Evaluation of the First Field Piloting of the THAI Process: Athabasca Pilot

Alex Turta, A T EOR Consulting Inc.
Ashok K. Singhal, Premier Reservoir Engineering Services Ltd
Ravinder S. Sierra, Hurshan Corp
Malcolm Greaves, University of Bath
Mohammad N. Islam, Southern Arkansas University

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INTRODUCTION

Toe-To-**H**eel **A**ir **I**njection (THAI) is an innovative **i**n-**s**itu **c**ombustion (ISC) process in which a horizontal producer is located close to the bottom of an oil layer with its toe close to a vertical air injection well. Once initiated, the ISC front propagates from the toe to the heel region of the horizontal section of the producer. THAI provides more control on the direction of the ISC front propagation (guided by the horizontal section of the producer), and it preserves the in-situ upgrading of the oil due to its short-distance oil displacement feature. Because of its controlled gas-liquid segregation, THAI is designed to mitigate the severe override experienced in conventional ISC processes.

The Athabasca THAI Pilot represented the first testing of THAI in the field, and it was designed and implemented by Petrobank Energy and Resources ("Petrobank"), based on the THAI patent (US Patent No. 5626191, 1997, Canada Patent No. 2176639, 2000); it was called Whitesands Pilot (sometimes referred as Conklin Pilot). The patents basically describe two separate well applications: a **d**irect **l**ine **d**rive (DLD) configuration and a staggered line drive (SLD) configuration, for which an eye-bird views are provided in Figure 1 and Figure 2, respectively. An illustrative cross-section of the process is shown in Figure 3.

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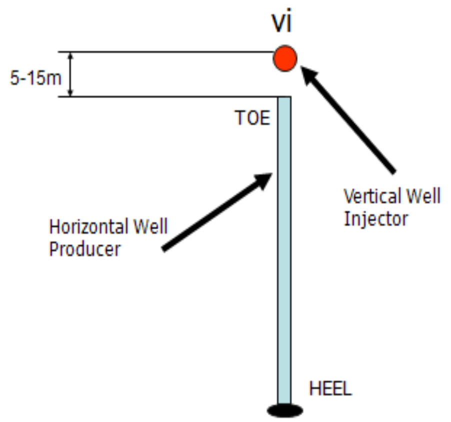

Figure 1: Plan view for Direct Line Drive THAI well configuration

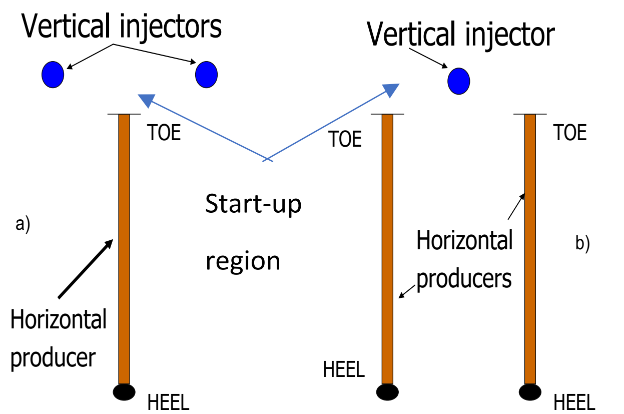

Figure2: Plan view for Staggered Line Drivel THAI Well configuration

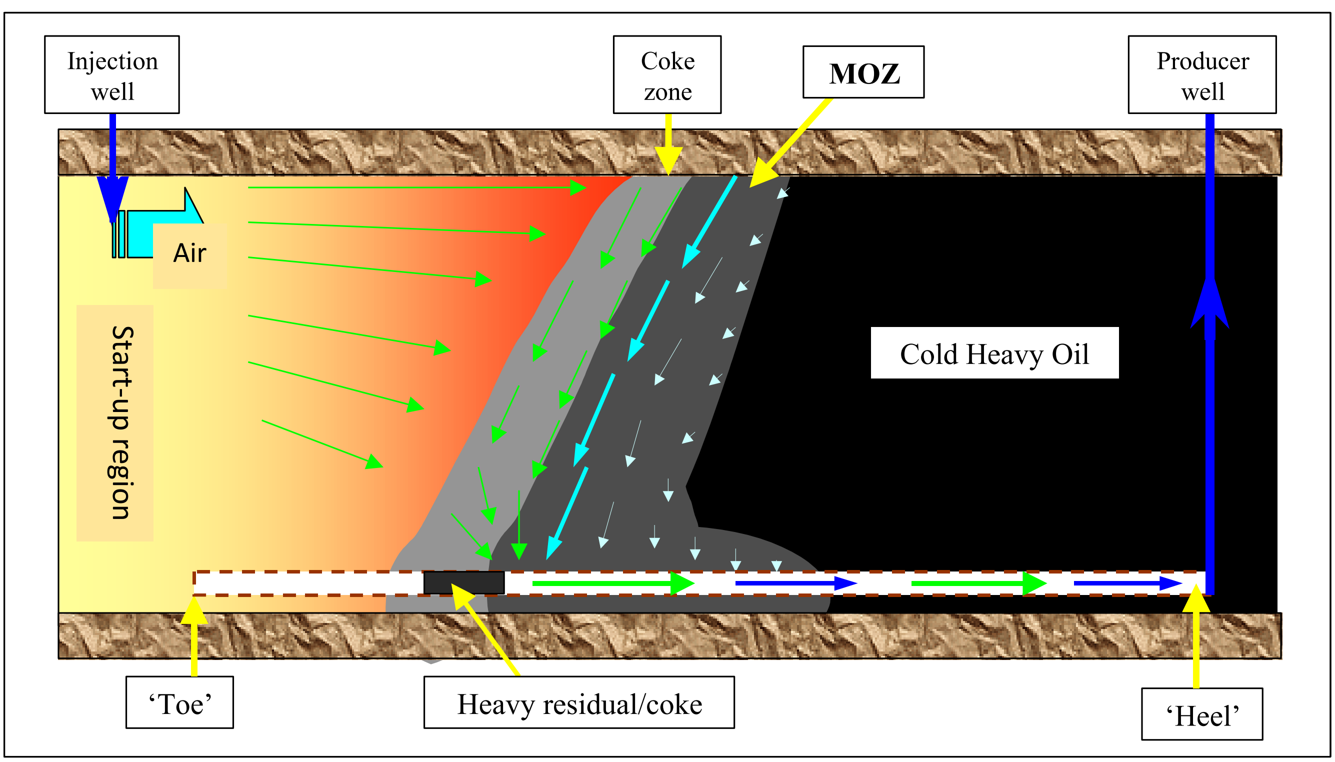

Figure 3: Simplified schematics of THAI process during the toe-to-heel propagation phase

In both cases, the patents indicate that the vertical injector should be perforated high in the oil formation. The Whitesands Pilot tested the DLD well configuration.

A new process called CAPRI (**CA**talytic upgrading **PR**ocess **I**n-situ) is developed, if the horizontal section of producer is surrounded with a catalyst layer, this way forming an underground radial in-flow reactor.

According to the USA patent: 5,626,191/1997 THAI is operated in line drive configuration and involves the following 3 phases:

1. Pre-heating of the start-up region
2. Ignition and generation of a quasi-linear, ISC front, and its propagation inside the start-up region
3. Then, ISC front is anchored at the toe of horizontal producer and propagated from the toe to the heel of horizontal produce.

The two first phases include the generation of hot communication and ignition (separately or lumped together); sometimes (in very particular situations) one or both of them can be skipped.

Starting in 2006, 7 THAI pilots in 3 countries (Canada-2, China-3 and India-2) have been operated.

Athabasca Pilot (Whitesands Pilot), Alberta Province, Canada, in Athabasca oil sands region was the first one worldwide, and it was operated in the period 2006-2011; it will be evaluated in this paper. The second pilot was Kerrobert Project, Saskatchewan Province, Canada, which started in 2009 and it is an ongoing project, although at a smaller scale.

In China, the pilots started in 2012. In India in 2016 a semi-commercial operation and a pilot were set up, which are still in operation.

Application has been in direct line drive (DLD) configuration in Canada and China, and using staggered line drive (SLD) configuration in India.

