THE SALT CREEK CO2 FLOOD: A STATUS REPORT AFTER ONE YEAR OF OPERATION

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Introduction

The Salt Creek Field Unit is located in Kent County, Texas, 70 miles southeast of Lubbock. Mobil E & P U. S. is operator of the waterflood, CO2 flood, a CO2 separation and re-injection plant, and a NGL recovery plant. CO2 injection began October 26, 1993, into the 57 pattern Phase I area. Oil production has increased from 18,500 BOPD in October, 1993 to 29,500 BOPD in November 1994. This paper is a status report of the CO2 operations to date.

Field History

Salt Creek Field was discovered in 1950 using surface mapping and recognition of a producing trend established by the Kelly Snyder (SACROC) Field. The discovery well, C. Hunt Estate Trust - Young #1 flowed 2,184 BOPD. The field was unitized in 1952, and centerline water injection was begun in 1953 along the crest of the main structure. Most of the produced gas was re-injected for pressure maintenance from 1952 until 1977. Infill drilling occurred in the early 1970's, and 40 acre infill drilling was completed in the early 1980's. Drilling on 20 acres was begun in 1986, and is near completion in 1994. Conversion to inverted 9-spot injection patterns occurred during 1984 to 1986. Conversion to 5-spot patterns was 90% complete by 1991. Future conversion of five producers in the Phase 1 area will compete the 5-spot patterns. Fifty-seven injectors were equipped for alternate water and CO2 injection (WAG) service during 1993 in the central portion of the field, which is designated the Phase I area. This area is approximately the area enclosed by the 4,250' contour on the attached structure map.

Geology

The reservoir is a Paleozoic carbonate buildup on the Northeast edge of the Horseshoe Atoll. It consists of two separate anticlines formed by a series of reefs, algal mounds, oolite shoals, and massive carbonates. It was later encased in Permian age shales which marked the end of carbonate sedimentation in the Horseshoe Atoll. The lithologic units are cyclical, with the most common being a shoaling-upward cycle of wackestone or mudstone, then algal boundstone, then oolitic grainstone or skeletal packstone.

Exposure and extended diagenesis resulted in oomoldic and biomoldic porosity at the top of most cycles. Porosity range as high as 30% in the oolitic grainstones. Each cycle is typically capped by an unconformity on which the next cycle rests. There are nine separate cycles defined, with each cycle often consisting of several separate porosity layers. This is a complex reservoir, which communicates vertically between cycles in some areas. A typical cross-section is shown in Figure 1. The largest zones in terms of original oil in place (OOIP) are the C2A, C2B, and the C3 found in the middle of the reservoir. The smaller anticline in the Northwest part of the unit has similar layering, but is separated from the main reservoir by a structurally low "saddle" where the top of the structure dips below the oil-water contact at 4425 feet sub-sea (See Figure 2).

Average depth is 6,500 feet, average net pay is 99 feet, average porosity is 12%. Average porosity-feet is 12, but ranges up to 54 porosity-feet. Average air perm is 20 millidarcies, and some thin zones exceed 500 md. Fluid properties are listed in Figure 3.

Waterflood Operations

In October 1993 prior to CO2 injection, production was 18,500 BOPD, 325,000 BWPD, and 12 MMCFD. A NGL extraction plant (propane refrigeration) recovered liquids, supplied lean fuel gas to the field and plant for water pumps and compressor engines. Make-up water was pumped from a 100 foot sand in the Salt Fork of the Brazos River, which runs through the Unit, at 25,000 to 30,000 BWPD. Well testing and gas separation was performed at seven test satellite facilities in the field.

The waterflood has been a very successful recovery technique. Secondary production peaked at 38,000 BOPD in 1972. Over 300 million barrels of oil have been produced to date. Cumulative recovery (primary plus waterflood) exceeds 40% of OOIP. Base oil production was declining at over 25% per year on waterflood, excluding workovers and new drill wells.

The primary lift method was, and continues to be, by electric submersible pump. Many wells were equipped with variable speed controllers. Rod pumps were used on all other wells, generally those producing less than 500 barrels of liquid per day. Under waterflood all producers were pumped.

