

1

3,016,352

PROCESS FOR IMPROVING INJECTIVITY IN
SECONDARY OIL RECOVERYFrederick A. Hessel, Montclair, N.J., assignor to General
Aniline & Film Corporation, New York, N.Y., a corpo-
ration of DelawareNo Drawing. Filed Oct. 30, 1959, Ser. No. 849,749
4 Claims. (Cl. 252-8.55)

This invention relates to the secondary recovery of 10
petroleum by the water flooding method and more particu-
larly is concerned with the treatment of water input wells
for the purpose of facilitating the injection of flood water
into an oil reservoir.

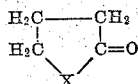
Oil exists in well sands or similar strata in two different 15
states, i.e., as free oil that is located in the voids of the
sand and as fixed oil which is held by absorption (and
perhaps to some degree by adsorption) on the particles of
sand and which is commonly referred to as the film of
oil that adheres to the particles of sand or the particles
of the oleiferous structure. Such fixed oil may be said
to be held by "sorption."

Free oil can be recovered by conventional methods of 20
oil producing such as draining the oil in conjunction with
liquid or gaseous pressure and creating an artificial fluid
or gaseous pressure in the sand bed so as to dislodge the
oil from the sand bed and thereafter conduct the dis-
lodged oil to the surface of the ground. Fixed oil, on
the other hand, cannot be recovered by any of the con-
ventional methods or means used to produce oil and can-
not be dislodged economically by either fluid or gaseous
pressure. In some cases, the amount of oil remaining in
the well after pumping has become unprofitable may equal
60 percent of the original oil present. Water is introduced
under pressure into a number of wells, and oil together
with water is produced from other wells by the resultant
water drive. The success of the water flooding operation
manifestly depends upon its total cost being less than the
value of the additional oil recovered from the reservoir.

A substantial factor in the economics of water flooding 25
is the cost of pumping the water into the formation. In
many cases pumping costs may be too high to permit this
secondary method to be employed successfully. This is
occasioned by unduly low rates of water injectivity into
the formation for a given pump pressure, which necessi-
tates the use of excessively high pressures to force the
water into the formation at the desired rate. When this
condition prevails, a conventional flooding operation can-
not be practiced economically.

The present invention is directed to a method of treat-
ing an input well so that the water injectivity rate can be
substantially increased for a given pump pressure level.

According to the invention, the formation adjacent the
input well is treated by means of a water miscible organic
treating agent which has the ability to increase the in-
jectivity rate of water or brine solutions in an oil bearing
formation. The organic treating agents, used according
to this invention, are compounds having the following gen-
eral formula:



wherein X represents either oxygen, an imino group (NH) 30
including lower alkyl (1 to 4 carbon atom) substituted
(NR) imino groups wherein R represents an alkyl group
of 1 to 4 carbon atoms. The compounds are completely
miscible with water, and when used to treat formation
surrounding the input well base, a substantial increase in
the water or brine injectivity rate is effected.

Examples of specific compounds contemplated by the

2

foregoing general formula and which may be used in
practicing the present invention include: γ -butyrolactone,
2-pyrrolidone, and 1-methyl, 2-pyrrolidone, 1-ethyl, 2-pyr-
rolidone, 1-isopropyl, 2-pyrrolidone and 1-butyl, 2-pyrro-
lidone.

The ability of these compounds to increase the in-
jectivity rate of water or brine into an oil bearing formation
was demonstrated in the following manner:

Eight core samples each measuring 3 inches in diameter
and 4 inches in length of an oil bearing formation were
obtained at a depth of approximately 1300 feet from the
Bartlesville sand, Washington county, Oklahoma. These
core samples had the following properties:

Sample Number	Permeabil- ity, Md. (Milli- darcies)	Porosity (Percent)	Percent Saturation		
			Oil	Water	Total
Core No.:					
1-----	38	17	32	44	76
2-----	42	17.5	36	43	79
3-----	41	17.4	35	42	77
4-----	39	17.3	34	44	78
5-----	40	17.5	35	42	77
6-----	42	17.5	36	43	79
7-----	41	17	33	44	77
8-----	40	17	34	45	79

A simple mounting provided means for flooding the sur-
face of the cores. The samples were treated as follows:

Core No. 1----- Treated with 10 cc. of water.

