Aug. 1, 1967 J. R. KYTE 3,333,632

ADDITIONAL OIL RECOVERY BY IMPROVED MISCIBLE DISPLACEMENT

Filed Feb. 27, 1963 4 Sheets-Sheet 1

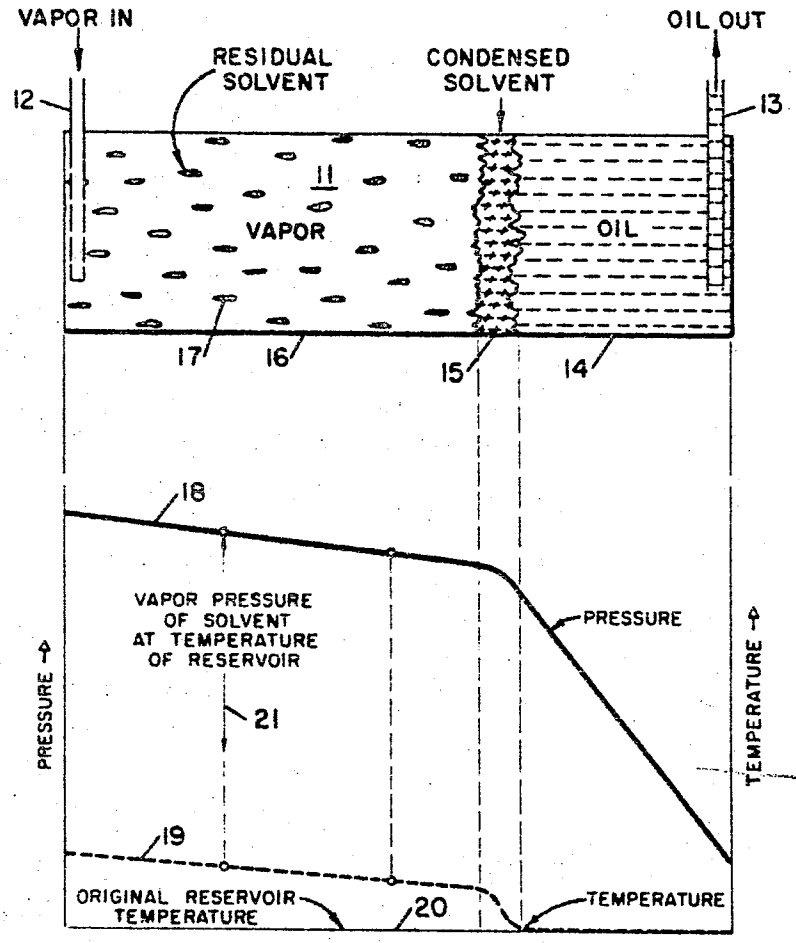


FIG. 1.

