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METHOD FOR INJECTION OF HOT FLUIDS INTO AN UNDERGROUND FORMATION

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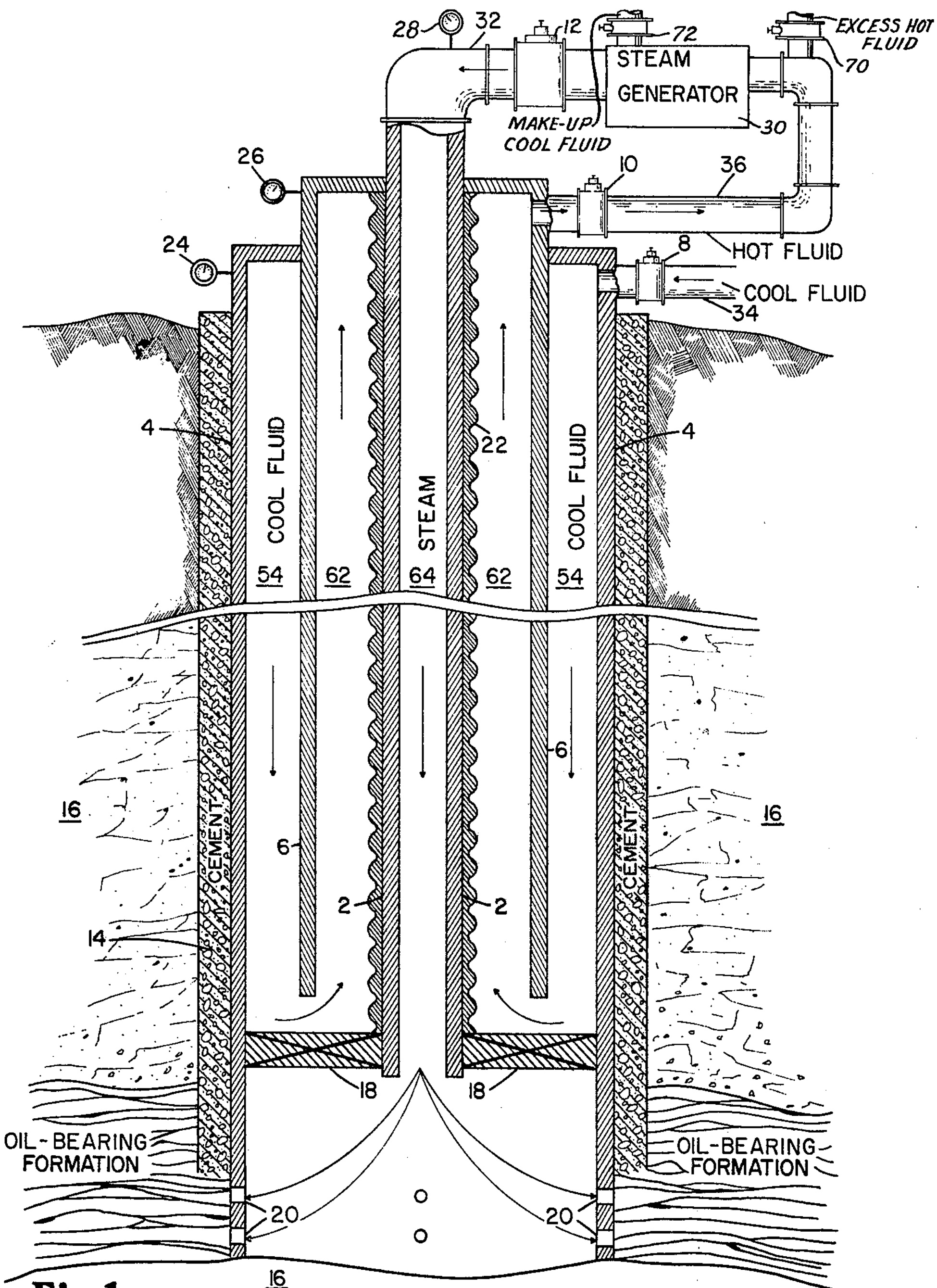

