An In-Depth Evaluation of Toe-To-Heel Air Injection Application in a Heavy Oil Reservoir Underlain by Bottom Water. Kerrobert Case

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INTRODUCTION

Toe-To-**H**eel **A**ir **I**njection (THAI) is an efficient **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 over 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 Kerrobert THAI Project represented the second 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). 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 birds-eye views are provided in Figure 1 and Figure 2, respectively. An illustrative cross-section of the process is shown in Figure 3; the start-up region is shown in all these pictures.

The patents indicate that the vertical injector should be perforated high in the oil formation in both cases. The Kerrobert Project was designed to use DLD well configuration, but during the operation, SLD configuration was also tested in a few cases.

According to the patented process, 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

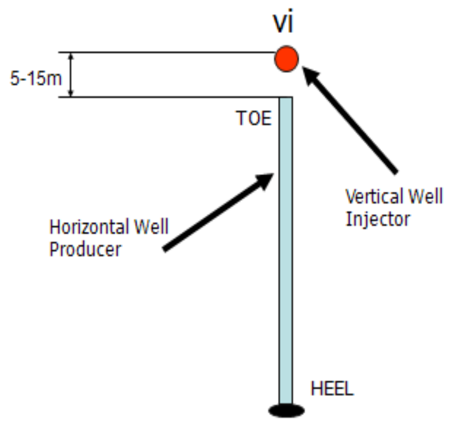


Figure 1: Plan view for Direct Line Drive THAI well configuration

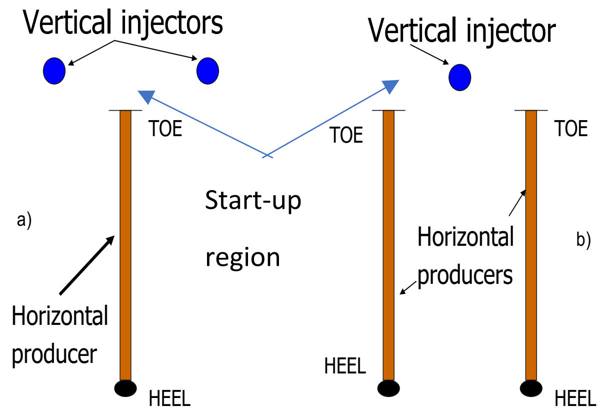


Figure2: Plan view for Staggered Line Drivel THAI Well configuration

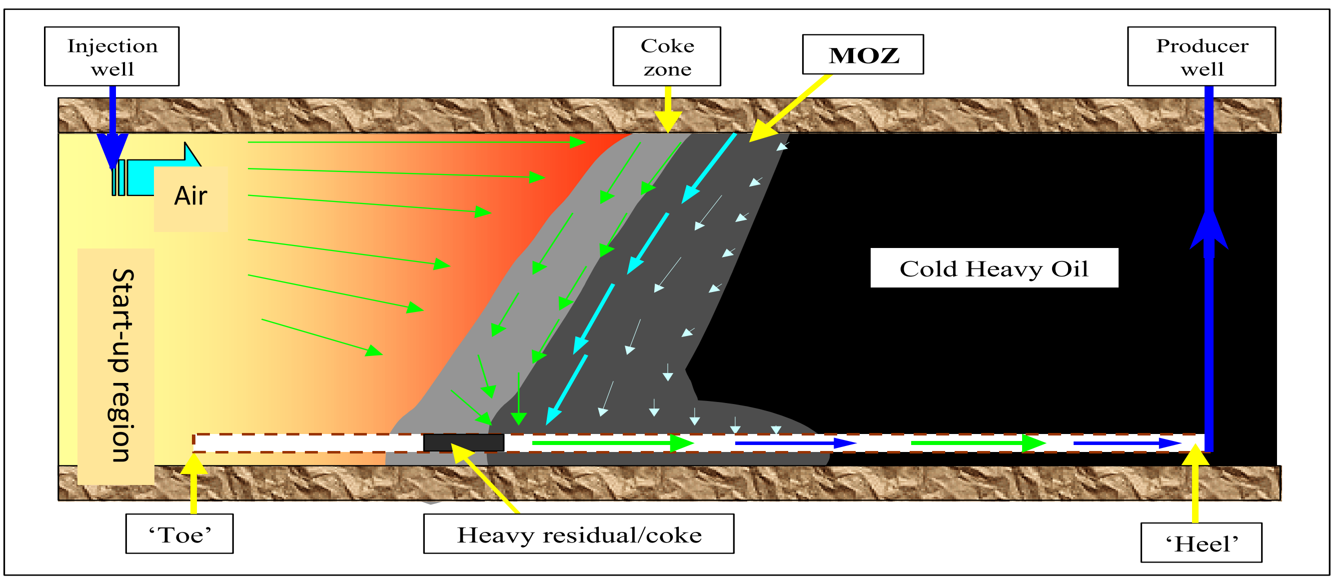


Figure 3: Simplified schematics of THAI process during the toe-to-heel propagation phase

3. Then, the ISC front is anchored at the toe of the horizontal producer and propagated from the toe to the heel of the horizontal producer.

The first two phases include the generation of hot communication and ignition (separately or lumped together).

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 (Turta, 2023). The second pilot is the Kerrobert

Project, Saskatchewan Province, Canada, which started in 2009 and is an ongoing project that will be analyzed in-depth in this paper. By design, application has been in DLD configuration in Canada and China, and SLD configuration in India.

The present paper analyzes and discusses the Kerrobert THAI project, which has been a pioneering work for a THAI application in a heavy oil reservoir with bottom water. It was supported by some laboratory tests, simulations and a few years of field piloting of THAI in Athabasca (Turta, 2018). In essence, an in-depth analysis is directed toward evaluation of the ignition operation leading to the generation of the ISC combustion front and the sustainability of the ISC process. In addition, the configuration of the burned zone is assessed, including the normal or abnormal 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 is made.

Unlike conventional ISC projects, however, this THAI pilot also came with an important additional aspect; it produced in-situ (underground) upgraded oil and this upgrading is evaluated.

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 by adding 10 more pairs. No observation wells were used in either the pilot or semi-commercial operation. However, a large amount of temperature data was generated by the horizontal producers, which had thermocouples along the horizontal section. This project is the first THAI pilot in a conventional heavy oil reservoir underlain by a relatively thick bottom water zone, which has a negative effect on ISC application. It is hoped that the question "Is bottom water more harmful than in the case of conventional ISC process?" can be answered from the results of this test.

The Kerrobert Project initially used the DLD) configuration for both the pilot and expanded semi-commercial project but later on **s**taggered **l**ine **d**rive (SLD) was also tested. Based on the lessons from Whitesands Project (Turta, 2023), two modifications were implemented:

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

Most of the data analyzed and referenced in this work was taken from >20Gb Petrobank data set released to the public in Jan 2016., Also open public sources (such as geoSCOUT) were used. All flow rates, gas composition and bottom hole temperatures, and pressure were continuously recorded and displayed at a Central Processing Facility (CPF) located in the Kerrobert Field.

SUMMARY OF THE PAST KERROBERT THAI PUBLICATIONS

Several analyses, therefore contributions to the knowledge regarding Kerrobert THAI piloting have been made by the University of Calgary researchers. There were five published papers, practically all of them incorporated in the Ph.D. thesis on the Kerrobert Project (Wei 2020). Out of those 5 contributions (Wei, 2018-2022), 4 of them studied only some aspects of the process or have a statistical character. However, one of them goes more in-depth (Wei 2020) and, based on a detailed analysis of the produced gas composition it found that the high-temperature oxidation (HTO) regime prevailed in Kerrobert. By studying the relationship between 'injected air' and 'produced oil' it was shown that a higher limit in air injection rate exists beyond which there is no gain in oil production (any excess air injected did not enhance oil production). However, in our opinion, the conclusion is correct but the cause of the threshold in air injection rate is not; our analysis of the myriad of the bottomhole temperature profiles does not lead to this cause. This conclusion refers to an apparent "cooling effect" of the 'injected air' when the air injection rate was increased over a certain threshold; however, such a conclusion was drawn due to ignoring the effect of the bottom water as will be clarified in this paper. Additionally, the conclusion that fuel availability limits the combustion zone development and hence the heat generated was insufficient to overcome the "cooling effect" of increased 'air injection' does not reflect reality. Thus, the authors of the current paper, although agreeing with Wei et al. (Wei 2020) regarding the maximum temperature at the toe not being correlated with the oil production or other parameters studied - it is our observation that such a lack of correlation is a direct follow-up of ignoring the advancement of the ISC front along the horizontal section since the bottom hole temperature (BHT) profiles were not studied. This ISC front advancement only to some extent reflects the *general status of ISC front*, as we cannot assume that the fire front conditions directly correlate with the temperatures in the production wellbores. Historical thermocouple failures and/or their malfunction made the BHT analysis more challenging. Unfortunately, there were no observations wells to bring additional data on this topic.

Another important contribution (Wei, 2020), consisted in developing a reaction system analysis in the THAI process, which was derived from production gas composition. Field-measured air injection and produced gas composition were used to examine various reactions' contributions. The relative role of different reaction groups was established from the analysis. It revealed that high-temperature oxidation (HTO) reactions are more dominant than low-temperature oxidation (LTO) reactions at most of the wells. At a well where LTO reactions were more dominant, the average oil production rate was among the lowest.

The same work (Wei 2020) made an interesting comparison of the THAI performance with the SAGD performance conducted in the same formation. The properties and conditions of testing are very close, but there is an important difference. While SAGD was applied as a primary recovery method, THAI was applied as a secondary method, when the water cut was around 90-95% due to exploitation in a regime of bottom water drive, when using horizontal production wells. The comparison revealed that the SAGD oil rate is 4-5 times higher, while its energy efficiency (expressed as energy injected/oil produced) is 2-3 times lower.

Recently, the field scale simulation of the THAI Process in the presence of Bottom Water (BW) in the Kerrobert Reservoir has been published (Hossein, 2022). Another similar simulation was conducted by Ado (2023). This last work indicated a negative effect related to the fact that some mobilized oil is penetrating and flowing via the BW and the oil recovery is affected by how large the thickness of the BW zone is. The severity is determined to be proportional to the thickness of the BW. It revealed that when the BW zone thickness is 50% of the oil zone thickness, less than 50% of the ISC mobilized oil will be recovered, when the entire reservoir is swept by the combustion front. In order to allow capturing and production of the mobilized oil from the BW thief zone, it is proposed that the horizontal section of the producer should be located at or below the oil-water interface. This proposal was also made by the earlier simulation study (Hossein, 2022). More comprehensive considerations on this proposal, by taking into account technical challenges and operational issues, are necessary.

PILOT LOCATION, RESERVOIR PROPERTIES AND PRIMARY RECOVERY

Kerrobert heavy oil pool is located 16 km southwest of the Kerrobert town of Saskatchewan Province in Canada. Oil production is from the Manville Group of the Lower Cretaceous age, more specifically, the Waseca Member of the Cantuar formation, (SMER Application, 2010). The reservoir is located on a big Waseca channel deposit, oriented SE-NW.

The THAI project is placed in a part of the Waseca channel, which has a width of 400-700m. Within this channel, multiple 3 pay sand intervals exist at different locations. 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 log of KA4, which represents a well type log (Fig. 4b) for the Eastern part.

Reservoir and fluid properties are provided in Table 1. Waseca reservoir is composed of fine-grained sands and slightly consolidated sandstone; the depth to the top of the formation varies between 758 and 774 m (oil-water contact is at 789m). The oil zone thickness is decreasing from East to West, while the bottom water (BW) zone is increasing in the same direction (Wikel, 2009). Therefore, the ratio of BW zone thickness to that of the oil zone shows more favorable conditions in the Eastern part; it goes from 0.3 to

b)

almost 1 from East to West. Other properties are provided in Table 1.

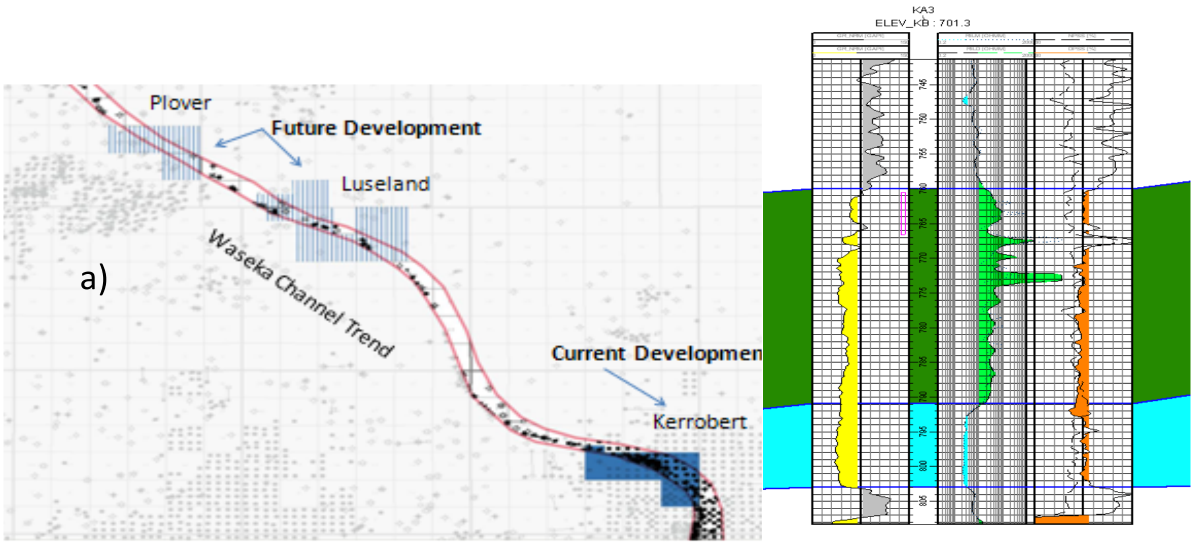


Fig. 4a: Waseca channel, and location of Kerrobert THAI project and Fig. 4b, a type log.

The dip is extremely low, while the bottom of the reservoir is almost flat. At reservoir temperature, the average dead oil viscosity is 33,500 mPa.s (range of 21,000 to 53,000 mPas (Wikel, 2012). Therefore, oil has some mobility, but very low, at reservoir conditions. Oil/water transition zone thickness is approx. 5 m and has an oil saturation of 55-75% (SMER, 2010).

Oil production started in 1995-1996. In total, 22 wells have been drilled on the pool, 18 of them being horizontal wells with their horizontal sections located in the upper half or even towards the top of the pay zone to minimize water production from the bottom water zone.

The wells are located in sections 12, 13, 14, 15 and 22, while practically all the THAI Project wells are located in Section 14. Horizontal well 192/09-14-033-24W3/00 was converted to a water injection well, in May 2008 and injected for one year. A portion of the channel trend can be seen in Fig. 4.