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ADDITIONAL OIL RECOVERY BY IMPROVED MISCIBLE DISPLACEMENT

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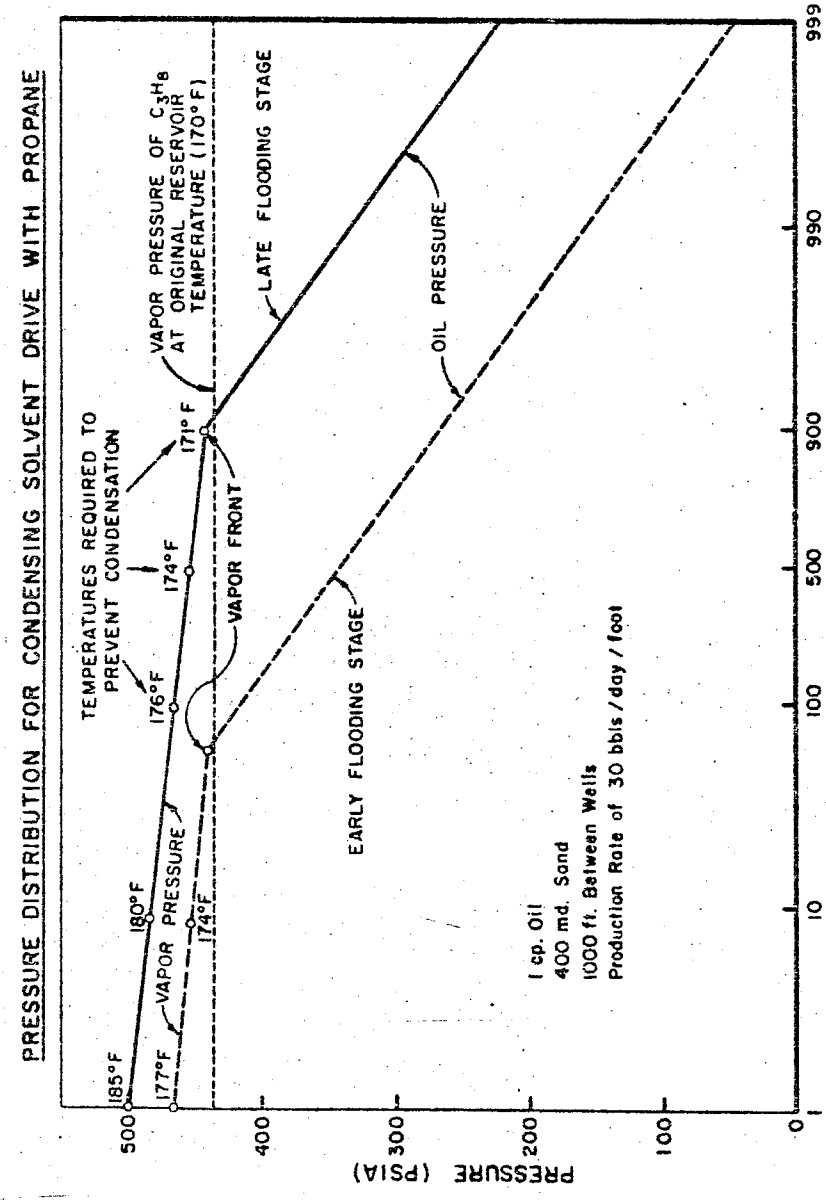


FIG. 2.

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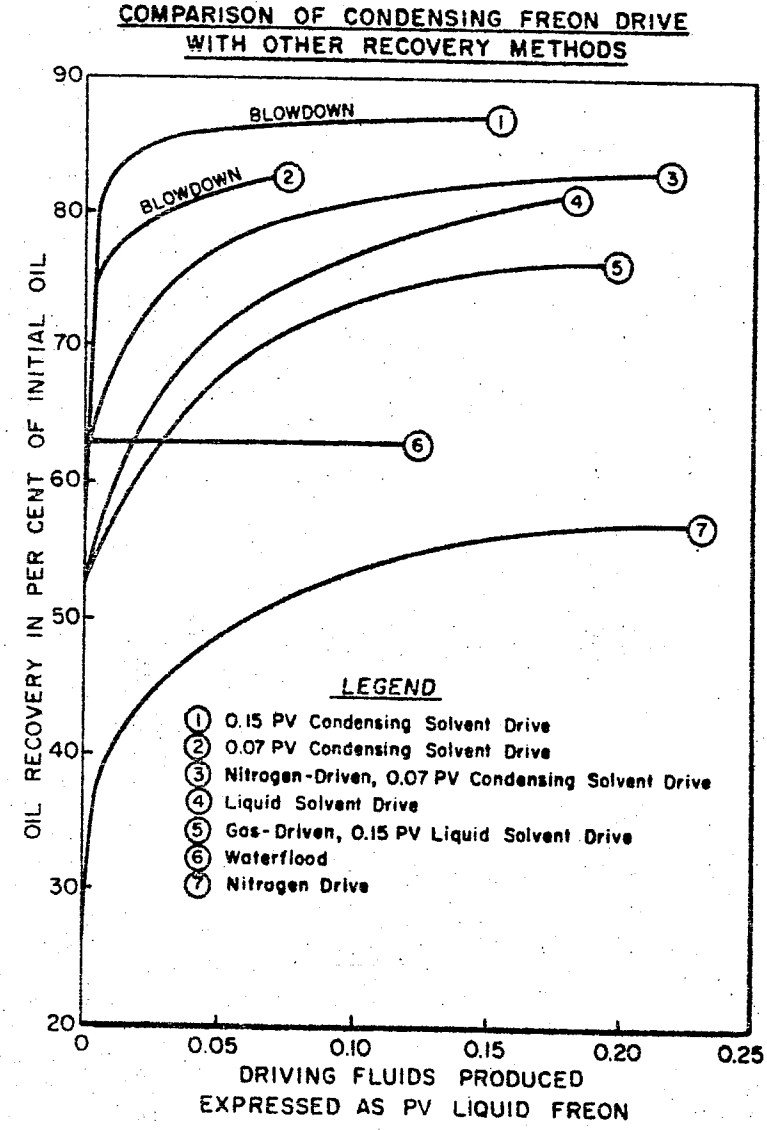


FIG. 3.

