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A Canadian Perspective on In Situ Combustion

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Abstract

Field in situ combustion projects are traditionally designed using air and fuel requirements as determined from a laboratory combustion tube test. While these parameters are important, of greater significance in predicting field performance is the observed stability of the combustion process in laboratory tests which are conducted at the operating pressures of the field project. This paper provides a review of the laboratory combustion performance of different reservoirs as a background for interpreting the field performance of some of the approximately 30 in situ combustion projects which had been or were still in operation in Canada as of 1993. Canadian field tests have been performed in reservoirs having oil gravities varying between 8 and 28˚ API; five of these projects involved the injection of pure oxygen.

Although some of the information contained in this paper as of the current publication is now out of date, due to companies changing hands and projects closing, the paper still provides a valuable review of the history of combustion in Canada up to and including the year 1993.

Introduction

Many of the operating problems which have contributed to the lack of success of in situ combustion as an enhanced recovery technique in Canadian field projects can be attributed to a poor understanding of the kinetics of the process. Laboratory combustion tube tests, which have been used for many years as a means for evaluating the air and fuel requirement parameters necessary for the design of field projects, tend to operate in the high temperature combustion mode. This has led to the classical definition of combustion, that being "the propagation of a high temperature front for which the fuel is a coke-like substance laid down by thermal cracking reactions."

Although the high temperature combustion mode represents the desired state for dry or normal-wet combustion, it may be very difficult to achieve this condition under the air fluxes and operating pressures of many field projects. On this basis, deviations between field and laboratory measured combustion parameters such as the air/fuel ratio or the fraction of oxygen converted to carbon oxides (which are dependent on the carbon oxides content of the produced gas) should not be assumed to indicate that the combustion tube test is faulty. Rather, the differences should be interpreted as indicating that the field project is not operating in the same combustion mode as the laboratory test. Once this is understood, it is possible to make educated guesses as to the actual state of the oxidation reactions as they are operating in a field project.

This paper will describe some of the abnormal, in the sense that it deviates from classical concepts of combustion, behaviour observed during the 20 years of laboratory experiments carried out by the In Situ Combustion Research Group at the University of Calgary. The group has performed 267 combustion tube tests on over 30 different reservoirs worldwide as of 1993; these tests have involved oils having gravities between 6° and 40˚ API at pressures up to 20 MPa. Approximately 65 of these tests have involved 95% oxygen enriched air. The combustion tube tests, as well as extensive research in other areas, have led to the formulation of a set of combustion kinetics which may be used to explain abnormal burning behaviour in both the laboratory and the field.

An understanding of the conditions which cause poor burning performance (high air or oxygen and fuel requirements, low oil production) or burn instabilities (non-uniform advancement of oxidation or combustion fronts) is required so that field data can be properly interpreted and operating strategies can be designed which enhance the probability of success of the field projects. This paper will provide a brief history of Canadian field projects, and discuss some of the abnormal behaviours which have been encountered in the field and the laboratory. Both sets of problems will be interpreted in light of these combustion kinetics, and the results will be used as the basis for considerations for the successful design of a field project.

In Situ Combustion Projects in Canada

The first in situ combustion project in Canada described in the open literature occurred in 1920, when combustion was attempted in the Athabasca reservoir near Fort McMurray[1]. This was followed in 1958 by Amoco's fireflood at their Gregoire Lake site in the Athabasca deposit[2], and approximately 30 combustion projects have been conducted in Canada since that time. Figure 1 shows the location of the major heavy oil and bitumen deposits in Canada, all of which are found in Alberta and Saskatchewan.

Based on longevity and the number of wells involved, the Battrum project in southwestern Saskatchewan, which is operated by Mobil Oil Canada Limited, must be considered the most successful combustion project in Canada. Pebdani and Best[3] provide some information on the Battrum fireflood, and there are a number of articles which describe its early history[4-7]. Another success is the Countess "B" combustion project operated by PanCanadian Petroleum Limited, which was initiated as dry combustion in 1982, although it has recently been switched to the wet mode. The Battrum and Countess "B" firefloods, as well as the Fosterton Northwest pilot, which was operated by Mobil from 1970 until 1989[8,9] involved the highest gravity oils in which combustion has been successful in Canada.

