Comprehensive Assessment of Toe-To-Heel Air Injection (THAI) Process. Guidelines for Development of Future Generations of In-Situ Combustion Processes

DETAILED REPORT

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3) Appendix K, regarding the development of a new method for the calculation of the apparent hydrogen-carbon ratio, taking into account the coke gasification and water-gas shift reactions occurring during THAI process was the result of a cooperation with Dr. Punitkumar Kapadia

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REPORT PREPARED FOR OIL COMPANIES

THIS REPORT IS THE RESULT OF A CO-OPERATION BETWEEN *A.T. EOR CONSULTING INC.* SUILVEN OIL & GAS LTD AND PETRO MANAGEMENT GROUP (PMG), ALL THREE COMPANIES FROM CALGARY, ALBERTA , CANADA

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The mottos for this Report

Facile est inventis adhere

(it is easy to add to things already invented)

AND

There is no substitute for experience

Confession: All along, during the execution of this study, all efforts have been made to be realistic and honest on the upside and downside of the Toe-To-Heel Air Injection (THAI) process

Value Statement

The most important value of this report is that it documents the development of a novel oil recovery process, Toe-To-Heel Air Injection (THAI) which, for the first time, achieves economically valuable underground upgrading of the oil production while mobilizing and producing oil via a horizontal well. Oil mobilization and production is achieved by using in-situ combustion applied in a unique well configuration, consisting of vertical air injection wells and horizontal production wells. The former of which have their 'toes' close to the injectors. The report summarizes in a critical way the whole knowledge acquired/produced during the last 25 years, from laboratory experiments, simulation and field testing. After 14 years of detailed field testing via six pilots and a semi-commercial project, in six different reservoirs, the process has been technically validated. However, improvements are needed to enhance its performance, more specifically, the daily oil production. The report shows what essential improvements are needed in four areas: well configuration, initial communication between wells, ignition procedure and operational practice. To conclude: a lot of knowledge has been acquired, and based on this knowledge, there are very good chances to make the THAI process more efficient, opening the doors towards its commercial application.

DEDICATION

We greatly thank our wives, Maria Turta and Juliet Greaves for their forbearance during the work on this project

Note: This Report can be easier viewed/perused in a digital form. Some graphs and maps may have small fonts and/or features better visible in digital forms and/or using a ZOOM feature

DISCLAIMER

EXECUTIVE SUMMARY

This study was carried out to assess whether the novel in-situ combustion process Toe-To-Heel Air Injection (THAI) has adequate potential to be considered as a possible **E**nhanced **O**il **R**ecovery (EOR) process for heavy oil reservoirs and oil sands.

Discovered around 1950, the conventional **i**n **s**itu **c**ombustion (ISC) process did not meet the operators' expectations. Tested in many field pilots, only something like 10 % of projects reached the semi-commerciall or full-commercial stage. The main disadvantage was the lack of control of the propagation of the ISC front, associated with many operational problems. Several disadvantages were mitigated by adopting the peripheral line drive exploitation and starting the process up-dip. In this way, a significant number of major commercial ISC operations have been successfully conducted for several decades. It is believed that most of the problems associated with–the conventional ISC process could be solved by further development of THAI process. THAI involves a vertical well injector and a horizontal producer with its horizontal section located towards the bottom of the oil layer, in such a way that its 'toe' is close to the vertical injector. An ISC front is created near the vertical injector, then anchored to the 'toe' of producer, and finally propagated along and above the horizontal section of the producer.

THAI is a gravity stable oil displacement process, operating in a so-called short-distance mode, with the mobilized oil flowing through a heated zone, called the mobile oil zone (MOZ). Some of the heavy fractions of the oil are thermally cracked, producing lighter components, which then mix with the original crude oil to create ~~a~~ partially upgraded oil within the reservoir *(a first upgrading).* Unlike the conventional ISC process, THAI preserves the underground oil upgrading, due to its short-distance oil displacement feature. THAI has a self-healing ability, due to controlled gas over-riding and also the existence of a moving coke-plug in and around the borehole of the horizontal producer. The presence of this 'local coke plugging,' in combination with gas override control, acts to prevent–air/oxygen short-circuiting into the horizontal well. These features were demonstrated in laboratory tests conducted by several research organizations. The generation of hydrogen is another feature of the process.

The THAI process was developed in long-term cooperation between the former Petroleum Recovery Institute of Calgary and University of Bath, UK. It was investigated for more than 12 consecutive years via laboratory tests, theoretical work and simulation studies involving more than 100, 3-D combustion cell–tests on bitumen, heavy crudes and lighter oils. Except for the communication phase, almost all other aspects have been investigated in the laboratory. The process was patented and then investigated using two configurations: **d**irect **l**ine **d**rive (DLD) and **s**taggered **l**ine **d**rive (SLD). DLD has the vertical injector very close and in line with the toe of the horizontal producer; SLD is somewhat more complicated in the application, as the vertical injector is laterally off-set from the horizontal producer. Because of this, the communication phase requires more extensive procedures.

In THAI, the horizontal section of the horizontal producer can also act as a radial in-flow reactor or in-situ upgrader; making possible the development of the CAPRI process (or catalytic THAI), as an 'add-on' process. This involves a catalytic gravel-packing, or fabrication of sections, to surround the horizontal section pipe with a catalyst layer. In this way, *a second upgrading* of the oil occurs in the CAPRI process, as the oil is flows from reservoir to wellbore. On the other hand, THAI only produces oil mainly from an active section of the horizontal well. This imposes a limitation on the oil rate compared to Steam Assisted Gravity Drainage (SAGD), which utilizes almost the whole length of the horizontal well.

In 2006 Petrobank Energy and Resources (Petrobank) initiated the first field piloting of the THAI process in the Athabasca Oil Sands region, close to Conklin (Whitesands project). The pilot consisted of three well pairs (three patterns/modules*) operating in a direct line drive (DLD).* After 5 years of operations, the pilot was completed, but it operated at lower than projected air injection rates, such that much less air was injected than it was designed. A comprehensive analysis of the WHITESANDS THAI pilot showed that a sustained ISC front was active, with no oxygen short-circuiting to the horizontal producer. The amount of hydrogen in the produced gas was 2%-5%, on average, up to a maximum of 10%.

Consistent upgrading (range 2-8^0 API) of the produced oil was obtained; THAI, therefore, constitutes a World-first in-situ (underground) upgrading process, while mobilizing and recovering oil. The initiation of the process (ignition) was realized using steam injection for 3-4 months; ignition occurred within 1-2 months from the start of air injection. In its stabilized phase, the oil production per well was in the range of 10-20 m^3/day. The total cumulative oil produced in this project was approximately 29,000 m^3 (180,000 bbls) at an air-oil ratio in the range of 5,000-6,000 sm^3/m^3 (28,500 - 34,000 scf/bbl). The main reasons for the low performance were the lack of confinement of the pilot area, related to the escape of air into the upper Mc Murray "A" formation and communication with the bottom water zone from the very beginning of the process (during steam injection for pre-heating). Although the bottom water zone is thin, a significant amount of water from this zone was produced during the pilot. A third important difficulty was that *it was not possible for the air injection rate per well to attain a value* *close to the maximum design value for the project; This may be related directly to the use of DLD operation, exacerbating sand influx as attempts were made to raise the air injection rate beyond a certain limit.*

The two major operational problems encountered, were sand influx and limited-duration endurance of the casing of the horizontal section of producers, due to the high temperatures experienced. Together, these factors (separately, or combined) may have led to the replacement of 2 of the horizontal producers. At the time, limited experience of operating the new process may also have been a contributing factor.
As seen from the bottom hole temperatures recorded in the observation wells, the lateral development of the burned zone was very limited for this direct line drive (DLD) configuration tested (not more than 40 m laterally around the horizontal producer trajectory), which could also have "contributed" to the operational problems. The ISC front advanced less than half of the distance toe-heel, along the horizontal section, meaning that the project target distance was not achieved. At the completion of the pilot, oil recovery was only about 7%. DLD operation was not able to ensure a good sweep efficiency.

The replacement wells had a disappointing performance. This was due, on the one hand, to a failure to prevent re-saturation of the burned zone, with consequent massive coke deposition in the reservoir and, on the other hand, to water encroachment from the thin bottom water zone into the burned zone during a 3 to 4 month-period of air injection stoppage for the drilling of replacement wells. Another important, negative factor, was a less than proper placement of the replacement wells; the hot communication/link with the old burned zone was not properly realized and a toe-to-heel ISC front propagation along the replacement wells was achieved only for one well-pair. These failures also encouraged the migration of air/combustion gas outside the THAI patterns, directly "contributing" to the poor performance.

Within the Whitesands project, Petrobank also conducted minimal field testing of the CAPRI in-situ upgrading process, but the result was inconclusive.

In 2009 Petrobank started the second THAI pilot in Kerrobert Reservoir, Saskatchewan, Canada, containing a heavy oil over a relatively thick bottom water zone (equal thickness for oil and water zones). The reservoir was exploited using horizontal wells, and when the piloting was initiated, the average water cut was 96% (with an oil recovery of 1.2%), so that THAI was implemented as a secondary recovery method. The THAI pilot consisted of two well pairs; 10 more well pairs were drilled, and the semi-commercial-scale THAI project started in late 2011. No observation wells were drilled due to the relatively greater depth of the Kerrobert reservoir (740m). All 12 patterns were designed in a DLD configuration and with a start-up region almost zero; however, there was a lateral offset distance of 2-7 m between the shoe of vertical injector and the toe/horizontal section of horizontal producer.

Ignition was performed after injecting steam for 1-2 months, for pre-heating. However, the generation of the ISC front took a very long time; there was a clear difference between the pilot and the field expansion due to the execution of the preheating phase. In the pilot, a significantly higher amount of steam was injected and at a considerably higher injection rate. Heat loss calculations indicated that in the semi-commercial patterns, practically only hot water was introduced into the layer, drastically reducing the input of heat. The ignition process was therefore not efficient, resulting in a very long ignition delay, estimated at 3 to 6 months, whereas it was only 1-2 months for the pilot. The prolonged ignition period promoted low-temperature oxidations (LTO), resulting in a lack of mobilization of the oil. Thus, no incremental oil was produced for 5-8 months.

Analysis of the THAI process based on the bottom hole temperature variation recorded in the horizontal producers, in time and space (from toe to heel), found that for this bottom water THAI application, two kinds of ISC development can happen. Either a **t**oe-**t**o-**h**eel (TTH) propagation or ~~a~~ formation of a **c**ombustion **c**hamber (CC). Therefore, the THAI process operation can involve:

- TTH propagation: anchoring of ISC front and then normally propagation along the horizontal well pathway
- Combustion chamber: anchoring of the ISC front with the formation of a **c**ombustion **c**hamber (CC), around the toe of producer, technically incorporating the space between the vertical injector and the toe region of the producer.

TTH propagation (for a distance of 40-90m) was seen for 6-7 pairs, while the combustion chamber development was seen for 3-4 cases. In two cases, anchoring of an ISC front to the toe of horizontal producers did not take place. Therefore, no positive combustion effect was recorded. Generally, TTH propagation was associated with better performance results. CC cases were associated with poor results, mainly when the CC was located at the water-oil interface. Actually, the penetration of air/combustion gas into the bottom water (BW) layer took place within less than one year of operation, following ignition. The best performance was recorded for the pattern K2, which is a confined pattern, with good THAI design and completion, including a good start-up region.

After the difficult period of ignition, the sustainability of ISC was clear, as witnessed by the composition of the gas produced. No oxygen was detected in the produced gas, while hydrogen production was a consistent feature. By propagating the ISC front from the toe towards the heel of horizontal producers, daily oil production rates per well eventually rose to 7-14m^3/day, with a water cut in the range of 30-50% for the wells with a positive reaction, and higher than 70-80% for the remaining ones. The high value of the water cut is related to the penetration of the ISC front into the bottom water zone, as confirmed by 3-D seismic measurements. It is believed that the old horizontal wells (located towards the top of the reservoir), but suspended during the THAI project, had a negative effect by providing pathways of channeling for air and/or steam. The total oil produced as of February 2015 was 55,200 m^3 (347,200 bbls).

Consistent, in-situ upgrading was confirmed, with upgrading in the range of 4-7^0 °API for the pilot, and 3-5^0 API for the expansion wells. Therefore, not all wells produced oil of the same upgrading intensity. Hydrogen in the produced gas was 1 - 2%, but increased up to 5-7% in a period in which maximum upgrading was recorded. It is speculated that the endurance of the casing of the horizontal production wells to the high temperature of the ISC front did not seem to constitute a serious problem; however, 4 wells were suspended (2 of them not related to excessive temperature damage. There were significant differences between the performance of the pilot and the semi-commercial process: the air-oil ratio (AOR) was around 1,500sm^3/m^3 for the pilot and around 2,800 for the semi-commercial operations.

Since 2012, five more THAI pilots were initiated outside Canada, three in China and two in India. The Chinese tests - conducted in extremely heavy oil reservoirs and using a direct line drive (DLD) configuration - have shown that at extremely high air injection rates, the oil rate is not proportional with air injection rate, and a high value of the average air-oil ratio (AOR) is recorded (8000sm^3/m^3); on the other hand, at very low injection rates, a good AOR is recorded, but the oil production is low. The tests confirmed the upgrading potential and production of hydrogen and how they are correlated with the burning process. Unlike all previous THAI tests, the tests initiated in India (in Balol and Lanwa reservoirs) by the end of 2016 have used a staggered line drive (SLD) configuration and been applied in correlation with a conventional in-situ combustion (ISC) process conducted for more than 20 years; they have been started in a region where conventional ISC was suspended for 3 years, due to lack of results. They fully demonstrated the superiority of SLD configuration for the case of heavy oil with reduced oil mobility at reservoir conditions and the ability of the THAI process to be used for regions with higher pay thickness where conventional ISC has been inefficient. AOR has been 3-fold lower than for conventional ISC, while the oil rates have been 4-5 times higher. The grafting of the THAI process on the existent conventional ISC was very easy.

Based on the limited field experience acquired so far, preliminary screening criteria have been developed. Until the efficiency of THAI technology is improved, it is recommended to be applied in heavy oil formations thinner than 12-14 meters and/or in formations deeper than 800m-1000m, where the SAGD method is not applicable.

At this stage of development, simulation models of THAI are using three different kinetics models. Using a kinetic model in which fuel deposition is generated by thermal cracking reactions (with no LTO reactions), it was possible to adequately describe the process, including temperature distribution and approximate gas composition. Also, it was possible to indicate that in THAI, there is primary and secondary fuel formation and consumption. The superiority of the staggered line drive (SLD) configuration over direct line drive (DLD was confirmed independently by three different organizations. The simulation models help in the explanation of the SLD superiority. THAI simulation requires the discretization of the horizontal section of the producer; at this time, there are some limitations as far as the prediction of oil production, underground upgrading of oil and hydrogen production are concerned.

Presently, 25 years since its discovery, and 14 years from the start of field testing, the technical feasibility of the process was demonstrated. However, further development is required in order that THAI can achieve full commercial success. So far, in the field, only **d**irect **l**ine **d**rive (DLD) has been tested. From a re-visiting of the old 3-D model laboratory work and a theoretical reservoir engineering analysis, and taking into consideration some results from Kerrobert Project, together with some dedicated simulations, **s**taggered **l**ine **d**rive (SLD) demonstrated superior performance to the DLD configuration and it should always be the first choice. SLD should be investigated and then systematically field-tested. In order to ensure a higher degree of success, in future THAI-SLD applications, there is a need to investigate, in detail, the communication phase with the main target of generating *a **broad initial linear combustion front***. To this effect, several solutions are presented for the classic case of using vertical wells for injection, with only horizontal wells for production. In principle, this assumes either propagation of a conventional ISC front between injection wells, or the use of a more complex wellbore trajectory/geometry, either for the injection wells or the production wells. Oil mobility and reservoir temperature are the most critical parameters in choosing the best approach. Also, some new schemes for the use of horizontal wells as injectors in a TTH configuration are provided (dual opposed horizontal injectors, repeated "L" configurations and cross lay-out). Horizontal injectors automatically generate a broader initial ISC front, but the safety of operations is critical, and all its details have to be considered. Also, the ignition operation is more complicated.

An analysis of past pilots and semi-commercial conventional ISC applications, as post-steamdrive operations, convincingly showed that ISC could constitute a very effective tertiary EOR method, and the use of horizontal wells is contemplated. Also, the use of horizontal wells is automatically assumed in developing a SAGD follow-up ISC process, and in this area, there is more interest in Canada. However, to this effect, the knowledge acquired in THAI development has to be used extensively. For this reason, THAI will always be a "stumble upon", in the sense that even in case the THAI is not directly applied, the THAI knowledge has to be used in these cases. Using the knowledge of THAI gained so far, *follow up ISC processes to SAGD (or just stand-alone ISC process in a SAGD-type configuration) are* proposed. Two approaches were examined; (1) drill new THAI modules in-between old SAGD pairs, to mobilize the oil towards the former SAGD pairs, which are fully converted to production, and (2) use a wet ISC process in the former SAGD pairs or as a stand-alone ISC process in a SAGD-type configuration; In this case, air would be injected as a dry foam form, and an extra-vent well is needed.

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Regarding the CAPRI process, there are many aspects to be further developed before considering systematic field pilots. The CAPRI process should be investigated mainly in an SLD configuration. Additionally, it should approach in a correlating manner the integration of underground upgrading and hydrogen production, with the potential to control the process towards enhancing upgrading or enhancing hydrogen production.

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Nomenclature

AOR=air-oil ratio as a performance technical indicator for in-situ combustion (ISC) process
BPP =bubble point pressure
BHT= bottom hole temperature
BW= bottom water
BW-ISC = conventional ISC in the presence of BW, with efforts to preserve ISC the oil zone
CAPRI = **CA**talytic upgrading **PR**ocess **I**n-situ, which is a catalytic THAI
CHOPS= Cold Heavy Oil Production with Sand
COSH = combustion override split-production horizontal well
CTO =catalyst to oil ratio
GOB=gas-over-bitumen
DB=Database
DLD configuration= direct line drive configuration
HI = horizontal injector
HP = horizontal producer
HS=horizontal section (of horizontal producer)
HPAI=High pressure air injection
h_{net} = net thickness of oil layer
h_{gross} = gross thickness of oil layer
ISC= in-situ combustion
LOAI=Light oil air injection
MD=Measured depth
MOZ = mobile oil zone formed during the application of THAI process
OOIP =Original oil in place
PCP = progressing cavity pump
PIHC = pre-ignition heating cycle (steam injection to heat the surrounding of injection well in view of ignition operation)
SLD configuration = staggered line drive configuration
SOR = steam-oil ratio
Top-down ISC = later on proposed under the name of multi-THAI (see Reference #7 of the Appendix B, Application 2,698,454)
THAI = toe-to-heel air injection
TTH=toe-to-heel
TTHP = toe-to-heel propagation

TTHS=toe-to-heel steamflooding (toe-to-heel steamdrive)
TTHW=toe-to-heel waterflooding
TVD= true vertical depth
WAR=water-air ratio in wet ISC
V_{AB} = velocity of the ISC front along the AB direction
VI=vertical injector
VP=vertical producer
VIHP = DLD configuration with one VI and one HP
VI2HP = SLD configuration with one VI and 2 HP
2VIHP = SLD configuration with 2VI and one HP
UOR = ultimate oil recovery

Comprehensive Assessment of Toe-To-Heel Air Injection (THAI) Process. Guidelines for Development of Future Generations of In-Situ Combustion Processes

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1. INTRODUCTION

The conventional **i**n-**s**itu **c**ombustion (ISC) process for heavy oil recovery was widely operated during the 1970-85's, in pilot tests and commercial developments, with the majority of tests located in the USA, Canada and Romania. It achieved varying degrees of success, some technical and economic, some with only technical success, but some of them were outright technical failures. It is the latter memory which has tended to prevail over time in forming a negative impression about ISC. Yet there were some outstanding successes, such as Suplacu du Barcau (Romania), Balol and Santhal (India) and the Bellevue Project (USA). Three of these employ a line drive configuration (using just vertical wells), where the combustion front advances down-dip against an edge water aquifer; only the Bellevue project has been conducted in patterns. While the Suplacu de Barcau project occurs in a shallow heavy oil reservoir with low pressure, the Balol and Santhal projects are applied successfully in more profound, higher pressure reservoirs, having strong lateral water drive.

The Suplacu de Barcau project is the largest project of its kind, and it has been in commercial operation for 45 years as a dry ISC process. The Balol and Santhal projects have been in operation for 19 years, and have been applied in a wet mode. The Bayou State Oil Corporation (BSOC) Project in Bellevue, Louisiana, USA has been in operation for 35 years. It is a dry ISC process; presently, it has 15 air injectors and 90 production wells.

Currently, the three major projects produce more than 500 m^3/day (3,450 bbl/day) from each project, while all three combined, produce approximately 2,300 m^3/day (15,860 bbl/day). Additionally, the project operated by BSOC produces 51 m^3/day (320 bbl/day). This figure of 2,350 m^3/day represents the total amount of heavy oil produced by ISC as of 2005 (Turta, 2007); there are a few more commercial ISC operations in China, but the total oil production figure is missing.

So far ISC process has not been proved (and applied commercially) in extremely high oil viscosity reservoirs and oil sands. The highest oil viscosity for which ISC was applied successfully was approximately 10,000cp. However, it is to be mentioned that for an oil viscosity higher than 1,500-2,000cp, the previous application of cyclic steam stimulation (CSS) for reservoir pre-heating is a must; many failures were due to the absence of pre-heating phase.

The general opinion within the industry, however, is that ISC is a difficult process to control, and operators have therefore been somewhat reluctant to treat conventional ISC as a preferred thermal heavy oil recovery technique. With a current **e**nhanced **o**il **r**ecovery (EOR) share of less than 0.03 % of world oil production, why then has ISC not been consigned to the dusty archives of technological history? Part of the answer is that ISC makes a potentially radical departure from other heavy oil/oil sands recovery methods, which include cyclic steam stimulation (CSS), and Steam Assisted Gravity (SAGD). The latter two processes use huge quantities of natural gas to produce steam for injecting into the reservoir. Theoretically, ISC is the most efficient EOR technique, and so it is no surprise that there is still the lingering possibility that it may be deployed more often as a heavy oil recovery process. The emergence of THAI in 2006 heralded a new dawn. Another reason is that, currently, computer models do not do a perfect job at simulating in-situ combustion, making it difficult to convince the oil industry that the technology will work as well in the field as it does in the laboratory. Misconceptions have also arisen because many people believed that the principles developed from simple analytical models could be substituted for otherwise less developed (or inadequate) numerical models. The reality is that ISC is far too complex for simple models to capture the essential details (assumed steady-state and dynamic) and therefore, accurate numerical modelling, supported by pilots and other field development data is the only way forward to understanding its behavior.

In parallel with the application of ISC in heavy oil reservoirs, a new development took place involving the successful application of ISC in very light and very deep, high temperature reservoirs, where spontaneous ignition was easily attainable. This happened in the Williston Basin of North and South Dakota, USA, where this process has been initiated at very low primary recovery factors. The process was applied in non-fractured dolomite reservoirs with low porosity (11%-19%) and permeability (less than 15 mD), containing very light oils (viscosity of less than 2 mPa.s under reservoir conditions), where water injection encountered significant problems due to extremely low injectivity. The process is known as High Pressure Air Injection (HPAI).

The most important HPAI projects are Cedar Hills, Medicine Pole Hills and Buffalo; Little Beaver and Pennel projects were started more recently (around 2004), and are being applied after waterflooding.

Cedar Hills is the biggest project and, currently, uses only horizontal wells for production and injection. By 2005, within Cedars Hill North Unit and West Cedars Hill Unit, there were a total of 30 air injection wells and the oil production was around 6,000 bbl/day; this oil production increased to around 13,300 bbl/day in 2012, with 127 horizontal producers and 126 horizontal injectors. Altogether, during 2012, the Williston Basin was producing approximately 20,000bbls/day, from these five operations (Turta, 2013).

The main factors leading to a successful ISC project in very light oil reservoirs are high reservoir temperature and high oil saturation. Also it is essential that spontaneous ignition occurs very easily and makes the process self-stabilizing.

During the last two decades, new ISC schemes have been conceived that incorporate horizontal wells and use gravity drainage in the recovery process; one of the most important is the Toe-to-Heel Air Injection (THAI) process. This study is an attempt to assess the THAI process together with its companion (add-on) process "Catalytic THAI" or CAPRI (for in-situ upgrading), and to identify concepts for further development of novel ISC/EOR processes for heavy, extra-heavy oil reservoirs and oil sands. The emphasis is on a rigorous evaluation of the recent field tests of the THAI process in one oil sand reservoir and another conventional heavy oil reservoir. The analysis was performed in light of the most recent scientific knowledge acquired in the area of toe-to-heel displacement. It is hoped that companies acquiring this Report will be able to save considerable time and effort for decisions on future field development of the THAI/CAPRI processes or other novel ISC processes involving horizontal wells.

2. BRIEF DEVELOPMENT HISTORY OF THAI PROCESS

SHORT DISTANCE AND LONG DISTANCE PROCESSES

There are two broad ways of applying **i**n **s**itu **c**ombustion (ISC) process:

- **S**hort-**d**istance **o**il **d**isplacement (SDOD) configuration
- **L**ong-**d**istance **o**il **d**isplacement (LDOD) configuration

The SDOD and LDOD processes are schematically illustrated in Figure 1. The application of ISC in an LDOD configuration is representative of conventional ISC, where the oil is displaced laterally by an ISC front (Figure 1a) for a few hundred metres; the distance traveled by the mobilized oil is very large and oil has to flow through the cold region for most of its trajectory to the producer.

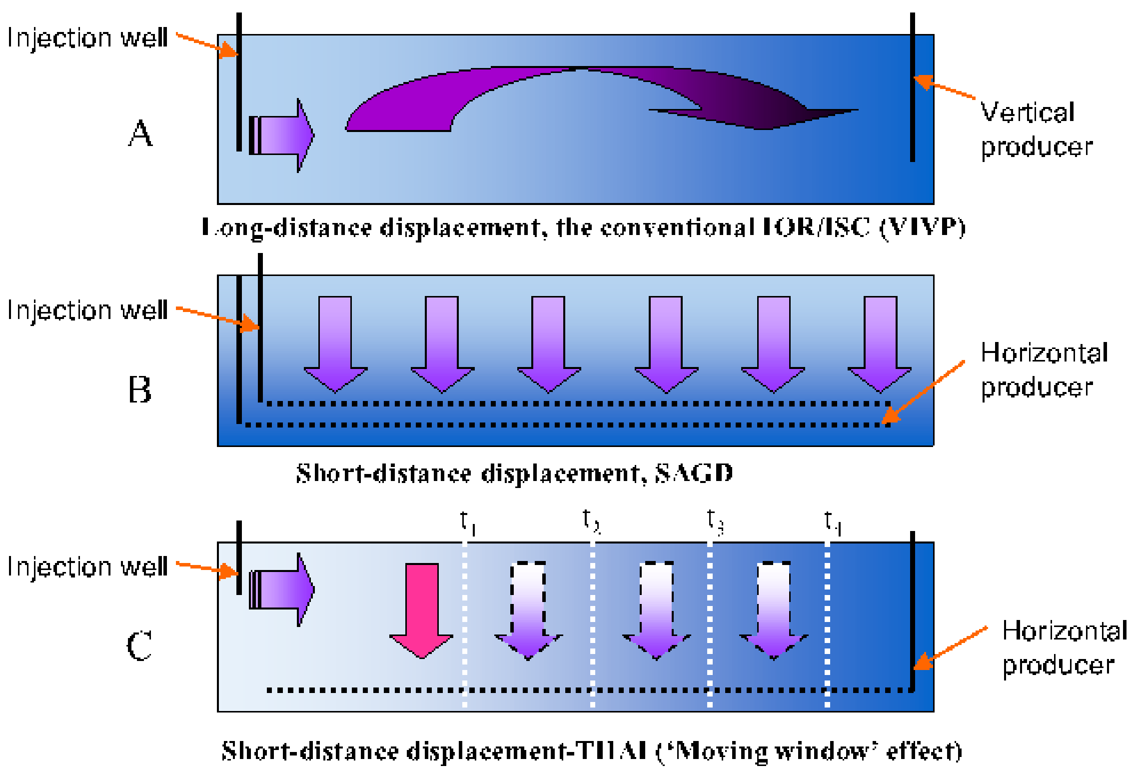

Figure 1: Long and Short Distance Oil Displacement Processes.

The application of ISC in an SDOD configuration is shown in Figure 1b for SAGD and Figure 1c for THAI. The distance traveled by the mobilized oil is significantly shorter since the mobilized oil no longer flows through the cold region. Instead, it flows through a **m**obile **o**il **z**one (MOZ) created ahead of the ISC front (more precisely, ahead but adjacent to the steam zone).

LONG -DISTANCE ISC (CONVENTIONAL ISC):

There are two approaches for the application of conventional ISC in an LDOD configuration:

- Pattern application
- Peripheral line drive application

These approaches have been extensively applied in the field, both experimentally and commercially. The pattern configuration consists of inverted five, seven or nine spot patterns with the air injection in the center. The patterns can be contiguous and located at the uppermost part of the structure. However, these patterns can also be located down-structure or can even be isolated patterns on the structure. The operation in patterns is considerably more difficult than the operation in a line drive configuration

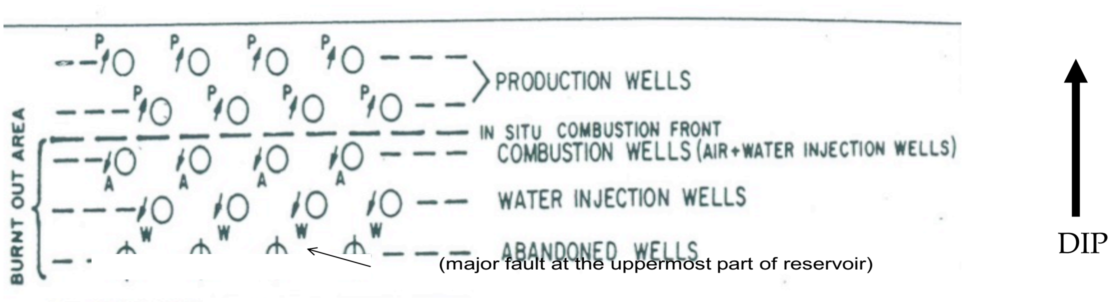

Figure 2: Schematics of peripheral line drive conventional ISC application

A peripheral line drive commercial application is shown in Figure 2. The process is initiated through a line of injectors located up-dip, parallel to the strike and usually, a combustion "basin" is formed by the "merging" of the individual ISC fronts. Then, this front is advanced down-dip until the entire reservoir is processed by ISC. Usually, the wells function initially as producers and subsequently, they are converted into injectors.

The advent of horizontal wells occurred in the late 1980', early 1990, being used as producers in LDOD systems. For the first time, horizontal wells were used in conjunction with a conventional ISC process (using only vertical wells) in two Canadian projects (Turta, 1994). The first one was Eyehill, Saskatchewan (Sa.), where three horizontal wells were drilled two years after the termination of a dry ISC process in adjacent five-spot patterns. A second project was Battrum, Saskatchewan, where, in 1993, one horizontal well was drilled within an active commercial wet combustion process, with the horizontal section positioned between the secondary gas tongue and the water tongue of an exploitation using pattern system. The third project was also Canadian – Brintnell Project – operated by Amoco and AOSTRA in 1994 - and involved intentional use of horizontal wells both as producers and air injectors (Thornton, 1996). Pressure cycling, dry ISC was tested in a face-to-face configuration formed by three horizontal wells with one air injector in the middle, parallel to two producers on either side. More details on the Eyehill pilot is provided in subchapter 7.3 and on the Brintnell project, in subchapter 10.1.

Although the results of horizontal wells in ISC LDOD systems had very mixed results (either very good or inferior), they allowed understanding what are their advantages and disadvantages and starting from that the ISC in the SDOD system was developed. Toe to Heel Air Injection (THAI) was the most prominent of them, as it is the only process with field testing and valuable experience acquired from this.

THAI PROCESS DEVELOPMENT:

The THAI process was developed from an understanding of the difficulties and successes of in-situ combustion (ISC), experienced over three decades of operating conventional ISC projects. It was inspired, in part, by the few successful commercial ISC projects, conducted in a line drive configuration and in a quasi-gravity stable mode. In reality, THAI is part of a larger category of toe-to-heel (TTH) displacement processes comprising both thermal and non-thermal processes. Non-thermal processes include the toe-to-heel waterflooding (TTHW), and the thermal TTH processes include THAI and CAPRI. Besides, there has also been a continuous effort to develop a steamflooding TTH configuration scheme.

The THAI process was developed during more than 12 years of cooperation, between Dr. Malcolm Greaves of the University of Bath (U of B), UK and Dr. Alex Turta of the former

Petroleum Recovery Institute (PRI) – now part of Alberta Research Council (ARC)/ Alberta Innovates–Technology Futures (AITF).

The development of THAI did not occur in isolation. Along with many other laboratories, in the US, Canada and Europe, the Improved Oil Recovery (IOR) Group at the University of Bath, conducted an extensive conventional ISC research program on heavy oil recovery, for more than 10 years. This work focused mainly on the use of combustion tube apparatus to investigate the performance of linear ISC behavior. Starting around 1990, the Bath group initiated work using a 3D combustion cell, equipped with both vertical and horizontal wells. The cell was operated quasi-adiabatically using heating tapes wrapped around it. An in-depth analysis of the results of these tests suggested that performance in specific well configurations was much better, or even outstanding, in some cases. Therefore, in 1993, systematic investigations were conducted using a configuration, which was subsequently assigned the designation of THAI. Starting in 1996, the investigations leading to the development of Catalytic THAI (CAPRI) began, and Dr. Conrad Ayasse of PRI joined the previous team of two, as a co-inventor. The CAPRI process was developed as an 'add-on' process to THAI. Basic understanding of the THAI process was derived from many systematic ISC experiments, carried out by the IOR Group at the University of Bath, throughout 1993 to 2002.

THAI-CAPRI PATENTS AND THEIR FIELD TESTING:

THAI USA patent (5,626,191) was issued in May 1997, while the CAPRI USA patent (6,412,557) was granted in July 2002 (see Appendix B for a list of patents). THAI Canadian patent (2,176,639) was granted in August 2002, while the CAPRI Canadian patent (2,255,071) was obtained in July 2003. The THAI patent has also been allowed in Venezuela and Colombia. For CAPRI, a PCT (Patent Cooperation Treaty) application was filed and currently, there is an European Regional Patent no. 1060326, which applies to Austria, Germany, U.K., France, the Netherlands and Romania. There are two more patents for Toe-To-Heel Waterflooding (TTHW) technology, which relate to the THAI well configuration.

The THAI and CAPRI patents were acquired by Petrobank Energy and Resources (Petrobank) of Calgary in November 2001, even before the CAPRI USA patent was granted. Petrobank bought the exclusive rights for these two patents. Archon Technologies Ltd., a wholly-owned subsidiary of Petrobank has handled the licensing of these technologies to other companies. So far, Archon Technologies Ltd. has applied for four new USA patents for improvements to the existing THAI and CAPRI technologies

By mid-summer of 2003, Petrobank applied to ERCB for approval for field piloting of THAI in the Athabasca Tar Sands (now commonly called Athabasca Oil Sands); this pilot started in 2006 and was completed by September 2011. Based on the first results of the pilot, Petrobank applied to ERCB for approval for a commercial-scale application of THAI in Athabasca Oil Sands (May River Project). However, later on, Petrobank canceled this commercial project and sold the property.

Application of THAI in the conventional heavy oil resource in Kerrobert Field, Saskatchewan, started in 2009. Based on the pilot results, a commercial operation was initiated in 2011 and is still operating. Planning for THAI testing in a conventional heavy oil pool, in the Peace River region – Dawson Pool, Alberta - reached an advanced stage, and was approved by ERCB. However, the Dawson lease was sold later on by Touchstone (successor to Petrobank), and the THAI project was canceled.

3. BASIC MECHANISMS OF THAI/CAPRI

3.1 General:

A schematic of the conventional ISC process is shown in Fig. 3. As seen from this figure, this is a **l**ong-**d**istance **o**il **d**isplacement (LDOD) process, as any oil particle, when displaced, has to travel the whole distance from its point of origin to the production well (hundreds of meters). Generally, in conventional ISC, the hot oil displaced by the combustion front banks ahead of the displacement front in the cold region, mixes with the original oil; this causes a severe reduction of relative permeability to the gas (Krg), leading to reduction in air flux rate, which promotes **l**ow-**t**emperature **o**xidation (LTO) reactions. This often leads to the poor performance of the process. Although in conventional ISC there is upgrading of the ISC displaced oil, this benefit is significantly reduced and is usually negated (at the production end) due to mixing with a large amount of the original oil during this LDOD process.

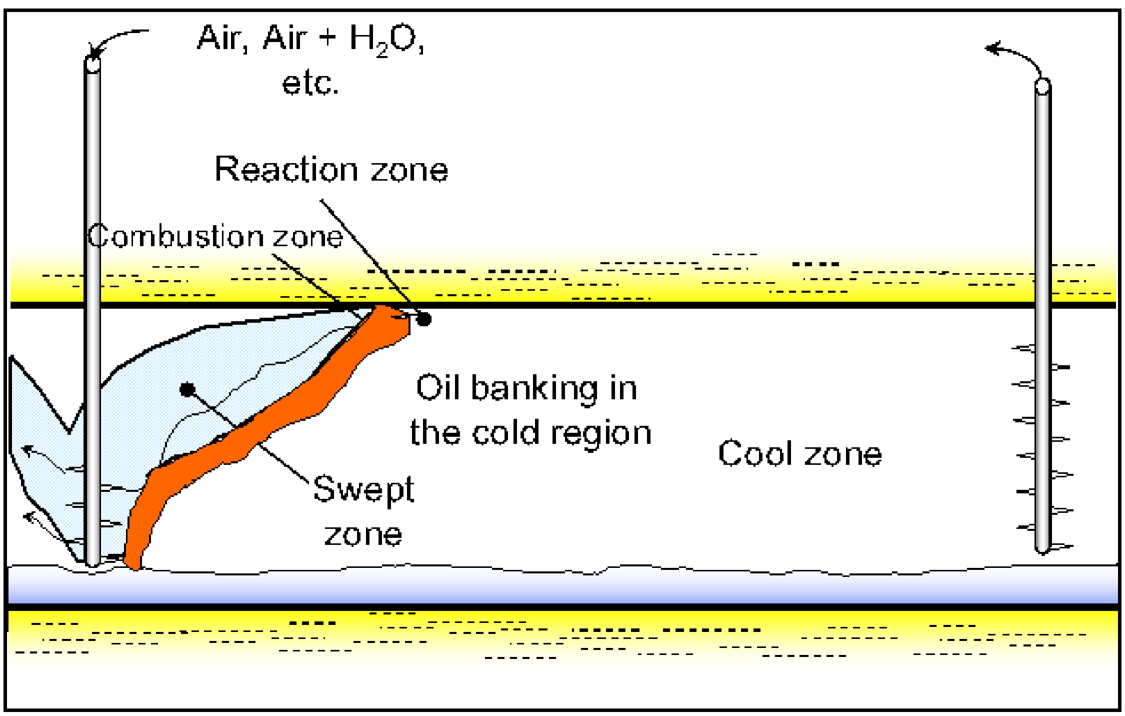

Figure 3: Schematic of Conventional In Situ Combustion Process
Courtesy of Prof. M Dusseault

The disadvantages of the conventional ISC process are summarized below:

- It is a long-distance oil displacement (LDOD) process; ahead of the ISC front, oil banks-up and flows through the cold zone mixing with the original *cold* oil and causing severe reduction of the gas flux (Krg becomes extremely low); this is conducive to LTO reactions, which result in oil viscosification and oil-water emulsification, further exacerbating the problems related to low air flux.
- Pronounced gas over-riding (due to gravity segregation)
- Heterogeneity/layering has a very negative effect (poor vertical conformance)
- Lack of control over the propagation of the in-situ combustion front
- Low volumetric sweep efficiency (20-30%) for the burning front.

All these negative features lead to premature oxygen breakthrough and resulting, eventually, in low incremental oil recovery and several operational problems

Even with these very significant disadvantages, the conventional ISC process attained commercial status during the decade 1960-1970, when large scale ISC projects were started; some of them are still active. The biggest ISC project is at Suplacu de Barcau Romania, which was in the testing phase from 1964 to 1971; this was followed by a commercial-scale dry ISC operation. The situation of the linear ISC front as of 2004, is shown in Fig. 4; the length of the linear front had grown to around 10km. Two major ISC commercial line drive operations have been operating for more than 20 years in India, where a wet ISC is in operation. Altogether, these projects produce almost 20,000 bbl oil/day (Turta et al., 2007).

As far as **s**hort-**d**istance **o**il **d**isplacement (SDOD) processes are concerned, they can be divided into two categories:

- Almost integrally gravity controlled: steam assisted gravity drainage (SAGD) process
- Pressure gradient and gravity controlled: **T**oe-**T**o-**H**eel (TTH) displacement processes

These processes are shown schematically in Fig.5. SAGD is limited by the injection rate; above a specific maximum value, there is no gain in oil production; gravity needs time to act. On the other hand, TTH processes have more flexibility. However, they still experience a limiting (maximum) value of the air injection rate, beyond which the efficiency starts to decrease (either due to the channeling of the injected fluid, kinetics limitations or aggravation of operational problems). *In both THAI and SAGD, the flow of oil through the cold oil region is avoided.* In both cases, a **m**obile **o**il **z**one (MOZ) is formed at the edge of the hot zone. And finally, in both processes, the negative effect of heterogeneity (stratification) is somewhat attenuated.

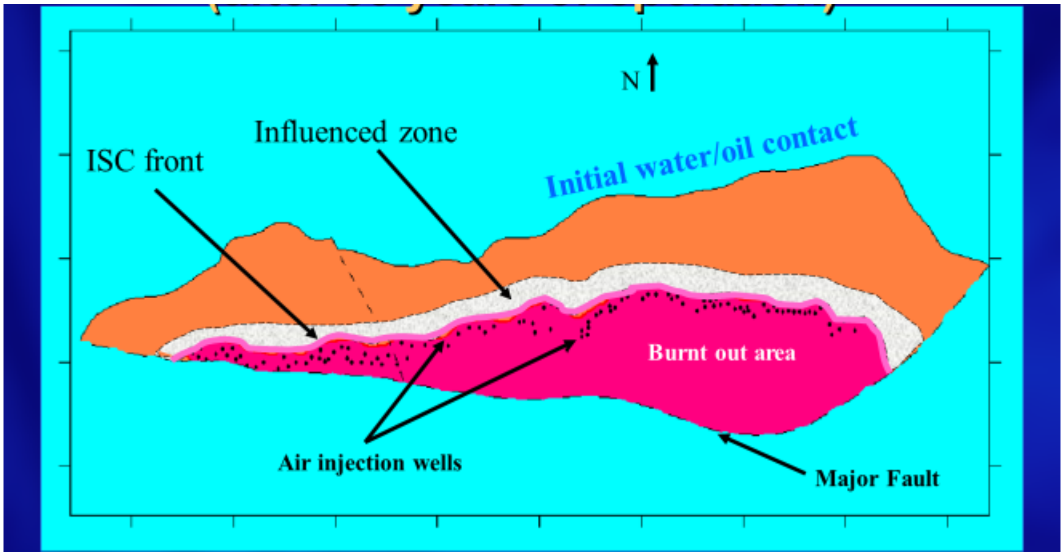

Fig. 4: The position of the in-situ combustion front at Suplacu de Barcau, as of July 1st, 2004, after 33 years of operation (Turta, 2007)

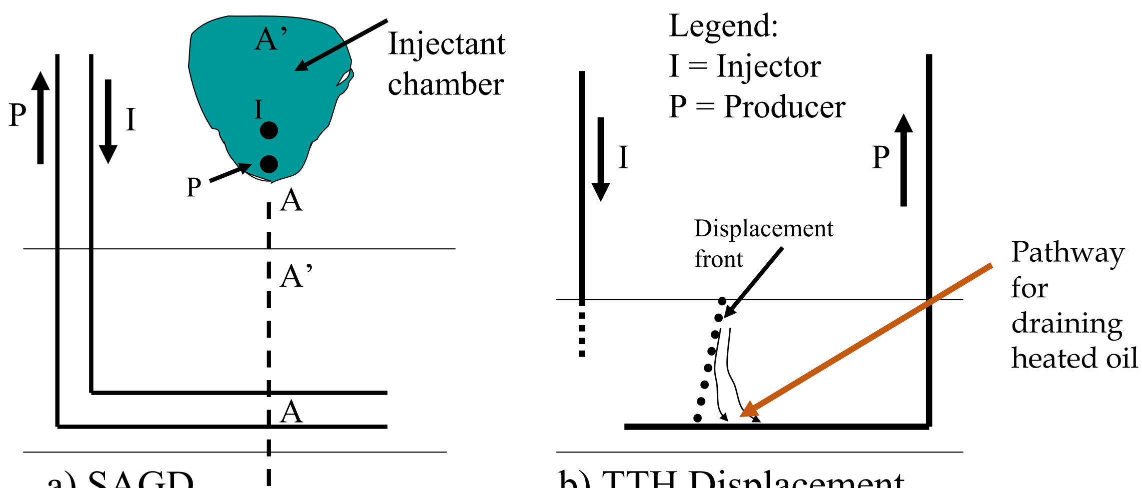

Figure 5: Schematic of integrally gravity controlled process SAGD (a) and pressure gradient and gravity controlled (TTH) processes (b). Figure 5b, Courtesy of C. Ayasse

THAI Process:
THAI is operated in a line drive configuration. A simplified schematic of the process is shown in Fig 6, while Figures 7a-b show a spatial (plan) view of the wells either in a **d**irect **l**ine **d**rive(DLD) or in a **s**taggered **l**ine **d**rive (SLD) operation.

Generally, a THAI process is operated in four phases, as follows:

- Linkage (hot communication) between injectors and, then, communication with the toe of the horizontal producer; generally, a heat/fluid communication within the start-up region

- Ignition (initiation of the ISC front): gas burner; electrical heater; steam injection alone, or followed by chemical ignition (linseed oil oxidant) may be used to achieve this
- Propagation of the ISC front/MOZ from the toe to the heel of **h**orizontal **w**ells (HW) located in the first row (adjacent to air injectors)
- Wind-up of the process in the first row of horizontal wells (HW), with the continuation of ISC front propagation down-structure towards the second row of HW

In general, the four phases (described) have to be applied in this order when THAI is applied "ab initio", i.e., in a virgin field. However, if THAI application is grafted on an existing ISC project or steamflood, application becomes significantly easier. When grafted on an existent ISC project, both hot communication and ignition phases can be skipped, while for an existing steamflood, the hot communication can always be skipped while ignition should be evaluated case by case. For this reason, this type of application (grafted on an existing thermal project) is the most attractive one. The same is valid when the application is made after the suspension - for a few years -of either ISC or steamflood.

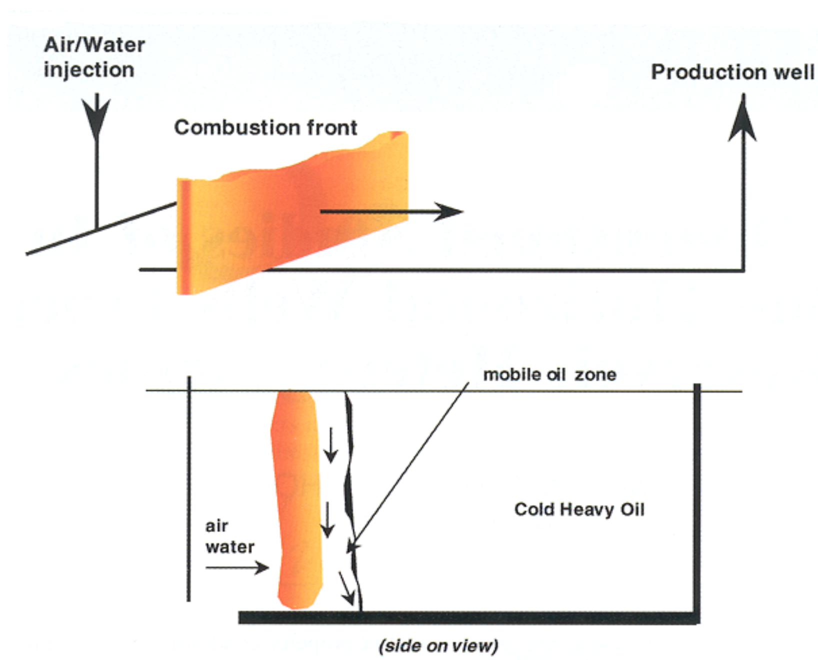

Figure 6: Oversimplified Schematics of Toe-to-Heel Air Injection (THAI) concept. In reality, the combustion front is inclined forward due to gravity segregation of the gases. Courtesy of C. Ayasse.

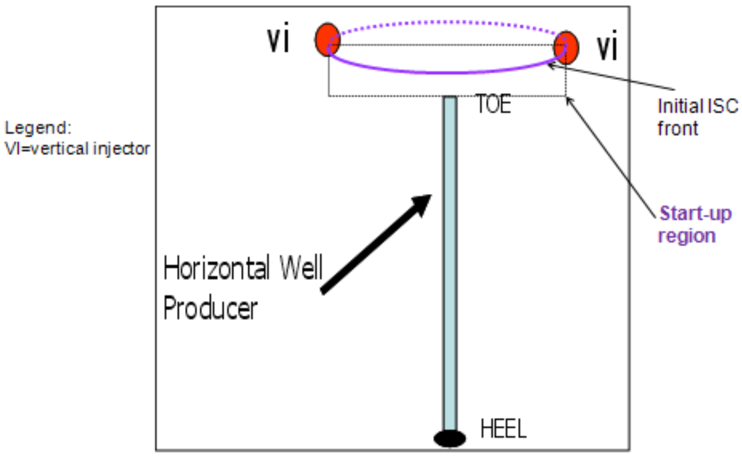

Figure 7a: Top (plan) view of Toe-To-Heel Air Injection (THAI): Staggered Line Drive Configuration. VI=vertical injector

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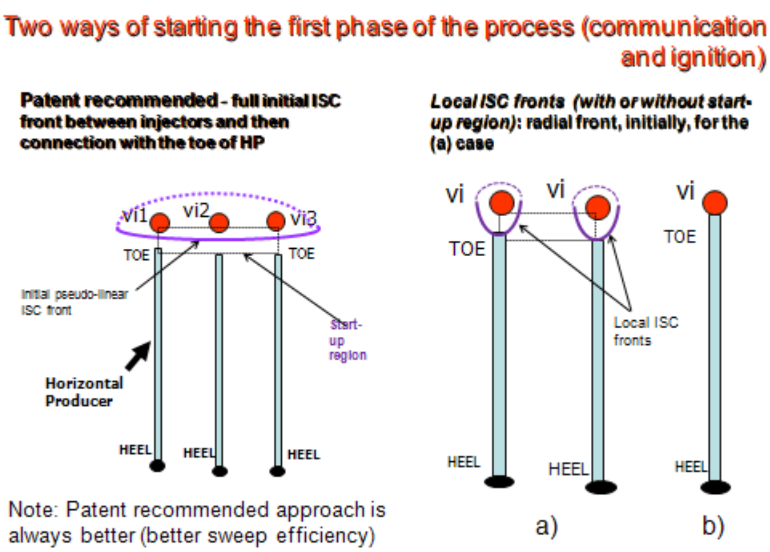


Figure 7b: Toe-To-Heel Air Injection (THAI): Direct Line Drive Configuration.
Plan View. U.S.A. Patent No.5,626,191; Canadian Patent 2,176,639

Communication between Injector and Production Wells:

Usually, communication (linkage) is achieved by steam injection and the ignition phase can also (but not necessarily) involve steam injection for pre-heating of the surrounding region of the air injection well. When steam is used both for communication and initiating ignition, this part of the process start-up is usually referred to as the PIHC (pre-ignition heating cycle). For a staggered line drive (SLD), as the distances between injectors and producers are larger (than in SAGD), the communication phase is generally more demanding than that in SAGD operations. As oil viscosity increases, the communication phase becomes increasingly important and, also more complex.

Based on the results of laboratory work, a simplified schematic of the process during the propagation of the ISC front along and above the horizontal section of the producer was developed, and it is shown in Fig. 8. Note the existence of the **m**obile **o**il **z**one (MOZ) ahead of the ISC front and, also, the presence of a coke plug in the horizontal section of producer, close to ISC front. These two aspects (MOZ and coke plug are related), and they are analyzed later in further detail. The existence of the coke plug is well-demonstrated from the results of the 3D THAI experiments. However, it may or may not exist, or may be necessary for the field. This is because there is a strong over-ride tendency of the ISC front (depending on the size of the start-up region) and, additionally, there is a coke layer above and /or surrounding the horizontal well, that to some extent acts as a barrier or resistance to air channeling directly into it.

Fig. 9a illustrates the ISC front expansion and the zones formed during the 3 stages of process development in the simplest case, namely the direct line drive (DLD) configuration (Liang, 2012). For the DLD THAI process, the side views show that immediately after ignition (Stage 1), the ISC surface is semi-spherical (around the upper half of perforations of the vertical well) and is advancing downwards. Then, during Stage 2, ISC is still occurring in a conventional mode of operation, undergoing a pseudo-radial expansion with a tendency to override. Hence, the ISC front propagates in the start-up region a conventional ISC mode. Any over-riding tendency from stage 2 depends on the distance between the injection well and toe of the production well; this entrance section, or 'offset' distance between the injector and producer, is what determines the size of the start-up region. This phase lasts until the ISC front arrives at the toe, and minimal upgrading is expected during this period. Stage 3 is the longest of these, where a pseudo-linear TTH propagation takes place. These three stages were confirmed in later laboratory investigations (Wei, 2016) The propagation of the ISC front during the second stage can be more complex, depending on the method of communication and is further discussed in the next sections.

Also, as shown in Fig 9a and 9b (in the top views) for the DLD THAI process, the burned and unburned rock in a plane perpendicular to the propagation path of the combustion front. As this cross-section is taken farther from the toe, the ratio between burned area and unburned one is reduced, (Greaves, 2009). This constitutes a pronounced wedging effect for the DLD THAI process, while this wedging effect is significantly reduced in the staggered line drive (SLD) configuration, as it is shown in the subsequent sections of the Report.

The potential THAI benefits are listed in Table 1. As the horizontal well produces a partially upgraded hot oil of relatively low viscosity, the oil rate should be much higher than that from primary recovery. Also, being less sensitive to the permeability heterogeneity of reservoir (mainly stratification), sweep efficiency, and hence the recovery factor are also expected to be higher. However, the areal sweep efficiency can still be reduced due to the tendency of the ISC front to tongue towards the production end of the reservoir, mainly in a direct line drive; a wedging effect may still be present during the ISC front propagation from toe to heel.

B

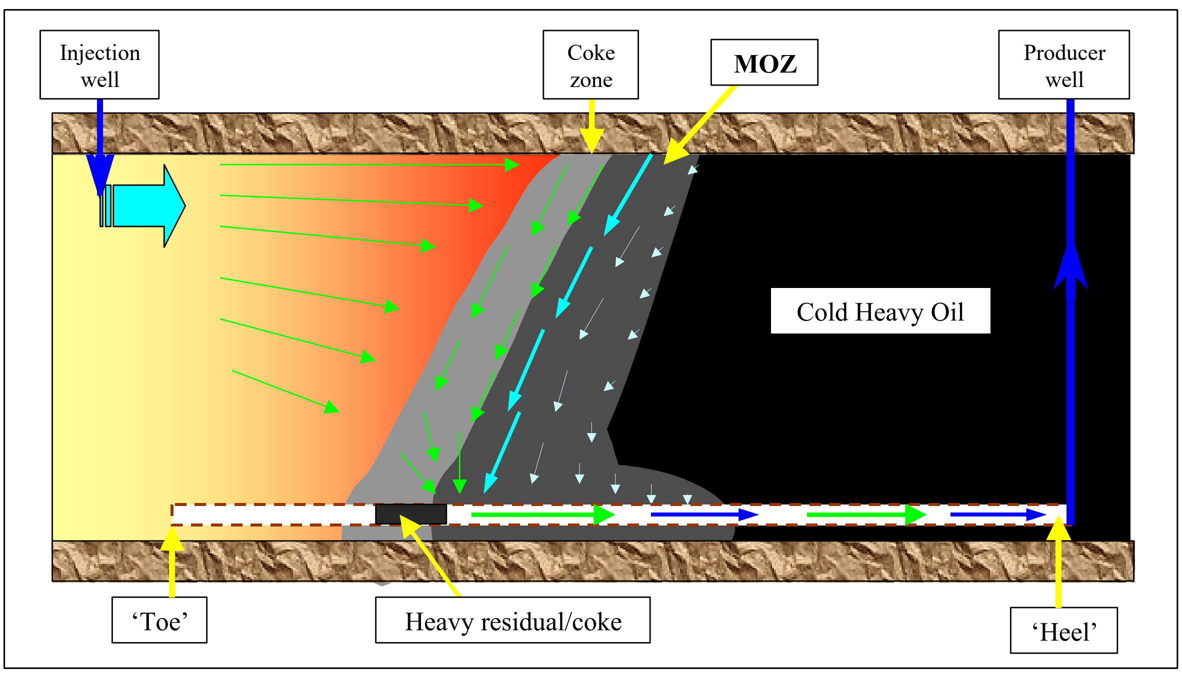


Figure 8: Schematic of THAI process during the toe-to-heel propagation phase

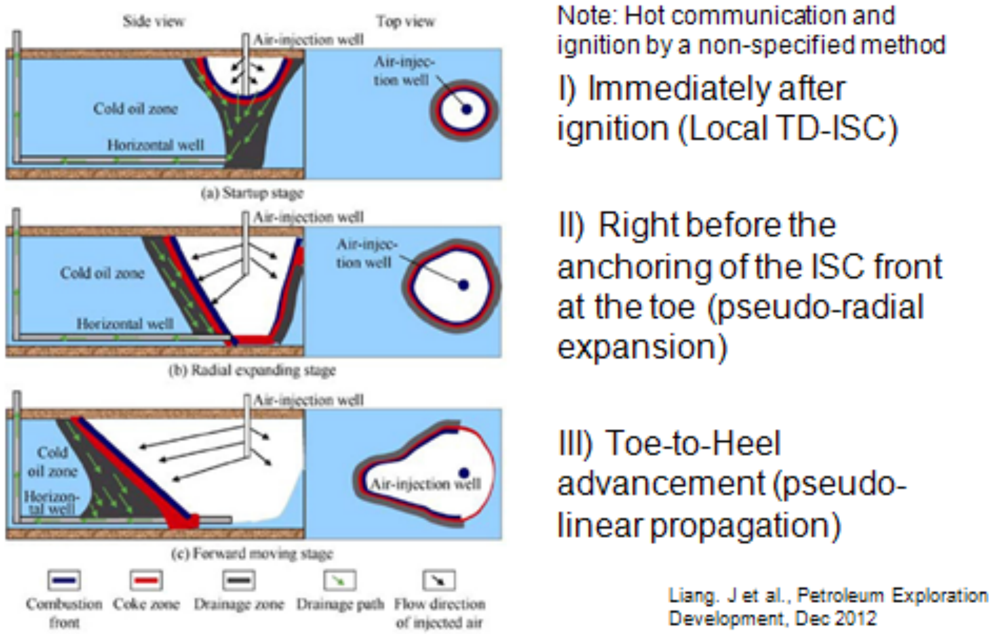


Fig. 9a: Direct Line Drive (DLD) Configuration with Local Link. ISC Front Expansion at Different 3 Stages, (Liang, 2012)

Fig. 9b: Direct Line Drive (DLD) Configuration. Burned and unburned rock in a laboratory test; it shows that in a section AA' (from Figure 9a), which is in a plane perpendicular to the propagation path of the combustion front. As this cross-section is taken farther from the toe, the ratio between burned area and unburned one is reduced (wedging effect). Greaves, 2009, test 2000-05

However, the areal sweep efficiency can still be reduced due to the tendency of the ISC front to tongue towards the production end of the reservoir, mainly in a direct line drive; a wedging effect may still be present during the ISC front propagation from toe to heel.

Table 1. POTENTIAL THAI BENEFITS (heavy oil reservoirs)

1. Gas override controlled due to the combination of gravity drainage and pressure drawdown in an a-priory design of the start-up region. This way, tilting-forward of the ISC front is assured

2. In-built guidance system, due to 'toe-to-heel' combustion front propagation along the horizontal section of production well

3. Very robust, overall stability of process (practically, 100 % oxygen utilization, and no premature O_2 break-though) due to a self-healing feature related to the controlled override and potential local plugging by coke.

4. Lower heat losses in adjacent formations due to compact burned zone

5. Clean formation in compact burned section and very little flow through the cold regions (short-distance displacement) can enable good air injectivity, sustaining vigorous, high-temperature combustion.

6. Higher stability to the air injection stoppage

7. 'Short-distance displacement' process; due to unique mobile oil zone, preserves most of the in-situ oil upgrading and produces hydrogen

8. It is less sensitive to reservoir permeability heterogeneity (mainly to stratification)

9. Increased vertical conformance factor, hence better volumetric sweep efficiency even for higher thickness formations

10. Better capture efficiency of the displaced oil

11. Theoretically, high productivity, due to production of heated and partially upgraded, low viscosity oil

12. Can work with small gas cap reservoirs or in reservoirs with thin bottom water, although with a lower performance; tolerant of shale lens-induced heterogeneities

13. Can operate in thin oil layers, down to 6m; Potentially, slightly lower heat losses in the overburden layer due to compact configuration of the burned zone

14. Reduced number of horizontal wells compared to SAGD

15. Significant environmental benefits: minimal natural gas, water use, reduced - sulfur (reduction of 20-30%) and reduction of 90% for heavy metals and nitrogen, produced water easily treated to industrial quality

Summarizing the first 3 benefits, it can be concluded that THAI is a short-distance oil displacement process *with a long-distance pathway for oxidation, more precisely for HTO* *reactions*. This explains why during the field application, there is no trace of oxygen, while in the laboratory tests, some oxygen (1-2 %) is still recorded in the produced gas.

3.2 Main **mechanisms** of **conventional ISC and THAI. Similarities and Differences**

In order to present the ISC reaction mechanisms, the schematic for the conventional dry ISC process is shown in Fig. 10. As the injection proceeds from the left side, it can be observed that most of the heat generated in the combustion zone remains behind the ISC front in the burned-out zone. This zone is free of any oil or water, but at the same time, the sand can become unconsolidated; the peak temperature of the ISC front is in the range of 450 to 600 ^{0}C. As we go downstream of the ISC front, two kinds of oxidation reactions can take place: **h**igh-**t**emperature **o**xidation (HTO) and **l**ow-**t**emperature **o**xidation (LTO). The heat of reaction for HTO and LTO, as expressed per kg of oxygen, is not very different, although for the heavy oil, generally, it has a slightly higher value for HTO. However, the rate of heat generation (release) is higher in HTO regime; this rate is strongly dependent on the temperature with which increases accordingly.

As a rule of thumb, every increase of temperature of 20^{0}C leads to a doubling of the reaction rate (hence of heat released). This rule holds everywhere except when passing from LTO to HTO when we encounter a region called "negative temperature gradient", where the rate of heat generation slows down. This is shown in Fig. 11 for a **r**amped **t**emperature **o**xidation (RTO) test in laboratory.

LTO reactions produce three significant effects:

a) An increase in the oil viscosity (downgrading of the oil); e.g., 23 hours of oxidation at 38 ^{0}C led to a 1.4 times increase in oil viscosity (Turta, 1994). Approximately 4-5% of the oxygen is absorbed in the oil as aldehydes, ketones and acids.

b) Changes in the composition of the oil such that the amount of fuel deposited increases.

c) reduction of oil-rock system reactivity, making it more difficult to ignite

Generally, the fuel (carbonaceous residue) **or coke** is made up of carbon and hydrogen, with proportionately more carbon than hydrogen burning, when the temperature is increasing towards the peak temperature of the ISC front. Hence, more carbon is consumed in HTO reactions; so, generally, combustion kinetics of heavy oil ISC means HTO reactions predominantly.

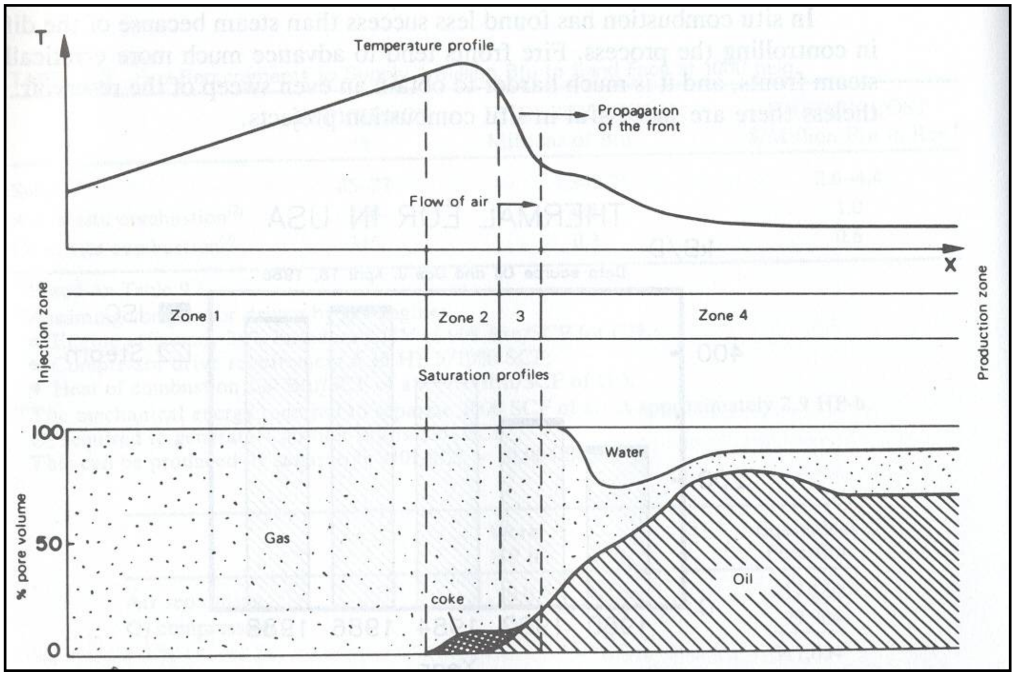


Figure 10: Temperature and saturation profiles during dry ISC process

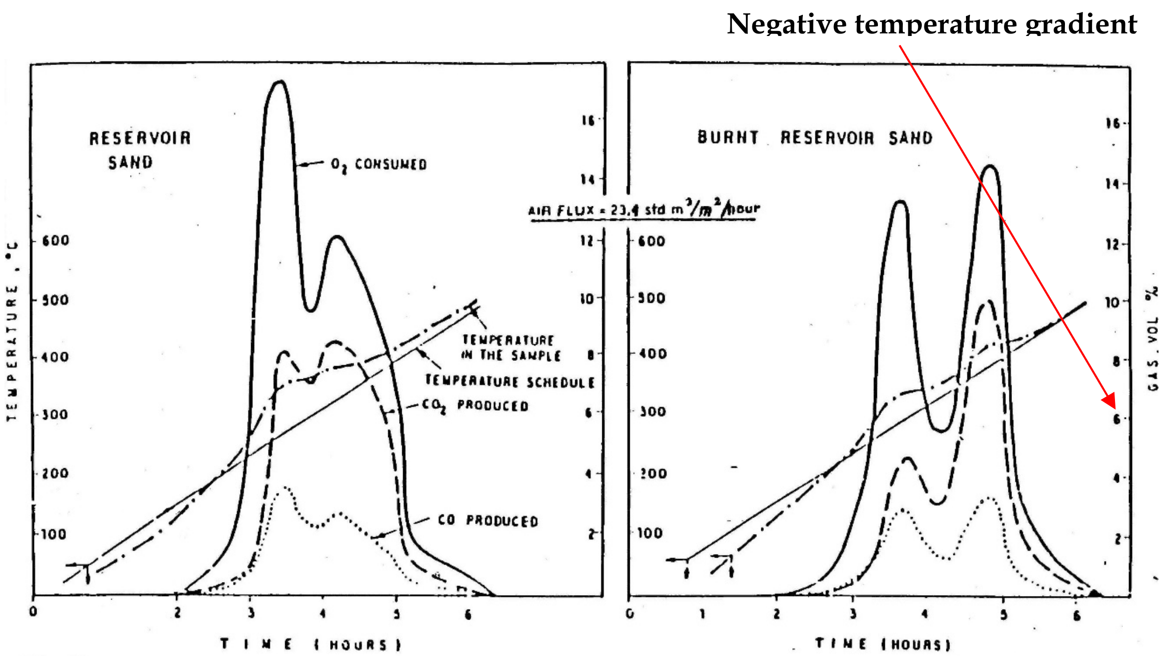


Figure 11: Oxidation of Videle oil in the reservoir sand and in the burnt-out reservoir sand (Turta, 1986)

H/C Ratio

The coke is characterized by the apparent atomic H/C ratio of the fuel (n); n is taken as *the unit molecular weight* of the coke, but in reality, it has a very large range of components with different molecular weights (very heavy ends)

- There are two categories of the H/C ratio:
    - True atomic H/C ratio
    - Apparent atomic H/C ratio (n)

True (real) atomic H/C ratio range for different oils is between 1.35 to 1.95, for oil density ranges of 822-980kg/m^3

On the other hand, the apparent atomic H/C ratio (n) can range as follows:

- 1 to 2 for the laboratory **c**ombustion **t**ube (CT) tests showing a vigorous propagation of the ISC front
- 0.5 to 5 (7) for field ISC processes (except during ignition)
- 25 decreasing to 1-2.5, during ignition operations (mainly in spontaneous and chemically aided ignition operations)
- 1 to 30 for laboratory **r**amped **t**emperature **o**xidation (RTO) tests

As far as the calculation of n, i.e. the apparent H/C ratio of the fuel used in air sustained ISC**,** assuming that only carbon oxides, combustion water and unconsumed oxygen are found in the combustion products, the following equation can be used, with percentages of individual gases from the dry produced combustion gases.

$n = [106+2CO-5.06\ (CO_2+CO+O_2)]\ /\ (CO_2+CO)$…………………..(1)

In practice, in addition, some light hydrocarbons (C_1, C_2 etc) or even H_2 can be present in the produced gas: in this case, the previous equation becomes:

$n = (1-(H/100)\ [106\ /\ (CO_2+CO)] + [2CO-5.06\ (CO_2+CO+O_2)]\ /\ (CO_2+CO)]$,……..(2)

where H represents the sum of the hydrocarbons percentage and the hydrogen percentage in the dry combustion gas produced (more generally, the total percentage of gases not taking part *directly* in the combustion process).

The apparent H/C ratio is used in practice, as follows:

- In a **c**ombustion **t**ube (CT) test, to determine the stabilized period over which the main calculations are made.
- Monitoring ignition and determination of the ignition delay (time)
- Control of the ISC process – a *synthetic indicator*; for instance, the percentage of O_2 by itself may not correctly indicate the state of the ISC front (peak temperature), except in case of a substantial percentage of O_2 (over 6-7%)
- Use of the Eqn. (2) is compulsory when other foreign gases (not generated from the combustion) exist (example: Marguerite Lake project where H_2 was produced in certain phases of the process). Otherwise, there is the possibility of grossly overestimating the H/C, indicating a situation worse than in reality)

Conventional ISC versus THAI. Similarities and Differences

Generally, and mainly for combustion reactions and flow dynamics, there are similarities and differences between conventional ISC and THAI, as follows:

Similarities

- The same average amount of fuel deposited and air consumption for normal dry ISC conditions was obtained in laboratory tests
- Almost the same peak temperatures in the ISC front
- In both cases, the apparent Hydrocarbon-Carbon ratio (n) provides a clear way of assessing the quality of the burning intensity in the ISC front; generally, a smaller n means better quality (higher T_{peak})

Differences:

- In THAI, due to the SDOD character of the process, LTO reactions play a much less significant role; generally, high values for (n) should not be recorded after the ignition operation is achieved
- In THAI, air flux does not suffer due to cold heavy oil banking
- While the development of the "coke plug"/or *local* coke generation in or around a *limited* portion of the horizontal section of producer, generally, is a positive phenomenon in THAI, it has a negative effect in conventional ISC process (using

only vertical wells), i.e. coke deposition in the production well perforations, blocking the production

- Wet combustion seems to be more appropriate for conventional ISC process; Usually, in the THAI 3-D laboratory tests, it produced a direct thermal shock on the combustion front temperature, continuously lowering the peak temperature. Therefore, new improved ways of application have to be developed.

For the THAI process, the most critical question to be answered is **Why there is no oxygen break-through during ISC front propagation?** The answer is provided in Fig. 12. A coke deposit (local plug) of a few cm exists where the coke zone touches the horizontal leg. This acts as a gas seal, preventing the air/gas flowing directly into the borehole. This coke plug travels with the ISC front. The proof that this plug is a reality (in 3D laboratory tests) is provided in Figures 13-16. Fig. 13 shows the location of the coke plug towards the heel – leading to flow blockage at the end of the 3-D test. Fig. 14 provides the temperature isotherms for this case. Fig. 15 shows a case where there was an intentional cessation of the laboratory test after the ISC front had propagated half-way through the model; the model was dismantled to locate the position of the coke plug. The temperature distribution at the time of the stoppage of air injection is shown in Fig. 16.

The existence of the coke plug and the tendency of the ISC front to be slightly inclined forward were confirmed by other independent investigations [Chang, 2012, Wei, 2016]; the 2012 work was doing this while investigating the feasibility of ISC application in an oil reservoir containing wormholes. In their laboratory set up this in fact consisted in performing a THAI experiment, where, instead of a "horizontal well" - located at the bottom - a rectilinear wormhole was located *axially* along a 12.5 cm-diameter ISC tube ; In several tests the wormhole contained very high permeability sand, but in one of them it was just an empty tube of 1cm-diameter. In this case, while dismantling the tube, the coke deposit was found close to the position of the former ISC front. The facts revealed show without a doubt that the THAI process has a *strong natural stability mechanism* preventing oxygen breaking-through into the horizontal section of the producer. The 2016 Wei work was done in an even larger 3-D model (36cm diameter cylinder) and brought even better proves, as the horizontal producer was located at the bottom of the cylinder; the conclusion was that this outstanding stability is ensured by both the local plugging (in and around

the horizontal producer) and the controlled gravity segregation of the ISC front.

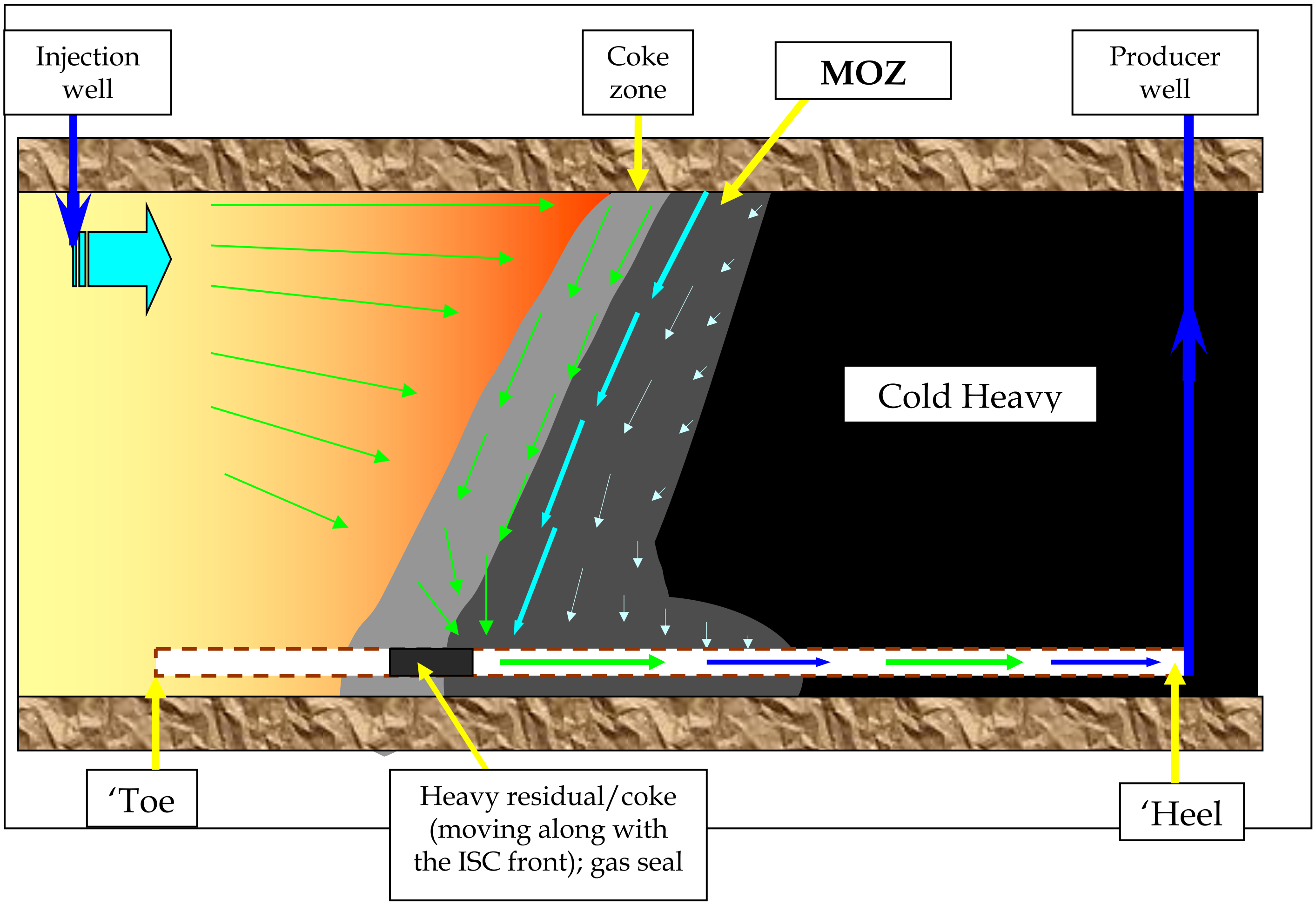


Figure 12: Stability of THAI.
MOZ = Mobile oil zone ; MOZ: Shows internal mobility (oil flowing inside the zone) & external mobility (zone moving along the horizontal well). The gas seal can be a total or partial obstruction to the flow of fluids

Knowledge gained from toe-to-heel (TTH) steamflooding laboratory tests was also useful in clarifying this aspect and other aspects related to the self-healing feature of THAI due to the existence of the coke-plug (Turta et al., 2008). In fact, for steamflooding in a TTH configuration, the self-healing mechanism of THAI process was absent; that's why only staggered line drive was found to be sound from a technical point of view, and, generally, the performance was lower in terms of sweep efficiency/ultimate oil recovery

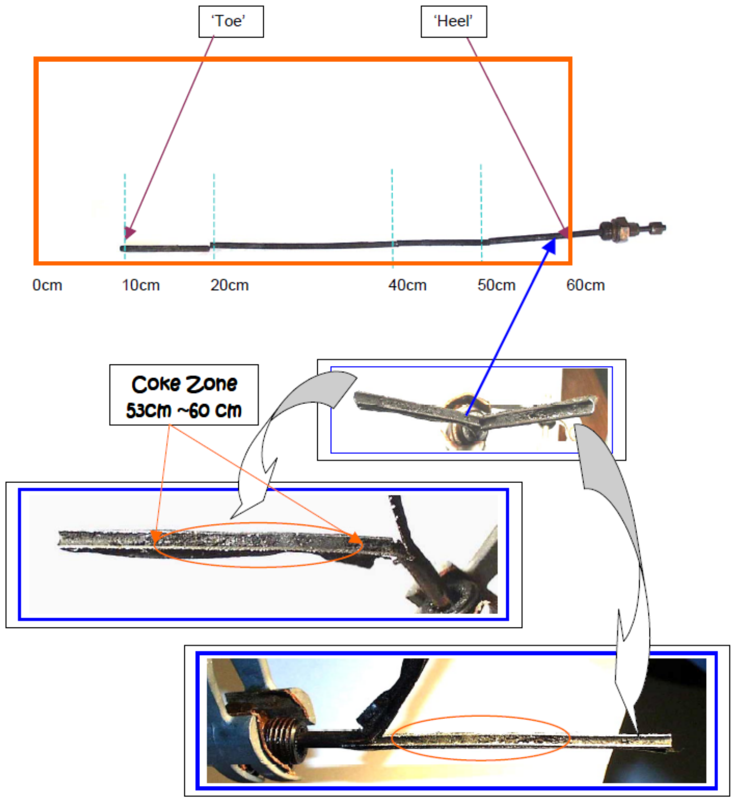
Although seen in the laboratory THAI experiments, the mechanism of coke plugging formation (in or around the horizontal production well) has not been extensively studied and fully understood. Refinery specialists put it in the category of "delayed coking, ie, accumulation of the coke from the very hot oil flowing through the reactor, in the absence of O_2 (during thermal cracking, in a batch operation)

The MOZ feature during THAI shares a commonality with the SAGD process. For THAI, another name is “Oil Bank with Internal and External Movements”. This is because, on the one hand, oil is heated and becomes mobile within the MOZ (flowing down in the borehole of HW) and, on the other hand, MOZ itself moves along the horizontal well.

The MOZ in THAI comprises the volume between ISC front and the 250^0C-300^0C region, including this region. In laboratory tests, the MOZ increased progressively, reaching up to 30-40% of the volume of the 3-D model. However, it may be difficult to scale this up to field conditions, since oil recovery is a function of both ISC front velocity and the MOZ volume. The flue gases and the steam generated during THAI may help with the over-ride control and enlargement of the MOZ.

A schematic of the catalytic THAI (CAPRI) process is shown in Fig. 17; The abbreviation CAPRI stands for **CA**talytic upgrading **PR**ocess **I**n-situ (Wood, 2018). 4.2that the latter has the horizontal section of the producer surrounded by an annular layer of catalyst. This can be emplaced, or else, pre-engineered sections can be used. This arrangement creates conditions similar to that for *a radial-in flow, fixed bed catalytic reactor,* along the horizontal well. As the partially cracked THAI oil flows through the annular catalyst layer, it is further upgraded (second upgrading), before being produced by the horizontal well.

The relative contribution of these two separate upgrading actions -as resulted from laboratory tests - is shown in Fig. 18; figures for upgrading are taken as the maximum obtained during the laboratory tests. The main CAPRI benefits are provided in Table 2. It is worth noting that the ISC process provides everything needed for upgrading, including the heat (*no external heat sources are necessary*); no other gases such as hydrogen or others are needed (injected) from outside, and the prevailing pressure of the reservoir itself seems to be enough. From this point of view, THAI can be considered as the ideal process to be adapted for in-situ upgrading.



3-D model:
length-60cm
width-10cm
height: 20 cm oil
and 20cm gas

Figure 13: Run 2002-01 (Wolf Lake oil); gas seal towards the heel. Xia, 2005

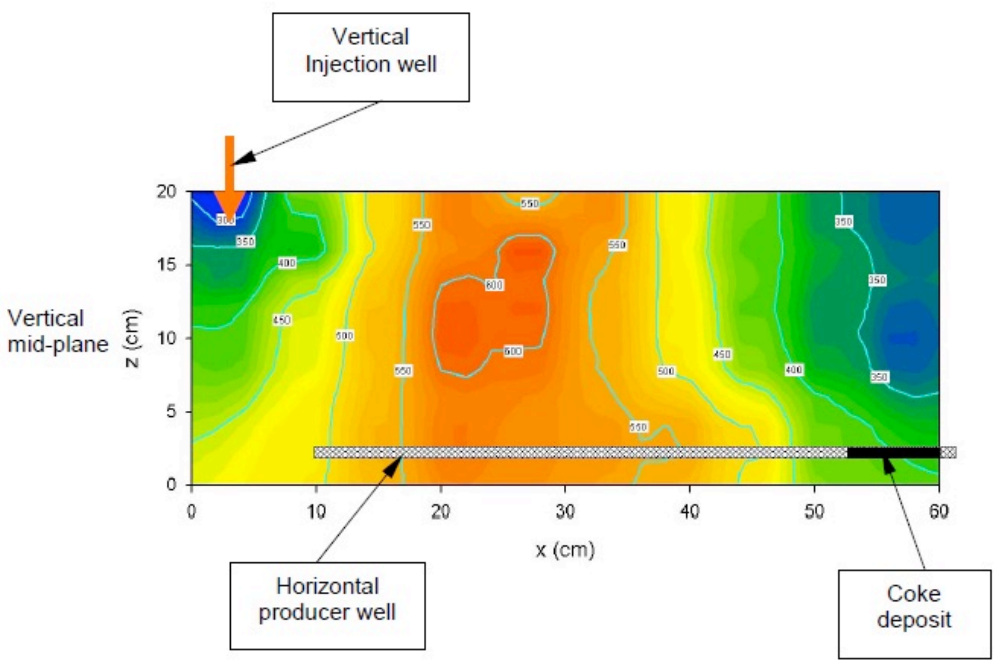
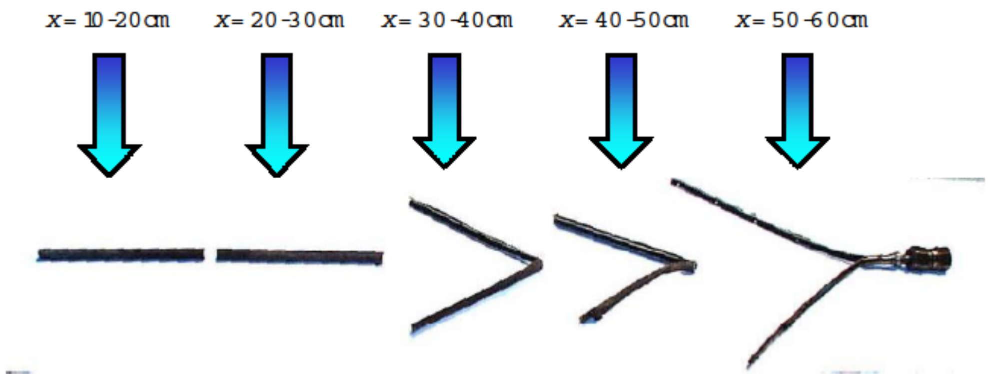


Figure 14: Run 2002-01 (Wolf Lake oil). Temperature distribution and coke plug location. Test conducted in a DLD configuration in 3-D model operated

on its side, to simulate a gas cap. Gas seal (local coke plugging) towards the heel. Xia, 2005



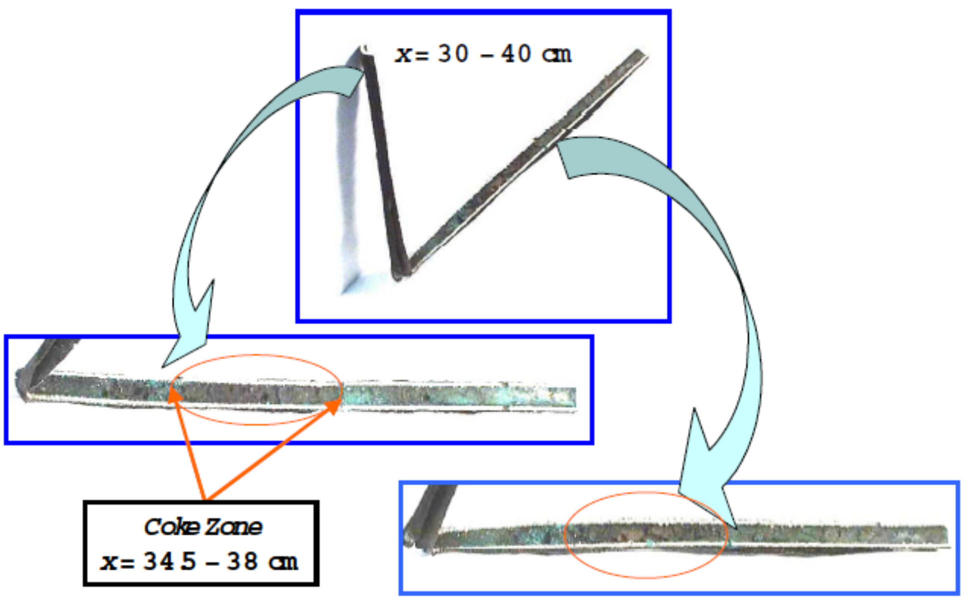


Figure 15: Run 2002-03 (Wolf Lake heavy oil). Post-mortem pictures of coke deposition in the horizontal producer. The test was conduced in a SLD configuration (2VI-HP); it was intentionally stopped mid-way. Length of cell is 60cm. For the corresponding temperature profile at the time of stoppage see Fig. 16. (Greaves, 2003, Xia 2005)

Legend: VI-vertical injector
HP-horizontal producer

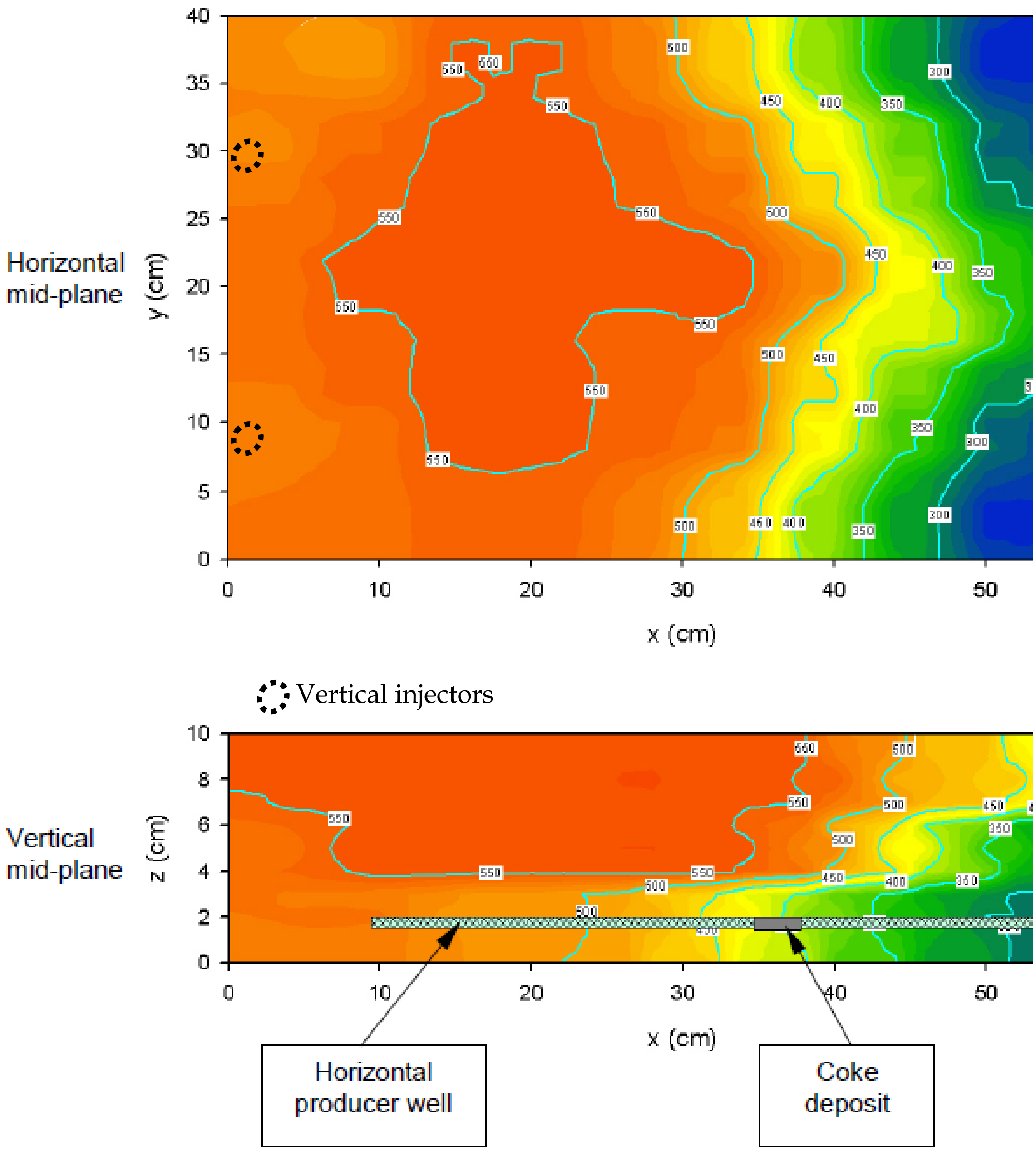


Figure 16: Run 2002-03 (Wolf Lake oil). Temperature distribution at the moment of test interruption. The test was conducted in a staggered line drive (SLD) configuration (2VI-HP); gas seal mid-way between toe and heel. Temperature distribution in the vertical plan shows that the local coke plug is located in a region having a temperature range of 350 to 450^0 C. (Greaves, 2003, Xia 2005)

Table 2. CAPRI: POTENTIAL BENEFITS

1	Add-on process to THAI, so no other special adjustments are required
2	'Toe-to-heel' combustion front propagation continually exposes fresh catalyst
3	*Partially upgrades heavy oil and bitumen* to lighter oil, in one-step reservoir process during the oil recovery process. Does not need any outside heat sources; also, produces hydrogen.
4	Oil flowing over the catalyst is partially upgraded oil, with majority of heavy ends removed, and significant reductions also in sulfur, Ni V and N_2
5	Standard refinery catalysts used – fresh, spent, regenerated, **f**luid **c**racking **c**atalyst (FCC) can be used. Improved catalysts could enable upgrading to light oil (>30^0 API)
6	Substantially reduces the cost of surface upgrading plant

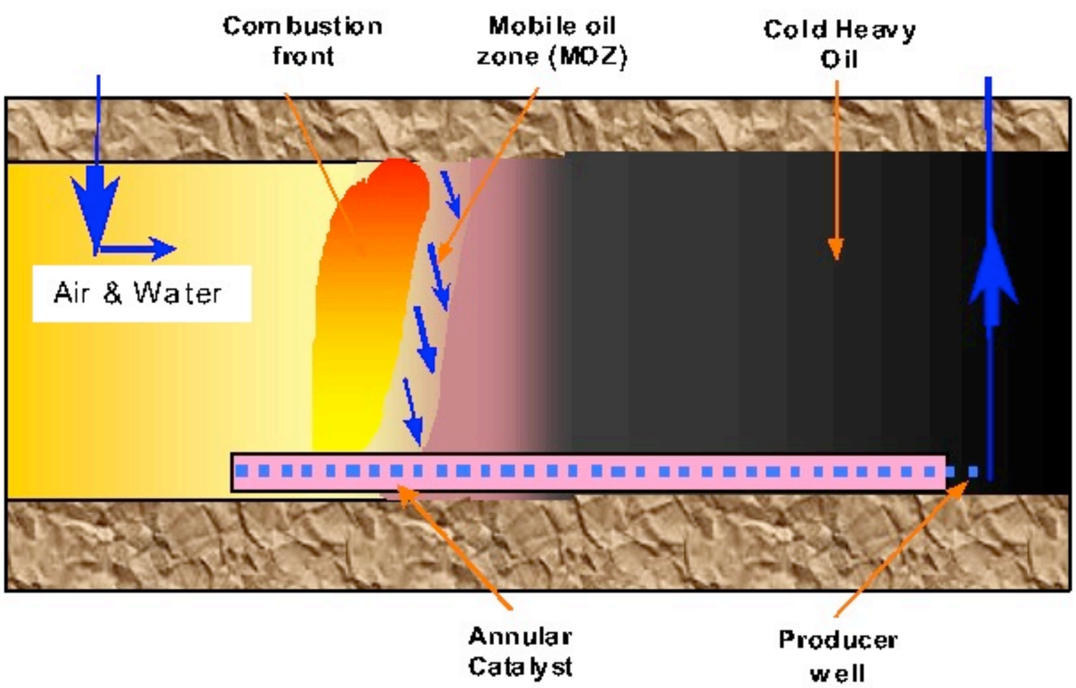


Figure 17: Schematic of the CAPRI process (horizontal producer - a sui generis radial flow catalytic reactor).

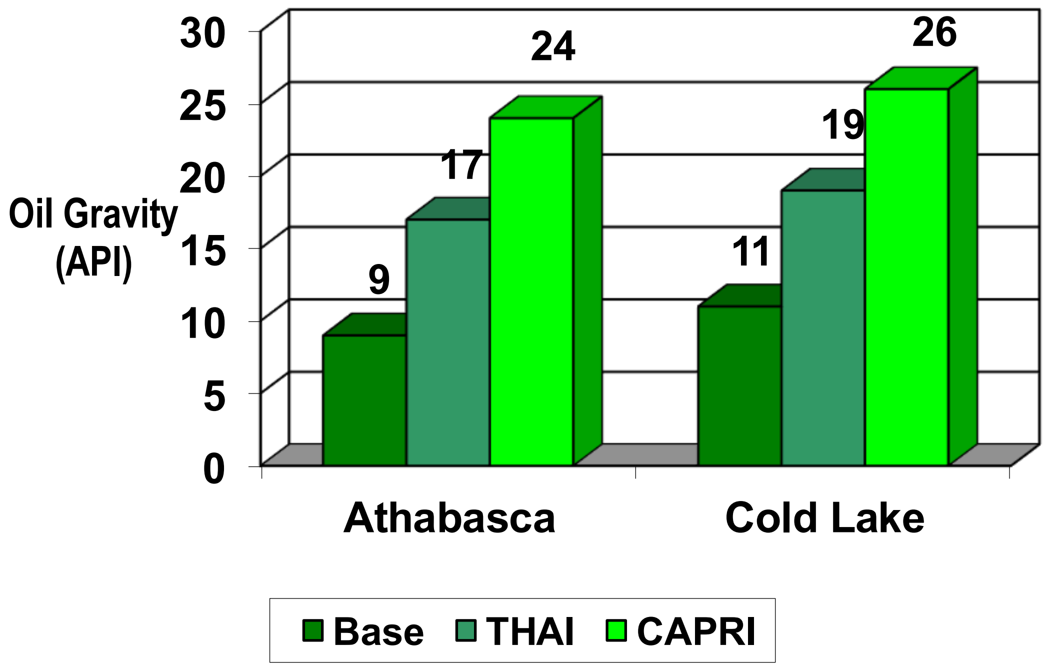


Figure 18: In-Situ Upgrading Potential of THAI™ and CAPRI™ (Courtesy of Computer Modelling Group)

Note: The values for THAI and CAPRI represent maximum values obtained towards the end of the laboratory 3-D tests

4. STATUS OF TECHNOLOGY; KEY LABORATORY TEST RESULTS

THAI and CAPRI processes were extensively tested in a low-pressure (60 psi maximum rating, but limited to 2 bar) laboratory 3-D model. It consisted of a rectangular stainless steel cell of 0.6 m x 0.4 m x 0.1 m. The 3D cell, containing oil/water saturated sand was operated at a near-adiabatic condition by wrapping several heating tapes around the cell. The set up used for the investigation of THAI/CAPRI processes is shown in Fig. 19. *It is important* to underline the fact that to initiate the ISC process the **whole start-up region,** adjacent to the inlet face of the 3-D model (Fig. 19) was heated to 300-400^0 C, and in some cases to even higher temperatures, using electrical coiled heaters (embedded in the start-up region), or by injecting hot gases, or superheated steam. Sustained ignition was not achieved, unless the stored heat in the inlet zone (start-up region) was sufficient to prevent excessive heat losses from the combustion zone. In this way, the initial ISC front was created, and this was an important feature affecting the subsequent development/propagation of the burning front/lateral sweep. Additionally, it must be mentioned that during this initial phase of hot communication/ignition there was a significant accumulation of heat in the inlet zone of the sandpack, probably accounting for 10-20% of the total heat generated during the process. There was no attempt to create this hot communication by injecting saturated steam, as it would be done in the field.

An illustration of the generation of the ISC front, its advancing downwards, its anchoring to the toe, and then the propagation from toe to heel within the first portion of the horizontal section for the THAI process applied in a direct line drive (DLD) configuration, was provided in Figure 9a of the previous chapter.

In most of the tests, Wolf Lake heavy oil (viscosity of around 50,000 cp) and Athabasca oil sands (immobile bitumen) were used. Some tests were also conducted with less viscous oils, with viscosities as low as 10 cp. However, these low oil viscosity tests were generally not successful; the minimum oil viscosity for a successful THAI test was ~ 300 cp (Clair oil).

4.1 THAI

More than 70 THAI tests on heavy oil/bitumen were carried out, both in dry and wet combustion modes. It was seen that THAI performed considerably better than the classical (conventional) in-situ combustion, conducted using vertical wells (Greaves, 2001). These tests showed that for the Wolf Lake oil, the ultimate oil recovery was upwards of 75% and the propagation of the front was not associated with excessive gas override. All of the tests exhibited a 'controlled gas override ', such that oxygen gas breakthrough never occurred, ie, all of the tests were entirely stable.

Besides, significant amounts of thermal upgrading took place, and the viscosity of the produced oil was reduced to as low as 50 cp, and sometimes even to 20 cp; some hydrogen was always noticed in the produced gas. Simulation of the THAI process showed that during the operation ISC front is quasi-vertical but slightly tilting forward (Xia, 2005), suggesting a stabilized mode. A feature of this process is the ease of control as its propagation path is well established (along the horizontal section of producer).

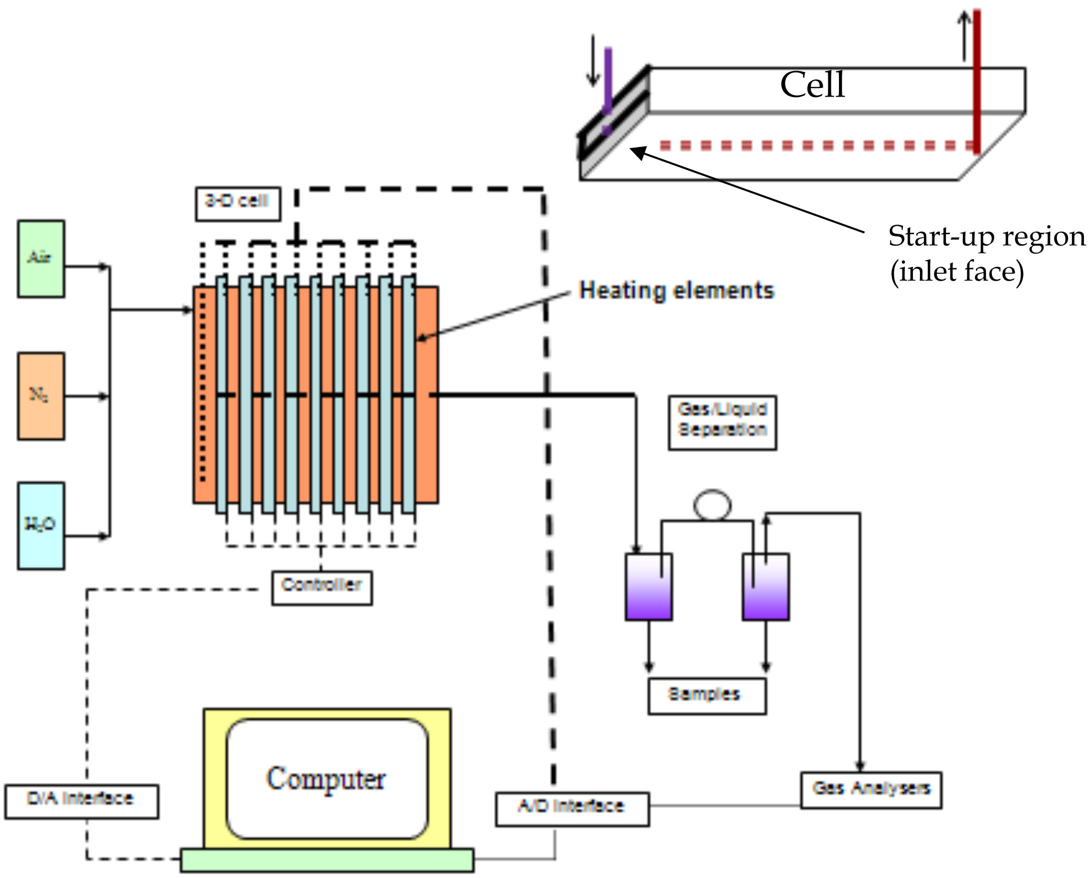


Figure 19: Laboratory set up for THAI/CAPRI testing. The inset shows the start-up region for a direct line drive (DLD) configuration.

Fig. 20 shows the variation in effluent gas composition during a dry ISC test conducted at different air fluxes; O_2% was in the range of 1.5-4%, slightly increasing with the air flux, while CO was relatively high (2-4%) at high air fluxes. Fig. 21 provides oil rate variations for a THAI test using Athabasca Oil Sands (virgin oil sand); it shows that the oil production starts early, and it is relatively even during the test; it slightly increases at the beginning of wet combustion application. Fig. 22 shows variations in upgrading for the Wolf Lake produced oil during the dry and wet ISC test; usually, at the beginning of the test, there is a short period without upgrading, and then upgrading gradually increases over time. Upgrading for dry and wet combustion does not significantly differ; it is slightly better for the wet combustion tests.

Most of the laboratory experiments involved only dry ISC; in the case of Athabasca bitumen wet combustion showed some instability, while for Wolf Lake oil these instabilities were not observed. Actually, the past experience with conventional ISC suggested that the wet combustion performs better with heavy oils with higher mobility.

Generally, the THAI tests showed some hydrogen (H_2) production; in different tests, the percentage of H_2 in the combustion gas was in the range of 1% to 2 %.

Fig. 23 provides variations in upgrading for Athabasca produced oil during THAI and CAPRI tests; again, at the beginning of the tests, there is a short period without upgrading and then upgrading increases with time; the upgrading for CAPRI is always higher than that for THAI.

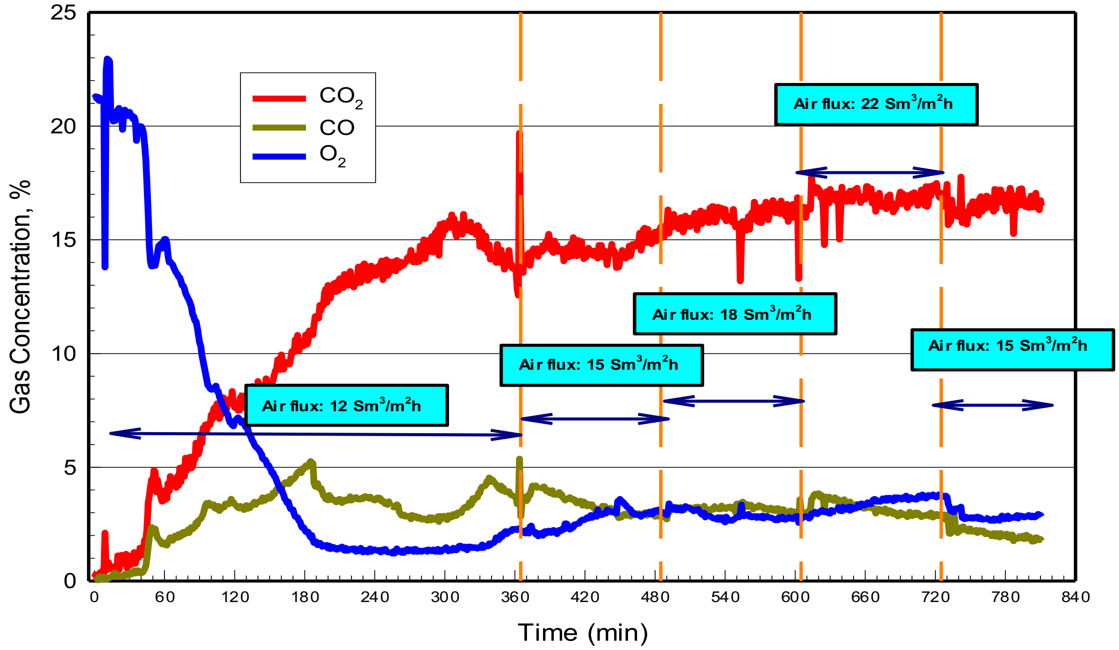


Figure 20: THAI: Variation of produced gas composition in a THAI test conducted with Athabasca sand in a dry mode, at different air fluxes. (Run 2000-04).

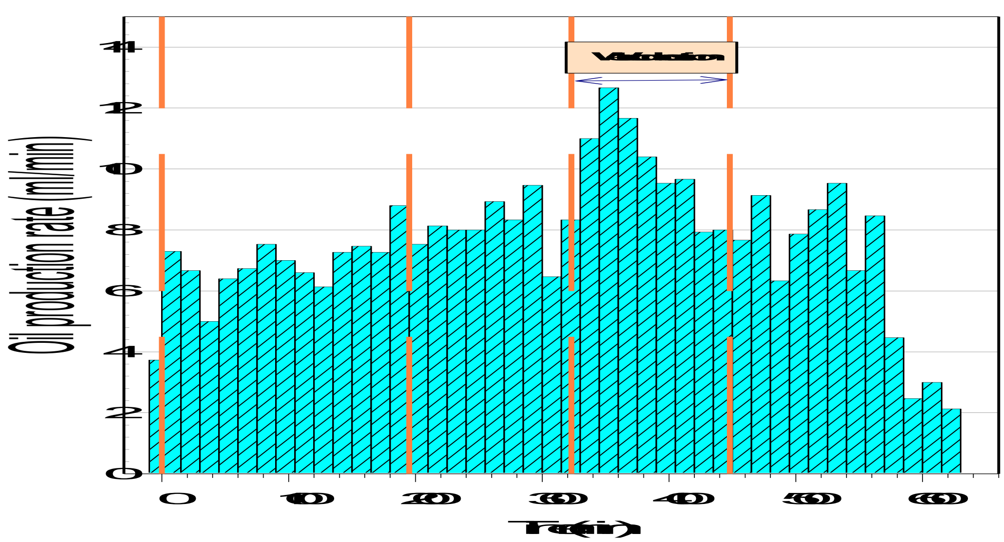


Figure 21: Oil production rate for Athabasca tar sand bitumen THAI test.

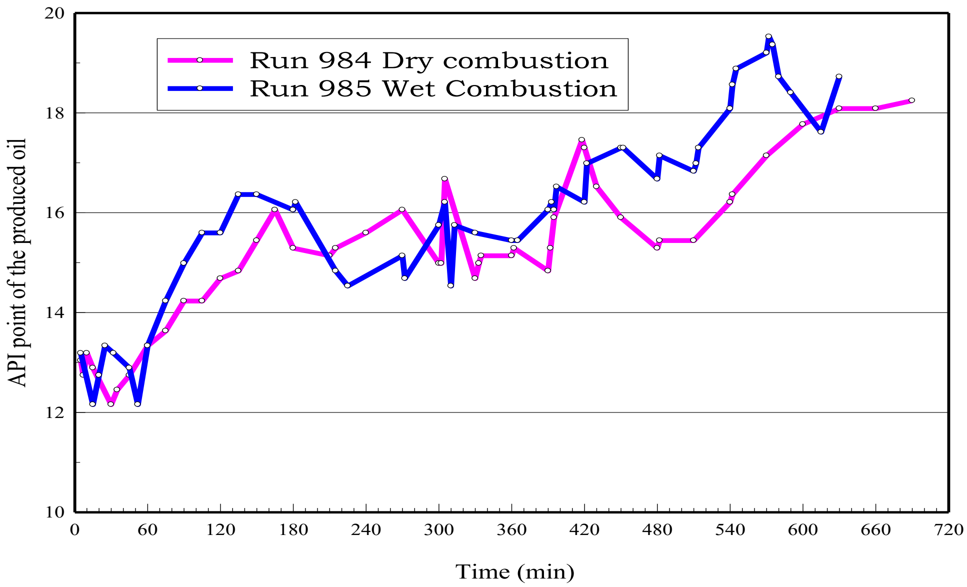


Figure 22: Variation of the upgrading during dry and wet THAI test using Wolf Lake oil; viscosity 50,000 mPa.s.

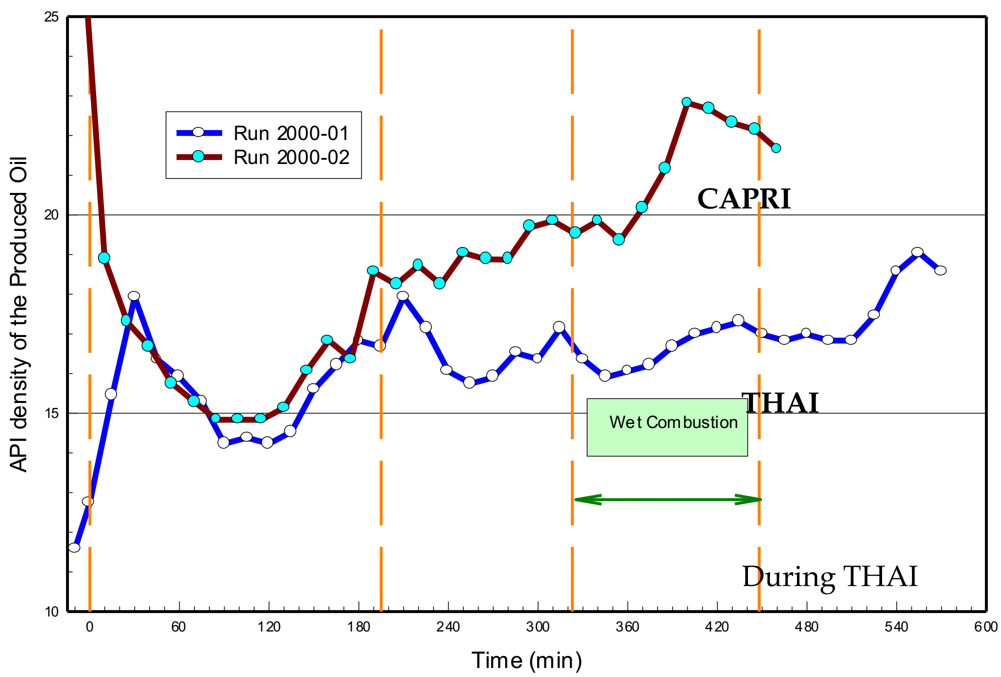


Figure 23: Upgrading of produced oil in THAI and CAPRI processes for Athabasca tar sand.

Vertical mid-plane and horizontal mid-plane temperature profiles for an Athabasca tar sand THAI tests are shown in Fig. 24. The isotherms at 300 min (5 hours) clearly show that the ISC front is tilted forward, and the lateral sweep is very good. The good lateral sweep efficiency is *considerably* helped by the fact that the ignition phase involves the heating of the inlet region of the sandpack to about half-way to the toe of the horizontal well (half of the so-called start-up region), to a temperature of around 500^0C. This can be considered equivalent to an extensive communication phase between the two vertical wells used in a field THAI module (see Fig. 7a.

A summary of the THAI laboratory tests is presented in Table 3. It can be seen that tests involved both oil sands as well as conventional heavy oils. The oil layer thickness was varied (3 values) while a gas cap was introduced in one test. A heterogeneous 3-layer system was also used to show that stratification effects are attenuated. In all of the tests, **a**ir-**o**il **r**atio (AOR) was in the range of 1,000 sm^3/m^3 to 2,000 sm^3/m^3, with slightly smaller values for the wet ISC process.

A schematic of commercial application of THAI is shown in Fig. 25. The first row of air injection involves only vertical wells. The rest of the pool area is covered with horizontal wells, which are provided with pilot wells. A typical module of 1000mx40m =4 ha is shown here for illustrative purposes. Once the ISC front reaches a point close to the heel of the horizontal wells, the vertical injectors are closed, and the first row of horizontal producers is converted to air injection (to this effect using the pilot wells), while the second row of horizontal producers is put into production. This way, the entire reservoir is swept, starting from the uppermost part to the lowest part. In some cases, an edge water aquifer may exist; in this case, the last row of horizontal wells may be located at some offset distance from the aquifer (and a little bit further from the bottom of formation) in order to avoid excessive water production.

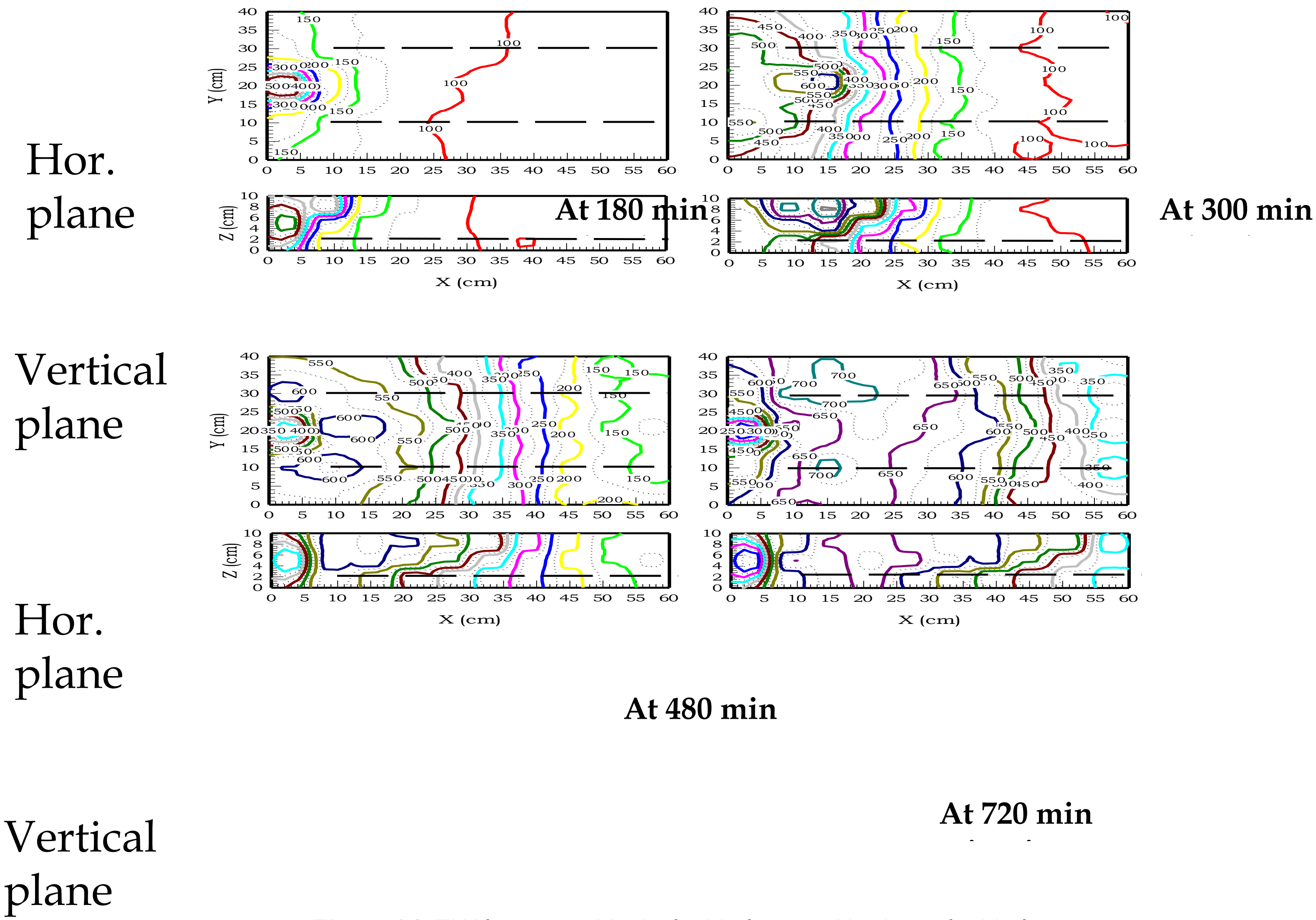


Figure 24: THAI process. Vertical mid-plane and horizontal mid-plane temperature profiles for Athabasca tar sand Run 2000-04, conducted in a staggered line drive (SLD) configuration (VI2HP).

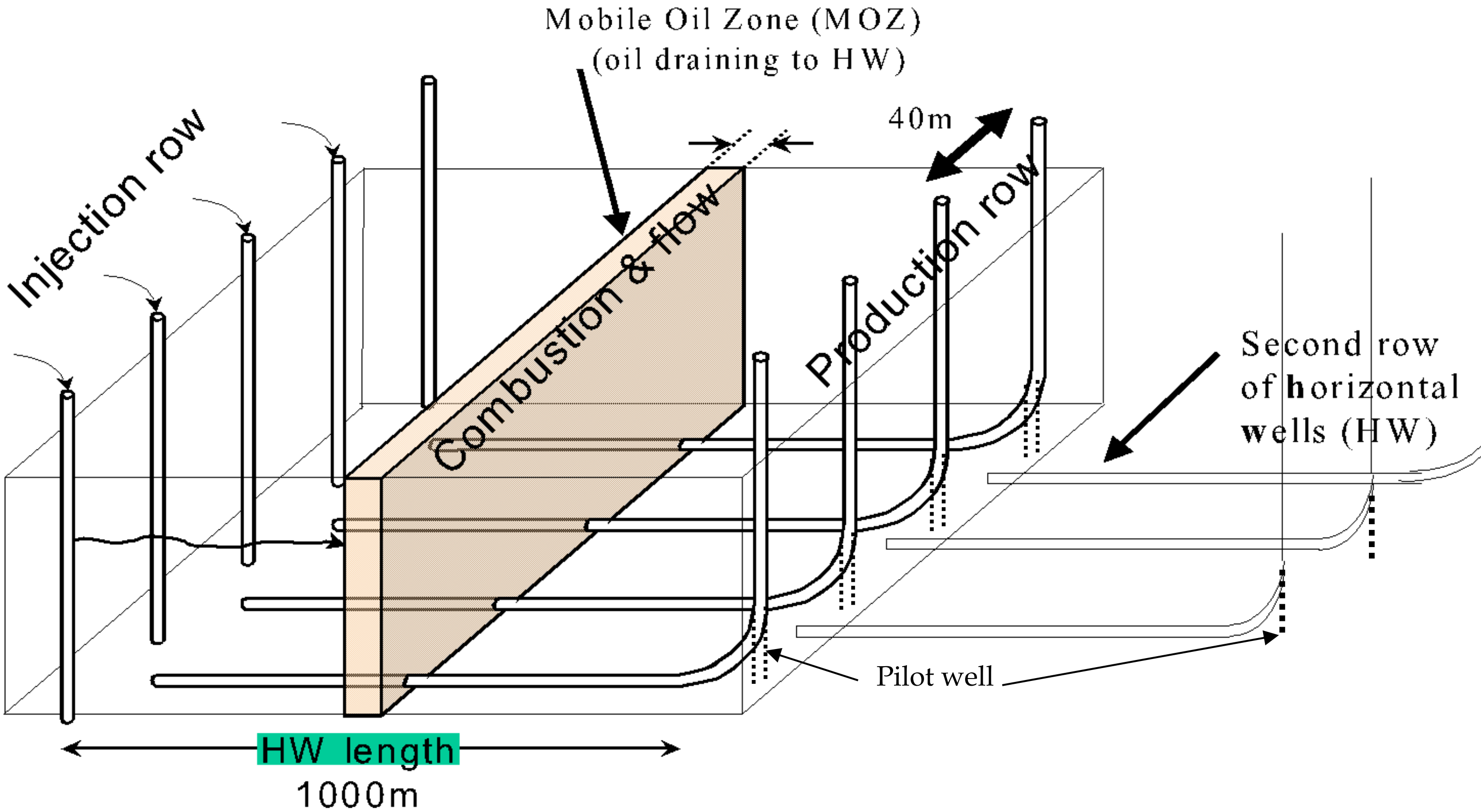


Figure 25 : Commercial Operation of THAI (Modified after M. Dusseault)

Table 3. Summary of 3-D THAI experiments at the University of Bath

Heavy Oil	Wolf Lake heavy crude oil, 10.5 °API
	Lloydminster heavy crude oil, 11.9 °API
	Athabasca Tar Sands Bitumen, 8 °API
	Clair West of Shetland, 19.8 °API (viscosity 300 cp)
Combustion mode	Dry combustion
	Wet combustion: WAR= 0.3 to 1.1m³/1000m³
Air flux	9 Sm³/m²h to 22.5 Sm³/m²h
Well configuration:	Both staggered line drive (SLD) and direct line drive (DLD)
Well configuration	DLD: VIHP ; *SLD*: 2VIHP, VI2HP* ; Others: HIHP, HI2HP
Oil layer thickness	10 cm, 20 cm (with a gas cap) and 40 cm
Primary recovery	Heavy oil and tar sands bitumen
Secondary recovery	Post-steam application
Sandpack type	Homogeneous
	Heterogeneous
	Original Athabasca Tar Sands

Legend: HI=horizontal injector; HP=horizontal producer; VI=vertical injector
* In a commercial operation 2VIHP is equivalent to VI2HP

4.2. CAPRI (CAtalytic upgrading **PR**ocess **I**n-situ

In refineries, heavy oil upgrading is performed in special upgrader process units; upgrading may involve either cokers or hydrocracker, or both. The upgrader feedstock is usually heavy oil distillation residue, usually referred to a VGO (Vacuum Gas Oil), which is generally more than 35%-50% of the original crude. Upgraders involve huge investments and are built for an enormous capacity, of at least 100,000-200,00bbls/day, costing around $5-8 billion. Upgraders may become uneconomic when the differential between light and heavy oil prices is small. For that reason, several alternatives for field upgrading have been explored, and they also targeted the reduction of the size of the upgrader in order to limit capital requirements.

There are two ways to upgrade heavy oil: (i) carbon rejection by *thermal cracking* (delayed coking), and (ii) hydrogen addition by hydro-processing/hydro-cracking.

The first proposal for upgrading directly in the field environment (as a surface upgrader integrated into overall field development) is the HTL (heavy-to-light) process of Ivanhoe Energy, which requires a minimum oil capacity of 10,000-15,000bbls/day, in order to be economical. This process uses pure sand for the coke support, and burning of the sand for its regeneration and also to provide heat–for thermal cracking. Upgrading of 5 ^{0}API was obtained (Koshka, 2008 and Silverman, 2011) for two oils of different viscosity (700 and 4,000mPa.s). The oil viscosity decrease was in the range of 11-34 fold. The process was tested in a small scale field-pilot (commercial demonstration facility capacity of 1,000 bbls/day); the process requires a vacuum distillation tower and a thermal cracking reactor, in which only the residue from the distillation tower is processed. The final product still needs some refining by adding hydrogen, but this can be accomplished later on, in the refinery.

So far, an in-situ hydro-conversion/hydro-cracking process has not been tested in the field, as the use of hydrogen is considered to be too risky. A proposal to use this technique during the flow of hot oil in the vertical tubing during thermal EOR applications was made, but it has remained at the concept stage (University of Calgary patent).

The first proposal for underground (in-situ) upgrading of was made by Weissman et al. in 1996; they were the first to investigate the upgrading **not only of the vacuum distillation residue (like in the surface upgraders) but also for in-situ upgrading of raw bitumen/heavy oil.** The effect of up to 50% water cut was found not to be harmful to the upgrading efficiency, while the Co-Mo and Ni-Mo catalysts were found to have similar activity. Based on this idea, some laboratory combustion tube tests were conducted *simulating the use of external heat sources along with an ISC process* in which only vertical wells were used (Weissman, 1996). For an oil of 500 mPa.s viscosity, at 325 ^{0}C, upgrading of 7 ^{0}API was achieved, while the percentage of CO in the exit combustion gases was reduced dramatically, from 2.8% to 0.05% (Moore, 1999).

With the advent of horizontal wells, the THAI process was developed as a short-distance oil displacement process, almost totally preserving oil upgrading achieved within the reservoir, immediately ahead of the ISC front. A further small step – emplacing an annular layer of catalyst around the production casing - was necessary to subject the oil to a second stage of upgrading, just during the flow of oil into the borehole. With this "completion improvement", a step-change technology for the underground upgrading was born. This new process is known as catalytic THAI or CAPRI. *Neither the first upgrading (by THAI) nor the second one (by CAPRI) requires any external heat source for the upgrading, while the process is fully continuous.*

More than 30 CAPRI laboratory tests were carried out, both in dry and wet combustion modes. It was observed that, except for the difference in upgrading, CAPRI performed almost identically to THAI (Xia, 1999), i.e., there was the same pressure differential, same oil production dynamics and ultimate oil recovery. No supplemental flow resistance was noticed. This clearly shows that CAPRI can be considered a THAI 'add-on' process; it is a THAI enhancement process.

Fig. 23 shows the variation of upgrading for Athabasca produced oil during THAI and CAPRI tests. The upgrading achieved with CAPRI is always better than that with THAI alone. As seen from Fig. 23 the maximum upgrading by combined THAI and CAPRI in the laboratory is more than 14 API, while full upgrading requires an increase of around 20 ^{0}API .

4.3. Limitations of the THAI Laboratory Testing

A 3-D combustion cell model is of limited size, owing to reasons of cost and safety. It nevertheless is one of the best experimental techniques that can be utilized to gain insight into the performance of the THAI process. The height of the model (oil layer thickness) was 10cm in the U of Bath tests. However, later on, in China, the model height was increased to 15 cm, and this allowed a more in-depth observation of the ISC front propagation, mainly during the first stage of the process (Liang, 2012). Unlike a combustion tube model (which has very thin walls ~1.5mm), the walls of these 3D combustion cell models are ~3mm. Thicker walls of the 3-D cell promote some artificial heating ahead of the ISC front due to the high thermal conductivity of the metal walls. This causes some slight distortion in the temperature distribution. Additionally, some distortion is also caused by the imperfect heat compensation applied via the heating tapes, which try to keep the temperature at the wall about 20-30 ^{0}C lower than the average temperature in that segment. Heating tapes do not discern between the heating of the "ceiling" and heating of the "floor" of the model (See Fig. 19). Generally, the ceiling" has a higher temperature than that of the "floor", due to the leaning-forward feature of the THAI process. Due to this temperature difference, the heating tapes will usually introduce a small excess heat at the bottom of the model, while allowing some heat losses from the upper part of the model. Thus, there is a slight leveling of temperature in the vertical direction, which may slightly reduce the leaning-forward of the combustion zone. Simple heat conduction calculations show that there is still a heat loss from the cell of the order of 10 %. It is interesting to observe (Fig. 24) that even after 5 hours of operation (by the middle of the sandpack) a relatively 'cold zone' or undisturbed zone exists in the sandpack (< 100-150^0 C. If the axial wall-heating effect was significant, this condition would not exist and the 'cold zone' (original or virgin oil) would not be preserved.

One limiting factor of the 3-D model is that, being relatively small (there is only a distance of a few centimetres between the vertical injector and the toe of the horizontal producer), the communication phase prior to ignition is not a very significant operation in the laboratory, whereas, in the field, ***it is very significant***. The implication from the experiments is that communication between injectors is vitally essential to create an initial large thermal front. Unlike the field situation, no steam injection is applied in the laboratory tests to create communication between injectors arranged in an SLD configuration. Gas communication is implicit in the 3D laboratory tests, because, in mixing the Athabasca Oil Sand (received in sealed pails, but usually in the lumped form, it was then homogenized in a cement mixer), and this inevitably introduced some air (typically around 5 % saturation– creating a gas communication path). Another point is that the ignition operation *is considerably more extensive*, compared with what might be achieved in the field. Heat (either electrically or hot gas) is used to raise the temperature of the start-up region/the inlet region of the sandpack (between the vertical well/inlet face and the toe of the horizontal producer) to facilitate and sustain ignition. If an electrical coil (imbedded into the start-up region of sandpack) is used, it may raise the temperature to as high as 400^0 C, and in some cases, to even higher temperatures. This pre-heating introduces some 10%-20% of the whole heat generated during ISC front propagation through the sandpack. **The heating of the inlet zone of the 3D cell in THAI simulates the creation of the broad initial burning surface, which constitutes a vital, and necessary pre-condition for the success of the THAI process. However, it is considerably more challenging to achieve that in the field conditions.**

Given the limitations factors of 3D cell combustion experiment discussed above, the results should be considered partially representative of the field scale situation. The reservoir engineer, nevertheless, has to use physical model results (preferably 3D) to innovate a field design, beginning with a pilot to gain further insight into the process and then incorporate this knowledge to make careful, detailed numerical simulations, in order to create a robust engineered field process.

In general, due to the small sizes of the laboratory model, the sweep efficiency of the burning front is a lot higher in the laboratory (52-68%), as compared to the field. A comparison of THAI laboratory tests conducted by three independent organizations gave ultimate oil recovery (UOR) in the range of 70%-80% by U of Bath, 60-70% by Alberta Innovates Technology Futures (AITF) and 56-60% by Petrobank; the latter Petrobank 3D experiment did not use heat compensation, only insulation and there was much greater heat loss.

Results from the 3D experiments did not allow to make a very rigorous performance comparison between direct line drive (DLD) and staggered line drive (SLD) arrangements. There are several limitations affecting performance and upgrading due to the small size of the 3-D model. Although the experiments may only be partially representative of the field scale situation (not necessarily capturing all of the detail), they do, nevertheless, provide a realistic basis for the experienced engineer to create an effective full-scale design for a reservoir process. We anticipate that in the field, the difference in performance between SLD and DLD configurations will be much higher than in the laboratory experiments. ***Selection of SLD over DLD is a crucial decision during the design stage***

4.4. **Toe-to-heel Waterflooding (TTHW) and Toe-to-Heel Steamflooding (THSF)**

In this section, we present two new processes, which are relatives of THAI process, namely Toe-to Heel Waterflooding (TTHW) and steamflooding in a TTH configuration. Unlike THAI, both of these processes do not exhibit the self-healing feature described previously, (local plugging with coke, to prevent channeling of air through the horizontal section of horizontal producer). While the TTHW has been subject to limited field testing, steamflooding in a TTH configuration is still at the laboratory testing stage. In the following, we present only those results which can help in a better understanding of the THAI process.

TTHW: Initially, it was developed based on Hele-Shaw lab tests, but later on, 3-D TTHW laboratory tests showed good results, mainly for application to thick reservoirs (Turta, 2006). From the very beginning, TTHW was proposed to be conducted in a staggered line drive (SLD) configuration, and both vertical and horizontal wells could be used as injectors. When using horizontal wells as injectors, their horizontal sections should extend far away from the toe of producers in order to preserve the SLD feature (and *avoid excess water channeling)*. This was validated in the field testing of the process lasting more than 5 years, in an intermediate- heavy oil reservoir (Medicine Hat Glauconitic C). Pairs involving horizontal injectors arranged in a DLD configuration did not perform very well; their performance was significantly weaker than that of pairs using vertical injectors (which were always in a SLD configuration) (Turta, 2010). Another interesting development was *laboratory testing* of the concept of progressive blockage of the toe region of the producer; this led to a reduction of water cut (by a few percentage points) each time the blockage was extended; four consecutive progressive blockages increased ultimate oil recovery from 29% to 33%, (Turta,2008).

Steamflooding in a TTH configuration (Toe-To-Heel Steamflooding - TTHS): It was tested in a laboratory set up for oils with some initial mobility at reservoir conditions (oil viscosities less than 15,000 mPa.s). A classic SLD configuration with two vertical injectors and one horizontal producer in-between (2VIHP) was used (Turta, 2009)

Generally, the limitations presented previously for the THAI laboratory tests apply here as well; besides, no external heating tapes were used, and for this reason, the heat losses from the model were excessively high, leading to an excessively high steam-oil ratio (SOR).

The TTHS tests in the laboratory involved a laborious procedure for establishing a cold and then a hot connection between vertical injectors; the hot communication was achieved by a two-step steam injection (in both the vertical wells). In the first half of the TTHS test (up to a SOR of 4-5), an oil recovery of approximately 18% was obtained, using a simple *steam+nitrogen* injection; under the same conditions for a *steam-propane* injection, an oil recovery of approximately 55% was relized. The addition of up to 6% by weight of propane in the steam dramatically accelerated the oil recovery (Figure 26). *The laboratory tests also showed that in the successful tests, a tilting forward of the displacement front occurred (like THAI); otherwise, a steam channeling was very pronounced.* The most significant observation was that when going from simple steam injection to steam+nitrogen and to steam+propane, the steam channelling through the horizontal producer decreased dramatically (Turta, 2009).

Implications: In *a field operation of THAI*, steam can generally be used to create the hot communication, first between the injectors and then with the toe of horizontal producer. The conclusions from the laboratory and simulation studies of TTH steamflooding can also be used for the design of the preheating phase (PIHC) of the THAI process.

Final remarque on THAI design and operation: For the THAI process development, the design of the start-up region and the pre-heating/communication phase are *__extremely important,__* as it prepares the reservoir for the next phase, and it has to be done in such a way that:

- Assure the anchoring of the future ISC front
- Achieve a forward-leaning ISC front as early as possible
- Leads to a good sweep of the combustion front (maximum) broad lateral extent.

The ultimate success of the THAI process will depend strongly on how the initial hot communication is achieved and, subsequently, how strong is ignition, including its deployment along the whole, previously-made linear communication path.

It needs to be stressed here that pre-heating/heating of the horizontal producer should be minimal; only to allow for good flow of oil and to keep the well clear. More details on this important topic can be found at the beginning of Chapter 11.

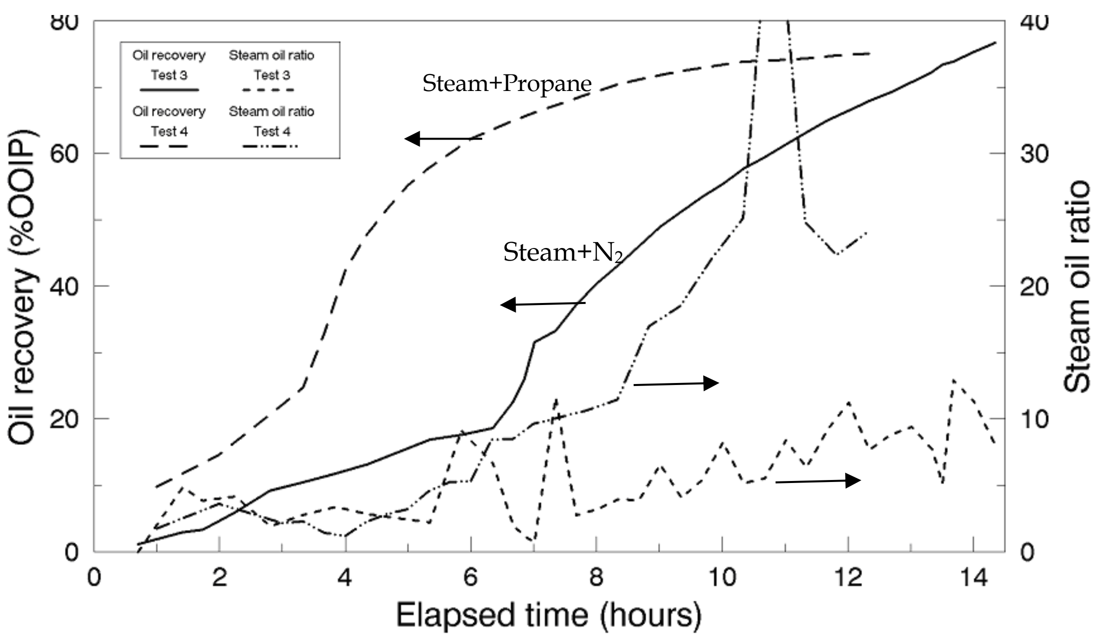


Figure 26: Oil recovery for the steam+nitrogen and steam propane injection in a toe-to-heel (TTH) configuration. Steam+propane injection leads to a very dramatic acceleration of oil recovery (Turta, 2009)

5. STATUS OF TECHNOLOGY: SIMULATION OF THE PROCESS

5.1. Introduction

Generally, simulation (either analytical or numerical) is essential for the design of the process at the field conditions. For conventional ISC a series of models are currently available. There are also a few predictive models, such as the Nelson and McNiel one, which is an empirical model. For THAI process, adequate analytical models have not been developed so far (Kulkarni, 2004).

Moreover, the analytical models developed for conventional ISC are applicable for radial systems, which can be used as qualitative models for THAI. The most reliable analytical model for temperature distribution in a radial system is provided by Chieh Chu and Thomas models, 1966 (Sheng, 2013). However, as far as the THAI process is concerned, detailed numerical simulation is the only way to explore all of the various critical factors affecting its design and operation.

For conventional ISC, (Gutierrez, 2012) has recently provided a comprehensive review of the literature pertaining to the simulation of conventional experiments (combustion tube) and, importantly, set out a workflow plan to develop a simulation model, comprising three steps; namely, the development of the reaction and fluid models, based on history-matching of quantitative kinetic experiments (e.g., RTO - ramped temperature oxidation tests), validation by history-matching combustion performance (e.g., combustion tube tests), and finally some reservoir simulation forecasts at both the experimental and field scales. However, for a forecast at the field scale, the simulation model needs to be history-matched against field data.

5.2. University of Bath (U of B) Simulation of the THAI Process

5.2.1 Laboratory THAI Experiments

Results from 3D combustion cell experiments with virgin Athabasca Oil Sands were the baseline starting point for an accurate STARS (Computer Modelling Group) simulation model of the THAI process at the laboratory (experimental) level (Greaves, 2012).

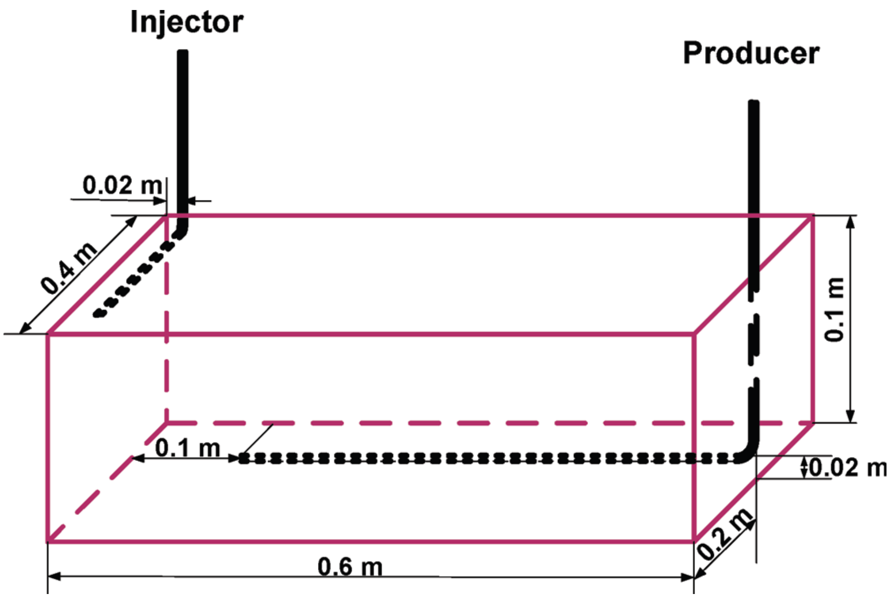
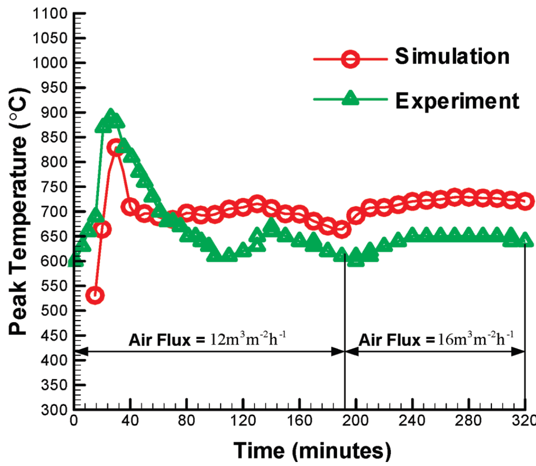


Figure 27: Physical dimensions of 3D Combustion cell; DLD configuration (horizontal injector-horizontal producer-HIHP)

The well arrangement depicted in Fig. 27 (HIHP), is a hybrid between staggered line drive (SLD) and direct line drive (SLD) configurations. In the field, SLD would typically consist of two vertical injectors and a single horizontal well (2VIHP) in-between. Therefore, the reader has to exercise caution when interpreting the results obtained; a rigorous evaluation of the difference has not been made. Consequently, the results should be considered only directional.

Phillips et al. 1985 kinetics was used to model the thermal cracking process, without any adjustment. **L**ow-**t**emperature **o**xidation (LTO) is not accounted for in this model, and it was not considered necessary to include because THAI operates predominantly in the **h**igh-**t**emperature **o**xidation (HTO) mode. The predicted accuracy of several dynamic parameters for dry combustion, including the oil production rate, peak combustion temperature profile and level of CO_2 in the produced gas was either good or very good. Robust stability in these experiments was achieved, despite the very high air injection rates used. The air injection flux was six to ten times larger than what would typically be employed in the field.



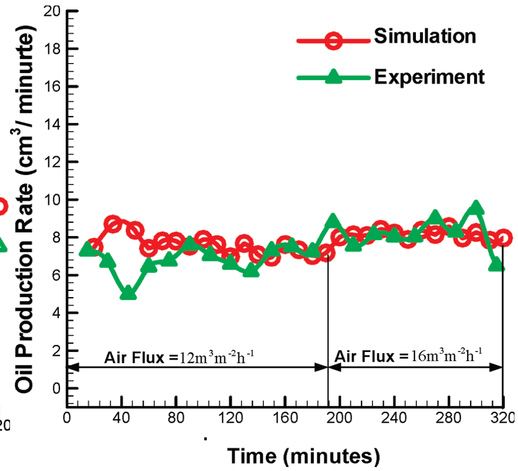


Figure 28: Peak Combustion temperature **Figure 29: Oil production rate**

Figure 28 and 29 show the simulated and experimentally results in the THAI 3-D test. The predicted peak combustion temperature (Fig. 28) was 50-100 ºC above the experimental value for an air injection flux of 12 m^3 $h^{-1}m^{-2}$, and 70 ºC above, at the higher air flux of 16 $m^3h^{-1}m^{-2}$. The numerical model used default parameters for heat loss, which may not have exactly replicated the actual heat losses in the experiment. There is a close agreement between experimental and predicted oil production rates, except for the initial period following the ignition. This is usually a good indicator of the dynamic capability of the model.

However, the model could not rigorously simulate the trend of the produced oxygen following a sudden change in the air flux (Fig. 30), which suggests that the kinetic parameters require further tuning. There is a good agreement for the first 190 minutes, but when the air injection flux is suddenly increased by 33 %, there is a very long delay in the "simulated" response. The discrepancy points to a lack of dynamic capability in the numerical model. Another explanation is that it could have something to do with the amount of fuel deposited (Fig. 31); in the center of the sandpack (vertical mid-plane), the coke concentration is around 0.006 to 0.012 gmols/cm^3 (72-144 kg m^{-3}). These apparently high fuel concentrations, compared with established values in the field (less than 50 kg m^{-3}), could be partly responsible; it seems that there is an over-prediction of fuel by the currently-tuned Phillips thermal cracking kinetics model. This seems to be confirmed by the fact that although the predicted temperature profile in the sandpack appears to be quite normal (Fig. 32), the computed combustion front velocity for both the lower and higher air flux regions, however, is too low compared to what is expected (0.03 cm h-1)]. More work is needed to fully clarify these aspects, mainly if the higher fuel deposit in THAI is an artifact or a real feature of THAI process.

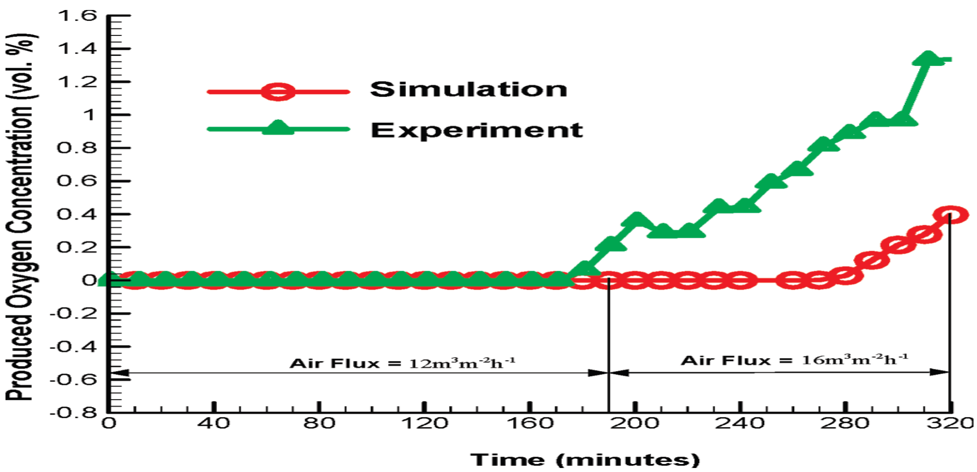
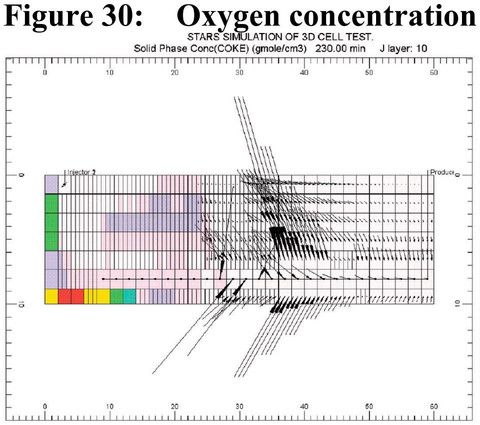
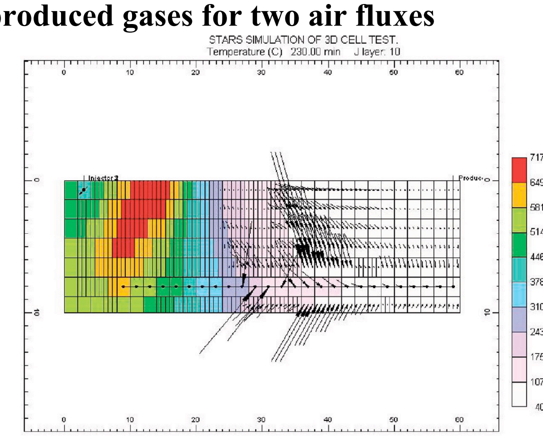


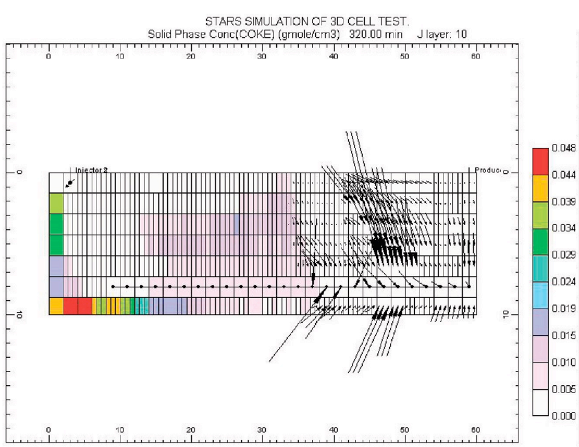
Figure 30: Oxygen concentration in the produced gases for two air fluxes



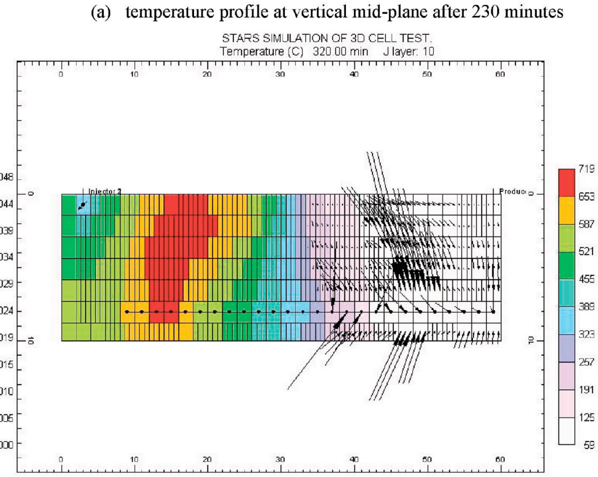
(a) coke profile at vertical mid-plane after 230 minutes?



(a) temperature profile at vertical mid-plane after 230 minutes



(b) coke profile at vertical mid-plane after 320 minutes



(b) temperature profile at vertical mid-plane after 320 minutes

Figure 31 Coke concentration in sandpack (vertical mid-plane) at 230 min and 320min.

Figure 32: Temperature in sandpack (vertical mid-plane) at 230 min and 320 min

Legend: All distances are in centimetres

As at the completion of the process, the advancement of the ISC front is no more than 1/3 of the total length of the model (Fig 32). A significant steam zone generation is indicated; this is an important factor for oil production. Therefore, depending on reservoir and process conditions, a steam zone, and the accompanying hot gases, may be important contributors to the bitumen/heavy oil production rates. More verifications have to be carried out to confirm these results.

5.2.2 THAI Simulation – Field Scale

Conventional ISC: during the 1970-80s, ISC simulation developments concentrated on field-scale modelling. Pioneering work by Grabowski et al. (Grabowski, 1979) dealt with the simulation of the heavy oil Cold Lake, Alberta case. They used six components: two oil pseudo-components, heavy oil and light oil, plus inert gas, oxygen, water, and coke. Four chemical reactions were simulated, including heavy oil pyrolysis, heavy oil combustion, light oil combustion, and coke combustion. However, the coarse-scale approximations used (necessary at the time, because of the limited computer power), generally led to serious under-prediction of the peak combustion temperature and a misleading inference that high combustion temperature was not an essential prerequisite to the successful operation of a (conventional) ISC process. It is now universally accepted that high combustion peak temperature (> 500 ^oC) is indeed vital for success.

Card et al. (Card, 2005), through their study of the ISC process, have suggested (from experience) that the largest size of grid block that can be used in the vicinity of the combustion front is 2m x 2m, and preferably 1m x 1 m. Typically, this will require use of advanced processer options like CMG's 'DYNAGRID' and parallel processing if considerable computing times are to be avoided.

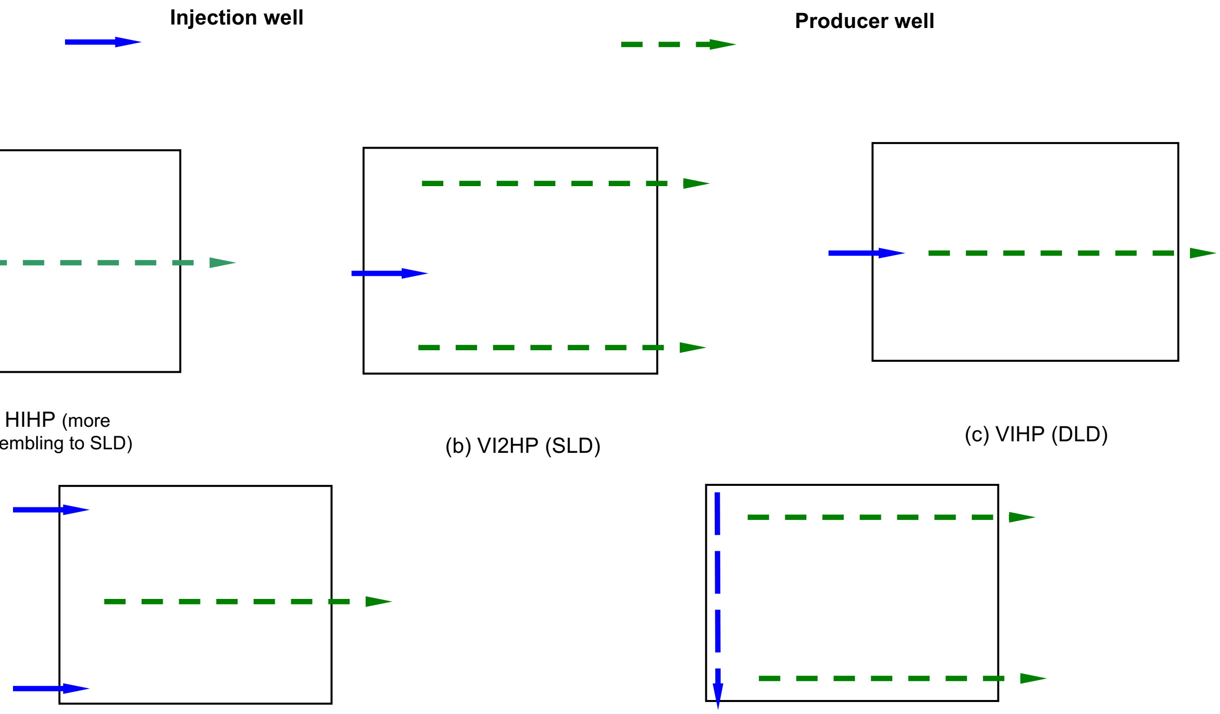
In their design study for an ISC pilot in Venezuela (Anaya et al, 2010), the authors used kinetic parameters and relative permeability curves from a combustion tube simulation, directly for the field pilot simulation. Interestingly, their selected well configuration involved vertical injectors and horizontal producers combinations, with the injector located in the centre of a 5-spot pattern. This had a vague similarity to THAI; the separation distance between the air injection well and the horizontal producer well was quite large, up to 200 m. High oil recovery was claimed, but this was only in the range of 30-43 %. The grid block size was 16m.

THAI Process: *Coates and Zhao* (Coates, 2001) were the first to attempt a simulation of the THAI process on a field scale; they simulated a direct line drive configuration. They used CMG's STARS simulator and Belgrave's kinetics scheme (Belgrave, 1993) for Athabasca and Lloydminster crudes. They found that the process had a good areal and vertical sweep. The combustion front velocity was highly dependent on the air injection rate. Predicted combustion front velocities were in the range 0.05 m/day to

0.1 m/day. Only a limited section of production well length was simulated, and accordingly, they obtained very low oil production rates, as low as 4.5 m^3/day. The highest combustion temperatures were around 450 ºC, over a narrow zone, and this temperature decreased towards the outer edges of the reservoir section. One factor that may have constrained the oil rate was assigning a relatively low permeability, of only 1 Darcy. Typically, horizontal permeability in Canadian bitumen reservoirs, especially Athabasca, can be as high as 10-12 darcies, with vertical permeability around 4-6 darcies.

Rahnema and Mamora (Rahnema, 2010) for their process - CAGD (Combustion Assisted Gravity Drainage) - an ISC process conducted in a SAGD-type configuration - simulated a field section with a 500 m long horizontal well, This was done to compare the process performance of CAGD with that of SAGD (Steam Assisted Gravity Drainage) and THAI processes, for the same length of the horizontal producer. Using the STARS simulator, for an air injection rate of a 200,000sm^3/day, they predicted that THAI only achieved an oil production rate of 10 m^3/day, compared with approximately 37.5 m^3/day for CAGD and 50 m^3/day for SAGD; the value of oil rate for THAI is *unrealistically low*, as it corresponds to an air-oil ratio of 20,000sm^3/m^3. From their description, it appears that the model used had 32 x 30 x 4 = 3840 grid blocks. Their diagrams show that they used grid refinement in the blocks above the horizontal producer and also around the injection well. They also employed Belgrave kinetics, allowing LTO reactions to produce coke. The predicted temperature profiles for THAI showed reasonably high values after 2 years (ca. 450 ºC), but the peak temperatures decreased to 300 ºC after 5 years, and 275 ºC after 7 years. This indicates that the ISC process was dying. This result does not appear to be consistent with the air injection rate of 200,000 m^3/day (injection flux = 3 $m^3\ h^{-1}m^{-2}$), which should be more than sufficient to achieve vigorous combustion. Definitely, something was wrong in the input data, or how the model was set up.

University of Bath Simulations: Various well configurations are possible for operating THAI (Fig. 33).



(d) 2VIHP (SLD)　　(e) HI2HP

Figure 33: Vertical (VI) and horizontal injector/producer well (HI/HP) configurations in THAI process (Xia et al. 2002). The DLD or SLD is marked for each configuration.

Most of the 3D combustion cell studies done at the University of Bath used configurations (a) and (c); (b), (c) and (d), which constitute either standard **d**irect **l**ine **d**rive (DLD) and **s**taggered **l**ine **d**rive (SLD) configurations. Configuration (a) is an extreme extension of (d), ie, between staggered line drive and direct line drive (if regarded as a whole). It is a kind of hybrid, but more difficult to interpret when compared to (c) and (d). It was suggested (Xia, 2002) that**, "**For a field piloting the scheme to be adopted is that of SLD, with at least two vertical injectors and one horizontal producer".

