

July 17, 1962

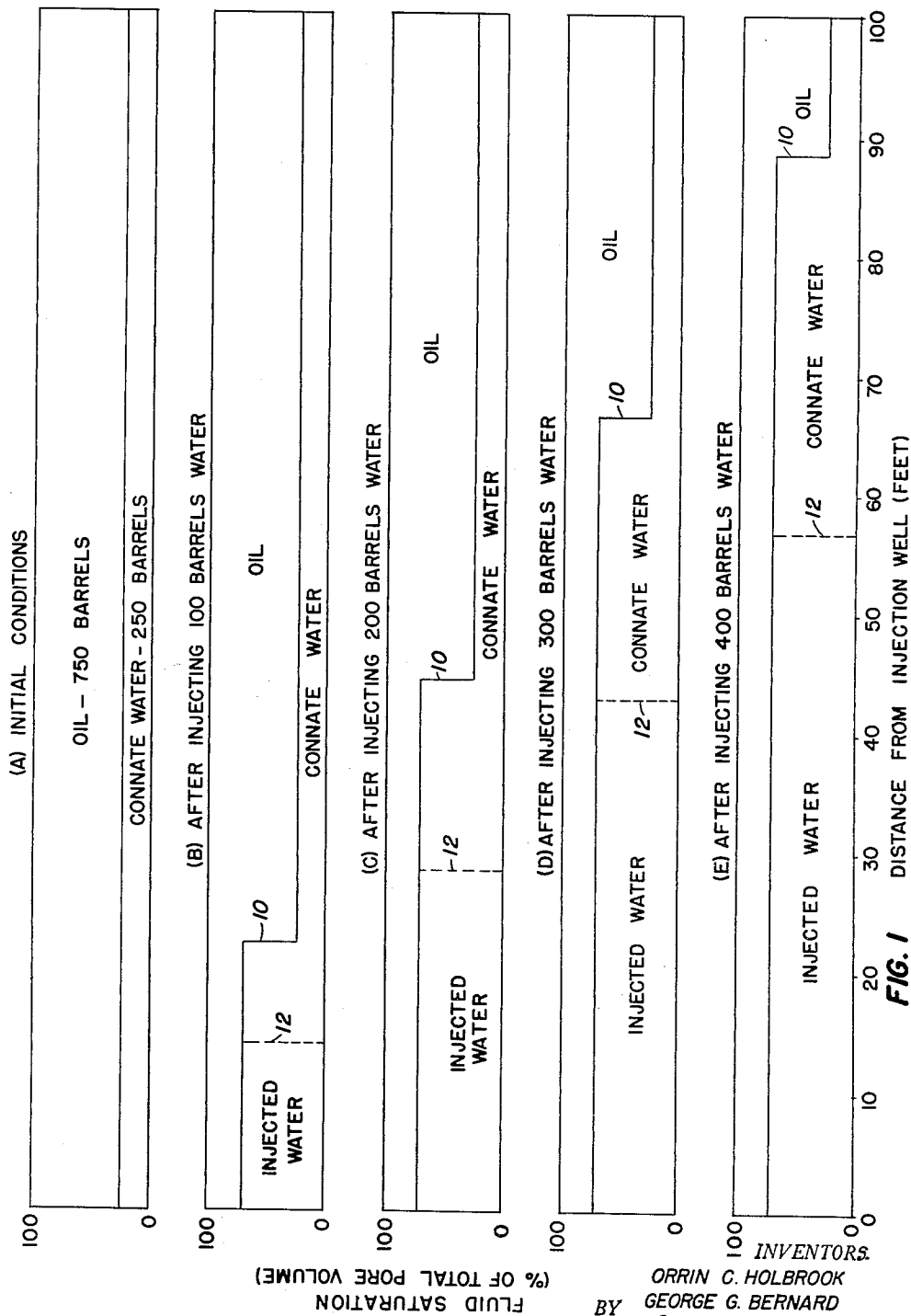
O. C. HOLBROOK ET AL

3,044,544

INCREASING OIL RECOVERY DURING WATER-FLOODING

Filed Dec. 29, 1958

2 Sheets-Sheet 1



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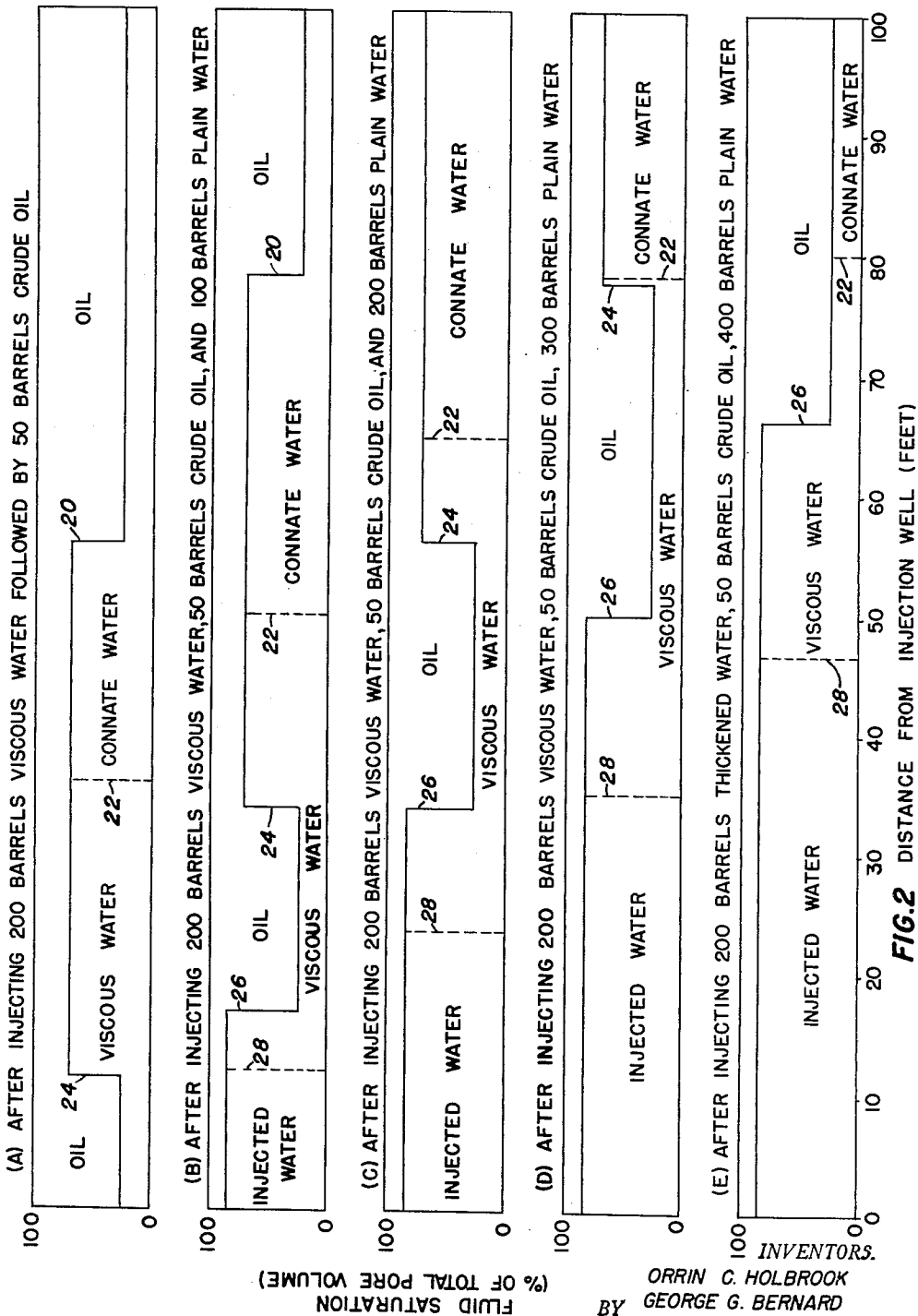
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INCREASING OIL RECOVERY DURING WATER-FLOODING

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6 Claims. (Cl. 166-9)

This invention relates to the recovery of petroleum from underground reservoirs, and is more particularly directed to a flooding process for recovering petroleum in greater amounts than is possible by conventional water-flooding methods.