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COMPARISON OF CONDENSING PROPANE DRIVE WITH OTHER RECOVERY METHODS

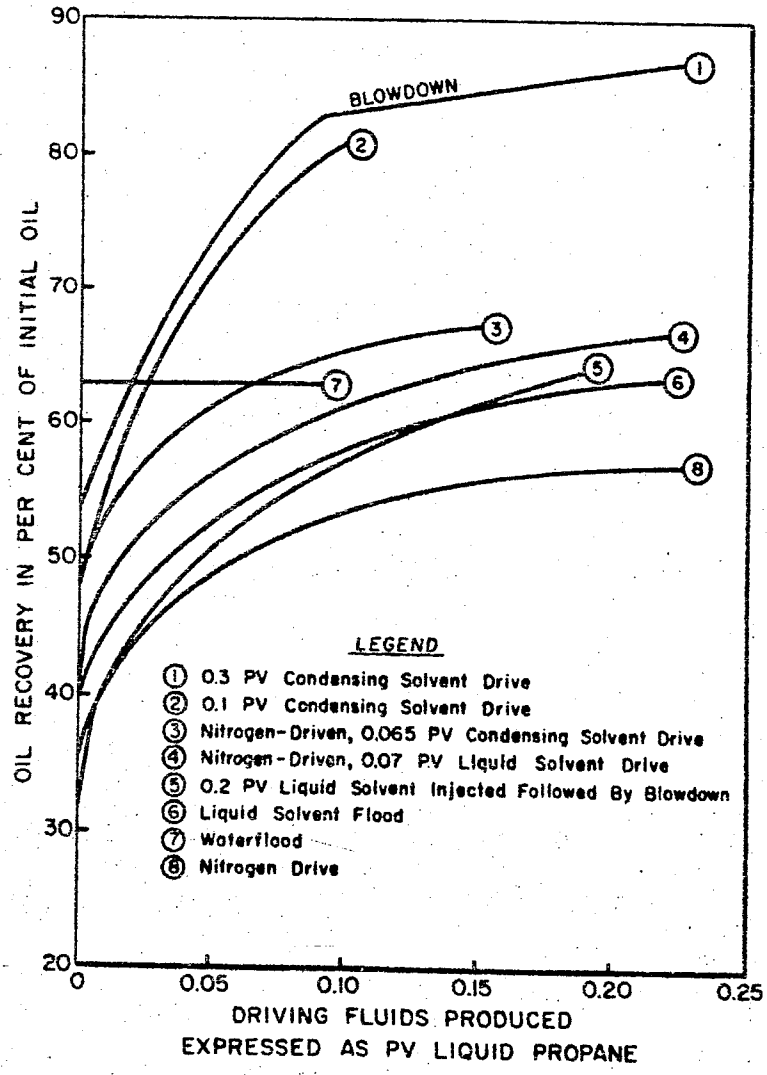


FIG. 4.

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ADDITIONAL OIL RECOVERY BY IMPROVED MISCIBLE DISPLACEMENT

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11 Claims. (Cl. 166—9)

The present invention is broadly concerned with an improved method for increasing the recovery of crude petroleum from subsurface reservoirs. More particularly the invention relates to the recovery of oil by an improved miscible displacement process which involves the injection of a solvent vapor which is readily condensable at reservoir conditions of temperature and pressure. Specifically, it is essential in accordance with the invention to select for injection a vapor which has a critical temperature higher than the reservoir temperature, and which also possesses a vapor pressure at reservoir temperature which is high enough to prevent excessive condensation. Other essential details of the process are explained below.

In the recovery of petroleum from natural reservoirs numerous methods have been proposed heretofore which involve the injection of a bank of miscible fluid which in turn is driven through the reservoir by various inert and inexpensive drive fluids, including for example, water or natural gas. It is well known that for various reasons such prior methods suffer certain disadvantages which prevent any substantial approach to that degree of success which, theoretically, can be achieved by miscible displacement. Typically, when a solvent bank is injected it demonstrates a tendency to finger or channel through the more viscous reservoir crude. Then, when an inert gas such as methane or natural gas is injected after the solvent it readily fingers through both the solvent bank and the reservoir oil. As a result the gas breaks through prematurely at the production wells, causing large volumes of gas and solvent to be produced with relatively unsatisfactory oil recovery. Because of the adverse viscosity ratio and gravity segregation, such processes frequently recover even less oil than conventional waterflooding techniques.

