OPEN-FILE REPORT 83-03

ESTIMATED OIL AND GAS RESERVES: KRAUTHEAD-BASELINE FIELDS AREA, WELD AND ADAMS COUNTIES, COLORADO

Compiled by
A. H. Scanlon

DOI: https://doi.org/10.58783/cgs.of8303.lkrv6990

Funded by the Colorado Oil and Gas Conservation Commission

Colorado Geological Survey
Department of Natural Resources
State of Colorado
Denver, Colorado
1983

OPEN FILE 1983-3

ESTIMATED OIL AND GAS RESERVES: KRAUTHEAD-BASELINE FIELDS AREA, WELD AND ADAMS COUNTIES, COLORADO

Compiled by

A. H. Scanlon

Funded by the Colorado Oil and Gas Conservation Commission

Colorado Geological Survey

Department of Natural Resources

State of Colorado

Denver, Colorado

1983

ACKNOWLEDGMENTS

The author wishes to thank the following companies and individuals who supplied data and/or made suggestions for this report: AMOCO Production Co., Champlin Petroleum Co., Griffin Petroleum Corp., Carl A. Houy, MGF Oil Corp., Rocky Mountain Prod., Zatar, Inc.

This project was compiled by the staff of the Colorado Geological Survey as part of a grant from the Colorado Oil and Gas Conservation Commission.

CONTENTS

FIGURES

TABLES

PLATES

ESTIMATED OIL AND GAS RESERVES: KRAUTHEAD-BASELINE FIELDS AREA, WELD AND ADAMS COUNTIES, COLORADO

INTRODUCTION

The area under study comprises six designated fields: Krauthead (1S-64W), Baseline (1S-63W), Banner Lakes (1N & 1S-64W), Fence Post (1S-64W), Horse Creek (1N-64W), and Sloan (1N-63W). The study area lies approximately 20 miles northeast of Denver, within the Denver Basin (Fig. 1). The area is classified as a stratigraphic trap with updip reduction of porosity, under a solution-gas drive. All production from these fields, excluding Sloan, is from the D sand of Cretaceous age at an average depth of 7,500 feet. A net porous sand isopach map (Plate 1) was constructed using sand thickness greater than 8% porosity (using a 2.68 grain density). A contour map on the top of the 'D' Sand was also constructed (Plate 2). The D sand averages 13.5 feet in thickness, with a maximum thickness of 30 feet. An east-west (A-A') and a northwest-southeast (B-B') cross section were also constructed (Plate 3). The cross sections and isopach map indicate this area was an elongate northeast-southwest-trending channel sand, bordered by thin, narrow levee deposits and splay deposits.

It has been documented that the D sand throughout this area is fractured. This fracturing can be directly related to the quantity of production, as well as to the permeability of the sand. Where producing wells have no D sand porosity greater than 8%, production is credited to the fracture system.

Development of this area has been rapid due to economics and recent frac treatment improvements. Most producers in this area consider all six fields to be of common source and supply, and are therefore commonly combined as a one-field area for reservoir and other related studies.

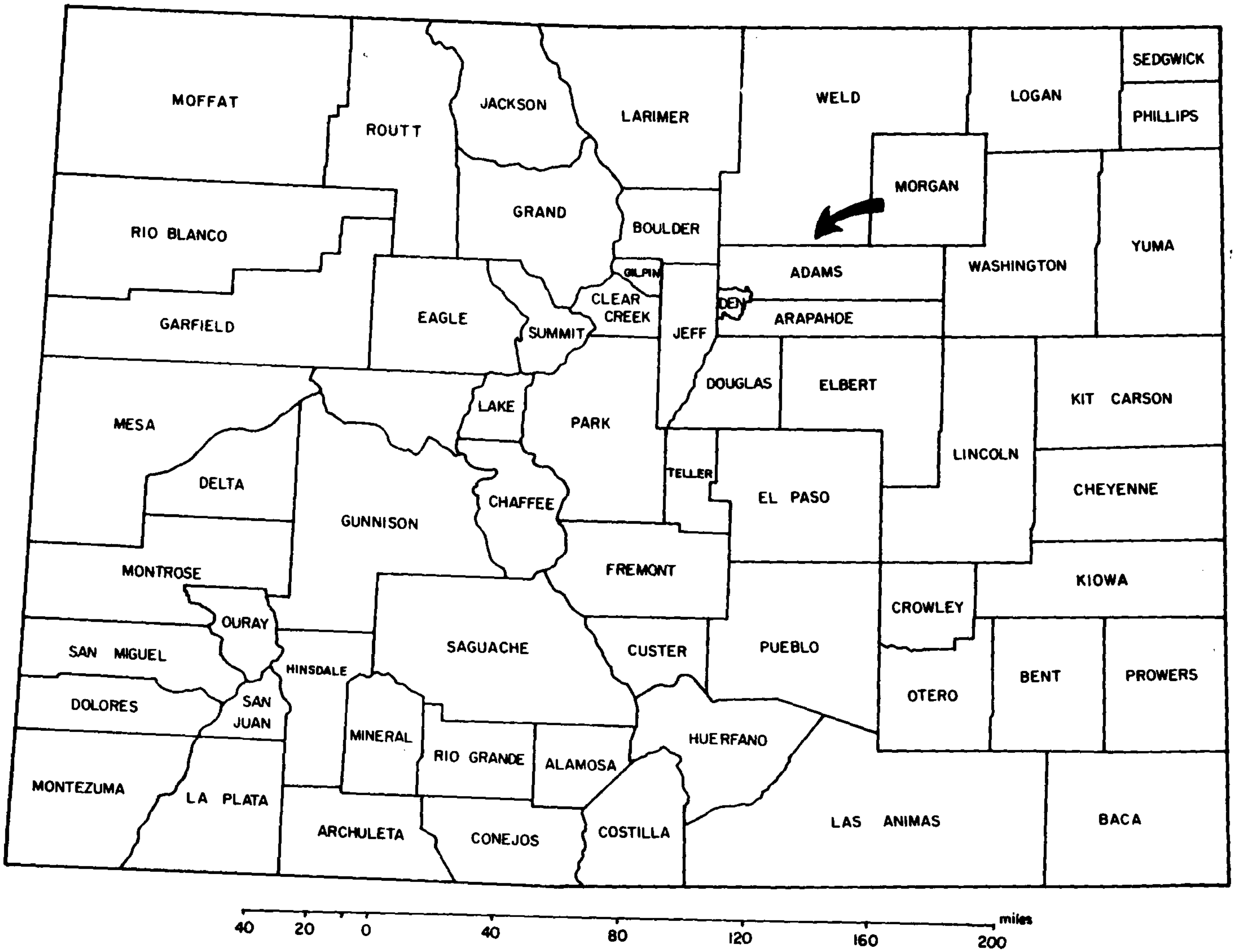


Figure 1. Location Map.

In addition to production from the D sand, the J sand often proves to be economic. Within the study area to date, only one well produces from the J sand, in Sloan Field.

TECHNIQUES USED IN THIS STUDY

Two methods of approach have been used to determine oil reserve estimates in this area: 1) based on case history studies, several relationships have been drawn and are used to predict reserves for other geologically similar situations, and 2) decline curve analysis.

The first method is taken from the American Petroleum Institute (API) publication A Statistical Study of Recovery Efficiency and the Society of Petroleum Engineers (SPE) study Correlation for Fluid Physical Property Prediction. By means of studying case histories on oil and gas reservoirs in the United States and abroad, several parameters which are normally measured by PVT Laboratory Analysis can be calculated by using the following equations. The solution gas-oil ratio is calculated using equation 1:

Equation 1:

$$Rs = \frac{(\delta g)\ (P)^{1.187}}{56.06}\ 10^{10.393\left(\frac{API}{T + 460}\right)}$$

Where: Rs = solution gas-oil ratio

δg = specific gravity of gas

P = Reservoir pressure at bubble point

API = API oil gravity

T = formation temperature, °F

The formation volume factor for API gravity greater than 30° is calculated using equation 2:

Equation 2:

$$Bo = 1 + 4.67\ (Rs)\ 10^{-4} + 0.11\ (T\text{-}60)\ \frac{API}{\delta g}\ 10^{-4} + 0.1337\ (Rs)(T\text{-}60)\left(\frac{API}{\delta g}\right)10^{-8}$$

where Bo = oil Formation Volume Factor

Rs, T, API, and δg = as above

Barrels per acre-feet can then be arrived at using equation 3:

Equation 3:

$$BAF = (3244)\left(\frac{\phi(1-Sw)}{Bob}\right)^{1.1611}\left(\frac{K}{\mu ob}\right)^{0.0979}\left(Sw\right)^{0.3722}\left(\frac{Pb}{Pa}\right)^{0.1741}$$

Where: BAF = Barrels per Acre Foot

ϕ = porosity

Sw = water saturation

Bob = oil Formation Volume Factor at bubble point

K = permeability

μob = viscosity of oil at bubble point

Pb = reservoir bubble point pressure

Pa = reservoir abandonment pressure

Finally, the recovery efficiency is calculated using equation 4.

Equation 4:

$$R.E. = 41.815\left(\frac{\phi(1-Sw)}{Bob}\right)^{0.1611}\left(\frac{K}{\mu ob}\right)^{0.0979} Sw^{0.3722}\left(\frac{Pb}{Pa}\right)^{0.1741} \text{ (in percent)}$$

Where: ϕ, Sw, Bob, K, μob, Sw, Pb, Pa = as above

R.E. = Recovery Efficiency

Using the values calculated from the above equations in conjunction with the values of acre-feet determined by planimetering the D sand isopach map, a value of the total recoverable oil was obtained. Using these data, a percent recovery efficiency was calculated. Values used for each field in these equations can be found in Table I. It should be noted that the accuracy of estimates using these equations will not be better than the reliability of the input data.

The second method of approach used is based on decline curve analysis and the associated relationships to arrive at the values for remaining reserves and ultimate recoverable reserves. The rate of yearly decline is calculated using equation 5.

Equation 5:

$$dy = \frac{q1 - q2}{q1}$$

Where: dy = yearly decline rate, in percent

q1 = production rate at time 1

q2 = production rate at time 2

Two types of curves are plotted: 1) a rate versus cumulative, (Figures 2-6), and 2) a rate versus time (Figures 7-12). The first case is a simple linear relationship and best results (closest approximation to a straight line, therefore a constant percentage decline) are obtained by plotting this data on regular coordinate paper. The second case is one of exponential decline (assuming a constant percentage decline) and can best be expressed as a straight line on semi-log paper. From equation 6 the remaining reserves can be calculated.

