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[54] **PROCESS FOR DEVELOPING INTERWELL COMMUNICATION IN A TAR SAND**

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[58] **Field of Search**.....166/266, 271, 272, 274, 259, 166/261, 260, 257, 302, 303

[56] **References Cited**

UNITED STATES PATENTS

2,288,857	7/1942	Subkow	166/272 X
2,882,973	4/1959	Doscher et al.	166/266
3,279,538	10/1966	Doscher	166/271
3,379,250	4/1968	Matthews et al.	166/271
3,396,791	8/1968	Meurs et al.	166/272
3,490,532	1/1970	Carlin	166/272 X
3,500,913	3/1970	Nordgren et al.	166/271 X
2,910,123	10/1959	Elkins et al.	166/271

FOREIGN PATENTS OR APPLICATIONS

639,050	3/1962	Canada	166/272
692,073	8/1964	Canada	166/272

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[57] **ABSTRACT**

A hot, competent, permeable communications zone, connecting injection and production wells completed in a tar sand, is developed as follows: A cold, aqueous solution containing sodium hydroxide and a non-ionic surfactant is injected into a propped fracture system connecting the wells. The solution is circulated between the wells at a pressure below the fracture propping pressure. Bitumen is slowly emulsified in the solution and removed through the fracture system; a competent, bitumen — depleted zone contiguous to the fracture zone is thereby developed. The temperature of the solution is then slowly increased and the quantities of sodium hydroxide and surfactant gradually decreased until pure steam only is being circulated.

4 Claims, No Drawings

PROCESS FOR DEVELOPING INTERWELL COMMUNICATION IN A TAR SAND

BACKGROUND OF THE INVENTION

This invention relates to a method for establishing a competent, permeable communication zone within a bitumen-containing sand bed. When formed, the zone connects injection and production wells penetrating into the bed. The zone is permeable to steam and is used to enable injected steam to gain access to the bed across a wide area of contact. In this way, steam is used, in accordance with known processes, to heat and emulsify bitumen contained in the bed and render it mobile so that it can be driven to and recovered from the production well.

There are a number of known, bitumen-containing sand reservoirs scattered around the world. One of the largest of these is the deposit located in the Athabasca region of Alberta, Canada. The present invention is discussed with reference to this particular deposit since the investigations leading up to the invention were carried out there. However, it will be appreciated that the process may find application in other deposits of the same type.

The Athabasca tar sand deposit has a lateral area of several thousand square miles. The bitumen or oilbearing sandstone reservoir (referred to hereafter as "the oil sand") is, in some areas of the deposit, exposed at ground surface. These areas lend themselves to open-pit type mining operations - the oil and sand are separated in a plant. The greatest part of the deposit, however, is covered with overburden. This overburden can range up to 1,000 feet in thickness. These portions of the deposit cannot economically be mined by open-pit methods. As a result, researchers in the field have worked toward developing in situ methods for recovering the oil.

The oil sand is mainly comprised of water-wet quartz grains. The oil or bitumen is located in the interstices between the water-sheathed grains.

The oil is extremely viscous at reservoir conditions. In fact it is a brittle solid having a viscosity of several million centipoises at 40°F, the approximate reservoir temperature. It is self-evident that the oil cannot be pushed through the formation to a production well using conventional means, such as a pressure gradient.

Workers have long been investigating ways and means for economically unlocking the subterranean tar sands so as to recover the contained oil. Generally speaking, these investigations have been concerned with converting the oil to a less viscous state so that it can be driven to and recovered from production wells using conventional pumping or gas lift means.

One such procedure which is particularly promising involves spontaneously emulsifying the oil to form an oil-in-water emulsion. The product emulsion has a viscosity approaching that of water. This procedure is described in the following patents: U.S. Pat. Nos. 2,882,973, 3,221,813, 3,279,538, 3,379,250 and 3,396,791; and Canadian Pat. No. 639,050.

From these patents, the following teachings are known:

Canadian Pat. No. 639,050 discloses the composition of a solution which, when injected into a tar sand, spontaneously emulsifies contained oil. The solution comprises water containing between 0.001 and 1.0 per-

cent by weight of sodium hydroxide. According to U.S. Pat. No. 2,882,973, the emulsifying power of the caustic solution described in Canadian Pat. No. 639,050 is improved by admixing with it a non-ionic surfactant, such as an oil-soluble monohydric alcohol. The surfactant is provided in an amount between 0.1 and 5 percent by weight.

