Improving heavy oil production rates in THAI process using wells configured in a staggered line drive (SLD) instead of in a direct line drive (DLD) configuration: detailed simulation investigations

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Abstract
As governments around the world prepare for a transition period to a decarbonised energy and economic future, petroleum is needed to smoothen that transition. Based on the analysis of the International Energy Agency’s 2020 projections, around 770 billion barrels of oil are required to meet demand from now to 2040. However, according to British Petroleum’s Statistical Review of World Energy 2020, as at the end of 2019, the global total reserves of recoverable conventional and unconventional oils is approximately 1734 billion barrels. Out of that, the conventional easy-to-produce light oil accounts for only 30% (i.e., accounts for only 520.2 billion barrels). Therefore, the remaining 249.8 billion barrels of oil needed to satisfy demand up to 2040 must come from unconventional oils, namely heavy oils and bitumen. However, these unconventional resources are very difficult to produce and the current production methods have very high environmental footprints. Consequently, in accordance with climate crisis mitigations, the vast reserves of the virtually unexploited heavy oils and bitumen must be developed using advanced and greener extraction technologies, such as the yet-to-be-fully-understood THAI process which provides partial upgrading of heavy oil/bitumen via in situ combustion. Using validated numerical models which are developed using the CMG’s reservoir thermal simulator, the STARS, which is also used in this study, field scale reservoir simulations of the THAI process were performed with the wells arranged in staggered line drive (SLD) and direct line drive (DLD). Over the 834 days of operating time, the cumulative oil recovery in SLD is 32% of oil originally in place (OOIP) which is equivalent to 26,100 m³ whilst that in DLD is 27% OOIP. This shows that more oil (i.e., an additional 5% OOIP) was cumulatively recovered in SLD compared to in DLD model. It is found that smaller reservoir volume was swept by the combustion front in DLD and thus making the heat-affected reservoir volume smaller than that in SLD model. Furthermore, in DLD, due to the nearness of the injector well to the toe of the horizontal producer (HP) well, oxygen production began much earlier, compared to in the SLD. It is also found that the temperature of the mobile oil zone is higher in the SLD model compared to that in the DLD model. This implies that higher quality oil is produced when the wells are configured in the SLD pattern. Therefore, this first-of-a-kind work has shown that SLD arrangement is far more efficient, safer, and produces higher quality oil than DLD pattern and that actual process engineering designs should use SLD wells configuration.

Keywords Toe-to-Heel Air Injection (THAI) · In situ combustion (ISC) · Enhanced oil recovery (EOR) · Bitumen/Tar sand/Heavy oils · Reservoir simulation · Horizontal well

Introduction
As governments around the world are setting targets to cut down greenhouse gas emissions through decarbonisation of their energy mix, fossil fuels have been predicted to continue to meet the major share of the increasing global energy demand to year 2040 (Amirian et al., 2018; Dejam, 2018; International Energy Agency, 2020; Saboorian-Jooybari et al., 2016, 2015). Other than for energy usage, this is also necessary since there is barely any alternative for meeting
the demands in the petrochemicals and transportation sectors. Since the conventional oil (light oil) resources are being rapidly depleted, the need to tap the vast reserves of the underutilised unconventional oil, such as heavy oil, bitumen, and tar sand which make up approximately 70% of the global oil reserves (Guo et al., 2016), has never been so important. However, heavy oil, tar sand, and bitumen are very difficult to produce as at the native reservoir conditions, their viscosities range from tens of thousands to millions of centipoise. As a result, they are virtually immobile and to produce them, their viscosity must be considerably decreased. Since the viscosity of hydrocarbon decreases exponentially with the increase in temperature, thermal upgrading technologies for heavy oil and tar sand provide preferentially the best route to upgrading and production of these untapped resources. These thermal upgrading and recovery techniques have been shown, both at laboratory, in field pilot testings, and at semi-commercial scales, to have highest recovery factors. However, some of the thermal enhanced oil recovery (EOR) processes, such as the steam-assisted gravity drainage (SAGD), the cyclic steam stimulation (CSS), and the steam flooding (SF), are not without disadvantages. Their disadvantages include: (i) suffering from considerable overburden, wellbore, and underburden heat losses, (ii) generating large amount of CO₂ during steam generation, (iii) achieving minor heavy-to-light oil upgrading, (iv) being applicable to only select few reservoirs, (v) generating large amount of wastewater, and (vi) having a low recovery factor compared to in-situ-combustion-type processes (Gates, 2010; Gates and Larter, 2014; Shi et al., 2017; Wang et al., 2019; Zhao et al., 2014, 2013). The in-situ-combustion-type processes, such as conventional in situ combustion (ISC) and toe-to-heel air injection (THAI), have been shown to have none of the disadvantages of the steam-based processes and have been shown to have so many advantages. These include: (i) achieving substantial in situ heavy-to-light oil upgrading, (ii) having energy self-sufficiency when waste heat is recovered to run utilities, (iii) providing the opportunity to incorporate catalytic add-on process in situ thereby turning the heavy oil and bitumen reservoirs into forms of catalytic reactors where further upgrading through heteroatoms removal is achieved, (iv) minimising the requirement of surface upgrading facilities, (v) not being wastewater-intensive, etc. However, the conventional ISC suffers from excessive pressure build up due to it is long distance displacement nature, gravity segregation and gas override. The toe-to-heel air injection (THAI) process has been shown, at laboratory scale, during field trails and at semi-commercial scale, to overcome all the disadvantages of the conventional ISC process (Chen et al., 2019; Greaves et al., 2008; Gutierrez et al., 2009; Liang et al., 2012; Rabiu Ado et al., 2018, 2017; Rahnema et al., 2017; Turta and Singhal, 2004; Xia et al., 2005; Zhao et al., 2019, 2018).

