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FOSSIL ENERGY

COMMERCIAL SCALE DEMONSTRATION ENHANCED OIL RECOVERY BY MICELLAR-POLYMER FLOOD

Final Report

By
D.F. Stover

November 1988

Performed Under Contract No. AC19-78ET13077

Marathon Oil Company
Findlay, Ohio

Bartlesville Project Office
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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

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SUMMARY

The M-1 Project, partially funded by the Department of Energy, is a commercial-scale test of the Maraflood enhanced oil recovery process. This report represents the final evaluation of the M-1 Project and includes discussions on project operations, production history, performance evaluation, and economic evaluation.

Micellar slug injection began in February, 1977. After 10% of a pore volume (PV) was injected into both the 2.5-acre and 5.0-acre pattern areas, mobility buffer (Dow 700 Pusher™ polymer) in tapered concentrations followed.

The 2.5-acre pattern area became uneconomic at the end of 1986 after injection of 104.7% PV of mobility buffer and 32.9% of drive water. The 2.5-acre pattern area recovered a total of 804,400 barrels of oil or 22.2% of the 40% post-waterflood oil saturation.

Injection of Dow 700 polymer continues on the 5.0-acre pattern area at a 200 ppm concentration. Through December, 1986, total polymer injection on the 5.0-acre pattern totaled 71.6% PV, and oil recovery totaled 494,700 barrels or 16.3% of the 40% post-waterflood oil saturation. With an estimated four years of economic life remaining, the 5.0-acre pattern area is forecasted to recover 583,000 barrels of oil or 19.2% of the post-waterflood oil saturation.

Total project ultimate oil recovery is forecasted to be 1,387,400 barrels of oil or 20.8% of the 40% post-waterflood oil saturation. This recovery is significantly lower than the original total project prediction of 36.6%. That figure was based on predicted recoveries of 38% from the 2.5-acre area and 35% from the 5.0-acre area. Poor vertical and areal sweep efficiencies caused by reservoir heterogeneities are primarily responsible for the lower than anticipated oil recovery.

An economic analysis of the M-1 Project shows a $4.3 million profit, a 6.1-year payout, and an 8% rate of return. This analysis includes the $14 million in investment funds recouped from the Department of Energy as part of a tertiary recovery incentive program.

™Trademark of Dow Chemical Company

CONCLUSIONS

1. Ultimate oil recovery from the total project is forecasted at 1,387,400 barrels or 20.8% of the 40% post-waterflood oil saturation.

2. The 2.5-acre pattern area became uneconomic at the end of 1986 after recovering 804,400 barrels of oil or 22.2% of the 40% post-waterflood oil saturation.

3. Approximately four years of economic life remain on the 5.0-acre pattern area. Ultimate oil recovery is forecasted at 583,000 barrels or 19.2% of the 40% post-waterflood oil saturation.

4. The 2.5-acre pattern area experienced an oil cut increase at 18.6% PV of Maraflood fluids injected. The 5.0-acre spacing did not experience an oil cut response until 24.1% PV injected.

5. An economic analysis using actual cash flow shows that, even though the 2.5-acre pattern area recovered 3% more of the post-waterflood oil saturation than the 5.0-acre area is projected to recover, the 2.5-acre area had only slightly better economic parameters.

6. A hypothetical economic evaluation, assuming identical oil price schedules, shows the 5.0-acre area having better economic parameters than the 2.5-acre area. Thus, the extra recovery of 3% of the post-waterflood oil saturation from the 2.5-acre area did not justify the costs of its additional wells.

7. The total M-1 Project shows a net profit of $4.3 million before federal income tax, which includes $14 million received from the Department of Energy.

8. Ultimate oil recovery for the M-1 Project was predicted to be 38% of the 40% post-waterflood oil saturation for the 2.5-acre area and 35% for the 5.0-acre area. The lower-than-anticipated oil recovery is primarily due to poor vertical and areal sweep efficiencies caused by reservoir heterogeneities.

9. Observation well logs indicated the presence of stacked-sand bodies which adversely affected vertical sweep efficiency.

10. Evaluation of core tests supported the presence of at least three zones in the Robinson sandstone. Further analysis indicated better oil displacement in the zone of highest reservoir quality.

11. The use of a tritium tracer identified directional flow trends, indicating an areal sweep inefficiency. Six of the ten test patterns showed a flow trend in the northeast-southwest direction, parallel to the direction of deposition of the sandstone reservoir.

12. Post-waterflood oil saturation appeared to have the largest impact on recovery performance of production wells. Wells located in areas of low oil saturation (indicating good waterflood performance) showed the poorest performance due to less available oil for tertiary recovery.

13. Hydraulic fracturing was the most effective method of injection and production well stimulation.

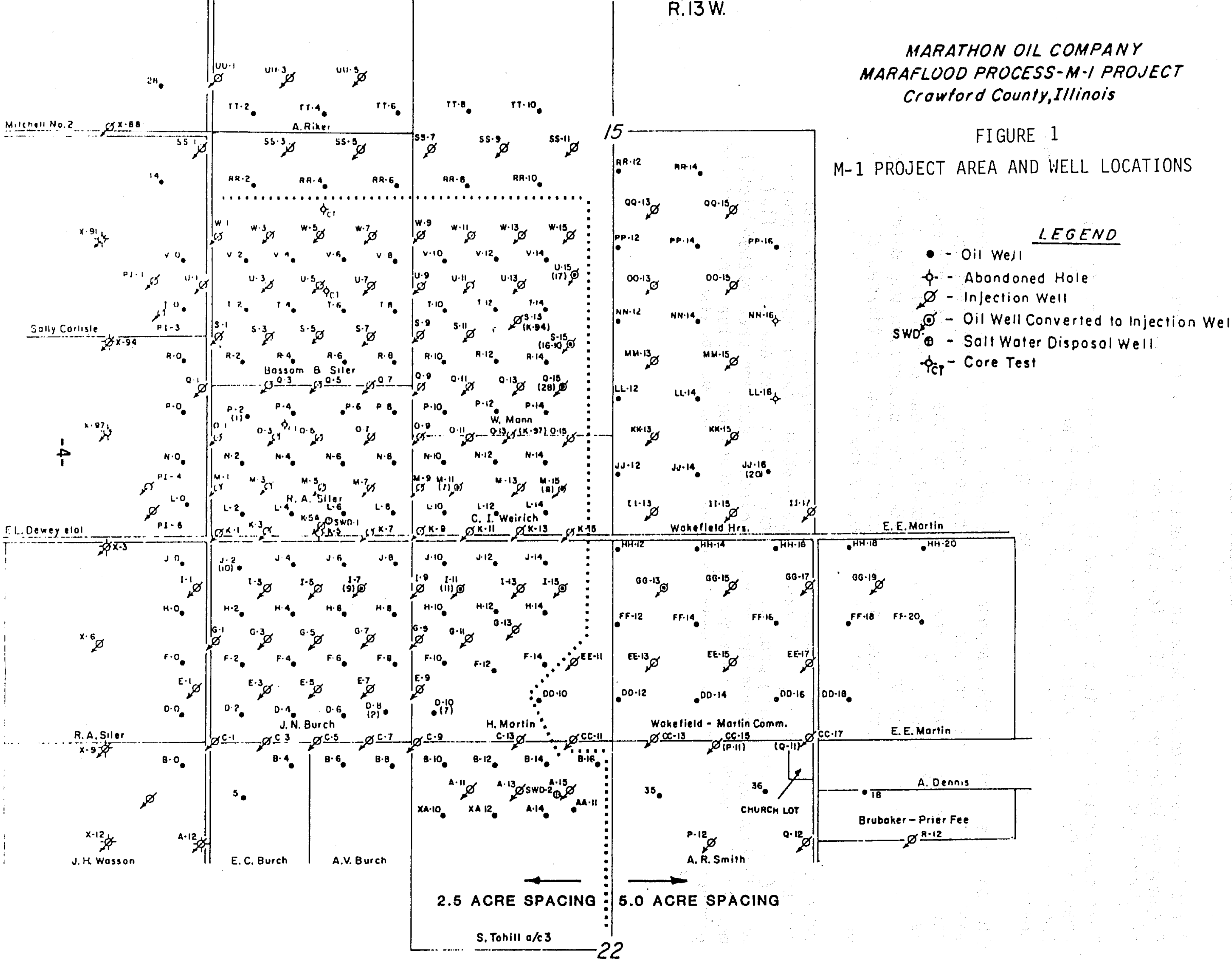
INTRODUCTION

A contract was executed between the Department of Energy and Marathon Oil Company on September 30, 1976 for the purpose of a commercial-scale test of the Maraflood enhanced oil recovery process.

This commercial-scale test, known as the M-1 Project, is located in Crawford County, Illinois. The project, which was partially funded by the Department of Energy, encompasses 407 acres developed on 2.5- and 5.0-acre spacings. Figure 1 shows the location of the project wells.

The oil reservoir is the Robinson sandstone, a meandering river deposit with migrating point bars occurring between depths of 750 feet and 1,000 feet. A summary of the average parameters for the net reservoir section is as follows: thickness of 27.8 feet, geometric mean permeability of 76.9 md, and porosity of 18.9%. After connate water saturation was determined from electric log data, material balance calculations estimated the post-waterflood oil saturation to be 40% of the reservoir pore volume.[1]

This report is the final evaluation of the M-1 Project. A discussion of project operations along with associated problems encountered are presented. A section regarding project performance includes analysis of fluid distribution using streamline maps, a selected pattern area mathematically modeled for performance behavior, and a discussion of actual and predicted performance. Finally, an economic analysis of the M-1 Project is presented.



MARATHON OIL COMPANY
MARAFLOOD PROCESS-M-1 PROJECT
Crawford County, Illinois

FIGURE 1
M-1 PROJECT AREA AND WELL LOCATIONS

PROJECT OPERATIONS

Fluid Injection

Development of the project began in late-1974. Micellar slug injection was initiated in February of 1977 and was completed after injection of 10% of a pore volume (PV) into both the 2.5- and 5.0-acre patterns. Dow 700 Pusher Polymer injection began in November, 1978 and was completed in the 2.5-acre pattern area in September, 1984 after a total of 104.7% PV of polymer in varying concentrations was injected. This was followed by 32.9% PV of drive water through December, 1986. A total of 71.6% PV of polymer has been injected into the 5.0-acre pattern area as of December, 1986. Table 1 shows the completed fluid injection sequence for the 2.5- and 5.0-acre pattern areas through December, 1986.

Figures 2 and 3 show the injection rate and plant injection pressure for the 2.5- and 5.0-acre pattern areas, respectively. Early in 1979, average plant pressure in both the 2.5- and 5.0-acre pattern areas exceeded 650 psig which approaches wellhead formation parting pressure. In March of that year, polymer was detected in two 2.5-acre pattern production wells, J-8 and J-12. As a result, the injection rates of offset injection wells I-15 and K-7, believed to have pressure parted, were decreased from 2.5 to 2.0 barrels per day per net foot (BPDNF). Pressure parting is usually indicated by a rapid rise in injection rate with a corresponding drop in injection pressure. Rate reduction has proven to be a satisfactory technique for restoring the well to normal operating conditions.[2]

At the end of March, 1981, plant pressure was again reduced from 670 psig to 650 psig to prevent additional pressure parting of injection wells. The pressure decrease resulted in a drop in the 2.5- and 5.0-acre injection rates of approximately 890 and 150 BPD, respectively.[3]

The decrease in injection rate on the 2.5-acre spacing beginning in 1985 (Figure 2) is the result of shutting in uneconomic injection wells.

A discussion of injection and production well stimulation techniques and production well failures is presented in Appendix A.

TABLE 1

M-1 PROJECT FLUID INJECTION SEQUENCE

(Through December, 1986)

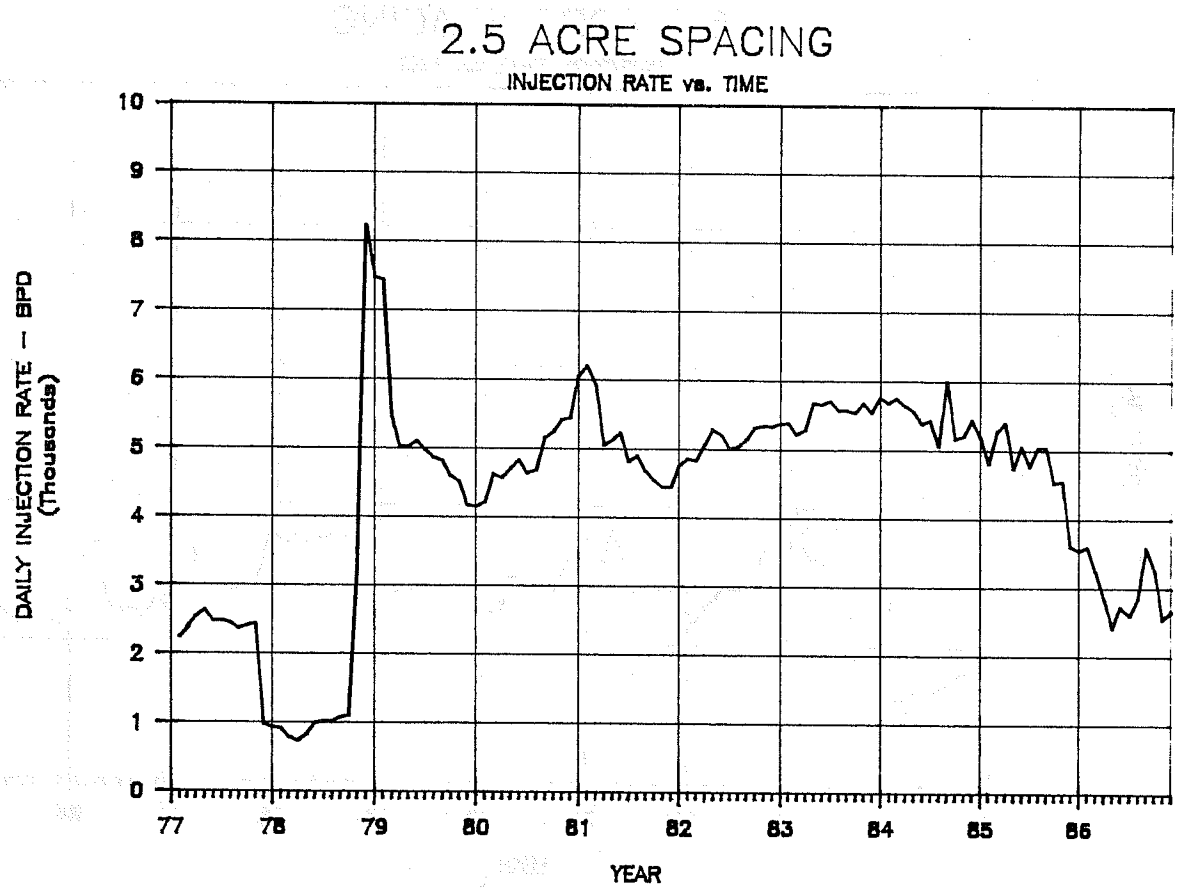
2.5-Acre Pattern Area

Fluid Type	Polymer Conc (ppm)	Cumulative Inj (% PV)	Date Initiated
Micellar Slug	-	0-10	February, 1977
Dow Pusher 700	1,156	10-21	November, 1978
Dow Pusher 700	800	21-40	May, 1979
Dow Pusher 700	625	40-72	July, 1980
Dow Pusher 700	411	72-84	May, 1982
Dow Pusher 700	200	84-94.7	January, 1983
Dow Pusher 700	100	94.7-104.7	August, 1983
Dow Pusher 700	50	104.7-114.7	February, 1984
Fresh Water	-	114.7-147.6	September, 1984