Data on Manville wells together with information on their performance show that 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 in production, and the reservoir pressure was around 3,000 kPa (initial pressure was approx. 5,500 kPa). The primary production performance is shown in Fig.5 which excludes THAI production wells, KP1 and KP12. In September-October 2009, when the THAI pilot started, the average

Table 1: Kerrobert reservoir and its fluid properties (Wykel, 2012; Wei, 2022; McDaniel, 2014; Saskatchewan Oil Reserves – 2008 and other sources)

Property	**Value**	**Observations**
Depth	770m	Oil/water contact at 789m
Oil pay thickness, h_{oil}	24 m westside and 35 m eastside	
Bottom water (BW) zone thickness*, h_{BW}	20 m westside and 10 m eastside	Higher negative influence of BW in the western part of the field
h_{BW} / h_{oil}	0.3 eastside and 0.8 westside	
Porosity	32%	28% to 37%
Horizontal permeability	2-6 D	
Vertical permeability	3.8 D	354 -7,800 mD
Reservoir temperature, T_R	20 ^{0}C	
Oil API (at 15.6 ^{0}C)	10.3 API degrees	
Dead oil viscosity at T_R	33,5000mPa.s	average
Live oil viscosity at T_R	21,000mPa.s	21,000-54,000 mPa.s
Initial pressure	5.5MPa	
Bubble Point Pressure (BPP)	Probably 5.5 MPa	Suspicion of a very small gas-cap
Current pressure (at start of THAI piloting)	3.5 MPa	Exploitation under solution gas drive and bottom water drive
Sulphur content of the oil	6 (wt%)	Determined during THAI piloting
Asphaltene content	14%	
Oil formation volume factor at BPP	1.111	
Solution gas-oil ratio (SGOR)	5 sm^3/m^3 (estimated)	

* An average bottom water thickness of 22m is quoted (McDaniel, 2014)

primary daily oil rate (per well) was approximately 0.5 m^3/day, with a water cut of around 90%. The predominant mechanism of oil production was a **b**ottom **w**ater (BW) drive, although some solution gas drive has also contributed. The contribution of BW is important as the thickness of the 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 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 completion and its position on the reservoir structure. In general, 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) and then, 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 90-96%, and the reservoir was almost at the end of primary production.. Hence, the use of ISC, in this case, is considered a secondary EOR method.

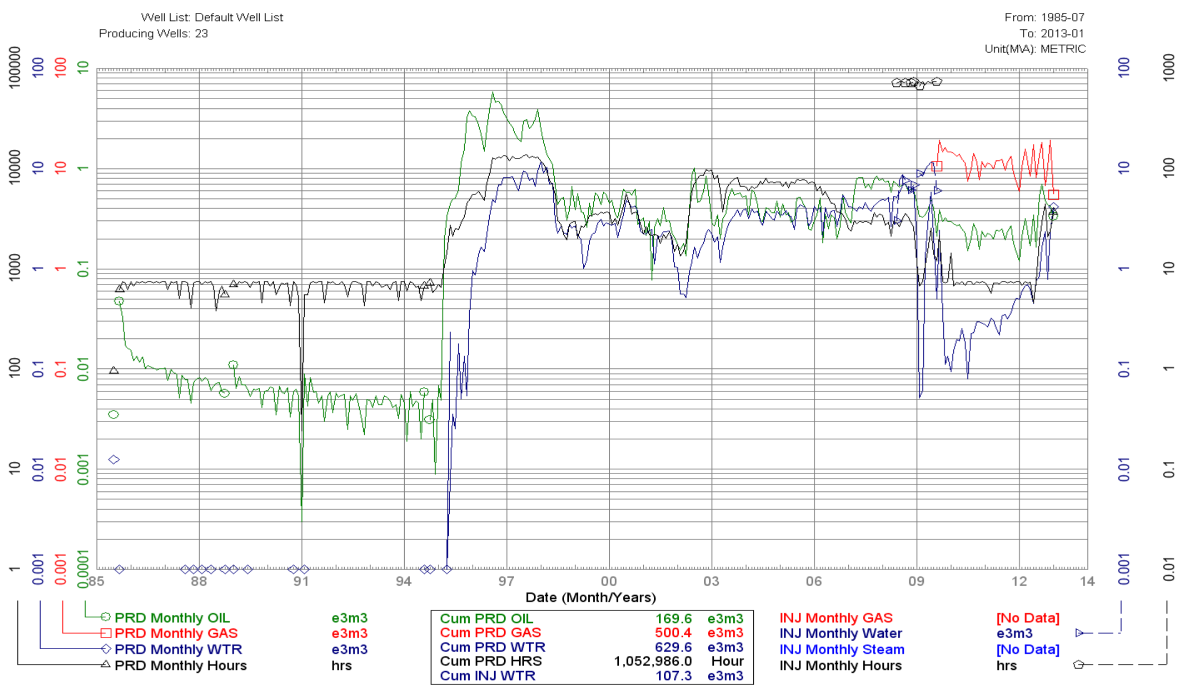


Figure 5: Kerrobert Field. Primary production performance. Source: geoSCOUT. Note: Wells KP1-KP12 are not included. THAI piloting started in 2009.

DESIGN CONSIDERATIONS

There are 9 old horizontal wells located in the region of the THAI project. None of these wells were ever used for oil production during the THAI operation as they had already been abandoned. Typically, at abandonment only a portion of about 200 m section closer to the heel is cemented; therefore, the entire horizontal sections were not cemented, which might have constituted channeling pathways. As mentioned, the horizontal sections were located in the upper half or even toward the top of the reservoir.

Only limited information is available on the design of the project or its anticipated performance. The design result is from simulation, and it is overly optimistic, showing an oil rate per well increasing from 17.6 m^3/day to 40 m^3/day within 10 years; an ultimate oil recovery factor of 69% is predicted (SMER, 2010). More importantly, there is **no analysis regarding the effect of bottom water on the performance** or on how the process needs to be modified to take into account the negative impact of the bottom water (SMER, 2010). The problem of 'heat drain-off or sink' experienced in thermal recovery operations of this kind was considered but not included and/or accounted for in any material way in the design. That's why, next, some essential information on conventional ISC application in the presence of bottom water will be given.

A SUMMARY ON THE PERFORMANCE OF CONVENTIONAL ISC IN THE PRESENCE OF BOTTOM WATER

For heavy oil reservoirs with **b**ottom **w**ater (BW) practically no EOR method has been proven feasible, so far. This is due mainly to the loss of the injection fluid and mobilized oil into the BW zone, making the recovery process uneconomic.

Laboratory testing of ISC in the presence of BW is difficult 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 plausible schematic of the BW-ISC was developed and it is shown in Fig. 6. The partitioning of the injected air between the main ISC front (at the upper part of the oil layer) and the secondary one in the thief, BW zone will probably decide the efficiency of the process. It is believed that at the oil/water (O/W) interface, an ISC front can exist, as the O/W transition zone still has a relatively good oil saturation to sustain ISC.

In the case of reservoirs with BW, ISC has not attained commercial operational status although the experience from these field tests is still precious. It is worth noting that most of the ISC field pilots were conducted during the 1970s and 1980s when the understanding of conventional ISC was rather limited and, they failed.

Two approaches can be 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 are applied using vertical injection and production wells. The difference between these two methods is the place where the combustion is initiated and the way ISC propagates. While in BW-ISC, the combustion is normally initiated at the upper part of an oil layer, in the BC process (Lau, 2000) however, the 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. The BC process has not been field-tested yet.

A comprehensive analysis of data/results from 9 conventional BW-ISC projects has been made previously (Turta, 2009). From this analysis, it was determined that the most successful application was in North Tisdale Project, which was the most complete testing. In this reservoir, the oil zone was 15.3 m thick, compared to 3.7m for the water zone, and this represents favorable reservoir conditions. This test involved 4 injectors and 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 4,500 sm^3/m^3 of incremental oil. The relatively high AOR is mainly due to low oxygen utilization, around 72%; for a BW-ISC operation, this AOR is the best ever obtained. The low oxygen utilization was due to some of the injected air entering and flowing through the bottom water zone. Variation of combustion gas composition during the process showed that for a few years, there was a continuous increase of produced oxygen and a continuous decrease of CO_2 in the produced gases which seems to be typical for any BW-ISC process.

In the majority of these tests, the injected air escaped through the BW zone. In the Carlyle pool, three different pilots were conducted. In one of them, Wiggins B dry ISC pilot, the injection well was perforated above the oil/water contact, but was drilled through a limestone intercalation (within the oil layer) into the water zone. After 7 years of operation, three coring wells were drilled into the burned-out zone, and they showed that although the ignition was achieved in the oil zone, ISC took place up to 7 m in the water zone. In this test (Wiggins B), the incremental oil recovery was 31% obtained at a very high water cut (90% or higher). The main limitation of the very low productivity of the wells practically impeded subsequent expansion to a commercial scale.

On the other hand, *no clear evidence of air flowing through the bottom water zone was found* in the Cado Pine test, which could have been related to the low oil viscosity, only 112 mPa.s, a characteristic of the respective reservoir.

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 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 4,500 to 7,600 sm^3/m^3. The estimated incremental oil recovery was around 14% (with the exception of a single pattern – estimated at 31%).

Therefore, 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.

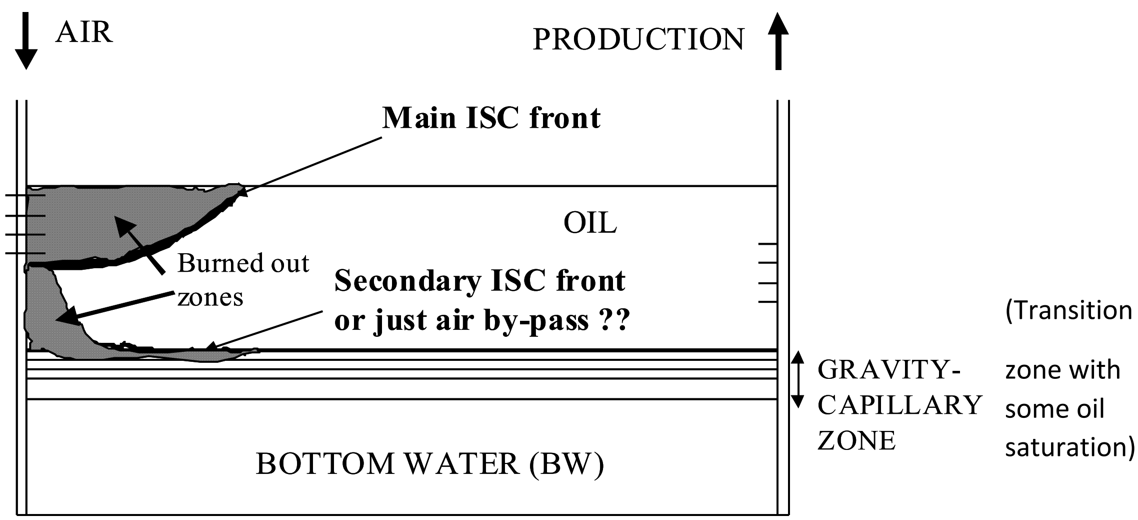


Figure 6: Schematic of Conventional ISC in the Presence of Bottom Water

For conventional ISC in the presence of bottom water, the crucial challenge is the lack of stable propagation of the ISC front. One indicator is a decrease in oxygen utilization with time, possibly associated with low-temperature oxidation (LTO) reactions due to heat diversion into the bottom water zone. Closely connected with this phenomenon is the propensity of air to bypass the oil zone associated with 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.

LAYOUT OF THAI WELS. INITIATION OF THE ISC PROCESS (IGNITION) AND ITS SUSTAINABILITY DURING THE PILOT AND SEMI-COMMERCIAL PROCESS

The project started in September 2009 with a pilot consisting of two pairs: KA1-KP1 (called pattern K1) and KA2-KP2 (called pattern K2) and later on, in 2011 extended with 10 more pairs such that 12 pairs were in operation from 2011 till 2016 by Petrobank Energy and Resources staff (along with Touchstone Co. in the last year). In 2016 project was sold to Quatro Exploration which was an operator till the summer of 2017, when Protone Technologies Canada became the project operator; period after 2017 was not analyzed in detail and/or included with details into this paper. Layouts of vertical air injection wells and horizontal production wells are shown in Figures 7a-c, where the net pay thickness of the oil layer as well as the position of old horizontal wells are displayed.

After a succinct analysis of the 2-year THAI pilot performance, an in-depth analysis of the initiation of ISC (ignition operations) in all patterns will be made. This was necessary as sustainability of an ISC process assumes first a valid ignition process to generate the ISC front and, then, the self-supporting ability to propagate an ISC front via air injection.

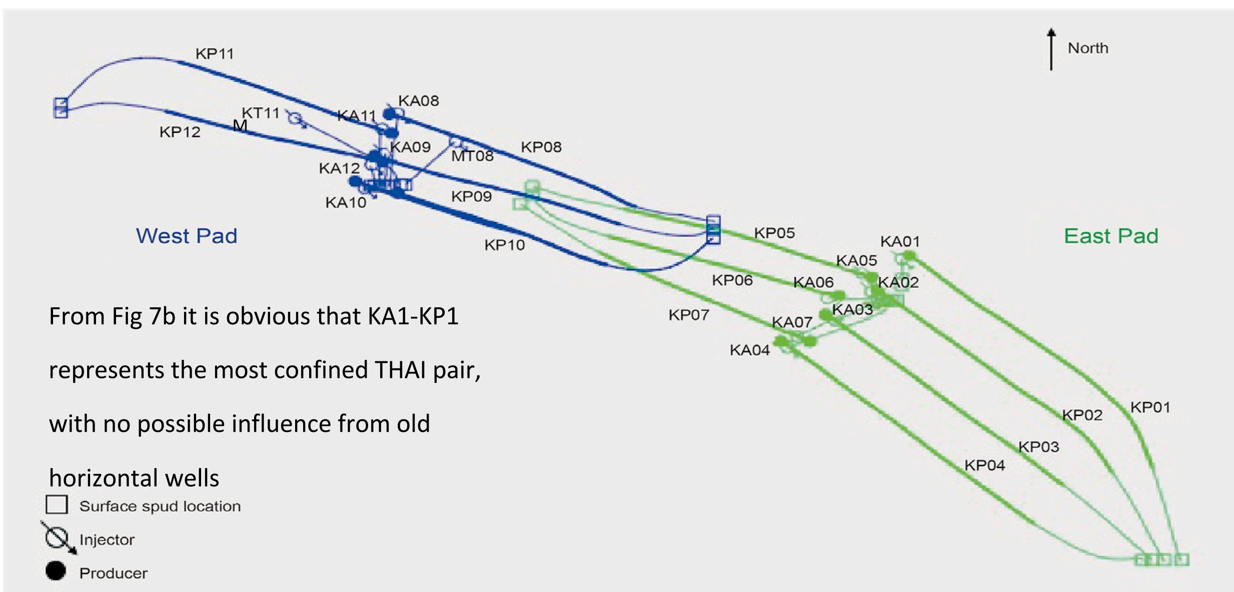


Fig 7a: Kerrobert Project. Layout of THAI wells. Eastern 7 pairs and Western 5 pairs (Wei,2022). KA1-KP1 and KA2-KP2 are the pairs of the THAI pilot. Wells MT08 and MT11 were used as additional vertical injection wells (Multi-THAI) for the patterns K8 and K11, and they have horizontal offset distances of 12m and 40m from those producers, respectively.

Kerrobert Pilot

A THAI pilot consisting of two patterns (two well pairs) was implemented in 2009. Detailed information on temperatures along the horizontal section of horizontal producers is available, having been continuously recorded by thermocouples and displayed at a Central Processing Facility (Fig. 7c). Fig. 8 shows the arrangement of the thermocouples along the horizontal section of KP1 and KP2 producers; there were 20 thermocouples having a higher density in the toe region. Fig. 8 also shows an inset with the positioning of THAI injectors and producers vis-à-vis an old horizontal well located nearby.

