CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

MOCO PRODUCTION COMPANY
WEARENGEN C NO. 2

DATE: 4/29/76
FORMATION:

FILE NO: 3102-9859
ENGINEER: NEF

MP. O.	DEPTH	PERM. TO AIR MD. MAXIMUM	90 DEG	VERT.	POROSITY GEX. FLD.	FLUID SATS. OIL	WTR.	GR. DEN.	DESCRIPTION
69	8161.0-62.0	<0.1	<0.1		0.6	0.0	71.4	2.71	LM
70	8162.0-63.0	<0.1	<0.1		0.2	0.0	93.3	2.72	LM,SHY
71	8163.0-64.0	<0.1	<0.1		2.3	0.0	94.7	2.71	LM,SHY
72	8164.0-65.0	<0.1	<0.1		0.7	0.0	60.0	2.73	LM
73	8165.0-66.0	<0.1	<0.1		0.5	0.0	75.0	2.73	LM
74	8166.0-67.0	<0.1	<0.1		0.7	0.0	33.3	2.74	LM
75	8167.0-68.0	<0.1	<0.1		0.7	0.0	69.2	2.71	LM
76	8168.0-69.0	<0.1	<0.1		0.6	0.0	77.8	2.73	LM
77	8169.0-70.0	<0.1	<0.1		0.6	0.0	71.4	2.74	LM
78	8170.0-71.0	<0.1	<0.1		1.4	0.0	62.5	2.73	LM,SHY
79	8171.0-72.0	0.4	<0.1		0.9	0.0	70.0	2.74	LM,VERT FRAC
80	8172.0-73.0	4.5	<0.1		0.7	0.0	85.7	2.72	LM,VERT FRAC
81	8173.0-74.0	<0.1	*		1.5	0.0	46.7	2.71	LM,STY
	8174.0-76.0	LOST CORE							
	8176.0-54.0	DRILLED							
	8354.0-66.0	DOL,FRAC							
	8366.0-67.0	LOST CORE							

AMOCO PRODUCTION COMPANY　　DATE: 4/29/76　　FILE NO: 3102-9859

SWEARINGEN C NO. 2　　FORMATION:　　ENGINEER: NEF

SMP. NO.	DEPTH	PERM. TO AIR MD. MAXIMUM	90 DEG	VERT.	POROSITY GEX. FLD.	FLUID SATS. OIL	WTR.	GR. DEN.	DESCRIPTION
	7880.0-82.0	SH							
	7882.0-90.0	LM,V/SHY							
	7890.0-92.5	SH							
	7892.5-08.0	LM,SHY							
	7908.0-12.0	LOST CORE							
	7812.0-42.0	DRILLED							
50	8142.0-43.0	<0.1	<0.1		1.9	0.0	71.4	2.74	LM,SHY
51	8143.0-44.0	<0.1	<0.1		0.3	0.0	75.0	2.71	LM,SHY
52	8144.0-45.0	<0.1	<0.1		0.3	0.0	83.3	2.74	LM,STY
53	8145.0-46.0	<0.1	<0.1		0.4	0.0	83.3	2.71	LM,STY
54	8146.0-47.0	<0.1	<0.1		0.4	0.0	85.7	2.75	LM,STY
55	8147.0-48.0	<0.1	<0.1		0.8	0.0	90.0	2.71	LM,SHY
56	8148.0-49.0	<0.1	<0.1		0.7	0.0	62.5	2.70	LM,SL/SHY
57	8149.0-50.0	<0.1	<0.1		1.2	0.0	83.9	2.71	LM,SHY
58	8150.0-51.0	<0.1	<0.1		1.0	0.0	70.0	2.73	LM,SHY
59	8151.0-52.0	<0.1	<0.1		0.7	0.0	66.7	2.73	LM,SHY
60	8152.0-53.0	<0.1	<0.1		0.5	0.0	62.5	2.73	LM,STY
61	8153.0-54.0	<0.1	<0.1		0.5	0.0	55.6	2.72	LM,STY
62	8154.0-55.0	<0.1	<0.1		0.6	0.0	66.7	2.72	LM,STY
63	8155.0-56.0	<0.1	<0.1		0.7	0.0	66.7	2.72	LM,STY
64	8156.0-57.0	<0.1	<0.1		0.4	0.0	80.0	2.72	LM,SHY
65	8157.0-58.0	<0.1	<0.1		0.4	0.0	42.9	2.73	LM
66	8158.0-59.0	<0.1	<0.1		0.3	0.0	83.3	2.72	LM
67	8159.0-60.0	<0.1	<0.1		0.4	0.0	66.7	2.72	LM
68	8160.0-61.0	<0.1	<0.1		0.4	0.0	85.7	2.72	LM

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

AMOCO PRODUCTION COMPANY
SWEARENGEN C NO. 2

DATE: 4/29/76
FORMATION:

FILE NO: 3102-9859
ENGINEER: NEF

SMP. NO.	DEPTH	PERM. TO AIR MD. MAXIMUM	PERM. TO AIR MD. 90 DEG	PERM. TO AIR MD. VERT.	POROSITY GEX. FLD.	FLUID SATS. OIL	FLUID SATS. WTR.	GR. DEN.	DESCRIPTION
24	7852.0-53.0	0.6	0.3		3.2	2.2	24.3	2.74	LM,SL/VGY
25	7853.0-54.0	8.1	5.0		8.5	3.6	31.4	2.70	LM,SL/VGY
26	7854.0-55.0	2.2	1.2		4.8	3.8	33.1	2.73	LM,STY,SL/VGY
	7855.0-56.0	SH							
27	7856.0-57.0	0.1	*		3.5	0.0	34.1	2.73	LM,STY
28	7857.0-58.0	<0.1	*		2.6	1.0	20.0	2.71	LM
	7858.0-59.0	SH							
29	7859.0-60.0	8.0	6.2		3.9	1.5	15.2	2.71	LM,VGY
30	7860.0-61.0	20.0	12.0		4.1	1.4	23.0	2.72	LM,STY,SL/VGY
31	7861.0-62.0	8.1	4.2		4.0	2.6	26.0	2.73	LM,VGY
32	7862.0-63.0	<0.1	*		2.3	0.0	23.3	2.72	LM
33	7863.0-64.0	0.3	0.3		2.5	2.2	44.4	2.72	LM,VGY
34	7864.0-65.0	2.4	2.4		2.8	1.3	26.0	2.72	LM,VGY
35	7865.0-66.0	3.8	3.6		1.7	1.9	37.3	2.72	LM,SL/VGY
36	7866.0-67.0	<0.1	<0.1		1.0	0.0	25.0	2.71	LM
37	7867.0-68.0	<0.1	<0.1		1.4	0.0	54.5	2.74	LM,STY
38	7868.0-69.0	<0.1	<0.1		1.5	0.0	63.6	2.71	LM,STY
39	7869.0-70.0	<0.1	<0.1		2.0	0.0	42.3	2.72	LM,STY
40	7870.0-71.0	<0.1	<0.1		1.0	0.0	46.2	2.72	LM,STY
41	7871.0-72.0	<0.1	<0.1		1.1	0.0	62.5	2.73	LM,STY
42	7872.0-73.0	<0.1	<0.1		1.1	0.0	82.4	2.73	LM,STY
43	7873.0-74.0	<0.1	<0.1		1.2	0.0	53.3	2.73	LM,STY
44	7874.0-75.0	<0.1	<0.1		0.8	0.0	84.6	2.71	LM,STY
45	7875.0-76.0	<0.1	<0.1		0.6	0.0	75.0	2.71	LM,STY
46	7876.0-77.0	<0.1	<0.1		1.0	0.0	80.0	2.72	LM,STY
47	7877.0-78.0	<0.1	<0.1		1.8	0.0	70.6	2.71	LM,STY
48	7878.0-79.0	<0.1	*		0.5	0.0	41.4	2.71	LM
49	7879.0-80.0	<0.1	<0.1		5.5	0.0	88.3	2.74	LM,SHY

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

PRELIMINARY PRINT

AMOCO PRODUCTION COMPANY	DATE: 4/29/76	FILE NO: 3102-9859
SWEARENGEN C NO. 2	FORMATION:	ENGINEER: NEF
PETERSON	DRLG. FLUID:	ELEVATION:
ROOSEVELT COUNTY,NEW MEXICO	LOCATION:	

* INDICATES PLUG PERM S INDICATES PRESERVED SAMPLE

SPECIAL CORE ANALYSIS

SMP. NO.	DEPTH	PERM. TO AIR MD. MAXIMUM	PERM. TO AIR MD. 90 DEG	PERM. TO AIR MD. VERT.	POROSITY GEX. FLD.	FLUID SATS. OIL	FLUID SATS. WTR.	GR. DEN.	DESCRIPTION
1	7826.0-27.0	<0.1	<0.1		15.0	0.0	46.7	2.71	LM,SHY
2	7827.0-28.0	<0.1	<0.1		1.2	0.0	53.8	2.72	LM,SHY
3	7828.0-29.0	<0.1	<0.1		2.0	0.0	73.3	2.72	LM,SHY
4	7829.0-30.0	<0.1	*		3.3	0.0	6[illegible].1	2.73	LM,SHY
	7830.0-34.0	SH							
5	7834.0-35.0	<0.1	<0.1		1.7	0.0	35.7	2.72	LM
6	7835.0-36.0	0.2	0.1		4.3	0.0	21.[illegible]	2.7[illegible]	LM,STY
7	7836.0-36.5	<0.1	<0.1		1.9	0.0	56.0	2.7[illegible]	LM
8	7836.5-37.0	<0.1	<0.1		3.[illegible]	0.0	84.2	2.70	LM,SHY,STY
9	7837.0-38.0	<0.1	*		3.5	0.0	51.5	2.72	LM
10	7838.0-39.0	<0.1	<0.1		4.3	0.0	84.8	2.73	LM,SHY
11	7839.0-40.0	<0.1	<0.1		4.1	0.0	75.8	2.72	LM,SHY
12	7840.0-41.0	0.2	0.1		4.2	0.0	58.8	2.76	LM,SHY
13	7841.0-42.0	<0.1	<0.1		4.0	0.0	72.2	2.72	LM,SHY
14	7842.0-43.0	<0.1	<0.1		4.1	0.0	73.0	2.73	LM,SHY
15	7843.0-44.0	<0.1	<0.1		3.5	0.0	83.2	2.70	LM,SHY
16	7844.0-45.0	<0.1	<0.1		3.0	0.0	81.1	2.71	LM,SL/SHY
17	7845.0-46.0	<0.1	<0.1		1.7	0.0	84.2	2.73	LM
18	7846.0-47.0	<0.1	<0.1		2.0	0.0	63.6	2.72	LM,STY
19	7847.0-48.0	<0.1	<0.1		1.9	0.0	52.2	2.74	LM,STY
20	7848.0-49.0	<0.1	<0.1		2.8	0.0	37.5	2.74	LM,STY
21	7849.0-50.0	<0.1	<0.1		1.4	0.0	45.0	2.73	LM,STY
22	7850.0-51.0	0.2	0.1		2.6	1.4	22.4	2.73	LM,SL/VGY
23	7851.0-52.0	0.6	0.3		1.8	3.4	33.7	2.72	LM,STY,SL/VGY

CA-19

CORE LABORATORIES, INC. CORE LAB *Petroleum Reservoir Engineering*

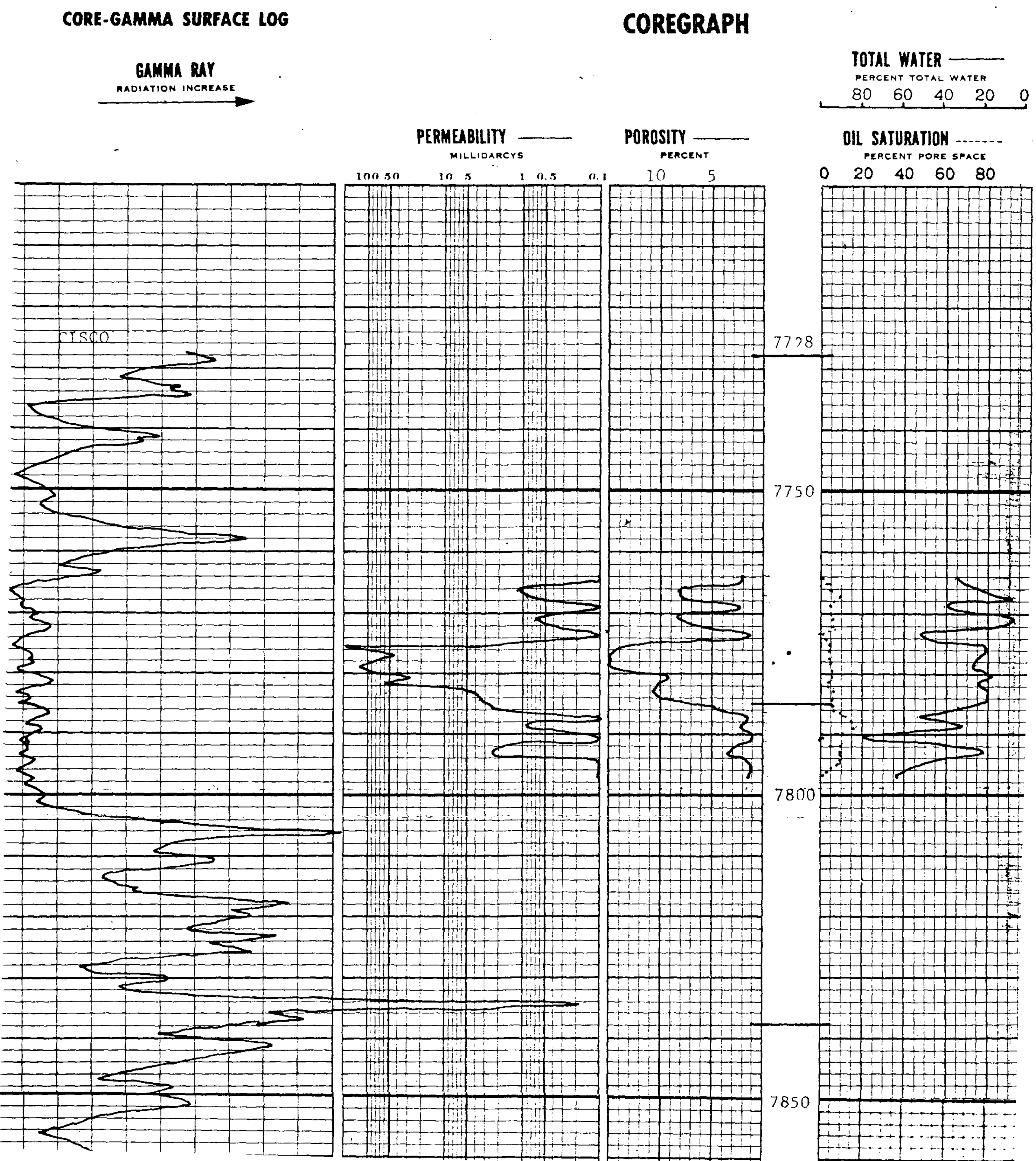
OMPANY AMOCO PRODUCTION COMPANY FIELD UNDESIGNATED PENN FILE WP-3-3516

ELL SWEARINGEN "B" NO. 1 COUNTY ROOSEVELT DATE 4-4-73

OCATION 1980 FN & WL SEC 20-5-33 STATE NEW MEXICO ELEV. 4417' RDB

CORE-GAMMA CORRELATION

VERTICAL SCALE: 5" = 100'



