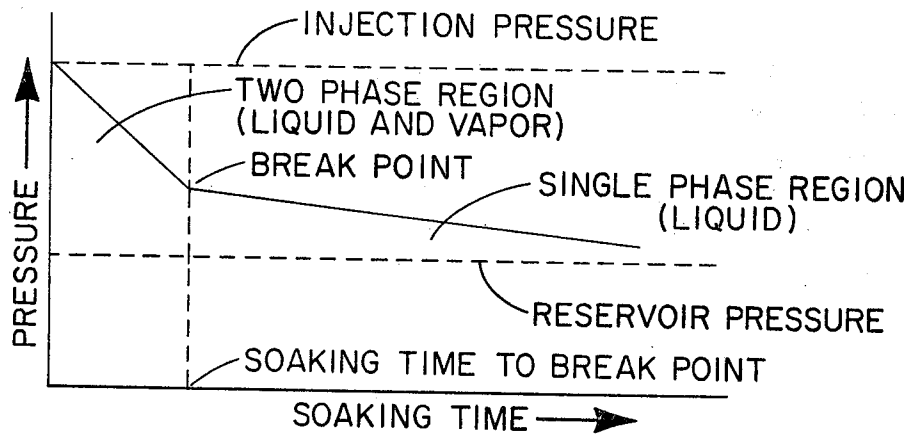


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METHOD FOR CONDUCTING CYCLIC STEAM INJECTION
IN RECOVERY OF HYDROCARBONS
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METHOD FOR CONDUCTING CYCLIC STEAM INJECTION IN RECOVERY OF HYDROCARBONS

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3 Claims

ABSTRACT OF THE DISCLOSURE

In the cyclic method of steam stimulation of an oil well steam is injected for a period of from several days to several weeks, then stopped and usually after a time—generally a few days—during which the steam is allowed to diffuse through the formation, the well is produced. There is considerable uncertainty in the art as to how long this soak period should be to secure efficient production. Too short a period of soaking is wasteful, much of the injected heat is lost in the initial production of live steam. Too long a soaking period allows the temperature to drop too low to obtain any value from oil viscosity reduction. The process described teaches a means for a definite determination of conditions under which both maximum heat utilization and oil recovery can be obtained.

SPECIFICATION

The present invention relates to the recovery of petroleum from deposits thereof by thermal means. More particularly, it is concerned with, but not necessarily limited to, the recovery of petroleum having an API gravity of not more than about 25°, i.e., hereafter referred to as heavy oil, by steam injection under circumstances such that the steam not only serves as a driving force to cause the oil to flow into the producing well, but to lower the viscosity of the oil over a substantial portion of the formation, thus aiding in increased production over a shortened period of time. The invention is especially concerned with the procurement of maximum utilization of heat introduced into the reservoir in the form of steam by careful control of the period injected steam is permitted to soak or remain in the oil-bearing formation.

BACKGROUND OF THE INVENTION

In many areas of the world large deposits of petroleum exist which, because of their relatively low gravity, either cannot be produced or can only be produced inefficiently by conventional methods. Such deposits include the Athabasca tar sands in Canada, low gravity crudes in the Jobo Field in Venezuela, and similar crudes in Western Missouri, Eastern Kansas and Southern Oklahoma. The application of thermal energy to such deposits in the form of the huff and puff or steam soak process to reduce the viscosity of the oil therein constitutes of the most significant advances in the history of secondary recovery. In addition to accelerating oil production which would have been produced at a much slower rate by primary methods, this production technique makes it possible to produce heavy crude oils previously considered unrecoverable by present conventional production practices.

The huff and puff or cyclic steam process is an individual well stimulation method which includes a steam injection cycle, a soaking period the length of which prior to the present invention has been the subject of considerable controversy. As ordinarily applied, the huff and puff technique is a well stimulation process in which the bulk of the oil in the reservoir is not affected by the injected steam. As the heated region surrounding the steam injection well cools with time, the stimulation effect declines. As the oil

viscosity increases, the well is then re-stimulated by successive steam injection and soaking cycles. The generally satisfactory and sometimes spectacular results achieved in the past in a number of steam soak projects has greatly intensified interest in this form of secondary recovery.

