METHOD FOR RECOVERING HYDROCARBON FROM TAR SAND USING NANOFLUID

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ABSTRACT

Method for recovery of bitumen from tar sand is provided. An aqueous fluid containing a wetting agent and nanoparticles is injected into a first horizontal well at a temperature above reservoir temperature. Bitumen is released from sand grains and flows into a second horizontal well, where it is transported to surface. In a surface treatment facility, a slurry of tar sand is formed and surfactant and nanoparticles are added to the slurry.
BACKGROUND OF INVENTION

[0001] 1. Field of the Invention

[0002] This invention relates to recovery of oil or tar-like hydrocarbons from tar sands. More particularly, a wetting agent including nanoparticles in water is used to increase separation of the hydrocarbons from the sand.

[0003] 2. Description of Related Art

[0004] “Tar sands” or “oil sands” are typically about 10% bitumen, 83% silica sand, 3% clay and 4% water, but the composition can vary widely. Bitumen is made up of large, carbon-rich and hydrogen-poor molecules, and is a semi-solid or solid at room temperature.

[0005] Production of bitumen from oil sands has been dominated by two processes. The first is based on mining, where relatively thin overburden allows open pit mines of the oil sands. The sand-and-bitumen mixture is removed from open pits and transferred to a tar sand treatment facility, where it is commonly placed in hot water containing surfactants to form a slurry. Air is injected into the slurry, so that air bubbles attach to the bitumen and cause it to float to the surface of the slurry. The bitumen-enriched mixture is collected at the top and sent to a refinery.

[0006] The second process is applied in deeper, relatively thick oil sands that are too deep for surface mining. These reserves are recovered by injecting steam or hot water to warm the reservoir and enable production. In recent years, horizontal wells have increasingly been used to recover the tar or bitumen. Steam-assisted gravity drainage (SAGD) using horizontal wells is now practiced by an increasing number of operators. This process will be described in more detail below.

[0007] There are formidable challenges to both surface and subsurface recovery. Large amounts of energy are required to heat the sand or reservoir. This energy comes from burning of hydrocarbon (usually natural gas). Typically, 60% of the operating costs are for energy. Emission of carbon dioxide and other gases then becomes one of the challenges. New processes that decrease energy requirements and address carbon dioxide emission are an obvious contribution to the technology.

[0008] In mining operations, surfactants are used in tar sand treatment facilities to facilitate wetting of the sand surfaces by water, which causes the hydrocarbon to separate from the sand. Surfactants that increase the rate of wetting by water can increase the rate of release of hydrocarbons and the total release so they can be separated from the sand.

[0009] One process that has been researched for decreasing energy needs as an alternative or supplement to SAGD is incorporation of hydrocarbon solvent, either alone or in conjunction with thermal energy. The possibility of solvent recovery and recycling has the potential to improve the economics of this process. Another recent study reported on an investigation of the use of a surfactant (SPE 128621, “Laboratory Evaluation of a Chemical Additive to Increase Production in Steam Assisted Gravity Drainage (SAGD),” 2010. A chemical additive in steam is said to enhance bitumen production by accelerating the release of bitumen encapsulating the sand grains of the reservoir.

[0010] What is needed is a chemical additive to enhance the separation of bitumen from the mineral particles in surface separation facilities of a mining operation or in the reservoir. The chemical should be applicable when fluids are injected in horizontal wells, with or without solvents or other additives. Preferably, the additive should also be effective at lower temperatures than stream temperature.

BRIEF SUMMARY OF THE INVENTION

[0011] A solution containing nanoparticles in water is provided to contact a tar sand to increase release of bitumen from the sand. The solution may also contain a solvent and other water-wetting surfactants.

BRIEF DESCRIPTION OF THE SEVERAL VIEWS OF THE DRAWING(S)

[0012] FIG. 1 is a cross-sectional sketch of a process for separating bitumen from mineral particles in the reservoir.

[0013] FIG. 2 illustrates wetting of a solid surface by a solution containing nanoparticles.

[0014] FIG. 3 illustrates laboratory apparatus for separating bitumen from sand in a tar sand after wetting has released the bitumen from sand grains.

DETAILED DESCRIPTION OF THE INVENTION

[0015] Surface separation facilities for mining operations are well known. See, for example, a description of mining operations at www.mining-technology.com/projects/Syr- crude. Oil sand is mixed with hot water and caustic soda in tumblers, forming a slurry and conditioning the oil sand for bitumen separation. It is then discharged onto vibrating screens where material is rejected and the blended slurry is fed into primary separation vessels, where bitumen froth floats to the top and sand sinks. The sand is further treated with surfactants to separate more bitumen. Improved water wetting of the sand by a surfactant solution will increase rate of bitumen removal and total recovery. This can be accomplished by adding nanoparticles as disclosed herein to the prior art surfactant solutions or by adding the nanoparticle-surfactant solutions disclosed herein to the water used to remove bitumen from sand in surface facilities.

