REPORT ON:

PILOT WATER FLOOD

SECTION 35 and SECTION 36, TOWNSHIP 9, RANGE 29, WPM

[illegible] AREA

PROVINCE OF MANITOBA.

BY:

BRALORNE PETROLEUMS LTD.

VIRDEN, MANITOBA

H. B. Elder

Petroleum Engineer

LIST OF ILLUSTRATIONS

INTRODUCTION

The Ebor Field is located two miles west of the south-west flank of the Daly Field. The area involved in this pilot flood lies in sections 35 and 36, Township 9, Range 29, WPM.

Eight wells had been drilled and placed on production in the subject area. (Fig. 1) Production rate decline had been very rapid and a low recovery of oil in place was indicated. Development drilling had ceased and pool limits had not been defined

The pilot flood was set up in an attempt to evaluate the area.

An application to Pilot flood was made to the Oil and Natural Gas Conservation Board and Order No. PW 6 was issued June 10, 1966.

MANITOBA REGULATION [illegible]

Being

THE OIL AND NATURAL GAS CONSERVATION BOARD [illegible]

ORDER No. [illegible]

[illegible] Pressure Maintenance by Water Flooding - Ebor Field.

Made and passed pursuant to "The Mines Act", by The Oil and Natural Gas Conservation Board.

(Filed June [illegible]th, 1966)

WHEREAS, subsection (8) (d) of Section [illegible] of "The Mines Act", as enacted by Chapter 45, Statutes of Manitoba, 19[illegible], provides as follows:

"5[illegible] (8) Without restricting the generality of subsection (7) the board, with the approval of the minister, may make orders

(d) requiring the repressuring, recycling, or pressure maintenance, of any pool or portion thereof where it is economical so to do, and for that purpose where necessary requiring the introduction or injection into any pool or portion thereof of gas, air, water, or other substance; ."

AND WHEREAS, the Board, pursuant to section 59 of "The Mines Act", held a public hearing on June [illegible], for the purpose of considering a Proposed Pilot Water Flood in a certain part of the Ebor Field in Manitoba, by Bralorne Petroleums Ltd.

AND WHEREAS, upon due consideration of the submissions and testimony at the hearing, the Board has found that it is reasonably necessary to conduct a pilot water flood in a certain part of the Ebor Field in Manitoba.

NOW, THEREFORE, the Board orders

1. (a) Bralorne Petroleums Ltd. shall conduct a pilot water flood by the injection of water to the Lodgepole Formation of the Mississippian Age underlying the Ebor Field.

(b) The pressure maintenance operation shall be in accordance with, and subject to, the following rules:

PRESSURE MAINTENANCE RULES

1. (1) Water shall be injected to the Lodgepole Formation of the Mississippian Age in the well:

Bralorne North Ebor 9-25-9-29

and, from time to time, in such other wells as the Board, after a further public hearing, may direct.

(2) The injection in the well referred to in this clause shall continue after commencement not more than one hundred and eighty (180) consecutive days from the date of this order.

2. (1) Before the injection of water is commenced, Bralorne Petroleums Ltd. shall satisfy the Board as to the source, suitability, and method of treatment of the water to be injected.

(2) Before any change is made in the source of the water being injected, Bralorne Petroleums Ltd. shall satisfy the Board as to the source, suitability, and method of treatment of the water to be injected.

Bralorne Petroleums Ltd. shall immediately report to the Board any indication of channelling or break through of injected water to producing wells, or any indication of other detrimental effects that may be attributable to the pressure maintenance operations.

In the interest of equity and good engineering practice, the Board may prescribe from time to time a maximum pressure, or a minimum or a maximum rate, at which water shall be injected in the well referred to in clause 1 hereof.

Bralorne Petroleums Ltd. shall, not later than the twenty-fifth day of each month, file with the Mines Branch a report of the quantity and source of water injected during the preceding month to the well referred to in clause 1 hereof.

(1) Bralorne Petroleums Ltd. shall, within ninety (90) days of the completion of the pilot water flood, file with the Mines Branch a report of the performance and efficacy of the pressure maintenance program.

(2) Subject to any direction in writing of the Board to the contrary, a report required by this clause may, at the discretion of Bralorne Petroleums Ltd., be in two parts, the first of which parts shall set out graphically and from the commencement of the operation of the pressure maintenance program,

(a) the daily average rate during each month of oil production of each producing well,

(b) the average water-oil ratio during each month of each producing well,

(c) the monthly cumulative oil and water production from each producing well,

(d) the daily average rate during each month of water injection to the well referred to in clause 1 hereof,

(e) the daily average water injection pressure during each month to the said well,

(f) the monthly cumulative volume of water injected to the said well,

(g) the average injectivity index during each month for the said well, which index, at the discretion of Bralorne Petroleums Ltd., may be determined as

(i) the daily injection rate divided by the average injection well head pressure, or

(ii) any similar index that the Board, on the application of Bralorne Petroleums Ltd., may approve, and

(h) the date and type of any well treatment or workover which shall be indicated on the graph, and the second of which parts shall contain

(a) calculations of the balance during each month between water injected to, and fluids withdrawn from, the Lodgepole Formation underlying the Ebor Field,

(b) such other interpretative information as Bralorne Petroleums Ltd. considers necessary to evaluate adequately the performance and efficacy of the pressure maintenance program, and

(c) an outline of the method actually in use for the quality, control, and treatment of the water.

(3) If a report required by this clause is in the form provided for in subclause (2), the Board, at any time, may make the first part of the report available to the public, and, after one year from the end of the period for which the report is made, may make the second part of the report available to the public, and, if the report is not in the form provided for in subclause (2), the Board may make the whole of the report available to the public at any time.

This Order shall be effective at the hour of seven o'clock in the forenoon, Central Standard Time, on the fifteenth day of June, 1966.

Oil and Natural Gas Order No. PM 6, made and passed this 10th day of June, A. D., 1966, at the City of Winnipeg, in the Province of Manitoba, by The Oil and Natural Gas Conservation Board.

J. Stuart Anderson,
Chairman,
The Oil and Natural Gas
Conservation Board

J. S. Richards,
Deputy Chairman,
The Oil and Natural Gas
Conservation Board

M. J. Gobert,
Member,
The Oil and Natural Gas
Conservation Board

APPROVED:

Sterling R. Lyon,
Minister of Mines and
Natural Resources

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SUBSURFACE DATA

The producing interval in this area occurs in the Lodgepole formation of the Mississippian period. A typical pay interval could be described as dolomite, brown to cream, dense, tight, microcrystalline-microgranular, siliceous interbeds and maroon shale laminae scattered throughout, poor intergranular to pin point vuggy porosity, anhydrite interbeds, 45% oil stained with spotty slow bleeding, pay occurs as scattered interbeds. Casing was set through and the pay interval perforated in all wells. Bralorne Ebar 9-35 was selected as the injection well because of its central location.

SURFACE INSTALLATION

The source of flood water was Pipestone Creek at an approximate distance of one mile from the injection well. Produced salt water was injected during September and October also. An earthen pit was dug adjacent to the creek to act as a reservoir and settling tank. A 6MZAU Waukesha gasoline motor driving a Gaso Model 2650 Duplex pump pumped water through a 3 1/2 inch OD welded line to two 500 barrel storage tanks located near the injection well. A Cuno Model 6AX2 cartridge type filter was installed in the line so that all water was filtered prior to entering the tanks. The injection pump was a Gardner Denver FG-3 Triplex powered by an Ajax E-42 engine.

OPERATIONS

The pump and rods were pulled from Ebar 9-35 and the wellhead rigged as an injection well. No packer was run. Injection was started on July 3rd, 1966, and, on casing fill up, injection pressure approached 2,000#, the pressure rating of the wellhead. The well was acidized July 5, 1966, with 500 gallons regular acid, 3/4 BPM at 1,500#. Injection was resumed at 1,400-1,500#. Operations were continued until October 30, 1966, when the injection was terminated due to freezing temperatures. Accumulative water injected was 65,164 barrels at a maximum pressure of 1,500#. Maximum daily injection rate for the period was 972 barrels with an average daily injection rate for the overall period of 547 BWPD. Sixteen full days were lost due primarily to engine mechanical difficulties. Daily average injection rate per operating day was 632 BWPD. It was noted that the injection rate varied directly as the head of water against the injection pump suction.

With full suction tanks, the daily injection rate was around 900 BPD. It was impossible to maintain full tanks without 24 hour supervision. Other than engine mechanical difficulties, only minor problems were encountered. Down time was experienced on two occasions when heavy rains resulted in mud laden creek water which plugged the Cuno filters and killed the Waukesha engine. Daily injection rate and pressure are illustrated graphically in Fig. 9.

BACTERIAL CONTROL

To prohibit the possible growth of bacteria in the formation, it was recommended that 30 to 40 PPM of Dowicide G beads be added to injection water. In operation, 10# of beads were dissolved in water and added to the injection water daily. Apparently there was no bacterial plugging of the formation as injection pressure remained constant throughout the test period.

RESULTS

At termination of pilot flood, overall evidence was insufficient to draw any definite conclusions. Evidence accumulated included individual well tests, chloride content of produced water, and fluid level determinations. Individual well production data is presented graphically in Figures 2-8; injection data in Figures 9 and 10; and field data in Figure 11. For comparison purposes, the time interval of the graphs covers the 30 days preceding and the 60 days following the test interval.

The chloride content in PPM of produced salt water indicated that there was no breakthrough of injection water. Tests are as follows:

Well	April, 1966	September, 1966	December, 1966
1-35	70,000	94,000	85,000
7-35	29,700	31,200	34,000
2-36	91,900	—	90,000
5 & 6-36	97,966	—	90,000
11-36	—	80,000	86,000
13-36	28,500	33,200	40,000

Monthly individual well tests and water cuts are presented in Figure 12.

Sonologs for fluid level determinations were run with the following results. Figures indicate feet of fluid in the hole.

Well	June	October
1-35	No indication	60
7-35	1595	1710
2-36	150	270
5-36	280	235
6-36	483	693
11-36	No indication	90
13-36	No indication	Nil

Injection vs withdrawal is as follows:

Month	Injection-Bbls.	Withdrawal-Bbls	Injection Minus Withdrawals
July	16,058	4,947	11,111
August	13,361	5,000	8,361
September	19,469	4,449	15,020
October	16,276	4,400	11,876
	65,164	18,796	46,368

An examination of production decline curves indicates that injection may possibly have had a small effect on production.

Figure 16 - Daily Oil Rate vs Accumulative Production.

The extrapolated decline curve was drawn from data available January 1, 1966. It can be seen that a slope change occurs beginning with August Production. The slope change indicates greater recoverable reserves than originally estimated. The October, 1966 plotted data should be disregarded in all decline curves since 2-36 was only on production for nine days.

Figure 17 - Production Decline Curve for Sections 35 and 36.

Disregarding October, 1966, data, a change of slope is also noted indicating increased recoverable reserves.

Figure 18 - Production Decline Curve for 1-35

A small production increase is noted. In retrospect, it appears likely that there was an error in determining the September, 1966, water cut (Figure 12)

Figure 19 - Production Decline Curve for 7-35.

No injection effect is evident.

Figure 20 - Production Decline Curve for 2-36.

Since 2-36 produced only nine days in October, 1966, due to a battery fire, results are not reliable.

Figure 21 - Production Decline Curve for 5-36.

Production is indicated as leveling off.

Figure 22 - Production Decline Curve for 6-36.

A production increase is noted. However, a bottom hole pump change and increased pump speed in August probably accounts for part or all of the increase.

Figure 23 - Production Decline Curve for 11-36.

A small increase is noted.

Figure 24 - Production Decline Curve for 13-36.

No injection effect is evident.

It is believed that the two decline curves for the group of wells offer more reliable data than individual well decline curves. Both group decline curves show a change of slope indicating greater reserves than were estimated prior to the pilot flood.

As stated previously, production performance is insufficient to evaluate pilot flood effects fully.

RECOMMENDATION

Since neither positive nor negative results were obtained, it is recommended that an extension of order No. PM 6 be requested, and, if granted, that injection be resumed during the summer months of 1967.

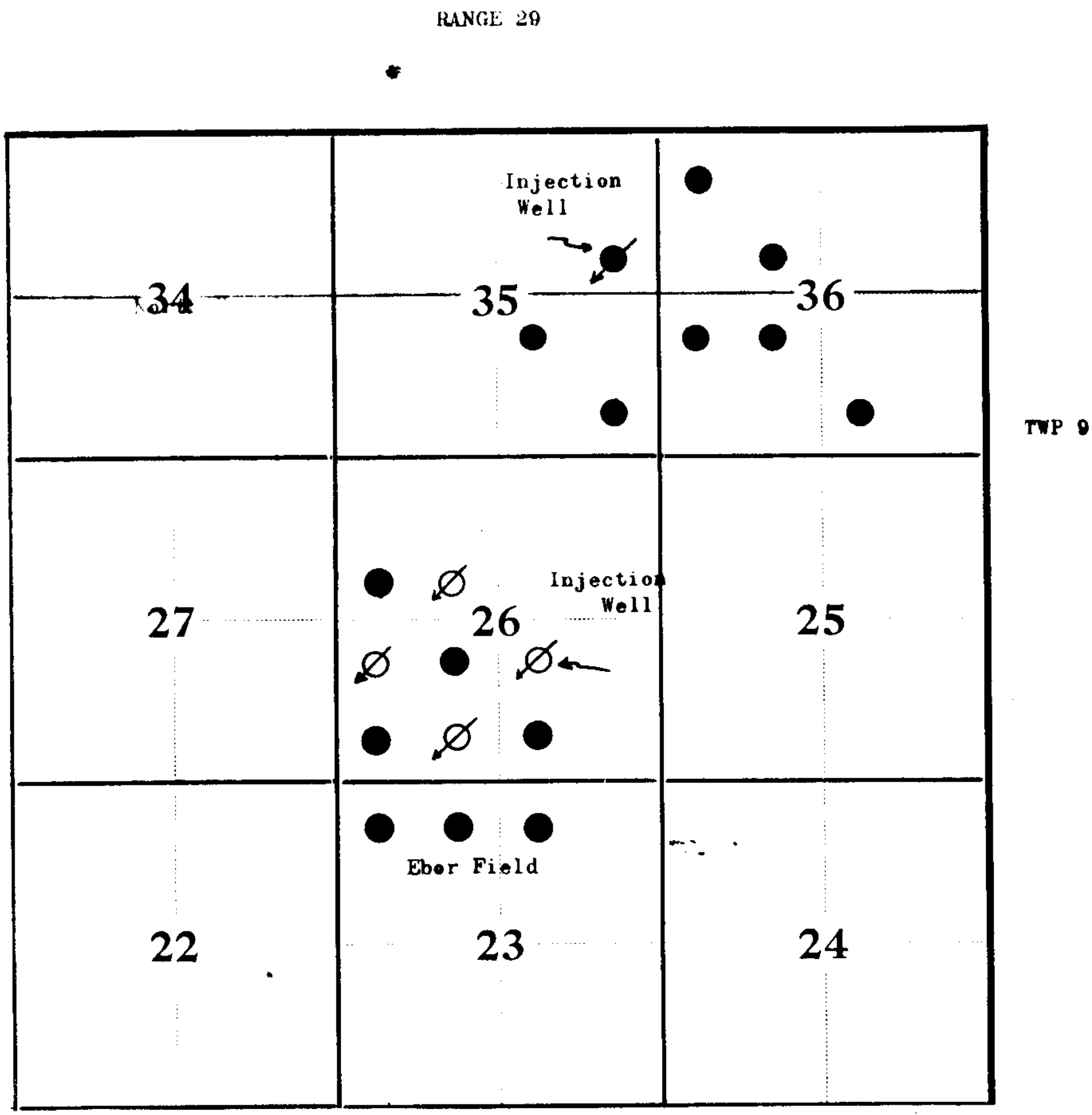
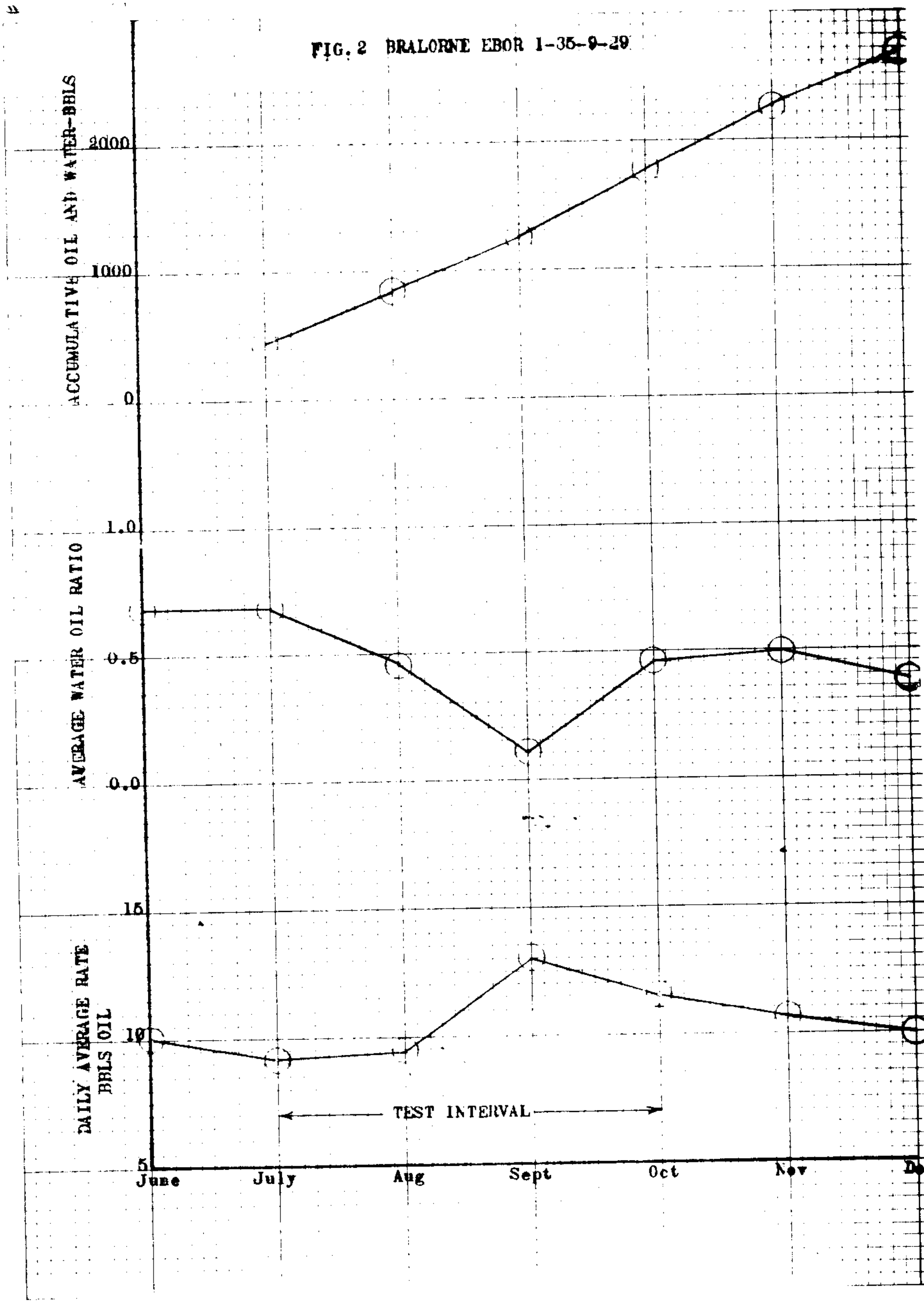


Figure 1. Section 35 & 36-9-29 WPM well location map.

