

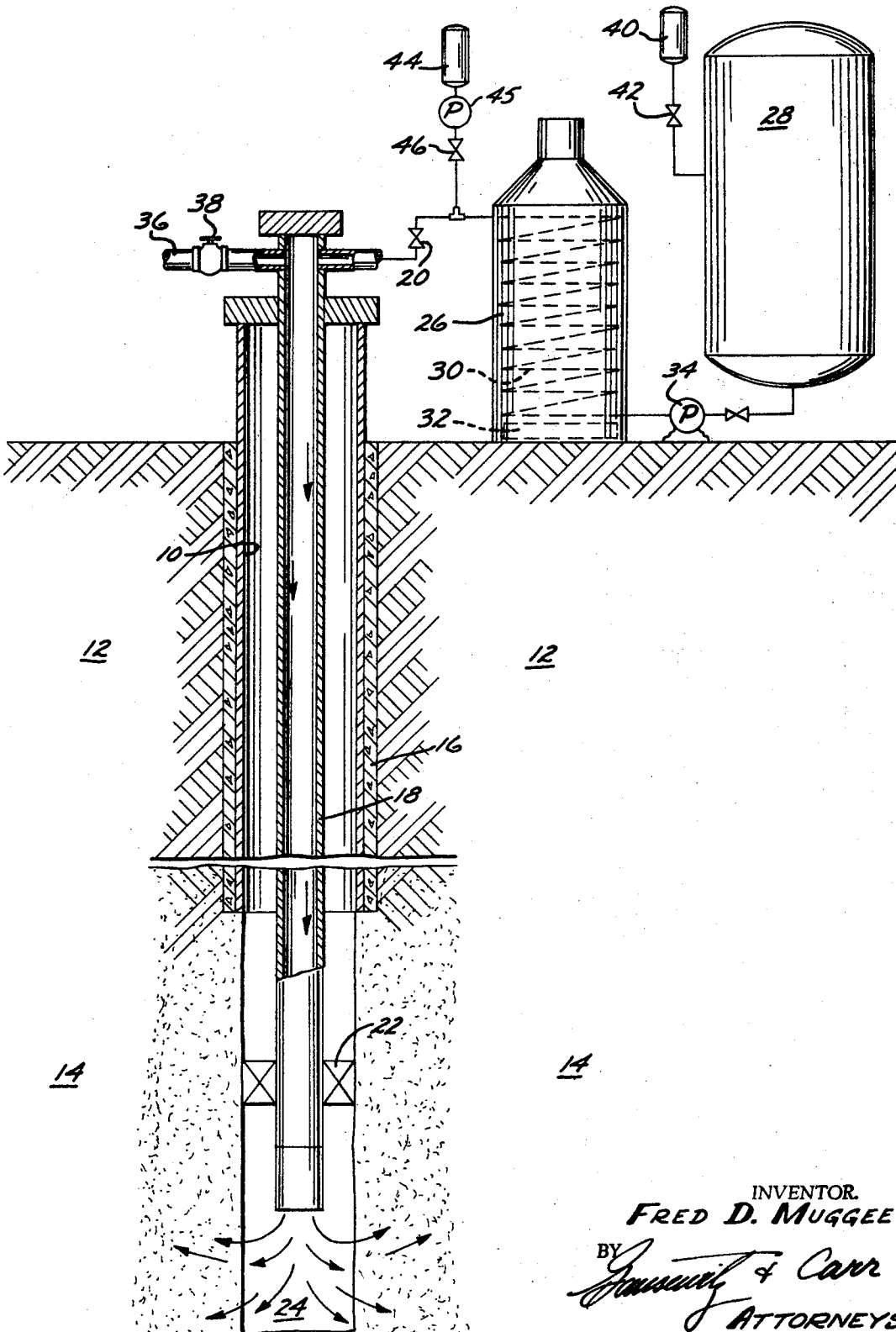
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F. D. MUGGEE

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PROCESS FOR RECOVERY OF PETROLEUM BY STEAM STIMULATION

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INVENTOR
FRED D. MUGGEE
BY *James & Carr*
ATTORNEYS