Locations of horizontal production wells KP1 and KP2 and vertical injectors KA1 and KA2 of the pilot are also shown in Figures 7a-c and some more details are provided below:

- Both THAI horizontal producers have their horizontal sections close to the bottom of the oil formation; the vertical injector KA2 is perforated in the upper half of the oil layer
- 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 seems 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.
- However, a caveat is necessary: although from the map of the reservoir, some well modules may appear isolated, they all are underlain by a common aquifer and hence, are in active pressure communication with each other. This is valid for both K1 and K2 pattern
- The pattern K2 has a more favorable start-up region (more toward staggered line configuration), compared to that of the K1 pattern; KA2 is located slightly off and outside the lateral drainage area of KP2. However, as seen in Fig.8, it is located close to an old horizontal well, which has its horizontal section placed at a higher vertical position compared with the horizontal section of KP2. Also, KA2 is not far away from the air injection KA5 of the pattern K5 arranged back-to-back with the pattern K2.

Given the K2 pattern characteristics, it can be concluded that the pattern K2 constitutes probably the most favorable THAI pattern. The lateral well spacing between horizontal producers is 70-90 m, while the lengths of horizontal sections are 400-450m.

The piloting started in both patterns with the preheating by steam injection on Sept 12, 2009. This pre-heating ignition cycle ("PHIC") lasted until Oct 27, 2009 (approx. 45 days) (Petrobank release of Oct 27, 2009); an amount of steam of 3,100m^3 was injected (Table 2). In both patterns, the air injection started on October 27, 2009 at 10,000 sm3/day/well, with a projected maximum injection rate of 80,000 sm^3/day/well; the production wells started producing in October 2009.

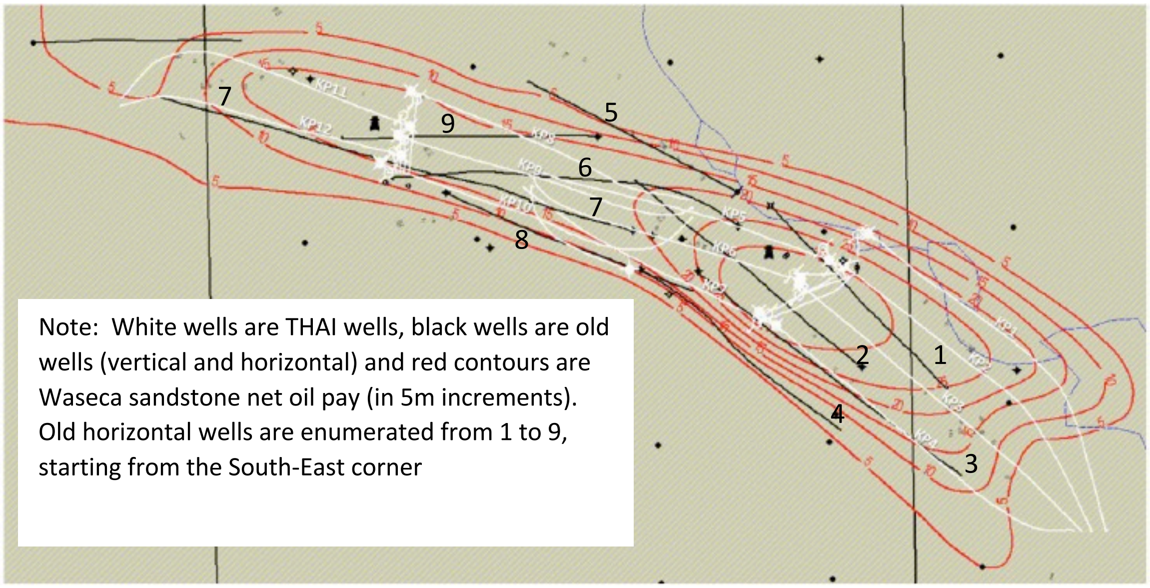
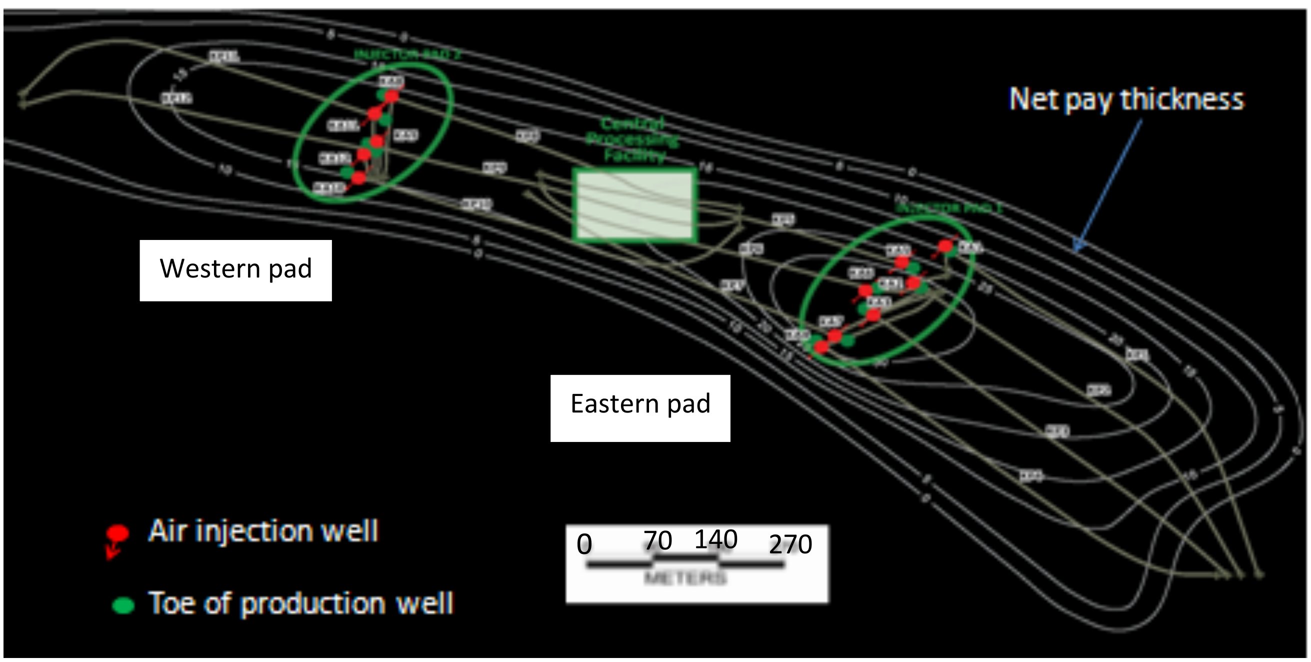


Fig 7b: Kerrobert THAI Project. The location of all existing wells (Wikel, 2012)Fig. 7c: Kerrobert THAI semi-commercial operation showing the two injection pads (Eastern pad and Western pad), central



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

Slight pre-heating of the horizontal section of producers was ruled out based on the results of the numerical simulation, which did not indicate this as a necessity.

On January 7th, 2010, it was stated that the temperature at the toe of the KA1 horizontal producer was in the range of 120-140 ^{0}C. Later on, in February-March 2010, the temperature at the toe was around 280 ^{0}C (McDaniel, 2014). This shows that by March 2010 – during ISC front anchoring at the toe - generation of the ISC front existed already, implying an ignition delay of less than 4 months. Based on production data, for KA1 well, the ignition delay was estimated at 2 months (See Table 2). Although the parameters of ignition (cumulative of steam injected, air injection rate, etc) were the same, the ignition time was longer for KP2 (around 4 months) as some steam injected in KA2 was lost via the old horizontal well #1, located nearby (Fig. 8).

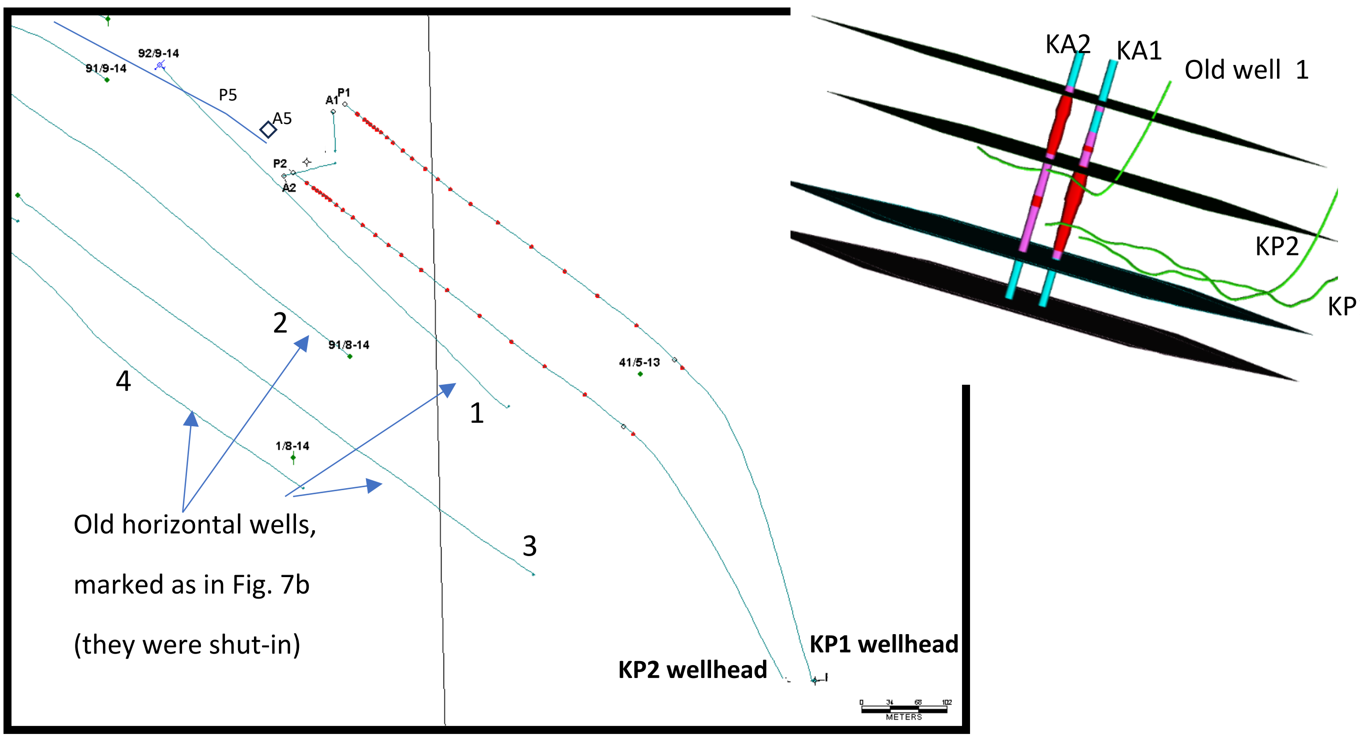


Figure 8: Kerrobert THAI Pilot. The position of thermocouples on the horizontal section of the horizontal producers. Note: KA1, KA2 and KA5 are marked here as A1, A2 andA5. Also, at the toe, KP1, KP2 and KP5 are marked here as P1, P2 and P5. The inset shows the positions of KA1 and KA2 vis-à-vis the old well trajectory located (horizontally) 17 m from KA2

The average oil rate for March 2010 was 19.6 m3/day /well, and this was accompanied by some indication of in-situ upgrading. However, significant and consistent upgrading started to be recorded 9 months after the start of air injection, by June 2010. The maximum total oil production from these two well pairs reached 48-64m^3/day, one year after the start (by October 2010), when the upgrading achieved was at its maximum.

The good performance of the oil production was 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 gases (less than 0.3%).

Fig. 9 shows the oil production performance for the two producers of the pilot, KP1 and KP2 in the period 2009-2015. In this period, the average daily air injection rate was in the range of 10,000-20,000sm^3/well.

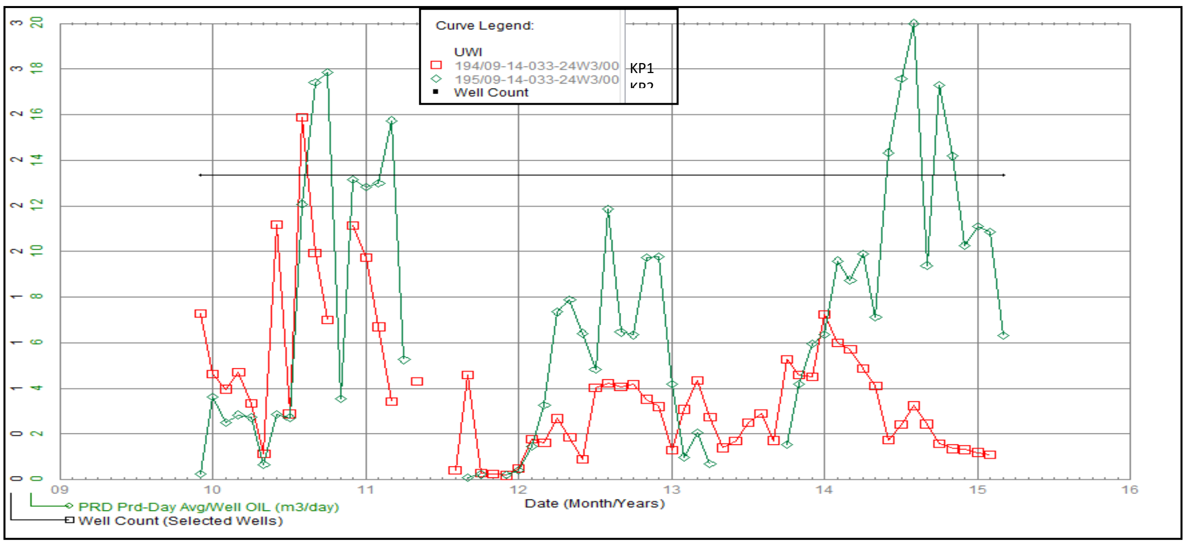


Fig. 9: The variation of average oil production per well for patterns K1 and K2 (geoSCOUT data). There was a general air injection interruption in 2011, while for K2 pattern there was an additional air injection stoppage in 2013 (see Fig. 10a)

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 29-48 m^3/day/well, with an oil cut as low as 40%. After increasing the KP1 well pump capacity, the total liquid production was in the range of 40-67 m^3/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 sm3/day; it is difficult to explain this big difference between air (gas) Injected and gas produced. It is speculated that a significant portion of flue gases flowed into the bottom water or towards the adjacent K2 pattern, or even towards the closest old horizontal well, which is at a distance of around 80m (Fig. 7b).

As far as the pattern K2 individual performance is concerned, more details are provided elsewhere (Anbari, 2023). Air injection and production of oil and combustion gases are shown in Figs. 10a-b. A reliable interpretation of these graphs is extremely important by assessing all parameters assuming a total confinement of this pattern. First of all, by taking into account the position of the old horizontal well (Fig. 8), it has to be accepted that some steam injected during ignition operation and subsequently some air injected via KA2 in the first period (Sept 2009-June 2010) had been preferentially flowing towards the old horizontal well, until it increased sufficiently the pressure in its region; this explains the low performance of the producer KP2 in this period. As seen in Fig. 10a, the air injection rates were higher in 2009-2019, as the operator tried to go towards the designed maximum air injection rates; this way the air injection rate was increased up to 85,0000sm3/day, but it has to be reduced due to difficulties in handling too high temperatures at the toe and oil production with excessive high gas-oil ratios. Also, from Fig. 10a it can be seen that the operator made a lot of changes in air injection rate; these changes were dictated by the selection of the best production pumps, in order to solve production operations problems.