To date, generally, horizontal air injection wells have been used in the field only for HPAI projects, in deep light oil reservoirs [e.g., Continental Oil Resources in Medicine Pole Hills (Belgrave 2006)], but not in heavy oil applications.

The University of Bath developed a mechanistic model of the THAI process (Greaves, 2011), using available (published) data on oil production trends experienced in the Whitesands field pilot (please see subchapter 6.1). Hence, the simulation model should not be considered to be predictive. Their approach was to tune the model by assigning a range of oil production rates; a daily oil production per horizontal well of 490 bopd of bitumen was assumed. This rate was selected by Petrobank as the design basis for their commercial May River Phase 1 Project, in their submission in 2008 to the Alberta Energy Resources Conservation Board (ERCB). The simulated reservoir section (Petrobank's Whitesands Pilot) for one of the three pairs used in the test is shown in Figure 34. The well arrangement was direct line drive (DLD), i.e. VIHP. The inter-THAI pair spacing was 100 m, and the air injection well was inset 3 meters from the inlet end of the reservoir section; the injection well was opened only on the upper 12.5m interval. The offset of the vertical injection well from the toe of the horizontal well was 15 m. The simulation was made for a homogeneous oil layer, without any interbedded shale layers. No thin bottom water zone was considered in the model. The air injection rate was constant at 80, 000 m^3/day.

Note: the design value of the daily oil production per horizontal well of 490 bbls/day proved to be too optimistic as in reality the average ***maximum*** daily oil production per horizontal well did not exceed 40 m^3/day (300 bbls/day) (See Fig. 55 of Chapter 6.1).

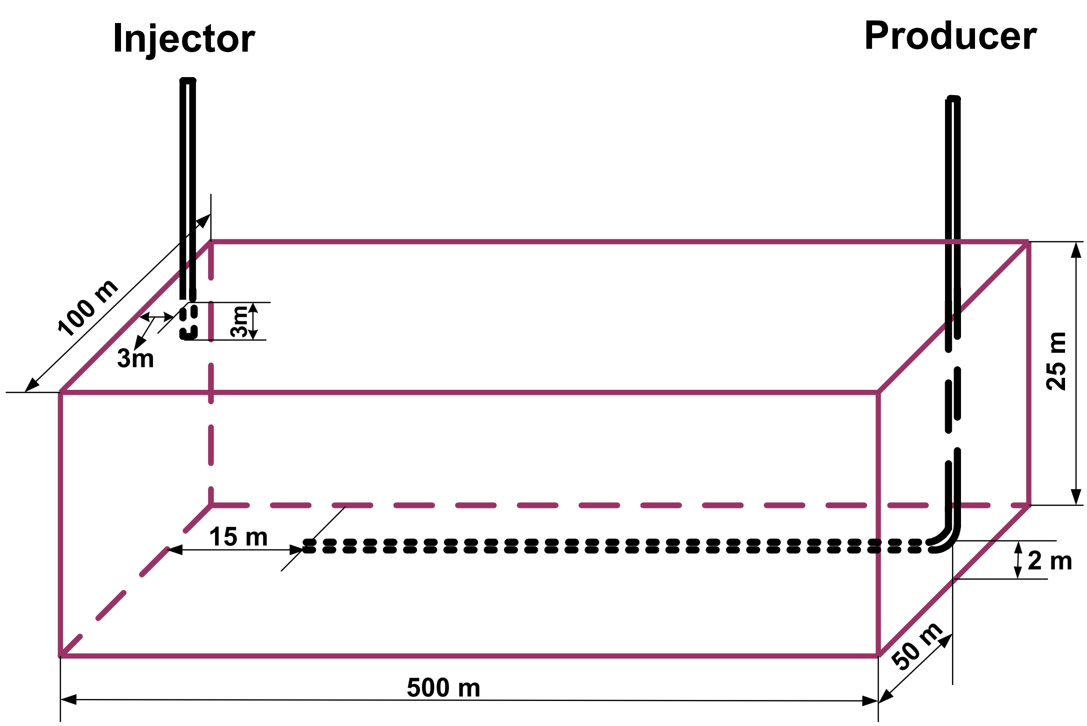


Figure 34: Dimensions of field pilot section simulated; direct-line drive (DLD) configuration

Reaction Model (Greaves et al. 2011): The reaction kinetics is described by equations 1-3. The bitumen was split (pseudo-ised) into two pseudo-components: a Heavy Oil component (HO), comprising asphaltenes and heavy oil, and a Light Oil (LO) component comprising all distillable – medium oil, light oil and hydrocarbon (HC) gases. The respective weight fractions are HO – 0.65, LO = 0.35, with corresponding molecular weights, MWs: HO = 500, LO = 150. Thermal cracking kinetics of Athabasca bitumen, as represented by Eqn. (1), was proposed by Phillips et al. (Phillips,1985). As mentioned, asphaltenes and heavy oil in Eqn. (1) are grouped as a single pseudo-component to represent the heavy fraction of the bitumen. The heavy fraction of the bitumen is designated as “Heavy Oil” in Eqn. 2. The Distillables in Eqn (1) are designated as "Light Oil", and include, medium oil, light oil and gases. The combustion of coke is represented by (Eqn. (3),

$$\text{Coke }(A_1) \xleftarrow{k_1} \text{Asphaltene }(A_2) \underset{k_3}{\overset{k_2}{\leftrightarrow}} \text{Heavy Oils }(A_3) \underset{k_5}{\overset{k_4}{\leftrightarrow}} \text{Distillables }(A_4) \qquad (1)$$

$$\text{Heavy Oil} \rightarrow 0.53\text{Light Oil} + 60.61\text{Coke} \qquad (2)$$

$$\text{coke} + 1.225O_2 \rightarrow 0.95CO_2 + 0.05CO + 0.5H_2O \qquad (3)$$

The stoichiometric coefficients in Eqn. (2) were obtained by tuning the model thermal cracking kinetics with experimental THAI data, aligned to a nominal oil production rate of around 400 bopd. The activation energy and the frequency factor for Eq. (2) were obtained from Phillips et al. (Phillips, 1985), whilst those for Eq. (3) are obtained from Xia and Greaves (Xia and Greaves, 2002). Direct combustion of heavy oil and light oil was found not to be significant in the previous 3D combustion cell simulation study. Also, LTO reactions were not included, as HTO (high-temperature oxidation) predominates in THAI.

Simulation Results: The STARS reservoir simulator (Computer Modelling Group) was utilized for this simulation, employing the parallel computing and DYNAGRID options to reduce computing time. The horizontal producer was represented by the Discretized Well Bore (DW) in STARS. A total of 37,120 grid blocks was used, with x,y,z dimensions of 3.1 m, 3.4 m, 3.1 m. Local grid refinement was used near the combustion zone and horizontal well regions.

The main criticism of the simulation is that the predicted fuel deposition (coke) is very high (Figure 35). This may have been because the numerical tuning procedure to align the model with field-scale conditions, did not adjust the reaction parameters relating to Eqn. 2 (activation energy, the pre-exponential rate constant) sufficiently, to ensure that fuel deposition due to thermal cracking was within an acceptable range, i.e.. 25 – 50 kg m-3.

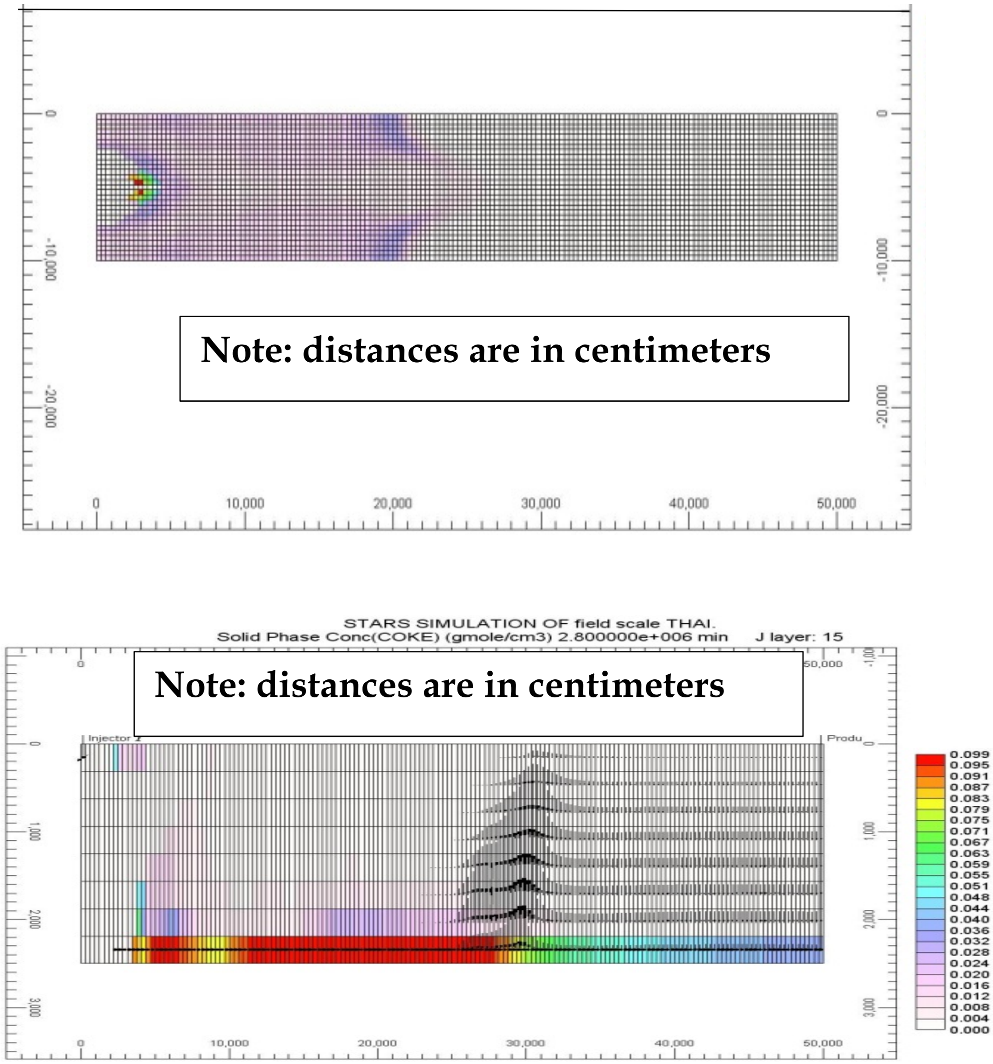


Figure 35: Predicted coke concentration profiles at the horizontal mid-plane (top) and vertical mid-plane (bottom) after 5.32 years. SLD configuration.

There is an **extensive coke** deposited ahead of the combustion zone and at quite high concentrations (164-192 kg $m^{-3)}$. The concentration of coke immediately ahead of the combustion zone (top of Figure 35) and also surrounding the horizontal well (see bottom of Figure 35) is even higher than this (> 1000 kg m^{-3}); the figure of 1000 kg m^{-3} is *totally unrealistic* for an in-situ coke deposit, as this exceeds even the maximum oil content of $1m^3$ of rock corresponding to initial oil saturation! It is very likely that such high coke concentrations are manifested as an artifact of the numerical tuning process, or pertaining to the simulator set up, and further investigation is required to ascertain whether much lower coke values are more appropriate.

The simulation of concentration of CO_2 in the produced gas seems to be correct, as during the steady air injection, it gives a value of 16.8%, signifying sustained vigorous combustion (HTO mode). The predicted temperature profiles (Fig. 36) show peak combustion temperatures of up to 800 ^{o}C, near the top of the reservoir, and higher still (nearly 900 ^{o}C) at the horizontal mid-plane; the fact that the peak temperature did not advance more than 30-40m after 5 years is associated with some doubts and requires more checking of the simulator. Assuming a temperature of around 400 ^{o}C, means that in 5 years the high-temperature zone advanced 150-200m along the axis of the horizontal producer. Note the position of the Mobile Oil Zone (MOZ), identified from the oil rate vectors (closely vectors, or darker shaded area) in Fig. 36 (top). This shows that the temperature of the MOZ is only about 180-200 ^{O}C.

Oxygen breakthrough: Oxygen breakthrough was predicted to occur at 10.8 years, with no oxygen in the produced gas before that. This demonstrates that THAI should be a very safe and robust process.

Steam zone: After nearly 8 years, a substantial steam zone was developed, extending over about 10 % of the length of the reservoir section. Over the central part of the steam zone, the steam saturation was higher than 60%. The leading edge of the steam zone contacts the colder edge of the oil layer at a temperature of around 200^{o}C. This corresponds to a bitumen viscosity of ~10 cp; The heated bitumen mixes with thermally cracked oil, so that the actual flowing oil viscosity will be lower.

Oil Saturation: all of the oil ahead of the combustion, up to the leading edge of the steam zone, is produced into the horizontal well. With the proviso that, from the initial oil saturation, one should subtract the amount of oil that is burnt, plus the oil that is left behind as coke, the predicted oil recovery after 10 years is near to 60 %.

Oil recovery: In the steady-state period of the process (lasting for nearly 4 years, out of 8 years of economic production) the oil rate reached a plateau production rate of over 58 m^3/day (~350 bopd); the last period (from year 8 to year 11) was a falling rate period. Over the 8 years of economic oil production, approximately 1 million barrels oil are produced. As a final remark, it has to be acknowledged that the simulated oil rate is somewhat optimistic; it is approximately 3 times higher than that obtained in the field. To some extent, this is because oil production in the field was constrained, since the maximum air injection rate was only 40,000-50,000sm^3/day, as compared to 80,000 sm^3/day, used in simulation.

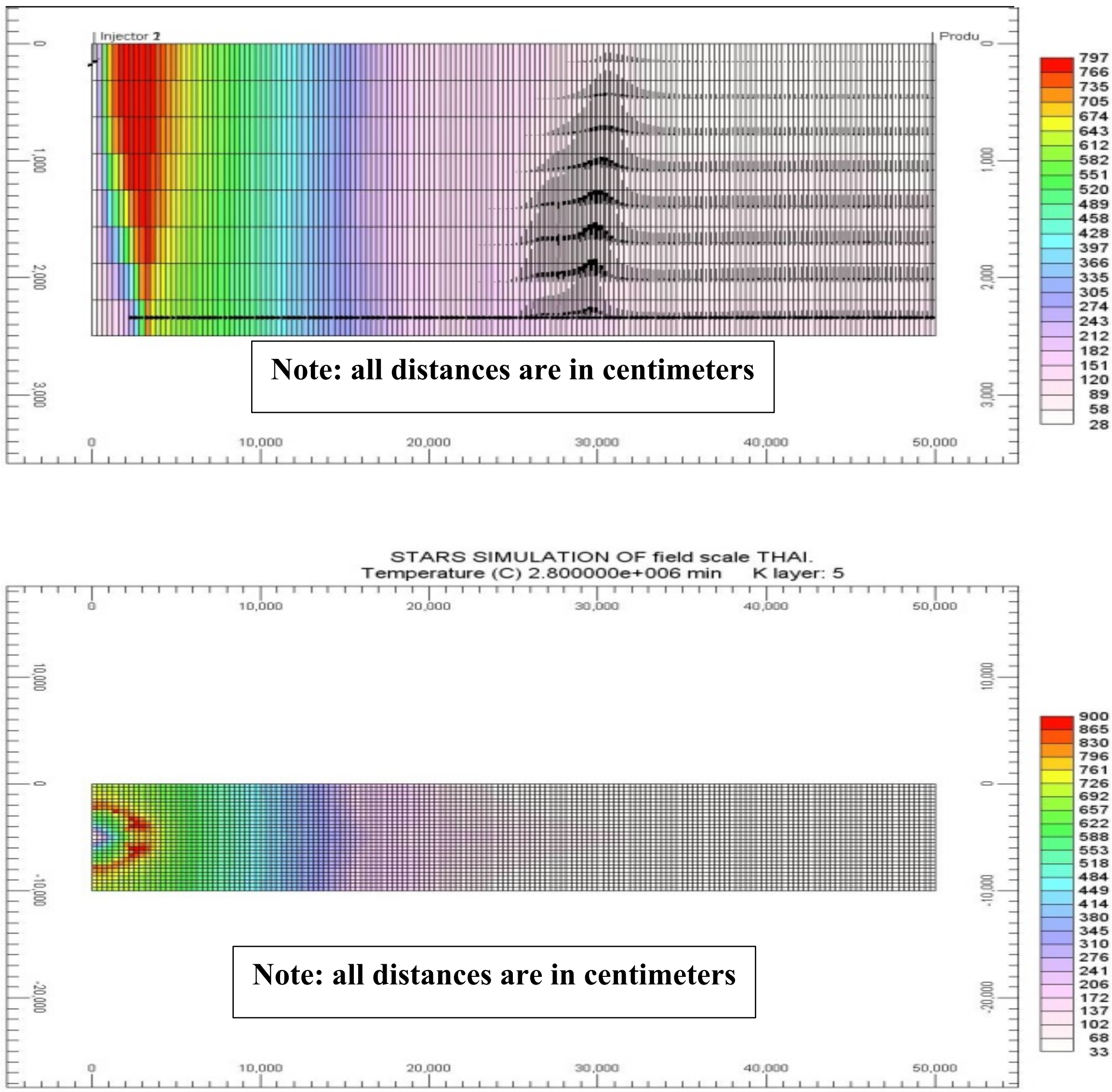


Figure 36: Temperature profiles in reservoir at the vertical mid-plane (top) and horizontal mid-plane (bottom) after 5.32 years (SLD configuration).

5.3. Other Simulations; Simulation of THAI Process in the Field and/or in the Laboratory Setting

The next two simulation studies are analyzed *mainly* in order to compare the THAI efficiency with that of conventional in-situ combustion and compare the effectiveness of two different THAI well configurations (direct line drive and staggered line drive).

5.3.1. Schlumberger Field-Scale Study

This study is quite comprehensive in terms of the number of parameters of the THAI process that were examined. It included five different well configurations (Ruiz, 2007), including their base case (VIHP – direct line drive), referred to as 'Simple Array' or the base case, and 2VIHP (staggered line drive), and these were compared against a conventional ISC arrangement (VIVP). The chief detraction of the simulation, as regards heavy oil/bitumen applications, is that the oil property selected was basically a light-heavy oil. Two sets of the simulation were made:

- Case 1: homogeneous reservoir
- Case 2: effect of heterogeneity

They also used a different set of reaction models, (SPE 8394) namely:

- Case 1- included three direct combustion reactions for the heavy oil, medium oil and light oil pseudo-components, but without a coke deposition, including from pyrolysis reactions (thermal cracking). This is more related to high pressure, or light oil air injection (LOAI-HPAI) process, which is a different process to heavy oil in situ combustion.

- Case 2 - used a two pseudo-component model for heavy oil and light oil combustion, but also included a thermal cracking reaction.

The molecular weight of the oil in Case 1 was 188, which can, therefore, be classified as medium-heavy oil, although the oil viscosity was stated to be 2300 cp at reservoir conditions (temperature was 54 ^oC). In the second case (same oil), the oil was characterized by a heavy oil component fraction (0.60) and a light oil component fraction (0.4) with a combined molecular weight of 119. Therefore, for their Case 1 and Case 2 simulations, the crude oil was relatively light, as compared to a typical heavy crude or bitumen. In their Case 2, relatively low oil density (low MW), suggests that fuel deposition from thermal cracking would be quite low to sustain vigorous combustion. This is exemplified by the fact that they quote a maximum temperature of only 700 ^oF (371 ^OC.

The simulations were made using Schlumberger's Eclipse 300 thermal simulator with a multi-segmented representation of a 821 foot horizontal production well (Case 1). They do not state what the width of the oil section is (from their schematics, it appears to be about 100 m), nor do they give the thickness of the oil layer. Typically, the reservoir properties selected (porosity 24 %, vertical permeability 700mD, vertical permeability 70 mD) resemble more those of a light-heavy oil reservoir, rather than a classic heavy oil reservoir.

Case 1 Simulation Results: comparing the 'Simple THAI array – DLD" with conventional ISC (C-ISC), results indicated that THAI produced 29.5 % more oil after 120 days of air injection (C-ISC stopped after 120 days, due to air channeling through to the producer) and 318 % more after 770 days. The average oil production during the first 120 days of THAI operation was 32.8 m^3/day (206 bpd), and 16.5 m^3/day (104 bpd) after 770 day; these production rates seem to be almost realistic as THAI potential rates, even for this case, where we do not know the air injection rate.

A HI2HP (horizontal injector-two horizontal producers) was found to be the best well combination. This was because the horizontal injector gave better air distribution, which was conducive to the development of a broader combustion zone on startup. It has to be mentioned that HI2HP configuration is a kind of pseudo-SLD configuration, actually an extreme form of staggered line drive (SLD) using vertical injectors.

They also investigated the effect of **oxygen enrichment** of the injected air, because, in the base case, the combustion peak temperature was below 700 ^{o}F, after 16 months, and also tended to decrease with time. Doubling the oxygen content - for the same injection rate - increased oil recovery by 27 % and also apparently increased the peak combustion temperature.

Case 2 Simulation Results: The effect of reservoir **heterogeneities** on THAI was examined, which they compared with the **homogeneous base case**. They selected (a) a **Random heterogeneity** case - porosity 5 to 47.6 %; horizontal permeability 10 to 1460 md; vertical permeability 1 to146 mD and (b) a **Stochastic heterogeneity** case – porosity 5 to 47.6 %; horizontal permeability 5 to 3811 md; vertical permeability 0.5 to 381 mD. After 5 years, there was no significant difference between the simulated oil production for three cases, in the amount of oil recovered. *They concluded that, in THAI, gravity forces and pressure drop caused by the production well have predominated over heterogeneity effects.*

5.3.2. Fatemi et al.; Simulation of THAI Process in Laboratory Experiments and a Field 'Block'

A review of this work is included, because they investigated, numerically, the effects of vertical and horizontal toe-to-heel well arrangements for THAI and Toe-to-Heel Steam Flood (THSF). The CMG simulator was used in both cases. The two investigations follow a similar pattern and are based on a study of the giant KEM heavy oil carbonate field in Iran. Details of the oil physical properties were not provided. The reservoir matrix had a porosity of 30% and a permeability of 100 Md; the reservoir temperature and pressure were 160 ºF (71 ºC) and 75 psia (Gotbi 2011). It is presumed that the raison d'etre *for* studying *THSF* was because the combustion temperatures in THAI were very close to the decomposition temperature of the carbonate matrix (600 ºC).

Laboratory scale simulation of THAI: it is not clear whether the study was done at reservoir conditions or very low pressure. The average porosity of the KEM reservoir laboratory model was 0.414, with a permeability of 127 mD. The different well configurations investigated are shown in Fig. 37. 2VIHP represents staggered line drive (SLD), wherein the total amount of air injected is split equally between the two wells to obtain a better distribution of the injected air, compared to DLD (VIHP). The 3D combustion cell simulated had the dimensions of 0.3m x 0.055m x 0.8 m, i.e. a slimmer and slightly longer cell than that used by the University of Bath in their experiments/simulations (Fatemi et al., 2009).

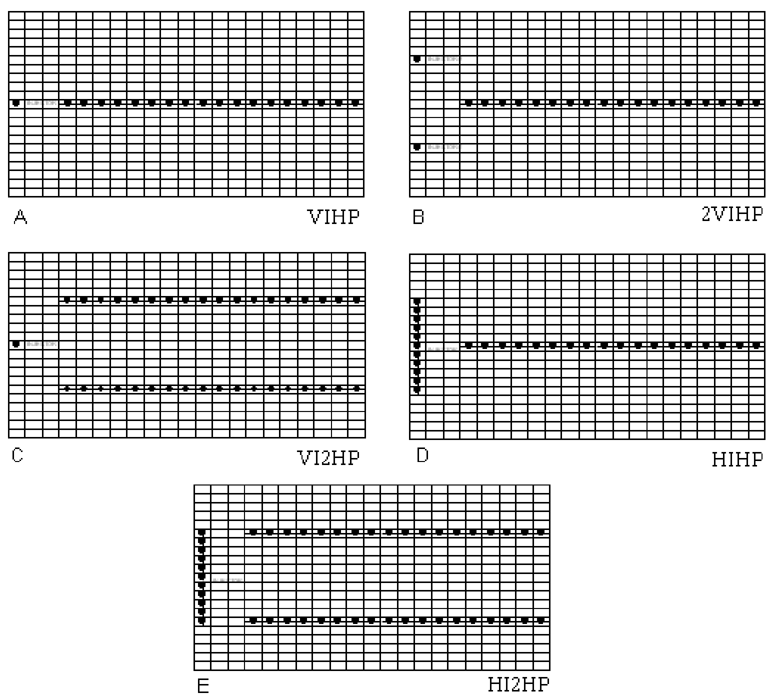


Figure 37 Different THAI well arrangements in KEM study(Fatemi et al, 2009)
Legend: VIHP = DLD configuration; 2VIHP and VI2HP are SLD configurations

Oil recovery was the best for 2VIHP, followed by HI2HP, HIHP, VI2HP and VIHP, in descending order.

They contend that, although the differences were not great, the differences would be expected to be higher at the field scale. The volumetric sweep efficiency was, in descending order: 2VIHP > HIHP > VIHP > VI2HP > HI2HP. *One may conclude, tentatively, from the results of this work that an SLD arrangement (2VIHP) appears to be the best choice for operating THAI.*

The sweep efficiency was determined from the residual coke profile (Fig. 38), at a distance of 0.4 m from the vertical injection well end.

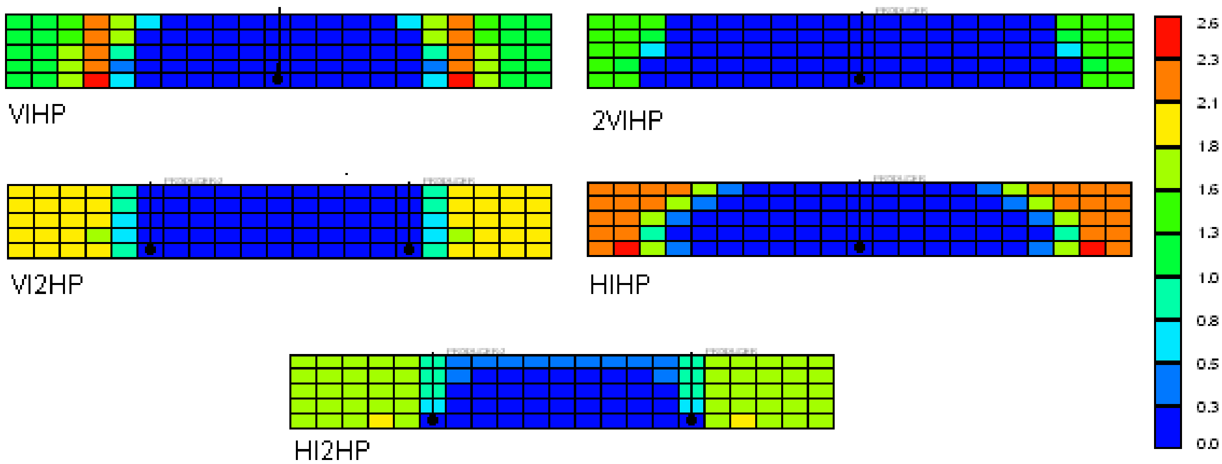


Figure 38 Post-mortem solid residue concentration (lb-mole/ft^3) for different THAI wells schemes at time = 8 hr (Fatemi 2009). Legend: VIHP = DLD configuration; 2VIHP and VI2HP are SLD configurations

This result also serves to emphasize the benefit, indeed almost an imperative, of obtaining a well-developed initial burn zone, following PIHC, so that a wide combustion zone propagates. The coke concentration, converted to metric units, are in the range 255 – 459 kg m^{-3}, which are exceedingly high, compared to what is typically quoted in practice (for non-carbonate reservoirs). As this was obtained in a U of B simulation, as well, more work is needed to clarify if this is a characteristic of THAI process (related to the kinetics adopted or the 3-D configuration of the burning surface) or an artefact of the simulator.

They confirmed that the best position for locating the vertical injector is at the top of the reservoir. Note that presently, a horizontal injector is not considered to be a safe technical design for the field case.

Field-scale "Reservoir Block" Simulation for Steamflood in a TTH Configuration: Although we cannot conclude anything directly about the operation of THAI from these simulations, there is one result that may be relevant. It shows that a 2VIHP, staggered line drive combination, is significantly superior to the other well arrangements, as far as the growth of steam chamber is concerned; growth of steam chamber is directly correlated to oil recovery This effect may be considered akin to creating an initial large combustion zone in THAI, so that it expands and propagates at the highest rate, compared to a less effective DLD (VIHP) arrangement

6.STATUS OF TECHNOLOGY. FIELD TESTING IN CANADA:WHITESANDS PILOT IN ATHABASCA

In evaluating the novel THAI process, the approach taken in the laboratory investigations was radically different to that taken in the field. In the laboratory investigations, THAI was first tested (and compared) with conventional **i**n-**s**itu **c**ombustion (ISC) for oil with some mobility (Wolf Lake). This was followed by the laboratory investigation of THAI's applicability to oil sands. In the field, first THAI's application to oil sands was evaluated, and later, testing in a conventional heavy oil reservoir began. As mentioned in the Introduction, the applicability of conventional ISC to oil sands exploitation has never been proven; many tests were conducted by Amoco, as well as, several other companies, but none reached the commercial stage (Turta 2006).

The Whitesands pilot conducted in the Athabasca Oil Sands is analyzed in this section, while the Kerrobert Project–conducted in a conventional extra-heavy oil reservoir - will be analyzed in the next section.

This comprehensive evaluation is based exclusively on open technical sources, including press releases from Petrobank Energy and Resources (Petrobank), interviews and presentations from Petrobank executives, etc. However, for the Whitesands pilot the fragmented information obtained in this way was scrutinized and fully checked using oil production data and temperatures recorded in the observation wells, including complete gas composition data, found in the official reports submitted by Petrobank to Innovative Energy Technology Programs (IETP), and in the Petrobank Annual presentations to the Energy Resources Conservation Board (ERCB) /Alberta Energy Regulator (AER); see IETP Reports, 2007, 2008 and 2009 and the Petrobank presentations to ERCB/AER in 2009, 2010, 2011 and 2012.

Although the analysis in this Report has been carried out in-depth, there are still some limitations due to lack of rigorous data, principally concerning the ignition procedure used in both projects. For instance, there is no specific information concerning the ignition delay, and in some cases, details of the gas composition in the period immediately after the initiation of air injection, following steam injection for pre-heating, or PIHC (Pre-ignition Heating Cycle). Therefore, experience/judgment was made use of to cover some of the gaps and to check the Petrobank press releases.

The Whitesands THAI Demonstration Pilot represented the first field piloting and it was designed and implemented by Petrobank, based on the THAI patent (Appendix B, reference 9) purchased from Alberta Research Council (ARC) in 1997; ARC became Alberta Innovates Technology Futures (AITF) in 2010 and InnoTech Alberta in 2017. The patent–basically - describes two different well applications: a direct line drive (DLD) configuration and a staggered line drive (SLD) configuration. These configurations are shown schematically in Figure 7a-b, Figure 33 and Figure 34. In both cases, the patent indicates that the vertical injector should be perforated high in the oil formation. The Whitesands THAI Pilot tested just one configuration, DLD.

Petrobank started the project using its own funding. After the project was underway, the Federal Government of Canada invested \$10 million; other investors were Richardsons of Winnipeg, who purchased a 14 % share of the project for \$10 million (subsequently redeemed by Petrobank). The Government of Alberta - via Innovative Energy Technology Programs (IETP) - and Technology Partnerships Canada, also, partially funded the project. The original total cost for the whole demonstration project was approximately \$34 million, but the total spent increased to \$40 million(Appendix D: Calgary Herald Nov. 8, 2006).

6.1. Geology and Reservoir Properties

The Whitesands Lease is located in the south-eastern corner of the Athabasca Oil Sands Region in Alberta, Canada, Figure 39. The THAI process was tested in the Middle McMurray (McMurray B) formation. The McMurray B formation is made up of very fine to medium-grained sands, having a general upwards coarsening tendency. The sand is slightly consolidated to unconsolidated.

The representative well logs are provided in Fig. 40. As seen in the log of OB3 well, as part of McMurray B formation, at its upper part, there is IHS layer (Inclined Heterogeneous Strata) of relatively low-quality rock, but oil saturated (see Figures 46a-e). Above IHS layer is the McMurray A layer with a separation of the only 2m between them; this separation can constitute a barrier for the flow of cold liquids but not for the in-situ combustion (ISC) front. While Mc Murray A formation is oil saturated, at its top there is a thin gas layer of 0.5-1m, which can be distinguished both in OB3 and OB7 wells (See well logs in Fig. 40), which are located diagonally, in the NE and SW of the testing area; therefore, it has to be assumed that this thin gas streak is continuous in the project area. Additionally, there is a significant gas accumulation in an upper interval (Clearwater sandstone), which is just above Clearwater shale (Fig. 40a) and extends into NE of the Whitesands pilot area; this gas reservoir had been partially depleted (low pressure) at the initiation of the THAI pilot.

The true cap rock, consisting of approximately 20 m of shale, is located above Mc Murray A formation; at this thickness, it constitutes a full barrier even for the ISC front Fig. 40.

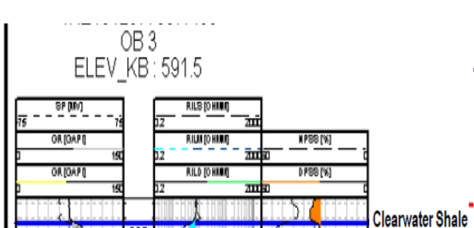
The detailed geology is relatively well known as 6 vertical wells (future air injection wells A1 and A3, and observation wells OB1, OB4, OB7 plus and exploratory well) were cored in the region of the THAI pilot (ERCB presentation, 2007). The depth of the formation is 360-400 m; the gross thickness ranges from 32 to 39m, while the net pay thickness is in the range of 13-20m (average hnet/hgross =0.47). Figure 41a shows the pilot wells and oil zone net pay thickness variations, while Figure 41b shows the bottom water zone thickness variations; thickness of the bottom water zone is small, in the range 0-3 m, with a trend to decrease from P1 well towards P3 well. As mentioned, there is a very thin gas cap in the McMurray A formation, with thickness 0.5-1m; however, there is a significant gas accumulation in an upper interval (Clearwater sandstone), which extends into NE part of the Whitesands pilot area, which had been partially depleted (low pressure) at the initiation of the THAI pilot. The McMurray B formation is almost flat (dip less than one degree; dipping from NE to SW), has an average porosity of 34% and an average initial bitumen saturation of 72%; connate water saturation is 28%.

Fig. 39: THAI pilot location, Courtesy of Orion Oil Canada

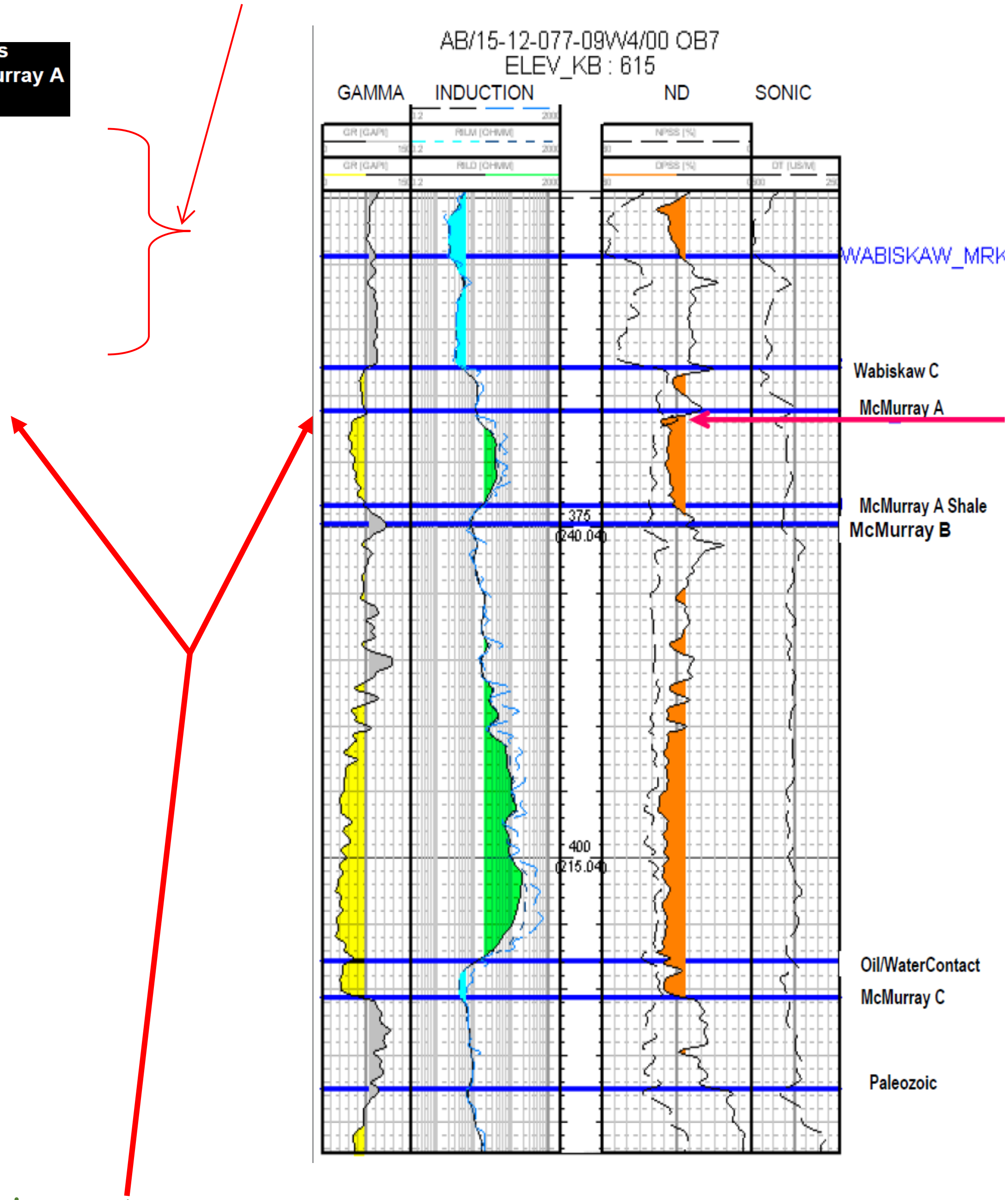
Note: Clearwater gas layer positioned above the Clearwater shale

≈20m of shale as the caprock

OB7



Very thin (<1m) gas zone is present at the top of McMurray A sandstone in a few wells.



Very thin(<1m) gas zone is present at the top of Mc Murray A sandstone

Fig. 40: Representative logs of observation wells OB3 and OB7 IETP presentations 2008 and 2010

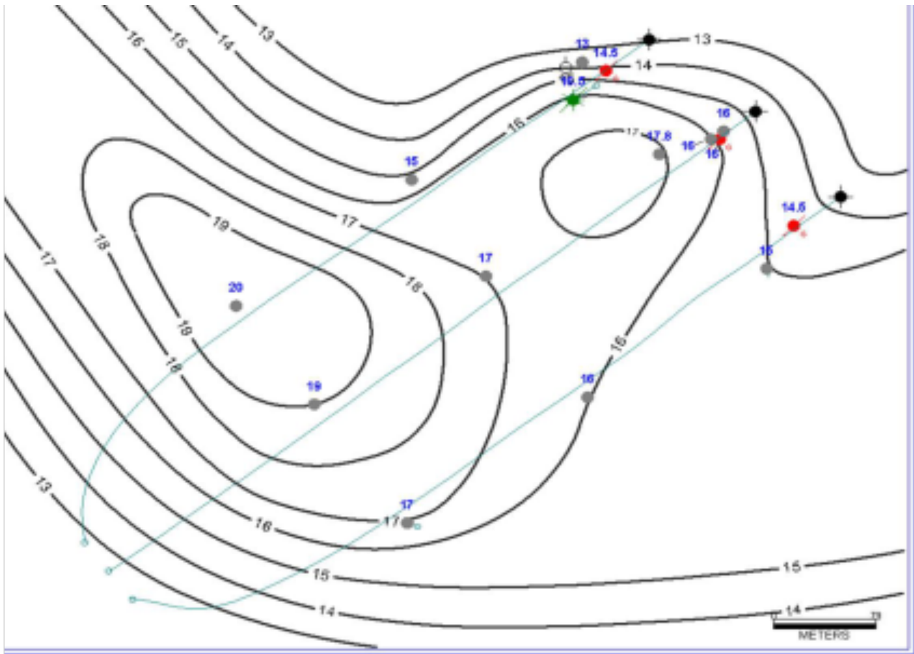


Fig. 41a: Isopach map with the net pay thickness of oil zone

IETP Presentation, 2008

Fig. 41b: Isopach map with the net pay thickness of bottom water zone. IETP Presentation, 2008

6.2. **Feasibility of ISC Process**

Before initiating the Whitesands pilot, Petrobank did not undertake any laboratory investigations in-house, which were directly applicable to the application of the THAI process in the McMurray B bitumen formation. Instead, a 3D combustion Cell THAI test was specially commissioned from the University of Bath (U of B) in July 2003. The dry combustion test used Wolf Lake heavy oil of 10.6 API gravity. Details of this test are not publicly available, except that a staggered line drive (SLD) configuration was used .

Subsequently, however, after the start of the Whitesands demonstration pilot, Petrobank performed some specific laboratory work on the THAI process. A dedicated laboratory was set up in 2007, and a 3-D model similar to the U of B combustion cell was constructed (IETP, 2007); the Petrobank 3-D model was 59cm*46cm*19 cm. The cell height (19cm) was almost twice that of the U of B (10cm) model, which enabled a more detailed investigation of the THAI process in a vertical plane. The IETP, 2007 Report contains the results for one laboratory test done on Deer Creek oil that has a viscosity of 309,000 mPa.s at 20 ^{0}C, which is less viscous than the oil from the THAI pilot area. The test was useful in showing the upgrading effect; the air-oil ratio was 2694 sm^3/m^3. Also, in 2007 a second test was conducted, this time using Whitesands bitumen (Shahin, 2007), using a **s**taggered **l**ine **d**rive (SLD) well configuration (2 vertical injectors-one horizontal producer - 2VI HP). The oil recovery was 76%. The upgrading was good and was noticeable after 1/3 of the test duration. The produced water was very acidic (pH decreased as low as 1.6, towards the end of the test)

In 2009 two more tests were performed, using a bitumen sample from the Whitesands pilot (bitumen viscosity 1,341,000 at 20 ^{0}C). Significant upgrading was again recorded in these tests. For the first test – using a direct line drive (DLD) configuration - an **a**ir-**o**il **r**atio (AOR) of 3,150 was obtained, while for the second test – using SLD configuration – an AOR of 4,675 was recorded; The final oil recovery was lower, 58-59% in both cases. All tests described were low pressure tests and, the results do not seem to be well correlated. The high value of AOR reported by Petrobank (4,700 sm^3/m^3) is higher than the AOR values obtained by U of B using the same oils; there is no detailed information to allow clarification as to why this happened. This difference may be related to the absence of heating compensation for the Petrobank 3-D model.

6.3. Design of the Pilot; Well Completions

The Whitesands THAI pilot consists of three parallel and adjacent well pairs. Schematics of the wells layout in the pilot are shown in Fig. 47a, and the details of the layout of the wells are depicted in Fig. 47b.

It is worth highlighting that the pilot was well instrumented~~,~~ and included:

- 16 observation/temperature/pressure wells; in these wells, 11 thermocouples were placed in the production zone (thickness of layer ≈20m) and 5 were located in the overburden
- Also, thermocouples were installed in the horizontal section of each of the three production wells
- Coiled tubing was placed in the production well to be used for different operations, e.g., steam injection, to regulate the temperature within the wells, sand cleaning, etc.
- There were also groundwater monitoring wells

As mentioned, the **d**irect **l**ine **d**rive (DLD) configuration was used; the horizontal producers (P-1, P-2 and P-3) were drilled 1.5-2 m from the bottom of the formation (ERCB Presentation, 2008), whilst the vertical injectors were opened in the upper part of the formation for air injection, and in the lower part (close to bottom water zone) for steam injection during the communication phase; a packer was installed between the upper and lower perforations. Practically, the shoe of the vertical injector is above the toe region of the horizontal producer, being some 3m laterally off. The completion of the vertical injectors is shown in Figure 48a, while that of horizontal producers is provided in Figure 48b. All the completions shown here are reproduced either from the EUB Application, October 2003 or from the first IETP reports; the producers were completed for natural flow production and, in-deed, they did not need any artificial lift systems during the test. As is seen later, the location of steam injection perforations was too close to the water/oil interface and "contributed" to the escape of steam and subsequently of air into the bottom water zone. Also, the horizontal section of producers seemed to be too close to the bottom of formation, given the fact that there is a thin bottom water zone.

Horizontal producers have a slotted liner which is perforated all the way from the heel to close to the toe, but for the last 30m there is no perforation, just a blank liner (blank liner past injection well's position). As the distance between vertical injector and the toe of horizontal producers (start of perforation) is 15-17 m it means that, approximately, the shoe of the vertical injector is facing the middle of the blank liner, extending both ways, i.e., towards the perforated zone and opposite to that (Fig. 47b). Due to this particular location of the toe-region, any air injection through the vertical well will not have an initial good radial propagation phase; channeling along the horizontal section of the horizontal well is promoted from the very beginning by the blank liner in both directions (the blank liner is a heat conductor and a conduit of infinity permeability). This design precludes the development of an initial relatively broad ISC front, following ignition.

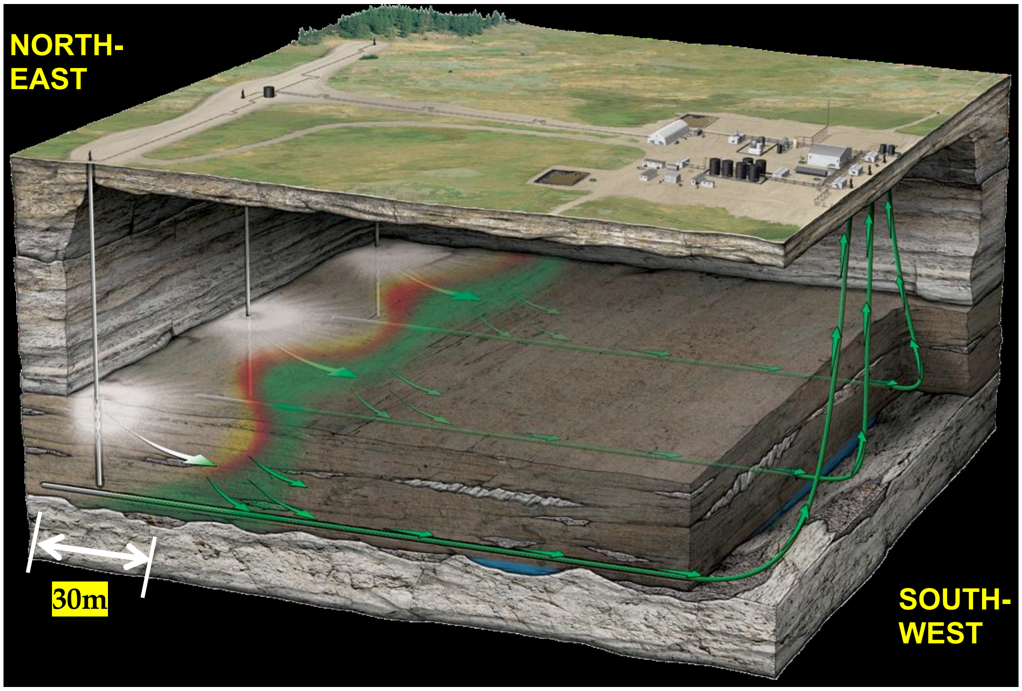
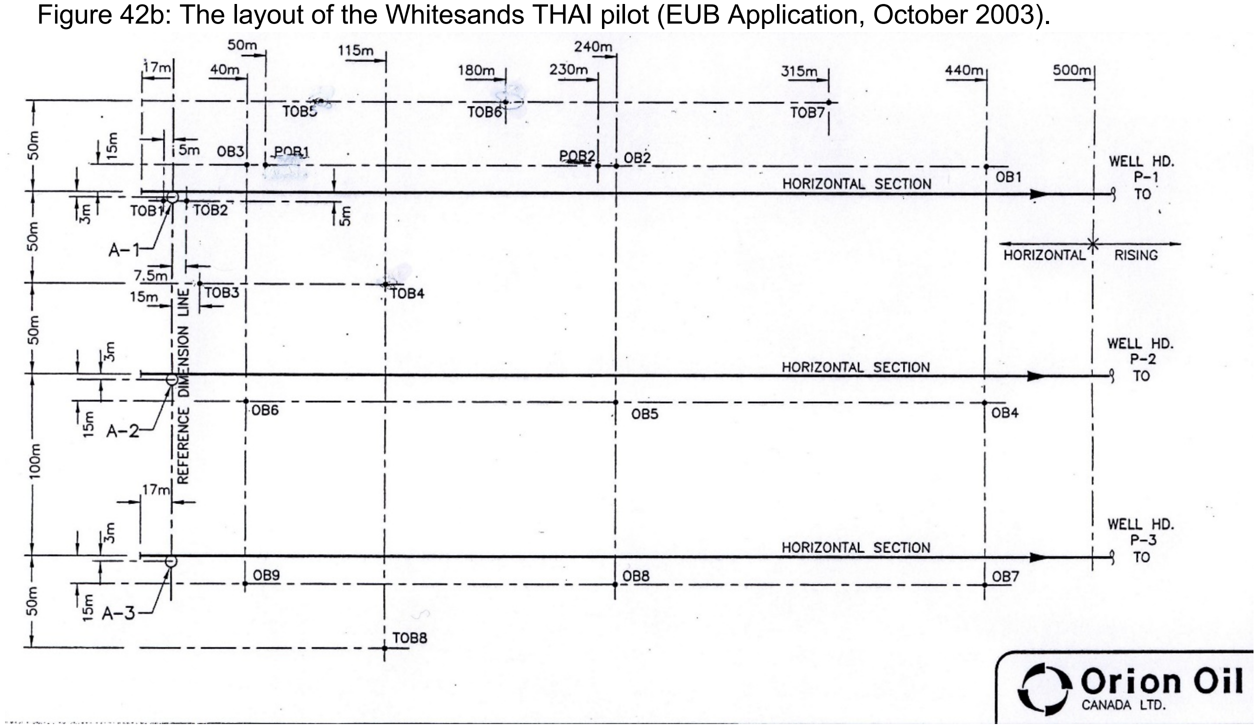


Figure 42a: Schematic layout of wells for the Whitesands THAI Pilot. Courtesy of Orion Oil, Canada. Please note the extension of the horizontal section (HS) of horizontal producers (HP) past the vertical projection of the shoe of the vertical injector. The last 30 m portion of HS of HP is a blank liner

Figure 42b: The layout of the Whitesands THAI pilot (EUB Application, October 2003).



Note: A-1, A-2 and A-3 are the vertical injectors. P-1, P-2 and P-3 are the horizontal injectors. OB1 to OB9 - observation wells. TOB1 to TOB8 – temperature observation wells. Wells POB1 to POB2 - pressure obs. wells

Note: Later on, the location of the wells TOB1 and TOB2 was changed; they were drilled around the toe of well P-2, as seen in the map presented in Figures 47a-b

The completion of observation wells (OB1 to OB9), temperature observation wells (TOB1 to TOB8) and pressure observation wells (POB1 and POB2) are shown in Figures 44a, b and c. It can be seen that the first two types of wells have no perforations (blind wells), while the pressure observation wells have perforations and can record pressure in Wabiskaw and Clearwater formations, separately (with a separating packer placed between perforations into these two formations). The (pure) observation wells are completed with a casing, while the (temperature) observation wells have no casing; they are small diameter wells completed with just a tubing, which is cemented up to the surface (outside and inside) and has an axial thermocouple cable inside.

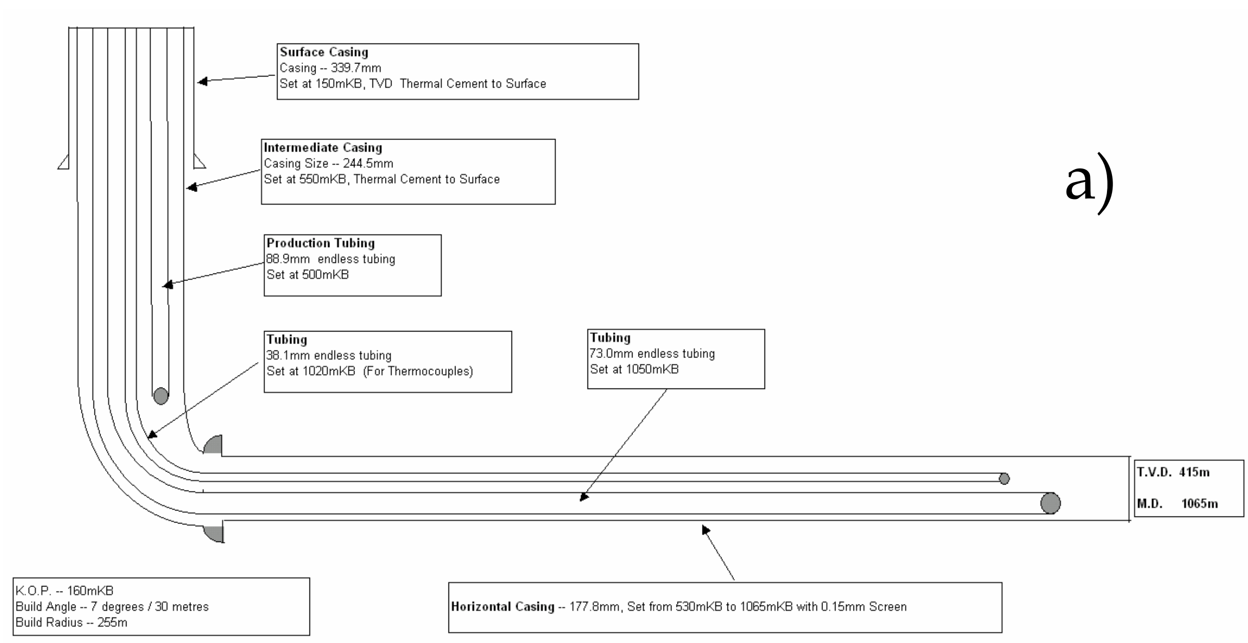
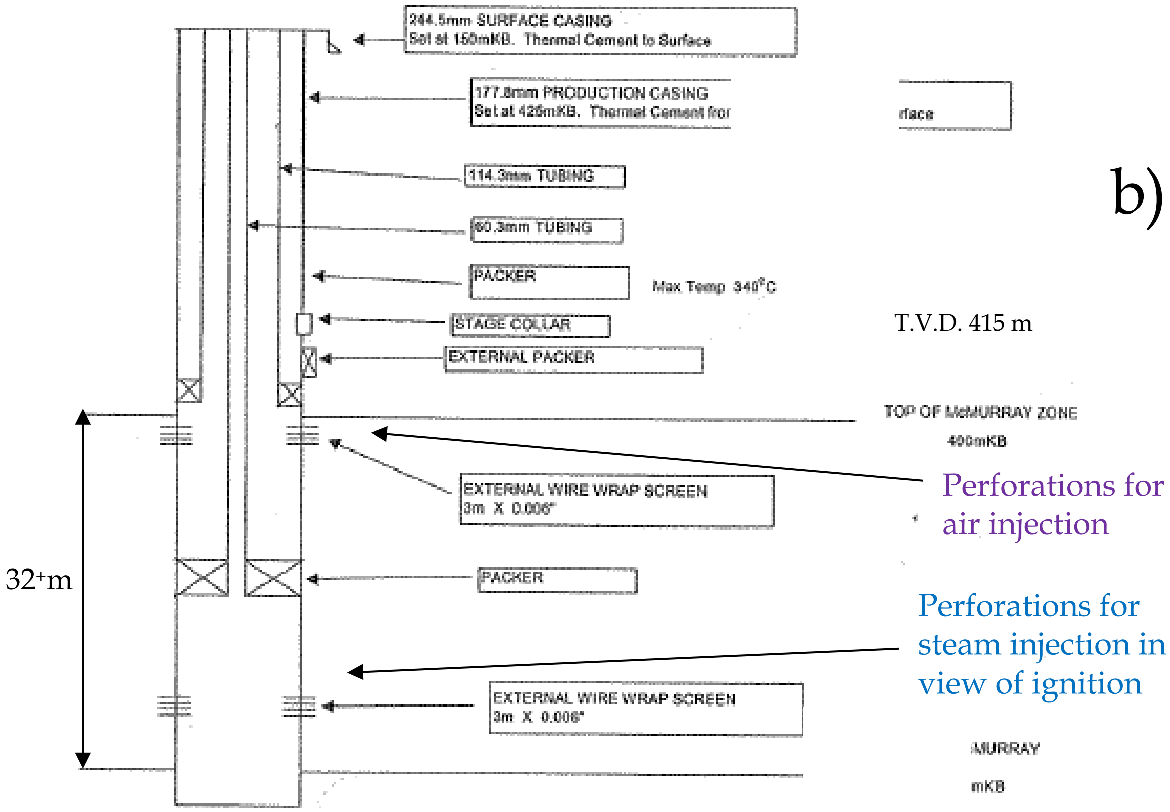
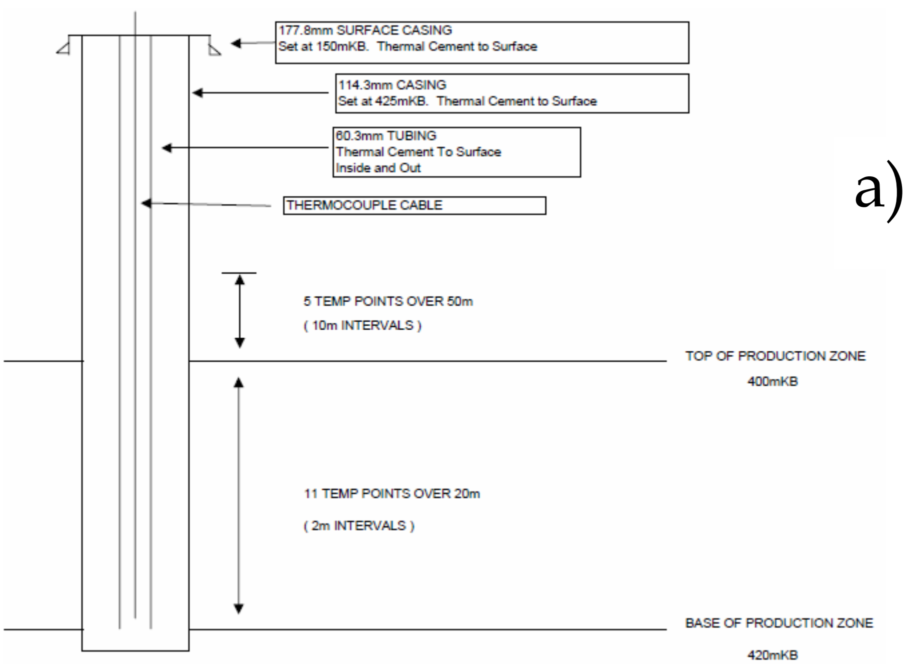


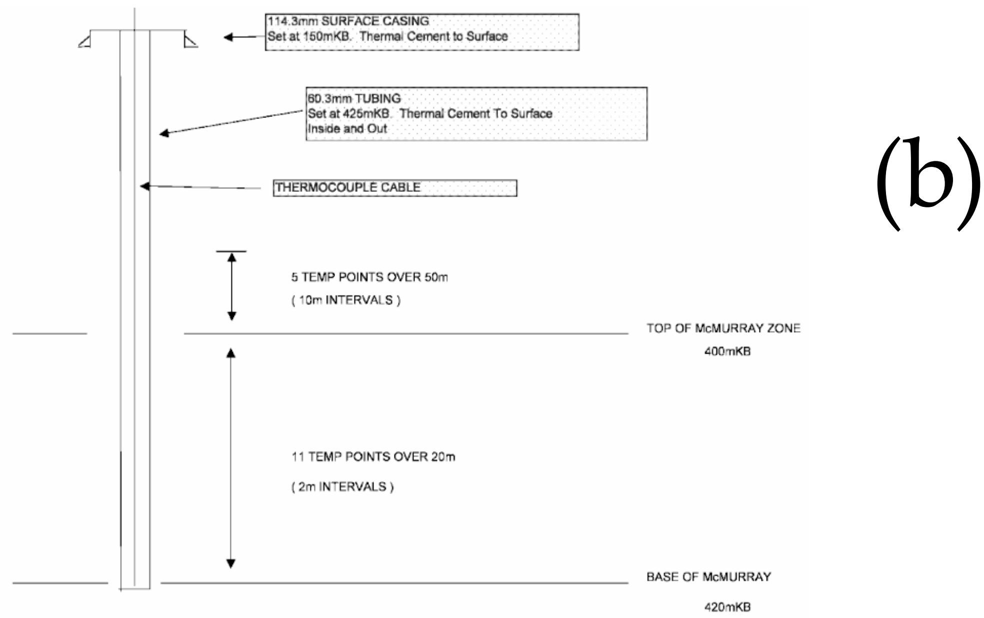
Figure 43: The diagram of the horizontal production well (a)



Figs 43: The diagram of the vertical air injection well (b)



Figures 44a: Diagram of (pure) observation wells OB1 to OB9; also, used for temperature measurement (completed with casing)



Figures 44b: Diagram of temperature observation wells TOB1 and TOB2, used for temperature measurement (it is completed with no casing; just tubing cemented up to surface, outside and inside; thermocouple cable inside)

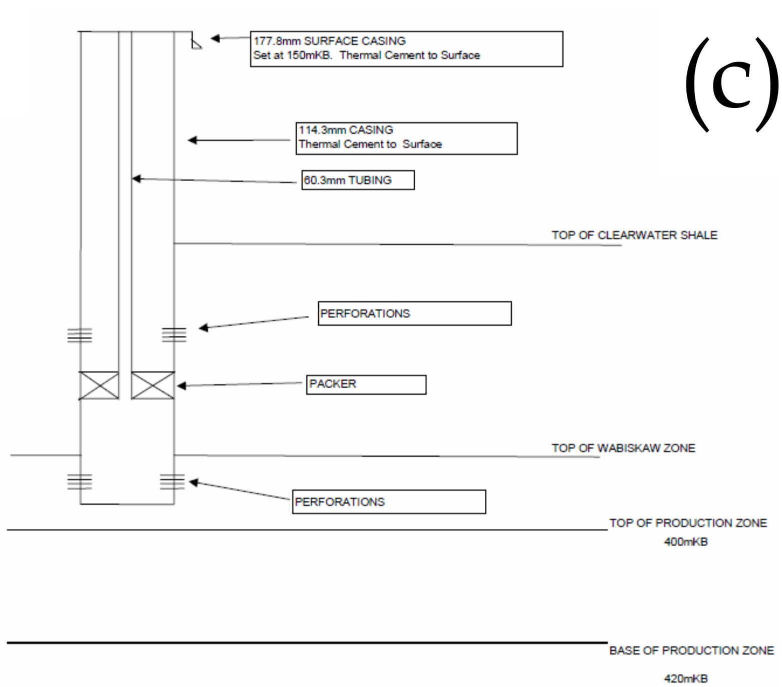


Figure 44c: Diagram of pressure observation wells, opened in McMurray and Clearwater formations, separately

6.4. Performance

The Whitesands THAI pilot was carried out between March 9, 2006 and October 7, 2011 (5.5 years). In the IETP reports detailed information (monthly data from IETP reports) is available for the first 4.5 years of oil production. Also, for the first 2.5-3.5 years, there is information regarding bottomhole temperature (BHT) profiles of the observation wells, as well as information regarding the BHT in horizontal producers; some combustion gas composition data was also available (4-7 months, in 2009). However, the annual Petrobank presentations to ERCB/AER include detailed information on the combustion gas composition and BHT, from the beginning up to the end of the pilot. Also, details relating to the replacement horizontal production wells are provided in those presentations.

6.4.1 Analysis Based on Petrobank's Press Releases and Interviews

The THAI field test was named "Whitesands Experimental Project" and was located in the Fort McMurray area, close to Conklin, in Alberta, Canada. The THAI pilot is located West of Encana's Christina Lake SAGD application. The location of Whitesands Project is shown in Figure 39. As mentioned, it used a **d**irect **l**ine **d**rive (DLD) configuration, with the shoe of the vertical well located (3 m offset laterally); the offset distance "shoe of vertical well - the toe of horizontal producer (start of perforation)" was 15-17m..

Petrobank planned the THAI pilot for total oil production of 1,800 bbl/day. It was a demonstration project (classified as an "Experimental Project") for bitumen recovery and in situ-upgrading.

For the first well pair (pair A2-P2, Fig 28a) pre-ignition heating cycle (PIHC) started in March 2006 and continued until July 2006, when air injection began. Air injection in the second well pair was started in January 2007, and in the third pair in July 2007. Although air injection was~~,~~ generally, continuous during these periods, some injectivity problems were reported for the third well pair.

Details on the First Pattern (module): the THAI test started in the central pattern (A2-P2 well pair), with pre-heating by steam injection (first as a kind of huff 'n puff operation). During March-July 2006, 8000m^3 (cold water equivalent of 50,000 bbl) of steam was injected into both the vertical and the horizontal wells (average injection rate = 70m^3/day). Steam injection in the vertical well was the most critical. As regards ignition operation, air injection started in July 2006; ignition was confirmed in less than 2 months (Appendix D: Calgary Herald Nov. 8, 2006); however, the ignition time was not rigorously evaluated, nor was there any report on how efficiently the combustion zone developed during these first two months of air injection. In other words, there is no very detailed reporting on variations of the produced gas composition. These details are needed in order to calculate the apparent atomic hydrogen-carbon ratio

(H/C ratio) and estimate the ignition delay, as well as, the intensity of combustion within and around the combustion zone, and whether **l**ow-**t**emperature **o**xidation (LTO) reactions were significant immediately after the start of air injection. In November 2006, it was reported that a temperature of 800 ^{0}C was recorded (at the toe of P2 producer, see Fig. 50b1), thus proving that ignition had taken place (Appendix D: Calgary Herald Nov. 14, 2006). As of December 2006, a (probable) maximum air injection rate was attained; later on, it decreased due to sand influx problems.

Some results for the first pattern (A2-P2 well pair) during the first two year-period, are:

- Achievement of high combustion front temperatures (600-800ºC recorded by temperature observation wells)
- Good oxygen utilization efficiency (lack of any oxygen short-circuiting into the horizontal producer); the reported produced gas composition was: CO_2=12-13%, CO=0.8-3%; hydrocarbon gas content 4-5% and the remainder nitrogen. In the first 3-6 months, the H_2% was up to 2% and afterward it exceeded this value (up to 8%-14%). Some H_2S was also produced (Greaves, 2009); a measurement using Draeger tubes showed a high H_2S concentration, in the range 6,000 to 8000 ppm, making a scrubbing operation necessary.
- There were no reports of any troublesome emulsion problems; produced water quality also did not pose any problems
- Oil upgrading was reported, but it was not very consistent (considerable variation from one measurement to the other). The methane content of the produced gas (compared to other conventional ISC commercial operations, worldwide) was relatively high; high methane percentages were recorded only in the pressure-cycling ISC pilots in Morgan Pilot (Margerrison, 1994. The occurrence of hydrogen production can be -probably -related to water -gas shift reactions and coke gasification reactions; high hydrogen percentages (up to 20%) were recorded in the Wolf Lake Pilot (Hallam, 1989) in Canada when ISC was conducted with oxygen injection; these phenomena are associated with three essential aspects, namely:
  - existence of high peak combustion temperatures, also causing thermal cracking of the oil
  - flow of oil partially through the burned zone; intentionally carried out in pressure-cycling ISC pilots, so that there is no oxygen present, or being part of the process mechanisms, (a long pathway for the flow of oil via the heated mobile oil zone, with only coke gasification and water-gas shift reactions on the last portion) as in THAI

- Short-distance oil flow as promoted by "wormholes", fractures or horizontal producers (our case), which permits the preservation of the upgrading.

Some methane may be a product of high temperature thermo-cracking (in the absence of oxygen) on the portion close to the horizontal producer and/or of coke+superheated steam reactions, the so-called methanation reaction, (Kapadia, 2011-2013).

The primary reported operational problem was related to high sand production volumes. To solve this problem, new (larger) sand knock-out facilities were installed. Likely, this problem was not totally solved (information as of 2007) as, later on, they installed a proprietary slotted liner (FaxRite^{TM}), which Petrobank claimed, solved the problem.

As far as oil production from the first pattern is concerned, after January 2007 (6 months following the start of air injection and initiation of the ISC front), gross liquids production was around 1000 bbl/day/well, with a bitumen cut of 40% to 50%, but with significant fluctuations. Total sand production was higher than 1%, but decreased to less than this value after Jan 2007. The sand influx was still leading to choking-back of production.

From the available information sources, it is not possible to establish exactly the time when in–situ upgrading was first observed in each production well. However, it was expected that there was a short initial period without any significant upgrading - probably until the oil from the start-up region was displaced and the combustion front became anchored at the toe of the producer. The properties of the THAI partially upgraded, produced oil for the average oil sales of June 2008 (0.5-1 year since the start of the pilot) were :

- API gravity improved by 4.4 points (from 7.9 ^{0} API to 12.3 ^{0}API)
- Dynamic viscosity @ 20 ^{0}C: reduced from 550,000 cp to 1550 cp (*350 times*);

As the requested pipeline properties are a minimum of 20 API and 350 cst, it can be seen that this constituted a partial upgrading. However, the above upgrading results did not include the amount of condensate, separated from the produced gases, which would have increased the upgrading (Greaves 2009); quantification could have been done based on the amount of C^{5+} fractions in the condensate.

The variation of the API density and oil viscosity - for the combined data from P1-P3 wells - for the period June 2009-October 2010 is shown in Fig. 45a; as seen from this figure, considerable fluctuations in the upgrading occurred. Upgrading was in the range of 2 to 7 API points, and it was tough to make any predictions, even on the short-term. This time, dynamic viscosity (@ 20 0C) experienced a smaller reduction [from 550,000 cp to approx. 5,000 cp (110 times)].

The SARA analysis of the original oil and THAI produced oil was as follows:

	Before	After THAI application
• Saturates, %:	21.1	25.5
• Aromatics, %:	30.3	22.6
• Resins, %	31.7	40.7
• Asphaltenes, %:	16.9	11.2

From above, a significant reduction of aromatics and asphaltenes is obvious; the quality of crude was improved significantly. Also, in the first year, there was no record by Petrobank as to what the sulfur reduction in the produced oil was, but in the 2010 ERCB Annual Presentation, it was stated that the sulfur content of the oil was reduced by 20% (from 3.2% to 2.6 %wt). The reduction in heavy metals contents of the oil (Ni and Va) was a reality, but it was not reported in the first year.

Actually, the properties of the THAI partially upgraded produced oil in 2010 (2011 ERCB Annual Presentation), were close to those in 2008, and they were, as follows:

SARA analysis	Before	After THAI application
• Saturates, %:	12.7	23.5
• Aromatics, %:	30.3	22.6
• Resins, %	19.0	17.2
• Asphaltenes, %:	16.9	11.2

Unintentional, in situ upgrading was also recorded in several *unconventional ISC field projects* as reported previously (Turta, 2006):

- Gregoire Lake, Athabasca, **p**ressure **c**ycling **ISC** (PC-ISC) project
- Marguerite Lake, (air ISC and O_2 ISC) in a pressure cycling (PC) mode
- Morgan Field, Lloydminster, Alberta, PC-ISC project
- Kyrock Project, Kentucky, USA

Comparing the upgrading in THAI with that in the unconventional ISC projects, we can summarize them as follows:

. **In-situ upgrading** from 3-D THAI and CAPRI laboratory tests; for THAI (7 API points) and for CAPRI (another 7 API points); a total of 14 points

- **In-situ upgrading**: Gregoire Lake, Marguerite Lake (ML) and Kyrock pilot projects (4 API points); up to 10% H_2 production in the produced gas for ML project

- **In-situ upgrading**: Morgan Field (10 API points)
- **In-situ upgrading** from the THAI field pilot (Whitesands project): 4.4-6.4 API points (51 – 74 %) of the laboratory upgrading (Xia, 2006).
- **Updates to Sept 2009:** oil production per pair was 20 m^3/day (125 bbl/day); for all 3 well pairs, 60 m^3/day (375 bbl/day), as compared to the design value of 1800 bbl/day.
- According to C. Ayasse (Sept 9, 2009) the replacement wells P1b, P2b and P3b were drilled 10-15 m laterally off the old production wells P1, P2 and P3, and were provided with special new slot system liners for sand influx control. Well P3b was put into production in August 2008, and for a limited period (August-October 2008), it was used to test the CAPRI process; The other two replacement wells (P1b and P2b) went on production in November 2009.
- **Updates to February–April 2010: A**s of February 2010, the oil production *per pair* was only 16 m^3/day (100 bbl/day) due to choking-back of oil production to avoid serious sanding influx into the horizontal wells. The plan was to increase oil production to around 300 bbl/day/well pair by the end of March/April 2010. Actually, the only consistent feature was in situ upgrading of the produced oil, generally 6-7 ^{0}API in a normal, uninterrupted production regime. However, this was reduced to about 4 ^{0}API, when oil production was resumed, following interruptions in air injection (Petrobank ERCB Presentation 2010).
- As mentioned, the replacement well P3-b was drilled close to the original P3; it was equipped with pre-fabricated 50 ft catalyst sections, with unique narrow slots to prevent sand influx. After a few months of testing, the conclusion was that the additional upgrading (due to the CAPRI catalyst) was not very significant (only 2-3 ^{0}API), and therefore not sufficiently economical. However, it appears that the sand influx problem had been resolved using the liner with narrow slots.
- In an interview with the Calgary Herald (Calgary Herald article: “Drillable Oil Sands Combat Dirty Tag”, April 3rd, 2010 - Appendix D) the Petrobank VP of Heavy Oil, Chris Bloomer, declared that at that time (April 2010) a total liquid production was 1500 bbl/day, of which, 700-750 bbl/day was oil and the remainder water. Therefore, on average, each well pair was producing oil at approximately 188 bbl/day (30 m^3/day).

6.4.2. Analysis Based on the IETP Reports and Annual Presentations to ERCB/AER

Innovative Energy Technology Programs (IETP) of Calgary partially funded the demonstration project; this funding required Petrobank to submit Annual Evaluation Reports on the project. Consequently, Petrobank submitted required reports for years 2007, 2008 and 2009, with the last Report (IETP Report 2009) being the last one. Although this final IETP Report does not give specific details for 2010 and 2011, it includes graphs for pilot performance (oil production and air injection) until August 2011, i.e., practically until the end of the pilot test period, to September 2011.

6.4.2.1. Analysis of the ignition operations

The first IETP Report gives information mainly on the geological data and the preparation for the pilot test. Details of the test itself started to appear in the second IETP Report. Our main criticism on the ignition process data/information is related to the fact that Petrobank did not identify whether there was a delay between the start of air injection and ignition. For instance, for Well A2 Petrobank considers the date of July 20 as the start of the combustion phase, which coincides with start of the air injection. However, this cannot be correct, because when relying on spontaneous or auto-ignition, there is a period – called ignition delay (t_{ign}) - during which in situ combustion develops into a self-sustaining operation. Based on the available data, a new analysis was performed for the determination of the ignition delay. Table 4 gives the main data regarding the pre-heating by steam injection in the three vertical injectors. Air was injected first in well A2, then in A1, and finally in A3. As shown in Figure 43b, steam injection took place through the lower perforations almost (or very close) at the same level with the horizontal section of the horizontal producer. This facilitated hot communication, but disproportionately, encouraged channeling of steam towards the horizontal producer.

By correlating the heat loss data with the experience obtained from the Pelican Lake ISC case, it can be tentatively concluded that in the case of A2 well, the ignition delay could have been up to 2-3 months. More details are needed to firmly establish this more precisely; the analysis is made more difficult due to the start of air injection in A1 on Oct 17th, 2006, resulting in *possible* interference between patterns. Superimposition of operations in these three well pairs can create problems in accurately determining the ignition delay for each of the THAI pairs.

*　　　*　　　*

It must be mentioned that Accelerated Rate Calorimeter (ARC) tests on the Athabasca bitumen, (Greaves, 2007) indicates an auto-ignition temperature of 350^0 C at 40 bar. For the ignition in case of some Athabasca combustion tube tests, University of Calgary (Abu, 2015), maintained (temporarily) a temperature of 350 ^{0}C in the first segment of the combustion tube.

Table 4: Main data regarding ignition operations for estimation of the ignition delay

Steam injection pressure range: 4,000 kPa (estimate based on air injection pressures); Steam quality: 80 %*; Steam temperature: 280^{0}C*

Note: Air injection starts at the end of steam injection for all air injectors

Well	Steam Pre- Heating Phase (PIHC)			Cumulative steam injected m^3	Average rate of steam injection, m^3/day	Estimated ignition delay (based on)		
						Oil production (See Figs. 55) (Date/months)	Bottom hole temperature (BHT) in observation wells (See Figs 50) (Date/months)	Temperature at toe of horizontal producer (See Figs 48) (Date/months)
	Start of steam injection	End of steam Injection	Duration of Injection Days/months	-	-		-	
A1	Oct. 17, 2006	Jan. 10, 2007	84/2.8	5,040**	60*	**March 2007 /2**	?	April 2007 /3
A2	March 9, 2006	July 20, 2006	134/4.4	8,000	60	Nov 2006/4	**August, 2006/1 (TOB1 well)**	Sept.25, 2007 / 2
A3	December 31 2006	May 11,2007	131/4.3	7,860**	60*	**July 2007/2**	?	August 2007/3

* Estimated; ** Estimated using an injection rate of 60 m^3/day (as in A2 well)

Note 1 : Steam injection (for preheating) of the horizontal section of horizontal producers started at the following date: P2 - April 21,2006; P1 - September 21,2006 and P3 - December 15,2006. A rough estimation of the amount of steam injected (Figures 55) - until the moment of ignition realization - gives an amount of cumulative in the range of 4000-5000m^3/well, injected at an average rate of 40 m^3/day. The graphs in Figures 50 show that at the end of preheating period, the maximum temperature of the horizontal section of the producer was in the range of 100-150 ^{0}C for P1, around 100 ^{0}C for P2, and 180 ^{0}C for P3; in case of P3 well, the steam injected flowed predominantly at the water/oil interface.

* IETP Presentation, 2007. Note 2: The best estimate of the ignition time is highlighted in BOLD

The heat losses occurring during steam injection in the pre-ignition heating cycle (PIHC) phase are given in Table 5.

Table 5: Pre-heating phase. Estimation of some parameters for different steam-slug size during PIHC (calculations similar to those in SelectEOR™). Depth: 360m; Net pay thickness: 20 m (average h_{net}/h_{gross} =0.470; Steam quality at wellhead: 80% (ERCB application, Oct 2003).

Pattern	Size of steam slug injected for ignition during (PIHC) (m³)	Duration of steam injection (PIHC) (days)	Average daily steam injection rate (m³/day)	Injection pressure (well head) (kPa)	Cum wellbore heat losses (end of inj) (% of heat available at well-head)	Steam quality @ bottom hole (in perfo-rations) (final value) (%)	Cum. heat losses in adjacent formations (end of inj) (%from heat available in perf-orations)
A1	5040*	84	60*	4,000	14?	62??	5
A2	8,000	134	60	5,500	15	64	6
A3	7860*	131	60*	5,500	15	64	6

* Value estimated

Table 4 shows that the ignition time was estimated by inspection of the temperature at the toe of producers, from the temperature evolution in very close (to air injection well) observation well and from the oil production profile. A reference temperature of 300 ^{0}C was considered for ignition achievement.

An inspection of the temperature at the toe of P2 indicates an ignition period of 2 months; full oil mobilization, i.e., visible incremental oil starts in November 2006 after 4 months. However, the best estimate is provided by the observation well TOB1, which indicates an ignition time of one month (since the start of air injection). Therefore, we consider an ignition time of one month for this case.

The temperature at the toe of P1 indicates an ignition period of 3 months; full oil mobilization, i.e., visible incremental oil starts in March 2007 after 2 months. In this case of no temperature indication from an observation well, we will consider an ignition time of two months for the A1-P1 pair.

The temperature at the toe of P3 indicates an ignition period of 3 months; full oil mobilization, i.e., visible incremental oil starts in July 2007, after 2 months. There are no temperature indications from an observation well. As in the case of A1-P1, we will consider an ignition time of two months for the A3-P3 pair.

In conclusion, an ignition delay of up 1-2 months is estimated. This additional time is added to the pre-heating time (3-4 months) resulting in a total time period of 5-6 months before significant oil production starts.

6.4.2.2. Air injection; sustainability of the ISC process

The variation in air injection rates for the three well pairs are shown in Figures 45b-d. In these figures, the injection wellhead pressure and gas production are also shown. From variations in air injection rates and air injection pressures, it can be seen that there is a pseudo-steady-state period (when these two parameters were relatively constant). This period is approximately two years, between August 2007 and June 2009; By August 2007, all three modules are seen to have been ignited (See Table 4). During this period, the injection pressure was 3.3-3.5 MPa in all the three patterns (it was slightly higher in A2), while air injection rates increased steadily from 20,000 to 60,000 sm^3/day/well. Well P3 experienced many interruptions in air injection, and hence the cumulative air injected was significantly reduced. Generally, all the patterns achieved air injection rates less than projected earlier (a maximum of 85,000 sm^3/day/well). However, even a value of 60,000 sm^3/day/well is still a good operating value for the air injection rate in this case of ISC assisted gravity drainage.

During THAI pilot operation, air injection was interrupted in order to solve some technical problems, mainly due to the intensity of sand influx into the horizontal producers. In 2009, sand 'clean outs' were routinely carried out in the three horizontal production wells (13 times); the cleaning was done using coiled tubing using nitrogen under pressure Some of the problems associated with unmanageable sand production were, possibly, burn-out, or blockage inside the horizontal wells (*our note).* In 2008-2009, the producers P1-P3 were replaced by producers P1b–P3b, drilled approximately 10-15 m laterally off from the original horizontal producers (P1 and P2), with their toes located approximately 40 m from the toe of P1 and P2 wells. (Figure 10). These wells were completed with a new, more efficient sand filter, namely the filter FAcsRite™, having more narrower slots (Petrobank presentation 2012). During drilling of the new wells, air injection was stopped. To summarize, the main interruptions to air injection were:

- 3 months in well A1 during the period of July-September 2009; 2.5 years after the start of air injection
- 4 months in A2 during the period of July-October 2009, 2 years since the start of air injection and approximately 22 months after the (estimated) ignition in A2
- 2 months in well A3 during the period of June-July 2008; 13 months after the start of air injection and 9 months since the (estimated) ignition in A3

Interruptions to air injection, as mentioned, may also be linked to a 'burn-out' inside one of the horizontal

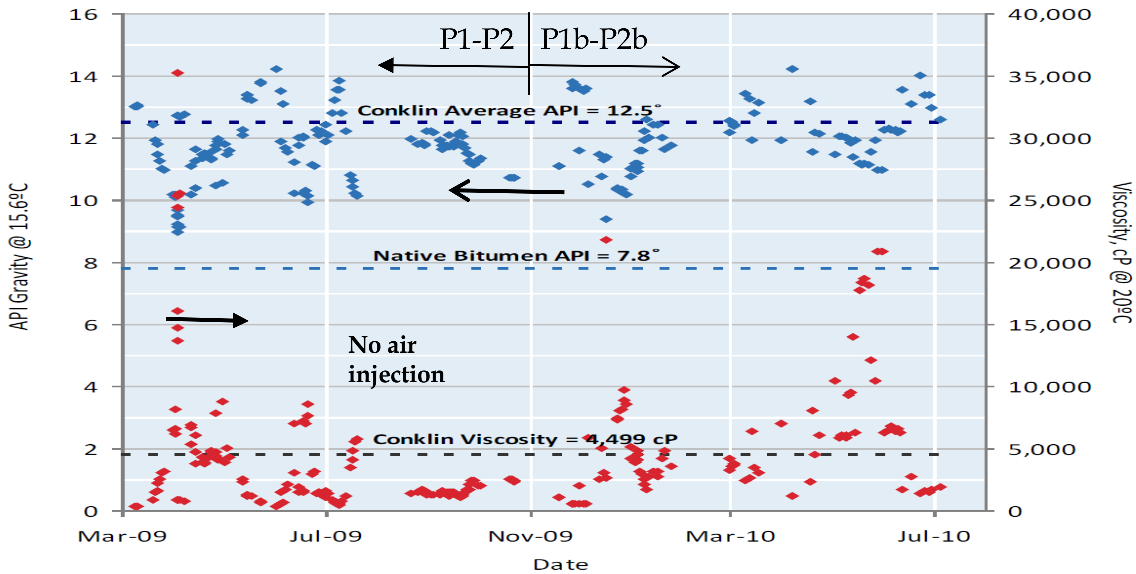


Fig. 45a: Whitesands THAI Pilot. Variation of API density and of oil viscosity for the period March 2009-July 2010, for wells P3b, P1/P1b and P2/P2b. (Ayasse, 2018). To be correlated with air injection rates in Figs. 45b-d.

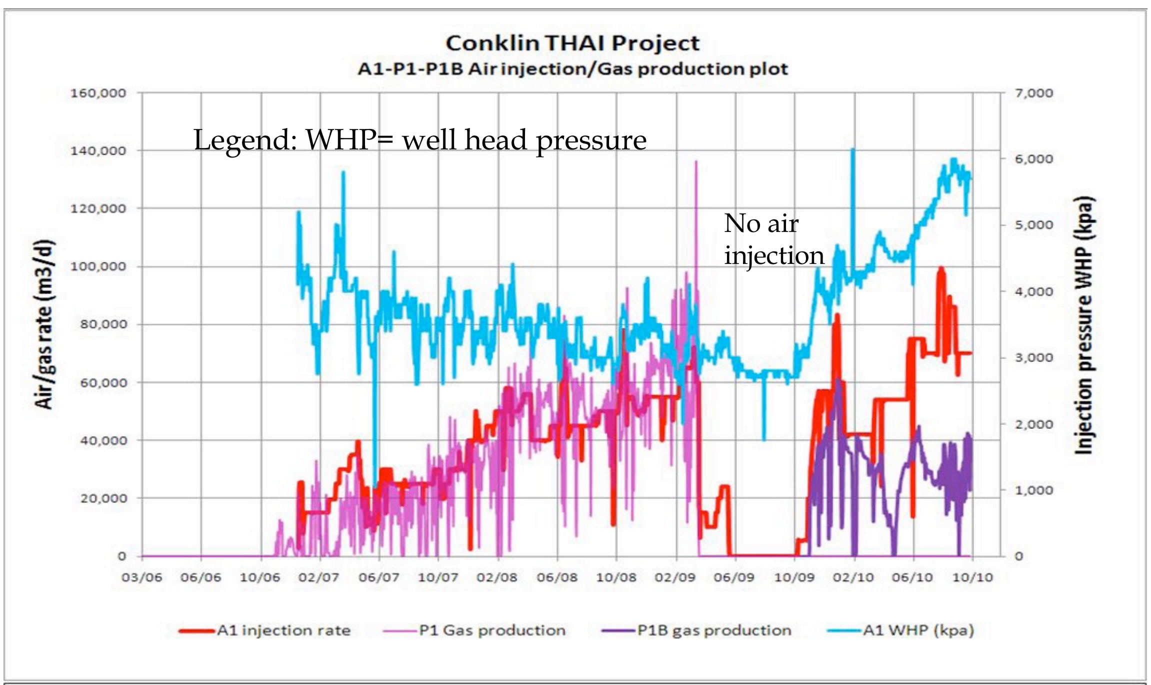


Fig 45b: Whitesands THAI Pilot. Air injection and gas production for A1-P1/P1b pair

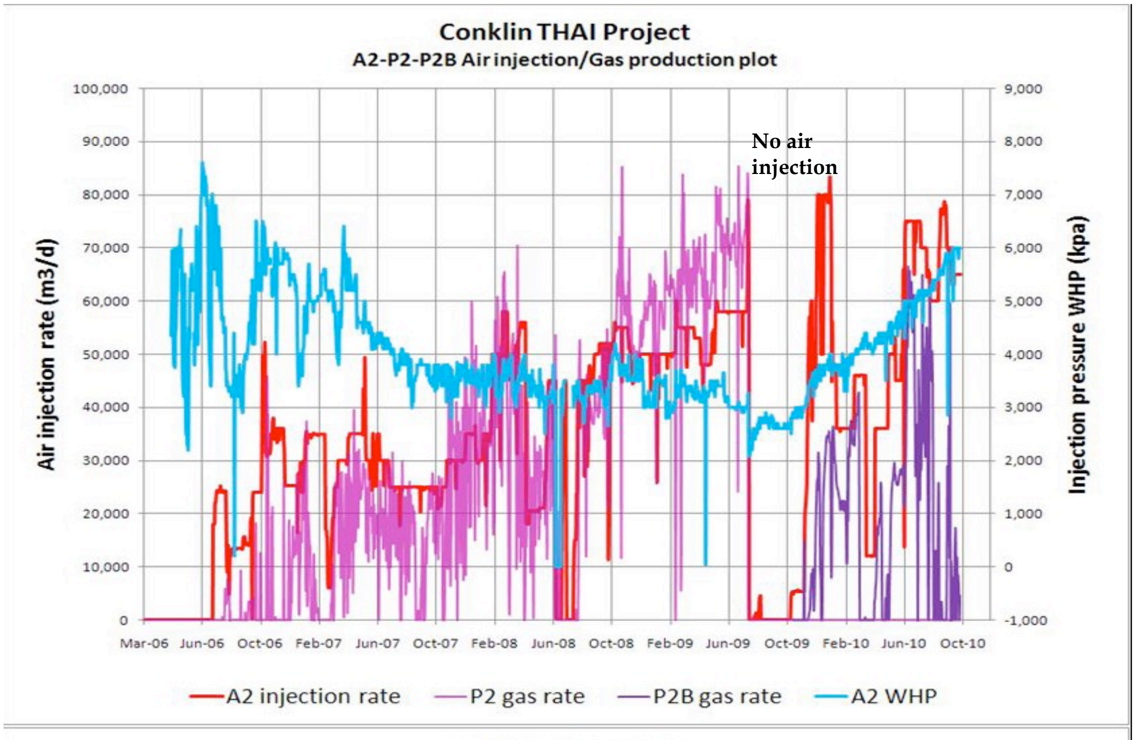


Fig 45 c: Whitesands THAI Pilot. Air injection and gas production for A2-P2/P2b pair

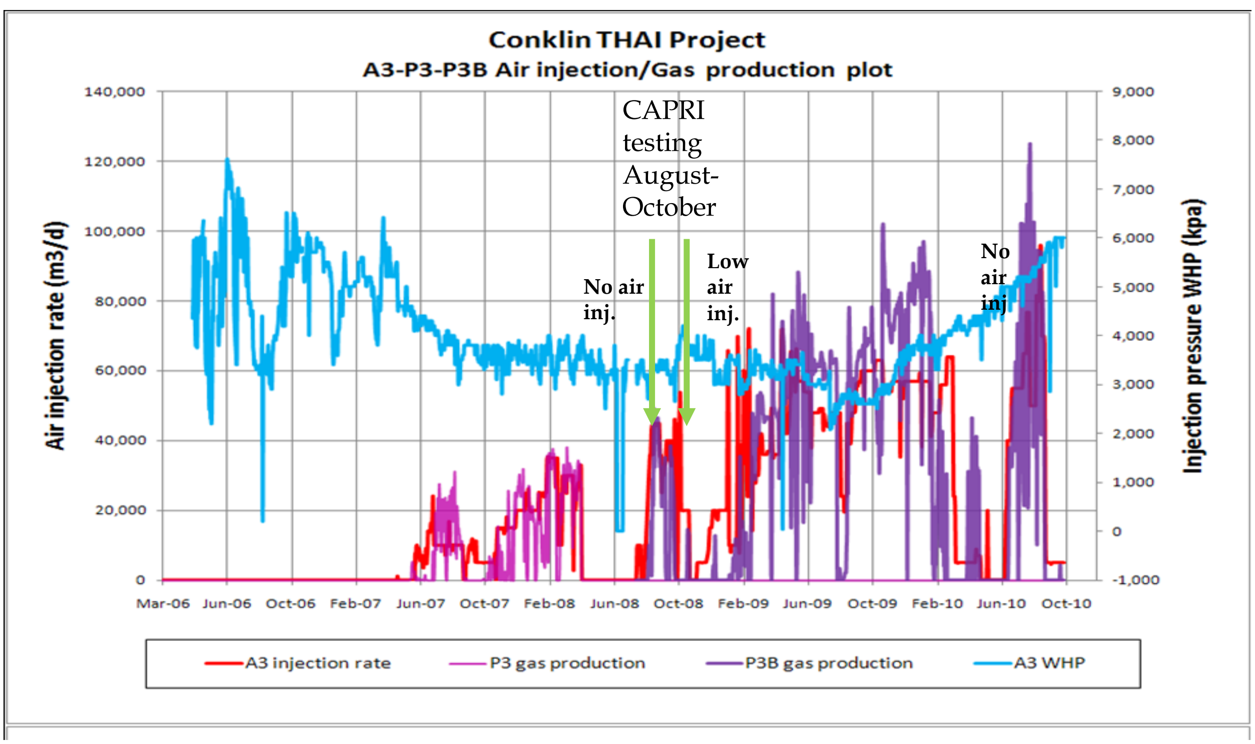


Fig 45d: Whitesands THAI Pilot. Air injection and gas production for A3-P3/P3b pair.
Legend: WHP=Well head pressure

producers, resulting in damage to the well; in March 2009, producer P1, experienced a high temperature of approximately 400 ^{0}C, at around 225 m from the toe (see Fig. 501a).

The data on the produced gas composition is of the utmost importance for establishing both the stability of the ISC process (to air injection interruptions) and also ~~a~~ possible 'burn-out' of the P1 well. The detailed gas composition variation for Jan 2009 to July 2009 (i.e. just before the air injection stoppage in P1) is provided in Table 6. The percentages of CO_2, CO and O_2, indicate a good burning efficiency. This is confirmed by Figure 46a-c. Correlating data from Table 6 with data from Figure..46a-c, it can be concluded that the longer than 3-month interruption in the air injection did not cause any serious problems for re-starting the process. After resuming air injection in P1, it needed approximately 3-4 months for the produced oxygen to decrease from 1-2% to 0.5% (similar to that before stoppage) and increase of hydrogen from 2% to 3-6% (similar to that before stoppage). Similarly, for well P2, for a 4-month interruption in air injection, it required 4 months for the produced oxygen to decrease from 2% to 0.5%, i.e., the value before the stoppage, and increase of hydrogen from 0.5% to 2% (as before stoppage). The percentage of CO_2 saw a slight temporary decrease due to the air injection interruption (from 15-16% to 12-14%).

The interruption of air injection in P3 is even more interesting as this happened after less than 9 months from the achievement of ignition in A3. The 2-month interruption in air injection resulted in no problems; after resuming air injection, it took 2 months for the produced oxygen to decrease from 2% to 0.5% and to hydrogen to increase up to 3-4%, i.e. the values before stoppage (Figure 46c). For this well, the detailed gas composition for Jan 2009 to July 2009 period (i.e., 5 months after the 2008 air injection stoppage) shows ~~a~~ good burning efficiency (Table 6). It is clear that re-starting the ISC process following interruption of air injection was easy.

Therefore, taking into account the results for all three well pairs, air interruption of 2-4 months was associated with a temporary (2-4 months) slight increase in produced oxygen, in parallel with a decrease in both CO_2 and produced hydrogen, after the resumption of air injection. There is no doubt that this is related to a reduction in the peak combustion front temperature during the stoppage period. In situ upgrading also decreased in intensity during the same period, immediately following the resumption of air injection.

Generally, ISC is a very robust process as far as the stability of the air injection stoppage is concerned (Turta, 2013). Also, as seen in other cases, in the Whitesands, pilot air injectivity decreased following the interruption of air injection. However, this time the decrease *was* ***far more pronounced*** *than reported anywhere previously, worldwide;* the air injection pressure increased from 3-3.5 MPa to 5-6 MPa for an air injection rate of 50,000 - 60,000 sm^3/day/well.

Detailed explanations for this phenomenon are provided later on (Section: Analysis of location and performance of replacement wells P1b to P3b). Due to the pronounced air injectivity reduction within the patterns P1 and P2, starting in October 2009, approximately half of the air injected flowed outside these patterns, and this also contributed to the disappointing performance of the patterns.

Checking if a possible 'burn-out' (inside the horizontal producer) or excessive coke blockage (of the horizontal producer) occurs can only be made if detailed, daily gas composition (not averages) for each producer is available. However, even in this case, it is rather complex. The malfunctioning (in time) of the thermocouples - in a kind of toe-to-heel order - indirectly indicates the occurrence of burn-out events, while the impossibility of coiled tubing to advance towards the toe points can be an indication of blockage by coke deposition in the horizontal producer, due to an overheated environment. Additional analysis will be made later on, taking into account also the bottomhole temperature profiles in the observation and production wells, and oil production behavior, in general.

General inspection of the gas composition data from Figures 46a-c shows that the sustainability of ISC process was fully demonstrated; oxygen short-circuiting the combustion front was never observed. This is confirmed by the excellent (low) values of the apparent atomic H/C ratio (around 1) in Table 6, for the period reported. Moreover, the test fully demonstrated that the THAI process is by far more stable that conventional ISC where, in fact, only a short-distance for HTO reactions exists. In conventional heavy oil ISC any step increase in the air injection rate results in an increase of oxygen in the produced gas. This never happens in THAI; as can be seen from Figures 46b and 55b showing the variation of air injection rate and gas composition for P2 well, in the 10 months of October 2008-July 2009, although the air injection rate of well A2 increased in 3 major steps, from 40,000 to 60,000 sm^3/day, the oxygen in the produced gas remained below 0.5%, all of the time. A significant conclusion results from this; namely: *THAI exhibits a short-distance character for oil displacement, but has a long-distance behavior for the oxidation (HTO reactions) pathway*. The last feature may be significant for in situ upgrading, coke deposition mechanisms, and also hydrogen production. However, more investigations are required in this area.

Comparing the gas composition recorded in other commercial and experimental ISC processes worldwide, the main characteristics of the process are ***the simultaneous*** production of relatively high percentages of hydrogen, methane and CO. *A combination of these 3 parameters at these high values has not been seen anywhere*. However, high CO in the produced gas was recorded in Suplacu de Barcau, Romania) ISC but at substantially lower operation pressure (less than 1.5-2 MPa). A high methane content in the produced gas was recorded in Balol, India, but at high operating pressure. The high hydrogen content in the produced gas was recorded in the Marguerite Lake (Canada) ISC pilot (Hallam, 1989), when using a particular form of ISC, namely pressure cycling – ISC with oxygen injection.

Unlike the conventional ISC process applied for heavy oil recovery, the THAI process for bitumen exploitation is associated with continuous production of relatively high amounts of hydrogen and methane. By correlating the gas composition and air injection rates from graphs of Figures 46a-c and 55a-c, it appears that peak H_2 percentages up to 18% were recorded for a short time during the periods of high air injection rates (40,000-60,000sm^3/m^3), when very high peak combustion temperatures were *likely* sustained. Recent systematic investigations related to hydrogen (H_2) generation in an ISC process, showed that H_2 is produced by thermal cracking (pyrolysis), water-gas shift (CO+superheated steam), coke gasification (coke+superheated steam) and aquathermolysis reactions, while methanation (coke+H_2) and H_2 combustion reactions would consume some of the H_2 produced (Kapadia, 2011, 2013). The individual contribution of each of these reactions in the THAI process (and conventional ISC) has never been investigated but previously, while studying this phenomenon for Marguerite Lake ISC pilot, (Hallam, 1989) suggested that the major H_2 production is due to coke gasification followed by water -gas shift reactions.

*

* *

The last observation on the composition of the combustion gases in Table 6 is that by re-calculating the atomic apparent hydrogen-carbon ratio (AAHCR) - last but one column in Table 6 - it was confirmed that the values included are correct. However, they seem slightly lower than the values obtained in other ISC field projects or combustion tube (CT) tests; for instance, values such as those in the range of 0.4-0.7 do not seem to be real. For this reason, in Subchapter 10.1.5 a correction for the CO_2 generated not from oxidation (with the oxygen injected) but from coke gasification and water-gas shift reactions was applied. The method was based on the assumption that the H_2 production was due exclusively to coke gasification followed by water - gas shift reactions. After correction, all the AAHCR values go in the range of 1.1-1.8, correlating better with other ISC projects, known so far. Still being under 2.5-3, the newly corrected values of AAHCR show a good quality ISC process (Moore, 1999). For the details of the new method developed to achieve this correction, see Subchapter 10.1.5.

Table 6: Combustion gas composition variation in the period January-July 2009 (before air inj. stoppage in wells A 1 and A2)

Legend: AAHC=Apparent atomic hydrogen-carbon ratio

P1 Monthly Gas Analysis

Month	H2	O_2	N_2	CO	CH_4	CO_2	C_2H_6	C_3H_8	C_4	C_5	H_2S	Total	CO_2/CO RATIO	AAHCR
Jan-09	5.14	0.23	71.23	1.90	4.83	14.71	0.82	0.42	0.11	0.06	0.56	100.01	7.85	0.74
Feb-09	5.25	0.28	69.85	2.38	6.36	13.74	0.90	0.47	0.11	0.06	0.59	100.00	5.92	0.85
Mar-09	3.56	0.20	73.06	1.62	5.59	13.95	0.86	0.49	0.12	0.06	0.49	100.01	10.31	1.16
Shut-In														

AAHCR corrected for coke gasification

1.58*

P2 Monthly Gas Analysis

Month	H2	O_2	N_2	CO	CH_4	CO_2	C_2H_6	C_3H_8	C_4	C_5	H_2S	Total	CO_2/CO RATIO	AAHCR
Jan-09	2.38	0.24	74.25	0.64	5.39	14.99	0.99	0.52	0.13	0.06	0.40	100.00	23.58	1.08
Feb-09	2.28	0.24	75.66	0.65	4.68	14.54	0.84	0.54	0.12	0.07	0.39	100.00	22.80	1.33
Mar-09	1.66	0.22	77.29	0.65	3.73	15.10	0.58	0.37	0.09	0.04	0.26	100.00	23.67	1.25
Apr-09	2.44	0.26	73.60	0.79	5.87	15.58	0.62	0.35	0.08	0.04	0.35	100.00	20.35	0.82
May-09	1.64	0.35	75.52	0.50	5.21	15.47	0.60	0.32	0.07	0.04	0.29	100.00	31.96	1.01
Jun-09	1.71	0.58	76.29	0.70	3.51	16.01	0.52	0.28	0.07	0.03	0.31	100.00	24.70	0.82
Jul-09	1.89	0.48	73.99	0.64	4.56	17.30	0.47	0.28	0.06	0.03	0.31	100.00	27.52	0.39
Shut-In														

1.47*

P3 Monthly Gas Analysis

Shut-In

Composite Monthly Gas Analysis - Sampler after the Sweetener

Month	H2	O_2	N_2	CO	CH_4	CO_2	C_2H_6	C_3H_8	C_4	C_5	H_2S	Total	CO_2/CO RATIO	AAHCR
Jan-09	4.00	0.07	73.05	1.40	5.24	14.61	0.92	0.51	0.13	0.06	0.00	100.00	10.54	1.04
Feb-09	3.93	0.15	73.84	1.65	5.71	13.15	0.86	0.55	0.11	0.06	0.00	100.00	8.30	1.53
Mar-09	2.91	0.03	74.20	1.28	5.38	14.78	0.79	0.47	0.10	0.05	0.00	100.00	12.42	1.09
Apr-09	2.74	0.08	74.81	1.39	5.37	14.38	0.66	0.43	0.09	0.05	0.00	100.00	10.81	1.26
May-09	2.37	0.10	73.88	1.54	4.94	15.96	0.63	0.43	0.09	0.04	0.01	100.00	13.02	0.67
Jun-09	2.91	0.16	73.28	1.48	4.16	16.75	0.65	0.46	0.09	0.05	0.00	100.00	12.29	0.42
Jul-09	4.00	0.13	70.83	1.50	5.27	17.08	0.62	0.45	0.08	0.04	0.00	100.00	12.35	0.24
P2 Shut-In														

Note: Up to 6000ppm H_2S was recorded in the combustion gases of P1 well and up to 4000ppm in the combustion gases of P2 well. A scavenger was utilized to remove the H_2S, and its utilization was in a batch-wise mode.

* See Subchapter 10.1.5 for details

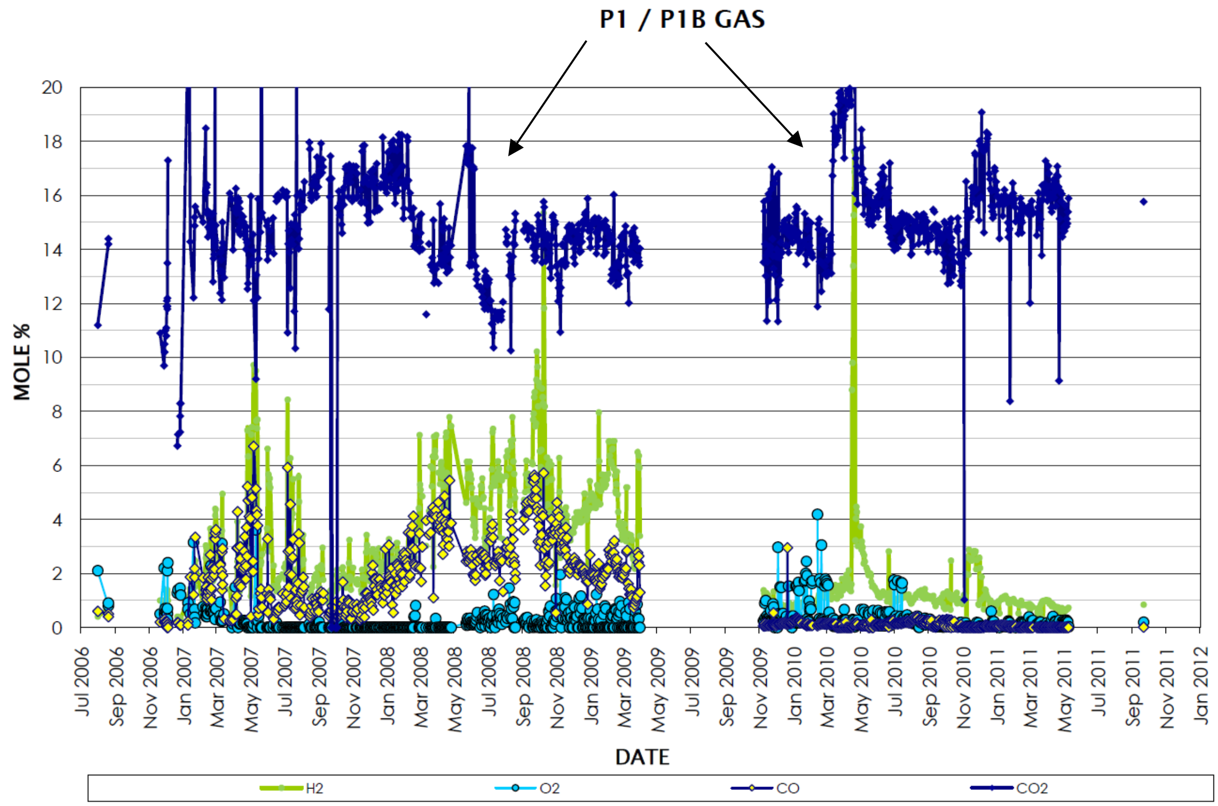


Figure 46a: Gas composition variation for production well P1 and its replacement well P1b

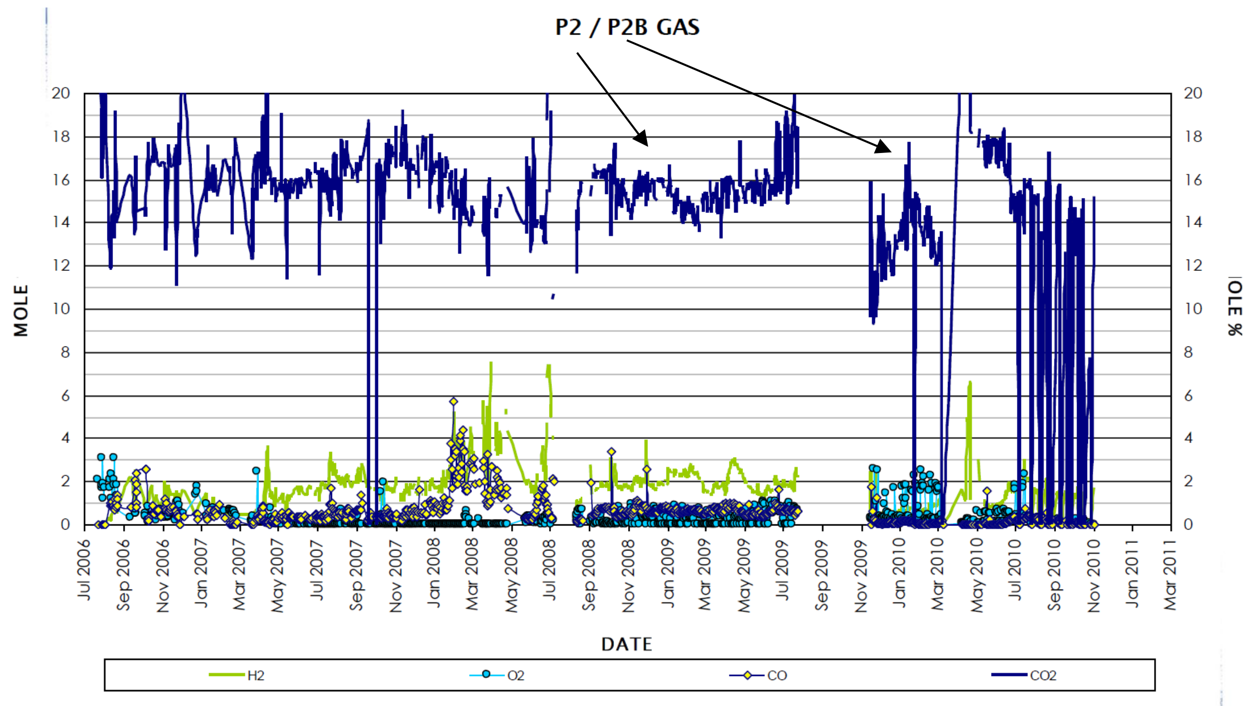


Figure 46b: Gas composition variation for production well P2 and its replacement well P2b

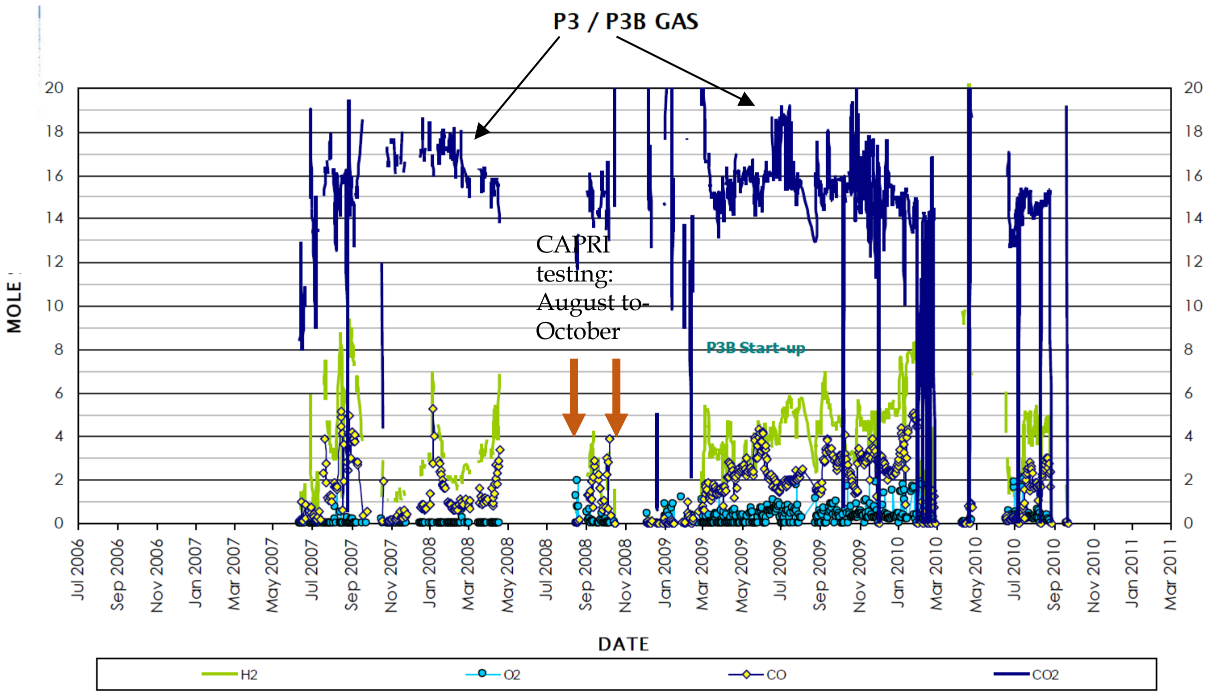


Figure 46c: Gas composition variation for production well P3 and its replacement well P3b (all Figures 46 are from Petrobank presentation, 2011). Air inj. stoppage before and after CAPRI testing in the period August-October 2008

Combustion gas production was relatively normal. Up until July 2009, a total of approximately 79 million sm^3 (MM sm^3) air was injected, while the total gas produced was 60.25 MM sm^3 million, representing 76% recovery of the injected gas. However, during the last period, after the replacement wells were put into production, only 65%-70% of the injected air was recovered as produced flue gas. It is possible that some of the combustion gases migrated into overburden formations (see Section 6.1.4.2.4 , including Fig. 53). Operational experience from big commercial ISC projects worldwide shows that in most of them, only a maximum of 85% of the produced gases was captured and measured (Turta 1994 and 2007). Taking this into account, it can be speculated that the amount of gas lost in the Fort McMurray "A" formation could have been in the range of 10%-15% of the injected gas, indicating that *ISC confinement was not a significant problem.* However, this estimate is complicated (made weaker) by the fact that the process produced an extra-amount of gas in the form of H_2, methane, and (to some extent CO), some of them probably associated with the strong underground upgrading feature of the process. Also, this does not say anything about the nature/type of foreign gases (air, flue gas, etc) entering the gas-bearing intervals of Fort McMurray “A”. Furthermore, analyses of possible effects are beyond the scope of this study.

6.4.2.3. BHT Recordings from Observation and Production Wells

Information relative to the **b**ottom**h**ole **t**emperature **(**BHT) is crucial for establishing the state of the ISC process, and development of the combustion zone, in different directions. The recordings from observation wells and replacement wells give valuable information on the lateral development of the burned zone (around each of the original production wells) and the confinement of the process in the McMurray "B" formation. Recordings from production wells provide direct information on the advancement of the ISC front along the horizontal section of the horizontal well (including the intensity of burning in the proximity of the horizontal section). In the IETP reports, these temperature records were available until December 2008, from the observation wells, and until March 2009 for temperature profiles along the horizontal section of producers. For the remaining time (mainly period March 2009-September 2011), these kinds of measurements were available from Petrobank presentations to ERCB/AER. The existence of the numerous temperature profiles in so many wells makes the Whitesands THAI Pilot one the best instrumented in the world. With such an abundance of data of this kind, it presents a precious opportunity to study in-depth the mechanisms of direct line drive (DLD) THAI process.

BHT from observation wells: The bottomhole temperatures (BHT) increased in observation wells TOB1, TOB2, OB3, OB6 and OB9; TOB1 and TOB2 are very close to the injector A-2; Figure 47 shows the evolution of the temperature profiles for these wells, while Figure 48c shows the maximum temperature recorded in each observation well. It is mentioned that the burned volume limits (and implicitly the temperature distribution associated) disagree with the Petrobank's representation as given in Fig. 47b; increase of temperature towards the middle of the space between two producers did not happen.

The maximum temperatures recorded in TOB1, TOB2, OB3, OB6 and OB9 and at the toes of P1, P2 and P3 wells are in the range of 340-760^{0}C, and this clearly shows that ignition has been achieved in all three air injection wells and that ISC fronts started their propagation towards the corresponding heels. However, there is no other temperature information from observation wells to show ~~a~~ combustion front propagation moves beyond observation well OB6, which is located approximately 50 m from the A2 injector (a lateral distance of 20m from P2). The maximum temperature of 93 ^{0}C in OB7 well, located at approximately 20 m laterally from well P3, in the region of its heel, cannot be taken as very strong support since high temperatures were not recorded in OB9 and OB8 which are much closer to the toe of well P3 and at approximately the same lateral distance (20 m) from P3 trajectory. This relatively high temperature was due to a heat communication between well P3 and OB7 - via the 2.8m thick bottom water zone – during the steam injection for pre-heating of P3 horizontal producer in the period Dec 15, 2016 -April 2007. The evolution of temperature profiles in well OB7 supports this interpretation as the maximum temperature of every profile is located at the water/oil interface.

The most significant temperature record is that for TOB2, as this observation well is located in the same *direction as the ISC front advancement,* at a distance of approximately 7.5m from the injector A2 (Fig. ??) ?????. The temperature profiles taken during the period March 2006 to July 2006 (Fig. 47b1), show that during the steam injection period (PIHC) before ignition, the temperature of the McMurray “B’ formation (the target of ISC application) did not rise more than 100 ^{0}C. Later on, the maximum temperature increased up to 800 ^{0}C in the period July 2006 to July 2007. July 2007 is considered to be the time when the ISC front intercepted this observation well - the maximum temperature gradually decreased over the next four months. On the other hand, the temperature profile shows that steam entered the McMurray "A' formation (in June 2006), situated 25 m above the McMurray “B’ formation. A maximum temperature of 240 ^{0}C was recorded in May 2007 and afterward it gradually decreased; it was reported that the entrance of steam into McMurray "A' formation was due to the exceeding of the fracturing pressure during the steam preheating period (Petrobank IETP presentation 2011).

The entrance of air into McMurray "A' formation was confirmed by the temperature profile of TOB1 (Fig. 47a) in which a maximum temperature of 336 ^{0}C was recorded in July 2007, then gradually decreasing (235 ^{0}C in August 2007). Therefore, ISC activity has occurred in this formation, since the temperature there exceeded the maximum temperature of the injected steam (280 ^{0}C). Mc Murray A formation has a good oil saturation (72%) and sustaining of the ISC front was easily achieved. The fact that the temperature decreased after July 2007 cannot be taken as a proof that combustion did not occur in the McMurray “A’ formation. A fraction of the injected air was consumed in the ISC front generated in this formation. A third observation well – OB3 – located laterally from P1 producer, also showed a tendency for some air to enter the McMurray “A’ formation (Fig. 47c). By correlating the temperature profiles from TOB1 and TOB2 it results that in McMurray A formation, the ISC peak temperature was eventually located in the thin gas cap (< 1m thickness) at the top of the formation (see well log in Fig 40a and Figs 46a and 46b). Analysis and more details on the amount of air flowing in Mc Murray A formation are provided in Appendix E, while more information on the possibility of the existence of an ISC front in a gas cap overlaying an oil formation is provided in Section 8.1.6, in conjunction with the application of an ISC process in a gas cap situation.

There was no temperature increase in observation wells OB1 and OB2, OB4 and OB5 and OB8, located towards the heels of the production wells. Therefore, the ISC front advanced up to a limit located between OB6 and OB5 (along P2 trajectory); In August 2010, the maximum temperature recorded in OB6 was 450 ^{0}C (Fig.46d). In the production wells, the maximum temperatures were recorded at a maximum distance from toe of 210 m, 107m and 110m, for P1, P2 and P3, respectively; It can be concluded that the ISC front did not advance more than 200-300m along the horizontal section of producers, which is less than half of the pilot area traversed by the ISC front in a toe-to-heel propagation.

As far as the lateral development of the combustion front is concerned (perpendicular to the trajectories of producers), observation well OB9 located in the vicinity of P3 toe, 20m North of P-3 well trajectory, recorded a maximum temperature of 335 ^{0}C in August 2010. This shows that the lateral development of the combustion front was therefore limited, probably to a lateral distance of 15-25m around the trajectory of horizontal producers; As mentioned previously, the temperature profiles from OB3 and OB6 fully support this conclusion. T*he previous conclusions regarding the development of the combustion burned zone, both along and perpendicular to the horizontal section of producers, is also supported by the information from the replacement wells P1b and P2b*, which were located <u>*with their toes at about 50 m from the original shoes of vertical injectors*</u> (and 14-15 m laterally from the original producers trajectories) (Figures 48 a, b and d and 49). The horizontal section of P1b and P2b were drilled 5m above water/oil (W/O) interface, while P1 and P2 were drilled 1.5-4m above W/O interface. Wells P1b and P2b did not intercept any hot zones! It was necessary to "hotlink" these wells to the former ISC process [SIR 3, 2011]. In the case of P3b, located approximately 20 m from A3 and 15m from the trajectory of P3, although the initial temperature profile showed a low temperature (100 ^{0}C), the link with the heated zone around P3 was more accessible due to the small distance from P3. Later on, a pseudo-ISC propagation occurred along the P3 trajectory; This type of propagation was never seen in for P1 and P2, as these wells were not properly located relative to the existing burned zones.

*

* *

Judging from the evolution of the temperature profiles in the observations wells (as discussed below), the time of ignition and the ignition delay were estimated (see Table 4).

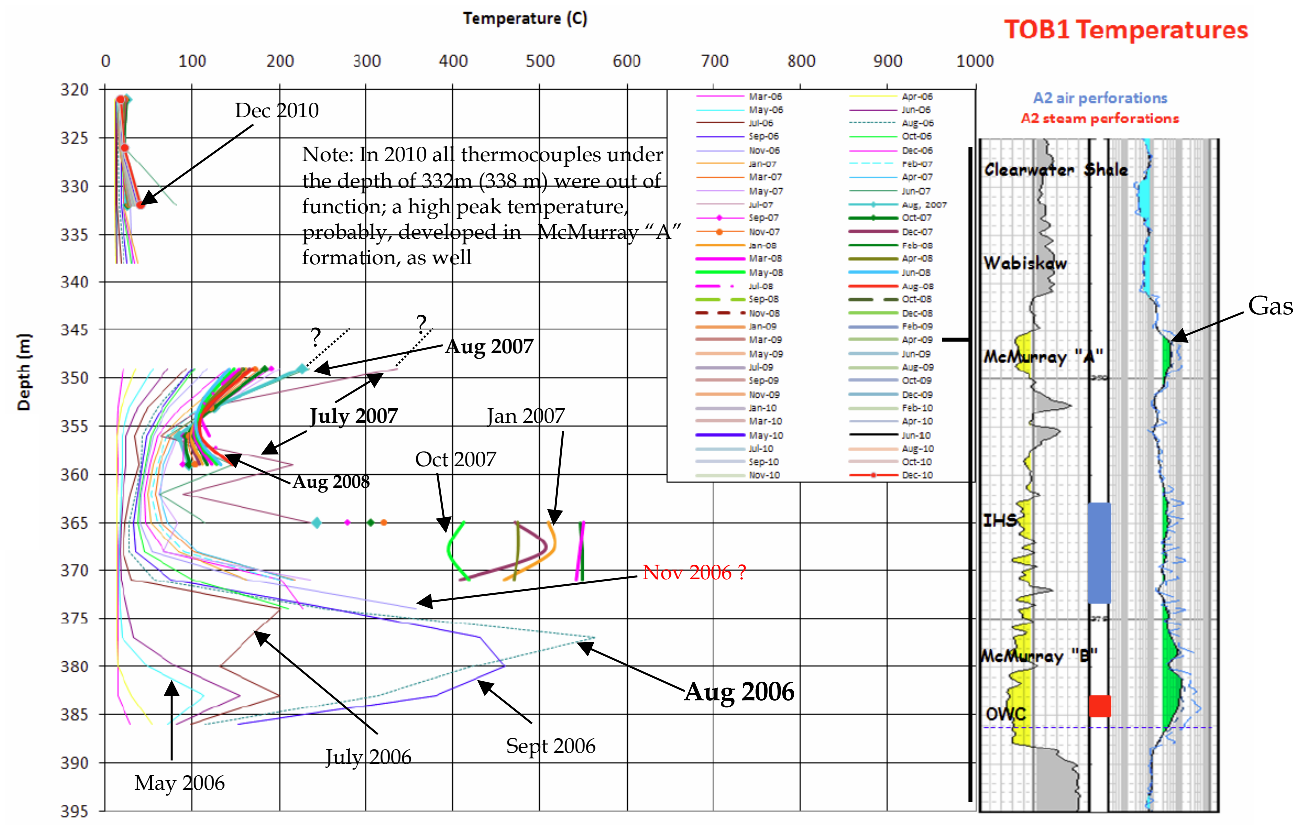


Fig. 47a: Whitesands pilot. Bottomhole temperature profiles for the temperature observation well TOB1, located 2-3m from the injection well A2 (in opposite direction relative to the heel of horizontal producer). There were three peak temperatures, located at 377m depth (McMurray "B"), 367.5m in Inclined Heterogeneous Strata (IHS) and less than 350m depth (McMurray "A").

Note 1: The thermocouple at a depth of 345m was defective since the very start of the process; it does not have anything to do with damaging due to excessive temperature, see more details in Appendix E.

Note 2: The peak temperature (T_{peak}) in McMurray "B" formation increased continuously until August 2006, when interception of this well by ISC front took place; at the same time, the T_{peak} moves towards the top of the formation being at the 367.5m in January 2007. The *probable T_{peak} in McMurray "A" formation* increased continuously until July 2007, when interception of this well by ISC front probably took place (extrapolated based on TOB1 and TOB2 existent profiles, T_{peak} was probably at least 400^{0}C; peak temperature should be located close to top of formation, where a thin streak of gas saturation exists). Therefore, an ISC front was generated in McMurary "A" formation, as well.

After September 2006, the thermocouples at a depth higher than 372m are out of service. Afterward, consecutively, the thermocouples at a depth higher than 358, 338 and 332 m went out of service. Starting in 2009, only 3 thermocouples, above 332m, were in function. This may be proof that eventually, an almost compact combustion zone formed, from top to bottom (from 332m to 385m), including McMurray A.

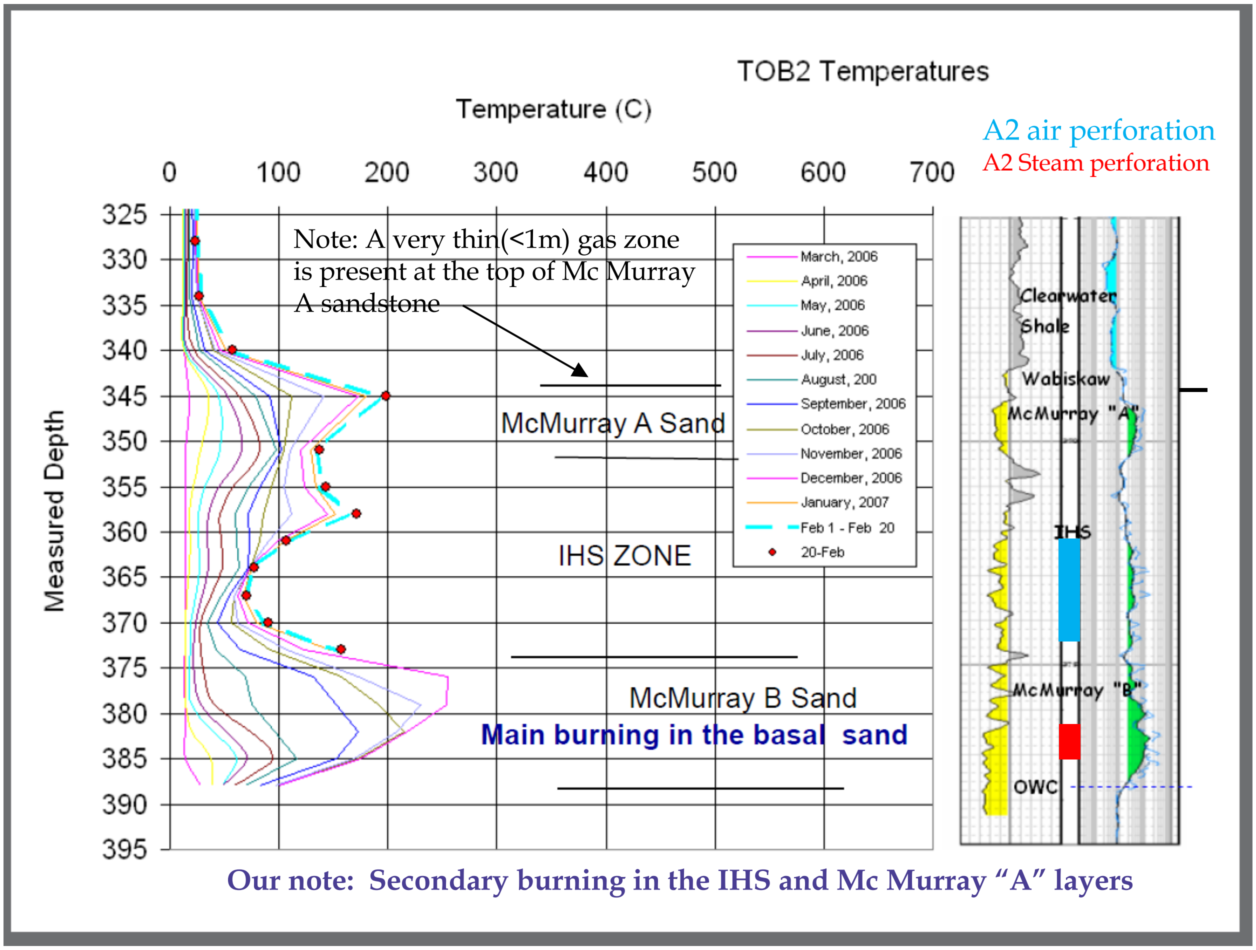


Fig. 47b1: Whitesands pilot. Bottomhole temperature profiles for the temperature observation well TOB2, in the period March 2006-February 2007. The well is located 7.5m from the injection well A2 (in the direction of the heel of horizontal producer), and 5m from the horizontal well P2. IETP Presentation, 2007

MAIN EVENTS:

-March 2006-July 2006 - Steam injection during pre-ignition heating cycle (PIHC)

-July 2007: Interception by the ISC at the McMurray B formation level

The first 5 profiles at the left of the picture (March-July 2006) show temperature distribution during steam injection. Steam injection caused a peak temperature (T_{peak}) of around 100 ^{0}C at two levels: depth of 350m (McMurray A) and depth of 385m (Mc Murray B). Once the air injection started (on July 20, 2006) those two peaks raised towards lower depth and eventually three T_{peak} developed at the level of 345m (McMurray A), the level of 358m (IHS layer) and 375-380m (McMurray B)

Also, after July 2006, the T_{peak} increased in value up to a maximum of 250 (at McMurray B), up to 200 ^{0}C (at McMurray A), and up to 180^{0}C (at IHS layer), in February 2007.

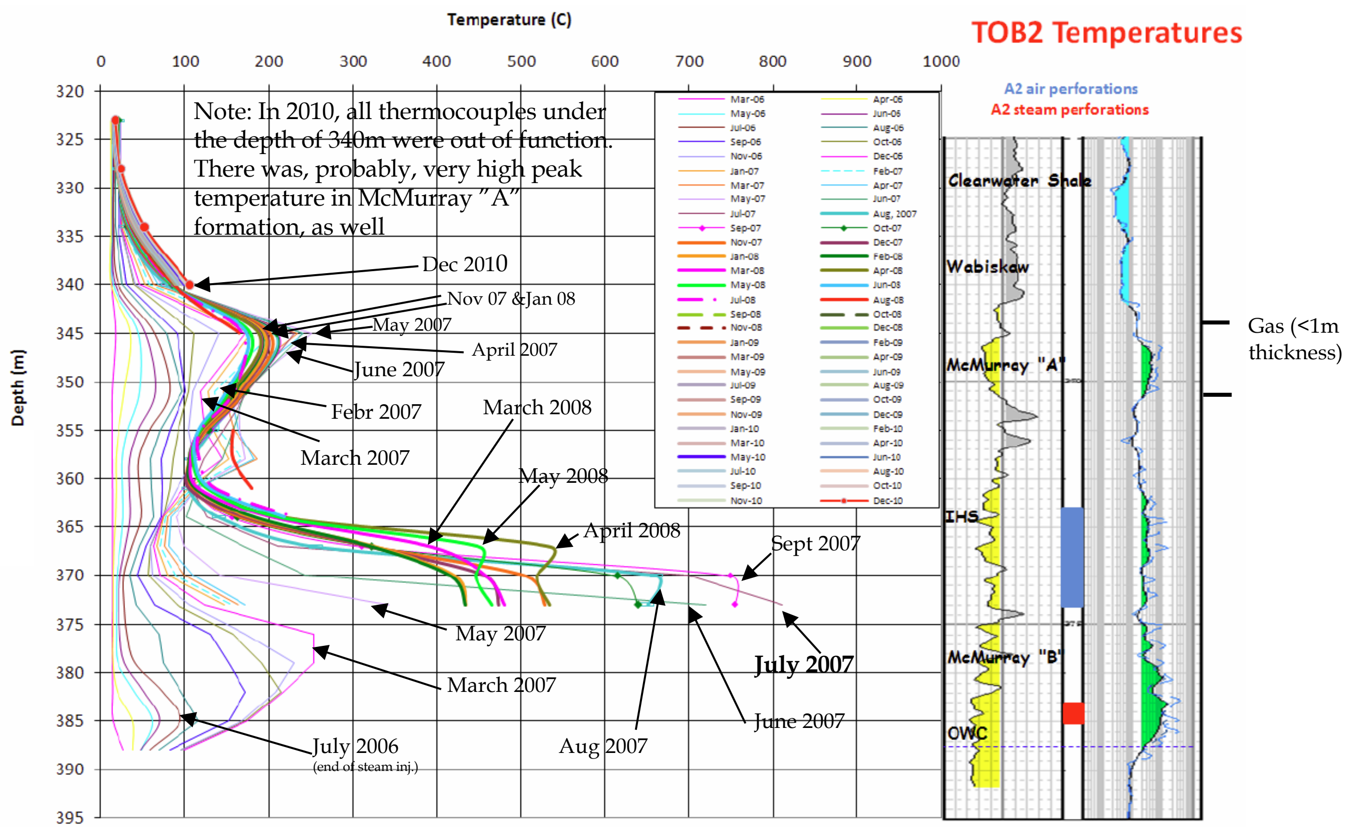


Fig. 47b2: Whitesands pilot. Bottomhole temperature profiles for the temperature observation well TOB2, in the period March 2006-December 2010 (it contains the curves from Fig. 47b1).

Interception by the ISC at the McMurray B formation level occurred in July 2007

The peak temperature (T_{peak}) in McMurray "B" formation increased continuously until July 2007, when interception of this well by ISC front took place. Then within one year, the T_{peak} raised towards lower depths; it moved from 375 m up to 367.5m. Simultaneously, the peak temperature at McMurray A consolidated (increasing up to 240 ^{0}C in April-May 2007), while the peak temperature at IHS layer disappeared (there was probably no oil saturation in that small interval).

After April-May 2007, the thermocouples at a depth higher than 373m are out of function. Since September 2008, the thermocouples at a depth higher than 340m are out of function; only 4 thermocouples (TC'c) are in function (position of TC'c marked on Dec 2010 curve). This confirms the finding from TOB1 that eventually a combustion front formed in all layers (from 332m-340m to 385m), including in McMurray "A" formation

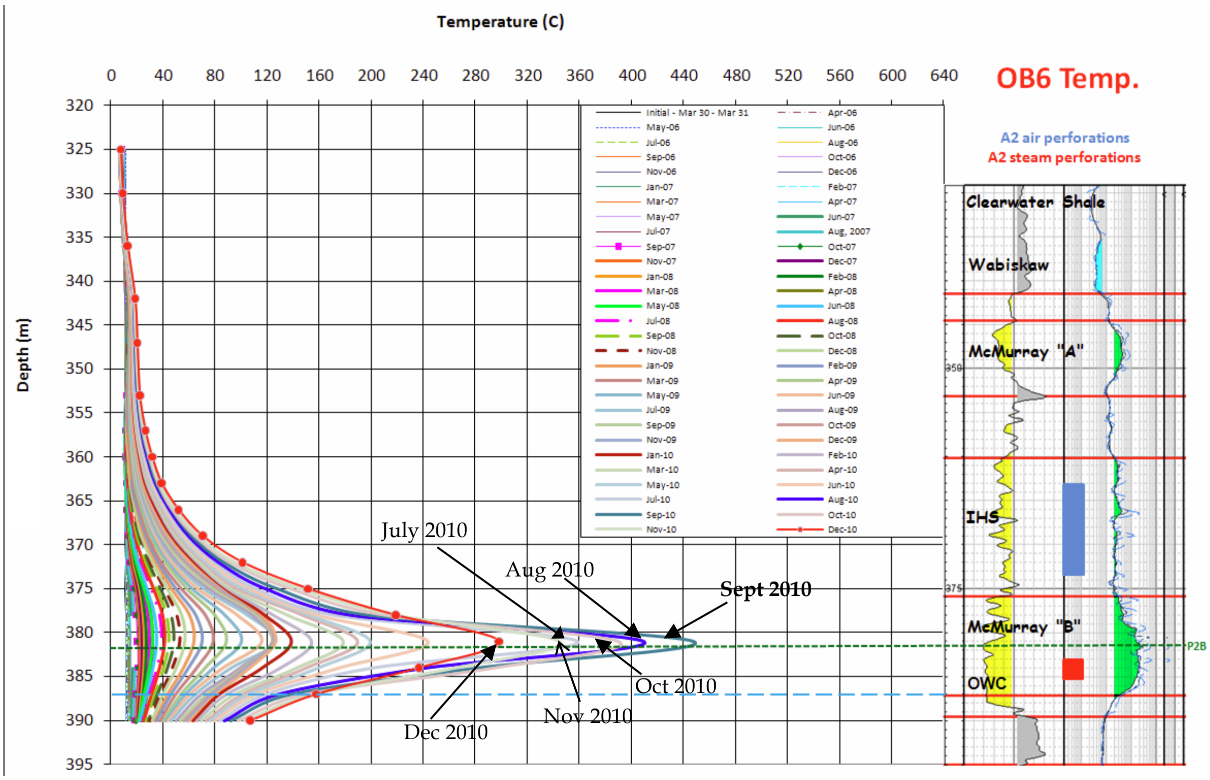


Fig. 47c: Whitesands pilot. Bottomhole temperature profiles for the observation well OB6, located 42m from the injection well A2 (and 15m laterally from the horizontal well P2). The peak temperature was located at 382m since the beginning of the process, remained at the same depth and increased gradually up to 410 ^{0}C, in September 2010, when the interception of the well by ISC took place.

Note: All the thermocouples have remained in function, all the time.

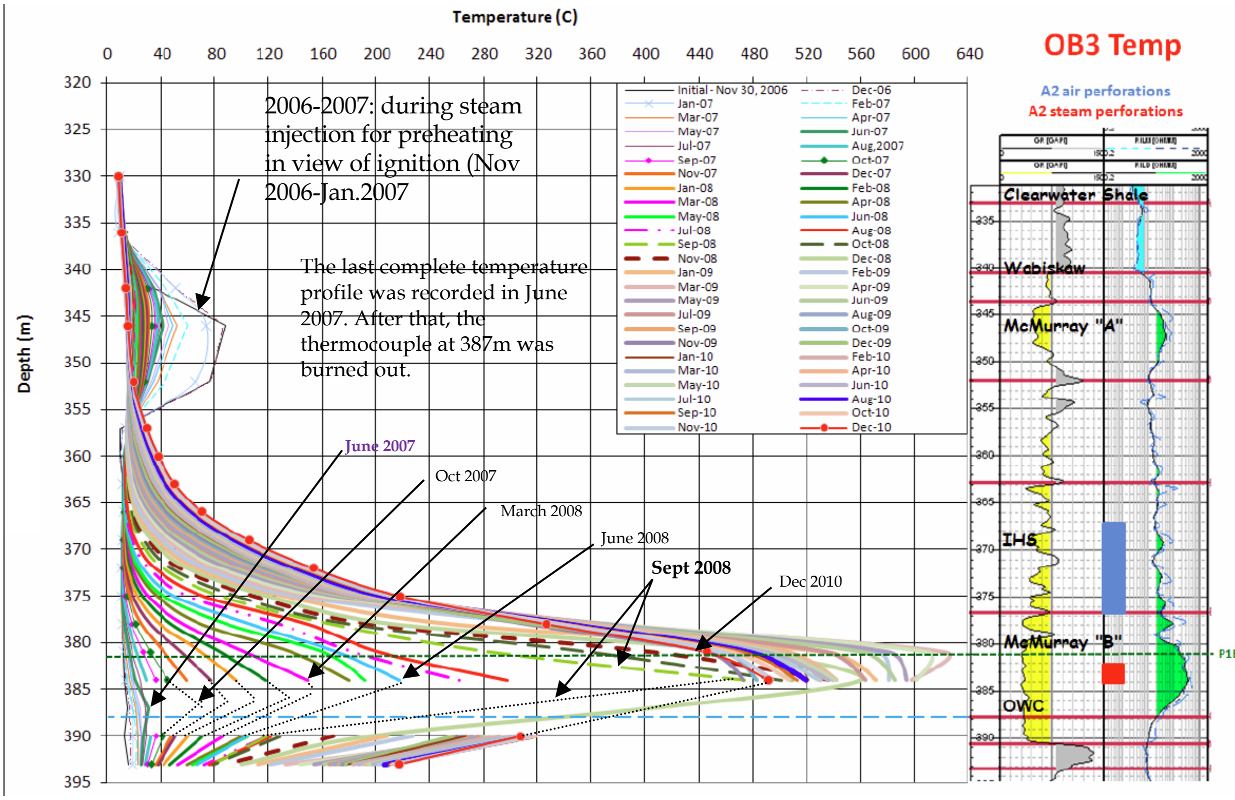


Fig. 47d: Whitesands pilot. Bottomhole temperature profiles for the observation well OB3, located 40m from the injection well A1 (and 12m lateral from the horizontal well P1). It shows some heating at McMurray A, due to steam injection in the McMurray "b" formation, at the distance (40m) from the A1 injector; however, there is no clear sign of air entering and oxidizing in McMurray A formation. The ISC peak temperature was located and remained in the interval 381-384m. The time of interception by ISC front is estimated as September 2008

Note: The thermocouples in the depth interval 384m-390 are out of function after June 2007. After this date, for this interval, which is just around the water/oil (W/O) interface, the temperatures were estimated with interrupted lines (………). The maximum temperature recorded at the W/O interface was 360-370 ^{0}C, showing burning at and under the W/O interface.

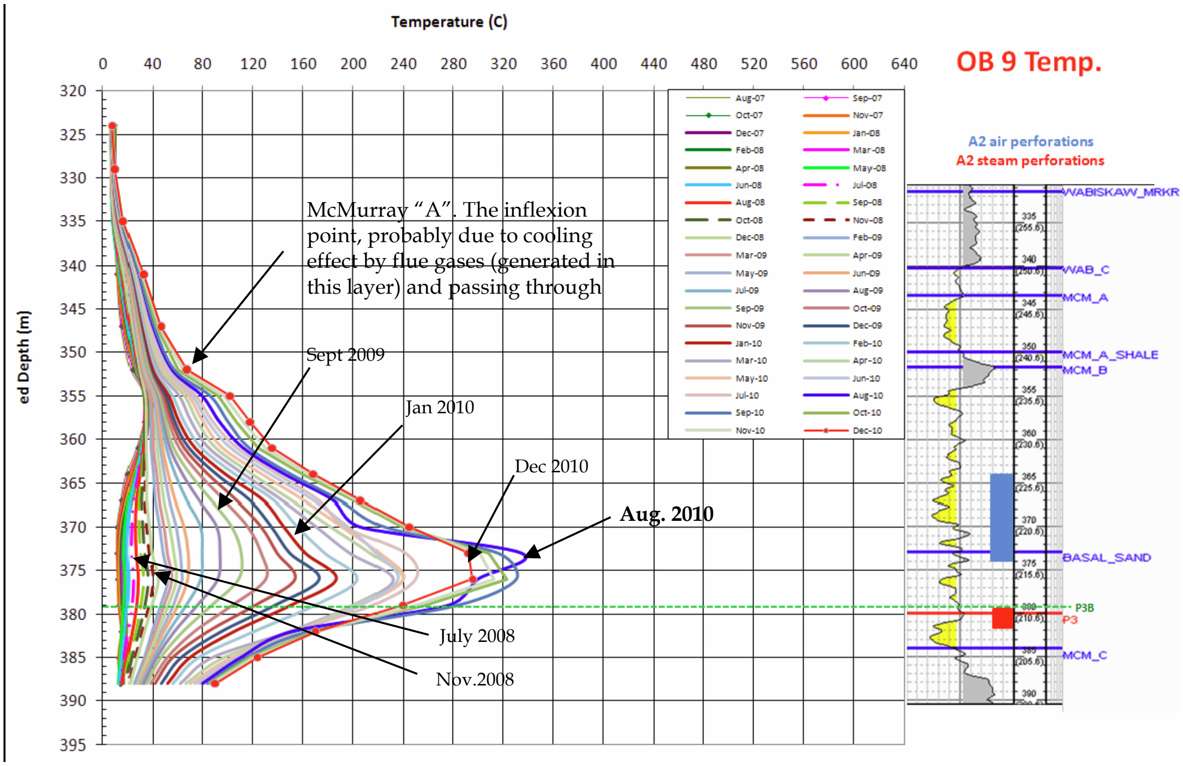


Fig. 47e: Whitesands pilot. Bottomhole temperature profiles for the observation well OB9, located laterally 15m from the horizontal well P3 and 17m from the injection well A3.

The peak temperature was located in the interval 373-377 m (slightly above A2 steam perforations) since the beginning of the process, remained at the same depth and increased gradually up to 335 ^{0}C, in August 2010, when the interception of the well by ISC took place.

Note: All the thermocouples have remained in function, all the time. In time, the gradual increase of peak temperature up to August 2010 (moment of ISC front interception) and, then, the gradual decrease of peak temperature after the interception of ISC front can be easily followed.

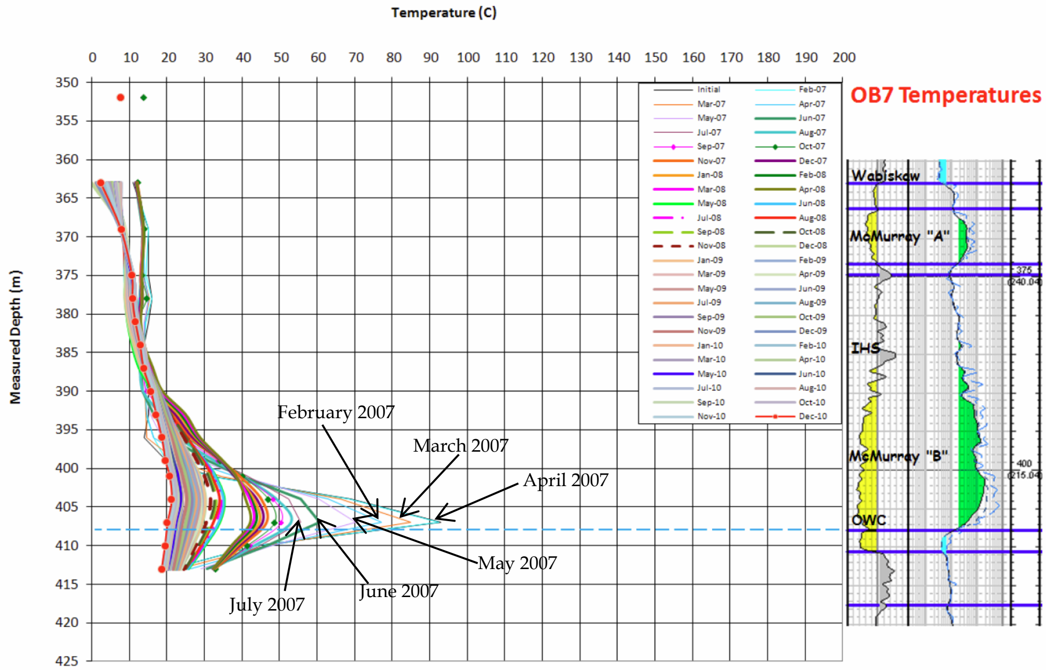
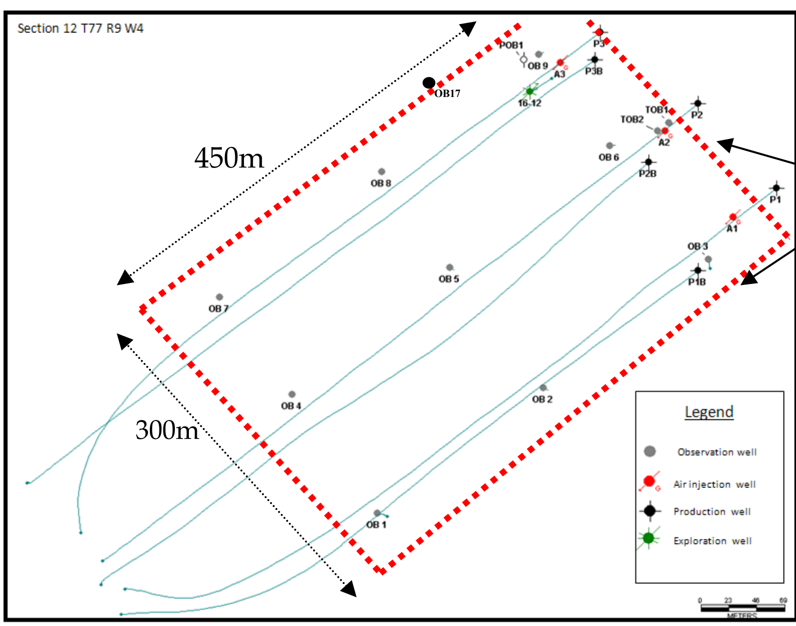


Fig. 47f: Whitesands pilot. Bottomhole temperature profiles for the observation well OB7, located laterally approximately 20m from the horizontal well P3, *but in the region of its heel*. The peak temperature was located at the oil/water interface; it reflects the heating process during the injection of a slug of steam for the pre-heating of the producer in order to facilitate putting it into production. Increase of temperature until April 2007 (steam injection in the interval of time: Jan 1st 2007-May 11, 2007); after April 2007, the gradual decrease of temperature occurs. The temperature profile is not related to the ISC front propagation along the horizontal section of horizontal producer P3.



Outline/contour of the pilot area as per the original design (100m between THAI pairs)

Fig 48a: Map with the location of wells: injection wells (A1-A3), production wells (P1-P3 and P1b-P3b), observation wells (OB1-OB9), temperature observation wells (TOB1-TOB2) and one exploration well (OB17), IETP study 2009.

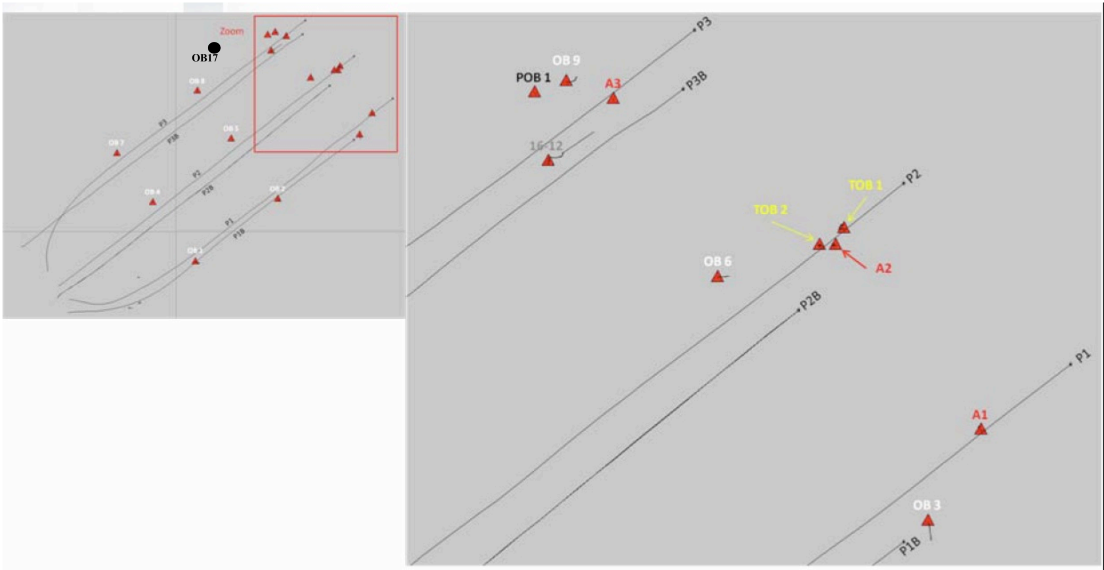


Fig 48b: Map with the location of wells in the region of vertical injectors (mainly to show distances of vertical injectors to the horizontal section of horizontal producers, for each THAI pair). The OB17 well, drilled later on (to check the presence of combustion gases in the bottom water), is also shown Petrobank presentation, 2011

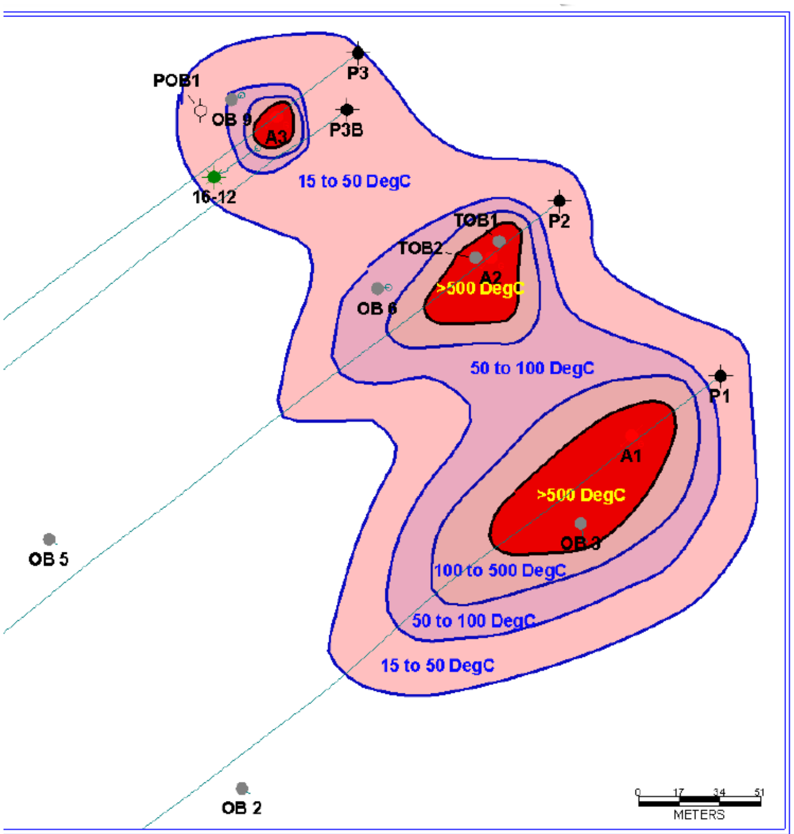


Figure 48c: Petrobank Temperature distribution as of March 2009

(based on temperature records from observation wells). IETP Presentation, 2009

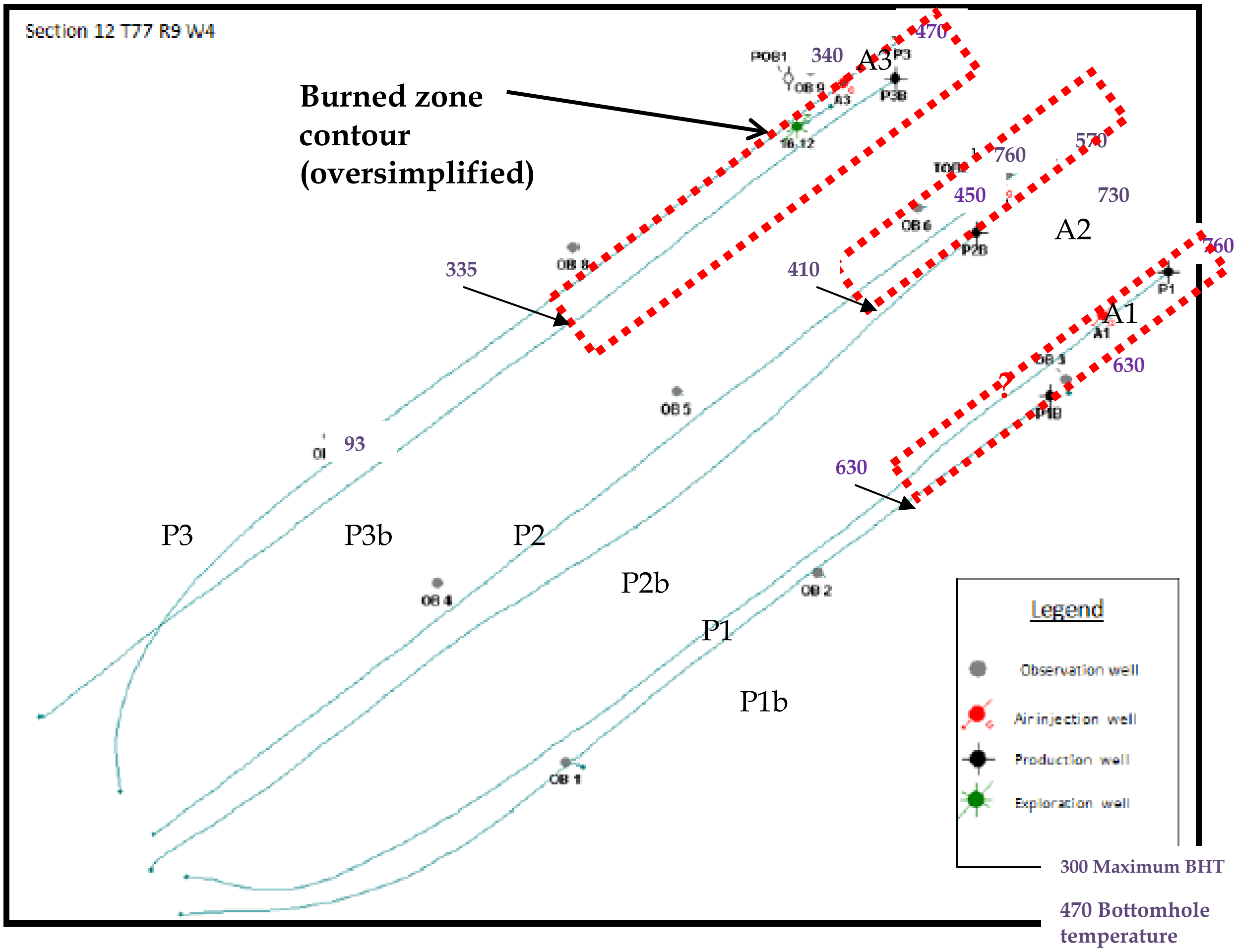


Fig 48 d: Map with maximum **b**ottom **h**ole **t**emperatures (BHT) recorded in the observations wells and in the horizontal producers (until July 2010). A rough estimate of the burned zone distribution around each THAI well pair, as of July 2010. Note: **?** Denotes the fact that there is no temperature control on that side (no temperature measurement)

BHT from production wells: the history of the variation in temperature near to and close to the toe of the producers is shown in Fig. 50a-c; it can be seen that for P1 and P2 producers, very high temperatures were recorded in 100-200m of the toe because the thermocouples in this region failed after 1-2 years. The maximum temperatures at the toe were more moderate in the case of well P3, which is located in a region with a 3m-thick bottom water zone. In general, at the heel the temperatures were in the range of 100-180 ^{0}C, while at the wellhead they were around 60-70 ^{0}C.