[0016] FIG. 1 is a sketch illustrating fluid flow in reservoir 10 having thickness 12 around horizontal wells 14 and 16, which are shown in cross-section. The wells are generally parallel and may extend hundreds or thousands of feet through reservoir 10. This is the well configuration normally used in the SAGD process. Normally, hot fluid is injected down well 14. The fluid may be steam or hot water and pH may range from 2.5 to 11. Fluid is produced from well 16. Fluids at temperature above reservoir temperature rise in the formation to form recovery zone 17. Released bitumen particles small enough to flow through pores of the rock then flow along with the fluid and tend to accumulate in zone 18, which flows into production well 16, and which may include steam condensate. Bitumen particles then flow along well 16 to surface, where the bitumen is gathered and sent to a refinery. Increased rate of release of the bitumen from particles of the reservoir rock will increase the bitumen content of the produced fluid. Temperature of injected fluid may range from superheated steam to water that is only about 20° F. above reservoir temperature. Lower temperature fluids will lower energy costs and environmental impact of the process.

[0017] FIG. 2 illustrates the principles of bitumen removal from tar sands using a fluid containing nanoparticles. The principles of the use of nanoparticles as they relate to removal
of unwanted fluids around wells during intervention operations in wells are discussed in U.S. Pat. Pub. No. 2010/0096939, which is hereby incorporated by reference herein for all purposes. Solid surface 20 represents the surface of the sand of a tar sand. Bitumen phase 22, in contact with the sand, may have an initial contact angle indicating an oil-wet surface or a water-wet surface, but in FIG. 2 water phase 24 has contacted the tar sand and is preferentially wetting the sand. Wetting agent 25 is adsorbed at the water-solid and at the water-bitumen interface. A range of wetting agents may be employed and may be selected from the group consisting of ethoxylated nonyl phenol, sodium stearate, sodium dodecyl sulfate, sodium dodecylbenzene sulfonate, lauraminole hydrochloride, trimethyl dodecylammonium chloride, cetyl trimethylammonium chloride, polyoxyethylene alcohol, alkylphenolethoxylate, Polysorbate 80, propylene oxide modified polyelectrolytes, dodecyl betaine, lauramidopropyl betaine, cocamidopropyl betaine, cocamido-2-hydroxy-propyl sulfobetaine, alkyl aryl sulfonate, fluorosurfactants and perfluoropolymers and terpolymers, and castor bean adducts.

[0018] Water phase 24 also contains nanoparticles 26, which increase the force to disjoin bitumen 22 from surface 20. This leads to more rapid recovery of bitumen from the tar sand. Nanoparticles 26 may have a size from about 8 nm to about 100 nm. A preferred nanoparticle dispersion for the fluid is an aqueous dispersion of 8.0 to 15.0 nm silicon dioxide particles, and an anionic charged wetting agent mixed in the water carrying the nanoparticles at 0.1-2.0% by weight, which is preferably an anionic surfactant from the group described above, at a pH in the range from about 6 to 8. The percentage of nanoparticles in the dispersion preferably ranges between approximately 5% and approximately 30% by weight in the water-surfactant mixture.

[0019] A variety of tests were performed to measure the increased removal of bitumen in the presence of wetting agent and nanoparticles. The wetting agent was SS-1000, a product of FracTech Services, which is a nonionic surfactant blend such as disclosed in U.S. Pat. Pub. No. 2010/0096939. The nanoparticles were Nalco 1130 (Nalco Chemical), which are silica particles having an average size of 19 nm. Grains of tar sand containing bitumen from Athabasca Tar Sand were placed in a clean well slide and a solution of wetting agent and nanoparticles was placed on the grains. Observations using a microscope or a projection microscope allowed comparisons of the rate at which bitumen was displaced from the sand grains in the presence of the water solutions. The presence of wetting agent and nanoparticles increased the rate of bitumen removal from sand grains and the total amount removed. Beaker tests were also performed with samples of the Athabasca Tar Sand by adding 50 gm of the tar sand to a 500 ml beaker, adding test fluids on the sand and placing the beaker on a stir plate with a stir bar at room temperature. The slurry (pH 7-10) was stirred for 30 min and then transferred to apparatus 30 illustrated in FIG. 3 to separate the bitumen that had been removed from the sand surface. Water was pumped with pump 30 upward through column 32 containing the bitumen and sand from a beaker test. Water flow fluidized the bed and separated the bitumen from the sand after the wetting solution had acted in the beaker. Bitumen particles flowed out of the bed and settled out in vessel 34. The elutriation was run until no more bitumen was being recovered. The bitumen was removed from vessel 34 and the volume of bitumen measured. The sand was then dried and the remaining bitumen was burned off the sand. The percent bitumen removed was measured from calculations using the amount of remaining bitumen that remained on the sand after treatment. Results are shown in Table 1. One or two additional samples were treated with the saved treatment fluid. For example, another 50 gm sample of tar sand was weighed out and treated with the saved treatment fluid in a beaker, stirred for 30 min and then run through the elutriation device shown in FIG. 3 to remove the freed bitumen from the sand.