FIG. 2 BRALORNE EBOR 1-35-9-29



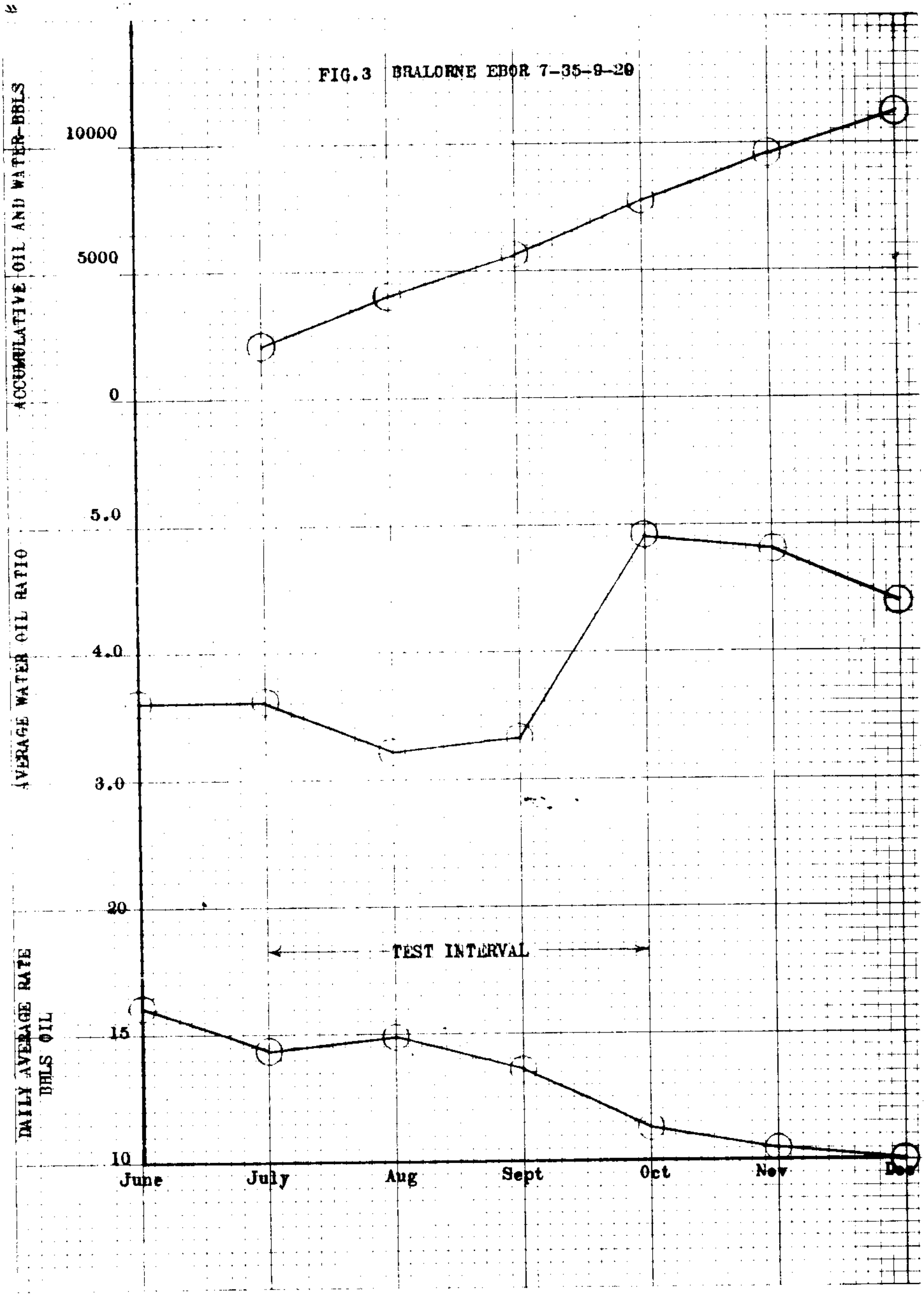
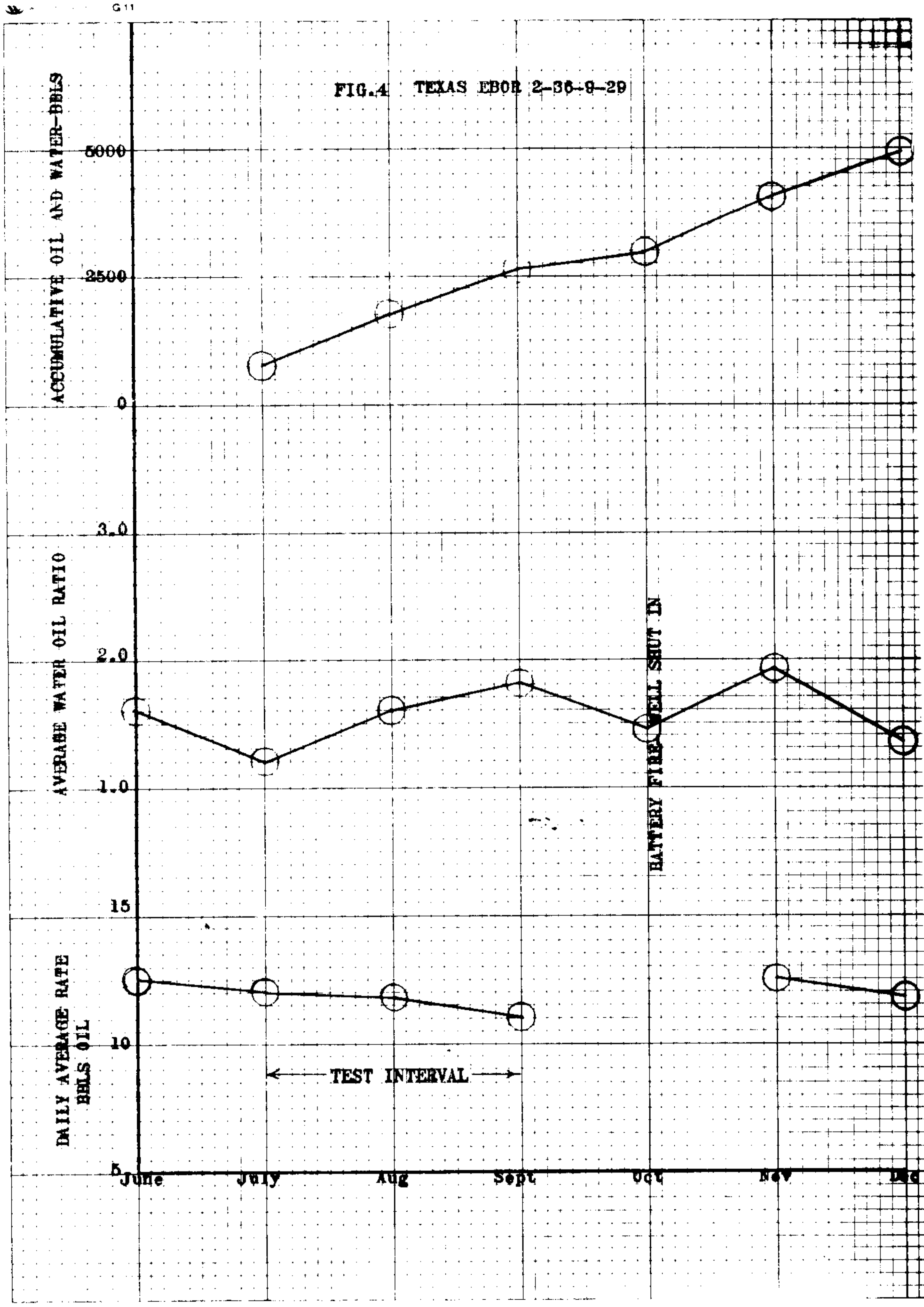


FIG.3 BRALORNE EBOR 7-35-9-29
ACCUMULATIVE OIL AND WATER-BBLS
10000
5000
0
AVERAGE WATER OIL RATIO
5.0
4.0
3.0
20
TEST INTERVAL
DAILY AVERAGE RATE
BBLS OIL
15
10
June
July
Aug
Sept
Oct
Nov
Dec



G 11
FIG.4 TEXAS EBOR 2-36-9-29
ACCUMULATIVE OIL AND WATER-BBLS
5000
2500
0
AVERAGE WATER OIL RATIO
3.0
2.0
1.0
BATTERY FIRE WELL SHUT IN
DAILY AVERAGE RATE
BBLS OIL
15
10
5
TEST INTERVAL
June
July
Aug
Sept
Oct
Nov
Dec

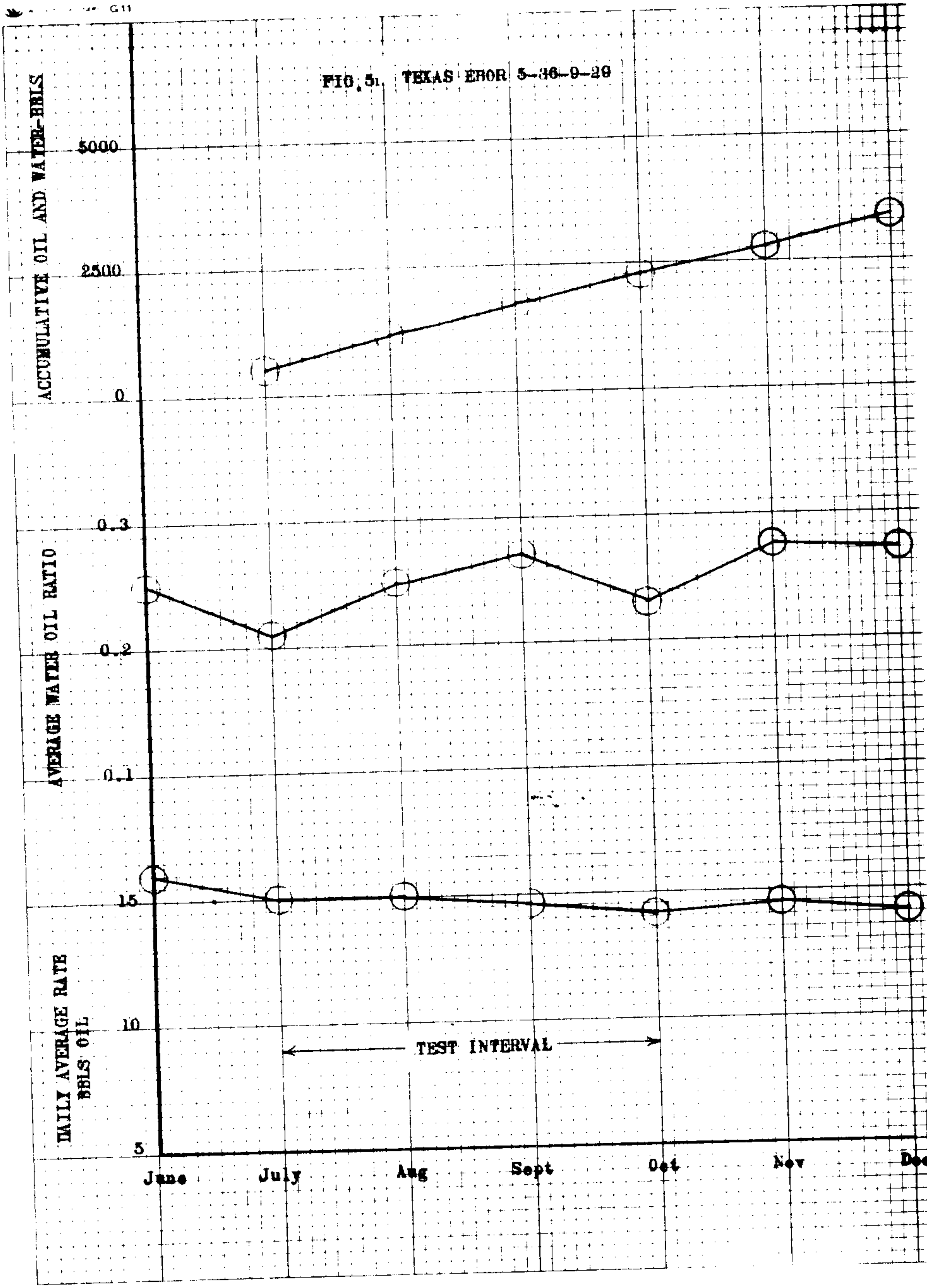


FIG. 5. TEXAS EBOR 5-36-9-29

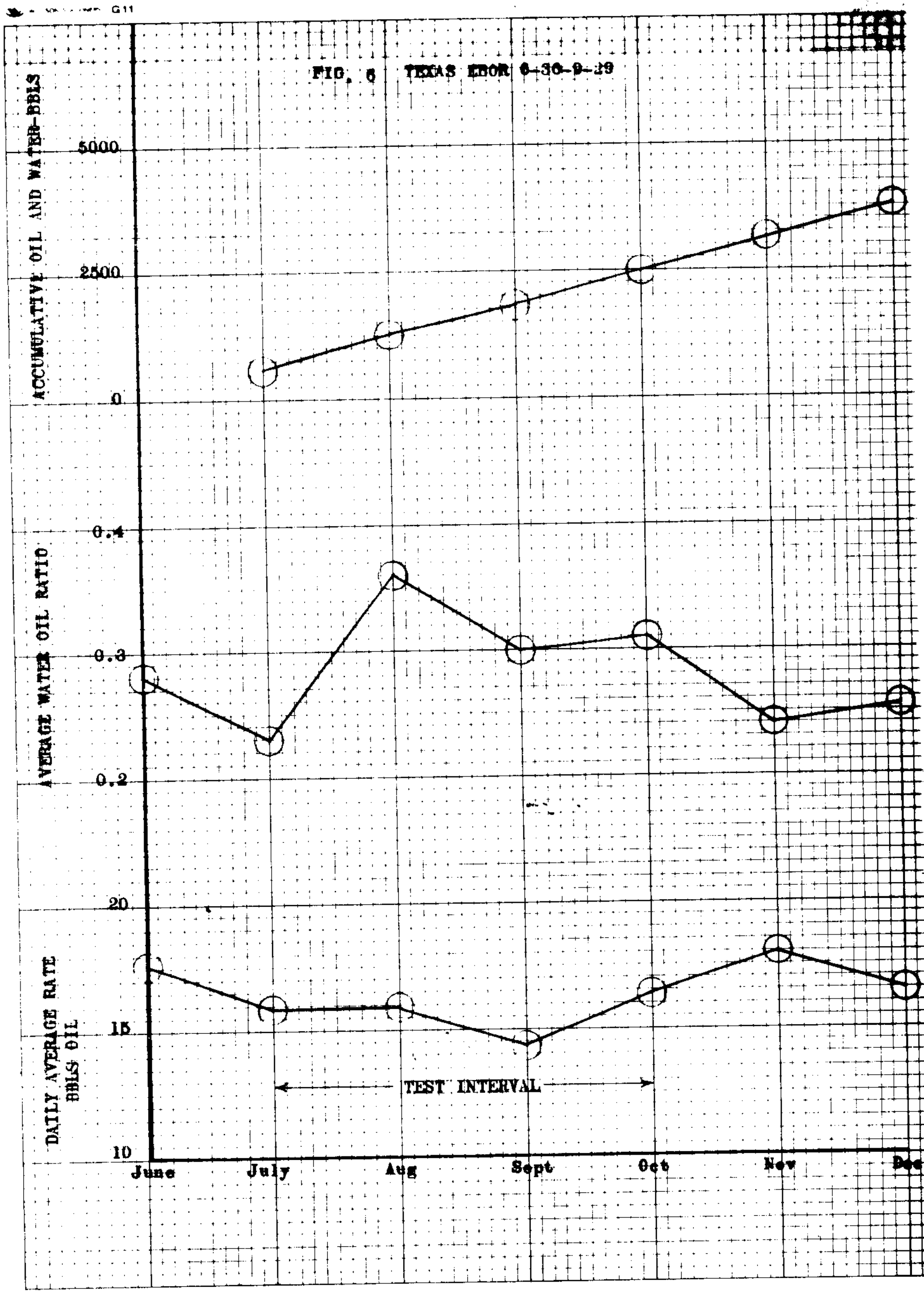


FIG. 6 TEXAS EBOR 6-30-9-29
ACCUMULATIVE OIL AND WATER-BBLS
5000
2500
0
AVERAGE WATER OIL RATIO
0.4
0.3
0.2
DAILY AVERAGE RATE BBLS OIL
20
15
10
TEST INTERVAL
June
July
Aug
Sept
Oct
Nov
Dec

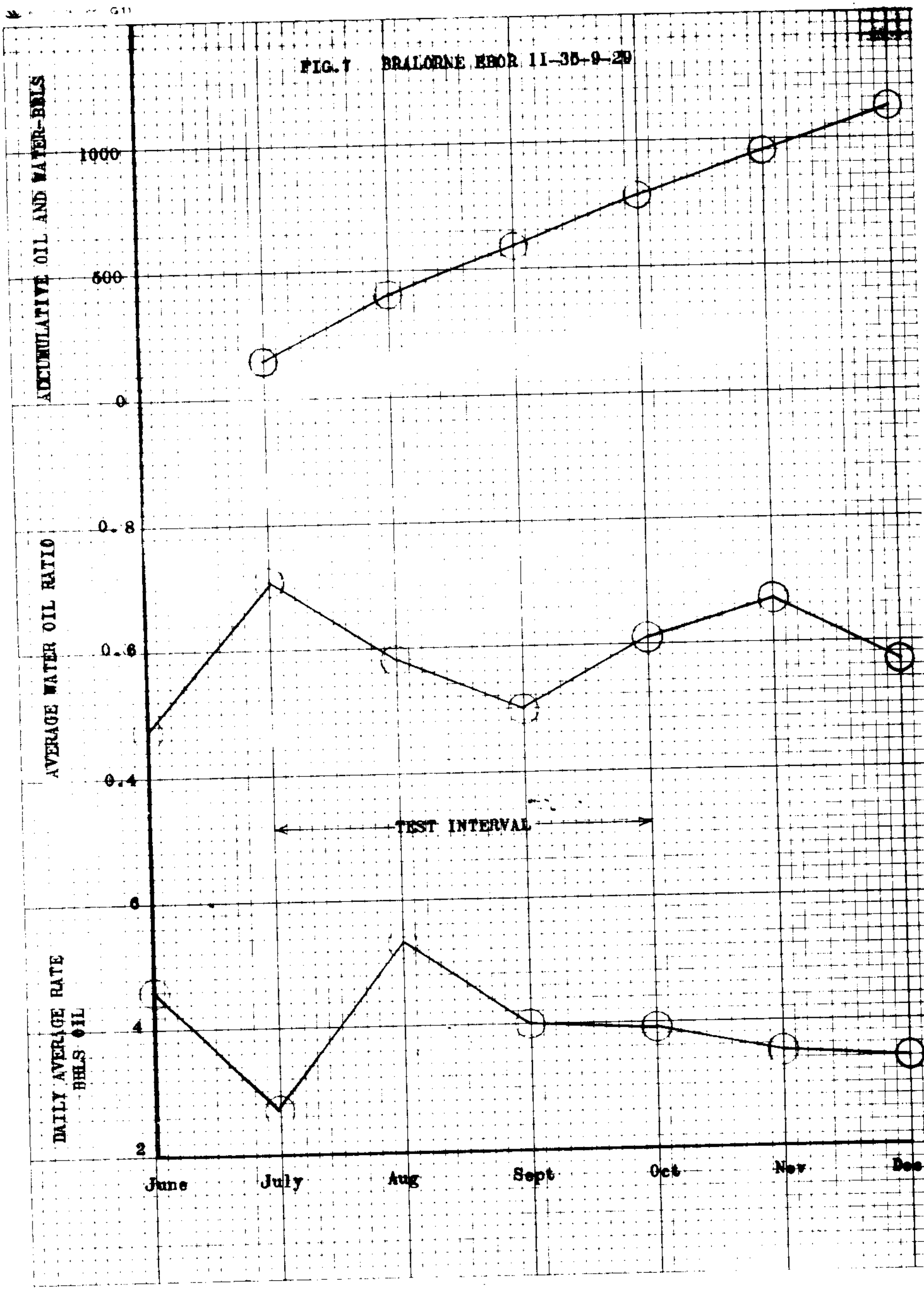


FIG. 7 BRALORNE EBOR 11-35-9-29
ACCUMULATIVE OIL AND WATER-BBLS
1000
500
0
AVERAGE WATER OIL RATIO
0.8
0.6
0.4
TEST INTERVAL
DAILY AVERAGE RATE BBLS OIL
6
4
2
June
July
Aug
Sept
Oct
Nov
Dec