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PROCESS FOR RECOVERY OF PETROLEUM BY STEAM STIMULATION

Fred D. Muggee, Anaheim, Calif., assignor to Magna Corporation, Santa Fe Springs, Calif., a corporation of California

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ABSTRACT OF THE DISCLOSURE

A steam-stimulation process in which a small amount of surface-active material is added continuously to the steam which is then injected into an oil-bearing formation. The surface-active agent is water soluble, heat stable, and effective to substantially prevent creation of water-in-oil emulsions in the formation. After a substantial period of steam injection, followed by a protracted soaking interval, the formation is produced in order to recover the crude as well as a substantial amount of condensate of the injected steam.

This invention relates to an improved method for recovering hydrocarbon material from producing formations, which may be in the form of oil sands, oil shale, or tar sands. The invention pertains more particularly to steam stimulation methods for the secondary recovery of petroleum.

The primary production of petroleum hydrocarbons from oil-bearing formations is usually effected by drilling through or into the oil-bearing sand and providing access to the formation around the bore hole so as to permit oil to flow into the bore hole from which it may be recovered by conventional methods. If the formation contains an oil of low or medium viscosity at reservoir conditions, the well may be produced either by flowing or pumping in the conventional manner. If, on the other hand, the formation contains a highly viscous oil at reservoir conditions, it may be necessary to heat the formation in the vicinity of the bore hole to reduce the viscosity of the oil so that the oil may flow into the bore hole. In time, even the wells containing free-flowing oil become uneconomical to produce, although a substantial amount of oil still remains in the producing formation. The residual oil left in the formation after primary production, or the oil which is highly viscous at reservoir conditions, is very difficult to produce and considerable research has been carried out on methods of recovering this residual, or highly viscous, oil. Such methods of increasing the production of residual or highly viscous oils are sometimes called stimulation techniques. Various stimulation techniques have been devised such as heating the formation by means of preheated fluids, e.g., gases, steam, or water, combustion in situ, flooding the formation with water, hot water, steam, or a miscible fluid, etc.

One commonly used method for stimulation of oil production in oil wells is the injection of steam into the formation. See, for instance, "Steam in Oil Production?", by T. M. Doscher, pp. 58-61, The Oil and Gas Journal, Nov. 22, 1965. The primary function of the steam in steam stimulation methods is to deliver heat to the reservoir formation, heating the residual or high-viscosity oil so that its viscosity is lowered and it flows more readily through the formation. In practice, one ton of steam is capable of releasing almost 2 million b.t.u. to a shallow reservoir.

The usual stimulation technique, sometimes called "the steam soak process," comprises placing a steam generator near the well at the surface, injecting steam through the tubing or casing of the well into the producing formation

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for a desired time period, shutting in the well to permit "soaking" for a second period of time, and then producing the well by conventional primary recovery methods. Steam may also be employed to stimulate production at production wells adjacent the injection well into which it is pumped. Although the results of steam stimulation vary, the more successful applications result in substantial increase in the rate of oil production persisting for up to one year.

One particularly troublesome side effect of steam stimulation in many wells is the production of a tight emulsion of oil and water in greater volume than that of the emulsion normally found in the effluent of those wells. The combined effect of heat and motion of the steam forced into the oil-bearing formation produces a water-in-oil emulsion between oil and connate water, or oil and the water resulting from condensation of the injected steam.

Unfortunately, certain types of crude which best respond to thermal recovery methods, e.g., steam stimulation, are also among those which most readily form extremely tight water-in-oil emulsions. This tendency is probably due to the fact that the specific gravity of these particular crudes is very close to that of water. For example, the specific gravity of Athabasca tar is typically about 1.03.

