PRELIMINARY DESIGN OF A SPECIAL CASING JOINT FOR A WELL EQUIPPED TWIN
HORIZONTAL DRAINHOLES IN THE OXNARD FIELD

BACKGROUND INFORMATION:

The Vaca Tar Sand reservoir is found at depths ranging from 1,800 ft to 2,500 ft. The reservoir, which is part of the Pico formation, is of Early Pliocene age for the Upper Sand. The Lower Pliocene Tar sand or Lower Tar Sand, is at depths of 2,800 to 5,000 ft. Both sands are Slope Basin reservoirs, listed in the DOE TORIS list, as eligible for an Advanced Technology Demonstration under the DOE Class 3 Oil Program. (see a structural and isopach map of the reservoir in the Oxnard, CA field on Fig.1)

The Oxnard field is presently under production, with a typical average monthly oil production of about 70,000 B, of which the Vaca Tar sand represents more than half. It is Unitized and operated under cyclic steam injection. The hot Tar and produced water are lifted to the surface with rod pumps equipped for injection of a diluent.

The produced WOR is about 2.5 and the GOR is about 150 scf/B.

The Vaca Tar sand originally contained about 400 Million STB. The estimated recoverable reserve under full-scale cyclic steam injection is 100 to 120 Million STB. Under steamflood, it might reach 240 Million STB.

The main problems are: 1) the low gravity of the produced oil (5 to 8 API), which makes it heavier than formation water,

2) its low market value, primarily as road paving material,

3) its very high viscosity (500,000 cp.at 100 F),which drops to about 10 cp.at 400 F.

The reservoir is an unconsolidated clean sand,of high permeability (≥ 500 md) and with an average net pay of 183 ft.The daily production per well (all vertical) is about 15 BO/D.

OBJECTIVES OF THE FIELD TEST:

OBJECTIVE 1: To increase well productivity by using a vertical well equipped with twin horizontal drainholes,each of about 1,000 ft reach.This is a well proven result,especially in relatively thin or discontinuous sands and in fractured reservoirs.This type of productivity improvement results solely from the improved flow connection between horizontal well and reservoir.In addition,for Heavy Oil in thick,dipping reservoirs,produced under cyclic steam injection, it has been shown by H.Dykstra,et al.(Ref.1) that gravity segregation effects also result in an acceleration of the oil recovery,leading to increased well productivity factors of about 2.5 during the first 5 years.This may explain the recorded success of steam injection through horizontal wells in many high permeability reservoirs.In Ref.2,S.Lacy et al.list the characteristics required for commercial viability of thermal oil recovery in horizontal wells: a) high oil content ($>1,400$ B/ac-ft),

b) shallow depth (500 to 2,800 ft),for lower drilling costs,lower injection pressure and lower steam temperature,

c) relatively thick sands (45 to 100 ft) and low shale content,

d) high sand permeability

(≥ 1 Darcy).

All these conditions are met in a large part of the Vaca Tar sand.

The results obtained both in Canada and in California fields with steam injection in horizontal wells have also shown some increase in the Oil to Steam Ratio (OSR), which are likely due to improved sweep efficiency.

OBJECTIVE 2: To maximize the well draw-down by locating the horizontal wells near the base of the sand layer. In under-pressured reservoirs, this may nearly double the effective draw-down. In the heavy Vaca Tar, this location is also where the heated tar is likely to accumulate, due to gravity segregation with steam and with water. In medium curvature horizontal drainholes, however, the produced oil and water must be lifted first through the curved part of the drainhole, over about 400 ft of measured depth, for a 260 ft of elevation, in order to reach the kick-off point. In such a case, rods are subject to rapid wear due to friction against the tubing wall even when rod centralizers are installed. Other types of artificial lift systems such as hydraulic jet pump might be preferable, but are not commonly used in California fields.

Another artificial lift approach, using steam-lift has been used in some Venezuelan Heavy Oil fields. Its major drawback was the high steam consumption, when used for lifting over the total depth. This difficulty is alleviated by reducing as much as possible the elevation difference over which the steam lift is operating. This in fact reduces the slippage of the steam bubbles with respect to the viscous tar, which is at the origin of the increased steam consumption.

The presence of dissolved gas (150 scf/B) in the Vaca Tar is also a favorable factor in making the steam lift more efficient. For these reasons, it is proposed that the interval over which the produced stream is steam-lifted be limited solely to the curved part of the drainholes. At the kick-off point, the produced stream is dumped into a vertical separator/sump from which a vertical rod pump will lift the de-gassed liquids to the surface, while the gas phase (solution gas and steam originating from condensate flashing and from the lift steam) is vented into the low-pressure casing annulus.

The consumption of some steam for production-lifting is also economically justified when it reduces, or eliminates, the need for a diluent. Heat is a far more cost-effective way of reducing tar viscosity than the addition of diluent, especially when steam is always readily available at the well head.

Maintaining the production tubing temperature at a high value will be obtained at a lower operating cost by using the Sequential Cyclic Steam Injection Process where a hot steam tubing is in close proximity of the hot production tubing within the same low-pressure gas-filled casing/tubings annulus.

OBJECTIVE 3: Capital cost reduction by using twin drainholes connected to the same vertical cased well. Despite the requirement of a larger casing to allow using two parallel tubings, there are significant Capital cost savings, when compared with two separate conventional horizontal wells of comparable reach:

- only one well site
- only one well head
- only one steam flow line and one set of steam valves

- only one production flow line and separator
- fewer cementing operations
- fewer logging services
- lower rig mobilization costs
- only one pumping unit
- only one pump and a shorter rod string

Compared with the present mode of exploitation of the Vaca Tar sand, using vertical wells only, the greatest cost savings, however, will come from the increased drainage area attainable with wells equipped with twin horizontal drainholes. The corresponding number of such wells required for efficiently depleting this large reservoir might be drastically reduced. The perforated intervals from both drainholes are separated by 500 to 600 ft, so that their respective drainage areas are unlikely to interfere with each other for many years of cyclic steam injection.

Conversion of the cyclic steam injection to a steamflood may then be easily done, at a later date, if the remaining reserves justify the added cost.

Existing vertical wells may be included in any pattern of horizontal drainholes. Some of the existing 51 shut-in wells may be used as observation wells during the pilot test of this new technology.