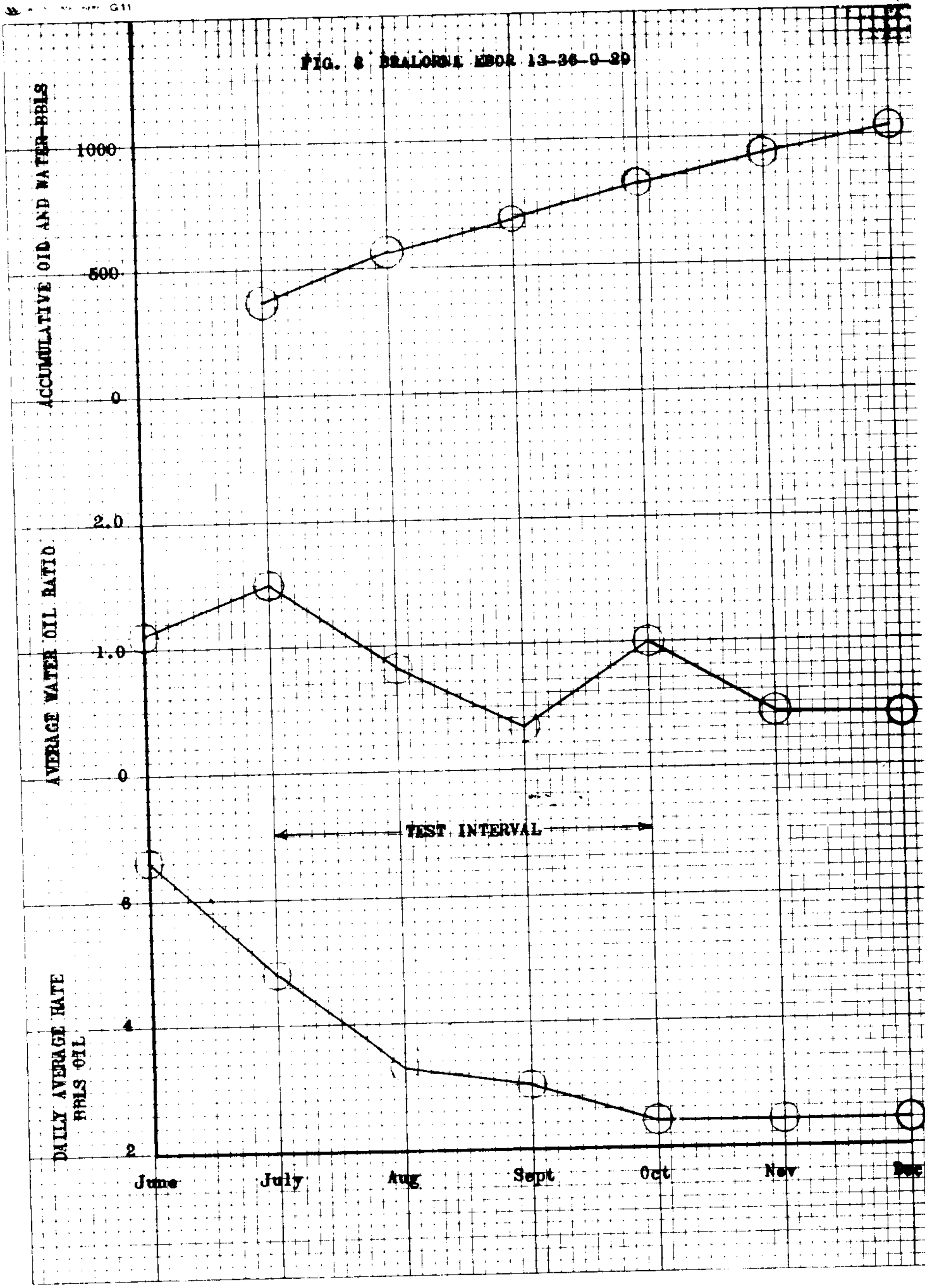


FIG. 2 BRALORNE EBOR 13-36-9-29

FIG. 9 BRALORNE EBOR 9-35-9-29
INJECTION WELL

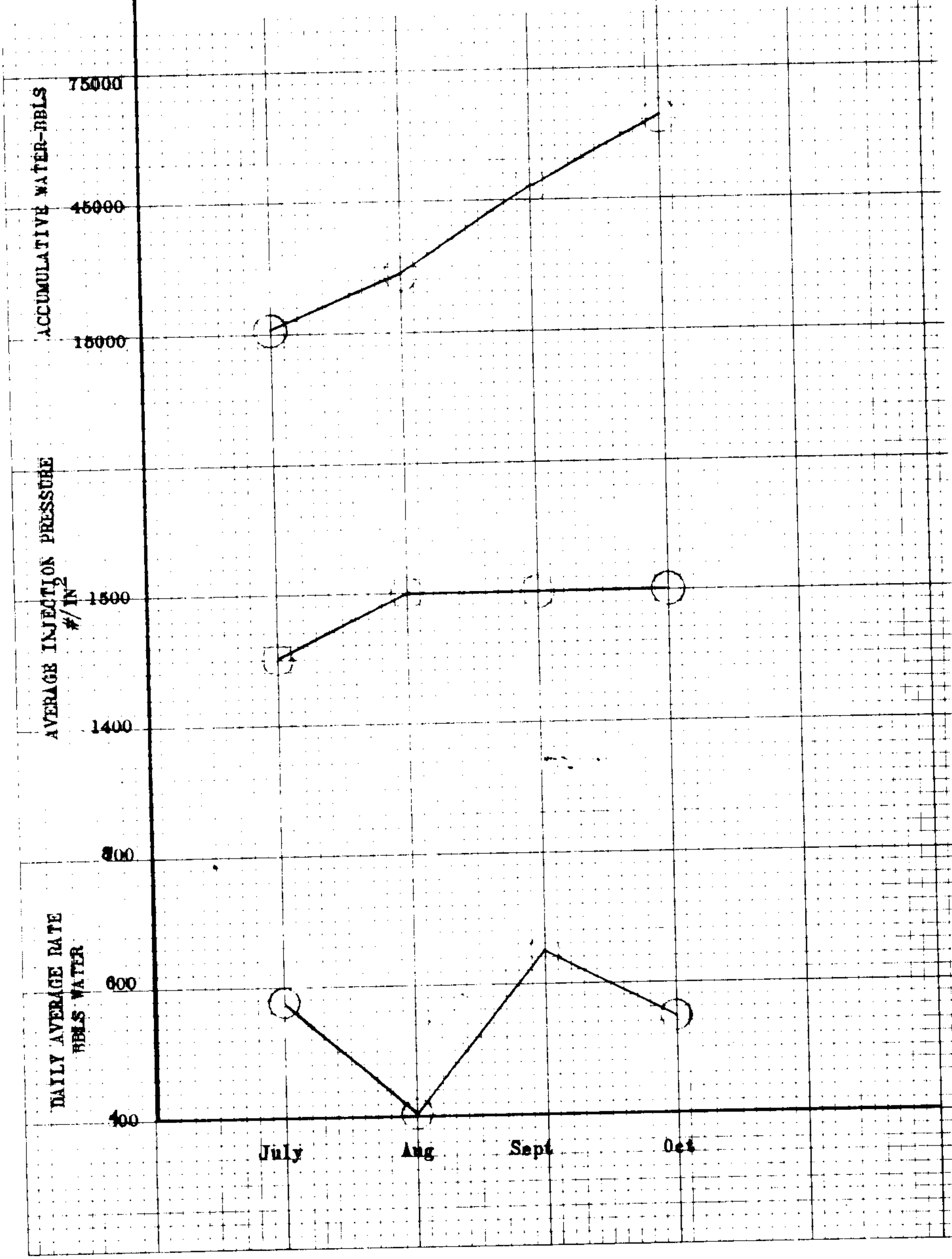
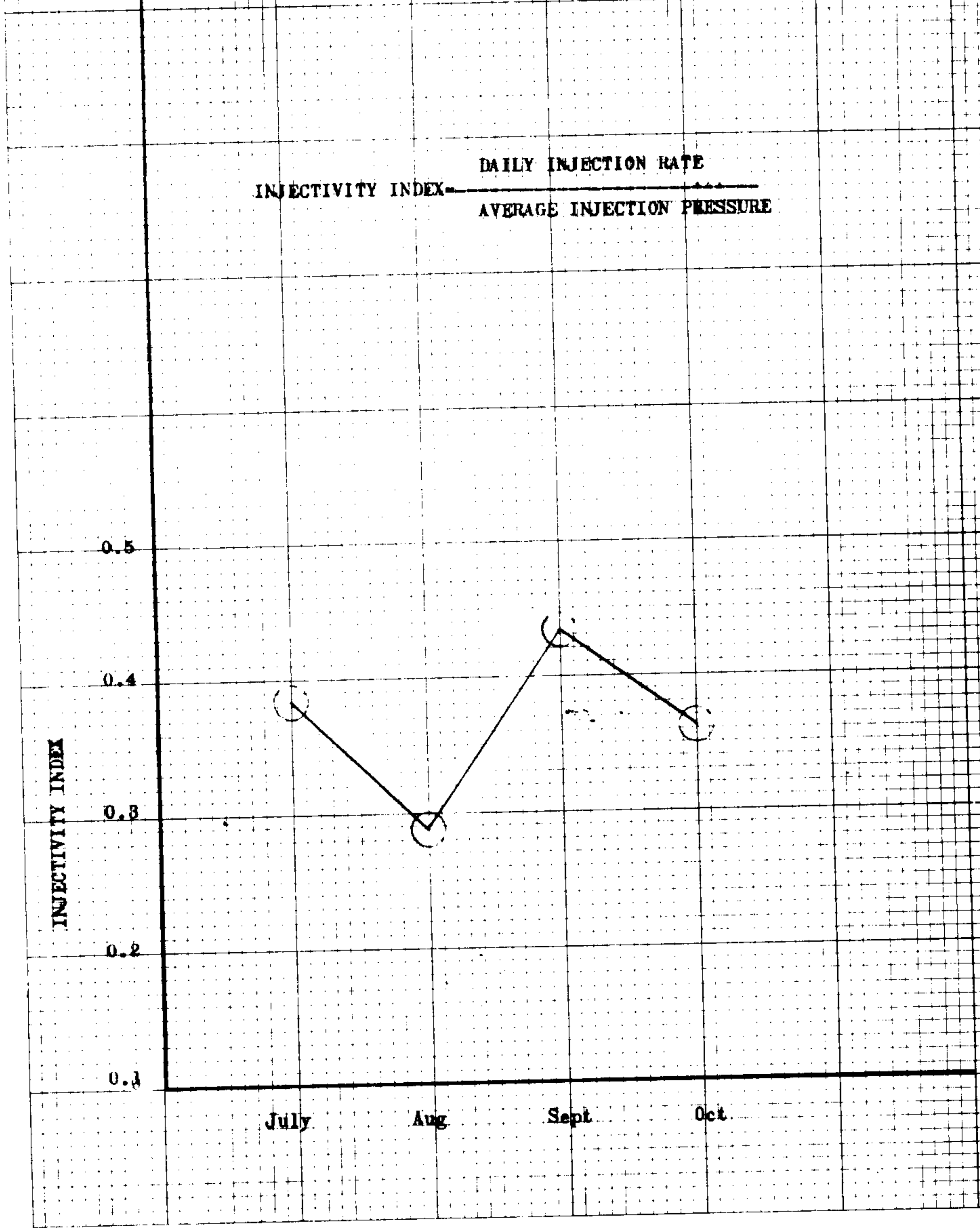


FIG. 10 BRALORNE EBOR 9-35-9-29
INJECTION WELL

INJECTIVITY INDEX



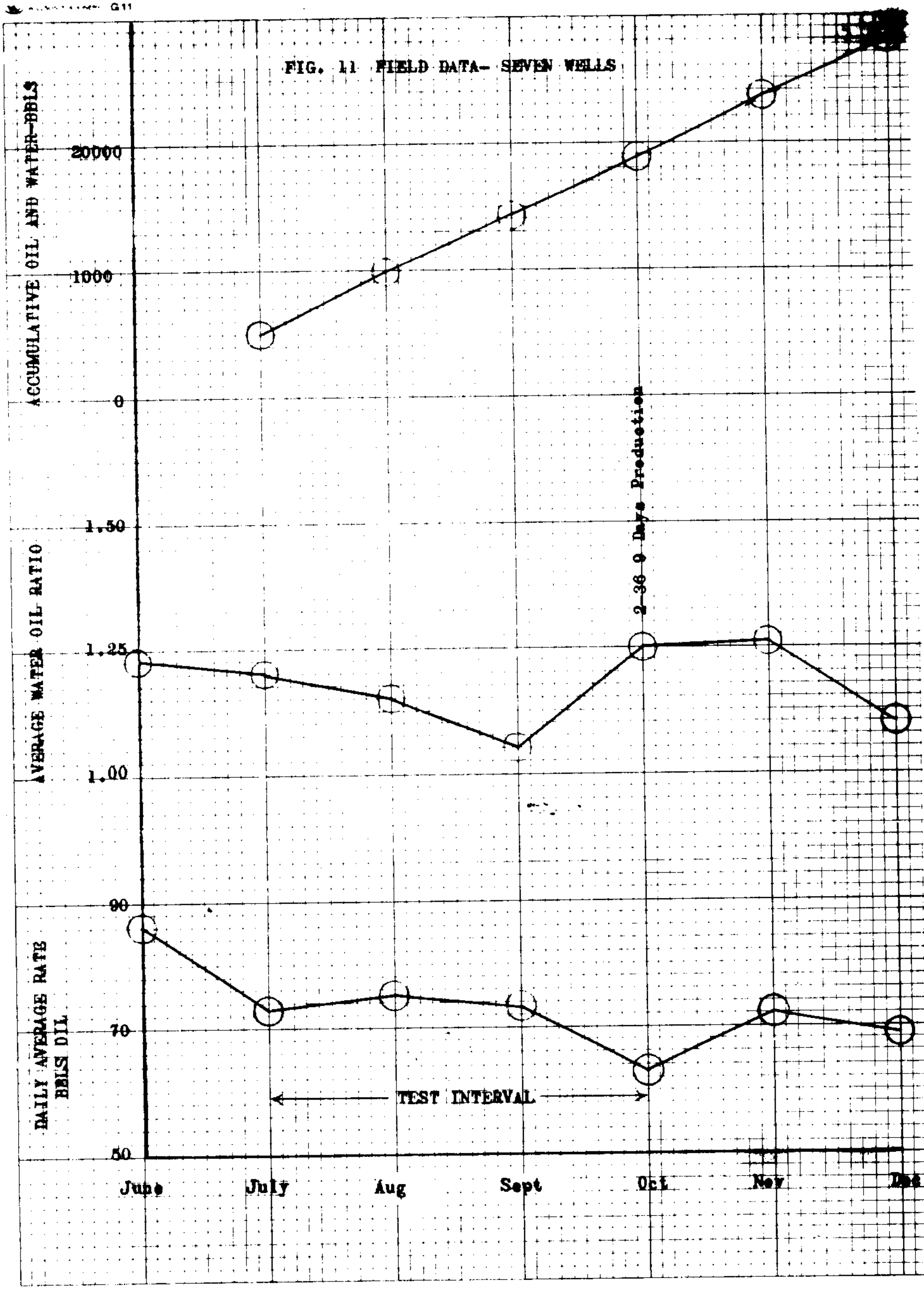


FIG. 11 FIELD DATA- SEVEN WELLS
ACCUMULATIVE OIL AND WATER-BBLS
20000
1000
0
AVERAGE WATER OIL RATIO
1.50
1.25
1.00
DAILY AVERAGE RATE BBLS OIL
90
70
50
2-36 0 Days Production
TEST INTERVAL
June
July
Aug
Sept
Oct
Nov
Dec

FIGURE 12.

MONTHLY WELL WATER CUTS AND TESTS

(Bbls Fluid per day)

Well No.	June BFPD	June Cut	July BFPD	July Cut	August BFPD	August Cut	September BFPD	September Cut	October BFPD	October Cut	November BFPD	November Cut	December BFPD	December Cut
1-35	18	40	18	40	14	32	14	9	17	32	16	33	15	28
7-35	75	78	75	78	75	77	75	77	72	83	70	83	55	81
2-36	32	62	27	55	32	62	31	64	29	58	35	66	29	58
5-36	20	20	18	17	19	20	19	21	17	19	19	21	18	21
6-36	22	22	20	19	22	26	20	30	21	24	22	19	20	20
11-36	7	32	5	41	8	37	6	30	6	38	7	40	5	36
13-36	15	52	13	60	5	45	4	25	5	50	4	30	3	29

FIGURE 13.

PRODUCTION SUMMARY

Well No.	June Oil	June Water	July Oil	July Water	August Oil	August Water	September Oil	September Water	October Oil	October Water	November Oil	November Water	December Oil	December Water
1-35	301	205	256	174	272	125	390	40	355	163	319	155	320	120
7-35	479	1709	443	1600	459	1480	390	1284	349	1723	313	1508	314	1381
2-36	375	594	373	412	365	604	329	600	112 (9 days)	162	375	724	367	500
5-36	476	120	466	100	464	116	437	120	437	99	436	120	441	120
6-36	529	150	489	112	493	178	429	130	504	155	541	130	510	130
11-36	138	65	84	60	164	95	120	60	120	73	105	70	105	60
13-36	198	220	148	230	102	83	90	30	73	75	72	30	74	30
	2496	3063	2259	2688	2319	2681	2185	2264	1950	2450	2161	2737	2131	2341
	5720		4947		5000		4449		4400		4898		4472	

FIG. 14 DAILY INJECTION RATE

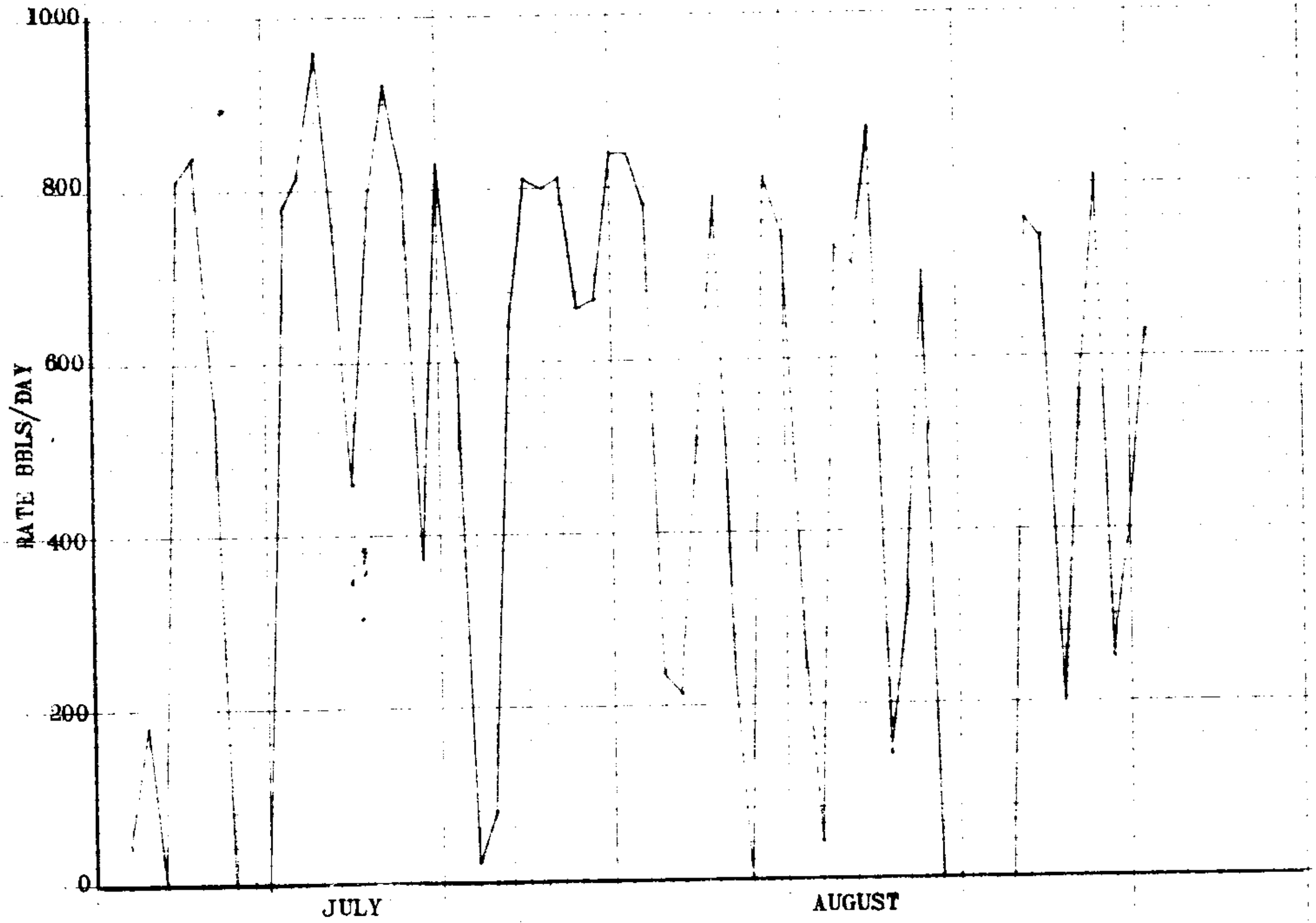
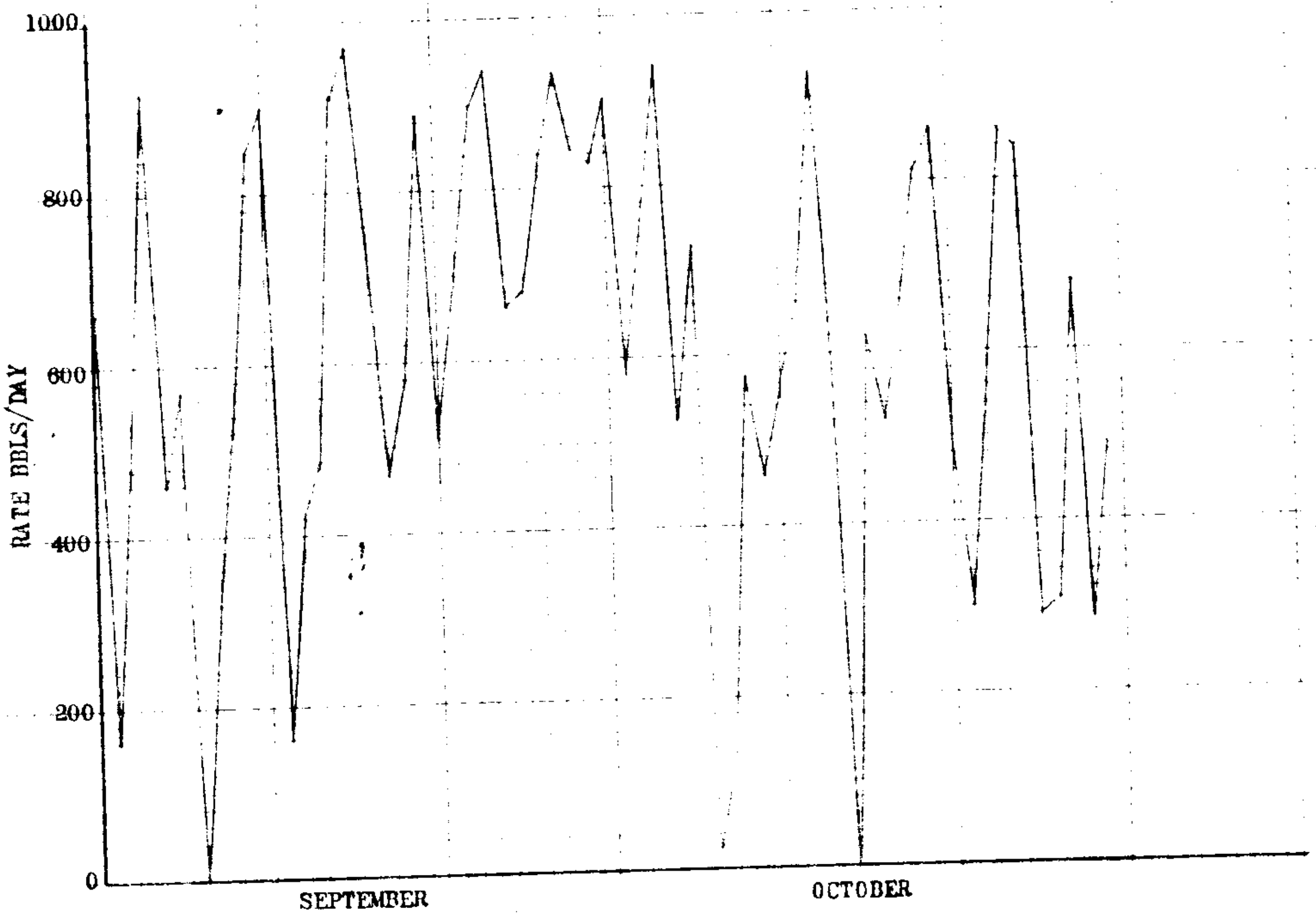


