S-CAL RESEARCH CORPORATION

SYSTEM TO INJECT STEAM AND PRODUCE OIL FROM THE SAME WELLBORE THROUGH
DOWNHOLE VALVE SWITCHING

Contract DE-FG01-92 CE 15553

FINAL REPORT

ABSTRACT:

Through direct contacts with many California Operators, the potential market for this technology and hardware was more closely defined. The largest market might be for re-entry into existing but shut-in wells, equipped with 7"OD cemented casings, for which a suitable configuration was designed. For field-testing any prototype Downhole equipment, however, Operators and Service Companies prefer to start with a new well, for better control of the well characteristics. In the relatively shallow reservoirs where Steam injection is currently used with success, the additional drilling cost, in soft formations, is sufficiently small that this became the main design case.

Substantial savings were obtained by reducing the number of Downhole valves from two to one and by replacing the twin hydraulically-controlled ball or flapper-type valves with a single sliding sleeve valve, operated by wireline. Laboratory tests conducted

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at UC-Berkeley confirmed the satisfactory operation of this type of valve with wet steam over extended periods.

Low reservoir pressures dictated the use of artificial lift methods, with rod pumps considered the most economical. The availability of live steam downhole at all times is, however, a major advantage which led to the selection of a combined method of artificial lift:

- 1) steam-lift of the produced fluids up to the kick-off point of the medium curvature drainholes,

- 2) dumping of the produced fluids into a vertical separator/sump below the kick-off points,

- 3) vertical rod pumping of the liquid phases from the downhole separator/sump to the surface through a dedicated production tubing.

The main benefits of this approach are: a drainhole draw-down comparable with that achievable with a pump operated with highly curved rods, without the wear problems associated with curved rod strings.

This same technology and hardware, when applied to mature Light Oil fields, may greatly extend the economic use of steam as a Tertiary Oil recovery method for Light Oil, even in very low-pressure reservoirs. This is a natural follow-up of the pioneering work done by the DOE at NPR #3 to demonstrate the technical feasibility of this recovery mechanism.

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1.DESIGN PHILOSOPHY

The well configurations required for simultaneously injecting steam in one horizontal drainhole, while producing oil from another horizontal drainhole connected to the same vertical casing may present many variations. All of those considered in this project were aimed at the use of parallel dedicated steam and production tubings, together with the patented Downhole valves required for switching each drainhole to the injection or to the production mode by the most economical means.

The objectives of using this type of well configuration and this operating method may be summarized as follows:

- 1) increasing the oil production rate per well
- 2) reducing capital investment per daily barrel of oil
- 3) reducing operating labor expenses per barrel of oil

- 4) reducing the steam to oil ratio (SOR)
- 5) reducing oil processing cost per barrel
- 6) maximizing operational flexibility.

The first objective is achieved by the following combination of effects:

- a) increased productivity index (PI) of horizontal drainholes as compared to vertical wells, a well-documented effect,
- b) increased effective draw-down pressure, by suitable artificial lift methods,
- c) reduced well down-time by reducing temperature variations and thermal cyclic stresses in all tubulars.

The second objective is achieved by minimizing the net cost of the well and twin drainholes and by using only a few such wells to drain the same volume of reservoir as a large number of conventional vertical wells. Shorter flow lines and steam lines also provide substantial savings.

The third objective is achieved by eliminating the need for a service rig for switching from one mode to the other and for most routine maintenance. The use of fewer pumps to lift a larger volume of oil also contributes to large savings. Minimizing cyclic thermal stresses and rod friction are expected to reduce maintenance labor.

The fourth objective is achieved by a combination of higher steam quality in the reservoir and more efficient gravity drainage of oil along the walls of the steam chamber. Cyclic steam injection also

reduces the net heat loss to the overburden where the heat front successively advances and recedes during successive cycles.

The fifth objective is achieved by an effective separation of steam from oil and water downhole, so as to reduce emulsion problems in the surface oil processing plant. A reduction of the sand volume reaching the surface is also an advantage.

The sixth and last objective is achieved by allowing easy access into each drainhole for logging or cleaning operations and by using proven controls and tools for all well operations. The multitude of differences between various reservoirs makes it imperative that the same equipment be easily adaptable to different conditions.

2. NEW WELL PREFERRED CONFIGURATION VERSUS RE-ENTRY INTO AN EXISTING WELL

The use of re-entry into existing wells may ultimately be the largest market, once the technology and equipment have been fully field-tested. A 7" OD casing also limits the sizes of the dedicated tubings to 2 3/8" OD and drastically limits the diameter of the twin drainholes. Continued progress in the use of coiled tubing drilling and completion methods and the trend towards miniaturized drilling tools are expected to contribute to the future development of this market if oil prices remain low. For the demonstration of this new technology, all Operators contacted, however, preferred to use a new well, drilled to take maximum advantage of the possibilities offered by this approach to reduce the well operating costs while increasing its production

rate. This is a significant departure from the conclusions of the First Quarter Report.

