Cedar Lake Southeast Field - San Andres Reservoir Behavior Under Water Flood

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INTRODUCTION

The Cedar Lake Southeast Field, as shown in Fig. 1, is located in extreme west-central Dawson County, Texas, some 18 miles west of Lamesa, the county seat of Dawson County, Texas. This location places the field in the northern portion of the deep Permian basin and just south of the northern shelf area of the basin.

The San Andres reservoir of the Cedar Lake Southeast Field was discovered in June, 1953 with the completion of the McClure, Hopkins & Logan #1, J. F. Fowler in Section 111 Block M, E.L. & R.R. Ry. Survey. This well was originally drilled to a depth of 8575 ft. as a Pennsylvanian Reef test by Universal Consolidated Oil Co. and was later plugged back to 4986 ft. for completion in the San Andres as a new field discovery.

The area surrounding the discovery well was sub-divided into numerous small tracts which led, naturally, to a rapid development program for the field. By November, 1954 a total of 12 wells had been completed in the Cedar Lake Southeast San Andres Reservoir to complete primary development.

The sharp decline in productive capacity observed in the earlier wells within their first year's operation discouraged additional development to the extent that, although some 800 productive acres can be shown by wells that were drilled, only the 480 acres attributed to the original 12 wells were developed.

Original development of the field was based on a spacing of 1 well to 40 surface acres.

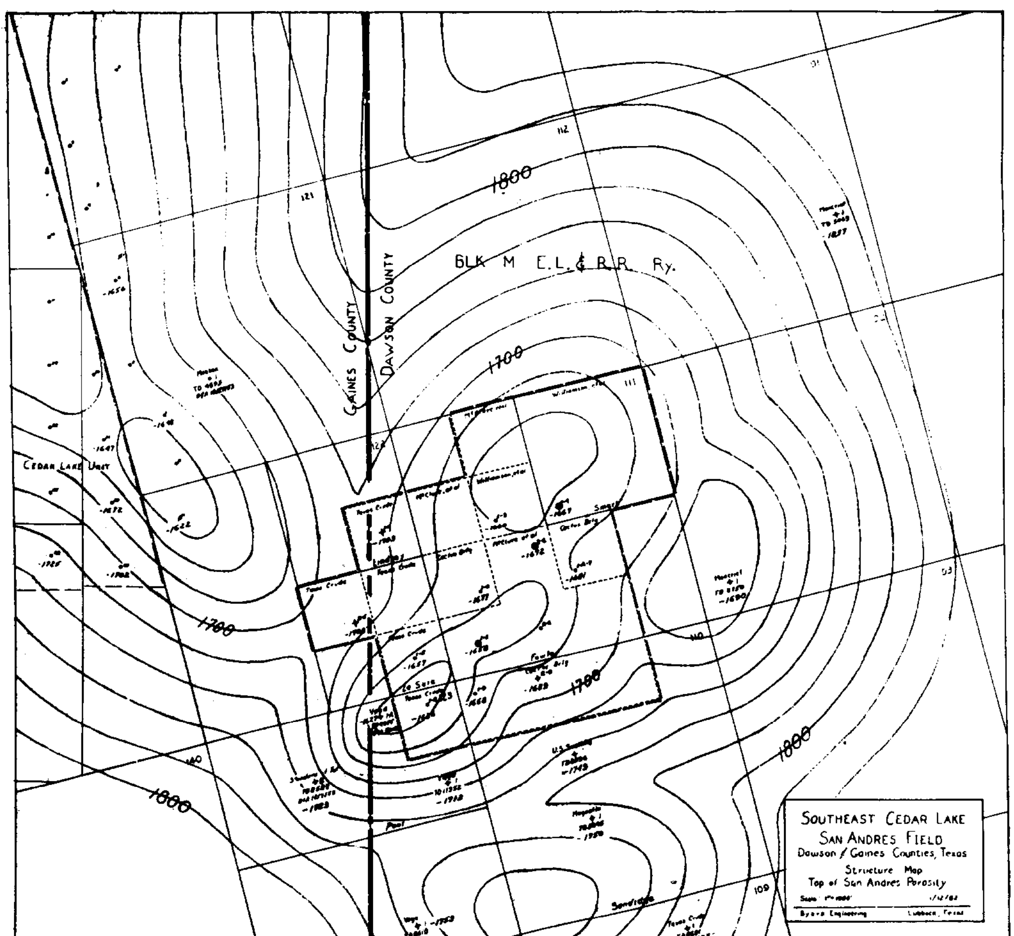

FIG. 1

WELL COMPLETION PRACTICE

Well completion practices employed in the field consisted of drilling to the top of the San Andres porosity at an average depth of 4920 ft. where the oil string (5-1/2 in. to 7 in.) was set and cemented. The hole was then drilled to an average 4990 ft. for open hole completion.