Toe-to-hel air injection (THAI) provides partial upgrading of heavy oil and bitumen via in situ combustion. The THAI process is a “short-distance displacement” process (Xia et al., 2005) that uses a horizontal producer (HP) well to produce mobilised partially upgraded oil to the surface. It is operation involves steam pre-heating around the inlet zone of the vertical injector (VI) so that fluid communication is established with the HP well. Immediately after the pre-ignition heating cycle (PIHC), air injection via the VI well is commenced. Then, the carbonaceous, immobile fraction of the oil around the VI well region is ignited using electrical ignitor (Ado et al., 2019; Rabiu Ado et al., 2018, 2017). Once a well-structured combustion front is established, the combustion is sustained by continuous air injection. Six different physicochemical zones are formed within the reservoir. These are: (1) combustion-swept zone; (2) combustion zone; (3) coke zone; (4) thermal cracking zone; (5) mobile oil zone (MOZ); and (6) cold oil zone (COZ). These zones partly contribute towards determination of the performance of the THAI process.

During field trials between 2006 and 2011, in the Whitesands, Conklin, in the Canadian Athabasca heavy oil and tar sand reservoirs, Petrobank Energy and Resources LTD. was able to obtain profitable oil production rates by operating the THAI process with the wells configured in a direct line drive pattern (Petrobank, 2008). This prompted them to carry out semi-commercial scale project in the Kerrobert, in the Athabasca heavy oil and tar sand reservoirs, between 2011 and 2016. Similarly, this THAI project was designed and operated with the wells arranged in a direct line drive configuration. For the most part of the Kerrobert project, profitable oil rates were obtained and high degree of upgrading was achieved. Although the oil production rates were satisfactory, optimum combustion front propagation was not achieved. At the beginning of 2016, the Kerrobert, Saskatchewan, project was terminated as a result of operating losses (Touchstone, 2016). Their inability to sustain and propagate an optimally stable combustion front resulted in a rapid decline of the oil production rates. It was suspected that air found a channel through which it bypasses the combustion front. Additionally, it was suspected that poor or inadequate PIHC could have caused the failure to establish combustion front that has no fingers (Rabiu Ado et al., 2018). Another possible explanation was that the location of the VI well in the same plane with the HP well (i.e. in a direct line drive (DLD) configuration) might have resulted in the combustion front reaching the toe of the HP well too early. Accordingly, the influence of the wells configurations (i.e. DLD versus SLD (staggered line drive)) on the performance of the THAI process is studied via reservoir numerical simulation which is the main aim of this paper.

The findings in this work have revealed that at the field scale, over the 834 days of operation, when the wells were
arranged in the SLD configuration, more oil (an additional 5% OOIP) was cumulatively recovered compared to in the DLD arrangement. It is concluded that a larger reservoir volume was swept by the combustion front in SLD compared to that in the DLD model. Unlike in the SLD model, in the DLD model, oxygen production began much earlier due to the closeness of the shoe of the VI well to the toe of the HP well. Consequently, SLD well configuration is safer and more efficient than DLD arrangement. On the overall, the predicted oxygen utilisation by the two models indicate that the combustion in the THAI process is highly stable and efficient, which are in accordance with findings reported from the Kerrobert’s semi-commercial scale THAI process project.