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

AMOCO PRODUCTION COMPANY
SWEARINGEN 8 NO. 1

DATE: 4-4-73
FORMATION: CISCO

FILE NO. 623-3516
ENGINEER: BOONE

CORE ANALYSIS RESULTS

WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE

* INDICATES PLUG PERM

SMP. NO.	DEPTH	PERM. TO AIR MD. MAX.	PERM. TO AIR MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
19	7791.2-92.7	1.1	0.2	2.4	10.1	43.2	LM,S/VGY
20	7792.7-94.0	2.3	2.0	3.4	9.3	22.6	LM,S/VGY
21	7794.0-95.5	<0.1	<0.1	1.8	9.5	51.5	LM
22	7795.5-97.0	<0.1	<0.1	1.4	2.8	63.8	LM
	7797.0-03.0	LM, NO ANALYSIS					
	7803.0-06.0	LM,SHY, NO ANALYSIS					
	7806.0-12.0	SH, NO ANALYSIS					
	7812.0-17.0	LM,SHY, NO ANALYSIS					
	7817.0-27.0	SH, NO ANALYSIS					
	7827.0-36.0	LM,SHY, NO ANALYSIS					
	7836.0-45.0	SH, NO ANALYSIS					
	7845.0-79.0	LM,SHY, NO ANALYSIS					

AMOCO PRODUCTION COMPANY
SWEARINGEN B NO. 1
UNDESIGNATED PENN FIELD
ROOSEVELT COUNTY, NEW MEXICO

DATE: 4-4-73
FORMATION: CISCO
DRLG.FLUID: WATER BASE MUD
LOCATION: 1980 FNL 1980 FWL SEC 20 T5S-R33E

FILE NO. 623-3516
ENGINEER: BOONE
ELEVATION: 4417 RDB

CORE ANALYSIS RESULTS

WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE * INDICATES PLUG PERM

SMP. NO.	DEPTH	PERM. TO AIR MD. MAX.	PERM. TO AIR MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
	7728.0-36.0	SH, NO ANALYSIS					
	7736.0-64.0	LM,SHY, NO ANALYSIS					
1	7764.0-65.6	<0.1	<0.1	2.3	0.0	35.2	LM
2	7765.6-67.0	1.2	1.0	8.4	5.8	20.6	LM,S/VGY
3	7767.0-68.6	0.9	0.9	8.0	9.3	8.8	LM,S/VGY
4	7768.6-70.0	<0.1	<0.1	2.4	4.1	41.8	LM
5	7770.0-71.6	0.7	0.5	8.1	6.4	8.9	LM,S/VGY
6	7771.6-73.0	0.3	0.3	5.1	6.9	20.9	LM,S/VGY
7	7773.0-74.5	<0.1	<0.1	1.3	0.0	52.7	LM
8	7774.5-76.3	196.0	150.0	13.6	5.9	20.5	LM,S/VGY
9	7776.3-78.0	44.0	38.0	16.1	5.9	23.0	LM,S/VGY
10	7778.0-79.3	131.0	120.0	17.0	5.4	26.0	LM,VGY
11	7779.3-80.7	30.0	22.0	9.4	5.6	18.0	LM,VGY
12	7780.7-82.0	59.0	50.0	10.0	3.7	23.6	LM,VGY
13	7782.0-83.5	4.6	4.1	10.6	5.4	21.6	LM,VGY
14	7783.5-85.0	3.5	3.1	8.0	5.2	20.5	LM
15	7785.0-86.5	2.6	1.4	4.4	6.0	34.1	LM,S/VGY
16	7786.5-88.0	<0.1	<0.1	1.8	10.6	53.5	LM,S/VGY
17	7788.0-89.5	0.9	0.4	2.0	17.4	33.4	LM,S/VGY
18	7789.5-91.2	<0.1	<0.1	1.1	0.0	78.3	LM

CA-19

CORE LABORATORIES, INC. CORE LAB *Petroleum Reservoir Engineering*

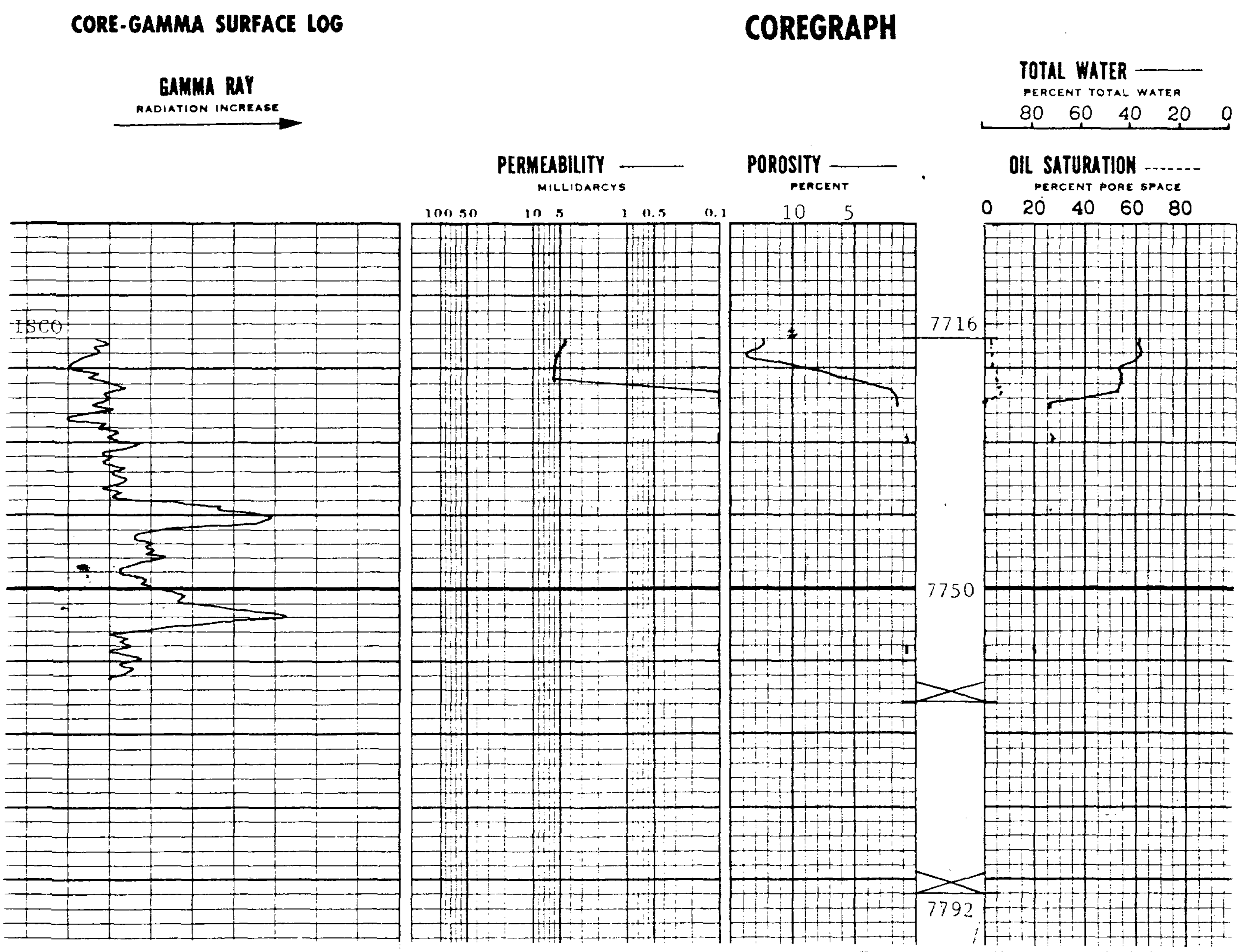
COMPANY AMOCO PRODUCTION COMPANY FIELD UNDESIGNATED FILE WP-3-3451

WELL SWEARINGEN NO. 1 COUNTY ROOSEVELT DATE 2-3-72

LOCATION 1650 FS & 1980 FEL SEC 19-T5S R33E STATE NEW MEXICO ELEV. 4416' RDB

CORE-GAMMA CORRELATION

VERTICAL SCALE: 5" = 100'



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

AMOCO PRODUCTION COMPANY	DATE: 11-13-72	FILE NO.	621-8923
PETERSON C GAS COM NO. 1	FORMATION: CISCO	ENGINEER:	HALL
PETERSON (PENN) FIELD	DRLG.FLUID: WATER BASE MUD	ELEVATION:	4445 RDB
ROOSEVELT COUNTY, NEW MEXICO	LOCATION: 1980 FSL 660 FEL SEC 18 T5S R33E		

CORE ANALYSIS RESULTS

CONVENTIONAL + WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE   * INDICATES PLUG PERM

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
	7610.0-11.0	LM,SHY, NO ANALYSIS					
	7811.0-17.0	LM, NO ANALYSIS					
	7617.0-24.0	SH, NO ANALYSIS					
	7624.0-31.0	LM,SHY, NO ANALYSIS					
	7631.0-34.0	SH, NO ANALYSIS					
	7634.0-37.0	LM, NO ANALYSIS					
	7637.0-45.0	LM,SHY, NO ANALYSIS					
	7645.0-47.0	SH, NO ANALYSIS					

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

AMOCO PRODUCTION COMPANY
PETERSON C GAS COM NO. 1

DATE: 11-13-72
FORMATION: CISCO

FILE NO. 621-8923
ENGINEER: HALL

CORE ANALYSIS RESULTS

CONVENTIONAL + WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE

* INDICATES PLUG PERM

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
	7647.0-49.0	LM,SHY, NO ANALYSIS					
	7649.0-57.0	SHALE, NO ANALYSIS					
	7657.0-71.5	LM,S/SHY, NO ANALYSIS					
	7671.5-72.0	SHALE, NO ANALYSIS					
	7672.0-75.0	LM,S/SHY, NO ANALYSIS					
	7675.0-80.0	LM,V/SHY, NO ANALYSIS					
	7680.0-84.0	LM, NO ANALYSIS					
	7684.0-86.0	SHALE, NO ANALYSIS					
	7686.0-94.0	LM,SHY, NO ANALYSIS					

AMOCO PRODUCTION COMPANY
PETERSON C GAS COM NO. 1

DATE: 11-13-72
FORMATION: CISCO

FILE NO. 621-8923
ENGINEER: HALL

CORE ANALYSIS RESULTS

CONVENTIONAL + WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE   * INDICATES PLUG PERM

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
	7694.0-97.0	LM, NO ANALYSIS					
	7697.0-01.0	LM,SHY, NO ANALYSIS					
	7701.0-04.0	LM, NO ANALYSIS					
1	7704.0-05.0	<0.1		2.9	0.0	58.7	LM
	7705.0-07.0	LM, NO ANALYSIS					
2	7707.0-08.0	<0.1		2.5	0.0	60.0	LM
	7708.0-24.0	LM, NO ANALYSIS					
	7724.0-32.0	SHALE, NO ANALYSIS					
	7732.0-34.0	LM,SHY, NO ANALYSIS					
	7734.0-38.0	SHALE, NO ANALYSIS					
	7738.0-50.0	LM,S/SHY, NO ANALYSIS					

CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

DALLAS, TEXAS

AMOCO PRODUCTION COMPANY
PETERSON C GAS COM NO. 1

DATE: 11-13-72
FORMATION: CISCO

FILE NO. 621-8923
ENGINEER: HALL

CORE ANALYSIS RESULTS

CONVENTIONAL + WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE

* INDICATES PLUG PERM

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
	7750.0-62.0	LM,S/SHY, NO ANALYSIS					
	7762.0-68.0	LM,V/SHY, NO ANALYSIS					
3	7768.0-69.7	<0.1	<0.1	2.1	0.0	50.5	LM,STY
4	7769.7-71.0	2.7	1.9	5.7	4.0	30.1	LM,STY,S/VGY
5	7771.0-72.3	2.6	2.3	6.8	4.1	24.4	LM,STY,S/VGY
6	7772.3-73.5	0.3	0.2	3.3	5.8	38.0	LM,S/VGY
7	7773.5-74.8	<0.1	<0.1	1.5	0.0	65.5	LM,STY
8	7774.8-76.2	0.1	<0.1	3.0	4.8	35.2	LM,STY,S/VGY
9	7776.2-77.4	13.0	12.0	3.9	7.2	45.7	LMSTY,S/VGY
10	7777.4-78.6	0.1	<0.1	2.7	5.8	47.7	LM,VGY
11	7778.6-80.0	0.6	0.5	6.2	3.7	42.5	LM,VGY
12	7780.0-81.5	3.8	2.8	6.8	3.6	50.7	LM,VGY
13	7781.5-82.7	3.0	2.3	5.2	5.3	41.5	LM,VGY
14	7782.7-83.9	1.8	1.4	4.8	5.4	40.0	LM,VGY
15	7783.9-85.5	0.8	0.7	3.0	3.9	58.1	LM,S/VGY
16	7785.5-86.9	0.2	0.2	1.9	3.7	61.0	LM,S/VGY
17	7786.9-88.0	0.1	<0.1	1.3	8.1	62.2	LM,STY
18	7788.0-89.2	0.7	0.5	1.4	2.1	80.9	LM,STY
19	7789.2-90.4	0.3	0.2	1.5	5.7	56.6	LM,STY,S/VGY
20	7790.4-91.8	0.3	0.3	1.5	3.2	59.7	LM,STY,S/VGY
21	7791.8-93.4	<0.1	<0.1	2.3	3.1	46.4	LM,STY,S/VGY
22	7793.4-95.0	<0.1	<0.1	1.2	1.9	53.8	LM,STY
23	7795.0-96.5	<0.1	<0.1	0.9	0.0	66.7	LM,STY

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

AMOCO PRODUCTION COMPANY
PETERSON C GAS COM NO. 1

DATE: 11-13-72
FORMATION: CISCO

FILE NO. 621-8923
ENGINEER: HALL

CORE ANALYSIS RESULTS

CONVENTIONAL + WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE

* INDICATES PLUG PERM

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
	7796.5-06.0	LM,S/SHY, NO ANALYSIS					
	7806.0-15.0	LM,SHY, NO ANALYSIS					
	7815.0-19.0	LM, NO ANALYSIS					
	7819.0-20.0	LM,SHY, NO ANALYSIS					
	7820.0-29.0	SH, NO ANALYSIS					
	7829.0-36.0	LM,SHY, NO ANALYSIS					
	7836.0-44.0	LM, NO ANALYSIS					
	7844.0-48.0	LM,SHY, NO ANALYSIS					
	7848.0-58.0	LM,V/SHY, NO ANALYSIS					

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

AMOCO PRODUCTION COMPANY
PETERSON C GAS COM NO. 1

DATE: 11-13-72
FORMATION: CISCO

FILE NO. 621-8923
ENGINEER: HALL

CORE ANALYSIS RESULTS

CONVENTIONAL + WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE

* INDICATES PLUG PERM

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
	7858.0-62.0	LM,FOS,SHY, NO ANALYSIS					
	7862.0-64.0	SH,FOS,LMY, NO ANALYSIS					
	7864.0-68.0	LM,SHY, NO ANALYSIS					
	7868.0-72.0	SH, NO ANALYSIS					
	7872.0-76.0	LM,SHY, NO ANALYSIS					
	7876.0-91.0	LM,V/SHY, NO ANALYSIS					
	7891.0-93.0	SH, NO ANALYSIS					
	7893.0-96.0	LM,S/SHY, NO ANALYSIS					
	7896.0-98.5	LM,V/SHY, NO ANALYSIS					

CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

DALLAS, TEXAS

AMOCO PRODUCTION COMPANY
PETERSON C GAS COM NO. 1

DATE: 11-13-72
FORMATION: CISCO

FILE NO. 621-8923
ENGINEER: HALL

CORE ANALYSIS RESULTS

CONVENTIONAL + WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE

* INDICATES PLUG PERM

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
	7898.5-08.0	SH, NO ANALYSIS					
	7908.0-12.0	SH,W/LM INCLUSIONS					
	7912.0-15.0	LM,V/SHY, NO ANALYSIS					
	7915.0-20.5	SH, NO ANALYSIS					
	7920.5-28.0	LM,V/SHY, NO ANALYSIS					

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

AMOCO PRODUCTION COMPANY	DATE: 2-3-72	FILE NO. 623-3451
SWEARINGEN A NO. 1	FORMATION: CISCO	ENGINEER: BOONE
UNDESIGNATED FIELD	DRLG.FLUID: WATER BASE MUD	ELEVATION: 4416 RDE
ROOSEVELT COUNTY, NEW MEXICO	LOCATION: 1650 FSL 1980 FEL SEC 19 T5S-R33E	

CORE ANALYSIS RESULTS

WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE * INDICATES PLUG PERM

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
1	7716.0-17.5	4.6	3.7	12.1	2.9	39.0	LM,VGY
2	7717.5-19.0	5.4	5.0	13.7	3.0	38.7	LM,VGY
3	7719.0-20.5	5.9	5.3	10.3	3.1	45.6	LM,VGY
4	7720.5-22.0	5.9	5.6	5.7	4.9	45.2	LM,F,S/VGY
5	7722.0-23.5	<0.1	<0.1	2.0	6.5	45.8	LM,F,S/VGY
6	7723.5-25.0	<0.1	<0.1	1.3	0.0	73.2	LM
	7725.0-29.0	LM, NO ANALYSIS					
7	7729.0-30.0	<0.1	<0.1	0.8	0.0	72.0	LM
	7730.0-40.0	LM, NO ANALYSIS					
	7740.0-58.0	LM,SHY, NO ANALYSIS					
8	7758.0-59.0	<0.1	<0.1	0.7	0.0	80.0	LM
	7759.0-63.0	LM,SHY, NO ANALYSIS					
	7763.0-66.0	LOST CORE					
	7766.0-68.0	ANHYDRITE, NO ANALYSIS					

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

AMOCO PRODUCTION COMPANY
SWEARINGEN NO. 1

DATE: 2-3-72
FORMATION: CISCO

FILE NO. 623-3451
ENGINEER: BOONE

CORE ANALYSIS RESULTS

WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE

* INDICATES PLUG PERM

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
	7768.0-86.0	SHALE, NO ANALYSIS					
	7786.0-89.0	LM,SHY, NO ANALYSIS					
	7789.0-92.0	LOST CORE					

CORE LABORATORIES, INC. — *Petroleum Reservoir Engineering*

COMPANY ______ TION COMPANY — FIELD WILDCAT — FILE [illegible]

WELL PETERSON NO. 1 — COUNTY ROOSEVELT — DATE 8-1-71

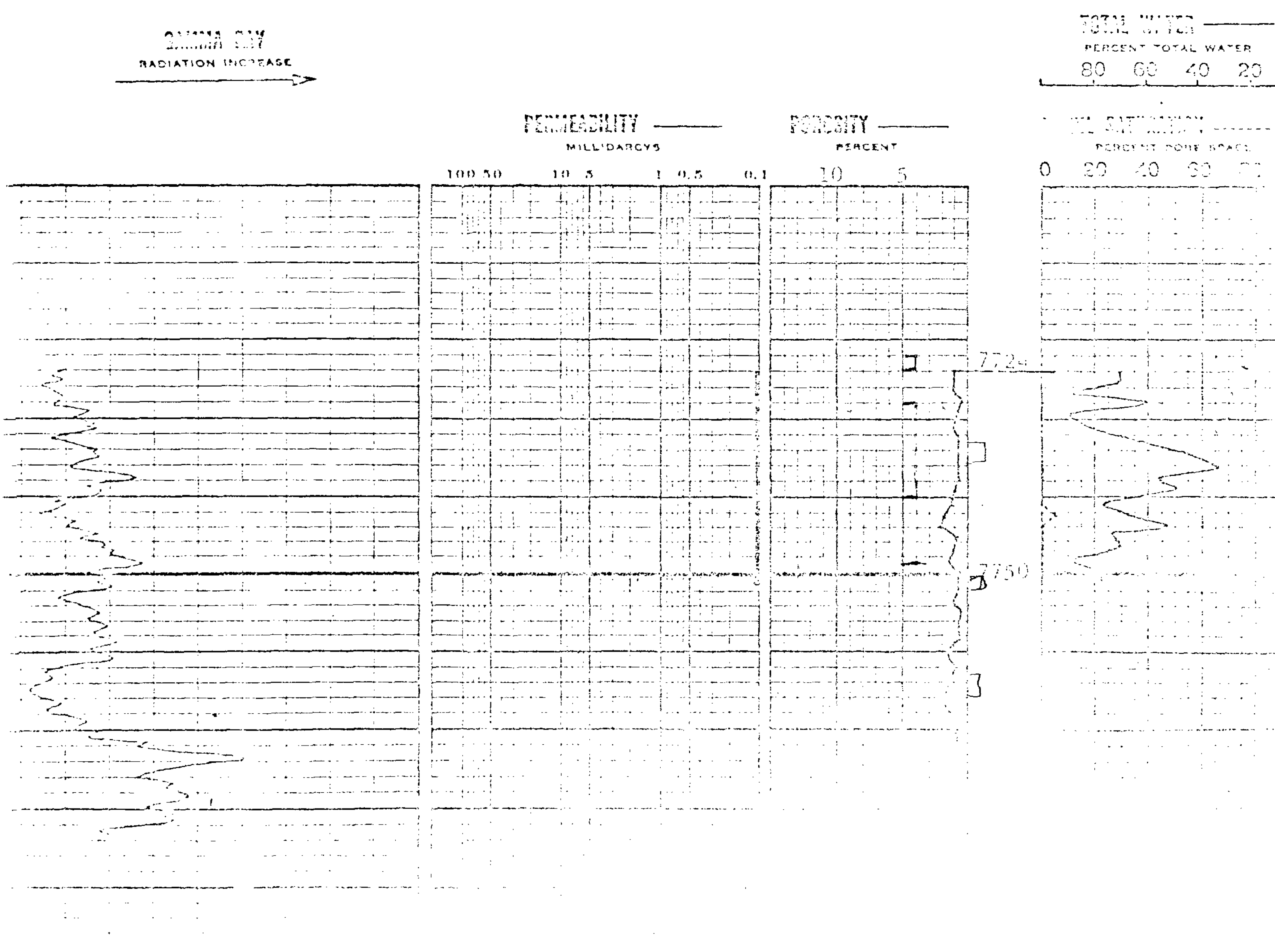
LOCATION SEC. 19-5-33 — STATE NEW MEXICO — ELEV. ______

CORE-GAMMA CORRELATION

VERTICAL SCALE: 5" = 100'

CORE-GAMMA SURFACE LOG

COREGRAPH



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

[illegible] PRODUCTION COMPANY
[illegible] NO. 1

DATE: [illegible]
FORMATION: [illegible]

FILE [illegible]

CORE ANALYSIS RESULTS

WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE

* INDICATES PLUG [illegible]

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	DESCRIPTION
27	7766.0-67.5			1.7			LM
28	7767.5-69.3			1.0			LM
29	7769.3-70.7			1.0			LM
30	7770.7-72.0			0.9			LM
31	7772.0-73.6			0.9			LM,S
32	7773.6-75.0			0.7			LM,S
33	7775.0-76.5			0.6			LM,S
34	7776.5-78.0			0.6			LM,S
35	7778.0-79.7			1.1			LM,S
36	7779.7-81.5			1.3			LM,S
37	7781.5-83.0			1.2			LM,S

Core Laboratories, Inc.
Petroleum Reservoir Engineering
DALLAS, TEXAS

FORMATION
LOCATION SEC. [illegible]-33

CORE ANALYSIS RESULTS

WHOLE CORE ANALYSIS

S INDICATES PRESERVED SAMPLE * INDICATES PLUG [illegible]

SMP. NO.	DEPTH	PERMEABILITY MD. MAX.	PERMEABILITY MD. 90	POROSITY PCT.	FLUID SATS. OIL	FLUID SATS. WTR.	[illegible]
1	7726.0-25.8	<0.1	<0.1	1.0	0.0	70.2	LM
2	7725.8-27.2	<0.1	<0.1	1.0	0.0	87.5	LM
3	7727.2-28.5	<0.1	<0.1	0.5	0.0	61.2	LM
4	7728.5-30.2	<0.1	<0.1	0.8	0.0	89.3	LM,S
5	7730.2-31.7	<0.1	<0.1	1.0	0.0	81.4	LM
6	7731.7-33.3	<0.1	<0.1	0.7	0.0	64.3	LM,S
7	7733.3-35.0	<0.1	<0.1	0.7	0.0	46.5	LM
8	7735.0-36.8	<0.1	<0.1	0.7	0.0	33.8	LM
9	7736.8-38.5	<0.1	<0.1	0.7	0.0	56.5	LM
10	7738.5-40.1	<0.1	<0.1	1.0	0.0	50.0	LM
11	7740.1-41.6	<0.1	<0.1	1.1	0.0	75.3	LM
12	7741.6-43.2	0.1	<0.1	1.9	5.3	67.5	LM
13	7743.2-44.5	0.1	0.1	2.2	0.0	53.1	LM
14	7744.5-46.2	<0.1	<0.1	0.9	0.0	74.0	LM
15	7746.2-47.6	<0.1	<0.1	1.1	0.0	71.3	LM,S
16	7747.6-49.3	<0.1	<0.1	1.2	0.0	88.0	LM,S
17	7749.3-51.0	<0.1	<0.1	0.7	0.0	79.8	LM
18	7751.0-52.7			0.8			LM
19	7752.7-54.0			1.0			LM
20	7754.0-55.7			0.5			LM
21	7755.7-57.6			0.6			LM
22	7757.6-59.3			0.6			LM,S
23	7759.3-61.2			1.4			LM,S
24	7761.2-63.0			0.8			LM,S
25	7763.0-64.6			1.1			LM
26	7764.6-66.0			1.5			LM

TABLE 1

DRILLING TIME-SPUD TO TOTAL DEPTH

WELL	DEPTH	DAYS	REMARKS
1	7,500	20	
2	7,455	53	Includes 28 days fishing
3	7,501	54	Includes 27 days fishing
4	7,419	25	Includes 5 days lost circulation
5	7,480	23	
6	7,550	23	
7	7,429	19	Plus 15 days lost time
8	7,325	19	Did not go to Sylvan
9	7,445	19	
10	7,550	18	
11	7,490	16	
12	7,427	16	
13	7,430	16	
14	7,551	17	
15	7,400	19	