Another unfortunate tendency of steam stimulation methods is that of diluting the salts naturally found in the oil-bearing formation. As is well-known, certain of these naturally occurring salts exhibit a tendency to precipitate certain dispersed systems. Thus, the presence of these natural salts in, say, primary production crudes, makes it relatively easy to break the relatively small amount of naturally occurring connate water-in-oil emulsion found therein. In steam stimulation methods, however, fresh water is generally employed, both because of the immediate availability at the well site of relatively fresh water and because the water used is often also treated to avoid deleterious effects on the water heating apparatus such as corrosion and the formation of heavy boiler scale. The addition of this fresh water, injected in the form of steam, to the connate water in the formation tends to dilute the salt content of the total water in the formation. So diluting the salt content of the total water in the formation, however, reduces the beneficial effects derived from the presence of the salt, both the tendency of salt in the formation to prevent emulsification, and the tendency of the salt carried with the crude to reduce the amount of precipitating, or de-emulsifying, chemical necessary to be added to the crude in the processing plant. Thus, steam stimulation has at least two unfortunate, co-acting concomitants which tend to produce undesired emulsions in the crude so produced, or to magnify the problems of dealing with such emulsions. The first of these concomitants is the tendency of the type of crude in which steam stimulation is most effective to form the tightest emulsions, while the second of these concomitants is the dilution of the salts naturally occurring in the formation by the fresh water used in steam stimulation.

In subsequent production of the well this additional emulsion must be broken to separate the water from the oil in order to make the oil saleable. It has been found that often greater heat is required in the treating system, more de-emulsifying chemical is needed in the produced fluid, and longer retention time is necessary in the treating system in order to remove the water (dispersed phase) from the oil (continuous phase) when steam stimulation has been used. These added, or more time-consuming steps and the use of additional heat, chemicals, or both, result in considerable additional cost for treating the additional emulsion caused by steam stimulation.

Perhaps even more important than the additional cost of treating the additional emulsion caused by steam stimulation, is the operational problem caused when a highly emulsified well is put on production. This may be particularly true, for instance, in the case of a well the primary production of which was not highly emulsified, but which, on secondary recovery by steam stimulation, produces a highly emulsified fluid. The added emulsion often cannot then be adequately handled in the existing treating equipment (designed for low emulsion primary production). Therefore, the storage tanks begin to receive oil containing more water than is acceptable for shipment. This means that the total production of the treating system must be curtailed until the emulsion problem can be resolved. Resolution of the emulsion problem may involve, however, extensive supplementation of the treating system by way of the addition of considerable amounts of equipment, e.g., storage tanks, heater treaters, wash tanks, de-emulsifiers, chemical storage facilities, etc.

It is therefore an object of this invention to prevent or reduce the formation of oil-water emulsions during steam stimulation of an oil well.

It is another object of this invention to eliminate the deleterious effect of dilution by steam stimulation of the salts naturally occurring in the oil-bearing formation.

It is another object of this invention to obviate the supplementation of treating plants when the crude treated thereby becomes highly emulsified, as on secondary recovery by steam stimulation, rather than lightly emulsified, as during primary production.

It is another object of this invention to prevent emulsification and reduce the trouble and cost of treating the subsequently produced oil by the addition of a chemical product to the steam injected into a reservoir so as to inhibit the emulsifying action of the steam and to destabilize any emulsion formed by the action thereof without the provision of expensive additional treatment facilities at the surface.

These and other objects will be apparent from the following detailed description taken in connection with the accompanying drawing which illustrates a well equipped to carry out the present invention, and particularly the methods whereby the chemical material of the present invention may be injected into the formation.

Briefly, the process of the present invention involves the addition of an extremely small amount of a chemical material to the steam employed in steam stimulation of the production of a well. The chemical so employed according to the present invention is a surface-active agent, or surfactant, of a type capable of reducing the tendency of the steam to form a water-in-oil emulsion in the reservoir. Exemplary of the preferred type of chemical for use in the process of the invention is a water soluble, non-ionic, surface-active agent which has the property of substantially preventing water-in-oil emulsions.

