Panel Discussion

STEAM INJECTION
FIELD PROCEDURES AND RESULTS

Thermal Oil Recovery

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Steam Injection - Field Procedures and Results

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INTRODUCTION

The benefits of steam injection have been known for many years in the oil industry. It is reported that steam injection was first used to accelerate production shortly after the discovery of oil in Pennsylvania.[1] In the early 1930's, Smith Stoval conducted extensive laboratory studies and performed a field test near Woodsen, Texas, to evaluate the steam drive mechanism.[2] Recently, the search for additional oil reserves has caused a great deal of effort to be directed toward the evaluation of thermal recovery methods. Improvements in steam generating equipment and spectacular results obtained from steam stimulation projects have accounted for increased popularity of steam injection. These spectacular results have also caused a cloak of secrecy to be placed on steam injection projects.

This paper discusses two steam injection methods which are currently being used by the oil industry: steam drive and steam stimulation. Each method has inherent advantages and disadvantages. Variations and/or combinations of these methods have been used to utilize the advantages of both processes.

STEAM DRIVE

This process involves continuous steam injection into a well(s), with production being taken from other well(s). Oil is displaced by a complex driving mechanism consisting of a cold water drive, followed by a hot water drive, which in turn is followed by a gas (steam) drive. Reduction in increases the sweep efficiency of a steam drive over a conventional waterflood. Thermal expansion of reservoir fluid in the heated zone increases recovery from both the swept and non-swept portions of the reservoir. In addition, a portion of the "residual oil" in the swept zone is recovered by steam distillation. Laboratory studies by Willman et al, and steam distillation data can be used to estimate oil recovery by steam drive.[3]

During steam injection, heat losses occur in the wellbore of the injection well and in the reservoir itself. Ramey has published data which are useful in estimating wellbore heat losses.[4] Heat losses in the reservoir mainly involve vertical heat flow by conduction to strata which occur above (and below) the reservoir being flooded. Several methods may be used to estimate these losses. [3,5,6,7] A graphical solution of heated radius (after vertical heat losses) using the Marx and Langenheim Method is shown in Fig. 1. [5,8]