In First well, Oswego & Mississippian open, well first pumped, then flowed one year — Pump or flow didn't change rate
#2 & 3 flowed

TABLE 2

PRODUCTION INFORMATION

WELL	DATE OF COMPLETION	INITIAL PRODUCTION BOPD	INITIAL PRODUCTION MCF/D	CUMULATIVE-12/31/76 OIL-BBLS	CUMULATIVE-12/31/76 GAS-MMCF
1	1-15-73	20	35	77,214	188
2	5-2-74	303	231	72,892	409
3	6-26-74	659	809	62,311	405
4	6-25-75	336	181	53,827	208
5	7-15-75	318	395	37,731	155
6	8-28-75	37	194	13,834	390
7	12-11-75	275	300	19,605	187
8	12-22-75	78	335	14,909	430
9	1-8-76	345	424	71,202	146
10	4-26-76	9	26	4,849	18
11	5-17-76	460	296	17,496	106
12	6-7-76	66	273	4,186	93
13	7-12-76	156	356	15,252	70
14	8-6-76	300	290	35,076	65

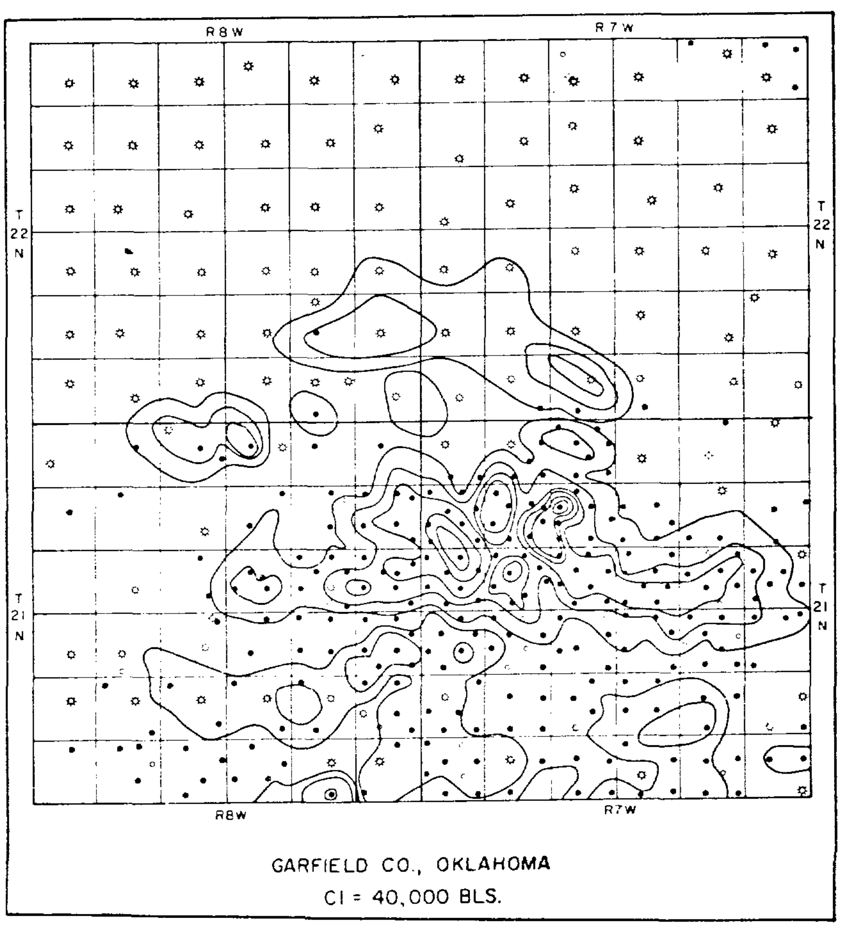


FIG. 1 - CUMULATIVE PRODUCTION CONTOURS - JUNE 1971.

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION

1

4962

H. W. BENISCHEK

6-22-77

Mcf of gas, flowing through a 12/64" choke, with a flowing tubing pressure of 775 psi and casing pressure of 1,520 psi.

Subsequent wells have varied considerably in their build-up time and pressures. Several of them have registered 2,000 psi or more at the surface, after being shut in for 5 - 10 days following completion. The fifth well drilled was in the NE SE of Section 9-21N-7W. It was such a surprise when its tubing pressure showed over 2,000 psi that a bottom-hole static pressure was run before the well was opened. The gauge showed 2,447 psi at 6,650', with a gas gradient all the way. Only three of the wells have failed to flow when opened. One had to be shut in, the tubing and casing pressures equalized, and then opened several times over a period of nearly two weeks before it would even flow into a frac tank located right at the location. It was another four days before it would flow to the battery. Another was shut in for 18 days, pressures building up to only 900 psi on the tubing and 1,400 psi on the casing. Then it would flow only by heads into a frac tank on location, and it was necessary to swab a couple of days to get it to flow continuously. This well produced a blacker, lower-gravity oil, initially, than the oil from other wells. After several days, the characteristics of the oil changed to more nearly those of oil from offsetting wells. One well refused to flow at all, although the tubing and casing pressures at one time built up to 1,675 psi and 1,625 psi, respectively. This well had to be put on the pump, and has not been a very good producer.

A resume of production information may be found in Table 2. The initial production figures are, in some cases, somewhat misleading. For instance, Well 1 had a very low initial on the pump, but later flowed as much as 314 BOPD. In other cases, the initials shown are greater than the allowables and continued for only a few days at most. The last well drilled is not yet on production as this paper is being written.

FLOW LINES

The tank batteries were built close to the original wells, so most of the new wells required flow lines approximately 2,000 feet in length. Shortly after completion of the first well, it became evident that it would be necessary to run hot oil through the lines to remove paraffin which was building up. The first such treatment was required three months after start of production, but in less than a year monthly treatments were required. Even then, in April 1974 the flow line plugged completely and had to be dug out in several places to remove the paraffin. The second and third wells had similar, but more frequent, problems. When the fourth well was drilled, it was decided that fiberglass lines would be more practical. All flow lines laid since then have been of fiberglass. In fact, the steel lines used for Wells 2 and 3 have been replaced with fiberglass pipe, and only the first well, now pumping less than 30 BOPD, is still producing through a steel flow line.

CONCLUSIONS

The infill drilling program has proven to be a successful venture. Considerable oil and gas have been and will be produced which never could have been recovered from the original wells. Of the fourteen wells completed and on production at this time, only one seems doubtful of being a financial success. It is expected that the program will be continued, with several wells scheduled to be drilled this year and more in succeeding years.

It is believed that many of the drilling problems have been brought under reasonable control, but it is highly unlikely that they have been or ever will be eliminated. With careful control of mud weight and other properties, caution in handling drill pipe and casing, and reduction of mud pump volumes to the minimum required to keep the hole cleaned, it appears possible to drill the Mississippi without undue difficulty.

No claim is made that the completion techniques described are the best available. They have proven highly satisfactory to date, and will no doubt be continued for the foreseeable future.

ACKNOWLEDGMENTS

The author thanks the management of Union Texas Petroleum Division, Allied Chemical Corporation for permission to publish this paper. Thanks also are due to other employees of the company who assisted in the assembling of the data, the preparation of the illustrations and the typing of the paper.

was supposed to have been 7,500 barrels, but the water ran out during displacement of the sand-bearing fluid. This larger treatment was, of course, designed to counteract the possible effect of the lost mud in the interval. Production results were excellent, as will be described later.

In the third well, the original lost circulation occurred when the bit was within 40 feet of the eventual bottom perforation. During fishing operations, additional mud was lost opposite the middle portion of the Mississippi. For this completion, it was decided that each of the lower sections should be given the larger treatment because of the mud in the formation at those intervals. Once again, production results were very good.

Procedure has now been standardized to a large extent. Only radioactive logs are run, after casing has been set and cemented. The Mississippi is divided into three intervals of as near equal thicknesses as seems feasible, after study of the log. The number of perforations is limited to a maximum of 35 and a minimum of 25, using 0.41" jets in most wells. Prior to the actual perforation, 500 gallons of 15% acid are spotted from the bottom of the interval to be perforated. A minimum of 25' is left between the sets of perforations to act as a barrier between them. Two factors are used in selecting the intervals to be left without perforations. In addition to the nearly equal thicknesses already mentioned, spots of minimum indicated porosity are chosen. The individual perforations are then spaced equidistant within the interval to be perforated, such that the number of perforations will fall between the numbers mentioned above.

Once the intervals to be perforated have been selected, each is scheduled for either a 7,500-bbl or 5,000-bbl frac. Typically, the 7,500-bbl treatment will consist of 2,000 barrels of treated water pad, 5,000 barrels of water with 30,000 pounds of 20-40 sand, and 500 barrels of flush. The only difference in the 5,000-bbl treatment is that the sand-carrying part of the treatment will be 2,500 barrels of water with 20,000 pounds of sand. The goal is to obtain an average injection rate of at least 2 bbl/min for each perforation being treated, without exceeding a surface injection pressure of 3,000 psi. Almost without exception, the injection rate has been reached or surpassed with less than the maximum pressure.

PRODUCTION

The first well, with both Oswego and Mississippi open, was shut in for 12 hours overnight after the tubing was run and the Xmas tree was installed. The tubing pressure built up to 260 psi, but the well died immediately after it was opened. It was swabbed for 8 hours, during which 103 barrels of water were recovered. A decision was made that swabbing would be excessively costly, since pumping equipment was readily available. The weather and other things caused a delay of about a week before the pumping unit could be set, during which tubing pressure built up to 860 psi and casing pressure to 350 psi. The well still would not flow, so pump and rods were run. After pumping about 10 days and recovery of some 10% of the 7,076 barrels total frac water, the well started flowing. The volume increased rapidly to a maximum of 314 barrels of oil with 180 barrels of water through a 24/64" choke, with 458 Mcf of gas per day. The well had been equipped with a polished rod blowout preventer, which was greatly appreciated when the flowing tubing pressure went as high as 850 psi. Flow continued for several weeks before it was deemed advisable to kill the well and remove the rods and pump. The well continued to flow for another year, at which time oil production was down to 60 bbl/day with nearly 45,000 barrels cumulative. It was thought that production might be increased by pumping, so pump and rods were run again. There was no appreciable change in rate of production, but pumping has been continued. It should be stated that in this first well, there were no perforations in the upper 170' of the Mississippi formation.

The second well was completed just after the first well was put back on the pump as mentioned above. In view of what had happened on the first well, it was decided this one should be swabbed into production. However, no swabbing unit was moved in immediately because of extremely muddy conditions. Two days after the tubinghead had been installed, tubing pressure was 500 psi and casing pressure was 650 psi. By the next morning the tubing pressure had increased to 525 psi, with no change in casing pressure, and there was no further change in the next two days. The well was opened to the frac pit, and within five minutes was flowing oil. Three days later it flowed 535 barrels of oil, 320 barrels of water and 522 Mcf of gas through a 24/64" choke, with a flowing tubing pressure of 250 psi and casing pressure of 1,500 psi.

The next well behaved very similarly, except it was permitted to flow on a large choke for only 12 hours after it started flowing. Maximum oil production was 249 bbl/day with only 3 barrels of water and 306 using ten spiral drill collars above the bit was initiated, to prevent possible differential sticking in case of lost circulation. The seventh well was drilled in the same manner, and reached a total depth of 7,429' in just over 19 days after spudding. Just as orders were given to start circulating for final hole conditioning, all returns were lost. At that time the mud weight was 8.3 lb/gal, viscosity was 59 seconds, oil was 18.5% and there were 10 lb/bbl lost circulation material. The pipe did not stick, but much effort was expended in unsuccessful attempts to get the hole cleaned out and in condition to run casing. One plug of thixotropic cement was set and drilled out, but circulation was lost again. A second such plug was set with the end of the drill pipe at 7,268', and this time the drill pipe stuck with the cement still pumpable, indicating caving up the hole. The cement was cleaned out inside the stuck drill pipe, using 1 5/8" drill pipe and a 2 1/4" mill, and then the drill pipe was backed off at 6,924'. Several days were spent trying to wash over and fish, and then a string of 5 1/2" casing was run, screwed into the drill pipe and cemented through holes perforated just above the connection between the casing and the drill pipe.

On the next well, the mud weight was held to 8.0 lb/gal or less after reaching the top of the Mississippi. The final mud weight was 7.7 lb/gal, viscosity 95 seconds, 24% oil and 14 lb/bbl lost circulation material. No loss of circulation was experienced. Since then the other seven wells have been drilled with similar mud, 7.7 - 7.9 lb/gal, viscosity 65 - 80 seconds, oil 20 - 30%, and up to 24 lb/bbl lost circulation material. In just one of those wells has there been any problem with lost circulation, and that was after the casing was on bottom. The casing was cemented with no returns, and it was necessary to squeeze opposite the upper part of the Mississippi prior to perforating for completion.

DRILLING TIME

A resume of drilling time is shown in Table 1. It will be noted that, except for lost circulation and fishing operations, drilling time has been fairly consistent. Wells 10 through 14 were drilled consecutively, with approximately seven days between reaching total depth and spudding the next well. The somewhat better time on Wells 11 - 14 may be partially the result of the continuity of the operations.

