AVERAGE TEMPERATURE INCREASE OVER INITIAL RESERVOIR TEMPERATURE AND CORRESPONDING WATER VAPOR PRESSURE

\[ T_0 = 130^\circ F \]

FIG. 2

THOMAS C. BOBERG INVENTOR.

BY Larry C. Honeycutt
AGENT
THERMAL WELL STIMULATION METHOD

Thomas C. Boberg, Houston, Tex., assignor to Esso Production Research Company, Houston, Tex., a corporation of Delaware

Continuation of application Ser. No. 178,399, Mar. 8, 1962. This application June 7, 1966, Ser. No. 562,415 13 Claims. (Cl. 166—40)

This application is a continuation of application Serial No. 178,399 of Thomas C. Boberg, filed March 8, 1962, and now abandoned.

This invention relates to the recovery of relatively viscous petroleum from porous underground reservoirs. A method of thermal stimulation is provided for increasing the rate of petroleum recovery from a producing well. Specifically, the invention involves the steps of injecting steam into an oil-producing formation, thereafter backflowing and producing steam condensate under a controlled back-pressure maintained to avoid re-vaporization of the condensate, and then resuming production of oil from the formation. After a relatively prolonged period of production at stimulated rates the well is again subjected to the steaming treatment.

A subterranean oil reservoir in the initial phase of its producing life generally produces oil as a result of natural pressure, rock pressure or water pressure. Thus, when a well first penetrates the reservoir the innate pressure drives oil from the reservoir to the wellbore and thence to the earth's surface. A pump is frequently used to aid in the removal of oil from the wellbore, and to reduce the back-pressure on the formation. This phase of the producing history of an oil well is generally referred to as its primary production phase or period. The method of this invention is applicable to stimulate primary production and is to be distinguished in this regard from so-called "secondary recovery" techniques.

However, this distinction is not to be construed as limiting the invention solely to the stimulation of primary production. Although the method is not itself a secondary recovery operation, it does have application in combination with prior art methods of secondary recovery which involve the generation of an artificial drive mechanism, such as wherein the art is to increase the water injection rate or otherwise to increase the effective driving force of the fluid in the reservoir. Accordingly, the terms "producing well," "producing oil well" and "oil-producing formation" as used in this disclosure are intended to denote any oil well or oil-bearing formation from which oil is readily producible and is being produced by some existing pressure drive mechanism, whether natural or artificial, independently of the present invention.

The invention is primarily a method of thermal stimulation. That is, heat is introduced into the oil reservoir for the purpose of reducing the viscosity of the oil, thereby facilitating flow of the oil into the wellbore and thence to the earth's surface either under natural pressure or by pumping. In a broad sense it has been recognized in the prior art that the introduction of heat into the wellbore facilitates the flow and production of viscous oil. Accordingly, various down-hole heaters have been developed to provide thermal stimulation. However, such methods have been found inadequate because of the extremely slow rate of heat transfer outward from the wellbore.

Also, the direct injection of steam has been resorted to in the past; but only when dealing with specific "problem reservoirs" wherein pressure drives were wholly lacking, or when underwater injection was used. In the former case, the reservoir were solid or semi-solid to the point of being completely immobile within the reservoir, such as in the case of the Athabasca tar sands along the Athabasca River of Alberta, Canada. An essential limitation, however, on such prior art methods of steam injection is of the step of concurrently producing oil from a region of the reservoir which is spaced from the region of steam injection. In essence, therefore, the prior art methods which involve steam injection are intended primarily to generate an artificial drive mechanism. An inherent defect in the efficiency of such processes arises from the lateral spacing of the output well from the injection well. That is, any thermal stimulation achieved by such methods is largely spent at the input bore where it is essentially ineffective until steam reaches the vicinity of the output well.

A modification of such prior procedures involves the use of a single wellbore with the injection of steam at one level and the simultaneous production of oil from a different level. This single well approach, however, suffers the disadvantage of short-circuiting or by-passing of the steam directly from the input level to the output level without producing appreciable quantities of petroleum.

