History of a Scurry County, Texas, Reef Unit.

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Sharon Ridge Canyon Unit

INTRODUCTION

The Sharon Ridge Canyon Unit is located in the south portion of the continuous oil reservoir which includes the Diamond "M" and SACROC units. Sharon Ridge is located approximately 20 mi. southwest of Snyder, Texas and is largely in southwestern Scurry County, extending only slightly into southeastern Borden County. The reservoir is one of a series of reef fields in the Horseshoe atoll. Disconnected, but to the north, are Cogdell and Salt Creek fields. In a southwest direction is North vonRoeder field. These fields are all unitized for pressure maintenance.

Humble's R. E. Bishop 1 (now known as Tract 35, Well 1) was completed during March 1949 as the discovery well of the Sharon Ridge Canyon Field. In November 1951, this field was combined with the Diamond "M" Field. Early in 1951 the "Sharon Ridge Canyon Engineering Committee" was formed, and after a great amount of work and study directed toward a conservation program, the Sharon Ridge Canyon Unit was organized with 100% of the operators signing the agreement. In May 1, 1955, unitized operations began with a peripheral water-injection pressure maintenance program.

GEOLOGIC AND RESERVOIR DATA

Canyon Reef is the name given the productive reservoir. Like some other carbonate reservoirs, its physical characteristics are far from uniform. Porosity and permeability vary widely both laterally and vertically. Several local highs are present and reservoir thickness, while sometimes uniform from one well to the next, does not necessarily follow any normal stratigraphic pattern. The water table is tilted slightly from southeast to northwest. In the Sharon Ridge Canyon Unit, the oil-water contact varies in this manner from about 4,420 to 4,475 ft. subsea.

Even though the reservoir seems to display erratic characteristics when local areas are compared, a broader view reveals several generalizations concerning the field as a whole. The porosity is lower on the periphery than in the inner portion. Permeability distribution over the vertical extent of producing formation is more uniform in the inner portion than on the periphery, and it seems to grade from one condition to the other. The field average thickness is approximately 98 ft. with a porosity of 8.8% and a connate water saturation of 28%. The average whole core analysis permeability was 44 millidarcies, while later productivity factor tests revealed a calculated average permeability of 78 millidarcies. Analysis of connate water showed an average salinity of 50,000 PPM NaCl.

Very early in the life of the field, bottom hole oil samples were obtained and analyzed. They revealed a reservoir fluid considerably under-saturated with gas at original conditions with an average saturation pressure of 1,900 psi and a dissolved gas-oil ratio of 1,153 cu. ft. per bbl. when flashed at 76° F and O psi separation conditions. The average stock tank oil gravity was 44° API, with the specific gravity of produced gas being 1.09.

PRIMARY HISTORY

The primary history of the Sharon Ridge Canyon Field is easily recognized as that of a solution gas drive type of producing mechanism. High initial reservoir pressure gave way to a fairly rapid decline rate which, in turn, began to contribute toward increasing produced gas-oil ratios. Thus, reservoir withdrawals necessary for the production of a stock tank barrel began to climb. It was calculated that the productive energy of the reservoir would be exhausted while recovering scarcely 1/4 of the original oil in place.

The original bottom hole pressure in the discovery well 11 days after completion was 3,135 psi at 4,300 ft. subsea with reservoir temperature determined as 128° F. These conditions resulted from a shut-in time of 50 hr.

