APPLICATIONS OF ADVANCED PETROLEUM PRODUCTION TECHNOLOGY AND WATER ALTERNATING GAS INJECTION FOR ENHANCED OIL RECOVERY - MATTOON OIL FIELD, ILLINOIS

COOPERATIVE AGREEMENT NUMBER DE - FC22 - 93BC14955

AMERICAN OIL RECOVERY, INC.
DECATUR, ILLINOIS

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Government Award for Current Year

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OBJECTIVES

The objectives of this project are to continue reservoir characterization of the Cypress Sandstone and identify and map a series of Facies Defined Waterflood Units (FDWS); and to design and implement water-alternating-gas WAG injection utilizing carbon dioxide. The producibility problems are permeability variation and poor sweep efficiency. Part 1 of the project focuses on the development of a computer generated geological model that will be used to select sites for the demonstration in Part 2. Included in Part 1 of the project is the drilling of an infill well, coring 100' of the Cypress Sand, and various injectivity testing to gather information used to update the model. Part 2 involves field implementation of WAG. Technology Transfer includes outreach activity such as seminars, workshops, and field trips.

SUMMARY OF TECHNICAL PROGRESS

GENERAL

Approximately 90 percent of the reservoir geology is complete including detailed stratigraphic cross sections, structure maps, isopach maps (see figures 1-6), lithofacies maps, and a 3-D reservoir computer model using STRATAMODEL software. Five distinct FDWS have been identified and nearly 6000 tons of liquefied CO2 have been used during injectivity testing. These tests are providing information, based on well response, regarding permeability variations and sweep efficiencies within the FDWS. This information is input into a 3-D compositional simulator model which will be continuously updated during the project. The simulator, being developed, will verify and enhance our reservoir characterization work and also aid in the site selection and design and reservoir management of the Part 2 WAG. Various laboratory testing including produced gas analysis and oil PVT tests are nearing completion as well. The site of the infill well has been selected and drilling is scheduled to commence in September. Minimum miscibility pressure tests will also begin in September. We continue to encounter mechanical problems with many wells in the project area. There have been many local operators on site during our workovers and injectivity tests and we continue to make all of our data and results available to these operators.

GEOLOGICAL MODELING

A three-dimensional geologic model of Cypress Sandstone of the project area was created using the STRATIGRAPHIC GEOCELLULAR MODELING (SGM) computer program. This model uses data from about 230 wells and includes data from the

Pinnell, Sawyer, Strong and other leases that are included in this project.

The 3-D visualizations produced by SGM assist in the interpretation of the location, continuity and size of the productive intervals. The distribution of the A,B,C,D and E sand zones in the Pinnell, Sawyer, and Strong projects are shown in Figure 7. The bright yellow color denotes clean sand while dark brown denotes shale.

Figures 8-11 show details of the Pinnell and Sawyer units.

PHASE BEHAVIOR OF MATTOON CRUDE OIL AND CO2

The objective of these tests are to determine the swelling and viscosity reduction effects of carbon dioxide (CO2) with Cypress crude oil from the Mattoon Field and to provide PVT data for engineering calculation and reservoir simulation.

A crude oil sample collected from the tubing head of the Pinnell Uphoff No. 1 was combined with CO2 in a PVT visual cell. Four -step differential vaporization tests were carried out with CO2-saturated oil samples at 500 psig and 1000 psig at the reservoir temperature of 80 F. Equilibrium gas volumes were measured at cell and standard conditions, and also analyzed by gas chromatographic techniques. Oil density, viscosity, solution gas to oil ratio and compositions were also determined (Tables 1-5, figs. 12-13).

Figure 13 shows that the volume of reservoir crude can increase by 1.55 times its original volume and its viscosity decreases from 4.71 centipoise to 0.81 centipoise as a result of carbon dioxide injection. This helps improve oil recovery by increasing the mobility of the oil phase as well as reducing residual oil saturation.

CORE DISPLACEMENT EXPERIMENTS

Core displacement equipment was set up and tested for the measurement of oil-brine and CO2-oil relative permeability data. Test runs were performed with a 2-inch diameter, 3.5-inch long Cypress sandstone sample from the Lawrence Field in Illinois.

Measurements on Cypress sandstone samples from the Mattoon Field will start when the core samples are obtained from the infill well.

FIELD TESTING

PINNELL "A" SUBUNIT

Approximately 3000 tons of liquefied CO_2 was injected into the "A" sand on the Pinnell Lease from 12 April 93 until 14 May 93. We injected for approximately 12 hours per day at an average rate of 11.27 tons per hour or 1.2BPM. The average CO_2 injection pressure was 597.82 psi. Shut in pressure after 45 days was 740psig at surface. The estimated bottom hole pressure was 850psi. We injected into the Pinnell 3W and monitored the 1 Pinnell Uphoff. On 29 April 93 we performed a gas chromatography test which showed 5.58 percent CO_2. Pressure on the annulus and on the tubing continued to climb. On 17 May 93 we repeated the gas analysis and found 72.91 percent CO_2. We made daily adjustments to the choke setting to stabilize the oil flow, gas flow, and pressures.

This injection test proved that the Pinnell "A" sand was present in both wells and also confirms the limited areal extent of this Cypress sand subunit. The casing pressure of 1 Pinnell Uphoff has built up to 390 psi surface with estimated bottom hole pressure of 455 psi. Immiscible CO_2 gas displacement showed a short oil response followed by a CO_2 gas breakthrough into 1 Pinnell Uphoff. Initial production peaked at 64 barrels per day, dropped considerably after the gas breakthrough, and has been maintained at 10 - 15 BPD using a choke system to control back pressure (see fig 14). Repeated cycles of production with and without back pressure shows that holding back pressure on the producing well increases production from the well. (see figs. 15-16).

We installed corrosion coupons in the flow line and the analysis show that there appears to be no significant corrosion problem. Production can be handled with standard equipment.

The Pinnell "A" sandunit has been partially repressured by the CO_2 injection. The minimum miscible pressure (MMP) has not yet been determined. The MMP is probably between 1100 and 1500 psi. At an MMP of 1200 psi the CO_2 formation factor is estimated at 1.0 reservoir bbls/MSCF. The hydrocarbon pore volume (HPV) for the sand unit is 243,600 bbls using: (a) porosity - 20 percent; (b) oil saturation - 65 percent; (c) reservoir volume - 240 acre feet. Thus the injection of 2947 tons or 50700 MSCF of CO_2 is equivalent to 0.2 HPV at miscible conditions.

With the establishment of injectivity and reservoir conformance in the initial CO_2 injection, water injection needs to be initiated in this WAG project. By injecting water we will attempt to:

1.Retard the gravity override of the CO2 in the reservoir.

2.Aid in bringing the reservoir up to miscible conditions.

3.Initialize the secondary recovery oil bank.

If one uses an average of a 2:1 Gas/Water injection the next step would be to inject 21,200 bbls of water. At 150 BPD the injection cycle would last for 140 days.

SAWYER "E" SUBUNIT

Approximately 2000 tons of liquefied CO2 was injected into the "E" sand on the Sawyer Lease from 19 May 93 until 30 June 93. We injected for approximately 12 hours per day at an average rate of 10.50 tons per hour or .95 BPM. The average CO2 injection pressure was 922 psi. Shut in pressure after 45 days was 800 psig at surface. The estimated bottom hole pressure was 875 psi. We injected into the Sawyer 1 Community 3 and monitored the Railroad 18 and 19. We produced from #2 Morris and the #1 Sawyer Community 2. On 11 June 93 we performed a gas chromatography test on the Railroad 18 and 19 wells which showed 95.48 and 97.91 percent CO2 respectively. We also tested the #1 Sawyer Community 2 (Water Tower)and found 61.20 percent CO2. On 29 June 93 we retested the water tower well. The CO2 had climbed to 73.03 percent and the Morris # 2 tested to 38.43 percent CO2 (see figs. 17-18).

To this point, this injection test proved that the Sawyer "E" sand was present in all these wells and also confirms the limited areal extent of this Cypress sand subunit. The casing pressure of Railroad 18 and 19 wells has built up to 765 psi surface with estimated bottom hole pressure of 900 psi. Immiscible CO2 gas displacement showed a short oil response followed by a CO2 gas break through into both the Railroad 18 and 19 units in less than one week. In order to maximize the efficiency of the CO2 we shut those wells in and continue to monitor the pressures on a daily basis and periodically repeat the fluid flow test.

We installed corrosion coupons in the flow lines and the analyses show no apparent significant corrosion problems. Production can be handled with standard equipment.

On the two producing wells we make daily adjustments to the choke setting to stabilize the oil flow, gas flow, and pressures. Average oil production during this period been 20 BPD. Average water production of 159 BPD. (see fig 19).

Mattoon Field Cypress Formation Lithology
yellow = clean sand, dark brown = shale

FIGURE 7

Mattoon Pinnell Unit Cypress Lithology
yellow = clean sand, dark brown = shale

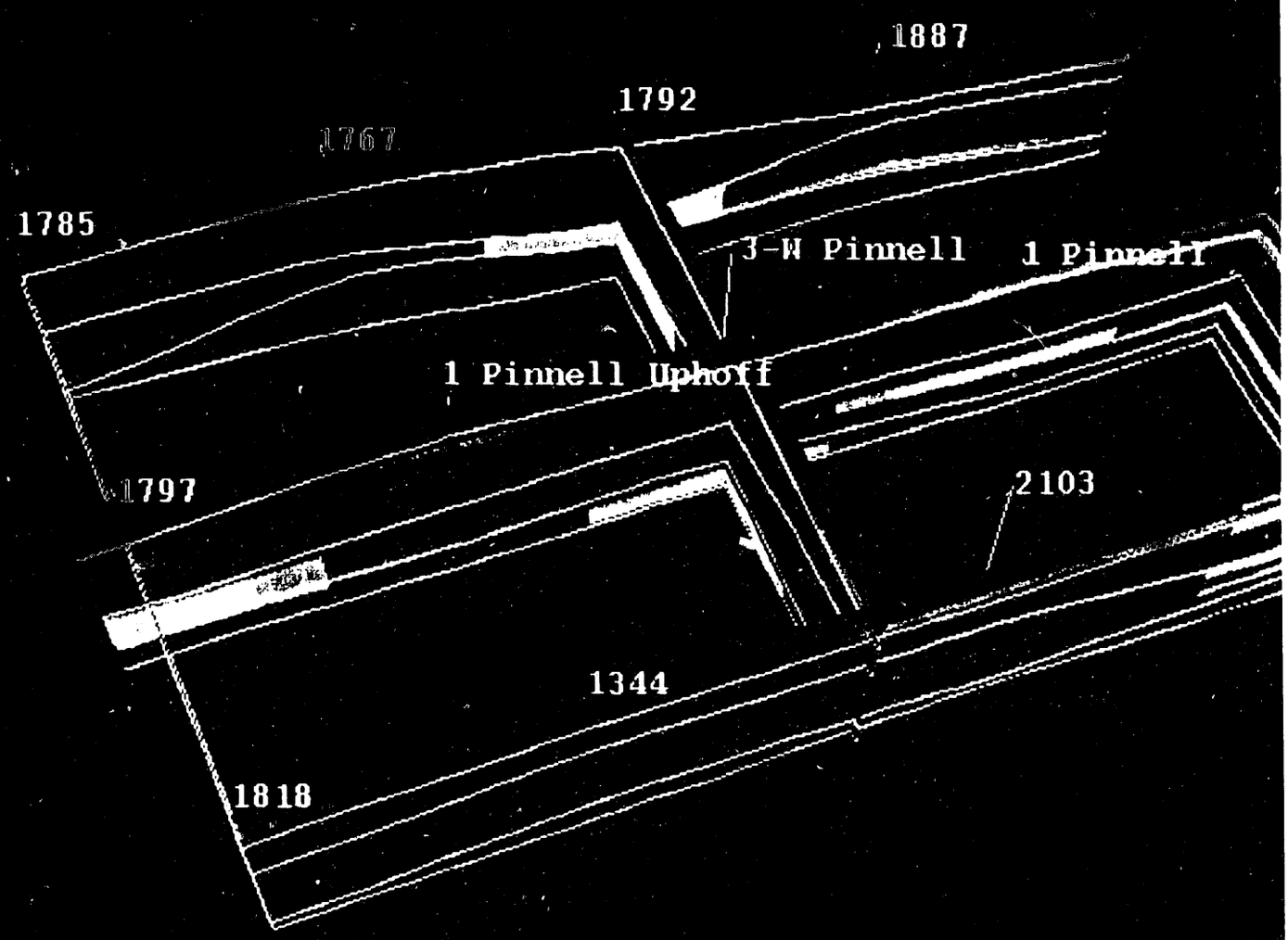
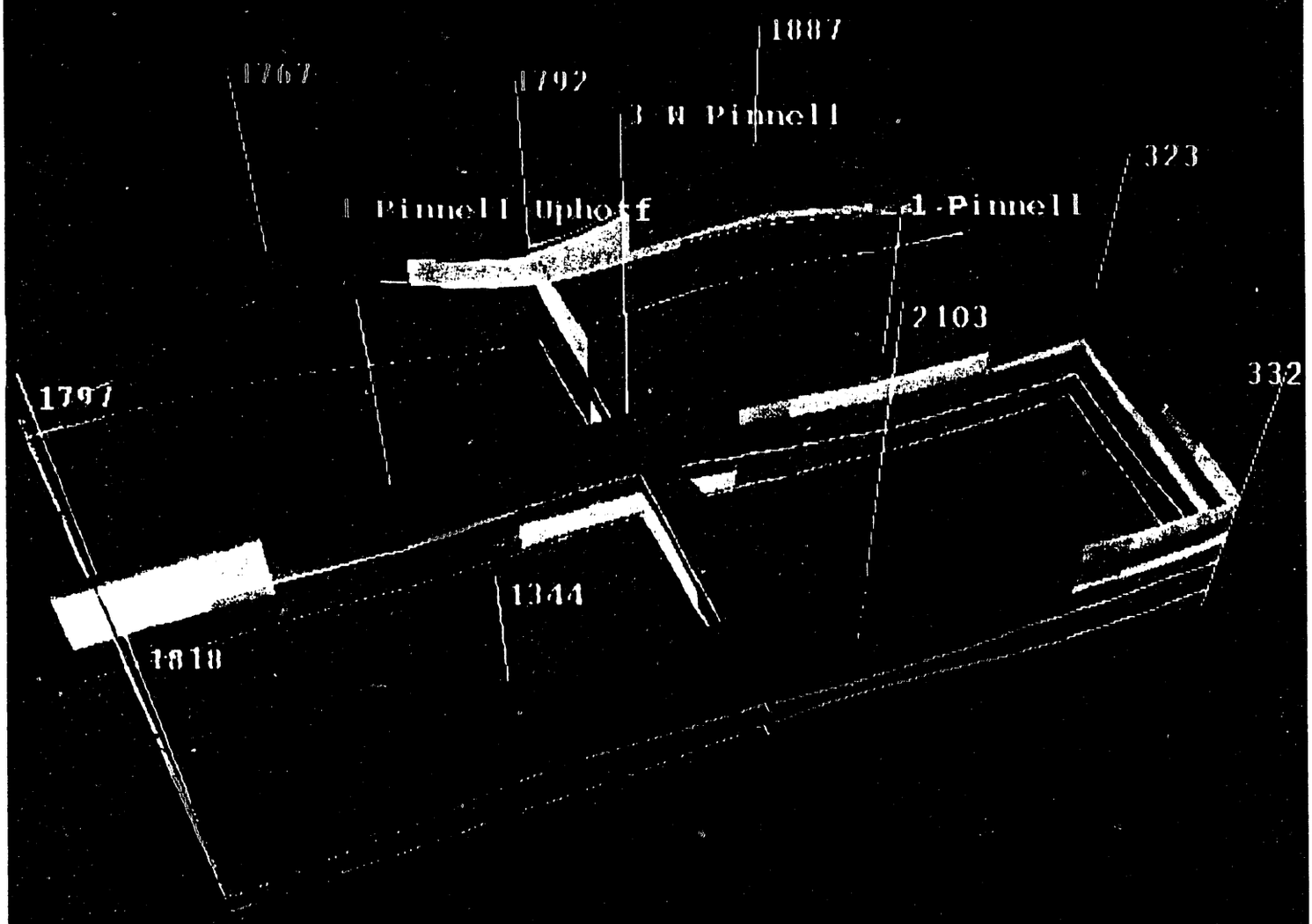