5.0-Acre Pattern Area

Fluid Type	Polymer Conc (ppm)	Cumulative Inj (% PV)	Date Initiated
Micellar Slug	-	0-10	February, 1977
Dow Pusher 700	1,156	10-21	November, 1978
Dow Pusher 700	800	21-40	January, 1980
Dow Pusher 700	625	40-72	March, 1982
Dow Pusher 700	411	72-81.6	September, 1985

FIGURE 2


2.5 ACRE SPACING
INJECTION RATE vs. TIME
DAILY INJECTION RATE — BPD
(Thousands)
10
9
8
7
6
5
4
3
2
1
0
77
78
79
80
81
82
83
84
85
86
YEAR

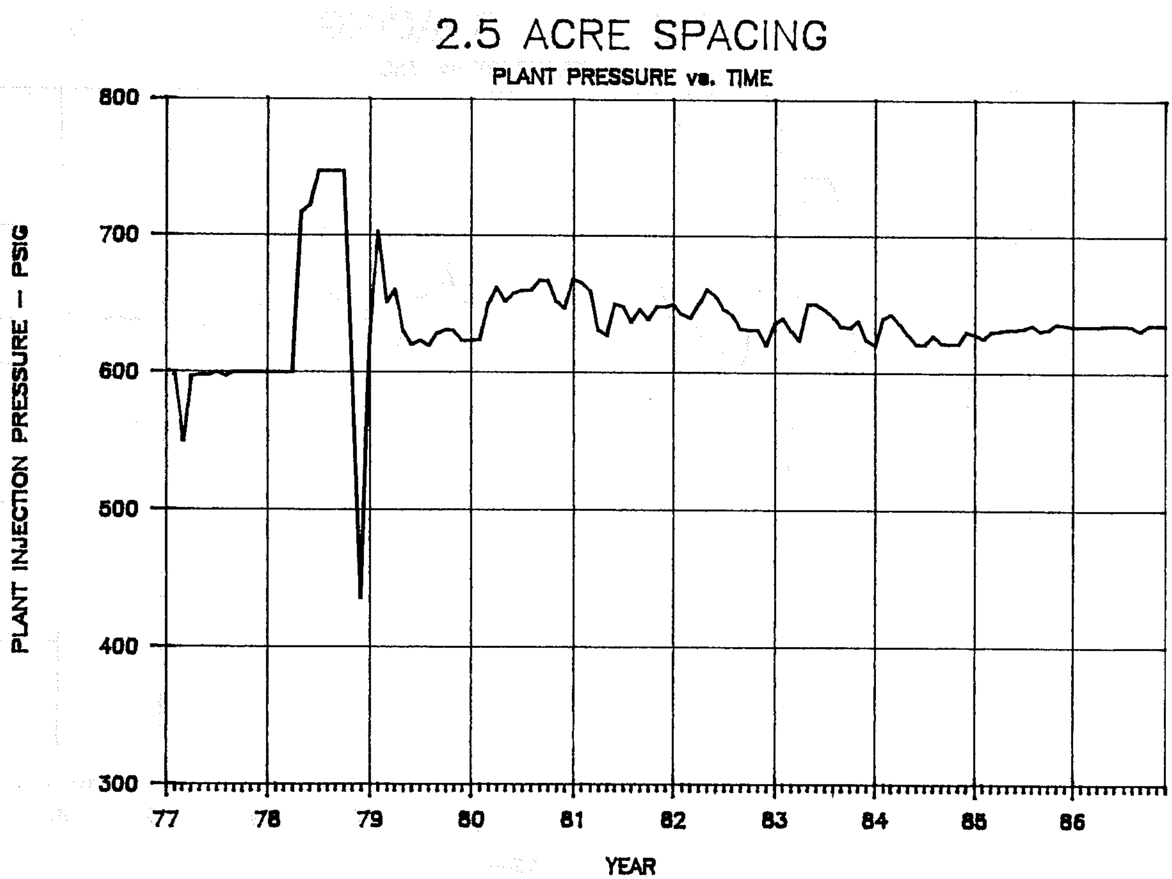
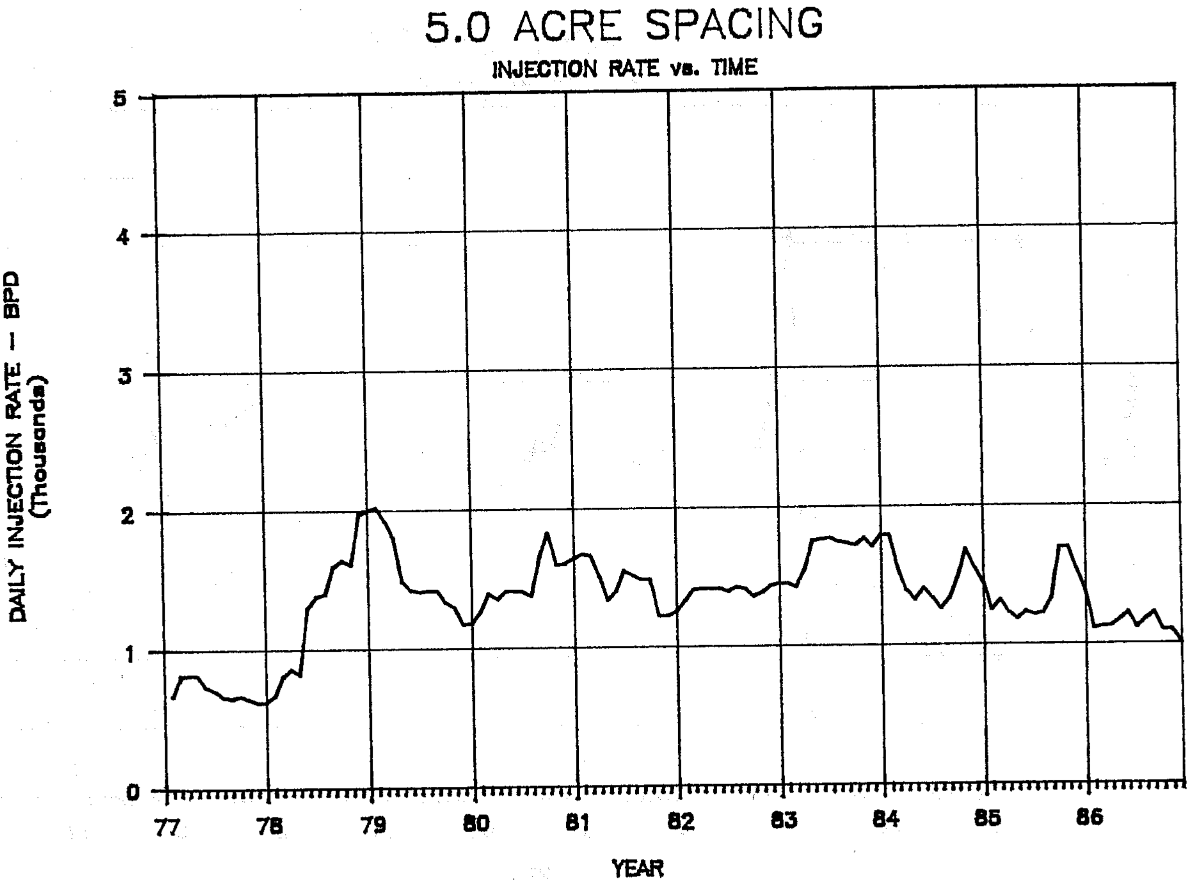
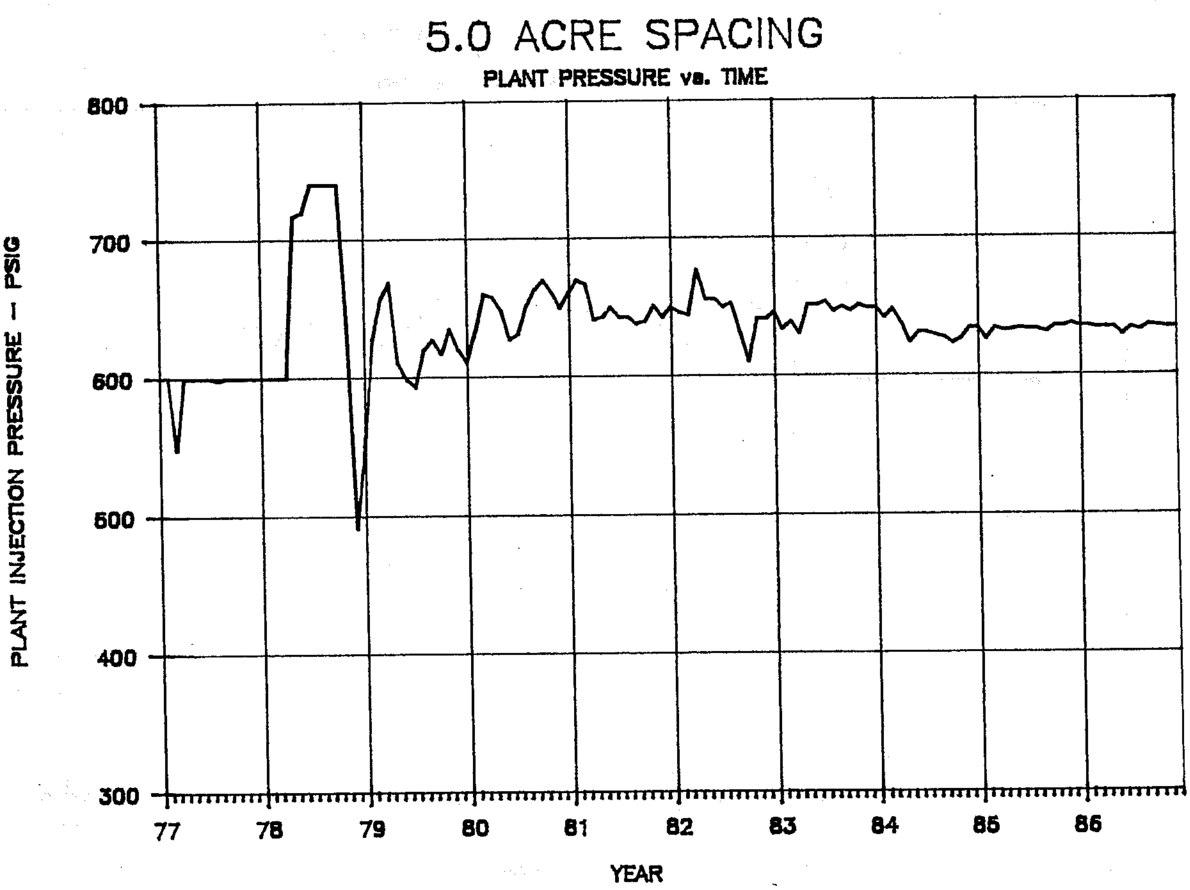

2.5 ACRE SPACING
PLANT PRESSURE vs. TIME
PLANT INJECTION PRESSURE — PSIG
800
700
600
500
400
300
77
78
79
80
81
82
83
84
85
86
YEAR

FIGURE 3


5.0 ACRE SPACING
INJECTION RATE vs. TIME
DAILY INJECTION RATE — BPD
(Thousands)
0
1
2
3
4
5
77
78
79
80
81
82
83
84
85
86
YEAR


5.0 ACRE SPACING
PLANT PRESSURE vs. TIME
PLANT INJECTION PRESSURE — PSIG
300
400
500
600
700
800
77
78
79
80
81
82
83
84
85
86
YEAR

Production History

Figures 4 and 5 are graphs of oil cut and oil rate performance for the M-1 Project, respectively. A sudden increase in oil production and oil cut on the 2.5-acre pattern area was observed in November, 1978 (10% PV injected). This initial response corresponded to a switch in injection from slug to polymer and was caused by a substantial increase in the injection rate. A sustained increase in oil cut was seen shortly afterwards in March, 1979 at 18.6% of a PV injected and is considered to be the true response of the Maraflood process. Oil production on the 2.5-acre pattern area peaked in October, 1980 (44.5% PV injected) at 577 BOPD and a 12% oil cut. Since the peak period, the production rate has steadily declined to 42 BOPD at a 2% oil cut in December, 1986. Cumulative oil production from the 2.5-acre pattern area totaled 804,400 barrels, or 8.9% of the pattern pore volume at the end of 1986.

The 5.0-acre pattern also showed an oil production increase in November, 1978. However, this increase was due to the increase in fluid injection, as no significant increase in oil cut was observed. Not until May of 1980 (24.1% PV injected) was an increase of oil cut seen. Oil production peaked in October, 1982 (45.6% PV injected) at 263 BPD at a 13.3% oil cut. Production then declined to 103 BPD at a 6.2% oil cut in December, 1986. Cumulative oil production from the 5.0-acre pattern area totaled 494,700 barrels or 6.5% of the pattern pore volume at the end of 1986. Total project oil production totaled 1,299,100 barrels, or 7.8% of the total project pore volume.

Figures 6 and 7 compare oil cut, sulfonate cut of produced brine, and chloride concentration as a function of time for the 2.5- and 5.0-acre pattern areas, respectively.

Figure 6 shows a sulfonate response on the 2.5-acre pattern area in March, 1979, the same time a sustained oil cut response was seen. Beginning in August, 1979, chlorides began to decline, indicating a breakthrough of polymer. The peak oil cut occurred in July, 1980 at 40.1% PV injected, whereas the peak slug cut occurred slightly earlier in April, 1980 at 36% PV injected.

Figure 7 shows a true sulfonate response (greater than 1%) on the 5.0-acre pattern area occurring in May, 1980, about the same time as the oil cut response. A decrease in chlorides began in December, 1980. The peak oil cut occurred in October, 1982 at 45.6% PV injected, whereas the peak slug cut occurred seven months earlier in March of 1982 at 40.6% PV injected.

Figure 8 shows the injection/production (I/P) ratio as a function of time for the 2.5- and 5.0-acre pattern areas. Allocated peripheral water injection was accounted for beginning in early 1978 to correct for the apparent fluid imbalance at the start of the project.[3] As indicated by the graph, the balance between injection and production has been reasonably good in both pattern areas since early 1979.

Treatment of produced fluids is discussed in Appendix A.