OBJECTIVE 4: Operating expenses reduction by eliminating the need for a service rig to pull-out the rods and pump before each steam injection cycle. This is achieved by using downhole three-way valves operated by wireline or by hydraulic lines.

OBJECTIVE 5: Adaptability to other operating modes.

Besides the possibility of conversion to a steamflood at a later date, the tubing completion is designed to be easily converted to other methods of artificial lift. This provides the assurance to the Operator of reaping the full benefits from the horizontal drainholes even if some aspects of the proposed mode of exploitation turn out to be less effective than other present or future technologies of artificial lift. The 10.75" casing string and the 4.5" drainhole liners provide all possibilities of well maintenance and tubing re-completion, such as:

- logging and/or cleaning of the drainholes,
- re-perforation with conventional gun perforators of the selectively slotted liners,
- extension of the tubings into the slotted part of the liners,
- replacement of the steam-lift system with hydraulic jet pumps, operated with hot water, or diluent,
- re-completion as dual conventional horizontal wells, using two parallel tubings and two rod pumping units,
- re-completion as dual conventional horizontal wells, using two parallel tubings and two progressive cavity pumps,
- extension of the 3.3" ID separator/sump into a vertical third drainhole,

Such modifications or conversions would require additional oil field services or a work-over, but their cost would be a small fraction of the initial investment in the well and drainholes. This provides the guarantee of a reasonable pay-out of the project, even if some unforeseen problems arise with the proposed mode of exploitation.

GENERAL WELL CONFIGURATION

The general well configuration is that of Appendix 1. There may be an additional possibility of eliminating the 13 3/8" surface string. The Thums operators in the Wilmington field, CA, indicate in Ref. 3 that the CA Division of Oil and Gas has accepted the omission of a surface casing to protect the uphole aquifer, when the production casing is equipped with a cement inflated formation packer located in a shale layer a short distance below the aquifer. The packer rubber membrane must be at least 20 ft long and of an accepted design. At least one supplier, CTC, meets those requirements. The inclusion of such a device in the 10.75" production casing might be less expensive than drilling and cementing 660 ft of 13 3/8" casing. This would also eliminate the need for underreaming the section 660 to 1,700 ft, further reducing costs.

The special casing joint assembly is located at the bottom of the 10.75" casing string. It comprises two 30 ft Lower Special Joints (LSJ) of 11.75" OD pre-assembled and welded together into a double joint tubular element, and a more conventional Upper Special Joint (USJ) of same OD. Each Lower Special Joint (LSJ) includes the slanted 5.5" ID channels used to kick-off a drainhole. Each of the two Lower Special Joints is equipped with welded top and bottom plates connected to inner tubulars.

The Upper Special Joint (USJ) includes the downhole flow control equipment used to switch the drainholes from "huff" to "puff" and for artificial lift of the produced fluids. The total length of this assembly of three 11.75" special joints is about 90 ft. It is terminated at its lower end by a 10.75" casing shoe and float collar. At its upper

end is a conventional 10.75" casing string.

The 10.75" string is cemented by the stab-in procedure. In the absence of any surface casing, this would require that the uphole formation packer, acceptable to the DOG, if used for aquifer protection, be also compatible with a stab-in cementation equipment.

The special triple joint assembly is connected at its top with the 10.75" casing string by a female round API thread in the joint wall, nearly 30 ft above the Top Lower Special Joint's top plate.

The dimensions of the main components of the Lower Special Joints (LSJ) are determined in Appendix 2.

The Upper Special Joint (USJ) is simply a 30 ft length of 11.75" casing (38 lb/ft) serving as receptacle for the freely expanding tubing completion, hung at the well head.

USE OF THE SPECIAL CASING JOINTS DURING DRILLING OF THE DRAINHOLES

Their OD is the same as that of the API casing joints: 11.75".

The Bottom Lower Special Joint (BSLJ) is closed by a welded inlet plate at the top and by the 10.75" OD casing shoe at the bottom. The inlet top plate presents 3 inlets. The largest one, of 5" OD, vertically leads to the bottom slanted (1.5 degree) 5.5" ID channel. The second larger (3.147" ID) leads to the suction part of an oil sump. The smallest hole (2.375" ID) is only an orifice through which liquids flow from above into the annulus of the BSLJ (see Fig. 2).

The Top Lower Special Joint (TLSJ) is connected to the two inlets of the BSLJ by two short vertical tubing nipples, respectively of 5" ID and 3.3" ID, and by two half-round clamps. It contains not only vertical tubing extensions of 5" and 3.143" ID linked to those in the BSLJ, but also a second 5" ID vertical tubing leading to a 5.5" ID

slanted channel. Consequently the top plate of the TLSJ presents two 5" ID inlets and one 3.147" ID inlet. There are, in addition two smaller diameter steam feeder lines vertical inlets, each one laterally connected with one of the 5" inlets. Finally a 2.375" orifice allows produced liquids to flow from above into the annulus of the TLSJ.

A perspective sketch of the Upper Special Joint (USJ) is shown on Fig. 2.1.

The orientations of both slanted channels, respectively in the BSLJ and in the TSLJ, are marked on these special casing joints and recorded with surveyed marks on all other joints above it in the casing string, during its assembly and run-in.

Access from above into each slanted channel is through a 5" ID vertical pipe terminated at its upper end by a female connection with an API round thread. Each slanted channel contains a telescopic 5.5" liner stub, with its drillable guides or longitudinal grooves and drillable end plug.

During the cementation of the casing string, both 5" ID inlets are closed by retrievable plugs. The stab-in work string is connected to the 3.147" ID inlet leading to a vertical pipe, also included inside both the 11.75" OD BLSJ and TLSJ and connected at its lower end to the cement float collar and shoe. This vertical pipe will later be used as part of an oil sump/separator. A sliding sleeve valve, located just above the float collar, provides a controlled flow communication between sump and annulus space in the Bottom Lower Special Joint. This valve will later be opened to provide a flow path from the annulus to the suction sump for the produced liquids entering the annulus via the 2.375" orifices. These may also be used later to insert a coiled tubing into the annuli of the TLSJ and BLSJ for cleaning and removal

of sand if its accumulation at the bottom of the oil sump becomes too rapid.

After a mud pre-flush and displacement of the thermal cement slurry behind the casing string, the mud pressure inside the casing is raised to extend the closed 5.5" OD liner stubs into the cement slurry filling the 24" underreamed cavity at the bottom of the hole, opposite the lower casing joint.