It is well known in the flooding of depleted oil reservoirs to inject an aqueous fluid having a viscosity greater than that of water to drive the petroleum in the formation toward a producing well. Various types of viscosity modifiers have been used for this purpose such as those disclosed in Patents 2,341,500; 2,731,404; 2,827,964; and 2,843,545.

Conventional water-flooding leaves about 20 to 50% of the original oil still in the reservoir, even after prolonged flooding. By adding viscosity improvers to the floodwater, as taught by the references cited, some additional oil may be recovered. The difficulty with conventional methods of flooding using viscosity improvers is that the injected viscous aqueous solution displaces the connate water naturally occurring in the formation, and builds up a bank of connate water ahead of the viscous injected water. Therefore, the water at the advancing water-oil flood-front interface is connate water. When the connate-water bank floods out a given area in the reservoir formation, it causes the oil in place to become discontinuous and the continuity of the oil phase cannot be restored even in the presence of the injected viscous floodwater. To obtain effective displacement of petroleum by the viscous floodwater, it is necessary to obtain and preserve an oil-viscous-water, flood-front interface. Unfortunately, no way has been found to prevent the build-up of a bank of connate water between the petroleum and the viscous-water flood-front.

This invention resides in the discovery that by injecting a slug of oil after injection of a quantity of viscous floodwater, and then flooding with ordinary water, a continuous oil phase is re-established by the injected oil ahead of a second flood-front at the interface of the viscous floodwater and the trailing edge of the injected oil slug, resulting in the establishment of a continuous oil-viscous-water flood-front and the removal of additional quantities of oil.

It is an object of this invention to provide an improved method for secondary recovery of oil from underground reservoirs. Another object of this invention is to provide a method for recovering a high percentage of the oil present in an oil-producing reservoir. Other objects of the invention will become apparent from the following detailed description.

Since in practice a bank of connate water is built-up at the leading edge of the flood-front, and it is this water rather than the injected water which actually floods out the formation, by the time the thickened water reaches a given area of the formation, the area has already been flooded with connate water and the oil in the reservoir has become discontinuous. It is very difficult to regain continuity in the oil phase once it has been lost. To illustrate this point, experiments were performed on three identical Elgin sandstone cores initially containing oil and connate water. The first core was flooded with ordinary water until no additional oil was produced. The residual oil saturation was 48.2%. The second core was flooded with a water solution having a viscosity substantially

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greater than that of water. The residual oil saturation was 22.2% of the oil originally in place. The third core was flooded with several pore volumes of ordinary water, and then flooded with several pore volumes of thickened water. This third experiment simulates the sequence of events that actually occurs when a petroleum-containing reservoir is flooded with viscous water using the techniques of the prior art. The water injected prior to the injection of thickened water had substantially the same effect as the bank of connate water which precedes the injected viscous water in actual practice. The residual oil saturation of the third core was 47.2%. This illustrates the profound effect of conditions at the oil-water interface on residual oil saturation.

This invention teaches a waterflooding process whereby it is possible to maintain water of the desired viscosity at a water-flood front at all times, thereby increasing oil recovery. Using this method, the first step is to inject a quantity of thickened water, usually between 0.1 and 1.0 pore volume, into the formation. This step in itself has very little effect on oil recovery; however, after a sufficient quantity of thickened water has been injected to establish a fairly wide band of thickened water, a slug of oil, preferably crude oil in an amount equal to 0.02-5.0% of the reservoir pore volume, is injected into the formation. The viscous water and the oil slug are then driven through the formation by the injection of ordinary water. When the leading edge of the oil slug reaches any given part of the formation, it reduces the water saturation to a low value and re-establishes continuity in the oil phase. The trailing edge of the oil slug forms a second flood-front, but the water at this second flood-front is the injected thickened water. The residual oil saturation after this second flood-front has passed will be lower than after either an ordinary water-flood or a water-flood using thickened water as taught by the prior art.