A large number of Canadian combustion projects have been

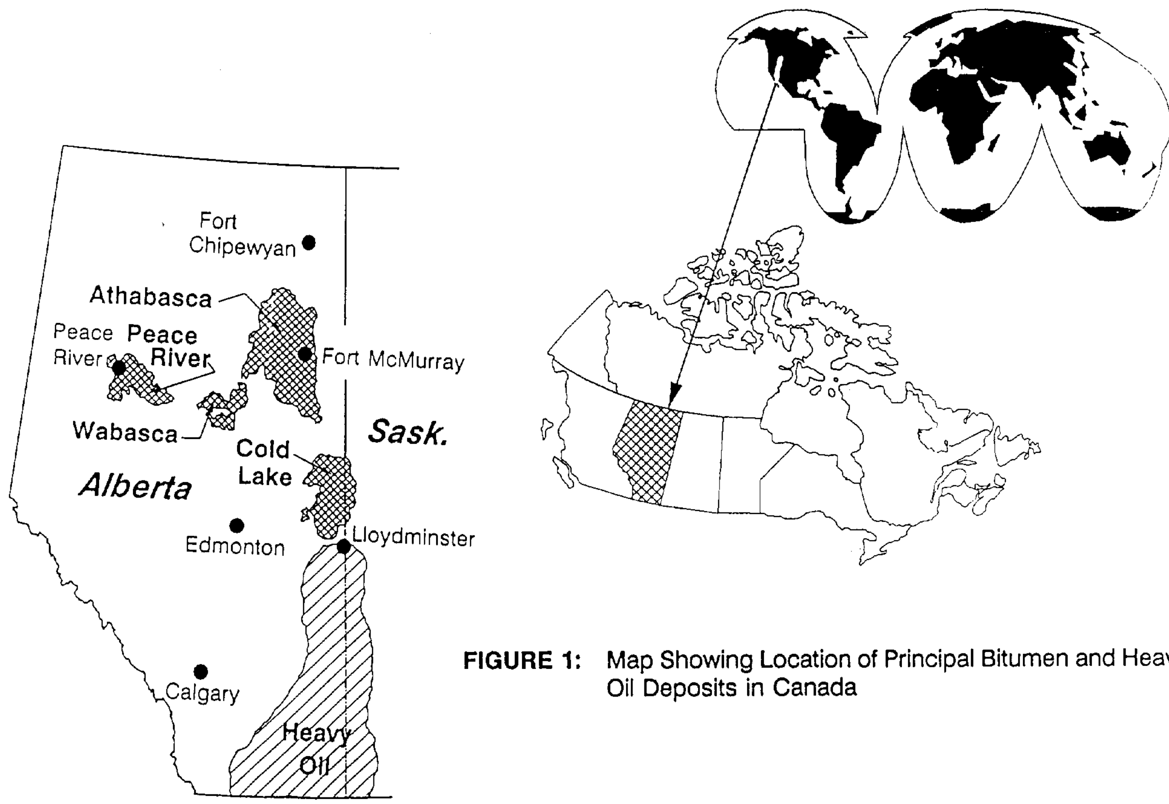

FIGURE 1: Map showing location of principal bitumen and heavy oil deposits in Canada[37].

operated in what are loosely classified as Lloydminster-type sands. Husky has been the most active company, and an excellent review of their five combustion projects is provided by Miller[10]. Additional details on the Husky Golden Lake fireflood is provided by Miller et al.[11] and on the Husky Tangleflags project by Tsang[12]. One of the characteristics of the Husky firefloods was the observation of an apparent upper limit for the air injection rate. As is described by Hallam[13], air injection rates were maintained such that the ratio of the air injection rate per pay zone thickness per distance between the injector and the producers was maintained in the range of 3 to 6 m^3(ST)/d/m^2. The actual air rates which would correspond to this ratio are very low when it is considered that the Tangleflags project was operated on an inverted seven spot pattern having an enclosed area of 12.0 ha. Elevation of the air injection rates above the upper limit was found to cause the combustion gases to channel to the producers (Tangleflags) or to push the oil production to the out-of-pattern wells (Golden Lake Sparky and Aberfeldy).

Norcen operated a successful fireflood pilot at Bodo[14], but attempts to operate the process on an expanded basis were generally ineffective. Part of the reservoir under the expanded pilot was underlain by water, which may have promoted the difficulties with the Bodo expansion. Problems due to bottom water were also experienced at the Murphy Eyehill[15] and the Alberta Energy Suffield[16] projects.

The Petro-Canada project in the Viking Kinsella Wainwright "B" pool operated in two phases: the first involved air injection, while oxygen was injected during the second phase. As is described by Dugdale et al.[17] and Byl et al.[18], the first phase was successful during the period that the air injection rate was increased to 17,000 m^3(ST)/d. The combustion zone kinetics then appeared to switch from the high to the low temperature mode when the air rate was decreased in preparation for oxygen injection. The switch to pure oxygen injection at rates up to 4,000 m^3(ST)/d was not successful at reversing the kinetics, and the oxygen phase was terminated due to excessive oxygen concentrations in the production wells. It is of interest to note that the high oxygen concentrations in the producers did not result from high oxygen volumetric flowrates. Because carbon dioxide was not produced in significant volumes due to operation in the low temperature mode, the volume of non-reactive gas (CO_2, N_2) entering the production wells was insufficient to dilute the unreacted oxygen.

Only one fireflood project continues to operate in the Lloydminster area. This project is the Morgan pilot operated by Amoco Canada, but there is no information available as to its performance.