CO2 Facilities

The potential for EOR via CO2 had been recognized since the start of the SACROC CO2 flood in Scurry County in 1972. Fully compositional simulators were run on two different 5-spot quarter-patterns under various pressures and WAG (water-alternating gas) ratios. The simulator results were scaled up based on the other pattern pore volumes and flow rates. The expected recovery due to CO2 is 11.9% of the OOIP in the flooded area. AFE approval was obtained in January, 1992. Construction on the CO2 removal plant, compression, and modifications to the existing NGL plant began in January, 1993. Careful scheduling of new equipment construction and re-working of old vessels, piping and old compressors enabled the NGL plant to stay in service with only minimal flaring of produced gas.

A 119 mile CO_2 supply line to the Unit from Denver City, Texas was completed in August 1993. Other CO_2 floods served by this supply line are OXY's Welch project, Amoco's Cedar Lake project, and Conoco's Huntley and S. Huntley floods. CO_2 sources are McElmo Dome in S.W. Colorado, and Bravo Dome in N.E. new Mexico. Mobil Pipeline operates the line (Este Pipeline) from Denver City to Salt Creek. Excess line capacity to serve future CO_2 floods in the area will be available after 1995.

Make-up injection water use ended in November, 1993. Up to 30,000 BPD of produced water is now disposed into the Wichita-Elm zone at 3,800 feet in up to 10 SWD wells. Waterflood injection is currently 260,000 BWPD. Waterflood optimization continues in areas outside Phase I.

Three 700 HP electric motors power the centrifugal pumps which boost the CO_2 pressure from 1,600 psig to a maximum of 3,100 psig. Positive pressure seal oil is used to prevent leakage of the CO_2 into the pump bearings. The pumps are controlled from within the new plant control room, where computers monitor operations continuously. Produced CO_2 is recompressed to 2,200 psig and combined with the pipeline CO_2 for re-injection. Pipeline delivery capacity varies from 141 MMCFD in summer to 157 MMCFD in the winter. As of December 1994 produced CO_2 averages 40 MMCFD.

To distribute the CO_2 to the 57 WAG injectors, a system of eight "clusters" was constructed during 1993 (See Figure 4). Each cluster serves three to twelve injectors. At each cluster header a "wedge" type meter measures total cluster CO_2 flow. Valves at the header enable isolation of individual injection lines to each well or sub-group of wells. The individual well injection is measured at each well through the same Halliburton MC-II turbine meters which have been in use during waterflood injection. By cross-checking the Este pipeline meter, the cluster meters, and the well meters daily, measurement errors are identified quickly and kept to a minimum. A total CO_2 injection of 40% HCPV is planned for each pattern. Slug sizes currently range from 0.25% to 1.0% depending on pattern GOR results. The distribution lines internally are bare J-55 steel, since no water is present in the CO_2 stream. In addition to line valves, "spectacle" blind flanges are used at each well to isolate the CO_2 line and water line from each other during WAG cycles.

Meter run components downstream of the spectacle blinds are all stainless steel. Tubing pressure, casing pressure, and flow rates are monitored electronically and stored in the field computer. The minimum miscibility pressure (MMP) for this oil is 1,800 psig. Injection and production rates are managed so that average reservoir pressure is maintained between 2,000 and 2,200 psig where possible. The wellheads, tubing and packers have special corrosion resistant metallurgy and/or coatings. (See Figure 5). Downhole profile logs are run at least every 12 months to measure the vertical injection distribution of both CO_2 and water. During the first few months of injection, injection was restricted to only two of the four injection wells in each producer pattern. This checkerboard pattern was to allow for easier identification of the CO_2 source in producers which exhibited quick CO_2 production. Out of 228 injector-producer pairs, 5 pairs were found to transmit CO_2 rapidly. Actions to limit CO_2 production include shutting in producers, converting pumping wells to flow, and shutting off selected intervals downhole. Injectors are grouped in trios for scheduling purposes. For example, well A is on CO2 while wells B and C are on water. When well A is switched to water, well B is switched to CO2, and so on. Each well is on CO2 approximately one-third of the time. Wells in trios have similar injectivities so far as pore volume rates versus time.