From the evolution of the temperature at the toe of the producers, the time of anchoring of the ISC front at the toe can be estimated as follows:

Well A2: September 25, 2006 (anchoring delay: 2 months)

Well A1: April 2007(anchoring delay : 3 months)

Well A3: August 2007 (anchoring delay: 3months)

It is known that in a direct line drive (DLD) THAI process, the ISC front intercepts the horizontal section of horizontal producers from the very beginning of the process. From the graphs in Figures 51a1; 51b1 and 51b2; 51c1 and 51c2 it can be estimated that by 2010 the maximum distance of the ISC front advancement took place, was as follows:

- Pair A1-P1: 225 m from the toe (maximum temperature=400^{0}C)
- Pair A2-P2: 150 m from the toe (maximum temperature=300^{0}C)
- Pair A3-P3: 100 m from the toe (maximum temperature=300^{0}C)
- Pair A3-P3b: 250 m from the toe (maximum temperature=300^{0}C)

The details on the ISC front advancement along the horizontal section of horizontal producers are provided in Table 7a. As seen from this table, the average ISC front velocity along the horizontal section was in the range of 25-31 cm/day. By far, the longest toe-to-heel propagation (TTHP) was recorded for the pair A3-P3(P3b), as the old ISC front generated and anchored initially to P3 performed a TTHP along P3 for 100 m and afterward, another 150m along P3b; in total 250m from the air injection well A3. Considering the total length of the horizontal section of 410m, it means that only a portion of approximately 160m (close to the heel) was not traversed by the ISC front.

On the other hand, the calculation of the average ISC front velocity towards the observation wells OB3, OB6 and OB6, located at 20-50m from the air injector (Table 7b), showed that the velocities for the oblique directions (wells OB3 and OB6 in Fig. 47) were 6 times lower than those along the horizontal section of horizontal producers, while for a pure lateral location (well OB9) the velocity was 12 times lower. It has to be underlined that the ISC front also advances laterally and even in a direction opposite to the horizontal section of producer (see also Fig. 9a, Chapter 3).

Table 7a: Whitesands Pilot. Estimation of the main thermal parameters; ignition and ISC front propagation along the horizontal section of producers, for the individual THAI patterns

Pattern or pair	Start date of operations	Ignition delay months	Date of full development of ISC front in the pattern	Quality of ignition: VG=very good; G=good;	Advance-ment of ISC along HS of HP (meters) / Date	ISC front velocity along the horizontal section of horizontal producer cm/day	Observations
A1-P1	10-2006	2	03-2007	VG	225 / 03-2009	31	Long TTHP
A2-P2	03-2006	1	08-2006	VG	150/03-2008	26	
A3-P3	12-2006	2	07-2007	G or VG?	100 / 08-2007	25	
A3-P3b	08-2008	7(?)*	03-2009*	G	+150** / 09-2010	24	Longest TTHP

Legend: TTHP = toe-to-heel propagation; HP = horizontal producer; HS=horizontal section

* Just anchoring of the old burning surface (pre-existing around P3) to the toe of P3b

** Total TTHP of the ISC front (considering both P3 and P3b) was 250m.

Table 7b: Whitesands Pilot. Estimation of velocity of the ISC front propagation towards the observation wells in the individual THAI patterns

Pattern or pair	Observation well	Location / distance from injector m	Distance from production well trajectory m	Date of full development of ISC front in the pattern	Quality of ignition: VG=very good; G=good;	Date of ISC interception	ISC front velocity towards the observation well cm/day	Observations
A1-P1	OB3	Oblique/40	12	03-2007	VG	09-2008	6	Fast propagation
A2-P2	OB6	Oblique/50	15	08-2006	VG	09-2010	3.4	Slow propagation
A2-P2	TOB1	Opposite* /3	2-3	08-2006	VG	09-2006	10	Very fast propagation
A3-P3	OB9	Lateral/17	15	07-2007	G or VG?	08-2010	2	Very slow propagation

*Opposite direction relative to the heel of P2 producer

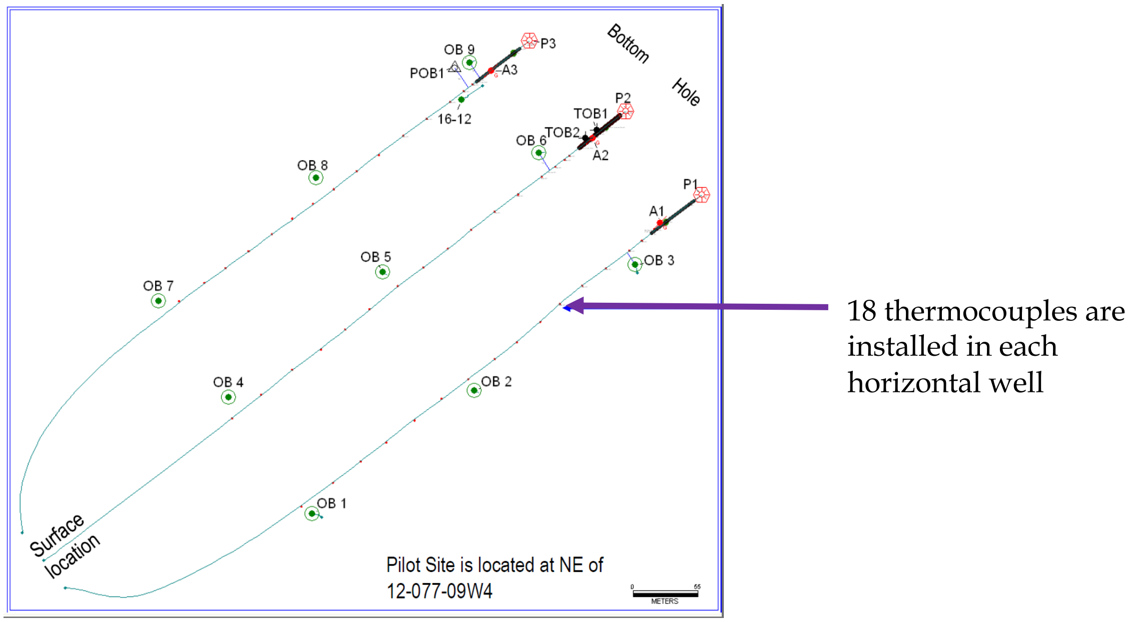


Fig. 49 : Well layout for the original wells and position of thermocouples in horizontal wells, IETP Presentation 2007

6.4.2.4. 3-D configuration and size of the volume burned. Confinement of the Project Area

In the first part of this section, the size and configuration of the burned zone is evaluated, while in the second part, the confinement of the project area will constitute a logical follow up to the first part conclusions, and completes the first part. The second part will also include recommendations on coring wells necessary for confirmation of the burned zones configuration in Mc Murray B and McMurray A and the entrance of oil in the bottom water zone, which is to confirm the results of our current analysis.

A. Size and configuration of the burned zone

The details for this topic are included in Appendix E. The main objective of this appendix was to determine the volume and the shape of the burned volume and calculate a value of the air requirement per m^3 of burned rock (A_{air}) based on field data. Then, to compare this value with the real figure resulted from laboratory combustion tube tests.

As the burned zones around P1, P2 and P3 were relatively small and have never merged, the value of the burned volume can be *estimated* for each THAI pair, using the bottomhole temperature measurements in the horizontal producers and in the observation wells. Then, based on the cumulative volume of air injected in each of them, the air requirement (A_{air}), can be estimated. Detail~~s~~ on the cumulative of air injected in each pattern are provided in Appendix E and are based on Fig. 51 and data from Table 8b.

As of September 2010, the cumulative volumes of air injected are:

Pair A1-P1: 55.5 million sm^3
Pair A2-P2: 57.5 million sm^3
Pair A3-P3: 33.1 million sm^3
It is assumed that all this air sustained the ISC fronts in the THAI patterns, directly contributing to the size of the burned volume; no escape of air was assumed via bottom water or in Mc Murray A formation.

The A3-P3 well pair was used for the estimate of air requirement from field data. This selection was based on greater certainty on the burned volume (size and shape), as there are control points on both sides of producer, notably, temperature profiles in wells OB9 and P3. Also, it was well established that a toe-to-heel propagation of the ISC front occurred both along P3 and replacement well P3b. For this pair, as seen in Figure 48c, the total width of the burned zone not far from air injector is estimated at 42 m (Appendix E, Table E1), while its length (along the horizontal well) is 265m, as indicated by the last peak temperature of 335 ^{0}C in this well (Figure 50c2); corresponding to this burned volume contour, the temperature decreases steeply beyond these burned rock limits. It is mentioned that the contour of the burned zone from Fig. 47c does not confirm the interpretation of Petrobank (Fig. 48c), which shows a continuous temperature distribution between A1-P1 and A2-P2 pair.

Looking at all the illustrations from Figure 9a and Figure 9b -which show the shape of a burned zone in a 3-D model laboratory test - we can develop a simplified representation of the 3-D configuration of the burned zone, as in Figure 51. Considering *the wedging effect (both in the horizontal and on vertical directions)* it was assumed that the burned volume is a rectangular horizontal truncated pyramid, which for P3 producer for instance, has an *advancement along the horizontal section of 250m,* but having the advancing trapezoid with both its sides half of the sides of the large trapezoid (located close to the air injector). Therefore, in our calculations, we try to estimate the volume ABFEHGCD (Fig. 49); the tilting forward of EFGH surface is not the focus, as it has a negligible effect on the value of burned volume; it should be approximated afterwards. Taking into account, also, that the ISC front propagated for a short distance opposite to the direction of the heel of the producer, a total advancement along the horizontal section of 265m (250+15m) was considered. In this case, the field air requirement would be 494 sm^3/m^3 (See Appendix E).

As shown in Appendix E, from the combustion tube laboratory tests, an air requirement of 420 sm^3/m^3 rock was determined. *This value assumes that the corresponding amount of fuel is formed in-situ from* *the original oil; only negligible LTO reactions occurred. The* field air requirement of 494 sm^3/m^3 is 18% higher than that determined in the laboratory. Thus, some additional coke formation may have occurred when hot oil travels through the burned zone close to the boundary with the mobile oil zone (MOZ). In other words, even the oil first displaced frontally may deposit some additional coke later on, while traveling through heated regions. On balance, however, a difference of 18 % is not so large, considering the petrophysical differences between the ideal laboratory sandpack and field geology.

In the case of A2-P2 pair, there is no proof of high temperature on both sides of producer trajectory; a toe-to-heel propagation of the ISC front did not occur around P2b as it was too far from the old burned area of P2; from the replacement well, we do not have any direct high temperature data.

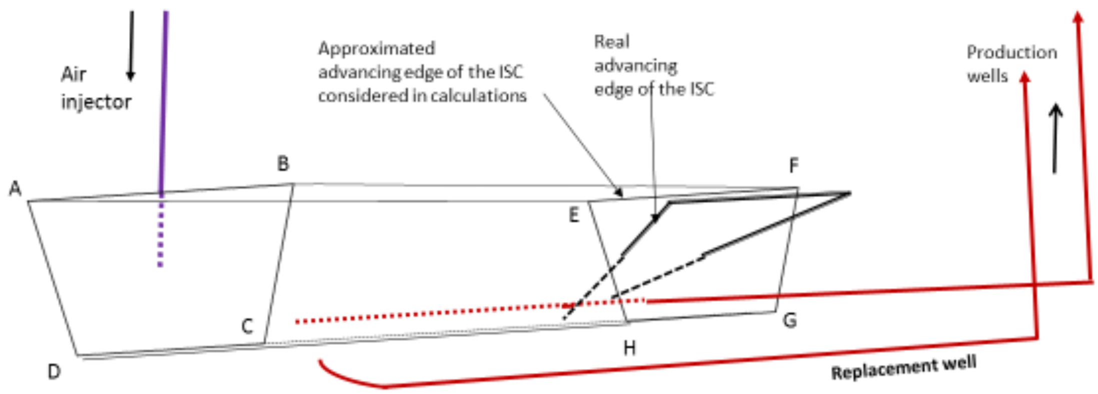


Figure 51: Schematic of the volume burned in a direct line drive configuration THAI (DLD-THAI) process. For illustration purposes, a replacement production well is shown.

In the case of A1-P1 pair, the situation was even more unfavorable, as both OB3 and the toe of P1b were on the same side; therefore, temperature measurement was missing on one side. For this reason, it was assumed that the burned zone was identical on both sides, and calculations were also conducted using the A3-P3 air requirement value.

By accepting that the estimate for A3-P3 air requirement of 494 sm^3/m^3 rock is a reliable figure, then the volume of truncated pyramid-shape burned volume for the pattern A2-P2 is 116,397, instead of 136,905 m^3, assumed initially (based on laboratory air requirement value). Similarly, using the A3-P3 air requirement of 494 sm^3/m^3 rock, then the volume of truncated pyramid-shape burned volume for the pattern A1-P1 is 112,348 m^3, instead of 132,143 m^3, assumed initially (based on laboratory tests).

Therefore, for A2-P2 the burned volume has an advancement of 196m along the P2 producer (Table 8), with a maximum lateral development towards the top of the oil layer of approximately 30m (in the proximity of the air injection well and behind it). Proceeding along the same lines, it can be stated that for A1-P1 the burned volume has an advancement of 276m along the P1 producer, while the maximum lateral development towards the top of the layer of 53m (in the proximity of the air injector (Table 8); However, the estimate for both A1-P1 and A2-P2

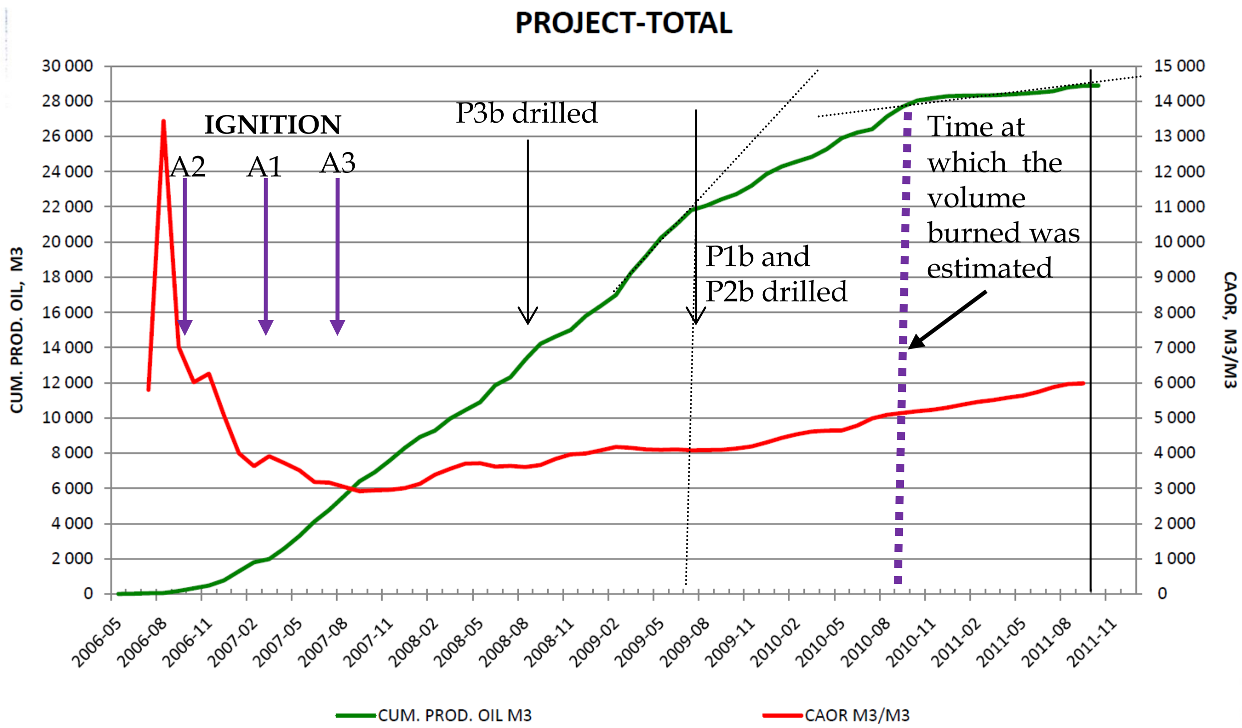


Figure 52: Whitesands Pilot. Variation of cumulative air-oil ratio (CAOR) and oil cumulative during the life of the project; all three pairs (Petrobank presentation to AER, 2012).

pairs is not very reliable, as too much uncertainty is involved in estimating the volume of the burned volume.

It should be noted that the extrapolation of the results from A3-P3 pattern to the remaining two patterns was made through the use of the air requirement, calculated based on data of A3-P3 pattern; this is how the volume of rock burned (column 3 in Table 8) in A2 and A1 patterns was estimated. Clearly, the results for A2-P2 pair are not physically meaningful, as the volume of the truncated pyramid, representing the burned volume, exceeds the volume of reference prism by large order. To some extent, this also applies to the A1-P1 pair, since a volumetric sweep efficiency of 68% seems to be too high for a field test.

However, in spite of our results showing these discrepancies, the better development of the combustion zone around P1 and P2 - mainly a very large lateral development - seems to be in agreement with the results of time-lapse seismic monitoring results (ERCB Presentation, 2012 shown in Figure E3 of the Appendix E); a slight trend for preferential propagation towards North and NW can be observed. A 2011 comparative judgment of the development of the burned zones from temperature measurements (Figure 48d) and seismic monitoring (last picture of Figure E3 from the Appendix E) tends to show that extension of burned zones along the horizontal producers and seem to agree from these two kinds of measurements. However, there is an apparent discrepancy in the evaluation of lateral development; the seismic monitoring does not seem to reflect the reality accurately. For instance, a major limitation of seismic monitoring seems to be the fact that it shows a development of high gas saturation around observation well OB17 (last picture of Figure E3 from the Appendix E), therefore outside the area of THAI pilot, but without a continuing development in-between these two zones; the existence of this kind of "island gas saturation region" is very improbable! This throws some doubt of the whole determination of the lateral development of burned zones. Based on all of the temperature information from observation and production wells (original and replacement wells) it is actually concluded that the lateral development of the burned zone was small (maximum 30-52m, around the horizontal section of producer).

Summing all the burned volumes in the three patterns (column 3 in Table 8), gives 295,790 m^3 of rock burned. The oil initially existent in this total burned volume and displaced by the ISC front is 65,168 m^3. The oil consumed as fuel and any coke gasified in the process was estimated at 10% OOIP, and it was accounted for. Since the total amount of oil produced was 29,000 m^3 representing 45% of the displaced (mobilized oil), this means that 55% of the displaced oil was left in the reservoir.

At first glance, it can be assumed that either the capture efficiency was extremely low or the oil consumed as fuel and for coke gasification was a lot higher than that estimated from our calculations. However, the estimate of air requirement (hence of fuel consumed) from A3-P3 pair data is relatively reliable as temperature data existed in all four directions and there was no bottom water present in the region of A3 air injector. It is more probable that capture efficiency might have been the main factor. If the capture efficiency happened to be extremely low, it follows that *much hot oil still exists either in the adjacent regions or in the thin bottom water zone*.

While it is possible to speculate as to the many possible causes affecting oil production efficiency, ie capturing all of the mobilized oil from the swept zone, (viz. excessive fuel deposition, capture efficiency, etc.), it is probably more fruitful to consider the effect caused by the permanent loss of some of injected air, either to the bottom water zone, or into the McMurray A formation. Such an effect would mean that the actual volume of air reaching the ISC fronts was much lower than that used in our calculations; this would explain (and reduce) the discrepancies obtained, as the burned volumes would decrease correspondingly. The evaluation of air lost in the McMurray A formation and the bottom water zone is presented in the next subsection.

Table 8: Whitesands Pilot. Estimated sizes of the burned volume in the pattern A3-P3 (P3b) based on Field temperature data. Attempt to extrapolate the results to the remaining two patterns

Pair	Volume of rock Burned (based on laboratory A_{air}) m^3	Volume of rock burned (based on field A_{air}) m^3	Upper AB side length m	Lower CD side length m	Length of HS of HP m	Estimated advancement along the HS of HP m	Upper EF side length m	Lower GH side length m	Volume of reference prism m^3	Volumetric sweep efficiency of the reference prism* %	Obs.
A3-P3 (P3b)	78,810	67,045	**42**	17	390	**265**	20	9	129,519	52	Basic estimate
A2-P2	136,905	116,397	**30**	7	386	**196**	15 *	3.5*	67,620	172???	Vague estimate
A1-P1	132,142	112,348	**52.8**	29.8	389	**273**	26.4*	15*	165,766	68	Very rough estim.

Legend: HS of HP = Horizontal section of horizontal producer

* Orientation values; they did not take part in calculations. Note: The horizontal lengths of the reference prism are highlighted in BOLD. The rectangle cap has the sizes 42m*11.5m for A3-P3 and 30m*11.5m for A2-P2, while for A1-P1 is 52.8m*11.5m, i.e., the product of the upper side with the effective thickness of layer. Please note that they are considerably lower than the corresponding caps allocated to each pair by design, which are 100m*11.5m. The reference prism is a prism supposed to circumscribe (and contain) the truncated pyramid represented by the burned volume.B.

B. Confinement of the project area. Air lost in the Mc Murray "A" formation and flow of air in the bottom water zone

An in-depth evaluation of the confinement of the Pilot region is provided in the second part of the Appendix E. It will deal not only with the evaluation of the air escape or air flow at the water/oil interface, but also with the main thermal events taking place in McMurray "A" and bottom water zone, mainly presence of a conventional in-situ combustion (ISC) in those regions. The analysis was based on the detailed inspection and interpretation of the temperature profiles in the observation wells and on the performance curves for the air injection wells and production wells. It is stated from the very beginning that the air flowed predominantly in the Mc Murray "B" formation, i.e the objective of the THAI piloting. However, as will be demonstrated, the lack of complete confinement did lead to the decrease of the efficiency of the process.

B1. Air lost via McMurray "A" layer; generation of the second in-situ combustion front

The analysis in Appendix E showed that the air escape towards the Mc Murray formation occurred mainly around A2 air injection well and therefore is related to the A2-P2 pair. An inspection of the performance of injection-production for air/gas for all three pairs showed that the air injection rate was approximately equal to the gas production rates for pairs A1-P1 and A3-P3, but not for A2-P2 pair, where for the period June 2006-June 2008, the gas production rate of P2 well was 15%-35% less than the air injection rate in A2, this difference decreasing in time, with a period of approximate balance between injection and production afterwards. This means that the Mc Murray "A" did see a conventional ISC front supplied with less and less air as no production wells in Mc Murray "A" existed, and consequently the pressure difference causing the flow decreased in time.

This is the reason that a gradual switching from a vigorous ISC process involving HTO reactions to a less efficient ISC, involving both HTO and LTO, happened. As shown in Appendix E, our evaluation is in disagreement with the evaluation of Petrobank, which downplayed the role of this air escape; Petrobank did not accept the hypothesis of a conventional ISC front generation in Mc Murray "A" formation. However, the existence of this ISC front is also supported by temperature recordings in the observations wells, as summarized here:

- ✓ The direct proves from TOB1 and TOB2 observations well, located very close to the A2 injector (2.5m and 7.5m, respectively); a peak temperature of 340 ^{0}C, recorded in TOB1 and 240 ^{0}C recorded in TOB2 (See Fig. 47a-b).
- ✓ The fact that observations wells OB6 and OB9 – located at 42 m from injectors A2 and A3, respectively - did not show high temperatures at Mc Murray A level, is not a prove of non-influence. This is so, as even for Mc Murray B the interception by the ISC front happened very late in

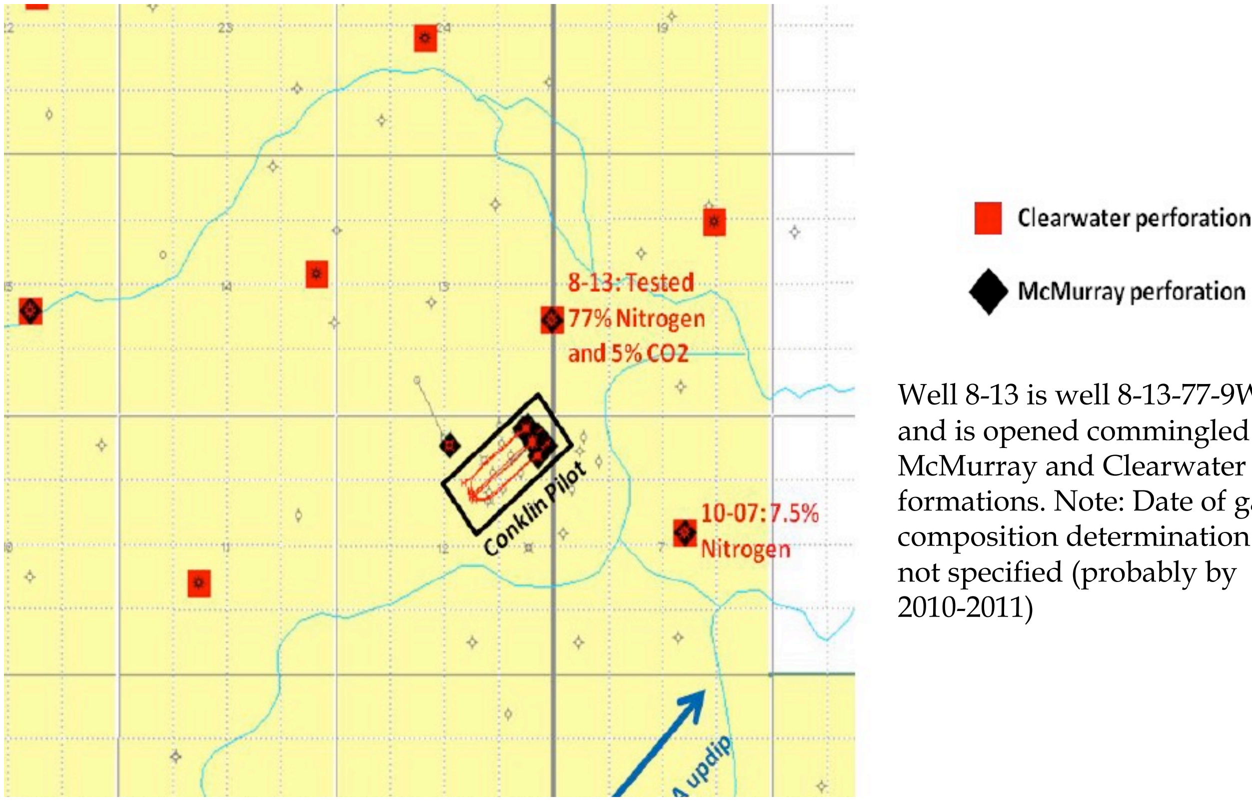
September 2010. Therefore, only combustion gases/flue gases flowed in their neighborhood; these wells were not intercepted by the ISC front yet at Mc Murray A formation.

✓ As far as well OB3 –located 40m from A1 – is concerned, some steam flowed towards Mc Murray A during steam injection, but it seems that the preference of air to flow in that direction decreased significantly as the easy flow into the bottom water zone was obvious; a peak temperature of 370 ^{0}C at the oil/bottom water interface confirmed this hypothesis.

Finally, a more rigorous proof of significant air escape from Mc Murray B to Mc Murray A, for the A2-P2 pattern, has been obtained by making the nitrogen balance for this pattern for years 2007, 2008 and 2009. This is simply a calculation of how much of the nitrogen injected via well A2 (as contained in the air) is contained in the nitrogen of the combustion gases produced by P2 well; it based on their average nitrogen percentage, calculated annually. In a typical THAI pattern, given the significant distance between pairs, almost all the nitrogen injected should be recovered via production well of the pattern; the nitrogen accumulated in the burned zone is practically negligible. *It is confirmed that at the beginning of the process, a high proportion of the injected air entered the Mc Murray A formation; in the 2006/2007 period, more than half of it (53%) went to Mc Murray A, sustaining a conventional ISC front. The proportion decreased to less than 35% for 2008, while a calculation just for 2009 showed that the injected air was entirely confined to A2-P2 pattern (a perfect balance between the injected nitrogen and the produced one, existed).*

A similar calculation for the entire Pilot, for the air escaped to Mc Murray A, gave a figure of 47% for 2006-2007, decreasing to less than 26% for 2008; for 2009, it showed a good balance between the injected nitrogen and the produced one, precisely as for A2-P2 pattern.

Therefore, for 2.5 years, a second ISC front was developed at Mc Murray A formation, but the oil displaced by this front has never been produced/collected, as there were no production wells open at this formation. The approximate 25-30% of loss of air from the entire injected air up to 2009, did directly lead to an increase of air-oil ratio (AOR), and it can be speculated that it caused the increase of AOR from 4,000sm^3/m^3 to 6,000 sm^3/m^3, which is the real figure. Consequently, until 2009 there was a THAI combustion in McMurray B and IHS formations and a conventional ISC process in Mc Murray A formation, where due to the decrease in time of the air flux, the combustion intensity decreased with more and more LTO reactions; eventually, by 2009, the ISC in McMurray A was almost quenched. The 4-month period of air injection stoppage in July-October 2009 caused some backflow from McMurray A to McMurray B as nitrogen produced slightly exceeded that injected. However, part of the combustion gases generated by the propagation of the ISC front in McMurray A formation travelled far away, up to almost 1 km distance, towards the updip of this layer. As seen in Fig. 53 the gas produced by the well 8-13-77-9W4M has a high content of nitrogen (77%), confirming that combustion gases were flowing towards that direction for an extended period. Actually, a second well (10-7-77-8W4), located laterally (not updip) also started to produce gases, heralding an increase of nitrogen in time.



Well 8-13 is well 8-13-77-9W4 and is opened commingled at McMurray and Clearwater formations. Note: Date of gas composition determination not specified (probably by 2010-2011)

Figure 53: Fig 53: Migration of the combustion gases via the McMurray "A" Layer, up to Clearwater Formation. IETP Presentation, 2012.

B.2. Air flow into the bottom water zone

An in-depth analysis of the air flow into the bottom water (BW) zone is provided in Appendix E. It was evaluated based on the temperature recorded by the observation wells. In the region of the THAI pilot the ratio thickness of the BW zone/the thickness of oil zone is less than 10%, as the BW zone thickness is smaller than 2-3m, while the thickness of oil zone is 20-40 m for different THAI pairs. It was found that for A1-P1 and A3-P3 pairs, in general, ISC process developed and remained mainly in Mc Murray B (not far away from the oil/water contact in case of A1-P1 pair). Flow of air at the W/O interface around A1 well was clearly seen; a maximum temperature of 400 ^{0}C was recorded, proving that there was full ISC at the W/O interface. The fact that air penetrated into the bottom water zone was also confirmed by the seismic surveys performed in the 2008-2011 (ERCB Presentation 2012), and which in 2011 showed some combustion gases in observation well OB17 (See Fig. E3 of the Appendix E), located at least 150m North-West, laterally from the trajectory of P3 producer (Figs 48a-b).

For A2-P2 pair, there was however, a clear tendency of the peak temperature to go upwards.

The oxygen from the air flowing at O/W interface was consumed entirely and therefore, only combustion gases are produced. Unlike conventional ISC process, there was no continuous increase of the O_2 in the effluent gases. The quality of burning at the O/W interface can be checked via variation of H/C ratio in time, but for this, detailed daily gas analyses are necessary. This could be done mainly for A1-P1 pair, where the most pronounced burning at the O/W interface is established. Therefore, one can talk about the temporary storage of flue gases as air is entering BW and only some of it is produced as combustion gases.

Permanent storage of flue gases could have happened in the Pilot area and far from the Pilot area, for instance, towards the North NE and NW and beyond it. Based on the isopach map of the bottom water zone (IETP Presentation, 2009), the evaluation of the maximum amount of gas possible to be stored in the BW zone was performed. An effective thickness of 1-2 m was estimated, and it was assumed that gases flowed and distributed into the whole region of BW existence at a gas saturation of 10%. This way, a pore volume of 187,000 m^3 and a gas storage capacity of 0.6 million sm^3 was obtained. This storage capacity is almost negligible compared to the amount of air sustaining a conventional ISC front in McMurray A formation.

Relative to the loss of oil in the bottom water (BW) zone, as the thickness of BW is very small, it can be assumed that this loss is not significant, and it could not have seriously worsened the performance of the process, as expressed by the value of air-oil ratio. Therefore, at this stage, *it is considered* that BW has constituted a conduit for oil transportation to the producers, but the loss of oil due to "oil flowing" via BW is minimal; more work is needed to confirm or reject the above statement. Of course, the oxidation at the water/oil interface could have increased the air requirement due to the LTO reactions at the W/O interface. It is to be noted that in this particular case, the oxygen efficiency utilization calculation by the classic methods is no longer valid; a new method is necessary to differentiate between oxygen taking part in HTO reactions and that one participating in LTO reactions. (Turta 2009)

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*   *

The movement of the ISC front from oil zone to BW and reversely (erratic movement), similarly to what was detected in laboratory work, was not possible to be assessed. More details on the interaction "oil zone-BW zone" in a THAI process will be provided in the presentation of Kerrobert THAI project.

C. Coring wells necessary for evaluation/confirmation of the burned zones configuration in Mc Murray B and McMurray A and entrance of oil in the BW zone

Finally, a full clarification of the development of the process, including the configuration of the burned zone and communication with Mc Murray A and Bottom water zone can be made by drilling at least 3-4 coring wells, with their positions suggested below, namely:

- ✓ Behind the A2, by the end of blind liner – one coring well to check mainly the burned zone in Mc Murray A formation; the tendency of flow was NE.
- ✓ Close to the A1 injector, towards the OB3 well – to check mainly the extension of the burned zone in the bottom water zone
- ✓ Middle distance between P1 and P2 – at a distance of 40-50m from the line of injection (at the level of observation wells OB3 and OB9) formed by A1 and A2 air injectors - to check the accuracy of seismic surveys.
- ✓ Checking lateral development for P3 and P3B (check the extrapolations using the velocity of ISC front and truncated pyramid assumed configuration) – one coring well by the last ISC front advancement, just 5 m from the P3B well

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*   *

The conclusions from these sections clearly show that even in the presence of a thin bottom water (BW) zone, the presence of BW should be taken into account in the design of the THAI process. Several simulations should be undertaken to establish the best location (vis-à-vis the W/O interface) of the horizontal section of the producer and the location of one or two sets of perforations in the vertical injector. Also, as seen, a thin shale (2-3m) between Mc Murray "B" and Mc Murray "A" formations was not enough for full confinement of the ISC; the last vertical barrier for the ISC process has to be reliably assessed during the design phase.

6.4.2.5. Oil Production Performance

The primary official sources used for the analysis of oil production are :

- The IETP reports 2007, 2008 and 2009
- SIR 3 (supplemental information request) ~~3 of~~ 2011

While the IETP reports provide detailed data for each well pattern for 2008 and 2009, the Supplemental **I**nformation **R**equest 3 (SIR3) lists oil production for 2007. For 2010 it can be seen from the performance graphs presented by Petrobank in the SIR 3 material (Figures 54a-c). ?? Finally, these estimates can be checked against the total oil production for the entire life of the project, as calculated from the Petrobank graph of Figure 52.

Table 9a provides an analysis based on the relevant data for each pattern (module) for the years 2008 and 2009. Year 2008 constitutes the most representative year for the performance of THAI pilot since during this period, a quasi-steady state was obtained; It is also the best production year of the pilot. From Table 9a, it can be seen that well pair A1-P1 performed the best. However, daily oil production decreased going in the direction from P1 to P3, and this may be related to the bottom water zone becoming thicker towards P3 region. During 2008, the **a**ir-**o**il **r**atio (AOR) was calculated to be 4,600- 5,000 sm^3/m^3, which is a fairly high value. For a successful commercial (conventional) ISC operation (using only vertical wells) in heavy oil reservoirs the AOR is typically in the range of 1,000- 3,500 sm^3/m^3. Table 9a data also suggests that the efficiency of the process decreased over time, as seen from the increase of AOR for all three pairs. This is further supported by the global data (combined for all pairs) in Table 9a, which shows a gradual increase of AOR from 3,500 sm^3/m^3 to 7,000 sm^3/m^3 in the 2007-2010 period. Confirmation of the decreasing efficiency trend is provided by the Petrobank graph depicting the increase in time of total cumulative of oil along with its cumulative air-oil ratio (CAOR), as shown in Figure 52, which shows that cumulative AOR increased up to 6,000 sm^3/m^3 by the end of the project; the instantaneous AOR reached up to 7,000 sm^3/m^3 in the 2010-2011 period.

Evolution of water cut; role of bottom water: in order to do analysis of the evolution of water cut with the aim of establishing the role of bottom water in the ISC process, first we have to mention that some injection of steam in the production wells has been done along the years. The effectiveness of steam for production well stimulation does not appear to be very clear; as described in different documents, in some periods a small rate of steam (20-80 m^3/day) was injected continuously into the production well (at a small over-pressure to the reservoir pressure); it is not exactly known if this was done only for production stimulation, and/or for other reasons, temperature control for instance (for temperature moderation). Very certain that actually at low injection rates, only hot water was injected. *The positive effect of the steam injection does not appear evident in oil production.* However, this water injected has to be accounted for in the balance of water produced by the process. The performance in terms of all injected fluids and all produced fluids (except gases produced) is shown in Figures 55a-b.

As far as the role of **b**ottom **w**ater (BW) is concerned, the most important question is: *at a BW thickness of approximately 10% from the oil zone thickness (see Fig. 45b), how important is the BW for the development of THAI process?* This is analyzed in detail in the Appendix F.

To clarify this topic, as seen in Appendix E, three periods, were considered, namely:

First period: March 2006-August 2007 (1.5 years) in which the steam injection for pre-heating and ignition process took place, consecutively in all three patterns. As seen in Figs.54a-c and 55b, in this period, practically, the entire steam injected was produced back as hot water. Therefore, this water will no longer be accounted for in future calculations.

Second period: August 2007-July 2009 (2 years) of constant, pseudo-steady state, good oil production

Third period: November 2009-November 2010 (one year), when the performance became poor (higher water cuts and lower oil production). The two periods are separated by 3 months (July - October 2009) of air injection interruption, necessary for the drilling of the replacement wells P1b and P2b.

The water to be produced is made of: water injected as steam in the producers for temperature control or stimulation (Q_{steam}), water produced as a result of connate water displacement (Q_{CW}), ISC-formed water (Q_{ISC}); water from the bottom water zone (Q_{BW}). The key assumption made was that all liquids (oil and water) displaced are completely captured, which is a very reasonable hypothesis in THAI. The calculation was made of the standard (theoretical) water cut without any bottom water production and compared this value with the real one from the field. In cases this last figure was higher it implied that water from the BW layer was produced

Doing these calculations, it was found that in the second period, the theoretical water cut (assuming no BW) would be 60%, but in reality, it was 71%. Similarly, in the third period, the water cut (assuming no BW) would be 71%, but in reality, it was 88%.

Therefore, the negative effect of bottom water was felt mainly in the last part of the process, when water cut increased considerably.

Taking into account these results and other information regarding production performance, it is believed that the mechanism of BW influence on the process is as follows: During the 3-4 month of air injection stoppage, the pressure within the burned zone decreased considerably (Fig. 49a-b, BIS) - from around 5 MPa to 3.25 MPa - and this allowed a large amount of water from bottom water to flow into the lower parts of the burned zone, mainly for A1-P1b and A2-P2b; this water accumulated during the stoppage of air injection and was produced at the resumption of the process. As seen in Fig. 45 b, the BW zone, although thin (1-3m) it extends at considerable distances laterally towards SE and practically extends infinity towards NE; therefore, there is a substantial supply of water.

Summary Remarks: the 3-4-month interruption of air injection had a very detrimental effect on the performance of the process, because (1) heated oil from the burned zone/adjacent-regions re-entered the burned zone and caused massive coking. This resulted in a decrease in permeability, mainly in the upper parts of the oil layer, where there were very high temperatures, and, (2) water from the BWZ flowed into the lower parts of the burned zone, substantially increasing the water cut when air injection was re-started.

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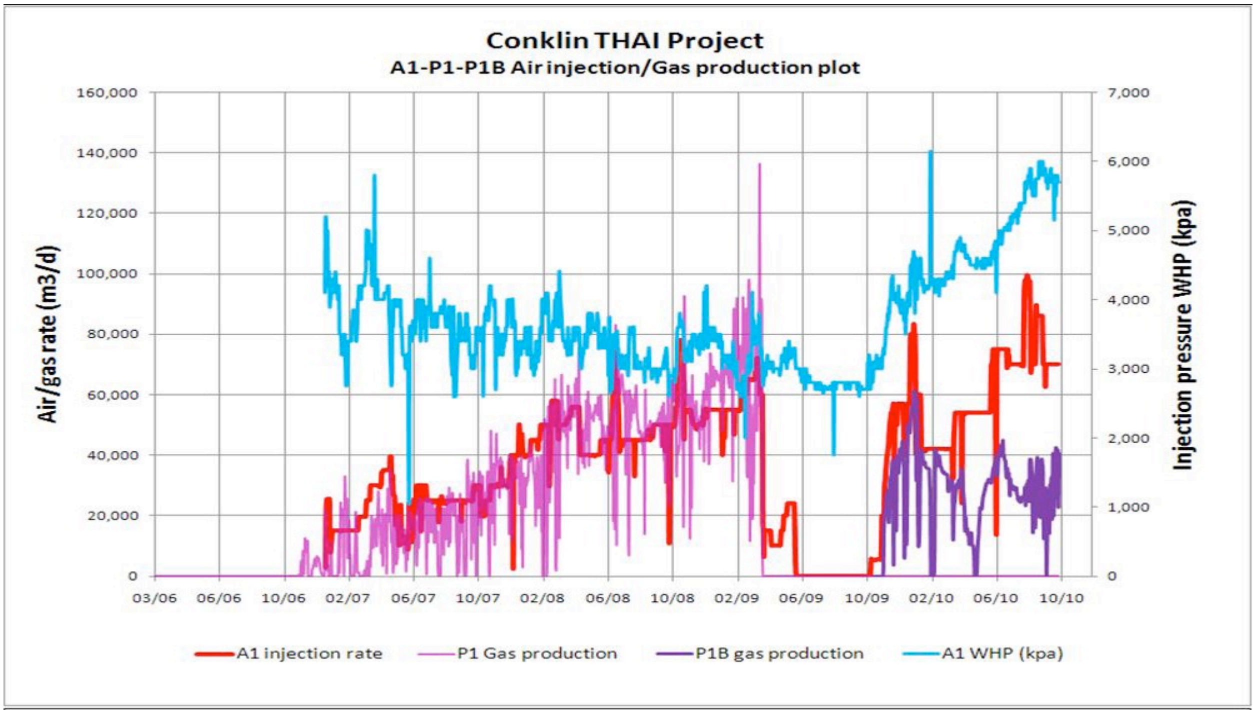
* *

According to the analysis above, the horizontal wells produced water from the BW zone. Still to be discussed are the following aspects:

Did steam and/or air enter the BW zone?

Did burning at the W/O interface occur?

Steam penetration into the BW zone occurred during the PIHC period, as shown by a quick inspection of the temperature profiles shows that in wells A 2 and A 1~~.~~ The temperature profiles from observation well OB6 demonstrate conclusively that steam injected in A2 flowed primarily at the W/O interface. In the case of A1, there is only indirect evidence to show that steam flowed primarily in the upper Fort McMurray A formation (as seen in OB3 well – Fig. 47d). However, the ISC front appears to have been formed (in A1) close to W/O interface and risen within the pay zone; the combustion peak temperature in the ISC front is above 500 ^{0}C in OB3 (located at 40m from A1 and 12m laterally from P1) and rises gradually (up to 6m) towards the upper part of pay zone. The temperature at the W/O interface was around 360 ^{0}C in the period July-Dec 2010 and clearly shows, in this case, that burning at the W/O interface occurred. In the A3-P3 region, there is no BW (Fig. 45b), so this problem does not exist.



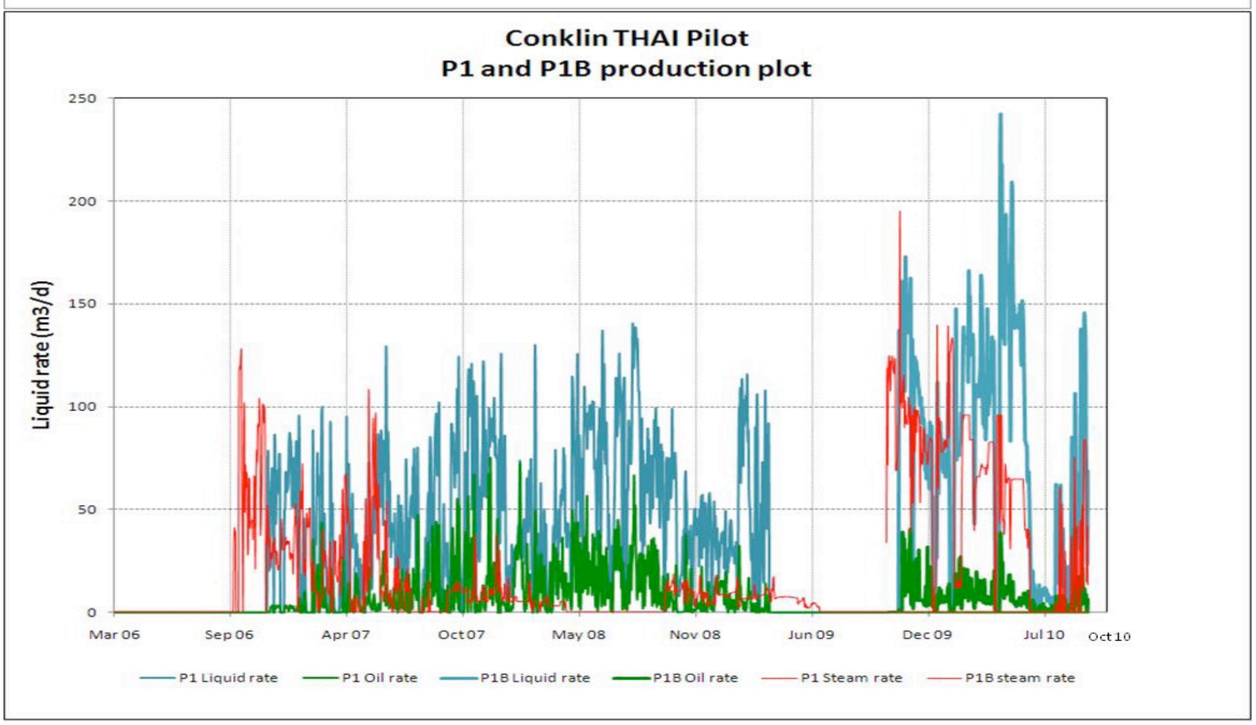


Fig 54a: Whitesands THAI Pilot. Air injection and oil production performance for A1-P1/P1B

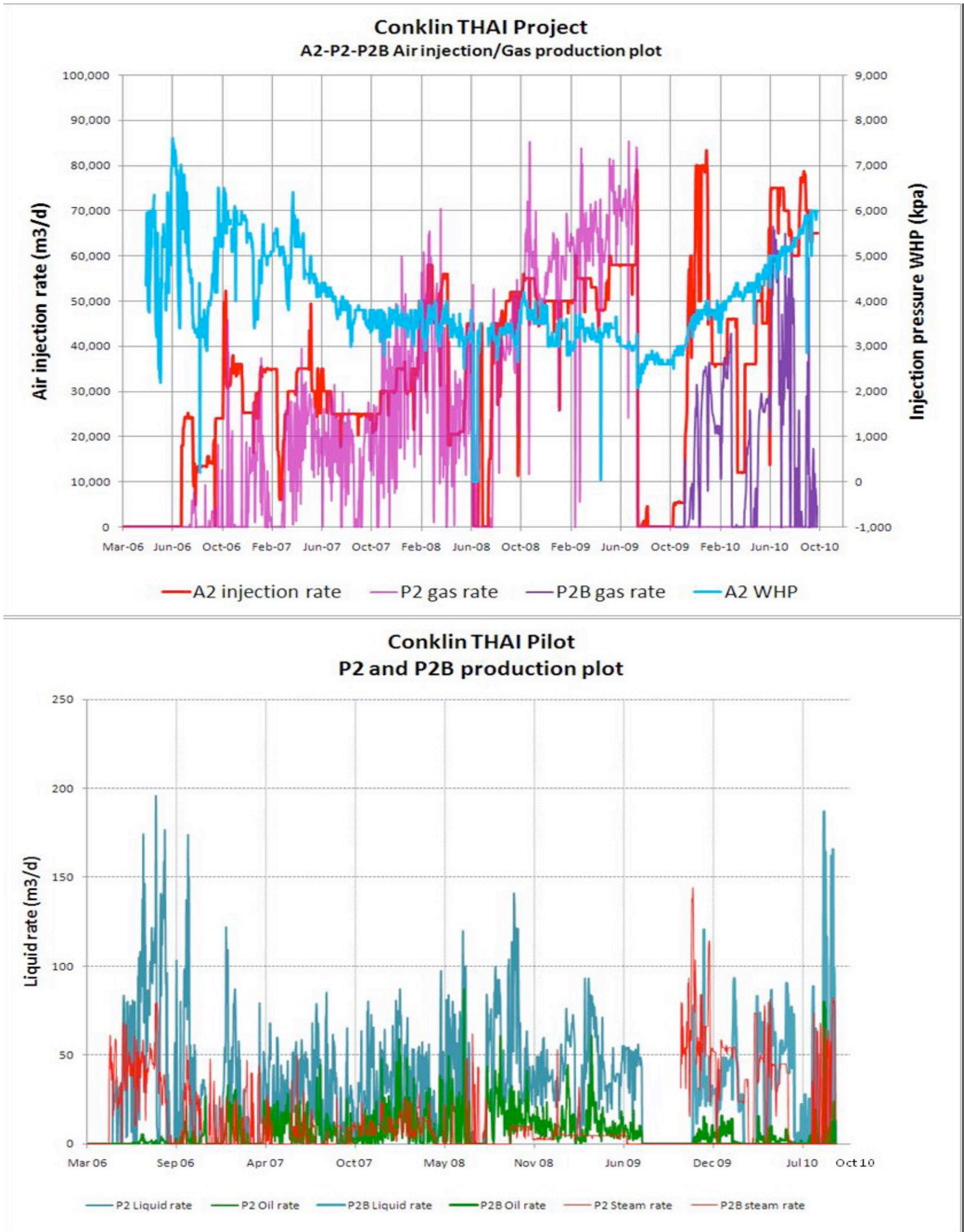
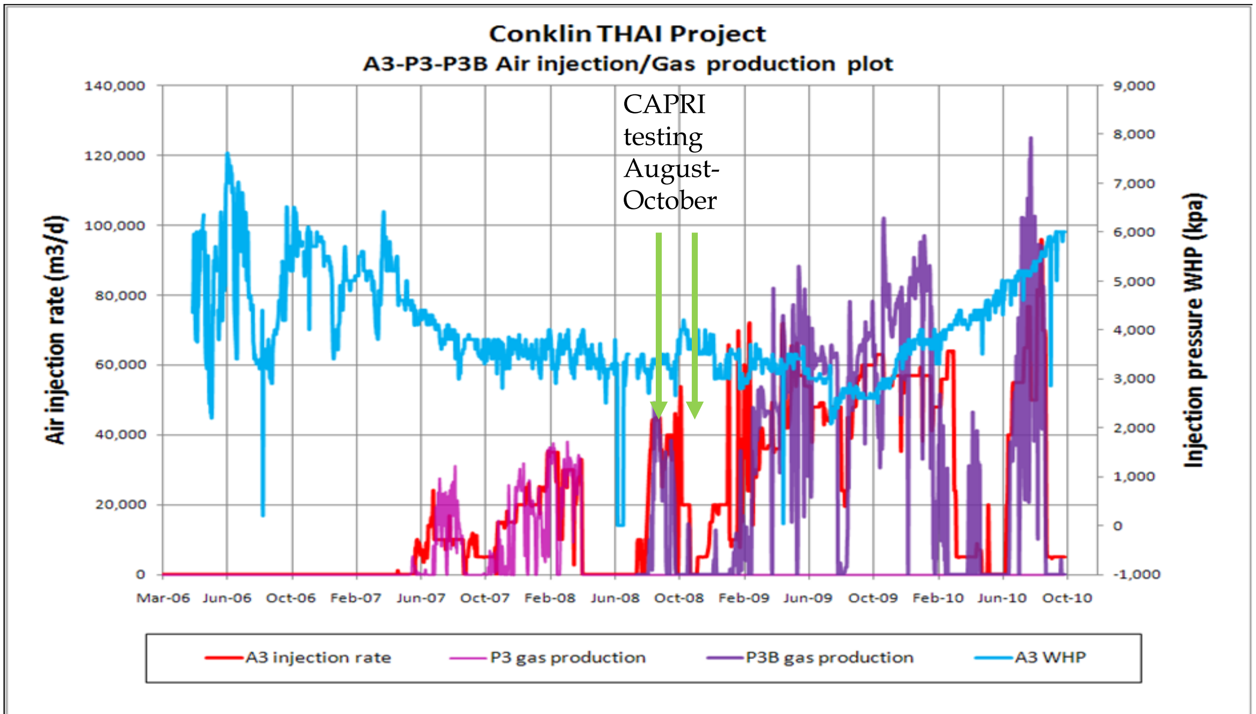


Fig 54b: Whitesands THAI Pilot. Air injection and oil production performance for A2-P2/P2B pair



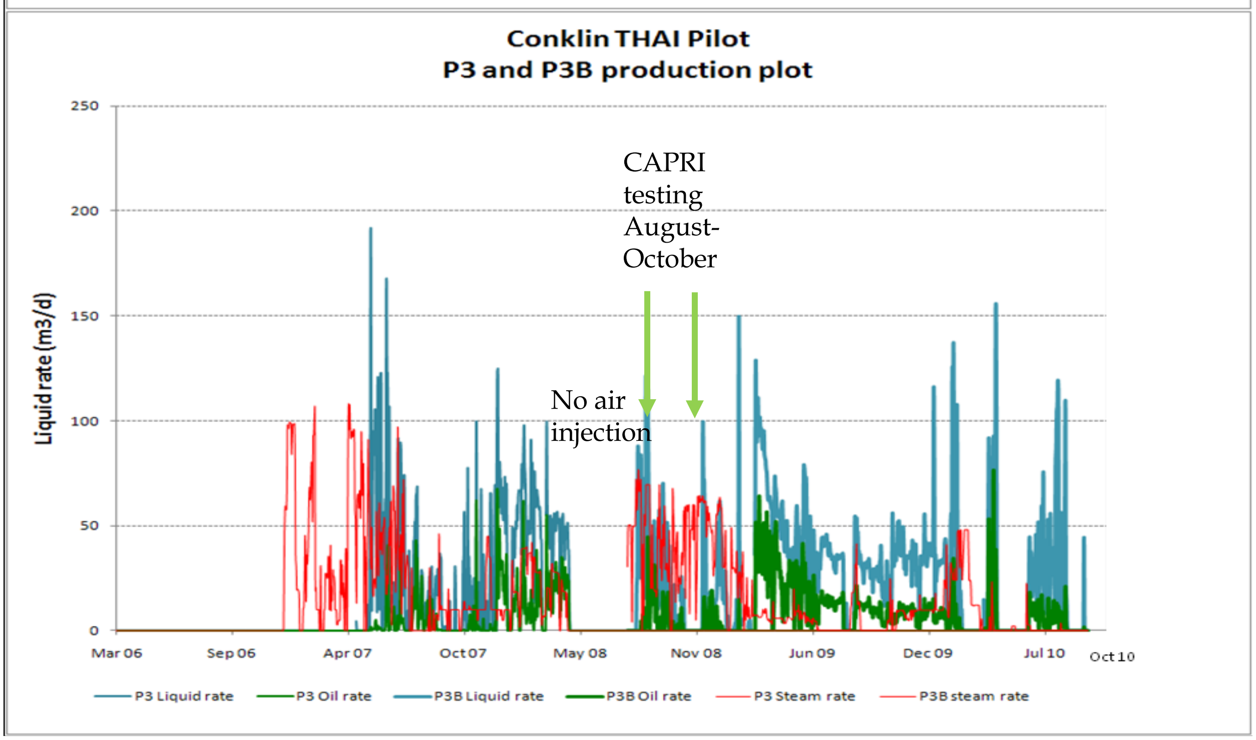


Fig 54c: Whitesands THAI Pilot. Air injection and oil production performance for A3-P3/P3B pair.

Legend: WHP=Well head pressure

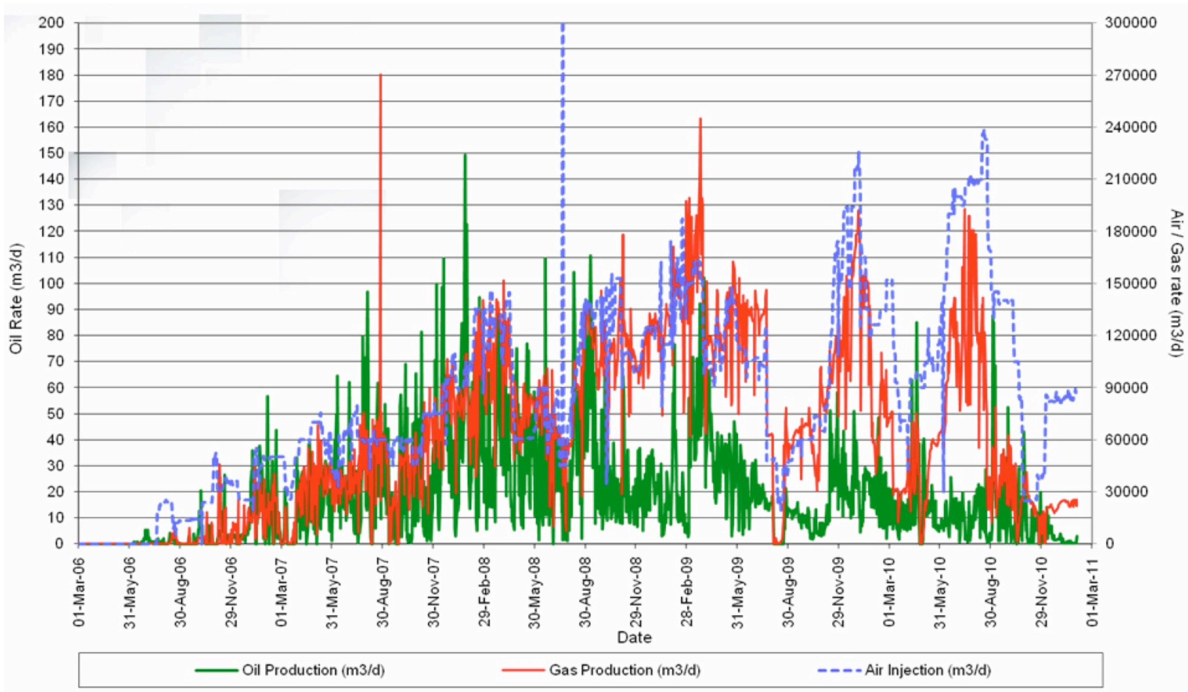


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Fig 55a : Whitesands THAI Pilot. Combined air injection and oil and gas production for all three pairs (A1-P1/P1b to A3-P3/P3b)

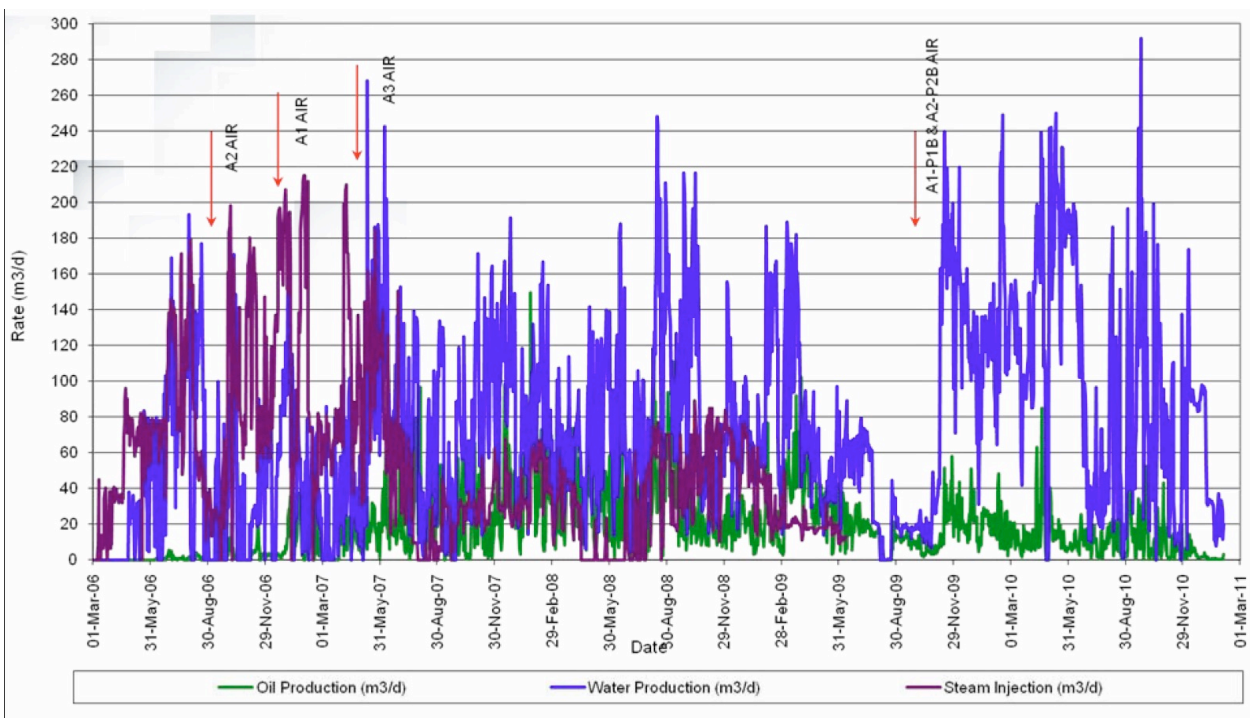

Fig 55 b: Whitesands THAI Pilot. Combined oil and water production and steam injection (in producers) for all three pairs (A1-P1/P1b to A3-P3/P3b)

For the year 2008, if we compare the oil rates (Figures 54a-c) with the average calendar oil rates (calculated from Table 8a), it can be seen that there is a significant difference. The oil rates from the graphs represent the oil rates measured in the field and are the effective oil rates (when the wells were on production). For the best case for well pair A1-P1, in 2008, the average calendar oil rate was $10m^3$/day, while the average effective oil rate was in the range of $15\text{-}25m^3$/day. The difference is mainly due to the problems caused by sand influx, as well as other operating problems; The sand influx required many workover operations for cleaning of the well (at least one cleaning every three months for each production well). Although not given in Table 8, it has to be mentioned that it was reported that the volumetric sand percentage had high values, many times higher than 20% (?!?). As known from the technology of cold heavy oil production with sand (CHOPS), for very viscous oils of 50,000 mPa.s, the stable (steady-state) sand ingress rate is not higher that 10%wt (M Dusseault, 2001,2002). It seems that sand from behind the ISC front was entrained *directly* into the production well. This phenomenon was aided, by the fact that the sand behind the ISC front is very fine and is *totally unconsolidated*; on the other hand, it is believed that the use of a direct line drive configuration strongly promoted sand entrainment due to relatively high pressure gradients.

6.4.2.6. Analysis of location and performance of replacement wells (horizontal producers P1b to P3b)

First, the experience acquired with in-fill horizontal wells in conventional ISC projects are presented, and using that experience, then, we analyze the Whitesands case (P1b-P3b wells). Although this experience was acquired in long-distance oil displacement (LDOD) ISC projects, it still can be used because when drilling either in-fill or replacement producers the same principle has to be respected: the placement has to be made in such a way that the new horizontal producer is located just nearby the originally formed oil bank (downstream it), and is ready to produce it, which means that some form of hot communication exists or can be easily established. Any other placement, such that intercepting the burned zone or being too far from the former ISC front are a recipe for failure. Therefore, the location of the replacement wells in THAI Whitesands Pilot is a susceptible topic.

A: Past Experience with Horizontal Wells in Conventional ISC Projects: For the first time, horizontal wells were used in conjunction with a conventional ISC process (using only vertical wells) in two Canadian projects (Turta, 1994). In the first project, at Eyehill, Saskatchewan (Sa.), three horizontal wells with horizontal legs of 1000 to 1200 m were drilled by 1985. The wells were drilled two years after the termination of the dry ISC process in eight adjacent 8 ha five-spot patterns, where the combustion was active for about 10 years; it was operated with relatively low air rates and achieved an oil recovery of

10%. Oil viscosity at initial reservoir conditions was around 2,000 mPa s and the net pay thickness was 5 to 8 m; the reservoir is underlain by bottom water with a water column height up to 15m. Of the three wells, one well – which was located very close to the boundary of the project area (just in the oil bank created by the former ISC process), but did not intercept any burned zones - had a very good production performance, with oil rates of 55 to 60 m^3/d. The second and third horizontal wells had mediocre results as they were placed either too far from the project area or intercepted a portion of the burned area. In the second project, at Battrum, Saskatchewan, one horizontal well with a horizontal leg of 610 m was drilled (in 1993). This was done in conjunction with the commercial wet combustion process, which had been in progress in this reservoir since 1964. This process took place in a reservoir having a relatively low oil viscosity (70 mPa.s), and a net pay thickness of 9 to 18 m. The horizontal section was positioned between the secondary gas tongue and the water tongue of an exploitation using a pattern system. The performance of this well was very good as the oil rate increased 5 to 10 times (from 3 to 15m^3/d for a vertical well, to 35 to 75m^3/d for the horizontal well) with a decrease in water cut from 90% to 20%. Another significant advantage of the horizontal well was a substantial reduction of operating problems like sand influx and emulsions. This advantage was linked to the extremely low drawdown during oil flow towards a horizontal well.

B: Replacement Horizontal Wells P1-b to P3b: As already mentioned, **s**ome relief (from sand influx) was obtained by the use of special slotted liners, but it seems that eventually, in order to radically solve the sand influx problem, replacement wells were drilled for all three production wells.

In commercial ISC projects, some 15-20% of the production wells are replaced (Turta, 2007); this happens when a production well is damaged prematurely before it has produced all the oil mobilized by the ISC front. In this case the location of the new producer is paramount; it has to be drilled ahead of the oil bank. This has been confirmed by the drilling of horizontal producers in old ISC projects such as Eyehill Project described previously. In the case of a THAI project, this becomes even more complex as the oil bank is generated by the ISC front (mobile oil zone) propagating from toe to heel, and has a particular spatial configuration around the horizontal section. For a new horizontal replacement well to capture the oil from the old mobile oil zone, the best method would be to drill its horizontal section exactly under the old producer's trajectory of horizontal section. This actually seemed to be a possibility as the P1, P2 and P3 wells were drilled 2 m from the bottom of the formation; however, the undulations of the horizontal sections (both for P1-P3 and P1b-P3b) might have been in a vertical space window of 2-3 m and this almost precludes the application of this alternative; very little undulations during the drilling is a necessary for this situation. A second possibility was to drill them parallel and laterally at 20m from the current trajectory but to bend the toe region in order to come very close to the burned zone; this is shown schematically in Figure 51. Without bending, they are too far from the heated zone. As showed in Figures 48c, except P3b well, they were located in a totally cold region and the hot link generation between their toe and the old burned zone was extremely difficult and never realized for P2. For P1 the heated communication developed very late and somewhere far from the toe of P2b (where the distance between wells decreased). The only almost appropriate location was confirmed only for well P3b, which has been drilled 20m from the old trajectory of P3 well but closer to the air injection well. As shown by the temperature profiles recorded in the replacement wells (Figures 50a3, 50b3 and 50c2), this is the only well that experienced a toe-to-heel ISC front propagation. Consequently, anchoring of the ISC front was not achieved for the replacement producers P1b and P2b. Unfortunately, well pair A3-P3 had a poor performance, both before and after replacement. This was despite injecting a significant amount of steam to stimulate it.

As mentioned previously, *a pronounced reduction in air injectivity was noticed* when starting to use the replacement wells P1b and P2b for production. Additionally, as far as the oil production performance is cooncerned, there was no improvement; the oil rate was less than before the replacement wells were installed, although the air injection rate was maintained at the same value for these two pairs. The pronounced reduction in air injectivity can be related to the massive oil penetration in the burned zone during the 3-4 month period of air injection interruption, when the pressure in the burned zone decreased significantly; *this was accentuated by the fact that the burned zone was located somewhere towards the middle of the layer.* Oil re-saturation of the burned zone occurred due to the gravity flow of the heated oil from the adjacent regions, which led to a massive coke deposit in the fringes of the burned zone. This caused the reduction of porosity and permeability of the air-flow pathways between the shoe of the old air injector and the toe of both old producer and the replacement producer. This massive coke deposit during ISC interruption also occurred in conventional ISC projects (conducted with vertical wells); at Suplacu de Barcau ISC Project a band of coke of 2.5m-thickness was found when drilling the coring wells in the burned zone (Turta, 1986???).

Therefore, the poor production performance can be related directly to two factors:

- General reduction of permeability in the old burned zone
- Lack of a hot link between the former hot region (around P1 and P2) and the toe region of the replacement wells; the existence of a cold region with no oil mobility in this space

These two factors were crucial in reducing the air flux (flow) within the new pattern. And when the air flux decreased substantially, the ignition and an ISC front anchoring failed. Therefore, this prevented an ISC front anchoring and then a toe-to-heel ISC front propagation along the P1b and P2b producers. To avoid the massive coke deposit in the burned region a simple slug of water injection in A1 and A2 with some secondary steam injection in P1 and P2 was necessary. As seen in Figures 51a-b, it was unfortunate that a lot of steam injection in P1 and P2 was conducted, but 2-3 months before the air injection interruption, little steam was injected.

*

*   *

In total, the Whitesands THAI pilot produced 29,000 m^3 (182,400 bbls) of oil over 5 years. Taking into consideration the Petrobank official OOIP figure of 422,280 m^3 (Petrobank presentation 2011), the oil recovery is about 7%. The pilot area associated with this OOIP figure is shown in Fig. 47 a, and it can be seen that this large area of the pilot results from taking an exterior/outward contour at 50 m distance from the producers P1 and P3. However, it has to be pointed out that the distance of 100m between pairs (corresponding to a pattern area of 450*100=4.5ha) was excessively large for a direct line drive THAI process. As seen previously, the burned and heated zone did not go farther than 20m outward, laterally from the production wells P1-P3 trajectories. Therefore, in this case, a distance between pairs of 50m (pattern area of 2.25ha/pair) would have been more appropriate. Accepting our hypothesis for this situation, the oil recovery would be 14%, at this stage of the project life~~.~~

A range of 7% and 14% for oil recovery for the pattern areas of 4.5ha/pair or 2.25ha/pair, respectively, seems to be a reasonable value, considered for the current status of THAI technology, using a DLD configuration in Athabasca oil sands. However, it has to be mentioned that the project was stopped at its half-life duration, such that a potential ultimate oil recovery up to 28%(for smaller patterns) could be expected for a full-fledged project.

To our knowledge, except for SAGD, which produces commercial amounts of oil, no other pilot in the Athabasca Oil Sands region has produced more oil than the Whitesands THAI pilot. In the ISC pilots, for example, conducted by AMOCO 20 years (1968-1988), the maximum amount of oil produced was 1,000 m^3 (7,000 bbls). From the current evaluation*, it can be stated that the Whitesands pilot has demonstrated the technical feasibility of the THAI process, while the economic efficiency needs to be* improved. A *similar assessment has also made by John Wright, the CEO of Petrobank, in 2013 (see Appendix D, January 4 or May 8, 2013).*

As outlined in the analysis by the Alberta Oil Staff magazine in 2015, "like many ideas, it may take longer to demonstrate its value than first expected" (see Appendix D, March 2015).

Table 9a: Performance analysis per THAI pair in the period 2008-2009 (missing information for 2007, 2010 and 2011)

Para-meter	Well Pair A1 - P1					Well Pair A2 - P2					Well Pair A3 - P3/ P3b				
	Air Injected	Steam injected	Oil pro-duced	AOR	SOR	Air injected	Steam injected	Oil pro-duced	AOR	SOR	Air injected	Steam Inject-ted	Oil produced	AOR	SOR
Year	10^3 sm^3	m^3	m^3	sm^3 / m^3	m^3 / m^3	10^3 sm^3	m^3	m^3	sm^3 / m^3	m^3 / m^3	10^3 sm^3	m^3	m^3	sm^3 / m^3	m^3 / m^3
2006	-			-							-			-	
2007															
2008	18,523	1,398	3,636	5,094	0.4	14,320	2,527	3,120	4,590	0.81	2,742	1,774	117.8	23,277	14.9
2009	5,612	0	577.2	9,723	0	10,940	0	1,842	5,940	0	14,700*	0	2,419	?	0
TOTAL	24,135	-	4,213.2	**5,728**	-	25,260	-	4,962	**5,091**	-	17,442	_	2,537	**6,875**	_

* Injected air estimated from Figure 51c

Legend: AOR=air-oil ratio; SOR=steam-oil ratio

Table9b: Performance analysis for the entire pilot (all three pairs); missing information for 2010 and 2011

Para-meter	Well Pairs: A1-P1 A2-P2 A3-P3/P3b				
	Air Injected	Steam injected	Oil Produced	AOR	SOR
Year	10^3 sm^3	m^3	m^3	sm^3 / m^3	m^3 / m^3
2006			778.2		
2007	23,920*	7,300*	6,856.6	3,488.6	1.1
2008	35,586	5,699	6,296.2	5,652	0.8
2009	33,995**	-	2,419.3	6,842	_
TOTAL (2007-2009)	93,501	?	15,572***	**6004**	-

Legend: AOR=air-oil ratio; SOR=steam-oil ratio

*Estimated from the graphs in Figure 54a-c; **For A3, estimated from the graphs in Figure 54c; ***Without 2006 oil production

Note: The replacement wells P1b and P2b were put into production in November 2009

6.5. Analysis/Interpretation of Whitesands Demonstration Project

In addition to the problems related to the lack of confinement (escape of air/gases to Mc Murray "A" formation and the bottom water), the main problems encountered during Whitesands operations, in the order of importance, are:

1. Weak lateral development of the burned zone (low areal sweep efficiency)
2. Sand influx
3. The complexity of re-drilling the horizontal producers
4. Relatively slow generation of the ISC front (slow/poor ignition operations), based mainly on *local hot linking* between the vertical injector and horizontal producer
5. Lower than desired/optimal air injection rates

Probably the most severe problem encountered during field testing *of the THAI process in a direct line drive (DLD) configuration* was the limited lateral development of the combustion zone/burned volume. This limitation caused a pronounced *wedging* tendency of the ISC front during its toe-to-heel propagation. The lateral expansion of the burned zone was constrained due to a weak lateral drive. This was because the DLD well configuration used was not the optimal choice to promote the expansion of the combustion zone. *The bottomhole temperatures recorded during the process indicate that the ISC front reached up to 20m laterally from the producer and a longitudinal distance of 40-45 m from the toe (observation well OB6)*. At distances from the toe less than 40-45 m the lateral development was probably higher than 20m, but data from other observation wells cannot entirely confirm this. There is no information on its progression beyond distances greater than 45 m from the toe. The replacement well P3B, when drilled, largely confirmed the latter statement, as it did not experience a high reservoir temperature (at its toe located at 15 m - laterally from the former trajectory of P3 production well and 25m from the A3 injector).

This ‘wedging effect’ of the combustion front (see Fig. ???) was exacerbated by the fact that the critical operation of hot communication described in the original THAI patent was not “ad-litteram” applied in practice. In the pre-ignition heating cycle (PIHC), the entire volume of reservoir between the vertical injectors was supposed to be hot-connected (Appendix B, patent #9), in order to create a broad initial ISC front (ISC burning surface). Then, in the second step, hot connection with the toe of the horizontal producer was to be realized. Instead, a simple "local" hot communication between the vertical injector and the toe of the producer was obtained, and this was not sufficient; The 'wedging effect' started from the very earliest stages of operation. The negative phenomenon of 'wedging' (or tonguing) was aggravated by the location of the 15m-portion of the 30 m blank liner end of the horizontal producer, past the shoe of the injectors. This promoted a narrowing of the developing combustion zone from the very start of combustion advance. Hence, *the chance for an expanding radial propagation, initially, of injected steam (for PIHC) was compromised*. This will be discussed further in Subsection 11.1.2.

An ISC process can also be assessed in terms of economic efficiency by the air-to-oil ratio (AOR), much like SOR (steam-oil-ratio) in SAGD, indirectly reflecting expenses to revenue ratio. Most commercial ISC projects (with vertical wells only) so far have achieved an AOR in the range of 1000-3,500sm^3/m^3 (Turta 2007). However, AOR alone does not reflect its efficiency entirely as the injection pressure is also important; for the same AOR lower injection pressure obviously reduces the compression load, and hence leads to better economic performance. To take this into account, a coefficient of performance ζ can be calculated; This is is equal to the ratio of the heating value of the oil produced by the process to the quantity of primary energy required in the surface facilities, mainly for air compression. The Whitesands THAI pilot was done using an average injection pressure of 3.5 MPa and an average AOR of 5,000-6,000 sm^3/m^3. Therefore, neglecting all of the energy consumed during the preheating/PIHC phase, steam injection into the horizontal producers during operation, and also ignoring the other energy consumed by pumps, oil and gas treatment, etc (all of these constitute a small fraction of the total energy consumed during THAI operations), Burger's method (Burger, 1985) gives a value of ζ = 5-6. (this is equivalent of saying, that approximately 20% of the produced energy is consumed by air compression). For successful commercial ISC projects the coefficient ζ is usually in the range 15-45. This shows that the overall energy performance of the Whitesands THAI pilot was quite low. Taking into account this small value of ζ and the fact that producers had to be replaced, it follows that the AOR needs to be decreased from 5,000-6,000sm^3/m^3 to 3,000-4,000sm^3/m^3, in order for the process to become competitive. Also, a second condition is to design and conduct the process in such a way that the maximum air injection rate can be, at least, doubled.

Although its performance coefficient for the Whitesands THAI pilot is equivalent to an SOR~2.5-3 for steam injection, the operational problems encountered during the project make THAI less attractive than SAGD. It is recommended, therefore, that THAI should be applied only in situations that are not suitable for SAGD eg, mainly in thin formation (>6m) and/or deeper than 1000m. The *proviso* being, of course, that if THAI can be operated economically, then it should also be considered as an alternative to SAGD, since it has the added bonus of producing upgraded oil.

6.5 Winding-down Alternatives for the Whitesands Demonstration Project

As a general rule, *conventional ISC projects* end up using continuous water injection into the burned zone, in order to utilize the huge amount of heat stored in the reservoir; This follow-up operation also helps in avoiding massive oil re-saturation of the burned zone – and generation of a large amount of coke. Usually, water injection is started, immediately air injection is stopped.

In some conventional ISC projects, in the past, a few years after the suspension of air injection, horizontal wells were drilled as in-fill production wells. An example is the Eyehil project in Saskatchewan (Farquharson, 1986), in which three horizontal wells with a horizontal leg of 1000-1200m were drilled. The wells were drilled two years after complete cessation of the dry combustion project, in 8 adjacent, inverted five-spot patterns. Combustion in this project was active for about 10 years, but it was operated with relatively low air rates. At the time of cessation of air injection, the oil recovery was 10%. The reservoir consisted of an oil zone 5-8m thick and a 15 m thick underlying bottom water zone. This is typical of a bottom water reservoir operated by ISC; the oil viscosity at reservoir conditions was around 2,000cp.

The first horizontal well in the Eyehil project had very good production performance. The well produced for a long time with oil rates of 55-60m^3/d. The good well productivity is explained by the fact that it was located very close to the boundary of the project area, *right in the oil bank formed by the former ISC process*. The second horizontal well was located on the other side of the first horizontal well, too far away from the project area and its performance was not very good. The third horizontal well intercepted a portion of the previously burned area and had a poor performance, as well. *Hence well location in the reservoir, following an ISC operation, is critically important and should endeavor to strike the mobilized oil bank that remains (and get enlarged) for an extended period after cessation of the active ISC process.*

From the above and other similar projects, it is clear that the success of horizontal producers drilled as in-fill wells would depend more on *the correct placement of the wells and less on the length of its horizontal section.*

The lessons to be learned from conventional ISC projects in the use of horizontal wells as in-fill wells, following an ISC operation, suggests several alternative operations/approaches that should be considered vis-a-vis the Whitesands project, namely:

1. Straight continuous *water injection* in the vertical wells for scavenging of the heat from the burned zone and oil displacement by steam and hot water; this should be done for a limited period of time and at the highest injection rate possible

2. Continuing the ISC process by using *control vertical wells* as air injection wells; these will be new lateral wells located in-between the current wells P1b, P2b and P3b, but further away from their toes to process areas which remained unswept.
3. *Use of a middle horizontal producer as a future air injection well*, as burning surfaces already exist in both directions, towards adjacent horizontal producers. In this case, air injection will be carried out only in P2b, while P1b and P3b will be used as producers; for safety reasons and to increase the efficiency, wet combustion should be applied, with continuous air injection in P2b and with continuous water injection in A2 well.
4. Using the current P1b, P2b and P3b wells as future production wells for *SAGD operations*; in this case, only the future steam injection wells are to be drilled parallel and 5 m above P1b, P2b and P3b wells.

The choice of the best procedure to be adopted should be based on the *current bottomhole temperature* (BHT) to be measured in all wells of the Whitesands project, including the injection, production and observation wells. The SAGD application (version 4) can be a choice to consider, but the distortion of the future SAGD chamber for the last 200m of the current toe region can significantly diminish the performance; simulation studies will be very critical.

The second alternative (control vertical wells) is more complex, as it involves a temporary application of reverse ISC through those lateral control wells in order to attract the ISC front, laterally towards them; then after their interception by ISC front, a forward ISC similar to THAI will be conducted using these wells; this is a kind of 'echoing ISC process', grafted onto THAI process (Johnson, 1980).

The third alternative (a current production well converted to an air injection well) involves the use of a former horizontal producer as air injection well and more detailed information about this possibility (and ways to implement it) is presented in Appendices G and H. In this situation, the air is first injected at the toe, and an ignition operation may or may not be necessary (depending on the BHT value); then, a very large/extended ISC front will displace oil at a potentially high rate towards the two horizontal producers; attention should be paid to avoid the blockage of the horizontal producers. To some extent, similar to the procedure proposed for operation 2 (in-fill production wells), this method may not be applicable if the mid-space between pairs is not at least mildly heated.

No matter what alternative is adopted, it must take into account the fact that the wedging of the burned zone towards the heel is a reality, and the current extension of the burned zone (along the horizontal section of horizontal producer, starting from the toe) is no longer than approximately 200m.

Before trying to select any of the suggested approaches, it is recommended to go more in-depth for clarifying the cause of approximately 50% of the capture efficiency of oil displaced by the ISC front, as found in our calculations (see subchapter 6.1.4.2). If by new additional work/field new instrumentations this is proved to be real, then the new wells to be drilled should aim at tapping the *uncaptured oil*, which may still be hot/warm even after 6-7 years from the suspension of the pilot. Otherwise, if the permanent air escape from the objective and/or in bottom water was substantial (close to 50%, all in all) for obtaining this low oil capture from calculations, then, there is no use in targeting the above-mentioned oil; practically, there is no uncaptured oil. The best way to clarify this dilemma is to drill 2-3 coring wells, strategically positioned, such that they can bring information about the presence of oil in the bottom water zone and about the degree of extensity of burning in the Mc Murray A formation. Therefore, these coring wells have to core all the way through the Mc Murray A and the Mc Murray B formation and bottom water. In addition, these coring wells will bring valuable information related to the fuel (coke)/air requirement associated with the process.

7. STATUS OF TECHNOLOGY. FIELD TESTING IN CANADA: KERROBERT PROJECT

This project consists of an initial 2-well pair (demonstration pilot), which, later on, was expanded to a semi-commercial operation of 12 THAI pairs; 10 more pairs were added. Neither the pilot nor the semi-commercial operation benefited from the installation of any observation wells. However, a large amount of data was generated by the horizontal producers, which had thermocouples along the horizontal section; also, the vertical air injection wells have thermocouples in the area of their perforations. This project is the first THAI piloting in conventional heavy oil reservoir underlain by a relatively thick bottom water zone, which has a negative effect on **i**n-**s**itu **c**ombustion (ISC) application. Therefore, the project tested two aspects of the THAI technology: (1) application in a conventional heavy oil reservoir, and (2) whether it could also work in the presence of a thick bottom water zone. What is in reality tested in this project is the effect of bottom water on THAI performance. It is hoped that the questions such this "Is bottom water more harmful than in case of conventional ISC process? Could it be answered from the results of this test?

Similar to Whitesands Project, the Kerrobert Project used the **d**irect **l**ine **d**rive (DLD) configuration for both the pilot and expanded semi-commercial project. Based on the lessons from Whitesands Project, the following improvements were implemented:

- The perforation of vertical injectors was done classically; i.e. in the upper half of layer and both steam injection and air injection conducted through the same perforations
- Steaming of horizontal producers were no longer done before putting them into production
- Also, the injection of steam into horizontal producers were no longer done during the THAI process

For this Project there were no IETP reports and ERCB/AER annual presentations, and for this reason, the fragmented information obtained was scrutinized and double-checked via the raw injection and production data, provided by the geoSCOUT software; the amount of steam injected of ignition purposes was checked this way; the THAI Applications were also used. However, similar to the Whitesands pilot, all the bottom hole temperature (BHT) profiles in the horizontal production wells were available. Some gas composition data was initially obtained during a visit to the Project by one of the co-authors of this Report, in February 2016 (later on, more gas composition was available). It was noticed that both gas composition and bottom hole temperatures were continuously recorded and displayed at a Central Processing Facility (CPF).

7.1 Geology, Reservoir Properties and Primary Recovery

Kerrobert heavy oil pool is located 16 km southwest of the Kerrobert town of Saskatchewan. Oil production is from the Manville Sand of the Lower Cretaceous age, more specific, the Waseca Member of the Cantuar formation, (SMER Application, 2010). The reservoir is located on a big Waseca channel deposit, oriented SE-NW, on which channel further to the North, Luseland, and Plover Lake pools are situated. Luseland pool has been exploited using **c**old **h**eavy **o**il **p**roduction with **s**and (CHOPS) (Dusseault, 2001, 2002/2003); some sand influx was also recorded in Kerrobert.

The THAI project is placed in a part of the Waseca channel (Fig. 56 and 57), which has a width of 400-700m. Within this channel, multiple discrete pay intervals exist at different locations, from top to bottom: Sands 1, 2 and 3 (See also Fig. 64a). The upper sands are saturated with oil, while the lower ones are mainly saturated with water. These sands and the contact bottom water-oil are clearly seen on the logs discussed in the Appendix G (Figures G1d and G1e), where other details are provided.

Waseca reservoir is composed of fine-grained sands and slightly consolidated sandstone; the depth to the top of the formation varying between 758 and 774 m (oil-water contact is at 789m). Oil zone thickness is 15-20m in the Western part and increasing up to 25-30m in the Eastern part (average net pay thickness is approximately 8m); bottom water zone thickness is around 10m in the Eastern part and approximately 20m in the Western part (locally it could be even more than 20m), Wikel, 2009). Therefore, the ratio of water zone thickness to that of oil zone shows more favorable conditions in the Eastern part; it decreases from 0.3 to 1 from East to West.

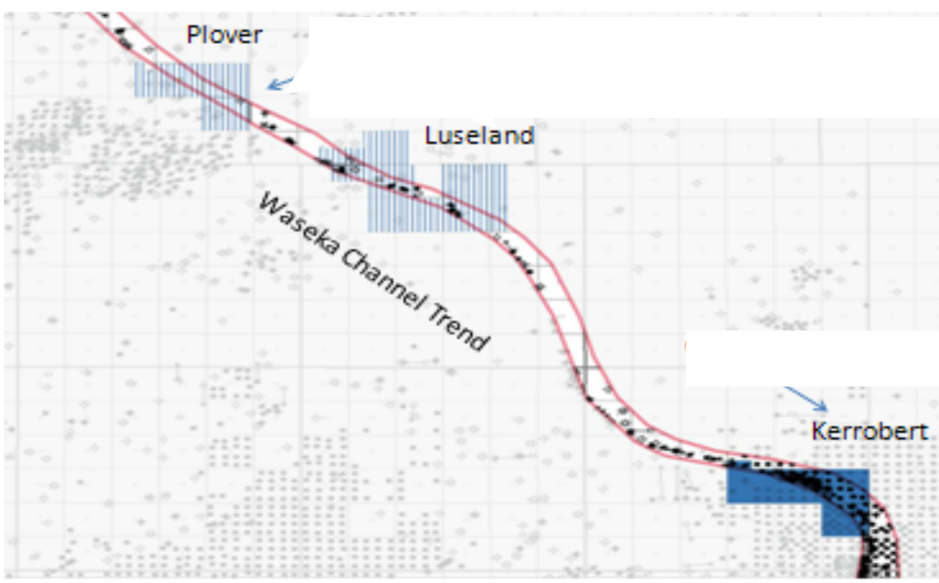

Fig. 56: Waseca channel, and location of Kerrobert THAI project (Appendix D; Petrobank corporate presentation, Aug 2012)

The dip is very low; while the top of the reservoir has a slight dip, the bottom is almost flat.

Reservoir temperature is 20 ^{0}C, and oil has an API gravity of 10.1 API (at 15.6 ^{0}C). At reservoir temperature, average dead oil viscosity is 33,500mPa.s (range of 21,000 to 53,000mPas), while in general live oil viscosity is higher than 21,000 mPa.s (being possible to go up to 42,000 mPa.s (Wikel, 2012 and Starkov 2015). Therefore, oil has some mobility, but very low, at reservoir conditions. The asphaltene content is 14%.

Other data (from Saskatchewan Oil Reserves – 2008) are:

- Oil formation volume factor: 1.111
- Porosity: 32 % (28%-37%)
- Horizontal permeability: 1,130-10,300mD (average 4,948mD) and other source (Wikel,2012) reports even higher horizontal permeabilities (2-6Darcy)
- Vertical permeability: 354-7,800mD (average 3,793mD)
- Initial oil saturation: 70%; connate water saturation: 30%
- Oil/water transition zone thickness is approx. 5m and has an oil saturation of 55-75% (Kerrobert Expansion Project, 2010)

Solution gas-oil ratio at bubble point pressure (BPP): is not determined probably; it is estimated at around 5 sm^3/m^3. It seems that BPP value was very close to the initial pressure of the reservoir as it is suspected that a tiny primary local gas cap existed.

Oil production started in 1995-1996, using *predominantly* horizontal wells. In total, 22 wells have been drilled on the pool; out of these 18 were horizontal wells. Horizontal wells have their horizontal sections located towards the top of pay zone to minimize water production.

Horizontal well 192/09-14-033-24W3/00 was converted to a water injection well, in May 2008, and injected for one year. A geoSCOUT schematic map of the Kerrobert Field is shown in Figure 57. The wells are located in the sections 12,13,14,15 and 22, while practically all the THAI Project wells are located in Section 14. A portion of the channel trend Figure 56, can also be seen in Figure 57.

Data on Manville wells, along with information on their performance is provided in Table 9. By December 2008, the cumulative oil produced was 182,216 m^3, representing a recovery factor of

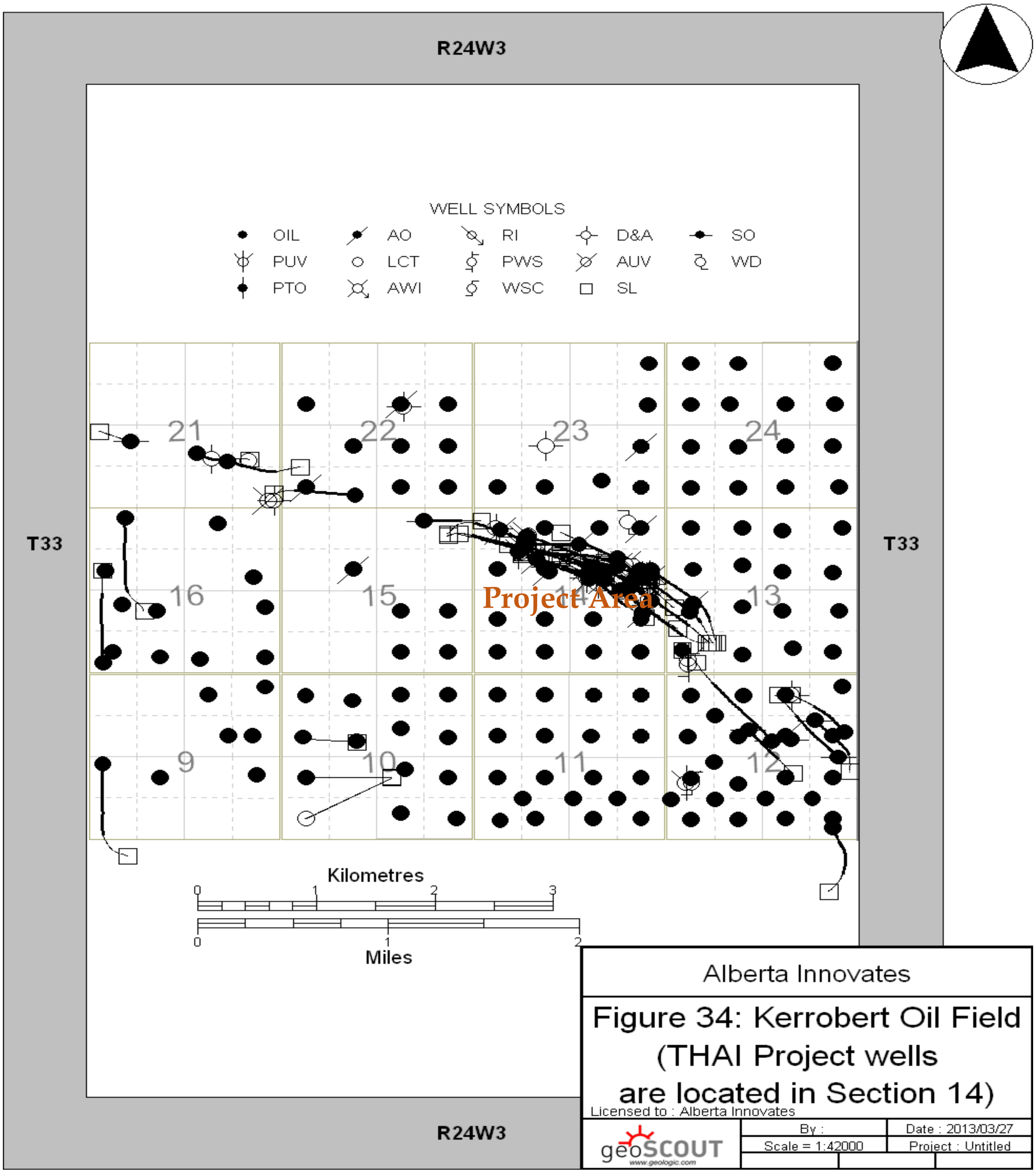

Fig 57: Kerrobert field. geoSCOUT schematic map

1.2% OOIP (Petrobank application, 2010); the estimated ultimate primary oil production was 10%. At that time, cumulative water injected was 107,000 m³, while the total cumulative water

Data on Manville wells together with information on their performance is provided in Table 9. By December 2008, the cumulative oil produced was 182,216 m^3, representing a recovery factor of 1.2% OOIP (Petrobank application, 2010); the estimated final primary oil recovery was 10%. At that time, cumulative water injected was 107,000 m^3, while the total cumulative water produced was 703,000 m^3. By December 2008, only 6 wells were on production, and the reservoir pressure was around 3,000 kPa (initial pressure was approx. 6,000 kPa). The primary production performance is shown in Figure 58 (THAI wells, KP1-KP12, are not included). In September-October 2009, when the THAI pilot started, the average primary daily oil rate (per well) was approximately 0.5 m^3/day, with a water cut of around 90%.

From Table 10 and Figure 58, the following conclusions can be drawn:

- The predominant mechanism of oil production was a **b**ottom **w**ater (BW) drive, although some solution gas drive may have also contributed. The contribution of BW is important as the thickness of bottom water is relatively large (almost equal to that of the oil zone in the Western part of the reservoir). The strength of BW can be considered as mild, somewhere between strong and weak, as the reservoir pressure decreased to half of its initial value.
- The initial oil rate per horizontal well was in the range of 2.5-22 m^3/day, while the initial oil rate per vertical well was in the range of 1.4-11 m^3/day, in both cases depending on well position on the reservoir structure.
- There was some sand production, but the attempts to fully use the CHOPS exploitation were not successful, such that the CHOPS contribution is considered extremely low.

Generally, the wells produced for approximately 10 years with a cumulative of oil in the range of 2,500-20,000 m^3 (average 9,000 m^3). They were suspended or abandoned due to a very high water cut, in the range of 93-98%.

In-situ combustion (ISC) began when the average water-cut had risen to around 96%, and the reservoir was almost at the end of primary production. There was virtually no prospect of achieving the predicted ultimate oil recovery by primary exploitation (10%). Hence, the use of ISC, in this case, is considered a secondary EOR method.

In Figure 58, the short-term oil production increase is mainly due to the suppression of the advance of bottom water due to pressurization of the reservoir via air injection.

Well type	Status	Initial	Data	Last	Prod	values	Sept - 2012	Dec Data	Cumulativ Dec	Values 2012	Water injected
Vertical (V) / Horizontal (H)		Production/ or inj date	F4M oil prod	Last prod date	L4M oil prod	Water cut	L4 M Oil prod	Water cut	Oil produced	Water produced	
			m³/day		m³/day		m³/day	%	m³	m³	m³
H	Prod	3/1/2007	13.5	-	-	-	5.3	73	20233	16176	-
H	Shut-in	6/1/96	8.6	12/31/07	8.9	67	-	-	4695	17254	
H	Susp	6/1/96	2.9	11/30/02	0.8	94	-	-	1461	1763	
H	Susp	6/1/96	10.1		-	-	0.2	99	2469	15213	
V	Shut-in	5/1/95	2.7	2/29/08	3.9	41	-	-	2589	730	
H	Shut-in	10/1/95	21.5	9/09	?	99	-	-	14555	53749	
H	Prod	6/1/96	6.2		-	-	2.3	61	4560	1675	

Table 10: Primary oil production of the Manville wells belonging to Sections 12-14, 15 &22, Township 33, 24W3/00, as of December 2012. Source: geoSCOUT

V	Susp?	8/1/96	5.0	8/09	1.3	98.4	-	-	19185	210980	
V	Susp	5/1/95	3.94	8/31/95	3.94	29.7	-	-	153	65	-
H	Prod	11/1/95	22.10	12/31/08	3.30	96.8	-	-	26943.5	110924.9	-
H	Shut-in	8/23/95	29.8	6/30/06	0.94	80.9	-	-	26621	79254	-
H	Water inj	11/1/95	2.7	7/31/05	0.04	93.3	-	-	12423	35647	107308
H	Susp	7/1/96	13.5	3/31/98	1.9	93.3	-	-	3207	12231	-
V	Shut-in	8/1/96	11	1/31/06	1.34	51	-	-	6609	18482	-
H	Susp??	10/1/95	17.8	10/?/09	1.71	97.8	-	-	12581	68995	-
H	Susp??	11/1/95	2.3	7/?/09	22	97.5	-	-	12661	48860	-
H	Shut-in	8/1/96	6.8	9/30/06	0.41	6.9	-	-	4858	693	-
V	Shut-in	5/1/95	1.4	5/1/95	1.4	99	-	-	-	28	-
H	Susp	7/1/96	18.1	3/31/98	4.6	84.3	-	-	4306	10484	-
H	Shut-in	5/1/95	19.3	4/30/05	0.35	88.9	-	-	6071	19495	-
H	Shut-in	12/1/96	2.8	7/31/06	-	99	-	-	3554	5752	-
H	Prod	7/1/96	18.7		-	-	1.8	46	4448	11817	-

Legend:

F4M oil prod =First 4 months daily oil production; L4M oil prod= Last 4 months daily oil production (average daily oil production in the last 4 producing months)

Note 1: Manville wells of Section 14, without oil production (6 wells): 111/09-14-033-24W3/00; 114/09-14-033-24W3/00; 115/09-14-033-24W3/00 (obs) ; 112/10-14-033-24W3/00; 194/10-14-033-24W3/00 (KP7- dry well); 143/12-14-033-24W3/02.

Note 2: Out of 50 wells located in Section 14, 18 were producing at other than Manville formation (Vykor, Deadwood, etc)

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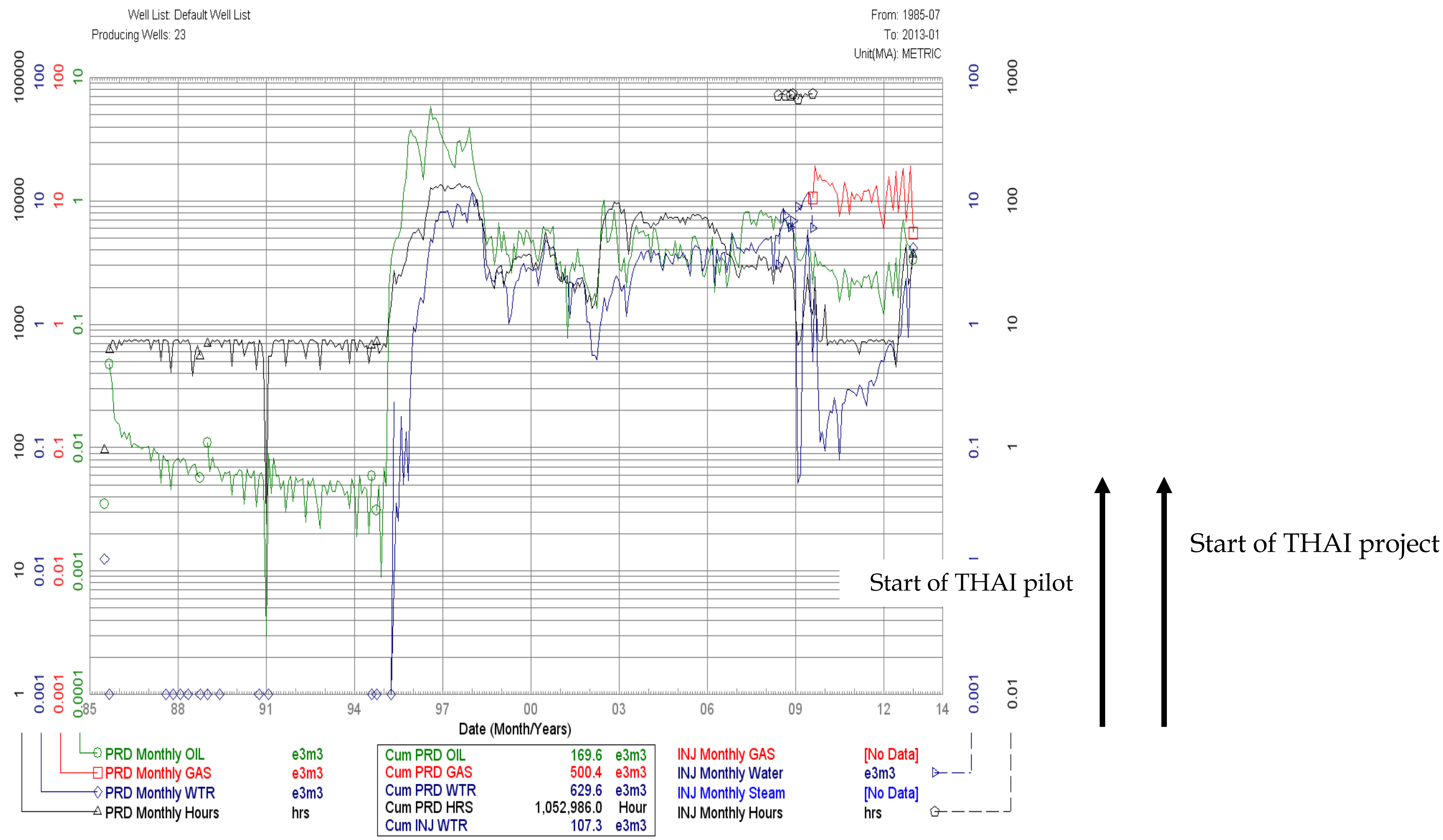

Figure 58: Kerrobert Field. Primary production performance. Source: geoSCOUT. Note: Wells KP1-KP12 are not included.

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7.2 Investigation of Feasibility of ISC Process and Design Considerations

The data on specific laboratory tests are very sparse. Here is one page summary of information on these, without any mention if one or several 3-D tests were conducted (SMER Application, 2010). Also, it was not mentioned if a direct line drive (DLD) or staggered line drive (SLD) was used in the laboratory test (s). Reported single THAI test showed a relatively good upgrading: API gravity increased from 10.1 to 13.8 ^{0}API, while oil viscosity decreased from 33,500 to 1,200 mPa.s (28 times). Asphaltene content was reduced from 14.1% to 10.4% mass%. Oil recovery for the test was 68%, but this is only for an idealized case, which is unlikely to be achieved in a field situation.

As mentioned previously, there are 8 old horizontal wells located in the region of THAI project (Fig. 57); a ninth horizontal well, immediately North of project, was not considered because it is unlikely to interact in any way with the THAI project. None of the old horizontal wells were ever intentionally used for oil production during the THAI operation as they had already been abandoned. There is no specific information on how they were abandoned; generally, only a portion of about 200m section, close to the heel, is cemented; therefore, the horizontal section was probably not entirely cemented. There is no mention, in their analysis, how these old wells would interact with subsequent THAI operations; they might constitute a severe channeling pathway, as their horizontal sections were located towards the top of formation, due to the presence of a bottom water zone underlying the oil pay.

There is very little information available on the design of the project or its anticipated performance. The only design result is from simulation, and it is overly optimistic, showing an oil rate per production well increasing from 17.6 m^3/day to 40 m^3/day within a 10-year span of time; an ultimate oil recovery factor of 69% is predicted (SMER Application, 2010. More important, there is **no analysis regarding the effect of bottom water on the performance** or on how the process needed to be modified in order to take into account the usual negative impact of the bottom water (SMER,2010); this was so in spite of the fact that even in case of Whitesands Pilot - where the thickness of bottom water is less than 10% of oil zone thickness - the negative effect of bottom water was apparent. This was a precarious path, taken by Petrobank, considering the problem of 'heat drain-off or sink' experienced in thermal recovery operations of this kind. Given this fact, in the following subchapter, we include some critical information on the application of conventional ISC in the presence of bottom water. Finally, the possible impacts of bottom water on the THAI performance are discussed. As is seen in this section, the conventional ISC process has not been proven so far for reservoirs with bottom water. *That the THAI process has been tested in conditions where no conventional ISC process has ever been successful, has been therefore, a risky strategy.*

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7.3 Performance of Conventional ISC in the presence of bottom water (BW)

For heavy oil reservoirs with BW practically no EOR method has been proven feasible, so far. This is due mainly to the loss of the injection fluid and energy into the BW zone, making the recovery process uneconomic. Laboratory tests of steamflooding in the presence of BW have not yielded very encouraging results (Chang, 1990). When considering thermal methods, there were suggestions that ISC could perform better than steam flooding (Farouq-Ali, 1983), probably due to the fact that air is less expensive than steam and its loss into the BW zone is, therefore not so economically detrimental. Recently, steam injection experience in the Pikes Peak field has shown somewhat limited encouraging results (Wong, 2003) in a reservoir with BW.

Laboratory testing of ISC in the presence of BW is not easy to perform. However, a study contributed to reasonable explanations of the failures of field pilots (Greaves, 1993). Correlation between laboratory and field tests would likely help in the design, operation, and evaluation of a project of ISC in a reservoir with BW. Based on the performance of field and laboratory tests, a schematic of the BW-ISC is shown in Figure 59. The partitioning of the injected air between the main ISC front (at the upper part of oil layer) and the secondary one in the BW zone will probably decide the efficiency of the process. It is believed that at the oil/water (O/W) interface, a real ISC front would exist, as the O/W transition zone still has a good oil saturation to sustain an ISC front.

In the case of reservoirs with BW, ISC has not attained commercial operational status, but the experience from these field tests is still precious. Most of the field pilots were conducted during the 1970s and 1980s when the understanding of conventional ISC was rather limited. Most of these field tests were considered failures. More recently there was one test of ISC in the presence of a BW zone at the Bechraji project in India, which began in 1996. Very few details of this test have been published (Oil and Gas Journal, April 2000), but it is known that it was developed on semi-commercial scale, and it was eventually stopped due to a lack of required efficiency.

Two approaches have been tested in oil reservoirs with BW; 1) a conventional ISC pattern, otherwise called bottom water ISC (BW-ISC) and 2) the **b**asal **c**ombustion (BC). Both of these have been applied using vertical injection and production wells. The difference between these two methods is initiating the combustion and the nature of its propagation. While the combustion is normally initiated at the upper part of an oil layer in the BW-ISC, in the BC process (Lau, 2000), ignition is in*tentionally* initiated at the water-oil contact with the aim of using the high mobility water-zone for oil flow towards the producers. New methods of applying ISC using horizontal wells in the presence of BW were proposed, but these are currently at a conceptual stage and need to be field tested; their analysis is beyond the scope of this Report.

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Table 10 presents data/results for 9 conventional BW-ISC projects; all of them used vertical wells in pattern exploitation schemes. From these tests the main observations are:

- Out of all the tests, the most complete and successful was the North Tisdale Project; oil zone was 50 ft (15.3 m) thick, compared to 12 ft (3.7m) for the water zone, and this represents favorable reservoir conditions. This test involved 4 injectors, 15 producers, and operated for more than 9 years. Oil recovery increased from 5% to 19% during ISC, with an **a**ir/**o**il **r**atio (AOR) of 25,400 scf/bbl (4,500 sm^3/m^3 of incremental oil). The relatively high AOR is mainly due to low oxygen utilization, around 72%, although for a BW-ISC operation, this AOR is the best ever obtained. The low oxygen utilization was probably due to some of the injected air entering and flowing through the bottom water zone. Variation of combustion gas composition is shown in Figure 60; it can be seen that for a few years, there was a continuous increase of produced oxygen and a continuous decrease of CO_2 in the produced gases. Unfortunately, no H/C was calculated in order to determine if the O_2 probably flowing at W/O contact was unconsumed or participated in LTO reactions.
- The Cado Pine test, although with relatively incomplete public information, revealed some interesting features. In this test, *there was no clear evidence of air flowing in the bottom water zone*. The oil zone was 9 m thick, while the bottom water zone was 30 m thick. The oil viscosity was only 112 cp. It is believed that this low viscosity was a contributing factor in explaining why there was no apparent flow of air through the BW zone.
- The S. E. Pauls Valley test also showed no evidence of air bypassing through the bottom water zone. The oil in this formation was very viscous (8,000 cp), and large sand volumes were produced with reservoir fluids. It is speculated that the oil recovery mechanisms of CHOPS (cold heavy oil production with sand) were unintentionally triggered in this test. The test was stopped after 16 months due to operational severe problems related to sand production that resulted in mechanical failures of production wells.

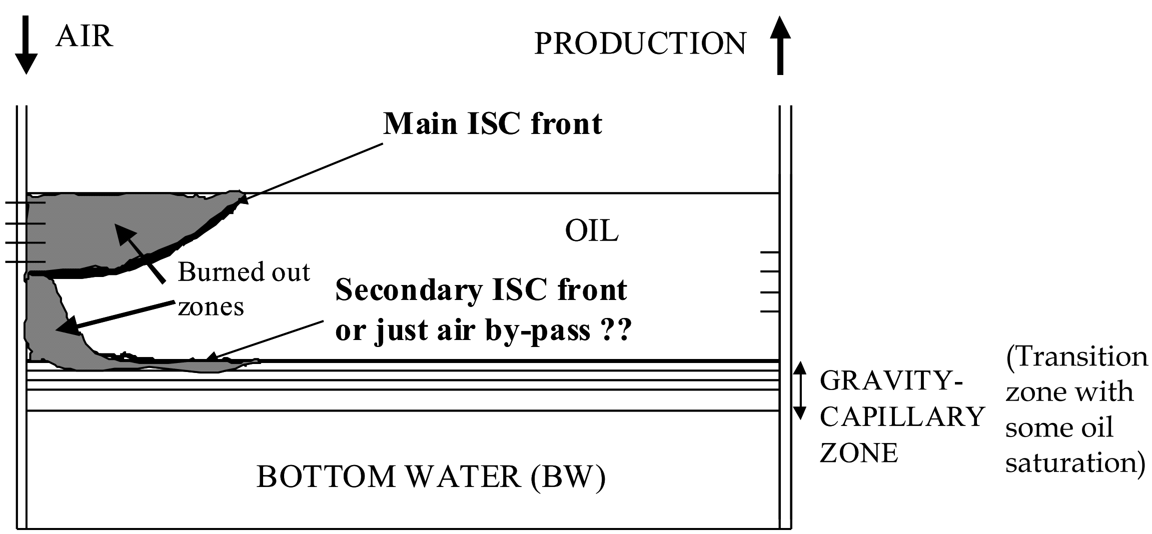

Figure 59 Schematic of Conventional ISC in the Presence of Bottom Water

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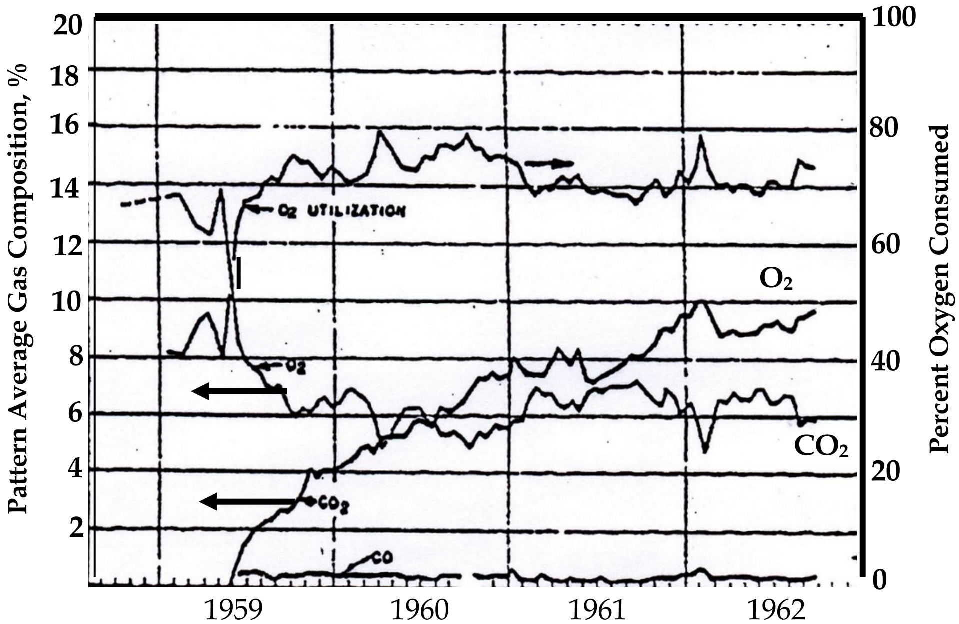

Figure 60: Variation of combustion gas composition and oxygen utilization in the North Tisdale ISC pilot (Martin, 1972)

- In the Carlyle pool three different pilots were conducted. Information is only available for two of these: Wiggins B pilot (dry ISC) and Riggs Pilot (wet ISC). In this formation, a thin interval of limestone exists above the oil/water contact.
  - In the Wiggins "B" pilot the injection well was perforated above the oil/water contact, but it was drilled through the limestone into the water zone. After 7 years of operation, three coring wells were drilled into the burned-out zone. They showed that although the ignition was achieved in the oil zone, ISC also took place up to 7 m in the water zone. Incremental oil recovery was 31%; however, this was obtained at a very high water cut (90% or higher). The main limitation was the very low productivity of the producers, which practically impeded subsequent expansion to a commercial scale.
  - In the Riggs pilot, the injection well did not go through the limestone. It was stopped in the oil zone, and ignition was achieved by a gas burner in the upper part of the oil layer. *In this case, burning was confined to a 3 m interval of high permeability oil zone interval. Oil recovery was only 8.5 %, while the AOR was very high, 42,900 scf/bbl (7,600 sm^3/m^3).*
- There is incomplete information in the public domain on Zerotin test. Although the reservoir temperature was very low, a proper ignition led to a vigorous ISC front and resulted in good oxygen utilization (88.5%). We may infer that very little air bypassed through the BW zone. Proper oxygen utilization may also be linked to an initial

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oil recovery (at the start of the pilot) of 25 %, which had generated higher gas saturation in the upper part of the layer, leading to a higher tendency of gas to over-ride. For this single pattern, operated for 4 years, AOR was 14,700 scf/bbl (2,600 sm^3/m^3).

- The Eyehill test involved 9, 5-spot patterns with 16 producers and was operated for 10 years. The water cut, around 80% at the inception of the ISC test, temporarily receded to 50% during the first 2 to 3 years of the project. For increasing the oil rates, attempts to apply cyclic steam stimulation were not successful. Although the combustion efficiency was satisfactory, the production performance was mediocre. This was probably related to significant heterogeneity in this channel type reservoir and also, due to numerous operational problems.

The last three tests (from Table 11) were conducted in reservoirs containing oil with viscosities >2,000 cp and they do not bring relevant information for our case.

In summary, the field applications of ISC in the presence of BW consistently yielded results inferior to those associated with the established commercial ISC projects, where the **a**ir-**o**il **r**atio (AOR) was in the range of 5,700 to 17,000scf/bbl (1,000 to 3,000 sm^3/m^3), (Turta,2007). For ISC pilots in the presence of BW the best applications realized an AOR of 25,400 to 42,900 scf/bbl (4,500 to 7,600 sm^3/m^3). Besides, the estimated incremental oil recovery was around 14% (with less reliable information - from a single pattern – estimated at 31%).

From this review of field pilots involving heavy oil reservoirs with bottom water zones, it is difficult to establish direct cause and effect relationships. Furthermore, it is very challenging to determine the most favorable conditions for ISC application, including definitive screening criteria. With minimal field information available, for BW-ISC the following *preliminary* screening criteria are proposed:

- The thickness of BW thickness to oil zone ratio <0.30*, with oil zone thickness > 8 m.
- The oil reservoir has recovered of at least 3% to 5% oil at the start of the ISC.
- Coarsening (increasing) upwards trend of permeability.
- Preferably oil zones with a very small gas cap.

* This criterion is in agreement with the general condition for application of all thermal recovery (steam injection and ISC) processes in the presence of BW (Farouq-Ali, 1983). The above screening criteria should be used only after the general criteria for application of conventional ISC were met.

Taking into account the foregoing discussion in this section, the following conclusions can be drawn:

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a. Design, implementation, operation, monitoring and evaluation of ISC projects in the presence of BW are different from those for conventional ISC. Specific procedures need to be developed that take into account inherent difficulties likely to be encountered in bottom water situations. So far, there have been no commercial operations involving ISC in heavy oil reservoirs with BW.
b. The crucial challenge of ISC in the presence of BW is a lack of stable propagation of the ISC front. One indicator is a decrease in oxygen utilization with time, possibly associated with LTO reactions due to heat diversion into the bottom water zone. Closely connected with this phenomenon is the propensity of air to bypass into the BW zone as well as some loss of mobilized oil in the BW zone. Laboratory tests have shown that the ISC front movement may be unpredictable and erratic, and it could cycle between the oil zone and the BW zone.
c. Using only vertical wells for both production and injection, two methods were tested in the field: BW-ISC and basal combustion (BC). BW-ISC uses only vertical wells and involves achieving ignition at the upper part of pay zone, while in BC the ignition is intentionally performed at the water-oil interface. There have been 9 field pilots of BW-ISC. One of them, North Tisdale, progressed to a semi-commercial stage. Although this pilot had a relatively low oxygen utilization (72%), it had the best AOR of 25,400 scf/bbl (4,500 sm^3/m^3), and had an incremental oil recovery of 14% (ultimate oil recovery increased from 5% to 19%). This value of AOR, however, is still less favorable compared with that obtained in commercial conventional ISC operations in the absence of BW.

Table 11. Reported Bottom Water ISC Pilots

Name of Field	Ref.	Depth Ft	Oil Zone Thick-ness ft	Water Zone Thick-ness ft	Por-osity /Oil sat. %	Perm. mD	Oil viscosity (Res. Temp.) cp(°F)	Res. Pressure/ Pattern size, psi/acres	Air Inj/ Water Inj Mscf/D/ bbl/D	AOR Ratio Scf/bbl	Oil Reco-very at start %	Notes
Cado Pine, Is, La, USA	Horne 1981	100	29	100	36.9/ 52.8	603	112(89)	65 / 5	1000/380	-	-	A
Suffield, AB, Ca	Wells, 1980 &Good, 1981	3000	60	30	25/75	1090	170(90)	1500 / 5	600/250	-	-	
N. Tisdale, Wyo, USA	Martin 1971	933	50	12	24.5/ 64.6	1034	175(73)	290 /10	900/0	25,000	5	B
Zerotin, CSSR	Juranek 1959	150	60	-	32/78	10000	605(50)	-/-	1270/0	14,600	25	C
Carlyle Wiggins B Pilot, Ka, USA	Elkins, 1973?	860	34-45	100-125	25/49	250	700(74)	230 /2.5	700/99	-		D1
Carlyle Riggs Pilot, Ka, USA		860	34-45	100-125	25/49	250	700(74)	230/ 2.5	700/99	43,000		D2
Eyehill, Sask, Ca	Farquha-rson 1986	2500	52	28	34/84	6000	2700(70)	730 /20	1000/-	-	--	E
SE Pauls Valley, Ok, USA	Elkins, 1972	4300	100	>50	23.5/ 80	900-2500	8000 (110)	1850/10	1727/0	6,000 (?)	3	F
Bodo, AB, Ca	Nazarko 1983	2360	59	39	30/78	1000-5000	2300-5000	<750/20*	$1x10^6$/230	?	2	G
Kearl Lake, AB, Ca	Raibek 1979	590	233	10	32/75	1500	10^6 (52)	- /28	-	-	0	H

Legend:
CSSR – Former Checoslovaquia; AB - Alberta, Canada; Sa - Saskatchewan, Canada
* After 7 years of piloting, plans to expand to semi-commercial (7 patterns) were made. However, never done, the project was terminated.
<u>Attention !</u> The notes (A to H) for this table are on the next page.

Notes for Table 10:

A. Weak bottom water. In the first eight months, total oil production was 2000 bbls for a total air injection of 147 MMscf.
B. Water was injected upon the termination of air injection.
C. Burned out thickness = 45 ft; oxygen utilization = 88%.
D. D1 - The injection well was drilled through the limestone into the water zone; D2 - The injection well had its shoe above the limestone (did not go through); in both situations ignition was made at the upper part of oil layer.
E. Water cut was 50% at the initiation of ISC.
F. ISC was successfully initiated and operated for 16 months (sustainable process-it seems at the upper part of layer); oil production increased from 100-170 bbl/day to 400 bbl/day; however, the project was terminated due to too many operational problems (mainly mechanical failures of producers) related to production of sand.
G. Relatively good oil production during primary (4 to 5 m^3/day/well); water cut = 50% at the initiation of ISC.
H. 16 injectors and 16 producers; oil production reached 500 bbl/day.

7.4. Performance of the THAI Process in Kerrobert

In the following section, we will first present details of the Kerrobert pilot (2 patterns) and then the expanded, semi-commercial operation (12 patterns). Some of the discussions and analyses for these two parts occasionally overlap. The only difference between pilot and semi-commercial operation was the number of thermocouples installed on the horizontal section of producers; there were 20 thermocouples installed in the pilot producers (patterns K1 and K2) and only 10 in the semi-commercial producers (for the 10 remaining patterns, K3 to K12). In both cases, progressive cavity pumps (PCP) were used for artificial lifting of the oil; the PCP was installed in the heel region.

7.4.1 Performance of the Pilot

In 2008 True Energy Trust signed a deal with Petrobank to apply *THAI* in Kerrobert heavy oil reservoir in Saskatchewan. Later on, True Energy was bought by Baytex Energy and, finally, Petrobank bought this property from Baytex Energy. A THAI pilot consisting of two patterns (two well pairs) was implemented in September 2009.

As mentioned at the beginning of Chapter 7, this evaluation is based exclusively on open technical sources, such as releases from Petrobank, interviews, and presentations from Petrobank executives, etc. However, the fragmented information obtained was scrutinized and cross-checkedd using available injection and production data, and all accompanying detailed data included in the geoSCOUT software application files; even the amount of steam injected in view of ignition was checked this way. Although this analysis is rather detailed, there are still some minor limitations due to a lack of official detailed information on the day-by-day variation of upgrading per well in the semi-commercial operations and on the details of the workovers conducted. Therefore, some minor guesswork was still required and is pointed out when it happens.

Unlike Whitesands Pilot, there were fewer temperature measurements available; unavailable were the temperature profiles in the production wells of the Pilot within the first two years or any temperature

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measurements in observation wells; no observation wells were utilized in the Project. However, during the Project (after 2012) detailed information on temperatures within the horizontal section of horizontal producers is available, having been continuously recorded and displayed at a Central Processing Facility (CPF), see Fig. 61a.

Locations of horizontal production wells KP1 and KP2 and vertical injectors KA1 and KA2 of the THAI pilot are shown in Figures 61a-c; some more details on the exact positioning of the toe of horizontal producer vis-à-vis the shoe of vertical injector are provided in Appendix G (Fig. G2 and Table G2), from which it can be seen that:

- Injector KA1 is arranged in a direct line drive (in relation to its corresponding producer KP1). However, the pattern itself is in a favorable situation, as it is completely isolated from other THAI modules (present and future modules) - therefore, an almost confined pattern; also, it is not close to any old horizontal wells.
- The pattern K2 has a more favorable start-up region (more towards staggered line configuration), compared to that of the K1 pattern; KA2 is located slightly off and outside the lateral drainage area of KP2. Additionally, as it will be shown in Appendix G, it has the best positioning of the horizontal section of producer and perforations of vertical injector, farthest from the water/oil interface when compared with all other pairs. Also, it does not seem to have any influence from an old horizontal well

Given the K2 pattern characteristics above, it can be concluded that the pattern K2 constitutes the best designed THAI pattern. The lateral well spacing between horizontal producers is 70-90 m, while the lengths of horizontal sections are 400-450m. As mentioned previously, in the region there are some old wells, both vertical and horizontal (see Figures 61b-c); however, as outlined previously, ***the pilot wells (both injectors and producers) were favorably positioned as they were located relatively far from any of the old wells in the region***. *Therefore, no interference in THAI pilot operations is expected from the old horizontal wells.*

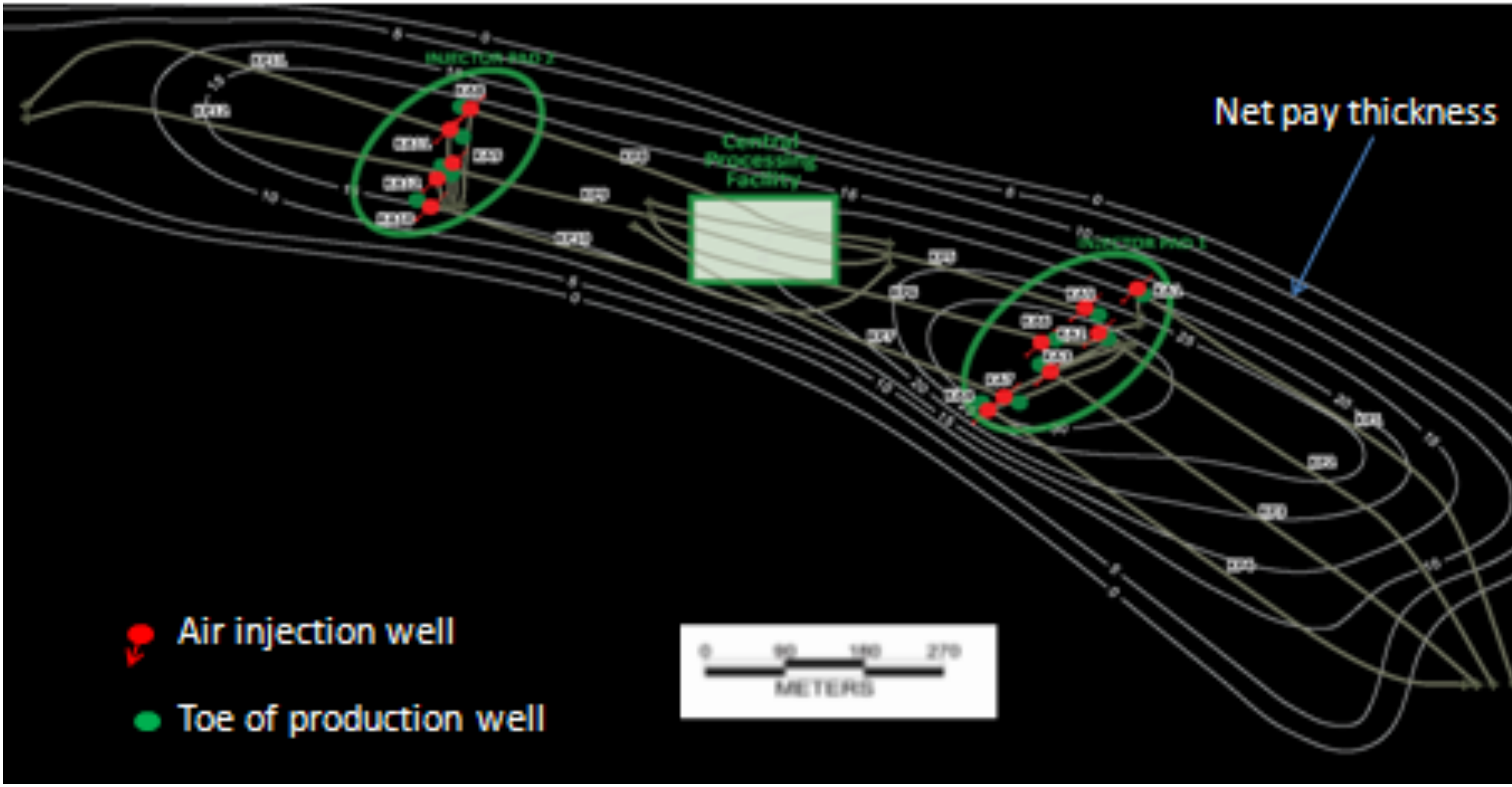

Fig 61a: Kerrobert THAI commercial operation showing the two injection pads, central processing facility (CPF) and the location of wells included in the THAI project (Petrobank corporate presentation, Aug 2012). Net pay thickness is shown in 5 m increments

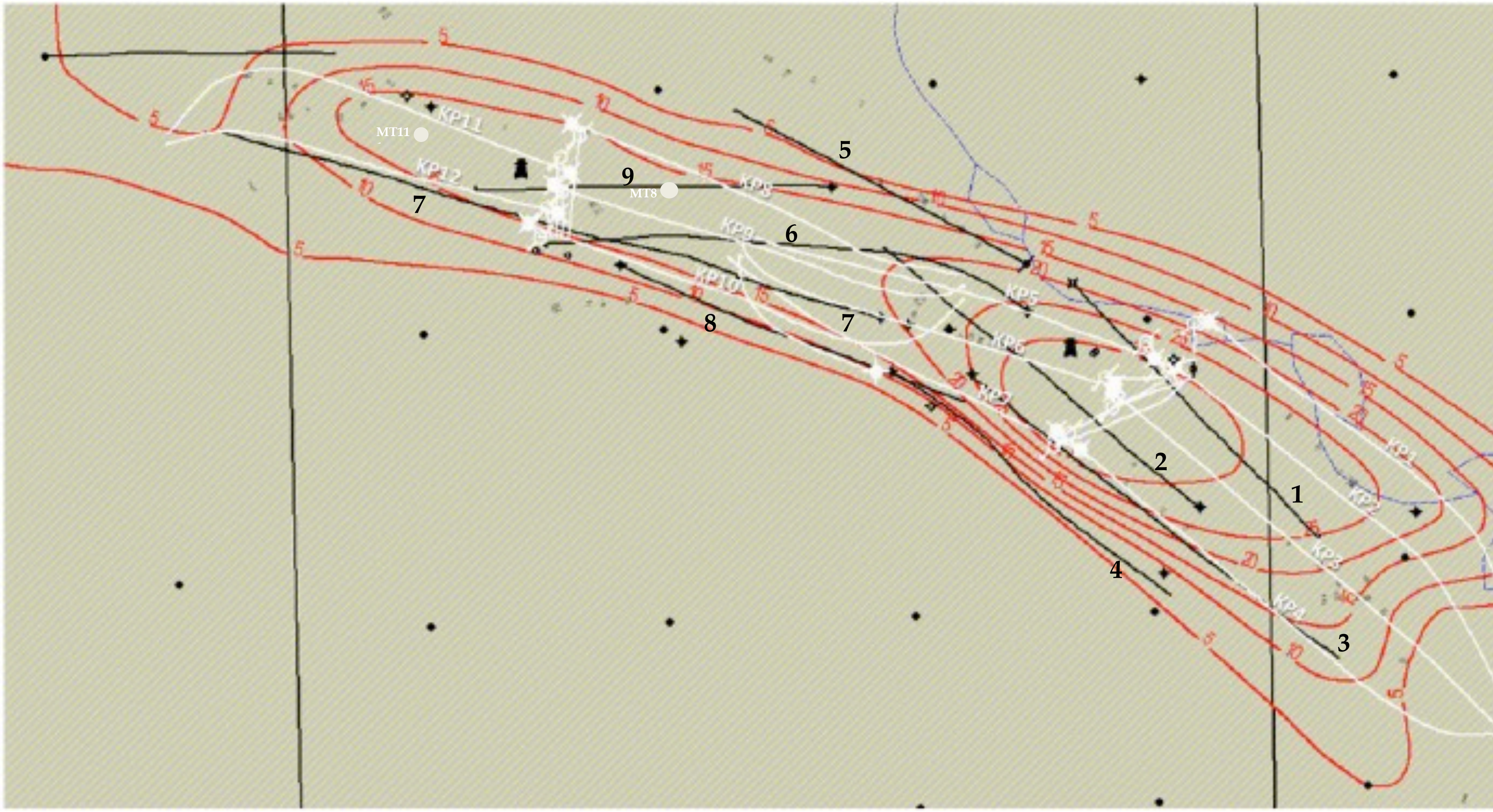

Fig 61b: Kerrobert Project. The location of wells. White wells are THAI wells, black wells are old wells (vertical and horizontal) and red contours are Waseca sandstone net oil pay (in 5m increments), Wikel, 2012.

Note: Old horizontal wells are marked/enumerated from 1 to 9, starting from the South-East corner. Please note a difference in how OHW7 was represented in Fig. 61b and 61c.

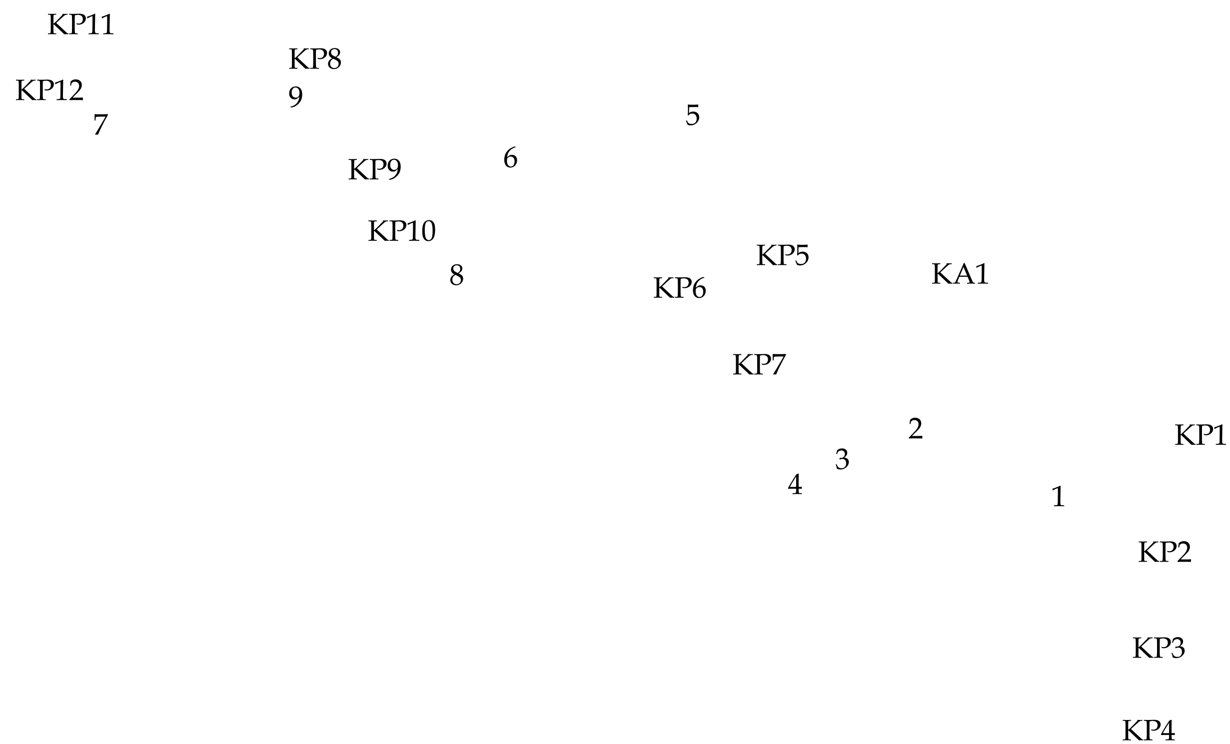

Fig 61c: Kerrobert Project. The location of THAI wells and old horizontal wells; the location of the vertical injectors (KA wells) relative to the toe of horizontal producers (KP wells) is clearly seen. Starkov, 2016.
Note: Old horizontal wells are marked/enumerated from 1 to 9, starting from the South-East corner. Please note a difference in how OHW7 was represented in Fig. 61b and 61c

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The piloting of THAI process in Kerrobert started in September 2009. The preheating by steam injection started on Sept 12, 2009; this **p**re-**h**eating **i**gnition **c**ycle ("PHIC") lasted until Oct 27, 2009 (approx. 45 days) (Petrobank release of Oct 27, 2009). The other information available is that "a designed rate of steam of 125 m^3/day would be injected in that period"(SMER 2010). Pre-heating of the horizontal wells was ruled out based on the results of the numerical simulation, which did not indicate this as a necessity. Therefore, a maximum cumulative of steam of 5,600 m^3 was scheduled to be injected into each vertical well of the THAI pilot; based on geoSCOUT data the actual amount is 3,100m^3 (Table 11). The initial air injection rate was 10,000 sm^3/day/well, with a projected maximum injection rate of 80,000 sm^3/day/well; the production wells started producing in October 2009.

On January 7th, 2010, it was stated that temperature at the toe of one of the horizontal producers was in the range of 120-140 ^{0}C. Later on, in March 2010, the temperature at the toe of one of the horizontal producers was in the range of 250-350 ^{0}C. This shows that by March 2010 - during ISC front anchoring at the toe - generation of the ISC front existed, implying an ignition delay of less than 4 months. Based on production data, the ignition delay was estimated at 1-2 months (See Table 12 in next section).

The average oil rate for March 2010 was 123 bbl/day/well, and this was accompanied by some indication of in-situ upgrading. However, significant and consistent upgrading started to be recorded after 9 months from the start of air injection. During the 6-month period (September 2010 – February 2011), the upgrading increased up to a maximum of 7 degrees API (from 10.3^0 to 17^0). This pronounced upgrading was associated with an increase of hydrogen content up to a maximum of 4-7% (See Appendix G for more details). Figure 62 shows upgrading up to July 2011 (when interference from the adjacent semi-commercial THAI patterns was felt). M*ost of the time oil was upgraded from 10 ^{0}API to 14-15^0 API*; *corresponding to that, the dynamic viscosity (measured at 20 ^{0}C, which also happens to be the reservoir temperature) decreased from 54,000 mPa.s to less than 3,000 mPa.s (18 times). The requested pipeline properties are a minimum of 20 ^{0}API and 350 cst. Therefore, a small amount of diluent (probably around 20%) is still needed.*

The good performance of the oil production is a clear indication that a strong in-situ combustion (ISC) front occurred; it is plausible that temperatures higher than 800 ^{0}C were generated, as it was reported that some thermocouples were damaged due to excessively high temperatures. Also, the combustion gas analysis was good, with CO_2 percentages in the range of 12-15%, and almost 0% oxygen, in effluent

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gases (less than 0.3%).

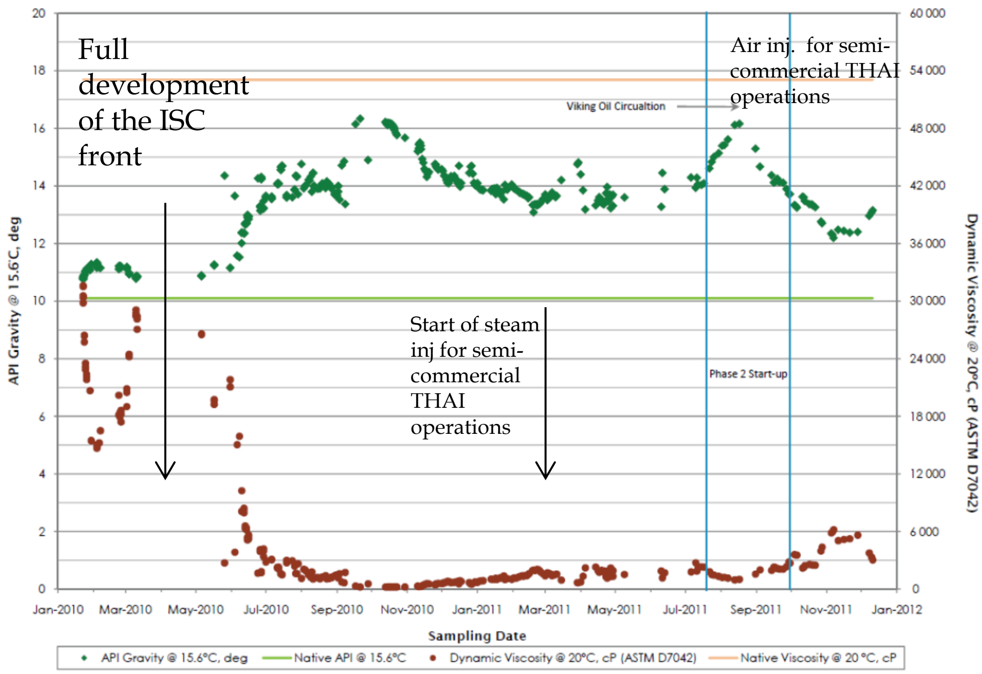

Fig 62: Produced oil quality during Kerrobert THAI pilot operation (in-situ upgrading) in the period January 2010-July 2011(Petrobank website).

The maximum total oil production from these two well pairs reached 48-64m^3/day (300-400 bbl/day) by October 2010, when the upgrading achieved was at its maximum. It is to be mentioned that although upgrading contributes to the high oil rate, its contribution - via the enhanced decrease of oil viscosity - cannot be very high as when it is combined with oil viscosity decrease contribution (due to pure temperature increase), this is reduced for a less viscosity oil.

Based on this encouraging oil production performance of the pilot during the first year, the engineering firm of McDaniel and Associates assigned a 10% price premium to reflect the higher-quality upgraded oil, and to recognize an additional 17% of THAI oil reserves - compared to SAGD (Appendix D: Calgary Herald, March 18, 2010). After three more months of operation, in January 2011, testing of the producers showed a total liquid production (restricted by the capacity of bottom hole hydraulic pumps) in the range of 180-300 bbl/day/well, with an oil cut of up to 40%. After increasing the KP1 well pump capacity, the total liquid production was in the range of 250-420 bbl/day/well, with an oil cut in the range of 35%-65%. Concurrently, for the pattern K1, the air injection rate was gradually increased to 50,000sm^3/day, with a produced gas rate (via the well KP1) of only 8,000 sm^3/day (Appendix C- Petrobank release of Jan. 7, 2010); it is difficult to explain this big difference between air (gas) injected and gas produced; it is

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speculated that a significant portion of flue gases flowed into the bottom water or towards a depressurized local gas cap *possibly* existent somewhere in the middle of the structure.

Daily air injection and oil production rates are shown in Figures 63a-b. It can be seen that although in 2012 there was a drastic reduction in the air injection, - in conjunction with the preparation of the semi-commercial operations - the daily oil production still remained in the range of 4-6 m^3/day/well; before 2012, during regular operation, the daily oil rates were in the range of 10-16 m^3/day/well. Also, it can be seen that for similar air injection rates, the oil production was slightly better for KA1 pattern in the earlier period, while the reverse is true, afterward. Taking into account the period of quasi-stable air injection and oil production of June 2010-June 2011, the air-oil ratio is around 1,500sm^3/m^3, showing a good performance.

To conclude, it must be highlighted that this pilot provided hands-on experience on THAI application in a bottom water situation in which the ratio of the thickness of the water zone to the thickness of oil zone (W/O ratio) is 0.3. *Therefore, we are in a situation relatively more favorable, as compared with the next patterns to be presented (semi-commercial operation), because of a lower* W/O *ratio and because the pilot patterns are relatively isolated and far away from old horizontal wells.* It showed that the maximum oil rate of a THAI pair might reach up to 150 bbl/day (24 m^3/day); the oil rate of 24-30 m^3/day represents the maximum potential of the THAI process applied in a direct line drive (DLD) configuration. As mentioned previously, based on the good performance of the pilot during the first year, the expansion to a semi-commercial operation (with 10 more patterns) was implemented in the Spring of 2011.

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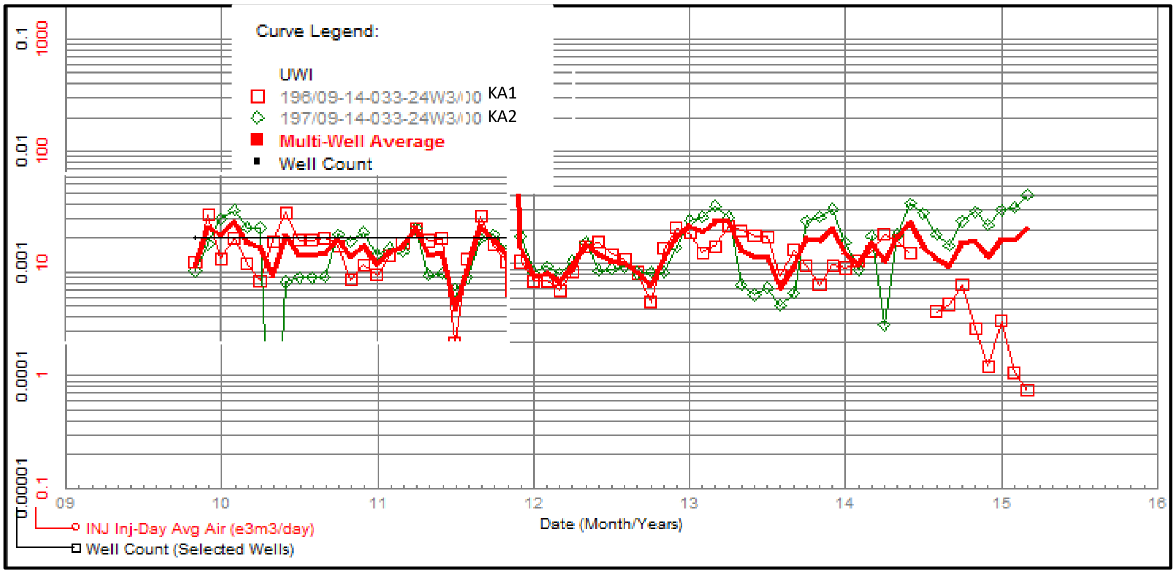
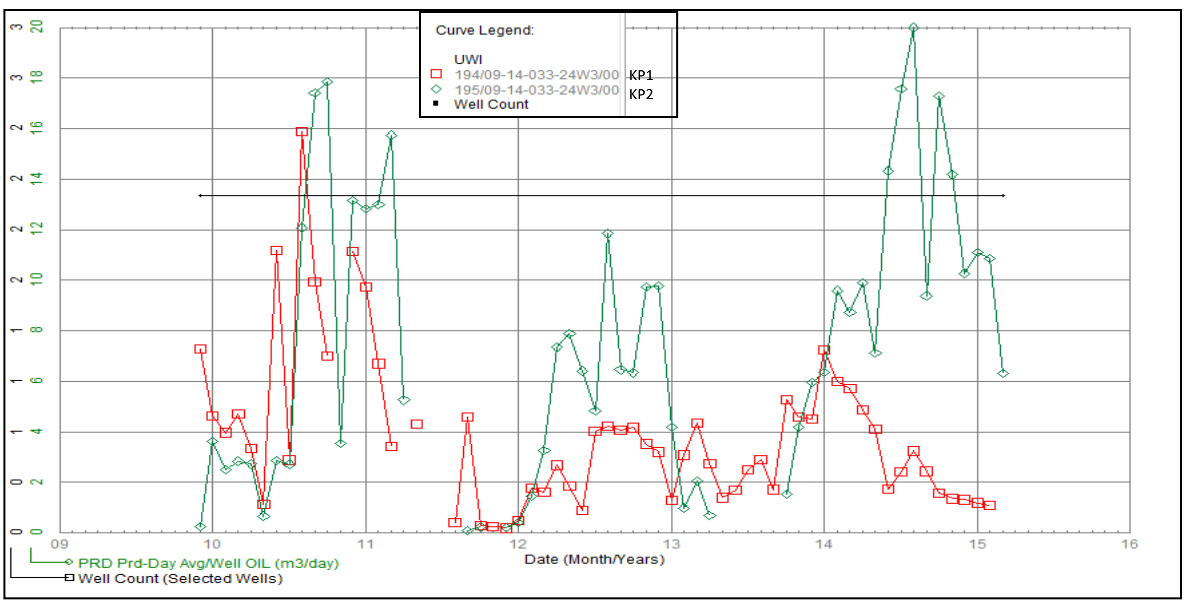
In an attempt to retroactively judge the ignition operation in the wells KA1 and KA2 the temperature profiles along the horizontal section of horizontal producers KP1 and KP2 were analyzed. In Figure 64a the perforation of injection wells and trajectories of the horizontal production wells are shown. It can be seen that an old horizontal well (well 92/9-14) is located at approximately 17 m from the injection well KA2. Figure 64b shows the position of thermocouples on the horizontal section of the two horizontal producers. The temperature profiles recorded by those thermocouples at different dates until July 2015 are provided in the Figures 64c and 64d. However, as mentioned, this is only for the period 2012-2015, i.e after the first two years of piloting. From Figures 64c-d it can be seen that by 2014-2015 the ISC front propagated along the horizontal producer for more than 200 m in KP1 and 100m for KP2 well. Due to the high peak temperature still present, it can be comfortably concluded that a strong ISC front was created in 2009; actually, the gas composition variation for the first two years of piloting (as shown in

Appendix G; Figures G7-KP1a and G7-KP2a) fully confirms this statement. ISC front velocity along the horizontal section of the horizontal producer was 14 cm/day in the case of KP1 and 8 cm/day for KP2. Detailed information on ignition is provided in the next section.



a)



b)

Figure 63a-b: Kerrobert THAI Pilot. The variation of average daily air injection rate (a) and average oil production per well (b)

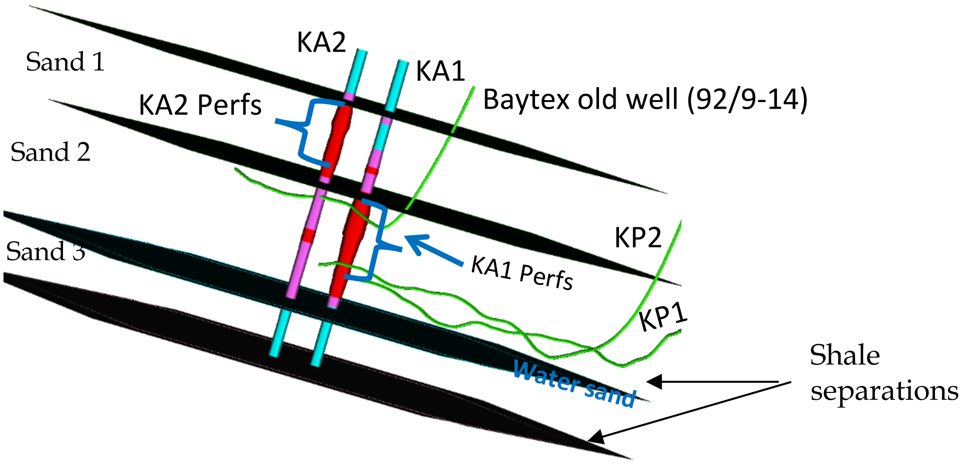


Figure 64a: Kerrobert THAI Pilot. The perforation of injection wells and trajectories of the horizontal production wells. The old horizontal well 92/9-14 is located at approximately 17 m from the injection well KA2 (see Fig. 64b). See also the log of KA3 well from Figure G1d of Appendix G.

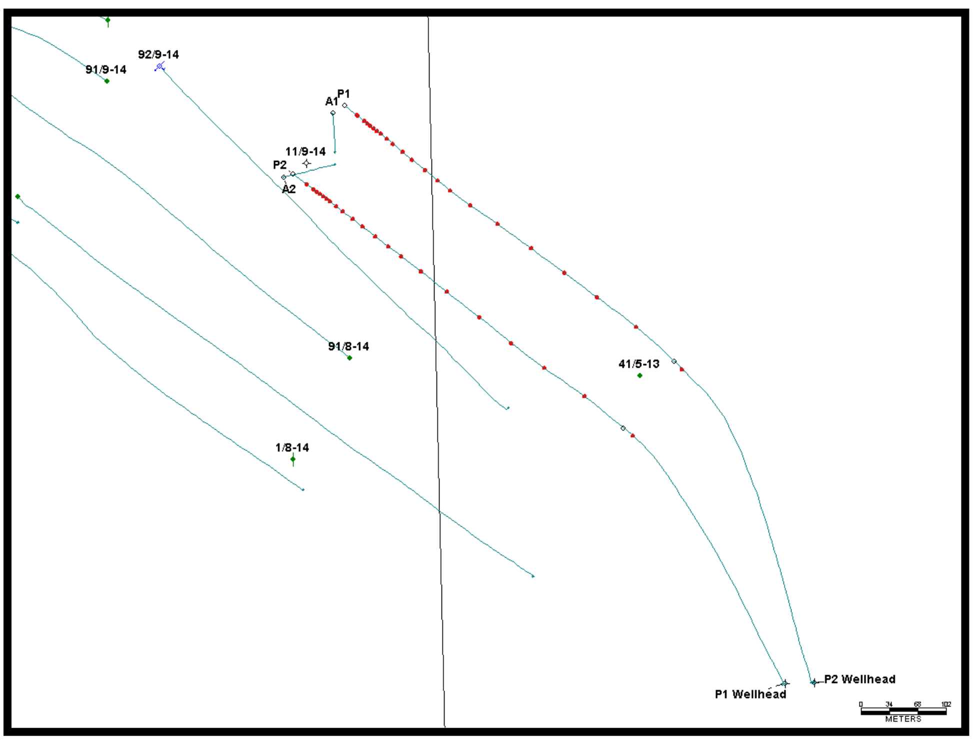


Figure 64b: Kerrobert THAI Pilot. The position of thermocouples on the horizontal section of the horizontal producers. Note: KA1 and KA2 are marked here as A1 and A2. KP1 and KP2 are marked here as P1 and P2.

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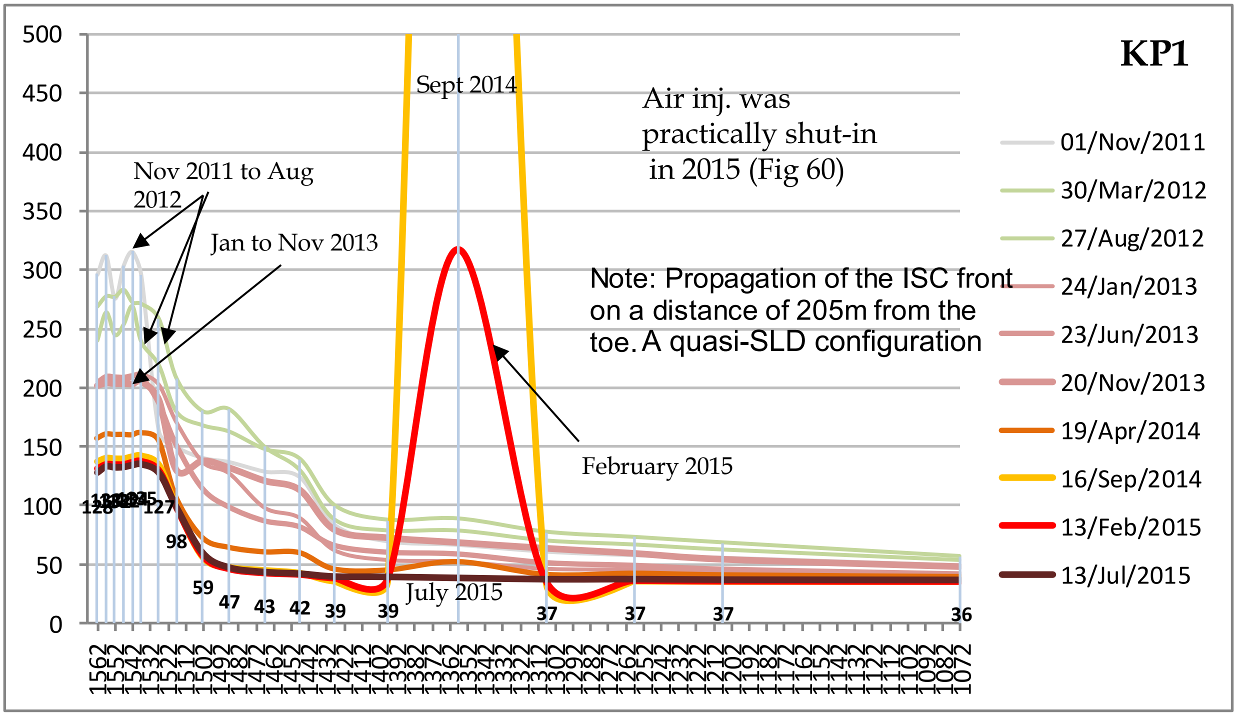

Figure 64c: Kerrobert THAI Pilot. The variation of temperature from the toe to the heel, for well KP1 after the first two years of piloting. Start of air injection: October 27, 2009; Ignition delay: one month. To be correlated with Figure from the Appendix E showing the variation in time of temperature at different points o horizontal section

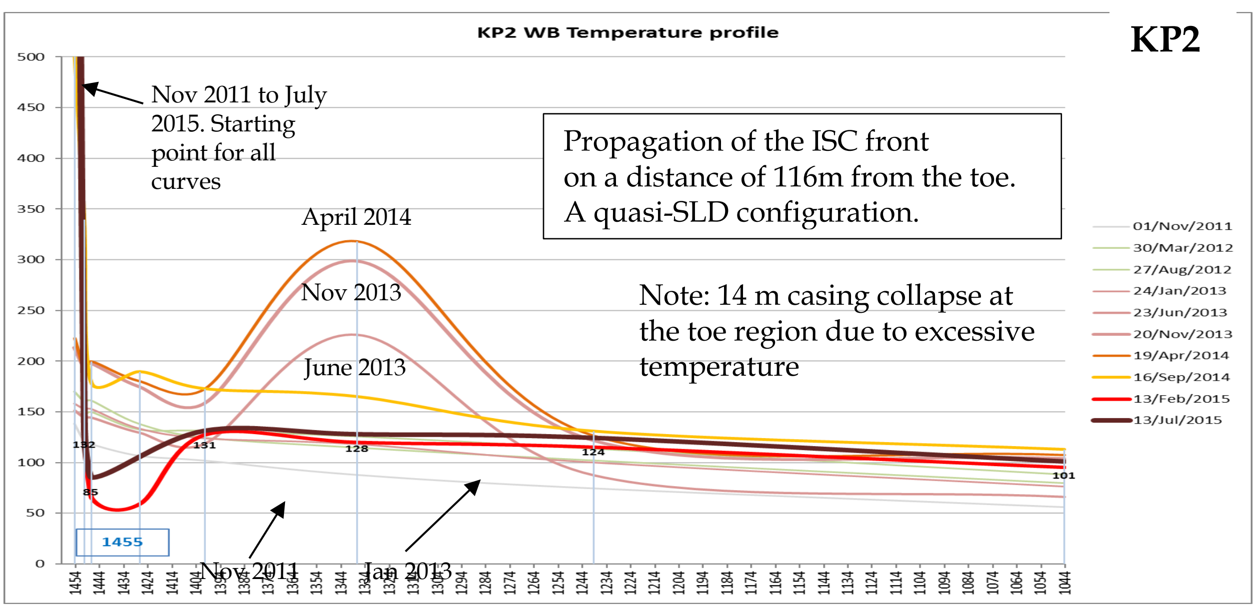

Figure 64d: Kerrobert THAI Pilot. The variation of temperature from the toe to the heel, for well KP2 after the first two years of piloting. Start of air injection: October 27, 2009; Ignition delay: 2 months. To be correlated with Figure from the Appendix G showing the variation in time of temperature at different points of horizontal section. Temperature remains very high in the toe region, but the ISC front advances along the horizontal well; it may suggest that some oil production occurs within the whole toe region as this configuration has a quasi-staggered line drive characteristic.