In accordance with the method of this invention a solvent bank is injected into the reservoir as a vapor. Initially, the vapor condenses in the vicinity of the injection wellbore, thereby forming a bank of liquid, condensed solvent. Once the release of latent heat from the condensing vapor has raised the local reservoir temperature sufficiently to prevent further condensation, the continued injection of solvent vapor displaces the liquid solvent bank, driving it progressively farther from the injection well. The reservoir oil is in turn displaced ahead of the condensed vapor bank.

Once the reservoir temperature behind the vapor front is raised a few degrees, the injected vapor is permitted to flow a great distance without appreciable transfer of heat to the reservoir, until the vapor passes through the heat front and contacts unheated reservoir. Essentially, the entire available heat content of the vapor is thereby preserved for delayed release at a time and place which most efficiently advances the heat front and replenishes the condensate bank, without progressively raising the reservoir temperature to higher and higher levels near the injection wells.

Preferred solvent vapors, suitable for injection in accordance with the method of this invention, include hydrogen sulfide, ammonia, propane, sulfur dioxide and sulfur trioxide. A particular solvent for use in flooding a given reservoir is selected to provide a vapor pressure at reservoir temperature of at least 50 p.s.i.a., and preferably at least 100 p.s.i.a. The critical temperature of the selected solvent must be higher than reservoir temperature in order to permit condensation and the release of latent heat. As a practical limit, the critical temperature should be at least 5° F. above reservoir temperature.

Particularly preferred solvent vapors are hydrogen sulfide and sulfur dioxide, because of the increased density imparted by these solvents to the reservoir crude at the transition zone between the leading bank of condensed vapor and the reservoir crude. In accordance with this embodiment, any vapor which may tend to override the reservoir crude will saturate the oil at the top of the formation. The solvent-containing reservoir crude is rendered more dense than the remaining reservoir oil. The dense mixture then flows downward from the force of gravity and will be replaced by undersaturated oil. Thus, any overriding tendency is corrected because the fresh undersaturated oil will converge upon any region of high vapor saturation near the top of the reservoir. This vertical mixing of solvent with oil greatly improves the displacement efficiency of the drive.

A mixture of a condensable solvent vapor with substantial volumes of "inert" or non-condensable gas is not suitable for the purpose of this invention. The injection of such a mixture, under properly controlled conditions of temperature and pressure, can lead to the formation of a condensed solvent bank. However, a critical distinction exists between the mixed gas-vapor system and the system of the present invention. In the mixed system the condensable portion of the gaseous phase is selectively condensed upon contacting unheated reservoir just ahead of the heat front. The non-condensable gas is then free to finger ahead of the condensate bank and create channels through which a portion of the gas-vapor mixture will flow. This results in a deterioration of the main solvent bank and inefficient displacement of reservoir oil.

A mixture of condensable vapors is suitable only when the condensing properties of the mixture are substantially the same as a single vapor; i.e., the separate vapors condense in the same proportion as their concentrations in the vapor. A mixture comprising substantial volumes of both propane and butane vapors is unsuitable, since butane would be selectively condensed, allowing the propane vapor to finger ahead in the same manner as a non-condensable gas. Propane and ammonia have nearly identical vapor pressures at temperatures between 20° and 40° C., and therefore form a suitable mixture. See the Chemical Engineers' Handbook, 2nd edition, pp. 2548 and 2549, John H. Perry, editor, McGraw-Hill Book Co., Inc., for a further disclosure of such mixtures.

It will be apparent to those skilled in the art that the fraction of injected vapor which condenses is an important variable in the process. This fraction will depend upon the physical properties of the solvent, upon the heat losses which occur in the reservoir, upon the temperature of vapor injection, and upon the pressure distribution in the reservoir between the input and production wells.

In the operation of a flood in accordance with the invention, it is desirable that the pore volume occupied by uncondensed vapor be at least as great as the volume occupied by the condensed, liquid solvent bank. Prefer-

ably, the ratio of vapor volume to condensed solvent volume should be at least 4 to 1.

