Preliminary Considerations on Application of Steamflooding in a Toe-To-Heel Configuration

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Abstract

*With the advent of horizontal wells a distinct change is tacitly taking place in our approach to the improved recovery of heavy oil: from displacing mobilized oil in a flood pattern from injector to producers over long distances of the order of hundreds of meters to **s**hort-**d**istance **o**il **d**isplacement (SDOD) processes (typically over a few tens of meters).*

*SDOD processes comprise Steam Assisted Gravity Drainage (SAGD), Cyclic Steam Stimulation (CSS) and **T**oe-**T**o-**H**eel (TTH) Displacement Processes, which comprise THAI (Toe-To-Heel Air Injection), with its variant catalytic THAI (CAPRI,) and Toe-To-Heel Waterflooding (TTHW). Presently SAGD is commercially used, while THAI has been under field testing for three years; testing of CAPRI is scheduled to start in 2010. TTHW has been under field testing both in USA and Canada for more than four years*

*Steamflooding in a **T**oe-**T**o-**H**eel (TTH) configuration (TTH steamflooding) uses vertical wells as injectors and horizontal wells as producers, arranged in a staggered line drive, with producers having their toes close to the shoes of vertical injectors; the horizontal section of producers is located at the base of the pay. The vertical wells are used for initiating the steam front, which subsequently is anchored at the toe of the horizontal producer; it is then propagated towards the producer's heel. In TTH steamflooding, the existing deficiency of conventional steamflooding schemes in terms of low vertical sweep is overcome by the beneficial use of gravity.*

To investigate the potential of TTH steamflooding, some laboratory tests were conducted. The objective was to assess the feasibility of TTH steam and thermo-solvent flooding (steam + propane co-injection) by carrying out 3-D model experiments using heavy oil with a viscosity of 15,000 cp.

Laboratory results showed that the concepts of TTH Steamflooding and TTH Steamflooding with solvent are feasible. All in all, stability of TTH steamflooding was relatively good, while the stability of TTH steamflooding with the addition of nitrogen or propane was much better. Significant improvements in design and operation of these processes were needed in order to promote override during the early phase, and obtain a stable and efficient process. The improvements included: a cold (gas fingering) and a hot (steam based) communication phase; and controlling lateral spread of steam by using two additional vertical control wells (positioned laterally but close to the heel of the horizontal producer) for conducting a limited steamflood. Nitrogen was injected along with steam in the conventional steamflood; propane replaced nitrogen in TTH Steamflooding with solvent. With these improvements, rise of steam chamber to the top occurred much earlier, and a favorable tilt-forward-angle of the thermal front was quickly obtained. TTH steamflooding with solvent proved superior to the TTH steamflooding, as the channeling of steam through the horizontal well was much better controlled, and the oil recovery was considerably faster. With these improvements, the oil recovery increased from 50-54% to 75-77%, and the operation became smoother. Presently, the process can be considered only for reservoirs where oil has some mobility under reservoir conditions.

In order to develop the full potential of TTH steamflooding technology means are needed for controlling channeling through the horizontal producer (this control occurs naturally in the THAI process); at present there are a few methods which seem promising.

Introduction

Conventional flooding methods (pattern or line drive configurations), as applied for the past 60 years, are long-distance oil displacement (LDOD) processes; mobilized oil typically needs to travel several hundred meters to the production wells. However, for flooding heavy oil pools short-distance oil displacement (SDOD) is highly desirable, especially in the context of widespread use of horizontal well technology in recent years. The main advantages of SDOD processes are outlined elsewhere[1].

SDOD processes are defined as a broad category of displacement processes in which any oil particle, before it is produced, takes a short-path flow from its original position (in the formation) to the producing wellbore; the mobility (viscosity) of the injectant though important, is no longer a strong controlling factor. In the new situation, *instead of looking for solutions for making mobility ratio more favourable as in LDOD, the SDOD processes try to reduce the importance of the mobility ratio, while reducing the flow-path.* This approach is far more practical, since for most heavy oil pools even if a mobility ratio of one is attained, injection pressures required to sustain an economically acceptable oil rate are impractical or lead to fracturing, which is always undesirable in displacement processes. Additionally, it is much easier to apply horizontal wells to reduce the flowing distance than to change the mobility ratio in a LDOD system.

A TTH displacement process can be non-thermal, such as Toe-To-Heel Waterflooding (TTHW) or thermal, such as Toe-To-Heel Air Injection (THAI^{TM}), which was initially developed early in 1992[1,2,3] for efficient deployment of the in situ combustion process.

In **Figs. 1** and **2**, the TTH concept is demonstrated for steamflooding in a TTH configuration and for the THAI process; the horizontal producer is located at the bottom of the pay, while the injection is through the vertical well, generally using the upper perforations. The plan view for both processes (**Fig. 3**) shows the well arrangement for a staggered line drive, as this is the configuration for which TTH steamfloding is most amenable.

As far as gravity segregation is concerned, its negative effect is mitigated due to the fact that the flow of any injected fluid is the result of two opposing effects: upwards flow due to gravity segregation and downwards flow due to the horizontal producer being a pressure sink, with the lateral pressure drop along the horizontal well promoting favorable fluid distribution. The negative effects due to gravity segregation, are attenuated, and in some favorable cases can be largely eliminated. Another important feature is the mitigation of the effect of heterogeneity. The negative effects of heterogeneity are mitigated since flow does not occur any more along the bedding planes. Also, as mentioned, the unfavorable mobility ratio does not aggravate the consequences of heterogeneity effects, as the importance of mobility ratio is significantly reduced. While the effect of heterogeneity is still felt behind the displacement front, the combined effect of heterogeneity and mobility ratio will be most sensitive in a limited zone (mobile oil zone – **Fig. 2**); for a long distance ahead of displacement front, the heterogeneity does not count in any way.

Presently, for the economic exploitation of heavy oil and tar sand reservoirs, SAGD and CSS are the only commercial in situ recovery methods. Generally, a SAGD pattern reaches a stage when the lateral growth of the steam chamber stops, because the amount of heat being lost to the overburden rock becomes equal to the amount of heat being injected as steam. To improve SAGD by reducing the heat losses, a small amount of non-condensable gas is added to the steam, so as to reduce the steam temperature near the top of the steam chamber. This is known as Steam And Gas Push (SAGP) process and has been tested in the laboratory. These tests showed the advantages of SAGP, namely [4,5]:

- Reduction of the heat losses to the overburden due to the accumulation of the non-condensable gas at the upper part of oil layer
- Reduction of temperature in the steam chamber, especially in the upper half of the pay.
- More confined heat distribution due to a steeper interface (more like vertical) of the steam chamber (better control of the upper lateral edge of the steam chamber, which is otherwise largely unconfined).

Both SAGD and SAGP were sensitive to heterogeneities in a test conducted in 1mm glass bead porous media of very high permeability (200-800 D); the ultimate oil recovery was around 54% for the homogeneous media, while it decreased to 37%, for medium contrast heterogeneity porous media, formed by a 220 D layer sandwiched between two layers of 830 D[6].

Although the investigation of SAGP started in 1996, only in 2000 was it recognized that the injected gas promotes upwards growth of the steam chamber[7]. SAGP produced the same oil rate, but with a smaller steam-oil ratio (20-30% lower). The SAGP related results were confirmed by other tests where the effect of CO_2 on Single Well SAGD (SW-SAGD) performance was evaluated. The SW-SAGD process uses the same well for both steam injection and for production and therefore the ability to control the process is much lower than for normal SAGD. Experiments in a three-dimensional physical model with the addition of CO_2 showed improved performance of SW- SAGD, for a dead oil of 40 mPa.s viscosity[8]. These tests were carried out with co-injection of superheated steam and CO_2.

Recently, the Expanding Solvent-SAGD (ES-SAGD) Process was investigated, in which a hydrocarbon additive at low concentration is co-injected with steam. To test this new concept, tests mimicking SAGD operations were carried out in a 10 cm diameter 170 cm-long vertical tube filled with heavy oil and sand[7]. *Steam-solvent was injected in the centre close to the bottom* of the tube, while production was from just below the injection point. Given the limited lateral spreading, the tests mimicked the phenomena occurring inside the vapour chamber, i.e. counter-current steam-oil flow. The results were best when the highest solvent concentration (7.4%) was used for which the ultimate oil recovery reached 76%, while the steam-oil ratio slightly decreased.