Fig.1

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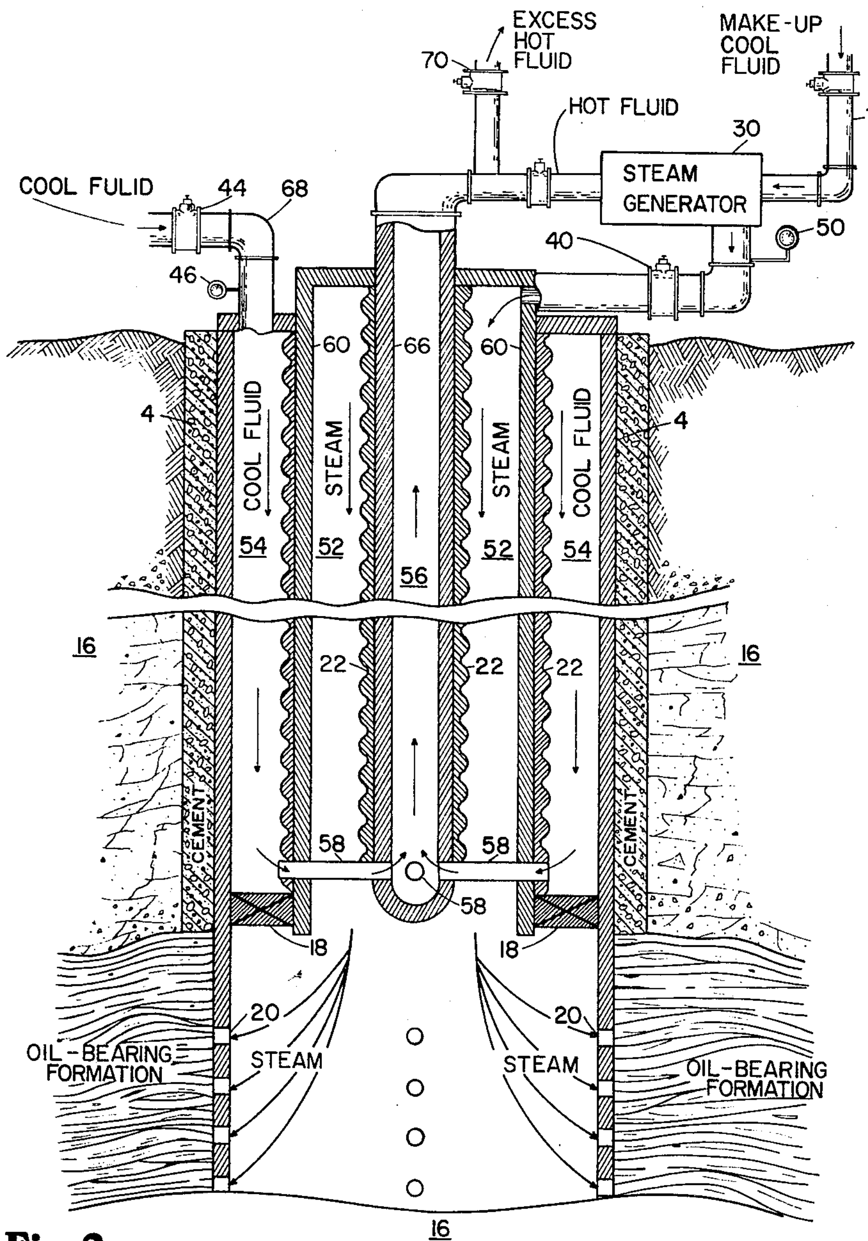

Fig. 2

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METHOD FOR INJECTION OF HOT FLUIDS INTO AN UNDERGROUND FORMATION

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ABSTRACT OF THE DISCLOSURE

The thermal efficiency of a hot fluid injection system for the recovery of hydrocarbons from subterranean oil-bearing formations is improved by inserting two or more concentric tubular strings within a casing wherein hot fluids are injected into a first tubing string which is in fluid communication with the oil-bearing formation, and a second tubing and the annular space between the well casing and the outer tubing is partitioned from the oil-bearing formation by a packer or other means so that a cool fluid may be injected into the outer tubing-casing annulus and returned to the surface through the second tubing. As the cool fluid approaches the surface through the second tubing string its enthalpy is increased by heat transfer from the hot injected fluids through the first tubing string.

