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Señor

SUPERINTENDENTE DE INDUSTRIA Y COMERCIO
DIVISIÓN DE NUEVAS CREACIONES

E. _____ S. _____ D. _____

SUPERINTENDENCIA DE INDUSTRIA Y COMERCIO



No. 06-128697- -00019-0000

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Tra. 11 PATENTEIYII

Eve: 378 FASENACIONALI

Act. 523 RESPUESTA

Folios: 13

Re: P1.-ARCHON TECHNOLOGIES LTD.-Solicitud de Patente de Invención en Fase Nacional PCT para "PROCESO DE COMBUSTIÓN IN SITU PARA LA EXTRACCIÓN DE HIDROCARBUROS LÍQUIDOS DE UNA RESERVA SUBTERRÁNEA".-Clase E21B 43/243.-Expediente número 06-128.697.-

1. Me refiero al auto dictado por ese Despacho notificado mediante fijación en lista de 13 de Mayo de 2011.

2. De acuerdo con el Concepto Técnico No. **1292** se tiene que:

"Como consecuencia de la búsqueda de anterioridades de materia relacionada con la de la presente solicitud, se determinó que existe en el estado de la técnica el siguiente documento que eventualmente afectaría los requisitos de patentabilidad de esta solicitud:

- **XIA, T.X. ET AL: "THAI a "short-distance displacement" in situ combustion process for the recovery and upgrading of heavy oil". Chemical Engineering Research and Design, 2003, 81 (A3), 295-304; y**
- **BA CI, S.: GÜMRAH, F. "An examination of steam-injection processes in horizontal and vertical wells for heavy-oil recovery". Journal of Petroleum Science and Engineering. Volume 8, Issue 1, July 1992, pages 59-72.**

3. Para responder a los requerimientos del señor Examinador de conformidad con el Artículo 46 de la Decisión Andina 486 de 2000, anexo me permito presentar a ese Despacho copia del siguiente documento solicitado:

- **XIA, T.X. ET AL: "THAI a "short-distance displacement" in situ combustion process for the recovery and upgrading of heavy oil". Chemical Engineering Research and Design, 2003, 81 (A3), 295-304; y**
- **BA CI, S.: GÜMRAH, F. "An examination of steam-injection processes in horizontal and vertical wells for heavy-oil recovery". Journal of Petroleum Science and Engineering. Volume 8, Issue 1, July 1992, pages 59-72.**

4. Adicionalmente, me permito informar a ese Despacho que renuncio al término de vencimiento (cuyo código de entrada es el 585) del auto de fecha 13 de Mayo de 2011, en aras de que la solicitud sea estudiada lo más pronto posible.

5. En vista de lo anterior, ruego a usted tomar atenta nota y proceder de conformidad.

Señor Superintendente,


ALICIA LLOREDA RICAURTE

T.P. 53.215

THAI—A 'SHORT-DISTANCE DISPLACEMENT' *IN SITU* COMBUSTION PROCESS FOR THE RECOVERY AND UPGRADING OF HEAVY OIL

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The integration of reservoir processes with horizontal well technology has led to the development of 'short-distance displacement' processes for more efficiently recovering heavy oil and tar sands bitumen. THAI, 'toe-to-heel' air injection, using horizontal producer wells in a line drive configuration, creates unique operating conditions in the reservoir that have special advantages for heavy oil recovery. Similar to the SAGD (steam assisted gravity drainage) and VAPEX (vapour extraction) processes, the distance that the mobilized oil has to travel to the producer well(s) in THAI is short (typically a few metres), compared with the long-distance (hundreds of metres) in a conventional flood pattern. SAGD, VAPEX and THAI are, therefore, classified as 'short-distance displacement' processes. In THAI, a gravity-assist mechanism exists by virtue of the mobile oil zone that develops immediately ahead of the combustion front. This occurs in a heavy oil reservoir when the vaporized oil and gases are prevented from communicating through the downstream oil zone and, instead, are forced to flow down into the exposed part of the horizontal producer well in line drive, i.e. short-distance displacement. The gravity-assist prevents gas override, ensuring an upright combustion front and hence a stable process. Three-dimensional combustion cell tests using heavy Wolf Lake (Alberta) oil have revealed the essential characteristics of THAI. The short-distance displacement provides for constant, stable process conditions in THAI. The thermal sweep efficiency of the process is very high and virtually all of the oil in the zones contacted by the combustion front is produced, except for the small fraction consumed as fuel. The potential oil recovery is very high compared with other processes. It also produces thermally upgraded oil, with an increase of 5–7 API points.

Keywords: *in situ* combustion; heavy oil; air injection; horizontal wells; downhole upgrading.

INTRODUCTION

In situ combustion (ISC) is achieved by burning a small fraction of the oil in the reservoir in order to enable flow of the unburned fraction. The history of *in situ* combustion for heavy oil recovery can be traced back to the turn of the twentieth century in the USA (Sarathi, 1998). ISC is a thermal enhanced oil recovery (EOR) process which uses air injection for improving oil recovery (Lake, 1989; Burger *et al.*, 1985). Because of the strong exothermic oxidation reactions between hydrocarbons and oxygen, oxygen is consumed to produce flue gases and, at the same time, the temperature of the oil-bearing matrix is greatly increased. ISC is particularly favourable for heavy oil reservoirs because the increase in temperature reduces the oil viscosity by several orders of magnitude.

By generating the thermal energy *in situ* in the reservoir, ISC has many advantages over other heavy oil EOR processes, such as a high efficiency in terms of heat utilization, highly efficient displacement drive mechanism,

and less total environmental impact (Moore *et al.*, 1997). This technology has been extensively studied in both the laboratory and the field. However, the conventional ISC process has not achieved general acceptance due to many apparent failures, mainly to do with inappropriate reservoir application and poor control of the process.

The most significant operational problems affecting recovery from heavy oil reservoirs using vertical-vertical well pattern *in situ* combustion are:

- (1) gravity segregation, or gas overriding, due to the difference between the gas and oil densities;
- (2) channelling, due to unfavourable rock heterogeneity;
- (3) unfavourable gas/oil mobility ratio;
- (4) difficulty in regaining a high temperature combustion mode, once it has slipped into a low temperature oxidation (LTO) mode, due to insufficient oxygen flux.

In conventional ISC, oil is mobilized ahead of the combustion front and displaced into the colder downstream

regions of the reservoir. The distance between the mobile oil zone (MOZ) and the producer well(s) is of the order of hundreds of metres, depending on the well spacing. Therefore, conventional ISC is classified as long-distance displacement (Figure 1). It is an arrangement which does not guarantee success, since the increased oil saturation, or oil-banking, nearer to the production wells, and also possible formation of emulsions, can lead to a severe loss of gas injectivity. Failure to supply sufficient air injection flux to maintain the process in a HTO (high-temperature oxidation) mode, has been one of the main causes for failure of the ISC process in the past. Paradoxically, if the gas flux is too high, this can cause gas overriding, leading to oxygen breakthrough at the production wells. Of course, as with any recovery process, it is also extremely important to make the correct choice of reservoir in which to apply it.

The development of advanced, high-efficiency, oil recovery processes is a necessity, if the trapped oil in a whole spectrum of oil reservoirs is to be economically produced. Examples already exist of recoveries at the level of 50% using steam assisted gravity drainage (SAGD), and even higher for miscible solvent flooding in light oil reservoirs.

The superiority of SAGD, compared with other steam processes, is manifested primarily in its gravity-assist mechanism, which allows a stable steam chamber to grow. The oil, which is mobilized at the steam-oil interface, drains down towards the horizontal producer well. The mobilized oil only flows over a short distance (a few metres) before it enters into the horizontal producer well.

To develop a new (advanced) ISC technique, the key point is to create a short flow path for the mobile oil ahead of the combustion front to be drawn into the producer well.

THAI—'Toe-to-Heel' Air Injection

THAI is a new EOR process, which integrates *in situ* combustion and advanced horizontal well concepts (Greaves and Turta, 1997). The main feature of the THAI process is that it uses a horizontal producer well instead of a vertical producer well (conventional ISC). Also, the toe of the horizontal producer is positioned close to the injection point. Thus, the combustion front propagates along the

horizontal production well, from the 'toe' position, to the 'heel' (Greaves *et al.*, 1993; Greaves and Al-Shamali, 1995, 1996).

The concept of THAI is represented by the schematic in Figure 2 (Greaves and Xia, 1998; Greaves *et al.*, 1999, 2001), and shows the combustion front traveling like a 'moving window'. Thus, a horizontal producer well is positioned in a line drive in the reservoir and air is injected via a vertical injection well (VIHP), or a horizontal well (HIHP). This well configuration can be extended through the reservoir in a direct staggered line drive by employing additional horizontal producer wells. In a field application, vertical wells are preferred for injection for safety reasons, using a 2VIHP configuration. However, in physical model laboratory studies, HIHP is considered to be the baseline well combination for the process.

The basic mechanism of THAI process for heavy oil recovery is the same as for the conventional ISC process, i.e. burning of a heavy residue, or coke fraction, produces the heat required to increase the temperature of the oil-bearing formation, reducing the *in situ* oil viscosity, and thereby, increasing oil mobility. The fuel for the combustion reactions (mainly coke) is generated ahead of the combustion front by thermal cracking of heavy residue (asphaltenes, resins and aromatics).

On the other hand, the pathway for oil displacement in THAI is radically different from that in conventional ISC processes. Because of the high oil viscosity in the downstream, cold region of the reservoir, the mobilized oil ahead of the combustion front (and coke zone) is drawn down into the exposed section of the horizontal well, immediately below. Thus, THAI is a 'short distance displacement' process. Like SAGD and VAPEX (vapour extraction), the mobilized oil does not pass through the cold (high viscosity oil) region, but takes the shortest pathway to the horizontal production well (Figure 2).

The coke zone (Figure 2), provides the fuel for the *in situ* combustion process. It is formed immediately ahead of the combustion front as a result of the precursor processes leading to oil displacement, including vaporization and thermal cracking. During the stabilized operating period, all of the fluids which are eventually produced (gas, steam, oil) pass through the MOZ, and are drawn down under forced flow into the exposed section of the horizontal producer well. Near the draining edge of the MOZ, at the

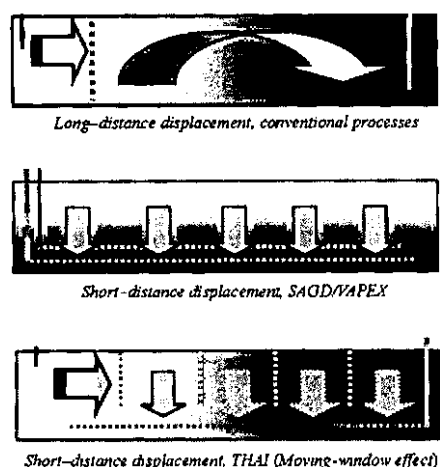


Figure 1. Long and short displacement processes.

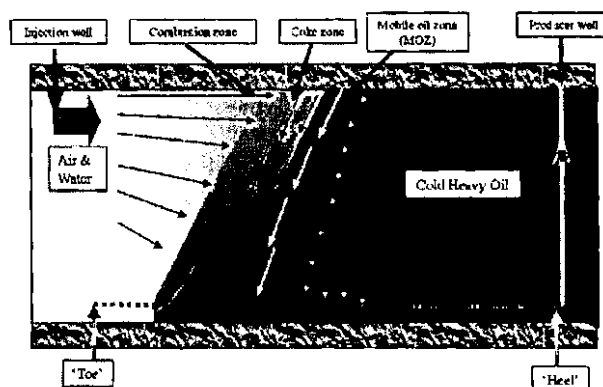


Figure 2. THAI—'toe-to-heel' air injection process.

boundary with the cold oil region, the oil is draining mainly by gravity.