The wells were all acidized for primary production stimulation with an average 7500 gal. of low surface tension hydrochloric acid. This stimulation resulted in an average pumping well capacity of 100 BOPD with G.O.R. 350/1 and relatively low water cut.

After some 90 days' operation, the average well's productive capacity had dropped to some 35 BOPD and continued to decline at an average rate of 1.2% per month.

During late 1955 and 1956, some 2-1/2 years after discovery, several of the field wells were re-stimulated by hydraulic fracturing. The average treatment consisted of 15,000 gal. refined oil with 1-1/2 lb. sand per gal. pumped into the wells at rates of 10 to 12 bbl. per minute at an average 2200 psi surface pressure.

After being treated with hydraulic fracturing, several of the wells produced high volumes of water with little oil for as long as 90 days before substantial increases in oil production were observed. After recovering from the high water cut production, the average well capacity increased materially for a short period of time and then, declined rather rapidly to a level of production that would have been predicted by decline curve extrapolation prior to fracturing treatment.

By June 1961, 8 years after discovery, the field had produced 380,000 bbl. of crude oil or an average 31,600 bbl. per well and the 9 active wells at that time were producing an average 9.3 bbl. oil per well per day.

With production at the level indicated above and with the established production decline rate, it was evident by early 1961 that very little economic potential remained for the field without production stimulation of some nature.

RESERVOIR DATA

The Cedar Lake Southeast Field consists of a broad terraced nose plunging to the southeast from the southeastern portion of the prominent Cedar Lake Field anticline. In the northwestern portion of this nose, between the Cedar Lake Field and the Cedar Lake Southeast Field, San Andres porosity is not developed high enough in the section to afford hydrocarbon accumulation either under the conditions of the Cedar Lake proper or Cedar Lake Southeast reservoirs. It may be suggested, therefore, that the 2 reservoirs are in hydraulic communication within the water bearing portion of the porous San Andres, but that the oil column of the 2 fields are separated by a considerable area of of porous San Andres formation that is below the oil-water contact of both reservoirs.

The south and east limits of the Cedar Lake Southeast Field San Andres reservoir are defined by dip of the formation below the oil-water contact for the reservoir. The productive nature of the southeast flank wells in this field also suggests that reservoir permeability tends to decrease in the down-dip region of the reservoir.

The areal extent of the reservoir occupies an 800 acre area with an average net effective pay thickness of 12 ft. Reservoir rock and fluid characteristics of this 9600 acre foot reservoir volume are summarized as follows:

Average Porosity, % of Bulk Volume	10.0%
Average Permeability, to air md.	6.9
Average Interstitual Water, % Pore Space	22.0
Average Residual Oil Content, % Pore Space	20.0
Original Reservoir Pressure, psig	1650.0
Original Reservoir Temperature, F	105.0
Crude Oil Gravity, API	34.0
Oil Formation Volume Factor, Bbl/bbl	1.15

These data are interpreted to indicate that at the time water injection was commenced, the reservoir had yielded 10.7% of its original movable stock tank oil and that there remained in the reservoir a total of some 3,182,000 bbl. of movable stock tank oil from which water injection practices were to be applied for additional oil recovery.

FLOODING OPERATIONS

As of May 1, 1962 the entire field was unitized and placed under one operator.

Development

Water flood development was commenced on May 1, 1962 with the development of a water supply and injection system and the conversion of 3 centrally located producing wells to water injection wells. Water injection operations were commenced on May 26, 1962 with a plant designed to inject 1400 BWPD.

Through January 1, 1964, after 584 days of operation, a total of 773,571 bbl. of water had been injected for an average 1325 BWPD or an average 94.6% of designed plant capacity.

