with me with regards to what has happened with this well. You don't have to give me the exact pressures but just give me a general guideline on what's occurring.

A Okay. The Hill Federal No. 2 is basically the same thing. The initial pressure in this particular well was measured during the latter part of February. It was at a level that was again lower than we anticipated for virgin reservir pressure, indicating that there had been some pressure decline at this point in the reservoir and a very minor amount of production has occurred in the Hill Federal No. 2-Y simply because it is not connected for gas sales, so the operator is making an effort to conserve reservoir energy by not venting unnecessarily the gas.

In the absence of production, or a very minor amount of production, pressure in this area of the reservoir is indicated to be declining in recent months, mainly beginning in the early part of March, has exhibited a pretty dramatic increase in the rate in which pressure is declining.

Q Let's go to the Dr. Daddy-O, which is identified in the top of the exhibit towards the middle and describe for us on the exhibit what's occurring with that well.

A Okay, again, the Dr. Daddy-O, the first pressure that we have was reported during the early part of May in 1985. Again it, the initial pressure that we recorded in the Dr. Daddy-O was at a level that was lower than we had predicted for had the pressure been in fact virgin.

In the absence of a significant amount of production the Dr. Daddy-O is again exhibiting a pretty dramatic decline in reservoir pressure. Rather than getting specific pressures off of this particular graph, we have a later exhibit that we do have detailed, specific pressure information that I will go over.

Q If you'll look at the righthand margin of this display and if you follow up from the June 1st, '86, entry, if you go up into the blue area, there's a blue shaded area. Across the top of that area is the number 43. What does the number 43 mean?

A That is the -- represents the number of wells that during the month of June had a production of some sort.

Q What is the significance of this shaded blue area?

A The -- that is the real point of our concern, that as the amount of blue on this graph becomes greater and greater, the amount of reservoir energy that is leaving the reservoir is increasing in the form of a free gas phase, and because our primary production mechanism is solution gas drive, the gas, it's important. In the interest of maximizing recovery from the reservoir we must utilize as efficiently as possible the indigenous gas.

Q During this period you have demonstrated a change in production with more free gas, as you've identified it, being produced. Do you see, or what affect do you see on the production of the wells depicted on the display? What's occurred with the lines of pressure?

A Okay. It's my -- my belief that you can draw, if you just draw some rough average trends through all this data, you can pick up a pretty dramatic steepening of that trend that you would establish beginning in March of 1986.

This also corresponds about the time that we are seeing the well count increase. By well count, in other words, there's been a lot of wells completed for some time but for some reason or another we have not been able or the operators have not been able to get the wells on production, so as these wells come on production along with the fact that the pressure in the reservoir is approaching a level that I believe, or has approached the bubble point pressure, the accelerating production rate by wells coming on plus the amount of gas that is produced in a free phase, because we have gone below the bubble point, that is resulting in an acceleration of the reservoir voidage and that acceleration is resulting in a dramatic increase in the amount of free gas that we're -- we're seeing produced, which is what we would expect based upon our predicted GOR performance.

Q You have identified 43 wells. How many additional wells are ready to be placed on production in this pool?

A There are 16 additional wells that are ready to produce.

Q Let's go to the next display. It's on green paper. Will you identify that for us, Mr. Roe?

A Okay, this first -- this is the first page of -- of four green pages and it will basically, the purpose of this page is to depict the well locations of -- of several wells within the study area, or three wells within the study area, and two wells in the West Puerto Chiquito Pool, the Canada Ojitos Unit, that were involved in the pressure interference test involving three operators, being BMG, Mallon Oil Company, and Dugan Production. This is a test that was conducted, authorized by the Oil Conservation Commission order, and the test began in December of 1985 and was conducted on a cooperative basis between the three operators involved.

Q Let's look at the exhibit in general and have you tell me what you have concluded from an examination of the interference test.

A Okay. The primary conclusion that I have reached from the information that we recorded over an approximate four month period is that this particular area, and let me identify more exactly the wells that were involved in this interference test.

The primary pressure observation well was the Canada Ojitos Unit No. 29, which we've indicated here to be E-6.

The Canada Ojitos Unit No. 31 to the north 2858 feet is identified in this graph by the operator's designation of N-31.

The E-6 is located in Unit E of Section 6, Township 25 North, Range 1 West.

The N-31 is located in Unit N of Section 31, 26 North, 1 West.

The Dugan Production Tapacitos No. 4, which is located 3848 feet to the northwest of our primary pressure observation well, Dugan's Tapacitos 4 is located in Unit O of Section 36, Township 26 North, Range 2 West.

Mallon Oil had two wells that we feel we obtained some information during the pressure interference test. The closest well would be their Howard 1-8, which is located 1751 feet west. This well is located in Unit 8 of Section 1, Township 25 North, Range 2 West.

The second well that we feel we had some interference with is their Howard Federal 1-11. This well is located in Unit K of Section 1, Township 25 North, Range 2 West.

We -- these four producing wells and one pressure observation well comprised the pressure interference test. There may be even additional wells. These are wells that we've made some effort to try to account for as causing some of the responses that we measured in the E-6 Well.

Some of the conclusions that I -- I feel are indicated from this graph is that these, the four wells, specifically the Howard 1-8, Dugan's Tapacitos 4, the N-31 and E-6, I think the data clearly indicates a direct communication between all four wells and this would be a true example of the drilling of unnecessary wells to develop a fixed amount of reserves.

Basically one well in the center of this location could have produced --

MR. PADILLA: Mr. Chairman, I'm going to object. This is not responsive and not within the scope of the application.

I would move to strike Mr. Roe's last testimony concerning the spacing. This is a collateral attack on the spacing order (inaudible).

MR. KELLAHIN: Mr. Chairman, I'll be brief. I believe it's relevant. The point of the inquiry is there's an interference test. Mr Roe's testimony is, and will be, that there's communication between the wells that's indicated in the interference test and he has said there's too many wells.

The next question is, what do we do with too many wells. His testimony will be that you reduce the producing rates in order to preserve the reservoir energy and that is the case we're here today to hear.

MR. STAMETS: We'll overrule the objection and allow Mr. Roe to continue.

A Okay, I'll -- I might just comment that all of our information is leading to a demonstration that we have made a real effort to identify a communication in the reservoir that appears to be rather extensive and much better than we originally anticipated. My exhibits are intended to support that statement and the pressure and GOR information we've depicted indicates a need for modifying our development practices in the reservoir almost immediately and this is where we're all leading to with my exhibits.

Q Let's turn to the specific information, then, from the interference test and have you draw our attention to the specific facts that you believe support your conclusion.

A Okay, the second green page of this exhibit is a presentation of what we measured reservoir pressure in the Canada Ojitos Unit E-6 with a very sensitive -- and all of the pressure presented on -- in my exhibits will -- have been recorded with a GRC Bellows pressure bomb. This bomb is manufactured in a manner that it's sensitivity is far superior to a normal Amerada pressure bomb and it does have an accuracy to .01 psi and we feel, based on some of our graphs, we have verified that accuracy.

Q I'm sorry, I missed. What is the sensitivity of this pressure bomb?

A It is able to measure minor pressure differences as small as .01 psi.

Q And the typical Amerada pressure bomb as used in the industry has a sensitivity range of what?

A Well, dependent upon the element size that you use in your bomb, it would range anywhere from 2 to 6 psi. It's normally .2 of a percent of the element rating.

Q Have you satisfied yourself as a professional petroleum engineer that the pressure bomb instrument used to obtain this pressure for the interference test is one that's reliable?

A It is and I hope to point that out in some of our exhibits, the reliability and accuracy of the pressure bomb.

Q All right, sir. Well, let's look at that second page of the green exhibits, and if you'll look at the bottom of the chart that says days in January of '86, if you'll look between day 13 and 15 and move up to the column, there's a space between where the circles start and stop?

A Yes, sir, there is.

Q What's occurring?

A Okay. Identified on this graph and all of our presentations we are having to remove the bomb from the hole periodically, and so what's identified or pressure that's presented days, January 10th through the early part of January 14th, was Run No. 9 that Mr. Greer made with his pressure bomb. He pulled the bomb from the hole, recovered the data that was recorded during this time period, reran the bomb on Run No. 10 to the same depth level that he had the bomb landed at on No. 9.

When he got the bomb to that level Run No. 10 recorded the data during the time period the latter part of January 14th through the early time of January 20th, and the important thing here is the gap that you see between the two runs, the last pressure measurement on Run No. 9 and the first pressure measured on Run No. 10, when the bomb was placed back in the hole it measured a pressure that we would have anticipated had we predicted or projected the trend indicated in the latter points of Run No. 9.

In fact, this particular, when we got the bomb back in the hole and placed at the proper depth, is almost exactly on that trend, less than a tenth of a pound difference.

Q Is there a special phrase that is used in your profession to describe that incident with the bomb?

A Well, it -- it's slipped my tongue, but it reflects the repeatability of the -- of the bomb and it's --

Q How about repeatability?

A That's -- that's it.

Q All right, sir, anything else on this display?

A Yes, there are several other items that I'd like to point out.

We -- we basically have the same indication of repeatability between Runs No. 10 and 11 depicted on July -- or January 20th. The -- I've identified trends on this curve, say, during the early time period, which is the data in the left of the curve, we have a rate of pressure decline that's averaging .15 psi per day. I ask you to remember, this is a well that is not producing and has not produced, so the pressure decline we're observing in this well is the result of production occurring somewhere else in the reservoir; not this well. And that pressure is declining at a rate of 1.15 psi per day early in the life.

In the latter part of the day indicated

to be January 16th, we see that trend slowing to a rate of

Now, all we're doing to measuring the response to pressure performance in this well and we look around the well to see what possibly could have caused that rate of pressure decline to slow from one, approximately 1 psi per day to about a half a psi per day.

It's interesting to note that on January 17th, in fact, it looks -- it appears that maybe during the 16th Mallon Oil shut their Howard Federal 1-11 in.

For instance, on January 14th the 1-11 was averaging 680 barrels of oil per day. On the 15th it averaged 329 barrels of oil per day. On the 16th it averaged 122 barrels of oil per day. And on the 17th it had no production. It was shut in from the 17th through the balance of the month.

Q How far is the Mallon Howard Federal 1-11 Well from the pressure observation well, the E-6 Well?

A Okay, the 1-11 is, and this information is on the first page of this exhibit, but it is 4757 feet to the southwest.

Q And in your opinion the pressure bomb in the observation well is registering changes in the way the Mallon Well is being operated and produced?

A That is my belief at this time because of all of the other production in the area there were no significant changes. The Mallon Howard Federal 1-11 is the only well that had a change and so it is my belief that that is what caused this reduction in pressure.

And I might just add, if that is the fact, this would indicate that at a distance of 4757 feet away within the same 24-hour period we've detected a pressure pulse created and this would indicate a minimum drainage radius of -- that would correspond to somewhere between 1600 and 2100 acres per well.

Q All right, sir, is there anything else on the second page of this presentation that you'd like to direct our attention to in terms of support for your opinion that the pressure information includes excellent communication between wells?

A Yes. The other item of interest that we need to not lose sight of is that the initial pressure that we indicated here was 1711 psi. We, during the nine days of data that you have, or the fourteen days of data you have presented here, the pressure in this well was reduced by 9 psi for an overall average of .64 psi per day.

Again I want to stress that there was no production and there was a 9 pound drop in the pressure at this well in a timeframe that was fourteen days.

Q All right, sir, let's go to the third green page and have you identify that display and explain its significance.

A Okay. This, the third display presents a continuation of the monitoring of pressure in the Canada Ojitos Unit Well E-6. This well is, again, is still shut in, has not produced and the first piece of information or the data presented on this graph is bomb Runs No. 13 and 14 that occurred between the time February 3rd through February 14th.

The -- one of the important things that we should note is that the initial pressure we measure in the early part of -- the latter part of February 3rd was 1698 pounds, approximately. This is down from 1702 psi, which was the last pressure we measured on Run No. 11, which was presented on the previous graph.

Again pressure during the time February -- January 24th and February 3rd, a continued drop in this well in the absence of production from this well.

Q I direct your attention down to days 13 and 14 in February. If you'll move up from those days, there's a little bump in the information depicted on the display. What's occurred there?

A This is probably one of the -- among one of the most important pieces of information we feel we recorded during this pressure interference, other than the fact we are seeking pressure decline in the absence of production.

As it turns out, and this was a planned observation, we intended to have the pressure bomb in the E-6 while Dugan Production stimulated the Tapacitos No. 4, which again is located 3848 feet to the northwest. Our stimulation of the Tapacitos No. 4 comprised or consisted of pumping 2860 barrels of water into the formation as the initial fracture stimulation and we did this at approximately 70 barrels a minute.

The deviation from established decline in pressure, at the particular time and for a little over 2-1/2 days prior to us doing our frac job, the pressure in E-6 was declining at .77 psi per day. We feel that within a very short period of time our pressure pulse that we introduced into the reservoir with our frac job was measured at the E-6 and did result not only in a deviation from the decline that was established but also resulted in an increase in reservoir pressure.

This particular well, it's admittedly a very small pressure increase but with the bomb we had in the hole it's certainly within the resolution of the bomb and the accuracy of the bomb.

Q How far away are the observation well and the Tapacitos No. 4 Well?

A The radial distance, the distance between the two wells is 3848 feet. If we convert this to a minimum distance that we are able to have pressure communication between wells and say that this could correspond to a minimum drainage radius, that would relate to a drainage radius that would exist somewhere between 1068 and 1400 acres per well.

Q Give us some perspective, Mr. Roe --

MR. PADILLA: Mr. Chairman, if I may, I'm wondering where we're going with this type of testimony. It's the same type of objection I made earlier on the drainage, which seems to go to a spacing change and unless Mr. Kellahin can tell us how this information is relevant to the allowable, I'm going to object.

MR. KELLAHIN: Mr. Chairman, I'm sure the suspense is killing all of us. I assure you that Mr. Roe will get to the point. As I told you earlier, the mechanics of how the reservoir is operated in specific light of its characteristics is the essential underpinnings for the reduction in producing rates as a temporary method to conserve the reservoir energy in this reservoir.

Simply because this same information can be utilized for the spacing hearing in March of '87 doesn't mean it's not admissible now for the very purpose that we intend it.

MR. STAMETS: The objection is overruled.

Q To give us a way to grasp and understand the impact of the interference information, Mr. Roe, do you have an opinion as an engineer whether or not if you laid a pipeline on the surface between the observation well and the Tapacitos No. 4 Well, whether you would have gotten a response any quicker?

A Well, it would depend upon the size of the pipeline and the rate we were pumping down that line, but the normal lines that we would lay and considering that this line would be approximately three-quarters of a mile long, I would say this would indicate at least as direct a communication as you would have had you had a line laid on the surface and trying to pump 70 barrels a minute down that line.

Q All right, sir, let's turn to page 4 of the series of green displays and have you identify that display for us.

A Okay. This graph is the continuation of our monitoring of pressure during this pressure interference test. Again the pressure bomb is located in the pressure observation well, the Canada Ojitos Unit E-6. Again the E-6 has not produced at all. It has been continually utilized as a pressure observation well.

The pressure presented on this graph occurred between the period of March 31st and through the period of April 11th. The important aspect, and again this was a planned test, we wanted to observe the pressure response that would occur at the E-6 while we were stimulating or while the north well, or the well to the north, the Canada Ojitos Unit 31, which is identified on our map as N-31, was stimulated.

This particular well was stimulated with about 10,000 barrels of water and was stimulated at about 115 barrels a minute.

This stimulation was done on April 1st and we believe is what resulted in the pressure increase that we observed initially showing up within a thirty minute period and resulting in a 6.6 pound pressure increase in the pressure observation well.

And this is the pressure increase that is indicated on the date of April 1st.

Q All right, sir. Is there any further point you'd like to draw our attention to on this page before we leave it, Mr. Roe, that supports your opinion on this matter?

A Yeah, there is one other item of information. Again beginning in our pressure interference test December 15th of 1985 and this would be the last piece of information I have in the Canada Ojitos E-6 that I intend to present at this hearing.

The initial pressure that we measured December 15 was -- the pressure we measured on April 11th has been reduced by a total of 76 pounds and I just want to stress the 76 pound pressure loss resulted totally from no production in this well. It resulted simply from production somewhere else.

MR. KELLAHIN: Mr. Chairman, Mr. Roe has been testifying for more than an hour. I wonder if we might take just a few minutes?

MR. STAMETS: We'll take about a fifteen minute recess.

(Thereupon a recess was taken.)

MR. STAMETS: The hearing will please come to order.

Mr. Kellahin, I presume you're not through with this witness.

Q Mr. Roe, at this time I'd like to direct your attention to the next page of your exhibit. This is on the white paper following the series of green sheets.

Would you identify and describe that exhibit?

A Yes. This is a reproduction of a typical printout of the data that is recorded in this GRC bomb and our purpose for including this is to, one, show that the way the data is presented and make an effort to -- because generally pressure data historically is recorded with a pressure bomb that is much less sensitive and requires a manual observation of a pressure chart, that chart being recorded with a stylus and a little actual etching of a line on that charts. There is none of that in this pressure bomb. The data is all recorded electronically and in order to have this presentation it's dumped from a recording device in the bomb that is lowered to the depth of a pressure measurement and it's basically an opportunity for introducing any error because of inaccuracy in your -- your ability, your eyeball to detect very minor pressures has been removed in the electronics of the tool.

This particular page, the second item of interest is to note the area that's bracketed. This is an approximate 10 minute interval that existed while we had the pressure bomb in the lubricator being -- preparing to run in McHugh's Dr. Daddy-O No. 1.

It's standard procedure by Mr. Greer's operator and on occasion Mr. Greer would loan his pressure bomb to other operators to run and under those circumstances a contract service might lower the bomb to the level that we're recording pressures. But each time we had the opportunity to verify a pressure that existed, for instance, when the bomb was in the lubricator we took a dead weight test at the wellhead pressure. A dead weight test, this particular day on July 8th, prior to running the bomb in the Dr. Daddy-O, we measured with a dead weight tester 407 psia as being the pressure and you can see that this would correspond to the interval that's bracketed there of approximately 487 psia.

We feel that this is a very close agreement with the dead weight test device and this is reflective only of many instances that we verified the accuracy of the bomb when we had the opportunity.

Q When you look at the top of the exhibit there is some dated information and just above each column, in the center it says DWT, it goes on, and then says psig.

A Yes, sir.

Q What's the difference between that and psia?

A The dead weight tester is in -- the difference is the atmospheric pressure that is not measured with the dead weight tester and that the bomb that Mr. Greer has is calibrated to incorporate atmospheric pressure, so the bomb is reflecting pounds absolute and the dead weight tester is gauge reference.

Q Prior to the break you led us through the pressure information from the interference test up in an area in the northeast portion of the pool.

Do you have information, pressure information, with regards to other portions of the pool?

A I'm sorry, Mr. Kellahin, I was distracted for a minute. Will you repeat the question?

Q Yes, sir. Prior to the break you led us through your opinions and conclusions concerning the pressure tests, the interference test up in the northeast portion of the pool.

A Yes.

Q Do you have other informaticn, other pressure information, from another area of the pool?

A Yes, we do.

Q Is that depicted on the next page, this blue display?

A Yes.

Q Would you identify for us and help locate the well upon which this information is based?

A Yes, I will. On the blue page we have pressure presented that was recorded with this GRC bomb that was the same bomb we had earlier in the Canada Ojitos Unit E-6.

The Loddy No. 1 is operated by Jerome P. McHugh and it is located in Unit F of Section 20, Township 25 North, Range 2 West, and it is a well that's located near the northwestern extremity of the pool study area and we're using this as evidence that we have -- well, this would be a pressure sensing point in the western part of the study area.

Q What opinions or conclusions do you draw from the pressure information obtained from the Loddy No. 1 Well?

A There are two pieces of information that I feel are important presented on this, this particular graph.

First off, the pressure we measured in the well upon initially placing the bomb in the well on June 7th, or I guess that's June 6th, and the pressure presented on the graph was recorded during the period of June 6th through June 10th of 1986, but the initial pressure that we recorded was approximately 1627 psia at the bomb depth and converting this pressure to a pressure that exists, to our datum level of a plus 370 feet above sea level, this represents a measured pressure of 1549 or 1550 psia and this is pretty much in line with what our field average pressure is indicated to be from an earlier exhibit that I had and it is also pretty much in line with the last pressure that we measured in the Canada Ojitos Unit E-6, which on March or April 11th was 1559 psia at our datum level of plus 370.

So the level of pressure in the reservoir to -- in the area to the northeast in the area of our interference test, is the same general level of pressure in the northwestern part of the reservoir.

The second piece of information that is very important from this graph is the Loddy No. 1 other than a minor amount of production that occurred in the completion process of the well, this well has not produced and is during this period shut in. It has not produced prior to running the bomb and this pressure that is declining at an average of .85 psi per day is declining as a result of production in the -- somewhere else in the reservoirs.

The closest well that was on production during this period is McHugh's ET No. 1. It's located approximately 1600 feet away from this well, that being to the southeast.

There are other closer wells to this Loddy No. 1, but it's our understanding that all of the other wells were shut in during this period.

Q You've indicated for us a calculated effective drainage area for some of the wells up in that northeast study.

Have you calculated a similar effective drainage area for the wells involved in this pressure information?

A Yes, I have.

Q What is that number?

A If the ET No. 1 was the well responsible for causing this decline in pressure, which, again, this would be the closest well to the Loddy No. 1 that was on production, if this in fact was the sole production point resulting in a .85 psi per day decline, this would equate to a minimum drainage radius, that being 6800 feet, would equate to a minimum drainage area of somewhere between 3300 and 4200 acres per well.

I might mention, I've given two numbers for drainage area. The lower of the two numbers would be if we assumed the drainage area to be radial. The second number would be if I simply, which is quite common, assumed that we had a little, square box that the well was in the center of.

MR. LYON: What was that area again, please?

A It ranged from exactly 3335 to 4246 acres per well. I think I rounded those numbers off a little in my original statement.

Q Mr. Roe, do you have pressure data information from other wells in the Gavilan-Mancos Pool?

A Yes, I do.

Q Let's turn to your next display and have you identify and describe for us the next well upon which you have pressure data.

A Okay, the next well that we have information on that is presented on this yellow graph is Dr. Daddy-O No. 1, also operated by Jerome P. McHugh. This particular well is located in Unit C of Section 33, Township 25 North, Range 2 West.

Q Have you measured any pressure decline in -- well, let me ask you this.

What is the status of the Dr. Daddy-O Well? Is it a producing well or a shut in well?

A It is a shut in well.

Q Have you --

A At the time this pressure test was recorded it had not produced, other than a minor amount of production associated with the completion process.

Q Does the pressure information show whether or not the pressure has declined in this shut in well?

A Yes, in fact, this is an example of some of the most dramatic rates of pressure decline that we have measured in the reservoir. This pressure was recorded during the period July 8th of 1986 through July 15th of 1986, and during the first, during the period July 8th through July 10th, we've indicated that the pressure was declining at rates up to as high as .95 -- .975 psi per day.

During the period of July 8th through the 15th, the pressure declined a total of 25 pounds during this seven day period for an overall average of 3.6 psi per day.

Q How far away is the Dr. Daddy-O from the closest well?

A Okay, the Dr. Daddy-O is in the vicinity, and this well, by the way, is located in the southwestern part of our study area. It is in the vicinity of some fairly high withdrawals in the Gavilan-Mancos Pool.

The nearest well that was producing at the time we ran this pressure is Jerome P. McHugh's Native Son No. 3. This well is located approximately 800 feet to the southeast and the next closest well would be 4200 feet to the northeast and that would be the Full Sail No. 2, and that is approximately 4000 feet from this well.

Q Based upon the pressure data, Mr. Roe, and your study of this reservoir, what is your conclusion?

A Based upon the -- the fact that we have measured pressure throughout the reservoirs that appeared to be in communication with each other, the individual wells, the pressure throughout the reservoir is declining at pretty much the same rate. We feel that the reservoir is in pressure communication north to south and east to west. The well to well communication that we have measured and I presented on some of our exhibits indicates that we have excellent communication between individual wells that are currently drilled on an established 320-acre spacing unit.

Q Based upon the engineering work you have performed and studied, do you have an opinion as to whether or not the Gavilan-Mancos Pool is one continuous, interconnected reservoir?

A Based upon the engineering data I have available, it's very clear to me that the reservoir is in good communication throughout.

Q Do you have an opinion, Mr. Roe, as to whether or not the pressure depletion occurring in the reservoir is occurring throughout the reservoir?

A Yes. The -- we have -- we've been making a real diligent effort, especially in new wells to observe initial pressure and in existing wells that are currently idle and not producing, we've been trying to use these as pressure observation wells and it's very conclusive to me that pressure is declining throughout the reservoir, including wells that -- that no production has occurred.

I, I did not mention it, but on the Loddy No. 1, we only presented a little bit of that pressure data. That particular well has never produced during the time period. Our initial pressure in that well was February 26th, '86, and we measured a pressure at our datum of 1599 psia and our last pressure was July 29th. We had a measured pressure of 1474 psia. This well having never produced has had a pressure decline of 135 pounds.

Q Apart from that example, do you have an opinion as to whether or not the pressure depletion that is occurring is in fact occurring in wells or in areas of the reservoir that have not been produced in which there are no wells?

A Yes. I have an opinion on that.

Q Do you have an opinion as to whether or not increasing withdrawals have caused increasing rates of pressure depletion?

A Yes. The amount of pressure decline in the reservoir is accelerating as additional wells are brought on production.

Q Do you have an opinion as professional petroleum engineer with regards to the entire reservoir in it's relationship to the bubble point?

A Yes, based upon the production data and pvt data that we have available, early in the life of the production in this reservoir we were above the bubble point and we are now producing at a level that is below the bubble point.

Q What will be the effect of the continuation of production in the reservoir below the bubble point?

A As indicated on the first exhibit, in my blue page, continued production below the bubble point will result in an accelerating increased gas/oil ratio. That in turn will result in an acceleration in the reservoir voidage that is occurring, and in my opinion will result, on the existing development of the reservoir, will result in a waste of natural reservoir energy on the part of a competitive operation.

Q Do you have an opinion as to what effect the additional wells that soon will be in a producing status, what effect those wells will have on increasing the rate of withdrawals?

A They will accelerate an already undesirable rate of pressure depletion and just make the currently bad situation worse.

Q Do you have an opinion as to whether or not the reservoir at this point has been over-drilled and whether or not the wells that do exist are draining more than 320 acres?

A Yes. It's my belief that --

MR. PADILLA: I'm going to continue to object on the same basis I have before.

MR. STAMETS: We certainly appreciate your objections, Mr. Padilla, and overrule them once again.

MR. PADILLA: As long as it's

on the record.

A We feel that the pressure data that we've measured and some of that information I've made an attempt to present here today very conclusively indicates that the reservoir has had more than an adequate number of wells drilled and under the existing spacing will require unnecessary wells to be drilled in the future.

Q What is your opinion, Mr. Roe, with regards to the proposal of Mr. McHugh to reduce the gas/oil ratio and the current allowables for the wells involved in this pool?

A Our -- at the current allowable of 702 barrels a day and a maximum GOR of 2000-to-1, individual wells are allowed to produce up to around a million and a half cubic feet of gas a day and 700 barrels of oil, 702 barrels of oil per day.

In order to be competitive with offset wells, it will be the practice to produce your wells at a rate that will result in the individual operators producing their allowable.

Mr. McHugh's intention of asking for an allowable reduction is simply an effort to slow down the currently undesirable rate of pressure depletion and as additional wells are brought on it will be an undesirable event that it will accelerate with additional wells coming on stream.

So our sole purpose in asking for an allowable reduction is to by some time to on a cooperative basis with all operators involved determine an alternate method to develop in the reservoir other than our competitive 320-acre basis that we now have.

Q If current competitive practices continue based upon the current gas/oil ratios and the current allowables for the wells involved in the pool, do you have an opinion at this point of the anticipated remaining life of this reservoir?

A I do, and just in simple terms, if we can take an overall average of -- of one to one and a half pounds per day and the current last pressure that I indicated on my graph was about 1400 pounds, you're looking at somewhere between a straight line extrapolation providing the reservoir voidage does not increase at all, of somewhere between one and a half to two years of remaining life.

Q Mr. Roe, do you have an opinion at this point as to whether or not the current methods of operating and producing wells in the pool are ones that are effectively and efficiently being maintained in terms of waste of hydrocarbons?

A It's my belief that the existing spacing and the existing allowable is forcing operators to unnecessarily produce gas that is the primary mechanism of moving oil to the wellbores in the reservoir and it is also going to cause the drilling of unnecessary wells in order to adequately develop individual acreage and protect individual operators' correlative rights and prevent lease expirations that may or may not exist.

Q Do you have an opinion, Mr. Roe, as to whether or not this is the type of problem and issue that can be referred to a study committee and studied for the next six months or whether this is an issue that requires immediate action?

A The reduction in reservoir voidage already at a currently undesirable -- and I keep saying undesirable, it's at a level that doesn't give us much future time if we allow it to continue at the level it is, it is my belief that we need to reduce that level of voidage immediately and we're asking that this be done on a temporary basis because it's my feeling that most operators in the pool are aware that we do have a situation that warrants further evaluation.

We've indicated that on a ccoperative basis we are trying to arrive at an understanding of what would be a better way to develop the reservoir, and we feel that allowable reduction is absolutely necessary in order to have sufficient pressure in the reservoir and minimize the amount of wells that are drilled unnecessarily.

On my first exhibit I indicated there are currently 13 wells that are planned and I'm almost certain there are several more that I don't have on my tabulation that are in some stage of planning.

Q Will the adoption by the Commission of the proposed temporary reductions result in the loss of hydrocarbons?

A No.

MR. KELLAHIN: Mr. Chairman, that concludes my direct examination of Mr. Roe.

We move the introduction of McHugh's Exhibit Three-D, being subsection D, and Dugan Petroleum Corporation Exhibits One and Two.

MR. LOPEZ: Mr. Chairman, first of all I would like to object or to join in the objection of Mr. Padilla with respect to testimony regarding the spacing nature of this case, and the implied unitization aspect of it.

With respect to the introduction of the exhibits, my only objection is that I think they were designed to magnify a situation as the McHugh camp sees it, and I know that the Commission will take it to its discretion and good judgment the (not clearly heard) of the exhibits.

MR. STAMETS: Are there any objections to the introduction of these exhibits?

They will be admitted.

For those who have objected, as I say, it's my opinion that the only way we could view the evidence which has been presented relative to drainage would be in relationship to the request for immediate action as opposed to any attempt to change the pool rules at this time, so I understand the nature of your objecticns but I think in this case what's been presented is important, perhaps, in a different way than we normally look at such (not clearly understood.)

Are there questions of this witness?

MR. LOPEZ: Mr. Chairman, if I might suggest, I think if we took a five minute recess it would save us more than five minutes later.

MR. STAMETS: All right, let's take about a five minute recess.

(Thereupon a recess was taken.)

MR. STAMETS: The hearing will come to order.

Mr. Kellahin, I've been sitting

up here looking at calendars and it looks as though the first opportunity we might have to continue this case would be to the 21st and 22nd.

I'd like you all to be thinking about those dates and checking on that and perhaps after we break for lunch we can determine whether or not those will be acceptable.

Mr. Lopez, I presume you have come up with a couple of questions during the break.

MR. LOPEZ: I can't take all the credit, Mr. Chairman.

CROSS EXAMINATION

BY MR. LOPEZ:

Q Mr. Roe, I'll try and ask my questions in the same order you presented your direct testimony.

I would ask you now to refer to McHugh Exhibit Number Three, Tab D and my first question is why did you only select 19 of the 43 actual wells and I know you stated that in your judgment they represented fieldwide production but my question to you is wouldn't having used the information available from all 43 wells have been representative of the actual reservoir characteristics?

A Yes. If we would have had pressure data from all 43 wells it certainly would have been more representative. We were able to record pressure and have data available only in 32 of the 43 wells and so the information we presented here today, we started out with a plot that had all 32 wells on it but we felt that the difference between the 19 and 32, there was no new data added by adding all 32 wells and what happened was our graph became very difficult to read and determine what the real data was because of our mass of well data, which I think I indicated earlier we left off data that was redundant.

Q And referring to the 19 wells that you plotted on the second page of Tab D, or that were plotted, I think you stated that they covered the reservoir generally, but my question to you is how did you select these 19? Did you take into consideration the time they were drilled? Are they old wells or relatively new ones?

A The -- we took advantage -- the wells that are presented on this graph are presented only to represent the fact that we have pressure data in many areas in the pool and certainly at the northeast, northwest, southeast, southwest boundaries of the pool.

Because we did not have the recognition of the problem early in the life of the pool that we do now, our pressure data early in the life isn't as good as our pressure data in the later life. The pressure information that was a big part of some of my exhibits was recorded in new wells or wells that have not produced simply because artificial lift equipment hadn't been installed in these wells and it's a simple matter to drop in and measure pressure.

Most of the older wells have artificial lift equipment in and you -- obtaining reservoir pressure would require removing the artificial lift equipment.

Q I want to make sure I understand you. Are you saying that the original pressure declines addressed or discovered in the initial stages of the reservoir are the same or different than they are today comparatively?

A I'm not sure I understood your question.

Q Well, I was wondering if the early pressure data from the McHugh wells didn't show a rate of decline for a barrel of oil was drawn to be about the same as the present decline?

A Well, bearing in mind early in the life of the reservoir the reservoir production, reservoir voidage, was fairly small, so the rate at which pressure was declining wasn't as fast as it is now. There wasn't as many wells on production and as one of my graphs indicated, the amount of gas that we were producing was at a lower level, so the voidage from the reservoir was at a lower level.

Was that your question? Or did that answer your question?

Q It's as good as I'm going to get, I

think.

Again referring to this first page of Exhibit D, I think if I heard your direct testimony correctly, that you stated that although the line graphs of various wells you've selected showed pressure decline, that that really didn't concern you terribly, or did I misunderstand you?

A Well, I think what I meant to say was the fact that reservoir pressure is declining with production is something we should expect from any reservoir barring some maintenance of the pressure, either by reinjection or a water drive.

This particular reservoir has -- the only reinjection of gas that exists would be in Mr. Greer's unit and there is no water drive, so -- and I think we indicated that solution gas drive is our primary production mechanism, so with production we should expect a decline in reservoir pressure, yes.

Q And I think, if I understood you correctly, also in the same vein, due to reservoir production that the increase in GOR's didn't trouble you greatly, either.

A The fact that the GOR's, if I said it didn't trouble me, I didn't mean that.

The fact that the GOR is increasing is something that is predictable and we should expect in a solution gas drive reservoir.

Q Well, isn't your principal concern then the fact that you don't want to drill more wells in order to produce the reservoir?

A Our -- I'd reword it just a little, but, yes, that's the primary concern, that we feel additional wells, we -- we do not feel that one well for 320 acres is going to be necessary to develop the amount of reserves that are indicated to exist.

Q What is your professional opinion as to the bubble point?

A We -- I -- I am using a bubble point pressure, I believe, of 1482 psia, and that is a pressure that was determined from a pvt sample, or pvt analysis of a fluid sample that Mr. McHugh took and CORE Lab analyzed in the Loddy No. 1.

Q If you'd refer to the first page of that graph D, would you show me where the decline in pressure meets the bubble point and then passes it?

A The -- it -- from that graph you're re-ferrng to you'll notice that there's quite a bit of red coloring underneath the GOR curve. This suggests that there was some free gas being produced all along. Whether this was from a free gas stringer, this is a very complex reser-voir, we're dealing with a reservoir that's about 400 feet, the primary producing interval is about 400 feet thick, and we have some pretty conclusive information to indicate that the vertical communication throughout the 400 foot interval is somewhat limited -- not somewhat, it is limited.

So for me to answer your questicn exactly like I think you meant it, is going to be pretty difficult to do it from this particular graph.

The best I can show you is that if you were to take the graph that you're looking at there, which reflects an average production of all wells in the pool, excluding the two wells that I mentioned earlier, and some of those were producing at a GOR above our 588 early in the life, but if you take and draw a straight line across there, and I think I mentioned prior to January 1st the average GOR on a poolwide basis was 1395.

Beginning about January 1st the GOR started to increase and this is also in a time frame that the reservoir pressure is getting close -- now again were dealing with fieldwide average pressure but we're dealing with areas of the reservoir that probably are operating, the operating wellbore pressure is at levels substantially below what we're plotting here.

What we're plotting here is an effort to represent pressue that would be at some drainage boundary. If you look at what is the pressure in the vicinity of an operating well, that's going to be down in the 5-or-600 pound range and because of the picture I have of the reservoir, it's a fractured system, you put a fairly large fractured area in an operating pressure of 5-or-600 pounds and the bubble point pressure is 1482, that adjacent area to the wellbore is -- is several hundred pounds below bubble point pressure, and will result in a GOR that you see plotted here.

Q How large an area around the wellbore?

A Well, from the interference test data that I -- we indicated, that I presented, I don't have an exact pressure profile drawn of the reservoir. I think this is one of the things that or engineering study committee might be able to address, because we do have several pressure build-ups that we are working on, but I have indicated that we've established pressure communication between pressure observation wells and producing wells as far as a mile and a half away.

Q Okay, now I'd like to discuss Dugan's Exhibit Number One with you, if you'll just give me a second here.

Okay, now I think the purpose of this exhibit was to show three things, if I might try to make myself clear.

The first was the actual reservoir production.

The second is the potential reservoir production or what it's capable of doing after any restriction, bearing in mind that many wells are not productive or were (not clearly understood) for various reasons and what the effects on the production of the various operators would be under your proposed formula of 200 barrels per 1000 cubic feet per well per day. Is that a fair characterization?

A All of that information was presented on this tabulation, yes.

Q And then the -- you didn't calculate but I think on the graph itself, and I think in your testimony, you alluded to how the various operators would be affected from current production levels if the Commission were to adopt your formula.

A Yes.

Q And I noticed that I think you -- have you made those calculations?

A Yes, I have.

Q Could we see them? I think it would be easier for all of us if we could discuss those calculations with you to see -- well, let me back up a minute.

A That is --

Q Well, let me -- I'll back up a minute.

MR. KELLAHIN: Mr. Chairman, I

have an objection.

I think it would help us all if Mr. Lopez would put his comments in the form of direct questions to the witness. I'm having a lot of difficulty following his narrative comments.

A And maybe I didn't understand your question.

Q Well, I think I'll help us all out if you'll bear with me.

Are there other formulas that could be adopted besides the one that you're recommending, that would solve the same problems here?

A Sure, there is -- our primary -- yeah.

Q And I think the principal problem as you've described it is that the declining pressures are going to damage the reservoir (not clearly understood).

A No, I didn't mean to say that the declining pressure would damage the reservoir.

We should expect a pressure to decline. That wasn't what I meant to say if that's what I said.

Q Well, what has the greatest effect on the declining pressure of the reservoir? Is it the oil production or the gas production?

A The gas production has a greater impact on the voidage in the reservoir.

Q So would it be possible, or if a well that was producing a great amount of oil yet had a low gas production, let's say a GOR of less than 1200, or less than 1000, what would be the reason for curtailing the oil production in that well?

A The primary reason for curtailing the oil is, I think, evidenced in the interference test data that we have presented. You have a high rate well, to offset, the people owning the offset acreage are going to be obligated to develop their acreage.

I think the pressure interference and communication data that we've presented indicates that some of the wells in the pool have the ability to drain radiuses that far exceed that that would correspond to 320-acre spacing, and so a well that is producing at a top allowable of 702 barrels a day and no gas, let's just ignore the gas totally, I think our data has indicated that it's likely that a drainage radius far exceeding 320 acres is probably existing, and our primary concern right now is that if we allow this situation to continue there's going to be a significant number of wells that are going to be drilled, going to be drilled into a reservoir that encounters a depleted pressure. They're going to be competing with each other and they are going to interfere with each other, as evidenced in the five wells that were presented on my pressure inter ference test.

Q Under your formula wouldn't it occur that some wells would experience no reduction in current producing levels while others would be severely curtailed?

A Yes, that is true, but the wells you're talking about are generally the very low rate wells that are providing a fairly insignificant amount of the problem, anyway.

Q I think you stated that McHugh's current production level of 39 percent of the total reservoir volume, including the Greer wells, will be reduced to 37.5 percent.

Have you calculated what Mallon's reduction would be?

A Yes, sir, that information is actually available on this tabulation. It's just a mere calculation.

Q If -- if I were to suggest that the Mallon production would be reduced in greater proportion significantly than the McHugh and Dugan production, that wouldn't surprise you, would it?

A No.

Q Now I'd like to refer you to your Dugan Exhibit Number Two.

First of all, would you explain to me how you arrived at the figure that this reservoir contains 1-

million barrels in place?

A Well, that was basicallyl a manipulation of data. This solution, the curve that Mr. Greer generated for his unit was actually generated for the bottom scale rather than oil was percent of oil recovery and so in order for us to plot our data on this without having a good handle of the oil in place and thus knowing the percentage of that recovery in time, we assigned an oil scale to the bottom that basically would equate to -- in other words, 1-million barrels would be 1 percent of 100-million barrels.

Q In your opinion what kind of producing mechanisms do there exist absent the solution gas drive?

A We feel that gravity drainage is occurring. There is gravity segregation within the reservoir that is occurring. There's possibly some gas cap expansion, although we aren't certain of that, and -- but the primary mechanism is the solution gas drive.

Q I think in explaining how you reached the million barrel figure you said you relied on the information provided by Mr. Greer.

How did you individually arrive at that number for Dugan?

A This graph is not intended to depict the fact that we think there's 100-million barrels in place in the Gavilan. This graph is indicated to depict the fact as pressure is declining in our area we have a predictable -- we haven't run a material balance and so our calculations are a plot only of actual data on a graph that does -- was generated with real data in the West Puerto Chiquito area.

Q Then how can you plot the Gavilan actual data on this exhibit when you're relying on one that has data that's not applicable to the Gavilan?

A What -- what we did was place a curve that was generated from the closest pool that we have, that we are immediately adjacent to West Puerto Chiquito and the Canada Ojitos Unit.

The actual construction of Mr. Greer's curve, I would defer that, that description to him at a later -- at a later time.

I have satisfied myself that the KgKo data that you used in generating his curve is the best available. It was actual laboratory test date in other pools and he utilized what he felt a representative average of fractured reservoirs, and it was KgKo data for fractured reservoirs, and he used his pvt data to generate this curve.

We feel that we're close enough and his data is good enough that it ought to present a good picture.

Q Wouldn't you agree, then, that the theoretical data shouldn't be compared to the actual data unless there are actually a million barrels of oil in place?

A No, I wouldn't agree with that.

Q Why not?

A The primary relationship that we're trying to generate here is -- and we're -- we're not making an effort to say that Gavilan is going to perform exactly like this. We have not generated this kind of a curve for the Gavilan area. Our study group committee is in the midst of having this work effort now and that's basically why we need an allowable reduction, is to have a time tc complete this analysis.

Our intention of using this graph is to show that in an adjacent pool that we've established we're in communication with, that our oil properties or fluid properties are similar, I see nothing wrong with drawing an analogy to what exists at West Puerto Chiquito.

Q I think you just stated that the two reservoirs could be in communication. What evidence do you have that the West Puerto Chiquito and the Gavilan are in communication?

A A big part of my green -- my exhibits that we've identified in the green, and a good part of my previous testimony was spent addressing that exact issue, specifically the Canada Ojitos Unit E-6 and Dugan Production's Tapacitos 4, and Mallon's Howard Federal 1-11 and 1-8, and --

Q You were only addressing those wells in the West Canada Ojitos Unit, though, were you not, and not those farther to the east that have been (not clearly understood).

A At this time I'm not prepared to say what within the unit is actually influencing us. I can say without any doubt that we have communication at least between those two wells, yes.

Q Again, I think we've covered this when we discussed the earlier McHugh exhibit under Tab D, but just to be sure we're clear for the record, these wells that are plotted on your second page of this Exhibit Two, you recognize a downward or a decline in pressures in the reservoirs, and again that's what we expect as a result of production, is it not?

A Yes.

Q And again, only 19 wells were used to -- for the information contained on this exhibit and -- is that correct?

A Well, 19 wells that represent the data that was obtained and amassed out of 32 wells throughou the unit, yes, or throughout the area.

Q And if the 19 wells selected had concentrated voidage around their wellbores, would that tend to accelerate the decline of production as represented in this graph?

A No, because a of this data was generated not just by myself but it was generated in a cooperative effort of all operators and we spent a fairly significant amount of time trying to generate what is a representative reservoir pressure, not what is an operating reservoir pressure.

As I've indicated, we've got data plotted on this graph that was recorded in several wells that have never produced other than the completion flowback.

Q Now, referring to the third page of your exhibit, please, and specifically to the N-31, E-6, Howard 1-8, and the Tapacitos 4 Wells, could you tell me what effective spacing pattern those wells are located on?

A The effective pattern that they're drilled on would be pretty much 160-acre locations. The actual, official spacing unit is 320 and this is primarily our concern, or McHugh and Dugan Production's concern, that in order to protect your acreage you're going to probably arrive at a spacing pattern real similar to this in other areas of the reservoir.

Mr. Lopez, I might add one thing to that. Even though the wells are drilled on that, we do have evidence that we have a drainage radius between the Tapacitos 4 and the E-6 didn't correspond to a 320-acre distance, roughly, and we have pretty well established communication that far.

Q What is your opinion as to the actual permeability of the fracture intervals in the reservoir?

A We are studying that mass of data right now in the engineering group that has been formed. I know that the reservoir transmissibility or the product of the permeability thickness, the viscosity ratio, is high. I don't have any specific numbers to quote right now.

Q Well, is it at least as great as one millidarcy, in your opinion?

A Again, I am not prepared to relate it back a very footage, or per foot. In other words, in order to arrive at what is the effective permeability I would have to -- you would have to be able to tell me what is the thickness.

I -- I am not prepared to know that. I do know that the product of the thickness times permeability divided by viscosity, the transmissibility is high, which it would have to be in order to have wells that are capable of producing over 1000 barrels a day.

Q But you have no professional opinion as to even the range, whether it's 5 millidarcies or 10 millidarcies based on your professional experience (not understood)?

A No, I have not made any effort to relate it back to an exact permeability, which I think would be a waste of time.

Q Have certain areas of the pool experienced more pressure decline than others?

A No, based upon the last exhibit in Section D of Mr. McHugh's exhibits, and based on one of my exhibits where we plotted the fieldwide pressure not only versus cumulative production but versus time, I think to me it's clearly indicated that the pressure is declining at a similar rate throughout the reservoir.

Q Well, during this period of your proposed restrictions or curtailments of those allowables, is it your opinion that there will tend to be equalization of pressures in the reservoir?

A I'd have to say, knowing a little bit about good mechanics, yes, that will happen, but not to as great a degree as would happen if we were to shut the reservoir in totally.

I don't think Mr. McHugh, and I know Dugan Production is not making a statement that 200 barrels a day is a magic number and an exact rate. All we did was try to arrive at a rate that would allow some continued production but knowing that there are sixteen additional wells fixing to be placed on production, there's one well apparently drilling, and there's thirteen wells that are right now permitted to drill, and I know there's additional wells planned to drill, we want to come up with the rate that's going to maintain approximately the same reservoir voidage as we now have and when I say now have, I mean prior to June; June is an unacceptable voidage. If we are to come up with some other way to develop the reservoir then we need that time to evaluate it.

Q Well, if this equalization of pressures does take place, which I think you said it will, what effect will that have on the correlative rights of the operators in the pool?

A Well, the most immediate effect that I think my pressure interference test data would indicate is that the offset acreage won't suffer quite as much depletion as now is existing.

Q Have the pressure declines been uniform through all the wells in the pool considering the cumulative production from each well?

A I think, referring again to the two graphs that presented pressure information on, we would have to conclude that the general trend of the rate of pressure decline, all wells throughout the reservoir regardless of cumulative production, is declining at similar rates. I think it -- you can make that conclusion, yes.

Q Mr. Ellis, I believe, testified about the pervasive fracture porosity but indicated little, if any, matrix porosity.

Do we have a fracture permeability?

A I think there is no question in my mind that fracture permeability exists, or permeability resulting from fracture, the existence of fractures is present, yes.

Q How much would it be?

A As I indicated earlier, we're -- our study group is trying to come up with a lot of this information now. For the same reason that I was unable to give you permeability by -- any place in the reservoir, I cannot give you a permeability of the fracture. Just what we know about the production and we see from pressure interference we know that it is high.

Q Well, could the uniform decline in pressure among the wells per barrel of oil produced be attributable to the size of the fractures from which each well is drawing?

A It undoubtedly is, yes.

Q On your interference test I believe you shut in one well and produced the others around it.

Would not a more meaningful test have been obtained the other way around by producing the E-6 and shutting in the others and then looking for the interference?

A An interference test could be done in either fashion, and the engineering calculations, if you've got control of all of the offsetting wells, could -- should result in similar answers.

We had one big problem and Mr. Greer was the only operator in the area willing to leave his well shut in while offset operators produced. I would not -- I did not support Dugan Production, support them shutting in their wells while Greer and Mallon produced their wells, and I'm almost certain Mr. Mallon would not have been in favor of that, and it was only because Mr. Greer recognized the importance of running this kind of a test and was willing to leave his well shut in and incur, I forget the exact number, but I think it was about 100 and -- I'll get the exact number -- during the pressure interference test, which began December 15th, and ended in the latter part of April, Mr. Greer experienced a 76 pound pressure drop in his well. He was aware of this happening but his desire to have this information and his recognition that this information is critical to understand the reservoir, he was the only operator that really would -- would be willing to do this.

Q Did you detect a boundary as each of the producing wells started showing (not understood)?

A No, we made no effort to do that.

Q Isn't it also true that while Mr. Greer's well was shut in that he was allowed to accumulate production on that well?

A Yes, sir, that's true. But Dugan Production was allowed that same opportunity by leaving our well shut in. We delayed the completion on our well several months just to accommodate this interference test, and to improve our control of offset activity while we were running an interference test with the well, so that was a part of the Commission order.

Q In this vein as to how all these operators in the pool are so cooperating, isn't it true that a study committee was discussed at least a year ago for the reservoir?

A I -- my memory is failing me. I'm unaware of that conversation.

Q Did any of the operators in the pool in the last year discuss a willingness to form such a study committee for the purposes of --

A Yes, Dugan Production is reluctant. Dugan Production was the first operator in the pool to accept the fact that we are dealing with a reservoir that's much more transmissibility, a higher transmissibility than we anticipated in the early development of the field.

As other wells came on production I think Mr. McHugh was able to see with his additional wells that there was need for something different. Until we had this pressure information generated beginning December of 1985, there was not, I think, information available to any other operator that maybe we needed wider spacing and I don't mean wider spacing. We need to use a different method to develop the reservoir, but if feel fairly certain that I could in all certainty say Dugan Production recognized that early.

Q Did Mr. McHugh want to participate in that study committee?

A Well, for the same reason that all operators -- once we got started gathering data and Mr. Greer spent, I'm not sure of his exact numbers, but Dugan Production is an interest owner in his unit and it was about $30,000 to purchase this sensitive pressure equipment, once he -- we started recognizing the need for this pressure information, Mr. Greer almost begged other operators to gather data in their wells and for the same reason that all other operators were reluctant to let that information be gathered, and none of the other operators were willing to spend this kind of money to purchase this kind of pressure recording equipment, Mr. McHugh was no different than other operators. He needed to be convinced internally that we really had a problem here before he was willing forge ahead and I think it should be undisputable that McHugh's efforts to organize such a study committee have been the only reason such a committee has been formed. He was responsible for the initial two meetings and has incurred a great deal of expense individually attempting to get all operators aware of the pressure data and the majority of the pressure data I've presented here today has been provided to each of the operators through this study committee.

Q And the reason for wanting the study committee wouldn't in any way be as a result that Mr. McHugh has drilled his wells in the pool and has produced the greatest amount and now he'd like to be the operator of a unit.

A I think, no, I think, if I understand your question, that's not why Mr. McHugh's in favor of this but because Mr. McHugh has 23 of 59 wells he certainly has the opportunity collect more data. He recognizes the significance of the problem and I think it would be very clear that he has a majority of the wells that have been completed in the pool.

Q You discussed an increase in the pressures in the E No. 6 Well when the Tapacitos No. 4 was fractured.

This Tapacitos No. 4 is in the northwest of 6. If we assume that fracture --

A I'm sorry --

Q -- is in a northwest-southeast direction, it would be right on strike with the field fractures, would it not?

A Mr. Lopez, first off, I didn't hear all your question because it's not clear which wells you're talking about.

The well in the northeast, there is no well in the northeast quarter of Section 6.

Q I guess it's in the east section of Section 6.

A Okay, that would be Mr. Greer's well.

Q The E-6 Well I guess is what I'm talking about.

A Okay, that is Mr. Greer's well.

Q Right.

A The pressure observation well.

Q Okay, when the Tapacitos No. 4 was shut in when it was fractured, the Tapacitos -- well, let me start all over.

If I understood my story better I might be able to ask the questions better, but I think I've got the story now, so maybe I'll get further.

Okay. Okay, you stated, I think, or you discussed at least an increase in the pressure in the E-6 Well when the Tapacitos No. 4 was fraced, right?

A Yes, sir.

Q Okay. Now, the Tapacitos No. 4 is located to the northwest of the E-6 Well, correct?

A Yes, sir.

Q Now if we assume the fractures in the northwest-southeast direction, this well would be right on strike with the field fractures, or these wells would be, isn't that correct?

A If we assume that the fractures are developed northwest-southeast, yes, that is correct.

Q Okay. In discussing the pressure decline from the Loddy No. 1 Well you said the nearest producing well is 6800 feet to the southeast, is that correct?

A Yes, that was the nearest well that was producing during the time we recorded this pressure data.

Q Well, wouldn't this also result in the wells being on strike with fractures if they're assumed to be in a northwest-southeast direction?

A Yes. The ET is southeast of the Loddy. I don't think that we can conclude that from the data, though, but with your statement that that is the direction of location it is correct.

Q In discussing the Dr. Daddy-O along the same line, you also discussed pressure decline in that well.

Isn't it also true that the nearest producing well in the vicinity with the highest withdrawals is the Native Son No. 3 and again we have wells located on strike of a southeast-northwest trend.

A You are correct. Those wells are located southeast of the Dr. Daddy-O, but again I don't think that we can conclude that there's a preferential trend of fracturing in that direction.

I think if you'll remember my exhibits relating to the interference test also established some direct communication between a well almost north or a little northeast of the E-6, at least at a 90-degree angle to the angle you're working at, and possibly more than that.

Q Okay. Assuming that, and recognizing that we are experiencing a pressure decline, and this will increase as we bring new wells on production, I think you've already stated that this is to be expected in any reservoir regardless of whatever the allowables are because of production.

A Yes.

Q Then if the problem is the drilling of unnecessary wells, as you said, how does reducing allowables solve your problem?

A Well, I think one of the things I've indicated is that the data we have indicates that we already have too many wells, that the wells are interfering with each other, with pressure depletion occurring in wells that have never produced. So what an allowable reduction does, it doesn't solve the problem, it keeps the problem from getting too much worse than we anticipated with additional wells coming on production and what we're proposing is during this time that we minimize the damage that will occur, and again I'm not saying damage in a reservoir. I'm saying we need to, on a cooperative basis, evaluate the true need for creating additional situations like I presented on our interference test data between Mr. Greer's two wells and Mallon's well and Dugan's well, and that's really what we're asking for, is we don't feel we need to spend to the tune of about $500,000 a well. We -- we think there will be true economic waste if we are forced to continue the development of the reservoir on a competitive basis.

MR. LOPEZ: No further questions.

MR. STAMETS: I presume there are other questions?

MR. PEARCE: Oh, I'm sorry, yes, there are.

MR. STAMETS: Mr. Pearce, how long would you anticipate your cross examination will be?

MR. PEARCE: I do not expect that he can teach me enough in twenty minutes, Mr. Chairman, if that's the gist of the question.

MR. STAMETS: Okay, well, in that case this would probably be a good time for lunch and plan on being back here at 1:00 o'clock.

(Thereupon the noon recess was taken.)

MR. STAMETS: The hearing will please come to order.

Mr. Roe is at his station. Mr. Pearce is waiting patiently.

You may proceed.

MR. PEARCE: Thank you, Mr. Chairman, hopefully, over the lunch recess I was able to shorten this some. Let's see if I was successful.

CROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Roe, during Mr. Ellis' testimony yesterday there was some evidence about some wells that were evidencing decreasing GOR's. Does that sound familiar to you?

A Yes, I remember the testimony.

Q And do you have any information available to you about which wells those are and what sort of decreasing GOR those wells were experiencing?

A The wells, I don't remember exactly the wells that were discussed. You might refresh my memory.

Q I do not recall well enough to say, sir. Do you have any information available with you?

A It's my general experience in the pool that the gas/oil ratios are not really in fact decreasing.

The, as I recall, one of the wells that was addressed was the Mesa Grande's Howard Federal No. 1, which from the date of first completion the GOR -- and it ws completed as a dual well, the Dakota formation completed and equipped in a manner that it should be produced on its own and the Mancos equipped in the same manner, that you should be able to produce Mancos without wellbore communication.

The GOR in that particular well was high from the Mancos formation from date of first completion and until Mesa Grande actually did some remedial work on the well and repaired the communication and I believe it was the testimony yesterday that resulted in a decrease in GOR from the Mancos and that is in fact true.

Again, just referring to -- to information that is on file with the Commission in the Form of C-115 Monthly Production records, the Mancos, say, during the month of April of 1986 had an average GOR of 80 -- 8,313 standard cubic feet per barrel. The remedial work, I don't know the exact date, but May's production was in fact lower, a lower GOR. During the month of May the gas/oil ratio from the Mancos reached 564 standard cubic feet per barrel, which was -- basically reflected a reduction in gas production from somewhere and as it turns out, the Dakota formation, that reduction in gas showed up there. So there was a communication indicated.

Now unless the communication is redeveloped June's production is almost double. During the month of June the GOR from that well was 1144, so it's true during the month of May the gas/oil ratio dropped from 8300 to 560 but I think once we remove the communication from the Dakota, and I might add that is the only Dakota in this pool that has the amount of gas associated with it that has -- well, it is the only Dakota well that has any significant gas production.

The Dakota formation is in an oil pool and an oil pool was established based upon the production potential that -- or production information and completion information that existed at the time.

Mesa Grande's well has performance that really is contrary to the other data that existed at the time we forged ahead with the Dakota formation.

Q Shifting gear slightly to another question we left open during yesterday's testimony. I believe Mr. Ellis was asked if he had an opinion as to whether or not the adoption of the recommendation made by Mr. McHugh in this case would allow for some recharge of the reservoir contributing in Mr. McHugh's wells from surrounding acreage.

Do you have an opinion on that?

A Yes, I do.

Q What is that opinion?

A The fluid, be it oil or gas, will always flow from an area of high pressure to an area of low pressure, and in the reservoir we're dealing with that is the case.

Now, one of the -- or two of the exhibits that I presented today depicted what we believe the reservoir pressure not in the vicinity of the producing wells but the reservoir pressure away from the producing wells was or is, and of course, the reason it's declining is because there is production from the pool and the -- I don't know if you remember, I could make reference to the specific graphs, but basically all of the data we have available so far and again we have sample pressure from over half of the wells that are completed, 32 out of the -- over half of the wells that are on production, and really over half of the wells that are completed.

To me that pressure information says we don't have dramatic pressure differentials in the reservoir. The reservoir pressure in the vicinity of Mr. McHugh's wells, in the high withdrawal wells, is not that much different from the average reservoir pressure all the way to the north in the area of Dugan Production's well or Mr. Mallon's wells.

So if we were to shut the reservoir in totally there would be some -- some minor adjustments in the pool, but the data we have right now suggests there are no major pressure differentials across the reservoir and so we wouldn't be really looking at pressure from the area to the north, which Dugan's Tapacitos 4 is in, down to the area in the south, which is where a predominant -- the majority of the production has occurred.

And basically the reason that it's occurred in that area to the south is that's where the bulk of the development activity has occurred. The area to the north is probably one of the areas that has the biggest chance of benefiting from what we're talking about today. That's where a lot of the undeveloped acreage is.

Q I'm sorry, a lot of the undeveloped acreage?

A Yes, sir.

Q There was some discussion with Mr. Ellis yesterday afternoon about the possible presence of free gas in the reservor prior to development. Do you have an opinion of whether or not there was free gas in this reservoir?

A Yes, sir.

Q And what is that opinion, sir?

A In -- based upon the fluid data that we have available, which is primarily some -- some pvt data from the West Puerto Chiquito Pool and we have two fluid samples from the Gavilan area, based upon that information if we had any production that exceeded the solution GOR of somewhere between 480 and 588 standard cubic feet per barrel, you would infer that there is some -- some gas that is being produced in addition to just the amount of dissolved gas that's coming to the wellbore.

Now there's a couple of reasons that you may be seeing a GOR higher than 588. One, these higher capacity wells, you're able to produce the well at a rate that allows your operating bottom hole pressure to fall below the 1482 psi bubble point pressure, you're going to start seeing not only the barrels of oil that come to the surface plus that dissolved gas, but you will see, probably, some dissolved gas from barrels of oil that are adjacent to the wellbore that are in the region, and again I don't know how far this region extends from the wellbore, but you will see that gas come to the surface in conjunction with the oil that you're producing and the reason the oil that's with that dissolved gas doesn't come too, is because of the differences in mobility of the gas in the fractured reservoir we have.

The relative permeability of gas to relative permeability of oil is very sensitive in a fracture reservoir such that a very small increase in gas saturation results in a tremendous increase in the gas mobility or gas ability to move.

Q What data do you have relating to the relative permeability of this fractured reservoir, gas versus oil?

A We have none that is specifically for the Gavilan Pool area. In fact, I really don't think there is -- this is a laboratory derived piece of information and the data we're relying upon is that that has proven to be fairly reliable in West Puerto Chiquito Pool, and again, this is a pool that's been in operation for 20-25 years and Mr. Greer took advantage of all the laboratory data that had been published at that time in fractured reservoirs.

Q Do you have reason to believe that Mr. Greer's reservoir was similar to reservoirs studied in the published data at that time and now your reservoir is similar to Mr. Greer's, is that the steps of logic dealing with relative permeability? Is that --

A In other words -- yes. I think I understood your question and it's pretty common practice in specifically reservoir engineering but in probably any field, when you -- you don't have the information you need for your specific instance, then you start looking at a distance away from where you're at and you try to get as close to the area as you're working and finding information that worked in that area.

That's basically what we've done with the Kg/Ko information and to some degree with the pvt data prior to Mr. McHugh actually obtaining this, and this is a fairly expensive operation and it requires a cash expenditure with basically no apparent, immediate return on your investment. Until Mr. McHugh obtained his pvt data and basically McHugh's pvt data is all we had until recently, and prior to that, Mr. Greer's pvt data was all we had to use, and because we are immediately adjacent to that pocl we felt it a prudent thing to use that information until we find something different.

Q When you say Mr. McHugh's pvt data was all you had until recently, is that mean that you have recently acquired some other information?

A Well, yes, sir. In Mr. McHugh's, he has, and I actually utilized McHugh's pvt data in my calculations that I've made. That was a fluid sample was taken in the Loddy No. 1 and again that -- that was the first pvt data that we had.

Mr. McHugh did sample the reservoir fluid in another well but -- and that being the Native Son No. 3. I have a real strong reason to feel that that data is not representative of reservoir fluid and so I've chosen to place my emphasis on the sample that was taken from the Loddy, which basically doesn't cast emphasis one way or the other. It brings us into a range of where I think it should be.

Q Do you have that pvt data available to you today, sir?

A I do not have a copy of it with me, Mr. Pearce. It -- in our study group that we've had basically two engineering subcommittees, I have personally provided a copy of that complete information along with Mr. Greer's pvt data to each of the engineering representatives that have participated in this study group which I -- the data is available. We're -- we're willing to share and give our engineering efforts to these committees to share a tremendous amount of data that Mr. McHugh's accumulated.

Mr. Greer's been more than willing to share his data with us and it's my understanding there is additional data that -- that other -- or it's not my understanding, other companies are beginning to be involved in this process.

Mesa Grande has actualy obtained a fluid sample that -- that we plan to have available to us when that information is available. It's so recent it's not available.

Q As I understand it at this time my clients do not have available that pvt data and we would like to get it as soon as we can, if you have no objection; whether you provide that through counsel or directly or directly to client. Mr. Kellahin?

MR. KELLAHIN: Mr. Chairman, I understand it's available to parties who attended the engineering committee meetings. If Mobil elects not to attend those meetings, I'll be happy to arrange with Mr. Pearce to provide him that information.

Q Mr. Roe, if you would turn with me, please, to what's been marked as your Exhibit Number Two, a graph which Mr. Lopez questioned you about. It's the orange sheet in front labeled Comparison of Solution Gas Drive Production History.

As I understand it, this graph was initially prepared and used sometime ago and represents the theoretical curves you would expect from a solution gas drive reservoir, is that correct?

A A solution gas drive reservoir that had a fluid in it that was similar to what we find in West Puerto Chiquito and that had a relative permeability characteristics similar to what exist -- what we believe exist in West

Puerto Chiquito, yes.

In other words, in order to compute this curve, in other words, you use a material balance equation. You need some pieces of factual information and Mr. Greer generated this curve in his area using data that was appropriate for his area and said that if solution gas drive is the only mechanism that you have in effect, this is what the performance of your GOR and pressure should be barring any other influence on recovery.

Now, this wasn't a forecast of his unit recovery for the simple reason that he had other factors influencing his production, but had nothing else other than solution gas drive been responsible for oil recovery at West Puerto Chiquito, this is the prediction of gas/oil ratio and pressure performance that we should expect, yes, sir.

Q Would you expect these curves to accurately reflect and/or depict the Gavilan-Mancos Pool production in view of the testimony which is this is at least primarily a solution gas drive reservoir?

A Our primary reason for using these curves is to show -- I'll answer your question specifically but I'd like to add some additional detail.

We use these curves not to predict what the gas/oil ratio is going to do in our Gavilan area. We just -- my reason for using these was to depict what the gas/oil ratio should do given our permeability properties and our pvt data properties that we think are valid, and so it was just a visual picture to show that as pressure comes down the gas/oil ratio should go up. The rate at which it goes up is something that really accelerates with time. I'm -- I do not intend this to be a predictive tool in our Gavilan area. Our reason for plotting -- I've even indicated that we plotted the gas/oil ratio versus cumulative as it occurred. Had I really wanted to use this as a predictive tool, I probably would have made an effort to reduce the cumulative production and back out the free gas production and try to plot what really happened with respect to pressure and gas/oil ratio.

But to answer your question, it's just to be a pointer of what we should expect and then show that gas/oil ratio is coming up as pressure goes down.

Q Okay, and as a pointer of what we should expect, looking at this graph it does not appear to be related at all to time; that the rate of production, of the recovery reflected along the lower axis does not appear to be affected at all by rate of that production.

A Yes, that's correct.

Q Is that a characteristic of a solution as drive reservoir?

A Yes. In a reservoir that has only solution gas as your drive mechanism, that is correct.

Q And would you expect that to hold for the Gavilan-Mancos Pool as you understand it now?

A No, sir.

Q And why is that?

A Well, because there are several other factors that -- that are going to come into play here. I do feel that solutin gas drive in our area is the primary means of moving oil from the reservoir boundaries to the wellbore.

I also feel, because we're dealing with a reservoir that's approximately 400 feet from top to bottom and there are some areas of the reservoir where we have a productive interval that extends approximately 800 feet. In other words, there's some areas of the reservoir we have additional pay development lower than what we're calling as the main Niobrara Mancos , Niobrara producing interval and that consists of three zones in the Mancos that are -- comprise about 400 feet.

Within that 400 feet we feel fairly certain that there is some fractures that -- that cover a fairly large vertical area, and within these fractures as you allow your pressure in the wellbore area to reduce, you allow gas to evolve from the -- from its dissolved state and form a free gas phase and that will allow gravity segregation within the fracture or within the reservoir and that in turn will allow the producing channel for gas to move through the reservoir and be produced without actually displacing oil along with it, and so this is where it becomes important that we give some thought to how the reservoir is produced from here forward because it's conceivable that a high GOR well being influenced by a free gas phase, no matter how it exists in the reservoir, the operator of that well is going to produce up to his allowable whether it's restricted by gas volumes of oil volumes in order to get his -- what he believes his share of the production to compete with his neighbor that may not be quite as influenced with this gas/oil ratio, and that will result in the dissipation of reservoir energy that will not be efficient in producing oil.

And this problem is really enhanced when you put high capacity wells offsetting undeveloped acreage. The people get in there and drill a well, protect their wells, they're going to encounter interference from the high capacity wells and it can possibly even encounter a gas/oil ratio.

Q Okay, that brought to mind another question.

I don't understand how you can calculate or discuss the permeability to gas or oil of a fracture. Could you try to explain to me -- as I understand, a fracture is just an open channel and I don't understand the discussion of permeability with regards to a fracture. Can you explain it to me?

A I'm not sure what you're asking, Mr. Pearce. You're wanting to know if -- what permeability is?

Q Well, I understood you to say that you had a Kg/Ko, that the relative permeability in this fracture system --

A Yes, sir.

Q -- and perhaps I don't understand when you say a fracture system. I thought of that myself untechnically as an open channel of some size, some dimension.

A That's correct.

Q It sounds to me like that would be infinite permeability as I understand permeability.

A Well, yes, that's correct. It would depend upon the width of the fracture and the continuity of the fracture. When -- whenever rock or anything is subjected to the stresses of fractures the fractures aren't necessarily nice long, continuous holes that are so far apart. Again I'm interjecting a little of my personal ideas of what the fractured reservoir looks like, but it might go for a little bit and it has a deviation over to another fracture that requires interconnection and earlier today there was some -- some direction towards maybe a preferential directional fracturing and it's not uncommon to see that, but the mechanism that causes fracturing also results in a lot of inner -- inner fracturing and so on a very large scale a fractured reservoir is -- is nothing more than probably would be similar to a reservoir that the matrix productivity is provided by these all interconnected fractures, which is totally that much different from a porous system on a very large scale.

Q As I understand it, Mr. Roe, in the theory of producing solution gas drive reservoirs, it is necessary for the pressure to decline, is that correct?

A Yes, sir, yes.

Q And you've indicated that the primary production mechanism in the Gavilan-Mancos Pool, in your opinion, is solution gas drive.

A Yes.

Q You've indicated to me that pressure in the Gavilan-Mancos Pool is decreasing.

A Yes, sir.

Q And that it is -- production is now occuring below the bubble point.

A That's my belief.

Q Your opinion. If that is what one should expect from a solution gas drive reservoir and we have a solution gas drive reservoir, I don't understand what the problem or the emergency is.

A The primary concern on our part is that the -- the rate that the pressure is declining is increasing. Two of my exhibits presented that information. In other words, the rate in terms of psi per day in the reservoir that -- the rate at which that pressure is declining is approaching a point that is very high.

To contrast this just a little bit, in the West Puerto Chiquito Pool Mr. Greer has tried to maintain the rate of pressure decline in the range of 10 pounds per year.

On one of my exhibits I showed you a well that was declining that much each day and I -- we're concerned that if we don't do something to reduce -- what we're really asking for is with the study we've done so far, it appears to us that the wells throughout the reservoir have the ability to drain areas much larger than we're currently developing on and if that is the case, which I believe it is, and I know there's a tremendous amount of undeveloped acreage.

On my Exhibit Number One I showed you there's 13 additional wells that are planned right now that I know about.

What -- what's going to happen is the operators in the general area are going to drill these wells to develop their acreage. They're either just being prudent to protect their leases from drainage; development to keep their leases from expiring; or just flat development because there's a big well offsetting them, and what they're going to find when they get in there and complete a well, they're going to find that the offset well -- our data indicates that they're going to find their part of the reservoir has already been influenced by the offset production and so you're going to have two wells that are going to be competing for the same reserves. That, in my opinion, will result in the drilling of one unnecessary well, but it is going to be a necessary well if we have the current development on 320 acres and competitive. In other words, it's going to be necessary by virtue that independent operators are going to have to develop their leases. We have a tremendous amount of data that says we don't need one well every 320 acres and I've been skirting around it all day, but we have a tremendous amount of information that says we need to look very seriously at unitizing our area so that we can control where we locate the wells, drill only the wells that are necessary in order to produce the reserves that are there, and our pressure data suggests that there is definitely a fixed amount of reserves.

We haven't tried to determine what that fixed amount is but we have determined that there is not an infinite amount of reserves in that reservoir.

Q Okay, looking back at the graph which we discussed earlier, it appears to me that that graph of solution gas drive reservoir in fact has a steep set of perfs.

A Yes, sir.

Q Pressure decreases steeply. The GOR increases steeply.

A That's what causes us concern, is that's what you should expect, yes.

And in, Mr. Pearce, let me just reiterate. I guess I'm not saying what I mean.

Because the data in the West Puerto Chiquito Pool says that -- and again I'm not saying this is West Puerto Chiquito Pool, because Mr. Greer has gravity drainage and he is maintaining pressure by gas injection, but using his data and accepting it as the best available right now, it tells us if we don't do anything else, which includes take advantage of the minor amount of gas or gravity drainage that probably will occur in our area, I believe we have some gravity drainage. It's not going to be as great as the area to the east of us simply because our beds are not dipping like they are in the West Puerto Chiquito Pool, but any time you have a reservoir that's 400 feet thick, even within the wellbore production -- or the wellbore area in the production unit, you will have gravity segregation occurring and what this curve is tellling us is exactly what you're saying, the pressure drops and we are approaching a point, and that's why I superimposed some data from Gavilan on this curve, is it says, by golly, we're approaching a point that our GOR is just going to go out of sight. Our production data tells us that's starting to happen on two of the curves that Mr. Ellis presented yesterday. We see that on several of the wells. We are approaching a point that just since the first of the year our gas/oil ratio is starting to go out of sight.

We've got -- Mr. McHugh has one well that the gas/oil ratio is going up every day.

Dugan Production operates, provides the daily operation of Mr. McHugh's wells and we -- we see that gas/oil ratio going up every day and it tells me that whether we're exactly right with our data or not, our data is in the right ballpark. The reservoir is producing like you'd expect it to produce and if we allow right now the -- as my two exhibits indicated, the rate of pressure decline that is occurring in the reservoir is at a rate that is accelerating. In other words, with each month that our voidage goes up our amount of pressure decline in terms of psi per month is accelerating to a point that our solution gas/oil -- this chart says it should, and in my own concern at this point, is in order to protect acreage from drainage operators are going to be forced to drill unnecessary wells.