In the period March 2011-January 2012 (9 months during the transition from pilot to semi-commercial operations) and the period April 2013-September 2013 (5 months) producer KP2 was shut-in, but the air injection in the well KA2 continued (Fig. 10b). This caused the development of a second ISC front toward K5 pattern and recovery of some generated flue gases by KP5. In reality, a potential interference occurred between patterns K2 and K5 as their injection wells were nearby; in the K5 pattern a combustion chamber developed (see Table 3). Later on, during 2014, air flow occurred inversely from KA5 to K2 pattern as the gas produced by KP2 was almost double of air injected. The interference could have been even between K1 pattern and K2 pattern; the suspicion is related to the fact that in the period 2013-2016 the cumulative gas produced was 30% higher than the cumulative air injected (Fig 10b). Due to this interference a switch from direct line drive configuration (DLD) to a staggered line drive (SLD) configuration (DLD) happened In general, this has a positive effect but its determination was extremely difficult in this case.

Figures 10a and 10b clearly show that the stable period was during 2015, with almost a steady-state injection and production. The air injection rate was in the range of 25,000-30,000sm^3/day while oil production was around 10.5 m^3/day; this corresponds to an air-oil ratio (AOR) of 2600 sm^3/m^3.

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. This was a more favorable situation, as compared with the semi-commercial operation patterns, because of a lower W/O ratio. It showed that the maximum daily oil rate of a THAI pair might reach up to 24 m^3/day; the oil rate of 24 m^3/day represents the maximum potential of the THAI process applied in a direct line drive configuration. The AOR of 2,600sm^3/m^3 represents the maximum efficiency a THAI process can have in a bottom water situation. Based on the good performance of the pilot during the first years, the expansion to a semi-commercial operation (with 10 more patterns) was implemented in the Spring of 2011.

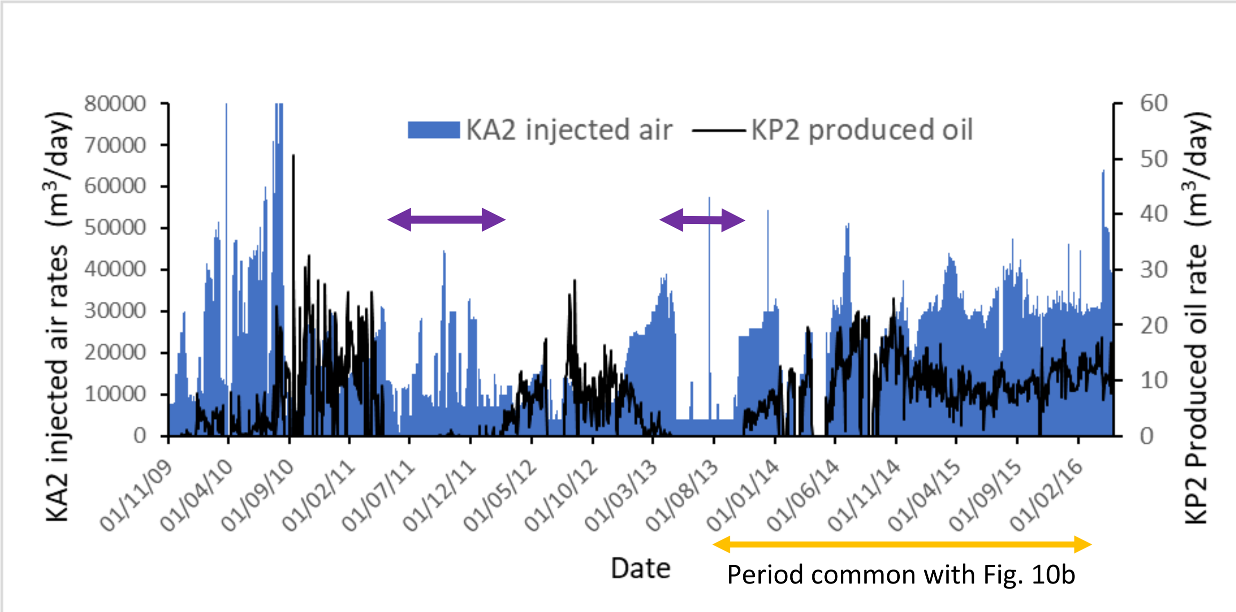


Fig.10a: Pattern K2. Air injected and oil production profiles in the period 2009-2016 [dataset] (Petrobank Energy & Resources Ltd, 2021). In the periods highlighted ( ), injection in KA2 continued in order to supply more air to the back-to-back pattern K7 and/or neighboring pattern K1

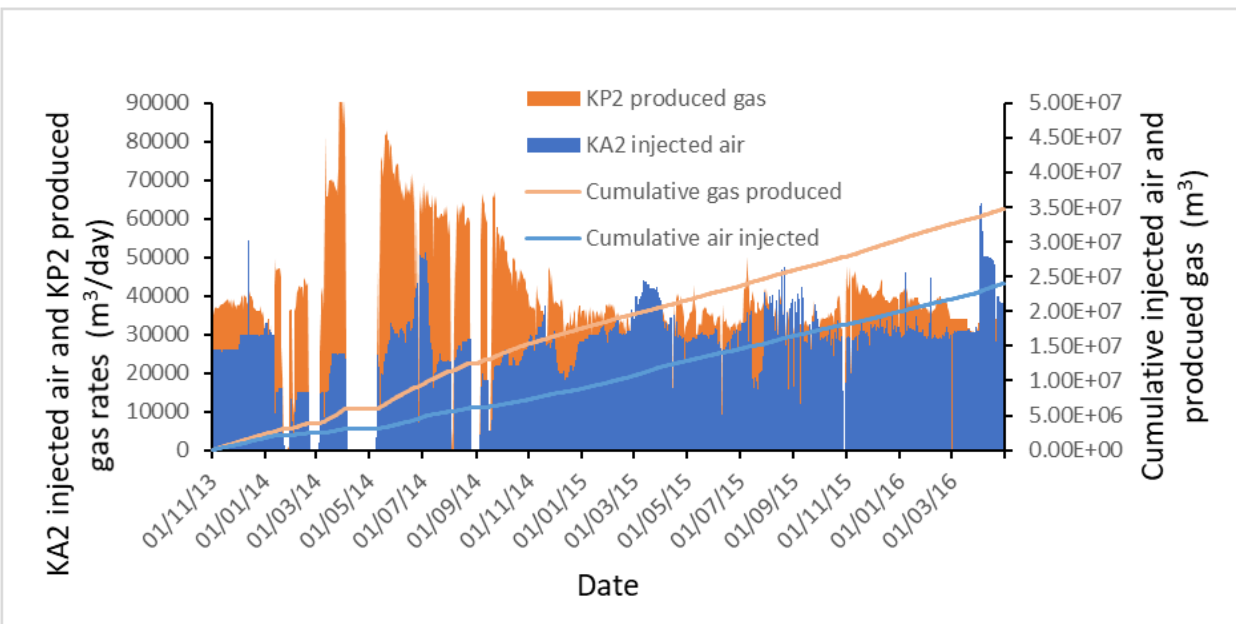


Fig. 10b: Pattern K2. The air injected and gas produced profiles, cumulative air injected and gas produced profiles during the period November 2013 to April 2016 [dataset] (Petrobank, 2021).

Initiation of ISC (ignition operations)

Although ignition operations were conducted separately for the pilot pairs and all other pairs, they are analyzed together. Table 2 provides information about pre-heating by steam injection in the twelve vertical injectors, also known as the pre-ignition heating cycle (PIHC) data. Steam injection took place in the pilot in 2009. Later, in 2011, steam was injected into all the air injectors of the semi-commercial operation.

Heat losses occurring during steam injection were 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. As cumulative heat losses in adjacent formations (expressed as % from heat available in perforations) at the end of the injection period were less than 12% they were considered not very important. As seen in Table 2, however, in the semi-commercial operations (patterns K3 to K12) high heat losses (76-80% out of heat available at the wellhead) were recorded around the wellbores, such that, except pattern K6, just hot water was introduced in the oil layer; steam quality calculated was zero (except well KA6, where it was 10%). This was due to the very low steam injection rate, recorded (12-31 m^3/day); in the application (SMER 2010), an injection rate of 120 m^3/day was recommended, but it could not be achieved.

From Table 2, it can be seen that – compared with the semi-commercial steam injection wells, the cumulative steam 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% for the pilot (corresponding to a steam quality of 46% in the perforations), as compared with over 76% for semi-commercial operations. *Therefore,* ***except for well KA6, only hot water was injected at all other wells of the semi-commercial process***; 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 ºC.

Although it can be speculated that a temperature of around 100 ºC (for the hot water) could have been attained at the sand face, the ignition was very difficult as a substantial amount of water had to be vaporized before a local temperature could increase to over 270 ºC-300 º C. The ignition delays in Table 2 are correlated relatively well with the heat losses around the vertical portion of the well; it can be seen that only well KA6 realized an ignition delay of approximately three months. The remainder of the wells had ignition delays in the range of 4-6 months.

The estimation of the ignition delay in Table 2 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 the 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 methods. The second method tends to give slightly longer t_{ign} values (given the distance of a few meters between the toe of the producer and shoe of the injector), while the third method tends to give slightly shorter t_{ign} values (given the fact that mobilization of the oil could be significantly helped by the steam preheating process).

Relative to the pattern K4 where ignition failed, this has to be linked to the fact that the production well of this pattern (KP4) did produce very little gas, and there was little air flow towards KP4 well. Apparent hydrogen-carbon (H/C) ratio in the range of 4-10 (LTO regime) was found. Further short-term air injection in KA4 – for 2 years - was done to supply air for the neighboring patterns K7. Therefore, in case of K7 pattern, the second value for the ignition delay might have reflected the achievement of ignition from the direction of KA4. Therefore, K4 and K7 patterns showed a very intense interference. Due to this interference a partial or full switch from a direct line drive configuration (DLD) to a staggered line drive (SLD) configuration (DLD) happened, for a limited period of time

The second failed ignition was recorded at K12 pattern. The production well KP12 did not produce any gas, and there was *almost* no air flow towards KP12 well; there was no ISC front generated in the pattern K12; full communication KA12-KP12 was never achieved, probably. Injection in KA12 probably supplied air for the neighboring patterns K9 and K10, automatically generating staggered line drive configurations, which usually are more favorable for the efficiency of oil displacement. .

Table 2 highlights the most probable value of the ignition delay in bold). The analysis indicates that KA12 did not experience ignition, whereas KP4 did experience a premature heat break-through (with temporary overheating), which, actually, resulted in no ignition in KA4. It is possible that KA4 lost a significant amount of steam due to the presence of a nearby old horizontal well labeled 3 in Fig.7b, which contributed to the absence of any ISC front anchoring to the toe of KP4. However, the steam loss may have decreased later, leading to the eventual formation and propagation of an ISC front towards KP7. Similarly, KA12 might have lost steam via the old horizontal well marked 7 in Fig.7b, leading to the lack of any ISC front anchoring to the toe of KP12. However, as with KP4, the steam loss may have reduced later, allowing for the eventual propagation of an ISC front towards KP9 and KP10 wells.

In 2013 two more ignition operations were carried out for the new wells MT8 and MT11 drilled close to KP8 and KP11 (Fig. 7a) to test a new THAI-related process, called Multi-THAI (Ayasse, 2012). Although

Table 2: Estimate of the ignition time. Source of data for steam injection: geoSCOUT. Injection pressure =>3,000 kPa (reservoir pressure before the start of pilot). Assumed steam quality at the wellhead: 80 %

Well	Steam pre-heating phase					Ignition time (delay), tign		
	Start of steam injection	End of steam injection	Total days of steam inj.	Cumulative steam injected m^3	Qsteam, m^3/day / Hwellbore, %	Based on oil production and water cut months	Based on variation of H/C ratio months	Based on peak temperature at the toe months
KA1	Sept. 12., 2009	Oct. 27, 2009	51	3132	62 / 31	Dec 2009 **/2**	February 2010/4	Dec 2009 /2 (?)
KA2	Sept. 12., 2009	Oct. 27, 2009	51	3132	62 /31	Nov 2009 /2 (?)	March 2010/**4**	Febr 2010/4(?)
KA3	Mar-11	Mar-11	?	100?	?	July 2011/**3**	August 2011/**4**	Aug 2011/**4**
KA4	Apr-11	May-11	41	1003	25 / 80	No ISC front toward KP4 direction		
KA5	Mar-11	Apr-11	55	1433(?)	26? /76?	August 2011/**4**	Nov 2011/<7 (?)	August 3011/4
KA6	Mar-11	May-11	53?	1630	31? / 60	June 2011/2	July 2011/**3**	July 2011/**3**
KA7	Mar-11	Apr-11	53	938	18 / >76	August 2011/**4**	Nov. 2011/6	Sept 2011/**5**; March 2012/11
KA8	Jul-11	Jul-11	30	649	22 / >76	January 2012/6 (?)	Nov 2011/**4**	Oct. 2011/3
KA9	Jul-11	Jul-11	30	780	26 / 76	August 2011 /1 **??**	March 2012 /8	Jan. 2012 /**6**
KA10	Jul-11	Sep-11	56	1177	21 />76	March 2012/**6**	February 2012/5	March 2012/**6**
KA11	Jul-11	Jul-11	30	663	22 />76	Nov 2011/**4**	Sept. 2011/2(?)	Dec. 2011/**5**
KA12	Jul-11	Aug. 2011	53	616	12 ?>76	No ISC front toward KP12		
Semi Com Op	**Mar-11**	**Sept. 2011**	**30-56**	**649-1630**	**12-31**	**Average steam injection=22 m3/day**		

Legend: : Qsteam = Steam injection rate; Hwellbore = Cumulative wellbore heat losses at the end of steam injection (% of heat available at the wellhead); H/C = Apparent atomic hydrogen-carbon ratio; Semi Com Op = Semi-commercial operation.

the ignition was successful, the tests failed due to inadequate preheating of the space between these wells and KP8 and KP11, respectively.

It can be concluded that for KA1 and KA2 wells, the ignition delay was relatively long (2-4 months), while for the commercial patterns, it was very long (3-6 months), far longer than the values reported in the conventional ISC literature. Although K1 and K2 patterns used identical parameters for ignition (steam

injected both as rate and cumulative) ignition delay for K1 was 2 months, while for K2 was 4 months. The explanation of this difference is related to the fact that KA2 well is located very close to an old horizontal well (see Fig. 8), which "stole" a substantial part of the steam injected in view of ignition. At the same time, pattern K1 shows a very small vertical distance (4m) between shoe of injector and toe of producer and therefore was able to provide a very reliable ignition time. Therefore, all in all, the best (shortest) ignition time was 2 months for the KA1 well, and this represents the best ignition performance in the case of Kerrobert using this method. This value (2 months) is still too long and reveals a need to improve this steam-based ignition. Well K6 showed the best (shortest) ignition time (3 months) in the semi-commercial operations.

As a concluding remark, it can be maintained that by injecting a steam slug for pre-heating before ignition (the 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 very little incremental oil production is expected. Only after developing the full ISC front, efficient oil displacement could be expected. In our case, the period March 2011-September 2011 was exactly that time for the realization of ignitions, and, as it can be seen on the performance graphs in Fig 14a and 14b the incremental oil was extremely low while the air oil ratio extremely high.

Low quality ignition and insufficient heat in the start-up region lead to poorly developed combustion zone and low performance.