FIGURE 8

Mattoon Pinnell Unit A & B Sands

yellow = clean sand, dark brown = shale



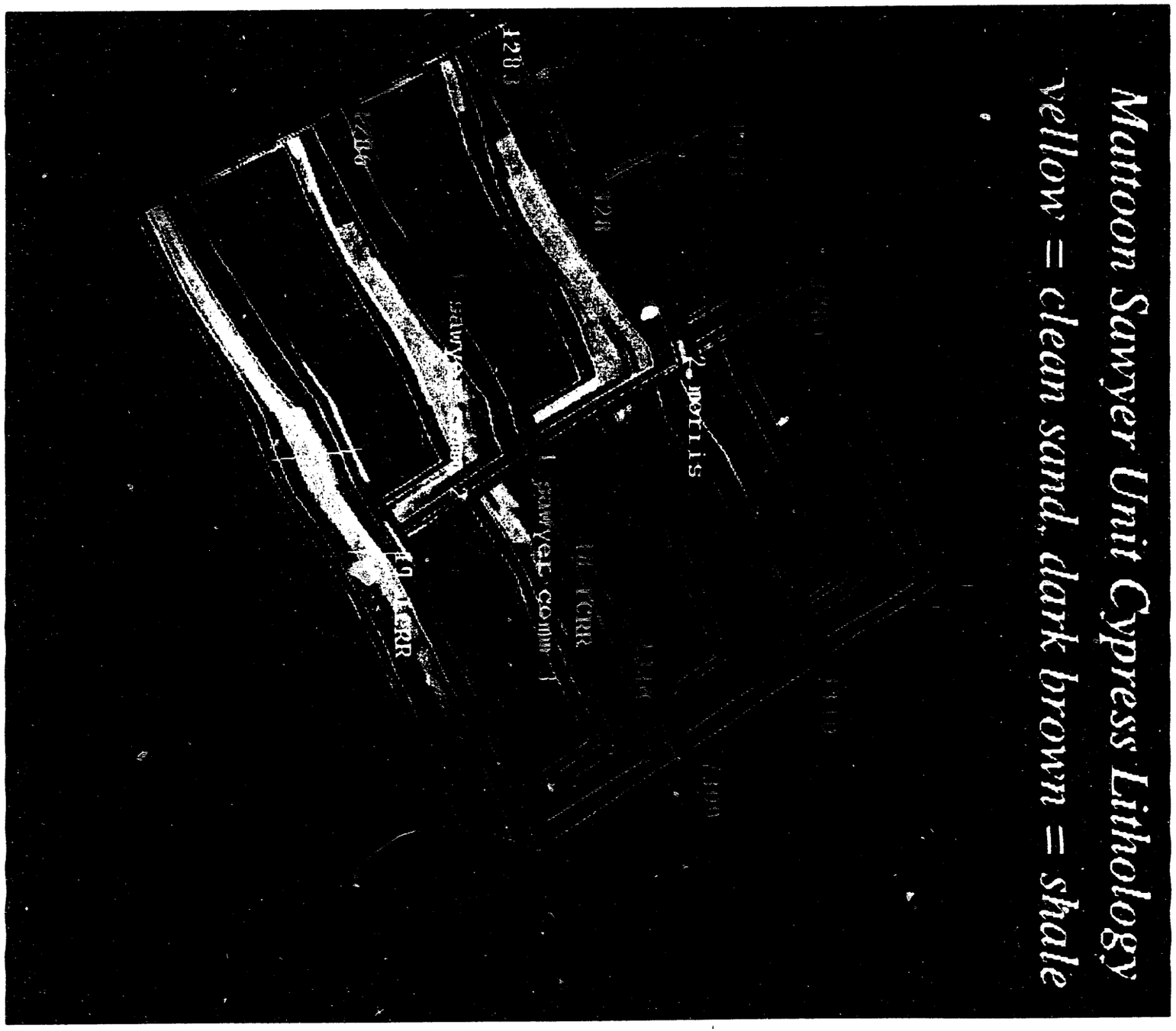

Mattoon Sawyer Unit Cypress Lithology
yellow = clean sand, dark brown = shale
2 morris
1 sawyer comm 1
17 TCRR

FIGURE 10

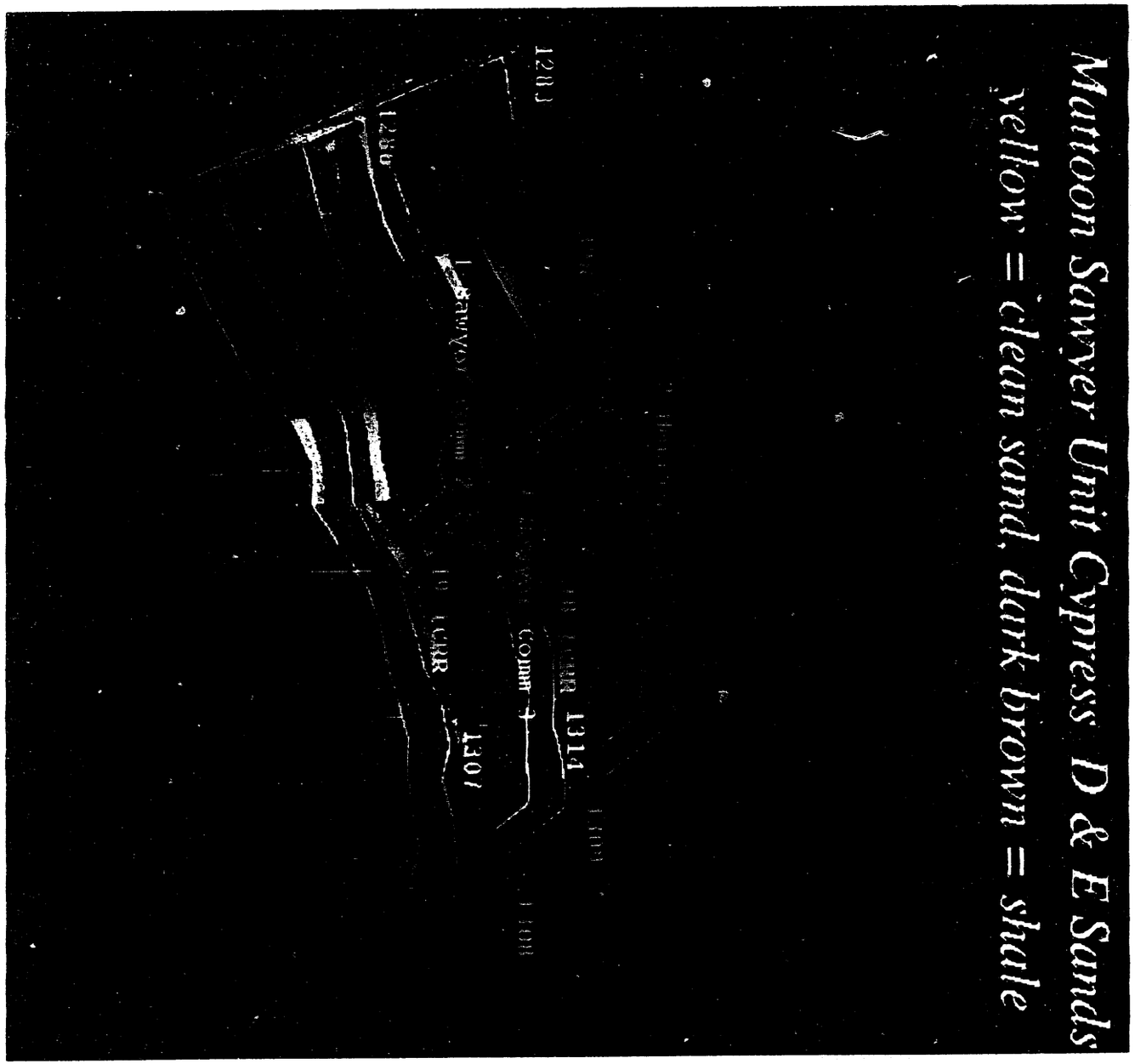

Mutoon Sawyer Unit Cypress D & E Sands
yellow = clean sand, dark brown = shale
1314
1301
1283
1280

FIGURE 11

Table 3 - Composition of gas liberated from Mattoon crude oil saturated with CO_2 at 500 psig

Pressure	100	200	300	400
CO_2	98.42	98.11	97.61	96.71
N_2	0.13	0.15	0.19	0.22
C1	0.12	0.35	0.61	1.10
C2	0.14	0.21	0.26	0.35
C3	0.26	0.32	0.40	0.70
IC4	0.06	0.08	0.09	0.11
NC4	0.20	0.24	0.35	0.37
NC5	0.11	0.11	0.10	0.09
IC5	0.23	0.18	0.19	0.16
C6+	0.33	0.25	0.20	0.18

Table 4: Composition of gas liberated from Pinnell crude oil saturated with CO_2 at 1000 psig

Pressure	500	600	725	850
CO_2	98.65	98.56	98.49	98.37
N_2	0.04	0.05	0.08	0.22
C1	0.17	0.20	0.24	0.33
C2	0.07	0.09	0.13	0.12
C3	0.27	0.33	0.35	0.33
IC4	0.03	0.05	0.05	0.05
NC4	0.21	0.23	0.22	0.21
NC5	0.07	0.06	0.06	0.06
IC5	0.15	0.13	0.12	0.11
C6+	0.33	0.30	0.26	0.19

Table 5 - Oil composition of differential vaporization test of Mattoon crude oil saturated with CO2

Pressure	1000	850	720	600	500	400	300	200	0
CO2	70.23	66.48	55.60	46.58	35.42	31.01	25.45	18.83	0
N2	0.16	0.15	0.05	0.02	0.04	0.07	0.05	0.03	0
C1	0.24	0.22	0.14	0.09	0.34	0.35	0.16	0.07	0
C2	0.09	0.08	0.07	0.04	0.21	0.11	0.07	0.04	0
c3	0.73	0.78	0.95	1.07	1.57	1.39	1.38	1.45	1.72
ic4	0.04	0.03	0.03	0.02	0.49	0.04	0.02	0.02	0.00
c4	1.06	1.17	1.50	1.78	2.06	2.27	2.43	2.61	3.17
ic5	0.46	0.51	0.67	0.79	1.15	1.01	1.10	1.19	1.45
nc5	0.88	0.99	1.29	1.54	1.83	1.96	2.13	2.31	2.81
c6	1.74	1.95	2.59	3.10	3.63	3.87	4.20	4.58	5.61
c7	3.33	3.77	5.07	6.14	7.49	7.91	8.61	9.41	11.64
c8	3.52	3.99	5.36	6.49	7.74	8.36	9.10	9.95	12.31
c9	2.28	2.59	3.47	4.21	5.02	5.42	5.90	6.45	7.98
c10	2.03	2.29	3.08	3.73	4.45	4.81	5.23	5.72	7.08
c11	1.52	1.72	2.31	2.80	3.33	3.60	3.92	4.28	5.30
c12	1.22	1.39	1.86	2.26	2.69	2.91	3.16	3.46	4.28
c13	1.21	1.37	1.85	2.24	2.67	2.88	3.13	3.43	4.24
c14	1.00	1.14	1.53	1.85	2.21	2.38	2.59	2.84	3.51
c15	0.91	1.03	1.39	1.68	2.01	2.17	2.36	2.58	3.19
c16	0.70	0.79	1.06	1.29	1.53	1.66	1.80	1.97	2.44
c17	0.65	0.74	0.99	1.20	1.43	1.55	1.69	1.84	2.28
c18	0.62	0.70	0.94	1.13	1.35	1.46	1.59	1.74	2.15
c19	0.52	0.59	0.79	0.96	1.14	1.24	1.35	1.47	1.82
c20	0.46	0.52	0.70	0.85	1.01	1.09	1.19	1.30	1.61
c21	0.40	0.46	0.61	0.74	0.89	0.96	1.04	1.14	1.41
c22	0.36	0.41	0.55	0.66	0.79	0.86	0.93	1.02	1.26
c23	0.33	0.37	0.50	0.60	0.72	0.77	0.84	0.92	1.14
c24	0.29	0.32	0.44	0.53	0.63	0.68	0.74	0.81	1.00
c25	0.28	0.32	0.43	0.52	0.62	0.67	0.72	0.79	0.98
c26	0.22	0.25	0.34	0.41	0.49	0.53	0.58	0.63	0.78
c27	0.22	0.25	0.34	0.41	0.49	0.53	0.58	0.63	0.78
c28	0.22	0.25	0.34	0.41	0.48	0.52	0.57	0.62	0.77
c29	0.18	0.20	0.27	0.33	0.39	0.42	0.46	0.50	0.62
c30+	1.91	2.16	2.90	3.52	4.19	4.53	4.93	5.39	6.67