Methodology

The Canadian Athabasca bitumen/tar sand reservoir is studied in this work using a previously developed and experimentally validated numerical model (Rabiu Ado, 2017; Rabiu Ado et al., 2017). The experimentally validated numerical model, which is shown to be capable of predicting both steady state and dynamic processes controlling the stable and safe operation of the THAI process, was then systematically upscaled before being used to, respectively, investigate the effect of a gas cap on the safety of the THAI process (Ado et al., 2019) and effect of a reservoir bottom water on the performance of the THAI process (M.R. Ado, 2020a). The same well-tested field scale numerical model is used to carry out the studies reported in this paper. The description of the reservoir dimensions in each study is detailed below. However, it should be noted that in all the studies, the reservoir was discretised into 90 mesh points in the i-direction by 57 mesh points in the j-direction by 7 mesh points in the k-direction thereby resulting in a total number of grid-blocks plus the grid-blocks of the discretised wellbore becoming 38,500. Also, these have shown that each grid-block has dimensions of 1.667 m × 1.754 m × 3.429 m. A discretised wellbore model option in the CMG STARS allows the momentum-, mass-, and heat-transfer in the horizontal producer well to be fully accounted for by using a set of discretised equations which are then coupled to the reservoir discretised equations. The overall discretised equations are then solved simultaneously in the STARS which uses fully implicit finite difference method. The server used has 8-core parallel processors with 32 threads. However, only 8 threads are used since the STARS’s parallel processing solver, the PARASOL, allows for only 8 threads to be specified and thus used. The STARS DYNAGRID option, whose function is to dynamically change grid-blocks size from child to parent grid-blocks and vice versa when given conditions are satisfied, was implemented so that the simulation time is optimised between results accuracy and computational time. The set of criteria assigned for the grid-blocks de-refining are that global mole fraction of any component is at most 0.03, oil mole fraction is at most 0.02, pressure and temperature differences between grids are within 20 kPa and 30 °C respectively. Otherwise, grid-blocks refining should be maintained. Since numerically simulating heavy oil and bitumen reservoirs when the THAI process is applied involves handling a multiphase, multicomponent reactive transport system through a porous medium, so many input parameters, such as the reservoir initial and boundary conditions, reaction kinetics, pressure, volume, and temperature (PVT) properties are required.

Reservoir initial condition and it is petrophysical properties

The typical Athabasca bitumen reservoir is characterised of having initial oil saturation of 80%, water saturation of 20%, and no gas. The reservoir initial pressure is 2800 kPa and temperature is 20 °C as reported elsewhere (Petrobank, 2008). Furthermore, Petrobank reported that the bitumen deposit has a porosity of 34% and horizontal and vertical absolute permeabilities of 6400 mD and 3450 mD, respectively. All these same parameters are used in all the studies reported in this paper. The relative permeability curves, which are not reproduce here, are the same as those used and detailed in previous studies (Rabiu Ado et al., 2018, 2017).

Pictorial comparison of the DLD and SLD configurations

A comparative study of THAI process arranged in both the direct line drive (DLD) and the staggered line drive (SLD) configurations is presented in this paper. The spatial arrangements of the wells in both configurations and the reservoir dimensions are shown schematically in Fig. 1. The reservoir domains in the two models have the same respective dimensions. Furthermore, the location of the horizontal producer (HP) well in the two models is the same. The internal diameter of each well in all the two models is 178 mm, which is of the same size as that used by Petrobank during their Whitesands’ field trials (Petrobank, 2008). In accordance with field practice during the Petrobank’s Whitesands project (Petrobank, 2008), both models were steam pre-heated at the rate of 495 bbl day⁻¹ cold water equivalent (CWE) for a period of 104 days before commencement of air injection. The steam injection pressure was 5500 kPa with a quality of 0.8, and the horizontal producer back pressure was 2800 kPa. At the end of the PIHC (pre-ignition heating cycle), in DLD model, 20,000 Sm³ day⁻¹ of air was injected.
via the single vertical injector well. Similarly, in SLD model, a total of 20,000 Sm$^3$ day$^{-1}$ of air flow rate was injected but at a rate of 10,000 Sm$^3$ day$^{-1}$ through each of the two vertical injector wells. Each model was run for a combustion period of two years.

**PVT properties of Athabasca bitumen**

The pressure, volume, and temperature properties of the Athabasca bitumen based on three oil pseudo-components and which are the same as those used and detailed in previous studies (M.R. Ado, 2020a, 2020b, 2020c, 2020d; Rabiu

![Fig. 1 Reservoirs dimensions and the schematic diagrams showing arrangements of wells in a DLD configuration (top) and b SLD configuration (bottom)](image-url)
Ado, 2017) are shown in Table 1. The three oil pseudo-components are represented by (i) LC = Light pseudo-component, (ii) MC = Mobile pseudo-component, and (iii) IC = Immobile pseudo-component. The viscosity of each pseudo-component as function of temperature and the respective K-values of each pseudo-component as function of both temperature and pressure are the same as those used in the previous studies (M.R. Ado, 2020a, 2020b, 2020c, 2020d; Rabiu Ado, 2017), and consequently, are not reproduced here. However, the viscosity as function of temperature for the Athabasca bitumen as a whole is shown in Fig. 2.