They're going to see these are not cheap wells. If you have no trouble at all and you have the best luck possible, you're looking at a half a million dollars per well in round numbers to drill, complete, and equip for production, and at the current market conditions, that's -- this is going to be an economic catastrophe if we go drill another hundred wells in the reservoir in order to protect our -- in order to -- forget whether we protect the leases from drainage, in order to develop your -- your leases you've got to drill to meet offset production and if we do it on the existing one well every 320-acre spacing units, the rate in terms of psi per month that the pressure is going to drop, already to the level where we can see an end to the life of the reservoir.

In other words, I said earlier, another year and a half or two years, that's not a magic number, but we -- the end is in the foreseeable -- we can see the end. In other words, we've come -- we're down to a level of 1400 pounds in the reservoir and we've confirmed that that pressure exists throughout the reservoir, and operators who have undeveloped acreage are really the ones that need to be concerned with what we're telling them here today.

Q But I gather that you do not expect any signficant impact on ultimate recovery from this reservoir.

You're talking about the number of wells that should be drilled to develop the reservoir and the amount of time which should be used to produce those reserves.

A No, that's not what I meant to say. The -- it's also my opinion that recovery from the reservoir will be affected. I did say that in the solution gas drive reservoir if there are no other mechanisms taking place, the faster you produce it or the slower you produce it, the ultimate recovery probably will be the same, but because we, I feel, we do have gravity segregation occurring, we do see wells in the reservoir that are producing with higher gas/oil ratios than other wells, we're going to see gas production in the form of what appears to be free gas at the producing well dissipated and that gas will not aid in any oil production. We'll wind up having a higher residual oil saturation in the reservoir if in an effort to get oil underneath any particular lease we produce a well with a high gas/oil ratio aimed towards getting all the oil we can, and so it is my belief that we do have gravity drainage no matter to what degree, I do believe it exists in our area.

If we could get together on a unit and control the number of wells it would allow us the opportunity to drill a well and produce wells, only the wells that have a lower gas/oil ratio and take advantage of the gas that has formed in a gas cap, if such a gas cap exists, and it seems only equitable to me that the people that have the undeveloped acreage down dip are the ones that are going to be hurt worst, because if a guy up structure produces an unequal amount of the gas in the reservoir, the guy down dip is not going to have the gas available to displace his oil to his wellbore through this media, the fracture system or whatever we have in the Mancos formation, and if that happens, we can affect oil recovery from the reservoir by controlling the number of wells that are drilled.

Q During his testimony yesterday Mr. Ellis indicated that he believes some period of interim rules were necessary, at least as I recall the gist of his conversation, for two purposes. One, to further study the area, and one to approach other operators in the area about the question of unitization.

A I -- if Dick didn't say that, I feel that that's necessary and I do think he said that.

Q Let's assume for a minute that McHugh and other interested parties are not successful in unitizing the Gavilan-Mancos Pool. How will other interest owners in the area protect their correlative rights?

A The, as I understand it, right now the only way to protect your correlative rights is to drill a well and I think we have a sufficient amount of data that tells us that additional drilling is going to encounter a reservoir that has been influenced by the existing wells and -- but right now, the only way everybody's correlative rights are going to be protected is with one well on every 320-acre spacing unit.

Q Do you think this reservoir is a likely candidate for some sort of secondary recovery?

A I have a lot of mixed emotions on that. I think if all of the operators agree upon some sort of a unit that would provide an equity everybody was satisfied with, and I think given the current market conditions, in other words gas isn't worth anything anywhere if somebody wants it, I think that it would be a prudent thing to do for the operators in our area, we have a gathering system already installed in the form of a -- in other words, most wells are connected for gas. Out of the 59 wells that are completed only 16 are not connected and some of those 16 are connected, they just haven't got their gas contract squared away, I think it would be a prudent thing to do to on a test basis put some gas into the ground and see if we can't esta-blish a -- or arrest the decline in pressure.

Now, I, because we don't have a lot of structural relief in our area, I'm not optimistic that we're going to have the same pressure maintenance project that exists in the West Puerto Chiquito Pool.

Q In view of your opinions about the fracturing and interconnection of these wells, do you suspect that the wells that have already produced in this pool have produced reserves outside of their 320-acre spacing units?

A I think that based upon the pressure interference data that we have, it's very clear to me that any well that has any production at all is probably draining an area larger than 320 acres.

Q To the extent that producition has drained undeveloped acreage at least to this point counter-drainage has not been possible, is that correct? You can't counter-drainage an undeveloped tract, can you, Mr. Roe?

A No, that's what's got us concerned is in order to develop your acreage you need to jump in there and drill a half a million dollar well and when you do you're going to get -- everybody has that right to do that tomorrow if you can get an agreement with the landowner and you can get a -- come up with a half a million dollars, you can find somebody who's going to provide you with tubular goods and find a contractor that's willing to do what you ask him to do, you know, that's -- that's right and right now that's the only way to preserve your correlative rights.

Q When you were discussing an area that was objected to some this morning, I just want to go back and have you explain what you do -- what you did when you were talking about the drainage you suspected was indicated from those pressure tests that you did, interference tests. You were simply taking the distance to the well that showed the interference, drawing a circle and calculating the acreage inside that circle?

A Yeah, I did two thingss. That was -- that calculation resulted in the lower number and that's why, if I didn't, I meant to say that would to me indiate a minimum drainage radius because that was telling me that something we did at one point in the reservoirs actually influenced a point that far away, therefore that would equate to a distance one directin from the well, and assuming that would be a minimum drainage radius, assuming that it would also affect something the opposite direction away from the well, then scribing a circle that had that radius, that would be an area that would be the lower of the two numbers.

Now the higher of the two numbers that I usually quoted was basically saying okay, we'll -- this imaginary reservoir that exists in nice square units, I just said okay, 6800 would be, assuming the distance between wells was 6800 feet, basically that would be just one-half of a square. It -- the square would be really somethig two times 6800 and then that would give you a nice, neat little square that this well's going to drain, which is the way reservoir's are always spaced, in nice, neat 40-acre units, 640-acre units.

Q In your work with this reservoir, Mr. Roe, have you developed an opinion on whether or not the matrix contributes to the production of the oil in this reservoir?

A I -- I have a personal feeling that the matrix is not going to contribute significantly, but this is a question that we had quite a bit of discussion in our engineering study group. I am aware that there's a big, a big variation from -- from my end of thinking the matrix is not going to contribute to another end of the thinking that the matrix is going to contribute.

With the data that's available right now, I don't think it's totally clear, it isn't clear to the point that we can all agree as engineering people; in other words, not representing individual companies.

When the nine people met at our last engineering committee meeting, we did not all agree what the facts were, or we all agreed what the facts were; we just didn't all agree to the importance of the facts, and so under the guidance of our operating engineering committee I -- I have prepared a letter that was distributed to all of the operators that basically are listed in my Exhibit Number One, requesting that, and this isn't -- I said I did, I took the responsibility to prepare the letter and sent it out, but it was mutually agreed by all at our engineering committee, because it is that important, apparently, to -- in other words if we're ever going to get a common agreement we have to resolve that issue and so we have proposed, the engineering committee, that on a cooperative basis, and Mr. Mallon has indicated he's willing to let us use his well to do this, that six 60-foot cores be taken and the cost of taking those cores be shared amongst the operators in proposition to the wells that are completed currently.

This core that we're proposing is in Mr. Mallon's well that he's got in the southeast quarter of Section 3, of Township 25 North, Range 3 West, that he spudded just recently and if all operators in fact approve our proposal, Mr. Mallon, providing well conditions permit this core to be taken, we plan to take that core. The analysis of that core will be determined cooperatively and the costs of all of this, which we're estimating to be $80,000, will be shared, and the information gained. The testing procedure will be determined on a property basis, so we think it's important enough to resolve that issue that even though I don't think it's necessary, I have strongly encouraged Dugan Production to participate in this. For what it's worth, the only company that has approved that AFE, or the only one that I'm assuming, Mallon Oil has approved the AFE, although I have not seen their AFE, the only AFE I have that is signed is McHugh's AFE and he represents about 39 percent of that total expenditure, or he'll have to pick up the tab for that.

And it is also my understanding that Mr. McHugh's people don't think this core is necessary, but because we recognize the importance of having this issue resolved, and it will be important to the reservoir, we're willing to -- to gather the data because if we are -- are wrong, there's no real harm done; we've just delayed things for a little bit. If the matrix does contribute, we're all going to be happier.

My boss thinks -- he hopes there is matrix and that it does contribute because then I'll be wrong and he's going to have a lot more oil than I've told him he's got.

Q But in order to produce that oil out of the matrix the pressure has to be lowered, doesn't it?

A That is -- that is totally correct. One of the basic fluid flow equations relates the rate at which pressure is -- or the rate at which fluid is produced as being dependent upon the amount of pressure drop, but as I've indicated earlier, the -- well, let me qualify that.

Given a constant permeability, the only thing the pressure drop is going to control is how fast the fluid moves from one area of high pressure to an area of low pressure.

Given the pressure performance that I've indicated earlier, pressure is declining in the reservoir and so if -- if there is matrix, it's contributing right now. Now it's true that the maximum rate that that matrix will contribute will be at the economic limit when the reservoir pressure is totally depleted but as far as whether the matrix is contributing or not, unless there's been some new revelations since Marcy did his work, any pressure drop will result in a fluid production and I think I've indicated that we've got wells that have had 300 pounds of pressure drop in them, so if the matrix, like I say, I have -- I don't think it does, but my boss sure hopes it does.

Q Looking, sir, at the plat of the area of the interference test that you discussed earlier, do you have an opinion on whether or not you'd expect to see the same sort of interference test results if this test were conducted in other portions of the Gavilan-Mancos Pool?

A Yes, I -- we would expect similar results. We already have kind of an interference test in effect from other areas of the pool that I presented on my exhibits for the Loddy No. 1 and the Dr. Daddy-O. The only difference between the two is we're not real sure what's causing the interference that we measure in the Loddy and Dr. Daddy-O because this is an area of the reservoir that there's too many other things going on.

One of the things that made this pressure interference nice was it was done cooperatively. Dugan Production, we physically did not complete our well for about three months even though we were ready to, we had one of our partners that had a drilling rig that wanted to do it. I really has my neck stuck way out there because only because I wanted to participate in this pressure interference test, we delayed our well being placed on productionk knowing that drainage probably was occurring, but between Mallon Oil, Dugan Production, and Greer, BMG, we were able to coordinate which wells were producing and which wells weren't producing.

Mr. Greer even delayed the completion on his N-31 in order so the early part of the interference test, the only well that was producing was the Mallon Oil to the -- to the west and Mallon even cooperated to the point of trying to fluctuate which wells he had on production so we could try to pick up which well we were seeing. Were we seeing the 1-8 or were we seeing the 1-11, and I think our test was conducted in a manner that this information is available on graphs and recorded so that I can tell you when we saw a change in the Howard Federal 1-A versus when we saw a change in the Mallon 1-11. I don't personally think that we observed any pressure interference in Dugan's well. The primary input Dugan's well had, once we completed it we monitored reservoir performance when we stimulated our well and the same thing goes with Canada Ojitos Unit N-31, the completion on that well was delayed for a sufficient length of time that it did not interfere with our test.

So even though these are located on 160-acre distances from each other, we -- we basically were observing the production of only one well at a time, not all of the offset wells at a time.

Q All right, sir, looking at that plat, the E-6 and the N-31 are in the Canada Ojitos Unit, is that correct?

A Yes.

Q And as I understand it, that reservoir is subject to a pressure maintenance program, is that correct?

A Yes, it is.

Q Do you have an opinion on what effect the pressure maintenance program in the Canada Ojitos Unit has upon the E-6 and the N-31 wells?

A You're -- you're asking a question that basically is answered only with further study. It's why we're here today. It's why I've been a strong advocate of Mr. Greer being involved in our engineering efforts and it's why Mr. Greer's here today, is we're not sure just exactly how production in our area is affecting the pressure maintenance in his area.

There are some pretty serious problems here and that's one of the primary reasons if we don't do something to come to a better understanding of what's happening in our area, how is our area affecting adjacent areas, there's -- there's some pretty serious problems, and we need that time and that's the basis of McHugh's application.

Q May I have just a moment, sir?

MR. PEARCE: I have nothing further. Thank you, Mr. Roe.

MR. STAMETS: Are there other questions of this witness?

Mr. Padilla.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Roe, you testified about a pressure decline, I believe, in the Dr. Daddy-O Well that was characterized as a drastic pressure decline of 10 psi per day, something to that effect, and you made a comparison with the pressure decline in the Canada Ojitos Unit.

Isn't the pressure maintenance in the Canada Ojitos Unit, isn't it a fact that the pressure declines in the Canada Ojitos Unit?

A Yes, I -- I didn't mean -- yes.

Q You've answered my question. Now, what wells offset the Dr. Daddy-O Well?

A In all directions?

Q Yes sir.

A Okay. To the west is Mobil's Lindrith B Unit No. 34 and to the northwest would be McHugh's Full Sail No. 1.

To the north would be McHugh's ET No. 1.

To the northeast would be McHugh's Full Sail No. 2.

To the northwest, also, is McHugh's Native Son No. 2. Now I'm taking the liberty to give you wells in an area that I think may influence this well.

Quite a bit to the east would be McHugh's Native Son No. 1.

To the southeast would be McHugh's Homestead Ranch No. 2 and to the southeast, also, would be McHugh's Native Son No. 3.

To the southwest Mobil has their Lindrith B Unit 37 -- southeast, Lindrith B Unit 37 and to the south, directly, is their Lindrith B-38.

And in the southwest is McHugh's Lady Luck No. 1.

Now these are all within a maximum distance of 8000 feet. The way I understand the reservoir, really, everyone in the reservoir offsets the Dr. Daddy-O No. 1.

Q How has McHugh produced the offsetting wells that -- during this time period, your period of --

A Well, all of the wells that I mentioned were -- were producing during the time -- well, I say all of the wells. I think even Mobil's wells. The Lady Luck is the only well that was not producing during our pressure interference test.

Now, again, I called it a pressure interference test. That is the weakness of measuring pressure at a point anywhere. You never really know for sure what's affecting it.

Referring back to that -- that graph that you're making reference to, there were some things that happened that we -- we can get some ideas of which wells may have been influencing the pressure drawdown. For instance, during July 10th the rate of pressure drop in that particular well changed from around 6.25 psi per day to 1.45 psi per day, a very dramatic change in the rate the pressure was declining.

Well, in the --

Q Is this one of the wells, is the Dr. Daddy-O well one of the wells you did not include in your 19 well representative sample?

A No, it, in fact, it was one of the wells. In fact I think we actually pointed that out in my testimony, is that the Dr. Daddy-O and the Loddy and the E-6 all -- all were on both plots.

They were at least on the second plot. I don't remember whether they're on the first one.

Q Well, is that a representative sample, then, the Dr. Daddy-O, is that a representative well in the group with that kind of pressure decline?

A Well, bearing in mind that this pressure is --

Q You're not answering my question.

A Okay, maybe --

Q My question is whether or not the Dr. Daddy-O is a representative well in your sample?

A It -- the pressure that is --

Q In view of the pressure decline.

A All right, forget the pressure decline. The final pressure that is measured --

Q My question is --

MR. KELLAHIN: He's asked the question of the witness. Let the witness answer.

MR. STAMETS: I believe the witness is being responsive to the question and I, like Mr. Padilla, would like to hear his answer to the question.

MR. KELLAHIN: May we have the question over, please?

Q In view of the pressure decline on the Dr. Daddy-O Well is that, is the Dr. Daddy-O Well a representative well in your sample 19 wells?

A Yes, I think so. There are other wells that have that same absolute pressure that we have measured currently in July. This is not the only well in the reservoir that we've measured this pressure in.

Q Well, then let me ask what other wells had a pressure decline that is that drastic, of those 19 wells.

A Okay, well, let me just emphasis the latter part of this pressure decline is more in line with the pressure declines I've presented on several of the other wells. In other words, the final rate of pressure decline is 1.57 psi per day. I believe that's a number that is presented on this graph.

What is happening in the early part where we have this approximate 10 pounds a day, and again, this was a fixed time period that we had approximately 1800 barrels a day in the immediate area, mainly from the wells that I just identified for you. They were all on production and that's what I was going to mention just a minute ago when you asked another question, was on July 10th the rate of production in a lot of those wells that are in this area was reduced simply because the pipeline pressure went up and the pressure decline changed from 6.25 psi per day down to 1.45 psi per day, and this is one of our biggest concerns, and this is one of our biggest concerns presented right here, is what we're seeing in the Dr. Daddy-O is what you're going to see in every other well out there is that in the vicinity of high capacity wells such as the Dr. Daddy-O.

So this isn't unique. This is what you're going to see. This is the only well we've measured these kind of pressure declines in simply because it's the only well we've had the ability to run a pressure bomb in that is also adjacent to approximately 1800 barrels of oil per day production.

Q But you've never run a formal interference test between this and other wells, is that correct?

A Not the Dr. Daddy-O but there is two other wells in this general area we have recently run a pressure interference test in, yeah.

Q You've testified, Mr. Roe, that you did not make a material balance calculation, is that correct?

A That is correct.

Q Have you used a material balance calculation in your work experience?

A Have I ever?

Q Yes, sir.

A Yes, I have.

Q Can you tell me what the material balance calculation is used for?

A You can do two things with a material balance.

You can, one, get an idea of what your oil in place really is and you can use it as a predictive tool once you -- for the future performance of the reservoir.

Q I refer you now to your Exhibit -- Dugan Exhibit Number Two and go to the yellow sheet.

As I understand in reference to the questions made by Mr. Lopez, the 100-million barrels in place is not -- is a guesstimate of some sort, is that correct?

A It -- it's an effort to provide a scale at the bottom of the graph. Yes, it's an estimate, that's right.

Q Would a material balance calculation help you in inserting a more correct figure in this estimate?

A I don't think it would have affected us putting a million barrels there because the exhibit was -- was prepared simply to reflect the percentage of oil in place, the recovery of percentage of -- recovery in terms of percentage of oil in place. But, yes, and this is one of the objectives of our study group, is to come up with that.

Q So in other words, we don't have what the total reserves in place are today.

A That is correct.

Q Now that we're on that exhibit, let me ask you some questions so I can understand this graph.

Assuming the pressure decline in the Gavilan would not be as drastic, in other words, the slope could be flatter, what effect -- what effect would that have on the GOR line at the bottom?

A Well, if that's what we're in fact measuring, which it isn't, it would shift everything to the right. In other words, it would delay the gas evolution from -- or it would delay the rate at which gas was evolved from the well.

But I would stress that's not what we're measuring.

Q Is there a relationship between the pressure decline line and reserves in the ground in this case?

A Yes.

Q What is that relationship?

A You want me to tell you what this gas material balance formula is?

Q Yes, sir.

A I can't do that off the top of my head but that information is pretty well documented and anybody that's been through petroleum engineering has had some exposure to that in school.

Q You don't have that figure yourself?

A Do I know it by memory?

Q (Not understood,)

A It's the same formula for any -- any pool. It's a formula that was generated and it doesn't make any difference where you're at, you use the same formula. The only variable would be Kg/Ko and oil pvt data and the properties that pertain to your particular reservoir, but the formula is not something unique to Gavilan.

Q You don't have any independent Kg/Ko data for the Gavilan wells?

A That is correct. We've done the best we can and that's used the data that's available at West Puerto Chiquito.

If all operators were as prudent as Mr. Greer is, that information would be available in the Gavilan.

Q Well, let me ask you, has Mr. Greer divulged that information to all the other people in the study committee?

A Yes, sir. I personally have provided a copy to each of the engineering representatives that have been in attendance. In fact, I even provided a copy of that to a lot of the working interest owners who've attended either our first or second meeting in Mr. McHugh's office in Denver.

Q But McHugh did not participate in the interference test of the wells in the northeast of the pool.

A Well, he had none of the wells involved. The only people that could participate were the people who had wells in the area, which the people that were there did participate, was, like I say, the only wells that could have been involved were -- were the people that did participate, and that's BMG, Mallon Oil, and Dugan Production.

Q What -- has McHugh formulated any plans to unitize the Gavilan-Mancos?

A We -- we haven't gotten past the point of recognizing -- for a long time there was a tremendous resistance to even considering that possibility. In fact I've made a big effort today to not use the word "unitize".

Q You've used it extensively today, I think.

A Yeah, I know. I'm trying to not use it as often as I wanted to.

There's -- there's a big difference of opinion as to whether we need to unitize or not but I do think Mr. McHugh's data, Mr. Greer's data, and any data that we've accumulated, plus data that all of the other operators have accumulated, including Meridian and Southland and Mallon Oil, Mesa Grande Resources, we have shared that data and I think the engineering and geologic people that have attended the two subcommittee meetings recognize the importance of evaluating that data and coming to a conclusion that, yes, we do need to unitize or no, the best thing to do is basically rape the reservoir and get what you can with the wells you've got, and a matter of importance is McHugh's in the best position to do that.

Q Has McHugh initiated any voluntary -- any efforts to voluntarily pool his acreage with other people?

A Pool it for units greater than 320?

Q Yes, sir.

A I'm not sure that I understand why there'd be a need for that under existing spacing.

Q You're an advocate of unitizing and I'm just wondering whether or not McHugh has made any efforts to voluntarily unitize the area, his acreage.

A Well, why would you want to have one unit allowable when you're going to be offset by everybody else who's drilling o 320's. I think that's what we need to evaluate at this current date of development. It appears to me that if anything's to be done it is unitization. A change in spacing isn't going to affect development unless everybody in the pool develops on a larger unit.

But Mr. McHugh has been strongly behind our -- our efforts to get something moving on our unitization evaluation.

In fact our first two meetins were in Mr. McHugh's office and any expenses related to those meetings were totally carried by Mr. McHugh.

Q You testified this morning about a well on your sample of (inaudible) wells and I believe you used the word "anomalous".

A I'm sorry, I didn't hear.

Q There was one well in your testimony that you described this morning that you characterized as anomalous and you took it out of your 19 well sample.

Could you tell me which well that was?

A I don't -- in other words, we excluded from the pressure data?

Q Yes, sir.

A Gosh, I don't think I said that. Now we did exclude production information from two wells that we -- in other words, when are generating our poolwide GOR history, we excluded production information from the Gavilan Howard 1 and the Gavilan 1 because I felt that to be anomalous, but I don't --

Q I believe it was the Gavilan 1. Why did yoiu exclude that well?

A Because from the date of first production it's had a gas/oil ratio of 1000 or greater, and that is anomalous to what we think the reservoir performance -- we don't really understand why it's that way.

Q Well, isn't that indicative that it's in a different pressure system?

A Our pressure data doesn't support that.

Q You don't have any other theory for it being different from the other wells?

A Yeah, I have. This is one of the things that we need to resolve in our engineering committee is what really happened there.

Q Well, aren't we here at a premature time, then, if we haven't resolved that sort of anomaly?

A I don't think so, Mr. Padilla. If we wait for another two months to come back and then discuss what we need to do, the pressure is going to be lower by another 60 to 70 pounds in the reservoir, and in what we would think the performance of the reservir should be, that's going to be a critical -- critical thing. Right now time is of very big importance.

Our study group has been trying to get engineers from all companies together and evaluate this very matter for some time now and --

Q Don't you also want to wait for the Mallon core sample as well to further study the reservoir?

A We don't want to wait until that -- it is available to start. We've already started. We would -- we're now waiting for the core data, and we are anxious to get that and we recognize there's a good chance that we won't get it.

As I indicated, Mr. Mallon is going to need to know from us within a week what -- whether -- because I'm pretty sure he's not going to pay an additional $80,000 to get a core so we can all benefit from it, and right now Mr. McHugh's the only one that's approved the taking of that core.

MR. PADILLA: I believe that's all I have, Mr. Chairman.

MR. STAMETS: Thank you, Mr. Padilla.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Roe, it's getting late in the day and I would hope that you can keep your answers as short as they possibly can be.

You've indicated that GOR's are

increasing in this pool and there have been numerous questions saying well, isn't that standard in a solution gas drive pool and everybody's agreed that that is standard operating procedure.

I'm not clear on why these high GOR's are more significant in this fractured shale reservoir than they would be in the sandstone reservoirs that we commonly have for oil.

Could you tell me why?

A Yes, sir, and I might just mention if time is important, I'm pretty sure that Mr. Greer has some of his exhibits that will address that very issue, but real quickly --

Q If Mr. Greer is going to discuss any of these issues then I'll defer to Mr. Greer for everybody's convenience at this point.

A I believe Mr. Greer is in a better position to present his data than I would be.

Q Okay, very good. Let's see if Mr. Greer's going to answer this question.

What potential actions can be picked in this reservoir that have an opportunity to work which will increase the ultimate recovery from the reservoir, not just save dollars on perhaps unnecessary wells, but actually get more oil out of the reservoir?

A Right now my primary thought would be that we could avoid the production of high GOR wells simply to make your allowable. We could preserve that reservoir energy in ower structural wells and that will result in improved recovery from the reservoir.

Q Okay. Perhaps you might want to take a crack at this while we are away before the continuation of this, or maybe Mr. Greer would -- no, he probably doesn't want to do this -- in any event I'm curious if -- if we would be as effective in reducing reservoir voidage by reducing the gas/oil ratio limit to some figure which approximates 588 MCF a barrel as we would be reducing the GOR to 1000 and reducing the oil allowable to 200.

A I made a calculation of just that very case and it's true we will have a reduction in voidage. I haven't -- not that exact case but I have taken a look at, say, reducing to 700 and 1000 GOR, and the reduction in reservoir voidage wasn't -- it didn't bring the reservoir voidage down to the current level or, say, May's level.

Q Let me ask you if you would have any objection to making those calculations at 588 or 600 before the next hearing?

A No, I would be happy to do that.

Q And I also would ask you to, through Mr.

Kellahin, to make it available to the other counsel as quickly as you could so they might be able to get it to their people and save all these conferences that we have every time somebody testifies as to something different.

MR. PADILLA: Mr. Chairman, we have that calculation.

MR. STAMETS: You do? At what GOR?

MR. PADILLA: 588.

MR. STAMETS: Outstanding, so we've just saved you a lot of work.

Would there be any objection to sharing that information with everybody else before it's put on?

I have no requirement at this time; just trying to speed things along.

MR. PADILLA: None whatsoever.

MR. STAMETS: Okay. Again if you could make those available to the other people, we would appreciate that.

Another area that I'm kind of interested in is economics. We are talking about additional and if we are talking about additional recoverable up here, what's the production today, what's the value of that additional recoverable oil? Whatever we do in preventing waste, we also have to consider that's sufficient economically, so if there will be any information on that by any of the witnesses we certainly will appreciate it.

Perhaps this is a question that doesn't need to be answered now but if you have an answer, I'd appreciate it.

Will ninety days be enough time?

A It conceivably could be and we hope that it is because we see the matter as being that important that we have an answer in ninety days.

MR. STAMETS: Are there any other questions of this witness?

He may be excused.

And as of right now we would reconvene this the 21st of August unless there is serious objection and we also have the 22nd. That would be Thursday and Friday.

The hearing will be in this room. If we have to go on Friday we will have to move up the street to the capitol building which is the only meeting hall available that we can think of.

Does anyone have anything further that they need to get done today?

There being nothing, we will --

MR. LOPEZ: Mr. Chairman, I might just inquire if Mr. Roe will be available for additional examination when we reconvene or whether he's going to be excused and whether we're going to continue the hearing or whether we're going to recess now.

MR. KELLAHIN: Mr. Chairman, Mr. Roe has just been excused as a witness and I don't know that I will recall him.

MR. STAMETS: The Commission always reserves the right to recall a witness; however, considering the number of witnesses we have, it would take something extremely serious which could not be covered by any other possible witness before we'd agree to bring him back.

If there is nothing further then, we will recess this hearing until August the 21st at 9:00 o'clock.

(Hearing recessed.)

CERTIFICATE

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

Sally W. Boyd CSR

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

21 & 22 August 1986

COMMISSION HEARING

VOLUME II

IN THE MATTER OF:

Application of Jerome P. McHugh and Associates for an amendment to the special rules and regulations of the Gavilan-Mancos Oil Pool... CASE 8946

and

Application of Benson-Montin-Greer Drilling Corporation for the amendment to the special rules and regulations of the West Puerto Chiquito-Mancos Pool ... CASE 8950

BEFORE: Richard L. Stamets, Chairman
Ed L. Kelley, Commissioner

TRANSCRIPT OF HEARING

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I N D E X

I N D E X CONT'D

I N D E X CONT'D

EXHIBITS

I N D E X CONT'D

MR. STAMETS: The hearing will come to order.

It's nice to see that there is undiminished interest in this case.

I would encourage everybody to be as brief as possible so that we can conclude this hearing in the two days we have allocated to it this week. I know that may be difficult for some of you but rest assured we are capable of listening very, very fast.

At this point, then, we will resume hearing this case and ask who's next?

MR. KELLAHIN: Mr. Chairman, we'd like to continue with our direct presentation.

At this time we would like to call Mr. Al Greer.

MR. PEARCE: Mr. Chairman, if I might, before we begin that I have one brief preliminary matter which I'd like to discuss, if that's acceptable.

MR. STAMETS: Certainly.

MR. PEARCE: In reviewing the transcript of the last day and a half hearing on this matter, it has come to my attention that, at least my clients are concerned, that we need to have a preliminary statement because of the break to remind the Commission that we've got two cases under consideration today. We've got two pools under consideration today. We've got two sets of information and my clients are concerned that because of the break, some continuity of organization might be lost and that they feel it's necessary to make clear that we've got two pools and we may have two sets of data.

They asked me to emphasize that.

In addition, after reading that transcript, it occurs to me that although I did not rise and join in a couple of Mr. Padilla's objections at the last hearing, there was a lot of discussion in that record about spacing.

Reading the ad of this case it is clear that what we are talking about is reducing allowables and reducing the gas/oil ratio and I have been asked to emphasize that. I may have been asked to emphasize it to myself as much as anyone else, but we are concerned because of time and because of the amount of information available, that we not get sidetracked into issues which are not before this Commission today and not try to keep clear lines about the applicability of the information that is being presented.

Thank you.

MR. CARR: Since Mr. Pearce has

decided that it is appropriate to make a brief opening statement, with your permission I would like to do the same and I'm going to keep in mind that it's important to keep this hearing moving, but I think what we're here talking about is a reservoir that's in trouble, and when we talk about what is happening in that reservoir, we necessarily must talk about what's going on in that formation and some of the evidence that is presented might be appropriate in a sapcing cased, but what we're presenting and will present today is evidence about what is happening in the Mancos formation and even though you may be able to utilize if we were here talking about a change in spacing, we're going to be talking about imposition of certain restrictions on withdrawals for a period of time and the data that we're going to be presenting is directed toward that and so even though it is true this information might to appropriate in another hearing, we submit to you today that everything we're going to be presenting is directed strictly to the issue that is presented to you for consideration in the applications of Jerome P. McHugh and of Benson-Montin-Greer Drilling Corporation.

There has been a break of two weeks. As you'll recall, two weeks ago Mr. McHugh called witnesses that discussed the geology of the area, the basic land situation of the Gavilan area, and also presented through Mr. Roe, some engineering testimony which I believe clearly identified that there's a problem in this particular area.

Today we're going to call Mr. Greer. Mr. Greer is going to talk about the formations and the area that are involved in the consolidated cases and we believe we'll show that immediate action should be taken if, in fact, you're to carry out your duty to prevent waste and protect correlative rights.

We're also going to show you why the limitation that we have proposed is the limitation that must be adopted by this Commission, and we're going to show you that you've got to limit the withdrawals from the reservoir as well as limiting the gas/oil ratio if in fact what you are being asked to do is done in a meaningful fashion.

At this time we call Mr. Greer.

MR. STAMETS: While Mr. Greer is coming to the stand, let me ask if there are additional appearances in this case today.

ALBERT R. GREER,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A Albert R. Greer.

Q Mr. Greer, where do you reside?

A Farmington, New Mexico.

Q What is your relationship to Benson-Montin-Greer Drilling Corporation?

A I'm an officer and engineer in that corporation.

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

A About twenty-five or thirty years.

Q What is your present office in Benson-Montin-Greer?

A I'm president.

Q And Benson-Montin-Greer is applicant in Case 8950?

A Yes, sir.

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

A Benson-Montin-Greer is the operator of the Canada Ojitos Unit, which lies within the West Puerto

Chiquito Pool.

Q For how long has Benson-Montin-Greer been the operator of the Canada Ojitos Unit?

A Since about 1963 or 4.

Q Briefly summarize for the Commission your educational background and your work experience.

A Yes, sir. I was graduated from what was then New Mexico School of Mines at Socorro in 1943; Bachelor of Science degree in petroleum engineering.

After a short time in the Navy during World War II I went to work for a subsidiary of El Paso Natural Gas Company in Jal, New Mexico, Western Natural Gas Company.

In a couple of years I went to work for Anderson-Prichard operating out of Hobbs; then for two or three years I was in Oklahoma City as a reservoir engineer for Anderson-Prichard.

Then I spent two or three years in Dallas working for an independent, Leland Fikes, and as an engineer.

Then, since about 1952 I've spent most of my time in the San Juan Basin of New Mexico, working as principally an engineer and involved in the drilling and production of wells in that area.

Q Have you personally been involved with the Canada Ojitos Unit since its creation?

A Yes, sir, we helped form the unit initially and have continued with it for some twenty-five years.

Q Have you during that time period personally been responsible for the engineering work and development of this unit?

A Yes, sir, we've made some rather intensive engineering studies because of the unusual nature of the formation, and I've been directly involved with that.

Q Mr. Greer, are you familiar with the applications filed in these consolidated cases for Jerome P. McHugh and Benson-Montin-Greer Drilling Corporation?

A Yes, sir.

MR. CARR: At this time, Mr. Stamets, we tender Mr. Greer as an expert witness in the field of petroleum engineering.

MR. STAMETS: Without objection Mr. Greer is considered qualified.

Q Initially, Mr. Greer, would you briefly explain to the Commission why you are here and what your purpose is here in testifying in this matter?

A Yes, sir. Mr. Chairman, I'm here today because one of your oil pools is in trouble. In Rio Arriba County the Gavilan-Mancos Pool, with only about a third of the wells on a third of the spacing units in the area that appears to be productive, the pool is over-drilled and over-produced.

There are three problems that we see that we will address and identify and set out for you to consider.

One is that if the existing rules continue, the existing competitive operation of the pool, there are going to be a large number of unnecessary wells drilled and this constitutes waste, waste which we hope that the Commission would recognize.

In addition, the high rate of production, the high rate of withdrawal, this high rate of depletion will deny the otherwise recoverable oil that might be realized through a gravity drainage depletion process. This constitutes underground waste.

Then there's a third problem, Mr. Chairman.

The majority of the tracts in the pool are being denied the opportunity to protect their correlative rights. This is a problem that's similar to the one that first occurred, first was recognized as a problem in the oil industry when commercial oil was first discovered over some 100 years ago in the continental United States, and that is that the operators in a pool had a complaint, they took their complaint to the courts for relief. Their complaint was that their neighbors were taking more than their fair share of oil from a pool. They were pulling oil out from under their land, and I know, Mr. Chairman, that you well know the -- the -- how the judge ruled in that case but for the similarity and the comparison in this case I thinkn it's appropriate to -- to note, and if I recall, about what his decision was, and that was that he concluded that oil in its underground movement was like a wild animal skulking through the underbrush and belonged to whoever could capture it, and thus the law of capture was born, and it persisted for many years.

Then in this century, in a more enlightened era, the states with their laws, the commissions with their regulations, adopted a change in a sense to go from the law of capture to protection of correlative rights, and New Mexico has been a model in the United States for regulation and for -- for moving in what we have considered as the right direction.

But now, Mr. Chairman, there is a blemish; there is a blemish on our record, for in Gavilan today the law of Gavilan is the law of capture, and this requires your attention and we suggest here today how -- how that can be corrected.

Now we feel that there should be no blame placed on anyone that this has come about. Until this hearing the Commission had no idea of this problem and until about a month ago the majority of the operators in the pool didn't realize there was a problem.

What the operators apparently felt and I believe in good faith felt, was that they had drilled into a bonanza, a world without end, reservoir without end that they could produce at high rates, that would last forever. They weren't deliberately trying to take oil out from under their neighbor's land but regardless of their intentions, that's what was happening.

They should not be blamed for that. The Commission should not be blamed. Now that we know about it we feel that the Commission and the operators should work together to correct this problem.

Now how could it come about? How in this age and with the regulations that we have, how could it come about that we're operating under the law of capture?

Well, it's because of the nature of the formation and I'll try not to be repetitious in my testimony today, but over twenty-five years that we've studied this -- this reservoir, this formation, we have testified before this Commission, we have pointed out how different it is from an ordinary reservoir in which the industry used to develop. In fact the words the geologists ordinarily use to characterize formation are not the kind of words really that we need to understand this formation, and I'm thinking of words like deceptive, deceptive. We're indebted to Mallon Oil Company for coring a well as late as last December, having the core analyzed, not only analyzed, a petrographic analysis, and the analyst in reporting on this analysis pointed to one of the log characteristics, and Mr. Chairman, we have testified to this Commission many times that logs and cores just cannot show the character of this formation.

Here core analysis made this comparison. One zone showed by the log to have a porosity of 10 percent but the analyst in writing up his report said, this is a deception. This is a deception. The core porosity was one percent. So the log shows 10 percent and the core shows one percent; that's a 1000 percent difference in the pore space. It's a deceptive formation.

Not only deceptive, it's treacherous, and I would go so far as to say that it's insidious, and how can that be? Well, an operator has a well producing 75 to 100 barrels a day; the pressure in the reservoir drops; the gas/oil ratio increases; the well has really had a higher productivity, he didn't realize it and he was pumping the well at pump capacity; now with the lighter column, the additional gas, the well starts to flow through the annulus, so where he was making 75 to 100 barrels a day, now he's making 2-to-300 and he feels that everything is great, when in truth, the reservoir is on the skids.

MR. LOPEZ: Mr. Chairman, with all due respect I would like to suggest that in the spirit of trying to get through the hearing, that if we're going to listen to all the conclusions that Mr. Greer has drawn, that we get to his evidence and data so that we can have Mr. Greer respond to direct questions.

I want to hear Mr. Greer's story but I think there's a more expeditious way of getting at it.

MR. CARR: Mr. Stamets, one common criticism of a lot of our testimony in the past has been that it's complicated, that it's extremely technical, and that it is difficult to fit within a framework and keep it understandable as we go forward.

Mr. Greer's been qualified as an expert. He can give his conclusions now and he then will go through and give you detailed information and comprehensive data that support the statements he's made and the problem that he's identified.

We'll be happy if Mr. Lopez wants to the other way now to move into particular exhibits, but our intention was to give you an overview of the problem so that as we develop each of the pieces they fit into some sort of a logical pattern.

MR. STAMETS: If that was an objection, we'll overrule it and permit Mr. Greer to continue.

Q Mr. Greer, you have identified a problem in this area. How does that problem affect your interest in the Canada Ojitos Unit?

A It affects the Canada Ojitos Unit in that if over-drilling is continued in Gavilan, and Gavilan joins Canada Ojitos, then in order to prevent drainage from the unit to the Gavilan area, we have to do something, and we would have to drill at a minimum, the same density, the same number of wells, as -- as in Gavilan, and it's clear from the information we now have that those would be unnecessary wells, and so what we are suggesting, if I might go so far ahead of my testimony to say this, is that if Gavilan be unitized, then we can work out a boundary agreement between Gavilan and Canada Ojitos such that the oil in the boundary area can be shared by the two units without having to drill the unnecessary wells.

For Gavilan to be unitized and be unitized in time to -- to hopefully get the benefit of some gravity drainage, it must be done soon and it must be done before significantly greater amount of depletion takes place, and we'll go into that later as to why that is.

But that's how it affects it.

Now, by reducing the allowables, which are the subject of these applications, it does two things.

The first thing in reducing the allowables is that it addresses the problem of getting the opportunity to protect their correlative rights.

The other thing it does is it slows down the rate of depletion so that an opportunity can be had for Gavilan to be unitized and solve these problems before its too late.

Q Now, Mr. Greer, you have testified in a general sense about the nature of the formation and withdrawal effects, correlative rights, and waste problems. Have you prepared particular exhibits which address these concerns?

A Yes, sir.

Q Would you refer to what has been marked as Benson-Montin-Greer Exhibit Number One, let's take a minute and pass that out, and then I'll ask you first to just identify those documents contained in this exhibit.

Mr. Greer, will you refer to what -- to the document behind reference Tab 1, or A in Exhibit Number One, and identify that, please?

A This is a copy of our application in this case.

Q If you'll now move to Tab B, and first I'll ask you to identify the first exhibit, or first document contained in that portion of the exhibit.

A The first map is a copy of -- out of Exhibit Number Nine, McHugh's Exhibit Number Nine, Section A, in Case 7980, November, 1983, which had to do with the spacing in this area, and we bring this out at this time to show the nature of the boundary problem between Canada Ojitos and Gavilan and why we have the two concurrent applications.

I'd point out first in the upper part of the map that the Boulder Pool had been spaced on 80 acres and drilled on 80 acres.

Under that we see Puerto Chiquito Mancos West was spaced on 640 acres. The density was about one well to four sections, 1 to 2500 acres.

The Puerto Chiquito Mancos East on the east side of the map, spacing 160 acres, density about 160 acres.

On the far west side of the map the Lindrith Gallup-Dakota West was spaced on 160 acres and drilled on about 160 acres.

Then between Lindrith and the new area of Gavilan was Ojito spaced on 40 acres with a drilled density at that time of approximately 160 acres.

So we show that at that time the spacing ran from 40 acres to 640 acres in the area. It seemed that a reasonable transition from one area to the other would be 320 acres for Gavilan. That was McHugh's application; we supported it at the time. We had special pool rules regarding wells along the boundary because we recognized at that time that the first well drilled in Gavilan had a pressure which appeared that it might have been affected by -- by wells in the Canada Ojitos Unit in the other pool; that there was probably some kind of communication, we didn't know how good it was. There appeared to be a permeability restriction, but two things were -- two points of evidence were very significant at that time.

One was that the discovery well had a productivity of approximately 100 barrels per day. The pressure build-up test run on that well indicated a transmissibility much like what we found in the Canada Ojitos wells but which was much less than what we found to be the reservoir transmissibility.

After six months of production the working -- casing pressure on the well didn't decline at all and so it was clear that the well was producing from a reservoir not like the characteristics shown by the pressure build-up test but that it was in communication with a high capacity fracture system very much like what we found in Canada Ojitos.

Farther to the north in Township 26 North, 2 West, Dugan's Tapacitos 2 Well had a flat decline curve indicating the same characteristics, even though it was a small well, about 40 barrels a day, it was obviously in communication with a high capacity fracture system.

So we anticipated that there would be production all along the west boundary of Canada Ojitos Unit and to have some way of recognizing the problem, trying to have a way to solve the problem, we had special pool rules for Gavilan for wells along the boundary and a year or two later we asked for special pool rules for the West Puerto Chiquito wells to help meet this problem.

We didn't know then how serious it is. We still don't know how serious it is, but we've made attempts to solve what could be a problem, and the problem being that in the Canada Ojitos Unit, for some eighteen years, we've had a pressure maintenance project. We've produced wells at rates which fit the -- our estimate of the gravity drainage potential so that we could get -- realize a maximum recovery from that pool. That requires restricting production to rates below the wells' capacities to produce.

If on the boundary we have to drill too many wells, then that means we have increased the production rate; we have exacerbated the problem of trying to realize gravity drainage potential when that required a low rate of production. So here was our problem. We had to restrict production to get the maximum recovery. We had to increase production to protect from -- from drainage.

So that's why the special pool rules we had at that time. It's clear now that they're inadequate to solve the problem and so now we have other -- other ways that we must go to solve this problem.

Q Mr. Greer, the pool boundaries as depicted on the first exhibit in Section A of Exhibit One are the pool boundaries as they existed at the time of the pool rule hearing, is that correct?

A Yes, sir, that's correct.

Q Now will you go to the next document contained in this section of Exhibit Number One and identify that, please?

A This shows our -- our estimate of -- of what I have referred to as effective hydrocarbon pore space for the different areas.

Q And if you would, I'd like you to go through the exhibit and indicate what that pore space is, and also, if you could while you're doing that, indicate how those figures are derived.

A All right, sir. First I might point out why -- why it's important to look at this -- this character of the reservoir rock.

There is a tremendous range of recoveries of oil from individual wells from as low as 10 or 20,000 barrels per well to up over 2-million barrels per well, and although there is this wide range of recovery of production from wells, the formation nevertheless over the same area has relatively similar characteristic in terms of hydrocarbon pore space per acre.

Starting at the top of the map with the Boulder Mancos, I've estimated 2500 to 4000 barrels per acre of effective hydrocarbon pore space and I arrived at that from the production decline curves in Boulder, comparing the rate of pressure decline when the pressure was above the bubble point, the rate of pressure decline when it's below the bubble point. By having those two -- two characteristics we can calculate what the oil in place per acre was.

Another way to estimate it would be to -- by recombination of the gas that was produced, the oil that was produced, but in Boulder the gas was not measured so we lack the -- the accuracy that we'd like to have to arrive at it that way.

Going farther south in the orange colored area in the Canada Ojitos Unit, by intereference test we estimated 2000 or 3000 barrels per acre, and this was over, we think represented a fairly large area, several thousand acres covered by the interference test.

Then by comparison of the rate of pressure decline and the -- and estimating, and, of course, this is a problem with the normal estimates of recovery, is how many acres are being drained. But from that calculation we come up with 1500 to 3000 barrels an acre and in Canada Ojitos we are producing primarily one zone, whereas in the Lindrith Gallup-Dakota area to the west all the zones have been opened and the first well or two in Gavilan, it looked like they were planning to open all three zones in Gavilan.

So we've estimated in round numbers that there is no reason to believe that there's any big difference in Gavilan than the other areas in terms of effective hydrocarbon pore space.

Now to determine from effective hydrocarbon pore space recoverable oil, depends on a number of things and we'll get to that as we get into the testimony.

But first we need to see the similarity. They're just quite similar throughout the whole area in terms of what we identify as effective hydrocarbon pore space.

Q Will you now go to your structure map which is behind index Tab C in Exhibit Number One, identify this and then review the information contained on the exhibit?

A Well, this is a structural contour map.

It covers the area of East and West Puerto Chiquito Pools and the Gavilan-Mancos Pool.

Q Does this show the current boundary of the Gavilan?

A The current boundary of Gavilan and West Puerto Chiquito is the heavy north/south line which goes through the upper green circle.

The formation outcrops on the -- as shown on the east side of the map by the dashed lines, dips to the west, initially dips very steeply at rates of 1000, in fact 3000 feet per mile initially, then down to 1000 feet per mile, and as we go farther west, 400 feet a mile and 200 feet per mile.

Then the re-entrant, which we've shaded with question marks in it, is an area where we anticipate or we have postulated that there might be a permeability restriction.

Also on this map we've identified with the green circles the area of high withdrawal, the areas that are causing the problems.

The upper green circled area, the two wells adjoining each other across the boundary are wells that were used in an interference test. We asked the Commission lst fall to conduct an interference test with the cooperation of the operator of the adjoining well, Mallon

Oil Company, who volunteered to help in such a test, and the purpose of that test was to determine how many wells would be required to protect the Canada Ojitos Unit from drainage. We had hopes that with two rows of wells along the boundary, drilled at the same density as Gavilan, that that might protect the unit from drainage.

Also we've had hopes to -- to have information that we could determine oil in place per acre, the same as we had years ago in Canada Ojitos Unit. Unfortunately, because of all the zones being open, the problem of producing the wells at uniform rates, we were unable to get the kind of information we needed to calculate oil in place per acre.

We did, however, find out that there was a very high transmissibility in the reservoir, much higher than is indicated on individual well tests. It's so high that there's no way that the lands can be protected from drainage by just drilling additional wells.

In this reservoir it's just like so many straws in a tank and so we then found not what we were looking for but another problem, and now to solve that problem is why we're here today.

Q Mr. Greer, you've identified certain high capacity wells in the Gavilan area. How do recoveries from these wells compare to recoveries within the Puerto Chiquito area, or the Canada Ojitos Unit?

A The overall recoveries, if the -- if the production rates continue as they have and drilling continues as it has, of being denied the gravity drainage potential that they might otherwise recover, will reduce their recoveries to something on the order of 200 barrels per acre; whereas the same formation in -- or the same characteristics in Canada Ojitos Unit, we anticipate three or four times that much.

Q This plat also has indicated on it the location of the injection wells for your pressure maintenance project.

A Yes, sir. The injection wells are shown by triangles.

Q Now, Mr. Greer, in preparing for today's hearing have you made comparison of certain characteristics of a fractured reservoir and contrasted those with a sand or matrix reservoir?

A Yes, sir, I have.

Q And are those what is set forth in what -- in the documents behind index Tab D in Exhibit Number One?

A Yes, sir.

Q Would you refer to the first exhibit behind that tab and then identify it and explain what it is?

A The first two gold colored pages show the title of one of the Transactions from which an article and statistics were taken, which is shown on the second gold page, an article by Bulnes and Fitting, which showed a relation between porosity and permeability for sandstone type reservoirs.

And then I have taken that information and gone to the next graph, the graph with the brown and yellow stripes on it. The brown colored area represents approximately the area covered by --

MR. PEARCE: Excuse me. Could the witness speak a little louder? We're having a hard time back here, sir.

A I'll try.

MR. PEARCE: Thank you.

A The brown colored area is the same as the area shown by Bulnes and Fitting, approximately, for the relation of permeability and porosity for a sandstone reservoir.

To make a comparison with the fractured reservoir, I started out with a simple system of parallel fractures running in parallel to the direction of flow, and I calculated the porosity and permeability relation for three different conditions.

The bottom line shows the relation for

one fracture per foot; the middle line for 10 fractures per foot; and the upper line for 100 fractures per foot.

Now this is a simple, exact relation readily calculated. It was first presented to this Commission in Case 3455, November 16th, 1966, Exhibit One, Figure 9. At this time my counselor suggested that although I know the calculations are right and he accepts them as right, it might be helpful to other people to know that someone else has calculated the same thing that I have.

So, if we skip over three or four pages to the white colored sheet titled The Flow of Homogeneous Fluids... we'll find where I -- I arrived at the -- or found the relation of fracture thickness to permeability, and this was by Muskat in the book identified there, page 425.

From that I went to the next sheet and you can see my original notes here where I calculated through the law of parallel flow what the permeability and porosity relation would be.

From that I constructed the graph which we just looked at.

Q Now, Mr. Greer, the red point upon the bottom line in the yellow shaded area, what is that?

A That -- that point is a point that is shown as calculated by Craft and Hawkins, by the two pink sheets which follow the white one that we were just looking at.

Q What is the blue point?

A And I might point out on the pink colored sheet, the page shown as 283, that in the center paragraph they have calculated the permeability for a fracture with 0.005 of an inch and an almost impermeable matrix. They have a more complicated formula there, of course, because of that. I eliminated that complication by assuming an impermeable matrix.

Then the blue colored sheet is the same kind of a calculation made a few, just a few years ago by another author where he shows a relation for three fractures per foot 0.01 of an inch thick, and in my penciled notations I show there, if you have one fracture per foot instead of three you would have 500 millidarcys instead of 13,000.

So those -- those pink and blue sheets, analyses there are, by happenstance those authors chose the same points that I did on the lower line of the yellow and brown colored graph, and we show this just simply to -- as confirmation of how -- that this is a simple, fixed relation. There's no judgment involved. If you have a fracture system, fractures running parallel to the direct of flow and for these characteristics that's what it is; there's just no question about it.

Now, to -- since we just don't have any

way of determining reservoir pore space and the relation of porosity to permeability from cores and logs, I wanted to have something that would give us some kind of an idea as to relation might be and I made the arbitrary assumption that in a fractured reservoir there's probably fractures running in different directions, not necessarily directions parallel to the line of flow. Mother Nature didn't know where we were going to drill the wells and how they would go.

If that's the case, it's probable that there would be a higher porosity for any given permeability if we had crossways fractures.

And so I have again rather arbitrarily assume the upper line as perhaps might be something representative of what actually happens in the reservoir.

I selected two points, one just above and one just below and then I came up with the graph on the next page, the gray shaded -- has the gray streak across it, and I said this might be the best representative as we could have, representation of porosity and permeability for a fractured reservoir and how it compares with a sandstone reservoir.

And there are two things that are significant here. One is if we take a range of -- as shown on the lower scale -- of 10 to 100 millidarcys permeability, we see that we're looking at porosities from 0.1 to .01 percent on the gray shaded area.

A sand for a similar permeability runs like from 10 percent to maybe 25 percent.

So we're looking at 10 to 50 times, perhaps, as much reserovir pore space in a sandstone as in a fractured reservoir for the same transmissibility, same permeability.

Now what that means is that an operator goes out and he drills a well in a sand reservoir and he drills another one in a fractured reservoir, they both make 500 barrels a day, the well in the sand reservoir he has every reason to believe that he has a high volume of oil in place, a high potential for recovery of oil, but in the fractured reservoir he probably has only one-tenth as much; not only one-tenth as much in place but if it's produced by solution gas drive there will be probably a third as much oil recovered from the initial oil in place.

So there's a tremendous difference in a fracture reservoir and a sand reservoir in the amount of oil that might be anticipated to be recovered from any particular potential.

Q Now, Mr. Greer, will you go to the next graph and identify that and review it, and could you speak as loud as possible?

(Thereupon a short recess was taken
and a microphone obtained for Mr.
Greer's use.)

MR. STAMETS: Mr. Greer, why don't you do some testing there and we'll see if everybody can --

MR. GREER: Testing, testing, can you hear me now? Testing.

MR. PEARCE: That's much better.

MR. STAMETS: You may proceed.

Q Mr. Greer, I believe you were testifying from an exhibit in index Tab D in Exhibit Number One. Would you identify the graph you're talking about and explain what it shows?

A Yes, sir. This shows on a different scale the same information we had on the previous yellow and brown colored graph and the information shown as yellow and brown on the previous graph is shown as yellow and brown on this.

Q And this graph is entitled Comparison of Relation of Poroisty to Permeability.

A Yes, sir, and the purpose of this graph is just to show an extension of the sandstone relation and the fracture relation and the fact that they join at an area somewhere around 50 to 100 percent porosity, and this is something that we would really expect to have. It doesn't make any difference if you call them a matrix porosity or a fracture porosity, once the porosity is 50 to 60 to 100 percent of the pore space we can call them the same thing.

So this seems to me adds a little bit of rationale or reason or credibility to -- to the relation that we came up with before. Certainly one would expect whatever relation you have would have to meet out in the righthand side of the graph as we've shown here.

Q Mr. Greer, would you go to your next graph which shows the relation of oil in place to transmissibility and identify the exhibit and then review what it shows?

A Yes, sir. This yellow colored graph shows for the three lines on this graph compared with the three lines that we have labeled A, B, and C, on the preceding graph, and by -- by taking the relation for, for instance, the A, the A line, if we had 17 feet of formation with the characteristics shown as A, then the botton line as we have shown on the yellow graph would be the relation of transmissibility to -- to stock tank barrels of oil in place per acre.

By the same token, 50 feet of the B characteristic or 150 feet of the C characteristic would give the same thing.

And then I calculated the same thing for the X and Y lines.

Then we've made a comparison of what we found from our interference tests and information for Boulder, and those points are shown on this yellow graph.

The blue dash mark shows approximately where the information derived from the 1965 interference test would lie.

The pink stripe shows a 1968 interference test and the green circle shows approximately the relation for the Boulder Pool, and so although we have drawn in a sense an arbitrary characteristic or relation for oil in place per acre, it does have some background in what would be the situation for a fracture system in which the fractures are all parallel to the line of flow, and it also by happenstance, perhaps, is about the same thing as we actually found in the field.

So we think there is some -- there is some reason to believe, until somebody comes up with something better, that for this particular area, for this formation, in -- in the West Puerto Chiquito and Gavilan areas, that this is about the best relation we can have, and it's significant in that we show that the porosity or the pore space varies as the cube root of the ratio of the transmissibility.

If we follow the line, say, from transmissibility of one darcy foot on the upper X line it would be about 2000 barrels an acre. It goes up to about 10,000 an acre for an increase in transmissibility of 100-to-1. So that's a relation that we think is -- has some application in the treatment of these formations in this reservoir in West Puerto Chiquito and Gavilan.

Q And is that relating transmissibility to productivity, is that what you're doing?

A Transmissibility and productivity will have some kind of a relation. The higher the transmissibility, the higher we can anticipate the productivity from wells drilled in that area.

We've found this to be a characteristic that probably covers a substantial part of the reservoir. There's just no way that we can -- can identify one particular small tract and say it has exactly this amount of oil in place per acre and its neighbor is substantially different. Overall and for a fairly large area of the reservoir they would be about the sames and I should point out an example as to how we really can't try to tie exactly a well's productivity to oil in place per acre. An example is that we drilled one well, produced it natural. We drilled it with air. We found about 60 barrels a day production. We had a downhole fire that melted the drill pipe, drill collars in two; we left about 1000 feet of them in the hole. We produced the well that way for nearly a year and that well, incidentally, was one that by analyzing its production behavior led me to believe that the oil was under-saturated, that we were dealing with a drainage area that was probably several miles in a fairly large reservoir.

So in order to repair the well we went back in, sidetracked the hole, bottomed the well about 100 feet from the initial point (unclear) and it showed absolutely nothing. It was dry.

We fraced the well and managed to get back the initial productivity, but this shows how in this particular reservoir individual tracts close by are substantially different, yet over all in that area the formation is contributing to the production and -- and this is the problem that we come up with.

We drilled a well which would be about 40-acre spacing, we didn't know any better in those days, north of this particular well. Instead of making 50 or 60 barrels a day, it made about 500 barrels a day.

Well, if the allowables were based on just productivities, then one well 40 acres north of the one we had the trouble with would get ten times as much oil form the reservoir and I know in my own mind that there's no way that there's ten times as much oil under that tract.

Q Mr. Greer, you just stated that using this approach you could see that the formation was contributing production.

What do you mean when you say the formation contributed production in this area?

A Well, we're speaking about the pore space in tne reservoir that forms the reservoir. In this instance it's fracture porosity and it's -- it's what forms the pool that the wells draw from.

Q What does this exhibit tell you, if anything, about the oil in place that you encountered in this area?

A Well, it tells me that -- that over fairly large parts of any one of the pools that the oil in place will vary but not significantly; vary -- to use the cube root of the productivity, if you have ten times the productivity in one area as compared to another it doesn't have ten times as much oil, it has maybe twice as much oil.

Q Now, would you generally describe for the Commission the lithology of the reservoir rock in the areas we're talking about?

A Yes, sir. We have a general description of the lithology under Section E of our Exhibit One and I believe I'd -- perhaps I'd best just read this.

"Although the majority of the industry's oil reservoirs that are fractured are those that comprise a rock with matrix porosity laced with fractures, the operators in the Boulder and Puerto Chiquito Pools have recognized the producing reservoirs to be of fracture porosity only."

And references are made to the -- to the study.

"Performance of wells in the Gavilan Pool are showing the same characteristics. It is clear that the Gavilan also produces from fracture porosity only.

The subject reservoirs are referred to as fracture reservoirs and occur in the Niobrara member of the Mancos shale formation. The lithology of the rock varies from shale to siltstone to sandy layers, and sometimes containing a high percentage of calcium or dolomite."

And we make reference to some papers that have studied that.

"The rock property which is significant n the determination of oil in place is 'effective hydrocarbon porosity'. It is an eluisive physical characteristic impossible to evaluate from currently available core and log data.

Effective hydrocarbon poroisty can be approximated from the statistics of depleted pools given a reasonable estimate of the pool's areal size. As to reservoirs early in their production lives, the only reliable method of estimating effective hydrocarbon pore space is be interference testing. Conventional drawdown and buildup analyses are woefully inadequate for this purpose."

Q Now, Mr. Greer, you have conducted interference tests in the Canada Ojitos Unit, have you not?

A Yes, sir.

Q What results did you obtain by conducting these -- in conducting these tests?

A We found that oil in place per acre to be on the order of 2000 to 2500 barrels per acre for -- for the zone that we were producing, and I might add, in Canada Ojitos we were dealing with one zone and so we had what an engineer might refer to as a nice, neat problem to deal with. We did not have the complication of additional zones to -- to influence the test, and so we were able to tell a very, what I consider very accurately for the kind of information otherwise available, the amount of oil in place per acre, and at the same time we determined the reservoir transmissibility.

The reservoir transmissibility much higher than the individual transmissibilities determined from buildup tests and drawdown tests on individual wells, simply because these wells are completed in what I call tight fractured blocks and the tight fractured blocks surrounded by high capacity fracture system, and this high capacity fracture system, it appears, contains maybe half of the oil in place.

Q Now, Mr. Greer, would you go to the next page in this exhibit and review for the Commission the results of your work in this area concerning fracture porosity as opposed to the matrix porosity in the subject area?

A Yes, sir. On the green sheet we make a comparison of what we found in this fractured reservoir with typical characteristics or characteristics typical of sand, and for this 2500 barrels per acre -- I've used 2500 here -- that could be contained in a sand with 10 percent porosity of about three feet, or about two feet of producing sand with 15 percent porosity.

So we showed on the bottom schedule a comparison, then, of the transmissibilities that would be anticipated from a typical sand.

If it's sand three feet thick and permeability one millidarcy, the transmissibility would be about 3 millidarcy feet as shown in the fourth column.

If the sand is two feet thick and 15 percent porosity and 10 millidarcy permeability, it would have transmissibility of 20 millidarcy feet.

Now we did not measure 3 or 20 or 100 millidarcy feet in our interference test. We measured transmissibility in the range of 5 to 10,000 darcy feet. This means to me that there's no way that the reservoir in which we were taking the interference test was a matrix or sand porosity. It just doesn't fit the characteristics of sand reservoir, and this is important when we get to the problem of studying the possibility or the potential of gravity drainage.

It really doesn't have much to do with whether Gavilan is in trouble. It doesn't make any difference whether it's producing from a fracture porosity or a matrix porosity, Gavilan's in trouble.

So from that standpoint it doesnt make any difference, but it does make a difference if we are dealing with sand or fracture reservoir when it comes to gravity drainage.

Q Now, Mr. Greer, at this time I'd like to ask you some questions and direct your attention to the effect of solution gas drive in the Mancos formation in this area.

MR. CARR: May it please the Commission, we have some slides that I think will assist Mr. Greer in presenting this part of the case. We also have hard copies of this material that we have marked as our Exhibit Number Two and can circulate at this time.

We need to, I think, dim the lights.

Q Mr. Chairman, what we want to show here is a comparison of recoveries from solution gas drive mechanism for a sand reservoir as compared to a fractured reservoir, and the solution gas drive recovery mechanism is dependent on the gas dissolved in the oil that gives it the energy to move and we find it is -- in deeper reservoirs there's more gas involved than oil.

In the Gavilan the pvt data that we have shows about 38 percent shrinkage or 38 percent of the reservoir pore space would be occupied by gas, if there were a way to separate the gas and the oil in reservoir and measure the comparative amounts.

Q Mr. Greer, you were talking from the first slide, or page one of Exhibit Two.

A Yes, sir.

Q Would you now go to the second page, which is an illustration showing relative permeability in a sandstone reservoir?

A Yes, sir, we show on this slide some sand grains surrounded by oil. I show no connate water in this instance to simplify it and this is for the -- we have assumed here 100 percent liquid saturation; pressure, if it's above the bubble point and the well is produced the oil will expand. The pore spaces would still stay filled with oil. You'll have 100 percent liquid saturation until you reach the bubble point. Then at the bubble point as the pressure drops, gas starts to come out of solution and we show that on the next slide.

Q Okay, and that's page three of Exhibit Number Two.

A Yes, sir. And in a sandstone reservoir with good relative permeability characteristics, the gas becomes trapped in the interstices between the sand grains and doesn't move and oil flows around it and as the pressure drops the gas, more gas comes out of solution, the oil shrinks and the oil expands and that takes a little while to get that concept in one's mind, but as the oil is withdrawn from the reservoir by production, the remaining oil tends to expand to take up that space but it can't go all the way and so some gas comes out of solution to help, and we speak even though the oil is expanding, we speak of it shrinking because the space occupied by the oil shrinks and there's just more -- gas space.

As production continues, then, the gas bubbles apparently begin to link together, as shown on the next slide, and at this point the gas then moves much more rapidly through the pore space. By moving rapidly through the pore space there's more gas produced with each barrel of oil and then the pressure drops faster with each barrel of oil produced than it did before, and as the pressure drops the oil shrinks, the gas space increases, and a vicious cycle is started in which there is a continually increasing ability for the gas to move through the pore space and the pressure to drop.

Q Now these first four pages or slides illustrate a typical cycle for a solution gas drive reservoir, do they not?

A Yes, sir, for a sandstone reservoir.

Q Are you ready to go to the next slide on page number five?

A Here we show the relative permeability characteristics. The three solid lines on the right represent relative permeability characteristics for a fractured reservoir.

The dashed line represents the line that I used in calculating what we might anticipate for a solution gas drive in this area.

The wavy line on the left is -- shows characteristics for a typical sand and we note at the bottom of the graph, if I could point to it, this is 100 percent liquid saturation on the right, 90 percent liquid saturation about where the gas first starts to appear as a free gas in a sand reservoir.

In a fractured reservoir the gas starts immediately.

Given this relative permeability ratio and the pvt data of the oil, the relative permeability characteristic is characteristic of the reservoir rock, the pvt data is characteristic of oil, given those two things an engineer can calculate the recovery of oil in place by the solution gas drive.

Q Will you now go to page six of Exhibit Two, identify this and review it?

A This is the -- shows the relation which I calculated for -- for solution gas drive for the dashed line relative peremeability characteristics and pvt data for West Puerto Chiquito.

Now Gavilan pvt data, as best we know it, is about the same as West Puerto Chiquito.

On the vertical scale on the left we show the pressure scale and this is the pressure line running down.

The gas/oil ratio scale is on the right and this is the gas/oil ratio curve.

For this reservoir, these characteristics, I come up with about 5-1/2 percent of the oil in place to be anticipated to be recovered then at about 175 - 150 pounds reservoir pressure.

If the price of oil and such allows continued operations, there could be a little bit more recovered at the lower -- lower pressures.

Q Now, Mr. Greer, are you ready to go to the next slide?

A Yes.

Q Would you identify this, please?

A I've shown schematically here some fractures and here we show by brown the impermeable matrix; green, a thin connate water film and then in the center of the fractures the (unclear) oil.

Q Now go to page number eight, please.

A And here we show what happens when we reach the bubble point in this particular reservoir. There are no -- there are no restrictions to the gas in the fractures. Once the gas comes out of solution and bubbles form, they're going to move right in the direction of wherever the oil is going. There's nothing to impede their progress and so that's why gas/oil ratios start high quicker in a fractured reservoir than they do in a sand reservoir.

Q All right, would you now go to the next slide or page number nine?

A And here we show the high capacity channel which is going to develop soon after the gas starts to move through the -- through the fracture.

The oil shrinks up against the walls, thickens as the pressure drops, and will be left in such a way that it's impossible to recover it by any enhanced means later on. If -- if a high recovery solution gas drive is intended or attempted to be achieved in the reservoir, you have to do it in the primary stages, or the initial stages. You can't wait to deplete it like you can in sand reservoirs, and go back and then with enhanced methods get the oil you left behind. Once it's left in the fractured reservoir, it's there forever.

Q Will you go to page number ten in Exhibit Number Two, the next slide? What does this show?

A Well, this shows that even in a sand reservoir, depending upon the cementing characteristics of the sand grains, it's possible to have a flow channel somewhat similar to the fractured reservoir, and in a sense this sand would have a poorer relative permeability characteristic.

We don't know if that's what happend in Gallegos Gallup but Gallegos Gallup, according to the study made by the consultants when secondary recovery measures were contemplated some thirty years ago, they came up with a relative permeability characteristic poorer than what I've selected for a fractured reservoir. Perhaps this is what happened in Gallegos Gallup. We don't know, but that's a possibility.

Q All right, Mr. Greer, would you now go to the next slide, the last page in the Exhibit Number Two and explain that?

A In this graph we anticipated the production histories of two reservoirs that had the same kind of oil but they had different relative permeability characteristics.

The upper curve shows pressure for a sand reservoir extending on out at depletion to about 20 percent of oil in place.

Q That's the curve that has BHP above it, is that right?

A Yes, sir.

Q All right.

A It's corresponding gas/oil ratio follows along this lower line and we know that by the time the gas/oil ratio for this particular reservoir reaches about 3000 cubic feet per barrel (unclear) 2000 - 3000, that more than half of the oil has been produced from this sand reservoir.

By the same token, for the fractured reservoirs we show a pressure decline by the red colored area runs from about 4 to 6 percent of the oil in place and the gas/oil ratios run much higher, of course, than in the sand resevoir, and so ultimate recoveries are substantially less then for the fractured reservoirs as compared to the sand reservoirs. Not only is there less oil in place in a fractured reservoir than a sand reservoir, of that oil in place a smaller percent is recovered in a fractured reservoir.

Q Now, Mr. Greer, I'd like you to go back for a minute to page eight and ask if you could briefly describe the effect of gravity segregation on this example.

A Yes, sir. We can see here how in a fractured reservoir it's possible to have gravity drainage and gravity segregation that's going to come about much ore readily than the sand reservoir.

For instance, once those bubbles form, if they have an up-dip direction to go and the pressure gradient from wherever these bubbles are to the producing well is less than the segregation pressure, the difference in densities of the gas and oil, those bubble would rise to the surface, you'll have gravity segregation and variable drainage, an opportunity to recover a high volume of oil.

This is a very powerful force. If those pressure gradients are held low in the reservoir in producing wells, there's just no way to stop those bubbles from moving to the top and the oil from going to the bottom.

Q Now, Mr. Greer, at this time I'd like to direct your attention back to Exhibit Number One, and that concludes the slide presentation, and direct your attention in Exhibit One to Section F and I'd ask you to first identify the first document behind the index Tab F.

Is this the same graph that was included in Exhibit Two on page number 5?

A Yes, sir.

Q And do you have anything to add to your testimony at this time from this particular exhibit?

A No, only that I guess we would apologize for not having all of these hard copies in this particular exhibit. We presented all of them at the hearing three years ago and in order to save time I thought that we could just skip over the details but upon review, why our counselor suggested that we should not make that -- to try to save time at this point, so that's why we have them in this fashion.

Q Would you identify the next exhibit in this packet?

A It's the same exhibit as the last slide and the last page of our Exhibit Two, Page 11.

Q And this is colored as the slide.

A Colored as the slide, yes.

Q All right. Would you now turn to the information contained behind index Tab G in Exhibit Number One and identify that and then, if you would, explain what this comparison shows?

A This is a comparison of the rates of depletion in West Puerto Chiquito and Gavilan, and the reason we show this is that I have said that Gavilan is being over-drilled and over-produced, and although the Canada Ojitos Unit may not be an ideal comparison of what Gavilan should -- should try to be the same as, the comparison is nevertheless helpful to see the difference in depletion rates that are taking place in the two different pools side by side.

In Line 1 we show anticipated recovery in barrels per acre for the two different pools and I have identified by the asterisk how I arrived at those recovery factors.

Q As to the 300 figure, would you review in detail what is included within that figure?

A Yes, sir. In that 300 barrels per acre we've included approximately 200 barrels an acre of solution gas recovery and then another 100 barrels per acre divided between oil production above the bubble point, a hoped for thing, we're not sure that there was a pressure above the bubble point when Gavilan was first drilled, but many of us think that's a possibility.

And the rest of it is from gravity drainage.

Now, this was what we had hoped for if there had not been too -- too many wells drilled and too high a rate of production unless a change is made in the way the pool is being developed.

So for Gavilan and for future production the 300 barrels per acre is probably high, so we might keep that in mind as we look down through the schedule.

Under Line 2, if we have an allowable production rate of 700 barrels per well per day, that's the same for both areas.

The depletion rate, then, in terms of acres per day, this may be a depletion rate that people have not really thought much about before, but in this instance it's significant, how many acres a day is a well depleting; in Canada Ojitos about one acre a day; in Gavilan, then, at least two acres a day, maybe closer to three.

The well density in West Puerto Chiquito, 2500 barrels per acre, or within the Canada Ojitos Unit, 2500 acres per well, I'm sorry; in Gavilan about 320 acres per well.

Then if we divide this well density in terms of acres per well by the depletion rate in terms of acres per day, we arrive at the number of days that it takes to deplete that particular well's tract.

In Canada Ojitos it's 2500 days, several years.

In Gavilan it only takes 140 days to pull all the oil out from under the well spacing unit and this doesn't mean that at the end of the 140 days that the well starts pulling oil out from under its neighbors. We've found from the testing that we've done that this begins to take place within if not days, a matter of hours from the time a well goes on production in Gavilan it's beginning to drain its neighbors.

Then if we have an allowable it's depleted at the same rate as Canada Ojitos is depleted. Canada Ojitos is 700 per well; the comparable depletion in rate allowable in Gavilan would be 39 barrels a day.

Q Now are you saying that's the proper allowable?

A No, sir, we're not saying that's the proper allowable. In this instance our applications are asking for 200 barrels per day. But what we're saying is that 200 barrels per day is plenty. It's more than adequate.

Q Do you present subsequent calculations that justify the 200 barrel allowable figure?

A Yes, sir.

Q And on this exhibit the 700 figure in the second line, we're talking about the state's depth bracket allowable, is that what we're talking about in Line 2, the production rate, that 700 figure?

A Yes, sir, the -- the allowable for Gavilan now is approximately 700 per well and 320-acre spacing, and within the Canada Ojitos Unit wells drilled on the same spacing, it's the same 700 barrels.

Q Now, Mr. Greer, have you participated in recent meetings with operators in the area?

A Yes, sir.

Q And at those meetings what concerns have you discussed concerning possible solutions of the problem in the Gavilan - Puerto Chiquito areas?

A We've talked about, and I believe that all the operators recognize that there's a problem, and they appear to have differences as to -- to how to solve the problem. They appear to be in agreement that allowable should be reduced. They appeared not to be in agreement as to the level at which the well was to be reduced and they've had some -- discussed some arguments against the allowables which McHugh and Benson-Montin-Greer recommended.