Some preliminary field results on using an heptane-equivalent solvent as an additive to steam for later cycles (> 6) of a CSS project were presented recently[9]. The oil-steam ratio increased from 0.2 to 0.3 m^3/m^3, for a thick Cold Lake oil formation (approx. 40 m), containing an oil with a viscosity of at least 100,000 mPa.s.

All the promising results presented so far referred to the addition of either a solvent or a noncondensible gas to steam injection performed in a short-distance displacement mode. Attempts to apply the same procedure to the classic long-distance displacement mode steamflooding (pattern applications for instance) did not show favorable results; Hong demonstrated that for the case of noncondensible gas[10], while Burger did the same for the case of a solvent[11].

Initially, TTH steamflooding was studied by simulation under the name of Pressure Controlled Gravity Drainage (PCGD) process in 1997[12]. Actually, PCGD is steamflooding in a TTH configuration with a minor modification of curving the toe of the horizontal section towards the shoe of the vertical injector to facilitate the generation of the initial communication. Simulations for both non-depleted and depleted oil reservoirs were carried out for two 800 m horizontal wells, with a separation of 100 m between them and a dead oil viscosity of 4,200 mPa.s. For formations with pay of 12 m and 22 m, the simulation indicated the existence of an upright steam displacement front with good sweep efficiency. The steam-oil ratio (SOR) was 1.7 for the non-depleted reservoir and 3.6 for the depleted reservoir.

In 2000, a 3-D physical model was used to test TTH steamflooding in Athabasca tar sand (oil viscosity approximately 1,000,000 mPa.s at 15°C)[13]. One vertical injector and two horizontal producers in the staggered line drive configuration were used. Slightly superheated steam was injected. During the test, the backpressure slowly increased up to 45 psi (0.31 MPa). The average steam temperature reached 134 °C after 3 hours. The test lasted 15 hours, and the oil production began at 3 hours (20% of the total run time), which practically constituted the period necessary for the pre-heating of the start-up region. Ultimate oil recovery was 23% at a cumulative steam-oil ratio of 3 during the stabilized period. A controlled steam override developed and the steam chamber became more and more enlarged along the horizontal section of the wells.

Recently, the process was simulated again this time for oil formations of very high thickness (70 m), and its efficiency was compared with conventional steamflooding[14]. The study found that only staggered line configuration was effective, and the direct line drive was totally inefficient due to premature steam breakthrough and further steam channeling. Sensitivity analyses were also performed on the permeability and oil layer thickness.

3-D Laboratory Model Investigations of Steamflooding in a TTH Configuration

Experimental Set-Up and Fluids Used

As shown schematically in **Fig. 4a**, the main cell consisted of a rectangular vessel containing the porous medium, with two vertical injectors and one horizontal producer in a general lay out of a staggered line drive. The details of the 3-D model and well locations are shown in **Fig. 4b**. The dimensions of the rectangular chamber are: 41.8cm×22.5cm×8.3cm; the total volume is 8.5 liters, while the pore volume is approx. 3.2 liters, at a porosity estimated at 37.7%.

The laboratory model consists of a thick aluminum wall with Teflon insulation inside (3” thick). It was estimated that even with this insulation, the heat losses from the model are large, and a steam injection rate higher than a threshold value, which is between 2 cc/min. and 5 cc/min. was needed to promote expansion of a steam chamber. The vertical injection wells are insulated from the horizontal box’s plane, at their entry points into the model, by that reducing considerably the direct heat losses from injectors to the box’s walls. However, the horizontal producer - which penetrates both vertical walls, at both ends - does not benefit from this kind of insulation

The model was filled with 120-140 mesh (0.18-0.22 mm) glass beads resulting in a permeability of 9-10 D. In all tests, superheated steam was injected. Dead oil, with a viscosity of15,000 mPa.s was used.

For each test, the model was initially saturated with water and the pore volume was measured. Then, water was displaced vertically downwards by the viscous oil, until no more water was produced. Therefore, at the beginning of each test, two liquids (water and oil) completely saturated the porous medium; gas saturation and relative permeability to gas were nil.

During the tests, the temperature in the glass bead pack was measured using 42 thermocouples (**Fig. 5**). Planes Z1, Z2 and Z3 were perpendicular to the horizontal well facilitating the examination of thermal front propagation, while vertical planes X1 and X2 were in the longitudinal direction, plane X2 actually containing the horizontal producer.

The Experimental Procedure

Four tests were performed, as follows:

- A basic conventional steamflood, using two vertical injectors and one vertical producer in a staggered line drive (Test #1)
- Two classic steamfloods in a TTH configuration- Test #2 (pure steam) and Test #3 (steam with nitrogen) - as reference tests
- A toe-to-heel steamflooding with solvent - Test #4 - by co-injecting steam and propane

The properties of the porous media used in these tests are listed in **Table 1**, while **Table 2** provides the operational parameters.

The start-up involved the generation of an initial steam chamber between the injection wells. Afterwards, the steam front was anchored at the toe and then propagated towards the heel of the horizontal well.

The following procedure was adopted:

- Steam or steam/solvent injection through both vertical injectors, with splitting of the total injection rate between the two wells; it was no possible to measure the steam injection rate per well.
- All tests were conducted at a constant **c**old **w**ater **e**quivalent (CWE) injection rate; superheated steam was injected with a degree of superheating of at least 100^0C.
- The back pressure at the production well was kept constant at 300 psi (2.1 MPa)
- The tests were discontinued when the steam-oil ratio increased over 20 m^3/m^3 or the oil rate became insignificant.

Once a test was finished, the model was dismantled and visually examined.

Results of the Laboratory Tests

Test #1: The Conventional Steamflood

The total duration of the test was 8 hours. The maximum value of the injection pressure was 900 psi (6.2 MPa), recorded just at the inception of steam injection. It decreased to a steady value of 450 psi (3.1 MPa), after approx 2 hours of operation.

Initial oil production was due to the high pressure gradient between the injectors and the producer. As expected, it achieved high oil recovery (more than 20%) in the first 2 hours, practically until the steam broke-through in the vertical producer.

In order to study how the steam chamber developed, the isotherms in different planes were constructed, based on thermocouple data. The isotherms in the longitudinal plane X1 at 6 hours showed a pronounced over-riding of the steam.

The oil recovery, instantaneous steam-oil ratio (SOR) and oil rate were also plotted as function of time. After injecting 1.5 PV of steam, the oil recovery was approximately 55%. The efficiency of the process was the highest in the first 5 hrs, when the SOR was less than 4.

Test #2: Steamflooding in a TTH Configuration— steam alone

The injection pressure was in the range of 400 psi (2.7 MPa) to 450 psi (3.1 MPa) for the entire duration of the test, which was more than 12 hours.

In this test, between the vertical injectors, at the upper part of the model, a narrow very high permeability streak – with a cross section of 20mm×15mm - was "installed" in order to facilitate the communication between vertical injection wells and to promote formation of the steam chamber (initial thermal front) at the upper part; this portion was made up of grains of 3mm diameter, having a permeability in thousands of darcy. The communication phase consisted of 25 minutes of steam injection through the first injector (while the second well was produced), and another 25 minutes of steam injection through the second injector (while the first well was produced). In this 50 minute-period, 600 cc of steam were injected and 65 cc (2% OOIP) of oil of were produced; the temperature of the toe did not increase at all. Live steam was produced in the second injection period. Then, for 14 minutes the steam injection was stopped, and in this soak period, pressure in the injection line decreased from 450 psi (3.1 MPa) to 250 psi (1.7 MPa). At this moment, steam injection was started for steamflooding in a TTH configuration, with a total rate of 10 cc/min.

The thermocouple temperatures showed that the steam failed to over-ride, and had a tendency to channel through the horizontal section of the horizontal producer; as seen in the vertical plane X2, the temperature at the upper part was lower than the temperature at a lower point (**Fig. 6**). To promote steam over-ride the injection rate was decreased to 5 cc/min for one hour, and then it was increased to 20 cc/min. This maneuver succeeded in producing override, and thus, after 7–8 hours of operation the process was brought into a desired TTH configuration mode, i.e. in a vertical plane the temperature in the upper part was higher than the temperature in the lower part (tilt-forward-angle for the thermal profiles). Oil production improved dramatically in this last mode, compared to the previous mode.

