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FIELD STUDY OF VISCOUS OIL PRODUCTION BY SOLVENT STIMULATION, WILMINGTON, CALIFORNIA

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ABSTRACT

Preliminary results are given of solvent stimulation of two wells producing viscous oil (14°-17° API) from the Tar zone in the Wilmington field, California. The solvent (coker oil, an intermediate refinery product) was injected into the formation, and after a soak period, the well was returned to production. Data are given on crude oil properties, solvent properties, determination of volume of solvent in the produced oil, rate of oil production before and after stimulation, volume of additional oil produced, and volume of solvent recovered. Although further study and improvement of the method are needed, cyclic solvent stimulation appears to be an unqualified success in one well and a moderate success in the other.

INTRODUCTION

The development of technology for increasing petroleum production is an important part of the mission of the Bureau of Mines. Research is a basic necessity to find new, improved, and economic methods to produce heavy, viscous crude oils that become ever more important as the Nation's reserve of oil diminishes. Some of these viscous oils respond to stimulation by steam injection. The added production in 1971 due to steam injection in 15,000 wells in California amounted to 150,000 bbl/day (2).[4] The number of fields that respond to steam injection is limited, however. With only a few successful projects, the U.S. oil industry overall has yet to recover its investment in steam (6). Better methods must be developed to add the large resource of viscous oils to the dwindling inventory of the Nation's energy. The use of solvent stimulation as an improved method of recovering viscous oil is a recent development.

The viscous oils that are considered to be most susceptible to solvent stimulation are those having gravity of less than about 20° API. The wells

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[2] Project leader.
[3] Research supervisor.
[4] Underlined numbers in parentheses refer to items in the list of references at the end of this report.

producing these viscous oils of especial interest have produced some oil profitably without stimulation, but recovery has been so low that most of the original oil is still in the reservoir. Reservoirs in the United States contained about 44 billion bbl of oil in this category in 1966, of which 33 billion bbl (75 percent) was in California (8, classes 1 and 2).

The cyclic solvent stimulation method consists of injecting a solvent, sometimes with additives, into the producing formation, allowing the well to stand idle for some time, and then producing the oil-solvent mixture from the well that was used for injection. The method has not been widely used, but laboratory studies (4) and a few field tests have been encouraging (3, 5).

The mechanics of the solvent stimulation process are not well known, but present indications are that the solvent not only reduces the viscosity of the oil in the reservoir but also increases the size of the flow channels by removing solids such as asphaltenes, paraffins, sand, and clays.

The Bureau's San Francisco Energy Research Laboratory is cooperating with an operator in the Wilmington field to obtain the most practical and scientific information possible from a series of solvent stimulation tests. Special attention is given to such factors as the volume of incremental oil produced, the percentage of the solvent recovered, the effect of various additives, and the applicability of the method in zones producing mostly water. (Incremental oil is the additional oil produced as a result of the stimulation.)

This report gives the preliminary results from the first two of a series of wells to be stimulated. Since it has been only a short time since the wells were stimulated, some of the information may be modified in the future. The information is of timely interest, however, and this interim report is being published now rather than waiting until the story is complete.

FIELD AND WELL DATA

The Wilmington field is located in the Los Angeles basin of California. The field is noted for its size and unusual crude oils. Some outstanding statistics follow: (1) The field has produced more than 1 billion bbl of oil, (2) reserves recoverable by primary methods in 1971 were over 900 million bbl, (3) in 1971 the field produced at the highest rate of any in the Nation--200,000 bbl/day, and (4) the waterflood in this field is the largest in the Nation--over 1 million bbl/day of water was injected during 1971.

The field is a faulted, multilayered reservoir. A large part of the field is under the Long Beach harbor and is produced from directionally drilled wells. The uppermost broad, oil-producing horizon is the Tar zone, with sands initially containing 2,150 bbl of stock tank oil per acre-foot. The oil gravity is low, ranging from about 14° to 17° API. The reservoir sand is unconsolidated; the porosity ranges from about 34 to 40 percent. Laboratory air permeabilities range from 1 to 8 darcys. Reservoir temperature is about 120° F.