The present paper analyzes and discusses the Athabasca THAI pilot, which has been a pioneering work, based on just extensive laboratory tests and simulation (Turta, 2018). In essence, an in-depth analysis was directed towards evaluation of the ignition operation leading to the generation of the ISC combustion front and sustainability of the ISC process. Also, configuration and the size of the burned zone was assessed, including the advancement of the ISC front along the horizontal drains of producers. Finally, as in any ISC field test, an estimate of the air-oil ratio and oil recovery was made. Unlike any conventional ISC projects, however, the THAI pilot came with two new aspects; it produced in-situ (underground) upgraded oil and hydrogen was contained in the produced gases; both aspects were also evaluated.

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It should be noted that all data for injection and production was taken from open public sources, while the data on gas composition and temperature recordings - when the source is not specified - was taken from Petrobank Energy & Resources presentations to ERCB and to Innovative Energy Technology Programs (IETP).

THAI PILOT LOCATION, WELLS LAY OUT AND RESERVOIR PROPERTIES

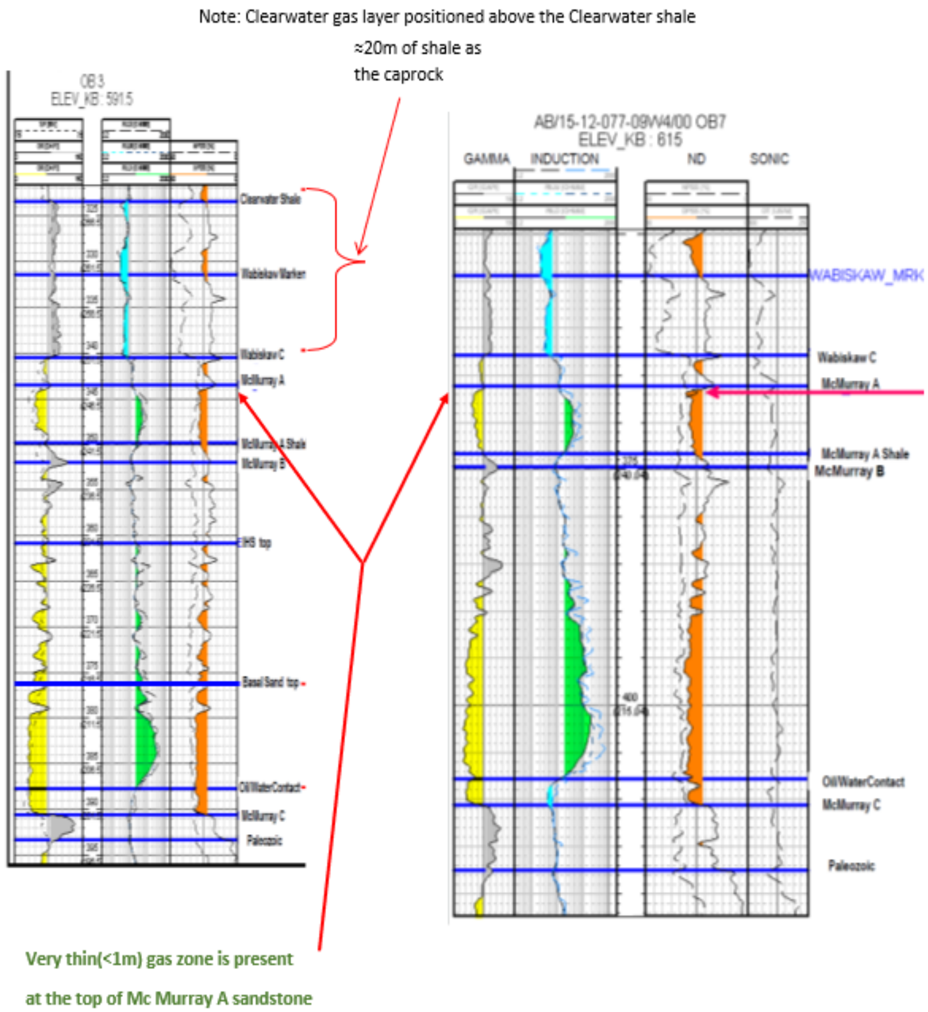
For more details on the geology and on the set up of the Whitesands THAI pilot, the reader is referred elsewhere (Ayasse, 2005; Petrobank Application, 2003; and Petrobank ERCB Presentation, 2009). However, a brief summary is provided below.

The Whitesands Lease is located in the south-eastern corner of the Athabasca Oil Sands Region in Alberta, Canada, not far away from the hamlet of Conklin. The THAI process was tested in the McMurray "B" formation, which contains at its upper part the IHS layer (Inclined Heterogeneous Strata) of relatively low-quality rock, which is also oil saturated.

Above the IHS layer - going upwards- the following formations were identified: McMurray "B" Shaley Sand, McMurray "A" layer, Clearwater shale and Clearwater sandstone. The first 3 formations are oil-saturated, while Clearwater sandstone is gas saturated and had been partially depleted at the initiation of the THAI pilot (IETP Presentation, 2009). Typical logs and reservoir properties are provided in Figure 4. As resulted from Figure 4, the geology is relatively well known. The target reservoir for the THAI pilot - McMurray "B" formation – has an average depth of 380 m. Its total gross pay thickness is about 37 m, with a net to gross ratio around 0.47, therefore a relatively low ratio. The porosity is 30-35%, while horizontal permeability is in the range of 4800-8500md.

It has to be mentioned that the upper McMurray "A" formation, although of much smaller thickness (6m) has lower but relatively good formation properties: porosity: 30%, permeability: 800mD and oil saturation: 72%. It was not the target of the THAI piloting.

The McMurray formations are almost flat (dip less than one degree; dipping from NE to SW), and therefore, for any practical purposes, the orientation of the toe-up or down on structure is not a consideration. However, the direction of the maximum permeability on a NE to SW direction was a consideration and unfortunately was not accounted for when positioning the horizontal section of producers (Figure 5).



Average gross pay thickness	37m
Average net pay thickness	~ 18m
Net/gross thickness	0.48
Depth	380m
Porosity	32 to 35%
Horizontal permeability	4800 to 8500mD
Vertical permeability	4400 to 7800mD
Oil saturation	0.7 to 0.75%
Oil asphaltene content	16.9%
Oil gravity	~8° API
Viscosity (dead oil) @ 20 ^{0}C)	550,000cp

Figure 4: Well logs of observation wells OB3 and OB7, and reservoir properties of McMurray “B” formation, the objective of the THAI piloting (IETP Whitesands Annual Progress Report: 2007)

The pilot consisted of three horizontal producers spaced at 100m from each other; all three producers (P1 to P3) had their toes in proximity of the vertical air injection wells (A1 to A3), which had lower perforations for steam injection and upper perforations for air injection.

There is a thin bottom water zone with a thickness in the range 0-3 m, which has a decreasing trend from P1 well towards P3 well.

As is shown in Figure 5, the pilot consists of three parallel and adjacent well pairs. It was one of the best instrumented in-situ combustion tests ever conducted, as evidenced by the completion information listed below:

- The pilot had 16 observation/temperature wells. In each of these wells, 11 thermocouples were placed in the production zone and 5 were located in the overburden.
- Thermocouples were also installed in the horizontal section of each of the three production wells (see Fig. 4).
- 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.

With the direct line drive (DLD) well configuration utilized in this pilot, the horizontal producers were drilled 1.5-2 m from the bottom of the formation (Petrobank Application to ERCB, 2003; Petrobank ERCB Presentation, 2009). Practically, the shoe of the vertical injector is above the toe region of the horizontal producer, being some 3 m laterally off.

Some observation wells had no perforations, but were completed with a casing, while others had no casing but they were small diameter wells completed with just a tubing, which were cemented up to the surface (outside and inside) and had axial thermocouple cables inside.

It should be mentioned that, eventually, a strong ISC front was developed in all three patterns. However, there were some differences between the performance of ISC in the three patterns. These differences were related to the very frequent air injection stoppage, which occurred mainly in the pattern A3-P3, showing the lowest performance. Compared to other two patterns, in this pattern, lower air injection rates were practiced due to injectivity problems.