In **Fig. 7**, the performance curves are provided. The oil recovery is approximately 50%. The efficiency of the process was high in the first 2-3 hours, when the oil rate was 5 the g/min and the SOR was around 5. Also it was high after the injection rate increase (from 5 cc/min to 20 cc/min) operated at 9 hrs, when the oil rate increased to 4-5 g/min and SOR decreased again to values in the range of 5 to 6. It can be concluded that only after 9 hours of operation, the process switched to a TTH mode (tilt-forward-angle for the thermal profiles).

Modifications to the 3-D Model to Improve Performance in the Subsequent Tests (Test #3 and #4)

The following modifications in the well arrangement and wells geometry were necessary to promote an early rise of the steam chamber at the upper part of layer:

- Increasing the distance between the producer's toe to the line of injectors from 2.5 cm to 7.5 cm (increasing the volume of start up region)
- Perforating the vertical injectors at the upper part of layer on a limited portion only (2 cm, compared to 5 cm previously, out of a total of 8.4 cm)
- Use of a partial obstructing insert rod in the horizontal producer (to increase the flow resistance in the horizontal well)
- Adding two control wells in direct line drive with the injectors, but positioned towards to the heel of the horizontal producer (**Fig. 10**)

Test #3: Steamflooding in a TTH Configuration— steam and nitrogen

The injection pressure was in the range of 300 psi (2.1 MPa) to 900 psi (6.3 MPa) for the duration of the test (13.5 hrs).

First cold communication was achieved between the vertical injectors and two control wells located close to the heel of the horizontal producer (**Fig. 8**). This was done by injecting nitrogen in both vertical injectors. Then, on the second day, both control wells were closed and cold communication was achieved between the vertical injectors. Oil production during cold communication was approximately 38 cc (1.2% OOIP). The cold communication was followed by a hot communication, which consisted of 40 minutes of steam+nitrogen injection through both vertical injectors, as in the previous test. In this period, 500 cc of steam and 6,000 Scc of gas of were injected: 75 cc (2.5% OOIP) of oil was produced; temperature at the toe did not increase at all. Predominantly live steam was produced towards the end of the second injection period.

Then, the limited conventional steamflood phase started with the steam+nitrogen injected in both vertical injectors and oil produced from the control wells. Steam+nitrogen injection was carried out with a total rate of 10 cc/min with nitrogen being 12 Scc/cc of water equivalent. After a short period, due to an excessive pressure increase, the steam injection rate was decreased to 5 cc/min, and with this rate the test continued for approx. 4 hours. The temperatures in the plane (Z1) – the closest to inlet cross-section - reached a maximum temperature of 80-100^{0}C. No over-ride or under-ride was observed. The oil recovery for the conventional steamflood was 20% OOIP.

Following the conventional steamflood, the true TTH process started by injecting steam+nitrogen in both vertical wells with a steam+nitrogen injection rate of 20 cc/min, the percentage of nitrogen being 12 Scc/cc of water equivalent. From the first indications of the temperatures in the first plane it was obvious that steamflooding in a TTH configuration mode occurred, i.e. in a vertical plane the temperature in the upper part was higher than that in the lower part. The oil production performance also confirmed the steamflooding in a TTH configuration mode.

After 3 hours of steam+gas injection, the gas injection was discontinued and only steam was injected until the end of the test. The oil production remained stable and also, the pressure drop along the model was extremely steady at around 7-8 psi; only towards the end did this pressure drop decrease to 4-5 psi.

The isotherms in a plane perpendicular to the horizontal well, namely plane Z2 are shown in **Fig. 9**. As indicated in this figure, steam had a preference to penetrate through the vertical injector at the left hand side of the model at 0.75 hours. At 1.25 hours, this maximum temperature increased to 220^{0}C, while being already located towards the top of model. At this time the steam invaded zone (temperatures approx. 220 ^{0}C) was practically located at the uppermost part of the model, (**Fig. 9b**). At 1.5 hours a classic steam over-ride was obvious. From these isotherms it can be inferred that at the beginning of steam injection mostly hot water was formed within the model. Subsequently, in time, the steam-invaded zone did form, and it migrated to the top of model

These conclusions are supported by the isotherms in the vertical plane X2 (**Fig. 10**), containing the horizontal producer; it can be seen that the steam front is almost vertical, while the hot zone has its maximum thickness in the lower third of the pay section, probably due to the pre-heating action of the produced stream in the horizontal producer and the gravity segregation of the hot water. Also, a substantial heating of the region below the horizontal leg seemed to occur.

The performance curves (**Fig. 11)** show that the oil recovery is approximately 77%, with 20% OOIP obtained during conventional steamflood and 57% during steamflood in a TTH configuration. It is clear that the oil rate increased considerably (approx. 4 times), once the switch from conventional to a TTH propagation occurred. Steam-oil ratio had a pronounced fluctuation, as from time to time, bursts of live steam through the horizontal producer were recorded These steam bursts through the horizontal producer became more and more frequent towards the end of the test. In the last period of the test, the produced fluid had a high temperature.

Test #4: Steamflooding in a TTH Configuration— steam and propane

The injection pressure was in the range of 450 psi (3.1 MPa) to 750 psi (5.2 MPa) for the duration of the test (12 hours, excluding the communication phase).

The same procedures for cold communication and initial conventional steam injection as for Test #3 were used in this test, except nitrogen was replaced by propane at the percentage of 6% vol/vol (liquid propane/water equivalent). The conventional steamflood lasted for slightly more than three hours with a recovery factor of 22%OOIP.

Then, the TTH process with co-injection of steam and propane started. From the indications of the temperatures in the first plane, it was obvious that a steamflooding in a TTH configuration mode was obtained. The oil production also confirmed the steamflooding in a TTH configuration mode, as the oil production seemed good and stable for the entire operation. The oil production remained stable and also, the pressure drop along the model was extremely steady at around 5-6 psi at the beginning and then having a gradual slight decrease, towards the end of the test.

From the isotherms in the plane Z2 (not shown), it was inferred that at the beginning of steam injection practically only hot water was generated in the model. Subsequently, in time the steam invaded zone did form, and it migrated to the top of the model.

The above conclusions are supported by the isotherms in the plane X2, vertical longitudinal section, **Fig. 12**. At 0.5 hr, the steam chamber is located at the top, while the steam front has left behind the toe of the producer. The bi-furcation of the temperature profile is very obvious for the temperatures less than 180^0C, representative for the hot water/hot oil; on the one hand, there is a local temperature maximum at the upper part, and on the other hand there is another one due to the pre-heating action around the horizontal leg. This kind of split temperature profile in the vertical mid-plane is a key characteristic of a thermal TTH propagation. It is always obtained in the THAI/CAPRI processes[13]. At the same time, if we compare **Fig. 14** with **Fig. 12** (Test #3), it can be clearly seen the dramatic difference between isotherms; this obvious split of temperature does not exist for pure steamflooding in a TTH configuration.

Fig. 13 shows that the oil recovery is 74%OOIP (22% OOIP for conventional steamflooding and 50% for TTH mode). The oil rate increased substantially, once the TTH propagation of the thermal front started. In reality most of the oil was produced in the interval 3 - 5 hours from the start of the test. In this test, steam-oil ratio variation was *very smooth*; no bursts of live steam through the horizontal producer were recorded, and the produced fluid has a low temperature, even towards the end of the test.