A more quantitative presentation of this invention is illustrated by the drawings, of which:

FIGURES 1 and 2 are graphs illustrating the flooding of a linear reservoir 100 ft. long, initially containing 750 bbl. of oil and 250 bbl. of connate water. FIGURES 1 and 2 are each divided into five charts labeled A to E, inclusive. Each chart depicts the conditions which exist in the reservoir at a selected interval during the flooding operation.

FIGURE 1 depicts the progress of the flood fronts established during a conventional water-flooding of the reservoir, and illustrates the build-up of a bank of connate water ahead of the advancing bank of injected water. FIGURE 1, chart A shows the initial conditions of oil and connate water distribution before water injection is begun. Charts B, C, D, and E of FIGURE 1 show the conditions after 100, 200, 300, and 400 bbl. of water have been injected, respectively. It can be seen that oil removed from the reservoir is initially replaced by a bank of connate water, and this bank of connate water increases in width as it is driven through the formation by the bank of injected water. The oil-to-connate-water flood-front 10 and the connate-water-to-injected-water flood-front 12 are shown in their respective positions in charts B to E, inclusive.

FIGURE 2 shows the flooding of this same reservoir using the process of this invention. In the example, 200 bbl. of viscous water is first injected. This is followed by the injection of 50 bbl. of crude oil, which is then driven through the formation by ordinary water. FIGURE 2, chart A, shows the fluid distribution in the formation immediately after the oil slug has been injected, and charts B to E show the fluid distributions after the injection of increasing amounts of injection water behind the oil slug. The oil-to-connate-water interface 20, the connate-water-to-viscous water interface 22, the viscous-

water-to-injected-oil interface 24, the injected-oil-to-viscous-water interface 26, and the viscous-water-to-injected-water interface 28 are shown in their respective positions after increasing amounts of water have been injected.

Referring to FIGURE 1 of the drawings, a subterranean reservoir initially contains 750 barrels of oil and 250 barrels of connate water. Such a reservoir is depicted in FIGURE 1A, it being understood that the connate water and oil are dispersed throughout the rock rather than existing in neat layers as depicted in the figure. The percentages of the various fluids in the formation are those shown in FIGURES A to E, inclusive, through the various stages in the flooding operation.

It has been established that materials injected into formation rock containing immiscible fluids, such as water and oil, will preferentially displace the fluid with which the injected material is miscible. Thus, when water is injected into a formation containing oil and connate water, the injected water will preferentially displace the connate water, and the connate water which coexists with the oil in the rock will displace a portion of the oil content of the rock. The remainder of the oil is retained in place, but the injected floodwater replaces connate water on a substantially 100% basis, leaving virtually no connate water in the formation behind the floodfront. Thus, when the reservoir depicted in FIGURE 1A is produced by the injection of water as shown in 1B, the connate water in the formation replaces a portion of the oil, driving the oil toward the producing well. As this replacement occurs, the percentage saturation of connate water in the reservoir rock ahead of the floodfront increases, since connate water is displacing oil. Thus, a bank of connate water builds up ahead of the interface 12 between the injected water and the connate water. There is a second interface 10 between the connate water and the oil which the connate water is replacing, but no interface between the injected water and the oil exists. As the injection process continues, the width of the bank of connate water behind interface 10 increases, due to the virtual 100% replacement of connate water by injected water.

Now, assume that the process depicted in FIGURE 1 is carried out by injecting viscous water instead of plain water. The oil is again replaced by the connate water with which it coexists, and a bank of connate water is built up ahead of the injected viscous water, which replaces the connate water with which it is soluble on a substantial 100% basis. Since the viscous water is not present at the oil-water interface, it is ineffective to prevent the fingering of the connate water through the oil or to substantially improve the oil recovery over that which would be obtained from the injection of plain water. The viscosity of the driving fluid has been increased, but the viscosity of the connate water has not been increased. Therefore, the mobility ratio between the oil and the fluid which displaces it has not been altered or improved.

