TWOFREDS FIELD
A TERTIARY OIL RECOVERY PROJECT

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ABSTRACT

The Twofreds Delaware Sand Reservoir was discovered in 1957 and developed as a water-flood unit in 1963. By 1973, after a moderately successful water-flood, the production rate had declined to near economic limit. Carbon Dioxide injection for oil recovery was instigated in 1974, therefore, oil recovery since 1974 represents tertiary oil recovery after water-flooding. This paper discusses the actual application of CO_2 injection procedures and the field performance for the 6-year period since CO_2 injection was started. Performance to date appears successful in recovering additional oil from reservoirs of this type.

INTRODUCTION

The Twofreds Delaware Sand Field is located in Ward, Loving, and Reeves Counties 17 miles northeast of Pecos, Texas. The reservoir is a stratigraphic sand trap and is found at a depth of from 4700 ft. to 4900 ft. Regional dip is in an easterly direction at a rate of approximately 80 ft. per mile. The Delaware sand is a medium to fine grained sand with thin shale laminations occuring throughout the section. Sand thickness averages 25 ft. over the 4400 acres, productive area with a maximum thickness of 42 ft. near the center of the northeast to southwest trending length of the field. Since discovery, the field has been subject to primary, secondary, and tertiary exploitation processes.

PRIMARY AND SECONDARY PERFORMANCE

The field was discovered in 1957 and rapidly developed by a number of major and independent companies. In 1963, a field wide unit was formed and a pilot water-flood was started. The water-flood was expanded to a field wide program in 1964 and 1965. A maximum oil production rate 2700 BOPD was achieved in the latter part of 1967. There are two reservoirs within the field separated by a permeability barrier (Fig. No. 1). This separation is well documented by reservoir pressure difference. The east reservoir did not respond well to water-flood and water injection ceased in this reservoir in 1969. Water injection was continued in the west reservoir until 1973 with a clear and well defined production decline history established as the field neared economic limit. (Fig. No. 2). The field produced 8,400,000 barrels by primary and secondary recovery of the estimated 52,000,000 barrels of oil in place. About 2,800,000 barrels were recovered as a result of the water-flood. The east reservoir did not respond significantly to water-flooding, however, the west reservoir performed moderately well recovering 9.5% of the estimated oil in place.

CO_2 SOURCE AND SUPPLY

Carbon Dioxide is obtained from the Oasis Pipeline Co.,'s MiVida Ellenburger Plant which removes CO_2 from the MiVida Ellenburger gas stream consisting of 55% hydrocarbon gas and 45% CO_2. A 6500 HP, 4 stage, compressor station compresses the gas from 2.5 psig to 1800 psig. The CO_2 gas is delivered to the field by an 8 in. high pressure pipeline approximately 12 miles in length. The capacity of the station is 15 MCF per day with a discharge pressure of 1800 psig and a discharge temperature of 125°F. CO_2 gas is measured by use of an orifice meter run used in connection with temperature and density measurements with back-up measurement by a standard orifice meter facility.

FIELD CO_2 INJECTION

Field injection of the CO_2 is obtained by use of turbine meters at the individual injection wells with wellhead pressure individually controlled to a maximum of 1400 psi to maintain a maximum bottom hole injection pressure below fracture pressure (approximately 2900 psi).

OIL AND GAS PRODUCTION

Wells in the field are produced through 5 satellite batteries where oil, water and gas production is measured frequently to obtain individual well response data. Production from the east and west reservoirs is determined to properly evaluate response to water-flooding and CO_2 injection..

CORROSION

There is no special provision other than chemical protection to equipment used in the field. The CO_2 delivered for injection is very dry with less than 2 lbs. of water per MMCF, therefore, there are no problems with corrosion in the injection system or injection well tubing because there is no water in contact with the CO_2 in this equipment.

Producing wells are "batch" treated weekly using a filming agent to protect the tubing, rods, casing, and other downhole equipment and to minimize corrosion from produced carbon dioxide. As the volumes of produced CO_2 have increased a bi-monthly chemical injection squeeze treatment was introduced into the producing formation as a supplemental method of maintaining the filming protection of downhole producing equipment and surface facilities.

The cement lined injection system for surface facilities and injection wells was used where available in the CO_2 injection program.