The prior art also teaches drilling production an injection wells into the formation, fracturing the tar sand horizontally to establish communications between the wells and then pumping steam through the fracture system. The steam moves upwardly from the fracture into the sand reservoir. In so doing, it heats the cold oil while the steam condenses. The heated oil and water combine to form an oil-in-water emulsion. This emulsion accumulates in the fracture and is forced to the production well by the pressure of the injected steam.

One problem with this system is that the emulsion cools as it moves away from the hot zone surrounding the injection well. As it cools, the oil again solidifies to form an impermeable block in the fracture system. The injection pressure then rises and undesirable vertical fracturing can occur.

Another problem is that the tar sand softens as it is heated to emulsifying temperatures; the formation then tends to slump into the fracture, thereby blocking it.

To overcome these problems, U.S. Pat. No. 3,221,813 teaches a procedure wherein steam is injected into the fracture at a pressure above the theoretical fracture propping pressure (about 0.7 p.s.i. per foot of overburden) but below the theoretical formation fracturing pressure. This apparently avoids the problems which arise from slumping. If blockage of the fracture system occurs, caustic solution is injected into the fractures to clean out the block. Steam injection is then again resumed.

While the procedure taught in patent 3221813 has application in areas having a thick overburden, it is not feasible in those areas where the overburden is thin, as in the order of 200–300 feet. Here the fracturing and propping pressures are so close to each other that vertical fracturing easily occurs if one attempts to operate at the propping pressure. This, of course, leads to blowouts or migration of the steam into thief zones.

SUMMARY OF THE INVENTION

The present invention is based on the proposition that it is desirable, before introducing steam to the formation, to create a hot, competent, permeable, depleted sand zone contiguous to the fracture zone and extending between the wells. By "hot" is meant that the temperature within the two zones is sufficient to cause reservoir oil to combine with water to form a mobile emulsion. The availability of this continuous hot zone within the tar sand formation means that solidification by cooling of emulsified bitumen moving through the fractures does not occur to any substantial extent. Slumping of the formation is not a problem as the high temperature of the fracture and depleted sand zones ensures rapid emulsification of the bitumen; the slumping bitumen is therefore removed, leaving competent clean sand.

Now, this is not a novel proposition. It has, for example, been suggested in U.S. Pat. No. 3,396,791. However, the prior art has only used techniques involving

high pressure and temperature to form the hot zone. Such processes are not suitable for use in tar sand areas where the overburden is thin.

It is an object of this invention to provide a low pressure process which can be used to develop a zone of communication between injection and production wells.

It is another object of this invention to provide a low pressure process for establishing a zone, permeable to steam, which extends through a tar sand formation and connects two wells which penetrate the sand, said zone being competent and having a temperature at which the reservoir oil will combine readily with water in the zone to form a mobile emulsion.

It is another object to provide a cheap, effective agent which is adapted to react with bitumen to render part of it soluble in water and increase its susceptibility to emulsification.

I have found that the emulsifying sodium hydroxide solutions of the prior art do not emulsify bitumen at temperatures up to about 60°F; additionally, they have slow emulsifying effect at temperatures between about 60° and 90°F. It is not until the solutions are at temperatures above about 90°F that they become emulsifying agents of any practical value. I have also found that the bitumen or oil in tar sand is brittle at 40°–60°F, begins to soften (so that it can slump) at about 60°–90 °F and begins to form mobile, viscous fluid at temperatures above 90°F. As heating is continued, more of the bitumen becomes fluid and the viscosity of the fluid lessens. Finally, I have found that a non-ionic surfactant, of the type described in U.S. Pat. No. 2,882,973, together with critical concentrations of sodium hydroxide slowly but effectively emulsifies bitumen at temperatures between 40° and 90°F. The emulsifying power of this solution increases with temperature. Having made these observations, I have developed the series of steps which comprises the invention.

For purposes of this disclosure, a "cold" solution is one whose temperature, when injected into the tar sand formation, is about the same as the formation temperature.

In accordance with the first stage of the invention, a cold agent is pumped through the fracture zone to emulsify and remove bitumen at temperatures below 90°F. The agent is capable of emulsifying and/or dissolving bitumen at temperatures between 40° and 90°F. One preferred agent is an aqueous solution containing sodium hydroxide and a non-ionic surfactant. Another preferred agent is ozone.