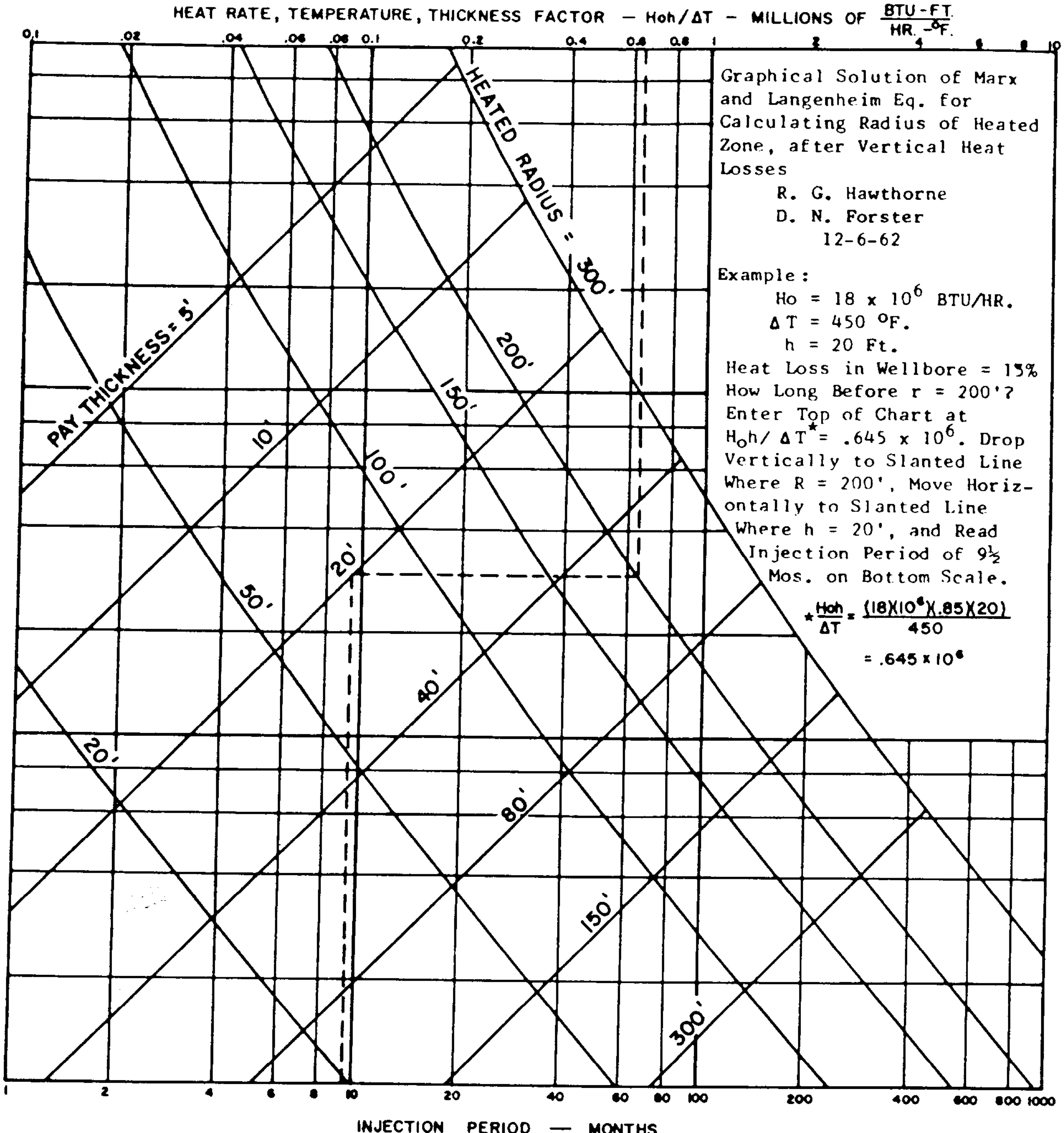


Fig. 1

STEAM STIMULATION

This process consists of a series of operations, all of which are conducted in a single well. Several colorful titles which have been used to describe this method are "Huff and Puff", "Steam Soak", "Cyclic Method", and "Push and Pull".

In this process, steam is injected into a well for a relatively short period of time, followed by a short shut-in period before the well is returned to production; this series of operations is called a cycle.

The purpose of the steam injection phase is to heat up a portion of the reservoir in the vicinity of the wellbore. This treated zone acts as a large heat exchanger, heating cold reservoir fluids which approach the vicinity of the wellbore.

Viscosity of heavy crude is greatly reduced with increased temperature as shown in Fig. 2 (after Owens and Suter).[9] For example, if a 10 °API crude is heated from 100°F to 200° at 250 psi, its viscosity will be reduced from 13,000 cps to 220 cps. This 60-fold decrease in viscosity will theoretically increase production rate 60 times the rate prior to heating. In comparison, heating a 20 °API crude from 100°F to 200°F at 500 psig