FIGURE 4

OIL CUT VS TIME

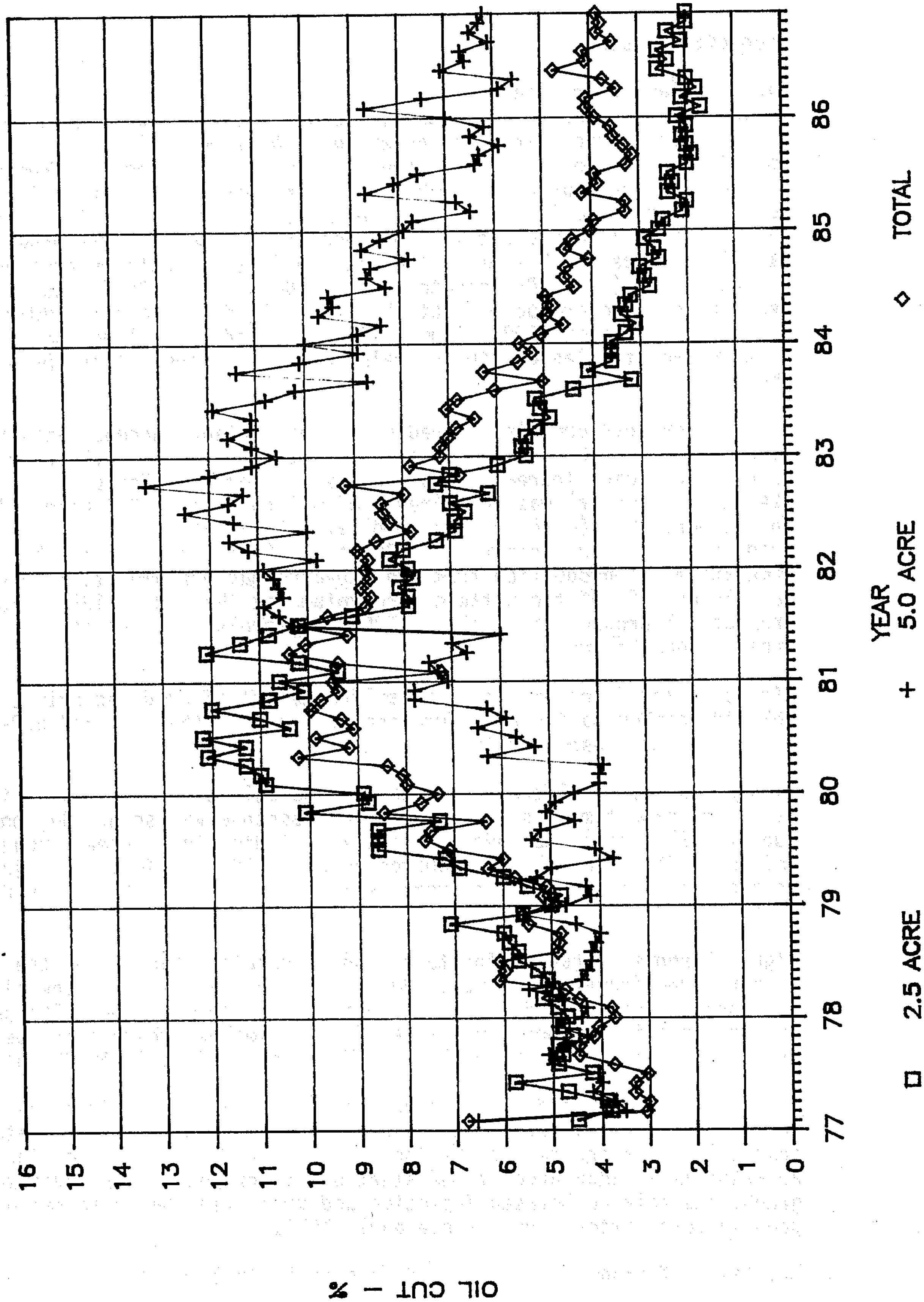


FIGURE 5

OIL RATE vs TIME

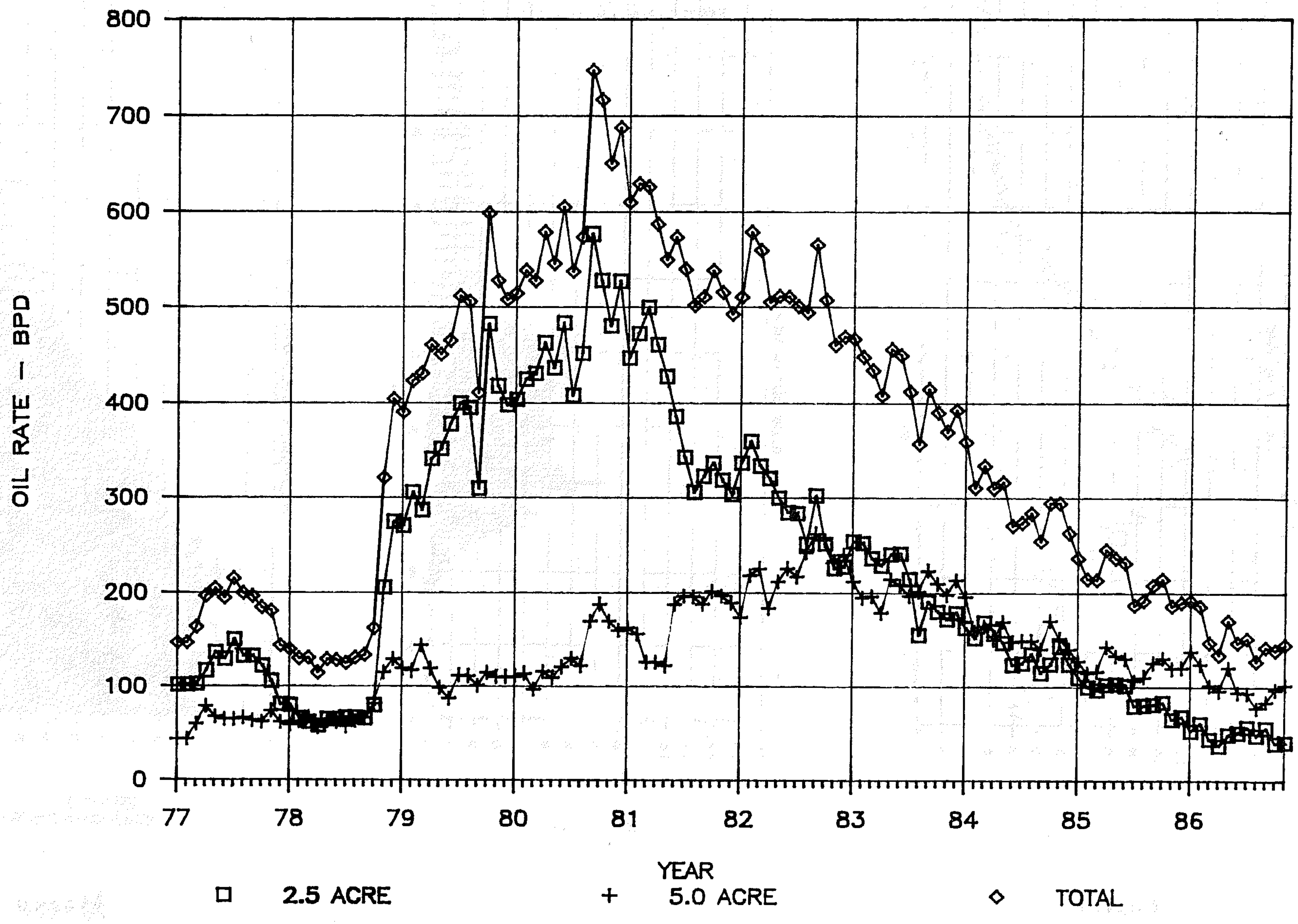


FIGURE 6

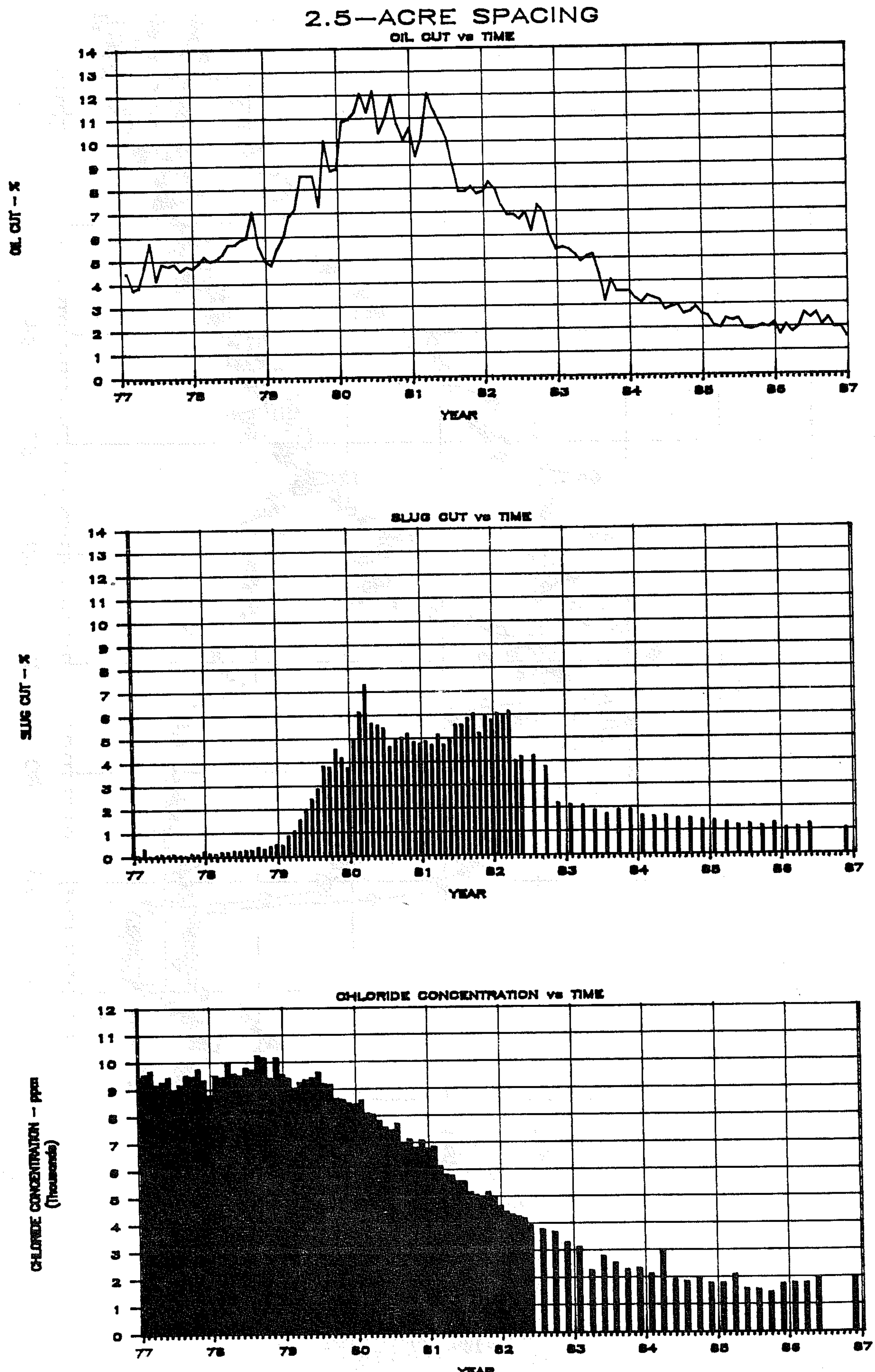

2.5—ACRE SPACING
OIL CUT vs TIME
OIL CUT - %
YEAR
SLUG CUT vs TIME
SLUG CUT - %
YEAR
CHLORIDE CONCENTRATION vs TIME
CHLORIDE CONCENTRATION - ppm
(Thousands)
YEAR