Compared to the TTH steamflooding with nitrogen (Test #3), TTH steamflooding with propane co-injection has the advantage that it has a very high oil rate from the very beginning (**Fig. 14**). To achieve oil recovery of around 40%-50%, a very significant shortening of the project life can be expected. *This merits further investigation, as channeling of steam through the horizontal producer is significantly reduced, almost eliminated.*

At the completion of tests #2, #3 and #4, the model was dismantled and visually inspected; colored photographs were taken from above, after taking off the lid. These pictures showed that both displacement efficiency and surface of steamed area increased from Test #2, to #3 and finally to #4; better displacement efficiency was inferred from the lighter color of the steam invaded zone. Definitely, a larger steam chamber was formed in the upper part of the model when a non-condensable gas (nitrogen) or a condensable gas, such as propane, was added to the steam. This shows that the effect of the added gas can be significant in promoting steam segregation, reducing heat losses and in general promoting the TTH propagation of the thermal front. Also, it is obvious that the lateral spread of the thermal front also improved. Therefore, the volumetric sweep was a lot better for the last two tests and this explains the significant difference between ultimate oil recovery figures in the last three tests (50% for Test #2 and over 70% for Tests #3 and #4).

Based on the information obtained in Test #2, #3 and #4 a schematic diagram of the TTH steamflooding is shown in **Fig. 15.** This is intended as a generic schematic, as there may be some differences between the schematics for the case of pure steam injection, steam and a non-condensable gas and steam and a condensable gas (solvent), respectively.

Discussion of the Results.SW-SAGD Connection

As seen in the preliminary TTH steamflooding test (Test #2), a forward-tilt-angle of the thermal front was eventually obtained. However, it is crucial to obtain this situation within a reasonable period. In reality the time of obtaining this forward-tilt-angle made the difference between the first and the second steamflooding in a TTH configuration test. In order to get this stabilized thermal front propagation, the following technical improvements are necessary:

- Use of slightly superheated steam for injection during all phases of the process: communication, conventional steam drive and TTH propagation
- Propagation of a limited frontal displacement (in a conventional steamflooding mode) using control wells in a direct line drive with the vertical injectors, after the preliminary cold (gas) communication; use steam and gas injection even for conventional steamflood phase
- Promotion of gravity segregation by adding some gas to the dry steam at least in the early period of TTH implementation

Therefore, the addition of a gas/solvent to the steam may lead to:

1) Faster development of the steam chamber in the upper part of the layer
2) A better lateral spreading of the thermal front

If the TTH propagation of the steam front starts earlier, it would also translate in a more effective overall performance.

Another important conclusion is that it is much more difficult to obtain a stable propagation of the thermal front in the TTH steamflooding, as compared to the THAI process. This is due to the necessity of obtaining a forward-tilt-angle of the thermal front, sooner rather than later, during the process. While this forward-tilt-angle is obtained very easily in the THAI process – due to the large difference in air (gas) and oil density - in steamflooding in a TTH configuration, on the one hand there is a tendency to over-ride for the steam and another tendency to under-ride for the hot water. In porous media, as the steam chamber can be relatively small compared to the condensed water zone, the process picture becomes very complicated. The magnitude of heat losses and the oil-water density contrast (either positive or negative) will have major implications. It therefore follows that more attention needs to be devoted to the start-up operation.

In order to investigate further the role of hot water, we first comparatively analyze TTH steamflooding and Single Well-SAGD (SW-SAGD) operation. SW-SAGD in fact is not “a relative’ of the dual well SAGD. It is rather a relative of the TTH steamflooding, namely it is the limiting case (*the most unfavorable case*) of pure steamflooding in the TTH configuration. TTH steamflooding becomes a SW-SAGD (switching from use of two wells to the use of one well), when the following “fictitious/mental” modifications are operated (step by step):

- Instead of a staggered line drive, a direct line drive is adopted
- The toe-offset distance (between the toe of horizontal producer and the shoe of vertical injector) becomes zero.

- Instead of perforating the vertical injector in the upper part, it is perforated at the lower part, just as in the "limited entry" method, at a point, which coincides with the toe of the horizontal producer.
- Finally, injection well is eliminated and the steam is injected through the coil tubing at the toe of the horizontal well; now, the horizontal well has a double role; injection mostly in the toe region, and production mostly from the heel region.

As seen here, three parameters, which allow control of the process, are eliminated from steamflooding in a TTH configuration, in order to get the SW-SAGD process. The short-circuiting of the injected steam in SW-SAGD is related to these conditions. This is the reason that the SW-SAGD process is considered extremely difficult to control, and its field applications have diminished considerably. However, to some extent, phenomena occurring in SW-SAGD process also occur in the TTH steamflooding. For example, the dichotomy between steam over-riding and hot water under-riding. That's the reason probably that some SW-SAGD tests gave better results when the horizontal leg was placed at the upper part compared to placing the horizontal leg at the bottom of the layer[8]. It is assumed that the formation of a large amount of condensate water while the steam chamber was very small or almost nonexistent, was the reason behind this behavior. Clearly, more investigations are necessary in order to completely clarify these phenomena.

In both processes, introduction of an additional resistance to flow in the horizontal section of the producer improved the performance by forcing the steam to further spread laterally[8]; the same positive effect was confirmed during the investigation of a non-thermal TTH process, namely Toe-To-Heel Waterflooding[2]. It must be emphasized that the TTH steamflooding process must be operated so that it is both *pressure gradient and gravity* controlled, for maximizing volumetric sweep of the oil. Gravity segregation helps in spreading the injected steam (and heat) vertically over the continuous pay zone, whereas lateral pressure drop within the horizontal well assists in sweeping the mobilized heavy oil towards (along and around) its length *within the reservoir*. Some amount of steam/ hot water channeling would inevitably occur in TTH steamflooding. As a matter of fact, the horizontal well itself would offer a conduit for channeling. For controlling this channeling, it is desirable that the lateral pressure gradient within the horizontal well *be comparable to that within the reservoir*, needed to facilitate thermal oil production. In order to increase this pressure drop within the well, in the field one could consider use of appropriate well design including pressure drops due to wellbore equipment such as tubing with limited openings.

In the laboratory, increased lateral pressure drop within the well was achieved by partially obstructing the horizontal wellbore by inserting a rod of small diameter. The pressure drop during the tests (Test # 3 and Test #4) using this insert was 8 to 4 psi (56 - 28 kPa), whereas without the insert (Test # 2) it was estimated to be about 2-3 psi (14-20 kPa).

Developing a Self-healing Feature for the TTH Steamflooding

The self-healing feature refers to the identification/ establishment/ implementation of a mechanism by which the steam channelling through the horizontal section of the horizontal producer is totally eliminated or significantly reduced; this leads to the achievement of high areal (lateral) sweep efficiency, as in the THAI process. While in THAI process the gas channelling through the horizontal producer is negligible due to a natural seal off by a coke-like residue plug[1], in TTH steamflooding this mechanism does not exist and a similar/equivalent mechanism has to be developed by the operator. For instance, the blocking of the upstream portion, close to the toe region can be achieved[15]. Also, a certain chemical blocking agent, to progressively block the toe region, could be contemplated, similarly to the case of Toe-To-Heel Waterflooding process[16].

Two prospective non-mechanical techniques are also identified, namely:

1) Solvent co-injection
2) Air co-injection

Technique 1 resulted from our own investigations (as presented), while the second technique resulted from an in-depth study of the technical literature. Although we do not fully understand the mechanisms of technique 1, further testing to try to clarify them is worthwhile. As far as the second technique is concerned, an in-depth mining of old laboratory and field data succeeded in bringing a relatively solid support for it; use of air co-injection in CSS operations gave significantly better results, compared to the operations where pure steam was injected[17].

The stability of steamflooding in a TTH configuration is due to gravity drainage and pressure gradient in the horizontal producer once the steam front is 'anchored' onto the 'toe' of this well. In a way similar to SAGD, it has a column of liquid between the injector and producer. If the pressure gradient in the horizontal well is small, not high enough to hold enough liquid, gas breakthrough (steam, steam+nitrogen) occurs. The key issue of TTH steamflooding process is to select the optimal pressure drop once the steam front is anchored to the 'toe' of horizontal producer. When the back pressure control was the main method to achieve stable steam propagation in a 'toe-to-heel' mode, it was called as 'Pressure Controlled Gravity Drainage'[13].

In practise, the operational variables can be the back pressure of the horizontal producer, injection pressure, steam injection rate, the amount of non-condensable gas or solvent, temporary shut in of the injection well, etc.