Many pilot projects as well as commercial operations are in progress in the Mid-Continent and Rocky Mountain areas and in several areas in Texas. The greatest concentration of steam-soak projects is in the heavy oil fields of California where large volumes of heavy oil (11°–20° API) in thick pay zones at shallow depths are left in place by present conventional producing methods. Production from over 257 steam projects is about 90,000–100,000 barrels per day.

The basis for the effectiveness of steam injection in changing the fluid properties is the sensitivity to heat of viscous low API gravity crude oils. A relatively small increase in reservoir temperature results in a substantial decrease in viscosity. As a result of the lowered viscosity, the pressure drop required for production is decreased and the oil flows more freely into the well.

A typical low API gravity crude oil having a viscosity of 2,000 cp. at 125° F. has a viscosity of only 35± cp. at 250° F. If the temperature of the oil is increased to 450° F., the viscosity is reduced to 2.5± cp. or a reduction ratio of 800 to 1. The temperature obtainable during steam injection in producing sands is directly related to the injection pressure. At an injection pressure of 450 p.s.i.a., the corresponding steam temperature is 456° F. and the viscosity is 2.5± cp. Bottom hole temperature at termination of the steam injection cycle usually varies between 350° F. and 450° F. indicating that this temperature is easily obtained.

Because of its high heat content per pound, steam is ideal for raising the temperature of the reservoir. Saturated steam at 350° F. contains 1,192 B.t.u. per pound compared with water at 350° F. which has only 322 B.t.u. per pound or only about one-fourth as much as steam. The big difference in heat content between the liquid and the steam phases is the latent heat or heat of evaporation. Thus, the amount of heat that is released when steam condenses is very large. Because of this latent heat, oil reservoirs can be heated much more effectively by steam than by either hot liquids or non-condensable gases.

Steam may be injected into tubing or annulus depending on capacity of the steam system and type of well completion. Ordinarily, steam is injected either through the casing or through the tubing with a packer set between tubing and casing above the pay. With the latter arrangement, heat losses, increases in casing temperature and resulting thermal stresses are minimized. The injection period varies between five and fourteen days, depending on the permeability of the reservoir and the boiler capacity. Because of the many variables involved, treatment time is often determined through experience in a particular field.

Since the rate of production after steam injection is a function of the oil viscosity, best results are obtained when the maximum amount of heat is injected in the shortest time. It is highly desirable, therefore, to inject steam into the reservoir at the highest temperature attainable to shorten the injection cycle and reduce heat losses in the well bore.

Following the injection period the well is shut in for an average soak time of one week (three to twelve days) and then returned to production. The initial production period varies widely from one to six or seven months. The second, third and subsequent steam injection cycles are started when the production declines to an uneconomic rate.

In spite of the rather extensive application of the huff and puff technique little seems to be known regarding the

length of the soaking period that should be employed for efficient operation of the process. Some investigators feel that the well should not be produced immediately after steam injection since a considerable amount of heat will be lost in the form of initial production of steam from the hot well. The soaking time is necessary to permit the reservoir rock and fluids to reach a thermal and hydrodynamic equilibrium, thus affecting a larger portion of the well's drainage area. Other workers in this field are of the opinion that a stimulated well should be placed on production as soon as possible after the steam injection step, if not immediately after steam injection, in order to take advantage of the high productivity even though it may be of relatively short duration.

Extended soaking periods are considered harmful since they tend to lower the temperature of the heated zone to a level such that the general benefit from reduction in oil viscosity is not realized.

SUMMARY OF THE INVENTION AND DESCRIPTION OF THE DRAWING

The accompanying drawing is a diagrammatic representation illustrating the variation in rate of formation pressure decline with steam soaking time.