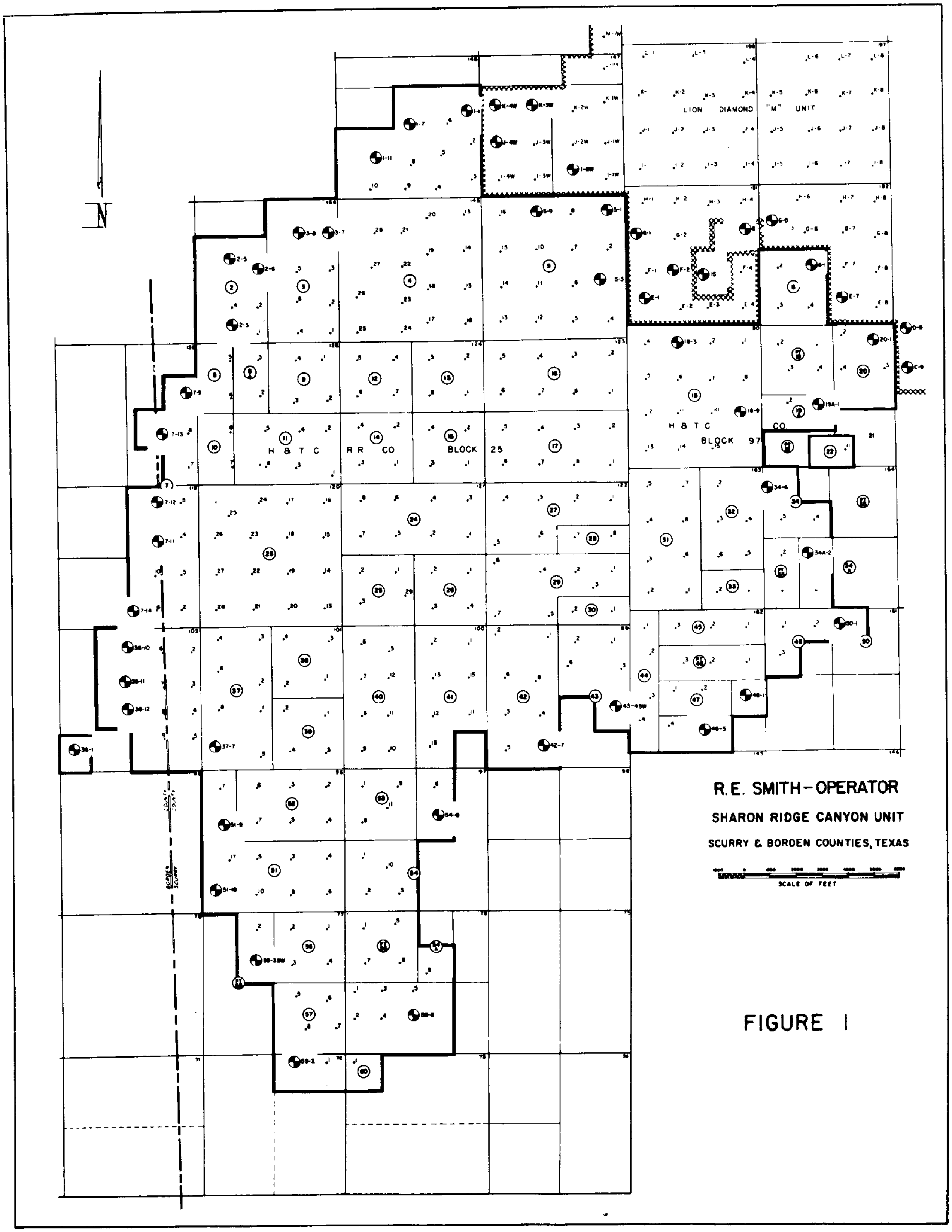
During the time from discovery to the initiation of pressure maintenance the oil recovery rate was approximately 6,000,000 bbl. per year, with a cumulative recovery of some 33,500,000 bbl. being attained. During this amount of oil recovery the bottom hole pressure declined 1,522 psi, representing a 49.5% depletion of the original reservoir pressure. The average annual gas-oil ratio based on 25 psi separation increased from 1,000 cu. ft. per bbl. of stock tank oil at discovery to 1,280 cu. ft. per bbl. by the start of pressure maintenance operations. Fig. 2 displays these reservoir data before and after pressure maintenance by water injection.

UNITIZED OPERATIONS

Development of the 13,873 acres productive area is on a 40 acre pattern resulting in 343 wells included in the unitized area. There are 39 injection wells completing a peripheral injection pattern which completely separates this unit from other producing areas in the field.

The injection wells were deepened 50 to 100 ft. below the oil-water contact to effect injection into the aquifer as well as laterally into the oil section. A composite water-input profile indicated 48% of the injected water entering above the oil-water contact and 52% below, with approximately 100% of the gross reef open to the injection wellbores taking water.

