## THE UNIVERSITY OF CALGARY

Steam Injection and In-Situ Combustion:

A Combined Approach to Heavy Oil Recovery

by

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### A THESIS

# SUBMITTED TO THE FACULTY OF GRADUATE STUDIES IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF MASTER OF SCIENCE

DEPARTMENT OF CHEMICAL AND PETROLEUM ENGINEERING

CALGARY, ALBERTA

APRIL, 1992

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies for acceptance, a thesis entitled, "Steam Injection and *In-Situ* Combustion: A Combined Approach to Heavy Oil Recovery" submitted by Pablo Andres Gomez in partial fulfilment of the requirements for the degree of Master of Science.

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#### ABSTRACT

A series of four laboratory combustion tube experiments was carried out to examine the combination of the steamflooding and combustion processes on heavy oil cores from the Primrose Reservoir. The effects of pressure, oxygen enrichment, and injection flux were examined, as well as incremental oil recovery during the waterflood, steamflood, and combustion phases. It was found that steam efficiency decreased as pressure increased; however, steam developed a highly mobile low oil saturation which enhanced the combustion process. The process operated very efficiently at low initial oil saturations when the core had been preheated and swept by steam. Low oxygen concentration and high gas flux maintained stable combustion at pressures as high as 10.3 MPa. The combination of steamflooding and *in-situ* combustion as an enhanced oil recovery process has potential future application in the low mobile and highly viscous oil of Canadian heavy oil reserves.

#### ACKNOWLEDGEMENTS

The author wishes to express his appreciation and gratitude to Dr. Gordon Moore for his guidance and assistance during this investigation. Funding and laboratory space provided by Dr. Moore is also much appreciated.

The author also wishes to express his thanks to Mr. Matt Ursenbach for his valuable assistance with data and computer matters, Dr. Raj Mehta for his encouragement and support, and to Dr. John Belgrave and Dr. Roger Butler for their scholarly assistance.

The invaluable technical support of the *In-Situ* Combustion Research Group, M. Hancock, M. Duong, B. Sibbald, P. Towle, C. Homan, and C. Leavitt, is very much appreciated.

Special thanks are express to Yvonne Turgeon for her unlimited support, encouragement, and comforting words during times of frustration.

The author wishes to thank the Federal Government (Energy, Mines and Resources Canada/CANMET) and the following corporations for funding the project: Amoco Canada Petroleum Company Ltd., B.P. Resources Canada Limited, Linde - Union Carbide Canada Limited, Liquid Air Energy Systems Inc. -Canadian Liquid Air Ltd., Mobil Oil Canada, Murphy Oil Company Ltd., Petro-Canada Resources, Saskatchewan Oil and Gas Corporation, and Unocal Science and Technology. Overall project co-ordination was provided by Dr. Kamal N. Jha from CANMET and is very much appreciated.

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The author is also indebted to the Alberta Oil Sands Technology and Research Authority, AOSTRA, and The University of Calgary, for their financial support. To my parents

# Roberto y Tulia

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## NOMENCLATURE

<b>A</b> .	Area (L <sup>2</sup> )
Н	Energy (ML <sup>2</sup> T <sup>-2</sup> )
L	Distance (L)
N	Pore volume
P	Pressure (ML <sup>-1</sup> T <sup>-2</sup> )
S	Saturation
T	Temperature (θ)
V	Volume (L <sup>3</sup> )
W	Cumulative volume of water (L <sup>3</sup> )
f	Fractional flow
g	gravity force (MLT <sup>-2</sup> )
k	Permeability (L <sup>2</sup> )
q .	Flow rate (L <sup>3</sup> T <sup>-1</sup> )
t	Time (T)
V ·	Velocity (LT <sup>-1</sup> )
x	Distance (L)
ф	porosity
ρ	density (ML <sup>-3</sup> )
θ	angle of inclination
μ	viscosity (ML <sup>-1</sup> $T^{-1}$ )

# Subscripts

L	distance L
R	rock
С	capillary
i	injection
0	oil
r	relative
ro	residual oil
S	steam
t	total
W,	water
wi	initial water
x	distance x

# CHAPTER ONE

Petroleum is found on every continent and beneath every ocean however, only about a third of the oil in most deposits is recoverable by present-day techniques. Many experts believe the major oil fields have already been discovered, however, the world's reserve of oil can be increased by the active development of better methods of recovery.

Research into new and improved thermal recovery methods holds success for the efficient extraction of remaining deposits in abandoned reservoirs and reserves unrecoverable by present-day commercial techniques. The application of energy into these reservoirs reduces the oil viscosity and improves the oil mobility which, up until now, has hindered recovery. Research into the complex reservoir conditions will help redefine present thermal recovery processes and bring a better understanding of oil production at high pressures and increased temperatures.

In an effort to gain insights into the application of thermal processes in Canadian heavy oil reservoirs, a laboratory program was developed to evaluate the combined effects of steam injection and *in-situ* combustion processes.

The injection of steam has proven to be very effective in recovering viscous oil. The injected steam creates a heated zone of highly mobilized oil which is driven towards the production wells. The energy required to produce steam is usually provided by burning fuel at the surface. The amount of fuel burned relates to the energy required to support the heat losses from the steam generator, surface lines and wellbore, while delivering high quality steam into the reservoir. However, limitations in the amount of fuel available to burn and heat loss control has hindered its use in deep, high pressure reservoirs. *In-situ* combustion which is a more energy conservative process than continuous steam injection, has been suggested as a solution to this limitation.

The *in-situ* combustion process consists of injecting an oxygen-containing gas, with or without water, into an oil-bearing reservoir. The method involves ignition of the formation, followed by propagation of the combustion front through the reservoir and maintaining the combustion by the continuous injection of the oxygen containing gas which reacts with the *in-situ* hydrocarbons. The low temperatures of the Canadian heavy oil reservoirs however, have hindered the wide-spread application of *in-situ* combustion. The high temperature combustion front drives oil and water forward into the cooler part of the reservoir and the high viscosities of the oil, at reservoir temperatures, make it difficult to displace the mobilized oil through the unheated region; thus, limits the applicability of the combustion process.

The potentially efficient use of the combustion process in the cold, Canadian heavy oil reservoirs inspired a modification of the fireflooding process. Steam preheating followed by *in-situ* combustion, as tested by **BP Canada Resources Ltd.**, appears to be an alternative process. Steam pre-heating can economically

provide sufficient oil mobility to allow combustion to achieve efficient operation.

The present study describes a series of four laboratory combustion tube experiments performed at the In-Situ Combustion Research Group at the University of Calgary. The objective of the laboratory program is to evaluate the recovery mechanisms by which the combined processes operate. Such operating parameters as, total pressure, initial oil saturation, maximum and preheat temperature, degree of oxygen enrichment and total injection flux were selected for further study. Chapter two presents an overview of thermal recovery methods. Emphasis is given to the steam drive and in-situ combustion processes. description of the equipment used and the test preparation and analysis are presented in Chapter Three. The test procedure, which involved sequential waterflooding, steamflooding and *in-situ* combustion is also presented in chapter three. The analyses performed to study the behaviour of these processes at reservoir specific conditions are discussed in the remainder of this thesis. The evaluation of the waterflood phase is presented first, followed by a detailed analysis of the steam injection phase. A simple analytical model which has been developed to aid the understanding of the different mechanisms involved during the water and steamflood phases of the experiments is presented next. In-situ combustion performance in the steamflooded heavy oil cores is analyzed subsequently with the inclusion of a discussion on potential applications of the combined processes.

This laboratory experimentation will serve the dual function of providing research about *in-situ* combustion as a follow-up method for reservoirs that have been steamflooded, and helps gauge the possibility of extending the production capacity of a reservoir.

#### **CHAPTER TWO**

#### AN OVERVIEW OF THERMAL RECOVERY METHODS

Thermal recovery is the intentional introduction of energy into a subsurface reservoir containing hydrocarbons in order to improve or accelerate oil recovery. Thermal recovery is a preferred method for viscous oils in which a temperature increase reduces the oil viscosity thus improving the displacement and recovery efficiencies and allowing the oil to flow freely to the production wells. A more favourable mobility is created for the viscous oil.

Literature dealing with thermal recovery has become very diversified and reflects the great variety in which this process has and is being used to address the array of problems in oil production. Hot water drive, steam drive, thermal stimulation, forward dry combustion, wet and superwet combustion, and reverse combustion have all been considered. These subjects have been studied using a combination of physical and mathematical models and by the analysis of field operations.

#### 2.1 Pioneer Work

Heating oil reservoirs to increase production was suggested as far back as 1865. In 1865, Perry and Warner issued a patent for the use of a down-hole heater in production oil wells. During the early 1900's hot gas injection and electrical energy application were proposed in air injection oil enhancement projects. The first *in-situ* combustion probably occurred during these projects. In

1923, Howard and Wolcott, after reviewing Perry and Warner's development of down-hole air-gas burners for well stimulation, began burning some of the reservoir oil in place. In the 1930's Russian engineers field tested an underground gasification process (Sheinman, 1938). The study of underground combustion continued in the 1940's with interest shown in ignition techniques and the effects of flow rate on oxygen utilization (Highsmith, 1948). *In-situ* combustion was developed rapidly starting in 1953 with the laboratory research work of Kuhn and Koch and the following year when Grant and Szasz published their work. Hester and Menzie (1954) presented a review of the early work in-*situ* combustion and a succession of technical papers soon followed these early publications.

Steam drives date from as early as 1931 when hot water vapour was injected into the Wilson and Slain reservoir for 235 days (Stovall, 1934). For the next twenty years the record contains no mention of steamflooding until a steam drive was operated by **Shell** at Yorba Linda (Stokes and Doscher, 1974). Schoonebeek (van Dijk, 1968) and Tia Juana (deHaan and Schenk, 1969) mark the first large-scale stream drives. However, an early steam drive pilot test at Mene Grande (Guisti, 1974) played a major role in the development of the cyclic steam injection process. This process, discovered accidentally in 1954, provided the main thrust for the early development of heavy oils in Venezuela, California, and Canada. A number of mature cyclic steam injection operations have now been converted to steam flooding.

Today, steam injection is the major enhanced oil recovery method and accounts for over ninety per cent of the oil produced by thermal methods. Steam flooding remains the main thrust in California and Venezuela, with cyclic steam stimulation increasingly more important in Canada.

#### 2.2 Steamflooding

Steamflooding involves a continuous injection of steam into specific injection wells where oil is driven to separate production wells. The injected steam creates a heated zone of highly mobilized oil which is driven toward the producers. The mechanism is complex in that the steam tends to migrate toward the upper portion of the formation due to gravity segregation, and as a result, the steam zone formed grows both laterally and vertically.

In continuous steam injection a number of complex thermal phenomena occur. Conduction and convection may be coupled with oil vaporization and steam condensation. Steam distillation, viscosity reduction, thermal expansion, solvent extraction and gas drive all aid the oil recovery. In order to better understand these phenomena, a number of laboratory and mathematical models have been developed through the years.

#### 2.2.1 Laboratory Experiments of the Steam Injection Process

Laboratory models of the steam injection process have seen success in both parametric studies and project designs. Although expensive to build and operate,

the greater definition provided, (as compared to numerical models), justifies the costs.

Laboratory models may be of two kinds: the high pressure model, and the vacuum model. Several investigators (Pursley 1974 and Pujol and Boberg 1972) have used high pressure models noting both scaling criteria and experimental difficulties. Stegemeier et al. (1980) first proposed the low pressure or vacuum model as one that could properly scale the ratio of latent to sensible heat. However, at low pressures the models cannot simulate steam distillation, solution gas, and compressibility effects. Wu and Brown (1975) presented a laboratory study on steam distillation on porous media, measuring the yield of hydrocarbon distillates produced by contacting steam with a series of crude oils. They found that distillation occurs to a much larger extent with light oils than heavy ones.

Laboratory experiments in linear systems have been presented by Willman et al. (1961) and Closmann and Seba (1983). The effect of various parameters on residual oil saturation was investigated, but these experiments had unscaled fluid flow rates, gravity forces, and heat losses. Willman et al. concluded that both hot water and steam injection recover more oil than a cold waterflood, finding that the mechanisms for increased recovery include 1) thermal expansion, 2) viscosity reduction, and 3) steam distillation. They also reported that steam-zone residual oil saturation is independent of initial saturation. Closmann and Seba experiments indicated that remaining oil saturation, both at steam breakthrough and after

passage of several pore volumes of steam, is a function of oil/water viscosity ratio at saturated steam conditions.

More recently, some work has been focused on the dependency of reservoir properties on thermal processes. Thermal conductivities of oil sands have been investigated by Somerton et al. (1974) and Messmer (1984). They have found that thermal conductivity decreases with increasing temperature, and that there are substantial increases as the wetting phase saturation increases. The effects of temperature on relative and absolute permeability of sandstones have been studied by Weinbrandt et al. (1975). They report that the irreducible water saturation increases while the residual oil saturation decreases with temperature The individual relative permeability to oil increases for all water increase. saturations. A set of relative permeability curves has been developed empirically by Dietrich (1981), during thermal simulation of heavy oil projects. In 1990, Sanchez and Schechter presented steam/water relative permeability curves under conditions of near adiabatic, two phase, steady flow in unconsolidated sand packs. They report that higher temperature steam/water relative permeability curves are almost identical to those for nitrogen/water at room temperature.

#### 2.2.2 Mathematical Models of the Steam Injection Process

The earliest models of steam injection focus on an energy balance and include the analytical models of Lauwerier (1955), Marx and Langenheim (1959), and Mandl and Volek (1966). As a first approximation, it is assumed that the

formation, at a constant temperature, retains the injected energy, and that a fraction of this retained energy is lost by conduction to the surroundings. Heat transfer ahead of the front is assumed to be negligible (Marx-Langenheim, 1959). This approximation holds true for thick formations, high steam quality, low pressures, and high flow rates.