Table 5 - Oil composition of differential vaporization test of Mattoon crude oil saturated with CO_2

Pressure	1000	850	720	600	500	400	300	200	0
CO2	70.23	66.48	55.60	46.58	35.42	31.01	25.45	18.83	0
N2	0.16	0.15	0.05	0.02	0.04	0.07	0.05	0.03	0
C1	0.24	0.22	0.14	0.09	0.34	0.35	0.16	0.07	0
C2	0.09	0.08	0.07	0.04	0.21	0.11	0.07	0.04	0
c3	0.73	0.78	0.95	1.07	1.57	1.39	1.38	1.45	1.72
ic4	0.04	0.03	0.03	0.02	0.49	0.04	0.02	0.02	0.00
c4	1.06	1.17	1.50	1.78	2.06	2.27	2.43	2.61	3.17
ic5	0.46	0.51	0.67	0.79	1.15	1.01	1.10	1.19	1.45
nc5	0.88	0.99	1.29	1.54	1.83	1.96	2.13	2.31	2.81
c6	1.74	1.95	2.59	3.10	3.63	3.87	4.20	4.58	5.61
c7	3.33	3.77	5.07	6.14	7.49	7.91	8.61	9.41	11.64
c8	3.52	3.99	5.36	6.49	7.74	8.36	9.10	9.95	12.31
c9	2.28	2.59	3.47	4.21	5.02	5.42	5.90	6.45	7.98
c10	2.03	2.29	3.08	3.73	4.45	4.81	5.23	5.72	7.08
c11	1.52	1.72	2.31	2.80	3.33	3.60	3.92	4.28	5.30
c12	1.22	1.39	1.86	2.26	2.69	2.91	3.16	3.46	4.28
c13	1.21	1.37	1.85	2.24	2.67	2.88	3.13	3.43	4.24
c14	1.00	1.14	1.53	1.85	2.21	2.38	2.59	2.84	3.51
c15	0.91	1.03	1.39	1.68	2.01	2.17	2.36	2.58	3.19
c16	0.70	0.79	1.06	1.29	1.53	1.66	1.80	1.97	2.44
c17	0.65	0.74	0.99	1.20	1.43	1.55	1.69	1.84	2.28
c18	0.62	0.70	0.94	1.13	1.35	1.46	1.59	1.74	2.15
c19	0.52	0.59	0.79	0.96	1.14	1.24	1.35	1.47	1.82
c20	0.46	0.52	0.70	0.85	1.01	1.09	1.19	1.30	1.61
c21	0.40	0.46	0.61	0.74	0.89	0.96	1.04	1.14	1.41
c22	0.36	0.41	0.55	0.66	0.79	0.86	0.93	1.02	1.26
c23	0.33	0.37	0.50	0.60	0.72	0.77	0.84	0.92	1.14
c24	0.29	0.32	0.44	0.53	0.63	0.68	0.74	0.81	1.00
c25	0.28	0.32	0.43	0.52	0.62	0.67	0.72	0.79	0.98
c26	0.22	0.25	0.34	0.41	0.49	0.53	0.58	0.63	0.78
c27	0.22	0.25	0.34	0.41	0.49	0.53	0.58	0.63	0.78
c28	0.22	0.25	0.34	0.41	0.48	0.52	0.57	0.62	0.77
c29	0.18	0.20	0.27	0.33	0.39	0.42	0.46	0.50	0.62
c30+	1.91	2.16	2.90	3.52	4.19	4.53	4.93	5.39	6.67

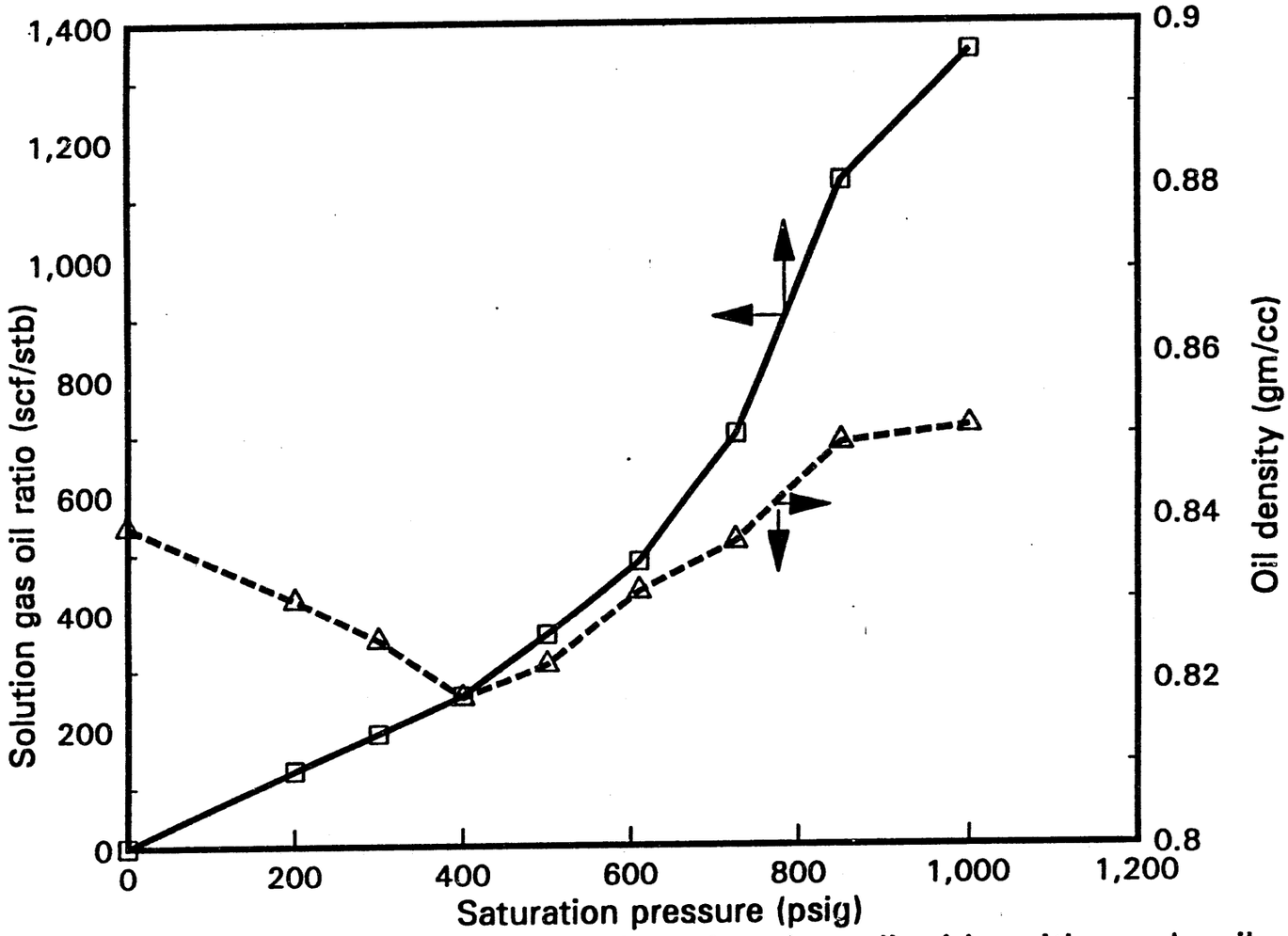


Fig. 12 - Phase behavior studies of carbon dioxide with crude oil from Pinnell Uphoff No. 1, Mattoon Field

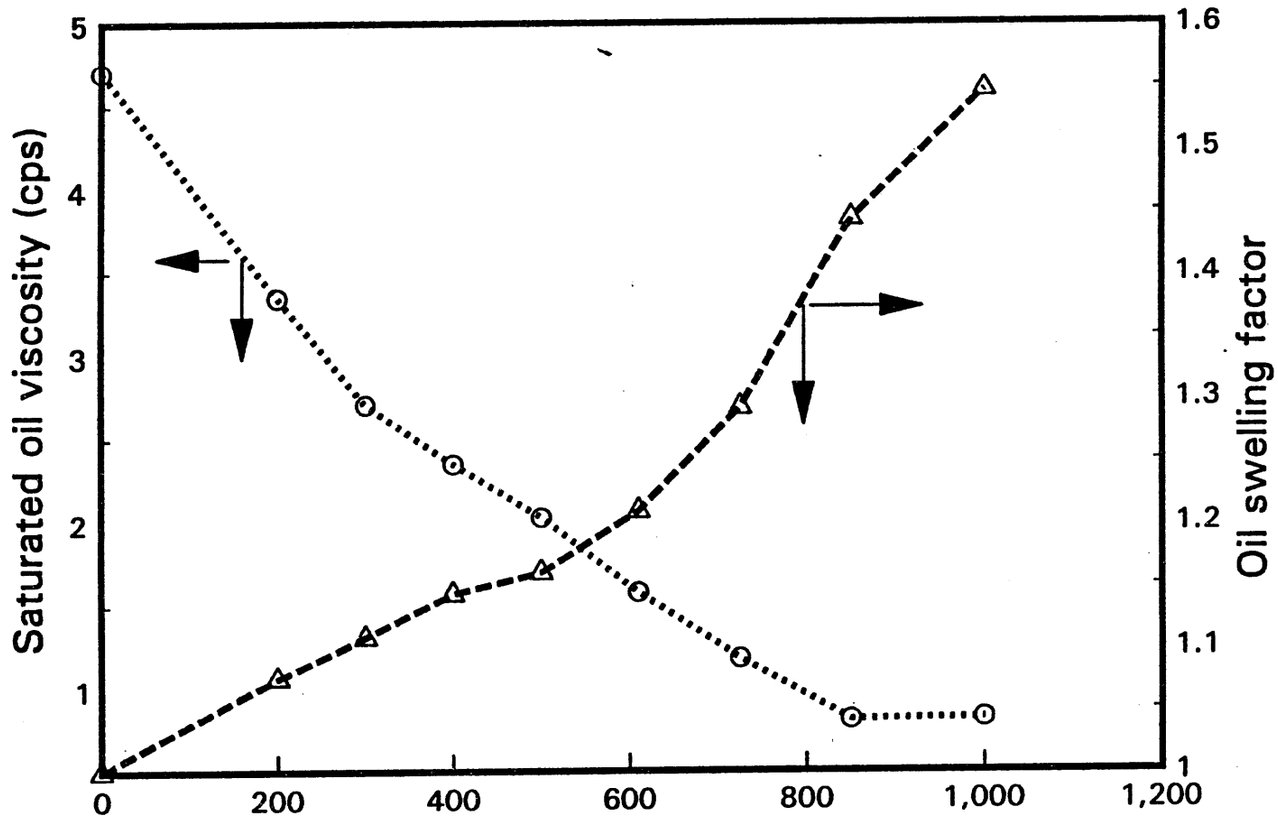


Fig. 13- Phase behavoir studies of CO2 with crude oil from Pinnell Uphoff No.1, Mattoon Field

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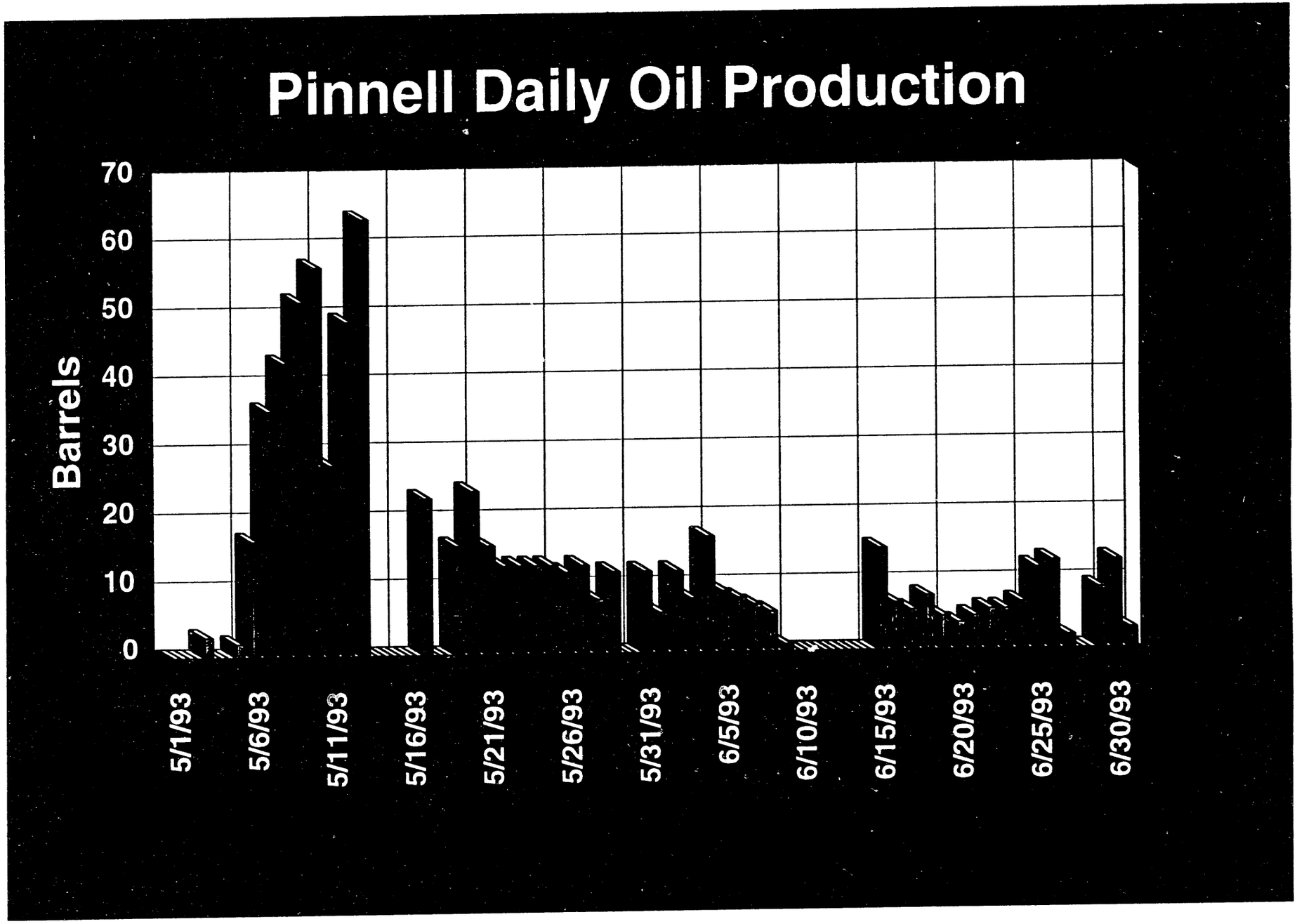