BP Resources Canada operated a successful in situ combustion project at Marguerite Lake in the Cold Lake deposit[19]. The reservoir was first preheated using steam so as to link the injectors and producers by heated paths. Both air and oxygen injection were evaluated. BP did not utilize continuous air/oxygen injection; instead, they developed a cyclic method which is known as the "Pressure Up Blow Down" (PUBD) process. BP felt the process was sufficiently promising so as to advance to a semi-commercial stage, but this stage was terminated due to problems not directly related to the combustion project.

While BP was the first, and certainly the most successful, operator to test oxygen injection in a Canadian reservoir, oxygen pilots were also conducted by Dome Canada at Lindbergh[20], by Husky at Golden Lake Waseca[10], by Gulf Canada Resources at Pelican Lake in the Wabasca Oil Sands, and by Petro-Canada at the previously mentioned Kinsella "B" pilot. In general, none of these pilots could be considered technical successes, although each proved that it is possible to safely inject oxygen in an oilfield environment. Oxygen breakthrough to the production wells was a major problem for all of these projects.

As was mentioned previously, the Athabasca deposit was the first site selected for the application of fireflooding technology. This is not surprising, given the immensity of the resource (151×10^9 m^3 bitumen in place) and the belief that in situ combustion was an effective method for injecting energy into a reservoir. In their review of 20 years of Amoco's involvement with the Gregoire Lake project, Jenkins and Kirkpatrick[2] state that Amoco tested pattern sizes ranging from 0.2 ha inverted five spots to 4.0 ha inverted nine spot patterns. Operation on the larger pattern size was not successful, and the multi-well pilot which was initiated in 1976 with the support of AOSTRA was based on nine inverted five spot patterns having enclosed areas of 1.0 ha. The Amoco/AOSTRA Gregoire Lake Block 1 pilot operated from fall, 1977 to mid-1981. The project was plagued by casing failures and by low gas recoveries, and it was never operated in the "Combination of Forward Combustion and Waterflood" (COFCAW) mode as per the original concept[21].

Observations from Combustion Tube Tests on Canadian Reservoirs

The air and fuel requirement parameters needed for the design of field projects are generally evaluated by means of laboratory combustion tube tests. The literature shows that these tests are often performed under high injection air fluxes (air injection rate divided by the cross-sectional area of flow) and with the outlet end of the core open to the atmosphere. Under these favourable conditions, combustion tube tests tend to operate in the classical high temperature combustion mode. It has been the experience of the University of Calgary In Situ Combustion Research Group that, when field conditions (in terms of operating pressures and air fluxes) are duplicated in the laboratory, abnormal burning behaviour often results. For the purposes of this paper, abnormal behaviour will be defined as poor burning performance as evidenced by high air or oxygen and fuel requirements and low oil production, or by burn instabilities such the non-uniform advancement of oxidation or combustion fronts.

The following sections describe some of the most common problems that have been observed in the laboratory for Canadian heavy oils and bitumens. Details of the combustion tube apparatus and the specific tests on which many of the comments provided in this paper are based may be found in Moore et al.[22], Tzanco et al.[23], Gomez[24], and Ursenbach[25].

Oil Mobility

For Canadian heavy oils and bitumens, the most common cause of problems with the conduction of in situ combustion tube tests is a lack of oil mobility in the region downstream of the elevated-temperature zone. Athabasca bitumen, which has a gravity of about 8˚ API and a viscosity of approximately 1×10^6 mPa•s at the nominal reservoir temperature of 13˚ C, exhibits very stable burning characteristics when a test is conducted at pressures of less than 6.0 MPa and the core is preheated to a temperature of approximately 90˚ C. Under these conditions, the air and fuel requirements for dry or normal wet operation using air are approximately 240 m^3(ST)/m^3 and 22 kg/m^3, respectively. These values are generally lower than those for much lighter oils, but they can only be achieved if the mobilized oil can be effectively displaced ahead of the combustion front.

For Athabasca bitumen tests conducted at temperatures of less than 90˚ C, oil and water mobilized by the combustion front will form a highly liquid-saturated region (usually referred to as the oil bank) in which the gas mobility is severely restricted. If the condition of restricted gas flow is allowed to persist, the burn front will stall and the oil production will become negligible. A stalled combustion front is characterized by a static region of high temperature just upstream of the location where the high temperature front had advanced when the plug started to develop. It is believed that the energy generation during a stall is associated with gas phase combustion reactions. Combustion tube tests have been observed to remain stalled for up to 32 hours without any perceptible movement of the high temperature front. For dry combustion, carbon dioxide concentrations in the product gas generally shift from the 14% level associated with stable high temperature combustion to values of 16% or greater. Carbon monoxide concentrations normally fall, as the high temperature mode reactions favour the formation of carbon dioxide. High carbon dioxide concentrations will only be seen for a short time, and this condition is followed by a continual decline in the carbon oxides content, indicating that the oxidation reactions are being pushed toward the low temperature mode.

Heavy oils from the Lloydminster-type reservoirs have a much lower initial viscosity than that of Athabasca bitumen. Despite this fact, stable combustion front propagation for these oils generally requires a preheat temperature in the region of 85˚ C. This behaviour suggests the formation of very viscous emulsions within the oil bank region.