The main arguments that they put forth are shown on this first page under Section H.

The first one is a change in allowable during development of a field is an improper regulation since it adversely impacts industry's plans made at an earlier time.

Another argument put forth is that the allowable change will caue economic hardship.

And another argument is reduction in production rates from current levels, if undertaken, should be proportional to current rates of production.

Q Mr. Greer, do you believe that changing allowables during the development of the field is an improper type of regulatory action?

A No, sir, I don't. We set out our position in that respect under -- on the second page, the pink colored sheet following the yellow colored sheet.

Q In Section H?

A Under Section H.

Q And basically what is that position?

A That position, as we describe it on the second page under Section H is that any rule or regulation of the Conservation Division is subject to change. The Conservation Division is obliged to make changes in any of its rules and regulations whenever information is developed supporting such a change and this information is brought before the Commission in accordance with its rules.

The operators cannot be guaranteed that any given allowable will remain fixed throughout any particular time or phase of development or depletion in the life of a pool, including an operator's payout period for his development program.

The risk of a change in allowable is just one of the many risks an operator assumes when he drills a well.

Q What about the argument that an allowable change will cause economic hardship on certain operators? What's your response to that?

A We set out our response to that on the blue colored page, the third page under this section.

And we say, as noted in Item 1, Page 2, the owner of a well assumes many risks when he undertakes the drilling of a well and some of those risks are factors affecting economics. Just as the Oil Conservation Division cannot guarantee a fixed allowable, it cannot guarantee the stability of other economic factors, such as fixed price for oil.

Those owners developing West Puerto Chiquito have in the past faced many economic adversities, including tier one category pricing and windfall profits tax for oil.

Initial development conditions in West Puerto Chiquito included a price for oil of $2.05 per barrel at the wellhead when drillins costs approximately $180,000 per well, compared to today's drilling costs of approximately $500,000 per well, this would equate to an oil price of about $6.00 per barrel at the wellhead.

Although current economic conditions are not favorable, they still are not as adverse as those under which the West Puerto Chiquito Pool was initially developed.

Q Mr. Greer, do you agree with the idea that any reduction in the current level of production in this area should be on a proportional basis?

(Thereupon a recess was taken.)

MR. STAMETS: The hearing will come to order.

Q Mr. Greer, when we recessed I had just asked you if you agreed with the idea that any reduction in the current level of production in this area should be on a proportional basis. Will you comment?

A Yes, sir, I feel very strongly that it should not be and --

Q Would you explain why?

A -- we set out on a green sheet, the last sheet under this section, our arguments, and although ordinarily I dont like to read my testimony, I think in this instance I need to read this information set out here.

This argument, implicit in it are two unwarranted assumptions. One is that the existing allowable is a proper allowable and the other is that each well's share is a proper allowable, and the other is that each well's share of the pool's recoverable oil is directly proportional to well productivity.

As to the first reason, and as shown earlier herein, the existing allowable is unreasonably high give the anticipated average recovery from a 320-acre proration unit, absent pressure maintenance and gravity drainage, which refutes this assumption.

As to Item -- the second one, Item B, listed above, that a well's productivity is in direct proportion to the well's share of the pool's recoverable reserves, we note the following:

1. As shown earlier herein, hydrocarbon pore space is greater for those parts of the reservoir which have higher transmissibilities. The proportion, however, is not one to one; rather the hydrocarbon pore space can be expected to vary with transmissibility approximately as the cube root of the ratio of transmissibilities of the two areas.

2. This variation in reservoir pore space throughout the pool can be described only on an area basis, not on an individual well basis.

Extensive testing in West Puertc Chiquito has shown that not only are individual well productivities not representative of area reservoir characteristics, but information derived from pressure buildup tests, although yielding better information than well productivities, still does not show the area's reservoir characteristics.

In this type of a reservoir such information can be determined only through interference testing.

4. As a consequence of the above, it is a practical impossibility to relate well productivities to reervoir volume directly, such that well productivity would be a proper parameter to use in determining well allowables.

We note, for example, that wells in West Puerto Chiquito have indicated productivities up to 10 to 20,000 barrels per well, and a 70 percent reduction thereof, the approximate reduction proposed in Cases 8950 and 8946, could still result in allowables of 3000 to 6000 barrels per day per well, unreasonably high figures.

Q Now, Mr. Greer, would you identify for the Commission the document contained behind index Tab I in Exhibit Number One?

A Yes, sir. This is a recommended proposed special rules and regulations which would apply to the pressure maintenance project in the Canada Ojitos Unit in the event the Commission adopts our recommendation. This would be a starting point for the Commission drawing up its rules.

Q Now, Mr. Greer, throughout --

MR. PEARCE: I apologize, Mr. Carr, for interrupting your examination of this witness.

We are not here on an application for a pressure maintenance project, are we?

MR. CARR: No, we are not here asking for a limit on that. We're here to restrict production as set forth in the application.

MR. PEARCE: In the -- and the way in which the witness just discussed the source of these special rules and regs, I don't understand. Could you have the witness go through that again?

MR. CARR: Yes.

MR. PEARCE: Thank you.

Q Mr. Greer, would you explain why the proposal is contained in the format it is as the last part of Exhibit One?

A Yes, sir. The regulations and the rules that we're currently living under in our pressure maintenance project sets out the allowable and a gas/oil ratio. For instance, it says the gas/oil ratio is 2000-to-1, so that if the Commission adopts a different gas/oil ratio, then it, perhaps, would just automatically flow through the rule that the pressure maintenance project is under.

But it would seem to me that it's appropriate for the pressure maintenance project special rules to be modified so that they're compatible with what this order will be if it's changed from the condition it's in.

MR. STAMETS: Mr. Greer, these rules would apply only to the West Puerto Chiquito Mancos Pool and the Canada Ojitos Unit.

A Yes, sir, that's all --

MR. STAMETS: They would not apply at all to the Gavilan.

A Well, no, no, sir. We're not talking about pressure maintenance.

Q And that's simply where these figures are contained in the rules under which you operate.

A Yes, sir, if we don't change these special rules, then there would be a conflict between the order which we hope the Commission will enter and the rules that we have to live under for the pressure maintenance project.

Q Now, Mr. Greer, throughout the -- this hearing one of the conflicts which bears on, I think, all the discussions is gravity drainage.

I'd like now to ask you several questions about gravity drainage and its impact on this reservoir, and would ask you now to refer to what has been marked as Benson-Montin-Greer Exhibit Number Three.

A Exhibit Number Three is in a red cover.

Q It's also in a red cover.

A Also in a red cover.

Q All right, Mr. Greer, would you refer to the first document contained in Exhibit Number Three, which is a portion of a well log, identify this, and review for the Commission what is shows?

A Yes, sir. This shows the three principal producing zones that we've identified as A, B, and C Zones. We recognize them in Canada Ojitos area and West Puerto Chiquito Pool.

It appears to be the same zones are -- are -- exist in Gavilan and with respect to gravity drainage, I have assumed that the different zones are separated.

Now we know that in places where a fault exists that probably all three zones are tied together and there could be gravity flow directly from top to bottom through the section.

To be on the conservative side I've assumed that the reservir is a stratified reservoir. We know that in some instances as far as individual wells are concerned, that the zones are isolated.

So in order to calculate gravity drainage

I've dealt only with the dip of the formation and the assumption that the oil will flow down dip, not down the -- directly down the well, or down the formation frcm top to bottom.

Q Will you now go to the pink sheets that follows the log section and identify those?

A I show here where I arrived at the method of calculating gravity drainage and, Mr. Chairman, I'd point out again, here where we're dealing with a different kind of a formation and not as typical, namely this fractured formation, that the formulas ordinarily used to calculate gravity drainage are not much help. The problem is, as shown on the second of the pink sheets, where Muskat shows gravity drainage in terms of barrels per day per acre, the third equation on the sheet, it's expressed in terms of permeability and we just don't -- can't measure permeability directly in this formation, nor can we measure pay thickness.

We can from interference testing come up with transmissibility in terms of permeability feet. We can get some kind of an idea from individual well testing, although not much, but there again we're limited to permeability feet, and to convert this to a practical formula that we can use and apply in this area, I took Muskat's formula and changed it as shown, or from that worked to a expression in terms of barrels per day per linear mile along strike, and this information was first presented to this Commission in Case 3455, in 1969, BMG Exhibit 2.

Q Now you're talking about the blue sheets --

A Yes, sir.

Q -- in this exhibit.

On the second blue sheet we show Muskat's formula at the first of the equations at the top of the page, then how we go through and just by very simple, elementary mathematics convert the relations to one that's useful to us, which gives us, at the bottom we show the different barrels per day per linear mile along strike.

And on the third blue sheet we show what that formula is, and --

Q Has anyone else used this basic approach to calculating gravity drainage rates?

A Generally -- generally no, and in searching through the literature to see if anyone else had developed this same kind of an approach, I found it very difficult to locate it, but I did find one article, which is shown on the yellow colored sheets, published in the AIME Transactions for 1949, and article by Elkins, French, and Glenn, we show the title page of their article on the second of the yellow sheets, and then on the third of the yellow sheets the formula that they arrived at, they determined in the pool that they were working in that they needed to know a gravity drainage in terms of distance along the strike, the same as I had done for this area, and their formula is shown as the third, third equation on this yellow sheet, and they expressed the density of the oil in terms of pounds per square inch per foot, and Muskat in his work used density in terms really of specific gravity in which water is equal to 1.

So we convert Elkins, French, and Glenn's formula by -- back to specific gravity and when we do, as shown by the penciled notations on the page, and we come up with exactly the same formula that I did by working straight from Muskat's initial work.

Q Mr. Greer, would you go to the graph contained in this exhibit on the green sheet, entitled Gravity Drainage Rates, West Puerto Chiquito --

A Yes, sir.

Q -- and would you review that, please? Are you ready to go to that yet?

A Yes, sir. By using the formula just described to calculate the gravity drainage rate in terms of barrels per day per linear mile along the strike, and I've shown it here for dips running from 800 feet per mile down to 100 feet per mile.

The work which McHugh's witness, Dick Ellis, mapped that he put on in the early part of this hearing, showed dip approximating 100 feet per mile. We used the bottom line here as the applicable dip for Gavilan, for a good part of Gavilan, and transmissibilities we've seen from the interference testing, although we can't calculate oil in place directly, we can make an estimate of transmissibility by analogy to the tests which we made in Canada Ojitos.

In Canada Ojitos we found that we could pick up an interference effect within 24 hours of observation wells a mile away from the producing well, and we found the same thing in Gavilan.

Now in West Puerto Chiquito we knew that the oil was under-saturated and in Gavilan we don't know that it's under-saturated at the time of the test. But what that means is that if the oil is under-saturated, otherwise the analogy is the same, we can expect the same transmissibility for the reservoir in the Gavilan as was found in Canada Ojitos.

Now if the oil is saturated and not under-saturated, then the transmissibility in Gavilan is higher than what we have shown.

Those transmissibilities run in the range of 5 to 10 darcy feet and those are the last lines on the righthand side of the graph which projected up to 100 feet per mile dip, show gravity drainage rates of 200 to 400 barrels per day per linear mile along the strike, and circling the Gavilan nose we can come up with 8 to 10 miles along the strike and so that means like 2000 to 3-or-4000 barrels per day possible potential gravity drainage rates in the Gavilan.

Now even if we were to cover only a small part of that, that's significant and it's something which we feel the operators should strive for in Gavilan.

Q Mr. Greer, when you make this comparison, does the dip in the West Puerto Chiquito area, is it comparable to what you see in the Gavilan?

A Yes, sir, it is comparable. The -- in some of the discussions we've had with engineers estimating gravity drainage rates, they point out, to where you have those real steep dips in the Canada Ojitos Unit, up to 1000, 2000 feet per mile. But those steep dips in the Canada Ojitos Unit are in the gas cap. They don't have anything to do with the rate of gravity drainage in the main part of the reservoir.

The main part of the reservoir with gravity drainage has dips of 200 to 400 feet per mile and the best gravity drainage area we have is 200 feet per mile, only twice that of Gavilan, so they are comparable. They are quite comparable.

Q Have you prepared a comparison of gravity drainage rates for a fractured reservoir and also for a matrix sand reservoir?

MR. STAMETS: Could we stop for just a minute?

MR. CARR: Yes.

MR. STAMETS: I'd like to be clear what Mr. Greer is telling me here, based on the last -- on Figure Five, the Gravity Drainage Rates.

Mr. Greer, are you saying that in what is now designated the Gavilan-Mancos Pool, that under -- well, under what you would consider maximum operating conditions or maximum efficient rates of flow, or production from this pool, that from the overall pool we could expect to get 2000 to 4000 barrels a day gravity drainage within the reservoir?

A Yes, sir.

MR. STAMETS: Okay. Now, is this at the production rates which have been proposed by you and Mr. McHugh and if the current production rates continue to prevail, will this 2000 - 4000 barrels a day go away?

A Yes, sir, the 2000 - 4000 a day is dropping every day and the comparison is this: As the gas/oil ratios rise and the -- as you'll recall from our -- our slide presentation, the ability of the gas to move increases rapidly. At the same time that the gas production and gas moving increases rapidly, the rate of oil movement decreases rapidly, and so once the bubble point is reached and the pressure drops below that, then the rate of movement of the oil through the reservoir drops off fast, and this may not show up in a well, in an individual well; as the gas/oil ratio increases in a flowing well, the column gets lighter and it will even produce better and you think you have a higher productivity for the reservoir. The rate at which the oil moves through the reservoir and the gravity drainage part drops off significantly, and it is so significant that that is one of the reasons for the timing, and why the timing is so critical.

I would estimate that somewhere in the range of six months to twelve months, that that gravity drainage rate will drop from its maximum amount down to almost zero. For all practical purposes it will drop down to where it just would not be feasible to attempt to recover and that's -- that's why the urgency of this order, to give the operators an opportunity to look at the problem, to see if they agree with this, and to do something about it, and if, for instance, and I've taken a simple for instance, but if we can change not 100 percent of the gravity drainage potential but 10 percent of the gravity drainage potential, just one-tenth of what's possible, then that is equivalent to the solution gas drive, because, you see, the gravity drainage potential is like 55 percent of the oil in place; from the reservoir information that's available we know about that. Solution gas drive is like 5 percent. So if we can get one-tenth of the gravity drainage potential, we can double the reservoir's recovery, and I'm estimating in round numbers from the rate at which the pressure is declining and the other information we had before, the Gavilan is looking at something like 5-milllion barrels in the future. If you double that to 10-million barrels, there's 5-million barrels of additional gravity drainage that can be recovered, can be recovered, say at $10 a barrel is $50,000,000.

If in a year that potential disappears, then we've lost $50,000,000 of future recoverable oil and you convert that to dollars a day and that's like $150,000 a day that we're losing. If it's direct proportion and it probably is, for every day this hearing continues, we're losing another $150,000.

So we're producing maybe 70, $60 or $70,000 worth of oil a day and we're losing twice that. I think that's a reasonable explanation.

I hope that's the answer to your question.

Q Mr. Greer, to follow up on that, if the application of Benson-Montin-Greer and McHugh is granted, something happens and gravity drive, anything doesn't work as you've done it, who's harmed?

A Oh, there'd be no harm. There'd be no harm. The oil is still there and if it's solution gas drive recovery that everybody is going to look to, why, then nobody would be harmed, it's still there.

Q What's the effect of not granting this application and continuing?

A Well, one of the effects is going to be that we have a very serious problem in continuing our operation in -- in Canada Ojitos Unit.

For twenty-five years we've done our best to recover the maximum amount of oil, utilizing gravity drainage, restricted production rates, and we just don't know that the permeability restriction which we hope is between the two pools will be effective enough to protect us or not, and in addition to the gravity drainage recovery that Gavilan is going to lose, we will lose the gravity drainage recovery that we have every reason to believe and expect that we should be entitled to.

Q And in a nutshell isn't that why you're here?

A That's why we're here.

Q Have you prepared a comparison of gravity drainage rates for fracture porosity reservoirs and also for matrix sand porosity?

A Sure. We've shown that comparison as the last sheet in this exhibit, Exhibit Number Three, and the reason we show this is because there's such a significant difference in attempting to recover oil from a sand reservoir by gravity drainage as compared to a fractured reservoir.

And that's why many sand reservoirs realize only small, small amount of gravity drainage.

Within a fractured reservoir you have high transmissibilities, the ability of oil to move rapidly down dip and there's not much oil in place, so by gravity drainage you can recover all of the oil that's possible to recover in a reasonable length of time, whereas in a sand reservoir that would be impossible.

We make this comparison and I think we just need to go down through every line.

We have two reservoirs with the same transmissibility of 10 darcy feet.

The sand reservoir let's say is 20 feet thick, porosity 20 percent, permeability of 500 millidarcys, and we have the 10 darcy feet transmissibility.

The fracture reservoir we don't know the sand thickness, don't know the porosity, don't know the permeability but by interference test or whatever we know that the oil in place is 3000 barrels.

The comparable oil in place per acre for the sand reservoir is about 31,000 barrels, and the oil in place in a 3 square mile section, say, is one mile along the strike and 3 miles down dip, in a sand reservoir would be 60-million barrels and in a fracture reservoir about 5.8-million barrels.

The solution gas drive recovery percent of oil in place, we'll say it's 20 percent to the sand and about 6 for the fractured reservoir. That gives us a recovery per acre of 6000 barrels for the sand reservoir, 200 for the fractured reservoir. That's solution gas drive recovery.

This recovery then for this 3 square mile section is 11-million barrels for the sand reservoir and about 400,000 barrels for the fractured reservoir.

The gravity drainage recovery, and here I've used 1/2 of a maximum of 55 percent of the oil in place, and I've used that because that's what we think we're realizing in Canada Ojitos, and if it's a good sand reservoir you'll probably get more than 55 percent, but to make them comparable, I've used about 1/2 of 55 percent for both of them.

The barrels per acre recovery under gravity drainage for the sand reservoir is about 8000 barrels, and about 800 for the fractured reservoir.

For the 3 square mile section, 16-million barrels for the sand reservoir, a million and a half for the fractured reservoir.

Gravity drainage rate for both reservoirs, now, is only 200 barrels per day per linear mile along the strike.

Despite all the oil, all the sand, all the volume in the -- in the sand reservoir, its gravity drainage rate is still only the same. I've assumed here that the vertical permeability is zero in order to make the two columns.

Then the number of years that it takes for gravity drainage to reach the equivalent solution gas drive recovery for a sand reservoir is something like 150 years, whereas in a fractured reservoir it's only 5 years.

To obtain the entire gravity drainage recovery it would be like 200 years in the sand reservoir versus about 20 in the fractured reservoir.

So whereas gravity drainage might not be feasible in all sand reservoirs, in a fractured reservoir the characteristics make it entirely possible and a target to shoot at.

Q Mr. Greer, you were present at the first two days of this hearing, were you not?

A Yes, sir.

Q And at that time you heard certain questions asked concerning the impact of your proposal on state revenue.

A Yes, sir.

Q Have you studied that question and prepared certain exhibits which address the overall impact on state revenue of what's being proposed?

A Yes, sir, I have.

Q Are those contained in the booklet with the green cover that's been marked Benson-Montin-Greer Exhibit Four?

A Yes, sir.

Q Would you refer now to the first item in that booklet behind index Tab A, identify that and review the information for the Commission, please?

A Yes, sir. We show under Tab A, we note here that the chairman ahs asked for this information and in order to answer it, to make an informed answer, we checked on what the State's current situation is with respect to earnings and borrowing.

And in Item 1 we show that in the week ending August 15th, that the excess funds on deposit were about 6.1 to 6.25 percent. Approximately $184-million of these kinds of funds were on deposit then.

The longer term interest earnings ran for

CD's about 6.01 percent for a year; for 182 days, 5-75 percent.

$256-million were earning interest at these rates at the time, according to our inquiry.

The cost of money for funds borrowed is that some severance tax bonds were sold in July at the rates indicated there, which was about 6-1/2 percent.

So from the above, then, I've assumed a discount rate of 6-1/2 percent per year to make my analyses, and I noted in this morning's paper that the Fed lowered the discount rate another .5 of a percent and that will soon be reflected in such things as this, and so the 6-1/2 percent that I used may be a little bit high.

Q But this is how you calculated the discount rate.

A Yes.

Q All right, will you go to the next page, please?

A The next page shows posted prices in the Four Corners area by two of the companies, Shell up until the end of 1984 and Giant Refining Company after that.

The price of oil was decontrolled in January, 1981, and since that time we can see how the price has gradually dropped until it reached its precipitous decline here early this year.

I've shown an approximate scale here of the 6-1/2 percent per year escalation, starting from the point at which oil is being sold here in mid-August, and the point of this, Mr. Chairman, is to show what would happen in terms of state revenue if for instance oil that could have been sold today was delayed until later on, say, for instance, it sold two years down the line, it sold for more than about $13.00 a barrel, the State would realize a higher discounted net worth from that oil than if it sold today.

In other words, the State could reduce the allowable, could sell some severance tax bonds for a similar amount, pay interest on those bonds and in two years sell the oil and be ahead financially as compared to producing the oil and getting the income now.

And the question, of course, is what is the price of oil going to do, and I'm sure that everybody in this room studies all the information they can get in that respect, and without exception we find that the analysts have concluded that the price of oil is at the bottom of its cycle now. It's going to have to go back up. It's just a question of when and how fast.

So what this -- what this shows is that for the current earnings or for borrowings for the State, the chances, in my opinion, are very, very good that production can be delayed and produced at a later date and the

State will be ahead by having done that.

Q Would you now go to the next page and explain that graph, please?

A The next graph shows what the current production rate is in terms of barrels per well per day and the purpose of this is to give one more, one more analysis of how the State will not be hurt by reducing the allowables. And we start off by saying, well, current average production rate is approximately 130 barrels a day. In May it dropped down. That was because some of the new wells didn't produce the full month. 130 barrels a day is a pretty good figure for the average production rate in terms of barrels of oil per day.

So I've made the comparison which will show the statistics under Tab B of two wells, and the assumption that I made is that Gavilan would be instantaneously drilled up on 320-acre spacing. We would have current production as fast as the wells would be allowed to produce it, and we'd compare that, then, against restricting the rate not by the amount that we're recommending in this application, but rather severely to about a fourth of what it currently is, and those statistics are set out on Page 1 and they're a little easier to -- to see the comparison on the second white sheet under Tab B, where we show for Example I the initial production rate, 130 barrels a day; for Example

II, about a fourth of that, 37.5 barrels a day.

Production decline rate in percent per year, 72.43 percent for Example I and 5 percent for Example II.

In this decline rate I've used the relation that the ratio of the productivity from one point to the next is equal to e - e raised to the power of the decline rate times ti (sic), e being the base of a natural logarithm.

The producing life, then, for Example I is 5.2 years; Example II, 6 years.

The ultimate recovery for Example I is 64,000; Example II, 71,000 barrels.

The discounted present worth for both examples is 59,000 barrels.

And why I've used more recovery for the well producing at the lower rate is because I have, as shown here, that if the lower rate of production obtained in the field and some gravity drainage results, it is necessary to obtain only one percent potential gravity drainage to realize 10 percent of the solution gas drive.

So I have said that if we increase the solution gas drive recovery by 10 percent, then this well getting some gravity drainage needs to get only one percent, one percent is substantial for gravity drainage to come up with enough oil that the discounted present worth is the same even if the price of oil stays the same, and the statistics for that are shown in the yellow pages following for a well for 130 barrels a day; on the second of the yellow pages we make a comparison with the continuous discount rate to see whether the engineer making these calculations could have had a big mistake. I come up with about the same thing that he did in the way of discount rate so I feel that the figures are accurate.

On the green colored pages are the statistics for the well starting off with 37-1/2 barrels per day and on the third page we show again the comparison there of the discount, the weighted average discounted at this rate.

Q Mr. Greer, will you go to the graphs that are contained in Section C of Exhibit Number Four and review that for the Commission?

A Under Section C we show these examples, first on the pink sheet plotted on semilog paper.

Q Initially, Mr. Greer, in the caption at the top you've got a figure there and it says Per Year Decline. Would you explain what you mean when you use that term?

A Well, that's the formula I just mentioned. The one I use is the instantaneous rate of decline where the ratio of productivity varies as the natural logarithm e raised to the power of the decline rate times time.

Q Now would you explain the exhibit?

A We show here graphically the statistics that were shown on the previous pages and of course a semi-log graph is sometimes a bit difficult to -- to realize or get the perspective of the differences in a comparison like this, so we plotted also the same information on the gold colored sheet, in which we used the coordinate scales there.

Here we show that the well reaches an economic limit at 130 barrels per day. If Gavilan was all drilled up, drilled up completely on 320-acre spacing, that's the decline rate that we would see. That's the fastest that you can get the oil out of the ground on average that you can get the oil out of the ground, on average, assuming that the new wells would have the average production of the old wells, which you have some of them making an allowable of 700 barrels a day; some of them are making a lot less.

Then the dashed line shows the restricted rate of production and the fact that you only need 10 percent more ultimate recovery to have the same discounted present worth, even if the price of oil does not change.

Q Now, Mr. --

A So all in all I feel that the State is taking no risk in -- in lost revenue by reducing allowables.

The State particularly has more incentive, it seems to me, to exercise its prerogative regardng conservation.

Q Now, Mr. Greer, you are recommending, as is Mr. McHugh, a production limitation factor that is 400 barrels per day for a 640-acre unit and in McHugh's case, 200 barrels per day for each 320-acre unit.

Could you explain to the Commission how this 200 figure is obtained or developed.

A Yes, sir, I will. But first I think I should point out that the 700 barrel per day allowable in Gavilan now has really no basis, no relation to reservoir characteristics whatsoever. It's based simply on the State's depth and acreage factor and overall it's probably fine for the State's reservoirs overall, but overall the State's reservoirs are normal reservoirs. They're certainly more normal than this reservoir; this is an unusual reservoir and so the allowables which are determined for you might say conventional or the average reservoir really has no application here, and so -- so we look at what factors might be reasonable to use in determining the allowable, and first we go to the statistics of the wells as of now.

Q And you're looking a the first sheet behind Tab D in Exhibit Number Four.

A Yes, I am. Now this sheet shows the total pool production, the production in terms of barrels per -- per well per month, and then we have some more statistics. We'll be looking at all the statistics on graphs in a minute. I'd like to just run through quickly and the second page, the white page, is statistics we have showing again the production rate in terms of barrels per day per well for all the wells in the set of figures on the lefthand side and then we've deducted out wells making more than 300 barrels per day on the righthand side.

Then the next sheet, the pink colored sheet, shows on the righthand side the same information where we've deducted from the pool average wells making less than 25 barrels per day.

Then the next graph, the next -- it's a blue colored sheet under this tab, Tab D, we show here graphically the production from the pool in total barrels per month.

Then the next graph, the second blue colored graph, using all wells, with the barrels per well per day, and this the same graph that we looked at a little earlier, approximately 130 barrels per day, the average production rate for all the wells in the pool.

Then we go to the next graph and we've

deducted out the large wells and we see then that the production for all wells except the large wells is about 80 barrels a day.

Q And that's the green shaded area?

A The green shaded area, and had Gavilan been developed, say, with wells like that, there would not be the problem that we before us today.

The next pink sheet shows by deducting the wells with less than 25 barrels a day, we deduct them, gives us a little perspective of the higher capacity wells, and you can see the jump that happens about the first of the year when more of the higher capacity wells came on stream.

Q All right, Mr. Greer, would you now, using this information, go to Section E of this exhibit?

A Yes, sir, in Section E we show in the first column productivies of sample wells and then in the second column an allowable, which would be -- which I would consider a reasonable allowable for the Gavilan given the Gavilan's characteristics, and for that we use as a base the average production rate of the wells in the pool now, which is 130 barrels per day.

Then we structure the allowable from that point up and down based on the cube root of the ratio of the productivities, which is what we had found earlier is one of the characteristics the formation apparently exhibits.

Now we realize that this would not be a practical formular to adopt explicitly because of difficulty in measuring productivities in the wells. The Commission has always controlled production by an allowable and a gas/oil ratio and I see no reason to change from that now.

But to give an example of just what the variation would be if we would adopt a theoretical formula that the allowable would vary as the ratio of the cube root of the productivities, then we have a second column what that allowable would be. For instance, at 130 barrels a day it's 130, which is our base.

We drop down to 300 barrels a day it would be 172 barrels a down or down to 700 barrels a day it would be like 228.

Compare those figures with what would be the allowable based strictly on productivity, in a sense that's what we have now, 200 barrels a day is more than the majority of the wells can make, and only a few can make 700 barrels a day, and so the net of it is that the allowable now is based strictly on productivity.

The comparison would be like at 200 barrels a day in both instances, the well would be allowed to produce 50 barrels a day more than its theoretical amount.

If you drop down to 500 barrels a day and under our -- this formula the well would be allowed to produce 4 barrels a day less than what its theoretical amount would be.

But on the other hand by comparison in the last column that the way we're producing now, the allowable we have now, it would receive nearly 300 barrels a day more than it should.

So there's no way to have a perfect formula but at least we can have one that's not as far out in left field.

For a 700 barrel a day rate we would come up with the well should have 228 barrels a day. By the application it would get only 200, so it would be 28 barrels a day less than it really should have and otherwise it's going to get nearly 500 barrels a day more than it's entitled to.

You can carry that on down to 1000 barrels a day or 10,000 barrels a day. There's no reason to stop at 700 barrels a day if allowable can be based on productivity.

At 1000 barrels a day under our formula it would be entitled to 257 barrels a day, 57 barrels a day less than what its theoretical amount should be but by the same token, based directly on productivity it would get 700 barrels a day more than it should, and so on, where under direct proportion the well would get 10,000 a day more allowable than it should.

The basing allowables on productivity we consider is absolutely the only way to determine allowables.

Q Will you now go to the graph which is the next page in Section E?

A This just shows graphically the same information that we looked at that if allowables were based on the cube root of productivity as to what it would be.

Q Okay, go to the next graph. What does that show?

A The yellow colored graph we've shown the difference in the theoretical allowable against the 200 barrels a day which we're proposing. The shaded area at the top of the two lines on the lefthand side show how far the theoretical allowable would be from 200 barrels a day, and for wells with productivities less than 450 barrels a day the stippled area on the bottom shows the difference there.

By comparison if the allowable is 700 barrels a day the area would be much greater and we show that in color on the next graph.

Q Okay, why don't you do that?

A Here in color we compare the amount of excess allowable that a well will receive with a 700 barrel per day maximum allowable, as compared to what we think would be a reasonable allowable if productivities -- or if allowables were based on the cube root of the productivity if 130 barrels a day is a base.

Q So this is the basis for the 200 figure for the 320-acre unit that you're advancing?

A Yes, sir.

Q Now, Mr. Greer, is it your testimony that production rates must be limited in this area as well as simply gas/oil ratio restrictions --

A Yes, sir.

Q -- ratios being restricted?

A Yes, sir, absolutely. The withdrawal rates, even if there were no free gas, the withdrawal rates are just excessive.

Q Will reducing the gas/oil ratio alone result in an effective relief for the time being for the problem you see out there?

A No, sir.

Q How soon in your opinion must action be taken if the problem is to be avoided?

A It's just a very critical problem and action is neede urgently and just as fast as the Commission can see its way clear to act.

Q If action isn't taken in the immediate future, what consequences do you foresee?

A Well, one of the consequences, of course, is the problem that we've had and we would have in continuing to produce our Canada Ojitos Unit in a manner in which we had hoped to recover the maximum amount of crude oil.

Q Do you believe granting this application and imposing these limitations for ninety days will have any adverse affect on the State of New Mexico?

A No, sir.

Q In your opinion, what is the ultimate solution to the problem that exists in this area?

A The ultimate solution is very clear. Gavilan has to be unitized. Gavilan just must be unitized. That's the only way to avoid the drilling of unnecessary wells. That's the only way that the maximum recovery of oil is going to be realized, and it's the best way to protect correlative rights.

Q In your opinion when we look a the Mancos formation in this area, are we talking about a typical solution gas drive reservoir?

A No, sir, this is one instance in which Mother Nature gave us a choice of -- of the kind of completion mechanism would take place.

It it's produced at a high rate it will be solution gas drive primarily.

If it's produced at intermediate rates there will be solution gas drive plus some gravity drainage and if produced at the lower rates it will be significant gravity drainage.

Q Sir, I'd like to hand you what has been marked for identification as Benson-Montin-Greer Exhibit Number Five and I'd ask that you identify that, please.

Would you identify that, please?

A Yes, sir. This shows the notices to the affected parties in the area, and the receipts.

Q Is the last document in that exhibit a copy of a letter that was actually sent?

A Yes, and that's the letter that was sent with the notices.

This is the notice.

Q And the return receipts and return letters are attached there, that's the original copy?

A Yes, sir.

Q Mr. Greer, were Benson-Montin-Greer Drilling Corporation Exhibits One through Five either prepared by you or compiled under your direction?

A Yes, sir.

Q Can you testify from your own knowledge as to the accuracy of those exhibits?

A I believe they're accurate.

MR. CARR: At this time, Mr. Stamets, we would offer into evidence Benson-Montin-Greer Exhibits One through Five.

MR. STAMETS: Are there any objections?

The exhibits will be entered.

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

MR. STAMETS: I'd like to ask just one or two questions before we take a break.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Greer, looking at Exhibit Number Four, and we're back the fourth from the last page, comparison of allowables, immediately behind Tab E.

A Yes, sir.

Q Now from your earlier testimony, are you saying that the cube root of ratio of productivity is roughly comparable to how much oil there is under any particular tract?

A The chain of thought, Mr. Chairman, is that the oil under the tract is proportional to the cube root of the transmissibilities of that area and it would be on a rather large area.

Now the productivities of individual wells within that area will be somewhat in proportion overall and on an average with the transmissibility of the formation. But it cannot be determined exactly, just that it's the best comparison that we have.

Q So what you're saying, in essence, is that the -- that the 200 barrels a day comes much more close to representing an allowable that will let everybody produce their share from the individual -- from the reservoir than the 700 barrels a day.

A That's exactly right. It will come very much closer to giving each operator the opportunity to protect his correlative rights.

Q Let me ask a question off the record.

(Thereupon a discussion was had off the record.)

MR. STAMETS: We will recess the hearing until 1:30.

(Thereupon the noon recess was taken.)

MR. STAMETS: The hearing will please come to order.

I assume that there may be a couple of questions of Mr. Greer.

Mr. Lopez?

MR. LOPEZ: Mr. Chairman.

CROSS EXAMINATION

BY MR. LOPEZ:

Q Mr. Greer, I'd like you to refer to your exhibit under Tab C in Exhibit One and I would like to discuss this exhibit with you.

Mr. Greer, I believe a great theme in your testimony this morning was that unless some measures are taken to restrict production immediately, that substantial waste will occur because there will not be the benefit of gravity drainage realized in the Gavilan-Mancos Pool, and in reaching these conclusions you compared the producing characteristics of the Puerto Chiquito Pool and your Canada Ojitos Unit to the Gavilan-Mancos Pool.

I believe you stated that, in this regard, that the angle of dip in the Canada Ojitos Unit where you realize the greatest recovery was approximately 200 feet per mile and that the angle of dip in the Gavilan-Mancos Pool was 100 feet per mile and therefore they compare, the two pools compare favorably.

I assume that the wells which are located in the Canada Ojitos Unit are located along the wester flank of that unit but on the east side of the permeability barrier or at least permeability restriction that you have located on this exhibit in the shaded area with question marks.

A Yes, sir, that's correct.

Q Isn't it true that these wells are at the bottom of the down dip of a dip that goes to the eastern boundary of the unit where you have pressure injection wells?

A I don't believe I understand what you're saying.

Q Well, I'm saying is it your opinion that the oil that you're recovering is drained from the eastern boundaries of the unit where you have pressure injection facilities?

A Yes, sir, to -- to take an example, about the center of the unit, Township 25 North, Range 1 West, Section 13, where we show a well K-13, if you can find that, about halfway between the K-13 and the injection well B-18, located in Section 18 of 25 North, 1 East, was where we felt the initial gas/oil contact was.

The gas cap had what we felt high gas/oil ratio saturation, not a pure gas cap, but the solid oil started at about that 1600 foot contour interval.

Going down dip from there to the west you can see it's approximately 400 feet per mile. Going further to the west you can see it's about 200 feet per mile. That's the area where most of the production has come.

Q Then you'd agree with me, would you not, that the dip across the unit, Canada Ojitos Unit, is much more severe than any dip we see reflected in the Gavilan-Mancos Pool.

A I believe what I said, that the best area of gravity drainage that we've had in Canada Ojitos was at the 200 foot per mile area, and that would be just east of the well located in Section 10, just west of the area you are presently talking about. You can see the contours there are roughly 100 feet per mile.

By happenstance, the transmissibility in that area, thanks to Mother Nature, was about twice as much as the transmissibility further east, where the dip was 400 feet per mile, so we were fortunate in that the area where it was 400 feet per mile and had the transmissibility, we had roughly the same gravity drainage potential there as we did lower down.

Q Now I note in the Canada -- in the Gavilan-Mancos Pool, in the heart of the pool where most of the wells are drilled, outside the northern end of the pool, that there is no dip whatsoever reflected on this exhibit.

A Oh, I see. Well, I have to apologize for that. As I indicated, by basic map was contoured on 200 feet per mile. I sketched in with the dashed line the 100 foot -- 200 foot contours, they are 200 foot contours. I sketched in with the dashed line a 100 foot contour but in order to be able to see the Gavilan nose. If I hadn't sketched that in, it wouldn't appear at all, but on this map I didn't see any need, it would be wasting my time to -- to try to contour it closely and accurately when the work had already been done by McHugh.

So to look a the dips we really would need to look at the map which I referred to this morning in discussing that, which Dick Ellis prepared.

I can find it here in a moment if you want to look at it.

It's McHugh's Exhibit Three under Section -- Section C.

Here Dick Ellis has contoured in fine detail the structure as accurately as it can be possibly known at this time. This map, of course, concentrates on the Gavilan structure itself, and you can see there that these are 50-foot contours and there is about two of them per section, which is roughly 100 feet per mile dipping to the west and to the northwest.

Right along the nose it's down to 50 feet per mile and then on the east side of the nose it gets back up to about 100 feet per mile.

Q And I believe you also stated that in your Puerto Chiquito Unit you encountered interference between wells one mile apart within 24 hours.

A Yes, sir.

Q In the Gavilan-Mancos you said you encountered the same experience.

A Yes, sir.

Q Which wells did you encounter this experience in?

A We ran an interference test between the Mallon Howard 1-A in the green circled area on the map that you had earlier referred under Section C in our Exhibit Number One, and the well just east of that, the Canada Ojitos Unit E-6, and some of the pressure data that was recorded during those tests was put on by John Roe in his testimony, and an example of the well approximately a mile away is the effect of the Howard 1-11 when it was shut in about mid-January and within one to two days I measured the pressure change occurred in the pressure recorded in the E-6.

Q Would this suggest to you that your well, then, in Section 6 is actually located in the Gavilan-Mancos Pool rather than the Puerto Chiquito Unit or the Canada Ojitos Unit?

A Mr. Chairman, they're all located in the same common source of supply, the East and West Puerto Chiquito and Gavilan.

Q Then how do you explain the permeability restrictive barrier between the two?

A Well, that's a postulation. I just sincerely hope it's there. We've had some indications that it's there and how effective it is, we don't know. Whether it's in all three zones we don't know, and it's just something I wake up in the night and hope it's there.

Q What indications have you had that indicates that it is there?

A Some small wells to the south, the finger pointing to the southeast to the K-8 Well, which is a rather small well. The finger pointing to the southwest there are some small wells on the Gavilan side.

Coming up to the north there's a small well in Section 31, the K-31.

Moving farther north, we don't know about 30, we'll be treating that well next week or so.

Moving farther north up to Section 8, the J-8 Well appears to be real tight, and moving farther north, the G-32 in Section 32 of 26 North, 1 West, is a rather small well, so we feel there's a permeability restriction through there. Again how effective it is, we just don't know.

Q What can you tell me about that J-6 Well in Section 6?

A The J-6 Well is a -- has lower productivity than the E-6, as we indicated in some of our discussions in the Engineering Committee.

The E-6 currently produces about 600 barrels a day; the J-6 about 200 barrels per day, so it's not as good a well as the E-6, and it would appear that perhaps it's getting (unclear) from the east, but that's not a certainty. There are wells within the Gavilan Pool where we go from 600 barrels to 200 barrels a day and the pool continues beyond that, so that alone doesn't tell us that we're going to have a restriction.

Q Now, changing the subject, I'd like to ask you whether or not the relationship of permeability to porosity which you described this morning as a cube root relationship and which you used to justify your 200 barrel a day allowable, whether that's no more than an assumption on your part?

A The relation of --

Q I'd like a yes or no, if possible.

MR. CARR: You can explain it. I think his answers are responsive to the questions and I think he should be permitted to answer them. I think the answer will be yes or no but I think he should be permitted to answer (unclear).

MR. STAMETS: We'll allow Mr. Greer to answer this question in his own way and see if it is something we can all live with.

We'll see about any further objection you might have to having yes or no answers.

A The relation of the porosity as a function of the cube root of the transmissibility, is an absolute, simple, engineering fact insofar as a fracture system of parallel fractures and flow in the same direction parallel to the fractures. That is an absolute, simple, fundamental engineering fact; no question about that.

Now, in the reservoir I had assumed , and I grant you that's an assumption, that the porosity would be a little bit higher than indicated there because the fractures are probably not all lined up directly in line with the directional flow and so that's the difference.

To the extent, then, that wells can represent the transmissibility of the formation, then the wells productivity may be indicative of the ratio -- the cube root of the ratio of the productivity then becomes a measure of the pore space in the (unclear).

MR. STAMETS: Did you get an answer to your question?

MR. LOPEZ: I think the answer was yes.

MR. KELLAHIN: I believe the answer was no, Mr. Lopez.

MR. CARR: Mr. Stamets, there

are certain questions which can be answered yes or no. Were you there on Tuesday at 10:30?

There are other questions that you'd never require a witness to answer yes or no because you are looking for an incorrect answer.

Mr. Greer admitted there were assumptions involved and there were facts involved and there were formulas involved that are reliable engineering formulas that are not subject to interpretation, and he was responsive to the question unless the question was, can we take this complicated area and write the whole thing off as an assumption, and if that is what he's being asked to answer yes or no, we object to the question because he cannot give you an honest answer.

MR. STAMETS: Mr. Lopez? Are you satisfied with where we are?

MR. LOPEZ: The answer is on the record and we can discuss it later.

Q I think when you were discussing the Howard No. 1 Well that you stated that the core porosities bore no relationship to the log porosities.

Did you do any -- did you independently do any log analyses of your own to vertify this fact?

A Oh, no, sir, I was just reporting the report of the technician.

Q In your direct testimony I think you also stated that the oil allowable should e 200 barrels a day.

A Yes, sir.

Q As I understand it, you didn't address the gas allowables so does this mean there should be no gas allowable restriction?

A Well, our application asked for the gas/oil ratio limit to be 1000 cubic feet per barrel. While we didn't go into that specifically, I believe, this morning, but that's our application.

Q And was no other independent evidence or data to support that, it is just in your application and you rest on the statement in your application and no other evidence (unclear).

A We're asking that the rate of reservoir depletion be reduced. The existing gas/oil ratio is 2000 to 1, so by reducing the allowable gas/oil ratio limit from 2000 to 1000, we're moving substantially in the right direction to help minimize the depletion rate.

Q And I believe you stated you wanted this limitation for a period of ninety days.

What is going to be your position if the Gavilan-Mancos Pool is not unitized at the end of the ninety days?

A Well, I haven't speculated on that. I

would sincerely hope that that's something that doesn't come about. Surely the operators will realize the situation and will respond. That's -- that's my hope. I haven't planned anything for our unit or West Puerto Chiquito beyond this working toward unitization of Gavilan.

Q Well, isn't it true that if in ninety days that no effort towards unitization are realized that you would want to make these temorary rules permanent, or maybe even just more restrictive allowables?

A Oh, I believe we'd want to think about that and discuss it with the other operators and it's just very impossible to say at this time the progress that will be made in ninety days. At the end of ninety days it may be so close to unitization that we might be ready to go forward with it.

MR. LOPEZ: I have no further questions.

MR. STAMETS: Are there other questions of Mr. Greer?

Mr. Pearce.

MR. PEARCE: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Greer, I want to thank you for using a mike (unclear) this morning.

Mr. Greer, if you would, please, sir, in your Exhibit Number One behind Tab C, which contains your structure map.

Do you have that before you, sir?

A Yes, sir, I have.

Q Looking at that, if you would, please, I'd like to refer you to a couple of specific wells. Could you tell me the difference in elevation between McHugh's Mother Lode No. 1 Well and Mesa Grande's No. 1 Gavilan Howard Well?

A Well, I should have brought my magnifying glass, but I believe the Moter Lode appears to be -513 and the Howard -- which one was it?

Q The Gavilan Howard No. 1, and that may be the 1-11, I'm --

A If it's the 1-11, well, I need to refer to --

Q The well I'm looking at, sir, this map shows Mesa Grande Resources Howard No. 1. I apologize.

MR. STAMETS: How abcut some sections, townships and ranges on this.

A Well, let's see, in Section 23 of 25 North, 2 West.

MR. CARR: That's the Howard No. 1?

MR. PEARCE: The Howard No. 1, yes, sir.

MR. STAMETS: And what about the --

MR. PEARCE: The Mother Lode?

MR. STAMETS: Yes.

MR. PEARCE: That well is in Section 3 of 24, 2.

A Okay, I'm looking at Dick Ellis' structure contour map, if I've got the well, I believe the Mother Lode is +511 and the Howard 1-11 is 438, and the Howard 1-H is 437, both in Section 1.

Q I'm sorry, I was looking at the Howard 1. In looking at your exhibit it appears to be in Section 23.

MR. CARR: Talking about the Mesa Grande Howard No. 1.

Q Mesa Grande Howard No. 1.

A Oh, Mesa Grande, I'm sorry.

I apologize for being so slow. Tell me again the quarter section in Section 23.

Q It appears to be in the northwest quarter section of Section 23, Township 25 North, Range 2 West.

A Okay, I believe that's a +568.

Q What's the difference between those two elevations, please, sir?

MR. STAMETS: For the record Mr. Greer is now utilizing the structure map in McHugh's exhibit rather than the structure map in his own.

MR. PEARCE: Yes, sir, apparently he is.

Those numbers, by the way, on your exhibit, sir, appear to be 513 and 574.

A Oh, I'm pleased that I can get that close to a geologist' interpretation.

Q They probably are, too.

A The difference there is about, looks like 57 feet, going by Dick Ellis' --

Q Okay, and what's the distance between those wells, please, sir?

A They're along the nose of the anticline about, oh, a couple of miles.

Q Approximately two or approximately three?

A Approximately three.

Q Thank you, sir. Mr. Greer, looking --

continuing to look at that exhibit, you indicate the permeability restriction which you answered some questions about, I'm wondering, sir, if you ever conducted a pressure interference test across that permeability restriction?

A No, sir, such a test was suggested by Meridian's engineer, Dick -- or Richard Fraley, and in line with that we're currently trying to work out plans to do that.

Q Mr. Greer, you previously testified about calculating the amount of expected oil in place from the results of interference tests, is that correct, sir?

A Yes, sir.

Q Would you explain to me once again how you did that, please?

A Yes, sir. If one can -- can stabilize a reservoir such that there are no strange pressure transients moving through it, and one has adequate control of the shut in wells and the producing well, and put the producing well to production, then during the transient period in which pressures drop rather rapidly initially and then gradually fall off, during that period of time if the test has been conducted properly and if conditions are such that it can be done, which we found possible in the two tests we ran in Canada Ojitos in 1965 and 1968, then one can calculate, in the instance of our 1965 test, simply by plotting the pressures against time on a semilog plot, one exactly the same relation that you had in the pressure buildup or pressure drawdown in the well, given the proper time period that that's taken.

From that you can calculate the transmissibility, Kh.

Then from the exponential integral solution of the disfusivity equation you can calculate the ratio of permeability to porosity.

So then you have two equations and two unknowns and it's a rather -- by now it's a rather commonly accepted method of calculation. At the time we did it there weren't so many of those -- that kind of test run.

There was a paper written by one of the Amoco engineers that described the process calculated slightly differently but with the same results.

Q Mr. Greer, were you in the hearing on a previous occasion when we met about two weeks ago?

A Yes, sir.

Q And were you here when Mr. McHugh's own geologist concluded that the Gavilan-Mancos Pool is a solution gas drive reservoir?

A Yes, sir.

Q Are decreasing pressures and increasing GOR's predictable and necessary results of production in a solution gas drive reservoir?

A Yes, sir, might I add that in this particular pool the depletion mechanism is dependent not just on the character of the reservoir itself but how it's produced.

If it is produced at a low rate there'll be substantial gravity drainage in addition to the solution gas drive.

If it's produced at (unclear) there will be no gravity drainage.

So I presume what Mr. Ellis was referring to was that under the current conditions of excessive rate of withdrawal that the depletion mechanism is principally solution gas drive and (unclear).

Q All right, sir, and in your opinion will gravity drainage be as effective a production mechanism in the Gavilan Pool as you believe it is in the West Puerto Chiquito Mancos Pool?

A I don't think quite as effective. It doesn't have to be as effective to be a practical process to try to achieve.

Q All right, sir. Looking back and Mr. Ellis' structure map which we've discussed for some time, a couple of times, am I correct in reading this structure map that the developed area of this pool at this time is on the high part of the pool and the undeveloped area is down dip from the developed area?

A Yes, sir, that's why there is an opportunity yet to achieve some gravity drainage if it's properly developed from this point forward.

Q And that will require further development in the undeveloped area of the pool.

A Yes, sir.

Q Looking, Mr. Greer, if we may, at I believe it is your Exhibit Number Three, in which you gave your gravity drainage calculations, is that Exhibit Three or am I --

A Yes, sir, that's Exhibit Three.

Q I'm looking at Page 4 of that exhibit. My question is in applying the Muskat formula, as you have modified it, will gravity drainage be eliminated as a production mechanism if production rates are not decreased?

A Yes, sir.

Q What factors in that equation, sir, will be changed to make the Q zero?

A If you look on the next page, Page Five, I believe you will see the formula says that the production rate will be equal to 2580 times Hk and that Hk is the transmissibility is the product of thickness and permeability.

The permeability there is the

permeability to oil and the permeability to oil decreases rapidly as the gas/oil ratio increases and the gas saturation increases in the reservoir.

So that's how -- how it affects the gravity drainage here.

Q Thank you, sir. One moment, please, sir.

If you could explain a little further, Mr. Greer, the last area, when you say that the relative permeability of oil changes, how is that affected in a fractured reservoir?

A Well, as we indicated this morning when we were talking about how when the pressure drops the gas expands and the oil in a sense shrinks and there's a higher volume of free gas in the reservoir, and that restricts the rate of flow of the oil.

Q How does it do that, sir?

A Well, it is very commonly understood in all the engineering treatises on relative permeability that as the gas saturation increases that the oil, permeability to oil decreases. I think it's a pretty common fact.

Q I'm sorry, sir, but if use is made of this transcript in the future I don't think it's going to be by a petroleum engineer.

So I'd like for you to explain to me as simply as you can for a layman that commonly accepted fact.

I don't understand how it works.

A I see. Well, the -- there have been many tests, laboratory tests. There have been many calculations of productivities of wells and you can arrive at it either way or both ways.

As to wells, the productivity of the wells will decrease substantially as the permeability to oil decreases and that's just a physical fact we can measure from time to time. As the oilfield is depleted tests are made on individual wells, the productivity index, and that's the amount of oil that will be produced for a drawdown of 20 pounds, will decrease, and it just happens in all reservoirs.

Q Do you have some indication that that is true of fractured reservoirs as well as matrix or I believe wht you referred to this morning as sand reservoirs?

A Yes, sir.

Well, sir, perhaps I should clear that up. I just realized I overlooked a point and that is if gravity drainage is taking place, then of course the oil and gas segregate and it's in the up dip wells that the productivity drops down, the oil saturation stays high in the low, the wells low on the structure, and so in that instance their productivities stay up.

But that's where gravity drainage is taking effect and having its influence rather than the solution gas drive.

Q Okay, I did not understand one answer you gave, I think to Mr. Lopez' question, and if you did I'd ask for you to repeat it and if you didn't, I'd like for you to answer it for me, please, sir.

Where is the gas/oil contact at this time as near as you can tell in the Canada Ojitos Unit?

A We put on an exhibit three years ago that showed pretty much how we think the gas/oil contact exists.

I don't have the exhibit now but I can tell you generally that I feel like gas cones down to the producing wells and with the gas/oil contact lying, the main gas/oil contact lying somewhat below the initial contact of 1600 feet, probably between, oh, 1200 and 1600 feet coning down to the individual wells.

Q Thank you, sir. Mr. Greer, short of unitization of the Gavilan-Mancos Pool, how can the present owners of undeveloped acreage protect their correlative rights?

A Well, the first step is production of allowables as we discussed this morning.

Q How does that participate in protecting correlative rights for someone with undeveloped acreage?

A Oh, I misunderstood, I'm sorry.

People with undeveloped acreage, of course, the only way they have to do to protect their correlative rights is to drill their wells under the regulations applying at that time.

MR. PEARCE: One minute, sir. Nothing further at this time. Thank you, Mr. Chairman. Thank you.

MR. STAMETS: Are there other questions of the witness? Mr. Padilla.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Greer, this morning you talked a little bit about the rule of capture and the rule of capture, or you indicated something to the effect that the rule of capture was actually in existence in the Gavilan-Mancos Pool, is that correct?

A Yes, sir, that's correct.

Q In an answer to Mr. Pearce now you just stated that everyone had an opportunity to drill the wells in order to protedt their correlative rights, is that correct?

A I think what I said is in order to protect your correlative rights you had an opportunity to do it, then you had to drill a well. That doesn't mean that the regulations are such that if you drill a well you cannot protect your correlative rights, so it's not quite the same thing.

Q But there exist spacing regulations presumably to protect correlative rights, is that correct?

A Yes, sir, and what we're saying is that they're not adequate. A man could go out now and drill his well on his tract and he would not be able to get his fair share of the oil because of the high allowable.

Q Mr. Greer, does your application include a spacing change?

A A spacing change, no, sir.

Q Does your application include the restriction of further drilling in the Gavilan-Mancos Pool?

A No, we've not asked that the drilling be restricted. We've asked that the allowables be reduced and we would hope that the operators would voluntarily get together and unitize and minimize the depletion rate.

Q In an emergency situation as you characterize the Gavilan-Mancos Pool as being in right now, wouldn't it be appropriate to expect further drilling in that pool?

A Mr. Chairman, I think that would probably be an appropriate action of the Commission to do that, because an action of the Commission is to reduce the allowables, minimize the depletion rate, and give the operators the opportunity to voluntarily come about a minimum drilling program.

I think it would be highly improper for the Commission to order restriction on the drilling at this time; certainly not until the operators have had an opportunity to produce their share.

Q Well, hasn't your testimony been that there are a lot of wells that are being drilled unnecessarily both for the Gavilan-Mancos Pool and then as a consequence you don't want to drill any unnecessary wells in the West Puerto Chiquito Pool.

A That's right. Unnecessary wells are being drilled and we'd like -- we would hope something could be done to stop that.

Q Now as I understand your testimony, there are no unproductive -- there is no unproductive acreage either in the West Puerto Chiquito Mancos Pool or in the Gavilan Pool. Is that accurate?

A It's pretty difficult to -- to say, Mr. Chairman. An example I gave this morning of a well drilled, produced 60 barrels a day, sidetracked the hole and bottomed it 100 feet away from the initial hole shows no production, one answer to that question would be that that tract was dry, but that's not the case. So --

Q Well, in answer to my question, my question is do I understand you to say that all acreage in both pools is productive, or it is underlain by equal amounts of oil per acre?

A No, sir, I believe I said that I thought there was a difference in the pool in areas, generally, depending upon the transmissibility of the formation.

Within any one of those areas wells can be drilled just like the one I mentioned that show absolutely nothing; move over 100 feet and you show a high productivity on an average; on an average that area generally is productive.

Q But it's not uniformly productive.

A In no way. This is the most non-uniform kind of reservoir that you can imagine.

Q So in your concept of unitization, unproductive acreage would participate equally with productive acreage.

A Oh, no, I'm not suggesting that at all. I would hope that the operators would see the virtue of unitization. They would sit down and work out the problems of unitizing after wells are drilled, and of course that's a -- that is a difficult problem, but hopefully, the operators would see the benefit of unitization and try to work out a method.

I would not suggest any formula at this time for Gavilan. That's just up to the engineers and the geologists as to how they can best work that out.

Now in the Canada Ojitos Unit we have based equities in the third expansion area strictly on acreage, which I think was a fair and proper thing to do.

Q Okay, but this morning you also testified that you did not agree that any proportional allocation based on the productivity of a well to individual owners in the Gavilan Pool, is that correct?

A I'm not sure I understood your question.

Q Well, aren't you against the proportional allocation of reserves in the Gavilan-Mancos Pool?

A I feel certain --

Q Based on productivity of wells?

A Yeah. I feel quite strongly that that the oil in place is not in direct proportion to the productivities of the wells.

Yes, sir, I feel quite strongly about that.

Q Yet in the West Puerto Chiquito you did at one time have a different allocation and not based upon straight acreage.

A In West Puerto Chiquito while we recognized the gas cap as having less value than the -- than the oil zone, and the net effect, I believe, was approximately one-sixth was assigned to the gas cap.

Q But you recognized that there were factors other than straight acreage which should play a role in that allocation of reserves.

A Oh, certainly.

Q Let me refer you to your Exhibit Number Two, Mr. Greer, and I believe that was the one that you had in slides.

During the lunch hour I've got to tell you that Mr. Nutter thought that you were going to give us a lecture on cholesterol when he saw that.

MR. CARR: I understand why Mr. Nutter would be concerned.

A I appreciate his sense of humor.

Q In looking at Phase III on page 9 of that exhibit, I believe that is the extreme case that you characterize there.

A Yes, sir, this is just a sketch to show the difference between fracture and matrix porosity.

Q Now you also testified that the oil would adhere to the walls of the -- the walls of the fracture and would not break loose.

Does this assume that pressure would be at zero?

A No, sir, as pressure declines and the gas comes out of solution, the viscosity gradually drops in the oil and this is a continuous process from the time the pressure reaches the bubble point until the pressure reaches abandonment pressure of the reservoir.

Q Did this exhibit show approximate time with respect to viscosity?

A It's a function of pressure rather than time. Time will influence it depending on how fast the pressure pulls down and so that's how time would affect it.

Q Well, at what -- at what pressure point would we have the Phase III?

A You say Phase III?

Q Well, yes, the phase that's characterized on that page 9.

A Well, I forget what we had. I believe on page 9, that was the first sketch so that I believe shows 100 percent oil saturation.

Well, I'd better check. Oh, okay, this is after the gas saturation has increased substantially and simply shows schematically how the oil will cling to the sides and not run down the center.

Q Well at what point, at what pressure point would you no longer have any oil production?

A Well, we could go back, Mr. Chairman, to a lot of the tests that we have on Canada Ojitos wells. We keep daily records of the pressures and the gas volume, and we could draw some curves that would show you how productivity has fallen off with depletions. I have not done that but it could be done for this reservoir, since we have the information.

It just happens as the -- as the gas saturation increases, the productivity of the oil decreases, that there's just less gravity drainage and this can be no other way.

Q In other words, your Exhibit Number Two simply -- simply shows in general terms what could occur in the reservoir.

A Oh, yes, sir, it's just schematic. It doesn't have any statistical exactness to it.

Q It doesn't show when we can no longer produce oil from the reservoir.

A Not that sketch.

Q Mr. Greer, with respect to the permeability barrier, I'd like to hand you a letter that I believe you wrote to three governmental agencies with respect to the expansion. This letter was received by Koch Industries, or Koch Exploration, and I'd like to have you look at the geological and engineering portion of that.

If I may, let me look at this page that I was --

A Is this the page?

Q Yes, sir, on page 3. Now I don't want to get into an argument with you as to the construction of your own language there, but it doesn't appear to me that it characterizes the situation as bad as you characterized it to Mr. Lopez in answer to Mr. Lopez' question, that you pray every night about that permeability not being there, and I'd like for you to read that, if you would.

A Yes, sir, I will. It's -- this report is entirely consistent with what I was telling you this morning.

On the top of the page -- well, let's see, the K-31 Well, it's west offset shows that the permeability is extremely low in this area and further supports that this is a good location for a boundary separating the reservoirs.

It now appears that wells drilled along this boundary area will probably be of low enough capacity that protective wells within the unit could stop migration of oil from the inner reservoir to the outlying lands. This statement can be true only if the "border area" is wide enough. We now believe this to be the case. I probably should have said hope rather than believe.

Q Well, I believe you used the word "hope" this morning.

A Yes, sir.

Q But it's certainly --

A It's a possibility, yes, sir. It's possible it's there; I still hope it's there.

Q Well, you've -- in your structural map you've actually mapped a permeability barrier there, haven't you?

A Well, I prefer to refer to it as a permeability restriction. I just don't feel I know enough about it to call it definitely a barrier.

Q In the letter you've called it a terrace, have you not?

A I believe so. I think that's probably accurate.

Q What's the -- what's the difference?

A Well, by terrace I meant the dip of the formation levels off and flattens out and I believe when that happens, of course, you re-enter an area where the permeability restriction is postulated.

Q Does that affect gravity drainage, then, in the Gavilan Mancos if indeed there is a -- a dip?

A The indication or the suggestion that I made, in my analysis of gravity drainage in that area, I made a reference to Dick Ellis' structural contour, McHugh's Exhibit Number Three, Section C, in which there is a dip from the north to the east and hopefully wells located just west of the permeability restriction would be good recovery wells for gravity drainage, but not too many; not too many.

Q Now, the gravity drainage in the West Puerto Chiquito and gravity drainage in the Gavilan-Mancos Pool are entirely different because of the -- the extent of the dip, isn't that --

A Well, as I said before, I feel they're not entirely different. We had a good gravity drainage in Canada Ojitos with 200 feet a mile. There's a lot of Gavilan along the east and west sides of the nose that are 100 feet a mile. Those are generally the same, same rates of dip.

Gavilan is about half as much as Canada Ojitos.

Q Are yours affected by your pressure maintenance project?

A Pressure maintenance definitely helps, yes, sir. I would hope that the Gavilan operators, if they unitize, it would be considered. It's certainly, I'm convinced, a very helpful adjunct.

Q Mr. Greer, your testimony here today is in relation to your own case, isn't that correct?

A I'm sorry, I didn't understand you.

Q Your testimony here today is with respect to your own case, the Benson-Montin-Greer case.

A Well, of course, it's hard to talk about just our case without discussing how it's tied in with Gavilan, and so that's the reason that we asked that the two cases be heard together. They're just really trying to solve a common problem and if allowables are reduced in Gavilan I think it's appropriate from a good faith standpoint that then Canada Ojitos, West Puerto Chiquito, that we restrict our production the same as Gavilan.

Q Is that a -- does the oil market have anything to do with your desire to restrict allowables, Mr. Greer?

A No, sir.

MR. PADILLA: Just a moment, Mr. Chairman.

I have no further questions, Mr. Chairman.

MR. STAMETS: Are there other questions of this witness?

MR. LYON: Mr. Chairman.

MR. STAMETS: Mr. Lyon, do you have some?

MR. LYON: I'd kind of like to ask a couple of questions, please.

QUESTIONS BY MR. LYON:

Q Mr. Greer, I've been looking through your data to see if there is any estimated porosity in here. Do you have an estimate of porosity?

A The -- the only estimates that we could come up with are based on the oil in place per acre which we calculated for the one zone in Canada Ojitos, and porosity then is just going to depend on how many feet of pay is effective and in round numbers there's about 2500 barrels an acre would equate to about .3 of the porosity times thickness, so that would be like 30 feet of pay and one percent porosity.

I think that's about as good as we can get. It might be 60 feet of pay and a half percent; might even be 1-1/2 percent and 20 feet of pay but it's somewhere in that, in that range and I ran the thing all the way up to 300 feet to see what -- what these figures looked like, but for a practical estimate of the one zone in Canada Ojitos, I'd say we're looking at something like that.

Q And as I understand your testimony, and that of the other witnesses, this porosity that encloses this reservoir is strictly fracture porosity and you're not giving any weight at all to matrix porosity.

A Yes, sir, that's my feeling. I just have not seen any indication of matrix porosity in any of the information available (not clearly understood.)

Q Have you given any consideration to the impact or the effect on the porosity with the reduction of reservoir fluid pressure?

A Yes, sir, we've made some studies of the fractured Mancos reservoirs and my conclusion is that the productivity drops off far more rapidly with the decrease in pressure than can be accounted for by the decrease in relative permeability, and I don't know what the answer is but we suspect, and one of the reasons we entered into the pressure maintenance project was that as the pressure decreases and the fractures squeeze together, there is a geometric effect on reduction in permeability and I just believe that that's a possibility. We measured productivity indices on the wells in the Canada Ojitos Unit prior to the time the pressure reached the bubble point when the reservoir was fully saturated with oil and the productivity indices dropped off with pressure, which in that instance there could be no -- no influence of the relative permeability restriction due to free gas, so it had to be some outside influence that I think can only be explained by the fractures squeezing together.

Q So as the pressure, the reservoir pressure declines, then, it looks probable that the permeability and the ability of the oil to flow to the well will be diminished.

A Yes, sir, I think that's true.

Q Do you think it's likely that some of those fractures will be closed entirely?

A Gosh, I don't know. That's another thing you hope for, you know, when you wake up at night, but I just don't know.

MR. LYON: I believe that's all.

RECROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Greer, the main thrust of your testimony today is about the Gavilan Pool and you've sort of indicated that you're proposing decreases in allowables in the West Puerto Chiquito just as a courtesy.

A Yes, sir, I just believe it would be, well, in a sense unfair when I think that there can be oil migrating across the boundary, not to have the allowables the same on both sides of the boundary. If we ask them to restrict production I just feel it's only proper that we do the same thing.

Q And even though there -- this tight streak that you've indicated with the -- whatever kind of a mark that is, a question mark --

A Yes, sir.

Q -- even though that is in there, there are wells in the West Puerto Chiquito Pool which lie to the west of that and I presume your opinion is that they're in communication with the Gavilan-Mancos Pool.

A Yes, sir, and of course one of the considerations which we discussed was, well, perhaps that's the only area that we should consider restricting our allowables, but I just can't have enough confidence in that permeability restriction to know that really that's a proper, fair, and equitable thing to do, so we ask that it be the same throughout the pool.

And, of course, another reason was we presumed that it would be difficult for a -- for the Commission to establish different allowables in different parts of the same common source of supply. I've never known a commission to do that so we felt like that was necessary.

MR. STAMETS: Let me ask if there is any party here who is opposed to the Benson-Montin-Greer application to reduce the allowables and the GOR to West Puerto Chiquito Pool?

I see no one standing up and indicating that there is any opposition to that application.

MR. PEARCE: Mr. Chairman, we're not sure what that question means. Mr. Greer has testified that he only wants those rules for his pool if they're adopted for the Gavilan Pool.

If not objecting to those rules in the West Puerto Chiquito means that I've agreed that they're appropriate for the Gavilan, I am clearly opposed to that, and I think Mr. Greer would object to those rules being adopted for the West Puerto Chiquito if our position is correct that they should not be adopted for the Gavilan.

MR. STAMETS: Let me see if I can phrase that to relieve your mind.

Q Let me ask Mr. Greer a question. Mr. Greer, if after this hearing the Commission chose to leave everything in the Gavilan-Mancos Pool as is, would it be your request that your application be dismissed for the West Puerto Chiquito Pool?

A Yes, sir, I feel that the rules need to be the same, Mr. Stamets.

MR. STAMETS: All right, now let me ask the audience, then, that should the Commission after this hearing adopt the rules for the Gavilan-Mancos Pool as proposed, would there be any party who would object to the adoption of Mr. Greer's proposed rules for the West Puerto Chiquito Pool?

Again I see no one --

MR. LOPEZ: Mr. Chairman, the response to that question I think would be no, there'd be no objection. It would be essential that it be done.

MR. STAMETS: Thank you. I would presume that the answer then would be probably the same if the Commission should adopt some variation of what has been proposed so that the -- what we come up with in West Puerto Chiquito would be equivalent.

Say that we gave 300 barrels a day for the Gavilan, it would be 600 for the West Puerto Chiquito, and I presume we have no objection.

That certainly makes order writing a lot simpler to know if there are objections or not.

Okay.

Q Mr. Greer, now you've indicated that the Mancos in this area is basically a single reservoir.

A Well, where it's faulted, and they're tied together, I believe I tried to indicate that it acts a lot like a stratified reservoir, the zones being separated by individual wells.

And so in parts of the pool where the faults tie the three zones together, then they will indeed act as a single reservoir, but otherwise the individual well tests, and it's one of the complicated factors we have in trying to analyze them, the strings where all zones are open will act as a stratified reservoir.

Q In asking this next question, or series of questions, I'm not asking you if you believe that we ought to change the pool designations out here ard create one or more pools out of what are now several pools. I'm just trying to get at what you were telling me.

Do you believe that what is currently designated as the Gavilan-Mancos Pool and the West Puerto Chiquito Pool are the same common source of supply?

A Yes, sir.

Q How about the Boulder Mancos Pool?

A I think Boulder is separate.

Q Okay, and then what about the East Puerto Chiquito?

A The East Puerto Chiquito we have found on the down dip side of East Puerto Chiquito that the zones contain water and we have indications of north/south faults running through that area, and they appear to be sealing faults, and so that pretty well separates East Puerto Chiquito from West Puerto Chiquito.

I believe at one time, I think in 1963, we asked that they all be one pool and then after that time we found this separation and -- and so those are separate.

Q At this time is there sufficient evidence for you to make the -- give the opinion about the Ojito Gallup, or Ojito Gallup-Dakota, is the Mancos portion of that in your opinion part of a common source of supply with Gavilan Puerto Chiquito?

A Mr. Chairman, I have to confess that I have not studied this particularly. I recall that when the hearing was held for spacing for Gavilan that I could see a distinction in the electric log charactertistics between Gavilan and the Lindrith Gallup-Dakota area.

And the characters of the wells at the time were substantially different and I felt that they probably were separated and I've not attempted to do anything since.

Q In both cases before us the gas/oil ratio has been proposed at 1000-to-1. We had testimony at the earlier hearing that at least as to Gavilan the solution gas/oil ratio is 588-to-1.

Why should -- why, if we're convinced by the testimony offered by McHugh and Greer, to adopt 1000-to-1 as a gas/oil ratio as opposed to 588-to-1?

A Well, there are a couple reasons. One is that the reservoir being stratified as it is, we've found that there's some free gas that is produced from some of the zones.

We found the A and B zones in the Canada Ojitos area to be more gassy than the C zone, and that appears to me to be a possibility in Gavilan.

So there is a possibility that a well

could have a gas/oil and this is in the range between 600 and 1000, that really the gas is not coming from the oil, the main bulk of the oil reservoir as I visualize it, and so you might be unfairly penalizing some wells. That's one thing.

Another is just a real practical application of the gas/oil ratio limit when one deals with -- with only the solution ratio, then the allowable becomes so sensitive to just small change in the gas/oil ratio, that just even the errors in calculation and measurement of the gas becomes a factor in determining allowable, and just from a practical standpoint, I would recommend that the 1000-to-1 is a reasonable and a practical limit.

And it's really, Mr. Chairman, not the gas/oil ratio that's causing a problem. The problem is the high oil productivity, that's the problem.

Q Mr. Greer, based on your testimony in this case, even if unitization were never achieved in the Gavilan-Mancos Pool, would reduction of the allowable to 200 barrels of oil per day result in substantial increases in recovery of oil from this reservoir?

A Yes, sir, any reduction in allowable will help. It's hard to quantify it with any reduction. If the pool was drilled up entirely on 320-acre spacing and allowables of 200 barrels a day were permitted, there will be the very minimum amount of damage occurring.

Q Earlier you talked about a potential value of the oil lost --

A Yes, sir.

Q -- in the Gavilan Pool of $50-million. At $16.00 a barrel that 's about 3-billion barrels of oil. Is that the range of volume you were talking about?

A I believe what I was talking about was 5-million barrels and $10.00 a barrel, $10 or $12.00 a barrel, would be $50 or $60-million, and that would be if 10 percent of the gravity drainage potential was realized; 1/10th of the maximum.

Q With your 200 barrels a day of oil production limitation is it reasonable to assume -- is it your engineering opinion that we would recover that 10 percent additional gravity drainage?

A Not if the pool is drilled up on 320 acres.

Q Even with the 200-barrel restriction.

A Even with the 200 barrel, that's just too much.

Q Do you have an opinion as to how much of that recover?

A Well, I haven't tried to put a figure, but I -- we can take a quick look at our Exhibit Four, our

Exhibit Four, Section C, and here we show if the pool is developed on 320-acre spacing the overall average production rate would be only 130 barrels a day and even at that low rate the pool is essentially depleted in five years and in round numbers, looks like about 75 or 80 percent of it would be produced in two years.

And that rate of depletion would be too high to achieve a substantial gravity drainage.

Q So the 200 barrel oil allowable is not a long term solution to this problem.

A No, sir, it's an interim solution and will help protection of correlative rights and give operators a chance to do something reasonable.

MR. STAMETS: Are there other questions of this witness?

MR. KELLAHIN: Yes, Mr. Chairman.

MR. STAMETS: Mr. Kellahin.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Greer, in making your analysis of the potential of the Gavilan-Mancos receiving benefit from gravity drainage, have you availed yourself of the information provided in the Dugan Production Corporation exhibits as well as the Jerome P. McHugh exhibits that were presented at the prior hearing?

A Yes, sir.

Q With specific reference to Mr. Ellis' structure map, the hearing on August 7th was not the first time you saw that structure map, was it, sir?

A No, sir, I'd seen it before that.

Q Mr. Pearce asked you some questions with regard ot the elevations of two wells that followed the general strike of the axis of the nose of the Gavilan-Mancos.

A Yes, sir.

Q It showed a difference of approximately 50 feet, I believe.

A Yes, sir.

Q If we go perpendicular to the axis of the nose, do we then see on the structure map a type of difference in structure that caused you to reach your opinion that the Gavilan-Mancos was a suitable candidate for gravity drainage?