Pinnell Daily Oil Production
Barrels
70
60
50
40
30
20
10
0
5/1/93
5/6/93
5/11/93
5/16/93
5/21/93
5/26/93
5/31/93
6/5/93
6/10/93
6/15/93
6/20/93
6/25/93
6/30/93

FIGURE 14

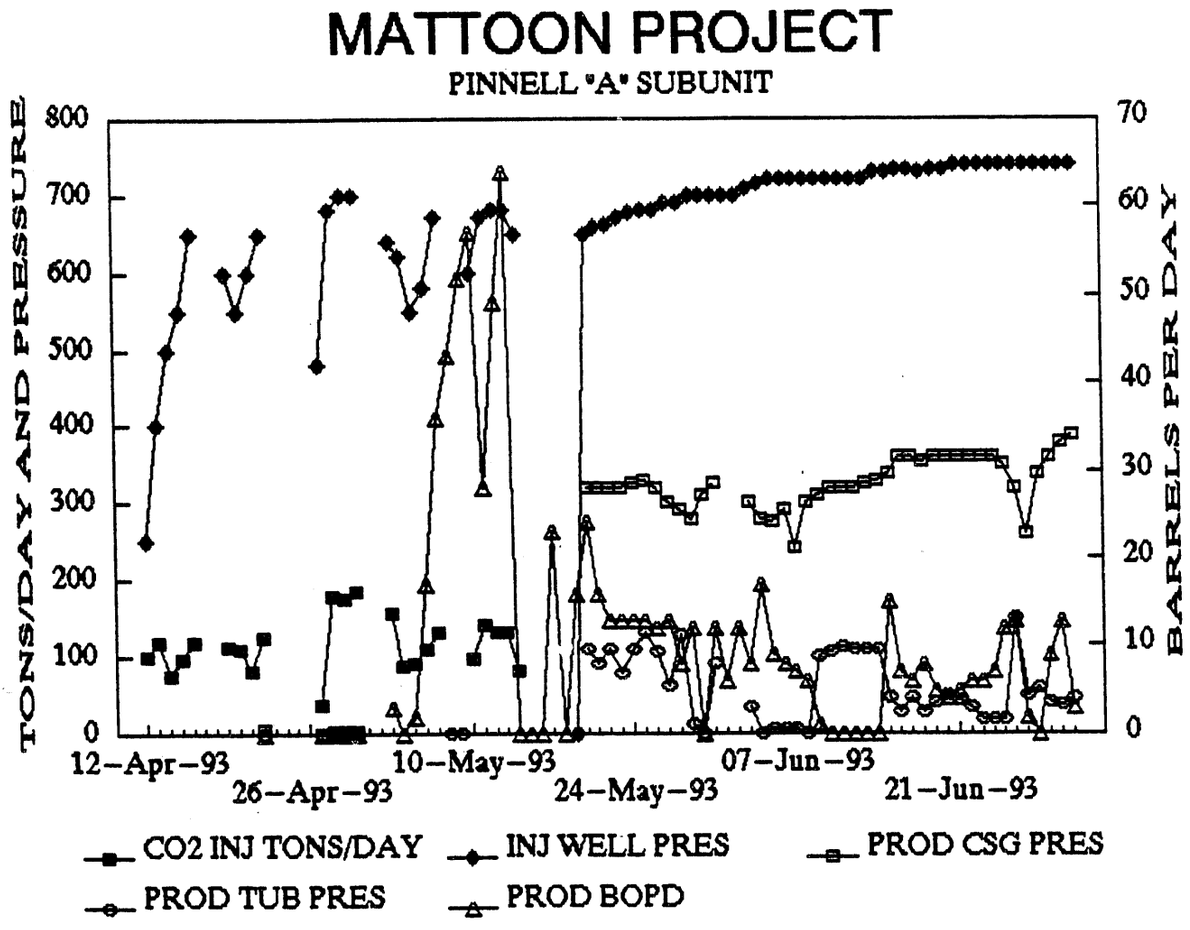

MATTOON PROJECT
PINNELL "A" SUBUNIT
TONS/DAY AND PRESSURE
BARRELS PER DAY
800
700
600
500
400
300
200
100
0
70
60
50
40
30
20
10
0
12-Apr-93
26-Apr-93
10-May-93
24-May-93
07-Jun-93
21-Jun-93
CO2 INJ TONS/DAY
INJ WELL PRES
PROD CSG PRES
PROD TUB PRES
PROD BOPD

FIGURE 15

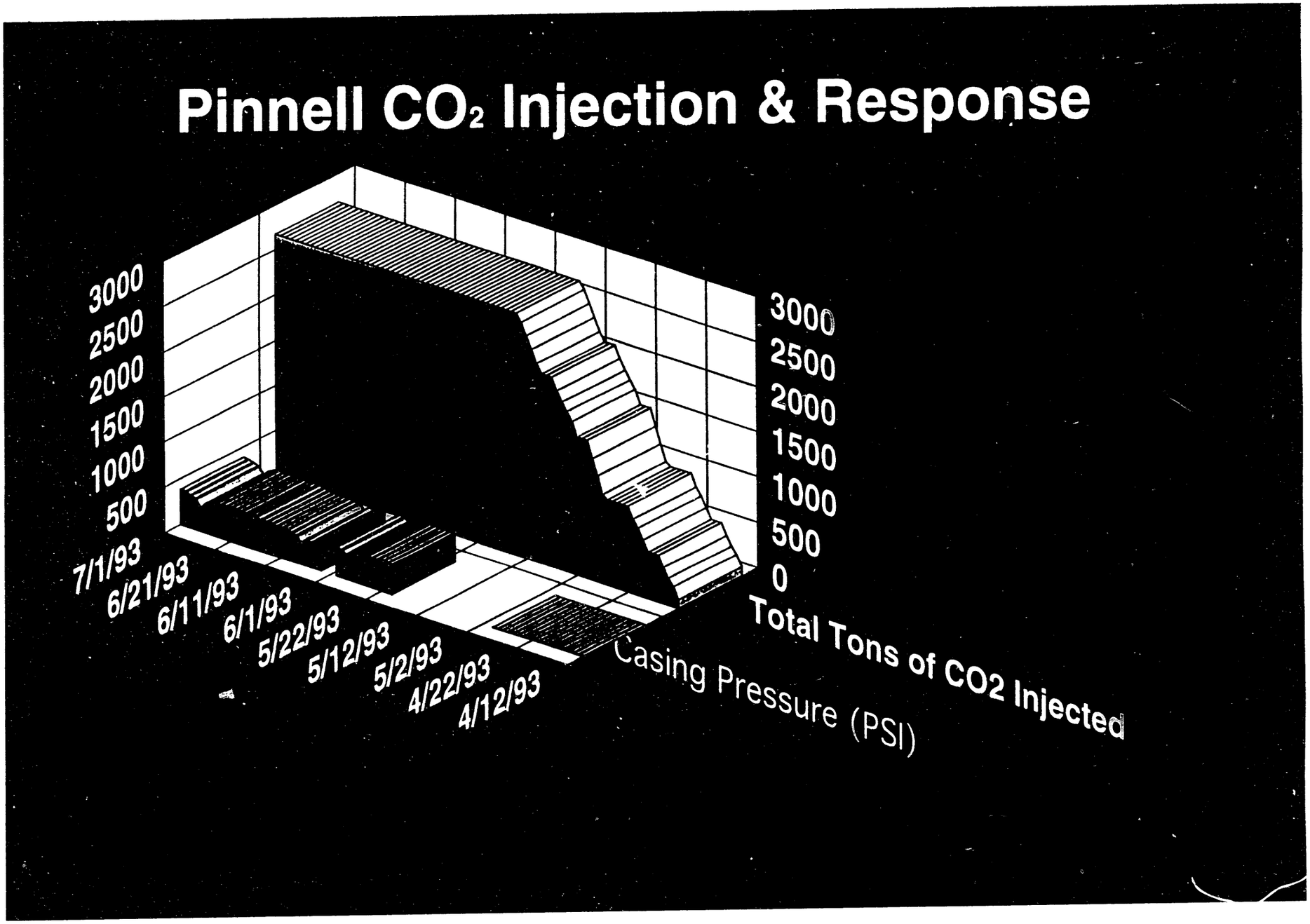

Pinnell CO2 Injection & Response
3000
2500
2000
1500
1000
500
7/1/93
6/21/93
6/11/93
6/1/93
5/22/93
5/12/93
5/2/93
4/22/93
4/12/93
Casing Pressure (PSI)
3000
2500
2000
1500
1000
500
0
Total Tons of CO2 Injected

FIGURE 16

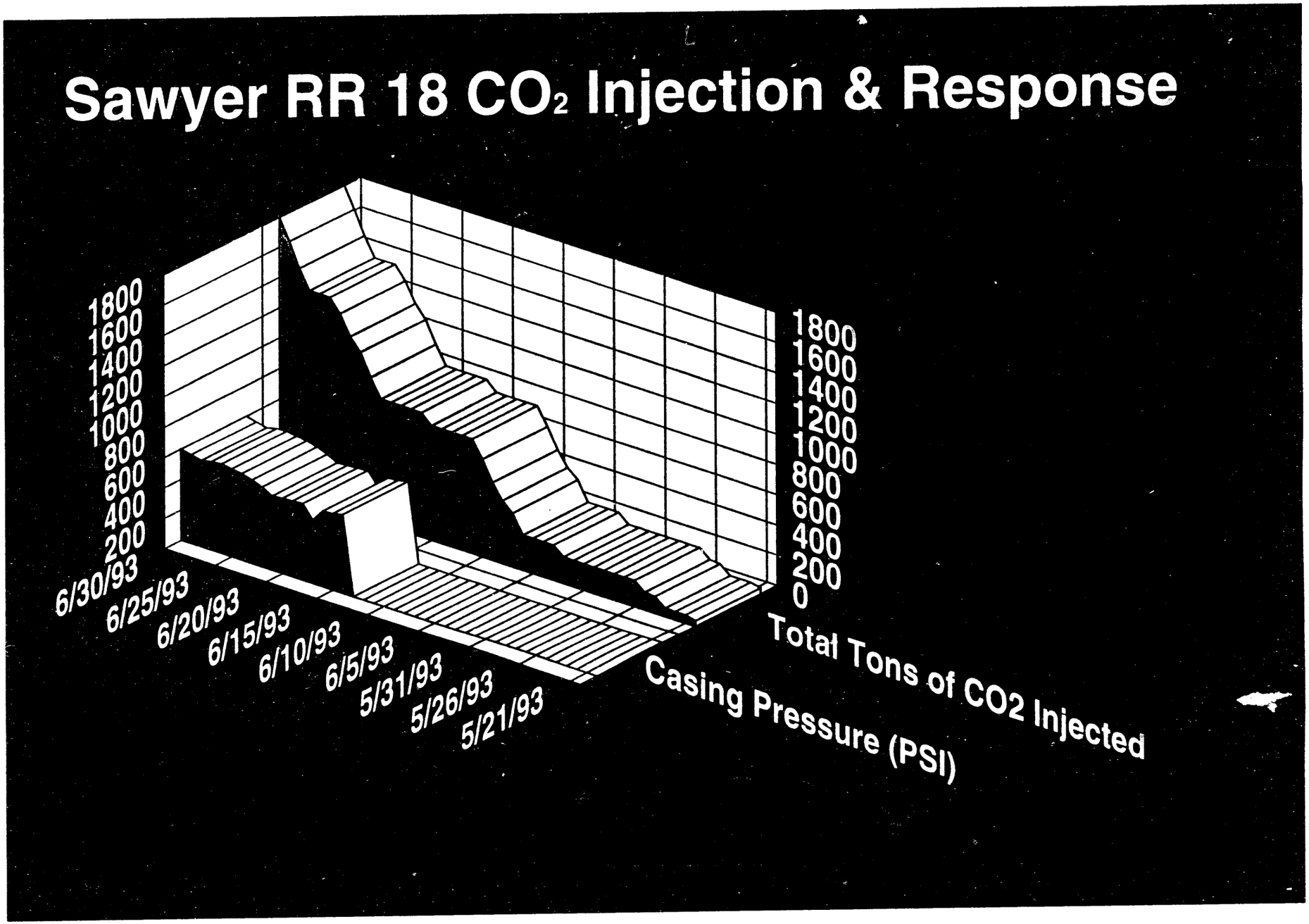

Sawyer RR 18 CO2 Injection & Response
1800
1600
1400
1200
1000
800
600
400
200
6/30/93
6/25/93
6/20/93
6/15/93
6/10/93
6/5/93
5/31/93
5/26/93
5/21/93
1800
1600
1400
1200
1000
800
600
400
200
0
Total Tons of CO2 Injected
Casing Pressure (PSI)