It has now been found that thermal stimulation by direct steam injection without simultaneous production either from a spaced output well or from a different level within the same wellbore overcomes the above disadvantages of prior art steam injection methods and is at the same time a most efficient method of imparting heat to the formation. In accordance with the invention, steam is injected into a producing oil well at a pressure which exceeds the oil-bearing formation pressure to the extent required to drive steam into the formation and heat that portion of the reservoir which extends radially a distance of at least one foot and up to 150 feet from the wellbore, preferably to 10 to 50 feet. From the standpoint of heat-efficiency and economy, the injection period must be completed as soon as possible. Accordingly, steam injection pressures are typically limited only by the capacity of available equipment. Suitable pressures range from 100 to 5,000 p.s.i.g., with 500 to 1,500 p.s.i.g. being usually preferred, depending upon the depth and permeability of the formation.

The stated range of injection pressures extends above the critical pressure of steam, requiring temperatures above the critical temperature, which is about 707°C. Accordingly, some mild cracking of hydrocarbons may occur. This is by no means detrimental, but is instead an additional benefit derived from the invention.

It will be recognized that the higher portion of the above pressure range may lead to fracturing of the oil-producing formation. Horizontal fracturing gives an added benefit to the method, as it accelerates the input of heat to the formation. However, vertical fracturing is likely to cause a loss of steam to adjacent, non-productive strata, and is therefore to be avoided.

The steam may be introduced at a temperature substantially above its condensation temperature, or it may be introduced at the minimum temperature required to maintain the desired pressure.

The rate of steam injection depends upon the permeability and thickness of the formation, and ranges from 1,000 to 100,000,000 pounds per hour, the higher the injection rate the better. Injection is continued for a period of 5 days to 10 months, preferably from 1 to 6 months. At the end of this period, the steam injection is interrupted and the production of condensate from the borehole is begun.

It is an essential feature of the invention that the production of condensate be carried out with a controlled back-pressure on the well sufficient to ensure that the condensate does not re-vaporize within the reservoir or within the wellbore. By avoiding re-vaporization while producing the condensate, the latent heat of condensation released during the injection period is allowed to remain in the formation. This maximizes the heat in
the formation around the well and enables high temperatures in the vicinity of the well to be maintained for a long period of stimulated production. The back-pressure on the well is decreased gradually, but as rapidly as can be tolerated without re-vaporization of condensate. Preferably, the bottom-hole pressure is then stabilized at the level which was established prior to application of the invention. This period of gradual pressure change continues for several days up to as much as six weeks, usually from 10 days to a month, the time being proportional to the time of steam injection. 

Calculations and field testing show that the stimulated rate of oil production obtained after the removal of condensate is more than double the rate of oil production experienced prior to injection. Calculations show that depending on the amount of steam injected the stimulated rate persists, while slowly declining, for six months to a year or more, at which time the cycle is repeated. As a net result, the average rate of production over the entire cycle is about 50% greater than the original rate of production.

A detailed description of a specific example of the invention is provided by reference to the accompanying graphs.

**FIGURE 1** shows the oil production rate of a particular reservoir versus time over a period which corresponds to one cycle of the method of the invention.

**FIGURE 2** shows a plot of the average heated zone temperature increase over the initial reservoir temperature, versus the months of time from the start of injection. Also shown is the corresponding vapor pressure of water, indicating a rapid decline after steam injection.

**FIGURE 3** shows the ratio of heated zone oil viscosity to the initial oil viscosity versus time from the start of steam injection.