The stab-in cementing string is then pulled out.

When cement has set, the plug closing one of the two 5" ID inlets in the top plate of the special casing joint is retrieved by wireline. The drill string equipped with a BHA suitable for drilling the first drainhole is run-in. It is inserted into the opened 5" ID inlet in the top plate, penetrates into the vertical 5.5" slanted channel (about 6.8 ft long) and into the cemented 5" ID extended liner stub. The bit drills through the stub liner plug, penetrates into the cement and begins drilling the first drainhole. An orientation tool in the BHA is first used to check that the orientation of the extended liner stub is correct. If not, a minor course correction will be applied while drilling the drainhole's curved part.

Angle build-up to 90 degrees is done by conventional methods over the following 400 ft of measured depth. Horizontal drilling then continues for about 1,000 ft. The hole is underreamed to a diameter of 6 to 8", sufficient to provide adequate annular space for effective gravel-packing and cementing of a 4.5" OD liner string.

The BHA and drill string are pulled out and a 4.5" OD liner string is run-in through the 5" ID (min.) channels and liner stubs, to about 15 ft off the end of the drainhole. This requires that the couplings OD be sufficiently small to go through the 5" ID liner stub.

Hydril or VAM special couplings are used for this purpose. The 15 ft of hole space at the end of the liner provides for some free thermal expansion of the liner.

The liner string includes a cement diverter valve at about 1,000 ft from its end, and a retrievable plug mandrel below it. It is ended with a 4.5" cement shoe. It is also equipped with centralizer springs to keep it off bottom in the horizontal part of the hole. At a distance of about 1,380 ft from its shoe, the liner string includes a 4.5" OD lock mandrel similar to OTIS type D, for setting into the 5" ID liner stub.

Gravel packing of the horizontal unperforated liner is done by displacing a gravel slurry behind the liner wall, between two conventional cementing plugs, and following a mud pre-flush, as normally done for a cement slurry.

The diverter valve is then opened and a small volume of additional gravel slurry is injected through it. A retrievable or drillable plug is set below the diverter valve and a cement slurry is displaced behind the curved part of the liner, between two stage-cementing plugs. When both plugs have bumped on the temporary plug, the diverter valve is closed by wireline or with suitable tubing-conveyed tools. The lock mandrel seal is expanded and hung into the cemented 5" ID liner stub. The liner string is broken immediately above the set lock mandrel. Any excess cement is circulated out of the channels in the casing joint. The cementing plugs and their supporting plug are removed or drilled-out with a small-diameter string or with coiled-tubing tools.

Selective liner slotting in the gravel-packed part of each drainhole is done as soon as the drilling mud has been circulated

out and the well left filled with clear water. It only requires a small coiled tubing and a hydraulic pump. In the unlikely event of a failure of the prototype hydraulic slot-cutter, a conventional gun perforator may be used instead, but at a higher cost. These operations, which only require a small-diameter coiled tubing string or a logging cable, may proceed while drilling the second drainhole, to save rig time.

The curved production tubing string, equipped at its lower end with a 3.5" max OD sidepocket mandrel is then run-in through the opened 5" inlet into the 4.5" (4.052" ID) liner and set with a lock mandrel into the 5" ID vertical channel.

The curved production tubing is run-in with a small diameter work string or tubing and inserted through the 5" ID opening of the top plate of the Top Lower Special Joint and into the curved 4.5" liner. The lower end of the tubing is equipped with a rubber cup packer and with a sidepocket mandrel for a 1" OD steam-lift valve.

The 2 7/8" OD production tubing string includes a 6 ft long 3.5" OD PBR compatible with a 2.7/8" sealing nipple. The PBR is directly threaded into the top of the 5" OD lock mandrel. The string is then broken above the vertical PBR, which is closed with a retrievable plug.

The other 5" ID inlet is then opened to start drilling the second drainhole. After drilling, underreaming of the second drainhole, its 4.5" liner is gravel-packed, cemented and sealed in the same way as for the first drainhole. The liner is selectively slotted and the curved production tubing is run-in and sealed in the top plate of the TLSJ. The liner inlet is also equipped with a 3.5" PBR, but only 5.5 ft long.

The two PBR's remaining after pulling-out the work string of the second curved tubing are of 3.5" OD (2 7/8" ID). The heavy drill rig may then be demobilized and replaced by a cheaper service rig for

installing the tubing completion and rod pump. The first task of this small rig is to install a 6 ft long small-diameter PBR in each of the two 1.875" ID inlets on the top plate of the TLSJ. These slim PBR's will be used to receive the sealing ends of the two steam feeder lines, when the lower branches of the H joint have reached their corresponding PBR's, of larger diameter (see Fig. 2.2).

TUBING COMPLETION ASSEMBLY FOR SEQUENTIAL CYCLIC STEAM INJECTION

The tubing completion assembly required for sequential cyclic steam injection, i.e. simultaneous steam injection into one drainhole and production from the other drainhole, is run-in with the steam tubing string and hung in one of the two bowls of a dual-tubing well head. The assembly consists of an H joint, welded to two small steam feeder lines, and of a sliding-sleeve, three-way steam valve. To facilitate its connection to the PBR's at the top of the special casing joint, it is oriented at the surface and pressed against the casing wall by an eccentralizer spring. The 2 7/8" OD lower branches of the H joint and the smaller diameter steam feeder lines are all of slightly different lengths, to act as guides in this four-prong type of connection. The longer prong is a lower branch of the H joint. It is inserted into the 6 ft-long PBR, while the next 2 7/8" prong, also equipped with "O" ring seals is next inserted into the second, shorter PBR. The next connections are those of the two small-diameter steam feeder lines. Each one of the four prongs is ended by a mule shoe (see Fig. 3).

The main dimensions of this assembly are determined in Appendix 3 for installation and retrieval through the 10.036" drift diameter of the 10.75" casing string.

Final selection of steel grades and of sealing materials will be done later, after consultation with sub-contractors and with Oil Operators, to make maximum use of their field experience.

To facilitate this four-prong connection of the lower end of the H joint, the H joint is equipped with spring-loaded lateral spacers spanning more than 5". These simple devices may be supplemented, if necessary, by a vertical orientation groove in the upper part of the inner wall of the upper special casing joint, in which a guiding pin on the wall of the H joint becomes engaged, when the H joint is properly positioned above the PBR's for its prong-type connection.