The agent is injected into the fracture zone at a bottom hole pumping pressure which is kept substantially below the fracture propping pressure. It is circulated between the wells for a period of time at low pressure so as to gradually emulsify and/or dissolve bitumen adjoining the fracture zone. In this manner a competent, bitumen-depleted zone contiguous to the fracture zone is developed. The fracture zone and contiguous depleted zone combine to provide a permeable communication zone connecting the wells.

After initial interwell communication has been developed using a cold solution containing sodium hydroxide and non-ionic surfactant, the injection temperature of the solution is slowly increased. It will be appreciated that, as the temperature of the injected solution is raised, the bitumen becomes mobile in increasing quantities; simultaneously, the emulsifying power of the solution is increased. The rate of injection and the composition and temperature of the solution are therefore controlled to achieve two objects:

a. removal from the formation of the bitumen which is emulsified; and
b. the maintenance of a bottom hole injection pressure which is substantially less than the fracture propping pressure.

After the injection temperature of the solution reaches about 60°F, one can begin to decrease the non-ionic surfactant content while simultaneously continuing to slowly raise the solution temperature and pumping rate. This is continued until the surfactant is eliminated from the solution. At about 70°F, one can also begin to gradually reduce the sodium hydroxide content of the solution. This is continued until the sodium hydroxide has been eliminated from the solution. Both the surfactant and the sodium hydroxide may be eliminated from the solution by the time its temperature is raised to 200°F.

It is found at this stage that the communication zone connecting the wells is sufficiently permeable to allow steam to be injected thereinto at desirable rates at pressures below the fracture propping pressure.

In the case where ozone has been used to develop the initial communication zone, an aqueous solution containing emulsifying compounds can be introduced to the zone and circulated at gradually increasing temperature, as just described.

DESCRIPTION OF THE PREFERRED EMBODIMENT

Geology and Completion:

The vertical geology of the Athabasca tar sand formation varies at different locations. In some areas, the oil-saturated zone is 100 feet thick with relatively few clay stringers or permeable water-saturated zones. In other areas, the formation may only be 35 feet thick and crowded with clay and water-saturated lenses. In some areas, the pay zone is capped with a thick, impermeable shale bed; in others, it is not.

The selection of a suitable area for carrying on an in situ oil recovery programme is important to its success. Ideally, the vertical section of the well should have a reasonably thick overburden and an impermeable cap rock over the pay zone. The overburden and cap rock thicknesses preferably are at least 100 feet each. The fewer the potential thief zones within the bed, the better.

I prefer to complete both the injection and production wells by drilling each well to the base of the tar sands and casing off all but the bottom 5–10 feet. By fracturing the formation at its base, a vertical steam sweep of the entire pay zone is a possibility; by casing off the potential thief zones the probability of directing the emulsifying fluids into the desirable regions of the reservoir is increased.

Well Spacing:

Spacing is controlled to a large extent by the thickness of the overburden. The thicker it is, the higher will be the pressures which can be used during fracturing without incurring blow-outs or excessive vertical fracturing.

I space the wells apart by about 1 foot of spacing for each pound of injection pressure which is applied. In other words, if one injects at 100 p.s.i., the two wells can be spaced about 100 feet apart.

Fracturing:

At the present time, hydraulic fracturing with a propping agents provides the best means for establishing initial interwell communication. Conventional techniques are used. To illustrate, I obtain communication between two wells 100 feet apart by breaking down the formation using cold water and then injecting water, carrying ½ lb/gal. of 20–40 mesh sand, into one well at a rate of about 180 bbl/hr until sand returns are obtained at the second well.

Completion:

It is desirable to provide means for excluding sand in the production well after fracturing. I use conventional slotted liners packed with 8–12 mesh sand.

Fluid Lifting:

Experience has shown that bottom hole pumps are inadequate for bringing the emulsion to surface through the production well. The produced sand and silt soon leaves the pump inoperative, even with a liner present. However, good results can be obtained using conventional air lift procedures.

Communications development:

Once communication has been achieved through a fracture system at the base of the tar sand, it is necessary to develop the system into a usable flow path which will accept large volumes of steam without sealing off. This is initiated by causing cold emulsification of the bitumen to occur within or immediately adjacent to the fracture path.

Cold emulsification is carried out by injecting an aqueous solution of sodium hydroxide and non-ionic surfactant into the fracture system. The sodium hydroxide is provided in an amount less than 1.0 percent by weight; the non-ionic surfactant is provided in an amount within the range 0.1 to 5 percent by weight.