TABLE I

Values Used

	Baseline 12-1S-64W	Krauthead 11-1S-64W	Banner Lakes 4-1S-64W	Fence Post 24-1S-64W	Horse Creek 36-1N-64W	Sloan 30-1N-63W
g	0.8788	0.89				
spec. grav. gas	----------use-----	0.88----------	----------	----------	----------	----------
P	----------	----2890----------	----------	----------	----------	----------
Tfm	--------178 ----------	----------	----------	----------	----------	----------
API	38 -40	38 -42	40	40	40	39.8
	----------	----------	----use 40 as average----	----------	----------	----------
Sw(Min/Avg)	14.6/19.2	14.7/18.4 -------18.8----------	----------	----------	----------	----------
K(Max/Avg)	4.1/0.79	61/10.7 ---------.80 &.10----------	----------	----------	----------	----------
ob (visc. oil@bub.pt.)	-0.35----------	----------	----------	----------	----------	----------
O(Max/Avg) C - core L - log	11.9/8.7 C 19/8.5 L	18.2/10.8 C 18/9.6 L	10 avg	10/8.5 L	12/8.6 L	12/8.3 L
Proven Prod. Ac.	1400	720	240	200	160	40
Net Pay(Max/Avg)	22/6.2	13/6.5		13/6.7	6/3	6/3.2

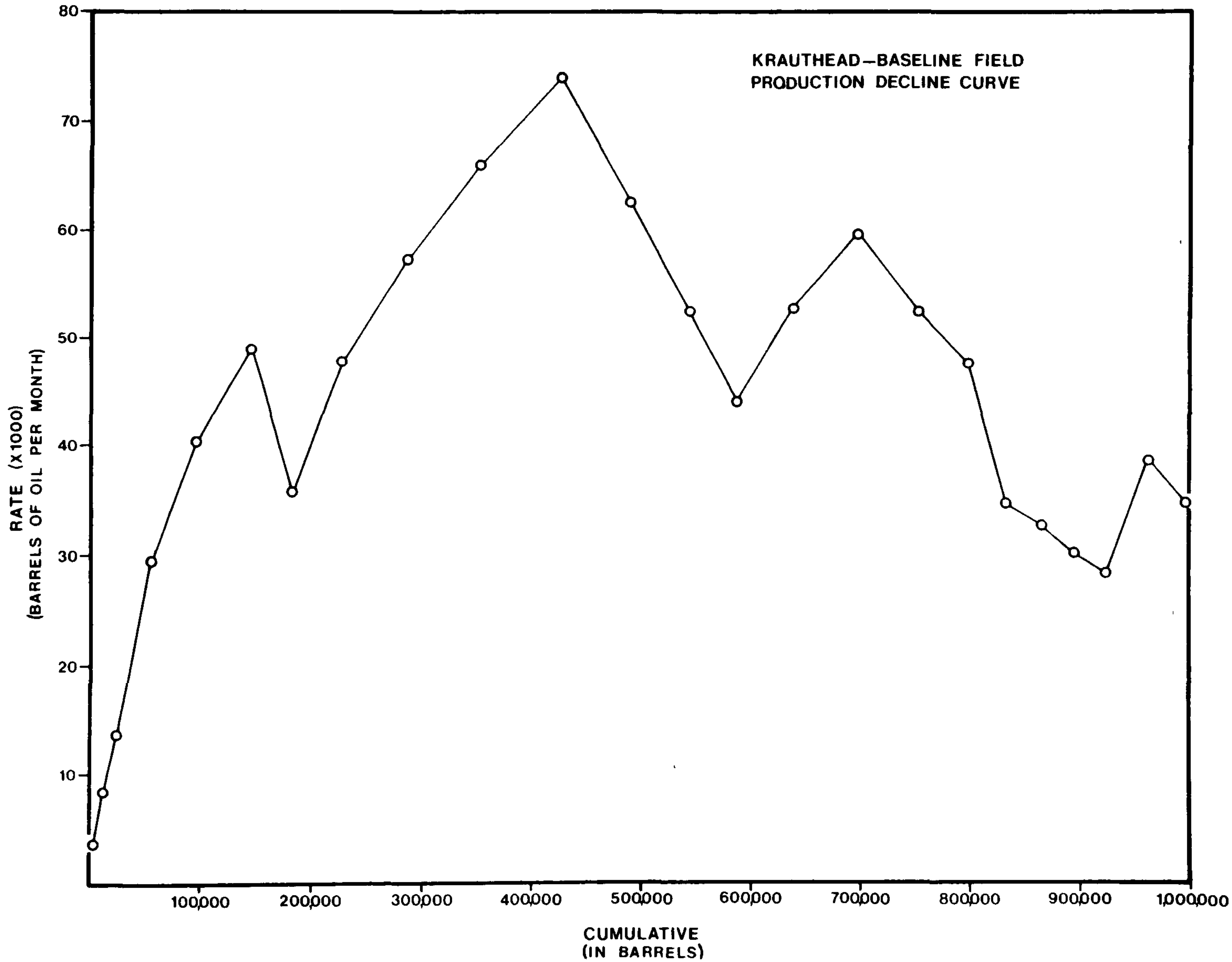

KRAUTHEAD–BASELINE FIELD
PRODUCTION DECLINE CURVE
RATE (X1000)
(BARRELS OF OIL PER MONTH)
80
70
60
50
40
30
20
10
100,000
200,000
300,000
400,000
500,000
600,000
700,000
800,000
900,000
1,000,000
CUMULATIVE
(IN BARRELS)

Figure 2.

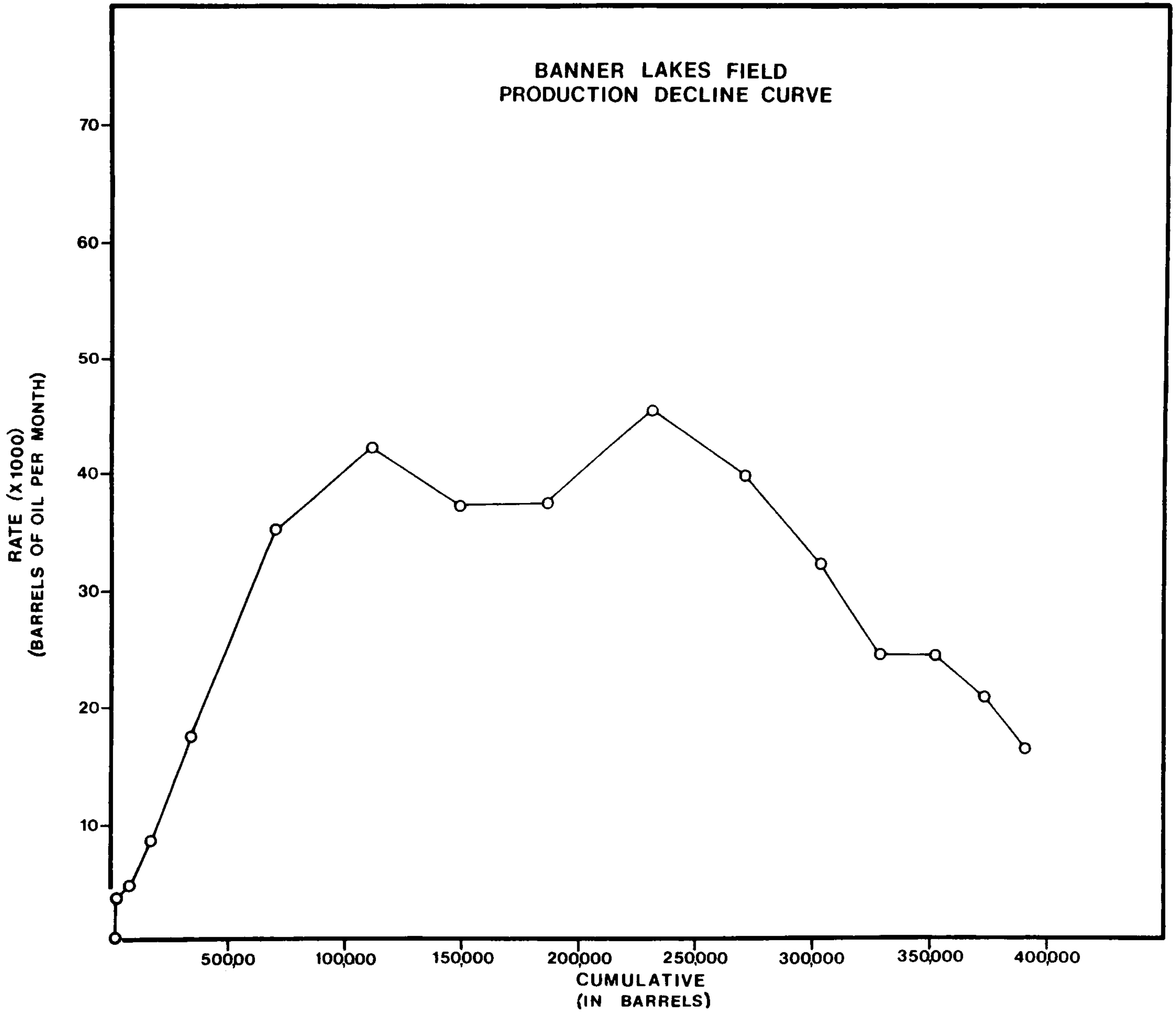
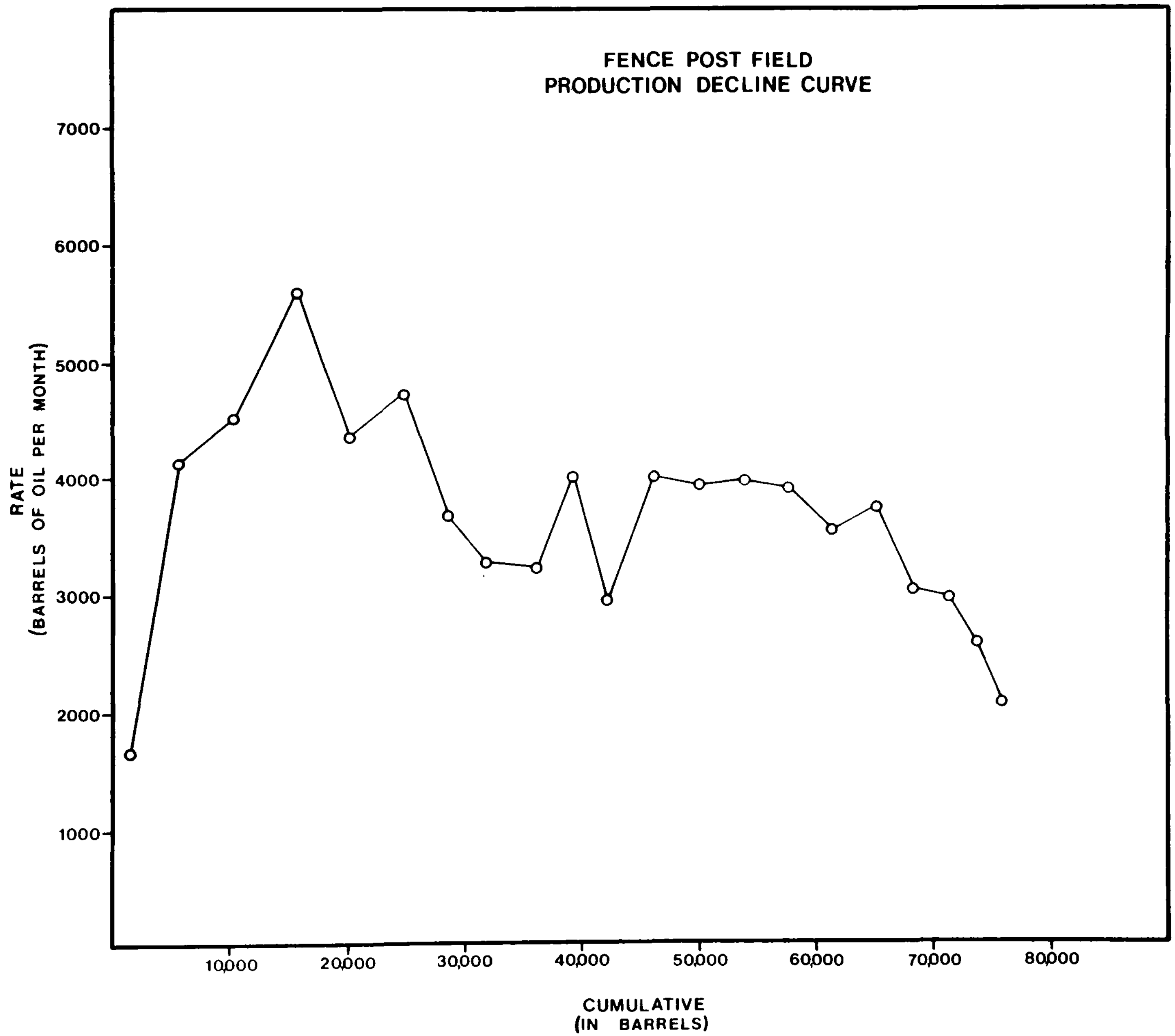