The cool fluid circulation system described above serves to insulate the injected hot fluids from the formation as well as act as a preheater of fluids for the production of hot fluids on the surface.

BACKGROUND OF THE INVENTION

This invention concerns the use of a hot fluid such as steam for the recovery of crude oil from subterranean formations. Steam flooding is a well known, important method for recovering petroleum. But, unfortunately, steam flooding has oftentimes proved to be uneconomic because of the inefficiency of the process. For instance, a problem which has caused considerable concern involves trying to reduce heat losses of the injected hot fluid to improve the overall thermal efficiency of the operation. Specifically, it is important that the steam injected into the formation has sufficient latent heat to transfer to the crude oil to improve its mobility for recovery purposes.

Previous processes for steam injection have had such high attendant heat losses between the injection point at the surface and the subterranean formation that much of the latent heat of the steam has been transferred to the formation through the well casing en route to the oil-bearing formation. For instance, steam when pumped into a formation through an injection well can lose about 20% of its heat content by the time it has descended approximately 2000 feet. In some deep well systems, the steam may lose practically all of its latent heat. Thus, the resulting injected fluid may be hot water rather than steam. Also, thermal stresses etc. are imparted to the casing by high temperatures of the fluid and this can cause failure of the casing which may necessitate its replacement. Furthermore, the hot casing loses heat to the cooler formation. These are some of the problems which traditional steam flooding techniques present.

Applicant has discovered a process to improve the thermal efficiency of a hot fluid oil recovery process by limiting heat losses to the well casing and adjacent formation and, in so doing, transferring a substantially greater percentage of the enthalpy or hot fluid potential to the subterranean formation.

SUMMARY OF THE INVENTION

This process is essentially an improved hot fluid injection oil recovery process wherein the improvement lies in the increased thermal efficiency of the injection system. Specifically, excessive heat losses to the formation by heat transfer through the well casing from the hot injected fluid are obviated. More specifically, the heat content, i.e. original enthalpy of the steam generated at the surface is retained to a much higher degree so that a larger heat "input" can be effected in the subterranean oil-bearing formation.

This invention embodies two or more concentric tubing strings within a well casing. Two preferred embodiments of injection methods are hereinafter more fully described as the preferred embodiments of this invention, but in general the hot fluid such as steam is injected into a first tubing string which is in fluid communication with a subterranean oil-bearing formation (herein also termed "formation"). A second tubing string is partitioned from the formation by a packer or other means so that a second fluid, cool with respect to the first injected fluid, is injected into the outer tubing-casing annulus and returned to the surface through the second tubing. In returning to the surface, the second fluid is in contact with the first tubing string, and as a result, absorbs heat (i.e. increases in enthalpy) from the hot fluid through the tubing wall. Thus, the recovered second injected fluid will be substantially hotter than when previously injected. As a result, heat "losses" from the injected hot fluid are transferred to the second fluid. This recovered second fluid is utilized by further heating it to obtain a hot fluid suitable for injection into the subterranean formation.

BRIEF DESCRIPTION OF THE DRAWINGS

Preferred embodiments of the invention are represented by FIGURES 1 and 2.

FIGURE 1 is a schematic cross sectional view of a steam injection process wherein steam (hot fluid) injection tubing **2** is concentric with and interior to second tubing string **6** and well casing **4**.

FIGURE 2 is a schematic cross sectional view wherein hot fluid injection tubing string **60** is concentric with well casing **4** and second tubing string **66**, but tubing string **60** is interior to the former and exterior to the latter.