Bypassing of air (oxygen) directly to the toe-position of the horizontal producer well does not occur in the THAI process. This is explained by reference to Figure 3. Prior to startup, gas communication paths are created (if needed) between the injectors (2VIHP), and between the injector(s) and the horizontal producer well by steaming. At start-up, high temperature ignition ($>500^{\circ}\text{C}$) is started in a small zone (chamber) near the top of the oil layer. As the air injection rate is increased, the combustion front expands outwards, away from the injection well (Figure 3a). A stable process condition exists (no oxygen channelling through to the horizontal producer well), because high oxidation utilization is achieved in the combustion zone burning at high temperatures in the top of the oil layer. As the combustion front extends and moves further away from the injection well region, heat conduction into the downstream oil region causes the MOZ to develop and increase in size. The stability of the THAI process now depends on two key factors: (1) a high temperature burning zone ($450\text{--}650^{\circ}\text{C}$), which is more advanced in the top part of the oil layer, exhibiting a type of controlled (stable) gas overriding; and (2) a seal in the horizontal producer well. In SAGD and VAPEX, there is a liquid seal between the injector and producer, or in the producer well itself. This is not the case in THAI, because the process operates at high GOR's (gas oil ratio) of the order of 10–80 at reservoir conditions. It is therefore possible for heavy residue at the bottom region of the coke/MOZ (Figure 3b), to drain into the horizontal well. As the temperature near the horizontal well begins to increase, the heavy residue inside the well becomes heavier, or is thermally cracked to form coke. It is postulated that this heavy residue, or coke, acts like a gas seal in the horizontal well, preventing air (oxygen) channelling through from behind the combustion front. The process of sealing is considered to be dynamic, due to the increasing temperature effect from the advancing combustion front. A gas seal is therefore continuously being formed, close to the bottom edge of the coke layer and adjacent MOZ.

The short displacement feature of THAI means that gas communication/connectivity is easily established and maintained, so that early oil production is achieved. The overall

sensitivity of the process to reservoir heterogeneity effects is also significantly reduced, since the combustion and oil displacement processes are effectively taking place in a small section of the reservoir.

Another potential advantage of THAI is the robust degree to which the air flux can be varied during operation. Since air injectivity into the reservoir actually increases, owing to depletion in the burned region, a high air flux can be employed to maintain oil production at the desired rate. Not least, using a high air flux maintains the process in an HTO mode, avoiding the complication of LTO reactions.

Furthermore, the thermal upgrading of heavy oil *in situ* is preserved in THAI. The high temperature ($>500^{\circ}\text{C}$) created by the combustion zone promotes thermal cracking of high molecular weight hydrocarbons. Thermally cracked oil is drawn down into the exposed section of the horizontal well, producing lighter oil from the heavy oil reservoir.

All of these features are very desirable for oil recovery, but there are also benefits for oil transportation and downstream refining. The main benefits of the 'toe-to-heel' air injection process are listed in Table 1.

All previous experience with *in situ* combustion in conventional VIVP air injection processes, now classified as HTO-IAF high temperature oxidation (immiscible air

Table 1. Potential benefits of THAI for heavy oil recovery.

- Gas override is controlled, resulting in a quasi-upright *in situ* combustion front
- High air flux maintain process in HTO mode, avoiding LTO reactions
- High sweep efficiency, related to the absence of any gas coning (channelling) in the producer
- Process produces significantly lighter oil because thermally upgraded oil is preserved
- Significant environmental benefits due to *in situ* removal of sulphur and heavy metals
- Unique mobile oil zone downstream of the combustion front reduces sensitivity (preferential advancement) to reservoir heterogeneity in the virgin zone, mainly for extra-heavy reservoirs
- Fluid injectivity is increased due to higher permeability in the burned out zone and production of mainly upgraded and heated oil.
- Front tracking capability via 'toe-to-heel' propagation with tight control
- For a commercial line drive operation, for a fixed well pattern, the number of wells is reduced to almost half owing to their use first as producers and then as injectors

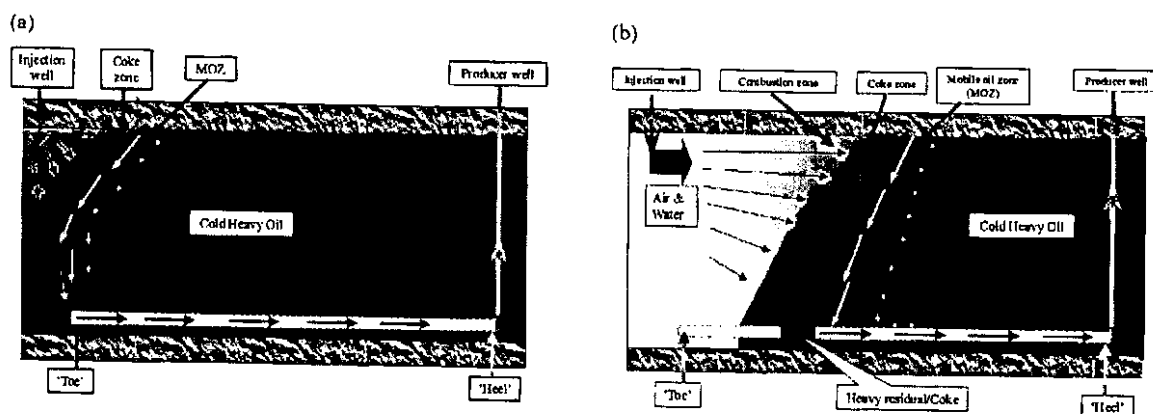


Figure 3. THAI: start and stabilized operating periods. (a) Startup phase; (b) Stabilized operating phase.

flood) (Turta and Singhal, 1998), was dominated by the inability to satisfactorily control gas overriding. However, THAI is radically different in that it controls the effect of gas overriding entirely. This single advance translates the potential of HTO-IAF in heavy and medium heavy oil reservoirs from the rank of interesting, but problematical, to a process that is potentially the most thermally efficient and highly desirable, owing to the ease of its control.

In this paper, two three-dimensional combustion cell tests of THAI are presented. The tests are aimed at understanding the mechanisms governing the high oil recovery and thermal upgrading achieved by THAI. Finally, a comparison of THAI with other thermal EOR processes is given.

THREE-DIMENSIONAL COMBUSTION CELL EXPERIMENTS

A rectangular stainless steel combustion cell measuring 0.4 m square by 0.1 m deep was used to carry out the ISC tests. The cell was fitted with an array of 76 thermocouples arranged on three levels: top, middle and bottom. These are placed, respectively, 0.02, 0.05 and 0.08 m from the top surface of the cell (see Figure 4).

An improved control system was used, in order to achieve a near-adiabatic condition as possible for the 3-D cell operation. Temperature regulation of the combustion cell surface was achieved by means of six tape heaters, which were wound around the cell. These provided the heat needed to compensate for heat losses from the cell walls, and maintain the cell at an approximately adiabatic condition. Temperature control was achieved automatically by a computer in response to the measured temperature profiles in the sandpack and the adjacent wall temperatures.

All measurement and data acquisition was carried out using Advantech 'Genie' software, running under Windows 95 on a Pentium PC 116 MHz platform.

One dry and one wet combustion test were completed using the standard THAI well arrangement, i.e. HIHP. The Wolf Lake oil (10.5° API) was produced from a steam flood operation and was specially dried at BP, Sunbury Research Center. The experimental conditions are given in Table 2. In both tests, Wolf Lake crude oil was used as representative heavy oil (Table 3).

In the tests, an electric heating element near to the horizontal injection well was used for ignition. It consisted of a coiled Nichrome wire, controlled by a voltage regulator.

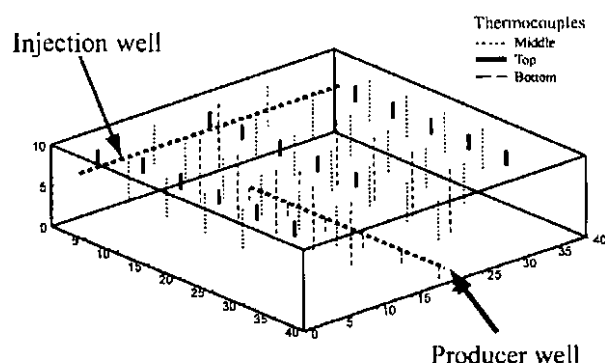


Figure 4. Placement of thermocouples, injection and producer wells in the 3-D cell.

Table 2. Experimental conditions of 3-D cell tests.

Run	984	985
Sand	Silica W50 + 3% clay	
Oil	Wolf Lake oil	
Porosity	38.5%	38.5%
Soi (%)	75	75
Swi (%)	20	20
Sgi (%)	5	5
Initial temperature (°C)	20	20
Combustion mode	Dry	Wet ^a
Air flux (m ³ m ⁻² h ⁻¹)	9.0	9.0
Water injection rate (ml min ⁻¹)	0	5.0 ^a
WAR (m ³ 1000 m ⁻³)	0	0.83
Well configuration	Direct line drive	Direct line drive
Back pressure (psig)	20	20

^aContinuous, co-injection of water at specific water-air-ratio (WAR).

Table 3. Physical properties of Wolf Lake heavy oil.

API Gravity	10.5
Viscosity (mPa s)	48,500 (15°C) 24,400 (20°C) 260 (80°C)
Elements (wt%) ^a	C 83.77; H 10.62; N 0.25; S 4.5
SARA composition (wt%)	Saturates 25.2 Aromatics 37.4 Resins 27.3 Asphaltenes 10.1

^aMaterial balance difference accounted for by Ni, V, Fe.

The energy introduced by the ignitor was about 1000 kJ, representing around 5–10% of the total energy generated by the combustion process.

RESULTS AND DISCUSSION

The main results from the two THAI tests are summarized in Table 4.

Table 4. Summary of results of 3-D cell tests.

Run	984	985
Combustion mode	Dry	Wet
Overall period (h)	14.25	12.5
Ignition period (h)	2.25	2.0
Air injection period (h)	12.0	10.5
Dry phase (h)	12.0	9.0
Wet phase (h)	0	1.5
Peak temperature (°C)	550	620
Produced gases (% average)		
CO ₂	12.74	12.13
CO	4.10	4.25
O ₂	1.96	2.15
CO/(CO ₂ + CO)	0.243	0.259
H/C ^a	0.490	0.671
O ₂ /fuel requirement (Sm ³ kg ⁻¹)	1.93	2.00
O ₂ utilisation (%)	90.7	89.8
Fuel consumption (% of OOIP)	9.31	8.17
Air/oil Ratio (Sm ³ m ⁻³)	1080	920
Oil recovery (% OOIP)	85.0	86.5
Combustion front velocity (cm h ⁻¹)	2.5	3.0
Residual oil (% OOIP)	6.8	6.0

^aApparent hydrogen-carbon ratio of the burned fuel.

Run 984—Dry Combustion

The peak temperature profile, which is obtained from the leading, highest temperature in the sandpack, during the experiment, is shown in Figure 5. After 180 min, the temperature remained steady at about 550°C, but decreased slightly towards the end of the run. The fact that vigorous combustion was maintained right up to the end of the combustion cell is evidence that there was no severe desaturation of the oil layer downstream of the combustion front.

The temperature profiles at horizontal and vertical middle sections of the sandpack are presented in Figure 6.