COMPLETION

Although the drilling of the first well was relatively routine, the completion was certainly a different matter. The thin section of Hunton encountered was tested and found non-productive. Plans called for perforating the Mississippi in two sections, as had been the practice in the original wells, and treating each section with a spearhead of acid followed by 3,000 barrels of treated fresh water with 15,000 pounds of 20-40 sand. The lower section was treated as planned, through 29 perforations, at an average injection rate of 59 bbl/min at 2,200 psi. The upper section was then perforated, the retrievable bridge plug was moved to above the lower set of perforations, and 500 gallons of 15% acid were spotted across the upper perforations. Unexpectedly, the acid went in on a vacuum, so another 500 gallons were pumped in with 50 ball sealers in an effort to insure that all 34 perforations would be open. The first part of the second frac treatment was normal, 64 bbl/min at 2,000 psi with sand at 3/8 lb/gal. Fifteen ball sealers were injected and the rate changed to 54 bbl/min at 2,400 psi. Mechanical problems caused a 3-hour delay, and when treatment was resumed the rate was again 64 bbl/min at 2,000 psi. Another 15 ball sealers were injected and rate changed to 56 bbl/min at 2,200 psi, 5 more ball sealers caused a change to 52 bbl/min at 2,600 psi, and 3 more caused a further change to 50 bbl/min at 2,900 psi. At that stage of the treatment the casing parted, and 16 or 17 days were spent repairing the casing. No additional treatment of the Mississippi was attempted. Several factors seem to have been involved in the casing failure, but the most significant probably was the temperature of the frac water. This operation was in December 1972, and the water was extremely cold. In such extreme weather, it is now the practice to warm the water somewhat.

The completion of the next well drilled set the pattern for all future completions. The lost circulation and sidetracking operations during drilling have already been described. The radioactive logs run after the casing had been set reflected the presence of the large quantities of mud lost in the middle part of the Mississippi. After considerable discussion, it was decided that the Mississippi would be perforated and treated in three separate sections. The upper and lower sections were each treated with 5,000 barrels of treated water and 15,000 pounds of sand, preceded by 500 gallons of acid. The middle section was treated with 7,350 barrels of water and 22,500 pounds of sand, preceded by 1,000 gallons of acid. The latter treatment original oil in place. A decision was made that a second well should be drilled on at least one of the quarter-sections to ascertain whether infill drilling could be justified. The NW/4 of Section 9-21N-7W was chosen for the obvious reason that the original well on that lease had the highest cumulative production, as shown in Figure 1. It should be pointed out that nearly half of that total was attributed to the Hunton formation, and it was expected that the infill well would be productive in the Hunton as well.

DRILLING

To date Union Texas Petroleum has drilled 15 wells in the area under discussion. With only one exception, all of them have been drilled to the Sylvan shale in order to check possibility of production in the Hunton. None of them have found productive Hunton, but some wells drilled by other operators have been more successful in that regard.

The first well should have warned of things to come. It was successfully drilled to total depth of 7,500' with mud having a weight of 8.9 lb/gal, viscosity of 40 seconds, 4% oil and 5 lb/bbl of lost circulation material. However, circulation was lost just after total depth had been reached, and it was necessary to pull several stands of drill pipe and work back down to bottom. During the 12 hours it took to reestablish circulation and wash back to bottom, the oil in the mud was increased to 5%, mud weight was reduced to 8.7 lb/gal and lost circulation material was increased to 10 lb/bbl. No further problems were encountered and the 5 1/2" casing was set and cemented with 340 sacks of 1:1 pozmix using 4% gel, 15% salt and 12 1/2 pounds of gilsonite per sack of cement. There was full circulation throughout the job, and the top of the cement was found at 5,500'.

It was some fifteen months later when the next well was drilled, and the small bout with lost circulation had not made too much of an impression. On this second well, no particular change was made in the mud program except that the viscosity was raised to around 45 seconds. Drilling had reached 7,064', somewhat below the middle of the Mississippi section, when circulation was lost and the drill pipe stuck with the bit just 19' off bottom. Fishing was unsuccessful, as was washing over. The hole was sidetracked once and the bit got back in the old hole. A second sidetrack was successful and the well was drilled to a total depth of 7,455'. The mud weight was still 8.9 lb/gal, but viscosity had been increased to 84 seconds and lost circulation material was 12 lb/bbl. The casing was cemented about as before, except that on this well the cement was preceded by 70 barrels of mud with 35,000 scf of nitrogen. This latter procedure has been continued on all subsequent wells, with slight differences in the amounts of nitrogen and mud.

The third well followed immediately, and this time the mud was carried at a weight of 8.6 lb/gal, with a viscosity of 57 seconds and 9 lb/bbl of lost circulation material. A trip was made at 7,181' to change bits, and then at 7,267' circulation was lost. The bit was pulled 140' off bottom but stuck at that point. Again attempts were made to fish and to wash over, equally unsuccessful. Drill-stem test tools were run on the chance that the sticking might be due to differential pressure. That was successful in retovering one string of wash pipe which had become stuck, but the tools would not go to the top of the original fish consisting of eight drill collars and the bit. The mud was switched to a salt gel base, and the hole was sidetracked and drilled to 7,501' with mud weight of 8.7 lb/gal, viscosity 110 seconds, 10% oil and 18 lb/bbl lost circulation material.

A year later, when a fourth well was drilled, it was decided to try something different. Soon after the top of the Mississippi was reached, a new bit was run so no trip would be necessary until total depth had been reached. At the same time, nitrogen was introduced into the mud stream to decrease the pressure against the formation. The mud had a weight of 8.7 lb/gal going in the hole and 8.4 coming out. Its viscosity was 52 seconds, it contained 10% oil and 12 lb/bbl lost circulation material. Nevertheless, at 7,084' circulation was lost and 700 barrels of mud were lost into the formation. The drill pipe did not stick, the mud system was switched to a salt gel base with a weight of 8.3 lb/gal, and the bit was worked back down to within 60' of bottom when circulation was lost again and another 500 barrels of mud disappeared. The bit was pulled and the pipe was run open-ended to total depth of 7,084' at which point a 200-sack thixotropic cement plug was set. Only 34' below the old total depth, circulation was lost again. A second plug was set, and the hole was drilled to total depth with mud weighing 8.1 lb/gal, having a viscosity of 54 seconds, and with 10.5% oil and 10 lb/bbl lost circulation material.

The next two wells were drilled with no difficulty, using fresh water mud with a weight of 8.2 - 8.3 lb/gal, a viscosity of 65 - 70 seconds, 14 - 15% oil and 12 lb/bbl lost circulation material. The practice of

Appendix "A"
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PAPER
NUMBER SPE 6462

Infill Drilling in the Mississippi Limestone - Garfield County, Oklahoma

by

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This paper was prepared for the 1977 Oklahoma City Regional meeting on Operating Practices in Drilling and Production of the Society of Petroleum Engineers of AIME, held in Oklahoma City February 21-22, 1977.

ABSTRACT

Development drilling of the Mississippi Limestone in southwestern Garfield County, Oklahoma, took place in the mid-1960's. Most of the development was either one well per quarter-section or one well per section, depending on the predominance of oil or gas in the hydrocarbon production.

In 1972, Union Texas Petroleum Division, Allied Chemical Corporation, drilled a second well on one of the quarter-sections to test the adequacy of the drainage by the original well. Results indicated that additional development was justified, and numerous new wells have been drilled since that time by Union Texas and by other operators as well. Drilling problems, completion techniques and some of the results obtained are discussed.

INTRODUCTION

The Mississippi Limestone is a massive fractured limestone underlying a large part of northwestern Oklahoma. It has been found productive of hydrocarbons in varying degrees over much of an area stretching from 12 miles east of Enid to 40 miles west and from 12 miles north to 15 miles south, give or take a few miles in any direction.

The specific part of this area to be discussed is north and west of the town of Waukomis, mostly in Township 21 North, Range 7 West. Most of this township had been developed in the mid-1960's with only one well per quarter-section, thought at the time to be sufficient to recover the hydrocarbons which were economically recoverable. Some of the sections in the northern part of T21N and all of those in T22N had only one well per section, because they had been predominantly gas productive when completed. In 1972 the Exploration Department of Union Texas Petroleum prepared several maps contoured on cumulative oil production through June 1971. The map of the Waukomis area indicated that the wells in T21N, R7W had recovered significantly more oil than in other areas, as shown in Figure 1.

The Mississippi Limestone has very low porosity, generally in the 3 - 6% range. At the same time, this porosity is present throughout the entire thickness, which exceeds 500' in most of the wells. It was evident that the indicated ultimate recoveries would be quite low when compared with the probable

Illustrations at end of paper.

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Original manuscript received in Society of Petroleum Engineers office March 27, 1977. Revised manuscript received May 10, 1977. Paper (SPE 6109) was first presented at the SPE-AIME 51st Annual Fall Technical Conference and Exhibition, held in New Orleans, Oct. 3-6, 1976.

carbonate reservoirs.

Extensions of the Archie technology were developed by several investigators through petrographic studies of the origin of porosity in carbonates and the establishment of carbonate pore-space (pore network) types that exert fundamental influence on the range and level of reservoir rock quality. The application of petrophysical technology is wide-ranging in that it can be used in the office and at the wellsite. The effective utilization of the technology requires the cooperation of several disciplines and an understanding of when to apply the technology. For example, permeability maps of various units in the Snipe Lake Beaverhill A Pool (Alberta) initially were constructed by combined geological and petrophysical studies. When numerical simulation studies indicated that adjustments were needed to match performance history, the maps were changed so as to be compatible with the geologic history of the formation.[36]

Synergy for the Future

Past industry activities have demonstrated the benefits to be derived from synergistic reservoir studies and reservoir management. But what of the future; will it be "business as usual" or should we have higher expectations in view of the need to increase recovery? There are at least three areas where improvements are needed: communications, new technology, and application of available technology.[37]

In the area of communication, the engineer, geologist, and geophysicist must develop a better understanding of each other's technology and concepts. We need to expand our contact beyond professional-society meetings to the point where we study together. Petroleum scientists need to meet on the outcrop to examine continuity and thickness patterns and to study porosity and permeability variations. Ideally, this would be done in areas where close-by production could supply data from the subsurface — including engineering, geological, and geophysical data.

Geologists lack a solid foundation and technology for reservoirs that were deposited in deep-water depositional sites off the continental margins, the largely untapped frontier for exploration. Data from existing fields that produce from such deposits need to be united and made available. Cooperative coring projects of modern and ancient deposits should be organized and the results communicated to industry. Other new technology needs are in the areas of predicting fracture density and whether faults are barriers or seals. Well interference testing is the best way to evaluate fractures and faults, but conditions are not always suitable for this technology. Plate tectonic theory and satellite imagery could add to the unifying approach needed.

Seismic modeling is a geophysical technology that needs to be utilized more often in reservoir description. Recent advances in this and other branches of geophysics make it possible to use seismic data to perform detailed structural and stratigraphic analysis in field development and delineation.

Available computer technology can greatly aid the construction of cross-sections and maps, especially where several hundred wells have been drilled. Also, some programs permit the routine construction of fence diagrams to show continuity and thickness patterns and pore-space variations. This technology greatly reduces time requirements for geologic activities, thereby allowing more time for interpretation and planning.

Conclusions

The opportunities for increasing recovery through synergistic activities are numerous. Experience indicates that there are corporate and personal benefits to be derived from this activity. Whether these opportunities and benefits are realized depends both on management *and* the petroleum scientists themselves. Management can provide an environment for professionals to work together. Whether synergy develops depends on the people involved. These persons must believe in and be willing to practice their technology. Even more, they must be willing to practice their technology in an environment of mutual understanding and cooperation. To do so will be in the best interests of synergy and will assure increased recovery.

Acknowledgments

We wish to express our appreciation to the managements of Exxon Production Research Co. and Marathon Oil Co. for permission to publish this paper. We also appreciate the counsel of R. M. Sneider (Sneider and Meckel Associates, Inc.), J. G. Richardson (Exxon Production Research Co.), and J. T. Morgan and F. G. Knight (Marathon Oil Co.).

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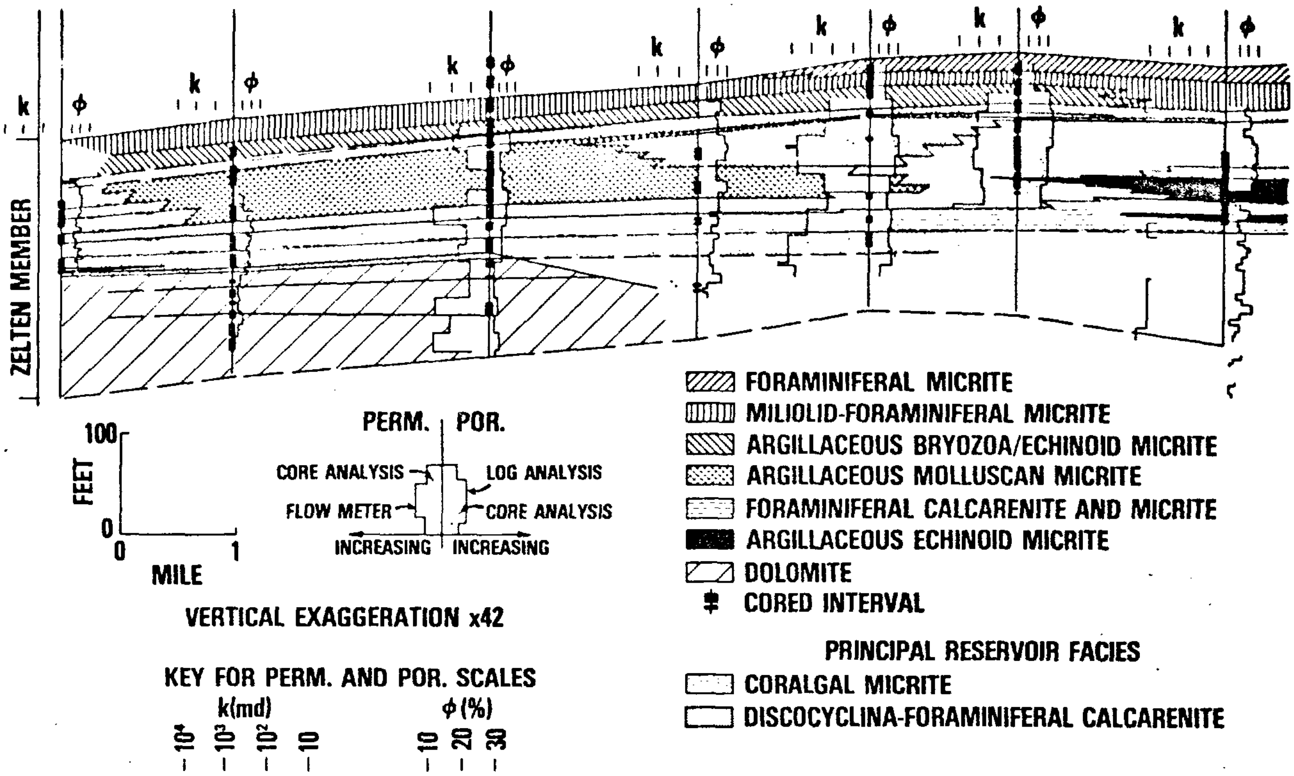

Fig. 13—Correlation section showing distribution of fundamental rock types and porosity-permeability profiles in the Zelten field, Libya.[33]

reservoir rock unit are shown in Fig. 14. The patterns portrayed by this map reflect the position of the carbonate bar that trends northwest-southeast through the field, being flanked on the northeast by the open ocean and on the southwest by a lagoon. Tidal passes (now filled with mud) interrupt the bar.