In the soft formations encountered in many of California's Heavy Oil fields, drilling of vertical wells is very fast and the additional cost of a larger-diameter bit is a relatively small component of the total well cost. Currently, the tendency of most Operators is for using larger, more rugged drilling tools to drill faster, even if the cost of bits, casing and cement are higher, rather than accepting the limitations of smaller-diameter drainholes over the lifetime of the well, for which operating costs may be made greater by lost time due to obstructions in small-diameter liners. Sand production problems are frequent in unconsolidated reservoirs. These can be reduced by gravel-packing, but this requires larger boreholes. In the end, an acceptable compromise (Fig. 1) is a 3.5" OD liner equipped with centralizers in gravel-packed horizontal drainholes of about 5" ID. The upper part of the 3.5" OD liner is connected to a 4.5" OD liner cemented in the curved part of the medium curvature drainhole, up to the kick-off point. To insure a good cementation, the curved part of the drainhole is under-reamed to about 6" ID. This configuration allows the use of a 2 7/8" OD tubing in the curved liner. When in the production mode, the curved tubing is used to steam-lift the produced stream to the kick-off point. For this purpose, the lower end of the tubing is equipped with a side-pocket mandrel and a 1" OD retrievable gas-lift valve. Other artificial lift alternatives considered were the use of a jet pump located at the lowest point of the curve or that of a rod pump operated with a curved rod string. The difficulty of efficiently pumping what is, in effect, a boiling liquid stream led to the selection of the steam-lift method, which has previously been used successfully

FIG. 1.B CASING / LINERS
CONNECTIONS

FIG. 1.A CASING STRING

to produce Heavy Oil over short differences in elevation (≤ 300 ft). This well configuration is also compatible with the application during the well lifetime of the Doscher process (Ref.1), which uses a mixture of steam, gases and a surfactant additive instead of only wet steam to recover additional oil.

At the kick-off point, the three-phase mixture of steam, hot water and oil is dumped into a vertical downhole separator (Fig.2). Steam is vented to the casing annulus, while the separated oil/ water are pumped to the surface by a vertical rod pump through a dedicated production tubing, as currently done in the vertical producing wells of a steamflood. This combination of a downhole separator and steam lift limited to the 300 ft between the lowest point of the drainholes and the separator also allows the simultaneous operation of both drainholes in the producing mode, using a reduced steam rate through the steam tubing.

The steam required for the steam-lift in the producing drainhole and that required for injection into the injection drainhole is supplied from the dedicated steam tubing through a sliding-sleeve three-way valve. For this purpose, the sliding sleeve presents two kinds of ports: small orifices throttling the steam flow to the liner/tubing annulus of the producing drainhole, at a very low rate, and a row of large openings through which the much larger injection rate flows freely from the steam tubing to the liner of the injection drainhole.

Besides the greater simplicity of the sliding sleeve valve over the flapper or ball-type valves is the capability of providing this small steam-lift stream without significant wear of the valve mechanism. The possibility of operating the sliding sleeve by wireline tools inserted in the steam tubing rather than by hydraulic controls

FIG. 2. COMBINED S-CAL RESEARCH AND DOSCHER PROCESSES

also offered a significant capital cost reduction.

In Heavy Oil reservoirs at relatively high pressure, the steam-lift operation may be omitted. In consolidated reservoirs where sand production is unlikely, gravel packing of the liner and the use of a Downhole Separator may also be omitted. In that case, the rod pump may then be located directly in the curved tubing of the producing drainhole, in the upper part of the curve. This rather conventional arrangement, however, requires the use of a service rig to transfer the pump from one drainhole to the other every time that the operating mode of the drainholes is changed, as shown on Fig.3 (see Fourth Quarterly Report)

A final improvement of the basic well configuration was the grouping of all flow control devices (three-way steam valve and transferable plugs) in a "H" joint coupled on top to the end of the steam tubing and terminated at the bottom by a four-prong connector made of four PBRs, allowing full thermal expansion of the steam tubing. In this arrangement both the steam tubing and the production tubing hang freely from the wellhead, as currently done in most steam injection wells and in nearly all Heavy Oil production wells. This also eliminates the need for costly expansion joints and makes it easy to pull out the "H" joint for repairs, if necessary (Fig.4).

To provide sufficient space for the two parallel tubings, respectively 3.5"OD for the steam tubing and 2 7/8"OD for the production tubing, a 10.75"OD casing is required. The curved channels used as whipstocks to kick-off the twin drainholes are also used in their lower part to hang the 4.5"OD curved liners and in their upper part to hang the curved 2 7/8"OD tubings. A conventional packer may be used to hang and pack-off the liner, prior to its cementation. The upper

FIG. 3 TWO MODES
OF OPERATION
OF THE LATERALS
WITH A SINGLE
CURVED ROD STRING

FIG. 4 STEAM TUBING COMPLETION
ASSEMBLY (Not to Scale)

end of each curved tubing is hung and sealed in the top plate of the middle casing joint by a threaded coupling, the rotation of which is allowed by inserting a conventional "hanger swivel" joint connector (by TIW) in the upper part of the tubing string. This change from the concept presented in the Third and Fourth Quarter Reports is justified by the lower cost of these couplings and their greater adaptability to seal against any imperfect or bit-scoured inner surface of the curved channels. The pressure-tight tie-in between casing and liners is obtained by conventional mechanically-set hanger/packers (TIW "LH" packer) set in the lower part of each curved channel. A conventional cement stage diverter valve is inserted at the junction between the 3.5"OD liner and the 4.5"OD liner. It is used successively to displace gravel behind the 3.5"OD liner string and to displace cement behind the 4.5"OD curved liner.