The four tubular prongs of the H joint are inserted into the four PBR's connected to the two drainholes. Thermal expansion of the steam tubing will be offset by the variable penetration of these branches, equipped with "O" ring seals, into the two pairs of PBR's. The remaining annular space in the upper casing joint serves as the upper part of the oil sump and also as a guide for the vertical production tubing (2 7/8" OD) into the 3.3" ID sump pipe of the lower casing joint.

The three-way steam valve is thus connected by the two steam feeder lines to the upper part of each of the two drainholes 5"/2 7/8" annulus, through lateral ports.

Inside the H joint, each lower branch is equipped with a lock mandrel profile of ID greater than 2.5", which is later used as receptacle for a wireline retrievable plug. The presence of this plug in the 2 7/8" end of one of the curved production tubings coincides with the connection of the steam tubing to the same drainhole liner/tubing annulus through the three-way sliding sleeve valve and through one of the two steam feeder lines. The corresponding drainhole is then

under steam injection, with its steam-lift valve removed.

Lateral ports in the wall of the H joint provide a flow path for the liquid phase produced from the other (unplugged) drainhole and steam-lifted into the casing annulus and dropped from there into the vertical sump/separator through the 2.375" orifices in the top plates the TLSJ and BLSJ and through the open diverter valve into the 3.143" ID suction sump pipe. It will be lifted from there to the surface by a rod pump in a vertical 2 7/8" production tubing.

The lift-steam is conveyed from a small orifice in the sleeve of the three-way valve to the liner/tubing annulus below the sealed liner/tubing end connection through the other feeder line. The orifice size reduces the steam flow to a small fraction of that injected into the other drainhole. The spring-loaded gas-lift valve at the bottom of the curved production tubing controls the flow of low-pressure annulus steam into the curved tubing to lift the produced fluids to the H joint, where the gaseous phase (solution gas and steam) is separated from the liquid and vented into the casing annulus through the open upper branch of the H joint. The separated liquid phase then flows into the sump, where it is picked up by the rod pump and conveyed to the surface through the vertical production tubing.

The sidepocket at the end of each curved production tubing is a MERLA (TMX) and connected via a short length of 2 3/8" NUE tubing. The gas-lift valve is 1" OD. When it is removed it provides a direct flow path for injected steam, below the rubber cup packer sealing the liner/tubing annulus, into the gravel-packed, selectively-slotted, liner.

Each curved production tubing is thus free to move into the liner, as a consequence of thermal expansion, while its upper end

remains fixed to a PBR to which the steam tubing completion assembly is connected. At any time during operation of the well, the 400 ft-long curved production tubings may be unlocked and easily retrieved after pulling-out the steam tubing and "H" joint assembly. This operation only requires a service rig. It provides direct access into the liners for cleaning, sand removal or for re-perforating, if necessary.

The vertical production tubing, equipped with a pump anchor, is inserted through the upper sump space in the Upper Special Joint (USJ) into the sump pipes of the Top Lower Special Joint and of the Bottom Lower Special Joint. It is hung into the second bowl of the dual-tubing well head. Its thermal expansion into the sump pipe is also entirely free. In view of the high density of the tar, the pump, at the end of the production tubing is preferably located within the lower sump pipe, i.e. within the BLSJ assembly, to maximize the separation efficiency of the gas/steam phase from the liquid phase and that of the heavier tar from the produced water over about 70 ft of vertical column. Operation of the rod pump is essentially the same as in present vertical wells, but through a 300 ft shorter tubing located in a hotter casing annulus. These improved conditions are expected to reduce the need for diluent in the wells, and the high water pollution risk which it presents. Maintenance operations of the pump and rods are the same as in conventional wells, but the pump is not unseated for each new cycle of steam injection. This is expected to reduce operating costs.

OPERATIONS REQUIRED FOR DOWNHOLE SWITCHING OF THE DRAINHOLES

In the Sequential Cyclic Steam Injection process, one drainhole with its curved production tubing plugged-off is under steam injection while the other drainhole, with its curved production tubing open, is

under steam-lift up to the "H" joint, where the produced liquids are dumped into the casing annulus for separation and lifting to the surface by a continuously-operating vertical rod pump set in the vertical production tubing.

To switch the respective functions of the twin drainholes, the plug closing the sleeve of the three-way valve is removed through the steam tubing. The steam-lift valve is then pulled-out from the producing drainhole through the open curved tubing and checked.

A kick-over tool is inserted through the steam tubing and the opened sleeve, to transfer the plug from the lower branch of the "H" joint corresponding to the drainhole under steam injection to the other drainhole.

The steam-lift valve is then run-in and set in the now open curved tubing of the previously steam-injected drainhole.

The first plug is then returned downhole to close the sliding sleeve, which is switched to its alternate position. This operation switches the previously steam-lifted tubing to full steam injection while sending the lift-steam to the transferred steam-lift valve.

All these routine operations are only conducted with a wireline unit, without the need for a service rig or a crane. Both vertical tubings remain unchanged and continue to carry the same fluids, at essentially constant temperatures, so that there is no movement of any tubing in the casing.

These operations also provide an opportunity for periodic checking and eventual replacement or re-adjustment of the steam-lift valve and of the steam plug seals.

CONCLUSIONS:

All the major dimensions of standard Oil Field tubular goods required and those of the two Lower Special Joints (BLSJ and TLSJ) and of the Upper Special Joint (USJ) have been specified.

The procedures to be used for vertical drilling, casing cementing, drainhole tie-in, drainhole drilling and liner completion are described in detail.

The sequence of operations for installing the curved production tubings, the steam tubing assembly and the vertical production tubing and pump is also given.

Removal, by wireline, of the retrievable plug from the sliding sleeve of the three-way valve and eventual transfer of the retrievable plug from one lower branch of the "H" joint to the other provide full access, at any time, through the steam tubing, of conventional 1 11/16" OD logging tools through the 2.375" ID curved production tubings.

Operational procedures for downhole switching of the drainholes and for steam-lifting, oil separating and rod-pumping of the produced stream are outlined.