Fresh water purchased from the Colorado River Municipal Water District is received at the water-treating plant located in conjunction with the main pump station in the southeast portion of the unit. Injection



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LION DIAMOND "M" UNIT
H & T C RR CO BLOCK 25
H & T C CO BLOCK 97
R.E. SMITH-OPERATOR
SHARON RIDGE CANYON UNIT
SCURRY & BORDEN COUNTIES, TEXAS
SCALE OF FEET

FIGURE I

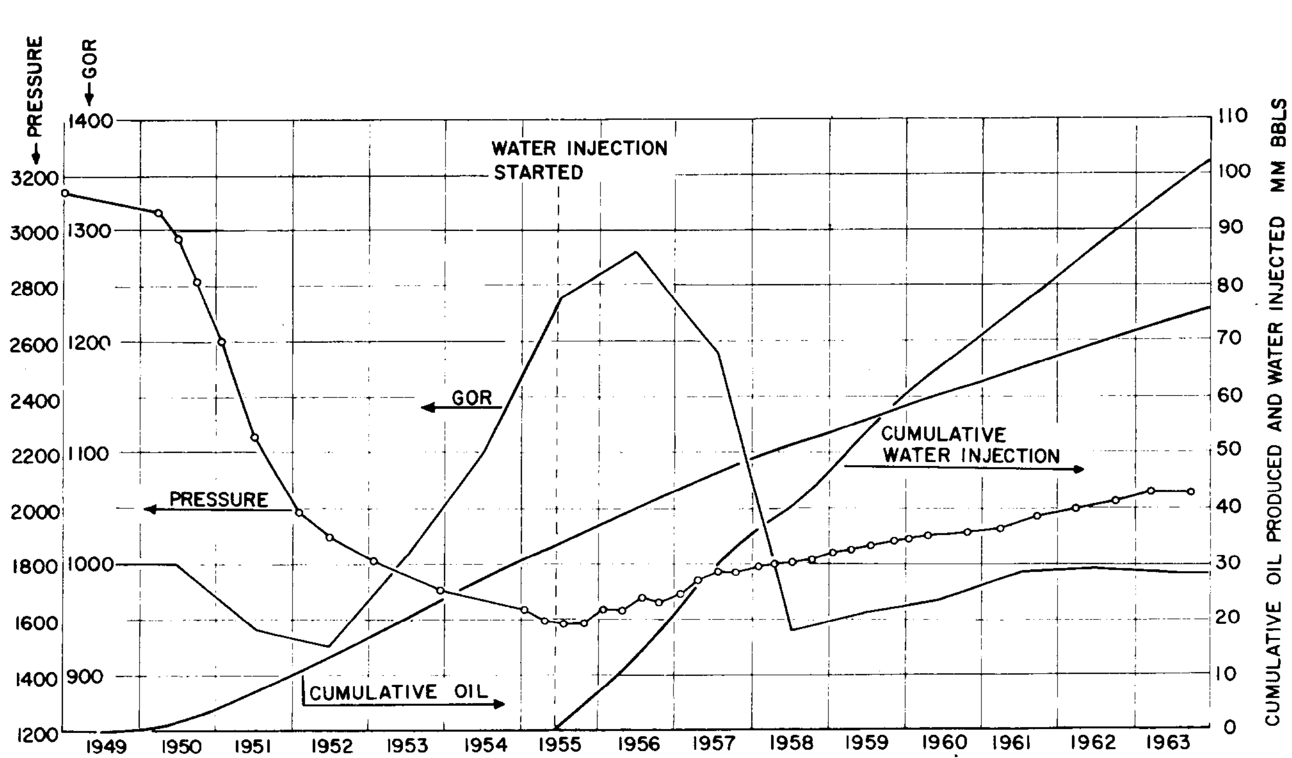

FIGURE 2 - RESERVOIR PERFORMANCE

volumes now approximate 23,000 BPD.

Raw water from Lake J. B. Thomas is measured in the water-treating plant, chemically treated in a solution-contact reactor, filtered, and stored in a surge tank to be available at the suction of the distribution system. The reactor removes most of the suspended solids by coagulation, and the filter battery completes the removal of turbidity.

The operation of the treatment process is controlled from a central panel board in the water-treating building. In the design of the plant, every effort was made to utilize automation. The control board graphically shows the flow pattern of the entire water-treating area. Pilot lights indicate the operation of all feeders, motors, and valves. Push-button controls are provided for manual initiation of the counters and timers.