A Yes, sir. I did not take into account or estimate that there would be any gravity drainage along the direction of the question at that time.

Q Your hypothesis about the potential of gravity drainage in the Gavilan-Mancos then was based upon specific data generated by Mr. Roe and Mr. Ellis?

A Yes, sir, I used their -- their information, as well as mine.

Q As a well respected petroleum engineer, Mr. Greer, would you articulate for me why the -- some of the information that the engineers and experts are looking at in the Gavilan-Mancos does not cause you to conclude that they're seeing what is characterized as the typical solution gas drive reservoir?

A I'm sorry, I didn't --

Q Yes, sir. There's been some discussion and questions of you and the other witnesses about characterizing the Gavilan-Mancos as the typical solution gas drive reservoir and you told us in your testimony that you disagreed with that; that you felt that that was now what we were seeing.

I would like you to summarize for me, if you can, sir, the reasons and basis that have caused you to conclude that the Gavilan-Mancos is not a typical solution gas drive reservoir.

A Yes, sir. The, as I thought I'd testified earlier, the Gavilan Pool in which an option is given to the producers as to the producing mechanism, and it depends on how fast the pool is depleted as to whether it will be entirely solution gas drive, primarily gravity drainage, or a combination of the two, and at the current rates of production, the way that the pool is scheduled to be developed on 320 acres with a high allowable, then there will be a minimum of gravity drainage, and so the process would degrade to primarily a solution gas drive.

Q You have posed for us a temporary solution or stopgap measure on restricting gas/oil ratios and allowables and you have used a combination of the two in which gas/oil ratios are reduced to 1000 cubic feet of gas to one barrel of oil and a production limitation of 200 barrels of oil per day.

Do you have an opinion, sir, as to whether or not you can significantly vary either one of those factors or eliminate one entirely?

A No, sir, I think it's a pretty good -- pretty good combination. To reduce the gas/oil ratio would not significantly help and I think would compound just the practical problem of handling it, and certainly the oil allowable should be any -- a bit higher than 200 barrels.

Q Thank you, sir.

MR. STAMETS: Any other questions of Mr. Greer?

REDIRECT EXAMINATION

BY MR. CARR:

Q Very briefly, Mr. Greer, you were asked by Mr. Padilla to read from a letter that you'd previously written.

Do you happen to know the date of that letter?

A I believe it was -- seems about a year ago, in March of '85.

Q Since that time has additional information come -- become available to you concerning this area?

A Yes, sir.

Q In your opinion is it safe today to characterize what you called a restriction, is it safe to charactize that as a barrier?

A Yes, sir, I feel like restriction is more proper term than barrier.

MR. STAMETS: Any other questions?

Mr. Padilla.

RECROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Greer, if I understood your testimony this morning you were concerned about the pressure decline and in answer to some of my questions you also -- concerning the Exhibit Number Two, you talked about decline in pressure and I understood you to mean decline in pressure associated with gas withdrawal. Is that correct?

A Well, the decline in pressure will cause gas to come out of solution and then the gas moves to the wellbore and then pressure drops more rapidly and a vicious cycle is started.

Q If gas is restricted, will that reduce -- will that cause a decreased pressure production?

A Well, restricting the gas/oil ratio and restricting the production simply slows down the rate of depletion so the operators can hopefully get together and devise a better plan for developing this reservoir before it's too late to realize some gravity drainage potential.

That's my feeling.

Q And it's your testimony that there's no correlation between a reduction in GOR and oil takes.

A A reduction in GOR and what?

Q Oil withdrawals from the reservoir.

A Okay, if you lower the gas/oil ratio limit you will lower somewhat the withdrawals, yes, sir, but not significantly and in the sense that one could simply reduce the gas/oil ratio limit and say that's all.

Q In other words, it doesn't make any difference in your opinion, it doesn't make any difference whether the GOR is 588-to-1 or 1000-to-1.

A Well, I tried to describe why I felt that it was impractical to go below 1000-to-1. It's possible and of course operators could probably live with it, and it's just kind of an impractical thing to do, I think.

Q Well, doesn't that leave more gas in solution at that point if you bring it down to 588?

A Well, if you bring the gas/oil limit down to 588 it would limit the production from the reservoir a little bit more than 1000-to-1, but it -- my opinion is that that would be a bad choice to go that direction rather than down to 200 barrels a day.

Q Then why don't we leave it at 2000-to-1?

A Well, as I've indicated, I think it's proper to reduce the gas/oil ratio. It's just from a practical standpoint of how it's handled and how the gas volumes are calculated and how the Commission calculates the gas/oil ratio limitation, but I think it becomes too sensitive, too sensitive to go down to 588.

Q Well, I'm just a little confused that you seem to be saying it doesn't matter what GOR we have, let's just reduce the oil and trying to make a big point on simply reducing the amount of oil that can be withdrawn from the reservoir and I don't understand the decision as far as GOR is concerned.

A Well, reducing both the allowable and the GOR will reduce the rate of withdrawal from the reservoir.

I think below 1000-to-1 is impractical and at 1000-to-1 it's necessary to come down to 200 barrels a day in order to have a reasonable -- a more reasonable rate of withdrawal.

The main thing coming down to 200 barrels a day, it will give the operators in the pool the opportunity to protect their correlative rights.

Q Well, let me ask you if your correlative rights, if you don't want to drill to protect your well and if you restrict the allowable to 200 barrels per day on oil, you wouldn't have to drill any wells.

A No, sir, that's not the answer at all. If you restrict the allowable to 200 barrels a day, then an operator can go in the pool, drill a well under the current spacing order, and he would have an opportunity to protect his correlative rights.

Currently, with the allowable 700 barrels per day, an operator can go in the pool, drill the well, it wouldn't otherwise be a commercial well, but his correlative rights are not being protected because the big wells are taking too much oil out from under his lands, so that's the concern on that.

Q On an undrilled tract or a drilled tract?

A That's -- we're talking about where an operator goes out and drills a tract, either one already drilled or where he would go out and drill a new one.

In either instance he's not afforded the opportunity to protect his correlative rights if he doesn't tunnel into a fracture that will give him 700 barrels a day.

Q He has an equal opportunity. It just so happens that he didn't hit the fracture, isn't that --

A Yes, sir, and then you're back to the law of capture in which the allowable is based upon the productivity of the wells and that's not related to oil in place and in my view it's an improper way to set an allowable.

Q Well, in the normal situation, wouldn't you agree, Mr. Greer, if you drill a well and it happens to be a dry well under -- under the current conservation laws, that's just the risk you assume.

A Yes, sir, and I think we all understand that. The problem we have here is we don't have a normal reservoir and it needs special consideration.

Q Well, Mr. Greer, let me ask you, how do you know whether or not you have a dry hole, whether you missed the fracture?

A Well, when you put the well on production you'll find out whether it's a producer or not.

Q Well, I understand that but let's assume the difference between a well that produced 25 barrels a day and one that produces 500 barrels a day. Did the 25-barrel well miss the fracture?

A Yes, sir. The man has had an opportunity to drill his well. He didn't hit a fracture and he's bound to his productivity and that we understand.

My concern is for wells that come in with productivities of in excess of 200 barrels a day and even at 200 barrels a day the big wells are taking oil out from under their lands.

Q Well, that's an assumption, isn't it?

A Well, it's my best estimate of what the character of the reservoir is like, made up on the work that we've done over the last twenty-five years.

Q As far as the West Puerto Chiquito is concerned.

A Yes, sir, and we feel that West Puerto Chiquito and Gavilan are quite similar.

MR. PADILLA: I don't have anything else.

MR. STAMETS: Any other questions of the witness?

He may be excused.

We'll take about a fifteen minute recess.

(Thereupon a recess was taken.)

MR. KELLAHIN: Mr. Chairman, I would renew my request to admit Jerome P. McHugh Exhibits One and Two, I think they were. They were our affidavits on notice that we submitted at the last hearing.

MR. PEARCE: As far as I know there are no problems with that in terms of accurately representing the ownership and on that basis we do not object to those exhibits being admitted.

MR. STAMETS: Those exhibits will be admitted.

Mr. Lopez, do you have any witnesses?

MR. LOPEZ: I sure do, Mr. Chairman. I'm just wondering if I'm the next appropriate person to address. Meridian is here in support of the issue.

MR. STAMETS: Yes, perhaps we ought to have a show of hands of those who have witnesses today. Other than Meridian, who else is in support of this application?

Okay, I see none. We thank you, Mr. Lopez. We will let Meridian put their testimony on at this time.

MR. COOTER: Mr. Examiner -- Mr. Stamets, I'm sorry, Paul Cooter, appearing on behalf of

I didn't really realize that we would be cast in a position of jumping in or staying out of the pond at this early stage. If those are our two alternatives, we'll jump into the pond, but we would prefer listening to the pros and cons before presenting our case, but if we're logically called on now, we're ready to proceed.

We won't be long.

MR. STAMETS: We'll allow you to go ahead at this time, Mr. Cooter.

RICHARD E. FRALEY,

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

DIRECT EXAMINATION

BY MR. COOTER:

Q State your name for the record, please, sir.

A My name is Richard E. Fraley.

Q And by whom are you employed, Mr. Fraley?

A Meridian Oil, Farmington, New Mexico.

Q What's your position with the company?

A I'm a Senior Reservoir Engineer for Meridian.

Q Relate, if you would for the Commission, your education and professional experience.

A I graduated in 1979 from Colorado School of Mines with a Bachelor of Science degree in geological engineering.

I was that employed by Superior Oil, beginning in 1980 in The Woodlands, Texas, as a production geologist for a period of about nine months.

At that point in time I went to work in Denver, Colorado, for Husky Oil as a production geologist. I worked there for approximately nine months.

In November of 1981 I went back to work for Superior Oil in Denver as a reservoir engineer. When Mobil took Superior over I was a reservoir engineer for Mobil and in February of this year I went to work in Farmington for Meridian as a reservoir engineer.

Q Are you familiar with the Gavilan-Mancos Oil Pool?

A Yes, I am.

Q And the special or the temporary proposals as advanced by the applicants, Mr. McHugh and Mr. Greer?

A Yes, I am.

Q Let me direct your attention, please, to your exhibits.

First, let's look at Exhibit One-A, if

you would, which is a plat, I believe, of the area.

Explain that.

A This is a map done under the direction of Van Gobel (sic), who is a landman with Meridian Oil in Farmington.

This map indicates Meridian's acreage in the area, whether it's 100 percent or partial interest acreage.

To this end I haven't specifically highlighted -- well, I have.

If you look, the wells in red with the red box around them indicate wells that Meridian currently has an interest in and I've enumerated those on Exhibit One, which I'll talk about in a minute.

We currently have an interest in nine wells in the area.

Also, I have colored in Meridian's interest in undeveloped acreage within the Gavilan study area, and that acreage is the acreage that shows up as yellow with no red box around it.

Q All right, let me direct your attention back for just one minute to what was introduced at the prior hearing as the Dugan Exhibit Number One. Were the figures or the interest credited to Meridian Oil Company in that exhibit substantially correct?

A I'd have to look at it. I don't have that exhibit with me.

Q Do you recall that exhibit?

A Yes, I do. It's a list that Dugan has supplied in previous testimony that indicates the wells that Meridian operates. There is no indication on this list as to wells that Meridian may have interest in other than the wells they operate.

Q Meridian's net interest is a greater amount than shown on that but those are just the operated wells.

A That's correct.

Q All right. Let's go from that, if you would, back to Exhibit Number One. The -- at the top of that you list several wells and included are the five wells that are shown on the Dugan Exhibit Number One, are they not?

A Correct.

Q Explain Exhibit Number One, if you would.

A Exhibit One, I'll go through rather quickly, indicates wells in the area that Meridian has an interest in.

Column two, if you go across from those wells, indicates what our working interests and net interests are in those wells.

What I'd like to point out here is the fact that we do have production from wells other than the ones that Meridian operates and the summary indicates there are nine wells total we have an interest in, 4.1 net, if you look at what our working interest is in those wells.

The next column across indicates what the June production was listed on the C-115's and the total production on the bottom indicates 13,154 barrels of oil produced that month, 18,568 MCF of gas produced for the month of June, and again I reiterate that Meridian has 2277.3 acres in this study area, including acreage in eight undeveloped locations, if we look at 320-acre drill sites.

Meridian also has a 4.15 percent working interest in Canada Ojitos.

Therefore we are concerned about what's happening at Cavilan and what's happening at Canada Ojitos.

One thing I'd like to point out, I'm not able to calculate all the company's effect on their net production in this area, and therefore it's directionally correct to look at the opertor's production, but it doesn't really tell the whole story and to say that Meridian is hurt only from production from their wells is incorrect. We're hurt from production in other wells, depending on whatever the allowables are set.

And addressing that point, using some of the assumptions going down through the page, that have been made in the Gavilan study committees, again Bo = 1.38, solution gas of 588, and Bg of 1.78, the total Gavilan production, if you look at the Gavilan Pool, from 43 wells in June of '86 is indicated and that amounts to, using these numbers for conversion, to 17,163 reservir barrels of oil produced per day for June.

As you can see, with the exception of the Mallon Post Federal 13-6, all of our production as allocated to Meridian for June came from four wells of the nine that we have an interest in and amounted to 1248 reservoir barrels a day production for June.

If you look at what that is as a percentage of the total, our production for June amounted to 7.3 percent of the total reservoir withdrawal for June, 1986.

This next section I indicate what the effect would be on Meridian's production for June --

Q Let me interrupt you right there, if I may, Mr. Fraley, and we'll come back to that in just a minute.

Let me go at this point to your Exhibit Number Two and ask you to explain that.

A Exhibit Two is similar to some that have been submitted already in previous testimony. As I note in the heading, these are wells that Meridian has a working interest in in the area and pressure points that have been reviewed and approved by the subcommittee, the engineering subcommittee, and again to reflect what is happening in the pressure in wells that Meridian has a specific working interest in.

Also indicated on this plot through time is what the actual reservoir barrel withdrawals were from the wells that are listed on this plot.

As you can see, with the exception of November of 1985 when we were testing our Hill Federal No. 1 Well, there is very little production associated with this pressure decline from wells that Meridian has an interest in. The initial pressure that we had was from the Hawk Federal No. 2 on April 13th, 1984, which indicated a pressure of 1740 pounds and you can see that through time the wells have come on at a lower pressure and have declined substantially with very little production associated.

You could think of these wells basically as observation wells on undeveloped acreage and they are indicating what is happening to the reservoir in terms of pressure drop through time.

This is something we are very concerned about.

Q Let me next direct your attention to Exhibit Number Three. Is that also compiled from information relating to the Meridian oil?

A Yes, it is. This is a static pressure test. It was run from July 26th to July 30th, 1986, in our Hill Federal No. 2Y, which, if you refer back to the map, is located in Section 25, Township 25 North, Range 2 West, and it indicates that during this test there was an average reservoir pressure drop of .8 of a psi a day. Again this is associated with no production.

Q There appears back on Exhibit Two on this Hill Federal No. 2Y Well an increase in pressure from December of '85 when it was -- or January of '86 when it was first placed on production. Can you explain that?

A Again that doesn't indicate the well is on production. It indicates the initial pressure tests that we had in the Hill 2Y, and I checked our records. To the best of my knowledge the only explanation I have for that increase in pressure is the fact that the well had not been fraced at that point in time and probably we're looking at some formation damage.

The well was IPed and tested on January 6th of 1986 and therefore I think that pressure point is probably invalid, but I presented it on this document to indicate that we are looking at all the data.

Q All right, now let's go back to Exhibit Number One, if you would, I interrupted you a little bit ago.

If the only alternatives would be to accept the recommendations that have been made, have you calculated what effect that would have on the wells in which Meridian has an interest?

A Yes, I have.

Q What would be that effect?

A Well, as you review this document, first looking at what total Cavilan Pool withdrawals would decrease to if they had been subject to 200 barrels a day, 1000 GOR in June, I indicate from my calculations that the total pool withdrawal would have been 13,952 barrels -- reservoir barrels per day, which is a decrease of 3211 reservoir barrels a day.

I haven't written it on here, but that's an 18.7 percent decrease in production for June from the total pool.

Withdrawal from Meridian's wells would drop for 1248 barrels a day to 414 barrels a day, which is -- I'm sorry to 834 barrels a day, which is a 414 reservoir barrel per oil -- reservoir barrels of oil per day drop for June.

I'd like to point out that that amounts to a 33.2 percent increase in Meridian's real production from all the wells that they have an interest in in the area.

So as you look at that, we are looking at a substantial cut over and above what the total pool would see as a total decline for June.

Q What is your company's suggestion for the time limitation for any special rules?

A We would request they be for no more than ninety days.

Q What abcut new wells coming on line between this time on?

A We've indicated to the various operators in the area that we'd like to see a 60-day clean out period for any new wells that are brought on. A lot of the wells increase slightly in their producing rates as they clean up, as the frac jobs are cleaned up through time, and therefore you need to test them for about 60 days to get a true idea of how the well is going to perform.

Q In addition to those recommendations, do you have any other suggestions or clasing statement to make?

A Well, I'd like to indicate that even though, as I stated, we see a disproportionate cut in production from the wells that we have an interest in in the Cavilan area, as I stated here, and as is highlighted in yellow, this in my mind and in Meridian's mind is inconsequential when you compare it to the rapid pressure decline that we see from our shut-in wells, as seen on Exhibit Two, and this points to the fact that a minimum allowable level should be set to conserve the reservoir pressure until a study can be done, and I'd like to indicate we feel like a study needs to be done as soon as possible, and as quickly as possible, and the study should focus on what the most prudent methods of development and production in the Gavilan Field are.

Also in summary I have a statement here.

It appears to me, and I think most people would agree, that there have been a variety of facts and opinions expressed to date, both in the context of this hearing and the subcommittee meetings, as to what the facts and opinions are concerning the producing mechanisms at the Gavilan area.

Meridian is not precluding unitization and we're not precluding the fact that the final allowable, and I stress the final allowable versus temporary, should be 200 barrels a day or 1000 GOR, but the evidence presented indicates that the reservoir pressures are dropping, the GORS are climbing at rates which in my experience are alarming compared to other reservoirs, and therefore the 200 barrel a day, 1000 GOR proposal should be implemented until such time as a study is completed to determine the most prudent plan of development and operation to produce the reserves in Gavilan, and in addition to prevent waste and to protect correlative rights.

Personally I don't like to see severe, rapid depletion of a reservoir that may have possible alternatives other than solution gas drive depletions, and I think these things need to be studied.

To this end I think Mr. Greer's testimony and McHugh's facts and opinions must be reviewed, as well as any other facts and opinions, the point being that the study needs to move forward very soon.

To that end we are in support of the 200 barrel a day, 1000 GOR.

Q In your opinion, Mr. Fraley, would a period of ninety days be sufficient for that study if all parties entered into it in a spirit of cooperation?

A Yes.

Q Were Exhibits, the four exhibits, One, One-A, Two, and Three, prepared either by you or under your direction and supervision?

A As I indicated, Exhibit One-A was prepared by Meridian's land department and under the direction of our land people.

MR. COOTER: We offer the four exhibits, Mr. Stamets.

MR. STAMETS: Without objection, the exhibits will be admitted.

MR. COOTER: That concludes my direct examination.

MR. STAMETS: For the record, Mr. Cooter, I presume you were qualifying Mr. Fraley as a geological engineer?

A I'm currently working as a reservoir engineer.

MR. STAMETS: Was your expert testimony offered as a reservoir engineer?

A Yes.

MR. STAMETS: Without objection his qualifications as a reservoir engineer will be accepted.

Are there questions of this witness?

MR. PEARCE: If I may have just a moment, please, Mr. Chairman.

CROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Fraley, just for purposes of clarification, looking at your Exhibit Number One, where you did the calculations of percentage restriction down towards the bottom of the page?

A Yes.

Q I notice that those calculations were

done in terms of reservoir barrels. Do you have the same calculoations in terms of oil production?

A Just straight oil production?

Q Yes.

A You could -- you could look at what a 200 barrel a day limit would do. I haven't presented that there. I have it in rough numbers on some yellow sheets of paper up here, I think, but --

Q Do you recall approximately where those percentage figures about the same as these? Were they higher, lower, one direction or the other?

A In reference to the wells that Meridian has an interest in, is that what you're --

Q Yes, sir.

A -- specifically addressing? Well, I'll go into detail here on the four wells that produce.

The Hill Federal -- the Hawk Federal No. 2, excuse me, averaged 141.5 barrels a day in June and the restriction on the allowable would have been based on a GOR which would have knocked it down to 80 barrels a day.

Q (Unclear) zero?

A Yes.

Q The Hawk Federal No. 3 produced 219.8 barrels a day. It's restriction was based on an allowable restriction; therefore it would have been knocked down to

200 barrels a day.

A Yes, sir.

Q The McHugh Native State -- I'm sorry, the Native Son No. 3 would not be restricted. The production was 68.3 barrels a day. The gas production was 20.8, therefore it would not be subject to either 200 or 1000.

And the McHugh New Horizon No. 1 averaged 8.8 barrels a day and 35 MCF a day and it would have been knocked down to 2.2 and 9; therefore its total production, it would have been GOR restricted but in the overall scheme of things you're not talking about much there.

Q And just looking at that -- okay, roughly, that's about 1030 barrels versus 357 barrels, approximately.

A 357, I don't know. Are we saying total production?

Q Yes.

MR. STAMETS: Are you saying that they currently enjoy 1000 barrels --

MR. PEARCE: 1031.8 barrels, I thought I added the numbers you gave me --

A Okay, and then it goes down to 351.

Q And the numbers would be, I think, 357.3.

A Well, I get 351, so we're in the ballpark.

Q Thank you. I can never figure out how to work that calculation.

MR. STAMETS: What kind of a cut are we looking at there? Is that a 60 percent reduction in allowable? Oil allowable?

A Yeah, and the only well that's severely restricted by the GOR would be the Hawk Federal No. 2.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Fraley, based on these numbers, Mr. Fraley, based on these numbers are we talking about a cut in allowable for Meridian wells of 60 percent, more or less?

A The production cut based on my figures was 33.2 percent (unclear).

Q Okay. How does that compare with the overall allowable reduction?

A The total pool would have seen a decrease of 18.7 percent.

Q So what you've got to say about oil alone is roughly equivalent to reservoir voidage. You're suffering greater than the average.

A Yes, that's correct and we are willing to suffer until we can study and figure out what needs to be done.

MR. PEARCE: Okay, Mr. Fraley, as I understood your closing statement there before the end, do you not yet have an opinion on what the production mechanism in this reservoir is or do you have such an opinion?

A I do have an opinion it's solution gas drive at this point and what I said was that I indicated that there may be alternatives to solution gas drive that need to be studied.

MR. PEARCE: I have nothing further. Thank you, sir.

MR. STAMETS: Are there other questions of this witness? Mr. Padilla.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Fraley, have you participated in the study committee for study previous -- previous to this hearing?

A Yes, I have.

Q During the course of that -- your participate in the study committee, did you make statements to the effect that gas wasn't a problem with regard to the Gavilan-Mancos Pool?

A I may have.

Q Is that your opinion today?

A My opinion is that the withdrawal of both oil and gas are what are affecting this rapid pressure drop that we're seeing here.

Q Which is the greater problem in your opinion?

A The oil, and I've stated that in subcommittee meetings.

I've indicated that I feel the high rate wells hurt the reservoir more than low rate high GOR wells.

Q In your testimony you said you were unable to calculate, make some calculation due to lack of information. Can you elaborate on that?

A Well, I don't have the data available in terms of everyone's working and net interests in the -- all of the wells at Gavilan. I have the information on Meridian's wells. I think it would be prudent for all the operators to calculate what their net pay-in is from any kind of a well's production because it's not strictly based on the wells that they operate.

If I had the data I'd be glad to do the calculations but I don't have any data on any of the wells we don't have an interest in.

MR. PADILLA: No further questions.

MR. STAMETS: Any other questions of this witness?

MR. COOTER: That's all.

MR. STAMETS: If there is nothing further then, he may be excused.

MR. COOTER: That's our case.

MR. STAMETS: Mr. Lopez, is there anyone you would prefer to have go on before you at this point?

KATHLEEN A. MICHAEL,

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

DIRECT EXAMINATION

BY MR. LOPEZ:

Q Would you please state your name and where you reside?

A My name is Kathleen A. Michael and I reside in Tulsa, Oklahoma.

Q Ms. Michael, by whom are you employed and in what capacity?

A I'm employed by Mesa Grande Resources as a landman.

Q Would you briefly describe your educational background and work experience?

A Yes. I graduated in 1972 from North Texas State University with a Bachelor of Science degree in secondary education.

I started working in oil and gas, or as a landman in oil and gas, for Fuel Resources Development Company, a subsidiary of Public Service Company of Colorado, in 1977. I worked there for two years and I specialized in Federal exploratory units there.

In 1979 I went to Northwest Pipeline Corporation and was employed there for four and a half years as a landman. There again I specialized in Federal exploratory units, and also I worked extensively on the Gavilan area from the beginning of the exploration.

Q From the beginning of the exploration program?

A After that I worked for two years as an independent land consultant and now I'm employed by Mesa Grande Resources.

Q And how long have you been employed by Mesa Grande?

A Since January.

Q And you are familiar, then, with the area in question that's being heard by the Commission in these consolidated cases?

A Yes.

MR. LOPEZ: I tender Ms. Michael as an expert landman.

MR. STAMETS: Without objection she will be considered qualified.

Q For the record we have prepared an Exhibit One but it was essentially identical to a McHugh exhibit so we're just going to skip Exhibit One and move directly -- and so we would remove that and we're going to start our exhibits with Exhibit Two.

On that basis I'd like to have you turn your attention to what's been marked Exhibit Two and have you describe what it shows.

A Exhibit Two is a plat of the Gavilan area. It includes a portion of the Canada Ojitos Unit and it shows color coded by owner the leasehold ownership in the Gavilan area, and it's basically to show the location and distribution of acreage within the Gavilan area.

Q Have you described the unit boundary which was shown on (interrupted) --

A Yes, we have. We've located the Canada Ojitos Unit boundary. We've also located the Gavilan Pictured Cliffs Pool, the Gavilan-Mancos Pool, and the Gavilan Greenhorn-Graneros-Dakota Pool, and we've also included two areas, the west half of Section 8 and the east half of Sec tion 17, which will become included in the Gavilan-Mancos Pool with a hearing that I understand is supposed to be initiated by the State.

MR. LOPEZ: I have no further questions of this witness.

MR. STAMETS: Are there questions --

MR. LOPEZ: Was Exhibit One prepared by you or under your supervision?

A Yes, it was.

MR. LOPEZ: Or Exhibit Two, I mean?

A Exhibit Two, yes, it was.

MR. LOPEZ: I'd offer Mallon-Mesa Grande Exhibit Two.

MR. STAMETS: Without objection Exhibit Two will be admitted.

Are there questions of this witness?

She may be excused.

ALAN P. EMMENDORFER,

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

DIRECT EXAMINATION

BY MR. LOPEZ:

Q Would you please state your name and where you reside?

A Yes. My name is Alan P. Emmendorfer. I liove in Broken Arrow, Oklahoma.

Q By whom are you employed and in what capacity?

A I'm employed by Mesa Grande Resources as a geologist.

Q Would you describe your educational background and work experience?

A Yes. I graduated from Southeast Missouri State University in 1977 with a BS in geolcgy.

Then I went to the University of Oklahoma and graduated with a Masters of Science degree in geology in 1979.

I started working for El Paso Exploration Company in 1979, based in Farmington, New Mexico, and my role there was a production development geologist for the San Juan Basin.

I worked there for two months shy of five years and then went to work in my current job with Mesa Grande Resources as a geologist.

Q You are familiar with the Gavilan-Mancos

Pool and are familiar with the cases that are before the Commission today as consolidated cases of McHugh and Benson-Montin-Greer?

A Yes, I am.

MR. LOPEZ: I tender Mr. Emmendorfer as an expert geologist.

MR. STAMETS: Without objection Mr. Emmendorfer is considered qualified.

Q I now refer you to what's been marked Exhibit Three and ask you to identify and explain that.

A Okay. Exhibit Number Three is a structure map of the Gavilan area and I've mapped this on the top of the Niobrara A zone or commonly called the Gallup.

I took the tops from the study committee. We had one day of referring especially to the geology.

The subcommittee got together and commonly in agreement picked the top of the Niobrara A zone with the well that we had with us at that time.

We used those values for most of the wells on this map.

The wells that we did not use, I used the same basis that we did in the study committee and correlated those wells and picked -- used that top as my basis for the structure map.

Q What does this exhibit show?

A It shows -- this is a structure map. It shows two structurally different environments.

We have on the east side of the structure map a deeply dipping monocline. This is evidenced by the structural contour lines and it goes together, this map is contoured on 50-foot intervals.

In the center of the map, which is centered in Township 25 North, 2 West, we see a small domal development commonly referred to as the Cavilan Dome. It is this area that the Gavilan-Mancos oil pool is producing out of.

Separating these two structurally different units, a deeply dipping monocline and a gently dipping dome, we have a well defined trough that's been defined by the drilling of several wells within the Canada Ojitos Unit, so therefore we have off the monocline wells with the formation dipping to the west and on the other side of this trough, on the east side we have the wells dipping towards the east.

Q Who participate on this subcommittee which you referred to in picking your tops for the structure map?

A Well, all the operators were invited to participate in this, send a geological representative. In fact there were four of us that were initially involved and three that actually did the picking.

The four geologists were myself, John Bircher with Meridian, Kurt Fagrelius with Dugan, and Dick Ellis with McHugh.

At the beginning we discussed our objectives and what we were going to do and in this agreement was Dick Ellis. He said that was fine, he was going to participate in the engineering meeting that was being held concurrently. So John Bircher, Kurt Fagrelius and myself picked the tops.

Q Is there anything else you want to talk about with respect to this exhibit now?

A I may refer to it later but this is all for now.

Q I'd now refer you to what's been marked Exhibit Number Four and ask you to identify and explain that.

Okay, what is it we have here?

A This is a structural cross section that I put together across the area that is represented on the structure map in Exhibit Number Three, and if you will look on the structure map you can see the actual trace of the cross section as it's represented on the structure map.

Q Okay, what does this show?

A Well, there are several things that I would like to point out on this structure, structural cross section.

I think the big picture here is to show the differences in structural dip across the area.

The wells over here are in the west -- the Canada Ojitos Unit on the monocline and as you can see, very steep dips, we've already heard testimony today as to what type of dips those are, what the rates of dip is, but this is a graphic reprsentation of this.

You have very steeply dipping Niobrara rocks with Gallup rocks, and as you come through the trough as indicated on the structure map, you see a leveling out of the -- of the dip. Then as you come onto the Gavilan Dome you see the wells coming back up into a domal configuration and then going off again and the last wells on the structure, structural cross section map is in the Ojito Gallup-Dakota Pool.

The big difference that you see on the structure is the fact that on the monocline you have very steep dips and on the Gavilan Dome it's very gentle and there is some structural relief here but it really is slight compared to the rest of the structure offsetting it.

Q Does it show any stratigraphic variation?

A Yes. I believe it does. Unfortunately I didn't have (unclear) the Canada Ojitos Unit wells available for our draftsman to put on the cross section so we included a stick diagram based on tops from PI scout cards, but what we have are induction logs and as you can see, the Gallup, this Niobrara is commonly broken down into the Niobrara A, B, and C zones, and likewise within the Gavilan-Mancos interval there is another basin unit called the Sanostee (sic) and then there is shale sections in between.

The Niobrara A and C zones on a cursory analysis look very similar. You can trace the sand or depositional unit across wide areas of the Gavilan area; in fact in a lot of areas of the San Juan Basin this basic interval is the same; however when you look at the induction curve or the SP curve, the gamma ray curve, you start to see some differences from well to well; that indeed it is not exactly homogeneous, it is heterogeneous.

The Gallup or Niobrara was deposited in an offshore environment consisting of sandstones, siltstones, and shales. Due to the depositional nature in any particular area we have more sand or more silt or more shale deposited. This is the nature of deposition and we can see that these ratios between the sands, silts, and the shales, indeed do vary from well to well across the area.

One major difference is we have in the northern part of the Gavilan area and a little bit of the northern part of the Canada Ojitos Unit, another portion of the Gavilan-Mancos interval some people have called the gray zone and it's well picked up on some wells as a high resistivity area. We don't see that everywhere within the Gavilan-Mancos Pool.

To the west and to the southwest portions of the pool this is absent. That's another thing that we looked at on our geological subcommittee meeting, we identified which wells had this gray zone in it and which wells didn't. We don't know the significance of it from production or not, but we felt we needed to identify that it was present in some wells and in some wells it is not.

Since there are some companies that perforate in that zone we feel that's something that needs to be addressed.

Another thing that I would like to point out on the structure map is that these zones, the gray zone, the A zone, B zone, the C zone and the Sanostee, they're very continuous across the area like I pointed out on a gross basis, although in the Gavilan Dome area operators, different operators have completed wells in the different zones.

Over in the Canada Ojitos Unit I believe on the historical monoclinal production the C zone was the only zone that was open.

Then on the Gavilan-Mancos we have operators that -- some operators perfed in the Sanostee. Some operators perfed in the gray zone, where present, and the A zone, the B zone, and the C zone, and in areas in between.

We feel that there's production occurring all up and down the Gavilan-Mancos interval.

Q And as you just indicated, that you do observe these differences on the logs themselves.

A I think so. Like SP development, which is a gross representation of permeability, porosity and permeability development, some wells show positive SP deflection, negative SP deflection, no SP deflection, within the same A interval across the area, or B interval, whichever interval you happen to look at. Those are -- those are brought out.

Likewise, the gamma ray, which is an indication of relative amounts of sandstones, siltstones or shales, those vary from well to well.

Q And do these logs also indicate the size of the structural differences, as you've already indicated, between the monocline and the Gavilan zones, the stratigraphic differences between the two areas?

A Yes. The -- there are, since we've known that there are differences from well to well, we also see that in the Gavilan or in the monoclinal wells in the Canada

Ojitos Unit, that the induction is so much lower on many of these wells as we see here in the Gavilan Dome area. So there are, at least seem to be differences.

Q Are there any differences in the Pictured Cliffs?

A Yes, there are. I believe in our other exhibit, Exhibit Two, that we have the boundary of the Pictured Cliff, the Gavilan Pictured Cliff Pool listed on there.

We do have production on the Gavilan Dome in the Pictured Cliff interval. It is -- the boundary stops at -- the boundary between the western tier of sections in 25, 1, with the rest of 25 and 1. For whatever reason, and I hope to point this out later, that Pictured Cliff production stops here at this trough area, the general area of this trough, and that there is no Pictured Cliff production on the monocline.

Q How about any differences in the Mesaverde?

A Yes, there are. We do not have production at this time but I have looked at the Mesaverde, have mapped for different parameters there and Point Lookout shows this relationship very good, that there are differences between the Gavilan Dome and the monocline.

Q Okay. I now refer you to what's been

marked Exhibit Number Five and ask you what it is.

Okay, well, first of all, what is this map?

A Okay, this -- this is actually a montage of a stratigraphic cross section and then two maps, one being the structure map from the top of the Point Lookout sandstone, and an Isopach map of the porosity feet as mapped within the -- within the (unclear) Point Lookout.

I must apologize that this map, the work that I did on this was done just about a year ago and there's been a lot of drilling since then but I haven't had a chance to update any new wells that are -- that have come -- been drilled in the area at that time.

Q Okay. What does the Isopach show?

A Okay, what I --

MR. KELLAHIN: Mr. Chairman, I'm going to object, file an objection at this point until there is a relevancy established for this exhibit. It's in the Gavilan-Mesaverde. I don't believe that's under discussion.

A There is no Gavilan-Mesaverde.

MR. KELLAHIN: How does that relate to this case?

MR. LOPEZ: I think if Mr. Kellahin will bear with us, this relationship and purpose will be amply demonstrated.

MR. STAMETS: We will allow the cross examination to continue and see if the relevance can be demonstrated.

Q Okay, is the Mesaverde productive?

A No, it isn't at this time but that was basically why I developed this map for my boss to let him know that I thought that in the future we would be able to develop the Mesaverde and produce oil and gas, but at this time, you know, with the gas market the way it is, we've chosen not to drill any wells at this time.

What I've attempted to do is map the porosity development which was in the top of the Point Lookout, the massive Point Lookout sandstone, and I had the interval marked off on each of these wells.

What I did was took the gamma ray neutron log and looked at the porosities and calculated the net amount of feet, effective pore feet within that interval and like on the Gavilan Howard No. 1 I found there was 3.35 porosity feet in that interval. Likewise, on the Gavilan No. 1-E I mapped 4.63 porosity feet, and farther on. I said that we hoped that the Mesaverde would be productive. On the stratigraphic cross section that I showed, only two of the wells have mud logs run on them. We saw excellent sample shows and mud logs shows and so we're very hopeful that we will get something out of the Mesaverde on the Cavilan Dome.

What the -- the most striking element on this map is we see the Point Lookout sandstone and it's been -- in the San Juan Basin there are offshore bars that are well developed, and on the cross section we see the development of a new bar we have more development in and you can see that in the net porosity feet. We jump from 2.3, 1.6,

We've Isopached these values from the well data I had at the time and we see a nice bar development occurring. As you go toward the center of this bar you have higher amounts of porosity being developed.

But the most, the thing that interested me whenever I first mapped this, was that as you approach the edge of the Gavilan Dome end of the trough, and again ths is an old map, but the structure on this map at the Point Lookout does not really show the trough as good as the new data that we have on the top of the Niobrara A, but I did some sort of trough here. Anyway, perpendicular to the development of the bar we saw the permeability of the Point Lookout sand stopping and it kept gettng lower and lower permeability, porosity and permeability, until from the data that I had at the time, we saw that as you did approach the synclinal trough there, at the west edge of the Canada Cjitos Unit, we have an effective permeability barrier, that the -- porosity and permeability barrier -- that the sandstone, excellent sandstone bar is being developed has been deteriorated since we cannot map it any more.

A lot of -- fortunately a lot of the Canada Ojitos Unit wells did not have -- are older wells and they did have gamma ray neutron log on them, but several of the wells were cored in the Mesaverde and I assume that they are nonproductive, no completions were attempted.

So what I envision is that we do have porosity development within the Mesaverde interval and that as we approach the trough as mapped on the -- between the Gavilan Dome and the monocline, that we see porosity, effective porosity being eliminated.

Q What about any differences in the Dakota formation?

A Well, I don't have a map showing the trends of the sandstones bars in there . All I can say is on Exhibit Number Two we did show the existence of the pool boundary for the Gavilan-Greenhorn-Graneros-Dakota Pool and we have established production. Some of the wells in that pool are complete or producing on their own and some of them are producing commingled with Gavilan-Mancos intervals; however, I'm of the opinion that the Dakota is nonproductive on the mononcline and that -- that indeed there were some wells drilled through the Dakota and tested in that way and there was no production found.

Again we might postulate that the Gavilan-Mancos, the Gavilan-Dakota Pool seems to stop at the trough. Again the same trough that the Pictured Cliffs, the Mesaverde, and the Dakota seems to stop at, that trough between the Gavilan Dome and the monocline.

Q How about the Pictured Cliffs?

A Pictured Cliffs?

Q Is there any evidence of Pictured Cliffs production on that?

A Monocline?

Q Yeah.

A No, there isn't. Of course the wells were drilled through the Pictured Cliff interval and I believe there were some wells that were drilled just to test the Pictured Cliff and no production at this time in that area.

Q Does Exhibit Two show the Pictured Cliff boundary?

A Yes, it does. I pointed that out, that the pool boundary stops right in the center of that trough as defined in the Gavilan-Mancos interval.

Q Okay. What about any differences between the two areas of the Gallup?

A Well, I feel that there are some differences in the Gallup or the Niobrara -- Mancos and the Niobrara interval between the Gavilan Dome area and the monocline.

Q And on what basis do you feel this?

A Well, wireline logs and I've already pointed that out on my structural cross section there seems to be differences, and from what I've witnessed in the Gavilan area from the limited core data that we had and from mud log shows and sample shows, we feel that there is matrix porosity developed within the Mancos interval in the Gavilan Dome area.

Q And what do you base this on?

A Again I base this on sample shows and mud logs we see as the well is being drilled. Mud logs have drilling breaks indicative of porosity development. The samples coming over the shale shaker lag back to this interval of drilling breaks. The mud loggers, many, many of the mud logs that I've seen in the area did cuts off of these samples, to me indicating that there is matrix porosity and that it is indeed filed with oil, and that it has some permeability.

I've been out on a well where I watched the samples come over, you know, I was with the mud logger when we looked for mineral fluorescence and we looked for sample cuts and all and we did see this, so I feel that there are -- is matrix porosity in this area.

I pointed out that we have limited core data and we've pretty well discussed that so far in the hearing.

Mobil has a core down in the southwest portion of the field.

Mallon has a partial core in Section 1 of 25 and 2, and Mallon is now drilling a well in Section 3. We're probably on the second to the last or the last core now. That coring effort is being paid for by the engineering and geological subcommittee meeting and we hope to see evidence, more evidence of matrix porosity.

The evidence I've seen on the core evaluations shows that there is some -- some matrix porosity.

Q Do you think this matrix porosity is high or low as the permeability goes?

A I think that probably the matrix porosity is on the low side and that indeed the permeability is probably low also.

We can look at the core data and as brought out by Mr. Greer this morning on Mallon's well, he didn't see very good relationship between the core porosities and the wireline log porosity measurements.

I would like to point out that I feel that there is probably an error on the CORE Lab handout that was given to Mallon whenever they paid for the analysis of the core, and when they shared the information with us at the geological and engineering subcommittee meetings.

The main error that I would like to point out is that CORE Lab realized that there was a depth problem between the core and how they had logged it with the wire-line logs and I believe they shifted it 16 feet and it says that here in the report; however, I look at it and I think they should have shifted it a little bit more and exactly 6 more feet lower.

What they did was they showed where there was less shale, a shale peak. They matched that against a gamma ray peak showing more shale and they probably based it on a little blip in the caliper. I think if you move that down 6 feet you will actually see that the -- then the shale corrections from the core actually match the gamma ray, and then if you take the corrections and using the wireline log porosity measurements and cross plot those, I think you would find that the wireline logs are in more agreement with the core porosities.

I know Mobil has done that with their core and have told me in conversations that these do, if you do the correct shale corrections, you do get a very close estimate between the core porosity and the wireline log por-osities.

Q Do you think the matrix can produce on its own?

A If it was strictly a sandstone, typical sandstone reservoir, no; however, I think that with the aid of fractures it can produce, since the initial development of the San Juan Basin, initial rapid development, I guess, in the fifties is what I'm trying to say, many of the companies realized that the sandstones and siltstones within the Gallup interval contained large amounts of oil. They realized that the porosities were low and permeabilities were low, and so for the most part it was pretty well bypassed.

They did try to mechanically frac the wells and put a fracture into the formation in hopes of draining some of this matrix porosity with the oil in there, and what happens is for awhile you get a real good well and then as you drain farther away from the frac, the manmade frac in the wellbore, and when you do frac a well you only have one -- one fracture going 180 degrees apart from each other from the wellbore, you -- you drain the area close to that fracture.

So what people do is try to find areas that are naturally fractured. You get a double benefit there. You have fracture porosity that's going to have oil in it so you're going to get oil thataway. You're going to get -- the more fractures that you have in the reservoir, scattered around in these tight sands, the closer any particular area of the tight sand will be to a fracture, and I think that in the Gavilan area, which in most areas are highly fractured, some areas appear to be less fractured than others, that we may only be one foot, two foot away from any fractures, any of the large fractures. We don't know about the microfractures, but if you're never more than a foot away or two foot away from a fracture, being an optimist, I think that these tight sands have a very good chance of giving up some of that oil that's in the matrix into the fractures system and then ultimately out the wellbore down the sales line.

Q And discussing fractures, have you been able to determine whether they're present and how they're oriented in the Gavilan Dome area?

A Yes, we -- determining their presence is fairly easy and that's by looking -- well, actually a lot of times it's being on the rig floor when you drill through it, and you can look at it from mud logs when you see rough drilling indicated. But you can't really tell the orientation of the fractures, and on the last three wells that Mesa Grande drilled we ran a fairly new log called a -- well, there's -- it's called different things by -- depending on which wireline company you have out there logging your well, but it basically allows you do detect the fractures and determine their orientation within the formation.

Q I'd now refer you to Exhbiits, I think, Six and Seven, and ask you to discuss how -- these exhibits and also explain how to determine fracture orientation.

A When we -- the oriented frac finding tool that we've been running in the area is a -- is another use of the dipmeter tool, which is widely used throughout the industry, and what it measures on four pads that are ninety degrees apart from each other are -- is micro-resistivity, and the computer utilizes the signals from these four pads to see if there are any differences.

First, in Exhibit Number Six I'd like to just show hypothetically how this tool would read or not read fractures in the wellbore if they were encountered.

We have one possibility to where there could be a fracture in the reservoir or in the formation that we don't see it with the tool. That is the one that's running from, if we looked at it at a compass orientation, from northeast to southwest. This fracture would be in the wellbore and none of the four pads would see this.

Q Maybe you should hold it up and point it out, if you would, please.

A That would be this particular fracture right here.

Q And that's the line that doesn't --

A That's the indication of a fracture that would cut the wellbore that the tool would not see because pads 1, 2, 3, and 4 are not sitting on top of the fracture.

Okay, the easiest case is when we use this data to get the orientation of the fractures, would be this fracture here running, basically, in a north/south direction. Pad 1 and pad 3, or it could be pad 2 and pad 4, any of the pads that are 180 degrees apart from each other. If both of these pads read it then they will see an anomaly that pad 2 and pad 4 don't.

Another case would be one where the fracture passes the wellbore, here sits the wellbore, and of course in this case it's pad 1 and pad 4, or it could be any of the two pads that are 90 degrees apart from each other to see that. It takes a little bit more calculation either on the computer or by hand to get the orientation of this fracture and from the last fracture I talked about, but it can be done.

And the last hypothetical case is where the fracture is the one shown on the righthand side of this exhibit, where it passes the wellbore and only one pad reads it. In this case all we can say is that there is a fracture present somewhere in the wellbore. We don't know the orientation; however, if you get a lot of these points where you only see one pad reading them, you do start to get a pattern and you can then get an idea as to its orientation.

Q Now referring to Exhibit Seven, why don't you explain that one?

A Okay. Exhibit Seven is a composite and what's shown are two of the three wells that we ran the dip-meter to along the frac finding log. The reason I didn't include all three of them was because Welex ran two of the logs; Schlumberger ran one, and what I'm trying to show is the method of how we arrive at orientating the fractures, and they're different, so I just -- I showed the Welex and the Schlumberger.

First I'll direct your attention to a Mesa Grande Well, to Bearcat No. 1. In there we ran a Schlumberger log and it's called the oriented micro-resistivity log, and what you see is each of the four pads are listed on the left in the center of the log and you can see them spiraling up the wellbore.

The pad number 1 is highlighted on the log as opposed to the other four pads, by the dark nature of the curve. It's also listed here on my composite log.

Knowing the -- the computer keeps tract of the orientation of this -- of the tool, and like I said, as you log the well the tools rotate up the hole.

Knowing the orientation of pad 1 you also know where pad 2 is. It's always 90 degrees away from there. Pad 3 is 180 degrees from pad 1. Pad 4 is 270 degrees going along and around that compass from pad 1.

As we see in the Bearcat No. 1, as you get down in what I've listed as the C zone on this well, you see the tool, the orientation of pad 1 and actually of all the pads, changing. This is because of the normal rotation of the tool as it goes up the hole as you log, the tool will rotate, and you can see that the tool is rotating. Then as you start getting farther up the hole, basically starting at about 6850, the orientation of the pad 1 is no longer normally, it's starting to maintain a constant direction, rotating slowly and as you get higher up, beginning at about 68 -- 6810 on the log, you see that pads -- the tool has stopped rotating and that the pads are maintaining a constant compass direction and then likewise, as you get to about 6730, the tool starts to slowly rotate again, although not fast, normal rotation again, but slow, and then as you get farther up on the log here, the tool is back to its normal rotation.

When you drill in a fractured interval, the fractures cause the hole to shift from a round hole more to an oval or elliptical shape in the direction of the fracture and what happens is if you come to a large fractured interval this tool can no longer rotate freely in that hole.

It's kind of squeezed in and it will go up -- log up the hole in that same elliptical orientation as the hole is due to the fractures that you penetrated.

Okay. I said that, back on Exhibit Six, the computer reads the information coming from all four pads and sees the different anomalies and on the Schlumberger presentation what they do is let's look at pad number 1 and where it shows pad number 1 written here, we see an area that's separated and darkened in. Well, if pad 1 is seeing the average of all the other pads then you have a direct overlay and if pad 1 sees something than the average from the other pads it kicks it out and separates it and that flag, that pad is seeing something different.

If you go and look at pad 3 and if it's seeing something different and pad 1 and pad 3 are seeing the same thing, then we have an indication that there's a fracture in the wellbore and that it is this case here where this fracture here is running north/south and pad 1 and pad 3 are seeing it.

We see this in the interval from about 6735 down to about 6810, where in that interval, as I pointed out earlier, that the tool was not rotating, but was actually probably following the fracture plane and we see here the indications are that pads 2 and pads 4 are seeing the fracture. Pad 1 and pad 3 are not, because of the separation on the curves as the computer has shown us.

Since we know the orientation of pad 1, the computer keeps track of that for us, we know that pad 2 is 90 degrees from that; pad 4 is 270 degrees away from that, so later I will show how you plot that up and determine the orientation of the fractures.

I would like to now go over to the other composite log. This is Mesa Grande Resources well, the Marauder No. 1.

Welex logged this well and their log is called a 4-arm dip fracture profile.

MR. STAMETS: Mr. Lopez, could I inquire at this point how much more testimony we have from this witness?

MR. LOPEZ: Half an hour max; 20 minutes.

MR. STAMETS: Much as I hate to interrupt, Mr. Kelley does have some obligations to leave and so I believe we're going to break at this point and then we will resume in the morning in Room 337 of the Roundhouse at 8:30.

So we will recess the hearing until that time.

(Thereupon the evening recess was taken
at 5:00 o'clock p.m.)

(Thereafter at the hour of 8:30 o'clock a.m. on the 22nd day of August, 1986, the hearing was again called to order in the Committee Room Number 337, New Mexico Capitol Building, Santa Fe, New Mexico, at which time and place the following proceedings were had, to-wit:)

MR. STAMETS: The hearing will please come to order.

When we recessed last night Mr. Emmendorfer was in the middle of his testimony.

You may resume when ready.

ALAN P. EMMENDORFER,

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

DIRECT EXAMINATION CONT'D

BY MR. LOPEZ:

Q Well, maybe we both can help each other pick up where we left off.

I think you were describing Exhibit Number Seven, which was the Welex and Schlumberger logs and how these logs help identify fracture orientation as you had described it in the process of your other exhibits.

So maybe you could pick up where you left off. I think you had completed discussing, as I recall, the Schlumberger log and now we're discussing the Welex log.

A Okay. Well, Mr. Commissioner, if I might, I'd might just review (not clearly understood) what I've said so far in my testimony and what I pointed out was we have very steeply dipping monocline over here to the east in 25 -- centered in 25, 1 West, and we have a slow, gently dipping structural dome here centered in 25, 2, and the structural cross section shows this very well. You have, again you see the very steeply dipping monocline which is where the historical Canada Ojitos Unit production has occurred; the trough that is outlined here on the structure map separating the two structural entities; and then you have again the low dome of the Gavilan Dome with very low structural dips.

Then I pointed that if we look back on Exhibit Number Two, the pool boundary of the Gavilan-Pictured Cliffs Pool, gas pool, the pool boundary ends and production stops right when we get to this trough as outlined on the structure map.

Likewise on the Point Lookout Isopach we saw the development of a good example of development of a bar, an offshore sand bar, and as you approach that same trough between the two structural features, we see that perpendicular to the bar you have evidence that porosity of this bar decreases rapidly as you approach this trough.

I also pointed out that the Gavilan-Greenhorn-Graneros-Dakota Gas or Oil Pool, we do -- the pool boundary stops at the boundary between Township 25 North, 1 West, and Township 25 North, 2 West, and that we have, we do have Dakota production established over here on the dome and there is no production, there has been drilling through the Dakota but no production on the monocline.

Then I started discussing the ways to detect fractures in the wellbore and their orientations.

If I may, I'll continue then on that.

Yesterday I talked about Schlumberger's log on the Mesa Grande Resources Bearcat No. 1.

We next go to the Mesa Grande Resources Marauder No. 1. The two companies use the same dipmeter tool. Their software packages to analyze it are slightly different.

Welex shows the raw data just as -- well, Welex shows the raw data.

The Schlumberger goes one step farther. It's strictly a software program to give the computer. The computer then reads everything and shows us the orientation

END OF VOLUME II

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

21 & 22 August 1986
29 August 1986

COMMISSION HEARING

VOLUME IV

IN THE MATTER OF:

Application of Jerome P. McHugh and Associates for an amendment to the special rules and regulations of the Gavilan-Mancos Oil Pool... CASE 8946

and

Application of Benson-Montin-Greer Drilling Corporation for the amendment to the special rules and regulations of the West Puerto Chiquito-Mancos Pool ... CASE 8950

BEFORE: Richard L. Stamets, Chairman
Ed L. Kelley, Commissioner

TRANSCRIPT OF HEARING

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I N D E X

I N D E X CONT'D

E X H I B I T S

I N D E X CONT'D

THEREAFTER at the hour of 8:25 o'clock a. m. on the 27th day of August, 1986, the hearing was again called to order in Committee Room 339, State Capitol Building, Santa Fe, New Mexico, before Chairman Richard L. Stamets and Commissioner Ed Kelley, at which time the following proceedings were had, to-wit:

MR. STAMETS: The hearing will come to order.

I tried to contact all of the attorneys yesterday and advise them of the plan for today but just to reiterate that, we will finish this case today.

We are going to allocate three hours for the pros, those who are in favor of the applications, which they may use in any way they see fit, putting on direct testimony or cross examination.

We'll allow three hours for the opponents, which they may use as they see fit.

We're going to start out this morning with the pros and let them do their thing. This will also, then, provide for some slippage in case the Commission wishes to allow some additional time for both sides.

Also we anticipate not more than fifteen minutes a side for closing arguments, unless either side chooses to use some of their three hours for closing arguments instead of either direct testimony or cross examination.

Are there any questions?

MR. LOPEZ: Well, Mr. Stamets, maybe just an observation.

I realize this is the way you want to do this, but it was suggested that perhaps a fair allocation of time would have been, since there seems to be three different positions, one which the McHugh-Greer camp is promoting, the one that the Mallon-Mesa Grande camp is promoting, and the one that the Mobil camp is promoting, which takes in three different spectrums on the scale, and therefore two hours and two hours and two hours would be more appropriate.

But knowing that yesterday you set the rules to begin with, we can live with them.

MR. STAMETS: Thank you, we appreciate that.

With that, then, we'll begin this morning with either Mr. Kellahin or Mr. Carrs.

MR. CARR: Mr. Stamets, it's my understanding that we may use our three hours anyway we choose and in any order that we choose.

MR. STAMETS: Correct.

MR. CARR: So initially we will call Albert R. Greer for rebuttal testimony.

I would request that the record reflect that Mr. Greer has previously been sworn and remains under oath and that he has been qualified as an expert witness in the field of petroleum engineering.

ALBERT R. GREER,

being recalled as a witness and having been previously sworn and remaining under oath, testified as follows, to-wit:

REDIRECT EXAMINATION

BY MR. CARR:

Q Mr. Greer, you were present last Friday and heard the testimony of Mr. Hueni, did you not?

A Yes, sir.

Q Do you agree with the interpretation of the Mancos formation in the subject area as presented by Mr. Hueni?

A No, sir, I do not.

Q Could you briefly summarize the interpretation presented by Mr. Hueni at that time?

A Mr. Hueni made a number of mistakes, Mr. Chairman, that led to his mis-interpretations and to begin with, he had the wrong bubble point and from that worked up a projected performance of the reservoir and came up with the -- the conclusion that the reservoir was performing as a solution gas drive reservoir would insofar as the pressures were concerned but his -- the gas/oil ratios of the pool were less than what he would have calculated and accordingly there was something strange going on.

And so he, having basically the wrong information to start with, he arrived at basically wrong interpretations.

In the course of this he found some anomalies in analyzing the behavior of the reservoir and -- and he took these anomalies as supporting his basic premise and he felt all along then that he was building on his case and that -- that the wrong interpretations, the wrong information, then, resulted in the wrong conclusions.

Q Now, Mr. Greer, what is the significance, actually, of using the wrong bubble point?

What impact does this have on the data?

A It has a very significant impact in that it shows the difference in the calculated gas/oil ratio and the observed performance of the pool to be a significantly different amount than it really is, and that then makes him feel that he has to -- to reach down deeper to find some kinds of strange behavior to explain this.

Q What was the basic information that Mr.

Hueni was relying on in calculating what the bubble point was?

A He makes reference to some bubble point -- some samples and reservoir fluid samples. He concludes that they were not accurate and so then he takes some separator samples and estimates the bubble point from that, a very inaccurate, if I might say, way of determining the bubble point, particularly in this stratified reservoir in which there are free gas stringers and can contaminate the samples such that a separator sample can -- may not, and probably does not represent the fluids which existed and would give that kind of a bubble point.

Q What kind of information or samples did you use in determining what the bubble point should be in this reservoir?

A Mr. Chairman, we went to great lengths to -- to get very accurate reservoir samples in order to determine the bubble point and we obtained one sample high on the structure, we determined from another one low on the structure, bubble points that checked within just a few pounds of each others; no question that we had accurates bubble point information.

Q And when were these samples actually taken properly?

A One, I believe, was in 1962, and then another one a couple of years later; three years later, maybe.

Q Will you review these samples and then your calculations with the Commission as part of your testimony this morning?

A Yes, sir, I'll review in detail how we determined the true bubble point pressure and how Mr. Hueni made his mistakes.

Q Now, Mr. Greer, did you also hear Mr. Hueni's testimony concerning oil and gas segregation in the reservoir?

A Yes, sir.

Q And have you reviewed his presentation?

A Yes, sir.

Q In your opinion was the presentation based on accurate information?

A No, sir.

Q And how so?

A Well, he used, as I mentioned a minute ago, the fact that the -- the gas/oil ratio measured in the pool was substantially less than what he would calculate for a solution gas drive reservoir. So we felt like there had to be some other strange reason for this. He found some anomalies in some -- the production behavior of some wells that seemed to lend credence to his supposition, and we just have to recognize, Mr. Chairman, that Mr. Hueni just did not have time to make the study necessary to understand this reservoir.

So he found some anomalies. He, without checking the anomalies to see if they really, truly existed, he just accepted them, made his determination that, yes, there is something strange going on, and so he just reaches down into the depths of the mysteries of these underground rocks and comes up with a bizarre interpretation that best can bes described only as -- as outrageous.

Q Now, Mr. Greer, will you review this presentation in detail as part of your case today?

A Yes, sir, I'll go every point -- over every point he discussed.

Q Now, Mr. Greer, as part of his case Mr. Hueni discounted the effect of the reliability of the interference test information that you've obtained.

A Yes, sir.

Q In your opinion was his approach to this test or this type of testing accurate and appropriate?

A No, sir, Mr. Chairman, it's pretty clear that -- that Mr. Hueni did not understand the type of interference testing we conducted.

We will explain the mistakes he made in those respects in detail.

Q Were you also present for the testimony presented by Mobil concerning the core data they have obtained in the two porosity systems which they assert is working in the reservoir?

A Yes, sir.

Q And in your opinion was this an accurate interpretation of the reservoir?

A Well, it doesn't -- it doesn't fit the general interpretations, Mr. Chairman, of -- of what geologists and engineers now consider a naturally fractured reservoir. He has eliminated the natural fractures in his calculations, apparently, and is dealing only with what must be induced fractures or fractures great distances apart, and as a consequence, then, by his calculations he feels that it's necessary to pull the pressure down in the fracturesa in order for the matrix, if there is any matrix, which I seriously doubt, to produce.

Now if the fractures are closer together, as they are normally in a fractured reservoir, then the matrix makes itself known, so to speak, early in the life of the reservoir. And so in the instance of Gavilan, if there is -- if there is matrix porosity and it's fractured, we know it's fractured, then the matrix is contributing now just as much as it ever can in respect to the pressures that exist.

And so, when we interpret the reservoir

behaviors now in terms of pressure decline versus cumulative production, we're seeing whatever is there in the fractures, in the matrix, whatever, and the net of this, Mr. Chairman, is that wherever the oil is coming from, the reservoir is in trouble.

Q Now, Mr. Greer, as time permits, will you have technical testimony concerning the possibility of matrix contribution in this reservoir?

A Yes, sir, if we have time we'll go into that.

Q Now, have you prepared certain exhibits for presentation here today?

A Yes, sir.

Q At this time if we could pass out Exhibit Number Six, please.

Now, Mr. Greer, referring to Benson-Montin-Greer Exhibit Number Six, before we go into the particular sections of this exhibit, could you generally characterize the analysis made of reservoir by Mr. Hueni?

A Yes, sir. This Exhibit Number Six will cover just a part of Mr. Hueni's testimony and it sets out how Mr. Hueni came about making his mistakes and -- and they're understandable, Mr. Chairman. I don't want to imply in any way that I think Mr. Hueni is not capable; he's obviously a capable, talented engineer, but he made mistakes;

mistakes that I very well could have made myself thirty years ago, before my hair got so gray.

They just come about and once you get started down a line and you have laid before you a lot of information, you don't have much time to work with it, you make a quick analysis of it. You jump, and that's the only word that can explain it, you jump to a conclusion, and then unconsciously as you develop information you accept the things that embellish your initial conclusion and you tend to kind of set aside things that might not contradict it, and it's not a deliberate thing. It's just a natural way that we humans work as we work on a problem.

Q Now, initially let's look at the calculated GOR and before we get to Tab A in Exhibit Number Six, there are certain documents.

I direct your attention first to the first blue page after the title page and ask you to identify that and review it, please.

A This is a copy of the gas/oil ratio and production history from Mr. Hueni's exhibit and which shows a very flat gas/oil ratio curve for the pool during the years 1985 and '86, when in fact the gas/oil ratio is declining rather fast at the end of this period.

Q And the notations on that are your handwriting --

A Yeah, my handwriting where I note the (unclear).

Q All right, would you go to the next page, please, and identify that?

A The next page shows the detailed calculations which our engineer made in arriving at the -- what might be a representative gas/oil ratio for the -- for the reservoir. In order to do that it was necessary to deduct the two wells which we feel would have, if their information is included, the No. 1 Gavilan and Gavilan Howard, because of communication from the Dakota on one and just where the gas came from on the No. 1 Gavilan, we don't know, but they're wells whose information needs to be deleted from the pool total in order to arrive at some kind of a representation of what the gas/oil ratio is really doing in the oil part of the reservoir.

Q Now if you go to the next document in this exhibit, which is a graph, please identify that and just briefly review it.

A All right, this is a copy out of Section D of McHugh's Exhibit Number Three in this case, and -- and the figures which our engineer came up with checks exactly with -- with McHugh's work in this calculated gas/oil ratio, and this shows the rapidly rising gas/oil ratio in the pool and more accurately depicts what's going on than what Mr.

Hueni was using.

Q Now this data goes through what period of time, Mr. Greer?

A I believe it ends about May of this year.

Q And that's what Mr. Hueni's exhibit also depicts?

A I believe that's right.

Q All right, now let's go to the pink sheet and I'd ask you to identify that and I think it's important to note that you have penciled certain notations on this exhibit, is that correct?

A Yes, sir. Basically this is one of Mr. Hueni's exhibits, pages out of his exhibit. There are some pencil notations on there showing, first starting on the lefthand side, the vertical penciled line, between the two vertical penciled lines, says it 1,750,000 barrels produced from the bubble point, and I believe that the bubble point is kind of hard to read in this scales, but it appears from the way the pressure dropped rather steeply at first, that Mr. Hueni, I believe, has assumed that that is the bubble point, that first solid dot on the -- on the pressure line.

From there over to the 1,950,000 barrel point there's then a million and three-quarters barrels of oil produced during that period of time.

You can see how Mr. Hueni's pressures fit the observed pressures, and it's my understanding that he used about 100,000,000 barrels of oil in place to calculate this.

When I used 100,000,000 barrels of oil in place, the same relative permeability ratio, and PVT data from the Loddy or the Canada Ojitos Unit, either one, they're very -- fairly close together, I get a much lower calculated gas/oil ratio.

Now, the difference, the difference may be, and it's a significant difference, Mr. Chairman, it's halfway between Mr. Hueni's projected point and his actual gas/oil ratio, and it's this big difference that leads Mr. Hueni to the conclusion that there's something strange going on in the reservoir.

So if the gas/oil ratio, the projected gas/oil ratio were actually lower than he has it, then he really doesn't have a strange reservoir, or a strange situation to deal with.

Now, the actual gas/oil ratio is probably -- would be higher than is shown here for the reason that part of the oil is still under-saturated, new wells are coming on line, and so although this -- this graph reflects the reservoir performance of the pool as a whole, it's really distorted in that as new wells come on, if they come in with a -- or they're drilled in an area where one of these stratified sections has gas in it, it will kick the gas/cil ratio up, a well that comes in with the -- fairly close tc the solution gas/oil ratio below the bubble point will distort it down.

So it's very difficult, really, to say from a curve like this that the performance is or is not following what would be expected for a solution gas drive reservoir of this type.

Now, as indicated, the difference between the red dot, Mr. Hueni's red dot and my blue dot, might be because he's used different PVT data than I did but I just can't think that that's the difference and we'll get to that in a minute where I compare it.

The Canada Ojitos PVT data and the Loddy, the difference I would think there is about the same as I would expect from what Mr. Hueni's used, and so I conclude that in addition to that, that the gas/oil ratio line is probably not very accurately calculated and the reason I say that is Mr. Hueni notes that it's calculated by the Horner method and there's nothing wrong with the Horner method if you use it correctly for this situation.

Here, where we're dealing with rapidly rising changes in the relative permeability ratios, for small differences in oil or total liquid saturation, requires a more accurate treatment of this problem than you ordinarily can get with the Horner method if you use big steps.

With the Horner method you need to use small steps to get it. Even the way I calculate it, I would use at the most that big a step the first time, and when I'm talking about that big a step, I'm talking about where the gas/oil ratio point breaks from level to its first increasing point at about 1,250,000 barrels, and the problem here is the compounding of problems.

First he uses the Horner method. Second he uses a computer, so then he had compunded the inherent inaccuracies of the Horner method with the errors that the computer is going to bring in and the errors that the computer brings in is it averages arithmetically between the two points and -- and the rising ratio of permeabilities is on a logarithmic scale. The end result, then -- well, then another thing. He uses too few points to define for the computer the relative permeability ratio. He shows on his information how -- the information he gave the computer.

What that means is that if at some particular point the computer is seeking its trial and error method of reaching a point, if that's close to the points he put into the computer, then it's fairly accurate, but if it's in between, then the computer picks up a higher KgKo ratio than really exists, and so that tends to give a higher gas/oil ratio. If the first point is off, then the amount of gas taken from the reservoir is off, the liquids left in the reservoir is off, this is all in the calculation, and then the end result is too high a gas/oil ratio, and so when you compound all of these problems, I'm not surprised that the gas/oil ratio calculated here is higher than it would -- should be.

Now, if you take into account the probability that the bubble point is much lower than what Mr. Hueni used, then the shift of the curves, of the computed curves, or the field performance curves, are to the left and John Roe brought this out in his testimony in pointing out the first time that he looked at the solution gas drive recovery, that, yes, there's a problem here and that is one of the probable solutions in addition to the fact that the gas/oil ratio is not fairly representated by taking the average of everything.

So, the net of it is, then, that I need to leave it clear to the Commission that there is a option to Mr. Hueni's interpretation. The option is that the reservoir is performing like you expect it to.

Q Now, Mr. Greer, you've just identified the document behind Tab A and then moved right into the document behind Tab B in this exhibit.

A This is -- under Tab A is just the reservoir fluid study of the Loddy and which I used to make a comparison with Canada Ojitos recovery.

Q Okay. Now going to Tab B, would you just identify the first document behind that tab?

A That's the relative permeability ratio curve which we've discussed earlier in this hearing.

Q And now go to the next sheet, please.

A The next one is the expanded curve, the same information as is shown by the dashed line on the blue sheet expanded to a wider scale and brought down to .001 relative permeability ratio, and the reason I've done that is to have a more defined line for comparing the difference in calculated performances with the Loddy PVT data and the Canada Ojitos Unit PVT data.

Q All right, now please go to the yellow or orange sheet that follows that and identify that and review it, please.

A This next sheet shows the comparison of the projected performance curves, using the Canada Ojitos data and the Loddy data, and points out that there's really not a lot of difference early in the life of the pool. The ultimate recovery is about the same. There'll be a higher gas/oil ratio, but the point is it's not significantly greater as would appear from Mr. Hueni's calculations and so, although I've not calculated the performance using Mr.

Hueni's PVT data, I just have the feeling that there's no way that there could be that much difference if they're properly calculated.

Q Now, moving from that data and going to the information behind Tab C, would you review that information and indicate how it relates to the calculation of relative permeability?

A One way, Mr. Chairman, to tell whether this reservoir is performing in one respect as a solution gas drive reservoir, which I've not had an opportunity to -- to recognize much gravity drainage, is to take a well that produces -- it produced a significant amount of oil, has a rather large drop in pressure so that we have the maximum range of pressures and hopefully, the maximum change in liquid saturation in that area, and from that, the producing information from a well such as that, we can then calculate the actual relative permeability ratio as it applies to that well, and that's what I've done here.

The first sheet show show oil to gas viscosity ratio from the Loddy data, plotted on the next graph, the white sheet. Then on the gold colored sheet we show what the liquid saturation would be at any particular reservoir pressure depending upon the bubble point.

The first horizontal scale shows for a 1500 pound bubble point; the second for a 1550 pound bubble point; the bottom one for a 1600 pound bubble point, and I used that information to go to that set out under Tab D.

Q Okay, will you now identify that and then review what that calculation shows?

A This shows the calculated relative permeability ratio taken from McHugh Native Son No. 2 Well for the four periods, 1 December '85, February, April, and June '86.

We take into account the fact, Mr. Chairman, that there is about a 300 foot difference in sections from the top possibly producing zone to the bottom one, which is roughly 100 pounds differences in the upper to the lower part of the pay zones and we don't know which, if any, is contributing -- or which of the zones are contributing the most of the production, but there just in this one well alone and the fact that we have the different zones, makes it impossible to tell what the liquid saturation would be in any one of the zones for a different pressure, and so what I've done is to cover that range and we plot that range. And the range is shown -- in the middle of the sheet is shown the relative permeability ratio for those producing conditions. The bottom three horizontal lines show the liquid saturation depending -- for each of the bubble point conditions. At the bottom of the page is shown the simple formula by which that's calculated.

Q Now go to the graph on the next page and discuss that.

A The next page is the same as the early one we looked at of the expanded graph, except I've left out the lower straight line which covers a lower liquid saturation, and it's on this graph, then, that I plot the data we just calculated, and that's shown on the pink graph.

On the pink graph we show for December '85 that -- that the liquid saturation would be 100 percent if the bubble point were 1500 pounds. The pink sheet is for 1500 pound bubble point pressure.

Then for February the range runs from about 99 percent to 100 percent.

In April it runs from about 98.3 percent to 100, and then in June, about 97.4 percent to about 99.5 percent.

And on the next page we see where the range of data would fall if the bubble point were 1550 pounds.

And then on the yellow sheet we show what the range of data would be for 1600 pound bubble point.

Q Now what do these three graphs actually show?

A What these show, Mr. Chairman, is that there is no reason to believe that insofar as this well is concerned, and I grant you it's very difficult to find characteristic wells which represent the average of the pool to be expecteds, but this well has produced a significant amount of oil, has the biggest drop in pressure, and is the one that I would think would be most apt to represent conditions, and if the relative permeability ratio for this fractured formation is as we think it is, if the bubble point is in the range that I think it is, then there is nothing unusual about the way this reservoir is performing as far as solution gas drive is concerned and there is no need, Mr. Chairman, to go to some strange behavior to explain why the pressure and production data do not fit Mr. Hueni's curves.

Q Now, Mr. Greer, would you go to the document contained behind Tab E in Exhibit Six and identify this, please?

A Yes, sir. Mr. Hueni sets out here, this is a sheet that -- out of his exhibit. The highlighted language says that the remaining samples, and he's talking now -- see, what happened, Mr. Chairman, Mr. Hueni was provided sample data on three wells, two were taken by the McHugh people, one that was taken by our company in the Canada Ojitos Unit. The two taken by McHugh were in the Gavilan Pool.

The information on one of the wells was obviously not good and on the Loddy there was a question about --about that information, and I understand his concerns about that. I have concerns abut the PVT data on the Loddy. The McHugh people, when they first told us about the samples that they took, said that they realized that he'd get some information on the reservoir, they had no bottom hole samples over there, they thought they would run out and the language they used, as I recall, was we would get some quick and dirty samples, and that's what they got. One of them was just no good at all; the other one appears to be somewhere in the ballpark, but I can understand here Mr. Hueni's reservations about that -- about the Loddy samples .

Then he says here, and we need to read this, "The remaining samples", now he's talking about the Loddy and the Canada Ojitos samples, he says, "they were both taken after significant production from their respective pools and it could not be determined if the lab reported bubble point pressure reflected true reservoir conditions or some gas evolution had occurred prior to sampling." Now that was true about the Loddy. We had no information about that, but it is untrue about the Canada Ojitos Unit sample, and you see, Mr. Hueni was in such a short time, such a short time to analyze this that he did not come to us and ask us about our sampling procedure, was it a good, valid sample, did we have any other samples, but he was at the point that he was really desperate to determine, well, what really is the bubble point, and so he goes then to separator samples, and he had to be desperate to do this because, Mr. Chairman, the -- to determine a bubble point from separator samples, you're just reaching in the bottom of the barrel for information. That's the last resort.

So it's unfortunate that he didn't have the time and no one who was helping him realized that they should have advised him to go check with Benson-Montin-Greer, they very carefully took the samples; they got some good samples. He didn't know that.

So he uses poor information to arrive at the bubble point. You need to look at how bad, how bad the information can be to use separator samples to estimate the bubble point.

Q Okay, now doing this, would you go to the next exhibit in Section E and identify that? I believe this is an exhibit we've seen before.