Primary recovery from the Tar zone to date is estimated to be about 12 percent of the original oil in place. Several waterflood and steam injection projects are underway to increase recovery (7). The fate of the steam injection projects is uncertain, but waterflooding will no doubt continue because of the necessity for disposing of waste water and preventing land subsidence and the increase in volume of petroleum produced.

Both of the wells discussed herein, called well A and well B, were completed with perforated liners and were gravel-packed. Production from both wells contained large quantities of water. Well A is located in a part of the reservoir that is thought to have a natural waterdrive; well B is in a fault block that does not have a strong influx of water and is being waterflooded. Formation properties and oil production are listed in table 1.

TABLE 1. - Formation properties and oil production

	Well A	Well B
Air permeability................................md..	2,000	1,600
Porosity..................................percent..	34	34
Productive sand thickness....................feet..	80	45
Prestimulation oil production......average bbl/day..	19	16
Prestimulation water cut..................percent..	95	94

CRUDE OIL PROPERTIES

A sample of crude oil from the Tar zone was obtained from well A before the solvent was injected to assure an uncontaminated sample. A sample of oil was not taken from well B before solvent was injected; however, a sample was obtained from a nearby well that produces from the same fault block of the Tar zone in the hope that it is representative of the oil from well B. Table 2 shows properties determined in the laboratory.

TABLE 2. - Properties of crude oils

	Well A	Well B
Gravity.................° API..	15.0	17.0
Viscosity at 100° F.........cp..	645	150
Molecular weight...............	410	377

Wilmington crude, like most California oils, contains many cyclic compounds and a relatively large amount of nonhydrocarbons. A composite sample of Wilmington crude oils contained, in weight-percent, 1.53 sulfur, 0.65 nitrogen, and 0.44 oxygen. This oil is an asphaltic oil containing a small amount of gasoline and large amounts of high-molecular-weight cyclic compounds. The hydrocarbon portion of the oil has been shown to contain primarily naphthenic compounds (1). Bureau of Mines crude oil analyses are widely used for general comparison and characterization of crude oils. Based on the carbon residue of the oil, the calculated content of 100-penetration asphalt is 32 weight-percent.

A sample of Wilmington Tar zone crude oil was found to have a viscosity of 645 cp at 100° F. The addition of 10 weight-percent of light coker oil reduced the viscosity to 193 cp at 100° F (4).

SOLVENT PROPERTIES

The solvent used in these stimulation tests was selected after laboratory studies of several solvents by the San Francisco Energy Research Laboratory, Bureau of Mines. The laboratory tests to determine the effectiveness of the solvents included the following: Reduction of viscosity of the Wilmington crude oil, removal of oil from packed columns containing sand and crude oil, and removal of crude oil from small-capillary tubes. The tests showed that the most effective solvents are those that contain a large percentage of aromatics and have a low molecular weight (4).

A solvent that was readily available in the field at a reasonable price was a light coker oil, which is an intermediate refinery product. This solvent was tested in the laboratory and found to be relatively effective in most of the tests mentioned above. The low molecular weight, 233, and high API gravity, 33°, were also favorable.

A sample of the coker oil was sent to the Laramie (Wyo.) Energy Research Center, Bureau of Mines, for determination of the distillation range and the types of hydrocarbons. The volume vaporizing at various temperatures was determined by simulated distillation in a gas-liquid chromatograph. The results are given in table 3.

TABLE 3. - Simulated distillation range of Wilmington coker oil

Distillation, vol pct	Temperature, ° F	Distillation, vol pct	Temperature, ° F
IBP[1]	240	50	538
1	275	60	572
2	320	70	609
5	360	80	652
10	380	90	713
20	434	95	766
30	473	EP[2]	830
40	505		

[1] Initial boiling point.
[2] End point.