A new variable in steamflooding analysis was introduced in 1969. Mandl and Volek's improved model referred to the variable "critical time". At the critical time the latent heat injection rate is equal to the vertical heat loss rate. As a result, convective heat transfer at the front dominates. Mandl and Volek provide equations for the steam zone volume and the critical time. Myhill and Stegemeier, (1978), present a mathematical model, based on a simple energy balance, used to predict oil-steam ratio and the efficiency of a steamflood. This model which incorporates reservoir and steam properties, involves the calculation of the size of the steam zone using Mandl and Volek equations. The oil steam ratio is calculated by assuming that the oil produced is equal to the steam zone pore volume times the change in oil saturation. This approach, however, gives unrealistically high production rates as it assumes that the oil displaced by the steam front is produced immediately.

Jones (1981) presents a practical approach which uses Myhill and Stegemeier's oil production prediction. The oil production rate is multiplied by empirical factors based upon field performance in order to correct for the unrealistically high production rates.

Farouq Ali (1982) presents a unified approach which combines many of the earlier concepts described above and unites them into a simplified approximate model. In later work, Van Lookeren (1983) developed equations to describe the degree of override that can be expected during a steamflood. These equations, based on Darcy's Law, have been developed for linear and radial flow cases.

Although multiphase flow was neglected in the above mentioned models, they are used for many conditions and are still of value for preliminary calculations. The hydro-dynamic aspects of fluid flow within the reservoir should be taken into account in order to obtain an adequate description of the oil production during steam injection. Therefore, the heat-transfer described by the above models must be coupled with advanced models that involve hydro-dynamics.

The next group of models added fluid displacement to the analysis of heat transfer phenomena. The Willman et al. (1961) model uses the Buckley-Leverett equation to predict the distribution of saturations beyond a steam zone in radial displacement. Other examples of models which couple the heat propagation with displacement include Fournier's (1965) for hot waterflood calculations, Landrum's et al. (1960) for steam injection, and Shuttler's and Boberg's (1972) for one-dimensional steamfloods. Rincon et al. (1970) further coupled the one-dimensional model with a Higgins-Leighton procedure (1962), sub-dividing a two-dimensional reservoir into channels within each of which a one-dimensional steamflood takes place.

More advance models have been proposed since 1969. Shutler (1969)

proposed a one-dimensional steam injection model, considering oil, water, and steam flow, but not allowing for solution gas. In 1970 he followed with a twodimensional version which was used for simulating an experimental steamflood. Ferrer and Farouq Ali presented mathematical models of three-dimensional steam injection processes in 1972. In 1974, Coats et al. proposed a similar model where steam was the sole gas considered. These models were improved in 1976 through the inclusion of solution gas (Coats et al. 1976). Later in 1978, Coats presented a "highly implicit" steam injection model treating a number of coefficients in the model equations in a non-linear fashion. Extensive research into advanced numerical techniques is presently occurring, both to improve the stability of the solution obtained and to reduce computer time.

#### 2.3 *In-Situ* Combustion

*In-situ* combustion, or fireflooding, is an important enhanced recovery process and has the potential, due to its energy efficiency, to be applied to a large resource of otherwise unrecoverable oil. The last forty years have seen an extensive investigation and field testing of *in-situ* combustion. However, application of the process continues to be difficult due to the complicated nature and limited understanding of the complex processes of simultaneous multi-phase flow, heat and mass transfer, and low and high temperature combustion.

The *in-situ* combustion process consists of the injection of an oxygencontaining gas, with or without water, into a oil-bearing reservoir. After igniting the wells, a combustion front propagates through the reservoir by the continuous injection of the oxygen containing gas which reacts with the *in-situ* hydrocarbons generating a heat wave.

Forward, reverse, and wet combustion make up the three types of combustion. During forward combustion, the front moves in the same direction as the injected air, while in reverse combustion, the front moves in an opposite direction. Wet combustion is a modification of dry forward combustion and includes, in addition to air, the simultaneous or alternative injection of water.

Forward combustion is preferred to reverse combustion, as forward combustion burns the oil fraction that is less desirable. During the process, this oil fraction is consumed as the heat from the combustion front distils the light oil ends and thermally cracks the oil. In the traditional concept of *in-situ* combustion, thermal cracking produces a heavy residue, coke, which is deposited on the core matrix, acting as the main fuel source for the process.

Reverse combustion was first studied as Reed et al. (1960) indicated that an upper limit of oil viscosity exists for forward combustion. If the combustion front runs countercurrent to the air (reverse combustion), very viscous oils can be displaced and produced. Reverse combustion has been tested in several canadian reservoirs but it is still not been proven as a commercial process. Dietz and Weijdema (1968b) report that reverse combustion is limited due to its tendency toward early spontaneous ignition near injection wells.

The addition of water during forward combustion provides many benefits

compared to dry combustion. It permits more efficient heat distribution and it has been shown to reduce fuel requirements. Hence, the combustion front moves faster through the reservoir, leading to more efficient use of injected air and, therefore, a more economic displacement process.

Laboratory investigations indicate three separate types of wet combustion: normal wet combustion, incomplete wet combustion (partially quenched combustion), and superwet or quenched combustion. Dietz and Weijdema (1968a) and Garon and Wygal (1974) observed that at sufficiently high water injection rates, coke combustion can be partially quenched. At higher water injection rates, the energy provided by combustion is less than the latent heat of vaporization of injected water. Under these conditions, a steam plateau forms; the temperature of which is determined by the partial pressure of the water at reservoir conditions. No peak temperature is observed and oxygen consumption occurs near the trailing end of what appears as a moving steam bank.

The modification of standard *in-situ* combustion technology through enriched air injection has the potential to overcome a number of problems that have hindered the wide-spread application of the process. The use of oxygen, (enriched-air), was first suggested by Ramey (1954) to provide a given oxygen flux at a lower injection rate and pressure. Garon et al. (1986), in an excellent review of the oxygen fireflooding literature, concluded that oxygen offers many process and operational advantages over normal *in-situ* combustion. Oxygen fireflooding could minimize many operational problems, increase oil productivity, and reduce the volumes of gas injected. However, Moore et al. (1990) report that the use of oxygen at high pressures decreased the stability of the process.

A further modification of the fireflooding process is the combination of steam and *in-situ* combustion. This is especially applicable in the cold, Canadian heavy oil reservoirs. This procedure recognizes that displaced oil mobility is a critical factor governing the success of any combustion process and it has been pioneered by **BP Canada Resources** (Hallam et al. 1989).

#### 2.3.1 Laboratory Experiments of the *In-Situ* Combustion Process

The majority of laboratory *in-situ* combustion studies are performed using combustion tubes. These studies primarily measure process variables, such as fuel availability for different crudes, porous media structures, and operating conditions. Some of the earliest *in-situ* combustion results were published by Showalter (1963), Wilson (1958), Wilson et al. (1963), and Alexander et al. (1962). Showalter suggests that air requirement is dependent upon fuel composition and fuel deposition, the amount of carbon not completely oxidized, and oxygen utilization.

Several investigators have measured the effect of pressure on combustion. Martin et al.(1958), indicate that the effect of air pressure is small for experiments having high combustion efficiencies. Wilson et al. (1963) report that combustion peak temperature and zone velocity are not sensitive to changes in pressure during high flux combustion. At low fluxes, increasing the pressure increases peak temperature and decreases the combustion zone velocity. Moore et al. (1990) report that at high pressures, the use of oxygen enriched-air results in increased low temperature reactions, resulting in increased fuel laydown and decreased burn stability.

Wu and Fulton (1971) report a number of distinct zones which develop after the combustion front propagates into a reservoir. Starting from the injection point, these regions are designated as 1) burned zone, 2) high temperature combustion zone, 3) cracking region, 4) evaporation and cracking region, 5) steam plateau, 6) water bank, 7) oil bank, and 8) initial zone. These zones result from the heat and mass transfer and the chemical reactions which occur during *in-situ* combustion.

Steam plateau behaviour was studied by Penberthy et al. (1968) using both an analytical model and an experimental simulation in a combustion tube. In other investigations Vossoughi et al. (1982) have reported on the effect of clay within the sand matrix. Combustion tube tests (Buesse 1971) show that fuel deposition increases with increasing air rate and higher surface area. Other investigators (Vossoughi 1985, Fassihi et. al. 1984, and Burger 1972) have found that fuel availability increases with an increase in the specific surface area or clay content.

The wet combustion mechanism has been described by several investigators (Dietz 1968, Garon 1974, Parrish 1969, Burger 1973, and Bennion et al. 1977). They report that the amount of air required to advance the combustion front through a unit volume of reservoir generally decreases as the water to air ratio is increased.

Analysis of the mechanisms of quenching and re-ignition of oil in sandpacks was studied by Bousaid (1989). Laboratory results indicate that the cycle of quenching and re-ignition can be repeated to yield a fast-moving front with an increase in oil production. He concludes that multiple quenching of the burn front consumed less fuel and required less air than dry or normal wet combustion.

Combustion tube tests have been performed to evaluate and compare the process effects of oxygen and air fireflooding. The earliest reported tests with enriched air were reported by Wilson et al. (1963). Pusch (1977) published a comprehensive report on the use of oxygen for oil recovery. Shu and Lu (1984) and Moore et al. (1984) substituted carbon dioxide for nitrogen in the injected gas. No difference in the fuel consumption was observed by Shu, but Moore reports that oxygen and fuel requirements are considerably reduced from those with air injection. As well, oil recovery was accelerated over that for normal air combustion. Moss and Cady (1982) report a set of combustion tube experiments performed using air or oxygen injection, with and without water. Oxygen and water injection was found to displace the oil faster than normal air wet combustion but did not change the peak temperature nor the oxygen utilization.

A series of eight combustion tube tests was performed at the University of Calgary to provide design information for an oxygen fireflooding project being operated by **BP Canada Resources** (Hallam et. al. 1989). Dry and wet air and enriched air experiments were carried out. A comprehensive study was reported by Hansel et al. (1984) with a range of oxygen concentrations using 31° API crude. Additional results by Shahani and Hansel (1984) confirm that the main benefit of oxygen enrichment in light and medium gravity oils is that combustion can be sustained where the use of air was unsatisfactory. A key aspect which seemed to be disregarded by these authors is that the tests were performed at a constant total gas flux, hence the oxygen flux was increased as the level of enrichment was increased.

Moore et al. (1990) present the results of ten enriched-air combustion tube test performed on Athabasca Sands core. They report that the use of oxygen at high pressures results in increased low temperature reactions between oxygen and the oil. Fuel load is increased and burn stability decreased. Although water injection may enhance the performance of high pressure oxygen combustion, they found it may also lead to increased oxygen storage in the swept zone. These results appear to be opposite to those of Shahani and Hansel (1984). The reason for the difference is that Moore et al. (1990) operated at a constant oxygen flux, as opposed to total gas flux.

A review of the combustion tube literature shows that a much higher air flux is required to produce a steady front in small diameter tubes (5-8 cm), (Reed et al. 1960, Langnes 1967, Penberthy and Ramey 1967, Couch and Rodriguez 1971, Alderman 1971, Sibbald 1987, and Bousaid 1989). Heat losses associated with the increased surface area to burn volume ratio for the small tubes tend to affect the reaction kinetics. At the peak combustion temperature levels reported (below 350°C), low temperature oxidation reactions seem to be predominant. These reactions consume considerably more oxygen than appears in the carbon oxides and leave residual hydrocarbons in the burned portions of the cores.

#### 2.3.2 Mathematical Models of the *In-Situ* Combustion Process

The earliest analytical approaches to *in-situ* combustion include those of Ramey (1959), Bailey and Larkin (1959), Thomas (1963), Couch and Selig (1963), and Baker (1962). Their approach to the problem considers a heat balance with conductive and/or convection heat transfer in an infinite medium. An improved model was proposed by Chu (1964) to include the energy effects of vaporization and condensation on the temperature distribution. Heat transfer models have been proposed to study reverse combustion (Berry 1960, and Warren 1960). An important theoretical study of the wet combustion process was presented by Beckers and Harmsen (1970). Smith and Perkins (1973) also dealt with numerical modelling of the wet combustion process.

In 1965, Gottfried published the first multi-phase one-dimensional *in-situ* combustion model, designed to simulate a laboratory flood. The model includes three-phase fluid flow, conduction and convection, vaporization and condensation of water, and heat generation by oxidation of oil through the use of a reaction rate equation. The solution procedure relies on an iterative scheme requiring vast amounts of machine time. In 1970, Smith and Farouq Ali reported the first single phase, two-dimensional *in-situ* combustion model. Their model accounts for

conduction, convection, heat losses, and heat generation, but assumes constant fuel consumption. Later, Eggenschwiler and Farouq Ali (1977) presented an improved version of the model. In 1975, Adler reported a one-dimensional multiphase, simulator. A more complete formulation of the process was published by Crookston et al. (1979). Their model considers four chemical reactions representing the oxidation of light oil, heavy oil, and coke, and thermal cracking of heavy oil to inert gas, light oil and coke. In 1980, Youngren and Coats presented more implicit and stable models of the process. Coats' formulation is considerably more general than any report to that date, allowing for any number of chemical reactions. Rubin and Buchanan in 1985 developed a fully implicit general purpose thermal model. Coats presented an excellent review on reservoir simulation in 1982. Breitenbach (1991) describes the state of the art in reservoir simulation, focusing primarily on advances that have occurred since Coats' paper.

#### **CHAPTER THREE**

#### LABORATORY EXPERIMENTAL WORK

Laboratory combustion tube tests are an effective means for evaluating the mechanisms of *in-situ* combustion and for determining parameters required for the design, implementation, and interpretation of field projects. Significant differences in the burning performance of individual reservoirs have been observed during these tests. At present, no method has been developed to a priori predict the performance of a given reservoir.