Referring now to **FIGURE 1** in detail, the production rate shown was based on calculations for a well producing from a multi-layered formation wherein 20 individual sands each 25 feet thick are separated by shale barriers which act as heat retaining media in the process. The initial production rate is assumed to be 300 barrels of oil per day plus 100 barrels of water per day. The bottom-hole pressure before injection is 300 pounds per square inch absolute. A steam injection rate of 20,000 pounds per hour for one month is carried out at an injection pressure of 1,000 pounds per square inch absolute, which corresponds to a condensing temperature of 35°F. The injection period as indicated continues, for example, 30 days at which time the heated region of the reservoir extends radially from the wellbore a distance of about 30 feet.

The initial production consists primarily of liquid steam condensate. The draw-down pressure differential is gradually increased, without re-vaporizing any substantial quantity of condensate, and is finally stabilized at a bottom-hole pressure of 300 pounds per square inch absolute, the pressure level which was maintained prior to injection. Production of the liquid condensate with a controlled back-pressure is somewhat less rapid than the injection rates. Accordingly, as shown on the graph, appreciable oil production does not reappear until a period of about 80 days from the time of initial injection. The stimulated oil production rate is, however, more than double the initial oil production rate before injection. As indicated by the graph, such a stimulated production reaches 700 barrels per day and slowly declines over a period of about one year, but remains at a rate appreciably higher than the unstimulated rate.

A comparison of total production over a 400 day period with stimulation, as opposed to no stimulation, is obtained by a comparison of the area which lies beneath the solid line with that beneath the dotted line. The dotted line, of course, represents the production which would be anticipated in the absence of stimulation. Comparison of these areas indicates that the stimulated production over a 400 day period is about 50% greater than would have been obtained without stimulation.

Referring now to **FIGURE 2**, calculations show, first of all, that the temperature of the heated zone of the formation can be raised approximately 415°F above the initial temperature of 130°F. The negative slope of the curve shows the rate at which the temperature of the formation declines after steam injection has ceased and back-flow begun.

At this point it is important to consider that steam condensate exists within the borehole in equilibrium with steam. Accordingly, if it is referred to produce condensate rapidly the result will be reduced bore hole pressure, accompanied by re-vaporization of condensate. The rate of temperature decline determines the rate of water vapor pressure decline, which in turn is a measure of how low the pressure in the bore hole may be without causing re-vaporization of condensate. It will be readily appreciated, in this regard, that bore hole pressure must be as low as possible without causing steam condensation to vaporize or permit an appreciable rate of condensate production in order to obtain any economic advantage from the invention. Indeed, the discovery that condensate can be produced by back-flow at practical rates without re-vaporization is an essential feature of the invention.

Referring now to **FIGURE 3**, the curve shows that the initial production of oil at stimulated rates is attributable to a viscosity reduction amounting to approximately 350 of initial oil viscosity. Initial oil viscosity assumed in the calculation is 40 cpo, at reservoir temperature (130°F). Even as much as one year after the time of the start of injection the viscosity ratio is still approximately 0.15. Although stimulated rates would undoubtedly continue far beyond 400 days from the start of injection, it is nevertheless optimum procedure to repeat the injection after this time.

A preferred embodiment of the process involves the additional step of injecting a bank of aqueous surfactant solution just before the steaming period. The added benefits derived from the surfactant injection include an improved injection pressure with respect to the steam injection and a more rapid back-flow of steam condensate, thus enabling the stimulated oil production to begin sooner after steam injection is terminated. Moreover, the permeability of the formation to oil is increased in the vicinity of the wellbore, leading to still greater stimulated rates of production.

A number of surface active agents are available for use in accordance with this improved embodiment. For example, the di-alkyl sulfosuccinates are especially suitable, as they effectively lower the oil-water interfacial tension and also are chemically stable at relatively high temperatures. Specifically, sodium dioctyl sulfosuccinate is stable up to 457°F. Although higher temperatures are readily attained in the hottest regions of the steamed area, the surfactant solution bank is not subjected to the severest conditions, since it moves just ahead of the steam front, where somewhat lower temperatures prevail.

The surfactant encounters higher temperatures during back-flow than during steam injection. But even then, of course, it is not subjected to a temperature as high as that of the injected steam. Most important, however, is the fact that the possibility of decomposing part of the surfosuccinate poses no substantial deterrent to the process, because the products of such decomposition are also surface active.