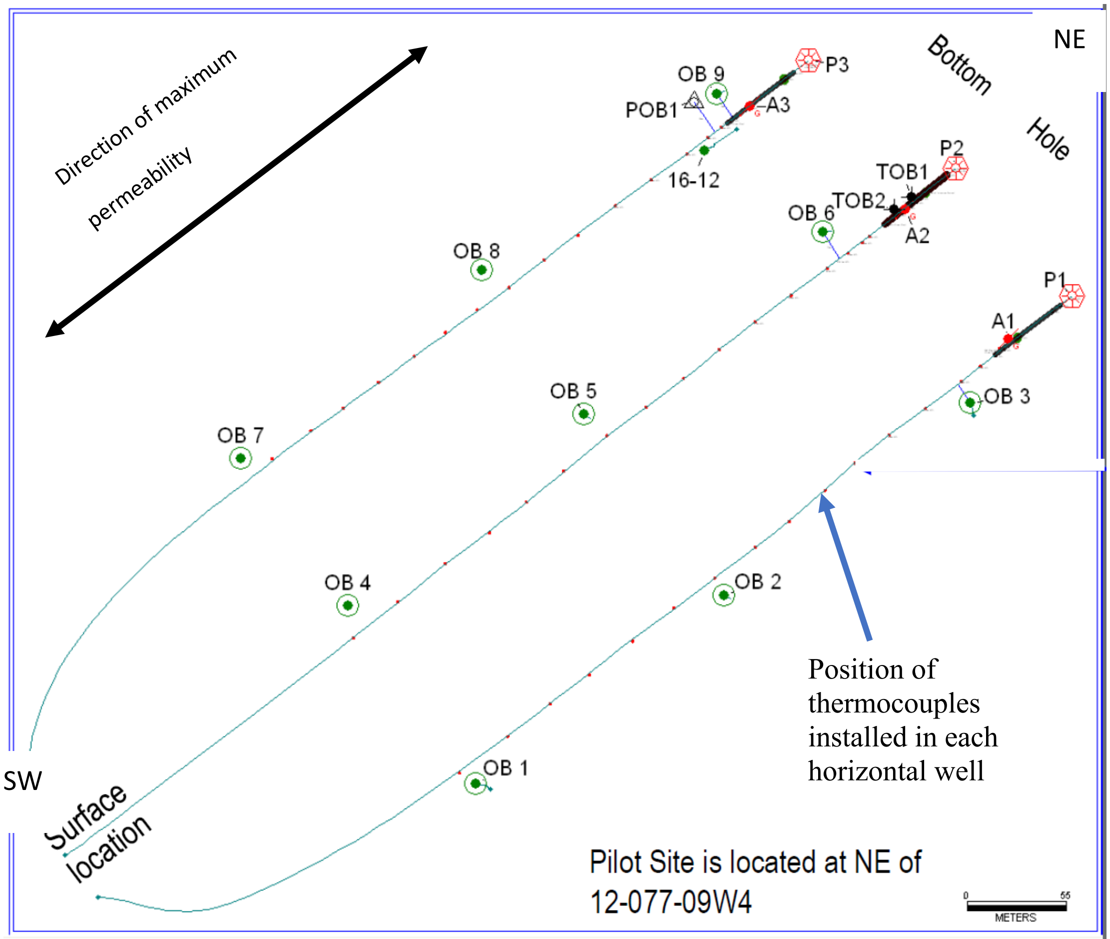


Fig. 5: Well layout for the Whitesands pilot wells: production wells (P1-P3); injection wells (A1-A3); observation wells (TOB1-TOB2) and (OB1-to OB9) (Petrobank IETP Presentation, 2009)

Pair A1-P1 displayed the strongest ISC front and a good performance; it seemed to have the best development of the ISC front. Also, a good and consistent performance was noticed for pattern A2-P2, which also provided the richest temperature information from the observation and the production wells; therefore, it allowed for the most accurate lessons to be learned from this THAI pilot.

All three horizontal wells were replaced with new producers in 2008-2009; for the pair A3-P3 this replacement occurred in 2008, and it was associated with testing of the CAPRI process in this well. For the other pairs, the replacement happened in 2009 and demanded a long period of stoppage of air injection (Figure 7).

INITIATION OF THE THAI PROCESS (IGNITION OPERATION). SUSTAINABILITY OF IN-SITU COMBUSTION

This section discusses the determination of ignition delay, which is the delay between the start of air injection and the generation of the self-sustaining ISC front in the oil-bearing layer. The initiation of the ISC process (ignition) was realized via preheating the surroundings of the injectors by steam injection followed immediately by air injection. Due to the increased temperature of the formation rock around the injectors, spontaneous ignition took place and ISC fronts were generated.

Spontaneous ignition in its original form was developed and investigated for the application at the original reservoir temperature (Burger,1976); its mechanism involves a very short period of reverse ISC. It is based on the existence of low temperature oxidation (LTO) reactions. These reactions, although they take place at a low rate, because they are exothermic, they eventually lead to a *progressive rise* of the peak temperature and generation of the ISC front.

During conventional ISC applications in the field, there are production wells around the injection wells, and the composition of the gases produced by those wells can be analyzed in terms of oxygen (unconsumed), nitrogen, carbon dioxide, carbon monoxide, hydrocarbon gases (mainly methane) and hydrogen content. Based on the variation of these individual gases, it is possible to draw a conclusion on whether an ISC front has been generated, and the time associated with this generation. However, a more rigorous approach is to combine these individual gas compositions into a synthetic parameter called the **a**pparent **a**tomic **h**ydrogen-**c**arbon **r**atio (AAHCR); a sharp reduction in time of the AAHCR marks the phenomenon of ISC front generation, and therefore indicates the ignition time. AAHCR also gives a clear detection of timing for the appearance of a high peak temperature (start of predominant occurrence of high temperature bond scission reactions); a value less than 2 - 2.5 indicates the completion of ignition. During THAI process, the parameter

AAHCR is determined based on the composition of gases produced by the horizontal producer. The spontaneous ignition was performed by injecting a slug of steam for local pre-heating of the injection wells surroundings (entire start-up region was not pre-heated), just before the start of air injection. Steam was injected for 2.5-4.5 months at an injection rate of around 60 m3/day; a steam title of 62% was estimated to enter the formation. Main details regarding enhanced spontaneous ignition operations for estimation of the ignition delay for the Athabasca THAI pilot are provided elsewhere (Turta, 2022). At the wellhead, steam injection pressure was around 4,000 kPa, steam quality: 80 % and steam temperature: 280 0C; a steam title of 62% was estimated to enter the formation.

The ignition delay (time) was established by four independent methods, namely:

1. Based on the oil production variation
2. **B**ottom **h**ole **t**emperature (BHT) in observation wells TOB1 and TOB2
3. BHT at the toe of horizontal producers
4. Variation of the of AAHCR parameter

The first method is very approximate and it is feasible here just because the oil is immobile at reservoir condition; it substantially overestimate the ignition delay. The second and third method also overestimate the ignition delay, but to a smaller degree. The most precise method is the fourth one but also is by far more labor intensive.

High temperatures were recorded in the closed observation wells. Anchoring of the ISC front to the horizontal drain occurred in all three cases and it was at the toe, as signaled by a very high toe-temperature (600-800 ºC) recorded by a thermocouple located close to the toe of P2 well, for instance.

The first ignition operation was executed for the injection well A2 of the pair A2-P2 located in-between the other two pairs (Figure 5). For this pair a better estimate was made using all four methods (as compared to the case of other two pairs), but particularly so for the fourth method. Operations were carried out in the period March 2006-August 2006, with generation of the ISC front in August 2006; ignition time was one month. For the other two THAI pairs the ignition was achieved in up to 2 months. However, the use of AAHCR variation method for these two other pairs was more challenging as being ignited later a distortion of gas composition occurred due to communication between A2-P2 pair and the adjacent ones. This distortion led to a more difficult application of the method based on variation of the of AAHCR parameter (Turta, 2022).