RESPONSE TO CO_2 INJECTION

During the CO_2 injection period the oil production rate in the east reservoir has significantly increased from 27 BOPD in 1974 to 750 BOPD during the first half of 1980. Water production during this time has declined from an initial rate of 1400 BWPD to a current rate of 1200 BWPD. Gas production started after approximately 14 months of CO_2 injection. As the oil production has increased the produced CO_2 volume has increased. Currently 2.80 MMCF of CO_2 is produced daily along with the 750 BOPD from the east reservoir. The average produced CO_2/oil ratio is 3230 cf/bbl.

West side oil production has reflected intermittent CO_2 injection into a pattern west of the water-flood pilot area and shows a slight response to this injection.

TERTIARY OIL RECOVERY

At the time CO_2 injection for oil recovery was instigated in February, 1974, production had declined to a field average of 174 BOPD plus 1600 BWPD. CO_2 injection was commenced in the east reservoir consisting of 30 wells with only 3 wells on production and an average of 27 BOPD plus 180 BWPD.

Water injection was stopped in the west reservoir in order to lower the bottom-hole pressure (330 psia) sufficiently to permit CO_2 injection below a BHP of 2900 psia BHP or a gradient of 0.61 which was determined to be the fracture gradient for this reservoir.

The existing salt water injection system in the east reservoir and the water injection wells were converted to CO_2 injection on a modified 5 spot pattern.

Currently CO_2 injection into the east reservoir varies from 8 MMCFPD to 14 MMCFPD with an average of 12 MMCFPD during the first part of 1980.

The east side production has increased to 750 BOPD plus 1200 BWPD and is currently producing 2.2 MMCFPD of CO_2 as part of a total field gas production of 3.2 MMCFPD.

The west side reservoir is continuing to produce at rates of approximately 150 BOPD plus 900 BOPD.

PREDICTED RECOVERIES AND FUTURE DEVELOPMENT

Current plans for the field are to start injection of an inert gas and water behind the injected CO_2 bank in the east reservoir with the CO_2 supply moved to the west reservoir for full scale continuous injection of CO_2 into a pattern area.

Ultimate recoveries cannot be predicted from the data available at this time, however, tertiary recovery from the east reservoir to date has been favorable when compared with primary and secondary recovery. As the project is expanded to a greater injection volume, increased oil producing rate is anticipated. Ultimate recovery from this field will be based on actual field production as modified and adjusted by dictates of the field performance.

CONCLUSIONS

1. The Twofreds CO_2 injection project shows that relatively large quantities of carbon dioxide can be injected into Delaware Sand Reservoirs without channeling to producing wells.

2. Oil produced during the injection period to date is believed to result primarily from the viscosity and swelling effects of CO_2 contacting oil within the reservoir and not necessarily a result of the displacement of oil and water bank ahead of a miscible oil-CO_2 bank.

3. Additional oil can be recovered from a "watered out" area of a water flood in Delaware Sand reservoirs of this type.

ACKNOWLEDGEMENTS

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TABLE NO. 1

TWOFREDS DELAWARE FIELD
PERTINENT RESERVOIR DATA

Discovered: 1957, 17 miles northeast of Pecos, Texas
Elevation: 2700 ft. Depth: 4820 ft. Porosity: 19.5%
Productive Formation: Bell Canyon (Delaware) Sand
Type of Geologic Trap: Stratigraphic
Sand Thickness: Average 25 ft. Range 0 - 42 ft.
Permeability: 32 md Water Saturation: 43.5%
Formation Volume Factor: 1.1179
Oil Viscosity at Res. Cond.: 1.467 cp
Solution Gas Oil Ratio: 441 cu. ft. per bbl.
Original Bottom 1 Hole Pressure: 2385 psia
Bottom Hole Temperature: 104°F
Productive Area: 4392 acres

Productive Acre Feet of Sand:	East Reservior	32,429
	West Reservoir	35,726
	TOTAL	68,155
Original Oil-in-place:	East Reservoir	21,470,000 bbls
	West Reservoir	29,662,000 bbls
	TOTAL	51,132,000 bbls
Primary and Secondary Oil Recovery		8,400,000 bbls