Other suitable surfactants include "Pluronic L-64," which is a mixture of propylene oxide and ethylene oxide, and "Trion X-100," which is a mixture of octyl phenol and ethylene oxide which lies between the dotted line. A surfactant active agent range from 0.1% to 1.0% by weight. However, these amounts are not to be construed as limit.
ing, since smaller amounts are sometimes beneficial, and since larger amounts are merely wasteful and not detrimental.

It is elementary that in working with steam the transfer of sensible heat is wholly negligible when compared with the latent heat released upon condensation. Accordingly, it is desirable to delay the condensation of steam during its passage downhole, in order to minimize heat losses to the overburden. This is accomplished, in accordance with a further embodiment of the invention, by mixing a diluent gas with the injected steam. The diluent lowers the condensation temperature of the steam and thereby permits a greater percentage of the steam to reach the pay zone uncondensed.

Although any gaseous, inert diluent is suitable, insofar as lowering the condensation temperature is concerned, an additional benefit is obtained by using air or other oxygen-containing gases as the diluent. The oxygen reacts with oil in situ to supplement the supplemental quantity of heat for stimulating production. Suitable concentrations of diluent, whether inert or oxygen-containing, range from 1% to 50% by volume, based on the total volume.

The method of the invention requires no special well completion or workover procedure prior to steaming. The steam is simply introduced through the conventional tubing string found in a typical producing well, and injected into the oil-producing formation through the existing perforations. The steam may be injected by way of the annulus surrounding the tubing, without departing from the scope of the invention; however, heat losses to the overburden would be undesirably great. When steam is introduced through the tubing, the gas space in the annulus serves as an insulating medium and thereby aids in maximizing heat efficiency.

One factor to be considered before utilizing the method of the invention is the possible adverse effect of steam and fresh water on the permeability of the oil-producing formation. Certain clays, especially those containing significant amounts of montmorillonite, are known to swell when contacted with fresh water. Accordingly, an oil-producing formation which also contains appreciable quantities of swelling clays must be pretreated in order to stabilize or deactivate the clay before the steaming operation is begun.

A suitable pretreatment is simply to inject salt water before steam injection. A 3% calcium chloride solution, for example, effectively stabilizes the clay. The amount of salt water injected is not especially critical, except that a sufficient volume is introduced to provide a continuous bank driven radially outward from the wellbore by the injected steam and, this salt water bank must contain a sufficient quantity of calcium ions to treat all the clay to be contacted with the steam. The volume required ranges from about 25 to 500 barrels or more, depending upon the thickness of the reservoir and the concentration of clay contained therein.

An alternative method of stabilizing such clays is to inject air and initiate an in situ combustion front in the vicinity of the wellbore, by conventional means. The front is then expanded radially from the wellbore by continuous air injection. The combustion temperatures irreversibly dehydrate the clays, thereby preventing dispersion and swelling upon subsequent contact with steam and fresh water.

It should be emphasized that a great many formation reservoirs do not contain significant amounts of clay, while still others contain clays of a non-swelling variety, and therefore need no pretreatment.

While various embodiments of the invention have been specifically described, it is obvious that further variations will readily occur to those skilled in the art. Accordingly, it is intended to include all such modifications within the scope of the following claims.

What is claimed is:

1. A process for thermal stimulation of a producing oil well which penetrates an oil-bearing formation being penetrated by an existing pressure drive mechanism, which comprises interrupting the production of oil from said well, injecting steam into the oil-producing formation penetrated by said well at a pressure sufficient to reverse the direction of flow in the formation surrounding said well, for a period of time sufficient to drive steam into the oil-bearing formation a distance of at least ten feet from the well, thereafter backflowing and producing steam condensate and oil from said well while maintaining sufficient back-pressure on the well to prevent substantial re-vaporization of said condensate, and then continuing production of oil from said well at a stimulated rate.