### Table 1 Pressure, volume, and temperature properties of the Athabasca bitumen pseudo-components

| Athabasca bitumen pseudo-components | LC   | MC   | IC   |
|-------------------------------------|------|------|------|
| Composition (mol%)                  | 42.50| 23.91| 33.59|
| Molar mass (kg kmol⁻¹)              | 210.8| 496.81| 1017.01|
| Critical pressure P_c (kPa)         | 1682.88| 1038.46| 729.22|
| Critical temperature T_c (°C)       | 464.68| 698.53| 940.36|
| Density ρ (kg/m³)                   | 828.24| 961.66| 1088.04|
| Acentric factor ω                   | 0.62 | 1.18 | 1.44 |
| Normal boiling temperature T_B (°C) | 281.47| 549.67| 785.78|

### Athabasca bitumen kinetics scheme and its parameters

One of the major challenges encountered when numerically simulating in-situ-combustion-type processes for heavy oil and bitumen upgrading and recovery at field scale is how to incorporate kinetics parameters derived from validating laboratory scale numerical model against a combustion tube experiment or a 3D combustion cell experiment. The major differences are that at laboratory scale, the grid-block sizes are in centimetres, sometimes even less than 1 cm, which are capable of accurately predicting the full physicochemical processes of the combustion front, whilst at field scale, the grid-block sizes are in metres thereby making it impossible to accurately capture the full dynamics of the combustion front. Moreover, the process time at laboratory scale is few hours whilst it takes years in the case of field scale. These mean laboratory scale kinetics parameters cannot be used to model field scale reservoir as are shown by many authors (Coats, 1983; Hwang et al., 1982; Ito and Chow, 1988; Kovscek et al., 2013; Marjerrison and Fassihi, 1992; Nissen et al., 2015; Rabiu Ado, 2017), because the time length scale is so high that conduction of heat downstream of the combustion front resulted in formation of very high, unphysical amount of coke. As a result, field scale kinetics parameters, which are derived systematically with very sound theoretical basis and tested in various studies (M.R. Ado, 2020a, 2020b, 2020c; Rabiu Ado, 2017), are used in this work as can be seen in Table 2 and Table 3.

### Table 2 Athabasca bitumen pseudo-components thermal cracking reactions schemes and their respective Arrhenius kinetics parameters

| Athabasca bitumen thermal cracking reactions | Reaction frequency factor (min⁻¹) | Reaction activation energy (kJ/mol) |
|---------------------------------------------|----------------------------------|-------------------------------------|
| IC→ 2.0471 MC                               | 8.186 × 10¹⁶                   | 239.01                              |
| MC→ 0.4885 IC                               | 7.209 × 10¹⁴                   | 215.82                              |
| MC→ 2.3567 LC                               | 2.425 × 10¹¹                   | 184.88                              |
| LC→ 0.4243 MC                               | 3.264 × 10¹¹                   | 180.45                              |
| IC→ 77.4563 COKE                            | 4.969 × 10¹¹                   | 180.88                              |

Fig. 2 Athabasca bitumen viscosity as function of temperature as used in each of the two models.
Both the thermal cracking and the combustion reactions follow Arrhenius relationship which is in accordance with previous studies (Abu et al., 2015; M.R. Ado, 2020a, 2020b, 2020c, 2020d; Cavallaro et al., 2008; Rabiu Ado, 2017; Shah et al., 2011; Weissman et al., 1996; Weissman, 1997; Xia and Greaves, 2001; Xia et al., 2002). The rate law for the thermal cracking reaction is first order with respect to each reactant and first order overall. For the combustion reactions on the other hand, the rate is first order with respect to each hydrocarbon and first order with respect to oxygen partial pressure thereby making it second order overall for each reaction.

It should be noted that although the individual oil pseudo-component combustion reactions are included, their effect was found to be negligible because there is no oil left immediately ahead of the combustion front. Additionally, even when there was little amount of oxygen bypassing the combustion front, the temperature in the cold oil zone is so low that no appreciable oil pseudo-component combustion takes place. Therefore, it is concluded that the THAI process, as were found in laboratory (Xia et al., 2005; Zhao et al., 2018) and recently from the field scale operation of Kerrobert’s commercial scale THAI process project (Turta et al., 2020), operates in high temperature oxidation mode.