Provisions are made for eventual clean-out and sand removal from the oil sump and for the retrieval of the curved production tubings, if needed. This allows to clean the liner-equipped drainholes and eventually to re-perforate the liners or to increase the curved tubing's total length, in order to change the steam distribution along the perforated length of each horizontal drainhole.

The steam tubing assembly and/or the vertical production tubing and rod pump may be pulled-out with a low-cost service rig, for routine maintenance of valves, seals and pump.

The drainholes may easily be recompleted with conventional production tubings and with dual pumps at any time, if necessary.

Two wells of the proposed design, each equipped with twin drainholes are sufficient to convert from sequential cyclic steam injection of four independant drainholes to two complete steamflood patterns, to increase oil recovery at a later date.

The well configuration meets all stated objectives. It is sufficiently detailed to establish an itemized cost estimate.

Additional cost reductions may be possible by asking the State DOG to allow the use of the casing completion program adopted by the Thums Operators, which eliminates the need for a 13 3/8" surface casing to protect the uphole aquifers.

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SPE 19827, 1989
- 2) "Horizontal Well Applications and Parameters for Economic Success"
by S. Lacy, W. Ding and S. J. Joshi, SPE 23676, 1992
- 3) "Cementing high angle wells using Cement-Expanded Formation Packers and/or casing rotation", by M. B. Webster and G. E. Ottot, Jr., SPE/IADC
16136, 1987

Figure Oxnard oil field. Isopachs are on the Vaca Tar Sand and the structure contours on the base of the Vaca Tar Sand.

FIG. 2.1 UPPER SPECIAL CASING JOINT

FIG. 3 STEAM TUBING COMPLETION
ASSEMBLY (Not to Scale)

APPENDIX 1

PRELIMINARY DESIGN OF A WELL EQUIPPED WITH TWIN DRAINHOLES IN THE OXNARD FIELD

INFORMATION OBTAINED FROM THE OPERATOR AND D.O.G.:

Target depth: 2,000 ft

Horizontal reach: 1,300 ft per drainhole

Vaca Tar Reservoir average thickness: 183 ft

Potable aquifer at about 600 ft.

PRELIMINARY WELL DESIGN:

Conductor Pipe:

Length (ft)	Steel OD(")	W (lb/ft)	ID	Drift D	Joint OD	Type	Bit OD
60	H 40 18 5/8	87.5	17.74	17.5	20	API	24

Surface Pipe:

660	J 55 13 3/8	48	12.715	12.559	14.375	API	16
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Casing:

1,700	K 55 10.75	32.75	10.192	10.036	11.75	API	12.25
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Collapse Pressure: 1,580 psi (pilot)

Burst Pressure: 3,130 psi to 14

Underreamer:

Grant 11.25 to 24

Lor, Inc. 11.75 to 24

Tri-State 12.25 to 24

Servco 2 stage 11.875 to 24

A-1 11 to 24

Consider DB Stratabit for drilling/underreaming
in same trip (see SPE 18043, enclosed)

Special Casing Joint:

30 to 60	N 80	11.75	NA	NA	5.0	NA	API	24
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Drainhole liner:

1,400	J 55	4.5	10.5	4.052	3.927	4.813	VAM	6 or 7 Spec.
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Underreamer:

Grant 4.5 to 6

Lor, Inc. 4.5 to 6

Tri-State 3.75 to 7.5

Servco 3.625 to 7

A-1 4.5 to 6

A-Z 4.625 to 7

CEMENT VOLUMES:

Cement Composition includes: Class C + 40 % Silica flour + 20 % light
filler + Gypsum + Na metasilicate + fluid loss additive

Conductor Pipe: 75 cu.ft

Surface Pipe: 278 cu.ft

Casing: 746 cu.ft

+ Special Joint: 72 to 144 cu.ft

Drainhole No.1: 63 cu.ft

Drainhole No.2: 63 cu.ft

ESTIMATED RIG TIME FOR DRILLING, GRAVEL PACKING AND CEMENTING:

Vertical well: 7 days* (including time for uphole logs)

Drainhole No.1 10 days (excluding any logs in the drainholes)

Drainhole No.2 8 days

----- " "

TOTAL 25 days

* Further evaluation of the feasibility of applying the combined drilling/underreaming procedure and tools described in SPE 18043 may reduce this estimate by one or two days.

ESTIMATED RIG TIME FOR TUBING COMPLETION AND WELL HEAD RIG-UP: 5 days**

** A service rig, less expensive than the drilling rig, may be used for this purpose, if potential savings exceed the cost of mobilizing a new rig. This is likely to be the case and the drilling rig must be moved away for installing the pumping unit, at any rate.

DUAL COMPLETION WELL HEAD SUPPLIERS:

Gray, Gulfco, FMC

HORIZONTAL DRAINHOLES CONTRACTORS

Slimdrill probably has the most experience with small downhole mud motors. (see Fig. 1a). Other equipment suppliers include Sperry-Sun, Eastman-Christensen, Becfield, etc...

Downhole motor characteristics are attached.

The drilling rig specifications required by Slimdrill are also listed. Excellent control of the mud characteristics by a mud

specialist is a "must" for successful drilling of horizontal wells.

APPENDIX 2

2.1 DETERMINATION OF THE MAIN DIMENSIONS OF THE LOWER SPECIAL CASING JOINT

PRELIMINARY DESIGN ASSUMPTIONS:

- 11.75" OD casing, with weight of 38 lb/ft (ID = 11.15")
- Wall thickness of all other tubulars: 0.25"
- Welded assembly of pre-machined tubular elements
- Conventional 10.75" OD cement float collar and shoe
- Machined top plate, welded to tubular elements
- Maximum angle between drainholes

DESCRIPTION OF FIG.2a:

Fig.2a is a cross section of the Lower Special Joint assembly, assuming that the top plates are transparent, to show the relative position of the welded tubular elements in both the BLSJ and TLSJ.

The two vertical inlet pipes are 5.0" ID, or 5.5" OD. The right pipe ID is tangent to the 6" OD slanted channel below the left vertical pipe.

The wall of the upper end of each slanted channel is integrated into the casing wall and welded to it. Consequently, the distance between the center of the right vertical pipe and the center of the left slanted channel is:

$$2.75 + 0.25 + 2.50 = 5.5" \text{ (distance OO')}$$

The two slanted channels are superposed, and separated so that the

lower channel, below the right vertical pipe, cannot interfere with the upper slanted channel on the left. Both slanted channels are identical and the right slanted channel is derived from the left one by a clock-wise rotation around the axis of the casing and a translation below the left channel.