FIG. 15 DAILY INJECTION RATE



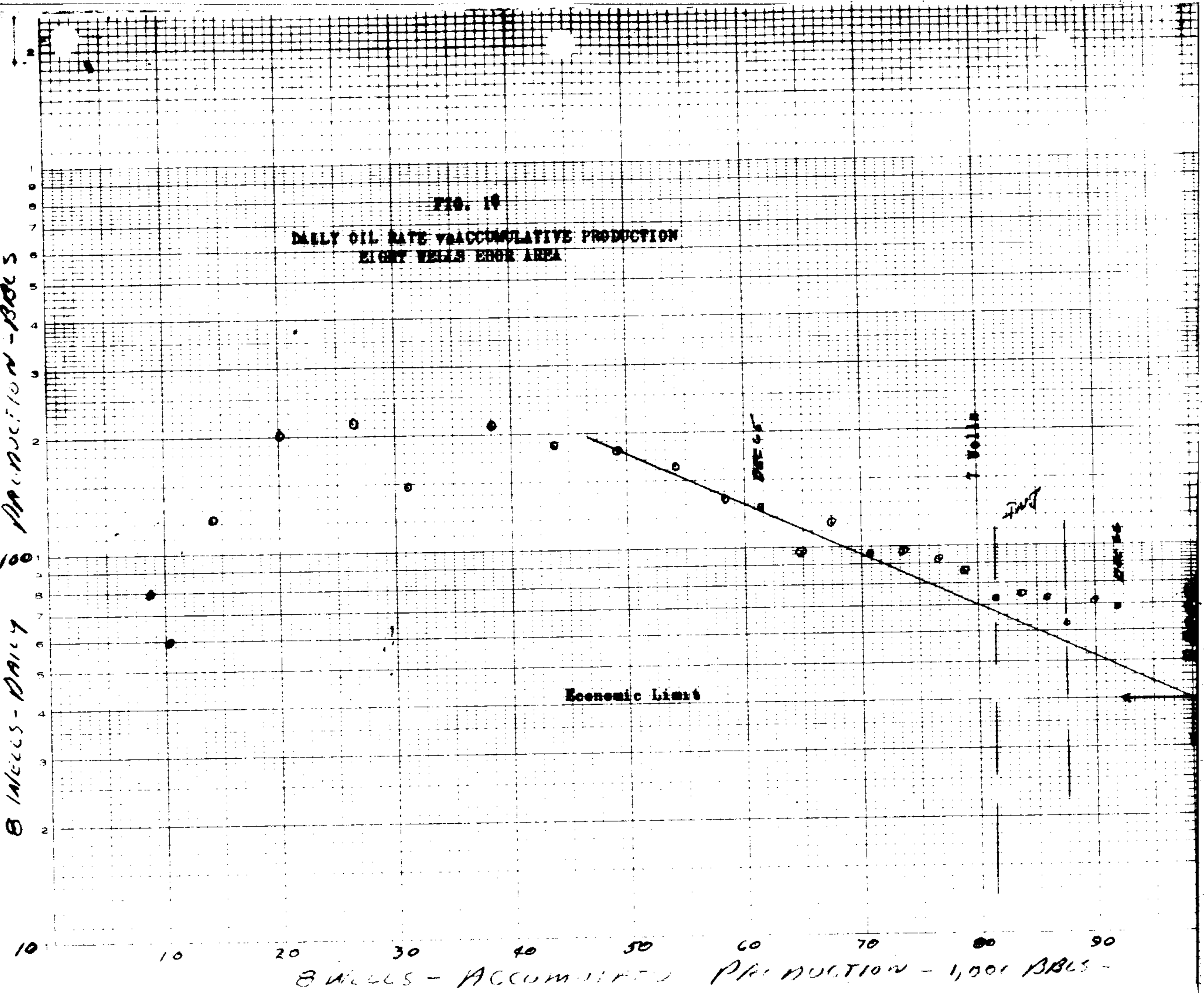


FIG. 1?
DAILY OIL RATE vs ACCUMULATIVE PRODUCTION
EIGHT WELLS EBOR AREA
Economic Limit
Dec 65
7 Wells
8 WELLS - DAILY PRODUCTION - BBLS
8 WELLS - ACCUMULATED PRODUCTION - 1,000 BBLS -
10
20
30
40
50
60
70
80
90

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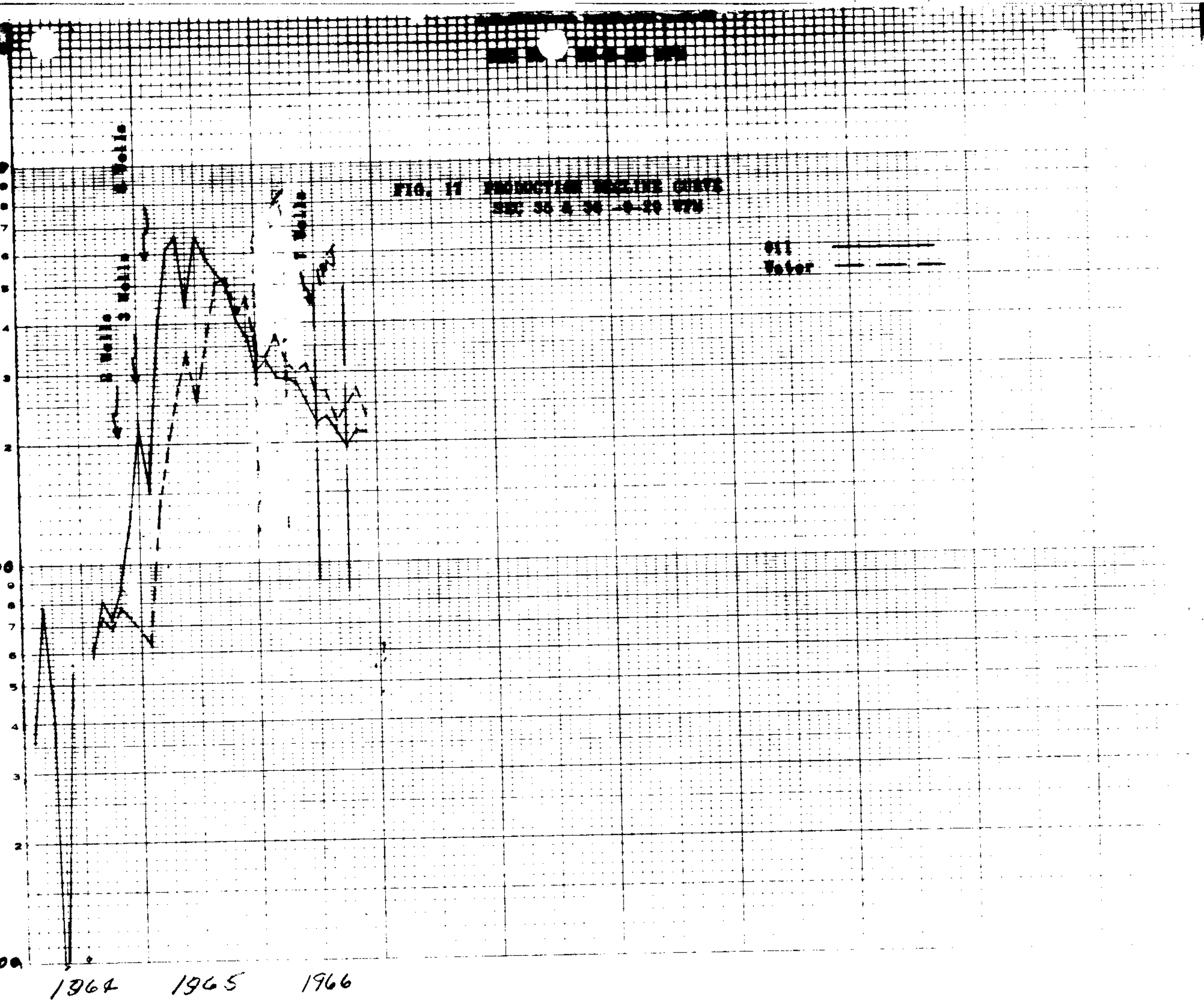


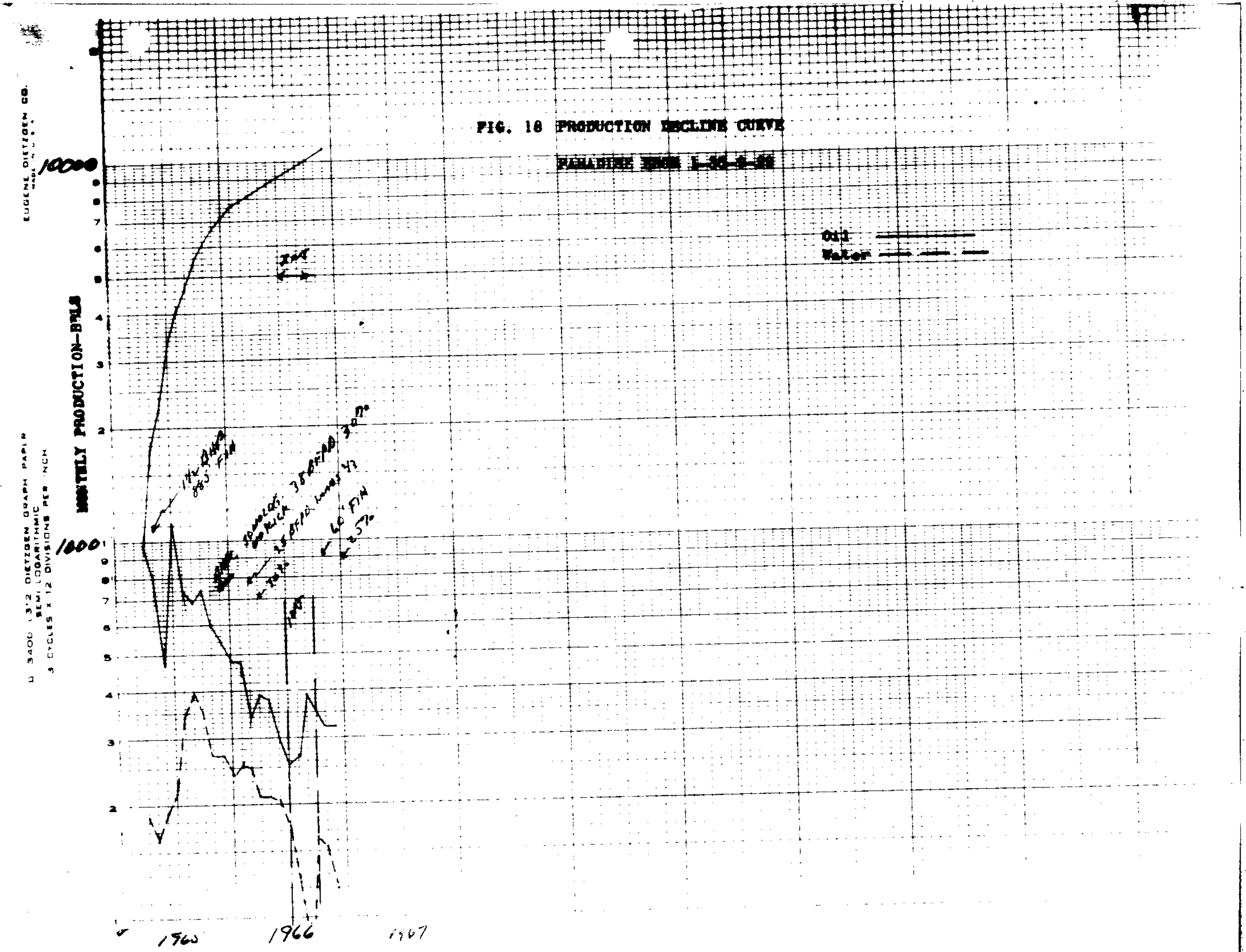


FIG. 18 PRODUCTION DECLINE CURVE

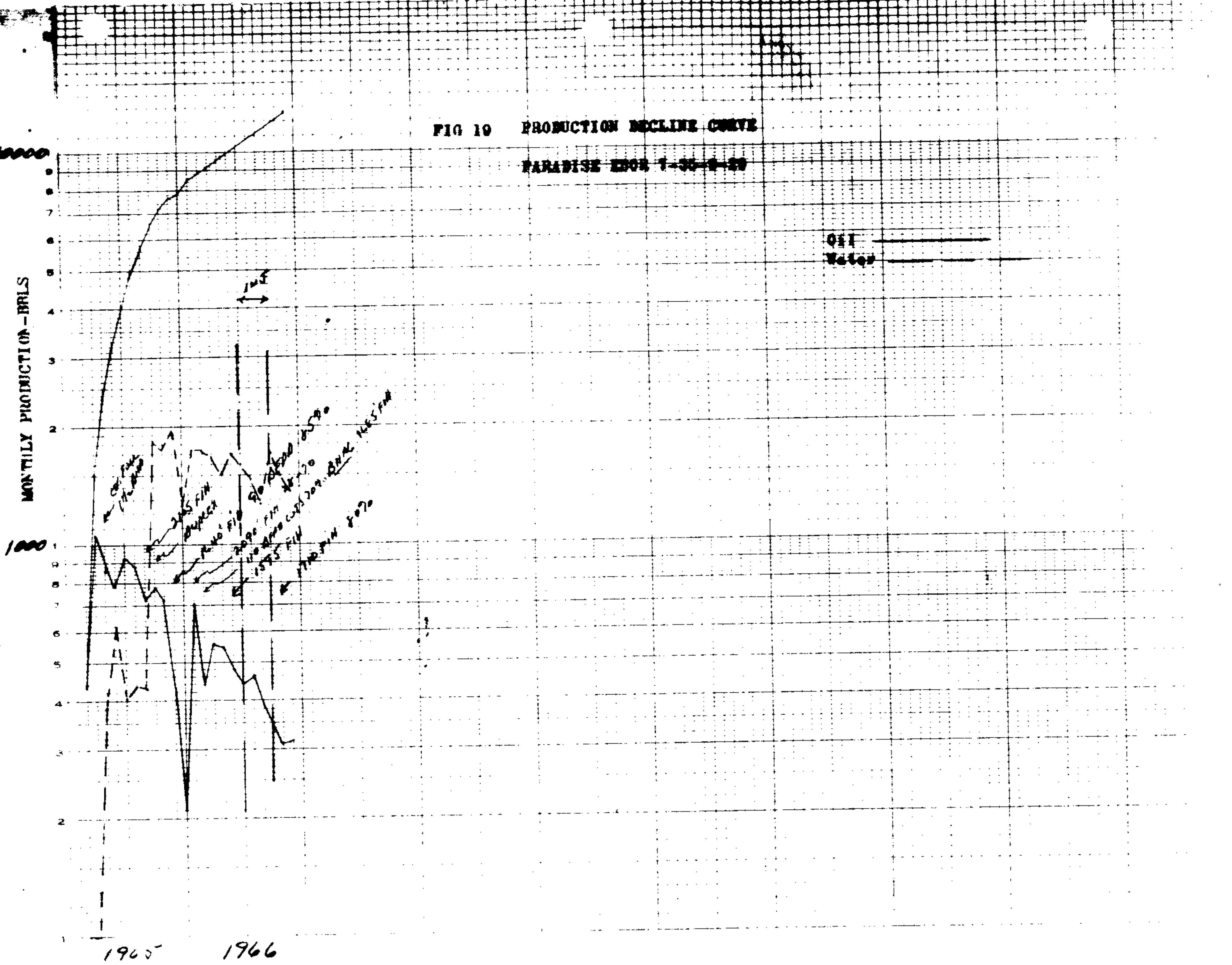


FIG 19 PRODUCTION DECLINE CURVE

PARADISE KDOR 1-36-[illegible]