### Results and discussion

To make the comparison between the two configurations, the key important parameters that are used to judge the performance and success of any heavy oil and bitumen upgrdading and recovery process are considered. These are: (i) oil production rate (ii) cumulative oil recovery as percentage of oil originally in place (％OOIP) and (iii) oxygen production (or breakthrough) and utilisation. Also considered are the two- and three-dimensional profiles of oil saturation and oxygen distributions respectively. Furthermore, to have a sense of the measure of the vigorousness of the combustion, the two-dimensional profiles of temperature distribution are discussed.

**Table 3** Athabasca bitumen pseudo-components combustion reactions schemes and their respective Arrhenius kinetics parameters

| Athabasca bitumen combustion reactions | Frequency factor (kPa min$^{-1}$) | Activation energy (kJ/mol) | Heat of reaction (kJ/mol) |
|----------------------------------------|----------------------------------|-----------------------------|--------------------------|
| IC + 98.869 O$_2$ → 77.456 CO$_{1.947}$ + 46.904 H$_2$O | 2.772 × 10$^3$ | 138.00 | 4.00 × 10$^4$ |
| MC + 49.069 O$_2$ → 37.075 CO$_{1.947}$ + 25.953 H$_2$O | 2.772 × 10$^4$ | 138.00 | 1.60 × 10$^4$ |
| LC + 32.025 O$_2$ → 14.600 CO$_{1.947}$ + 35.623 H$_2$O | 2.772 × 10$^5$ | 138.00 | 4.91 × 10$^2$ |
| COKE + 1.22 O$_2$ → CO$_{1.875}$ + 0.565 H$_2$O | 1.530 × 10$^5$ | 123.00 | 3.90 × 10$^2$ |

**Oil production rate**

Pre-ignition heating cycle (PIHC) was assumed to be ideal in both cases, ensuring a perfect hot connection between vertical injector(s) and horizontal producer wells. However, despite that, there are differences on the time when fluid communication is established in the two models. On termination of steam injection, the oil production rates in both models dropped rapidly and instantaneously which is attributable to the fact that energy in form of heat and pressure was stopped being supplied to both the already mobilised and the immobilised oil. Immediately on initiations of air injection and combustion, the oil production rates in both DLD and SLD models shoot up suddenly with the same trends before dropping quite rapidly (Fig. 3). These rapid oscillations occurred within a space of seven to ten days. The first sharp increase was as a result of air pushing (i.e. air exerting pressure on) the already steam-mobilised oil, forcing it into the exposed section (i.e. around the toe) of the horizontal producer (HP) well (Fig. 3). The drop that followed, which is initially rapid before then becoming slow, is caused by the cold air absorbing the heat in the already steam-heated area as the combustion was just starting, and therefore the heat of combustion was not high enough within that very small time period to balance the heat consumed by the cold air and allow the oil rates to be steady. This is the same phenomenon that was observed in Petrobank’s Kerrobert semi-commercial THAI process project (Wei et al., 2020).

From around 10 days after the initiation of the combustion to 24 days, the oil rates in both models overlap each other implying that similar mechanism of energy- and momentum- transfers take place. The oil production rates in both models continue to decline with the same trends until they reach minimum oil rates of 10 m$^3$ day$^{-1}$ in DLD and 17 m$^3$ day$^{-1}$ in SLD at around 184 days after the start-up of the whole process (Fig. 3). The continual declining of oil production rates over the first 80 days of the combustion is found, in both models, to be as a result...
of insufficiency of the generated heat of combustion to balance the heat being absorbed by the cold injected air. Thereafter, there was a pseudo-steady increase in oil production rates in each model, with DLD model steadying out at around 30 m$^3$ day$^{-1}$ up to the end of the 2 years combustion period. The oil production rate in model SLD which lies above that of model DLD for nearly 97% of the 2 years combustion time increased, reaching a maximum of 40 m$^3$ day$^{-1}$ at 417 days before steadily decreasing and steadying out at around an average of 35 m$^3$ day$^{-1}$ up to the end of the 2 years of combustion. The increasing trends of the oil rates prior to steadying out indicate that the combustion heat had already heated the reservoir rock near the inlet zone of the vertical injectors to so high a temperature that the incoming cold air is heated enough behind the high temperature combustion front. As a result, the subsequent heat generation in the combustion zone is used to heat up, mobilise and upgrade the oil downstream. Steady state was reached in each model once there was constant heat absorption by the reservoir rock and the incoming air. However, as noted earlier with regard to SLD, the slight decline prior to steadying out at constant rate can be described by the fact that larger reservoir volume is heat-affected (see Fig. 7), hence it is higher oil production rate. In an attempt to minimise heat loss to the flue gases, it has been found and reported in a newly published study (Ado, 2021) that oil production rates can substantially be improved by injecting pure oxygen instead of air. In fact, an increase of 3.85% OOIP (percentage of oil originally in place) in the oil recovery was achieved over a production period of 833 days when the same quantity of pure oxygen was injected as the oxidant in place of air containing the same amount of oxygen. Also, the study has shown that large flue gas flow rate is partly impeding the oil production rate. These mean that the presence of nitrogen results in not only loss of otherwise useful heat but also limiting the quantity of oil that can get into the HP well at any time. These findings will be factored in in designing future THAI or THAI-CAPRI process projects.