The axis of the casing forms with the centers O and O' a triangle of base 5.5" and sides 2.875". The height H of this triangle is:

$$H = \sqrt{2.875^2 - 2.750^2} = 0.8606"$$

The minimum length of full thickness of the slanted channel is projected in L.

$$L = H + y, \text{ where } y = \sqrt{5.875^2 - 5.750^2} = 1.2051$$

$$L = 0.8606 + 1.2051 = 2.0658"$$

For a kick-off angle of exactly 1.5 degrees, the minimum length of the slanted channel is equal to its horizontal projection times $1/\tan 1.5 = 38.19$.

The minimum usable length of the slanted channel is then: $38.19 \times 2.0658 = 78.9$ " or 6.6 ft.

The length of the lock mandrel anchoring the 4.5" liner is about 2 ft, leaving a maximum clearance of 4.6 ft for any thermal expansion of the liner into the 5.5" channel.

By comparison the maximum unrestrained thermal expansion of the 1,400 ft liner when heated by an additional 400 F over its temperature during installation is $7 \times 10^{-6} \times 400 \times 1,400 = 3.92$ ft.

(this would assume that the cementation of the curved part of the drainholes totally fails, that none of the liner's expansion occurs towards its end, by penetration into the gravel pack and finally that steam temperature exceeds 470 F).

The risk of occlusion of the 5" inlet pipe by any thermal

expansion of the liner is therefore NON EXISTANT, but in the past the Operator experienced unexpected failures of vertical 7" casings due to thermal expansion and judged this safety margin as insufficient.

A much greater safety margin is, however, provided by the extension of the 5.5" OD telescopic stubs from the slanted channel into the 24" ID underreamed cavity. This effectively doubles the available length for such thermal expansion to a value of $4.6 \times 2 = 9.2$ ft.

The angle between the two drainholes is 145.2 degrees.

The maximum inner radius r of the sump pipe is determined by the following equations:

$$z = V (5.625 - r)^2 - (r + 0.25)^2 \dots \dots \dots (1)$$

$$(r + 3)^2 = (z + 0.8606)^2 + (2.5 - r)^2 \dots \dots \dots (2)$$

elimination of the length z between these equations yields:

$$2r = 3.147"$$

This ID provides sufficient clearance for inserting a 2.875" OD vertical tubing less than 60 ft into the sump pipe.

The minimum length of the Bottom Lower Special Joint (BLSJ), from its bottom plate, above the cement float collar to its top plate is:
 $(0.5 \text{ ft} \times 38.19) + 6.6 \text{ ft} + 2 \text{ ft} = 27.7 \text{ ft}$

The addition of the 10.75" float collar, shoe and of the 11.75" connecting nipples and coupling clamp at the top makes a total length of about 30 ft for the BLSJ.

The length of the Top Lower Special Joint (TLSJ) is slightly less.

The complete assembly of the two Lower Special Joints is less than 60 ft long and can be handled by the rig as a single tubular element.

The Upper Special Joint (USJ) is essentially a standard 11.75" OD casing joint with a bottom male API round thread for coupling it into the top plate of the TLSJ and with a welded half of a female round

thread API coupling joint for connecting it to the 10.75"OD casing string. Its length is about 30 ft. Its enlarged section (ID 11.15") provides an easy access of the drill string and of the drainhole liner strings into their 5"ID inlets in the top plate of the TLSJ, which are slightly eccentric. Its 30 ft length also easily accommodates the 6 ft maximum length of the longest female PBR, 6ft of male sealing prong connector tube and leaves ample space for the length of the H joint assembly, which, by comparison with a conventional sidepocket mandrel for 2 7/8 tubing, does not exceed 10 ft. After insertion of the four prong-type connectors over about 1ft into their respective PBR's, the free length of steam tubing into the USJ is about 6ft. Subsequent to the maximum expected free thermal expansion of the steam tubing (about 4.8 ft) the top of the H joint and the top of the three-way sliding sleeve valve (about 3 ft-long) will be respectively 14 ft and 11 ft within the 30 ft-long USJ.

CALCULATION SHEET

$$Z^2 = (5.625 - r)^2 - (r + 0.25)^2 \quad (1)$$

$$(r+3)^2 = (Z + 0.8606)^2 + (2.5 - r)^2 \quad (2)$$

$$Z^2 = (5.625)^2 + r^2 - 11.25r - r^2 - 0.0625 - 0.5r$$

$$Z^2 = 31.578 - 11.75r \quad (1')$$

Substituting Z^2 in (2):

$$(r+3)^2 = 31.578 - 11.75r + (0.8606)^2 + 2 \times 0.8606 Z + (2.5 - r)^2$$

Re-arranging:

$$Z = \frac{r^2 + 9 + 6r + 11.75r - r^2 - 6.25 + 5r - 31.578 - (0.8606)^2}{2 \times 0.8606}$$

$$Z = \frac{22.75r - 29.5686}{1.7212} \quad (2')$$

$$Z = 13.2175r - 17.1791 \quad (2'')$$

Squaring (2''):

$$Z^2 = 174.7029 r^2 + 245.1215 - 454.1295 r \quad (2''')$$

Eliminating Z^2 between (1) and (2'''):

$$0 = 174.7029 r^2 + 245.1215 - 31.578 - (454.1295 - 11.75)r$$

$$0 = 174.7029 r^2 + 263.5435 - 442.3795 r$$

$$0 = r^2 - 2.5322 r + 1.5085$$

$$\Delta = (2.5322)^2 - 4 \times 1.5085 = 0.3779$$

$$2r = 2.5322 \pm \sqrt{\Delta} = 2.5322 \pm 0.6147 = \underline{\underline{3.147}}''$$

APPENDIX 2

2.2 PROCEDURE FOR COUPLING THE BLSJ TO THE TLSJ AT THE RIG SITE

(Refer to Fig.2.2a)