Carbonate Pore-Space Characterization

Pore-space characteristics of Zelten reservoir rocks were determined by integrating lithologic, core analysis, and well test data.[34] Rock description determined that five types of porosity occurred in these rocks: intergranular, intragranular, leached skeletal, leached micrite, and vuggy (both solution cavities and solution-enlarged fractures). Core analysis and well test data were used to determine the reservoir rock properties for different porosity types within each lithologic class. The addition of the core analysis and well test data to correlation sections (Fig. 13) showed that postdepositional modifications by solution activity and cementation were mostly parallel to the depositional boundaries, implying that porosity and permeability maps could be constructed using the depositional maps as guides for contouring (not shown). Exceptions to the parallelism were handled by adding petrophysical terms to the lithologic names — that is, coralgal micrite (highly leached to vuggy).

The Zelten permeability data show a common characteristic of carbonate reservoirs, that permeability determined by flowmeters differed from that determined by core analysis. In this case, flowmeter data were consistently higher than the core analysis measurements, primarily because of the hair-line fractures and solution voids created during postdepositional time.

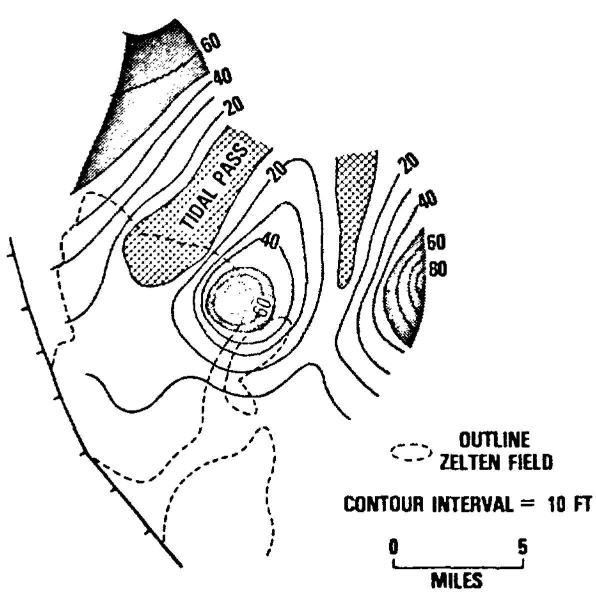

Fig. 14—Thickness pattern of a principal reservoir unit in the Zelten field, the Discocylina-foraminiferal calcarenite unit.[33]

Bases for Pore-Space Characterization

The preceding section mentioned the need to perform detailed pore-space studies for most carbonate reservoirs. This type of work is highly specialized because it represents the utilization of data from rock description, well log analysis, core analysis, and well testing. Petroleum scientists are familiar with this work as being the multidisciplinary subject called "petrophysics."

The pioneer in petrophysics was Archie,[35] who both developed and applied much of the technology that is still being used today. Archie recognized the influence of rock texture and pore-space character on reservoir quality and established techniques for incorporating such data into formation analysis studies of both sandstone and ates are more susceptible to postdepositional processes, particularly solution activity.

Example of Continuity Patterns

A dramatic change occurred in continuity concepts (Fig. 12) when surface and subsurface studies of the San Andres formation in West Texas were supported and guided by concurrent studies of past producing performance of the San Andres in the Wasson field.[29] Early studies of reservoir management had utilized a gross model of continuity but production history showed that a more detailed model was needed.

The revised model consists of 10 mappable pay units, some of which are not continuous over the 40-acre spacing of the field. The pay intervals are, at places, separated by impermeable barriers that prevent crossflow. These findings led to the discovery of somewhat deeper oil-bearing strata and of areas where infill drilling uncovered uncaptured oil.

The determination of continuity pattern and pore-space variability was aided significantly by the outcrop studies. In addition to providing an understanding of depositional history, continuous exposures showed that impermeable beds have large areal extent and that pore-space variations are random. Based on both the surface and subsurface studies, it was determined that waterflooding would be highly effective if sufficient infill wells were drilled. In other fields where areal heterogeneities are less pronounced than they are at the Wasson field, the effect of lateral discontinuities can be minimized by proper selection of infill drilling locations.[30] Continuity patterns in other types of carbonate reservoirs are described by Jardine *et al.*[31] and by Reitzel and Callow.[32]

Bases for Determining Continuity and Thickness Patterns

Cross-sections and maps are used to describe carbonate reservoirs, too. These illustrations also require input from studies of depositional origin, reservoir model references, and investigations of postdepositional modifications. Geologic activities in carbonate reservoir description usually follow the steps described earlier, with increased emphasis on fossil content, postdepositional alterations, and pore-space characterization.

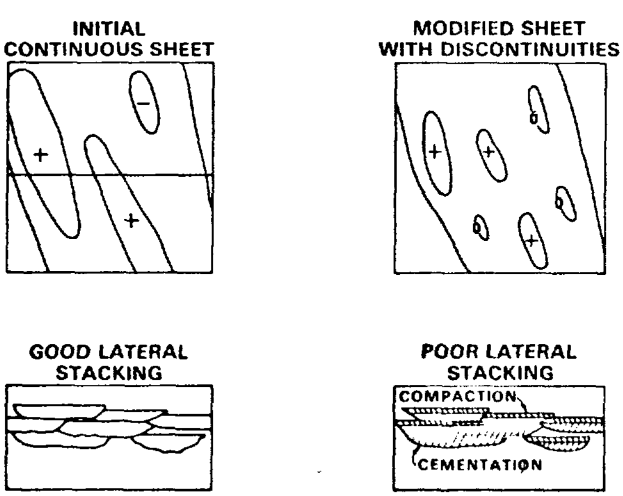

Fig. 11—Diagrammatic representation of the modification of a continuous sheet by compaction and cementation.[19]

Carbonates important to industry formed in marine areas favoring biochemical production of carbonate (and associated) minerals. The rock types were deposited in both shallow marine (tidal flats, beaches, and offshore bars) and deep marine (turbidite channels and fans) environments. The shallow-water depositional sites may have been located adjacent to the mainland, on the continental shelf some distance from the mainland, or along the shelf margin. The shelf has been a favored place for reef development.

Carbonate reservoir geometry is wide-ranging. Banks are tabular, sheet-like bodies, whereas reefs tend toward linear to oval bodies with vertical dimension ranging from 50 to 1,000 ft. The varied form of modern reefs has been identified in ancient reefs (atoll, pinnacle, etc.). Some of the largest known fields are in carbonate rocks. Jardine *et al.*[31] discuss carbonate depositional sites and reservoir geometries in more detail.

Controls on reservoir characteristics and the complex methods of carbonate reservoir description will be illustrated by the Zelten field of the Sirte basin, Libya.[33] A typical correlation section (prepared from core and thin-section study) is shown in Fig. 13. The complex rock names indicate the diagnostic fossils and the relative amount of grains to lime mud in a lithologic unit. These complex names are needed to reconstruct the depositional patterns of various rock types. The two principal reservoir units at Zelten are identified in Fig. 13; the method of identification is discussed below.

Thickness patterns for all lithologic types were developed by studying correlation sections, preparing facies horizon maps, and constructing standard thickness (contour) maps.[33] Thickness patterns for one principal

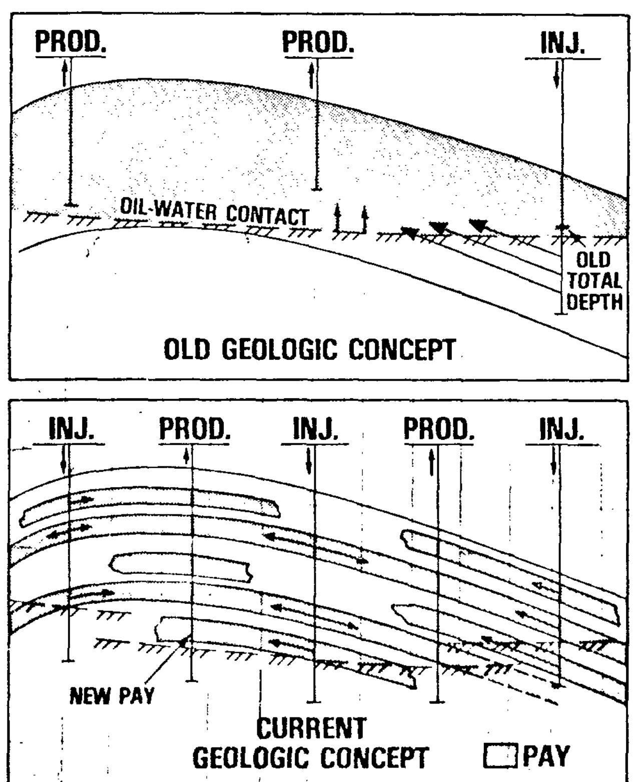

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Fig. 12—Old and new concepts of carbonate continuity patterns in the San Andres formation in the Wasson field.[29]

The spatial distribution of porosity and permeability in the Robinson sandstone influenced performance in the Fry pilot,[20] in that the profile of the burned zone (Fig. 10) followed the coarser rocks having large-scale cross-beds and beds with even (parallel), horizontal layers. In other words, combustion proceeded preferentially in the more continuous, porous, and permeable portions that generally followed the thickness trend of the over-all sand development.

Similar to predicting continuity and thickness patterns, prediction of pore-space variations requires reference models. Hutchinson *et al.*[21] pioneered the study of rock-property variations in outcrops of genetic sand-body types. Other studies in the subsurface[22] and surface, both of ancient and modern deposits, have contributed to the understanding of rock-property controls.

Pore-space variations occur in four types of geometric configurations: (essentially) homogeneous, stratified, multidirectional, and random. Many dune and beach deposits show little variability (initially) in pore-space properties, whereas many braided stream and deltaic deposits range from stratified to multidirectional. Deposits of meandering streams tend to be multidirectional to random. A significant contribution by Pryor[23] showed that pore-space characteristics are inherited largely from time of deposition.

Subsurface, laboratory, and computer studies of carefully controlled operations also have contributed greatly to our understanding of variations in pore-space properties. Laboratory models (sand packs scaled to pilot operations) of the river deposits in the Chandler, Okla., miscible-flood test site[24] matched field performance rather closely when the model represented the three-dimensional permeability and thickness variations determined from cores and well tests. Computer simulation studies in other field tests[25] also have demonstrated the need to identify the type of rock-property variations to optimize reservoir management or match production history.

Compaction and Cementation Controls On Rock Properties

Although depositional controls exert great influence on the external and internal characteristics of reservoir sandstones, certain postdepositional factors, such as compaction, cementation, and solution, are sometimes important. Indeed, the wide range in pore-space properties, as well as certain modifications in continuity and thickness patterns, cannot be satisfied by depositional models alone.

Changes in pore-space properties as a consequence of burial for long periods are related to compaction, a global process. Permeability is usually changed more than porosity, because pore size is decreased. Usually, compaction proceeds faster in beds containing the smaller (effective) grain size. During compaction, deposits that are characterized by cyclic variations in particle sizes will undergo complex changes that can alter reservoir geometry to a less desirable form.

Cementation is a process that fills pores with mineral matter, with or without associated compaction. Initially, the pore space may be free of interstitial matter but various minerals may be introduced subsequent to deposition of sand grains. Certain types of clay (a common pore filler) expand when contacted by fresh water,[26] and can be harmful to injection operations. Even in sandstones, solution activity can remove minerals and enhance porosity and permeability.

The result of compaction and/or cementation may be to modify greatly storage capacity and fluid flow conditions. As Morgan *et al.*[27] and Cordiner and Livingston[28] show, selective cementation can form stratified sheets from homogeneous ones. At advanced stages, compaction and/or cementation can create discontinuous sheets from continuous ones (Fig. 11). Obviously, such modifications are significant to both exploration and exploitation programs.