BANNER LAKES FIELD
PRODUCTION DECLINE CURVE
RATE (X1000)
(BARRELS OF OIL PER MONTH)
70
60
50
40
30
20
10
50000
100000
150000
200000
250000
300000
350000
400000
CUMULATIVE
(IN BARRELS)

Figure 3.



FENCE POST FIELD
PRODUCTION DECLINE CURVE
7000
6000
5000
4000
3000
2000
1000
RATE
(BARRELS OF OIL PER MONTH)
10,000
20,000
30,000
40,000
50,000
60,000
70,000
80,000
CUMULATIVE
(IN BARRELS)

Figure 4.

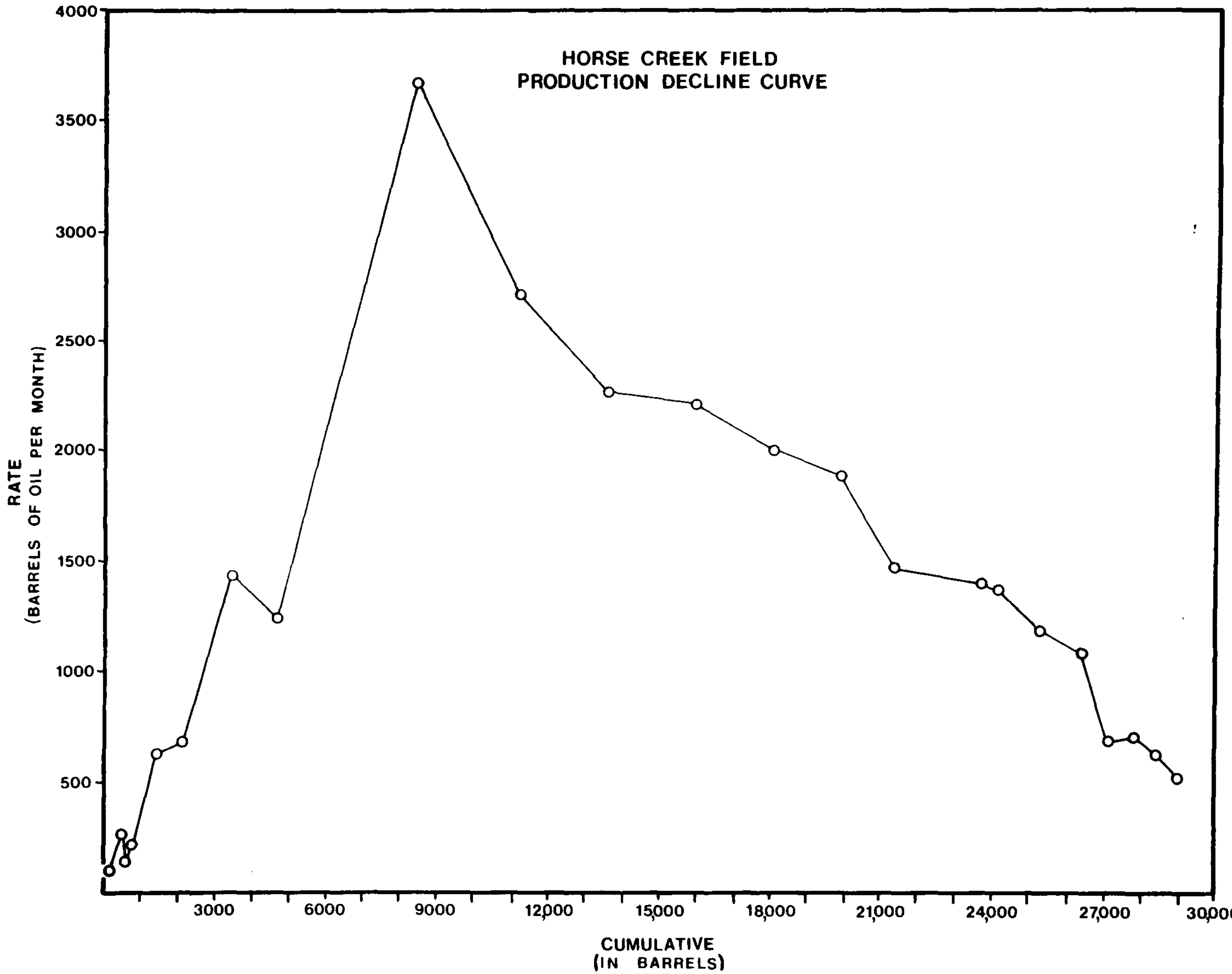

HORSE CREEK FIELD
PRODUCTION DECLINE CURVE
RATE
(BARRELS OF OIL PER MONTH)
4000
3500
3000
2500
2000
1500
1000
500
3000
6000
9000
12,000
15,000
18,000
21,000
24,000
27,000
30,000
CUMULATIVE
(IN BARRELS)

Figure 5.

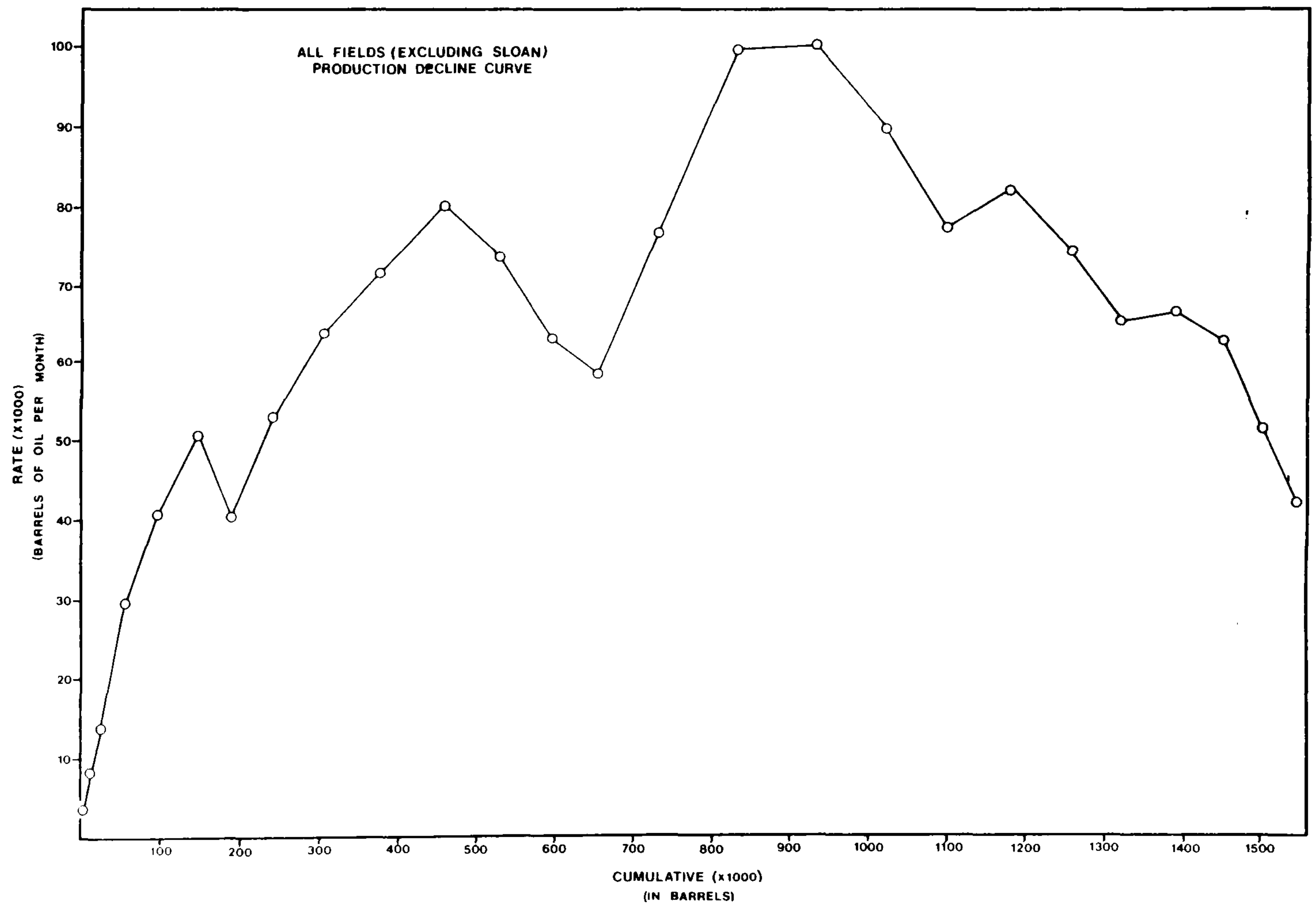

ALL FIELDS (EXCLUDING SLOAN)
PRODUCTION DECLINE CURVE
RATE (X1000)
(BARRELS OF OIL PER MONTH)
100
90
80
70
60
50
40
30
20
10
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
CUMULATIVE (x1000)
(IN BARRELS)

Figure 6.