At 180 min, the combustion front is a nearly vertical zone located just before the 'toe' of the producer well. At 360 min, the leading edge of the combustion front (500°C horizontal contour) is centred along the horizontal producer well, about half-way through the sandpack. The MOZ, immediately ahead of the combustion front, is now becoming more extended. This is because the combustion front is also starting to propagate in the top part of the sandpack. The effect can be seen more clearly from the vertical temperature profiles during the later stages of the run. This 'top burning effect' was sustained after the combustion front moved onto the 'toe' of the producer well.

The fact that combustion takes place in the upper part of the sandpack, and does not lead to an uncontrolled gas override condition usually experienced in the conventional ISC process, is a key feature underlying the success of THAI. Injected air (oxygen) preferentially migrates to the upper layers by virtue of gravity segregation. Thus, most of the injected oxygen is consumed in this high-temperature region, well away from the production well, thus preventing breakthrough of oxygen into the production well below.

Oxygen utilization is very high, averaging 90.7%. However, in Figure 5, the CO₂ concentration in the produced gas averages less than the full stoichiometric value, at 12.7%, although CO is higher at 4.10%. These values are indicative of the levels of combustion performance likely to be experienced in an actual reservoir with 3-D flow effects, unlike the more idealized values obtained from a 1-D combustion tube. Although the produced oxygen is less than 2%, the trend inclines steadily upwards towards the end of the test, i.e. in the heel region of the horizontal

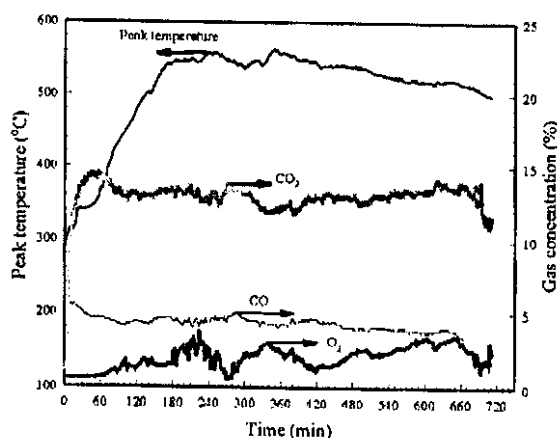


Figure 5. Peak temperature and produced gases during dry combustion, run 984.

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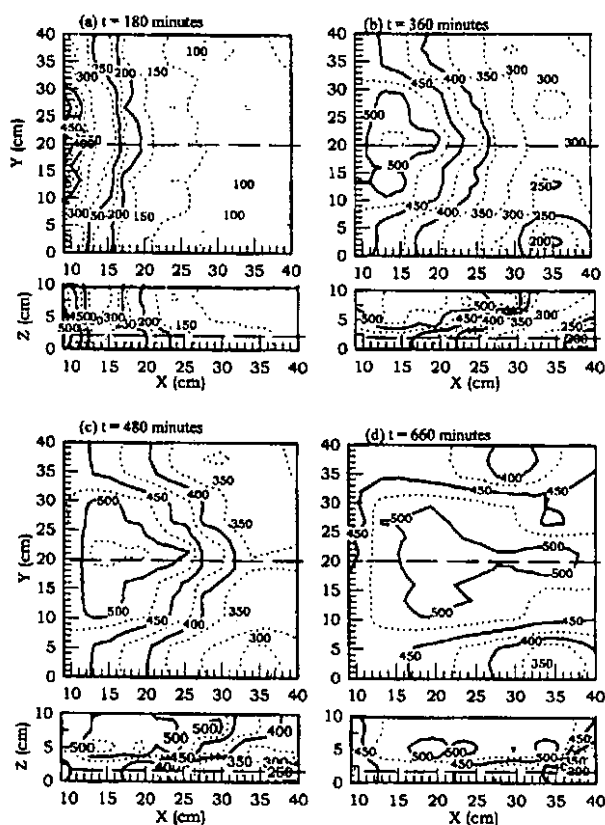


Figure 6. Temperature profiles during dry combustion, run 984.

producer. In a field operation, it may be better to stop the process, before produced oxygen begins to rise and oil production falls off.

Oil production (Figure 7) peaks at about 300 min, but declines at a steady rate as the MOZ approaches the heel region. Overall, the oil recovery is very high, at 85% OOIP.

Run 985—Wet Combustion

There are two periods of continuous water injection, or wet combustion, as shown in Figure 8. The first period was started just after the ignitor was switched off, at 180 min, and the second, shorter period, commenced at 350 min. The water-air ratio was 0.83 m³/1000 m³, representing a normal

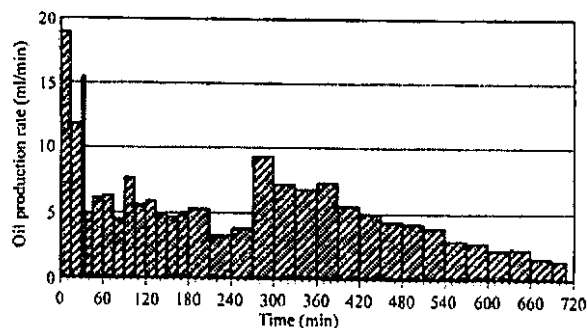


Figure 7. Oil production rate during dry combustion, run 984.

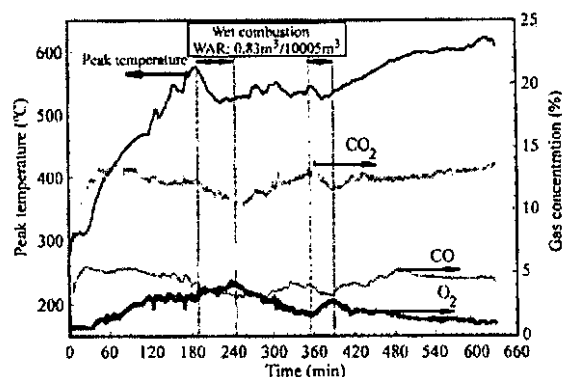


Figure 8. Peak temperature and produced gases during wet combustion, run 985.

wet combustion condition, according to the conventional ISC analysis. However, since the combustion peak temperature decreased about 40 and 20°C, respectively, in the first and second periods, it would appear that even this WAR is too high to define a normal wet combustion mode in THAI. It is quite obvious from the temperature profile, that there is no steam plateau formed ahead of the combustion front, as would usually be observed in conventional 1-D ISC tests. Rather, the steam generated exits the process directly, via the MOZ, along with other fluids. This is quite a different process from conventional ISC. After water injection was stopped at 390 min, the peak temperature increased from 530 to 600°C.

The areal temperature contour at the mid-plane (Figure 9) reveals that combustion front propagation in the top layers

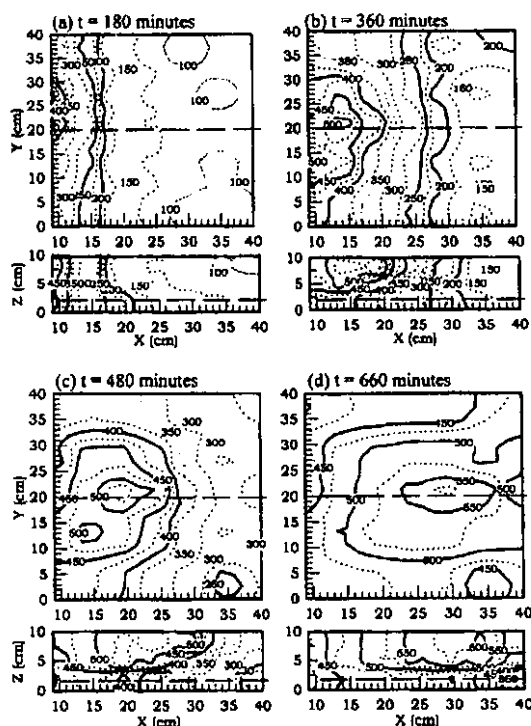


Figure 9. Temperature profiles during wet combustion, run 985.

of the sandpack is the same as that observed in the dry combustion case. There is evidence of cooling occurring near the inlet of the injection well, which distorts the symmetry of the temperature profiles. Without this effect, the temperature contours just ahead of the combustion front region would be more laterally extended. This region, from about 350 to 475°C, can be envisaged as corresponding to the MOZ in Figure 2, in which hot gases (oil, steam, inerts) and oil which is draining at the leading edge, flow into the exposed section of the producer well.

The lateral extension of these contours is further curtailed due to the cooling at the edges of sandpack, because the experiment (sandpack) is not perfectly adiabatic. The 'composite' nature of the combustion front temperature profile, represented by the 500°C contour in the vertical mid-plane, remains essentially unaltered (360, 480 min) until the combustion front reaches the end of the cell. Thus, there is an upper-riding zone covering about one-third of the oil layer and a lower section extending down to just beyond the centre line. The mid-period region of the experiment should be most representative of stable operation, and less affected by any downstream end-effects, owing to non-ideal (non-adiabatic) conditions. The invariant 'composite' combustion front temperature profile observed during the stabilized operating period is evidence, therefore, of a controlled gas override condition in the top part of the oil layer. Combustion temperatures are also highest in the top part of the oil layer and gas (air) naturally gravitates to this region. Consequently, oxygen utilization is also very high.

The ISC process operates because the fuel, which is laid down ahead of the combustion front, determines a preferential path for the injected oxygen (assisted by the controlled gas overriding), even when there are local heterogeneities present. All of the mobilized fluids are drawn down directly into the exposed section of the horizontal producer well ahead of the combustion front. This forced drainage ensures that gas override is controlled.

The produced gas composition in Figure 8 shows a broadly similar result to that in the dry combustion test. However, during the wet combustion periods, the amounts of CO₂ and CO in the produced gas are reduced, but O₂ is increased. The reason is the decrease in the combustion temperature during the wet combustion periods. After water injection was stopped, CO₂ increased and O₂ decreased. The oxygen level continues to decline towards the end of the experiment, to around 1%. There is a corresponding slight improvement in combustion intensity, with the CO₂ level increasing gradually to over 13%. These changes are in response to the increase in peak combustion temperature after the second period of water injection.

Again, the cumulative oil recovery in this test is very high, at 86.5% OOIP. This is hardly surprising, since almost 100% of the sandpack has been affected by a high temperature thermal front (>450°C). Figure 10 shows that water injection results in an increase in oil production initially, reducing to a lower level after the first wet phase, but increasing again after the second wet combustion period.

Post-mortem Photographs

The photographs in Figure 11 show the state of the sandpack after each experiment. Horizontal distance is

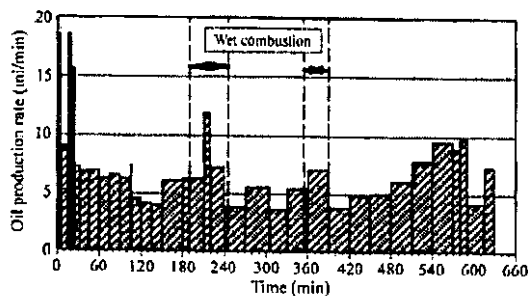


Figure 10. Oil production rate during wet combustion, run 985.

measured from the inlet (injection) end of the cell. The more extensive lighter areas at $x = 9$ cm, and also $x = 14$ cm in run 985, are completely burned, i.e. there is no residual oil or fuel left. Towards the sides of the cell, and increasing in area as the distance into the sandpack increases, is a darker region containing residual oil. Figure 12 shows a plot of the unburned area containing residual oil as a function of the distance through the sandpack. The residual oil measured approximately 2 wt% of the sandpack. The total residual oil in the sand pack was measured to be 6.8% OOIP for run 984 and 6.0% OOIP for run 985. The oil and water material balance agreed, to within approximately 1% (Table 5).