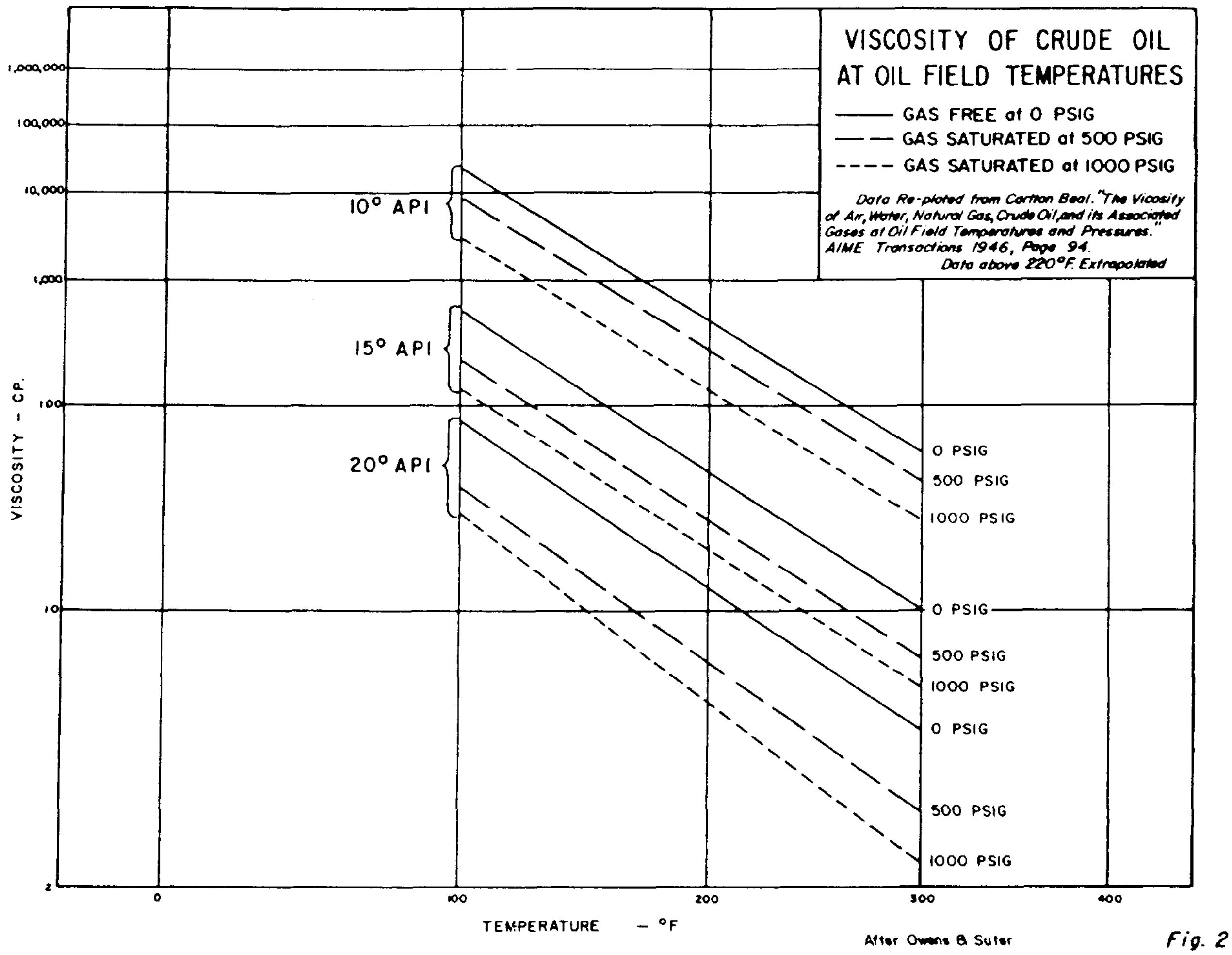


Fig. 2

will reduce its viscosity from 34 cps to 6.7 cps. This only represents a 5-fold decrease in oil viscosity; therefore, steam stimulation is limited to wells which produce low gravity oil.

The low inflow rate of cold fluids outside the boundary of the treated zone does not restrict flow rate into the wellbore because the flow area at the boundary is much larger than the flow area at the face of the wellbore.

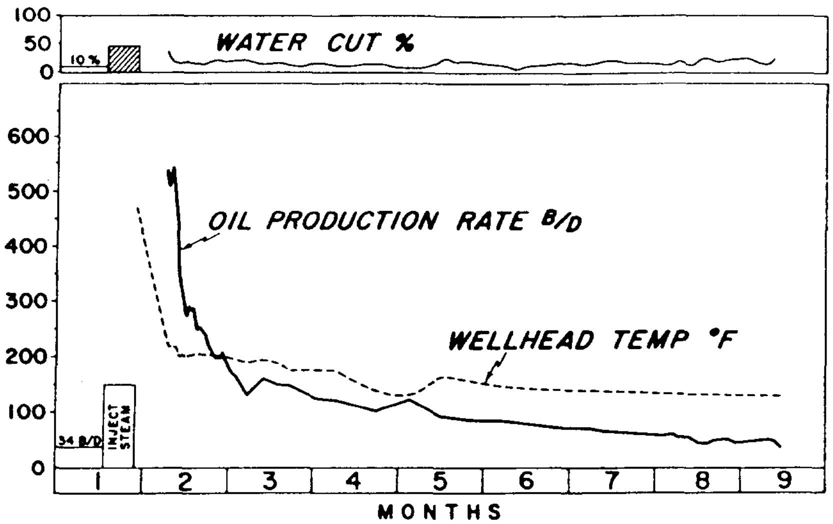
The purpose of the short shut-in period is to allow sufficient time for the injected steam to condense. If a treated well is prematurely returned to production, steam will be produced at the surface, resulting in high heat losses and dangerous operations.