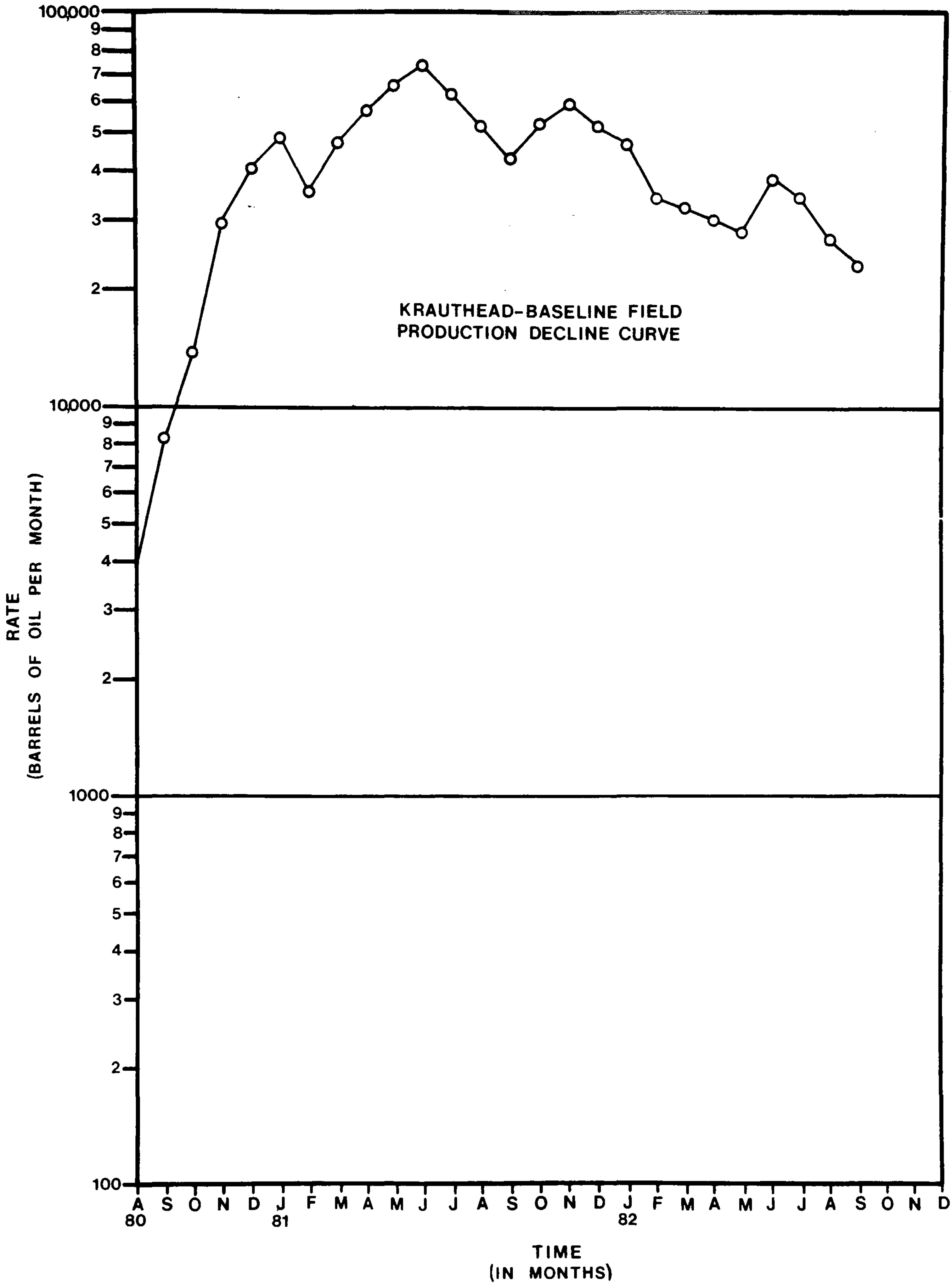

KRAUTHEAD-BASELINE FIELD
PRODUCTION DECLINE CURVE
RATE
(BARRELS OF OIL PER MONTH)
100,000
10,000
1000
100
TIME
(IN MONTHS)
A S O N D J F M A M J J A S O N D J F M A M J J A S O N D
80
81
82

Figure 7.

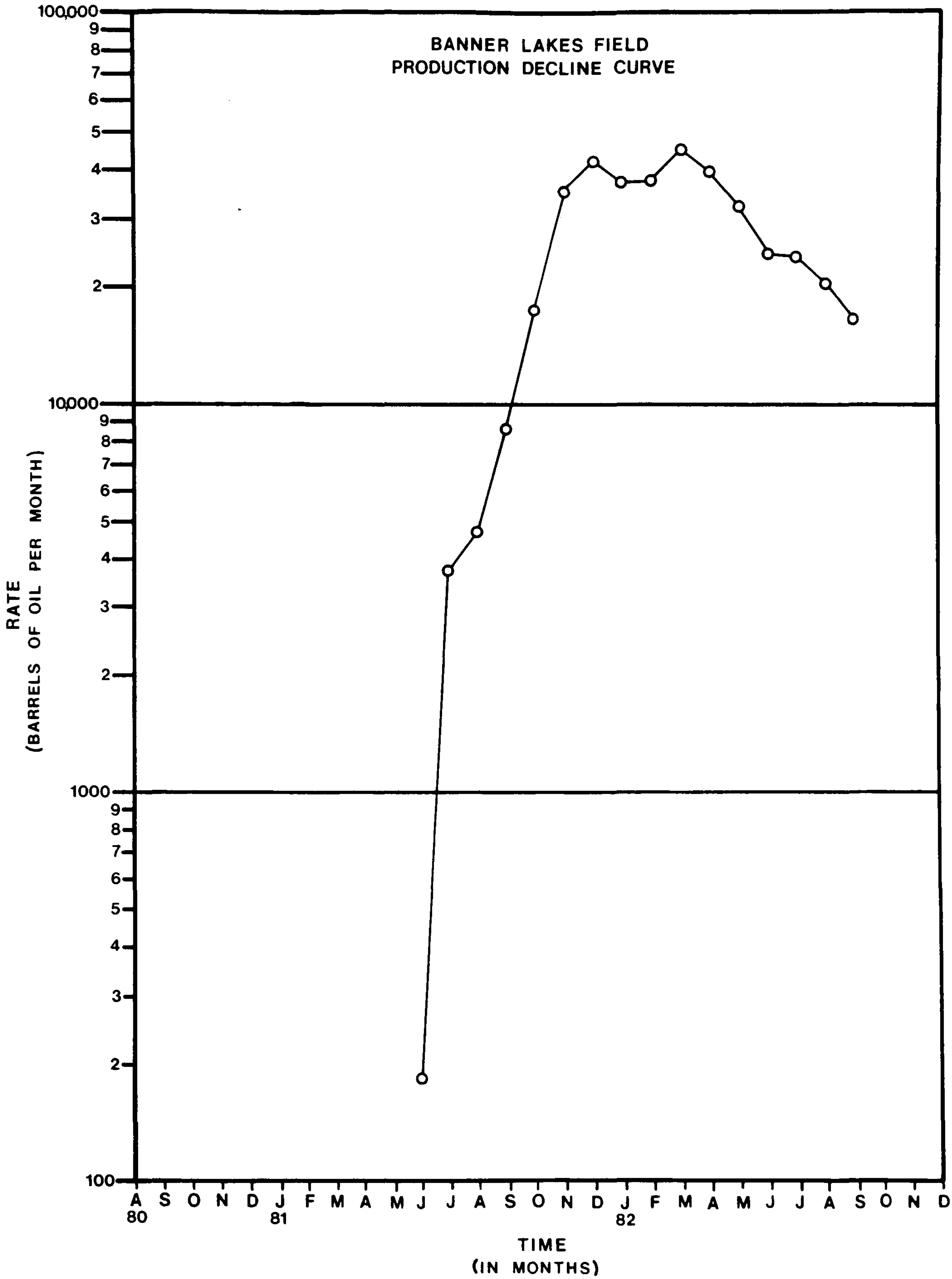

BANNER LAKES FIELD
PRODUCTION DECLINE CURVE
RATE
(BARRELS OF OIL PER MONTH)
100,000
10,000
1000
100
TIME
(IN MONTHS)
A S O N D J F M A M J J A S O N D J F M A M J J A S O N D
80
81
82

Figure 8.