Conclusions

1. Results from four steam injection 3-D laboratory tests indicate that steamflooding in TTH configuration was feasible for a heavy oil with a viscosity of 15,000 mPas.
2. The conventional steamflood test experienced a very high pressure drop. The injection pressure increased to 900 psi (6.2 MPa), for a back pressure of 300 psi (2.1 MPa). The final oil recovery was 55%.
3. First steamflooding in a TTH configuration test was relatively unsuccessful as the steam chamber, for the most of the test duration did not reach the upper part of the model, but developed around the horizontal producer similar to the SW-SAGD mode; intensive steam channeling through the horizontal producer was noticed. Ultimately, the steam chamber did rise to the top. The final oil recovery was 55%, and the steam oil ratio was extremely high.

4. In a TTH steamflooding tests with co-injection of nitrogen and propane, the following modifications were adopted: development of cold communication (by gas fingering), a hot communication phase (steam based), a limited conventional steamflood, a partial obstructing rod in the horizontal well. With these improvements, when using nitrogen co-injection, the steam chamber rose to the top much faster and a tilt-forward-angle of the thermal front was noticed. The final oil recovery was around 77%. However, steam bursts (indicative of steam channeling) through the horizontal producer occurred; the temperature of the produced fluids was high and the steam-oil ratio fluctuated widely.

5. When using propane instead of nitrogen for co-injection with steam, TTH steamflood process is able to achieve the desirable feature of tilt-forward-angle of the thermal front very quickly. The final oil recovery was around 74%. No steam bursts through the horizontal producer occurred, and the temperature of the produced fluids remained low; there was no significant fluctuation of the steam-oil ratio.

6. *Contrary to the common belief*, the SW-SAGD process is not a "relative" of the dual well SAGD, but a relative of steamflooding in a TTH configuration. It represents the limiting case (*the most unfavorable case*) of the (pure) steam flooding in a TTH configuration. The TTH steamflooding becomes a SW-SAGD (by switching from use of two wells to the use of one well), when some parameters, which allow control of the process are eliminated. Intensive short-circuiting of the injected steam in SW-SAGD is related to these conditions.

7. Developing a self-healing feature for the steamflooding in a TTH configuration is an important aspect in the advancement/improvement of the process; intensive steam channeling through the horizontal well has to be controlled. Process control methods have to be developed to provide a solid mechanism for a stable TTH steamflooding process.

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Table 1 Properties of the porous media used in the steam injection tests

Test #	Type of flooding	Porosity (%)	Pore volume (Liter)	Initial water saturation (%)	OOIP (ml)	Permeability (D)
1	CS	35.6	3.49	8.5	3267	9.1
2	S-TTH-1	39.8	3.32	8.0	3056	9.3
3	S-TTH-2	40.5	3.26	5.8	3070	9.4
4	TS-TTH	40.6	3.30	3.1	3298	9.8

Legend

CS = Conventional steamflooding

S-TTH = Steamflooding in a toe-to-heel (TTH) configuration

TS-TTH = Steam+solvent (thermosolvent) flooding in a TTH configuration

Table 2: Operational parameters for the steam injection tests

Test #	1	2	3	4
Type of flooding	CS	S-TTH-1	S-TTH-2	TS-TTH
Communication phase (CPh)	--	Steam	Steam+N_2	Steam+N_2+C_3
Steam injection rate during CPh (g CWE/min)	--	10♣	10	10
Conventional steamflood (CS) phase in TTH	--	--	yes	yes
Fluid injected during CS	steam	--	Steam+N_2	Steam+N_2+C_3
Steam injection rate during CS (g CWE/min)	10	--	10-5♥	20
Steam injection rate during TTH process* (g CWE /min)	--	10-5-20**	20	20
Nitrogen injection rate during TTH (Sml/min)	--	--	50	--
Propane injection rate during TTH (ml liquid/min)	--	--	--	1.2

Legend

♣= Steam soak for 14 minutes

♥= Some injectivity problems (BPR functioning problems)

C_3 = Propane

* = Total steam injection (through both injectors)

CWE= Cold water equivalent

** = Change of injection rate in order to promote steam over-ride

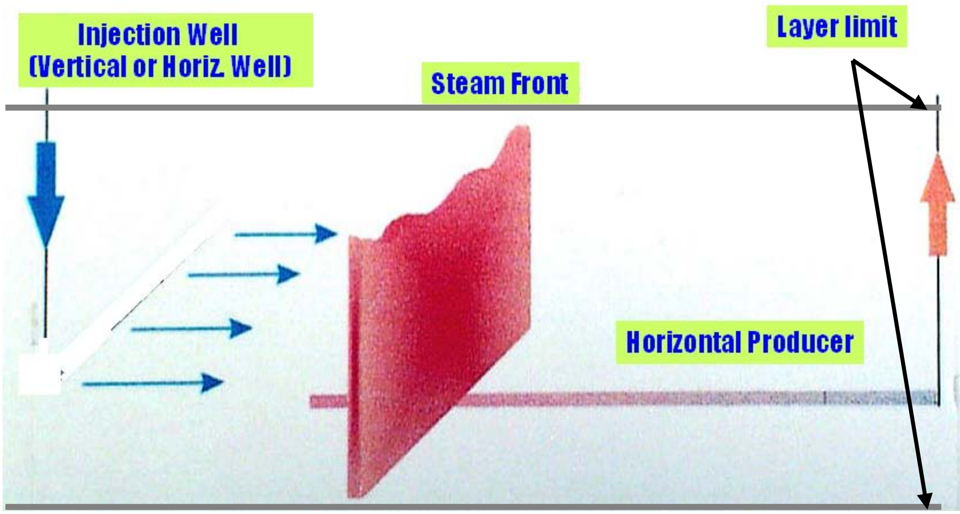


Figure 1: Concept of steamflooding in a TTH configuration

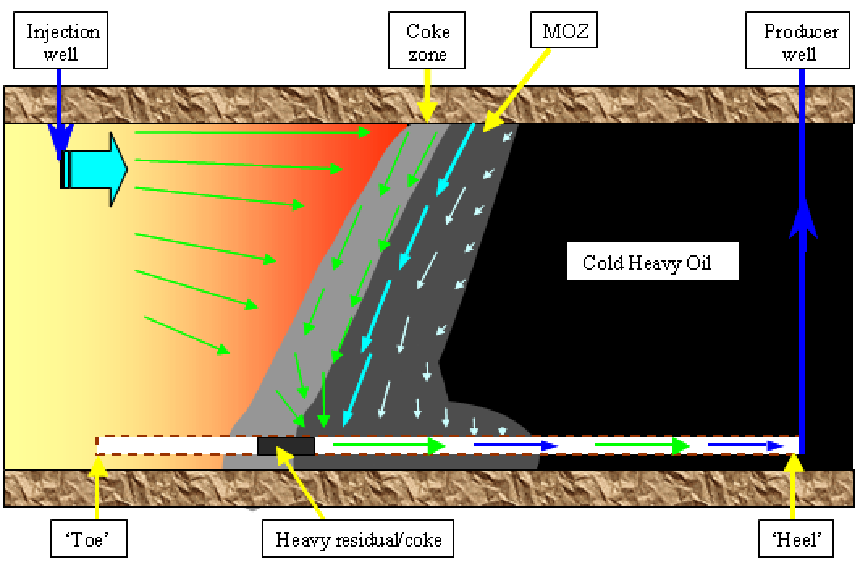


Figure 2: Schematic of THAI™
Legend: MOZ – Mobile oil zone

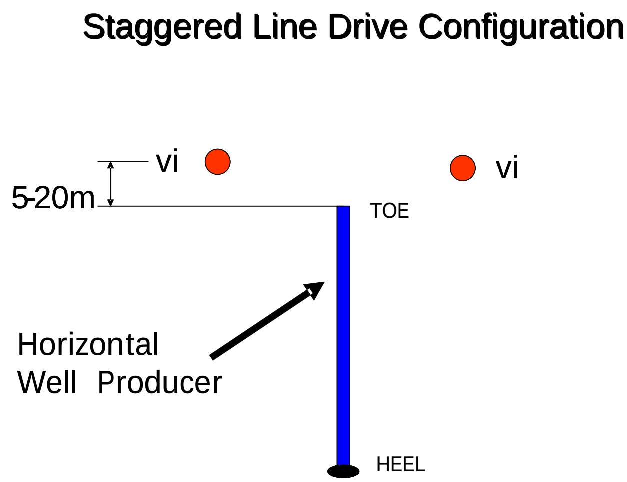


Figure 3: Bird`s eye view of the THAI and TTH steamflooding processes; well configuration. Legend: VI - vertical injector