Guidelines for Carbonate Reservoirs

Overview of Carbonate Reservoirs

Continuity and thickness patterns and pore-space variations in carbonates are more complex than they are in sandstone reservoirs. The conditions under which carbonates are deposited involve mechanical, chemical, and biologic processes that are closely interrelated and subject to a wide range of influences. Additionally, carbon-

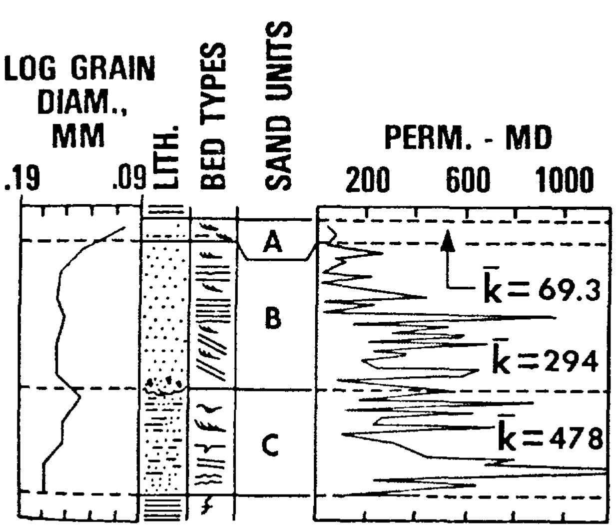


Fig. 9—Lithologic and permeability variations in the Robinson sandstone, Fry in-situ combustion test site.[7]

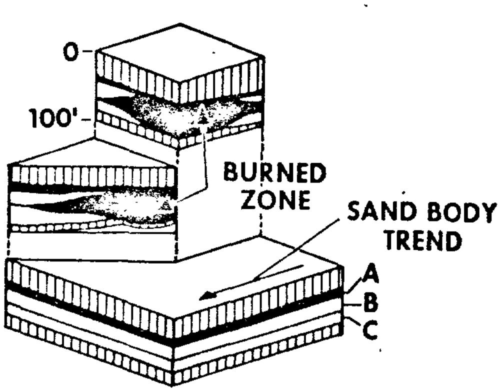


Fig. 10—Profile of the burned zone, Fry test site.[20]

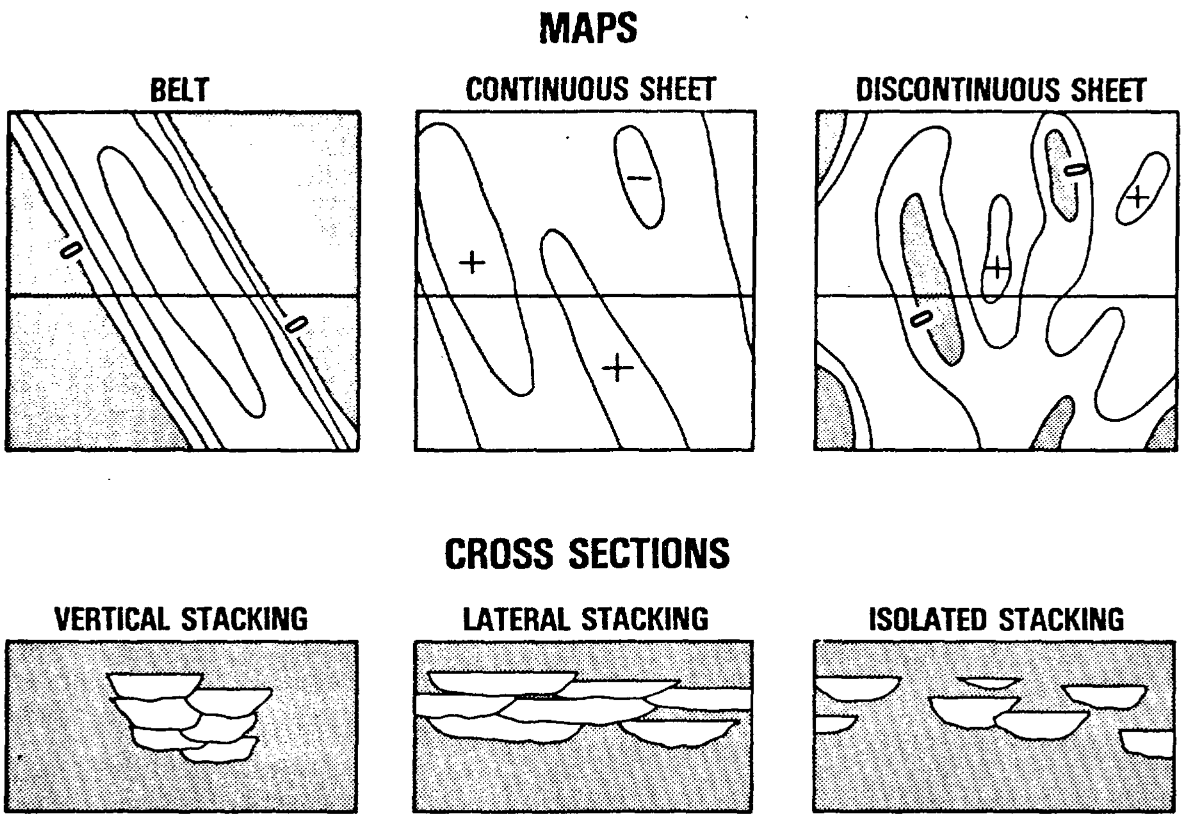


Fig. 7—Principal types of sandstone reservoir geometries.[19]

areas can be poorer.

Although certain fields are characterized by a single type of reservoir geometry, in others more than one type is common. The Loudon field in the Illinois basin, for example, consists of an anticlinal trap that spans portions of a belt and both continuous and discontinuous sheets. Generalized thickness patterns in the field, shown in Fig. 8, are based on a well spacing of about 10 acres. In the southernmost part of the field, belt and continuous-sheet geometries afforded better recoveries than did the discontinuous sheet that characterizes the northern part. Thus, recovery efficiency is related to the distribution of genetic sandstone units and can be predicted (in a relative sense) from maps and cross-sections of these units.

Variations in Pore-Space Properties

Within and between individual sand units, porosity, permeability, and capillary-pressure characteristics can vary widely, with the degree of variation depending on the particular depositional processes that developed the rock framework. In this case, we are concerned with small-scale properties within the sand body.

The influence of grain size and bedding on reservoir performance can be illustrated by the Fry in-situ combustion pilot test.[20] The variations in permeability in the Robinson sandstone (Fig. 9) are related to particle-size variations (and are exemplified further by bedding types) within and between the various sand units that make up this river deposit. Permeability decreases from bottom to top, both within and between the sand units, and porosity (not shown) varies similarly. (Additional information, including core photographs, can be found in Ref. 7.) Petrophysicists and core analysts are well acquainted with the effects of variations in grain size and bedding types on core analysis and well log data.

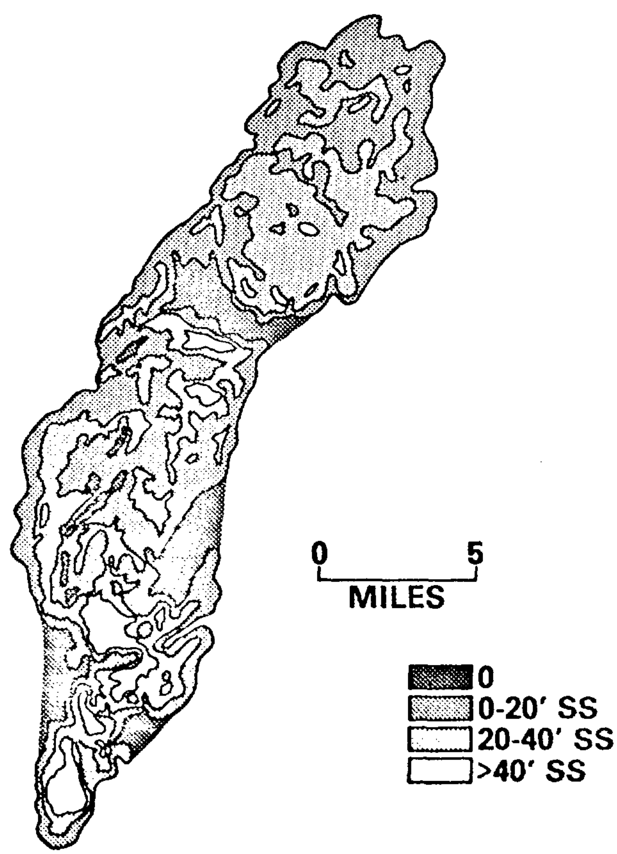


Fig. 8—Thickness pattern of the Cypress (Weiler) sandstone in the Loudon field.[19]

tance of the stream in the watershed. Internally, the structure of these deposits, best seen in cross-section, consists of smaller components that represent the various positions of ancient channels; the coalescence of these (filled) channels leads to the over-all thickness pattern portrayed by the map.

In contrast to the Degonia pattern, the Booch sandstone of Oklahoma[9] shows an irregular, fan-shaped pattern (Fig. 5). The highly irregular areal pattern, as well as the outline, is related to the spacing of distributary channels in this delta and to the relative sizes of the channels. Production rates can be contoured to form the same pattern as that for the thickness map.[10]

These examples, whether shown to illustrate continuity or thickness patterns, indicate that a wide range exists for sandstone reservoirs. Thus, the need exists for unifying concepts to aid the interpretation of well data.

Bases for Determining Continuity and Thickness Patterns

Continuity and thickness patterns are determined commonly by means of cross-sections and maps, the development of which is guided principally by three factors: (1) identification of the depositional origin of the reservoir and nonreservoir strata, (2) comparison with reservoir models that are based on detailed outcrop and subsurface studies, and (3) recognition of postdepositional modification (discussed in a later section).

Sand accumulates in a variety of depositional sites (Fig. 6); each site has a somewhat different sand continuity and thickness pattern and a different pore-space character associated with its particular sand bodies. Although each site is important to petroleum occurrence, the coastal sites, particularly the deltaic occurrences, are the most important. This happens because much sand is dumped in coastal sites and physical processes tend to distribute the sand over large areas. Also, many coastal areas have been the sites for repeated occurrences of sand deposition throughout geologic time.

Depositional origin is interpreted from lithologic and paleontologic data, including the determination of mineralogy, grain size, and bedding types, and the identification of plant and animal remains. Cores, cuttings, and well logs provide the basic data. Observations of modern deposits guide the interpretation of the basic data. Le Blanc[11] presents more information on this important but specialized topic. Refs. 2 and 12 through 15 present field case studies.

Sandstone reservoir continuity is related to depositional origin, as was shown by the Bradford and Robinson examples. In an attempt to quantify sandstone and shale continuity, Zeito[16] undertook a systematic study of selected depositional sand-body types in outcrop. Although the sample was small, there was strong evidence that marine deposits tend to be more continuous than nonmarine deposits. Other investigators[17, 18] have confirmed Zeito's work, but more information is needed on specific sand-body types.

Many of the common reservoir sand-body types can be classed into three principal sandstone geometry models[19] that serve to assist in predicting continuity and thickness patterns (Fig. 7). These models are characterized by their geometric form, as seen on maps and cross-sections. Belt reservoir models are prismatic features with internal structure characterized by vertical stacking of constituent elements. Continuous sheets are tabular features that are characterized by lateral stacking of constituent units, whereas discontinuous sheets are characterized by isolated stacking. These models, of course, apply both to the productive area and the aquifer that surrounds it.

Not all reservoirs exactly fit the scheme shown in Fig. 7. There are variations in the types of physical contact among the constituent elements, for example, that affect pressure communication. The elements portrayed in Fig. 7 represent different types of river channels that are "cut into" older elements, thus creating good physical contact. Other types of deposits (particularly nearshore deposits) are characterized by accretionary contacts in which the constituent elements stack by plastering onto previously formed elements. Because the down-cutting action characteristic of channeling is now replaced by the plastering action, hydrologic communication over large

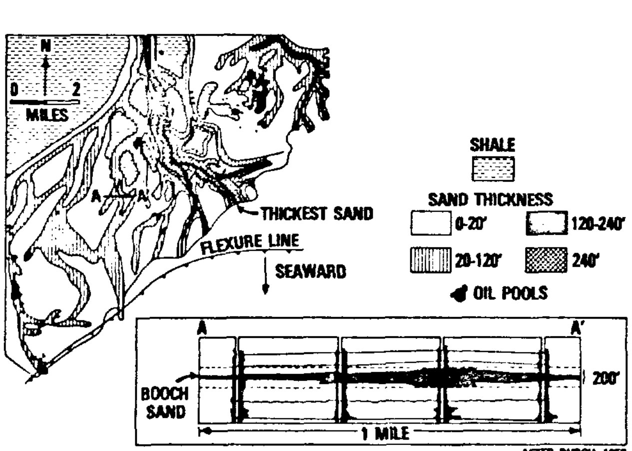
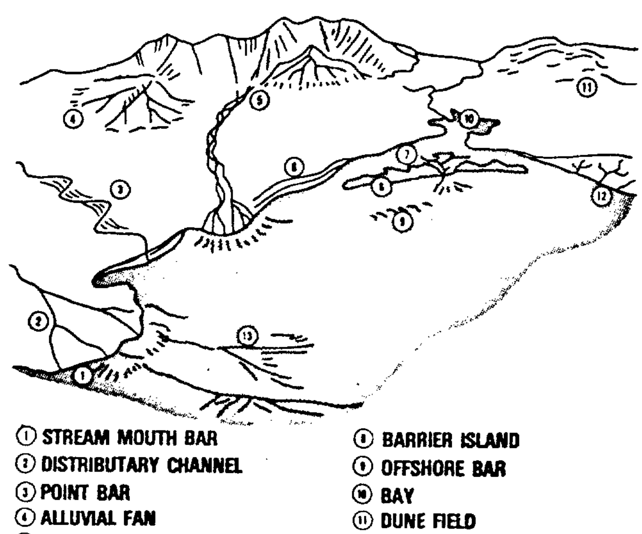


Fig. 5—Thickness and continuity patterns of the Booch sandstone, a deltaic deposit.[9]



1 STREAM MOUTH BAR
2 DISTRIBUTARY CHANNEL
3 POINT BAR
4 ALLUVIAL FAN
5 BRAIDED STREAM
6 BEACH
7 LAGOON
8 BARRIER ISLAND
9 OFFSHORE BAR
10 BAY
11 DUNE FIELD
12 TIDAL FLAT
13 TURBIDITE FAN AND CHANNEL

Fig. 6—Depositional sites of sand and names of sand-body types.

(Table 2). The presence of coal and pyrite, for example, affects the efficiency and character of the burn profile because these materials consume fuel as they oxidize.

Integration studies are particularly important to tertiary recovery projects involving fluid injection, whether surfactant, chemical, or steam. In both field- and pilot-scale projects, it is important to develop the three-dimensional, quantitative geologic descriptions suitable for input into reservoir simulation programs.