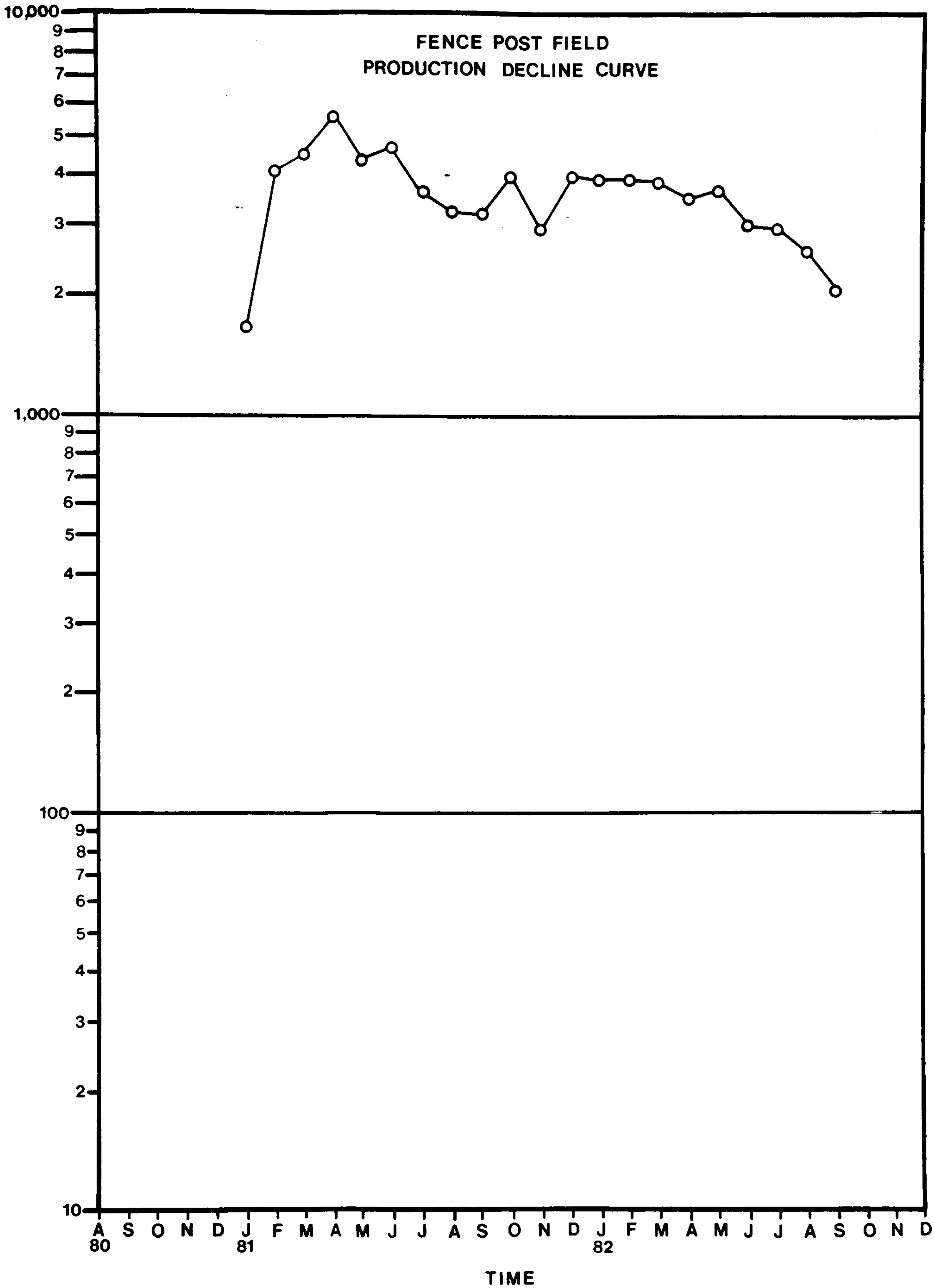
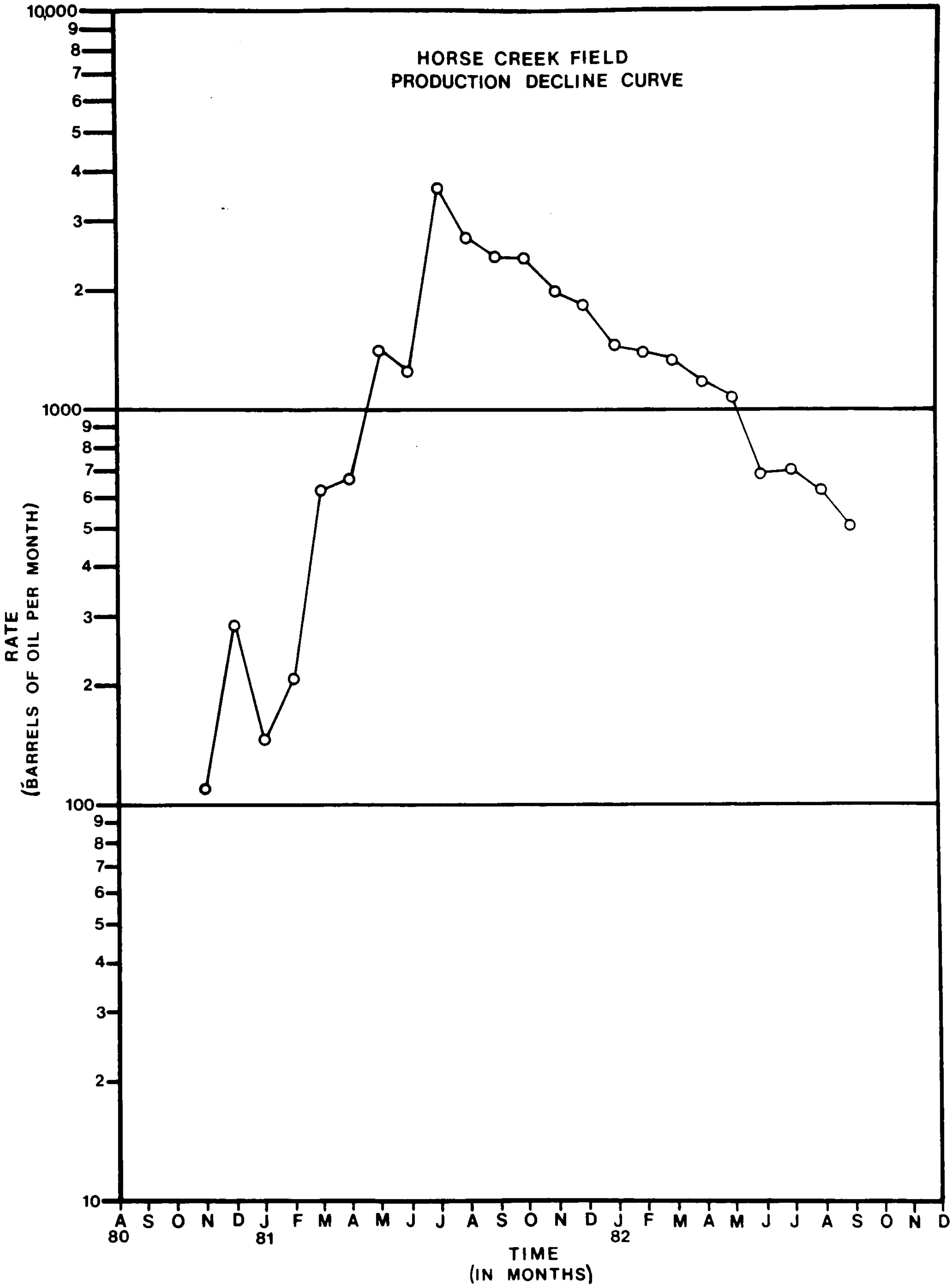

FENCE POST FIELD
PRODUCTION DECLINE CURVE
10,000
1,000
100
10
A S O N D J F M A M J J A S O N D J F M A M J J A S O N D
80
81
82
TIME
(IN MONTHS)

Figure 9.



HORSE CREEK FIELD
PRODUCTION DECLINE CURVE
RATE
(BARRELS OF OIL PER MONTH)
10,000
1000
100
10
A
80
S
O
N
D
J
81
F
M
A
M
J
J
A
S
O
N
D
J
82
F
M
A
M
J
J
A
S
O
N
D
TIME
(IN MONTHS)

Figure 10.

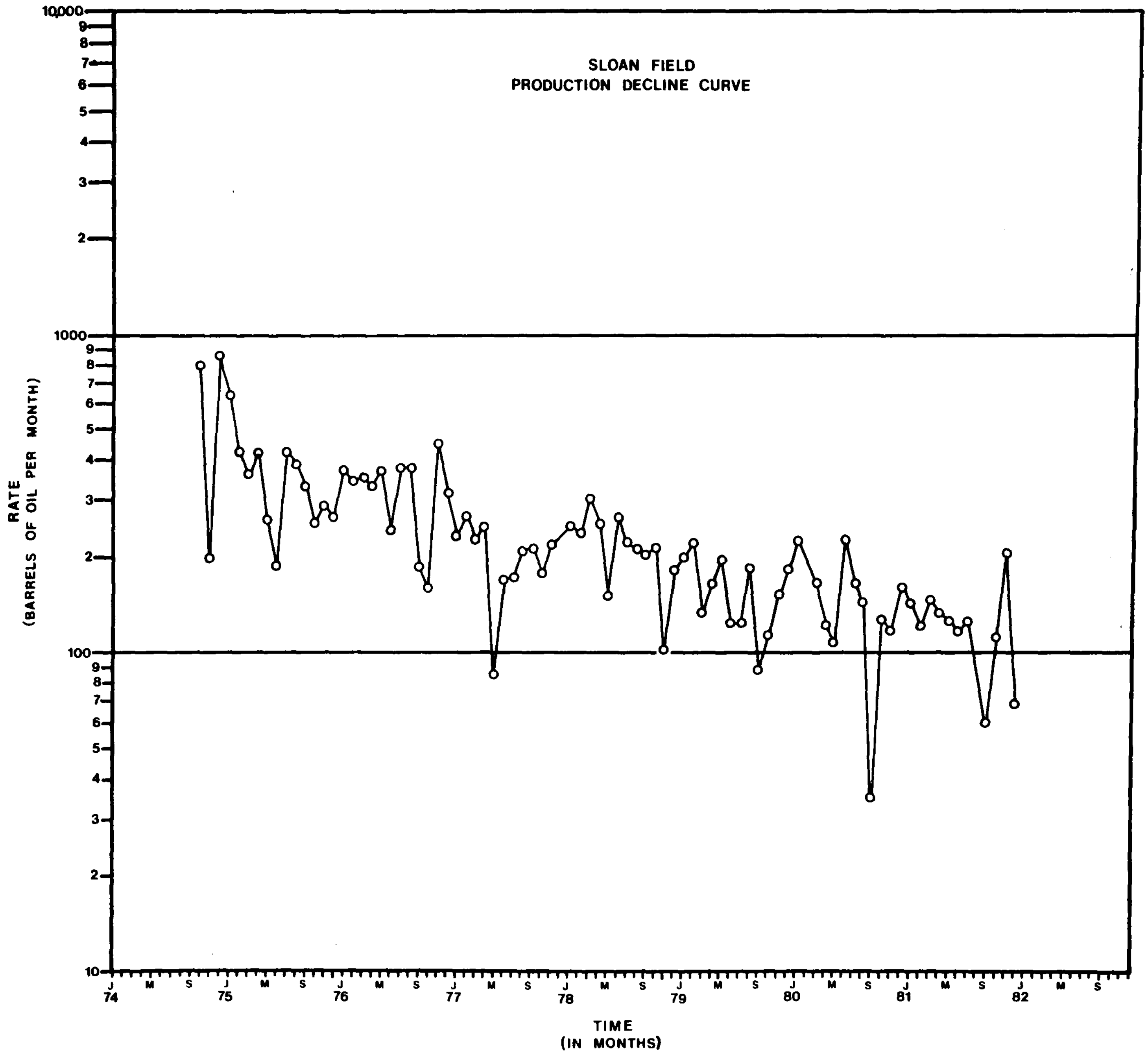

SLOAN FIELD
PRODUCTION DECLINE CURVE
RATE
(BARRELS OF OIL PER MONTH)
TIME
(IN MONTHS)
10,000
1000
100
10
74
75
76
77
78
79
80
81
82

Figure 11.