When a stimulated well is returned to production, it will initially produce at high rates. As heat is removed from the treated zone, production rates will decline. Production rate will return to normal when temperature of the treated zone declines to its original value. Exceptions to this occur when permanent permeability improvement or impairment is effected in the vicinity of the wellbore. Permeability improvement may result from the removal of bitumen or waxy deposits in the vicinity of the wellbore. Permeability impairment may be caused by clay swelling, due to contact with fresh water.

After production has declined to normal, the entire process may be repeated. The number of cycles which can be profitably performed, and the ultimate recovery by steam stimulation is unknown at this time.

STEAM DRIVE - FIELD RESULTS

Data from two steam drives have been reported in recent literature. T. M. Doscher et al reported the results of a modified steam drive conducted in Canada's Athabasca Tar Sands.[10] Recovery efficiencies of 50-70-per cent were reported. This test employed the injection of an alkaline solution (in addition to steam injection) to recover the bitumen contained in the Athabasca Tar Sands.



PRODUCTION AND TEMPERATURE CURVES

STEAM STIMULATION AREA A

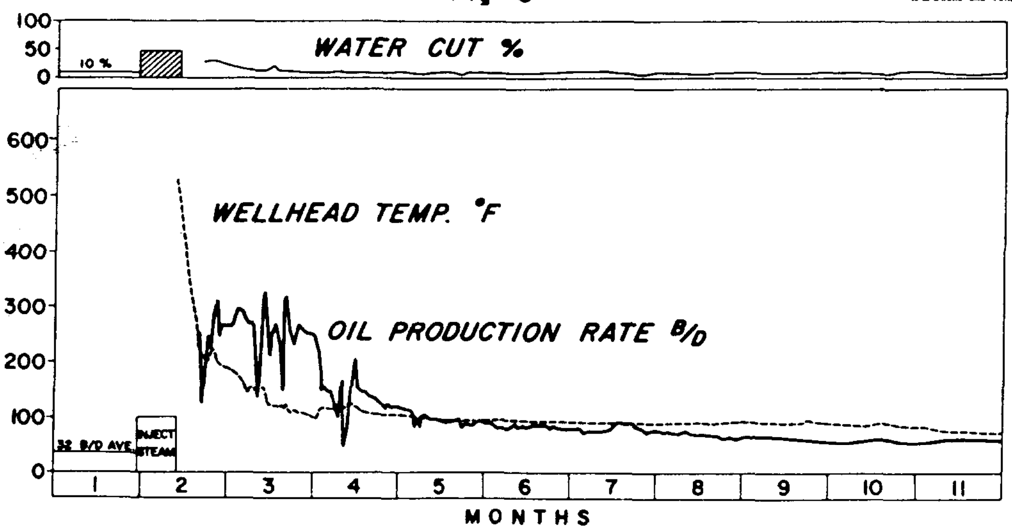
RESERVOIR PROPERTIES	
Sand at	700 ft
Oil gravity	12° API
Reservoir press.	150 psig
Reservoir temp.	97° F
Oil viscosity	900 cp at res. cond.
Zone thickness	500 ft

DETAIL OF STEAM STIMULATION	
Injected	5 billion Btu 11,500 bbl. water
Injection time	12 days
Shut-in time	11 days
Injection temperature	470° F
Injection pressure	240 psig
No packer	
Est. steam quality	70° superheat

PRODUCTION DATA	
OIL:	
Cum. prod. prior to stim.	45,100 bbl.
Production since stim.	24,700 bbl.
Prod. rate before stim.	32 B/D + 10% water
Current producing rate	51 B/D + 13% water
Incremental oil	17,000 bbl. or 3.4 bbl/MM Btu
WATER:	
Cum. prod. since stim.	4,756 bbl.

Fig 3

W.D. Owens and Vane E. Suter



PRODUCTION AND TEMPERATURE CURVES

STEAM STIMULATION AREA B

RESERVOIR PROPERTIES	
Sand at	3,000 ft
Oil gravity	10° API
Reservoir press.	1,000 psig
Reservoir temp.	131° F
Oil viscosity	330 cp at res. cond.
Zone thickness	47 ft

DETAIL OF STEAM STIMULATION	
Injected	3.1 billion Btu 12,500 bbl. water
Injection time	13 days
Shut-in time	8 days
Injection temperature	532° F
Injection pressure	900 psig
Packer	
Est. steam quality	60%

PRODUCTION DATA	
OIL:	
Cum. prod. prior to stim.	68,583 bbl.
Production since stim.	30,464 bbl.
Prod. rate before stim.	32 B/D + 10% water
Current producing rate	62 B/D + 11% water
Incremental oil	20,500 bbl. or 6.6 bbl/MM Btu
WATER:	
Cum. prod. since stim.	5,311 bbl.