Water Supply

The water supply source for this project is a 1921 ft. well completed in the Santa Rosa sand section. The water supply well was drilled to 1708 ft. where 8-5/8 in. casing was set and cemented to the surface by circulation. The well was then drilled to 1921 ft. T.D. where a 7 in. slotted liner was set without cementing. No artificial stimulation was employed to increase productivity of the well which is produced by pumping with a submersible electric turbine pump which has a capacity of 3000 BWPD against a total 1600 ft. head. Stable producing fluid level of this well is approximately 800 ft.

The annular space between 8-5/8 in. casing and 2-7/8 in. tubing is filled to static level with diesel fuel and the casinghead sealed for prevention of aeration of annular water.

Injection System

The water injection system consists of 1,000 bbl. clear water storage in the form of two 500 bbl. (16 ft.) tanks. Water is produced into 1 tank and plant suction derived from the other.

Each of the water tanks is sealed with a 6 in. cushion of diesel fuel stored under atmospheric pressure.

Tank water level is controlled by hydrostatically operated switches which start and stop the water supply well on demand.

Water pressure for injection is provided by 2 electrically driven horizontal triplex pumps which discharge into a header system providing outlets to individual wells with throttling, metering and pressure fittings at the header for convenience in maintaining adjustment of pressure volume relationships.

The injection system for this project was designed to handle 1400 BWPD at 2000 psi plant discharge pressure. Provisions have been made to expand this capacity to 3000 BPD without major alteration of existing equipment.

Water is delivered to the individual injection wells through 2 in. steel line which terminates at cartridge type filters at each injection wellhead.

The wells selected for use as water injection wells were cleaned out with bailer and sand pump prior to first injection. Each of these wells was loaded with 10 bbl. of kerosene over the open hole formation face prior to first injection.

Injection performance is shown in Fig. 2.