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7.4.2. Ignition Operations

The ignitions operations are analyzed both for the pilot wells and for the semi-commercial wells. Table 12 provides data regarding pre-heating by steam injection in the twelve vertical injectors [**p**re-**i**gnition **h**eating **c**ycle (PIHC) data]. As mentioned, steam injection took place in 2009 in the pilot wells KA1 and KA2. Later on (in 2011), steam was injected almost simultaneously in all the air injectors of the semi-commercial operation.

Heat losses occurring during steam injection are provided in Table 13. They are calculated using analytical methods similar to those established in the SelectEOR software, (Turta, 1998), assuming that a thermal packer (with atmospheric pressure in the annulus) was used during the injection.

From Table 12, it can be seen that – compared with the semi-commercial steam injection wells - the steam cumulative injected for the ignition of pilot wells was considerably higher (2-5 times), and steam was injected at a higher injection rate (3 times higher). This substantially reduced the wellbore heat losses and provided for considerably more heat to the reservoir. The wellbore heat losses were approximately 31% during the steam injection for the pilot, while during the commercial operation, they were over 76%. Practically, the steam quality in the perforation (at sand formation face) became zero at a steam injection rate lower or equal to 26m^3/day. *Therefore,* ***except for well KA6, only hot water was injected at all other wells***; the temperature of the hot water at the perforations, as of the last day of injection, could not be estimated without using many assumptions. However, it is known that for the corresponding injection pressure, the saturated steam temperature is around 255^{0}C.

Although it can be speculated that a temperature of around 100^{0}C (for the hot water) could have been attained at the sandface, the ignition was difficult as a substantial amount of water had to be vaporized before a local temperature could increase to over 270^{0}C-300^{0}C. The ignition delays in Table 12 are correlated relatively well with the heat losses around the vertical portion of the well (Table 13); it can be seen that only well KA6 in which probably some live steam was injected (although at the low steam quality) realized an ignition delay of approximately three months. The remainder of the wells had ignition delays in the range of 4-6 months.

Table 12: Data regarding the **p**re-ignition heating **c**ycle ("PIHC"). Source of data: geoSCOUT. Estimate of the ignition time.

Injection pressure =>3,000 kPa (estimate based on reservoir pressure before the start of pilot). Assumed steam quality at the wellhead: 80 %

Well	Steam pre- heating phase			Cumulativ of steam injected, m^3	Average rate of steam injection*, m^3/day	**Time of ignition /ignition delay, t_{ign}** (based on peak temp at the toe of producer) months	**Time of ignition /ignition delay, t_{ign}** (based on oil production and water cut performance) months	**Time of ignition /ignition delay, t_{ign}** (based on variation of H/C ratio) months	Observations
	Start of steam injection	End of steam injection	Total days of injection	-	-	-	-		
KA1	Sept. 12., 2009	Oct. 27, 2009	51	3132	62	Nov 2009 /**1**	Nov 2009 /1-2	February 2010 / 3?	
KA2	Sept. 12., 2009	Oct. 27, 2009	51	3132	62	Dec 2009/**2**	Nov 2009 /1	February 2010 /4 (?)	
Pilot wells	**Sept, 09**	**Oct, 09**	**51**	**3132**	**62**	-	-		
KA3	March 2011	March 2011	?	100?	?	Aug 2011/**4**	July 2011/**3**	Aug 2011/**4**	
KA4	April 2011	May 2011	41	1003	25	Likely, no ISC front towards KP4 direction	-	-	LTO; apparent hydrogen-carbon ratio: 4-10

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KA5	March 2011	April 2011	55	1433(?)	26?	Nov 2011/<7 (?)	August 2011/**4**	August 2011/**4**	
KA6	March 2011	May 2011	53?	1630	31?	July 2011/**3**	June 2011/2	July 2011/**3**	Very good ignition. Rapid watering
KA7	March 2011	April 2011	53	938	18	Nov 2011/6	August 2011 /4	Sept 2011/**5** March 2012 /11+	2 ignitions reflected +
KA8	July 2011	July 2011	30	649	22	Nov 2011/**4**	January 2012/6	October 2011/3	
KA9	July 2011	July 2011	30	780	26	March 2012 /8	August 2011 /1 **??**	Jan 2012**/ 6**	
KA10	July 2011	Sept 2011	56	1177	21	March 2012/**6**	February 2012/5	March 2012/**6**	
KA11	July 2011	July 2011	30	663	22	Nov 2011**/4**	Sept 2011/2 ??	Dec 2011/5	
KA12	July 2011	Aug. 2011	53	616	12	No ISC front towards KP12 ***	-		Typical LTO; H/C between 15 and 4,all the time;
Comm-ercial operation	**March 2011**	**Sept. 2011**	**30-56**	**649-1630**	**12-31 (average =22)**	**-**	**-**		

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* In the application (SMER 2010), an injection rate of 120 m^3/day was recommended. However, it seems that due to very low injectivity, it could not be achieved.

** As the production well of this pattern (KP4) did produce very little gas, there was little air flow towards KP4 well, such that there was no ISC front generated in the pattern KA4-KP4. Further short-term air injection in KA4 – for 2 years - was done to supply air for the neighboring patterns K7, where a t_{ign} of 5-6 months was found.

*** As the production well of this pattern (KP12) did not produce any gas, there was *almost* no air flow towards KP12 well, such that there was no ISC front generated in the pattern KA12-KP12; full communication KA12-KP12 was not achieved, probably. Further air injection in KA12 was done to supply air for the neighboring patterns K9 and K10, where, for both patterns, a t_{ign} of 6 months was found.

+ Reflects the achievement of ignition from the direction of KA4, as KP4 did not produce enough gases to produce and then sustain the propagation of an ISC front along KP4. KA4 and KP7 have been in a staggered line drive (SLD) configuration.

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The estimation of the ignition delay, t_{ign}, in Table 12 was done using three methods, namely:

1. Based on the variation of apparent atomic H/C ratio, calculated from the gas produced
2. Based on peak temperature at the toe of producer and along its length
3. Based on oil production and water cut performance

For the conventional ISC process, the first method is the most reliable one, as the H/C ratio is a synthetic indicator of the burning quality/peak temperature in the ISC front; it is by far more reliable than the simplistic estimation of the CO_2/O_2 percentages. For the THAI process, also it should remain the most reliable method, following, as reliability, by the second and third method; the second method tends to give slightly longer t_{ign} values (given the distance of a few meters between the toe of producer and shoe of injector), while the third method has the tendency to give slightly shorter t_{ign} values (given the fact that mobilization of the oil could be significantly helped by the steam preheating process).

The variation of the apparent atomic H/C ratio, calculated from the gases produced from KP1 to KP12 are analyzed in Appendix G. Also, the in-depth analysis of temperature variation profiles (both in time and along the horizontal section) and of the oil production/water cut performance was conducted in Appendix G. This allowed to consolidate the estimated values of the ignition delay (t_{ign}). Thus, the most probable value of t_{ign} was determined, and this is highlighted in bold in Table 12. The values of t_{ign} from Table 12 account for the information presented in Appendix G, where the absence of ignition in KA12 and a premature heat break-through in KP4, (therefore no ignition in KA4) were confirmed.

Taking into account a similar experience obtained in the Pelican Lake case, (Turta, 2012) - for a conventional ISC pilot where the ignition was done by steam preheating - it can be concluded that for KA1 and KA2 wells, the ignition delay was relatively short (1-2 months), while for the commercial patterns it was longer (3-6 months), generally longer than the normal values reported in the conventional ISC literature.

As a concluding remark, it can be maintained that by injecting a steam slug for pre-heating prior to ignition (during PIHC phase) for the above conditions (very low steam injection rates), an ignition delay of at least 4-5 months could be expected. By adding this time to the pre-heating time (1-2 months), a total of 5-7 months is assumed as a period when no significant incremental oil production is expected. Only after developing the full ISC front, efficient oil displacement could be expected. Thus, *there is a clear need for acceleration of the ignition operations in order to reduce the ignition delay to one month, and ideally, to a much shorter period.* It is crucial to emphasize again that the PIHC must be such as to raise the temperature in the startup region of the reservoir, to as close as possible to the steam boiling temperature at that pressure. Otherwise, poor ignition and lack of sufficient heat in the startup region,

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will inevitably give rise to a retarded and poorly developed combustion zone and consequent reduced oil production, subsequently.

The influence of the **o**ld **h**orizontal **w**ells on the achievement of the ignition in different patterns is extremely difficult to evaluate. Some steam losses – facilitated via these wells as channeling pathways - might have happened, but, practically, it cannot be estimated; some steam losses of this kind could have been recorded for KA2, KA4 and KA12 wells, which are very close to some old horizontal wells (Figure 61c).

KA4 might have lost a large amount of steam due to the proximity of old horizontal well marked 3 in Fig. 61c and this contributed to the lack of any ISC front anchoring to the toe of KP4; later on, probably this steam loss diminished, and an ISC front eventually was formed and propagated towards KP7. KA12 might have lost steam via old horizontal well marked 7 in Fig. 61c and this contributed to the lack of any ISC front anchoring to the toe of KP12; later on, probably this steam loss diminished, and an ISC front eventually propagated towards KP9 and KP10 wells. For KA2 this was not very important (as the cumulative steam injected was large enough) but still this might have contributed to a t_{ign} of two months as compared to one month for KA1.

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It is crucial to emphasize again that the pre-ignition heating cycle (PIHC) must be such as to raise the temperature in the startup region of the reservoir, to as close as possible to the steam boiling temperature at that pressure. **Otherwise, poor ignition and lack of sufficient heat in the startup region will inevitably give rise to a retarded and poorly developed combustion zone and, consequently, reduced oil production, subsequently**. This is precisely what happened in most of the THAI modules of Kerrobert, and it was difficult to recover from this poor start-up procedure!

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Table 13: Estimation of the heat losses during the steam slug injection in view of ignition **[p**re-**i**gnition **h**eating **c**ycle ("PIHC")]. Depth: 736m (731-741m); Net pay thickness: 10 m (average h_{net}/h_{gross} =0.75 ; Assumed steam quality: 80% (SMER, 2010). Normal completion (no insulation tubing)

Pattern	Size of the steam slug injected for ignition (m^3)	Duration of steam injection (days)	Average daily steam injected (m^3/day)	Cum wellbore heat losses (end of inj) (% of heat available at well head)	Steam quality @ bottom hole (in perfo-rations) (final value) (%)	Cum. heat losses in adjacent formations (end of inj) (% from heat available in perf-orations)
KA1	3132	51	62	31	46	12
KA2	3132	51	62	31	46	12
KA3	100?	?	?	-	-	-
KA4	1003	41	25	80	0	12
KA5	1433	55	26?	76?	0	12
KA6	1630	53?	31?	60	10	12
KA7	938	53	18	>76	0	-
KA8	649	30	22	>76	0	-
KA9	780	30	26	76	0	12
KA10	1177	56	21	>76	0	-
KA11	663	30	22	>76	0	-
KA12	616	53	12	>76	0	-

Note: Data in the first 4 columns are from geoSCOUT; data in the last 3 columns were calculated.

7.4.3 Performance of the Semi-Commercial Operation

First, we will present certain aspects of performance and then, our interpretation of the results.

7.4.3.1 Performance

The semi-commercial operation consisted of 12 THAI well pairs; 10 new ones and the two former pilot patterns (started in September 2009, which were analyzed previously). The location of these patterns (modules) is shown in Figures 61b. The vertical injection wells and horizontal production wells were

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drilled from two pads; each pad has two sets of vertical injectors serving two clusters of horizontal producers going in opposite directions. T*he injectors are placed in a direct line drive (DLD) configuration relative to the horizontal producers.* Length of the horizontal sections of horizontal producers is in the range of 350-550m, while the distance between them is 70-80 m (pattern area is approximately 3.5 ha). Generally, the horizontal sections of THAI producers are located towards the bottom of the oil layer, 2-6 m from the water-oil interface (Wikel, 2012), while the injection wells are perforated towards the top of the oil layer. Towards the toe, the horizontal sections end with a portion of up to 30-35m, either an open hole or a blind liner; more details are provided in Appendix G.

It can be noticed that two cold heavy oil producers still existed in the North and NW of the THAI application area, but those wells are sufficiently away for not interacting with the THAI operations. However, 8 old horizontal wells existed within the THAI application area, with some of their trajectories "intercepting" the horizontal sections of horizontal producers KP4, KP6 and KP8 in a portion of the reservoir between the toe and middle of horizontal section. *Notice that in a plan view, it appears as an interception of their projections on a horizontal plane. However, as the horizontal sections of old horizontal wells are located towards the upper part of the oil layer (due to existence of bottom water), while the THAI producers are located towards the bottom of the oil zone, they do not intercept in reality.*

There was no way to obtain any information on the effect of old horizontal wells during the operation of THAI process. Unlike Whitesands Pilot, unavailable were any temperature measurements in observation wells; no observation well was utilized in the Project. Although in the design of the Project Expansion (SMER 2010) a recommendation was made to convert the former water injection well (horizontal well 192/09-14) into a temperature observation well, this was never realized. This was extremely unfortunate as it eliminated the last resort for at least a minimum information to be obtained.

Out of 10 new modules of the semi-commercial operation, steam was injected in the first 8 well pairs during March-July 2011; the remaining two pairs (KA10 and KA12) underwent steam injection for preheating in August-September 2011; in the months of May and June 2011 there was very little steam injection. As mentioned, the pre-heating period was much shorter as compared to that for the Kerrobert pilot; it was reduced to 3-8 weeks (20-60 days), compared to at least 8 weeks for the pilot and 15 weeks for Whitesands Pilot. Additionally, steam injection rates were also much lower. As seen from the ignition analysis in Tables 11-12, the ignition delay was in the range of 3-6 months. However, it can be considered that by December 2011, the ISC front was generated in many patterns.

For oil production, the most critical period in the life of this THAI project was the period between November 2011 and March(April) 2012, i.e., during and immediately following the slow ignition operations. It is well known that the ignition period can be as short as 3 to 6 days if artificial ignition

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devices were used, or as long as 6 to 12 months for spontaneous ignition. ***In all cases, the effective mobilization of oil occurs towards the end of this period and depends critically also on the creation of a sufficiently large heated zone between the injector and toe of the horizontal producer.***

Based on our analysis, it can be assumed that the time taken to achieve ignition operation was too long and that significantly impeded oil mobilization. For instance, during the third quarter of 2011, *total* oil production was extremely low (30 bbl/day); in the last (fourth) quarter of 2011 oil production was 41 bbl/day (Appendix D: Calgary Herald, March 9, 2012). A better representation can be seen in Figure 63a. By March 2012, total oil production increased to 200-225 bbl/day (70 m^3/day); afterwards, the production was approximately 300 bbl/day, and it reached a maximum of 400 bbl/day in August 2012; for the third quarter of 2012 it averaged 305 bbls/day. Water production also increased, and finally, it was in the range of 800-1000bbl/day, corresponding to a water cut of 70-75%. Figures 63a and 63b tend to indicate that the ignition did not occur until December 2011–January 2012; therefore, it seems that the ignition period might have been even longer than that estimated in this study (greater than 5-6 months). This is not very dissimilar to two other past projects (Morgan and Pelican Lake in Canada), where ignition was aided by steam injection, and it was found that the ignition delay was in the same range (Turta 2011). This may explain the poor performance during this period at the Kerrobert semi-commercial THAI project. *Thus, the poor oil production performance was affected by several factors, principally, the very slow ignition and lack of enough heat input into the startup/inlet region of the reservoir*

During the 3 months of relatively stable production, April 2012-July 2012, for an average total oil production of 280 bbl/day (44.5 m^3/day), the average total air injection rate in this Project was 100,000sm^3/day; this corresponds to an air-oil ratio (AOR) of 100,000/44.5=2247 sm^3/m^3, which is in the normal range for an ISC project. However, the crucial issue is *the ability to increase the air rate, while still maintaining the same low AOR (i.e same efficiency of the process). As seen in Fig. 66a an attempt to slowly increase the total air rate during the period October 2012-March 2013 did not lead to an increase in the oil rate; on the contrary, there was a continuous decrease. F*inally, in March 2013, very low performance was recorded; for a total of oil production of 29 m^3/day (180 bbl/day), the total air injection rate was 280,000sm^3/day; this corresponds to an air-oil ratio (AOR) of 280,000/29=9,655sm^3/m^3, which indicates a very low efficiency of the process for that period. The overall trend of oil production was commensurate with a sharp increase in gross liquid production (up to 1400 m^3/day), This was due to the production of a large amount of water from the bottom water zone (water cut: 88-90%).

Very likely, this increase in AOR is due to bypassing of the injected air via the bottom water, where an ISC front is sustained by burning at the oil/water (O/W) interface or by burning a fuel “recruited” from the *low oil saturation* in the transition zone. Of course, very little of the displaced oil is captured; mostly,

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water is produced from this zone. As discussed earlier, there may be a splitting of the injected air flux between the oil zone and the water-oil interface. The detailed analysis made in Appendix G showed an almost normal propagation of the ISC front along the horizontal section of some producers and the forming of a "local" combustion chamber close to the toe, for some other producers. Mainly in the last case, the *combustion chamber* may have been located (very early during the process) at the O/W interface with the production of large amounts of water, therefore low performance.

On the other hand, experience from other ISC projects shows that in cases of slow ignition operations, during and immediately after ignition, the development of emulsion problems can be a significant barrier to achieving a rapid increase in oil production' Kerrobert semi-commercial operations faced such problems. In Kerrobert, progressing cavity pumps (PCP) in large diameter wells were used, but these did not work effectively in a semi-lift regime. However, the number of effective days as a percentage of calendar days was relatively high for these pumps. Similar problems were experienced in the operation of the Balaria ISC pilot in Romania (Petcovici, 1982), when the ignition was achieved by spontaneous ignition, and consequently involved a longer ignition delay, these problems appeared. Hence, the generation of the emulsions may be directly related to extremely slow ignition; the fact that the mechanism of ignition is by LTO, significantly promotes the formation of emulsions. *Therefore, this ignition period needs to be reduced considerably in order to minimize this extended and pronounced negative effect.*

It is to be stressed that although it was rather prolonged, the ignition was eventually achieved in 10 out of 12 patterns. For these 10 patterns, the produced gas composition was normal for a fully sustained ISC process; a typical gas composition (that for well KP2 recorded on February 4th, 2016 - Table 14 - for about one year, but which reflects the composition for all patterns) would be:

CO_2: 14.6-16%; CO: < 0.3%; O_2: < 0.3%
CH_4: 2.5 - 4.5% ; $C2^+$: approx.. 1% ;
H_2: 1.2 - 1.6%; H_2S: 0.3 - 04% (3000-4000ppm)

The percentage of hydrogen in the produced gas is lower than for the THAI application in Athabasca Oilsands (Whitesands Project). The higher hydrogen and hydrocarbon/methane content can be related to the thermal cracking (pyrolysis) process/coke gasification/methanation processes, etc (Kapadia 2011-2013), but here produced methane rate is also related to the injection of a certain rate of hydrocarbon gases (mainly methane) in the annulus, in order to mitigate corrosion (due mainly to H_2S). Therefore, an accurate evaluation of the amount of methane generated during the THAI process is not possible.

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Time	KP2-Lab	H2 MOL%	O2 MOL%	N2 MOL%	CO MOL%	CH4 MOL%	CO2 MOL%	C2H6 MOL%	C3H8 MOL%	C4 MOL%	C5 MOL%	H2S MOL%	Total MOL%	Norm. Factor	
/16 13:5	Field, J. Elliott	1.27	0.31	76.87	0.01	3.93	15.58	0.77	0.45	0.26	0.14	0.463	100.0	0.99951	
/16 11:4	Field, J. Elliott	1.28	0.28	76.29	0.05	3.85	15.39	0.74	0.43	0.18	0.14	0.465	99.1	1.00924	
/16 12:1	Field, J. Elliott	1.26	0.19	76.22	0.01	3.87	15.65	0.75	0.46	0.27	0.14	0.474	99.3	1.00720	
/16 13:3	Field, J. Elliott	1.28	0.23	76.51	0.04	3.59	15.59	0.71	0.44	0.28	0.14	0.464	99.3	1.00738	
/16 10:4	Field, J. Elliott	1.25	0.19	76.49	0.08	3.76	15.52	0.75	0.47	0.29	0.15	0.467	99.4	1.00605	
/15 10:1	Field, J. Elliott	1.27	0.23	76.90	0.05	3.90	15.17	0.68	0.38	0.24	0.12	0.440	99.4	1.00645	
/15 13:1	Field, J. Elliott	1.24	0.30	77.22	0.00	4.00	15.08	0.60	0.33	0.12	0.05	0.412	99.3	1.00662	
/15 11:2	Field, J. Elliott	1.27	0.16	76.45	0.00	3.85	15.16	0.57	0.32	0.18	0.06	0.420	98.4	1.01599	
/15 10:3	Field, J. Elliott	1.28	0.20	77.29	0.00	3.83	15.36	0.57	0.32	0.20	0.06	0.421	99.5	1.00469	
/15 09:4	Field, J. Elliott	1.35	0.16	77.28	0.00	3.19	15.87	0.60	0.38	0.26	0.14	0.447	99.7	1.00336	
/15 15:3	Field, J. Elliott	1.28	0.23	77.49	0.00	3.75	15.22	0.53	0.31	0.18	0.06	0.392	99.4	1.00567	
/15 10:2	Field, J. Elliott	1.25	0.14	76.98	0.00	4.49	15.18	0.55	0.30	0.18	0.05	0.386	99.5	1.00507	
/15 11:2	Field, J. Elliott	1.26	0.33	77.05	0.00	4.12	15.23	0.55	0.31	0.19	0.07	0.391	99.5	1.00490	
/15 13:0	Field, J. Elliott	1.25	0.27	77.49	0.00	4.28	14.68	0.54	0.31	0.19	0.05	0.390	99.5	1.00542	
/15 17:2	Field, J. Elliott	1.35	0.14	76.63	0.00	2.47	16.00	0.58	0.34	0.13	0.06	0.418	98.1	1.01911	
/15 14:3	Field, J. Elliott	1.35	0.23	76.02	0.00	3.58	15.31	0.51	0.28	0.17	0.05	0.399	97.9	1.02154	
/15 10:4	Field, J. Elliott	1.57	0.17	76.78	0.00	3.60	15.53	0.56	0.32	0.18	0.75	0.419	99.9	1.00129	[illegible]
/15 10:1	Field, J. Elliott	1.45	0.24	75.80	0.00	4.20	15.18	0.47	0.25	0.10	0.05	0.388	98.1	1.01909	7
/15 09:5	Field, J. Elliott	1.49	0.22	76.65	0.00	4.29	15.14	0.48	0.25	0.16	0.05	0.396	99.1	1.00895	79
/15 11:3	Field, J. Elliott	1.86	0.40	76.63	0.00	2.44	15.93	0.44	0.25	0.16	0.05	0.422	98.6	1.01450	56
/15 14:4	Field, J. Elliott	1.53	0.25	76.68	0.26	3.57	15.47	0.45	0.24	0.14	0.04	0.399	99.0	1.00967	83
/15 13:3	Field, J. Elliott	1.32	0.14	77.06	0.00	3.66	15.68	0.43	0.24	0.14	0.04	0.410	99.1	1.00894	876
/15 10:4	Field, J. Elliott	1.42	0.18	77.78	0.00	4.02	15.60	0.44	0.24	0.12	0.00	0.402	100.2	0.99805	890
/15 17:3	Field, M. Wright	1.33	0.24	76.43	0.21	4.27	14.82	0.37	0.18	0.11	0.07	0.377	98.4	1.01618	895
/15 11:4	Field, D. Tetarenko	1.48	0.21	76.28	0.36	3.52	14.62	0.38	0.22	0.12	0.07	0.375	97.6	1.02441	887
/15 11:4	Field, D. Tetarenko	1.10	1.69	76.72	0.31	3.12	14.62	0.38	0.22	0.12	0.07	0.375	98.7	1.01313	811
/15 13:5	Field, M Wright	1.37	0.18	76.45	0.00	3.49	15.13	0.44	0.23	0.12	0.06	0.406	97.9	1.02182	821
/15 09:1	Field, D. Tetarenko	1.38	0.27	77.45	0.00	3.55	15.90	0.44	0.22	0.09	0.02	0.419	99.8	1.00250	862
/15 12:3	Field, M Wright	1.41	0.14	76.64	0.00	3.45	15.68	0.43	0.22	0.12	0.06	0.399	98.5	1.01473	718
/15 14:0	Field, D. Tetarenko	1.45	0.21	77.00	0.00	3.81	15.55	0.47	0.24	0.12	0.08	0.406	99.3	1.00677	1496
/15 10:5	Field, D. Tetarenko	1.54	0.20	77.97	0.22	3.15	15.75	0.43	0.22	0.12	0.07	0.427	100.1	0.99907	855
	Average	1.32													

Table 14: Produced Gas Composition for Well KP2 During 2015 and January 2016. Obtained during the visit to Kerrobert THAI Project (by one of the authors of this report) on February 4th, 2016.

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Similar to the THAI Pilot, in Kerrobert, upgrading of the produced oil was recorded, but this appeared a lot later, after the long ignition period. Also, due to the complexity of operations in different well pairs (being at different stages of ignition), as well as low or inconsistent upgrading in some patterns (KP8 and KP12, for instance), large fluctuations existed and the quasi-steady-state upgrading recorded was slightly less than in the pilot (Figure 62), being in the range of 3-4.5 ^{0}API degree (Figure 65); although not represented in Fig. 65, the decrease of produced oil viscosity was from original 54,000cp to as low as 500-3,000cp for the wells KP1, KP2, KP6 and KP7, which displayed the best upgrading; as a medium upgrading performance, a decrease of viscosity to as low as 10,00-20,000cp can be considered (therefore an approx. 4-fold reduction of viscosity). An analysis of the upgrading per individual wells also showed that in the case of producers KP4 and KP9, the upgrading is very difficult to explain, if this is to be correlated with all other events at these two wells. A separate, more detailed analysis is worthwhile in order to explain the upgrading and its connection with hydrogen production, fully.

In petroleum refinery operations, upgrading of at least 3 API degrees is considered to be a minimum; from the THAI pilot and semi-commercial THAI operations, therefore, this minimum value can be achieved by the THAI process.

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It is concluded that the main difference between the performance of the well pairs during the first period (2009-2011) of operations, and the second period (that of the semi-commercial operation: 2012-2016) is due to three main factors:

- Better reservoir conditions; a lower ratio between water zone thickness and oil zone thickness
- A higher degree of confinement of patterns
- A higher quality of pre-heating in view of ignition.

A good confinement of the pilot (mainly vis-a-vis old horizontal wells) and t*he faster ignition achieved during the pilot promoted a substantially better performance.* However, it is to be realized that even the performance of the pilot wells (KP1 and KP2) also degraded *to some extent* after 2011, as the loss of injected air in the bottom water increased due to higher reservoir pressure associated with semi-commercial injection.

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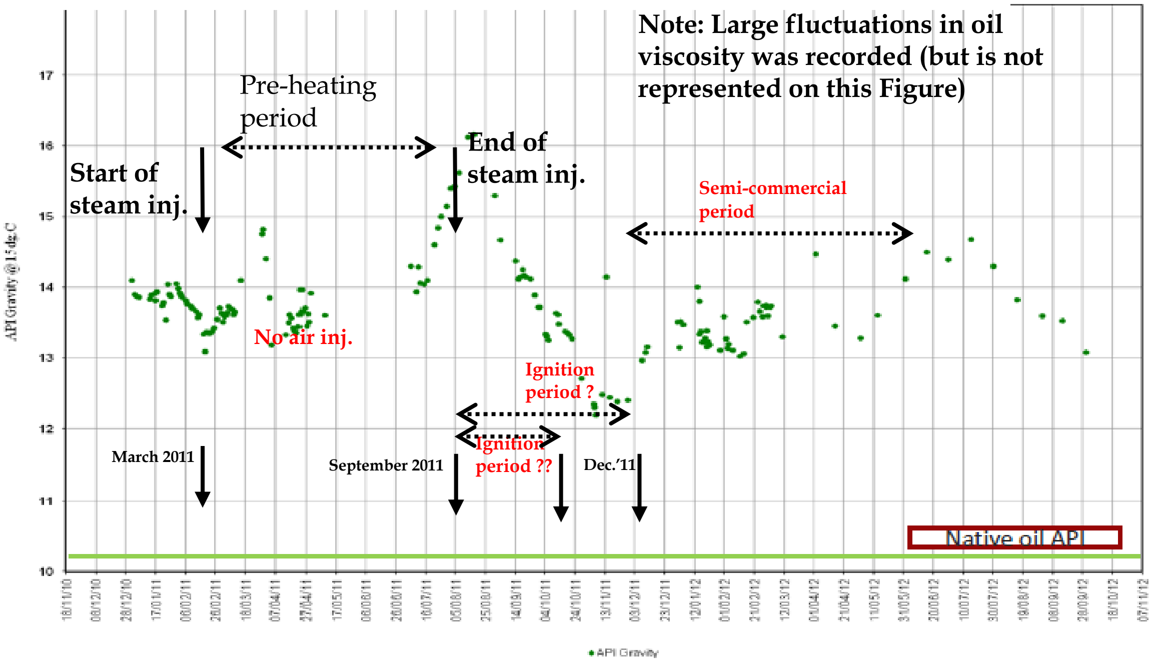

Fig 65: Produced oil quality during Kerrobert THAI semi-commercial operation; in-situ upgrading during the period February 2011- November 2012 (www.petrobank.com).

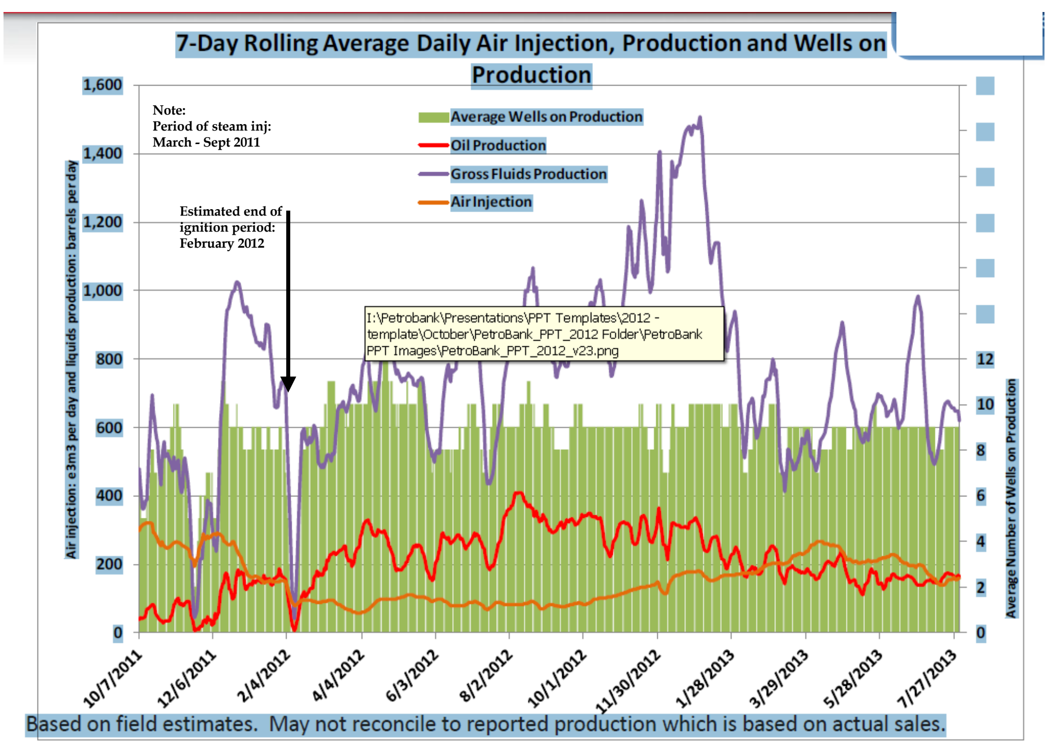

Fig 66a: Oil production during semicommercial Kerrobert THAI operation (period: October 7, 2011-July 27, 2013). Source: Petrobank presentation, August 2013 (www.petrobank.com)

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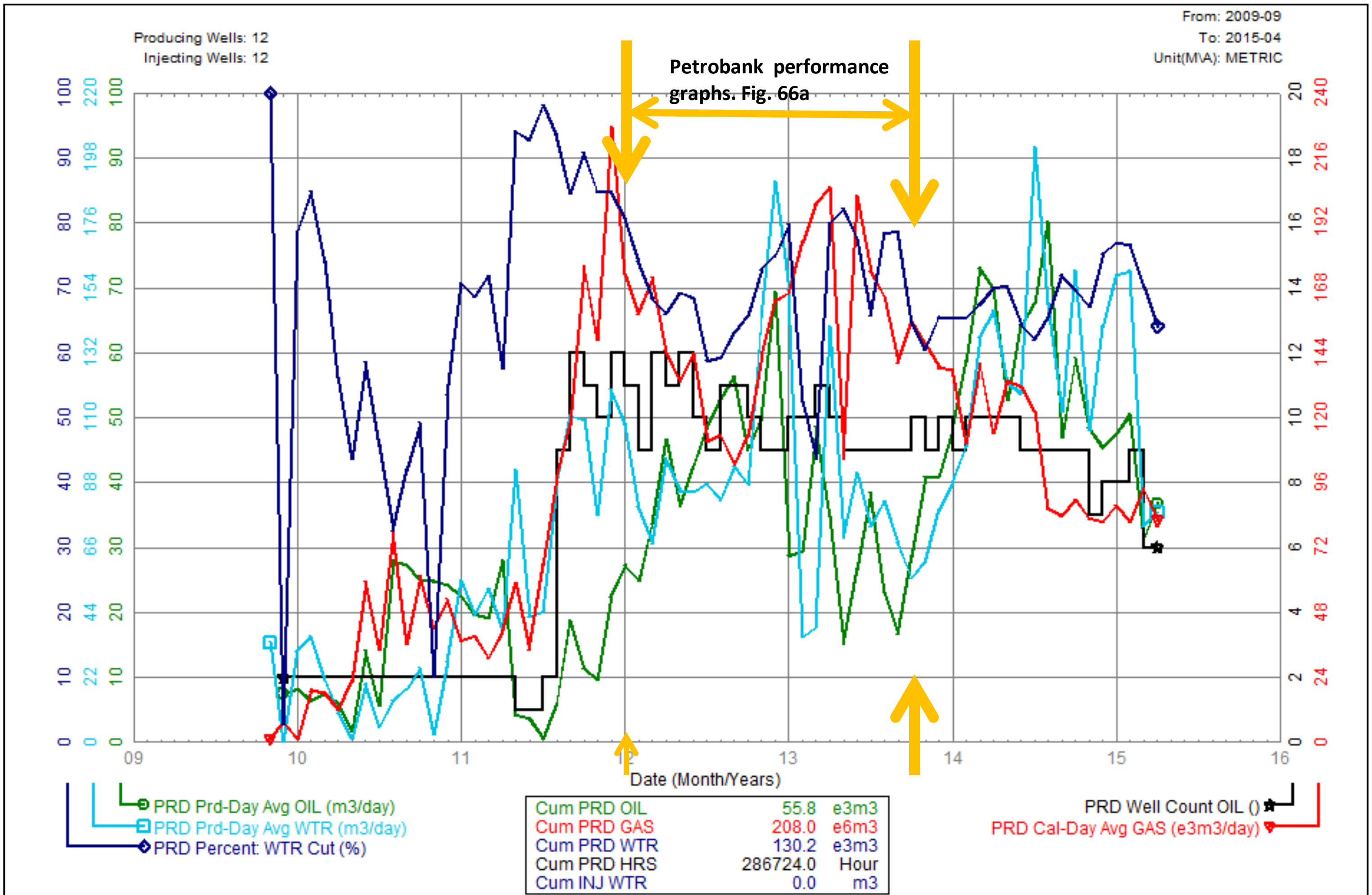

Fig 66b: Oil production for Kerrobert THAI Project (period: October 2009-February 2015), according to the field reported production data; geoSCOUT data.

It is also seen that both from oil production and from an upgrading point of view, the performance varies from module to module. An in-depth analysis per patterns was carried out in Appendix G. The Main results of this analysis are provided in Table 16, which presents the performance for 3.5 years of semi-commercial operation (until February 2015). For simplification, by the pattern Ki we denote the pair KAi-KPi .

An in-depth performance analysis was made using the software geoSCOUT. To February 2015, the cumulative oil production was 52,200m^3 (328,300bbls). However, by February 2016, the project was still producing oil, although at a lower rate. From Appendices C, it can be seen that in this period (February 2015 to February 2016), the total oil production decreased almost linearly from approximately 50m^3/day to 25 m^3/day; therefore, an average of 37.5 m^3/day is estimated for this period. With this approximation,

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it results that another 13,700 m^3 oil was produced. Consequently, the total oil produced by Kerrobert THAI project, as of February 2016, was 65,900 m^3 (414,498.5 bbls).

The air used for ignition, amounted to a significant percentage (up to 16%) of the total air. As seen from Table 16, this effect contributes directly to 17% of the increase in air-oil ratio (AOR); for the whole semi-commercial operation the AOR is 2,800 sm^3/m^3, but increases to 3,200 sm^3/m^3, when the air used for ignition is included. Another conclusion from Table 16 is related to the balance of air injected and gas produced for each pattern (module). It is noteworthy that the patterns K2 (which has one of the best performances) and K3, produced much higher amounts of effluent gas, compared to the cumulative of air injected in the respective patterns.

As shown in Appendix G, there was some interaction between neighboring air injectors of patterns going in opposite directions. There is no doubt that the producer KP7 benefited from the air injection in KA4 (as KP4 was closed); the distance between KA4 and the toe of KP7 is only 30m. Probably, some oil produced by KP9 and KP10 is also due to air injection in KA12, as when considered it separately, the AOR of K9 and K10 patterns are too low (1413 and 709 sm^3/m^3, respectively) to be credible. As seen in Table 16, when looking at the 4 groups of modules (patterns) –as defined in Appendix G - the best performance *seems* to be of the group K8-K10, which together has the lowest AOR value, actually *reflecting the combined contribution of air injection from their own and other adjacent patterns. As mentioned,* the patterns K9 and K10 received a lot of air/gas from pattern K12, as the air injected in these two patterns was approximately half of the gas produced in these patterns.

At the same time, the group K5-K7 (except K7, as seen previously) had the most confined pairs, with each pair having almost a perfect balance between injected and produced gas. It goes without saying that operating isolated, confined, pairs is a lot easier then a group of interacting pairs; their performance evaluation is much simpler. However, this did not mean automatically a very good performance; air-oil ratio (AOR) was higher than the average for the whole project.

Actually, the overall AOR (2,800-3,200 sm^3/m^3) of the whole semi-commercial operation was not extremely high, especially for ISC in an oil reservoir with bottom water. From this point of view, we can consider the performance of Kerrobert THAI project to be satisfactory. However, the most challenging feature was the fact that the oil rates were relatively low as the air rate *could not be increased, and this was due to the following factors (in order of importance):*

- *Excessive production of the water from the bottom water zone*

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- *Tendency for sand influx; on average, each producer required 2-3 workovers/year to clean the sand deposited in the horizontal section (Starkov, 2015)*
- *Possible burn-out inside some of the horizontal producers, although no producer was abandoned (as showed by the loss of the thermocouples, one by one, from toe towards the heel – Appendix G)*

It is believed that the operator was forced to inject air at a low rate in order to control water cut and/or sand influx. This was more critical towards the second half of the project life when the communication with the aquifer was more intense (initially, it was probably created in the start-up region of the THAI patterns, but in time, it might have enlarged due to some possible blockage/collapse around the toe region). ***The inability to increase air injection rates was the biggest challenge for the Kerrobert THAI project*.**

During July 2013-December 2015 period, two vertical air injection wells – MT8 and MT11- were drilled to improve the performance of the process (Figure 61b). They were intended to test a "multi-THAI" process (Ayasse 2011 and 2012), which consists of adding several vertical air injectors *right above horizontal producer*, for supplying and distributing more air at several points of oil displacement, along each horizontal producer. However, the configuration achieved in the field was different from the initial target (vertical injector directly above the horizontal producer); the wells were drilled approximately 30m off, from the trajectories of the producers. For this reason, in reality, the well MT8 provided additional, *conventional ISC fronts* (therefore not short-distance displacement) to displace oil towards KP8 - KP9 producers. In these two cases, the ignition was significantly better as insulated tubing was utilized during steam injection; the temperature at the sand face was higher than 255 ^{0}C (probably around 300 ^{0}C) after 15-30 days of steam injection. As expected, due to the high distance (30-40m) between the injector MT8 and the adjacent horizontal producers (KP8 - KP9), cold oil production was noticed during the exploitation, therefore low productivity. Due to the previously mentioned reason, very low air injection rates were practiced. In the MT11 case, the cumulative of air injected was 2.3 million sm^3, while in MT8 was 4.4 million sm^3 (considering both wells, average calendar air injection rate was in the range of 2,500-5,000sm^3/day). The achievement of a slightly higher injection rate in MT8 seems to be related to its position, very close to an old horizontal well (Figure 61b); this fact, otherwise, had a negative effect, the old horizontal well "stealing" some steam and some air. In case of MT11 - located at an approximately equal distance from the heel and the toe of KP11 - the ISC front propagated towards the heel, eventually broke-through in the heel region and practically blocked the heel region with a 30m-long coke plug,

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causing the suspension of the well (Starkov, 2018). All in all, the effect of this "multi-THAI" test was too low, and the trial was abandoned in 2015.

When comparing the performance of individual patterns (excepting the pilot modules), it can be seen that the best performance was recorded in patterns K7, K9, K10 and K11, which achieved the lowest AOR, and the highest oil rate and also cumulative of oil (Table 16). K7, K9 and K10 patterns owe this good performance to the fact that they have benefited from the air injection in two vertical wells one of them being in a staggered line drive (SLD) relationship with them; namely, K7 had the contribution from air injection into KA4, as well, while K9 and K10 had the contribution from air injection into KA12, as well. In the case of K11 pattern this seems to be due to the fact that this is the only pattern of the semi-commercial operation located very far from any old horizontal wells - almost an "isolated pattern".

The worst performance was recorded in patterns K4, K6 and K12, which had the highest AOR, and the lowest oil rates and cumulative oil. In patterns K4 and K12 there was no ISC front propagated along KP4 and KP12 horizontal sections, respectively, therefore only some immiscible displacement happened. It is speculated that the low performance of K6 pattern can be related to the development of a combustion chamber around its tow, with this chamber located probably at the water-oil interface.

All in all, the explanation for the best performers KP1, KP2, KP7, KP9 and KP11 are as follows:

- K1 and K11 patterns are isolated, as far as air injection and influence of old horizontal wells are concerned (no air injected in other modules flowed towards it), as shown in Appendix G

- The patterns K1 and K2 are the ideal THAI pilots as far as their completion of injector and producer and the geometric shape of the start-up region [close to staggered line drive (SLD) configuration] are concerned; the lateral distance of the toe from horizontal section trajectory is 12-15m and from the toe to the line of injection there is a distance of 8-10m. As an added advantage of the toe-to-heel (TTH) ISC propagation is the fact that although the region adjacent to the toe of well KP2 was subject to a technical accident (collapse) for some 10 m near the toe, the remaining portion of the horizontal section was capable of normal functioning.
- As mentioned, producers KP7 and KP9 benefit from air supply from a second air injector located in an SLD configuration.

As far as the endurance of horizontal section of horizontal producers to the high temperature experienced is concerned (first at toe and then in a region of the toe), it can be concluded that:

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- For the horizontal producers KP1 and KP2, 20 thermocouples (TC's) were installed along the horizontal section with a proportionately higher density at the toe (5 of them within 15m from the toe) and the remainder at large intervals, up to the heel (Fig. 64b); the same principle in the distribution of TC's was respected for all other horizontal producers, but only 10 TC's were installed.
- Out of 12 producers, 4 producers – KP1, KP3, KP6 and KP11 – have not experienced temperatures higher than 475 ^{0}C and therefore they have not seen any thermocouple failures
- 4-5 thermocouples from the toe region (within 15 m from toe) failed in two wells (KP5 and KP7), while for other two wells (KP8 and KP9) 8 thermocouples from the extended toe region (within 110 m from toe) failed
- No production well was completely damaged. This was proven by the access of coiled tubing during workover operations. The only production well KP11 was substantially damaged during the multi-THAI experiment (as shown previously) with an ISC front originating in MT11 coming directly to the heel of well KP11; however, this was due to an improper design and execution of a novel procedure, not a classic THAI process. On the other hand, producer KP2, with a 14 m casing collapse at the toe region (due to excessive temperature), continued to produce, being the best producer of the project.

The temperature profiles along the **h**orizontal **s**ection of producers (HSP) was analyzed in Appendix G. Based on that analysis, the maximum advancement of the ISC front along the HSP was determined, and it is shown in Table 15. This maximum advancement had the highest value for K1 and K2 patterns, where it was 215m and 116m, respectively.

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Table 15: Kerrobert Project. Estimation of the main thermal parameters – ignition and ISC propagation/behavior – for the individual THAI patterns

Pattern	Start date of operations	Ignition delay months	Date of full development of ISC front in the pattern	Quality of ignition: VG=very good; G=good; M=mediocre	Combustion behavior: TTHP or CC	Advance -ment of ISC along HS of HP (meters) / Date	ISC front velocity along the horizontal section of horizontal producer cm/day	Observations
K1	09-2009	1	11-2009	VG	TTHP	205 / 01-2013	13.5	Longest time of TTHP
K2	09-2009	2	12-2009	VG	TTHP	116/10-2013	8.3	Longest time of TTHP
K3	03-2011	4	9-2011	G	TTH/CC??	32-64 / 06-2013	-	
K4	04-2011	No ISC Fr.	Never	No ignition	-	-	-	KA4 injected air for KP7
K5	03-2011	4	11-2011	VG	CC	13 / 06-2013	-	
K6	03-2011	3	6-2011	VG	CC	12-20 ? / 07-2013	-	Best ignition. Typical CC situation*
K7	03-2011	5	11-2011	G or M ?	CC/TTHP??	20? / 05-2013	-	+air from KA4
K8	07-2011	4	11-2011	G	TTHP	56 / 04-2014	6.5	Slow TTHP
K9	07-2011	6	03-2012	?	TTHP	55 / 01-2013	18(?)	2 burning regions**
K10	07-2011	6	03-2012	?	CC	15 / 04-2014	-	2 burning regions**
K11	07-2011	4	11-2011	VG	TTHP	?? / 12-2012	?	Good ignition
K12	07-2011	No ISC Fr.	Never	No ignition	-	-	-	KA12 injected air for KP9 & KP10

Note: K_i pattern denotes pattern KA_i-KP_i pair

Legend: Ign = ignition ; TTHP = toe-to-heel propagation

CC = combustion chamber ; HP = horizontal producer; HS=horizontal section

No ISC Fr. = No ISC front

* Both HS of HP and perforations of vertical injector are close to water/oil interface

** Supplied, also, with air from KA12

KP2

Table 16: The performance of individual patterns, as of February 28, 2015 (for almost 3.5 years of semi-commercial operation). Data from geoSCOUT

Parameter	Close to Pattern	Old HW Inter-cepted	Fluids injected		Oil and gas produced			Observations
			Air injected* as of February 28, 2015	Steam Injected in PIHC	Oil produced	Gas produced	Air-oil ratio (AOR)***	
Pattern			10^3 sm^3	m^3	m^3	10^3 sm^3	sm^3 / m^3	
K1**	--	-	23,650	3,132	6,600	22,600	3,583	
K2**	K5	1?	24,176	3,132	10,300	47,400	2,348	
K3	K2	?	11,886	0?	4,400	21,900	2,701	
K4++	K7	1	6,674 (for KP7)	1,003	80	1,800	83,425 (?)	KA4 suspended in 2013 ; KP4 suspended in Dec 2011
Group I			66,386	7,267	21,380	93,700	3,105	
K5	K2	2	12,345	1,433	3,100	13,800	3,982	
K6	-	1	13,485	1,630	522	12,600	25,795	KA6 &KP6 suspended in 2014
K7	K4	1	16,937	938	6,700	18,400	2,528	
Group II	-		42,767	4,001	10,322	44,800	4,143	
K8	K11	2	6,954	649	1,500	15,700	4,636	KA8 suspended in 2012 ?
K9	K12	2	9,893	780	7,000	14,400	1,413	
K10	K12	1-2	4,891	1,177	6,900	16,200	709	
Group III			21,738	2,606	15,400	46,300	1,412	
K11	-	-	12,549	663	7,000	19,600	1,793	Suspended in 2015 during multi-THAI test
K12++	K9 K10	1	10.469 (mainly for KP10 & KP9)	616	1,100	2.200	9,517 (?)	KP12 suspended since 2013
Group IV			23,018	1,279	8,100	21,800	2,842	
GRAND TOTAL			153,900	3,132	55,202+	206,600+	2,788	

Observation: See all explanatory notes on the next page

Legend: HW = Horizontal well; PIHC =Pre-ignition heating cycle

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- Estimate based on data on multi-well performance graphs (Graphs from Figures G1 and G2 of Appendix G), taking into account the estimated annual average air injection rate and the number of injection days for each year

** Pilot patterns

*** AOR expressed as the ratio between total air injected and total oil produced (it is not per incremental oil); AOR per incremental oil should be slightly higher

+ Value confirmed by the global performance (see Figures G5 to G16 from Appendix G)

++ Air injection in KA4 was on in this period in order to supply additional air to K7 pattern, while air injection in KA12 was to supply additional air to K10 and K9 patterns

Best performance Worst performance

Another interesting aspect is related to the comparison of the cumulative volume of gas produced by the horizontal producers and cumulative volume of air injected in the corresponding vertical injectors. In three of patterns, the cumulative volume of gas produced was around 30% higher than the cumulative volume of air injected. This was more obvious in the patterns K1, K2, and K11. It is believed that this can also be related to the higher degree of upgrading achieved in these patterns; it is speculated that more intense thermal cracking, at higher temperatures, caused more methane to be produced. The same substantial upgrading (accompanied by excess methane production) was noticed in another Canadian ISC project, the Morgan ISC project (Marjerisson 1994, Turta 2006 and Chang 2009), although the mechanisms were not well understood, and a lot of unanswered questions remain for that project. However, in Kerrobert THAI Project - to some extent - this is also related to an operational procedure, namely, injection of a certain rate of hydrocarbon gas (mainly methane) in the annulus, in order to mitigate corrosion. That's why, a very precise material balance of injected air/produced gases can be made only based on the comparison of the nitrogen contained by the air injected with the nitrogen contained in the produced gases; this would allow a rigorous evaluation of the confinement associated with this project, or how much gas is lost from the project area. As seen in Table 13, the average nitrogen percentage in the produced gas of KP2 well in 2015 was around 77%, but this figure cannot be used for the whole life project of KP2 or for any other producers. It follows that the 30% additional gas produced is made up of hydrocarbon gas injected in the annulus (in order to mitigate corrosion), methane produced by methanation reactions, hydrogen produced by coke gasification and water-gas shift reactions, CO produced either by burning or by other reactions, H_2S and hydrocarbon gases which existed dissolved in the oil. This conclusion, however, needs more verification.

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Appendix G provides an in-depth analysis of the individual performance of the Kerrobert THAI pairs, about:

- influence of the geometrical shape of the start-up region
- influence of the completions of the vertical injectors and horizontal producers
- variation in air injection rates and oil production rates per individual well pairs
- overall individual performance for each pair of the semi-commercial operation (modules K3 to K12), including the variation of produced oil, water and gas.

Also, Appendix G contains an analysis of different groups of producers. Based on the location of the THAI pairs (see Figure 61a-b), well patterns were divided into four groups:
Group I: patterns K1 to K4
Group II: patterns K5 to K7
Group III: patterns K8 to K10
Group IV: patterns K11 and K12

From analyses of the performance (Appendix G), plus the foregoing discussion, and the fact that Kerrobert reservoir is a conventional heavy oil with underlying bottom water, the following observations/conclusions are be made:

- In Kerrobert heavy oil reservoir THAI was operated on a semi-commercial basis, and it was tested as a secondary recovery method. It was initiated when the water cut had risen to 85-96% for an extremely low recovery factor (1.2%) via cold production mechanisms; at the initiation of THAI the reservoir pressure was half the initial pressure; therefore some relative permeability for the gas existed.
- The in-situ combustion (ISC) front was generated relatively slowly. Ignition delay was up to 1-2 months in the Pilot and 3-6 months for the semi-commercial project. In this period, due to LTO reactions, the oil production was extremely low. After the full development of the ISC front, the burning seemed good/normal, as indicated by the composition of the gases. The typical ISC performance, as it is discussed here, came after this period. For most of the pairs (except K4 and K12) the ISC front was anchored to the toe. Then, it either propagated toe-to-heel or the propagation did not happen, and a combustion chamber around the toe developed (up to 10-20m from the toe). When normal toe-to-heel propagation happened, the ISC front advanced up to 40-60m; in a few cases, it advanced 100m-200m. In other cases, after anchoring, the propagation did not occur, and a *combustion chamber* developed around the toe (up to 10-20m from the toe)
- Positive effect – *efficient oil mobilization via THAI application* was seen at 6 well-pairs (K1, K2, K7, K9, K10 and K11) out of a total of 12 well-pairs. This was demonstrated by a continuous decrease in water cut (to as low as 30-50%), and also, by oil production showing a clear increasing tendency.

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- For the whole period of the semi-commercial operation (7.5 years for K1 and K2 modules and more than 5 years for the remaining 10 well-pairs), *the average effective oil rate* increased by a factor of 8 (from around 0.5 m^3/day to 4 m^3/day); however, for the production wells exhibiting a clear sign of ignition and normal ISC front propagation, the increase in the effective oil rate was more than 8 times. The wells with very good performance (KP7, KP9, KP10 and KP11) produced a cumulative of oil of approx. 7000 m^3 (until February 2015). It is to be highlighted that in case of K7, K9 and K10 patterns, the air injection wells are in a *slightly (some meters laterally off)* staggered line drive (SLD) configuration with the production wells and this probably helped; K11 pair seems to be free of any influence from outside.
- Production wells exhibiting a lack of positive ISC activity generally had a permanently very high water cut, and accordingly, the oil rate failed to show any substantial increase. Sometimes, this was associated with difficulties in keeping the production well active (utilization coefficient as low as 30-50%). This was seen in the patterns K4, K6 and K12. These patterns produced a cumulative of oil of 80 m3, 520 m3 and 1100 m3, respectively (until February 2015). For the patterns K4 and K12, ISC front anchorage to their toes, failed, while K6 pattern experienced frequent interruptions in production and appeared to develop a combustion chamber at the oil/water interface.
- The performance of pairs (K3, K5 and K8) was more difficult to decipher; their oil cumulative was 5,500, 3,100 and 1,500m3, respectively. For K5 and K8 pairs, the water cut did not decrease during ISC application, while in the K3 case, it decreased to 40-50% only in the first year; then it increased to 80-90%.
- The 4-D seismic survey conducted during the ignition operations for K3-K12 patterns (in October 2011) and after one year of full THAI semi-commercial operation (in November 2012) confirmed the conclusions about the development of the ISC front and its efficiency in displacing the oil. In 2012, while the best development of the ISC was noticed around KP1, KP2, KP3, KP5 and KP6 in the SE region and KP9 and KP11 in the NW region, for K4 and K12 pairs, no combustion front /combustion activity was seen (Starkov, 2014). Also, it showed that after one year of full semi-commercial operation, the combustion gases/air flowed along the oil/water interface, with a deeper penetration into bottom water in the NW part of reservoir, which is also slightly more elevated compared with the rest of reservoir (Figure 67b). The early seismic survey of 2011 (Fig. 67a) allowed to detect some anomalies in relation with secondary gas caps formed along the old horizontal wells 2,5,6 and 7 (see Fig. 61b), around the intersection point between well 2 and 6 and these 4 old wells may have communication between them. The secondary gas cap is due to the decrease of reservoir pressure as low as half of its initial pressure (Wikel 2012).

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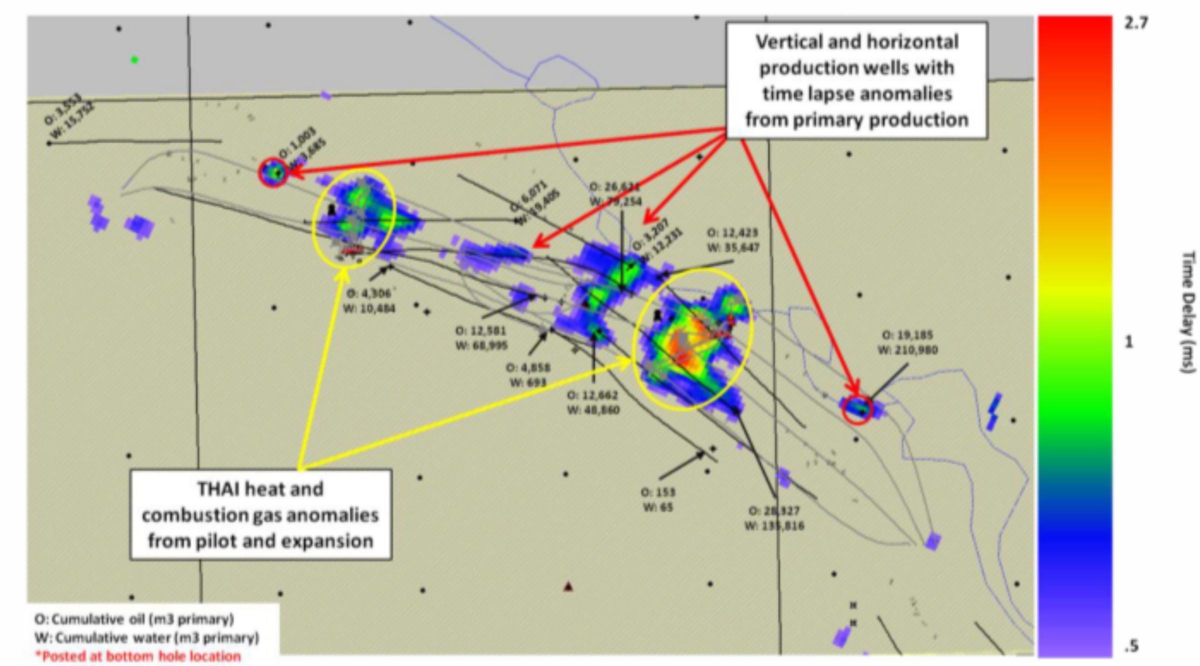

Figure 67a: Kerrobert seismic survey conducted in ***October 2011***, during ignition operations for semi-commercial THAI operations; in the period April-October 2011, the air injection in view of ignition started in all patterns (K3-K12). Secondary gas caps are visible. Wikel 2012

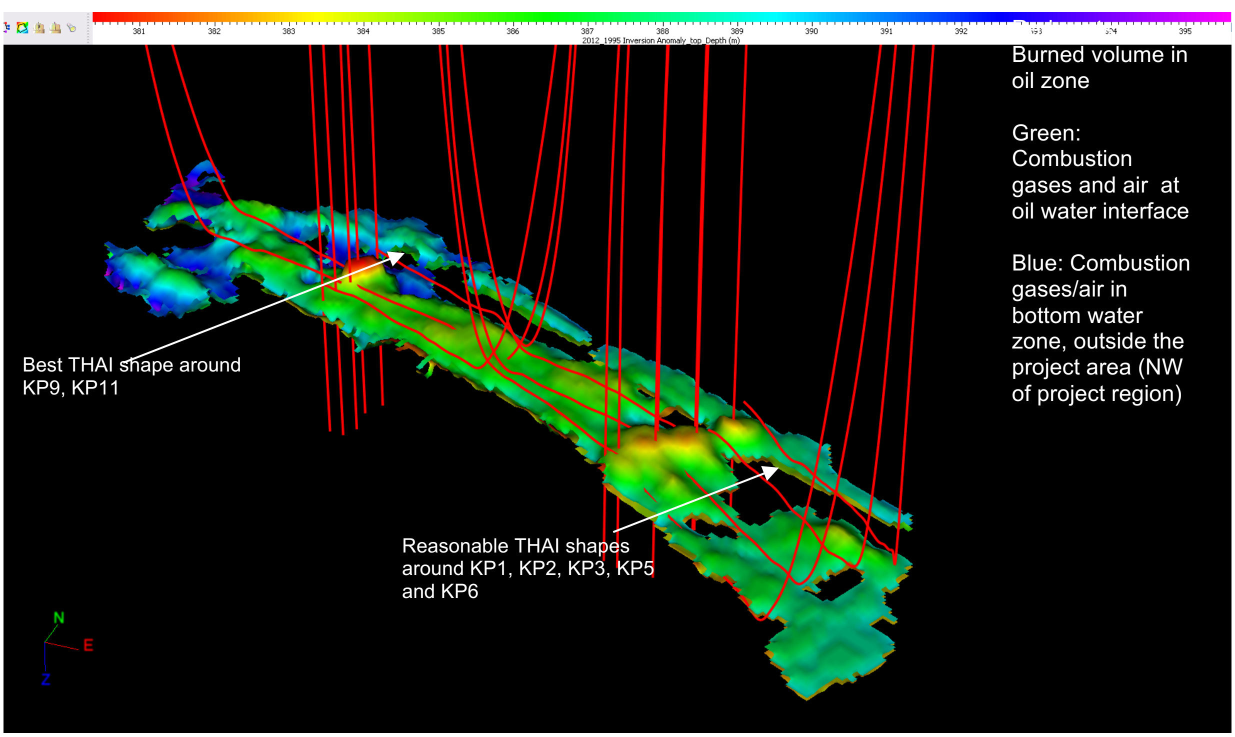

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Figure 67b: Seismic representation of burned volumes, gas invaded volumes and penetration of gases/air into the bottom water zone as of the end of ***November 2012***, after approximately one year of full ISC operation. Starkov 2014

- Both seismic measurements and the temperature profiles along the horizontal section of the horizontal producers confirmed that the ISC front did not advance more than half of the length of the horizontal section of horizontal producers. From these data, it is possible to determine under which conditions the sweep efficiency and the efficiency of the process were better. This has allowed the main mechanisms of THAI operation in the presence of bottom water to be deciphered. A long period of potentially viable operation remained.

Optimization of the process in this phase (of the second part of exploitation) should be made taking into account the current situation of each pair (including where the burned volume is located), existence of bottom water and the possible influence of the old horizontal wells.

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It is reasonable to admit that during the pilot period and the first year of semi-commercial operation, the quality of burning in the reservoir was good; high peak temperatures were recorded in the production wells. It is very likely that in this first period, the ISC front propagated *predominantly* in the oil zone (it was predominantly confined within the oil zone). Afterwards, as the reservoir pressure increased and the control of the process was gradually lost - in connection with bottom water existence and, probably, the presence of old horizontal wells; actually, even during the air injection for ignition of semi-commercial patterns (in October 2011) the seismic survey detected some gas/air towards the middle of structure around the intersection of old horizontal well 2 with old horizontal well 6 (see Fig 61b and 67a) . Therefore, some air was lost in the bottom water and some via the old horizontal wells, and due to these phenomena the performance of the process decreased continually. The performance of each production well appears to depend on how long the combustion zone remained in the upper part of the oil layer, before moving to the water/oil interface; which was even more important in cases in which a combustion chamber (near to the injection well) was generated.

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In November 2013 Petrobank (subsequently taken over by Touchstone), announced that they would terminate the Kerrobert THAI semi-commercial operation by *June 2014*, if the profitability of operations remains low. However, this did not happen and the process continued for a more extended period (at least until November 2022), with some details listed below:

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- In February 2015, Touchstone declared that 4 production wells and 2 injection wells had been shut-in due to a lack of allocation of resources for maintenance work.

- *As of July 2015*, one year later, the process was still operating, perhaps it was turning towards economic profitability. It appeared that maintenance work was reduced to a minimum in order to keep the cost down. The instantaneous air/oil ratio was in the range of 3,500 - 4,000 sm^3/m^3 during this period.

- As of June 2016, the process was still operative; the daily oil production was around 217bbl/day (35 m^3/day) from 4 active production wells; water cut was in the range of 40-60%. The instantaneous air/oil ratio was also in the range of 3,500 - 4,000 sm^3/m^3.
- As of October 2016, the project is on-going, with 4-5 wells producing; the daily oil production is in the range of 250-300bbls/day (40 - 50 m^3/day)
- As of March 2017, the project is still on-going; the daily oil production is about 250bbls/day (40 m^3/day)
- **May 2018: The continuous air injection has taken place until this month. After May 2018 the air injection was discontinuous with very long periods of extremely low rates of air injection or no air injection, at all. Water cut increased gradually from an average of 65% to 85-90%. Testing of the normal THAI process (with its day-to-day upgrading) is considered to be terminated at this date.**
- As of August 2018, the project is still on-going; the daily oil production is 94bbls/day (15 m^3/day) from 4-5 producing wells (KP5, KP6, KP7 and one of KP9 or KP10), even during the period when no air injection was done; the air injection interruption lasted for approximately 2 months.
- As of September 2019 the project is still on-going; the daily oil production is 94bbls/day (15 m^3/day) from 3-5 producing wells, even during the period when no air injection was done.
- April 2020 (*5.5 years after the June 2014 shut-off decision*): Performance is similar to that recorded in September 2019 (DB Petrobank, Starkov, 2020)
- ????

Overall, by April 2020, the Kerrobert Project has been operated for 10.5 years, and precious experience was gained. In April 2020, the project was still producing 94 bbls/day (15m^3.day) from 3-5 production wells. ???????

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Fig. 68: Oil, water and gas production of Kerrobert THAI Project (period January 2013 -September 2020) according to field reported geoScout data (Starkov, 2020)

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To go to the landscape orientation and arrange everything accordingly

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Compared to the performance of Whitesands pilot (Figure 54a-c), the following observations can be made:

- The application of THAI process led to a cumulative of oil of 23,000 m^3 in the Whitesands pilot and a cumulative of oil of 66,000 m^3 in Kerrobert project; the **a**ir-**o**il **r**atio (AOR) obtained in Kerrobert was around 3000 sm^3/m^3, which compares favorably with the performance of all known *conventional ISC application*, so far in a bottom water situation. Also, this value of AOR was significantly better than that achieved in the Whitesands Pilot.
- In both projects, continuous upgrading of the produced oil was observed; in the Semi-commercial Kerrobert Project this was of varying intensities at different production wells.
- *The crucial difficulty registered in both projects was the impossibility to increase the air injection rates (per well) to values higher than 20,000 sm^3/day.*

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Compared to the conventional ISC process conducted in the presence of bottom water (BW-ISC), and operated with vertical wells - as seen in subchapter 7.3 - the most notable difference is that THAI practically has never recorded any oxygen in the produced gas, while in BW-ISC projects the O_2 concentration is relatively high and increasing with time.

7.4.3.2 Discussion of Petrobank's statement concerning problems with the Kerrobert Project

The following is an excerpt from Alberta Oil E-Newsletter, January 2013. C. Bloomer (the VP Heavy Oil, Petrobank) admitted that "*there have been some growing pains for the technology to date, as Petrobank works out the kinks in terms of how to prepare a reservoir for it and properly deploy it once it's ready"*. Petrobank was forced to reduce the pace of operation at Kerrobert early in 2012. *"We should have gone slower at the start," Bloomer says. "We put a lot of air and a lot of energy into it, and we had operating issues. The reservoir was not ready to accept that amount of air."*

Our analysis in Chapter 7 clearly shows that from the beginning of the project, specific operational procedures were conducted in a less than optimal manner. A particular weakness was the procedure used for ignition, mainly in the expansion of well-pairs KA3-KA12, which significantly compromised the efficiency of the process. "The reservoir was not ready to accept that amount of air" - because, as we

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have already identified, the ignition procedure was flawed. The key point is that prior steaming of the reservoir (ie PIHC), specifically in the start up region (the inlet region between the injector and the toe of the horizontal producer), must be long enough and conducted at highest possible injection rate in order to ensure that there is extensive 'heat soak' into this region and that the temperature around the injection well reaches as high a value as possible. This should be close to the steam condensation temperature. *This is so because the ignition by injection of hot water is not a proven ignition technology and it took by far too long.*

7.4.3.3 Ways to Improve the Performance of Kerrobert THAI Project

Two main aspects are discussed here, namely the effect of bottom water and the effect of old horizontal wells located near the top of the formation, within the project area. The existence of bottom water is closely related to the loss of confinement, accompanied by *injected air loss*, either in the bottom water zone itself or in other zones/regions of the reservoir, while the existence of old horizontal wells could also cause a *loss of control* on the propagation of the ISC front as they provide pathways for gas channeling, generally, at the upper part of the formation (preventing efficient displacement).

As discussed previously (subchapter 7.3), for conventional ISC application in the presence of bottom water three situations can develop: 1) ISC is fully contained within the oil zone, 2) ISC takes place at the oil/water interface (in the transition zone) and 3) injected air splits between the upper oil zone (ISC front in the oil zone) and oil/water interface (creating an ISC front within the transition zone).

For the Kerrobert Project, plausibly, the third of the above situations occurs as the ignition is conducted in the upper half of the pay zone. A simplified schematic for this situation is shown in Figure 65a; it shows the ISC front as was anchored at the toe of the horizontal producer, and a short distance was traveled (towards the heel). As seen from this *illustration*, initially, the ISC front was probably fully contained within the oil zone; once the ISC front was anchored at the toe of the horizontal producer, in the start-up region (between the toe of the horizontal producer and the shoe of the vertical injector), gradually, the coke band (visible in Figure 9b) was totally burned out and the injected air preferentially flowed in the BW zone (Figures 9c and 46). It is possible that the tilting forward of the ISC front continued.

A second illustrative picture (Figure 68b) is for the combustion chamber situation, i.e., when a direct channeling of air "shoe-of-the vertical-injector – toe-of-the-horizontal-producer" occurs and, after anchoring of the ISC front at the toe, the ISC front is tilting backward. In this case, the oil displacement efficiency is low, and the combustion chamber can be entirely developed at the oil/water interface; very high water cuts can be expected depending on the position of the combustion chamber.

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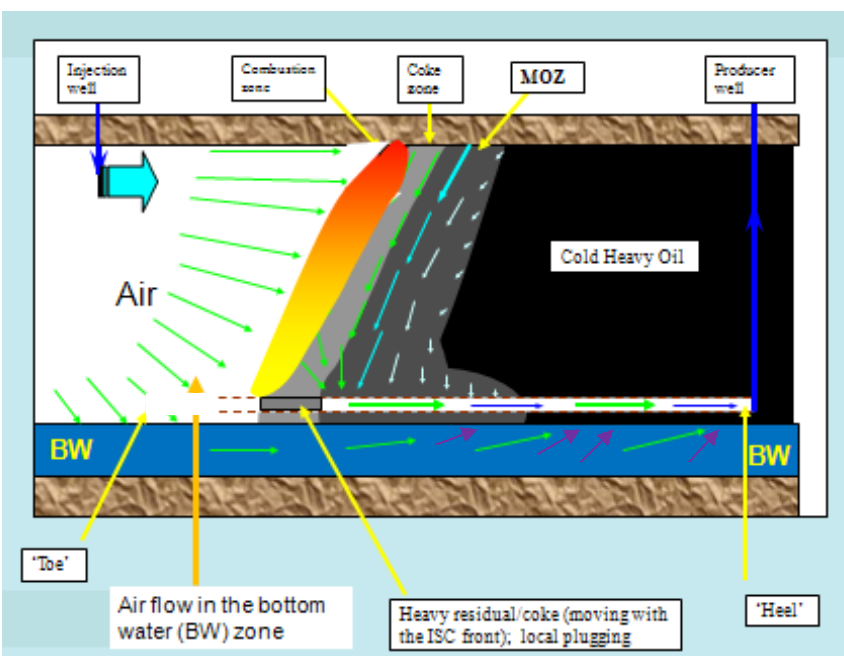
A cursory inspection of performance (Figures 68a and 68b) allows us to identify the moment of predominant migration of air in the bottom water zone (between November 2012 and February 2013). During this period, the gross liquid production (oil &water) increased from 900 to 1,500bbl/day, while the oil production decreased from 300 bbl/day to 200bbl/day, even though the air injection rate remained essentially constant. This was because the oil mobilized via the O/W transition zone was mostly not captured by the production well. The 3-D seismic measurements at the end of 2012 confirmed this interpretation and to some extent, it confirmed the analysis of consecutive temperature profiles taken in the producers (correlated with their water cut performance). *It seems likely that the combustion was able to remain predominantly in the upper part of the layer for just one year.*

The complete produced gas analysis for all the pairs and the apparent hydrogen/carbon ratio (H/C ratio) calculated based on the composition of the produced gases (including hydrocarbon gases) helped in clarifying which reactions (HTO or LTO) existed at the O/W contact. It was seen that in 4-5 patterns the LTO reactions lasted longer, even after the 4-7 month ignition-delay, estimated in this Report.

Also, as mentioned, confinement of the process could have been ***gradually*** lost for a number of patterns (6-7), due to channeling paths provided by the old horizontal wells; however, although supported to some extent by individual performance of horizontal producers – it is difficult to fully confirm the loss of confinement for each of the horizontal producers, given different periods (of loss of confinement); it needs to be verified with additional field data.



Legend: → air flow direction; → water flow direction;

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Fig. 68a: Illustrative schematic of THAI process for an oil reservoir with **b**ottom **w**ater (BW), after the moment ISC front was anchored at the toe. This is valid for cases where an almost *toe-to-heel (TTH) propagation took place*. Before anchoring, the forward inclination of the ISC front is higher and no air flow in the BW takes place. Modified from U of Bath (with the illustration of air loss in the BW zone).

From the analysis presented in this document, it follows that for improving the performance of the THAI process, there are specific simple measures to consider for conventional heavy oil reservoirs underlain by bottom water, namely:

- Use of a more robust ignition procedure, especially when using steam for preheating. This should involve either higher steam injection rates over a more extended period (i.e. increased total amount of steam injected) or using an enhanced ignition combining the steam injection with linseed oil
- It is essential to monitor that steam enters only into the upper part of the oil layer. Fracturing in order to increase injectivity of steam is not recommended as the access to bottom water can be opened.
- In some instances, artificial ignition using electric devices or gas burners should be considered, in order to initiate and conserve the ISC front in the upper part of the oil layer, preventing its premature entrance into the bottom water.
- Application of wet ISC should be investigated as the alternative air-water injection may delay the establishment of full communication with the bottom water zone in the start-up region. However, total preservation of the ISC in the oil zone during the entire project life in general may be impossible; it may be possible only for very thick formations having a continuous shale lens of a high thickness (at least 3-4 m) above the bottom water (original restricted communication bottom water–oil zone), while the horizontal section of the horizontal well is located above this shale lens.

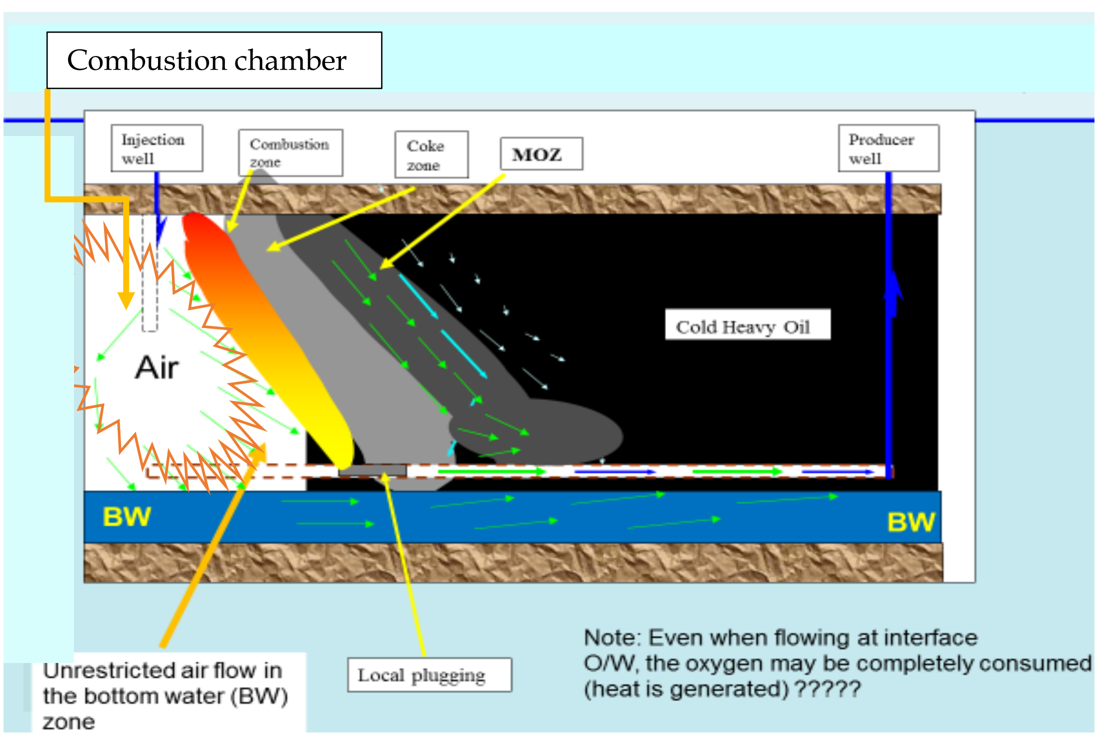

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Fig. 68b1: Illustrative schematic of THAI process for an oil reservoir with bottom water after the moment ISC front was anchored at the toe. This is valid for cases where a *combustion chamber* was generated. The anchoring of the combustion may occur, but the toe-to-heel propagation may be stalled. Please notice the backwards inclination of the ISC front (channeling type). The air flux to the ISC front is decreasing upwards towards the top of layer.

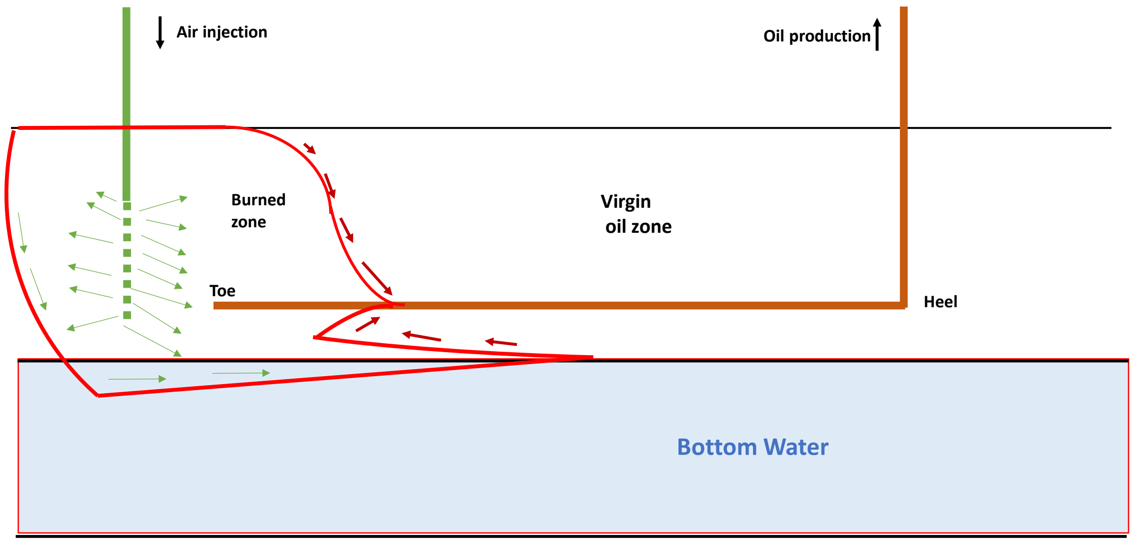

Fig. 68b2: More details for schematic of THAI process with formation of a *combustion chamber due to the presence of the bottom water.* Please note two leading edges of the ISC front; one along the horizontal section (HS) of producer and one along the water-oil interface. The tilting backwards of the ISC front (channeling type) is a main feature. The air flux to the ISC front is decreasing upwards, towards the top of layer. Why the stalling of the ISC advancement along the HS takes place is not fully understood.

7.4.3.4 Winding-down Alternatives for the Kerrobert Project

As a general rule, *conventional ISC projects* end up with a continuous water injection in the burned zone in order to use the huge amount of heat stored there; this operation also helps in avoiding a massive oil re-saturation of the burned zone (with the generation of the substantial amount of coke). Usually, the water injection starts up immediately after combustion process is stopped.

In other conventional ISC projects, a few years after the suspension of air injection, horizontal wells were drilled as *in-fill drilling production wells*. An example, given in Subchapter 6.4.2.6 was the Eyehill project in Saskatchewan (Farquharson, 1986) in which three horizontal wells were drilled after two years following a complete cessation of the dry combustion project in 8 adjacent, inverted five-spot areas. The combustion process was active for about 10 years; at the time the project was stopped, the oil recovery was 10%. The reservoir consisted of an oil zone of 5-8m and an underlying bottom water zone (thickness up to 15m); with an oil viscosity at reservoir conditions around 2,000cp - a typical bottom water reservoir operated by ISC.

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From the above example and other similar projects, it was seen that the success of horizontal producers *drilled as in-fill wells* in a conventional ISC project depends more on *the correct placement of the wells and less on the length of its horizontal section.*

In the Kerrobert Project, although the ignition was slow, after the generation of the ISC front, the burning seemed to be good, as indicated by the standard composition of the gases produced. Due to lower than projected air injection rates, the ISC front did not sweep a substantial volume of the reservoir. Both seismic work and the temperature profiles along the horizontal section of horizontal producers confirmed that the ISC front did not advance more than half of the length of the horizontal section of horizontal producers. There is still a long period up to the end of the Project.

The air injected/oil produced ratio(AOR) is approximately 3,000sm3/m3 and is lower (better) that the best AOR value obtained in a conventional ISC in the presence of bottom water. The main operational challenge was the impossibility to increase the maximum air injection rate over 20,000 sm^3/day/well and this severely limited the value of the maximum oil production

Optimization of the process in this phase (the second part of exploitation) should be made taking into account the current situation of each pair (including how the burned volume has been developed/located), existence of bottom water and the possible influence of the old horizontal wells

To continue Kerrobert thermal exploitation, there is the possibility to choose between three alternatives:

1. Simple optimization taking into account the experience with the application of ISC in bottom water situations (general experience from conventional ISC projects, experience from other THAI field tests and specific experience from analysis of Kerrobert THAI process); no additional expenses
2. Optimization based on some additional instrumentation in order to define/clarify some aspects/mechanisms not fully understood at this stage. Slight process modifications; minimal additional expenses
3. Radical improvement of exploitation based on additional instrumentation and some new wells to be drilled; some significant modifications to the exploitation may occur, requiring additional investments and expenses.

The first alternative involves three variants, namely:

- Straight continuous water injection *<u>in some vertical injectors</u>* for the scavenging of heat from the burned zone and oil displacement by steam and hot water; this should be done for a limited period of

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time and at the highest injection rate possible, just before wrapping up the Project (in case a shut-in of the Project is intended). A maximum volume of water of 0.8 “PV burned” is anticipated for injection.

- Switching from direct line drive (DLD) to staggered line drive (SLD). This involves the optimization of current exploitation by re-organization/restructuring of the injection and production wells, with the reduction of the number of active pairs (closing of some injection and production wells).
- Optimization of the currently applied method; intermittent exploitation with heat re-distribution during the non-production periods; based on KP5 well performance and other indications; it is about heat-re-distribution mainly in oil zone above the water/oil interface.

  Some 6-7 wells could be included in this program. It may involve a 2 month-period cycle. To be decided after an analysis of the past events

The second alternative involves the following instrumentation additions, leading to the following potential solutions::

Additional instrumentation/measurements:

- ➢ Temperature profiles in all THAI production wells (in function or shut-in wells)
- ➢ Temperature measurements in all old shut-in wells (both vertical and horizontal);
- ➢ Gas analysis of the gas collected from old shut-in wells (both vertical and horizontal)
- ➢ Gas analysis of the gas collected far away from the project region, from the NW region, along the geological channel, where there is a tendency for gases to migrate (small tilting) via the bottom water.

Possible solutions:

- ➢ Use of some old horizontal wells as air/water injection wells, where appropriate
- ➢ Total blockage to remove the gas channeling via some of these old horizontal wells –in cases they have a pronounced detrimental effect on the process
- ➢ Use of cyclic ISC process in the wells MT8 and MT11 drilled and partially used for Multiple-THAI pilot.
- ➢ Attempt to define better the situation and contribution of well KA12, which was not ignited and the temperature around this well is only 130 ^{0}C. This well supplied air for KP9 and KP10. A decision either to continue the ISC process (but in better defined conditions) or to ignite it and operate the K12 pattern from A to Z. The same situation exists for K4 pattern.

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- Conversion of the current THAI process (using vertical wells for injection) to a THAI process using only horizontal wells. The old vertical injectors may be used for water injection if necessary; the pairing of water injection and oil production may be changed as compared to the air injection/oil production before (Use of a middle horizontal producer as a future air injection well, as burning surfaces already exist in both directions, towards other horizontal producers; In this case, for example, air injection can be carried out only in KP2, while KP1 and KP3 will be used as producers; for safety reasons and to increase the efficiency, wet combustion should be applied, with alternative air/water injection (with very low water-air ratio and a 2 week air /1 day water injection cycle) in KP2 and continuous water injection in KA2 well. More detailed information about this possibility (and ways to do it) is presented in Appendices F and G. In this situation the air injection may be made first at the toe, and an ignition operation may or may not be necessary (depending on the BHT value); then, a very large/extended ISC front will displace oil at a potential high rate towards the two horizontal producers; initially, the newly adjusted ISC front will be in a staggered relation (not face-to-face) to the production segment of adjacent producers. Attention should be paid to avoid blockage of the horizontal producers.

The third alternative relates to the following approaches:

- Use of new horizontal producers as in-fill wells, strategically positioned in-between the current pairs. The disadvantage of this approach is that there are no observation wells to estimate the temperature in this space (temperature is very low at this time). To compensate it is recommended first to drill 1-2 coring wells, strategically positioned, to get this information, and additionally, to get some essential information on the fuel/coke deposition during the process. This approach is recommended after a few years since the complete stoppage of air injection.
- Continuing the ISC process by using vertical control wells as air injection wells; these will be new wells located in-between the current pairs, but further from their toes in order to process the area which remained unswept by the previous direct line drive ISC conducted from the original injectors. This approach is more complex, as it involves a temporary application of reverse ISC through those lateral control wells in order to attract the ISC front, laterally towards them; then after their interception by ISC front, a forward ISC similar to THAI will be conducted using these wells; this is a kind of 'echoing ISC process".
- Using the current production wells as future production wells for SAGD operations; in this case, only the future new steam injection wells are to be drilled parallel and 5 m above them; the new SAGD injector will be drilled from the current production pad. That approach should be considered for application immediately to the wells KP12 and KP4 which did not experience an

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ISC front anchoring to the toe and subsequently a toe-to-heel propagation; in conjunction with that, the past effect of LTO reactions should be analyzed. However, for the remaining pairs the distortion of the future SAGD chamber for the last 60m-100m (200m) of the current toe region can significantly diminish the performance; preliminary simulation is recommended.

- Using the current production wells as future production wells for testing a radically new thermal process in which a SAGD-type configuration may be used; in this case, only the future injection wells are to be drilled parallel and above them; the new wells may be drilled from the current production pad. Again, this procedure can be easily applied, immediately, to the wells KP12 and KP4 which did not experience an ISC front anchoring to the toe and subsequently a toe-to-heel propagation.

No matter what alternative is adopted, it has to be taken into account that the wedging of the burned zone towards the heel is a reality, and the current extension of the burned zone is no more than 40-100m - from the toe - along the horizontal section of horizontal producers.

7.5. Planning for Expansion of THAI Application in Canada

During the period 2008-2013, two more major THAI applications were made to the ERCB (Energy Resources & Conservation Board): May River Project in Athabasca Oil Sands and Dawson Creek Pilot in Peace River (Grand Prairie region), both by Petrobank. Only essential information on them is provided here.

Planning of a Commercial Operation; May River Project: Based on the Whitesands pilot in the first two years (2007 and 2008) in 2009 Petrobank made an application for scheme approval of the May River large-scale commercial project¸ with a total capacity of 100,000 bbl/day (filed with Alberta ERCB in December, 2008). The project was to be located in the same region (2 km north of the Whitesands pilot). However, on March 9th, 2012, a cancellation of the project was announced, and the property was sold.

A detailed inspection of the May River commercial project proposal reveals that the project proposal was made at the end of 2008. This was in fact the year of the best performance for the Whitesands THAI pilot, whereas the cancellation of the project occurred in March 2012. This cancellation can be related to the following events:

- Disappointment with the performance of the Whitesands replacement producers and other operational problems, which appeared towards the end of 2011

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- The underperformance of the Kerrobert THAI project expansion (semi-commercial phase) due to the very long ignition period.

Additional to these technical reasons, there were difficulties in dealing with exaggerated claims from First Nations (Wood Buffalo) community.

The Peace River THAI Pilot (Dawson Creek Pilot): In November 2007, Duvernay Oil Co. signed a deal with Petrobank to apply the novel THAI process in Peace River (Grand Prairie region - Dawson Creek property). Later on, Duvernay Oil Co. was bought by Shell Oil Co. Finally, Petrobank bought all rights from Shell, and this project became a 100% Petrobank project.

A scheme approval application for the new THAI field pilot at Dawson Creek property was made in April 2009 (Petrobank Application 1611539/April 2009). The intention was to test THAI process in a conventional heavy oil field in Peace River Region.

The future Petrobank THAI pilot is planned to operate in Bluesky Formation (BSF). BSF is located at 550m-depth, and contains a heavy oil with an API of 11^0 at the top of formation and decreasing up to 8^0 at the base; the sulfur content is generally higher than in other regions being around 6% wt. The thickness is in the range of 15-20m, and the net to total thickness ratio seems to be high (favorable). Confinement seems very good both at the top and at the bottom. Porosity is 20-30%.

This is a North-South channel dipping South, and a pilot consisting of two THAI pairs was planned to be positioned along the channel. As of March 2013, the planning work was under way; in this area, normally the horizontal wells are used predominantly; on July 2015 (Appendix C) it was announced that Touchstone Exploration Inc. sold the property, after trying unsuccessfully to apply the CSS in view of preparation towards eventual application of THAI process.

Petrobank carried out some 3-D lab tests related to Dawson Pilot, but the data on laboratory tests are very sparse. They consist of two pages of summary information, without even mentioning if one or more tests were conducted (Application 1611539/2009). It was not mentioned if the **s**taggered **l**ine **d**rive (SLD) or DLD configuration was used in the laboratory test (s). The only information reported was that a spectacular upgrading of the produced oil was obtained: API gravity increased from 8 to 21 API, while oil viscosity decreased 600 times from 20,338 to 33 mPa.s (@20^0C); molecular weight was reduced from 485 to 204; asphaltene content from 35% (for original oil) to 10% (mass%), while Sulfur content was reduced from 6% to 4.7 % wt (for the produced oil).

Typically, under cold production conditions, the oil recovery ranged from 5% to 8%. It seems that there is no gas cap or bottom water in the region. Currently, a true economic recovery process for the Bluesky formation of Peace River deposits does not exist. Cyclic Steam Stimulation (CSS) from horizontal wells

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is being used in the main Peace River deposit with marginally-good economics, but poor ultimate recovery. Fracture Assisted CSS has been tried in North Peace River, but due to thin pays it is marginally uneconomic (David Redford, private communication, 2013).

Taking into account all the above information and the main findings from this study, we express our strong opinion that the conditions in Peace River Area are conducive to a more successful THAI pilot compared to the previous THAI pilots in Athabasca and Kerrobert. However, to enhance effectiveness, specific improvements to the process also need to be implemented.

7.6. A Parallel Between Whitesands THAI Pilot and Kerrobert THAI Project; Similarities and Differences. Main Mechanisms Involved

Due to the very different reservoir conditions and instrumentation/operation differences, formulating a synthesis of similarities and differences is challenging. However, this is attempted in the hope that it helps in the future design of other THAI pilots/projects.

7.6.1. Startup Conditions:

1. The Kerrobert reservoir is at a depth of 760m, compared to 380m for Whitesands.
2. Whitesands is a virgin, bitumen reservoir, with a very thin bottom water layer (less than 10% of the oil layer thickness). Kerrobert is a conventional, very heavy oil reservoir with a thick bottom water zone (30% to 100% of oil layer thickness); in Kerrobert, the influence of bottom water on THAI process is crucial.
3. The Kerrobert THAI project was started as a secondary oil recovery operation, following primary oil recovery of 1.2%, at a water cut of 88%. The Whitesands THAI project was applied as primary recovery.
4. The Kerrobert project started with many old wells; some horizontal wells were located unfavorably vis-à-vis the new THAI wells and, generally, for the THAI process.

7.6.2. Operation

1. In Kerrobert, the vertical air injection wells were perforated in the upper half of the pay zone. In Whitesands they were located in the upper half for air injection and the lower half of the pay zone for steam injection.

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2. The PIHC (Pre-heating Ignition Cycle) was a lot more effective in Whitesands, because the steaming period was around 3 months, compared to less than 2 months in Kerobert. Also, this was due to a smaller depth in Whitesands project.
3. Steam pre-heating of the horizontal section of the producers (in view of putting them into production) was performed in Whitesands, but not in Kerrobert.
4. Steam injection into the horizontal section of the producers was performed for stimulation and/or well protection, for the entire testing period in Whitesands. This did not occur in Kerrobert.
5. A total of 17 observation wells were installed in Whitesands Project. Kerrobert had no observation wells.
6. In the Whitesands project, there was *relatively* good confinement of the individual THAI well pairs. In the Kerrobert project, crossflow occurred between several well pairs, making the project operation more complicated.
7. Anchoring of the ISC front to the toe of the horizontal producer was established for all well pairs in Whitesands, and for 10 out of 12 well pairs in Kerrobert. In Kerrobert, toe-to-heel (TTH) propagation of the combustion front, and also combustion chamber development (without TTH propagation), were observed.
8. The most critical operational problems experienced during the operation of the Whitesands and Kerrobert projects were, respectively, sand influx and excessive production of bottom water. These factors severely limited the air injection rates achieved in the two projects.

7.6.3. Results

1. The peak combustion temperatures recorded in Whitesands oil sand pilot were higher than those recorded in Kerrobert Project; the lower atomic apparent hydrogen/carbon ratio in Whitesands tends to confirm that. Two out of three producers were replaced in Whitesands Pilot, while none was completely damaged in Kerrobert project. In Kerrobert at producer KP2, 14 m casing collapse at the toe region happened due to excessive temperature. However, well has continued to produce, being the best producer of the project.

2. The Whitesands pilot produced more hydrogen and CO than the Kerrobert project; hydrogen - 3.5 % vs. 1.25 %, carbon monoxide ~ 1.3 % vs (< 0.3 %).
3. Oil displacement in the Kerrobert project was significantly more efficient compared to Whitesands, as indicated by the AORs of 2,000-3,000 sm^3/m^3 and 5,000-6,000 sm^3/m^3, respectively.

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It is apparent from the comparison of the two THAI projects, that Kerrobert was more efficient, despite the extra degree of operational complexity and less monitoring and control. Kerrobert also demonstrated better performance than all previous conventional ISC projects, operated similarly, with a thick underlying water layer. *The lesson to be drawn here is that initial oil mobility in the reservoir (before startup) is a vitally important factor affecting the operational efficiency of the THAI recovery process.*

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Being a gravity-stable process, the air injection rate was not the controlling factor. In normal conditions, the maximum value of the air injection rate was limited by the sand influx intensity in the Whitesands pilot, while being limited by bottom water encroachment in the Kerrobert project. Both projects were operated in Direct Line Drive (DLD) configuration (so-called DLD-THAI), and in both of them, it seems that the advancement of the ISC front, i.e., enlargement of the burned volume together with capturing of the mobilized oil are the crucial factors for the efficiency of the process. Enlargement of the burned zone is a direct function of the total fuel deposit (in-situ fuel deposit and potential fuel deposit while oil is flowing via the burned zone); this is so because DLD-THAI is a short-distance process for oil flow, while being a long-distance process for burning/oxidation (O_2 is consumed long before its arrival in the horizontal producer) with thermal cracking of the oil during its approach to the producer. Although the usual fingering from the conventional ISC process may be practically eliminated, for the DLD THAI application (mainly when the start-up procedure is not comprehensive) the wedging of the burned zone in time still has a negative effect on the process.

8. STATUS OF TECHNOLOGY. FIELD TESTING OUTSIDE CANADA

Five more THAI pilots have been conducted outside Canada starting in 2012; as of May 2018, three of them are ongoing, while two are completed. Although one of the authors is knowledgeable about these projects, due to confidentiality obligations, only summary information is included for two of them, while some details are available for the other three pilots, either due to extensive private communications with the operators or due to recent public papers and presentations. Three tests have been conducted in China and two in India.

8.1 THAI pilots in China

All Chinese tests have been carried out using a **d**irect **l**ine **d**rive (DLD) configuration for a pattern made up of one vertical well for air injection and one horizontal producer. In all of them, substantial **c**yclic **s**team **s**timulation (CSS) operations were performed to pre-heat the horizontal section of the horizontal producer. The main properties of oil reservoirs, where the THAI pilots were located, are provided in Table 17.

The first THAI Pilot (Shuguang Pilot, in Liaohe province): It was operated in 2012-2013 by Petrochina in a reservoir with oil viscosity (reservoir conditions) of 30,000cp, having very low mobility at reservoir conditions (Wang Lei, 2016 and Guan Wenlong 2017). Table 17 gives all the details. The pattern was located updip of the reservoir block in which other horizontal wells were used for primary recovery by solution gas drive (including some stimulation by CSS leading to the decrease of reservoir pressure to 3-4 MPa; however, in the THAI pattern no CSS was executed.

Produced gas composition showed that the ignition by steam injection followed by electrical heating was excellent, and a strong ISC front was generated. Before the ignition, for pre-heating, 3,000 m^3 of steam was injected in the vertical well, while 10,000m^3 was injected in the horizontal producer to keep the temperature high.

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Table 17: THAI pilots in China: Main properties of oil reservoirs and information on the set up of the pilots

Current No.	Parameters/Pilots	Shuguang Pilot Wellgroup: S1-38-32	Fengcheng Pilot; well-group: FH003	Fengcheng Pilot; well-group: FH005	Observations
1	Depth, m	875-1015	215-230	215-230	
2	Pay thickness, m	33	9.5	12	
3	Reservoir temperature, Tr, ^{0}C	40	19	19	
4	Oil viscosity (dead oil/live oil), cP	59,834/30,000	One million	One million	Super-heavy oil
5	Layer nature	Sandstone	Sandstone	Sandstone	
6	Porosity , %	26	30	30	
7	Permeability, mD	2,000	5990-9000?	?	
7	Initial oil saturation, %	65	v. high	v.high	
8	Length of HS of HP, m	300	550	470	Pre-heating of HP via CSS
9	WS for HP, if several, m	N/A	70	70	
10	Instrumentation used	-	7 TC	8 TC	
11	Distance VI to toe of HP, m	5m	1.8	3	
12	Thickness of layer, m	33	9.5	12	
12	Location of perforation in VI	Lower half, 5m above HP	Upper half of layer	Upper half of layer	
13	Ignition	SI &EH	SI &EH	SI &EH	Strong ignition
14	Procedures used. Operations during the test	Temperature of HS of HP maintained at 150-200 ^{0}C*			

Legend: WS=Well spacing; VI=Vertical injector; HP=Horizontal producer; HS of HP = Horizontal section of horizontal producer CSS= cyclic steam stimulation; TC = Thermocouples;

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SI &EH = Steam injection and then use of electrical heater for several days

*Steam and water was injected to keep the temperature in that range

During the process, the burning was satisfactory, as indicated by the produced gas analysis:

CO_2 : 12-13%; CO : <0.5%

O_2 : 1-3% (average 1.8%); N_2 : approx. 80%

Hydrocarbon gases: 4-5%; H_2% - not measured

The pilot was operated with extremely high air injection rates (up to 180,000 sm3/day), while the daily oil rate was up to 40 m^3/day; **a**ir-**o**il **r**atio (AOR) fluctuated between 4,000sm^3/m^3 and 9,000 sm^3/m^3. During the test, after 1.5-2 months since ignition, the horizontal producer was frequently stimulated via the CSS operations (with steam injection involving the heating of the whole horizontal section, and preferentially the zone closed to the heel); during these CSS operations, the air injection was not discontinued

In general, gases produced represented 75% of the air injected, so it is possible that some gas went to form a kind of secondary gas cap, but this is not certain. After a CSS operation (in THAI horizontal producer) the produced gas rate was only 15,000sm^3/day, as compared to the injected rate of 180,000sm3/day, clearly showing that a combination of some obstruction developed in the horizontal producer (HP) with the gas migration in a secondary gas cap could have happened.

A maximum temperature of approx. 733 ^{0}C, was recorded at the toe of horizontal producer. Temperature profiles in the HW were not available.

The test was prematurely terminated after 6 months, due to a total blockage of the horizontal producer (Wang Lei, 2016, and private communication with a group of Petrochina specialists visiting Canada in 2014).

Looking in retrospect and correlating the information with the operators' details of the problem, it can be concluded that the blockage consisted of the massive deposition of a coke-like material within the horizontal section of the producer. This confirms a violation of a cardinal principle of THAI operating procedure, namely; that the ISC front should divide the reservoir volume into two regions. One, upstream of the front, which is relatively hot, and the other, downstream of the front, and close to the heel of the HP, which is relatively cold. The worst-case-scenario is when the horizontal producer is heated (on the whole length) to 200-250 C, leading to a massive buildup of coke. As shown elsewhere (Condrachi, 1993), this can easily lead to the building of coke bridge within the borehole

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The cumulative oil produced was approximately 8,000m^3. Oil was produced at an air-oil ratio in the range of 4,000-9,000sm^3/m^3. Water cut decreased from 60% to somewhere in the range of 40%-55% during the THAI test. Oil upgrading was reported to exist, but no quantification was available.

The Fencheng Pilots*:* These tests started in 2014-2015, and have been operated by Petrochina through its Xinjiang Heavy Oil Subsidiary in the Fengcheng, Xinjiang Oil Field, NW China. Table 17 gives all the details for both pilots; this is a shallow reservoir (depth 230-400m) and there is no oil mobility at reservoir conditions.

The most important conclusions from these two tests are related to the fact that in both pilots, the vertical injector was located extremely close to the toe of horizontal producer (3m and less), and the horizontal section of the horizontal producer was intensely heated during the pilot. Also, it is to be noted that the reservoir temperature was low, only 19 ^{0}C. The schematic of the well locations for these pilots is shown in Fig. 69. As shown in this Figure there were 5 THAI patterns, but only FH003 and FH005 have been operated. As the distance between these two operated patterns is 140m, they are considered separate pilots. Actually, they also used different operation protocols and experienced different operation problems; in the FH003 test more intensive pre-heating and slightly higher air injection rates were used. For both pilots, along the horizontal section, 8 thermocouples were installed, with the first 4 ones positioned within 40m from the toe.

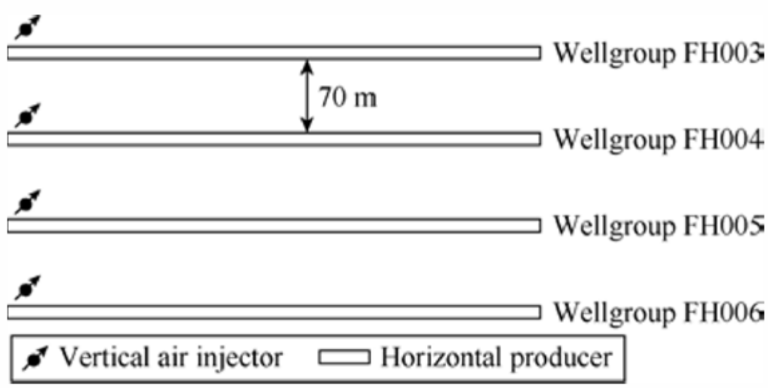

Figure 69: Well locations for the pilots FH003 and FH005

Pilot FH003: This was the first pilot and started in September 2014. The vertical injector was located extremely close to the toe of horizontal producer, just at 1.8 m, and this, together with the intensive heating of vertical injector and horizontal producer (too much steam injected), led to the failure of the test. Although ignition was successful [the initial air injection rate (for ignition) was 4,200sm^3/day], after

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approx. two months, due to intensive channeling, oxygen break-through in the production well occurred (O_2%.>5%), and the test was prematurely finished. No adjustment procedures worked once the oxygen break-through happened; the decrease of oxygen percentage in the effluent gases was not possible.

However, the test furnished very interesting information for the ignition operation and immediately after. In Figure 70a the variation in time of temperature for different monitoring points along the horizontal section of the producer is shown, while in Figure 70b the air injection and production rates are displayed. The moment of ignition achievement and anchoring of the in-situ combustion to the toe can be easily established; by October 15 the temperature of the toe region (first 3 thermocouples) was higher than 400 ^{0}C. The advancement of the ISC front along the first portion of horizontal section of the producer is apparent (Fig. 70a). While air injection rate was maintained at about 4,300sm^3/day, a large variation of daily oil production occurred, with an average of 11m^3/day. Air-oil ratio was around 1929 m^3/m^3.

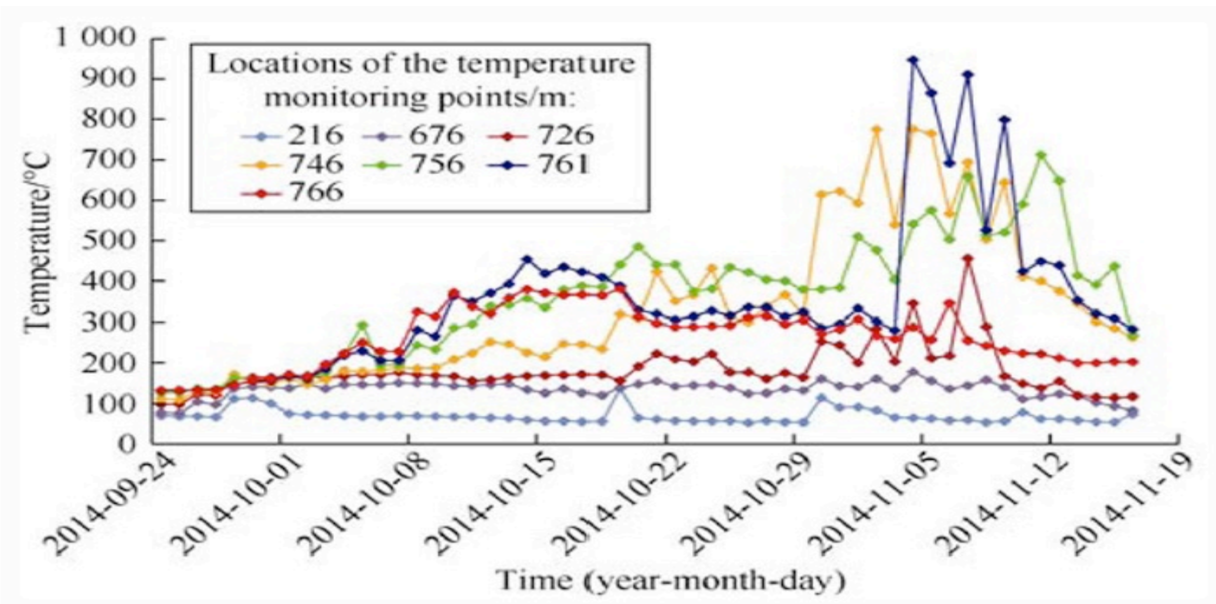

Figure 70a: The temperature variation in time along the horizontal section of producer in FH003 pilot

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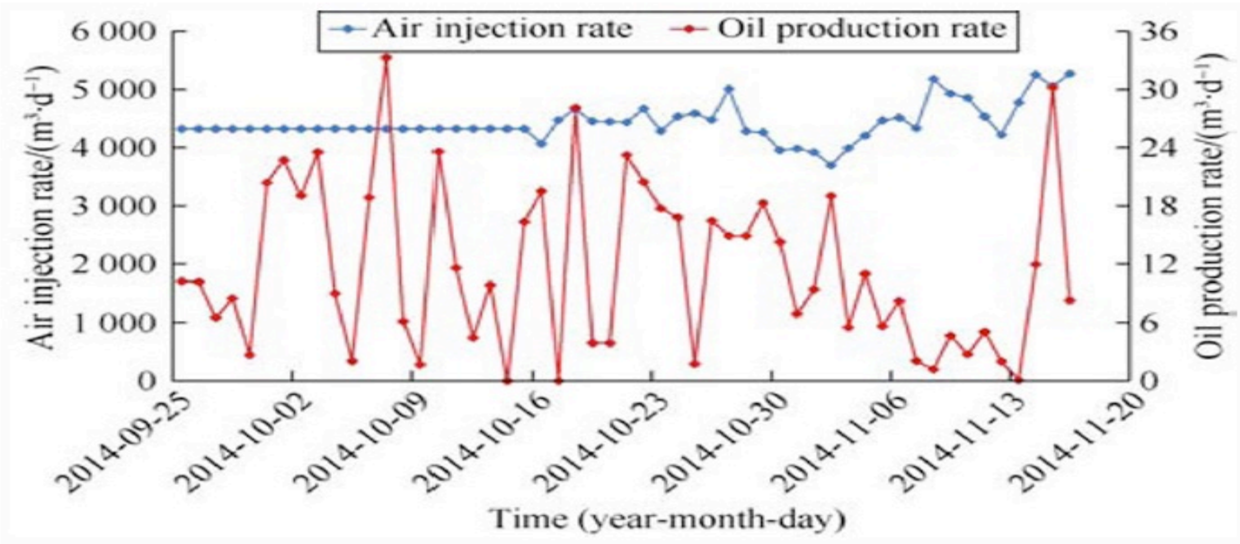

Figure 70b: The air injection and production rate variation for the FH003 THAI Pilot

Pilot FH005: This was the second pilot and started in October 2015. For this pilot, some details were presented in a public EOR Forum (Guan, 2017-June) and afterwards published (Guan, 2017-October). The length of the horizontal section of the horizontal producer was 470m.

The ignition was conducted by steam injection in the vertical injector, followed by the use of an electrical heater. The horizontal producer was also pre-heated via a CSS operation; however, compared to FH003, less steam was injected in these operations. Even in this situation, the temperature along the horizontal section of the producer was still raised up to approx. 200 ^{0}C. Unlike FH003 test, the initial air injection rate (for ignition) was lower (only 3,000sm3/day); a stronger electrical heater was used for ignition.

The results of temperature recording (temperature variation in time) during the first year (November 2015-December 2016) are presented in Figure 771a. The anchoring of the ISC front to the horizontal section of the producer took place after 37 days (1.25 months), and the peak temperature of 300 ^{0}C (and then 400 ^{0}C) was recorded 10m from the toe (at 677m measured distance). This was due to an existence of an inclined fracture linking the vertical injector to the horizontal section of the producer; even the steam, injected initially, appeared in the producer within 24 hours. As seen in Fig. 71a, this fracture constituted the main flowing pathway, such that the 10m length at the toe was short-circuited; the peak temperature at 677m was recorded twice within the first 3 months, with the last value higher than 600 ^{0}C. The advancement of the in-situ combustion (ISC) front along the horizontal section of the producer could be traced on the portion 677m-657m, as the peak temperature (mentioned previously) moved from 677m (to 667m) and then to 657m within 10 months; The average velocity of the ISC front was around 7 cm/day.

Due to the intensive pre-heating of the producer (via CSS), the temperature along its horizontal section was maintained all the time between 150 ^{0}C and 220 ^{0}C. This procedure made it more challenging to visualize the advancement of the ISC front along the horizontal section via the contrast of temperature between toe regions (where the ISC front was initialized) and heel regions. Only in the last period (October-November 2016), the temperature contrast became discernible. As of October 2017, the pilot is on-going.

It was reported that the produced gas contained up to 3% hydrogen (H_2). The operators discovered an interesting phenomenon: just before the high-temperature spike occurred [at the point 677m (measured depth), where the fracture intercepted the horizontal section of producer], the H_2 content increased significantly. So, it was proposed to use the hydrogen content spikes as signals of combustion front break-through or local over-heating (Guan, 2017); a coiled tubing was installed (and used) in the

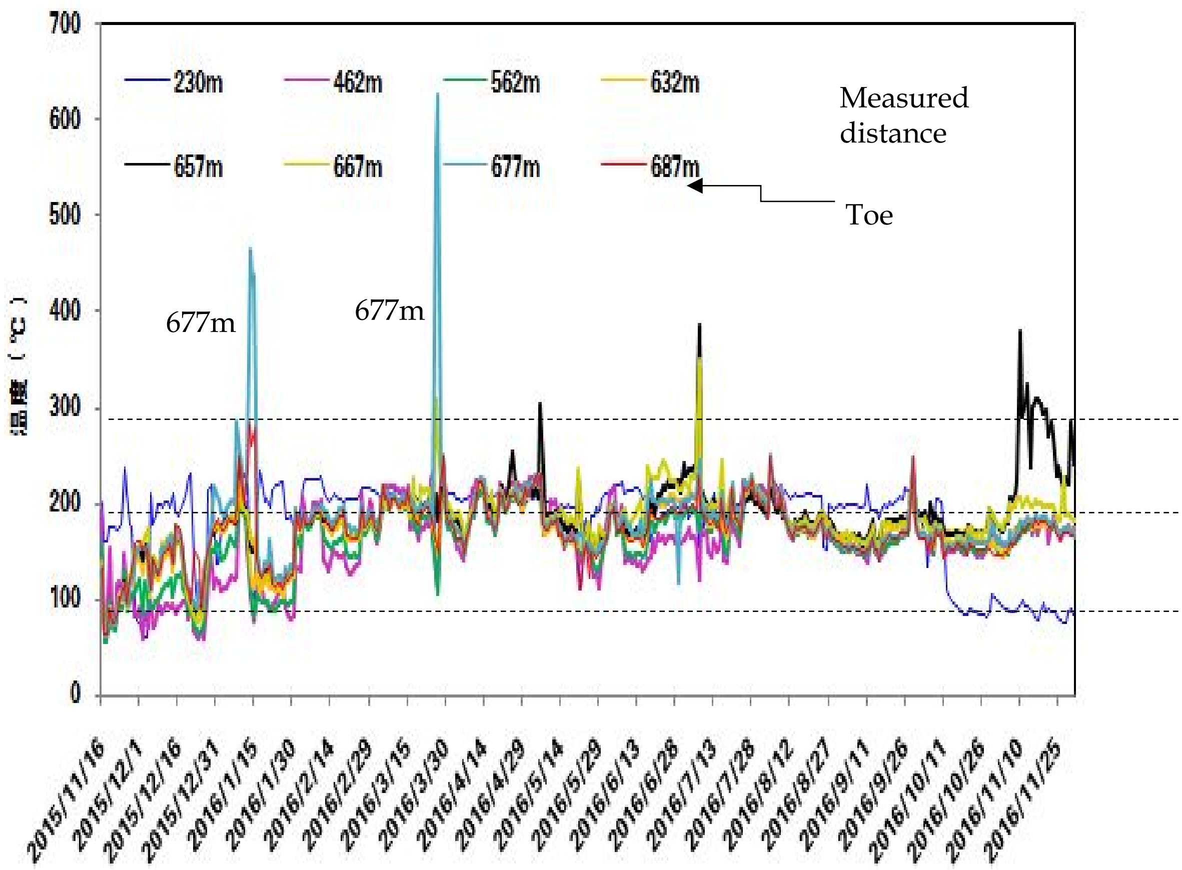

Figure 71a: The temperature variation in time along the horizontal section of the producer in FH005 pilot (Guan, 2017)

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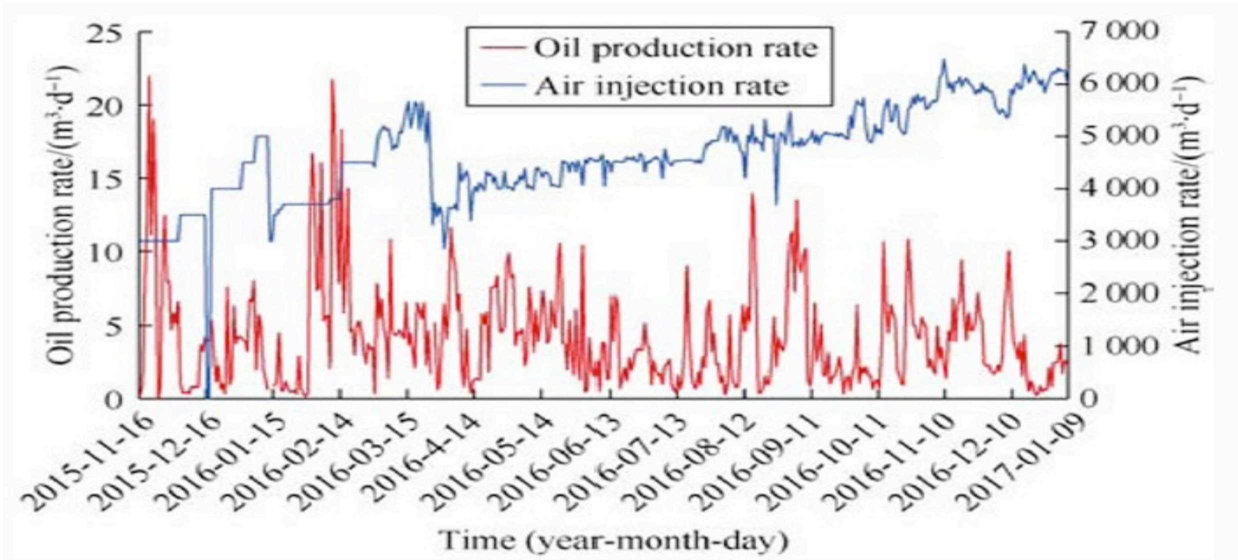

Figure 71b: The air injection and production rate variation for the FH005 THAI Pilot

horizontal section of the producer in order to allow cool water injection to suppress excessively high temperatures. As seen in Fig. 72, after the first temperature peak, the water injection succeeded to temporarily decrease the temperature as low as 100^0C, while after the second temperature peak similar operation, this did not happen.

Looking at Fig. 71a, it is believed that the pre-heating of the horizontal section of the producer was too intensive and this complicated the management of the process and its interpretation via the temperature recordings along the horizontal section. Also, it is believed that this exaggerated pre-heating had the effect of delaying the achievement of a forward-tilting ISC front (or even its suppression), hence creating difficulty in increasing oil production when ramping the air injection.

Oil production and air injection are provided in Fig. 71b. It shows that air injection had a slow tendency to increase (3,000 to 6,000sm^3/day), while the daily oil production was 7-8m^3/day. For the first 400 days of operation, the air-oil ratio (AOR) was 1032 sm^3/m^3. Therefore, the pilot displayed a good AOR, but the oil production was low, as the pilot was operated with very low air injection rates. The primary task is to check if the oil production is increasing as the air injection rate will be ramped to higher values. Theoretical calculations showed that a maximum daily oil rate of 15-22 m^3/day was possible, with some doubts that this can be accomplished given the lack of forward-tilting of the ISC front, as mentioned previously.

Remarks concerning the THAI pilots in China:

Shuguang Pilot: In this test the air injection rate was excessively high, and too frequent CSS operations were executed in the horizontal producer during THAI operation. For this reason, the entire horizontal

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section of the horizontal producer was unintentionally converted into a coking reactor. The coke deposition in the horizontal producer created a total blockage of the well, leading to a cessation of oil production and abandonment of the Pilot. This was further aggravated by the fact that the vertical injector was perforated not in the half upper part of layer but in the lower half part of the layer; this caused the formation of a back-tilting ISC front, which had a low efficiency, being associated with a channelling type of displacement.

Fengcheng Pilots: In this pilots, the amount of steam injected in the horizontal producer was too high, although it was slightly reduced in the second pilot. In practice, the amount of steaming of the horizontal well section *should be restricted to a minimum, just sufficient to allow the heavy oil to flow smoothly along the well*. This statement is supported by Fig. 71a, which shows temperature at the heel constantly at 200 ^{0}C, for almost one year. Fortunately, since the air injection rate was very low, coke deposition in the horizontal well was low, and the total blockage did not happen as in Shuguang pilot.

In both pilots the produced oil was upgraded. As shown in Table 18, the saturated hydrocarbons increased, while the amounts of aromatic and resin slightly decreased; the decrease of asphaltene, however, is less than expected. This is shown by the FH005 pilot, which has more consistent data; for FH003 pilot, the results refer to the first 2 months after ignition, therefore in a relatively non-stabilized period.

Table 18:SARA analysis of oil in the Fengcheng Pilots

Wellgroup	Status	Saturated/ %	Aromatic/ %	Resin/ %	Asphal./ %
FH003	Prior ignition	48.67	16.56	29.13	5.63
	Post ignition	50.87	19.36	24.28	5.49
FH005	Prior ignition	43.10	20.88	33.33	2.69
	Post ignition	50.24	18.48	28.71	2.57

8.2 THAI Pilots in India (Balol and Lanwa)

The first THAI pilot was initiated by Oil and Natural Gas Corporation (ONGC) India, at the beginning of December 2016. THAI process is tested in Balol oil reservoir, which has relatively good oil mobility (around 1,000cp oil viscosity). The reservoir already has a commercial conventional ISC process

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operating since 1991; in 1991, the oil recovery was around 2%, at an average water cut of 60%; the average daily oil production per well was 5-6 m^3/day. The primary recovery mechanism has been the edge water drive with a strong aquifer, which has maintained the reservoir pressure at about 10MPa, i.e above the bubble point pressure (Roychaudhury 1995, Chattopadhyay 2003). Table 19 provides the average values for the main properties of oil and rock. More details about the Balol reservoir and the conventional commercial ISC process can be found elsewhere (Roychaudhury 1995, Chattopadhyay 2003 and 2004, and Turta 2007).

The first THAI pilot is grafted on the existing large-scale ISC process, but it is located in a region (North Balol) in which active ISC was suspended for 3 years. The pilot is using a **s**taggered **l**ine **d**rive (SLD) configuration, with two updip air injectors and one to-up horizontal producer in-between; other details of the pilot (such as length of the horizontal section of the horizontal well, well spacing, size of start-up region, vertical well perforation, instrumentation, etc) are provided in Appendix H, where the paper published by operators (Pareek ,2015) is integrally duplicated. Figure 74a-b shows both the map of the Balol field, the location of the first THAI pilot, including the start-up region size, perforation of vertical injectors, and the placement of toe-up horizontal section of producer above shale intercalation.

The context of THAI testing should be linked to the fact that going from South to North (Fig. 72) the effective thickness of the layer increases from 6-8 m to 20-22m, while the oil viscosity also increases from 150-400cP to around 1000cP. This causes a pronounced decrease of efficiency of ISC application marked by a pronounced decrease of oil rates and ultimate oil recovery (UOR) by ISC; UOR has attained approximately 50% in South Block, while it is at 7% for the North Block. Repeated trials to remedy that situation by in-fill drilling of more vertical producers or increase of air injection rates failed to bring any positive results. However, as it will be seen, the success of SLD THAI opened up a new way of development of thick and heavy blocks in Balol.

The first results are very encouraging – in fact, the performance far exceeds that of any other THAI pilots in Canada and China. As of June 2019, the pilot is on-going. Piloting in this block has been extended; a second pattern, adjacent to the current one, was started in August 2017, and three more patterns were initiated towards the end of 2017; their locations are provided in Figure 75a???. All of them use an irregular SLD configuration and together are considered a semi-commercial operation. As seen in Fig. 75b, for 5 toe-up horizontal producers, and with air injection in 7 new air injection wells, the oil production of the block increased from an average of 30 m3/day (before the suspension of conventional ISC operations using 20 vertical producers) to approximately 60 m3/day; the average oil production per

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well increased 3-5 fold. Initially, the water cut was low (40-60%) and slowly increased towards 80%. The initial oil rate of an up-toe horizontal producer was in the range of 20-30m3/day and slowly stabilized at 15-20m3/day. Many lessons were learned from this first testing of the SLD configuration; a new feature of it was the recording of a very suppressed (low) gas-oil ratio values for all the up toe horizontal producers. As an average, the air-oil ratio (AOR) was around 1000 sm3/m3, being by far more favorable compared to the value for conventional ISC applied in this field, which was around 3000sm3/m3.

The successful THAI testing fully confirmed the ability of THAI process to be used for Balol North regions, with higher pay thickness (and higher oil viscosity), where conventional ISC has been inefficient.

It is to be mentioned that placing the well close to the bottom of pay (within 1-2m) and against the dip was a challenging task due to variation in local dip. Also, the placement of screen & gravel packing up to the toe was a challenge (Rakundla, 2019)

A second pilot on the second heavy oil reservoir (Lanwa reservoir, located North of Balol) was initiated towards the end of 2017 (Fig. 72); it is still ongoing. The properties of Lanwa reservoir are similar to those of Balol, with slightly higher oil viscosity (Table 19).

Table 19 : THAI pilot in India: Main properties of Balol oil reservoir (Chattopadhyay 2004 and Turta 2007)

Current No.	Parameters/Pilots	Balol Pilot	Observations
1	Depth, m	1000	
2	Pay thickness, m	3-18	
3	Formation dip, degrees	4-7	Monocline
4	Reservoir temperature, Tr, ^{0}C	70	
5	Dead oil density, kg/m3	0.962	
4	Oil viscosity, cp	100-1000	
6	Layer nature	sandstone	With thin carbon intercalations
7	Porosity , %	28	

8	Permeability, D	3-8	
9	Connate oil saturation, %	30	
10	Reservoir pressure, MPa	10	V. strong aquifer

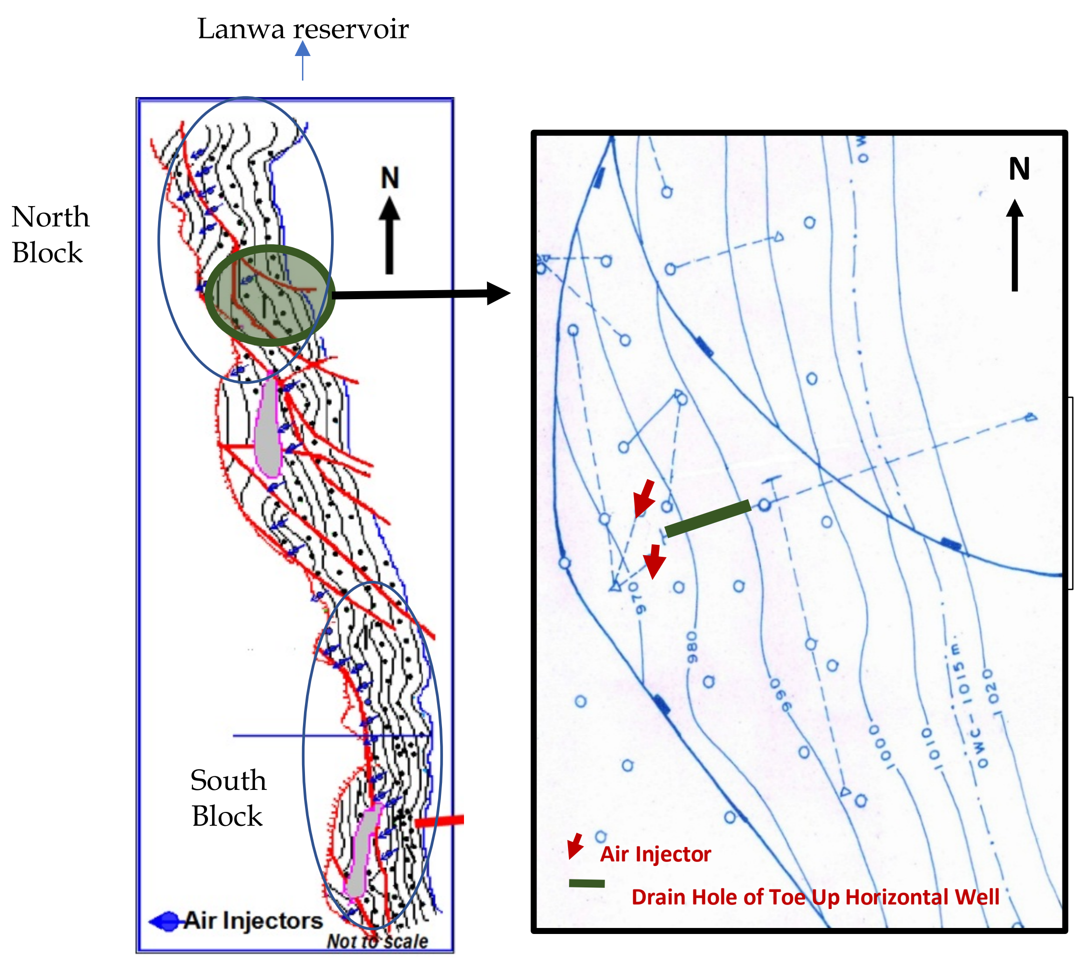


Figure 72: Balol Oilfield, the location of the first THAI pilot and some details of its staggered line drive (SLD) configuration (two vertical air injection wells and one toe-up horizontal producer)

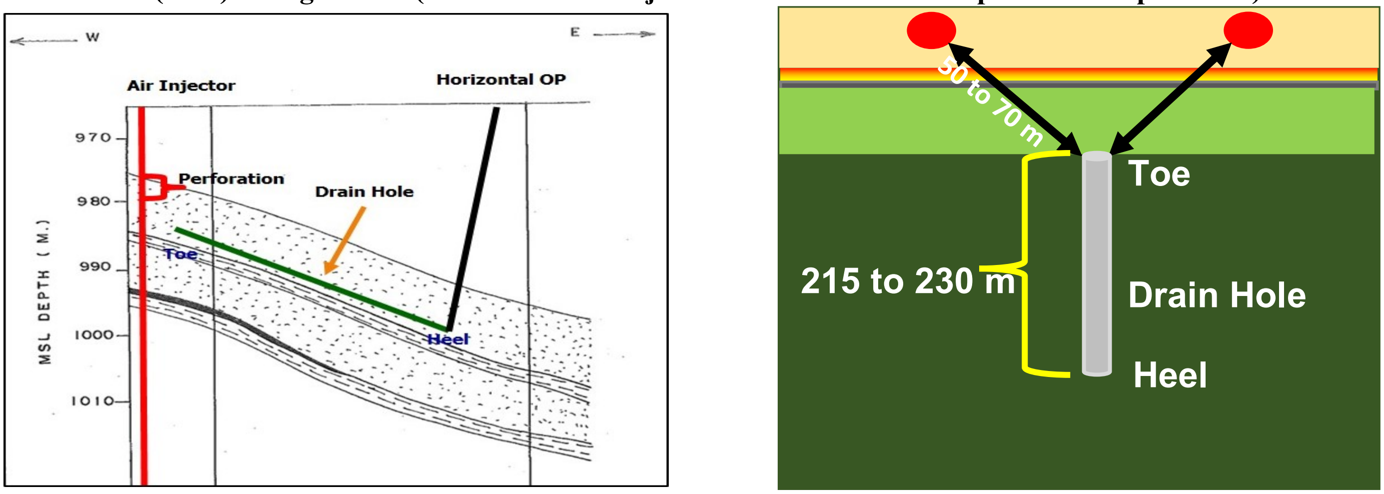
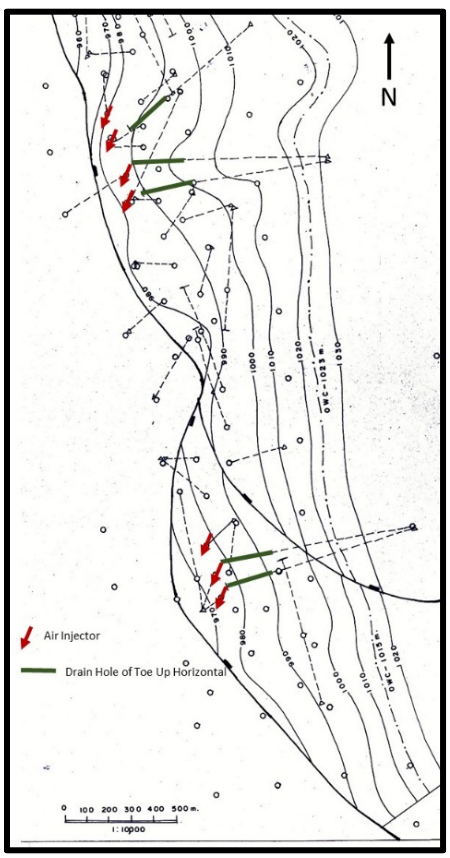
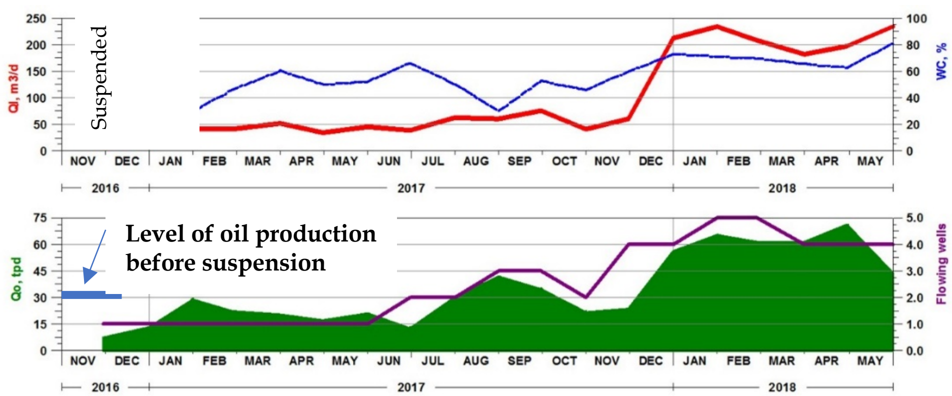


Figure 73: THAI pilot in Balol Oilfield. Details of the SLD configuration including the start-up region size, perforation of vertical injectors and the placement of toe-up horizontal section of producer above shale intercalation





(b)

Legend: Qo-oil rate; Ql-total rate (oil & water); WC%-water cut; Flowing wells-number of producing wells

Fig. 74: Location of the THAI patterns in the North Block of Balol Field (a) and the performance of this Block due to THAI application.

(a)

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8.3 Final Remarks on the THAI Process. Five Key-conditions for a Correct THAI Application

While the cumulative oil produced from the Chinese experiments is not available, it is worth recording that THAI process has produced 92,000m^3 (579,000 bbls) of upgraded oil from Athabasca and from Kerrobert,extra-heavy oil conventional reservoirs, in Canada.

Therefore, so far, over a half million barrels of crude oil was upgraded within the reservoir during its displacement and recovery by THAI process. It can be concluded that from the point of view of underground upgrading, the THAI process is FULLY field validated.

In these applications, the THAI process was applied in a direct line drive (DLD) configuration, i.e. the DLD-THAI process. However, the original patent described a second version of the process, namely, staggered line drive (SLD) i.e., SLD-THAI, which started only recently to be tested in India. In the next chapter, details on the similarities and differences between these two processes are discussed, and it is shown that the SLD-THAI process would provide comparatively better technical and economic results.

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For both SLD-THAI and DLD-THAI process, it is imperative to respect the following five key-conditions rigorously:

1. A horizontal production well having its horizontal section located at the bottom of the layer to collect the produced oil
2. A vertical air injector (s) located within the drainage area of the toe of the horizontal producer.
3. Anchoring of the ISC front to the toe region of the corresponding horizontal producer, and then, preserving the stable anchoring
4. Existence of self-healing features during the advancement of the displacement front (along the horizontal section of the horizontal producer); local plugging being the one and controlled gravity segregation being the second one
5. Existence of *a **hot region** of high fluid mobility behind the displacement front and a **relatively low temperature region** of low fluid mobility* ahead of displacement front (along or parallel to the horizontal section of producer), with a tilting forward of the separation between these two regions.

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These key-conditions resulted from in-depth processing of the information produced by the field, laboratory, and simulation for more than 20 years. Violation of any of these critical conditions will result in failure or substantial decrease of performance, as it has been confirmed by some field tests.

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For potential future, new THAI or quasi-THAI applications, in the 5 screening criteria described, the horizontal producer should be replaced with a high permeability pathway at the bottom of the layer or "simple wormhole", or a disk-fracture to collect the produced oil.

9. DLD-THAI AND SLD-THAI PROCESSES: DIFFERENCES AND SIMILARITIES; PRELIMINARY SCREENING CRITERIA

9.1 DLD-THAI versus SLD-THAI; Main Differences

Comparison between the performance of field tests and laboratory tests and simulation results revealed important clues to differences between the DLD-THAI process and the SLD-THAI process. Initially, from the laboratory 3-D test results, these differences were not apparent due to a very small size of the 3-D model. However, the field pilots help clarify a few aspects, although they were not designed to do that. Although all field tests were theoretically conducted in a DLD configuration, in practice, not all THAI pairs were in a perfect DLD configuration; there was some lateral-off distance; this distance was up to 15-17m in the Whitesands pilot and the range of 2-7 (8) m??? in the Kerrobert Project. Also, in two cases (case of KA12 and KA4 Kerrobert supplying KP9 and KP10 and KP7, respectively), in a non-intentional way, some almost classic SLD configurations developed, This led to some preliminary conclusions regarding the potential operational problems and about overall performance.

Comparative field simulations for DLD and SLD configurations have been beneficial, and some significant results are analyzed in this subchapter, while other details will be provided later on. Figure 75 shows the well arrangements used in this simulation for the case of an immobile oil (Athabasca bitumen);

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the same Athabasca oil was also used in the comparative simulations to be analyzed further on, in Subchapter 10.1.4. The field simulation has been done for a first part of the process, i.e. for the propagation of the ISC front for 150m, such that for a horizontal section of 400-500m, some extrapolation is necessary. Therefore, the system simulated is 150m – long, 100m -wide and 24m – high (the pay thickness), and it is identical for both DLD and SLD configurations. The simulation has been done for 2.3 years and a cumulative of air injected of 14 millions of sm^3, at a constant rate of 20,000 sm^3/day.

It can be seen that in SLD configuration, the vertical injectors (VI) are located slightly off from the lateral boundary of the pilot, but this does not invalidate the results. The same air injection rate was used in both situations, but in SLD case, it was split equally between the two injectors.

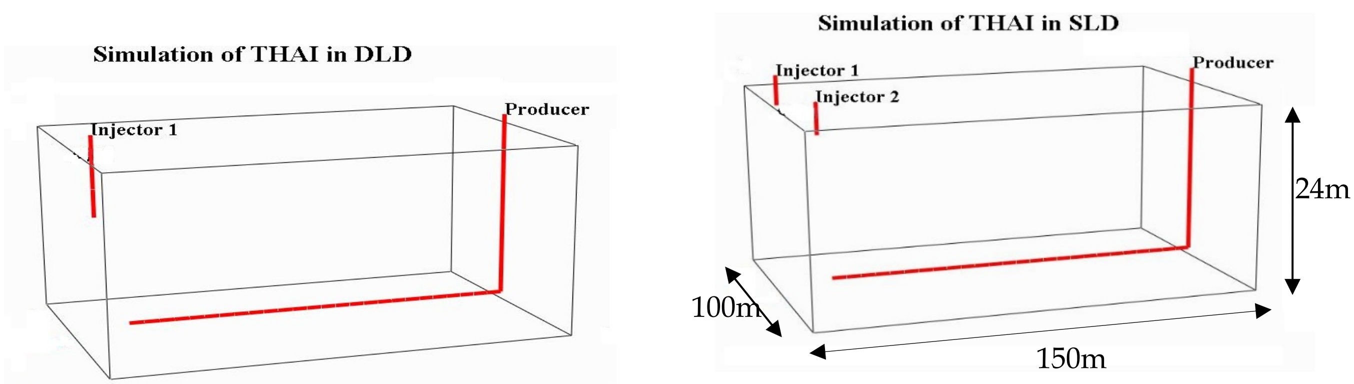

Figure 75: The well arrangements used in the comparative simulation of DLD and SLD THAI process (Ado, 2017)

100m

For the system described in Figure 75, Figures 76a, 76b and 77 show a 3-D distribution of oxygen (O_2) and the temperature (T) distribution (3-D distribution and in the mid-vertical plane) after 1.3 and 2.3 years of ISC. As seen from these figures, the most important differences between the two processes are:

- Only one advanced leading edge of the O_2 existed in the DLD (just above the horizontal section of the producer), while in the SLD there are three different advancing (leading) edges, two of them being on the laterals. For SLD simulation this feature would be a lot more obvious if finer

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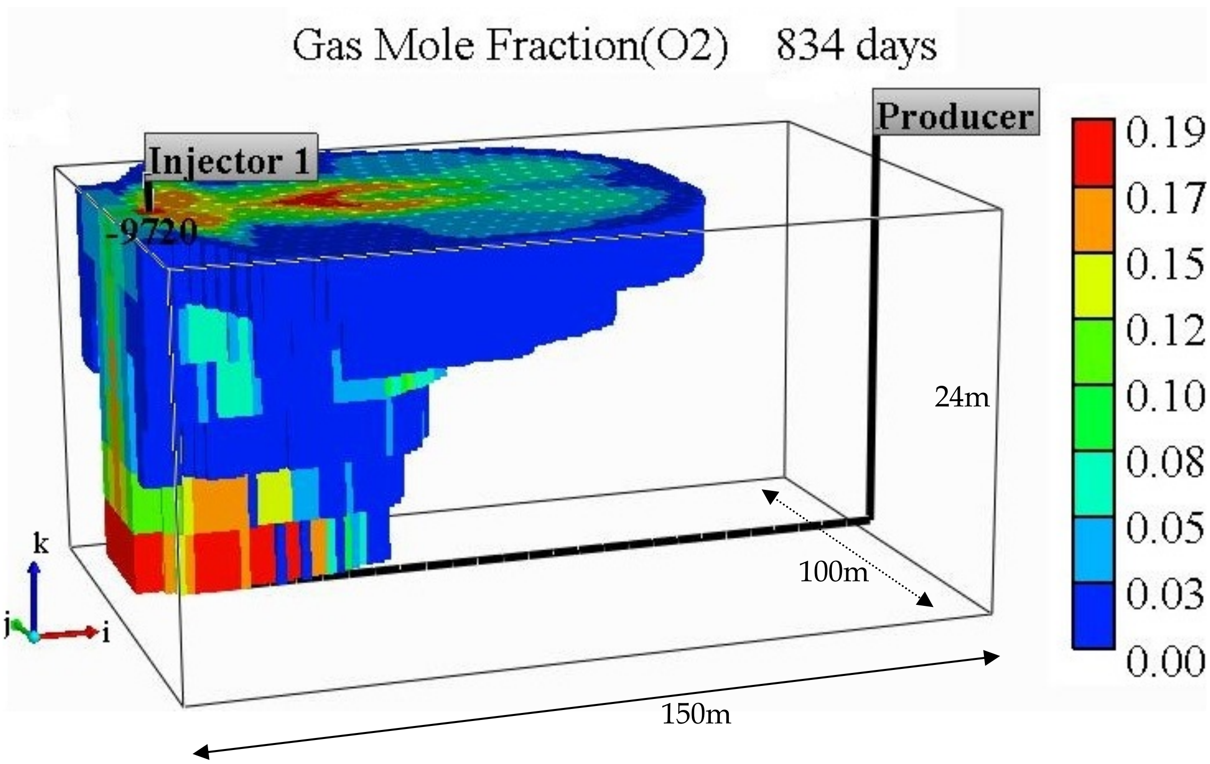
grid blocks had been used around the ISC front; smearing of the contour of ISC front occurred when using big grid blocks.

- No oil was produced from behind the ISC front in the DLD configuration, while there was production from this region during the SLD THAI in the first period of the process (Figure 77).



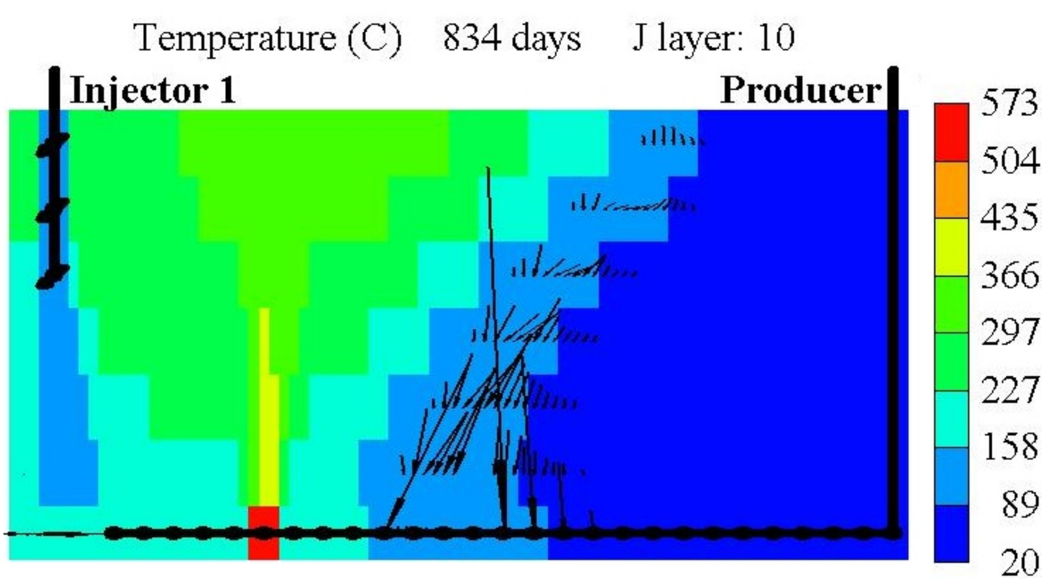


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Figure 76a : DLD-THAI process. Distribution of oxygen (O_2) and temperature (T) in the mid-vertical plane after 2.3 years of ISC. 3-D O_2 distribution and isothermal contours are shown [M. Ado, PhD work result, University of Nottingham, UK. (Private Communication, March 2016) and Ado, 2017]. Note: Arrows show the velocity vectors for oil flow.

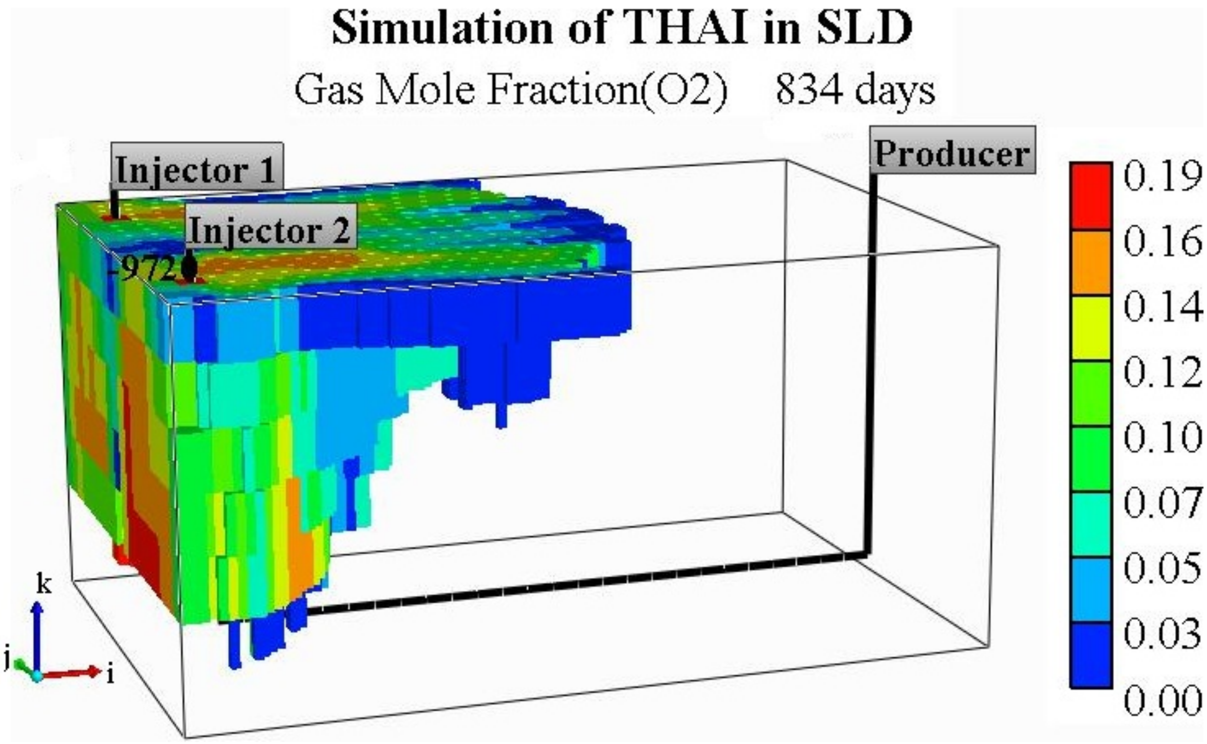

Figure 76 b: SLD-THAI process. Distribution of oxygen (O2) after 2.3 years of ISC. 3-D O_2 distribution is shown [M. Ado, PhD work result, University of Nottingham, UK. (Private Communication, March 2016) and Ado, 2017]

Analyzing oxygen and temperature distributions from Fig. 75, 76 and 77 it can be seen that after 2.3 years of operation in SLD configuration, the ISC front *did not intercept the horizontal section of the horizontal producer*, yet; in DLD configuration this interception occurs from the very beginning, ie., when the ISC front is anchored to the toe (after traversing the small start-up region between the show of vertical injector and the toe of horizontal producer). This confers a considerably longer resistance of horizontal section of the producers to the high peak temperatures experienced.

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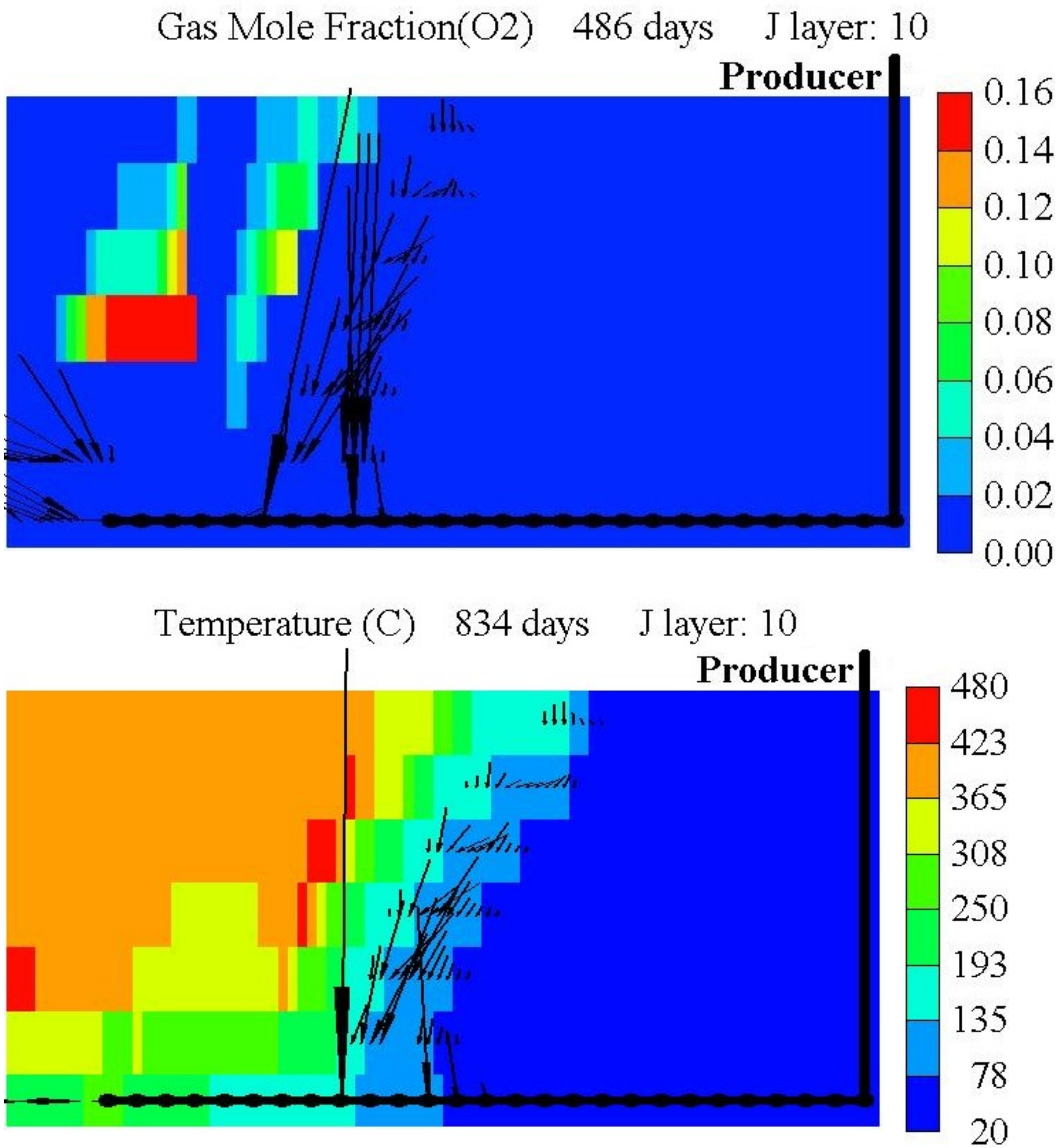

Figure 77: SLD-THAI process. O2 distribution after 1.3 years and temperature (T) distribution after 2.3 years in the mid-vertical plane of layer [M. Ado, PhD work result, University of Nottingham, UK., Ado, 2017]. Note: Arrows show the velocity vectors for oil flow. Some oil flow behind the ISC is shown.

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In fact, the volumetric sweep of the SLD is higher, as the oil recovery is higher in this system. Figure 78 shows this comparison both in term of oil production and oil recovery variation; after 2.3 years of equivalent air injection, the oil recovery is 4%OOIP higher in the SLD system.

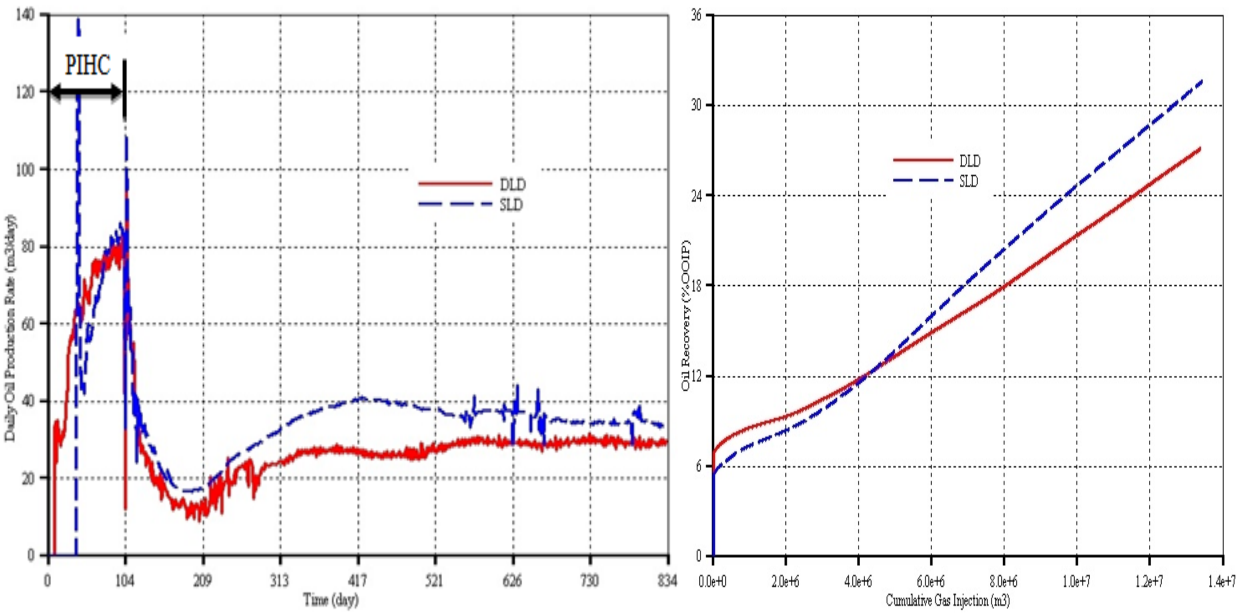

Figure 78: Oil production variation and oil recovery for the first period of 2.3 years of DLD and SLD THAI process (Ado, 2017). PIHC=Pre-ignition heating cycle

A complete summary of the differences between Direct Line Drive (DLD) THAI process and Staggered Line Drive (DLD) THAI process is provided in Table 20, and this summary refers only to the normal application of the THAI process; in case of THAI application in the presence of bottom water, several differences may not be applicable. These differences are based either on simulation or on some field and laboratory test results. From this table, it is seen that the SLD-THAI process has multiple advantages over DLD-THAI, and generally, it should be the process of choice.

Table 20 : Summary of the main differences between DLD-THAI process and SLD THAI process

1. For SLD THAI process for a very long period after ignition, the peak temperatures of the in-situ combustion (ISC) front are recorded far away from the horizontal section (HS) of horizontal producer (HP). The maximum temperatures recorded by the horizontal section of the producer

are always lower in SLD THAI compared with DLD THAI. The risk of damaging the horizontal producer is significantly lower.

2. There is in-situ upgrading in both configurations, but it may be slightly lower in SLD, as there is slightly more mixing with the original (un-upgraded) oil.

3. The "local coke plugging" of the horizontal section of the producer represents a self-healing feature of THAI process. It may be more developed in the DLD configuration

4. There may be less risk of coke blocking of the horizontal section of producer when using the SLD configuration.

5. The lateral development of the burnt-out zone during THAI is greater in the SLD configuration, as the ISC front has an initial higher velocity far from the vertical plane (passing through the HP). Wedging effect is less pronounced and starts later on, compared with the DLD configuration

6. There is less risk of sand influx with the SLD configuration, as the pressure gradients are smaller.

7. Generally, the SLD configuration is associated with a broader oil displacement front allowing higher air injection rates and higher oil production rates. Another reason is that because, for a period of time, production of oil occurs through an extended portion of the horizontal section; this is because of the existence of two mobile oil zones: one ahead of the ISC front and a second one behind this, up to the toe of horizontal producer

8. In the SLD configuration, the completion of the vertical air injections is less critical than for DLD, where it has to be in the upper half of the pay zone. Actually, for SLD configuration, when possible, it is recommended to be at the lower half of the pay or for the entire pay zone, pending on the heterogeneity of the pay zone.

9. For reservoirs containing immobile oil, the communication phase is relatively more complex for the SLD configuration as the distances are longer; first, the whole start-up region has to be heated to 100-120 ^{0}C and then a linear ISC front has to be built along the line uniting the vertical injectors.

10. The application of the SLD THAI is a lot easier for the reservoirs containing oil with some mobility at reservoir conditions (viscosity up to 2,000-3,000cp). In this case, the communication phase (as per previous Point 8) can be eliminated. However, for better results, the mild heating of the start-up region is still recommended.