FIGURE 7

5.0—ACRE SPACING

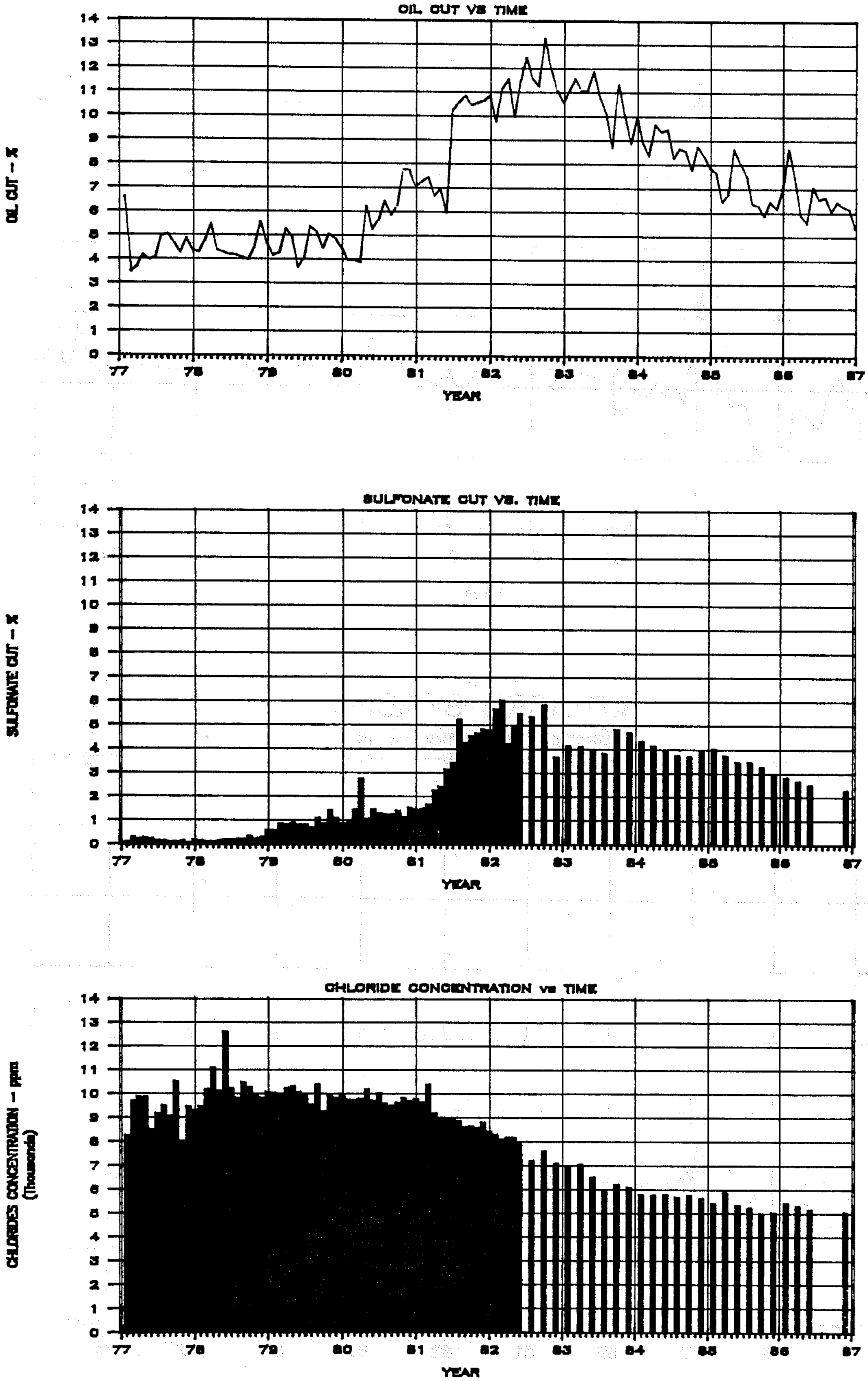
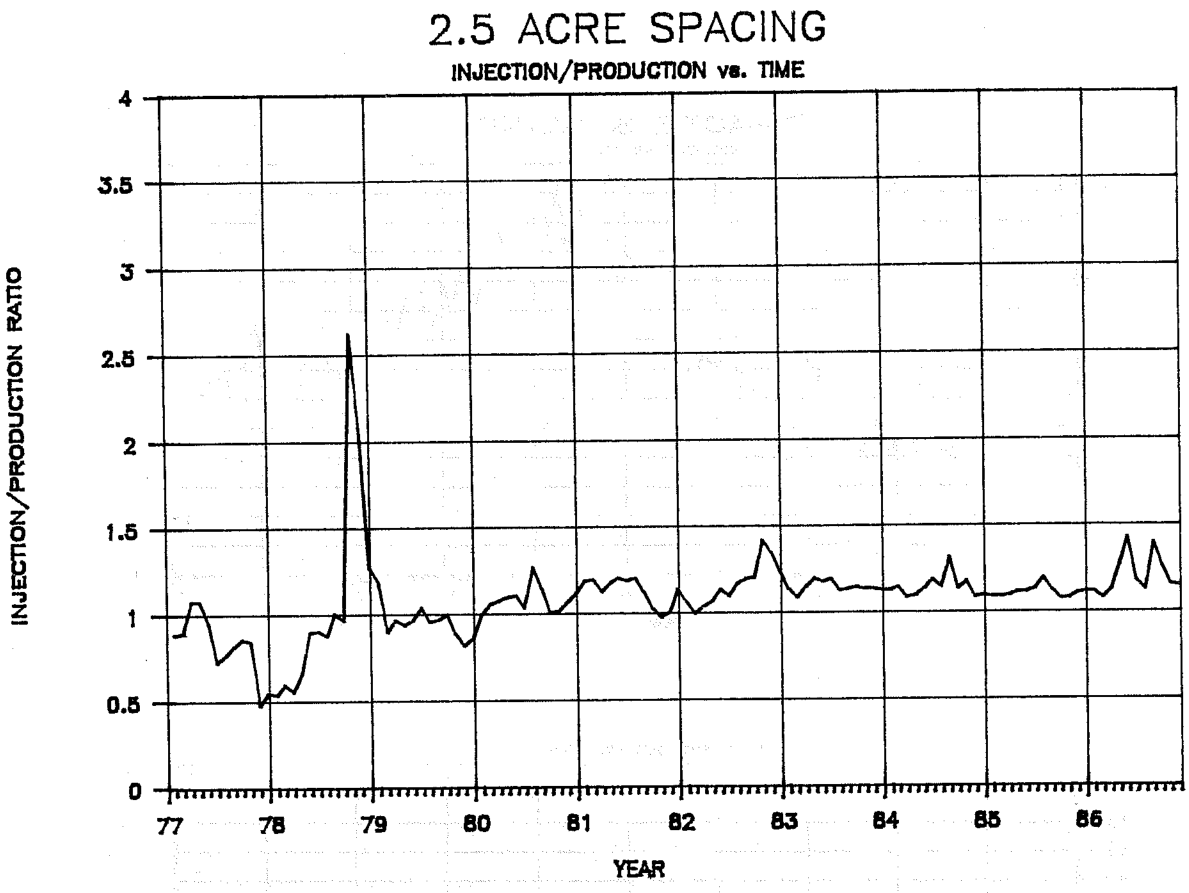
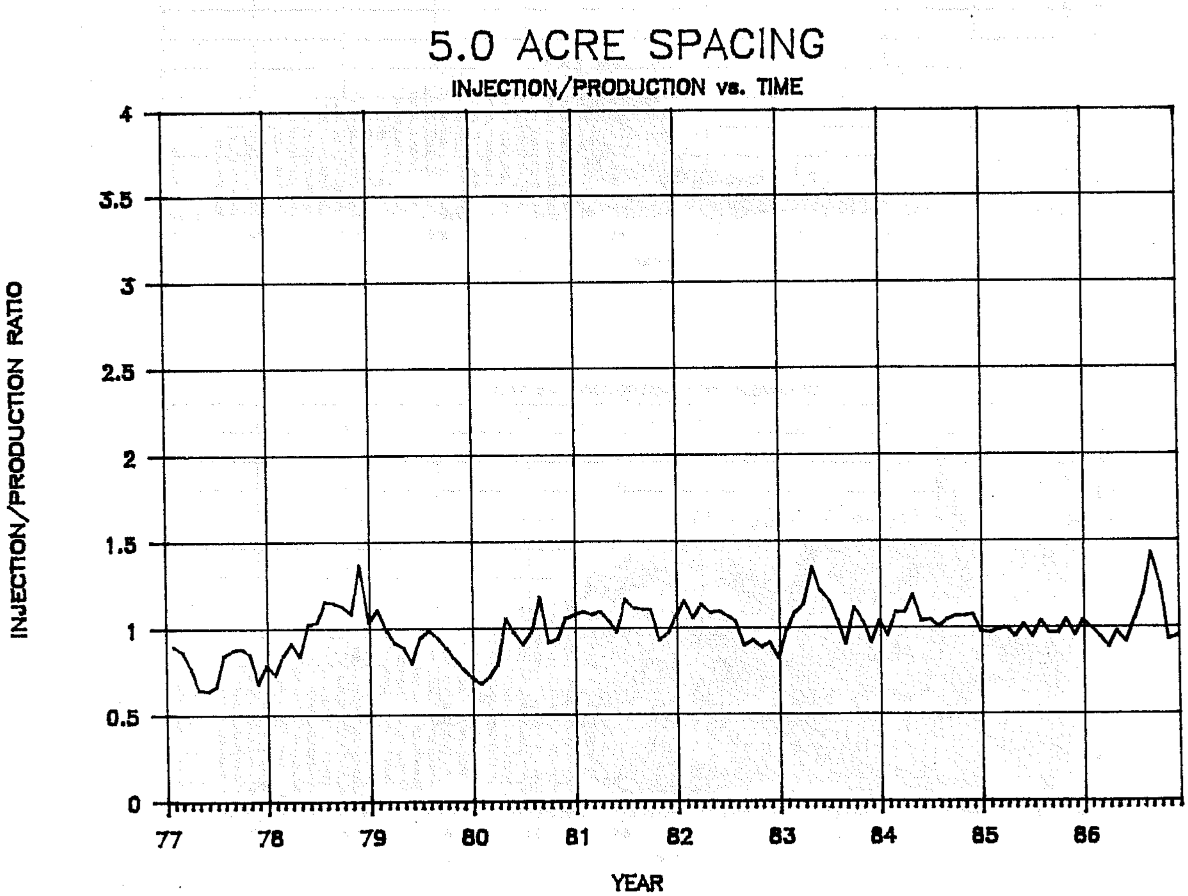


FIGURE 8


2.5 ACRE SPACING
INJECTION/PRODUCTION vs. TIME
INJECTION/PRODUCTION RATIO
4
3.5
3
2.5
2
1.5
1
0.5
0
77
78
79
80
81
82
83
84
85
86
YEAR


5.0 ACRE SPACING
INJECTION/PRODUCTION vs. TIME
INJECTION/PRODUCTION RATIO
4
3.5
3
2.5
2
1.5
1
0.5
0
77
78
79
80
81
82
83
84
85
86
YEAR

PROJECT PERFORMANCE EVALUATION

Performance By Well Groups

Table 2 compares average oil recovery (as a percent of pore volume) between three sub-groups of M-1 production wells on both the 2.5- and 5.0-acre patterns. Oil recoveries are calculated using producer-centered pore volumes through December, 1986.

The first grouping compares unconfined patterns with confined patterns. Unconfined patterns are defined as patterns represented by producers that have less than four offset injectors. In most cases, these patterns are along the project boundary. Confined patterns are represented by producers that have at least four offset injectors (Figure 9). Only two wells, LL-12 and JJ-12, have more than four offset injectors due to their location near the boundary of the 2.5- and 5.0-acre pattern areas.[3]

Table 2 shows that the unconfined patterns' production wells performed the best of all the groups in both the 2.5- and 5.0-acre pattern areas. This behavior is somewhat unexpected but was also observed at the 219-R Maraflood Project. Most likely, this is attributable to reservoir heterogenities such as lower initial oil saturation (better waterflood sweep-out) in the confined patterns.[3]

The second grouping compares wells in areas having low post-waterflood oil saturation (Sor less than 40% PV) and low chlorides concentration (less than 9,000 ppm, due to the injection of fresh water during waterflood operations) with wells outside of those areas.

Areas of low post-waterflood oil saturation were determined by using fractional-flow laboratory data and producing oil cut data to estimate oil saturations at each production well. This data along with a constant oil saturation value assigned to each injection well were used to generate an oil saturation contour map for the project. A chloride concentration distribution map was generated using post-waterflood chloride concentrations from individual produced water analysis.[3]

As expected, the wells in areas of low oil saturation and low chlorides performed the worst in both the 2.5- and 5.0-acre pattern areas, due to less available oil for tertiary recovery. Also, as mentioned above, most of these wells were in confined pattern areas.

The third grouping compares new producers with old, reconditioned producers. On the 2.5-acre pattern area, new producers significantly outperformed old producers. The inferior performance of the old wells on the 2.5-acre pattern area is most likely attributable to the location of well EB-5 in a low oil saturation area and not to operational difficulties. Well EB-5 recovered only 3.15% PV compared to an average of 7.25% PV for the remaining old wells on the 2.5-acre pattern area. On the 5.0-acre areas, the old wells slightly outperformed the new production wells.

Based on oil recovery as a percentage of pore volume, Table 2 shows the total 2.5-acre pattern area outperforming the total 5.0-acre pattern

Performance By Well Groups (Continued)

area. However, possible differences such as post-waterflood oil saturation and reservoir heterogeneity between the two areas, and not well spacing, may explain the 2.5-acre pattern area's better recovery performance. Therefore, larger well spacing should not be overlooked in the design of future micellar polymer projects.

TABLE 2

PERFORMANCE OF M-1 PROJECT WELL GROUPS
PRODUCER-CENTERED PATTERNS

2.5-Acre Spacing

# Wells	Well Group	Oil Rec % PV
91	Total Pattern Area	8.87
26	Unconfined Patterns (fewer than four offset injectors)	10.21
65	Confined Patterns	8.64
18	Patterns in Areas Where Low Post-Waterflood Oil Saturation and Low Chlorides Concentration Coincide (good waterflood recovery)	5.81
73	Patterns Outside of Areas Where Low Sor and Low Cl Coincide	10.01
86	New Producers	8.98
5	Reconditioned Old Producers (D-8, D-10, J-2, P-2, EB-5)	6.37

5.0-Acre Spacing

# Wells	Well Group	Oil Rec % PV
41	Total Pattern Area	6.52
19	Unconfined Patterns (fewer than four offset injectors)	8.34
22	Confined Patterns	5.82
6	Patterns in Areas Where Low Post-Waterflood Oil Saturation and Low Chlorides Concentration Coincide (good waterflood recovery)	5.81
35	Patterns Outside of Areas Where Low Sor and Low Cl Coincide	6.68
36	New Producers	6.49
5	Reconditioned Old Producers (JJ-16, SC-14, BPF-18, AS-35, AS-36)	6.87

MARATHON OIL COMPANY
MARAFLOOD PROCESS-M-I PROJECT
Crawford County, Illinois

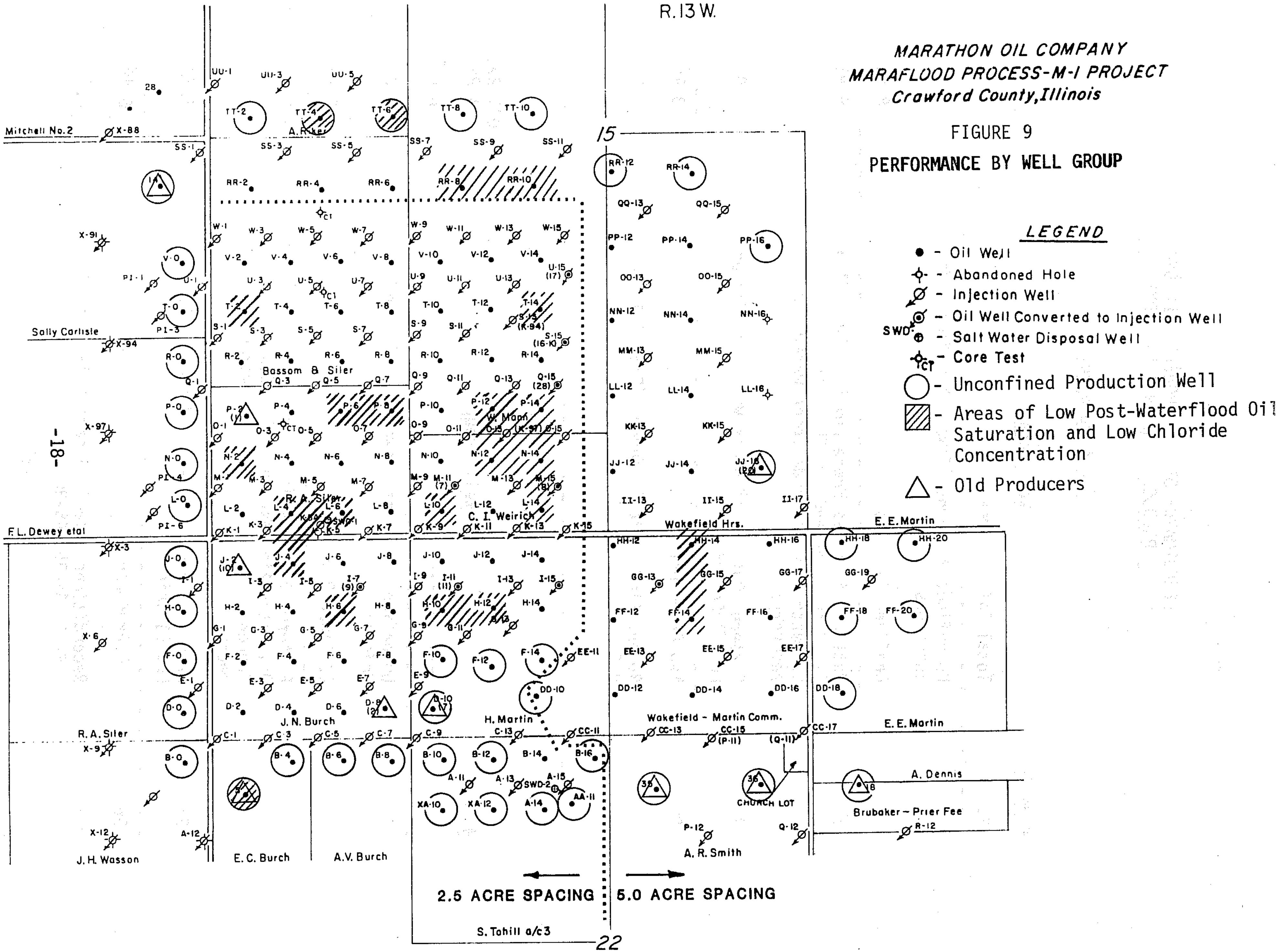


FIGURE 9

PERFORMANCE BY WELL GROUP

Observation Well Logging

Induction logs have been conducted at three observation wells located in the stacked-sand area of the project to monitor fluid movement during micellar slug and polymer injection. The stacked-sand area is located in the central 100 acres of the project and consists of two or more sand bodies "stacked" one above the other.[1]

Figure 10 shows the location of the three observation wells. Observation wells GI-7 and GI-8 were completed with fiberglass casing across the Robinson sandstone. Observation well GI-3 was reworked and completed open hole.[3]

Dual induction logs, performed at regular intervals, measured changes in resistivity resulting from the different injected fluids moving past the observation wells. The movement of the higher-salinity slug is indicated by a decrease in resistivity. The movement of the fresh water polymer is indicated by an increase in resistivity due to the polymer's low salt content.