Guidelines for Sandstone Reservoirs

Overview of Sandstone Continuity and Thickness Patterns

Because geologic conditions are never exactly the same in time or space, sandstone continuity and thickness patterns vary from one field to the next, and from one reservoir zone to the next within a particular field. Many factors are involved that together develop the specific features of a reservoir zone: depositional mechanism, amount of material supplied to a depositional site, tectonic stability in the source and receiving basin, etc. Thus, we need to know the types of patterns that are important to reservoir management and need to develop a unifying principle that will enable us to make predictions in the face of the established nonuniqueness of reservoirs.

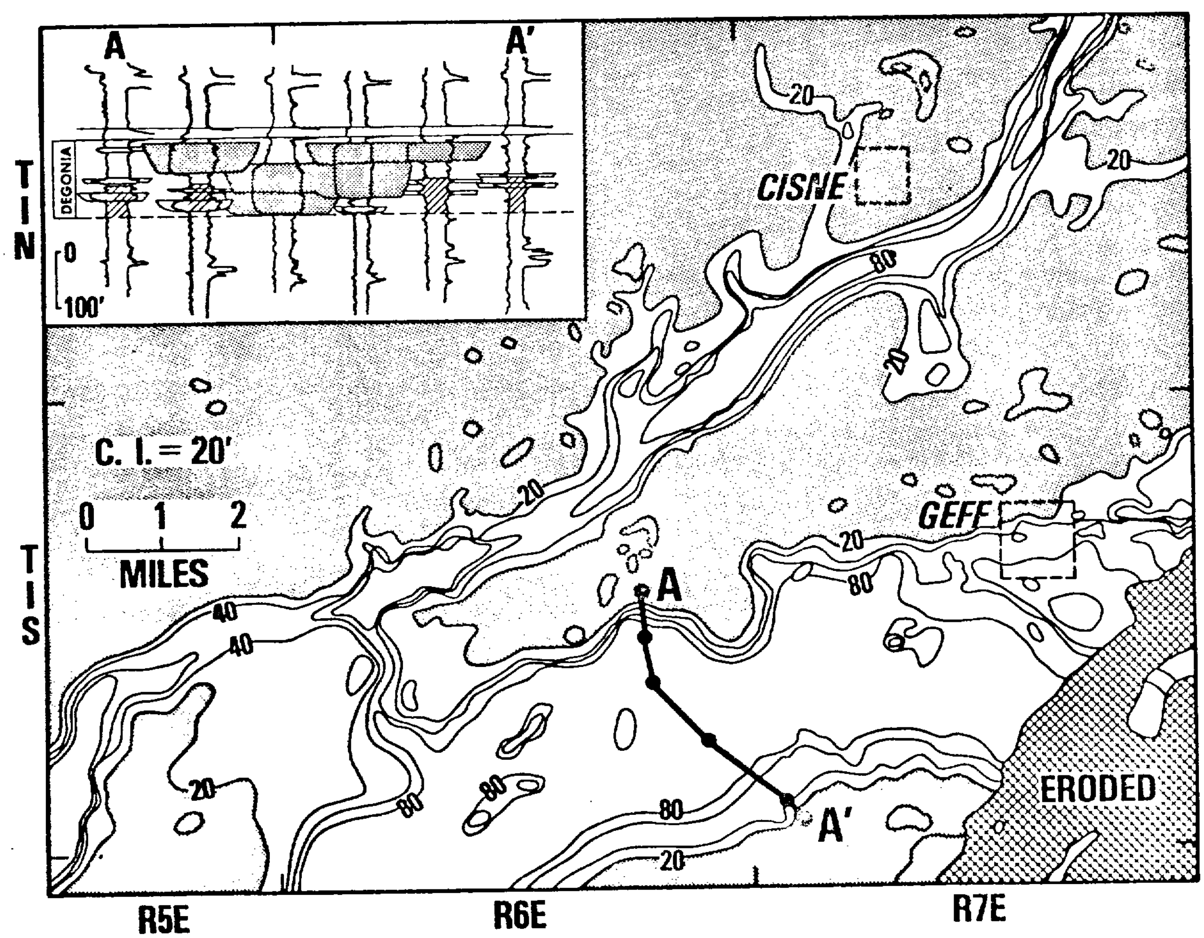
Examples of Sandstone Continuity Patterns

Good continuity, as shown locally by the Bradford sandstone in western Pennsylvania (Fig. 2), is typical of marine strata. In such deposits, sandstone and shale units are correlatable over wide distances, usually in terms of thousands of feet to possibly several miles. The shale units, even when only a few feet thick, consistently separate the sand units and prevent crossflow. Many deltaic deposits and other nearshore marine deposits (beaches, barrier islands, tidal flats, etc.) show this continuity pattern, though the actual distance over which the continuity is maintained can be different in different areas.

An example of both poor and good sand continuity in the same reservoir is illustrated by the Robinson sandstone of the Illinois basin. Typical of some river deposits, the Robinson sandstone units in the Robinson Main extend over variable distances (Fig. 3). In some parts of the field, thicker sands (50 ft) are correlatable for distances of several thousand feet; thinner sands (10 to 20 ft) usually extend for about 1,000 ft.[7] Where economic conditions do not allow close well spacing, recovery will be small from the thin sands.

Examples of Thickness Patterns

Two examples are presented to show patterns and to indicate their significance. The first example is the Degonia sandstone of the Illinois basin (Fig. 4).[8] The linear and uniform thickness pattern is typical of ancient and modern braided streams. Such deposits range from 1 to 10 miles in width and from tens to hundreds of miles in length. The dimensions are related to the over-all impor-



AFTER POTTER, 1962

Fig. 4—Map and correlation section of the Degonia sandstone showing thickness and continuity patterns of an ancient river deposit.[8]

of cross-sections and maps, guided by knowledge of the patterns known to occur in settings of similar depositional origin, is a time-consuming but vital step in any reservoir study. Frequently, the cross-sections and maps are completed in an iterative fashion, making certain that the two types of illustrations support each other and agree with well test data. In complex frameworks, panel or fence diagrams are useful illustrations, particularly in situations where shales or other tight streaks in the pay zones could influence displacement efficiency.

Reservoir quality studies utilize well log, core analysis, and well test data to ascertain pore-space attributes and distributions. Special core analysis and petrophysical studies may be required to identify the pay zone and to predict fluid saturation distribution. Based on these studies and previous maps and cross-sections, the net sand or "net pay" may be mapped.

Integration studies are the epitome of the total effort, because both data and professional experience must be used to complete the description activity satisfactorily. Porosity and/or permeability maps can be combined with net-thickness maps to provide the pore-volume or transmissibility maps needed in complex situations. With such data and others, reservoir simulation techniques can be used to match history and to predict future performance. The geologist's knowledge of critical factors such as shale distribution within and between the pay zones may be critical to the determination of the most efficient recovery plan.

Application to Oil Recovery

Because emphasis shifts as reservoir objectives shift, different management projects require different geologic approaches. For example, rock and framework studies are undertaken in all projects, but with different detail and data input. Primary recovery projects require gross continuity and thickness information for *both* the field and aquifer. Geophysical studies[2] may be useful in defining the trap and evaluating the stratigraphic framework in the field and aquifer. On the other hand, secondary and tertiary projects require detailed information to predict conditions between injectors and producers.[3-6] Outcrop studies may be useful in determining well spacing, and geophysical input may help locate water sources.

Reservoir quality studies are important in secondary and tertiary projects. In fluid injection projects, rock framework parameters (including the pore space) influence various operational parameters (Table 1), particularly from the standpoint of porosity and permeability distribution. Also, the presence of swelling clays may cause formation damage if water of incompatible salinity is injected. In in-situ combustion projects, porosity and permeability are also important, but so are other factors

TABLE 1—ROCK EFFECTS ON FLUID INJECTION PROJECTS

Rock Framework Parameter	Operational Parameter Affected
Surface area and pore geometry	Unit displacement efficiency
Permeability profile	Vertical sweep
Directional permeability	Directional front movement

TABLE 2—ROCK EFFECTS ON IN-SITU COMBUSTION PROJECTS

Rock Framework Parameter	Operational Parameter Affected
Surface area, coal, and pyrite	Fuel and air requirements
Permeability profile	Ignition conditions and vertical sweep
Directional permeability and structural dip	Directional front movement

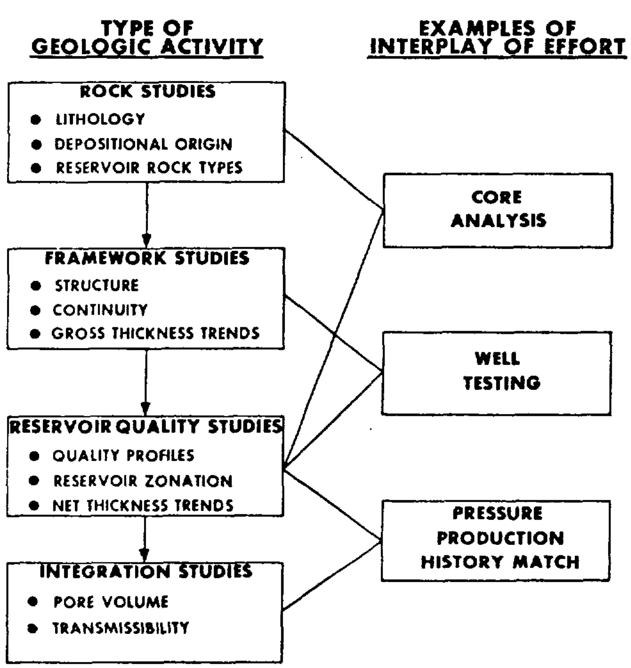


Fig. 1—Flow chart of geologic activities in reservoir studies, with selected topics to illustrate joint activities with other petroleum scientists.[1]

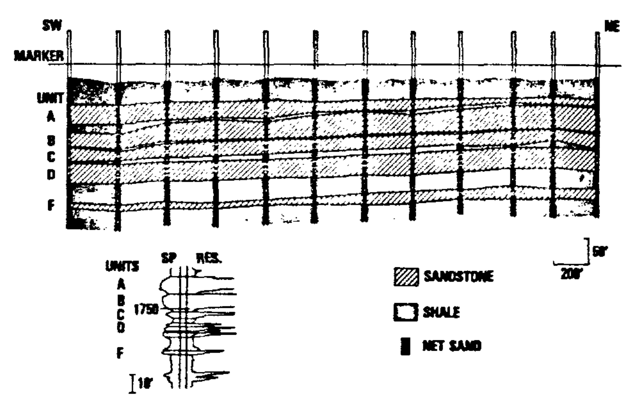


Fig. 2—Correlation section showing continuity pattern of the Bradford sandstone in the Sage Lease.

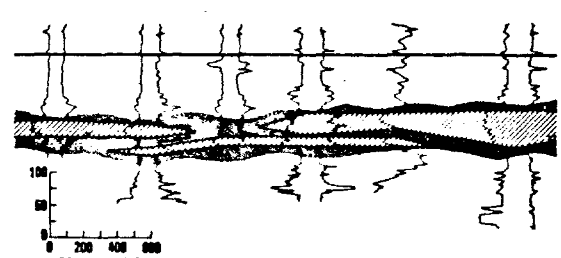


Fig. 3—Correlation section of the Robinson sandstone showing continuity pattern in the Robinson Main field.

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Synergism in Reservoir Management — The Geologic Perspective

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Introduction

Rather than being homogeneous tanks or uniformly layered entities, most reservoirs exhibit complex variations of reservoir continuity and thickness patterns and of pore-space attributes (porosity, permeability, and capillary-pressure properties). The reservoir interval is commonly subdivided vertically and areally into "pay zones" that are separated by impermeable rock units; the pay zones themselves often contain thin shale or tight carbonate streaks. Thickness distributions of pay zones may be sheet-like or linear and, within the rock framework, pore-space attributes may vary in a predictable or random manner. It is this complexity of rock framework and pore-space variation that challenges petroleum scientists to apply their technology and experience in reservoir description, with the aim of improving recovery.

The best way to identify and quantify rock framework and pore-space variations is through the deliberate and integrated use of engineering and earth-science technology. Reservoir studies are more effective when geologists and engineers determine jointly, at the outset, the course of investigation, the work-area responsibility for each professional on the description team, and the target dates for combining results. Such an approach to reservoir description requires an understanding of the technology used by other professionals and an awareness of the principles and concepts upon which the technology is based. Furthermore, this understanding and awareness will promote the free exchange of ideas — a fundamental facet of synergistic activities.

This paper presents an overview of geologic technology and the concepts and principles that guide its use. Four topics are covered. First, the geologic procedures used in reservoir description are presented together with a brief discussion of the emphasis required for different recovery projects. The next two topics deal with the details of the technology and guiding principles and concepts used to describe sandstone and carbonate reservoirs. Finally, synergy needs for the future are discussed.

Geologic Activities in Reservoir Studies

General Activities

The steps commonly followed by the geologists are indicated in Fig. 1, together with some work areas where the geologist needs to combine his efforts with those of the engineer.[1] These steps are listed in their general order of accomplishment, although sometimes it is worthwhile to "look ahead" before completing a particular step.

Rock studies involve using cuttings, cores, well logs, and routine core-analysis data to identify the rock types (both potential reservoir and nonreservoir types that make up the reservoir interval) and to interpret the depositional origin of the interval. These data provide fundamental information for predicting reservoir continuity and thickness patterns and variations in pore-space properties. Typical of the information developed in this step are core-description graphs and porosity-permeability cross-plots.

Framework studies determine the geometric configuration of the trap and the vertical and lateral distribution of the rock types identified previously. The construction

Improved hydrocarbon recovery can be obtained through the coordinated use of engineering, geology, and geophysics. Particularly in synergistic studies, geologists must be able to identify the rock properties that will be significant to oil and gas recovery. This paper presents an overview of geologic technology and the concepts and principles that guide its use.