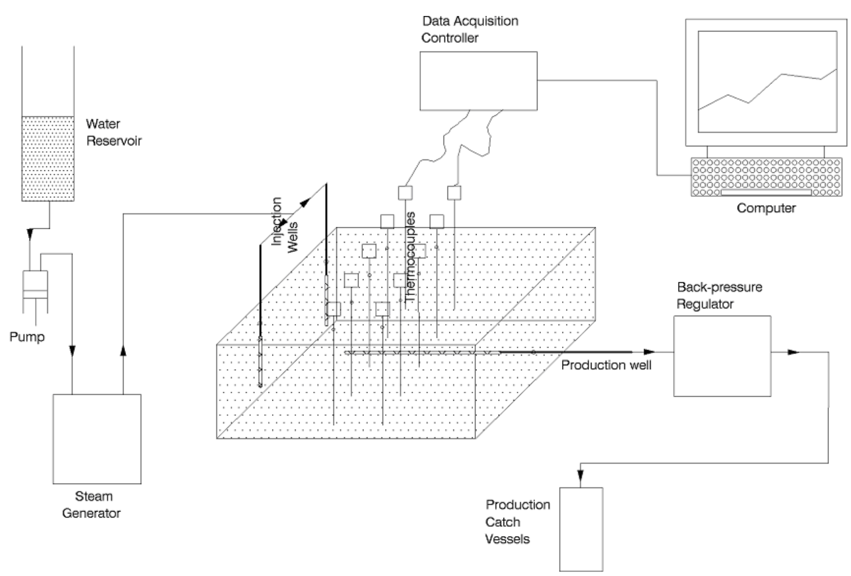


Figure 4a: Equipment schematic for the laboratory testing of steamflooding in a TTH configuration (3-D model)

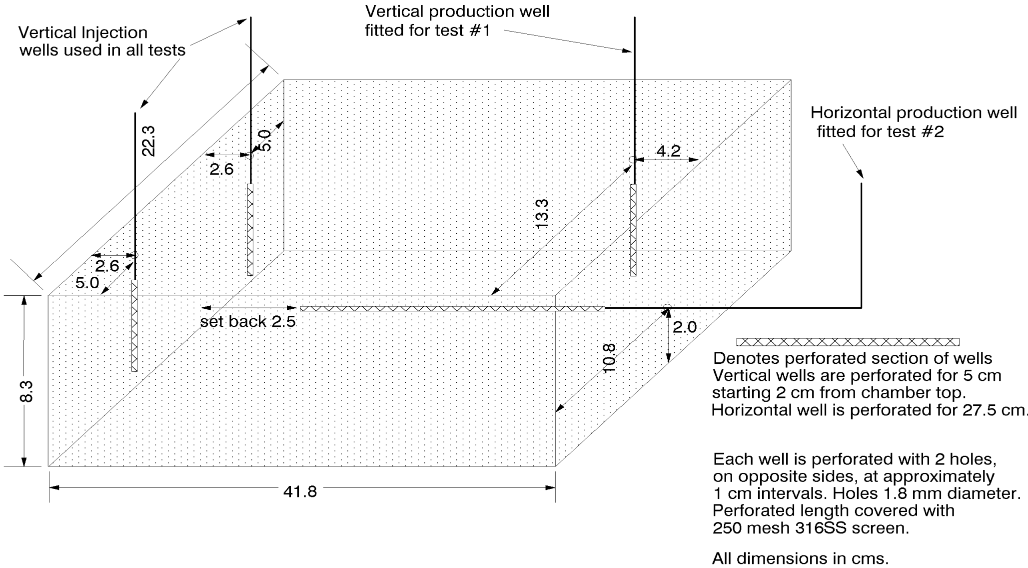


Figure 4b: 3-D model -- Cell and well dimensions for the experimental set up used in tests #1 and #2

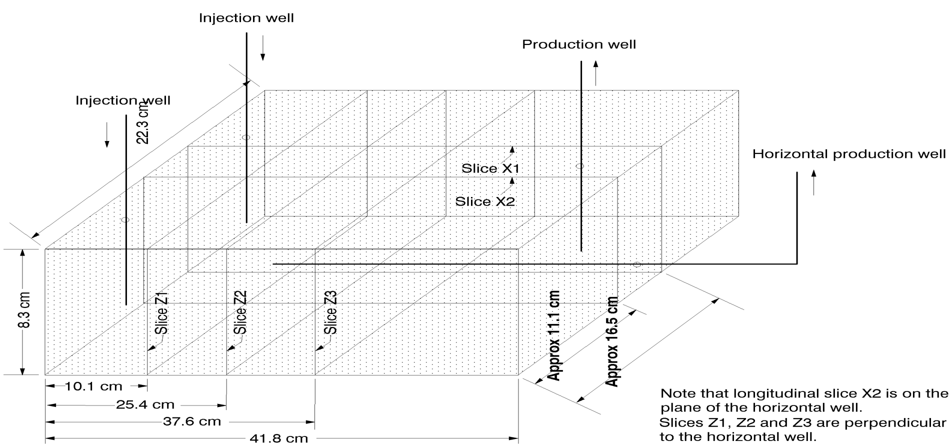


Figure 5: 3-D model -- The isotherm planes (for all tests). Well locations for tests #1 and #2

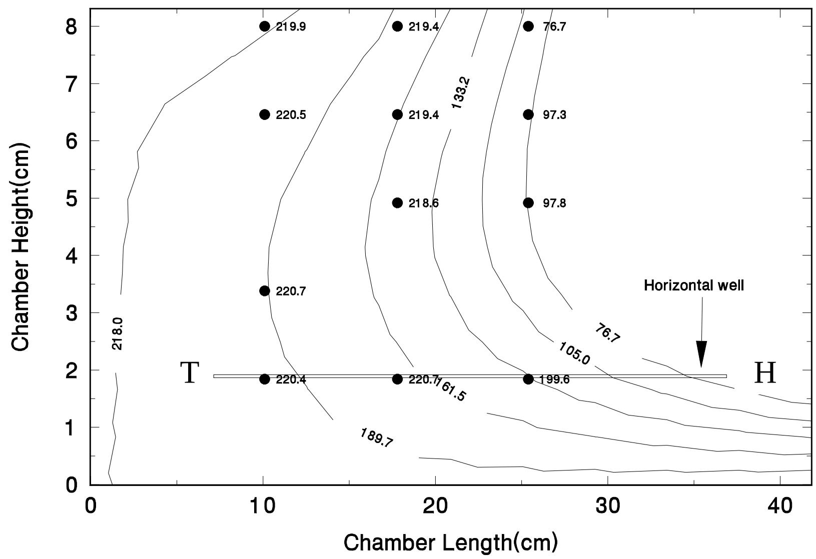


Figure 6: Test #2: TTH Steamflood isotherms in the longitudinal plane X2 at 4 hours
Legend: T = toe; H = heel