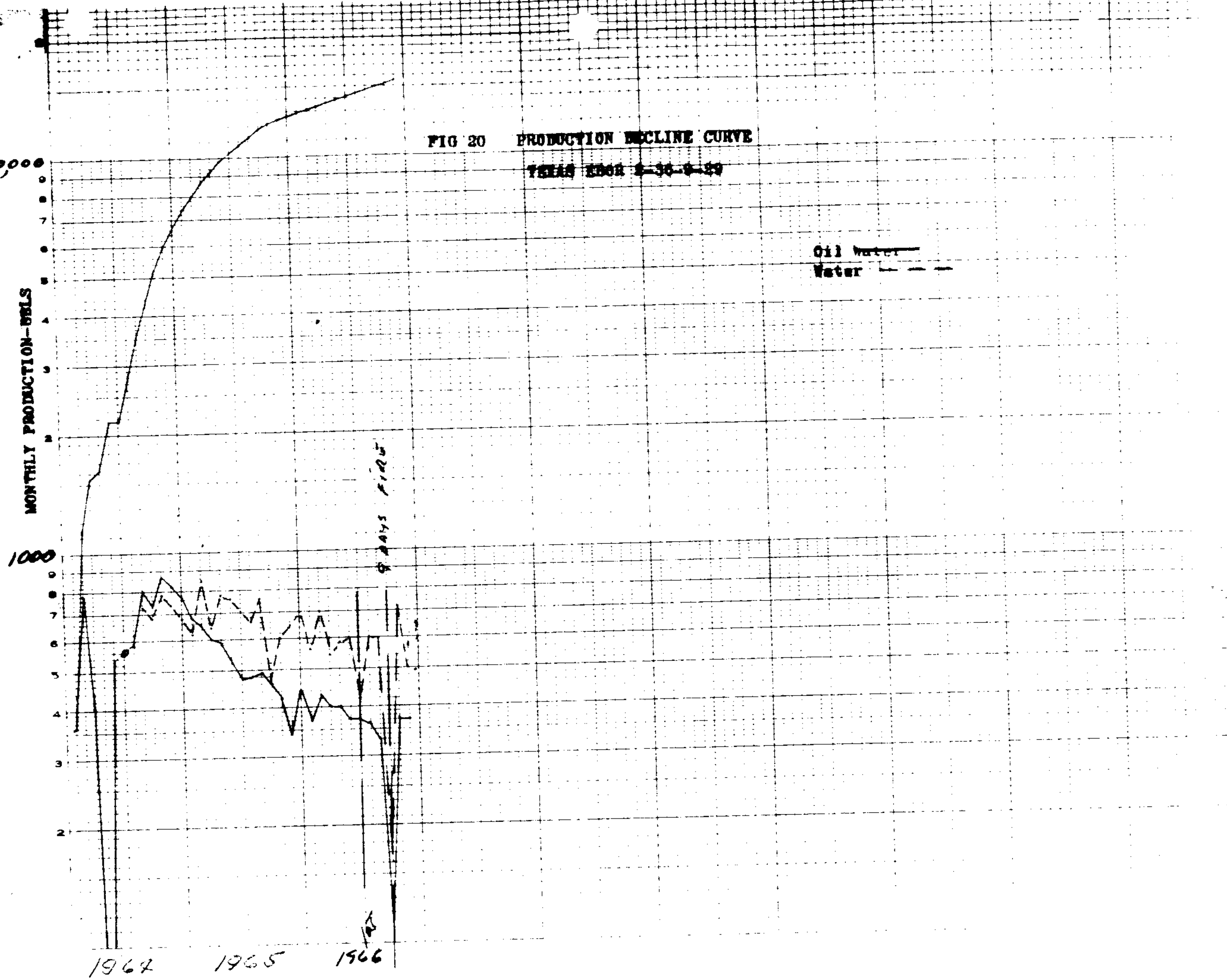


FIG 20 PRODUCTION DECLINE CURVE
TEXAS EBOR 2-36-9-29

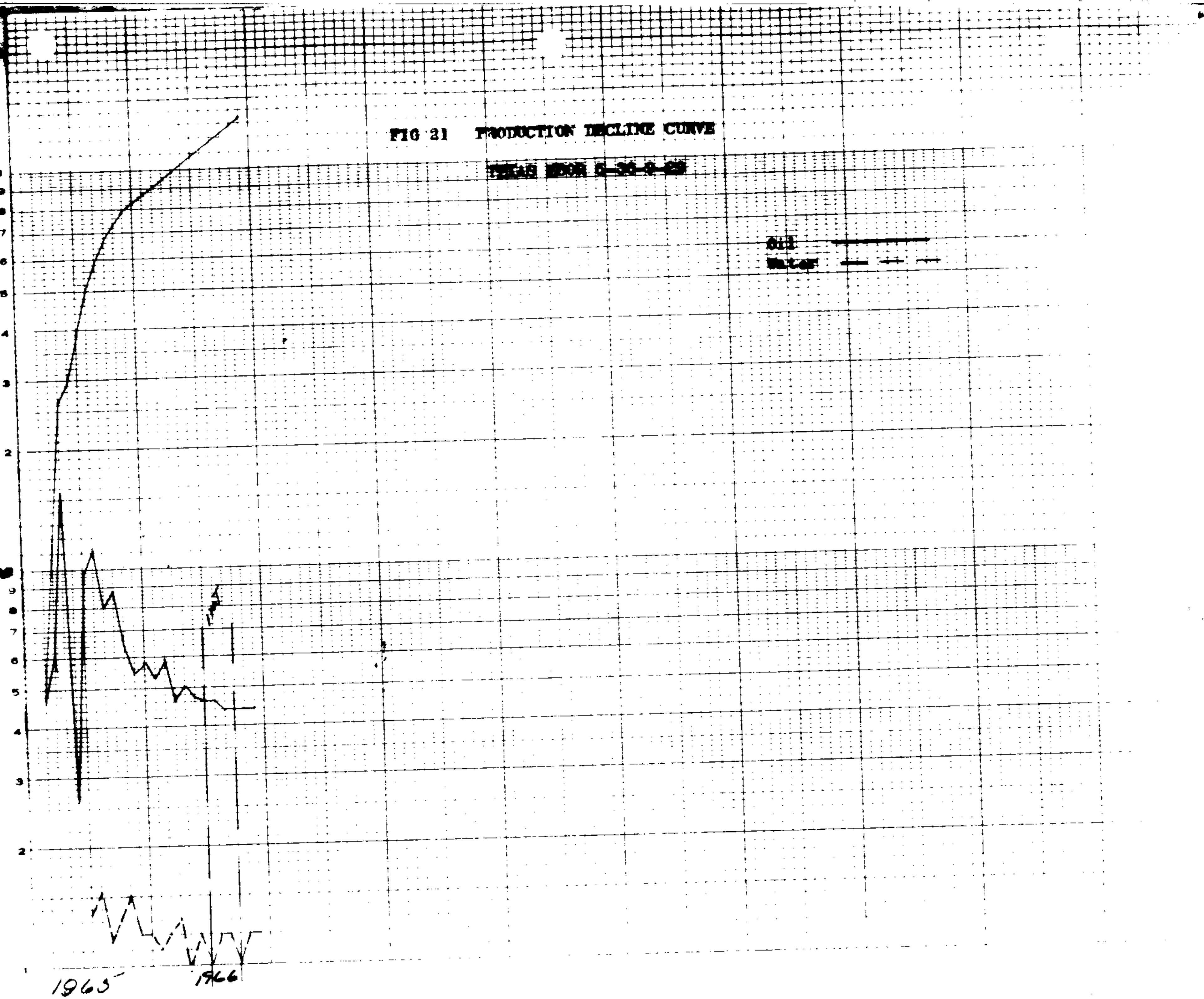


FIG 21 PRODUCTION DECLINE CURVE

FIG 22 PRODUCTION DECLINE CURVE

TEXAS EBOR 6-36-9-20

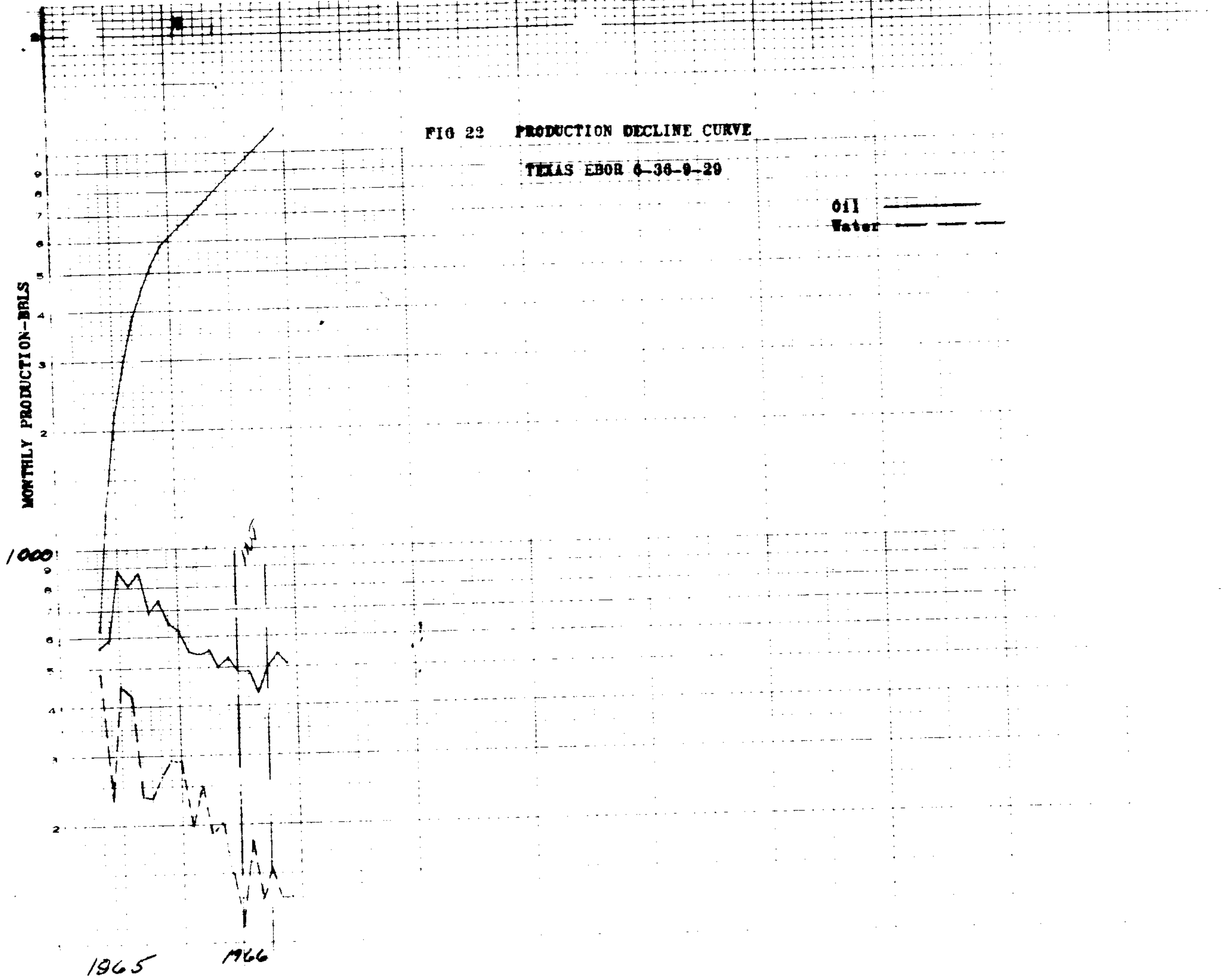


FIG 23 PRODUCTION DECLINE CURVE

PARADISE N. EBOR 11-38-0-29

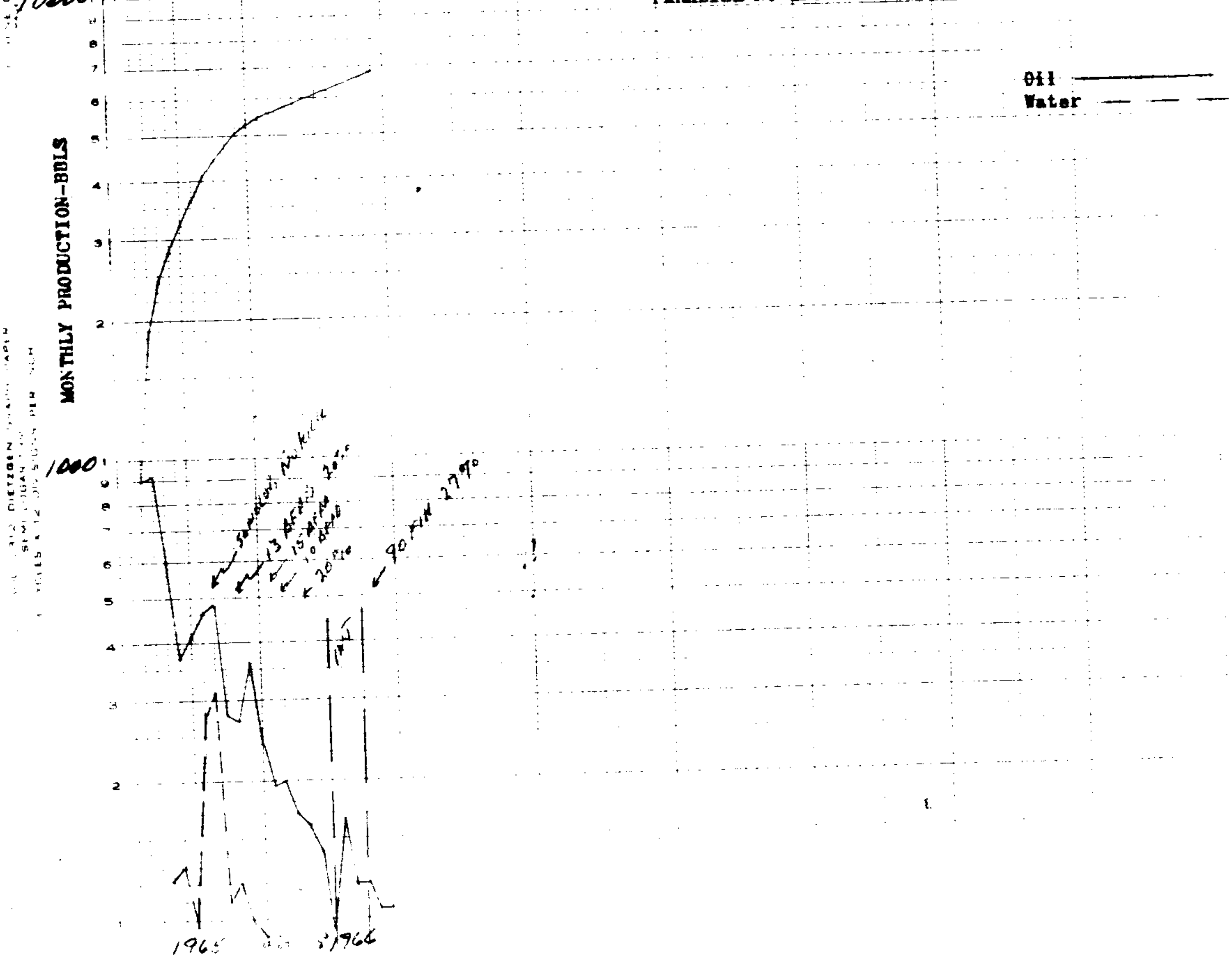
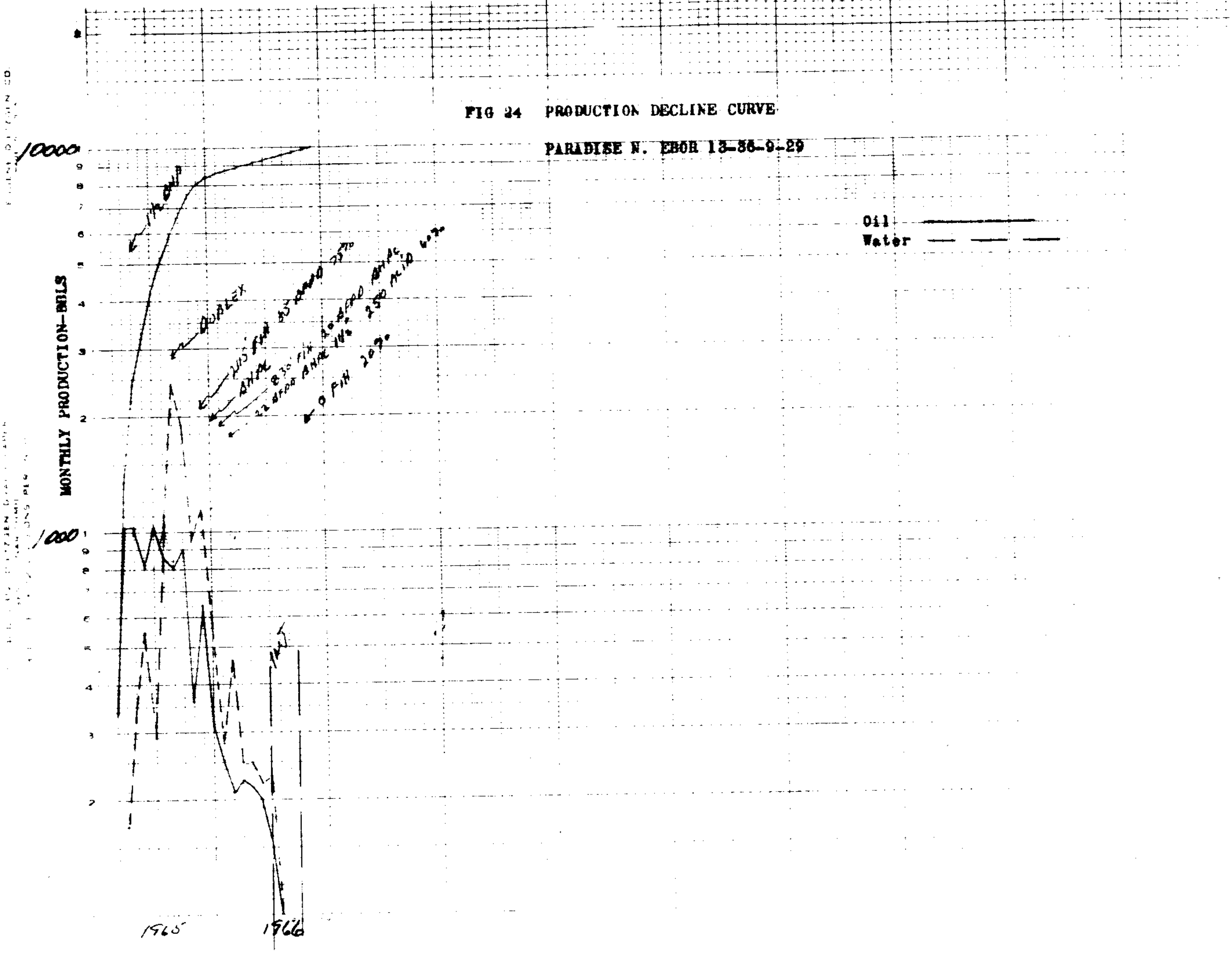


FIG 24 PRODUCTION DECLINE CURVE

PARADISE N. EBOR 13-36-9-29



BRALORNE PETROLEUMS LTD.

P.O. Box #1240

Virden, Manitoba

November 17, 1966

Department of Mines and Natural Resources,
Petroleum Engineering Division,
Room 911 Norquay Building
Winnipeg, Manitoba.

Attention: F. S. Gamey.

Dear Sir:

MONTHLY WATER INJECTION

Bralorne Ebor 9-35-9-29 WPM

Water Source: (1) Pipestone Creek
(2) Ebor 9-35-9-29 battery

Date	Barrels	
October 1, 1966	589	1,500# injection pressure
" 2, 1966	761	
" 3, 1966	938	
" 4, 1966	525	
" 5, 1966	728	
" 6, 1966	26	Motor Repairs
" 7, 1966	136	" "
" 8, 1966	575	
" 9, 1966	463	
" 10, 1966	566	
" 11, 1966	658	
" 12, 1966	932	
" 13, 1966	587	
" 14, 1966		Heavy Rain. Duplex inaccessible
" 15, 1966	618	
" 16, 1966	523	
" 17, 1966	660	
" 18, 1966	814	
" 19, 1966	862	
" 20, 1966	483	Motor Stopped
" 21, 1966	297	
" 22, 1966	565	
" 23, 1966	864	

........2.

Department of Mines and Natural Resources
Attention: F. S. Gamey.

November 17, 1966

Date	Barrels	
October 24, 1966	840	
" 25, 1966	291	Motor Stopped
" 26, 1966	308	" "
" 27, 1966	678	
" 28, 1966	286	Sub freezing temperatures
" 29, 1966	488	
" 30, 1966	205	1500# injection pressure
" 31, 1966	Shut down	

Total injection for October, 1966, 16,276 bbls. Accumulative injection to November 1, 1966, 65,164 bbls. Sub-freezing temperatures have forced a termination of the pilot flood.

Yours very truly,

BRALORNE PETROLEUMS LTD.

Per: H. B. Elder

H. B. Elder, P. Engineer.

HBE/dml

MONTHLY REPORT - EBOR PILOT FLOOD, OCTOBER, 1966.

1. **PRODUCTION:** Seven Wells

Oil	1950 bbls.
Water	2450 bbls.

2. **INJECTION:**

   16,276 bbls at 1,500#

3. **INJECTION vs WITHDRAWALS:**

   Injection exceeded withdrawals by 11,876 bbls.

4. **GENERAL:**

   Evidence is insufficient to draw any definite conclusions. Sub-freezing temperatures have forced a termination of the pilot flood.

5. **PRODUCTION SUMMARY:**

	July		August		September		October		
Well	Oil	Water	Oil	Water	Oil	Water	Oil	Water	
1-35	256	174	272	125	390	40	355	163	
7-35	443	1600	459	1480	390	1284	349	1723	
2-36	373	412	365	604	329	600	112	162	(9 days)
5-36	466	100	464	116	437	120	437	99	
6-36	489	112	493	178	429	130	504	155	
11-36	84	60	164	95	120	60	120	73	
13-36	148	230	102	83	90	30	73	75	
	2259	2688	2319	2681	2185	2264	1950	2450	
	4947		5000		4449		4400		

Injection started July 3, 1966.

cc: Calgary office
  : Texas Crude Oil Company
  : Canadian Industrial Gas
  : J. W. Clarke
  : Pete Oley
  : File

Amended Copy

MONTHLY REPORT - EBOR PILOT FLOOD, SEPTEMBER, 1966.

1. **PRODUCTION:** Seven Wells

    Oil 2185
    Water 2264

2. **INJECTION:**

    19,469 BBLS at 1500"

3. **INJECTION vs WITHDRAWALS:**

    Injection exceeded withdrawals by 15,020 BBLS.

4. **GENERAL:**

    Evidence is insufficient so draw any definite conclusions.

5. **PRODUCTION SUMMARY:**

Well	July Oil	July Water	August Oil	August Water	Sept Oil	Sept Water
1-35	256	174	272	125	390	40
7-35	443	1600	459	1480	390	1284
2-36	373	412	365	604	329	600
5-36	466	100	464	116	437	120
[illegible]-36	489	112	493	178	429	130
11-36	84	60	164	95	120	60
13-36	148	230	102	83	90	30
	2259	2688	2319	2681	2185	2264
	4947		5000		4449	

Injection started July 3, 1966.

cc: Calgary Office
Texas Crude Oil
Pete Oley
File

C16

, October 18, 1966

Department of Mines and Natural Resources,
Petroleum Engineering Division,
Room 911 Norquay Building,
Winnipeg, Manitoba.

Attention: Mr. Stan Gamey

Dear Sir:

MONTHLY WATER INJECTION

Bralorne Ebor 9-35-9-29 WPM

Water Source: 1) Pipestone Creek 18996 BBLS.
2) Ebor 9-35-9-29 Battery 473 BBLS.

Date	Barrels	
August 1, 1966	667	1500 Injection pressure
" 2, 1966	163	
" 3, 1966	477	
" 4, 1966	918	
" 5, 1966	462	
" 6, 1966	570	
" 7, 1966		Motor Repairs
" 8, 1966	314	
" 9, 1966	538	
" 10, 1966	850	
" 11, 1966	897	
" 12, 1966	163	
" 13, 1966	424	
" 14, 1966	486	
" 15, 1966	913	
" 16, 1966	972	
" 17, 1966	469	
" 18, 1966	577	
" 19, 1966	887	
" 20, 1966	508	
" 21, 1966	700	
" 22, 1966	898	
" 23, 1966	937	
" 24, 1966	661	
" 25, 1966	679	
" 26, 1966	826	
" 27, 1966	935,	
" 28, 1966	845	
" 29, 1966	828	

August 30, 1966 905 Injection Pressure 1500"

Total injection for month of September, 1966, 19,469BBLS.

Accumulative injection to October 1, 1966, 48,888 BBLS.

Yours very truly,

BRALORNE PETROLEUMS LTD.

Per:

HBE/sgf

H. B. Elder, P. Engineer.

MONTHLY REPORT - EBOR PILOT FLOOD, SEPTEMBER, 1966.

1. **PRODUCTION:** Seven Wells

   Oil 2185
   Water 2264

2. **INJECTION:**

   19,469 BBLS at 1500"

3. **INJECTION vs WITHDRAWALS:**

   Injection exceeded withdrawals by 15,020 BBLS.

4. **GENERAL:**

   Evidence is insufficient so draw any definite conclusions.

5. **PRODUCTION SUMMARY:**

Well						
1-35	256	174	272	125	390	40
7-35	443	1600	459	1480	390	1284
2-36	373	412	365	604	329	600
5-36	466	100	464	116	437	120
6-36	489	112	493	178	429	130
11-36	84	60	164	95	120	60
13-36	148	230	102	83	90	30
	2259	2688	2319	2681	2185	2264
	4947		5000		4449	

Injection started July 3, 1966.

cc: Calgary Office
Texas Crude Oil
Pete Oley
File

BRALORNE PETROLEUMS LIMITED
P.O. BOX 1240
VIRDEN, MANITOBA
CANADA

September 27, 1966.

Department of Mines and Natural Resources,
Petroleum Engineering Division,
Room 911 Norquay Building,
Winnipeg, Manitoba.

Attention: F. S. Gamey.

Dear Sir:

MONTHLY WATER INJECTION

Bralorne Ebor 9-35-9-29 WPM

Water Source: Pipestone Creek and ~~Ebor 9-35-9-29 Battery~~.

Date	Barrels	
August 1, 1966	845	1500#
" 2, 1966	778	
" 3, 1966	244	Motor Stopped
" 4, 1966	214	" "
" 5, 1966	512	
" 6, 1966	792	
" 7, 1966	256	
" 8, 1966	Shut Down	
" 9, 1966	813	
" 10, 1966	743	
" 11, 1966	279	Motor Stopped
" 12, 1966	38	" "
" 13, 1966	729	
" 14, 1966	713	
" 15, 1966	873	
" 16, 1966	141	
" 17, 1966	335	
" 18, 1966	694	
" 19 to 23, 1966	Down for repairs.	
" 24, 1966	762	
" 25, 1966	741	
" 26, 1966	205	Motor Stopped
" 27, 1966	559	
" 28, 1966	810	
" 29, 1966	253	Motor Stopped
" 30, 1966	400	" "
" 31, 1966	632	1500#

..............2.

Total injection during the month of August:

Fresh Water - 12,516 barrels.

Accumulative injection to September 1, 1966:

29,419 barrels.

Yours very truly,

BRALORNE PETROLEUMS LTD.

Per:

H. B. Elder

HBE/dmb

H. B. Elder, P. Engineer.

Ebor [illegible]

BRALORNE PETROLEUMS LIMITED

P.O. BOX 1240
VIRDEN, MANITOBA
CANADA

August 23, 1966.

Department of Mines and Natural Resources,
Petroleum Engineering Division
Room 911 Norquay Building,
Winnipeg, Manitoba.

Attention: Mr. F. S. Gamey

Dear Sir:

Monthly Water Injection

Bralorne Ebor 9-35-9-29 WPM

Water Source: Pipestone Creek.

Date	BBLS	Accum.	Pressure	
July 3	40	40	2000#	
" 4	178	218	1400#	500 gals acid
" 5	--	218		
" 6	814	1032		
" 7	840	1872		
" 8	552	2424		
" 9	--	2424		Engine repair
" 10	--	2424		
" 11	--	2424		
" 12	774	3198		
" 13	818	4016		
" 14	962	4978		
" 15	742	5720		
" 16	464	6184		Engine stopped
" 17	778	6962		
" 18	925	7887	1500#	
" 19	809	8696		
" 20	368	9064		Engine stopped
" 21	827	9891		
" 22	601	10492		Engine stopped
" 23	244	10736		Engine stopped
" 24	79	10815		Engine stopped
" 25	639	11454		
" 26	807	12261		

Department of Mines and Natural Resources,
Petroleum Engineering Division

August 23, 1966.

Attention: Mr. F. S. Gamey

Date	BBLS	Accum.	Pressure
July 27	802	13063	
" 28	815	13878	
" 29	665	14543	
" 30	670	15213	
" 31	845	16058	1500#

Yours very truly,

BRALORNE PETROLEUMS LTD.

Per: HBElder

H. B. Elder, P. Engineer.

HBE/lmb

Place with Unit file.

High-pressure flood design

Report on 5,600 psi House Mountain waterflood

By C. J. Simr,
Shell Canada Limited

On behalf of the working interest owners of House Mountain Unit No. 1, Shell Canada Limited, as operator, has installed a 25,000 bwd, 5600 psi plant discharge pressure, waterflood during the winter of 1965-1966 in the House Mountain field of north-central Alberta. The injection pressure requirements of this flood, believed to be the highest in the world, required the application of the most advanced technology in the design of the system and in the selection of the materials, manufacture and installation of the injection pumps.

The purpose of this paper is to outline some of the more significant features of the design of this installation.