Important insights into this process have been gained at the *In-Situ* **Combustion Research Laboratory** located in the Department of Chemical and Petroleum Engineering at the University of Calgary, where research into *in-situ* combustion has been ongoing since 1972. To date, the research group has performed 258 *in-situ* combustion tube tests in either a 1.83 metre, ten centimetre diameter core holder or a 1.07 m long by 5.1 cm diameter unit. Tests have been conducted on reservoirs from Canada and other parts of the world.

In an effort to better understand the application of thermal processes in Canadian heavy oil reservoirs, a laboratory program has been developed to evaluate the combined effects of steam injection and *in-situ* combustion on restored cores from the Primrose reservoir. The program is part of a larger study funded by a consortium of Canada's **Department of Energy, Mines and Resources** and several industrial participants.
### 3.1 Experimental Apparatus

The laboratory experimentation is performed in the small diameter core holder equipped with a steam generator mounted on the injection end flange (**Figure 3.1**). To allow the use of a thin wall combustion tube (0.1 cm nominal wall thickness), which is required to minimize heat transfer along the wall, and reservoir pressures, the tube is set inside a 2.10 m long, 30 cm diameter, 20.8 MPa rated pressure vessel.

The tube, composed of 321 stainless steel, is equipped with fourteen heating zones of 7.62 cm length. Each zone consists of a nominal 850 W heater, with a centreline and wall K-type dual junction (3.2 mm diameter) thermocouples mounted at the midpoint of each heating zone. The heaters operate in response to a radial temperature gradient between the tube centreline and the tube wall. In order to operate at near adiabatic conditions, a combination of active heater control and passive insulation is most desirable. Therefore, ceramic blanket insulation is used in the space between the tube and the heaters to protect the tube from hot spots and control the heat losses more efficiently. The annular space between the pressure jacket and the tube system is filled with a porous insulating material and pressurized with helium.

Six pressure taps are located at 15.24 cm intervals along the tube. The first is located at the inlet of the core holder and the last placed at the production end. The steam generator consists of a 5.1 cm (O.D.), 24 cm long, 321 stainless steel

# FIGURE 3.1 SCHEMATIC OF THE COMBUSTION TUBE



\* Not to scale

grooved mandrel block. A one-eighth inch stainless steel tube spirals around the outside thirteen centimetres of the block, and then down through the centre and into the core holder (**Figure 3.2**). Three 850 W heaters are clamped around the outside of the steam generator to vaporize the water. Temperature control is possible with the aid of two thermocouples, which measure the temperature of the water in the coiled tubing and at the inlet of the core. To ensure consistent heating and reduce heat losses, the heaters and the steam generator block are insulated with ceramic and porous insulation. This design assures that superheated steam is injected at the sand face.

**Figure 3.3** is a schematic diagram of the combustion tube assembly. The assembly is highly instrumented and capable of either normal or enriched air operation, with or without the simultaneous injection of water. Further details of the facility can be found by consulting Harding (1976), Belgrave (1987) and Sibbald (1990).

Support analytical equipment includes a 5830 Hewlett-Packard Process Gas Chromatograph, a 5880 Hewlett-Packard Gas Chromatograph for simulated distillation, a C-H-N Analyzer and organic carbon analyzer, a Perkin-Elmer Model 467 infrared absorbtion spectrophotometer, a pH meter, a Horiba Sulphur analyzer, a Brookfield viscometer, and a Paar densitometer. A full array of core extractors, centrifuges, and rotary evaporators is also included allowing for the preparation and analysis of individual samples.



FIGURE 3.3 COMBUSTION TUBE ASSEMBLY (Sibbaid et al. 1990)



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#### 3.2 Experimental program

#### 3.2.1 Core and Fluid Preparation and Packing Procedure

The reservoir material used for the experiments was obtained from the Primrose reservoir in the Clearwater formation, supplied by **Amoco Canada Petroleum Company (Amoco)**. The core matrix for Run 239 came from a depth of 476 to 496 m from a well located at 10-5-67 W4M. For the other three runs, the core matrix was produced sand from the surface treating facilities. Oil was extracted from the sand using a modified Soxhlet apparatus with toluene as the solvent. The extracted sand was then placed in an oven at 326°C for about sixteen hours to remove any residual hydrocarbons.

A X-ray diffraction analyses of the bulk and clay fraction of the extracted sand used in the different tests performed by the Department of Geology at the University of Calgary, is shown in **Table 3.1**.

The oil and brine came from a producing well at the field. **Amoco** supplied a 45 gallon drum of produced oil and a 30 gallon drum of produced brine to the University of Calgary. The produced oil contained about 25% free and emulsified water. The oil was cleaned by heating with toluene addition followed by centrifuging. Rotary evaporation removed the toluene. The brine was filtered through a Whatman #5 filter paper. Properties of the oil and brine used for the experiments are presented in **Table 3.2**. The solvent extraction procedure is regularly used by the *In-Situ* Combustion Analytical Group and follows the separation procedure described by Vorndran et al. (1980).

TABLE 3.1	PRIMROSE SAND COMPOSITION				
Rur	ר #	239	250	251	252
Bulk Fraction			Mass	%	
Quartz		26	57	57	57
Feldspar		63	33	33	33
Clays		11	11	11	11
Clay Fraction					
Montmorillonite		4	11	11	11 .
Chlorite		5	6	6	6
Illite		17	35	35	35
Kaolinite		50	48	48	48
Mixed		24		-	-

TABLE 3.2	OIL AND BRINE ANALYSIS		
Oil		Brine	
Ultimate Analysis	Mass %	Total Solids (mg/l)	8720
Carbon	83.66	Total Carbon (mg/l)	3550
Hydrogen	10.71	рН	8.72
Nitrogeń	0.58	Anions	mg/l
Sulphur	4.78	CO3	50
Density	g/cm <sup>3</sup>	HCO <sub>3</sub>	180
25°C	0.9953	CI	5300
Viscosity	mPa s	SO4	8
. 80°C	556	Cations	ˈ mg/l
95°C	236	К	110
110°C	107	Ca ·	50
Pseudo Components	Mass %	Na	4100
400°C Distillate	22.34	Mg	40
400°C Residue	56.06	Fe	<1
Asphaltenes	21.60		

The packing procedure consisted of manually tamping 50 g increments of dry extracted sand into the tube. Gravel packs using #16 mesh silica placed at both ends of the test material prevent fines from being pushed into the injection or production lines. This simple packing technique was successful in achieving dense, uniform packing.

On completion of the packing operation, the tube was sealed and the heaters and thermocouples mounted. The unit was tested for leaks at 1.2 MPa then insulated and inserted into the pressure jacket. In the annular space between the tube wall and the pressure vessel wall, a differential pressure of 2.1 MPa was imposed and the production end checked for any leakage from the annulus. A limiting differential value of 2.1 MPa was imposed because of the crushing of Primrose material at higher differential pressures. A vacuum was then applied and maintained for about fifty hours.

The pack was saturated with brine and the porosity and permeability calculated from the material balance and Darcy's law respectively. Oil was then forced into the sand pack from the injection end at a temperature of 80°C until breakthrough at the production end.

The creation of the restored state was accomplished successfully. Phase distributions inside the core approximated the fluid saturations found at reservoir conditions, while the porosity of the laboratory sand pack was higher than the reservoirs' porosity. The fluid saturations and other properties pertaining to the sand pack are presented in **Table 3.3**.

TABLE 3.3 INITIAL SAND PACK PROPERTIES				
Run #	239	250	251	252
Porosity (%)	37.3	37.4	37.4	37.8
Permeability (µm <sup>2</sup> )	2.4	2.5	4.2	2.3
Oil Saturation (%)	78.4	79.7	80.9	77.9
Water Saturation (%)	21.6	20.3	19.1	22.1
Gas Saturation (%)	0.0	0.0	0.0	0.0

The final step in preparing for a run involved the installation of the flow and instrumentation lines. The pressure vessel was placed in a vertical position with the injection end at the top. All connections were made, including all thermocouples and heater contacts, pressure tabs and injection and production lines. At this point the tube was ready for an experimental run.

## 3.2.2. Operating Procedure

At the start of the experiment the computer data acquisition and control programs were activated (see Belgrave, 1987, for program details). With the liquid saturated core at ambient conditions, the annulus was pressurized to 2.1 MPa using helium. The production valve on the core was opened to the production trap and the core was slowly heated to 90°C. The production valve was then closed and distilled water injected to bring pore pressure to 2.1 MPa. The production system was also pressurized using helium to 2.1 MPa. Next, the annulus pressure was increased with the use of helium, the core was pressurized by water injection,

and the pressure of the production system was increased. This same technique was followed to bring the annulus, core, and production system to the nominal test pressure. At this point the production valve on the core was opened.

Continuous water injection was initiated and continued at the design rate for several hours. The temperature was maintained at 90°C throughout the core and the back pressure kept at the designed level. The first signs of oil production were normally evident at this point.

The next phase of the test was the performance of superheated steam injection until steam breakthrough. The steam generator was activated and the heater temperature set at 50°C above saturation temperature. Distilled water was injected through the steam generator at the desired rate. Automatic control of a particular zone was turned from a set point mode to a differential control mode (ie. adiabatic operating mode). A differential temperature, of 1°C was kept on all zones as the steam front progresses.

On completion of the steam flood, the water injection was stopped, the zone closest to the injection end was placed on set point control at 400°C, and the remaining zones placed on set point control at 90°C. This procedure was modified on Run 252 were Zones 2 to 14 were set at 225°C and Zone 1 at 250°C.

Continuous injection of helium was initiated and enriched air injection commenced. The co-injection of helium and enriched air over this short period of time was performed to provide a gradual enrichment of the feed gas stream. As soon as combustion activity became evident, from the rapid increase of the centreline temperature in the ignition zone, the heater located at this zone was

converted from set point to differential mode using a centreline-wall temperature difference of 5°C. This procedure was repeated as the combustion front propagated through the core.

All throughout the run, temperature, pressure, flow rates, and other measurements were taken both manually and by the computer data acquisition system. At some designated time interval, temperature and pressure readings were recorded and printed. Produced liquids were bottled, labelled and weighed throughout the run.

Gas injection and production rates, and produced gas compositions were performed during the combustion portion of the experiment. In addition to these standard gas analyses, which were obtained using the Hewlett-Packard 5830 Process Gas Chromatograph, "GasTec Detector Tubes" were used to measure the concentrations of trace sulphur components.

The enriched-air injection was terminated when the high temperature front reached zone twelve of fourteen zones. Helium was once again injected through the core and when a rapid decrease in temperature was seen, the heater power was cut off. In some runs, helium was injected through the production line to dilute oxygen concentrations in the product gases. This procedure was followed to protect the production system from possible explosive mixtures of liquid hydrocarbons and oxygen. This process was continued until all system pressures were bled down to atmospheric conditions.

## 3.2.3 Core and Fluid Post Burn Analysis

A set of physical and chemical analysis was performed on the produced fluids and core material after a burn was terminated. After the system was depressurized, all process lines were disconnected and flushed with a solvent to remove any oil and water remaining in the system. The oil and water were accounted for so that a complete mass balance could be obtained on all phases.

The tube was unpacked in 8 to 12 cm sections. Each sample was visually inspected, weighed, and then packed in a plastic bag for further analysis.

Both the liquid production and the unpacked core material were extensively tested in the analytical laboratory. The liquid production samples were separated into oil and water phases by adding toluene, heating and stirring to remove any freewater present, and centrifuging at high speed (Vorndran et al. 1980). A Dean Stark procedure was performed to separate water from the mixture and the solvent diluted hydrocarbon was rotary evaporated to remove the toluene from the oil. Oil and water masses were determined and tabulated for each sample. The post-burned core extraction process results in solvent cleaned core, oil, toluene, and water. Oil and water samples were measured and analyzed. The solvent cleaned core was analyzed for non-toluene extractable hydrocarbons. The percent coke was calculated by determining the mass difference caused by firing each core sample at 600°C overnight at atmospheric pressure.

The produced oil from the liquid production and the core extraction was then analyzed. Density at 25°C, viscosity at three standard temperatures used by the

*In-Situ* Combustion Group (80, 95, and 110°C), and sulphur content were determined for each sample. The oil samples were split into pseudo-components, maltenes and asphaltenes, the separation determined by the solubility of the fraction in pentane. The maltenes fraction (pentane soluble) was subjected to simulated distillation analysis. Mass percent of all fractions was then determined.

Elemental carbon, hydrogen, and nitrogen (CHN) were not measured for some runs, due to problems with the apparatus.

The analysis of the produced water included total solids and total organic carbon content, pH, and cation and anion measurements.

#### 3.3 Experimental Runs

A laboratory program was followed to examine the combined effects of steam injection and *in-situ* combustion for thermal recovery of Primrose oil. This program was part of a larger study of various in-situ combustion tests which was funded by a consortium of **Canada's Department of Energy, Mines, and Resources** and by Industrial participants. As a part of this work, four experiments were performed following the experimental procedure detailed in **Section 3.2**. The study of the behaviour of combustion in steamflooded cores under various operating conditions was done with the aid of combustion tube experimental runs.

Test 239 was started at 11:00 (zero time), May 22, 1990 at a back pressure of 4.1 MPa and an overburden pressure of 6.2 MPa. The initial phase was a designed water flood at an injection rate of 111 ml/h with the core at 90°C. Water injection was initiated at a rate of 60 ml/h at 1.53 h. The water injection rate was increased to 111 ml/h at 1.90 h and to 222 ml/h at 3.00 h. Water injection continued at an average rate of 222 ml/h until 5.15 h. The inability to build-up pressure inside the core led to the increased water rate from the designed rate of 111 ml/h to 222 ml/h. **Table 3.4** provides the water injection history for the waterflood portion of this test.

TABLE 3.4	WATER INJECTION HISTORY (RUN 239)			
	Waterflood	Steamflood		
Time	Cumulative Water	Cumulative Water		
(h)	(grams)	(grams)		
1.53	65			
3.00	196			
5.00	643			
6.00	•	79		
. 9.00		546		
12.00		1201		
15.00		1866		
18.00		2516		
18.27		2572		

The next phase was the performance of a steamflood to near-residual oil saturation. It was intended to inject superheated steam at a back pressure of 4.1 MPa.