In the prior art, chemical additives which act as emulsion inhibitors or destabilizers have been used when hydrochloric acid solutions were pumped into the formations of oil wells for the purpose of scale removal or stimulation. Prior to this invention, however, chemical additives which act as emulsion inhibitors or destabilizers have not been used in steam stimulation, and the type of chemical compound effective as an emulsion inhibitor or destabilizer in conjunction with acid solutions is not always effective for the treatment of emulsions caused by injection steam. The primary reason for this difference in the required chemical additives is the wide difference in pH of the stimulating fluids: hydrochloric acid solutions have a very low pH, in the vicinity of 1, whereas steam has a pH in the range of 7 to 9. An additional reason is that acid injection involves a liquid, whereas steam injection utilizes primarily a gaseous fluid. Indeed, practice has shown that the emulsions produced as the undesired byproduct of steam stimulation when chemical emulsion inhibitors are not used are much more stable

and consequently more difficult to separate than the corresponding undesired byproduct emulsions produced when acid stimulation is employed without the addition of chemical emulsion inhibitors.

In the past, chemical additives have also been used in the process of generating steam for stimulation, e.g., for protection of the steam generator, but none have been employed for the purpose of reducing the emulsifying tendency of steam, or for destabilizing any undesired byproduct emulsions which might be formed. For example, sodium sulfite or hydrazine is often added to remove oxygen from the water used to supply the steam generator. Likewise, the sodium salt of ethylene diamine tetra-acetic acid is added to the water to control hardness. Neutralizing amines, such as morpholine, or filming amines, such as n-octadecylamine, are used to control corrosive action of the steam on the well tubing. None of these chemical additives, however, acts as an emulsion inhibitor or destabilizer.

It is also known in the prior art, e.g., U.S. Patent 3,115,929, to inject a surface-active agent into the water bank existing ahead of the combustion front in the process of stimulating well production by the use of underground, or in situ, combustion. The purpose of thus adding a surfactant in the in situ combustion process, however, is not to improve the product quality, as with the present invention, but to decrease the amount of oil remaining after the passage of the water bank and which must subsequently be consumed by oxidation, thereby economizing in the amount of oxygen which must be supplied to the combustion volume. In the invention of said patent, the presence of the surfactant in the water bank lowers the interfacial tension at the oil-water contact, thereby increasing the efficiency of the oil displacement by the water bank. Consequently, less oil is left behind to be thermally cracked, and hence less carbonaceous material, such as coke, is formed, reducing the quantity of oxygen-containing gas which must be injected to burn through a given volume of reservoir. Thus, not only is the invention of said patent concerned with fuel economy, rather than product quality, but the object of the process disclosed therein is to facilitate the entrainment of oil in the water bank, rather than inhibit the entrainment of water in the oil of the reservoir.

The invention will be further illustrated by reference to the accompanying drawing wherein a casing 10 is set through the overburden 12 and extends for a short distance into the oil-bearing formation 14. Casing 10 is held rigidly in place by cement 16. Steam is injected into the well through tubing 18. The flow of steam, controlled by valve 20, proceeds down the well and along the face of the formation 14 situated below packer 22 mounted on tubing 18. Due to its pressure, the steam (arrows) is forced into that portion of the formation communicating with the space below packer 22. In the usual case, i.e., when at least some primary recovery has been undertaken, there will be a region adjacent to the space below packer 22, which may be quite extensive, from which the economically available crude, or tar, has been drained. This region may be called the "depleted region." When the steam enters and penetrates the formation, it gives up its heat to the formation. Beyond the depleted region, this addition of heat lowers the viscosity of the remaining crude, or tar, enabling it to flow toward the bore 24. This flow, however, will not be very large during the injection period, when steam under high pressure is being continuously supplied via tubing 18 to bore hole 24, and thence diffusing into the formation. At the end of the injection period the well may be closed off for a "soaking" period during which the heat in the formation produced by the steam continues to reduce the viscosity of ever-greater quantities of crude, or tar, outside the depleted region. When, after the soaking period, the well is again opened up, and the pressure in bore hole 24 reduced, most wells so treated, as shown by experience,

will produce a greatly increased yield of crude, or tar, in the bore hole 24, this increased production then being brought to the surface by conventional pumping means (not shown). A substantial amount of the injected water (resulting from condensation of the steam), and also connate water, is produced with the crude.