Fig 4

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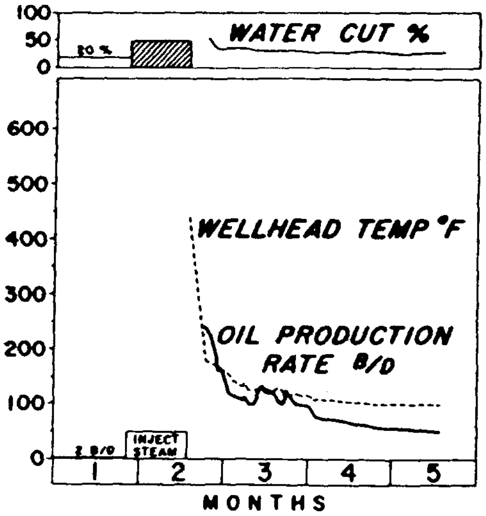

PRODUCTION AND TEMPERATURE CURVES

STEAM STIMULATION AREA C

RESERVOIR PROPERTIES	
Fractured shale at	1,550 ft
Oil gravity	8.5° API
Reservoir pressure	300 psig
Reservoir temp.	115° F
Oil viscosity	10,000 cp at res. cond.
Zone thickness	300 ft

DETAIL OF STEAM STIMULATION	
Injected	3.6 billion Btu 14,000 bbl. water
Injection time	22 days
Shut-in time	6 days
Injection temperature	440° F
Injection pressure	380 psig
No packer	
Est. steam quality	60%

PRODUCTION DATA	
OIL:	
Cum. prod. prior to stim.	42,645 bbl.
Production since stim.	8,021 bbl.
Prod. rate before stim.	2 B/D + 20% water
Current producing rate	51 B/D + 29% water
Incremental oil	7,780 bbl. or 2.2 bbl/MM Btu
WATER:	
Cum. prod. since stim.	4,043 bbl.

Fig. 5

W.D. Owens and Vane E. Suter

Jiri Juranek reported oil recoveries equal to 550 per cent, expressed as 100 times the ratio of output energy to input energy, for a steam drive in a Czech reservoir.[11] In other words, the heating value of the crude recovered from this steam drive was equal to 5.5 times the amount of energy used to generate steam for injection into the reservoir.

STEAM STIMULATION - FIELD RESULTS

Owens and Suter reported results of three steam stimulation treatments (first cycle) made in three separate areas.[9] Figs. 3, 4, and 5 show the results of these tests. These treatments do not represent optimum treatment; however, they are representative of several treatments on different wells in each particular area.

These results show high initial well productivity, and incremental oil recoveries ranging from 2.2 to 6.6 bbl per million BTU injected at the surface. Incremental oil recovery is defined as extra oil recovered during the producing period. The heating value of incremental oil recovered ranges between 7.9 and 23.6 times the energy used to generate the injected steam (based on boiler efficiency of 60 per cent and net heating value of oil equal to 18,000 BTU/#). Produced fluids from the well in Area B (see Fig. 4) removed 143 million BTU from the treated zone before the BHT returned to normal. This represents only 4.6 per cent of the total heat injected at the surface.

Water production after stimulation was negligible, and ranged from 29 to 43 per cent of the amount of water used to generate the steam slug.

Owens and Suter reported that tests made in other areas indicate that an upper oil gravity limitation of 15 °API exists for profitable application of steam stimulation.[9]

CONCLUSION

Steam injection has recently become an important secondary recovery method, especially in its application to reservoirs which contain low gravity crude. Steam drive application is limited by the magnitude of heat losses, and the amount of additional oil which is recoverable. Steam stimulation can be successfully applied to wells which produce 15 °API crude, or less.

It is anticipated that industry technology will be greatly improved as restrictions are lifted in the exchange of information on steam injection operations.

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