Induction logging, which began in January, 1978, showed resistivity changes at all three observation wells. The logs showed the movement of fluid over several intervals, indicating the presence of the stacked-sand bodies. The fluid banks advanced at different rates and appeared to be controlled by each interval's reservoir properties. The advancement of the polymer bank was greatest in the Upper Robinson sand where reservoir quality is superior to the lower intervals.[6] Table 3 compares an induction log response with corresponding reservoir properties obtained from a nearby core test.

Core Test Evaluation

In December of 1981, three core tests were drilled near the observation wells shown in Figure 10. The core samples were evaluated to compare the intervals swept with those indicated by the induction logs. The core analysis revealed the presence of at least three distinct zones in the Robinson sand in the test area. Induction logs also showed evidence of these zones as depicted in Table 3.[6]

The core samples also provided an indication of the effectiveness of the Maraflood Process. The upper zone showed the best oil displacement with remaining oil saturations of only 5.3 to 9.8% PV. The middle zone was moderately swept, leaving oil saturations of 12.5 to 20.5% PV. The lower zone had the poorest displacement efficiency with residual oil saturations of 11.0 to 27.5% PV.[6]

Further core analysis showed that, in areas of low residual oil saturation, the sulfonate content was also low. This indicates that in the areas where micellar slug was effectively displaced by polymer, a considerable reduction in reservoir oil saturation took place.[6]

FIGURE 10

2.5-Acre Spacing

M-1 Observation Well and Core Test Locations

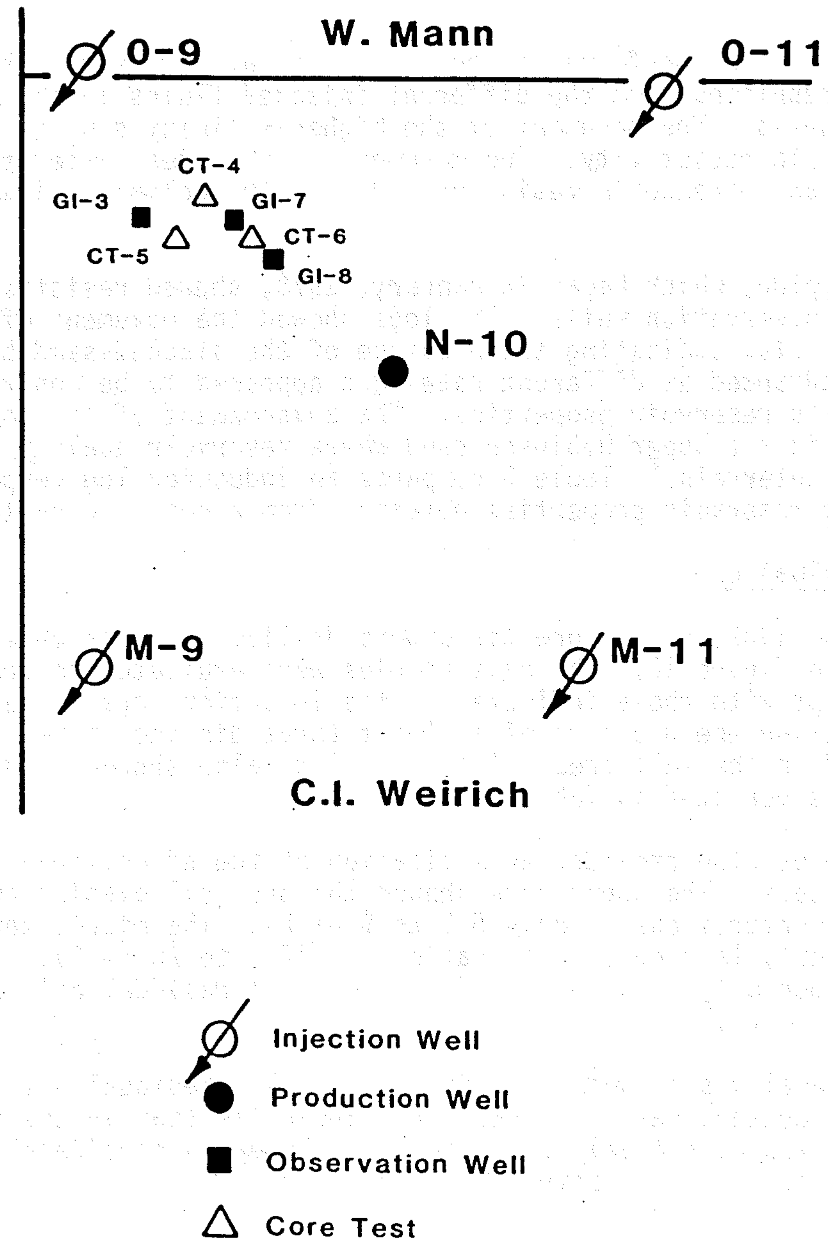
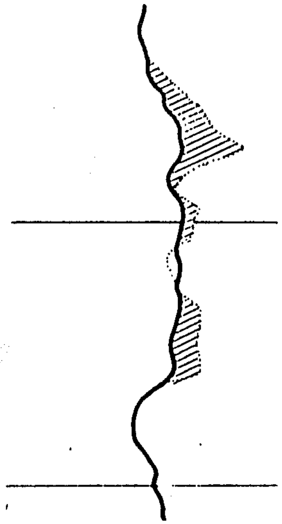


TABLE 3

COMPARISON BETWEEN INDUCTION LOG DATA AND CORE TEST DATA

Typical Induction Log*
Well GI-8



Average Reservoir Data by Zone
Core Test No. 6

Interval Zone (ft)	Gross Sand ft	Net Sand (h) ft	Por (Ø) %	Øh ft	Perm (k) md	Flow Cap. (kh) md-ft	Est Flow % kh	Oil Sat % PV
870-896 (upper)	26	23.4	21.6	5.054	279	6,529	69	9.8
896-908 (middle)	12	11.5	19.2	2.208	75	863	9	20.5
908-930 (lower)	22	17.1	19.3	3.300	123	2,103	22	27.5
Totals	60	52.0	20.3	10.562	183	9,495	100	17.6

*Comparison made to Base log.
Shading indicates an increase in resistivity.

Mathematical Modeling

The performance of producer-centered pattern N-10 was mathematically modeled to compute cumulative oil production and oil cut using Marathon's SURFS program.

Based on reservoir data observed from both core evaluation and induction logs obtained from within the pattern area, the computer model was set up with three distinct layers as follows:[7]

Layer	Net Thickness (ft)	Por (%)	Perm (md)
Upper	23.8	21.5	275
Middle	11.1	19.6	77
Lower	16.6	19.3	129

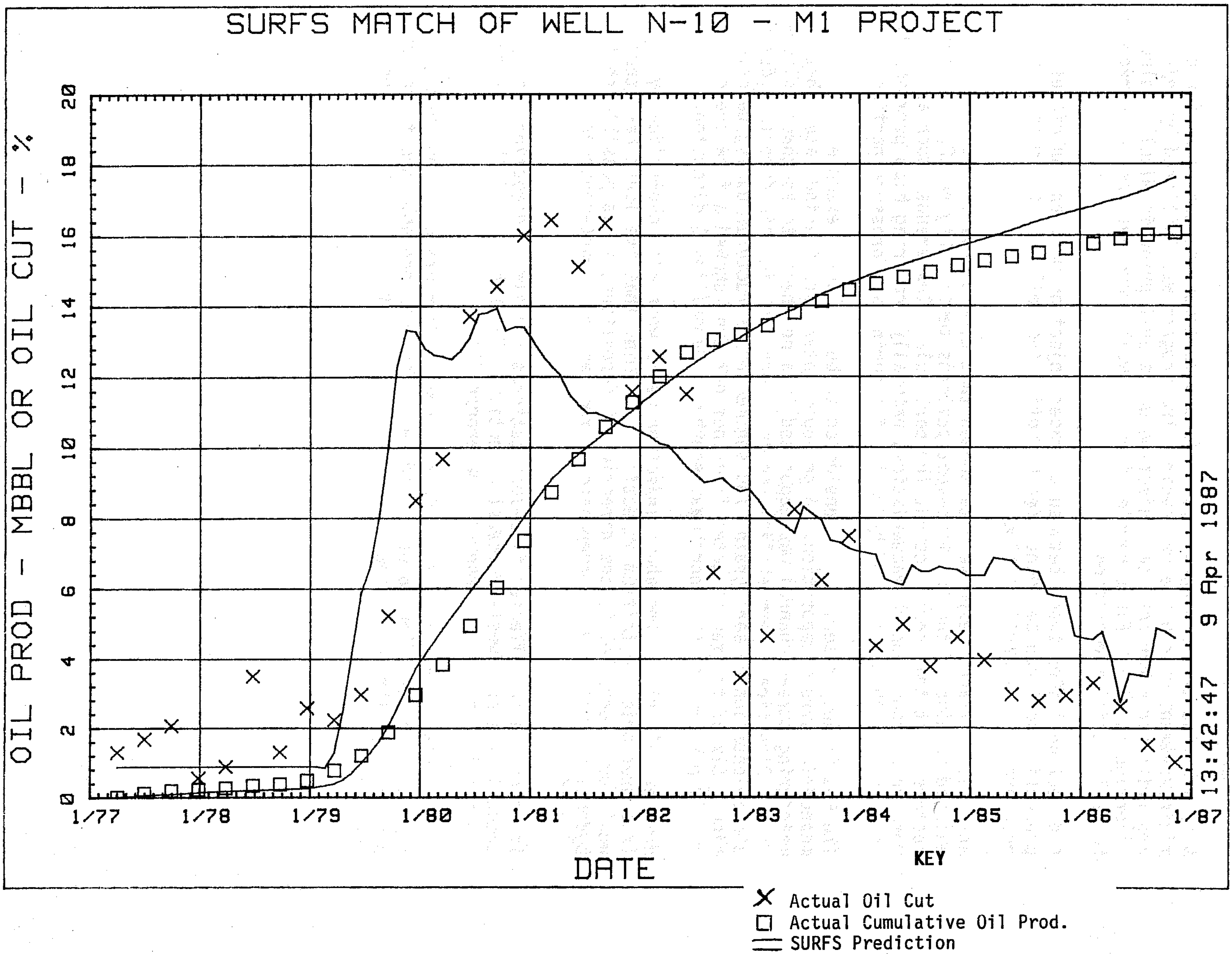
An initial computer match was based entirely on the northwest quadrant of the pattern and used an allocation factor of 25% of the 0-9 and N-10 wells. A uniform pattern, initial oil saturation of 40% was assumed, and the ratio of vertical to horizontal permeability was set at 0.1 for each layer. The initial model was used to generate a tabulation of well N-10's cumulative oil production as a function of cumulative allocated injection of offset injection wells. Allocation factors for the offset injection wells were based on a streamline fluid distribution computer program (SNAPS), then normalized to well N-10's production. The allocation factors assigned to the offset injectors are as follows:

Well	Allocation Factor
0-9	0.31
0-11	0.23
M-9	0.25
M-11	0.19

In order to further improve the match, the initial pattern oil saturation was reduced to 38% PV, and the vertical to horizontal permeability ratio increased to 0.2.[7]

Figure 11 compares the final simulated performance (shown by the solid lines) with actual pattern performance. Over prediction of performance during the final three years cannot be accounted for in the model and is possibly caused by poor mobility control.[7]

FIGURE 11


SURFS MATCH OF WELL N-10 - M1 PROJECT
OIL PROD - MBBL OR OIL CUT - %
0
2
4
6
8
10
12
14
16
18
20
1/77
1/78
1/79
1/80
1/81
1/82
1/83
1/84
1/85
1/86
1/87
13:42:47 9 Apr 1987
DATE
KEY
Actual Oil Cut
Actual Cumulative Oil Prod.
SURFS Prediction

Tritium Tracer Evaluation

A radioactive tracer program was conducted to determine the direction of fluid movement within the reservoir. The program was initiated by injecting tritiated water into ten injection wells just prior to micellar slug injection in 1977. Fluid samples from all wells were analyzed on a regular basis for tritium detection.