2. A process as defined by claim 1 wherein said steam is injected at a pressure of 100 to 5,000 p.s.i.g., for a period of 5 days to 10 months.

3. A process for thermal stimulation of a well which is producing oil from an oil-bearing formation due to an existing pressure drive mechanism which comprises interrupting said production, then injecting steam into the oil-producing formation penetrated by said well, thereafter backflowing and producing steam condensate from said well while maintaining sufficient back-pressure on the well to prevent substantial re-vaporization of said condensate, then resuming production of oil from said well for a period of at least one month, gradually reducing said back pressure and then repeating the above sequence of steps.

4. A process for thermal stimulation of a well which is producing oil from an oil-bearing formation due to an existing pressure drive mechanism which comprises interrupting said production, then injecting steam into the oil-producing formation penetrated by said well for a period of at least 10 feet from the wellbore, thereafter backflowing and producing steam condensate from said well while maintaining sufficient back-pressure on the well to prevent substantial re-vaporization of said condensate, gradually reducing said back pressure and then resuming production of oil from said well.

5. A process as defined by claim 4 wherein said steam is injected at a pressure of 500 to 1500 p.s.i.g., for a period of at least 5 days.

6. A process for thermal stimulation of a producing oil well which comprises interrupting said production, injecting a bank of aqueous surfactant solution into the oil-producing formation penetrated by said well, then injecting steam into said formation, thereafter backflowing and producing steam condensate from said well while maintaining sufficient back-pressure on said well to prevent substantial re-vaporization of said condensate, and then resuming production of oil from said well.

7. A process as defined by claim 6 wherein said steam is injected at a pressure of 100 to 5,000 p.s.i.g., for a period of 5 days to 10 months.

8. A process for thermal stimulation of a producing oil well which comprises interrupting said production, then injecting a gaseous mixture of steam and an oxygen-comprising gas into the oil-producing formation penetrated by said well, thereafter backflowing and producing condensate from said formation while maintaining sufficient back-pressure on said well to prevent substantial re-vaporization of said condensate, and then resuming production of oil from said well.

9. A process as defined by claim 8 wherein said gaseous mixture is injected at a pressure of 100 to 5,000 p.s.i.g., for a period of 5 days to 10 months.

10. A process for thermal stimulation of a producing oil well, wherein said well penetrates an oil-producing formation containing water-sensitive clay, which comprises interrupting said production, stabilizing said clay in the vicinity of said well, thereafter injecting steam into the oil-producing formation penetrated by said well, thereafter backflowing and producing steam condensate from said well while maintaining sufficient back pressure on the well to prevent substantial re-vaporization of said conden-
sate, and then resuming production of oil from said well.

11. A process as defined by claim 10 wherein said clay is stabilized by the injection of salt water.

12. A process as defined by claim 10 wherein said clay is stabilized by the injection of an oxygen-containing gas under combustion-sustaining conditions.

13. A process for thermal stimulation of a producing oil well which comprises reversing flow at the well by shutting in production and thereafter injecting steam into the well and thence into the oil-producing formation under conditions of temperature and pressure which cause a major proportion of the steam to condense within said formation, then again reversing the flow at the well to produce steam condensate and oil therefrom while maintaining sufficient back-pressure on the well to prevent substantial reevaporation of condensate, gradually reducing the back-pressure on said well while continuing to produce condensate therefrom, and then continuing the production of oil therefrom at a stimulated rate.

References Cited by the Examiner

UNITED STATES PATENTS

3,126,961 3/1964 Craig et al. 166-40
3,139,928 7/1964 Broussard 166-40 X
3,155,160 11/1964 Craig et al. 166-40
3,180,414 4/1965 Parker 166-40 X

FOREIGN PATENTS

511,768 8/1939 Great Britain.

CHARLES E. O'CONNELL, Primary Examiner.
S. J. NOVOSAD, Assistant Examiner.