The photographs clearly show that the main region of burning, i.e. path of the combustion front, is in the upper part of the sandpack, above the producer well (Figure 11). This apparent gas overriding condition is stable and does not result in oxygen breakthrough, even when the lower limit of the burning zone reaches nearly down to the horizontal producer well ($x = 14$ cm, run 984). This means that the oil layer immediately downstream of the combustion zone is

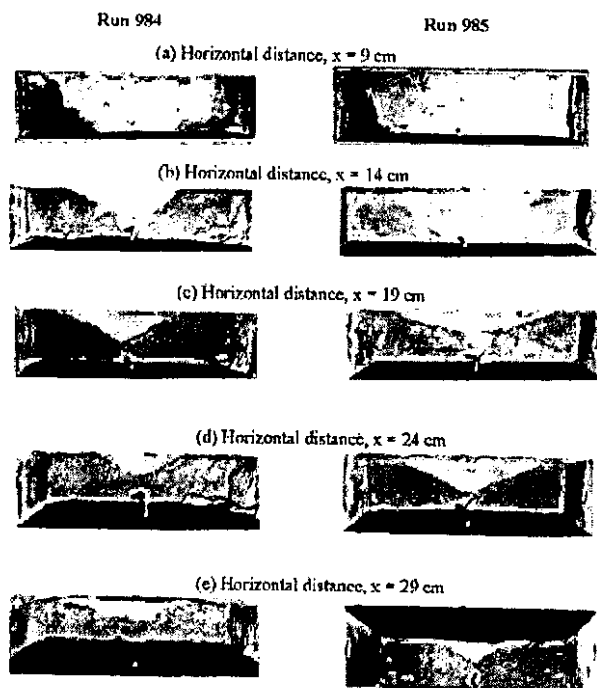


Figure 11. Post-mortem pictures of run 984 and run 985.

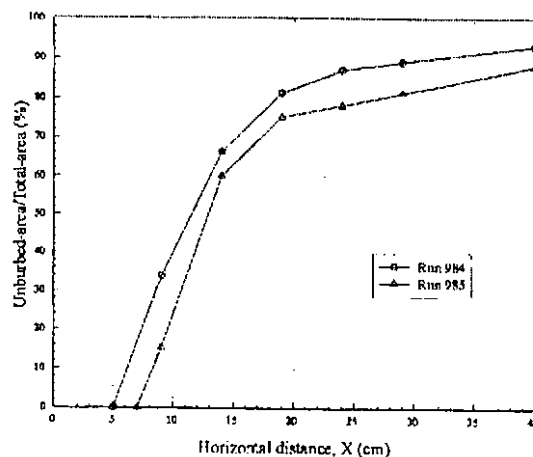


Figure 12. Ratio of unburned area/total area of the sandpack vs horizontal distance.

swept by the hot gases. Above 450°C , all fluids having a lower boiling point are vaporized and are drawn down into the producer well. Also, hydrocarbons having a higher boiling point are thermally cracked into lighter compounds and coke. The cracked hydrocarbons are also produced and only the solid coke is left, deposited on the sandpack.

Freitag and Exelby (1998), investigated the mechanism of heavy oil recovery by ISC in the laboratory, using a combustion tube. They performed two different experiments: (1) wet *in situ* combustion; and (2) a gas flooding using a mixture of carbon dioxide and nitrogen only, of approximately the same composition as the produced gases in the combustion test. At the same time, the ignitor was used to generate steam from injected water, creating a steam front, advancing along the combustion tube in a manner similar to that in the combustion test.

Using Wolf Lake crude oil, they found that steam distillation contributes only a few per cent towards the total amount of heavy oil displaced by *in situ* combustion. This means that thermal sweeping by the hot combustion gases and vaporized oil fraction is the main mechanism for oil recovery. The residual oil saturation in the area swept by the combustion front was only 1–2% OOIP, but about 50% OOIP after steam-gas sweeping. The temperature during the steam-gas run was not clearly stated in the paper.

Simulated distillation of the Wolf Lake crude oil shows that, at 500°C , the residual oil saturation is about 50% under distillation conditions (Al-Shamali, 1986). The distillation characteristic of Wolf Lake oil and the amount of residual oil left after steam-gas flooding clearly indicates that, without thermal cracking taking place, the unburned sandpack

Table 5. Example of material balance (run 985) (unit: kg).

Input		Output	
Initial oil in sandpack	4.6	Oil produced	3.98
Initial water in sandpack	1.23	Fuel burned	0.376
Water injected into sandpack	0.405	Oil/coke residual	0.276
Water generated by combustion	0.178	Water produced	1.705
Total	6.41	Total	6.34

will contain a much higher residual oil content. Furthermore, in both the dry and wet 3-D combustion experiments, the volume of clean burned sandpack represents only about 38–43% of the total volume of the sandpack. Since the oil recovery is very high at 85% OOIP, this strongly indicates that the high temperature front created by *in situ* combustion plays a major part in the displacement of the heavy oil.

Oil Upgrading

A potential major advantage of THAI is its ability to capture and preserve almost the full extent of the thermal upgrading achieved by thermal cracking and distillation. This is because the mobilized fluids ahead of the combustion front are produced directly into the exposed section of the horizontal producer well, rather than being displaced and banked-up in the colder downstream regions of the reservoir, which is the situation in a conventional *in situ* combustion process. Figure 13 shows the variation of the API gravity for samples of produced oil collected during the experiments. The trends overall are similar during the dry and wet combustion experiments, except that the level of upgrading is somewhat higher during the later stages of the wet combustion. Overall, the upgrading is approximately 5–7 API points above the original crude value. This is a very significant in terms of the potential economic value of the produced oil.

It is well known that *in situ* combustion is an extremely complex process, owing to the reservoir properties, the chemical reactions of cracking and burning of the oil and, not least, because of multiphase fluid flow in the porous medium. Most previous laboratory research on *in situ* combustion was conducted using combustion tubes. Since the information obtained from combustion tube tests is essentially one-dimensional, it is therefore not possible to use this type of information to elucidate the 3-D characteristics of the problem.

Based on the results obtained from the present experiments, it is clear that the high temperature combustion front in THAI plays two important roles in oil displacement: (1) reducing the viscosity of the heavy oil to increase its mobility; and (2) cracking of the immobile, high boiling point components into lighter, lower viscosity, mobile products. The thermal cracking reactions, which produce lighter oil, are not only beneficial for upstream operations, but they are also essential in the *in situ* combustion process, in order to achieve high oil recovery.

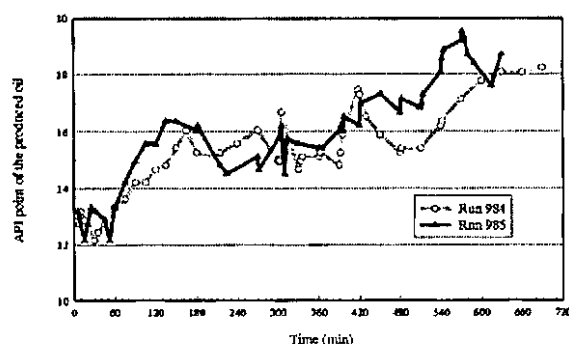


Figure 13. Thermal upgrading of produced oil in THAI.

In a stable combustion process, the fuel consumption is usually about 10% OOIP. In the data presented by Freitag and Exelby (1998), the residual oil saturation downstream of the combustion front was high (30–50%) and the oil recovery was about 55–60% OOIP in their combustion tube test using Wolf Lake oil. The high oil recovery in THAI is connected to the contributions in points (a) and (b) above. The 'controlled gas override' effect makes it possible to achieve near 100% thermal sweep.

By creating a 'short-distance displacement' for the mobilized oil ahead of the combustion front, the thermal upgrading of heavy oil is almost completely preserved. This unique feature of the THAI process makes it superior to other thermal EOR methods. In order to fully understand the mechanism of oil upgrading, it is necessary to distinguish between the effects of vaporization and cracking of the oil.

Comparison with Other EOR Processes

Other EOR processes, which use horizontal wells are COSH (Combustion Override Split-Production Horizontal Well), SAGD (Steam Assisted Gravity Drainage) and VAPEX (Vapour Extraction).

COSH

COSH is an *in situ* combustion process, which uses a horizontal well as a producer. The air is injected through several vertical injectors located above and close to the horizontal producer well (Kisman and Lau, 1993). Special gas production wells are located laterally in relation to the horizontal production well. These are designed to collect combustion gases and thereby discourage production of flue gases via the horizontal production well. The main disadvantages of this process are: (1) the control of several *in situ* combustion fronts intercepting the same horizontal producer is extremely difficult (and this has not yet been reported, even for the laboratory scale); (2) it requires special gas collection wells (more expensive); and (3) it does not create favorable conditions for *in situ* upgrading.

SAGD

SAGD is a very unconventional process. It is not a displacement process, like in the conventional five-spot, seven-spot or other pattern configurations. It uses a modified two-spot configuration, in which two horizontal wells are placed parallel (one on top of the other), located in the lower part of the formation. The injection well is placed 2–10 m above the production well. The two wells do not span the entire drainage area. The main idea is that steam creates a steam chamber; and the heated oil flows towards the production well by gravity.

Of all short-distance processes, SAGD is the only one that has been field tested since it was originally conceived (O'Rourke *et al.*, 1997). Presently, there are more than 20 field pilots either planned or being tested. The DOVER process (former UTF) is in a semi-commercial phase (O'Rourke *et al.*, 1997; Komery *et al.*, 1998); a commercial application is already planned for the DOVER project. The time gap between field testing and the start of commercial application is rather long, compared with some other EOR developments. The explanation for this may reside in the fact that SAGD is a very complex and labour-intensive

process. The applicable conditions for SAGD are rather demanding, mainly in terms of formation thickness (large thickness) and permeability (higher than 5000 mD) (Batycky, 1997; Farouq, 1997). However, SAGD seems to be very effective for thick high permeability formations. The limitations on SAGD triggered field trials of SW-SAGD, but the process is somewhat unstable and is more like steam stimulation. SAGP (steam and gas push) was proposed as a variant of SAGD, in order to improve its performance and range of applicability.

In principle, SAGD has two phases (Butler, 1991): (1) rising steam chamber; and (2) spreading steam chamber. The efficiency of the process is greater in the first phase, when heat losses to the adjacent formations are lower. Although the mobilized oil *remains hot as it flows towards the production well* in both SAGD and THAI, there are several differences, namely:

- (1) Through laboratory experiments, THAI has demonstrated robust operation when applied in a stratified three-layer reservoir with a 5:1 permeability contrast; the horizontal section of the producer was parallel to the bedding planes (Greaves and Al-Honi, 2000); similar laboratory tests on SAGD showed that this led to a pronounced distortion of the steam chamber (Butler, 1991), and consequent lower efficiency.
- (2) Owing to the very unconfined character of SAGD (comparable to that of a two spot pattern when using vertical wells), its efficiency in the later stages can decrease significantly; some oil is heated but not produced (capture efficiency is low). THAI has almost constant performance, as the displacement front 'travels from the toe to the heel of the horizontal well', i.e. from the start to the end of the process.
- (3) Owing to its unique configuration, and 'naturally occurring' high temperatures for thermal cracking, THAI creates ideal conditions for *in situ* upgrading, which cannot happen in SAGD.
- (4) Owing to counter-current flow in most of the drainage area in SAGD, the utilisation of existing reservoir energy (natural drive) and gravity drive are not very efficient. This is the main reason why SAGD was correctly recommended for application in reservoirs with low reservoir energy (low current pressure and low solution-gas oil ratio), as in tar sands (Batycky, 1997). On the other hand, the combination of gravity drive and forced drive is extremely efficient in THAI and there is no counter-current flow in any part of the drainage area.