Oil Saturation

One of the reasons why tests involving bitumen and heavy oil are prone to forming plugs is that they generally have high initial oil saturations. Because the initial saturations for combustion tube tests are in the range of 75 to 85%, the water saturations are close to residual levels. It appears that oil (as opposed to water) must be displaced in order to maintain a gas saturation within the oil bank region; this implies that oil must be displaced downstream at a rate equal to or greater than that at which it can be mobilized by the combustion zone.

Operating Pressure

Operating pressure is a parameter which is generally not reported to have a strong effect on the in situ combustion process. The experience of the authors has shown this to be true for dry combustion so long as the combustion kinetics remain in the high temperature mode. For an oil such as Athabasca bitumen, unstable burning characteristics begin to appear at pressures of approximately 6.0 MPa, and they can become quite severe by 10.0 MPa. The unstable burning characteristics reported for some of the Countess "B" dry combustion tests[23] were probably due to the fact that the burns were operated at a pressure of approximately 10.0 MPa.

The combustion characteristics of the Countess "B" oil (28˚ API) are worthy of mention as they characterize the behaviour of many other lighter oils. For the Countess "B" dry normal air combustion test, the core was ignited at a temperature of 400˚ C. Helium or nitrogen was injected to establish communication prior to ignition, then air injection was started. A peak temperature in excess of 500˚ C was observed at the first thermocouple (located 76 mm from the injection face), but the high temperature zone failed to propagate to the next thermocouple location (located 152 mm further along the core). Instead, the elevated temperature zone took on the appearance of a propagating steam bank. Since the development of this length of steam bank would not be possible for a dry burn, it was apparent that the elevated temperature region was advancing as an oxidation zone, and thus that the oxidation kinetics had switched to the low temperature mode. The oxidation zone continued to propagate for a time, but it then became static, as the oxidation zone had grown to the extent that it was consuming essentially all of the injected oxygen and there was no longer a sufficient oxygen flux at the leading edge to continue the growth. From this time on, the leading edge remained essentially static, but the oxygen utilization decreased as the oil within the elevated temperature region became progressively more oxidized. While increased volumes of oxygen became available at the downstream end of the oxidation zone, the flux was never sufficient to re-establish the sustained advancement of the oxidation zone. The temperature in the oxidation zone slowly declined in response to the falling oxygen uptake rates, and the oxidation reactions ultimately approached exhaustion.

When the first Countess "B" test was performed, it was assumed that the burn front had exhausted due to a lack of residual hydrocarbon. It was not until a number of tests using 95% oxygen-enriched air were performed on Athabasca cores that it was possible to develop the correct explanation for the behaviour of the Countess "B" dry test.

Moore et al.[22] described the effect of operating pressure on the performance of enriched air (95% oxygen) combustion tube tests on Athabasca oil sands cores. They found that increasing the operating pressure caused a significant rise in the oxygen and fuel requirements as compared to normal air tests on the same core. These observations were based on tests in which the oxygen flux was held constant, and it became very obvious that, under these

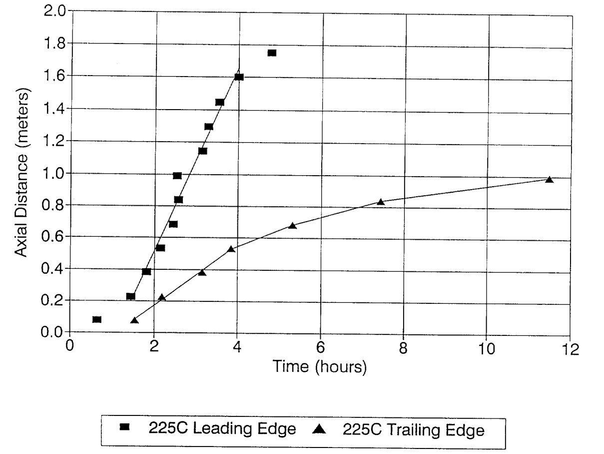

FIGURE 2: 225˚ C leading and trailing edge locations for Countess "B" Test No. 4 showing stalling of trailing edge during superwet in situ combustion.

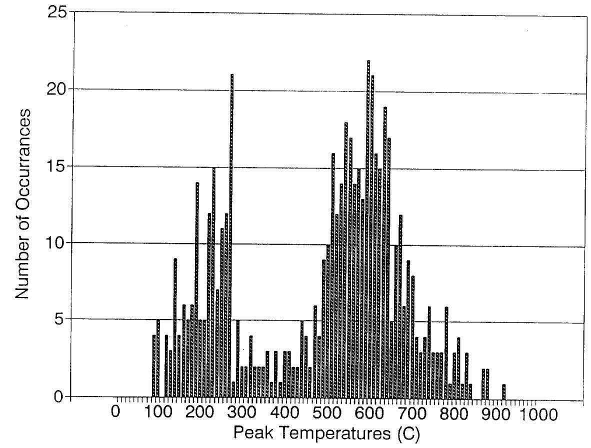

FIGURE 3: Frequency distribution of observed peak temperatures by zone for over 50 Athabasca Oil Sands in situ combustion tube tests.

conditions, the destabilization of the combustion process was the result of increased pressure. An interesting note is that the burning instabilities observed for Athabasca bitumen using enriched air at 10.0 MPa were very similar to those seen in the normal air Countess "B" tests at the same pressure.