Sustainability of ISC was firmly proven; a vigorous ISC front was generated. Very good gas composition of the produced gas with almost no oxygen. There was very good oxygen utilization efficiency (total lack of oxygen short-circuit through the horizontal producer). The produced gas composition for the producer P1 is shown in Figure 6; a percentage of hydrogen in the range of 2-5% was recorded; sometimes it increased up to 15%. As seen in this figure there was a long duration air injection stoppage in the period June-October 2009; this was necessary for the drilling of the replacement wells P2b and P3b. While well P3b was drilled in 2008, wells P1b and P2b were drilled in 2009 (Fig. 6). Figure 7 shows both the original producers (P1-P3) and their replacement (P1b-P3b); the outline of the area taken into account for OOIP calculation is also shown.

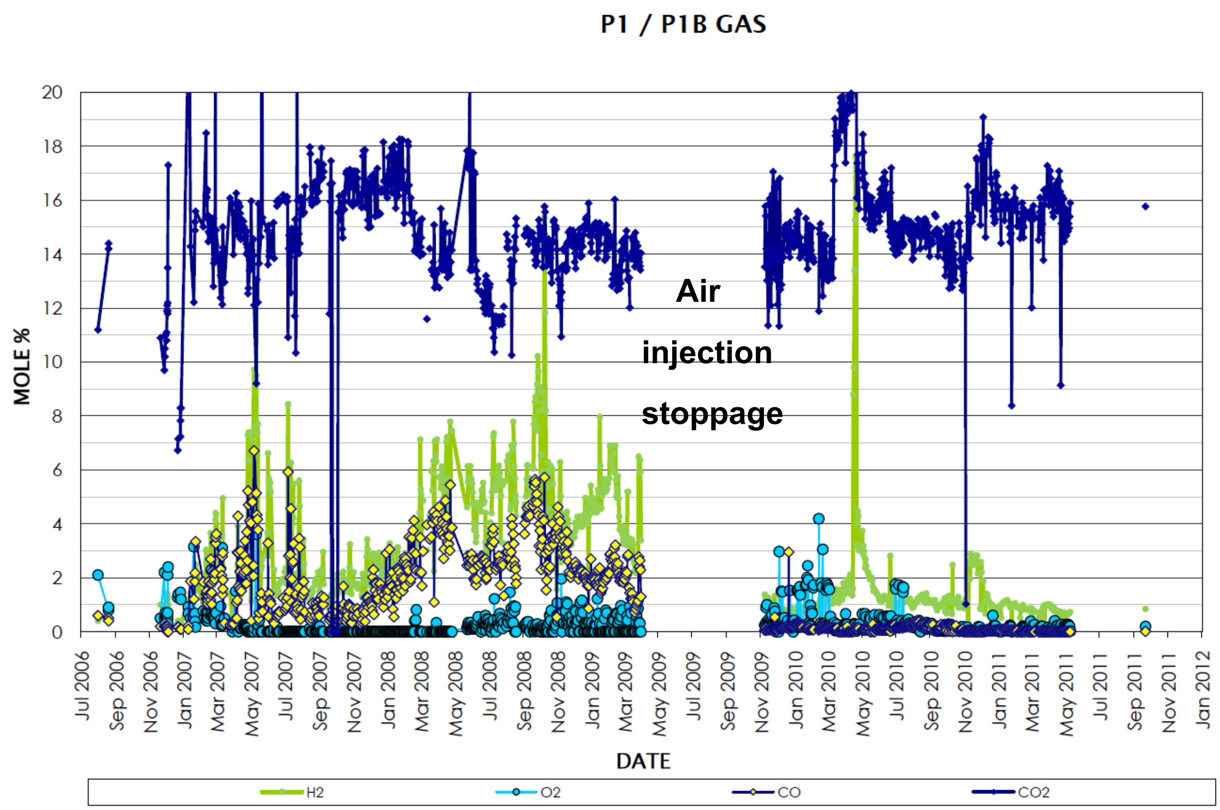


Figure 6: Variation of the produced gas composition for the horizontal producer P1 of the pair A1-P1

As seen in Figure 6, there was very high stability to the long air injection interruption. Additionally, this high stability was confirmed during sudden, pronounced air injection rate increases, where, unlike the case of conventional ISC processes, no unconsumed oxygen appeared.

The replacement wells P1b to P3b also had thermocouples installed along their horizontal sections and they recorded the temperature profile in order to find out if the anchoring of the ISC front happens and afterwards propagates toe-to-heel along the new horizontal drains. However, this time no new preheating and/or ignition operations were carried out.

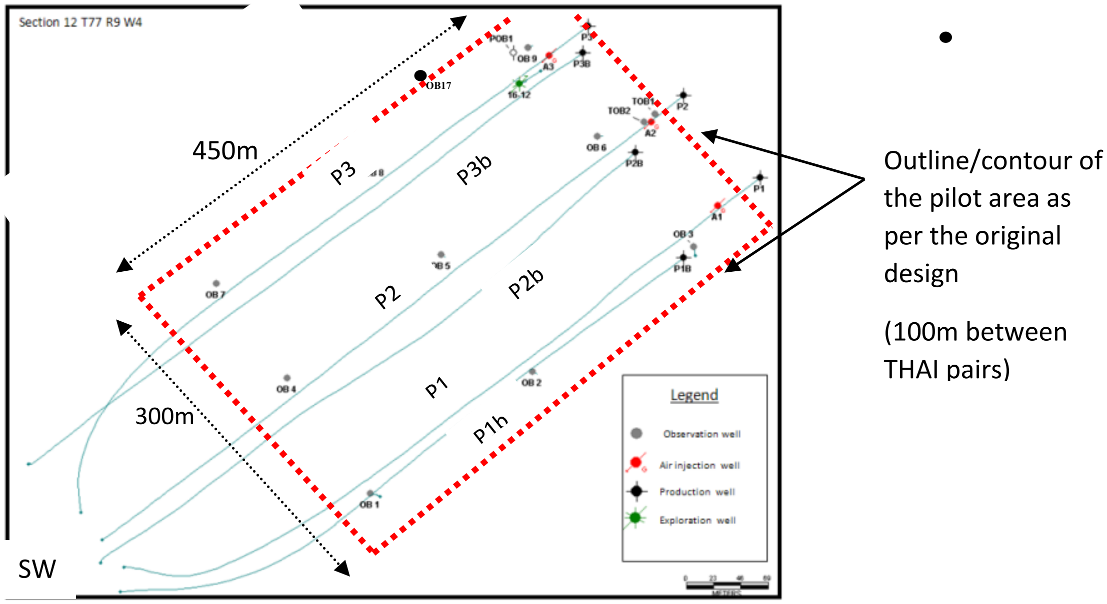


Figure 7: Map with the original production wells (P1-P3) and their replacement (P1b-P3b).

CONFINEMENT OF THE PILOT AREA. CONFIGURATION AND SIZE OF THE BURNT-OUT VOLUME

While the confinement of the pilot area refers mainly to the air escape to an upper formation as interpreted from the **b**ottom**h**ole **t**emperatures (BHT) of the observation wells, the configuration and size of the burnt-out volume of reservoir resulted from interpretation of BHT records of both observation wells and production wells.

Confinement of the pilot area

The analysis of the confinement of the pilot area has been carried out both for the escape of injected air into the bottom water (BW) zone and towards the upper formation McMurray "A".

Although the BW thickness was very small (1-2 m), detailed calculations confirmed that BW had a role both in letting air escape within, and in water (belonging to BW) being produced as excess water cut. The detailed calculations showed that the real water cut corresponded to an amount of water higher than that resulting from the displacement of connate water and generated by ISC process, therefore, higher than this theoretical (calculated) water cut.

For analysis, taking into account the performance of the pilot (Figure 13), three periods were established, namely:

- First period: until August 2007

- 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).

For the first period (initial one), there was almost equality between theoretical (calculated) water and produced in reality (given the amount of steam injected for stimulation), therefore the real water cut was approximately equal to the calculated one. However, for the second period, real water cut was 71% instead of 60%, while for the third, last period it was 88% instead of 71% (Turta, 2018). These values are by far higher than the value of 23%, from the initial design (Ayasse, 2005), which definitely represented an error. consequently, it was clearly demonstrated that water from the BW zone was produced most of the time. Probably, there was some oil trapped in BW but it was not been possible to estimate it. Via the BW, some gases travelled high distances, as it was shown by the observation well OK17 located 150m North-West of the A3 air injection well of the Pilot (Fig 7). This was confirmed by the seismic surveys performed in the 2008-2011 (ERCB Presentation 2012), which in 2011 showed combustion gases in well OB17.