**Cumulative oil recovery**

Since there is a time lag at which oil production began as it started earlier in DLD, and the oil production rate is mostly slightly high in DLD (see Fig. 3 above), it is expected that more oil should be recovered in DLD during the PIHC. Consequently, Fig. 4, which shows the percentage cumulative oil recovery in terms of percentage of oil originally in place (%OOIP) as function of cumulative injected air, shows that prior to the start of air injection (i.e. at cumulative injected air of 0 m$^3$), 6.5%OOIP was recovered in the DLD model, which is higher than that in the SLD model by 1.4%OOIP (Fig. 4). This difference is not only due to the delay in the oil production in SLD but it is also because the vertical injector (VI) and the horizontal producer (HP) well in the DLD are both on the same plane (i.e. on the same vertical mid-plane as can be seen in Fig. 6a) and they are separated by a shorter vertical perpendicular distance compared with in SLD. Furthermore, the depth penetrated by (or the length of) the VI well in DLD is far longer (8.91 m) compared to (1.8 m) in SLD (Fig. 1). Since the oil production rate is higher in SLD since after around 24 days from the commencement of air injection and ignition, it makes logical sense that more oil should be cumulatively recovered in SLD compared to in DLD. This can be seen in Fig. 4 in which SLD model overtook DLD model at around 338 days from the start of the process (i.e. after approximately 4.7 million Sm$^3$ of air was
injected). The fact that the two vertical injectors in SLD are located at a distance of 28 m offset from vertical mid-plane implies that larger fraction of the reservoir is affected by the heat from the combustion (Figs. 8 and 9) and that from the combustion gases. As a result, from 338 days onward, higher cumulative oil recovery is achieved in SLD compared to in DLD.

**Oxygen production and utilisation**

Monitoring the composition of the gases being produced in the HP well is essential not only with aim of determining valuable components, such as hydrogen as was shown to be produced in the Kerrobert’s semi-commercial THAI process project (Turta et al., 2020; Wei et al., 2020), and to ensure emissions regulations are met such as in terms of $\text{H}_2\text{S}$, $\text{CO}_2$, and $\text{CO}$, but also to monitor the efficiency and burning characteristics and stability of the combustion (Sharma et al., 2021; Zhao et al., 2021). Furthermore, it permits decision about when to choke or shut in the HP well before the oxygen concentration reaches an unsafe level to permanently damage the well or cause safety problems. As can be seen from Fig. 5, oxygen production began much earlier (i.e. around 30 days after the start of air injection) in DLD compared to in SLD in which it began 104 days after the start of air injection. The earlier production of oxygen in DLD is attributed to the fact that the VI is on the same vertical mid-plane as the HP well and also due to the close proximity of the shoe of the VI well relative to the toe of the HP well. The trends predicted by the two models are completely
different because in DLD, there are intermittent oxygen productions, e.g. from \( \approx 134 \) to \( \approx 280 \) days the production is continuous but afterwards, the amount of oxygen produced is so low that there is barely any increase in the cumulative volume, staying at roughly \( 5600 \) m\(^3\) up to \( \approx 480 \) days. Thereafter, there is a slight oxygen production for a period of 24 days (i.e. up to 505 days). This is then followed by a period of very low oxygen production causing the value of the cumulative oxygen produced to remain at around \( 6720 \) m\(^3\) up to approximately 782 days. Thereon, there is a sharp rise in the amount of oxygen produced, reaching an estimated value of \( 11,600 \) m\(^3\) by the end of the two years of combustion. These alternations or fluctuations are also observed in previous laboratory experiments and validated numerical simulations studies (Rabiu Ado et al., 2017). They are caused by alternating high and low coke concentrations along the coked zone of the exposed section of the HP well. When the combustion zone reaches high coke concentration region, nearly all the oxygen reaching there is used up. However, when the combustion front reaches the low coke concentration zone, only partial amount of oxygen reaching there is consumed and hence part of it slips through and is produced with flue gases. In SLD, the oxygen production is continuous albeit with increases and decreases in the concentrations at different times which cause the slopes of the cumulative oxygen production curve to change from time to time. Unlike in the case of DLD, the oxygen production in SLD is caused by a slight controlled gravity override due to the shoes of the VI wells being located at the top of the reservoir, penetrating to only 1.8 m into the oil layer. It should be pointed out that from around 650 days to the end of the two years of combustion, the concentration of the produced oxygen decreases as implied by the decrease in the slope of the SLD curve (Fig. 5). This decreasing trend is anticipated to continue whilst the fully developed combustion front continue to expand and advance until it reaches and starts to propagate along the HP well at which point breakthrough will occur (as will be seen in Fig. 11b). In the case of DLD in which the VI well is close to the HP well, the concentration of the produced oxygen is expected to continue to increase albeit slowly until breakthrough occurs (as will be seen in Fig. 11a). However, future full field-scale studies are needed to ascertain that. Over the two years of combustion, the percentage of oxygen produced was 0.38% for DLD model and 0.43% for SLD model, thereby indicating oxygen utilisation of 99.62% and 99.57% respectively. On the overall, the predicted oxygen utilisation by the two models indicate that the combustion in the THAI process is highly stable and efficient, which are in accordance with findings reported from the Kerrobert’s semi-commercial scale THAI process project where oxygen utilisation lies between 93 and 100% (Wei et al., 2020).