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Vol. of Bitumen Released</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hot water</td>
<td>4.9 ml</td>
</tr>
<tr>
<td>5% Treating Fluid</td>
<td>6.0 (from two treatments)</td>
</tr>
<tr>
<td>10% Treating Fluid</td>
<td>7.6 (from two treatments)</td>
</tr>
</tbody>
</table>

[0020] One preferred procedure for using the chemical system disclosed herein is to inject the solution of wetting agent and nanoparticles under conditions such that the released bitumen will flow through the pore spaces of the reservoir sand. This requires that the bitumen particles be smaller than the pore sizes of the tar sand under conditions around the well when fluid is injected. The tests reported in Table 1 were not in a packed sand, but were performed to measure the removal of bitumen from the sand using agitation of the tar sand and treatment fluid. It is believed that this process reasonably simulates recovery of small droplets of bitumen from an injection zone around a SAGD well, i.e., a horizontal well where warm or hot fluid is being injected at a higher temperature than reservoir temperature, as shown in FIG. 1. Either steam or hot water may be injected. Circulation of fluid in the reservoir is achieved by placing a horizontal well below the injection well and producing fluid from the lower well as fluid is injected into the upper well. Preferably, the injection fluid is at a temperature at least 20° F. above reservoir temperature.

[0021] Although the present invention has been described with respect to specific details, it is not intended that such details should be regarded as limitations on the scope of the invention, except to the extent that they are included in the accompanying claims.

We claim:
1. A method for recovering bitumen from a tar sand at a reservoir temperature, comprising:
   - injecting an aqueous fluid into a first horizontal well through the tar sand;
   - producing fluid from a second horizontal well approximately parallel to the first horizontal well, wherein the aqueous fluid injected contains a wetting agent and nanoparticles.
2. The method of claim 1 wherein the wetting agent is selected from the group of wetting agents consisting of ethoxylated nonyl phenol, sodium stearate, sodium dodecyl sulfate, sodium dodecylbenzene sulfonate, lauraminole hydrochloride, trimethyl dodecylammonium chloride, cetyl trimethylammonium chloride, polyoxyethylene alcohol, alkylphenolethoxylate, Polysorbate 80, propylene oxide modified polyethylene oxide, dodecyl betaine, lauramidopropyl betaine, cocamidopropyl betaine, cocamido-2-hydroxy-propyl sulfobetaine, alkyl aryl sulfonate, fluorosurfactants and perfluoropolymers and terpolymers, and castor bean adducts.
3. The method of claim 1 wherein the nanoparticles are in the size range from 9 nm to 100 nm.
4. The method of claim 1 wherein the nanoparticles are composed of silica.
5. The method of claim 1 wherein pH of the aqueous solution is between 2.5 and 11.

6. The method of claim 1 wherein the aqueous fluid injected into the first horizontal well is at a temperature greater than 20 degrees above the reservoir temperature of the tar sand.

7. The method of claim 1 wherein the aqueous fluid is hot water.

8. The method of claim 1 wherein the aqueous fluid is steam.

9. A method for recovering bitumen from tar sands in surface processing facilities, comprising:
   forming a slurry of the tar sands in water;
   adding a surfactant to the slurry; and
   adding nanoparticles to the slurry.

10. The method of claim 9 wherein the surfactant is selected from the group of surfactants consisting of ethoxylated nonyl phenol, sodium stearate, sodium dodecyl sulfate, sodium dodecylbenzene sulfonate, lauralamine hydrochloride, trimethyl dodecylammonium chloride, cetyl trimethylammonium chloride, polyoxyethylene alcohol, alkylphenoxylethoxylate, Polysorbate 80, propylene oxide modified polymethylsiloxane, dodecyl betaine, lauramidopropyl betaine, cocoamido-2-hydroxy-propyl sulfobetaine, alkyl aryl sulfonate, fluorosurfactants and perfluoropolymers and terpolymers, and castor bean adducts.

11. The method of claim 9 wherein the nanoparticles are in the size range from 9 nm to 100 nm.

12. The method of claim 9 wherein the nanoparticles are composed of silica.

13. The method of claim 9 wherein pH of the water is between 2.5 and 11.

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