The House Mountain field or Pool "C" of the Swan Hills field is located in north-central Alberta approximately 150 miles north-west of Edmonton, 25 miles south of Lesser Slave Lake. The field was discovered in March 1958 with the drilling of McCall Code, Mic-Mac, Swan Hills 10-14-69-9-W5M and subsequent step out drilling to the north and west. The 42° API gravity oil is produced from the Swan Hills member of the Beaver Hill Lake "C" pool formation in the Middle Upper Devonian at 4,530 feet subsea. The field covers approximately 50,000 acres and there are 205 wells on 160 acres spacing within the boundary of House Mountain Unit No. 1. Studies conducted in the early stages of the field development showed no evidence of water level in this area of the Swan Hills member and no effective water drive could be anticipated. The primary recovery was estimated at 12 percent of the original oil-in-place. Studies of pressure maintenance by waterflooding showed this to be the most desirable method which would also increase the ultimate recovery efficiency to 42 percent of the oil-in-place. A study of injectivity and pressure distribution around injection and producing wells indicated close spacing of injectors would be required to permit balancing of withdrawals and maintaining pressure throughout the reservoir. A nine-spot pattern was selected on the basis of best balance between injectivity and maximum voidage replacement while still retaining flexibility for further conversion if needed. The injectivity at 3,000 psi wellhead pressure was insufficient with the nine-

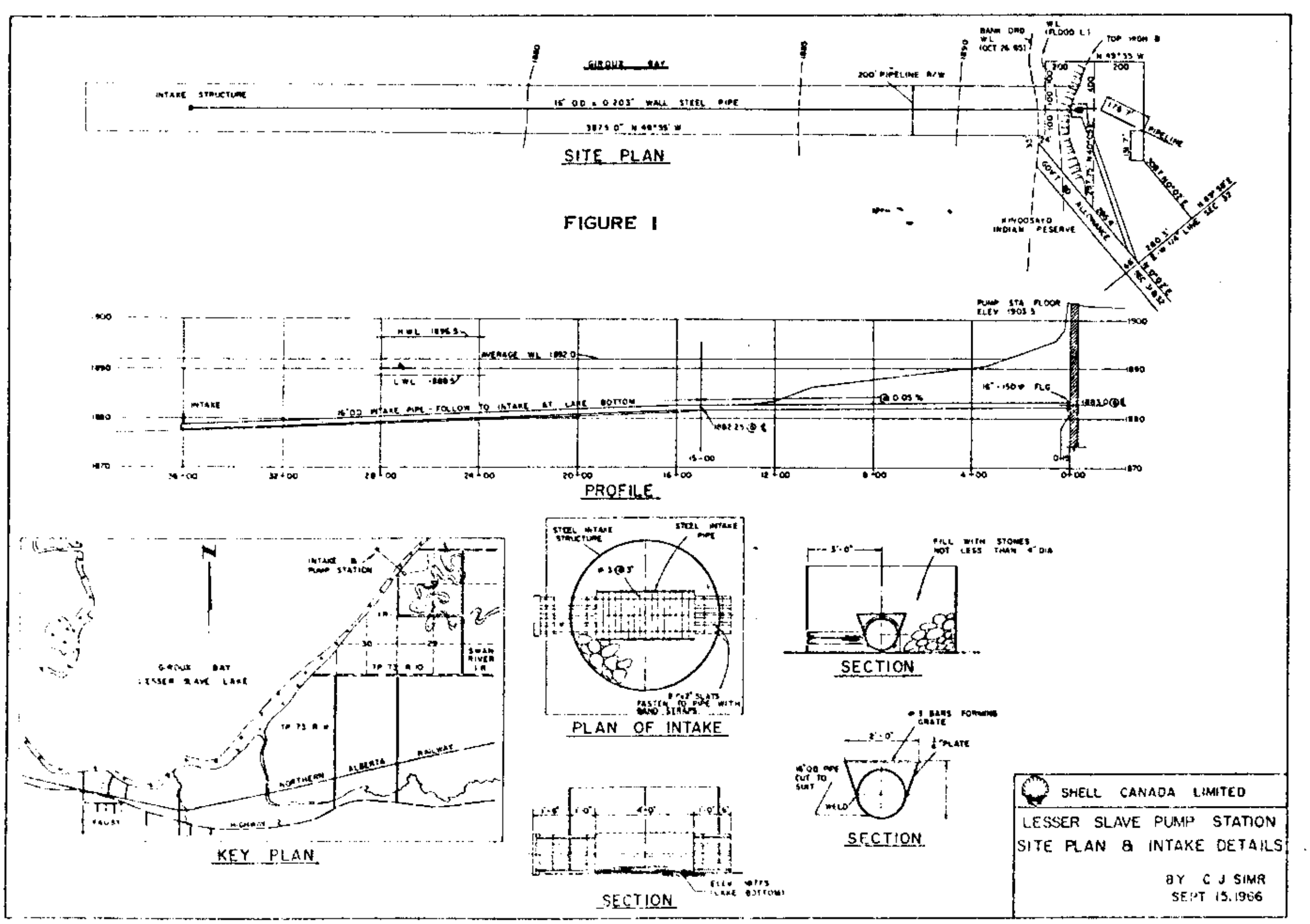


FIGURE 1

CRITICAL PROPERTIES OF PUMP FLUID END MATERIALS

TABLE 1

Material	Chemistry	Heat Treatment	Tensile Strength 10^3 psi	Yield Strength .2% Offset 10^3 psi	Elongation in 2"	Reduction in area	Hardness	Corrosion Resistance to Salt Wtr	Fatigue Strength 10^8 cycle psi
K-Monel 500	63-70% Ni 2 - 4% Al .25-1.0% Ti .25% Max. C 1.5% Max. Mn 2% Max. Fe .01% Max. S 1.0% Max. Si Balance Cu.	Forged water quenched at 1600° F. Preheated to 1100° for 12 hours — cooled at 100° F./hr. to ambient	142-155	97-112	28-25%	50-46%	250 - 285 BHN	Good	51,000 at 155,000 psi tensile
A-70 Titanium	.5% C .15% Ni .2% Fe Balance Ti	Stress relieved at 1000° F.	80 - 90	70 - 75	20-15%	30%	92-100Rb	Good	6,300 at 90,000 psi tensile
316 SS	16-18% Cr 10-14% Ni 2 - 4% Mo .8% C	Annealed	95	35	60%	70%	150 BHN	Good	25,000 at 85,000 psi tensile
Monel 400	66% Ni .12% C .9% Mn 1.35% Fe 31% Cu .15% Si	Annealed	84 - 120	55-100	35-22%	60%	160-225 BHN	Good	40,000 at 120,000 psi tensile

spot pattern (36 injectors) to provide required voidage replacement. Conversion of additional producers was not economical since the field production capability would have been seriously affected. Economic evaluation of a 3,000 psi wellhead pressure system with additional in-fill drilled injection wells and a 5,000 psi wellhead pressure system without additional in-fill drilled injection wells favoured the latter design.

A subsurface water source capable of continuously providing 30,000 b/d of water was rejected after the unsuccessful drilling of several shallow and deep wells within the field area. Other operators' experience in the vicinity also confirmed the lack of a reliable continuous subsurface water source. The Inverness River flowing through the centre of the field was investigated and although limited test results showed a safe withdrawal rate of two cubic feet per second could be attained year-round, the possibility of the river running dry during the winter months could not be ignored. This, together with the wide variation in turbidity during spring run-off, and after frequent heavy rains during the summer dictated the necessity of an off-stream storage. The off-stream storage was to serve as a settling basin as well as ensure a continuous supply during low or no flows in the river. The design and specifications were prepared to contract for the construction of an earth-filled dam. The poor soil conditions of muskeg, till, sand and reworked shale required a conservative dam design. The dam size was to be 1,600 feet long, 60 feet high at the deepest point and 800 feet through the toe with six-to-one slope providing approximately 400 acre feet of reservoir storage. It became evident that a dam of this magnitude, because of weather and soil conditions, could not be built economically in this area at any time and meet the required compaction of 95 to 100 Proctor. An alternative water source was therefore investigated. Lesser Slave Lake offered all the advantages of a reliable, long term, low turbidity water supply at a comparable cost to the Inverness River. In addition, the Slave Lake

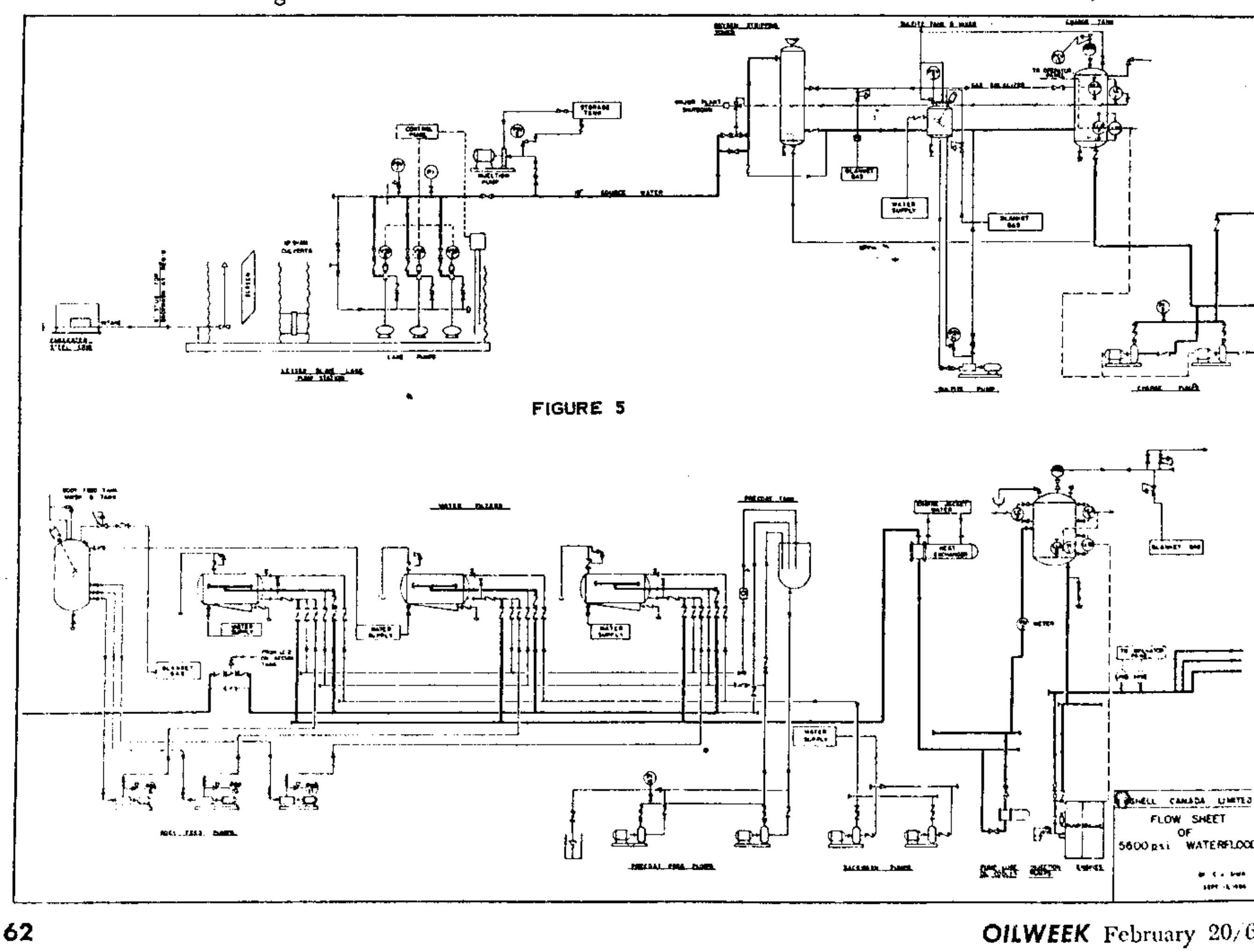
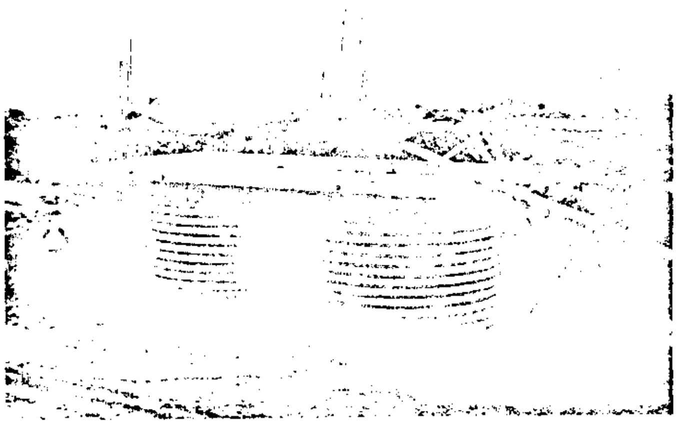
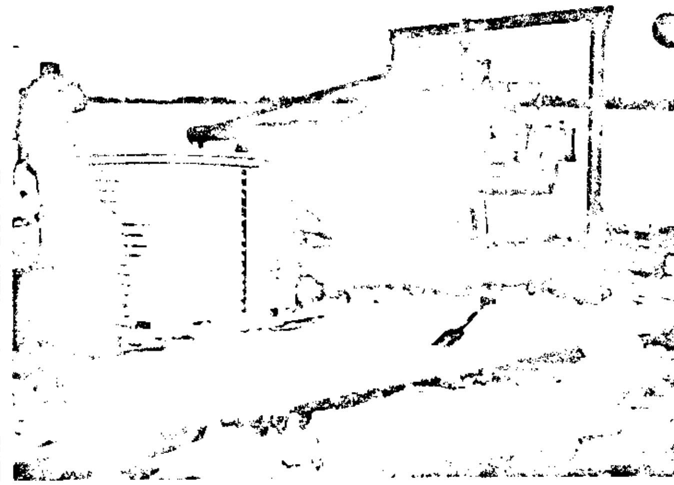


FIGURE 5





On left, (Fig. 3) 10-foot culverts form pumphouse floor. Right, intake cribbing (Fig. 2) is welded to end of intake line.

intake and supply line could be constructed during winter months without major difficulties. Construction on the Slave Lake intake started in January 1966 with 30 degrees F below weather and carried out without undue costs or delays.

Source water intake

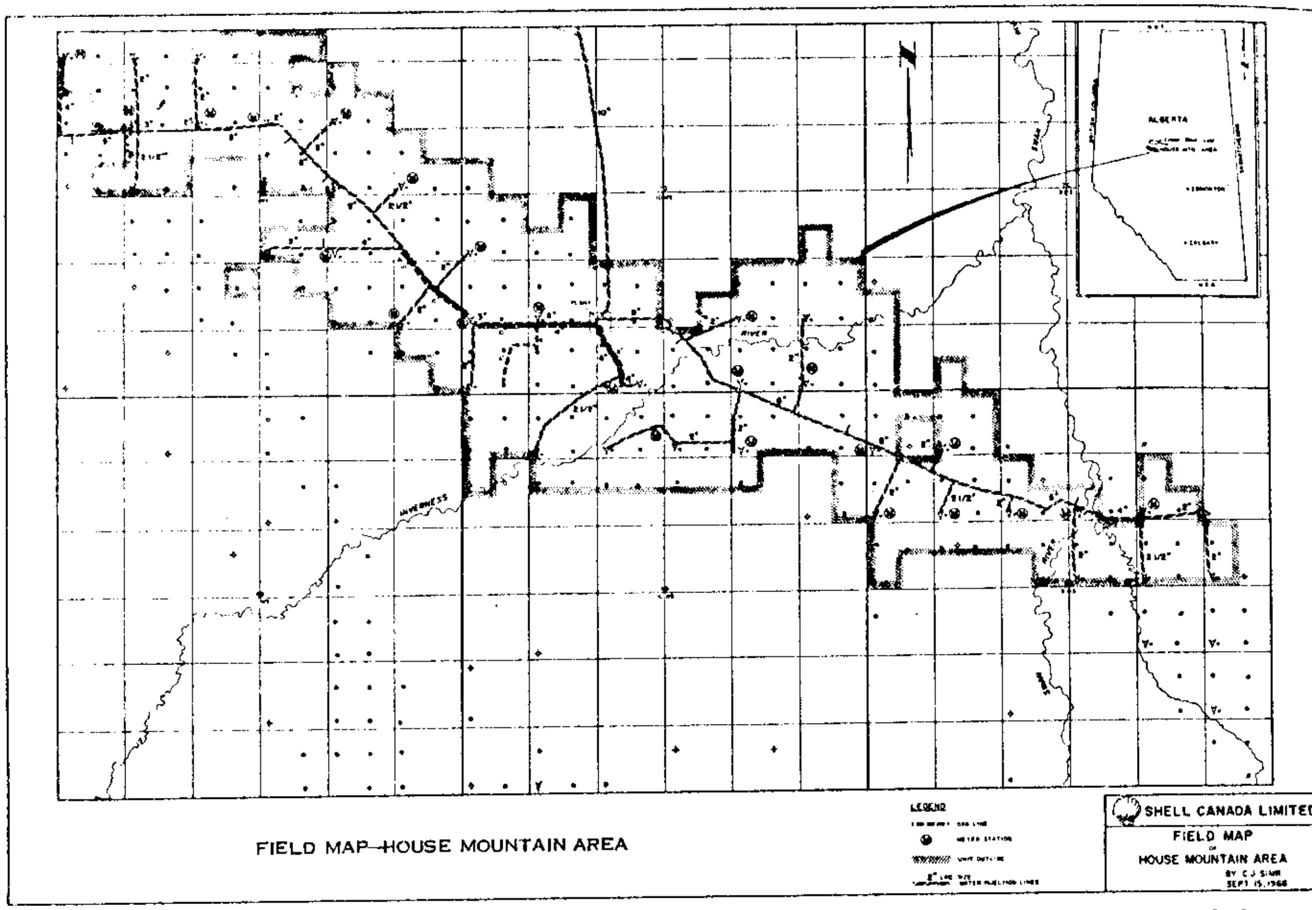
The pump house is located on high ground on the shore of Lesser Slave near Kinuso, Alberta. The lake intake cribbing is located 3,600 feet from the pump station at the lake bottom in 15 to 18 feet of water. The intake cribbing consists of a 36-inch diameter culvert welded to a half-inch steel plate. The intake line passes through the culvert and flares open longitudinally to reduce entrance losses. The pipe opening is covered with grating and 40-pound rock to a depth of two feet. The rocks will restrain the entrance of large pieces of debris. The intake line is 16 inches diameter internally cement-lined and externally coated with 45-50 mils of "Yellow-Jacket" and was installed on the ice under winter conditions. The line is buried for 1,500 feet closest to shore at a depth from 0-25 feet. (See Fig. 1). The ditch was excavated in loosely consolidated sand with four-to-one back slopes to maintain the ditch bottom. The ice was built up from the natural 25-28 inches to 40-45 inch thickness to help carry the 100-ton equipment loads. Wooden piles were driven at 10 foot intervals into the lake bottom for two to three feet, notched at the ice level and frozen into the ice. The piles were on both sides of the ditch line in line with the tracks of the dragline. A wooden mat extending across three piles on each side supported the dragline which permitted the distribution of the load to the lake bottom and so relieve the load on the ice. The remaining 2,100 feet of ice into the lake was ditched with a conventional pipeline ditcher after other ice-cutting (such as chain saws) methods had failed. The line was welded in four 900-foot sections on shore and floated into position. The intake cribbing was welded to the pipe and the pipe lowered into place by controlled submergence. (See Fig. 2). The final tie-in of the intake line to the pump house was done by a diver in 25 feet of very silty water. The pump house at the shore was excavated to 30 feet below grade. The difficulties in pouring concrete in -40 degree F weather and keeping the excavation free from water necessitated the installation of a one-foot-thick precast concrete base. This base was constructed in two sections with provisions for welding two circular culverts in a vertical position. A precast base eight inches thick is welded to the top of the culvert. (See Fig. 3).

The first culvert serves as a small settling basin with manual screens. The water then enters the second culvert through a 24-inch diameter equalizer at the bottom of the culverts. Three 250-hp vertical turbine pumps, electrically driven, are installed in the second culvert. Two pumps provide the design volume of 31,000 bbls. per day at a total head of 1,700 feet. Only two pumps operate at any one time with the third pump being standby. The selection of the lead pump can be made by changing the plug-ins in the automatic control panel. The pumps will shut down on (a) excessive vibration, (b) low water suction level, (c) high-line pressure or (d) power failure. In the event that any one of the above conditions calls for the pumps to shut down, time delays shut the pumps down in sequence (except on power failures) in order to minimize line water hammer. If one pump goes down on vibration the third standby pump will automatically cut in to provide the necessary volume. In the event of power failure, time delays will sequence the automatic restart of the two lead pumps. A pressure relief valve in the pump discharge header provides protection in the event of excessive line pressure and/or water hammer. A controlled-volume pump is also provided to inject bacteriacide into the water supply.

The 23½ mile water supply line from Lesser Slave Lake to the high pressure injection plant is 10¾" by .188" grade X42 cement-lined and Yellow-Jacketed pipe designed for a pressure of 880 psi since the change in elevation between the pump station and the waterflood plant is +1,000 feet. Two air vent valves and a block valve are installed in the supply line at the high points of the line.

Waterflood plant

The waterflood plant was designed to handle a maximum of 31,000 bbls. per day of water at 5,600 psi maximum discharge pressure. (See Fig. 4 and Fig. 5). To minimize corrosion as well as formation plugging by suspended solids, the source water from Lesser Slave Lake is extensively treated. A 72-inch diameter by 42 feet internally plastic coated gas deaerator tower with two ten-foot high packed sections of one-inch ceramic Intalox saddles removes dissolved oxygen in the water by the counter-current flow of natural gas. A gas rate of three to five cubic feet per barrel of water will strip the dissolved oxygen to .3-.5 parts per million.



FIELD MAP—HOUSE MOUNTAIN AREA

The remaining oxygen is scavenged by the injection of sodium sulphite; to ensure the complete removal of oxygen an overbalance of 15 parts per million of sodium sulphite is maintained. All process vessels after the deaerator tower are internally plastic coated and closed, and a 2-3 oz. pressure natural gas blanket is maintained to ensure no oxygen will redissolve in the water. Undissolved solids in the source water are removed be three 500 sq. ft. diatomaceous earth filters. The filters were designed to handle 0.5 gpm per sq. ft. of filter surface area. The filter shell is constructed of SA-285 steel, 100 psi working pressure and coated with epoxy. The filter leaves are constructed of rubber with a steel inner plate and covered with a screen of double twill weave of polypropylene cloth. The DE filters were selected over other types of filters on the basis of desired final water quality with .5 ppm of undissolved solids or less. The source inlet water varies between 20 ppm of undissolved solids in the winter and 40-60 ppm in the summer. The filter outlet water is maintained at .3 to .5 ppm of undissolved solids. Filter runs vary between 100 and 20 hours depending on water quality of the incoming stream.

Injection pumps

Prior to soliciting bids for injection pumps, a questionnaire was sent to 14 major pump manufacturers to obtain engineering information on plunger, turbine and centrifugal pumps for 30,000 b/d at 5,500 psi discharge pressure. Only five manufacturers indicated their capability of meeting the pressure requirements.