11. SLD THAI has higher oil production and higher oil recoveries

12. The application of wet ISC may be more favorable in SLD THAI compared with DLD THAI. The risk of water channeling is lower in SLD THAI. Moreover, some more oil may be displaced from the layers located close to the bottom of reservoir. The air-oil ratio may be slightly reduced in cases where wet ISC application is favorable.

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9.2 Preliminary Screening Criteria.

Here, only one set of criteria - for DLD-THAI - is provided as these criteria are preliminary; additional comments on differences in possible applications are made at the end of this Report.

Table 21a: Preliminary screening criteria for THAI application:

- ❑ *No extensive bottom water (preferably less than 40%-50% thickness of the oil zone)*
- ❑ *Net pay thickness >8m*
- ❑ *Depth > 150m*
- ❑ *Permeability > 200 mD*
- ❑ *Porosity, fraction >0. 2*
- ❑ *Water cut < 85%*
- ❑ **Oil viscosity > 200-300 mPa s***
- ❑ **Oil content (porosity * oil saturation) >0.065**

*In case of tertiary application, after a steam-injection based process or in a very deep, heavy oil reservoir (with high temperature) this value may be lower; as low as 70 mPa s.

As these criteria apply "ad litteram" for DLD-THAI process, in case of SLD-THAI process the following two modifications may be necessary:

- ❑ *Net pay thickness > 6m*
- ❑ *Permeability > 400-500 mD*

Therefore, the permeability should be slightly higher in SLD-THAI, as the distances for oil flow are more extended. These criteria may be slightly modified to account for the hydrogen generation in case this is regarded as a secondary task of the process, and there is interest in hydrogen production.

Based on the THAI field test experience, so far, involving 7 pilots and one semi-commercial operation (Kerrobert), from the more promising to lower potential, the conditions of THAI application to heavy oil reservoirs are:

1. In an area where a conventional ISC operation took place, and it was suspended 2-6 years ago; an oil recovery factor less than 35-40 % is assumed for that area
2. Grafted within a current conventional ISC commercial operation
3. An oil reservoir exploited in a solution gas drive regime (without gas cap and bottom water)
4. A reservoir with a tiny gas cap

In the first two situations, not only that the best results are anticipated, but also it is the easiest and the least expensive application, as the hot communication and ignition phases can be skipped/avoided.

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For CAPRI, the screening criteria are more demanding; actually, in order to apply CAPRI the reservoir needs a-priori to be entirely acceptable for THAI application. The criteria presented here are very preliminary as they are based only on simulation and laboratory test results; the limited field testing contributed very little. They, instead, express the conditions under which the application of CAPRI is worthwhile, such as necessities for oil viscosity reduction by upgrading and in-situ removal of refineries' pollutants (sulfur, nitrogen, heavy metals).

Table 21b: Preliminary screening criteria for catalytic THAI (CAPRI) field testing:

- ❑ *No substantial bottom water (preferably less than 10%-20% thickness of the oil zone)*
  - ❑ *Net pay thickness >8m*
  - ❑ *Depth > 150m*
  - ❑ *Permeability > 1000 mD*
  - ❑ *Porosity, fraction > 25%*
  - ❑ *Water cut < 60%*
  - ❑ **Oil viscosity > 10,000 mPa s**
  - ❑ **Oil content > 0.125 (non-tertiary)**
  - ❑ **Sulfur content of the oil > 3 (wt%)**
  - ❑ **Clay content > 3%, but < 20%**

The criteria proposed for THAI use, as a starting point, the corresponding criteria proposed for the conventional ISC (Turta, 1998) and have to be obeyed "ad literam" during ISC front propagation through the start-up region. However, compared with conventional ISC process, the THAI and CAPRI processes are more demanding in the application, and the proposed modifications reflect their specificities. As one can see from these criteria, CAPRI should be applied for much higher oil viscosities and oil saturations. CAPRI aims to have oil at surface, which for Refinery crude intake is considered “partially upgraded," i.e. it is ready for pipelining without diluents but still needs some quality improvement in upgraders/refineries, by hydrogenation or other equivalent procedures.

Advantages of THAI process for heavy oil/bitumen are:

- Field unitization is not always a MUST as it is in the case of conventional line drive ISC projects
- Very diverse areas of application: heavy oil reservoirs at greater depths and heavy oil reservoirs with relatively small gas caps can also be considered

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- Heterogeneity, such as that related to normal stratification does not rule out the application
- The production of hydrogen is a consistent feature of the process and, in some cases may be exploited.
- The production of additional methane and hydrocarbon-gases (formed by coke gasification) may be a feature of some modified processes, and in some cases, may be exploited.
- Generally, requires only very limited additional laboratory testing to support a field project design; standard parameters needed to be determined include fuel deposition per m^3 of rock and air consumption; just a few 3-D tests are highly recommended (mainly to determine upgrading potential and in-situ removal potential of pollutants (sulfur, nitrogen heavy metals).

9.3 Limitations of THAI Process and Peculiarities in Application

The main limitations of THAI (including CAPRI processes) for heavy oil applications are:

- In some cases, intensive heterogeneity such as those associated with "worm-holed reservoirs" may be problematic. Therefore, for applying THAI process as a follow up to cold heavy oil production with sands (CHOPS), one needs to study in-depth the intensity and 'anatomy" of the worm-holing process, in order to have some clues on their impact on the control of the ISC front propagation.
- The existence of old horizontal wells within the THAI project area could constitute a discouragement if they were drilled for primary oil recovery purposes in a bottom water situation, with their horizontal sections located towards the top of the pay zone. The wells to be used in the THAI project should be located and operated in such a way that the old horizontal wells do not hamper the application.
- *Applicability in the presence of thick bottom water has not been fully proven yet.* However, in the presence of a weak, relatively thin bottom water [thickness of bottom water zone/thickness of oil zone (W/O), lower than 0.3-0.5] the application could be feasible, although the efficiency will be lower (Turta, 2009). The Kerrobert THAI *pilot* (with an average W/O thickness ratio of 0.6) provided hands-on experience for this situation; its performance was better than the best conventional ISC applications in a bottom water situation.

The field experience to-date allows us to identify several features of the THAI process, conducted in different situations, as follows:

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- For an application in a *heavy oil reservoir*, it is expected that oxygen content in the produced gas will always be zero, almost irrespective of the value of air injection practiced. However, at this time, for DLD configuration, the value of air injection is limited by other factors (bottom water encroachment, sand influx, etc). In reality, although THAI is a short-distance displacement for oil, the oxygen molecules have a longer residence time in THAI than in conventional ISC (where ISC front is usually very narrow. Therefore, it is very probable that the oxygen is consumed entirely long before it reaches the horizontal section of horizontal producer. This creates, on the one hand, large potential for thermal cracking, water-gas shift and coke gasification reactions producing hydrogen, and on the other hand, some consumption of the above shown produced H_2 by forming additional methane by methanation reaction (coke+H_2 reactions). These reactions are fully explained elsewhere (Kapadia, 2011-2013).

- For an application in a light or light-heavy oil reservoir a relatively high oxygen content in the produced gas (probably at least 3-4%) may be expected. This application does not seem to be proven in this case; more field development work is needed.

- For heavy oil reservoirs with gas-cap, it is speculated that two situations are possible:

    1. Gas cap with zero oil saturation
    2. Gas cap with non-zero oil saturation (it is generally the case with Canadian oil sand deposits)

  In the first case, it is believed that only THAI in a direct line drive (DLD) configuration may be technically feasible, and this has a lower efficiency compared to a staggered line drive (SLD). The second case pertains to the gas-over-bitumen (GOB) situations, where the pressurization of the gas cap may be necessary in order to assure a subsequent successful SAGD application. In this case, in the first phase, an ISC front can be designed to be propagated in the gas cap to produce (in-situ) flue gas, simultaneously with re-pressurization to enable the production of natural gas from gas-cap. In a second phase - as an alternative - a horizontal producer can be drilled in the bitumen zone to capture the oil mobilized by the ISC front. More details on this scheme are provided in the Subchapter 10.1.6.

- In a tertiary application, following steam-based exploitation (steamdrive or SAGD), the oxygen content in the produced gas should be zero, but the apparent hydrogen-carbon ratio may be slightly higher than the normal, reflecting a slightly increased LTO activity (mainly in SLD-THAI). The amount of hydrogen produced may be higher than usual as the superheated steam will always be present. The operation is not straightforward since it has to be carried out in such a way that the negative effect of the steamdrive or SAGD-induced heterogeneities are minimized, and potential blocking of the horizontal producer is avoided.

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- In a tertiary application, following cyclic steam stimulation (CSS) operations, as mentioned previously, for the time being it is recommended to consider that only after CSS operation carried out with horizontal wells drilled from a pad and using long cycles, which assumes a significant amount of heat stored.

- For application in a heavy oil reservoir with a bottom water, the feasibility of application is a direct function of, on the one hand, the absolute value of thickness of oil zone and, on the other hand, the ratio between the thickness of bottom water (BW) zone and the thickness of the oil zone; also, the confinement in the oil layer, first of the steam injection (for preheating), and then of the ISC burn is important. The decreased low water cut during the THAI process is an indicator of a successful application. A bottom water THAI simulation (Ado, 2017) showed that the tilting forward of the ISC front is always achieved, and no premature O_2 break-through occurs. The simulation also shows that, for this particular BW case, DLD THAI is more efficient than SLD THAI.

Extensively fractured formations normally would not be amenable to THAI applications. However, it is speculated that the very thick formations containing a high density of small fractures (*statistically homogeneous micro-fractured rocks*) may be amenable to the application of SLD-THAI. In this case, we may see a relatively high oxygen percentage in the produced gas recorded during the first period of ISC front propagation through the start-up region. As learned from conventional ISC projects, ignition methods would need to be radically modified, in order to account for fracturing.

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10. POSSIBLE IMPROVEMENTS OF THE PROCESS LEADING TO ITS COMMERCIALIZATION

At this stage, commercial application of THAI has not been achieved. As expressed by the CEO of Petrobank Energy and Resources in his interview of June 2013 (see Appendix D, 2013), namely: "THAI is pretty straight forward. We inject air into a heavy oil reservoir, and we get oil out. It's frustrating for all of us that we haven't cracked the code on commerciality because we cracked the code on technical success". It has been amply demonstrated that THAI mobilizes heavy oil. In addition, ***it is the first-ever EOR method that produces a consistently in-situ upgraded heavy oil and hydrogen.***

At this stage, the THAI has been field tested, whereas CAPRI, practically, remains an untested process. For this reason, in this chapter, our focus is only on THAI. We surmise that by improving THAI, favorable conditions will also be created for CAPRI, which, essentially, is a THAI 'add-on' process, a variant of THAI with a modification related to the interaction of heated oil with a catalyst, while flowing in the horizontal section of the producer. However, we will discuss certain aspects that are specific to CAPRI.

The main ways to bring substantial improvements to the THAI process are:

- Using staggered line drive (SLD) configuration instead of direct line drive (DLD) configuration, whenever possible
- Creating an initial broad ISC front

10.1 THAI

10.1.1. **Maturity of Process. Challenges**

Establishing Initial Communication: Extensive laboratory tests have been conducted on almost every aspect of THAI, except its hydrogen production feature and communication/ignition phase.

Presently, operating practices during the startup phase are mainly based on field experience from SAGD projects. For the SAGD communication phase, significant progress has occurred recently, as the practice of steam injection during the communication phase appears to be easier than previously anticipated. The so-called practice of 'bullhead injection', i.e. straightforward injection of steam (or steam and solvent), without any preliminary steam circulation in both wells, is currently being evaluated in the field. For THAI process, more work is needed on similar lines.

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Operational problems: Two significant operational problems were encountered: a) sand influx and b) short-duration endurance of casing in the horizontal section of the producer to the high temperature of the ISC front.

The casing of horizontal producer may be frequently exposed to temperatures as high as 600^0C or even higher in case of direct line drive (DLD) THAI; once the ISC front "touches" the casing, it remains continuously in contact with it throughout the rest of life of the project. Ways to reinforce casing endurance need to be further investigated. Compared to the conventional ISC process, the THAI process has an advantage, namely, a damaged *toe region* would not necessarily lead to a whole horizontal section of producer suspension (or abandonment of the well). The damaged region (usually located in the toe region) can be isolated, and the well can be further used for production; Kerrobert Project has encountered this situation several times.

It is expected that for the **s**taggered **l**ine **d**rive (SLD) THAI, this problem will be significantly attenuated as absolute maximum peak temperature is expected to be far away from the horizontal section of producer for a long *first period of production* and, even later on, is not expected to be so high in the horizontal section of the producer; however, this substantial advantage needs to be confirmed via further field tests.

In any THAI application, sand influx may constitute a severe challenge and appropriate solutions/preventative remedial should be developed from the very beginning. The operator (K. Starkov, Production Operations Specialist for the Kerrobert Project) has stated that -based on field experience - the sand influx problems would slightly diminish if the direct line drive (DLD) configuration is modified towards the SLD configuration; one way could be by locating the shoe of vertical injector more laterally off from the toe of horizontal producer (away from the horizontal section of the horizontal producer, not along its line). Another measure would include the need to unload some gas (reduce the amount of gas produced by the horizontal producers). New solutions may need to be developed. One option is utilizing some additional vertical wells as vent wells (for flue gas production), similar to the approach proposed in the COSH process. Another option is the use of oxygen-enriched air instead of air injection; this last solution is far more complex, and it may need a long investigation period for development.

Winding down the process: The winding down of the process also needs to be clearly defined, as so far, there has not been any field experience in this area. In the last period of the project life, the end portion (probably 30-40m) of the horizontal section of the producer (near the heel) may be blocked by the local coke plug inside the horizontal section, or by an excessive coke deposition around the horizontal section. Appropriate ways of continuing the ISC front propagation from the first row of production wells to the next need to be developed. Also, there is a need to protect the vertical section of the horizontal producers (the curbed section in the vicinity of the heel) - or pilot well, if that exists - so that this can be

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subsequently used for air injection for further propagation of the ISC front, beyond that row; this includes avoiding excessive temperatures. These protection measures should be considered mainly in case that the horizontal well continuously produces with low water cuts.

DLD versus SLD: At the end of 2011, after 5 years, the Whitesands pilot in Athabasca oil sands was completed. Also, the second THAI pilot - Kerrobert Pilot – has been in operation for more than 7 years and generated important information related to the application of THAI process in conventional heavy oil reservoirs. The final evaluation of those two pilots can now provide an **estimate** of the average daily oil production, the cumulative amount of oil produced per pair, air-oil ratio (AOR), degrees of upgrading (and hydrogen production), and various operational problems. However, in the Whitesands pilot, AOR and **u**ltimate **o**il **r**ecovery (UOR) and, the performance in general, pertain to the **d**irect **l**ine drive(DLD) system/configuration used; in the Kerrobert project, AOR and UOR and the performance are also for the DLD configuration in the presence of bottom water. As discussed later, a staggered line drive (SLD), while it involves a more complicated communication phase, could lead to better performance due to a better lateral sweep.

Three schematics for staggered line drive (SLD) are shown in Figures 77, 78 and 79 and briefly discussed here; more will be analyzed later on (Subchapter 10.1.3). The first suggested solution is inspired by the pressure controlled gravity drainage (PCGD) process (Sawhney, 1997) and it involves a multi-branched construction for all horizontal producers from the first row of horizontal producers (Fig. 77). This would facilitate the communication phase. The second suggested solution is proposing a reverse ISC operation just in the row of vertical wells, in order to generate the initial broad ISC front for the main operation. Then, the main THAI process is started by injecting air in vertical wells, arranged in a staggered line drive (SLD) relative to the long horizontal producers from the first row of horizontal producers (Fig. 78). The third suggested solution is more complicated: in the first row, vertical air injectors are alternated with opposed dual lateral, short ,horizontal production wells (Fig. 79). In this way, first, a DLD THAI-like *auxiliary process* is conducted only in the first row ("injector row") in order to generate the initial broad burning ISC for the main operation. Then, the primary THAI process is started by injecting air in the vertical wells, arranged in a staggered line drive (SLD) relative to the long horizontal producers from the first row of horizontal producers. The horizontal sections of the former dual horizontal producers from the "communication row" are shut-in (fully cemented), and their vertical curbed sections (or pilot wells) kept as observation/control wells.

For improving the THAI technology, the following work/investigations need to be considered :

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- Investigation of staggered line drive (SLD) configuration as the main mode of THAI application in the field; this investigation could be done through simulations, via laboratory wide 3-D models and field pilots

- Improving the communication/ignition phase, especially for the case of SLD application, which would be the preferred mode of operation. The selection of ignition methods should account for the existence of bottom water.

- Solving the main operational hurdles in the field; sand influx issues and metal resistance (mainly in DLD configuration). These are important mainly for the oil sands application and for reservoirs with the intensive sand influx

- More investigations to understand the outstanding overall robust stability that THAI has so far demonstrated in the field

As mentioned previously, to improve the performance of THAI the first step is to fully switch to a staggered line drive (SLD) configuration. In this chapter we are starting the investigations targeting this; we are doing this based on conventional reservoir engineering; then, we analyse the relevant results from laboratory testing and simulations and even some accidental revealing situations from the Kerrobert Project.

10.1.2 Superiority of Staggered Line Drive Configuration; Fundamentals, Laboratory and Field Results

General Considerations: After the 5-year operation of the Whitesands project the conclusion is that relatively low oil production rate, and ultimate oil recovery (UOR) were achieved using the direct line drive (DLD) configuration. It is now clear that this is directly due to poor areal sweep efficiency of the burning front, more precisely poor lateral development of the burned zone; the wedging of the burned zone occurs as it advances towards the heel. This was indicated by numerous bottomhole temperature records from both the observation wells and also replacement production wells. Thus, the DLD THAI configuration, although it may have a strong self-healing feature (a coke-plug at the intersection of the horizontal section with the ISC front), it does not seem to assure a good lateral sweep efficiency, due to lack of strong drive in lateral directions. It appears that the DLD THAI self-healing feature is related mainly to the avoidance of the oxygen (O_2) short-circuit. Therefore, in the DLD THAI process, the role of coke plug is mainly to contribute to the total consumption of the O_2; its role in assuring a good sweep efficiency seems to be secondary (just local/ at best, a limited regional effect). Another contributor to this complete O_2 consumption is the slight/controlled over-riding (forward-tilting) feature of the process; air (O_2) does not enter directly in the borehole of the horizontal producer, it flows towards and along the

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mobile oil zone (MOZ) in a kind of long-distance pathway, which means a long residence time for oxidation. *Therefore, it seems that the* ***wedging effect*** *during DLD-THAI process is not prevented just by the existence of the coke plug and gas/air slight over-riding feature.*

Simulation results for steamflooding in a toe-to-heel configuration (THSF) showed that for similar conditions, SLD was *superior* to DLD, and it was also proposed *that DLD steamflood be altogether removed from future considerations* (Bacgi, 2008). It is believed that, in principle, sweep efficiency should be relatively close (but not identical) in both thermal processes; THSF and THAI. Later on, some differences are highlighted in conjunction with the impact of partial oxygen pressure effect on ISC front advancement in DLD and SLD configurations (subchapter 10.1.4).

Another toe-to-heel (TTH) process, Toe-To-Heel Waterflooding (TTHW), also definitely has shown that SLD is more advantageous then DLD; theoretical studies – which do not take into account the gravity effect - showed that the sweep efficiency of waterflooding DLD configuration is low and decreases as the length of horizontal producer increases, (Strickland, 1991). Actually, this was confirmed by the field piloting of the TTHW process in the Medicine Hat Glauconitic C Field, where the modules with horizontal injectors, injecting directly into the toe of producer, did not perform well (Turta, 2010); their performance was inferior to that of the normal TTHW modules using vertical injectors in an SLD configuration.

DLD vs SLD THAI - Laboratory Tests : an attempt was made to compare the results of THAI laboratory 3-D tests conducted in DLD and SLD configurations at the University of Bath, UK. The comparison was made having a hard look at the limitations of these kinds of tests, as mentioned in Section 4.3. It is to be expected that 3D combustion cannot wholly predict all of the outcomes in the field. Still, nevertheless, they provide a significant basis for comparing different operating strategies, especially DLD vs SLD. The DLD and SLD configuration results are shown in Figure 7 of chapter 5-Simulation ???.

All tests were conducted as dry ISC. The 1997 tests (Greaves, 1997) were conducted in a short cell using Wolf Lake oil. The test parameters were better for SLD configuration; the volumetric sweep efficiency increased from 53% to 69.5%, while the air-oil ratio (AOR) decreased from 1960 to 1554sm^3/m^3. Similarly, in the tests conducted in 2020 (Xia, 2002) - with a longer cell and using Athabasca oil sand - the ultimate oil recovery (UOR) increased from 70% to 83%, while the AOR decreased from 2020 to 1690sm^3/m^3. Therefore, the SLD showed a better performance in SLD configuration, both with Wolf Lake and Athabasca bitumen. It is believed that this difference should be more significant at the field scale. Actually, in the 3-D laboratory model, due to the short length of the 3D cell, the experiment can only capture the steady operating period for perhaps three-quarters of the total experimental time, before

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heat conduction along the cell walls begins to reduce the 'THAI-effect', i.e. zone of cold oil ahead of the MOZ begins to heat-up significantly.

General Reservoir Engineering Considerations: better performance for the SLD compared to the DLD is also supported by the basic reservoir engineering principles of oil displacement when comparing the sweep efficiency in regular, uniform configurations.

A line drive configuration is characterized by two parameters “d” and “a”; “d” represents the distance between the injection row and production row, while “a” is the distance between wells in the same row (Figures 79a-c). The line drive can be intra-contural or peripheral. For a line drive configuration having d/a=1/2 (inverted five-spot pattern usual used in an intra-contural configuration), for a mobility water-oil ratio of 1, the sweep efficiency at water break-through is 30% for DLD and 72% for SLD [(Fig. 49), Smith, 1966, page 77] when going from DLD to SLD, Fig. 79?. In the case of DLD THAI projects, d/a ratio (where “d” is the distance between the vertical well and the toe of horizontal producer) is a lot smaller such that the sweep efficiency is a lot lower than 30% for DLD configuration (Fig 80) .

All the considerations above are based on reservoir engineering knowledge of oil displacement by different fluids, for different mobility contrasts between injected agent and oil. This involves isothermal displacement with no interaction between displacing and displaced phases; the pressure gradients are predominant. *However, this is not the case for ISC process; in this case the ISC front advances in all directions where the air/O2 has access to the combustion surface, with this advancement even opposite to the pressure gradient action (like in reverse combustion).*

As seen in Fig. 76b and even better in Fig. 88a-b, in case of SLD, the advancement of the ISC front laterally (parallel to the outside edge of the pattern/perpendicular to the line of injectors), far from the horizontal section of horizontal producer should be more rapid as the rate of oxygen supply is greater; this is helped by the distribution of the streamlines; later on in the process, the higher density of streamlines towards the horizontal section (HS) of horizontal producer (HP) will also cause a slower ISC front advance along the direction of center-line coinciding with the direction of HS of HP. It is seen that unlike a non-thermal displacement, in the ISC process *different burning rates at different points - laterally out from the horizontal producer - contribute to a more uniform advancement of the ISC front, and hence to a better areal sweep efficiency*. Therefore, the wedging effect is discouraged to a significant extent. Of course, in these considerations, it was assumed that a strong initial planar ISC front was created between the air injection wells. This was confirmed to some extent in the 3-D laboratory THAI tests, when using a staggered line drive operation of VI-2HP, as seen in Figure 24; there, it was clearly seen that in the first 300 minutes the advancement of ISC front was faster in-between the well space (starting from injector) as compared to on directions of the shoe of horizontal producers. This phenomenon increases the value of sweep efficiency for SLD at values even higher than 50%, while the corresponding value for DLD may even have a negative effect on sweep efficiency, decreasing it to lower than 25%.

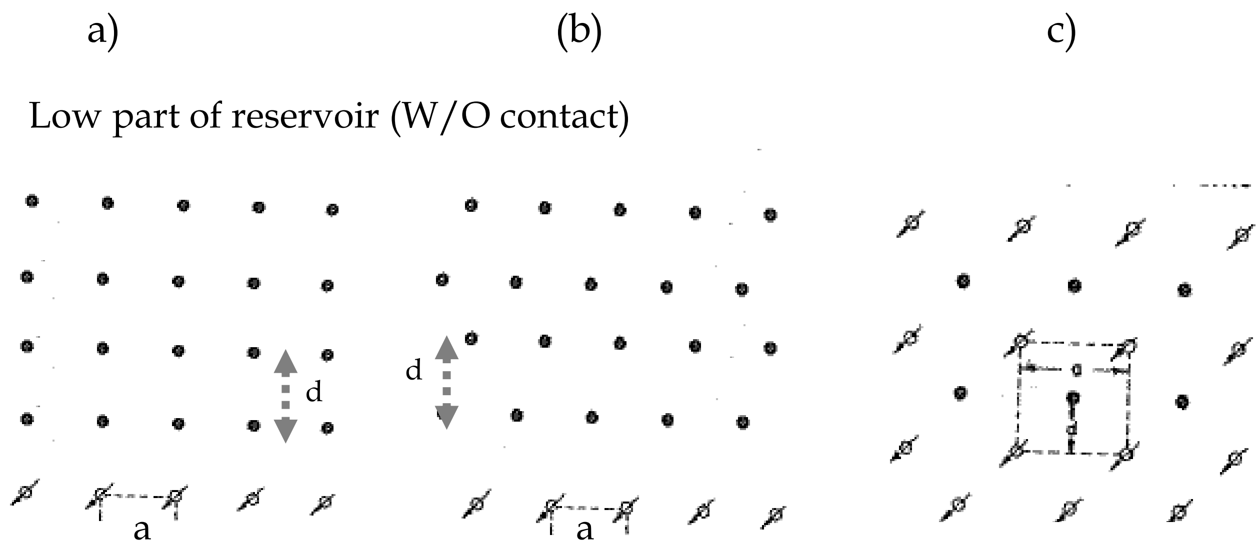

Fig 79 a-c: a and b: peripheral direct line drive (DLD) and staggered line drive (SLD) configurations; c represents the well-known case of inverted five-spot pattern (d/a ratio = 1/2)

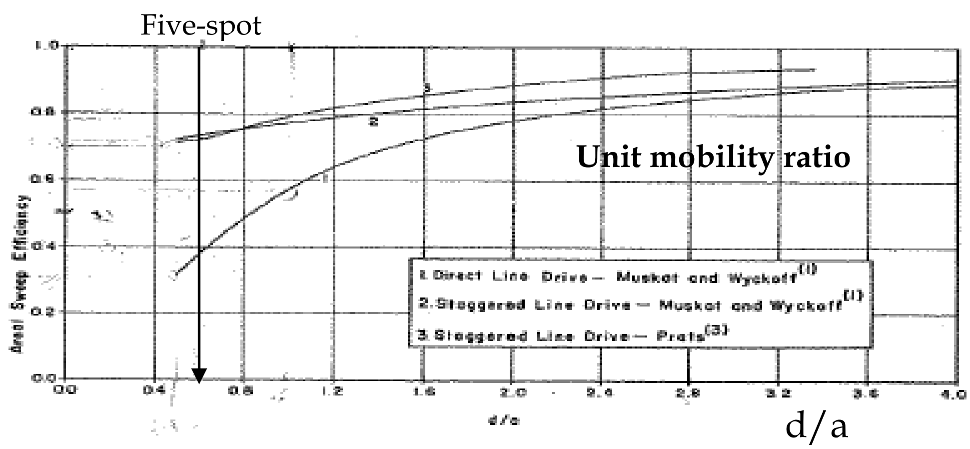

Fig. 80: Sweep efficiency at break-through for direct line drive (DLD) and staggered line drive (SLD) configurations (Smith, 1966, page 77)

Field Evidences From the Kerrobert Project: There are two **pieces of** evidence from this Project, namely: 1) case of air migration from KA4-KP4 pair towards the production well KP7 of the

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adjacent pair KA7-KP7 and 2) case of air migration from KA12-KP12 pair towards the production wells KP9 and KP10 of the adjacent pairs KA9-KP9 and KA10-KP10, respectively.

In both cases, air migration led to producers KP7, KP9 and KP10 having two ISC fronts approaching them, one of them being generated in an SLD configuration. *All these three producers had a very good performance, and for all of them, the double ignition and double ISC front propagation can be visible in the production performance graphs.* These two cases will be analyzed separately.

Air migration from KA4 towards the producer KP7: As seen in the map of Fig. 61b and 61c or from Appendix E, the air injector KA4 is located very close (25-30m) to an old horizontal well (OHW), namely OHW3 (marked 3 on the map of Fig. 61b); also, the projected trajectories of KP4 and OHW3 intercept after a short portion (approx. 200m) from the toe of KP4 and toe of OHW3. Therefore, it was extremely easy for the air injected to flow upwards towards this old well, which provided a pathway of least resistance for the flow; this could have happened from the very beginning, even during the steam injection for the preheating and then for air injected for ignition. Actually, the temperature profile in KP4 on Nov 1st, 2009, 5 months since the termination of steam injection in KA4 (Apendix E, Fig. E7b-4) does not show any high temperature increase at the toe; the temperature was found at a maximum of 175 ^{0}C at a distance of 140m from the toe on Nov. 1st, 2011. The well KP4 produced just 80 m^3 oil, only until December 2011, when it was suspended. The injection well KA4, however, continued to inject air for two more years until the end of 2013; during this period, it injected 6.7 million sm^3 of air, i.e., almost 30% of the total cumulative of air injected through KA7 and KA4.

It is speculated that the air migration from KA4 to KP7 occurred according to the following mechanisms: steam injected for pre-heating had a straight channeling towards the old horizontal well OHW3 and flowed into this well all along during the operation. Then, air injected for ignition followed the same pathway; this happened until the reservoir pressurization (in this region) via this old well, happened. Subsequently, the air started to flow towards the KP7 and produced the ignition on the direction of KP7; however, this ignition was extremely slow (6 months) as showed by the variation of H/C ratio (4 to 7 for an extended period) based on the gases produced by KP7.

*Air migration from KA12 towards the producer KP9 and KP10***:** As seen in the map of Fig. 61b and 61c or from Appendix E, the air injection well KA12 is located very close (25-30m) to an old horizontal well (OHW) namely OHW7 and to the toe of KP9 well. Therefore, there was a possibility for the air injected to flow upwards towards the OHW7, which provided a pathway of least resistance for the flow; this could have happened from the very beginning, even for the steam injected for the preheating and then, for air injected for ignition. Actually, the temperature at the toe of KP12, both immediately after the termination of steam injection in KA12 and afterwards (Apendix E, Fig. E7b-4) has never exceeded a maximum of

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150 ^{0}C. The well KP12 produced only 8 months, until June 2012, when it was suspended. The injection well KA12, however, continued to inject air for three more years, until the end of 2014; during this period it injected 10.5 million sm^3 of air, while the gas produced via KP12 was only 2.2 millions sm^3; no ISC was generated, only LTO reactions occurred with this very low flux of air towards KP12. The air/gas difference of 8.3 million sm^3 flowed towards KP9 and KP10; it is practically impossible to determine how much flowed in each direction. Producers KP9 and KP10, combined, produced a cumulative of gases of 20.6 million sm^3, as compared to 14.6 million sm^3, the combined cumulative air injected (Table 16); the excess air injected in KA12 of 8.3 million sm^3 is not too far from the excess gas produced by KP9 and KP2, together (8.3 million sm^3) .

It is speculated that the air migration from KA12 to KP9 and KP10 occurred according to the same mechanisms as in case of air migration from KA4 towards the producer KP7. However, in this case, it is more complex, as OHW7 is in communication with OHW6, which, at its turn, is in communication with OHW2, and therefore "absorbed" more air for pressurization; almost 3/4 of the reservoir volume is in communication. Eventually, the air started to flow towards the KP9 and KP10 and produced the ignition on the direction of these two wells; however, this ignition was extremely slow (8 months for KP9 and 6 months for KP10) as showed by the variation of H/C ratio (2 to 3.5), based on the gases produced by KP9 and KP10, respectively.

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Although the evidence from THAI laboratory testing, simulation work (with more details later on) and field piloting is not complete (when we take each of them taken individually), it converges to show that the SLD configuration is superior to the DLD configuration; the similar toe-to-heel processes applied in waterflooding and steam drive also confirmed that. Of course, finally, a firm conclusion will come from systematic field tests deployed in an SLD configuration.

10.1.3 Creating an Initial, Broad ISC Front - Improving the Communication and Ignition Phase

In this section, in the first part, we present the classic case of using vertical wells for injection, while the horizontal wells are used *only for production*; in the second part, the application of THAI using horizontal wells for both production and air injection is presented. In principle, in both cases, this may assume propagation of a conventional ISC front in some phases of the process. The main goal is to improve the efficiency of hot communication phase and ignition operations. Once improved, they become more expensive, and for this reason - for large scale operations - a second goal is to reduce the number of the

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hot communication and ignition operations to a minimum; this is emphasized mainly for the case of using horizontal wells for both production and injection. As seen previously, when grafted on an exiting ISC conventional project, the application of THAI becomes most attractive as both these two phases can be eliminated. Therefore, al in all, the operator either significantly improve them or eliminate them, as the case may be.

10.1.3.1. Using Vertical Wells as Air Injection Wells

The following discussion refers mainly to the case of SLD, but to some extent, also touches on DLD, in order to exemplify the procedure. Therefore, even when using the DLD configuration, the most important thing is not just communication between the shoe of the vertical injector and the toe of the horizontal producer *but, first of all, communication between the injectors from the injection row. Only after the double communication is confirmed (between the injection wells, on the one han,d and between the injection well and the horizontal producer, on the other hand) can the ignition phase begin*. However, as the distance between the injectors in a row can be of the order of 100m, two injectors for each producer may be necessary. In this case, the communication has to be achieved over a distance of 50 m; always, first between adjacent vertical injectors and subsequently between the line of injectors and the toe of horizontal producers. After a good-quality communication is established, only the vertical injectors arranged in a DLD configuration are used for injection; other vertical wells should be shut-in or used as observation wells. As discussed previously, this version generally is not recommended, but in some cases, it may be the only acceptable option.

Next, the main topic of improving communication/ignition in the SLD configuration is examined. In order to realize an effective communication, the number of wells and their type in the first two rows are analyzed. The following options are considered:

A. Using branched double-toe horizontal producers in the first row, Fig. 81

B. Doubling/tripling the number of vertical injectors close to or in the first injection row, Fig. 82

C. Using alternative vertical injectors and dual opposed horizontal producers in the first row to create the initial linear ISC front, Fig. 83

In order to evaluate these ideas and make it easier to understand, we assume a distance of 100 m between adjacent horizontal producers for all of these options. Details of the application are presented in Appendix H. Some of these methods constitute radically new methods and may be further developed (some of them in patentable processes).

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Option A (double-toe horizontal producers): is better than the DLD configuration, but some wedging effects may persist (Fig. 81). Probably, it should be applied only for oils with good mobility (at reservoir conditions). i.e., oil viscosity up to 4,000-5,000 cp, where a preliminary hot communication between the vertical injectors is possible by steam injection (cyclic steam stimulation followed by steam drive).

Option B (using reverse ISC in the vertical well row): In this case, the communication needs to be achieved between two adjacent vertical injectors (at a distance of 100m), and, subsequently between the line of vertical injectors and the toe of horizontal producers (See Fig. 82). Then, both vertical injectors can be used for simultaneous air injection. This version could be applicable for bitumen reservoirs and reservoirs containing oil with a viscosity up to 30,000-50,000 cp, where a hot communication between the vertical injectors is possible by reverse ISC; low reservoir temperature precluding the possibility of spontaneous ignition is a condition for application. For this option, further details are included in Appendix H; a document describing the details of this procedure was proposed by the principle author.

Option C (opposed dual lateral, horizontal producers in the air injection row)**: A** linear ISC front is first created within the first row of wells by using the DLD THAI process itself. The DLD configuration does not result in a high sweep efficiency; the goal of this operation is just to generate the initial linear ISC front (Fig. 83). After the hot communication is generated, the horizontal sections of the opposed horizontal wells *are fully cemented* in order to shut-in any flow. Their vertical perforated section can still be used for some water injection if favourable conditions exist. This option is more intensive but, at the same time, it radically increases the chances of successful operation of the THAI process for oil sand situations, where there is no initial oil mobility. The generation of the initial ISC front in the first row can take up to 2-3 years, depending on the ISC front velocity possible to be achieved. However, the operations for generating new ISC fronts will never be repeated, until the entire reservoir is exploited using the THAI process.

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Appendix H provides guidance on what is the most suitable method to choose depending on reservoir temperature and mobility of oil at initial reservoir conditions. Other conditions, such as permeability of the bitumen saturated rock, absolute permeability, etc. may also influence this selection.

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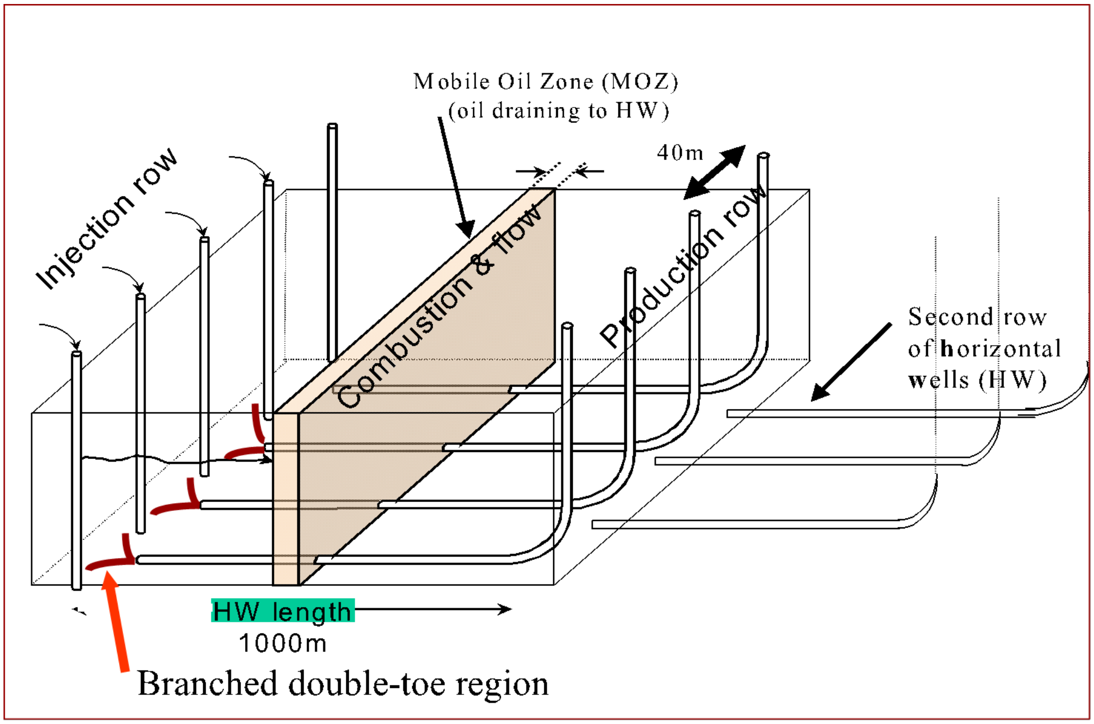

Figure 81: Option A - Commercial operation of THAI using staggered line drive scheme as inspired by Pressure Controlled Gravity Drainage (PCGD) process, Sawneey, 1997

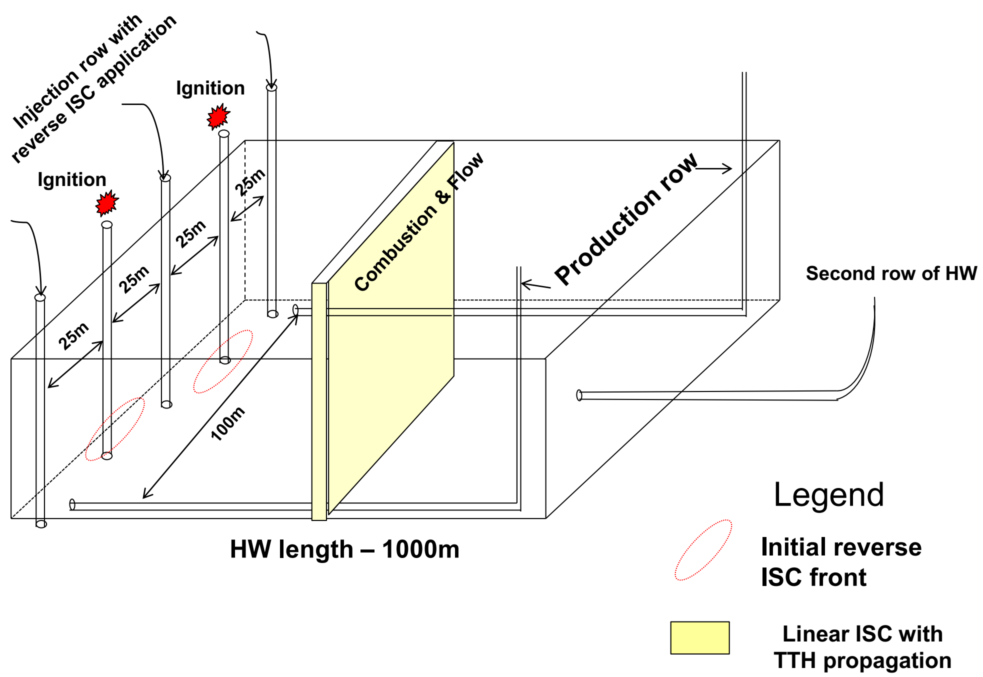

Fig 82: Option B- Applying reverse ISC to build the initial broad ISC front within the first row

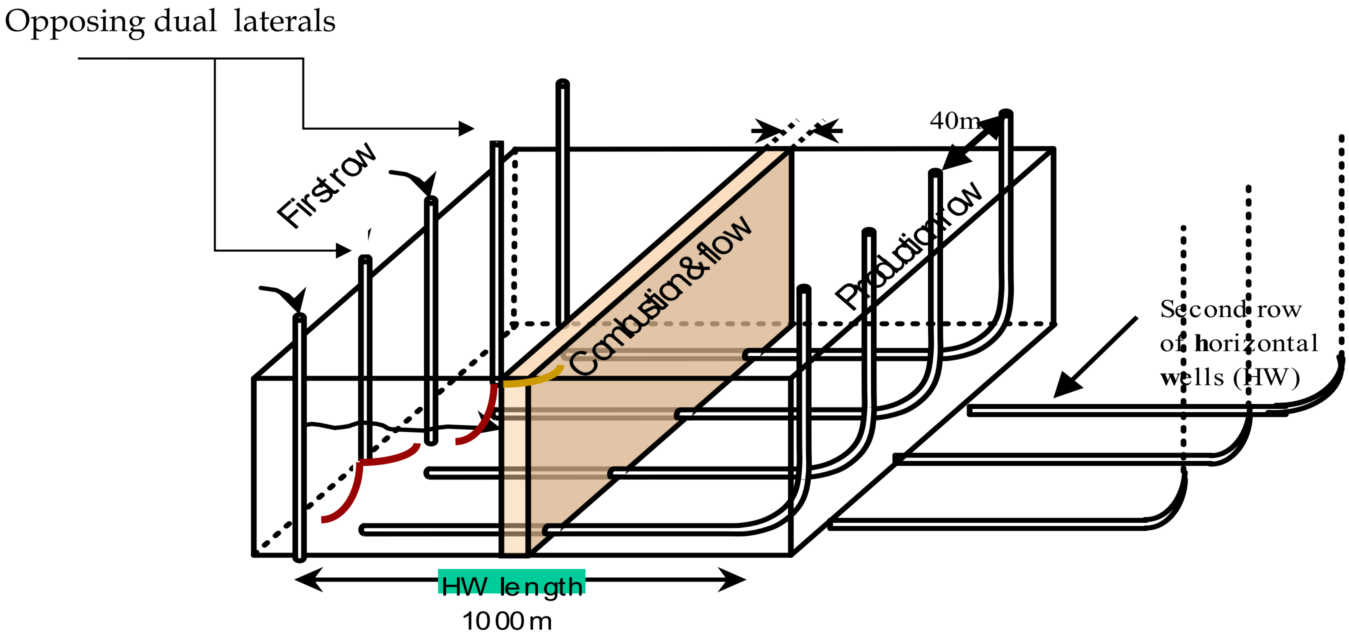

Figure 83: Option C - Commercial operation of THAI using the SLD configuration (injectors located in-between horizontal producers (see Fig. 7b). Note: Please note the toe-to-heel (TTH) configuration in the first row, as well; vertical air injectors alternating with opposed dual lateral, horizontal wells in order to generate the initial broad burning ISC for the main operation

10.1.3.2. Using Horizontal Wells as Air Injection Wells

Using a horizontal injector instead of a vertical air injector in an ISC process should lead automatically to a broader ISC front. However, so far, horizontal injectors have been used more intensely only in the particular situation of ISC operation in reservoirs located very deep and with high reservoir temperature (Belgrave, 2006); under these conditions spontaneous ignition is usually easily achieved. Their use in an ISC process applied in a shallow heavy oil reservoir is riskier as explosions in the horizontal section of horizontal injector can occur due to poor control of the flow intensity of different fluids in different segments of the well.

In the case of heavy oil reservoirs, the only application of this kind was at Brintnell Project conducted by Amoco and AOSTRA in 1994 (Thornton, 1996) in the Peace River region of Canada. The reservoir is located at a depth of 425 m; pay thickness is small (4-7m), and it contains a heavy oil, with a viscosity of 5,000-10,000 mPa.s, at a reservoir temperature of 15^{0}C. Dry ISC was tested in a large face-to-face configuration formed by three 1100m-horizontal wells with one injector in the middle, parallel to two producers on either side, located at 210m and 320m, respectively. The CSS operations in preparation for the ISC process were not extensive; a slug of steam (7,500 m^3) was injected in the future horizontal injector, in 4 months. This steam barely penetrated a few meter-distance from the injector. *Most certainly, no communication between injector and producers was created.*

The process started in January 1994 with spontaneous ignition for which no evaluation data are available (ignition delay was not estimated). The air was injected below the fracturing pressure for 4 months (the maximum air injection rate was 65,000 sm^3/day), and then for 8 months, there was a pressure cycling/

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blow-down period (injector closed, production wells open). During this testing, some oil was recovered, but the figures are not available. An in-depth analysis is difficult to conduct as details on combustion gas analyses are missing, and because the pressure cycling procedure resulted in non-stabilized operations. The exact date of abandonment of this project is also not available, so perhaps it was not considered economical.

Although not considered a success, the project showed that it was possible to use a horizontal well as an air injector for a limited duration (four months). Therefore, it is concluded that the use of horizontal well as air injectors should not be totally ruled out in future projects.

Taking the previous statements into consideration, several solutions are listed in Appendix H. None of those proposed solutions has been tested in the laboratory or simulated. Still, they constitute a good starting point for new investigations. Before providing the essential information for the proposed solutions, the laboratory work investigating the extension of the THAI application from classical use (with vertical injectors) to that using horizontal injectors (allowing a TTH ISC front propagation along the horizontal producers) will be presented.

Laboratory Testing of Extended THAI in a SAGD-type Configuration

Testing the ISC process, not as a follow up to SAGD, but just using a SAGD-type configuration was conducted for the first time by Rahnema et al (Rahnema, 2011, 2012, 2013 and 2017).

The authors of the process used a quasi-THAI process, using two horizontal wells, with the air injection into the horizontal well located at the top of the reservoir and with the horizontal producer at the bottom (Fig. 84). Initially, the horizontal wells were located close to each other precisely as in SAGD. But in this case, very high temperatures (burn-outs) in the lower production well were experienced; these raised serious problems, and for this reason, the distance between wells was increased.

As seen in Figure 84, due to practical considerations (mainly when using artificial ignition devices), the ignition had to be done at the portion adjacent to the heel of the upper well. Then the ISC front propagated heel-to-toe along the upper well, while taking place in a toe-to-heel (TTH) mode for the production well; with double anchoring of the ISC front. Because the *ISC front propagates along the horizontal producer in a TTH mode*, although the authors called the process CAGD (combustion assisted gravity drainage) in this Report the process will further be called "THAI in a SAGD-type configuration", as being a generalized THAI application (*extended THAI*) for this case. During laboratory tests, uncontrollable blockages of the horizontal producer frequently occurred. In other words, not only a coke-pug formed (local blockage) *and helped the process like in a conventional THAI process, but because of the too high temperatures on a very large section along the producer, too much coke was formed and it totally blocked the horizontal producer*. In a THAI application, the coke plug has to produce only a local plugging, but as seen in the second picture of Fig 84 (380 minutes), the horizontal section of the horizontal producer was blocked on a portion approximatively equal to half of its total length.

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Extended THAI or “THAI in a SAGD-type configuration", as described previously, is used in the subsequent proposals trying to generate the broadest ISC front possible. Although this is the most expensive generation of the ISC front, it is, without any doubt, a way to create a very broad initial ISC front; it is a kind of “Cadillac” of the procedures for broad ISC generation methods. From the point of view of oil production/oil recovery, it seems to be similar to direct line drive THAI as it is not expected to have a very high sweep efficiency; its paramount merit is the formation of a very broad ISC front (surface) to start with.

All in all, for field application, the operator should be aware of the following disadvantages:

- ✓ High risk to have a collapse of heel region in the air injector, and this puts an end to the test
- ✓ Persistent blockages of the horizontal producer
- ✓ O2 utilization is very low (70%) and with 5-7% O_2 in the production gases, it may not be usable in the field (if the laboratory results repeat in the field)

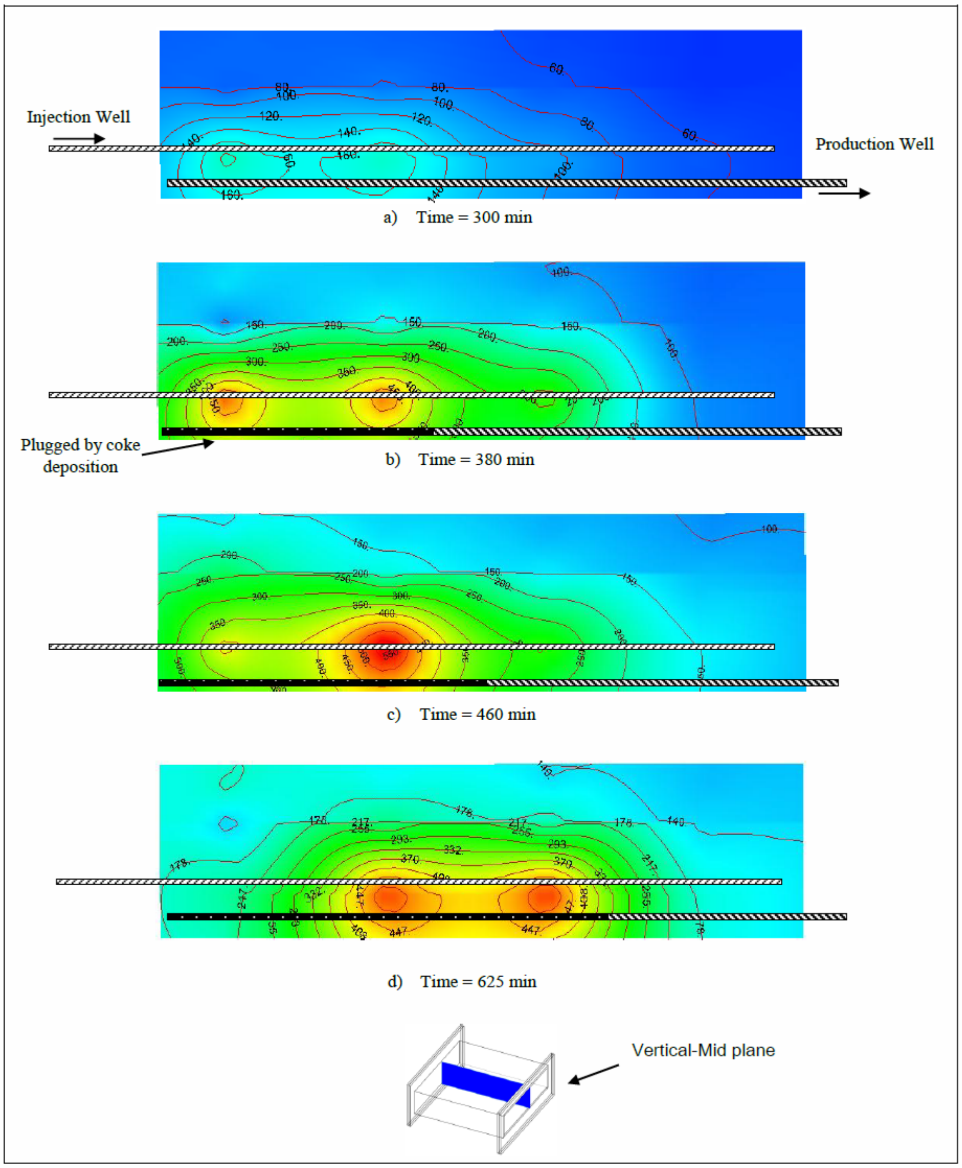

Figure 84: THAI in a SAGD-type configuration (CAGD process). Temperature profiles at the vertical mid-plane of the laboratory 3-D model (Rahnema, 2011)

Application Versions for THAI with Horizontal Injectors

The options detailed here regards both THAI in a SAGD-type configuration with horizontal injectors, and more general proposals, not including SAGD-type configurations.

In all these proposals, the crucial two new procedures/approaches utilized are:

- Generation of a very broad ISC front using a SAGD-type configuration (as proposed by Rahnema, 2010,2011 – see the previous section)
- Transfer of air in the ISC-intercepted producers

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While the first procedure was tested only in the laboratory, the second procedure was extensively used in commercial conventional ISC projects (with vertical wells). When combined, these two procedures offer a pronounced increase of economic efficiency as the number of ignition operations is reduced to a minimum, sometimes to just one operation. Air transfer in an ISC-intercepted producer can be considered once a production well has a temperature of at least 120-130 ^{0}C.

Three main options, described in details in Appendix H, are:

1) Dual opposed horizontal well injectors arranged in an SLD configuration. Therefore, dual opposed horizontal wells are necessary to replace the standard vertical well injectors in the initial injection row (Fig. 85a-b and Fig. F4a-c from Appendix H)

2) Horizontal wells – injection and production wells in a repeated "L" configuration (repeated "L" configurations of horizontal wells) (Fig. 86)

3) Horizontal wells arranged in "cross" layout configurations (Fig. 87)

It should be mentioned that compared with the previously presented approaches, these proposals are designed to be more efficient, but at the same time, it requires a more in-depth understanding of the ISC process, including THAI.

The main observations on each of these options are:

The option 1 at #1Point (above) differs from the procedure proposed as B2 in the previous section because this time *the continuous ISC front in the line of injectors is created by propagating an ISC front along the horizontal wells* HI11, HI12, etc. (Fig. 85a). When an artificial device is used for ignition, this front has to be propagated from the heel to toe (htt). It assumes that these horizontal wells will remain active after this stage of the ISC front propagation, such that a coiled tubing could be introduced up to the well's toe and air injection at the toe would begin. This would initiate a TTH propagation of a broad ISC front along the main horizontal

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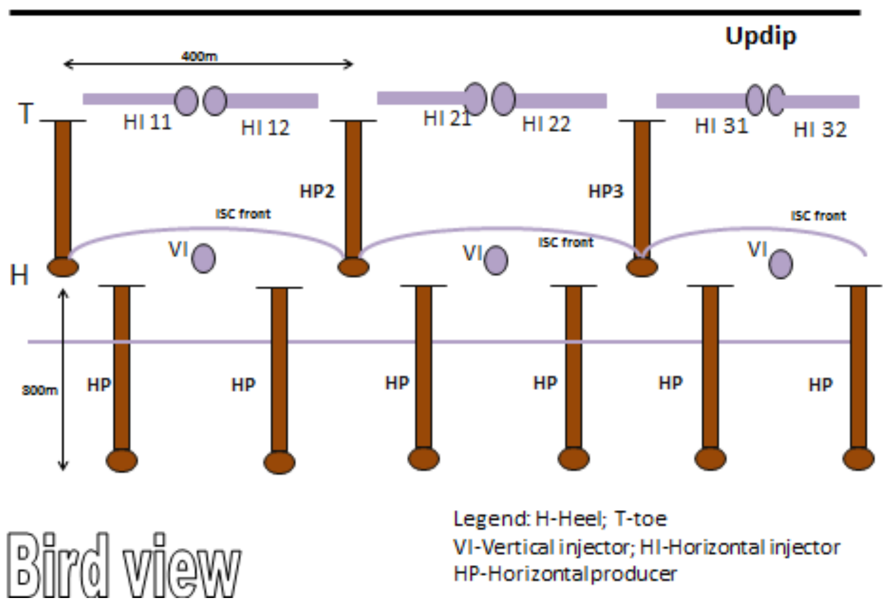

Figure 85a: Version C1-2. Replacing the current dual horizontal injector (see Fig. F 4a) with two horizontal wells. Not at scale.

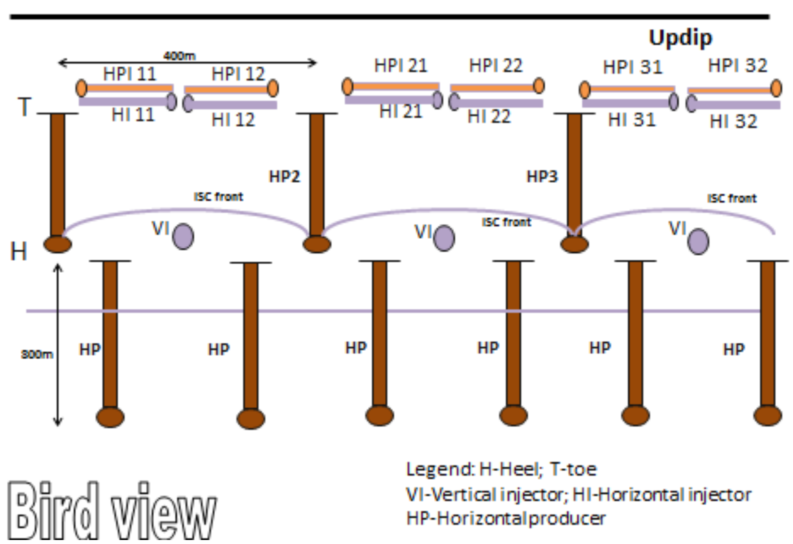

Figure 85b : Version C1-3. Replacing the current dual horizontal injector (see Fig. E 4a) with two horizontal well pairs. Not at scale.

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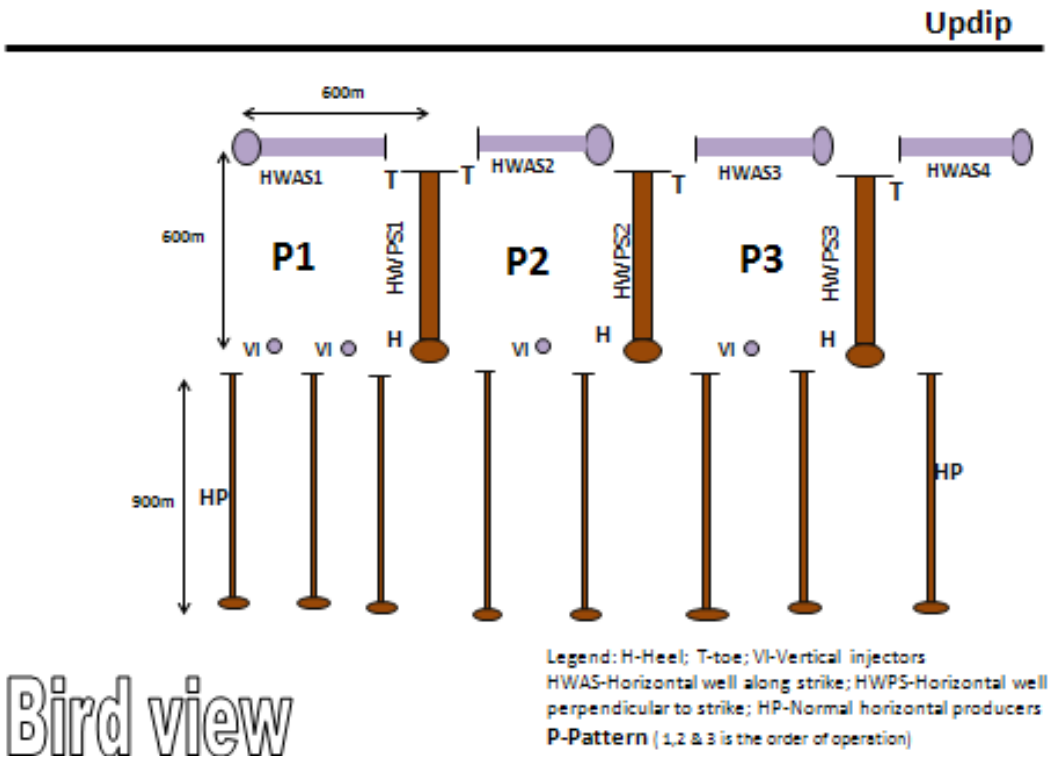

Figure 86: Version C2. Repeated "L" configurations of horizontal wells to form an initial broad ISC front. Note: Normal operation – afterwards. Not at scale.

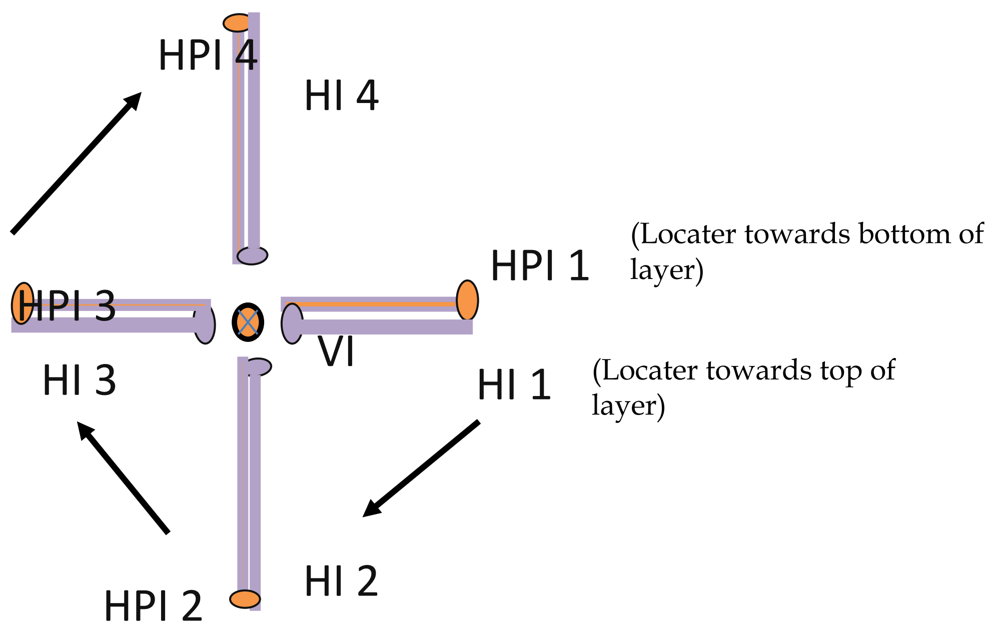

Figure 87: Version C3. SAGD-type pairs (except HP1-HI1) arranged in "cross" lay-out configuration; HI1 and HPI1 forms the first pair of horizontal wells (called pair H1) to be operated by ISC. Then, consecutively, the other pairs (H2, H3 and H4) are operated.

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wells HP (Fig. 85a). When a high reservoir pressure exists, the ignition by a steam-based process can be tried, but the ignition at the toe may be very difficult; even in this case, an ignition at the heel with a htt propagation may be necessary. The two horizontal wells (HI11 and HI12) can be replaced with opposed horizontal well, but in this case the control of the process is more difficult via two opposed branches. Anyway, both options require the production of combustion gases via the horizontal producers, although not much oil production may be obtained during the stage of the heel to toe (htt) ISC front propagation.

For this reason, a third option is presented in Fig.85b. In this case, the replacement of each single well with a SAGD-type configuration is solving the problem of creation of a broad combustion surface without using the main horizontal producers, HP, in the first stage, they will be used only in the second stage. This involves the use of THAI application in a SAGD-type configuration, in the first stage of the process. This method doubles the number of horizontal wells, but creates a broad ISC front and, further, air-water injection in a safe way is possible.

T*he option #2,* is characterized by the fact that ignition via only *one well is necessary for the entire injection row. However, the processing of different modules has to be consecutive, and it would take longer* for the whole injection line to be ignited. Then, a regular line drive operation could be carried out for the subsequent rows (Fig 86). The method introduces a new procedure, already used in the conventional ISC process involving the transfer of air injection in a production well already intercepted by the ISC front, with a relatively high temperature around it. This procedure will also be used in the option 3 (Horizontal wells arranged in "cross" layout configuration).

T*he option #3:* As shown in Fig. 87, in this case *the initial ISC front is created around the central vertical well (VI)*; then using the wells HI1 and HP1, the broad ISC front is generated. As described previously (by ISC front propagation from heel to toe along HI1 while HP1 is a producer). Once this is done, air-water is injected via wells HI1-HP2 (and VI) and the broad combustion surface is propagated along the well couple HI2-HP2. Then in a similar way, the combustion surface is propagated in the third quadrant and the fourth quadrant; more details are given in Appendix H.

10.1.4 Superiority of the SLD Configuration. Simulation Results; with and without Generation of an Initial Linear ISC Front

In this section, we consider extremely high viscosity oils (no initial mobility at reservoir conditions) in order to rigorously compare the Staggered Line Drive (SLD) with the Direct Line Drive (DLD). It is a-priori assumed that - using one of the methods described in the previous sections – a linear high-temperature region or a linear ISC front *can be achieved* in the vicinity of the first row, and it can be a starting point for both DLD and SLD configuration operations. Actually, this has been done in all

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laboratory tests, irrespective of the oil viscosity. However, in the field, for reservoirs containing mobile oil at reservoir conditions, a direct ignition without any pre-heating or only with local heating around the vertical injector (s) – for the extremely heavy oil reservoirs - was carried out. For optimization of THAI application, simulations for these cases are analyzed. The analysis is done first for simulations of the laboratory tests and then for the limited work done in simulations of field cases. It is to be underlined that the simulations have been done only for cases where vertical wells are used for air injection.

It has to be highlighted that irrespective of configuration, at the beginning (immediately after ignition), for a very short period – for approximately 10% of the pattern area – the radial propagation of the ISC front occurs; the "pattern area" should be assimilated here with the start-up region (and it would represent less than 1% of the whole area of a THAI pattern). Then, the distortion of the front contour is dependent on configuration and other reservoir parameters (thickness, heterogeneity, etc.) and operational variables (injection rate, etc.)

Laboratory tests simulations (assuming an initial linear ISC front): Temperature and oxygen distribution after 360 minutes (a) and 480 minutes (b) in a THAI laboratory test conducted in a staggered line drive (SLD) configuration –"2VIHP" are shown in Figures 88a-b. Wolf Lake oil (viscosity around 40,000cp) was used in both laboratory tests and in simulations. The simulation was carried out for a THAI process conducted in a 3-D model having a start-up volume of approximately 30% of the whole volume of the model (Xia, Greaves, Werfilli and Rathbone, 2002) and implementing a very strong ignition procedure (higher ratio of heat introduced for ignition divided by the heat generated during the test in the laboratory, compared with the field); this contributed to very high efficiency of the process.

Temperature and O_2 distributions for 360 minutes (6 hrs) showed the ISC front when it was anchored and then advanced past the toe of horizontal producer (HP). At 480 minutes (8 hrs), it was located half-way through the cell (Fig. 88). The main conclusions from this SLD simulation are:

- The advance of the ISC front (mainly towards the top of pay) is faster along the AB side of the cell compared to the centre line of the cell (DC), which comprises the HP; the rate of oxygen supply is greater along the outside edge of the cell, in other words, the air flux is higher. This is very obvious from temperature distribution at 360 min;
- Even a short time after the anchoring of the ISC front at the toe, as the HP borehole guides the ISC front, the velocity of ISC front in the AB direction is slightly higher than that in the DC direction ($V_{AB}>V_{DC}$)
- It seems that the volume of the start-up region is essential for the subsequent development (and performance) of the THAI process. This is so in the context of the fact that *horizontally* the

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distribution of flow streamlines causes a faster advance of the ISC front in the AB direction (due to a faster burning velocity, related to a higher air flux on that direction)

- It seems that for SLD configuration, during the propagation of the ISC front, both in the start-up region and subsequently, there are two opposing factors contributing to a better volumetric sweep efficiency, namely:
    - Vertically: the gas-liquid segregation effect and the horizontal producer acting as a pressure sink
    - Horizontally: the flow pattern effect on one side and the horizontal producer as a sink, on the other side

While the gas-liquid segregation effect seems to be uniform irrespective of the location, the remaining effects vary with the distance from the horizontal section of the producer. Also, they have different intensity, while the ISC front is within the start-up region or beyond it.

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The major difference between SLD and DLD configuration is that in case of SLD, <u>*compensatory effects*</u> exist, but they do not occur in the DLD configuration; wedging effect occurs in DLD, leading to a poor sweep efficiency. The better sweep efficiency for SLD is not only due to the favorable geometric arrangement (like in waterflooding, for instance), but also it is related to the *additional favorable effect of variable air flux from the injection point region to the horizontal producer region, along the broad ISC front*; as per the configuration of the flow stream lines.

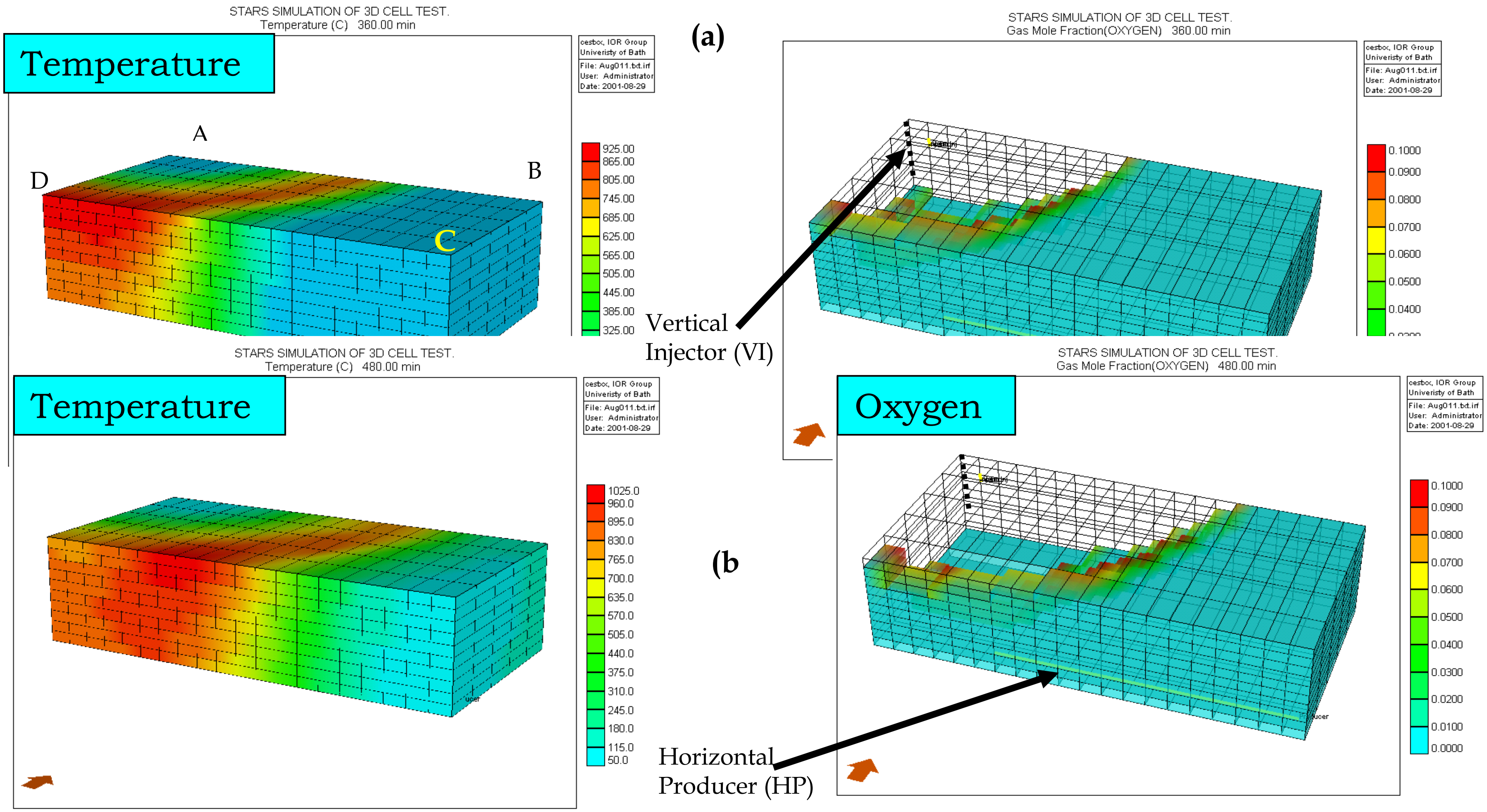

Figure 88a-b: Simulated temperature and oxygen distribution after 360 minutes (a) and 480 minutes (b) in a THAI laboratory test conducted in a staggered line drive (SLD) configuration – "2VIHP". Note: As an element of symmetry, only half of the combustion cell is simulated. Air injection well located at point A (Xia, 2002).

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Field Simulations: Two cases are provided here:

A. The cases of SLD and DLD for *oil with initial mobility at reservoir conditions*, when ignition was done without preliminary pre-heating, and no initial linear ISC front was generated (Andrade, 2015)

B. The case of DLD and SLD, with or without a broad, initial ISC linear front for *oil without mobility at reservoir conditions (Athabasca bitumen).* (Grabowski, 2016)

While the case A is part of the technical literature, case B was studied and analyzed as part of this Project. More details on the vase B are provided in Appendix J. The results for case B should be correlated with the results presented in Subchapter 7 for the Athabasca oil case, as well.

Case A: The SLD and DLD system and oil with some mobility: An in-depth simulation study investigated the performance of DLD and SLD configurations for a reservoir containing oil with viscosity of 917 cp (Andrade, 2015).

Unlike all other previous simulations, the kinetic model of Crookston and Culham was used. As in the simulation, the maximum temperature in the combustion zone is relatively low, probably they used some artifacts to impose the complete burning of the fuel at this relatively low peak temperature; however, a low fuel deposit coupled with high oxidability might have been a factor, as well. Their results must be used with caution. For this specific medium-heavy oil, the results obtained were the closest to those provided in the field THAI application both for oil production and oil recovery. The kinetic model incorporating 8-reactions may have contributed to that. The results of the simulation – mainly expressed in terms of ultimate oil recovery and oxygen utilization efficiency - showed *that the SLD is a superior configuration for application of the THAI process.*

This study seems to have correctly determined the limitation of the THAI in a DLD configuration, relative to the maximum air injection rate. A maximum value of 20,000 sm^3/day was found as the limit beyond which the process efficiency decreases. This is a very significant finding, in respect of DLD operation, and it seems to be consistent with the field tests analyzed in this Report.

Case B: DLD and SLD, with or without a broad, initial ISC linear front for Athabasca bitumen (Appendix J) : as mentioned, two cases are considered namely: 1) normal case with generation of the initial linear broad heat temperature region ISC front and 2) a case when just a *local heating/communication* (shoe of vertical injector – toe of horizontal producer) was realized, i.e. the configuration adopted in all of the field tests, so far.

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As mentioned, preliminary simulations of THAI were carried out in conjunction with the present Project; they were conducted to determine the effect of the extent of pre-heating on the effectiveness of the THAI process, (Grabowski, 2014). Using CMG's STAR simulator, it was found that pre-heating (of the full pay thickness), between injection wells (i.e. full communication: broad initial ISC front) was superior to the pre-heating with only local communication, for both DLD an SLD configuration. The former case (broad initial ISC front) quickly generated a tilting forward ISC front and heated a larger volume of rock to high temperature (418 ^{0}C). For the DLD case *with only local communication*, it was found that a more efficient ISC process is obtained when the pre-heating is conducted only on the upper half-thickness of the layer (as the tilting forward of the ISC front occurs earlier in the project).

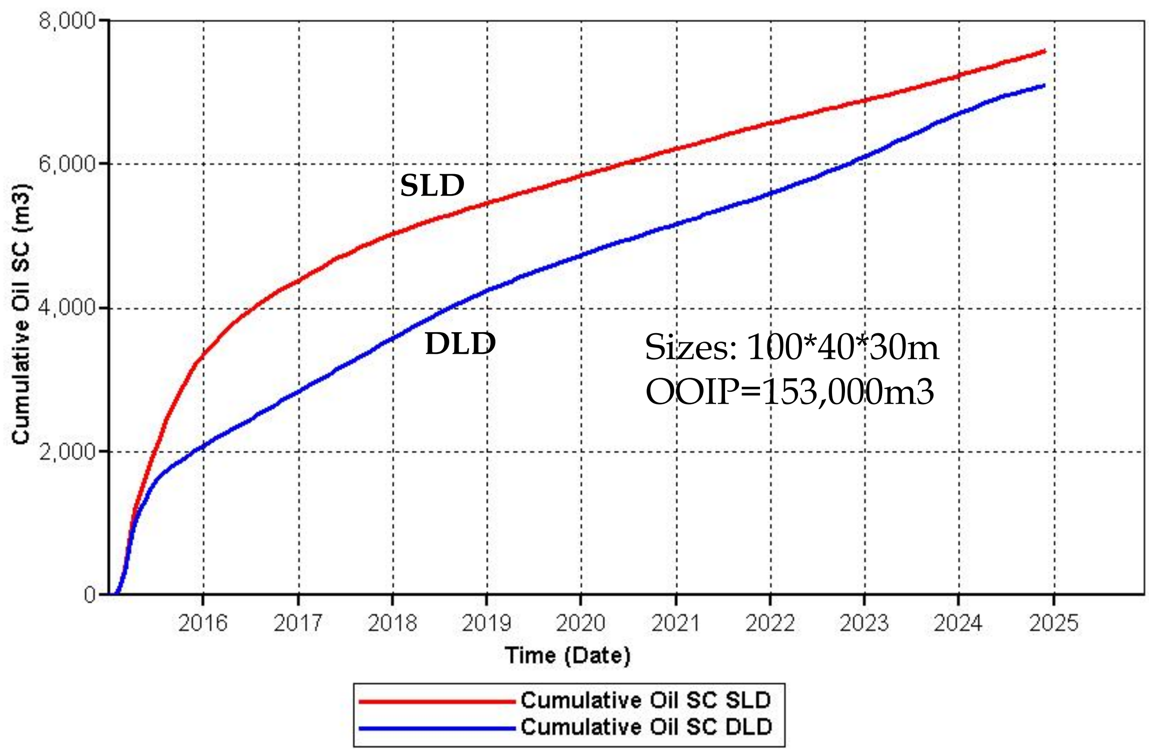

Fig. 89: Simulation results. Comparison of cumulative oil produced in DLD and SLD configurations (Grabowski, 2016). Note: this is the cumulative from the half of model, as simulated (symmetry considered)

When running both DLD and SLD configurations *with full initial communication, ie. broad initial ISC front,* it was found that the oil production for SLD is higher than the oil production for DLD; after 3 years, the oil recovery is 4%OOIP higher for SLD, and in time this difference is

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gradually decreasing; after 10 years, the oil recovery is still 2% higher for SLD. It should be mentioned that so far, the THAI projects have run for approximately 5 years. Figure 89 shows this difference and generally confirms the similar results presented in Figure 78 of Chapter 7.

The difference between Figures 78 and 89 at the beginning (first 3-4 months) is due to different procedures of pre-heating in the two cases; steam injection associated with the results in Figure 78 and intensive electrical simulated heating for the results in Figure 89.

More in-depth field-scale simulation has to be further conducted in order to understand the process completely; this proposed study should start with the following premises (as determined in this preliminary study by Grabowski, 2016):

- A threshold temperature, above which the deposition of coke occurs, should be established for each oil; currently, the coke can be deposited (according to most of kinetic reactions models used) even at reservoir temperature! But in reality, coke is only formed at higher temperatures. Typically, coke will begin to form (visbreaking) at around 250 – 330^{0}C, depending on the oil composition. At lower temperatures, reactions lead to coke precursors but not, actually, coke.
- At discrete, localized positions in the reservoir, depending on its position, two categories of coke generation may be considered in the THAI process:
    1. Coke from the rock volume in which oil originated (on the original spot *deposition*)
    2. Generated and burned or gasified at a location different from the original location (from oil flowing through the heated rock towards the production well); deposition/burning/gasification during oil traveling

For the first category, the mass of coke cannot exceed the mass of the oil originally in place; the coke is formed and burned at the same location. In the second category, the coke formation may happen far from the original location of the oil; this means that, as the discreet positions are closer to the horizontal producer, the amount of coke deposit may increase but, *for a certain short time*, cannot exceed the volume of that element; taken as a cumulative figure, however, it can exceed the volume of that element, as some coke may be burned/gasified (if O_2 or a gasification agent has a presence in that region) and other oil will flow again in that heated element of reservoir. The pronounced coke deposit around the horizontal producer may be building up due to this

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phenomenon. The existence of the second category of coke deposit should be tested with more specific laboratory work.

- Related to the previous point, efforts should be made to represent details of the potential coke deposit inside and around the borehole of the horizontal section of horizontal producer, mainly for the DLD configuration.

10.1.5. Correction of atomic apparent hydrogen-carbon (H/C) ratio for the CO_2 formed by coke gasification and water-gas shift reactions

The H/C ratio is an important indicator of the quality of burning; lower H/C values indicate a better quality of the burning, i.e. a higher peak temperature in the ISC front.

As mentioned, in the THAI process, we can talk about two categories of coke, namely:

- Coke from the rock volume in which oil originated (on the original spot *deposition*)
- Generated and burned or gasified at a location different from the original location of the oil (from oil flowing through the heated rock towards the production well); deposition/burning/gasification during oil traveling

At a high temperature, the non-in-situ coke is predominantly burned if oxygen (O_2) is present, while it is gasified if O_2 is not present but steam at a supercritical state is present; in the last situation hydrogen (H_2) is produced. There are many reactions producing H_2, but it is believed that the major mechanisms of hydrogen production are the coke gasification followed by water-gas shift reactions (Hallam, 1989, Kapadia 2011, 2013). Simply represented, they are:

$C + H_2O = CO + H_2$ (coke gasification) - endothermic reaction; eq. 1

$CO + H_2O = CO_2 + H_2$ (water-gas shift reaction) – exothermic reaction; eq. 2

Considering only these two major reactions in Appendix L we tried to estimate how much CO_2 does not come from pure oxidation (with the oxygen injected). From previous chemical equations (1 and 2), it results that 2 moles of H_2O participating in the consecutive reactions of coke gasification and water-gas shift reactions (WGSR) are associated with the production of one mole of CO_2 and 2 moles of H_2. Therefore, all in all, 2 moles of H_2 corresponds to 1 mol of CO2, which is not coming directly from an oxidation process.

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More generally, the number of moles of CO_2, which are not coming directly from an oxidation process, is half the number of H_2 moles found in the produced gas.

Globally speaking, the endothermicity is higher than exothermic, when considering both reactions; however, this will not be taken into account in our future considerations.

It is now well established that H_2 production occurs in the THAI process and the Pressure-Cycling In-Situ Combustion (PC-ISC) process, but not (usually) in the conventional in-situ combustion (ISC) process. Therefore, in these two processes there are conditions when/where O_2 does not exist any more; in PC-ISC these conditions are created when air injection is stopped and oil is flowing in the overheated zones, *while in THAI process these conditions may be found along the burning surface towards the horizontal section of the producer*.

In connection with the existence of these two categories of coke in the THAI process, the most important aspects to be clarified are:

- To evaluate how much CO_2 is generated from the burning process and how much is due to the coke gasification and water-gas shift reactions;
- To assess how accurately the apparent hydrogen/carbon ratio (H/C) can be calculated in order to characterize better, *exclusively*, the oxidation process.

To solve the first point, the amount of H_2 produced may be an indicator, *although not perfect.* *In case that the water-gas shift reactions consume entirely all CO from coke gasification and practically only CO_2 is formed, it means that the CO_2 formed in this way should be somehow equivalent to the H_2 produced*. For this more straightforward case, the second aspect can be approached as well, as the (H/C) may be calculated more precisely after reducing the CO_2 recorded by subtracting the CO_2 corresponding to H_2 generation($CO_{2coke\text{-}gas}$). This way, we can adjust (reduce) the CO_2 percentage further used in the calculation of H/C ratio, and this more correct value would be called $CO_{2\text{-}burn}$. *This is necessary as the H/C ratio is supposed to characterize only the burning process.*

One question mark still remains; what about if the CO percentage in the combustion gas is high? How is this affecting our calculations? This is a difficult question to answer; either some CO formed in the coke gasification did not participate in the second reaction (water-gas shift reaction), or there was excessive CO amount formed from oxidation or other reasons. Therefore, in this case, it is more difficult to assume that our hypothesis (equivalence with H_2 of the $CO_{2coke\text{-}}$

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$_{gas}$) is valid. Moreover, means to distinguish between CO generated by oxidation and CO generated in our analyzed/displayed reactions are not developed yet. *Therefore, for the beginning, we are going to deal only with cases where CO percentage is extremely low, and it can be considered negligible.* The simple case of NIL CO production has been practically a reality in the Kerrobert THAI process. Therefore, it is assumed that in this case, all the CO generated from the first reaction (coke gasification) is used in the water-gas shift reaction producing CO_2. This way, the attempt to estimate the $CO_{2coke\text{-}gas}$ and $CO_{2\text{-}burn}$ has correct premises.

In Appendix K we analyzed first the simplest case of practically NIL CO (Kerrobert case) and then the more complicated case of high CO in the combustion gases (Witesands case); more details on the analysis of Kerrobet case are also provided, elsewhere (Turta 2019). It should, however, be understood that the results from Whitesands constitute just a starting point, and they need by far more verifications.

For Kerrobert Project first, we analyzed an example by considering the KP2 producer, which has detailed gas composition data for 2015 (Table 14), where the CO percentage was less than 0.1% and H_2=1.4%

As mentioned, from the 2 consecutive chemical equations 1 and 2, it results that 2 moles of H_2O participating in the reactions of coke gasification and water-gas shift reactions, produce one mole of CO_2 and 2 moles of H_2. Therefore, for a number "N" of H_2 molecules produced, "N/2" molecules of CO_2 are generated. In that case, the CO_2 percentage due to coke gasification ($CO_{2coke\text{-}gas}$) will be half of the H_2 percentage.

As the current H_2% is H_2=1.4%, translated to percentage, the $CO_{2coke\text{-}gas}$ will correspond to approximately 0.7%. Consequently, the CO_2 percentage due to pure burning will be:

$CO_{2\text{-}burn} = CO_{2\text{-}r} - CO_{2\text{-}coke\text{-}gas}$, where $CO_{2\text{-}r}$ is the recorded value of CO_2 percentage.

$CO_{2\text{-}burn} = 0.155 - 0.007 = 0.148$ (14.8%)

The recorded average composition for December 2015 was:

CO_2=15.5%; CO=0.05%; O_2=0.22; N_2=77%; H_2 =1.4%; CH_4=3%; C_2^+=1% and H_2S=0.4%

Based on this composition, and taking into account the gases not participating directly to the oxidation, the so called foreign gases (FG = $H_2 + CH_4 + C_2^+ + H_2S$) for H/C ratio calculation, the equation 1 applies, where FG=6.6%:

$$H/C = (1-(FG/100)) \{[106 \;/\; (CO_2+CO)] + [2CO-5.06\,(CO_2+CO+O_2)] \;/\; (CO_2+CO)\} \qquad \text{eq. 3 (Turta, 1971, 1975)}$$

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$H/C = [106+2CO-5.06\ (CO_2+CO+O_2)]\ /\ (CO_2+CO)$ eq. 4(Moss and White, 1986?)

Equations 3 and 4 are equivalent and give the same results. While in equation 3 the percentages as recorded are applied, when using equation 4, the normalized percentages of CO_2, CO and O_2 have to be used.

In order to normalize, from the recorded composition :

CO_2=15.5%; CO=0.05%; O_2=0.22; N_2=77%, we have:

CO_2 % + CO% + O_2 % + N_2 %= 93.4% and 93.4 will be the new base for calculation of normalized percentages, i.e.:

CO_2=15.5/93.4=16.6%; CO=0.05/93.4=0.054%; O_2=0.22/93.4=0.236% and

N_2=77/93.4=82.44 %, with 16.6+0.054+0.236+82.44=99.3%

Application of the equation 3, or of equation 4 (using the normalized percentages, just calculated), would give:

H/C = 1.24

But in order to correct for the CO_2, which is generated by coke gasification, for the calculation of a more representative H/C ratio, when using the equation 3, the average percentages of gases should be considered, as follows:

CO_2=14.8%; CO=0.05%; O_2=0.22; N_2=77%; H_2 =1.4%; CH_4=3%; C_2^+=1%, H_2S=0.4% and $CO_{2coke\text{-}gas}$ =0.7%. Furthermore, in the equation of H/C, the percentage of $CO_{2coke\text{-}gas}$ is to be considered as part of foreign gases.

Applying eq 3 with the last values, the calculated H/C ratio will be **1.49**, as compared with 1.24 when the correction for coke gasification was not considered.

This fully corrected value (1.49) is higher. Therefore, without correction, the value of H/C is smaller (1.25), which *artificially* shows a better quality of burning than in reality.

Similar calculations for a day when the CO_2 was maximum (16%) and another day, when the CO_2 was minimum (14.62%) - highlighted in Table 14 - gave H/C values of 1.17 and 1.58, respectively, while with coke gasification and WGSR corrections these values increased to 1.39 and 1.87, respectively. It can be noghghticed that with or without correction, the values suggest a higher peak temperature for the case when CO_2 was maximum.

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Accepting the same hypotheses, similar calculations were made for the Whitesands Project based on the gas composition of producers P1 and P2 in January 2009, that is after two years of process and just before the stoppage of air injection in the injectors A1 and A2, therefore when the process was well established. This composition is provided in Table 22 and reproduced in the Table K1 from Appendix K.

In Whitesands Pilot, both H_2 and hydrocarbon content of gas is higher than in Kerrobert Project; also, CO content is a lot higher. The last but one column in Table 22 shows our normal (non-corrected for coke gasification) H/C ratio calculation; the foreign gases (H_2, CH_4, C2+ and H_2S) were taken into account. Our results are extremely close to those of Petrobank, and for further comparison - between non-corrected and corrected H/C - the Petrobank values were used.

As an example, for P1 and P2 producers, in January 2009, the H/C values were 0.74 and 1.08, respectively, while with coke gasification correction, these values increased to 1.58 and 1.47, respectively.

Rapid inspection of Table 22 reveals that the highest corrections were found for P1 producer in January and February 2009; 1.58 versus 0.74 and 1.47 versus 1.08 (more than 30% increase). On the other hand, the lowest correction was found for P2 producer in May 2009; 1.26 versus 1.01 (less than 20% increase). As expected, the highest and the lowest corrections correlate very well with the value of H_2 percentage. Another observation is that for P2 producer in June and July 2009 the corrected H/C ratio is practically identic, reflecting the same quality of burning, while according to the non-corrected H/C the quality of burning would be a lot different (better in July); however, the value of H/C of 0.39, in July, seems to be dubious, being by far too low.

For Whitesands Pilot, the current estimates are more prone to errors and more verifications are necessary. First of all, it has to be demonstrated that all the assumptions accepted for Kerrobert (where CO was practically NIL) remain valid for Whitesands Pilot, which produced a lot more CO. In other words, the new calculated values of H/C can be correct or either overestimated or underestimated, depending on the origin of CO; if all the recorded CO has nothing to do with coke gasification – all CO is from oxidation reactions - then our calculations are rigorously correct. If part of recorded CO is from a non-complete participation (of the CO from coke gasification) in the water-gas shift reactions, then the H/C value may be underestimated. if some CO from oxidation reactions participated in water-gas shift reactions, then it may be overestimated.

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Table 22: Whitesands Pilot. Combustion gas composition in the period January-July 2009. Verification of the apparent atomic hydrogen-carbon ratio (AAHCR) and calculation of the AAHCR corrected for the coke gasification and water-gas shift reactions ($AAHCR_{cor}$)

Legend: AAHCR=Apparent atomic hydrogen-carbon ratio

P1 Monthly Gas Analysis

Month	H2	O_2	N_2	CO	CH_4	CO_2	C_2H_6	C_3H_8	C_4	C_5	H_2S	Total	CO_2/CO RATIO	AAHCR	Petro-bank	This Work AAHCR	AAHCR corrected for coke gasification
Jan-09	5.14	0.23	71.23	1.90	4.83	14.71	0.82	0.42	0.11	0.06	0.56	100.01	7.85	0.74		0.72	1.58
Feb-09	5.25	0.28	69.85	2.38	6.36	13.74	0.90	0.47	0.11	0.06	0.59	100.00	5.92	0.85		0.82	1.73
Mar-09	3.56	0.20	73.06	1.62	5.59	13.95	0.86	0.49	0.12	0.06	0.49	100.01	10.31	1.16		1.13	1.79
Shut-In																	

P2 Monthly Gas Analysis

Month	H2	O_2	N_2	CO	CH_4	CO_2	C_2H_6	C_3H_8	C_4	C_5	H_2S	Total	CO_2/CO RATIO	AAHCR	Petro-bank	This Work AAHCR	AAHCR corrected for coke gasification
Jan-09	2.38	0.24	74.25	0.64	5.39	14.99	0.99	0.52	0.13	0.06	0.40	100.00	23.58	1.08		1.05	1.47
Feb-09	2.28	0.24	75.66	0.65	4.68	14.54	0.84	0.54	0.12	0.07	0.39	100.00	22.80	1.33		1.3	1.73
Mar-09	1.66	0.22	77.29	0.65	3.73	15.10	0.58	0.37	0.09	0.04	0.26	100.00	23.67	1.25		1.23	1.52
Apr-09	2.44	0.26	73.60	0.79	5.87	15.58	0.62	0.35	0.08	0.04	0.35	100.00	20.35	0.82		0.80	1.19
May-09	1.64	0.35	75.52	0.50	5.21	15.47	0.60	0.32	0.07	0.04	0.29	100.00	31.96	1.01		0.99	1.26
Jun-09	1.71	0.58	76.29	0.70	3.51	16.01	0.52	0.28	0.07	0.03	0.31	100.00	24.70	0.82		0.79	1.04
Jul-09	1.89	0.48	73.99	0.64	4.56	17.30	0.47	0.28	0.06	0.03	0.31	100.00	27.52	0.39		0.34	1.04
Shut-In																	

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Looking at the new values of H/C obtained after the correction for coke gasification and water-gas shift reactions we can conclude that in some cases there is some – although very small amount – low-temperature oxidation (LTO); values of 1.7-1.9 suggest some limited amount of LTO reactions taking place. It may be difficult to find where they occur as oxygen percentage is always extremely low (less than 0.3%); even some LTO reactions in the wellbore of the horizontal producer cannot be ruled-out, but this was not possible to be correlated/checked with temperature profiles along the horizontal section of producers, as these profiles are not available exactly on those months when the calculations were performed.

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The last important aspect relative to the chemical mechanisms of THAI is to clarify if there is a correlation between oil upgrading and H_2 production. If there is one, it has to be established, mainly if this is a direct or a reverse correlation. In other words, to determine if it is possible to conduct the process in such a way that either upgrading or H_2 production is promoted; they may be tightly correlated and challenging to enhance one or the other. This is a more complicated aspect, and, probably, the specialists from refineries/upgraders should be involved.

10.2. CAPRI (**CA**talytic upgrading **PR**ocess **I**n-situ)

So far, most laboratory investigations in this area used solid catalysts (fixed-bed catalyst). To improve catalyst performance and advance the CAPRI technology, the following aspects need more in-depth considerations:

- The main similarities and differences between in situ and surface upgrading should be well understood. A comparison should be made regarding the thermodynamics, mechanisms and kinetics between CAPRI type processes and the refinery type processes, respectively. Processing of heavy oils may undergo a complex array of thermo-catalytic reactions associated with carbon removal – by delayed coking, viscosity reduction – by visbreaking, molecular weight reduction – by thermal and/or catalytic cracking, hydrogen addition – by hydrotreating / hydrocracking, etc.
- Catalyst loading, expressed as grams catalyst/grams oil ratio (‘CTO - catalyst-to-oil ratio’), was generally high in the THAI laboratory tests; there was an approximately linear increase in upgrading

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with increasing this CTO ratio. On the other hand, this ratio from refineries/upgraders may not be very relevant and/or directly applicable for in situ CAPRI upgrading.

- The influence of less controlled conditions in the field (hot water/steam production, sand influx, etc.) has not been examined. In the laboratory tests, the initial water saturation was low (10-20%). To be representative, tests with up to 40-50% water saturation should be conducted. Also, wet combustion CAPRI tests involving very low water-air ratios should be contemplated, especially if horizontal wells are favored for air injection in the future.
- If the potential of hydrogen production of the CAPRI process is higher, compared with that of the THAI process, then the producing mechanisms favoring that should be clarified. Precisely, tailored laboratory tests should be planned to emphasize this effect.

Investigations to select the most efficient catalysts for CAPRI process have been carried out systematically for the last consecutive 10 years in University of Birmingham, UK, and they continue (Wood, Hart, Shah, Al-Marshed, Dim, Brown, 2011-2016). It was found that catalyst fouling can drastically reduce upgrading, and hence practical means to combat are needed. Hart (2012-2014) investigated the use of guard layers to mitigate this adverse effect.

Overall, the conclusion (Hart, 2015) is that using an in-situ fixed-bed catalyst – despite the good results: 2-7 ^{0}API increase, 80% viscosity reduction, etc. – coke, asphaltenes and metal deposition drastically deactivate the catalyst. The investigations into the use of catalyst nano-particles - probably *introduced in the mobile oil zone (MOZ)* - with a batch reactor at 425 ^{0}C and a residence time of 10 minutes, showed an 8-10 ^{0} API increase and over 90% oil viscosity reduction. Hart's experiments showed sustained catalyst activity for up to 77.5 hours (approximately 3 days); this value of the maximum catalyst lifetime is still low for a field application.

Compared to THAI, the CAPRI process has been much less investigated in the laboratory and also theoretically. Many aspects of the process are not fully understood. Despite this, Petrobank carried out a limited field pilot (for about 3 months) in 2008. The results were not very conclusive, confirming the need for by far more laboratory investigations.

The field testing occurred within the frame of Whitesands Pilot in Athabasca, and Petrobank used one of the replacement wells (P3B -see Subchapter 6.1.4). The fixed-bed catalyst was enclosed between two concentric slotted liners (exterior liner 9 5/8"; interior liner 5 1/2") (Fig. 90). The concentric slotted liners containing the catalyst were pre-fabricated before being installed in the well. The "catalytic slotted liners", the so-called "CAPRI liners", were introduced one by one for the whole length of the horizontal section, from the heel and ending at the toe. It seems that the CAPRI liners lasted a maximum of 3

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months; it was possible that due to poisoning and other factors, the catalyst became inactivated, became mushy, and might have even restricted the flow. During CAPRI testing there was no noticeable oil production increase/reduction and change in the content of hydrogen and CO of the produced gas (Figs 45c and 51c), believed to be related to the catalyst presence (air injection interruption, before and after CAPRI testing period, seemed to have a higher impact on gas composition). More likely, the incremental upgrading obtained did not justify the upfront investment. However, on the positive side, it was demonstrated that a catalyst pre-packed screen could be installed. Of course, in the future, the catalyst gravel packing concept could also be tried, and this may allow the construction of a thicker wall of catalyst around the well, therefore increasing the residence time (and catalyst to oil ratio) for the flowing oil.

The future investigations in the area of CAPRI process should be tightly correlated with the progress made in the application of THAI process; they should monitor and follow the THAI advancements. However, these CAPRI investigations, although not probably to come with a quick solution, should be continued as the underground upgrading can increase the value of crude oil (due to direct field partial upgrading) by at least US$ 0.5/bbl of oil, for each of API degree upgrading (Ovalles, 2016). As the average underground upgrading is 3-4 ^{0}API, this is equivalent to at least US$1.5-2/bbl of oil upgraded in the THAI process, and of course, it may be even higher, when a CAPRI efficient process is developed and brings incremental upgrading.

Additionally, the future investigations should approach in a correlating manner the integrating achievement of underground upgrading and hydrogen production, with the potential to control the process towards enhancing upgrading or hydrogen production.

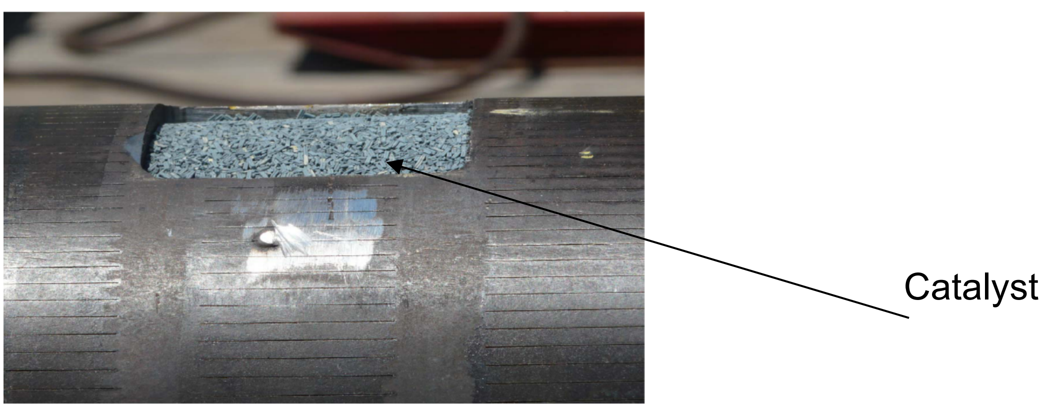

Fig. 90: Horizontal section of horizontal producer P3b of the Whitesands Pilot, converted to a catalytic "downhole reactor" in the CAPRI testing in the period August-October 2008 (2009 Petrobank Presentation to ERCB)

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11 . THAI as a "Stumble Upon" Process

This chapter gives a few thermal applications in which the basic knowledge of THAI is necessary. The meaning of "THAI, as a ", Stumble Upon' Process", is related to the fact that any time a horizontal producer is to be drilled in a thermal process (mainly ISC), basic knowledge of THAI is a condition "sine-qua-non" for the success.

First of all, it has to be emphasized that the application of THAI process in light oil reservoirs proved to be a lot more challenging than in heavy oil reservoirs. This was seen in the laboratory tests. There is insufficient fuel to produce the coke plug, and, also, there is a pronounced oil de-saturation ahead of the mobile oil zone (MOZ), which allows more O_2 to get into the horizontal producer before being consumed in the ISC front. Therefore, for the time being, *THAI/CAPRI processes are restricted mainly to heavy oil recovery.*

For the successful application of THAI, the following general principles should be strictly respected:

1. High permeability pathway at the bottom of the layer (Horizontal Producer- HP)
2. Vertical air injector (s) has to be located within the drainage area of the toe of the horizontal producer
3. Proper anchoring of the ISC front to the toe of corresponding horizontal producer
4. Existence of self-healing features in the advancement of the displacement front (along the high HW); local plugging being the one and controlled gravity segregation being the second one
5. Existence of *a **hot region** of high fluid mobility behind the displacement front and a **relatively low temperature region** of low fluid mobility* ahead of displacement front (along or parallel to the HP), with a tilting forward of the separation between these two regions

Looking at these conditions, it is easy to understand why the THAI process has problems when its application to light oils is contemplated; the formation of the coke-plug is not fully ensured, while some air can penetrate towards the horizontal-producer-sink without passing through the ISC front (conditions 4 and 5 are not fully met).

More details on each condition are provided below:

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- If condition 1 is not fully met, the process may still work up to the point where the high permeability pathway is located towards the middle of the layer; but as the location is higher within the pay interval, the performance decreases progressively. Finally, with a high permeability pathway at the top of the layer, it may almost entirely cease to work.
- Condition 2 is a "sine-qua" condition, as, without the successful anchoring of the ISC front, the THAI or a similar process cannot exist.
- Condition 3 requires that the ISC front divides a hot region of high mobility behind and low mobility ahead of the ISC front and also is very critical; low mobility ahead (of the ISC front) does not necessarily mean cold rock, but even when the temperature is raised it should be moderate and oil still must have some level of low mobility, compared to that behind the front. This moderate temperature ahead of the ISC front is necessary to avoid the intensive coke generation on a very long portion, which eventually leads to the total blockage of the producer, loss of production well. This is the reason that the horizontal producer needs to be pre-heated (before putting it in production) at a minimum (to allow drainage of the oil displaced by ISC front).
- The condition 4 of forward-leaning of the ISC front is an essential condition for the success of the process. Lack of forward-tilting means that the displacement will have a tendency to "channeling" via the horizontal producer, usually leading to a premature end of the test. This important aspect should be considered during the design phase, *by designing a proper geometric configuration and correspondingly a proper start-up region size*, taking into account the mobility of the oil, the method of creation of the broad ISC front (including the hot link), etc . In case of not properly designed start-up region (therefore, not a reliable controlled over-ride of the ISC front), the coke-local blocking to avoid oxygen short-circuit is important; when this is not fully respected, O_2 in the flue gases can increase over 4-6% and a burn-out can occur in the horizontal section of the horizontal well; the well can be damaged.

THAI Application in Heavy Oil Reservoirs with Gas Caps: In cases where the gas cap is not extensive (less than 0.3 volume of oil zone) THAI application is possible, provided that the economic losses due to the loss of the injected air into the gas cap (for pressurization of the gas cap) are not too high. There are two situations:

- Gas cap with zero oil saturation
- Gas cap with non-zero oil saturation (which is normally residual oil saturation in all oil sand reservoirs)

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In the first case, laboratory tests showed relatively good results (Xia, 2002). However, *to keep the ISC front strongly anchored to the horizontal producer*, only THAI in a DLD configuration may be technically feasible, and this would result in a lower efficiency compared to the case of SLD configuration, in which anchoring of the ISC front to the toe may be a challenge.

An example of the second situation is a reservoir with gas-over-bitumen (GOB), where the pressurization of the gas cap is necessary in order to assure a successful subsequent SAGD application. In this case an ISC scheme was designed to be run in the gas cap to generate flue gas in-situ (EnCAID process) and was field-tested by Cenovus (Freeman, 2008). Although an ISC front was generated and conducted into the gas zone, the combustion also partially penetrated in the bitumen zone. This caused the operator to drill a non-initially planned horizontal producer; this was drilled in the bitumen zone to capture the mobilized oil (Hogue, 2015). Eventually, the horizontal producer was re-completed in order to encourage flow towards the toe, i.e., they *inadvertently* converted to a quasi-THAI process, operated in a quasi-staggered line drive configuration. It confirmed again that THAI is a stumble-upon process; the knowledge of THAI would have helped significantly! Extensive field simulations are necessary to justify a field application in both situations.

Feasibility of THAI application after CHOPS (cold heavy oil production with sands) exploitation: Laboratory tests for an oversimplified case of. a "single" wormhole located in the axis of a large-diameter cylinder containing sand saturated with heavy oil provided encouraging results (Chen, 2012). However, designing the best approach for scaling up to field scale application is almost impossible, as reliable, adequate technical means to have a full characterization of the architecture of the reservoir (matrix+wormholes) at the end of CHOPS exploitation *do not exist at this point*. Any way, in case this characterization of the architecture of the reservoir could exist, the knowledge from THAI is still necessary in order to design at least a horizontal producer to compete/cooperate with the wormhole (s) and function properly.

Feasibility of converting an existing conventional ISC project to a THAI application: This could be easily feasible in cases where the current conventional ISC project is conducted in a DLD configuration, starting updip and moving in the downdip direction. In this case, the horizontal producers could be placed as in-fill wells, between rows of vertical producers (perpendicular on strike) with their updip-toes just ahead of the existing ISC "linear" ISC front. *In this case there is no need for an initial communication or an ignition operation*; the horizontal producers are ready to start producing. More details on this topic are presented in subchapter 11.1, and the illustrations for THAI application in a DLD configuration or an SLD configuration are provided in Figures 88a and 88b.

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Post-Steam Flood Application of THAI: There has been very little activity in investigating the application of THAI after conventional steam flooding. Recent successful semi-commercial projects of *conventional ISC* after steamflooding operations widened the prospective areas for ISC application; these are discussed in the next chapter.

After several years of steamflooding most reservoirs have both heated zones and un-heated zones. On the one hand, the application of THAI for the un-heated zones is a regular operation. Still, it may necessitate full communication and generation of the broad ISC front using more complex operations, while, on the other hand, the already heated zones should be treated almost like zones already having the communications paths, to some extent as for light oil cases. As shown previously, the THAI application to lighter oils is more difficult. In this particular case, i.e., application in intensely heated zones, the choice between conventional ISC and that of THAI applications should be made based on extensive simulations. At the entire reservoir scale, sometimes, it may be worthwhile to apply both methods, side-by-side.

Feasibility of THAI application as a SAGD Follow-up Process: As shown previously (section 8.1.3.2), in the tentative to test a quasi-THA operation with two horizontal wells in a laboratory set up, the main problem was the protection of the lower production well from the exceedingly high temperatures generated by the ISC front generated in the horizontal injector located just above. That's why the injection well was positioned at the top of the layer, with the horizontal producer at the bottom, therefore enlarging the distance between them. Only doing this, it was possible to complete the test in the laboratory. However, uncontrollable blockages of the horizontal production well occurred. In other words, not only a coke-plug formed (local blockage) *and helped the process like in a standard THAI process, but because of the exceedingly high temperatures on a very large section along the producer, too much coke was formed, and it totally blocked the horizontal producer* (Rahnema, 2011 and 2012).

Therefore, ISC application as a follow-up to SAGD or in a SAGD-type configuration needs to cope with this ever-present problem of blocking of the production well. This is where the knowledge from the THAI area is beneficial. G*enerally, those investigators trying to develop post-SAGD-ISC processes – irrespective if THAI process is accepted or not (by them) – they have to understand THAI mechanisms (mainly local plugging phenomenon). That's why it is safe to say that THAI will always constitute "a stumble upon" process, anytime somebody tries to use a horizontal producer in a novel post-thermal ISC process.*

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12. ISC AS A TERTIARY EOR PROCESS. FUTURE GENERATIONS OF ISC PROCESSES

Conventional in-situ combustion (ISC) is generally perceived *to be a complicated process*. Previous experience with the process was usually fraught with difficulties in controlling the process, compared with other EOR processes. When it attracted considerable interest during the 1970s and 1980s, in many cases, operators had only a superficial understanding of the ISC process; at that time, there was also very little understanding of the reservoir itself, or a poor choice of the candidate reservoir was made.

Ignition operations, in many cases, led to subsequent problems. Even when the ignition was appropriately conducted, the remedial measures (to fully control the propagation of the ISC front in various directions) were not very effective. The design of the process that takes into account various reservoir conditions (mainly heterogeneity and dip) is more important than in any other EOR process; the process design is crucial for the success of ISC projects. Unlike any other EOR processes, the operator must take an integral approach even at the design stage. The exploitation of the whole reservoir by ISC needs to be evaluated. In other words, an ISC pilot should be considered as an integral part of a future commercial-scale exploitation plan.

Recently, advances have been made for controlling the process. An example is via the THAI process. Here, the horizontal production well creates an *'in-built' guidance path for the movement of the combustion front*. However, as discussed in the previous section, further improvements are necessary in the area of sweep efficiency, to increase the efficiency of THAI.

ISC has often been applied *as a tertiary process* in the field, after waterflooding, **c**yclic **s**team **s**timulation (CSS) and steamdrive, and ways to apply it as a post-SAGD operation have been intensely investigated. In this section, these topics are further explored, first for the potential of conventional ISC and finally for the potential of THAI.

12.1. Conventional ISC as a Tertiary EOR Process after Waterflooding and Steamflooding

12.1.1 Post-waterflood ISC: The most extensive application of ISC as a post-waterflooding, tertiary process was undertaken in the Videle-Balaria Reservoir (Petcovici, 1982, Turta, 1986 and Machedon 1994). The reservoir is located at a depth of 400-600m, and it is thin (3-8m); the oil viscosity is in the range of 40-1,000cp, and the reservoir temperature is 46 ^{0}C. At the start of ISC application, oil recovery was in the range of 14-22%, while water cut was in the range of 85-95%. The ISC was conducted at a semi-commercial/ commercial scale for more than 15 years, using a large well spacing (300-400m). Chemical ignition using linseed oil was successfully applied in this project. Although technically

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successful, the air-oil ratio (in the range of 4,000-7000 sm^3/m^3) was too high, and the project was considered marginal and discontinued; it was not implemented in the entire reservoir. *Therefore, the post-waterflooding conventional ISC is still not proven commercially at this time.* It is likely, however, that the proof can come in case that the original temperature of waterflooded heavy oil reservoir is high and it remains relatively high even after waterflooding; also, another ingredient for success would be the existence of a good dip and a line drive ISC application feasible.

At this time, the use of ISC with horizontal wells is considered only when vertical wells result in very high water cuts as a direct result of channeling of water (water under-riding). In case high water cut results from uniform pattern waterflooding (not much channeling), the chances for successful ISC are a lot lower. This may be the case for the THAI application, as well. Great caution should be exercised as the performance of THAI deteriorates with increasing average water saturation in the reservoir; in many cases, it may not be feasible.

12.1.2 Post-steamflood ISC:

As far as the tertiary application of conventional ISC after steamflooding is concerned, this is at the field semi-commercial stage. The results, so far, are very encouraging for the planning of a future commercial application. The main data for four, very different cases, are shown in Tables 23a-b; oil viscosity was between 100 and 9,000 cp. In all cases, dry ISC process was applied.

Charco Redondo Project (Haynes, 1976; Howard, 1976; Widmyer, 1976 and Widmyer 1977): This project used a very sophisticated network of 20 observation wells, mainly for the study of heat losses in adjacent formations during steamflooding. Initiation of ISC (ignition operation) was conducted in the former steam injection well using a strong ignition procedure, typically using a gas burner for over 20 days.

Before ignition, oil saturation near the future air injection well was measured and was found to be very low (6-10%). Despite the perception regarding the ease of ignition in wells pre-heated via steam injection, it needs to be stressed out that there are some negative factors which may "contribute" to a problematic ignition. The most important of them is the presence of the least reactive fractions of oil along with a high water saturation in the vicinity of the injection well. This explains why the ignition took more than 20 days, even when using a powerful ignition method (gas burner); usually, only 3-5 days are sufficient with the use of a gas burner.

Midway Sunset, Potter Sand: Steamdrive was implemented for 4 years in an inverted five-spot (located updip), and subsequently, an experimental ISC process was deployed for secondary recovery of oil, for a period exceeding 2 years (Couniham, 1977). At the start of the ISC process, the reservoir temperature was

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99^0C, as compared with the original reservoir temperature of 49^0C. An air injection rate of 28,000 sm^3/day was used, and the performance was very good, as the oil rate (obtained during steamflood) was maintained for two more years at an air-oil ratio of 1,700 sm^3/m^3. Ultimate oil recovery increased from 37% to 73%. N*o excessive bottomhole temperatures were recorded in the production wells.*

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Table 23a: Reservoir Properties and Steamflooding Parameters

Reservoir temperature range: 18-23 ^{0}C (except Midway Sunset, where it is 49 ^{0}C)

Cur-rent No.	Project/ Company/ Country	Reservoir Properties			Steam flooding				Obs
-	-	Depth m	Pay thickness m	Dead oil visc. cp	Duration Years	Pattern Size ha	No. of patterns	Results	
1	Charco Redondo, Texaco, Tx, USA	61	3	95	>4	1	1	SOR:20 S_{ro}=9%	
2	Midway Sunset, Potter Sand, Chanslor-Western Oil , Ca, USA	500	21	1,630	4	?	1		
3	Suplacu de Barcau, Petrom, Romania	120	6-8	2,000	5-6	2	6	UOR=27 %	
4	Bloc H1, Jurassic Badaowan Formation, Petrochina, Xinjiang,China	550	8	9,000 - 11,000	>10	<1	3	UOR=30% 100% W/C	Very hetero-geneous formation

Legend:

UOR=Ultimate oil recovery; S_{ro}=Residual oil saturation after steamflooding (field measurement); 100% W/C= CSS & Steam flooding conducted until 100% water-cut was recorded

Suplacu de Barcau (Machedon, 1993 and 1994): There were two events to demonstrate the benefits of a higher ultimate oil recovery by ISC.

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1) Six 4ha inverted nine-spots were exploited using steamdrive for 6 years, and an oil recovery of 27% was obtained. In parallel, an adjacent region containing six 4ha inverted nine-spot patterns were exploited via ISC for 7 years, and an ultimate oil recovery of 41% was obtained.

2) Subsequently, the main line-drive commercial ISC front (generated at a higher isobath) was used for the second harvest of oil (while ISC front propagated through the former steamflood region, mentioned above). The oil recovery increased from 27% to 52%, and the air-oil ratio was about 2,000 sm^3/m^3. The results are considered very good. A powerfull ignition device (gas burner) was used for the initiation of the ISC process.

Bloc H1 in Xinjiang Oil Field (Guam, 2013 and Changfeng, 2016); This is the most recent project; it started in 2009. The region was exploited via steam injection (CSS and steam drive) for 10 years. When the ISC was implemented, *it was actually in a tertiary mode, as the water cut was virtually 100%.* Here, again, as in the previous cases, a strong ignition device (electrical heater) was used; during the ignition, the temperature within the perforation was kept at 450^0C. Initially, three updip wells were ignited for ISC in three adjacent 9-spot patterns; thereafter, four more air injection wells were added such that an updip line drive was formed. The project included 16 production wells. After 4 years of line-drive operation, very favorable results were obtained. The test was convincingly successful, as the water cut decreased to 60%, while oil production started at around 10t/day, and gradually rose to as high as 50t/day (Figure 91). Air-oil ratio (AOR) started at around 5,000 sm^3/m^3, and gradually decreased to as low as 2,200 sm^3/m^3. The cumulative oil produced was 23,000m^3 for the 3 years of testing; an increase of oil recovery from 30% to 65% is predicted. The last author analyzing this process reports a high temperature (500 ^{0}C) in the perforation of a producer and is highlighting the fact that the ISC process worked very well despite the high heterogeneity of the Jurassic Badaowan formation (Changfeng, 2016).

The last three tabulated cases indicate the increase in oil recovery at a reasonable AOR. It was seen that oil recovery could increase very significantly from 27-37% (average 32%) to 52-73% (average 62.5). At the same time, the bulk of incremental oil was obtained at low AOR (in the range of 1,700-3,500sm^3/m^3); these AOR ratios are relatively low considering that the ISC process was implemented in a tertiary mode.

It is important to mention that there were significant periods between the end of steamflooding and start of ISC application; in the two cases analyzed – Suplacu de Barcau and Bloc H1 in Xinjiang - these periods were 5-6 years. However, it is difficult to definitively conclude whether this delay had significant *positive influence* on ISC performance; it should be quantified. It is speculated that a minimum of 2-3 years of suspension time after steam drive is needed for a reasonable uniformization of the temperature over the surface processed via steamdrive.

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Table 23b: Results of the In-Situ Combustion Post-Steam Applications

Project	Instru -men- tation	ISC Process Details				Results		
-	-	Ignition	Duration of ISC process years	Type of application	Number of patterns	AOR, sm^3/m^3	UOR %	Other results
Charco Redondo	20+2* OW	GB	≅1	Pattern	1	?	?	VLID
Midway Sunset, Potter Sand	4 coring wells	?	2	Pattern	1	1,700	73	T=99^{0}C @ start of ISC
Suplacu de Barcau	-	GB	6	Pattern & LD	6	2,000	41 (pattern) 52 (LD)	
Bloc H1, Xinjiang, Petrochina	1	EH	4	Pattern & LD	3 (pattern) 7 (LD)	Initial: 5,000 Final:2,200	65**	Some up-grading noticed ***

Legend: OW= Observation wells ; GB=Gas burner; EH=electrical heater

LD=Line drive starting updip; AOR=air-oil ratio; UOR=Ultimate oil recovery; W/C = water cut

VLID= Very long ignition delay (longer than 20 days);

* 20 observation wells (OW) for both processes (steam and ISC) and 2 extra OW for ISC evaluation

** Predicted.

*** Emulsion problems were recorded.

In the cases described here, only vertical wells were used (conventional ISC). The results indicate that commercial application of ISC after steamflooding is not far away; this statement is valid for the cases, where the recovery by steamflood is less than 37%. However, where the recovery is higher, more testing is required. The following improvements could be considered, to make the process more efficient, and fully commercial:

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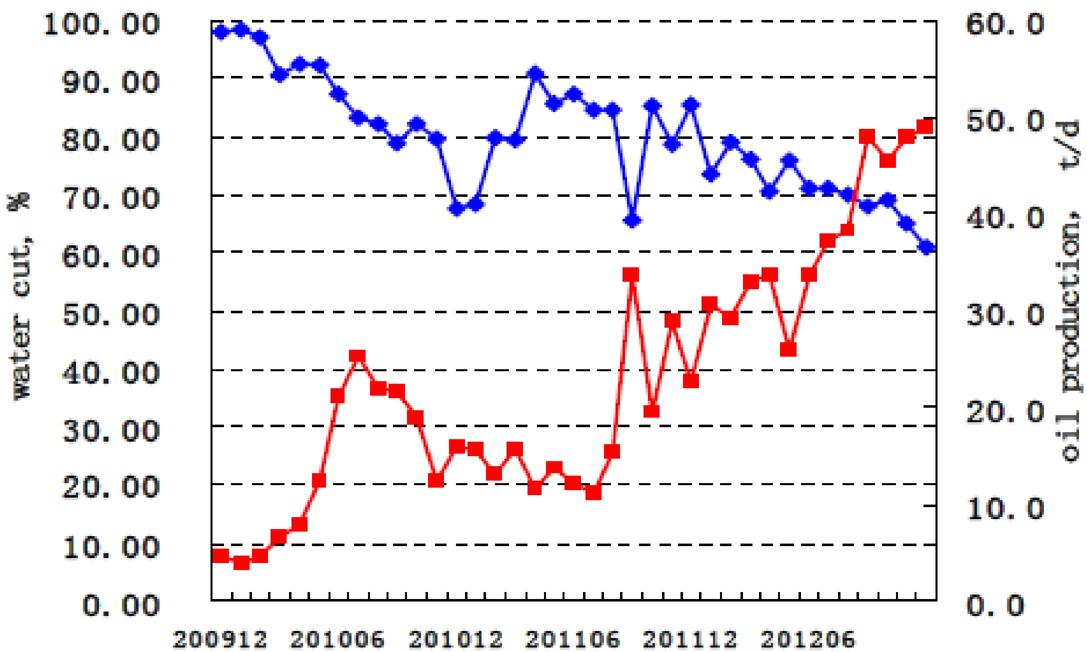

Fig. 91: Jurassic Badaowan, Bloc H1: Variation of oil production and water cut (Guam, 2013)

- For a successful application, the ignition procedure needs to be very strong
- The pattern exploitation used in the steamdrive has to be abandoned in favor of a gravity-stable displacement using an updip peripheral line drive operation for ISC. This is necessary as the flow lines need to be changed; otherwise, the same steamflood reservoir channellings/gas overriding will happen. This switch to line drive is easily achieved if the dip of reservoir is at least 2-3 degrees.
- A certain period of time (a few years), elapsed between end of steamflooding and start of the subsequent ISC application, may have a positive effect on obtaining a rather quasi-uniform field of temperature; at the start of ISC application, ideally the reservoir temperature should be at least 70-80^{0}C in most areas of the reservoir.
- The use of horizontal producers is highly desirable, as they may improve the performance. However, there is not much experience in this area and more developments and evaluations are required.

The analysis made in this section indicates that for the heavy oil reservoirs, there are by far more chances of a successful ISC application as a tertiary process after steamflooding, compared to as a post-

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waterflooding application. To some extent, this is surprising, but the enormous amount of heat stored from the previous steamflood makes a big difference.

12.2. THAI Applied Tertiary as a Post-Thermal Process

The application of THAI mainly after a conventional steam-flood or after a conventional fireflooding (in-situ combustion), both conducted with vertical wells, is discussed here. At the end of this subchapter, just essential information is given in the case of THAI application for the horizontal wells drilled from a pad and using long-cycle, **c**yclic **s**team **s**timulation (CSS) operations.

In all these cases, a key factor for success is a significant amount of stored heat and a well developed hot oil bank from the application of the former thermal process; that's the reason that by far more favorable conditions for the application exist for CSS operated with horizontal wells as compared with CSS operated with vertical wells. What is essential in this application is the accurate determination of the approximate position of the thermal front/hot oil bank in view of a proper location of the horizontal producer (s) of THAI. In general, new vertical wells are not necessary, as there is a sufficient number of them. The application can be made either "on the fly" converting the old thermal process in a THAI process or after a few years since the suspension of the conventional thermal process. By applying the THAI process in this situation, a very significant problem of conventional thermal methods is solved, namely these methods *displace oil very efficiently, but they do not capture it efficiently*. This is very valid for the pattern application and, to some extent, for a peripheral line drive, as well; the use of horizontal wells is designed to solve this problem.

A preliminary schematic of THAI application is shown in Figures 92 a-b, both for the case of *existing* direct line drive (DLD) and staggered line drive (SLD) configuration. I both cases, in order to apply the THAI process, we need up-toe horizontal wells drilled along the strike ,and they should have a length equivalent to 3-4 rows of conventional spacing of vertical wells.

12.2.1. The case of existing line drive with the DLD configuration (Fig 92 a): the vertical wells continue to be utilized first as producers and thereafter as air injection wells (once they are intercepted by ISC front). *Compared to a typical THAI application in a virgin reservoir, there are two very significant advantages:*

- A large start-up region already exists, and a significant amount of oil is already heated (high mobility) within this region; the time-consuming phase of creating hot communication is suppressed.

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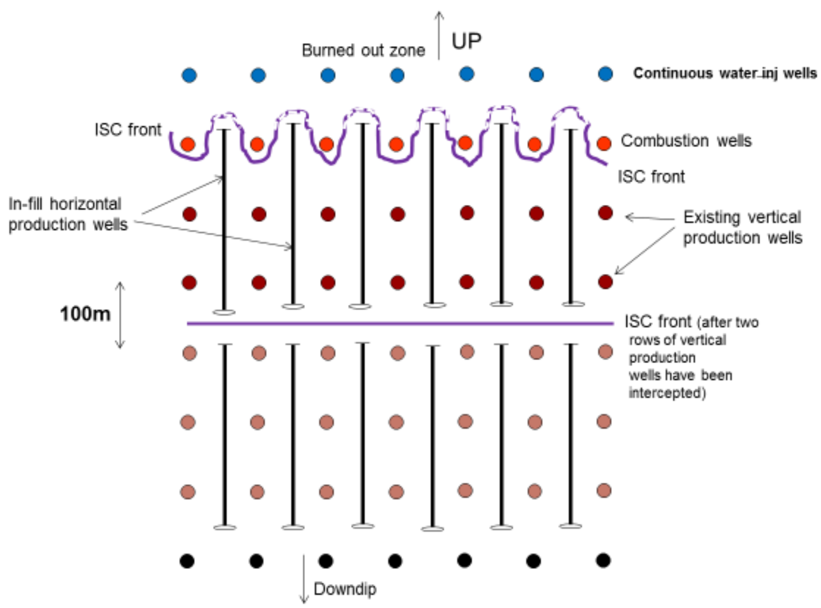
➢ The wedging of the burning volume is significantly reduced as the vertical wells act as control wells, thus constituting an SLD configuration in relation to the horizontal producer of the ISC process.

This qualifies THAI as a prime time candidate process. In Figures 92a-b, the illustration is made for two rows of vertical producers, and for an existing DLD, line drive ISC project. The proposed process can be applied, however, similarly to a post-steamflood process. In all cases, the horizontal wells are to be used only for production, while the vertical



wells

Fig. 92a Schematics for the use of horizontal wells in a THAI project implemented on a pre-existing DLD configuration, used in a thermal flooding project (conventional ISC or steamflood)

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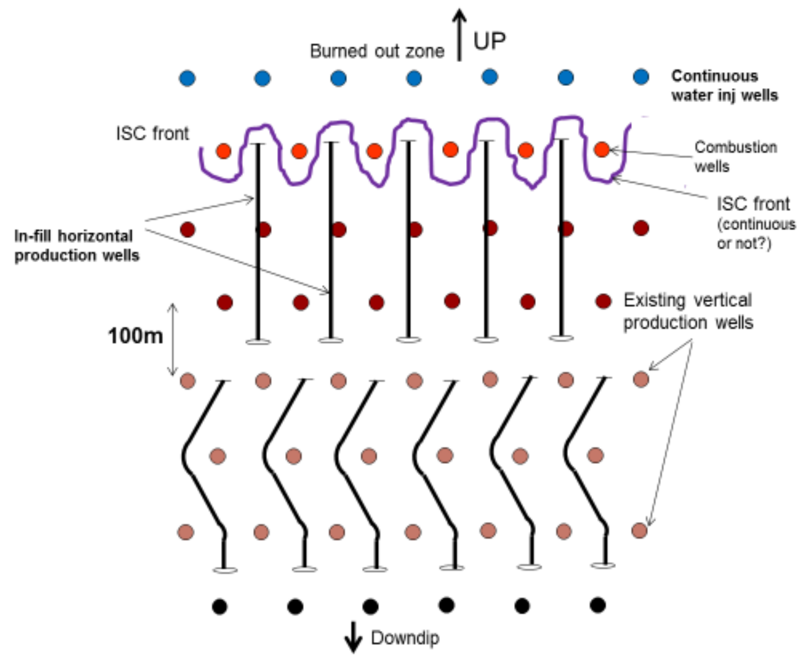

Fig. 92b Preliminary schematics for the use of horizontal wells in a THAI project implemented on a pre-existing SLD configuration used in a thermal flooding project (steamflood or conventional ISC)

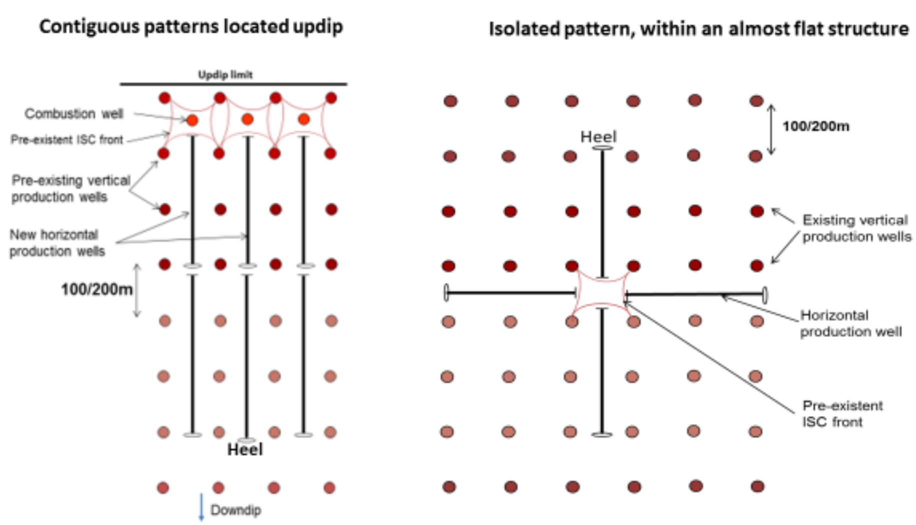

Figure 92c: Preliminary schematics for the use of horizontal wells in a THAI project implemented on existing 5-spot pattern configuration (s) for a thermal flooding project (steamflood or conventional ISC). Exemplification for ISC conducted in contiguous patterns at the updip limit of reservoir and for an isolated ISC pattern.

will be used for production and injection.

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12.2.2.Case of an existing line drive with an SLD configuration: two alternatives can be considered; for the first three rows we can use straight horizontal producers and one former vertical production well is converted to an observation well (for monitoring the temperature very close to the horizontal producer), while for the remaining rows, once some experience has been acquired, there is less need for observation wells and the horizontal production wells can be in-fill drilling "snake wells" as depicted at the bottom of Fig. 92b.

It is important to note that for both pre-existent DLD and SLD configurations, *the newly applied THAI process is conducted using an SLD configuration.*

12.2.3.Case of existing repeated 5-spots: A preliminary schematics for the use of horizontal wells in a THAI process implemented on existing thermal exploitation (ISC or steamflood process) in a 5-spot pattern configuration is shown in Fig. 92c; exemplification is for a pre-existing conventional ISC project. When some dip exists as shown in Fig 92c, the pre-existing vertical production well located downdip from the pre-existing combustion well and intercepted by ISC front will be further used as air injection wells; they are in an SLD relationship with the new horizontal producers. Another alternative is first to convert the entire exploitation in a line drive exploitation and then apply the THAI process, as in Fig. 92a. The schematics proposed for an almost flat reservoir having a pattern somewhere on the structure is also shown. In case that even 1-2 ^{0} dip exists, however, the horizontal producer having its toe towards updip region (up-toe horizontal well) may still have a better performance.

Otherwise, short and very short horizontal wells can be used inside the commercial thermal application area, while the long horizontal wells can be used only at the edge of this area, for further development in the outside, new areas.

12.2.4.Case of existing horizontal wells used for application of cyclic steam stimulation (CSS) with long cycles

In case of horizontal wells drilled from a pad, if they are up-toe horizontal wells drilled along the strike

(therefore the heel located down-structure), as the horizontal sections should be located close to the bottom of the layer; in this case, a field testing of THAI process can be contemplated. It should be applied in a staggered line drive (SLD) by drilling vertical injectors in the toe region, mid-distance between toes. The best performance can be anticipated when the application is made 0.5-1.5 years after the CSS operations have been terminated, as in this situation, the re-distribution of the remnant heat from CSS was done to a large extent, and the conditions are more favorable. However, the first stage of hot communication and second phase of ignition may still be necessary to be performed, mainly in cases

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whereby CSS operations the toe region was not heated enough. Also, the confinement towards the up-structure should be carefully evaluated.

*As mentioned at the beginning of this subchapter, the key factor for success in this case is a significant amount of stored heat from the application of the CSS process. B*y far, more favorable conditions for application exist after CSS operated with horizontal wells as compared with CSS operated with vertical wells, in which case the heat stored may not be enough, and the gravity effect is not totally utilized. Therefore, after CSS with vertical wells, sometimes, the application of THAI can be considered almost similar to a THAI virgin operation.

12.3. Post-SAGD ISC Processes (Conventional ISC and/or THAI)

Steam Assisted Gravity Drainage (SAGD) has proved to be a very effective method for recovery of bitumen and extremely heavy oil, when reservoirs have the benefit of a continuous thick oil formation. For formations with thickness in the range of 30-40 m, SAGD has no competition among other current EOR methods. Therefore, in this case, ISC can be evaluated as a possible follow-up method. However, as the pay thickness reduces towards 12-14 m, ISC can be competitive with SAGD even as a primary recovery technique.

The major challenge is to conceive an **i**n-**s**itu **c**ombustion (ISC) scheme that could yield oil rates similar or close to the SAGD rates, mainly for high pressure (higher than 3 MPa) applications, and temperature higher than 240^0C-270^0C during SAGD process. This constitutes a radically different approach relative to everything described so far; it tries to simulate SAGD mechanisms with energy generated in-situ, as opposed to injecting steam from the surface as in the classic SAGD operation.

So far, all attempts to develop a post-SAGD ISC process have been unsuccessful. There have been many simulations and laboratory investigations of the potential application of conventional ISC as a SAGD follow up. However, all of the laboratory tests so far have met with very little success. The first problem is related to the fact that unlike SAGD, the operation of the ISC in a SAGD-type configuration (*the upper well on air injection and the lower well as a production well) is not possible at the current distance of about 5 m.* Protection of the lower production well from a very high temperature generated by the ISC front is not ensured under the current development of technology. In a recent development (Chhina 2006 and Lim 2012), it was erroneously assumed that the operation of the production well will have no problems during an ISC process following a SAGD operation.

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Another proposal to apply ISC in a top-down system in a SAGD chamber (with the air injection at the top of the chamber) showed that this was also extremely challenging, as the O_2 utilization was extremely low (less than 30-40%) (Oskouei, 2013); the oxygen content in the produced gas was very high, between 8% and 16%. Therefore, radical modifications to the process or to the configuration may be necessary.

More encouraging were the results of applying ISC, not as a follow up to SAGD, but just using a SAGD-type configuration. Details on this process, called THAI in a SAGD-type configuration, were given in Section 10.1.3.2 and Chapter 11, where the problems related to the potential blocking of the producer and excessive temperatures in the producer were analyzed.

Here, two new potential post-SAGD ISC processes are discussed; one of them is attempting to simulate (as close as possible) the SAGD mechanisms using a SAGD-type configuration to run a stand-alone ISC process, therefore being a modified conventional SC process. A second one proposes to use direct line drive (DLD) THAI in order to drain additional amounts of oil via the pre-existing SAGD well pairs.

Therefore, the following two new potential processes presented are:

- DLD-THAI process application by using additional wells (horizontal and/or vertical) in the inter-space of the pre-existing SAGD pairs,
- Wet combustion process as a follow up to SAGD or applied as a stand-alone ISC in a SAGD-type configuration (using all the pre-existing SAGD well pairs, but sacrificing some of them for wet combustion, while some of them will continue to be used as producers). A vent well is to be used in order to evacuate the flue gases generated.

Details on these potential processes are provided in Appendix I.

THAI Process: To develop an ISC process as a follow up to a normal SAGD process, **a**s shown in Figure I1 of Appendix I, a DLD THAI configuration (using a new vertical and a new horizontal well) is operated in the middle of the space in-between two SAGD pairs, during the mature stage of the SAGD project life. Then, the steam injection is discontinued in the SAGD wells and the SAGD wells are converted to producers; SAGD injector (upper well) mainly for gas production and SAGD producer (lower well) mainly for oil production.

In case that a new ISC process has to be developed as a follow-up to an improved SAGD process in which an in-fill drilled horizontal well was already located in-between old SAGD well pairs (the so-called offset well), then the initial broad ISC surface can be generated by operating a DLD quasi-THAI operation using two parallel horizontal wells (the in-fill one and a new additional one), as shown in Fig. G2. Please note that unlike SAGD wells location, the new well is placed towards the top of the layer, and

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is drilled from a position opposite to the old drilling platform. This last version seems to be more complex in operation as the plugging of the production wells can occur both in the first stage of initiation of the broad ISC front and in the second phase for the former SAGD wells; for the first version, only the risk of coke plugging in the second phase may exist.

Wet Combustion Using the Pre-existing SAGD Wells (and, additionally-Vent Wells): Taking into account the recent developments in the area of ISC and foams, an ISC process conducted in a SAGD-type configuration is proposed (either as a follow up to SAGD or a stand-alone ISC process). The intent is to mimic the mass-transfer and flow phenomena occurring in SAGD closely, but with the heat generated in-situ, not at the surface facilities. The idea of injecting foam in an ISC process is inspired by a recent field test ISC, where the foam was manufactured using pure oxygen (McGee, 2011).

This version will preserve the position and the role of SAGD wells: upper well for injection and lower well for production. The air (or oxygen-enriched air) and water will be co-injected as *a very dry, pre-formed foam;* an extremely low concentration of surfactant would be dissolved in the injected water just to preserve the foam while traveling via the wellbore and a few meters (up to 2-3 m) inside the porous medium. The use of this dry (weak) foam (foam quality over 90%) would be necessary not only in order to mimic as closely as possible the SAGD operations, but also to avoid extremely high corrosion, possible explosions and pronounced gravity driven gas-water segregation before entering the formation (McGee, 2011). Also, the horizontal producer should always be protected from any burnout, as its location is very close (generally 5-7m) to the air injector.

There will be a third horizontal well (*vent well*) – parallel to the SAGD wells, but positioned laterally - located towards the top of the formation (Figure 93 and Fig. I3 of Appendix I) and its role is to produce a part of the flue gases generated in the process. *Therefore, while air-sustained-ISC generates the necessary heat to produce a significant amount of steam in-situ, some of the flue gases are produced via the top well* (wells HPG1 and HPG2 in Fig. 93) and this way they do not interfere much with the oil flow resulting from steam-flue gas displacement within and around the steam chamber. At the same time, the amount of gas produced via the vent well (HPG) can be adjusted further to help in sustaining the drainage of the oil in the producer. Finally, in the last stage of the process, the HPG wells can be used in two ways:

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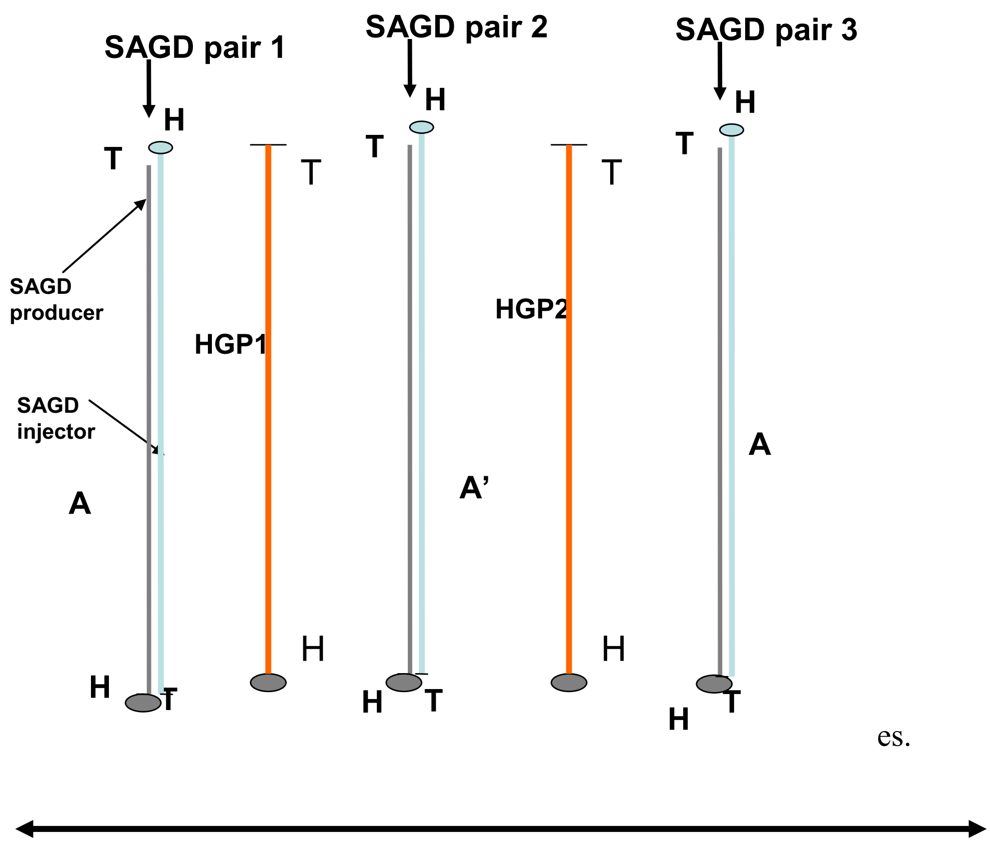

Fig. 93: Schematics of multi-pattern super-wet ISC process. Bird's eye view

Legend: HPG- horizontal well for gas production; H-heel of the horizontal well; T- the toe of horizontal well

- For a low rate nitrogen injection, for pressure maintenance
- For a true ISC operation, in which case a relatively high air injection rate is needed. The well can start air injection only when the temperature at its heel is higher than 350 ^{0}C (with no need for ignition) or if converted earlier, a special ignition operation has to be executed.

In all these cases, oil production takes place predominantly via former SAGD production wells, while the former injection wells are predominantly producing gases; they can also be shut-in or used as observation wells.

A potential objection to this proposed process (pre-existing SAGD wells and vent wells) is that generally in the conventional ISC process, the area surrounding the injection well is cooled down by the injected fluid (air or air & water). However, this is the case only in the conventional process (using vertical injectors) involving a horizontal displacement. In a SAGD-type configuration ISC, the area around both

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the production well and the injection well is still at a temperature in the range of 150-200^{0}C; this is indicated in Fig. 94a (simulation results for a dry ISC process - Rahnema, 2010) conducted in a SAGD-type configuration from the very beginning process (not as a SAGD follow-up process), therefore without any pre-heating by steam injection); it is related to the production of the hot fluids along the edge of the thermal chamber. Also, as seen in Fig. 94b, this is similar for a SAGD-ISC Hybrid or when the ISC is applied as a follow-up to a SAGD operation (Yang, 2008). The Yang's simulation has been done both for continuous air injection (dry ISC) as a follow up to SAGD and for SAGD alternating with air injection. However, in the last case, oxygen is injected instead of air; the cycle is 1/1 i.e. one-year SAGD and one-year O_2 injection. Three proportions of O_2 were considered, namely: 20%; 50% and 80%. The steam was saturated and had a quality of 90%. For the SAGD process, the temperature in the SAGD chamber is around 250 ^{0}C, while during the SAGD-ISC hybrid process, the maximum temperature reaches 400-500 ^{0} C.

These two simulations are both realized using STARS simulator, but there are differences in the sizes of physical systems considered, initial and boundary conditions and Athabasca reservoir properties; also, the run time is different. Therefore, the comparison of results is only qualitative, at best semi-quantitative, and it appears reasonable that there is a difference between the temperature distribution in these two cases. However, even considering these observations, the relatively high temperature around the injection and production wells is a common characteristic in both cases.

To conclude, it is recommended to explore further the potential processes presented in this section.
Dedicated simulations should be conducted for specific reservoir cases in order to field-test the process.

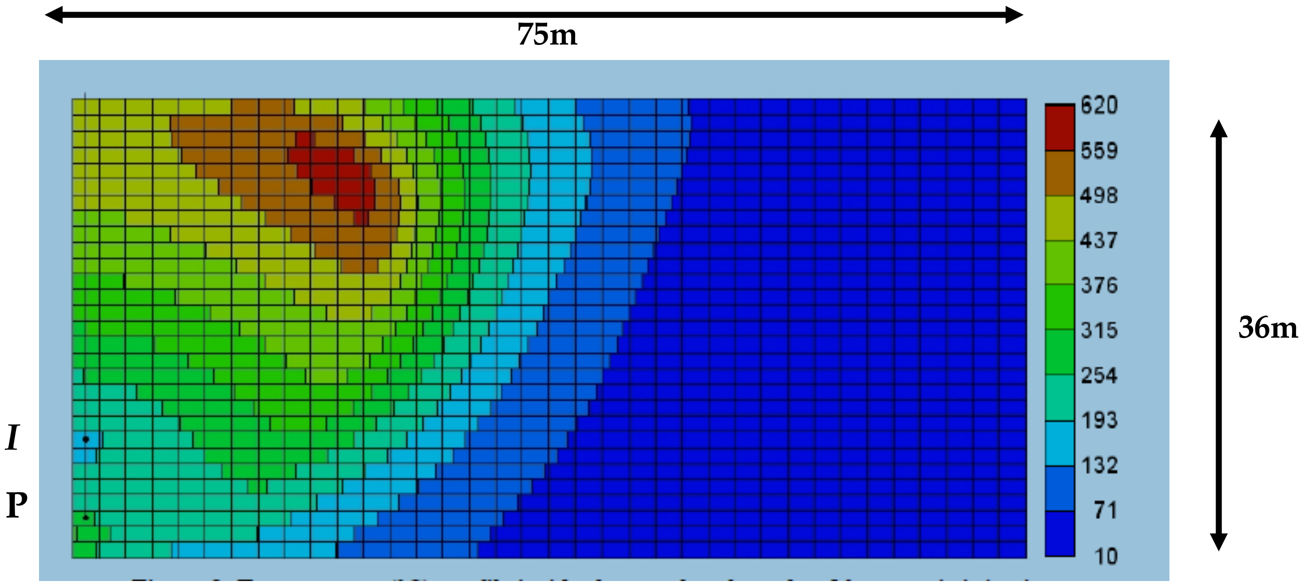

Fig. 94a: Simulated temperature profiles (^0C) for a dry ISC process conducted in a SAGD-type configuration after 7 years (Rahnema, 2010). Please note the relatively high temperature (193-315 ^0C) around the production well. Legend: P=production well; I=inj. Well

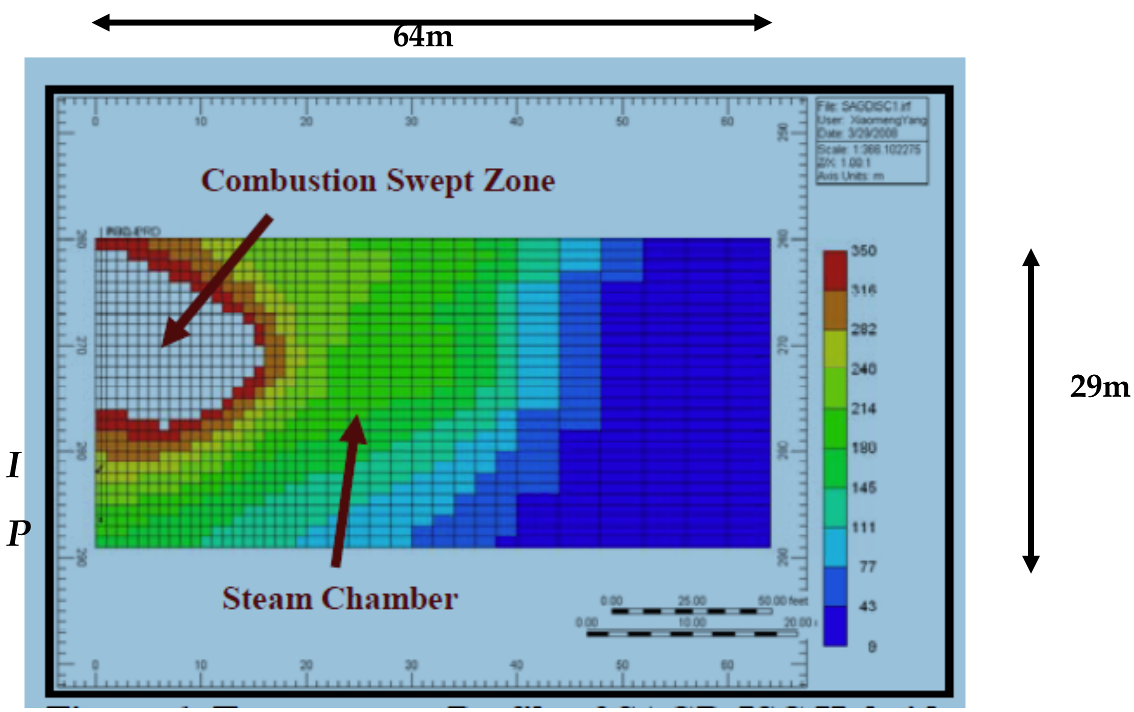

Fig. 94b: Simulated temperature profiles (^0C) for the SAGD-ISC Hybrid process or for a dry ISC process conducted as a SAGD follow up after 11 years of injection (Yang, 2008). Note the high temperature around the production well. Legend: P=production well; I=inj. Well

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13.CONCLUSIONS AND RECOMMENDATIONS

13.1. Conclusions

1. The conventional **i**n **s**itu **c**ombustion (ISC) has been first tested in the field by 1950. Generally, it has not lived up to the operators' expectations. The main disadvantage was a lack of control over the propagation of the ISC front. Some of the disadvantages were mitigated by adopting a peripheral line drive exploitation started updip of reservoir. This way, some major heavy oil commercial ISC operations have been successfully conducted for more than 40 years. In this study, we examine if some of the major problems of the conventional ISC process can be minimized via the **T**oe-To-**H**eel **A**ir **I**njection (THAI) process.

2. The THAI process was patented in 1997; it has been investigated for more than 12 years via laboratory tests, theoretical work and simulation studies. In 2006, field testing was initiated. Compared with the conventional ISC, the THAI process is an improvement due to its gravity stable and **s**hort-**d**istance **o**il **d**isplacement (SDOD) features, and with full control on the direction of propagation; oil is flowing predominantly through a heated zone, called mobile oil zone (MOZ), located just ahead of the ISC front. Due to its SDOD feature, thermal (partial) upgrading of the mobilized oil is realized. The controlled over-ride character of the process and a *self-healing feature* due to the existence of a moving coke-plug in the borehole of the producer entirely prevents oxygen breakthrough/short-circuiting.

The sequential use of the horizontal section of the horizontal producer made possible the development of a catalytic THAI process (CAPRI^{TM}) by surrounding the horizontal section with a refinery catalyst; in this way, a second upgrading of the already upgraded THAI-oil occurs, when it flows into the borehole of producer

3. In the THAI patent, the process was described in detail for two application schemes; **d**irect **l**ine **d**rive (DLD) and **s**taggered **l**ine **d**rive (SLD) configuration. DLD is more straightforward in application, because the vertical injector is very close and "in line" with the toe of the horizontal producer. The communication phase can be similar to that for SAGD process. SLD has the vertical injector some distance away (laterally) from the toe of horizontal producer and for this reason is slightly more complicated, as the oil viscosity increases; this is so because it makes communication phase generally more extended in time and more labor-intensive than for DLD application. However, once the communication is accomplished, compared to DLD, SLD configuration is designed to have a substantially better lateral sweep efficiency, potentially less operating problems and, hence, a better performance.

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4. More than 100 THAI experiments have been carried out in 3-D laboratory combustion cells. In all cases, a broad ISC front was created initially, for both DLD and SLD configurations. A stable propagation of the ISC front from the toe to the heel of horizontal producer was observed. The existence of the coke-plug in the horizontal producer was confirmed in laboratory tests. Several organizations performed simulation both for laboratory tests and for field tests. Simulation models of THAI process at field scale are at an early stage of development, and they are only partially useful. They are helpful only in studying the effect of various parameters on the process.

5. Given the relatively good understanding of the THAI process, in 2006 Petrobank Energy and Resources Inc. (Petrobank) started a field demonstration pilot in Athabasca oil sands (Whitesands project), Mc Murray B formation, at a depth of 380m, in an oil layer of 32-37m gross thickness with very thin bottom water; the presence of bottom water was not accounted for in the design of the pilot.

The THAI pilot consisted of three pairs (3 vertical injectors and 3 horizontal producers) arranged in direct line configuration (DLD) configuration. After 5 years of operations, it can be concluded that the pilot was technically successful; the technical validity of THAI in a DLD configuration was proved. However, its economic efficiency was marginal, as the cumulative air oil ratio was high (5,000-6,000sm^3/m^3); the main reasons for the low performance is the lack of confinement of the pilot area, related first to the escape of air into the upper Mc Murray "A" formation and secondly, full communication with the bottom water zone from the very beginning of the process (during steam injection for pre-heating). Although the bottom water zone is thin, a significant amount of water was produced from this zone during the pilot. A third important difficulty was that *the air injection rate per well couldn't attain a value close to the maximum value from the project; this might have to be related directly to the use of DLD operation, favoring the sand influx*. A comprehensive evaluation of this pilot based on the publicly available information was made, and the following conclusions were drawn:

- It was possible to perform the initiation of ISC using steam injection for pre-heating for a period of 3-4 months; then, by air injection, the ignition was achieved in 1-2 months; the ISC front generated was self–sustaining and there was no oxygen short-circuiting. The test demonstrated the technical robustness of the process.
- The steam injection (for pre-heating in view of ignition) was conducted via lower perforations (at the level of the tow of producer), while air injection was done via the upper perforations of vertical injectors. This location of steam injection favored the communication with the bottom water zone from the very beginning and then for air as well; the burned volume was not always located (or did not always extend) up to the top of the formation, but around its mid horizontal plane.

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- By propagating the ISC front from the toe to the heel, daily oil production rates per well in the range of 10-20m^3/day were obtained. The total cumulative oil produced in this project was approximately 29,000 m^3 (182,000 bbls). To our knowledge, except for SAGD projects, there have not been any other in-situ recovery processes to produce so much oil from the Athabasca oil sands.
- The process constitutes a *WORLD FIRST* as far as day-to-day in-situ upgrading of the produced oil is concerned. *THAI is, therefore, the first EOR process in which the upgrading was obtained underground during oil recovery, without using any exterior heat sources. The upgrading fluctuated in the range of 4-8 ^{0}API degrees; some* hydrogen was also produced.
- Two significant operational problems were encountered: intensive sand influx and, probably, the limited-time endurance of the casing (of the horizontal section) to the high temperatures recorded. These (separately or together) probably caused the damage of the liners and required drilling of replacement wells for 2 out of the three production wells.
- The pilot had one of the best instrumentation among all the ISC pilots performed worldwide, so far. This allowed estimating the size and the shape of the burned zone around one well-pair, based on temperature records from observation and production wells. This way, an estimate of the air requirement based on field data was made; a value 18% higher than that from laboratory combustion tests resulted, suggesting that the process may consume some additional fuel. The combustion zone lateral development was small; it did not extend across the entire interwell distance, and was generally limited to about 40 % of this distance. It is believed that this contributed to the sand influx problems. The advancement from (the toe) of the ISC front along the horizontal section was less than 200m, which meant that only something up to half of the project life was attained. The DLD system was not able to ensure a satisfactory sweep efficiency.
- The replacement wells had a disappointing performance. This was due, on the one hand, to failure to prevent the burned zone oil re-saturation accompanied by massive coke deposit within it and, on the other hand, to a pronounced water encroachment (from the thin bottom water zone) in the pilot area during the long 3 to 4 month-period of air injection stoppage. Less than appropriate location of replacement wells (the hot communication/link with the old burned zone was not properly realized and a toe-to-heel ISC front propagation along the replacement wells was achieved just for one pair) was another important factor leading to the poor performance. One replacement producer tested the CAPRI process for a short period (3-4 months). At the completion of the pilot, the oil recovery was around 7%, and for a full-fledged project of this kind (DLD THAI), 14% oil recovery can be anticipated.

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6. In 2009, Petrobank started the second THAI field project at Kerrobert, Saskatchewan, consisting of two well pairs and extended to a semi-commercial operation of 12 well pairs. Kerrobert is a conventional heavy oil reservoir with a relatively thick bottom water zone (bottom water thickness is almost equal to that of the oil zone thickness). The project started when the primary recovery was 1.2%, with an average water cut of 96%. In other words, its use as a secondary recovery method was attempted. After two years of operations, the pilot was deemed successful (the air-oil ratio was around 1,500sm^3/m^3), and the semi-commercial operation in an adjacent region started. This assessment study is based on a comprehensive evaluation of the publicly available information; also, detailed geoSCOUT well data and other information (gas compositions and bottomhole temperatures), were available. In-depth analysis of the Kerrobert THAI Project led to the following conclusions:

- All 12 patterns (modules) were designed in a direct line drive (DLD) configuration with a start-up region almost zero; an average lateral distance of 2-7 m between the shoe of the vertical injector and the trajectory of horizontal producer, with a few cases having this distance 12-15m.
- For the depth of the Kerrobert reservoir (740m), it was possible to perform the ignition using steam injection for pre-heating. The generation of the ISC front was achieved only after a long period. In this respect, there was a clear difference between the pilot and the semi-commercial expansion, due to different execution of ignition operations. In the pilot, 3,000 m^3/well of steam of was injected in less than 3 months, while in the expansion project, 600-1,600 m^3/well was injected in 1-2 months, with low injection rates. Heat loss calculations indicated that in the pilot a low-quality steam was injected, while for most of the expansion modules, essentially hot water was introduced in the oil layer. Due to this fact, the ignition achieved was not very efficient (the ignition delay was very long); as an average, it was estimated at 3-6 months for the expansion wells as against 1-2 months for the pilot wells; the ignition followed by an ISC front propagation has never occurred within the patterns K4 and K12. This extremely slow ignition was an essential factor for the delay in obtaining incremental oil and, generally, "a contributor" to the low performance recorded; within the semi-commercial project, this "promoted" **l**ow-**t**emperature **o**xidation (LTO) reaction. This was associated with the decreased mobilization of oil, and no incremental oil was seen for a period of 8-10 months.
- Analysis of the process based on the bottom hole temperature recorded in the horizontal producers showed that high temperatures (400-600 ^{0}C) were recorded. It was found that for this bottom water THAI application, two kinds of ISC development can happen: either a **t**oe-**t**o-**h**eel (TTH) propagation or formation of a **c**ombustion **c**hamber (CC) around the toe of the producer. The pilot pairs K1 and K2 showed a very good performance; ISC front propagated 116-205m within approximately 3 years. Out of the semi-commercial pairs K3-K12, TTH propagation mode was seen for 6-7 pairs (for a

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distance of 30-60m, in general, and 90m for K11 pattern). The combustion chamber (CC) developed in 3 cases. For patterns K4 and K12, anchoring of an ISC front to the toe of horizontal producers did not take place and no ISC influence was noted. Generally, TTH propagation was associated with better performance results. CC cases were associated with inferior results, mainly when the CC was located just at the water-oil interface. The penetration of air/gas into the bottom water (BW) took place within less than one year of operation; the start of significant losses of injected air/flue gases in the bottom water zone was clearly identified on the production performance curves. The best performance was recorded for the pattern K2, which is a confined pattern, with good THAI design and completion, including a good start-up region; if the rest of the semi-commercial patterns had been designed and operated as K2 pattern, then Kerrobert would have been a commercial success.