In order to provide the steam necessary in this method of stimulation a boiler 26 and associated feed water storage tank 28 are provided at the well head. Boiler 26 contains coils 30 and a heater 32. Heater 32 heats coils 30, and thus heats the water from feed water tank 28 pumped through coils 30 by pump 34. Steam from the output end of coil 30 is supplied to tubing 18 via valve 20. Tubing 18 is also provided with an efflux pipe 36, including valve 38, by means of which oil raised through tubing 18 by a pump (not shown) can be routed to storage tanks, and the like.

The process and apparatus so far described in connection with FIGURE 1 is the conventional steam stimulation method and well-known apparatus for carrying it out.

According to the present invention, however, there is added to this well-known equipment at least one small supply tank and associated control valve. Such a supply tank and control valve are 40 and 42, which coact to provide a metered supply of chemical to the water in feed water storage tank 28. A second possible location of the supply tank and control valve is shown by tank 44 and valve 46. Tank 44 and valve 46 coact to continuously supply a metered quantity of chemical to the steam coming from boiler 26 to tubing 18 via valve 20.

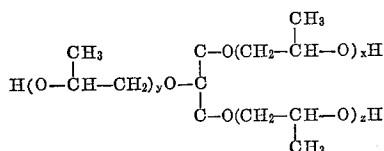
The chemicals referred to as contained in tanks 40 and 44 are, of course, the emulsion inhibiting and destabilizing chemicals referred to herein.

The emulsion inhibiting chemicals can be added to the steam in several ways. The preferred method (using supply tank 40) is to inject the chemical continuously in metered quantity into the water supplied to the steam generator. The compounds described are easily miscible with the water and are readily carried with the steam out of the boiler into the well. Because of their heat stability they are not chemically altered in the steam generator. A second method of treatment is by pumping the chemical continuously into the steam line after the generator, and thus into the oil well. As shown in the drawing supply tank 44, pump 45, and control valve 46 may be used for this purpose. Emulsion inhibiting chemical may also be added elsewhere in boiler 26, or in the line between feed water tank 28 and boiler 26, on either side of pump 34.

In general, then, the chemical compounds which are to be used in the practice of the present invention are the surface-active materials that are water soluble, heat stable and will substantially prevent or destabilize water-in-oil emulsions.

Among the preferred chemical compounds which are found most effective for control of emulsion by steam stimulation are the compounds formed by the combined ethylene oxide and propylene oxide adducts of oxypropylated glycerin as well as the ethoxylated nonyl phenols and the ethoxylated alkyl phenols. An example of the preparation of a suitable compound from the first class is as follows:

(a) Propylene oxide is reacted with glycerin until a molecular weight of about 3,000 is obtained. In this reaction propylene adds in chain-like fashion to each of the three hydroxyl groups giving a mixture of molecules a similar structure and which can be represented by the general formula:



(A)

where x, y and z are of the same general order of magnitude and large enough to give an average molecular weight of about 3,000.

(b) The product (A) is further reacted with a mixture of ethylene oxide and propylene oxide in a molar ratio of 6 parts (A), 3 parts ETO, and 1 part PRO, until a final product (B) is produced having an average molecular weight of about 5,000.

More specifically, the materials which may be used in carrying out the present invention include the following:

(I) Materials that are polymers with labile hydrogens ($\text{R}-\text{OH}$, $-\text{NH}_2$, $-\text{COOH}$) with sufficient oil solubility such as but not limited to (a) Polypropylene glycols (Dow—Polyglycol-P-2000 and Union Carbide Max Polyol PD62025), (b) Polyoxypropylate and glycerin (Union Carbide Max Polyol LG-56 and Jefferson-Triol G 3250), (c) Polybutylene glycol (Dow—Polyglycol B-2000), (d) Polyetherdiamine L-2000 of Union Carbide, (e) alkylphenol formaldehyde resins (Reichhold—Super Beckasites and Archer Daniels Midland—Arofone), (f) Oil soluble alkyds (Reichhold—Beckosol, Archer Daniels Midland—Aroplaz).

(II) Materials that are polyoxyethylene glycol adducts of I to give water soluble, heat stable products that prevent or break steam formed water-in-oil emulsions.