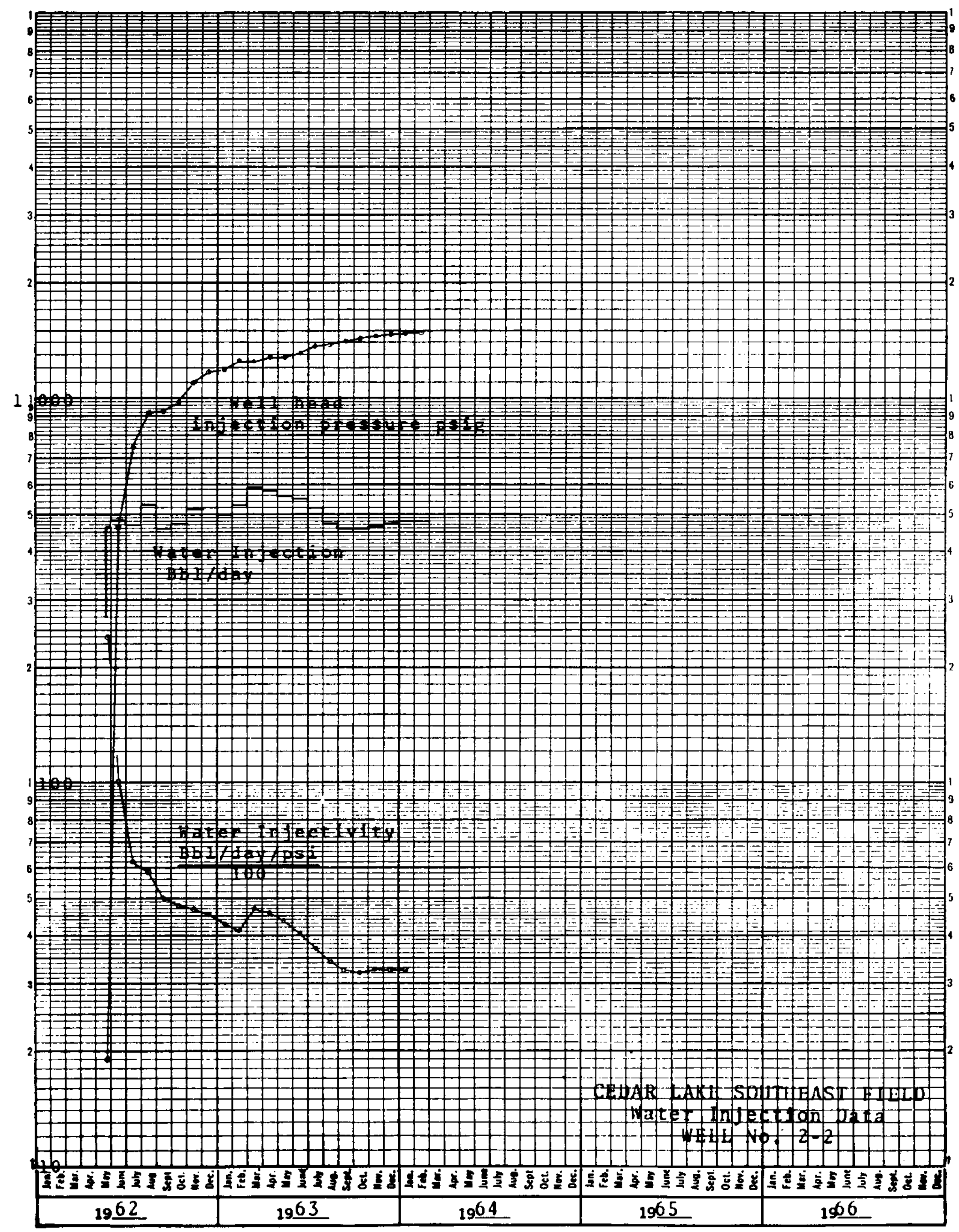

FIG. 2

Water Treatment

Water treatment consists of the injection of a water soluble organic inhibitor at the water supply tubing head. To date, a concentration of approximately 6ppm inhibitor has been used.

Corrosion coupons of J-55 steel have been placed throughout the system both in turbulent flow areas and the most stagnant areas built into the system. To this time, these coupons have indicated virtually no loss of steel. Filter elements have provided further confirmation of the absence of corrosion in this system.

Water injection volumes were controlled in accordance with volumetric requirement for fillup until such time that fillup was reached. After fillup, these volumes have been controlled by a balance of individual well injectivity and reservoir withdrawal from the area being served by the individual well.

At the present time, total water injected represents approximately 80% of total calculated reservoir withdrawals.

Present injection averages 0.33 BWPD per psig wellhead injection pressure with the maximum injection wellhead pressure being 1450 psig.

Oil Production

Production, under water flood operations, in this reservoir has been typical of that expected for a grossly under-saturated oil in a reservoir with good general continuity.

The first influence of water injection on well production was noted after 70 days' operation. This influence occurred after injection of some 23% of produced stock tank oil or approximately 12% of reservoir voidage. From this point of first definite influence, production continued to increase in a relatively orderly fashion at an average 4% per month until the producing capability reached top allowable for the project. Production has been maintained within allowable limits from that time.

At the present time, individual well productivity averages approximately 4 times that prior to water injection operations and on an individual well basis, averages 1.08 times peak primary production.

Producing water cut at the present time averages 22% of gross production. This water cut is some 12% of gross production higher than that prior to water injection operations. In fact, actual water cut has been reduced over pre-water flood operations in all wells with one exception; this one well is producing approximately 50% water at the present time.

Peak water production from the project area reached 36% of gross liquid production when gross water injected equaled approximately 70% of net reservoir oil withdrawals. This was approximately the same time at which water injection had been adequate to totally replace reservoir voidage attributable to injection wells.

To the time of this study, the reservoir has produced a volume of oil that is directly attributable to water flood operations and is equal to 10.4% of that recovered in primary operation of the field.