Enriched air Countess "B" tests showed more unstable burning characteristics than the normal air burns carried out at the same pressure. As reported by Tzanco et al.[23], the enriched air tests had significantly higher oxygen requirements than the corresponding normal air tests. Moore et al.[26] also found that oxygen requirements rose with increased oxygen partial pressure for a Primrose heavy oil.

Water Injection

An additional feature of the Countess "B" combustion tube tests was that the burning characteristics were stabilized by water injection. The experiments in which water was injected soon after ignition exhibited more stable burning characteristics, especially the tests which operated in the superwet mode. It was therefore apparent that the Countess "B" oil favoured operation at oxidation temperatures of less than approximately 300˚ C.

Residual Energy Generation

An unexpected characteristic of the superwet tests on the Countess "B" core was the tendency for the trailing edge, or vapourization front, to stall (see Figure 2). This behaviour confirmed that enough energy was generated by the residual hydrocarbon present at the trailing edge so as to prevent total quenching by the injected water. Dry burns also exhibit residual energy generation within the swept region, and it is not uncommon for a zone previously swept by a high temperature combustion front to remain at temperatures in the region of 300˚ C. Similar behaviour was observed by Ejiogu et al.[27] during combustion tube tests on Pembina Cardium oil (which has a gravity of approximately 40˚ API).

It is now recognized that residual energy generation in the swept region is responsible for the spread out combustion zones reported previously by Hallam et al.[28] Combustion tube tests on Cold Lake cores routinely exhibit temperatures in the swept region upstream of the leading edge of the high temperature combustion zone which are in the range from 800 to 900˚ C. Although it is still unclear as to the nature of the hydrocarbon which results in the residual energy generation, it seems to be associated with pockets of bypassed hydrocarbon which become trapped behind the leading edge of the oxidation zone. It also appears that the rate of energy generation is governed by the rate of diffusion of oxygen and product gases if coke is the fuel source, or the rate of diffusion of volatile reactive components if the energy generation is associated with gas-phase reactions. It has been observed during 95% oxygen enriched air tests that residual energy generation has, on occasion, caused the injection line to become discoloured due to elevated temperatures. This suggests the counter-diffusion of gas phase hydrocarbon fractions into the injection system, which supports the concept that the residual energy generation is associated with gas phase combustion reactions.

In Situ Combustion Kinetics

The need to develop an adequate understanding of the phenomena which account for the abnormal combustion behaviours described above led to the establishment of a number of research programs which concentrated on the kinetics of in situ combustion. Results from many of these studies have been described in the literature[29-31]. These studies contributed greatly to the authors' understanding of the combustion kinetics for Athabasca Oil Sands, but it was still not clearly understood what was causing the instabilities. Recent kinetics studies carried out at the University of Calgary have therefore concentrated on the use of a ramped temperature apparatus. The ramped temperature oxidation test is similar in concept to those used by Burger and Sahuquet[32] and Fassihi et al.[33], and it involves the heating of core at a predetermined rate while injecting either normal or enriched air. Moore et al.[34] presented the results of a number of ramped temperature oxidation tests which were performed on Athabasca Oil Sands cores, and two of their observations are particularly relevant here.

First, they describe the existence of the negative temperature gradient region, which is the temperature range over which the oxygen uptake rate decreases with increasing temperature. This behaviour can be clearly seen from the data of Fassihi et al.[33], Burger and Sahuquet[32], and Toth et al.[35] The negative temperature gradient region can be considered to be the temperature interval which separates the low and high temperature oxidation regions, and an important aspect of this low reaction rate region is that the oxidation reactions will not operate stably within this temperature range. Tzanco et al.[23] found that there were no peak temperatures within the 310 to 350˚ C temperature range for Countess "B" oil. Similar behaviour is evidenced in Figure 3, which shows a histogram of the 12 individual peak zone temperatures for approximately 50 combustion tube tests which were conducted on Athabasca Oil Sands cores[25]. Originally, it was assumed that the lack of peak temperatures over the 300 to 500˚ C (310 to 350˚ C for Countess "B" oil) range was a reflection of the switch to superwet combustion, in which the reaction temperature is primarily controlled by the thermodynamic properties of steam. This is, of course, partially true, but a comparison of the Athabasca combustion tube data as reported by Ursenbach[25] with the apparent energy generation data reported by Moore et al.[34], which were determined in the absence of water injection, confirms