The types of hydrocarbons, table 4, were determined by adsorption chromatography. Each fraction (naphtha, etc.) was passed through a silica gel column, and each type of hydrocarbon in the effluent was determined by measuring the refractive index. Since coker oil is not widely marketed, the selling price has not been fixed, but the company estimates that the price would be about $3.60 per barrel in tank truck lots.

TABLE 4. - Composition of Wilmington coker oil

Fraction	Boiling range, ° F	Percent of oil, vol pct	Composition, pct of fraction		
			Saturates	Olefins	Aromatics plus polars
Naphtha................	[1] 240- 400	11.5	43.7	31.9	24.4
Light distillate.......	400- 600	56.0	38.5	29.3	32.2
Light gas oil..........	600- 800	30.1	41.9	2.0	56.1
Heavy gas oil..........	800-[2] 830	2.4	([3])	([3])	([3])
Total oil..............	240- 830	100.0	[4] 40.2	[4] 21.2	[4] 38.6

[1] Initial boiling point.
[2] End point.
[3] Too small to determine.
[4] Not including heavy gas oil.

SOLVENT CONTENT OF PRODUCED OILS

After the solvent was injected into the formation and production from the well was resumed, samples of the produced oil-solvent mixture were taken periodically and the gravity was measured. Because the API gravity of the crude oil (about 15°) was less than the gravity of the solvent (33°), the quantity of solvent in the produced mixture was estimated at the well by observing the gravity of the mixture. Although the mixture was spun for several minutes in a hand-operated centrifuge, it still contained considerable water that made the results unreliable.

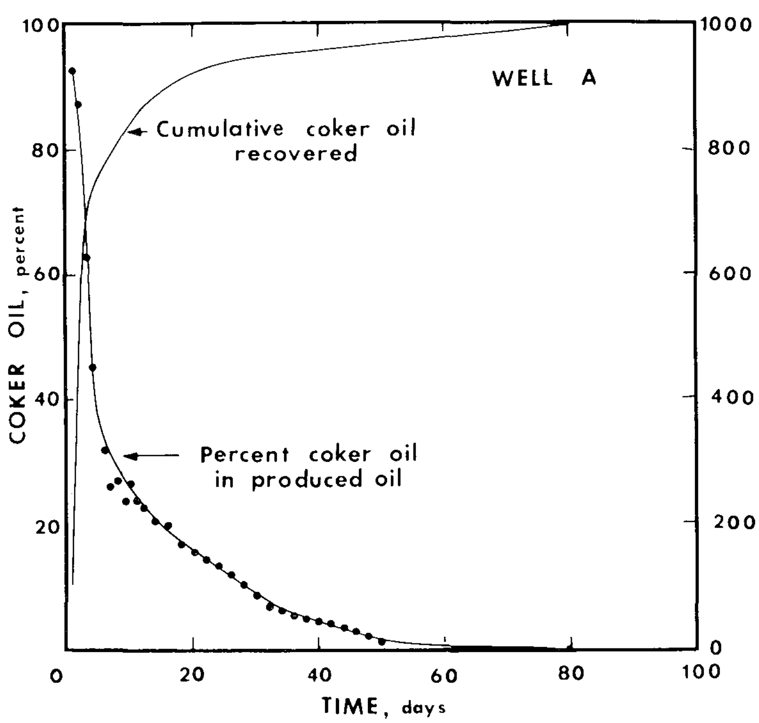

FIGURE 1. - Percent Coker Oil in Produced Oil and Coker Oil Recovered, Well A.

Samples of the produced oil-solvent mixture were centrifuged in the laboratory to remove water and then analyzed. The solvent content of the mixture was determined by using the vapor pressure osmometer and the gas-liquid chromatograph (GLC). The instruments were calibrated by using samples containing known percentages of crude oil and solvent. The GLC was modified to accept oils containing nonvolatile fractions at the column temperature of 100° C. Excellent results were obtained by using a glass insert in the injector.