The individual pump designs and recommended materials were reviewed in detail with the manufacturers. Basic pump design and material requirements were set out in the bid solicitation. Although initial capital cost of the equipment was important, long-term, trouble-free performance with low maintenance cost and good factory service were equally important considerations in the final selection. The pump requirements were as follows:

a) **Power End** — To avoid gear and bearing failures as well as end thrust loads helical or herringbone gears were preferred. The power end should be manufactured from a casting rather than prefabricated from a plate. A fabricated power end is more difficult to manufacture to the required close tolerances and necessary alignment. Minor misalignment or warpage in the frame would be difficult to detect and could result in operating problems. The pump speed should be limited to 250 rpm if possible to reduce the number of stress reversals and pressure surges in the fluid end and also extend the packing life. Lower speed pumps offer longer life between component failures due to reduced wear.

b) **Fluid End** — The design of the fluid end, the material selection and the quality control during manufacture all play an important part in reducing the frequency of fluid end failures at high pressures. The basic requirements set out were as follows: 1) The pump valve covers should be bolted instead of screwed. A screwed cover will breathe during the pressure reversals. The threads are more apt to wash out and if this occurs to the female thread in the fluid end, a major expenditure is involved in replacing the fluid end. 2) Suction and discharge valves should be independently removable. If one valve is pulled through the opening of the other valve, then hydraulic requirements of the valve may be sacrificed to meet the clearance requirements. 3) Tapered valve seats are not desirable since they contribute to unpredictable stress concentrations in the valve and fluid end and ultimately contribute to early failure. 4) Plungers should be easily removable to reduce maintenance time. Self-aligning plungers will also avoid excessive packing and plunger damage. 5) All intersecting bores should be rounded to 3/32" or preferably ¼" radius to minimize stress concentrations. 6) All fluid end machined surfaces should be smooth and polished to 63 rms or better. From a corrosion-resistance and fatigue properties point of view, Monel 400 or K500 is the preferred material to be used in high pressure fluid ends, if frequent failures are to be avoided. See Table I for properties of various materials. 8) Plungers with a welded-on colmonoy coating will perform better at high pressures than ceramic plungers which tend to spall either from flexing or from fluid penetration. 9) To avoid excessive pulsations and vibrations quintuplex pumps are preferred. The flow variation of quintuplex pumps is approximately one third of that of a triplex pump. 10) The valve entrance velocity should not exceed two to four feet per second. 11) An analog study of the suction and discharge piping was also requested. This study was expected to assist in the design of the piping system to minimize fluid pulsation and eliminate mechanical vibration caused by acoustic-mechanical energy coupling.

The five vertical quintuplex pumps selected and installed at House Mountain met nearly all of the above requirements and after four and a half months of operation, no major failures have occurred. Initial excessive pump and piping vibration was traced to weak pump valve springs which caused a loss in pump efficiency. Packing failures have also occurred, however, with changes in packing material and lubricating oil, a packing life of two to three months is presently being attained. The results of the analog study indicated that suction volume tanks should be installed as close to the pump suction manifold as possible. No suction or discharge desurgers would be required if the discharge from the pump was taken from both ends of the manifold. Actual field operating experience to date is in line with the pulsation and vibration prediction made by the analog study.

Prime Mover

Both electric motors and gas engines were investigated as prime movers for the injection pumps. The lower operating costs of the gas engines over the life of the field favoured their use.

The following engine specifications were set out for long term trouble free operation: 1) The maximum engine speed was limited to 900 rpm. Higher engine speeds require costlier gear reducers as well as increase the wear of working parts. The additional wear would necessitate more frequent shut down for overhaul. 2)

Gas engines run at 900 rpm maximum speed. (Fig. 4)

The engines must be naturally aspirated and the bmep should be limited to 80 psi. These conditions were again set out with trouble-free operation in mind for prolonging the life of the working parts. 3) A solid-state low-tension system was also specified to reduce operating problems. 4) A service factor of 85 percent at maximum load must be maintained. 5) Torsional analysis of the engine power components when coupled to the pump was also requested.

Five 825 bhp gas engines were selected to drive the injection pumps. To date, no operating difficulties have been experienced with any engine components.

Distribution system

The high-pressure pipeline distribution system was installed in November, December 1965 and January 1966. The relatively narrow but long field outline favoured a trunk line distribution system design. The pipe specifications were as follows:

2⅜"	.173 WT	4.07#/ft.	SMLS X52	90,000 ft
2⅞"	.209 WT	5.95#/ft.	SMLS X52	30,000 ft
3½"	.255 WT	8.8#/ft.	SMLS X52	6,500 ft
4½"	.328 WT	14.61#/ft	SMLS X52	30,000 ft
5-9/16"	.405WT	22.31#/ft	SMLSX52	40,000 ft
6⅝"	.482 WT	31.62#/ft	SMLS X52	21,000 ft

The following specifications were set out to ensure the suitability of the pipe for installation under anticipated adverse winter conditions, as well as the necessity to maintain good weldability on heavy wall pipe. 1) % Mn. divided by %C to be greater than or equal to 2.50 2) %C + ¼% Mn. shall be less than 0.55%. 3) The lowest charpy impact value shall be 15 ft. lbs. at 0°F. 4) All pipe shall be hydrostatically tested to 6,000 psig.

Since cement lining had to be applied and handled in freezing weather, tests were conducted on the coating prior to actual start-up. A 20-foot section of two-inch cement lined pipe was placed in a deep freeze where the temperature was maintained at -20 degree F. A bending jack was placed under the middle of the pipe while the pipe ends were restrained. The pipe was bent to give a permanent deflection of four to six inches. Upon examination of the lining, there was no evidence of cracking or spalling except at the point where the jack actually deformed the pipe out of round. As a result of this test, the cement lining of all injection lines was used with the following requirements: i) The pipe spinning time was increased to two times the normal spinning cycle. This ensured the removal of all free water. ii) The steam curing time was 48 hours at 150 - 175 deg. F. iii) After the initial cure, the temperature was gradually reduced to ambient over the next 48 hours. No water was added to the inside coating once the curing was completed.

The pipe was handled in the same manner as during summer with the exception of stockpiling. Any pipe which could not be strung on the right-of-way was left on the high-boy trailer while the tractor returned to the yard for another load. A field tractor strung pipe as required. This arrangement minimized unnecessary handling of the cement-lined pipe.

Normal cold weather welding procedures were employed and when the final line test of 6,000 psi was conducted only two leaks were found. The system has been in service now for six months without any difficulties.

REFERENCES

(1) Engineering Study—House Mountain Engineering Committee, May, 1965.

(2) Water Supply for House Mountain Oil Field — T. Blench and Associates.

THE AUTHOR

C. J. Simr is senior field facilities engineer with Shell Canada Ltd., in Edmonton. He graduated from McGill University in 1954 with a degree in mechanical engineering. In 1960, he obtained a masters degree in business administration from the University of Toronto. He joined Shell in 1961.

This report referred to by H.B. Elder in Virden.
it is not named in the Submission - See page 7 -
in reference to high pressure - high volume water floods

High Pressure Waterflood Halts Rapid Decline

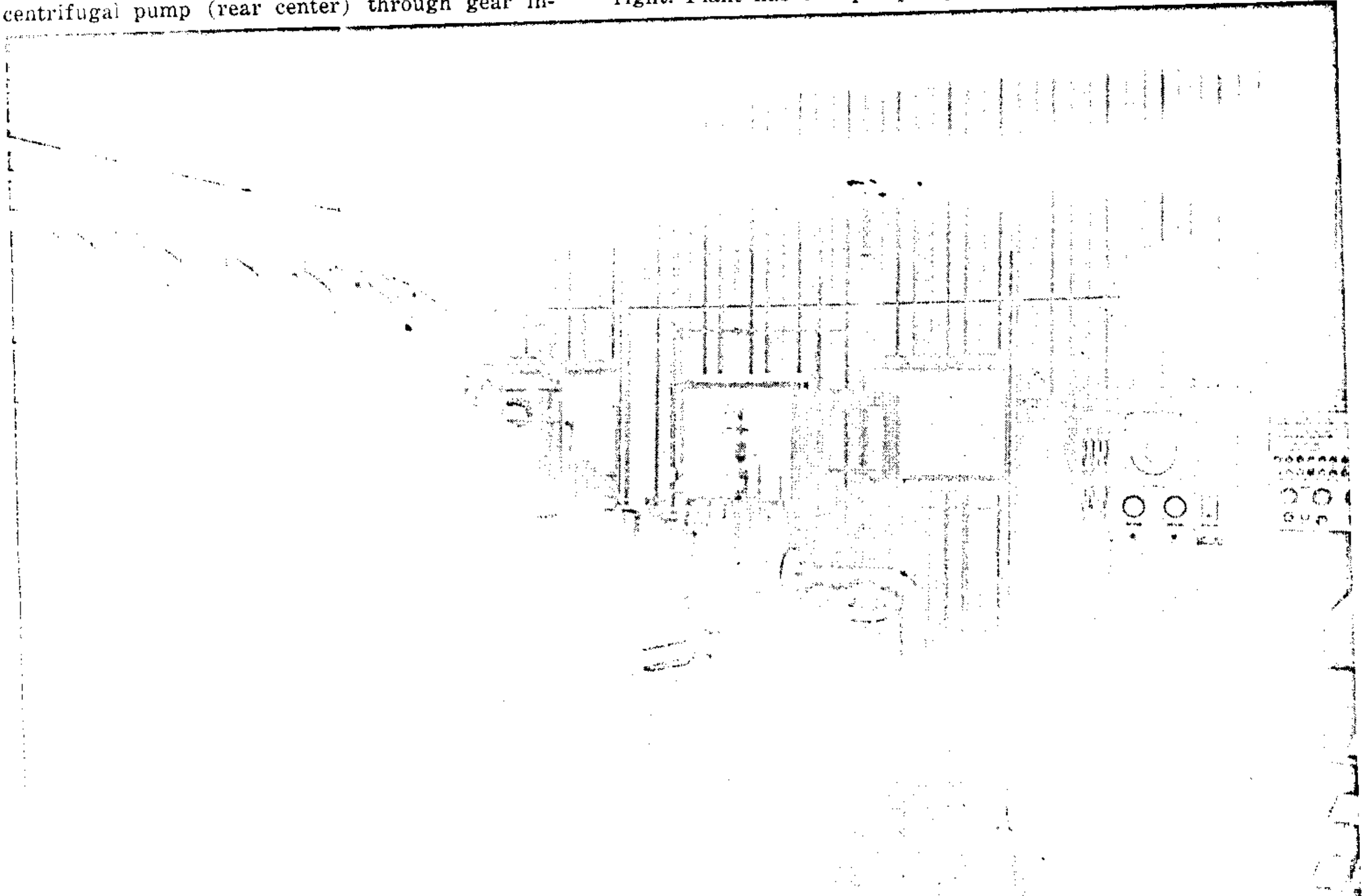
by Tom Covington and Fred Wilcox
Perkins-Prothro Co. Wichita Falls, Tex.

If halting a 30% annual production decline in a difficult reservoir is any criteria, Perkins-Prothro Co. as operators, can call their joint project with Pennzoil Co. in the Jameson Strawn field of Coke County, Tex., a success. Two special-designed engine-powered centrifugal pumps provided the needed injection pressure and rates to continue retarding production decline when previous injection of 20,000 bpd at 2500 psi appeared to be loosing ground.

Each of the two new pumps is capable of handling 22,000 bpd at a differential pressure of 3500 psi with a maximum working pressure of 4500 psi. At this writing, both units are injecting 42,000 bpd at 3125 psi discharge pressure. This volume of water is all that is available at this time. As injection pressures increase to maintain this higher rate, it will be necessary to add booster pumps to reach eventually the 4500 psi discharge pressure for which the pumps were designed.

Some idea of the difficult nature of the reservoir may be found in the reservoir characteristics. Permeabilities of the interconnecting sandstones lenses average only 0.8 millidarcy with the bulk of the 69-ft net pay (varies from 10 to 100 ft) in the order of 0.1 to 0.2 md. Core analysis shows an average porosity of 12.2%, average water saturation of 43.9% and average residual oil saturation of 10.0%. Ultimate primary oil recovery is

Big V-16 cylinder engine at left drives high-speed centrifugal pump (rear center) through gear increaser. Operating and safeguard controls are at right. Plant has two pump-engine units.



calculated to be 7% of the stock tank oil in-place.

The waterflood project described here was installed on the operator's W. C. Blanks lease. Original water injection efforts commenced in October 1959, helped to retard declining production, but, later proved to be inadequate due to limitation of injection rates.

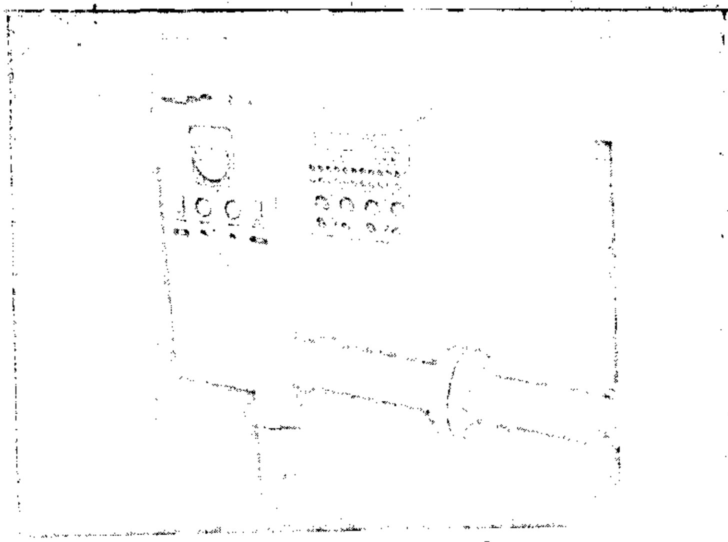
Oil production for the lease in May 1956, amounted to about 100,000 bbl for the month. By mid-1959, production had dropped to 20,000 bbl per month. Extrapolated decline shows that without water injection, production could be expected to drop to less than 10,000 bbl per month by mid-1965. Instead, the original water injection program was started in October 1959, and oil production was maintained around 25,000 bbl per month. With the advent of higher injection pressures and higher rates, available from the new high-pressure, high-volume pump, oil production appears to be increasing from 28,000 bbl/month.

Background of Project

The first Jameson Strawn field well was completed on May 11, 1949, as a marginal producer pumping four bpd. Drilling was stopped until February 1952, when a flush-flowing producer was completed, and development proceeded rapidly. At present, there are 521 oil producing wells in the Jameson Strawn field which covers some 27,500 productive acres. From February 1952, until May 1, 1965, the field has produced nearly 28 million bbls of oil for an average recovery per well of 53,613 bbls and an average recovery per productive acre of 1016 bbls.

The producing formation in the Jameson Strawn field is a body of inter-connecting sandstone lenses occurring in approximately 200 ft of Pennsylvania section topped at about 6050 ft. The lenses pinch-out or shale-out up-dip to the east on the Jameson Strawn Reef field. From the eastern limit, they dip fairly uniformly to the west at a rate of about 150 ft per mile. The Jameson Strawn Reef at its crest is built up into and through the sand section. The sand section thickens rapidly west of the reef crest. The west, north and south limits of the sand are delineated by shale-outs. The reservoir rock is a tan-to-gray fine-grained sandstone with varying amounts of dark gray to black shale partings. The grains are angular to sub-angular, well sorted and are cemented with varying amounts of silica and anhydrite.

The major structural feature of the reservoir is a westward plunging monocline from a crest of the Jameson Strawn Reef field. In this crest area there are several localized gas caps. The



Control brain of pump station are these supervisory operating controls. At left is pneumatic controls for pressure-volume limits; at right are electronic controls for temperature limitations throughout plant.

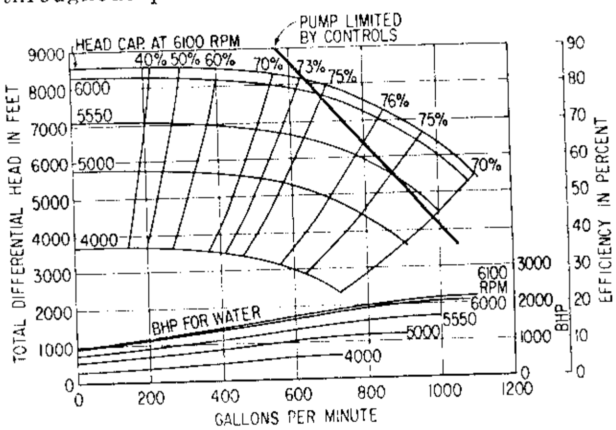


Fig. 1. Performance curves for newly-designed 3 x 8-in. 10-stage centrifugal pumps. Pneumatic controls limit pump output (indicated by heavy sloping line) to the maximum brake hp available from engines.

gas-oil contact has been established at a subsea depth of —3829 ft. A known oil-water contract has not been established on the structurally low west edge of the monocline.

Reservoir fluid of the Jameson Strawn sand is a high gravity saturated crude oil. 60 F API gravity is 49 deg. A reservoir fluid sample showed the crude oil to have 1530 cu ft per bbl of solution gas with a bubble point of 2673 psi. At 2673 psi, the crude oil had a formation volume factor of 1.860. The reservoir has a solution gas drive. Its performance has been marked by high gas-oil ratios which could be expected from a tight sand reservoir and a high solution gas crude oil.

Early Waterflood Efforts

Perkins-Prothro Co. and Pennzoil Co. own 9115 acres of which 7772 acres are productive and include 155 wells. Due to the low permeability of the reservoir, the first question

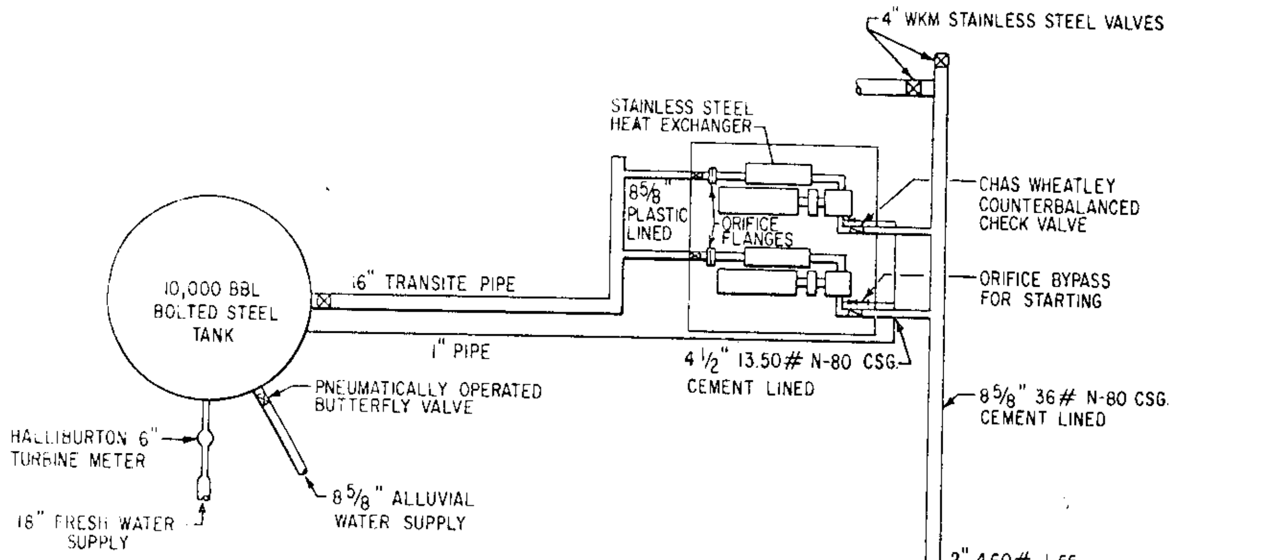
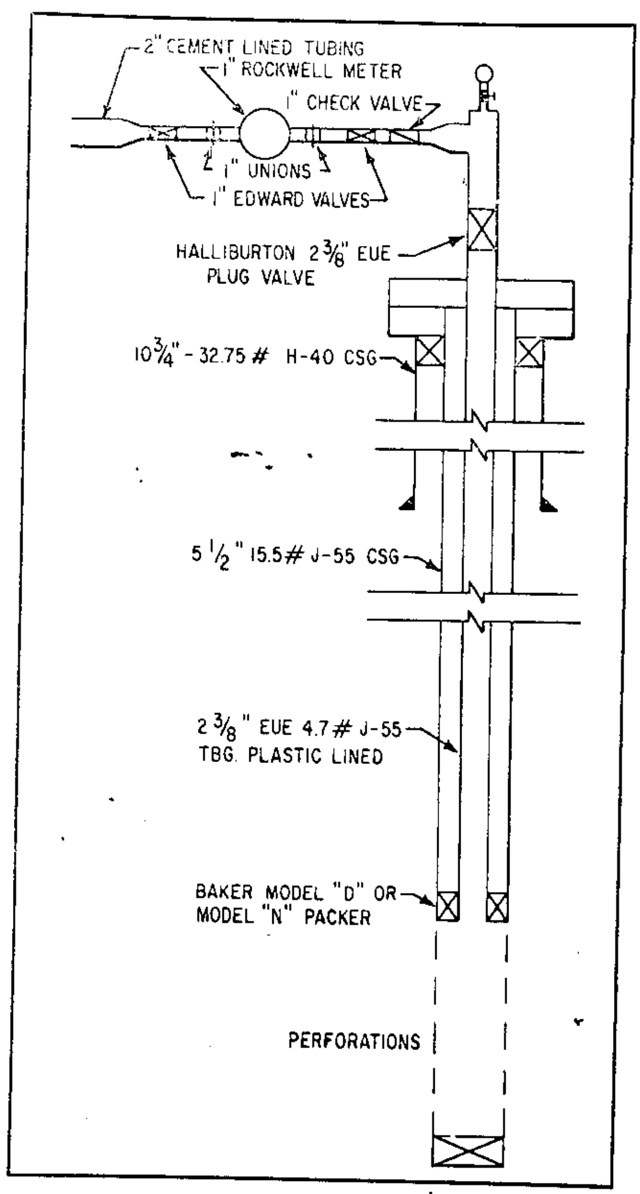


Fig. 2. Hookup at new pump station showing reserve water supply tank, arrangement of engine-pump units and discharge piping. Heat exchangers provide cooling for engines, lubricating oil for engine, gear increaser and pump bearing oil.