Upon condensation at typical reservoir pressures, the injected vapor "shrinks" to a liquid volume only one-tenth to one-thirtieth of its vapor volume. Accordingly, if 90% of an injected vapor condenses, over the entire history of a flood, the remaining 10% of the vapor occupies a volume at least as great as the condensed portion. If only 50% of the vapor condenses, then the remaining vapor occupies a volume 10 to 30 times as great as the liquid bank. Therefore, in accordance with this invention, a flood is readily completed with a volume of solvent vapor equivalent to only one-tenth pore volume of liquid solvent, as demonstrated by the laboratory-scale examples which follow.

FIGURE 1 shows a vertical cross section of a reservoir subjected to the condensing vapor drive of the invention. Also, the pressure and temperature gradients established in the reservoir are illustrated graphically.

FIGURE 2 illustrates the pressure distributions established within a reservoir during an early flooding stage and a late flooding stage, when displacing reservoir oil with a condensing propane drive.

FIGURE 3 is a comparison of oil recoveries obtained with a condensing Freon drive versus other recovery methods.

FIGURE 4 is a similar comparison of a condensing propane drive with other recovery methods.

Referring again to FIGURE 1, reservoir 11 is penetrated by input wellbore 12 and production wellbore 13. An advanced flooding stage is illustrated, wherein reservoir oil 14 is being displaced by a bank of liquid solvent 15, which in turn is being driven by solvent vapor 16. Small volumes of condensed solvent 17 are formed behind bank 15, but only that amount necessary to balance heat losses from the formation.

Curve 18 indicates the pressure distribution between wells which corresponds to the flooding stage illustrated in reservoir 11. Note the relatively small pressure drop between the input well and the vapor front, compared with the sharp drop between the vapor front and the production well. A uniform reservoir permeability between wells is assumed. The break in curve 18 is due to the difference between the viscosities of the solvent vapor and the reservoir oil.

Curve 19 illustrates the temperature distribution established by vapor condensation between the input well and the leading portion of bank 15. The input vapor temperature is maintained at least 5° F., and preferably at least 15° F., above the initial reservoir temperature. Considerably higher input temperatures may be employed, but the excess sensible heat would be rapidly dissipated near the injection wells, without significant benefit to the process. Line 20 represents the original reservoir temperature. Behind the vapor front corresponding points on curves 18 and 19, such as joined by line 21, represent saturated vapor conditions. That is, the pressure is the vapor pressure characteristic of the solvent at the given temperature. In the vicinity of an injection well, some departure from this condition is desirable as a means of minimizing injectivity loss. A superheating of injection vapor will prevent any condensate from remaining near the injection wellbore to cause a reduced permeability to vapor.

The process is further illustrated by reference to FIGURE 2 which shows calculated pressure distributions within a reservoir for a condensing propane drive with injection and producing wells spaced one thousand feet apart in a four hundred millidarcy sand. The logarithmic scale of distances is based on adjacent radial flow systems, each having a radius of 500 ft. This approximates a conventional "five-spot pattern" of well spacing. The reservoir is assumed to be at 170° F. initially, and a constant oil production rate of 30 barrels per day per foot of sand is chosen as a convenient example. A higher production rate can be obtained, if desired, by increasing the temperature and pressure of the injected vapor. However, this would reduce the efficiency of the process by increasing heat losses.

Initially, saturated or slightly superheated propane vapor is injected at a temperature 15° above the reservoir temperature. As this vapor moves into the formation, it will be cooled and begin to condense. At the same time, the heat of condensation will warm the formation until condensation diminishes to only that amount necessary to balance heat lost by conduction to the earth above and below the oil-bearing formation. In this manner a heat bank is moved outward from the injection well. Most of the injected vapor flows through the heated region without condensing until it contacts cooler regions of the reservoir at the front of the heat bank. Thus a condensing solvent bank is maintained at the heat front, as shown in FIGURE 1.

The temperatures associated with the pressures in the vapor bank are shown on the pressure distribution curve for an early flooding stage and for a late flooding stage. That fraction of the reservoir which lies between one hundred and nine hundred feet from the injection well must be heated only about 1° to 6° F. above the initial reservoir temperature. Since this represents about 96% of the reservoir volume, heat lost from the formation will be very small as compared with conventional heat bank processes in which temperature differentials are sometimes as great as several hundred degrees.