**Oil saturation distribution profiles**

The oil saturation profiles give the measure of oil distribution inside the reservoir. In both the two models, the oil saturation distributions along the vertical mid-plane are both qualitatively and quantitatively different from each other. Starting from the toe of the horizontal producer (HP) well, it can be seen that in DLD model (Fig. 6a), the mobile oil zone (MOZ), which is characterised by the presence of large concentrations of oil flux vectors that are superimposed on the two-dimensional plots, at the bottom is located at a distance of 48.15 m from the toe of the HP well and at the top, it is located at a distance of 96.30 m. However, in the SLD model (Fig. 6b), the MOZ at the bottom is located at a distance of 43.33 m and at the top, it is located at a distance of 86.67 m. These show that the MOZ in either model is forward-leaning although that in DLD model is at an angle of 26.5° relative to the axial line along the HP well and that in SLD model is at an angle of 29° relative to the axial line along the HP well. Therefore, it follows that the MOZ in DLD model is leaning forward more than in SLD. In other words, the heat-affected zone in DLD is nearer to the heel both at the top and at the bottom of the reservoir and at the same time, it is more tilted forward towards the heel than in SLD. Furthermore, the surface area along the vertical mid-plane where the oil saturation is zero is larger in
DLD than in SLD. This implies that the MOZ in the former moves at faster rate along the vertical mid-plane compared to in the latter. Additionally, the largest oil flux vector in the MOZ that is located downstream of the combustion front is smaller in DLD when compared to that in SLD. This further shows that more oil is draining into the HP well in the SLD than in DLD, which is consistent with the oil production rates (Fig. 3) and the cumulative oil recoveries (Fig. 4).

Figure 7 shows the three-dimensional oil saturation distributions in both models. Again, the qualitative and quantitative natures of the oil distribution in the reservoirs are well-configuration dependent. In DLD (Fig. 7a), most of the oil is preferentially produced from the top horizontal layers and the mid-vertical plane which is axially (i.e. in i-th direction) along the HP well and its immediate adjacent planes on either side. Most of the oil at the axially vertical planes at the edges of the reservoir and their vicinities are not displaced despite the fact that the oil saturations there are at least 88% (Fig. 7a). These are caused by the preferential advance of combustion front in the top of the reservoir leading that at the bottom (i.e. gravity override). Thus, larger volume at the top and around the mid-axis of the reservoir is affected by the heat of combustion compared to around the base of the reservoir (Figs. 8 and 9). In the case of SLD however, Fig. 7b shows that oil is displaced not only from the top horizontal layers and from around the vertical mid-plane but also from the j-th vertical planes at the edges of the reservoir. These have shown that larger volume of the reservoir is swept when wells are arranged in an SLD compared to in a DLD pattern, which is consistent with the previous findings from the one-dimensional plots. Another factor that results in more efficient oil displacement and production in SLD model is the fact that heat loss is considered to take place from the overburden and underburden only. That means, heat loss in the DLD model is larger than that in SLD because of the pronounced gravity override of the combustion front as will be seen in Fig. 8. This is despite the fact that the shoe of the vertical injector (VI) in the DLD model is located at a deeper depth than those of the SLD model.
Temperature distribution profiles