- After the extended ignition period, the composition of produced gas was standard, with full oxygen consumption and some hydrogen production. By propagating the ISC front from toe towards the heel of the horizontal producers, daily oil production rates per well were in the range of 7-14m^3/day; the water cut decreased to 30-50% for 6 pairs responding positively and 70-80% for the 3 pairs with a medium performance. The total cumulative oil produced as of February 2015 was 55,200 m^3 (347,200 bbls), and it was obtained at an air-oil ratio (AOR) of 2,800 sm^3/m^3. As of February 2016, the project was still active, and the cumulative oil produced was 66,000 m^3 (415,100 bbls); as of October 2019, the project is still ongoing. *For this secondary recovery method of a heavy oil in a reservoir with bottom water, this constituted a step forward compared to all previous conventional ISC projects applied in similar situations; its AOR was also better.*

- The project *fully* validated the in-situ upgrading potential of THAI process. On an average basis, the upgrading was 5 ^{0}API points for the pilot and 4 ^{0}API points for the expansion. Hydrogen percentage in the produced gas was 1 - 2%, and increased up to 5-7% in a period in which the upgrading was maximum.

- The crucial difficulty was that *due to pronounced water cut increase, it was not possible for the air injection rate to be increased and attain a value close to the maximum value from the project.* The endurance of casing (of the horizontal section of the horizontal producers) to the high temperature reached *did not seem* to be a very critical problem. It might have been mitigated by the relatively high water cuts due to the existence of bottom water; two producers were suspended, and several thermocouples in the toe region were damaged during the project.

- Based on the bottomhole temperature in the producers it was concluded that presently the advancement of the ISC front was less than half distance toe-heel, which meant that only something

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like less than half of the project life elapsed; the life of this project is at least double of the time elapsed and measures to improve the process were proposed.

7. Since 2012, five more THAI pilots were initiated outside Canada, three in China and two in India. As of May 2018, three of them are ongoing. The Chinese tests - conducted in extremely heavy oil reservoirs and using a direct line drive (DLD) configuration - have shown that at extremely high air injection rates, the oil rate is not proportional with air injection rate, and a high value of the average air-oil ratio (AOR) is recorded ($8000 sm^3/m^3$); on the other hand, at very low injection rates, a good AOR is recorded, but the oil production is low. The tests confirmed the upgrading potential and production of hydrogen and how they are correlated with the burning process. Unlike all previous THAI tests, the tests initiated in India (in Balol and Lanwa reservoirs) by the end of 2016 have used a staggered line drive (SLD) configuration and been applied in correlation with a conventional in-situ combustion (ISC) process conducted for more than 20 years; they have been started in a region where conventional ISC was suspended for 3 years, due to lack of results. They fully demonstrated the superiority of SLD configuration for the case of heavy oil with reduced oil mobility at reservoir conditions and the ability of THAI process to be used for regions with higher pay thickness where conventional ISC has been inefficient. AOR has been 3-fold lower than for conventional ISC, while the oil rates have been 4-5 times higher. The grafting of the THAI process on the existent conventional ISC was very easy.

8. By simulation using a kinetic model in which fuel deposit is generated only by cracking reactions (with no LTO reactions), it was possible to properly describe the process, including temperature distribution and approximate gas composition. Also, it was possible to indicate that in THAI, there is primary and secondary fuel formation and consumption. Except for the case of THAI application in the presence of bottom water, the superiority of the staggered line drive (SLD) configuration over direct line drive (DLD) configuration was confirmed independently by three organizations. The simulation models help in the easy explanation of the SLD superiority. THAI simulation requires the discretization of the horizontal section of the producer; at this time, there are limitations as far as the prediction of oil production, underground upgrading of oil and hydrogen production are concerned.

9. Based on the current knowledge of the THAI process, the main pros and cons were highlighted, and preliminary screening criteria were developed. With the current field experience, when making a choice between SAGD and THAI, for oil sands and extra-heavy oil reservoirs, the application of SAGD should always be considered first; only when the thickness and/or depth of reservoirs is not favorable to SAGD application, then THAI should be contemplated. Another situation in which THAI may be a better solution is that of very remote reservoirs, where hydrogen production and/or oil upgrading constitute (s)

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an absolute necessity. It could also be considered for heavy oil reservoirs located in remote regions (such as arctic regions, where SAGD may not be easily applicable.

10. After more than 20 years since its initial conceptualization and 12 years of field testing, *THAI still requires further development, to attain its full potential as an oil production method; its potential for upgrading and hydrogen production was demonstrated.* So far, in the field, only the **d**irect **l**ine **d**rive (DLD) configuration has been systematically tested. From a re-visiting of 3-D model laboratory work, coupled with simulation results and analysis of its theoretical reservoir engineering principles, plus some limited results from the Kerrobert Project, staggered line drive (*SLD) was indicated to be superior to the DLD configuration, and it should always be the option of choice; this has been confirmed by SLD testing of THAI in India.* DLD may be preferable only in some special cases (exploitation of a heavy oil reservoir with a thin gas cap, in combination with SAGD, etc.). The SLD configuration should be more investigated in the field and via more detailed simulation studies. There is a special need to systematically investigate and improve the communication phase for the SLD configuration, especially so, for the reservoirs with extremely high oil viscosity.

11. *The fundamental pre-requisite for a better performance of the THAI process is the generation of a broad initial linear (or quasi-linear ISC front).* Several solutions were presented for the classic case of using vertical wells for injection; in principle, this assumes either propagation of a conventional ISC front between injection wells or the use of a more complex wellbore trajectory for horizontal producers; in this case the process is slightly more complex. *Mobility of the oil and reservoir temperature are the most important parameters in choosing the best approach for the generation of the broad initial ISC front.* The horizontal air injectors automatically generate a broader initial ISC front, but the safety of operations is critical; some schemes for the use of the horizontal wells as air/water injectors in a TTH configuration were explored (dual opposed horizontal injectors, repeated "L" configurations and cross lay-out).

12. An analysis of past pilots and semi-commercial conventional ISC applications after steamdrive operation convincingly showed that ISC can constitute a very effective tertiary EOR method for this case. The pre-requisites for post steamdrive conventional ISC success are a vigorous ignition and switching from a pattern to a line drive operation. The use of horizontal wells should be contemplated in order to increase efficiency significantly, and to this effect, the knowledge acquired in THAI development has to be used extensively; THAI will always be a "stumble upon"/"chance-upon" process. Using the THAI knowledge, next-generation ISC processes were scrutinized for applications both after steam-injection-based-methods or as stand-alone processes. Several configurations and associated procedures were proposed, such as L-shaped configurations, cross-layout arrangements with air injection transfer from well to well, etc. For SAGD follow up new ISC processes, two approaches were proposed; either to drill

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new DLD THAI modules in-between old SAGD pairs, which eventually will mobilize the oil towards the former SAGD pairs or to use a wet ISC process in the former SAGD pairs; air would be injected under a dry foam and there is still a need for a vent well; this wet ISC process was also proposed as a stand-alone ISC process conducted in a SAGD-type configuration.

13.2. Recommendations

1. The ignition operations have to be improved in order to reduce the ignition delay under one month.

2. The grafting of the THAI process within the existing conventional ISC operations is highly recommended, and this can be done very easily in the ISC operations conducted in China and Romania

3. Testing of THAI in Peace River region would constitute the first testing of the THAI process in a typical conventional oil reservoir (without an underlying bottom water zone) in Canada, and it seems to offer better conditions than in Kerrobert and Athabasca Oil Sands. A successful operation can occur if a staggered line drive configuration is adopted, and a broad initial ISC front is generated.

4. It would be desirable to test again the THAI process in a conventional heavy oil with bottom water, utilizing the experience from Kerrobert project. The effect of the existing old horizontal wells (including their potential use) should be fully evaluated before deciding on this testing. For a first test, it would be best to avoid a field with many horizontal wells that were designed for use in primary recovery operations. It is surmised that the performance will be better if the reservoir has a bottom water thickness zone of less than 35% of the oil zone thickness. Perforating the vertical wells just under the top of layer on a short distance and positioning of horizontal sections of producers farther from the water/oil contact is recommended.

5. Testing the THAI process in the Athabasca Oil Sands again should not constitute a priority at this time; more experience is needed. When tested again, the lessons from Whitesands Project should be fully understood. In the new pilot, the SLD configuration can be evaluated; a broad initial ISC front using one of the methods proposed here (for oils without mobility within the reservoir) is to be considered. Therefore it means more complexity and a lot more experience for the people involved. Smaller well spacing may also be necessary.

6. When developing a new ISC process or testing THAI (or any other newly proposed ISC) within an existing conventional commercial ISC or steam injection Project, while using horizontal producers,

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the focus should be the control of the local coke plugging, during the process; otherwise, the total plugging of the producer can occur.

7. A CAPRI limited field test was tried in 2008, but everything was premature for such a test. The laboratory investigations of the CAPRI process should continue; the possible adaptation of the later developments in the surface upgrading to in-situ conditions is desirable. An integrating approach, involving the decision to direct the process towards maximizing oil upgrading or maximizing hydrogen production, is necessary. Therefore, field testing should be delayed until the mechanisms involved are thoroughly understood, and there are definite chances that a meaningful field test can be evaluated properly. *A relatively long road ahead of us is visualized!*

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APPENDIX A
List of Toe- to-Heel Air Injection (THAI) and CAPRI Related Publications/Presentations

List of Toe- to-Heel Air Injection (THAI) and CAPRI Related Publications/Presentations

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February 3rd, 2024

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Appendix B

List of Toe- to-Heel Air Injection (THAI) and CAPRI Related Patents

1. Ayasse, C.: **“**Horizontal well line drive oil recovery process”. Canadian patent 2,759,362
   A horizontal well combustion line drive: producers are sequentially converted to injectors, reducing the number of required horizontal wells by half.

2. Ayasse, C.: “Staggered horizontal well oil recovery process”. Canadian patent 2,759357
   In an in situ combustion process, in which air injectors are placed in a staggered configuration with the injectors near the top of the reservoir and the producers near the base. All fluids are produced with the same wells. The process applies only to reservoirs containing mobile oil (not bitumen).

3. Ayasse, C.: “Oil recovery process using crossed horizontal wells”. Canadian patent 2,759,356
   In an in situ combustion process, injection and production horizontal wells are perpendicular. Perforations in the producers are selected strategically to prevent gas short-circuiting

4. Menard, W. P., Wheeler, T.J. and Dreher, W.R. : “Completion Method for Horizontal Wells in In Situ Combustion” USA patent 8,387,690B2, March 5, 2013
   Injecting an obstructing agent into the toe region of the horizontal section of the production well during the THAI process to prevent an oxygen short-circuit, when needed

5. Ayasse, C.: “Diluent-enhanced in situ combustion hydrocarbon recovery “USA patent 7,984,759
   A diluent, namely a hydrocarbon condensate, is injected within a horizontal wellbore portion, preferably proximate the toe, of a vertical-horizontal well pair, or alternatively into an adjacent injection well, or both, to increase mobility of oil. This assists in moderating wellbore pressure, carrying sand and lifting the hydrocarbons.

6. Ayasse, C. : “Well liner segments for in situ petroleum upgrading and recovery, and method of in situ upgrading and recovery”. US Patent 7,909,097

   This patent covers a completion design for placing bitumen - cracking catalyst in the annular space of a double horizontal well liner to intercept and upgrade hot draining oil using the heat and hydrogen generated in the THAI process. Upgrading the oil several points API density was achieved when the process was tested in the reservoir.

7. Ayasse, C. : “Improved in-Situ Combustion Recovery Process Using Single Horizontal
   Well to Produce Oil and Combustion Gases to Surface” (the Multi-THAI process).
   Canadian Patent Application 2698454/2011
   The proposed process is equivalent to the top-down ISC (TD-ISC) process; for further information see the website: www.insitucombustion.ca

8. Ayasse, C., Wu, X. and Bloomer C. : “Modified Process For Hydrocarbon Recovery Using In-Situ Combustion”. USA patent 7,841,404/ Nov. 30, 2010
   Single horizontal well used in a THAI style, to produce oil and combustion gases to the surface; instead of a vertical well, the vertical portion of horizontal well is used for air injection

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9. Ayasse C. : “Oilfield Enhanced In-Situ Combustion Process” US Patent 2008/0169096 A1. , March 13, 2008.
Water, steam, and/or a non-oxidizing gas, which acts as a gaseous solvent, is injected into the reservoir for improving recovery in THAI process, via either an injection well, a horizontal well, or both.

10. Ayasse C. : “Oilfield enhanced in situ combustion process” US Patent 7,493,953
Co-injection of carbon dioxide and oxygen combines the benefits of combustion with solvent extraction to increase the oil production rate and oil recovery factor.

11. Ayasse C. : “Oilfield enhanced in situ combustion process” US Patent 7,493,952
Inert fluids are injected to the toe of the horizontal production well in the THAI process to control temperature and pressure. This enables higher safe air injection rates and higher oil rates

12. Turta, T. A., Wassmuth F., Shrivastava, V. and Singhal K.A.: “Toe-To-Heel Waterflooding (TTHW) with Progressive Blockage of the Toe Region” USA patent 7,328,743, February 12, 2008 The improvement in the TTHW oil recovery process is due to progressive blockage of the toe-region of the horizontal producer. In other words, increasing portions of the horizontal leg, adjacent to the toe, are blocked completely, while only the remaining portion of the horizontal leg, adjacent to the heel, receives the oil production. This progressive blockage results in reduced water cuts and improved oil recovery.

13. Ayasse, C, Greaves, M., and Turta, A.: “Oilfield In-Situ Hydrocarbon Upgrading Process” US Patent 6,412,557, July 2, 2002. Canadian Patent obtained on July 8, 2003.
This is the catalytic THAI (the CAPRI process). In a THAI combustion process, catalyst is placed in the annular space of a horizontal producer to partially upgrade draining oil while flowing from reservoir to borehole.

14. Ayasse, C and Turta A.: “Toe-To-Heel Oil Recovery Process - Toe-To-Heel Waterflooding (TTHW) process” US Patent 6,167,966, January 2, 2001. Canadian Patent 2,246,461, June 18, 2002
Medium or light oil are produced by injecting water in a vertical injection well and producing from a horizontal well located near the top of the reservoir. The process uses a unique toe-to-heel configuration (of injection and production wells) to achieve "gravity-stable" oil flow in the reservoir. Besides increasing oil recovery in light oil reservoirs, the process greatly increases the range of oil grades amenable to water-flooding.

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15. Greaves M. and Turta, A.: Oilfield In-Situ Combustion Process. U.S.A. Patent No.5,626,191, May 6, 1997. Canadian Patent 2,176,639, August 8, 2000

This is the basic patent for toe-to-heel air injection (THAI) process; technically, it is described in detail in the body of this report. Here, only some essential information on the administrative aspects will be provided:
The USA patent expires in May 2017, while Canadian patent 3 years later. From different conversations with Petrobank/Touchstone employees it resulted that the conditions for the application of the patent are so that there is no royalty to be paid for the piloting; the royalty provision is for the case when the semi- or commercial THAI application exceeds 7,000 bbls/day. When Touchstone bought the Petrobank they bought the THAI and CAPRI patents, as well. When Touchstone sold the Kerrobert Project to Quattro, Touchstone offered the THAI and CAPRI patents to John Wright, former Petrobank CEO, and to Dr. Conrad Ayasse.

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Appendix C

Chronologic listing of the Petrobank Energy and Resources and of Touchstone Exploration press releases related to the THAI piloting (design, implementation, operation, evaluation, etc). Former websites: www.petrobank.com and www.touchstoneexploration.com; current website: info@qxp-petro.com

2005:
Dec 22: Petrobank Provides Operational Update

2006:
July 21: Petrobank Fires Up Whitesands Thai™ Project
Sept 12: Petrobank Encouraged by Early Combustion Operations at Whitesands Thai™ Project

2007
Jan 16: Petrobank Fires Up Second Thai™ Well Pair At Whitesands
May 14: Petrobank Strengthens Oil Sands Asset By Increasing Whitesands Ownership From 84% To 100%
May 28: Petrobank Elects To Fund $120 Million Acquisition Of Minority Interest In Whitesands With Cash
Jun 18: Petrobank Fires Up Third Well Pair at Whitesands
Nov 1: Petrobank Signs Thai™ Licence Agreement and Acquires Heavy Oil Assets
Nov 14: Petrobank Receives $10 Million Whitesands Funding From Canadian Federal Government

2008
Sep 22: Petrobank Announces First Thai™/capri™ Production
Nov 21: Petrobank Enters Into Thai™ Royalty And Technology Licence And Joint Venture Agreement.
Nov 27: Petrobank's Whitesands Expansion Approval Advances
Dec 18: Petrobank Files May River Application

2009
Oct 27: Petrobank Fires Up Kerrobert THAI Project

2010
Jan 7: Petrobank Ramps Up THAI™ Operations
Oct 19: Petrobank Consolidates Heavy Oil Assets
Nov 15: Petrobank Provides Update For Heavy Oil Business Unit
Nov 29: Petrobank Receives Final Regulatory Approval For Dawson
Dec 14: Petrobank Terminates THAI® Licensing Negotiation

2011
Mar 10: Petrobank Announces 2010 Reserves, Including First Thai® Reserves
Jun 28: Petrobank Announces An Increase In May River Contingent Resources

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Sep 29: Petrobank Announces May River Regulatory Hearing Date and Suspension of Conklin Operations

Dec ??? Lay off of some technical staff (one of them Ravinder Sierra, Manager Technology Development) related to THAI field piloting

2012

January Petrobank hires Rob Richardson as VP Operations Heavy Oils

Jan 31: Petrobank Announces Sale of May River Property

Feb 28: Petrobank Announces Closing of May River Property Disposition

Apr 20: Petrobank Provides Kerrobert Operational Update

Aug-Sept Petrobank Announces the resignation of Rob Richardson, VP Operations Heavy Oils

2013

March 12 Petrobank Announces the resignation of Chris Bloomer, VP Heavy Oil and Chief Operating Officer

August 12 Petrobank reports Q2 2013 financial results and operational update. (Section: operational update on Kerrobert THAI Project)

October Corporate Presentation

November 12: Petrobank reports Q3 2013 financial results and operational results, update corporate strategy. The drilling of two vertical air injection wells as part of a trial to apply a multi-THAI process is mentioned; injection starts in September 2013 (Section: operational update on Kerrobert THAI Project)

2014

March 6: Petrobank and Touchstone Exploration Inc. (Touchstone) combine to create a high growth, fully capitalized oil company (Petrobank is bought by Touchstone)

April 28: Petrobank and Touchstone announce shareholder approval of Plan of Arrangement

July 16: Touchstone provides operational update; total oil production is 410 bbl/day. Two Dawson (Peace River) cyclic steam stimulated (CCS) wells give approx. 110bbl/day

October 23: Touchstone provides operational update; total oil production is approx. 324 bbl/day. Dawson CCS operations are suspended

2015

January 13: Touchstone provides operational update; total oil production is 308 bbl/day.

July 22: Touchstone announces the Dawson disposition. CSS operations did not give expected results; the plan for THAI application, following CSS operations, was also cancelled.

August 13: Touchstone announces 2015 second quarter results. Total oil production is probably around 161 bbl/day.

2016

January 20: Touchstone Announces that Kerrobert is sold to Quattro Exploration and Production (Quattro) . This way, Touchstone sold all heavy oil properties in Canada in order to focus on its main light oil core properties in Trinidad.

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February 1: Touchstone Announces closing of Kerrobert Saskatchewan disposition; The deal is to be finalized on February 15, 2016

February 4: The co-author of this report, Alex Turta, visits the Kerrobert THAI project along with Konstantin Starkov, Production Engineer Specialist in Petrobank/Touchstone, taking care of Kerrobert Project

August 11: In time, Quattro has contracted high debts. Quattro is granted court protection to allow for its orderly completion. Hardie and Kelly Inc. is appointed as the trustee to help Quattro in its efforts.

September 8: Creditors' Arrangement Act is finalized; Quattro is under creditors protection for a certain period of time.

2017

February 2: Quattro went into receivership. Hardie & Kelly Inc. are the court appointed receivers and they have engaged Veracity Energy Services Ltd. to manage Quattro's operations

February 13: Quattro Exploration and Production becomes bankrupt; Hardie and Kelly Inc. is assigned as Receiver in order to manage the assets of Quattro including the Kerrobert Oil Field, while the directors and officers of Quattro remain in place but with their power limited by the Receivership Order. Hardie and Kelly Inc. assigns Veracity Energy Services of Calgary for temporary, day-by-day operation of Kerrobert oil exploitation, until the Receiver takes a decision of what to do; a selling of the Field is contemplated.

August: The Kerrobert Project is sold to Proton Technology Canada, located in Calgary. This is a company interested in developing methods for separation of hydrogen from gas streams. Website: www.info@proton.energy. Operation of the Kerrobert Project is assigned to the company Superb Operating Company Ltd, a subsidiary of Proton Technology Canada.

2019

September Although a patent application for separation of hydrogen from gas streams was filed by Proton Technologies Canada (in 2016), no patent has been granted up to this date. The devise to be tested in the Kerrobert field has not been tested. The oil production activity continues - under the Superb Operating Company supervision - but at a very reduced scale.

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Appendix D

Chronologic listing of the Petrobank Energy and Resources personnel and other individuals' <u>interviews / declarations / publications</u>, in different newspapers and magazines, related to the THAI field testing

2004
Oil week, March 1: A Calgary company researches a step-change in bitumen recovery technology

2005
Dec 19: Graham Chandler – " The underground Refinery"
(http://grahamchandler.ca/journal/2005/12/underground-refinery.html

2006
Oil and Gas Network, October**:** Petrobank optimistic about early results at Whitesands
Calgary Herald Nov 8: Petrobank innovation could change the rules in the oilsands
Calgary Herald Nov 14: Trials of cleaner oilsands process encourage inventors
New Technology Magazine, December: Rise in legal skirmishes and intellectual property protectionism force companies to re-examine technology policy

2007
Calgary Herald May 15: Petrobank becomes sole owner of oilsands pilot
Calgary Herald, June 21: Who's hot: oilsands. Who's not: gas juniors. CAPP Conference
Calgary Herald Nov 2: Petrobank, Duvernay pair up

2008
Calgary Herald, June 14: Tech Revolution (Oil sands innovations generate investor buzz)
Energy News, Sept 26: Petrobank uses new thermal process to unlock heavy oil deposits
GOB Committee, October 16: presentation by C. Ayasse: Three strong businesses. One powerful company
Calgary Herald, Nov. 22: Oil recovery technique benefits Petrobank
Calgary Herald, Nov. 29: Oilsands regulatory delay frustrates Petrobank boss
Calgary Herald, Dec. 19: Petrobank seeks nod for thermal project

2009
Calgary Herald, March 13: Petrobank boasts record year
Calgary Herald, July 9: Asset sale gives Petrobank chance to shine
Daily Oil Buletin, August 14: Petrobank Defends Whitesands, Readies Three More In-Situ Combustion Projects
New Technology Magazine, September: Fired Up. Grilled Over Fire Project. With long-running commercial projects in Romania, India and the U.S. in-situ combustion is proven, researchers say
Calgary Herald, Oct 28: Petrobank CEO praises Sask approval process
Energy and Technology, Dec19: The battle for the oilsands 2.0

2010

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Calgary Herald, Jan 8: Petrobank to hit stride
Calgary Herald, March 18: Petrobank technique has potential to tap 1.8 B barrels
Calgary Herald, April 3: IN-SITU: Thermal projects gaining
Globe and Mail, June 25: Report on Business. The top 1000
Calgary Herald, August 14: Output gains boost Petrobank
Calgary Herald, August 17: Petrobank sets Dawson demo plan
New Technology Magazine, September: Three For The Money
Calgary Herald, September 25: Producers see rich potential in Seal Lake
Calgary Herald, October 20: Petrobank to spend $15M on fireflood buyouts
Calgary Herald, October 20: Joint venture partners agreeing to disagree
Calgary Herald, November 17: Petrobank cash flow and production boom

2011

Calgary Herald, March 11: Petrobank gets credit for THAI reserves
Calgary Herald, November 16: Petrobank Energy says innovative technology will pay off next year

2012

CIBC Investor Conference, Whistler , BC, January 18 presentation by P. Cheung: Two public companies - three unique investments
Calgary Herald, February 1: Petrobank sells lease for $225M
Calgary Herald, March 9: Petrobank says oilsands process will prove viable
August 2012: Petrobank corporate presentation (www.petrobank.com)

Pipeline News, Sept 2012 (Posted on Sept 6, 2102 in Prosperity Saskatchewan): Kerrobert THAI project ramping up, communication by Geoff Lee.

2013

Alberta Oil e-Newsletter: January 4: Is Petrobank's THAI technology ready for the spotlight? (Bitumen barbecue has encountered setbacks; executives optimistic). By Max Fawcett

Globe and Mail, Jan. 21: The tangled tale of Petrobank's THAI extraction technology By Carrie Tait

Alberta Oil, February: Page 36: New Wave

Alberta Oil, April: Page 62: Petrobank and Synodon are risky bets for investors (but the potential for upside is huge with these companies if their unproven technologies pan out). By Jody Chudley.

Calgary Herald, May 8: Petrobank notes THAI issues

Alberta Oil, June: Page 50: Petrobank Energy Ltd. By Darren Campbell

Calgary Herald, August 13: Petrobank cuts budget on production setback (Stock falls after THAI heavy oil output plunges to just 135 bpd) By Dan Healing

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Calgary Herald, Nov. 14: Petrobank puts deadline on THAI (to run it until July 2014)

2014

Calgary Herald, March 8: Merger spells end of Petrobank (Petrobank is bought by Touchstone Exploration Inc); see new website: www.touchstoneexploration.com

2015

Calgary Herald, July 23: Company (Touchstone Exploration Inc – my note) shifts focus to Trinidad assets

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Appendix E

Whitesands THAI Pilot : Shape and Size of the Burned Zones. The Analysis of Air Lost via McMurray "A" Formation and Bottom Water

A. Shape and Size of the Burned Zones

The first objective of this analysis is to estimate the 3-D configuration of the volume burned, inclusive its lateral development, by taking into account the longitudinal development (along the horizontal section of producers) and the dates of ISC intercept of the observation wells, already determined. The second objective is to determine the air requirement per m^3 of burned rock based on field data from this pilot. The reference point for the calculations is September 2010. For calculations, we will go through the first three approximations of the burned volume, using the third one for concrete evaluation:

- Horizontal regular rectangular prism (both rectangular caps of equal surface), Fig. E1-a; this is considered the reference burned volume (a maximum possible)
- Horizontal rectangular truncated pyramid (*rectangular caps* of different surface, with advancing one being smaller), Fig. E1-b
- Horizontal irregular rectangular truncated pyramid [*with both caps being trapezoidal* and of different surface, advancing one (EFGH) being smaller in surface], Fig. E1-c
- *Same as previous but with the leading trapezoidal cap being tilted forward,* Fig. E1-d

The initial approximation assumes a horizontal regular rectangular prism which is similar to the 3-D model used in the laboratory tests (Fig. E1-a). Then, this volume is distorted in order to account for the horizontal wedging and vertical wedging (Fig. E1-b and E1-c).

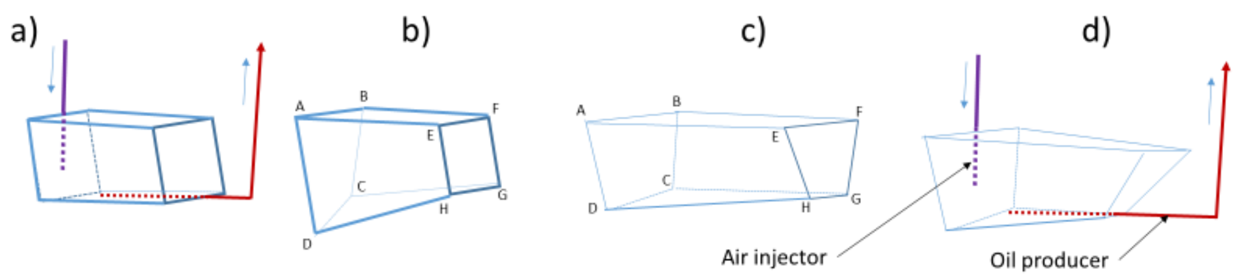

Figure E1: Evolution of the concept for schematic of the volume burned in a DLD THAI process, taken into consideration for calculations. From left to right: a) regular rectangular prism, b) rectangular truncated pyramid, c) irregular rectangular truncated pyramid with both caps trapezoidal and d) same as previous but the leading cap is tilted

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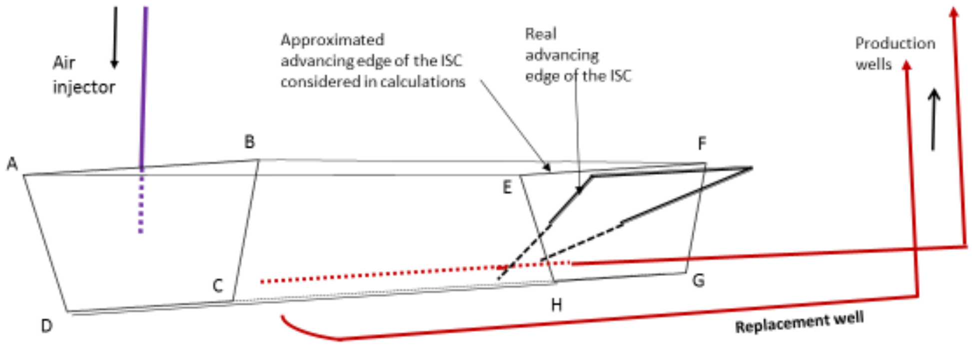

Figure E2: Detailed schematic of the volume burned in a THAI process conducted in a direct lined drive (DLD) configuration. For illustration purposes a replacement well is shown

Finally, the calculation of the volume burned was made for a horizontal irregular rectangular pyramid (trapezoidal caps of different surface, with advancing one being smaller) Fig. E1-c, which is shown with more details in Fig. E2. More details behind the thinking leading to this final schematic of the burned volume considered for the calculations are provided in Section 6.1.4.2 of the Report. For the time being, the trapezoid close to the injection well (ABCD) is bigger, passing through the injection well and considered immobile; the assumption of no-propagation in the direction opposite to the air flux is accepted as a first rough approximation. The trapezoid representing the advancing edge (EFGH) of the ISC burned volume is a smaller trapezoid whose surface is decreasing in time by having a smaller lateral extent. These trapezoids are still vertical and, in reality, the advancing cap (EFGH) is an average for the forward portion/volume of the advancing burning zone, as actually this trapezoid is tilting forward; the true tilting is difficult to estimate such that 45 degrees is considered, Fig. E2.

The air requirement determined for the pilot will be then compared with a corresponding value from the combustion tube tests, in which *only HTO reactions are assumed* to take place. Taking into account the results of 27 combustion tube tests conducted at the University of Calgary (Ursenbach, 1992) it is estimated that the fuel deposited would be in the range of 35-50 kg/m^3 rock, with the air requirement in the range of 360-460 sm^3/m^3 rock. For our comparison, the fuel deposited will be taken as 40 kg/m^3 rock, with a corresponding air requirement of 420 sm^3/m^3 rock. These values assume that t*his fuel deposition is always formed in-situ, from the original oil; no extra-fuel is assumed while the oil is flowing through the burned zone and mobile oil zone (MOZ) - actually close to the boundary between two regions - towards the horizontal well.*

As, according to temperature measurements, the burned zones around P1, P2 and P3 have never merged, an attempt is made to estimate the value of the air requirement for each THAI pair based on the

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cumulative volume of air injected and a field estimate of the burned volume around each producer of the pattern (Figure 47 c) taking onto account the temperature profiles from observation and production wells (original and replacement wells); more precisely accounting for the time of interception of observation wells by ISC front (September 2010) and the maximum advancement of the ISC front along the horizontal section of producers at the same reference time (September 2010).

In Figure 50 from the body of the Report, it can be seen that as of September 2010, for the whole project, the total cumulative oil produced was 28,000 m^3, with a final air-oil ratio of 5,200 sm^3/m^3. For all three pairs, a cumulative total volume of 146 million sm^3 (28,000m^3 x 5,200 sm^3/m^3) of air is estimated. As we do not possess the total cumulative volume of air for each air injector, an estimate for A3-P3 (P3b) is made based on the A3-P3 graphs of variation for cumulative oil and cumulative air-oil ratio (AOR) in time, for the period 2006-March 2008 and March 2008-September 2010 (ERCB Presentation 2011); these graphs are similar to the graph for the whole Pilot in Figure 50. For those two periods, the result is, 4.5 million (1000 m^3 x 4,500 sm^3/m^3) for the first period and 28.6 million (6,500 x 4,400) for the second period. Therefore, the total air injected in A3-P3 (P3b) pattern is: 33.1 million sm^3. The remaining of: 146 million - 33million=113 million sm^3 was the total volume of air injected in A1-P1 and A2-P2 pairs. In order to split this total of 113 million sm^3 between the A1 and A2 pairs, an estimate based on the figures in Table 8b (main body of Report) is made. It is assumed that the air injection rates from 2008-2009 period will have the same trend as that in year 2010), ie, they will be proportional to the amounts injected in the period 2008-2009 (see also Fig. 51a-b from the Report). Using this assumption, as of September 2010, the cumulative volumes of air injected are estimated as follows:

Pair A1-P1: 55.5 million sm^3

Pair A2-P2: 57.5 million sm^3

Pair A3-P3: 33.1 million sm^3

Total: 146.1 million sm^3

The above values assume that all the injected air is flowing towards the THAI producers; no air permanently escapes (via bottom water or into the Mc Murray A formation).

Next, we are trying something that it has never been done in the past application the in-situ combustion: estimate of the air requirement using the field data. Although this is very approximate, in the THAI process, *unlike conventional ISC process*, the estimate of the burned volume is more reliable because this volume is very compact around the horizontal producer. This is also supported by the fact that the instrumentation in the Whitesands Project was *one of the best of any ISC pilots conducted anywhere previously (*because it had many observation wells). In case of the A3-P3 well pair, there is greater certainty about the burned volume on both sides of producer because there are temperature measurements

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in wells OB9 and P3b located on both sides of P3 well; in addition, it is well established that a toe-to-heel propagation of the ISC front occurred both around P3 and P3b.

In A3-P3(P3b) pattern, by September 2010 (which also happens to be the date of the interception by ISC front of the OB9 - Fig. 46e and Table 7b), *the width of the burned zone was around 42 m (15m on the OB9 side and 27m on the P3b side). Also, at the same date,* its length (along the horizontal well) was 250 m (from the toe) as indicated by the last peak temperature of 335 ^{0}C in well P3b in September 2010 (Figure 48c1 and Table 7b). The 27m extrapolated lateral distance was calculated assuming that since March 2009 (date of merging/anchoring of the old burned zone to the P3b toe -see Table 7a) until September 2010, the lateral velocity of the ISC front was 2 cm/day, as determined in OB9 observation well; this way, the front propagated laterally another 11m beyond the 16m (which is the distance between P3b toe and trajectory of P3).

Taking into account the net pay thickness of 11.5m the volume of the regular rectangular horizontal prism (Fig E1-a) formed is 120,750m^3 (42*250*11.5

The wedging effect of the combustion occurs in both horizontal and vertical directions. For wedging in horizontal direction it is assumed that the burned volume is a rectangular horizontal truncated pyramid, *with an advancement along the horizontal section* of 250m (Fig E2-b), but having the surface of advancing edge the *rectangle* EFGH which is approximated at half of the surface of the rectangle ABCD (located close to air injector); the assumption is made that by the time the leading edge reaches the heel of producer, the trunk of pyramid becomes almost a pyramid with its top at the heel. In this case, in a first approximation, considering a horizontal *rectangular* truncated pyramid, the volume is that of a pyramidal frustum (Wolfram Alpha encyclopedia) and it would have the general equation:

$V= (1/3)* \text{Height} *(A1 +A2 +\sqrt{(A1*A2)})$

Where height is the longitudinal advance of the ISC front, A1 is the area of the immobile rectangular cape at the injection well (11.5*42m) and A2 is the area of the rectangular leading edge, considered here at the half of the horizontal section, with the upper side of the cap reduced from 42m to 21m (area=11.5m* 21m); the ISC front will still extend from top of layer to its bottom. In this case the calculation will give: V=88,837 m^3. After considering only wedging in the horizontal direction, this burned volume represents 74% of the rectangular reference prism (Fig. E1a) (120,750). To consider the wedging in vertical direction it is assumed that the burned volume is a rectangular *horizontal truncated pyramid with the same advancement along the horizontal section* (250m - Fig E2-c), but having the surface of advancing edge the trapezoid EFGH being smaller than the trapezoid ABCD (located close to air injector); consequently; the assumption is made that the ***advancing trapezoid*** will have both its big base (EF) and its

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small base (GH) approximately half of the corresponding bases of the immobile trapezoid (ABCD). Also, it is assumed that tilting of the lateral surfaces (ADHE and BCGF) against vertical direction planes is *approximately* 45 degrees (angle EFG is 45 degrees).

The same approach will be applied for the calculation of the burned volume, where the height is the longitudinal advance of the ISC front, A1 is the area of the immobile trapezoid cape at the injection well [11.5*(42+19)/2] and A2 is the area of the trapezoid leading edge [11.5*(21+9.5)/2]. The ISC front will still extend from top of layer to its bottom.

The calculation gives V=64,496 m^3. This value represents 53% of the rectangular prism (120,750 m^3) and it is in agreement with 3-D laboratory tests of University of Bath, where a volumetric sweep efficiency of 53-69% was found for the direct line drive THAI in a rectangular 3D combustion cell (Greaves, 1997). In the field situation, it is assumed that the rectangular volume (reference prism) have both caps equal to 42*11.4 m^2 surface (in reality, only 42 m is burned out of 100m, considered in the design as the well spacing).

Assuming that the process operated *with a full consumption of oxygen, for HTO and LTO reactions*, the field air requirement is:

33,100000 /64,496 = 513 sm^3/m^3

The calculation made so far had the limitation that no advancement of the ISC front in a direction opposite to the heel of the producer was assumed; the large cap of the burned volume (ABCD) remained fixed (Figs E1) at the injection well. To eliminate this limitation, the advancement of the ISC front in the direction opposite to the heel of the producer P3b at the reference date of September 2010 is estimated as being **15m** i.e half of the length of the blind liner (at the toe); this is a conservative estimate in this direction (using a velocity of 2cm/day as per the observation well OB9) and it is further estimated at a value of 4-5cm/day for the direction perpendicular to the trajectory of the blind liner; this is a very reasonable assumption as pre-heating and ignition took place along the blind liner. Therefore, the longitudinal advancement becomes: 250+15= **265 m**, while the lateral development is assumed to remain at **42m**. This means that, finally, an approximate pyramid having a height of 265m is considered and its large cap is just at the end of the blind liner, and it has a width of 42 m (Fig. E1-c).

With this correction, the initial reference regular rectangular horizontal prism (Fig E1-a) of 42x250x11.5 (120,750m^3) becomes 42x265x11.5 (128,000 m^3).

For the calculation of the burned volume we will be using the same methodology, where height is the longitudinal advance of the ISC front (265m), A1 is the area of the immobile trapezoid cape behind the injection well [11.5*(42+19)/2] and A2 is the area of the trapezoid leading edge [11.5*(21+9.5)/2], with

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the ISC front still extending from top of layer to its bottom. However, as noticed, the bases of the advancing cap A2 will be slightly smaller (20m and 9m, instead of 21m and 9.5m).

A1= 11.5(42+19)/2 and A2 =11.5(20+9)/2

The calculation will give: V=67,045 m^3.

The field air requirement would be:

33,100,000 /67,045 = 494 sm^3/m^3

This value (494 sm^3/m^3) is 18% higher than that from laboratory combustion tubes (420 sm^3/m^3), and shows that it is possible that the THAI process consumes more fuel than a conventional ISC process. However, probably, any additional fuel is not consumed~~,~~ *in situ (at the original location of the oil) ,* but when the hot oil flows through the burned zone (in the proximity of the mobile oil zone) towards the horizontal section of horizontal well. More detailed targeted investigations are necessary to clarify this aspect.

In case of A2-P2 pair we also have some temperature controls on both sides of P2, as temperature measurements were made in both OB6 and toe of P2b; however, there was no temperature increase at the toe of P2b in 2009, such that there is no a precise control on this side of P2. Also, no lateral correction can be estimated as the interception of OB6 well occurred in September 2010). By accepting that the estimate for A3-P3 air requirement of 494 sm^3/m^3 rock is our reliable figure, then the volume of truncated pyramid-shape burned volume burned in the pattern A2-P2 will be: 57,500,000 / 494 = 116,397 m^3, instead of 136,905 m^3 , assumed initially (based on laboratory combustion tube tests).

In case of A1-P1 pair we do not have temperature control (measurements) on both sides of P2 trajectory; both OB3 and the toe of P1b are on the same side. For this unfavorable situation (from the point of view of our calculations) we will assume that the burned zone is identical on both sides. For A1-P1 the longitudinal correction will be also taken as 15m, but there will be a lateral correction as well, as the interception of observation well OB3 took place in July 2008 and more lateral advancement happened after this date. Based on velocity towards OB3 well and considering the same velocity after July 2008 the correction is 14.6m, that is the lateral distance for the burned volume at the OB3 position at September 2010 is estimate at 26.4m (12+14.6); considered on both sides it is estimated at 52.8m. Similarly, using the A3-P3 air requirement, the volume of truncated pyramid-shape burned volume for this pattern will be: 55,500000 / 494 = 112,348 m^3, instead of 132,143 m^3, assumed initially (based on laboratory tests).

Using notations from Fig. E2, the irregular horizontal truncated pyramid having the large trapezoidal cap (ABCD in Fig. E2) 15m behind the injectors and a smaller trapezoid cap (EFGH in Fig. E2) at the

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maximum advancement along the horizontal producer will have the sizes given in Table E1. As far as the maximum advancement from the Table E1 is concerned, some additional advancement of the ISC front along producer's horizontal section is estimated based on the date of the last maximum temperature (300 ^{0}C) recorded (Table 7a from the main report). For instance, for the pair A1-P1, 33m was added to the recorded 225m, as the 225m was recorded in March 2009 (See Table 7a). So, for the period March 2009-September 2010 the velocity found for OB6 (6cm/day) was applied for this period to find additional advancement.

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Table E1: Whitesands Pilot. Estimated sizes of the burned volume in the pattern A3-P3 (P3b) based on Field temperature data. Attempt to extrapolate the results to the remaining two patterns

Pair	Volume of rock Burned (based on labor-atory A_{air}) m^3	Volume of rock burned (based on field A_{air}) m^3	Upper AB side length m	Lower CD side length m	Length of HS of HP m	Estimated advance-ment along the HS of HP m	Upper EF side length m	Lower GH side length m	Volume of reference prism m	Volumetric sweep efficiency of the reference prism* %	Obs.
A3-P3 (P3b)	78,810	67,045	**42**	**17**	390	**265**	20	9	129,519	52	Good Estim
A2-P2	136,905	116,397	**30**	**7**	386	**196**	15 *	3.5*	67,620	172???	Vague Estim
A1-P1	132,142	112,348	**52.8**	**29.8**	389	**273**	26.4*	15*	165,766	68	Very Rough Estim

Legend: HS of HP = Horizontal section of horizontal producer; Estim = Estimation (Estimating)

* Orientation values; they did not take part in calculations

Note: The sizes of the reference prism are highlighted in BOLD. The rectangle cap has the sizes 42m*11.5m for A3-P3 and 30m*11.5m for A2-P2, while for A1-P1 is 52.8m*11.5m; please note that they are considerably lower than the corresponding caps allocated to each pair by design, which are 100m*11.5m. The reference prism is the prism supposed to contain the truncated pyramid represented by the burned volume.

The same procedure was applied for the pair A2-P2 for the period March 2008-September 2010 with an average velocity of 3.4 cm/day recorded at OB6. The additional advancement was found to be 31m.

It is to be highlighted that the extrapolation of the results from A3-P3 pattern to the remaining two patterns is made through the use of the air requirement calculated based on data of A3-P3 pattern; this is how the volume of rock burned (column 3 in Table E1) in A2 and A1 patterns is estimated. From Table

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E1, it is obvious that the results for A2-P2 pair do not seem to be physically meaningful, as the volume of the truncated pyramid, representing the burned volume, exceeds the volume of reference prism. To some extent this applies to A1-P1 pair as well as the volumetric sweep efficiency of 68% seems to be too high for a field test. However, in spite of these discrepancies, the good development of the combustion zone around A1 and A2 and in the inter-space between P1 and P2 - mainly a large lateral development in this region - seems to be in agreement with the results of time-lapse seismic monitoring (ERCB Presentation, 2012 shown in Figure E3); a slight trend for preferential propagation towards North and NW can be observed. A limitation of seismic monitoring seems to be the fact that it shows a development of high gas saturation around observation well OB17 (Fig. E3 – last picture), therefore outside the area of THAI pilot, but without a continuing development in-between these two zones; the existence of this kind of "island gas saturation region" is very improbable!

Summing all the burned volumes (column 3 in Table E1) in the three patterns, gives:

67,045 + 116,397 + 112,348 = 295,790 m^3

The amount of oil displaced from this total burned volume is:

[295,790 x 0.34x0.72 – 0.1x295,790 x0.34x0.72] = 65,168 m^3

A porosity of 34% and initial oil saturation of 72% were used; the amount of oil consumed as fuel and in coke gasification *was estimated* at 10%; more refined calculations are worthwhile to come with a more precise value for the amount of oil consumed as fuel and in coke gasification.

However, the total volume of oil produced from this pilot was only 29,000 m^3, which represents 45% of the mobilized oil, displaced from the burned volume. In case all the injected air flowed towards the respective THAI producers*, in the target layer (objective*), it is conjectured that, two factors can be considered: either the capture efficiency was extremely low, or else, the oil consumed as fuel and in coke gasification was a lot higher than that estimated from the above calculations.

If the capture efficiency happened to be extremely low it follows that *a lot of hot oil still exists either in the adjacent regions or in the thin bottom water zone*. However, an additional third major factor exists; this factor could have been repreented by the permanent loss of a substantial part of injected air either via the bottom water or via the McMurray "A" formation, therefore not displacing any oil within the target formation. If that could be considered, the total cumulative of air entering the target formation and hence the volume burned would be smaller; in this case the discrepancy between produced and displaced oil would be smaller. The analysis of potential air loss is made in the next section of this Appendix.

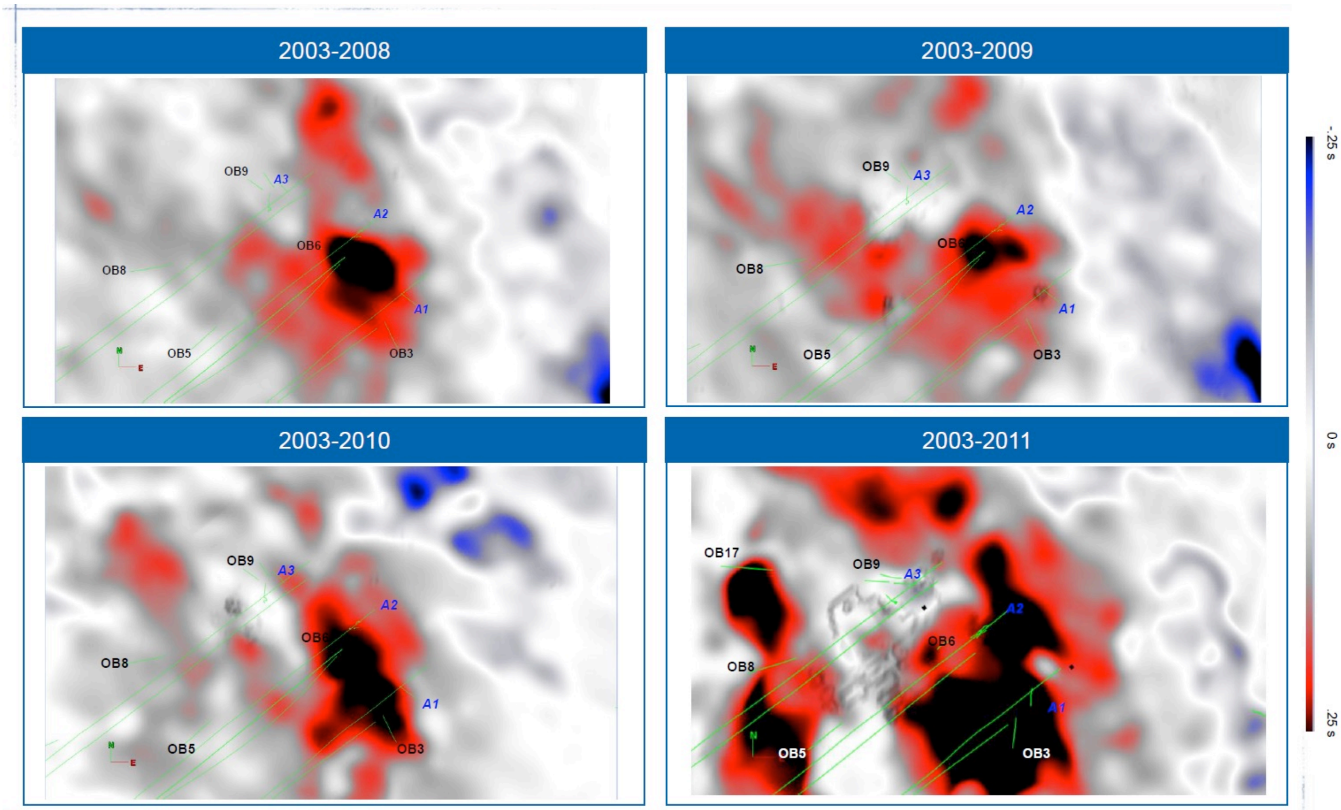

Figure E3: Whitesands Pilot. Time-lapse seismic monitoring interpretation in the period 2008-2011, using the reference survey from 2003 (ERCB Presentation, 2012)

It is difficult to draw a strong conclusion, however, except that, the air requirement and oil consumed by the process in the field may be higher than in the laboratory (combustion tubes). Of course, this last statement is pending on the correctness of our assumption of considering the wedging effect causing the original 42m length of the upper side of the original trapezoidal cap being reduced to approximately 20-21m – the length for the leading trapezoidal cap at 265m from the toe and a tilting of lateral ISC surfaces of 45 degrees, for A3-P3 pattern.

B. Analysis of Air Lost via McMurray "A" Formation and Air Flow into the Bottom Water Zone

The analysis in this section is a very in-depth one, as it will deal not only with the evaluation of the air escape, but also with the main thermal events taking place in McMurray "A" Formation and Bottom Water Zone, mainly presence of a conventional in-situ combustion (ISC) in those regions. The analysis is based on the detailed inspection and interpretation of the temperature profiles in the observation wells and

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on the performance curves for the air injection wells and production wells. It is accepted from the very beginning that the air flowed predominantly in the Mc Murray “B” formation, i.e. the objective of the novel in-situ combustion (ISC) piloting. However, the lack of complete confinement did lead to the decrease of the efficiency of the process.

B1. Air lost via McMurray “A” formation; generation of a conventional ISC front in this formation

In the 2011 ERCB presentation, provided in the Table E2, the air escape into the Mc Murray “A” formation is entirely downplayed, and it is assigned a very temporary role, insignificant for the development of ISC in the THAI patterns. Next, each point from that slide will be discussed: It is true that during the pre-ignition heating cycle (PIHC) operation, steam entered the Mc Murray “A” formation, probably due to the fracturing of the thin shale (2-3m) existent between “A” and “B” Mc Murray formations, and this probably happened around or extremely close to injection well A2. It is also true that this way steam provided a flow conduit towards Mc Murray “A”. *However, it is not true that only combustion gases from the ISC front flowed via that conduit. In reality, it was predominantly air that flowed*, as the conduit was very close to the injection well A2. This is clearly shown by a peak temperature higher than 340 ^{0}C in well TOB1 (which is located at 2-3m from A2), and by a peak temperature of 240 ^{0}C in well TOB2, located at cca 7.5m from A2 (see Figs 47a and 47b1 and 47b2 from Report). In case of TOB1, it may be correct that the thermocouple (TC) at depth 345m failed not due to excessive temperature, but failed from the very beginning from reasons independent of this. However, even in this case (with absence of a working thermocouple at 345m) there *is a clear tendency of temperature to increase in the depth interval 357-348m*, as two thermocouples worked normally. Even a temperature of 340 ^{0}C should be convincing enough that an ISC front did develop in Mc Murray “A” formation; variation of incomplete temperature profiles after the date (July 2007) of maximum of 340 ^{0}C confirms that after that date, that peak temperature decreased due to the passing of ISC thru that well (well remained behind the ISC front and cooling down started).

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Table E2 Slide 93 of ERCB Presentation 2011 with Petrobank interpretation of communication between Mc Murray “B” and McMurray “A” formations

This temporary heating of the McMurray A sand during start-up at TOB1/2 and was due to the high injection pressures for steam injection.

- The steam injection pressure likely fractured the McMurray A2 shale and provided a communication conduit for steam heat at first and then hot combustion gas from the advancing front after the PIHC.
- From the profile at TOB1 and TOB2 this communication was decreasing dramatically before the thermocouples were lost in August of 2008.

There is no evidence that these thermocouples failed due to excessively high temperatures. The following reasons could be the cause of the thermocouple failure:

- **Surface lead issues** – Rain, snow, and hot/cold thermal cycling. This also extends to any surface cable that may have been moved or cycled.
- **Corrosion** – if the metal sheath corrodes moisture gets in and shorts the thermocouple. This is the second most common problem after the surface problems
- **Strain** – in places where the thermocouple is spliced together, you can pull apart the splice. This often happens during installation but can also occur downhole.

In addition, the heating of the McMurray A appears to be an extremely localized effect as OB6, which is only 42 meters away, shows very little heating in the time period of this apparent communication.

- OB3 more than likely had a similar scenario with steam heat being transferred during the PIHC at A1.

There is no evidence that combustion gas, due to the time of the temperature increase, affected the McMurray A sand temperature at OB3.

- The OB3 profile shows that the McMurray A sand is now at native temp and has been for some time.

In all of these profiles there is no evidence of a negative impact of the resource in the McMurray A sand.

The value of 240 ^{0}C in well TOB2 also supports the interpretation just presented, as this peak in Mc Murray “A” formation was recorded at the same level as in TOB1. By 2009, the thermocouples located in Mc Murray “A” formation (depth higher than 332m in TOB1 and depth of 340m in TOB2) were already burned out due to excessive temperatures; this is another confirmation of existence of ISC front in Mc Murry “A”.

Petrobank cites as a prove of non-influence to Mc Murray “A” the fact that observations wells OB6 and OB9 – located at 42 m from injectors - did not show high temperatures, eye-witnessing the closeness of an ISC front. This is true, but it is normal, as even for Mc Murray “B” the interception by the ISC front happened very late, in September 2010. Therefore, only combustion gases/flue gases flowed in their neighbourhood; these wells were not intercepted by the ISC front yet.

As far as well OB3 –located 40m from A1 – is concerned some steam flowed towards Mc Murray A during steam injection, but it seems that the preference of air to flow in that direction decreased as the

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easy flow into the bottom water zone was obvious; a peak temperature of 370 ^{0}C at the oil/bottom water interface was recorded.

The previous analysis, based on the temperature profiles in observation wells, showed that the air escape towards the Mc Murray "A" formation occurred mainly around A2 air injection well and therefore is related mainly to the A2-P2 pair; some air escape from A1-P1 occurred, but it was less than in A2-P2.

An inspection of the performance of injection-production for air/gas for all three pairs fully confirmed that; while generally the air injection rate was approximately equal to the gas production rates for pairs A1-P1 and A3-P3, this was not the case for A2-P2 pair. In case of A2-P2 pair, for the period June 2006-June 2008, the gas production rate of P2 well was 15%-35% less than the air injection rate in A2, and this difference decreased in time. Follows a period of approximate balance between injection and production (June-October 2008). Then, in the period following October 2008 (actually October 2008 to October2009, when the stoppage of air injection happened) the reverse was observed, i.e. the gas production was higher than air injection. It is believed that this could be related to the fact that the Mc Murray "A" did see a conventional ISC front supplied with less and less air as no production wells in Mc Murray "A" existed, and consequently the pressure difference causing the flow to decrease in time.

For this reason, a gradual switching from a vigorous ISC process involving HTO reactions to a less efficient ISC, involving both HTO and LTO, happened; this can be checked by comparing the values of H/C ratios for those two periods. For the last period it is difficult to estimate how much gas from Mc Murray "A" returned to Mc Murray "B" and how much flowed further towards upper gas formation, including Clearwater formation, where Devon Canada had gas production wells (IETP Presentation, 2012)

The conclusions about flow of air into McMurray "A" formation so far have been based on temperature profiles in TOB1, TOB2 and OB6, and on the well established principle that, in a conventional ISC process, the amount of air injected is approximately equal to the combustion gas produced, all in standard atmospheric conditions. However, in our case is different, as additionally, hydrogen, more hydrocarbon gases and H_2S gas are produced, compared with a conventional ISC Project. For this reason, a more rigorous evaluation of the proportion of the injected air flowing to Mc Murray A formation was performed based on the balance of nitrogen injected and produced. This was made for the A1-P2 pair and for the total Pilot, i.e. all three pairs.

In Table E3 an evaluation is made for the fraction of the injected air, which was produced (as combustion gases) via the producer, for the pair A2-P2, where we have seen the highest tendency of air to flow into Mc Murray "A" formation. For checking, we do this calculation for the whole Pilot as well (Table E4).

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Table E3: Nitrogen balance for A2-P2 THAI pattern

Period / year	Cumulative air injected $10^3 sm^3$	Cumulative nitrogen (N_2) injected $10^3 sm^3$	Cumulative gas produced $10^3 sm^3$	Annual average N_2 percentage %	Cumulative N_2 produced (N_2-prod.) $10^3 sm^3$	N_2-prod. / N_2-inj. Fraction	Source
2006	5.49	4.3	0.74	0.74$^+$	0.55	0.13	Pr. IETP 2007
2006-2007	14,248	11,125	6,845	76.82*	5.258	0.47	PR. IETP 2008
2006-2008	28,593	22,327	19,471	74.67**	14,539	0.65	Pr. IETP 2009
ONLY 2009	10,940	8,542	12,348	75.24	9,291	1.09$^+$	Pr. IETP 2009

Legend: Pr. = presentation

$^+$ Estimated

* Weighted average from daily gas analyses for period July 2006-November 2007

** Weighted average from daily gas analyses for period Dec 2007-November 2008

Note: During the period July – October 2009, the air injection in A2 well was stopped

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Table E4: Nitrogen balance for the whole THAI Pilot (A1-P1, A2-P2 and A3-P3 patterns)

Period / year	Cumulative air injected (N_2-inj.) $10^3 sm^3$	Cumulative nitrogen (N_2) injected $10^3 sm^3$	Cumulative gas produced $10^3 sm^3$	Annual average N_2 percentage %	Cumulative N_2 produced (N_2-prod.) $10^3 sm^3$	N_2-prod. / N_2-inj. Fraction	Source
2006	6,150	4,802	1.35	73?	0.99	0.21	Pr. IETP 2007
2006-2007	24,950	19,481	13,769	74.70*	10,285	0.53	PR. IETP 2008
2006-2008	63,503	49,586	49,609	73.57**	36,497	0.74	Pr. IETP 2009
ONLY 2009+	16,553	12,925	19,131	74++	14,157	1.1+++	IETP Report 2009

Legend: Pr. = presentation

* Weighted average from daily gas analyses for period July 2006-November 2007

** Weighted average from daily gas analyses for period Dec 2007-November 2008

+ From Fig 2 of the IETP report 2009

++ Estimated

+++ During the period July – October 2009, the air injection in A1 and A2 well was stopped

The results from Table E3 confirm that at the beginning of the process a high proportion of the injected air entered the Mc Murray A formation; in the 2006/2007 period, more than half of it (53%) went to Mc Murray "A", sustaining a conventional ISC front. The proportion decreased to less than 35% for the 2008, while a calculation just for 2009 showed that the injected air was totally confined to A2-P2 pattern (a good balance between the injected nitrogen and the produced one); the 1.09 value is due to some air from McMurray "A" flowing back to McMurray B during the 3-4 months of air injection stoppage in 2009.

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A similar calculation for the entire Pilot, for the air escaped to Mc Murray "A", gave a figure of 47% for 2006-2007, decreasing to less than 26% after for 2008, while for 2009 it showed a good balance between the injected nitrogen and the produced one, exactly as for A2-P2 pattern.

B2. Air flow into the bottom water zone

Air flow into the **b**ottom **w**ater (BW) zone was evaluated mainly based on the temperature recorded by the observation wells. In the case of this THAI pilot actually the ratio thickness of BW zone/thickness of oil zone is less than 10%, as the BW zone thickness is smaller than 2m, while the thickness of oil zone is 20-40 m for different THAI pairs. Actually, this oil layer thickness is around 20m for A1-P1 and A3-P3 pairs and around 40 m for pair A2-P2, where there were 3 peak temperatures, in Mc Murray "B", IHS and Mc Murray "A" strata, with a trend of the peak temperature to rise toward the upper part. For A1-P1 and A3-P3 pairs, in general, ISC process developed and remained mainly in Mc Murray B (not far away from the oil/water contact in case of A1-P1 pair). The proves for that are:

- ✓ In the OB3 well a high T peak of 240 ^{0}C at the oil/water interface was recorded in Sept 2008, 1.5 years after the ignition in A1; this increased to 400 ^{0}C by December 2010. A clear ISC front eventually developed at the water/oil interface
- ✓ Immediately around the A3 pair there was no bottom water zone, still, the ISC front developed and remained in the lower part of layer. At the location of OB7, close to heel of P3, there was communication with bottom water (detected during PIHC), but no air was expected to flow to bottom water; in the worst case, only combustion gases could have flown there. However, additional proof that even in this zone, further on from A3, it was still possible to have gas flow in BW was provided by the due diligence well OB17, drilled (later on) to check the seismic anomaly in the BW and to test for ISC gases in Clearwater formation, related to gas migration discussion with Devon Canada (see Fig. 53 from the Report). Flue gases at the BW/oil interface were found by this well.
- ✓ It is clear that the oxygen from the air flowing at O/W interface is consumed entirely and therefore only flue gases with no oxygen are produced. Unlike conventional ISC process, there was no continuous increase of the O_2 in the effluent gases. The quality of burning at the O/W interface can be rigorously checked via variation of H/C ratio in time, but for this, detailed daily gas analyses are necessary. This should be done mainly for A1-P1 pair, where the most pronounced burning at the O/W interface is established. Therefore, one can talk only about some temporary storage of flue gases, when air is entering in BW and is produced as combustion gases.

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However, one can talk about permanent storage of flue gases, when these gases flow very far from the Pilot area, for instance towards the North and the NW in the region of OB17 and beyond it. A very rough estimate of the amount of gas possible to be stored in the BW zone at a gas saturation of 10%, according to the isopach map (Fig.41b) considering that gases go and distribute into the whole region of BW existence, give a value of 0.6 million Sm^3; a reservoir pressure of 4MPa was assumed in these calculations. This amount of gas is very small compared to the cumulative of air flowing in McMurray "A" formation, showing that the results for air escape into McMurray "A" remain valid; the main source of un-confinment of Pilot area is represented by McMurray "A" formation.

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Relative to the loss of oil in the BW zone, as the thickness of BW is very small, it can be assumed that this loss is not significant. An estimate similar to that for the amount of gas possible to be stored in the BW zone, but considering only the surface of the patterns (Fig. 48a) and only half of the thickness of BW zone invaded by the oil, gave a value of the oil lost in the BW zone of 2,500m^3, which would represent only 4% of the total oil displaced (65,00m^3); also, it would represent 9% of the total volume of oil produced from the pilot (29,000 m^3). At this time, it is speculated that this could not have seriously worsened the performance of the process, as expressed by the value of air-oil ratio. However, a more in-depth, more refined analysis - in order to double check this estimate - should be undertaken.

All in all, the conclusion from this Appendix is that the main loss of efficiency of the THAI pilot was due to the loss of air in the McMurray "A" formation. The loss of air in the BW zone and a possible increase of fuel consumed by burning and coke gasification constituted secondary factors for the decrease of ISC efficiency.

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Appendix F

Whitesands THAI Pilot : Role of Bottom Water

The objective of this analysis is to find out if the water from the *thin bottom water* was in-deed produced via the THAI producers and what was its effect.

In the main text, some details on the use of steam during the pilot was provided. Although there is a great deal of uncertainty as to whether the injection of steam for well stimulation (or temperature moderation) had any positive effect, it has to be accounted for as regards water produced by the process. Figs. 52a-b from the body of the Report shows the amounts of all injected fluids and produced fluids (excluding produced gases). Of chief concern is the role that bottom water (BW) plays in this. The developing water cut is examined at different stage of the pilot for each of the three well pairs.

To clarify this topic three periods are considered, namely:

First period: March 2006-August 2007 (1.5 years) in which the steam injection for pre-heating and ignition process took place, consecutively, in all three patterns. As seen in Figs.51a-c and 52b from the body of the Report in this period, practically, the entire steam injected was produced back as hot water. Therefore, this water will no longer be accounted in the future calculations.

Second period: August 2007-July 2009 (2 years) of constant, pseudo-steady state, good oil production

Third period: November 2009-November 2010 (one year), when the performance became poor (higher water cuts and lower oil production). The two periods are separated by a 3-4 month period (July - October 2009) of air injection interruption, necessary for the drilling of the replacement wells P1b and P2b.

By considering that all liquids (oil and water) displaced are completely captured (which is a reasonable hypothesis in THAI), the water to be produced is made of: water injected as steam in the producers for temperature control or stimulation (Q_{steam}), water produced as a result of connate water displacement (Q_{CW}), ISC-formed water (Q_{ISC}) and possibly, water from the bottom water zone (Q_{BW})

Therefore, theoretically, the total water produced daily (Q_{water}) will be:

$Q_{water\text{-}TH} = Q_{CW} + Q_{ISC} + Q_{steam} + Q_{BW}$

Let us suppose that *no water from the BW zone* is produced; in that case:

$Q_{water\text{-}TH} = Q_{CW} + Q_{ISC} + Q_{steam}$

Analysis of the second period:

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The real values for the daily steam injected, and for the daily oil (Q_{oil}) and water (Q_{water}) produced rates, respectively, are:

Q_{oil}=40 m^3/day (see Figures 52b)

Q_{water}=100 m^3/day (see Figures 52b)

Q_{steam}=30 m^3/day (see Figures 52b)

However, theoretically we have:

Q_{cw}= Qcw * (S_{oi}/S_{cw}) , S_{oi} and S_{cw} initial oil and water saturations

Q_{CW} =40*(0.72/0.27) ≈ **16 m^3/day**

Q_{ISC} = (Qair/A_{req})*Z_{fuel} , where Qair is the total daily air injection rate for the period, A_{req} is the air requirement per m^3 of rock (completely burned). Z_{fuel} is the amount of fuel (coke) burned. The equation takes into account the fact that the water formed by ISC is approximately equal to the oil burned as fuel (fuel is $CH_{1.0}$). Then, approximately:

Q_{ISC} = 120,000 *(40/400) =9000kg/day=12 **m^3/day** (assuming density of fuel~1.0)

Therefore: $Q_{water\text{-}TH}$ =16+12+30 =60 m^3/day

However, the real water cut figure is approximately 100 m^3/day

Consequently, the theoretical water cut (assuming no BW) would be: 60/(60+40) = 0.6 (60%)

In reality, the water cut is: 100/140=0.71(71%)

Hence, even during good performance periods, water was produced from the bottom water zone.

Analysis of the third period:

The real values for the daily steam injected, and for the daily oil (Q_{oil}) and water (Q_{water}) rate, respectively, are:

Q_{oil}=20 m^3/day (see Figures 56a-bBIS)

Q_{water}=140 m^3/day (see Figures 56a-bBIS)

Q_{steam}=30 m^3/day - estimated from ??????? (slightly overestimated)

However, theoretically we have:

Q_{CW} =20*(0.72/0.27) ≈ 8 **m^3/day**, where the ratio of initial oil and water saturations were used.

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Q_{ISC} = $(Qair/A_{req})*Z_{fuel}$, where Qair is the total daily air injection rate for the period, A_{req} is the air requirement per m^3 of rock completely burned and Z_{fuel} is the amount of fuel (coke) burned. The equation takes into account the fact that the water formed by ISC is approximately equal to the oil burned as fuel. Then a very approximate calculation gives:

Q_{ISC} = 120,000 *(40/400) =12,000kg/day=**12 m^3/day**

Therefore: $Q_{water\text{-}TH}$ =8+12+30 =50 m^3/day

However, the real water cut figure is 140 m^3/day

Consequently, the theoretical water cut (assuming no BW) would be: 50/(50+20) = 0.71 (71%)

In reality, the water cut was: 140/160=0.88(88%)

It follows that in this third period, proportionally, more water was produced from the bottom water zone. Therefore, in the second period there was some detrimental effect of BW, but this negative effect was by far more pronounced in the third period, when water cut increased considerably.

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Appendix G

Kerrobert THAI Project: Details on the Patterns(Modules) and Their Performance

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Figure G7-KP12c: The variation of the oil and water product**ion**, water cut and gas produced for well KP12.

Location and Geometrical Details

The geometrical configuration of the THAI pattern is extremely important. As the **d**irect **l**ine **d**rive (DLD) configuration was applied, normally the shoe of the vertical injector (VI) should have been in the extension of the horizontal section of the horizontal producer (See insets of Figures G1-a and G1b); the distance between them is called co-linear shoe-toe distance (cs-td). In this case, in conjunction with this

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distance, a start-up region can be clearly defined in the DLD configuration. The surface of the start-up region is equal to the product of cs-td with the well spacing between two adjacent HP.

However, in general this was not possible and a certain small lateral distance exists between the shoe of the VI and the toe of the HP; this distance is called lateral distance (ld), and is measured either on a perpendicular to the horizontal section of HP or to its extension (Figure G1b).

Figure G1a presents the isopach map with the lay-out of new and old wells. There are 12 new horizontal wells – used in the THAI Project – and 9 old horizontal wells, which are presently suspended or abandoned. Most of old horizontal wells are abandoned, with a few suspended, and just one (well 191/03-22-033-24W3/00) is active with an oil production of 2 m^3/day (as on April 2015). This active horizontal well is located in the NW corner (close to the heel of horizontal producers KA11 and KA12), and does not seem to influenced by the in-situ combustion (ISC) process.

Table G1 provides the results of the calculation of the distance between the shoe of vertical injector (VI) and the toe of horizontal producer (HP) for a certain THAI pair. This distance is measured between the bottom whole coordinates of the VI and toe of HP on a horizontal plane (as these points are not in the same horizontal plane).

Figure G1b can give more indications on the relative position of VI relative to the toe of HP. However, even in this case it cannot give accurate details on the shape of start-up region and, in general, on the exact placement of the VI vis-à-vis the horizontal section of HP. For this reason, Figures G2-a and G2-b present these details both for the North-Western platform and for South-Eastern Platform. Actually, the representation in these Figures were done based on the data in Table G1. From Figures G2 it can be seen that only two pairs had a real start-up region, namely pairs K1 and K2. The patterns K1 and K2 (Fig G-1b and G-2b) are a quasi-staggered line drive (SLD) configuration for which the lateral distance (ld) is 12-15m, while toe to injection line distance (td-il) is 8-10 m; the injection point is located outside the *lateral drainage area* of the producer.

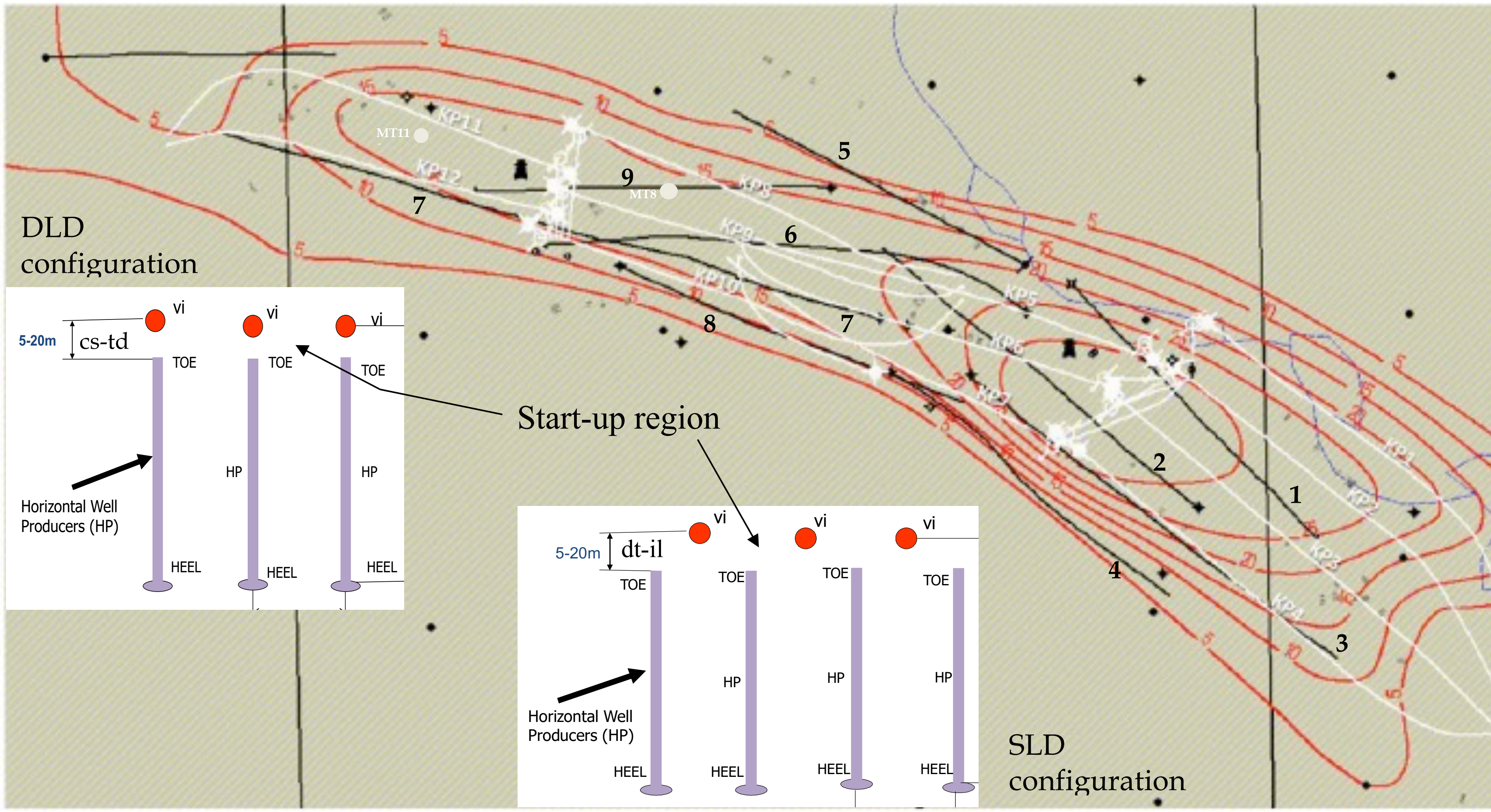

Fig G1a: Kerrobert Project. The location of wells. White wells are THAI wells, black wells are old wells (vertical and horizontal) and red contours are Waseca sandstone net oil pay (in 5m increments), Wikel, 2012. Old horizontal wells are marked/enumerated from 1 to 9, starting from the South-East corner. Please note a difference in how OHW7 was represented in Fig. G1b and G1c

Note: Direct line drive (DLD) THAI and staggered line drive (SLD) THAI configurations are shown in the insets.

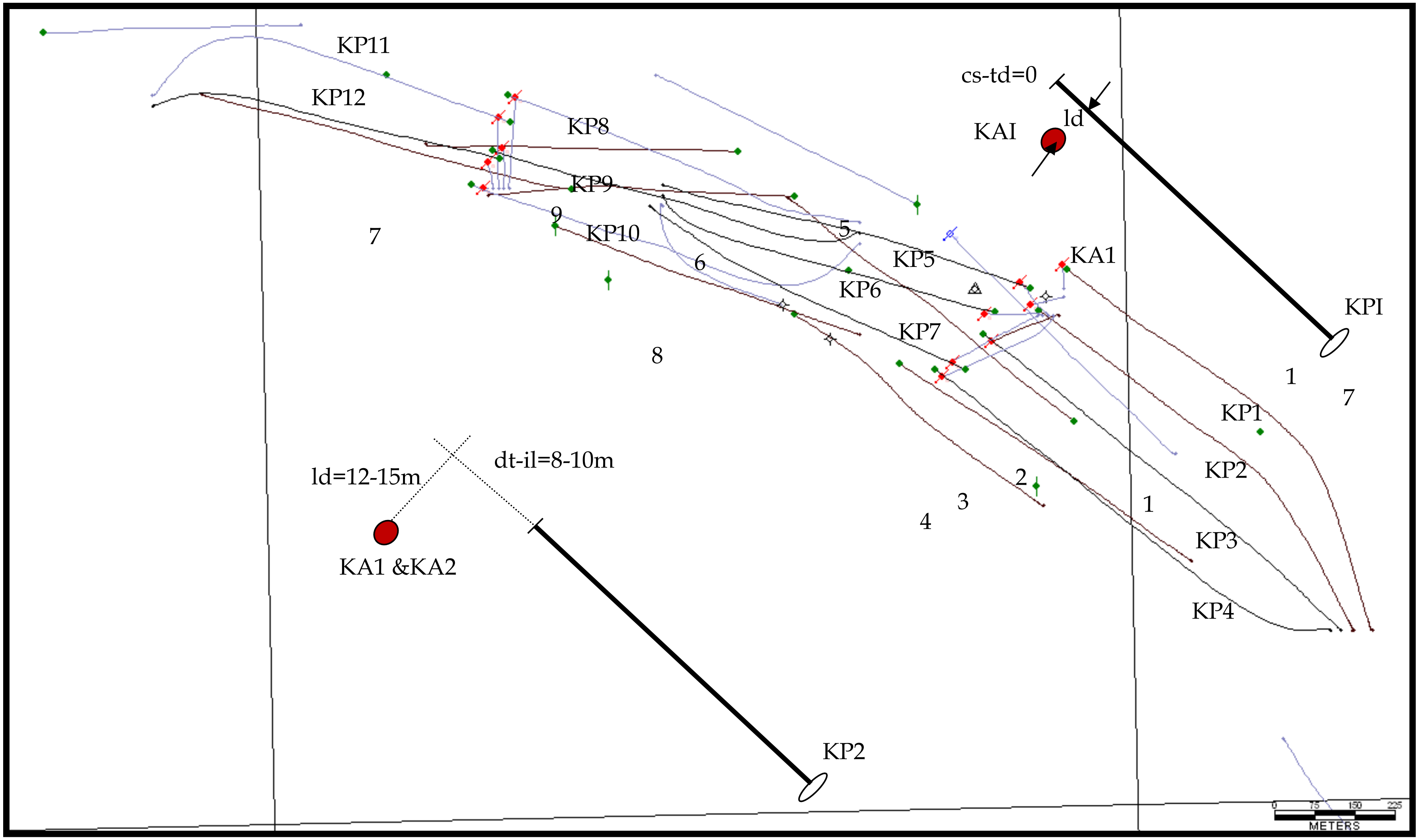

Fig G1b: Kerrobert Project. The location of THAI wells and old horizontal wells. The location of the vertical injectors (KA wells) relative to the toe of horizontal producers (KP wells) is clearly seen. Starkov, 2016.

Note 1: Old horizontal wells (OHW) are marked/enumerated from 1 to 9, starting from the South-East corner. Please notice a difference in how OHW7 was represented in Fig. 61b and 61c

Note 2: A quasi-staggered line drive (SLD) THAI configuration for KA2-KP2 pair and the general direct line drive (DLD) THAI used for all other pairs (KAI-KPI) are shown in the insets.

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Table G1: Calculation of distance between the vertical well and the toe of horizontal well.

[all coordinates and distances are in meters (m)]. Based on geoSCOUT data

Well	Bottom hole coordinates Vertical well				Well	Bottom hole coordinates Horizontal well toe				Pattern	Distance, N/S, E/W and compound				Other	distance I-P	Observations
	N/S		E/W			N/S		E/W			N/S dist	E/W dist	Distance I-P	Shortest D			
KA1	612.6	S	128.7	W	KP1	603.1	S	113.5	W	KA1-KP1	9.5	15.2	17.9	15.0			
KA2	688.7	S	190.4	W	KP2	684.6	S	177.8	W	KA2-KP2	4.1	12.6	13.3	12.0	KA2-KP5	31.400	
KA3	755.2	S	263.4	W	KP3	742.4	S	282.7	W	KA3-KP3	12.8	-19.3	23.2	<5	KA3-KP6	56.389	
KA4	791.5	N	360.5	W	KP4	804.5	S	373.8	W	KA4-KP4	13.3	-13.3	18.8	<5	KA4-KP7	46.620	
KA5	644.9	S	209.7	W	KP5	657.3	S	190.5	W	KA5-KP5	-12.4	19.2	22.9	6.0			
KA6	703.7	S	278.5	W	KP6	699.1	S	257.7	W	KA6-KP6	4.6	20.8	21.3	10.0			
KA7	792.9	S	340.0	W	KP7	804.4	N	315.7	W	KA7-KP7	-12.0	24.3	27.1	<5			
KA8	273.9	S	459.0	E	KP8	274.6	S	443.7	E	KA8-KP8	-0.7	15.3	15.3	5.0			
KA9	368.9	S	431.8	E	KP9	372.0	S	414.4	E	KA9-KP9	-3.1	17.4	17.7	9.0	KA9-KP11	50.128	
KA10	442.9	S	394.8	E	KP10	458.6	S	461.0	E	KA10-KP10	-15.7	-66.2	68.0	15?	KA10-KP12	64.981	Uncertain
KA11	310.3	S	427.4	E	KP11	321.1	S	446.9	E	KA11-KP11	-10.8	-19.5	22.3	7.0	KA9-KP12	18.572	
KA12	394.4	S	405.9	E	KP12	387.1	S	428.1	E	KA12-KP12	7.3	-22.2	23.4	13.0	KA12-KP10	84.603	

Legend:
N/S = distance measured North-South starting from the Northern limit of Section 14
E/W = distance measured East-West starting from the Eastern limit of Section 14
HP=horizontal producer
HS = horizontal section of HP

Distance I-P = The distance between the shoe of the vertical injector and the toe of horizontal producer
Shortest D = The shortest distance between the shoe of vertical injector and the horizontal section of the horizontal producer

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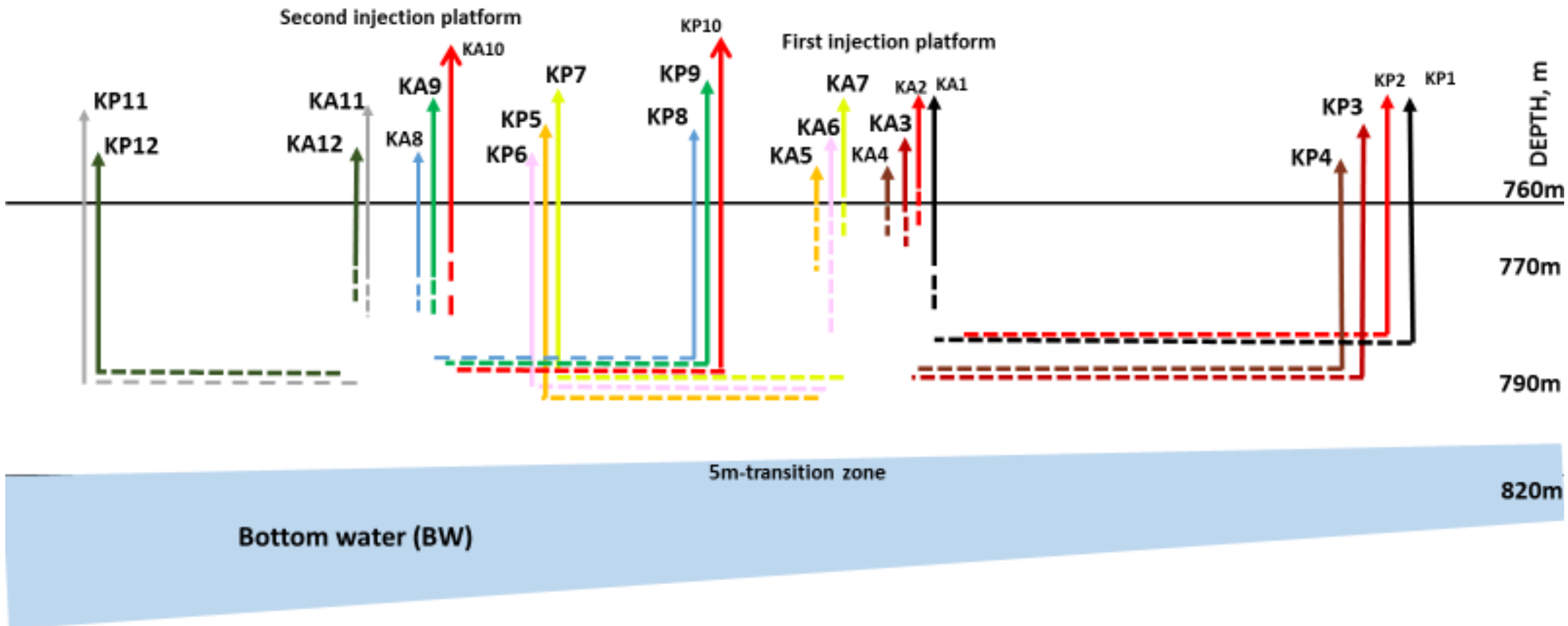

Figure G1c: Simplified "collapsed" cross-section showing the location of the perforations of vertical injectors relative to the placement of the horizontal section of producers. A different color is used for each THAI pair; KA-injectors; KP- horizontal producers. Based on data in Table G2 and correlated with the data from the logs in Figures G1d and G1e. Thickness of BW zone slightly increases towards West.

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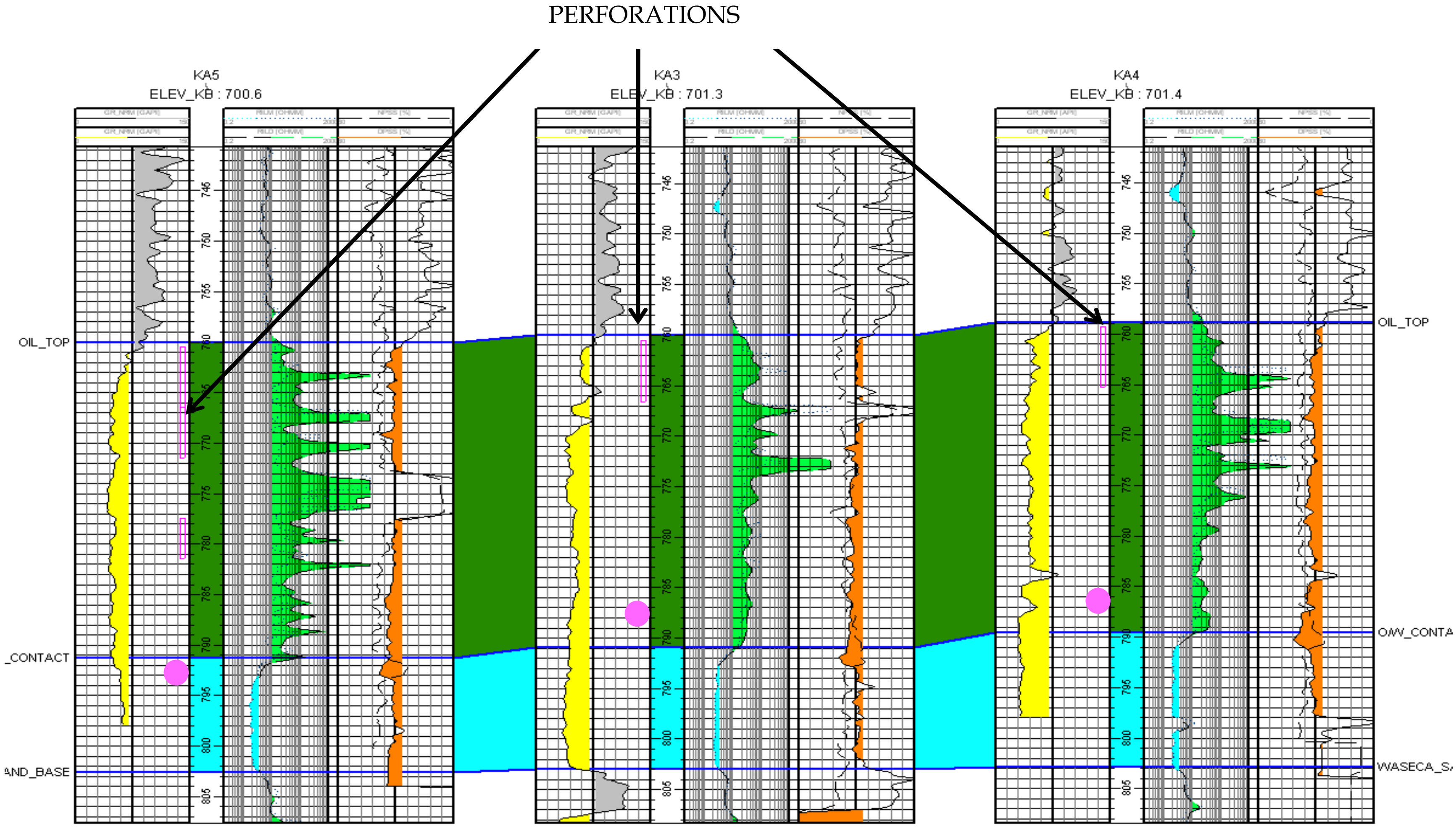

Fig. G1d: Stratigrafic cross-section through vertical wells KA5-KA3-KA4 showing their perforations within the oil layer, the approximate depth of the location of horizontal section of the horizontal well (●) and the position of oil-water contact (???, ???)

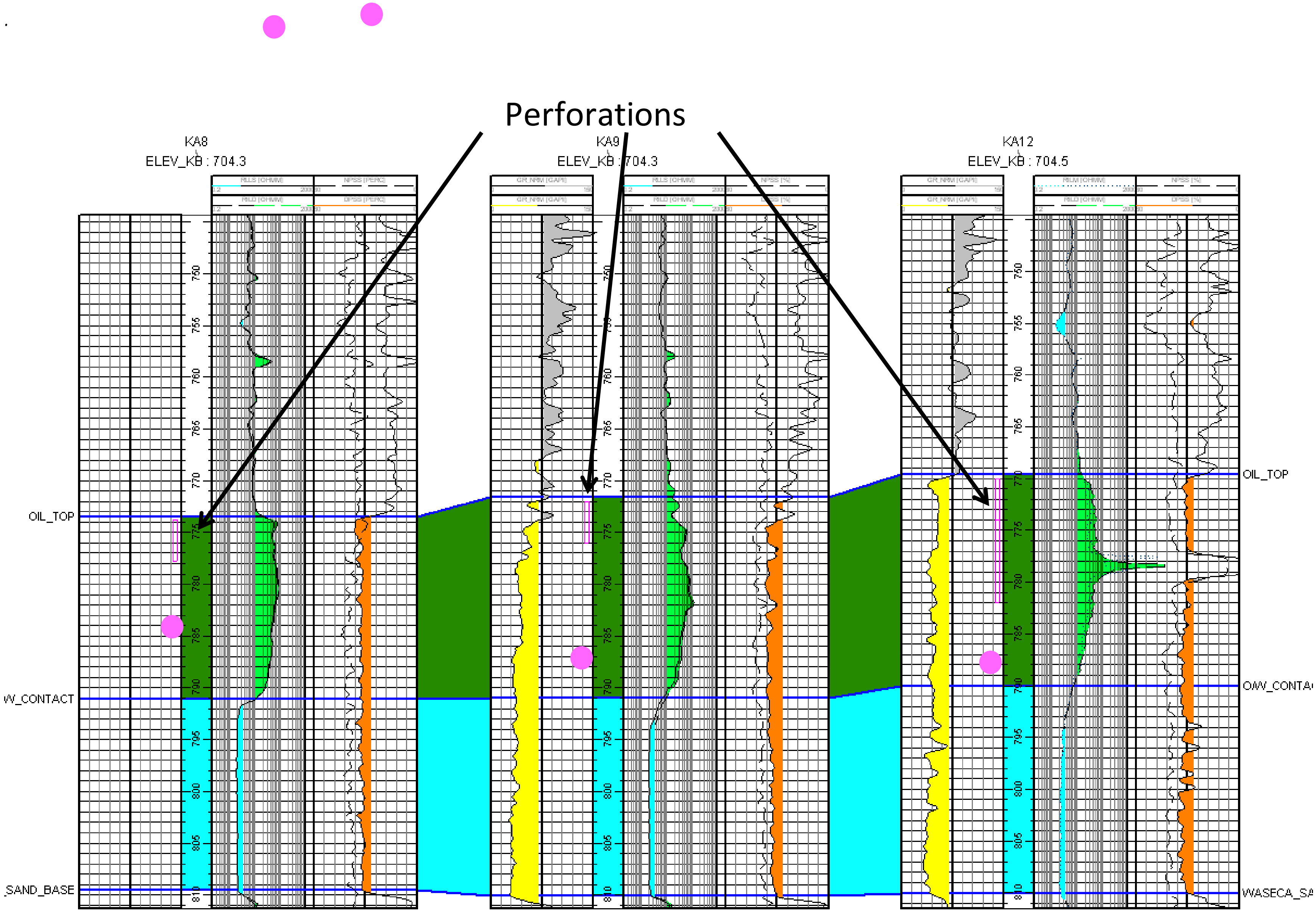

Fig. G1e: Stratigrafic cross-section through vertical wells KA8-KA9-KA12 showing their perforations within the oil layer, the approximate depth of the location of horizontal section of the horizontal well (●) and the position of oil-water contact (???, ???)

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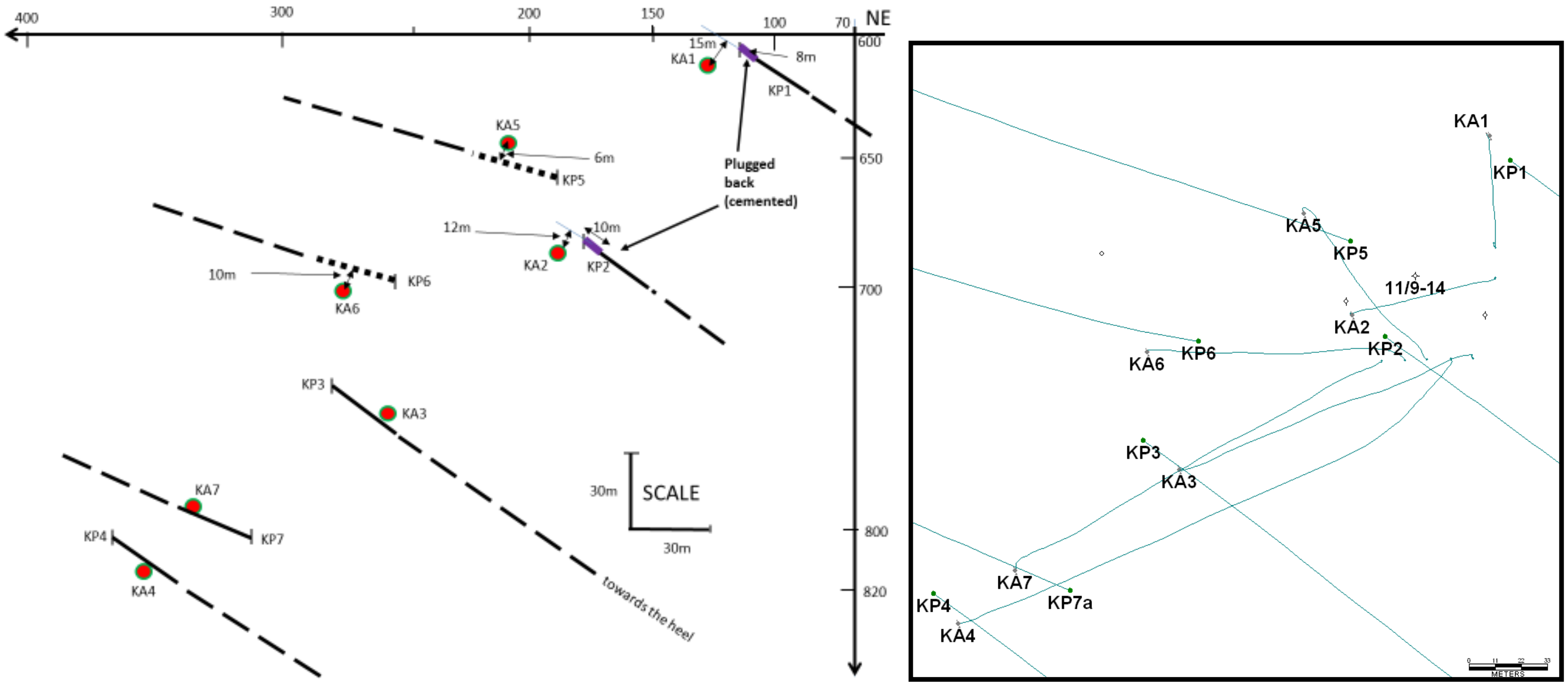

Legend:

KAI = Air injection well

KPI= Production well

HP =Horizontal producer

HS =Horizontal section of HP

Toe of HP

Open hole

27-34m-long blind liner

Perforated portion of HS

Fig. G2a: Details regarding the lay-out of air injection and production wells of South-Eastern Drilling Platform. Based on data in tables G1 and G2 (geoSCOUT data). On the right-hand side map, the wells KP1 and KP2 are shown after the plugging operations

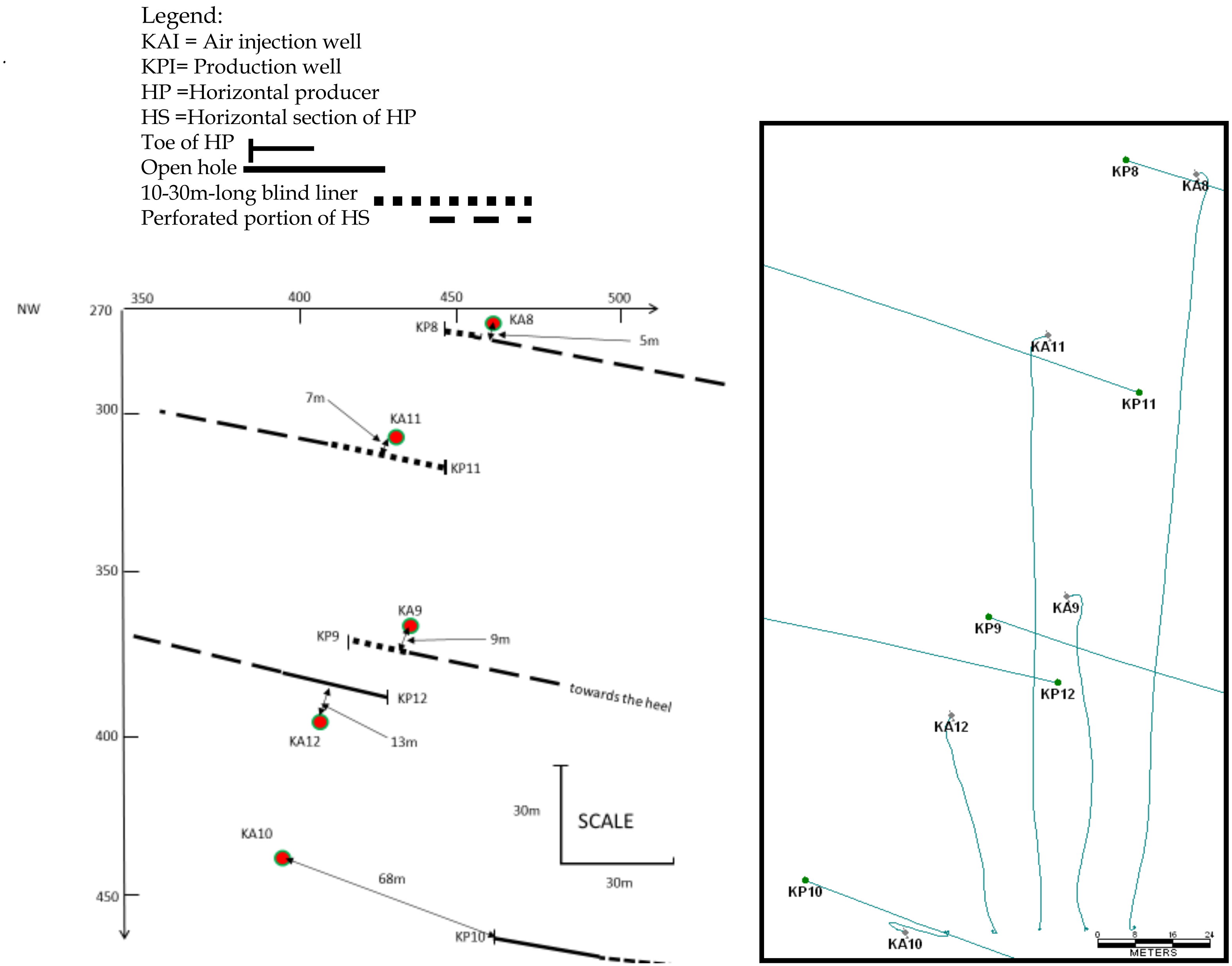

Fig. G2b: Details regarding the lay-out of air injection and production wells of North-Western Drilling Platform (based on data in tables G1 and G2- geoSCOUT data). The correct position of KP10 is on the right-hand side map. KP10 was re-drilled.

Table G2: Kerrobert Reservoir, Manville formation: Completions of Vertical Air Injectors and Horizontal Producers

(Distance VI bottom perforation to toe of HP). Based on geoSCOUT data

Completions of VI's		Completions of Horizontal Producer (HP)					Toe @	Vertical distance	
Well	Perforations, TVD	Well	TVD	Interval completed	HS length	Plug back @	MD	between bottom of	Observations
	Perforations, MD							VI perf. and toe of HP	
	m		m	MD in m	m	MD in	m	m	
KA1	771.6-777.6/6m	**KP1**	785.4	975-1592.3: L	617	1592.3	1600	7.8	
	775-781/6m								
KA2	758.3-764.3/6m	**KP2**	784.5	1036-1528: L	492	1528	1538	20.2	
	764-770/6m								
KA3	760.6-766.6/6m	**KP3**	787.9	1004-1528:L	524	-	1533	21.3	
	784-790/6m								
KA4	759.3-765.3/6m	**KP4**	787.4	878.5-1572:L	694	-	1577	21.6	
	823-829/6m								
KA5	760.51-766.5 & 767.5-771.5/10m	**KP5**	793	1385-1413:OH & 954-1385: L	431	-	1413	21.5	28m OH
	771-777 & 778-782/10m								
KA6	762.7-772.7 & 778.7-784.7/16m	**KP6**	792	1340-1367:OH & 960-1340: L	380	-	1367	7.3	27m OH
	779-789 & 795-801/16m								
KA7	759.4-765.4/6m	**KP7**	790	976-1358:L	382	-	1358	24.6	
	797-803/6m								
KA8	773.7-777.7/4m	**KP8**	784.3	1399-1404:OH & 928-1399: L	471	-	1404	6.6	5m OH & Acid.
	808-812/4m								
KA9	772-776/4m	**KP9**	786.8	1399-1410:OH & 971-1399: L & 1270-1328:L*	426	-	1410	10.8	11m OH &Treat.
	780-784/4m								
KA10	768.1-772.1 & 77.1-782.1/12m	**KP10**	788.7	977.2-1364:L	387	-	1364	6.6	
	771-775 & 777-785/12m								
KA11	772.7-776.7/4m	**KP11**	788.8	1362-1396:OH & 1018-1362: L	344	-	1396	23.3	34m OH
	796-800/4m								
KA12	770-774 & 774-776/6m	**KP12**	788	990-1350:L	360	-	1350	12	
	774-778 & 778-780/6m								
			* Double liner on the interval 1270-1328m (58m)						
		Legend: VI=Vertical injector; HP-Horizontal producer; TVD=True vertical depth/distance							
		HS= Horizontal section of HP; MD=Measured depth/distance;				OH=Open hole; L-Liner			
		Acid. = Acidification; Treat. = Treatment							

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Two more categories of lay out can be defined, namely:

1. DLD with cs-td close to zero
2. SLD with dt-il close to zero

The first category include the patterns: K3 and K7, while the second category include the patterns: K5, K6, K8, K9, K11 and K12, with injection point located *inside* the lateral drainage area of producer. It has to be highlighted that in all these cases some length of the horizontal section, immediate close to toe, may be lost as the in-situ combustion (ISC) front may intercept the horizontal section on the shortest distance; therefore, that portion between ISC interception and the toe may remain unswept by the ISC front or excessively high fuel consumption may take place for that region, as the air flux will be significantly lower. For the patterns mentioned previously this distance is in the range of 10-25m, representing less than 10% of the length of horizontal section of producer It is believed that at this proportion (from the active horizontal section of HP) it may not have a major negative influence on the process.

Other observations drawn from Figures G2-a and G2-b and Table G1 include:

- The smallest distance between two injectors is 35m (KA9 to KA12); a good part of the air injected in KA12 flowed towards KP9, especially after the stoppage of oil production in KP12. There was a drastic reduction of effective length of KP9, which became just 58 m, starting in 2013 (see Table G2). Also, a good fraction of air injected in KA12 flowed towards the producer KP10. This is confirmed by the fact that KA10 injected only 5 million sm^3 air, while KP10 produced 16 million sm^3 gas. At the same time, well KA12 injected 10.5 million sm^3 while producing only 2.2 million sm^3. Therefore, it seems that KA12 air/gases flowed to both KP9 and KP10.
- This inter-pair, gas cross-flow was also visible between K4 and K7 as most of the air injected in K4 flowed towards K7.
- From the balance of injected/produced gas it resulted that the most "confined pairs" were K5 and K6, from the second group, where the injected air value was very close to the produced gas value.

Table G2 provides the main data on completion of vertical injectors and horizontal producers; the true vertical depth(TVD) of the vertical injectors's perforations was calculated by applying a correction for the inclination of the trajectory, as most of air injectors were drilled from almost the same point (drilling platform); this correction was determined from geoSCOUT data as the difference between the measured depth (MD) and the TVD at the top of Manville formation, therefore is not exact, but approximate within a relative error of 2-3%.

Based on data in Table G2 a simplified schematic of a cross-section type ("collapsed cross-section") is shown in Figure G1c. Generally, the THAI rule is respected as the lowest limit of the perforation interval in vertical injectors is above the horizontal section of horizontal producer (HP) - above its true vertical depth(TVD). For the pairs K2, K3, K4, and K7 this distance is 21-22 m, while for the pairs K10, K11 and K12 this is 6-12m. The pair K2 seems to be one of the best designed for a bottom water condition as the horizontal section of KP2 is located a little farther from the water/oil interface and the vertical injector KA2 is perforated just under the top of layer; to some extent this is valid for the K1 pair. The pair K5 and K6 are unique: the KA6 well is perforated on a very large interval, which goes very low, at just 5m from the depth of toe of KP6 well, which itself is low; this favors the steam and then air injection at the water/oil interface heralding the formation of a combustion chamber. As far as the horizontal producer KP5 is concerned, as shown by the log in Figure G1d, this well seems to be placed the lowest compared to all horizontal producers; it is positioned just at the water-oil contact or even a little under it; however the this should be double checked.

In case of KP7, KP9 (and KP10) these producers also received a bank of oil generated by air injection wells KA4 and KA12; they showed a good performance as they were in a staggered line drive configuration relative to KA4 and KA12, respectively.

Air Injection and Oil Production

In Figure G3 the variation of the air injection per well, as per February 2015, for all patterns is shown. For the K3-K12 patterns, the start of the graph is towards the end of ignition period (November 2011), such that a short initial period of 4 months (July-October 2011) is not represented. Please note a small discontinuity in the curves around April 2012. This is due to a mistake in geoSCOUT reporting before this date; geoSCOUT artificially magnified 1000 times the data before this date. Therefore, an adjustment of curves was necessary and it was made; for this reason the local scale for this portion should be disregarded; the reading should use the general scale.

Air injectivity problems were recorded for the wells KA4, KA6, KA10, KA11 and KA12; well KA4 was prematurely suspended at the end of 2013. Well KA6 had many interruptions in air injection. As far as KA11 and KA12 wells were concerned, by 2013, a new injection well was drilled between these two pairs to increase the total air rate injected in this region.

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Figures G4a-d provide the air injection variation (per well) per groups of wells. Based on the location of the wells (see Figure G1b), four groups of wells were formed, namely:

Group I: wells KA1 to KA4

Group II: wells KA5 to KA7

Group III: wells KA8 to KA10

Group I: wells KA11 to KA12

The same grouping will be applied to the KP1- KP12 production wells and the pairs KA1-KP1 to KA12-KP12 will be called, in a simple way, modules K1 to K12, respectively.

From Figures G4, it can be noticed that most of the time and for most of the wells, the air injection rate per well was in the range of 10,000-20,000 sm^3/day; only by the end of 2011 and in the period of February 2013-June 2013, mainly for some wells in the second and third group, the injection rate increased up to 30,000 sm^3/day. The highest rate (50,000 sm^3/day) was tried for the K5-K7 patterns in April-May 2013 period. In general, on a short-term basis, the value of oil production per well did not correlate with the value of air injection rate per well.

Also, generally, the injection rate had a trend of slow increase for the groups III and IV, while for the first groups it was relatively constant; the wells KA1 and KA3 in Group I had a pronounced decrease in injection in 2015.

An inspection of the air injection graphs also reveals that, in general, the wells injected almost continuously. Only wells KA6 and KA10 experienced interruptions; KA6 had frequent interruptions of air injection: two months in Dec 2011-Jan 2012, three months in April-June 2013, two months in September-October 2013 and a very long interruption (4 months) in May-September 2014 period (all in all - 11 months of interruption) . Well KA10 probably also has had very low injectivity, as its air cumulative is the lowest one (see also Table 16).

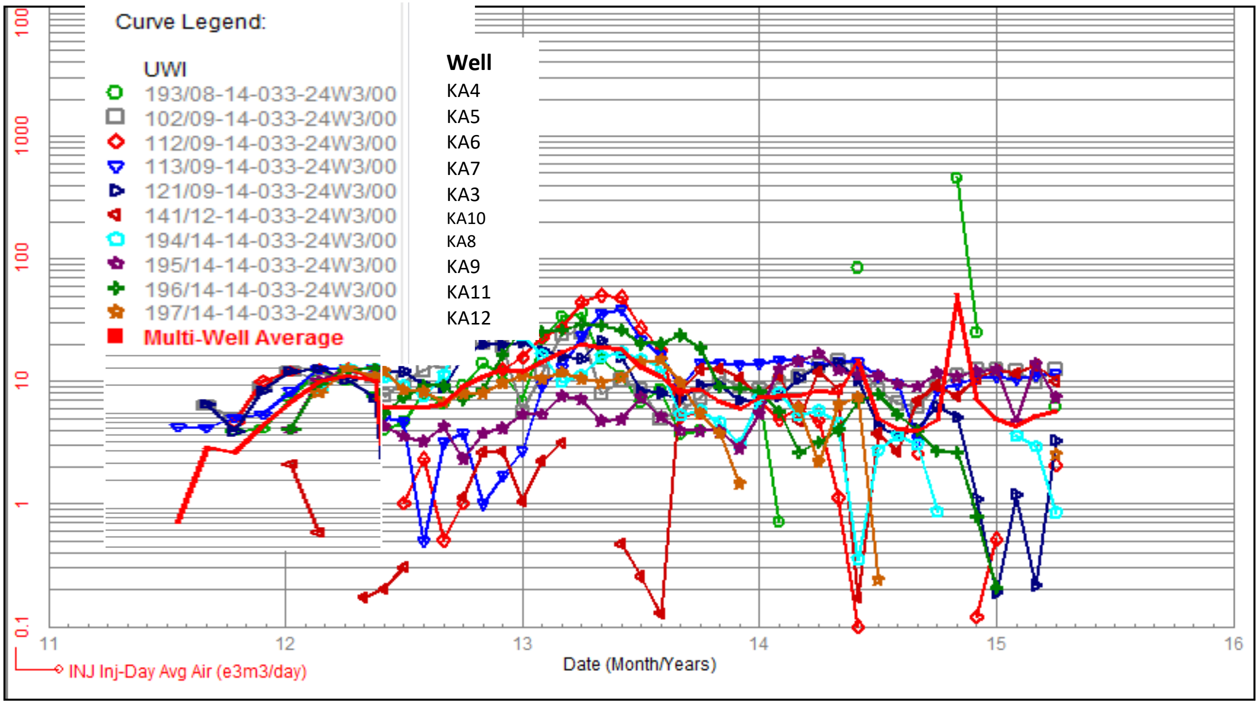

Figure G3: The variation of the air injection rate per well for all injection wells of the semi-commercial operation. GeoSCOUT data

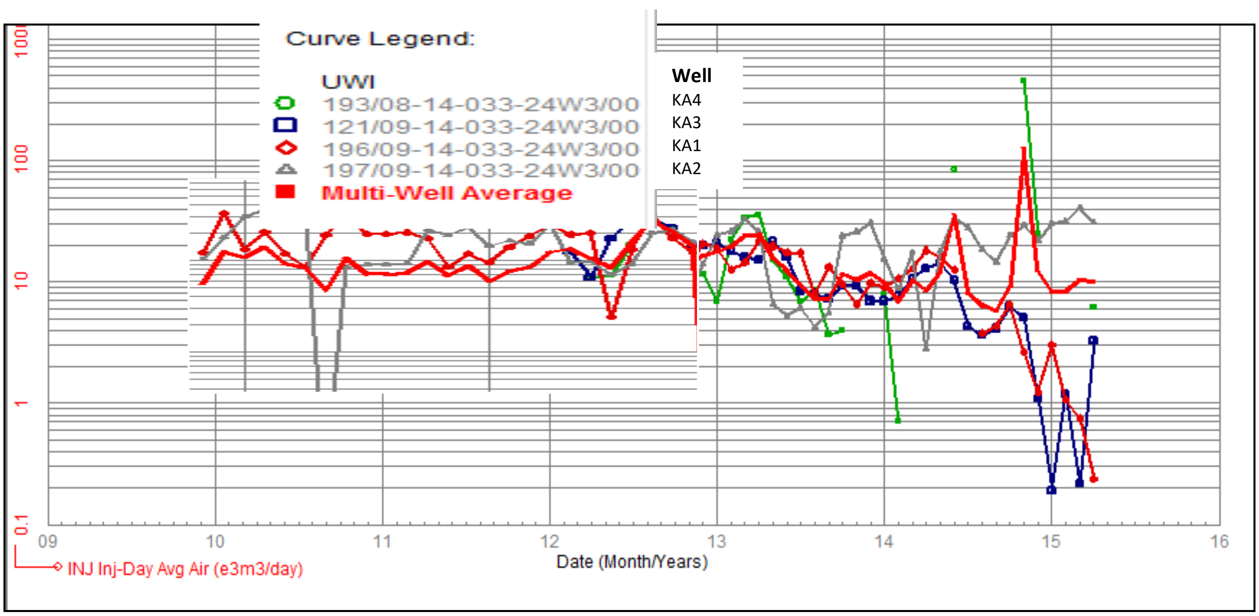

Figure G4a: The variation of the air injection rate per well, for the wells in Group I (KA1 to KA4). GeoSCOUT data

Note 1: Starting on February 2012, the KA4 well provides air which contributes to the oil production in KP7. Note 2: Air injection for year 2012 was drastically reduced

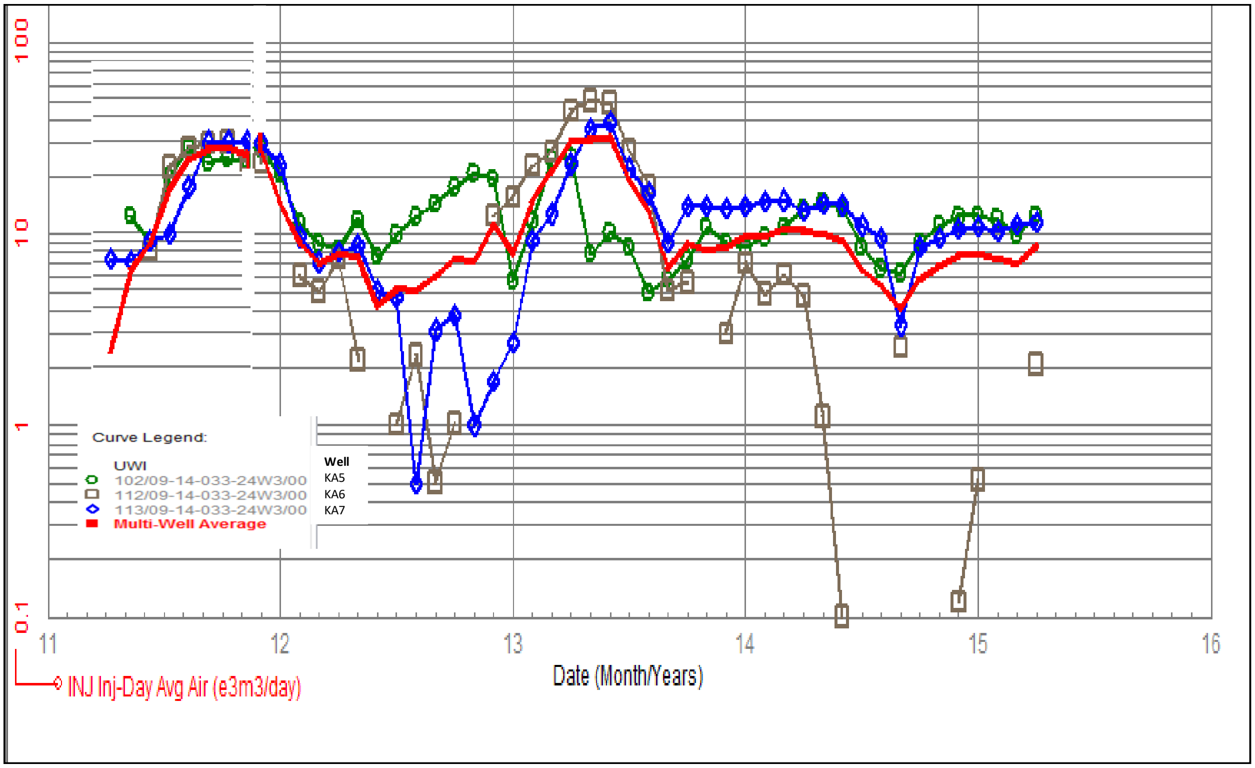

Figure G4b: The variation of the air injection rate per well for the wells in Group II (KA5 to KA7). KA6 has 4 long interruptions in air injection. GeoSCOUT data

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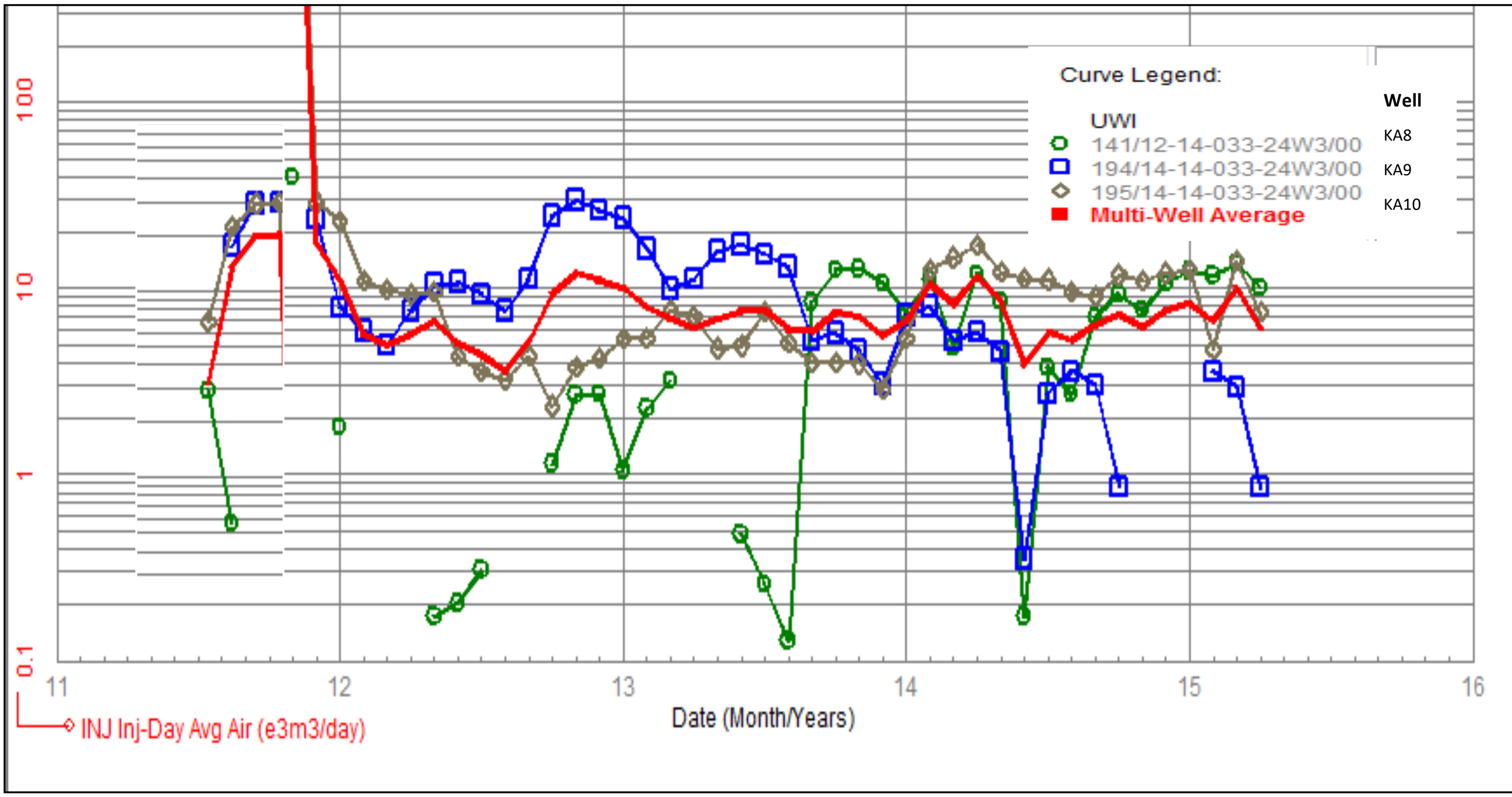

Figure G4c: The variation of the air injection rate per well for the wells in Group III (KA8 to KA10). GeoSCOUT data

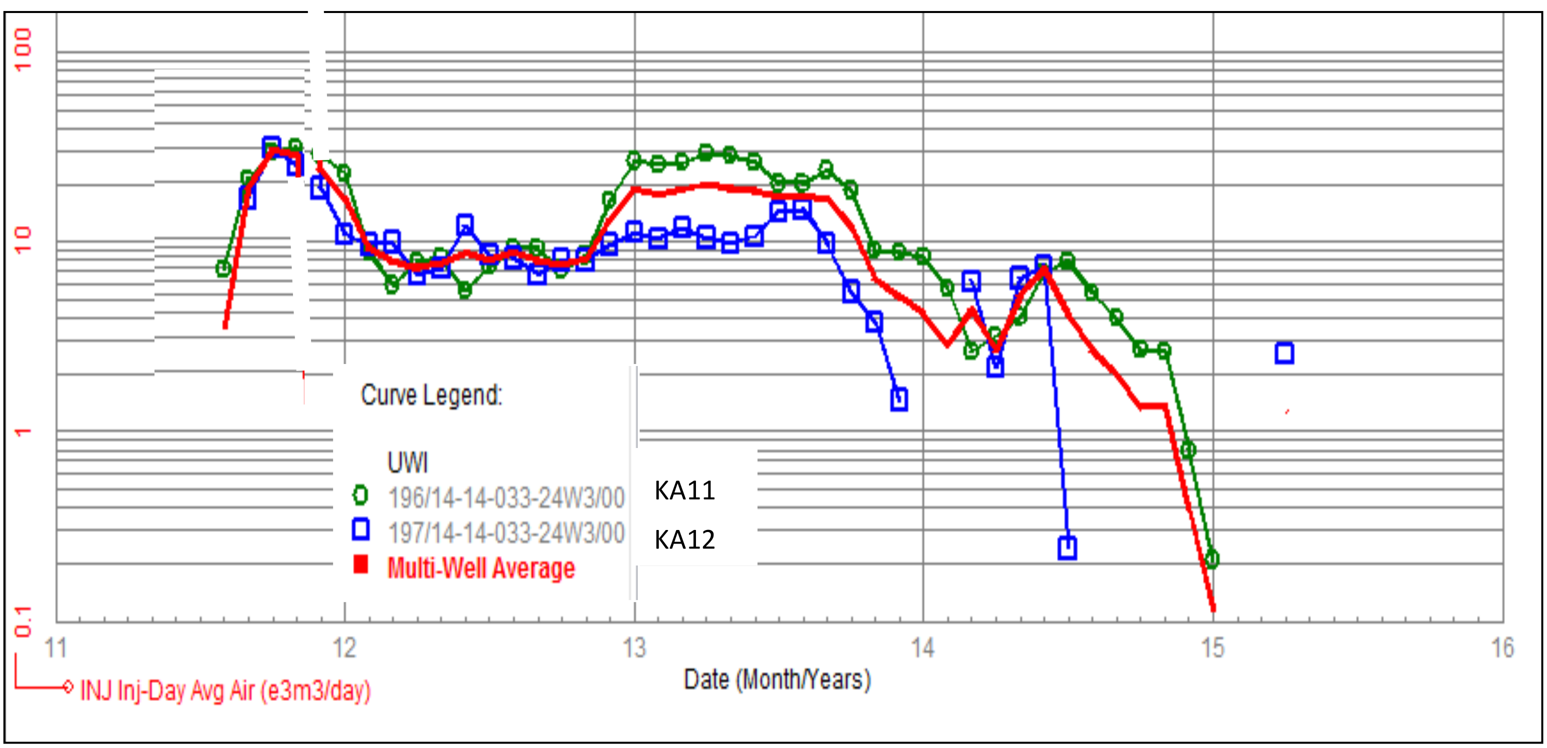

Figure G4d: The variation of the air injection rate per well for the wells in Group IV (KA11and KA12). GeoSCOUT data

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In Figure G5 the variation of the oil production per well, as per February 2015, for all patterns (except K1 and K2) are shown; the start of the graph is towards the end of ignition period (November 2011), such that a short period of 4 months is not represented. It can be noticed that average oil rate per well increased in time from the primary value of around 0.5 m^3/day up to a value of 3.5 m^3/day. The range of variation of the average oil rate per well in the relatively stabilized period of 2013-2014 was 2-5 m^3/day. Three of wells (KP3, KP7 and KP11) produced up to 15-20 m^3/day for some short periods of time (2-4 months). The variation of oil production seems to show two maximums: one in the second half of 2012 and a second peak in 2014. Year 2013 was characterized by a minimum in oil production.

Figures G6a-d provides the representation of the oil production (per well) per groups of wells, with the groups defined previously. The appearance of the two maximums is more pronounced in the first two groups. An inspection of the production graphs reveals that in most cases the oil production has an ascending profile (5 cases: K1, K2 K5, K7 and K11). For instance, in K1 and K2 patterns, it increased continuously after ignition for almost 1.5 years; however, after an interruption in the oil production in the months of April-May 2011, when resuming the oil production this was substantially lower than before the interruption and needed 6-9 months in order to come to a level close or equal to that before the interruption.

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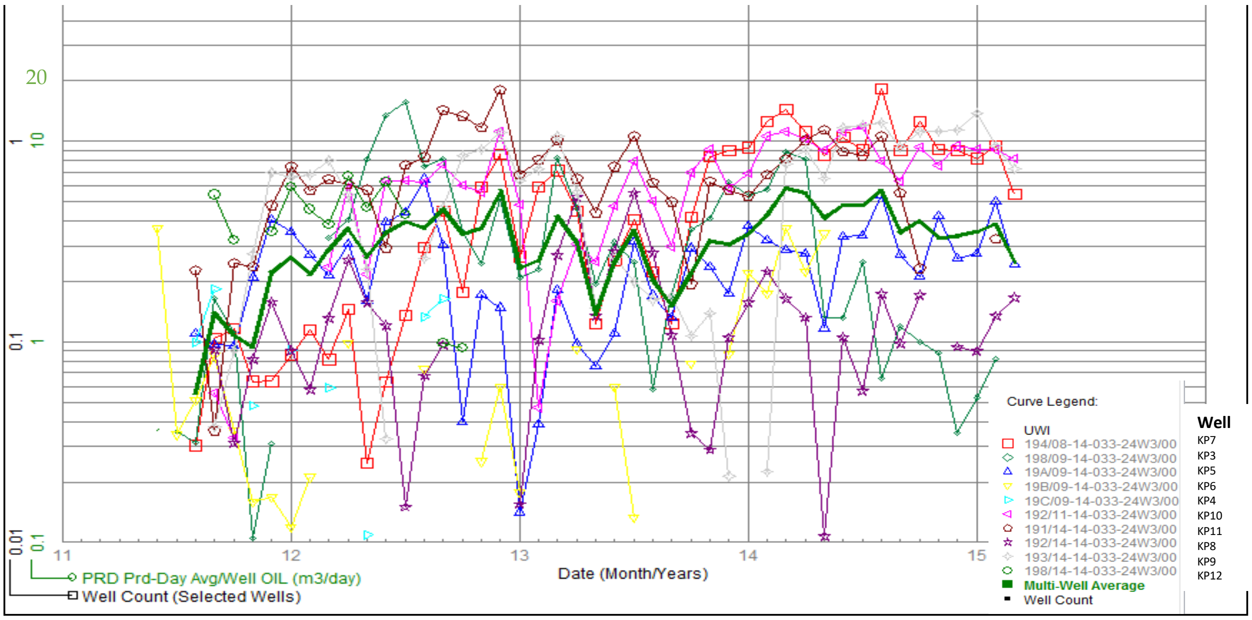

Figure G5: The variation of the oil production per well (module) for the production wells KP3 to KP12 of the semi-commercial operation. GeoSCOUT data

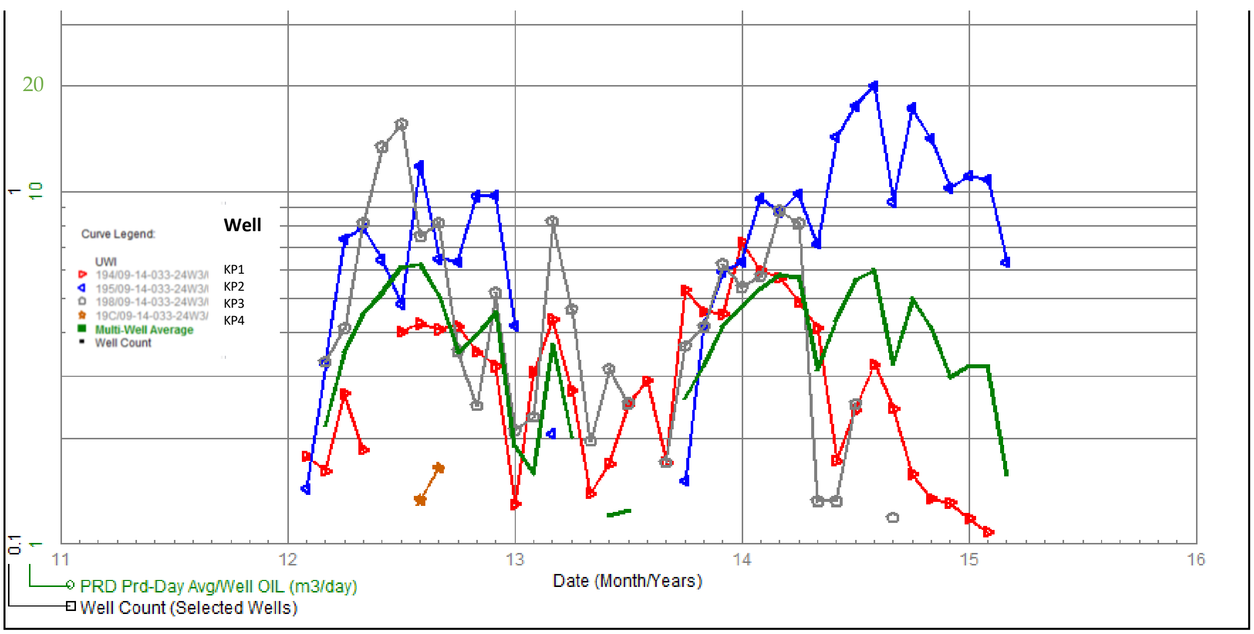

Figure G6a: The variation of the oil production rate per well for the wells in Group I (KP1 to KP4). GeoSCOUT data

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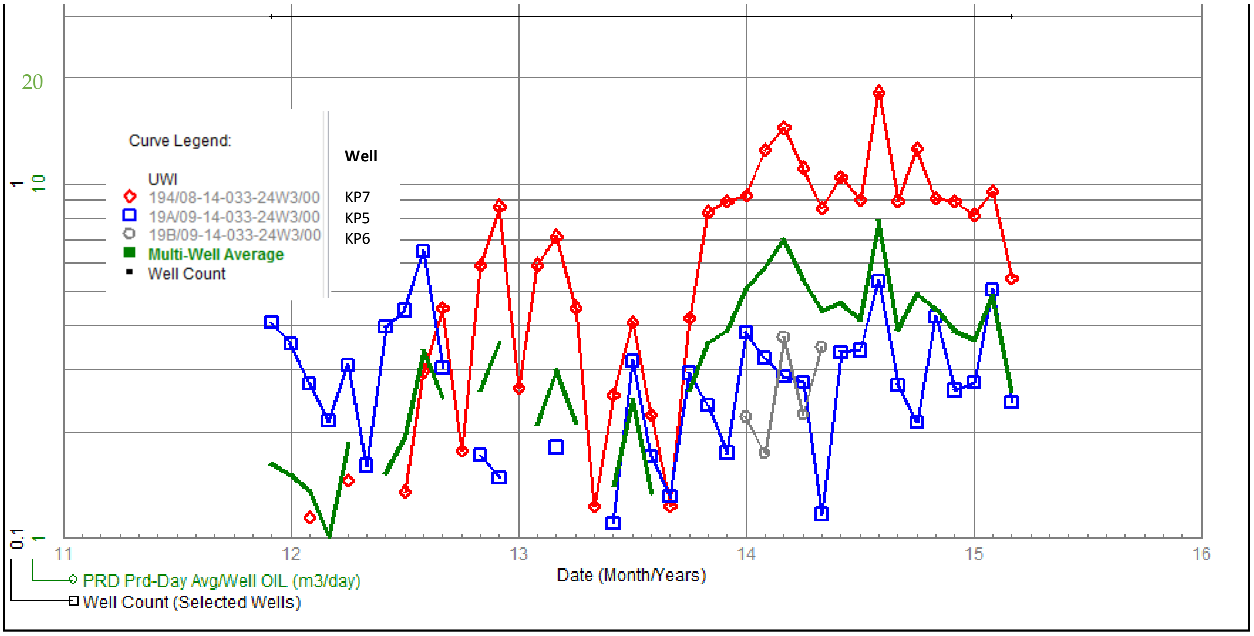

Figure G6b: The variation of oil production per well for the wells in Group II (KP5 to KP7). GeoSCOUT data

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Figure G6c: The variation of the oil production rate (per well) for the wells in Group III (KP8 to KP10). GeoSCOUT data

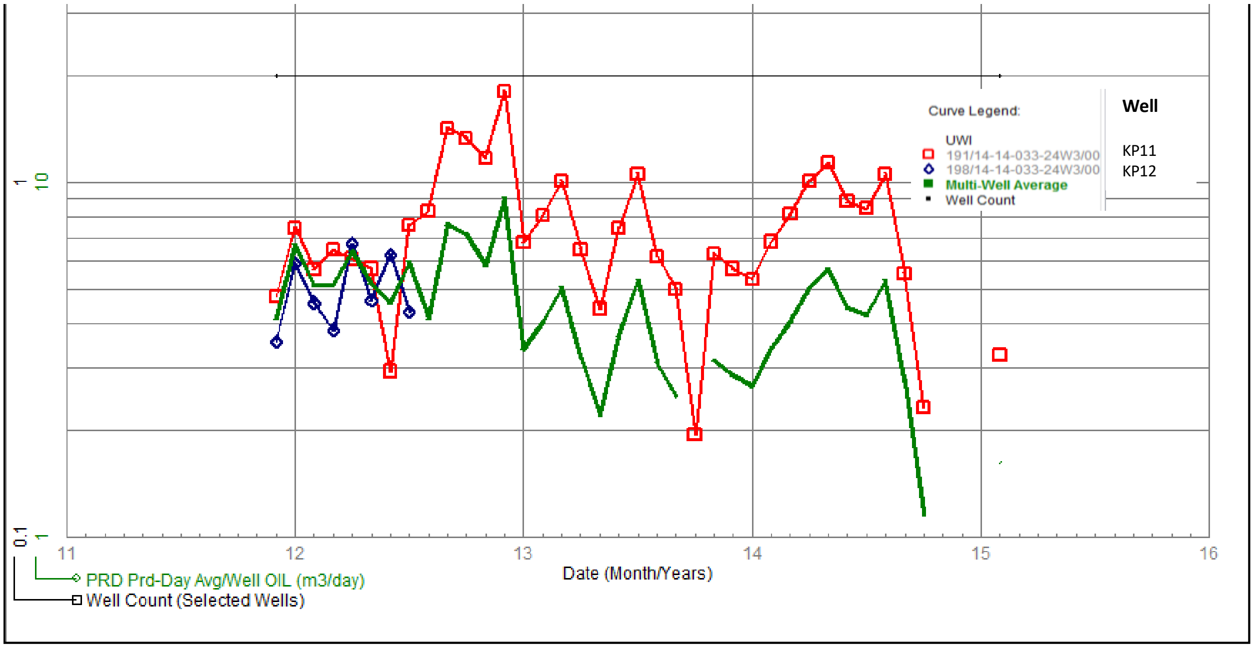

Figure G6d: The variation of the oil production rate (per well) for the wells in Group IV (KP11 and KP12). GeoSCOUT data.

For the poor performance patterns K4, K6, K8 and K12 the oil production had been low (or very low) and relatively constant. K4 and K12 poor performances are related to the absence of a well sustained ISC front propagation along their horizontal sections (there was no oil mobilization). K6 pattern seems to be the best representative of a pattern in which the bottom water had a decisive influence, probably with a main burning surface along the water/oil interface; in K6 case there were many interruptions in the air injection. For the pattern K8 it is more difficult to explain the performance as the water cut has never decreased under 70%.

It can be speculated that almost in all cases – irrespective of the mode of variation of oil production – at the beginning, a high value of oil production is recorded and this characterizes the steam-heated, oil displacement from the start-up region. Then, a valley in oil production is recorded as the ISC front gets anchored to the toe, followed by an increase of oil production as the normal ISC process front propagation from toe to heel is established.

Complex interpretation by correlating the composition of produced gas with temperature measurements and oil/water/gas production

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In Figures G7-KP1a to G7-KP1c, up to Figures G7-KP12a to G7-KP12c, for each pattern, first a graph of variation of gas composition (G7-KP?a), then a graph of bottomhole temperature profile along the produce(G7-KP?b), and then a complete production performance (daily oil production, water cut and gas produced) (G7-KP?c) – as per February 2015 are shown; question mark is for a number 1 to 12 for the producer K1 to K12. The production performance graphs are also showing the production monthly hours, in order to distinguish between effective and calendar production.

It can be noted that in the composition graph a novel system was adopted; instead of representing the classic CO_2, CO, O_2, H_2 and CH_4 the CO, O2, H2 and H/C ratio were represented. The modification adopted was justified by the fact that CH_4 percentage does not have a significant role in any interpretation as some CH_4 was injected continuously in the annular space to combat corrosion. However, the apparent hydrogen -carbon ration (H/C ratio) eliminates the CH_4 parasitic effect and in fact gives a very accurate semi-quantitative measure of the burning quality in the ISC front; lower H/C means better burning quality (higher peak temperature). Also, there was no need for CO_2 representation as the H/C ratio takes care of the CO_2 generation, as well. To demonstrate the equivalence, for the pattern K11 the graph G7-KP11a is split in three graphs G7-KP11a-1, G7-KP11a-2 and G7-KP11a-3; as seen from the first two graphs when everything is stabilized, the H/C is between 1.2 and 2.2, while the CO_2 is in the range of 12-15%. The popular way of judging ISC quality is by taking into account the gas composition mainly CO_2, but here due to sometimes higher CH_4 rates injected into annular, the procedure may not work properly, all the times; CH_4 content varies between 4% and 20% and significantly modifies the value of CO_2percentage. Moreover, the variation of H/C at the beginning of the process is the best way to evaluate the ignition delay, therefore how much times is consumed until the full generation of the ISC front occurs. For each pattern, the values of ignition delay in Table 12 of the Report were determined from these graphs.

The graphs from G7-KP11a-1, G7-KP11a-2 and G7-KP11a-3 allows us to determine important mechanisms of the THAI process. As shown in graph G7-KP11a-3 there is a *very tight correlation between the generation of hydrogen and generation of H_2S*; and they have the same tendency, to increase or decrease, when the quality of burning (as indicated by the variation of H/C) is higher or lower. In May-June 2012, when H/C takes its minimum value (in the range of 0.8-1) showing the best quality of burning (very high peak temperature), the H_2 increases at its maximum value (2.2%), while the H_2S increases at its maximum value (0.9 %).

Correlating the information from Figures G7-KP1a to G7-KP1c, up to Figures G7-KP12a to G7-KP12c, other important conclusions are:

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- The full consumption of the oxygen was confirmed once again; in general, O_2% is less than 0.3 - 0.5%, and a few exceptions could be recorded at producers KP3, KP5 and KP11, where an extremely short duration peak of 5% -10% O_2 was recorded probably during a very abrupt increase in air injection rate. At KP9 for a limited period it was up to 0.8%.
- Practically there is no CO produced; it is close to Nil; some small percentages (up to 0.4%) are generally recorded at the beginning of the process, for 6-12 months, in conjunction with the spontaneous ignition process. Exception to this rule was seen for the wells KP8 and KP10 where percentages of up to 0.4% were recorded all the time
- The highest hydrogen percentage (5-7%) was recorded at the producer KP2 for 6 months in the period September 2010-February 2011; in this period the H_2S percentage also took a maximum value of around 2.6%. The second highest hydrogen percentage (4-5%) was recorded in the same period at the producer KP1; H_2S also took a maximum value of around 1.2%. The third highest percentage (2.81%) was recorded at the producer KP6 for 3 months
- The most typical variation of the H/C ratio was seen for the producers KP2, KP7, KP9 and KP11; typical variation meaning a steep variation at the beginning, reflecting the ignition process and then stabilization in a range of 1-2. For producers KP4 and KP12 the H/C ratio varies in the range of 4 to 15 indicating a lack of a sustained ISC front propagation in these patterns. Well KP6 showed a large cyclical variation of the H/C ratio, but within the range of relatively low values pointing towards a good quality burning. Probably, it indicates the development of a burning at the water/oil interface; in this case, the value of H/C ratio took negative values at two different periods, indicating the desolubilization of CO_2 from the bottom water.
- There is a correlation between H/C ratio and the hydrogen percentage in the produced gases; better burning quality (higher peak temperature - indicated by lower H/C ratios) leads to a higher percentage of hydrogen. This good correlation can be easily observed at producers KP5, KP6, KP8, KP10 and KP11
- For wells KP1 and KP8 there is a deterioration of burning quality towards the end of the process, in 2014-2015 period; this is directly associated with the decrease of hydrogen content of the produced gases. This is due to a pronounced decrease of the air injection per well (under 5000-8000 sm3/day); see Figures G4-a and G4-c. In this stage of the process, at this very low air flux, the peak temperature in the ISC front decreased; the LTO reactions started to predominate and the oil mobilization decreased significantly.

The inspection of the performance graphs (Figures G7-KP?-c) shows that two wells – KP4 and KP12 - were suspended towards the end of 2012. In both of them the water cut remained very high (96-99%), as there was no ISC front in these patterns. Well KP6 – having both horizontal section of producer and the perforations of vertical injector very close to water/oil interface and displaying numerous interruptions in injection and production - also had a poor performance as the water cut remained relatively high (around 98%) with a slight decrease in the water cut during the second half of 2013; it was suspended in April 2014. The best performing wells were KP2, KP7, KP9, KP10 and KP11, with oil production rates in the range of 4-12 m^3/day/well; the best performer was well KP2 of the initial pilot, with oil productions of up to 20 m^3/day. For all these wells, in general, water cut decreased from 70-90% to as low as 30-50%. *These wells showed the potential of the THAI process applied in a bottom water situation; they were definitely influenced by the ISC process, including a good mobilization of the oil by the ISC front.*

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Gas production is either increasing or decreasing in time, according to the channelings created during the process, as, later on, the injected air/combustion gases may migrate from pattern to pattern. In general, the wells with a good performance showed higher combustion gas rates.

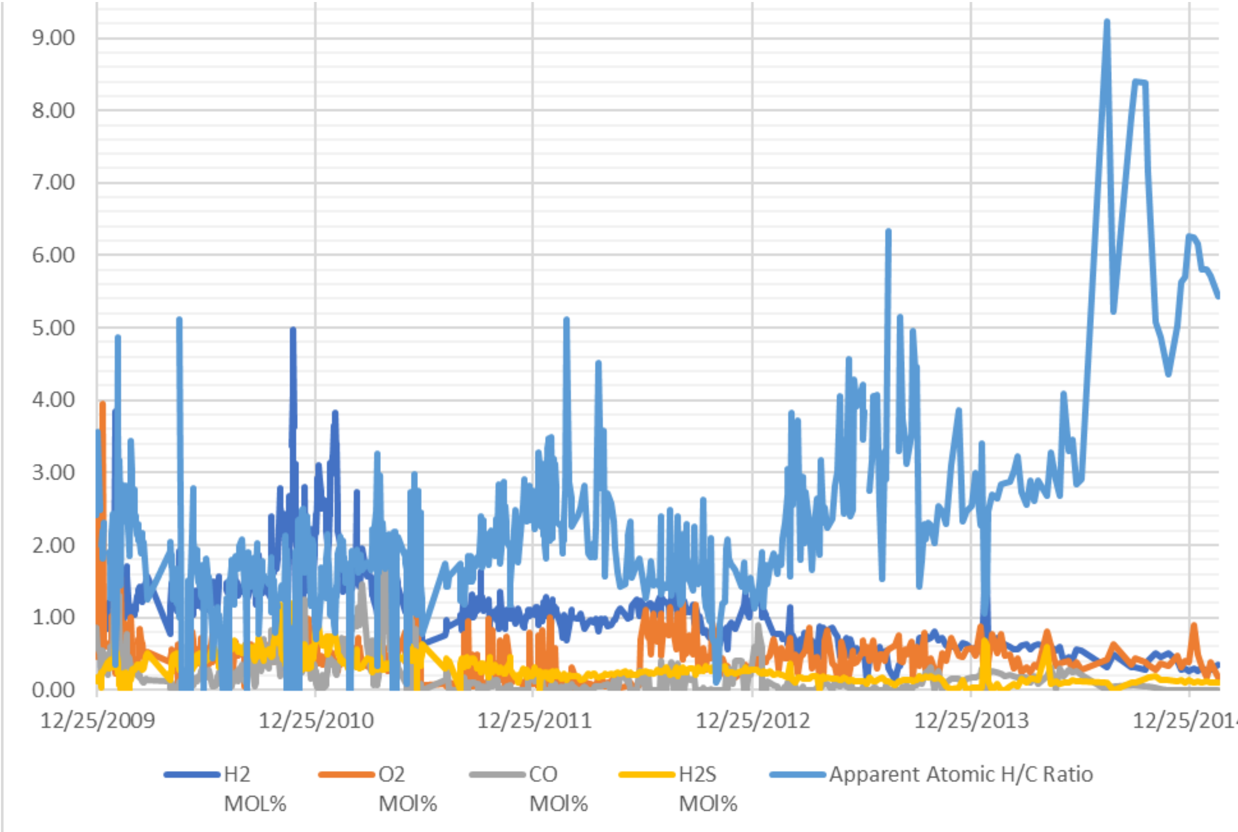

Fig G7-KP1a: Horizontal producer KP1. Variation of the gas composition and of the apparent hydrogen-carbon ratio (H/C ratio)

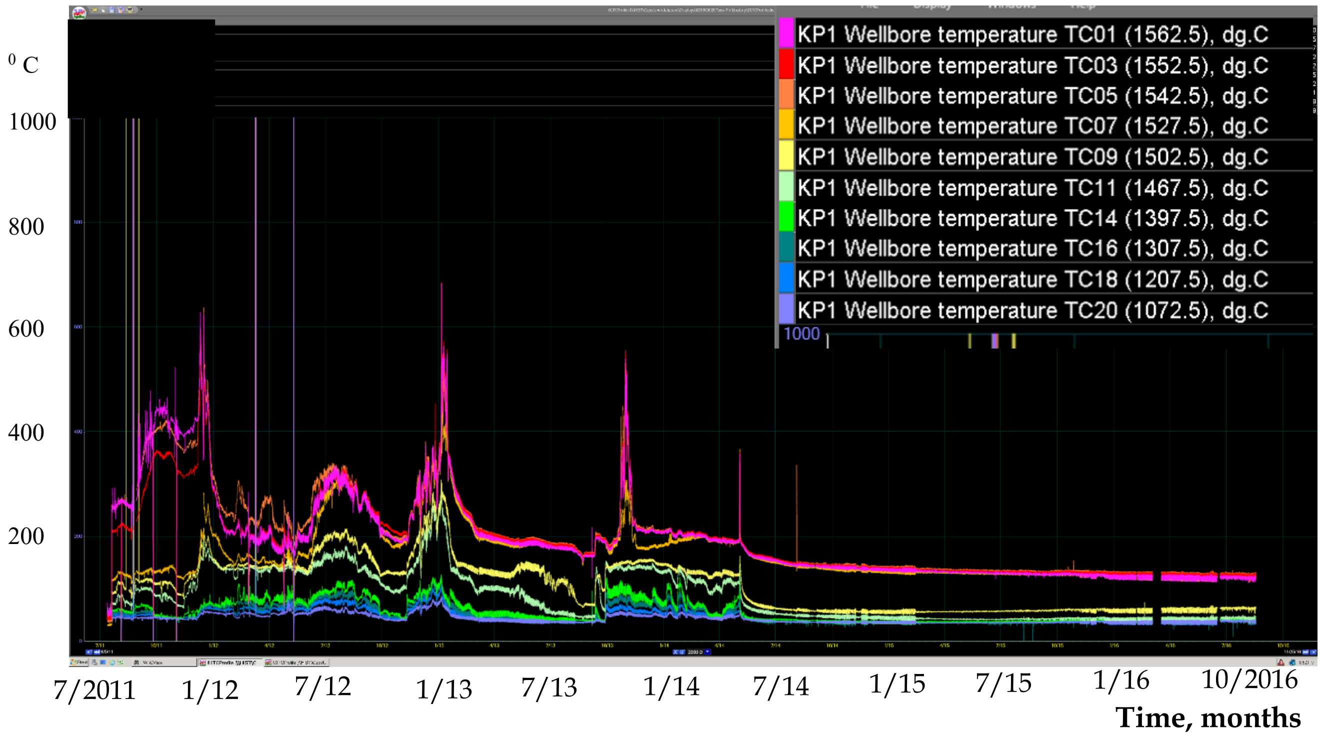

Fig G7-KP1b: Horizontal producer KP1. Variation (in time) of temperature in different points (measured depth, indicated in the upper right corner) in the period of September 2012-September 2016. Toe at 1562.5m. TC=thermocouple

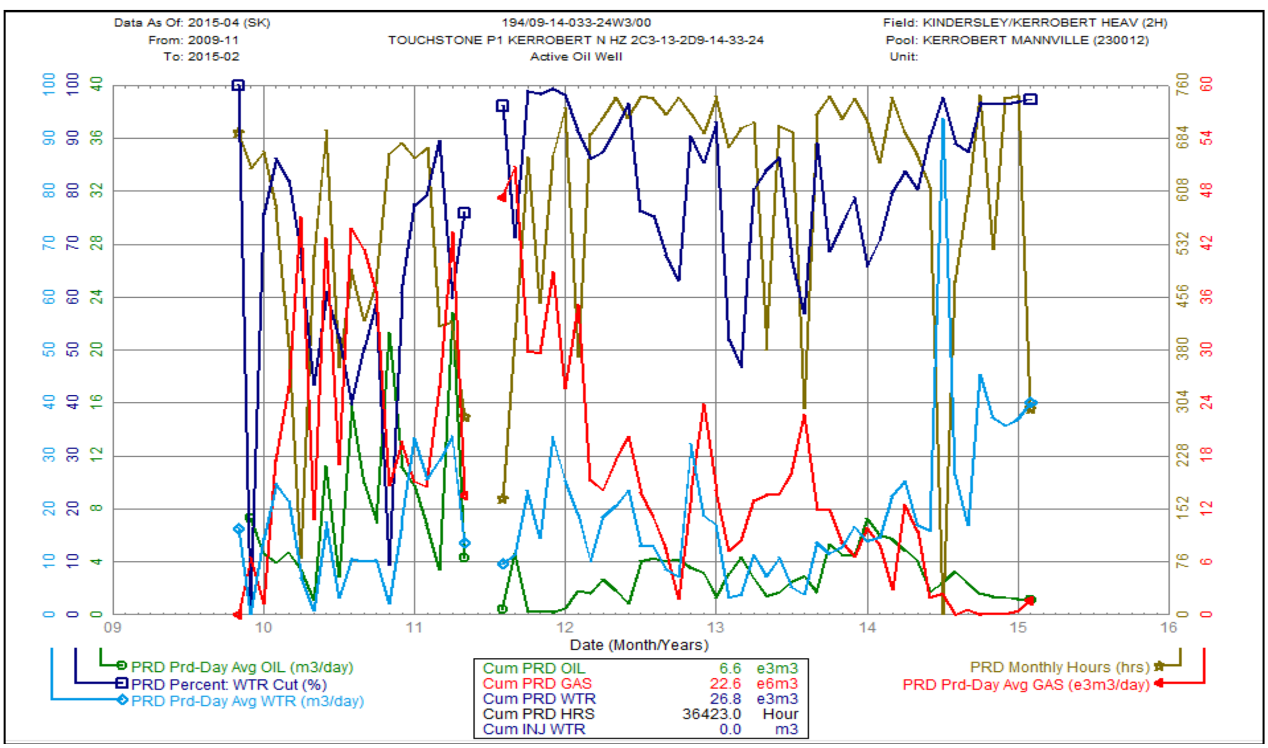

Figure G7-KP1c: The variation of the oil and water production, water cut and gas produced for well KP1. GeoSCOUT data

⁰ C
1000
800
600
400
200

7/2011 1/12 7/12 1/13 7/13 1/14 7/14 1/15 7/15 1/16 10/2016
Time, months

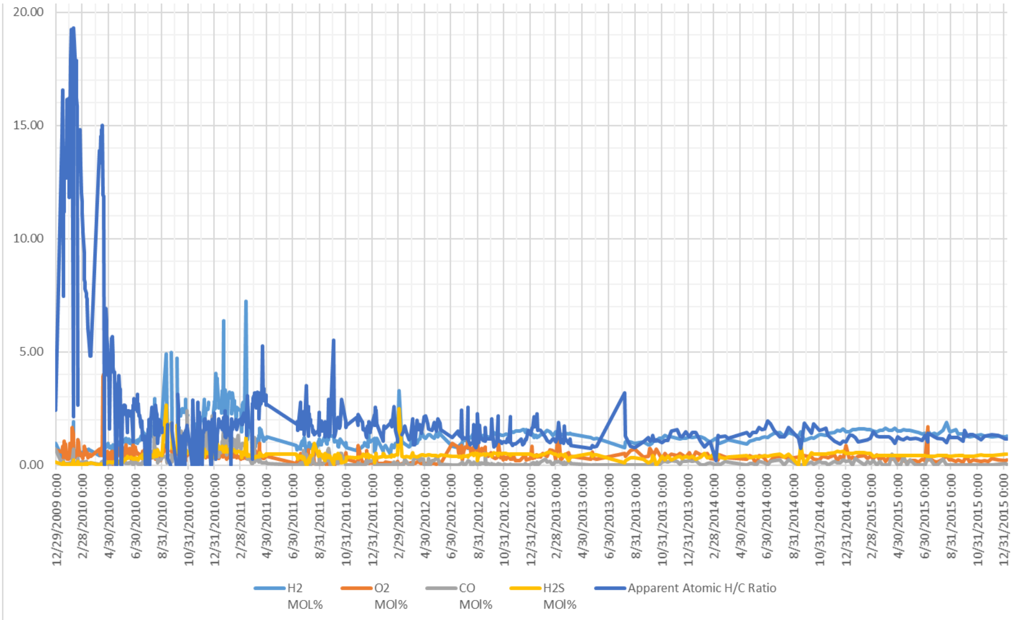

Fig G7-KP2a: Horizontal producer KP2. Variation of the gas composition and of the H/C ratio

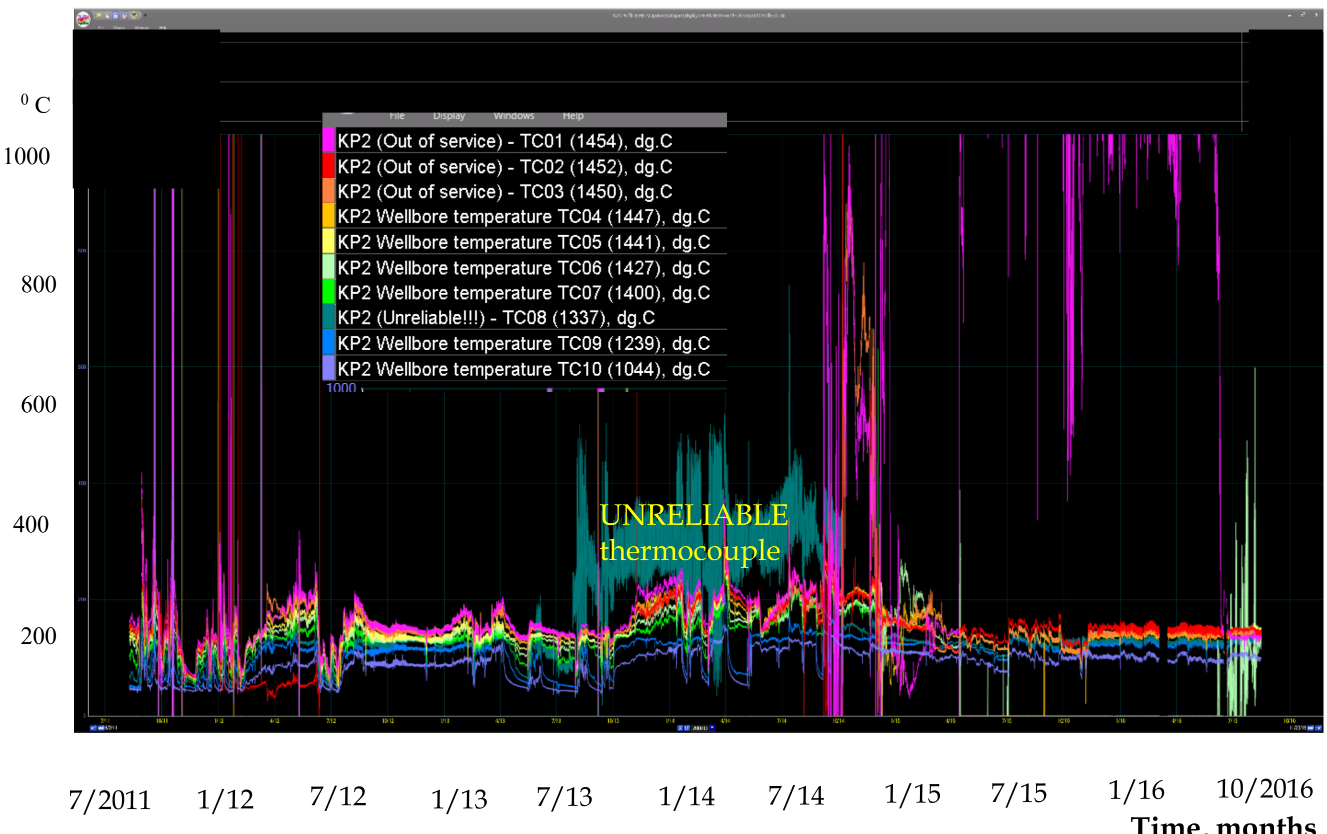

Fig G7-KP2b1: Horizontal producer KP2. Variation (in time) of temperature in different points in the period of September 2011-September 2016. Legend of colors and measurement points indicated in the middle of picture; TC=thermocouple. TC01 is located at the toe (1454m) ; measured depth in meters.