During the initial stages of a flood, there is of course no benefit to be obtained from the maintenance of a back-pressure at production wells. During the latter stages of a flood, however, back-pressure at production wells is usually desirable to maintain the necessary pressure for condensation at the vapor front. In FIGURE 2 the back-pressure maintained at the production well is indicated by the point of intersection of each pressure curve with the right-hand margin of the chart. As indicated, the back-pressure required to provide a constant production rate of 30 barrels per day per foot of reservoir sand becomes progressively greater during the latter stages of a flood.

The injected solvent is readily recoverable, upon termination of the drive, by reducing the pressure at the production and/or injection wells. Preferably, this "blow-down" stage of the process is begun when the produced oil is found to contain substantial volumes of solvent.

A principal advantage of the present method over the conventional gas-driven solvent bank is the virtual elimination of the normal tendency for a gas to finger or channel through the reservoir. This is readily accomplished since vapor fingers will be condensed once they contact unheated portions of the reservoir ahead of the main vapor bank. Although a finger may eventually form after sufficient condensation has occurred to create a hot spot in the reservoir the fingering tendency is nevertheless opposed by heat transfer considerations. Since heat will be transferred from the hot spot to the surrounding cooler portions of the reservoir, excess condensation will occur where the fingers do form thereby correcting the initial tendency. At the same time the rock in the vicinity of the fingers will be preheated by this condensation so that the main vapor bank will continue to travel through these regions at higher than average velocity and with less than the average amount of condensation. Stated otherwise heat transfer from hot spots will minimize the propagation of vapor fingers which are so detrimental to the conventional gas-driven solvent flood.

Laboratory tests were conducted to illustrate the benefits of a condensing solvent vapor drive. These tests were performed in a 13-inch Weiler sandstone core having a diameter of about 2 inches. The permeability of the core was about 100 millidarcies and the oil viscosity was 1.3 centipoises. The tests were performed using Freon (dichlorodifluoromethane) as the condensing solvent drive. Its gas and liquid viscosities are 0.012 and 0.26 centipoise,

respectively, and it has a density of about 80 pounds per cubic foot. These values are almost identical with the viscosities and densities of sulfur dioxide.

FIGURE 3 shows a comparison of a condensing Freon drive with other recovery methods. Oil recovery in percent of original oil in place is plotted against the quantity of driving fluid produced. The latter parameter is expressed as pore volume of liquid Freon. For example, in the nitrogen gas drive the volume of nitrogen produced at atmospheric conditions was assumed to be Freon vapor; then computations were made to convert this vapor to Freon liquid at room temperature. Admittedly, this represents an arbitrary simplification of the data, but for a comparison of the various recovery methods this treatment of the data is valid on a semi-quantitative basis.

The uppermost curve in FIGURE 3 shows the recovery for a condensing Freon drive in which the total amount of Freon vapor injected was equivalent to 0.15 pore volume of liquid. In this experiment the inlet end of the metal-mounted core was heated to 100° F. and the outlet end was held at 72° F. At these temperatures the saturated vapor presure of Freon is 117 and 73 p.s.i.g., respectively. Freon vapor was introduced into the core at 100 p.s.i.g. and 100° F. with a back-pressure of 73 p.s.i.g. imposed at the outlet end. Thus the Freon vapor was slightly superheated at the core inlet.

Heating of the core is a necessary control feature in these laboratory experiments because of the difficulty of simulating reservoir conditions with insulation alone as a means of reducing heat loss. The large heat capacity of the metal surrounding the core would otherwise cause all the Freon vapor to condense. Heating of the core to establish a temperature gradient along its length does, in effect, satisfactorily simulate reservoir conditions.

In the above tests, 87 percent of the original oil in place was recevored using a total amount of Freon equivalent to 0.15 pore volume of liquid Freon. Of particular interest is the high recovery (80 percent of the original oil in place) obtained with the production of only 0.005 pore volume of solvent. When compared with other solvent methods of oil recovery for this core, this demonstrates that the condensing solvent drive of the present invention is by far the most efficient.

Another condensing Freon drive was performed using a volume of solvent vapor equivalent to only 0.07 pore volume of liquid. As seen from FIGURE 3 the condensing drive using a total of only 0.07 pore volume of liquid Freon is almost as efficient as the test where 0.15 pore volume was injected. This experiment was performed in the same manner as the first test with the exception of injecting less vapor, as indicated, and with the further modification of maintaining a back-pressure on the core 4 p.s.i. lower than in the first test, to reduce the amount of condensation.