However, a more important effect was related to the injected air escaped in McMurray "A" formation and generating a secondary conventional ISC front. This happened from the very beginning, due to the entrance there of the steam injected for the pre-heating in view of ignition operation. Downplaying of this event by the operator has been observed.

The escape of air into McMurray "A" formation is well documented through **b**ottom**h**ole **t**emperature (BHT) profiles in observation wells. Figures 8 and 9 show the BHT of observations wells TOB2 and TOB1 located close to the toe of producer P2 (and to air injection well A2); A2-P2 was the first THAI pattern (module) to be operated starting with March 2006, when the steam injection for pre-heating/ignition started. The BHT from these two observation wells are complementary and they strongly sustain each other; while TOB2 (located at 7.5m) shows a clear peak temperature (250 ^{0}C) in McMurray "A" formation, well TOB1 (located at only 2.5m from A2 air injection well) shows a peak temperature of 320 ^{0}C, with an extrapolated value of more than 350-500 ^{0}C, as the thermocouples were damaged by excessive temperatures (Fig. 9). These peak temperatures were located at the top of McMurray "A", showing a high degree of gravity segregation for this conventional ISC process developed in this formation.

In Figure 10, both the nitrogen balance for well P2 and the map with appearance of combustion gases in upper formation of Clearwater formation are provided. The balance of nitrogen was similar for the other two patterns. For the whole THAI pilot (3 patterns) the values of ratio N2-prod/N2-inj are: 0.53 for 2006-2007, 0.74 for 2006-2008 and 1.1 for 2009. As mentioned, in 2009 the air injection was interrupted for 3-4 months and reservoir pressure declined pronouncedly. Gases from McMurray "A" flowed back to McMurray "B" formation. However, in the period 2006-2009 a substantial portion of air injected flowed towards the McMurray "A" formation; this is estimated at 25-30 % for this period.

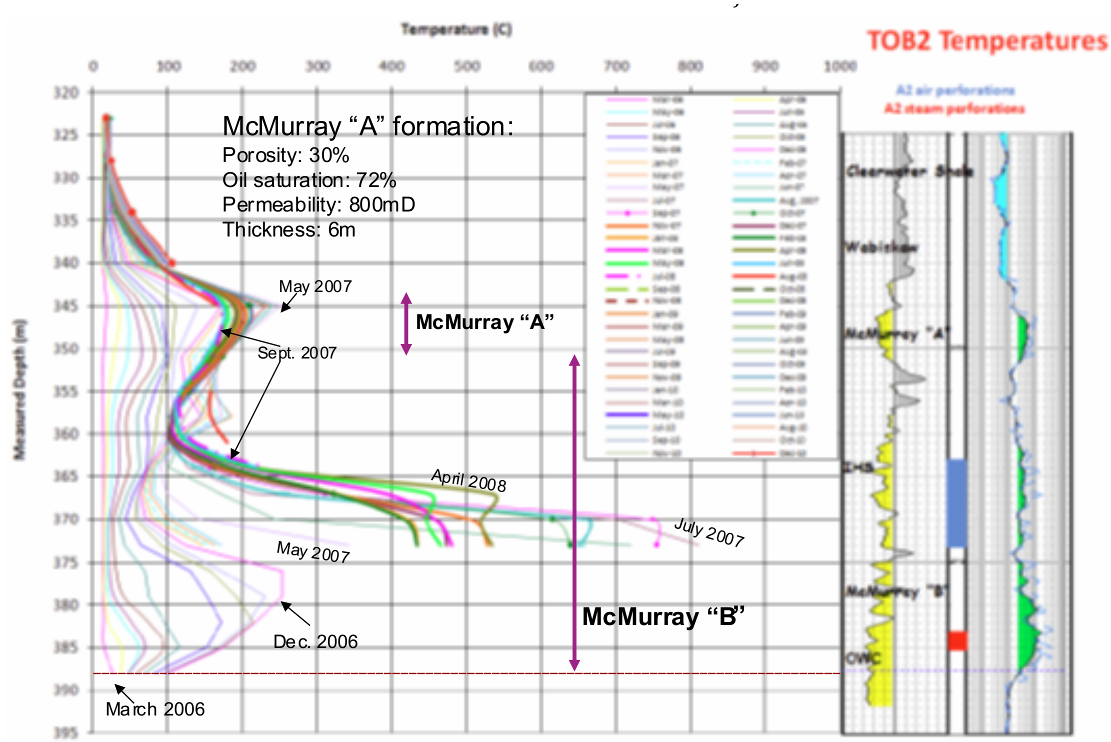


Figure 8: BHT Temperature Recording in Observation Well TOB2 Showing the Unintended conventional ISC Front Generation in McMurray "A" Formation. TOB2 is located 7.5m from the injection well A2

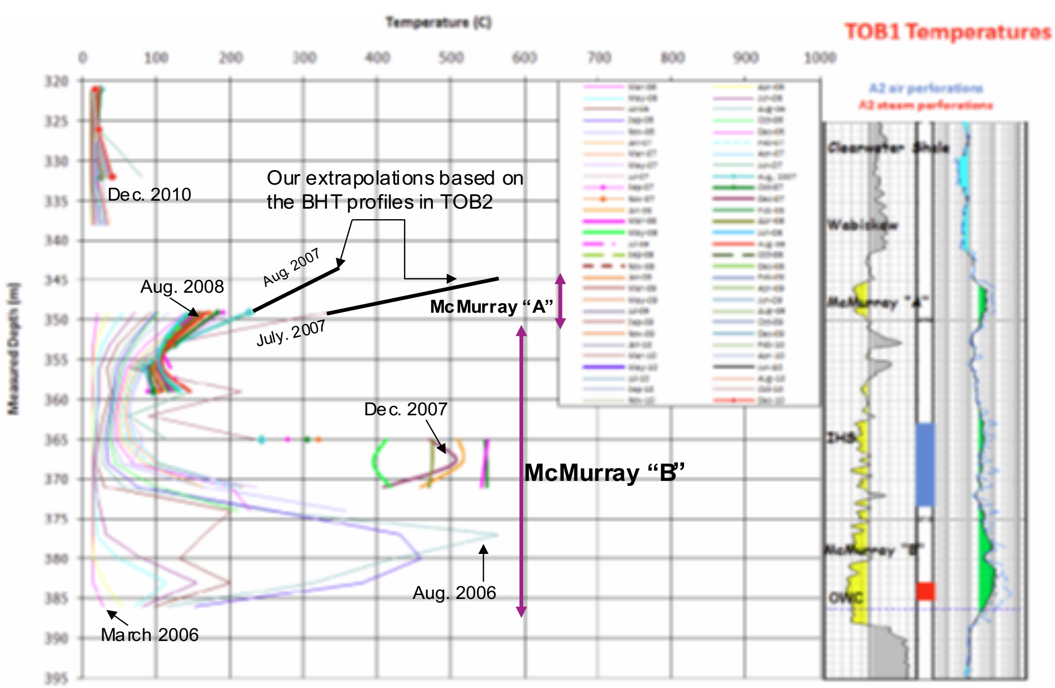


Figure 9: BHT Temperature Recording in Observation Well TOB1 Showing the Unintended conventional ISC Front Generation in McMurray "A" Formation. TOB1 is located 2-3m from the injection well A2

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.) $10^3 sm^3$	Ratio N_2-prod. / N_2-inj.	Source
2006	5.49	4.3	0.74	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

Migration of the combustion gases via the McMurray "A" Layer. Data from 2011.
IETP Presentation

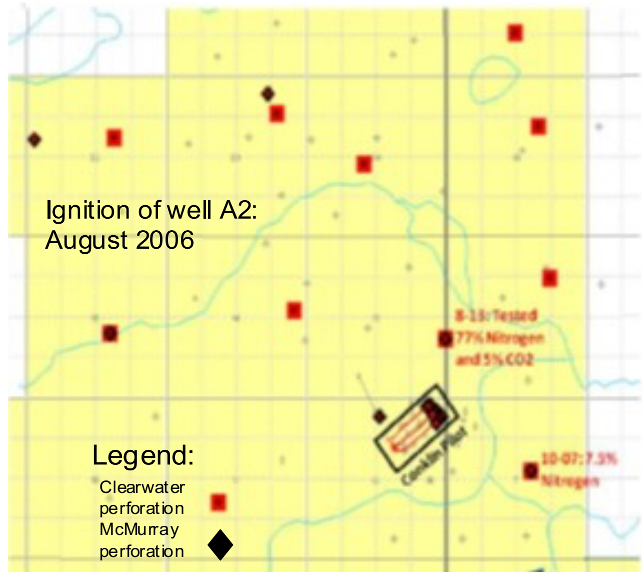


Figure 10: Confirmation of air escape from McMurray "B" formation to McMurray "A" formation as expressed by the nitrogen balance and migration of combustion gases long distance via the McMurray "A" formation. Nitrogen balance for A2-P2 pair.