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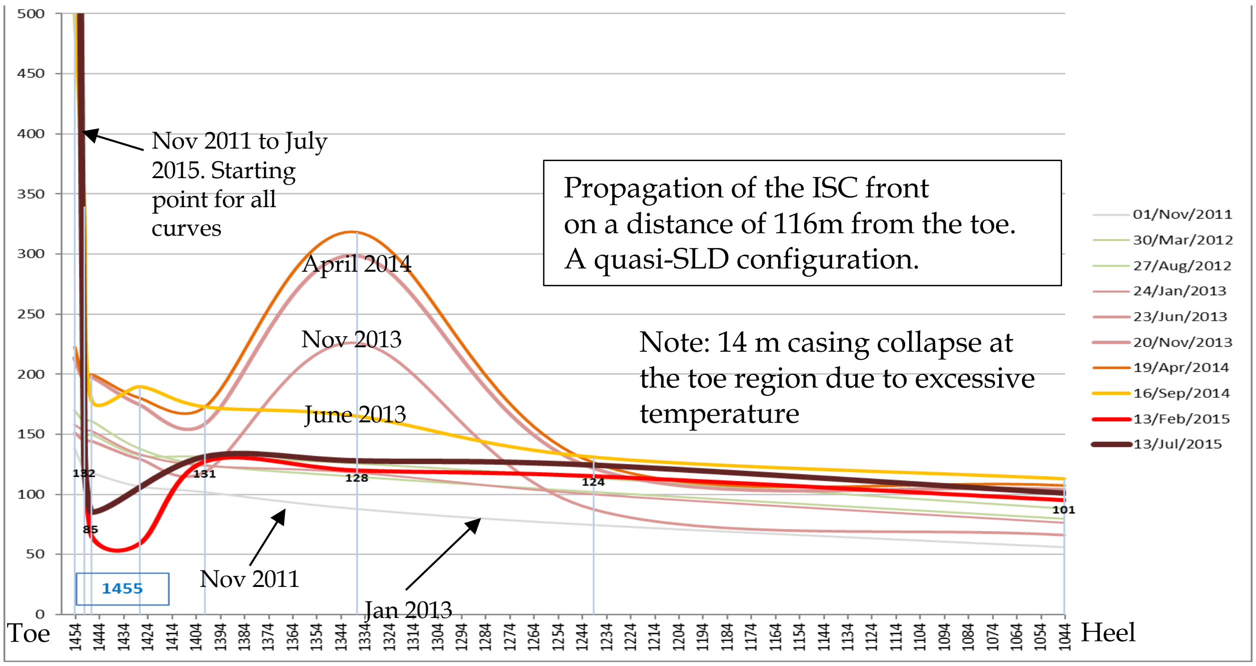

Fig. G7-KP2b2: Kerrobert THAI Pilot. The variation of temperature from the toe to the heel, for well KP2 at different dates. Ignition date: Dec 2009. To be correlated with Fig. G7_KP2b1. Temperature remains high in the toe region, but the ISC front advances along the horizontal well; it suggests that some oil production occurs within the whole toe region as this configuration has a quasi-staggered line drive characteristic.

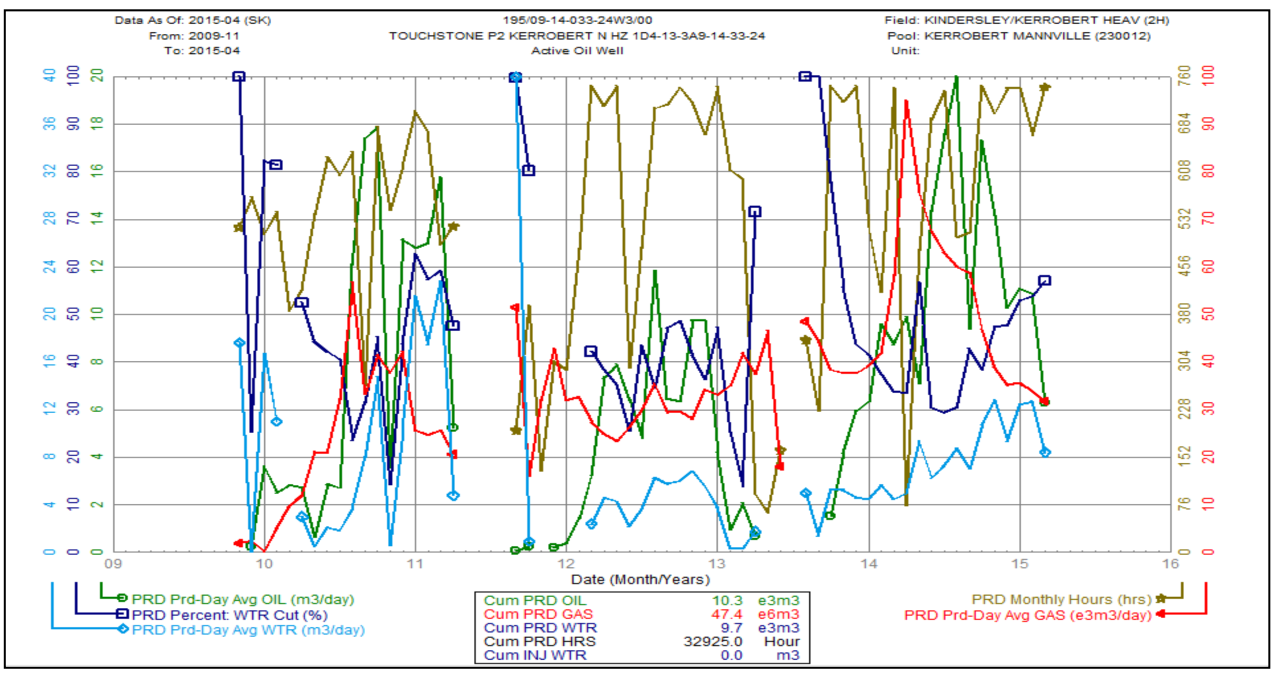

Figure G7-KP2c: The variation of the oil and water production, water cut and gas produced for well KP2. GeoSCOUT data

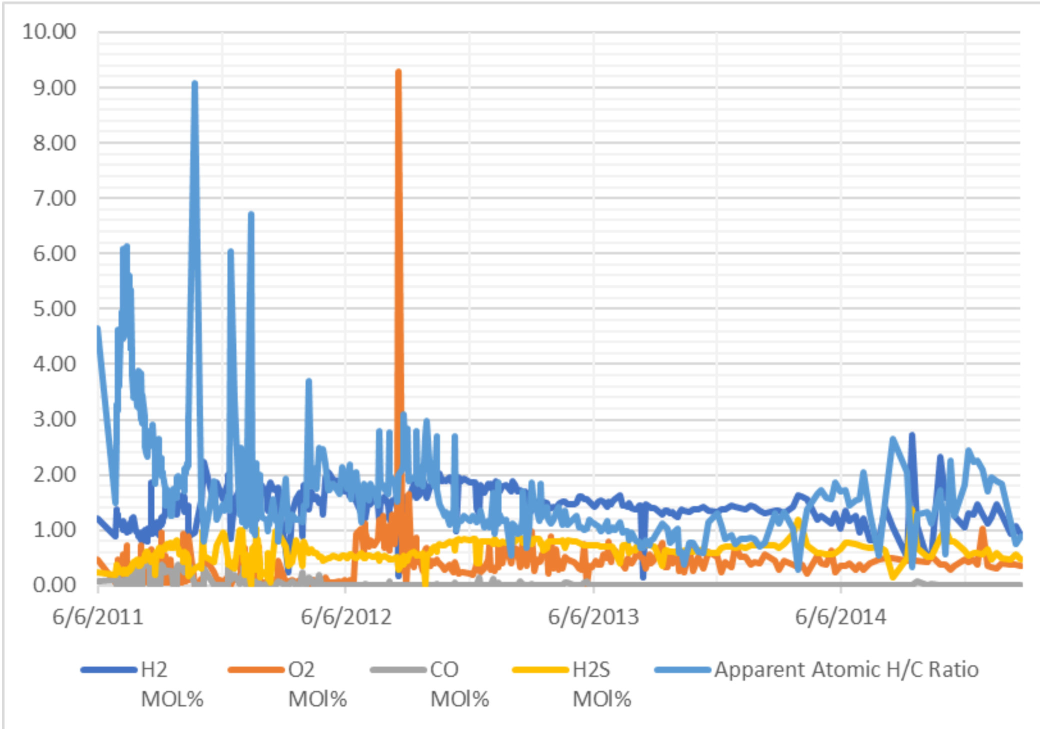

Fig G7-KP3a: Horizontal producer KP3. Variation of the gas composition and of the H/C ratio

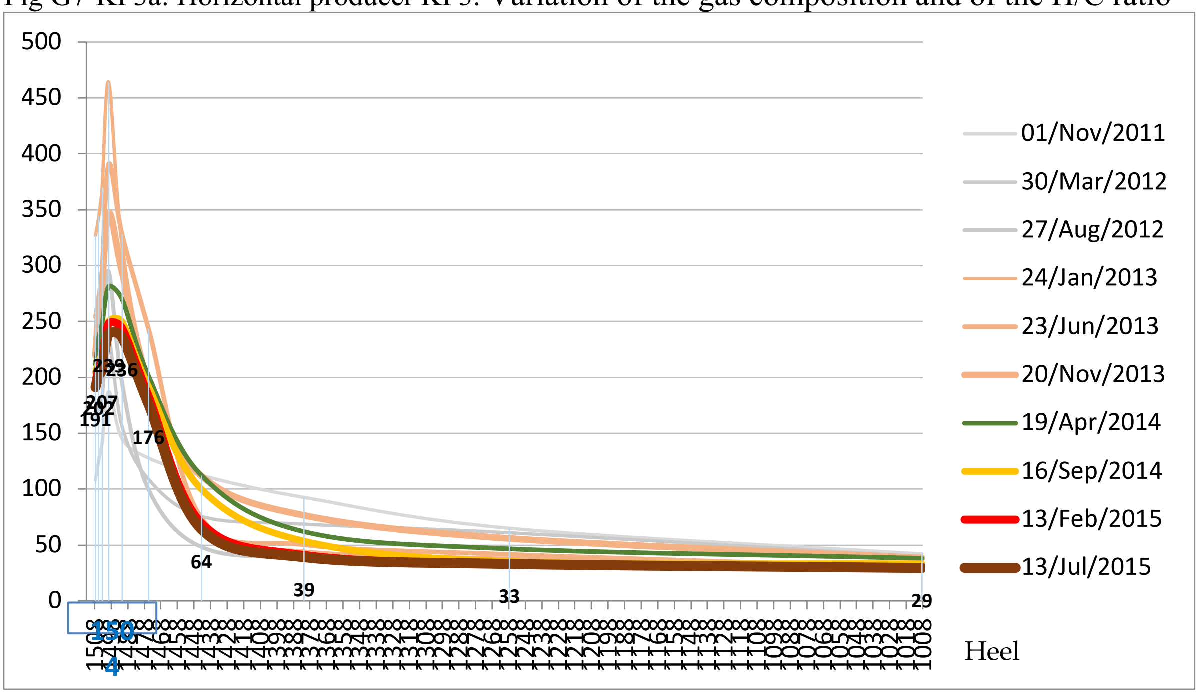

Fig G7-KP3b: Horizontal producer KP3. Variation of temperature along the horizontal section from toe to heel in the period of November 2011-July 2015. Toe at 1508m measured depth (MD) and heel at 1008m MD

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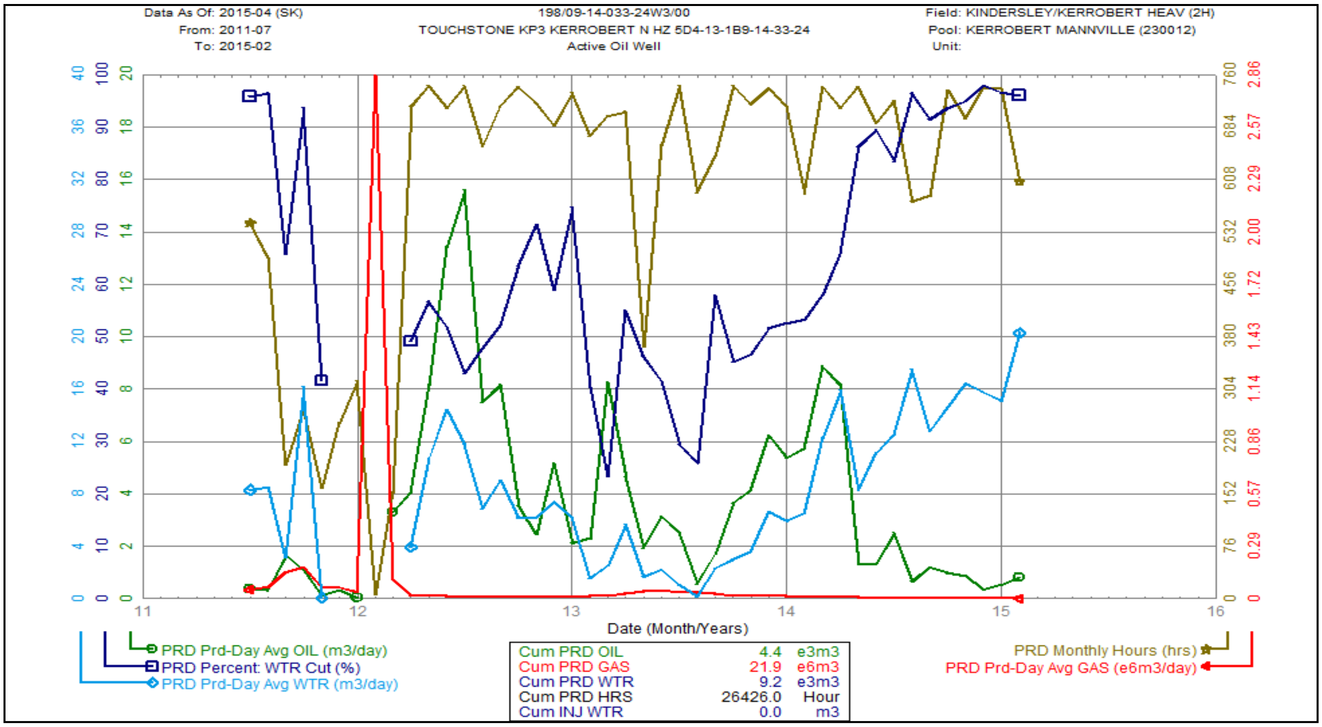

Figure G7-KP3c: The variation of the oil and water production, water cut and gas produced for well KP3. GeoSCOUT data

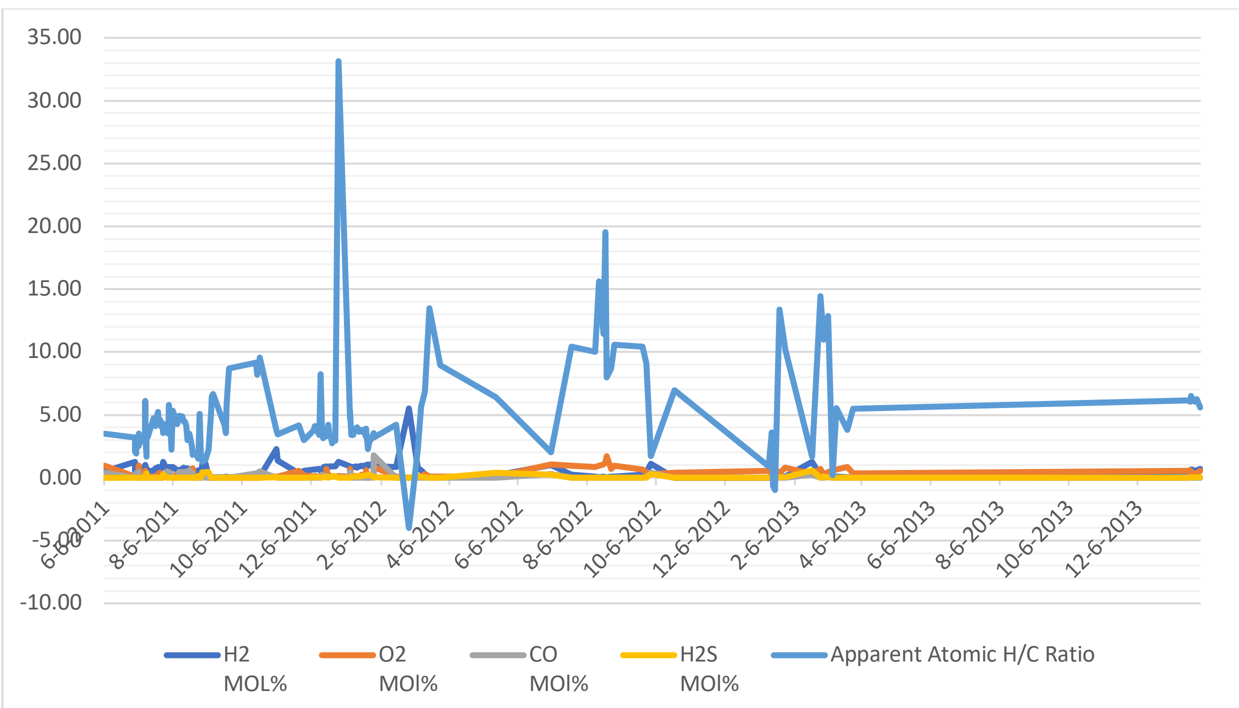

Fig G7-KP4a: Horizontal producer KP4. Variation of the gas composition and of the H/C ratio

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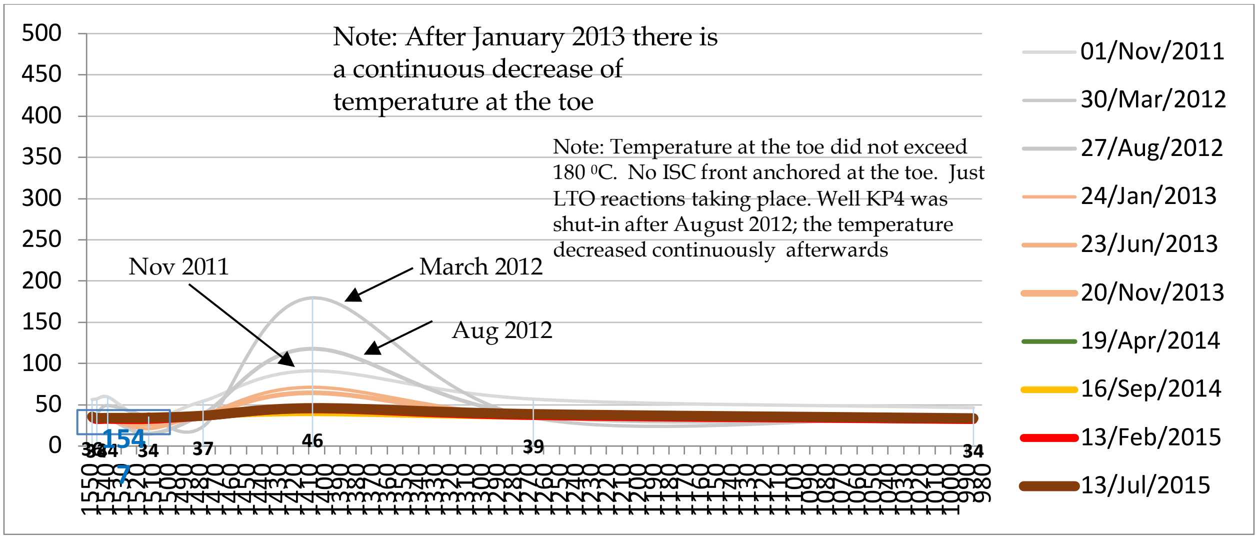

Fig G7-KP4b: Horizontal producer KP4. Variation of temperature along the horizontal section from toe to heel in the period of November 2011-July 2015. Toe at 1550m measured distance/depth (MD) and heel at 980m MD

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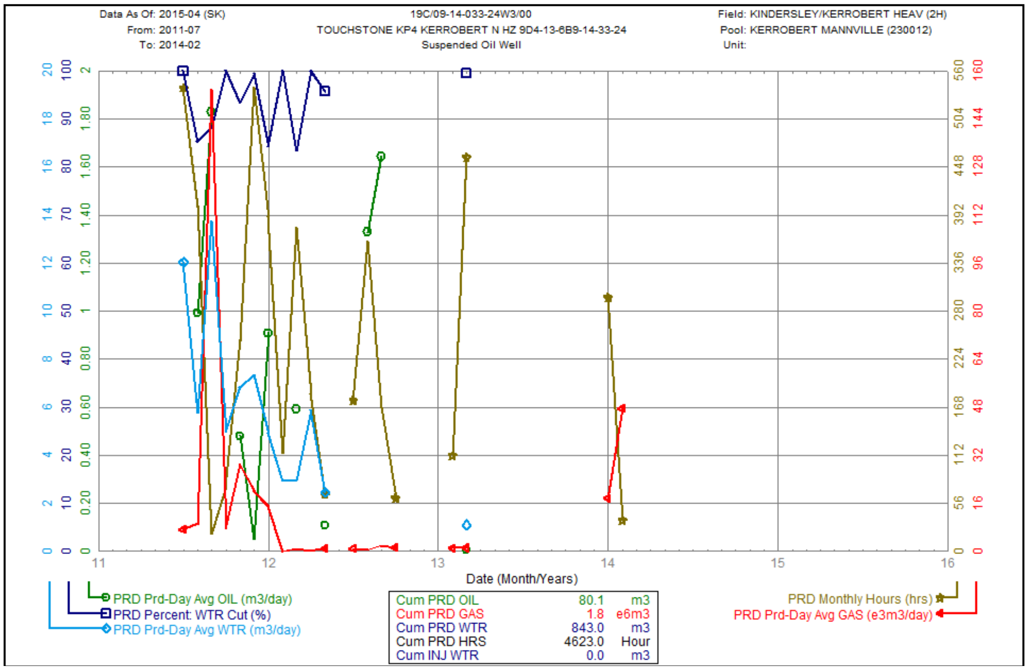

Figure G7-KP4c: The variation of the oil and water production, water cut and gas produced for well KP4. GeoSCOUT data

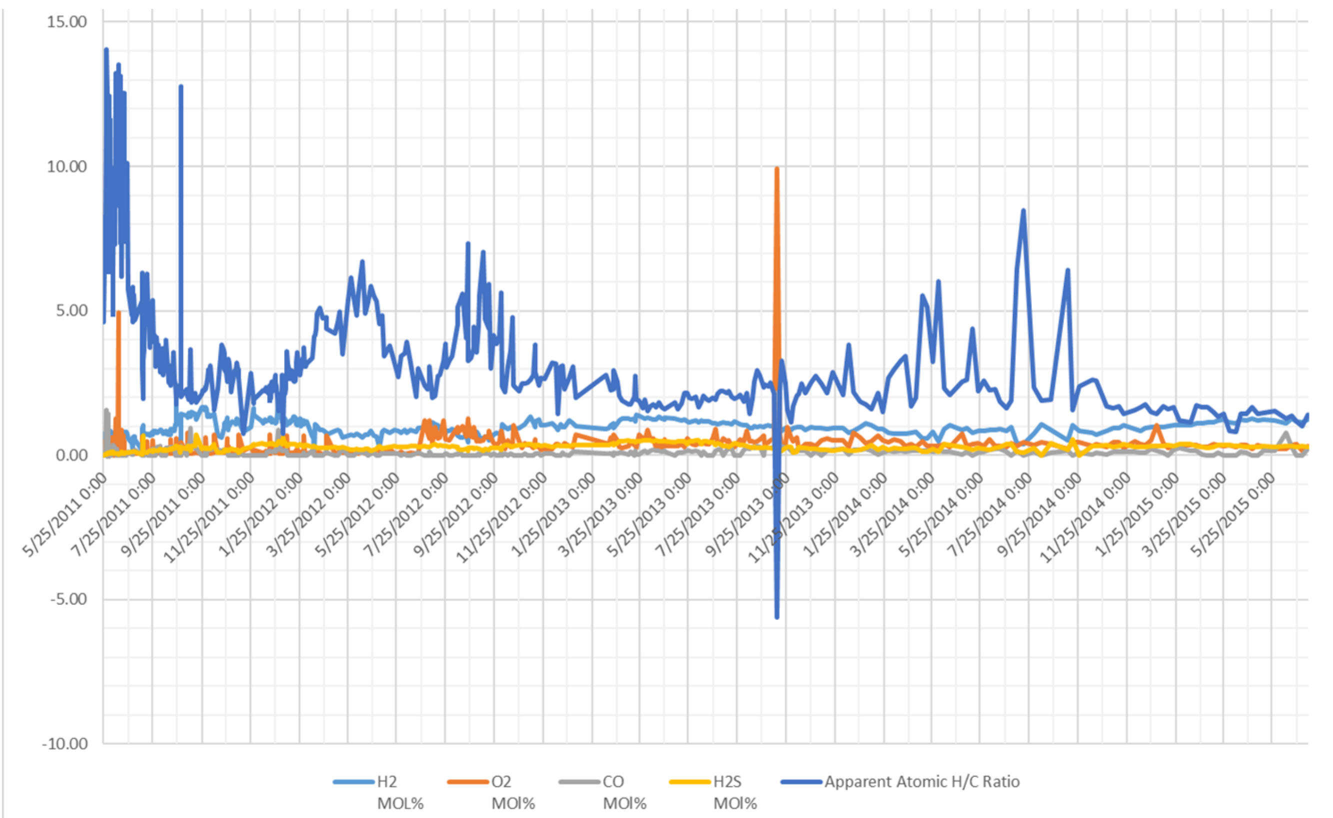

Fig G7-KP5a: Horizontal producer KP5. Variation of the gas composition and of the H/C ratio

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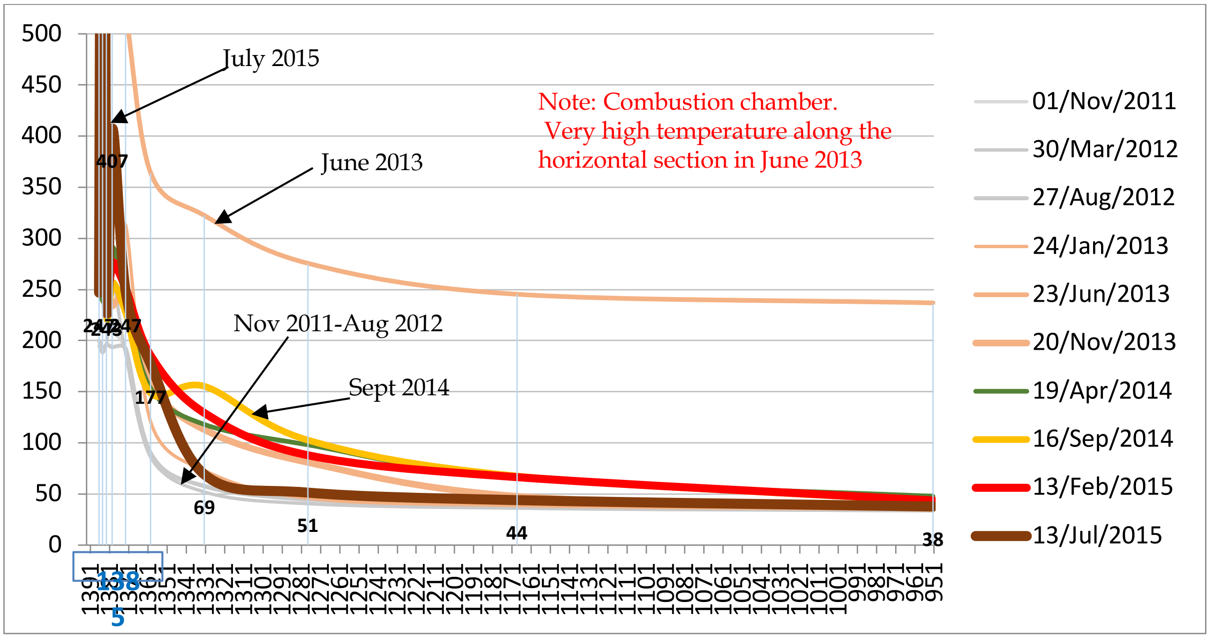

Fig G7-KP5b: Horizontal producer KP5. Variation of temperature along the horizontal section from toe to heel in the period of November 2011-July 2015. Toe at 1391m measured distance (MD) and heel at 951m MD

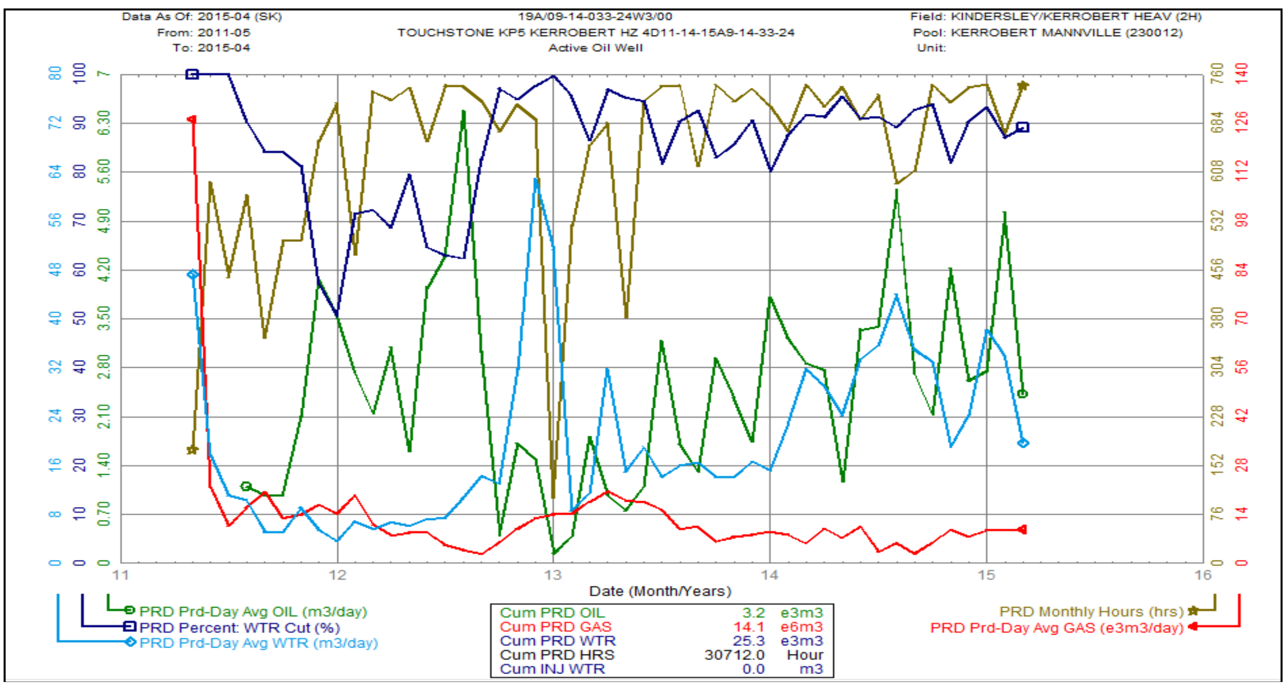

Figure G7-KP5c: The variation of the oil and water production, water cut and gas produced for well KP5. GeoSCOUT data

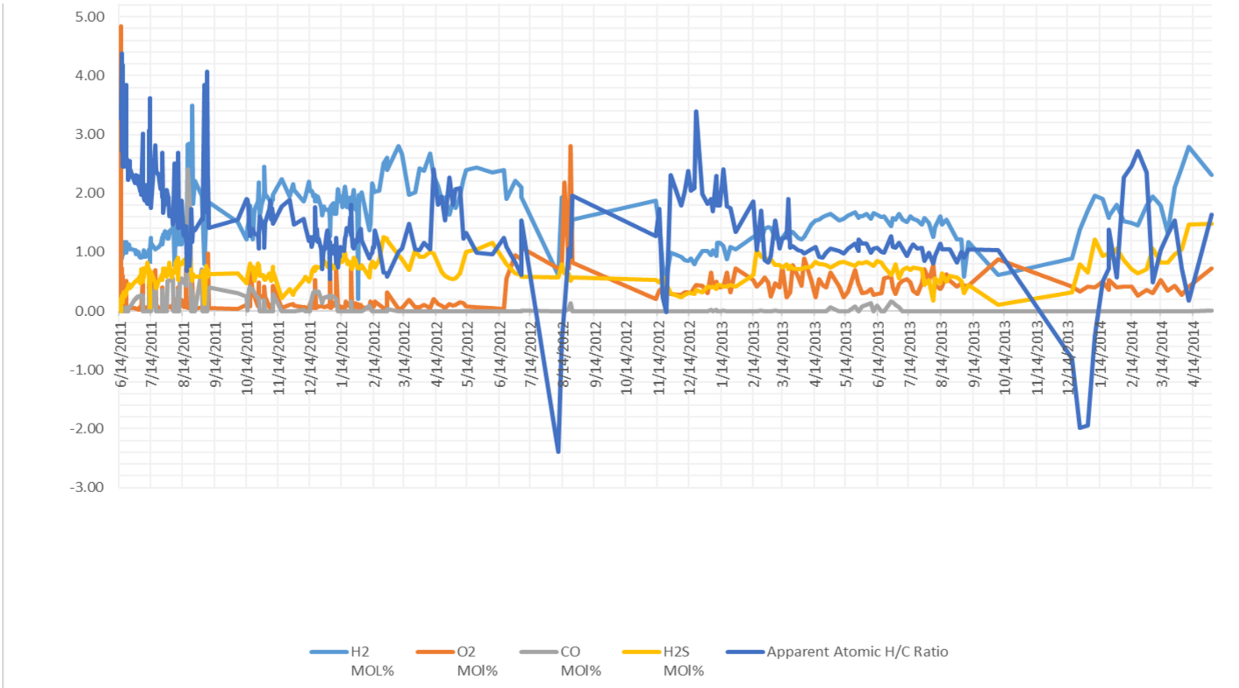

Fig G7-KP6a: Horizontal producer KP6. Variation of the gas composition and of the H/C ratio

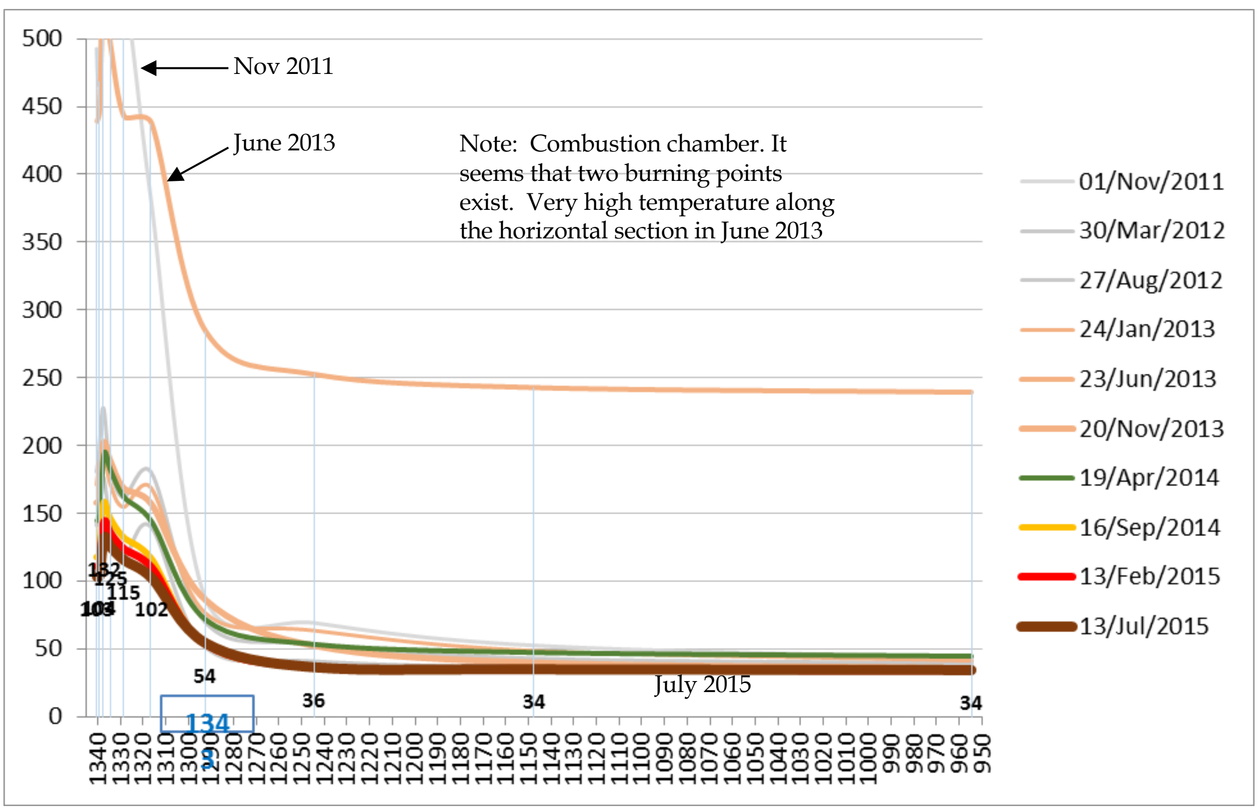

Fig G7-KP6b: Horizontal producer KP6. Variation of temperature along the horizontal section from toe to heel in the period of November 2011-July 2015. Toe at 1340m measured distance (MD) and heel at 950m MD

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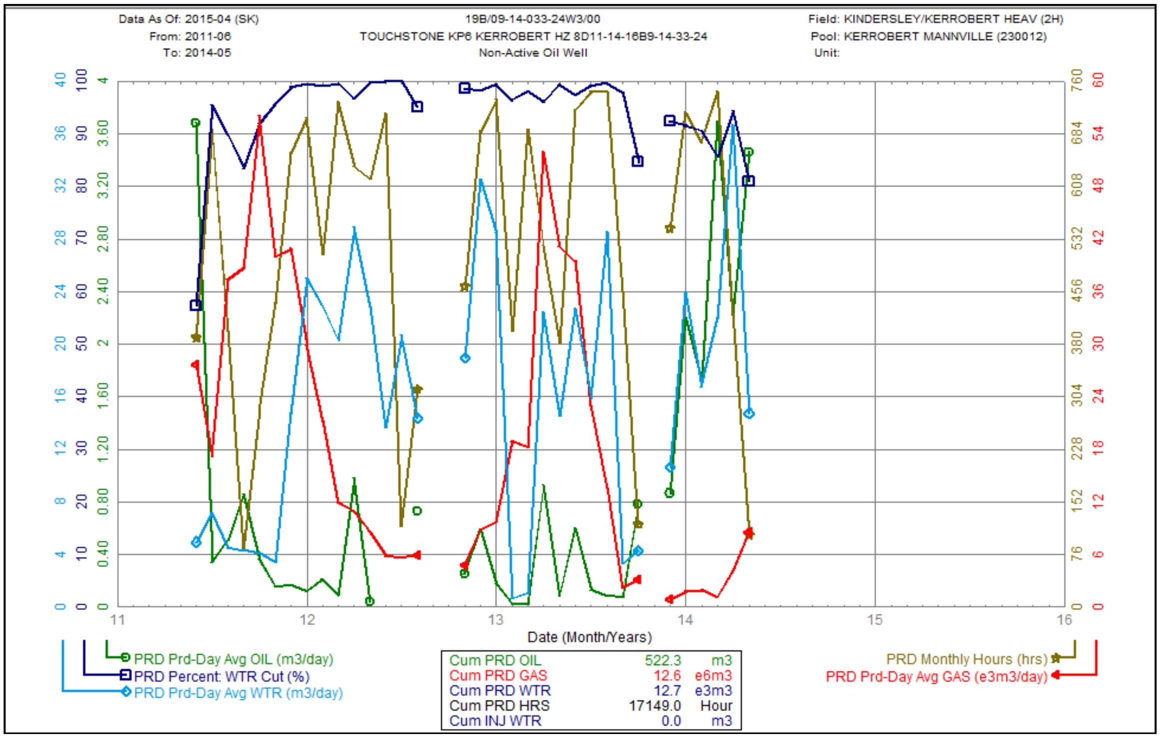

Figure G7-KP6c: The variation of the oil and water production, water cut and gas produced for well KP6. GeoSCOUT data

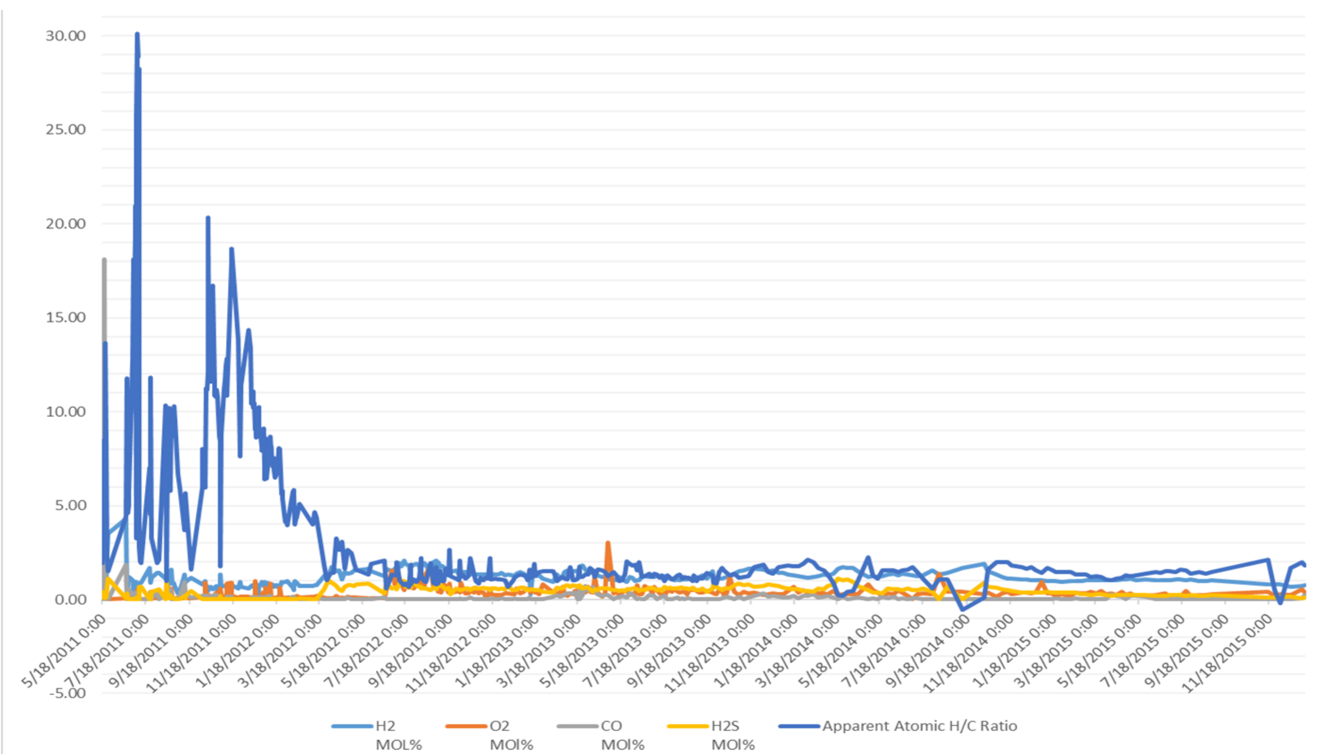

Fig G7-KP7a: Horizontal producer KP7. Variation of the gas composition and of the H/C ratio

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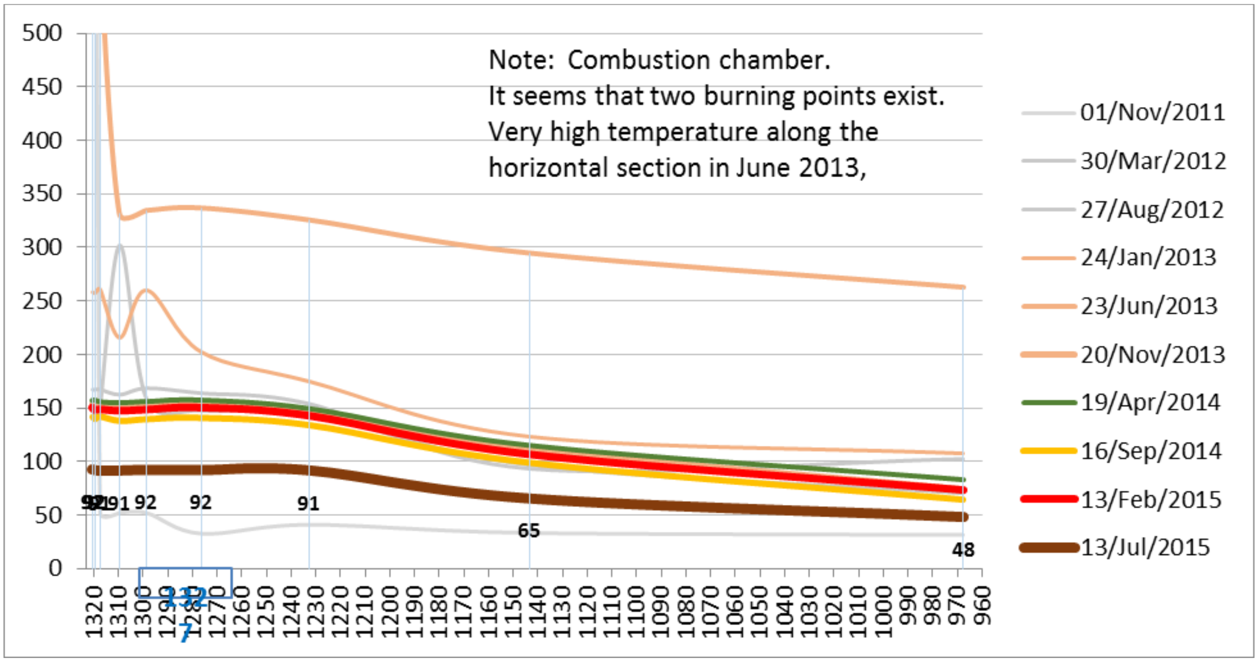

Fig G7-KP7b: Horizontal producer KP7. Variation of temperature along the horizontal section from toe to heel in the period of November 2011-July 2015. Toe at 1320m measured distance (MD) and heel at 960m MD

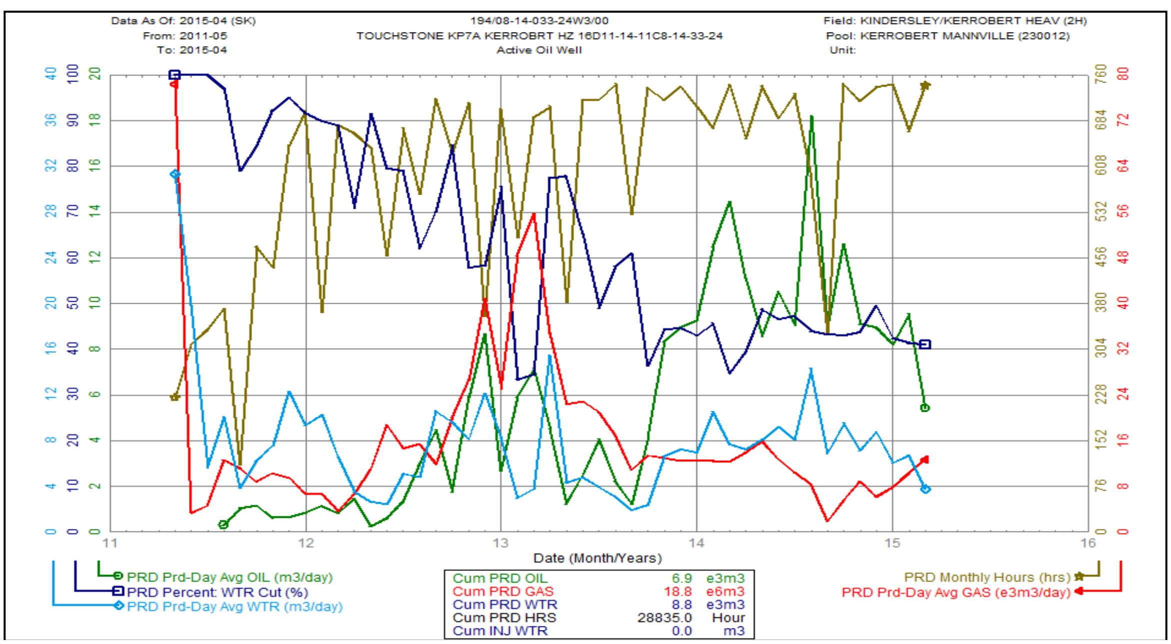

Figure G7-KP7c: The variation of the oil and water production, water cut and gas produced
for well KP7. The well is responding to the air injection in both KA7 and KA4 (starting in February 2012). GeoSCOUT data

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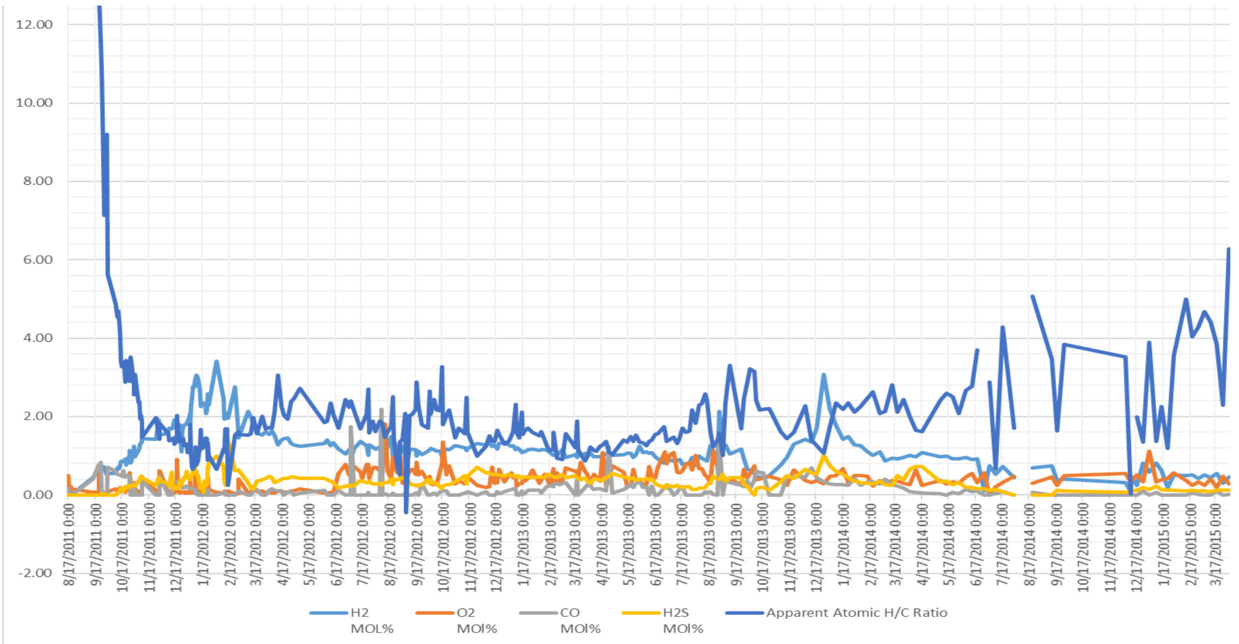

Fig G7-KP8a: Horizontal producer KP8. Variation of the gas composition and of the H/C ratio

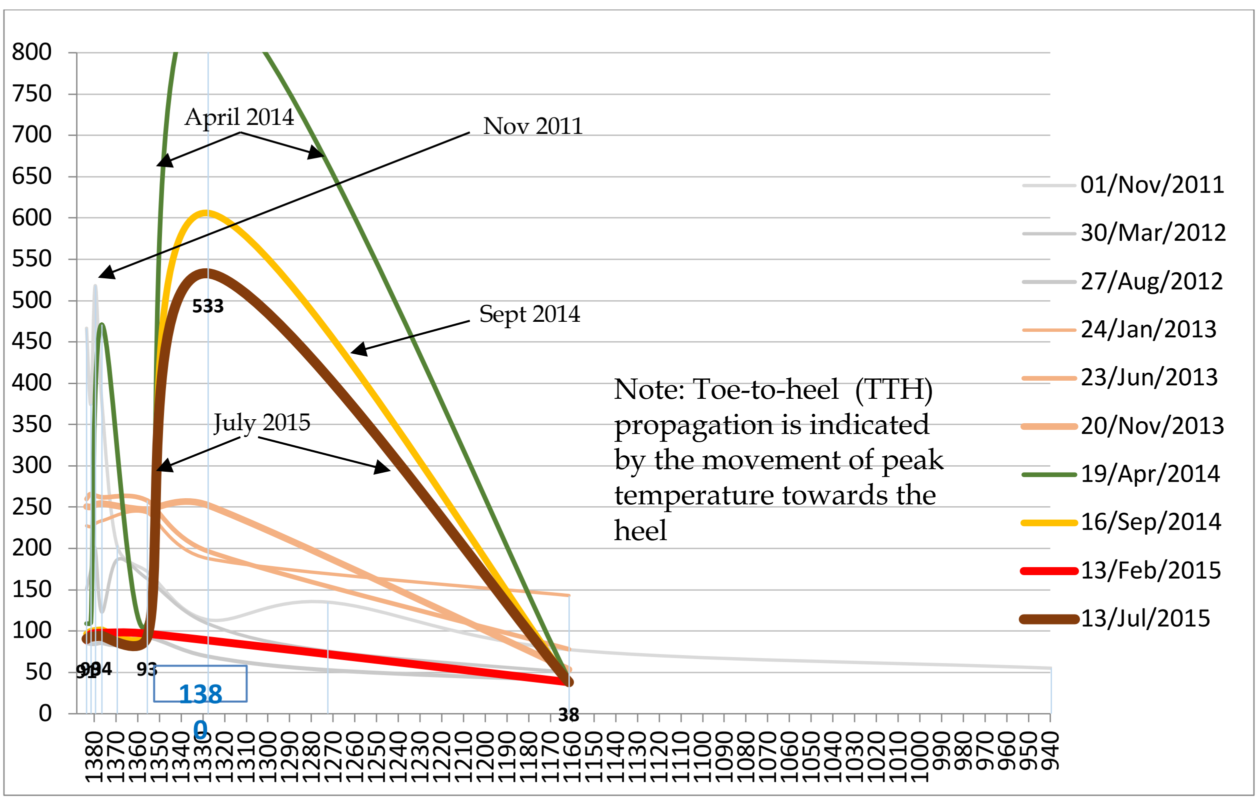

Fig G7-KP8b: Horizontal producer KP8. Variation of temperature along the horizontal section from toe to heel in the period of November 2011-July 2015. Toe at 1380 m measured distance (MD) and heel at 940 m MD

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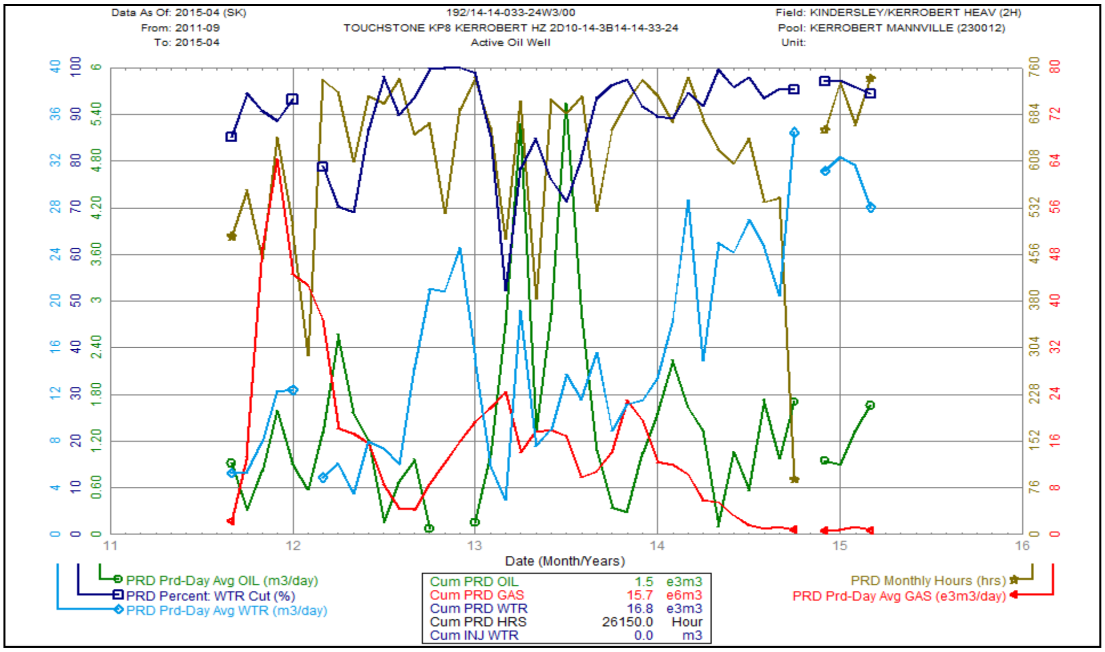

Figure G7-KP8c: The variation of the oil and water production, water cut and gas produced for well KP8. GeoSCOUT data

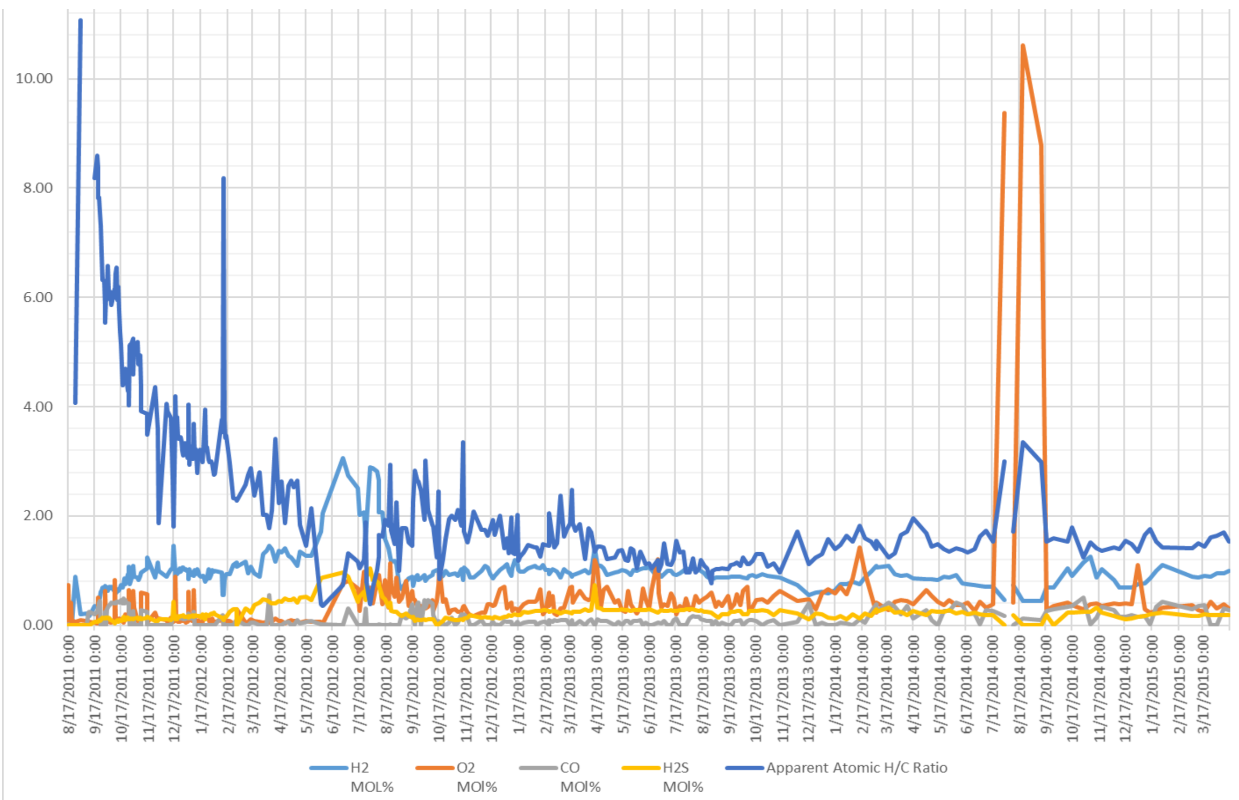

Fig G7-KP9a: Horizontal producer KP9. Variation of the gas composition and of the H/C ratio

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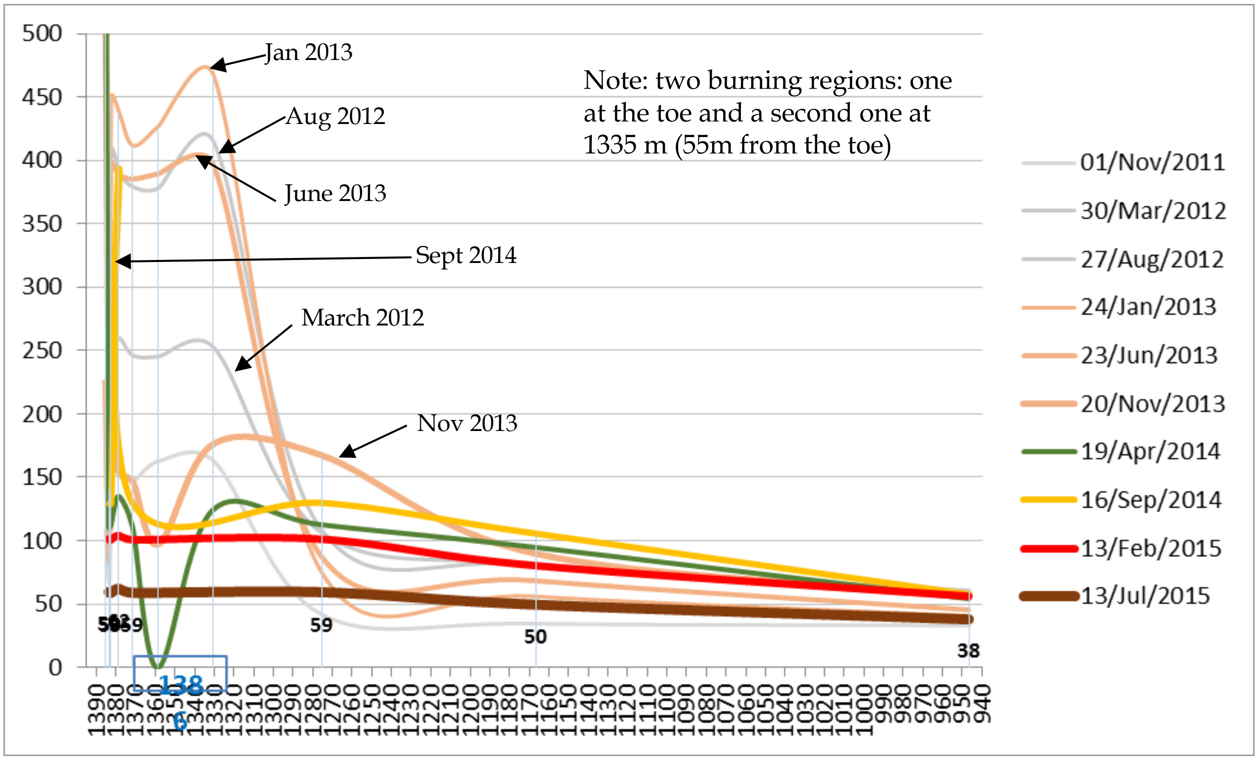

Fig G7-KP9b: Horizontal producer KP9. Variation of temperature along the horizontal section from toe to heel in the period of November 2011-July 2015. Toe at 1390m measured distance (MD) and heel at 940m MD

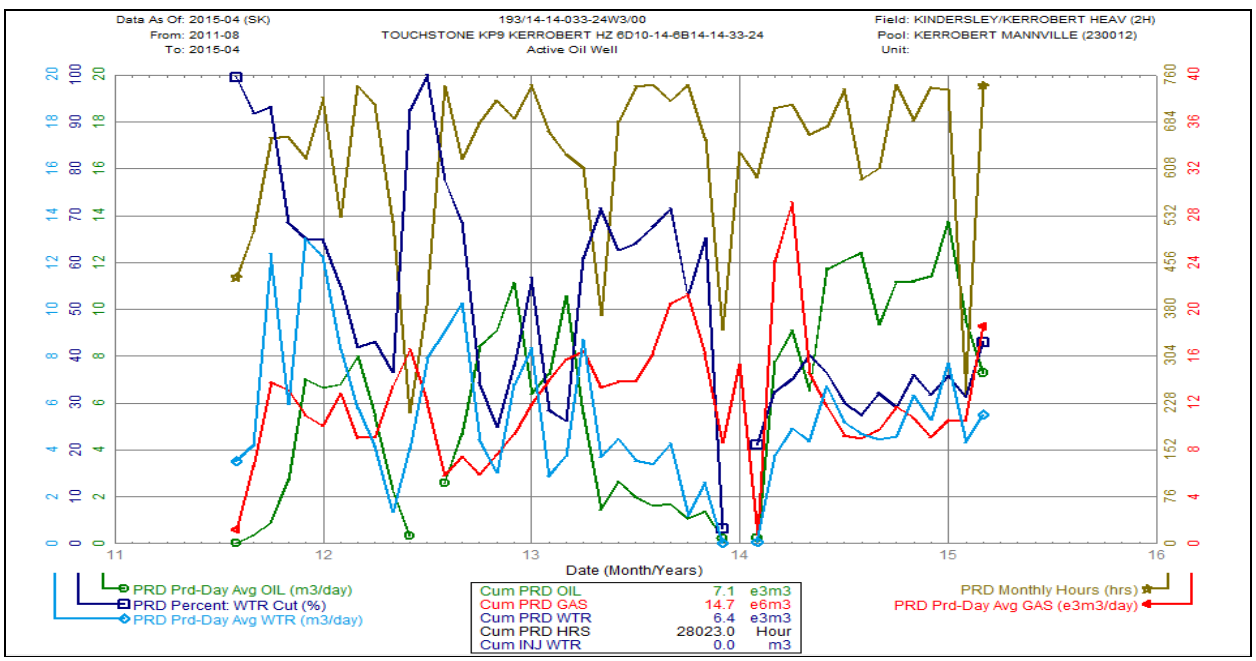

Figure G7-KP9c: The variation of the oil and water production, water cut and gas produced for well KP9. The well is responding to the air injection in both KA9 and KA12 (starting in 2013). GeoSCOUT data

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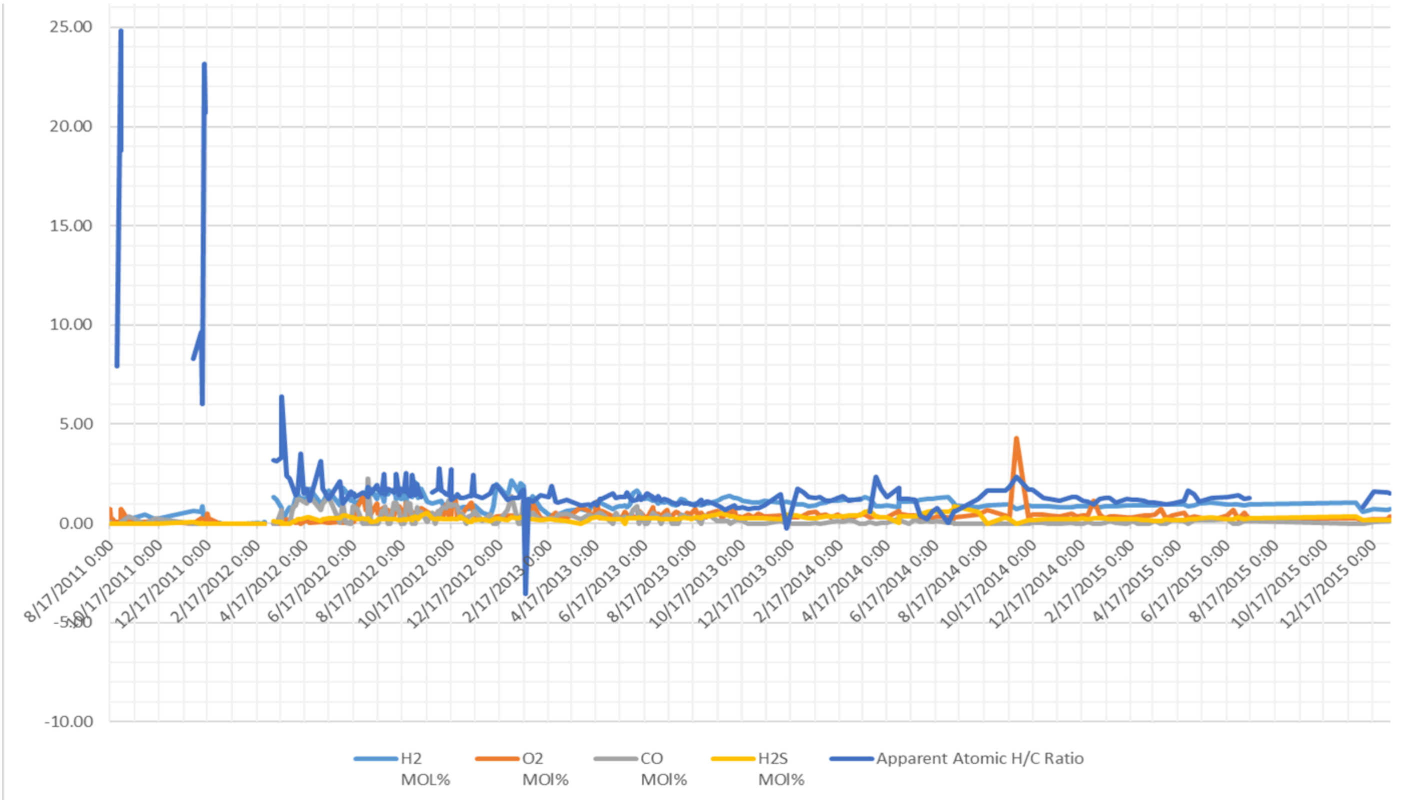

Fig G7-KP10a: Horizontal producer KP10. Variation of the gas composition and of the H/C ratio

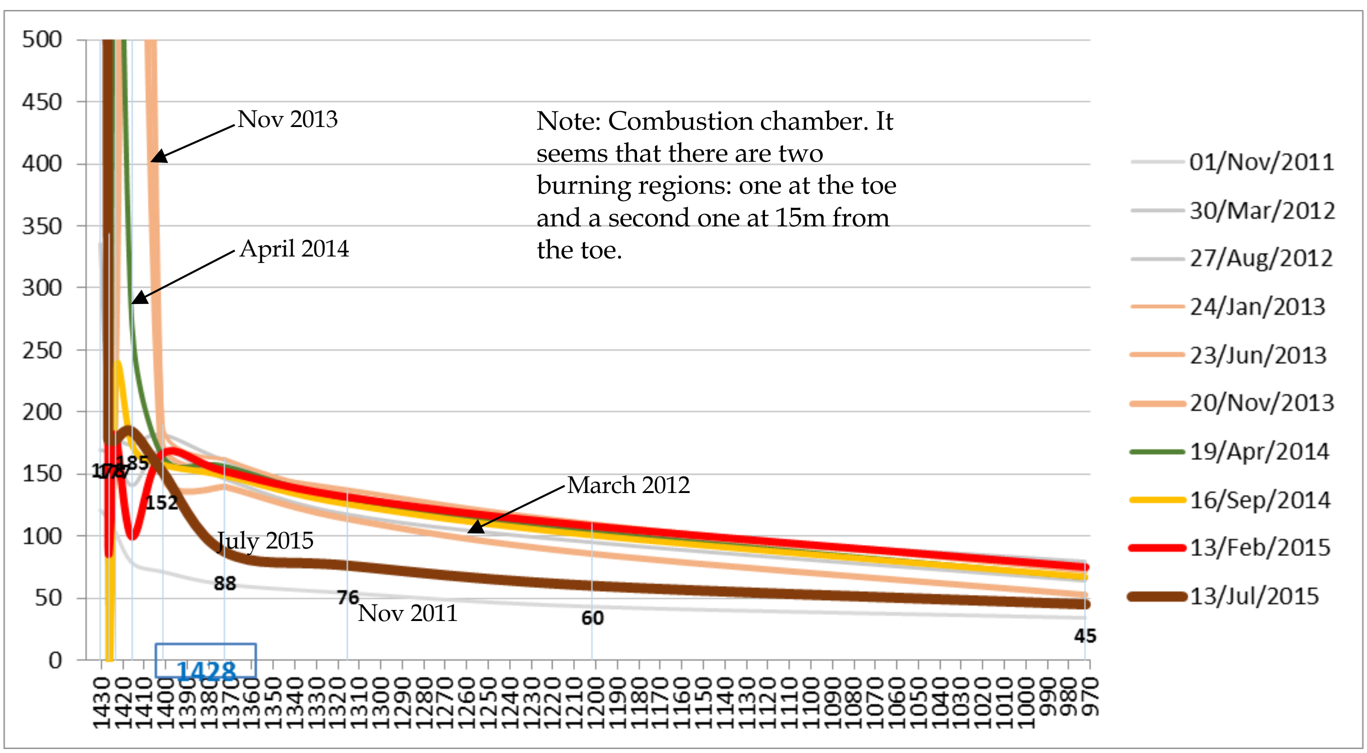

Fig G7-KP10b: Horizontal producer KP10. Variation of temperature along the horizontal section from toe to heel in the period of November 2011-July 2015. Toe at 1430m measured distance (MD) and Heel at 970m MD

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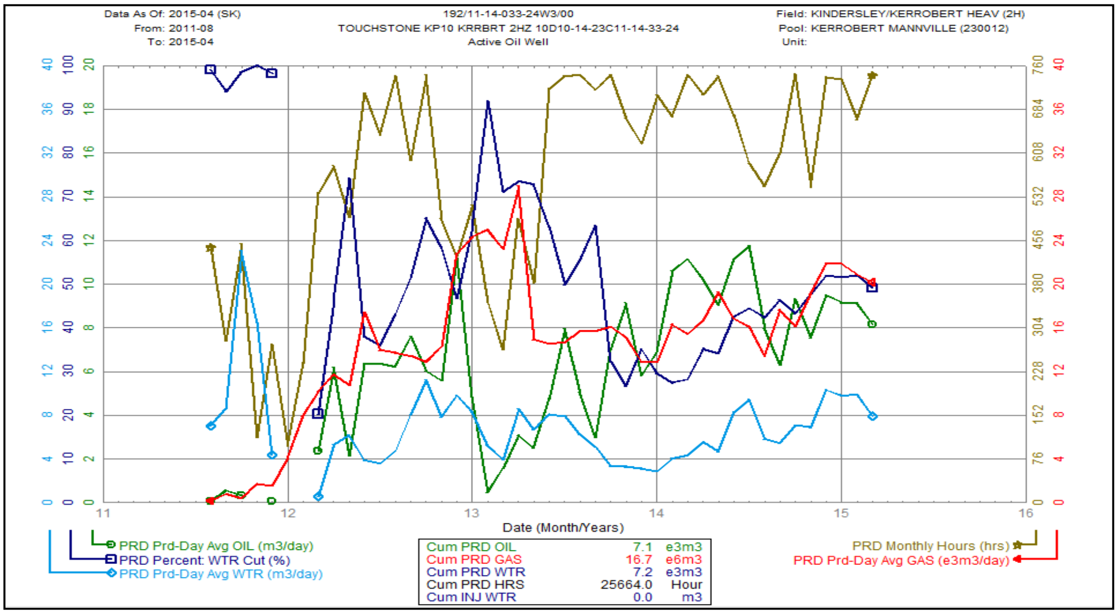

Figure G7-KP10c: The variation of the oil and water production, water cut and gas produced for well KP10. GeoSCOUT data

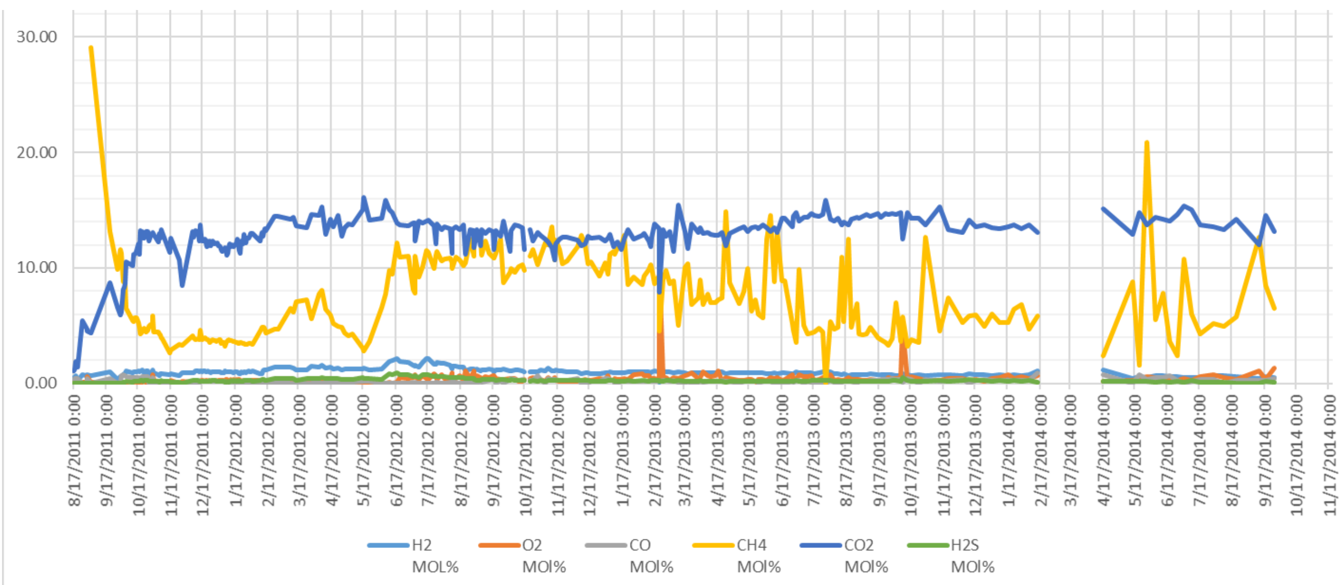

Fig G7-KP11a1: Horizontal producer KP11. Classical representation of the variation of the gas composition (with CO_2 and CH_4 percentages represented)

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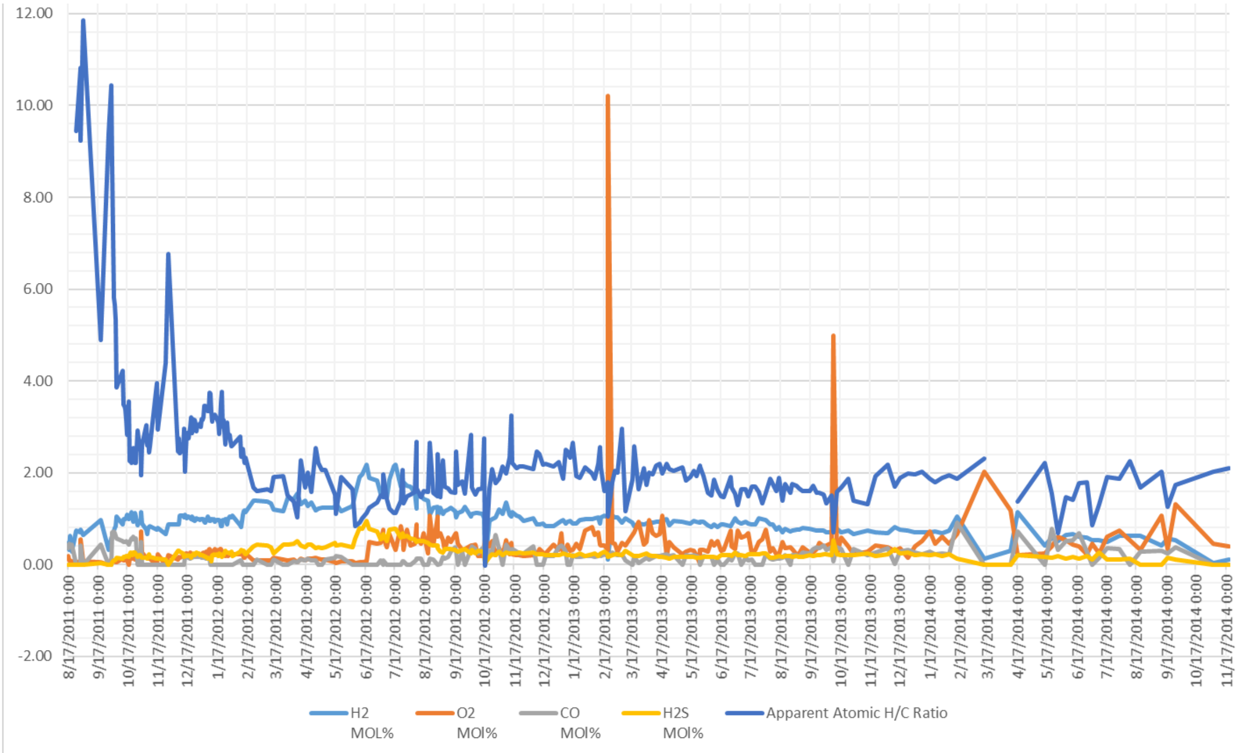

Fig G7-KP11a2: Horizontal producer KP11. Variation of the gas composition (without CO_2 and CH_4) and of the H/C ratio

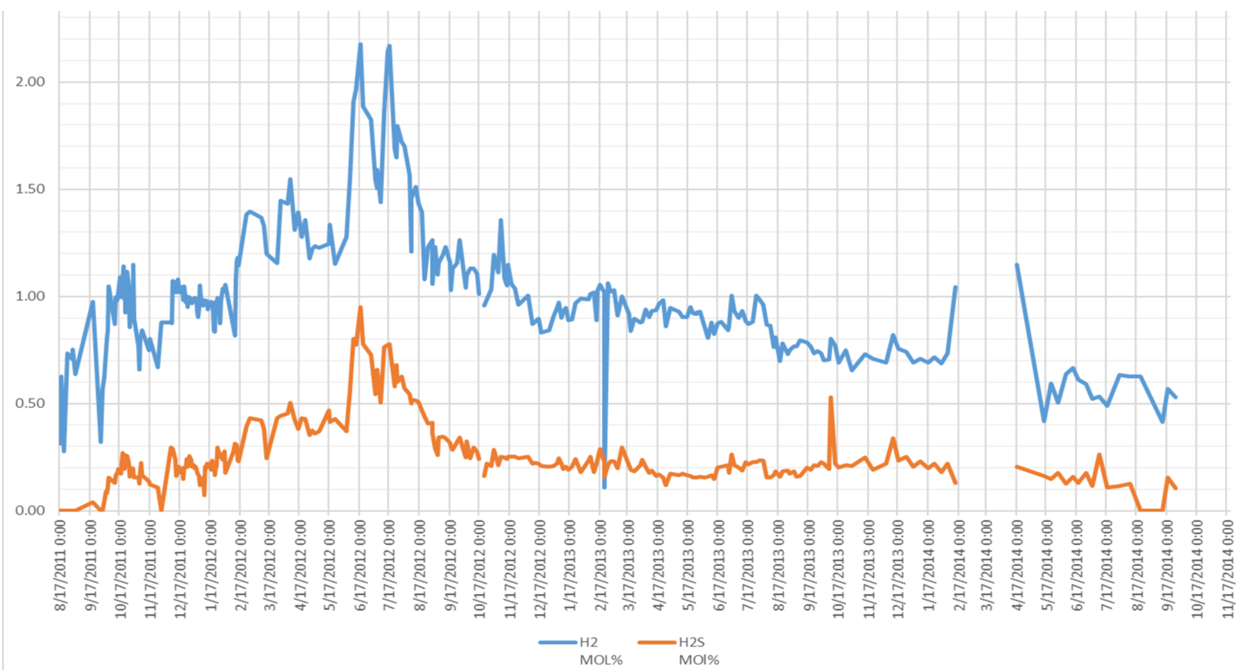

Fig G7-KP11-a3: Horizontal producer KP11. Variation of the hydrogen and H_2S content of the produced gases showing a very tight correlation between the generation of these two gases

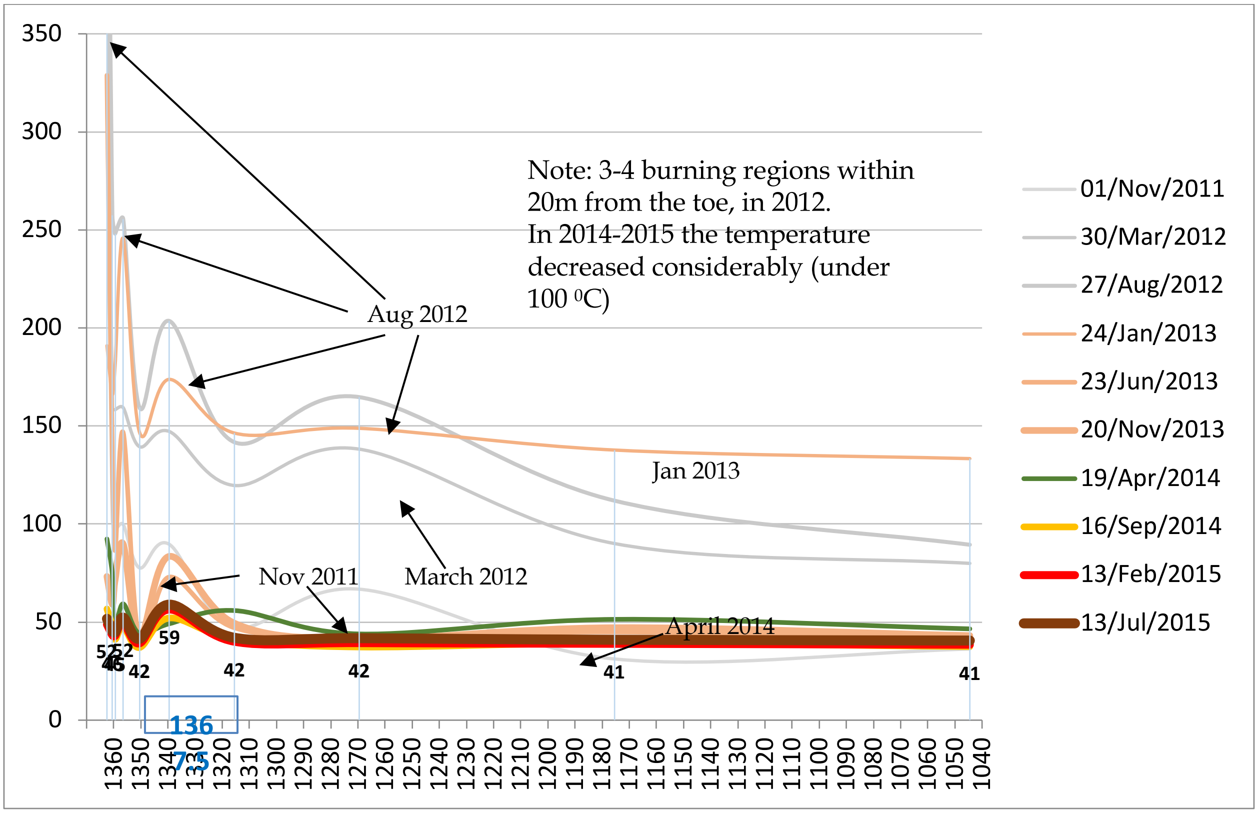

Fig G7-KP11b: Horizontal producer KP11. Variation of temperature along the horizontal section from toe to heel in the period of November 2011-July 2015. Toe at 1360 m MD and heel at 1040m MD.

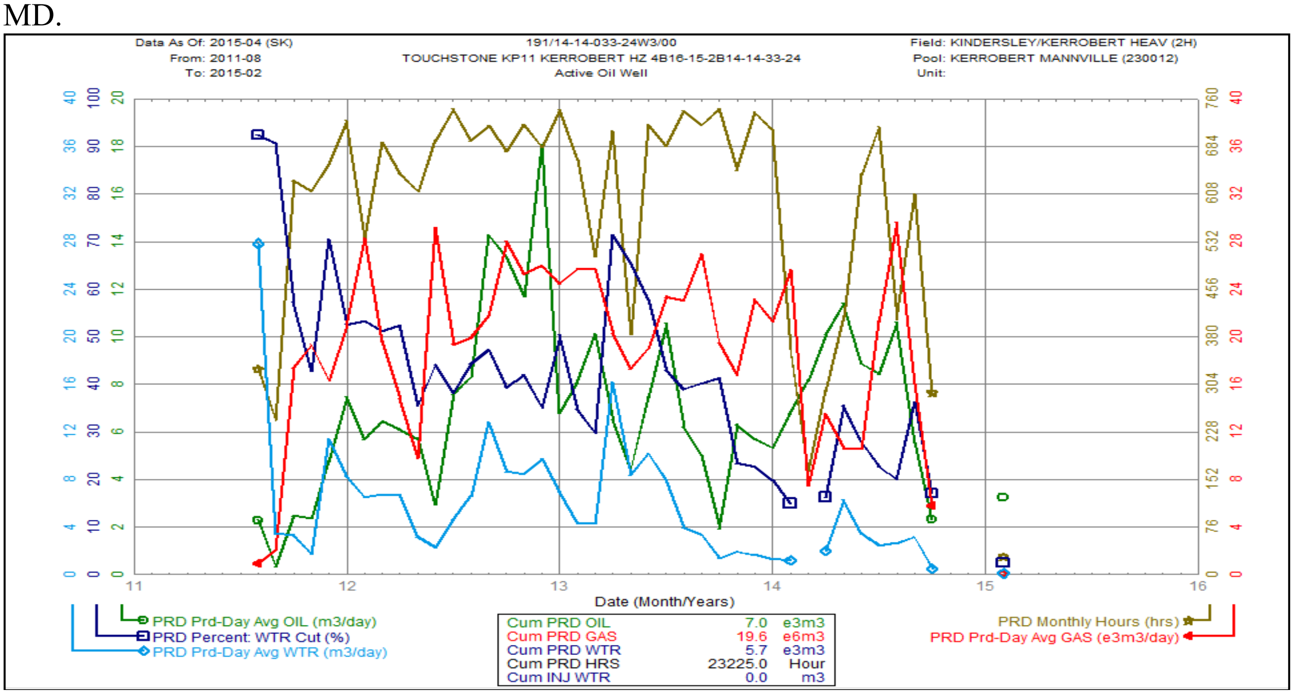

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Figure G7-KP11c: The variation of the oil and water production, water cut and gas produced for well KP11. GeoSCOUT data

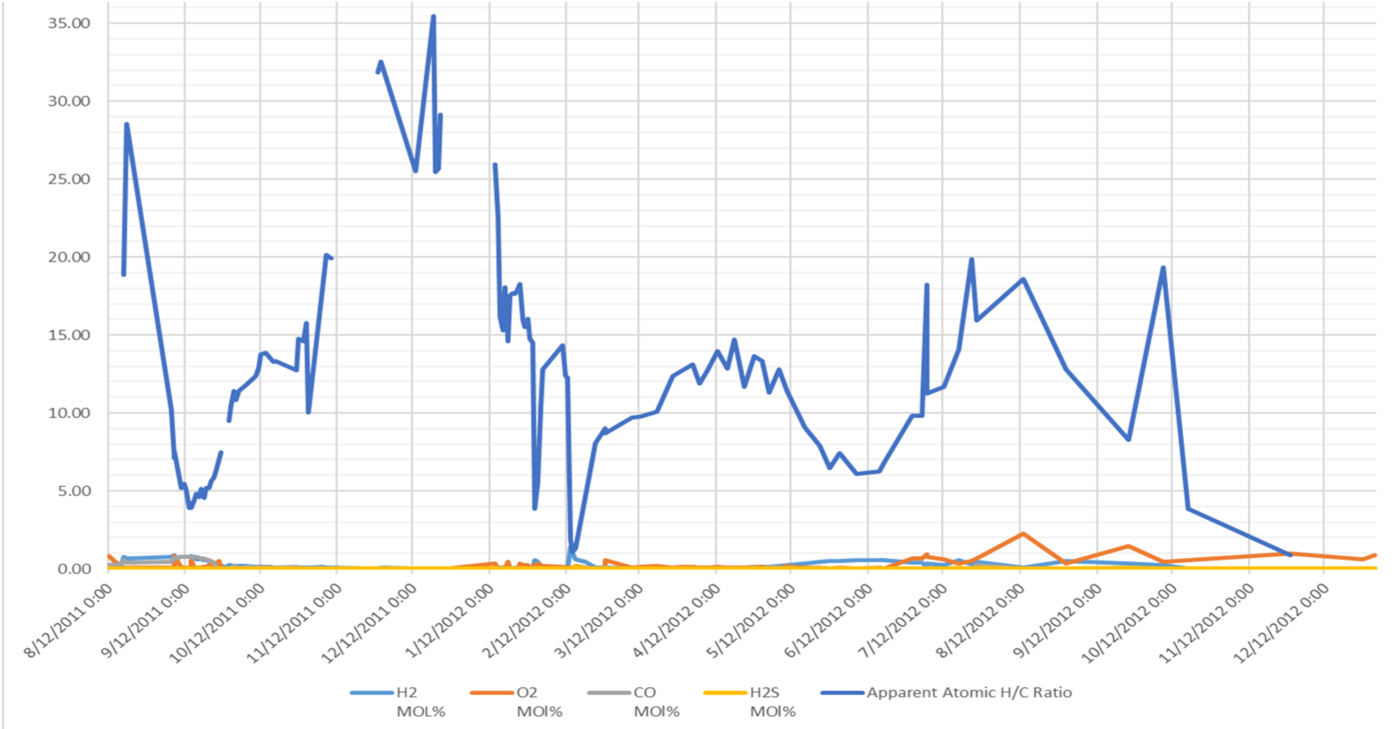

Fig G7-KP12a: Horizontal producer KP12. Variation of the gas composition and of the H/C ratio

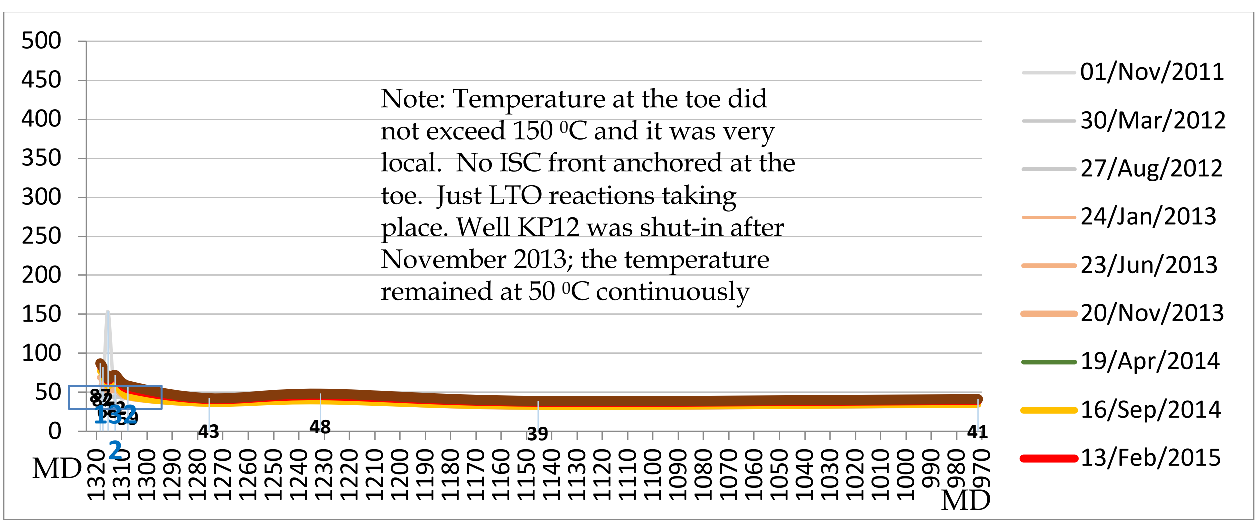

Fig G7-KP12b: Horizontal producer KP12. Variation of temperature along the horizontal section from toe to heel in the period of November 2011-July 2015. Toe at 1320m, measured distance/measured depth (MD) and heel at 970m MD

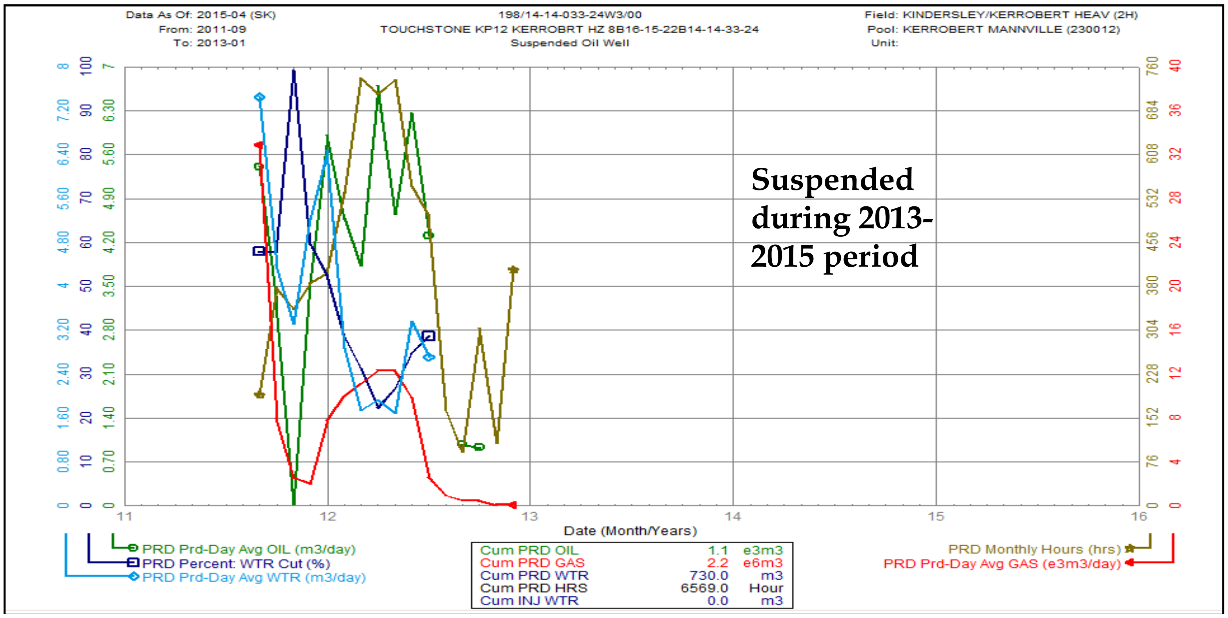

Figure G7-KP12c: The variation of the oil and water production, water cut and gas produced for well KP12. GeoSCOUT data

In Figures G7-KP1b to G7-KP12b the detailed variation of the temperature along the horizontal section of the horizontal producers – as per July 2015/or January 2016 - are shown; unfortunately, for KP1 and KP2 producers, the temperature information for the period 2009-2011 is not available; for these wells, the variation in time was represented (as the variation along the horizontal well is provided in subchapter 7.4. i.e. in the THAI Pilot analysis section). The correlation of the bottom hole temperatures (BHT) profiles with the gas composition and oil/water/gas production performance is very important as it can explain how the oil production and BHT are correlated and in what conditions the oil production and the control of the process are better.

The analysis of the temperature graphs in this appendix allow us to conclude the following:

- The first increase of temperature occurred at the toe of production wells in all cases.
- The analysis has to account for the fact that patterns K1 and K11 are totally confined, while pairs of patterns K4-K7 and K9-K12/K10-K12 are operated together as the air injection in KA4 contributed to KP7 production and the air injection in KA12 contributed to KP9 and KP10 production. KP7, KP9 and KP10 are in a slight staggered line drive (SLD) relation with the above mentioned air injection wells.
- The in-depth analysis of temperature variation profiles (both in time and along the horizontal section) allowed us to consolidate the estimated values of the ignition time (t_{ign}); the maximum possible value of t_{ign} was in this way determined. The values of t_{ign} from Table 12 account for the information presented here. Also, the absence of an ISC front in K4 and K12 patterns was confirmed.

- After anchoring of the ISC front at the toe, two ways of development of the process occurs: 1) either a propagation of the ISC front along the horizontal section or 2) practically a stalling of the ISC front with the formation of a "combustion chamber" at the toe. A combustion chamber is defined in the situation when the length of propagation along the horizontal section is comparable to the average gross thickness of the oil layer, which is around 24m
- An almost normal propagation of the ISC front happened in the case of pairs K1, K2 and K11. In these cases, the ISC front propagated some 50-200m. The best propagation of the front, from toe to heel, occurred for well K11.
- Combustion chambers, with a burned distance (along horizontal section) of 12-20m was generated within the pairs K3, K5, K6, K7 and K10. In the absence of any observation wells it is almost impossible to make an exact determination of the spatial configuration the combustion chamber (ie. to indicate if it is formed towards the top of formation, to the oil/water (O/W) interface, or split in two in those two regions). However, the fact that a pronounced water cut increase happens at the increase of air injection rate shows that the location may not be confined towards the top of formation. Such a situation was recorded for pairs K3, K5 and K6. It is very possible that the combustion chamber development should be related to the massive flow of steam and air at the O/W interface. Pair K6 is typical for this situation, as the H/C ratio also tends to point towards this interpretation; producers of KP5 and KP6 displayed a very high temperature (200-250 ^{0}C) all along the horizontal section by June 2013
- Pair K9 had a unique performance displaying two burning regions, one close to the toe and another one 45m away from the toe. The second one is related directly to the air injection in well KA12 (while production well KP12 was closed); it is difficult to put this pair in one of the above two categories. To some extent, a similar situation has the well KP7 (being influenced by KA4 injector), but it seems less clear.

Appendix H:

Note 1: This paper was presented at PETROTECH; 13th International Oil and Gas Conference and Exhibition, 10-12 February 2019, Greater Noida, Delhi, India

Note 2: The captures of the Figures (Plates) are as in original paper

ID: A-1582

Integration of Toe Up Horizontal wells with In Situ Combustion Process

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Abstract

This paper illustrates the successful application of the toe up horizontal wells to improve the process performance and oil recovery in heavy oil field of Balol. The field is under commercial application of In Situ Combustion (ISC) process since 1997. Balol field is a heavy oil reservoir having significant amount of oil in place. The field is on production since 1985. The oil is viscous in nature having API gravity of 15.5° and viscosity in the range of 150 cP to 1000 cP. The pay thickness varies in the range of 6 to 22 m. Both the viscosity and pay thickness increases from southern to northern parts of the field. The main pay is Kalol sand which is unconsolidated in nature and occurs at a depth of about 1000 m. The dip of the pay sand is in the range of 3°-7°. Due to adverse mobility ratio, the envisaged primary recovery from the field is 13 % of OIIP.

In order to improve oil recovery from the field, ISC process is under commercial application since 1997. Depending upon the pay thicknesses and viscosity of oil, different blocks responded differently to the air injection. The process is successful in southern part of Balol field having moderate viscosity (150-600 cP) and pay thickness (~6-8 m). Oil recovery from this part is more than 50 % of OIIP. In the northern part which has high viscosity (800 -1000 cP), large pay thickness (~ 20-22 m) and consequently high oil in place, the process performance in terms of combustion efficiency is very good but in terms of oil recovery is poor. The oil recovery from this block is 7 % of OIIP.

Conventional produced gas, oil & water analysis and produced gas quantity indicated very good combustion efficiency but did not help much in understanding the reasons for poor displacement of oil. To understand the reasons conventional coring along with Side Wall Cores (SWC) were carried out in replacement/new air injectors. The core data indicated that in thick pays the burning is taking place only in top few meters indicating poor vertical sweep efficiency. In moderate pay thickness area the cores indicated that 80 % of pay is taking part in the burning.

To improve the process performance, efforts were made to reduce injectors to producers distance from 300 m to 200 m through infill drilling but there was no improvement in displacement efficiency. As a result, air injection was totally suspended for three years. In mean time, to improve the performance of these blocks a new combination by use of conventional air injectors and toe up horizontals wells was studied and implemented in the field. In this configuration, horizontal wells were drilled against the dip & the toe of the drain hole was placed much closer to the air injectors. Detailed geological correlation & maps were prepared & the drain holes were placed perfectly by Geo steering. The drain hole length is in the range of 215 to 230 m with 95° to 97° angle. In thick pay reservoirs burning occurs in top few meters and conventional wells are not able to capture the displaced oil. In such cases any increase in air injection rate resulted into the early flue gas breakthrough and subsequent loss in oil production. The reduction in spacing through conventional wells is also not able to capture the displaced oil in thick reservoirs. Placement of the drain hole close to the air injectors & against the dip had proved an effective way for capturing the displaced oil as it has shortened the distance for mobilized oil to reach producer. It has also helped in avoiding early gas breakthrough as the heel is away from the air injection point. This is a gravity stable configuration resulting into improved reservoir sweep and capture efficiencies.

The integration of the horizontal wells with the ISC process in the underperforming blocks has yielded very good result. The production from these blocks have been increased two to three fold. The average productivity of the wells in these blocks are in the range of 2 to 4 tpd/well whereas horizontal wells are producing with an average of 15 tpd/well.

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Introduction

The Cambay basin of western India is a rich hydrocarbon bearing province. This basin is subdivided into various blocks. The Ahmedabad-Mehsana block of this basin is having both heavy & light oil fields. Lanwa, Bechraji, Balol & Santhal are the major heavy oil fields of Mehsana Asset (Plate-1). The primary recovery of these heavy oil fields is low in the range of 6 %-17 % of OIIP due to viscous nature of oil. Based upon the laboratory investigations at IRS, Ahmedabad, Thermal In-Situ Combustion process (ISC) was found encouraging for enhancing the oil recoveries of these fields to the level of 40% of OIIP.

Balol field is part of heavy oil belt of Mehsana Asset. It was discovered in 1972 and put on stream in 1985. Kalol formation of the Eocene age is the hydrocarbon bearing formation. The average depth of pay sands is around 1000 m & dipping 3° to 7° E. The layers abut at horst in west direction and supported with active edge water with common OWC from east direction. The pay sands are unconsolidated in nature and having very good porosity and permeability (28-30% and 5-8 Darcy respectively). The reservoir is hydrostatic. The API gravity of the oil is about 15.5° and viscosity of the oil at reservoir temperature (70°C) increases from south to north from 150 to 1000 cP. Pay thickness increases from south to north from 6 to 22 m respectively. The field is divided into different fault blocks by NNW-SSE curvilinear faults (Plate-2).

ISC process was initiated on pilot scale in March'1990 in Balol field with an objectives to test the efficacy of the process & get the operational experience. Based upon the success of the pilot, the process was implemented on commercial scale since 1997 using updip line drive strategy in which injectors have been placed in the structurally up dip area & displaced oil is captured through down dip producers.

Balol Field Performance

Balol field was put on production in 1985. Due to adverse mobility ratio water cut of the field increased very sharply with decrease in oil production. The envisaged primary recovery from the field was 13 % of OIIP. Laboratory studies were carried out to find out a suitable EOR method to enhance the recovery during 1978 to 1983 at IRS, Ahmedabad and found ISC process is suitable for field implementation. The process was tested on pilot scale in inverted 5-spot pattern of 150 m x 150 m well spacing during March'1990 to May'1997. The performance of the pilot was very encouraging in terms of sustained combustion, increased oil production at low Air-Oil Ratio and reduction in water cut.

With the application of this process, oil production from Balol field increased from about 300 tpd in 1997 to 700 tpd in 2003 with corresponding reduction in average field water cut from 80 % to about 55 %. Further, updip air injection was also very effective in arresting edge water movement from aquifer. Plate – 3 indicates the improved production performance of EOR affected well and Plate – 4 indicates the overall performance of the field.

Journey of the field with the process is quite exciting in terms of the success of the process in southern blocks & moderate to poor in northern blocks. Recovery is more than 50 % of OIIP in the southern part of the field which has moderated pay thickness (~6-8 m) and viscosities (50-400 cP) (Plate- 5).In the northern part of the field which has large pay thickness (~20-22 m) and higher oil viscosities (800-1000 cP), process performance was not encouraging in terms of oil recovery (7 % of OIIP) (Plate-6). Further, wells which showed any improvement in production were immediately affected by early breakthrough of hot oil and subsequent rise in GLR due to gravity override of the produced gases.

Conventional produced gas, oil & water analysis indicated very good combustion efficiency but did not help much in understanding the reasons for poor displacement of oil.

To get insight into the subsurface occurrences, Side Wall Core (SWC) & conventional coring were carried out in the burnt zone. The core data indicated that only 6 m out of 20 m pay is taking part in combustion and major part of pay is unaffected by the process (Plate-7). Similar SWC analysis in the southern part well having moderate pay thickness (~6-8 m) indicated that the 80 % of the pay participated in active burning indicating good vertical sweep (Plate-8).

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Development of Toe Up Horizontal well concept in ISC area

Efforts were made to improve the process performance in northern blocks through reduction in injectors to producers distance from 300 m to 200 m through infill drilling but there was no improvement in production performance of the wells (Plate-9). The poor performance could be due to the resistance offered by viscous cold oil in between conventional air injectors and producers to the mobilized oil compounded by low vertical sweep. Subsequently air injection was suspended in northern blocks for three years.

The key to improve the performance of the process lied in reducing the travel distance between mobilized oil and the capture point. The innovative combination of toe up horizontal producer & vertical air injectors was thought of as possible step in this direction. This combination would capture the displaced oil at short distance and further mitigate gas override (Plate-10).

Integration of Toe UP Horizontal Wells with ISC

The first pair of toe up horizontal producer and two vertical air injectors have been drilled and completed in northern block of Balol field in October'16. It is an ISC affected area where air injection was suspended in September'13. In this configuration drain hole of horizontal well drilled against the dip & toe is kept around 50 m away from injectors in staggered manner.

As strata is eastward dipping, placement of the drain hole against the dip in a particular direction avoiding the collision with existing large density of drilled wells was very challenging. As the drain hole placed closed to bottom any variation in local dip might have resulted into entering into bottom or increases the dog leg severity. This would have created further complications in lowering GP screens for sand control. To overcome the challenges detailed geological correlation & maps for each formation/markers were prepared. With meticulous planning and proper geosteering, the drain hole was placed as per the design of the configuration. The drain hole length is 215 m having 95° angle.

The well was put on production in November'16 with simultaneous air injection in corresponding air injectors @10,000 Nm3/d/well. Initially the well started producing oil @ 30 tpd with 30 % water cut. The average productivity of the conventional wells in this block is in the range of 2 to 4 tpd/well. Based on the encouraging result, four additional horizontal wells have been drilled on the toe up horizontal producer and air injector configuration. The drain hole length of toe up horizontal wells is in the range of 215 to 230 m with 95° to 97° angle. The part structure contour map of pay sand indicating configurations of toe up horizontal well & vertical air injectors is depicted in Plate-11.

The overall performance of these horizontal wells are very encouraging and is indicated in Plate-12. The horizontal wells are producing with an average rate of 15 tpd/well. At present in northern block around 100000 Nm3/d air is being injected through 7 air injectors. The production from northern block has increased two to three fold (from ~30 tpd to ~90 tpd) (Plate-6).

Advantage of Toe Up Horizontal wells

Induction of this process in an ongoing ISC process is relatively easy as the air injection facilities are already available. Application of this process in already ISC affected area has got the added advantage of the presence of heated zone close to the air injectors.

Conclusions

1. In thick pay reservoirs burning occurs in top few meters and conventional wells are not able to capture the displaced oil. In such cases any increase in air injection rate results into the early flue gas breakthrough and subsequent loss in oil production.

2. In thick reservoirs, reduction in spacing through conventional wells is also not very effective in improving the process performance.

3. Placement of the drain hole close to the air injectors & against the dip has proved an effective way for capturing the displaced oil as it has shortened the distance for mobilized oil to reach the producer. This has also helped in avoiding early gas breakthrough.

4. This is a gravity stable configuration resulting into improved reservoir sweep and capture efficiencies.

Acknowledgments

The authors are thankful to ONGC Management for giving us opportunity to present this paper.

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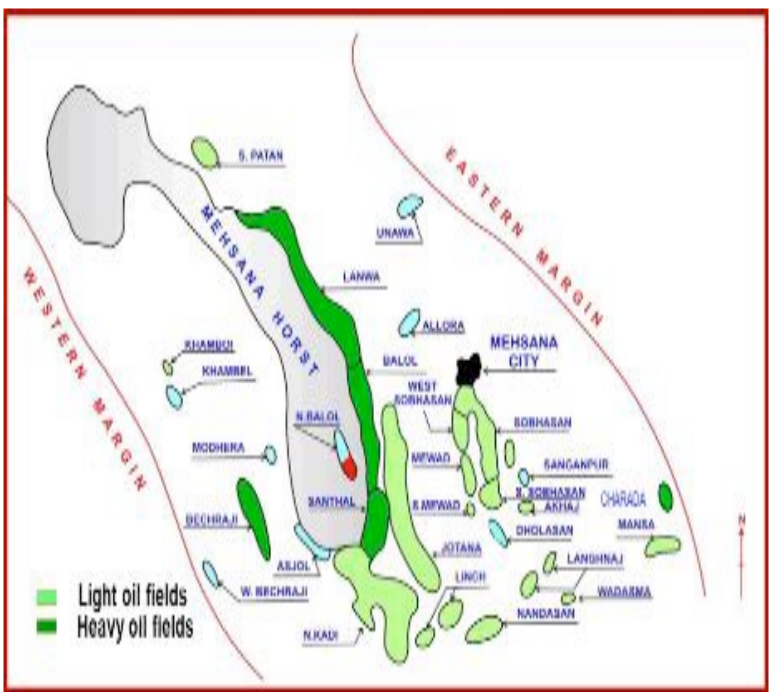

Plate-1: Fields of Mehsana Asset

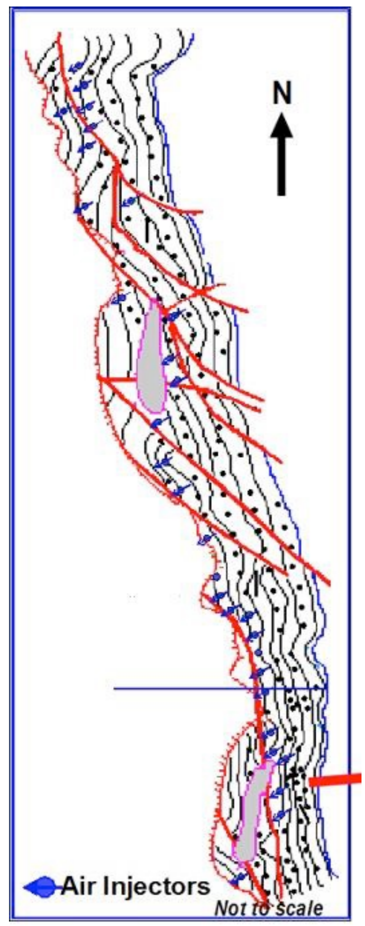

Plate 2: Structure Contour Map of Balol Field

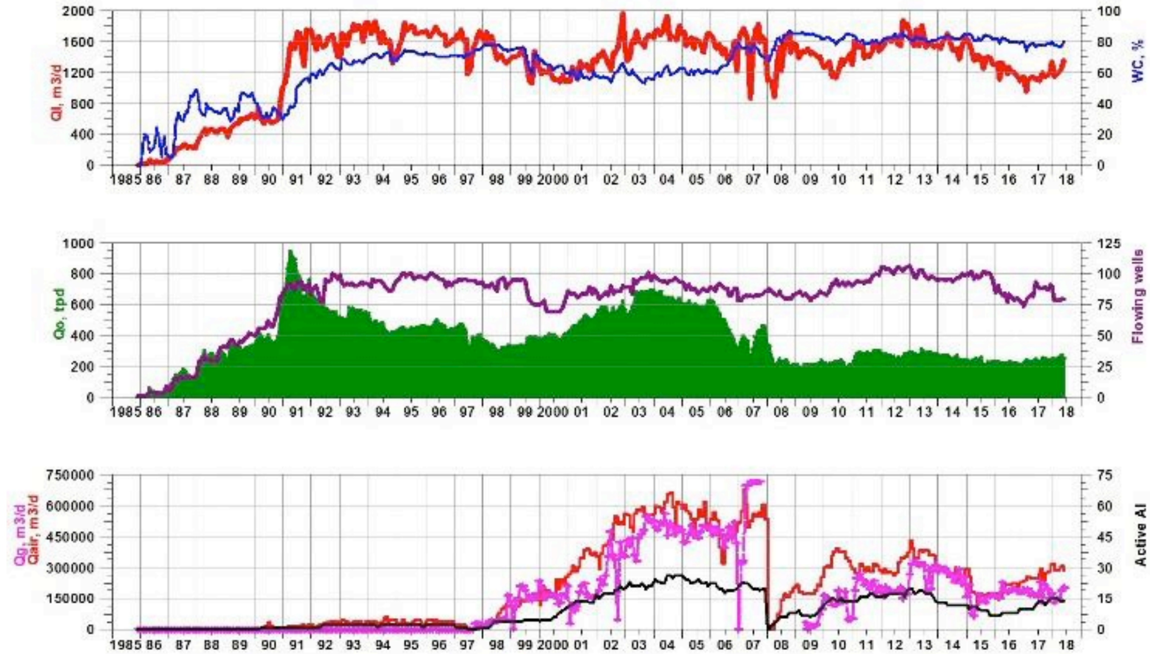

Plate-3: Effect of the ISC on well Performance

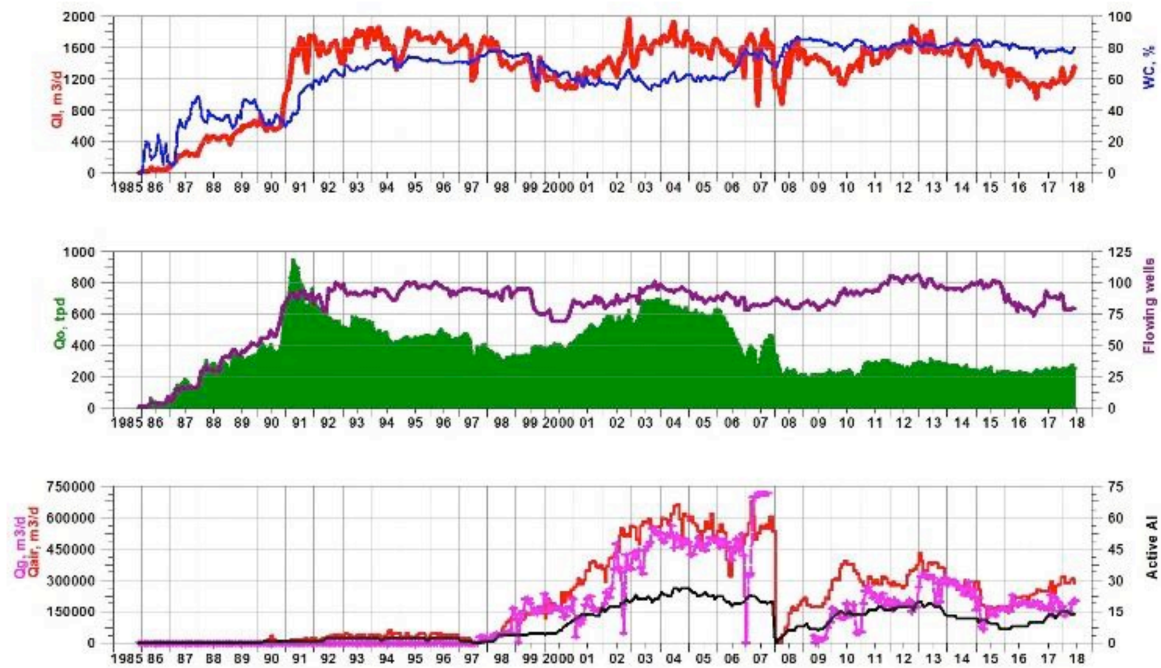

Plate-4: Production Performance of Balol Field

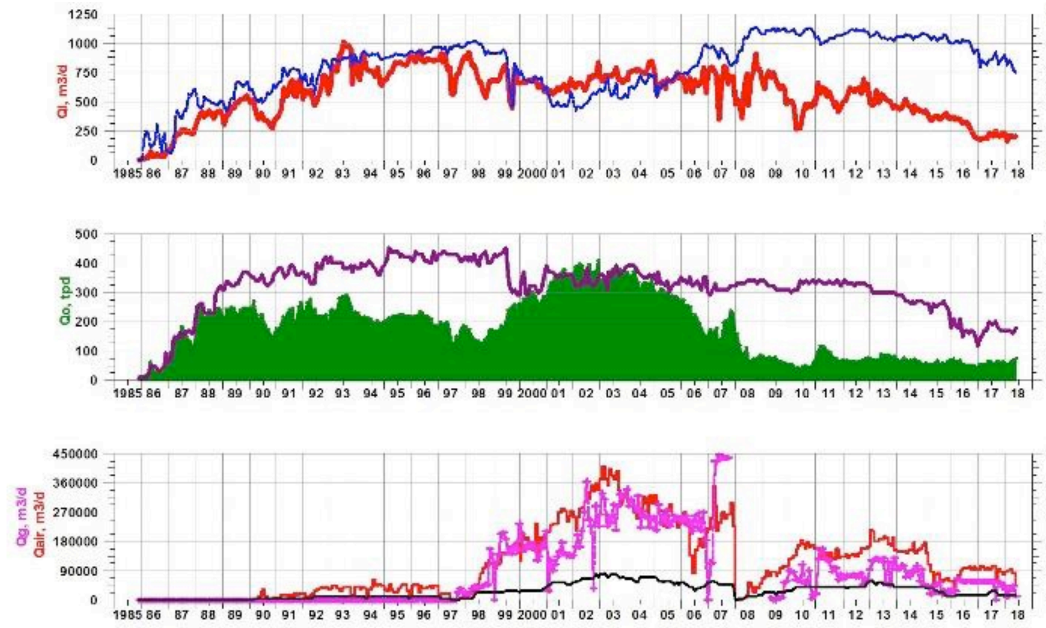

Plate-5: Production Performance of Southern Block

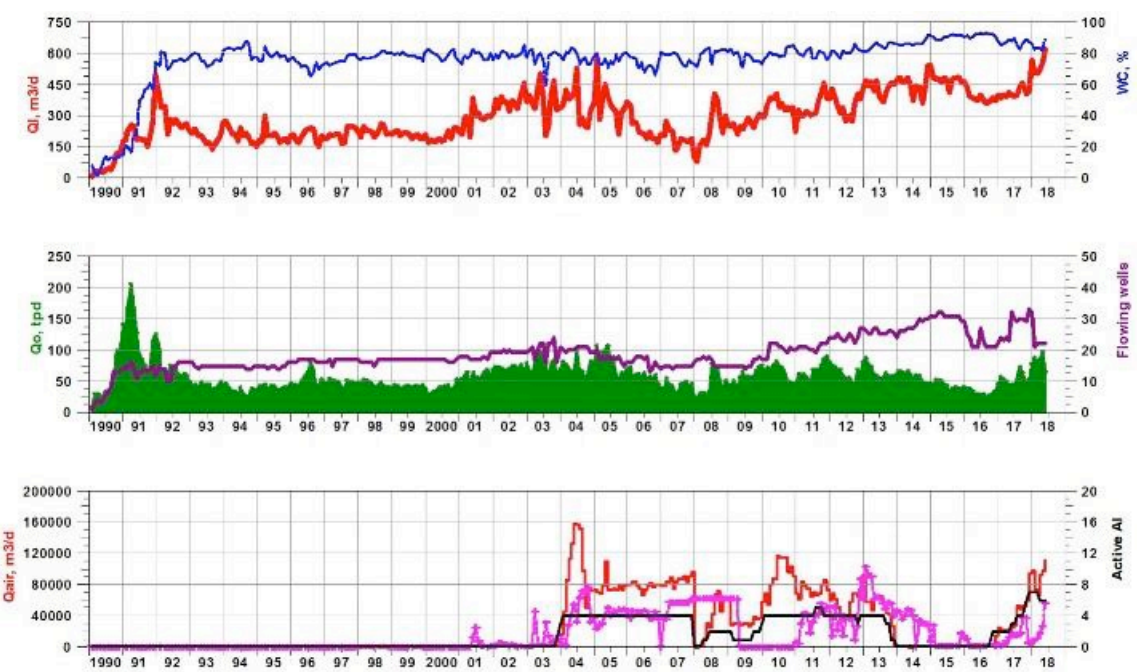

Plate-6: Production Performance of Northern Block

Plate 7: Conventional Cores of Air Injector from Northern Block showing Burnt & Unburnt Zone

Plate-8: Side Well Core (SWC) of Air I
Block showing Burnt & Unburnt Zone

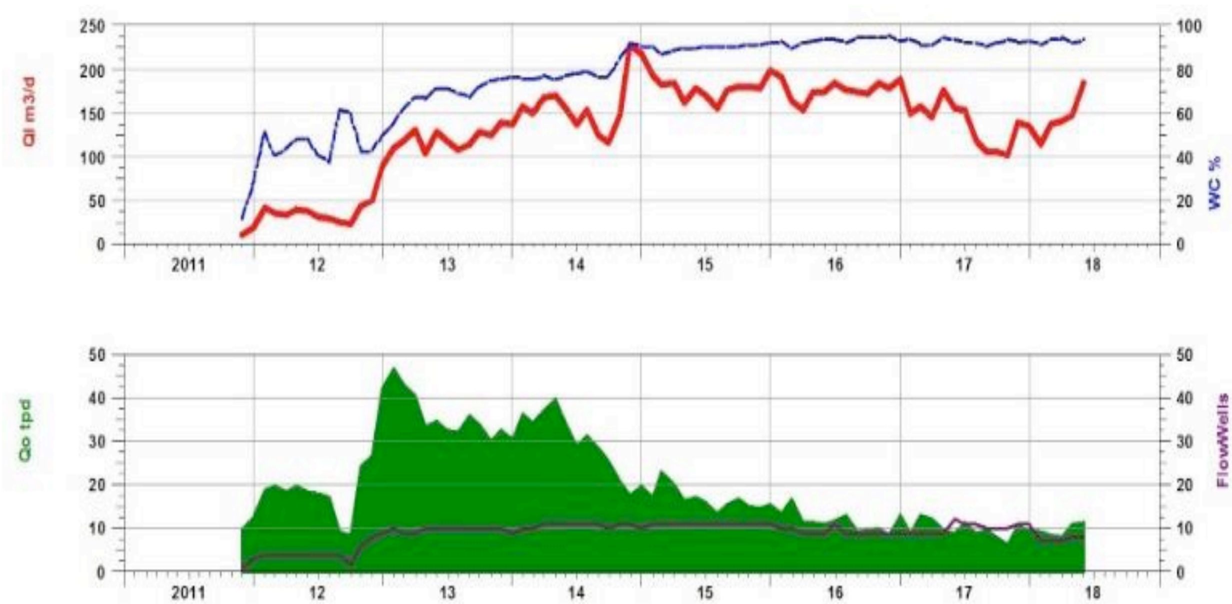

Plate-9: Performance of infill wells in Northern Block

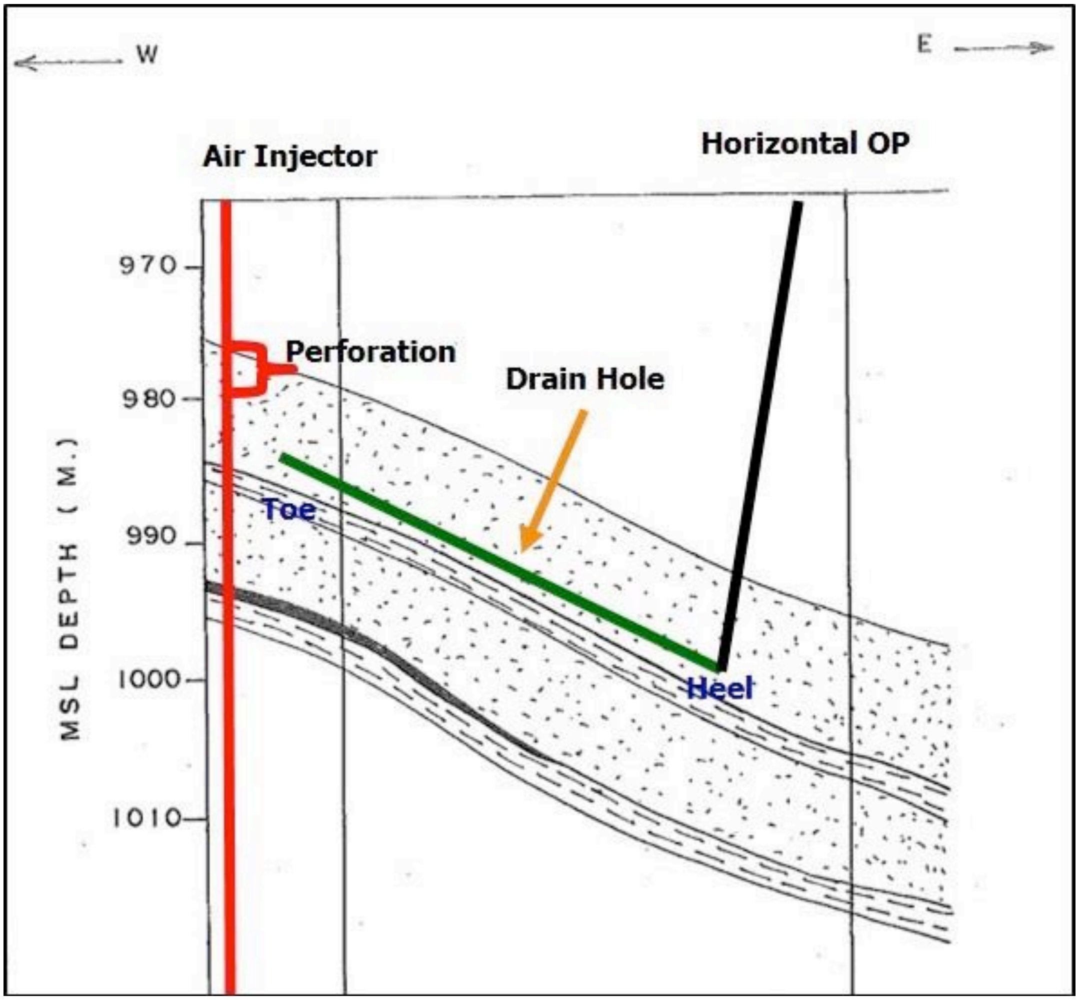

Plate-10: Schematic of THAI application in a Staggered Line Drive (SLD) configuration comprising of one toe-up horizontal producer and two vertical air injectors. (Note: only one vertical injector is shown in this E-W cross-section on the structure)

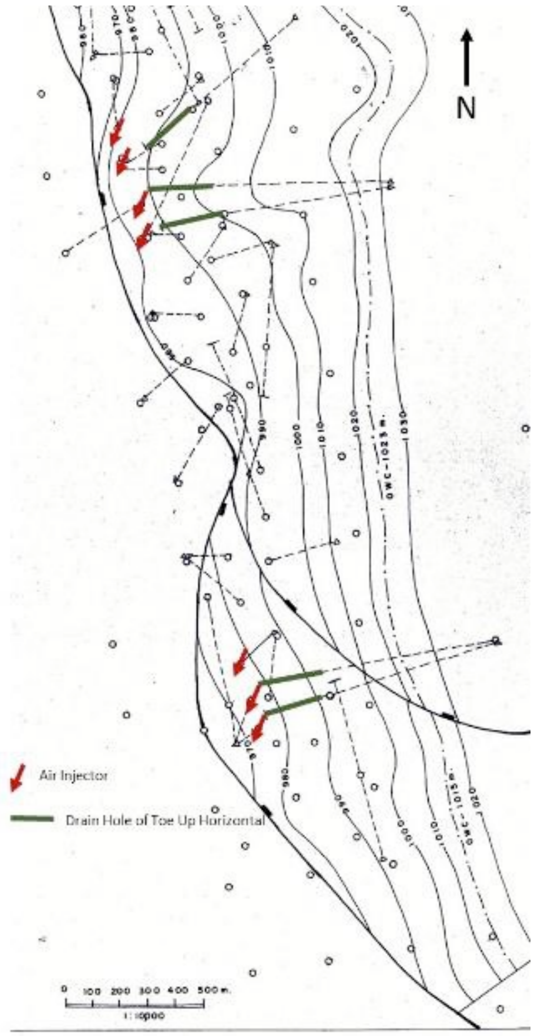

Plate-11: Part Structure contour map of Balol depicting the location and configuration of THAI patterns

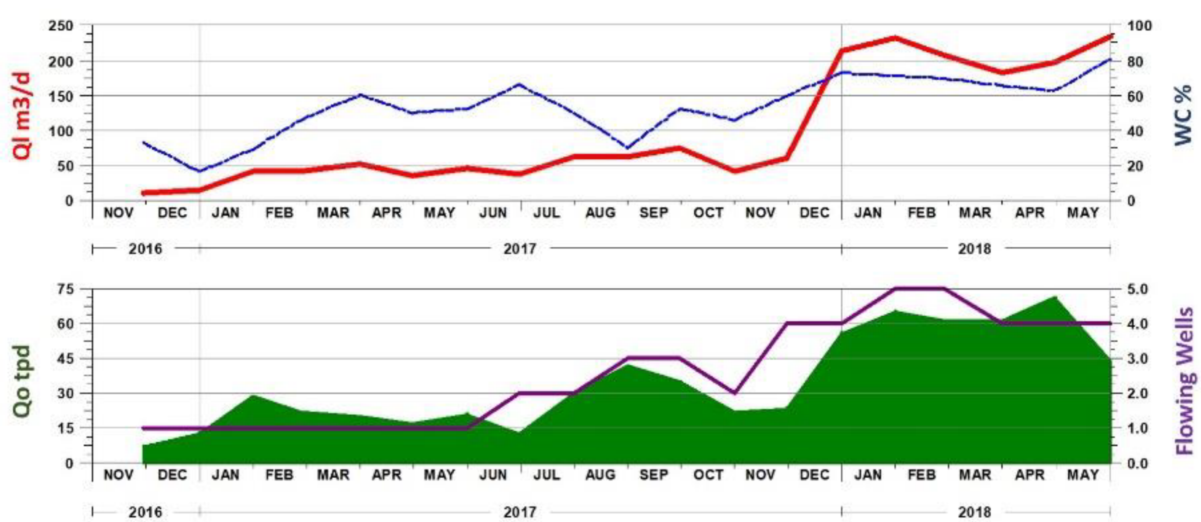

Plate-12: Production Performance of Toe Up Horizontal wells from the 5 THAI patterns

Summary of the Appendix I

Startup of the Toe-To-Heel Air Injection (THAI) Process with a Broad Linear ISC Front

Note: The appendix follows after the summary; the full appendix is available upon request only.

Summary of the Appendix:

The Appendix presents essential details on the procedures to generate a broad initial linear ISC front – a necessary prerequisite to ensuring successful, development of the Toe-To-Heel Air Injection (THAI) process

Two options are developed in detail in the Appendix:

(i) Use vertical wells for air injection, which is the classic system
(ii) Use horizontal wells for air injection, which can automatically form a broad combustion front.

The use of horizontal wells for air injection is not a common practice at this time, as specific techniques, equipment and procedures are needed in order to ensure the safety of the operation and the achievement of ignition along long intervals of a horizontal well; these technical means are not readily available.

For the first category (vertical wells for injection), the following solutions for three reservoir cases are presented:
Case A: The case of oil with some mobility, which permits the easy application of cyclic steam stimulation operations and steam drive.
Case B: Immobile or extremely low mobility oil with, a reservoir temperature (T_R) higher than 20-25 ^{0}C
Case C: Immobile or extremely low mobility oil, with T_R less than 20-25 ^{0}C

In almost all these cases normal **t**oe-**t**o-**h**eel (TTH) configurations are used; Case A is almost the routine operation one. For case B, two options are described:

B1: Curving the adjacent portion of the toe of the horizontal section of the horizontal producer(s) towards the shoe of the vertical well(s).
B2: A DLD configuration is used within the line of injectors, in order to create the linear combustion front. This is achieved by using alternatively, vertical injectors and short dual-opposed horizontal production wells, arranged in a direct line drive (DLD) TTH configuration. This arrangement requires additional short dual-opposed horizontal wells to be included in the injection row. Therefore, case B2 is slightly more complex than a classic TTH configuration. Case C is based on the application of reverse

ISC. However, all these cases refer to the operations within the first 2 rows; in the remaining of the rows, the THAI process is applied with normal TTH configuration and operation.

For the second category (horizontal wells for air injection), the following processes (and their corresponding configurations) are presented:
Version 1: **D**ual **o**pposed **h**orizontal **w**ell injectors (in the first row) arranged in a staggered line drive (SLD) configuration
Version 2: Horizontal wells (injection and production wells) in a repeated “L” configuration
Version 3: SAGD-type pairs (injection and production wells) arranged in “cross” lay-out configurations

Similar to the first category (vertical wells for air injection), versions 1 and 2 refer to the operations within the first 2 rows; in the remaining of the rows the THAI process is applied with a normal TTH configuration, although slightly modified. Version 3 requires a complete new concept in the large-scale, commercial application, and it is a non-conventional application of the THAI process. All these versions have to apply a long-distance ignition in the future air injection horizontal well, which is not an established procedure, yet.

Version 1 can be applied as is, with DOHW injectors arranged in a classic SLD configuration. However, in this case the evaluation and control of multiple ignition operations and the process operation itself are more challenging. For this reason, each DOHW injector can be replaced with two simple horizontal wells.

Version 2 requires using horizontal wells *of the same length* in the first two rows (both parallel and perpendicular to the strike). The advantage is that this time *just one horizontal well is ignited* and for the remaining wells just transfer of air injection is necessary.

Version 3. This version consists of a vertical air injector in the center of “cross’ formed by four SAGD-type pairs. It is recommended only when the dip of the reservoir is negligible (almost flat reservoir). The line drive operation is no longer used and the pairs are, one by one, used for production first and injection afterwards. As in Version 2 *just one horizontal well (or horizontal pair) is ignited,* and for the remaining wells only transfer of air injection is necessary.

Appendix I

Startup of the THAI Process with a Broad Linear ISC Front

Objective of this Appendix: To present essential details of the strategy for generating a broad initial linear ISC front – a necessary prerequisite to ensuring successful, development of the THAI process

There are two categories of options for creating an initial, broad linear combustion front in the THAI process: (i) Using vertical wells for air injection – the classic system – or (ii) Using horizontal wells for air injection, which can automatically form a broad combustion front. However, the use of horizontal wells for air injection is not a common practice at this time, as specific techniques, equipment and procedures are needed in order to ensure the safety of the operation. Also, methods required to perform ignition along long intervals of a horizontal section of a horizontal well are not readily available.

These various options are developed in more detail in the following sections.

F1) Using the classical system (vertical wells for air injection)

Current Technology: So far, the THAI process has been applied in the field only in a direct line drive (DLD) configuration, without an initial broad linear combustion front. Moreover, only local communication between the shoe of the vertical injector and the toe of the horizontal producer was realized using this well arrangement. Therefore, there is a need to test in the field a second THAI configuration - staggered line drive (SLD). In developing the THAI patent (see Chapter 2 and Figure 7b of Chapter 3) the SLD configuration was found to be the preferred configuration for application in the field. Subsequent simulation of DLD and SLD configurations also found the SLD system to be the most efficient one (see Chapter 5 – Fatemi's et al results, Ado's results and our own simulation results, from this report -Appendix J). An investigation of the steam drive and waterflooding in a toe-to-heel (TTH) configuration also found that SLD was superior to DLD (Turta 2009 and 2010).

New Approaches: Use of the Intellectual Property (IP) presented here (which is not to be patented) is intended to be used freely by the organizations /businesses acquiring the present Report. The main impetus of this IP is to provide means to help in the application of THAI in a SLD configuration, which we have established that is superior to the DLD configuration, tested at Whitesands and Kerrobert. Additionally, we document that the application of THAI using the DLD configuration can be further improved. There are three different situations to be considered, with a progressive increase of technical complexity:

A. The case of an oil reservoir containing oil with *some mobility*, which easily permits the application of cyclic steam stimulation (CSS) operations and steam drive
B. The case of an oil reservoir containing immobile or *extremely low mobility oil,* and having a reservoir temperature higher than 20-25 ^{0}C
C. The case of an oil reservoir containing immobile or *extremely low mobility* oil, and having a reservoir temperature less than 20-25 ^{0}C

CASE A) Reservoir containing oil with *some* mobility, which permits the easy application of cyclic steam stimulation (CSS) operations and steam drive

Operation in this case can employ either DLD or SLD configurations (Figures 7a and 7b Chapter 3.1). First, a few CSS operations are carried out in all of the vertical wells VI (future air injection wells). Then, a steam drive is conducted in every other vertical well, with the other non-injecting wells open for production. This is done until steam break-through occurs in the open vertical wells. The vertical injection wells are then shut-in and the non-injecting wells become injectors. The operation is continued until the bottom hole temperature at the toe of the horizontal wells reaches 60-80 ^{0}C. At this point, the horizontal wells are opened for production This helps in generating a good hot communication along the line of injectors, and a minimum one towards the toe of the horizontal well (to avoid a future channelling). Once this multiple hot communication is obtained, steam injection is started via all of the vertical wells *for a limited* *period of time (1-3 weeks)*. This procedure is done in order to achieve uniformity of the hot communication and thus prepare the reservoir surrounding the injectors for ignition. Then, the ignition operation can be initiated. When using the chemical ignition based on linseed oil , creating a strong ignition sequence is absolutely essential for achieving a successful THAI process. To this effect it is desirable to inject a slug of a liquid of low latent heat content, miscible with the water, in order to remove the water (from steam flooding operations) from the reservoir space surrounding the wells. Following this, crude oil is first injected, followed by a slug of linseed oil, and then chased with crude oil again. The linseed oil rapidly oxidises and thereby facilitates rapid ignition of the pre-heated original reservoir crude oil, or alternatively, a lighter, more reactive one. Using this procedure, as soon as the air injection is started, a broad combustion front is generated, so that the THAI process can be operated at relatively high air injection rates from the very beginning. This will ensure good oxygen utilization, without the risk of it diminishing as operations are extended further into the reservoir. The other benefit is that incremental oil will appear a lot quicker.

In different wells, the ignition operations can be carried out sequentially or simultaneously; in the last case the detection of the ignition will be slightly more difficult due to the interference phenomena; probably the strongest ignition should be adopted in this case.

As a general guidance, the CSS operation take a few months, while hot communication between all the vertical injectors, may take 6-8 months. Ignition operations may take 1-2 months. Therefore, the preparation of an *initial broad combustion front* will take approximately one year. In general, except the ignition of the first row, no new ignition procedures will be necessary during a commercial THAI line-drive operation.

CASE B: Reservoir containing immobile or *extremely low mobility oil* with *a temperature higher than 20-25 ^0C*

In practice, this case will not occur very often, and approach recommended in Case A may not be possible due to the extremely low injectivity of the steam. For this situation, the operator may opt either for the approach presented here, or, if conditions allow, other technical means, such as reverse ISC presented in Case C. The two methods described below (B1 and B2), require specially designed horizontal wells, or the use of DLD to generate the initial combustion front within the row of injection wells.

B1: A SLD configuration is used, allowing easy connection between the toe of horizontal producer and the vertical well, by curving the adjacent portion of -the-toe of the horizontal section of the horizontal producer(s) towards the shoe of the vertical well(s)s.

B2: A DLD configuration is used within the line of injectors in order to create the linear combustion front. This is achieved by alternating vertical injectors with short dual-opposed horizontal wells, arranged in a TTH configuration. This arrangement requires additional short dual-opposed horizontal wells to be included in the injection row.

The B1 approach is illustrated in Figure I1. It is derived from the Pressure Controlled Gravity Drainage (PCGD) method first proposed by (Sawhney,1997) for steam drive in a **t**oe-**t**o-**h**eel (TTH) configuration. There will be some ‘wedging’ of the burned out area, but still less than that experienced in a classic DLD configuration. Each horizontal producer will produce under the influence of the air injection in the two adjacent injectors (oil banks coming from two air injectors)

The B2 approach is illustrated in Figure I2. Compared to B1 approach this is significantly more efficient as it improves the areal sweep efficiency. However, it is more labour intensive and also more expensive, requiring two phases: a) Generation of the initial ISC front within the first row of injectors and b) Propagation of this front along the main horizontal production wells. As shown in Figure F2, this method involves two categories of horizontal wells: the main horizontal wells HP1, HP2 and HP3 and the auxiliary horizontal wells P-I (injection-production wells). P-I wells and the vertical wells marked with ‘Air” are to be used solely for generation of the initial linear ISC front. The THAI process for linking the injectors in the injection line is initiated by igniting the wells “Air” and then, the ISC front is propagated along the horizontal sections of P-I horizontal wells, from toe to heel. Because the control of the ISC front propagation simultaneously in opposing directions may be difficult, this can be done first in one direction in all “AIR” wells and then in the opposing directions in all wells; stability of ISC front is robust and ISC process will be resumed easily in previously burned zones.

This is the most important example of a DLD–THAI process where it is not necessary to generate initially, a broad linear ISC front. In this case, it is only required for hot linking between future injection wells. A narrow burned volume along the line between injectors (low areal sweep efficiency) will be achieved, with only some oil production and not an extremely good performance in terms of **a**ir-**o**il **r**atio (AOR) for P-I wells. However, once the heel of the P-I wells is intercepted, these wells (more precisely the vertical pilot portion of these wells) will be converted from production to air injection wells, while their horizontal sections will be cemented with thermal cement; technical means to cement the horizontal section and to isolate the vertical

pilot portion should be developed. Please note the necessity of pilot well existence for these opposed dual laterals.

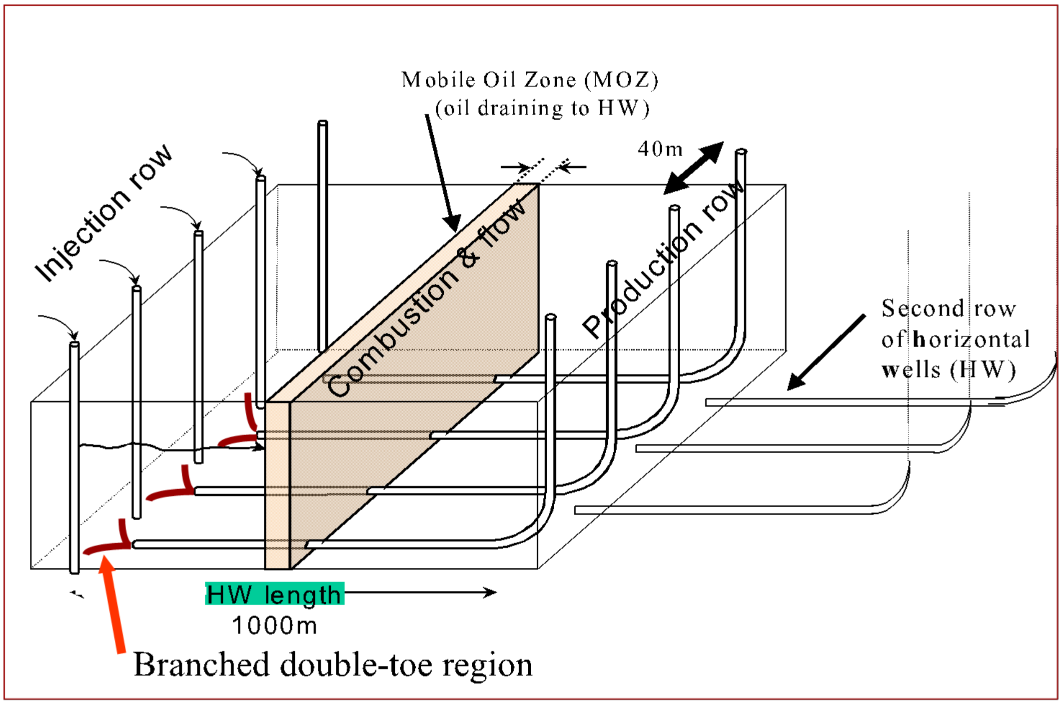

Figure I1. Commercial operation of THAI using staggered line drive configuration, as inspired by Pressure Controlled Gravity Drainage (PCGD) process, Sawneey, 1997

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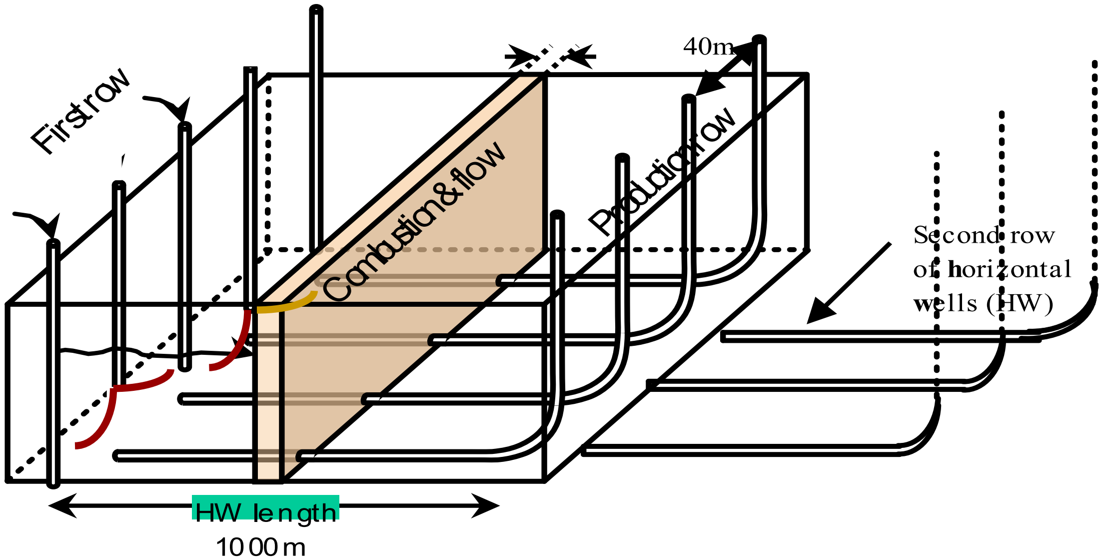

Figure I2. Operation of THAI using the staggered line drive configuration (injectors located in-between horizontal producers (see Fig. 7b, subchapter 5.1). Please note the DLD toe-to-heel configuration in the first row: vertical injectors alternating with opposed dual lateral, horizontal wells, in order to generate an *initial* broad burning ISC front to be used in the subsequent main operation

The initial air injection wells "Air" will be temporarily shut-in during the thermal cementation and they will resume the air injection later, when some increase in temperature is felt at the toe of horizontal producers, HP. At this stage, the linear ISC front can be considered complete, and from then on, continuation of air injection, propagates the linear ISC front along the horizontal section of the main horizontal producers HP1, HP2 and HP3, in a direction perpendicular on the line of injectors. When air is supplied to all injectors, very high air injection rates can be practiced as the ISC front is broad and well developed; this will lead to a good performance in terms of oil production and AOR.

The generation of an initial broad linear ISC front within the first row I (including the pre-heating and ignition phases) – assuming just two well patterns (pairs) will take some 1.5-2 years Since the process is conducted as a line drive operation, for a commercial operation there is no need to generate any new ISC fronts in the subsequent rows (no new ignition operations are needed).

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CASE C: Oil reservoir containing *immobile or extremely low mobility oil with a temperature ghless than 20-25 ^{0}C. Reverse combustion-based procedure*

This is a new method to create the hot communication between the future air injection wells (vertical wells), when applying the THAI process in a reservoir with a temperature less than 20 ^{0}C; if the reservoir temperature is even slightly higher than 20-25 ^{0}C, then this reverse ISC method may not be possible. This is because supplying air to the reverse ISC front via the original low temperature oil saturated zone is not possible due to the consumption of the oxygen through **l**ow **t**emperature **o**xidation (LTO) reactions. Laboratory oxidation tests can give provide some indication regarding the feasibility of this method.

This method is based on fundamental reservoir engineering knowledge and experience from past reverse **i**n **s**itu **c**ombustion (ISC) pilots in which the "drying" of the reservoir in an experimental area of *sandstone saturated with bitumen* was made by simple gas injection. Even though there is no gas relative permeability air is still able to displace the connate water. It is like the bitumen is part of the solid rock, and only water saturates this “rock”, *which, actually, “behaves” like a very low permeability rock.*

The first example of this “drying operation” is provided by Northwest Asphalt Ridge, Utah, USA (Johnson, 1980, and Arscott, 1977) Project. It contained bitumen with a viscosity >1,000,000 mPa s at the reservoir temperature of 11 °C. Pay thickness is 4-6 m. The permeability is 85 mD for the bitumen–saturated cores. *Although the bitumen is not mobile, low permeability is ensured because of the pore space saturated with connate water*. This bitumen–saturated *rock can be assimilated with a* low permeability limestone, in which air (or CO_2) injection is still possible, although the absolute permeability is very low. In the field test, *a few days of air injection* was necessary to create an adequate gas relative permeability, needed in subsequent operations of reverse ISC.

The second example is Bellamy Field reservoir, Montana, USA, in which the a*bsolute* permeability is 800 mD (Trantham, 1966). It contains bitumen with a viscosity of 500,000 mPas at the reservoir temperature of 13 °C. Pay thickness is only 2 - 4 m. In this case *two weeks of air injection was necessary* before sufficient gas relative permeability was developed, and the ignition operations were possible.

These two examples clearly show that even in bitumen saturated sandstones it is possible to obtain *cold communication* between vertical wells (without fracturing) and hence create some gas permeability for future operations, ie the next step, hot communication. In two previous examples, following cold

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communication, reverse ISC was applied. The testing of reverse ISC took place in very small patterns (less than 0.5ha).

In order to explain the main features of the novel method of creating a hot communication, a simple schematic of the THAI process is shown again in Figures I3a-b, for DLD and SLD configurations.

The main difference between Figure 3a (DLD) and Figure 3b (SLD) is that in DLD, *as a minimum requirement,* just one communication has to be made (between injector and the toe of producer), while for SLD configuration first communication is created between the two injectors; then, a second communication between the line of injection and the toe of producer has to be made. Therefore, this two-step communication is more laborious in the SLD configuration. Nevertheless, the SLD configuration is superior, as it can realize a better lateral development of the ISC process, since the 'wedging effect' during the ISC front advancement along the horizontal section of horizontal producer is substantially less.

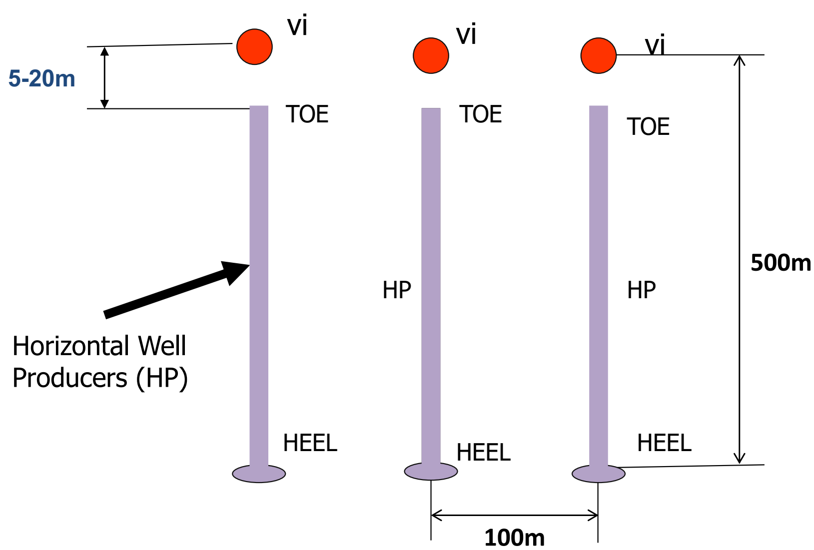

Figure I3a: Bird's Eye View of Toe-To-Heel Air Injection (THAI^{TM}).
Direct Line Drive (DLD) Configuration

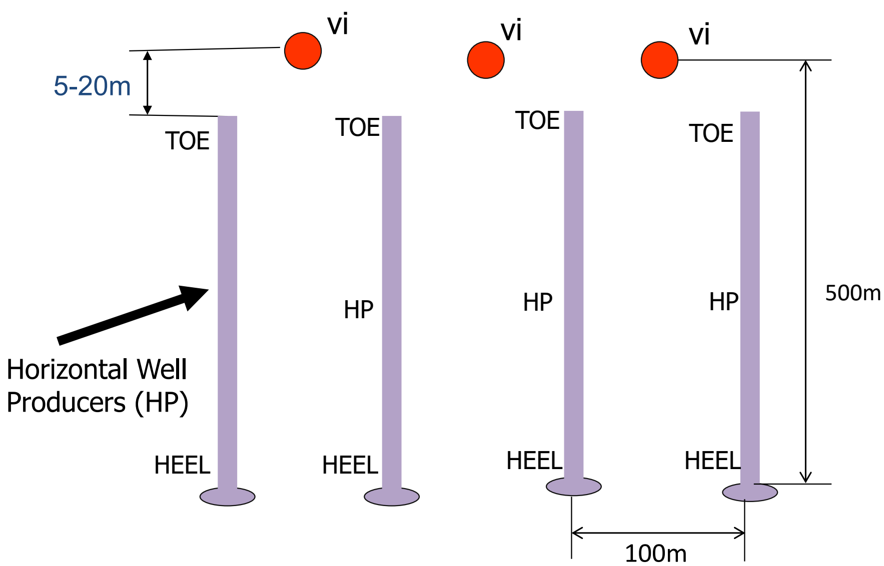

Figure I3b: Bird's Eye View of Toe-To-Heel Air Injection (THAI^{TM}).
Staggered Line Drive (SLD) Configuration.

Procedure for creating hot and cold communication in bitumen/extra heavy oil reservoirs: The goal of the present proposal is to provide a method, which can easily realize, first cold communication and then the hot communication, before starting the normal THAI process in an oil sand or an extra-heavy oil having very low oil mobility. While the recovery of a substantial amount of oil during the creation of communications is not a main target, the generation of all prerequisites for the development of a THAI process leading to a quick increase in the oil rate, the achievement subsequently, of good lateral sweep and a high oil recovery are the main targets.