A Yes, sir, this is an exhibit we've seen before and about the center of it is a cross section identified from the Mallon Howard 1-A east to the Canada Ojitos Unit E-6 and down to the J-6, and the main thing I want to point out here is that the J-6 is just about the lowest well in the trough on the east side of the Gavilan nose and the low part of the structure from Canada Ojitos Unit.

And why this is significant is because in this stratified reservoir there's free gas, we know at least in what we call the gray zone, and we'll look at that cross section that next falls.

Q Okay, and that's the next exhibit in -- or document in Section E of Exhibit Six.

A Now, Mr. Chairman, we're talking about the bubble point but we don't have much time and I need to talk also about stratification, so if you'll bear with me I'd like to jump to stratification now so we won't have to come back to this exhibit.

The three main producing zones that we have in West Puerto Chiquito and Gavilan are the A, B, and C zones. The gray zone is one that kind of comes and goes and in my view from what we've seen so far is just probably gas productive.

These zones are stratified, Mr. Chairman, and they may, as indicated in my initial testimony, be tied together in a place or two by faults. There are not very many faults in the pool. McHugh's structure map by Dick Ellis is the only one that I remember seeing that showed any -- any identifies faults. So in general, in general the -- when individual wells are produced, completed, they produce as stratified zones.

We have on numerous occasions, Mr. Chairman, completed a well in the bottom zone, in the C zone, and with that thick, nonproductive section between the brown and the green zone, we have found separation. We've gone back after packing wells and found that the zones are separated.

We've even found separation, Mr. Chairman, between the A and the B zones where the perforations were as close together as 20 or 30 feet. We have, for instance, fraced the A and B zones together, put a bridge plug between the two zones, produced the well for two or three years, production rate ten or fifteen barrels a day; drilled out the bridge plug and picked the production rate up to 40 or 50 barrels a day. No question, Mr. Chairman, the zones are stratified. There is no vertical communication as Mr. Hueni has suggested.

Now, to talk about the bubble point, we show here the perforations through small horizontal lines on the insde of each of these logs.

Mallon has perforated the zones pretty much from a gray zone down to the unidentified zones at the bottom. The uncolored zones at the bottom are, the top is the Sanostee, the bottom is the Niobrara, base of the Niobrara silt.

Sometimes they produce very small amounts of oil but very small.

When Mallon perforates most of their section, in our offset well we feel like we're obligated to perforate most of ours for legal if no other reasons.

But when we get farther off to the east where we're not directly offset, we perforate the zones which are reasonably thought to be productive, which is A, B, and C zones, a little bit down in the Sanostee and the basal Niobrara.

Now, when we completed the E-6, the center well, we did not want additional gas there. We were planning to use this as an interference test well. We didn't want to perforate the gray zone. We realized Mallon had perforated it but to protect our interest we would need to have a well somewhere over there that would produce the gas out of the gray zone.

We left that until we drilled the J-6, the well on the right. We perforated the gray zone here along with the other. This well then showed about 400,000 feet of free gas out of the -- out of the gray zone, and how that -- and so now we looked at what would happen if we took a separator sample on the J-6 to estimate the bubble point. And I show that on the --

Q And that's the document in yellow behind Tab E?

A Yes, sir, and this is one of the old, twenty-five year old methods of correlating bottom hole sample data. They have more accurate information now but in general we can see from this information how if, in taking a separator sample, you have commingled with the oil some free gas from one of these stratified zones, then --

Q Go to the -- go to the graph now behind it and show -- review for the Commission what this shows about the reliability of separator samples.

A The -- the -- we start on the lefthand side of the graph and start with the green line. The green line starts at a gas/oil ratio of about 500 cubic feet a barrel, drops down vertically to the 40 or comes over horizontally to about the 0.7 gas gravity line, drops down to the approximately 40 degree oil line, goes over horizontally to approximately the 150 degree reservoir temperature, and you come up with 2000 pound bubble point. Now, this is approximately what we had in Canada Ojitos, about 480 cubic feet a barrel and true bubble point's about 1520; this shows it within, you know, 4-or-500 pounds, not too bad for a rough guess.

But what would happen if we had a high gas/oil ratio well, free gas mixed in the separator samples, and the first sample we had on the J-6 would have been 5000 cubic feet a barrel. The chart doesn't go that high to follow it over to the righthand side but we just go up to about 15-or-1600 cubic feet a barrel and what would it show.

Well, we follow the same path over to

0.7 gravity, down to the 40 gravity, over to the 150 degrees and we find a bubble point of 5000 pounds.

Now, this is the problem that you have, Mr. Chairman, in a stratified reservoir mixing oil from an oil zone, gas from a gas zone, and trying to estimate a bubble point. So Mr. Hueni used the most unreliable method available to estimate the bubble point.

Q All right, would you now go to the log section which is the next page behind Tab E?

What does this show?

A This shows what we found in a number of wells cored in the basin, not in this area, but in the same general section of the Mancos on the west side of the basin. Cores were analyzed about fifteen years or so ago.

We found that we could -- that we had very little reliable information we could get from cores, but what we did find was -- well, mainly we found that in their analysis and their recording of the samples that they took out not only what might be oil in the -- in the effective hydrocarbon pore space, but they took out the kerogen of the shale, just like oil shale that they have in Colorado for -- that they run through the plants in order to get oil out of the oil shale. In the core analysis process they took out the kerogen, they took out the water hydration, and so it's really difficult to determine from a core analysis in this formation what, really what's going on.

But one thing we did find, one thing we did find is that whether it's oil kerogen or whatever that you took out of the shale, there isn't any of it when the resistivity gets down around 15 ohmeters. Now this was for -- and even as high as 30 ohmeters we'd have to go before we find the significant amount of oil.

So we find in these zones, the separations of the producing zones, these low resistivity shales, and they just don't have any oil in them. If they have any oil it's just by happenstance of a fault or a fracture that's come down from above, and we note, for instance, that Mobil in its core analysis didn't even analyze these shales between the producing zones. This is just some more of the evidence that shows that the zones are stratified and not vertically connected.

Q Mr. Greer, what does this tell you about the concept of one 600 foot producing interval?

A It's just impossible, Mr. Chairman, there's no way it can beds.

Q Now, Mr. Greer, you talked about samples that you had taken early in the life of the reservoir. Would you go to the information contained behind exhibit or Tab F in Exhibit Six, identify this, and then very briefly summarize what this information is.

A This - this shows the sample that we took, the bottom hole sample on the discovery well in the West Puerto Chiquito Pool.

One of Mr. Hueni's statements was that the samples had been taken after substantial amount of production had been had from the pool and they couldn't tell whether gas had evolved from the sample or not.

We show here the drilling history when this well was spudded, the complete drilling report, some of the core descriptions and over on page five of the green sheets we had drilled this well with air and we found oil in the C zone at -- on August the 10th, 1962.

Three days later we ran tubing and shut the well in.

We blew the well for another day.

A total of about four days of production was taken from that well before it was shut in. Well made about 15 barrels a day and then we shut it in to determine a -- get a bottom hole sample.

We put the well on production about two months later in October and you see on page six of the green sheet where it's capable of something like 15 barrels a day.

On the pink sheet following the green sheets there's a bottom hole pressure survey for this well we took at the time it was shut in.

The pressure build-up passed what -- we did not know or have any idea at that time what the bubble point pressure was. We got 1520 pounds, which it reached that in about September the 4th. Then for another two or three weeks the well was shut in to stabilize and at 1635 pounds, according to the dead weight test that we used at that time for calibrating our logs.

We later changed the different dead weight test to determine that probably that was closer to 1620 pounds or somewhere in that range, 1620 to 1635.

We then took a bottom hole sample that's shown here on the yellow sheet following that and that bottom hole sample shows on the fourth yellow sheet, the bubble point pressure of 1524 pounds at 152 degrees Fahrenheit. That we consider, Mr. Chairman, was a good sample.

Now, any engineer is a little concerned about a bottom hole sample where the well productivity is only 15 barrels a day and even though it was allowed to build up slow, there -- you wonder just a little bit about it, and so you like to have confirmation of it.

So we confirmed the bottom hole sample that was good by taking another one and the next --

Q Is that information behind Tab G?

A Yes, sir, behind Tab G. What we show here on Tab G when this particular well was drilled, the L-

11 we called it at that time -- or 12-11 at that time and now the L-11 -- and the well was completed as we show here on the third blue sheet in November of 1964.

The well was produced then for several months at about 500 barrels a day. We got -- we fraced the well with oil but I think we recovered probably in that length of time, oh, maybe 100,000 barrels.

We know that we had an uncontaminated reservoir to deal with, but in order to be certain that we could get a good bottom hole sample from this well, we pulled the tubing up to 2000 feet, bottom of the tubing 2000 feet from the surface, and we did that so that there's no way that the crew in swabbing oil from the well could pull oil at a faster rate, would pull the bottom hole pressure down faster than -- than -- so fast and to so low a point that it would cause gas to evolve from the -- from the sample.

And you can see that we conditioned the well for some ten days to two weeks swabbing at a rate of -- at the maximum rate of 4 barrels an hour, which would be about 100 barrels a day. The well had a PI of about 2.25 as shown on the pink sheet following at the bottom of the page, under those conditions the drawdown pressure was approximately 45 pounds and the static bottom hole pressure of about 1670, so the minimum, the minimum bottom hole pressure, Mr. Chairman, that could have existed at the time that we were conditioning this well and conditioning very carefully, Mr. Chairman, we were very careful in determining and making sure that we got a good bottom hole sample. And the closest that the pressure got to the presumed bubble point was 100 pounds.

That sample then was taken on July 1st, 1965, and on page, the third of the yellow pages, we see where CORE Lab came up with a bubble point of 1519 pounds at 162 degrees Fahrenheit. I don't know just how accurate those temperatures were that we took in those days, but they're probably somewhere in the ballpark.

So now we want to estimate or make an estimate, what would be the logical pressure for Gavilan, but just before we look at that, we have a confirmation, a confirmation that the oil definitely was undersaturated and that's shown by the second from the last sheet under this section, the white --

Q The white graph.

A The white graph. The white graph is a plot of initial pressures in the Canada Ojitos Unit versus cumulated production, and you'll note on the upper lefthand side of the graph that the initial pressure decline was at a rate of about 2650 barrels per pound.

Then at about 150 barrels it increased to

3000 barrels a pound, and it continued to increase and you can see at about a million barrels of production that the -- this coefficient had increased to 7000 barrels per pound. Now why did that increase, Mr. Chairman? It increased because the -- in this -- in this reservoir which is on an incline, the oil was undersaturated probably through most of the oil column. As oil is produced and the pressure drops, then the bubble point in a sense moves down the structure. Where it was initially 1600 pounds at one point in the structure you produce oil. The pressure drops. It drops down to 1500 pounds. It's now down to the bubble point. All the oil remaining above that part of the reservoir in the structure is now saturated. Being saturated it has a higher compressibility. Having a higher compressibility it adds that force to the overall reservoir system compressibility and then that allows more oil to be recovered per pound of pressure drop.

This confirms, Mr. Chairman, the fact that -- that the oil was understaturated.

Now this reservoir was such a high transmissibility, pressures equalizing over miles within just a few days, there's no question that this is what happened and that the oil was understaturated at about the bubble point pressure.

Q Now go to the last sheet in --

A The last sheet is a green sheet. We now estimate the bubble point for Gavilan from these bubble point pressures that we have in Canada Ojitos.

The upper line shows from the K-13 we would estimate 1524 pounds plus 54 pounds where we would estimate 1578 pounds for Gavilan.

From the L-11 we would have 1519 pounds plus 24 pounds would be 1543.

We get those differentials, Mr. Chairman, from CORE Lab's analysis of the oil as to how the bubble point changes with temperature, and you can see there that we have a spread of about 30 or 40 pounds, 35 pounds.

That's a reasonable range, Mr. Chairman, for the bubble point. We think that the temperature in Gavilan is 170 degrees. That's what we're measuring now with the bottom hole pressure equipment that we're using that records temperature simultaneously with pressures.

So this is what -- what I would estimate as the range of the bubble point pressure and that checks fairly well with what we saw earlier for bubble point versus relative permeability in the Native Son No. 2.

A Do you believe you've used the most accurate data available to you to determine what this -- the reasonable range for the bubble point would be?

A Yes, sir.

Q Would you now go to Exhibit Number H, and here, Mr. Greer, I'd like to now shift your testimony to the question of the oil and gas segregation within the reservoir.

I'd first ask you, can you offer any explanation for the anomalous situation that Mr. Hueni testified to last Friday?

A Yes, sir. Mr. Chairman, you have to realize here, now Mr. -- Mr. Hueni made -- placed great significance, great significance on the fact that the Native Son No. 1, shown by the data on the yellow sheet, and the Homestead Ranch No. 2, data shown on the blue sheet, that these low gas/oil ratios, and I think he even mentioned 184 cubic feet a barrel or 180, on the Native Son 1, this is an anomaly.

Here we have a reservoir that has, I think, about 480 cubic feet per barrel (unclear) solution gas. Mr. Hueni estimates a little higher, but whichever, whichever is the case, here's an anomaly. Here's a well shows much less than that.

Mr. Hueni has interpreted that as meaning that as the well is produced, the pressure is drawn down in the vicinity of the wellbore and back out along the well's drainage radius, that as the pressure is pulled down the gas evolves from solution; then rather than coming to the wellbore along with the oil it migrates up, segregates and goes up. The oil goes up the -- the oil goes down, the gas goes up vertically but not laterally, and he says this supports his contention that this is what's happening.

Now, again, Mr. Chairman, when you're hair gets as gray as mine and you find an anomaly like this, before you use that to support a bizarre theory of reservoir performance, you look to see is the anomaly really an anomaly. Is it really there?

One of the first things we look at, let's look on the blue sheet and you see the gas/oil ratio 229 then zero then 372, then it comes down 371, 371, 371. What does that mean? Well, that means that this is before now, you see, this is before this well is hooked into the -- into the gas line, so these gas/oil ratios are estimated, Mr. Chairman, on a test that somebody's made in the field. We don't know whether it's a pitot tube test or orifice well test, we don't know what the separator pressure is, probably about 100 pounds, and the 371, 372 might be pretty good. The gas goes through the tester.

But if there's a 100 pound separator ahead of the separator, then there's about 100 cubic feet a barrel goes over to the stock tank through the air. And so the true gas/oil ratio in this instance would probably have been somewhere around 480 cubic feet a barrel, which is what the PVT data from the Canada Ojitos Unit wells would suggest.

Okay, we come down and it shows 210 in this first month. Now that's the first month that the well went into McHugh's gas system that goes into a system on which I think there are three or four other wells, and so there is the problem of allocating back to each well how much gas came from each well, and so there is an opportunity for -- for a mistake, just plain, old, human, ordinary error.

But the main thing, the main thing, and I presume Mr. Hueni didn't know this, is that these two wells are flowing wells. They're flowing wells. Now what does that mean? That means that with a gas/oil ratio of 180 cubic feet a barrel, a gas/oil ratio of 210 cubic feet a barrel, they can flow only if they've got bottom hole pressures of 2000, 2500 pounds, and that's not available.

So what's the answer? Well, the answer is that the gas/oil ratios, as shown here, are not accurate. That's unfortunate. It's unfortunate that Mr. Hueni accepts information that's inaccurate and then goes and develops a theory based on that, and if you'll look at the next -- the last white sheet under this section you'll understand what -- what I'm talking about.

These flowing wells in this area have

pressures on the order of 1000 pounds on the annulus and particularly if they have somewhere around a low gas/oil ratio of wells in the pools. And so what does that mean? That means the flowing bottom hole pressure at the tubing where the oil is coming into the wellbore can be drawn down only to about 1150 pounds.

Now at 1150 pounds, some gas has evolved from solution, but there's a lot left in solution; depending on which of these PVT data curves you choose, there's between 400 and 475 cubic feet per barrel still dissolved in the oil when it comes into the wellbore and comes up the tubing from the bottom of the well.

So that means that there can be a gas/oil ratio no less than 400 to 450 cubic feet a barrel. Anything less than that, there's a mistake. It happened in the field. These oilfields, Mr. Chairman, are operated by humans. We make mistakes and something has happened. I don't know what it is but it's clear to me that there is something wrong. The anomaly that Mr. Hueni places so much emphasis on is erroneous and his conclusions are likewise erroneous.

Q Now, Mr. Greer, I'd like to shift the focus of the case now to the effects of fractures on oil in place and productivity and the validity of interference tests, and in this regard I'd like to now pass out and refer to Benson-Montin-Greer Drilling Corporation Exhibit Number Seven.

Now, Mr. Greer, have you studied the effect of fractures on oil in place and productivity?

A Yes, sir.

Q And are -- is the study a portion of what is identified as Benson-Montin-Greer Exhibit Number Seven?

A Yes, sir.

Q Would you go to the first tab in that exhibit, Tab A, and identify the documents contained behind that tab and briefly review what they show?

A What this shows is the logic behind two different theories of fracturing, which -- and the fractures form the reservoir in this area, and generally most -- most students of this -- of this geological phenomenon have concluded that fracturing often results from folding, flexure of the beds. Whether that's what caused it or not, we cannot be positive and if it is caused by folding, we're not sure that where the folds are now are where the folds were when the fractures were created and so we can't tie exactly in 1986 where the best fracturing might be, but one thing that we do know, of which there's no doubt, no question, no argument, the beds have somehow or other had to be placed in tension. It had to be pulled apart and when they're pulled apart, and caused the voids and the fractures, that's where the reservoir space is.

If they're compressed, and a fracture is pushed together, then there is no reservoir space. So they have had to be put in tension.

Now what I've compared here, and the reason, Mr. Chairman, why I prepared the exhibit which was first presented here twenty years ago, as to how productivity and porosity increase as the width of fractures increase, and the probable relation, since the porosity to pore space varies with the cube root of the permeability, and so --

MR. PADILLA: Mr. Chairman, I'd like to, before the witness starts on this exhibit. I'd like to find out from Mr. Carr how this relates to rebuttal testimony.

MR. STAMETS: Mr. Padilla, I'm going to overrule you because I've given everybody ninety minutes to do whatever they want to do today, or three hours, for whatever they want to do, and it's up to them to determine whether it's relevant or not and we'll allow Mr. Greer to proceed.

Q Okay, Mr. Greer, would you go on now and explain the first exhibit behind Tab A in Exhibit Seven?

A So how I've approached this problem, Mr. Chairman, is I have taken two -- two sections of the reservoir that are folded equally and they have equal fractures, and that's in Plate I and Plate II, and I show the two fractures on the opposite sides of the plate.

Now, in Plates III and IV, if we place additional stress on a formation, stress that's a tension stress, that pulls -- pulls that formation apart, and on Plat III I have shown that the formation is pulled apart until the fractures are increased in width to the extent that we now have 100 times the permeability that you had before, 100 times, and to do that requires about that they be stretched about 4.6 times what they originally were.

On the other hand, and now this is what I think happens. Now, Mr. Hueni, when he was criticizing my -- my approach, said, well, you could just as well have twice as many fractures, twice as much porsity, ten times as much porosity, ten times the porosity, and carried it on to 100 times the fractures, 100 times the porosity. So what Mr. Hueni says what happens is that when we place this additional tension on the formation, is that you don't spread the original fractures, they stay in place, but what happens is you create 100 new fractures, all of the same width as the first fracture.

Mr. Chairman, I'm an engineer. We studied strength of materials, stress and strain, when you place something like a formation like this under stress and it cracks and breaks open, and you place it under further tension, unless there's something to hold this loose block that's in the middle here for it to part and additional fractures create, it's not going to do it. The initial fractures are going to widen. That's just simple logic.

That's my kind of logic; it's not Mr. Hueni's kind of logic.

Q Mr. Greer, go to the next page and review the comparison you've made of porosity and permeability in the area.

A All right. Here we take a direct comparison and in order to understand the significance here, then you put it in perspective, what we're talking about. Now both Mr. Hueni and I have gone from , say, oh, something like 100,000,000 barrel of oil in place in Gavilan. The solution gas drive recovery for that is going to be 5-6,000,000 barrels depending on the detail of what you come up with.

But that's something, what we're looking at for all the wells in Gavilan with a solution gas drive.

Now, that gives you an idea of the total amount of oil that we're looking at, say, from 56 wells.

Here we compare the two different methods, two different logics, and compare what recoveries we might anticipate from comparing two different wells and the two wells that I have chosen are one of our small wells, the C-2, which is shown on the bottom line, had initial productivity of about 56 barrels a day.

Our B-29, if we put big enough casing in it, would have a productivity of about 15,000 barrels a day.

The ratio of the B-29 to the C-2, this is a ratio of the productivity, is about 270.

I say that, you know, just my horseback estimate of how much oil you might expect from -- from the B-29 if you compare it to the C-2, if all other things were equal, and of course they're not equal. One of them is going to drain more area than the other, and such as that, but just for a rough comparison, then this is what my -- my theory would show, about a million and a half barrels, then, would be expected from the B-29.

By direct ratio of the produtivities, the theory that Mr. Hueni propounds, you would have 62,000,000 barrels, completely out of reason.

Q All right, Mr. Greer, go to the next document and identify that.

A The three or the sheets following, the gray sheets, are an article by Mr. Murray, where he investigated fracturing and what the relation of pore space and permeability might be. I didn't -- now Mr. Murray made this study about the same time I made mine. I didn't know about it until years later.

But it's interesting that he comes up with about the same conclusion that I do.

You can see on page -- on the fourth gray page that's entitled page 60 of this article, he goes into a rigorous treatment of how a formation might flex and he even goes so far as to take the radius of the flexure and comes up with a triangular shape fracture and gives it rigorous mathematical treatment, the end result of which is that he comes up with that the porosity is a function of the cube root of the permeability, the same as I do.

Q All right, Mr. Greer, now I'd like to direct you to the information contained behind Tab B, and as you recall, Mr. Hueni discounted interference data on Friday, that had been obtained from an interference test.

Could you briefly initially state what Mr. Hueni's conclusions were?

A Yes, sir. I'll read the first three items here.

It's clear from Mr. Hueni's response that he didn't understand what we were doing in Canada Ojitos Unit because he made three statements.

He said:

1. Interference testing can only show informtion about the formation between the test wells, and

is complicated with fracturing.

2. The EI straight line solution does not apply to a heterogeneous reservoir.

3. The best way to determine the reservoir characteristics is from individual well pressure build up tests.

Q Now are these statements correct?

A No, sir, they're all incorrect.

Q Why were interference tests actually needed out in the Canada Ojitos Unit?

A Well, the very reasons that we needed it was because of the heterogeneous type reservoir. That's why we designed the test in the first place. So, as I indicated, Mr. Hueni just didn't understand.

As to item 2 where he says the EI straight line solution does not apply to heterogeneous reservoir, he's using it, of course, in his analysis in Gavilan. When you use the Horner plot, that's nothing but the EI formula in its most pure form.

I really need to read these last two paragraphs here.

We note that heterogeneity of the formation, whose <u>average</u> characteristics could not be determined from well testing, made need for the interference tests. A reservoir substantially larger thant he drilled area was indicated from some of the pressure testing; and the unit operator required more information about the reservoir so that an orderly and informed development plan could be implemented.

One option was pressure maintenance by gas injection, and a question here was the degree of anticipated gas channeling; the answer to which turned on the level of transmissibility (Kh), not of the "tight blocks" in which the wells were completed, but of the reservoir average.

Interference testing was decided on since it was the only method, then and now, available to determine the necessary characteristics of this fractured reservoir rock.

And I point out here, Mr. Chairman, the example I mentioned earlier in my direct testimony a well that we drilled made 60 barrels a day natural. We sidetracked it 100 feet and made nothing. It would make no difference how you cored or logged those two points 100 feet part; one shows productivity, one shows nothing. There's no way that cores and logs can tell the engineer what he needs to know about this reservoir.

As set out in our direct testimony, the stratified reservoir of the Gavilan presents problems in interference testing, as well as for the individual well pressure build-up surveys, but the Canada Ojitos Unit 1965 and 1968 interference tests were of only one zone and were thus not affected by this complication.

Q Mr. Greer, what response do you have to the assertion that interference testing can only show information between test wells and is complicated by fracturing?

A Well, although most interference tests are just conducted for relatively short times, and they're -- they're necessarily short because of delayed production, the lost income, and also the diffusivity constants are ordinarily low in these reservoirs, and in a sand reservoir, a fairly homogeneous reservoir, you can take a build-up test, determine the Kh, the transmissibility of the formation, then with a short interference test just determine the drawdown and the effect and you can calculate what you need to know, mainly the pore space of the reservoir.

In this reservoir you just can't do that. The individual well tests vary like on an order from 20 to 1, from 200 Darcy feet to 4 or 5, 4 or 5 Darcy feet.

So there is no way that we could average -- average these characteristics and determine what we needed to know.

Now, I'd like to point out how we can determine what we need to determine. Here we have some wells fairly close together, half a mile, a mile apart. We know there's a big reservoir extends beyond it with no wells in it. How do we determine something about the average characteristics of this bigger reservoir?

And we do that by comparing the EI solution, exponential integral solution and, Mr. Chairman, that's a solution to the diffusivity equation, which is based on a point source, just a single point. We use it for wellbores that have a finite diameter but it's relatively small and doesn't check the calculation overall.

When we get to a larger, a larger wellbore, an induced fracture or such as that, then we have to take into account other things.

How do we determine, then, what -- what effect might a large fracture, induced fracture, in your test well, what effect might that have on your interference tests if you used the EI solution, the point source solution?

Well, to determine that we make a comparison and that comparison is that we take two wells, an interference test well, a producing well, an observation well, and I'd like to refer with respect to how this is calculated by going to the blue sheet and look at what happens when a well is put on production in a reservoir, a closed reservoir.

On the upper graph we show that at, for

instance, in two days, that's the first line, the well 2000 feet from the producing well would show a pressure drawdown of about 12 pounds.

One 4000 feet away would be about 5 pounds; 8000 feet away about 1 pound.

After about 15 days the influence of the producing well is clear out to the five mile radius and effects begin to show up out there.

We see down on the lower graph, then, how these lines plot on a semilog graph in order to apply the EI solution to determine the transmissibility, and we see that the well at 2000 feet has a straight line from about one day up to 30 days; for the 4000 foot radius it's a shorter time, about 7 days to 30 days.

But those wells, then in that range, Mr. Chairman, we could use to determine the characteristics we need to know.

Then on the next sheet we see how this all works out.

We show here a reservoir 5 miles in -- 5-1/2 miles in diameter, a shut-in observation well and producing well in the center, and if you have a homogeneous reservoir, no complications, the production and the pressures through the reservoir would be about as shown on the blue sheet.

Now, what if we have complications inside the reservoir between the red dot and the observation well, a large fracture, or whatever, and so to make that comparison, Mr. Chairman, I just assume that we expand the wellbore radius all the way out to that interference test well; just make it no formation. Now Mr. Hueni says interference testing shows only information between the two wells.

So we take an example where we remove the (unclear). There is no formation. It's a wellbore that's 2000 feet in diameter. It has infinitesimal volume but infinite conductivity. And so we make the comparison there. What would happen? What would be the difference, then, in the pressures in this interference test well if we had formation all the way to the observation well or if we had no formation, nothing there, what would the difference be?

Well, we can make that calculation. Muskat has shown us how to do that, and that's shown upon the brown pages. The second -- the first page shows the text; the second page the relation. My pencil notes at the bottom have no significance here; they're just converting to oilfield units. On the third brown page we have the graph and the same data converted to oilfield units.

Then on the pink sheet we show the comparison, the comparison of the EI formula with this larger internal radius, and to see how much error, how much effect there would be, then, if we when we made this test instead of having a formation between a producing well and the interference test well, there was nothing there, nothing, and we find that they're very nearly the same.

It needs to be clear, Mr. Chairman, that I'm not saying that it should pull the pressure down in this large wellbore radius, that this would be the same. What I'm saying is you take the same volume of oil from the well with the entire formation present or you take the volume of oil from a well with no formation present, and this is what you get.

Now, if you make a calculation within one or two days you'll have maybe 100 percent error but you carry it on out to ten or twenty days and you find that your error is only 15, 20, 30 percent at the most, and so what this means, Mr. Chairman, is that the kind of an interference test which we ran in Canada Ojitos, which was designed to determine the characteristics of the formation beyond the distance between the two wells, this is what we would have found. We would have been in error but not very much.

Now, we fraced the producing well, but that was of not consequence. What we have in Canado Ojitos is a system, a high capacity fracture system surrounding tight blocks in which wells are completed. There's probably many a flow down the -- down the channels, down the fractures, but overall, overall a system like a jigsaw puzzle, the channels concentrate toward the producing well, and results in a radial flow solution being a reasonable approach to the calculations of the oil in place.

Q How did this compare to Mr. Hueni's characterization of the reservoir?

A Well, Mr. Hueni says that you can't -- can't calculate it, and, of course, he didn't realize the kind of a test that we made.

The next thing is if it's not a homogeneous reservoir, he says the EI solution won't apply.

Well, whether it's -- whether it will apply or not, Mr. Chairman, depends on whether the tight blocks, the tight parts of the reservoir, whether there is a rate of diffusion fast enough for those tight blocks to make their volumes known to the system as you produce, and we determine that, Mr. Chairman, by -- as shown on the brown graph under Section C.

One of the -- one of the wells that we used, one of the observation wells that we used, had a transmissibility of .02 Darcy feet. We come over to the graph which we've shown before which shows oil in place versus transmissibility, we come up from .02 Darcy feet to the circles and we see there that it has a ratio of permeability to porosity of about 0.4.

Then we go to the next graph, the white graph with the green stripe across it, and we find that for a ratio of permeability to porosity of 0.4 and the saturation situation that existed, compressibility in Canada Ojitos at that time, that we're looking at a diffusivity constant data of about 2 times 10 to the fifth, and then we got to the yellow graph and all this yellow graph is is a solution to the diffusivity constant, to save you having to calculate it, and find the 2 times 10 to the fifth line, which is shown here, the tight block in which this observation well was completed was roughly 40 acres, which would have at best something like 600 feet dimensions. So we come over to 600 feet. At this diffusivity constant we find that it would have equalized in about 0.6 of a day, and so -- not equalized, but we would have -- that would be the time required to reach steady state conditions for it to make -- the oil in the tight block to make itself known to the system.

Now that is depending on a diffusivity constant where the source is in the center and the trenches flow outward.

In this instance we have a block surrounded by the high capacity system that flows the other way; it's much faster, I would estimate, by three or four hours.

So it's just how -- how practical, how true is this?

Well, we found out. We ran an interference test. Within 24 hours the well completed in this tight block had shown the production or the pressure drop which later when we made the calculations for the field as a whole prove out to be true, and that was a mile, it was a mile away from the -- from the producing well.

So there's no question, Mr. Chairman, the interference testing which we did is reasonable. There's no way to get the perfect, exact answer to these reservoirs, but it supports our other information that the porosity of the formation probably varies something like on the order of the cube root of the ratio of productivity to permeability. As such it supports our application, that if we apply that formula to the average production rate of 130 barrels a day in the field, that 200 barrels a day is a reasonable maximum top allowable that this Commission should set.

MR. CARR: Now, Mr. Stamets, we have one additional exhibit but we'd like to take about a five minute break, a short recess.

So far we have used an hour and 22 minutes.

MR. STAMETS: Okay, we'll take a fifteen minute break.

(Thereupon a recess was taken.)

Q Mr. Greer, at this time I direct your attention to Benson-Montin-Greer Drilling Corporation Exhibit Eight, and at this time I will let you testify about the two porosity system and core information.

I would ask you to refer to the document contained behind Exhibit Tab A and identify that, please.

A Yes, sir. I would like to talk about briefly here, Mr. Chairman, that we've had some discussion about there may be a two porosity system here in fractures and perhaps matrix porosity, and so we look at some of the generally accepted theories of fractured reservoirs.

This is -- one of the more recent treatises on this subject is one by Mr. Nelson shown here in the first page.

Following that --

MR. STAMETS: I'm sorry. Is this the --

MR. CARR: Yes, this is the black exhibit, in the black binder.

A Looking now at the second page under Tab A, and we note that in his analysis of naturally fractured reservoirs, he shows fracture spacing running a tenth of a centimeter up to 1000 centimeters. The maximum that he deals with is a spacing of 1000 centimeters, which is approximately 30 feet, and so what we want to do is look at how long it takes for -- for oil in a matrix in a reservoir that's naturally fractured, how long does it take for that oil to make itself known into the fracture system and make its contribution, and so we look here at the 30 foot spacing as being a probably maximum for an ordinarily fractured reservoir.

Then we go to Tab B to see how long it takes for these pressure transients to take place, and we refer here to one of the exhibits which we presented twenty years ago in covering this pool, and if you'll look on the second sheet that has a vertical pink line, we look at a sandstone of 10 millidarcies permeability and we see that it's, in the yellow colored range, that it's ratio of permeability to porosity will run from about .04 to 0.1.

And then on the next page with the vertical green column we find here for that range of ratio of permeability to porosity of .04 to 0.1, and then go up vertically to -- to the compressibility, which would represent the -- probably the slowest rate of diffusion, which would be for saturated oil in the Gavilan area, and we find a diffusivity constant ranging from about 2 to 4 times 10 cubed.

And taking that information we go to the next graph, which is simply a graphical calculation, of course, of the diffusivity constant, and the blue stripe shows where it would be for this particular sand of 10 millidarcies. And we see down at the bottom that for a distance of 30 feet, that's a very bottom line, and the time that it would take for -- to reach steady state conditions in a sand of 10 millidarcies, about a tenth of a day for a 30 feet distance. Now, for this, if the fractures are 30 feet apart, they're really only 15 feet between them, and so it would be much shorter time required to do that.

Now this is for a 10 millidarcy sand, 10 to 20 percent porosity.

Now if you have a one millidarcy sand and one percent porosity, the time is the same. We can tell that by the diffusivity constant shown at the bottom right-hand side, it depends on the ratio, and so the ratio of 10 to 10 is the same as the ratio of one to one.

So if we had a one millidarcy sand and one percent porosity, we'd still be looking at the same blue line.

Now if you have 0.1 of a millidarcy permeability, then it takes ten times as long, and so instead of 0.1 of a day it would be maybe a day and then for .01 of a millidarcy, then that would be 100 times as long, maybe 100 days, or that would be 10 days, 10 days.

So we're really looking at fairly short

times, Mr. Chairman, for the matrix, if there is a matrix, to make itself known if there exists a naturally fractured reservoir, which there's no question the Gavilan is naturally fractured. How close are the fractures? We don't know. Mesa Grande's people in their presentation in viewing fractures which they see by the frac finder logs and wells, have found fractures in every well that they -- that they looked at and there's a six inch diameter piece of the reservoir several miles apart, there's probably quite a few fractures.

It's reasonable to believe that if there's a matrix porosity that it's contributing, it's making itself know to part of the reservoir presssures, and it's not lurking back there to be produced at some future time.

Q Now, Mr. Greer, if there is contribution from the matrix, (not clearly understood) this question, does that change your concern about what's happening to this reservoir at this time?

A No, sir, it's still in trouble.

Q Would you now go to Tab C and identify the documents contained behind that tab?

A I just want to look briefly at some of the pressure build-up tests and drawdown tests and what they show and whether we're dealing with a two porosity system, and one of the better known authors in this regard, or two of them, are Warren and Root. They've shown by the first sheet under the green -- under the blue tab, is the green shaded language says, that "Since the build-up curve associated with this type of porous system is similar to that obtained from a stratified reservoir, an unambiguous interpretation is not possible without additional information."

What that means is, Mr. Chairman, you get a pressure build-up that looks like it might be a two porosity system, it could just as well be a stratified reservoir.

In Gavilan, with the formations being separated as I know them to be, the chances are that it's going be the reflection of a stratified reservoir rather than two porosity system.

Now we go to the next pages which describe some of the methods that are being used to make this evaluation. The white sheet gives an overview of Aguilera by Pollard's method.

Then on the gold colored sheet we see Warren and Root, how their -- their model is shown in the upper lefthand square.

Then on the pink sheet we see a build-up curve from Warren and Root's theory and we note there the straight line where it says omega equals 1, and that -- those numbers there, 1, 0.1, 0.01, 0.001, is the ratio of matrix to -- or fracture to matrix reservoir. If there's all fractures you have a straight line all the way up. If there's matrix contribution, then we have these parallel lines that come in depending upon what percent is what, and that's where the parallel line build-up comes from.

Then Kazemi has a different model. He shows kind of a pancake effect and makes a calculation which he says is better than the Warren and Root's.

And then on the blue colored sheet we come over and we see a comparison of Kasemi's model and Warren and Root's model, and the significant thing here is that they're fairly close together and -- but more important for this particular case, which deals with a low permeability system, they show that the transient effect wipes out in about ten hours and so generally, Mr. Chairman, when we're thinking of a two porosity system and we see it on logs, if it's really there, the matrix is, as we indicated before, is probably contributing and making itself known.

Q Now, if you'd go to Section D, I'd ask you to compare log porosity with that that you can ascertain from core analysis.

A This is the information mentioned in our direct testimony which Mallon received from CORE Lab on their analysis of this curve, in which they feel that the log porosity does not reflect core porosity.

We understand now that Mobil has - has a way of calculating porosity and eliminate these problems, and of course, if so, we are proud of that advancement. I may have to change my way of describing the problem here, that this formation fools just some of the people all of the time and all of the people just some of the time except Mobil it doesn't fool on the core analysis (unclear) the log analysis.

Q Mr. Greer, let's go to Tab E, if you would.

A Tab E is a copy of the core analysis that Mobil provided our engineering committee, or provided one of the members and was given to the engineering committees, and I've referred to that in some calculations that I have following.

Mr. Chairman, the problems that we found with cores in this formation is that conventional core analysis are just not reliable and I know that Mobil's witness, and we're indebted to Mobil for going to the cost and trouble to core the well and get the information and try to help evaluate this reservoir, and Mobil's witnesses say that they used generally accepted industry standards for core analysis, but generally accepted industry standards just doesn't take care of this formation.

We found out the hard way years ago that we've got to do something different.

Here, in order to try to analyze and see really -- really does this low porosity -- we're talking about very low porosity and Mobil's engineer says like we have a 1.9 percent porosity with a cutoff of one percent, and just on the face of it, Mr. Chairman, that's slicing the loaf awfully thin. There just is not much room in there for error and there might be some errord.

What I've done on the yellow colored sheets is just a rough first look at the core analyses and does it seem like it's reasonable, and the way I approached this is I assumed that when this core is taken, ahead of the core head there's some flushing action and it flushes the formation a little bit ahead of it. How much does it flush? Well, we just make a guesstimate, maybe 10 percent, flushes 10 percent. Sometimes that's a reasonable amount.

Now, what happens then? So let's say that it flushed 10 percent of the oil out of the -- out of the pore space. The core then is brought to the surface. As it comes to the surface the oil by solution gas drive expands, drives out the -- first this flush water that came in and then follows it by it's solution gas drive recovery, and in round numbers, if it produces like it should, we ought to have like a 20 percent production to atmospheric pressure.

So we calculate that and we start off by taking the water saturation shown in column four, deduct that from the 100 in column five, we get the initial oil in place, less the flush in column six, less the production in column seven. Then we take column seven and convert it to stock tank barrels by dividing by the formation volume factor, which gives us number eight, and so by subtracting column three from column eight, then we have an idea of -- of how much oil has produced and it should be, we should have zero in that righthand column, if it's the way we figured, 10 percent flush, 20 percent production.

Well, we've got a lot of negative numbers over there. That gives me some concern. Maybe -- maybe we're not flushing the core.

So we make the next calculation on the green sheets and we assume there's no flush. It's zero flush and we take our production, and still we find some negative numbers, and so I'm still concerned.

I go to the white colored sheets and then we assume neither flushing nor production. We just calculate what the production really is and by that we just take the oil that was in place originally and deduct from that what's left, and then in the righthand column we see what was produced, and this is just, Mr. Chairman, it's just like taking a small sample of the reservoir, bringing it to the surface. It's produces what's the recovery factor, and then these blue shaded lines, they're recoveries less than 20 percent. If you're going to get a 20 percent recovery from a sand down in the reservoir, for certain you're going to get 20 percent recovery when you bring it up to the surface, because all the oil certainly had to come out of it.

So we get some pretty small numbers. If they're less than 20 percent I consider them suspect, and there's a lot of blue shaded lines.

If they're more than 40 percent, they're suspect the other way and for instance, let's see, one of the red lines, well, there's 100 percent on sample number 25. It shows 100 percent, the red shading. We look over and it shows the saturation that will bring the core out is is zero and, of course, there we -- something really must be wrong and perhaps the oil was entirely flushed from the core; maybe it was a fracture, and I think maybe that was indicated that way. Maybe all that porosity is fracture porosity.

And I know that Mobil throughout most of threw out most of the fracture -- the core analyses that indicated fractures.

But when you get through with it there's lots of pink lines, lots of blue lines. There's lots of question in my mind, Mr. Chairman, whether there might be something wrong with the coring or with the analyses and I would think that there's a possibility that there's something wrong with the analyses.

So we go to Section G and we plot water saturation versus permeability and it's hard, of course, to tell whether there's any really direction to these lines or not but there are certainly concentrations of the points down around 30 percent porosity and .01 or less millidarcies and we wonder, is this characteristic of sand, sant reservoirs, and for comparison we look at a couple of fairly clean sand reservoirs on the blue sheet, permeability to porosity, and these -- this information, Mr. Chairman, is in the technical literature. It's available to anyone.

The solid lines represent the measured amounts; the dashed lines are extrapolations, and we can see when you get below 0.1 of a millidarcy that the water saturation in most sands increases pretty rapidly.

For the Elk Basin extrapolation it would be up to 100 percent water saturation at 0.1 of a millidarcy.

Then on the pink sheet we compare what we've found from Mobil 4 with this -- these two reservoirs, and we find that it doesn't parallel, it doesn't track the -- the other information, and, Mr. Chairman, ordinarily if we'd had time we would have asked the Mobil people had they done certain things. Had they run analyses to determine the irreducable water saturation? Had they done things that we don't know. They may have a lot of information that we don't know about, but from what we've seen, I have concerns. I have concerns as to whether this is -- really represents what's in the reservoir, and you can see some of my concerns if we look under Section H.

This shows a number of wells that we cored about 15 years ago, had analysed by conventional analyses, and you can see on the first blue sheet how high these porosities run, 5, 6, 7 percent.

On the pink sheet we get the same thing; up as high as 8 or 9 percent, and we go to the yellow sheet and we have the same thing, 7, 8, 9 percent porosity for this shale, and we follow all the way over on the yellow sheets and on the last of the yellow sheets we show some hole core analyses. We were interested -- oh, I'm sorry, it's not the last two, it's the, let's see, one, two, three, four, five, six, the seventh and eighth yellow sheets from the back, and here we have some hole core analyses and we were trying to determine, Mr. Chairman, if there's some way to measure the volume of the tiny fractures, the hairline fractures, the micro-fractures.

So we went to the trouble of doing a hole core analysis and we find the same thing, high, high porosi ties.

The the next following yellow sheets are the core description where we were looking for fractures; how we -- how we tried to identify them.

The last yellow sheets shows where we fraced this particular well. It shows the high porosities, high with respect to Mobil 4, and we treated the well with 200,000 pounds of 20/40 sand, 26,000 pounds of 10/20 sand, 3400 barrels of crude oil. We gave it a fair treatment, a reasonable treatment to test the formation.

This well and the others that were cored here showed capacities after completion and recovery of load oil of like 4 or 5 barrels a day, something entirely noncommercial.

So we knew that something was wrong. With these high porosities we should have gotten something out of them. So we checked back with CORE Lab and we found then, and I don't know just how they are recently, but at that time they assumed that we knew more about the formation than they did, and when we ordered a conventional analysis, we got a conventional analysis, and conventional analysis, where they retort the samples cooks out the kerogen and the water hydration, and so what we were measuring was not the effective hydrocarbon porosity but the sum of the fluids of water and kerogen and such as that, that was in the shale.

Now in the Mobil's core, the conventional anaylses now, they've learned, I guess, that even though most operators know more about it than they do, that they still recommend that they measure the porosity a litte different, so they measure it by what they call the so-called Boyle's Laws method.

And so they get, hopefully, a better porosity and we find then these low porosities that Mobil comes up with, real, real low, 1, 2, 3 percent porosities. They probably are more accurate, but just how accurate there's still a question in my mind, Mr. Chairman.

We see how the saturations don't check. They're still a conventional analysis. They take a sample of the formation and they retort it. They took out the kerogen, the water hydration, along with the -- along with the movable oil, and then they got a problem of how they match all that and come up with the -- with the saturation, so we really don't know whether there is oil in -- in this matrix in this real, low porosity that might actually contribute to production. There's just a real serious doubt in my mind. There's a possibility that it's full of water that this won't move.

In addition that, Mr. Chairman, and I don't know whether this can be accepted as hearsay evidence, we understood a geologist, looking at the core, not having time to -- to cross examine Mobil to ask them about this, all I can do is pass on what I understand, and that is that the core was laminated; that there was like -- 4/5ths of the core was shale, and about 1/5 of it was sand.

Now whether the engineer knew this, whether it's true or not, I can't say definitely, but I have an idea that it probably is true because that's the kind of thing that we found other places.

If so, in the 50 feet of net sand that Mobil's engineer uses might only be 10 feet, and so if it is, it certainly is not going to contribute much to the production, and in addition to that, Mobil's engineer used arithmetic average of permeability. We didn't get a chance to ask him how that compared with the geometric average, but we know that in cases where wells have been tested and compared core analyses permeability with -- with a build-up test permeability, that a geometric average of the permeabilities fits the situation better, and in that instance, then, there is substantially less permeability than -- existing than what the Mobil engineer used.

So I have all these questions in my mind as to whether the matrix, even with Mobil's core, is contributing anything in this area.

Q Were Exhibits Six, Seven, and Eight prepared by you?

A Yes, sir.

MR. CARR: At this time we would offer into evidence Benson-Montin-Greer Exhibits Six, Seven, and Eight.

MR. PADILLA: Mr. Chairman, I would ask that (inaubible) concerning the Mobil core inasmuch as it is purely speculative.

MR. CARR: Mr. Greer has been qualified as an expert witness in petroleum engineering. He advised you of what he was relying on. I think this testimony should be admitted and you can give it whatever weight you feel is appropriate.

MR. STAMETS: Mr. Greer identified it as hearsay and the Commission will take it as hearsay and give it that degree of weight.

MR. LOPEZ: I would also call the Commission's attention to the fact that the Mobil witnesses aren't here and aren't subject to cross examination and Mr. Greer and his counsel have had ample opportunity (unclear.)

MR. CARR: As does Mr. Lopez. If he would like to talk to him about that I'm certain Mr. Greer would do that also, Mr. Chairman.

I have some additional examination of Mr. Greer, with your permission.

MR. STAMETS: (Not heard clearly.)

Q Mr. Greer, what conclusions have you reached about Mr. Hueni's analysis of this reservoir?

A Well, it's been reached through erroneous data, interpretation of anomalies that were not there. His -- his whole case rests on things that were not facts and he's come up with a theory of vertical segregation, gas going up, oil going down, and it doesn't fit what's been found in the field with respect to -- to the stratified nature of this reservoir.

And it just is not that way, Mr. Chairman, it just is not that way.

Q Now, Mr. Greer, Mr. Hueni recommended a certain reduction in the gas/oil ratio. In your opinion will a reduction of the gas/oil ratio alone maximize the potential of increasing ultimate recovery in the Gavilan-Mancos formation from gravity drainage?

A No, sir.

Q If the Oil Conservation Commission should accept Mr. Hueni's reservoir interpretation, and particularly the vertical segregation which he has testified to, what do you believe the Oil Conservation Commission must do if in fact it's to carry out its duties to prevent waste and protect correlative rights?

A Mr. Chairman, if the Commission really believes that this fantastic theory of Mr. Hueni's is credible, that there exists this tremendous vertical communication, then the reservoir has a potential not of solution gas drive recovery, but of gravity drainage recovery, which is some ten times the solution gas drive recovery.

In that instance, Mr. Chairman, the Commission, I feel, to carry out its responsibilities and obligations, would be obliged to require all the operators to seal off the A, B, and C zones in this pool and perforate only the bottom of the reservoir and produce the bottom part in order to achieve this gravity drainage potential.

I realize one of the arguments might be composed of, well, you couldn't get enough productivity if you do that, but all the wells are limited by 50 to 100 perforations in the pipe now where they attempt to get limited entry. They could seal off those perforations, put another 50 or 100 in the bottom and if this tremendous boiling of the reservoir up and down, as Mr. Hueni suggests is really taking place, then this would be the proper action of the Commission to assure the maximum recovery from the reservoir.

Q If Mr. Hueni's proposal is accepted, what effect would that have on waste and correlative rights?

A They would continue; the problems which we identified earlier would continue. Correlative rights, an operator would not have opportunity to protect his correlative rights. The big wells take all the oil.

There would be a loss of the oil which I think is recoverable from gravity drainage, not straight down, but along the dip of the formation, and there would be a number of unnecessary wellsd drilled and resulting waste occur.

Q If the Commission is to act to protect correlative rights and prevent waste, what is your recommendation?

A That they immediately reduce the allowable to 200 barrels a day and place a practical gas/oil ratio limit of 1000 cubic feet a barrel.

Q Do you have anything further to add to your testimony?

A No, sir.

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

I'd like the record to show that we have used 1 hour and 50 minutes of our time.

MR. STAMETS: Thank you, Mr. Carr. I'm going to ask Mr. Greer just two or three questions and then I think we'll move on. I presume you have another witness?

MR. KELLAHIN: Yes, sir, we do.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Greer, did I understand you to say that you believe that the solution gas oil ratio in the Gavilan-Mancos Pool was 480 cubic feet per barrel?

A Yes, sir.

Q And that's a lower number than I remember hearing any place else in the testimony.

A I believe, Mr. Chairman, it's in McHugh's Exhibit -- let's see if I can find the right one.

Maybe it was Dugan's exhibit, Dugan's Exhibit -- well, McHugh's Exhibit Number Three, under Tab D, the lower line is 480 cubic feet a barrel; the upper line 588, and McHugh recognizes that these are the numbers to be considered.

Q So it is your opinion that the lower number is more accurate?

A Yes, sir.

Q Refresh my memory, what did you testify was the bubble point pressure, really, in this case?

A For Gavilan?

Q Yes.

A I came up with a range, I believe, between 1535 or 40 and 1575 or 80; somewhere in that range.

It's written in one of our exhibits.

MR. STAMETS: We'll excuse Mr. Greer. He'll be available for cross examination later.

Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

At this time we would call Mr. John Roe back to the stand and would like the record to reflect that Mr. Roe has been previously qualified as an expert petroleum engineer and he has been sworn and he's still under oath.

JOHN ROE,

being called upon to testify and having been previously sworn, remains under oath and testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Roe, I'd like to direct your attention to the package of exhibits I have passed out in the hearing room and specifically ask you to identify what is offered as Dugan Production Corporation Exhibit Number Three.

Would you identify that for us, please?

A Yes, sir. Exhibit Number Three is a presentation of the current production and/or my estimate of the potential production for every well, all 59 wells that have been drilled and completed and are ready for production in the Gavilan-Mancos Pool area, plus information on one well that's drilling and 13 locations for the nine different operators that are active in the Gavilan-Mancos Pool area.

In addition we've included the data, production data on four Canada Ojitos Unit wells that have been completed and one that is currently in the completion process.

I will point out that the left portion, the 13 columns on this graph, were presented initially in my testimony on August 8th as Dugan Production Exhibit Number One.

Q Is this exhibit identical to Dugan Production Corporation Exhibit Number One with the exception of the additional information on the far right of the exhibit?

A That is correct. The information on the far right was addeds to Dugan Production Corporation Exhibit Number One at the request of the Commission in order to present the effect on individual operators and individual wells that the imposition of a GOR restriction only, leaving the current allowable as is.

Q Mr. Stamets just asked Mr. Greer a question about the solution gas/oil ratio Mr. Greer had used in the Canada Ojitos Unit.

You have testified earlier that the solution gas/oil ratio that you used or determined applied to the Gavilan-Mancos Pool was the 588 cubic feet of gas to 1 barrel of oil.

Would you explain to us why you have utilized the 588 number as a solution gas/oil ratio?

A Yes, sir. I am aware of Mr. Greer's PVT data and up until PVT data was available from well in the Gavilan-Mancos Pool, which is McHugh's Loddy No. 1, we were using PVT data that was available from the Canado Ojitos Unit.

Basically, as a result of our study group, engineering study group subcommittee studying this pool, we have agreed that it probably would be more appropriate to utilize PVT data from a well in the Gavilan-Mancos Pool area if we had confidence in that data and I personally have confidence in the data that we obtained in the fluid sample from the Loddy No. 1, which is where the 588 comes from.

Q You heard the testimony on Friday, Mr. Roe, by Mr. Pomeroy with regards to his tabulation and his comments with regards to the apparent effect the various suggested restrictions would have on various interest owners.

Do you have an opinion, Mr. Roe, as to whether your presentation, Exhibit Number Three, is a more accurate and reliable presentation of the effect on the operators of the various proposed reductions in producing and gas/oil ratio (unclear)?

A Yes, I have an opinion.

Q What is that opinion?

A I believe that upon reviewing Koch's Exhibits Number Four and Five that there's a good chance that there is an impression given that Dugan Production and Jerome P. McHugh have some hidden benefits in asking the Commission to restrict the gas/oil ratio and oil production rate.

On Koch's exhibit it indicates that McHugh and Dugan both recognize the largest percentage increases after allowables are restricted as proposed.

There -- there are some misleading calculations there. It's my feeling that the real impact upon individual wells or individual operators is more properly presented in my Exhibit One initially, as revised and presented in Dugan Production Exhibit Three.

The main problem that I see in Koch's presentation was that by comparing April to June and then contrasting the percentage change between April and June's production for each operator, and then also contrasting the reduced production rates with April's rate, if you're unaware that during this April to June time framed operators were putting additional wells on production, which is the case for Dugan Production and McHugh, plus two other operators, Mobil and Mesa Grande, the actual oil, increase in oil production that occurred between April and June, appears as a positive benefit that could easily be misunderstood that this is simply a positive thing that resulted because of our proposed application.

For instance, Dugan Production rates during April of 1986 averaged 25 barrels of oil per day. This was from two wells that we were operating. During May we placed the Tapacitos 4 on production and during June our production from the Tapacitos 4 alone averaged 153 barrels a day.

Our company production during June was 188 barrels a day, and so a large part of the 430 percent that was shown as a change in production is simply because Dugan put one well on; McHugh put ten wells on production during this period of time. Also not reflected on Koch's exhibit was the fact that Mobil put all three of their wells on production between April and May, resulting in a production during June of 388 barrels of oil per day for them, which basically is an infinite increase if we use this same line of thinking.

Mesa Grande putting their four wells on production during this time periodd resulted in an increase in production from them from a daily average in April of 399 barrels a day to an average of 725 barrels a day in June.

Now the numbers that I just quoted are different from what was presented on Koch's numbers. Koch basically reflected a very small increase in production for Mesa Grande between April and June.

Q Mr. Roe, let's turn to page four of Exhibit Number Three and if you'll look at the middle of the tabulation where it says total Gavilan Pool area, and as you read from left to right, if you'll find that portion of the exhibit that refers to the June '86 production, the reservoir barrels of voidage a day, the 26,000 barrel number, and then go over and look at the proposed allowable reduction under the McHugh proposal of approximately 14,000 reservoir barrels a day, and then finally, under the sensitivity case that was used in Mesa Grande's proposal of only the solution gas/oil ratio, the 21.5 number.

Having directed your attention to that portion of the exhibit, Mr. Roe, can you explain to us what the significance is of the tabulation in terms of what you're trying to accomplish with the proposed reduction in the producing rate to 200 barrels a day and the gas/oil ratio down to 1000-to-1?

A Yes, sir. As we've indicated there, and I might just clarify now what I show under June '86 production and/or potential reflects actual production based upon June's production as reported to the Commission and for wells that had -- had no production during June but were completed and ready to produce, which we have approximately 16 of those wells, I have estimated, based upon production test data that's available, or maybe a well produced -- did not produce in June for some other reason; it was maybe shut-in for lack of a gas market or problems with their gas contract, but the 8188 barrels that I show as being June's production, it's comprised of 2117 barrels of estimated production from wells that we really have shut-in and to date we have not seen the production, the impact upon the reservoir from production from those wells.

It also includes 6071 barrels, which is an actual per producing day average from wells that did produce in June.

Q What's the rationale behind the proposed McHugh reduction in producing rate and gas/oil ratio?

A The -- what we were trying to obtain is recognizing the fact that during June we have right now wells completed that could cause a reservoir voidage of approximately 26,000 barrels a day. We recognize -- and that voidage is causing a rate of pressure decline in the reservoir that is -- that we're uncomfortable with. We feel a need to study the reservoir to be sure there is not a different method to develop and produce the reservoir than we're currently operating under. Right now we think there's a good chance there is.

So recognizing that we currently have potential for 26,000 barrels a day, we're unhappy with the rate of pressure decline. We feel that the rate of pressure decline needs to be slowed down to some lower rate, and we have chosen an oil rate and gas/oil ratio that is -- we feel to be practical considering that the reservoir has been on production, the gas/oil ratio has increased. Our intentions were to buy some time with the reduction but still maintain a production level that hopefully wouldn't cause undue economic hardship on operators in the pool.

Q If the Commission adopts Mr. McHugh's proposal and reduces reservoir voidage to 14,000 barrels a day, what period of production time does that relate to or correspond to?

A This is a production level that existed in March and April of this year, which is about the time we started formulating our plans and trying to get something moving with regards to studying the reservoir.

Q Let me direct your attention now, Mr. Roe, to Dugan Production Corporation Exhibit Number Four, which is the colored bar graph following the last exhibit.

Before we discuss your interpretation of the exhibit, would you take a moment and orient us as to how the exhibit is prepared and what you're attempting to depict?

A Yes, sir. The purpose of making this exhibit, and this exhibit consists of five pages, the first page is really the only page we'll talk about, the information presented on the last four pages is simply the tabular data that supports each individual sensitivity case that we considered. It's presented in the same manner by well by operator as was the Exhibit Three that we just discussed.

For ease in comparison of one case versus another case, we've presented the top page of Exhibit Four. We've identified each case that we're -- we have presented at the bottom. For instance, the leftmost case, which I've got a red arrow under, that is what we showed to be June '86 actual and/or potential production. It was presented on Exhibit One and again on Exhibit Number Three.

I've chosen the four largest companies which would be McHugh, Mesa Grande, Mallon Oil, and Meridian, and I've identified those in color code, yellow, orange, green, and blue, and I've been consistent across the graph. So the comparison of each operator's share of the production under any one scenario is -- is hopefully a little easier as far as just a visual comparison.

Q On the graph on the far left there are some horizontal red lines approximately 9000 and then it continues up and there's two more lines, what's the significance of those lines?

A Okay. Those -- those are the approximate reservoir voidages that existed in January, as Mr. Kellahin said, that the first, the bottom line is 9306 reservoir barrels a day. Now this reflects the actual, not any potential, this is the actual pool production that did occur during January '86, and it corresponds, I've indicated on the righthand portion of the -- of Exhibit Four, it corresponds to a daily rate of 4234 stock tank barrels a day and 4435 MCF a day and this did come from 34 wells.

The next line up is the production voidage, which is approximately 11016 reservoir barrels per day, that did occur during May of 1986.

The uppermost line is the approximate reservoir voidage that actually occurred during June of 1986 and that volume was approximately 17,163 reservoir barrels per day.

So by having the three lines across the page, you get an idea of where each case would relate to the reservoir voidage during January, May, and -- or January, May, and June.

Q If we go to the far right side of the tabulation, the bar graph, and look at the sensitivity test that's based simply on reducing the gas/oil ratio down to 588, in your opinion, Mr. Roe, is that a significant enough decrease in reservoir voidage?

A No, sir, it does not provide the level of voidage that we feel necessary in order to slow the rate of pressure decline. It basically gives us a rate of pressure -- or rate of voidage that is not grossly different. In other words, the total reservoir voidage under that scenario would be a bout 23,700 reservoir barrels per day, which compares to the current potential of 29,000 and a desired level of about somewhere between 11 and 14,000 barrels per day.

Q Do you have an opinion as to whether or not we are being as effective with preserving the reservoir energy if we only reduce the gas/oil ratio to the 588 number as opposed to the proposed McHugh solution?

A Yes. I have an opinion and I feel that if we do not also make an adjustment on the oil rate, as I've indicated with the visual presentation on Exhibit Four or the actual tabular information on Exhibit Three, if we restrict only the gas/oil ratio to 588 and leave the oil at 702, we will still have a reservoir voidage potential of about 24,000 barrels a day.

McHugh's proposal would put the reservoir voidage at a range of about 15,000 reservoir barrels per day.

And again, now, that is going to put us back at a level that we're still not happy with. The reservoir pressure is declining at a rate that's still pretty -- pretty fast, and we don't have a whole lot of time even at that level of reservoir voidage to arrive at a conclusion as should we be doing something different to the reservoir.

Q Let's turn, Mr. Roe, to Exhibit Number Five and have you identify the three pages that compose Exhibit Number Five.

A Okay. Exhibit Number Five, as Mr. Kellahin said, consists of three pages. These are nothing more than a reproduction of a production graph that we keep monthly, plotting monthly production data for Jerome P. McHugh's ET No. 1 on page one; the Janet 2 on page number two; and the Native Son No. 2 on page three.

Q Mr. Hueni, in his testimony last week advised us that he had not utilized production data after the May '86 production information.

In your opinion is there significant production occurring in June and July that would affect the formulation of opinions about the gas/oil ratio?

A Yes, sir. As I indicated on these plots, and I have chosen wells that we are really concerned with, we are starting to see dramatic increases in gas/oil ratio and corresponding decreases in oil rate. A bulk of this is just within the last few months.

Q Would you take one of these as an example and show us what is occurring since May's production?

A Okay. For instance, in the first page of this -- this exhibit would be the ET No. 1. I -- even during May the gas/oil ratio in this particular well was -- was exhibiting an increase that we were not real certain of. That increase became more obvious in June and July and even so far in August it's actually increasing.

Using ET-1 as an example, say, during February our gas/oil ratio was 439 standard cubic feet per barrel.

During July the gas/oil ratio has increased to 6492 standard cubic feet per barrel, and we've had a corresponding drop in oil production from 236 barrels a day at its peak level, which I might add was substantially higher rate than we had obtained from the well before, and I personally feel that this higher rate we observed was primarily a result of us approaching a bubble point in this well, additional free gas becoming available, the well flowing, it probably had the potential for this all along; it's just with the production equipment we had, we just were not seeing the potential until it began to flow with additional gas.

As we approach the bubble point the well began to flow, production increased from 900 to 1000 barrels a month, to 5-or-6000 barrels a month, and that production rate is dropping off as the gas/oil ratio is -- is really going out of sight.

I haven't plotted August data on here but during the first 18 -- first 15 days in August the gas/oil ratio has averaged 10,470 -- 52. It's actually going up every day.

Q Mr. Roe, Mr. Pomeroy testified on Friday and I think he related to his Exhibit Number Ten in his conclusion and said that the McHugh's proposed cut would save only a meaningless few pounds of pressure.

Do you agree with that conclusion?

A No, sir, I do not. Referring back to Koch's Exhibit Number Six, it's my understanding that from Exhibit Six, that meaningless few pounds -- at least Exhibit Six covered a 7-month interval. He was talking about 100 pounds of pressure.

In order to make that forecast it's my understanding that a constant rate of production that existed in June was utilized, and it's also my understanding that -- well, basically a constant rate of production and a rate of pressure decline that was already established in

June, which utilized the forecast in the future.

Q Mr. Pomeroy forecasted over a 7-month period a loss of 100 pounds of pressure, I believe?

A Yes, sir.

Q What in your opinion would be the estimated loss of pressure over the same interval?

A It -- if we make no effort to restrict reservoir voidages that are increasing, it's my opinion that the rate of pressure decline will increase to a level that I have not been able or I cannot calculate, but I would estimate that it would be at lest 150 to 300 pounds of pressure loss during the same 7-month period.

Q In your opinion, Mr. Roe, as a petroleum engineer, is that a meaningless few pounds loss of pressure?

A It is not.

Q What action, Mr. Roe, can the Oil Conservation Commission take to give the working interest owners an opportunity to produce more oil from this reservoir?

A Well, it's my opinion that the Commission must take some action to immediately reduce the rate of reservoir withdrawal, the reservoir voidage, and the reason that this is necessary is to give the operators of the Gavilan-Mancos Pool, buy them some time that they won't have at the existing rates of pressure decline, to evaluate in a more complete manner what should be done with regards to future development of the reservoir and future production operations of the reservoir.

Since conducting our pressure tests or our interference tests in December of '85, we, we being McHugh and Dugan, primarily, but I think probably most of the other operators are -- that are aware of the pressure data are also concerned, that there is a urgent need to arrive at a conclusion as to is there a better way to produce the reservoir and is there a better way to further develop the reservoirs.

It's my feeling that to date we have established in my mind undoubtedly that pressure communication, good pressure communication, exists well to well on a current development pattern.

It also exists throughout the reservoir. I feel this is supported in Dugan Production's Exhibit Number Two presented on August 8th.

In addition to that, I feel that on the existing spacing of 320 acres per well there will be unnecessary wells drilled on a competitive basis. These wells will be required, in order to develop undeveloped acreage, prevent lease expirations, protect correlative rights, and prevent drainage. This also was presented in some detail in Dugan Production's Exhibit Number Two.

I feel that we have information and have enough data to feel gravity drainage potential, or there is potential to recognize some gravity drainage in the Gavilan-Mancos area, and gravity drainage is occurring.

We also, it is my believe, that by allowing continued competitive operations of the reservoir there will be an effort, or there will be waste of natural reservoir energy in the production of higher gas/oil ratio wells, in their efforts to compete for their share of the oil, daily oil production.

MR. KELLAHIN: That concludes my examination of Mr. Roe.

We move the introduction of Exhibits Three, Four, and Five.

MR. STAMETS: Without objection these exhibits will be admitted.

I've got just a couple of questions of Mr. Roe, and then we will see what everybody else wants to do.

MR. KELLAHIN: Mr. Chairman, my timekeeper here tells me we've used 2 hours and 18 minutes and we'd like to reserve the balance which we believe is, what, 42 minutes, 42 minutes for a later time.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Roe, there was some discussion about -- a lot of discussion about how this would affect individual operators and they will, some operators would be losing current allowable in production.

Would it be possible at some time ninety days from now to go through there and calculate again how much each operator has lost or gained in comparison to the others between the allowables as they would have been and the allowables as calculated under your proposal, and then to restore balance should that prove to be the correct thing to do?

A The way you asked the question I'd have to answer yes, that's possible.

Q Thank you. The second question is one that I asked a number of folks on the other side last week and they all answered in the negative and I kept thinking I was asking the question wrong.

In this solution gas drive reservoir, if we allow wells to produce at GOR's above the solution gas-oil ratio, you say it's 588, if we allow wells to produce at 1000 or 2000, are we pooping off our reservoir energy and not making the best use of it in producing the oil out of reservoir?

A If I could just clarify a little bit, if solution gas drive is the only mechanism that's in effect, I think possibly the answers you got earlier would be the same as mine, is the rate that you allow the pressure to decline and the gas to evolve is probably not going to substantially affect ultimate recoveries from the reservoir.

But what we have here and why it's important and maybe why you're expecting a different answer, and why I'll give you a different answer, is I don't feel solution gas drive is the only mechanism that exists.

I do feel solution gas drive is going to be important if Mr. Hueni is right, and we have a reservoir 600 feet thick, which I don't agree with, but if we do, we will have some of that gas that evolves from solution go to the top of the structure that's 600 feet thick and basically act as a gas cap.

You have these wells that are completed in this gas cap or completed close enough to the gas cap that then will start producing gas out of the gas cap and that's where the reservoir waste is going to occur, is rather than that gas being trapped in the gas cap and serving to displace oil downward, as Mr. Greer said, in order to take advantage of that, we've got to go in and squeeze off all of our upper perfs and let this gas cap drive the oil down to the bottom of the pool.

If we don't force that mechanism to operate in the reservoir, then there will be reservoir energy wasted by anybody that's producing gas out of the gas cap, whether that gas cap exists at the top of the 600 foot reservoir or at the top of the reservoir that we're referrng to as the Gavilan Dome.

And that's one of our primary concerns right now, is an operator that's got a high gas/oil ratio, if he has the only restriction of 1.4-million a day or 700 barrels of oil a day, he can produce up to 1.4-million trying to get more oil and using McHugh's ET as an example, the gas/oil ratio right now is 10,000-to-1.

We're going to be able to produce a lot more gas trying to get our share of the oil out of that well than -- than really is going to be effective for the reservoir, and again, that's -- my statement of that is because I feel some of that gas is probably going to be more than just the solution gas drive process working. It's also producing some gas from a free gas phase in the reservoir.

Q Under those conditions you would be using more than your fair share of reservoir energy.

A Yes, sir.

Q All right.

MR. STAMETS: We'll excuse this

witness and move on, then, to the cons, the opponents over here, and what is your pleasure at this point?

Who's first?

MR. LOPEZ: Mr. Chairman, let me ask you then a couple things off the record.

(Thereupon a discussion was had off the record.)

MR. LOPEZ: On behalf of Mallon and Mesa Grande, I would at this time, Mr. Chairman, request we be given for procedural, substantive due process reasons, the same opportunity to prepare surrebuttal to the testimony we heard today.

The testimony we heard this morning from Mr. Greer and Mr. Roe goes far beyond anything contemplated as rebuttal. It was new evidence, new testimony with respect to matters occuring thirty years ago, and I would think that it would be only fair and equitable that we be given the same time frame in which to prepare our case with our books of exhibits, if necessary, to rebut what we've heard this morning and at least the four days that they were given since the hearing was recessed last Friday.

MR. CARR: Mr. Stamets, I would submit that every bit of Mr. Greer's evidence was locked in and in response to testimony that was presented by the cons, if you want to call them that; that it was properly rebuttal testimony and if they were not anticipating that, they should have been when Mr. Kellahin advised the Commission and everyone in the room that we would call Mr. Greer for rebuttal testimony this morning.

We believe that there is no unfair advantage in going ahead and wrapping this up.

We found out yesterday that we had about four or five hours worth of testimony that we had to reduce, hopefully, into ninety minutes. We didn't make that, but we came close.

And perhaps you want to break for lunch now and give them an opportunity to respond, and we would like to conclude this hearing today.

MR. PADILLA: Mr. Chairman, earlier I objected for the same reason, especially when Exhibits Number Seven and Eight were -- at least Exhibit Seven was being presented by Mr. Greer.

In looking at Exhibits Seven and Eight, most of that information is entirely new evidence. The question on (unclear) and the questions on reservoir materials presented by Mr. Greer this morning are entirely different.

On Friday Koch reviewed our testimony, engineering testimony that was going to be presented through Mr. Bennett. We thought at that time that that might be cumulative evidence and it might not be necessary in light of the Commission's admonition of shortening the hearing.

Part of what we were going to introduce through Mr. Bennett involved reservoir studies of fractured formations and anticipating whether or not Mr. Bennett, who also had a conflict today, and in deciding whether or not we should put on -- we needed him today here, we anticipated that we would be looking at some type of rebuttal and the scope of the testimony would be on rebuttal.

We do not have that type of case and it's evident that we've been somehow set up in trying to -- trying to view Mr. Greer's testimony today.

So I would concur and I would join Mr. Lopez' motion.

MR. STAMETS: The Commission is going to not continue this case. We are going to allow it to go to conclusion today.

Each side was aware of that when we concluded last week.

I don't think that the testimony that we've heard today is new, startling, or unavailable to anybody, and at best, we would take a recess till 1:00 o'clock if that's everybody's choice, and allow you to organize the data that you have, and certainly we did not suggest that you leave any of your experts at home for today.

MR. PADILLA: Well, if I may respond to that, Mr. Chairman.

Normally we follow, and I believe the rules of the Commission state that the rules of civil procedure will be followed (not understood) on trial to a court. In that event, normally, the rules and the scope of testimony are limited to what has been previously testified to whether it's rebuttal or surrebuttal (not clearly understood).

MR. KELLAHIN: Mr. Examiner, point of clarrification. The New Mexico Rules of Civil Procedure do not concur with Mr. Padilla's analysis of those rules. You are not limited to rebut only that information that is presented on direct, and they are not so construed.

MR. PADILLA: Well, you're certainly not allowed to introduce or bring in entirely new testimony on rebuttal.

MR. STAMETS: The Commission does not believe that we heard anything new this morning.

We believe we heard simply a massaging (sic) of information which had been presented in one form or another in this case at an earlier date.

Also, I believe that -- that it says we are going to follow those rules generally but not exactly, and this is going to have to be one of those times when we follow them generally. I don't consider any of the participants here without resources or disarmed or without experts of high caliber who are capable of going on with this hearing today.

And since the time is as it is, we're going to recess till 1:00 o'clock and allow those --

(Thereupon the noon recess was taken.)

MR. STAMETS: The hearing will please come to order.

Where is Mr. Lopez?

MR. PADILLA: I would like to cross examine Mr. Roe at this time.

MR. STAMETS: Very good.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Roe, let me direct your attention to a few things you testified about this morning.

It's my understanding that -- that based upon the schedule that you have on page number one, Dugan has approximately eight wells in the Gavilan-Mancos Pool, is that correct?

A I have listed four wells that we -- are actual wells, and four additional wells that are planned; they are locations for planned wells.

Q In other words, only the ones with the figures on columns -- well, I'll just column, the first column on cumulative production is the only wells that show any production there are the ones that are producing, is that correct?

A Yes, sir.

Q Let's go now to the June 6th, 1986, production, and let me ask you to identify for the Dugan Production the June production was 228 barrels a day, is that correct?

A Yes, sir. I have indicated that during the month of June Dugan could have produced 228 barrels. Of that 228 you'll notice that 40 of it has subscript E, which means we don't have a pipeline connection for that well and if we could get permission to vent the gas, it's my best estimate it would produce 40, but what we actually produced was 188 barrels of oil per day, and that is an actual number.

Q Going across the exhibit, then with the proposed allowable, you still have a figure of 228 barrels, is that correct?

A Yes, sir.

Q So you show no reduction of allowable (inaudible to the reporter.)

A That is correct.

Q And the same applies with respect to the last column.