It is found that caustic does not emulsify bitumen below about 56°F. At about 79°F, bitumen is emulsified on prolonged contact (18 hours or more) with solutions containing 0.10 to 0.20 percent by weight of caustic. At 90°–100°F, emulsions readily form when using solutions containing 0.05 percent caustic but take at least 3 hours to form when using solutions containing 0.10 percent. From the foregoing it will be noted that the effective bitumen emulsification power of caustic begins at about 90°F and increases with temperature. It will also be noted that the optimum concentration for emulsion formation shifts to lower values as the temperature is increased.

With reference to the non-ionic surfactant, it is preferable to use an octylphenoxypolyethyleneoxy ethanol wherein the side chain of the benzene ring is branched and wherein there are 5 polyethylene groups. This compound is sold by Rohm and Haas under the designation Triton X–45. The quantity used is preferably within the range 0.4 to 0.1 percent by weight.

The optimum concentrations of these agents, relative to temperature, are in the order of the following:

TABLE I

Temperature (°F)	TX45 concentration (%)	NaOH concentration (%)
40–50 °F	0.4	0.2
50–60	0.4	0.2
60–70	0.2	0.2
70–80	0.2	0.15
80–90	0.1	0.15
90–100	0.1	0.15
100–110	0.1	0.1
110–120	0.1	0.1

The solution is pumped at low pressure throughout the period of developing the communication zone. For example, I try to keep the wellhead injection pressure for a 230 foot deep well below 140 p.s.i. When working with deeper wells which have a thicker overburden, one can use higher injection pressures.

The following example further illustrates the invention:

EXAMPLE 1

Three wells, A,B and C were drilled into the Athabasca tar sand at 50 foot intervals along a line. The injection well A was bottomed in limestone at 223 feet. It was cased to 212 feet. The temperature survey well B was bottomed in limestone at 225 feet and cased to total depth. It was perforated in the tar sand at 223 feet. The production well C was bottomed in limestone at 230 feet and cased to 209 feet.

The tar sand, about 60 feet thick, immediately overlaid the limestone. The formation was, in turn, overlain with glacial till. There was no impermeable cap rock, such as a shale bed, above the tar sand.

The tar sand was hydraulically fractured through the temperature well B. The formation was broken down using water at 550–200 p.s.i.g. Water carrying ½ lb/gal. of 20–40 mesh round sand was fed to the formation at 3 bbls/min. until sand returns were observed at wells A and C.

The production well was then completed with a gravel pack.

Following completion, injection down well A was begun. The solution used contained 0.4% by weight Triton X–45 and 0.2 percent by weight caustic. It had an injection temperature of 40°F. The solution was fed to the formation at 2–4 bbls/hour for 8 days at less than 25 p.s.i.g. Returns of ¾ bbl/hour were observed at the production well C 6 hours after lifting began. After 3 days, the returns comprised an emulsion containing 1.5 percent by weight bitumen. These conditions remained constant throughout this injection period. The returns were removed from the production well using an air lift. Injection through well A was stopped for 6 weeks.

After this period, injection was resumed through temperature well B. Production was recovered through both the injection and production wells A and C. The well head temperature of the solution was increased from a starting temperature of 50°F to a final temperature of 200°F over a period of days at a rate of approximately 10°F every 2 days. During this period, the wellhead pressure rose from 50 to 140 p.s.i.g. and then dropped to a steady level of 50–100 p.s.i.g. at an injection rate of 4–5 bbls/hour. The composition of the solution was varied as follows:

TABLE II

Temperature (°F)	Triton X-45 (lb/gal.)	NaOH (lb/gal.)
50–60	0.4	0.2

60–70	0.2	0.2
70–80	0.2	.15
80–100	0.1	.15
100–150	0.1	.1
150–200	0.1	.05

Production commenced through well C at 2 bbl/hour, declined after a week to ¼ bbl/hour, remained at that level for 3 weeks and then increased to 3–4 bbls/hour for the last week. The product contained 1–2 percent by weight bitumen during the first 3 weeks; this content rose to 7–10 percent by weight during the final week.

The final wellhead injection temperature was about 200°F and the final production temperature about 140°F.

Low quality steam was then injected through well A at temperatures up to 350°F and bitumen emulsion produced at well C at temperatures up to 280°F.