Due to the increased produced gas rates, modifications were necessary at the four test satellite facilities in the Phase I area. Wedge meters which are capable of a wider range of gas measurement were installed in parallel with the existing turbine meters. The turbines are still used when gas rates of less than 250 MCFD are measured. Larger gas header lines were installed to lower the pressure drop through the satellites. Additional production vessels, test vessels, and larger diameter flowlines (on selected wells) were also installed to increase the gas handling capacity at each satellite. Average production per well in the CO2 area is 310 BOPD + 2,500 BWPD + 650 MCFD. Temporary gas flow rates over 2 MMCFD per well are common. The highest volume wells currently produce up to 1,200 BOPD + 5,000 BWPD + 1.5 MMCFD. Unit total well statistics and current rates are shown in Figures 6 & 7. Because of the large changes in volumes of each produced fluid phase, wells are now tested as much as four times per month for surveillance and volume allocation purposes. The tests are recorded in the field computer as they are validated by the facility operators. The field computer was used extensively during the waterflood operations, and is even more heavily utilized with the increased data flow of the CO2 flood. Injection rates per well in the CO2 area average 3,000 BWPD or 9 MMCFD of CO2.

Produced oil and water are sent to the central tank battery from each satellite for final separation. Produced gas from each satellite goes to the gas plant inlet header. Gas from batteries outside the Phase I area which have less than 3% CO2 is sent directly to the NGL recovery plant. All other gas is separated in membranes made of bundles of hollow fibers which preferentially transmit CO2 and H2S faster than hydrocarbon gases. Final removal of low concentrations of CO2 from the hydrocarbon gas is completed in an Amine absorption process. The operation of the gas engines both within the separation plant and NGL plant are unusual in that a distributed control system run by a central computer controls all engines. The usual controls are located at the individual engines. This central computer system also allows for monitoring and managing the plant air emissions.

Some leaks have occurred in annhydrite cured fiberglass flowlines. The majority of the fiberglass system is amine cured for better CO2 resistance. As of December 1994 no other corrosion related leaks in surface equipment, tubing or packers has been detected. Except for treating asphaltenes, chemical treatment has not changed from waterflood operations. Continuous annulus injection of corrosion chemicals is in use on all ESP-pumped producing wells. Batch treatment is used on rod pumped wells. Emulsion breaker, reverse demulsifier, and scale preventer is used at all separation vessels. Scaling tendency has increased since CO2 injection began. Batch bacteria treatment is performed on a few wells. Surfactants are used on producers with high iron sulfide content. A toluene-based solvent is used to treat asphaltenes in some producers.

CO2 Flood Results

Production response to CO2 injection has been very good. First EOR production occurred in December, 1993. Unit production increased from 18,500 in October 1993 to 29,500 by November, 1994, when the total Unit gas production reached the gas plant capacity of 70 MMCFD. (See Figure 8). Waterflood base production in November 1994 without the CO2 injection is estimated to be 13,500 BOPD. Of the 16,000 BOPD total Unit production increase, 13,000 BOPD is attributed to CO2 EOR. The remainder is from infill drilling and workovers. NGL production is up 2,000 BPD to 5,000 BPD. The oil production and gas-oil ratios are slightly higher than the predicted rates in the simulation. One of the reasons for the higher oil rate is the higher than simulated injection rates which have been achieved. On the basis of response versus hydrocarbon pore volume injected, the results have been close to the simulation predictions. Through September, 1994, 50 BCF of CO2 has been injected, and 5 BCF has been produced.

A 2:1 WAG ratio is being used to limit gas production. By utilizing the SACROC results (on a hydrocarbon pore volume basis) on Salt Creek's pore volume and injection rate, it was determined that this WAG ratio would minimize the producing gas-oil ratio. Fifty-six of the fifty-seven WAG injectors have had CO2 injection as of December 1994. The operating philosophy has been to maximize total CO2 injection rate while distributing the CO2 within the Phase I area so as to not overload any one satellite with excess gas production. As this paper is being written (12/94), the flood management team is selecting high GOR wells to reduce gas production to stay within the plant capacity. It will become necessary to shut in producers, perform workovers, and/or reduce CO2 injection soon. Emphasis is being placed on obtaining the most accurate well tests possible to use in these decisions.

Challenges

A number of challenges face the Salt Creek Team. The zone by zone perforations are not uniform across the patterns. Cross-flow between the zones within the reservoir is not well understood. There are varying degrees of isolation between the layers due to ineffective cement, plugs, & casing failures. Measurement of producer inflow profiles is not possible. The optimum producing bottom hole pressure varies from pattern to pattern. There are an increasing number of obstructions in injectors (iron sulfide, polymers, and corroded casing). Downhole power cable failures are increasing due to CO2 and higher casing pressures. Higher GOR's cause ESP bearing failures. There is some erosion in surface piping due to higher than expected fluid velocities. CO2 related corrosion is expected to increase. Asphaltene deposition in both producers and injectors appears to be increasing. An expansion of the CO2 removal plant up to a total of 110 MMCFD capacity is being evaluated. The CO2 flooding of the Northwest portion and the South portion of the reservoir must be scheduled as gas plant capacity becomes available.