A Yes, sir.

Q Let's go on down to the Mallon group of wells and you show for June an average daily production of 1811 barrels a day, is that right?

A Yes, sir.

Q Under your proposal they would have a reduction of 772 barrels or a reduction to 772 barrels.

A Yes, sir.

Q Approximately how much of a reduction is that?

A Okay, under the existing, actual conditions, June '86, the number right below the 1811 indicates that Mallon Oil has 19-1/2 percent of the production or potential that would -- could exist during June.

Q Now, Mr. Roe, this is not based on the number of proration units that Mallon operates, correct?

A I'm sorry.

Q In other words, there's no acreage factor in this computation.

A No, sir, it's strictly based on barrels of oil per day.

Q Okay. Now, let me go back to my previous question. What's the approximate reduction -- or let me ask you this question instead.

Would you agree that the reduction from 1,811 to 772 would be greater than 50 percent?

A Yes, sir.

Q Now let's go on to the next page and I'd like to ask you some questions with regard to the McHugh wells.

In looking at the McHugh wells would you agree with me that only, possibly only one well of all the wells listed in that is capable of producing like the first three Mallon wells on the first page?

A Only one well?

Q Yes, the one that's right in the middle of the page. The one that produces 619 and another, the Native Son No. 2 produces 440.

A I think we need to clarify one thing just a little. Basically most of McHugh's wells are producing against pipeline pressure, which is averaging around 250 pounds.

If we had our wells, a lot of which are

flowing, producing into a gathering system which has a lower operating pressure, such as Mallon's wells, our wells might be a little higher during June than they are. They're later in their productive life and McHugh has had higher productivity from his wells. But basically, under existing pipeline conditions your assessment is correct; there is only one well that's capable of producing higher rates at --

Q Would reducing the GOR reduce the pipeline pressure?

A No.

Q You're producing directly into the pipeline, is that correct?

A Yes.

Q No gathering system whatsoever?

A Well, that's not true. Mr. McHugh has installed several gathering systems in order to deliver gas. That is -- that is correct, but he has not installed compression or processing facilities such as Mallon has.

Q In other words, what you're telling me is that if you reduce the oil allowable there is a possibility that most of these McHugh wells would run up to 200 barrels a day.

A I think I have some numbers on -- on my tabulation that would basically reflect what you're trying to get at. For instance, during the month of June '86

McHugh's wells represented 39.7 percent of the total pool production. That is the number that lies right below the daily average production during June.

Under McHugh's proposed application his -- rather than 39.7 percent of the total production, McHugh would only produce 37.5 percent of the total production, so in fact his total production with respect to the total would actually be decreased and that was basically my comments with respect to Koch's exhibits, is -- is McHugh would experience actual reduction in percent of the total pool.

Now any operator that basically has small volume wells isn't going to be affected as much as the operators with larger volume wells, and that is correct.

Q Well, let's look at your subtotal line on the bottom of page two. The deduction as you have calculated it for June 1986 production of 36 -- 2,686 to your proposal of 2,035 is a reduction that's over 50 percent, correct?

In other words, you're not going to be cut as drastically as Mallon wells would be cut.

A That is correct. Mallon Oil will, if you look at the percentages underneath Mallon's production, he will share or carry a larger burden, in other words, existing he has 19-1/2 percent of the total pool. Under the existing proposal of McHugh's application, he would have 14.2 percent of the total pool. So he would take a greater percentage but he -- his wells are causing a big part of the problem that we're concerned with. A lot of my pressure data did indicate that we are -- his wells are likely draining more than 320 acres.

And that was the big part of my presentation in Exhibit Number Two.

Q And you've also shown here that McHugh has 28 wells, is that correct?

A Again, there's 28 entries on this tabulation. There's actually only 23 completions and 5 locations.

Q Of these wells listed here you already have a cumulative production of 1.3-million barrels of oil, isn't --

A Yes, sir.

Q -- that also correct?

A Yes, sir.

Q A little greater than 1.3-million.

A Yes, sir. We've been producing those wells since early -- or the latter part of 1983, also.

Q So let me see if I understand this correctly. We have -- Mallon is going to suffer the larger reduction. McHugh has already produced a considerable amount of oil from the pool and now you're asking Mallon in your proposal to have further reduction, a disproportionate reduction, isn't that true, in a nutshell?

A Well, that's -- from the standpoint of just cranking through the numbers, that's the way it is, yes, but part of my testimony was that the allowable of 702 barrels a day allows the wells capable of producing that much of draining areas that exceed the 320-acre unit that they have allocated to them, and I feel we've substantiated that fairly -- fairly conclusively with pressure measurements between Mallon's wells and Dugan Production's wells or Mallon's and Canada Ojitos wells.

Q Well, would you agree with me that the number of wells out in the field is in direct proportion to the spacing?

A I'm sorry, the number of wells is --

Q The number of wells out in the Gavilan-Mancos Pool is directly proportional as far as the spacing rules.

A Yes.

Q For every well there's a 320-acre proration unit.

A Yes, sir, I'd agree with that.

Q And that's -- those are the rules that --

A Well, that's not true. There is one spacing unit that has two wells in it, which is operated by Mr. --

Q Possibly with an exception, valid exception.

A Yes. There is one authorized exception, yes, sir.

Q If we go on an acreage basis, just from looking at your Exhibit Number Three, Dugan has eight proration units out there. He doesn't have a whole lot of production.

Mallon has six wells and they have quite a bit of production.

And McHugh -- well, three of those wells, Mallon wells, have quite a bit of production, but on an acreage basis McHugh as a disproportionate number of proration units, isn't that correct?

A McHugh has a larger acreage position in this area and he has been more expeditious in developing his acreage, that is correct.

Now, I might add, you know, Dugan Production has we -- it's true, we only operate four wells but we do have an interest in 38 wells that exist in the pool.

Dugan Production's acreage position is about the third largest in the pool, which brings back Meridian's witness testified to the real way to analyze this in the impact upon individual companies would be from a net interest basis. That would be a much more tedious calculation and we did not -- the true impact upon each operator is not --

Q It's not reflected in your exhibits, is that correct?

A That is correct. In other words, you have to look at the net interest in each well and I was not prepared to make that calculation.

Q Let me quickly have you refer to your Exhibit Number Four and ask you, sir, to -- do you agree with me that this exhibit does not show an acreage factor in it?

A I'm not sure I understand what you mean, an acreage factor.

Q Well, looking at Exhibit Number Three, McHugh has at least 28 proration units out there and if I look at the little, yellow rectangles here, that -- there's no acreage computation or factor in that --

A In other words, what's presented there is basically the wells operated by Mr. McHugh, that's correct.

In other words, I have not made an effort to account for only McHugh's ownership in the total pool, as I haven't in Dugan's or any others.

What I've presented here would be basically the wells operated by each operator.

MR. PADILLA: I believe that's all I have, Mr. Examiner -- Mr. Chairman.

MR. STAMETS: Next? The witness may be excused.

GREGORY B. HUENI,

being called as a witness and having been previously sworn and remaining under oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. LOPEZ:

Q The record will show that you're still under oath and that you're the same Mr. Hueni that testified previously in these hearings.

Have you had an opportunity to review the testimony and evidence presented by Mr. Greer this morning in this hearing?

A Yes, I have.

Q Over the lunch hour?

A Yes, I have.

Q And if so, I would like you to comment on this, please.

A Yes, we have reviewed the information presented in Mr. Greer's exhibits.

What I'd like to do is I'd like to look at the various exhibits he presented and comment with respect to those individually.

Before we would look at the first one, I'd like to make a general statement that gas cap expansion is not a bizarre phenomenon that happens in reservoirs; that it is something that's been observed worldwide and, in fact, it's the same equivalent, or more or less equivalent to the gravity drainage that Mr. Roe discussed in his testimony, as well.

So it's not -- it's not a bizarre phenomenon and it is one which we still believe is one of the principal mechanisms for production in this particular field.

If possible, I would like to refer now to the BMG exhibit with the yellow cover on it and I'd like to try and comment on the various exhibits within this overall exhibit that are perhaps pertinent.

The first plot following the title of the exhibit is a blue sheet which was taken from our report, which shows oil production and it shows gas/oil ratio, and it has circled in the period 1985-1986 the gas/oil ratio information and it is designated as -- or a handwritten note saying that this is wrong.

The data that we have presented includes two wells that Greer elected to exclude. That was the Gavilan Howard No. 1 and the Gavilan No. 1. Both of those wells are wells in which we unfortunately don't know the exact amount of gas being derived from the Mancos formation as opposed to the Dakota formation. It is perhaps not completely correct to characterize this as wrong. It's simply there is a certain amount of gas production that is attributable to, perhaps, the Dakota in those two wells that should not be included in the Mancos, but unfortunately nobody really knows what the volume of that -- that gas production is. So, we have included those two wells in this plot. We mentioned in our direct testimony that we recognize the difficulty of doing that and subsequently we had referred to the gas/oil ratio information presented by Mr. Roe, which excludes the Gavilan No. 1 and the Gavilan Howard.

That gas/oil ratio information was presented as a plot of pressure and gas/oil ratio versus pool total cumulative oil production. It showed pressure trends for individual wells. It showed the producing gas/oil ratio from 1984 through, I believe, June of 1986. It showed what they interpreted to be the PVT data, indicated solution GOR.

They had two lines on that, a 588 and a 489 line. This is one of the exhibits in -- in the yellow notebook, is this particular plot.

We would like to note with respect to that plot that once again, that a pool total cumulative oil production of 200,000 barrels, a gas/oil ratio goes to a value greater than the solution gas/oil ratio. We've had --

we've heard the argument that the bubble point pressure is a value lower than the one we used in our analysis. Our analysis was based on a bubble point pressure of 1770, which pressure was reached about the same time that the solution GOR went greater than the PVT data indicated GOR.

We realize the difficulties in obtaining good fluid samples and representative fluid samples, and we don't underestimate those -- those difficulties, but we believe that the fluid sample data has to be in agreement with field producing conditions and this is actual producing conditions that have indicated that we have production of free gas from the reservoir, and that can only occur if we drop below the bubble point pressure over a large area of the reservoir.

So we have used as an indication that the bubble point pressure is higher the actual field producing GOR behavior, as shown on that particular plot.

I'd like to move to the next page back, which is a pink sheet. It is a Horner solution gas drive analysis run for the -- the Gavilan Mancos Pool. We have once again curves showing predicted GOR and actual GOR, actual pressure and predicted pressure, and we have on that particular exhibit, we have our predicted GOR -- well, we have the notes that -- that Mr. Greer has penciled in; our predicted GOR being 3100, the Greer predicted GOR being 2200.

It was his contention that that was not a result of the difference in fluid properties but more a difference in the rock properties, as well as, perhaps, some incorrect calculation of solution gas drive performance.

I'm not sure how to respond to that, that type of criticism, other than the fact that we have used this program in several studies. We've hand-checked it. We've checked it against published literature data, and it has been consistently valid in all cases and we see no reason why it should experience some sort of problem in this particular calculation.

We would note that regardless of whether we would take our curve, where we predict a GOR of 3100 or Greer's curve, where we predict a GOR of 2200, both of those are far in excess of the actual GOR that's been realized in the field, which has been between 1000 and 1500.

We would like to next turn to the tab marked Section A. It is a reservoir fluid study performed -- it is information taken from a reservoir fluid study performed for McHugh and Associates on the Loddy No. 1 Well.

We would like to make the point with respect to any kind of fluid analyses that in order to have a valid fluid analysis the reservoir fluid cannot be disturbed either prior to the sampling, either by production from the field or by pressure drawdown at the well itself in which the sample was taken. In essentially all of the fluid samples which we've seen presented by Mr. Greer, there is a very distinct possibility that the drawdown in the vicinity of the wellbore was sufficient over an extended period of time to cause gas to come -- to evolve from the oil, such that the gas that's recovered in the sample chamber is less than that originally contained in the oil.

Once again, if this is not the case, it's very difficult to explain the production of free gas prior to after 200,000 barrels of cumulative production.

We -- we have reviewed the Loddy No. 1 data. If we would turn in this particular set of information back, let's see, there is the title page, there is a page that gives reservoir fluid analysis, formation characteristics, and well characteristics. Following that is a summary of samples received in laboratory. Following that is a hydrocarbon analysis of reservoir fluid sample. Following that is a volumetric data reservoir fluid sample. The next page back, which is 5 of 12 is a pressure volume relations, and finally, on page 6 of 12 there is differential vaporization data presented at a temperature of 170 degrees Fahrenheit.

The -- this differential vaporization data goes from the lab test of bubble point pressure of 1482 at which they record a solution gas/oil ratio of 588, and then it goes for pressures below that.

It also indicates the relative oil volume factor column, which is the third from the left.

If we would read subscript 1 on the solution gas/oil ratio column, it indicates cubic feet of gas at 15.025 psia and 60 degrees Fahrenheit per barrel of residual oil at 60 degrees Fahrenheit.

It does not indicate that that is per barrel of stock tank oil.

Reservoir engineers before they perform reservoir engineering calculations have to make the conversion from a residual oil basis to a stock tank barrel oil basis. In order to do that you have to use separator tests run on the crude sample that reflect the field separator conditions.

So the differential vaporization data presented on page 6 of 12 cannot be used directly in reservoir engineering analysis.

To the best of my knowledge in reviewing all the data that's been -- or all the calculations that's been done on the Canado Ojitos Unit, as well as on the Gavilan-Mancos Pool up to this point in time, nobody has made that conversion, which is required and is very clearly explained in classical reservoir engineering texts, such as Amex, Bass, and Whiting. (sic)

It is essential to make that -- that correction before you do any reservoir engineering analysis and that is the reason we have separator tests.

Now, when we said that we used separator test data, contrary to what Mr. Greer said that that's highly inaccurate, basically it is extremely necessary to make that separator test correction to the differential vaporization data prior to using the data in the calculations.

So we have basically used the differential vaporization corrected for actual field separator conditions, which has not been done by any of the other parties to the best of our knowledge.

We would like to move from that particular chart to the next tab in Mr. Greer's exhibit, which is charts -- or which is Tab B.

Followiong Tab B there is a set of rock property curves, relative permeability of fractured formations, plotted as versus total liquid saturation percent of pore space. As we indicated in our testimony and as Mr. Greer has indicated in his testimony, the curves used in calculation are the same one as shown by the dashed line.

For some reason, well, the next page, the pink page is an expansion of the chart, particularly for values of total liquid saturation in the lower end of the range, or the higher end of the liquid saturation range, running from 90 to 100 percent total liquid saturation, and he indicates that there is a non-linear behavior in that, in that area, and hypothesized, perhaps, I didn't take into account this non-linear behavior.

I would say that if we took the results of my Horner solution gas drive analysis, the values of KgKo versus total liquid saturation and plotted those points on this non-linear relative permeability curve, we would find that my points fall directly on top of that curve.

So it is not a matter of using incorrect relative permeability data.

If we would turn to the next page following the pink sheet, turn to the gold sheet, which is titled Calculated Solution Gas Drive Production Histories for Fractured Formations, and we see a plot of pressure and producing gas oil ratio versus recovery, we would note on this particular -- on this particular chart that at a given pressure level the gas/oil ratio should be relatively constant for the field, and it's not constant for the field. There are wells that produce widely varying GOR's. We've seen examples of wells presented by Mr. Roe in his exhibits, which we'll look at later, that indicate very high GOR's, but there are many, many more wells that have much more moderate GOR's that are not increasing to the extent that

Mr. Roe indicated that the McHugh wells are increasing.

If we would turn to Tab C, this is viscosity data at 170 degrees Fahrenheit. I don't believe that I have any differences with this information.

So we then move beyond that tab to Tab D, where Mr. Greer has calculated -- he's calculated the liquid saturation for the Native Son No. 2 for four points in time, December, 1985, through June, 1986. He's used the data that's shown in that calculation. He's used an equation that's designated with an asterisk.

At the bottom of the page it says the relative permeability ratio is equal to this producing GOR, which is R minus the dissolved GOR, and then it is adjusted for Ug and Uo and there should be a division sign between the Bo and the Bg values; those shouldn't be one following right on to the other. That's not correct.

But we would use the exact same equation. We believe that is a good indication of what KgKo is and from that we could imply some liquid saturation for the well itself.

The one thing that we would have to note about this is that this calculation assumes that all the gas is coming as solution gas from the oil zone and it doesn't give any possibility for gas coming from the gas cap itself or from the higher regions of the reservoir to make this kind of calculation.

But we would note with respect to that, if we skipped over the green page and we went then to the KgKo estimates from the Native Son No. 2 production data, that for the assumed bubble point pressure of 1500 psi, that the points that are shown December '85 through June of '86 fail to fall on the dashed curve, which is a curve of relative permeability ratio versus liquid saturation.

If we were to assume a higher bubble point pressure those curves once again approach the dashed curve that is shown -- shown on the sheet.

It appears that the assumed bubble point pressure of 1600 psi tends to give the best match to the dashed curve, indicating once again a higher bubble point pressure than that reported on the laboratory analyses, so once again we don't believe the laboratory analyses are correct. We recognize the difficulty in making this kind of calculation because the gas from the Native Son No. 2, we don't really know if it's coming from the oil zone or from the gas, the gas saturated region at the top of the reservoir.

If we turn to Tab E, there is a section taken from our report on the fluid properties. This section, which is highlighted, states that the remaining samples were both taken after significant production from their respective pools and it could not be determined if the lab reported bubble point pressure reflected true reservoir conditions or if some gas evolution had occurred prior to sampling.

Once again gas evolution can take place because of withdrawals from the reservoir as a whole or it can take place as a result of withdrawals from the specific well that is -- from which a sample is being taken.

He charactertized as taking a higher bubble point pressure a desparate act on our part. It wasn't a desparate act on our part. It was simply trying to take a bubble point pressure that gave us a gas/oil ratio performance consistent with observed field performance for the Gavilan-Mancos Pool.

We would also note that in his direct testimony Mr. Greer testified initially that the reservoir oil in the Gavilan-Mancos Pool may have been very close to the bubble point pressure at the time it was -- was described.

If that is the case, then I would have to say that our value of 1770 is more accurate than what's indicated on the fluid property analyses.

I would like to turn to the second of the foldouts which is in that section, that shows a -- the log sections for the Howard No. 1-A, the Canada Ojitos Unit E-6, the Canada Ojitos Unit J-6.

On these particular logs certain sections have been shaded based on, it appears, their silt content, as indicated by the resistivity logs, so that we see, we do see the gray zone, the A, B, and C zones.

We also see the difference in operator philosophies out there in the sense that the Canada Ojitos wells were perforated primarily in the silty intervals, whereas the Mallon well has been perforated from top to bottom.

All wells have been subjected to a large frac job. The results on the Mallon wells indicate that there has been sand entry throughout most of the reservoir. We would think that that large frac job establishes vertical communication. We would point also to the testimony of Mr. Habenmeyer (sic), who indicated that the frac log surveys indicated a presence of fractures over an extended vertical interval.

We would also refer to a recent core taken in the last few days from the Davis No. 1 Well, which in essentially all of the samples that have been looked at thus far over approximately a 200-foot interval have indicated vertical fracturing with as much fracturing taking place in the shales as takes place in the siltier sections.

That particular core also, in some cases they've observed fractures, more than a single fracture, more than one parallel fracture in the core itself, so we know that the fracture density is quite high.

They've also observed intersecting fractures in at least one case, so all fractures are not necessarily oriented exactly -- exactly parallel.

MR. LOPEZ: I think Mr. Hueni said Habenmeyer (sic) and I think it's Emmendorfer.

A I'm sorry, that's correct.

We would note with respect to this that one of the comments that was made dealt with the productivity of a well in which both the A and B zones, I believe, were perforated and stimulated, and that a bridge plug was set between the A and B zones. The A zone was not terribly productive, so the bridge plug was withdrawn and the production increased.

With respect to that comment we would have to say that that is normally to be expected. You complete in the larger section, you get more productivity, and that is basically what we would expect from a particular well. I don't necessarily believe that that means that there's no vertical communication between the two zones.

Following the foldout is a correlation of bottom hole sample data. These correlations that are presented here, and in general all correlations for oil properties, are based on certain assumptions and one of those assumptions is that the gas that is recovered from the well is all that is dissolved in the oil at whatever the reservoir pressure is at the time the well is flowed.

In the event the gas escapes from the oil prior to reaching the wellbore, or in the event that free gas is produced, these correlations are not valid. In using such correlations, therefore, it's simply making the assumption that -- well, it's basically assuming the answer and then -- and then using the correlations to prove the answer.

Turning beyond the yellow sheets to the comparison of core analysis with gamma ray induction log information, we would note that this particular well that is shown here is a well that's not located anywhere in the vicinity of Gavilan-Mancos Pool, and we cannot comment as to the relevancy of that particular pool with respect to the Gavilan-Mancos Pool. We believe that there are signficant differences between Gavilan-Mancos and the Canada Ojitos Unit. In that, between those two areas we might expect that -- that if we go even further away, that we would still have other differences that would occur.

We talked, or mention was made of a 600-foot producing interval being -- that we had used a 600-foot producing interval as being the basis on which we made our calculations.

We used a 600-foot interval as perhaps the maximum thickness that we saw productive out there in order to arrive at a permeability. By dividing by 600 feet we ended up with a lower permeability estimate than we would of had we used, say, 200 feet or 300 feet.

We frankly are not sure what the overall producing interval thickness is ourselves, but we felt that we would err on the conservative side, get a lower permeability, if we used the maximum thickness that we say, and that is typically perforated by many operators out there.

Q Would you care to comment on your opinion with respect to whether -- whatever that is, whether it's consistent throughout the pool?

A The --

Q The producing intervals?

A Well, the producing interval is not going to be -- is not necessarily going to be consistent throughout the pool. That is going to depend on the degree of fracturing and the degree to which those fractures are interconnected.

It also will depend on -- potentially on the completion interval and the size of the frac job, as well.

If we would move to Tab 5, or I'm sorry, Tab F, in which the history is presented for the Canada

Ojitos Unit No. 2. Prior to actually recovering a fluid sample that's used in the analysis, we would note that in this producing history, that the well produced several days before it was sampled. It was a low productivity well. It had a high pressure drawdown. That pressure drawdown was shown on the pink sheet.

It showed a well flowing pressure as low as 800 psi at the wellbore, such that -- which considerable below what any of us believe the bottom hole pressure or the bubble point pressure might be for the particular reservoir.

So there is certainly ample opportunity for gas to escape from the oil during this period of pressure drawdown prior to actually recovering the sample itself in this particular well.

So once again, we have the possibility, not only the possibility, the probability that the -- that some gas had escaped from the oil prior to sampling and as a consequence the bubble point pressure was higher than recorded on the CORE Laboratories information, which was presented in the yellow sheets, or the gold sheets for that particular tab.

If we turn to Tab G, the Canada Ojitos Unit L-11, once again we are presented with the operations that occurred at completion and then mention was made that this well produced over 100,000 barrels of oil prior to actually being sampled.

There was an attempt made to produce the well at low rates for a period of time prior to sampling but it's highly unlikely in this fairly thick reservoir that sufficient oil was withdrawn during the conditioning period to actually remove all the oil that might have a lower gas-/oil ratio, and once again, there was substantial production that occurred in this particular well.

If we would now turn to Tab -- no, still under that tab but following the yellow sheets, we would turn to the white sheet, which is a presentation of pressure versus cumulative production for the Canada Ojitos Unit. It is the pressure measured at datum of plus 1195 feet expressed in terms of pounds per square inch versus cumulative production in hundreds of thousands of barrels.

In this particular plot, if I heard correctly, there was an indication that the field produced for a period of time at pressure above the bubble point, at which point during which time the pressure decline was 3000 barrels of oil produced per psi pressure drawdown in the reservoir.

Subsequently, when the entire reservoir fell below the bubble point pressure, the rate of pressure decline decreased from 3000 or -- well, it decreased but it caused then an increase in recovery per psi -- per psi drop of reservoir pressure, and such that we then went in the period from 8-million to 12 -- from 800,000 to 1.2-million cubic -- barrels of production. We then had a 7000 barrel per psi pressure drop.

If you would recall the pressure versus cumulative production plots that we showed in our exhibit, we showed that pressure versus cumulative production is not concave upward. In other words, the pressure tends to be -- stay flat for an extended period of time and it's actually maybe increased a little bit withi increase in production recently.

In other words, we don't have this two -- two slope curve of pressure versus production that's presented for the Canada Ojitos Unit. That is indicative of the fact that the reservoir in the Gavilan-Mancos Pool was at the bubble point to begin with, and continues above the bubble point. We've never seen any kind of break indicating a change in the number of barrels that can be produced per psi drawdown in the reservoir.

And we have pointed that out previously.

The other thing that might be of interest is the fact that in the Canada Ojitos Unit this break occurs at approximately July 20th, 1965, when the pressure is at approximately 1520 psi, measured at a datum of 1195 feet. That was after production of what appears to be about

300,000 barrels of oil.

If we were to correct from the datum depth of 1195 feet down to a datum depth of 370 feet, which is more appropriate for the Gavilan-Mancos Pool, then we would add on approximately 240 psi to the point at which this curve breaks. That would put the pressure in the Gavilan-Mancos Pool at which this break would occur at about -- at over 1700 pounds, approaching 1750 psi, once again an indication that the bubble point pressure in the Gavilan-Mancos Pool is more on the range of 1750 psi.

Q Greg, I think earlier on this point you misspoke and said production above rather than below the bubble point.

I think this is a very important point in our presentation and would ask you to go over this point again, if you would, please.

A Okay. The pressure versus cumulative production plot can be -- well, if we have a reservoir that has pressures that are in excess of the bubble point pressure, in other words, we have no free gas, the only thing that can take the place of the oil that's been withdrawn from the reservoir is the expansion of the remaining fluid, plus any, let's say, contraction of the pore space itself. And as a result of that, those two being the only influences we can see, we would expect to see pressure drop quite rapidly as fluid is withdrawn from the reservoir.

So -- and then when we go to pressures below the bubble point where we have a free gas saturation in the reservoir, then that gas has a great -- greater degree of compressibility or expansibility (sic) and so we can take out, provided we don't take out the gas with the oil, we can take out more oil and per psi of pressure drawdown.

Normally you expect to see in a reservoir that is what we call under saturated or above the bubble point, you expect to see a period of rapid pressure decline followed by a period of less substantial pressure decline, and that is what we've observed for the Canada Ojitos Unit, but it is not what we have observed for the Gavilan-Mancos Pool.

We have a final tab in that presentation. It is Tab H. It is the production history taken from our report for the McHugh Native Son No. 1 and the Homestead Ranch No. 2, indicating a very low gas/oil ratio for those two wells, for those two particular wells.

We had used that as evidence of migration already occurring. That's not our only evidence of migration but that is one, one set of evidence of migration. It was pointed out, and I think probably correctly so, that -- in fact, Mr. Lyon pointed it out -- that for that kind of low GOR that we see for the Native Son No. 1, that is not consistent with what the flowing bottom hole pressure would be.

So I would have to agree with Mr. Greer that there is undoubtedly some problem with the reported gas production on this well. I don't know what it is but it does appear that these wells are low gas/oil ratio wells. Unfortunately, if the reported data isn't correct, I don't know what we have to work with.

That -- that concludes my review of Greer's exhibits that are contained in this yellow volume and --

Q You might as well move right on to the other volumes.

A Well, I had an exhibit that I'd like to present.

Q Okay, why don't you turn to Exhibit Number Twelve --

A Number Twelve?

Q Exhibit Twelve.

A All right.

Q Okay, I'd ask you to refer to what's been marked as Exhibit Number Twelve and ask you to discuss it.

A Exhibit Number Twelve is a calculation of oil in place using a material balance approach for the Gavilan-Mancos Pool based on the pressure production history that we had presented in our direct testimony, but instead of using a bubble point pressure of 1,770 psi we've revised our fluid properties to include the fluid properties from the Loddy No. 1, which had a bubble point pressure of 1496 psi.

So we have replaced our table fluid properties in the middle of the page with -- that reflected a higher bubble point pressure of 1770, with these -- this new set of bubble -- of fluid properties from the Loddy No. 1.

The bottom of the page indicates the results of our oil in place calculations. In our direct testimony we indicated that there would be a period of time in which the reservoir was undersaturated or was partially undersaturated, such that the oil in place calculations could not be used during that -- that period of time.

As it turns out, in the event that we are so undersaturated that the bubble point pressure is down around 1500 psi, then we will not reach a partially undersaturated condition through at least 1985, so the values of oil in place that are calculated up to 1985 are the values that should be representative of the reservoir, and I think in reviewing this we can see that the oil in place value that would be calculated in this manner is in excess of 400-million barrels. That's just saying that if we can take -- that if we have a reservoir that contains an oil with such a low bubble point, then we must have an awful lot of reser voir down there to take out the amount of oil that we've taken out, seeing the kind of pressure drop that we've seen.

We do not believe that the oil in place value of 400-million barrels is correct. We don't believe probably that any other people would -- would feel that same way.

We went through this type of reasoning when we were doing our study as a basis for, once again, ap- praising what the value of the bubble point pressure was and we -- this is one of the reasons that we once again elected not to use a 1500 psi bubble point pressure. We elected to use the 1770 psi bubble point pressure.

Q Okay, now going to the next volume of ex- hibits introduced this morning, would you care to comment on those?

A Yes. The next set of exhibits that I have in front of me are contained in a -- in a brown folder. I'm not sure what the exhibit number was on this.

Q Exhibit Seven?

A Exhibit Seven. On this the first tab following -- in Exhibit Seven is followed by a yellow sheet talking about comparison of porosity and permeability for two systems of fracturing.

MR. STAMETS: I believe that's

blue.

A Wait, what color did I --

MR. STAMETS: Yellow.

A Yellow. After awhile you get color blind, after awhile.

Okay. The first page following Tab A is indeed blue and it is a comparison of porosity and permeability for two systems of fracturing.

The -- I believe that -- well, the point that we would like to make on this is that we believe that over the Gavilan-Mancos area that there has been, perhaps, more than one event that's led to fracturing, not a single event such as a flexuring shown here, and in combination we would expect that these multiple events would give rise to -- to different degrees of fracture, fracture density and not necessarily a variation in fracture width.

So once again, we are now prepared to accept the proposition that porosity is related to the cube root of permeability. That is one possibility but we recognize that in a geologically complex situation that is just one of multiple possibilities.

We would like to turn, then, to Tab B. Tab B has a yellow sheet following it.

There are several points that are made here. If I were to read the first part of this presentation simply stating, "With respect to Mr. Hueni's response to the chairman's questions about interference tests conducted in the Canada Ojitos Unit, we assume that Mr. Hueni apparently did not understand the nature of the subject interference tests for his responses were to the effect that:

1. Interference testing can only show information about the formation between the test wells and is complicated by fracturing.

2. The EI, or exponential integral straight line solution does not apply to a heterogeneous reservoir; and

3. The best way to determine the reservoir characteristics is from individual well pressure build-up tests."

With respect to this we would once again repeat, the best way to determine reservoir characteristics is from individual well pressure build-up tests.

We would also repeat that the EI straight line solution does not apply to a highly fractured reservoir. We would like to present our next --

Q Exhibit Thirteen. In this connection and in response to the comment, I now ask you to refer to Exhibit Thirteen and explain why you would introduce this exhibit.

A Following the statement --

Q Okay, I think we're all with you.

A The final paragraph following those three points states that, "Since all three of these statements are incorrect as to the subject reservoir and tests, it is assumed that Mr. Hueni didn't have time to study them so his failure to correctly assess the tests is understandable; however, his statements are in the record and the record needs to be set straight."

I'd like to turn now Exhibit Thirteen, which is a paper published in October, 1983, by the Society of Petroleum Engineers in the Society of Petroleum Engineers Journal.

It is a paper written by Tatiana D. Streltsova, a researcher at Exxon Production Research Company, assigned to study naturally fractured reservoir behavior.

The first page is simply the cover sheet from that paper.

The second page indicates that the -- that there is a section of that paper that deals with interference test analysis; talks about pressure pattern for interference test analysis.

And on the third page highlighted is the statement that we would like to set the record straight with.

"Therefore, if one uses a conventional analysis based on the EI curve which does not take account the pressure support offered by matrix blocks on drawdown measurements, then the calculated formation permeability will be overestimated."

Not only will the formation permeability be overestimated but so will the storativity (sic) of the reservoir.

This is the basis on which we said that the permeability and storativity (sic) numbers presented earlier in Mr. Greer's testimony are higher than we believe -- than properly reflect actual reservoir parameters. That is the reason that we have gone with pressure build-up analyses. In fact, if we were to read this entire paper, we would see that a conventional Horner plot used on a single well, pressure build-up survey, would provide reasonable estimates of fracture conductivity.

Q What is your opinion will respect to the value and reliability of the paper?

A I believe that this is the most recent information that is available on naturally fractured reservoirs in terms of pressure transient testing. They have taken this and they've -- basically they've updated the work of Warren and Root, which has been quoted in Mr. Greer's testimony, and have shown the failings of the Warren and

Root model, and they've used the data presented by Warren and Root, reanalyzed it using the techniques developed in this -- in this paper and have showed the consistency of results.

Q If necessary, would you make the entire paper available to the Commission?

A Yes, I would.

Q Okay.

A One final point that I might make with respect to the yellow sheets in that tab, or on page 2, item 2, there is a statement in the Canada Ojitos Unit test area, the geometry of the reservoir is that of individual tight blocks surrounding by a high capacity fracture system.

Once again, this is exactly the same type of situation identified by Stretlsova in the paper that we've just referenced to.

From there on I would have no comments on the exhibits, simply from the fact that I don't believe the exponential integral solution is the appropriate way to analyze the tests.

Q Okay, now would you refer to the final volume I think was introduced this morning, Exhibit Eight?

A Yes.

Q And have you comment on that.

A Exhibit Number Eight, which is presented in the black folder, on the Greer testimony, in reviewing that information we would like to turn to Tab A and following Tab A there is a title Geologic Analysis in Naturally Fractured Reservoirs, and then following that sheet we see several plots of -- and one in particular that was highlighted in pink, it's Figure 1-56, "Fracture porosity as a function of fracture width and fracture spacing".

If I understood correctly, the fracture spacing that was selected from this particular exhibit was a fracture spacing of 1000 centimeters, which I believe approximated 30 feet, if I understood correctly.

We would note from the information that we have available in terms of fracture density, we would think that the fracture density of one well per 30 foot is -- is excessively large. It would be much smaller than that or that there would be a much tighter fracture spacing than that that's shown highlighted in this particular exhibit.

The significance of that, if we would turn, then, to Tab B, if we had a much tighter fracture spacing we believe that the graph that was shown under Tab B, it is the fourth page back, it has a blue line on it, showing radius of circular drainage area versus producing time to establish steady state conditions in days, that if we had a much tighter fracture spacing, the length of time required to establish steady state conditions would be much shorter than is shown on this particular graph.

So that to infer that the matrix cannot contribute significantly, or the tighter portions of the reservoir cannot contribute significantly, is based simply on the assumption of the fracture spacing and if that fracture spacing is not correct, then the extended length of time predicted by this plot for a response to occur is considerably overstated.

We would turn then to -- to Tab C, the Warren and Root paper under the Behavior -- titled The Behavior of Naturally Fractured Reservoirs, and highlighted in that is item number 3, "Since the build-up curve associated with this type of porous system is similar to that obtained from a stratified reservoir, an unambiguous interpretation is not possibly without additional information."

This is basically the exact same statement that we made in our direct testimony. We reviewed the pressure build-up surveys. We identified places where it occurred. We had dual porosity system, and we said that in our analysis that it was not critical that we had matrix porosity but we thought the possibility existed and we recognize the fact that this highlighted statement is somewhat true, that it -- that in a pressure transient test such as this it is extremely difficult to differentiate a stratified reservoir from a dual porosity system.

But nevertheless, we believe that it is

certainly a reasonable possibility to think that matrix contribution exists.

I'd like to turn to Section E, which is the conventional core analysis for Mobil's Lindrith B No. 38 Well. This presents the results of the CORE Lab studies, showing helium porosity as well as fluid saturations in terms of oil and water saturation.

In the center, in the top center of the page under the date and under the formation, it talks about the drilling fluid and in the drilling fluid it talks about it being water based mud.

To the extent that water is used as a coring fluid, we would expect some alteration in the water saturation of the -- of the core itself. To what extent that actually occurred is difficult to determine. If you want to obtain an accurate value for water saturation you normally core with an oil base mud.

So to assume that the water saturation number as shown on -- on the CORE Lab report is accurate, is -- is not correct.

So if we were to turn, then, to Tab F, followed by several yellow sheets, or a couple yellow sheets, and we were to look then at the saturation shown in columns three and four, we would see that those saturations are exactly the same saturations as -- as taken form the CORE Lab report.

We would note, however, that those saturations in column four, the water saturation, is undoubtedly disturbed by the fact that they used a water based mud system, such that when they take a water saturation in column four and subtract it from 100 percent saturation, the initial reservoir oil in place value that's shown in column five is not correct. It is understated.

The water saturation in column four is not the connate water saturation of the rock as it existed in the reservoir.

So the calculations that follow that are not particularly meaningful, because those are not the correct saturations.

If we would turn to the first tab following -- or the first page following Tab G, which is a plot of water saturation versus permeability, taken from the core data of the Mobil Lindrith B No. 38, this is just an illustration that it's not reasonable because the direction of that trend is to the upper right and as was shown two pages later by the -- by the pink tab, the trends for other fields, such as Rangely and Elk Basin, are in a trend running from the upper left to the lower right and the Lindrith B-38 is just opposite from that trend.

Well, if we were to look back, then, at the gold trend, that says simply that it is incorrect to plot water saturation versus permeability with the water saturation taken from the core data because that is not connate water saturation and that's exactly what that -- that gold sheet implies.

We would finally turn to the last section of this exhibit, which is titled Section H, and we note under the sample description, we see sample descriptions primarily of shale, and we see almost the way through that the interval is fractured. Once again this is not a well that is locateds directly in the area, the study area that we're concerned with but it does illustrate that shales as well as silts are fractured, such that vertical communication can exist within the reservoir.

Q Having heard Mr. Greer's and Mr. Roe's testimony today, would what you've heard and analyzed change the conclusions you reached last Friday, and I'd ask you to elaborate and in this respect ask you to comment on Exhibit Fourteen, when appropriate.

A Okay. The conclusions that we drew last Friday, we feel that at this point there is no reason to change those conclusions.

Once again we believe gas segregation is occurring. We believe that we have a reservoir that is at a pressure below the bubble point pressure, that it's been that way for a substantial period of time. The gas has evolved from the oil; that it has migrated away from the well to some extent, not completely. There is always some lateral movement of gas as well as vertical movement of gas, resulting in -- in whatever the observed gas/oil ratio values are.

With respect to that point, I wculd like to comment on Mr. Roe's exhibit, that was titled Dugan Production Corporation Exhibit Number Three, and at the -- at the final three pages of that exhibit, which are titled Exhibit Number Five, are gas/oil ratio plots and production plots for three wells, three of McHugh's wells in the field.

We would like to note with respect to those three individual well production plots that those three plots are all -- are for wells that are all located in a high depletion area of the field, more or less following along this northwest/southeast trending direction that we've identified through fracture orientation logs, as well as through some fault mapping; that these gas/oil ratios are in structurally down -- or in structurally intermediate wells, not in the structurally highest wells; that the gas/oil ratios have gone up in response to increased production in those specific wells; that they are not representative of current GORs in many of the wells in the field.

For example, we could take the current GORs for the Mesa Grande wells and we would find that those in many cases are in the range of 1-to-2000 standard cubic feet per stock tank barrel.

So once again we realize the gas/oil ratios can increase very rapidly with a small increase in gas saturation in a given area of the reservoir. We believe that those -- that that particular area of the reservoir has experienced high depletion, historically high depletion, and it is -- has a slightly higher gas -- gas saturation in that area and higher gas/oil ratios as a result.

In the Mallon area of the field, based on July production, the Ribyowids 2-16 had a GOR of 1978.

The Fisher 2-1 had a GOR of 1,085.

The Howard 1-8 had a GOR of 1344.

The Howard 1-11, a GOR of 2214.

Once again we see variations between individual wells in the field. We don't see GORs that are necessarily as high as they are on the McHugh wells as presented in Exhibit Five.

Q I think you're referring to the McHugh wells as Exhibit Five, not Exhibit Three?

A Well, it was attached to Exhibit Three.

Q Okay, I think it is

A Okay.

Q And not Exhibit Five, and in this connection were any of those wells -- do any of those wells have commingled production?

A As a matter of fact, in reviewing Exhibit Five we do see commingled production for the ET No. 1 and we note that the amount of gas that's allocated from the Dakota is only 6 percent. A higher drawdown in that well, associated with incresed production, may have resulted in higher gas production out of the Dakota. That's certainly an unknown at this point in time.

The other commingled well is the Janet No. 2 and it has 10 percent of its gas allocated as coming from the Dakota, of its total gas.

So once again, higher producinc rate in that well, we are not sure if there's still 10 percent of the gas coming from the Dakota.

The only well that is a single Mancos producer, I believe, is the Native Son No. 2, and in that particular well, while we have an increasing trend in GORs, it is perhaps not quite as high as the other wells.

Q I'd now refer you to what's been marked Exhibit Fourteen and ask you to discuss this.

A Exhibit Number Fourteen is a presentation of the amount of gas production that is -- would be withdrawn together with the oil production, and depending on the gas/oil ratio limit.

Under the present allowable scheme and for the Mobil proposal, unrestricted production limited only by the depth bracket allowable would result in 702 barrels a day of production with a 2000 GOR, implying that as much as 1.4-million cubic feet of gas could be withdrawn from -- from the reservoir, together with the oil.

The McHugh proposal at 200 barrels a day and 1000 GOR represents a reduction down to 200 MCF per day, which is a substantial reduction.

In the event that the McHugh proposal were increased in terms of the oil production rate a bit, but on the other hand, the gas/oil ratio declined down to a value of let's say 588, then the gas allowable would increase a bit but would still not amount to the volume of gas proposed by either Koch or Mallon.

The Koch proposal would provide for a gas allowable of 413 MCF per day; Mallon-Mesa Grande proposal, 453 MCF per day.

Once again, in our direct testimony, based on the segregation tendencies of gas and oil, physical properties as we can best arrive at them for the Gavilan-Mancos Pool, we have actually calculated a gas withdrawal rate in excess of this 453 MCF per day value that we propose as being sufficient to be withdrawn while still not doing any kind of damage to the reservoir, still permitting the gravity segregation tendencies to occur within the reservoir itself.

So the Mesa Grande-Mallon proposal does represent a substantial reduction in the amount of gas production that would come with the oil, and once again it is our conclusion and our belief that it is the gas, free gas production taken from the reservoir, together with the cil, that does damage to the reservoir.

We believe that a low GOR provides the incentive to the operator to do the work that is necessary to reduce the GORs. That means sealing off the upper portions of the productive interval. Then that provides an incentive for them to do that.

MR. STAMETS: Excuse me, did you say the proposal is to lower the GOR to 626?

A That is what our proposal was, was to lower the GOR but not to change the oil -- oil rate.

MR. LOPEZ: One hour and 25 minutes, Mr. Stamets.

MR. STAMETS: All right. That's very good. Are you all through?

MR. LOPEZ: We reserve the rest of our three hours to see what we can do with it.

MR. STAMETS: Okay. I just somehow think we've already got more hours here today than I had planned on because of the 47 minutes that the pros had left over there.

The opponents have completed their direct re-whatever today.

MR. KELLAHIN: Does that include Mr. Pearce?

MR. PEARCE: Yes, it dces.

I try to help, Mr. Chairman.

MR. STAMETS: Do you choose to use any of your time in cross examination?

MR. CARR: I might have just one question in cross examination.

We will ask for a brief recess and then we'll be recalling Mr. Greer for some brief testimony, which might not require our 47 minutes; might not require even 42.

CROSS EXAMINATION

BY MR. CARR:

Q Mr. Hueni, you've studied the reservoir, the Mancos, in this area and as I understand your testimony, you have come up with a theory about the segregation tendencies within that reservoir of the gas and oil; gas moving up, the oil moving down.

In his first exhibit, Section H, Mr. Greer pointed out some shortcomings in that, the base data. If I understood your testimony, there may be some difficulties there but that's what you had to work with, now is that correct?

A I'm sorry, which section were you referring to?

Q H, H in Exhibit One, the yellow book.

A We used the data from the Engineering Subcommittee.

Q And if there are problems with that data, that still was what you had to work with.

A That is correct.

Q And if there are problems with that data, it might affect your conclusions.

A I -- I think it would have to be in terms of identifying the reservoir drive mechanism. I think it would have to be extremely substantial problems with the data.

Q So you don't need very good data to get your conclusions.

A To get -- to understand what's directionally correct, that is the case.

MR. CARR: Thank you.

MR. STAMETS: Mr. Kellahin, any questions?

MR. KELLAHIN: No, sir.

MR. STAMETS: This witness may

be excused.

And you all would like a few minutes?

MR. CARR: Yes.

MR. STAMETS: We'll take a fifteen minute recess.

(Thereupon a recess was taken.)

MR. STAMETS: Mr. Lopez, would you like to introduce your exhibits?

MR. LOPEZ: Yes. I would.

Were Exhibits Twelve through Fourteen prepared by you or under your supervision?

MR. HUENI: Yes, they were.

MR. LOPEZ: We'll tender Exhibits Twelve through Fourteen.

MR. STAMETS: Without objection they will be admitted.

Mr. Carr, do you have some redirect, or Mr. Kellahin?

MR. CARR: I have some redirect for Mr. Greer.

MR. STAMETS: Are you ready?

MR. CARR: Yes.

ALBERT R. GREER,

being recalled and remaining under oath, testified as follows, to-wit:

REDIRECT EXAMINATION

BY MR. CARR:

Q Mr. Greer, you've been present this afternoon for the testimony presented by Mr. Hueni, have you not?

A Yes, sir.

Q I'd like to direct your attention to Benson-Montin-Greer Exhibit Number Six, the yellow book, and first direct your attention to the pink page immediately preceding Tab A and ask you to respond to Mr. Hueni's comments concerning this exhibit.

A Yes, sir. Mr. Chairman, I understand that -- what I understood Mr. Hueni to say was that they used this method all over the world and therfore it's okay.

I'm really disappointed. I had hopes that during the noon hour they would have called their office and had a new run made by their computer with points more closely spaced to give us a more accurate reading, but they had time to do some other things with their computer but they didn't evidently have time to do that.

There's no question that the calculated curve is in error. They just don't know by how much, and the fact that it works in the North Sea or Egypt has no bearing on this situation because the problem is in reservoirs that have relative permeability ratios that are considered good, most of them have a critical gas saturation which is fairly high, 5 to 10 percent, and so a large volume of oil can be produced as gas saturation picked up before the KgKo relation picks up real fast, and in that situation you can take big steps and it doesn't make much difference.

So, then ordinarily in the North Sea and other big oil producing areas of the world they have these good resevoirs that -- that really are easier to analyze in this respect than ours.

Q Now, Mr. Greer, would you go to Tab E in this exhibit and to the cross section contained in that, the third document, third page.

A Yes, sir.

Q And I'd ask you to relate the information on that to recent information from the Mallon core.

A If we could look under that section over to the cross section, we've heard once again how there's so much vertical communication among these zones and up and down the formation, and that it shows up in cores as well as vertical communication being caused by fracture treatments.

I'd say first with respect to the fracture treatments tying the zones together, we have done that and they haven't been tied together, and we've demonstrated that.

Now, on the core that the companies have jointly gone together in their coring Mallon's Davis Federal Com 3-15, southeast quarter of Section 3, 25 North, 2 West, and it's my understanding that between the B and the C zones there have been no fractures found in -- in that core, which confirms what we've been talking about all along about the stratified nature of the reservoir.

Q Now, in that core, what zones were cored, do you know, in the Mallon well?

A Of the information I have they cored the A and the B zone and part of the C zone, and we had hopes they would get -- or I had hopes they'd get below the C zone a way, the area that we were interested in, but I'm not sure just where they quit.

Q All right, if you'll now go to Tab F, the blue page behind it and respond to Mr. Hueni's comments concerning the bubble point.

A Mr. Hueni's noted that the pressure had been pulled down to 800 pounds while we were testing the well, and therefore that the sample that we got would not be a valid sample because the pressure had been pulled down and the bubble point would be a false bubble point.

The thing that I point out, Mr. Chairman, that's kind of strange, is that if that's the case, why didn't we get a bubble point, say, at 900 pounds, 1000 pounds, 1100, 12, 13, 1400 pounds, and of course, one can say, well, that's just -- just happenstance.

It seems like strange happenstance that two wells that we took bottom hole samples on and Mr. Hueni says the pressure has been pulled down, the samples aren't valid, why would they check within just a few pounds of each other, and here's one that the pressure could have been as low as 800 pounds. If the sample had been contaminated, so to speak, by the pressure being pulled down to that point, it should have shown a bubble point of 800 pounds and not 1500.

Q Now if you'll go on to Section G and go to the beige pages, the brown pages in that exhibit and review what they are and why they were included?

A I would just point out once again how carefully we conditioned this well in order to get a bottom hole sample, and again when we got that bottom hole sample, it checked very closely with the other one that we had before.

We tested the well with a minimum bottom hole pressure of 100 pounds higher than the anticipated pressure and sure enough, we got a bottom hole sample that was a good sample, checked within a few pounds of the other one, and there's no way just by happenstance that would happen.

But Mr. Hueni then concludes that the bubble point is high, 1700 pounds.

Then Mr. Hueni goes over to -- to our pressure production graph and having said five minutes before that that the bubble point was like 1700 pounds, he comes along and tells us how this undersaturated reservoir, the pressure production coefficient changes. So it had to be undersaturated for that to happen.

So he's given us a contradiction when he says the bubble point is higher than 1700 pounds and yet he comes along and shows exactly the same thing that I did, how the pressure, the production pressure coefficient increases as the bubble point moves down the structure and the oil becomes saturated and the compressibility increases so that you get more oil for each pound of pressure drop.

Then Mr. Hueni, with Exhibit Twelve, instead of giving us what I had hoped he would give us, a computer run, tells us about how we could have 400-million barrels in place if we had a bubble point of around 1500 pounds, and could we introduce our Exhibit Nine now?

Q Will you now refer to what's been marked as Exhibit Number Nine? I'd like to have you identify it, identify it and then review the information contained on that exhibit, please?

A Mr. Chairman, this is an exhibit that shows how the oil in place calculation can vary depending upon your choice of fluid properties that you use.

In this particular instance this graph is calculated on a pressure -- production pressure relation of 10,000 barrels per pound, and what that says for Gavilan at the time that about 10,000 barrels per pound of reservoir space was being voided, that if the oil were entirely undersaturated, we look at the upper line, then there would be some 400-450-million barrels of oil in place, similar to what Mr. Hueni shows on his Exhibit Twelve.

But I point out, Mr Chairman, if there's some free gas in that reservoir and there's only five percent, then the oil in place is more like 150-million barrels, or if there's 10 percent free gas in communication with the -- with the oil, then there's like only 100-million barrels in place, and I know that it seems strange that you could have free gas in communication with undersaturated oil in a reservoir. Most engineers will tell you that's impossible.

Mr. Chairman, we've studied in this area four reservoirs, Boulder, East Puerto Chiquito, West Puerto

Chiquito, on the west side of the Basin La Plata Mancos. In all four instances there was undersaturated oil in the reservoir, unquestionably undersaturated. In every instance there was a free gas cap and how much saturated oil there might have been below the gas and above the undersaturated oil, we don't have any idea, but in every instance that happened.

And the reason I prepared this graph, Mr. Chairman, was an an aid to the Engineering Committee in their study as to how the volume of oil that we're dealing with might depend upon these various factors, and the fact that the reservoir is stratified, the fact that there's free gas, there's no way, no way to tell exactly what you have, and the estimates that we've made, which show 100-million barrels in place, we've estimated that the system compressibility is such that about 80 percent was undersaturated at the time that we were making our estimates, about a 5 percent free gas, and that shows on this graph about 100-million barrels.

It's a rough estimate but this is how the oil in place varies, and so it really doesn't mean very much that they come up with this Exhibit Twelve and say that this is unreasonable, if you have a 1500 pound bubble point it doesn't mean a thing. You can still have a 1500 pound bubble point and still have maybe 100-million barrels in place and the reservoir performs something like it's doing right now.

Q Do you have anything further on Exhibit One -- or Exhibit Six?

A I think that's all.

Q Mr. Greer, was Exhibit Number Nine prepared by you?

A Yes, sir.

MR. CARR: At this time we move the admission of Benson-Montin-Greer Drilling Corporation Exhibit Number Nine.

MR. STAMETS: With no objection Exhibit Nine will be admitted.

Q All right, Mr. Greer, would you now refer to your Exhibit Number Seven and I'd ask you first to refer to the cartoon and diagram you prepared of different kinds of fracturing in formations.

A Yes, sir, the blue sheet, the comment that Mr. Hueni had was that there had been more than one event causing fracturing in the area. We still think that it could be like we've shown in Plate IV, and I would point out, Mr. Chairman, that that's exactly how I arrived at the presentation I have here, is that I assumed that there was more than one event; that in the first event you have certain fracturing and in the second event you have the fractures spreading.

Q Now would you now proceed back into the exhibit behind Tab B, and I'd like you to refer to the yellow sheets which relate to the interference testing information.

A Yes, sir. We'll refer to that and the paper, and I don't have the exhibit number of the paper that was presented --

Q This was Mr. Hueni's paper --

A Exhibit Thirteen, the SPE paper, and I'd point out once again, Mr. Chairman, that people dealing with fractured reservoirs have it so locked in their mind that there's only one kind of a fractured reservoir and that's a reservoir with matrix porosity and fractures in it, and of course that's what this paper has to deal with, which does not have anything to do with our pure, fractured reservoir in Canada Ojitos, and I would like to note that we made the interference test, we made determinations from that interference test that outside of the test area, this large area, which I say is being sampled by the interference test and which Mr. Hueni declines to comment on because he doesn't think the EI formula applies, we concluded that the transmissibility was some 20 to 40 times higher than what we measured in the individual wells, the average reservoir transmissibility.

Two years after we ran an interference test we drilled a well a couple of miles from the test area, and sure enough, we found the reservoir had that high transmissibility.

We ran a test after injecting gas, a steady state test that showed the transmissibility to be between 5 and 10 Darcy feet, just like we had calculated from our test.

So, Mr. Hueni says it doesn't apply. It certainly applied in our instance.

Q All right, Mr. Greer, are you now ready to go to the diagram you have (not understood) --

A Yes, sir.

Q The circle showing the wellbore correlation?

A Yes, sir, this is the relation where I show that the EI formula really does apply. It's under Tab B, where I showed the close correlation between the EI formula and the reservoir with the large internal radius, and Mr. Hueni refused to comment on that. I think it would be interesting, since it was a fractured reservoir he said doesn't apply.

If it's a homogeneous reservoir there's no question about it, no question about it, and still his statement that interference testing measures only the formation between the two wells is just wrong.

Q Now, Mr. Greer, will you go to your exhibits in the black book, Benson-Montin-Greer Exhibit Number Eight, and I'd like you to refer to the information you have behind Tab F concerning the water analyses on --

A Yes, sir. Mr. Hueni says that the saturations, the water saturations shown here, are not representative connate water saturations because water has been added by the drilling fluids. That's the very purpose of this -- of this first calculation on this yellow sheet.

It's pretty hard, Mr. Chairman, to push fluids into the core without pushing some oil out and that's what this is directed at, and it shows that with all those negative numbers, that it doesn't appear that there's a lot of flushing. If there's not a lot of flushing there's probably not a lot of contamination.

I notice that the water saturations used by the Mobil engineer pretty well fit the average as to what we show here, but I agree, I agree that there -- that the saturations shown here probably are not right. That's the whole point of the core analyses that we showed and how cooking the kerotin and the water hydration out of the shale completely invalidates the calculation which determines oil and water saturation. So that's my concern, Mr. Chairman.

I don't know. I don't think Mobil really knows. I don't believe anybody knows what that water saturation is and that's why I say it's possible to be assigned 100 percent and not any effective permeability whatsoever.

That's a possibility.

Q Mr. Greer, do you have anything further to add to your testimony at this time?

A No, sir.

MR. CARR: That concludes our re-rebuttal.

MR. STAMETS: Okay. Do you all have anything further?

MR. CARR: At this point we do not.

MR. STAMETS: Are there questions of Mr. Greer?

MR. LOPEZ: No.

MR. STAMETS: Does anyone have anything they wish to offer at this time, any additional direct testimony, cross examination, or are we ready for closing statements?

MR. LOPEZ: I have just two things to do, Mr. Stamets.

GREGORY D. HUENI,

being recalled as a witness and having been sworn and remaining under oath, testified as follows, to-wit:

REDIRECT EXAMINATION

BY MR. LOPEZ:

Q Mr. Hueni, you've heard what Mr. Greer just stated, so does this testimony in any way change any of the opinions or conclusions you've reached in your testimony this morning?

A No, it doesn't change any of my conclusions.

MR. LOPEZ: At this point before getting to closing I would like to offer our Exhibits Fifteen and Sixteen. They are letters addressed to the Commission by American Penn Energy, Inc., and Kodiak Petroleum, Inc.

The first letter from American Penn is dated August 26th, 1986, and is submitted by Mr. Al Hermanson, Vice President of Production. Mr. Hermanson attended all the hearing through last Friday but couldn't be here today.

The same is true for Mr. Kent A. Johnson, President, who signed the letter from Kodiak.

Apparently some of these exhibits have the signature page left off of them. I think if you just take a minute to read these two letters, rather than my reading into the record (not clearly understood), but I would like them included in the record.

MR. KELLAHIN: Mr. Chairman, we would object to formally including these letters in the transcript of the hearing. Obviously the witnesses are not available to authenticate the letters. I believe the custom and practice of the Commission is to allow various interested parties to submit communications directly to the Commission and have the Commission read them and use them for whatever purpose you want, but I believe they're not properly authenticated and ought not to be part of Mr. Lopez' case and marked as exhibits.

MR. LOPEZ: My response to that, Mr. Chairman, is I did enter my appearance on behalf of both companies at the beginning of the hearing. We have three hours to do with as we wish today. We've certainly heard from Mr. Greer on much hearsay, which he admitted as much this morning. It it's allowed in, I don't see how this is any different.

MR. STAMETS: The Commission will accept these exhibits and give them the weight that we have always given letters which have been received.

That is, we'll accept them for what they're worth.

We have also received a letter from Amoco Production Company which says a number of things including that it's their opinion that the applicants and protestants presented technically competent testimony concerning the reservoir and various production considerations.

The fact that the testimony presented was in part so diametrically opposite demonstrates the need for additional collective reservoir studies.

They say if we err, we should err on the side of the prevention of waste. They take no position on spacing and unitization issues; whatever we do should be of limited duration, not exceeding ninety days.

And there are copies here for everybody at the close of the hearing.

Are there closing statements?

MR. LOPEZ: I'd be glad to do it. Are there any comments from the audience? I mean I know the Howards are here but I don't think they could stand the distance, either.

But there are other people here.

MR. STAMETS: Feel free to go ahead. I'm ready to.

MR. LOPEZ: Mr. Chairman, Members of the Commission, I'm certain I can be quite brief. I think after five days you've either got it figured out or you're so hopelessly confused that nothing I could say could straighten that out.

I would first like to state that it is our position that there clearly is no crisis. We don't reserve to epithets and we will try and restrain ourselves from sanctimonious self-congratulation and the condescension that we saw evidenced on the other side and to which we take exception.

The position of Mallon and Mesa Grande in this case is one which is a sincere and intense attempt to reach what we consider to be a rational and prudent compromise between the two opposing views taken on the reservoir producing characteristics of the Gavilan-Mancos Pool.

We believe that the restriction on production based on the gas/oil ratio limitations, as we've recommended, is the only one that made sense. For the period during which the Technical Subcommittee can continue its work, it would seem, as we've recommended, that this period of study probably should be concluded by the time the whole issue of spacing on the Gavilan-Mancos Pool is re-examined by the Commission in March pursuant to its earlier order.

This is a classic case where Mr. Greer has gone from preaching to meddling. It has been demonstrated that Mr. Greer has no interest in the Gavilan-

Mancos Pool. His interest lies in the West Puerto Chiquito Pool.

There are three wells that I will address later, but which clearly lie on the western side of the permeability barrier or restriction, however you wish to characterize it, which have producing characteristics clearly more similar and identifiable with the Gavilan-Mancos Pool and which should be treated similarly.

The interests of Mallon and Mesa Grande have been demonstrated to be significant and large. The interests of the other working interest owners who support our position have also been demonstrated to be of significance and major.

We will hear that Mr. Greer has had twenty-five years experience in the Canada Ojitos Unit and that our various witnesses, because of their youth, and because of their inexperience in the San Juan Basin, which has not really been demonstrated, carry no weight.

I think quite the contrary. There may be some benefit to traveling outside of San Juan County and seeing how the rest of the world operates and how comparisons with other comparable reservoirs throughout the world may shed light and knowledge with respect to the producing characteristics of the Gavilan-Mancos. So if it is a condemnation that our witnesses have in fact traveled outside San Juan County, so be it. We think it's a positive benefit and that they haven't been subjected to the blinders of having one year experience repeated twenty-five times over the course of history.

The good faith and serious nature of Mallon-Mesa Grande is further demonstrated by the fact that they selected as competitors who have been in dispute before this Commission on this various pool, to select an independent third party in whom they had confidence to tell them the real facts.

The acreage position and the producing position of both these companies clearly demonstrate their major commitment to this pool. There are no two operators that want a bigger bang for their buck and it is in this vein and in this sense that they presented their testimony here today.

What we've heard from McHugh and Greer is what at best can be characterized as a misguided attempt to compare apples and oranges.

At worst it is a thinly disguised attempt to intimidate the other working interest owners in the pool into a unit of their making while at the same time allowing McHugh to capture the reserves of offset operators in the pool because of his position and because of the history of the production of his wells, as well as providing an opportunity for Mr. Greer to continue his traditional posture of not drilling any wells and of claiming that one well will drain the entire San Juan Basin.

The evidence that we have that we are comparing apples and oranges, and that the West Puerto Chiquito is different and not applicable to the Gavilan-Mancos Pool, is first demonstrated by the fact that after twenty-five years of drawdown in the Puerto Chiquito, and after the production of millions and millions of barrels of oil, we only have 80 pounds difference in initial reservoir pressures between the Puerto Chiquito and the Gavilan-Mancos.

In addition, this separation is further supported by the fact that the interference test performed on the Dugan-Greer wells up in the northwest, or the northeast portion of the Gavilan-Mancos Pool, across the unit boundary, experienced immediate interference within a matter of hours.

There is further support for the separation by the fact that Mr. Emmendorfer's testimony demonstrated that both horizons above and below the Gavilan-Mancos experienced different geological characteristics and pinch-out at the area of the permeability barrier.

The real similarity between the

two pools is that it's a highly fractured, both of them are highly fractured reservoirs. At least this is what we initially heard from Mr. Greer as of two weeks ago.

If I understood the testimony of Mr. Roe and Mr. Greer at that time, we were all in agreement that the Gavilan-Mancos, as well as the Puerto Chiquito, were one great, big barrel with communication throughout the horizon.

Now we've heard contradictory testimony today that we have stratified horizons in the Gavilan-Mancos. I don't know what their true position is. The record currently reflects that they've taken both sides of the issue.

I don't think it would gain us anything to re-examine all the engineering testimony that you have heard today. It is clear that the two camps have diametrically opposed views.

The thinly disguised attempts of the Greer-McHugh camp to intimidate other working interest owners into a unit simply won't fly. We're pretty mcuh divided 50/50. In order to get statutory unitization it's going ot take at least 75 percent volunteer joinder and that can't be reached.

The Greer camp suggested that the 1,200 barrel a day ratio should only be temporary for ninety days until unitization were accomplished. If we were all in agreement, I seriously doubt that unitization could be accomplished within ninety days of today's date.

The only true issues before the Commission are the issues of correlative rights and the prevention of waste.

Let's take the first -- or the last first, with respect to the prevention of waste.

There has been no evidence, in fact without re-arguing it, I would say the evidence is convincing that from the position of Mobil and clearly from the position of Mallon-Mesa Grande, that there will be no gain or loss to ultimate recovery in the pool if you restrict or don't restrict production. I'll let the testimony and the record speak for itself.

The only -- the basis, only basis on which Mr. Greer claims waste will occur is due to down dip drainage, or gravity drainage. I think the evidence has been ample that the difference between the degree of slope of the Puerto Chiquito and the Gavilan-Mancos indicates that the Gavilan-Mancos will not experience the kind of vertical drainage recovery that Mr. Greer has enjoyed over the last twenty-five years, but assuming for purposes of argument that there is something to what he says, we move on to the issue of correlative rights.

His position would be a clear violation of other working interest owners correlative rights because the evidence is uncontroverted that the McHugh wells lie on the down dip slope, have enjoyed the greatest production historically in the pool, and have the greatest presssure drawdowns; consequently, this thinly disguised attempt is no more than an effort to severely restrict production so his portion of the pool can be repressured and any oil that might otherwise be drained by others, according to the rules of the Commission, would migrate towards their leases, clearly in violation of the other parties' correlative rights.

My final point would be that if the Commission were to adopt any other recommendation than the one that we've suggested, which we feel is a conservative and rational approach, and one that is clearly between totally contrary views as to how to produce the reservoir, that the effect, or if you were adopt the McHugh-Greer approach, that it would indeed affect the drilling of additional wells, especially at a time, which the Commission can recognize, may be the time that we will enjoy the highest price for the product, because historically, after January the prices drop, and that in fact the result will be that the ultimate recovery will be affected because prudent operators will not be allowed to develop the pool on a consistent and rational spacing pattern so that it can be -- so that the production can be fully realized.

My final comment would be to call your attention to the last Dugan Exhibit Four and point out that the only scenario under which the effect of restricted production on the operators in the -- the major operators in the pool that would have less than two percent variance between operators, would be the proposal that the Mallon-Mesa Grande group has put forth, namely, the -- or close to it, it's 588 GOR; we selected 646, with the current oil allowable remaining at 702.

That has the most even effect across the operators as their exhibit shows. Any other exhibit would have a greater impact adversely on the Mallon-Mesa Grande group and a commensurate advantage to the Greer-McHugh group.

I'm sure my other cohorts will have other things to add but I think that fairly well summarizes our position.

MR. STAMETS: If your other cohorts have about five minutes apiece that they'd like to add at this point, we would provide that opportunity.

MR. PADILLA: Mr. Chairman, Members of the Commission, Mr. Kelley, this is a very important case just by the cross section of audience that has been here during the course of this hearing.

We have had producers. We have had royalty owners. We have had refining companies and obviously the parties involved in this case who have contested the application vigorously.

We are comparing in this case the West Puerto Chiquito and the Canada Ojitos type of production with a competitive basis. Probably it is too late at this point to even attempt to compare those.

We have a number of producing wells in the Canada Ojitos Unit that on the relative basis produce a lot of oil. The mechanisms for recovery of the oil are two entirely different things.

If we go and say that an analogy of apples and oranges is incorrect. It's more an analogy of apples and a brick.

With respect to the nature of the emergency, I was working on what I was going to say today last night and I looked at Webster's definition of emergency. That definition is that it's -- refers to any sudden or unforeseen situation that requires immediate action.

A synonym for emergency is crisis, another word that has been used around here by the applicants in this case. It refers to an event regarded as a turning point which will decisively determine an outcome.

Now, we have had two sides present testimony here. On Friday the chairman pointed out that both sides had done an equally good job and I don't see anything decisive about the application and the case presented by the applicants in this case. The true nature of what's going on here is that you have, especially in the McHugh application, they have at least twenty-eight wells or in that order, which have cumulative production of 1.3-million barrels.

At the same time they're trying to restrict the allowable and at the same time severely and -- penalize the production that can be obtained from the Mallon wells, in which Koch Exploration has its working interest.

So what we really have here is that on the Greer side Mr. Greer, obviously, doesn't want to drill any wells because it's not within the contemplation of the operation of his unit.

On the competitive side, on the Gavilan Unit, you simply are bound by the current regulations on spacing. It's must a matter of producing that and there has been on compelling testimony here one way or the other that the emergency exists and that we should be bound by what the applicants say, other than the fact that this morning we have reduced the scale, I guess, from a reservoir in an emergency or crisis situation to a reservir in trouble.

As I view that, it seems like it's a down -- it no longer is an emergency situation, presumably based upon the presentation that was made by Mr. Hueni.

As far as a compromise is concerned, we have presented evidence here that in the nature of a compromise, to try to get some kind of a study that has been going on. Now, as I understand this compromise, we may have compromised ourselves away. As I see this thing, we have through the course of this hearing seen only the cartoon and the main feature is to be presented later by the applicants.

I'd venture to say that there are going to be further proceedings regarding this development of the Gavilan-Mancos Pool and I think we have made objections regarding testimony that was presented regarding units and with regard to spacing.

Certainly acreage has been totally ignored in this case. Twenty-eight wells and twenty-eight proration units, maybe with one exception. Acreage is important and I think that the Continental Oil case versus the Oil Conservation Commission has not been followed and I understand you have to determine total reserves as reasonably as can be done, or as practically as can be done, but I think that that has been totally ignored and that has been missing. You're simply taking some kind of a new formula and it's not followed any case authority for any equitable method of allocating production in accordance with the conservation laws that have been (inaudible) by the Commission.

Thank you.

MR. STAMETS: Thank you, Mr. Padilla.

MR. PEARCE: Thank you, Mr. Chairman.

Following along the line of my witnesses to this proceeding, I'll try to move swiftly. I think that's for the benefit of everybody here, but let's see.

What I want to do in the next couple of minutes is try to bring this thing back down out of what I consider the ether. We've got conflicting petroleum engineering opinions. We've got more data floating around this room than we can possibly analyze and frankly I'm not sure we know what to do with it.

I want to bring us back down to where I think we're supposed to be in this proceeding.

We're here today because Jerome McHugh filed an application for a lower limiting gas/oil ratio and lower production allowables for the Gavilan-Mancos Pool.

Now this case was consolidated with the case from the West Puerto Chiquito Mancos Pool but the applicant in that case has said he doesn't want to be here by himself and if you don't grant Mr. McHugh's application, he don't want you to grant his.

For that reason I'm not going to pay any attention to the West Puerto Chiquito because it hasn't got anything to do with what's going on here. He's talking about some possible future boundary agreement between the two pools. That's far enough down the road that I'm not going to worry about that. I don't think we have to worry about that in this room today.

What we've got to worry about today is Mr. McHugh's application, and when we started this hearing five hearing days ago, and a couple of weeks, counsel for Mr. McHugh said that we have a state of emergency and he said that he'd show that the pool was in the midst of a dramatic, irreversible, reservoir-wide pressure decline and production changes. He said that he'd show that the accelerated pressure declines and the increasing dissipation of reservoir energy are resulting in waste.

Now, Mr. McHugh filed this application and by filing that application Mr. McHugh took the burden upon himself. I don't think the record shows that he's met that burden and in the absence of him meeting that burden, I don't think you can grant his application and I don't see any need to compromise on an application that ought to be denied. I don't think that's fair.

This pool is operating under statewide rules and those rules were themselves a compromise, I think. I think history will show that if the Division did not know specifically what should be done, the determined statewide rules ought to apply.

I don't think the Division or anybody in this room knows what ought to be done and I think the statewide rules ought to apply. I think that's why we have statewide rules.

Let's look at what Mr. McHugh has shown us so far.

The first witness to this proceeding, outside of a landman, I guess, the second witness, was Mr. McHugh's own geologist.

Mr. McHugh's geologist testified that the developed area of this pool showed what he called very low relief. All the structure maps that we've seen in this proceeding so far confirm that. Maybe a thin pancake up there on top, but it's flat.

The same McHugh expert witness

concluded that this was a solution gas drive reservoir. That's what he said it was.

Mr. Roe, the petroleum engineer who's primarily responsible for the applicant's operation in this area agreed with that. He said, and I quote: We indicated that solution gas drive is our primary production mechanism.

Further on he said, the fact that GOR is increasing is something that is predictable and we should expect in a solution gas drive reservoir.

Mr. Roe plotted some Gavilan production data dealing with pressures and GORs on a graph which have been around for a long, long time, and we all showed you that graph. It was that infamous orange piece of paper and it looked like that, and Mr. Roe said, that if you exclude the early production when he thought this pool was producing above the bubble point, if you excluded that data, that he suspected that pressures and GORs in this pool would match the predicted solution gas drive curves, which are in his exhibit.

That graph indicates that ultimate recovery from a solution gas drive reservoir is not rate dependent. I asked him the question and he answered the question. He said, no, if it's solution gas drive it doesn't matter whether you take it out quickly or you take it out slowly, you don't get any more oil.

Mr. Chairman, if the reservoir is performing as you would expect it to perform, and if the pressures and the GORs are matching the predicted curves for those two sets of data, and if the ultimate recovery is not increased by reducing the rate of production, I don't understand what the emergency is out here.

(Interrupted by turning tape) primarily a solution gas drive reservoir, there may be a gravity production mechanism which needs to be utilized.

Let me just hang this up for a minute so I can talk about it and maybe it will speed me up, Mr. Chairman.

This is -- this happens to be Mobil's structure map. It's not all that different from other folks structure maps. The testimony, Mr. Chairman, indicated that the flattest part of the West Puerto Chiquito Pool is twice as steep as the steepest part of the Gavilan Pool and therefore gravity is a factor in the Gavilan Pool.

Now I didn't follow that logic, since their own geologist indicated that it was an area of very low relief, but if you look at the pool, Mr. Chairman, what you find is that there are only two sections which are going to benefit from gravity drainage, if there is any, Sections 20 and 29 of 25 North, 2 West. Both those are

McHugh tracts.

To the west of that are two short sections in which Mr. McHugh, the applicant in this matter, has proposed well locations.

We've also had the indication during this case, Mr. Chairman, that these is a possibility of secondary gas cap recovery mechanism. We don't see the type of structures which would lend themselves to that mechanism.

In addition, the geologist for Mr. McHugh testified that high GORs seem to be related primarily to areas of higher production rather than structure.

In contrast to this gravity structure theory bouncing back and forth across the table, one party to this case has presented you with core data which indicates that the matrix will contribute production in this reservoir. That core analysis has been backed up by properly done log analysis.