After the steam injection step, the heated zone around the well bore contains a portion of the injected steam as vapor. If the well is given time to soak, the steam is condensed into saturated water because of the heat losses primarily due to heat conduction into the surrounding non oil-bearing formations or into the relatively low permeable portion of the formation. As steam condenses a void is created resulting in re-saturation of the heated zone by oil and water flowing from the hot liquid bank immediately surrounding the heated zone. Thereafter the pressure difference between the heated zone and the rest of the reservoir causes the liquids in the heated portion to move slowly into the rest of the reservoir resulting in a reduced rate of decrease in pressure as shown in the accompanying drawing illustrating the effect of soaking time on pressure. Thus it is seen during the first portion of the soaking period the well bore pressure decreases at a relatively rapid rate. During this time both liquid and vapor (steam) are in the immediate vicinity of the well bore. As complete condensation of the steam in the reservoir is approached, the rate of pressure decrease becomes substantially less. This point at which the system changes from a two-phase liquid-steam condition to a completely liquid state is defined and referred to hereinafter as the "break-point." At this point in time, in accordance with our invention, the well is placed on production and continued until the production rate becomes uneconomic. This cycle may then be repeated until the reservoir reaches a level of practical depletion.

The accompanying drawing shows that when steam is injected into a well and then into the formation after which the well is shut in, the pressure decreases at a relatively rapid rate while the system contains both liquid and vapor phases. However, when the rate of pressure decline decreases, such conditions indicates the existence of a liquid single phase system. It is at the occurrence of the single liquid phase that the well should be opened to production. This provides maximum diffusion of heat through the oil bearing formation and the maximum production of steam as a driving agent for the oil when the well is placed on production. In the drawing, below the pressure decline curve and to the left of the vertical dotted line, there exists a two phase liquid-vapor region. To the right of the aforesaid dotted line and below the pressure decline curve, a single phase liquid region exists. When the latter is determined, it signifies that the break point has been reached and that the well should be placed on production as soon as possible for maximum benefit.

The period of time required before the above men-

tioned break-point is reached depends on a number of variables. One factor is the quantity of steam injected. The steam initially introduced tends to condense rapidly since it contacts reservoir rock which is at a temperature substantially less than that of the steam and hence does not figure directly in the steam pressure existing at the time the well is shut in. Also, the rate at which steam is injected is important. At the higher injection rates heat losses are less and therefore the desired pressures can be reached more rapidly. Typical injection conditions are 6,000 to 20,000 lbs. of steam per hour at pressures of 250 to 2500 p.s.i. The depth at which steam is injected is still another important factor in determining the occurrence of the break-point since the greater the depth the greater is the quantity of steam that condenses before it enters the formation at the desired level. Likewise the thickness of the pay involved is important because as the thickness of the zone of interest decreases the faster the heat losses increase. For this reason the minimum thickness of the pay zone in which the process of our invention should be carried out is about 25 ft.

It has been our experience that in one-well cyclic (huff and puff) steam injecting operations even after a period of several days' soaking time, mostly steam and hot water are produced for a number of days resulting in a needless waste of heat. When such wells finally show a peak oil production rate the fluids are produced at very high temperatures causing removal of valuable heat from the reservoir itself. Heavy oil viscosities are drastically reduced when heated to 300° to 400° F. beyond which viscosity reduction is not significant. In many huff and puff steam stimulations, steam is injected at above 500° F. In those cases, although a long soaking time can reduce the temperature around the well bore, the temperature may still be high enough to yield a significant rate increase due to viscosity reduction. A longer soaking time ensures not only condensation of all the injected steam, but also effects a larger (than at the time of termination of steam injection) portion of the well's drainage radius causing such portion to have a substantially increased temperature. A larger heated area results in a higher increase in oil production rate.

The process of our invention will be further illustrated by the following specific example:

Example

Saturated steam at 55° F. (1045 p.s.i.a.) was introduced into a thousand foot well penetrating a fifty foot thick heavy oil bearing section at a depth of 975 feet. The steam injection rate was 22.5 million B.t.u.'s per hour. This rate was maintained for 110 hours resulting in a total heat injection during this period of 2.5 billion B.t.u.'s or 50 million B.t.u.'s per foot of oil bearing formation thickness. On completion of the steam injection step, the well was shut in and the injected heat allowed to diffuse out into the formation. At the time the heat soaking period was initiated, the registered well head pressure was slightly in excess of 1000 p.s.i.a. However, this pressure was observed to decline at a relatively rapid rate for the first 35 hours after soaking began, following which the pressure decline rate decreased very substantially as may be seen from the following table:

TABLE

Well head pressure, p.s.i.a.:	Time, hours
1040	0
930	10
820	20
720	30
660	35
650	40
640	50
630	60
625	70
620	80

From the above data it will be seen that the "break-point" occurred, or the rate of pressure decline became substantially less, at about 35 hours after the steam soaking interval started. While it is not always possible to place the well back on production exactly at the break-point, it is apparent from the above information that when the pressure decline rate shows a substantial decrease, the break-point has been reached. The results reported above show that this well should be placed on production by no latter than the fortieth hour after initiation of steam soaking.