PREFERRED EMBODIMENTS OF THE INVENTION

Injecting hot fluid into a subterranean oil-bearing formation is preferably carried out utilizing two tubing strings and well casing as illustrated in FIGURE 1. It is understood that in FIGURES 1 and 2 even though the cool fluid is shown to be injected through the casing-tubing annulus **54**, and returned via an inner tubing, it is equally conceivable that the reverse directions may be employed. With two tubing strings within a well casing, there are a total of four combinations of fluid flow, two for each of the embodiments in FIGURES 1 and 2.

Although the herein mentioned apparatuses utilized for injection and recovery of fluids are referred to, inter alia, as "tubing strings" and "well casing," they may be generically described as "conduits" without deviating from the intended scope of the invention.

In FIGURE 1, steam is generated in steam generator **30**, fed by make-up water controlled by valve **72** and returned second injected fluid controlled by valve **10**, transferred through valve **12** and then flowed through conduit **32** under pressure, the pressure being indicated by pressure valve **28**. Conduit **32** is connected to first injection tubing string **2** so that the steam will travel into the subterranean oil-bearing formation and then through perforations 20. Hereafter, conventional methods of steam flooding sweep the reservoir of oil to at least one production well where the oil is recovered. Preferably, the injected hot fluid is steam as embodied in this figure, however, other economical drive fluids may be utilized so long as they possess the required latent heat to effectively sweep the reservoir of oil. For saturated steam the temperature is preferably from about 300 to about 700° F. and more preferably from about 380 to about 570° F. The quality of the steam will preferably be from about 50 to about 100%. The injection rates will preferably be from about 2,000 to about 25,000 lb./hr., and more preferably from about 8,000 to about 20,000 lb./hr.

Examples of other useful hot fluids include hot water, superheated steam, and like materials, and any of the foregoing with compatible additives such as corrosion inhibitors, surfactants, bactericides, etc. The steam injection pressure will be a function of the conditions of the particular reservoir, i.e. depth and permeability of the formation, volume of the reservoir to be swept, diameter of the injection tubing string, output of the steam generator, rate of sweeping, etc. Examples of injection pressures include preferably from about 70 to about 3000 p.s.i.a. and more, and more preferably from about 200 to about 1200 p.s.i.a.

In FIGURE 1, a cool fluid, with respect to the steam, is injected concurrently with respect to the steam into conduit 34 through valve 8 into the annulus formed by second tubing string 6 and well casing 4. The annular tubing strings are preferably concentric and are partitioned from formation 16 and interior 64 of tubing string 2 by packer 18. The second tubing string 6 and tubing string 2 form annulus 62 which is in fluid communication with annulus 54. This allows the cool fluid injected in annulus 54 to travel down annulus 54 and up annulus 62. The communication between the two annuli is effected by leaving a space below second tubing string 6 and packer 18.

The injected cool fluid is preferably water at about ambient temperature. This cool fluid may contain additives compatible with the fluid, examples include corrosion inhibitors, surfactants, etc. as desired. Cool fluid in annulus 62 is flowing countercurrently to steam traveling through tubing 2; as a result, the enthalpy of the cool fluid increases as heat transfers from the steam. Near the top of annulus 62, the cool fluid has obtained its highest temperature due to heat transfer from the steam. The highest temperature depends on such variables as the original temperature of the cool fluid, the length of the tubings, the temperature of the steam, the rate of flow of cool fluid, the manner in which the tubing is insulated, etc. Valve 10 is opened and the hotter "cool" fluid is sent through conduit 36 and preferably recirculated to steam generator 30, although any excess fluid may be exited or used for other purposes by regulation of valve 70. The advantage of cycling hotter "cool" fluid through the steam generator is obvious since less heat will have to be provided to the hotter "cool" fluid to elevate its temperature to a suitable level to produce steam in steam generator 30. This improves the economics of the operation.