A directional flow trend between a tracer injection well and an offset production well can be identified by noting the well with the most tritium recovered at the earliest time.[3]

Analysis of tracer response data showed that directional flow trends existed in nine of the ten five-spot patterns tested (Figure 12). Several factors exist that could account for particular flow trends, such as reservoir deposition characteristics, naturally occurring high permeability streaks, and the effects of hydraulic fracturing and pressure parting.[8]

The M-1 Project reservoir is considered to be a classic example of a meandering stream deposition. A geologic interpretation indicates that the meandering stream channel was deposited in a northeast to southwest direction. Directional permeability should be greatest in this direction due to the orientation of sand grains and sedimentary structures during deposition. Six of the ten affected five-spot patterns showed a flow trend nearly parallel to this northeast-southwest depositional direction.[8]

However, all six of the above injection wells were also hydraulically fractured prior to tritium injection. Assuming that the least resistance would occur parallel to the direction of deposition, it is possible that a hydraulic fracture would propagate in the same northeast-southwest direction.[8]

Three of the ten affected five-spot patterns revealed a directional flow trend in the northwest-southeast direction. The behavior of those patterns can possibly be due to reservoir heterogeneities.[8]

The behavior of pattern GG-15 did not show any directional trend but instead a uniform flow to each producer. This was probably due to uniform sand quality throughout the pattern and the fact that GG-15 had not been fractured.[8]

MARATHON OIL COMPANY
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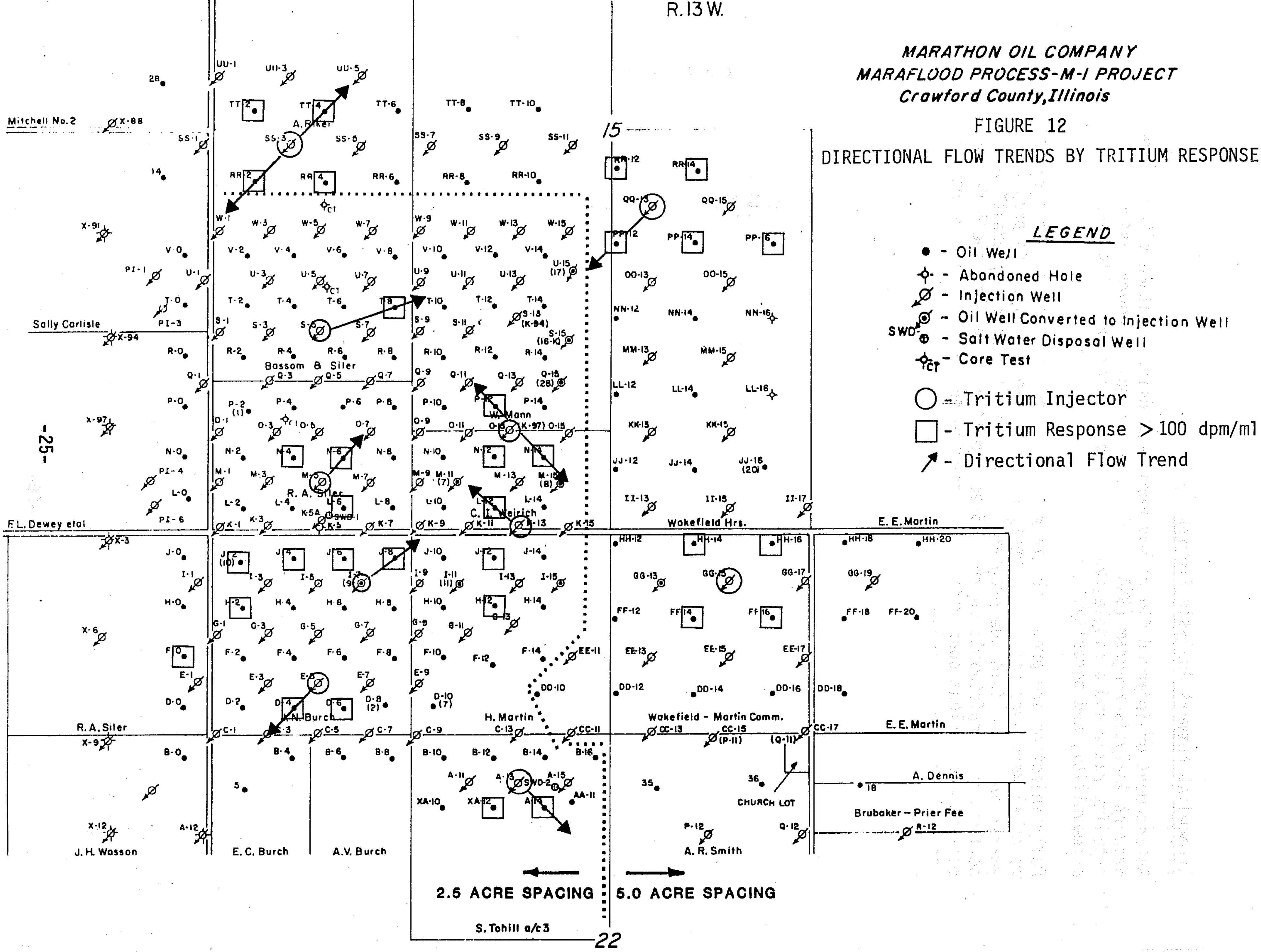
Crawford County, Illinois

FIGURE 12

DIRECTIONAL FLOW TRENDS BY TRITIUM RESPONSE



Streamline Network Analysis Program (SNAP)

Advancement of injected fluids was monitored using Marathon's Streamline Network Analysis Program (SNAP). The SNAP computer program assumes a unit mobility ratio and a single[9] reservoir layer of constant thickness, permeability, and porosity.

Daily injection and production rates (normalized to injection for overall balance) were averaged on an annual[9] basis for each of the ten project years, and input into the program. The SNAP-generated map exhibited better areal conformance on the 2.5-acre pattern area than the 5.0-acre pattern area. That observation was expected due to the 2.5-acre pattern area's closer well spacing.

Actual Versus Predicted Performance

As mentioned previously, total oil production from the 2.5-acre pattern spacing through 1986 was 804,400 barrels. The 2.5-acre area became uneconomic at this time, therefore, the cumulative oil production reported represents 22.2% of the 40% residual oil saturation after waterflood.

Total oil production for the 5.0-acre pattern spacing through 1986 was 494,700 barrels or 16.3% of the 40% residual oil saturation after waterflood. However, the 5.0-acre area has about four years of economic life remaining. A decline curve analysis was used to predict ultimate oil recovery from the 5.0-acre spacing (Figure 13). Using an economic limit of 25 BOPD, the analysis gives a cumulative oil production of 583,000 barrels or an ultimate oil recovery of 19.2%.

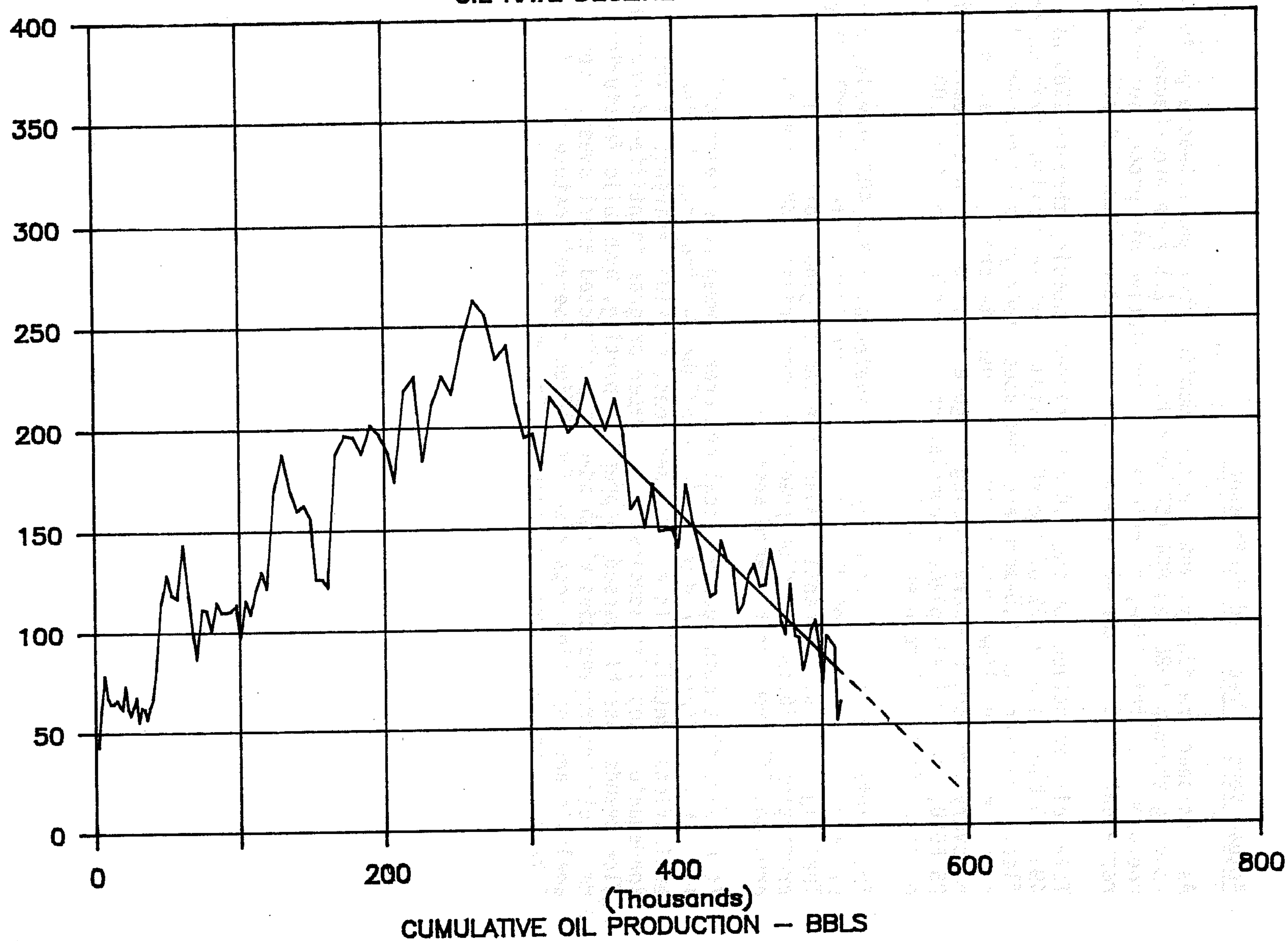
Thus, total project oil recovery is estimated at 1,387,400 barrels, or an ultimate oil recovery of 20.8% of the oil remaining after waterflooding. That figure is significantly lower than the original total project prediction of 36.6%, based on predicted recoveries of 38% from the 2.5-acre area and 35% from the 5.0-acre area.

It appears that both poor vertical and areal sweep were responsible for the less-than-predicted field performance of the M-1 Project. Various evaluations, detailed in earlier sections, provided evidence of the inadequate sweep efficiencies. The tracer program identified directional flow trends possibly caused by pressure parting, hydraulic fracturing, or reservoir heterogeneities which adversely affected areal sweep. Core analysis and injection logs also identified reservoir heterogeneities (stacked sands) which were responsible for poor vertical sweep.

FIGURE 13

5.0—ACRE SPACING

OIL RATE DECLINE ANALYSIS



ECONOMIC ANALYSIS OF THE M-1 PROJECT

Table 4 presents a comparison of economic data for the total M-1 Project from 1976 when the project was first begun, to current data (1987). The early project economics were generated using oil reserves corresponding to recoveries of 38% and 35% of the 40% PV post-waterflood oil saturation for the 2.5- and 5.0-acre patterns, respectively. The current project economics were generated using the actual recovery of the 2.5-acre pattern (22.2%) up to its economic limit at the end of 1986, and the forecasted recovery for the 5.0-acre pattern (19.2%) up to its economic limit in 1991.

As shown in Table 4, the M-1 Project shows a $4.3 million BFIT (Before Federal Income Tax) profit on a $22.86 million investment, at an 8% rate of return. Included in the profit figure is $14.0 million in investment funds recouped from the U. S. Department of Energy. If not for the funds received from the D.O.E., this project would show a loss. All economics run assumed that the project salvage value is equal to the abandonment cost - a generous assumption in the current oil field economy.

The total project revenue and project profit were much lower than originally predicted, primarily because of the much lower-than-predicted oil recovery (55% of original prediction). The reasons for the low recovery (poor areal and vertical sweep) are detailed elsewhere in this report.

The other reason for the lower-than-predicted revenue and profit were much higher-than-anticipated project operating expenses. Project operating expenses include lease expenses, along with severance, ad valorem, and Windfall Profits Taxes. Included in the M-1 Project operating expense is $5.83 million in Windfall Profits Tax that was not anticipated in 1976. Because the M-1 Project was begun before 1980, when the Windfall Profits Tax was initiated, the M-1 oil was taxed at the tier 2 stripper rate (60%) instead of the lower tier 3 tertiary rate (30%). A breakdown of the project lease expense is detailed by category and by year in Table 5. One of the largest expenses by category was for injection water. The average per barrel water cost from 1976 through December, 1986 was $0.18. This cost was for water pumping (ten miles from the Dewey fresh water pit to the M-1 facility), diatomaceous earth filtering, and softening. Another large expense was project oil treating expense which amounted to approximately $1.15/barrel during peak oil production and is included in the chemical expense and R & M surface equipment categories.

The average project oil price was approximately $5/barrel higher than predicted, which helped the project economics somewhat. A gradual increase in oil price was predicted from 1977 on. As shown in Figure 14, however, the oil price accelerated rapidly between 1979 and 1980 because of the Arab Oil Embargo and has declined since then. The peak oil prices corresponded to times of peak M-1 oil production which resulted in the high average project oil price.

The project investment by category and by year is detailed in Table 6. Of the $22.86 million total investment, $14.38 million (or 63% of the total

Economic Analysis of the M-1 Project (Continued)

investment) was spent for micellar fluids (slug and polymer), and $5.66 million (or 25% of the total investment) was spent to drill and complete the project's 252 injection and production wells.

Future micellar polymer projects should attempt to lower investment costs by utilizing existing waterflood production wells instead of drilling new wells and also by optimizing the amount of crude oil sulfonate in the micellar slug.

Table 7 compares the economics of the 2.5 acre patterns vs. the economics of the 5.0-acre patterns. The additional 3% of 40% post-waterflood saturation recovered on the 2.5-acre patterns does not appear to have justified the additional investment and operating expense for the extra wells. The 2.5-acre pattern shows only a slightly higher net profit (lower net loss) than the 5.0-acre pattern. The 2.5-acre pattern had even a higher average project oil price than the 5.0-acre pattern ($30.12/barrel vs. $26.73/barrel) because it experienced its peak oil production during a time of higher oil prices (Figure 14). If the 5.0-acre pattern had experienced the same high oil prices, it would have had better economic parameters than the 2.5-acre pattern. If the oil embargo of the 1970's had not occurred and the oil price continued a steady upward trend, the 5.0-acre pattern would again have had much better economic parameters than the 2.5-acre. Table 8 compares the economics of the 2.5-acre pattern vs. the economics of the 5.0-acre pattern assuming no Windfall Profits Tax and using an oil price schedule, which predicted a gradually increasing oil price.