Sustainability of the ISC Process

Although the ignition was rather prolonged, the ignition was eventually achieved in 10 out of 12 patterns (except patterns K4 and K12). For these 10 patterns, the produced gas composition was normal for a fully sustained ISC process. A typical gas composition recorded for well KP2 on February 4th, 2016, for about one year, may represent the composition for all patterns:

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% (3000-4000 ppm)

The percentage of hydrogen in the produced gas is lower than that for the THAI application in Whitesands Project of Athabasca Oilsands (Turta, 2023). The higher hydrogen content (by far higher than in conventional ISC processes) can be related to the thermal cracking (pyrolysis) /coke gasification/methanation processes, etc (Kapadia 2011-2013). Methane % is also higher than in conventional ISC processes, but this is partly due to the injection of hydrocarbon gases (mainly methane) in the annulus to mitigate H_2S corrosion. Therefore, an accurate estimation of the amount of methane generated during the THAI process appears to be a rather difficult task. The methane content of 9.9%, mentioned in Wei et al. (Wei, 2020), may not be used to calculate ratios such as methane/hydrogen ratio or other ratios involving methane. As a whole, the average composition of produced gas determined here and in the paper by Wei et al. (Wei, 2020) are very close and in both papers, it is established that an HTO regime prevailed; some LTO reactions and a higher percentage of CO appeared only in the period of initiation of ISC by spontaneous ignition (Fig.11).

Fig. 11 shows a typical variation of the gas composition and of the apparent hydrogen-carbon ratio (H/C ratio) in horizontal well KP2 (Turta, 2019). The H/C was in the range of 1-2, except in the period 2012-2014, when it increased over 2, due to frequent suspensions from the production of well KP2 and a general reduction of the air injection rate in the pattern K2 during these suspension periods in which, actually, air injection in KA2 continued in order to supply more air to the back-to-back pattern K7. This can be clearly seen in Fig. 10a.

Generally, the graph shows a robust ISC front development; CO_2 % was not represented in the graph of Fig. 11, but it was accounted for in the H/C calculation. It is to be mentioned here that the calculation of H/C ratio was made with a newly developed method taking into account the amount of CO_2, which did not result from an oxidation, but from a coke gasification (CG) followed by water-gas-shift reactions (WGSR) producing hydrogen. For developing the new equation, it was assumed that all CO produced in CG reacted with water to give more hydrogen; this assumption was possible because the produced CO was almost ZERO (<0.3%).

Variation of H/C for all other THAI pairs revealed the same low value of H/C indicating the existence of HTO regime of combustion. Moreover, compared to the conventional ISC process - a decrease in time of intense burning was never observed while some of the injected air certainly flowed into the bottom water. The existence of HTO regime of combustion is further supported by the observation that neither 'the gas composition variation when resuming the ISC after 1-2 months air injection interruption' nor 'the gas composition variation when increasing the air injection rate significantly all of a sudden' displayed any significant increase of O_2 % at the resumption of air injection.

Based on the graph in Figure 11, it can be seen that the H_2% was in the range of 1-1.5% during the period of normal, steady-state ISC period of 2010-2011; in this period, the H_2S content in the produced gas was higher, reaching 4000ppm. The H/C ratio indicated a better burning quality, resulting in a higher peak temperature. A recent study (Ping Song, 2023) on hydrogen generation during ISC application revealed that a peak temperature of at least 600-700 ^{0}C is required for significant hydrogen generation. The first THAI pilot in Whitesands (Turta, 2023) seemingly confirmed the results from this simulation study relating hydrogen generation with peak temperature.

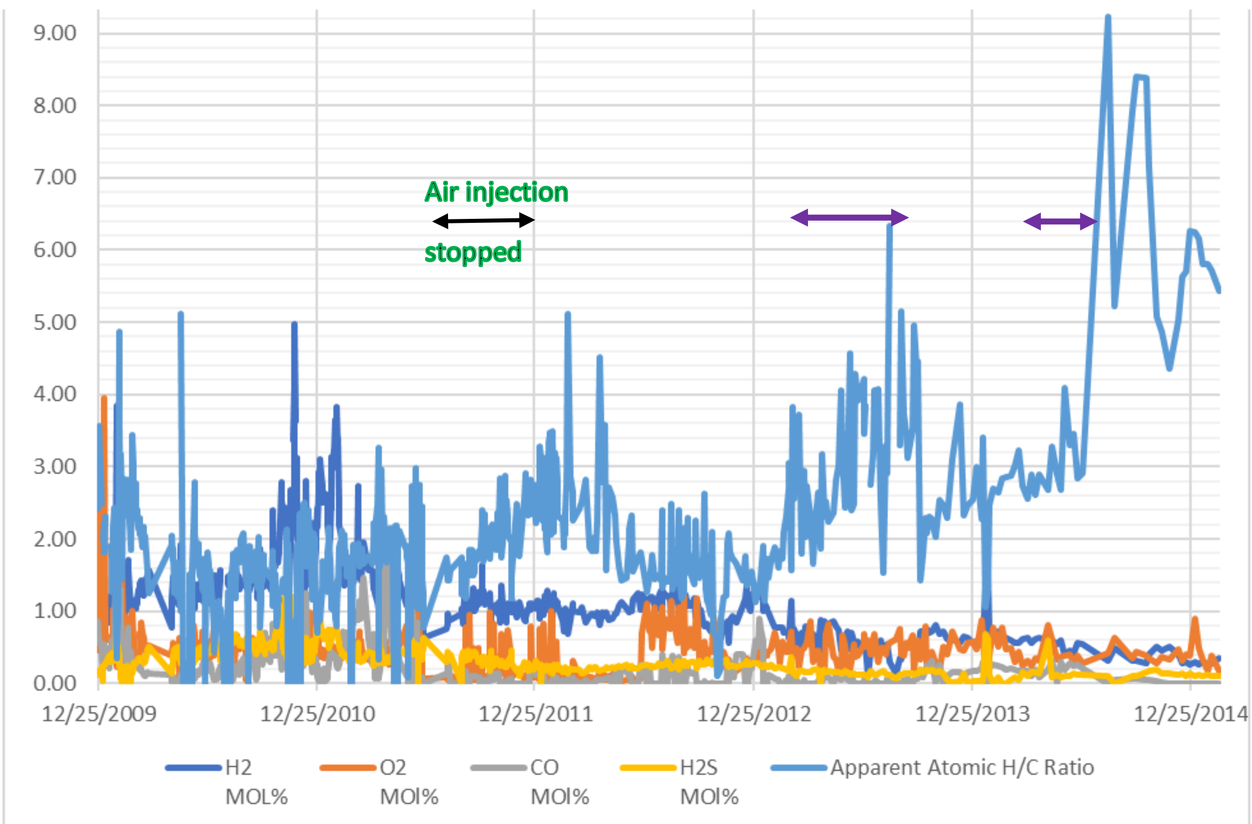


Fig. 11: Typical variation of the gas composition and the apparent hydrogen-carbon ratio (H/C ratio); horizontal production well KP2 (Turta, 2019). In the periods highlighted (⟷), injection in KA2 continued in order to supply more air to the back-to-back pattern K7. However, well K2 did not produce any oil (see Fig 10a-b), as it was under workover operations

ADVANCEMENT OF THE ISC FRONT ALONG THE HORIZONTAL DRAIN. CONFIGURATION OF THE BURNT-OUT VOLUME

A detailed analysis of the bottomhole temperature (BHT) profile along the horizontal section of producers is important from several reasons:

1. It confirms the propagation of the ISC front along the horizontal drain, guided by this drain, with the peak temperature first recorded at the toe
2. At a certain time, it indicates the highest temperature region along the horizontal drain and its possible effect on oil production
3. It confirms the potential damage of the horizontal section not on the entire length but on a small fraction of it located at the toe

A detailed analysis of the BHT profile along the horizontal section of producers as correlated with their performance can establish an almost normal propagation of the ISC front along the horizontal section of some producers with a better performance. However, in a few cases, the forming of a "local combustion chamber" close to the toe was observed and this was indicative of poor performance. Indeed, in the latter case, the *combustion chamber* may have been located at the O/W interface (very early in the process) resulting in the production of large volume of water.

Due to the lack of any observation wells and limited BHT data along the horizontal section of the producers, it was not possible to determine a geometric 3-D form of the burnt-out volume. Therefore, determination of the configuration of the burnt-out volume was limited to categorizing the 'toe-to-heel propagation (TTHP) of the ISC front' along the horizontal section of producers and '**s**talled **c**ombustion **f**ront (SCF)' closer to the toe, when a combustion chamber was generated.

Table 3 provides the essential distances between shoe of the vertical injector and toe of horizontal producer for all pairs, along with the identification of either TTHP along the entire horizontal length of the producer or SCF in the toe region (combustion chamber). From Table 3, the following observations are made:

- ✓ Although the entire semi-commercial THAI process is considered to be using direct line drive (DLD) configuration, for some well pairs there was some deviation towards staggered line drive (SLD) configuration, as the shoe of vertical injector was not co-linear with horizontal section of producer but laterally off by a small distance. In theory, SLD is more efficient than DLD and in Kerrobert, the patterns K1, K2, K3, K7 and K9 having lateral off distances in the range of 18-23m, with K2 pattern having the highest distance make the case for SLD much stronger
- ✓ A toe-to-heel propagation (TTHP) of the ISC front along the horizontal section of producers was detected for the patterns K1, K2, K8, K9 and K11
  - ✓ For the patterns K3 and K7, the TTHP detection is not very conclusive. Instead, it could have been an SCF. The better performance of K7 is supported by the argument for a TTHP

Table 3: Kerrobert Project. Main geometrical distances and the ISC propagation mode for the individual THAI patterns

Pattern	Start date of operations	Horizontal distance shoe-toe (m)	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 the horizontal producer cm/day	Observations
K1	09-2009	18	VG	TTHP	205 / 01-2013	13.5	Farthest from O/W contact Longest time of TTHP
K2	09-2009	23	VG	TTHP	116/10-2013	8.3	Farthest from O/W contact Some SLD deviation
K3	03-2011	22	G	TTH/CC??	32-64 / 06-2013	-	Some SLD deviation (?)
K4	04-2011	-	No ignition	-	-	-	No ISC anchoring. KA4 injected air for KP7
K5	03-2011	7	VG	CC	13 / 06-2013	-	Closest to O/W interface
K6	03-2011	10.5	VG	CC	12-20 ? / 07-2013	-	Best ignition. Typical CC situation*
K7	03-2011	21	G or M?	CC/TTHP??	20? / 05-2013	-	Some air from KA4
K8	07-2011	10	G	TTHP	56 / 04-2014	6.5	Slow TTHP
K9	07-2011	18	?	TTHP	55 / 01-2013	18(?)	2 burning regions Some air from KA12
K10	07-2011	8	?	CC	15 / 04-2014	-	2 burning regions. Some air from KA12
K11	07-2011	5	VG	TTHP	?? /	?	Good ignition
K12	07-2011	-	No ignition	-	-	-	KA12 injected air for KP9 and possibly KP10

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

HP = horizontal producer; HS=horizontal section; SLD -Staggered Line Drive

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

- ✓ Clear SCFs were detected in the patterns K5, K6 and K10.

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 their horizontal sections, therefore only some immiscible displacement happened. The poor performance of K6 pattern may be attributed to the stalled combustion front, i.e. the development of a combustion chamber around its toe, with this chamber located probably at the water-oil interface, therefore involving an early watering.

The best performers were the patterns K1, K2, K9 and K11, which showed a clear advance of the ISC front along their horizontal sections. K7 pattern, also shows a good performance although the TTHP is not a certitude. Surprisingly, pattern K8 although identified with a TTHP is not among the best performers. The performance of the patterns K3, K5 and K10 has been very difficult to explain.

Figures 12 a-b shows the ISC advancement for the pilot production wells KP1 and KP2. It can be seen that by 2014-2015 the ISC front propagated along the horizontal producer for more than 205 m in KP1 and 116m for KP2 well. Due to the high peak temperature still present, it can be concluded that a strong ISC front was created in 2009. In KP1, in September 2014 the peak temperature at the ISC front (intersection with the horizontal drain) exceeded 500 ^{0}C, while later on - due *to a very pronounced general reduction* of the air injection rate (see Fig. 15b-c) - it decreased to around 300 ^{0}C. Well KP2 also experienced very high peak temperatures as the 14" casing in the toe region collapsed due to excessive temperature. It should be mentioned that the peak temperature along the horizontal drain does not necessarily fully characterize the peak temperature of the ISC front, laterally, far from this drain; however, it can be considered a certain indication of the general state of burning quality in that pattern.

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 where many interruptions in air injection (at least 3 major ones -see Fig. 10a-b) slowed down the ISC front advancement.

It is speculated that the performance of each pattern depended on how long the combustion zone remained in the upper part of the oil layer, before moving to the water/oil interface; probably, this was even more important in cases in which the stalled combustion front (SCF) happened.
In the case of a *combustion chamber* (or SCF) the anchoring of the combustion may occur, but the toe-to-heel propagation is stalled.

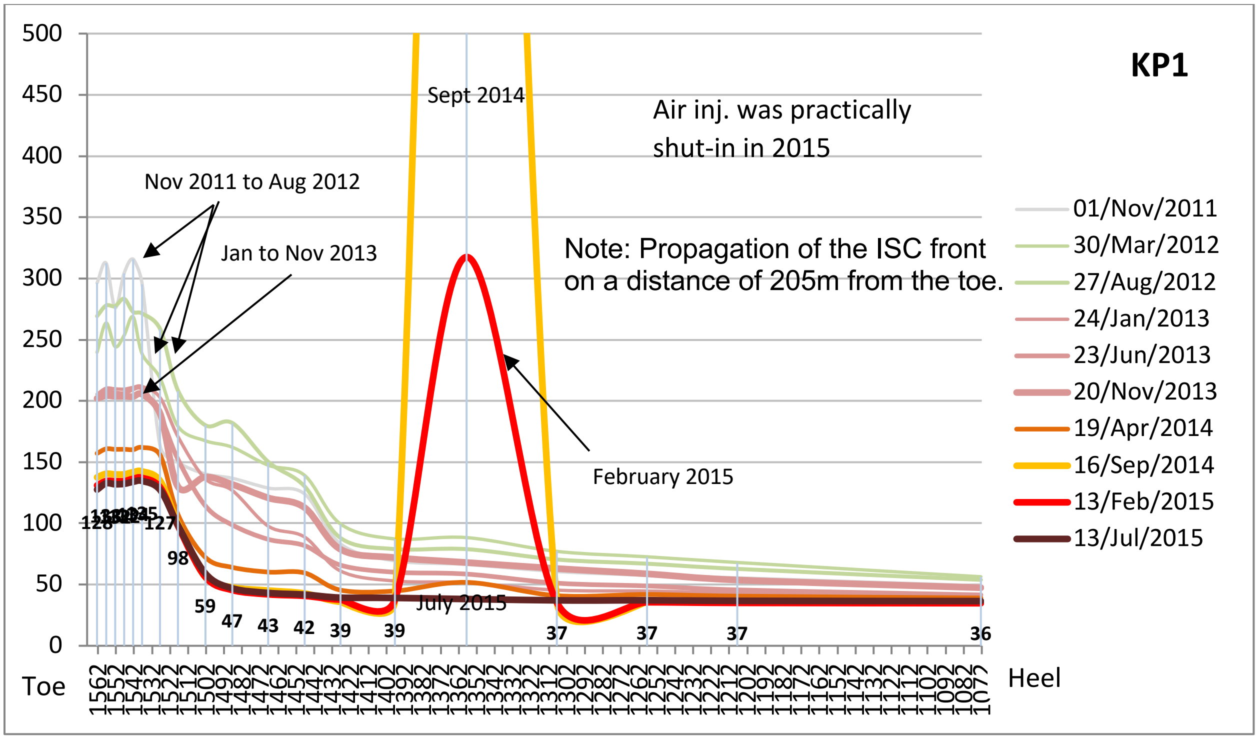


Fig. 12a: Kerrobert THAI Pilot. The variation of temperature from the toe to the heel, for well KP1 in the period 2011-2015. Start of air injection: October 27, 2009. On April 26, 2010 temperature at the toe was 520 ^{0}C, and it decreased in time gradually to around 300 ^{0}C in November 2011