A third condensing Freon drive was conducted, involving an interruption of Freon injection followed by nitrogen injection after about 35 to 40 percent of the original oil in place had been produced. In this manner it was sought to determine whether the condensing solvent system, once established, could be driven through the remainder of the reservoir with the injection of an inert gas. As seen from FIGURE 3 this was the least efficient of the three condensing solvent drives tested. Nevertheless, even this modification is an improvement over prior miscible displacement processes, and is therefore considered to be an inventive embodiment.

Similarly, once the condensing vapor drive is established and a substantial proportion of the original oil in place has been produced, it is possible to follow the solvent vapor with other conventional flood media, although not necessarily with equivalent results. For example, the condensing vapor system may be followed by the injection of hot water, cold water, natural gas, air or steam.

From FIGURE 3 it is seen that the recovery characteristic of the condensing solvent drives is significantly better than either a straight solvent flood or a gas-driven solvent bank. In the straight solvent flood it should be remembered that the core contains liquid solvent; thus the amount of Freon required to recover 81 percent of the original oil in place would be about 0.75 pore volume as contrasted with 0.07 or 0.15 pore volume used in the condensing vapor drive of the invention.

FIGURE 4 shows laboratory test data for propane similar to the results shown for Freon in FIGURE 3. Qualitatively, results for the propane are the same as with Freon. Eighty-nine percent of the original oil in place was recovered by a condensing vapor drive using a volume of propane vapor equivalent to about 0.3 pore volume of liquid. Eighty-one percent of the original oil in place was recovered using a total of 0.1 pore volume propane. The liquid propane drive and the gas driven propane bank are much less efficient.

Referring again to FIGURE 3, the condensing Freon drive does show a marked increase in oil recovery over waterflooding. Moreover, and equally important, high recovery is obtained with very little production of the driving fluid. The reason for this increase in recovery of Freon compared with propane is undoubtedly due to the difference in fluid viscosities of the two materials.

While various embodiments of the invention have been specifically described, other modifications will occur to those skilled in the art, without departing from the spirit of the invention. Accordingly, it is contemplated that no limitation be placed on the scope of the invention, other than as recited in the appended claims.

What is claimed is:

1. A method for increasing the recovery of oil from a porous sub-surface reservoir penetrated by an injection well and a production well which comprises introducing into said reservoir through said injection well a condensable solvent vapor selected from the group consisting of hydrogen sulfide, sulfur dioxide, ammonia, and sulfur trioxide, under conditions of temperature and pressure which cause a partial condensation of the injected vapor upon its approach to thermal equilibrium with the reservoir, thereby forming an oil miscible condensate bank; driving the resulting condensate bank through the reservoir by continuing to inject said condensable vapor stream under conditions of temperature and pressure which establish and maintain a vapor bank having a volume at least as great as the volume of the condensate bank; and producing reservoir oil from said production well.

2. A method as defined by claim 1 wherein said condensable vapor comprises hydrogen sulfide.

3. A method as defined by claim 1 wherein said condensable vapor comprises sulfur dioxide.

4. A method as defined by claim 1 wherein said condensable vapor comprises ammonia.

5. A method as defined by claim 1 wherein said condensible vapor comprises sulfur trioxide.

6. A method for increasing the recovery of oil from a porous surface reservoir penetrated by an injection well and a production well which comprises introducing into said reservoir through said injection well a displacing medium consisting essentially of a single condensable solvent vapor, under conditions of temperature and pressure to cause only a partial condensation of the injected medium upon its approach to thermal equilibrium with the reservoir, thereby forming an oil-miscible condensate bank, driving the resulting condensate toward said production well by continuing to inject said condensable vapor stream, thereafter injecting into the reservoir through said injection well a fluid selected from the group consisting of hot water, cold water, natural gas, air and steam, and producing reservoir oil from said production well.

7. A method as defined by claim 6 wherein said fluid comprises hot water.

8. A method as defined by claim 6 wherein said fluid comprises cold water.

9. A method as defined by claim 6 wherein said fluid comprises natural gas.

10. A method as defined by claim 6 wherein said fluid comprises air.

11. A method as defined by claim 6 wherein said fluid comprises steam.

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