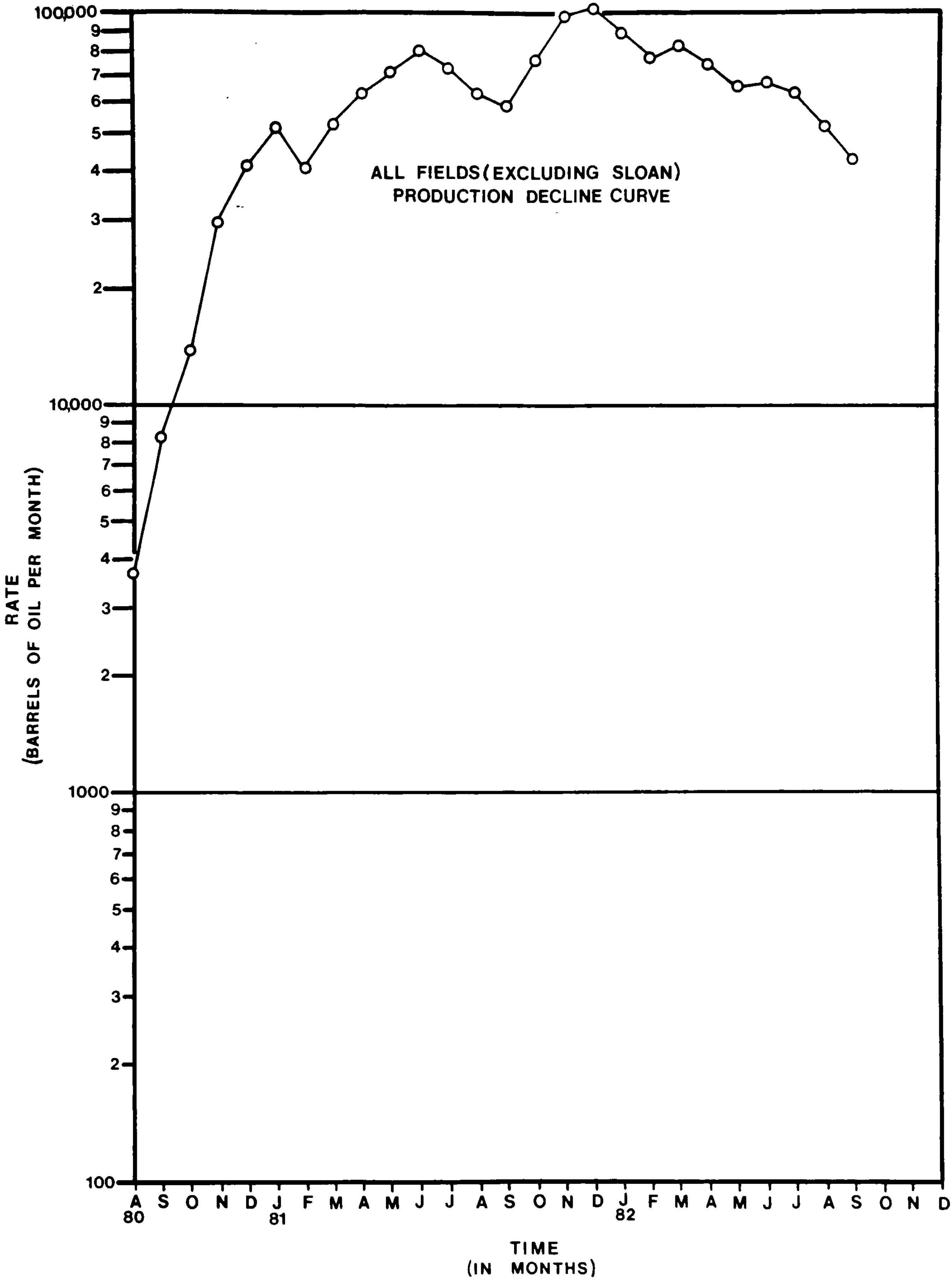

ALL FIELDS(EXCLUDING SLOAN)
PRODUCTION DECLINE CURVE
RATE
(BARRELS OF OIL PER MONTH)
100,000
10,000
1000
100
A S O N D J F M A M J J A S O N D J F M A M J J A S O N D
80
81
82
TIME
(IN MONTHS)

Figure 12.

Equation 6:

$$Rr = \frac{q - qf}{- Ln\ (1-dy)} \times 12 \text{ months}$$

Where: Rr = remaining reserves

q = production rate

qf = final economic production rate

Ln = natural log

dy = yearly decline rate, in percent

Several assumptions must be made to obtain this value. A reasonable number of producing wells must be used at the time of field "abandonment" for the field to still be considered economic. In addition, an economic amount of production for each of those wells must be arrived at. At present crude oil prices, it is commonly accepted that a one- to two-BOPD value per well is considered economically feasible. The ultimate recoverable oil is calculated by adding the cumulative production and remaining reserves. The original oil in-place is volumetrically calculated by equation 7.

Equation 7:

$$\frac{BAF}{R.E.} \times A.F. = O.O.I.P.$$

where: BAF = Barrels per acre feet

R.E.= Recovery Efficiency

A.F.= acre-feet

O.O.I.P.= Original oil in place

Then, the actual recovery efficiency is calculated by equation 8.

Equation 8:

$$R.E._A = \frac{U.R.}{O.O.I.P.}$$

where: $R.E._A$ = actual recovery efficiency

U.R. = ultimate recovery

O.O.I.P. = original oil in place

RESULTS

As previously stated, the quality with which the outcome can be relied upon is only as good as the quality of input data. All data used in this study is taken from production reports, logs, and well files received by the Colorado Oil and Gas Conservation Commission. Any data which did not fit well with the surrounding data was either not used or was checked for errors in reporting. The problem of bad data was rarely encountered, and with the abundance of data available, no major problems developed.

In general, several rules can be followed in interpreting the resulting information. The following quote from J. J. Arps, 1956, gives some insight into the discrepancies seen using the two methods discussed previously. "Oftentimes it is difficult to fit the projected performance to the volumetric estimate. If both types of estimates are based on good, reliable information, but cannot be reconciled, some important conclusions may be drawn from this discrepancy. If the performance indicates a substantially lower ultimate recovery than the volumetric calculation would indicate, this may mean that there is something fundamentally wrong with the production practices used. Possibly more drainage points are needed or the wells need stimulation treatments or cleanout jobs.

"On the other hand, if the well performance projection indicates an ultimate recovery well in excess of the volumetric estimate, it would mean that the subsurface interpretation used may be in error and that there may be a larger oil reservoir on hand than current subsurface interpretation indicates. In that case, it may be highly desirable to look for a possible extension to such an oil reservoir."

Table 2 summarizes the results of two methods used in this study. The reserves calculated for the study area was done for each field with the exception of Krauthead and Baseline fields. These two fields are considered one reservoir by the author and most operators in the area. In addition, reserves were calculated for all fields combined, excluding Sloan field.

In general, the results obtained using a decline curve analysis indicate a slightly below average value of recovery as compared to the recovery results calculated using the volmetric method. The latter indicate values within an acceptable range as predicted by API, "A Statistical Study of Recovery Efficiency."

There a numerous possible explanations as to why the actual production (decline curve analysis) does not approach the expected production (volumetric analysis).

One factor which should be considered is the short production time for the

Table II. Summary of Results

Field Name/ Discovery Date	Rate- Cum.	Rate- Time	Rs	Bo	P 100, 200, ..500	R.E.	Acre-feet	Total Recoverable	% of OOIP	% of cum.	Production	Remaining Reserves	Ultimate Recoverable Reserves	O.O.I.P.	Actual R.E. (in %)
Krauthead-	.49	.62	890	1.48	132	33	25,615	3,381,180	33	31	1,046,626	15 wells @ 30 BOPM		10,246,000	10.5
Baseline					117	29	[61,610]	2,996,955	29	35		24,643 R/T	1,071,269	10,334,328	10.4
August 1980/					109	27		2,792,035	27	37		38,316 R/C	1,084,942	10,340,870	10.4
October 1980					103	26		2,638,345	26	40				10,147,481	10.6
					99	25		2,535,885	25	41				10,143,540	10.6
Banner Lakes	.713	.615	903	1.47	118	28	10,300	1,215,400	28	35	426,273	4 wells @ 30 BOPM		4,340,714	16
March 1981					105	25	[31,910]	1,081,500	25	39		249,932 R/T	676,205	4,326,000	16
					98	23		1,009,400	23	42		171,896 R/C	598,169	4,388,696	15
					93	22		957,900	22	45				4,354,091	16
					89	21		916,700	21	47				4,365,238	15
Fence Post	.564	.640	903	1.49	96	27	2,645	253,920	27	30	75,795	2 wells @ 30 BOPM		940,444	37
December 1980					85	24	[9,305]	224,825	24	33		269,460 R/T	345,255	936,771	37
					80	22		211,600	22	36		363,426 R/C	439,221	961,818	36
					76	21		201,020	21	38				957,238	36
					73	20		193,085	20	39				965,425	36
Horse Creek	.732	.79	903	1.49	98	27	1,500	147,000	27	20	28,972	1 well @ 30 BOPM		544,444	6
December 1980					87	24	[2,715]	130,500	24	22		3,922 R/T	32,894	543,750	6
					81	23		121,500	23	24		5,194 R/C	34,166	528,261	6
					77	21		115,500	22	25				550,000	6
					74	20		111,000	20	26				555,000	6
Sloan	--	.160	896	1.48	94	27	570	53,580	27		22,478				
October 1974					84	24	[2,770]	47,880	24			5164 R/T	27,642	198,444	14
					78	22		44,460	22					199,500	14
					74	21		42,180	21					202,091	14
					71	20		40,470	20					200,857	14
														202,350	14
All fields	.610	.616	903	1.49	103	27	40,060	4,126,180	27	38	1,577,666				
(except Sloan)					91	24	[105,540]	3,645,460	24	43		20 wells @ 30 BOPM		15,282,148	14
					85	23		3,405,100	23	46		588,026 R/T	2,165,692	15,189,417	14
					81	22		3,244,860	22	48		563,297 R/C	2,240,963	14,804,783	15
					78	21		3,124,680	21	50				14,749,364	15
														14,879,429	15

fields in this area. If this area is in the early stages of production, it can be inferred that the decline rates have not yet leveled off. It is difficult to obtain a one-well decline curve due to the methods used by the Colorado Oil and Gas Conservation Commission in keeping production records. The author is presently attempting to obtain one-well decline curves for the various fields to be able to get a more reasonable decline rate. The straight line extrapolation used for these fields assumes a constant percentage decline. This assumption generally provides results which are too conservative. This is normally corrected by graphically flattening out the decline slope in the latter stages of development. By using a field production decline curve, the decline rate has been influenced by the additional drilling of wells throughout the field history. There also appears to be several 40-acre tracts where new wells can be drilled. This additional infilling will influence the production rate for these fields, and therefore the reserve estimates based on these production rates.