FIGURE 17

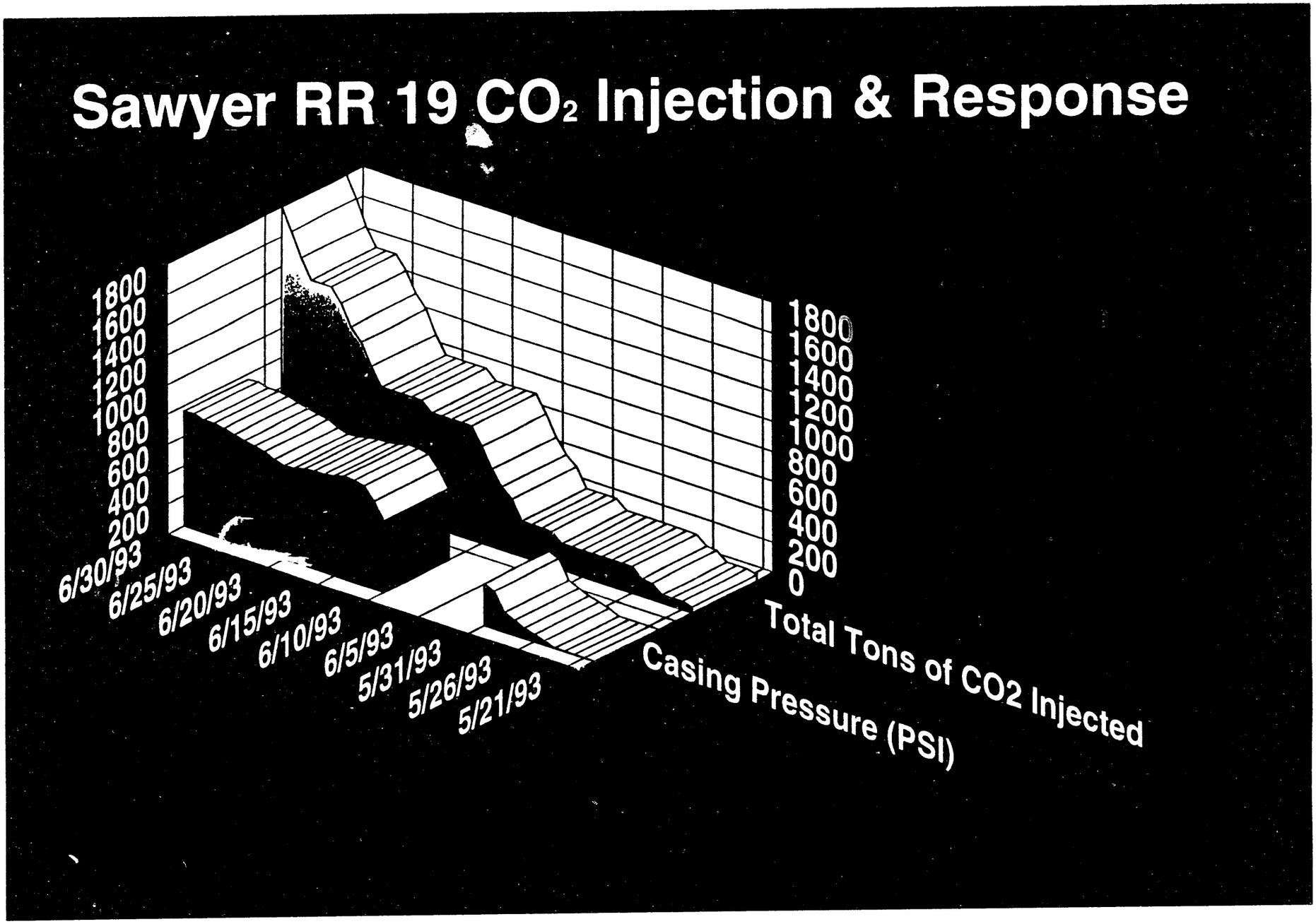

Sawyer RR 19 CO2 Injection & Response
1800
1600
1400
1200
1000
800
600
400
200
6/30/93
6/25/93
6/20/93
6/15/93
6/10/93
6/5/93
5/31/93
5/26/93
5/21/93
1800
1600
1400
1200
1000
800
600
400
200
0
Total Tons of CO2 Injected
Casing Pressure (PSI)

FIGURE 18

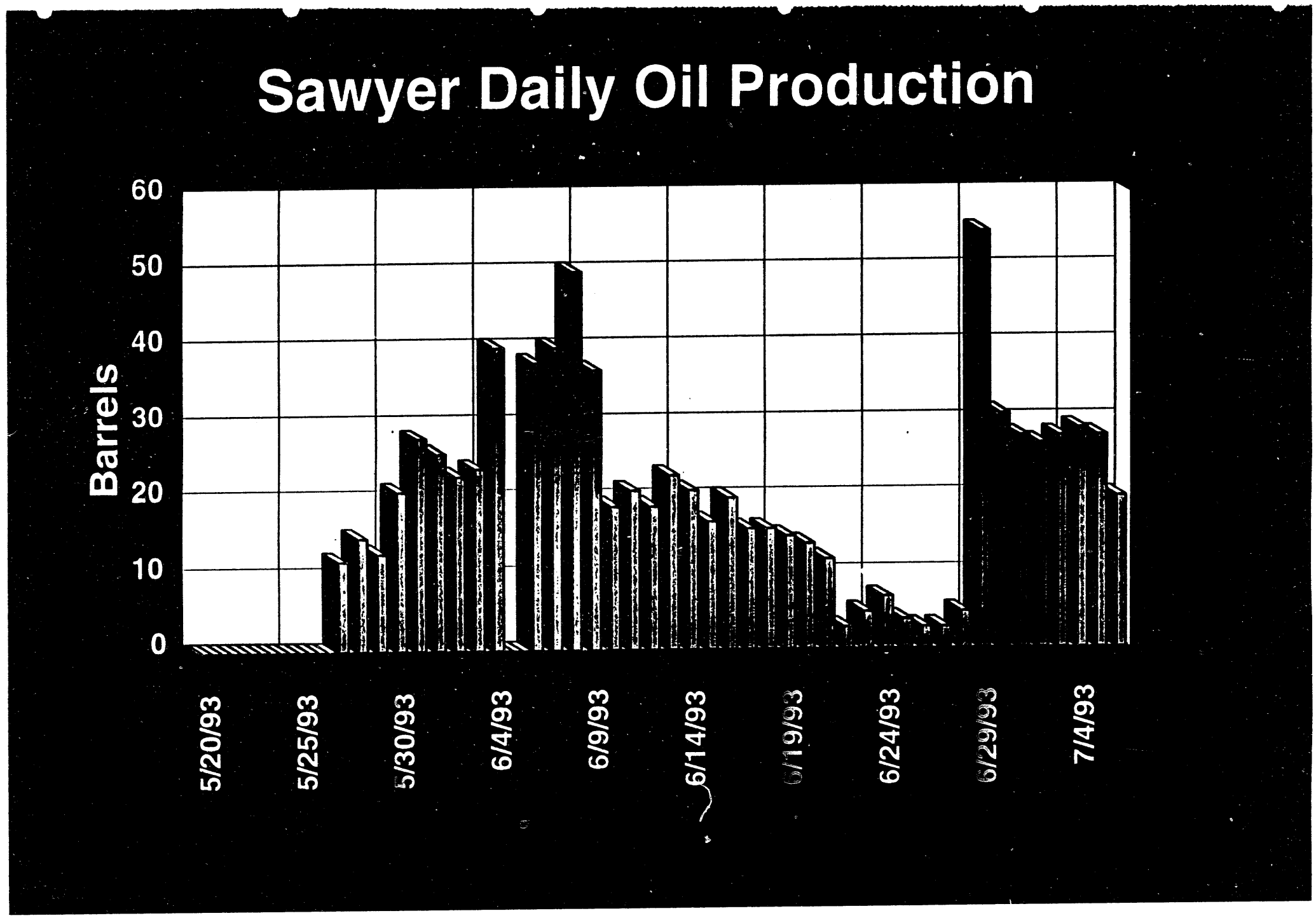
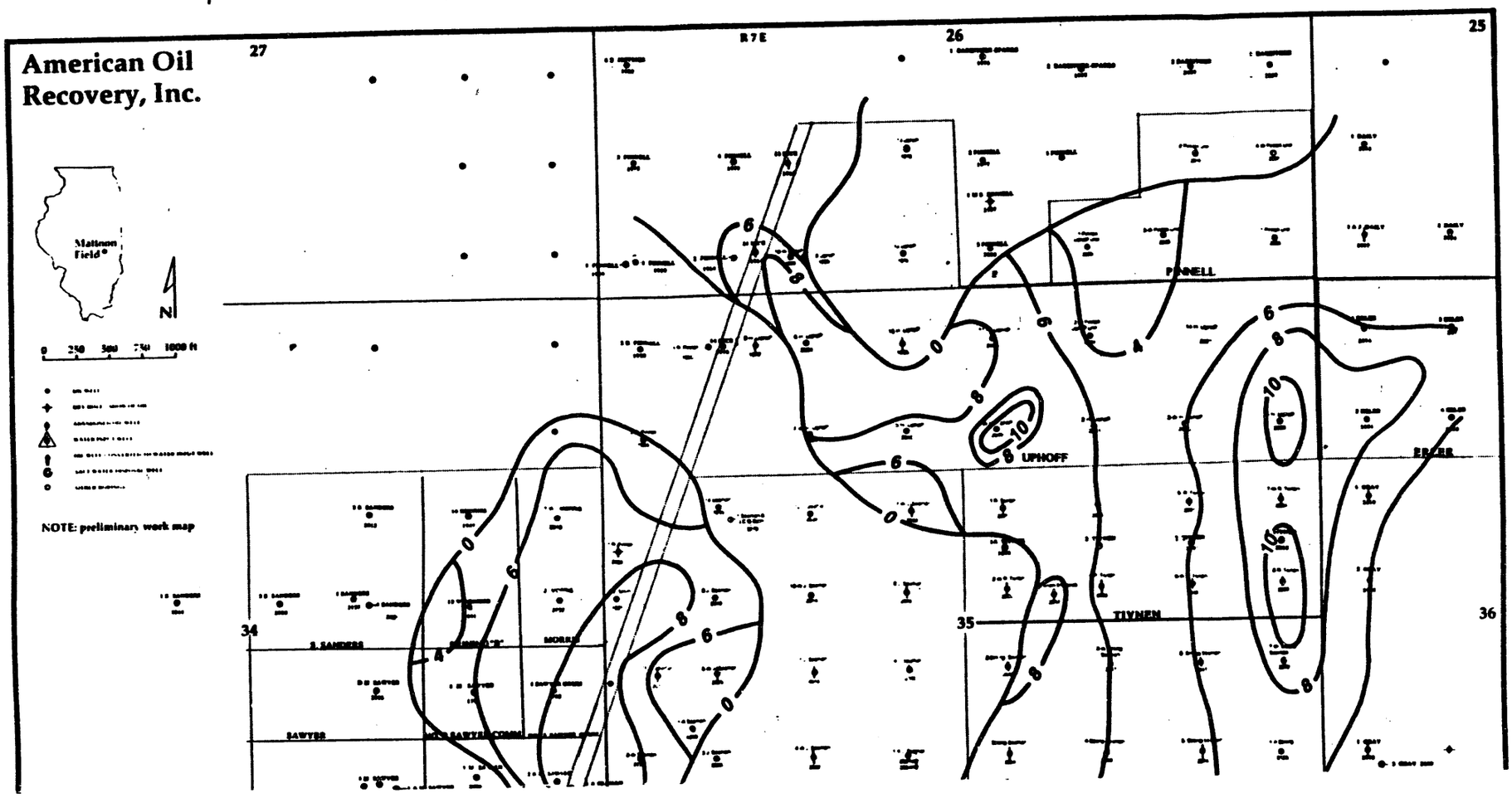

Sawyer Daily Oil Production
Barrels
60
50
40
30
20
10
0
5/20/93
5/25/93
5/30/93
6/4/93
6/9/93
6/14/93
6/19/93
6/24/93
6/29/93
7/4/93

FIGURE 19


American Oil
Recovery, Inc.
Mattoon Field
N
0 250 500 750 1000 ft
NOTE: preliminary work map
27
R7E
26
25
PINNELL
UPHOFF
ERLER
TIVNEN
34
35
36
S. SANDERS
SAWYER
MORRIS
0
4
6
8
10