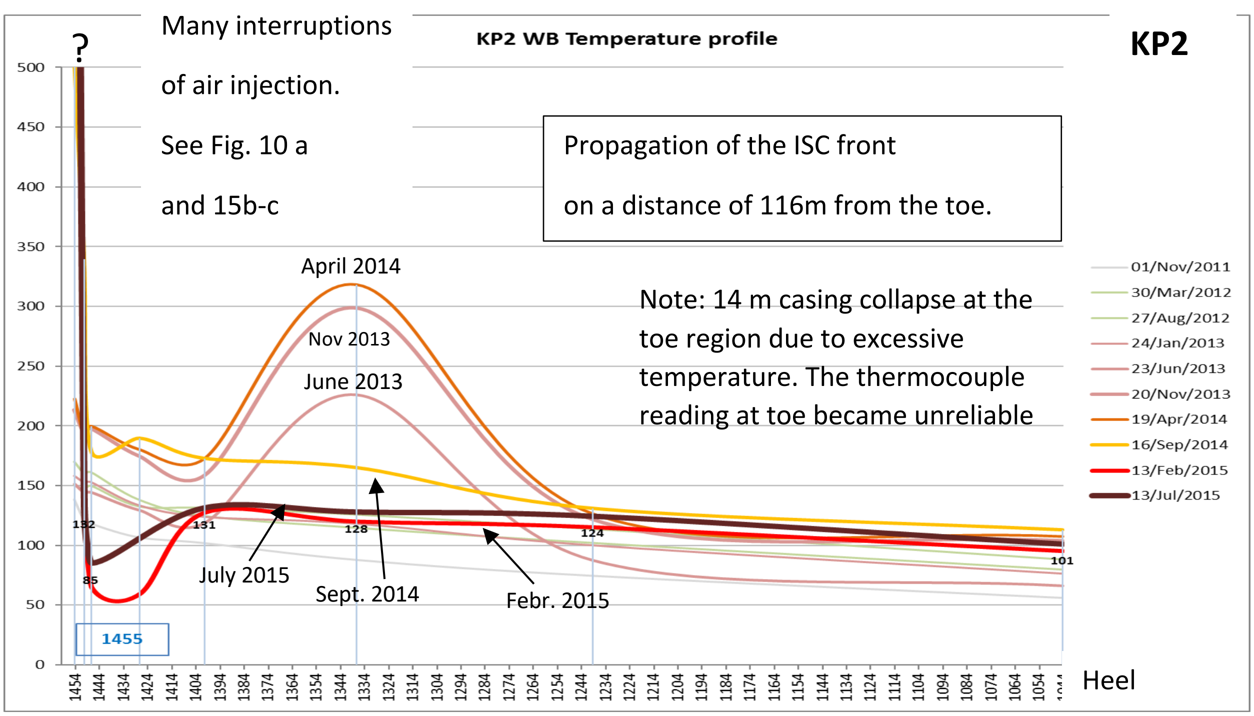


Fig. 12b: Kerrobert THAI Pilot. The variation of temperature from the toe to the heel, for well KP2 in the period 2011-2015. Start of air injection: October 27, 2009

It is speculated that there may be backward inclination of the ISC front (channeling type) as compared to the normal forward tilting in case of a normal THAI propagation of the ISC front along the horizontal drain (Fig. 3). Pronounced heat losses around the channeling may stop further propagation along the horizontal section. As shown in Fig. 13, it is possible to have two leading edges of the ISC front; one along the horizontal section (HS) of the producer and one along the water-oil interface. The tilting backward of the ISC front may be a main feature, but the combustion chamber may have different 3-D shapes. Although penetration of air in the bottom water zone is quite imminent, the unconsumed oxygen does not appear at the production outlets, which leads to the conclusion that the burning would take place under the oil/water interface making the oxygen utilization at almost 100%. The calculation of the H/C ratio revealed that there were some LTO reactions, but not very intensive.

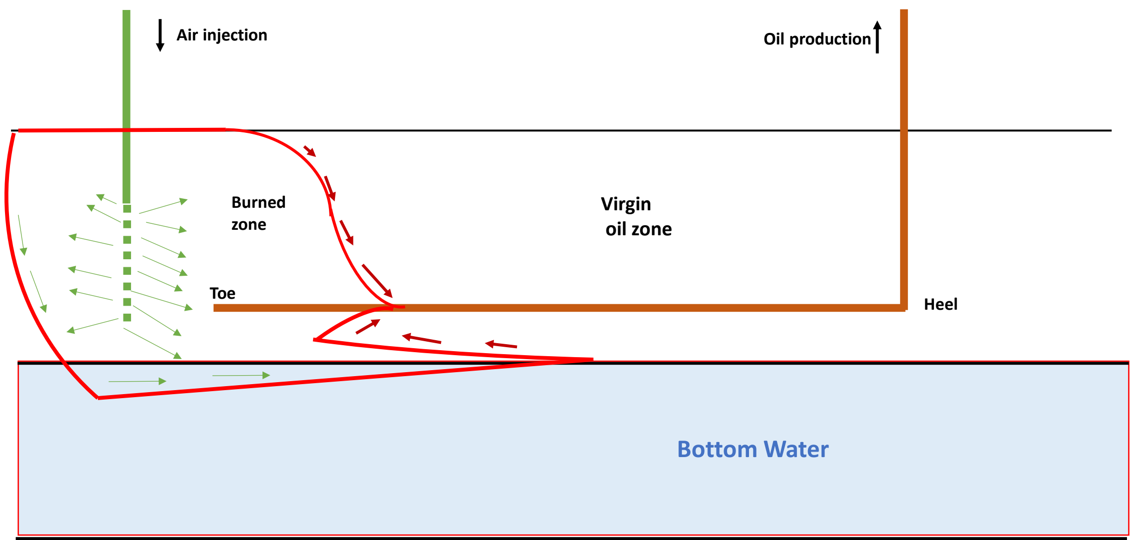


Fig. 13: Hypothetical schematic of THAI process with formation of a *combustion chamber*. Here, it is assumed that a common combustion chamber includes both the toe region and the oil-water interface.

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

This section presents the essential on the performance of the semi-commercial operation, including the in-situ upgrading of the produced oil, but with the mention that it was not possible to estimate the contribution of the in-situ upgrading toward the increase in oil production. Dedicated special field tests will be needed to fully understand this effect.

In this section, the global performance of the pilot patterns K1 and K2 - both in terms of oil production and of in-situ oil upgrading - is provided individually and as part of the semi-commercial operation.

Performance

A high amount of information and details on the individual performance is presented elsewhere in a different report (Turta, 2018), which, now can be accessed from the website www.insitucombustion.ca. In order to make the analysis easily digestible, in Table 4 a Project operational history is provided (Wei, 2020). From this table, the main observations are the following:

- The performance during year 2011 was very poor, as all 10 ignition operations were carried out and for each operation a period of 5-7 months was lost for production due to extremely slow ignition process; it has just one message: ignitions have to be speeded up in order not to take more than 1-2 months

- Year 2012, however, is representative of a semi-commercial THAI operation as all 10 patterns were active with all producers in operation. It is characterized by an air injection rate of 10,000 sm3/day/well. AOR was 2500 sm^3/m^3

- In the period 2012-2023, the number of air injection wells (and of active producers) decreased continuously from 9-10 wells down to as low as 3-4 in 2021-2023. Air injection rate was in the range of 12,000 to 22,000sm^3/day/well, while AOR was in the range of 2000 to 3300 $sm^3/m^{3,}$ in this period

- Regarding the 'air injection rate – oil production' relationship, increasing the air injection rate from one year to the next while keeping the same number of active patterns - there are two very clear examples:

    - From 2012 to 2013, when increasing the field air injection from 103,000 sm^3/day to 170,000 sm^3/day - corresponding to the increase of air injection rate per well from 10,000 to 17,000 sm^3/day - the AOR increased from 2500 sm^3/m^3 to 5700 sm^3/m^3

    - From 2016 to 2017, when increasing the field air injection from 89,000 sm^3/day to 108,000 sm^3/day - corresponding to the increase of air injection rate per well from 18,000 to 22,000 sm^3/day - the AOR increased from 2500 sm^3/m^3 to 3300 sm^3/m^3

Table 4: Kerrobert THAI Project operational history (from Wei, 2020, with add-ons)

Year	Event	Average No. of production wells	Field air injection rate Sm^3/day	Injection rate per well Sm3/day	Field Oil production m^3/day	Oil rate per well m3/day	Air-oil ratio (AOR) Sm^3/m^3
2009	Pilot started operation in Nov. 2009	2	48,274	24,137			
2010		2	45,542	22,771		6.39	
2011	Semi-commercial operatios started in May-August 2011 period	5	129,228	25,846	11	2.2	11,748 AOR very high due to very slow ignition
2012		10	103,045	10,305	41.27	4.13	2,497
2013		10	170,368	17,037	29.85	2.99	5,707
2014		8	97,565	12,196	51.6	6.45	1,891
2015	Petrobank Energy merged with Touchstone Exploration	4	70,538	17,635	23.08	5.8	3,056
2016	Quatro Exploration acquired the Project in Jan. 2016	5	88,695	17,740	34.71	6.94	2,555
2017	Proton Technologies acquired the project in August 2017	5	108,868	21,774	33.15	6.63	3,284
2018		5	118,953	23,800	25.29	5.1	4,700

Note: It is automatically assumed that each pair has at least one air injection well
Legend: Transition =Transition period from piloting to semi-commercial operation (period of ignition for 10 pairs; pairs 3 to 12), involving 5-7 months of almost no oil production

From the analysis, the best and worst well performers have been established. It was seen 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, confirming low performance. Well KP6 – having both horizontal section of the producer and the perforations of the 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. It seems to be an example of a combustion chamber formed at the oil/water interface.

The good 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 24 m^3/day. For all these wells, in general, water cuts 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.*

In fact, the in-depth analysis of the individual performance, taking into account the fact that Kerrobert is a conventional heavy oil reservoir with underlying bottom water, came to the following observations and conclusions:

- In Kerrobert, THAI was operated on a semi-commercial basis, and it was tested as a secondary recovery method. It was initiated when the water cut rose to 85-96% for an extremely low recovery factor (1.2%). The primary recovery utilized horizontal wells located in the upper half or even under the top of the oil layer to delay the water encroaching from the bottom water. At the initiation of THAI, the reservoir pressure was half the initial pressure; therefore, some relative permeability for the gas existed. Also, the primary recovery was characterized by intensive water channeling from bottom water.
- The ISC front evolved 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, oil production was extremely low. After the full development of the ISC front, the burning was 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 stalled combustion front (i.e., 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 for the semi-commercial patterns, while in the pilot pairs it advanced 100-200m.
- 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 by oil production showing a clear upward trend.

- For the entire 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* per well 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 oil of approx. 7000 m^3 (until February 2015).
- Production wells exhibiting a lack of positive ISC influence, 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%) which was seen in the patterns K4, K6 and K12. These patterns produced a cumulative oil of 80 m3, 520 m3 and 1100 m3, respectively (until February 2015). For the patterns K4 and K12, ISC front anchorage to their toe, failed, while the K6 pattern experienced frequent interruptions in production and appeared to develop a combustion chamber at the oil/water interface.
- The performance of pairs K3 and K5 was more difficult to decipher; as of February 2015, their oil cumulative was 5,500 and 3,100 m3, respectively. In the K3 case, water cut decreased to 40-50% only in the first year and then it increased to 80-90%. For K5 pattern, which showed a full interference with the back-to-back pattern K2, the water cut did not decrease during ISC application (mainly in the period 2013-2015)
- An attempt to displace more oil toward KP8 and KP9 via a multi-THAI (Ayasse 2012) process - by using an additional air injection well, MT8 - did not give results. Also, in the same period (2013-2015), a similar attempt with the KP11 well by using the additional air injection well, MT11 – failed. These two failed additionally-generated ISC fronts are directly connected to the lack of intensive preheating of the large space (20-30m) between MT8 and MT11 and KP8/KP9 and KPP11, respectively (Fig. 7a). Peaks of O_2% in the range of 5-10% were recorded in KP9 and KP11 in February and October 2013.
- 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 activity was seen (Starkov, 2014). In addition, it showed that after one year of full semi-commercial

operation, the combustion gases/air flowed along the oil/water interface, with deeper penetration into bottom water in the NW part of the reservoir, which is also slightly more elevated compared with the rest of the reservoir. The early seismic survey of 2011 allowed to detect some anomalies in relation to secondary gas caps formed along the old horizontal wells 2,5,6 and 7 (see Fig. 7b), around the intersection point between well 2 and 6 and these 4 old wells might have had communication between them.

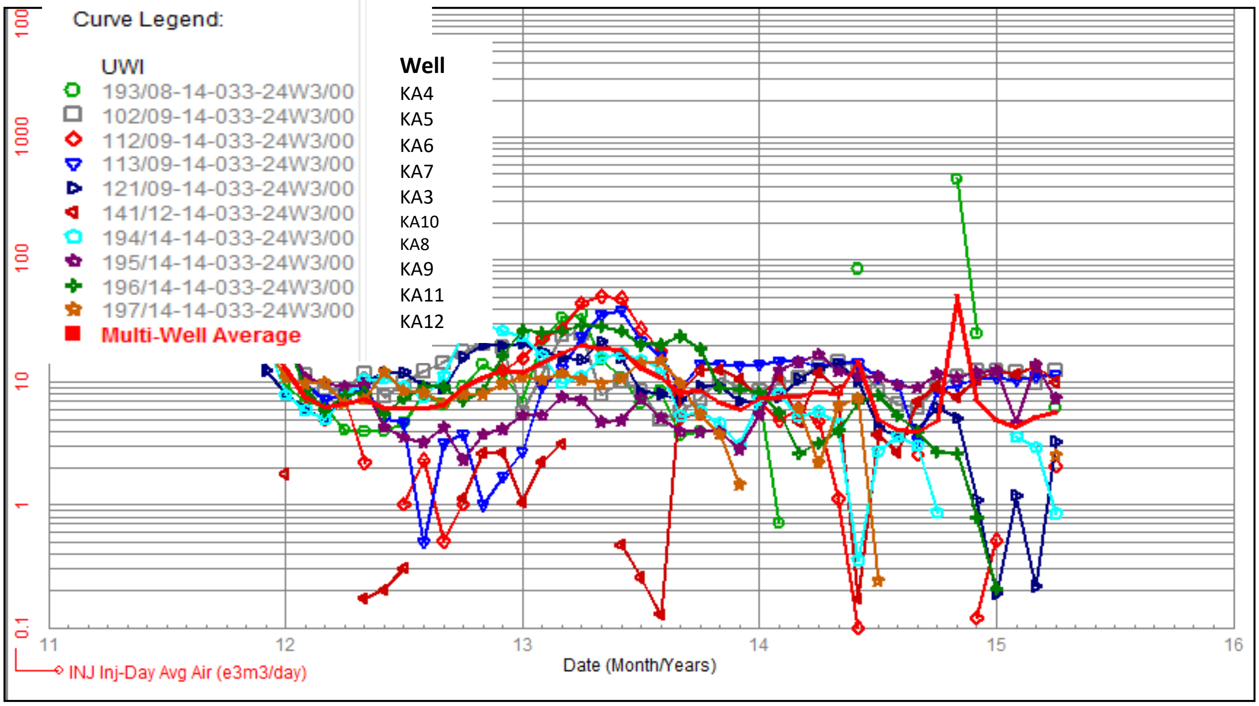


Fig. 14a: Air injection for the patterns K3 to K12 of semi-commercial operation

The oil production performances for the two producers of the pilot, KP1 and KP2 were provided earlier in Fig 9. Figures 14a and 14 b show both air injection and oil production for all other patterns (K3 to K12) of semi-commercial operation. Most of wells injected with an air rate in the range of 3000-23,000 sm^3/day/well, with an average of around 10,000 sm^3/day/well. Well KA3 injected with a very low rate (2000-3000 sm^3/day/well. As seen in Figures 14a-b, oil production per well was in the range of 1-10 m^3/day (average 4 m^3/day). An average of air-oil ratio of about 2500sm^3/m^3 was estimated for the K1 and K2 during semi-commercial operation. In the pilot, as is visible in Figs 9 and 10 , a 2-month interruption of air injection occurred in 2011 during the transition to semi-commercial operations. Although in 2011 there was a drastic reduction in the air injection, the daily oil production still remained in the range of 3-6 m^3/day/well.