(III) Materials that are polyoxypropylene glycol, polyoxyethylene glycol adducts of I to give water soluble, heat stable products that prevent or break steam formed water-in-oil emulsions.

(IV) Materials that are polyoxypropylene glycol and polyoxyethylene glycol mixed adducts of I to give water soluble, heat stable products that prevent or break steam formed water-in-oil emulsions.

(V) Materials that are polyoxybutylene glycol, polyoxyethylene glycol adducts of I to give water soluble, heat stable products that prevent or break steam formed water-in-oil emulsions.

(VI) Materials that are any combination of I, II, III, IV, V to give water soluble, heat stable products that prevent or break steam formed water-in-oil emulsions.

These products, which have been found to be effective as emulsion inhibitors or destabilizers in steam stimulation are soluble in both water and in aromatic hydrocarbon solvents, but generally insoluble in aliphatic hydrocarbons. They are also stable at elevated temperatures so that they do not undergo chemical decomposition in the high temperature steam. The solubility characteristics of these compounds are such that when they enter the reservoir with the steam they concentrate at the interface between the oil and water where they can most effectively function to inhibit emulsion formation or to destabilize any emulsion that should be formed. It is known that emulsions are stabilized by emulsifying agents which form a third phase between oil and water droplets in the oil and thus prevent the normal coalescing of the water droplets. The inhibiting compounds described in this specification will counteract the effect of these stabilizers so that the motion and heat of the steam will produce substantially smaller quantities of emulsions, and much less stable emulsions, than would form if these inhibiting compounds were not used.

The amount of chemical emulsion inhibitor needed has been found to vary with the nature of the reservoir, the rate of injection, the total volume and temperature of the steam, and the characteristics of the oil and connate water. As a general rule, however, the volume of water injected as steam can be used to determine the quantity of chemical required. On the average, a suitable treatment is to inject the chemical into the water supply to the boiler or into the steam running into the well at such a rate as to maintain a concentration of 5 to 50 parts of chemical per million parts by weight of water or steam, though it is to be understood that more chemical may be employed when economically justified by sufficient

reduction in the quantity of emulsion formed. After the first day of injection, it has been found that the dosage of chemical can generally be about 10 parts per million and still provide adequate emulsion inhibition or destabilization.

As may be seen below, tests of the method according to the invention carried out in five actual producing wells showed surprisingly good results. The results of these tests in actual wells were far better than the results indicated by preliminary laboratory tests.

Five adjacent oil wells in the same zone of one locality (the San Joaquin Valley) all producing from the same formation were chosen for these tests. All five wells were stimulated by steam generated in the same manner from the same source water treated in a similar way.

No chemical additive was used in wells No. 1 and No. 2 for inhibition and destabilization of emulsion, whereas 40 pounds of the product (B) described above were used in conjunction with the steam in wells No. 3, No. 4, and No. 5. The chemical was added on a continuous basis at the rate of 8 pounds per day for the first five days of steam injection. The effluent from each of the five wells was periodically tested for water and emulsion content after the steam injection and soaking period, the first test ("Day 1") being made within a week of the end of the soaking period in each test. The results are shown in the data below. As can readily be seen, the use of the emulsion inhibitor during steam injection substantially reduced the amount of emulsion which was present during subsequent production of the wells.

Test #1, a control test, was run on one of the five wells described above, by steam stimulating the well without the addition of emulsion inhibitor used in the method according to the present invention.

TEST #1

WELL CHARACTERISTICS BEFORE STEAMING

Total production, 7 bbl./day.

Steam stimulation:

Heat capacity of steam, 30 million B.t.u.

Days injection, 6.

Emulsion inhibitor treatment, none.

PRODUCTION AFTER STEAMING AND SOAKING

Day	Gross Prod. (Bbl./Day)	Free Water Prod. (Percent)	Emulsion Prod. (Percent)
1*	266	2.0	25.0
2	143	0	15.0
5	133	8.0	10.0
10	110	5.0	17.0
15	183	0	14.5
24	104	0.6	7.0
28	92	6.6	0
37	92	10.0	0
46	68	10.0	0.1
48	60	45.0	0.1

*First day of recorded data.