EXAMPLE II

This example illustrates the use of ozone as a means for establishing a bitumen-depleted zone within the tar sand.

A 1 ½ × 18 inch glass tube was packed with 800 grams of Athabasca tar sand. Oxygen containing 6–7 percent by volume ozone was passed through the tube for 2 days at 170 millimeters per minute. The experiment was carried out at room temperature.

During this period, the color of the sample changed from black to gray as many white, clean sand grains appeared.

At the end of the period, water was passed through the tube. The collected solution was dark brown in color and foamed when shaken lightly. It was evaporated to dryness and the solid product analyzed as follows:

TABLE III

Constituent	% by weight
carbon	41.6
hydrogen	5.0
oxygen	37.3
nitrogen	1.3
sulphur	6.6
drying loss	8.2

A portion of the remaining tar sand was divided into three 50 gram parts A, B and C. These parts were each placed in a tube.

Part A was saturated at 40°F with water containing 0.2 percent by weight sodium hydroxide and 0.4 percent by weight Triton X–45. Within 30 minutes the solution turned dark brown, indicating very rapid emulsification.

Part B was saturated at 40°F with water containing 0.2 percent by weight sodium hydroxide. No change in the color of the solution had occurred after 2 days.

Part C was saturated at 40°F with water containing .4% by weight Triton X–45. Some darkening of this solution occurred in 30 minutes.

A fourth part D of the ozonized tar sand was stirred with water at room temperature under a microscope. The sand grains became water wet and bitumen separated to form globules in the water phase. When non-ozonized tar sand was subjected to the same test, nothing happened.

From these results it will be noted that:

a. treatment of tar sand with ozone converts some bitumen to a water-soluble form;
b. some of the ozonized bitumen has surface active characteristics; and
c. ozonized tar sand is more amenable to spontaneous emulsification with an aqueous solution of sodium hydroxide and non-ionic surfactant than is otherwise the case.

EXAMPLE III

This example illustrates that ozone is effective at formation temperature.

A horizontal 3 foot × 2 inch column was tightly packed with 5.2 pounds of Athabasca tar sand. A ⅛ inch diameter path of 20–40 mesh round sand was incorporated in the tar sand along the bottom of the column.

Oxygen containing 5–6 percent by volume ozone was passed through the column for 61 hours. The exit gas contained only 1 percent ozone.

A 50 gram sample of the ozonized tar sand was extracted in 500 milliliters of water. The product solution was dark brown in color and foamed when shaken slightly. The solution was evaporated to dryness and 0.237 grams of solid collected. This solid analyzed as follows:

TABLE IV

Component	% by weight
carbon	28.7
hydrogen	3.7
oxygen	51.3
nitrogen	1.3
sulphur	8.2
drying loss	6.8

A second 50 gram sample was extracted with 1.1 liters of water. The solution required 41.4 cubic centimeters of 0.1 sodium hydroxide to neutralize it. This test indicated the formation of acid groups due to reaction between the ozone and bitumen.

What is claimed is:

1. A method for establishing a hot, permeable communication zone in a bitumen-containing sand formation extending between production and injection wells, said formation having a propped fracture zone extending between the wells, which comprises:

pumping a solution, having a temperature substantially the same as the formation temperature, into the fracture zone, said solution being capable of emulsifying bitumen at temperatures between 40° and 90°F;

forcing the solution from the injection well to the production well by pumping it through the fracture zone at a bottom hole pumping pressure which is substantially less than the fracture propping pressure;

contuing to pump the solution, while simultaneously gradually increasing its temperature, through the formation at a bottom hole pumping pressure which is substantially less than the fracture

propping pressure, whereby bitumen in and adjacent to the fracture zone TABLE emulsified and forced to the production well, through which it is removed, thereby gradually developing a hot, permeable communication zone extending between the wells.

2. The method as set forth in claim 1 wherein:

the solution comprises water containing sodium hydroxide in an amount less than 1.0 percent by weight, and a non-ionic surfactant in an amount between 0.1 and 5 percent by weight.

3. The method as set forth in claim 2 wherein:

the non-ionic surfactant is octylphenoxypolyethyleneoxy ethanol and it is provided in the solution in an amount less than 0.4% by weight.

4. The method as set forth in claim 2 wherein:

the non-ionic surfactant content of the solution is gradually decreased after the injection temperature of the solution rises above about 60°F.

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