A second factor to be considered are the various field characteristics, example: varying permeability, porosity, sand quality, etc. These characteristics, considered individually or when combined, may be influencing the production rates. One characteristic which is playing a significant part in influencing the production rate in this area is permeability. This value is usually low when compared to other geologically similar fields. The core analyses, which are few in this area, indicate a permeability between 0.1 and 10 millidarcies. API studies indicate values of 6, 51, and 940 millidarcies as minimum, medium, and maximum values, respectively. Core analyses for the Rocky Mountain area, as displayed in Frick, (Petroleum Production Handbook, Fig. 13) show a range of permeability of 0 to 900 millidarcies for the D sand, with an average value of 192 millidarcies. In this area, when a well produces at

Formation	Fluid prod.	Range of prod. depth, ft	Avg prod. depth, ft	Range of prod. thickness, ft	Avg prod. thickness, ft	Range of perm. K md	Avg perm. K md	Range of perm., K_{90} md	Avg perm., K_{90} md	Range of porosity, %	Avg porosity, %	Range of oil satn., %	Avg oil satn., %	Range of total water satn., %	Avg total water satn., %	Range of calc. connate water satn., %	Avg calc. connate water satn., %	Range of gravity, °API	Avg gravity, °API
Aneth	O	5,100–5,300	5,200	3.8–23.1	14.0	0.7–34	9.35	0.2–23	6.10	4.4–10.5	8.1	14.5–35.9	25.0	12.5–30.5	23.6	13–31	24	41†	41
Boundary butte	G	5,500–5,600	5,600	8–27	17.5	0.1–2.0	1.05	...	...	4.3–6.5	4.7	4.7	4.7	23.8–35.0	29.4	23–35	29		
	O	5,400–5,900	5,600	2–68	16.2	0.1–114	13.3	0.2–33	12.5	5.4–21.6	11.0	4.8–26.7	12.5	9.3–48.8	28.3	7–45	27	40–41	41.1
Cliffhouse	G	3,600–5,800	4,800	2–56	13.7	0.1–3.7	0.94	...	...	7.0–16.2	11.3	0–19.8	4.5	10.2–60.3	36.9	10–59	36		
D sand	O	4,350–5,050	5,800	7–33	15.0	0–900	192	...	...	8.6–29.5	21.6	8.4–39.5	13.2	...	...	9–48	23	36–42	38
Dakota	G	500–7,100	5,700	2–24	9.5	0.1–710	28.6	0.08	0.08	7.3–19.6	11.2	0–7.8	3.5	14.8–55.3	40.6	15–52	38		
	O	3,400–7,200	5,600	4–19	7.9	0.1–186	22.3	33.0	33	5.0–23.3	11.2	13.8–35.9	24.4	11.6–44.3	31.0	11–44	29	38–43	40
Desert	O	5,400–5,500	5,500	11.6–18.3	14.9	1.0–11	4.4	0.4–2.4	1.13	11.9–13.8	12.7	13.4–16.8	15.2	14.8–24.7	19.2	14–25	19	41	41
Frontier sands	O	265–8,295	2,950	8–100	46	0–534	105			6.3–29.8	20.0	7.6–37.6	14.9		...	28–45	33	31–50	41
Gallop	G	1,500–6,900	5,000	5–25	11.6	0.1–324	26.5	0.3–20	10.2	8.5–20.8	13.3	0–25.6	5.7	20.7–59.2	40.0	20–54	37	39	39
	O	500–6,400	4,600	2–43	12.4	0.1–2,470	48.2	0.1–3.2	0.7	6.9–23.1	12.5	8.5–43.7	25.3	17.2–76.9	35.7	14–77	34	36–42	39
Hermosa	G	4,900–7,700	5,600	5–30	14.1	0.1–91	18.6	45.0	45.0	5.5–16.5	10.2	0–6.5	3.0	14.2–45.3	32.7	12–45	32		
	O	5,300–6,000	5,600	3–38.2	15.1	0.1–37	7.32	0–26	4.26	2.7–17.9	8.3	3.9–29.1	10.8	11.6–60.0	35.6	12–60	35	41–42	40
Hospa	G	4,800–7,100	5,500	3–17	10.5	0.1–70	18.2			7.4–11.9	10.5	0.5–23.8	7.5	8.7–49.7	38.1	8–49	37		
	O	4,600–5,100	4,800	6–18	13.3	0.7–25	8.63			6.6–14.8	11.3	20.4–29.8	25.0	32.3–44.8	36.0	31–45	35	40	40
J sand	O	4,470–5,460	4,900	15–62	25	0–1,795	330	...	...	8.9–32.7	19.6	8.8–46.5	13.9	...	...	6–42	20	36–42	38
Madison lime†	O	3,400–6,200	4,900	41–450	186	0–1,460	13	...	...	1.8–26.4	11.9	6.0–43.5	17.4	...	...	22–33	27	21.6–30	26
Menefee	G	5,200–5,700	5,400	7–25	12.7	0.1–20	5.04	...	...	8.7–13.5	11.2	0.3–5.3	1.6	14.5–45.1	27.5	15–43	27		
Mesa Verde	G	1,500–6,100	4,700	2–22	10.0	0.1–17	3.57	...	...	10.0–19.8	14.6	0–6.8	3.3	14.5–68.4	42.0	15–64	40		
	O	*	300	...	4.0		60	...	...		26.2		8.3	...	61.0	...	44		
Morrison	O	1,600–6,900	4,500	24–54	40	0–1,250	43	...	...	9.9–25.5	17.5	5.0–26.0	13.1	...	...	15–41	35	29–56	42
Muddy	O	930–8,747	1,845	7–75	20	0–2,150	173		...	2.3–32.9	22.3	7.6–48.5	30.8			5–47	19	26–42	38
Paradox	G	5,100–9,500	6,900	4–44.2	12.2	0.2–42	11.6	0.1–28	4.43	1.4–19.4	7.4	0–10.1	3.1	9.9–57.9	34.7	10–58	34		
	O	5,300–6,100	5,700	2–66	14.8	0.1–119	10.4	0–57	4.57	3.3–21.8	10.5	3.6–38.7	12.4	10.8–60.5	33.6	10–61	33	40–43	41
Phosphoria (formerly Embar)	O	700–10,500	4,600	5–100	64	0–126	3.7	...	...	2.0–25.0	8.9	3.0–40.0	22.5	...	...	5–30	21	15–42.3	25.4
Picture Cliffs	G	1,800–5,800	3,400	3–43	16.8	0.1–7.68	1.12	...	...	8.5–25.5	15.7	0–21.1	2.6	23.6–67.5	46.7	23–63	43	55	55
	O	*	2,900		23.0	...	0.5	...	...		11.4		23.2		49.1	...	49		
Point Lookout	G	4,300–6,500	5,500	2–101	22.9	0.1–16	1.74	...		5.6–21.6	10.9	0–9.1	2.9	11.9–55.6	36.7	12–55	36		
	O	*	4,700		7.0		2.90	...	2.40	...	13.3		23.8	40	40.9	...	41	...	39
Sundance	O	1,100–6,860	3,100	5–100	44	0–1,250	100		...	15.0–25.0	19.0	8.0–25.0	17.0			20–49	35	22–63	39
Tensleep	O	600–11,800	4,700	10–200	118	0–2,950	120	...	...	5.0–27.0	13.6	6.0–30.0	23.3	7.0–59	25.7	5–50	19	17–58.5	26.2
Tocito	G	*	7,900		7		230	...	...		20.2		4.0	...	51.8	...	43		
	O	1,400–5,100	4,600	4–58	17.3	0–31	3.36	...	...	12.8–17.8	14.7	11.9–26.6	21.3	40.8–55	46.3	40–55	46	36–40	36

* Not enough wells to justify range of variations.
† Data limited to BigHorn Basin.

Figure 13. Rocky Mountain Area Typical Core Analysis of Different Formations (from Frick, pg. 24-13, Table 24-9). Reprinted with permission from the Society of Petroleum Engineers of A. I. M. E., copyright 1962, Dallas, Texas.

greater rates than surrounding wells or produces where there is 0 net feet of sand greater than 8% porosity, the production is attributed to fracturing. Due to the lack of core data, and therefore a lack of permeability data, it is difficult to determine whether the latter may be attributed to differences in the expected and actual production.

A third factor to be considered is based on Arp's conclusions as stated earlier. Being that the present production techniques are not adequate for the conservation of oil from this area.

There are many other factors that can be attributed to the large differences seen in the expected versus the actual production from this area.

CONCLUSIONS AND SUGGESTIONS

At the present time, the author proposes that the more conservative values, those determined by declined curve analysis, be assumed correct until either future production records can be incorporated and/or when a one-well decline curve can be analyzed or until additional production technique studies can be undertaken.

With reference to secondary and tertiary recovery, it is the author's belief that until more reasonable values are assigned, it would be futile to assess those values. At present, it appears that some type of secondary gas injection project would be best suited to enhance the future recovery in this area. As new production techniques are adapted, and more efficient secondary and tertiary recovery projects are established, this approach may change. Reasonable values for tax revenue expected from this area are also not feasible at this time for the same reason stated above.

It has been proposed to the Colorado Oil and Gas Conservation Commission that the production for Krauthead, Baseline, and Horse Creek fields be combined, as they are all considerd one reservoir. This will aid the production staff and also any future studies for these fields. Finally, the author proposes to suspend further study into this area for a period of six months, at which time an update will be undertaken to determine if more reasonable values can be assigned at that time.

REFERENCES

1. American Petroleum Institute Subcommittee on Recovery Efficiency, 1967, A statistical study of recovery efficiency: Am. Petroleum Inst., 33 p.

2. Amyx, J. W., Boss, D. M., Jr., and Whiting, R. L., 1960, Petroleum reservoir engineering: New York, McGraw-Hill Book Co., 610 p.

3. Arps, J. J., 1956, Estimation of primary oil reserves: Soc. Petroleum Engineers of AIME Repor. Ser. 3, p. 24-33.

4. Bowman, P. A., and Foster, D. I., 1982, Baseline/Krauthead fields area, _in_ Crouch, M. C., III, ed., Oil and gas fields of Colorado, Nebraska, and adjacent areas: Rocky Mtn. Assoc. Geologists, v. 1, p. 28-37.

5. Clark, N. J., 1960, Elements of petroleum reservoirs: Am. Inst. Mining Metal. Petroleum Engineers, Henry L. Doherty Ser., 250 p.

6. Craft, B. C., and Hawkins, M. F., Jr., 1959, Applied petroleum reservoir engineering: Englewood Cliffs, N.J., Prentice Hall, Inc. 437 p.

7. Dake, L. P., 1978, Fundamentals of reservoir engineering: New York, Elsevier Sci. Publ. Co., 443 p.

8. Frick, T. C., ed., 1962, Petroleum production handbook, v. 2--Reservoir engineering: Soc. Petroleum Engineers of AIME.