Mr. Chairman, it's right, if you let the matrix produce in a field, it will produce, and once again, that matrix production is not rate sensitive. The matrix will give up that oil slowly or quickly, and I don't think it is waste to let that matrix give it's oil up more quickly. It's not going to give up more oil if you slow it down. It's just going to make everybody wait longer.

Finally, Mr. Chairman, I feel compelled to express my concern about some of the testimony that's gone on in this case.

Mr. McHugh's geologist took the stand and he testified, and I'm quoting him, Mr. Chairman, if we are not prepared at the end of this proposed ninety day temporary rule to make application for a Gavilan unit, then we will be back for a further reduction in production rates at that time.

Mr. Chairman, that has an ominous ring to us and we don't like it. This Commission is not authorized by the Legislature to force anybody into a unit for primary recovery. There are very limited circumstances when this Commission can force anybody into a unit for secondary or terciary recovery, and we are concerned what we have here is an application that tries to get the Commission to help the applicant do indirectly what the Commission itself cannot do directly, and that's force people to join a unit to save their businesses.

This morning I sat down and I looked through Mr. Roe's Exhibit Number Three, Dugan Exhibit Number Three, which had the cumulative productions, and as has been pointed out to you a couple of times in the last couple of minutes, Mr. McHugh's wells so far have produced more than a 1,300,000 barrels of oil. Mr. McHugh has twenty-three wells out here and he's indicated during his testimony that those wells cost about $500,000 a well.

If you take into consideration the gas production that he's had with that oil production, I think Mr. McHugh's got payout on his wells. He doesn't have any money on the table. He can afford to reduce his income string for as long as it takes to force everybody into a unit because he's got payout. That's not the case for other operators in this pool, Mr. Chairman.

We're extremely concerned. We don't have wells that have been a long time and we've got a lot of money on the table right now and if you reduce allowables and you reduce production, we can't earn return on that money.

During his testimony this morning Mr. Greer indicated that there was in his opinion a normal human tendency to accept the things that support your initial conclusion. It seems to me that we've got some of that going on from the applicant in this matter. I'm afraid the applicant has concluded that he needs to reduce allowables in order to enhance the recovery from his already partially depleted wells. The operators and owners of other tracts in this pool have come to a radically different conclusion.

For these reasons, Mr. Chairman, Mobil asks that the application of Jerome P. McHugh to lower the limiting gas/oil ratios and lower the allowables in this pool be denied so that other operators in this pool who have not been the beneficiaries of long, high production, be allowed to drill the wells that are necessary, necessary wells for them to recover their fair share of reserves by utilizing their fair share of this reservoir's energy.

Thank you, Mr. Chairman.

MR. KELLAHIN: Mr. Chairman, I'll be the first one to tell you that most of the cases we do over here are routine, garden-variety cases that I venture to say both you and I forget after we do them. We've done it over again.

But occasionally, every five or six years, a case coms along and grabs everyone's attention and gives the Commission the unique opportunity to exercise its discretion and make a permanent contribution to oil and gas conservation. This is one of those kinds of cases.

We think that you do not have to decide right and wrong in this case. You don't have to be an engineer, a geologist, or any technical person, to resolve this case. We hav abundant quantities of all those kinds of people that can talk ad infinitum about what to do with this reservoir.

What we need is some wisdom and some common sense from you gentlemen to help us out of this predicament. It's one we are creating for ourselves and you can see by the polarization of the parties in this case you must intervene or serious consequences will occur to this reservoir.

Mr. Padilla indicated that there was no Oil Conservation concept that was involved in this. This case is a bedrock of conservation; it's a question of waste. It has nothing to do with economics. If we could resolve the economic issue we'd have done that among ourselves.

The waste question is one you need to address and help us resolve and it's simply whether or not this pool is being operated in such a way that it's inefficient, excessive, and improper. That's the very first sentence out of your book.

It's not very often you get a case squarely on that issue. Why don't you need to decide right and wrong? Because what you need to do is write the next chapter of what may be a very long book.

The first chapter was the spacing case where the Commission agreed several years ago to 320-acre spacing on a temporary basis.

This is the next chapter in the story and it's a chapter based upon whether or not we take and seize the fading opportunity to get gravity drainage recovery out of this reservoir or forever lose that chance. Depending upon how you write that chapter we're either going to have a tragic example on how to mismanage a reservoir or a textbook case on how the Commission ought to conduct its affairs.

I said awhile ago you don't have to be an engineer or a geologist to figure out how to handle this case and I sincerely believe that. I've sat here for as many days as you have listening to testimony that I couldn't comprehend; I haven't a clue as to what some of these guys are talking about, but I don't think you have to understand that in order to break the polarization of the parties. This is not a one time case. It's a temporary solution to give us a time so that these fine technical people can help us resolve the issue of how to produce this reservoir.

I think there's only two things that you have to do. One is come up with a solution that compells the working interest owners to resolve their own problem in this reservoir.

The second thing is you must take sufficient action to prevent waste and conserve the reservoir energy in this pool.

What position will you don? It's not the classic one where you can take each extreme, cut it down the middle somewhere in a compromise and think you've solved the problem. We've got a stalemate now. I suggest to you that if you adopt Mesa Grande-Mallon approach, that just perpetuates the stalemate and we're no farther along tomorrow than we are today.

Let's examine the position of the various parties in the case.

Mobil's got an interesting position. They've got two wells that produce in this pool. They come in here and say, "There's nothing wrong, looks fine to me. Got a lot of matrix production down there, we're going to suck it out and draw that pressure right down." Wouldn't that be great? We'd love it if they're right.

But what if they're wrong? What if you don't take action and they turn out to be wrong? We've blown our chance to get what Mr. Greer and Mr. Roe have said they think will occur in this reservoir, the impact of gravity drainage.

Mobil's not alone on that position. Koch, Mesa Grande, and Mallon, as well as McHugh and Greer, all realize something must be done. It's a question of degree. Mesa Grande and Mallon have suggested that in order to effectively produce the reservoir we must reduce the gas/oil ratio, if nothing else; bring that down to the solution gas/oil ratio, and then Mr. Hueni says everything works just fine.

That's great. What if Mr. Hueni's wrong? We've missed the chance to get the gravity drainage that Mr. Greer has experienced and established for you in the Canada Ojitos Unit, which he says will occur in the Gavilan-Mancos.

We need to seize upon that opportunity. In order to do that, I'm intrigues with Mr. Kelley's suggestion several days ago. I think he said why don't we just shut the whole thing in. That would get somebody's attention.

Maybe that is the approach except it's too extreme because that kind of drastic action will solve the first problem. It will get everybody to some kind of solution within the ninety day period, which is a small window to try to resolve the tremendous disparity of opinions you have here today, but it's going to take drastic action to get to that point.

How do we solve both of the solutions? Mr. Kelley's suggestion of shutting in the whole reservoir will accomplish one. It gets everyone's attention, but we contend it would be wasteful and it would violate correlative rights.

We've got to have a minimum producing rate in this reservoir that continues to let the operators recover some income source from this reservoir. We suggest that the level of voidage Mr. Roe has spent weeks and months examining is the level that ought to be adopted and it's the one that restores this reservoir to the producing rates in April prior to the drastic effects that he's testified to that we are seeing with the June and July produciton and the gas/oil ratios. They're going right out the (unclear). Everything we said to you back on June 7th has been supported by the testimony of our witnesses.

We think that's the solution; it's drastic. It's going to get the economic attention of the operators. It's what we have to have. It avoids potentially the stalemate and allows you, then, not to have to decide who's right or wrong about how the pool operates. You've taken the most conservative action available to you in order to give that mechanism of gravity drainage an opportunity to be further examined by these fine technical people.

As we went along I thought of all kinds of cute and clever things I thought were interesting and I've forgotten most of them. The one thing I think has made the biggest impression upon me in the last five days of hearing is Mr. Greer's testimony with regards to the effect of each day's delay in action in reducing the levels of withdrawal in the reservoir.

Mr. Roe has told us there is no loss of production; we're simply postponing it until some later date, but Mr. Greer has told us that at the rate of $150,000 a day we are losing the opportunity to take advantage of the gravity drainage.

This hearing started on August 7th. It is now August 27th and we've just thrown away $3,000,000.

MR. CARR: May it please the Commission, Benson-Montin-Greer Drilling Corporation is here before you today because we have an interest in the Mancos formation in the area which is the subject of these consolidated cases. This is a common resevoir. There's communication in varying degrees throughout the reservoir, and we have wells on both sides of the permeability restriction which runs across the subject area.

We're also here today because we have a problem with that reservoir. I don't want to be now accused of downgrading emergency to trouble to problem, but we have a problem because the reservoir is in trouble and it is in trouble because we have an emergency situation and we're here today because the operators in the pool cannot agree as to what must be done right now to deal with that problem, and so we come before you and we're presenting to you what is certainly a complex question. In doing this we are not looking for Solomon to come and split this for us. We're not asking somebody to give everybody a little something. We're asking for a decision that is based squarely and soundly on the statutory duty imposed on each of you by the New Mexico Oil and Gas Act.

This Commission is a creature of statute. Your powers are expressly defined and limited by the Oil and Gas Act and it is your duty to take what actions must be taken to prevent waste and to protect correlative rights.

If you are to carry out your duty in this case in view of the evidence presented, we submit you have no alternative but to act, to act now, to take meaningful action, action that will effectively address the problem which is clearly before you. A half decision, a compromise which merely reduces gas/oil ratios, is no decision at all. It leaves us with the same problem. It leaves us with no solution in the foreseeable future and it really gives no one here any incentive to get together and try and work this problem out.

We submit you must act immediately. You must limit production in the Gavilan-Mancos and the West Puerto Chiquito Mancos Pools. You need to limit to the 200 barrels a day per 320-acre unit and you need to set a gas/oil ratio of 1000-to-1 for a ninety day period, and if you do, it is our hope that the operators can get together and that real progress can be made towards solving the problem which is before you.

Now the evidence presented in this case has been extensive; it's probably better to characterize it as exhaustive, but I think any characterization of the evidence shows that we probably have excessive withdrawal rates in the Gavilan; that we have potential reservoir problems unless action is taken, unless it's taken now. If no such action is taken underground waste will occur.

We have evidence that excessive -- an excessive number of wells will have to be drilled in the area. This is surface waste, and the evidence shows that correlative rights in the area will be impaired unless action is taken.

If you take action, if we can work out something that will enable us to efficiently produce the reservoir, then all operators in the pool are afforded an opportunity to produce their just and fair share of those reserves.

If no action is taken and we are right and permanent reservoir damage occurs, then everyone's correlative rights are impaired.

Now those who are in opposition to this application would say, well, we're going to lose all this revenue. That's not true. That is simply not true. The revenue will be deferred and all we're seeking is that that be deferred and those reserves will be there and those reserves can be made up at a later time.

You have basically two solutions being proposed, one by Mr. Hueni for Mesa Grande and Mallon; one by Mr. Greer for Dugan, McHugh, and Benson-Montin-Greer.

Now what are we really looking at? We are looking at four weeks work, compared to the work of more than a quarter of a century.

We're looking at the work and the testimony of a man who's spent a large portion of his life studying and developing this area, and we contrast that testimony with a man who's hired to tear this work down.

Mr. Greer's testimony, we submit to you, is accurate and the reasons it's accurate, the reason it is accurate, is that it was not developed for the purposes of this hearing. It was developed so he could operate effectively the Canada Ojitos Unit. It was developed, it was used, and whether it is one lesson that took twenty-five years to learn or twenty-five one year lessons it's been proven right and his testimony is right.

Mr. Hueni's data and conclusions are based on information which is inaccurate and incomplete.

If you accept Mr. Greer's position and he is right, we submit you will have carried out your statutory duty.

If you accept Mr. Greer's position and he's wrong, some income will be deferred, but the reserves will still be there.

If on the other hand you want to accept Mr. Hueni's testimony and he is wrong, the only thing you will have done, and it will come back to you, you will have authorized waste and you will have impaired the correlative rights of every single operator in that area in that formation.

Yes, you're being asked to decide a complicated question but we submit it isn't difficult. What we're asking you to do is limit production, limit withdrawals for a ninety-day period, and we submit what we are asking you to do is consistent, based on this record, with what the New Mexico Oil and Gas Act directs you to do.

MR. STAMETS: Thank you, Mr. Carr.

(Thereupon a recess was taken.)

REPORTER'S NOTE: The following is the decision of the Commission as announced by Chairman Richard L. Stamets following the conclusion of presentation of testimony on Wednesday, 27 August, 1986.

MR. STAMETS: First of all let me begin by saying that this is probably the most difficult case that I have seen in many, many years. Also the overall quality of the testimony I thought was excellent on both sides, which is one of those things that makes it extremely difficult to render a decision in this case.

I would personally like to grant everybody's request, everybody's position; however, that cannot be. Perhaps Amoco said it best when they said that if we must err, there's always the opportunity to err, that we must err on the side of prevention of waste.

When we look at the evidence in this case, we believe that the preponderance of the evidence indicates that there will be some benefit to the reservoir from the gas which disassociates itself from the oil. We believe that McHugh, et al, indicated that might be from a major gas cap.

Mallon-Mesa Grande indicated that might be a gas cap on each individual well.

Nevertheless, to allow that gas

to be dissipated without doing its work certainly would waste reservoir energy.

Therefore we will reduce the gas/oil ratio, limiting gas/oil ratio in this pool as of September 1, beginning the proration period, the proration period beginning September 1, to 600 cubic feet a barrel.

As to the oil allowable, that is a much more complex issue.

702 barrels a day which applies currently in this pool is no magic number. This is certainly a number which would represent what an average pool in the state at that depth with that spacing should have.

At this point there seems little doubt that this is not an average reservoir. There is apparently little or no matrix participation in this reservoir; certainly not compared to the average sandstone reservoir or the average limestone reservoir.

There would seem to be less oil in each unit of reservoir in a fractured shale, in this fractured shale reservoir than you would expect under a similar sandstone or limestone reservoir.

We believe that there is a strong potential for gravity drainage to work in this reservoir.

There are equity problems, as well. Obviously McHugh's wells have been in this reservoir for some period of time. He has enjoyed the drainage.

Those who have recently completed would like to enjoy that same amount of drainage.

Nevertheless, the spectre of waste is quite clear in this pool.

We've had recommended a production level of 200 barrels a day. While this may serve to prevent waste, if the gravity drainage is as strong a factor as some of the testimony in this case would indicate, that does not address the situation of an operator who has only recently completed his well based upon the anticipated production which he will get from that well.

Therefore the Commission will for the short term adopt the lower allowable of 400 barrels per day, an allowable which we may reduce at a later time, or an allowable which we might increase at a later time.

We are most impressed by the engineering testimony on both sides. We would desire to see those people testify for the same ends the next time this comes before the Commission.

We would encourage everybody to try and arrive at a position which everyone can support. We believe that at any future hearing we must have much clearer evidence about gravity drainage in the Gavilan Pool. We must have much clearer evidence as to what -- how much oil is there in the unit or reservoir and how do each of the units relate to one another.

We would ask that the attorneys for McHugh and Greer supply us with a draft order which will have the appropriate findings and ordering paragraphs in conformance with the decision that we have announced here today, and which will go into effect at the beginning of the proration day, September 1, 1986.

I'd like to have that order by no later than a week from Friday morning.

MR. PEARCE: Excuse me, is it your intention to have this order in effect until it is changed or is there some time limit on this order?

MR. STAMETS: The application was for ninety days.

MR. KELLAHIN: Mr. Chairman, it said not less than ninety days.

MR. STAMETS: Not less than ninety days, thank you, Mr. Kellahin. Ninety days from September 1 is December 1, isn't that correct?

MR. LYON: Right.

MR. STAMETS: Not a very good time to have a hearing.

January? New legislature in session? Not a very good time to have a hearing.

They don't go home till March the 15th.

I don't really see a good time to have a hearing. What -- what my choice to do would be to have these in effect until further order of the Commission but to have a report from the committee and preferably a come in to Santa Fe and sit down with the staff, by about the middle of November, and let's see what kind of progress has been made at that time, and we will determine whether or not we should reopen this case again early in December, and attempt to take some additional action before the -- before January, 1987.

Any other questions?

If there is nothing further, I want to thank each of the participants and I look forward to seeing you again in a few months.

(Hearing concluded.)

C E R T I F I C A T E

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

Sally W. Boyd CSR

NMOCC/~~NMOCD~~ Case No. 8946
Hearing Date 8/7/86
Dugan Production Corp
Exhibit No. 1

GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico

Operator / Well Name	Location U-S-T-R	Completion Date	Cumulative 7/01/86[A] BO	MCF	RB	06/86 Production or Potential BOPD	MCFD	GOR	RB/D	Production 6/86 with Proposed Allowable Reduction BOPD	MCFD	RB/D
Amoco Production Co.												
Oso Canyon Fed #1	E 24-24N-2W	12/10/84	1508	NR	1508	10e	30e	3000e	57	10	30	57
Oso Canyon Fed A-1	F 14-24N-2W	02/03/85	0	0	0	10e	30e	3000e	57	10	30	57
Oso Canyon Fed B-1	F 11-24N-2W	02/05/85	2167	NR	2167	10e	30e	3000e	57	10	30	57
Oso Cny Gas Com C-1	F 15-24N-2W	Location	-	-	-	-	-	-	-	-	-	-
SUBTOTAL			3675	NR	3675	30	90	-	171	30	90	171
Dugan Production Corp.												
Divide #1	H 35-26N-2W	05/13/83	0	0	0	40e	30e	750e	67	40	30	67
Divide #2	P 35-26N-2W	Location	-	-	-	-	-	-	-	-	-	-
Divide #3	K 35-26N-2W	Location	-	-	-	-	-	-	-	-	-	-
Lindrith #1	O 36-25N-2W	11/19/84	4566	23438	43242	8	40e	5000e	74	8	40	74
Tapacitos #2	L 25-26N-2W	10/30/80	24877	17060	38660	27	22	797	48	27	22	48
Tapacitos #3	D 36-26N-2W	Location	-	-	-	-	-	-	-	-	-	-
Tapacitos #4	O 36-26N-2W	03/01/86	6591	4803	10747	153	115	751	256	153	115	256
Wendy #1	A 26-26N-2W	Location	-	-	-	-	-	-	-	-	-	-
SUBTOTAL			36034	45301	92649	228	207	-	445	228	207	445
Mallon Oil												
Davis Fed Com 3-15	O 3-25N-2W	Drilling	-	-	-	-	-	-	-	-	-	-
Fisher Fed 2-1	A 2-25N-2W	06/17/85	99375	54196	137138	455	576	1265	1177	158r	200	409
Howard Fed 1-8	H 1-25N-2W	07/18/85	70611	32402	97443	418	523e	1250e	1070	160r	200	409
Howard Fed 1-11	K 1-25N-2W	11/18/85	66250	72514	151160	583	914	1567	1821	128r	200	399
Johnson Fed 12-5	E 12-25N-2W	10/24/85	13014	30040	57810	95e	290e	3050e	548	66r	200	378
Post Fed 13-6	F 13-25N-2W	03/18/86	0	0	0	100e	80e	800e	176	100	80	176
Ribeyowids Fed 2-16	P 2-25N-2W	02/11/85	53786	17498	74225	160	162	1011	342	160	162	342
SUBTOTAL			303036	206650	517776	1811	2545	-	5134	772	1042	2113

GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico

Operator / Well Name		Location U-S-T-R	Completion Date	Cumulative 7/01/86[A] BO	Cumulative 7/01/86[A] MCF	Cumulative 7/01/86[A] RB	06/86 Production or Potential BOPD	06/86 Production or Potential MCFD	06/86 Production or Potential GOR	06/86 Production or Potential RB/D	Production 6/86 with Proposed Allowable Reduction BOPD	Production 6/86 with Proposed Allowable Reduction MCFD	Production 6/86 with Proposed Allowable Reduction RB/D
Jerome P. McHugh													
Beek's Babbitt #1		G 17-25N-2W	10/15/85	0	0	0	300e	225e	750e	501	200	150	334
Boyt & Lola #1		I 11-24N-2W	12/03/84	4648	28121	51605	7	25	3629	47	7	25	47
Boyt & Lola #2		D 12-24N-2W	01/10/85	8284	14482	28540	17	33	1946	64	17	33	64
Continental Divide #1		B 12-25N-2W	Location	-	-	-	-	-	-	-	-	-	-
Dr. Daddy-O #1		C 33-25N-2W	05/16/85	1887	629	2604	100e	75e	750e	167	100	75	167
E. T. #1		C 28-25N-2W	09/19/83	90346	50079	124677	104	340	3268	640	61r	200	376
Four O's #1	Lot	3 19-25N-2W	Location	-	-	-	-	-	-	-	-	-	-
Full Sail #1		O 29-25N-2W	06/15/84	106148	91703	198617	142	295	2078	572	96r	200	388
Full Sail #2		I 28-25N-2W	05/24/85	3819	7841	15230	171	440	2575	840	78r	200	382
Full Sail #3		F 29-25N-2W	11/01/85	2414	3484	7006	37	49	1312	100	37	49	100
Full Sail #4	Lot	3 30-25N-2W	Location	-	-	-	-	-	-	-	-	-	-
Greener Grass #1		J 10-24N-2W	08/20/85	2367	779	3266	72	24	329	99	72	24	99
High Adventure #1		H 8-25N-2W	Location	-	-	-	-	-	-	-	-	-	-
High Adventure #2		M 9-25N-2W	Location	-	-	-	-	-	-	-	-	-	-
Homestead Ranch #2		N 34-25N-2W	05/16/85	73849	29055	101912	619	374	604	872	200	121	282
Janet #1		A 27-25N-2W	02/17/83	123968	84871	192396	94	77	818	168	94	77	168
Janet #2		I 21-25N-2W	09/01/83	111815	94291	205113	156	350	2246	675	89r	200	386
Janet #3		E 21-25N-2W	12/18/85	2002	1066	2763	78	45	571	108	78	45	108
Lady Luck #1		A 5-24N-2W	02/21/86	1774	142	2448	100e	75e	750e	167	100	75	167
Loddy #1		F 20-25N-2W	08/30/85	0	0	0	350e	263e	750e	585	200	150	334
Mother Lode #1		H 3-24N-2W	09/02/83	2524	631	3483	222	297	1339	603	149r	200	406
Mother Lode #2		K 3-24N-2W	01/23/86	148065	123317	268863	49	21	426	68	49	21	68
Native Son #1		A 34-25N-2W	06/07/84	204242	59230	281854	288	154	536	397	200	107	397
Native Son #2		N 27-25N-2W	11/18/83	323124	364536	756591	440	1247	2834	2366	71r	200	380
Native Son #3		I 33-25N-2W	02/21/85	2762	624	3812	293	650e	2220e	1255	90r	200	386
New Horizon #1		O 2-24N-2W	10/01/85	553	1058	2068	9	36	4008	67	9	36	67
Twilight Zone #1		J 12-24N-2W	01/21/85	1998	4656	8954	4e	13e	3136e	24	4	13	24
Wright Way #1		C 2-24N-2W	09/29/83	98892	72799	162549	34	54	1601	107	34	54	107
SUBTOTAL				1315481	1033394	2424351	3686	5162	-	10492	2035	2455	5237

GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico

Operator / Well Name	Location U-S-T-R	Completion Date	Cumulative 7/01/86 A BO	Cumulative 7/01/86 A MCF	Cumulative 7/01/86 A RB	06/86 Production or Potential BOPD	06/86 Production or Potential MCFD	06/86 Production or Potential GOR	06/86 Production or Potential RB/D	Production 6/86 with Proposed Allowable Reduction BOPD	Production 6/86 with Proposed Allowable Reduction MCFD	Production 6/86 with Proposed Allowable Reduction RB/D
Meridian Oil Company												
Hawk Federal #2	C 35-25N-2W	03/25/84	68862	167004	320223	142	355	2500	679	80r	200	383
Hawk Federal #3	K 35-25N-2W	01/03/85	109583	144405	293571	219	189	865	409	200	173	375
Hill Federal #1	F 24-25N-2W	09/17/85	4986	15919	29998	200e	620e	3100e	1170	65r	200	378
Hill Federal #2Y	G 25-25N-2W	01/10/86	386	4	533	170e	119e	700e	268	170	119	268
Hill Federal #3	D 36-25N-2W	01/09/86	2300	50	3174	190e	147e	775e	325	190	147	325
SUBTOTAL			186117	327382	647499	921	1430	-	2851	705	839	1729
Merrion Oil and Gas												
Krystina #1	K 14-24N-2W	01/07/85	4944	20928	38900	20	133	6640	243	20	133	243
Oso Canyon Gas Com C-1	F 13-24N-2W	01/11/85	2390	7196	13606	10	31	3123	59	10	31	59
Rocky Mountain #1	N 24-24N-2W	01/22/85	1349	12528	22750	3	36	11879	65	3	36	65
SUBTOTAL			8683	40652	75256	33	200	-	367	33	200	367
Mesa Grande Resources												
Bearcat	O 22-25N-2W	04/21/86	2589	3980	7947	103	163	1580	324	103	163	324
Brown #1	N 17-25N-2W	03/20/85	20705	11149	28573	238e	857e	3600e	1605	56r	200	375
Gavilan #1	A 26-25N-2W	03/21/82	80810	501763	920077	36	526	14600	948	14r	200	361
Gavilan #2*	J 26-25N-2W	02/14/85	1207	23356	41976	6	182e	30400e	326	6	182	326
Gavilan #3	E 26-25N-2W	07/23/83	29149	239389	435830	43	111	2573	212	43	111	212
Gavilan-Howard #1	F 23-25N-2W	04/23/84	81071	773644	1404112	122	140	1144	290	122	140	290
Hatley Hawkeye #1	I 23-25N-2W	Location	-	-	-	-	-	-	-	-	-	-
Hellcat #1	F 22-25N-2W	10/19/85	533	0	736	100e	75e	750e	167	100	75	167
Invader Fed #1	D 1-24N-1W	05/04/86	957	1378	2772	24	53	2196	102	24	53	102
Intruder #1	I 20-25N-2W	Location	-	-	-	-	-	-	-	-	-	-
Marauder #1	N 8-25N-2W	04/17/86	1756	4847	9213	92	254	2760	483	72r	200	380
Phantom #1	M 16-25N-2W	Location	-	-	-	-	-	-	-	-	-	-
Rucker Lake #2	K 24-25N-2W	08/26/83	127271	85615	194822	118	344	2917	652	69r	200	379
Rucker Lake #3	L 25-25N-2W	08/10/83	93385	88403	188488	109	99	910	213	109	99	213
SUBTOTAL			439433	1733524	3234546	991	2804	-	5322	718	1623	3129

GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico

Operator / Well Name	Location U-S-T-R	Completion Date	Cumulative 7/01/86[A] BO	MCF	RB	06/86 Production or Potential BOPD	MCFD	GOR	RB/D	Production 6/86 with Proposed Allowable Reduction BOPD	MCFD	RB/D
Mobil Oil Corp.												
Lindrith B Unit 34	G 32-25N-2W	01/29/86	2354	5531	10630	111	306	2759	582	72r	200	380
Lindrith B Unit 37	G 4-24N-2W	01/29/86	5111	7072	14292	234	176e	750e	391	200	150	334
Lindrith B Unit 38	K 4-24N-2W	Completing	808	2670	5022	43	32e	750e	71	43	32	71
SUBTOTAL			8273	15273	29944	388	514	-	1044	315	382	785
Reading and Bates												
Howard Fed 43-15	I 15-25N-2W	03/04/86				100e	75e	750e	167	100	75	167
SUBTOTAL						100	75	-	167	100	75	167
TOTAL GAVILAN POOL AREA			2300732	3402176	7025696	8188	13027	1591	25993	4936	6913	14143
BMG Drilling Corp.												
COU #26 (K-31)	K 31-25N-1W	01/28/85	2126			2	1	700	3	2	1	3
COU #29 (E-6)	E 6-25N-1W	12/02/85	24854			616	795	1290	1620	155r	200	408
COU #30 (F-30)	F 30-25N-1W	Completing	0			100e	70	700	158	100	70	158
COU #31 (N-31)	N 31-26N-1W	04/09/86	11603			273	120	440	377	200	88	276
COU #32 (J-6)	J 6-25N-1W	05/31/86	1709			104	520	5000	960	40r	200	369
SUBTOTAL			40292			1095	1506	-	3118	497	559	1214
TOTAL STUDY AREA			2341024			9283	14533	1566	29111	5433	7472	15357

NOTES: Oil and Gas PVT Data: Bo = 1.38 RB/STB, Bg = 1.78 RB/MCF, Rs = 588 SCF/STB
* = Operated by E. Alex Phillips
r = Production Restricted by GOR Limit
e = Estimated
A = Amoco Production Co. Information for May and June not available at NMOCD
RB= Reservoir bbls.

DUGAN PRODUCTION ENGINEERING: 08/02/86: JR/BW - JR

Exhibit
#2

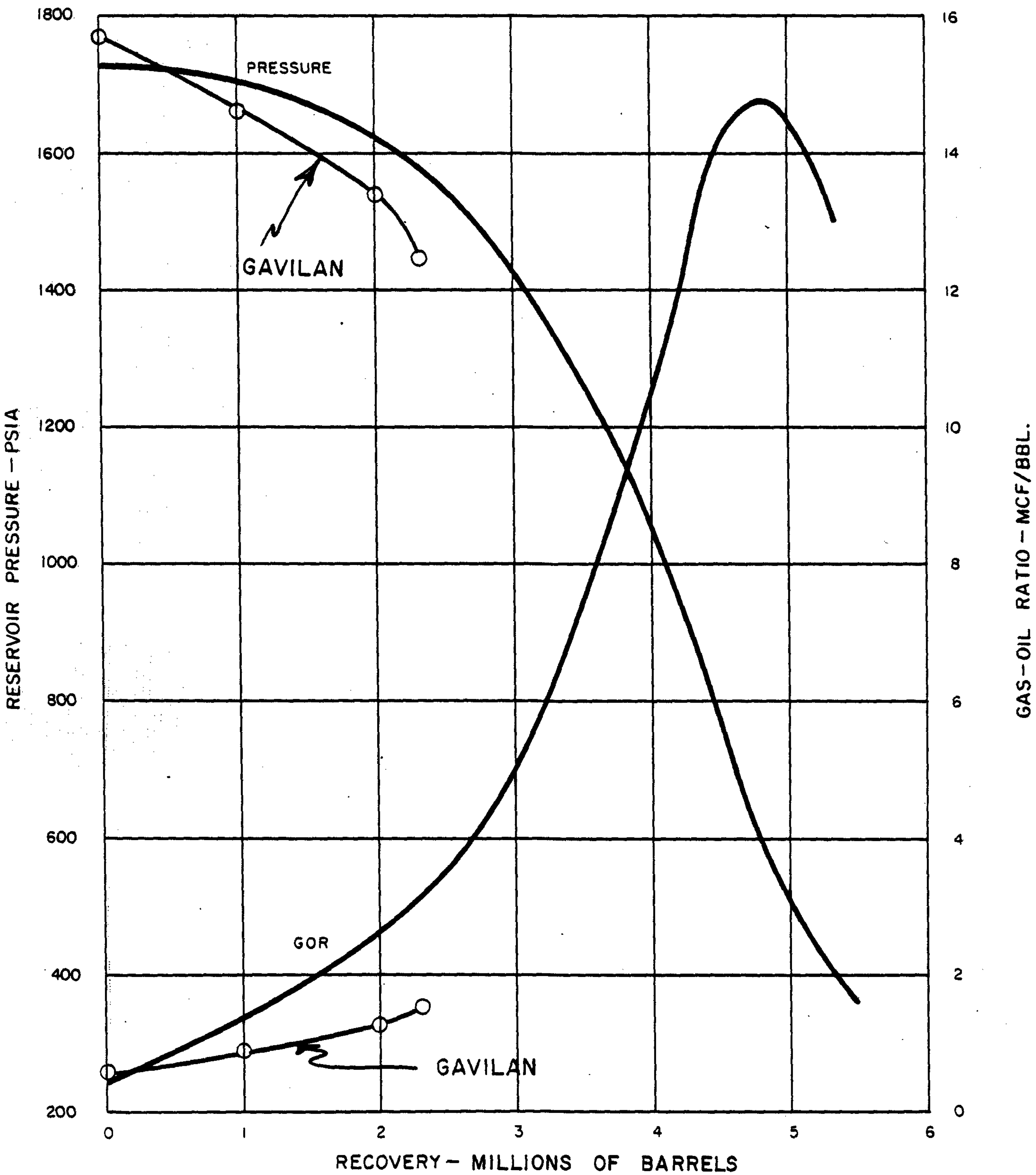
DUGAN PRODUCTION CORP.
EXHIBITS IN CASE NO. 8946
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

AUGUST 7, 1986

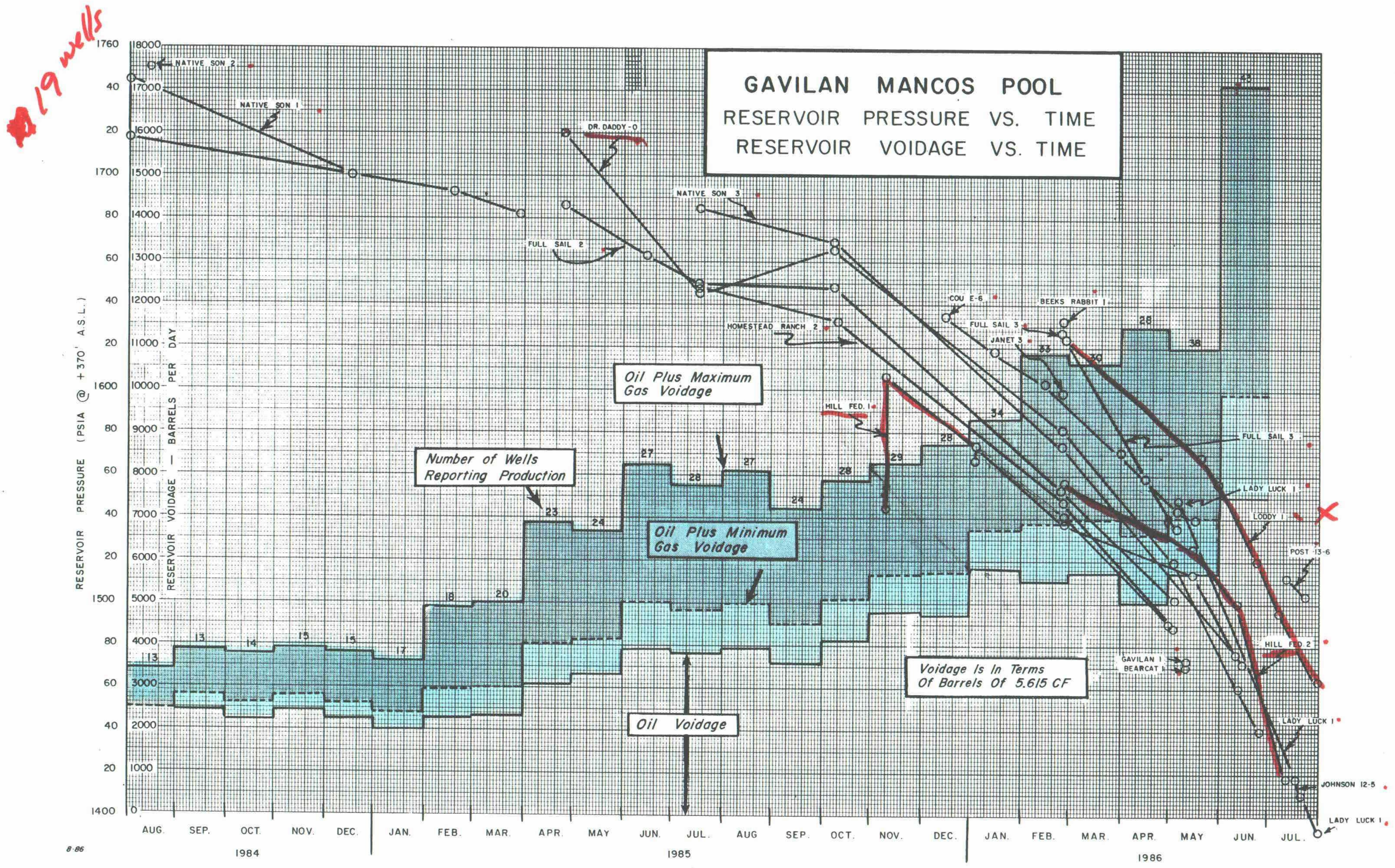
BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No.________ Exhibit No. 2
Submitted by________________
Hearing Date________________

COMPARISON
of
SOLUTION GAS DRIVE
PRODUCTION HISTORY

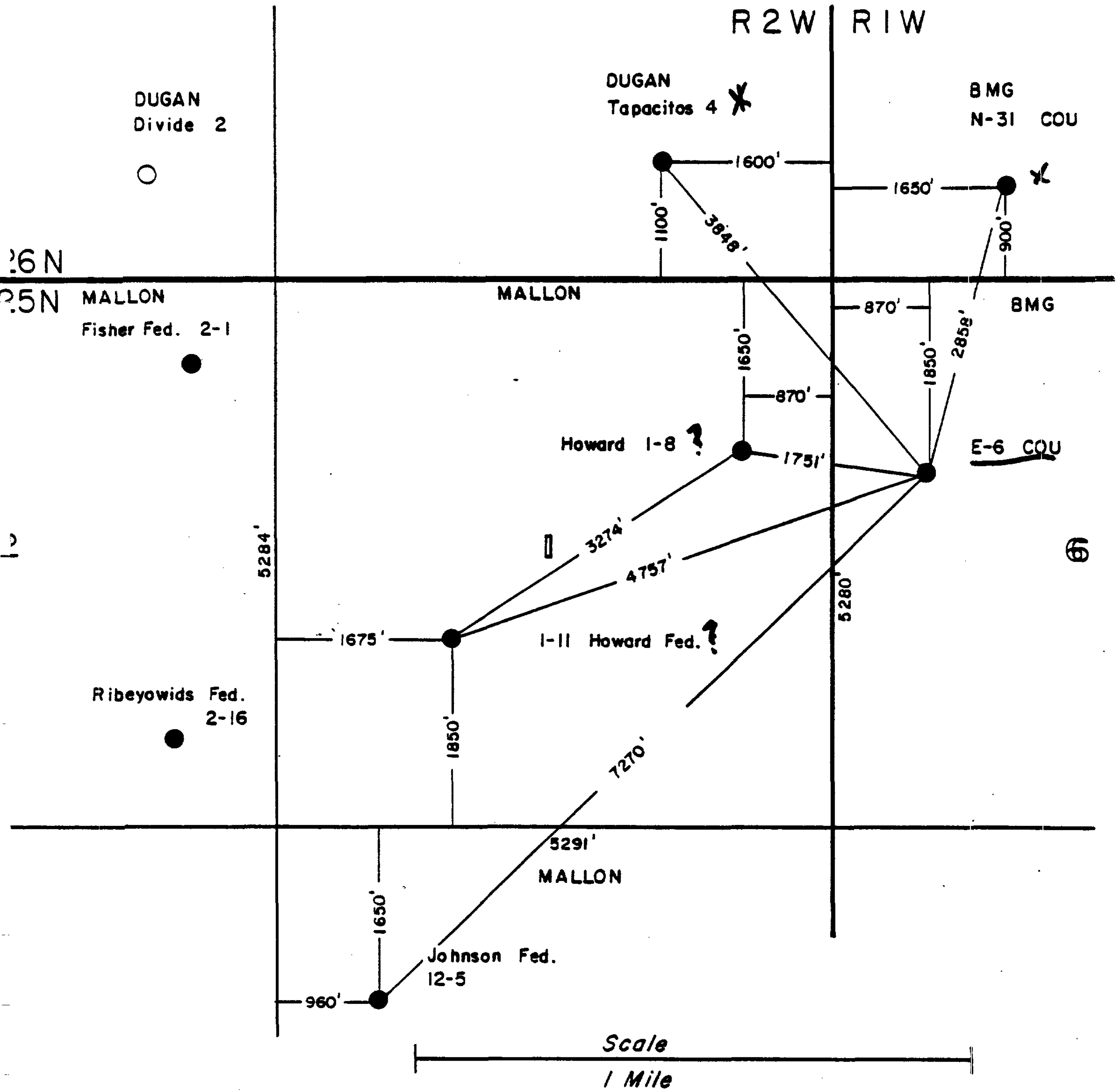
FOR A FRACTURED RESERVOIR
CONTAINING 100 MILLION BARRELS IN PLACE
WITH
GAVILAN ACTUAL PRODUCTION
(PVT Data Similar To Gavilan)



8-86


#19 wells
GAVILAN MANCOS POOL
RESERVOIR PRESSURE VS. TIME
RESERVOIR VOIDAGE VS. TIME
RESERVOIR PRESSURE (PSIA @ +370' A.S.L.)
RESERVOIR VOIDAGE — BARRELS PER DAY
Oil Plus Maximum Gas Voidage
Oil Plus Minimum Gas Voidage
Oil Voidage
Number of Wells Reporting Production
Voidage Is In Terms Of Barrels Of 5.615 CF
NATIVE SON 2
NATIVE SON 1
DR. DADDY - 0
NATIVE SON 3
FULL SAIL 2
HOMESTEAD RANCH 2
HILL FED. 1
COU E-6
BEEKS RABBIT 1
FULL SAIL 3
JANET 3
LADY LUCK 1
LODDY 1
POST 13-6
GAVILAN 1
BEARCAT 1
HILL FED 2
JOHNSON 12-5
AUG. SEP. OCT. NOV. DEC. JAN. FEB. MAR. APR. MAY JUN. JUL. AUG SEP. OCT. NOV. DEC. JAN. FEB. MAR. APR. MAY JUN. JUL.
1984
1985
1986
8-86

PLAT OF AREA OF PROPOSED INTERFERENCE TEST
MALLON #1-8 HOWARD
AND
BENSON-MONTIN-GREER #E-6 CANADA OJITOS UNIT

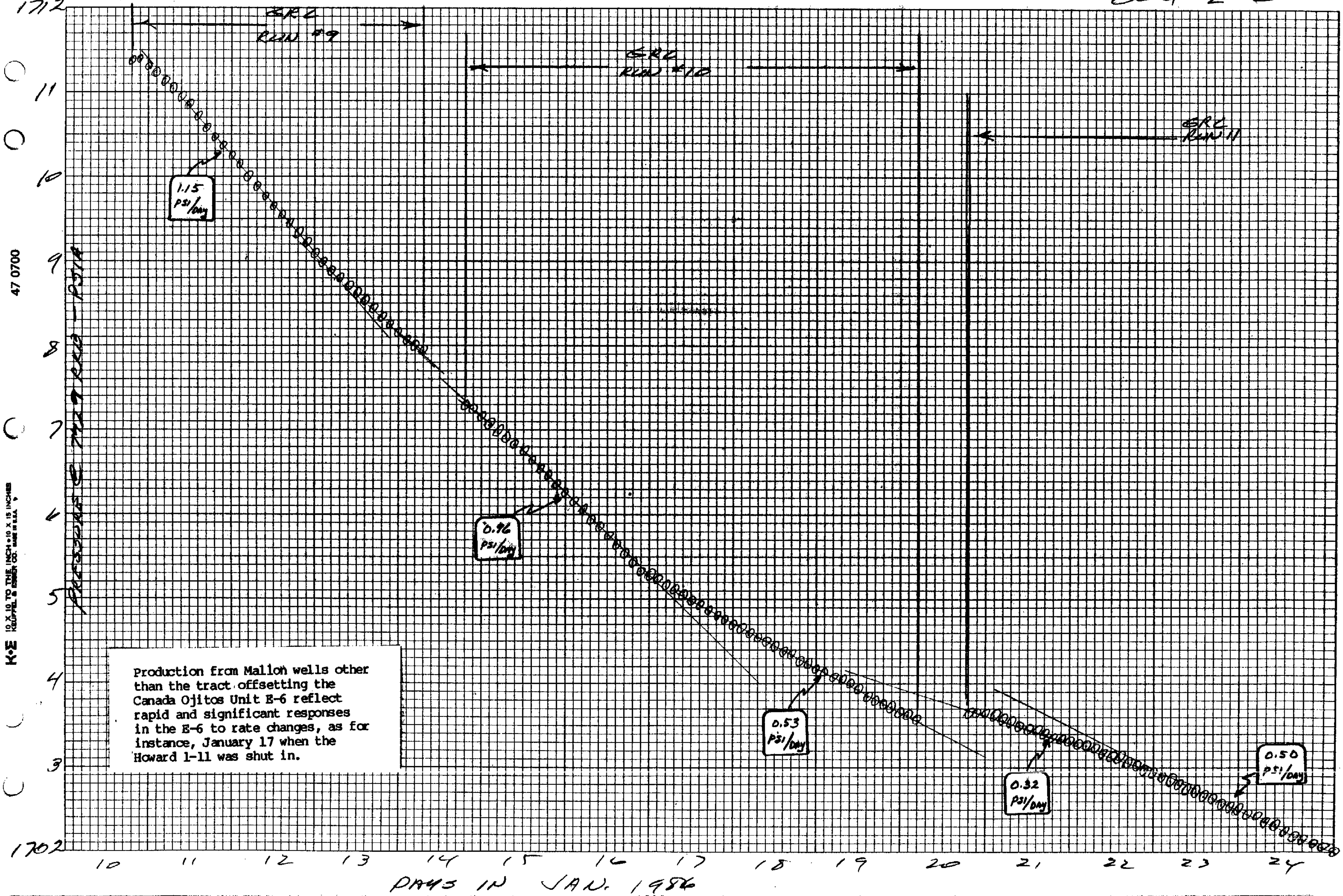


/85

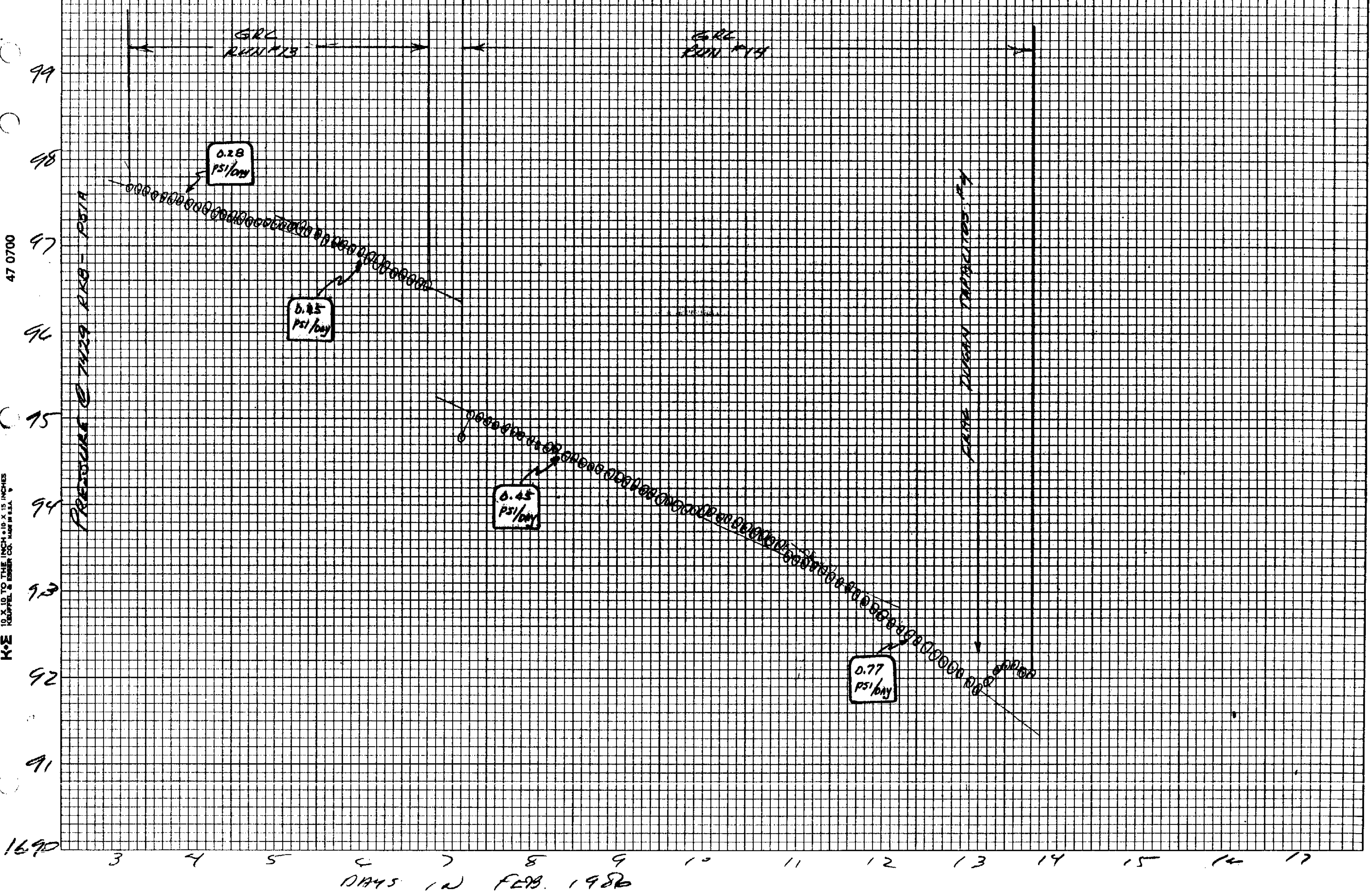
Revised: 6-23-86

GRAPH 3

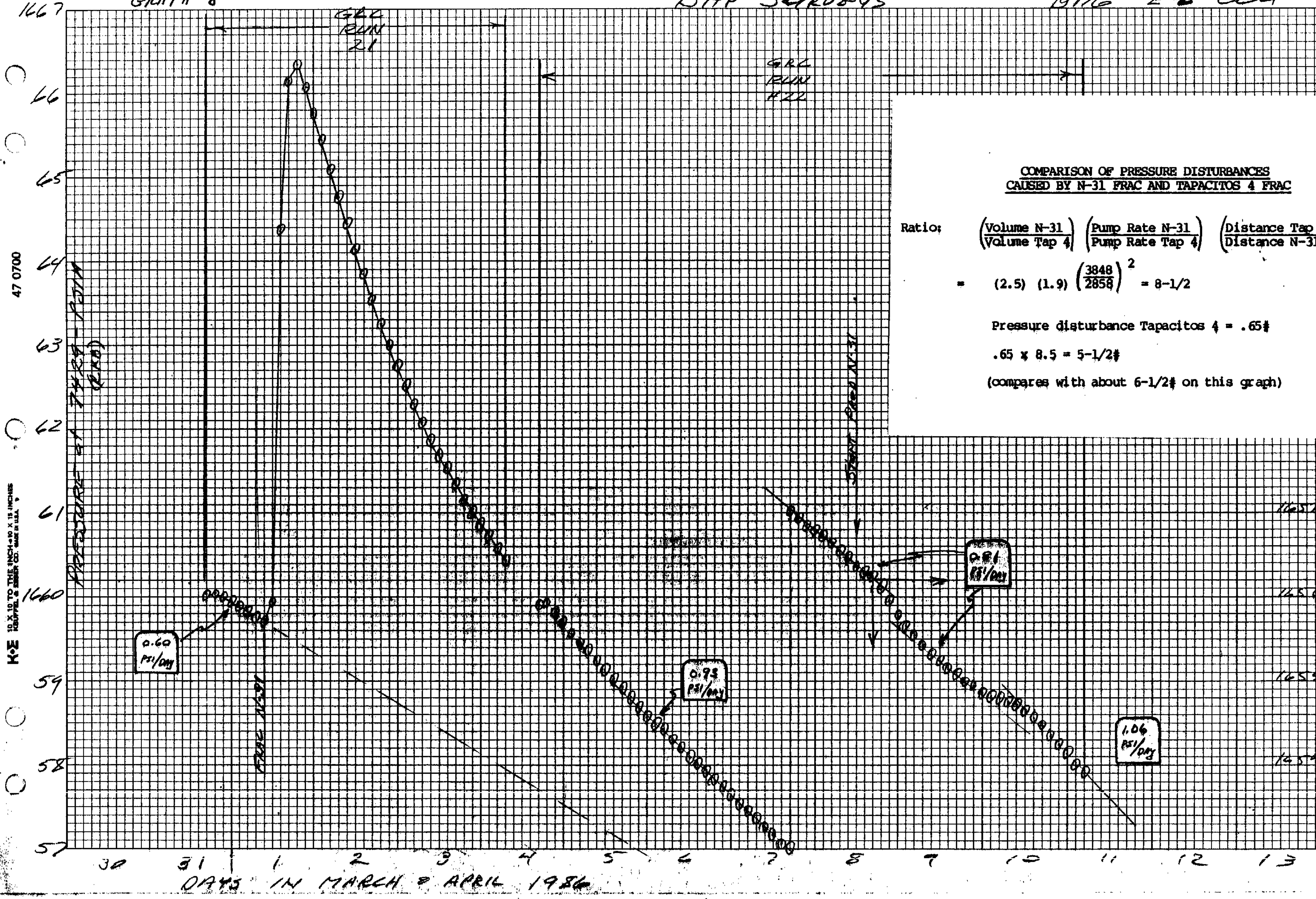
COU E-6



GRAPH 5 BHP SURVEYS BHG #E-6 COU



GRAPH 8 BHP SURVEYS BMG #E-6 COM



COMPARISON OF PRESSURE DISTURBANCES
CAUSED BY N-31 FRAC AND TAPACITOS 4 FRAC

Ratio: $\left(\frac{\text{Volume N-31}}{\text{Volume Tap 4}}\right) \left(\frac{\text{Pump Rate N-31}}{\text{Pump Rate Tap 4}}\right) \left(\frac{\text{Distance Tap 4}}{\text{Distance N-31}}\right)^2$

$= (2.5)\ (1.9) \left(\frac{3848}{2858}\right)^2 = 8\text{-}1/2$

Pressure disturbance Tapacitos 4 = .65#

.65 x 8.5 = 5-1/2#

(compares with about 6-1/2# on this graph)

DATE: 7/ 8/86 COMPANY: BMG
GAUGE SN # 69160 CLIENT: McHugh
WELL # 0 WELL NAME: Dr Daddy-o
TEST # 37 TEST OPERATOR: MO
DATA FILE: 3 LOCATION:
COMMENTS: BHP @8850' GL
DWT TBG 476 psig

INT	TIME	DELTA T HRS	FREQUENCY HZ	PRESSURE PSIA	TEMPERATURE °F
1	15:45:57	3.216	6638.13		73.87
1	15:46:55	3.232	10618.06	14.08	
1	15:47:52	3.248	6633.41		73.50
1	15:48:50	3.264	10617.70	13.63	
1	15:49:48	3.280	6620.69		72.49
1	15:50:45	3.296	10618.11	13.77	
1	15:51:43	3.312	6610.20		71.67
1	15:52:40	3.328	11078.11	487.38	
1	15:53:38	3.344	6625.30		72.86
1	15:54:36	3.360	11076.64	486.05	
1	15:55:33	3.376	6612.23		71.83
1	15:56:31	3.392	11076.98	486.18	
1	15:57:28	3.408	6602.35		71.05
1	15:58:26	3.424	11077.30	486.36	
1	15:59:24	3.440	6594.93		70.46
1	16: 0:21	3.456	11077.54	486.49	
1	16: 1:19	3.472	6588.72		69.97
1	16: 2:16	3.488	11077.71	486.56	
1	16: 3:14	3.504	6499.92		62.97
1	16: 4:12	3.520	11083.86	491.68	
1	16: 5: 9	3.536	6431.24		57.57
1	16: 6: 7	3.552	11092.78	500.19	
1	16: 7: 4	3.568	6491.99		62.35
1	16: 8: 2	3.584	11095.73	504.47	
1	16: 9: 0	3.600	6540.04		66.13
1	16: 9:57	3.616	11097.35	507.09	
1	16:10:55	3.632	6584.53		69.64
1	16:11:52	3.648	11098.87	509.53	
1	16:12:50	3.664	6630.21		73.25
1	16:13:48	3.680	11100.95	512.61	
1	16:14:45	3.696	6676.07		76.87
1	16:15:43	3.712	11102.82	515.45	
1	16:16:40	3.728	6725.71		80.80
1	16:17:38	3.744	11102.62	516.11	
1	16:18:36	3.760	6740.22		81.95
1	16:19:33	3.776	11103.54	517.37	
1	16:20:31	3.792	6775.78		84.76
1	16:21:28	3.808	11103.83	518.32	
1	16:22:26	3.824	6791.47		86.01
1	16:23:24	3.840	11105.51	520.43	
1	16:24:21	3.856	6827.51		88.87
1	16:25:19	3.872	11107.51	523.24	
1	16:26:16	3.888	6872.70		92.46
1	16:27:14	3.904	11107.44	523.96	
1	16:28:12	3.920	6887.57		93.64
1	16:29: 9	3.936	11109.36	526.32	
1	16:30: 7	3.952	6922.09		96.39
1	16:31: 4	3.968	11112.08	529.90	
1	16:32: 2	3.984	6992.24		101.98
1	16:33: 0	4.000	11115.16	534.47	

10 minutes

RECORDER IN LUBRICATOR AT SURFACE (TBG PRESS)

DATE: 7/ 9/86
GAUGE SN # 69160
WELL # 0
TEST # 37
DATA FILE: 7

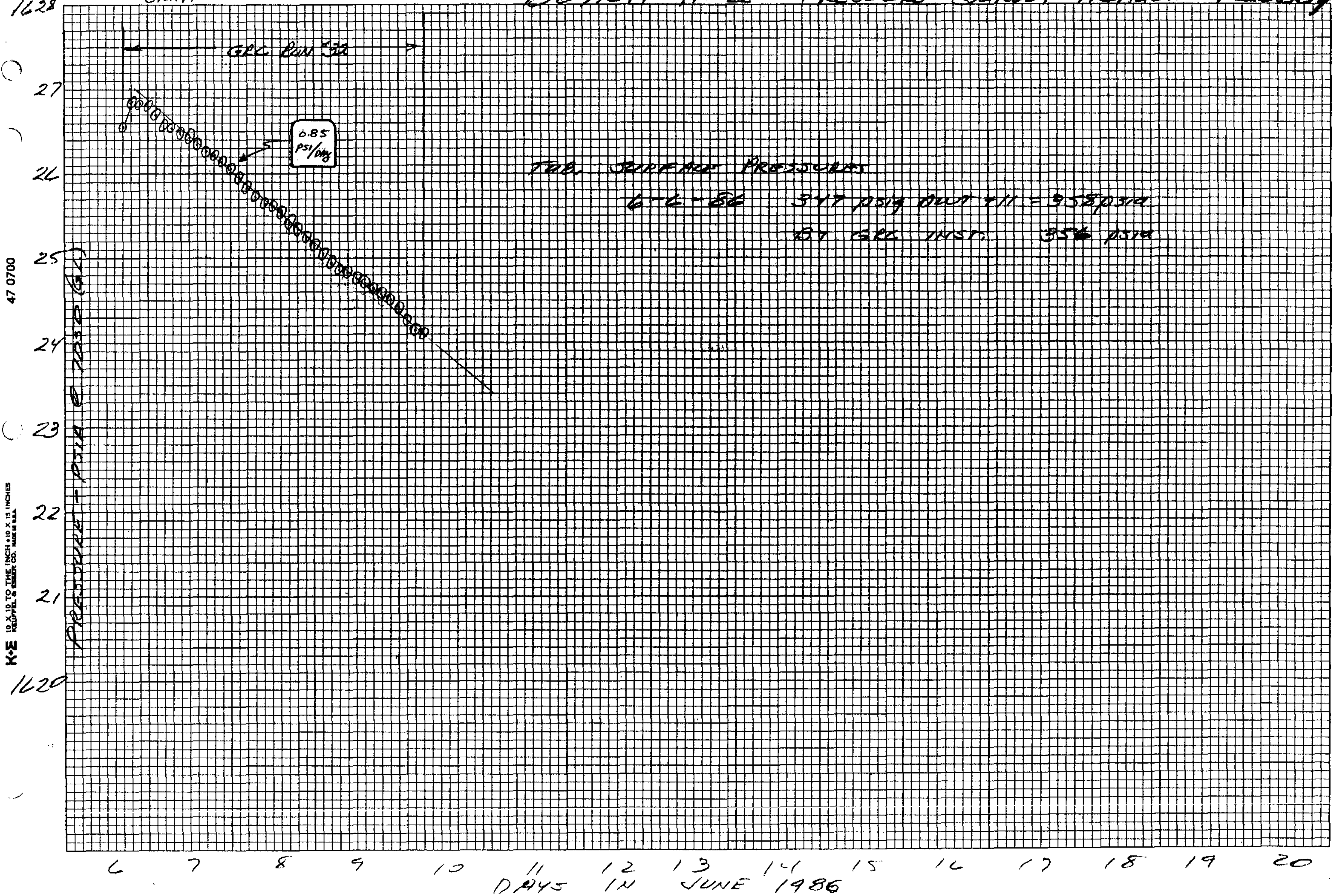
COMPANY: BMG
CLIENT: McHugh
WELL NAME: Dr Daddy-o
TEST OPERATOR: MD
LOCATION:
COMMENTS: BHP @6950' GL
DWT TBG 476 psig

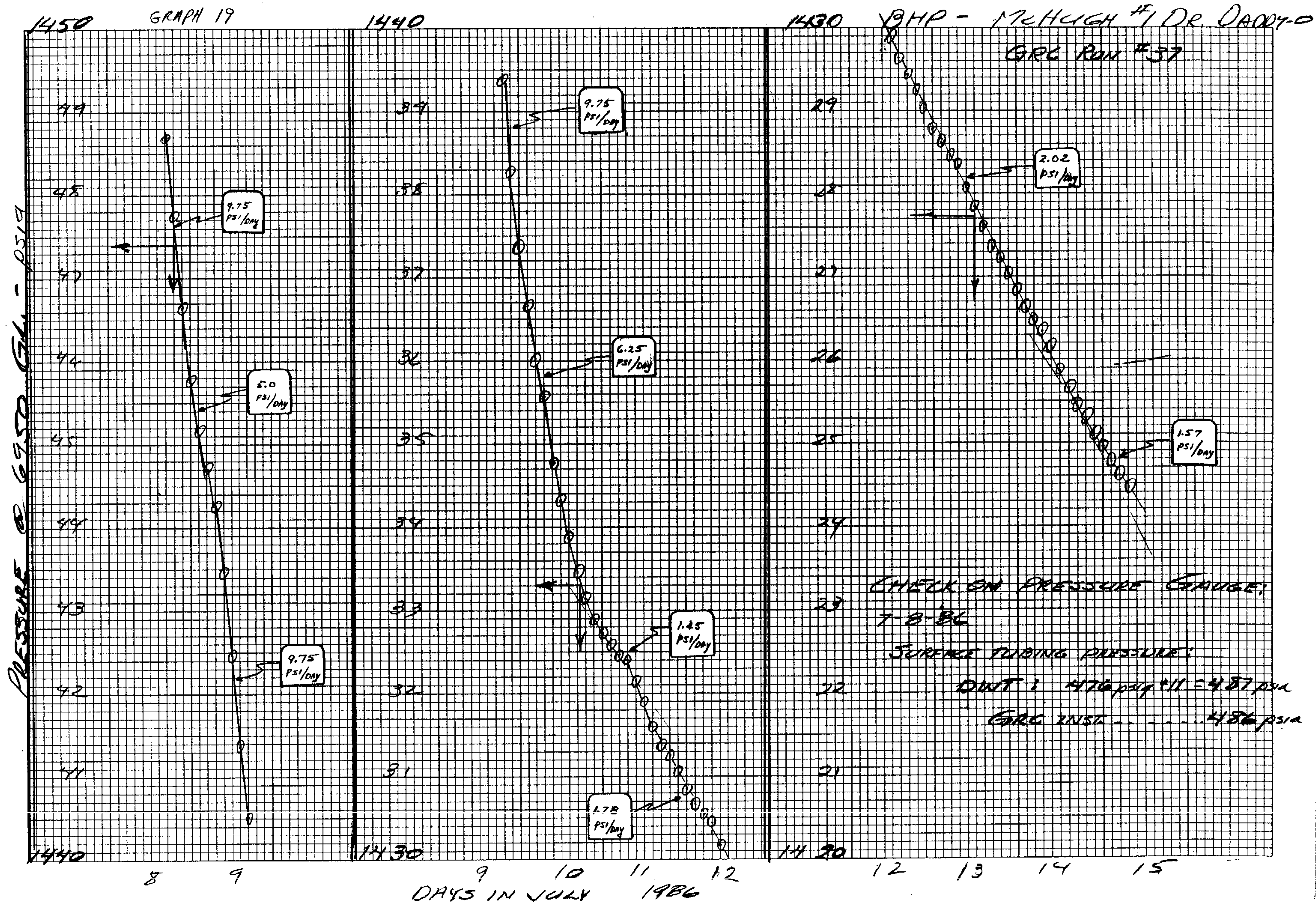
INT	TIME	DELTA T HRS	FREQUENCY HZ	PRESSURE PSIA	TEMPERATURE 'F
4	21:48: 0	33.250	7851.03		171.23
4	22: 3: 0	33.500	11863.48	1438.06	
4	22:18: 0	33.750	7850.97		171.22
4	22:33: 0	34.000	11863.33	1437.86	
4	22:48: 0	34.250	7851.04		171.23
4	23: 3: 0	34.500	11863.20	1437.69	
4	23:18: 0	34.750	7850.97		171.22
4	23:33: 0	35.000	11863.07	1437.53	
4	23:48: 0	35.250	7850.96		171.22
4	0: 3: 0	35.500	11862.96	1437.38	
4	0:18: 0	35.750	7851.00		171.23
4	0:33: 0	36.000	11862.83	1437.22	
4	0:48: 0	36.250	7851.02		171.23
4	1: 3: 0	36.500	11862.71	1437.07	
4	1:18: 0	36.750	7850.98		171.23
4	1:33: 0	37.000	11862.61	1436.93	
4	1:48: 0	37.250	7850.98		171.23
4	2: 3: 0	37.500	11862.50	1436.79	
4	2:18: 0	37.750	7850.99		171.23
4	2:33: 0	38.000	11862.39	1436.66	
5	2:48: 0	38.250	7851.02		171.23
5	3: 3: 0	38.500	11862.29	1436.52	
5	3:18: 0	38.750	7850.99		171.23
5	3:33: 0	39.000	11862.18	1436.38	
5	3:48: 0	39.250	7850.84		171.22
5	4: 3: 0	39.500	11862.08	1436.26	
5	4:18: 0	39.750	7851.01		171.23
5	4:33: 0	40.000	11861.99	1436.14	
5	4:48: 0	40.250	7851.04		171.23
5	5: 3: 0	40.500	11881.89	1436.01	
5	5:18: 0	40.750	7851.04		171.23
5	5:33: 0	41.000	11861.80	1435.90	
5	5:48: 0	41.250	7851.04		171.23
5	6: 3: 0	41.500	11861.71	1435.78	
5	6:18: 0	41.750	7851.07		171.23
5	6:33: 0	42.000	11861.62	1435.66	
5	6:48: 0	42.250	7851.05		171.23
5	7: 3: 0	42.500	11861.53	1435.55	
5	7:18: 0	42.750	7851.04		171.23
5	7:33: 0	43.000	11861.41	1435.40	
5	7:48: 0	43.250	7851.08		171.23
5	8: 3: 0	43.500	11861.28	1435.22	
5	8:18: 0	43.750	7850.99		171.23
5	8:33: 0	44.000	11861.14	1435.04	
5	8:48: 0	44.250	7850.99		171.23
5	9: 3: 0	44.500	11861.00	1434.86	
5	9:18: 0	44.750	7851.09		171.23
5	9:33: 0	45.000	11860.94	1434.79	
5	9:48: 0	45.250	7850.95		171.22
5	10: 3: 0	45.500	11860.86	1434.69	

± 2.4 hrs (1/10 day)

GRAPH 14

BOTTOM HOLE PRESSURE SURVEY McHUGH #1 Loddy




GRAPH 19
BHP - McHUGH #1 DR DADDY-O
GRC RUN #37
PRESSURE @ 6550 GL. - psig
1450
1440
1430
1420
49
48
47
46
45
44
43
42
41
39
38
37
36
35
34
33
32
31
29
28
27
26
25
24
23
22
21
9.75 PSI/DAY
5.0 PSI/DAY
6.25 PSI/DAY
1.45 PSI/DAY
1.78 PSI/DAY
2.02 PSI/DAY
1.57 PSI/DAY
CHECK ON PRESSURE GAUGE;
7-8-86
SURFACE TUBING PRESSURE:
DWT : 476 psig + 11 = 487 psia
GRC INST. . . . . . 486 psia
8
9
10
11
12
13
14
15
DAYS IN JULY 1986

NMOCC/NMOCD Case No. 8946
Hearing Date 8-27-86
Dugan Production Corp.
Exhibit No. 3

GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico
Revised 08/11/86
To Include Sensitivity Case
For 702 BOPD and 588 GOR Allowable

Operator / Well Name	Location U-S-T-R	Completion Date	Cumulative 7/01/86 BO	Cumulative 7/01/86 MCF	Cumulative 7/01/86 RB	06/86 Production or Potential BOPD	06/86 Production or Potential MCFD	06/86 Production or Potential GOR	06/86 Production or Potential RB/D	Production 6/86 with Proposed Allowable Reduction BOPD	Production 6/86 with Proposed Allowable Reduction MCFD	Production 6/86 with Proposed Allowable Reduction RB/D	Sensitivity Case 6/86 Production with 702 BOPD / 588 GOR BOPD	Sensitivity Case 6/86 Production with 702 BOPD / 588 GOR MCFD	Sensitivity Case 6/86 Production with 702 BOPD / 588 GOR RB/D
Amoco Production Co.															
Oso Canyon Fed #1	E 24-24N-2W	12/10/84	1508	NR	1508	10e	30e	3000e	57	10	30	57	10	30	57
Oso Canyon Fed A-1	F 14-24N-2W	02/03/85	0	0	0	10e	30e	3000e	57	10	30	57	10	30	57
Oso Canyon Fed B-1	F 11-24N-2W	02/05/85	2167	NR	2167	10e	30e	3000e	57	10	30	57	10	30	57
Oso Cny Gas Com C-1	F 15-24N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
SUBTOTAL			3675	NR	3675	30	90	-	171	30	90	171	30	90	171
% of Total						0.3	0.6		0.6	0.6	1.2	1.1	0.4	0.8	0.7
Dugan Production Corp.															
Divide #1	H 35-26N-2W	05/13/83	0	0	0	40e	30e	750e	67	40	30	67	40	30	67
Divide #2	P 35-26N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
Divide #3	K 35-26N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
Lindrith #1	O 36-25N-2W	11/19/84	4566	23438	43242	8	40e	5000e	74	8	40	74	8	40	74
Tapacitos #2	L 25-26N-2W	10/30/80	24877	17060	38660	27	22	797	48	27	22	48	27	22	48
Tapacitos #3	D 36-26N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
Tapacitos #4	O 36-26N-2W	03/01/86	6591	4803	10747	153	115	751	256	153	115	256	153	115	256
Wendy #1	A 26-26N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
SUBTOTAL			36034	45301	92649	228	207	-	445	228	207	445	228	207	445
% of Total						2.5	1.4		1.5	4.2	2.8	2.9	2.9	1.8	1.9
Mallon Oil															
Davis Fed Com 3-15	O 3-25N-2W	Drilling	-	-	-	-	-	-	-	-	-	-	-	-	-
Fisher Fed 2-1	A 2-25N-2W	06/17/85	99375	54196	137138	455	576	1265	1177	158r	200	409	326r	413	844
Howard Fed 1-8	H 1-25N-2W	07/18/85	70611	32402	97443	418	523e	1250e	1070	160r	200	409	330r	413	845
Howard Fed 1-11	K 1-25N-2W	11/18/85	66250	72514	151160	583	914	1567	1821	128r	200	399	264r	413	823
Johnson Fed 12-5	E 12-25N-2W	10/24/85	13014	30040	57810	95e	290e	3050e	548	66r	200	378	95	290	548
Post Fed 13-6	F 13-25N-2W	03/18/86	0	0	0	100e	80e	800e	176	100	80	176	100	80	800
Ribeyowids Fed 2-16	P 2-25N-2W	02/11/85	53786	17498	74225	160	162	1011	342	160	162	342	160	162	342
SUBTOTAL			303036	206650	517776	1811	2545	-	5134	772	1042	2113	1275	1771	4202
% of Total						19.5	17.5		17.6	14.2	13.9	13.8	16.3	15.5	17.7

GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico
Revised 08/11/86
To Include Sensitivity Case
For 702 BOPD and 588 GOR Allowable