At 5.15 h the water-feed rate was decreased to 111 ml/h and the steam generator heater activated to a set point of 350°C (5.67 h). The temperature was

then decreased to 330°C at 5.88 h and to 310°C at 6.07 h. A restriction in the steam generator became apparent at this time. It was discovered that field brine instead of distilled water was being injected. The feed-water burette was drained and filled with distilled water and the steam generator temperature was lowered to 270°C in an attempt to flush the coil tube with subcooled water. Attempts to remove the restriction were unsuccessful. At 6.38 h the temperature was reset at 300°C and the water was bypassed around the heater coil and injected directly into the central bore of the steam generator block. The failure almost certainly caused saturated rather than superheated steam to be injected.

The water injection rate was increased from 111 ml/h to 222 ml/h at 7.27 h. With the steam generator set at 300°C the steambank was propagated through Zones 1-8 inclusive. The differential temperature setting of 5°C was decreased for all zones to 1°C at 11.10 h. With this differential setting, the steam generator temperature was increased to 320°C at 11.58 h and to 350°C at 11.77 h. The steam flood was continued until 18.27 h (05:16 May 23, 1990).

**Table 3.4** provides the water injection history for the steam flood portion of the test. The mass of water injected was 2572 g (3.28 pore volumes) at an average injection rate of 219 ml/h over the period from 9.00 to 18.27 h.

Helium was then injected at a flux of  $36.2 \text{ m}^3(\text{ST})/\text{m}^2\text{h}$  from 18.25 to 19.00 h and at a flux of  $21.63 \text{ m}^3(\text{ST})/\text{m}^2\text{h}$  from 19.00 to 19.50 h. Enriched air injection commenced at 18.67 h at a flux of  $13.09 \text{ m}^3(\text{ST})/\text{m}^2\text{h}$  until 24.43 h. At this time the enriched air injection was terminated and helium was once again injected

through the core until 26.73 h and the system bled down until 28.67 h (13:45 May 23, 1990).

**Table 3.5** presents a summary of the gas injection rates during the combustion phase of the experiment. Column 1 shows the times at which meter readings were taken. Column 2 gives the cumulative gas (helium plus enriched air) injection ( $m^3(ST)$ ) into the core. Column 3 summarizes the cumulative helium injection to the production system. The purpose of this stream is to ensure that the oxygen concentration in the production system never exceeds the nominal 21% level of normal air. The total injected gas, including the helium and enriched air injected through the inlet sand face, and diluent helium, is given on a cumulative basis in Column 4.

TABLE 3.5	GAS INJECTION HISTORY (RUN 239)			
Time	Cumulative Cumulative Gas Helium		Total Gas Injected	
(h)	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	
0.50	0.016	ັ0.00	0.016	
1.00	0.058	0.00	0.058	
3.00	0.128	0.00	0.128	
5.00	0.177	0.00	0.177	
7.00	0.226	0.023	0.249	
8.73	0.281	0.093	0.373	
10.67	0.281	0.093	0.373	

Test 250 was performed at 14:00 (zero time), April 9, 1991 at a back pressure of 6.2 MPa and an overburden pressure of 8.3 MPa. The initial phase was a designed water injection rate of 222 ml/h at a temperature of 90°C. Water injection was initiated at a rate of 60 ml/h at -0.72 h. The water injection rate was increased to 111 ml/h at 0.0 h and to 222 ml/h at 1.03 h. Water injection continued at an average rate of 218 ml/h until 3.00 h. **Table 3.6** provides the water injection history for the waterflood portion of this test.

TABLE 3.6	WATER INJECTION HISTORY (RUN 250)			
	Waterflood	Steamflood		
Time (h)	Cumulative Water Injected (grams)	Cumulative Water Injected (grams)		
1.00	195	· _		
2.00	420			
3.00	630			
4.00		180		
5.00		380		
6.00		600		
7.00		810		
<sup>`</sup> 8.00	· ·	1035		
9.00	• •	· 1271		

The next phase was the performance of a steamflood to near-residual oil condition. It was intended to inject superheated steam at a back pressure of 6.2 MPa.

At 3.00 h the water-feed rate was decreased to 111 ml/h and the steam generator heater activated to a set point of 350°C (3.53 h). The temperature was decreased to 330°C at 3.58 h and the injection rate increased to 222 ml/h.

The water injection rate was maintained at 222 ml/h while the steambank was propagated through the core. The steam flood continued until 9.00 h (23:00 April 9, 1991).

**Table 3.6** provides the water injection history for the steam flood portion of the test. The mass of water injected was 1271 g (1.73 pore volumes) at an average injection rate of 218 ml/h over the period from 3.00 to 9.00 h.

Helium was then injected at a flux of  $36.2 \text{ m}^3(\text{ST})/\text{m}^2\text{h}$  from 9.00 to 10.00 h. Enriched air injection commenced at 9.58 h at a flux of  $13.08 \text{ m}^3(\text{ST})/\text{m}^2\text{h}$  until 15.82 h. At this time the enriched air injection was terminated and helium was again injected through the core until 18.58 h and the system bled down until 19.00 h (9:35, April 10, 1991). Table 3.7 presents a summary of the gas injection rates during the combustion phase of the experiment.

Test 251 was performed at 4:00 (zero time), May 1, 1991 at a back pressure of 10.3 MPa and an overburden pressure of 11.0 MPa. The initial phase was a designed water injection rate of 222 ml/h at a temperature of 90°C. Water injection was initiated at a rate of 60 ml/h at -0.05 hours.

TABLE 3.7	GAS INJECTION HISTORY (RUN 250)			
Time	Cumulative Cumulative Gas Helium		Total Gas Injected	
(п)	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	
1.00	0.077	0.00	0.077	
2.00	0.102	0.00	0.102	
3.00	0.127	0.00	0.127	
5.00	0.176	0.00	0.176	
7.00	0.225	0.023	0.225	
9.00	0.273	0.093	0.273	
9.60	0.288	0.093	0.288	

The water injection rate was increased to 111 ml/h at 0.25 h and to 222 ml/h at 1.35 h. Water injection continued at an average rate of 218 ml/h until 3.50 h. **Table 3.8** provides the water injection history for the waterflood portion of this test.

TABLE 3.8	WATER INJECTION HISTORY (RUN 251)			
	Waterflood	Steamflood		
Time	Cumulative Water	Cumulative Water		
(h)	(grams)	(grams)		
0.50	140			
2.00	380			
3.50	695			
5.00	•	355		
7.00		790		
9.00		1255		
11.00		1705		
11.50		1821		

The next phase was the performance of a steamflood to near-residual oil saturation. It was intended to inject superheated steam at a back pressure of 10.3 MPa.

At 3.50 h the water-feed rate was decreased to 111 ml/h and the steam generator heater activated to a set point of 350°C (3.80 h). At 4.03 h the steam injection rate was increased to 222 ml/h until a high pressure drop developed. The injection rate was then decreased to 111 ml/h at 5.03 h and maintained at that level until 5.17 h when the 222 ml/h rate was re-established.

The water injection rate was maintained at 222 ml/h while the steambank was propagated through the core. A differential temperature of 1°C was kept for all zones. The steam flood was continued until 12.00 h (16:00 May 1, 1991).

**Table 3.8** provides the water injection history for the steam flood portion of the test. The mass of water injected was 1821 g (2.49 pore volumes) at an average injection rate of 222 ml/h over the period from 4.50 to 12.00 h.

Helium was then injected at a flux of  $36.2 \text{ m}^3(\text{ST})/\text{m}^2\text{h}$  from 12.02 to 13.12 h. Enriched air injection commenced at 12.60 h at a flux of  $13.08 \text{ m}^3(\text{ST})/\text{m}^2\text{h}$  until 18.45 h. At this time the enriched air injection was terminated and helium was again injected through the core until 21.62 h and the system bled down until 21.83 h (1:40, May 2, 1991). Table 3.9 presents a summary of the gas injection rates during the combustion phase of the experiment.

TABLE 3.9	GAS INJECTION HISTORY (RUN 251)			
Time	Cumulative Gas	Cumulative Total Helium Injec		
(h)	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	
0.50	0.033	0.00	0.033	
1.00	0.077	0.00	0.077	
3.00	0.134	0.00	0.134	
5.00	0.183	0.00	0.183	
7.00	0.235	.0.00	0.235	
8.00	0.259	0.013	0.272	
9.83	0.299	0.039	0.339	

Test 252 was performed at 11:00 (zero time) June 6, 1991 at a back pressure of 4.1 MPa and an overburden pressure of 6.2 MPa. The initial phase was a designed water injection rate of 222 ml/h at a temperature of 90°C. Water injection was initiated at a rate of 60 ml/h at 0.08 h. The water injection rate was increased to 111 ml/h at 1.9 h and to 222 ml/h at 0.50 h. Water injection continued at an average rate of 218 ml/h until 4.00 h. **Table 3.10** provides the water injection history for the waterflood portion of this test.

The next phase was the performance of a steamflood to near-residual oil condition. It was intended to inject superheated steam at a back pressure of 4.1 MPa.

TABLE 3.10	WATER INJECTION HISTORY (RUN 252)			
	Waterflood	Steamflood		
Time	Cumulative Water	Cumulative Water		
(h)	(grams)	(grams)		
1.00	105			
2.00	235			
3.00	435			
4.00	640			
5.00		110		
7.00		530		
9.00		980		
9.50		1085		

At 4.00 h the water-feed rate to the steam generator was decreased to 111 ml/h and the steam generator heater activated to a set point of 320°C (4.77 h).

The water injection rate was increased from 111 ml/h to 222 ml/h at 5.00 h and maintained at this level while the steambank was propagated through the core. A differential temperature of 1°C was kept for all zones. The steam flood was continued until 9.52 h (20:31 June 6, 1991).

**Table 3.10** provides the water injection history for the steam flood portion of the test. The mass of water injected was 1085 g (1.44 pore volumes) at an average injection rate of 219 ml/h over the period from 5.00 to 9.50 h.

Helium was then injected at a flux of 36.2  $m^3$ (ST)/ $m^2$ h from 9.50 to 11.55 h. Enriched air injection commenced at 10.77 h at a flux of 13.09  $m^3$ (ST)/ $m^2$ h until 15.02 h. At this time the enriched air injection was terminated and helium

was again injected through the core until 18.32 h and the system bled down until 19.00 h (6:00 June 7, 1991). **Table 3.11** presents a summary of the gas injection rates during the combustion phase of the experiment.

TABLE 3.11	GAS INJECTION HISTORY (RUN 252)			
Time	Cumulative Gas	Cumulative Cumulative Gas Helium		
(h)	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	
1.00	0.067	0.00	0.067	
2.00	0.153	0.00	0.153	
3.00	0.181	0.00	0.181	
5.00	0.230	0.00	0.230	
7.00	0.279	0.00	0.279	
8.82	0.323	0.00	0.323	
9.50	0.324	0.00	0.324	

#### **CHAPTER FOUR**

#### EXPERIMENTAL RESULTS

The experimental program developed a more complete understanding of heavy oil displacement mechanisms in the thermal recovery process and their dependence upon reservoir parameters and operating conditions. The experiments focused on the steamflood and the *in-situ* combustion processes in a combustion tube apparatus. The results of these processes, production of incremental oil after steamflooding, heat losses, and the possibility of sustaining a combustion front at low saturations are presented in this chapter.

As previously described in **Chapter Three**, all experimental tests involved three separate phases. Phase one consisted of a waterflood at 90°C, phase two involved a steamflood with the injection of superheated steam, and phase three was comprised of dry forward *in-situ* combustion injecting enriched air. A summary of the operating parameters is given in **Table 4.1**. The oxygen concentration and flux were modified from the proposed values due to a helium leak presented during the progression of the runs.

#### 4.1 Waterflooding

Phase one of each run involved the injection of formation water into a 90°C core. This injection pressured the tube to the desired level. After pressurizing the tube, the injection of water continued at a stabilized rate for three to four hours until about 1 pore volume (PV) of water had been injected. Cold oil and water production began after two hours of injecting water. This production, purely based

on the immiscible displacement of water displacing oil, produced large volumes of water with the oil. The enormous difference in the viscosity of the fluids at 90°C ( $\mu_0/\mu_W \approx 1600$ ) and its relationship to the mobility ratio between the displaced and the displacing fluid, (M≈120), produced this result.

TABLE 4.1	OPERA	ATING CONDITIONS		
Ru	n # 239	250	251	252
Back Pressure (MPa)	4.1	6.2	10.3	4.1
Annulus Pressure (MPa)	6.2	8.3	11.0	6.2
Water Injection Rate (ml/h)	222	222	222	222
O <sub>2</sub> Concentration (%)	76.55	76.55	11.50	22.00
O <sub>2</sub> Flux (m <sup>3</sup> /m <sup>2</sup> h)	12.47	12.47	12.60	12.53

Theory indicates that the oil recovery from a waterflood is a function of both the oil/water viscosity ratio at reservoir temperature and the relative permeabilities of the flowing phases (Dake 1978). **Table 4.2** presents the oil recovered as a percentage of the original oil in place (OOIP) at a specific quantity of water injected. The differences in oil recovery are due to variations on the relative permeability curves for both the oil and water and the absolute permeability to water (**Table 3.3**), and to the amount of water injected. Viscosity ratio was not a determining factor on the differences found on oil recovery for the different tests, due to the fact that the tests were conducted at the same core temperature.