The temperature distribution profiles give the measure of the extent of the combustion zone mode (i.e. either it is operating in the high temperature oxidation (HTO) or the low temperature oxidation (LTO) mode). Figure 8 shows the two-dimensional profiles of the temperature distribution. Two major findings can be seen by comparing the two models. First, the highest temperature in the combustion front or zone is seen in SLD compared to in DLD model, i.e. 550 °C in the latter (Fig. 8a) compared to 690 °C in the former (Fig. 8b). This supports the earlier findings from sub-section 3.4 that heat loss is higher in DLD than in SLD model. Secondly, the heat-affected area in DLD and the geometry of the combustion front are parabolic in shape which is unlike in SLD where it is more like an arc. In the latter, the heat has distributed up to the j-th vertical planes located at the either lateral edge of the reservoir whilst in the former, the j-th vertical planes are not affected as enough heat did not reach there. The fact that the two VI wells in the SLD models are located near the edges of the reservoir means that heat can easily reach the edges, thereby making the process more efficient.

Oxygen distribution profiles

The oxygen distribution profiles give the measure of the shape and stability of the combustion front. Figure 10 shows the oxygen distribution and thus the combustion-swept zone along the vertical mid-plane after one year of combustion. In DLD, due to the fact that the VI well is located on the same plane as the HP well, it can be seen that the combustion has a larger areal sweep (Fig. 10a) compared to in the SLD model (Fig. 10b). In fact, the concentration of the oxygen in the DLD model is higher than that in the SLD model.
Furthermore, in the DLD model, within one year of combustion, the combustion front has already reached the toe of, and is being propagated along, the HP well (Fig. 10a). Unless there is fluid or coke providing a total sealing ahead of the combustion front that is being propagated along the HP well, the injected air will have a pathway via which it will be channelling and be bypassing the combustion front. Whilst in the SLD, the combustion front is yet to reach the HP well (Fig. 10b) despite the fact that the combustion is run for one year. These indicate that operating the THAI process in the SLD pattern results in more stable and safer combustion front propagation. Additionally, in the DLD model, at the top of the reservoir and along the vertical mid-plane, the combustion front has already swept around 60% of the axial (i.e. in $i$-th direction) length of the reservoir (Fig. 10a). In SLD, at the top of the reservoir and along the vertical mid-plane, only around 45% of the axial length of the reservoir is swept by the combustion. These show that the gravity override is much more pronounced in the DLD model thereby implying that air channelling via the heel of the HP well will start much earlier in the DLD model.

From the three-dimensional shape of the combustion front, it can be seen that in either of the two models, non-relatively speaking, the combustion front is stable (Fig. 11). However, that in the DLD model is already propagating along the HP well which is unlike in SLD in which it just started to reach the toe of the HP well. Considering the $j$-th direction, the combustion front of the DLD model is yet to touch the vertical planes on either lateral edge of the reservoir (Fig. 11a). Rather, it preferentially swept most of the top horizontal plane and the adjacent vertical planes of the vicinity of the vertical mid-plane of the $j$-th direction. These have made the combustion front of the DLD model to be excessively leading at the top of the reservoir. In the case of the SLD model, the combustion front has touched and swept the vertical planes on the lateral edges of the reservoir (Fig. 11b). In other words, the zone around the vertical injectors in the SLD model is uniformly swept by the combustion front. These mean that larger volume of the reservoir is swept by, and thus affect by the heat of, the combustion front. Furthermore, they imply that the combustion front in the SLD model is more stable as it is much more well distributed and structured. Similarly, in terms of the long-term stability, the SLD well configuration will be much more stable and efficient as it has highly controlled gravity override which is unlike when the wells are in DLD configuration.

**Conclusions**

Using validated numerical models, field scale reservoir simulations studies of the THAI process are carried out. At the field scale, over the 834 days of operating period, when the wells were arranged in the SLD configuration, more oil (an additional 5%OOIP) was cumulatively recovered compared to in the DLD arrangement. It is concluded that a larger reservoir volume was swept by the combustion front in SLD when compared with that in the DLD pattern. In the DLD model, oxygen production began much earlier, compared to in the SLD model, which is partly caused due to the closeness of the shoe of the VI well to the toe of the HP well. It is also found that the temperature of the mobile oil zone is higher in the SLD model compared to that in the DLD model thereby implying that higher quality oil is produced when the wells are configured in the SLD pattern. Consequently, SLD well configuration is safer, more efficient, and produces higher quality oil than DLD arrangement. Therefore, this first-of-a-kind work has shown that during actual process engineering designs, the SLD wells configuration should be used.

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Declarations

Conflict of interest The author declares that there is no conflict of interest.

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