The percentage of coker oil in the produced mixture was found to decrease with time in both wells, as was

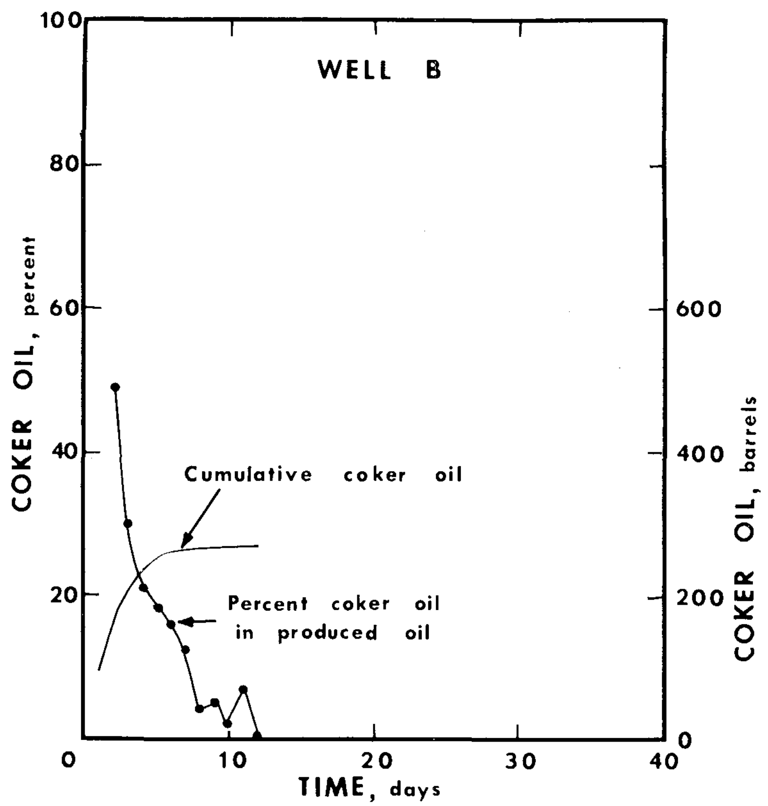

FIGURE 2. - Percent Coker Oil in Produced Oil and Coker Oil Recovered, Well B.

expected. All of the coker oil was recovered from well A, but apparently a considerable volume was lost in well B (figs. 1-2). These results are discussed in more detail in the following section.

STIMULATION OPERATIONS AND RESULTS

Although the two wells are only about one-half mile apart, and both produce from the Tar zone, they produce from different fault blocks (different oil reservoirs), and the reservoirs have somewhat different properties, as shown in table 1. Because of these differences and because the wells responded differently to solvent stimulation, the wells are discussed separately.

Well A

Production from well A before treatment averaged 19 bbl of oil and 377 bbl of water per day. The pump was pulled, and 1,000 bbl of solvent was drained from the tank truck into the tubing by gravity. About 970 bbl of the solvent entered the formation by gravity head. The pump was rerun soon after injecting the solvent, but the well was allowed a soak period of 54 hours before production was resumed. Figure 3 shows oil production data for 235 days after stimulation and solvent production data for 80 days.

The important information concerning the stimulation and results on well A is summarized as follows:

1. Solvent used--1,000 bbl. Thickness of sand open to production--80 ft. Solvent-thickness ratio--12.5 bbl of solvent per foot of sand. The solvent was not followed with water to displace it farther into the formation.

2. Solvent recovered--850 bbl (85 percent) in 10 days and 1,000 bbl (100 percent) in 80 days.

3. Rate of oil production--average 19 bbl/day before stimulation and 30 bbl/day for the period of 10 to 235 days after stimulation.