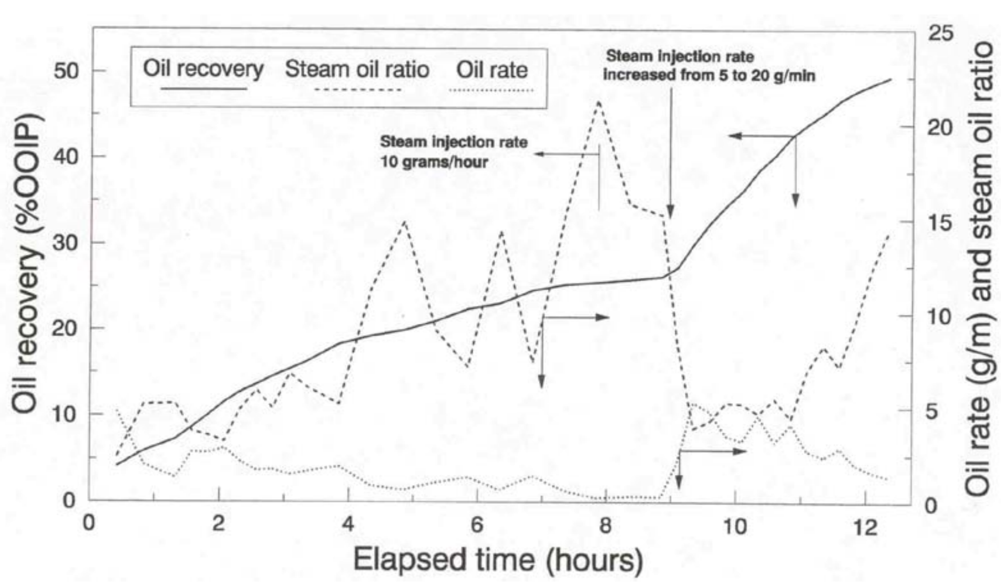
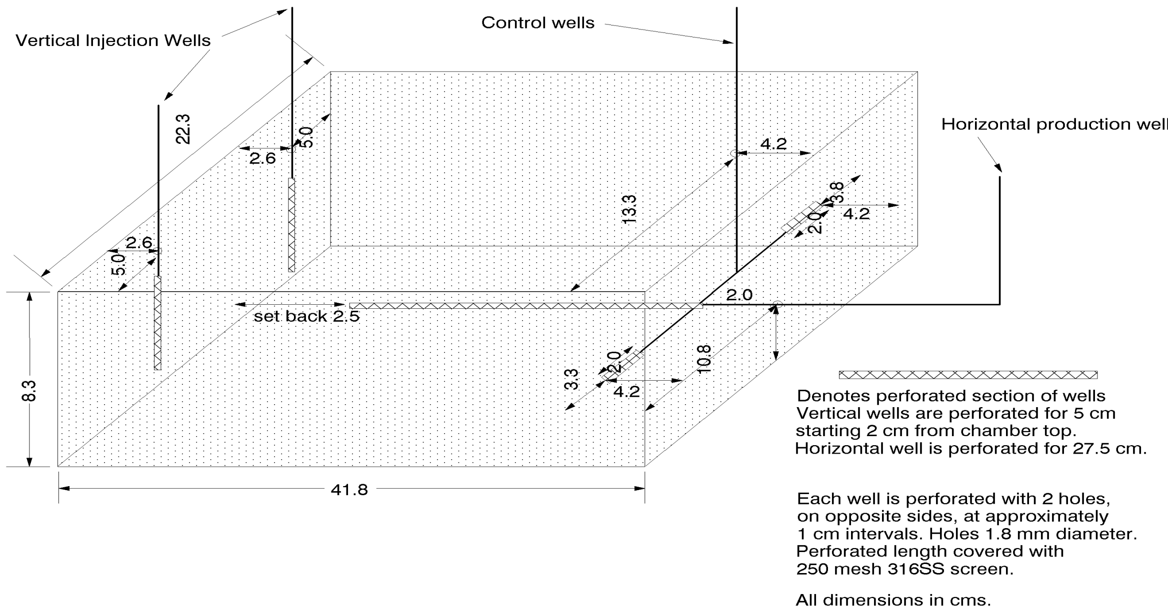
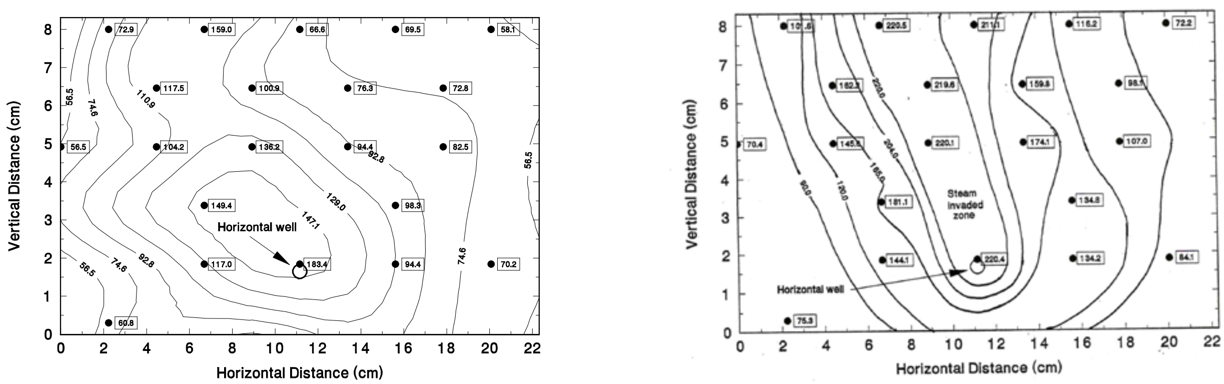


Figure 7: Test # 2: Toe-To-Heel Steam flood (TTHS) test. Variation of oil recovery, oil rate and steam-oil ratio in time





(a) (b)

Figure 9 a-b: Test #3: Toe-To-Heel Steam flood test. Isotherms in the plane Z2 at (a) 0.75 hours and (b) 1.25 hours

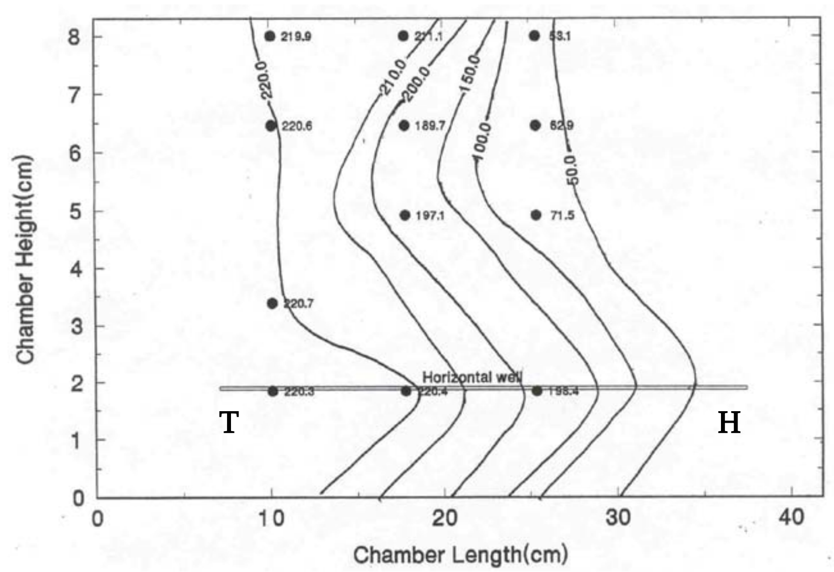


Figure 10: Test #3: Toe-To-Heel steam flood test. Isotherms in the longitudinal vertical plane X2 at 1.25 hrs. Legend: H =heel; T = toe

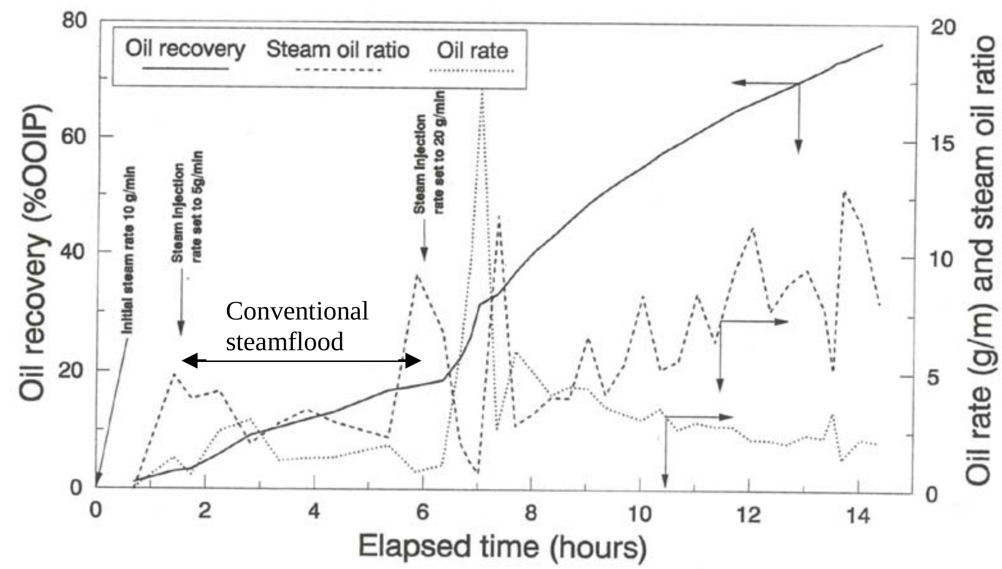


Figure 11: Test #3: Toe-To-Heel steam flood test. Variation of oil recovery, oil rate and steam-oil ratio in time