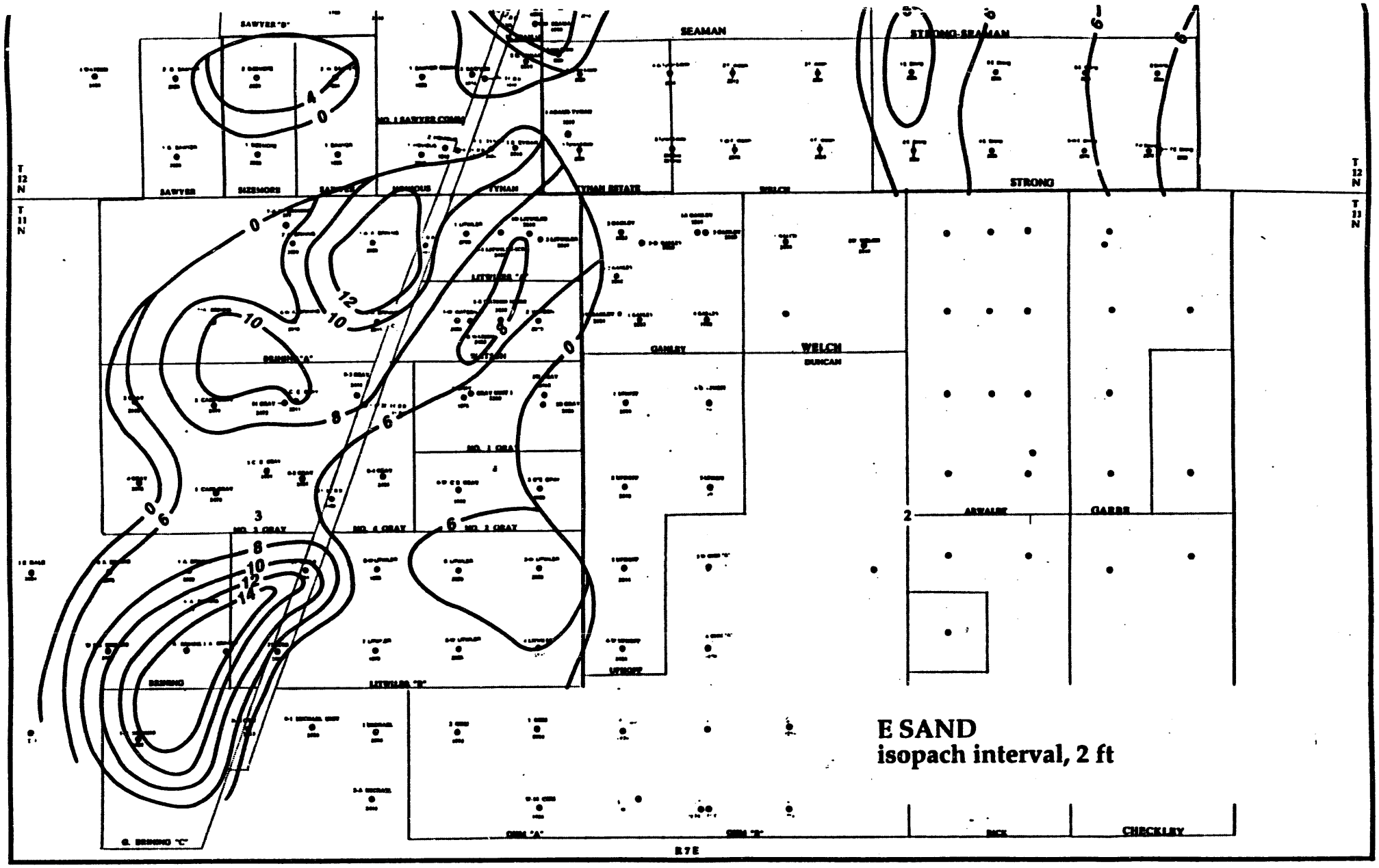
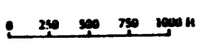
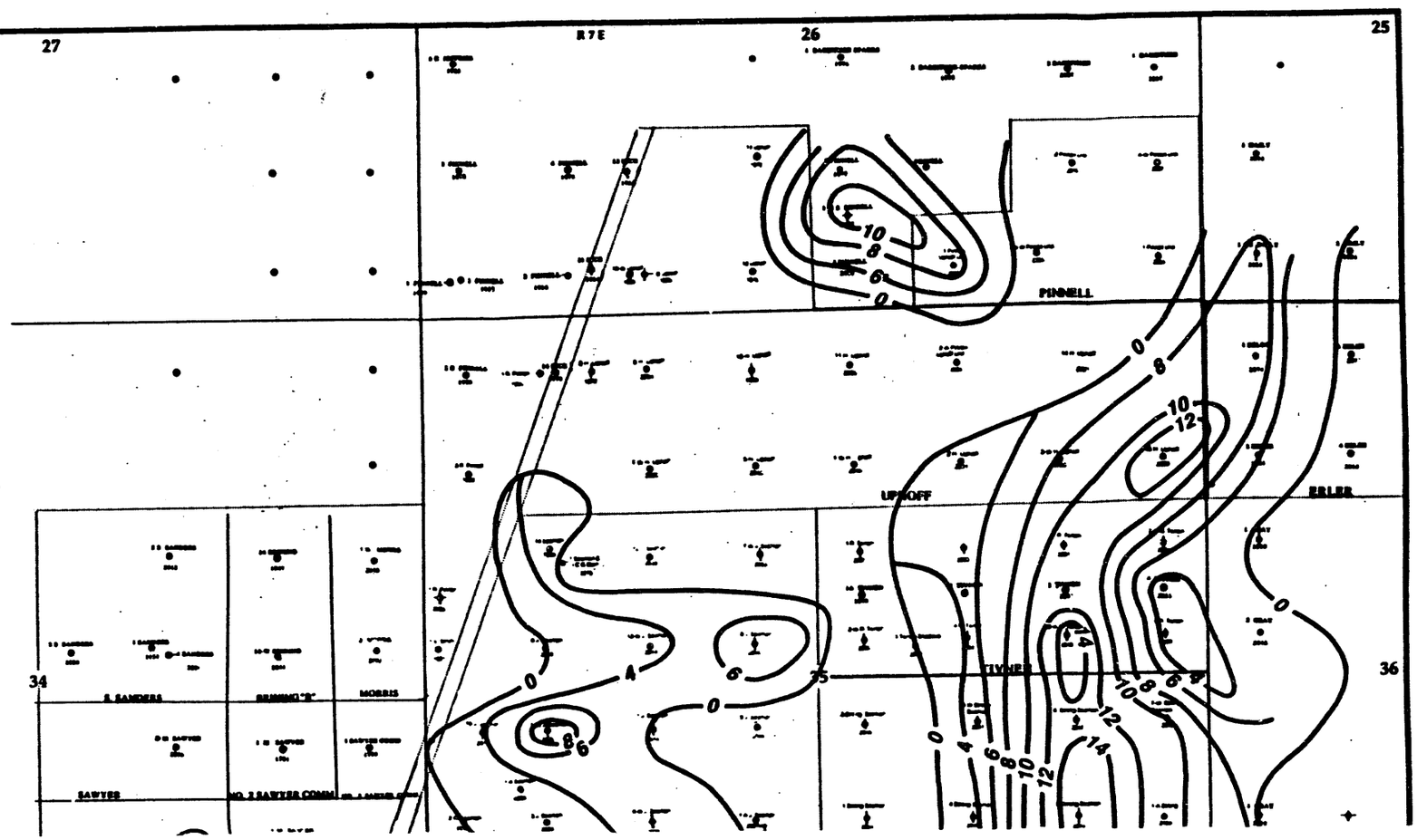

E SAND
isopach interval, 2 ft
T 12 N
T 11 N
R 7 E
SEAMAN
STRONG-SEAMAN
STRONG
WELCH
DUNCAN
GANLEY
ARVALIE
GARRE
CHECKLEY
SAWYER
SIZEMORE
TYNAN
TYNAN ESTATE
LITWILLER "A"
LITWILLER "B"
DRENNING
NO. 1 GRAY
NO. 2 GRAY
NO. 3 GRAY
NO. 4 GRAY
NO. 1 SAWYER-COMM
SAWYER "B"
0
2
4
6
8
10
12
14

FIGURE 6

American Oil Recovery, Inc.



NOTE: preliminary work map



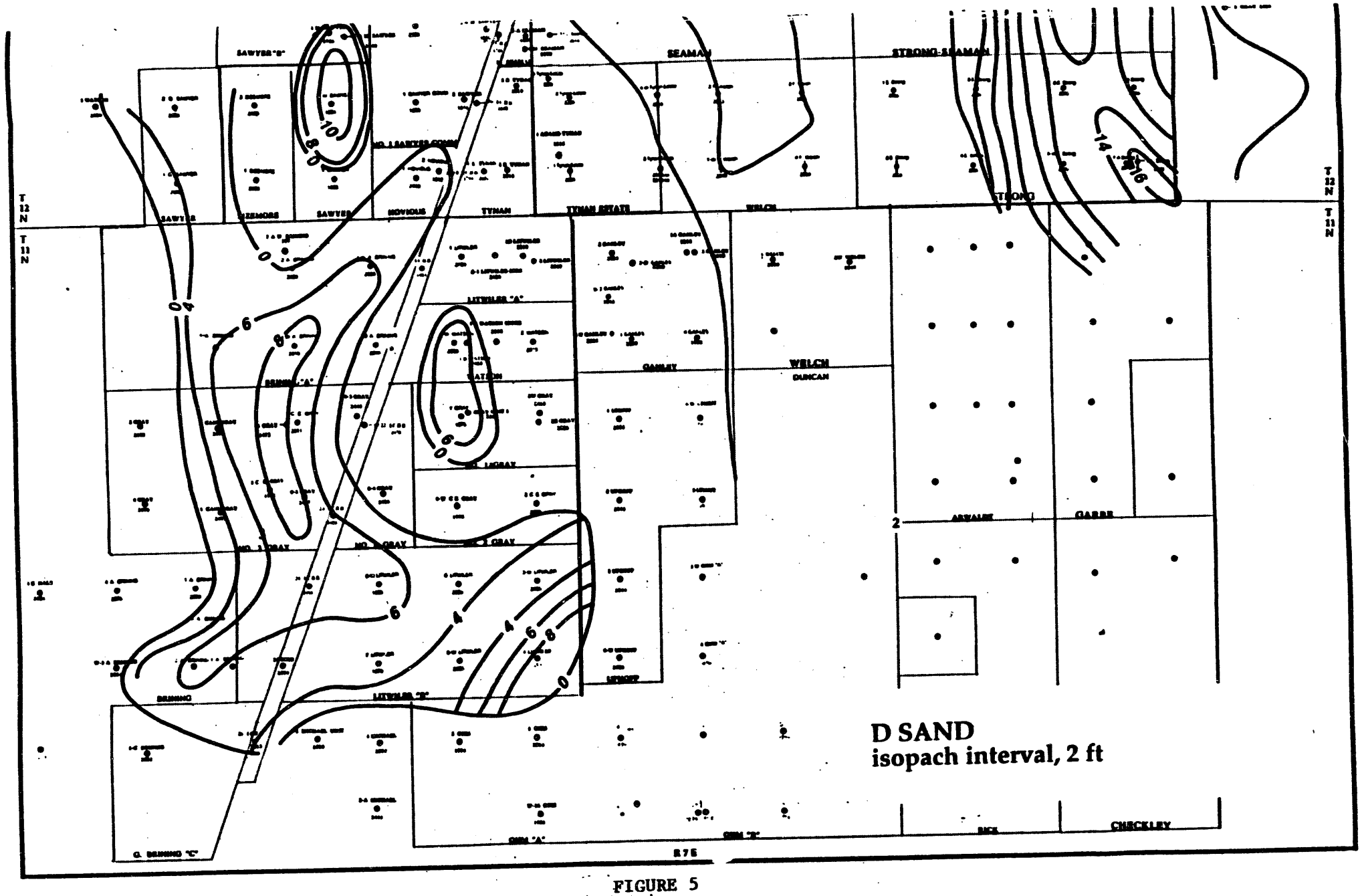
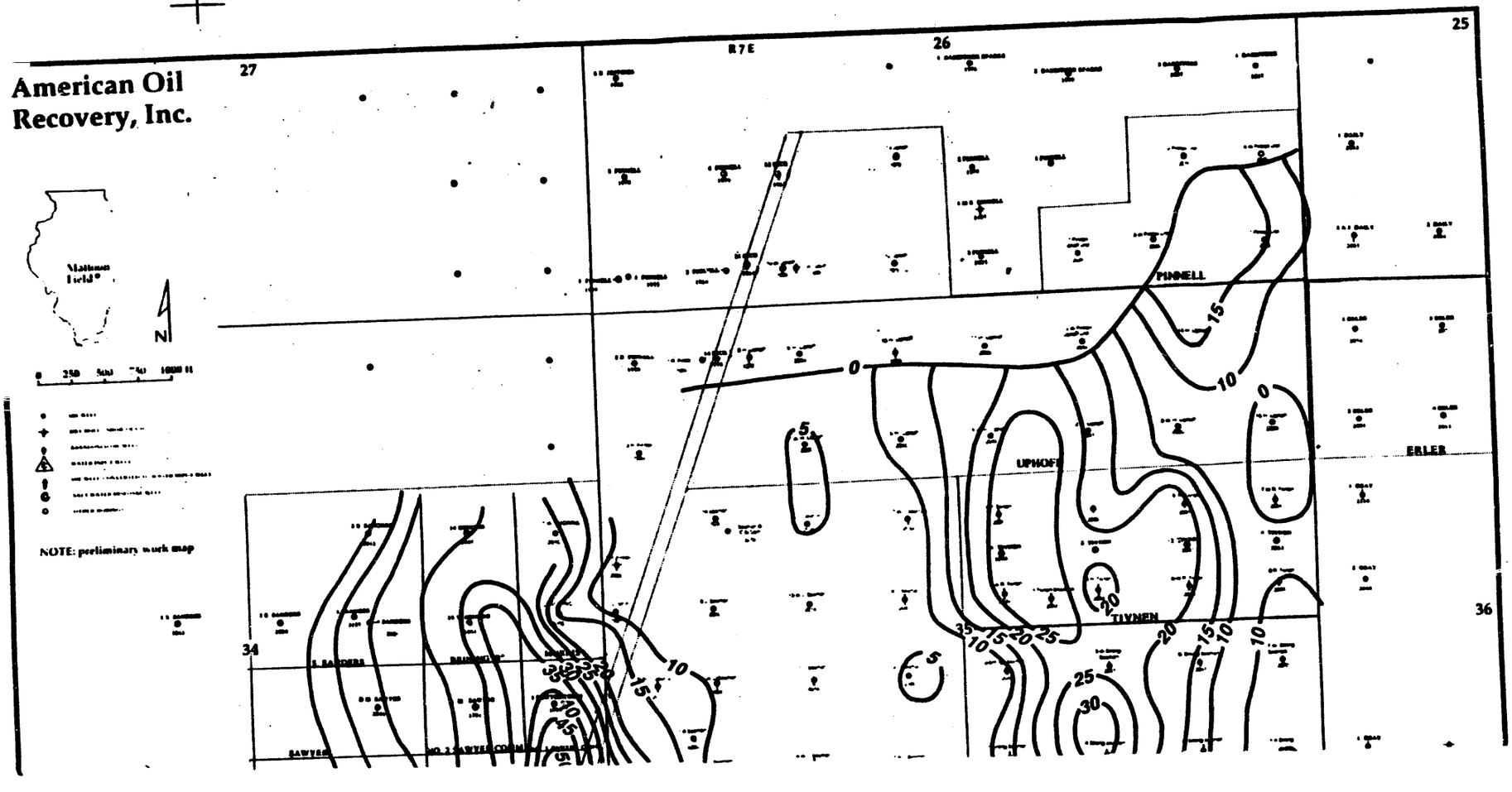

D SAND
isopach interval, 2 ft
SAWYER "B"
SEAMAN
STRONG-SEAMAN
SAWYER
SAWYER
NOVIOUS
TYNAN
TYNAN ESTATE
WELCH
STRONG
LITWILER "A"
WATSON
GANLEY
WELCH
DUNCAN
ARWALDE
GARRE
BRINING
LITWILER "B"
CHECKLEY
T 12 N
T 11 N
R 7 E

FIGURE 5

American Oil Recovery, Inc.