The appearance of combustion gases in upper formation was confirmed by Devon Co. operating a gas reservoir (Clearwater formation), located at a lower depth; a percentage of 77% nitrogen was recorded in 2011 at a well located more than 1 km from the point of air injection.

Configuration and size of the burnt-out volume

As mentioned, the anchoring of the ISC front to the toe of producer happened in all three cases. A typical case for P2 producer is shown in Figure 11. For this producer the ISC front advancement along the horizontal section of producer was around 31cm/day. For the other pairs this velocity was in the range of 24-26 cm/day.

As a general rule, the thermocouples went out of function (due to BHT values higher than 700 ^{0}C) in an order starting from the toe and then going closer to the heel for a portion almost equal to half of the length of the horizontal section.

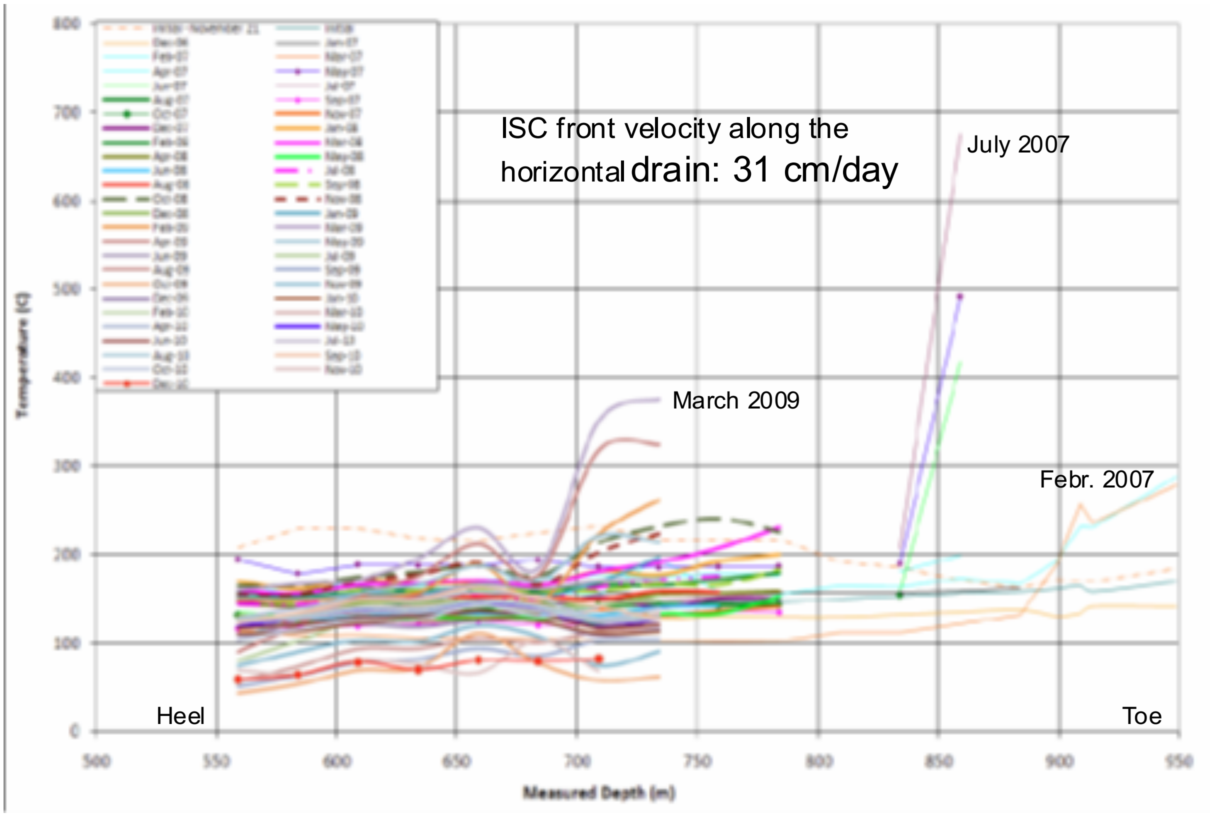
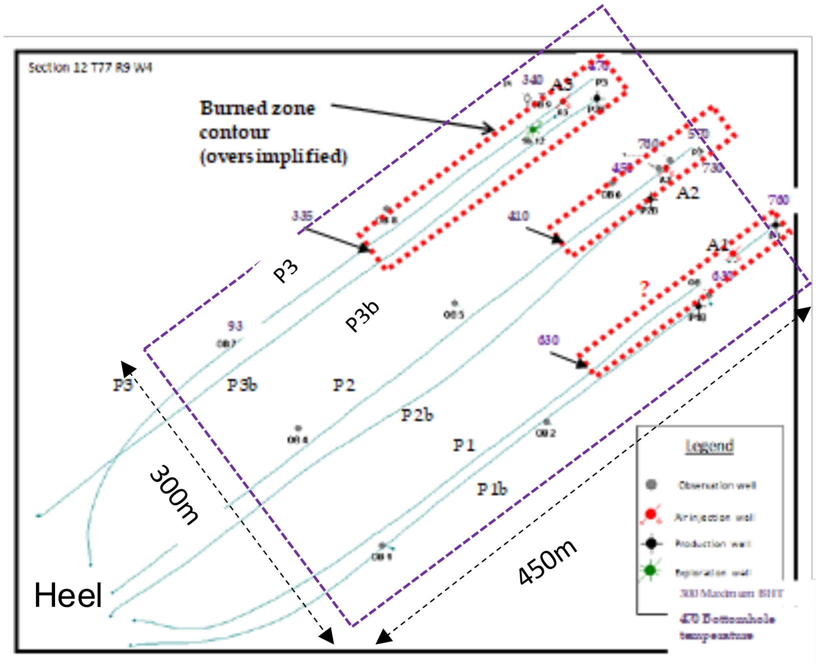


Figure 11: Advancement of the ISC front along the horizontal drain of producer P1, as indicated by the BHT recorded. Ignition of A2 well in March 2007.

Based on the BHT recorded in the observation wells an ISC front velocity towards the observation wells (therefore a lateral ISC front velocity) in the range of 3 to 10 cm/day was estimated. Figure 12 shows a rough, ultra-simplified estimate of the burned zone in a horizontal plane. As seen from this figure, the replacement wells P1b and P2b have their horizontal drains outside the burned zone and their toes are not close to the burned or heated zone (adjacent to the burnt-out zone). This explained their poor performance.

In reality, the 3-D configuration of the burnt-out volume is that of a half-truncated cone having its big base in the toe region; one of its geometrical generator is located along the horizontal section of producer, while its height may be parallel to or just at the interface oil formation/overburden; velocity of the advancement of the ISC front was considered for the vertex (apex) of the semi-cone.



Note: ? Denotes the fact that there is no temperature control on that side (no temperature measurement)

Figure 12: Maximum BHT recorded in the observation wells and in the horizontal producers. Rough estimate of the burned zone distribution around each THAI well pairs, as of July 2010

PERFORMANCE OF THE PILOT, INCLUDING IN-SITU UPGRADING OF THE OIL

The technical performance is analyzed in terms of air oil ratio, oil recovery and operational problems, while in-situ upgrading of the oil will be related to the permanent, substantial decrease of oil viscosity along with increase of its API density. However, the contribution of the in-situ upgrading to the improvement of the performance, including the oil rate increase was not evaluated in this pioneering THAI pilot.