1. Align and orient the BLSJ AND TLSJ on the rig floor or ramp, end to end,
2. Insert the 3.143"ID sump nipple respectively into corresponding cavities in the top plate of the BLSJ and the bottom plate of the TLSJ,
3. Position the threaded 5.5"OD nipple between the two plates and reduce their spacing by tightening the (left and right threads) threaded nipple connection,
3. Insert Spacer Block # 1 between the plates and complete tightening until pressure-tight nipple connections are obtained,
4. Spot weld the periphery of both nipples with both plates,
5. Weld the short corrugated strap to the 3.143"ID nipple sump while the corrugations of both plates are engaged with those of the strap,
6. Insert Spacer Block # 2 between the plates,

7. Thread the connecting threaded stem between the long strap and the short strap,
8. Weld the long strap end to the sump nipple, while the corrugations of both plates are engaged by those of the strap,
9. Tighten the two straps to the required design tension.
10. Pick-up the 60 ft LSJ assembly with the rig elevator.
11. Run-in the LSJ and hold it in the slips while making up the special threaded connection with the USJ, using torque-controlled tongs as for a Hydril coupling joint.
12. Run-in the LSJ and USJ assembly and make-up the lowest joint of the 10.75" casing string.

FIG. 22a COUPLING OF BLSJ (Top Plate)

WITH TLSJ (Bottom Plate)

APPENDIX 2

2.3-SELECTION OF EQUIPMENT FOR CONNECTING THE LINER STUB,LINER AND CURVED PRODUCTION TUBING TO THE SPECIAL CASING

The connection of the 5.5"OD liner stub to the 5.5" ID channel and that of the 2 7/8" curved production tubing to the top plate of the TLSJ are based on the use of modified Baker Type F seating nipple for 6 5/8" tubing and of its corresponding F lock mandrel in welded assemblies. These devices provide respectively a 5.50" ID seal bore for the upper end of the liner stub and a 5.25" ID seal bore for the curved tubing. The seating nipple at the upper end of the stub is directly welded at both ends to a 6"OD (5.542"ID) tubing and at its lower end also welded to the 11.75"OD casing joint. This provides the 5.5" ID channel through which the telescopic liner stub (5.5"ID) is hydraulically extended into the cement-filled 24"ID cavity (see Fig.2.3a).

The connection of the 4.5"OD liner inside the lower end of the 5.5"OD (5.014"ID) liner stub is necessarily of smaller diameter. It is based on the use of a modified Baker type F seating nipple and of its F-type lock mandrel, of 4.84" maximum OD. It provides a seal bore ID of 4.75", which is sufficient for the insertion of the drill bit, of the BHA and of the 4.5" liner with VAM or Hydril couplings. The liner/extended stub tie-in is cemented, in addition to the mandrel seal.

The lock mandrel ID is 3.75", which easily allows to run-in the

3.5"OD (max.) MERLA sidepocket at the end of the 2 7/8"OD curved tubing.

The fixed, but breakable, connection of the 2 7/8"OD curved tubing to the top plate of the TLSJ is by means of a Baker Type F lock mandrel for a 6 5/8"OD tubing. Its maximum OD is 5.353" and it is sealed in the 5.25"ID seal bore of the F profile machined in the top plate of the TLSJ. Another possibility would be to make this connection using Baker's Type R profile and corresponding lock mandrel of only 5.240"OD, but the profile includes a "No-go" ring of 5.150"ID. This is fully compatible with the use of a 5.5"OD (5.014"ID) tubing in the TLSJ, but the thin "No-go" ring is more likely to stop the drill bit on its way downhole during trips, with the increased risk of scouring the seal bore surface, located just above the ring. This is why the F type has a slight advantage over the R type.

The 4.0"OD (3.35"ID) PBR, is suitable for receiving the steam tubing assembly with a sealing mandrel of 2.375"min.ID, comparable with that of the 2 7/8"OD (2.441"ID) steam tubing. It is available from BOT in the required 6 ft length. It is directly connected to the top of the 5.353"OD Baker lock mandrel by a round thread connector piece.

Conversely, the bottom of the 5.353" OD Baker lock mandrel, of 3.75"ID is directly connected with the upper end of the 2 7/8" curved tubing, by a doubly threaded reducing connector inserted in the string.

Neither OTIS nor Camco offers lock mandrels for 6 5/8"OD tubings and the seal bore ID of their seating nipples for 5.5"OD tubing are significantly smaller than 4.75", thus leaving less clearance for the drilling tools and for the curved liner string which must go through them. This why the Baker equipment is specified.

The availability of seating nipples, lock mandrels and PBR's

which can easily be included in the special downhole equipment, with minor modifications and threaded or welded in place, is very cost-effective not only for building the prototype equipment, but also for any future servicing or well work-over required during the 20 years or more lifetime of the new well.

Baker F Plug
for 6 5/8" OD Seating Nipple
(5.25" ID seal bore)

Top Plate or TSSJ

APPENDIX 3

PRELIMINARY DESIGN OF THE STEAM TUBING COMPLETION

1. PRELIMINARY DESIGN OF THE "H" JOINT ASSEMBLY

The "H" joint assembly consists of a flattened tubular body terminated by four branches. The inter-axes distance between the lower branches is necessarily the same as that between the two 5" ID inlets of the top plate in the Top Lower Special Joint: 5.5". These inlets are equipped with PBR's connected to the upper ends of the 2 7/8" curved production tubings, set and sealed within the 5" ID vertical inlet pipes by means of lock mandrels.

The ID of the seal mandrel terminating the lower branches of the "H" joint is that of a 2 7/8" tubing: 2.375". The corresponding BOT polished bore ID is 3.25" and the polished bore OD is 4". This means that, to preserve the option of eventually pulling-out the whole curved production tubing, including its PBR, through the lower and upper branches of the "H" joint, these branches would have an ID bigger than 4". The corresponding size of "H" joint body would reach 10.00". The 10.15" ID (10.036" drift) of the 10.75" OD casing string still could allow the insertion of such a large, and costly, "H" joint body.

A more cost-effective approach is to accept that any eventual removal of the curved production tubing string will be done only after removal of the steam tubing and of the "H" joint, with the required service rig. This approach would allow to reduce the "H" joint body size to 8.75", with two lower branches of 3.25" OD separated by an inter-axes distance of 5.5".

The "H" joint is used not only as part of the oil sump/separator system but also as part of the downhole flow switching system. In this function, a 2,313"OD plug mandrel is transferred by wireline from one of the lower branches of the "H" joint to the other. With the approach of a reduced size body, an existing OTIS kick-over tool may be used with only minor modifications for this plug transfer operation. This is an important additional reason for taking this lower-cost approach.