Test #2, a control test, was run on a second one of the five wells described above by steam stimulating the well without the addition of the emulsion inhibitor used in the method according to the present invention.

TEST #2

WELL CHARACTERISTICS BEFORE STEAMING

Total production, 6 bbl./day.

Steam stimulation:

Heat capacity of steam, 250 million B.t.u.

Days injection, 4.

Days soaking, 8.

Emulsion inhibitor treatment, none.

PRODUCTION AFTER STEAMING AND SOAKING

Day	Gross Prod. (Bbl./Day)	Free Water Prod. (Percent)	Emulsion Prod. (Percent)
1*	104.5	2.5	60.0
2	288	25.0	15.0
3	184	9.8	10.1
6	186	2.0	0.5
18	153	0.7	17.0
25	147	3.0	10.5
31	51	6.0	4.0
38	48	6.9	0.9
45	39	7.0	32.0

*First day of recorded data.

Test #3 was run on a third one of the five wells described above by injecting emulsion inhibitor according to the present invention continuously during five days of steam injection.

TEST #3

WELL CHARACTERISTICS BEFORE STEAMING

Total production, 9 bbl./day.

Steam stimulation:

Heat capacity of steam, 324 million B.t.u.

Days injection, 6.

Emulsion inhibitor treatment, 40 pounds injected continuously over five-day period.

PRODUCTION AFTER STEAMING AND SOAKING

Day	Gross Prod. (Bbl./Day)	Free Water Prod. (Percent)	Emulsion Prod. (Percent)
1*	98.0	17.0	0
3	93	18.0	0
4	90	16.0	0
8	80	42.0	0
11	69	11.9	0
12	69	11.0	0
16	69	10.0	0
19	67	12.0	0
22	64	9.0	-----
24	62	7.8	T
29	62	8.0	T
33	56	5.4	T
35	55	3.8	T
40	53	2.1	T

*First day of recorded data.

Test #4 was run on a fourth one of the wells described above by injecting emulsion inhibitor according to the present invention continuously during five days of steam injection.

TEST #4

WELL CHARACTERISTICS BEFORE STEAMING

Total production, 7 bbl./day.

Steam stimulation:

Heat capacity of steam, 200 million B.t.u.

Days injection, 5.

Days soaking, 6.

Emulsion inhibitor treatment, 40 pounds injected continuously over five-day period of steaming.

PRODUCTION AFTER STEAMING AND SOAKING

Day	Gross Prod. (Bbl./Day)	Free Water Prod. (Percent)	Emulsion Prod. (Percent)
1*	180	34.9	1.0
4	150	32.0	0.2
5	156	27.0	0.4
7	148	18.0	1.6
8	146	19.0	1.8
9	145	19.0	2.0
11	140	21.0	2.4
12	142	15.0	2.0
15	124	12.4	1.2
16	119	9.2	1.0
22	105	10.4	0.6
25	100	8.0	2.0
26	98	6.0	2.0
27	96	6.0	2.0
31	89	19.0	1.5
34	91	6.3	0.6
39	79	6.0	2.5
43	76	6.9	0.2
48	70	-----	0.1
57	64	6.4	0.4
66	57	6.0	0.1

*First day of recorded data.

Test #5 was run on the fifth one of the five wells described above by injecting emulsion inhibitor accord-

ing to the present invention continuously during five days of steam injection.

Test #5

WELL CHARACTERISTICS BEFORE STEAMING

Total production, 6 bbl./day.

Water produced, 2 bbl./day.

Steam stimulation, days injection, 6.

Emulsion inhibitor treatment, 40 pounds injected continuously over first five days of steaming.

PRODUCTION AFTER STEAMING AND SOAKING

Day	Gross Prod. (Bbl./Day)	Free Water Prod. (Percent)	Emulsion Prod. (Percent)
1*	280	14.7	0.1
2	191	8.9	1.0
3	161	7.7	2.0
4	138	8.0	0.5
5	121	5.9	3.0
6	112	6.7	0.8
7	102	5.0	3.0
8	100	4.5	0.2
9	96	3.9	0.3
10	94	5.0	0.2

*First day of recorded data.