Performance of the pilot

As the THAI technology know-how is still in its infancy, the evaluation of the pilot will be pursued making use of the extensive know-how and parameters from the area of conventional ISC application (Turta, 2018).

As seen in Figure 12, the lateral development of the burnt-out zone for this **d**irect **l**ine **d**rive (DLD) configuration was low, just 20m off the trajectory of the horizontal drain. Coupled with the fact that the ISC front advanced only half the horizontal drain, the volumetric sweep efficiency was less than 20%. The DLD configuration was not able to assure a good volumetric sweep efficiency for this design of 100m-distance between pairs. Taking into account the original contour of the pilot area -as seen in Figures 7 and 12 – an oil recovery of 7 % OOIP of that pilot area was estimated.

Figures 13a-b provide the variation of air injection and oil production performance for A1-P1 THAI pair, which was very similar to that of A2-P2 pair, while for A3-P3 it was a bit different due to frequent air injection stoppages. The graph for the whole pilot also is almost similar in character. Figure 13 b shows some steam injection in the horizontal producers, which was carried out via a coiled tubing. Its goal was to stimulate oil production, and it was more intensively applied in the first period of P1-P3 original producers, and in the first period of P1b-P3b replacement producers; the daily injection rates were in the range of 20-70m^3/day. Their effectiveness was doubtful, as the best oil production was actually obtained in the 2008-2009 period, when very little steam was injected (less than 10m^3/day/well).

From Figure 13, it results that the effective oil rate per well was in the range of 10-30 m^3/ day. This compares favorably with that of 3-4 m^3/day in all previous old ISC trials in Athabasca (Turta, 2018). However, this does not compare favorably with the design daily oil rate of 100m^3/day for a maximum air injection rate of 85,000sm^3/day (Ayasse, 2005). As the maximum air injection rate in the Pilot reached only 40,000sm3/day, an oil rate of 50m^3/day was supposed to be reached but this did not happen; only 15-30m3/day was achieved.

Within 5 years, the THAI pilot produced a cumulative of oil of approx. 29,000 m^3 (Figure 14), and also this figure was higher than that of any other ISC tests, conducted in this region.

From Figure 14, it results that the final cumulative air-oil ratio (AOR) was around 6,000sm^3/m^3. However, from Figures 13 and 14 it is clear that the stabilized period was 2008-2009, and in this period the AOR was 3000-4000sm^3/m^3, while the effective oil rates were highest. This stabilized period can be considered for a future design of a THAI process, being accepted as a maximum performance for a THAI process applied in a DLD configuration.

From Fig. 14 it can be observed that the stabilized period of 2008-2009 was obtained just before the time of the drilling of the replacement of horizontal producers. An official statement of the reason (s) for the drilling of replacement wells does not exist. However, the main consultant of this pilot maintained that they were drilled due to existing liners' failure (as related to excessive temperatures and sand influx); as it was claimed at that time, liners with new slots were designed, for a better performance (Donnelly, private communication, 2021).

Definitely, this replacement did not bring the desired outcome. Due to a lower performance, after the replacement the AOR gradually increased; cumulative AOR increased from 3000-4000sm^3/m^3 to 6000sm^3/m^3 in the last period of the pilot. There are two main reasons for this low performance, namely:

1) The placement of the horizontal drains of the replacement wells
2) An excessive period of air injection stoppage

The placement of the horizontal drains was not properly made as the toe of the replacement wells was not located close enough to the burned zone of original producers, such that a new ISC front was not properly anchored to the toe of replacement well, and therefore a toe-to-heel propagation was not noticed.

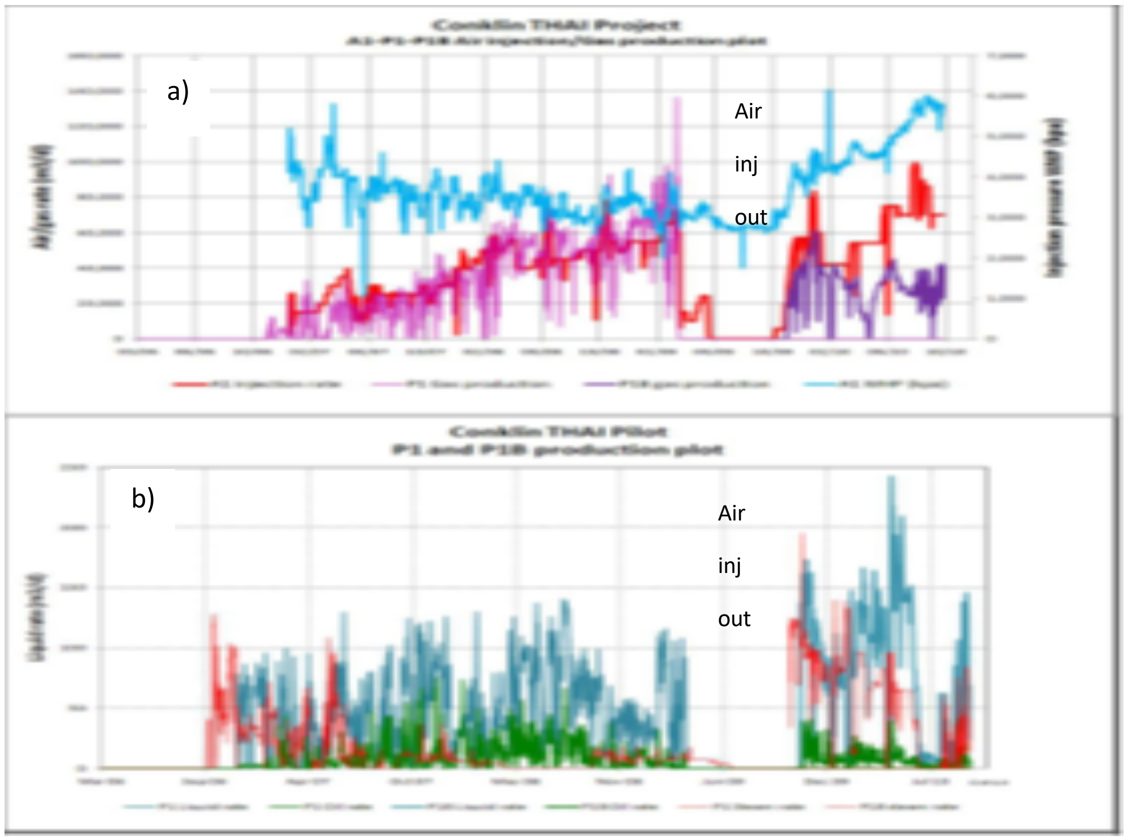


Figure 13: Air injection and oil production performance for A1-P1 THAI pair of WhiteSands Pilot