The Procedure: Referring to Figure H3b, initially a limited amount of gas (N_2 or even air) is injected through one of vertical injector (VI1) while the other VI (VI2) is used to produce fluids until the injected gas breaks through. Then, gas injection is conducted through VI2 with the production of fluids through VI1. Finally, some gas is injected through the future horizontal producer, while fluids are produced through both VI wells. When cold communication is definitely established, the horizontal producer is closed and the vertical wells (VI) are then used to create the hot communication. To this effect, an ignition operation is conducted within well VI1, with the generation of an ISC front around VI1 well. Once generated, ISC front (around VI1) is supplied with air in a reverse ISC mode, i.e. the air is injected through the VI2, flows through the cold region towards the ISC front causing its advancement in counter-current (to the flow of air), towards VI2. Combustion gases and hot fluids are produced through well VI1, as in a cyclic ISC operation. During these operations, the bottomhole temperature (BHT) at the toe of horizontal producers is recorded, in order to sense the proximity of the ISC front for an easy hot communication later on, when the horizontal producer is put on production.

When ISC front intercepts the well VI2 (providing the air) the hot communication is established. At this moment, by injecting air in both VI wells and *opening the horizontal well for production*, the normal propagation of a *forward ISC front* starts towards the heel of the horizontal producer; a partially upgraded oil is displaced and then produced via the horizontal producer(s) from the very beginning.

As a general rule of thumb, the gas used for cold communication can be nitrogen, flue gas or even air. Air can be used in cases the reservoir temperature is much lower than 20 ^{0}C, such that spontaneous ignition does not occur, and the operation can be still easily interpreted.

The gas injected during the reverse ISC operation is air. As mentioned, the proposed procedure can be used only when the reservoir temperature is lower than 20 ^{0}C. Therefore, the method seems fit for the Canadian reservoirs from Lloydminster, Athabasca and Peace River Area, with a reservoir temperature in the range of 8 to 18 ^{0}C.

The generation of the initial broad linear ISC front within the first row (including the air-drying phase and ignition phase) – assuming just two adjacent modules from a commercial line drive operation - will take some 1-1.5 years. However, once is done, it will never be repeated again (during the life of the project); further-on a simple air transfer to ISC intercepted wells will be necessary.

F2) Using Horizontal Wells for Air Injection

Replacing a vertical injector with a horizontal air injector in an ISC process automatically provides for a broad ISC front. However, so far, horizontal injectors have been used only in special situations, for ISC operations located in very deep, high temperature light oil reservoirs, where spontaneous auto-ignition is easily achieved (Belgrave, 2006). Their application in bitumen/heavy oil reservoirs appears to be by far more risky. The potential hazards are the explosions occurring in the horizontal section of horizontal injector due to a poor control of the fluids in different segments of the well, ie mainly backflow of hot mobilized oil. There is also the perceived risk of excessive oxygen storage in the horizontal injector, exacerbated by long lengths. However, Intercontinental Resources Inc. have operated such systems in their Dakota properties for a number of years, with a relatively high degree of safety. Unfortunately, very little information has been made available on the subject.

In case of the heavy oil reservoirs, the only application of this kind was the Wabasca, Brintnell Project, conducted by Amoco and AOSTRA in 1994 (Thornton, 1996). This project was carried out in a reservoir located at a depth of 425 m, with a small pay thickness (4-7m), containing an oil with a viscosity of 5,000-10,000 mPa.s, at a reservoir temperature of 15^0C. A conventional, dry ISC, was tested in a large, face-to-face (side-by-side) configuration formed by three 1100m-long horizontal wells with one injector in the middle, parallel to two producers located at 210m and 320m, respectively. CSS operations were carried out in preparation for the ISC process, but were not extensive. A slug of steam of just 7,500 m^3 was injected in the future air injector over a period of 4 months. The steam barely penetrated a few meters- from the injector, so that no communication between injector and producers was achieved.

This ISC process was started in January 1994 via spontaneous ignition; there was no evaluation of the ignition time delay. Air was injected below the fracturing pressure and during the 4 month-period of injection, the maximum air injection rate was 65,000 sm^3/day. Then, for 8 months there was a pressure cycling, blow-down period. The whole test lasted for only 12 months (until Dec. 1994). During testing, some oil was recovered, but the data are not available.

An in-depth analysis is difficult to conduct as the details on combustion gas analyses are missing and due to the complexities related to the pressure cycling procedure (non-stabilized analyses). The period of testing of one year is much too short to establish if a stable process was achieved. However, in the 4-month injection-period, the ISC front advanced around 10-30 m out of 200-300 m interwell distance. When the production wells were put into production (*after shutting-in the injection well*), the ISC front was still very far from the producers and also there was no communication (as in conventional ISC) to facilitate the transportation of the heated/mobilized oil to these wells. Although the project was considered a failure, *it showed that it was possible to use a horizontal well successfully and safely as an air injector for a duration of four months.*

Pros and Cons of Using Horizontal Wells as Injectors:

- There is a need for full and very detailed safety assessment of the operations in the injection wells, including specific measures during the stoppage of air injection;
- Full assessment of the protocol for fully heating the start-up region and for achieving a strong ignition, with an easy control of these operations

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- Control measures for avoiding local hot spots along the horizontal section
- Measures for reduction of operational problems, eg corrosion and the erosion/sand influx

As presented here, most of the options using horizontal wells for air injection will involve two crucial new procedures/approaches, namely:

- Generation of a very broad ISC front using a SAGD-type configuration (as proposed by Rahnema, 2010,2011 – see section 8.1.3.2.1)
- Transfer of air in the ISC-intercepted producers (ignition operation; no longer necessary)

The first procedure was tested only in the laboratory, while the second procedure was extensively tested in commercial ISC projects using vertical wells.

The process can be applied in three configurations:

C1) Dual opposed horizontal well injectors arranged in an SLD configuration (DOHWI-SLD). Dual opposed horizontal wells are necessary to replace the normal vertical well injectors in the initial injection row (Fig. I4a-c)

C2) Horizontal wells – injection and production wells in a repeated "L" configuration (repeated "L" configurations of horizontal wells) (Fig. I5)

C3) Horizontal wells arranged in "cross" lay-out configurations (Fig. I6)

In all these cases, air (or oxygen-enriched air) and water are *co-injected* as a pre-formed foam, using an extremely low concentration of surfactant dissolved in the injected water. This preserves the foam while travelling down the well bore and a few meters (3-4 m) inside porous medium. The use of this weak foam is necessary not only to avoid extremely high corrosion, but also to avoid possible explosions and pronounced gravity gas-water segregation before entering the formation. Either moderate wet ISC, or super-wet ISC can be applied, according to reservoir conditions. The horizontal section of horizontal injector can be located at the upper part of the oil layer, in the middle plane, or even towards the bottom of the formation; this has to be decided during the design and simulation stage. The horizontal section of the horizontal producer should always be located towards the bottom of the formation

The operation of the Variant C1 is a bit more complex, as both ignition and subsequent air injection has to occur in both laterals of the opposed horizontal injector, in a symmetrical way. On the other hand, the operation of the Variant C2 offers more control, as each module is operated separately.

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For both versions, the ignition operation is the first to be carried out. This can be done either using steam injection (for the pre-heating around the horizontal section of future air injectors) or using artificial devises (electrical heaters, electrical induction coils, etc). However, in the last cases, if a specific methodology is not fully established, then, steam pre-heating-based ignition methods should be adopted, but used in an improved/enhanced version.

Version C1 (DOHWI-SLD): Dual Opposed Horizontal Well Injectors arranged in an SLD configuration]: First, steam injection is performed for a certain time, until the temperature at the toe of horizontal producers (kept closed) reaches 60-70^{0}C. At that point, a classic nitrogen-steam pre-formed foam is injected for a short period of time, in order to identify and eliminate any possible steam channels. The nitrogen content may be around 5-10% (for uniformity of the injectivity profile along the well). After that, the ignition operation for the generation of the ISC front will start and this will be conducted using air. Either pure spontaneous, or a strong chemical ignition (steam and linseed oil) will be implemented, depending on the temperature and pressure in the steam zone. During the ignition operation, the production wells are open to allow produced gas to be analysed in order to establish the ignition delay. In this way, an ISC front is generated and propagated for a short period of time, up to 3-4 m from the injector. A peak combustion temperature in the range of 400-600^{0}C is expected. At the end of the ignition period, the pre-formed dry air-water foam injection is started, and continued, with gradually increasing water-air ratios and higher percentages of oxygen (in case of O_2-enriched air). This will cause the process to go into a moderate wet, or super-wet mode. For most of the time, a very dry foam is injected (with a quality in the range of 85%-97%). Monitoring of the temperature in the producer(s) will signal when any excessive heat breakthrough is likely. If so, a strong nitrogen-based pre-formed foam, or even water, can be injected, until the hot spot disappears.

As seen in Fig. I4a for a pattern of 800m x 400m, when the ISC front is propagated as far as the heel of the horizontal producers, there is no need for other ignition operations *or other horizontal wells to be used as injectors.* However, one more vertical injector (labelled “2” in Fig I4a) is enough for further operations, and it has to be drilled in the middle. Please note that the second row of horizontal producers are now drilled at the half-well spacing (lateral distance), compared with the horizontal wells from the first row of producers. Air injection is conducted in both wells labelled “1”(the pilot boreholes of former horizontal producers from the first row) and new wells labelled “2” (the special vertical injectors). In such a way, a broad combustion front will be propagated along the horizontal wells from the second row of horizontal producers. The process is repeated in the line drive configuration (with the remaining rows) until all of the reservoir is produced by this peripheral line drive (starting at the upmost part of reservoir). The use of more vertical injectors in the subsequent rows can be adopted or not depending on the target ultimate oil recovery value.

As mentioned before, the operation of this version (option) is more complex, as both ignition and subsequently a balanced air injection has to occur in both laterals of the opposed horizontal injector (in a symmetrical way). This may be possible in very homogeneous reservoirs. In reservoirs where heterogeneity is the norm this version (which will be called **C1-1**) can be modified in order to obtain more control over the operation. There are two modified options:

C1-2) Replacing the current dual horizontal injector with two horizontal wells drilled from the same location and whose vertical portions are next to each other
C1-3) Replacing the current dual horizontal injector with two horizontal well pairs, whose vertical portions are close to each other (drilled from the same platform)

These two options are illustrated in Figures I4b-c, where only the first row of injectors and the first row of producers are represented. The propagation of the ISC front to the remaining production rows and the well lay-out are identical to those described in the basic variant (C1-1).

*In the option **C1-2*** the number of injectors in the first row is 2 for each horizontal producer, as one dual opposed horizontal injector is replaced with two horizontal wells. This option, although provides for better control of the ISC front propagation, similar to case C1-1, still has a difficulty as far as the ignition operation is concerned. This is so because for a correct TTH propagation of the ISC front, ignition has to be performed at the toe and this may have a chance of success only if high pressure steam can be used for ignition. In this case, artificial ignition is practically impossible, because ignition at the toe (starting from the toe) has not been developed yet.

*The option **C1-3***, is a lot more expensive, because the number of injectors in the first row is 4 injectors for each horizontal producer. However, it offers the perfect lay-out for the generation of a broad ISC front and its subsequent propagation, which is associated with a very good lateral development (sweep efficiency), and therefore the highest ultimate oil recovery. The horizontal wells, in each pair of wells from the injection row, are of a SAGD-type, with the difference, that one is located at the bottom of formation and the other one at the upper part of formation. These two wells have their toes in opposite directions. In this case, *ignition is performed at the heel of the upper horizontal wells, while the front will*

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be generated as a planar vertical ISC surface between upper and lower horizontal wells (THAI using SAGD-type wells, as proposed by Rahnema, 2010,2011). Once the whole vertical surface between these two wells is covered by the ISC front propagation (once the ISC front exceeded the half of the horizontal section of the upper well), both horizontal wells will be used for injection; air and water (for wet ISC) in the lower one, and water injection in the upper one. It can be seen that in this case the use of foam can be avoided, as the operation of wet ISC will ensure the full safety of the operation. More detail on this kind of TTH operation in two parallel horizontal wells was provided in the section 8.1.3.2.1 of the Report.

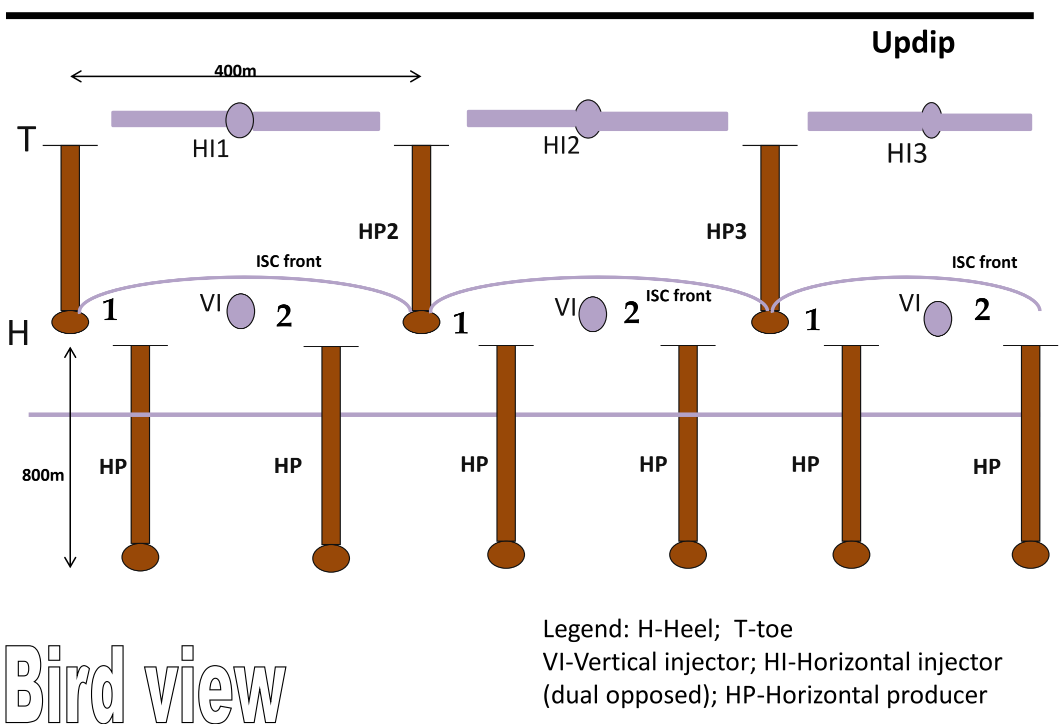

Figure I4a: Version C1-1. Dual opposed horizontal well injectors arranged in a Staggered Line Drive (SLD) configuration, in order to form a broad initial ISC front. Not at scale.

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Figure I4b: Version C1-2. Replacing the current dual horizontal injector (see Fig. F 4a) with two horizontal wells. Not at scale.

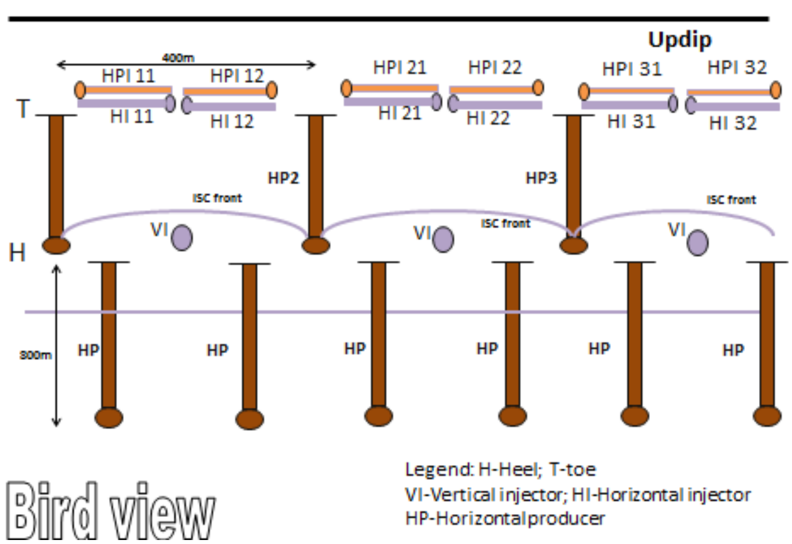

Figure I4c: Version C1-3. Replacing the current dual horizontal injector (see Fig. E 4a) with two horizontal well pairs. Not at scale.

Version C2: Horizontal wells – injection and production - in a repeated "L" configuration
Unlike all C1 versions, this version requires *using horizontal wells of the same length in the first two rows,* ie. horizontal wells along the strike (HWAS) and horizontal wells perpendicular on the strike

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(HWPS) having the same length for the horizontal section. *Additionally, this version involves just one horizontal well to be ignited*; this is designed to take place in the Module 1 (Pattern 1 - P1). As a result, there is no ignition, just air injection into the already heated zone from the previous ISC operation. Ignition, solely by full steam injection, seems to be feasible mainly if high pressure steam can be used. In this case, the generation of a broad ISC front is assured using just one well (HWAS1). If this is not the case and the ignition is difficult, then a more complex procedure has to be used; this would consist in using two parallel horizontal wells positioned as in a SAGD configuration, with the upper well towards the top and lower well towards the bottom of the oil layer. Then ignition "by segments", starting from the heel is initiated at the upper well, until a complete ISC front is generated. Therefore, in the latter situation two horizontal wells, instead of one HWAS, are used. As mentioned, this procedure is developed from the ignition operation in a laboratory set up devised by Rahnema, 2010, 2011).

As seen in Fig H5, for a pattern of 600mx600m, once the pattern P1 is completely burned, the horizontal producer HWPS1 becomes sufficiently heated, and then air injection in this well can be transferred, starting a new ISC process for P2 pattern; The ISC front is propagated along the HWAS2 and later on towards HWPS2 of pattern P2. Therefore, in this arrangement in the last stage of the process, the ISC front displaces oil towards two producers. ?????? Then, the process is repeated for pattern P3 and so on. From the above description it is evident that this design requires non-simultaneous, consecutive operation of P1 P2, P3 etc patterns., in that order; O*nly in this way, it is possible to make just one ignition operation.*

Once the ISC exploitation in P1 to P3, etc is completed, vertical injection wells (VI) are drilled in order to provide air injection for the second row of producers, which are perpendicular to the strike (normal producers). All of these vertical wells together with the pilot wells of the former HWPS wells will be used for further air injection, i.e. vertical wells with ignition operation and pilot boreholes with just air transfer (no ignition). Subsequent operations will involve only vertical injectors and horizontal producers in a normal line drive operation. The horizontal wells from the second and other subsequent rows can be longer than 600m.

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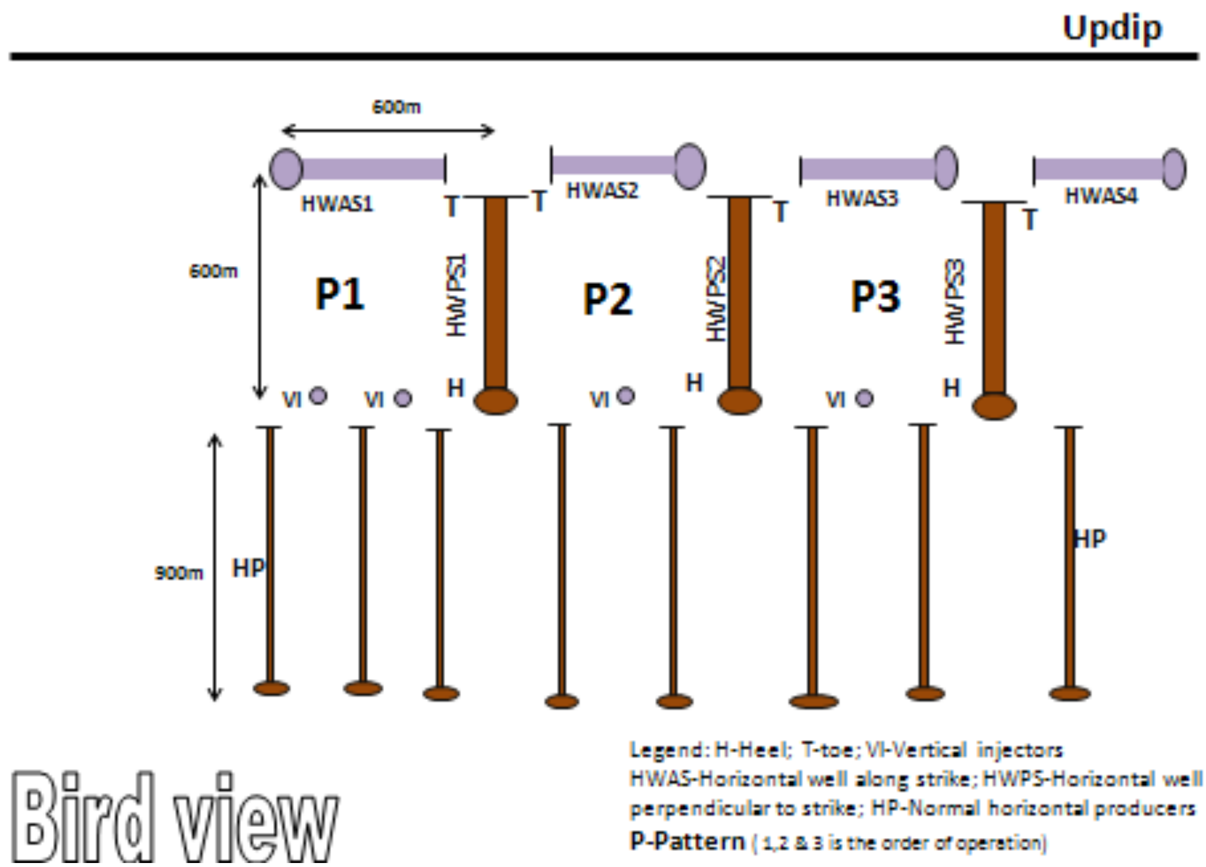

Figure I5: Version C2. Repeated "L" configurations of horizontal wells to form an initial broad ISC front. Note: Normal operation – afterwards. Not at scale.

Version C3. Horizontal wells arranged in "cross" lay-out configuration:

This version uses horizontal well pairs everywhere, but injection is done without foam injection, just using wet ISC.

Unlike version C2, this version is superior, as the ignition is made only once and only in the vertical injector (VI), located in the middle of the "cross" formed by the horizontal well pairs (Fig. H6). In this case, the vertical injector is used mainly to generate an ISC front along the HI1 well, and later on, to be used in the wet ISC process, as needed. While HI1 and HPI1 are located at the upper part and lower part of the oil layer, respectively, all other three other pairs are of SAGD-type, i.e. they have the horizontal wells located exactly as in a SAGD operation. The mentioned lay out of HI1 and HPI1 wells is in such a way that a kind of TTH ISC is conducted respective to the horizontal producer HPI1, while the ISC advances heel-to-toe along the horizontal well HI1; this approach is inspired by similar, concrete laboratory tests (Rahnema, 2012)

More precisely, initially, the ISC front is propagated along the H1 pair (HI1-HPI1), injecting air initially in VI and later on air (and water) in HI1 in the idea of long-distance ignition of the well HI1, from heel to toe. Only water can be injected in VI in this period, during which well HPI1 is open for production due to a toe-to-heel ISC front propagation in this well. Once the ISC front reaches the heel of HPI1, the HPI1 stop the production and is converted into air injection. At the same time the H2 pair is opened for production as an ISC front starts to be propagated in a TTH system due to injection in the H1 pair, **but this time** air+water injection (moderate wet combustion) is carried out via HPI1, while water injection occurs via HI1. This is possible as horizontal well HPI1 develops a broad ISC front, and therefore, the air transfer is possible. Similarly, later on, when the ISC front reaches the heel of HPI2, the H3 well pair is opened for production; a front is propagated in a TTH system due to injection into the H2 well pair, with the air injection carried out via HPI2 and water injection via HI2. This process continues until the pair H4 finishes its production phase. Then, the space between H4 and H1 would be exploited either using H1 pair for injection (in this case the conservation in time of integrity of H1 is necessary) or H4 for production or vice -versa. During the operations, the central vertical injector can be used for water or air or water/air injection any time, with any of the modules around it.

The consecutive operations of the modules around the vertical injector can be replaced with the operation of two modules, simultaneously, but this is a little more difficult to control. In this case, once the broad ISC front was created in H1 pair, simultaneously both H2 and H4 pairs are opened for production. In this case finally the pair H3 will produce oil displaced from two directions (from H2 and H4). This way, the project life for a group of 4 pairs (around vertical injector) will be reduced in half.

From the inspection of these options, it can be seen that, while in the first two versions (C1 and C2) the line drive exploitation of the field (downhill advancement of the ISC front) is still possible, the last configuration cannot fully exploit this feature. Therefore, the operator cannot use to his advantage the dip of reservoir. However, the operator can operate simultaneously as many groups of 4 pairs as he wants, and in this way, a high rhythm of exploitation can be adopted.

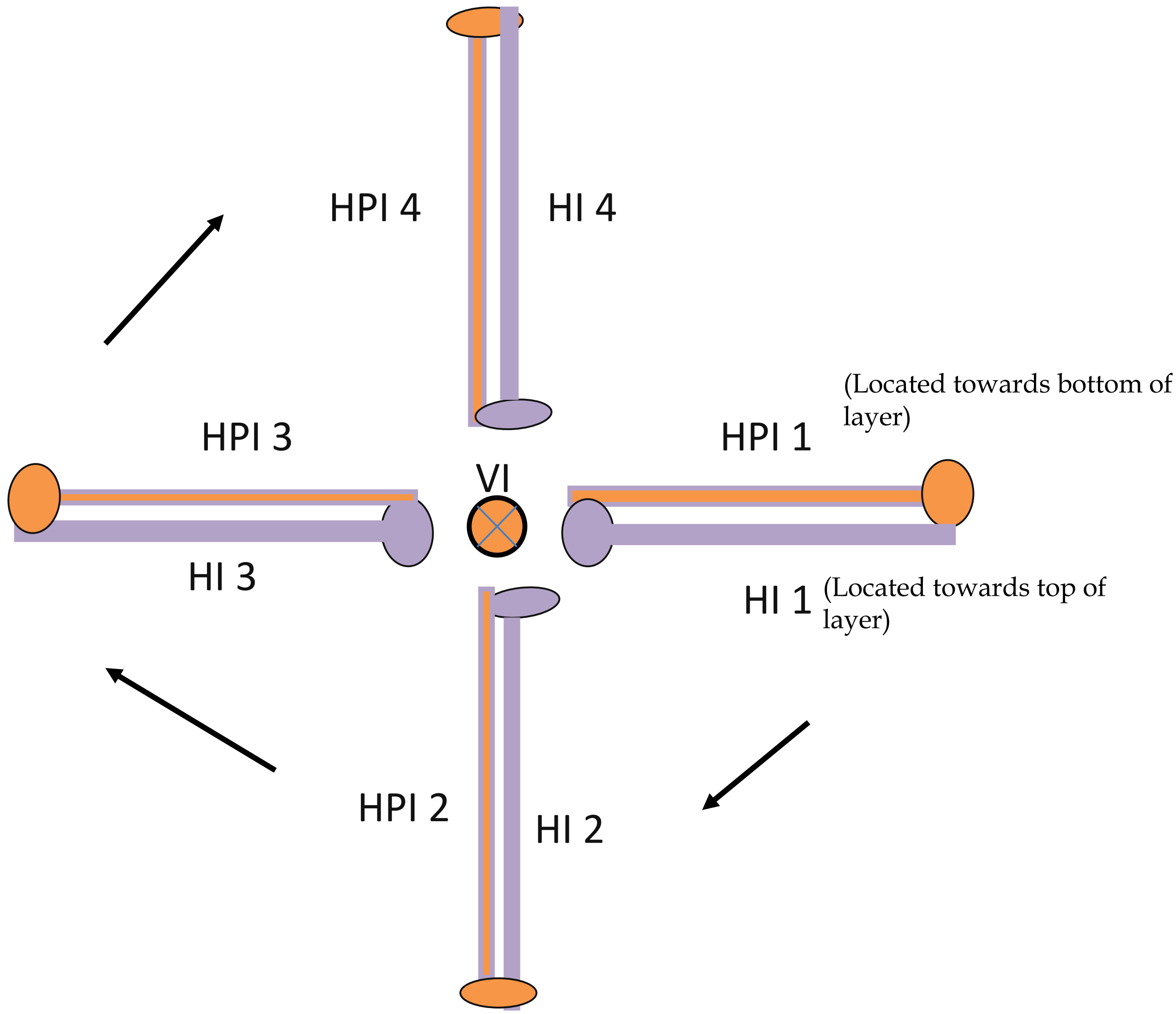

Figure I6: Version C3. SAGD-type pairs (except HP1-HI1) arranged in "cross" lay-out configuration; HI1 and HPI1 forms the first pair of horizontal wells (called pair H1) to be operated by ISC. Then, consecutively, the other pairs (H2, H3 and H4) are operated.

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Summary of the Appendix J

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Potential SAGD Follow-Up In-Situ Combustion (ISC) Processes and a Stand-Alone ISC Process Carried out in a SAGD-type Configuration

Note: the appendix follows after the summary; the full appendix is available upon request only.

The first objective of this appendix is to present details of THAI-related Steam Assisted Gravity Drainage (SAGD) follow-up in-situ combustion (ISC) processes. Also, based on the knowledge acquired in this report, a second objective is to propose a potential stand-alone ISC process, conducted in a SAGD-type configuration.

There are two main options for developing *SAGD follow-up ISC processes*:

A) By using either classic THAI configurations or THAI in a SAGD-type configurations, drilled as infill wells mid-way, in-between old SAGD pairs, which are used for further oil recovery

B) By using ONLY the existing SAGD wells, but sacrificing some SAGD well pairs, in order to use them for injection, while other pairs produce the *horizontally displaced oil*

or case A two situations are considered:

1) Follow up to a *normal SAGD process and* 2) Follow up to *an improved SAGD process* in which an in-fill drilled horizontal well is located in-between old SAGD well pairs. In (A) cases, either a classic DLD THAI configuration (emplaced in-between adjacent SAGD pairs) is used, or a full SAGD-type configuration is drilled mid-way between old SAGD pairs. In case C, a new quasi-THAI lay-out using two parallel wells is used, and wet ISC is carried out in the lower horizontal well, while the upper horizontal well would inject water. Super-wet combustion is realized in the lower well of a former SAGD pair by injecting *a dry air foam,* with a quality in the range of 85-97%; other old adjacent SAGD pairs are put into production. Depending on the injection rates and the water-air ratio adopted, there may be a need for an additional horizontal well for gas venting, parallel to SAGD pairs and located towards the top of layer.

As far as the *stand-alone ISC in a SAGD-type configuration* is concerned, for all pairs, two modifications are compulsory (due to operational constraints required by a long-distance ignition in a horizontal well):

- SAGD-type wells (of each pair), have to be drilled from opposite surface points
- Distance between wells has to be greater than in SAGD; upper well is located close to the top, while the lower well is located close to the bottom of the layer.

Appendix J
Potential SAGD Follow-Up In-Situ Combustion Processes ISC) and a Stand-alone ISC Process Carried out in a SAGD-Type Configuration

Essential information on current art and some background information were provided in the body of the Report (Chapter 11). Here, in the first part (G1), the operation of the ISC process is provided, with some basic specifications/directions of applications as a SAGD follow up, or instead of SAGD. In the second part (G2), the development of a stand-alone ISC process within a SAGD- type configuration is presented; more details on ISC in a SAGD-type configuration are provided in Subchapter 10.1.3.2.1. These potential procedures can form a starting point for the detailed development of some procedures to be simulated and then tested in the field. Most of them are based on the knowledge regarding the generation of an initial broad ISC front during the THAI process application, as presented in the previous appendix. In addition, they are devised in such a way that the safety of the operations is not compromised.

G1: SAGD Follow-Up In-Situ Combustion Processes

There are three options for developing SAGD follow-up in-situ combustion (ISC) processes, namely:

A) By using either classic THAI configurations or THAI in a SAGD-type configurations, drilled as infill wells mid-way, in-between old SAGD pairs, which are used for further oil recovery

B) By using only the existing SAGD wells, but sacrificing some SAGD well pairs, in order to use them for injection

A1) Using additional wells with the existing SAGD wells in order to apply a classic DLD-THAI process:

Two different situations are considered:

- Follow up to a normal SAGD process
- Follow up to an improved SAGD process in which an in-fill drilled horizontal well was already located in-between old SAGD well pairs

For the first option, a simplified schematic is shown in Figure J1. For the illustration, the classic case of well pair distance of 100m is used. In this approach, at a 50m distance from the pairs, a parallel horizontal well will be drilled (in-between) from the old platform, having its horizontal section located close to the bottom of the layer. Close to its toe, a vertical well will be placed. The operation consists of two phases. In the first phase, a DLD THAI operation will be conducted using the newly drilled wells. Once the ISC front advances more than half of the length of the new horizontal well, a double-plane combustion surface exists, and the air can be transferred in the former horizontal well. Therefore, in the second phase air will be injected at the toe of horizontal well, simultaneously with water injection in the vertical well. To this effect, it is important to preserve the integrity of the horizontal section of the THAI producer. While in the

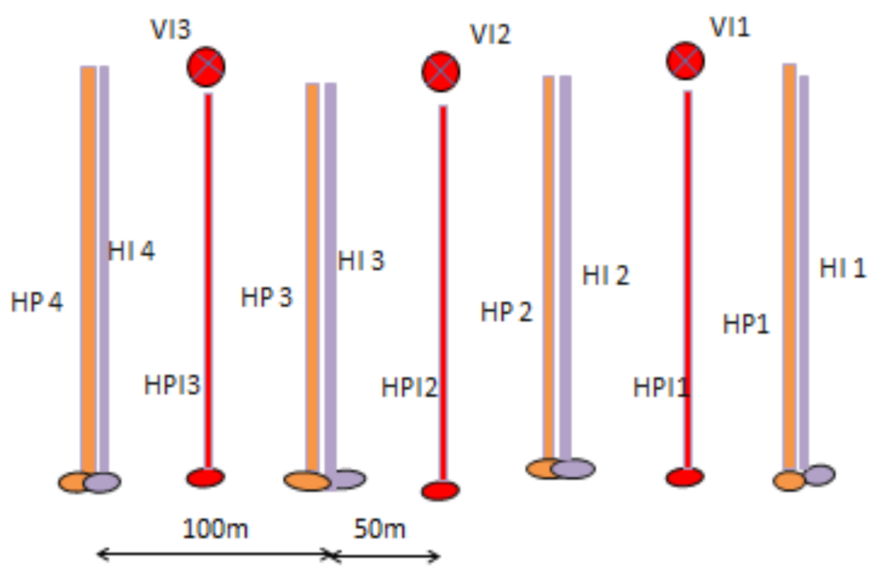

Figure J1: A SAGD follow up ISC using new wells for combustion
Note: the wells HPI can be old wells (offset wells in SAGD) or new wells

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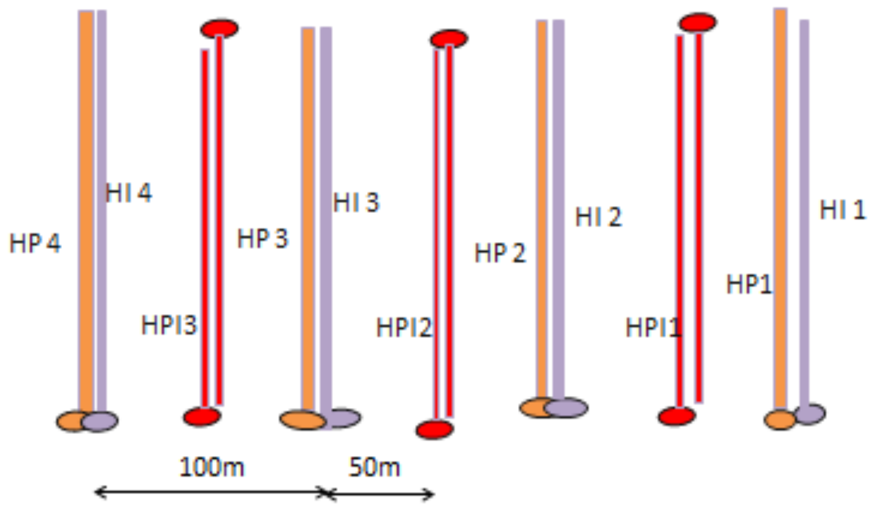

Figure J2: A SAGD follow up ISC when new horizontal wells are used towards the end of SAGD operation
Note: The HPI denotes pairs of parallel horizontal wells; one located at the bottom and the other one at the top of formation. Generally, they are new wells designed specifically for the application of ISC process. In some cases, former offset wells in SAGD are used as the bottom horizontal producers and only the upper ones have to be drilled. THAI in a SAGD-type configuration is applied for the generation of the initial very broad ISC front

first phase the SAGD pairs in the vicinity can continue to work in a SAGD regime (preferentially injecting a lower quality steam), in the second phase, the former SAGD pairs are converted to production wells. The upper well will produce mainly gas, while the lower one will produce mainly liquids (oil and water). To prevent a potential blockage of the production well by hot oil coking, a coiled tubing will be installed in the bottom horizontal well in order to be used for preventing a too intensive coking, as needed.

The proposed process can be considered when the ultimate oil recovery by SAGD is less than 40-45%, for a pay thickness less than 20-25 m in reservoirs without bottom water or having very thin bottom water zone.

In the second case, for the illustration, the well pairs distance of 100m was taken. In this case at a 50m distance from the pairs a parallel offset horizontal well was previously drilled (in-between) from the old platform and was used during the SAGD operation. The application of the ISC in this case may be less frequent to be considered as in this situation the ultimate oil recovery by SAGD could be higher. Currently, the field results of offset wells in SAGD are good and in full deployment in several pools. Therefore, it should be taken into consideration only when ultimate oil recovery by SAGD is less than

50%, for pay thickness less than 20-25 m in reservoirs without bottom water or having very thin bottom water zone.

Actually, the application is identical with previous one (Fig. J1) with the difference that the horizontal well mid-distance (between SAGD pairs) already exists and the temperature around this well may be high, probably over 80-90^{0}C; a new vertical well is to be drilled close to the toe of this offset horizontal well. The procedure to follow is that from case A1 with the difference that t*here is a higher risk of the blockage of producers both in first and second phase*. In the first phase, some injected gas may flow towards the SAGD producers, as well. As in case A1, the installation of a coiled tubing in the offset horizontal producer is necessary.

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In principle for the first application, there is a lot of flexibility: the SAGD pair wells can be drilled either as are used today, i.e toe-toe and heel-heel (both wells drilled from the same surface point), or using toe-heel and heel-toe configuration, i.e. SAGD wells drilled from opposite surface points.

A2) Using additional wells with the existing SAGD wells in order to apply a THAI in a SAGD-type configuration

In this case the goal is to displace additional amounts of oil via the existing SAGD wells; ISC in SAGD-type pairs are drilled as infill, mid-way, in-between old SAGD pairs (Figure J2)

Also, in this case two different situations are considered:

- Follow up to a normal SAGD process
- Follow up to an improved SAGD process in which an in-fill drilled horizontal well was already located in-between old SAGD well pairs

In this case, the couple vertical injector-horizontal producer (presented previously) is replaced with a SAGD-type configuration, but the upper well is located towards the top of formation (Figure J2); actually, the former vertical injector was replaced with the upper horizontal well (HP1). As seen in Fig. J2, this newly drilled horizontal well located at the top has its heel above the toe of the new horizontal producer or old offset horizontal well HPI1). In this way, the upper horizontal well will be ignited at the heel and in a first phase (*Phase I*) a DLD TTH operation will be conducted with these two horizontal wells. In the lower horizontal well (HPI1) a toe-to heel (TTH) ISC front propagation will take place (Rahnema, 2012). More details on the procedure is provided in Subchapter 10.1., where a laboratory setup, along with some experimental results are shown in Fig. 74. Once the ISC front advances more than half of the length of the horizontal well, a double-plane combustion surface exists and the air can be transferred in the offset horizontal well, starting the second phase, namely horizontal oil displacement towards SAGD pairs HP1 to HP4. Actually, in *the second phase* air will be injected at the toe of former horizontal producers HPI1 to HPI4, simultaneously with water injection at the heel of upper horizontal wells HP1to HP4.

While in the first phase, the SAGD pairs in the vicinity can continue to work in a SAGD regime (preferentially injecting a lower quality steam), in the second phase both former adjacent SAGD pairs are converted to production wells, with upper wells to produce mainly gas and the lower wells to produce mainly liquids (oil and water). *There is a high risk of blockage of oil producers both in the first and the second phase*. In the first phase, some combustion gas may flow towards the SAGD producers, as well. To prevent the blockage of the production well by "very hot oil coking" a coiled tubing has to be installed in the horizontal producers in order to be used to combat the blockage by too intensive coking.

B) By using only the existing SAGD wells, but sacrificing some SAGD well pairs, in order to use them for injection (wet combustion by injecting an air foam)

Operation: In order to apply an ISC process first the ignition operation has to be carried out. It can be executed either by using the steam injection (for the heating around the horizontal section), or by using artificial devices (electrical heaters, gas burners, etc). However, in the last case the specific procedures and equipment have not been fully developed (for ignition on a long distance) yet. Therefore, in the following, it is assumed that a relatively high pressure SAGD has occurred and a steam-based ignition is possible, therefore without making use of artificial devices; in the unfavourable cases, some chemical products as ignition enhancers may be used with the steam injection.

Preparation of the future ISC pair: With reference to Figure J3, the process assumes a preliminary SAGD operation. Ideally, the steam injection for SAGD will continue until the steam chamber touches the top of formation (or a little bit after), depending on the reservoir conditions. At that moment, for the future ISC pair, a classic nitrogen-steam pre-formed foam would be applied for a short period of time, in order to identify and eliminate steam short-circuits between injector and producer. Nitrogen content may be around 5-10%; this is a measure to prevent future pre-mature ISC front breakthrough in the production well of the pair (uniformization of the injectivity profile along the well). After that, the ignition operation for the generation of the ISC front will start in the lower well of the pair, and this will be conducted using air. As mentioned, either spontaneous ignition or a strong chemical ignition will be designed, pending the temperature in the steam chamber. During the ignition operation, both the upper well of the pair and the gas production well (vent well) will be open. They are expected to produce gas that will be analysed for composition in order to establish the ignition delay. This way an ISC front is generated and propagated for a short period of time of up to 3-4 m maximum distance from lower well up to the upper well. The peak temperature expected is high, in the range of at least 400-500 ^{0}C. At the end of this operation, ideally, a large burning surface of a rectangular shape will be formed, with its surface size: length of well * distance between SAGD wells. Subsequently, t*his burning surface is to be propagated towards the other adjacent SAGD pairs in opposite directions.*

At the end of the ignition period, air-water pre-formed foam injection will start in the lower well, and it will continue with gradually increasing water-air ratios and higher percentages of oxygen (in case of O_2-enriched air operation). This will cause the process to go in the super-wet mode, with moderate temperatures like in the steam injection. For most of the time, a dry foam will be injected; the quality of the foam will be in the range of 85-97%. Monitoring of the temperature in the upper well (of the pair) has to be made, and when an excessive heat breakthrough is signalled, a strong nitrogen-based pre-formed foam (of varying quality) will be injected for a period of time, until the hot spot disappears. This will be carried out just by replacing air with nitrogen in the composition of foam. Then, when the upper well (of the pair) is fully intercepted by the ISC front, water injection will be carried out in the upper well, and this will facilitate the achievement of a super-wet combustion regime.

The adjacent former SAGD pairs will be open for production due to a horizontal displacement, via super-wet combustion producing steam for this horizontal displacement, while some of the gas is captured by the vent well in order to decrease the gas load in the SAGD producing pairs. In these adjacent pairs, the upper wells may produce predominantly gas, while the lower wells will produce predominantly liquids.

In a commercial SAGD operation, the method proposed allow to use all SAGD pairs. Half of the well pairs for injection/combustion and half of them will remain for production; additionally, vent wells are proposed. After gaining more field experience it may be possible to operate the process without vent wells, but this will be possible only if the gas load in the production wells will be acceptable (in order not to suffocate the producers). However, for the first field test, the vent wells may be necessary.

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Note: Theoretically, the super-wet ISC is net superior to moderate wet or dry ISC, as it does not have so high peak temperatures and the fuel burned out in the process is significantly reduced; some residual fuel remains in the burned-out zone. However, even with these significant advantages, so far, this process – in its conventional form (using vertical wells in a long-distance displacement process) - has not been applied commercially, because of the fear of blockage due to **l**ow **t**emperature **o**xidation (LTO) reactions, as this has been always seen in the laboratory combustion tube tests. While this is a real reason for a frontal displacement, there is a strong belief that there are no risks during a SAGD-type application. The water–air ratio of the pre-formed foam for the super-wet ISC process will be in the range of 7-17 litres water/sm^3 (equivalent to an air concentration of 0.06-0.14 % weight, in the total mixture) when using air, while for pure oxygen this will be in the range of 35-85 litres water/sm^3 of O_2. Although pure oxygen has been considered in the above considerations, in practi, the O_2 enrichment of the air is not recommended to exceed 60%-70%, with a recommended concentration of 40%-45%. *An important limitation for the proposed process is the pressure limitation; for the application of the super-wet ISC process, a minimum reservoir pressure of 0.8-1 MPa is necessary; for lower reservoir pressures the process is not sustainable.*

The novel process is to be further analysed as far as the simulation is concerned and afterwards scrutinized for the testing in a laboratory set up. Therefore, it is required to cheque/analyse at least some of its aspects.

Some adjustments will be necessary in order to optimize the application in each case. These adjustments refer mainly to the reservoir pressure value, which will lead to some important adjustments to the ignition operation and the process itself.

Two specific situations for the application of the proposed method:

C1) Combination of a commercial SAGD operation at high pressure with a commercial ISC sustained via-O2 enriched air: This process represents *a grand prize* as it can be applied in an integrated way with the conventional commercial SAGD operations in the same field, but in different adjacent geographical areas of the application. This way, the benefit of the economy of scale will be very important. In this case the vent wells are not necessary, but an air separation plant would be needed, and this plant will be *fully utilized,* as O_2-rich air would be used for the novel ISC processes, while N_2-rich gas will be used in multiple SAGD patterns as a gas-injection (and re-pressurization) follow up process, which showed very good results in the UTF project, in Canada. This way, for each super-wet ISC application (pattern), 4-8 conventional SAGD pairs can be operated by nitrogen injection. This will create the opportunity to apply this thermal combination process for thinner formations and/or at higher depth, as the efficiency will be much higher. As an illustration, for a number of 4 enriched-air injection well pairs (and 4 production well pair) and area comprising at least 16 SAGD pairs can be operated in nitrogen injection for the wrapping up of SAGD operations.

C2) Follow-up to a SAGD operation at very low pressure (LTO process). In this case, the super-wet ISC may not be sustainable and an LTO process may be considered. The LTO process consists in the injection of a *very low air injection rate,* in order to cause the consumption of the O_2 in the former steam-invaded zone, while nitrogen will do the re-pressurization/displacement work. The LTO reactions will have the role of oxygen stripping. The schematics of the wells would be the same, but the process is preferentially applied very late in the SAGD process, when a significant steam chamber has been formed. The process is to some extent similar to HPAI process, but makes use of a lot more precautions against explosions. *Practically, there are no expectations for the recovery of oil from the former steam chamber around the air injector* (as the residual oil is low and the displacement is of low efficiency due to LTO reactions). However, the nitrogen displacement of the oil from outside this chamber towards other SAGD pairs should be normal. Therefore, in a commercial operation, while the well pair used for injection is sacrificed (as far as oil production and recovery is concerned,) the flue gas produced by this injection can provide pressure support for at least 2 adjacent well pairs In this way, in a 30 well pair operation, 10 well pairs will be used for injection and 20 pairs for oil production and oil recovery.

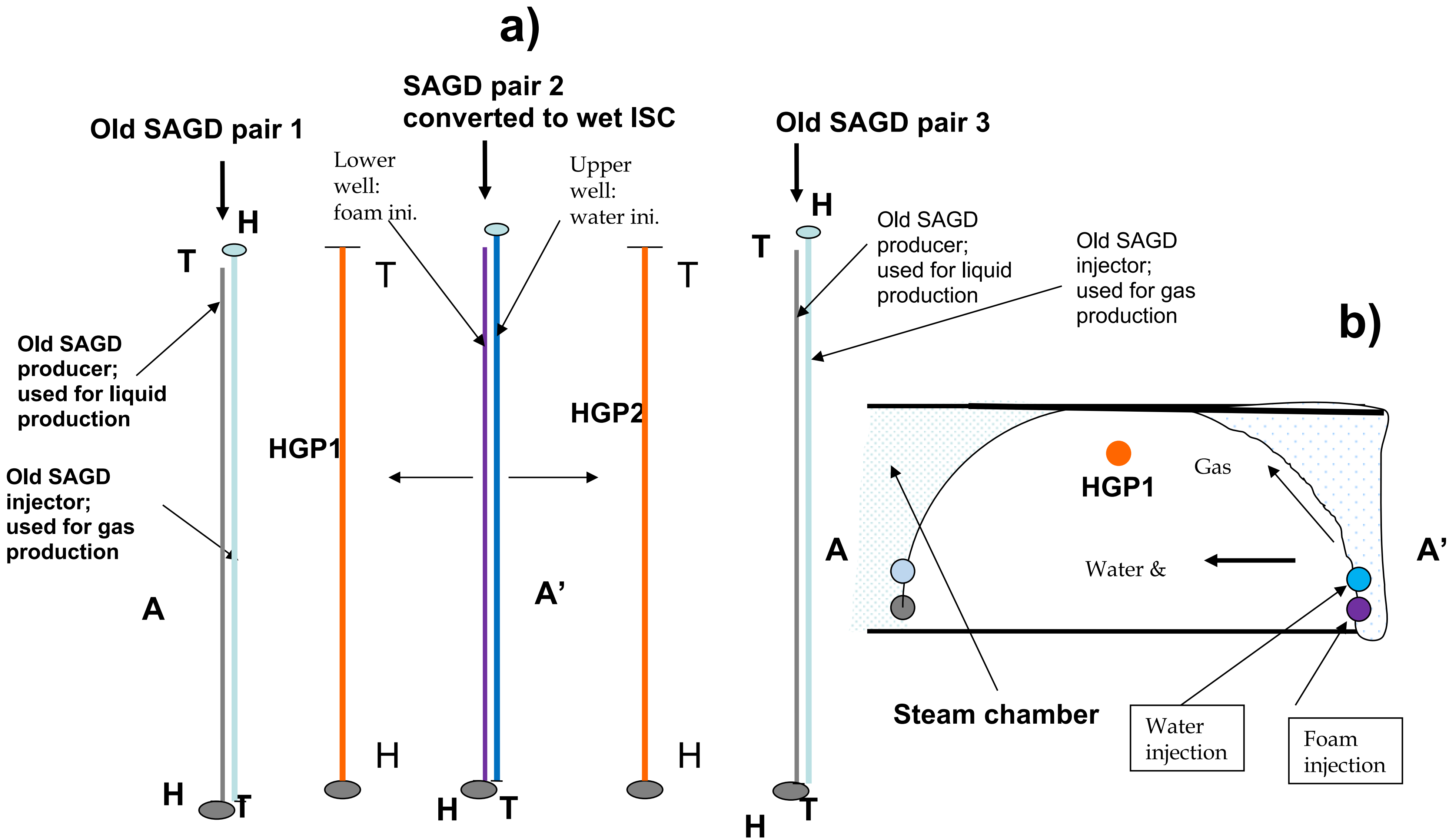

Figure J3. Schematics of Multi-Pattern Super-Wet ISC process. a) Bird’s eye view b) Cross-section AA’ containing the vent well HPG1 (for flue gas production). In some cases, the vent wells may not be necessary.
Legend: HPG – vent well (horizontal well for gas production);
H-heel of horizontal well; T- toe of horizontal well

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J2: A Stand-alone ISC Process Within a SAGD-type Configuration

In the approach described here only the toe-heel and heel-toe configuration is indicated, that is, wells have to be drilled from opposite surface points. This means that SAGD-type parallel wells, but drilled from opposite surface points are indicated (Fig I4). The reason is that the ignition is more complex; it has to be done first in the region close to the heel. Only this kind of ignition can create an ISC front propagating toe-to-heel (TTH) along the horizontal producer. In addition, depending on the oil and reservoir properties, while the lower well is always located close to the bottom, *the upper well may be located a little bit vertically farther than that routinely used in SAGD operations, sometimes being located just under the top of formation.*

As mentioned, the ignition has to be done first in a region close to the heel. The length of this segment will depend on the capability of the ignition equipment/procedures used for ignition. It may be in the 10-20 m or even up to 50-100m. This will be established by the future practices; it is to be noted that in this case the ignition by steam injection is not assumed automatically. This approach has been inspired from some dedicated laboratory tests (Rahnema, 2012). However, to make it practical for the field application, instead of dry ISC, the super wet ISC will be applied. Also, for safety concerns, the air will be injected in the form of a dry foam.

Operation consists of conducting a super-wet ISC process, by injection of a dry foam in the upper well, while the lower well is used for production. As in the case B described earlier in this section, in the case of an ISC premature break-through in the producer, a nitrogen-foam based will be temporarily injected. As super-wet ISC is the process of choice, this would be a proper method in the case of relatively high pressure reservoirs. As in the case of SAGD, the thickness of the layer should be higher than 12-14 m

To prove the novel technology, the following tasks have to be completed:

- Complex engineering evaluation of the proposed process, based on a comprehensive review of the technical literature regarding the pre-formed foam, super-wet ISC process and feasibility for an application in relatively deep heavy oil reservoirs.
- Technical details on how the novel technology can be applied in the field. Possible, anticipated operational problems.
- Process simulation and considerations on how the process can be tested in a simple laboratory set up.
- Essential laboratory work in a 3-D set up
- Design of a pilot test.

Reference:

Rahnema, H et al.: "Self-Sustained CAGD Combustion Front Development; Experiment and Numerical Observations" SPE IOR Symposium, Tulsa, USA, 14-18 April 2012.

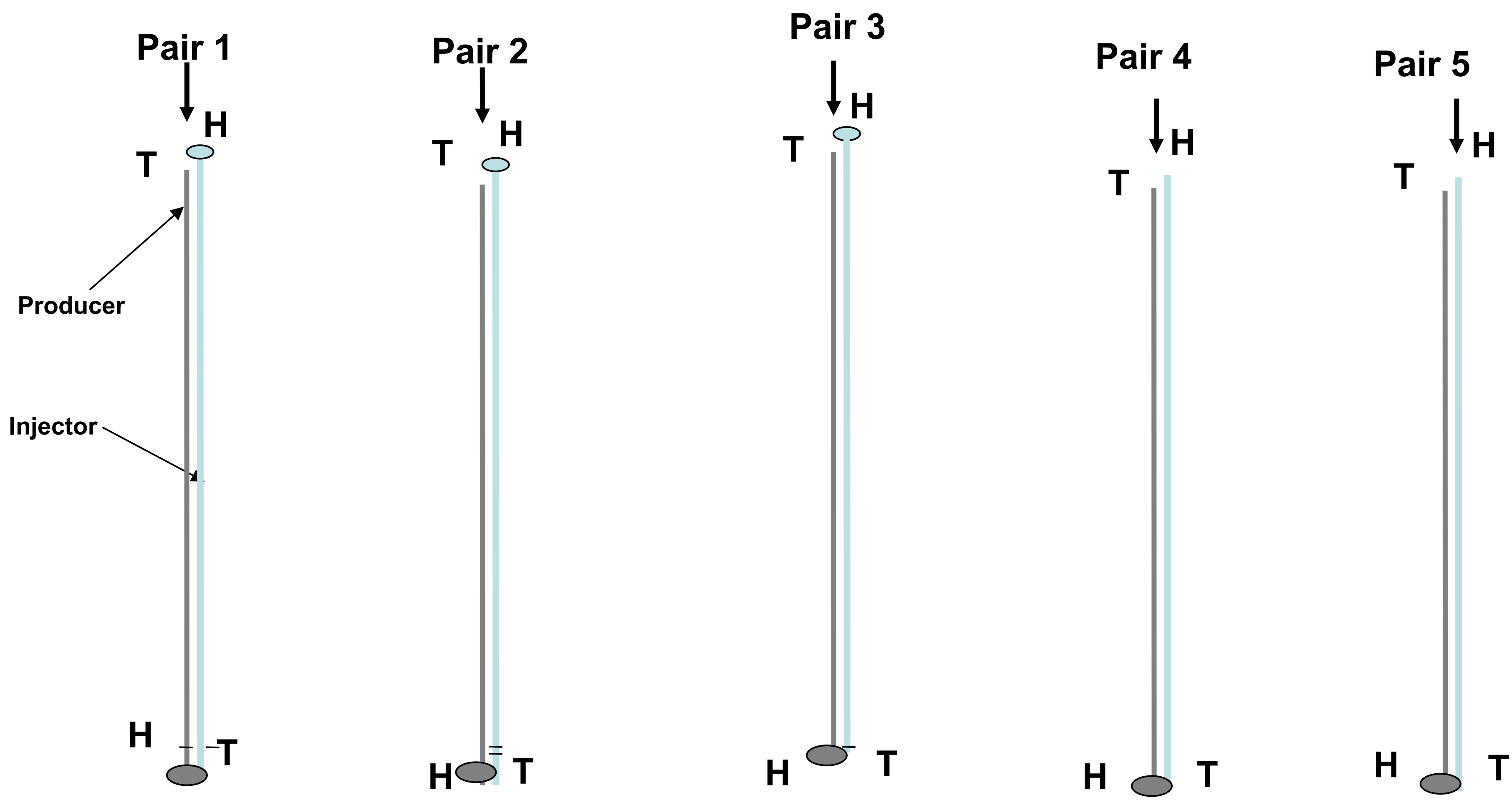

Figure J4. Schematics of Multi-Pattern Super-Wet ISC process in SAGD-type configurations Bird's eye view.
Legend:
H-heel of horizontal well; T- toe of horizontal well

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Appendix K

Comparison of the THAI performance for the direct line drive and staggered line drive configurations. The effect of the pre-heating

This is a comparative study of the simulation of Toe-To-Heel Air Injection (THAI) process in a typical direct line drive (DLD) well configuration, once done with local pre-heating and secondly, with comprehensive preheating and generation of a full linear hot communication between injectors [broad initial in-situ combustion (ISC front)]. Second part compares the DLD configuration with (staggered line drive) SLD one, when in both cases a broad initial ISC front was achieved.

Note: this appendix constitutes a separate study (65 pages), and is listed in the References; it will be provided by request, in an electronic copy. A VIDEO showing the advancement of the ISC front will also be available upon request.

Summary of the Study:

The preliminary simulation of the THAI combustion process was conducted in a Direct Line Drive (DLD) and Staggered Line Drive (SDL) well configurations for the case of Athabasca oil sand.

Two options for the reservoir pre-heating with heaters were investigated:

- Case A: Local pre-heating of the space along the injector well
- Case B: Preheating of total side surface of the injector well (pre-heating on the whole injection line).

The combustion front was created and it propagated in both configurations.

A number of preliminary runs followed by 8 basic runs were conducted. From the runs carried-out, the following conclusions were made:

- For both modes of pre-heating (entire or upper half of layer) the case B was more favorable than case A, as it created a larger rock volume of high temperature (approx. 418 ^{0}C), while promoting generation of a stronger, forward tilting ISC front sooner, during the project; a better oil recovery was obtained in Case B
- For DLD configuration, a better ISC process is obtained when the pre-heating is conducted only on the upper half thickness of the layer (as the tilting forward of the ISC front occurs earlier in the project)

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- When comparing the SLD configuration with DLD configuration, Case B (preheating whole side of reservoir) it shows a better oil recovery in SLD compared to that of DLD configuration.

The THAI process is a promising (oil recovery factors are promising), but the simulator has a series of limitations related to unrealistically low oil rates (compared with those obtained in a field test). Also, the oxygen utilization coefficient is unrealistically low and air-oil ratio is unreasonably high. *These limitations make this simulator results inappropriate for THAI performance predictions, but do not invalidate the results of comparisons made in this report.*

APPENDIX L

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THAI Process: Estimating the Quality of Burning from Gas Composition. Calculation of the atomic apparent hydrogen-carbon ratio taking into account the coke gasification and water-gas shift reactions

Authors: Alex Turta

Punitkumar Kapadia

L1: Introduction

During the THAI process, along with physical changes, chemical changes are inevitable. These chemical changes are because of interaction of bitumen/heavy oil with injected oxygen and superheated steam. The chemical interaction among these reactants is complex and results in large number of multiple reactions which consists of different combinations of series and parallel elementary reactions. For the conventional ISC (C-ISC) and to some extent in THAI, going upstream, these reactions can broadly be classified into following:

1. Low temperature oxidation (LTO), (Belgrave et al. 1993)

2. Aquathermolysis: Steam and bitumen/heavy oil chemical interaction (Hyne et al. 1977)

3a. Pyrolysis: Thermal cracking of bitumen/heavy oil (Hayashitani et al. 1977)

3b. Water gas shift reactions (WGSR), coke gasification and methanation reactions. Chemical interaction among the products of above reactions (Hajdo et al. 1985). While the first two reactions generate hydrogen, the last one (methanation) consumes some of it.

4. High temperature oxidation (HTO), (Belgrave et al. 1993)

The reactions from 1 to 4 happen both in series and parallel, with a very complex pattern of elementary reactions.

The families of reactions mentioned above contribute to the production of coke, gas, and upgraded oil in different capacity depending upon extent of reaction, which is function of temperature and pressure. For example, the amount of gas produced during aquathermolysis is less than 1% of the total gas produced during pyrolysis (Hyne 1986),

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because of less severe conditions. Hence, effect of aquathermolysis can safely be neglected during THAI process as other reactions are faster and dominating.

The amount of gas produced during pyrolysis is significant and it requires due consideration (Hajdo et al. 1985). For the C-ISC process, hydrogen produced during pyrolysis is not more than 5 to 6 percent of total gas produced (Hajdo et al. 1985 and Hayashitani et al. 1977). Having known that most of the thermal cracking occurs immediately ahead of the ISC front, there is a good likelihood that produced hydrogen would burn in the presence of oxygen to produce steam; also, where oxygen concentrations may not be considerable, some steam is produced by connate water vaporization. On the other hand, HTO reactions are dominant at the ISC front and contribute significantly to the production of carbon oxides. Hence, the overall percentage of hydrogen would be significantly less than what we have during pyrolysis.

A recent comprehensive simulation of the ISC with the generation of hydrogen used to this effect 25 reactions (Kapadia, 2013). In order to correctly consider all the assumptions and limitations, those equations are reproduced below (Figs L1, L2 and L3): It can be seen that:

- CO_2 is produced during aquathermolysis, pyrolysis, HTO and WGSR; most of it is produced via the 4 HTO reactions (See Fig. 3). At the same time CO_2 is consumed only in coke gasification (with CO_2) reactions;
- hydrogen is produced during aquathermolysis, pyrolysis, coke gasification, and WGSR. H_2 is consumed in HTO and methanation reactions;
- CO is produced during aquathermolysis, pyrolysis, HTO and coke gasification. At the same time CO is consumed in HTO and WGSR;
- H_2S is produced by aquathermolysis and pyrolysis

In reality, LTO reactions also produce small amounts of CO_2 and CO, but they are neglected in the model presented in Fig. 3 (Adegbesan et al., 1986).

From the conventional ISC projects which functioned in full HTO regime it is known that the H_2 in the produced gas is extremely low almost NIL (less than 0.05-0.1%) Similarly, the conventional ISC projects which functioned in full HTO regime showed that for high pressure ISC processes, the CO is very low, almost nil (0.2-0.4%) and only in low pressure ISC projects (pressure less than 4-6 MPa) the CO was higher, up to 1.5%.

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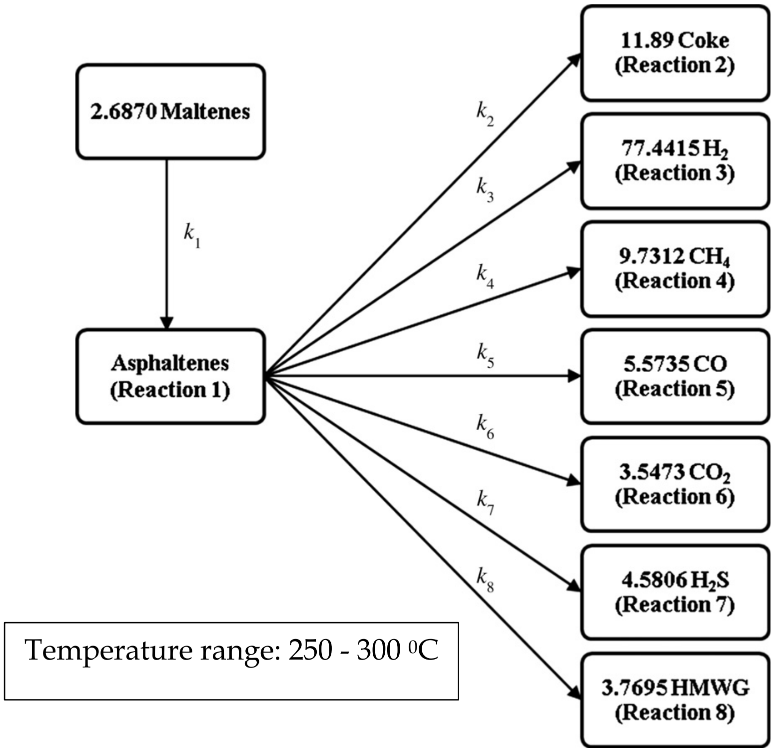

Fig. L1: Bitumen pyrolysis (thermal cracking) reaction scheme

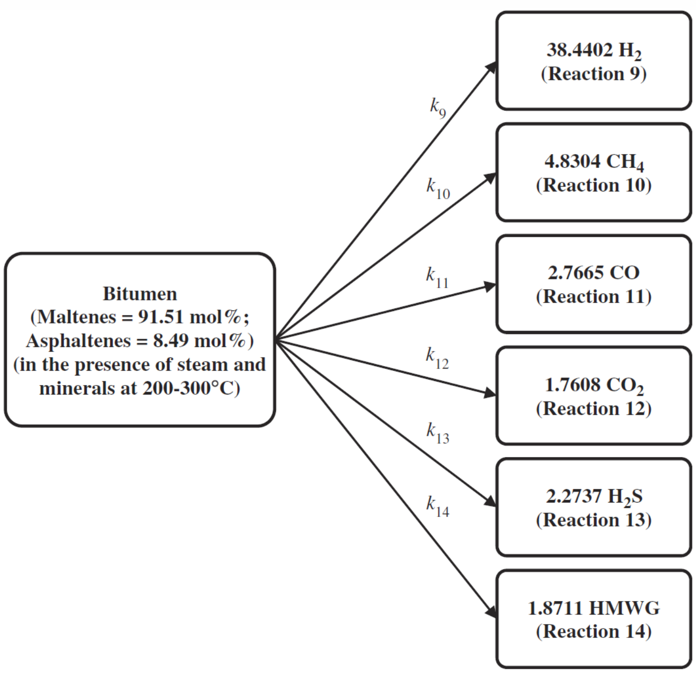

Fig. L2: Bitumen aquathermolisis reaction scheme

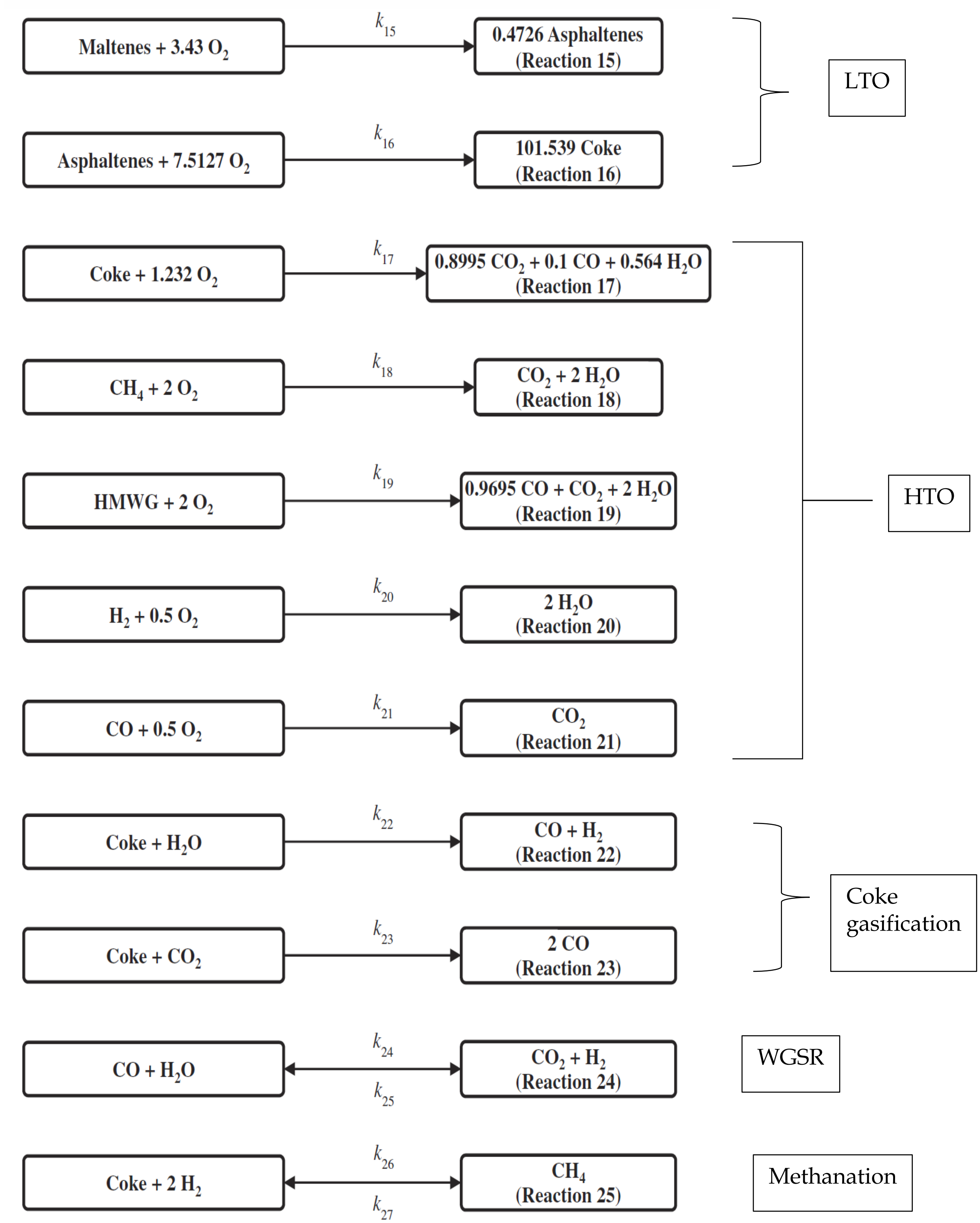

Fig. L3: Reaction schemes for LTO, HTO, coke gasification and water gas shift reactions (WGSR)

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The generation of conditions in which high temperature is associated with lack of oxygen is an important factor to favour the water gas shift and coke gasification reactions. In oxygen deficient areas in reservoir (which may be purposely created by adapting the ISC process), the chances of progression of water gas shift and coke gasification reactions are very high; for this case, actually, conditions are assumed for hydrogen generation reactions from Fig 3 to prevail as compared to the reactions from Fig. 1. This is how some past ISC processes fortuitously produced upgraded oil and H_2; in principal, they were pressure cycling ISC processes, with total interruption of air injection periods, and in these periods high temperature and lack of O_2 existed in some parts of reservoir. Therefore, periodic upgrading and H_2 production occurred (Hajdo et al. 1985, Hallam et al. 1989).

However, in the THAI process the production of upgraded oil along with the production of hydrogen is a constant feature, not a periodic one. At this time, THAI is the first EOR process to produce underground upgraded oil and H_2 on a constant basis. Unlike the conventional ISC process -which is a long-distance oil displacement process with short-distance chemicals reaction zone (including intensive oxidation) - THAI is a short-distance oil displacement process *but with a long-distance chemical reactions zone (including intensive oxidation)*. Although LTO reactions exist, THAI provides less favorable conditions for LTO reactions as the O_2 molecules travel along an enlarged and very hot surface of the burning front. An estimate of the burning quality can be made in both processes (C-ISC and THAI) by calculating the apparent hydrogen-carbon ratio (H/C) from the composition of the produced gas. However, in THAI some of the produced CO_2 and/or CO may not be due to oxidation processes and consequently, is not due to HTO or burning reactions, does not characterize the burning process. This work attempts to evaluate the reaction pathways responsible and develops a novel method for calculating the H/C ratio fully applicable to the THAI process.

Hajdo et al. 1985 suggested that water gas shift reaction has a significantly higher equilibrium coefficient and hence forward reaction rate above 400 ^{0}C. Hence, a significant amount of hydrogen must come from water gas shift reaction, which consumes carbon monoxide to produce hydrogen and carbon dioxide; however, this carbon dioxide is not generated by oxidation and should not contribute to the

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characterization of the burning process. As far as generation of methane during ISC is concerned, in the field this is extremely difficult to quantify, and therefore is excluded-from our investigations at this stage.

L2: Assumptions and Limitations; the Approach Adopted

Unlike conventional ISC, in THAI process, two categories of coke can be formed, namely:

- Generated and burned at the original location (in-situ coke)
- Generated and generally gasified at a location different from the original location of the oil (non-in-situ coke); it may even be burned if oxygen is present (for instance at a sudden increase of air/oxygen flux)

As mentioned, in-situ coke will produce very little H_2, practically negligible. At the same time, at a high temperature, the non-in-situ coke is predominantly gasified if O_2 is not present (having already been already consumed), and steam and/or CO_2 is present; this way hydrogen (H_2) is produced. There are many reactions producing H_2 but, as mentioned, it is believed that the major mechanisms are the coke gasification and water-gas shift reactions (Hallam, 1989, Kapadia 2011, 2013). Simply represented they are:

$C + H_2O = CO + H_2$ (coke gasification) - endothermic reaction ($1.314 * 10^5$ J/gmol) (1a)

$C + CO_2 = 2CO$ (coke gasification) - endothermic reaction ($1.788 * 10^5$ J/gmol) (1b)

$CO + H_2O = CO_2 + H_2$ (water-gas shift reaction) – exothermic reaction ($4.1 * 10^4$ J/gmol) (2)

It is now well established that H_2 production occurs in the THAI process, but not (normally) in the conventional in-situ combustion (ISC) process; *in THAI process the necessary conditions may be found along the burning surface towards the horizontal section of producer*.

In connection with the existence of these two categories of coke in the THAI process, the most important aspects to be clarified are:

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- To evaluate how much CO_2 and/or CO are generated from the real burning process and how much are due to the coke gasification and water-gas shift reactions; as a first approximation at this time this evaluation will be based on the amount of hydrogen in the produced gases
- Assess how accurately the apparent hydrogen/carbon ratio (H/C) can be calculated. The H/C ratio is a very important indicator of quality of burning; lower H/C values indicate higher peak temperature at the ISC front. In conventional ISC (C-ISC) it is well established that all CO_2 recorded (from the produced gas) is generated by oxidation.

Therefore, considering the three major reactions presented in equations 1 and 2, we will try to estimate how much CO_2 does not come from pure oxidation (with the oxygen injected). However, it should be noted that the equations 1a and 2 will be accounted for separately from 1b and 2; in other words, the entire CO from eq 1a or 1b will be consumed in eq 2. Consequently , the CO generated by gasification both with superheated steam and with CO_2 will be taken into account. In general, the rate of coke gasification with CO_2 is a lot lower than that with superheated steam (Kook, 2017); it is conducted at temperatures above 900 ^{0}C, which, generally, are out of the temperature range for ISC process; however just in case it may happen it will be accounted for.

Given the previous information, two situations will be considered, namely:

- The case of almost zero CO production
- The case of substantial CO production

As expected, for the first case our calculations will be almost correct, as CO will not have any erring effect; it can safely be assumed that all CO generated by eq. 1a and 1b is used in eq 2; therefore, no CO appears in the produced gases. In the second situation, a further in-depth analysis of the errors involved needs to be done, and alternatively possible ways to account for, should be investigated.

The first case approximately, is represented by the Kerrobert semi-commercial THAI operation, case where the CO% is in the range of 0.2-0.4%, while the second case is more represented by the Whitesands THAI Pilot where the CO% is in the range of 0.5-5%. In both situations H_2 is produced, in a range of 1-2% in Kerrobert and 2-7% in Whitesands.

In both major cases considered it is assumed that no hydrogen is produced by aquathermolysis and pyrolysis; all H_2 is produced in coke gasification and/or WGSR. Also, it is assumed that methanation can just decrease the H_2 production, but its effect cannot be determined.

At first let us consider only the chemical equations 1a and 2. This is done in order to simplify and make the calculation of a H/C (taking into account coke gasification by superheated steam and WGSR) possible. From the equations 1a and 2 it can be seen that if H_2 and CO are formed from coke gasification and WGSR - and assuming that all CO formed in the eq 1a reacts with steam to form CO_2 and H_2 - *then the H_2 amount should be 2 times the amount of CO_2 produced. A similar analysis shows that this is also true for coke gasification with CO_2, i.e considering eqs 1b and 2..* It is assumed that the two reactions (either 1a and 2 or 1b and 2) can proceed simultaneously or consecutively with reaction from eq 1 being first as temperatures for coke gasification are required to be higher than those for WGSR; however, given the temperature distribution in THAI process it is assumed that the consecutive reactions will prevail. The amount of H_2 can be slightly less than double amount of CO_2, if some extra CO_2 will be formed by WGSR with CO coming directly from HTO reactions or due to a consumption of H_2 by methanation, for instance. Alternatively, any extra amount of H_2 over the double CO_2 has to be attributed to other phenomena, producing H_2, as aquathermolysis and pyrolysis, for instance.

Case of practically no CO production (similar to Kerrobert): In this case, theoretically, three different possibilities can be discussed, namely:

1. Only coke gasification
2. Only WGSR
3. Coke gasification and WGSR as consecutive reactions (eq 1a followed by eq 2 or eq 1b followed by eq 2)

For all three possibilities, assuming that produced hydrogen does not get consumed by methanation and or other phenomena, for the first possibility we would have a 1:1

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proportion of H_2 and CO in the produced gases. However, this case is not applicable when CO production is nil, such that this situation is excluded.

For the second possibility (only WGSR) it has to be assumed that the CO originates from the oxidation process (that one from pyrolysis is neglected). For this case it results that the number of H_2 molecules should be equal with the number of CO, which took part in reaction. Trying to re-construct what was before this reaction happened (in order to determine the correct CO% from oxidation), in the equation of H/C ratio, a percentage of CO equal to that of H_2 should be assumed. In other words, some incremental CO% should be accepted as part of the global composition to be considered for the H/C calculation. However, at the same time the CO_2 formed via WGSR is not coming from a burning process; in this case the total CO_2 produced has to be reduced with an amount of CO_2 equal to that of H_2 (as each CO_2 molecule corresponds to one H_2 molecule in the second part of eq 2). Although this is a case where no CO will appear in the produced gas, being more complex, the calculations for this case were not carried out in this study.

For the third possibility (coke gasification and WGSR), all in all, considering equations 1a and 2, per two moles of water reacted consecutively in these two reactions, one mole of CO_2 will be formed for two moles of H_2 formed (one from first reaction and another from second reaction), while CO is only an intermediary product and does not appear in the final gas produced. The same (one mole of CO_2 will be generated for two moles of H_2 formed) will happen when eqs 1b and 2 are considered. It is obvious that the case of Nil CO seems to be a very good fit for the consideration of situation when these two consecutive reactions take place. An exception, would be just when other compensatory phenomena cause the CO to be nil in the produced gas, or the case 2 previously discussed, but these cases were not studied this time.

Globally speaking, the endothermicity is higher when considering both reaction pairs; however, this will not be taken into account in our future considerations.

Therefore, in this case to evaluate how much CO_2 are generated from the real burning process and how much are due to the coke gasification and water-gas shift reactions the amount of H_2 produced may be an indicator, *although it may not be perfect.* *Assuming that the water-gas shift reactions consume entirely all CO from coke gasification and practically only CO_2 is formed - and recorded in the produced gas - it means that the CO_2 formed this way should*

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be equivalent to the H_2 produced, in a certain proportion; as shown the equivalence CO_2:H_2 was 1:2. Furthermore, the (H/C) may be calculated more exactly after reducing the total CO_2 recorded, by subtracting the CO_2 corresponding to H_2 generation($CO_{2coke\text{-}gas}$). This way one can adjust (reduce) the CO_2 percentage further used in calculation of H/C ratio, and this reduced value would be called $CO_{2\text{-}burn}$. *This is necessary as the H/C ratio is supposed to characterize only the burning process.*

Therefore, for the beginning we are going to deal only with cases where CO percentage is extremely low and it can be considered negligible. As shown, the simple case of practically NIL CO production has been almost a reality in the Kerrobert THAI process. *Therefore, it is assumed that in this case, all the CO generated by coke gasification is used in the water-gas shift reaction, producing CO_2*. This way, the attempt to estimate the $CO_{2coke\text{-}gas}$ and $CO_{2\text{-}burn}$ has correct premises. Additionally, as mentioned, it is assumed that there is no H_2 generated by aquathermolysis or thermal cracking. Similarly, no H_2 formed in those two reactions (1 and 2) will be consumed in the reaction of H_2 with oxygen to form water or in a methanation reaction. The errors introduced by those 3 assumptions, at this time are not estimated.

Case of substantial CO production (similar to Whitesands): This is a much more complex case, as it is not known if the high percentage of CO is coming from an excess of CO produced by oxidation or due to other phenomena.

Anyway, more theoretical possibilities can occur, namely

1. Only coke gasification
2. Only WGSR
3. Coke gasification and WGSR as consecutive reactions

For all the possibilities, it is assumed that always the H_2% is higher than CO% (as shown by field THAI data).

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Possibility 1 (only coke gasification) cannot exist, as always the H_2% is much higher than CO%; eq 1a requires a 1:1 proportion, while eq 1b does not show any H_2 production.

For the second possibility (only WGSR) it has to be assumed that the CO originates from the oxidation process (that one from pyrolysis is neglected). Following along the same lines of previous analysis made for the case of NIL CO, it results that corrections for both CO and CO_2 may be necessary. Although theoretically this is an interesting case, the calculations for this case were not carried out, as it is not known how to make a correction for the CO present in the produced gas.

For possibility 3 (both reactions as consecutive ones) as previously shown, $CO_{2coke\text{-}gas}$ % = 0.5 H_2%, and $CO_{2\text{-}burn}$, used in the H/C ratio calculation will be $CO_{2\ total}$ - $CO_{2coke\text{-}gas}$. *As far as CO% is concerned it will be assumed that the whole amount produced is a result of oxidation, as no CO is produced by the consecutive reactions. As shown previously, the CO produced by pyrolysis is forcefully neglected, as there are no means to estimate it.*

One question mark still remains; why the CO percentage in the produced combustion gas is so high, and how this can be explained? This is a difficult question to answer; either some CO formed in the coke gasification did not participate in the second reaction (water-gas shift reaction) or there was excessive CO formed from oxidation or there are other factors. Therefore, in this case it is more difficult to assume that our hypothesis (equivalence with H_2 of the $CO_{2coke\text{-}gas}$) is valid; our estimated value may be lower or higher than the real figure. Moreover, for this complex case, more investigations are necessary, on the one hand, to evaluate the errors made by our simplified method and, on the other hand, if necessary, to develop more advanced methods; some CO may have been produced by non-oxidation reactions and this amount has to be estimated somehow and taken into account for the H/C calculation. Until these advanced methods will be available it is assumed that within the frame of Possibility 3, all CO is produced by oxidation; a correction to account for the presence of CO has not been developed yet.

L3: Examples of H/C Calculations Taking Into Account the Coke Gasification and WGSR as Consecutive Reactions

Examples of calculation of H/C ratio will be performed for both Kerrobert and Whitesands THAI processes. However, as outlined previously it is probable that the

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calculations for Whitesands are affected by more errors, as it is likely that the process taking place may be more remote from the consecutive coke gasification by superheated steam and WGSR, assumed.

Kerrobert Case (extremely low CO% in the produced gas):

KP2 producer of Kerrobert Project, has gas composition data for year 2015 (Table L1a), which is identical to Table 14 in the Report); Table L1b gives even more details including the exact time of the analysis as sometimes in Table L1a an averaging was made (this explains the highest number of rows in Table L1b). In general, the CO percentage was less than 0.2%, although there were a few periods with high CO concentration (up to 0.6-0.9%). Further on, the data in Table L1a will be used. The recorded average composition was:

CO_{2-r}=15.5%; CO=0.05%; O_2=0.22; N_2=77%; H_2 =1.4%; CH_4=3%; C_2^+=1% and H_2S=0.4%

Where CO_{2-r} is percentage of CO_2 as recorded.

The daily gas production of KP2 is around 30,000sm^3/day (Appendix G, Fig. G7a-2). The amounts of CO_2 and H_2 produced daily are:

CO_2= 0.155 * 30,000 = 4650 sm^3/day

H_2= 0.014 * 30,000 = 420 sm^3/day

Table L1a : Kerrobert Project. Produced Gas Composition for Well KP2 during 2015 and January 2016 (Table 14 from Report). Picture from a computer

Time	KP2-Lab	H2 MOL%	O2 MOL%	N2 MOL%	CO MOL%	CH4 MOL%	CO2 MOL%	C2H6 MOL%	C3H8 MOL%	C4 MOL%	C5 MOL%					AAHCR	AAHCR corrected for CG and WGSR
/16 13:5	Field, J. Elliott	1.27	0.31	76.87	0.01	3.93	15.58	0.77	0.45	0.26	0.14					1.137	1.35
/16 11:4	Field, J. Elliott	1.28	0.28	76.29	0.05	3.85	15.39	0.74	0.43	0.18	0.14						
/16 12:1	Field, J. Elliott	1.26	0.19	76.22	0.01	3.87	15.65	0.75	0.46	0.27	0.14						
/16 13:3	Field, J. Elliott	1.28	0.23	76.51	0.04	3.59	15.59	0.71	0.44	0.28	0.14						
/16 10:4	Field, J. Elliott	1.25	0.19	76.49	0.08	3.76	15.52	0.75	0.47	0.29	0.14						
/15 10:1	Field, J. Elliott	1.27	0.23	76.90	0.05	3.90	15.17	0.68	0.38	0.24	0.15						
/15 13:1	Field, J. Elliott	1.24	0.30	77.22	0.00	4.00	15.08	0.60	0.33	0.12	0.12						
/15 11:2	Field, J. Elliott	1.27	0.16	76.45	0.00	3.85	15.16	0.57	0.32	0.18	0.05						
/15 10:3	Field, J. Elliott	1.28	0.20	77.29	0.00	3.83	15.36	0.57	0.32	0.20	0.06						
/15 09:4	Field, J. Elliott	1.35	0.16	77.28	0.00	3.19	15.87	0.60	0.38	0.26	0.06						
/15 15:3	Field, J. Elliott	1.28	0.23	77.49	0.00	3.75	15.22	0.53	0.31	0.18	0.14						
/15 10:2	Field, J. Elliott	1.25	0.14	76.98	0.00	4.49	15.18	0.55	0.30	0.18	0.06						
/15 11:2	Field, J. Elliott	1.26	0.33	77.05	0.00	4.12	15.23	0.55	0.31	0.19	0.05						
/15 13:0	Field, J. Elliott	1.25	0.27	77.49	0.00	4.28	14.68	0.54	0.31	0.19	0.07					1.17	1.39
/15 17:2	Field, J. Elliott	1.35	0.14	76.63	0.00	2.47	16.00	0.58	0.34	0.13	0.05						
/15 14:3	Field, J. Elliott	1.35	0.23	76.02	0.00	3.58	15.31	0.51	0.28	0.17	0.06						
/15 10:4	Field, J. Elliott	1.57	0.17	76.78	0.00	3.60	15.53	0.56	0.32	0.18	0.05						
/15 10:1	Field, J. Elliott	1.45	0.24	75.80	0.00	4.20	15.18	0.47	0.25	0.10	0.75						
/15 09:5	Field, J. Elliott	1.49	0.22	76.65	0.00	4.29	15.14	0.48	0.25	0.16	0.05						
/15 11:3	Field, J. Elliott	1.86	0.40	76.63	0.00	2.44	15.93	0.44	0.25	0.16	0.05	0					
/15 14:4	Field, J. Elliott	1.53	0.25	76.68	0.2	3.57	15.47	0.45	0.24	0.14	0.04	0					
/15 13:3	Field, J. Elliott	1.32	0.14	77.06	0.00	3.66	15.68	0.43	0.24	0.14	0.04	0.					
/15 10:4	Field, J. Elliott	1.42	0.18	77.78	0.00	4.02	15.60	0.44	0.24	0.12	0.00	0.4					
/15 17:3	Field, M. Wright	1.33	0.24	76.43	0.21	4.27	14.82	0.37	0.18	0.11	0.07	0.3				1.58	1.87
/15 11:4	Field, D. Tetarenko	1.48	0.21	76.28	0.36	3.52	14.62	0.38	0.22	0.12	0.07	0.3					
/15 11:4	Field, D. Tetarenko	1.10	1.69	76.72	0.31	3.12	14.62	0.38	0.22	0.12	0.07	0.37					
/15 13:5	Field, M Wright	1.37	0.18	76.45	0.00	3.49	15.13	0.44	0.23	0.12	0.06	0.40					
/15 09:1	Field, D. Tetarenko	1.38	0.27	77.45	0.00	3.55	15.90	0.44	0.22	0.09	0.02	0.41					
/15 12:3	Field, M Wright	1.41	0.14	76.64	0.00	3.45	15.68	0.43	0.22	0.12	0.06	0.399					
/15 14:0	Field, D. Tetarenko	1.45	0.21	77.00	0.00	3.81	15.55	0.47	0.24	0.12	0.08	0.406					
/15 10:5	Field, D. Tetarenko	1.54	0.20	77.97	0.22	3.15	15.75	0.43	0.22	0.12	0.07	0.427	100.1	0.99907	855		

display

Average 1.32

Legend: AAHCR = Apparent atomic hydrogen-carbon ratio

Table L1b : Produced Gas Composition for Well KP2 during 2015. Detailed record

Kerrobert KP2 Gas Composition												
Date/Time	**H2 MOL%**	**O2 MOl%**	**N2 MOl%**	**CO MOl%**	**CH4 MOl%**	**CO2 MOl%**	**C2H6 MOl%**	**C3H8 MOl%**	**C4 MOl%**	**C5 MOl%**	**H2S MOl%**	**Observ.**
12/5/2014 12:52	1.44	0.46	77.35	0.18	3.23	15.78	0.51	0.30	0.21	0.00	0.5473	
12/11/2014 13:33	1.54	0.21	77.58	0.09	2.56	16.27	0.56	0.34	0.24	0.00	0.6086	
12/18/2014 13:26	1.49	0.38	77.03	0.10	3.14	16.17	0.58	0.32	0.21	0.00	0.5661	
12/25/2014 9:19	1.60	0.25	77.79	0.24	2.39	15.96	0.59	0.34	0.24	0.00	0.6046	
1/1/2015 17:18	1.47	0.86	76.63	0.16	3.96	15.38	0.53	0.29	0.20	0.00	0.5278	
1/9/2015 12:21	1.48	0.23	77.38	0.20	4.12	15.14	0.51	0.27	0.17	0.00	0.5050	
1/15/2015 16:39	1.55	0.36	77.85	0.01	3.50	15.25	0.51	0.28	0.18	0.00	0.5163	
1/22/2015 9:21	1.58	0.29	77.81	0.28	3.13	15.43	0.50	0.27	0.17	0.00	0.5360	
1/29/2015 16:12	1.60	0.40	77.40	0.20	2.97	15.93	0.50	0.29	0.17	0.00	0.5417	
2/12/2015 16:03	1.59	0.42	77.48	0.00	3.18	15.86	0.49	0.28	0.17	0.00	0.5361	
2/19/2015 12:12	1.56	0.30	77.37	0.16	3.55	15.64	0.47	0.26	0.16	0.00	0.5230	
2/26/2015 15:06	1.57	0.38	77.54	0.08	3.54	15.49	0.46	0.26	0.17	0.00	0.5223	
3/5/2015 10:07	1.49	0.28	77.60	0.19	4.43	14.73	0.52	0.25	0.12	0.00	0.3833	
3/12/2015 14:13	1.47	0.46	77.55	0.00	3.83	15.27	0.52	0.29	0.16	0.05	0.4092	
3/19/2015 13:31	1.52	0.23	77.83	0.18	3.50	15.42	0.49	0.26	0.14	0.02	0.4124	
3/26/2015 14:24	1.53	0.39	77.80	0.00	3.51	15.38	0.48	0.27	0.14	0.07	0.4120	
4/2/2015 12:30	1.62	0.16	77.64	0.00	3.74	15.58	0.46	0.24	0.13	0.03	0.4164	
4/10/2015 10:33	1.55	0.36	77.78	0.00	3.51	15.46	0.45	0.25	0.13	0.08	0.4198	
4/16/2015 11:10	1.54	0.25	77.21	0.47	3.78	15.38	0.48	0.26	0.14	0.07	0.4337	
4/23/2015 10:05	1.62	0.40	77.37	0.20	3.01	16.07	0.44	0.24	0.14	0.08	0.4308	
4/30/2015 15:32	1.51	0.19	77.86	0.00	3.59	15.61	0.43	0.22	0.12	0.03	0.4271	
5/7/2015 15:24	1.50	0.40	77.75	0.00	3.49	15.67	0.42	0.22	0.11	0.04	0.4148	
5/14/2015 10:08	1.56	0.19	77.54	0.38	3.39	15.70	0.45	0.24	0.13	0.00	0.4276	
5/22/2015 15:52	1.54	0.14	77.40	0.00	3.24	15.61	0.42	0.23	0.13	0.85	0.4266	
5/28/2015 10:54	1.54	0.20	77.89	0.21	3.15	15.74	0.43	0.22	0.12	0.06	0.4266	
6/11/2015 14:07	1.46	0.21	77.52	0.00	3.84	15.66	0.47	0.24	0.12	0.08	0.4087	
6/18/2015 12:33	1.43	0.14	77.77	0.00	3.50	15.92	0.44	0.22	0.12	0.06	0.4049	
6/25/2015 9:16	1.38	0.27	77.65	0.00	3.56	15.94	0.45	0.22	0.09	0.02	0.4200	
7/2/2015 13:56	1.39	0.18	78.12	0.00	3.57	15.46	0.45	0.23	0.13	0.06	0.4149	
7/9/2015 11:41	1.11	1.71	77.73	0.32	3.16	14.81	0.39	0.22	0.12	0.07	0.3799	
7/9/2015 11:45	1.52	0.21	78.15	0.37	3.60	14.97	0.39	0.22	0.12	0.07	0.3842	
7/16/2015 17:31	1.35	0.24	77.67	0.21	4.34	15.06	0.37	0.19	0.11	0.07	0.3831	
7/24/2015 10:41	1.41	0.18	77.63	0.00	4.01	15.57	0.44	0.24	0.12	0.00	0.4012	
7/30/2015 13:30	1.33	0.14	77.75	0.00	3.69	15.82	0.43	0.24	0.14	0.04	0.4137	
8/12/2015 14:49	1.55	0.25	77.42	0.27	3.61	15.62	0.45	0.24	0.14	0.04	0.4029	
8/21/2015 11:38	1.89	0.40	77.74	0.00	2.47	16.16	0.44	0.25	0.16	0.05	0.4281	
8/28/2015 9:50	1.50	0.22	77.34	0.00	4.33	15.28	0.48	0.25	0.16	0.05	0.3995	
8/29/2015 10:10	1.47	0.24	77.25	0.00	4.28	15.47	0.48	0.26	0.10	0.05	0.3954	
9/11/2015 10:44	1.57	0.17	76.88	0.00	3.60	15.55	0.56	0.32	0.18	0.75	0.4195	
9/17/2015 14:36	1.38	0.23	77.65	0.00	3.66	15.64	0.52	0.29	0.17	0.05	0.4076	
9/29/2015 17:27	1.38	0.15	78.10	0.00	2.52	16.30	0.60	0.35	0.13	0.06	0.4260	
10/2/2015 13:02	1.25	0.27	77.91	0.00	4.30	14.76	0.55	0.31	0.19	0.05	0.3921	
10/8/2015 11:22	1.27	0.33	77.43	0.00	4.14	15.30	0.56	0.31	0.19	0.07	0.3929	
10/14/2015 10:20	1.26	0.14	77.37	0.00	4.51	15.25	0.55	0.30	0.18	0.05	0.3880	
10/22/2015 15:31	1.29	0.23	77.93	0.00	3.77	15.30	0.53	0.31	0.18	0.06	0.3942	
11/9/2015 9:40	1.36	0.16	77.53	0.00	3.20	15.92	0.60	0.38	0.26	0.14	0.4485	
11/17/2015 10:30	1.29	0.20	77.65	0.00	3.84	15.43	0.57	0.33	0.20	0.06	0.4230	
11/26/2015 11:20	1.29	0.16	77.67	0.00	3.91	15.40	0.58	0.32	0.18	0.06	0.4267	
12/4/2015 13:19	1.24	0.30	77.73	0.00	4.02	15.18	0.61	0.33	0.12	0.05	0.4147	
12/18/2015 10:11	1.28	0.23	77.40	0.05	3.92	15.26	0.69	0.38	0.24	0.12	0.4428	
1/4/2016 10:44	1.25	0.19	76.95	0.08	3.78	15.61	0.75	0.47	0.29	0.15	0.4698	
1/8/2016 13:32	1.29	0.23	77.07	0.04	3.62	15.70	0.71	0.44	0.28	0.14	0.4674	

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From previous chemical equations (1a and 2), it results that 2 molecules (or moles) of H_2O participating in the consecutive reactions of coke gasification and water-gas shift reactions (WGSR), produce one molecule (or mole) of CO_2 and 2 molecules (or moles) of H_2.

Therefore, for a number "N" of H_2 molecules produced, "N/2" molecules of CO_2 are generated. In that case the CO_2 due to coke gasification and WGSR ($CO_{2coke\text{-}gas}$) will be:

$CO_{2coke\text{-}gas} = 420 * 0.5 = 210$ sm^3/day

As the current H_2% is H_2=1.4%, translated to percentage, the $CO_{2coke\text{-}gas}$ will correspond to approximately 0.7%. Consequently, the CO_2 due to pure burning will be:

$CO_{2\text{-}burn} = CO_{2\text{-}r} - CO_{2coke\text{-}gas}$

$CO_{2\text{-}burn} = 0.155 - 0.007 = 0.148$ (14.8%)

Taking into account the gases not participating directly to the oxidation, the so called foreign gases ($FG = H_2 + CH_4 + C_2^+ + H_2S$) for H/C ratio calculation, the equation 3 applies, where FG=6.6%:

$H/C = (1-(FG/100))\ \{[106\ /\ (CO_2+CO)] +$

$[2CO-5.06\ (CO_2+CO+O_2)]\ /\ (CO_2+CO)\}$ **eq. 3**

$H/C = [106+2CO-5.06\ (CO_2+CO+O_2)]\ /\ (CO_2+CO)$ **eq. 4**

In the above equations it is automatically considered that the CO_2 recorded is due exclusively to oxidation reactions.

While in the equation 3 the percentage as recorded are applied, when using equation 4 the normalized percentages of CO_2, CO and O_2 have to be used.

In order to switch to normalized percentages, from the recorded composition :

CO_2=15.5%; CO=0.05%; O_2=0.22; N_2=77%, we have:

CO_2 % + CO% + O_2 % + N_2 %= 93.4% and 93.4 will be the new base for calculation of normalized percentages, i.e.:

CO_2=15.5/93.4=16.6%; CO=0.05/93.4=0.054%; O_2=0.22/93.4=0.236% and

N_2=77/93.4=82.44 %, with 16.6+0.054+0.236+82.44=99.3%

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Application of the equation 3, or of equation 4 (using the normalized percentages, calculated), would give:

H/C = 1.24

In order to correct for the CO_2, which is generated by coke gasification and WGSR, for the calculation of a more representative H/C ratio, in the equation 3, the average percentages of gases should be considered, as follows:

$CO_{2\text{-burn}}$=14.8%; CO=0.05%; O_2=0.22; N_2=77%; H_2 =1.4%; CH_4=3%; C_2^+=1%, H_2S=0.4% and $CO_{2\text{coke-gas}}$ =0.7%. It is to be underlined that in the equation 3, the percentage of $CO_{2\text{coke-gas}}$ will be considered along with hydrogen, methane, C_{2+} and H_2S, as being gas not taking part directly in the oxidation; therefore, the FG = 7.3%. Similarly, in calculation of normalized percentages the new base will take into consideration a reduced CO_2 percentage (14.8%).

The calculated H/C ratio will be **1.49**, as compared with 1.24, when the correction for coke gasification was not considered.

This fully corrected value (1.49) is higher. Therefore, without correction for the coke gasification the value of H/C is smaller (1.25), which may *artificially* show a better quality of burning than in reality.

For a certain day, for example the day of February 4th, 2016 (the first record from Table K1-highlighted in blue), the real composition is:

$CO_{2\text{-r}}$=15.58%; CO=0.01%; N_2=76.87%; O_2=0.31; H_2 =1.27%; CH_4=3.93%; C_2^+=1.62% and H_2S=0.463%. (total 100%)

With FG=7.28%

In this case, **H/C=1.137**

In order to make the correction for coke gasification and WGSR:

As H_2%=1.27%, then $CO_{2\text{coke-gas}}$ =0.635%

$CO_{2\text{-burn}}$= 15.58-0.64 = 14.94%, and the modified composition (to account for correction) will be:

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$CO_{2\text{-burn}}$=14.94%; CO=0.01%; O_2=0.31; N_2=76.87%; H_2=1.4%; CH_4=3.93%; C_2^+=1.62%, H_2S=0.463% and $CO_{2\text{coke-gas}}$ =0.64%.

In this case: FG= 7.28+0.64=7.92

And the corrected for coke gasification and WGSR **H/C = 1.35**

Similar calculations for a day when the CO_2 was maximum (16%) and another day, when the CO_2 was minimum (14.62%) - highlighted in Table K1 - gave H/C values of *1.17 and 1.58*, respectively, while with coke gasification and WGSR corrections these values increased to *1.39 and 1.87,* respectively. It can be noticed that with or without correction, the values suggest a better burning quality, hence a higher peak temperature for the case when CO_2 was maximum.

The difference between normal value of H/C ratio and the corrected one is not very high in Kerrobert Project. Finally, based on the detailed data in table K1b, a calculation of the normal H/C ratio and of the H/C ratio corrected (for the coke gasification and WGSR) was carried out; actually, this calculation has been done for the entire life project for both KP1 and KP2 wells. The results - not displayed - confirmed that in the case of extremely CO% in the produced gases, the correction for the coke gasification and WGSR is not very high, although it is still necessary to be made.

Whitesands Case (high CO% in the produced gas)

Accepting the same hypotheses, similar calculations were made for the Whitesands Pilot based on the gas composition of producers P1 and P2 in January 2009, that is after two years since the initiation of the process and just before the stoppage of air injection in the injectors A1 and A2. This composition is provided in Table 6 from this Report and is reproduced here as Table K2, where only the gas composition for individual producers is utilized; the composition for the combining mixture of gases after the sweetener is not used, as H_2S was removed from the gas. As mentioned, in Whitesands Pilot, both H_2 and hydrocarbon content of gas are higher than in Kerrobert Project; also, CO content is a lot higher.

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Table L2: Whitesands Pilot. Combustion gas composition in the period January-July 2009. Verification of the AAHCR and calculation of the apparent atomic hydrogen-carbon ratio corrected for the coke gasification and water-gas shift reactions ($AAHCR_{cor}$)

Legend: AAHCR=Apparent atomic hydrogen-carbon ratio; CG=Coke gasification; WGSR = Water gas shift reactions

P1 Monthly Gas Analysis

Month	H2	O_2	N_2	CO	CH_4	CO_2	C_2H_6	C_3H_8	C_4	C_5	H_2S	Total	CO_2/CO RATIO	Petro-bank AAHCR	This Work AAHCR	AAHCR corrected for CG and WGSR
Jan-09	5.14	0.23	71.23	1.90	4.83	14.71	0.82	0.42	0.11	0.06	0.56	100.01	7.85	0.74	0.72	1.58
Feb-09	5.25	0.28	69.85	2.38	6.36	13.74	0.90	0.47	0.11	0.06	0.59	100.00	5.92	0.85	0.82	1.73
Mar-09	3.56	0.20	73.06	1.62	5.59	13.95	0.86	0.49	0.12	0.06	0.49	100.01	10.31	1.16	1.13	1.79
Shut-In																

P2 Monthly Gas Analysis

Month	H2	O_2	N_2	CO	CH_4	CO_2	C_2H_6	C_3H_8	C_4	C_5	H_2S	Total	CO_2/CO RATIO	AAHCR		
Jan-09	2.38	0.24	74.25	0.64	5.39	14.99	0.99	0.52	0.13	0.06	0.40	100.00	23.58	1.08	1.05	1.47
Feb-09	2.28	0.24	75.66	0.65	4.68	14.54	0.84	0.54	0.12	0.07	0.39	100.00	22.80	1.33	1.3	1.73
Mar-09	1.66	0.22	77.29	0.65	3.73	15.10	0.58	0.37	0.09	0.04	0.26	100.00	23.67	1.25	1.23	1.52
Apr-09	2.44	0.26	73.60	0.79	5.87	15.58	0.62	0.35	0.08	0.04	0.35	100.00	20.35	0.82	0.80	1.19
May-09	1.64	0.35	75.52	0.50	5.21	15.47	0.60	0.32	0.07	0.04	0.29	100.00	31.96	1.01	0.99	1.26
Jun-09	1.71	0.58	76.29	0.70	3.51	16.01	0.52	0.28	0.07	0.03	0.31	100.00	24.70	0.82	0.79	1.04
Jul-09	1.89	0.48	73.99	0.64	4.56	17.30	0.47	0.28	0.06	0.03	0.31	100.00	27.52	0.39	0.34	1.04
Shut-In																

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The last but one column in Table K2 shows our results for normal (non-corrected values for coke gasification) H/C ratio calculation; the foreign gases (H_2, CH_4, C2+ and H_2S) were taken into account. Our results are extremely close to those of Petrobank (calculated using normalized percentages), and for further comparison the Petrobank values will be used.

As an example, for P1 and P2 producers, in January 2009 the H/C values were 0.74 and 1.08, respectively, while with coke gasification and WGSR correction, these values increased to 1.58 and 1.47, respectively.

A rapid inspection of the Table K2 reveals that the highest corrections were found for P1 producer (more than 30% increase), *where the CO% was the highest*. On the other hand, the lowest correction was found for P2 producer in May; 1.26 versus 1.01 (less than 20% increase), when the CO% was the minimum. *As seen, the highest and the lowest corrections correlate well with the value of CO percentage.*

In general, for both P1 and P2 the values of H/C corrected are in a smaller range of variation as compared with the values for the non-corrected H/C values. Also, it has to be outlined that the corrections for the Whitesands Pilot are significantly higher than those for Kerrobert project.

Another observation is that for P2 producer in June and July the corrected H/C ratio is practically identic, reflecting the same quality of burning, while according to the non-corrected H/C, the quality of burning would be a lot different (better in July); however, the value of H/C of 0.39, in July, seems to be by far too low, signalling a necessity for correction.

L4: Interpretation of Results, Limitations and Possible Further Developments

The production of hydrogen in THAI process can be used to evaluate the CO_2, which may not be generated by oxidation but in reactions of coke gasification and water gas shift, which also produce CO_2. Taking into account this non-oxidation-generated CO_2 it was shown that the H/C ratio would slightly increase actually eliminating the error due to neglecting of the coke gasification and water gas shift reactions. Although slightly increased, the H/C has never taken

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values higher than 2 showing again that, generally, in the THAI process the intensity of LTO is considerably lower.

Above analysis suggests that there is a great potential for coke gasification and water gas shift reactions to occur during THAI. Consumption of produced CO should be in line with the production of hydrogen through water gas shift reactions (WGSR). It has been shown that,probably, higher CO production is a condition for higher H2 production. Therefore a correlation between CO production and H2 production may be anticipated. Further on it will be more in-depth analyzed.

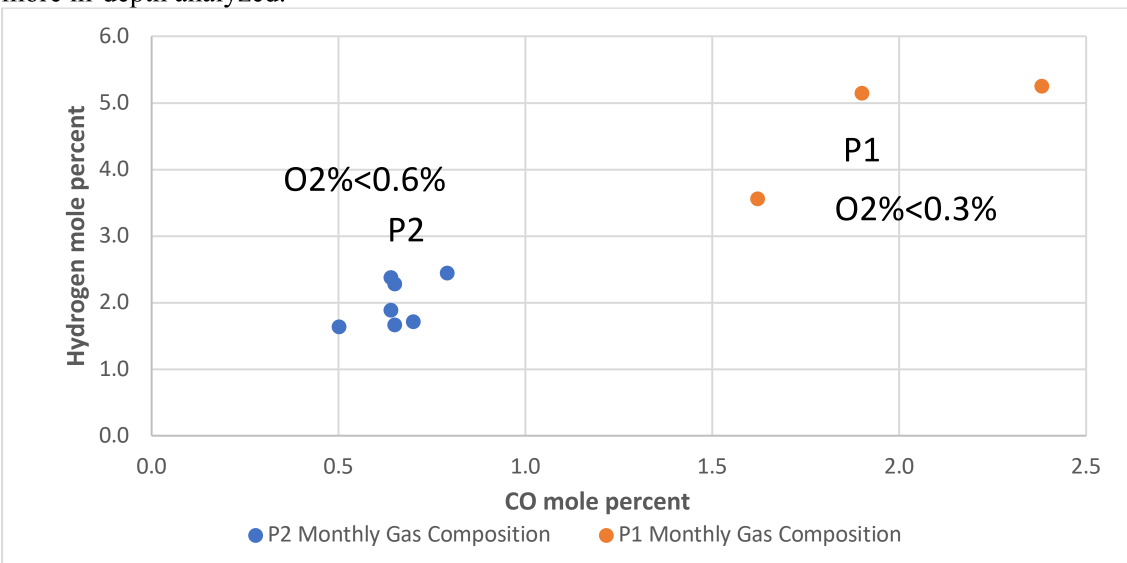

Fig. L4: The good correlation between CO and H_2 produced by wells P1 and P2 in Whitesands Pilot, just for the gas compositions in Table L2 (January-July 2009)

The plot from Fig.L 4 has been made by using gas composition data reported in Whitesands Pilot. (Table K2) and it shows that increase in hydrogen production is because of higher concentration of CO (or is associated with higher concentrations of CO). This trend is more strongly observed in P1 well, at higher CO concentrations.

Finally, a step ahead was made by considering the whole evolution in time, of the hydrogen and CO percentages in the produced gas for the well P1 in WhiteSands pilot (Fig. L5). This seems to show a very strong correlation between these two parameters. In Fig. 5 the variation for O_2 is also shown. This allows to understand more in-depth the complex correlation between CO and H_2 production; it can be seen that the correlation is very strong when the O_2 percentage is Nil or close to Nil. For all the spikes of H_2 (over 8%) the spikes for CO correspond to a range of 4-6% and, associated to all these spikes, the O_2% is less than 0.2=0.4%; when O_2% is around 1%, for example during the period November 2008-March 2009, practically it does not seem to exist a correlation between CO and H_2. It seems that this is due to the fact that O_2 is able to react with H_2 and decrease its percentages in the produced gas. In order to completely clarify this aspect, similar to Fig. L4, a representation O_2-H_2 and another one for O_2-CO are necessary; if the correlation factor for O2-H2 is higher than for O_2-CO it means that the statement above is valid. Of course, finally a direct, similar to Fig. 4 representation CO-H_2 can be produced for the periods

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for which O_2% is less than 0.2-0.4%. From Fig. L5, the highest 3 H_2 spikes (associated with no O_2 produced) are associated with the following CO percentages:

Date:	H_2%	CO%
May 2007	9	6.8
July 2008	8.5	6
Oct 2008	14	5.8

While the CO% is close to the H_2 % for May 2007 and July 2008 (some 70-75% of it) for the month of October 2008, this is not true; it is just 41% of the H_2% value. It can be speculated that for the months of May and July from all the CO formed by coke gasification, 25-30% did not participate to WGSR reactions, while for the month of October 2008, from all the CO formed by coke gasification, 59% did not go to the WGSR reactions and appeared as CO in the produced gas. However, this is pure speculation and more work is needed to elucidate this aspect.

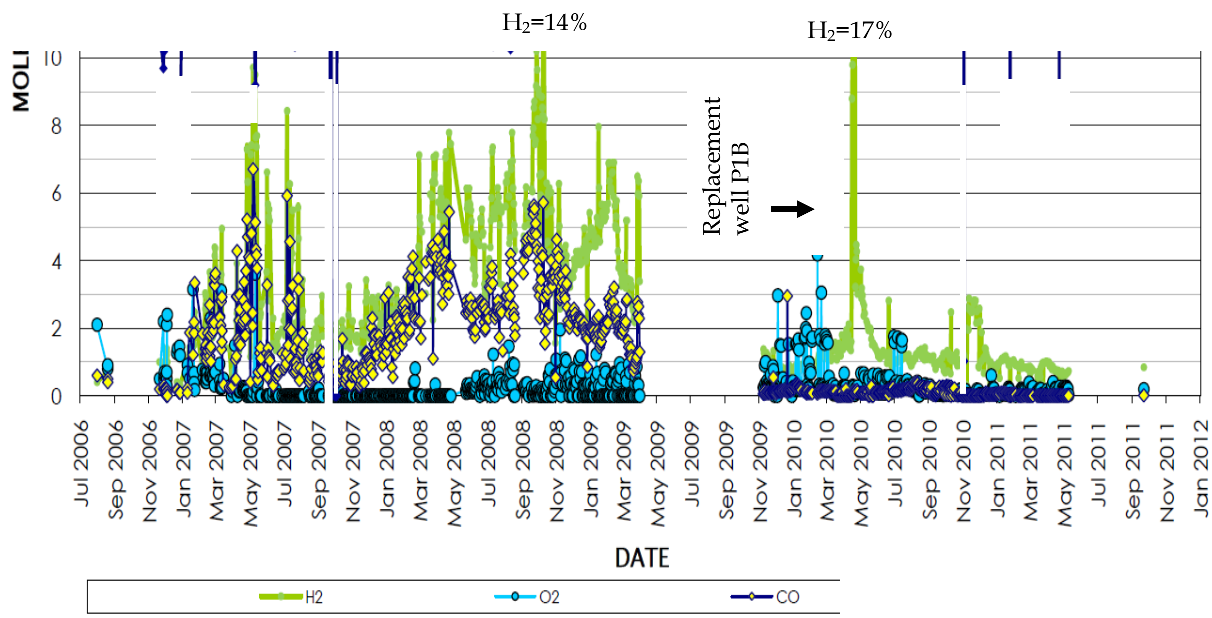

Fig. L5: Evolution of CO, H_2 and O2 in well P1, Whitesands; replacement well P1B, due to technological reasons, cannot be considered in this analysis

The Chinese investigators reported that in their field THAI pilot, a spike in hydrogen heralded an increase of the peak temperature in the in-situ combustion front (Guan, 2017). In our case we were able to confirm this only for the first H_2 peak of 9% in May 2007; this H_2 peak heralded a 700 ^{0}C peak temperature recorded (along the horizontal section of producer) in July 2007. All in all, these high spikes in H_2 are very difficult to explain. It seems that in Canadian pilots they appear in the following situations:

- ✓ On a background of a constant air injection rate, every time that the gas rate of the production well is decreased relative to the value of gas production practiced before;
- ✓ A sudden decrease of the air injection rate, while the gas rate of production well remains relatively constant

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This seems to show that this really corresponds to a situation when the burning surface is starved of oxygen on larger areas of the its surface.

That higher production of hydrogen, attributed to the higher concentration of CO as per water gas shift reactions was also supported by the Kerrobert Project; when hydrogen content was 1.4 and 1.27 percent, the corresponding CO content was 0.05 and 0.01 percent, respectively (Table L1a). For a more in-depth look at the Kerrobert Project, the whole evolution in time, of the hydrogen and CO percentages in the produced gas for the well KP1 is shown in Figure 6a, while in Fig. 6b this is shown for well KP2. In these figures, also, the O_2 percentage was added to the graph.

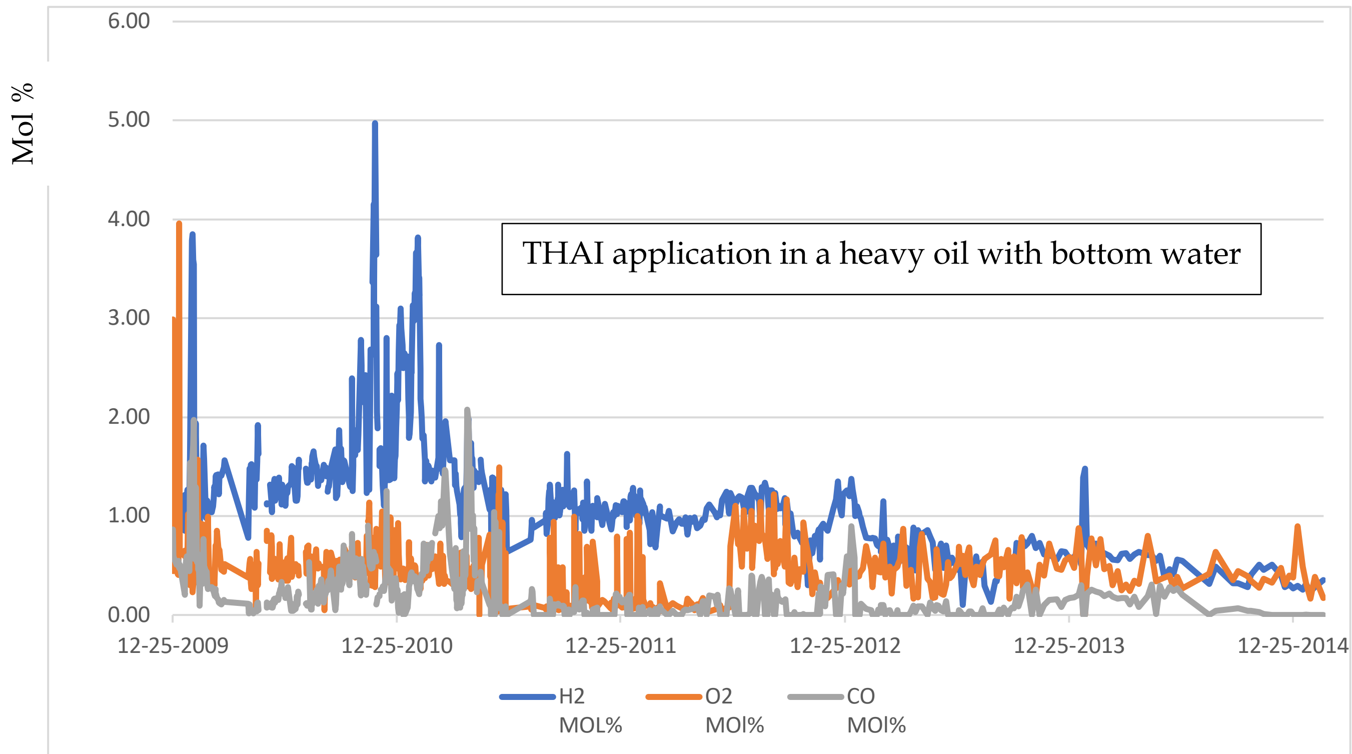

Figure L6a: Variation of the hydrogen, carbon monoxide and oxygen percentages in the produced gas for the well KP1 Kerrobert

THAI application in a heavy oil with bottom water ?????????

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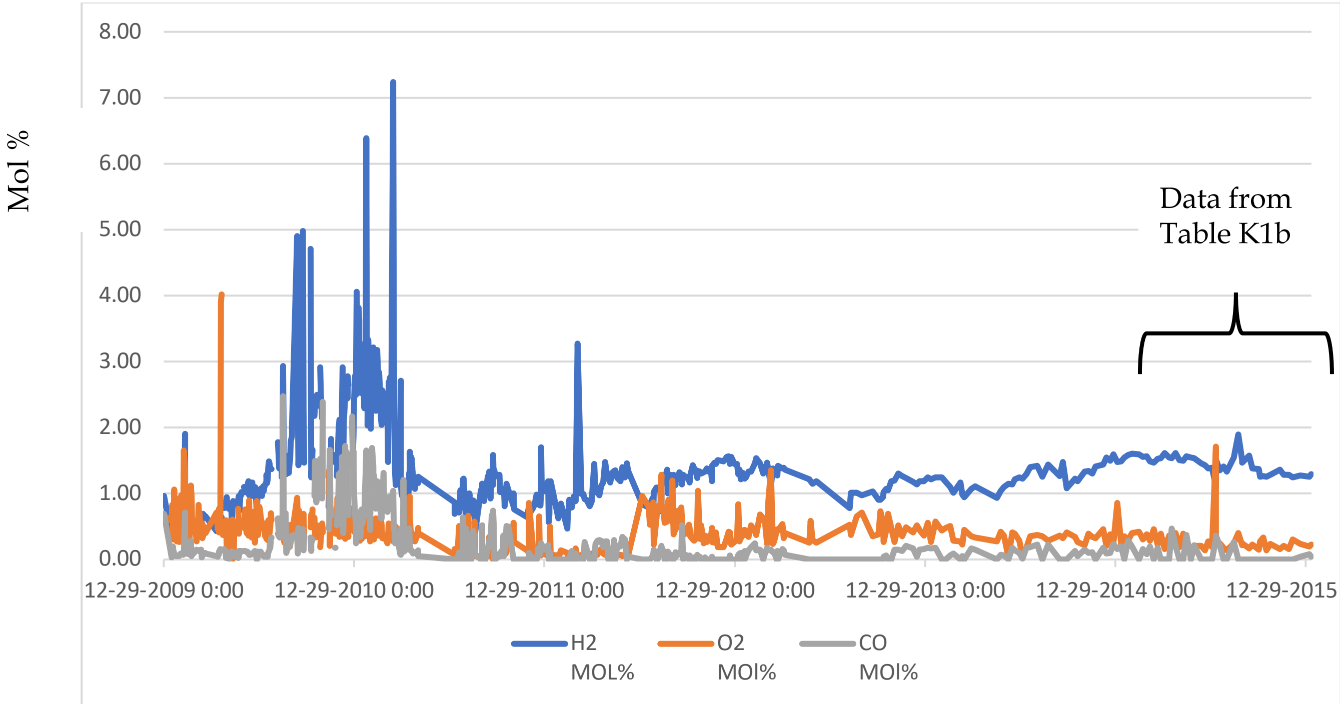

Figure L6b: Variation of the hydrogen, oxygen and CO percentages in the produced gas for the well KP2 Kerrobert

Inspecting Figs. L6a and L6b the following conclusions can be drawn:

- It is confirmed that for both wells, always the H_2% is higher than the CO%; there is just an isolated exception for KP1 in April 29, 2011 when CO% slightly exceeds H_2% (2% versus 1.8%)
- For both wells, for a first 1-1.5 year period after initiation of ISC, CO percentage was higher (0.5-1.5%) than afterwards, when it was less than 0.3%; H_2 percentage was also slightly higher in this first period (1-2%), but it stabilized at around 1% (range 0.5%-1.5%) afterwards. Therefore, the difference in CO production was higher than the difference in H_2 production
- In this first period of high CO and H_2 percentages, it seems that there is a correlation between them, but it is very weak; sometimes, spikes of CO lead to spikes in H_2 production, otherwise the parameters are not very correlated. For instance, for well KP1 the highest H_2 percentages recorded

were *3.85%, 4.97% and 3.82%* at the dates of January 26, 2010, November 19, 2010 and January28, 2011, respectively. At these dates, the CO% were *1.6%, 0.61% and 0.25%*, such way not showing a clear correlation between CO and H_2.

- For well KP2 the highest H_2 percentages recorded were *4.9%, 4.98%,4.71 and 7.42%* at the dates of September 11 and 22, 2010, October 6, 2010 and March 14, 2011, respectively. At these dates, the CO% were *0.4%, 0.5%, 0.33 and 1%,* also showing a weak direct correlation between CO and H_2. However, it has to be pointed out that at those dates the H_2S had an extremely high value, respectively *2.7%, 1.84, 1.74% and 1.2%* (12,000ppm), as compared to the normal range of 0.4-0.6%; a reverse correlation between H_2 and H_2S may exist but seems very week. These very high H_2S values may suggest the existence of very high peak temperatures, as it was shown that, in SAGD, H_2S production increases with increasing temperature in the SAGD chamber (Kapadia, 2012). At this time it is not known if a correction for H_2 production due to H_2S production is necessary; in other words, it is not known if H_2S production causes hydrogen consumption or produces additional hydrogen. It seems to be a difficult task; it may be worthwhile to be approached, in a separate project.

The somehow non-structured (non-systematic) results (correlations) discussed may be due to complex burning behavior inside the oil layer or at the water-oil interface. An attempt to correlate with the air injection rate is not successful and a correlation with peak temperature along the horizontal section of producer is also extremely difficult. As already mentioned, the Chinese investigators reported that in their field THAI pilot, a spike in hydrogen heralded an increase of the peak temperature in the ISC front (Guan, 2017). However, in the Kerrobert Project we were not able to clearly confirm that finding yet.

- There are three main differences between wells KP1 and KP2 performances, namely:
  - In the last two years (2013-2014) the H_2 percentage decreased continuously in KP1 (up to as low as 0.5%), while stayed in the range of 1-1.5% in KP2; the decrease of H_2% in KP1 seems to be due to a continuous and pronounced decrease of air injection rate from approx. 36,000 sm^3/day to approx. 12,000 sm^3/day in this period for the well pair KA1-KP1 (see Fig. G7-KP1c in Appendix G), which led to a slight decrease of the burning quality (hence of the decrease of peak temperature in the ISC front) as indicated by the H/C ratio pronounced increase in that period (see Fig. G7-KP1a in Appendix G),
  - The O_2 percentage was higher in KP1 (in the range of 0.5-1%), while having a large variation; it has been almost always less than 0.5% in KP2.

Of course, for both wells, only building and analyzing separate representations for O_2-H_2 and O_2-CO, on the one hand, and then making a final attempt for a correlation H_2-CO it may be possible to find how the O_2 in the produced gases may have an influence (if any) on the strength of the CO-H_2 correlation. As a first step further processing of complete data from Figs. 6a and 6b were done, as suggested, and the results for well KP1 - which had the largest O_2 variation - are provided in Figs.7a and 7b. The results for KP2 are very similar to those for KP1.

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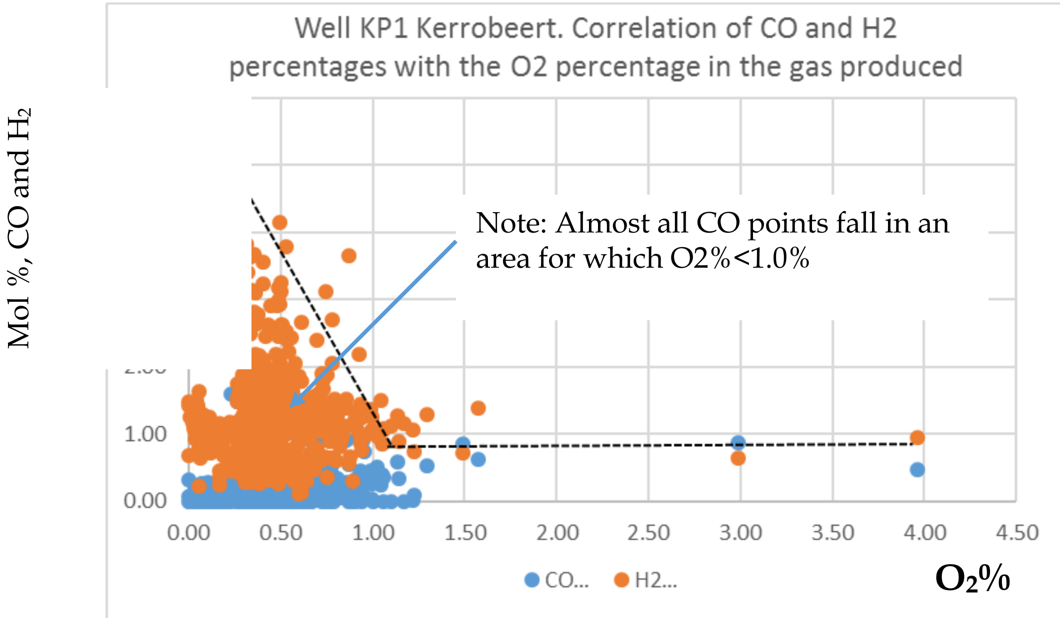

Fig. L7a: Well KP1 Kerrobert. Influence of the O_2 percentage on CO and H_2 percentages

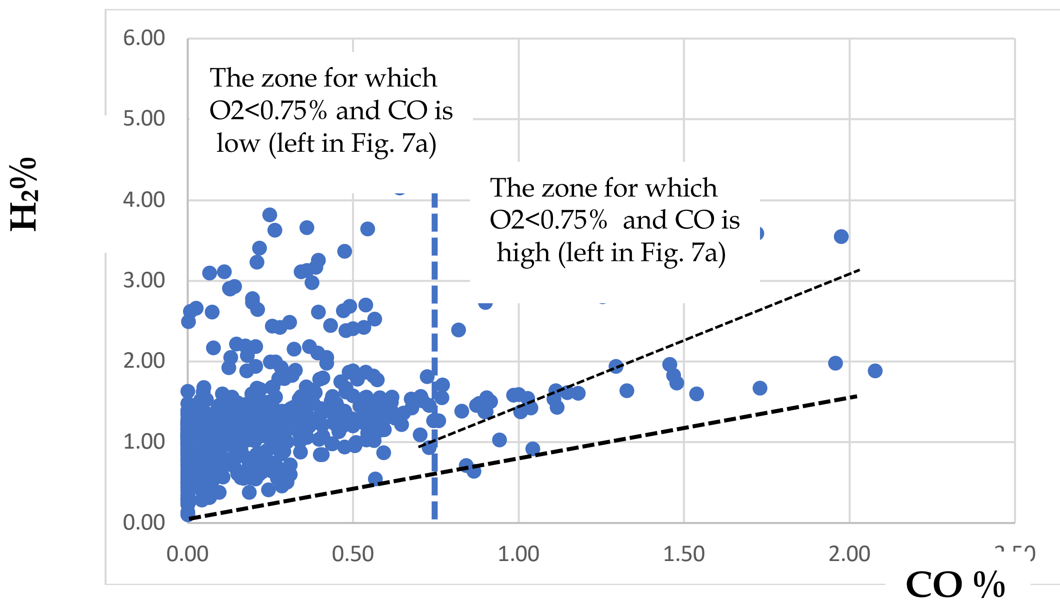

Fig. L7b: Well KP1 Kerrobert. Attempt to correlate the H_2 percentage with CO percentage, mainly for O_2<0.75%

From Fig L7a and L7b two conclusions can be drawn:

- As seen in Fig. L7a, up to an O_2% of 1-1.3% the maximum values (possible to be reached) for H_2% are always decreasing as O_2% increases. Otherwise, it does not seem to exist a correlation between H_2 and O_2 percentages. The trend for the CO % values cannot be seen on Fig. L7a.

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- As seen in Fig. 7a, when O_2 is higher than 1-1.3%, both CO% and H_2% are less than 1%; the figures for CO and H_2 are exactly halved for well KP2
- In Fig L7a it is known that the points for CO% not visible, corresponds to O2 < 1-1.3% in the produced gas. In this case, as seen in Fig. L7b CO% does not seem to correlate with H_2 for low CO%, while for high CO%, a weak correlation exists. Therefore, as seen in Fig. L7b -and correlated with Fig. 7a – for lower O_2 percentages (less than 0.75-1%) it seems that a correlation between CO and H_2 percentages can exist, if the values of CO% are high. For O_2 higher than approx. 1% a correlation does not exist, but in this case it is not very important, as both CO and H_2 percentages are very small.

The last conclusion from above (lack of CO-H_2 correlation for O_2 percentages less than 0.75-1% and low CO percentages was easily confirmed for the 2015 gas analyses of KP2 well (Table L1b,) which shows O_2% < 0.5% almost all the time (Fig. 8), which is a strong support for this finding.

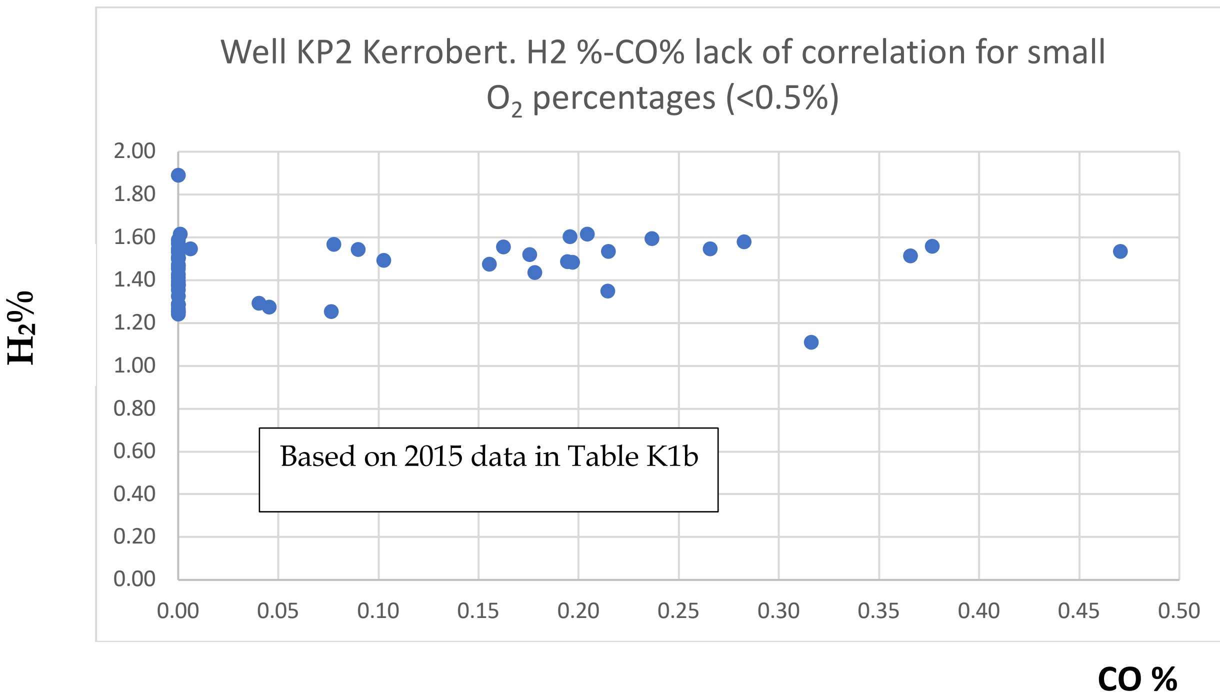

Fig. L8: Illustration of a lack of correlation between CO and H_2 percentages for very low oxygen concentrations (<0.5%) and <u>low CO concentrations</u> in the produced gas of KP2 Kerrobert

K5: Conclusions

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1. A novel method to calculate the apparent hydrogen-carbon (H/C) ratio for the THAI process, was developed. The method takes into account the coke gasification and water gas shift reactions, and assumes that all CO produced from the coke gasification is utilized in the water gas shift reactions. In principle, the method is based on the determination of the CO_2, which is not generated by oxidation. This is done starting from the amount of H_2 produced, which is considered coming exclusively from coke gasification and water gas shift reactions.

2. The novel method was applied both for the Whitesands THAI Pilot and for Kerrobert THAI Project. After applying the newly developed correction, it was found that the H/C increases, but it still shows that in the THAI process the LTO reactions are insignificant. While there was a slight increase for the Kerrobert project, the difference (increase) between H/C ratio and its value when corrected (for the coke gasification and water gas shift reactions) was much higher for the Whitesands pilot.

3. While Whitesands Pilot produces substantial amounts of CO, the Kerrobert Project produces minor amounts, frequently less than 0.5%. In both projects the H_2 content is always higher than CO content. It was found that in Whitesands there is a good correlation between CO and H_2 production for the periods when oxygen in the produced gases is less than 0.4%. For the Kerrobert Project this correlation was validated when O2 < 1-1.3% in the produced gas, *but only for high CO% values* (>0.75%); for CO%<0.75% a correlation does not exist. For Kerrobert, O2 percentages higher than 1-1.3% cause both CO and H_2 to be low, less than 1%. The complexity of the THAI execution in the presence of bottom water may cloud, to some extent, some of the correlations

4. The developed method has the limitation that the effect of CO and CO_2 produced by pyrolysis and aquathermolysis was not accounted for. Also, it was not determined if there is an effect related to the production of H_2S on the H/C estimate in the THAI process. Finally, the consumption of hydrogen by methanation process should be considered, as well, at least from a theoretical point of view.

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Appendix M

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Profile of the Authors

Alex Turta: Alex has a reservoir engineering background. He is the President of his own company, A T EOR Consulting Inc., specialized in EOR and Heavy Oil Recovery. He is also working as a consultant for his former employer, Alberta Innovates – Technology Futures (AITF), former Alberta Research Council (ARC); he has been with AITF more than 25 years. Alex has a Ph.D. in oil recovery by **i**n **s**itu **c**ombustion (ISC), with a subsequent in-depth specialization in ISC applications.

For more than 12 years, Alex was involved in the implementation and management of Suplacu de Barcau commercial project, the world's biggest ISC project. He has served as an ISC consultant in North and South America, Europe and Asia and been engaged in assignments from the World Bank and the United Nations Development Programs (UNDP); as an UNDP expert he has guided the development of Balol and Santhal ISC projects in India, from pilot to commercial stage operation.

All in all, he has been involved in 8 commercial ISC operations and 16 ISC pilots, worldwide. Alex has written over 40 technical reports directly related to the design, implementation, monitoring and evaluation of ISC projects. He has held courses on oil recovery by ISC in Canada, Romania, Brazil, Colombia, Ecuador, Malaysia, China and Japan.

Alex is the recipient of 2012 Society of Petroleum Engineers Canada Regional Reservoir Description and Dynamics Award for his contributions in theory and practice of ISC application; the citation reads "*he was instrumental in developing the theory and practice of commercial exploitation of heavy oil reservoirs by ISC using the peripheral line drive operation starting from the uppermost part of the structure; this theory has been confirmed by the successful operation of the commercial ISC projects at Suplacu de Barcau (Romania), and Balol and Santhal (India)".*

Since 2012 Alex has been maintaining a personal professional website (www.insitucombustion.ca), entirely dedicated to the in-situ combustion process. Also, he is the author of the ISC chapter in the 2013 published book, namely "Enhanced Oil Recovery. Field Case Studies", Elsevier, 2013, Editor James J. Sheng.

Since 1992, Alex has been part of the "split-team", which has continuously worked on both sides of the Atlantic, to develop novel ISC processes for heavy oil recovery, namely Toe-To-Heel Air Injection (THAI^{TM}) and its version for in-situ upgrading, CAPRI^{TM}; he and Prof. Malcolm Greaves of University of Bath, UK are principal co-inventors of these novel processes. Along with Malcolm, he has been instrumental in the formulation of the mechanisms of THAI^{TM} and CAPRI^{TM} processes. For the use of horizontal wells in heavy oil recovery, Alex introduced and defined the concept of short-distance oil displacement as opposed to the concept of long-distance oil displacement, used in conventional light oil recovery, when using only vertical wells.

Since 1996 Alex has also been instrumental in developing the Toe-To-Heel Waterflooding process, which has been under field testing in Canada and USA. Later on, he investigated the steamflooding in a toe-to-heel configuration; this process is still not entirely defined and no field testing has been initiated yet. In the last few years he has focused exclusively on heavy oil recovery, using thermal recovery methods, mainly in-situ combustion.

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Professor Malcolm Greaves: Malcolm was previously head of the Improved Oil Recovery Group, Department of Chemical Engineering at the University of Bath, England, where he is now Emeritus Professor and a consultant. His main research interests are in thermal techniques and advanced processes for in situ recovery and upgrading of heavy oil and bitumen, air injection processes in heavy oil and light oil reservoirs, horizontal wells, downhole gasification in light oil reservoirs and reservoir simulation. He is the principal co-inventor of the THAI^{TM} process for heavy oil recovery and co-inventor of the CAPRI^{TM} process for downhole catalytic upgrading. He is also guiding development on a new process (DHG) for downhole gasification in light oil reservoirs. He has authored/co-authored more than 120 original research papers on improved/enhanced oil recovery, and is a frequent contributor/invited speaker at international conferences/workshops/forums. He is a co-inventor on six patents. He has also consulted for a number of oil majors and been the lead researcher on many government/industry funded research projects and JIPs concerned with advanced oil recovery processes.

Janusz Grabowski : Janusz has a Ph.D. in Theoretical and Mathematical Physics. For last thirty five years Dr. Grabowski has worked as a numerical reservoir simulation expert with varied experience in practical applications of reservoir simulation in the oil and gas industry, as well as teaching at introductory and advanced levels. Large part of his carrier relates to reservoir simulation of thermal oil recovery. He was leading the pioneering development of the first thermal recovery simulator at Computer Modeling Group. He conducted numerous simulation studies of existing and proposed thermal EOR of steam injection, SAGD and in situ combustion for heavy oil reservoirs in Canada, USA, South America, and Africa. His experience is in integrated reservoir simulation analysis and field production optimization for a variety of oil and gas recovery processes. He has provided his expertise services for Canadian and international companies.

With the constant growth and change of the industry, he has held positions entailing supervision and management and he has successfully devised new venues for computer applications, such as efficient computer software and tomographical core analysis, and put them into operation by acting as a director within a team environment.

He is presently engaged as reservoir simulation consultant with Canadian and International Companies and has his own interest in research into renewable energies and environmentally friendly technologies.

Appendix N

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A summary of major observations arising out of the review of this report by Dr. Ashok Singhal

Note: this appendix is available upon request only.

REVIEW OF THE PENULTIMATE DRAFT OF THE REPORT

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“A Comprehensive Assessment of Toe-To-Heel Air Injection Process. Guidelines for Development of Future Generations of ISC Processes”

Ashok Singhal, Premier Reservoir Engineering Services Ltd. (2017-03-29)

The initial intent of this review was to provide a third party objective critique on *engineering soundness and scientific rigour* of this report. Earlier versions (drafts) were read, critiqued and discussed. Many parts were rewritten or revised by the principal author (AT) in order to clarify key messages in various sections. In the process, revised drafts might have incorporated the reviewer's opinions and biases. However, the reviewer has tried to remain as objective as feasible in his comments in this review. To minimize unduly influencing this report, the reviewer has confined his comments to the contents of the penultimate draft only. The reviewer focussed mainly on interpretation of Whitesands and Kerrobert Pilot projects in the penultimate draft. As of March 2017, performance data for these pilots for years 2010-2015 was gradually becoming available to the authors and much of these data was analyzed by the principal author (Alex Turta).

Innovation

For exploiting extra heavy oils (API gravity <10^o and μ<10,000 mPa.s) and oil sands bitumen resources (API gravity <10^o and μ>10,000 mPa.s), feasible enhanced recovery techniques (to-date) involved *mobilization of oil by heat/solvent followed immediately by its production over relatively short distances of travel to the nearest production wells* [‘short distance oil displacement (SDOD)’] as discussed by Turta and Singhal, (JCPT, Feb. 2004). This became apparent after many successful and unsuccessful field trials of exploitation of oilsands bitumen involving various EOR techniques. Examples of successful EOR methods in these resources include Cyclic Steam Stimulation (CSS) at Cold Lake (Alberta, Canada) and Steam Assisted Gravity Drainage (SAGD) at Athabasca Oil Sands (Alberta, Canada).

In situ Combustion (ISC) was originally designed as a Long Distance Oil Displacement (LDOD) process for reservoirs containing heavy oils with certain minimum oil mobility under reservoir conditions (oil API gravity between 10^o and 22.3^o and large enough reservoir permeability to enable adequate sub-fracture air injection rates, or for field-wide implementation of drive processes). Application of a variation of ISC in a SDOD mode (Short-Term ISC or Burn & Turn) was attempted at Wolf Lake (Alberta), where initial oil mobility was extremely low. It demonstrated the feasibility of mobilizing extra heavy oil via ISC. However, it was not considered economically viable. The authors of the current Report (specifically, Turta and Greaves) proposed another innovation, “Toe-to-Heel Air Injection (THAI)” that makes ISC applicable to reservoirs containing oil sands bitumen/extra heavy oils in the SDOD mode (Greaves and Turta, US Patent # 5,625,191, May 6,1997 and Canadian Patent #2,176,639, August 8, 2000).

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The THAI innovation involves application of dry in situ combustion (ISC) in a short distance oil displacement (SDOD) mode using vertical injectors and horizontal producers, such that the combustion front advances from the toe towards the heel of the producers.

Report's Objectives

In my opinion, an ideal "Comprehensive Assessment" for validating the new and emerging technology of THAI should contain:

A. A summary of the current state of art of the THAI technology (mechanisms, operating practices, anticipated oil rates, volumetric sweep, and recovery);
B. Description in-depth, of the two THAI pilots reviewed (Whitesands and Kerrobert: their objectives, operation, and performance);
C. Discussion of key findings impacting on design and operation of future THAI projects;
D. Exploration of various optimizing ideas; and
E. Identified niches for THAI applications. This, in turn, might involve projections of 'scoping' production profiles and degrees of oil upgrading.

This review critiqued on how far the above key objectives were addressed in the penultimate Draft Report. In this reviewer's opinion, ***the first two objectives were fairly addressed, and a good beginning was made on the last three***. The reviewer's, detailed assessment regarding meeting each of these objectives are discussed in a later section.

The Main Messages of the Penultimate Draft of the Report

The authors tried to obtain relevant data from various sources in absence of the operator's full cooperation. Due to unavailability of a more complete set of relevant data, some of the conclusions in earlier Drafts were tentative at best and often speculative, based on limited data available *then* from operator's press releases or discussions with certain key personnel. For the two field pilots studied (and their subsequent expansions), operator's main efforts were in capturing data such as temperatures, pressures, production logs, and occasional oil, water & gas samples. The data available to the authors (in increments) were analyzed and included in this penultimate draft. It was appreciated that sometimes, the incomplete data-sets could still be useful but may be inadequate in diagnosing process limitations or, in determining remedial or optimising measures. Incomplete data also prevent one from making definite conclusions. One example is the assertion of THAI having achieved a "consistently upgraded oil production" in Whitesands Pilot, without explanations on what might have caused API gravity variations of the produced oil at different times. An interesting observation from Whitesands Pilot was a short term loss in upgrading when air injection was interrupted.

My take-away from reading of the penultimate Draft of the Report were:

- THAI is application of ISC in a SDOD mode using vertical injectors and horizontal producers. The SDOD nature of the process offers many advantages, but also many challenges.
- The key to THAI's success is occurrence of fuel deposition upstream of the combustion front that – in the vicinity of horizontal section of producer - obstructs short-circuiting of the injected air into producers. This phenomenon causes a local blockage within the producer wells and their surroundings by formation of a 'coke plug'. This also seems to regulate the advance of the ISC front.
- A strong initial combustion front needs to be established for success of a THAI project.
- To initiate combustion, it is advisable to use artificial devices (e.g. gas burners, electrical heaters) to minimize ignition delay.
- THAI field projects in Whitesands and Kerrobert were carried out over for many years involving multiple injection-production well pairs and, they were conducted in a direct line drive (DLD) configuration (DLD-THAI). These resulted in sustained oil rates of several tens of cubic meters per day per well pair. However for DLD-THAI, these rates are smaller than those obtained in SAGD operations since <u>only a short section of the horizontal producer contributes to the bulk of the mobilized oil production at any given time,</u> while the combustion front migrates from the toe towards the heel of the horizontal producer.
- One of the 'niches' for THAI could be situations such as 'thin' oilsands intervals underlain by 'thick' bottom water, where THAI shows promise but other methods like SAGD or CSS are not feasible.
- There seems to be occasional but momentary instability of the heat front as many thermocouples from the toe region experienced very high temperatures leading to their failures. This phenomenon or its underlying causes are not well-understood, but could have a negative impact on commercial scale THAI operations.
- During steam stimulation of wells for facilitating initial oil production by THAI, one must use sufficient volume and rate of steam injection to ensure that at least some live steam is being injected at the sand-face.
- Since air-oil ratios are important from economic points of view, one must take into account injected air losses to regions/intervals other than the target. Bottom water intervals may provide conduits for such losses. Also, it appears that air-oil ratios could be optimised via operating procedures, including management of the reservoir pressure.
- There existed a widespread bottom water zone in the Kerrobert THAI pilot project and a relatively thin bottom water interval in the Whitesands Pilot. Since these water bearing intervals underlying the heavy oil strata act as 'thief zones' during air injection, it is expected that distribution of injected air and effective utilization of its oxygen content (in HTO reactions) was impacted by existence of these intervals.
- A further complication was suspected in the Whitesands project where there was some indication of communication between the target reservoir and overlying McMurray A reservoir. It was suggested from an overall nitrogen balance that a significant amount of air was being lost to the McMurray A interval.
- Wells need to be well protected against corrosion, erosion or scales. Re-drilling of producer wells during ongoing THAI operations - as in Whitesands Pilot - is not an option.

General Comments

To put THAI in a perspective, it is worth remembering that although there are some encouraging results, from the five reported THAI field tests worldwide, all the detailed results presented in this Report are solely from two pilot projects. Both these pilots involved direct line drives (DLD) configurations. The conclusions are therefore specific to these DLD-THAI operations. Efforts to generalize these results would involve several implicit and explicit assumptions that may not always be valid. At best, the generalizations based on such limited field results are tentative and cannot be accepted as universally "established" or "proven".

Clearly, details from additional THAI projects, when completely available, would help in improving THAI operations as well as, in further defining its niche.

Some of important questions remain unanswered due to insufficient data capture or their non-availability/access to the authors. Some of these merit further discussion and are briefly described in the following:

Effect of Bottom Water Intervals on THAI performance

While reviewing performance of the two field pilots, it became apparent that the injected air was not fully contained within the pilot areas, more specifically in the Whitesands Project. Although the thickness of the bottom water zone was relatively small (1-2m), escaped amounts of the injected air and/or generated flue gases and steam were indicated to be significant. More importantly, inferred air escape to the non-target formation (McMurray A) had potentially serious economic impact.

As mentioned, one of the 'niches' for THAI could be bottom water situations where THAI shows advantages over competing EOR methods like SAGD or CSS. Although the two pilots indicate it is possible to exploit bottom water situations by THAI, the air-oil ratios are too high compared to those seen in conventional ISC operations in absence of bottom water. Economic analyses of THAI performance (based on the two pilots and generalized simulation), and competing processes (e.g. CSS or SAGD) in the same reservoir (based on performance elsewhere and simulation) might reveal situations where THAI offers a clear advantage.

Performance assessments of role~~s~~ of bottom water in the two pilots were limited by a lack of relevant monitored data capture. In Whitesands, 'leaked' injected air from the McMurray B to the McMurray A might have caused secondary ignition there but its economic significance remains undetermined in the absence of any detailed measurements in that interval/formation. Similarly, although there are some indications of LTO in the Kerrobert project, no reservoir data were captured to study its impact. In Whitesands, there are some indications of occurrence of the main HTO above the producer well and a secondary, but cooler HTO region at oil-water contact. However, role of the latter in oil mobilization could not be ascertained.

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Why the replacement wells in Whitesands Project performed poorly?

Most likely, the reasons were:

- Mobilized oil bank downstream of the combustion front might have been dissipated during the air injection stoppage period due for the required reservoir pressure reduction/cooling for facilitating drilling; and/or
- Inappropriate location of the replacement wells vis-à-vis the old ISC front position; the communication with the old ISC front was extremely challenging, almost impossible
- Continued oxidation (HTO) by the retained oxygen was insufficient to maintain lateral expansion of the combustion/steam chamber towards replacement wells; and
- Continued water encroachment and coke formation (during the air injection stoppage period) further aggravated the situation, as pointed in the Report. Furthermore, the results suggest that it would take much longer to partially restore pre-interruption conditions once air injection resumed. It follows that for this case the re-drilling in the midst of THAI progression was not a viable option.

Next, this reviewer's comments on the Reports' meeting the objectives of an ideal "Comprehensive Assessment" are discussed.

Objective # 1: Summarize the current state of art of the THAI technology (mechanisms, operating practices, anticipated oil rates, volumetric sweep, and recovery)

The authors have done a good job of summarizing the current state-of-the-art for this evolving technology. This involved comprehensive analyses of data from the laboratory, simulation and field pilots for conventional in-situ combustion as well as, THAI processes.

THAI is essentially an SDOD process, where the travel distances between oil mobilization points in the heated region and production points in the horizontal producers are relatively short. This implies short residence times for combustion products including the heated oil within the reservoir. One of the shortcomings of the penultimate draft is inadequate elucidation of implications of THAI being an SDOD process. This reviewer would like to see more discussion of its practical implications included.

For THAI being an SDOD process, we would expect a greater degree of upgrading benefits than in a LDOD process like the conventional fire flood (ISC). Due to the shorter travel time for the mobilized oil to be produced within the reservoir, there would be relatively less mixing between the warmer upgraded and the cooler non-upgraded oil before being produced, yielding a better (upgraded) commodity. Also, since the DLD well configuration involves shorter travel times compared to staggered line drive (SLD), the latter may yield oil that is comparatively less upgraded.

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THAI, especially in a DLD mode could also increase risks of burn-out of the tubular due to being located in close proximity to the advancing HTO regions. These risks would be expected to be comparatively less severe for the SLD mode. Another mechanical implication of the DLD could be relatively high flux of flue gases at the active producing intervals, leading to sand influx/erosion of the tubular.

Due to the above, there are increased mechanical risks of completion failure. Hence, operating practices and proper design of facilities/completion (flux rates, tubular specifications for sizes & materials, and maintenance) would be critical. Obviously, these need to be verified in any field pilot for a new technology such as THAI. THAI operations in Kerrobert, however, brought encouraging information in this area; in 7.5 years none of the 12 producers was completely damaged, as the damage itself takes place from toe to heel. One-two wells experienced a liner collapse in the toe region but the rest of the length of horizontal section remained technically valid for exploitation.

Similarly, the most intriguing aspect of the THAI process is formation of a moving dense hydrocarbon blockage within the reservoir and/or tubular. This obstructs channeling or short circuiting of the injected oxygen. This phenomenon - along with gravity controlled over-riding feature - seems to be critical to success of the THAI process. It seems to be well managed in the laboratory and in the two pilots analyzed. However, the penultimate draft of this report does not sufficiently dwell on this, perhaps due to an incomplete current understanding of this phenomenon. It certainly merits further elucidation.

Just like having a strong initial combustion front is important for any THAI well configurations or pattern in sustaining oil rates, it is equally important to continuously obtain a front of fuel deposition near the burning front that would give rise to coke plugs to effectively prevent air bypassing such that oxygen content in the flue gas remains within safe, acceptable limits. The two pilots described in this report seem to have adequately accomplished this. There have never been reports of a pre-mature oxygen break-through (although several well burnouts have occurred) in these two THAI pilots. However, this needs to be explicitly addressed.

Projection of Oil Recovery and Rates: From Whitesands THAI Pilot, it was seen that for THAI-DLD in oilsands, oil was ultimately mobilized up to a length of about 250 m of the horizontal well and a width of up to 40 m on either side of the producer. Due to a lack of instrumentation, corresponding distances could not be estimated for Kerrobert but they are likely to be of similar orders of magnitude. These data could provide a way of envisioning a commercial scale THAI operation in terms of well lengths, spacing, and the ultimate recovery. The main author (Alex Turta) has attempted to estimate the shape of the combustion zone by combining certain observations and assumptions in one of the Appendices of the Report. At any given time, only a part of this region will be actively contributing to oil production. Since no oxygen breakthrough was reported in any of the two pilots, it can be speculated that it was totally consumed by a combination of HTO and LTO reactions. Assuming oil production being solely resulting from the former, one can attempt to estimate oil rates by making certain additional assumptions regarding the inferred geometry of the combustion front.

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These concepts, along with results of the two pilots provide a good starting point for estimating oil rates during THAI operations.

Other related questions needing further work are:

- How do we determine optimal air injection rates for a given reservoir and well configurations?
- What are the factors limiting achievable air injection rates as the project matures?
- Since economics of combustion projects is strongly influenced by compression costs, how can we optimize compression costs as the project matures? Would that also involve managing reservoir pressures?

Objective # 2: Describe in-depth, the two THAI pilots reviewed (Whitesands and Kerrobert: their objectives, operation, and performance)

The authors were to some extent handicapped by non-availability of complete sets of captured data on the two THAI pilots in Canada, and these data becoming available in increments. They did a very creditable job of accessing various sources (Alberta Energy Regulator, Albert Energy, EOR Projects of Saskatchewan Energy-Government, Saskatchewan Energy-Environmental Aspects in Oil Industry, Press Releases by the operator, geoSCOUT data, individual interviews, etc.). Overall, they were able to compile the available information in a coherent document.

Objective # 3: Discuss key findings impacting on design and operation of future THAI projects

One question needing clear elaboration was, "Learning from the THAI performance at Whitesands and Kerrobert pilots, what should be done differently in a new THAI project?"

The authors have discussed certain related issues in the penultimate draft of the Report, but have not pulled their conclusions in a concise "do's and don'ts" format. For example, it was inferred that a lot of air leaked into the bottom water and McMurray A zones, but implications on "what should be done differently in similar situations in future THAI operations" were only partially presented; they need to be addressed in an integrated way.

Similarly, in the two field pilots discussed, there was a clear indication that in the DLD-THAI some wells were exposed to very high temperatures and if not controlled, could have burnt out. If there is a practical way to protect the horizontal producers, it should be duly highlighted.

Nonetheless, a good start was made.

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For empirically identifying “Best Practices”, the following can be attempted:

1. By comparing the best, worst and average performing THAI well pair in the Kerrobert pilot, derive inferences on what parameters/ factors contribute to good/bad performance.

2. Do the same for the Whitesands pilot.

3. Determine if these inferences are collaborative, complementary or contradictory to each other. If contradictory, advanced analyses/ simulation can be used as aids in identifying ideas worth further investigating.

Objective # 4: Explore various optimizing ideas

Many interesting but untried ideas are included in Appendices H. and I. They need further vetting (practicality, risks, economics, etc), and Rank-Ordering.

Other approaches could emanate from fundamental analyses. For example, for identifying optimal operations for THAI, we need to determine the limiting injection rates for the specific projects. It could be that without bottom water (BW), oil mobilization in the THAI process is controlled kinetically. That is, controlled by the rate of oxygen consumption. Also, for BW situations, it may be further constrained by water coning/cusping. We can estimate these limiting conditions in terms of air injection rates and use field results from the two projects to test what actually happened when these limiting air injection rates were exceeded or were honored.

Supposing that without BW, combustion zone (HTO) resides only in the upper part of the pay and alternately with BW, a secondary combustion zone is also created at the oil-water contact, we can estimate the maximum rates of oxygen consumption. For estimating the first, we can use data from Whitesands and for the second, data from Kerrobert. We can then test the hypothesis that any excess air injection in Whitesands will mostly be wasteful. That is, it would increase AOR without increasing oil rates. If verified, we can confirm the futility of increasing air rates beyond the limiting conditions. In this way, we can define not only the range of minimum/maximum injection rates, but also the range of oil rates to be realistically expected. The Pilot result can thus be used to testing various hypotheses.

Objective # 5: Define niches for THAI applications. This, in turn, might involve projections of 'scoping' production profiles and degrees of oil upgrading

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Screening Criteria: THAI targets exploitation of heavy oil/oil sands bitumen resources that may also be amenable to application of other thermal recovery technologies. THAI's niche would be situations where it offers distinct advantage over competing technologies (conventional ISC, steam flooding, CSS or SAGD) in improving oil rate, and/or oil recovery, or economics of exploitation. Could this include immobile oil pay underlain by thick, passive bottom water zone or alternately, supported by an active aquifer? The reviewed draft of the Report only partially addresses this question.

As part of EOR screening, it would also be useful for illustrative purposes, to quantify economic benefits of 'consistent upgrading' and hydrogen production achieved during THAI, and also, of GHG emissions during THAI, compared to those from competing processes.