The reactor, located adjacent to the water-treating plant, is a 47-ft. diameter by 17-ft. high concrete tank containing baffles for hydraulically separating clarified water from coagulated solids. Alum and chlorine are added to the raw water ahead of the reactor to assure complete mixing of the chemicals and oxidation of organic matter. Lime is added in the reacting zone to provide necessary alkalinity for alum-floc formation.

Clarified water is drawn off the top of the reactor and pumped through the filters. Seven 10-ft. diameter pressure filters containing graded sand and gravel are in service with space for 3 additional filter installations to reach the ultimate design capacity of 75,000 BWPD. Sodium hexametaphosphate is added after filtration to insure against scaling or corrosion in the system.

Clarified water from the filters flows to the 5,000 bbl. surge tank and enters the main pump station, located adjacent to the treating facilities, for distribution to the high-pressure pumps in the main station and the substation located on the west periphery where higher injection pressures are encountered.

The main-station site is located for distribution of water to the south and east peripheries which are areas that will take water at lower pressures. Additional flexibility has been included in the design by looping the high-pressure distribution lines of the substation with the main-plant line providing injection water to the southern part of the unit. It is thus possible at this time to inject 31,100 BWPD at a pressure of 2,500 psi to the entire distribution system from the main plant without operating the substation.

The 2 pump stations are identical except that a low-pressure double-suction 800-gpm centrifugal pump is located in the main pump station adjacent to the water-treating plant for providing water to the substation. The low-pressure pump is powered by a 75-hp induction motor.

Both pump stations contain two 6-in.-stroke vertical septuplex single-acting plunger pumps. The pumps have feed lubrication and the suction and discharge manifolds are integral with the cylinders. The valves have individual covers for easy inspection and maintenance. The pumps in the main station are equipped with 3-1/4-in.-diameter plungers which operate at 300 rpm to provide 15,500 BWPD at a discharge pressure of 2,500 psi. The 2 pumps in the substation are identical except that they have 3-in. plungers which displace 13,250 BWPD at 2,820 psi.

The 4 pumps, with present plungers, have an output of 57,600 BWPD. If different injection volumes or pressures are needed, the stuffing boxes of the pumps are changeable so that different-size plungers may be installed.

The 4 pumps are driven by six-cylinder, 16-in.-bore by 20-in.-stroke, vertical, four-cycle gas engines rated at 725 bhp at 300 rpm.

Engine speed is controlled by hydraulic governors at rates adjusted manually at each engine. In order to operate the plants with a minimum of personnel, as many pneumatic safety shutdown engine controls as possible have been added. The supply of fuel gas is shut off and the magnetos are grounded if the engine lube-oil pressure or jacket-water pressure fails, temperature becomes excessive, or if the main-pump discharge pressure becomes excessive. Also included are shutdown devices for engine overspeed, low main-pump suction pressure, and low main-pump lube-oil pressure.

The distribution system is composed of about 29 mi. of pipe, and, other than the 10-in. low-pressure pipe connecting the 2 pump stations, is designed for a working pressure of 3,000 psi. High-pressure piping is sized from 8 to 3 in. for an ultimate injection of 75,000 BWPD. All pipe east of the main pump station is cement-lined. The 10-in. low-pressure pipe, likewise, is cement-lined because the pipe is thin-walled and must last for the life of the flood. Throughout the system insulated flanges are used to mitigate electrolytic corrosion. Provisions for internally scraping the pipe are provided.

Consolidation of tank batteries and construction of a salt water gathering system for the entire Sharon Ridge Unit was completed in June 1958. This action was taken to eliminate the use of surface pits for salt water and to collect the produced salt water for injection use. A considerable savings in manpower and equipment was also effected through consolidation.

In the beginning of unitized operations there were 67 tank batteries. Consolidation reduced this number to 7. Terrain and workability dictated the location for the 7 consolidated batteries. The batteries utilize 76 - 1,000 bbl. galvanized steel tanks of the 210 tanks previously in use. This affords storage capacity for several calendar days production. The present allowable is 44,320 bbl. prorated. Heater treaters are used for treating of emulsion.

There are 28 test stations provided for testing the producing wells. Oil, gas and water production from a test treater is metered at each station. Gas lines from the test treaters connect to the gasoline plant pipeline facilities which were already at that location. Oil and water production from the test treaters is metered through one-barrel dump type meters and flows into the production line to a consolidated battery. At the present time 87 flowing wells and 77 pumping wells are being utilized to produce the allowable. The testing design allows for several tests per well per month which facilitates closer control of the recovery program and water advance.