Assume now that the condition of the reservoir is that depicted in FIGURE 1C, except that the injected water is viscous water. A slug of oil is now injected into the formation. Viscous water is displaced by the oil with which it coexists, the percentage saturation of oil near the injection zone is increased, so that the oil again becomes a predominant and continuous phase in the reservoir. At the termination of the oil slug injection step, a major portion of injected oil coexists with a minor portion of viscous water near the injection well. Farther out from the injection well, but behind the connate water bank, a major portion of viscous water coexists with a minor portion of reservoir oil. This condition is depicted in FIGURE 2A. The injection of plain water is then commenced. The injected oil and that oil initially contained by the reservoir and not replaced by the connate water is replaced by the viscous water with which it coexists, and thus a bank of viscous water builds up behind the mixed injected oil and residual oil initially present in the reservoir. Because the displacement of oil by viscous

water is more efficient than the displacement of oil by natural or connate water, the residual oil saturation of the oil reservoir is reduced to a lower percentage behind the oil-viscous water interface 26. The reason for the build-up of the bank of viscous water between the oil-viscous water interface 26 and the viscous water injected water interface 28 is the same as that which caused the build-up of a bank of connate water between the injected water and oil of FIGURE 1B. It is simply that the oil is displaced by the liquid with which it coexists rather than by the injected liquid. The injected water replaces the viscous water on a virtual 100% basis, and thus the thickness of the viscous water bank continually increases as the fluid progresses from the injection to the production wells.

Since the residual oil concentration behind the oil-viscous water interface 26 is lower than the residual oil concentration in the zone ahead of the injected oil slug, as a result of the higher replacement efficiency at the oil-viscous water interface, the width of the oil slug increases as it is driven through the reservoir. Thus, the leading edge of the oil slug advances at a more rapid rate than the trailing edge of the oil slug. Moreover, interface 22 between the connate water and the viscous water advances at a rate less rapid than that of the leading edge 24 of the oil slug, since it is the viscous water that is replacing the oil and the width of the band of viscous water behind the oil slug is continually increasing. Therefore, the leading edge 24 of the oil slug will catch and pass through interface 22 between the connate water and viscous water. This condition almost occurs in FIGURE 2D and has occurred in FIGURE 2E.

It is evident that if the quantity of viscous water injected were too small, or the flooding carried out over too great distances, the connate water-viscous water interface 22 will eventually fall behind the oil-viscous water interface 26. If this condition is permitted to occur, the oil at the point of replacement, the point surrounding interface 26, will coexist with connate water and be replaced thereby. If this occurs, the increased efficiency previously gained by the use of viscous water will no longer be obtained.

Inspection of these figures shows that the width of the oil slug increases as it progresses through the formation, due to the improved oil recovery at the second flood-front, that is, the oil-to-viscous-water flood-front 26. The rate of advance of the oil slug is greater than the rate of advance of the thickened-water zone. This is so because at the time injection of ordinary water is begun, the formation adjacent to the point of injection contains oil and thickened water. Just as a bank of connate water was built up ahead of the injected thickened water, a bank of thickened water is built up ahead of the last injected ordinary water. In each case the oil is replaced by the fluid with which it co-exists in the formation, and a bank of this co-existing fluid builds up between the displaced oil and the injected water. If the thickened-water zone had been much thinner, say only 150 bbl. of thickened water had been injected, the oil slug would have advanced completely out of the thickened-water zone. If this had happened, the second flood-front 26 would have become an oil-to-connate-water interface. Had this happened, no additional oil from that point in the formation onward would have been recovered since no oil-to-viscous-water interface would have continued to exist. This illustrates the criticality of the volume of thickened water injected.

For maximum oil recovery, the amount of viscous water injected must be large enough to insure that the viscous water is present at the second flood-front throughout the entire secondary recovery operation. The minimum volume of viscous water required is determined mainly by the amount of connate water present in the formation; the greater the connate water saturation, the larger the volume of thickened water must be. The residual oil saturations at both flood fronts also influences the volume

of thickened water which must be injected. Since these conditions vary from one oil-producing reservoir to another, it is best to determine these saturations from an examination of cores obtained from the formation to be flooded. The minimum volume of the viscous-water slug should be roughly equal to the volume of connate water originally in the field to be flooded. This volume can be determined by restored-state studies of cores from the field. In the example shown in FIGURES 1 and 2, the formation initially contained 250 bbl. connate water. It is seen in FIGURE 2, E that with the injection of 200 bbl. of viscous water, the injected-oil-viscous-water interface 26 had almost caught up to the viscous-water-connate-water interface 22. A viscous water slug of 250 bbl. would assure that this did not happen.