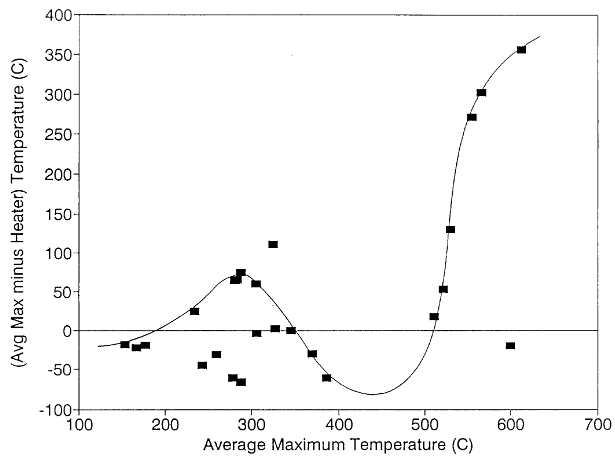

FIGURE 4: Energy generation resulting from ramped temperature oxidation of Athabasca Oil Sands bitumen.

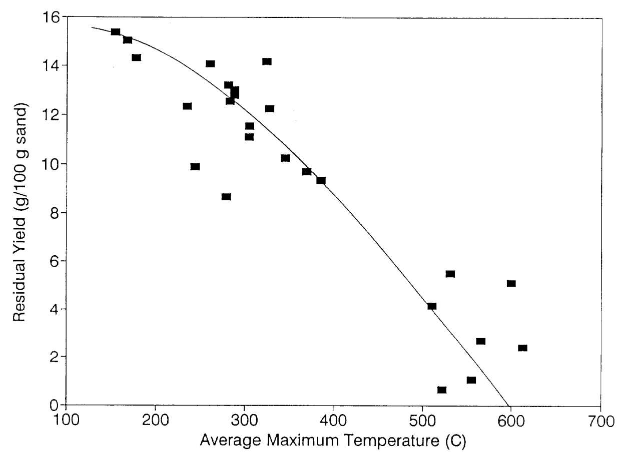

FIGURE 5: Hydrocarbon remaining on core following ramped temperature oxidation of Athabasca Oil Sands bitumen.

that the existence of this temperature interval is associated with the oxidation kinetics of a particular oil. Figure 4 shows the data of Moore et al.[34] plotted as the difference between the average maximum core temperature and the maximum heater temperature as a function of the maximum core temperature for a series of tests performed under a continuous heating ramp. Significant temperature differences indicate high energy generation rates, while small changes reflect low energy generation. The negative temperature gradient region, which lies between 300 and 500˚ C for Athabasca bitumen, is clearly indicated in this figure.

It has been observed that, for oils like Athabasca bitumen or Countess "B," it is very difficult to force the oxidized oil to undergo the transition from the low temperature mode to the high temperature regime. This implies that the presence of oxygen in the steam bank region can have a major effect on the ability of the oil within that zone to undergo the transition to high temperature combustion stoichiometry. Since this transition must occur for a successful dry combustion process on all Canadian oils tested to date, the degree of oxidation of the oil within the steam bank region, which is a function of the oxygen uptake rate in the high temperature region, has a direct impact on the stability of the high temperature combustion front as evidenced by the temperature profiles observed during a given burn.

With regard to burn stability, the important consideration is not the operating temperature, but the effect which operation at a given temperature has on the oil displacement efficiency. The second key observation made by Moore et al.[34] was that, for Athabasca bitumen, effective mobilization of the oil was only achieved when the oxidation kinetics were such that bond scission reactions, which result in the generation of carbon dioxide, were dominant. These are the reactions which are normally referred to as high temperature combustion. While they are normally associated with temperatures in excess of 350˚ C, bond scission reactions can also occur at lower temperatures. For Athabasca bitumen under dry combustion conditions, bond scission reactions dominate at temperatures in excess of the upper limit of the negative temperature gradient region. The residual hydrocarbon concentrations for this oil represented approximately 80% of the initial oil whenever the oxidation temperatures were below the lower limit of the negative temperature gradient region. Thus, the hydrocarbon residuals were reduced to the level normally associated with in situ combustion only when a distinct high temperature oxidation zone was observed to traverse the core [see Figure 5, which is based on the ramped temperature data of Moore et al.[34]] Although it is acknowledged that Athabasca bitumen is a highly viscous oil, similar behaviour has been observed for Canadian oils as light as the 40˚ API Pembina Cardium. For Pembina Cardium, residuals of approximately 40% of the initial oil were observed at oxidation temperatures as high as 300˚ C.

It should be clarified that not all oils need to operate at temperatures greater than the upper limit of the negative temperature gradient regions in order to achieve efficient displacement of the oil by the oxidation zone. High recoveries have been observed by the authors during dry combustion when the peak temperatures were in the order of 275˚ C, although never for a Canadian oil. The key for effective displacement of any oil is that the oxidation reactions must be primarily of the bond scission type.