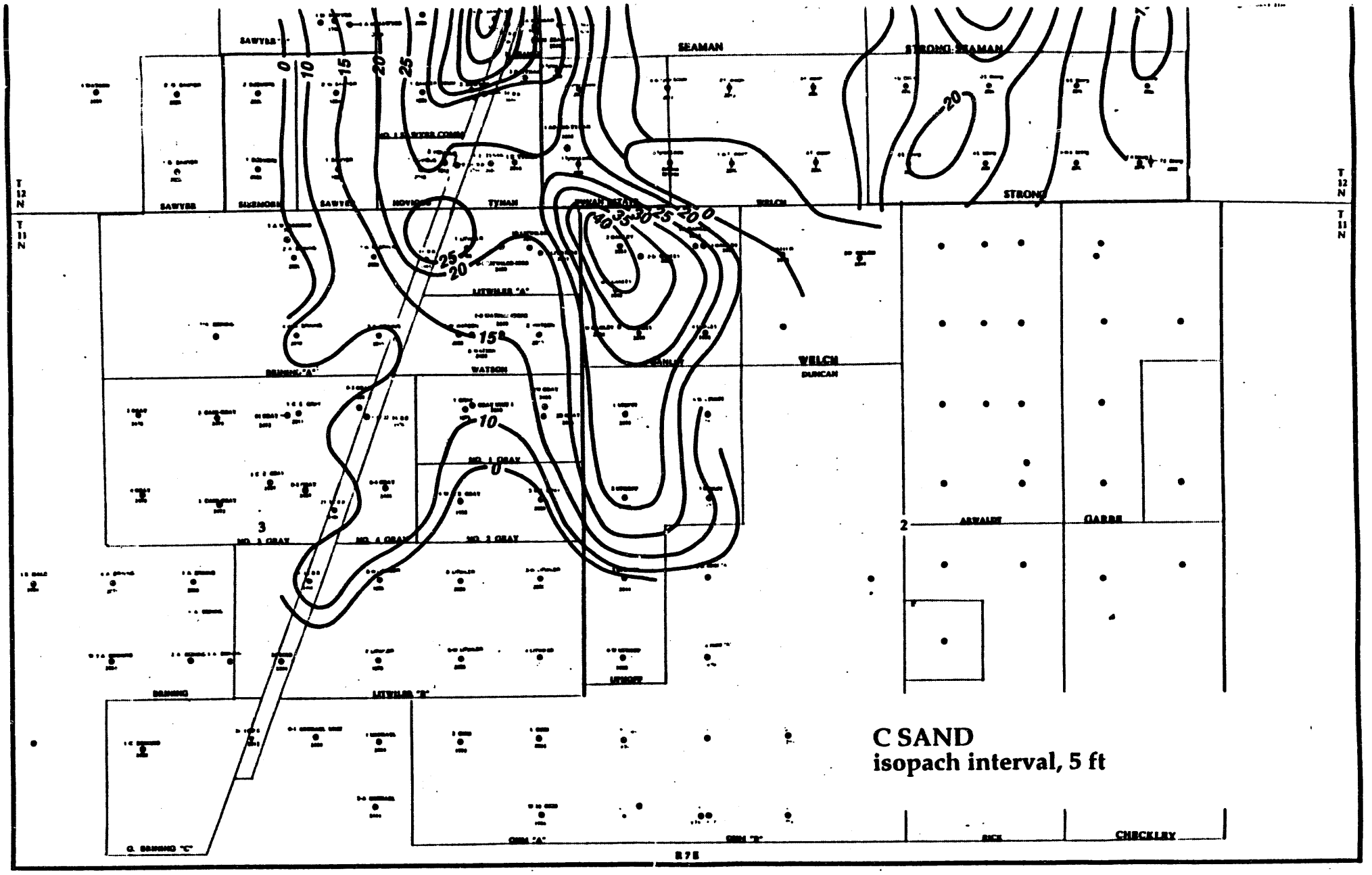
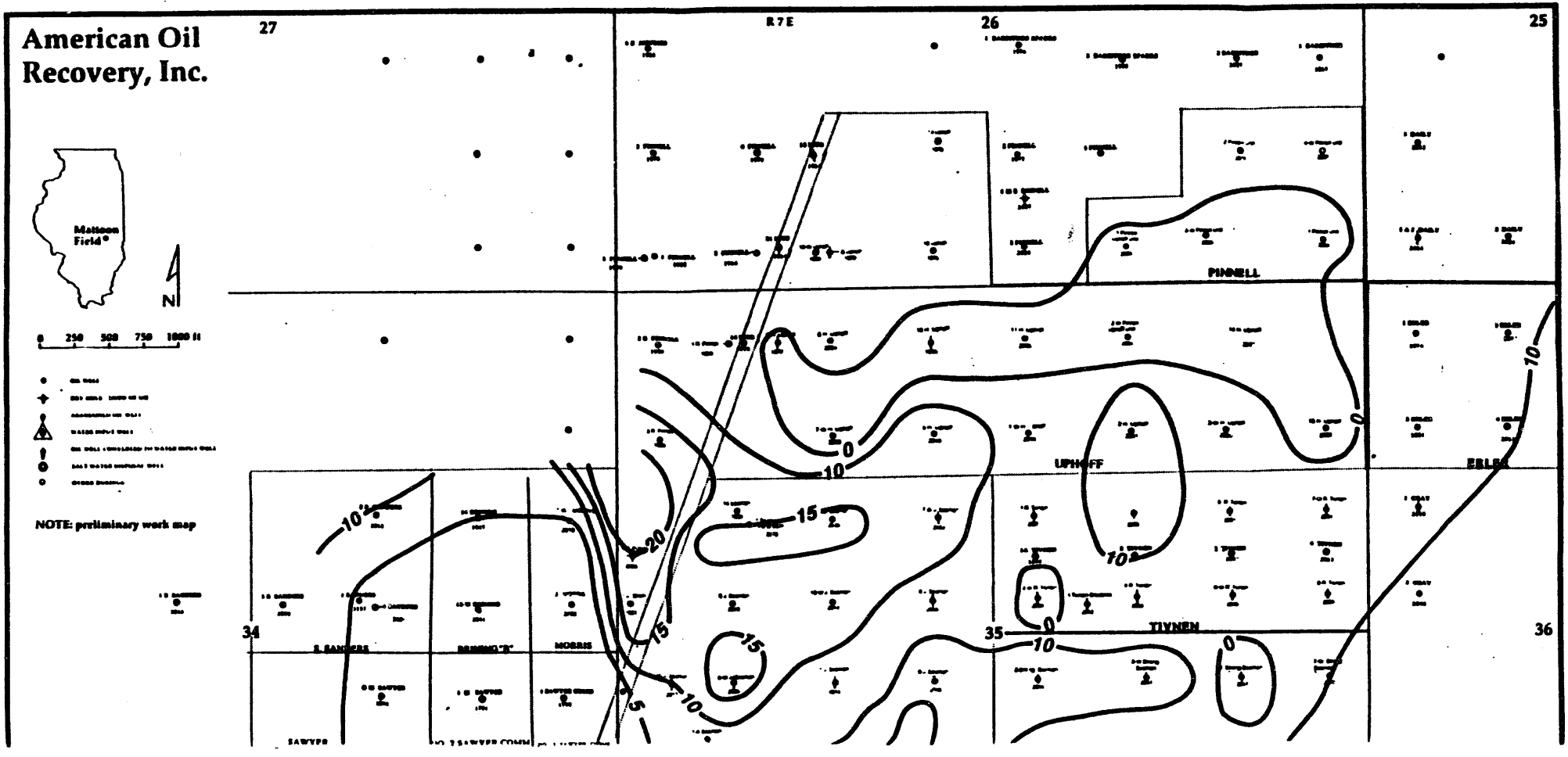

SEAMAN
STRONG-SEAMAN
SAWYER
SIXEMORE
SAWYER
NOVICE
TYNAN
WELCH
STRONG
LITWILER "A"
WATSON
WELCH
DUNCAN
NO. 1 GRAY
NO. 3 GRAY
NO. 4 GRAY
NO. 2 GRAY
ARWALDT
GARBE
BRINING
LITWILER "B"
UPHOFF
G. BRINING "C"
CHECKLEY
T 12 N
T 11 N
R 7 E
C SAND
isopach interval, 5 ft

FIGURE 4


American Oil Recovery, Inc.
Mattoon Field
N
0 250 500 750 1000 ft
NOTE: preliminary work map
27
R7E
26
25
PINNELL
UPHOFF
ERLER
34
35
36
TIVNEN
S. SANDERS
MORRIS
SAWYER
0
10
15
20
5

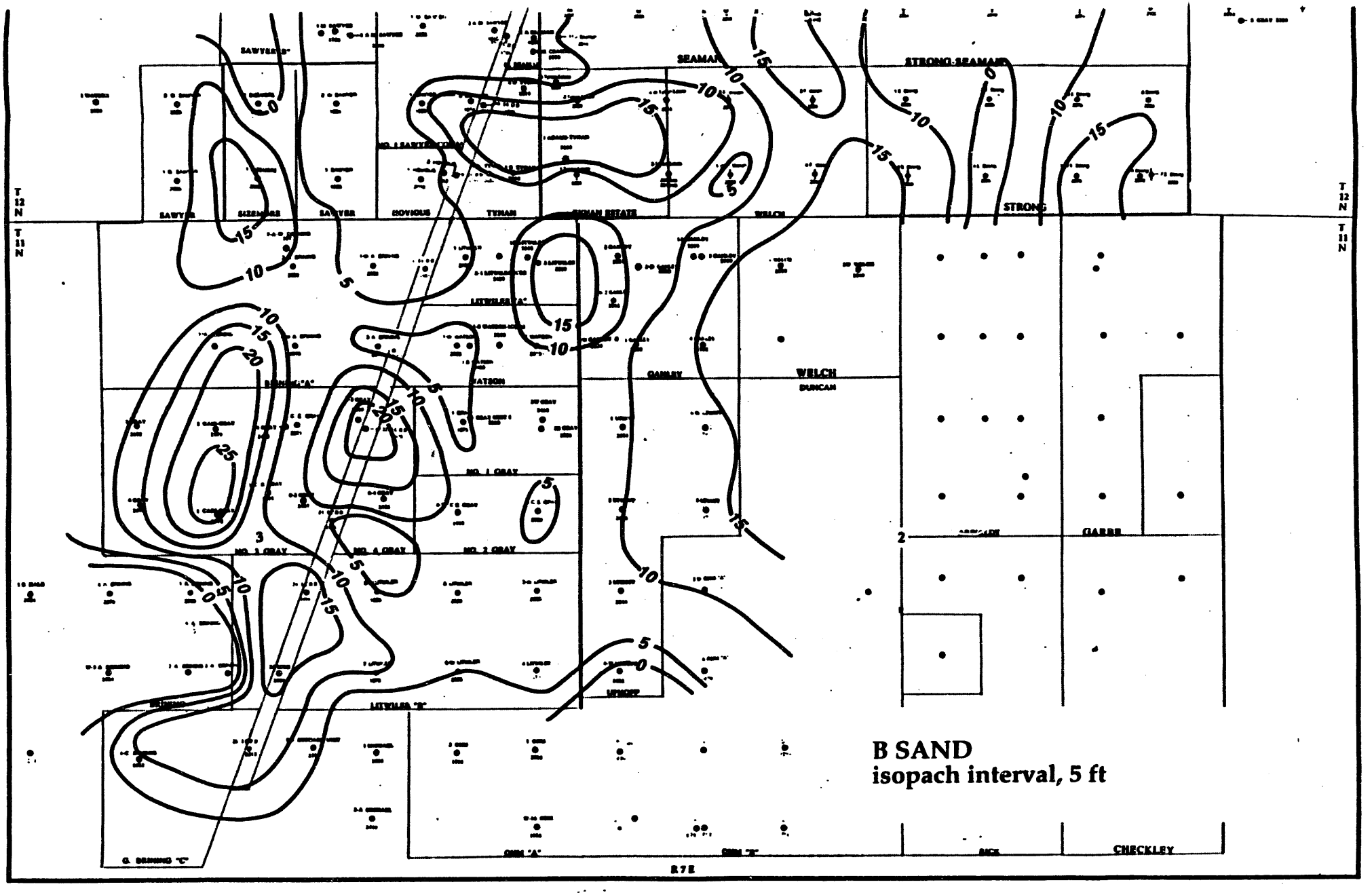
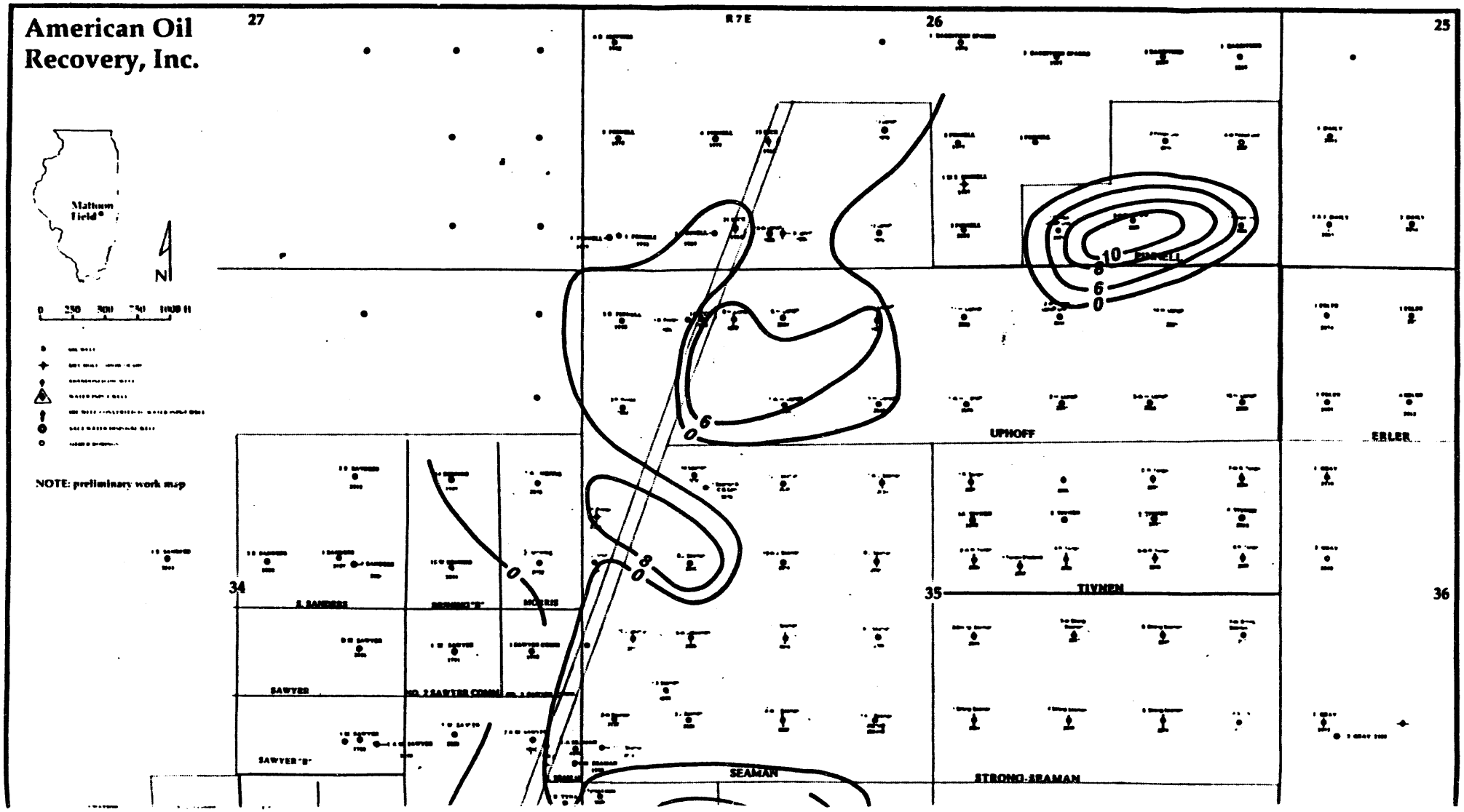