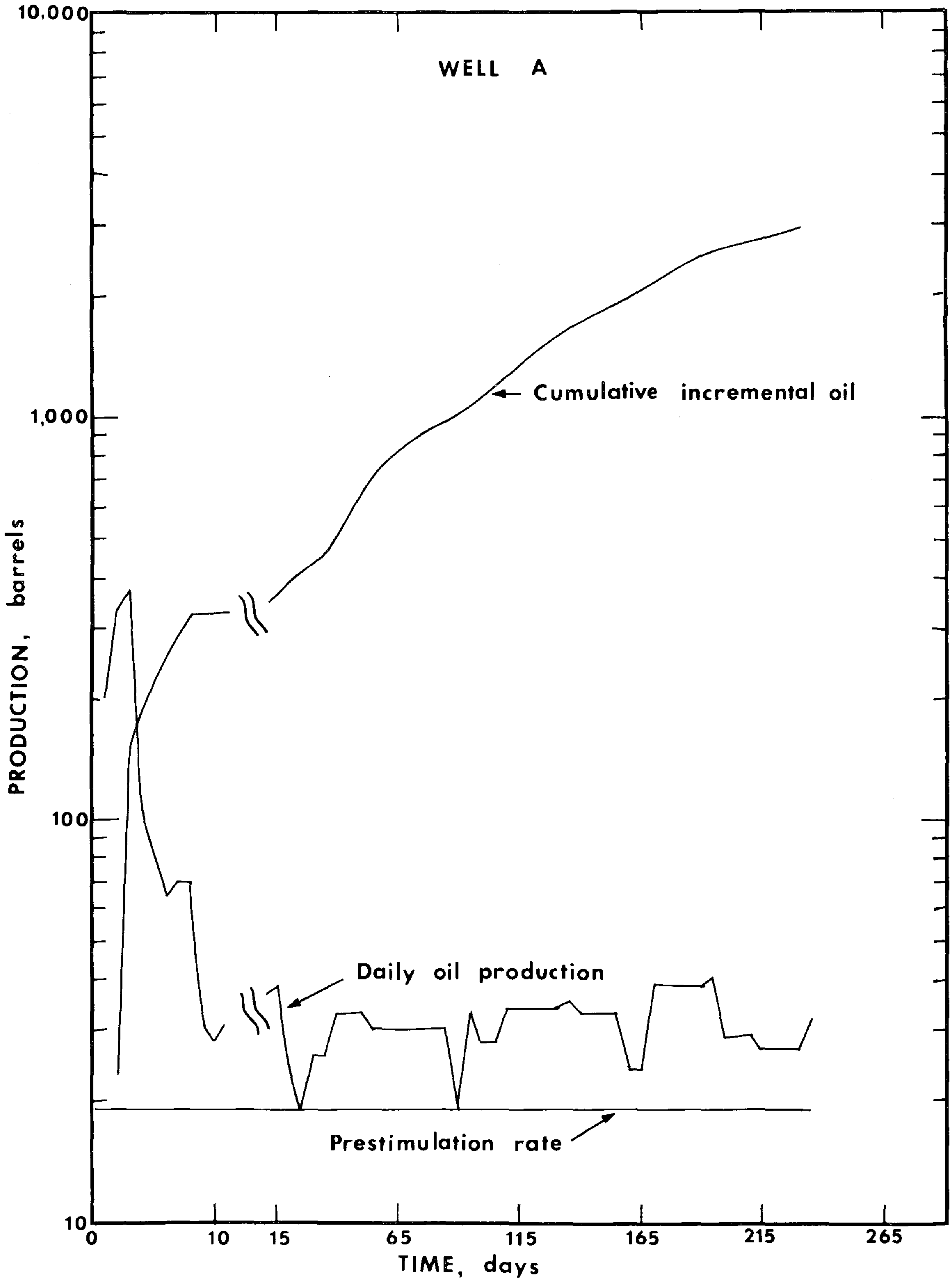

FIGURE 3. - Incremental Oil Produced and Daily Oil Production, Well A.

4. Incremental oil produced during the first 235 days after stimulation--2,900 bbl.

5. Prospects for additional incremental oil--promising. If the rate of oil production declines by about 1 bbl/day each month (the prestimulation rate of decline), then an additional 2,000 bbl of incremental oil will be produced in the future, before the well returns to the prestimulation rate of 19 bbl/day. This would give a total recovery of incremental oil of about 5,000 bbl.