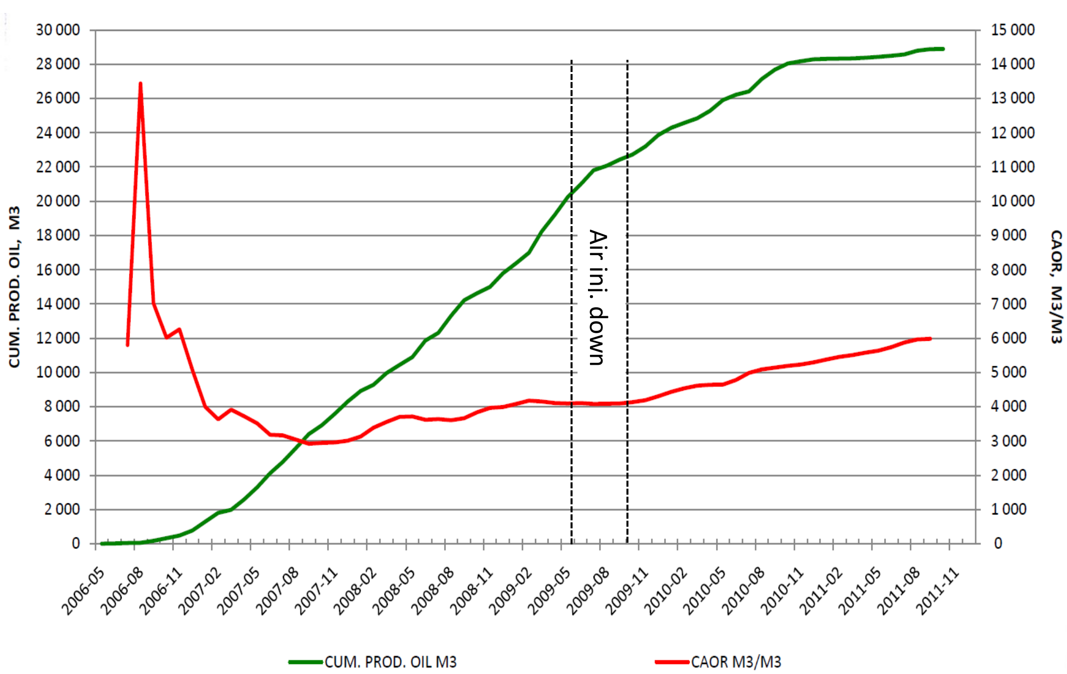


Figure 14: Variation of the cumulative air-oil ratio (CAOR) and of the cumulative oil produced by THAI pilot (all three patterns together). 2012 Annual Presentation to ERCB

This was seen from numerous BHT profiles along the horizontal drains of the replacement wells. Only well P2b made an exception as it was better placed, vis-a-vis the burnt-out zone contour and had its toe closer to the injection well A3 (Fig. 12); unfortunately, this well pair had a poor performance, both before and after replacement.

As far as the second reason is concerned, *a pronounced reduction in air injectivity was noticed* when starting to use the replacement wells P1b and P2b for production (Fig. 13a). Additionally, from the point of view of oil production performance 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 4-month period of air injection interruption, when the pressure in the burned zone decreased significantly. Oil re-saturation of the burned zone occurred due to gravity flow of the heated oil from the adjacent regions, which led to a massive coke deposit in 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 occurred also 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, 20018). Simultaneously, more water from bottom water (BW) encroached in the pilot area and increased the water cut.

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

- Drastic decrease of pressure in the burned zone leading to a general reduction of permeability and more influx of water from BW
- Lack of a hot link between the former hot region (around P1 and P2) and the toe region of the replacement wells; existence of a cold region with no oil mobility in this space

In-situ upgrading of the oil

It was 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 producer. The properties of the THAI upgraded, produced oil for the average oil sales of June 2008 (0.5-1 year since the start of the pilot) were as follows:

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

As the requested pipeline property is a minimum of 20 API and 350 cst, it can be seen that this constituted a partial upgrading; some slight dilution is necessary for pipeline transportation. However, the above upgrading results did not include the amount of condensate to be separated from the produced gases, which would have increased the upgrading; this measurement of condensate was not undertaken.

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. 15; as seen from this figure, large fluctuations in the upgrading occurred. Upgrading was in the range of 2 to 7 API points, and it was

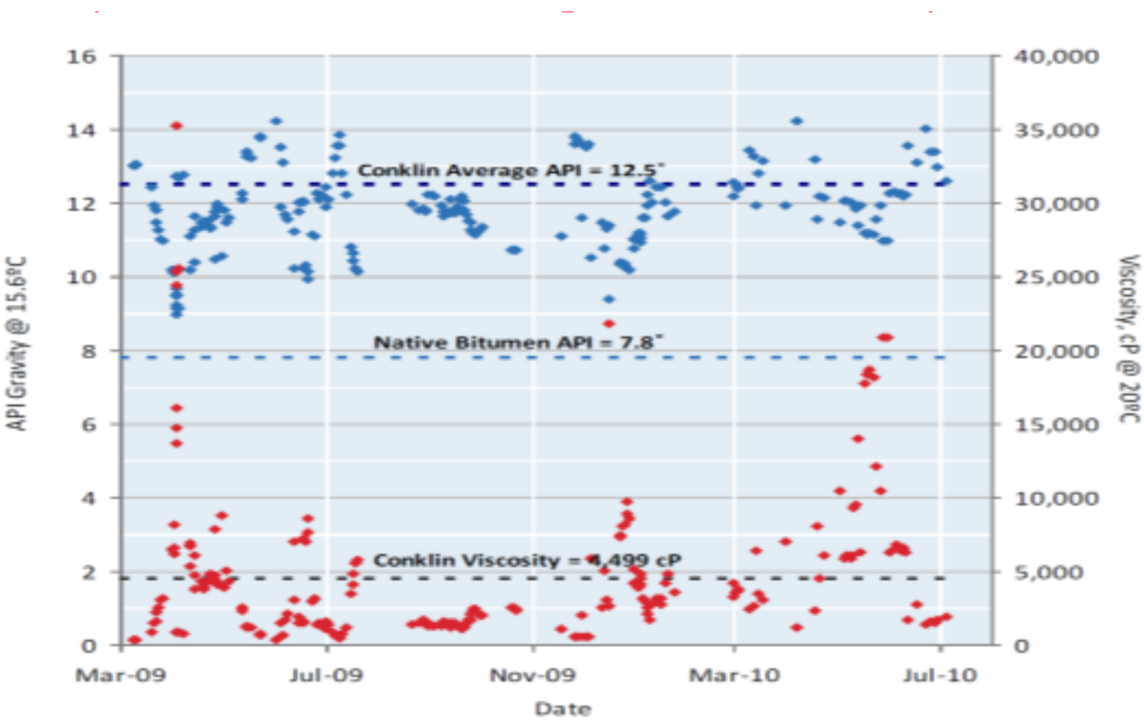


Figure 15: Variation of API density and of oil viscosity for the period June 2009-July 2010, combined, for all production wells (Ayasse, 2018). Conklin Pilot is another name for the WhiteSands Pilot.

very difficult to make any predictions, even on short-term. Dynamic viscosity (@ 20 ^{0}C) experienced a reduction from 550,000 cp to 2,500- 5,000 cp (110-220 times reduction).

SARA analysis (Table 1) shows improved quality of oil almost constant in time in the period 2008 to 2010. Asphaltenes content decreased 33%, saturates content increased 21%. Heavy metal and sulfur content of the oil were reduced by 20% (sulfur reduction from 3.2% to 2.6 %wt.). Also, it has to be mentioned that the quality of water produced was good; it did not raise any problems.

Table 1: SARA Analysis of the oil, before and

After THAI application

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

CONCLUSIONS

1) Testing of the toe-to-heel air injection (THAI) process in a direct line drive configuration, using three patterns for a period of 5 years, proved that the in-situ combustion (ISC) front could be generated, anchored to the toe of horizontal producers and made to advance towards the heel. The particularly good instrumentation helped substantially in the evaluation of this first field testing of the THAI process.

2) Initiation of the ISC was achieved by enhanced spontaneous ignition, injecting a slug of steam just before starting the air injection; ignition delay was 1-2 months.

3) Burning quality was excellent with no oxygen short-circuit. Very high stability of the ISC process was documented by easy resuming the process even after 4 months of air injection interruption. Also, it was fully confirmed by stability to large, sudden variations of the air injection; this stability is by far higher than that of conventional ISC process.

4) It was proven that in-situ upgrading of produced oil can be achieved. THAI becomes the first EOR process fully proven for producing underground upgraded oil without using any additional exterior heat sources. Hydrogen generation was another constant feature of the process, as hydrogen was contained in the produced gases.

5) The main setback of the pilot was related to the air escape in an upper formation, where it formed a secondary, conventional ISC front and functioned this way for a certain period of time. The second shortcoming was the failure to improve exploitation by drilling replacement wells for the horizontal producers.

6) The cumulative air-oil ratio (AOR) was 5,000- 6,000 sm^3/m^3, while the instantaneous AOR was higher than this after the drilling of replacement producers.

7) The pilot demonstrated only the technical feasibility of THAI process; economic efficiency is still to be improved. However, the pilot fully demonstrated the in-situ upgrading of the oil.

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