Summary

The implementation of this large-scale CO2 flood has been successful due to the teamwork and skills of all the persons of the various disciplines involved. The operating practices used in other CO2 floods in the Permian Basin were studied and often utilized in the design of the Salt Creek Flood. The construction was completed within 105% of the AFE amount, and both injection and production are ahead of schedule. The members of the Salt Creek Team wish to expresses their appreciation to the partners and numerous contractors who have helped make this project a tremendous success.

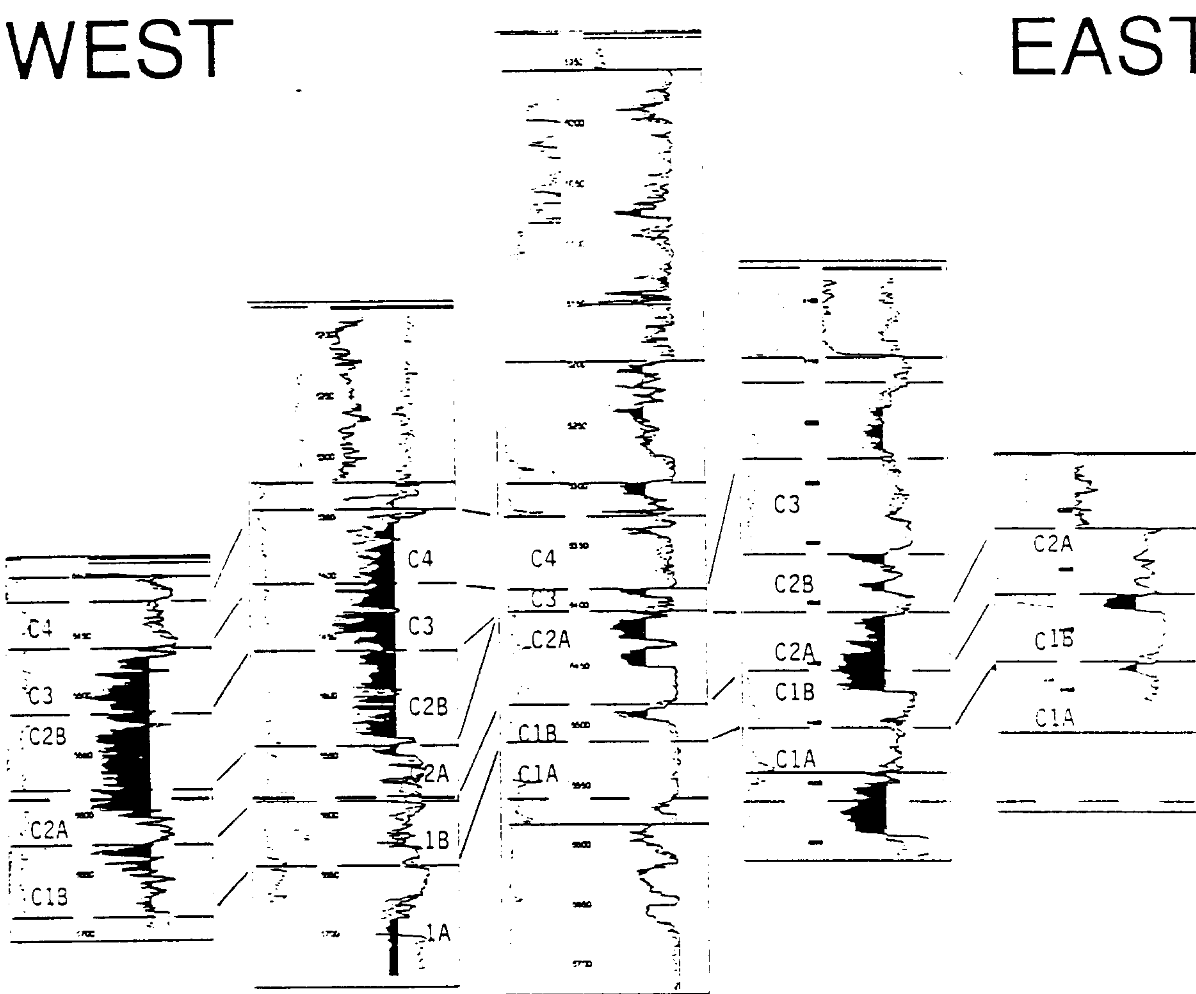

Figure 1

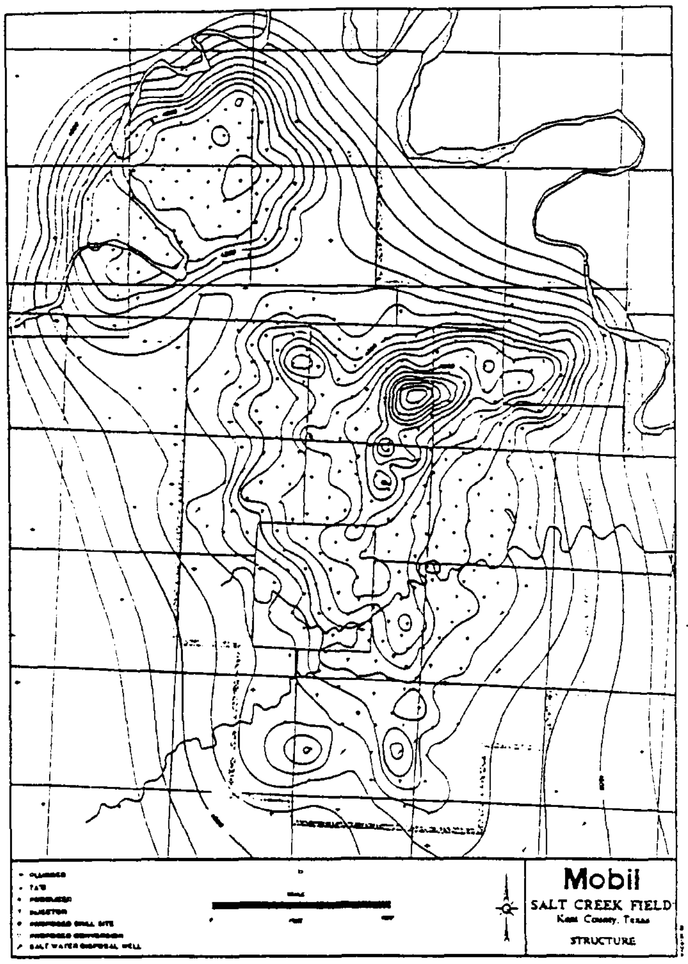

Figure 2

Oil gravity	39.2 Deg API
Initial Oil Viscosity	0.85 cp
Initial GOR	500 SCF/B
Initial Pressure	2,940 PSI
Bubble Point	1.24 RB/STB
Temperature	125 Deg F
Sulfur class.	Sweet
Initial Oil Saturation	89%
CO2 FVF	2.2 MSCF/RB
Est Avg Res Pressure	2,500 PSI