Well headers and separators are maintained at the old battery locations utilizing most of the existing flow line system. The headers were connected to the test station with a test line and to the battery with a producing line. All new pipe for the consolidated system is thin wall steel pipe, cement lined, doped and wrapped. Gas lines from the separators were connected to the existing gas pipeline facilities at that location.

Produced water from 6 of the consolidated tank batteries is gathered by means of a trunk line to the salt water station located near the main plant site. This affords the injection of large volumes of produced water in the future through existing cement lined injection lines. Because of terrain and distance the produced water from the south-end wells is handled through its own system. The salt water gathering system is a completely closed system. Pipe is asbestos cement and tanks are internally coated with coal-tar epoxy and are 1,000 bbl. capacity.

The only method employed to date in artificial lift producing wells has been the conventional beam type pumping equipment, using no larger than 1-1/2 in. plunger size.

RESERVOIR PERFORMANCE

When water injection began, the volumetric average reservoir pressure had declined from the original 3,135 psi to 1,593 psi. The reservoir withdrawals necessary for the production of a stock tank barrel had increased from 1.545 to 2.3. Soon after water injection began, the pressure decline was halted. The average annual gas-oil ratio continued to increase but at a reduced rate. Within a year it began to decline.

As the pressure effects due to the water injection began to be felt at the producing wells, it was realized that some general plan should be adopted concerning how to produce in response to the water advance. In the northwest one-third of the field, there had existed an area of higher gas-oil ratio than the average. In order to help the pressure maintenance effort, 55 wells in this area were shut-in. Their allowables were distributed uniformly among the wells which had experienced pressure increase. The decision of where to place the allowables was based on the receiving well's bottom hole pressure, ability to produce and structural position in such a manner as not to withdraw too heavily from any one well. A flexible transfer rule, granted the unit by the Railroad Commission, provides an efficient and instant means of adjusting reservoir withdrawals into such patterns as may be best in dealing with changing effects brought on by injection-water advance.

Studies were conducted to determine a general producing philosophy. The permeability capacity distribution[1] basis for analyzing and predicting behavior of a water advance was used. The results of some model studies[2] were also considered. The decision from these was that wells should be produced to a high water-oil ratio before being closed-in, and that uniform distribution of withdrawals over the producing area was desirable insofar as was possible, considering varying individual abilities. Injection into sectors of the periphery is kept in proportion to withdrawals from the area they serve in an attempt to create a balanced water advance. Producing to a high water-oil ratio in individual wells means continual water production of a certain amount. Since water injection began, the unit has averaged producing at a water cut of approximately 20%. Current water cut is 27%. The unit could produce water-free if desired, but is believed that producing to economically feasible high water-oil ratios will insure more recoverable oil from the reservoir. The total allowable prior to water injection was 33,240 bbl. per schedule day. Present allowable, although on a percentage basis, is equivalent to 44,320 bbl. per schedule day. The ability to produce has increased with time and has become more efficient since production is now accomplished without free gas production.

Cumulative oil recovery to January 1, 1964, was 76.1 million stock tank bbl. By solution gas drive calculations it was determined that without pressure maintenance, recovery to January 1, 1964, would have been approximately 57 million bbl. Thus, approximately 19.1 million bbl. of additional oil has been realized by the effects of water injection.

Actual recovery to date from peripheral areas producing with high water-oil ratios has exceeded the predicted ultimate recovery by both primary and secondary means for the wells in these areas. The permeability distribution and linear flow type of waterflood prediction was used to forecast the ultimate behavior of the peripheral areas and the unit as a whole. The peripheral area performance indicates that if actual behavior, compared to that predicted, remains at the level experienced to date, ultimate recovery of the Sharon Ridge Canyon Unit under the influence of water injection will be at least 50% of the original oil in place.

CONCLUSIONS

Experience in the Sharon Ridge Canyon Unit has demonstrated that carbonate reservoirs, heterogeneous in nature, will respond efficiently and economically to a pressure maintenance type of recovery program.

Almost 9 years of performance supports the conclusions of the representatives of the companies who contributed to the original study from which this highly successful conservation program evolved. Certainly, without the splendid cooperation of the many operators, owners and the Railroad Commission of Texas this would not have been possible.

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