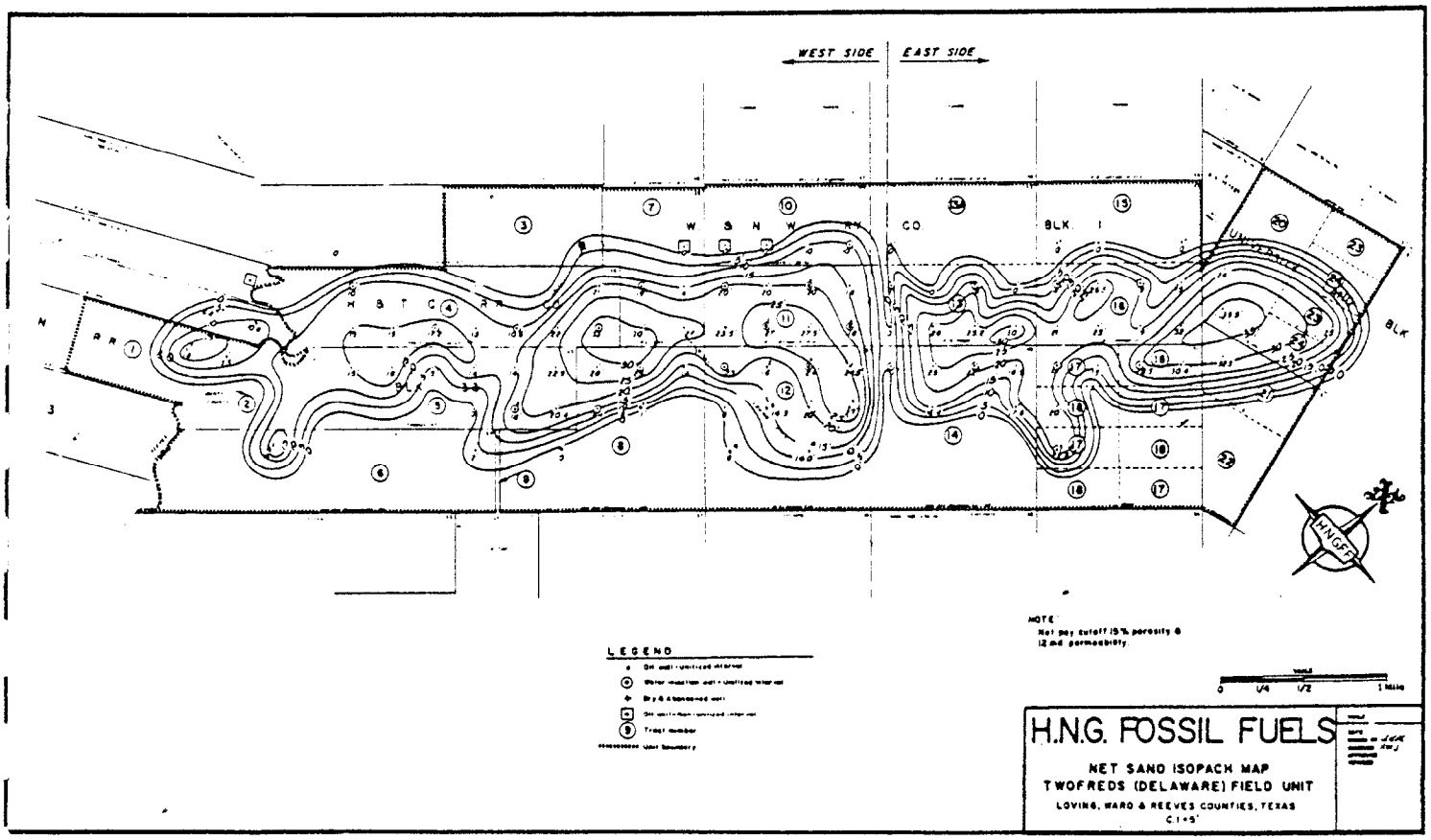
TABLE NO. 2

TWOFREDS FIELD
CO_2 INJECTION - OIL RECOVERY DATA

	Current Status Jan. 1980		
	Total Field	East Reservoir	West Reservoir
Producing Wells	40	16	24
Injection Wells	22	25	7
Shut-in Wells	24	0	24
	86	31	55

Cumulative CO_2 Injection		20,299 MMCF
Average Injection since Jan. 1, 1974		9.27 MMCFD
Cumulative % P.V. Injected		15.63
Average Oil Production	891 BOPD	
Average Water Production	2153 BWPD	
Average Gas Production	2.98 MMCFPD	
Average CO_2	2.13 MMCFPD	

Cumulative Oil Prod. since Jan. 1, 1974	1,161,048 BBLS
Cumulative Water Prod. since Jan. 1, 1974	6,023,200 BBLS