References, continued

9. Haun, J. D., Cardwell, A. L., Herrod, W. H., and Cronoble, J. M., 1976, Oil and gas reserves of Colorado: Colorado School Mines Research Inst. Mineral Industries Bull., v. 19, no. 5, 10 p.

10. Society of Petroleum Engineers, 1970, Oil and gas property evaluation and reserve estimates: Soc. Petroleum Engineers AIME Rept. Ser. 3, 235 p.

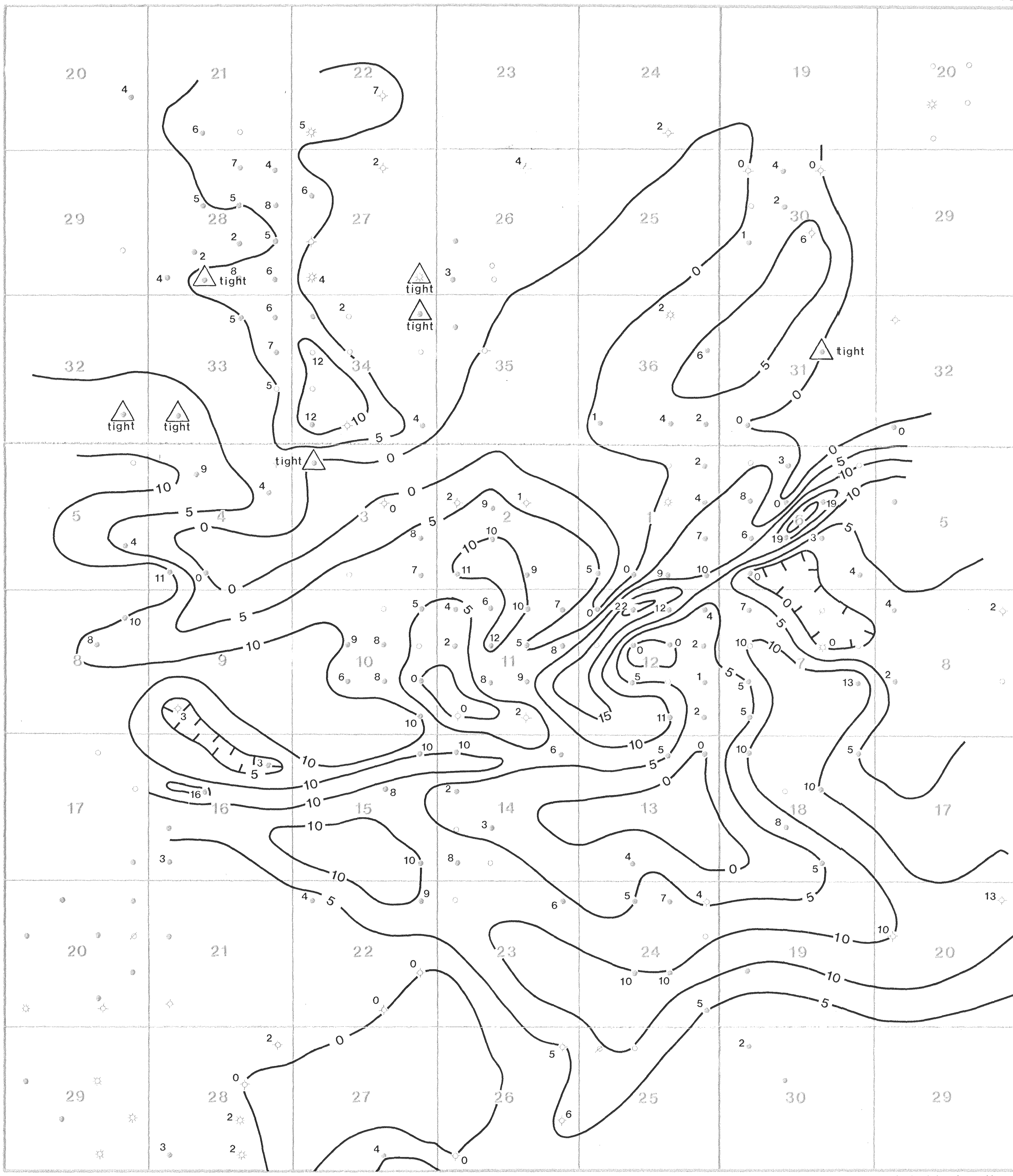
11. Vazquez, Milton, and Beggs, H. D., 1977, Correlations for fluid physical property prediction--Paper presented at Society of Petroleum Engineers 52d Ann. Fall Tech. Conf. and Exhibition, Oct. 9-12, 1977, Denver, Colo.: Soc. Petroleum Engineers of AIME, 8 p., 9 tables, 9 figs.

ISOPACH MAP OF NET POROUS "D" SAND OF KRAUTHEAD-BASELINE FIELD AREA
(>8% POROSITY USING 2.68 GRAIN DENSITY)

BY ANN SCANLON

COLORADO GEOLOGICAL SURVEY
DEPARTMENT OF NATURAL RESOURCES
JOHN W. ROLD, DIRECTOR

OPENFILE 83-3
PLATE I
1983



drafted by Anne Magee

scale
1 mile
1 kilometer

EXPLANATION

8 net porosity (in feet)

• oil well location

Isopach

C.I. 5'

tight confidential information

• oil well

gas well

dry hole

○ location

abandon location

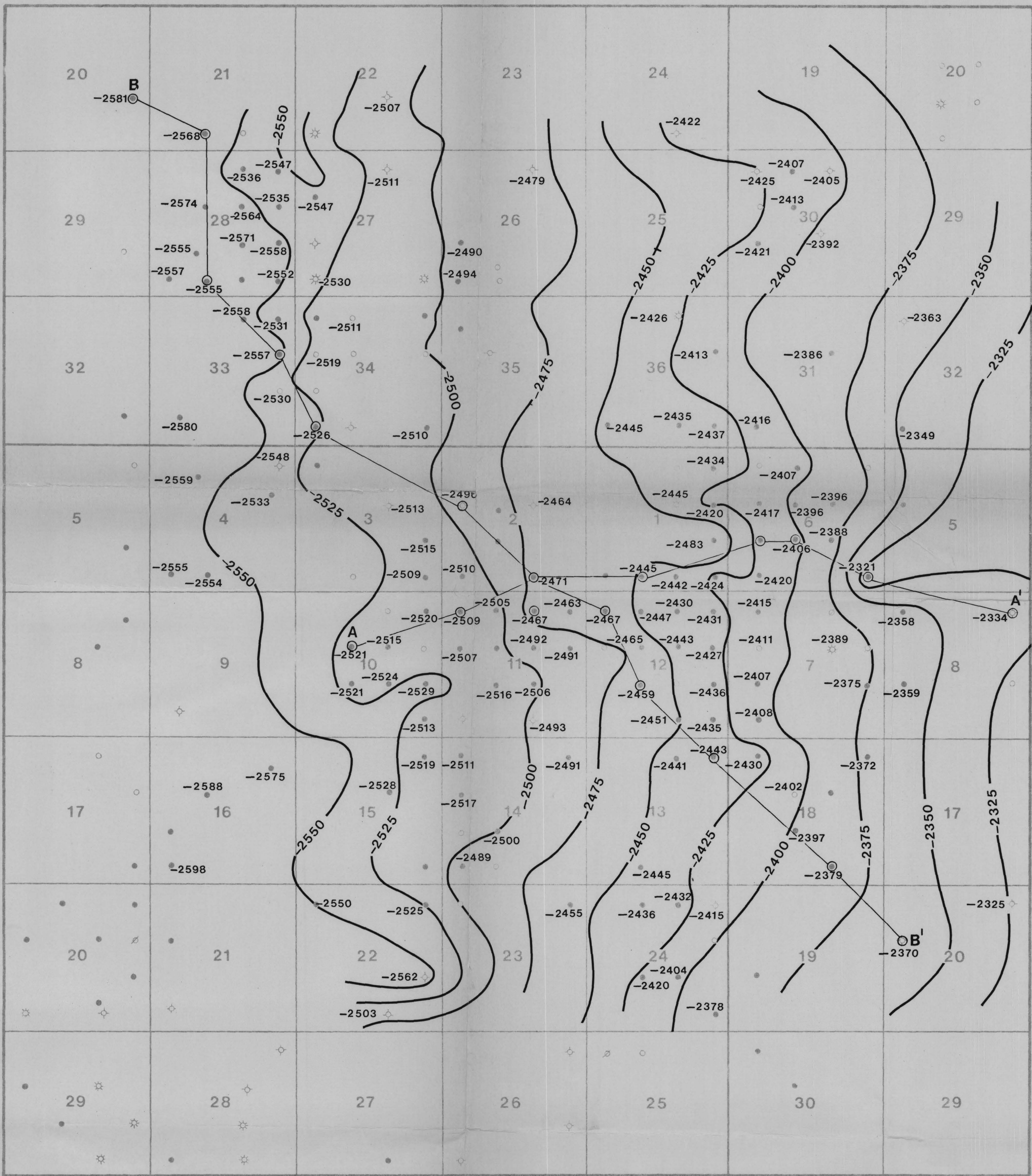
Base from Colorado Oil and Gas Conservation Commission Plat Maps

STRUCTURE CONTOUR MAP TOP "D" SAND OF KRAUTHEAD-BASELINE FIELD AREA

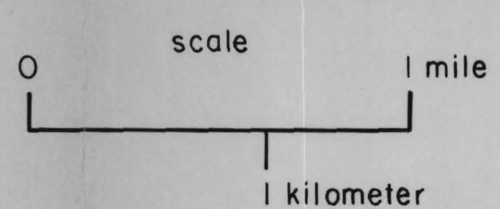
BY ANN SCANLON

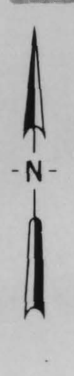
COLORADO GEOLOGICAL SURVEY
DEPARTMENT OF NATURAL RESOURCES
JOHN W. ROLD, DIRECTOR

OPENFILE 83-3
PLATE-2
1983



drafted by Anne Magee





EXPLANATION

-2510 subsea elevation

• oil well location with subsea elevation

subsea structure contour

C.I. 25'

A–A' stratigraphic cross section

• oil well

gas well

dry hole

o location

abandoned location

Base from Colorado Oil and Gas Conservation Commission Plat Maps

COLORADO GEOLOGICAL SURVEY
DEPARTMENT OF NATURAL RESOURCES
JOHN W. ROLD, DIRECTOR

KRAUTHEAD–BASELINE FIELD AREA, ADAMS AND WELD COUNTIES, COLORADO

STRATIGRAPHIC CROSS SECTION

DATUM: J SILT

VERTICAL SCALE: 1" = APPROX. 40' HORIZONTAL SCALE: 8" = APPROX. 1 MILE

OPEN-FILE 83-3
PLATE 3
1983