Operator / Well Name	Location U-S-T-R	Completion Date	Cumulative 7/01/86			06/86 Production or Potential				Production 6/86 with Proposed Allowable Reduction			Sensitivity Case 6/86 Production with 702 BOPD / 588 GOR		
			BO	MCF	RB	BOPD	MCFD	GOR	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D
Jerome P. McHugh															
Beek's Babbitt #1	G 17-25N-2W	10/15/85	0	0	0	300e	225e	750e	501	200	150	334	300	225	501
Boyt & Lola #1	I 11-24N-2W	12/03/84	4648	28121	51605	7	25	3629	47	7	25	47	7	25	47
Boyt & Lola #2	D 12-24N-2W	01/10/85	8284	14482	28540	17	33	1946	64	17	33	64	17	33	64
Continental Divide #1	B 12-25N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
Dr. Daddy-O #1	C 33-25N-2W	05/16/85	1887	629	2604	100e	75e	750e	167	100	75	167	100	75	167
E. T. #1	C 28-25N-2W	09/19/83	90346	50079	124677	104	340	3268	640	61r	200	376	104	340	640
Four O's #1	Lot 3 19-25N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
Full Sail #1	O 29-25N-2W	06/15/84	106148	91703	198617	142	295	2078	572	96r	200	388	142	295	572
Full Sail #2	I 28-25N-2W	05/24/85	3819	7841	15230	171	440	2575	840	78r	200	382	160r	413	788
Full Sail #3	F 29-25N-2W	11/01/85	2414	3484	7006	37	49	1312	100	37	49	100	37	49	100
Full Sail #4	Lot 3 30-25N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
Greener Grass #1	J 10-24N-2W	08/20/85	2367	779	3266	72	24	329	99	72	24	99	72	24	99
High Adventure #1	H 8-25N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
High Adventure #2	M 9-25N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
Homestead Ranch #2	N 34-25N-2W	05/16/85	73849	29055	101912	619	374	604	872	200	121	282	619	374	872
Janet #1	A 27-25N-2W	02/17/83	123968	84871	192396	94	77	818	168	94	77	168	94	77	168
Janet #2	I 21-25N-2W	09/01/83	111815	94291	205113	156	350	2246	675	89r	200	386	156	350	675
Janet #3	E 21-25N-2W	12/18/85	2002	1066	2763	78	45	571	108	78	45	108	78	45	108
Lady Luck #1	A 5-24N-2W	02/21/86	1774	142	2448	100e	75e	750e	167	100	75	167	100	75	167
Loddy #1	F 20-25N-2W	08/30/85	0	0	0	350e	263e	750e	585	200	150	334	350	263	585
Mother Lode #1	H 3-24N-2W	09/02/83	2524	631	3483	222	297	1339	603	149r	200	406	222	297	603
Mother Lode #2	K 3-24N-2W	01/23/86	148065	123317	268863	49	21	426	68	49	21	68	49	21	68
Native Son #1	A 34-25N-2W	06/07/84	204242	59230	281854	288	154	536	397	200	107	397	288	154	397
Native Son #2	N 27-25N-2W	11/18/83	323124	364536	756591	440	1247	2834	2366	71r	200	380	146r	413	784
Native Son #3	I 33-25N-2W	02/21/85	2762	624	3812	293	650e	2220e	1255	90r	200	386	186r	413	797
New Horizon #1	O 2-24N-2W	10/01/85	553	1058	2068	9	36	4008	67	9	36	67	9	36	67
Twilight Zone #1	J 12-24N-2W	01/21/85	1998	4656	8954	4e	13e	3136e	24	4	13	24	4	13	24
Wright Way #1	C 2-24N-2W	09/29/83	98892	72799	162549	34	54	1601	107	34	54	107	34	54	107
SUBTOTAL			1315481	1033394	2424351	3686	5162	-	10492	2035	2455	5237	3274	4064	8400
% of Total						39.7	35.5		36.0	37.5	32.9	34.1	41.7	35.2	35.1

GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico
Revised 08/11/86
To Include Sensitivity Case
For 702 BOPD and 588 GOR Allowable

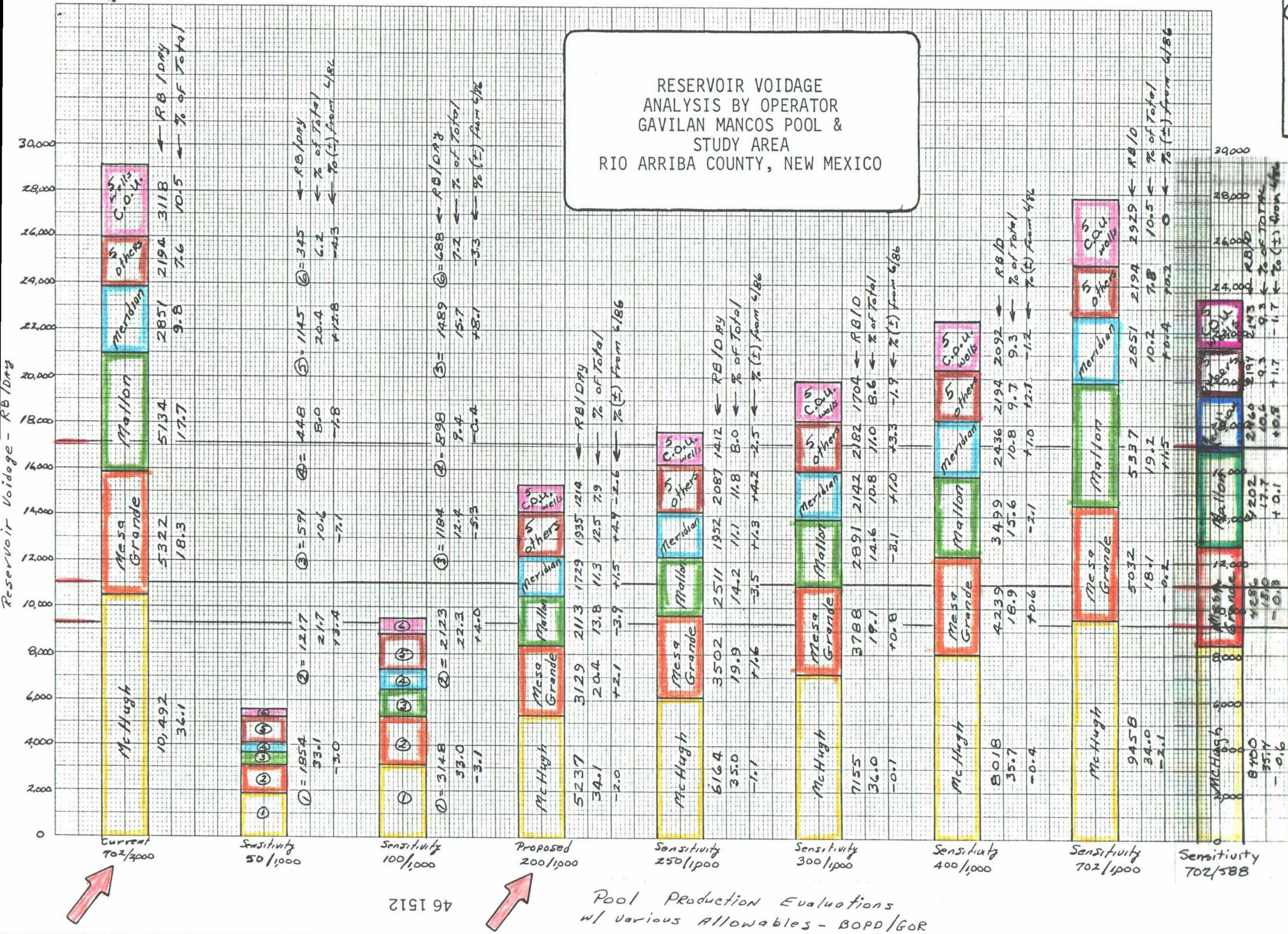
Operator / Well Name	Location U-S-T-R	Completion Date	Cumulative 7/01/86 BO	Cumulative 7/01/86 MCF	Cumulative 7/01/86 RB	06/86 Production or Potential BOPD	06/86 Production or Potential MCFD	06/86 Production or Potential GOR	06/86 Production or Potential RB/D	Production 6/86 with Proposed Allowable Reduction BOPD	Production 6/86 with Proposed Allowable Reduction MCFD	Production 6/86 with Proposed Allowable Reduction RB/D	Sensitivity Case 6/86 Production with 702 BOPD / 588 GOR BOPD	Sensitivity Case 6/86 Production with 702 BOPD / 588 GOR MCFD	Sensitivity Case 6/86 Production with 702 BOPD / 588 GOR RB/D
Meridian Oil Company															
Hawk Federal #2	C 35-25N-2W	03/25/84	68862	167004	320223	142	355	2500	679	80r	200	383	142	355	679
Hawk Federal #3	K 35-25N-2W	01/03/85	109583	144405	293571	219	189	865	409	200	173	375	219	189	409
Hill Federal #1	F 24-25N-2W	09/17/85	4986	15919	29998	200e	620e	3100e	1170	65r	200	378	133r	413	779
Hill Federal #2Y	G 25-25N-2W	01/10/86	386	4	533	170e	119e	700e	268	170	119	268	170	119	268
Hill Federal #3	D 36-25N-2W	01/09/86	2300	50	3174	190e	147e	775e	325	190	147	325	190	147	325
SUBTOTAL			186117	327382	647499	921	1430	-	2851	705	839	1729	854	1223	2460
% of Total						9.9	9.8		9.8	13.0	11.2	11.3	10.9	10.6	10.6
Merrion Oil and Gas															
Krystina #1	K 14-24N-2W	01/07/85	4944	20928	38900	20	133	6640	243	20	133	243	20	133	243
Oso Canyon Gas Com C-1	F 13-24N-2W	01/11/85	2390	7196	13606	10	31	3123	59	10	31	59	10	31	59
Rocky Mountain #1	N 24-24N-2W	01/22/85	1349	12528	22750	3	36	11879	65	3	36	65	3	36	65
SUBTOTAL			8683	40652	75256	33	200	-	367	33	200	367	33	200	367
% of Total						0.4	1.4		1.3	0.6	2.7	2.4	0.4	1.7	1.5
Mesa Grande Resources															
Bearcat	O 22-25N-2W	04/21/86	2589	3980	7947	103	163	1580	324	103	163	324	103	163	324
Brown #1	N 17-25N-2W	03/20/85	20705	11149	28573	238e	857e	3600e	1605	56r	200	375	115r	413	773
Gavilan #1	A 26-25N-2W	03/21/82	80810	501763	920077	36	526	14600	948	14r	200	361	28r	413	744
Gavilan #2*	J 26-25N-2W	02/14/85	1207	23356	41976	6	182e	30400e	326	6	182	326	6	182	326
Gavilan #3	E 26-25N-2W	07/23/83	29149	239389	435830	43	111	2573	212	43	111	212	43	111	212
Gavilan-Howard #1	F 23-25N-2W	04/23/84	81071	773644	1404112	122	140	1144	290	122	140	290	122	140	290
Hatley Hawkeye #1	I 23-25N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
Hellcat #1	F 22-25N-2W	10/19/85	533	0	736	100e	75e	750e	167	100	75	167	100	75	167
Invader Fed #1	D 1-24N-2W	05/04/86	957	1378	2772	24	53	2196	102	24	53	102	24	53	102
Intruder #1	I 20-25N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
Marauder #1	N 8-25N-2W	04/17/86	1756	4847	9213	92	254	2760	483	72r	200	380	92	254	483
Phantom #1	M 16-25N-2W	Location	-	-	-	-	-	-	-	-	-	-	-	-	-
Rucker Lake #2	K 24-25N-2W	08/26/83	127271	85615	194822	118	344	2917	652	69r	200	379	118	344	652
Rucker Lake #3	L 25-25N-2W	08/10/83	93385	88403	188488	109	99	910	213	109	99	213	109	99	213
SUBTOTAL			439433	1733524	3234546	991	2804	-	5322	718	1623	3129	860	2247	4286
% of Total						10.7	19.3		18.3	13.2	21.7	20.4	10.9	19.5	17.9

GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico
Revised 08/11/86
To Include Sensitivity Case
For 702 BOPD and 588 GOR Allowable

Operator / Well Name	Location U-S-T-R	Completion Date	Cumulative 7/01/86 BO	MCF	RB	06/86 Production or Potential BOPD	MCFD	GOR	RB/D	Production 6/86 with Proposed Allowable Reduction BOPD	MCFD	RB/D	Sensitivity Case 6/86 Production with 702 BOPD / 588 GOR BOPD	MCFD	RB/D
Mobil Oil Corp.															
Lindrith B Unit 34	G 32-25N-2W	01/29/86	2354	5531	10630	111	306	2759	582	72r	200	380	111	306	582
Lindrith B Unit 37	G 4-24N-2W	01/29/86	5111	7072	14292	234	176e	750e	391	200	150	334	234	176	391
Lindrith B Unit 38	K 4-24N-2W	Completing	808	2670	5022	43	32e	750e	71	43	32	71	43	32	71
SUBTOTAL			8273	15273	29944	388	514	-	1044	315	382	785	388	514	1044
% of Total						4.2	3.5		3.6	5.8	5.1	5.1	4.9	4.5	4.4
Reading and Bates															
Howard Fed 43-15	I 15-25N-2W	03/04/86				100e	75e	750e	167	100	75	167	100	75	167
SUBTOTAL						100	75	-	167	100	75	167	100	75	167
% of Total						1.1	0.5		0.6	1.8	1.0	1.1	1.3	0.7	0.7
TOTAL GAVILAN POOL AREA			2300732	3402176	7025696	8188	13027	1591	25993	4936	6913	14143	7042	10391	21542
% of Total						88.2	89.6		89.3	90.9	92.5	92.1	90.1	91.1	91.0
BMG Drilling Corp.															
COU #26 (K-31)	K 31-25N-1W	01/28/85	2126			2	1	700	3	2	1	3	2	1	3
COU #29 (E-6)	E 6-25N-1W	12/02/85	24854			616	795	1290	1620	155r	200	408	320r	413	842
COU #30 (F-30)	F 30-25N-1W	Completing	0			100e	70	700	158	100	70	158	100	70	158
COU #31 (N-31)	N 31-26N-1W	04/09/86	11603			273	120	440	305	200	88	276	273	120	377
COU #32 (J-6)	J 6-25N-1W	05/31/86	1709			104	520	5000	960	40r	200	369	83r	413	763
SUBTOTAL			40292			1095	1506	-	3046	497	559	1214	778	1017	2143
% of Total						11.8	10.4		10.7	9.1	7.5	7.9	9.9	8.9	9.0
TOTAL STUDY AREA			2341024			9283	14533	1566	29039	5433	7472	15357	7820	11408	23685

NOTES: Oil and Gas PVT Data: Bo = 1.38 RB/STB, Bg = 1.78 RB/MCF, Rs = 588 SCF/STB
* = Operated by E. Alex Phillips
r = Production Restricted by GOR Limit
e = Estimated
A = Amoco Production Co. Information for May and June not available at NMOCD
RB= Reservoir bbls.

DUGAN PRODUCTION ENGINEERING: 08/02/86: JR/BW - jr



17,163 RB/D - APPROXIMATE PRODUCTION 6/86
(5436 STBOPD + 8624 MCFD)
43 of 59 wells PROD.

11,016 RB/D - APPROXIMATE PRODUCTION 5/86
(4153 STBOPD + 5411 MCFD)
38 wells ON PROD.

9306 RB/D - APPROX. PRODUCTION 1/86
(4234 STBOPD + 4435 MCFD)
34 wells ON PROD.

NMOCC ~~NMOCD~~ Case No. 8946
Hearing Date 8/27/86
DugAN PRODUCTION CORP.
Exhibit No. 4

5 other operators

Amoco Production
Dugan Production
Merrion Oil
Mobil Oil
Reading & Bates

46 1512

ALLOWABLE REDUCTION
SENSITIVITY CASES
GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico

	6/86 Prod. with 50 BOPD+1000 GOR Limits			6/86 Prod.with 100 BOPD+1000 GOR Limits			6/86 Prod.with 250 BOPD+1000 GOR Limits			6/86 Prod.with 300 BOPD+1000 GOR Limits			6/86 Prod.with 350 BOPD+1000 GOR Limits			6/86 Prod.with 400 BOPD+1000 GOR Limits			6/86 Prod.with 702 BOPD+1000 GOR Limits		
Operator / Well Name	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D
Amoco Production Co.																					
Oso Canyon Fed #1	10	30	57	10	30	57	10	30	57	10	30	57	10	30	57	10	30	57	10	30	57
Oso Canyon Fed A-1	10	30	57	10	30	57	10	30	57	10	30	57	10	30	57	10	30	57	10	30	57
Oso Canyon Fed B-1	10	30	57	10	30	57	10	30	57	10	30	57	10	30	57	10	30	57	10	30	57
Oso Cny Gas Com C-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUBTOTAL	30	90	171	30	90	171	30	90	171	30	90	171	30	90	171	30	90	171	30	90	171
% of Total	1.5	3.3	3.1	0.9	1.9	1.8	0.5	1.0	1.0	0.4	0.9	0.9	0.4	0.9	0.8	0.4	0.8	0.8	0.3	0.7	0.6
Dugan Production Corp.																					
Divide #1	40	30	67	40	30	67	40	30	67	40	30	67	40	30	67	40	30	67	40	30	67
Divide #2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Divide #3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lindrith #1	8	40	74	8	40	74	8	40	74	8	40	74	8	40	74	8	40	74	8	40	74
Tapacitos #2	27	22	48	27	22	48	27	22	48	27	22	48	27	22	48	27	22	48	27	22	48
Tapacitos #3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tapacitos #4	50	38	84	100	75	167	153	115	256	153	115	256	153	115	256	153	115	256	153	115	256
Wendy #1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUBTOTAL	125	130	273	175	167	356	228	207	445	228	207	445	228	207	445	228	207	445	228	207	445
% of Total	6.3	4.7	4.9	5.0	3.6	3.7	3.7	2.4	2.5	3.4	2.1	2.2	3.2	2.0	2.1	3.0	1.9	2.0	2.5	1.6	1.6
Mallon Oil																					
Davis Fed Com 3-15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fisher Fed 2-1	40r	50	102	79r	100	204	198r	250	511	237r	300	613	277r	350	715	316r	400	817	555r	702	1435
Howard Fed 1-8	40r	50	102	80r	100	205	200r	250	512	240r	300	614	280r	350	716	320r	400	819	562r	702	1437
Howard Fed 1-11	32r	50	100	64r	100	199	160r	250	498	191r	300	598	223r	350	697	255r	400	797	448r	702	1399
Johnson Fed 12-5	16r	50	94	33r	100	189	82r	250	472	95	290	548	95	290	548	95	290	548	95	290	548
Post Fed 13-6	50	40	88	100	80	176	100	80	176	100	80	176	100	80	176	100	80	176	100	80	176
Ribeyowids Fed 2-16	49r	50	105	99r	100	211	160	162	342	160	162	342	160	162	342	160	162	342	160	162	342
SUBTOTAL	227	290	591	455	580	1184	900	1242	2511	1023	1432	2891	1135	1582	3194	1246	1732	3499	1920	2638	5337
% of Total	11.4	10.6	10.6	12.9	12.5	12.4	14.7	14.4	14.2	15.2	14.7	14.6	15.7	15.1	15.0	16.5	15.7	15.6	21.1	19.9	19.2

ALLOWABLE REDUCTION SENSITIVITY CASES
GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico

	6/86 Prod.with 50 BOPD+1000 GOR Limits			6/86 Prod.with 100 BOPD+1000 GOR Limits			6/86 Prod.with 250 BOPD+1000 GOR Limits			6/86 Prod.with 300 BOPD+1000 GOR Limits			6/86 Prod.with 350 BOPD+1000 GOR Limits			6/86 Prod.with 400 BOPD+1000 GOR Limits			6/86 Prod.with 702 BOPD+1000 GOR Limits		
Operator / Well Name	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D
Jerome P. McHugh																					
Beek's Babbitt #1	50	38	84	100	75	167	250	188	418	300	225	501	300	225	501	300	225	501	300	225	501
Boyt & Lola #1	7	25	47	7	25	47	7	25	47	7	25	47	7	25	47	7	25	47	7	25	47
Boyt & Lola #2	17	33	64	17	33	64	17	33	64	17	33	64	17	33	64	17	33	64	17	33	64
Continental Divide #1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dr. Daddy-O #1	50	38	84	100	75	167	100	75	167	100	75	167	100	75	167	100	75	167	100	75	167
E. T. #1	15r	50	94	31r	100	188	76r	250	470	92r	300	565	104r	340	640	104r	340	640	104	340	640
Four O's #1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Full Sail #1	24r	50	97	48r	100	194	120r	250	485	142	295	572	142	295	572	142	295	572	142	295	572
Full Sail #2	19r	50	95	39r	100	191	97r	250	477	117r	300	573	136r	350	668	155r	400	764	171	440	840
Full Sail #3	37	49	100	37	49	100	37	49	100	37	49	100	37	49	100	37	49	100	37	49	100
Full Sail #4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Greener Grass #1	50	16	69	72	24	99	72	24	99	72	24	99	72	24	99	72	24	99	72	24	99
High Adventure #1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
High Adventure #2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Homestead Ranch #2	50	30	69	100	60	138	250	151	352	300	181	422	350	211	492	400	242	564	619	374	872
Janet #1	50	41	90	94	77	168	94	77	168	94	77	168	94	77	168	94	77	168	94	77	168
Janet #2	22r	50	96	45r	100	193	111r	250	482	134r	300	579	156r	350	675	156	350	675	156	350	675
Janet #3	50	29	69	78	45	108	78	45	108	78	45	108	78	45	108	78	45	108	78	45	108
Lady Luck #1	50	38	84	100	75	167	100	75	167	100	75	167	100	75	167	100	75	167	100	75	167
Loddy #1	50	38	84	100	75	167	250	188	508	300	225	609	350	263	585	350	263	585	350	263	585
Mother Lode #1	37r	50	101	75r	100	203	187r	250	507	222	297	603	222	297	603	222	297	603	222	297	603
Mother Lode #2	49	21	68	49	21	68	49	21	68	49	21	68	49	21	68	49	21	68	49	21	68
Native Son #1	50	27	69	100	54	138	250	134	322	288	154	397	288	154	397	288	154	397	288	154	397
Native Son #2	18r	50	95	35r	100	190	88r	250	474	106r	300	569	124r	350	664	141r	400	759	248r	702	1332
Native Son #3	23r	50	97	45r	100	193	113r	250	483	135r	300	579	158r	350	676	180r	400	772	293	650	1255
New Horizon #1	9	36	67	9	36	67	9	36	67	9	36	67	9	36	67	9	36	67	9	36	67
Twilight Zone #1	4	13	24	4	13	24	4	13	24	4	13	24	4	13	24	4	13	24	4	13	24
Wright Way #1	34	54	107	34	54	107	34	54	107	34	54	107	34	54	107	34	54	107	34	54	107
SUBTOTAL	765	876	1854	1319	1491	3148	2331	3000	6164	2662	3479	7155	2931	3712	7659	3039	3893	8018	3494	4617	9458
% of Total	38.4	31.9	33.1	37.4	32.1	33.0	38.1	34.8	35.0	39.5	35.8	36.0	40.5	35.5	35.9	40.3	35.3	35.7	38.5	34.9	34.0

ALLOWABLE REDUCTION SENSITIVITY CASES
GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico

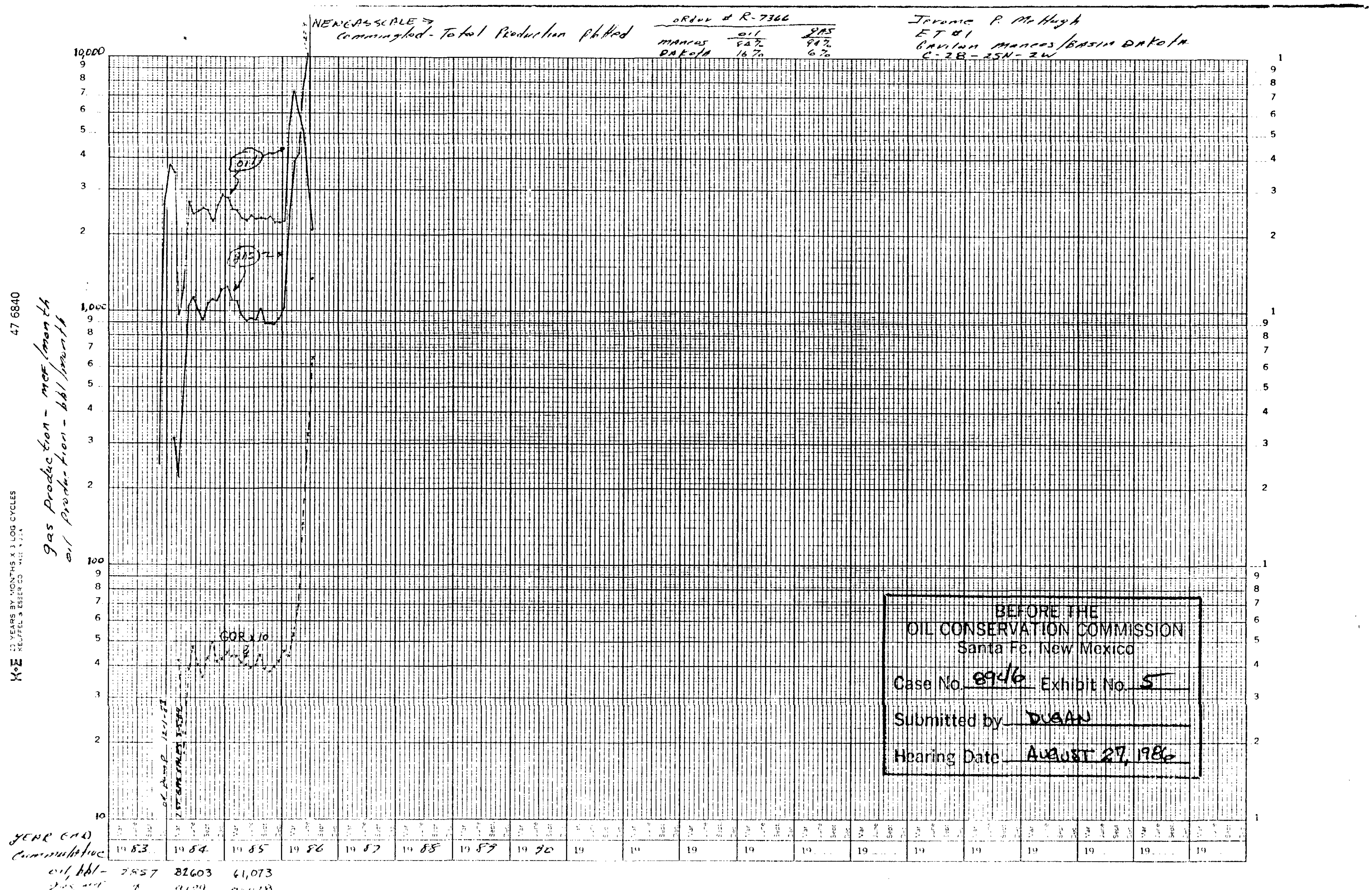
	6/86 Prod.with 50 BOPD+1000 GOR Limits			6/86 Prod.with 100 BOPD+1000 GOR Limits			6/86 Prod.with 250 BOPD+1000 GOR Limits			6/86 Prod.with 300 BOPD+1000 GOR Limits			6/86 Prod.with 350 BOPD+1000 GOR Limits			6/86 Prod.with 400 BOPD+1000 GOR Limits			6/86 Prod.with 702 BOPD+1000 GOR Limits		
Operator / Well Name	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D
Meridian Oil Company																					
Hawk Federal #2	20r	50	96	40r	100	191	100r	250	478	120r	300	574	140r	350	670	142	355	679	142	355	679
Hawk Federal #3	50	43	93	100	87	188	219	189	409	219	189	409	219	189	409	219	189	409	219	189	409
Hill Federal #1	16r	50	94	32r	100	189	81r	250	472	97r	300	566	113r	350	661	129r	400	755	200	620	1170
Hill Federal #2Y	50	35	79	100	70	158	170	119	268	170	119	268	170	119	268	170	119	268	170	119	268
Hill Federal #3	50	39	86	100	78	172	190	147	325	190	147	325	190	147	325	190	147	325	190	147	325
SUBTOTAL	186	217	448	372	435	898	760	955	1952	796	1055	2142	832	1155	2333	850	1210	2436	921	1430	2851
% of Total	9.3	7.9	8.0	10.6	9.4	9.4	12.4	11.1	11.1	11.8	10.9	10.8	11.5	11.1	10.9	11.3	11.0	10.8	10.1	10.8	10.3
Merrion Oil and Gas																					
Krystina #1	20	133	243	20	133	243	20	133	243	20	133	243	20	133	243	20	133	243	20	133	243
Oso Canyon Gas Com C-1	10	31	59	10	31	59	10	31	59	10	31	59	10	31	59	10	31	59	10	31	59
Rocky Mountain #1	3	36	65	3	36	65	3	36	65	3	36	65	3	36	65	3	36	65	3	36	65
SUBTOTAL	33	200	367	33	200	367	33	200	367	33	200	367	33	200	367	33	200	367	33	200	367
% of Total	1.7	7.3	6.6	0.9	4.3	3.9	0.5	2.3	2.1	0.5	2.1	1.8	0.5	1.9	1.7	0.4	1.8	1.6	0.4	1.5	1.3
Mesa Grande Resources																					
Bearcat	50	79	157	100	158	315	103	63	324	103	63	324	103	63	324	103	63	324	103	63	324
Brown #1	14r	50	94	28r	100	187	69r	250	468	83r	300	562	97r	350	655	111r	400	749	195r	702	1315
Gavilan #1	3r	50	90	7r	100	180	17r	250	451	21r	300	541	24r	350	631	27r	400	721	36	526	948
Gavilan #2*	2r	50	90	3r	100	179	6	182	326	6	182	326	6	182	326	6	182	326	6	182	326
Gavilan #3	43	111	212	43	111	212	43	111	212	43	111	212	43	111	212	43	111	212	43	111	212
Gavilan-Howard #1	44r	50	104	87r	100	207	122	140	290	122	140	290	122	140	290	122	140	290	122	140	290
Hatley Hawkeye #1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hellcat #1	50	38	84	100	75	167	100	75	167	100	75	167	100	75	167	100	75	167	100	75	167
Invader Fed #1	23r	50	97	24	53	102	24	53	102	24	53	102	24	53	102	24	53	102	24	53	102
Intruder #1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Marauder #1	18r	50	95	36r	100	190	91r	250	475	92	254	483	92	254	483	92	254	483	92	254	483
Phantom #1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rucker Lake #2	17r	50	95	34r	100	189	86r	250	474	103r	300	568	118	344	652	118	344	652	118	344	652
Rucker Lake #3	50	46	99	100	91	195	109	99	213	109	99	213	109	99	213	109	99	213	109	99	213
SUBTOTAL	314	624	1217	562	1088	2123	770	1723	3502	806	1877	3788	838	2021	4055	855	2121	4239	948	2049	5032
% of Total	15.8	22.7	21.7	15.9	23.4	22.3	12.6	20.0	19.9	12.0	19.3	19.1	11.6	19.3	19.0	11.3	19.2	18.9	10.4	15.5	18.1

ALLOWABLE REDUCTION SENSITIVITY CASES
GAVILAN MANCOS POOL AND STUDY AREA
Rio Arriba County, New Mexico

Operator / Well Name	6/86 Prod.with 50 BOPD+1000 GOR Limits			6/86 Prod.with 100 BOPD+1000 GOR Limits			6/86 Prod.with 250 BOPD+1000 GOR Limits			6/86 Prod.with 300 BOPD+1000 GOR Limits			6/86 Prod.with 350 BOPD+1000 GOR Limits			6/86 Prod.with 400 BOPD+1000 GOR Limits			6/86 Prod.with 702 BOPD+1000 GOR Limits		
	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D	BOPD	MCFD	RB/D
Mobil Oil Corp.																					
Lindrith B Unit 34	18r	50	95	36r	100	190	91	250	475	109	300	570	111	306	582	111	306	582	111	306	582
Lindrith B Unit 37	50	38	84	100	75	167	234	176	391	234	176	391	234	176	391	234	176	391	234	176	391
Lindrith B Unit 38	43	32	71	43	32	71	43	32	71	43	32	71	43	32	71	43	32	71	43	32	71
SUBTOTAL	111	120	250	179	207	428	368	458	937	386	508	1032	388	514	1044	388	514	1044	388	514	1044
% of Total	5.6	4.4	4.5	5.1	4.5	4.5	6.0	5.3	5.3	5.7	5.2	5.2	5.4	4.9	4.9	5.1	4.7	4.6	4.3	3.9	3.8
Reading and Bates																					
Howard Fed 43-15	50	38	84	100	75	167	100	75	167	100	75	167	100	75	167	100	75	167	100	75	167
SUBTOTAL	50	38	84	100	75	167	100	75	167	100	75	167	100	75	167	100	75	167	100	75	167
% of Total	2.5	1.4	1.5	2.8	1.6	1.8	1.6	0.9	0.9	1.5	0.8	0.8	1.4	0.7	0.8	1.3	0.7	0.7	1.1	0.6	0.6
TOTAL GAVILAN POOL AREA	1841	2585	5255	3225	4333	8842	5520	7950	16,216	6064	8923	18,158	6515	9556	19,435	6769	10,042	20,386	8062	11,820	24,872
% of Total	92.4	94.2	93.8	91.5	93.2	92.8	90.3	92.1	92.0	90.1	91.9	91.4	90.1	91.5	91.1	89.8	91.0	90.7	88.7	89.3	89.5
BMG Drilling Corp.																					
COU #26 (K-31)	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3
COU #29 (E-6)	39	50	102	78	100	204	194r	250	510	233r	300	612	271r	350	713	310r	400	815	544r	702	1431
COU #30 (F-30)	50	35	79	100	70	158	100	70	158	100	70	158	100	70	158	100	70	158	100	70	158
COU #31 (N-31)	50	22	69	100	44	138	250	110	279	273	120	377	273	120	377	273	120	377	273	120	377
COU #32 (J-6)	10	50	92	20	100	185	50r	250	462	60r	300	554	70r	350	646	80r	400	739	104	520	960
SUBTOTAL	151	158	345	300	315	688	596	681	1412	668	791	1704	716	891	1897	765	991	2092	1023	1413	2929
% of Total	7.6	5.8	6.2	8.5	6.8	7.2	9.7	7.9	8.0	9.9	8.1	8.6	9.9	8.5	8.9	10.2	9.0	9.3	11.3	10.7	10.5
TOTAL STUDY AREA	1992	2743	5600	3525	4648	9530	6116	8631	17,628	6732	9714	19,862	7231	10,447	21,332	7534	11,033	22,478	9085	13,233	27,801

NOTES: Oil and Gas PVT Data: B_o = 1.38 RB/STB, B_g = 1.78 RB/MCF, R_s = 588 SCF/STB
* = Operated by E. Alex Phillips
r = Production Restricted by GOR Limit
RB = Reservoir bbls.

DUGAN PRODUCTION ENGINEERING: 08/05/86: BW/JDR/cg



BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case No. 8946 Exhibit No. 5

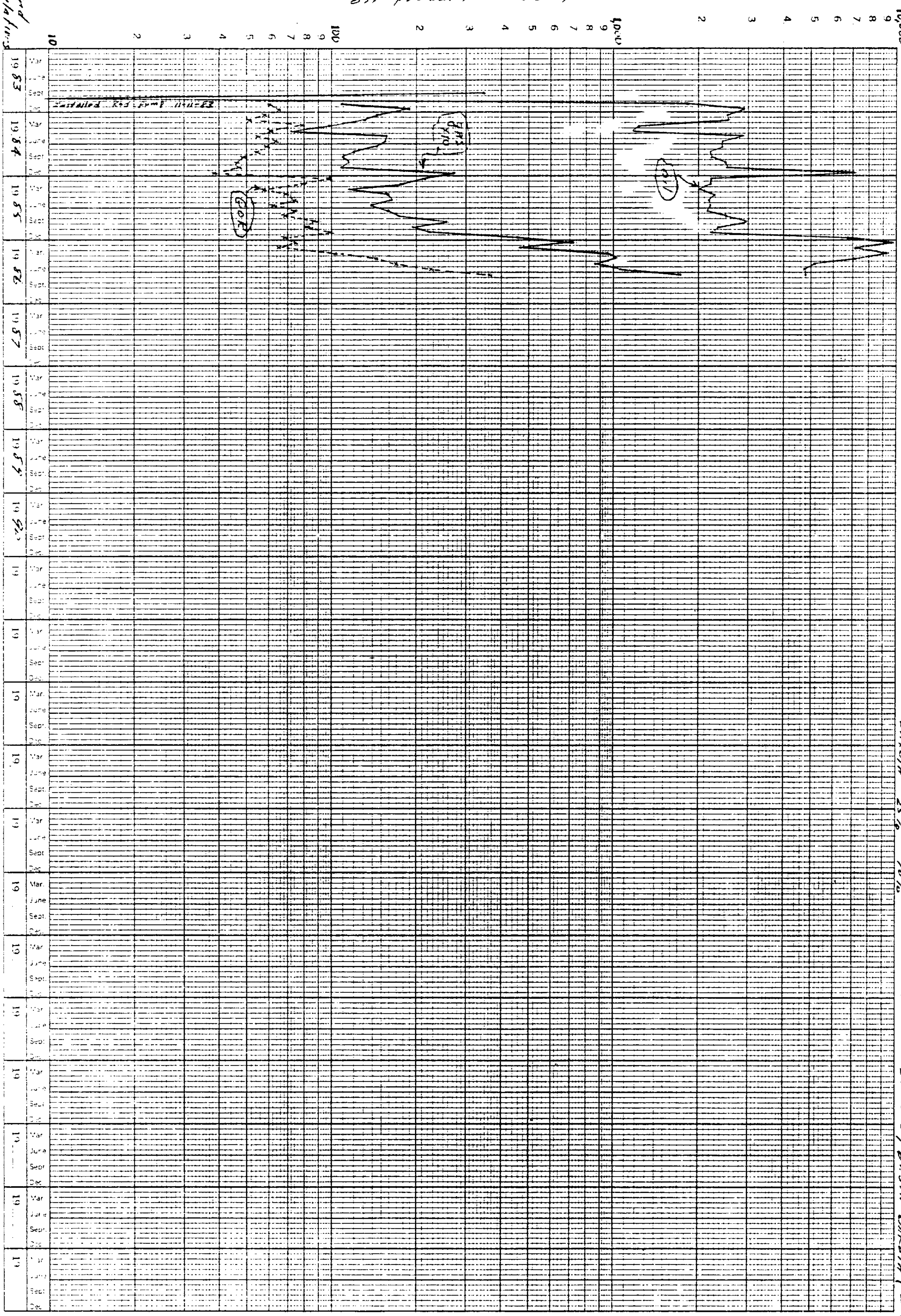
Submitted by DUGAN

Hearing Date AUGUST 27, 1986

K+E 20 YEARS BY MONTHS X 3 LOG CYCLES
KEUFFEL & ESSER CO.

47 6840

gas production - mcF/month x10
oil production - bbl/month



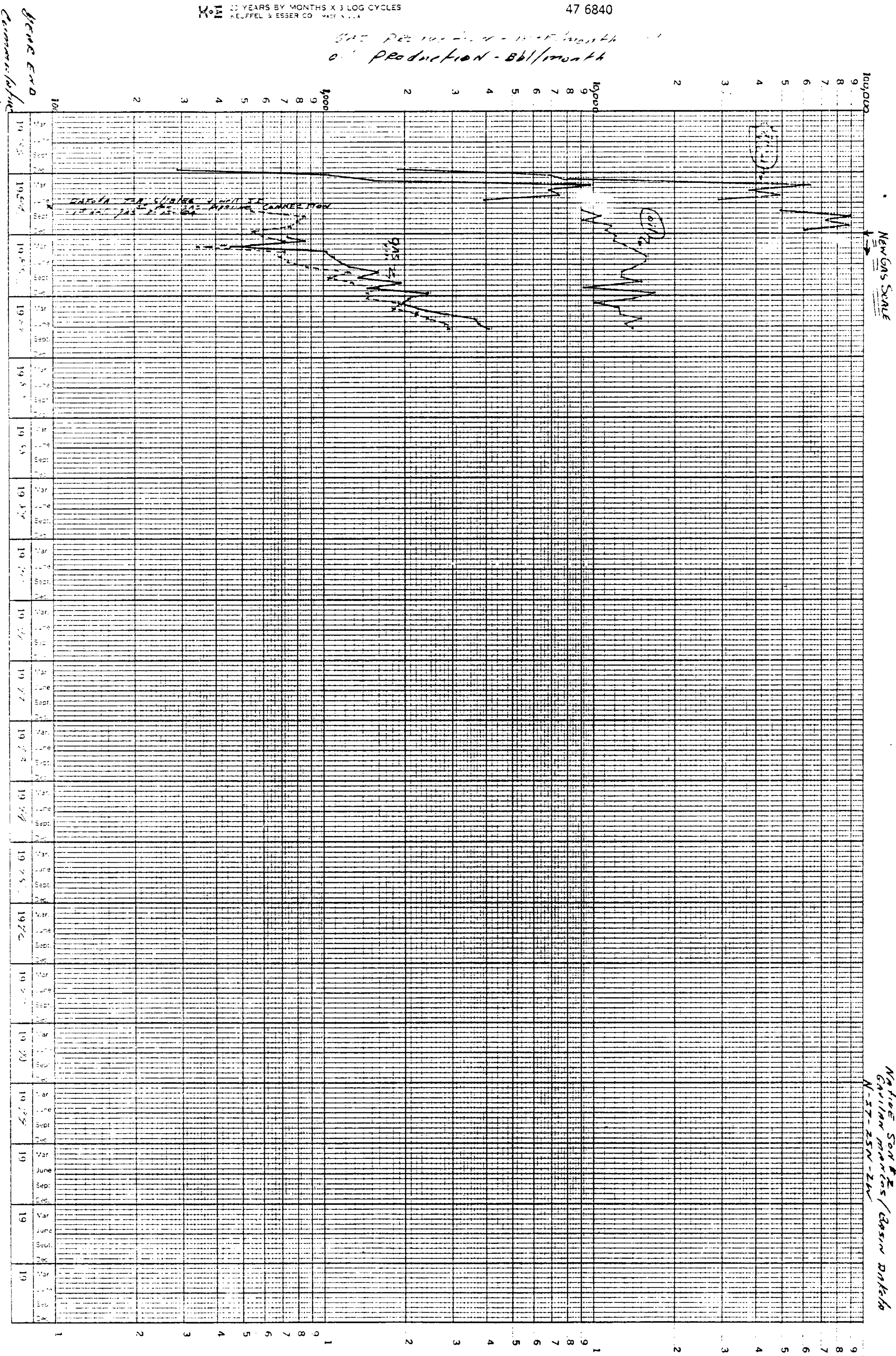
Commingled - Total production plotted

order #R-7312 oil gas
Mancos 75% 90%
Dakota 25% 10%

Jerome P. McHugh
Janet #2
Gavilan Mancos / Basin Dakota (I-21-25N-2W)

K+E 20 YEARS BY MONTHS X 3 LOG CYCLES KEUFFEL & ESSER CO. MADE IN U.S.A.

47 6840



BEFORE THE OIL CONSERVATION COMMISSION

OF THE STATE OF NEW MEXICO

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 8946 Exhibit No. 1
Submitted by McHugh
Hearing Date 8/7/86

IN THE MATTER OF THE APPLICATION
OF JEROME P. MCHUGH AND ASSOCIATES
FOR AMENDMENT TO THE SPECIAL RULES
AND REGULATIONS OF THE GAVILAN-
MANCOS OIL POOL, PROMULGATED BY
DIVISION ORDER NO. R-7407.

CASE NO. 8946

AFFIDAVIT OF MAILING

STATE OF NEW MEXICO)
) ss
COUNTY OF SANTA FE)

The undersigned, being first duly sworn, upon oath, states that on July 1, 1986, the undersigned did mail in the United States Post Office at Santa Fe, New Mexico, true copies of the Application of Jerome P. McHugh and Associates in this case to all of the operators of wells and each unleased mineral owner within the existing Gavilan-Mancos Oil Pool and all operators of wells within one mile of such boundaries by regular mail as set forth on Exhibit A attached hereto, and on July 14, 1986, the undersigned notified all of the parties listed on Exhibit A that the hearing had been rescheduled for a Commission hearing to be held on August 7, 1986.

W. Kellahin

W. Thomas Kellahin

SUBSCRIBED AND SWORN TO before me this 6th day of August 1986.

Notary Public

My Commission Expires: May 25, 1987

GAVILAN WORKING INTEREST OWNERS
ADDRESSEE LIST

Amoco Production Company
1670 Broadway
P. O. Box 800
Denver, Colorado 80201
Attention: Richard Bottjer

ARCO Oil and Gas Company
Permian District
P. O. Box 1610
Midland, Texas 79702
Attention: T. S. McCorkle

Arriba Co., Ltd.
P. O. Box 35304
Tulsa, Oklahoma 74153
Attention: G. L. Morris

Robert L. Bayless
P. O. Box 168
Farmington, New Mexico 87499

Chevron U.S.A.
P. O. Box 599
Denver, Colorado 80201
Attention: Randy Hagood

Warren Clark Trust
Mabel Reed, Trustee
P. O. Box 1846
Austin, Texas 78767

Testamentary Trust under the
Will of Warren Clark
Mabel Reed and H. M. Reed, Trustees
P. O. Box 1846
Austin, Texas 78767

Carolyn Clark Oatman
P. O. Box 1846
Austin, Texas 78767

Conoco Inc.
P. O. Box 460
726 East Michigan
Hobbs, New Mexico 88240
Attention: Donald W. Johnson

Crestone Energy Corporation
718 17th Street, Suite 520
Denver, Colorado 80202
Attention: Randall C. Thompson

Mr. Jerry K. Debolt
272 Church Center Road
McMurray, Pennsylvania 15317

Dugan Production Corp.
P. O. Box 208
Farmington, New Mexico 87499
Attention: Robert G. Stovall

Mr. Steve S. Dunn
3100 Western
Farmington, New Mexico 87401

Mr. Ralph Gilliland
7420 Caruth
Dallas, Texas 75225

Mrs. Ardis North Hamilton
141 East South Street
Worthington, Ohio 43085

Rear Admiral Thomas J. Hamilton
7580 Caminito Avola
La Jolla, California 92037

Ms. Janet J. Hewes
c/o The Johnson Offices
90 Cricket Avenue
Ardmore, Pennsylvania 19003

A. G. Hill, Oil Producer
5000 Thanksgiving Tower
Dallas, Texas 75201
Attention: Philip Garner

Hooper, Kimball and Williams, Inc.
P. O. Box 520970
Tulsa, Oklahoma 74152
Attention: George Owens

Gavilan Working Interest Owners
Addressee Listing
Page Two

Ibex Partnership
P. O. Box 911
Breckenridge, Texas 76024

Mr. Eldridge R. Johnson
c/o The Johnson Offices
90 Cricket Avenue
Ardmore, Pennsylvania 19003

Mr. George F. Johnson
c/o The Johnson Offices
90 Cricket Avenue
Ardmore, Pennsylvania 19003

Kenai Oil and Gas Inc.
One Barclay Plaza
1675 Larimer Street, Suite 500
Denver, Colorado 80202
Attention: Joseph R. Mazzola

Kindermac Partners
650 South Cherry Street, Suite 1225
Denver, Colorado 80222

Koch Exploration
P. O. Box 2256
Wichita, Kansas 67201
Attention: Carl Pomeroy

Mallon Oil Company
1616 Glenarm Place, Suite 2850
Denver, Colorado 80202
Attention: Kevin Fitzgerald

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

McHugh Lindrith 1982 Ltd. Partnership
650 South Cherry Street, Suite 1225
Denver, Colorado 80222

McHugh Lindrith 1983 Ltd. Partnership
650 South Cherry Street, Suite 1225
Denver, Colorado 80222

Mr. Horace F. McKay, Jr.
P. O. Box 14738
Albuquerque, New Mexico 87191

Meridian Oil Inc.
P. O. Box 4289
Farmington, New Mexico 87499-4289
Attention: Land Department

Mr. J. Gregory Merrion
P. O. Box 840
Farmington, New Mexico 87499

Merrion Oil and Gas Corp.
P. O. Box 840
Farmington, New Mexico 87499
Attention: Steve Dunn

Mesa Grande, Ltd.
1305 Philtower Building
Tulsa, Oklahoma 74103
Attention: Larry Sweet

Mesa Grande Resources, Inc.
1200 Philtower Building
Tulsa, Oklahoma 74103
Attention: Gregory Phillips

Mrs. Anne K. Milinovich
64 Sycamore Street
Waynesburg, Pennsylvania 15370

Mobil Producing Texas & New Mexico
P. O. Box 633
Midland, Texas 79702
Attention: John Faulhaber

Mountain States Natural Gas Corp.
P. O. Box 35426
Tulsa, Oklahoma 74543
Attention: Jack Blair

PC, Ltd.
P. O. Box 911
Breckenridge, Texas 76024

Gavilan Working Interest Owners
Addressee Listing
Page Three

Mr. Paul J. Puglia
294 West Wayne Street
Waynesburg, Pennsylvania 15370

Reading & Bates Petroleum Company
3200 Mid-Continent Tower
Tulsa, Oklahoma 74103
Attention: Eric Koelling

Tenneco Oil Company
P. O. Box 3249
Englewood, Colorado 80155
Attention: George Calstrom

Texaco Oils Inc.
P. O. Box 2100
Denver, Colorado 80201
Attention: Bill Smallwood

True Oil Company
P. O. Drawer 2360
Casper, Wyoming 82602
Attention: Tom Walker

Duer Wagner, Jr.
2906 Texas American Bank Building
Fort Worth, Texas 76102

Duer Wagner, III
2906 Texas American Bank Building
Fort Worth, Texas 76102

Mr. Hunt Walker
P. O. Box 2409
Denver, Colorado 80201-2409

Bob Andes
P. O. Box 1067
Farmington, New Mexico 87499

W. E. Lang
P. O. Box 1067
Farmington, New Mexico 87499

Southern Union Exploration Company
Texas Federal Building
Suite 400
1217 Main Street
Dallas, Texas 75202

Dunn-Mar Oil and Gas Company
27 S. College St.
Washington, Pennsylvania 15301

Northwest Pipeline Corp.
295 Chipeta Way
Salt Lake City, Utah 84108

Michael W. Murphy
200 N. Jefferson, Suite 500
El Dorado, Arkansas 71730

R. K. O'Connell
P. O. Box 2003
Casper, Wyoming 82602

Union Texas Petroleum Corp.
14001 E. Iliff Ave., Suite 500
Aurora, Colorado 80014

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

U. S. Department of the Interior
Bureau of Land Management
P. O. Box 6770
Albuquerque, New Mexico 87197
Attention: Gary Stephens

Schalk Development Co.
P. O. Box 25825
Albuquerque, New Mexico 87125

Edith H. Payne
1018 Idlewilde Lane S.E.
Albuquerque, New Mexico 87191

Kodiak Petroleum, Inc.
American Penn Energy, Inc.
5700 S. Quebec, #320
Englewood, Colorado 80111

Allison Beach
c/o William A. Martin
430 Mayo Building
Tulsa, Oklahoma 74103

David Beach
c/o William A. Martin
430 Mayo Building
Tulsa, Oklahoma 74103

Betsey Stone
c/o William A. Martin
430 Mayo Building
Tulsa, Oklahoma 74103

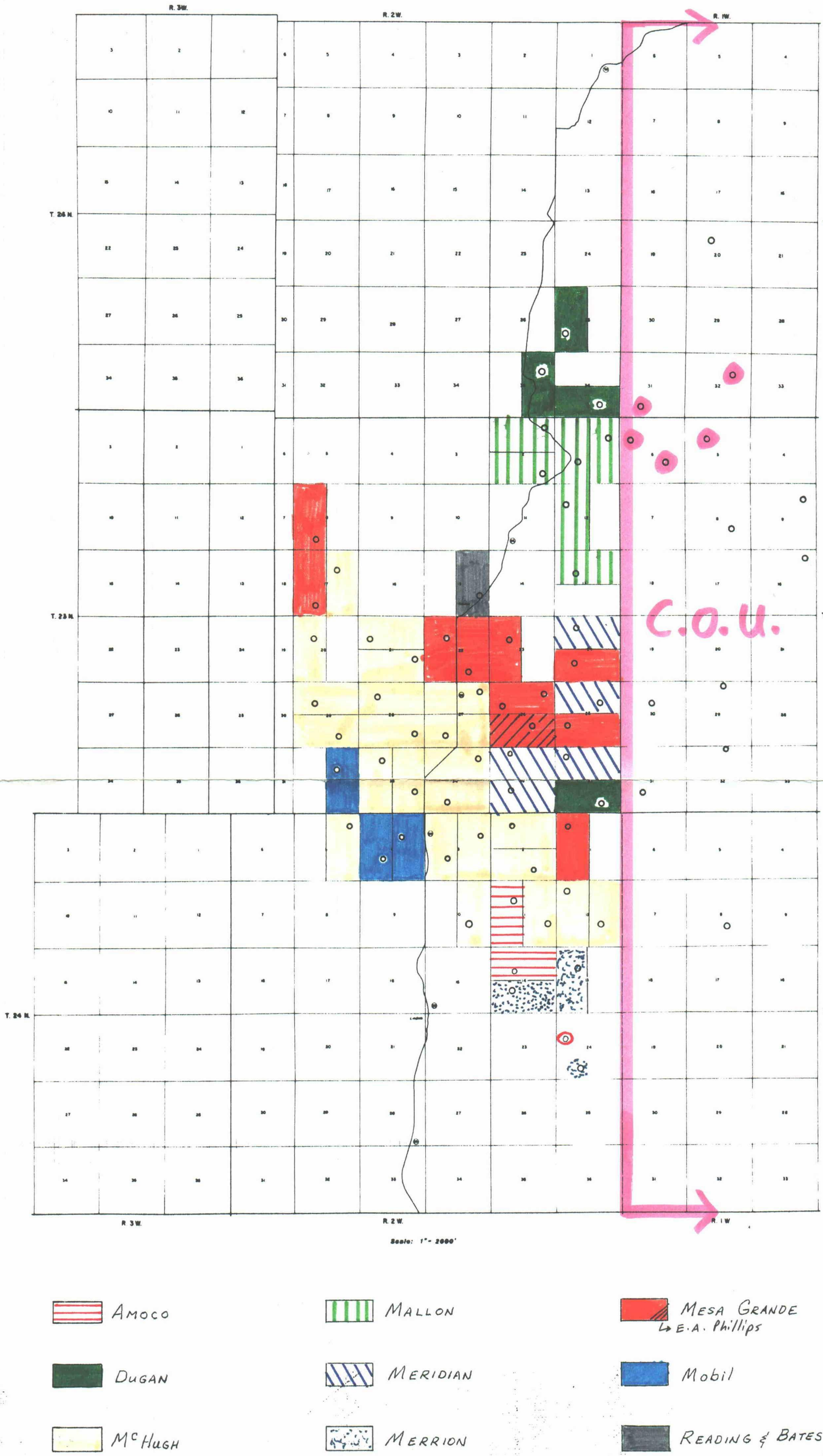
Daniel Beach
c/o William A. Martin
430 Mayo Building
Tulsa, Oklahoma 74103

Priscilla B. Guest
c/o William A. Martin
430 Mayo Building
Tulsa, Oklahoma 74103

Helmerich & Payne, Inc.
1579 E. 21st St.
Tulsa, Oklahoma 74114

Forest Oil Corporation
700 Colorado Federal Building
821 - 17th Street
Denver, Colorado 80202

Peter J. McMahon and Grace F. McMahon, Trustees under Trust Agreement dated December 1, 1981
320 S. Boston Ave., Suite 1605
Tulsa, Oklahoma 74103

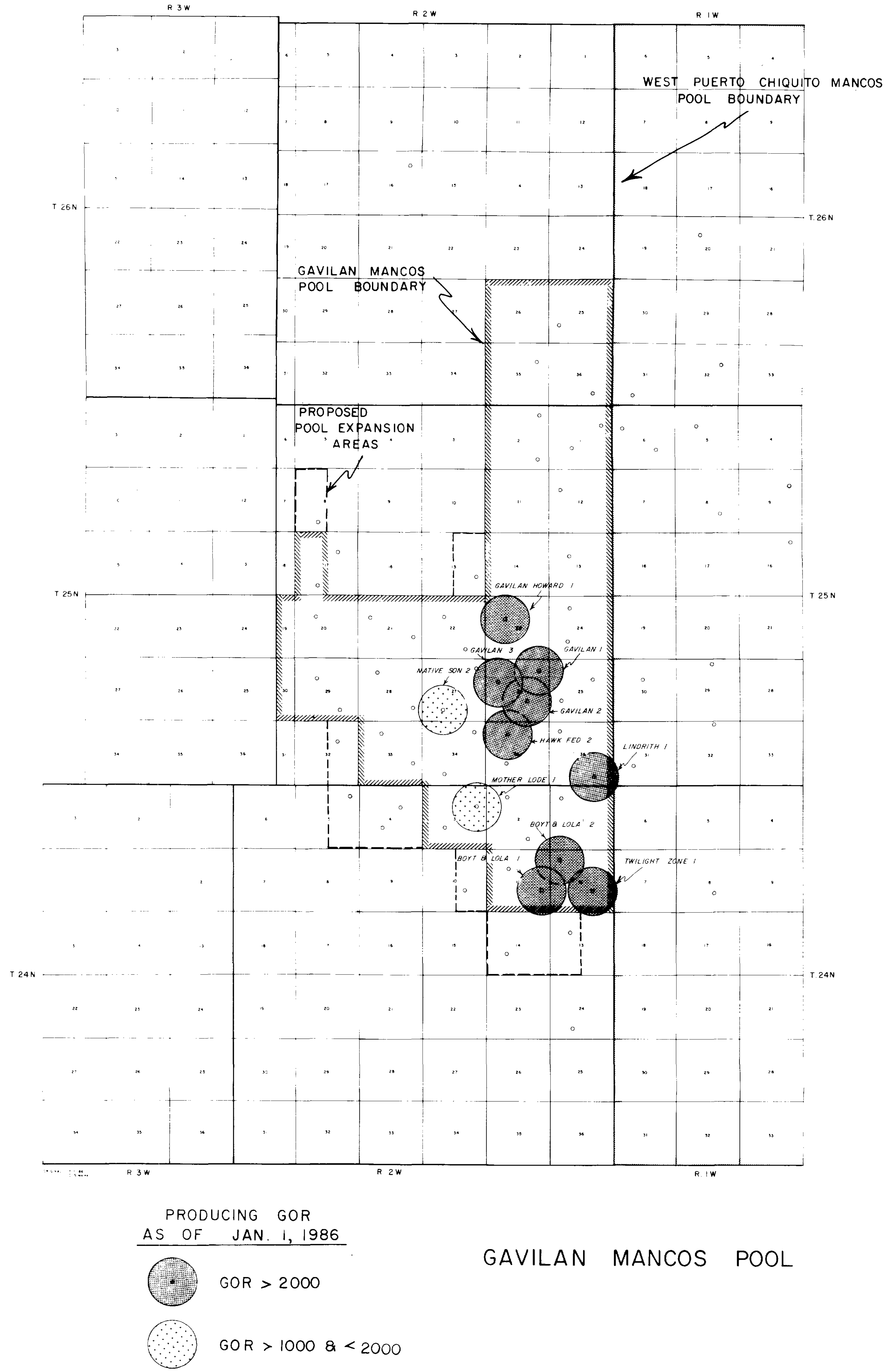


BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 8946 Exhibit No. 2
Submitted by McHugh
Hearing Date 8/7/86

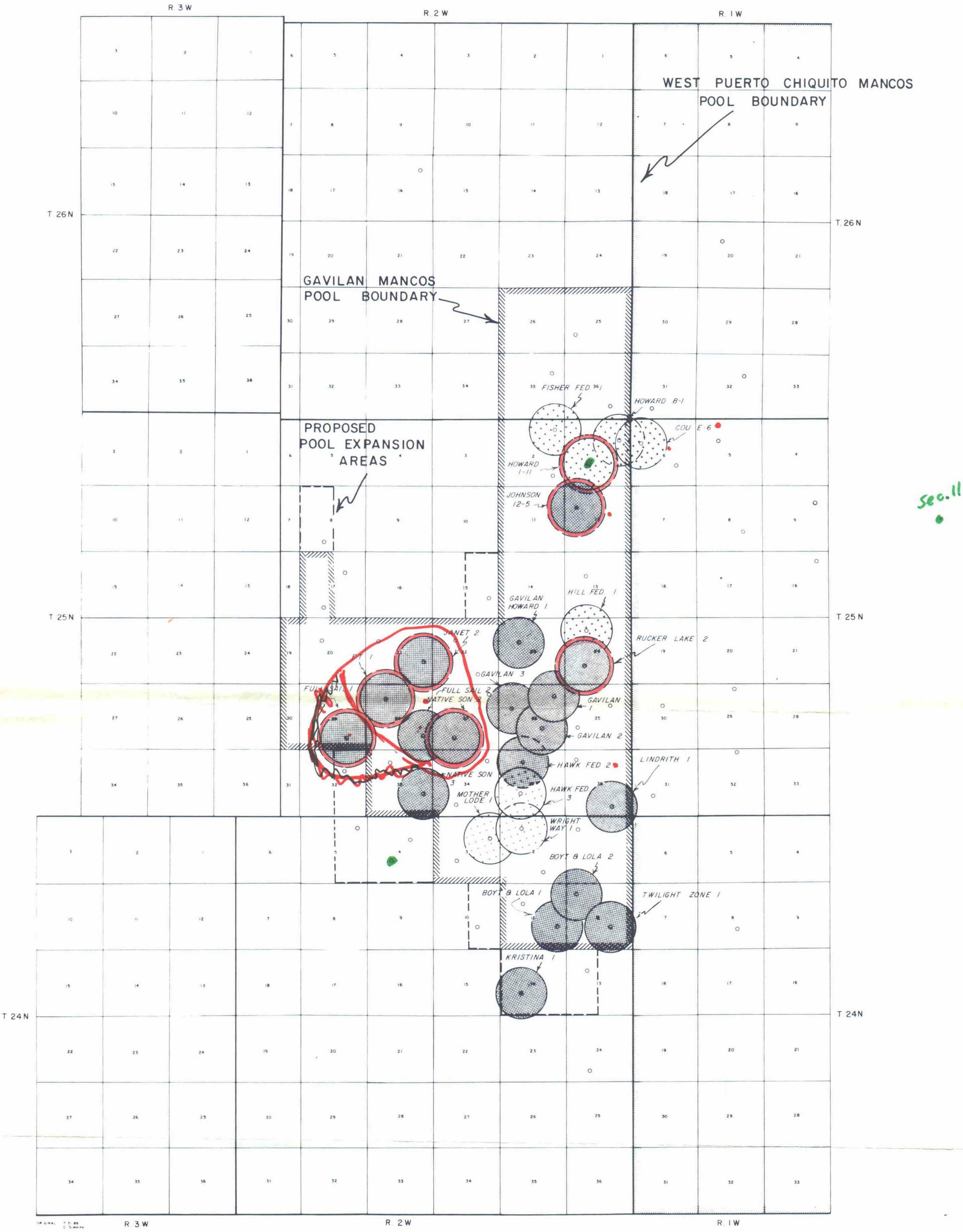
JEROME P. McHUGH & ASSOCIATES
EXHIBITS IN CASE NO. 8946
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

AUGUST 7, 1986

BEFORE THE
OIL CONSERVATION DIVISION
Santa Fe, New Mexico
Case No. 8946 Exhibit No. 3
Submitted by McHUGH
Hearing Date AUG. 7, 1986



GAVILAN MANCOS POOL



PRODUCING GOR
AS OF JULY 1, 1986

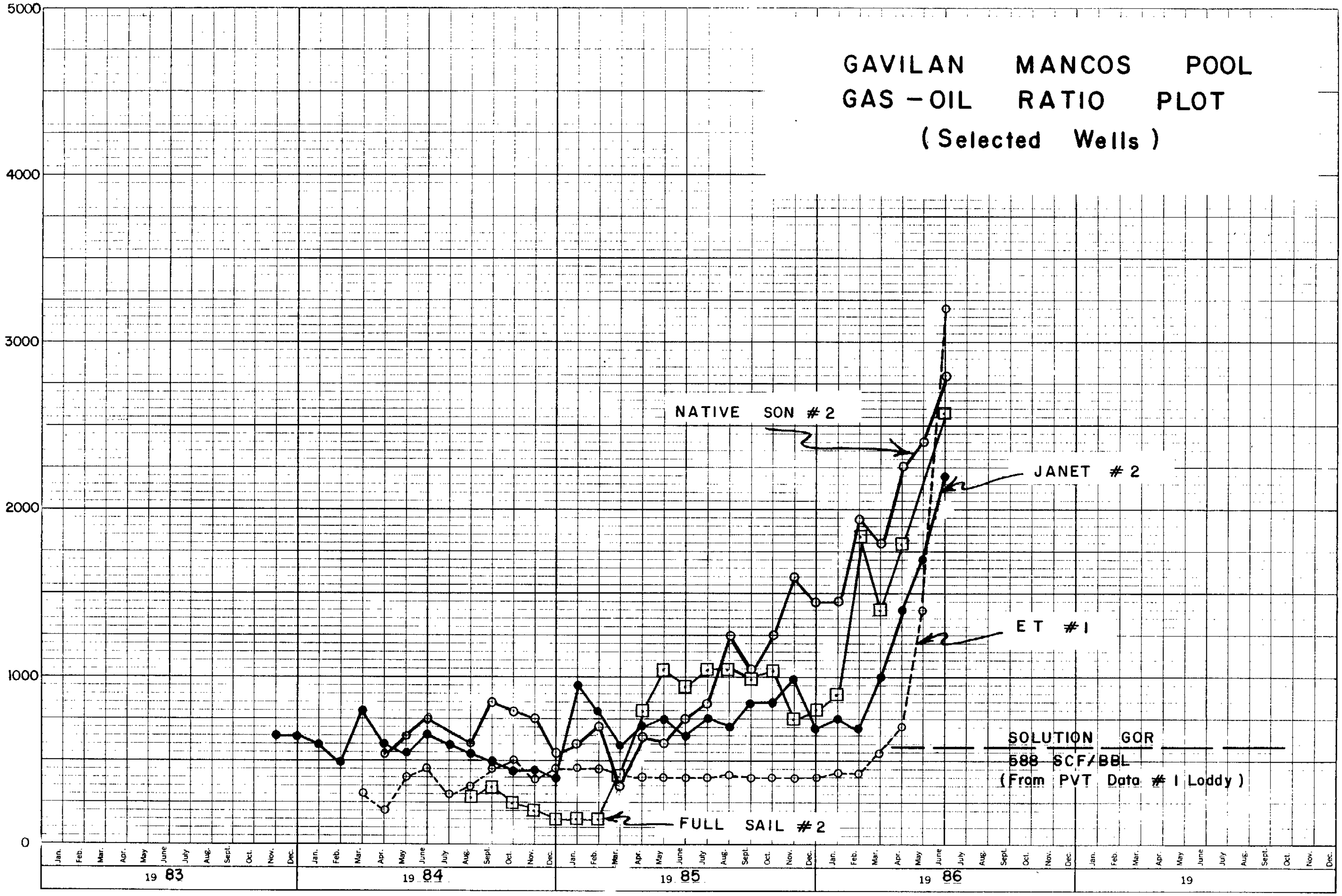
GOR > 2000

GOR > 1000 & < 2000

Well With GOR History Plotted

GAVILAN MANCOS POOL

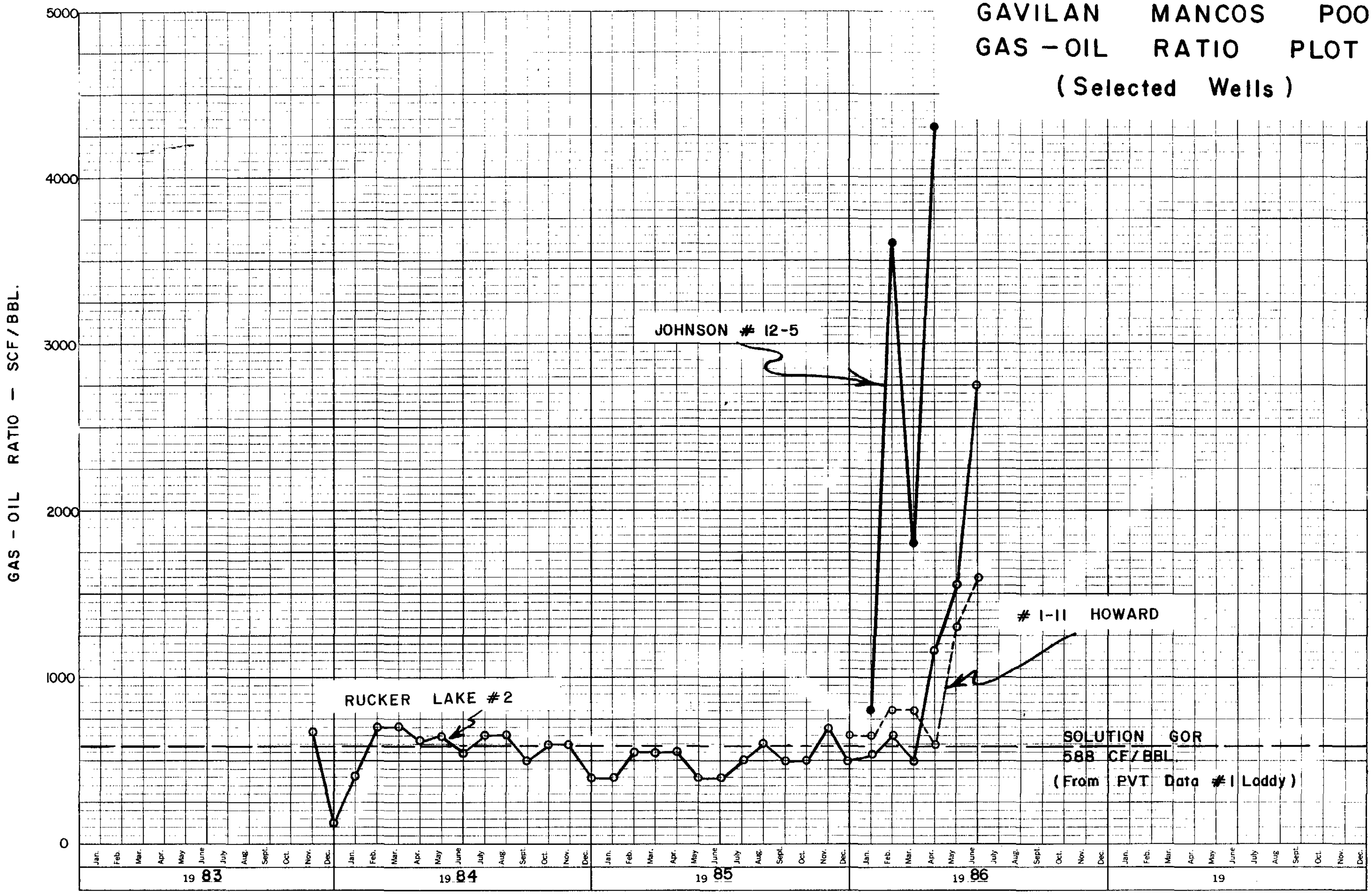
•: core data


GAVILAN MANCOS POOL
GAS - OIL RATIO PLOT
(Selected Wells)
NATIVE SON # 2
JANET # 2
E T # 1
FULL SAIL # 2
SOLUTION GOR
588 SCF/BBL
(From PVT Data # 1 Loddy)
GAS-OIL RATIO — SCF/BBL.
5000
4000
3000
2000
1000
0
Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.
19 83
19 84
19 85
19 86
19

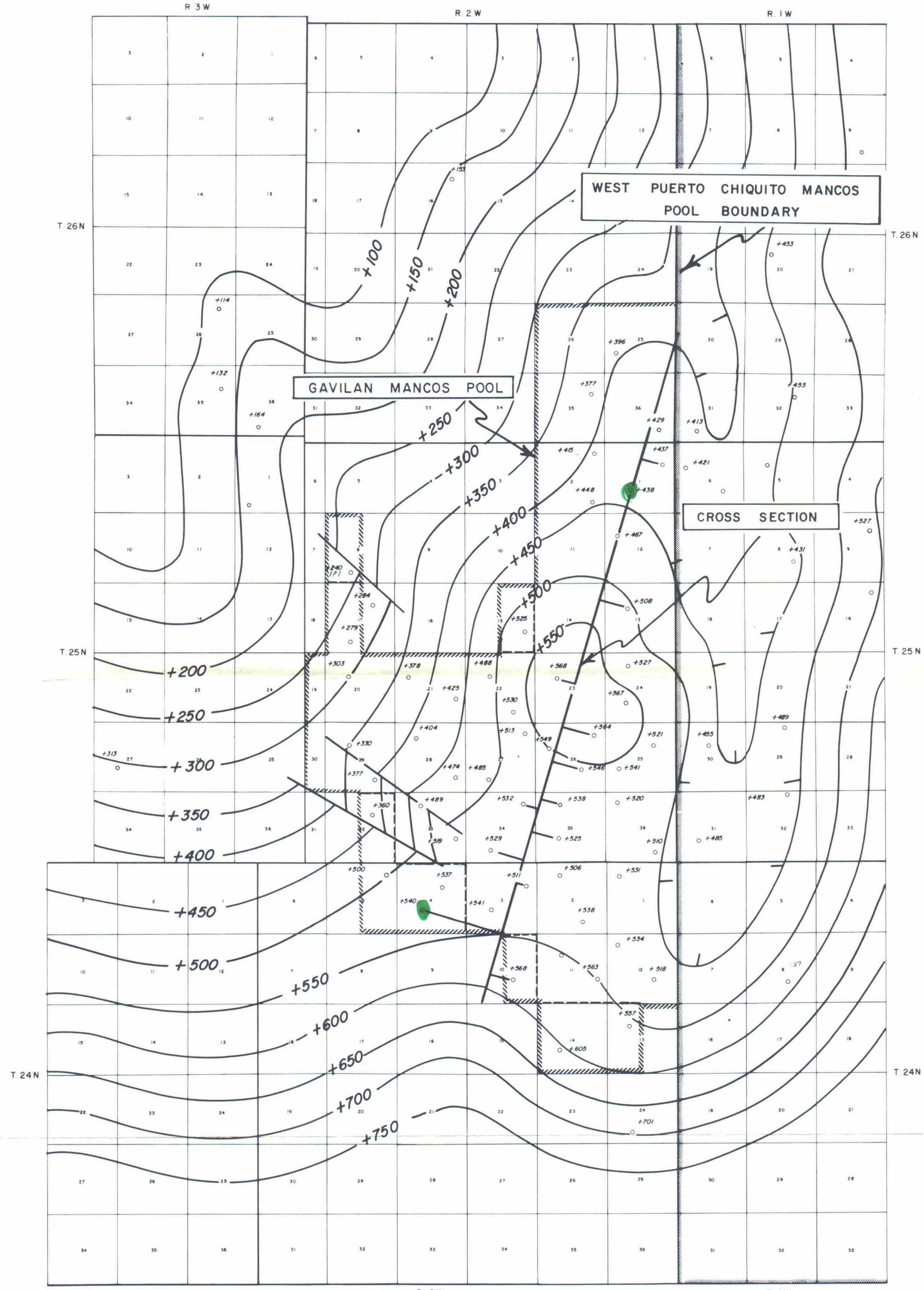
B

7-28-86
CS

GAVILAN MANCOS POOL GAS - OIL RATIO PLOT (Selected Wells)



7-28-86
CS



Core
Sec 11

GAVILAN MANCOS POOL
RIO ARRIBA CO., NEW MEXICO
STRUCTURE TOP NIOBRARA "A"

C.I. = 50'
SCALE: 1" = 8,000'
DATUM: Sea Level
DATE: August 1, 1986