Preferably, casing 4 is cemented in place with either bonded or nonbonded cement 14. Tubing string 2 may also be insulated to insure proper heat transfer between the cool fluid and the steam. Again, the amount and type of insulation 22 to be used is dependent upon the parameters of the particular system.

FIGURE 2 illustrates two tubing strings within well casing 4. Steam is generated as in FIGURE 1 in steam generator 30 and sent through the annular region 52 of tubing string 60 by opening valve 40. Tubing string 60 is in fluid communication with the subterranean oil-bearing formation via annular spacing 52 and perforated holes 20 within casing 4. Packer 18 partitions or substantially isolates the annular region 54 between casing 4 and tubing string 60. Annular space 54 is in fluid communication with steam generator 30 via second tubing string 66 via special tubing shoe 58. As the cool fluid is injected through conduit 68 via valve 44, it traverses the annular region 54, connecting shoe 58, and returns to the surface through space 56 within tube 66. The cool fluid becomes much hotter by heat transfer from the steam in adjacent annular region 52. Opening valve 42 allows the hotter "cool" fluid to be recycled to steam generator 30. Any excess hotter "cool" fluid may be exited as desired by opening valve 70. Tubing shoe 58 comprises a plurality of pipelike connections between annular region 54 and tubing interior 56. It is important that the cool fluid in annular region 54 be solely in fluid communication with region 56 via passages 58.

As in the previous embodiment of FIGURE 1, the hot fluid injection tubing string 60 may be insulated from the circulating cool fluid by insulation 22. The desirability of insulating and the extent of insulation to be effected is dependent on the particular parameters of the reservoir and injection well system. It should also be apparent that the rate of injection of cool fluid will determine how hot the returned hotter "cool" fluid will be. The injection rate should be determined so that minimum heat loss to the entire system will occur. Generally, for the purposes of this invention, a well of preferably less than 3000 ft. and more preferably less than 1000 ft. in depth will most efficiently be run, at a cool fluid injection rate of from about 2,000 to about 25,000 and more preferably from about 8,000 to about 20,000 lb./hr.

There are many parameters of operation in injection well systems that the person skilled in the art will take into account when operating this invention. For instance, the rates of injection or selection of injection fluids based upon heat content might depend upon the downhole temperature of the formation. These and other considerations should be taken into account when selecting the various parameters.

The following example is a working embodiment of the invention. It is presented to illustrate the overall improved thermal-efficiency of this steam injection system. It is not meant to restrict this invention in any way.

EXAMPLE

A casing and packer are set in an injection well at a depth of 492 feet. The inner diameter of the casing is 5.299 inches and the outer diameter is 6.000 inches. A first tubing string is inserted and centrally disposed within the casing and has an inner diameter of 1.880 inches, roughness 0.00065 inch, and an outer diameter of 1.995 inches. The insulation diameter of the first tubing string is 3.000 inches and the thermal conductivity of the insulation is 3.0 B.t.u./(hr. ft. ° F.) and the thermal conductivity of the pipe is 26.5 B.t.u./(hr. ft. ° F.). The second tubing string having an inner diameter of 3.958 inches and an outer diameter of 4.500 inches is placed concentric with the first tubing string, and also has a thermal conductivity of 26.5 B.t.u./(hr. ft. ° F.). The thermal conductivity of the earth surrounding the well bore is 1.4 B.t.u./(hr. ft. ° F.) and the thermal diffusivity of the earth is 0.04 ft.^{2}/hr. The geothermal temperature at the surface is 60° F. and the geothermal temperature gradient is 0.0207° F./ft. Eighty percent quality steam at 518.2° F. is injected at a rate of 18,500 lb./hr. and at a pressure of 800 p.s.i.a. into the first tubing string. The heat injected at the surface is 1,061 B.t.u./lb. Into the annulus between the well casing and the second tubing string, coolant water is injected at a rate of 18,500 lb./hr., circulated around the bottom of the pipe, and produced up through the annulus between the first and second tubing strings where at the surface its temperature is calculated to be 164° F. It is then fed to the steam generator as feed water. After one year from start of injection, the following heat loss and efficiency calculations are obtained:

Steam pressure at formation level, p.s.i.a.	641
Steam temperature at formation level, ° F.	493
Steam quality at formation level, percent	62.4
Maximum observed casing temperature, ° F.	447
Heat injected into formation:	
B.t.u./lb.	931
Million B.t.u./hr.	17.22
Net heat lost:	
B.t.u./lb.	26
Million B.t.u./hr.	0.481
Energy supplied boiler by fuel: [1]	
B.t.u./lb.	1165
Million B.t.u./hr.	21.55
Cost of energy supplied boiler, $1/day	155
Cost of heat entering formation, [2] $/million B.t.u.	0.375
Efficiency of process—percent of energy supplied to boiler which is injected	80.0

[1] Assumes 80% efficiency of boiler, 3% heat loss in hot water from well to boiler.

[2] Based on natural gas as fuel at $0.30/m.c.f, 10^6 B.t.u./m.c.f.

It should be understood that the invention is capable of a variety of modifications and variations which will be made apparent to those skilled in the art. Such are to be included within the scope of this invention as defined in the specification and appended claims.

What is claimed is:

1. In a process for the recovery of hydrocarbons from an oil-bearing subterranean formation wherein a hot fluid is injected through a well into the formation to facilitate movement and recovery of the formation hydrocarbons, the improvement of increasing the overall thermal-efficiency of the recovery process comprising in combination the steps of:
   (a) injecting through a first conduit in said well the hot fluid into the subterranean formation,
   (b) injecting downwardly into said well concurrently through a second conduit in said well a second fluid relatively cool with respect to the hot fluid, said hot fluid and said second fluid partitioned from each other below the surface,
   (c) recovering the second fluid by flowing said second fluid upwardly through a third conduit in said well, said third conduit being positioned in heat transfer relationship to said first conduit, whereby the second recovered fluid obtains an increase in enthalpy due to heat transfer from the hot fluid, and
   (d) incorporating at least a portion of said second recovered fluid with the hot fluid.

2. The process of claim 1 wherein the first injected fluid is selected from the group consisting of hot water, steam, and superheated steam.

3. The process of claim 1 wherein the second injected fluid is water.

4. The process of claim 1 wherein the first conduit is interior to the second and third conduits.

5. The process of claim 1 wherein the first conduit is interior to the second conduit and exterior to the third conduit.

6. The process of claim 1 wherein the first conduit is variably insulated from the second injected fluid so as to maintain the desired heat transfer between the injected hot fluid and the second injected fluid.

7. An improved process for the recovery of hydrocarbons from an oil-bearing subterranean formation wherein a hot fluid is injected through a well into the formation to facilitate movement and recovery of the formation hydrocarbons, the improvement comprising increasing the overall thermal-efficiency of the process comprising in combination the steps of:
   (a) injecting through a first conduit in said well the hot fluid into the subterranean formation,
   (b) injecting concurrently through a second conduit in said well a second fluid relatively cool with respect to the hot fluid, said hot fluid and said second fluid partitioned from each other below the surface,
   (c) recovering said second fluid by flowing said second fluid upwardly through a third conduit in said well, said third conduit being positioned in heat transfer relationship to said first conduit, whereby the recovered second fluid obtains an increase in enthalpy due to heat transfer from the second hot fluid,
   (d) and recycling the recovered second fluid to a hot fluid generation apparatus to be regenerated as the hot fluid to be injected through the first conduit.

8. The process of claim 7 wherein the first injected fluid is selected from the group consisting of hot water, steam, and superheated steam.

9. The process of claim 7 wherein the second injected fluid is water.

10. The process of claim 7 wherein the first conduit is interior to the second and third conduits.

11. The process of claim 7 wherein the first conduit is interior to the second conduit and exterior to the third conduit.

12. The process of claim 7 wherein the first conduit is variably insulated from the second injected fluid so as to maintain the desired heat transfer between the injected hot fluid and the second injected fluid.

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