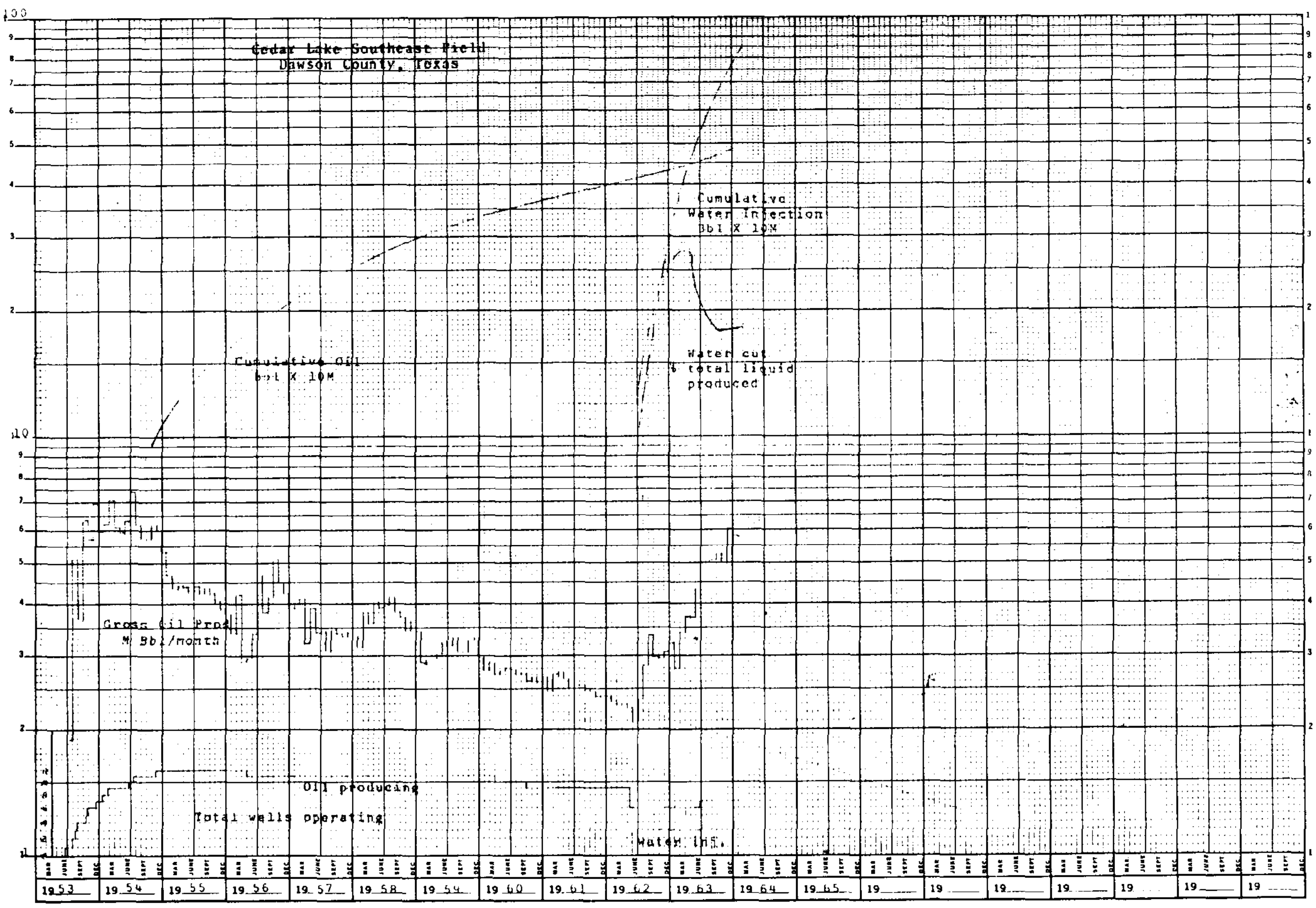

FIG. 3

Under present operations, water flood recovered oil each month is accounting for an increase in field recovery of some 1% over that of primary produced oil. Oil production performance is shown in Fig. 3.

Production Practices

Production Practices employed in this field are not different from those of the conventional primary field operation. All producing wells are powered with electricity and production proration is attained through control of operating time of each well.

The precipitation of paraffin in flow lines and tubing has increased with increasing production. The period of well operation between paraffin cleaning operations has decreased with increasing production but not in direct proportion. The average well, when producing 8 BPD, required treatment about every 120 days. That well, now producing 30 BPD, requires treatment every 90 days. Therefore, treatment costs now average only about 36% of that prior to water injection on a produced bbl. basis.

Gyp type deposits, although anticipated in an operation of this type, have not to this time been found to be abnormal as compared to that prior to water flood operations. The absence of significant scale type deposits is believed largely due to lack of injection water break-through and possibly, in part, to the manner of operation of the producing wells.

Economics

Costs of operation of this project, to the present time, have not changed from primary type operations with the exception of that cost attributable to delivery of water under pressure to the reservoir.

The cost of delivered water to the reservoir, including amoritization of water supply and injection plant facilities on a straight line basis over 9 years, has been $0.027 per bbl. of water. In terms of oil recovered, this cost amounts to $0.54 per bbl. of oil recovered to date and is directly attributable to water flood operations.

From experience in this field during 21 months of operation, it now appears evident that water flood operations in the San Andres can be conducted within the requirements of sound economy and on an essentially trouble free basis. In order to accomplish this end, however, sound design of the injection system and carefully guided operational practices to conform to the conditions of fluids being handled must, as in other oil and gas production operations, be followed.