6. Rate of oil production at the time when no more solvent was being produced with the oil--30 bbl/day after 80 days, for an increase of 58 percent over the prestimulation rate.

7. Cost of stimulation job--about $2,800 for pulling pump and tubing, well cleanout, etc., and about $3,600 for solvent.

8. Insufficient time has elapsed since stimulation to be certain of overall results.

Well B

Production from well B before treatment averaged about 16 bbl of oil and 270 bbl of water per day. Five hundred fifty barrels of solvent was pumped down the annulus and was followed by about 550 bbl of water. The operator estimated that all of the solvent and about 322 bbl of water were displaced into the formation. The well was allowed to stand idle for about 48 hours before production was resumed. Oil production data for 74 days after stimulation are shown on figure 4.

The important information concerning the stimulation and results on well B is summarized as follows:

1. Solvent used--550 bbl. Thickness of sand open to production--45 ft. Solvent-thickness ratio--12.2 bbl solvent per foot of sand. The solvent was followed with 550 bbl of water to displace it farther into the formation.

2. Solvent recovered--370 bbl (67 percent) in 12 days, but no more produced during the remainder of the 64 days.

3. Rate of oil production--average 16 bbl/day before stimulation, and 20 bbl/day for the period of 22 to 52 days after stimulation; the rate then dropped and may be approaching the prestimulation rate.

4. Incremental oil produced during the first 64 days after stimulation--660 bbl.

5. Prospects for additional incremental oil--doubtful. The well may be returning to the prestimulation rate after a rather short time.