VAPEX

This process is similar to SAGD, but uses a solvent instead of steam (Mokrys and Butler, 1993). VAPEX appears to be very attractive, given the fact that it is a non-thermal process that can produce upgraded oil via *in situ* de-asphaltation. In principle, VAPEX is also based on a counter-current flow. Although no laboratory results are available in the public domain, it is speculated that, given the absence of a heat conduction mechanism, VAPEX probably has a lower volumetric sweep efficiency, and

hence a lower ultimate oil recovery, compared with SAGD or THAI.

The conditions leading to *in situ* precipitation of the asphaltenes do not seem to be easily controllable. While THAI produces *in situ* upgrading by thermal cracking, VAPEX achieved this without using high temperatures. However, the oil produced by THAI is more highly *upgraded* (plus almost total removal of the heavy metals and a significant amount of the sulphur); VAPEX achieves much lower *upgrading*, similar to solvent fractionation (Gray, 1999) in surface upgrading facilities.

The THAI process uses a cheap injectant (air), and does not require any special pressurization of depleted patterns (they remain pressurized), on the other hand, VAPEX requires repressurization when recovery of expensive injected solvent is important, as it is. Further work on VAPEX and THAI is needed to delineate the most favourable conditions for their application. Recent investigations of the effect of heterogeneity on the VAPEX process showed significant losses in process efficiency (Jiang, 1997).

All three processes, SAGD, VAPEX and THAI, are radically different, not merely because of different well configurations, but also because of the mechanism of oil viscosity reduction and displacement. In THAI, the main flow effect is forced flow, which is more effective than the gravity-assist in SAGD or VAPEX.

Although in all three processes, the injector-producer couple does not span the entire drainage area, oil recovery from a significant area can be anticipated. However, how large this area is, it is still an open question.

CONCLUSIONS

THAI, 'toe-to-heel' air injection, is a highly efficient method of heavy oil recovery. The very high oil recoveries achieved (85% OOIP) make it a very attractive EOR method, for either primary production or as a follow-up in partially depleted reservoirs, previously operated through cyclic steam injection or steam drive.

High-temperature thermal sweep is the main driving force for heavy oil recovery, assisted by forced flow into the horizontal producer well. Thermal cracking plays an essential part in the THAI process to maintain: (1) stable combustion; (2) high oil recovery; and (3) upgrading of heavy oil.

The unique MOZ created ahead of the combustion front ensures that thermal upgrading of the heavy oil is preserved, contributing very substantial added value to the product. Wolf Lake oil was upgraded from its original API of 10.5, to a maximum of 19 points. The average upgrading was about 5–7 API points. The injection of water had little effect on oil upgrading.

Compared to other EOR methods for heavy oil recovery, THAI is a more robust process, *vis-à-vis* reservoir heterogeneities, and leads to higher ultimate oil recovery.

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An examination of steam-injection processes in horizontal and vertical wells for heavy-oil recovery

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ABSTRACT

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This study presents an experimental investigation of heavy-oil recovery by steam injection in a three-dimensional model containing 17° API crude oil. The first part of this paper describes the experimental apparatus. Emphasis in this paper is on the effect of the combination of horizontal and vertical wells on steam-injection efficiency. Four cyclic steam-injection experiments were conducted. Two used a vertical well at the center of the model, and two used a horizontal well scheme, showing better oil recovery and steam/oil ratios than the vertical well scheme. Soak time as well as the amount of steam injected per cycle were investigated. For both schemes, small slug sizes seem to give initially better steam/oil ratios than expected, however, cumulative oil recovery for vertical wells do not depend on slug size, while for horizontal wells, small slugs followed by larger slugs gave a better recovery by 8% of the original oil-in-place (OOIP), compared with large slugs followed by smaller ones.

Steam-drive experiments were conducted in three different well configurations: (a) a vertical injector and horizontal producer, (b) horizontal injector and producer, and (c) injector and producer both vertical. The combination of two horizontal wells gave by far the best results. Temperature data show that the use of horizontal wells gives a better sweep efficiency and reduces gravity override of steam.

This paper demonstrates the potential of using horizontal wells for steam injection. In cyclic operations, the use of horizontal wells improved the recovery by 30–50%. In a drive process, the recovery using two horizontal wells was 70% higher than the vertical wells configuration.

Introduction

In Turkey, 80% of the oil reservoirs are heavy-oil reservoirs (Kantar and Topkaya, 1983). These heavy oils are usually mobile at reservoir conditions and most can be produced with primary production but recovery is very low. Waterflooding is not effective because the mobility ratio is not favorable.

Steam injection by steam stimulation and/or steam drive is the most widely used process

for enhanced oil recovery. In heavy-oil reservoirs, a combination of steam heat and horizontal wells can be used to increase heavy-oil production.

Horizontal wells can lead to high production rates when used for steam-injection recovery of heavy oils. Horizontal wells produce a more uniform distribution of the steam front leading to improved sweep efficiency and oil recovery.

The objective of the present study was to evaluate cyclic and continuous steam-injection processes using horizontal wells to produce heavy oils. In addition, the study examined the effect of well configurations on oil

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production. For cyclic steam-injection tests, the effects of cycle periods and amount of injected steam per cycle on oil production also was investigated.

Literature review

Horizontal wells can be used for cyclic steam stimulation, continuous steam drive and steam-assisted gravity drainage process (Joshi, 1987; Butler, 1989).

In cyclic steam stimulation and steam drive, even though gravity drainage plays a part in oil production, most of the oil production is due to the pressure gradient between the reservoir and the production well. In steam drive, the pressure gradient between injection and production wells determines the oil production rates. In the steam-assisted gravity-drainage process, there is no pressure drop other than the gravity head, between injection and production wells. The oil is produced solely by gravity drainage. The rate of gravity drainage is enhanced by steam heating which reduces the oil viscosity (Butler and Stephens, 1981).

Huygen and Black (1982) conducted scaled model experiments to investigate the effectiveness of different horizontal and vertical well combinations for steamflooding Athabasca oil sand. They concluded that communication must be established between wells for the steamflood to be practical and efficient, and that steamflooding through a single horizontal well was a viable strategy to mobilize bitumen.

Toma et al. (1984) examined the results of fourteen cyclic steam-stimulation experiments carried out in a horizontal-well physical model. They concluded that increasing the axial pressure drop could increase the production of a horizontal well in cyclic operations.

Joshi and Threlkeld (1985) extended the previous work on steam-assisted gravity drainage. They included the effects of well completion, shale barrier, and limited steam entry on oil recovery. They found that, for res-

ervoirs with shale barriers, a vertical injection and horizontal production scheme yielded faster oil recovery than was obtained from a pair of horizontal wells. The presence of shale barriers resulted in higher steam/oil ratios and lower instantaneous oil production rates, but the barriers did not change the final oil recovery. Limited steam entry, caused by vertical fractures perpendicular to the horizontal well, led to high initial production rates.

Chang et al. (1990) performed steamflooding experiments through horizontal wells to determine optimum production strategies for bottom-water reservoirs. The results showed that the horizontal injector/horizontal producer combination recovered 68% of the oil in the presence of 10% thickness of bottom water zone. In the absence of bottom water, the horizontal combination was only slightly better than the vertical wells.

Doan et al. (1990) developed a mathematical model to represent flow in the vicinity of, and inside, a horizontal wellbore. This model also was used to obtain the scaling criteria for a series of scaled model steam-injection experiments. A variable-diameter horizontal well offered superior performance when compared to a conventional, constant-diameter, horizontal well. It could lower well-pressure loss by reducing friction inside the well, and thus could lead to higher production rate and oil recovery. In addition, a variable-diameter well resulted in a more uniform growth of the steam zones, and thus led to better steam sweep efficiency and slower breakthrough of steam.

Sufi (1990) placed a horizontal well at the base of a scaled model to heat the formation from a vertical injector to a vertical producer. Results of injecting steam into the region heated by the horizontal well were disappointing due to low mass-injection rates. Sufi suggested a process of alternating the injection of steam and hot water, to obtain a balance between high mass-injection rates and high oil-production rates. This allowed the reservoir to be heated as hot water was injected into the

reservoir and oil to be produced by gravity drainage during steam injection.

Ahner and Sufi (1990) conducted a series of scaled physical-model steamflood tests at several injection rates and various flow configurations on heavy-oil systems using horizontal wells. They observed that the steam rose to the top of the model and swept it from the top down (gravity drainage) even when communication between the injector and producer is provided by a horizontal well at the base of the model. More efficient sweeping of the model occurred when the well spacing was decreased. The steam-injection rate also influenced the water/oil ratio and oil-production rate.

This study is not made in a scaled model. Instead we use rocks and fluids typical of a Turkish heavy-oil reservoir to investigate, qualitatively, the effect of various well-positioning strategies in a rectangular block representing the reservoir.

Experimental equipment

Equipment description

Figure 1 is a schematic diagram of the ex-

perimental equipment used in the study. It includes the following essential components: steel three-dimensional (3-D) model, steam generator, production system, oil- and water-saturation system, oil-level indicator, temperature control and data-recording system.

The three-dimensional model was a rectangular box with $50 \times 50 \times 15 \text{ cm}^3$ dimensions. One face of the model was removable and the plate to close this end was made from a 1.03-cm-thick steel plate of $24 \times 59.5 \text{ cm}^2$; greater than the model dimensions. Rubber sealing glands were used to prevent leaks.

Figure 2 shows the internal features of the model, including the location of thermocouples and well positions. The three-dimensional temperature distribution is measured from 38 Fe-constantan thermocouples as shown in Fig. 2; 22 thermocouples were located at 2.5 cm distance from the top and from the bottom of the model and 16 center thermocouples were located at the center of the model. This arrangement allowed monitoring of gravity segregation of fluids and temperature gradients perpendicular to the direction of fluid flow.

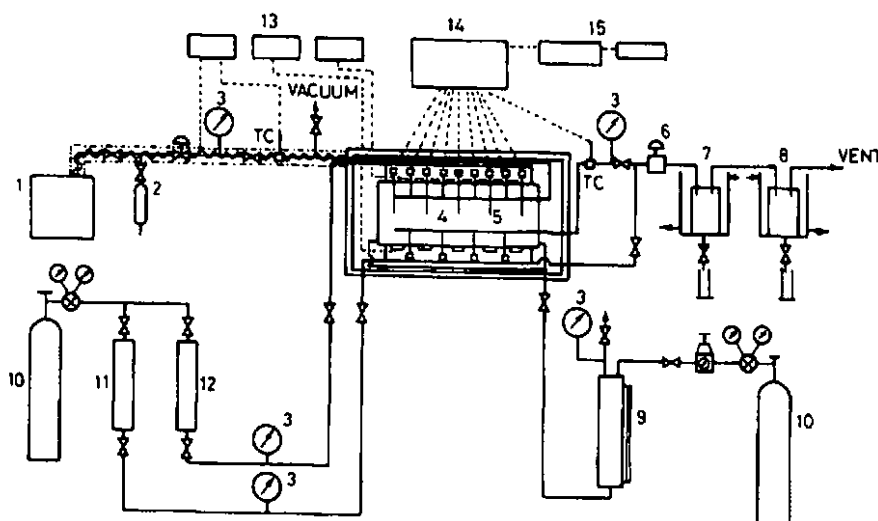


Fig. 1. Schematic diagram of experimental equipment. Description of experimental equipment: 1. Steam generator, 2. Bleed system, 3. Pressure gauges, 4. 3-D Model, 5. Thermocouples, 6. Back pressure regulator, 7. Gas, steam and crude oil separator, 8. Condensate and gas separator, 9. Graduated oil indicator, 10. Nitrogen supply, 11. Brine container, 12. Crude oil container, 13. Temperature controller, 14. Electronic temperature scanner, 15. Temperature indicator.