TABLE 4.2 OIL RECOVERY (WATERFLOOD)									
Run #	Water Injected (PV)	Oil Recovery (% OOIP)	Sw (%)						
239	0.92	13	32						
250	0.87	6	25						
251	0.95	2	21						
252	0.85	16	34						

The displacement of very viscous oil by water is inefficient even at 90°C. The water tends to run more rapidly than the oil being displaced and, possibly, as separate fingers through the core. The ratio in viscosity of the displacing to the displaced fluid, and the direction of the displacement relative to gravity causes the higher water velocity and instability. With oils as heavy and viscous as Primrose oil, nearly all production comes with a large volume of water and occurs after water breakthrough.

The Buckley-Leverett Theory (1942) is used to describe and analyze the isothermal one-dimensional immiscible displacement of oil by water. The flow of water is assumed to occur as numerous fingers representing a linear relationship between the relative permeability and the saturations (see Section 4.3). The post-waterflood average water saturations were calculated using this theory and are presented on Table 4.2.

# 4.2 Steamflooding

Oil displacement during steamflooding is achieved through a number of complex heat and mass transfer mechanisms. **Figure 4.1** illustrates the variation of temperature and oil-water-steam concentrations against distance in a onedimensional displacement process. The oil is contacted first by cold water, then by hot water (condensate), and finally by the steam. The high recoveries that result from steam injection are the consequence of several mechanisms, principally the reduction of oil viscosity. Thermal expansion, steam distillation, gas-drive effects, and solvent extraction also contribute to the improved oil recovery.

A number of researchers have observed shifts in the relative permeability curves as temperature increases; usually representing enhanced oil recovery (Poston et al. 1970 and Weinbrandt et al. 1975). Shifts in the oil relative permeability at higher temperatures may increase oil recovery by reducing residual oil saturation. The relative permeability to the water tends to decrease due to the formation of emulsions, resulting in water being restrained by the slow moving oil (Butler 1991). In general, relative permeability shift effects appear to be important solely in the case of hot waterfloods or for steamfloods where significant recovery occurs ahead of the steam zone in the hot waterflooded region.

The laboratory experiments performed during this study were affected by the marked reduction in oil viscosity, thermal expansion, gas-water drives, and, possibly, by shifts in the relative permeability curves. Steam distillation and solvent

# FIGURE 4.1 ONE-DIMENSIONAL HYPOTHETICAL STEAMFLOOD







extraction were not considered to be significant as evidenced from the analysis of the produced oil.

### 4.2.1 Temperature Profiles

The propagation of the steam bank for each run is clearly illustrated in the stacked-temperature plots of **Figure 4.2** to **4.5**. The individual zone temperature profiles are presented with the injection zone (Zone 1) at the bottom and the production zone (Zone 14) at the top. The steam front leading edge is to the left of the elevated temperature region. **Table 4.3** presents the times and maximum temperatures observed during the steamflood phase for each experiment. For reference, the saturation temperatures at the absolute pressures are also presented. As expected for steamflood operations, the maximum temperatures are related to swings in the back pressure; therefore, a number of zones showed maximum temperatures at the same time.

These maximum temperatures would also be affected by helium leakage to the core which was the case for Run 252. The significant temperature change between Zones 6 and 7 is believed to relate to the existence of a helium leak at Thermocouple 6.

Comparison of the maximum temperature in each zone with the saturation temperature for each run suggests that high quality steam was not present throughout the core. For example, during Run 239 superheated steam swept Zones 1 to 7 inclusive, while saturated steam swept the remaining core. However,

# FIGURE 4.2 STACKED TEMPERATURE PROFILES



FIGURE 4.3 STACKED TEMPERATURE PROFILES



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(Run 250)

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# FIGURE 4.5 STACKED TEMPERATURE PROFILES



(Run 252)

TABLE 4.	3	MAXIMUM TEMPERATURE LOCATION								
	Run	239	Run 250		Run 251		Run 252			
Zone	Temperature (C)	Time (h)	Temperature (C)	Time (h)	Temperature (C)	Time (h)	Temperature (C)	Time (h)		
1	331	4.00	338	4.75	340	2.50	299	2.75		
2	282	3.50	318	5.75	328	1.50	274	3.75		
3	280	3.50	298	1.25	315	2.50	258	2.00		
4	280	3.50	299	1.25	318	2.50	259	2.00		
5	272	4.25	. 294	1.50	313	7.50	254	2.00		
6	267	4.75	288	1.75	312	7.50	254	2.00		
7	262	5.00	285	2.00	310	7.50	244	2.25		
8	254	9.25	279	2.25	305	7.75	239	2.50		
9	249	9.25	276	3.25	308	7.75	233	2.75		
10	251	9.75	276	5.50	300	7.75	230	2.75		
11	253	9.75	276 .	5.50	306	7.75	229	3.00		
12	252	9.75	278	5.50	293	7.75	227	3.00		
13	251	12.75	273	5.50	281	7.75	220	3.75		
14	249	12.75	242	5.50	230	7.75	220	3.75		
Saturation				_						
Temperatu	ire C 253		278.6 <sup>°</sup>		313.8		253			

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due to operational problems with the steam generator it was not possible to maintain the injection of superheated steam throughout the run, indicating that saturated steam swept the core during the latter part of the experiment.

Run 250 shows that Zones 1 to 7 were swept by superheated steam, Zone 8 by saturated steam, and the remainder of the core swept by condensate.

During Run 251 a more dramatic pattern was observed. Only Zones 1 and Zone 2 showed the presence of superheated steam flow, Zones 3 to 5 were swept by saturated steam, while the rest of the core was swept by water condensate. At high pressures, increased heat loss from the tube to the surrounding annulus, in addition to a lower enthalpy of vaporization, caused this pattern. Possible heat transfer mechanisms include conduction through the tube wall, heaters, and insulation, and natural convection in the annular region. Conduction appears not be a sizeable effect as noted from an absence of a radial temperature gradient.

Temperature readings from the centerline and wall thermocouples for all zones were almost identical. For the type of operational system used, heat transfer by natural convection in the annulus between the combustion tube and pressure vessel is caused by helium motion resulting from the variation of density with temperature. Hot helium near the tube wall is less dense than the helium in the centre of the annulus and tends to rise. Similarly, helium near the pressure vessel wall is cooler, and denser, than in the centre and tends to fall. Numerical studies demonstrate that such heat transfer mechanism occurs even with a 0°C

differential setting between the tube wall and centerline temperature readings (Belgrave and Moore 1992). These investigators indicated that the heat loss effects tend to increase with increasing pressure.

Run 252 showed a significant decrease in temperature towards the end of the run. The decrease occurred from Zones 7 to 14 due to a helium leak from the annulus through to the Zone 6 thermocouple. Superheated steam swept Zones 1 to 4, high quality saturated steam swept Zones 5 and 6, and a mixture of steam, water, and a non-condensable gas swept Zones 7 to 14. The lower steam partial pressure caused the saturation temperature in these lasts zones to be lower than the initial saturation temperature.

The steam front rate of advancement for all runs was calculated from the thermocouple temperature responses at different locations. **Figure 4.6** (Run 239) presents the location of the leading edge of the steamfront as defined by the 225°C temperature level. Based on the slopes of the best fit solid lines shown in this figure, the front average velocity was 0.190 m/h for the time interval between 2.6 and 4.6 h, and 0.242 m/h for the period from 6.4 to 7.6 h. Changes in the operating procedure for Run 239, due to the steam generator blockage, caused the appearance of two different steam front velocities. A similar analysis was performed for all the runs and the calculated average velocities follow:


Run #	Time Interval (h)	Front Velocity (m/h)	Leading Edge Temperature
239	2.6 - 4.6	0.190	225°C
	6.4 - 7.6	0.242	225°C
250	0.7 - 2.0	0.430	250°C
	2.0 - 4.7	0.144	250°C
251	0.2 - 3.4	0.167	250°C
	5.0 - 6.5	0.144	250°C
252	1.0 - 3.0	0.398	225°C

The front velocity changes observed during the progression of Run 250 and 251 may be explained by energy transfer phenomena coupled with the thermodynamic state of the steam at nominal test pressures. Following is a brief discussion of this phenomena.

Heat losses have the effect of reducing the energy available to advance the front, while reducing the quality of the flowing steam. This effect varies with time due to the increasing size of the steam zone. Heat losses are relatively small at the start of the steam injection process because of a concise area for heat to be transferred. As the steam injection progresses and the steam zone grows, the rate of heat loss increases and a smaller fraction of the injected energy is available to advance the front. In addition, as latent heat of vaporization decreases with increasing pressure, less energy is available for heat front advancement. Furthermore, as time elapses more energy is carried forward by the condensed water in the form of sensible heat, resulting in an increased convective heat

transfer. Injectivity problems during Run 251 also had an effect on the rate of advancement of the front in the early stages of the run.

The retardation of the steam front can be seen by a thorough observation of the axial temperature profiles at different times (**Figure 4.7** to **4.10**). At the start of each run the temperature at the shock front (leading edge) declines sharply. As time elapses and the above mentioned effects become more pronounced, condensation occurs and the sharp front tends to spread out slowing down the advancement of the front. A small decline in temperature in the swept zone is also noticed. This temperature reduction is mainly due to the decline in pressure as the run progresses. The pressure drop across the tube is reduced as the saturation of steam increases and its ease to flow through the core increases.

The time required for the production end temperature to reach the saturation temperature is defined as the steam breakthrough time. Steam breakthrough time for Run 239, 250, and 252 was 9 h, 6 h, and 4 h respectively. Even though operating conditions for Run 239 and 252 were the same, the much longer breakthrough time experienced during Run 239 was due to the operational disturbances encountered during the first few hours of steam injection. It is of interest to note, by observation of the temperatures profiles presented in **Figure 4.9** that, due to the premature termination of steam injection, it was not possible to propagate the steamfront through the complete core length during Run 251.



## FIGURE 4.8 AXIAL TEMPERATURE PROFILES RUN 250





FIGURE 4.10 AXIAL TEMPERATURE PROFILES RUN 252



## 4.2.2 Oil Recovery by Steamflood

A summation of results for the steamflooding phase appears in **Table 4.4**. The average back pressure and saturation temperature are presented in columns 2 and 3 respectively. The post-waterflood oil and water saturations are given in the next two columns (Soi, Swi). The oil recovery presented in column 6 refers to the amount of oil produced as a percentage of the original oil in place (% OOIP). The pore volumes of steam injected measured as water are listed in the last column.

**Figure 4.11** illustrates the oil recovery against the pore volumes of steam injected (cold water equivalent). Pressure, the varying parameter, has a marked effect on the time required to produce a certain amount of oil, the total oil recovery, saturation temperature, and, as discussed in **Section 4.2.1**, the time for steam breakthrough.

TABLE 4.4		SUMMARY	OF S	OF STEAMFLOOD RESULTS			
Run #	Pressure (MPa)	Saturation Temperature (°C)	Soi (%)	Swi (%)	Oil Recovery (% OOIP)	PV Injected (cwe)	
239	4.4	256	68	32	56	3.54	
250	6.2	278	75	25	39	1.75	
251	10.53	316	79	21	41	2.45	
252	4.1	252	66	34	49	1.44	

The higher saturation temperature for Runs 250 and 251 as compared to Runs 239 and 252, caused an additional oil viscosity decrease, improving oil mobility through the core. However, the lower pressure runs, for the same amount of steam injection, produced a higher oil recovery. The higher pressure runs demanded more energy to raise the temperature of the core and its saturating fluids to the saturation temperature. Furthermore, the amount of latent energy injected per unit mass, (**Table 4.5**), decreased as the pressure increased. The lower enthalpy of evaporation results in less energy available to support the increasing heat losses as time elapses. These effects tend to overshadow the benefits of a higher saturation temperature, and to prolong the time for steam breakthrough.



FIGURE 4.11 OIL RECOVERY (Steamflood)

TABLE 4.5	ENERGY INPUT DURING STEAMFLOODING					
Run #	Pressure	Temperature	Enthalpy of			
	(MPa)	(°C)	(kJ/kg)			
239	4.4	256	1681.9			
250	6.2	278	1557.5			
251	10.53	316	1279.3			
252	4.1	252	1704.4			

The oil recovery at steam breakthrough was calculated for all runs except Run 251. Run 239 had an oil recovery of 46% of the oil in place. Run 252 performed at the same pressure, gave a recovery of 44%. Even though oil recoveries for these two runs were very similar, the time for producing this amount of oil differed significantly. Thirty-nine per cent of the oil in place was recovered at steam breakthrough for Run 250. At the time when steam injection was terminated for Run 251, 41% of the oil in place was recovered.

Run 252's higher oil production is due mainly to the large volumes of helium injected which notably increased the gas drive effects and induced a multiphase displacement pattern. Three different phases, (helium and steam, water, and oil) probably occurred downstream of the location of the helium leak. The lower temperatures observed after 2 h of steam injection (**Figure 4.10**) were the result of a lower bubble point temperature associated with the presence of the non-condensible gas.

Finally, the total oil recoveries given in **Table 4.4** can be seen as the consequence of several different mechanisms. In addition to the oil viscosity reduction, large steam volumes enhance oil recovery. Steam contains less energy

per unit volume than water, requiring larger volumes to heat a reservoir. These larger volumes more effectively displace oil from the heated zone. A simultaneous gas water drive is also taking place in the steam zone, displacing oil to the production end. Steam temperature and the amount of displacing fluid contacting the oil affects the non-distillable oil recovery. However, if vaporization should occur, the oil recovery would increase proportionally to the fraction of distillable oil present at the saturation temperature.

It is useful to present the recovery curves not only as a function of the mass of water injected but also as function of the total liquid produced (oil plus water). Figure 4.12 shows the effect of the steamflooding process on the oil recovery as a function of the produced fluids in a liquid state at the initial core temperature.





An oil bank was formed as evident by its arrival after 0.5 PV of produced water. This oil bank formation is marked by a sharp increase in the oil recovery rate.

**Tables 4.6 to 4.9** present the liquid production history for the water and steamflood phases. Times presented are based on the waterflood zero time (see **Section 3.3**). Based on the initial oil in place in the core and correcting for the initial oil in the lines (46.5 g), 69% of the oil in the core was recovered during Run 239. Run 250, 251, and 252 showed recoveries of 48, 43, and 65% respectively.