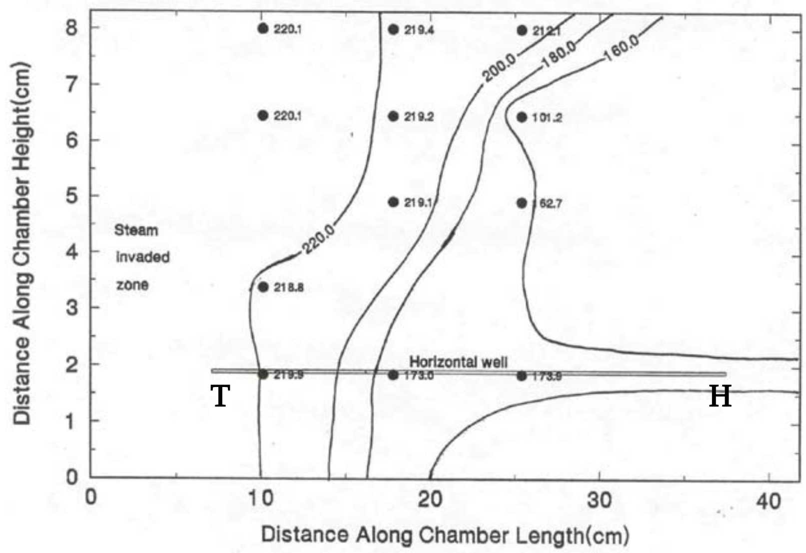


Figure 12: Test #4: Toe-To-Heel Thermo-solvent flood (TTH-TS). Isotherms in the vertical mid-plane X2 at 0.5 hours.
Legend: T=toe; H=heel

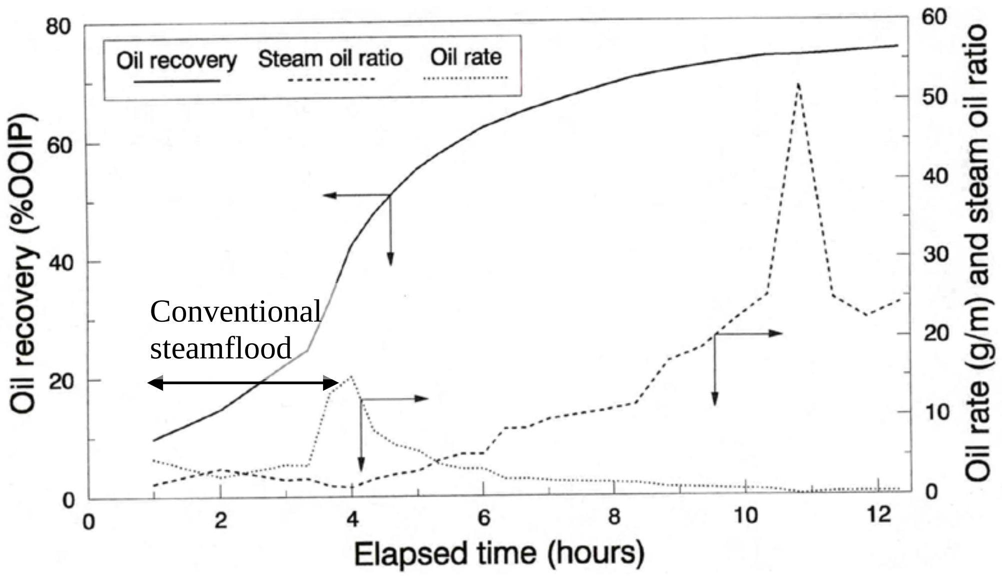


Figure 13: Test #4: Toe-To-Heel Thermo-solvent flood (TTH-TS). Variation of oil recovery, oil rate and steam-oil ratio in time

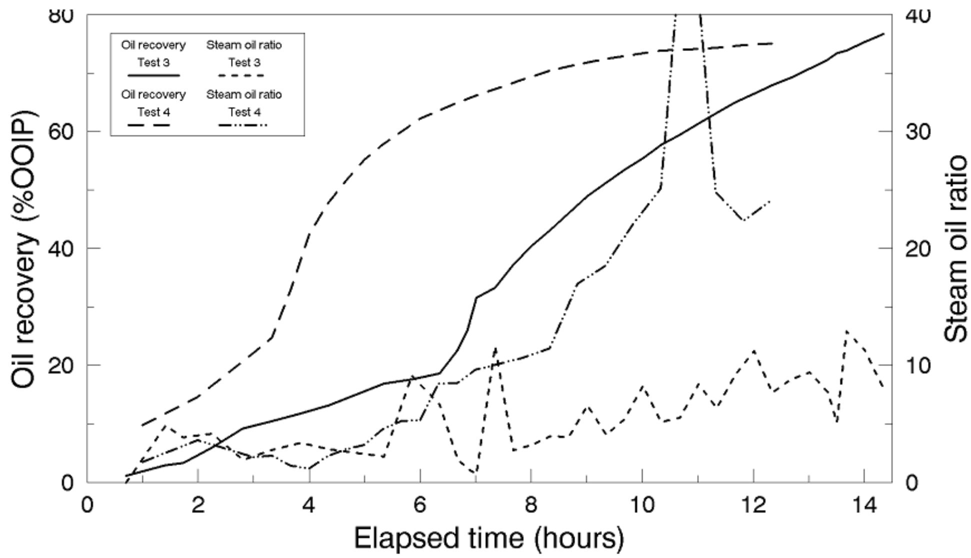


Figure 14: Comparison of cumulative oil recovered for the steamflood and thermo-solvent flood tests in a toe-to-heel configuration. (Test #3 versus Test #4) -- excluding communication phase and conventional steamflooding phase

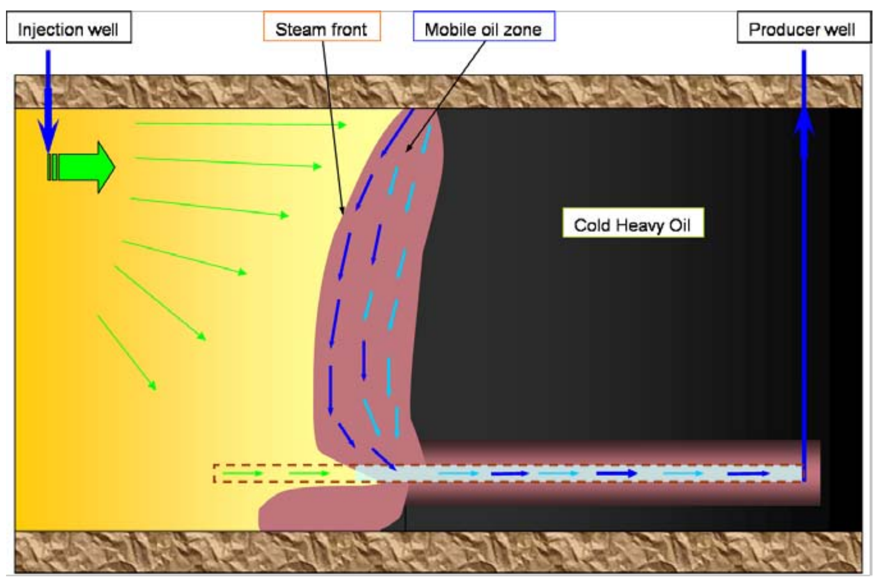


Figure 15: Schematic diagram of steamflooding in a TTH configuration; the hot oil and water are flowing down through the mobile oil zone. Some live steam is present in the horizontal section of the producer.