The upper branches of the "H" joint may then be identical to the lower branches. The space available in the 10.036" drift diameter for inserting the three-way steam valve through the 10.75"OD casing string is more than sufficient for a 3.5"OD OD OTIS Circulation/Flow Sleeve Assembly, located directly above one of the upper branches of the "H" joint. The available space may be used for connecting the three-way valve to the steam feeder channels.

Fig. 3a shows in cross-section the position of the "H" joint and three-way valve assembly with respect to the Upper Special Joint (USJ) inside diameter and also with the ID of the 10.75" casing string. It also shows the positions of the steam feeder lines sealing mandrels. Their ID is limited to 1.875", to fit in PBR's of 3.0"OD, so as to avoid any interference with the 3.147" ID of the sump/separator, in which the vertical production tubing, of 2 7/8" ID will later be inserted.

With the location of the two prong-type steam feeder sealing mandrels partly below the base of the "H" joint body, the steam feeder lines may have a cross section in the shape of a slice of a circle, as shown on Fig. 3a. The area of these steam feeder channels is about 3.0 times greater than that of the 1.875" ID (2.761 sq.in) prong-type steam connectors, so as to minimize the steam pressure drop

from the three-way valve to the curved production tubing/liner annulus (of 6.07 sq.in.area).This shape also reinforces the tubular body of the "H"joint.

Flow communication between the "H" joint and the upper part of the sump/separator above the top plate of the TLSJ is through two sets of lateral ports and through one central slot through the bottom plate of the "H"joint,for periodic sand removal after each production cycle.

The solution gas/steam separates from the produced liquid phase (boiling water and hot tar) which flows through the 2.375" ID orifices in the top plates of the TLSJ and BLSJ into the 11.15" ID casing annulus and separates into a water layer above the hot tar layer.The gas/steam mixture is vented into the annulus of the USJ through the open branch of the "H" joint.

The separated tar and water phases flow from the annulus of the BLSJ into the 3.147" ID suction sump through the open diverter and enters the pump's standing valve at the foot of the 2 7/8" vertical production tubing.

2.PRELIMINARY DESIGN OF THE SLIDING SLEEVE THREE-WAY VALVE

A cross-section of the three-way sliding sleeve valve is shown on Fig.3b.It consists,for instance,of two superposed modified OTIS Circulation/Flow Sleeves in which the bodies are connected vertically together and the lateral ports of each body are connected through a sealed annular space to each vertical steam feeder channel (Fig.3c).

The two sliding sleeves are also coupled to each other.They are shifted by wireline tools,so that,when the top sleeve is closed,the bottom sleeve is open,and vice versa.When in the closed position,the small lateral orifices,normally used for pressure balancing,provide a

small flow of lift steam through the valve body, which is conveyed to the annulus of the drainhole under production, while the main steam flow is conveyed through the main ports of the other sleeve. A closed retrievable 2.313"OD lock mandrel set in a lock mandrel fastened to a nipple in the lower sleeve provides a wireline retrievable plug with which access into the "H" joint from the steam tubing is obtained for the kick-over tool used to transfer the 2.313"OD plug mandrel from one 2 7/8"OD curved tubing string to the other.

A possible advantage of the OTIS Circulation/Flow Sleeve over similar devices offered by other oil field equipment suppliers is that it could also be pulled out to the surface by wireline, for inspection and eventual repair of the seal rings. This would, however, require the use of a 3.5"OD steam tubing, instead of a 2 7/8" OD presently considered. This possibility may be maintained by using a dual tubing well head capable of hanging a 3.5" tubing and a 2 7/8 tubing in parallel. This is feasible in a 10.75"OD production casing. The convenience of this larger steam tubing, which would allow to replace the 2.313" OD lock mandrel by a blanked sleeve, must, however be weighed against the increased steam heat loss through the greater tubing surface. Pulling out the whole steam tubing assembly with a service rig for inspection and eventual repair of the seals in the sliding sleeve is not a very expensive operation and it would also allow the inspection and maintenance of the seals on all four sealing mandrels of the four-prong connector. It is also possible to disconnect/pull-out only the 2 7/8" steam tubing and the 3.5"OD three-way steam valve while leaving unchanged the "H" joint assembly and its four-prong connection.

These various options will be jointly evaluated with the

Operator and with sub-contractors in the coming months.They illustrate the flexibility offered by this downhole steam flow control system.

FIG. 3a CROSS-SECTION OF "H" JOINT IN USJ

Scale: 2cm = 1 in.

MODIFIED SLEEVE

New Threaded
Fix Plug

TOP SEAL

OTIS CIRCULATION /
FLOW SLEEVE (See Fig. 3c)

New Coupling

TOP SEAL

OTIS NO-FLOW
SLEEVE WITH ORIFICE (See Fig. 3c)

New orifice

OTIS LANDING
NIPPLE

FOR X MANDREL

FIG. 3b CROSS SECTION
OF THREE-WAY SLEEVE VALVE
DERIVED FROM OTIS DEVICES
(For 3.5" OD Steam Tubing)

WIRELINE-RETRIEVABLE SLEEVE ASSEMBLIES - Continued

Otis Dual Flow Sleeves allow flow both through the ports and from below. They are designed primarily to protect and preserve the polished surfaces from erosion caused by flow.

Otis Circulation/Flow Sleeves feature an equalizing valve and integral plug. These sleeves are used to allow communication between the tubing annulus and the tubing inside diameter while plugging the tubing below. They incorporate a positive hold-down and equalizing feature. The sleeve with equalizing valve is set in the ported no-go landing nipple and plugs the tubing below the landing nipple flow ports. This protects the polished honed areas

of the nipple. An equalizing valve equalizes the pressure above and below the plug prior to retrieving the flow sleeve, which is run and retrieved by standard wireline procedure. The flow sleeve can be redressed on the surface and reinstalled.

Otis No-Flow Sleeves with equalizing valve and integral plug may be used to prevent flow from below or through the ports of the nipple. These are identical to the circulation/flow sleeves, except ports in the fishing neck of the lock mandrel are removed, which effectively stops all flow through the ported nipple.

Otis Circulation/Flow Sleeve

Otis No-Flow Sleeve

DATE

FILMED

5/2/94

END