A noticeable amount of oil was produced after steam breakthrough during Run 239 and Run 252. For the other two runs, the steam injection was terminated at (Run 250) or prior to (Run 251) steam breakthrough; hence, no clear conclusion can be drawn regarding oil production after steam breakthrough.

The cumulative oil recovered illustrates the efficiency of the steamflood as compared to the waterflood (**Figures 4.13** to **4.16**). For Run 239 an oil bank was observed at 2.8 h after the start of steam injection with oil breakthrough (based on the produced oil to produced water ratio) occurring at 7.8 h. Run 250 showed oil breakthrough at 5 h with a high oil production rate lasting until 7 h. During Run 251 an oil bank effect was noticeable at 6 h. An increase in the oil production rate appears at 6.42 h and again at 10.13 h. The spread out condensation zone possibly influenced Run 251's retarded oil production. Throughout Run 252, the gas drive effect produced by the helium leak induced a steady rate of oil production without any existence of an oil bank.

Time	Oil	Cumulative	Wator				
(h)	(9)	Oil (g)	(g)	Cumulative Water (g)	WOR	Free Water (%)	Water in Oil (%)
2.83 3.30 3.72 4.15 4.50	42.34 26.40 12.61 12.27 12.05	42.34 68.74 81.35 93.62 105.67 117.86	16.06 40.50 64.09 92.83 55.05	16.06 56.56 120.65 213.48 268.53	0.38 1.53 5.08 7.57 4.57	0.00 41.32 73.89 78.53 71.46	27.50 32.76 37.04 45.61 37.08
5.98 6.87 7.80 8.37 9.00	10.10 13.78 37.53 27.13 29.62	127.96 141.74 179.27 206.40 236.02	138.50 115.92 14.47 73.47 118 18	534.84 650.76 665.23 738.70 856.88	13.71 8.41 0.39 2.71	88.23 84.03 0.00 62.96 73.00	41.62 42.25 33.46 27.83 27.19
9.77 10.35 11.00 11.70 12.47	30.56 58.87 25.99 8.97 11.46	266.58 325.45 351.44 360.41 371.87	169.54 123.03 131.51 141.53 170.44	1026.42 1149.45 1280.96 1422.49 1592.93	5.55 2.09 5.06 15.78 14.87	79.72 58.38 77.08 89.32 89.20	24.69 22.23 28.01 44.22 41.68
13.28 14.30 14.83 15.82 16.57 17.78	4.89 3.83 16.29 8.72 16.62 12.69	376.76 380.59 396.88 405.60 422.22 434.91	167.71 207.67 170.41 176.08 212.18 289.61	1760.64 1968.31 2138.72 2314.80 2526.98 2816.59	34.30 54.22 10.46 20.19 12.77 22.82	94.17 96.73 85.55 88.66 86.09 91.58	51.39 44.57 39.60 58.38 47.77 50.14

TABLE	4.7	PRODUCTION HISTORY (RUN 250)					
Time	Oil	Cumulative Oil	Water	Cumulative Water	WOR	Free Water	Water in Oil
<u>(n)</u>	<u>(g)</u>	(9)	(9)	(g)		(%)	(%)
1.08	24.8	24.8	12.8	12.75	0.52	0.00	34.00
1.67	21.0	45.7	76.0	88.78	3.63	67.61	33.26
2.17	19.1	64.8	76.9	165.67	4.02	69.70	34.31
2.75	16.1	81.0	102.0	267.64 `	6.32	78.65	36.04
3.58	16.0	96.9	129.2	396.86	8.09	81.77	39.63
4.08	7.4	104.3	106.3	503.17	14.39	88.81	41.90
4.42	12.7	117.0	150.4	653.59	11.86	87.75	36.54
5.00	26.6	143.6	121.7	775.33	4.58	73.92	31.32
5.58	40.8	184.4	101.7	877.05	2.49	61.13	26.38
7.05	76.6	261.0	315.1	1192.15	4.11	74.41	23.58
9.00	42.1	303.0	372.2	1564.39	8.85	84.54	0.00

TABLE	E 4.8 PRODUCTION HISTORY (RUN 251)						
Time	Oil	Cumulative Oil	Water	Cumulative Water	WOR	Free Water	Water in Oil
<u>(n)</u>	<u>(g)</u>	<u>(g)</u>	(g)	(g)	`````	(%)	(%)
2.08 3.40	8.8 5.5	8.8 14.3	67.2 138.8	67.2 206.0	7.64 25.24	77.63 92.45	48.24 49.54
4.25	14.9 0.0	29.2 29.2	153.4 83.0	359.4	10.30 N/A	87.11	31.34
5.20 5.97	9.7 0.0	38.9 38.9	160.0 83.1	602.4 685.5	16.49 N/A	91.04	36.18
6.05	31.9 42.8	70.8	65.5 61 8	751.0	2.05	54.00	28.79
6.82	0.0	113.6	77.9	890.7	N/A	42.35 100	29.02 N/A
7.92	36.0	208.4	134.9	1149.0	3.75	56.64 70.39	25.57 28.85
10.13	0.0 70.1	208.4 278.5	163.6 276.7	1312.6 1589.3	N/A 3.95	100 65.68	N/A 29.63
.11.00	0.0 8.5	278.5 287.0	99.4 157.4	1688.7 1846.1	N/A 18.52	100.00 86.26	N/A 62.72
11.90	19.6	298.1	208.8	1897.5	10.65	86.65	35.74

TABLE	BLE 4.9 PRODUCTION HISTORY (RUN 252)						
Time	Oil (a)	Cumulative Oil (a)	Water	Cumulative Water	WOR	Free Water	Water In Oil
<u>_</u>	(9)	(9)	(9)	<u>(9)</u>		(%)	(%)
1.67 3.33	9.2 81.0	55.2 136.2	4.0 109.0	. 4.0 113.0	0.07 1.34	0.00 50.82	6.77 13.29
4.20 4.92 6.87 8.62	30.2 58.4 58.8 108.6	166.4 224.9 283.6 392.2	163.7 103.9 433.8 355.4	276.7 380.5 814.4 1169.8	5.42 1.78 7.38 3.27	79.66 56.18 83.15 68.57	23.36 17.86 29.20 25.55
9.70	31.7	423.9	294.1	1463.9	9.27	85.26	33.96

# FIGURE 4.13 PRODUCTION HISTORY



FIGURE 4.14 PRODUCTION HISTORY RUN 250



## FIGURE 4.15 PRODUCTION HISTORY RUN 251



In most runs, the oil bank was followed by an increase in water production. Usually, an extra amount of oil was produced during this period of time in the form of emulsions. The last column in **Tables 4.6-4.9** presents the percentage of oil in the emulsified water. Run 239 presented the highest fraction of water in oil while Run 252 presented the lowest. Run 239's higher values possibly relate to the extended steam injection time due to the operational problems with the steam generator. The lower operating pressure during Run 252 in comparison to Run 250 and 251, had an effect of reducing the amount of emulsions. In any case, the emulsions produced during the steamflood were harder to break than those produced by the cold waterdrive.

#### 4.3 Theoretical Results

Analytical models have been developed to aid the understanding of the different mechanisms involved during thermal recovery processes. These models are of great value for making first estimates of the performance of the process and as a starting point to a more comprehensive study using numerical methods. In many cases, inaccurate input data and the complexity and cost inherent with numerical models, justify the use of simpler analytical models. This section presents an analytical approach utilizing the Buckley-Leverett shock front theory, (1942), to calculate saturation distributions in the steam zone and in the colder zone ahead of the steam front.

The one-dimensional displacement of oil by water and by steam will be considered in the analytical model. Within the steam zone, the model allows for an isothermal displacement of oil by steam. Beyond this zone, the oil and water flow through the porous medium contacting the colder portion of the reservoir. Between these two regions lies the advancing condensation front, the position of which is determined by heat balance considerations.

## 4.3.1 The Buckley-Leverett Displacement Theory

In 1942 Buckley-Leverett presented what is recognised as the basic equation for describing the one-dimensional immiscible displacement (Dake 1978). For water displacing oil, the equation determines the velocity of a plane of constant water saturation travelling through a linear porous system. The conservation of mass of water flowing through a volume element  $A\phi dx^1$  may be expressed as

Mass flow rate Rate of increase of mass  
In - Out in the volume element  

$$q_{\mu}\rho_{\mu}|_{x} - q_{\mu}\rho_{\mu}|_{y} + = A\phi dx \frac{\partial}{\partial}(\rho_{\mu}S_{\mu})$$
 (4.3.1)

∂t

or

$$q_{w}\rho_{w}|_{x} - (q_{w}\rho_{w})|_{x} + \frac{\sigma}{\partial x}(q_{w}\rho_{w})dx) = A\phi dx \frac{\sigma}{\partial t}(\rho_{w}S_{w}) \qquad (4.3.2)$$

<sup>1</sup> All symbols are defined in the nomenclature section.

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which can be reduced to

$$\frac{\partial}{\partial x}(\boldsymbol{q}_{w}\boldsymbol{\rho}_{w}) = -\boldsymbol{A}\boldsymbol{\varphi}\frac{\partial}{\partial t}(\boldsymbol{\rho}_{w}\boldsymbol{S}_{w}) \qquad (4.3.3)$$

and for the assumption of incompressible displacement

$$\frac{\partial \boldsymbol{q}_{w}}{\partial \boldsymbol{x}}\big|_{t} = -\boldsymbol{A}\boldsymbol{\phi}\frac{\partial \boldsymbol{S}_{w}}{\partial t}\big|_{\boldsymbol{x}}$$
(4.3.4)

The full differential of the water saturation is

$$dS_{w} = \frac{\partial S_{w}}{\partial x} |_{t} dx + \frac{\partial S_{w}}{\partial t} |_{x} dt \qquad (4.3.5)$$

and since it is the intention to study the movement of a plane of constant water saturation, that is,  $dS_w = 0$ , then

$$\frac{\partial S_{w}}{\partial t}\Big|_{x} = -\frac{\partial S_{w}}{\partial x}\Big|_{t}\frac{dx}{dt}\Big|_{S_{w}}$$
(4.3.6)

Furthermore,

$$\frac{\partial \boldsymbol{q}_{\boldsymbol{w}}}{\partial \boldsymbol{x}}\big|_{t} = \left(\frac{\partial \boldsymbol{q}_{\boldsymbol{w}}}{\partial \boldsymbol{S}_{\boldsymbol{w}}} \cdot \frac{\partial \boldsymbol{S}_{\boldsymbol{w}}}{\partial \boldsymbol{x}}\right)_{t}$$
(4.3.7)

and substituting equations 4.3.6 and 4.3.7 into 4.3.4 gives

$$\frac{\partial \boldsymbol{q}_{w}}{\partial \boldsymbol{S}_{w}}|_{t} = \boldsymbol{A}\boldsymbol{\Phi}\frac{d\boldsymbol{x}}{dt}|_{\boldsymbol{S}_{w}}$$
(4.3.8)

Again, for incompressible displacement of all flowing fluids,  $q_t$  is constant (rate of water injection ( $q_t = q_j$ ) and, since  $q_w = q_t f_w$  (evaluated at x), equation 4.3.8 may be expressed as

$$\mathbf{v}_{S_{w}} = \frac{dx}{dt} |_{Sw} = \frac{q_{t}}{A\phi} \frac{df_{W}}{dS_{w}} |_{S_{w}}^{\cdot}$$
(4.3.9)

This is the Buckley-Leverett equation which implies that the velocity of a plane of constant water saturation is directly proportional to the derivative of the fractional flow equation evaluated for that saturation. Integrating for the total time since the start of injection gives

$$x_{S_w} = \frac{1}{A\varphi} \frac{df_w}{dS_w} \int_0^t q_t dt$$

or

$$\boldsymbol{X}_{\boldsymbol{S}_{\boldsymbol{w}}} = \frac{\boldsymbol{W}_{i}}{\boldsymbol{A}\boldsymbol{\Phi}} \frac{\boldsymbol{d}\boldsymbol{f}_{\boldsymbol{w}}}{\boldsymbol{d}\boldsymbol{S}_{\boldsymbol{w}}} |_{\boldsymbol{S}_{\boldsymbol{w}}}$$
(4.3.10)

where  $W_i$  is the cumulative volume of water injected and it is assumed, as an initial condition, that  $W_i = 0$  when t = 0. When  $x_{Sw}$  equals *L*, the total length of the reservoir, water breakthrough occurs. The total water injected to this time can be found from equation 4.3.11, which is a rearranged form of 4.3.10

$$W_i = \frac{A \Phi L}{df_w / dS_w}$$

or

$$N_{BT} = \frac{1}{df_{wL}/dS_{wL}}$$
(4.3.11)

where  $N_{BT}$  is the number of pore volumes of injected water at breakthrough.

