Polymer reduces channeling, ups waterflood oil recovery

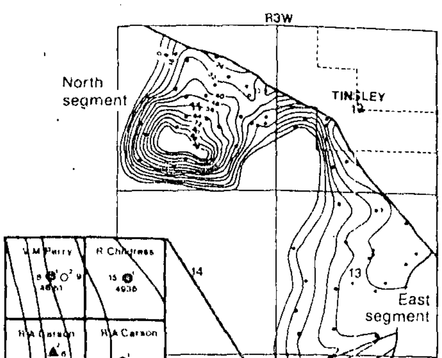

Fig. 1—Tinsley (Woodruff sand) field is isolated by a fault on the northeast and east and a pinchout on the west and south. A northeast-southwest trending fault effectively divides the field into three segments. Sand thickens toward the faults and disappears to the west, note zero isopach line. Numbers beneath wells on insert are total depths, with sand thickness across from well number. V. M. Perry 2 is a water disposal well.

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10-second summary

Rapid water break-through on a Mississippi waterflood indicated very poor sweep efficiency. A monomer that polymerizes in situ was injected in an attempt to correct the problem. The monomer followed the injection water path, polymerized into an extremely viscous liquid and forced water into other sections of the sand, displacing additional oil.

A MONOMER that polymerizes into a highly viscous liquid in existing water channels is helping Pennzoil Producing Co. solve a poor sweep efficiency problem. Following a severe water breakthrough in a waterflood in Yazoo County, Mississippi, a pilot project substantially improved oil production without an increase in water production. Substantial increases in production from the three producing wells affected by the monomer treated injection well are leading to monomer use in other parts of the field.

Tinsley Field, Yazoo County, Mississippi, is a multi-zone field with the Late Cretaceous Woodruff sand being the most prolific producer. Faulting and a west side pinchout effectively divide the field into three distinct segments: north, west and east, Fig. 1.

Production from the Woodruff sand in the west segment was by solution gas drive in the north and a partial water drive in the south. Water drive is very efficient with movement being a few hundred feet per year. North wells, however, decreased to low production rates requiring the field to be unitized and secondary recovery by waterflood initiated.

Rapid breakthrough in the north portion indicated a very low sweep efficiency. Plugging and diverting materials designed to plug the formation face and reservoir immediately around the well bore failed to improve flood pattern. This prompted Pennzoil Producing Co., the unit operator, to investigate other methods to improve recovery in the north portion. After careful study of options available to improve sweep efficiency, Pennzoil decided to treat with k-Trol, fluid furnished by Halliburton Services, a batch injected monomer that polymerizes in situ.

RESERVOIR PROPERTIES

The Woodruff sand is a fine to medium grain, light gray, calcareous sand with gray lime streaks stratified with the sands. Lime streaks are from 1 inch to 1 foot thick and sand string-

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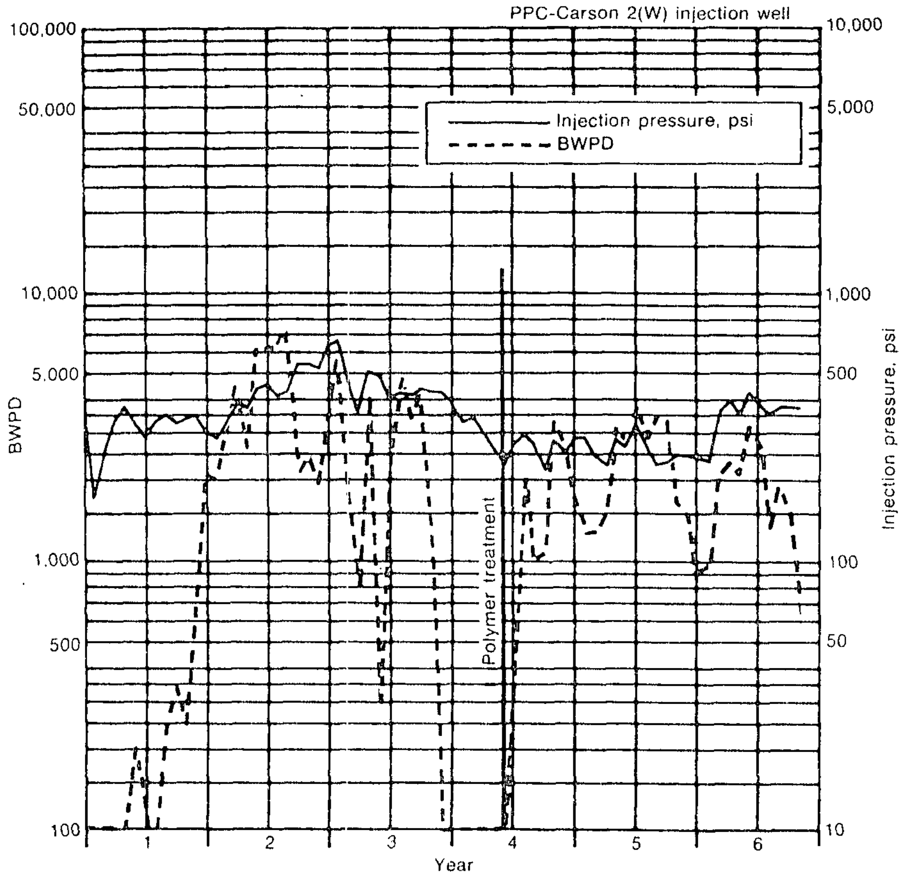