30 Core No. 2----- Treated with 10 cc. of Arbuckle
lime brine (obtained K & S
Project Oil Recovery Corp.,
Miller WSW#1 well, Township
27 north, Range 13 east, N.W.
quarter of Section 5, Washing-
ton County, Oklahoma).

	First treated with 2 cc.—	Followed within 15 minutes by—
Core No. 3-----	γ -butyrolactone (B.P. 240° C.)-----	10 cc. water.
Core No. 4-----	γ -butyrolactone-----	10 cc. Arbuckle lime brine.
Core No. 5-----	2-pyrrolidone (B.P. 245° C.)-----	10 cc. water.
Core No. 6-----	2-pyrrolidone-----	10 cc. Arbuckle lime brine.
45 Core No. 7-----	1-methyl, 2-pyrrolidone-----	10 cc. water.
Core No. 8-----	1-methyl, 2-pyrrolidone-----	10 cc. Arbuckle lime brine.

The number of minutes for the absorption of water or
brine into the core is tabulated below:

Core No. 1-----	Not absorbed in 1 hour.
Core No. 2-----	Not absorbed in 1 hour.
Core No. 3-----	15 minutes.
Core No. 4-----	15 minutes.
55 Core No. 5-----	15 minutes.
Core No. 6-----	15 minutes.
Core No. 7-----	10 minutes.
Core No. 8-----	10 minutes.

60 It is quite evident from the above data that these com-
pounds which are soluble in water have nevertheless the
ability to increase materially the injectivity of water and
brine in an oil bearing formation. It is well known that
an increase in water throughput in a given formation helps
materially in the recovery of oil.

The following example further illustrates the use of the
present invention.

A water input well in an oil bearing formation being
subjected to a water flooding operation located at a depth
of about 1300 feet and having an oil sand thickness of
22 feet was selected. Core studies showed that the forma-
tion had an average porosity of 17%, a permeability to

3

air of about 40 millidarcies and a residual oil content of 35%. Prior to treatment the rate of pumping water into this input well was about 200 barrels per day. The formation was then treated by pumping thereinto, through the water input well, 20 gallons of 1-methyl, 2-pyrrolidone. The pumping of flood water into the input well was then resumed with the same pump pressure with the result that the injection rate was more than double that obtained prior to treatment.

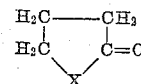
It is not known why treatment with the type of compounds described above will substantially increase the permeability of an oil bearing formation to water or the injectivity rate of water or brine into the input wells. One possible explanation is that these compounds in some manner help to move the droplets of residual oil that otherwise would not flow through the formation. By flowing this residual oil away from that portion of the formation adjacent to the pore hole of the input well, the resistance to water flow is considerably reduced and the injection of water is correspondingly facilitated, possibly due to the fact that a greater area of oil free sand is now present for the injection of the water. Once the removal of residual oil from the immediate vicinity of the pore hole has been accomplished, the resistance to flow of water will remain low during further injection of water or brine. It is understood, however, that we do not limit ourselves to this theory of operation.

I claim:

1. In the secondary recovery of petroleum from an underground formation by the water flooding method

4

wherein water is injected through an input well into an underground oil bearing formation to force the oil through the formation toward an output well from which oil is withdrawn, the step of increasing the injectivity of flood water into an input well which comprises introducing through the input well into the adjacent formation a water miscible compound of the formula



wherein X represents a member of the group consisting of 0 and an imino group and a lower alkyl (1 to 4 carbon atom) substituted imino group.

2. The method according to claim 1 wherein the compound introduced through the well is γ -butyrolactone.

3. The method according to claim 1 wherein the compound introduced through the well is 2-pyrrolidone.

4. The method according to claim 1 wherein the compound introduced through the well is 1-methyl, 2-pyrrolidone.

References Cited in the file of this patent

UNITED STATES PATENTS

2,262,428 Lietz Nov. 11, 1941

OTHER REFERENCES

Orco Pins Hopes on Carbonated Flood Water, Article in the Oil and Gas Journal, Sept. 2, 1957, pages 88 and 89.