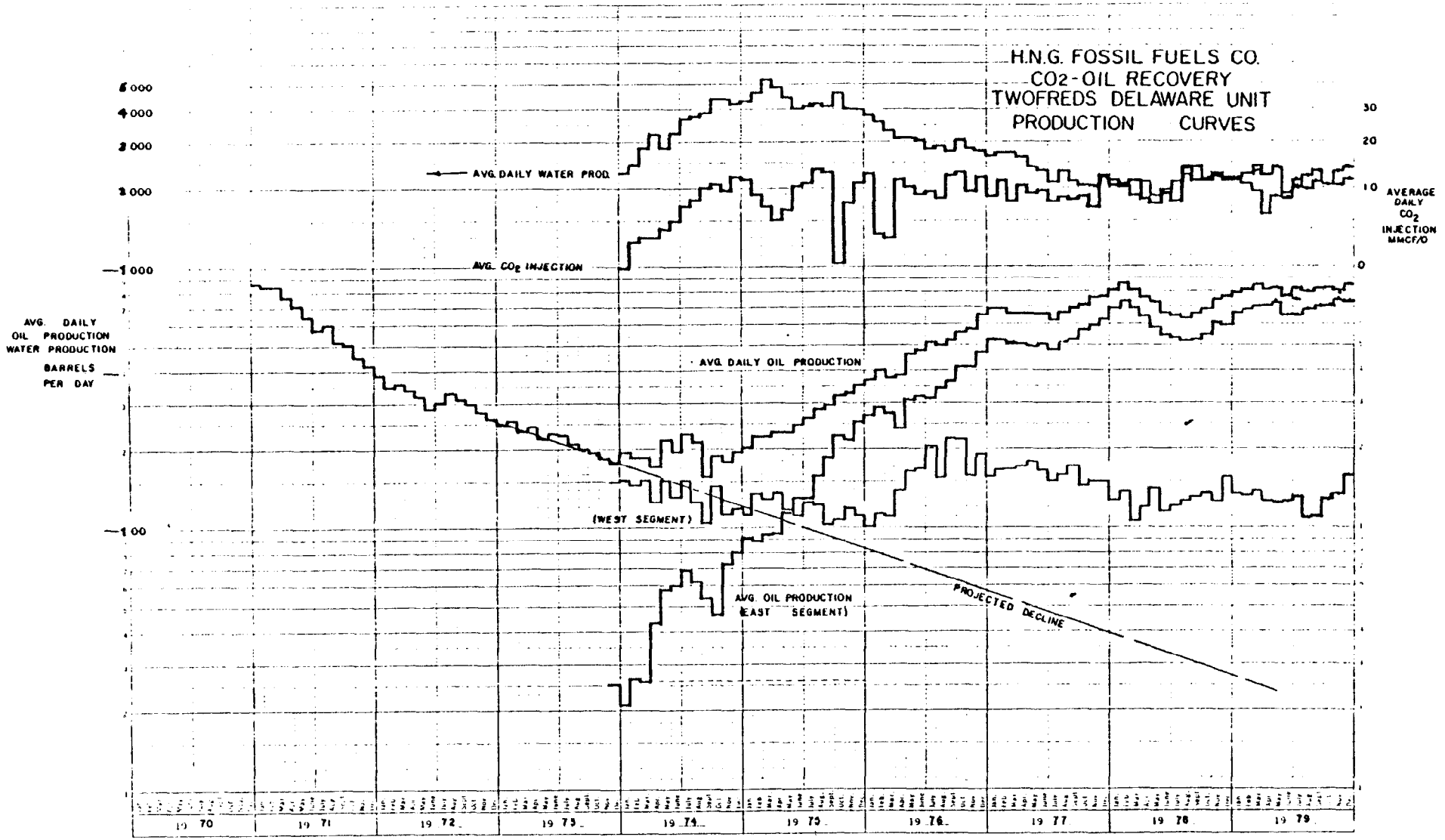

H.N.G. FOSSIL FUELS CO.
CO2 - OIL RECOVERY
TWOFREDS DELAWARE UNIT
PRODUCTION CURVES
6 000
4 000
3 000
2 000
1 000
100
AVG. DAILY WATER PROD.
AVG. CO2 INJECTION
AVG. DAILY OIL PRODUCTION
WATER PRODUCTION
BARRELS PER DAY
(WEST SEGMENT)
AVG. OIL PRODUCTION (EAST SEGMENT)
PROJECTED DECLINE
30
20
10
0
AVERAGE DAILY CO2 INJECTION MMCF/D
19 70
19 71
19 72
19 73
19 74
19 75
19 76
19 77
19 78
19 79

FIGURE NO. 2