Fig. 2—Plot of injection rate and pressure shows that the polymer treatment did not cause the injection pressure to increase although the injection rate approximated that of the initial flood.

ers are 1 to 10 feet thick with good permeability and porosity.

The west Woodruff sand segment is a beach deposit with a north-south strand line forming the west boundary of the reservoir. The north and east boundaries are northwest-southeast and north-south trending main field faults. To the south, the sand dips below an oil-water contact which originally occurred at -4,714 feet. From the west strand line, sand thickens to a maximum of 33 feet near the north-south fault, Fig. 1. Reservoir characteristics and fluid properties in the west segment are listed in Table 1.

INITIAL FLOOD PERFORMANCE

Waterflood operations in the Woodruff sand began with water being injected along the strand line, behind the natural water encroachment front, and into two interior injection wells along the east reservoir boundary. Response to water injection occurred almost instantaneously, and oil production increased from 810 bopd to a peak of 2,500 bopd in 11 months.

Initial pattern was continued for about five years until all producers virtually were watered out. Then the injection pattern was changed to concentrate more water along the strand line to efficiently sweep oil from west to east and recover it along the north-south fault. Water breakthrough occurred rapidly in most producing wells, indicating poor sweep efficiency. This led to the search for a better recovery method.

WELL SELECTION

Initial injection into Carson 2 (Fig. 1) was 3,300 bwpd at 50 psig. The well maintained good injectivity and, at time of polymer treatment, about 5 million barrels had been injected. Injection rate at this time was 4,000 bwpd at 400 psig, Fig. 2.

All three offset wells showed excellent response to water injection into Carson 2 and other Woodruff sand injection wells. Response was immediate, occurring within one to five months after injection began. Production increases in each well ranged from 90 to 400 bopd, with peak production occurring in about 18 months.

Increased oil production was accompanied by, or followed immediately by, increased water production. Water production reached 80% within one year and increased to 95% before polymer treatment. Oil production from each well was on a straight line decline curve at 20 to 60 bopd. Cumulative oil production from the three wells under waterflood operations was 331,000 barrels. These facts, along with the early breakthrough, strongly indicated poor sweep efficiency and provided justification for the polymer treatment. Typical production performance of a producing well affected by Carson 2 is shown in Fig. 3.

TABLE 1—Reservoir characteristics and fluid properties

Reservoir depth	4,600 ft
Productive area	2,438 ac
Average thickness	13.3 ft
Reservoir volume	32,503 ac ft
Porosity	25.7%
Permeability	402 md
Water saturation	22.5%
Original solution GOR	100 cf/stb
Original BHP	2,021 psi
Reservoir temperature	164° F
Formation volume factor, res bbl/stb	
Original	1.075
Current	1.04
Oil gravity at 60° F	34° API
Current viscosity at res temperature	3.8 cp

POLYMER CHARACTERISTICS

The polymer-type chemical used is a 1.2-cp viscosity monomer solution of acrylamide in concentrations from 30,000 to 50,000 ppm, plus an activator, and is prepared at the wellsite. With this process there is no need to install a dry polymer feeder with the injection equipment. The mixture is pumped into the formation at the same rate and pressure as the injection water.

Under these conditions, treatment should follow the same path as injection water, because the solution is a low-viscosity aqueous fluid similar to injection water. Complete polymerization occurs within 120 hours, and the resulting polymer solution may attain a viscosity as high as one million cp. Formation temperature and activator concentration determine the in-situ polymerization rate.

After injection is re-established, injection water should enter the formation through paths of least resistance. Because the polymer reduces permeability in high sweep efficiency areas, subsequent injection water is diverted to less permeable sections. Injection water flows around the periphery of the concentrated polymer and fingers through it. Because the polymer is