The emulsion produced from the untreated wells was so tight it was not possible to break it by the usual processing with the heater treater unit and addition of chemical emulsion breaker. Accordingly, it was diluted with produced oil already separated from emulsion and then treated successfully by the usual procedure. On the other hand, the emulsion in the production from wells steamed with chemically treated steam was easily broken by the usual field procedures of heater treater and chemical emulsion breaker. Thus, use of the chemical product in actual steaming of oil wells was surprisingly effective both in inhibition and destabilization of emulsion formed by the steam.

In the above tables a hyphen indicates that no data is available, and a T indicates that a trace amount only of emulsion was measured in the test.

The foregoing detailed description is to be clearly understood as given by way of illustration and example only, the spirit and scope of this invention being limited solely by the appended claims:

What is claimed is:

1. A method of recovering crude oil and water from a formation into which a well bore extends, comprising the steps of:

generating steam at the surface and by means of a steam-generating means,

causing said steam to contain a small amount of a surface-active material which is water soluble, heat stable, and effective in preventing water-in-oil emulsions,

injecting said steam containing said surface-active material down said bore into said formation and in sufficient quantity to heat major amounts of the oil in said formation and thereby reduce the viscosity thereof, and

producing said formation to recover said reduced-viscosity oil and also substantial amounts of the condensate of said steam,

whereby the production fluid delivered to the surface contains only small amounts of emulsions, said emulsions in the production fluid being relatively unstable.

2. A method of recovering oil from an oil-bearing formation as claimed in claim 1, in which said surface-active material is caused to be present in said steam by being incorporated into the feed water supply to said means for generating said steam.

3. A method of recovering oil from an oil-bearing

formation as claimed in claim 2, in which said surface-active material is supplied to said means for generating steam continuously at a substantially fixed rate.

4. A method of recovering oil from an oil-bearing formation as claimed in claim 1, in which said surface-active material is caused to be present in said steam by being admitted to the steam line from said steam-generating means to said well bore.

5. A method of recovering oil from an oil-bearing formation as claimed in claim 4, in which said surface-active material is supplied to said line at a continuous rate of flow which is substantially constant.

6. A method of recovering oil from an oil-bearing formation as claimed in claim 1, in which said well bore is sealed for a soaking period after the discontinuation of the supplying of said steam, and prior to commencement of said step of producing said formation.

7. A method of recovering oil from an oil-bearing formation as claimed in claim 1, in which said surface-active material comprises a compound formed by the combined ethylene oxide and propylene oxide adducts of oxypropylated glycerine.

8. A method of recovering oil from an oil-bearing formation as claimed in claim 1, in which said surface-active material comprises an ethoxylated nonyl phenol.

9. A method as claimed in claim 1, in which said surface-active material comprises an ethoxylated alkyl phenol.

10. The invention as claimed in claim 1, in which the concentration of said surface-active material, in said steam being injected into said formation, is caused to be in the following general range: 5 to 50 parts of surface-material per million parts by weight of steam.

11. The invention as claimed in claim 1, in which said surface-active material is caused to be present substantially continuously in the steam being injected down said bore, and in which said steam is injected substantially continuously down said bore for at least a substantial number of days.

12. The invention as claimed in claim 11, in which said steam injection is terminated, and then followed by a soaking period of substantial duration, prior to said step of producing said formation.

13. A method of recovering oil from an oil-bearing formation into which a well bore extends, comprising the steps of:

generating steam at the surface,

supplying said steam to said oil-bearing formation by way of said well bore,

supplying a surfactant to said formation to inhibit the production of oil-water emulsion as a result of the interaction of said steam with the oil and water in the formation, and

recovering from said formation oil and water which was subjected to the action of said steam.

14. A method of recovering oil from an oil-bearing formation as claimed in claim 13, in which said surfactant is water soluble and heat stable.

15. A method of recovering oil from an oil-bearing formation as claimed in claim 13, in which said surfactant is non-ionic.

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