Fig. 3. Completion of an injection well to handle high pressures. Water is metered through a 1-in. turbine-type meter and injected down 2⅜-in. plastic-lined J-55 tubing below packer.



unanswered was whether a sufficient volume of water could be injected into the reservoir at a reasonable pressure. A producing well was converted for water injection on Sept. 1, 1957, and water injected into this well until Sept. 1, 1958. During this time, a total of 202,109 bbls of water were injected at a maximum pressure of 2000 psi. Tracer logs were run during injection which indicated approximately 81.2% of the sand was receiving water. Offset wells indicated slight production increases during water injection and tapered off after the project was shut down.

On Oct. 1, 1959, waterflood operations were commenced in the Jameson Strawn by Perkins-Prothro Co. and Pennzoil Co.

The first water pumping station consisted of nine 115-hp engines and nine pumps with a total capacity of 20,000 bpd at a discharge pressure of 2500 psi. Initial oil increases were noted in approximately two months following initial injection. However, these increases did not hold up. Since then, four additional waterflood projects have been initiated.

Water Source

The first injection water was produced from the Cisco formation. It was highly corrosive and necessitated protection of all metal surfaces by either cement lining or plastic coating. Parts that could not be coated were made of

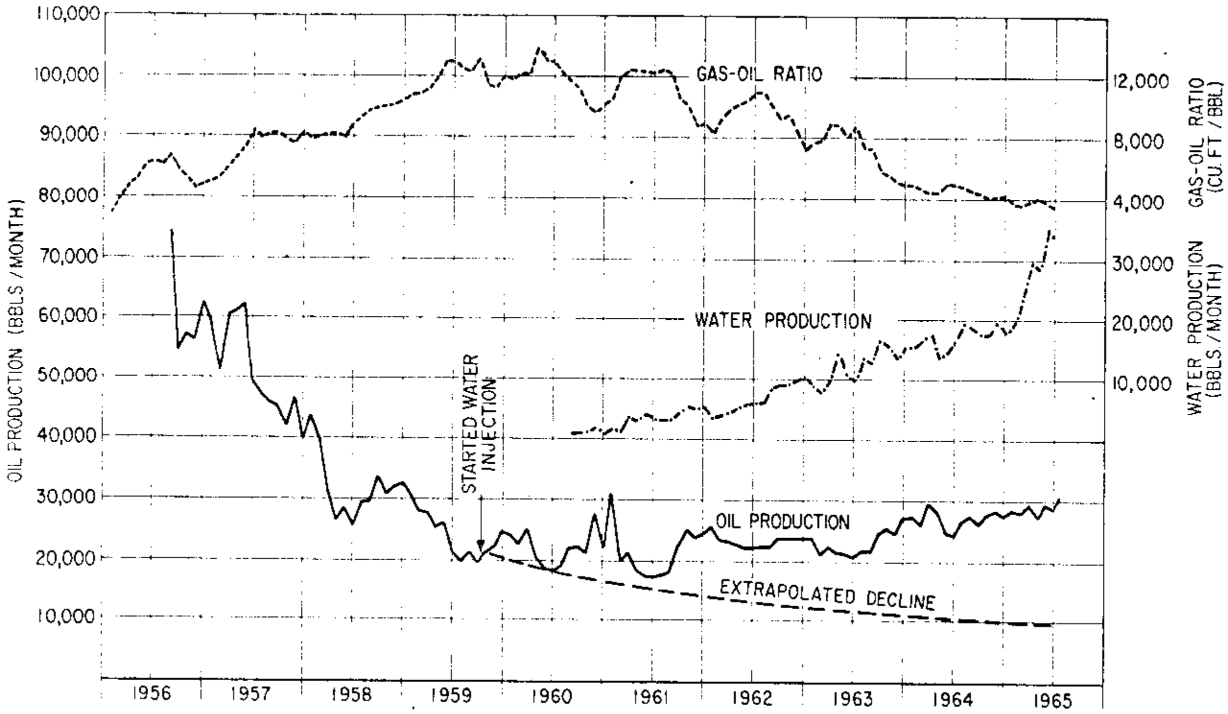


Fig. 4. Production history of the W. C. Blanks lease of the Jameson Strawn field where a high-pressure water injection program initiated in 1959 halted the extrapolated oil production decline of this lease.

aluminum bronze, stainless steel or Monel. A total of four wells were drilled for water supply. One of the wells testing the Cambrian sand at 8000 ft was dry.

During February 1962, alluvial water supply was developed along the Colorado River with a capacity of 15,000 to 20,000 bpd. At this time, the Cisco water supply was shut down. This alluvial supply was sufficient until the new plant was installed in December 1964. Additional water was obtained from The Colorado River Municipal Water District from Lake J. B. Thomas and treated in Sun Oil Co.'s plant at Silver, Tex. Volume contracted for is 25,000 bpd to be increased later to 35,000 bpd.

Analysis of Injection Problem

Since inception of waterflood operations, lease oil production has been fairly constant. This represents a substantial oil increase since the primary decline was approximately 30% per year. At the present time, 68% of the total lease production is due to water injection.

The area under waterflood operations was originally developed on 40-acre spacing and the injection pattern chosen was a five-spot. Calculated voidage totaled 500,000 bbl per well or 1,000,000 bbl per 80-acre five-spot. These high voidage figures were due to the reservoir conditions, i.e., high initial gas in solution and the bubble point being original reservoir pressure. For instance, of the 500,000 bbl voidage per well, only 70,000 bbl were stock tank oil.

When calculated fill-ups were reached and the producing wells were not responding as anticipated, it was determined that the water injection efficiency was only 25% due to the north-east south-west fractures system of the field. Water has been traced three to four miles from injection wells. To overcome this situation, it was decided during May 1963, to increase pressure from 2000 to 2500 psi on seven of the injection wells. With this increase in pressure, lease oil production increased approximately 25%. This was encouragement enough to justify increasing pumping plant facilities.

New Pumping Facilities

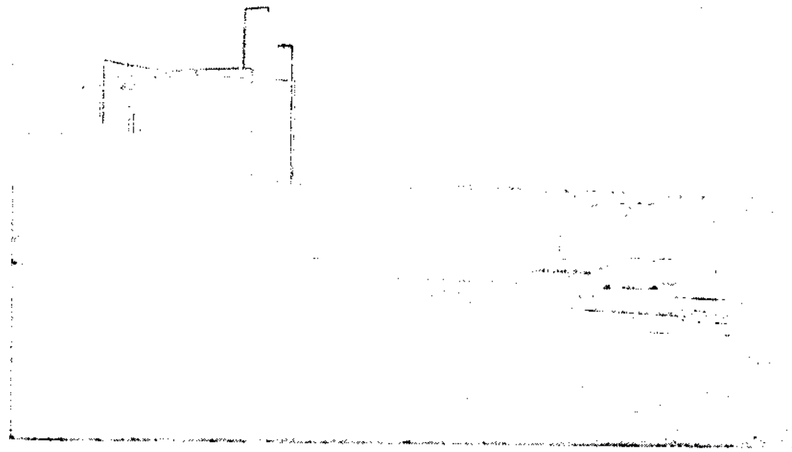
To handle the high volumes and pressures anticipated, horizontal, split-case 10-stage 3 x 8½ centrifugal pumps were chosen. These pumps will handle 22,000 bpd each at a differential pressure of 3500 psi, with a maximum working pressure of 4500 psi. They are constructed of 316 stainless steel throughout and are designed to operate at a speed of 6100 rpm. These are the first two pumps of this new design made. Prime mover for each pump is a new design 1850-hp, 10 x 10½-in., turbocharged V-16 cylinder gas engine rated at 850 rpm. The pump and prime mover are connected by a speed increasing gear with ratio of 1:7.17, or 850 rpm input speed to 6100 rpm output speed. The gear is designed for 2000 hp with a service factor of 1.75, and

Central station is equipped with this lease automatic custody transfer unit which controls the flow of fluids from each satellite station, makes appropriate readings and records.

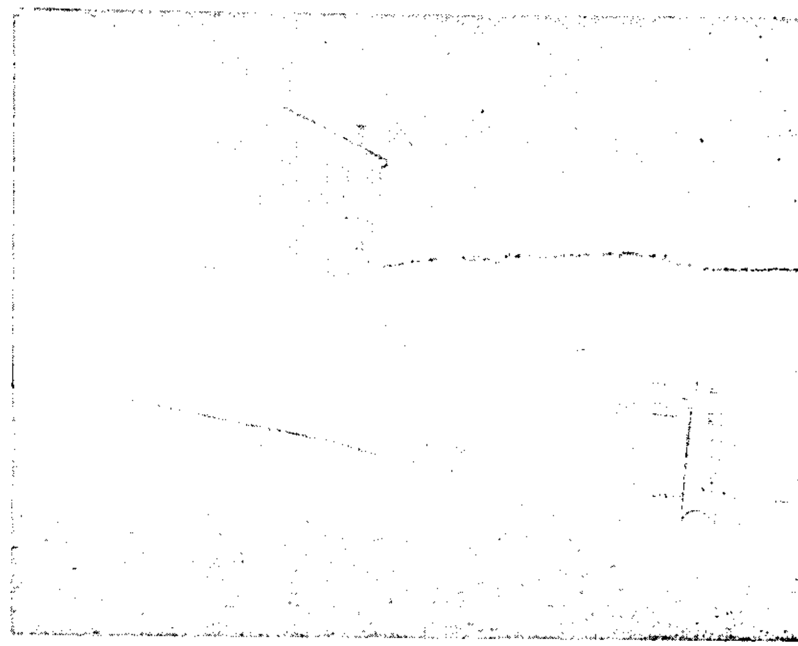
was especially engineered for this project. This plant was built by White Superior under a turnkey contract and is capable of pumping 50,000 bpd at 3000 psi or 44,000 bpd at 3500 psi. It was designed also to operate eventually at 4500 psi if necessary. To achieve 4500 psi pressure, it will be necessary to install 1000 psi booster pumps to the suction of the present pumps. At the present time this plant is handling 42,000 bpd at 3125 psi which is all the water supply available at the present time. The original plant is being used as a produced water plant, which is re-injecting produced water in the producing formation in a separate system.

Pump Station Controls

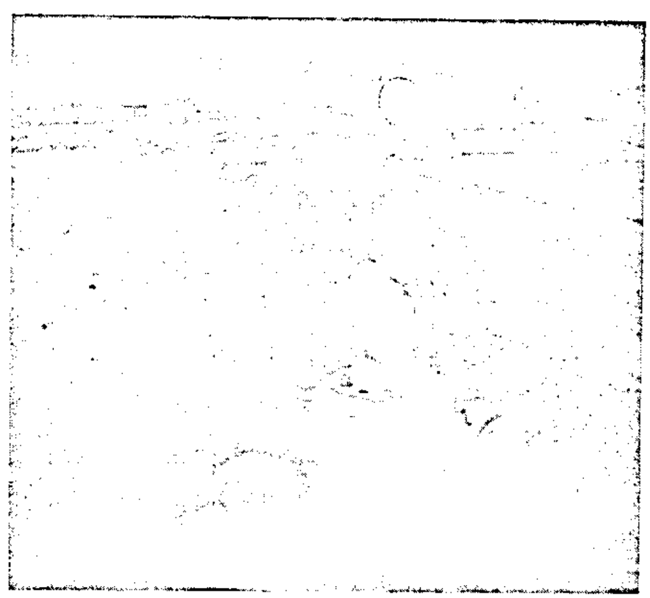
The pump station is attended only seven hours daily, so it was necessary to install controls to protect the equipment during the unattended time. The two different supply waters entering a 10,000-bbl epoxy-lined tank are controlled by two different systems. The fresh water supply coming from Sun Oil Co.'s treating plant is controlled by a snap-acting level control switch. When water in the tank reaches a certain level, a mercury switch closes and sends a signal to an electrical-pneumatic operated valve on the discharge of the centrifugal pump at Sun's plant some 5$\frac{1}{2}$ miles away. This is a three-way, two-position, butterfly valve which diverts the flow and allows the pump to circulate back to their tank. When the



One of the satellite stations which handle produced fluids artificially lifted by hydraulic pumping.



Both pumps discharge into this high-pressure header made of 8$\frac{5}{8}$-in. N-80 casing and cement lined for corrosion protection.



Typical injection well hookup to handle water from the new pump station at pressures over 3000 psi.

level drops in the tank, the circuit is interrupted to allow the valve to return to its original position and deliver water again.

This type of control was used for two reasons. First, the 18-in. water supply line was designed for very little back pressure. Second, the centrifugal pump at Sun's plant is operated by a two-cycle gas engine which would have to be started manually if shut down.

The alluvial system is controlled by a pneumatically controlled butterfly valve which operates as a throttling valve as the level in the tank changes. At a pre-determined pressure, the vertical turbine pump which supplies the alluvial water, is shut down so that it would not be pumping against a closed valve.

Emergency shut down switches for the new centrifugal pumps, gear and driving engine are enclosed in a panel and operated by the pulse generator on each engine. They do not require an outside power source. Each switch has a tattletale to indicate cause of a shutdown. These switches determine bearing temperatures, cooling water temperature, cooling water pressure, oil pressure and temperature, pump suction and discharge pressures. The engine control panels include a scanning device which indicates individual cylinder temperatures and exhaust temperatures. If temperatures become too high, the affected engine is shut down.

Engine Overload Control

Of concern from the beginning was a way to prevent the pump from overloading the engine. A decrease in pump pressure when operating at maximum horsepower would cause the engine to overload. It was decided to install a pneumatic panel to control engine speeds. This panel consists primarily of an orifice plate on the suction side of the pump which indicates volumes. A pressure instrument on the pump discharge indicates discharge pressures.

These differentials and pressures are converted to a 3-15 psi signal and transmitted to the panel. By pneumatic computing, this signal is converted to a second pneumatic signal sent to the engine governor to control engine speed. The desired volume may be set on a dial on the panel and the engine will maintain this volume. If conditions are such that the engine is overloaded, as calculated from the pump curve, the panel will slow the engine down until the maximum horsepower curve is reached.

Also included in the panel is a low flow shut down switch. If flow falls below 250 gpm, this

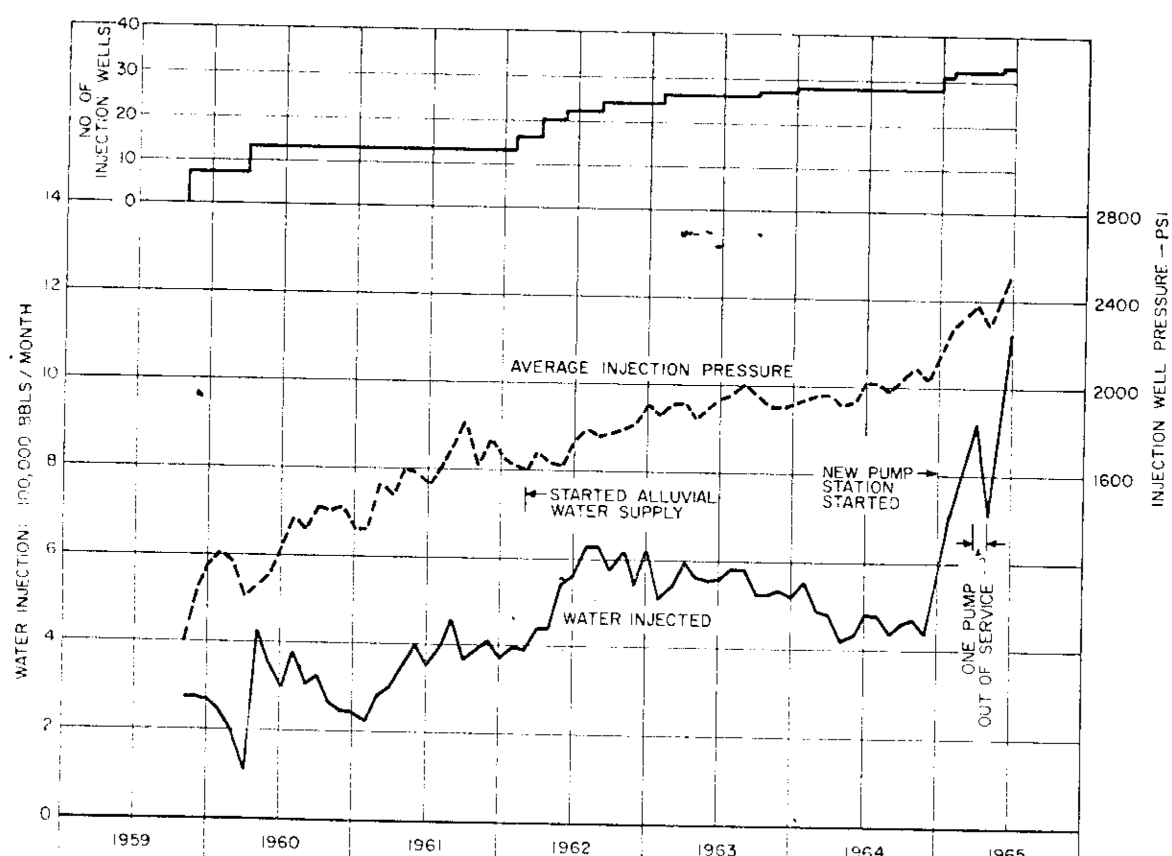


Fig. 5. Water injection history of the W. C. Blanks lease. Note steady decline of injection rates with former pump station. Rapid increase of injection rates are noted immediately after start-up of new pumping facilities. Drop in April was due to taking one pump out of service.

switch will shut the engine down to prevent damage to the pump because of the heat generated in the pump at low volumes.

In conjunction with the above shut down switches is an alarm system. In case of engine shutdown for any reason, a circuit is energized to set off a rotating beacon located on top of the 10,000-bbl tank. This beacon may be seen from almost any place in the field. When the plant is unattended, this alarm will ring three different phones in the field camp in rotation. If these phones are not answered, it will dial and ring a phone in Colorado City, Tex. If an answer is still not obtained, the sequence will be repeated until a phone is answered. When the phone is answered there is an audio tone which indicates trouble at the plant.

Water Distribution System

To contain the high injection pressures anticipated, it was necessary to install casing and tubing as injection lines. The main line out of the plant is 8⅝-in., 36-lb, N-80 casing. Main laterals off of this line are 7-in., 29-lb and 32-lb, N-80 and P-110 casing, 5-in., 19.50-lb, Grade E drill pipe, 2⅞-in., 6.50-lb, N-80 tubing and 2⅜-in., 4.7-lb, J-55 tubing. All injection lines were cement lined and welded. High pressure water is metered at individual injection wells through 1-in., turbine-type meters. The 2⅜-in. tubing in each injection well is plastic-coated and set on a production packer with a latch-down mandrel also plastic coated.

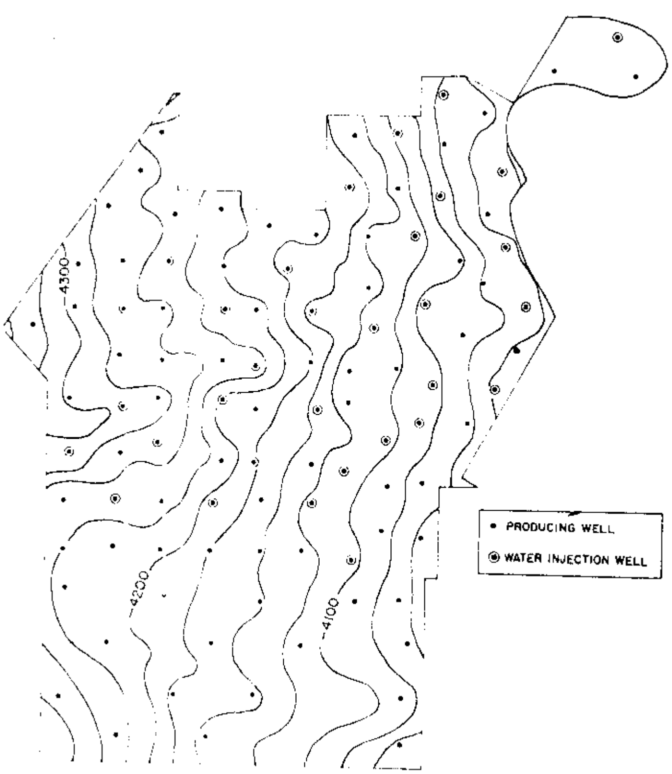


Fig. 6. Injection pattern in relation to producing wells shown on contour map of the pay sand within the boundary of the W. C. Blanks lease. Depths are sub-sea.

Measuring Results

The final objective is to increase oil production from the W. C. Blanks lease. Earlier water injection operations did halt a drastic production decline, but limited volumes and limited injection pressures (2500 psi) appeared to be losing ground in this rate-sensitive reservoir with a high voidage factor. It appeared to be a matter of injecting water at a high enough rate to fill the voids and improve oil recovery rates. This meant injecting greater volumes of water . . . which also meant higher injection pressures.

The new pump station has made the later objective successful. After the usual operational problems were corrected, the pump station began design capacity operations of 1,260,000 bbl per month in June 1965. It is much too early at this writing to evaluate the new high-pressure, high-volume injection operation as a commercial success. It may take months before the effects are felt through this extremely tight formation and show up as sustained oil production increases. The first engineering objective has been achieved by the higher rates. With this difficult hurdle completed, an optimistic outlook is maintained and it is anticipated that recovery will be doubled.

About the Authors

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Tom Covington is general superintendent for Perkins-Prothro Co. of Wichita Falls, Tex. He was graduated from The University of Oklahoma in Jan. 1949 and worked for Tidewater Oil Co. in Venice, La. and later transferred to Victoria, Tex. as a district engineer. He joined Perkins-Prothro in 1954 at Silver, Tex., and was made general superintendent in 1958.

Fred Wilcox is an engineer for Perkins-Prothro Co. at its Wichita Falls, Tex. headquarters. Following graduation from The University of Tulsa in Jan. 1950, he became a roughneck on a Parker Drilling Co. rig, and later that same year joined Deep Rock Oil Co. as an engineer in Tulsa, Okla. He was transferred to Kansas in 1952 as a waterflood engineer. In March 1955, he was employed by Perkins-Prothro Co. to work in the Jameson Strawn field of Coke County, Tex., and was moved to the Wichita Falls office in 1961. ■