The ramped temperature oxidation tests and combustion tube tests have demonstrated that the parameters which have a very strong effect on the ability of an oil to achieve the high temperature combustion mode are the operating pressure, oxygen partial pressure and the oxygen flux. The ease of overcoming the negative temperature gradient region is very dependent on the degree of oxidation of the oil at temperatures below those corresponding to the high temperature combustion region. The higher the degree of oxidation, the more difficult it is to achieve the high temperature combustion regime. For the purposes of quantifying the degree of oxidation, it is defined as the mass of oxygen reacted to form products other than carbon oxides (low temperature oxygen uptake) divided by the initial mass of oil. For Canadian oils, the oxygen not reacted to carbon oxides is primarily involved in oxygen addition reactions which result in the formation of liquid or solid phase oxidation products. Water is also formed; however significant water generation is not observed during the tests which do not achieve the high temperature bond scission state.

The degree of oxidation of the oil is proportional to the integral of the oxygen uptake rate with respect to time during the time that the oil at the leading edge of the oxidation zone is heated from the initial reservoir temperature to the temperature corresponding to the transformation to high temperature combustion (generally around 350˚ C). While this is not an easy integral to evaluate given the transition in the oxidation kinetics associated with the negative temperature gradient region, the concept of degree of oxidation allows one to explain why any factor which increases oxygen uptake under low temperature oxidation kinetics will make it more difficult to achieve the desired high temperature combustion mode. This is the reason why operation at high levels of oxygen enrichment or high oxygen partial pressures can cause the combustion fronts to be unstable. Because pure oxygen reacts very quickly within the temperature range corresponding to low temperature oxidation, the oil is often very highly oxidized by the time it attains the temperature in which bond scission reactions can be sustained. Low oxygen fluxes create the same effect, since the energy generation rate is often so low that the reaction temperatures remain in the low temperature oxidation range for extended periods of time, and the oil becomes too highly oxidized to easily undergo the transition to the high temperature combustion mode.

As was mentioned previously, high initial oil saturations can also promote operation in the low temperature regime due to the region of restricted gas permeability downstream of the combustion zone. It is the reduction in the oxygen flux, even if it is only for a short duration, which promotes oxygen uptake in the low temperature mode and, in turn, makes it difficult to re-establish the oxidation kinetics in the high temperature regime. The oxidation front then becomes inefficient at mobilizing oil, and this leads to the redevelopment of a gas saturation in the highly saturated oil bank region, which allows the combustion gas to again flow through the oxidation region. If the oil is not too highly oxidized, the increased oxygen flux may result in the re-establishment of the high temperature combustion front. The reactions will only remain in this mode if the oil bank region does not again restrict the oxygen flux. It is this type of behaviour which can cause combustion projects to appear cyclic, with periods of good and poor burning.

The indicators of the switch in oxidation kinetics in a laboratory experiment are, of course, the temperature and also the pressure and the oil production rates. When the kinetics shift to the low temperature mode during a dry test, the pressure drop over the oil bank region declines quickly, and the oil production rates fall almost immediately. This is an important observation with regard to the interpretation of field data. Gas composition data will also indicate the switch, but the time delay for identifying the problem is much longer.

Analysis of combustion tube tests performed on a number of different reservoirs under varied operating conditions shows that in situ combustion is a reservoir specific process. It also confirms that the conceptual model for in situ combustion, which involves the propagation of a high temperature combustion front for which the fuel is a coke-like substance laid down by thermal cracking reactions, is inadequate for describing the performance of many of the individual tests. Combustion tube tests also demonstrate that the consumption of oxygen does not guarantee that the process in operating in the desired mode. If combustion is only analysed on the basis of high temperature combustion reactions, it is impossible to understand the instabilities which are observed in one dimensional laboratory cores, let alone field projects.

Comparison of Laboratory and Field Performance for Canadian Oils

The Canadian firefloods which were operated in the Athabasca, Cold Lake, Wabasca and Lindbergh reservoirs confirmed the role of oil mobility in the success of an in situ combustion process. Amoco showed that operating on small pattern sizes also contributes to the successful burning of an Athabasca reservoir. Steam pre-heating followed by fireflooding was shown by BP to be an effective recovery process for the Cold Lake reservoir; they also determined that it was advantageous to modify the combustion process from that of continuous to cyclic air or oxygen injection. Failure of the combustion projects in the Wabasca and Lindbergh reservoirs can almost certainly be attributed to the combination of large pattern sizes (generally inverted seven spots) and the lack of any heated communication paths within the reservoir.

All of these observations are consistent with what would be expected from laboratory observations. Essentially all of the problems reported for the above bitumen and heavy oil reservoirs can be related to restricted gas fluxes in the oil bank region. As would be predicted from laboratory experiments, the injection of pure oxygen is not a way to overcome the mobility problem, and it will almost surely result in the kinetics operating in the low temperature mode within the regions where gas mobility is limited.

The mixed success of the firefloods operated in the Lloydminster-type reservoirs illustrates the problems of operating this process in relatively-thin heavy oil reservoirs. Many of the operating problems reported for the Lloyminster-type reservoirs suggest that the combustion projects were operating in the low temperature mode. This was, in part, due to elevated energy losses associated with the thin reservoirs, but is was also promoted by the low mobility of this oil as was evident from combustion tube tests and from the use of low air injection rates when servicing large patterns.