Suspension of air injection was made in the following order: KA8 in 2012, KA4 and KA12 in 2013, KA6 in 2014 and KA11 in 2015, such that after 2015 less than 7 air injection wells were active.

The oil production per individual pairs of semi-commercial operations (Fig. 14b) shows that there was a large variation in the oil rates; oil rate per well was in the range of 3-15m^3/day, with an average of around 4 m^3/day/well. As in the pattern K8 there was no THAI process occurring, the producer KP8 had very low rates (0.2-2 m3/day). The best producer was KP7 with a continuous gradual increase of production. Also, wells KP9 and KP10 had a good performance, while KP5 had an average performance. An average air-oil ratio of about 2800sm^3/m^3 was estimated for the semi-commercial operation.

Currently, the mechanisms of THAI process in a heavy oil with bottom water are poorly understood as there was just one laboratory testing of this process (Greaves, 1993); there is also limited experience even with application of conventional ISC in bottom water situation. However, a complete performance set of curves (Fig. 15a-c) will help in deciphering the effect of bottom water.

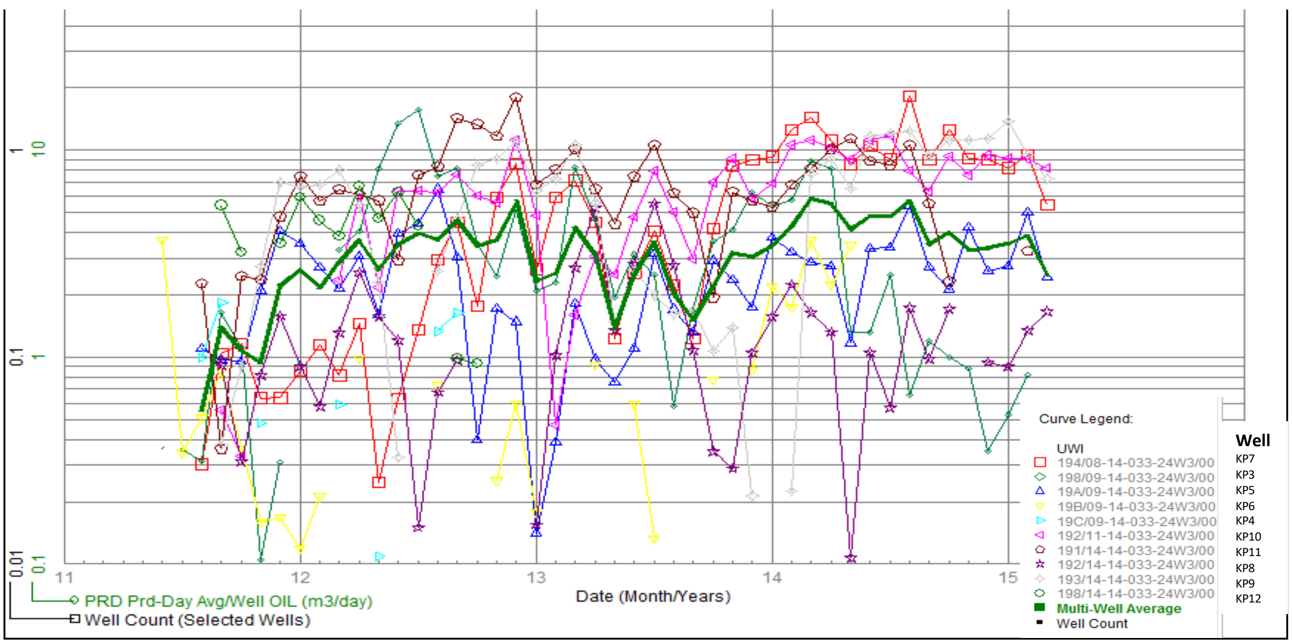


Fig. 14b Oil production per pattern for patterns K3-K12.

As seen in Fig. 15a, 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 2247 sm^3/m^3, which is in the normal range for an ISC project. However, the crucial issue of this Project was *the ability to increase the air rate, while still maintaining the same low AOR (i.e same efficiency of the process)*. Further on, *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. The increase of air rate led to a dramatic increase of the water cut, which climbed up to 80%. F*inally, in March 2013, very low performance was recorded; for a total oil production of 29 m^3/day (180 bbl/day), the total air injection rate was 280,000sm^3/day; this corresponded to a water cut of 80%-90%, while AOR was 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) but this was due to the production of a large amount of water from the bottom water zone. Other repeated trials of operators to increase the air rate for certain THAI pairs led to an identical result.

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; little of the displaced oil is captured; mostly 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, with 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 (Table 3).

Therefore, the existence of a threshold air injection rate per well beyond which there is no gain in the oil production is directly attributed to the existence of bottom water with a very high mobility to flow as compared to the oil zone. Attributing the existence of this threshold to a so-called "cooling effect" of air injected, when exceeding a certain air injection rate (Wei, 2020) does not have a realistic base in this case. There is no "cooling effect" by air injected in the ISC process; in the worst case, there are low temperature oxidation (LTO) reactions; however even the LTO reactions generate heat.

As Fig. 15a shows the oil and water production only up to 2014, in Fig. 15c the monthly oil and water production in the extended period 2013- 2023 is displayed. Please notice that year 2013 is represented in both Figures; a continuous decrease of gas production occurred, which actually by July 2013 became half of what was in March 2013. As seen in Fig. 15b, this seems to reflect a decrease in the injection pressure on a background of continuous air injection decrease, leading to a decrease in the reservoir pressure, which allowed more water from bottom water to be produced; the average daily water production doubled in this period.

Fig. 15 c shows that 4 owners operated the THAI Project: Petrobank, Touchstone and Quattro each for 2-3 years and Proton starting in 2017. Each owner needed a period of adaptation and, in general, there was less

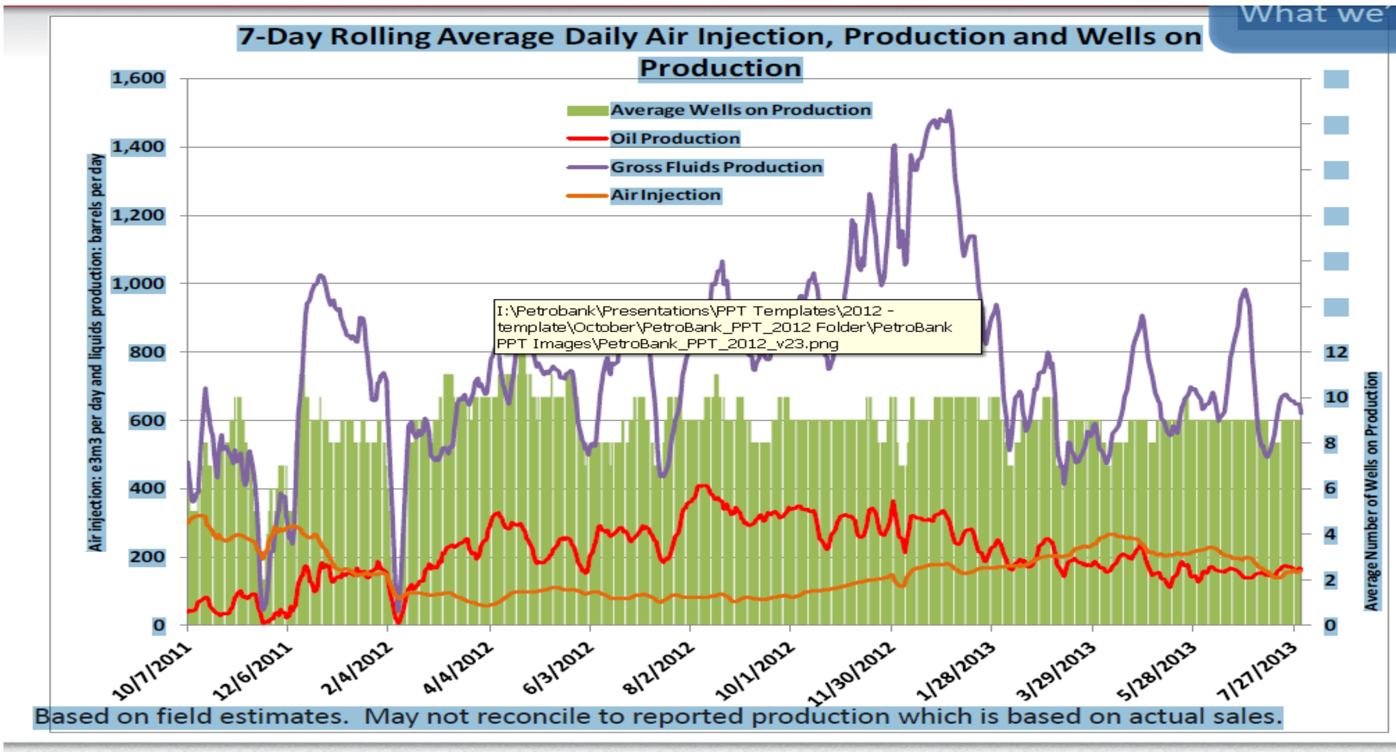


Figure 15a: Oil production during semicommercial Kerrobert THAI operation (period: October 7, 2011-July 27, 2013). Source: Petrobank presentation, August 2013 (www.petrobank.com)

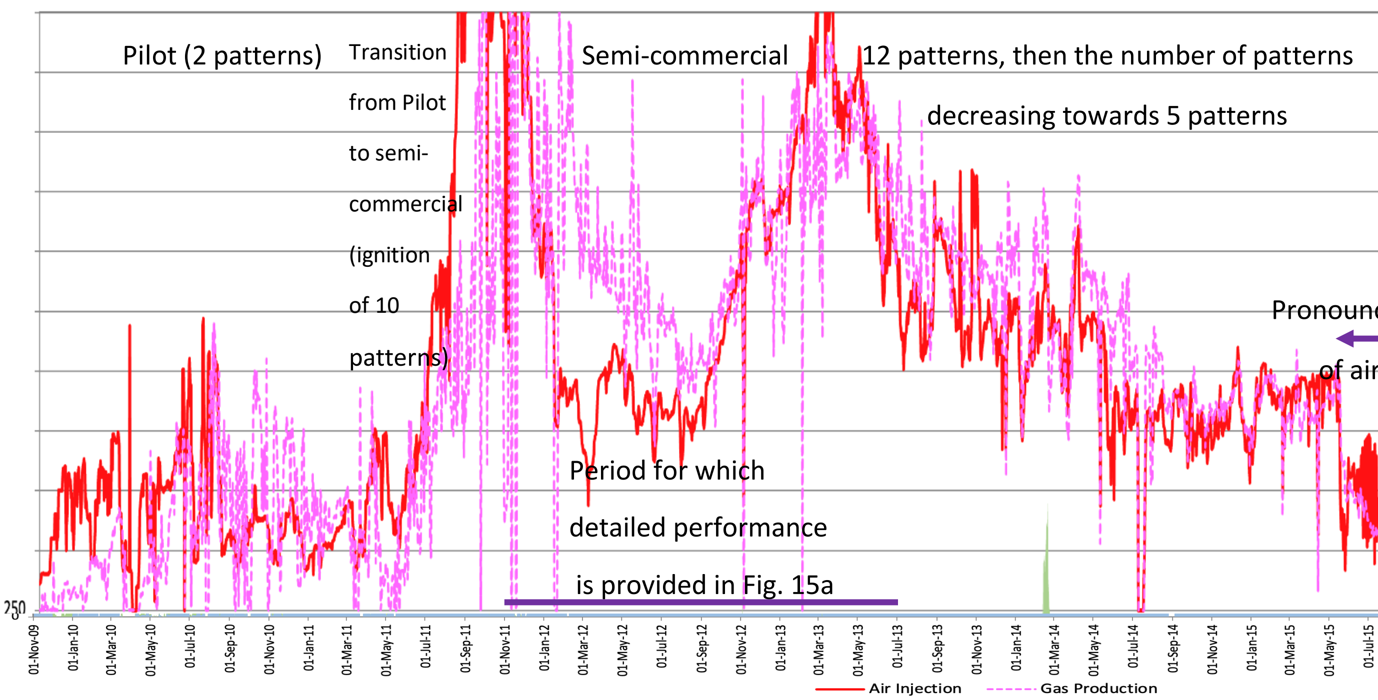


Fig 15 b: Kerrobert THAI Project. Average daily air injection and gas production for the period

November 2009 – May 2016

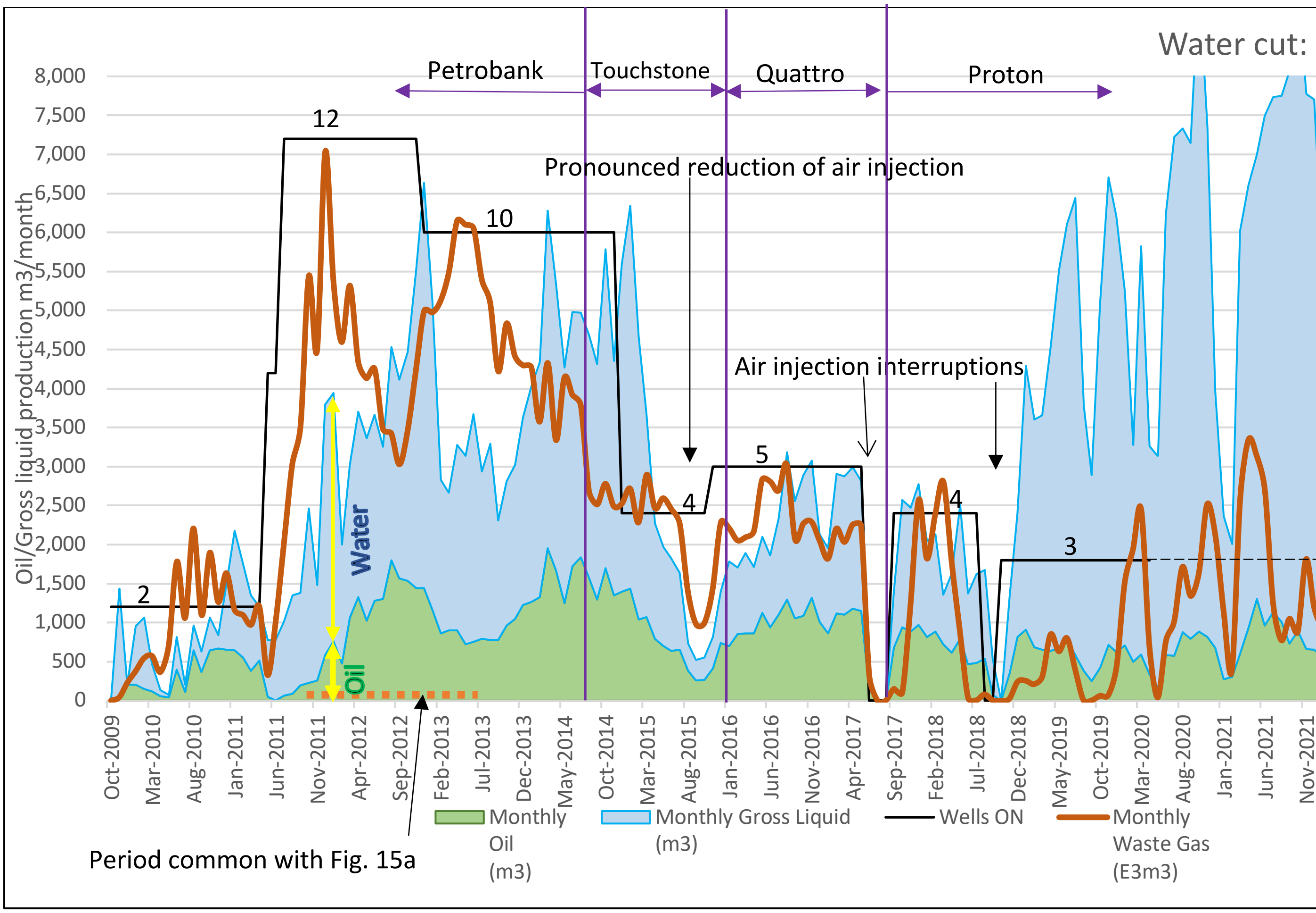


Fig. 15c: Monthly oil, water and gas production of Kerrobert THAI Project (period October 2009 - July 2023), showing the various companies conducting the process (geoSCOUT data and private `communication with K. Starkov). Average number of wells from Table 2 (Wei 2022). Until May 2016, the air injection is provided in Fig. 15b. Quattro =Quattro Exploration.

and less efficiency in operation. This is reflected in the fact that in time number of operating patterns decreased, while the field oil production had a general trend to decrease while the water cut tended to increase; in 2020-2023 period, the water cut was hovering around 90 %. Also, in time, the total gas production of the semi-commercial THAI project decreased continuously from around 180,000sm^3/day in 2012-2013 to as low as 15,000sm^3/day in 2020-2023.