B SAND
isopach interval, 5 ft
SAWYER
SIZEMORE
SAWYER
HOVIOUS
TYNAN
SEAMAN
STRONG-SEAMAN
STRONG
WELCH
DUNCAN
GANLEY
WATSON
NO. 1 GRAY
NO. 3 GRAY
NO. 4 GRAY
NO. 2 GRAY
LITWILER "A"
LITWILER "B"
UPHOFF
GARBE
CHECKLEY
T 12 N
T 11 N
R 7 E

FIGURE 3


American Oil
Recovery, Inc.
Mattoon
Field
N
0 250 500 750 1000 ft
NOTE: preliminary work map
27
R 7 E
26
25
34
35
36
10
8
6
0
UPHOFF
ERLER
TIVNEN
SAWYER
SAWYER "B"
SEAMAN
STRONG-SEAMAN

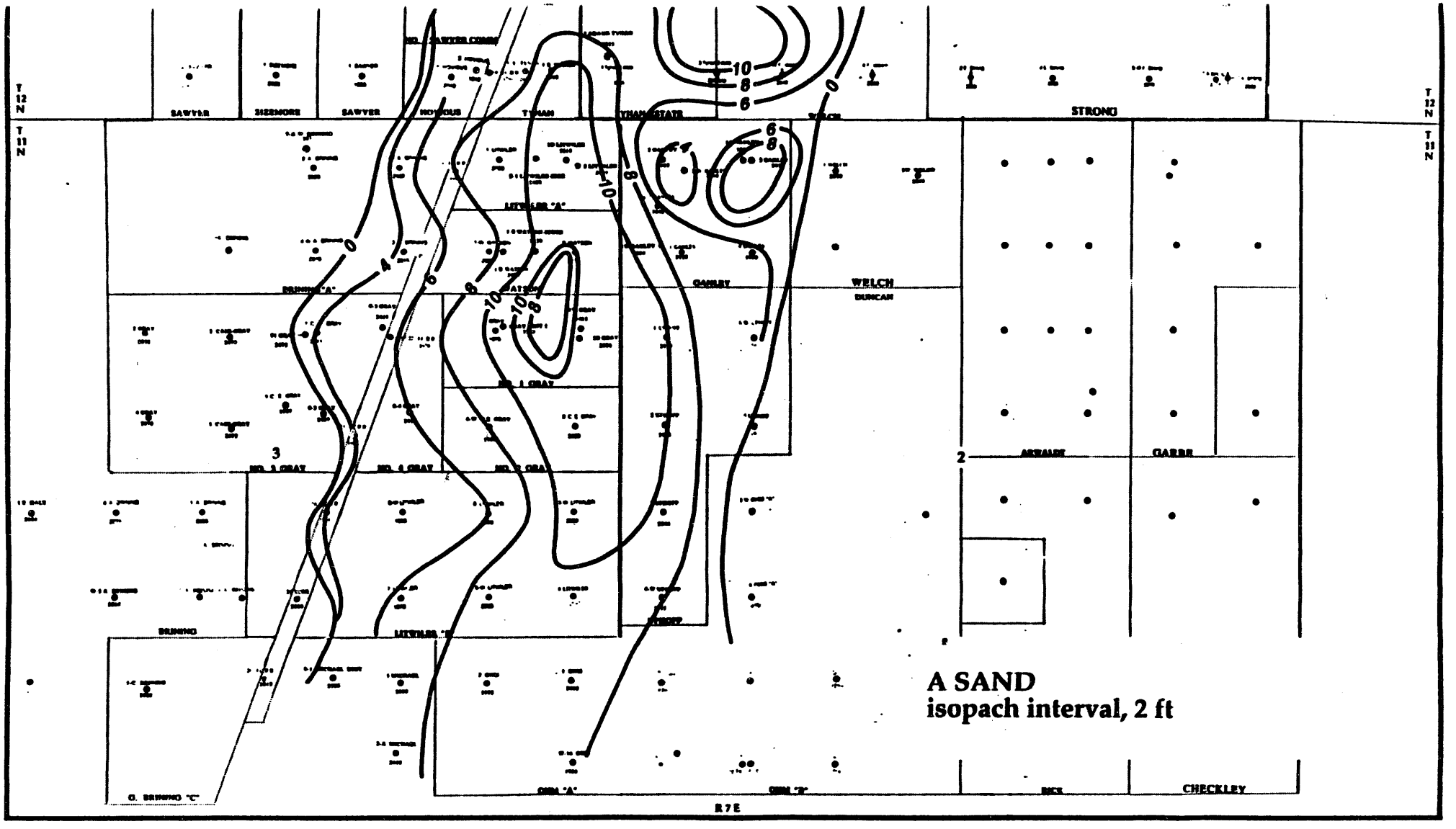
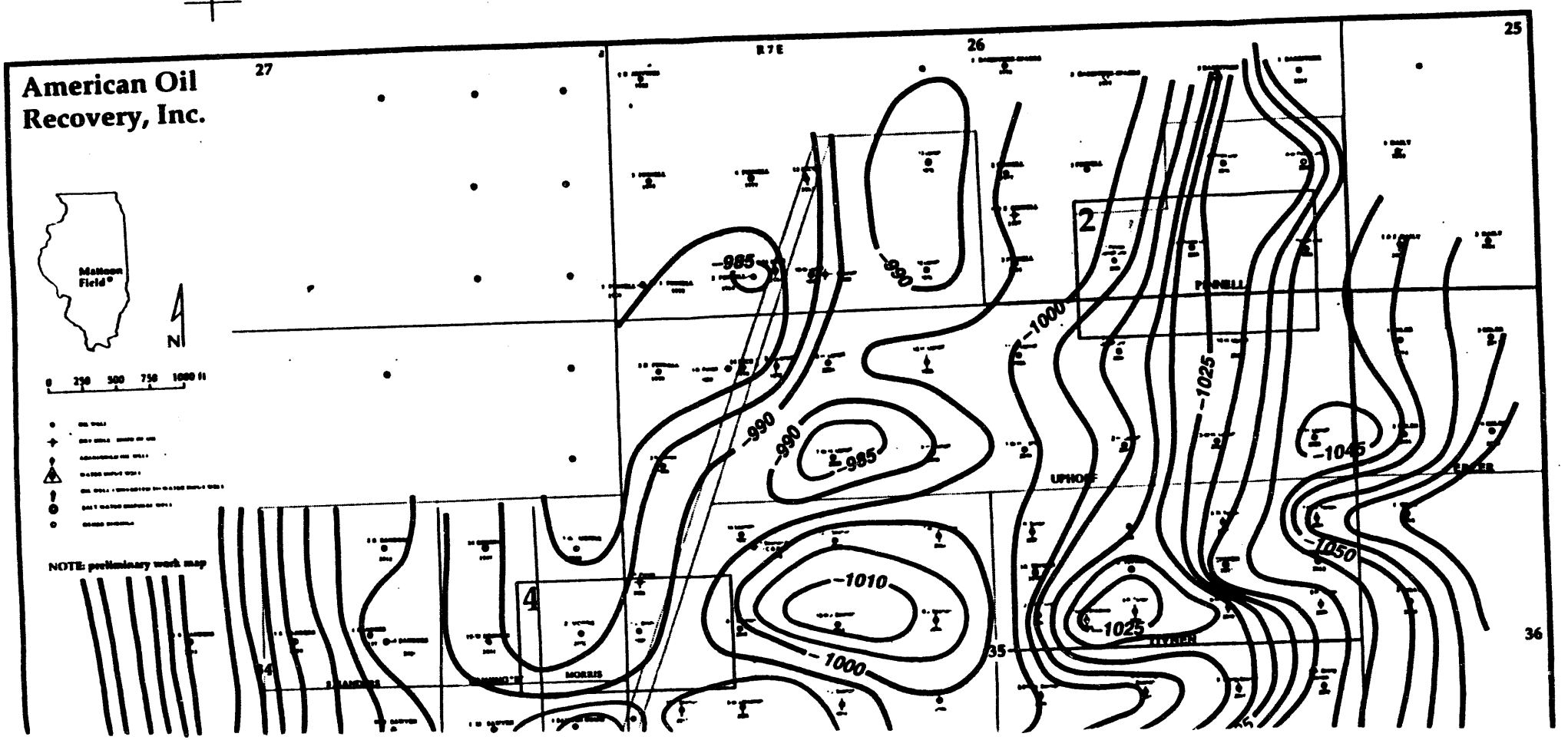

A SAND
isopach interval, 2 ft
T 12 N
T 11 N
R 7 E
SAWYER
SIZEMORE
SAWYER
HOYOUS
TYHAM
TYHAM ESTATE
WELCH
STRONG
LITWILER "A"
BRINING "A"
GANLEY
WELCH
DUNCAN
NO. 1 GRAY
NO. 3 GRAY
NO. 4 GRAY
NO. 2 GRAY
ARWALDT
GARBE
BRINING
LITWILER "B"
O. BRINING "C"
CHECKLEY
0
4
6
8
10
2
3

FIGURE 2


American Oil
Recovery, Inc.
Malteon Field
N
0 250 500 750 1000 ft
NOTE: preliminary work map
27
26
25
R7E
2
4
-985
-990
-1000
-1025
-1045
-1050
-1010
35
36
MORRIS
TYNEN

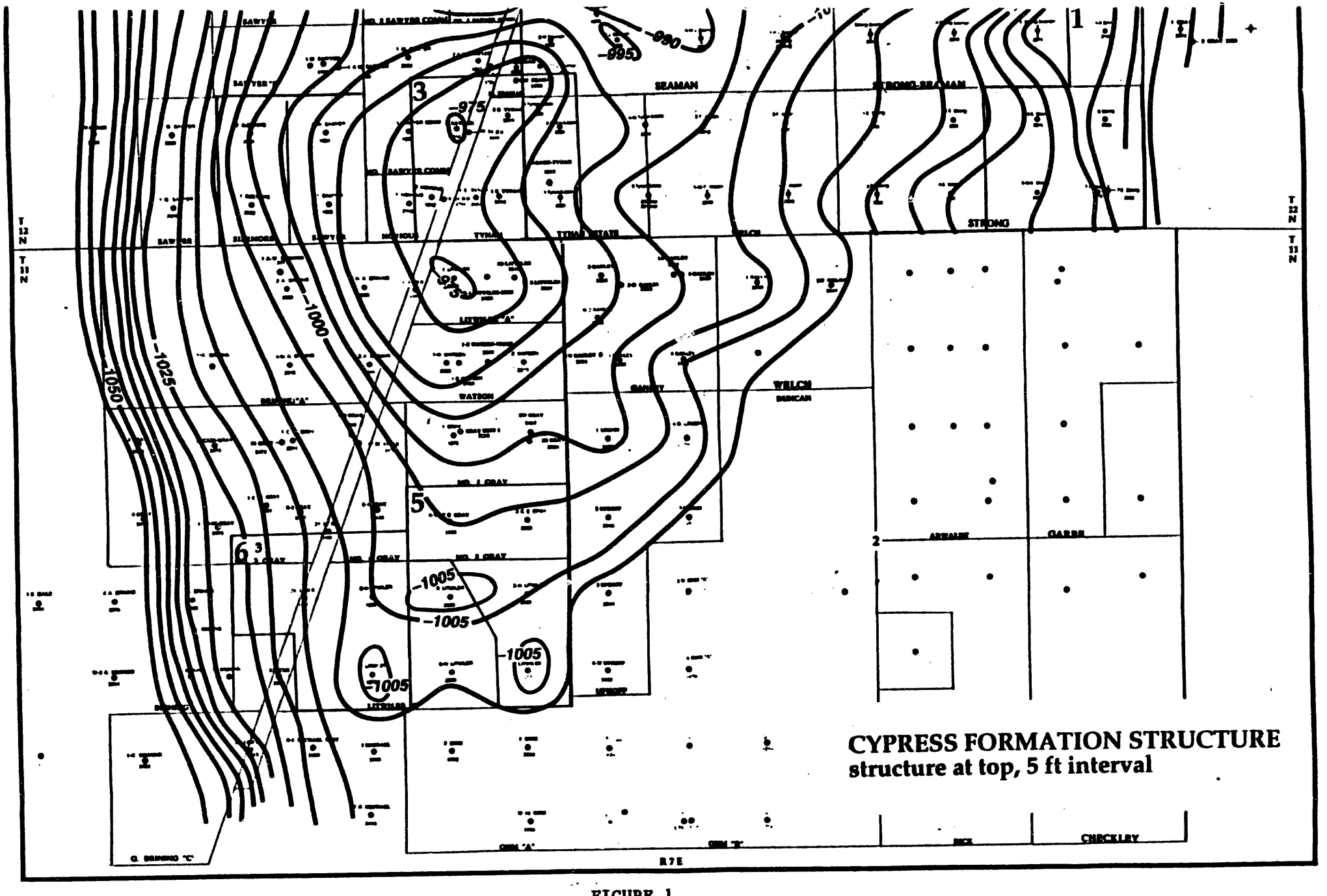

CYPRESS FORMATION STRUCTURE
structure at top, 5 ft interval
SEAMAN
STRONG-SEAMAN
STRONG
WELCH
DUNCAN
WATSON
GARBE
CHECKLEY
R 7 E
T 12 N
T 11 N
-990
-995
-975
-1000
-1025
-1050
-1005
1
2
3
5
6

FIGURE 1

END

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3/28/94