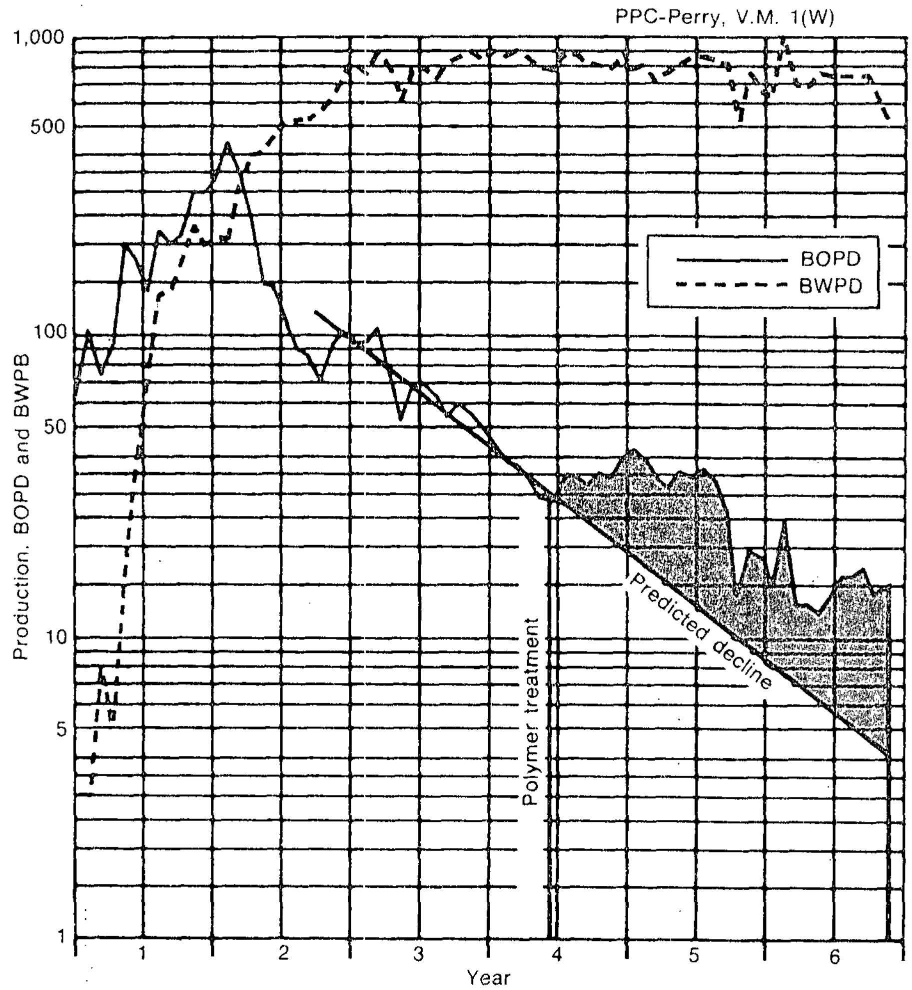

Fig. 3—Increase in oil production in one well affected by the polymer treated well shows the incremental oil recovered by the treatment. Note that water production remained about the same.

miscible in water, the water viscosity increases, greatly improving overall sweep efficiency.

TREATMENT DESIGN

A computer program developed to determine treatment parameters using Darcy's Laws of linear and radial flow indicated that an 800-barrel polymer treatment should be distributed totally to a radius of 131.6 feet and completely absorbed in the reservoir after 10,095 days of injecting 3,228 bwpd. Because of the mechanism that delays dilution of the polymer, this extremely long time is required to reduce viscosity of the entire treatment to one cp. Improved sweep efficiency should continue as long as there is a favorable mobility ratio.

Carlson 2 received an 800-barrel polymer treatment, requiring less than nine hours and costing about $14,000. Treatment consisted of pumping 16 50-barrel batches of 2% KCl water with an acrylamide concentration of 50,000 ppm and activator. A 20-barrel preflush of 6% KCl water preceded the treatment and 18 barrels of 2% KCl water was used as flush.

All fluid was pumped at 2 bpm, slightly lower than normal injection rate. The well remained on vacuum until the start of batch 10, when pressure increased to 75 psi. A maximum pressure of 200 psi was reached during batch 12 and pressure stabilized at 100 psi from batches 13 through 16. The well immediately went on vacuum when pumping stopped at the treatment end. The well was shut in for five days to allow complete polymerization and then was returned to normal injection of 2,700 bwpd at 0 psi. The pressure increased to about 150 psi within 30 days and injection rate was controlled near 2,700 bwpd for the next 18 months.

RESULTS

Although injection pressure did not change, producing wells responded within two months. All three continued to produce oil above their predicted decline for 30 months, recovering a cumulative total of over 35,000 barrels of incremental oil. Water production did not appear to be affected by the treatment.

Additional oil probably has been produced since the 30-month period. However, installation of additional downhole electric submergible pumping systems and proximity of another injection well has masked polymer performance since the 30-month period.

Another Woodruff sand injection well, the south offset to the Carson 2, was treated with polymer near the end of this period. The performance of the treatment has been masked because of the proximity of another injection well. However, known production rate increases recognized from treating Carson 2 cause additional polymer applications to be considered in other field areas.

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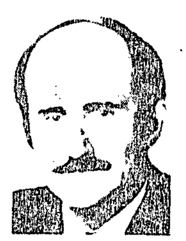

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