It has previously been noted that, once the kinetics have been allowed to drop into the low temperature mode, it is very difficult to return them to the proper high temperature regime. This is an observation which should always be borne in mind when designing an ignition procedure. For Canadian oils, ignitions which do not result in the development of a high temperature combustion region will almost certainly suffer poor burning characteristics unless other steps are taken to rectify the low temperature condition.

With regards to reported operating problems, the switch from high temperature combustion reactions (which generate carbon dioxide) to a low temperature oxidation mode (which generates liquid and solid phase oxidation products) will result in a significant decline in the efficiency of a fireflood process to mobilize oil. In a field sense, this condition will be marked by a significant reduction in the air (or oxygen) injection pressure and the rapid breakthrough of combustion gas to the production wells. Since oil is not being effectively mobilized by the oxidation zone, the oil and gas production characteristics will suggest that the production wells are gas locked. In addition, the lack of oil production will remove much of the corrosion protection from the tubing; hence, corrosion becomes a problem.

The performance of the oxygen injection phase of the Kinsella "B" project confirmed that oxygen injection should not be viewed as an automatic method for improving combustion efficiency. This does not imply that oxygen injection should not be considered, but only that it may be necessary to adapt the process using procedures such as those developed by BP at their Marguerite Lake project. As was shown by the Kinsella "B" project, an important operating feature of oxygen injection which should not be overlooked is that small volumes of oxygen breakthrough at a production well can cause high oxygen concentrations if the oxidation kinetics are not in a mode which results in the generation of carbon dioxide.

In general, combustion projects such as Murphy Eyehill, Norcen Bodo and the Alberta Energy Suffield project which were underlain by water exhibited difficult operating problems. Although it may be thought that the pattern sizes at Eyehill and Bodo were too large in view of the bottom water, this should not have been the case at Suffield. The Suffield project(16) is interesting because, like the PanCanadian Countess "B" project, initial operating pressures and air injection pressures were high. As was explained previously, the operating pressures associated with these projects promoted operation in the low temperature regime. The combination of the reservoir properties (high initial saturation of a relatively viscous oil in a consolidated formation with bottom water) and the operating pressure would have almost surely driven the oxidation reactions into the low temperature mode. As described by Byl et al.(18) and Tzanco et al.(23), operation in the low temperature regime will cause the oil phase to be immobile, but the energy generation associated with these reactions will cause hot water to be displaced from the heated region. Since the heated water will have the greatest mobility in the water leg, the displaced hot water will preferentially flow to the water leg and, in doing so, will create a heated path along which the oxidation zone will follow. The oxidation zone would therefore become established in the water zone. In retrospect, the Suffield project would have been an excellent candidate for the installation of a cyclic air injection process.

Analysis of the Countess "B" reservoir as described in the publication of Metwally(36) would suggest that this project is operating in a low temperature mode. This behaviour is consistent with the behaviour observed in the laboratory. The experimental data suggest that the combustion process should be operated in the wet mode, but this has yet to be proven in the field.

The success of the Mobil Battrum fireflood shows that combustion can succeed in Canadian reservoirs. This project has demonstrated that it is possible to operate on large spacings. A point which should not be overlooked is that Mobil utilized much higher air injection rates than are usually noted in the literature during the early life of the project.

Future of Combustion in Canada

At first glance, the history of in situ combustion in Canada might lead to the conclusion that there is a limited future for the process here. This is the opinion of a large part of the Canadian oil industry; however, the success of the Battrum, Fosterton Northwest, Golden Lake Sparky, Marguerite Lake, Countess “B” and Morgan projects has been overlooked. Also ignored is the fact that, because of the operating procedures which were applied in many of the reservoirs, combustion had no chance of success. A thorough analysis of the Canadian literature shows that there have been a large number of advances in terms of well design and production techniques which have enabled firefloods to operate under some very severe conditions. Since much of this technology will be available to future projects, all that is required to increase the probability of success of the in situ combustion process is the development of some operational guidelines.

Given the good agreement between field behaviour and what might be expected based on laboratory experience, the authors are optimistic that field operating procedures can be developed so that the theoretical advantages of the combustion process can be realized. It must be recognized that firefloods do not always operate in the high temperature mode, but rather that they can operate in a regime which does not provide for efficient recovery of the contacted oil. Once it is understood how the process fails, it is possible to make sense out of the great diversity of opinion which exists concerning the in situ combustion process.

Two good starting points are the application of wet combustion and cyclic combustion, as the application of both techniques has been shown to be effective in both field and laboratory experiments. The incorporation of horizontal wells into combustion projects also has great potential. Given the strong effect which many firefloods have on the offset wells, it is possible that the horizontal wells may not be incorporated within the actual combustion pattern. Should this be the case, the pattern under combustion would be viewed as an energy generation region, and it would have to be operated so as to maximize the benefits on the offset wells.

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