All other flow connections are pre-installed in the Lower and Middle Casing Joints in a manner similar to that described in the Fourth Quarterly Report. They include two steam feeder lines leading from the two steam PBRs to the annular spaces of the two drainholes and a 3"ID vertical collector pipe in which the vertical production tubing and pump is inserted. This pipe is in flow communication with the annular space between the 11.75"OD Middle and Lower Casing Joints and the two curved channels. This annular space serves as Downhole Oil Separator into which the production stream is dumped from the lower part of the "H" Joint, while steam and gases are vented into the casing annulus through the top of the "H" Joint. One of the functions of the Downhole Separator is to collect any entrained sand and to prevent its entry into the rod pump. Suction cleaning of the Downhole Separator with a coiled tubing may periodically remove any significant sand

accumulation on the Separator bottom, without requiring a service rig. This is accomplished by raising gas pressure in the casing annulus while opening the coiled tubing to the atmosphere, through a filter bag. This operation may be performed even while both drainholes are in the injection mode, so as to eliminate lost time.

The 3" ID pipe, with its circulation valve closed to the separator space, is initially used to convey the cement slurry from a stabbed-in work string to the casing shoe during the displacement of cement behind the casing string, prior to drilling the twin drainholes. (see Fig. 5)

3. APPLICATION TO LIGHT OIL RECOVERY BY STEAM INJECTION

The same well configuration and downhole hardware may be used in mature Light Oil fields in which the residual oil saturation remains high but where low reservoir energy limits the oil recovery. The successful application of steam injection at NPR # 3 and NPR # 2 shows that significant additional oil volumes could be recovered from such reservoirs. This is outlined in the Fifth Quarter Report for the Tea Pot Dome field. It is believed that the use of a few vertical wells equipped with twin drainholes in that field could very effectively recover oil from an area which, with vertical wells on a 1 ac. spacing remains only marginally economic for steam injection. The benefits of horizontal drainholes in highly fractured formations are such that well rates could be increased almost ten-fold, thus greatly reducing capital cost and operating expenses in that field.

4. CONCLUSIONS

Fig. 5. Perspective View of Bottom Casing Joint

- The well configuration has evolved from the case of re-entry into an existing 7" casing to that of a newly-drilled well equipped with a 10.75"OD casing.

- Alternatives options in the drainholes design and operation include:

1) a 2 7/8" curved tubing from which the produced stream is lifted to the surface by a rod pump located near the tubing base and operated by a curved rod string,

2) a partial steam lift from the base of the curved production tubing to the kick-off point where the production stream and lift steam are separated in a vertical downhole separator, from which the liquid phases are pumped to the surface by a vertical rod pump.

- The downhole hardware cost has been reduced and its operational reliability increased by the following improvements:

a) use of wireline tools for downhole switching of the drainholes mode of operation,

b) use of a single sliding sleeve three-way steam valve and of a wireline-transferable plug instead of two hydraulically-operated flapper-type valves,

c) use of two conventional injection packers set in the curved channels for the drainhole liners and of a swivel hanger / threaded connector for the curved tubings to reduce the drainholes completion cost,

d) use of a four-prong PBR connector at the end of the steam tubing to distribute steam coming out of the single three-way steam valve and to allow free thermal expansion of the steam tubing,

e) use of an "H" joint with its two lower branches equipped with a wireline-transferable plug to select the production drainhole and to gather the produced stream. Under alternative Option 1, the upper branch of the "H" joint opposite to that connected to the steam tubing is connected through an expansion joint to the production tubing and flow communication between the bottom of the "H" joint and the casing/channels annulus is closed.

Under Option 2, this upper branch of the "H" joint is open to vent the lift steam into the casing annulus, while flow communication is open to the casing/channels annulus, used as downhole separator/sump.

- As a result of this project, a more adaptable and cheaper downhole hardware system was designed and its valve component was successfully laboratory-tested. This operational flexibility is an important feature required by the variety of field conditions to be covered, as indicated by many contacts made with Oil Operators, large or small, in several fields varying in depth, reservoir characteristics, oil properties and operational difficulties. Easy adaptability of oil production facilities to changing economic conditions is now recognized as a common goal of many Oil Operators.

- This new technology and hardware, originally conceived for use in Heavy Oil fields is also readily usable in mature Light Oil fields where tertiary oil recovery by steam injection is feasible. This adaptability may greatly expand the market for this technology.

REFERENCES

- 1) "Field Demonstration of steam drive with ancillary materials" by T.M. Doscher and E.C. Hammershaimb, SPE/DOE Paper 97/7, 1981

Other References in 5 previous Quarter Reports