TABLE 4
M-1 PROJECT ECONOMICS

	1976 Predicted	1987 Predicted
Marathon Participation		
Working Interest, %	100.0	100.0
Revenue Interest, %	87.5	89.8
Project Net Reserves		
Oil, Barrels	2,263,000	1,246,300
Total Project Economics-MOC Net		
Average Oil Price, $/Bbl.	23.40	28.71
Total Revenue, M$	52,963	35,781
Investment, M$	25,263	22,855
Total Operating Expense, M$	9,884&+	22,620&@
Net Profit (BFIT), M$	17,816	4,306*
Profit-to-Investment Ratio (BFIT)	0.7	0.2
Payout Time, years (BFIT)	6.9	6.1
Annual Rate of Return-DCF, % (BFIT)	9	8
Project Life, years	14	15
Total Investment/Equivalent Barrel	11.16	18.34
Oper. Expense/Equivalent Net Barrel	4.37	18.15
Profit/Equivalent Net Barrel	7.87	3.46*

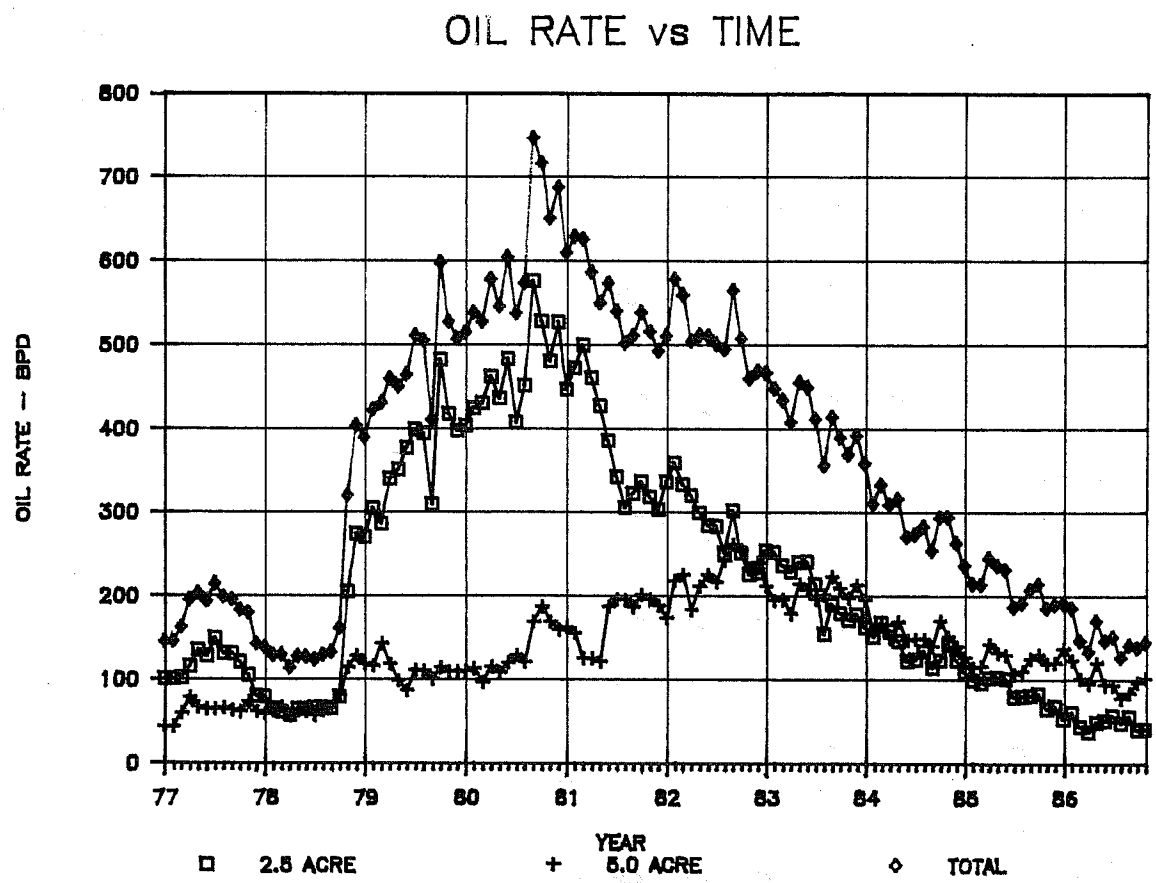
*Includes $14,000,000 in investment funds recouped from the D.O.E. as part of a tertiary recovery incentive program. This money was recouped over the first six years of the project.
&Includes Ad Valorem and Severance Taxes.
@Includes Windfall Profits Tax of $5,831,000.
+Excludes Some Overhead Costs (General and Administrative Expenses)

TABLE 5
M-1 PROJECT LEASE EXPENSE SUMMARY

	1974-1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	Total
Pumping Expense, M$	68	103	115	277	289	303	372	371	290	275	161	2,623
R & M Producing Wells, M$	24	65	32	91	69	142	189	101	107	58	24	903
R & M Surface Equipment, M$	227	196	217	363	486	443	488	375	369	301	172	3,638
Workover Expense, M$	2	35	18	8	87	113	54	0	24	1	0	342
Salt Water Disposal, M$	3	36	59	80	24	78	51	57	50	64	39	542
Injection Expense Water, M$	34	377	418	420	347	355	429	353	426	356	204	3,718
Injection Expense Wells, M$	8	87	38	13	58	100	41	67	127	75	39	653
Corrosion Control, M$	9	19	21	24	61	111	39	59	38	25	4	410
Chemical Expense, M$	2	18	9	117	195	132	159	300	102	109	53	1,196
Abandonments*, M$	645	10	8	0	0	6	4	0	0	10	0	684
Other Expenses, M$	55	71	65	88	73	101	57	75	58	53	37	735
Total Expense, M$	1,077	1,017	1,000	1,481	1,689	1,884	1,883	1,758	1,591	1,327	733	15,444
Maraflood Well Abandonments**												1,342
Estimated 1987-1991 5.0-Acre Pattern Operating Expense												1,322
Estimated Total Project Lease Expense												18,108

*Pre-Project Waterflood Well Abandonment
**244 Wells at an Estimated Cost of $5,500/each

FIGURE 14


OIL RATE vs TIME
OIL RATE -- BPD
800
700
600
500
400
300
200
100
0
77
78
79
80
81
82
83
84
85
86
YEAR
2.5 ACRE
5.0 ACRE
TOTAL

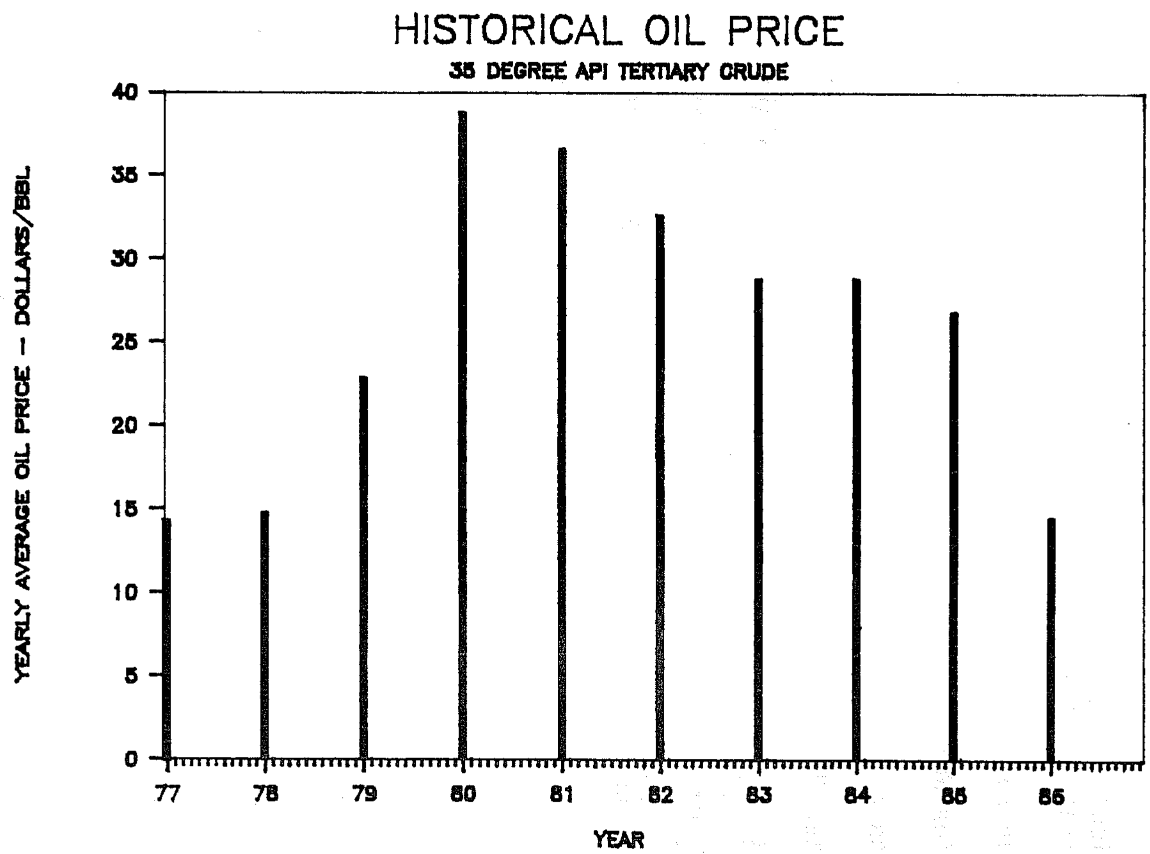

HISTORICAL OIL PRICE
35 DEGREE API TERTIARY CRUDE
YEARLY AVERAGE OIL PRICE -- DOLLARS/BBL
40
35
30
25
20
15
10
5
0
77
78
79
80
81
82
83
84
85
86
YEAR

TABLE 6

M-1 PROJECT INVESTMENT SUMMARY

	1974-1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	Total
Production Facility and Staging Areas, M$	484	0	51	619	17	0	0	0	0	0	0	1,171
Injection Facility, M$	697	1	74	0	0	0	0	0	0	0	0	772
Production Wells, M$	2,806	248	0	0	0	0	0	0	0	0	0	3,054
Injection Wells, M$	2,504	85	17	0	0	0	0	0	0	0	0	2,606
Salt Water Disposal System, M$	194	0	0	29	0	0	0	0	0	214	0	437
Slug, M$	0	5,510	4,553	0	0	0	0	0	0	0	0	10,063
Polymer, M$	0	0	1,657	480	595	786	724	80	0	0	0	4,322
Miscellaneous, M$	208	43	166	0	0	0	0	0	11	0	0	428
TOTAL	6,893	5,887	6,518	1,128	612	786	724	80	11	214	0	22,855

TABLE 7
M-1 PROJECT ECONOMICS
2.5-ACRE vs. 5.0-ACRE PATTERNS
ACTUAL OIL PRICE, NO D.O.E. RECOUPMENT

	2.5-Acre	5.0-Acre
Investment, M$	13,148	9,638
Net Reserves, M Bbls.	726	519
Average Oil Price, $/Bbl.	30.12	26.73
Revenue, M$	21,875	13,876
Operating Expense, M$	10,486	6,805
Net Profit (BFIT), M$	-1,759	-2,566
P/I (BFIT)	--	--
Payout, years (BFIT)	--	--
Rate of Return, % (BFIT)	--	--
Total Investment/Equivalent Net Barrel	18.10	18.56
Operating Expense/Equivalent Net Barrel	14.44	13.11
BFIT Profit/Equivalent Net Barrel	-2.42	-4.94

TABLE 8
M-1 PROJECT ECONOMICS
2.5-ACRE vs. 5.0-ACRE PATTERNS
GRADUALLY INCREASING OIL PRICE, NO WINDFALL PROFITS TAX

	2.5-Acre	5.0-Acre
Investment, M$	13,148	9,638
Net Reserves, M Bbls.	726	519
Average Oil Price, $/Bbl.	19.24	22.80
Revenue, M$	13,970	11,839
Operating Expense, M$	9,998	7,255
Net Profit (BFIT), M$	-9,175	-5,053
P/I (BFIT)	--	--
Payout (BFIT), Years	--	--
Rate of Return (BFIT), %	--	--
Total Investment/Equivalent Net Barrel	18.10	18.56
Operating Expense/Equivalent Net Barrel	13.77	13.97
BFIT Profit/Equivalent Net Barrel	-12.64	-9.74

Injection Well Stimulation

Various stimulation techniques have been used to maintain adequate injection rates and ensure fluid conformance in each pattern area.

Hydraulic fracturing was the most effective stimulation technique, indicating damage beyond the near wellbore region. However, hydraulic fracture treatments must be properly designed with small fracture lengths to prevent direct communication with offset wells.[3]

In addition, hydrogen peroxide treatments were effective in removing skin damage caused by the accumulation of concentrated or cross-linked polymer at the sand-face.[3]

Production Well Stimulation

Hydraulic fracturing has been effective in ensuring adequate withdrawal rates and maintaining acceptable fluid conformance in each pattern. As mentioned earlier, care was taken to prevent direct communication with offset wells.[3]

Production Well Failures

The 132 M-1 Project producers were pulled for downhole equipment failures an estimated 641 times (or an average of five pulls/well) from 1977 through 1986. The charges for repair and maintenance of producing wells amounted to 5% of the total project expense. Table 9 summarizes the number of failures and the type of equipment that failed in each producer. The total number of failures is broken down by equipment type as follows.

Rods	Tubing	Pumps
24	352	265

Very few wells were pulled for rod parts although large numbers were pulled for tubing and pump failures. All new equipment was installed in these wells at the project start. Because the M-1 produced fluid was not very corrosive (low chlorides content - less than 10,000 ppm and low H_2S content except during peak sulfonate production) and the producers were batch treated with Tretolite corrosion inhibitor KP-3409 on a regular basis, very few of the well failures were due to internal corrosion. Figure 15 shows the percentages of tubing and pump failures caused by various factors, such as internal corrosion and wear.

The majority of tubing failures (74.1%) were holes and splits caused by wear. Two groups of producers in the north and south portions of the 2.5-acre pattern had the largest number of failures. See Figure 16, M-1 Producers With Five Or More Tubing Failures. Most of these wells were drilled with air instead of rotary mud (for faster penetration rate and lower well cost) and are believed to be crooked holes. Field personnel have run rod guides in these problem producers (two per rod). They did not seem to help the failure problem. It is believed that the problem may be related to a barium sulfate scale paste present in some of the producers.

Production Well Failures (Continued)

This material is very abrasive. It could have adhered to the rod guides and boxes, scoring the tubing until a hole was developed.

The leading cause of pump failure was also wear (47.9%). All of the M-1 producers were kept pumped down in order to maintain a favorable injection to production ratio (favorable in terms of preventing injected fluid migration). Many producers were pumped at rates even higher than the well inflow, resulting in fluid pound and premature equipment failure.

The second leading cause of pump failure was scale (31.8%). Some areas of the M-1 reservoir contain a large enough concentration of barium to form a barium sulfate scale when contacted by sulfate present in the micellar slug. This scale was produced in a paraffin mush which plugged the downhole pumps. In addition, iron sulfide scale became a problem later in the project as polymer production increased.

TABLE 9
M-1 PROJECT
PRODUCER EQUIPMENT FAILURES
1977 - 1986
(Excludes May-December, 1982 for which time no failure reports are available.)