In 2017, Proton Energy of Calgary bought the Kerrobert THAI project with the aim of testing bottomhole separation of hydrogen from the produced gas. As can be seen from Fig 14c, before the transition from Quattro to Proton, in August 2017, practically all the activity (injection and production) was ceased for 2-3 months. Another global interruption of slightly longer than 2 months took place in June-August 2018.

The stability/robustness of combustion process of THAI was very good as the resuming of the process was easy even after 2-3 months of no air injection. Moreover, no blockages were recorded and some oil production was obtained during some periods without air injection.

In-situ upgrading of the oil and the hydrogen content of the produced gases

The ISC front in the pilot two pairs was fully developed by December 2009-January 2010. As of March 2010, there was some indication of in-situ upgrading. However, it started to be visible in the period May 2010-November 2010, therefore started to clearly show up 4-5 months after the generation of the in-situ combustion (ISC) front. During the 6 months of May 2010 – November 2010, the upgrading increased up to a maximum of 6 degrees API (from 10.3^0 to 16.3^0). This pronounced upgrading was associated with an increase of hydrogen content up to a maximum of 4-7% (average of around 1.5%), as compared to the conventional ISC process, where it is lower than 0.2-0.3%. Fig. 16a 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 14^0 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, that constituted a partial upgrading; a small amount of diluent was still needed for pipelining.*

It is to be mentioned that a strong 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 very good, with CO_2 percentages in the range of 12-15%, and almost 0% oxygen in effluent gases (less than 0.3%).

Similar to the THAI Pilot, in the commercial operation, upgrading of the produced oil was recorded, and it appeared after 4-5 months since the ignition operations, after the long ignition period necessary for initiation of ISC in the 8 patterns (see Table 2). 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, large fluctuations existed and the quasi-steady-state upgrading recorded was slightly less than in the pilot (Fig. 16b), being around 3 ^{0}API degree (an increase from 11^0API degree to 14 ^{0}API degree); although not represented in Fig. 16b, the decrease of produced oil viscosity was from original 54,000mPa.s to as low as 500-3,000 mPa.s 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 3,000cp can be conservatively considered (therefore an 18-fold reduction of viscosity).

Fig. 16c shows viscosity reduction in the case of KP2 producer, up to August 2015, i.e. for 6 years of THAI operation. Oil viscosity decreased from around 90,000mPa.s, during ignition operation period of

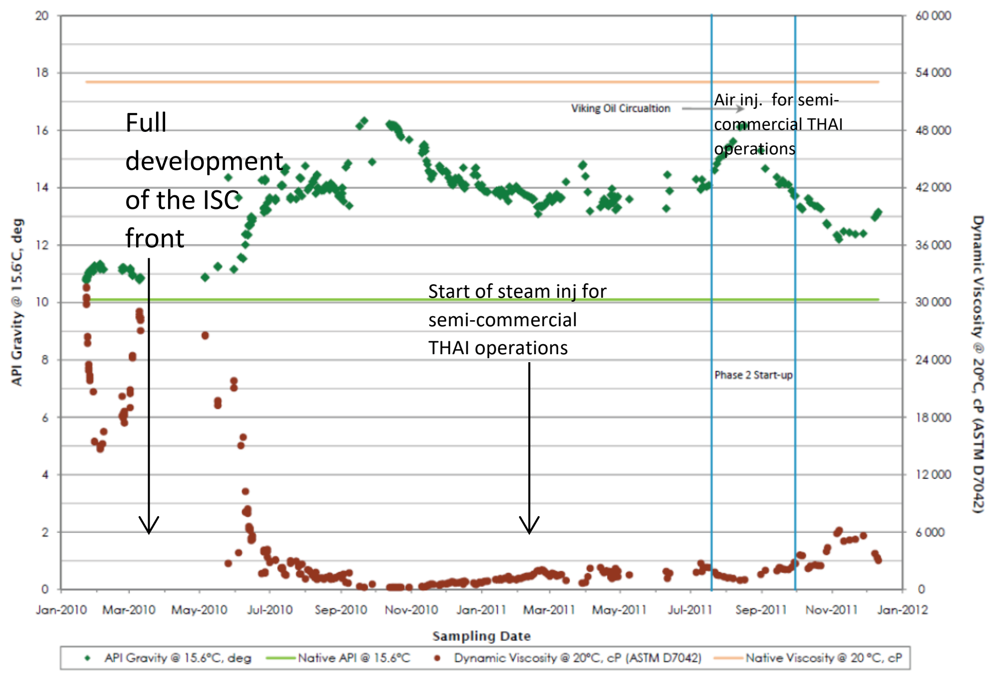


Fig. 16a: Increase of produced oil quality by in-situ upgrading during Kerrobert THAI pilot operation (in the period January 2010-July 2011 (Petrobank website). Wells KP1 and KP2

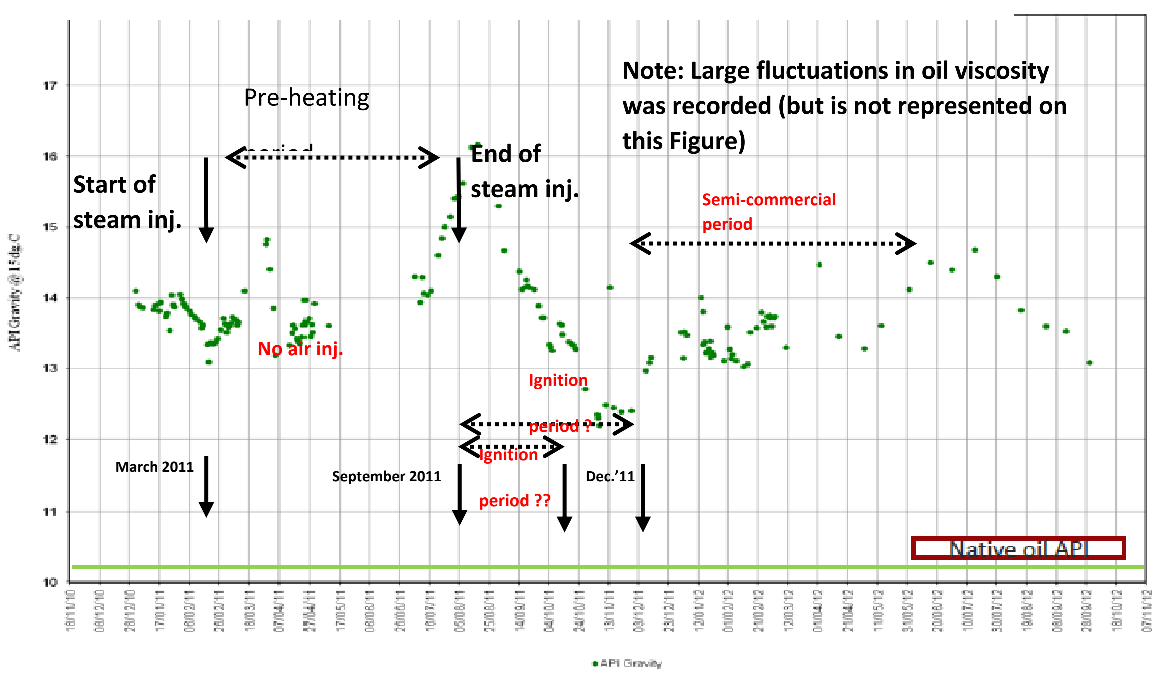


Fig 16b: Increase of produced oil quality by in-situ upgrading during Petrobank operated Kerrobert THAI semi-commercial operation during the period February 2011- November 2012 (www.petrobank.com). It includes all 12 THAI patterns(K1-K12).

September-December 2009 - when some LTO reactions were recorded - to as low as 100-1,000mPa.s, with an average of 500mPa.s. Considering original viscosity of 54,000mPa.s, a decrease up to 1,0000mPa.s means a 54-fold reduction. Therefore, in general, the oil viscosity reduction would be in the range of 20 to 50-fold.

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

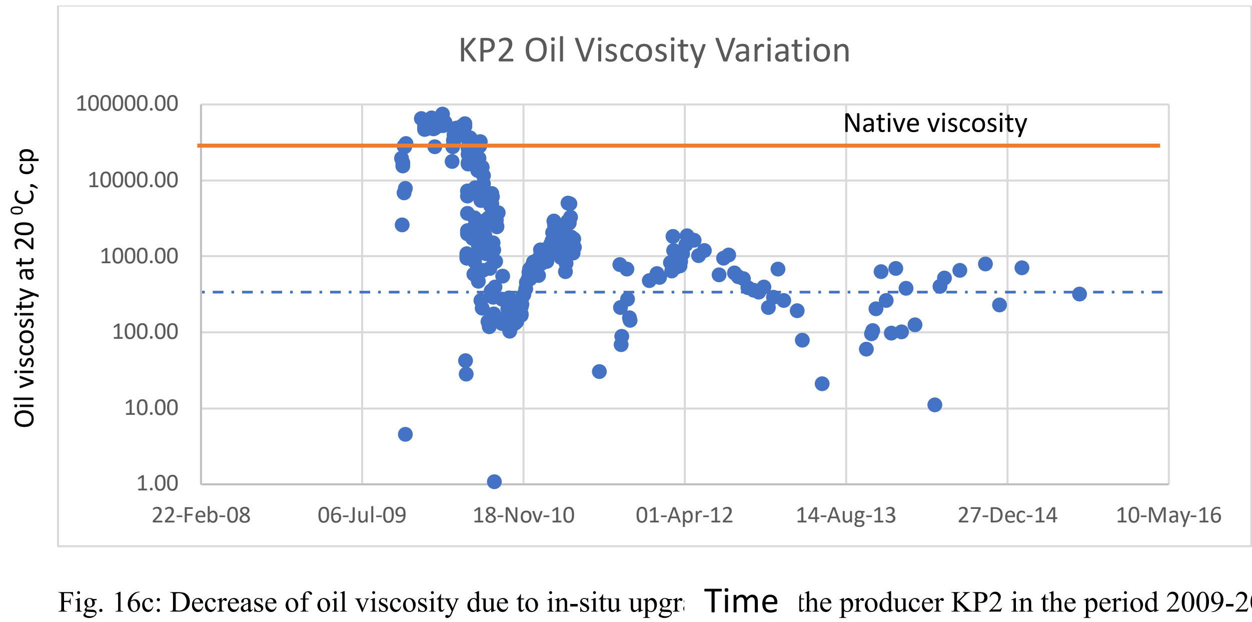


Fig. 16c: Decrease of oil viscosity due to in-situ upgr[illegible] the producer KP2 in the period 2009-2015

CONCLUSIONS

1) For a heavy oil underlain by bottom water, testing of the toe-to-heel air injection (THAI) process using 12 patterns for 14 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; after 4 years, the advancement was up to 205m out of 485 m the length of horizontal section of producers. However, this advancement did not happen in all cases. In three cases, the ISC front stalled and a combustion chamber was formed around the toe of the producer, showing lower performance; in two cases, ignition failed and prevented any ISC front development.

2) Although the design of the process was for a direct line drive (DLD) configuration application, in the real conditions of the field, for a few patterns, a very small deviation from a DLD configuration towards a staggered line drive (SLD) configuration was noticed. Also, the interference between

some adjacent patterns and back-to-back patterns for limited periods of time was amenable to operating in a SLD configuration.

3) Initiation of the ISC (ignition) was achieved by spontaneous ignition, injecting a slug of steam just before starting the air injection; ignition delay was 2-4 months for the pilot and 3-6 months for the semi-commercial pairs. It is imperative to improve the ignition operations.

4) Burning quality was very good reflecting a high-temperature oxidation regime; oxygen utilization was very high. There were some low oxygen fractions in the produced gas, and some low-temperature oxidation reactions during ignition operation periods, but this is normal for any ISC process. Very high stability of the THAI process was documented by easily resuming the process after long periods of air injection interruption and its high stability at any value of air injection rate. This stability is significantly higher than that of the conventional ISC process.

5) The Kerrobert project showed that the THAI process may constitute the first EOR process fully proven for producing underground upgraded oil in case of heavy oil reservoirs with bottom water; in Kerrobert, oil viscosity was reduced from 54,000mPa.s for the original oil to 3,000 mPa.s for the upgraded produced oil. Hydrogen generation - although in small proportions (1-1.5%) - was another constant feature of the process, as hydrogen was contained in the produced gases.

6) The main setback of the project was related to the air escape in the bottom water, where, it probably formed a secondary ISC front; this made it impossible to increase the air injection above a critical value, as this caused an exaggerated increase of water cut with negligible or no oil production increase or even its decrease.

7) Despite the high complexity of the process, including factors such as the bottom water effect, the interference between patterns, and the potential impact of old horizontal wells, this semi-commercial THAI process has achieved a cumulative air-oil ratio of around 3,000 sm^3/m^3. This is a better result than that of the best-performing conventional ISC process applied in heavy oil reservoirs with bottom water.

8) The economic efficiency of the Kerrobert THAI semi-commercial process is still to be improved. However, it fully demonstrated the in-situ upgrading of the oil, for the application of the THAI process in a heavy oil reservoir underlain by bottom water.

Acknowledgement
We acknowledge that in the development of THAI technology former Petrobank Energy and Resources (Petrobank) with its activity in the period from 2000 to 2016, has a special place, given its pioneering effort in the field piloting of the THAI process. Petrobank is to be admired for its courage to enter into a domain of unknown technology. In 2016 Petrobank released Kerrobert THAI data to the public.

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