By practicing the process of our invention as described immediately above, maximum benefit of the steam is secured in reducing the viscosity of the largest volume of heavy oil in the shortest period of time. Otherwise stated, the use of our invention reduces to a minimum lost production time resulting from steam soaking. Thus by our process useful heat is neither wasted by returning the well prematurely to production after steam injection nor is the heat dissipated throughout the reservoir to such an extent that little, if any, steam drive is available when the well is again placed on production.

From the foregoing description it will be seen that a number of advantages are afforded by conducting steam injection operations in accordance with our invention. Thus, when following our teachings all of the injected steam condenses giving up its heat to the reservoir. Secondly, the relatively low permeable sections of the pay which may not have taken an appreciable amount of steam during the steam injection phase can be heated due to heat conduction during the time of soak. This results in an overall favorable conformance as far as heat distribution is concerned. Finally, when the well is put on production time resulting from steam soaking. Thus can be flashed into vapor due to decrease in pressure. For example, the volume of saturated water at 1,000 p.s.i. may be increased by a factor of 57 if the pressure is reduced to 100 p.s.i. The increase in volume owing to flashing is primarily a function of the initial pressure and the final flashed pressure. What is important is that oil is displaced by the flashed vapor similar to the mechanism of oil displacement by solution gas drive. This type of gas drive process is quite beneficial especially in recovering a portion of the oil in the relatively low permeable sections of the pay. If soaking is not provided, oil recovery from the low permeable sections is not as efficient.

It is desirable that pressure and temperature measuring devices be placed in the bottom of the well and the pressure and temperature recorded during the soaking period. Without these bottom hole devices the pressure and temperature at the well head can be monitored and the well put on production when the break-point is reached as explained above.

We claim:

1. In a method for the recovery of petroleum from an underground deposit by thermal means, said deposit being penetrated by a well wherein steam is injected into said deposit via said well until the amount of heat thus introduced corresponds to from about 10 million to about 100 million B.t.u.'s per foot of oil-bearing formation, thereafter shutting in said well to permit the resulting heat to diffuse away from said well and into said deposit, allowing said steam to condense in said deposit while said well is shut in and reducing the pressure on said deposit by producing the fluids in said deposit via said well, the improvement which comprises maintaining said well shut in until the system changes from a two-phase liquid-steam condition to a substantially completely liquid state at which change the break-point is reached, immediately thereafter placing said well on production, and continuing until further production becomes uneconomical, said break-point being defined as a point on a curve resulting from plotting the formation pressure against steam soaking time and being further defined as that point in time at which the rate of formation pressure decline becomes substantially less.

2. The method of claim 1 wherein the steam injection rate ranges from about 6,000 to about 20,000 pounds per hour and said deposit is a continuous hydrocarbon-bearing formation at least 25 feet in thickness.

3. The method of claim 1 wherein said deposit contains a zone of relatively low permeability whereby heat is transferred to said zone by conduction and after placing said well on production the connate water in said zone flashes into steam thereby serving to force oil of reduced viscosity toward said well.

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JAMES A. LEPPINK, *Primary Examiner*.

UNITED STATES PATENT OFFICE
CERTIFICATE OF CORRECTION

Patent No. 3,434,544

March 25, 1969

Abdus Satter et al.

It is certified that error appears in the above identified patent and that said Letters Patent are hereby corrected as shown below:

Column 1, line 57, after "constitutes" insert -- one --. Column 2, line 63, "wall" should read -- well --. Column 3, line 60, "conditions" should read -- condition --. Column 4, line 38, "effects" should read -- affects --. Column 5, line 10, "latter" should read -- later --; line 34, cancel "time resulting from steam soaking. Thus" and insert -- a portion of the hot water in the heated zone --.

Signed and sealed this 7th day of April 1970.

(SEAL)

Attest:

Edward M. Fletcher, Jr.

Attesting Officer

WILLIAM E. SCHUYLER, JR.

Commissioner of Patents