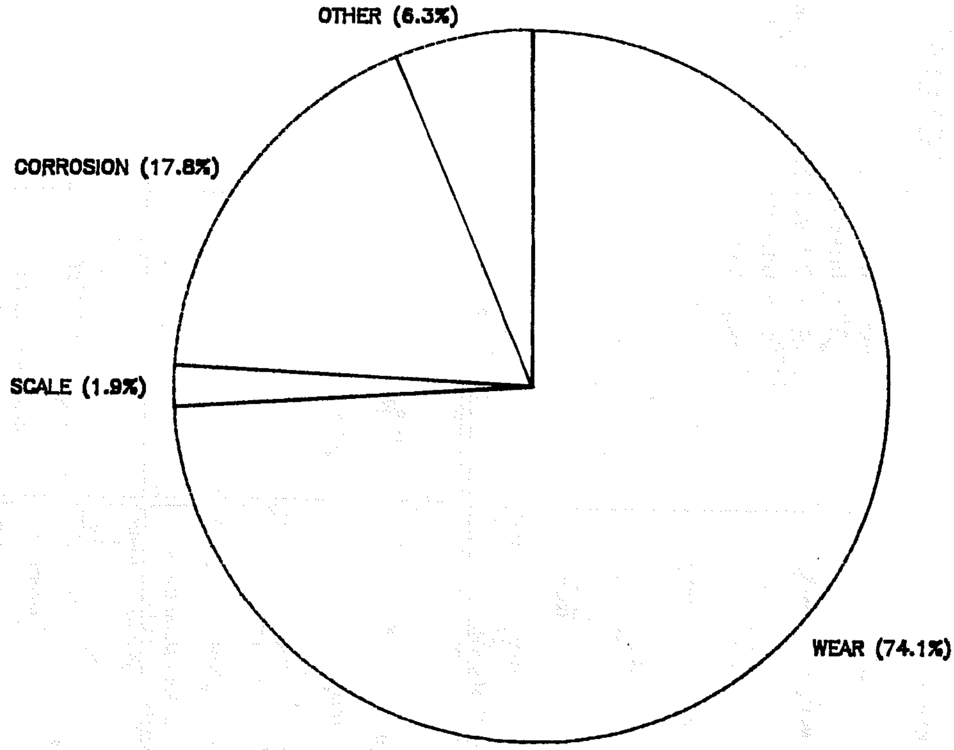
Well	Rod	Tubing	Pump	Well	Rod	Tubing	Pump
XA-10	-	1	-	L-4	-	-	1
XA-12	-	2	4	L-6	-	4	1
XA-14	-	1	2	L-8	-	3	1
AA-11	-	2	-	L-10	-	1	1
B-0	1	4	1	L-12	-	4	2
EB-5	-	-	-	L-14	-	-	3
B-4	-	4	1	N-0	-	1	-
B-6	-	-	2	N-2	-	5	2
B-8	1	-	1	N-4	1	6	-
B-10	-	-	-	N-6	-	2	1
B-12	-	5	2	N-8	2	2	1
B-14	1	2	4	N-10	-	2	2
B-16	-	2	2	N-12	-	1	4
D-0	-	1	0	N-14	-	9	4
D-2	-	1	1	P-0	-	-	3
D-4	-	5	2	P-2	1	2	4
D-6	-	6	2	P-4	1	5	2
D-8	1	-	-	P-6	-	1	4
D-10	-	1	2	P-8	-	2	6
F-0	-	1	-	P-10	-	2	1
F-2	-	5	4	P-12	2	4	2
F-4	-	3	1	P-14	-	1	4
F-6	-	5	3	R-0	-	1	3
F-8	-	1	1	R-2	-	2	1
F-10	-	-	-	R-4	-	4	3
F-12	-	-	1	R-6	-	4	3
F-14	-	3	2	R-8	-	1	1
H-0	-	4	3	R-10	-	2	5
H-2	-	3	-	R-12	-	-	4
H-4	-	4	1	R-14	-	3	-
H-6	-	7	1	T-0	-	1	-
H-8	-	6	2	T-2	-	6	2
H-10	-	6	2	T-4	-	9	4
H-12	-	4	4	T-6	-	6	-
H-14	-	4	-	T-8	1	7	-
J-0	-	3	-	T-10	-	1	2
J-2	-	7	10	T-12	-	3	6
J-4	1	4	2	T-14	-	1	2
J-6	-	7	3	V-0	-	1	3
J-8	2	9	1	V-2	-	5	-
J-10	1	3	-	V-4	-	6	2
J-12	-	3	2	V-6	-	2	1
J-14	-	4	2	V-8	-	6	1
L-0	-	2	4	V-10	-	1	2
L-2	-	2	1	V-12	-	1	3

TABLE 9 (CONTINUED)
M-1 PROJECT
PRODUCER EQUIPMENT FAILURES
1977 - 1986
(Excludes May-December, 1982 for which time no failure reports are available.)

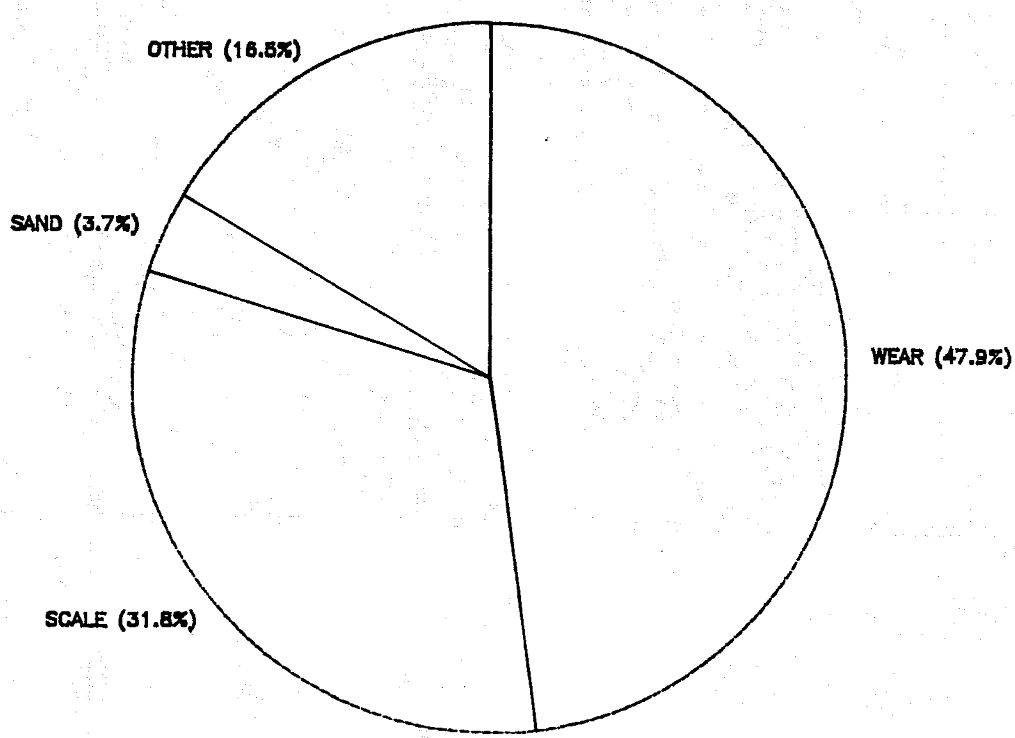
Well	Rod	Tubing	Pump
V-14	3	4	3
AS-35	-	4	1
AS-36	-	-	3
DD-10	-	4	1
DD-12	-	1	2
DD-14	-	1	2
DD-16	1	2	4
DD-18	-	1	6
FF-12	-	1	2
FF-14	-	-	1
FF-16	-	2	7
FF-18	1	2	2
FF-20	-	1	1
HH-12	-	2	3
HH-14	-	2	3
HH-16	-	-	2
HH-18	1	-	2
HH-20	-	1	2
JJ-12	-	5	1
JJ-14	-	2	1
JJ-16	-	-	5
LL-12	-	7	1
LL-14	-	1	2
NN-12	-	1	-
NN-14	-	-	4
PP-12	1	3	-
PP-14	-	2	3
PP-16	-	-	4
RR-2	-	2	1
RR-4	-	4	4
RR-6	-	2	1
RR-8	-	2	7
RR-10	-	3	1
RR-12	-	2	2
RR-14	-	-	3
TT-2	-	5	1
TT-4	-	4	3
TT-6	1	2	-
TT-8	-	1	-
TT-10	-	3	1
SC-14	-	1	-
BP-18	-	1	-
Totals:	24	352	265

FIGURE 15

CAUSE OF PRODUCING WELL TUBING FAILURES



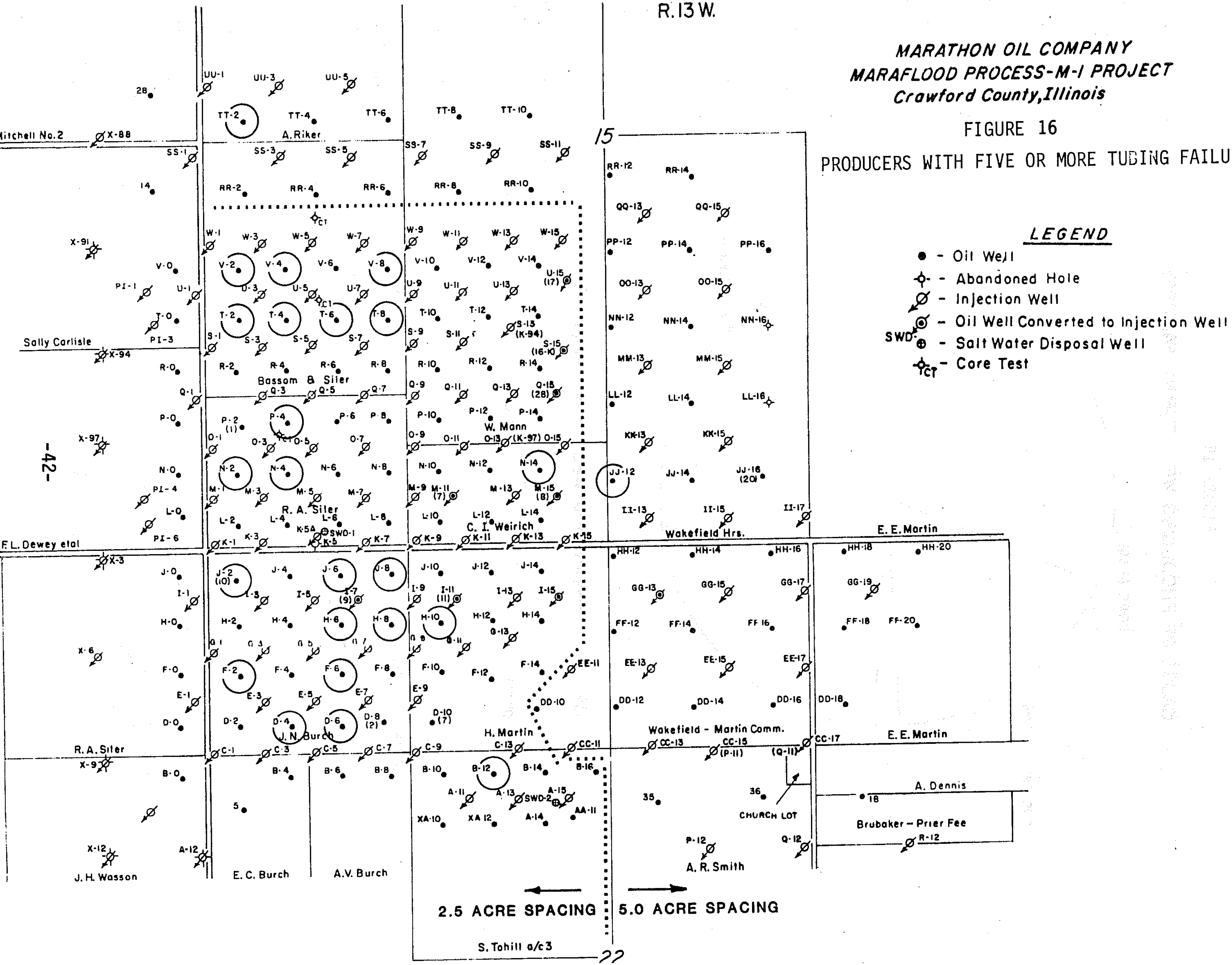
CAUSE OF PRODUCING WELL PUMP FAILURES



MARATHON OIL COMPANY
MARAFLOOD PROCESS-M-I PROJECT
Crawford County, Illinois

FIGURE 16

PRODUCERS WITH FIVE OR MORE TUBING FAILURES



Produced Fluid Treatment

Produced fluid from the M-1 Project consists of three phases: an oil phase (or water-in-oil emulsion), a sulfonate-rich middle-phase emulsion, and a brine (or oil-in-water emulsion). Sulfonate-stabilized emulsions present a different treating problem than ordinary oil field emulsions and will be discussed in more detail below.[4]

Before entering the production facility, produced fluids from the 2.5- and 5.0-acre patterns are treated separately with a demulsifier to remove oil from the brine. Production from the two pattern areas is sampled for oil cut, then combined in a 10,000-barrel receiving tank. Storage in the tank provides retention time for phase separations.[3] Oil production was allocated to each pattern by using daily oil cut tests normalized to monthly well tests.

Produced brine, or lower-phase emulsion, flows from the bottom portion of the 10,000-barrel tank to disposal. The upper-phase emulsion flows from the upper part of the receiver and is subsequently washed with a demulsifying chemical. The oil is heated, separated, and sold. Karl Fischer and simulated desalter tests are used to determine oil quality.[3]

The sulfonate-stabilized, middle-phase emulsion (MPE) occurring at the M-1 Project required unconventional treatment techniques. The MPE was brown in color, quite viscous (up to 2,000 cp), and contained up to 50% oil. Though the MPE accounted for only a small volume of the total produced fluids (approximately 1%), several thousands of barrels of MPE had to be processed.[5]

To effectively process the MPE, it was very critical to isolate the MPE in the 10,000-barrel receiver. If the MPE was handled with the lower-phase emulsion, large volumes of oil would be lost, resulting in lower oil recoveries. If the MPE was handled with the upper-phase emulsion, high concentrations of metals and water (associated with the MPE) would cause operational problems in downstream treating equipment.[5]

The distribution of the three emulsion phases in the receiver was checked periodically by visual inspection of samples drawn from various tank levels. The MPE was allowed to build downward in the receiver, displacing the lower-phase emulsion. When the MPE would reach the lower 25% of the receiver, it would be drawn off to a specific facility for treatment.[5]

Oil was liberated from the middle-phase emulsion by caustic hydrolysis, chemically treating with citric acid and hydrogen peroxide, and heating. The resulting oil was then brought to sell quality with a demulsifier-demetalizer chemical along with additional water to reduce the total metals concentration below 15 ppm.[5]

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