In 1952, Welge presented a technique for calculating the oil recovery as a function of water injection and time (Dake 1978). At some time after breakthrough, the average water saturation over the length L will be given by equation 4.3.12, which can be integrated by parts, i.e.

$$\int u dv = uv - \int v du$$

$$\overline{S_{w}} = \frac{1}{L} \int_{0}^{L} S_{w} dx = \frac{1}{L} \{ |xS_{w}|_{0}^{L} - \int_{1-S_{ro}}^{S_{wL}} x dS_{w} \}$$
(4.3.12)

Substitution of  $xdS_w$  from equation 4.3.10 into 4.3.12 and integrating gives

$$\overline{S_w} = S_{wL} + \frac{W_l}{A \phi L} (1 - f_{wL}) \qquad (4.3.13)^2$$

Rearranging,

 $\overline{S_w} = S_{wL} + \frac{1 - f_{wL}}{df_{wL}} dS_{wL}$ 

or,

$$\frac{df_{wL}}{dS_{wL}} = \frac{1 - f_{wL}}{\overline{S_w} - S_{wL}}$$
(4.3.14)

The displacement of oil by steam has been described quantitatively using the Buckley-Leverett Theory in the same manner as has been described for waterflooding. In order to correctly use this approach, a number of approximations and assumptions must be made. The method described here follows that of Butler (1991) and considers only injection of 100 percent quality steam, assumes no lateral heat losses, and neglects any hydrocarbon vaporization. It also assumes that the temperature of the solid is equal to the fluid temperature at any point, fluid velocities are uniform across the section, and that thermal conduction can be ignored. For the steamflooding case, the number of pore volumes of steam (measured as vapour) injected is equal to  $1/(df_S/dS_S)$  at any particular time. (analogous to equation 4.3.11) The corresponding volume of steam remaining in the steam zone can be calculated by the following equation. (Butler 1991)

$$\frac{V_{s}}{V_{inj(s)}} = \int_{S_{s}}^{1-S_{n0}-S_{mi}} \frac{df_{s}}{dS_{s}} dS_{s} + \frac{df_{s}}{dS_{s}} S_{s} = 1 - f_{s} + \frac{df_{s}}{dS_{s}} S_{s}$$
(4.3.15)

The volume of water in the steam zone is equal to

$$\frac{V_w}{V_{inj(s)}} = S_{wi} \frac{df_s}{dS_s}$$
(4.3.16)

The quantity of oil remaining in the steam swept zone is

$$\frac{V_o}{V_{inl(s)}} = \frac{df_s}{dS_s}S_o - 1 + f_s \tag{4.3.17}$$

with the corresponding rock matrix volume equal to

$$\frac{V_R}{V_{inl(s)}} = \frac{1-\phi}{\phi} \frac{df_s}{dS_s}$$
(4.3.18)

where  $V_{inj(s)}$  is the volume of steam injected.

The fractional oil recovery can be deducted from these set of equations, and is given by

$$Recovery = \frac{1 - f_s + \frac{df_s}{dS_s}S_s}{\frac{df_s}{dS_s}(1 - S_w)}$$
(4.3.19)

The position of the condensation front is determined by an energy balance. This balance is determined by equating the total energy content of the steam chamber to the energy supplied by the condensing steam. Equation 4.3.20 presents the energy balance, based on a unit volume of steam injected. The heat content terms  $H_j$  are measured above the initial core temperature.

$$H_{s} = (1 - f_{s} + \frac{df_{s}}{dS_{s}}S_{s})H_{s} + S_{wf}\frac{df_{s}}{dS_{s}}H_{w}$$

$$+ (\frac{df_{s}}{dS_{s}}S_{o} - 1 + f_{s})H_{o} + \frac{1 - \phi}{\phi}\frac{df_{s}}{dS_{s}}H_{R}$$

$$(4.3.20)$$

### 4.3.2 Analysis and Results

The manner is which the preceding equations are used to analyze the one dimensional displacement process of oil by water and steam is described by Dake (1978) and Butler (1991).

The fractional flow of water is calculated using the following equation:

$$f_{w} = \frac{q_{w}}{q_{o}+q_{w}} = \frac{q_{w}}{q_{t}}$$

$$= \frac{1 + \frac{kk_{ro}A}{q_{t}\mu_{o}} \left(\frac{\partial P_{c}}{\partial x} - \Delta \rho g \sin\theta\right)}{1 + \frac{\mu_{w}k_{ro}}{k_{rw}\mu_{o}}}$$
(4.3.21)

For the waterflood phase of the analysis, the relative permeabilities are considered to be linear functions of saturation, (Leverett 1939 and Butler 1991)

$$k_{ro} = k_{ro}^* \left[ \frac{1 - S_{ro} - S_w}{1 - S_{ro} - S_{wl}} \right]$$

and

$$k_{rw} = k_{rw}^* \left[ \frac{S_w - S_{wi}}{1 - S_{ro} - S_{wi}} \right]$$

where  $k_{ro}^{*}$  is defined as the relative permeability to oil at irreducible water saturation ( $S_{wi}$ ) and  $k_{rw}^{*}$  is defined as the relative permeability to water at  $S_{w}$  = 1 - $S_{ro}$  ( $S_{ro}$  = waterflooding residual oil saturation).

For the purpose of the steam flood analysis, the relative permeabilities for the oil and steam are expressed by the following equations: (Butler 1991)

$$k_{ro} = k'_{ro} \left[ \frac{S_o - S_{ro}}{1 - S_{ro} - S_{wi}} \right]^n$$

and

$$k_{rs} = k'_{rs} \left[ \frac{S_s}{1 - S_{ro} - S_{wi}} \right]^n$$

where  $S_s = 1 - S_w - S_o$ ,  $K_{ro}$  is the relative permeability at  $S_{wi}$  and  $K_{rs}$  is the relative permeability to steam at  $S_s = 1 - S_{ro} - S_{wi}$  ( $S_{ro}$  = steamflooding residual saturation), and *n* is the saturation exponent. For an adiabatic, one dimensional steamflood, where steam is injected as dry saturated vapour, the fractional flow curve for the steam is represented by

$$f_{s} = \frac{1 + \frac{kk_{ro}A}{q_{t}\mu_{o}} \left(\frac{\partial P_{c}}{\partial x} - \Delta \rho g \sin\theta\right)}{1 + \frac{\mu_{s}k'_{ro}}{k'_{rs}\mu_{o}} \left(\frac{1 - S_{s} - S_{w} - S_{ro}}{S_{s}}\right)^{n}}$$
(4.3.22)

To better represent the behaviour observed during the experiments, the heat loss effect upon oil recovery has been incorporated into the calculations by assuming that wet steam instead of dry steam displaces the oil. In order to adequately apply the Buckley-Leverett theory, the combined water and steam phases are treated as a single component.

The solution to the problem is obtained by means of a tabular calculation using a spreadsheet program. The "history" of the experiments (i.e. fluid production and temperature as a function of time) is matched by varying the endpoint relative permeability, saturation exponent, steam quality, and amount of energy available to advance the condensation front.

**Table 4.10** presents the results obtained for the waterflood phase of the experiments. The calculated and observed oil recovery values, as a function of pore volumes of water injected, are presented. Average water saturations after the waterflooding are also shown. The match was obtained relatively easily by modifying the endpoint relative permeabilities.

Modelling of Run 252 was not possible by means of this theory. The gas drive effects induced by the helium leak determined a different displacement mechanism. The average water saturation was calculated by material balance considerations.

	TABLE 4.10	OIL RECO	VERY (WAT	rerflood)	
Run #	Endpoint <sup>k</sup> ro <sup>k</sup> rw	Water Injected (PV)	Oil Re Observed (% (	ecovery I Calculated OOIP)	Sw (%)
239	0.9 0.64	0.92	13	13	32
250	1.0 0.6	0.87	6	6	25
251	1.0 1.0	0.95	2	2	21
252	0.87 0.3	0.85	16	Not done	34

Mass balance

The analysis of the steamflooding phase presented some difficulty in matching calculated values to observed data due to the following reasons:

a) Operational problems with the steam generator during Run 239

produced an unknown steam condition at the injection end of the core and prolonged the steam injection phase of the experiment.

b) An additional gas phase (due to the helium leak) appeared in the displacement process of Run 252 and was not accounted for within the existing relative permeability data.

c) The high pressure runs presented unexpectedly high heat losses. As the model assumes that the volumetric velocity of the injected fluid is constant, it could not adjust for the unsteady velocity caused by high heat losses.

Despite these difficulties, the calculation of the saturations in the core was pursued. The effect of condensation on steam and water saturations was approximated by calculating the flowing volumes of water and steam as if they had achieved an average velocity with no condensation occurring.

**Table 4.11** presents the parameters used in the calculations. The endpoint relative permeabilities, residual oil saturation after steamflooding, steam quality, and the saturation exponent, which best fitted the observed values, are presented.

TABLE 4.11		HISTOR	-			
Run #	Endpoint <sup>k</sup> ro	Endpoint <sup>k</sup> rw	Endpoint <sup>k</sup> rs	Sro	Steam Quality	Saturation Exponent
239	0.9	0.64	0.82	0.15	75	1
250	1.0	0.6	1.0	0.15	50	1
251	1.0	1.0	1.0	0.15	30	1
252 *	0.87	0.3	0.8	0.15	95	1

Approximate values due to helium leak

**Table 4.12** compares the calculated results with the data obtained from the laboratory experiment. It was possible to match calculated oil recovery with the observed recovery by modifying the average steam quality. This modification was performed to adjust for the effects of the heat losses on the quality of the steam. The heat losses reduce the quality of the steam and reduce the energy available to advance the steam front. The calculated average saturations remaining in the steam swept zone are presented in **Table 4.13**.

TABLE 4.12	CALCULATE	D AND OBSER	VED STEAMFLC	OOD RESULTS
Run #	Average Quality Calculated (%)	PV Injected (cwe)	Oil Recovery Observed (% OOIP)	Oil Recovery Calculated (% OOIP)
239	75	3.54	56	55
250	50	1.75	39	40
251	30	2.45	41	42
252	95	1.44	49	49

TABLE 4.13 CALCULATED SATURATIONS IN THE SWEPT ZONE							
Run #	steam br	eakthrough	end of steamflood				
	PV Injected (cwe)	Oil Saturation	PV Injected (cwe)	Oil Saturation			
239	2.3	31.2	3.54	23.12			
250	1.75	43.5	1.75	43.5			
251	2.45	45.6	2.48	45.6			
252	1.0	36.3	1.44	26.4			

The average steam quality was used to calculate these saturations and the effect of pressure can be noticed in the higher saturations obtained. At the higher pressure, the steam occupies less volume and therefore displaces less oil. As well, as pressure increase, thermal effects result in a lower enthalpy of vaporization which increases the amount of steam required to raise the core temperature to the steam saturation level.

The following features arise from the above analysis:

- Steam was less effective in mobilizing oil at the higher pressures due to the shrinking of the steam, and to the lower thermal efficiency. A much larger volume of steam, measured as cold water equivalent, is required to sweep one core pore volume.

- For the higher pressure runs, a greater fraction of the oil recovery is from the hot waterflooded region just ahead of the condensation front. Relative permeability variations could more significantly affect the oil recovery.

- An initial mobile water saturation causes a delay in oil production. About 0.5 PV of vapour, measured as cold water equivalent, must be injected before the production of oil. This phenomena relates to the viscosity of the flowing phases (water and oil) through the colder region. Water, with a much lower viscosity, has a greater mobility and is produced first. In the model, this phenomena is accounted for by use of an average shock front velocity for each of the two isothermal zones (cold waterflood region and steam region).

- Zone 1 closest to the injection end of the core saw the passage of many

pore volumes of steam. The effectiveness of these large volumes of steam in displacing oil, provoked a low oil saturation in this zone. The residual oil saturation, representative of this zone, was calculated to be 15%. This zone will be used for as the ignition zone during the in-situ combustion phase of the experiments.

It was of interest to quantify the residual saturation at the inlet zone (first zone exposed to the enriched-air) in order to define a lower limit on the saturation for combustion to proceed.

### 4.4 *In-Situ* Combustion

The next phase of the program was the performance of combustion tube experiments on the steamflooded cores. The tests were accomplished by injecting enriched air (95%  $O_2$ ) at a flux of 13.09 m<sup>3</sup>/m<sup>2</sup> h at a specified pressure until the combustion front had propagated through about 85% of the core. An analysis of each of the tests was then performed to determine the overall and stabilized combustion parameters and liquid production history.

The first step in this procedure involved closing the overall gas balance to ensure that the nitrogen injected equals the produced nitrogen. Stabilized and overall combustion parameters, including oxygen and fuel requirements per unit volume of reservoir, oxygen to fuel ratio, apparent hydrogen to carbon (H/C) ratio, oxygen utilization, carbon oxides to carbon monoxide, and carbon oxides to nitrogen ratio, were then calculated. In addition to these parameters, temperature profiles, produced gas compositions (used in the above calculations), and specific produced fluid properties were analyzed. The data presented will be useful in the interpretation and evaluation of field cases.

**Table 4.14** presents a summary of the overall-run gas injection and production rates. Column 1 shows the times at which meter readings are taken while column 2 gives the total gas injected into the system on a cumulative basis. The production gas rates, based on wet-test meter readings, are presented in column 3. Column 4 provides the instantaneous difference between the cumulative gas production (column 3) and the cumulative gas injection (column 2). A review of column 4 for Run 239, (**Table 4.14.1**), shows that for times greater than 5.0 h, the volume of gas produced was greater than the volume of gas injected. Volumetric flow data indicates the development of a helium leak at 5 h. Run 251 developed a major leak at 1.5 h. Run 252 presented a major helium leak over essentially the total run duration. Volumetric helium balances during the water and steamflood phases indicate that no helium leakage occurred prior to the start of the combustion phase for Run 239, 250 and 251.