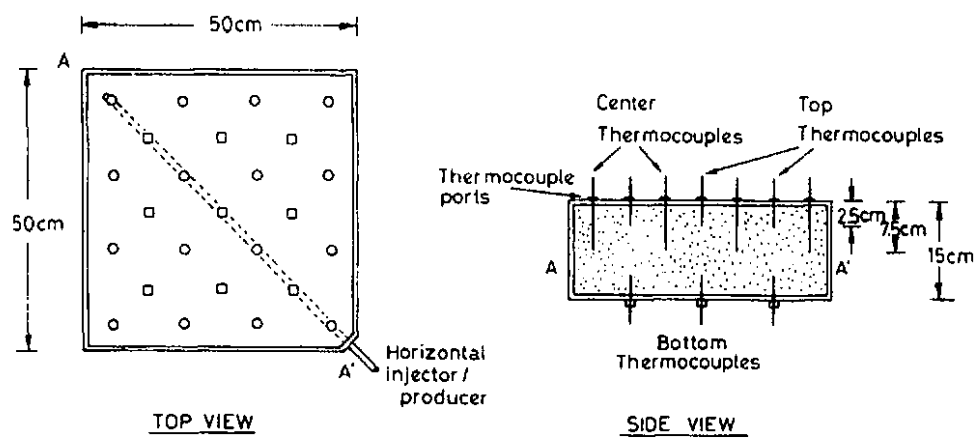


Fig. 2. Schematic diagram of thermocouple positions.

Well configurations

Field application of cyclic and continuous steam-injection processes is possible by employing different well configuration schemes as shown in Fig. 3. These schemes are:

(A) A vertical steam-injection well and a

horizontal production well: steam is injected from a vertical well placed on one side of the model, and oil and water are produced from the diagonally placed horizontal well.

(B) A horizontal well pair: two horizontal wells are drilled with one placed slightly above the other. Steam is injected into the top well,

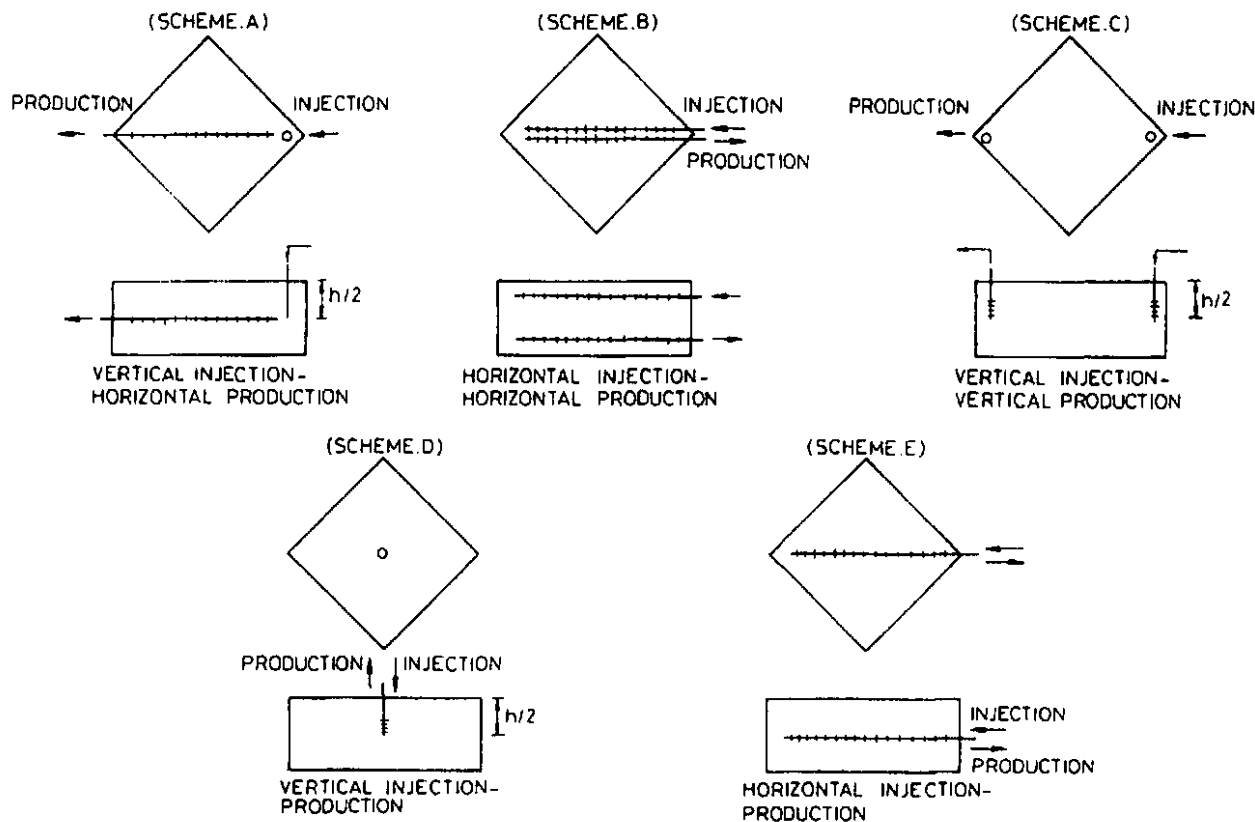


Fig. 3. Experimental well configurations.

and oil and water are produced from the bottom well.

(C) A vertical steam injection and a vertical production well: steam is injected from a vertical well placed on one side of the model and a production well located on the other diagonal side of the model. These first three configurations were used for the steam-drive experiments.

(D) A vertical injection/production well is placed at the center of the model.

(E) A horizontal injection/production well is placed diagonally into the half height of the model. These two configurations were used for cyclic tests.

Perforated 8-mm diameter, stainless steel tubing, was used for the injection and production wells. Several 3-mm diameter holes were drilled along the length of the tubing and were covered with 100-mesh metal screens to prevent sand production.

For cyclic and continuous steam-injection experiments, the well configurations were installed in a 3-D model. After installation of the top, bottom and center thermocouples, the box was filled with 0.420–1.190-mm diameter crushed limestone which gave porosity of about 38%. Absolute liquid permeability was found to be 6 darcies. X-ray diffraction analysis of limestone samples indicated a composition of 92% calcite, 6.6% dolomite and 1.4% quartz by weight.

Experimental procedure

The model was horizontally positioned and evacuated. It was then saturated with a brine containing 60,000 ppm sodium chloride, and heated to about 60°C and then the water was displaced with hot oil. The oil and water saturations were calculated. Table 1 summarizes typical crude oil and porous pack properties.

After establishing the oil and water saturations in the sand pack, the steam generator was brought to its maximum temperature and

TABLE 1

Crude oil and porous pack properties

Crude oil	Raman
API gravity (°API)	17
Viscosity (@ 60°F, mPa s)	2261
Water salinity (ppm NaCl)	60,000
Porosity (%)	38.0
Permeability (darcy)	6.0
Pore volume (cm ³)	15,175
Mass of sand (gram)	59,180
Matrix	Crushed limestone

steam injection was started at about 150°C injection temperature in all experiments. During cyclic steam-injection runs, the graduated and pressurized oil-level indicator was used to measure the injected steam volume during each cycle. For each cycle, first the steam was injected (injection period), and then the injection well was closed for a soaking period. After the soaking period, the well was opened to production. During the production period, the constant-pressure reservoir boundary condition was sustained using a graduated and pressurized oil-level indicator. When oil production decreased, the first cycle was terminated and then, the second and third cycles were conducted.

In continuous steam-injection runs, steam was continuously injected into the model. The injection and the production pressures were measured and the produced fluids were collected in graduated cylinders which allowed easy measurements of produced volume and the water/oil ratio.

Results and discussion

The following series of cyclic and continuous steam-injection runs were conducted in a 3-D model. The first four runs investigated heavy-oil production with cyclic steam injection through horizontal and vertical wells. The second group of runs was conducted for three vertical/horizontal well configurations in one quarter of a five spot: vertical producer/verti-

cal injector, vertical injector/horizontal producer, and horizontal injector/horizontal producer.

Cyclic steam injection runs

General observations

Four cyclic steam-injection runs were conducted to investigate heavy-oil production with cyclic steam injection through horizontal and vertical wells (the experimental conditions are presented in Table 2). Two different well configurations are present: scheme D includes a vertical well located at the center of the model, and scheme E has a horizontal well located at the diagonal of the model.

Figures 4, 5 and 6 show oil and water production rates and production pressure for each cycle in vertical and horizontal well configurations. The results of Run 1 are not shown, however, the performance of Run 2 was similar. As seen in the figures, maximum oil production was obtained during the second cycle and then decreased during the third cycle. In horizontal wells, although the oil-production rates were similar in the first and second cycles, (Runs 3 and 4), maximum oil production was

obtained during the first cycle and gradually decreased during the second and third cycles. The increase in production rate and the production period decreased after the first cycle. The reason for this lower performance was attributed to the decrease of oil saturation near the wellbore and slow movement of the crude oil from unheated sections of the model. An other reason was that the steam zone accumulates at the upper part of the model where increased heat losses cause the water/oil ratio to increase and the oil production rate to decrease.

At the beginning of the production period (for the first and second cycles), there was less water production from the horizontal well; steam accumulated at the upper part of the model and condensed there during the soaking period. Thus, the crude oil was swept by condensed steam from the top downward, during the production cycle. Thus gravity drainage is an important mechanism in oil production using horizontal wells.