Figure 3 - Fluid Properties

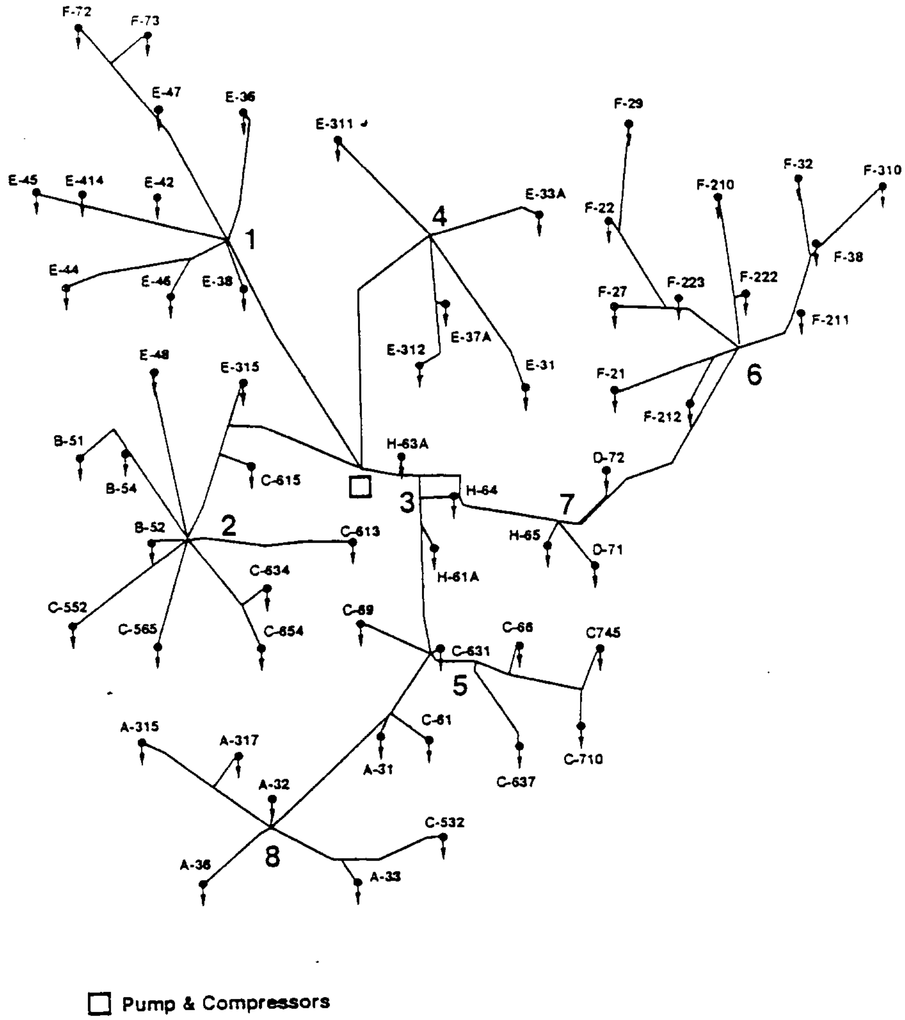

Figure 4 - SCFU CO_2 Distribution Lines

Producers

- Replaced stems and gates with monel

Injectors

- One new master valve 316 SS
- Tubing hanger and spool replaced with 316 SS

Internally coated tubing

- TK-70 phenolic, or Duo-Line fiberglass sleeve cemented in place
- Pin end seal rings (MMS)
- Plastic coated packers inside & out
- MMS connections on packer top

No leaks to date

Figure 5 - Wellheads & Tubulars

178 Active Producers

- 146 ESP — 82%
- 29 Rod pumps — 16%
- 3 Flowing — 2%
- +20 TA'd

135 Active Injectors

- 57 WAG injectors — 42%
- 78 Water injectors — 58%
- +3 TA'd

10 Salt Water Disposal wells

12 Source water wells

Figure 6 - Well Statistics 10/94

PRODUCTION

Oil	29,500 BOPD
Water	290,000 BWPD
Total Gas	8 MMCFD
Gas RB/D	26,000 RB/D
Total Prod	345,500 RB/D
CO_2 Prod	55 % of Gas

INJECTION

Water	265,000 BWPD
CO_2	
Purchase	145 MMCFD
Re-cycle	30 MMCFD
Total	175 MMCFD
CO_2 RB/D	80,000 RB/D
Water + CO_2	345,000 RB/D

I/W — 0.99

Figure 7 - Current Rates 10/94

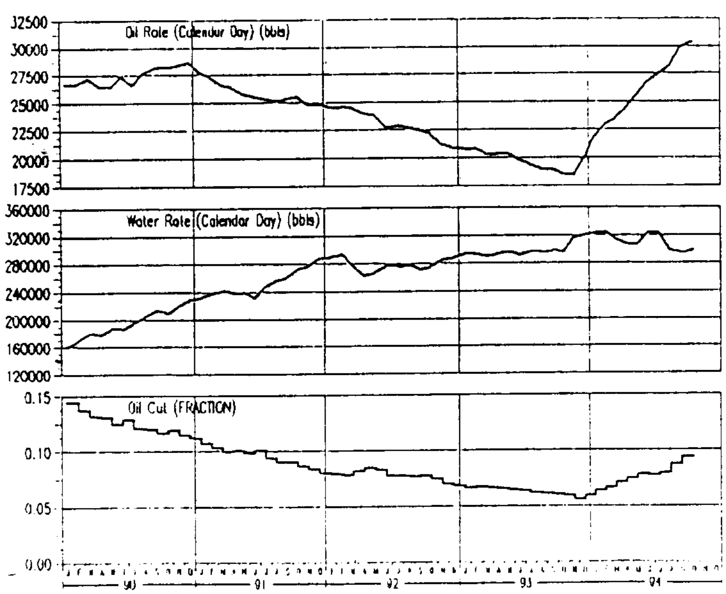

Figure 8 - Salt Creekl Field Unit, Unit Total