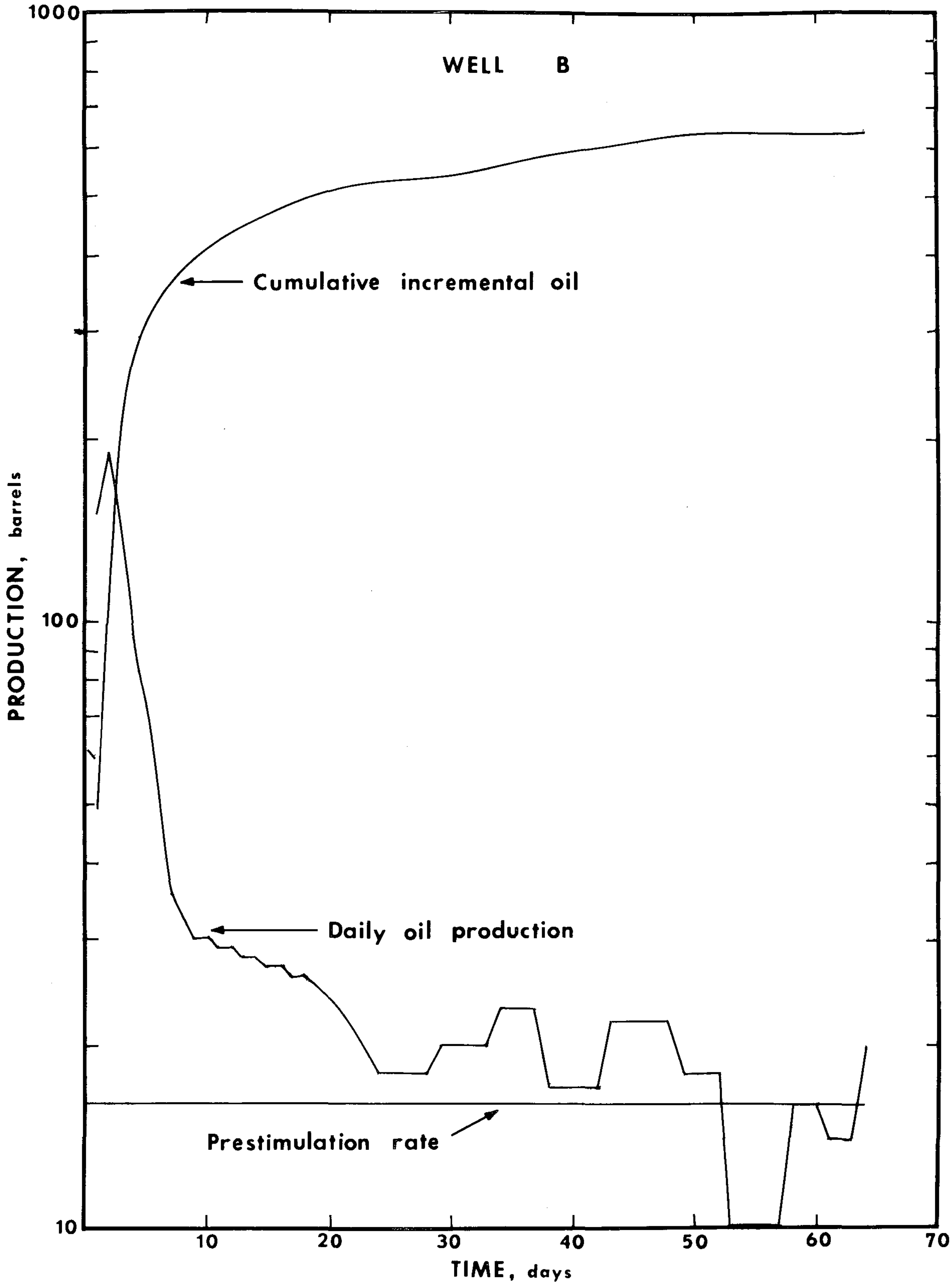

FIGURE 4. - Incremental Oil Produced and Daily Oil Production, Well B.

6. Rate of oil production at the time when no more solvent was being produced with oil--29 bbl/day after 12 days, for an increase of 81 percent over the prestimulation rate.

7. Cost of stimulation job--about $2,600. This includes the cost of the solvent. Well costs were considerably less than on well A because the pump and tubing were not pulled.

8. Time may not be long enough to observe significant trends.

DISCUSSION OF RESULTS

The details of the chemical and physical processes involved in the stimulation of wells by solvents are not clearly understood. One of the purposes of our laboratory and field studies is to try to determine what happens when a solvent is injected into an oil-producing formation. When the mechanics of the method are understood, it can be improved by varying such factors as type of solvent, choice of additives, rate of injection, length of soak period, and time between successive stimulations.

The increase in the rate of oil production in wells stimulated with solvents may be due to any of several factors, either separately or in combination. Some of the important factors are reduction of oil viscosity; enlargement of flow channels by removal of asphaltenes, clays, and other solids; and increase in relative permeability to oil in the reservoir due to increased oil saturation. The data from these two wells do not clearly show which of these factors was dominant.

If viscosity reduction were the dominant process, the increased rate of oil production should be directly related to the percentage of solvent in the produced oil. (This assumes that the solvent is thoroughly mixed with the oil in the reservoir, which may not be the case; also, some of the solvent may have entered a zone producing only water.)

In well A, the rate of oil production was high during early times of production when the percentage of solvent was also high (figs. 1 and 3). The rate of oil production decreased to 30 bbl/day after 10 days, and at that time the produced oil contained 26 percent solvent.

Subsequently, the rate of production did not decrease as the solvent decreased to zero at 80 days but remained at about 30 bbl/day until the present time of the test at 235 days. This indicates that the sustained higher rate of production, after the first flush production, was not due to reduced oil viscosity but was due to some other factor.

The rate of oil production in well B declined as the percentage of solvent declined for the first 12 days of production. All of the solvent to be recovered was recovered in 12 days, but the rate of oil production continued to decline for another 10 days and then leveled off at about 20 bbl/day.

Here again, the rate of oil production cannot be directly related to the percentage of solvent in the produced mixture over the whole time of the test. The increase of rate of oil production to 20 bbl/day from the prestimulation rate of 16 bbl/day suggests that the solvent may have enlarged the flow channels in the well or in the reservoir, or both.

These studies clearly show that further study and improvement of the solvent injection method are needed before it can be added to the list of reliable methods that are available to extract additional viscous oil from stubborn reservoirs.

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