Agents suitable for thickening water for use in this process are described in the aforementioned patents and in Patent 2,827,964. The material specified in a copending application of George G. Bernard, Serial No. 732,455, is especially suitable as a thickening agent for use in this invention since it has several properties in addition to its viscosity-improving ability that would be useful in a water-flood operation. This preferred thickening agent is a material containing at least one compound from the group consisting of metal, ammonium, and substituted-ammonium salts of an aminopropionic acid in which a fatty radical has replaced one of the amino hydrogen atoms, and an especially preferred compound is sodium lauryl beta-aminopropionate. Three percent by weight of the last-named compound will produce a water solution having a viscosity of approximately 20 centipoises, when the pH of the solution is substantially neutral.

When a water solution of sodium lauryl beta-aminopropionate is acidified, the viscosity of the solution is reduced. Thus, a 3% by weight water solution acidified to a pH of 2 has a viscosity of only 2.4 centipoises. It is therefore possible to inject such an acidified solution into the formation more readily than the neutral solution could be injected. Calcium deposits typically existing in the reservoir will neutralize the acidity of the solution, which will return to its normal neutral viscosity of about 20 centipoises. In this way the energy expended in the injection process may be greatly reduced.

Sodium lauryl beta-aminopropionate is manufactured by General Mills Corporation and marketed under the tradename "Deriphats 170." Compounds of the aforementioned class are especially desirable as viscosity-improving agents in that they also have surface-active properties which are beneficial in increasing oil recovery.

In actual practice, some of the thickening agent might be adsorbed on the surfaces of the formation. Also, vari-

ations in permeability in the formation might exist which would tend to disperse the viscous-water zone. Both of these factors will probably be operating to unknown degrees in various parts of the formation, with the result that the exact size, shape, and location of the viscous-water zone is not known with any degree of certainty. Where such conditions exist, it is advisable to inject an appreciably larger slug of thickened water than the minimum amount calculated from core analysis data.

As specific examples, the conventional waterflooding illustrated in FIGURE 1 produces 450 bbl. of the 750 bbl. of oil originally contained in the reservoir, leaving 300 bbl. in the formation as residual oil. If, in accordance with this invention, 0.2 pore volume of 3% weight aqueous solution of Deriphats 170 and 0.05 pore volume of crude oil are injected before initiating the injection of plain floodwater, 600 bbl. of the original 750 bbl. of oil are produced, leaving 150 bbl. of residual oil in place.

What is claimed is:

1. A method for recovering petroleum from a natural underground reservoir, comprising injecting into the reservoir an aqueous fluid having a viscosity substantially greater than that of water but not so great as to prevent injection, in an amount in the range of about 0.1 to 1.0 reservoir pore volume, injecting a slug of oil behind said fluid in an amount in the range of about 0.0002 to 0.05 reservoir pore volume, injecting floodwater behind said oil slug, and producing petroleum from said reservoir.

2. A method according to claim 1 in which the viscosity of said fluid is not less than 10 centipoises.

3. A process according to claim 1 in which the oil slug is composed of lease oil.

4. A process according to claim 1 in which the aqueous fluid is an aqueous solution containing 1-5% by weight of at least one compound from the group consisting of metal, ammonium, and substituted-ammonium salts of an aminopropionic acid in which a fatty radical has replaced one of the amino hydrogen atoms.

5. A method according to claim 4 in which the compound is sodium lauryl beta-aminopropionate.

6. A method according to claim 1 in which the amount of aqueous fluid is about 0.2 reservoir pore volume, the viscosity of said fluid is about 20 centipoises, and the volume of said oil slug is about 0.05 reservoir pore volume, said slug being composed of lease oil.

References Cited in the file of this patent

UNITED STATES PATENTS

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2,827,964	Sandiford et al.	Mar. 25, 1958
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