Comparison between the runs

Comparing Runs 1 and 2 (Table 3), the duration of the soaking period for Run 1 was 4.5

TABLE 2
Experimental conditions for cyclic-steam injection runs

Run:	1		2			3			4		
Cycle:	1	2	1	2	3	1	2	3	1	2	3
Well configuration	Vertical (Scheme D)		Vertical (Scheme D)			Horizontal (Scheme E)			Horizontal (Scheme E)		
S _o , (%)	62.0		59.0			62.0			61.0		
s _w , (%)	38.0		41.0			38.0			39.0		
Injection temp. (°C)	148	155	148	148	153	148	154	155	155	148	148
Injection pressure (kPa)	314	339	445	440	445	415	415	420	390	389	403
Injection time (min)	17	15	14	24	39	15	18	32	39	30	20
Soaking time (min)	96	10	21	23	29	8	15	20	17	15	20
Production time (min)	52	70	54	105	81	89	86	61	114	62	43
Injection steam (PV (cwe))	0.06	0.20	0.11	0.13	0.22	0.11	0.18	0.28	0.24	0.16	0.07
Cumulative injected steam (PV (cwe))	0.06	0.26	0.11	0.24	0.46	0.11	0.29	0.57	0.24	0.40	0.47

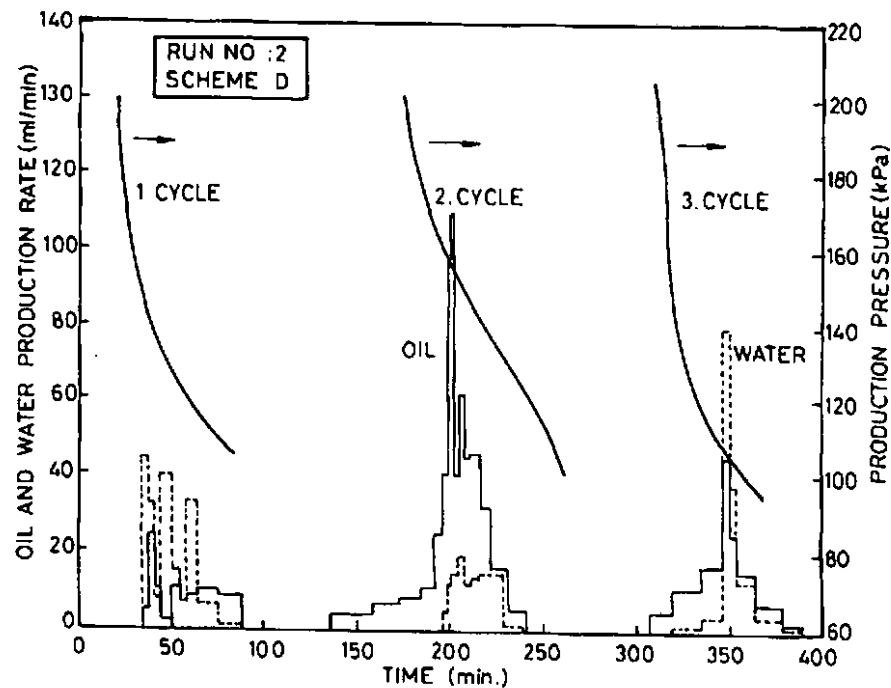


Fig. 4. Production history for vertical well (Run 2).

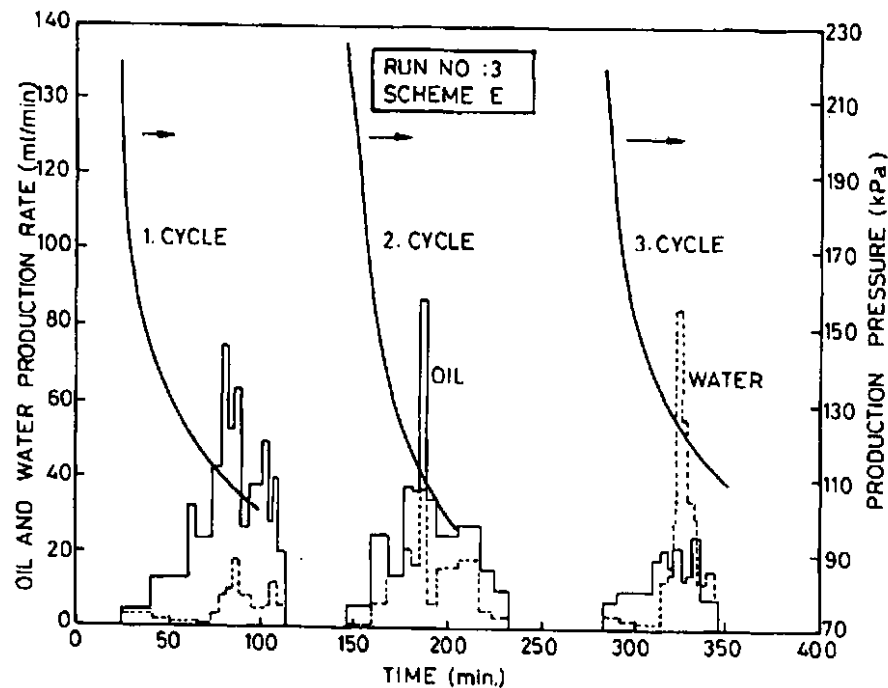


Fig. 5. Production history for horizontal well (Run 3).

times higher than for Run 2. The increased heated volume during the first cycle gave a higher oil production. Although the cumulative, injected steam volume (cold water

equivalent, cwe) of Run 2 was about 0.20 pore volume (PV) more than in Run 1, the cumulative oil recovery was nearly the same for both runs. The dominant mechanism for oil mobi-

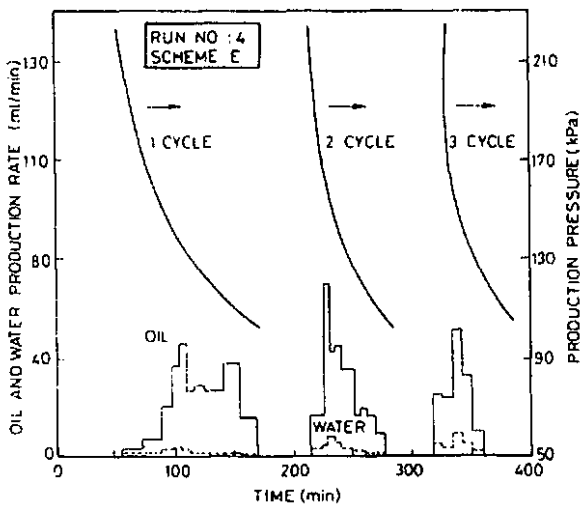


Fig. 6. Production history for horizontal well (Run 4).

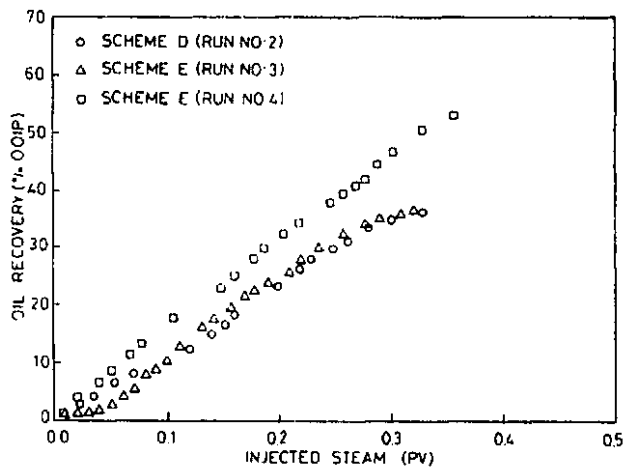


Fig. 7. A comparison of oil recoveries for well configuration schemes D and E.

TABLE 3

Experimental results for cyclic steam-injection runs

Run:	1		2			3			4		
Cycle:	1	2	1	2	3	1	2	3	1	2	3
Well configuration	vertical (scheme D)		vertical (scheme D)			horizontal (scheme E)			horizontal (scheme E)		
Injected steam (PV (cwe))	0.06	0.20	0.11	0.13	0.22	0.11	0.18	0.28	0.24	0.16	0.07
Oil recovery (% OOIP)	14.9	21.0	5.3	22.5	8.8	22.1	18.7	6.6	25.3	16.9	12.5
Cum. oil recovery (% OOIP)	14.9	36.0	5.3	27.8	36.6	22.1	40.8	47.4	25.3	42.2	54.7
Water production (PV)	0.05	0.11	0.033	0.02	0.038	0.026	0.061	0.017	0.01	0.01	0.011
Steam/oil ratio (ml/ml)	1.55	1.09	2.03	1.21	1.65	1.18	1.48	2.27	1.05	1.08	1.15
Cum WOR (ml/ml)	0.55	0.09	1.03	0.21	0.65	0.18	0.48	1.27	0.05	0.09	0.15

lization was pressure drive in the vertical wells.

Figure 7 shows the comparison of oil recoveries for all runs. The oil recoveries in horizontal wells were 30–50% higher than for vertical wells. From the comparison of oil recoveries for horizontal wells (Runs 3 and 4), the high amount of injected steam during the first cycle did not significantly affect oil production. Although the injected volume of steam in Run 4 was two times higher than in Run 3, oil recovery increased from 22.1% to 25.3%. However, the injected steam volume in Run 4 during the last cycle was about four times less than for Run 3 and the cumulative oil recovery was about 15% higher.

Figures 8 and 9 show the diagonal temperature distributions (section AA' in Fig. 3) of each cycle at five different time periods of vertical and horizontal well runs (Runs 2 and 4). As shown in Fig. 8, after the injection of steam into the vertical well, steam rises to the upper part of the model. Then the heat is propagated from top to bottom during the steam-injection period. The temperature gradually decreased at the top of the model due to heat loss during the soaking period. During this period, the center of the model was continuously heated by conduction. The system temperature was reduced and heat flow near the well was continued. In the horizontal well (Fig. 9), the vi-

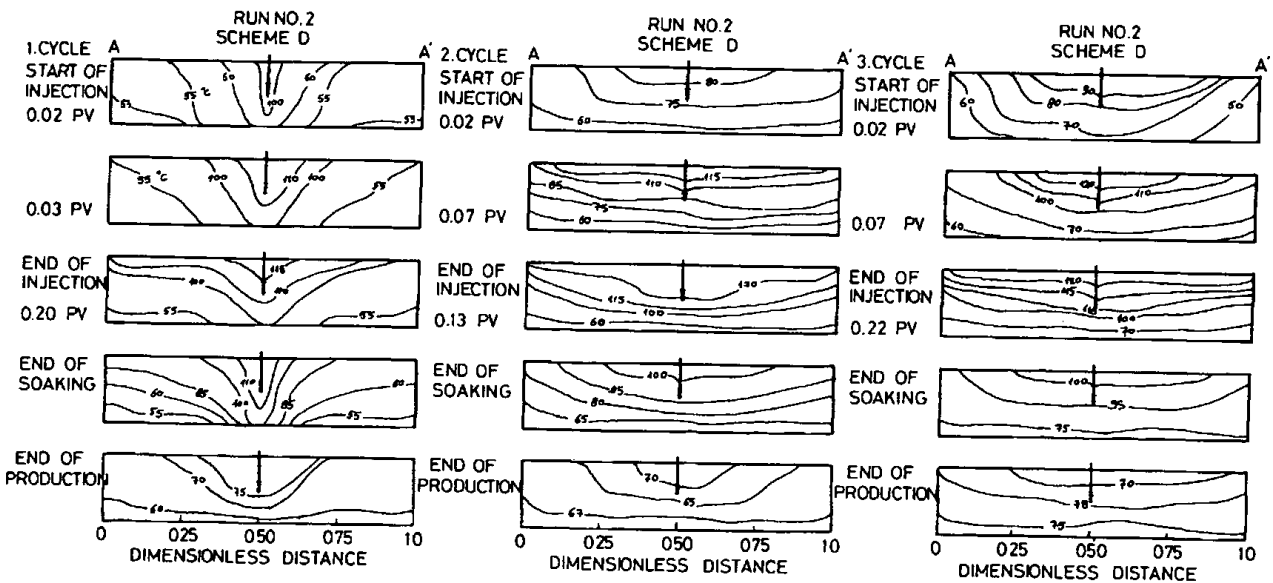


Fig. 8. Diagonal temperature distribution at various periods of cyclic steam injection for vertical well (Run 2).

Fig. 9. Diagonal temperature distribution at various periods of cyclic steam injection for horizontal well (Run 4).

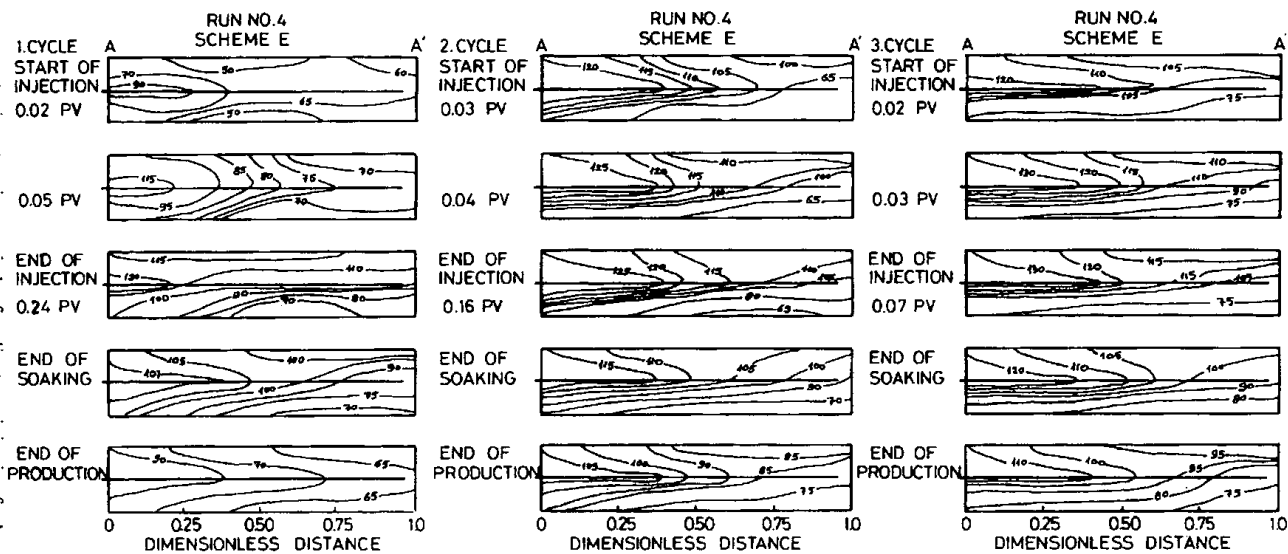


TABLE 4

Experimental conditions and results for continuous steam-injection runs

	Run 5	Run 6	Run 7
Well configuration	(scheme A)	(scheme B)	(scheme C)
Injection well	Vertical	Horizontal	Vertical
Production well	Horizontal	Horizontal	Vertical
S_{wi} (%)	25.0	25.0	21.0
S_{or} (%)	75.0	75.0	79.0
Steam rate (ml/min (cwe))	38.8	56.5	48.
Steam pressure (kPa)	461	466	352
Steam temperature ($^{\circ}$ C)	155	156	157
Oil recovery (% OOIP)	46.0	74.0	49.0
Steam/oil ratio (ml/ml)	2.31	1.42	2.08
Steam breakthrough (PV)	0.34	0.55	0.06

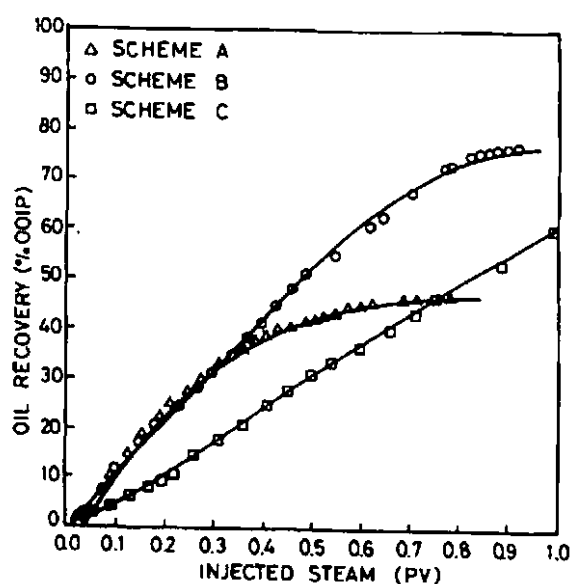


Fig. 10. A comparison of oil recoveries for well configuration schemes A, B and C.

cinity of the well and top of the model were quickly heated due to the larger contact area of the horizontal well.

Continuous steam injection runs

General observations

Three continuous steam-injection runs were conducted using three different well configurations. The experimental conditions and results are presented in Table 4. The horizontal injector/horizontal producer well configura-

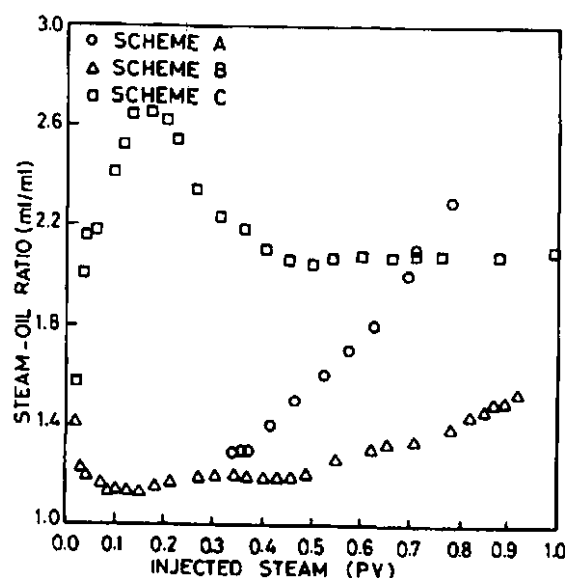
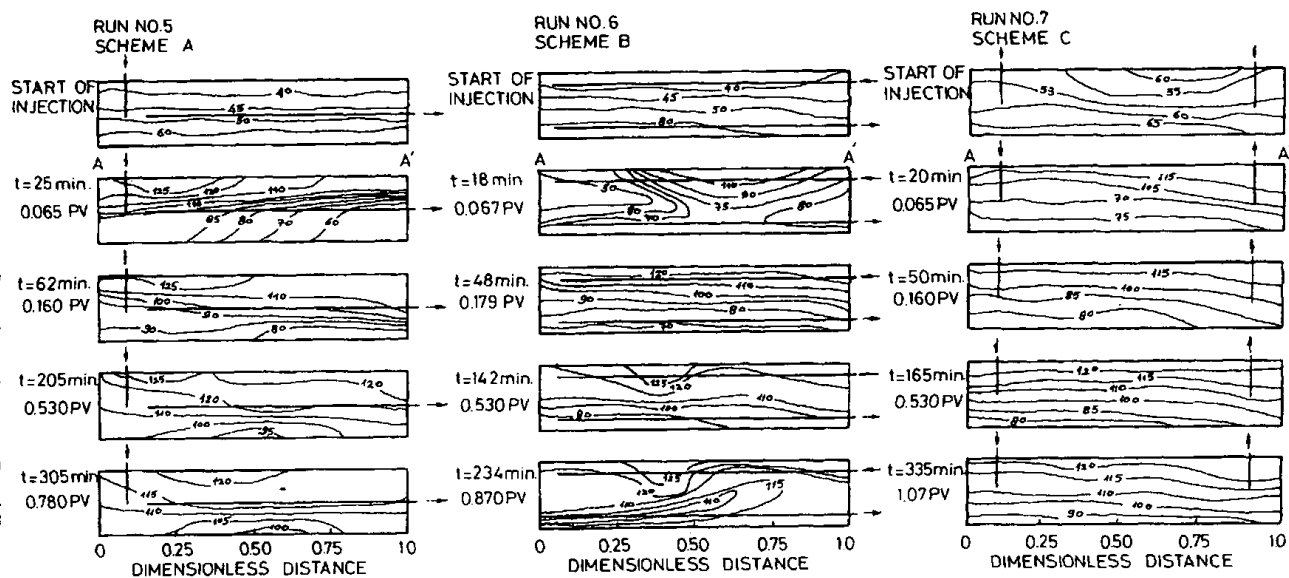


Fig. 11. Steam-oil ratios as a function of injected steam for well configuration schemes A, B and C.

tion gave the best results for this crude oil reservoir. Oil recoveries were 73% of OOIP for horizontal injector/horizontal producer case, 49% of OOIP for vertical injector/horizontal producer case, and 46% of OOIP for the vertical injector/vertical producer when 0.80 PV of steam were injected into the model. Figure 10 shows the oil recoveries for each series of well configurations. In all horizontal well configurations, the initial oil production is high and tapers off rapidly after 0.80 PV of steam injection. The initial oil production in the vertical

Fig. 12. Diagonal temperature distributions for well configurations schemes A, B and C.



injector/vertical producer configuration case is not as high as the situations incorporating horizontal wells.

Comparison between the runs

From the comparison of oil recoveries for continuous steam-injection Runs 5, 6 and 7, with cyclic steam-injection test (Run 4), oil recovery was 54.7% of OOIP with 0.36 PV of steam injection, while oil recoveries were 37% of OOIP for horizontal injector/horizontal producer, 36.5% of OOIP for vertical injector/horizontal producer, and 21% of OOIP for vertical injector/vertical producer configurations after injection of the same volume of steam. As a result, the project life will be longer for cyclic steam injection than for continuous steam injection to produce the same amount of crude oil.

Figure 11 shows the steam to oil ratios as a function of injected steam for each series of well configurations. Steam/oil ratios were 1.42 ml/ml for horizontal injector/horizontal producer, 2.31 ml/ml for vertical injector/horizontal producer, and 2.08 ml/ml for vertical injector/vertical producer well configurations, when 0.80 PV of steam were injected into the model. Therefore, a lower amount of steam will be required to produce the same amount of crude oil using horizontal injector/horizontal producer configuration.

Temperature distributions throughout the runs are presented in Fig. 12 for three different well configurations. In the vertical injector/vertical producer case, the injected steam is propagated through the upper part of the model and the model is heated from top to bottom. As seen in Fig. 12, the profiles do not show significant steam-override effects. Using horizontal well injection, the vicinity of the well and the top of the model was heated more rapidly than for vertical well injection due to the larger contact area presented by the horizontal well. First, steam reaches the upper part of the model and then heated crude oil is displaced by condensed steam towards the pro-

duction well due to the pressure difference between the injection and production well. In the vertical injector/horizontal producer well configuration, steam reaches the production well in a short time due to the short distance between injection and production wells compared to other configurations. As a result, the area swept by steam is reduced and oil recovery is also less than for other configurations. This suggests that the distance between the vertical injector and the horizontal producer should be increased, or the perforations of the production well should be concentrated at the outlet of the model.

Conclusions

(1) The following conclusions were drawn from cyclic steam-injection tests: (a) Steam injection through a horizontal well accelerated oil production from heavy oil. The cumulative oil recovery was about 30 to 50% higher than obtained with injection of steam into a vertical well. (b) The injected amount of steam during the first cycle influenced the water/oil ratio and oil recovery. A 54% increase in injected steam volume decreased the oil recovery by 36% and increased the water/oil ratio by 55% in vertical well runs. For horizontal well runs, a 46% increase in injected steam volume increased the oil recovery by 11% and the decreased water/oil ratio by 28%.

(2) For steam-drive experiments: (a) Oil production for the horizontal injector/horizontal producer well configuration was higher than for the other well configurations. However, oil recovery obtained using either vertical injector/horizontal producer or vertical injector/vertical producer well configurations were almost the same. (b) Steam breakthrough for the horizontal injector/horizontal producer well configuration was 0.55 PV of steam injection, while it was 0.06 PV of steam injection in the vertical injector/vertical producer well configuration case. (c) A steam/oil ratio of the order of 1.40 indicated the high thermal efficiency of the horizontal injector/

horizontal producer well configuration. (d) The produced water/oil ratio and water/oil emulsion was increased due to early production of steam in the vertical injection/vertical producer well configuration.

(3) The laboratory data demonstrated the success of steam-injection processes using horizontal wells for the production of heavy oils. The primary recovery mechanism for steam injection through horizontal wells appeared to be a combination of viscosity reduction, gravity drainage, and pressure gradient.

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