TABLE	4.14.1 GAS INJEC	GAS INJECTION AND PRODUCTION HISTORY (Run 239)				
Time	Cumulative Gas Injected	Cumulative Gas Produced	Cumulative Gas Out-In			
(hours)	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))			
0.50	0.016	0.004	-0.012			
1.00	0.058	0.045	-0.013			
3.00	0.128	0.113	-0.015			
5.00	0.177	0.177	0.000			
7.00	0.249	0.288	0.039			
8.73	0.373	0.495	0.122			
10.67 ·	0.373	0.609	0.236			

TABLE 4.14.2GAS INJECTION AND PRODUCTION HISTORY (Run 250)						
Time	Cumulative Gas injected	Cumulative Gas Produced	Cumulative Gas Out-In			
(hours)	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))			
1.00	0.077	0.049	-0.028			
2.00	0.102	0.066	-0.036			
3.00	0.127	0.083	-0.044			
5.00	0.176	0.125	-0.051			
7.00	0.225	0.165	-0.060			
9.00	0.273	0.205	-0.068			
9.60	0.288	0.219	-0.069			

TABLE 4.14.3GAS INJECTION AND PRODUCTION HISTORY (Run 251)					
Time	Cumulative Gas Injected	Cumulative Gas Produced	Cumulative Gas Out-In		
(hours)	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))		
0.50	0.033	0.028	-0.005		
1.00	0.077	0.073	-0.004		
3.00	0.134	0.440	0.306		
5.00	0.183	0.873	0.690		
7.00	0.235	1.270	1.035		
8.00	0.272	1.482	1.209		
9.83	0.339	1.825	1.486		

TABLE 4.14.4GAS INJECTION AND PRODUCTION HISTORY (Run 252)					
Time Cumulative Gas Injected		Cumulative Gas Produced	Cumulative Gas Out-In		
(hours)	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))	(m <sup>3</sup> (ST))		
1.00	0.067	0.189	0.122		
2.00	0.153	0.395	0.243		
3.00	0.181	0.506	0.325		
5.00	0.230	0.762	0.532		
7.00	0.279	1.004	0.725		
8.82	0.323	1.249	0.925		
9.50	0.324	1.325	1.002		

**Table 4.15** presents the principal operating parameters for each test. The oxygen concentration and flux were modified from the proposed values due to the helium leak present in various runs.

TABLE 4.15	TABLE 4.15 OPERATING CONDITIONS (COMBUSTION)					
Run	¥ 239	250	251	252		
Back Pressure (MPa)	4.1	6.2	10.3	4.1		
Saturations						
Öil (%)	23.1	43.5	45.6	26.4		
Water (%)	. 38.0	30.6	27.4	37.6		
Steam (%)	38.9	25.9	27.0	36.0		
0 <sub>2</sub> Concentration (%	76.55	76.55	11.50	22.00		
$O_2$ Flux (m <sup>3</sup> /m <sup>2</sup> h)	12.47	12.47	12:60	12.53		
Total Gas Flux (m <sup>3</sup> /m <sup>2</sup> h)	16.30	16.30	109.0	57.0		

### 4.4.1 Temperature Profiles

Combustion tube runs provide temperature histories which are used to evaluate the rate of advancement of the various fronts, to facilitate interpretation of combustion performance in relation to the product gas compositions and fluid productions, and to aid in the evaluation of the stability of the process. **Figure 4.17** to **4.20** present the axial temperature profiles for each test. The progression of the high temperature peak through successive zones along the tube can be observed. Note the consistent peak temperatures and consistent rates of advance of the high temperature front. The lack of evidence of secondary burning behind the front and steam plateau formation, suggests high oxygen utilization in the front. The progression of the front with consistent peak temperatures and high oxygen utilization reflects the stability of the combustion process. It is also observed that the temperature along the core, for early times (**Figures 4.17-4.19**), drop steadily



FIGURE 4.18 AXIAL TEMPERATURE PROFILES RUN 250 Combustion





0+ 0

FIGURE 4.19 AXIAL TEMPERATURE PROFILES **RUN 251 Combustion** 



Distance Along Tube (cm)



until stabilizing at 90°C. This was due to the core being at a set point heater control of 90°C. Such was not the case for Run 252 (**Figure 4.20**) which had a core set point temperature of 225°C.

**Table 4.16** records combustion peak temperatures observed in each zone. As the tests were terminated when the combustion front reached Zone 12, the zones nearest to the production end of the core (Zones 13 and 14) do not show meaningful peak temperatures. Zone 1 (ignition zone) peak temperatures for Run 239, 250, and 251, which were preheated to 400°C after steamflooding, are 602, 611, and 608°C respectively. Run 252, ignited at 250°C, achieved a peak temperature of 550°C.

The calculated arithmetic mean average peak temperature of zones 1 to 12 for each run is presented in **Table 4.16**. A trend of lower peak temperature at higher pressure is present, similar to a previously observed trend in combustion tests on Primrose core without steamflooding. The decreasing trend is inversely related to the pressure, and possibly reflects increased energy losses from the tube (see **Section 4.2.1**). The lower average peak temperature (541°C) observed during Run 251 compares to a previous value obtained from a normal air run (544°C) performed on a Primrose core at the same pressure; indicating an effect of injected oxygen concentration. Run 252 had an average peak temperature of 562°C and hence did not fall in the pressure trend. Lower oxygen concentration and a higher initial core set point temperature (225°C), affected the composition of the residual fuel and produced a lower peak temperature as compared to Run 239 performed at an identical pressure of 4.1 MPa.

TABLE 4.16     COMBUSTION PEAK TEMPERATURE								
	Run 239		Run 250		Run 251		Run 252	
Zone	Temperature (C)	Time (h)	Temperature (C)	Time (h)	Temperature (C)	Time (h)	Temperature (C)	Time (h)
1	602	0.95	611	0.92	608	1.05	550	2.00
2	628	1.42	587	1.50	526	1.80	631	2.47
3	571	2.08	483	2.00	504 ·	2.20	525	2.92
4	622	2.55	572	2.67	495	2.60	546	3.23
5	602	2.93	648	3.07	586	3.23	616	3.55
6	622	3.28	571	3.58	555	3.67	563	3.87
7	618 .	3.85	572	4.08	550	4.08	544	4.12
8	592	4.38	564	4.67	537	4.57	548	4.42
9	589	4.80	603	5.20	536	5.03	575	4.73
10	612	5.30	558	5.75	532	5.50	543	5.02
11	674	5.90	615	6.12	519	6.00	564	5.30
12	640	6.50	560	6.73	542	6.43	530	5.62
13	459	7.00	358	7.50	331	6.75	520	6.00
14	_ 212	7.25	128	8.00	126	7.00	176	6.25
Average			570		544		500	
remperatu	Jre C 61	4	579		541		562	

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**Figure 4.21** presents the location of the steam front and high-temperature leading edge positions as defined by the 250°C and 450°C temperatures respectively, for Run 251. Based on the slopes of the solid lines shown in this figure, the high-temperature leading edge velocity is 0.158 m/h for the time interval between 1.0 and 6.4 h. The advancement rate for the 250°C leading edge, or steam bank location, is 0.162 m/h for the time interval from 1.9 to 6.1 h.

A similar analysis was performed for all the runs and the calculated average velocities are presented in **Table 4.17**.

	TABLE 4.17 COMB	USTION FRONT VE	LOCITIES
Run	Time Interval (h)	Front Velocity (m/h)	Leading edge Temperature °C
239	0.8 - 6.3	0.158	450
	1.7 - 5.9	0.157	225
250	0.8 - 6.7	0.144	450
	1.8 - 7.0	0.144	250
251	1.0 - 6.4	0.158	450
	1.9 - 6.1	0.162	250
252	1.8 - 2.8	0.146	450
	<b>3.1</b> - 5.5	0.253	450
	1.3 - 2.8	0.100	225
	2.8 - 5.3	0.231	225

The rate of advance for the various fronts has been affected by the low initial oil saturation and high oil mobility. High gas flux and operating pressure also had an effect on the front velocities (**Table 4.15**). Increased gas flux, due to the



helium leak into the core, is responsible for the high front velocities noticed for Runs 239, 250, 251. The velocity increase seen for the latter part of Run 252 represent the effect of the leak location (Zone 6). Within Run 251 any possible pressure effects were overwhelmed by the high gas flux and low oxygen concentration. In contrast, the lower front velocity observed in Run 250 relates to the higher oxygen partial pressure and lower gas flux. Run 252's low front velocity for the time period of 1.3 to 2.8 h relates to the lower ignition temperature and probably greater oxygen uptake by low temperature oxidation reactions during the ignition phase. It will be shown subsequently, that the high rate of advance of the 450°C leading edge during Run 252 is also associated to the kinetics of the combustion reactions.

## 4.4.2 Oil Recovery

With the implementation of *in-situ* combustion after steamflooding, high oil recovery was achieved in all four tests. **Table 4.18** presents the oil recovery as a percentage of the oil in place after steamflooding, at a specified volume of oxygen injected. The volume of oxygen presented in the table refers to the total volume of oxygen injected at initial core conditions divided by the total core pore volume. Four significant factors can be seen from *in-situ* combustion after steamflooding. First of all, the effect of pressure on total recovery seems less significant for the *in-situ* combustion phase than for the steamflooding phase. Secondly, a higher initial oil saturation affected the total oil recovery as seen from

the high recovery observed during Run 251 (10.3 MPa). Thirdly, the recovery data points out that combustion can produce incremental oil after steamflooding. Finally, burning properties of steamed cores confirm that combustion will operate well in the lower oil saturated steam channels; however, the low amount of oil contained in these steam channels might not justify the use of in-situ combustion.

TABL	E 4.18 SU	MMARY OF IN	-SITU COM	BUSTION RESULTS
Run	Pressure (MPa)	PV O <sub>2</sub> Injected	Soi (%)	Oil Recovery (post-steamflood)
239	4.1	5.53	23.1	40.0
250	6.2	4.10	43.5	48.2
251	10.3	2.22	45.6	65.5
252	4.1	5.63	26.4	47.2

The observation of residual saturations in the post-burned core further proves the efficiency of *in-situ* combustion after steamflooding. **Figure 4.22** to **4.25** presents the residual saturations of oil, coke, and water and maximum temperature observed in the individual zones as a function of distance along the core. Oxygen injection was terminated when the combustion front progressed about 0.83 m along the core in order to obtain data representative of the oil, coke, and water distributions ahead of the front. Oil concentration is detected about 10 cm from the burning zone and rapidly increases in the remaining 15 cm of the core. The mass of coke peaked about 5 cm ahead of the temperature front and then declined to almost zero. This maximum concentration of coke is observed





at a temperature of about 400°C (Run 239), 420°C (Run 252), 380°C (Run 250), and 350° (Run 251). The oil concentration behind the front is negligible, indicating a very high sweep efficiency. High amounts of water were noticed in the first half of the core due to the water entraining the core through the injection zone while the pack cooled and slowly depressurized.

A striking feature of the concentration distributions and temperature profiles is the narrow length of the combustion zone and the resulting high temperature gradient at the advancing front. The transition from hot clean sand to relatively cool oil and water saturated sand occurred over a distance of approximately only 10 cm (**Figure 4.22** to **4.25**).

**Table 4.19** presents the average viscosity and density of the produced oil during the steamflood and *in-situ* combustion portions of the test. The decline of both viscosity and density during the latter portion of the test (*in-situ* combustion phase) indicated an upgraded oil. For a stable process, high temperature oxidation is the dominant reaction, oxygen is totally consumed at the front, hydrocarbon undergoes thermal cracking, a heavy residual is deposited, and a lighter oil is produced. The lighter oil then moves forward miscibly displacing the remaining oil in place.

TABLE 4.19 AVERAGE PROPERTIES OF PRODUCED OIL						
	Original Oil		Steamflood		In-situ Combustion	
Run #	density @ 25°C	viscosity @ 80°C	density @ 25°C	viscosity @ 80°C	density @ 25°C	viscosity @ 80°C
239	0.9981	612	0.9999	905	0.9269	145
250	0.9981	786	1.0000	1026	0.9923	520
251	0.9981	786	0.9990	1041	0.9821	187
252	0.9981	786	0.9986	908	0.9810	120

Composition profiles for the produced combustion gases reflect stable high temperature burning of an enriched air combustion process (**Figure 4.26** to **4.29**). The product gas analysis data shows that the produced gas composition varied little during the progression of the runs. As the burning zone neared the end of the core, the oxygen injection was terminated, the CO and  $CO_2$  concentration decreased towards zero, and the oxygen concentration increased. Run 239 and 252 did not show a significant oxygen concentration increase. However, the higher pressure runs (250 and 251) produced a significant amount of oxygen at the end of the run. This behaviour has been noticed by other researchers (Ursenbach et al. 1990) during dry, high pressure enriched air combustion tests, and is reported to be caused by oxygen storage in the burned region.

Run 251 shows oxygen present in the produced gas at around 3 h. This oxygen production is apparently caused by an incomplete oxygen consumption at the high temperature reaction zone as indicated by the lower peak temperatures (see **Figure 4.19**). Martin et al. (1957) concluded that when residual material





(coke) is not present in sufficient quantity to ensure a high combustion temperature (550-600°C), the kinetics of combustion will prevent the oxygen supply from being entirely consumed as it passes through the front. However, due to the process being mass transfer limited, oxygen bypass also occurs because of changes in the oxidation rate in that zone. This excess oxygen may be produced as unreacted oxygen.

The presence of the helium stream, contaminated with nitrogen present in the annulus, has an effect on the product gas composition. This nitrogen contamination is significant compared to the nitrogen in the injected gas stream and results in an increase in the nitrogen concentration and under estimation in the composition of the other components.

# 4.4.3 Combustion Parameters

Evaluation of commercial possibilities of an *in-situ* combustion recovery process requires the knowledge of reservoir-specific combustion parameters. Both the total air or oxygen required to burn a unit of volume of reservoir and the amount and composition of fuel available for burning must be determined. Laboratory combustion experiments on reservoir samples can provide these specific parameters.

For this report, the overall and stabilized combustion parameters were calculated assuming that the global reaction can be represented by the equations for high temperature combustion. Details of the calculations are presented in the appendix. As has been discussed, nitrogen entered the system as a contaminant in the helium stream, which leaked into the core from the annulus. The uncertainty associated with quantifying the volume of contaminant nitrogen, makes it impossible to calculate valid gas phase combustion parameters.

Overall combustion parameters are presented in **Table 4.20**. Overall combustion parameters were calculated from the cumulative production of the components  $CO_2$ , CO, and  $O_2$ , and from the volume of core swept by the combustion front.

TABLE 4.20 O	ERALL C	OMBUSTIO		TERS
Run #	239	250	251	252
O <sub>2</sub> partial pressure (MPa)	3.1	4.7	1.2	0.9
O <sub>2</sub> required (m <sup>3</sup> (ST))	0.1293	0.1455	0.1330	0.1000
O <sub>2</sub> requirement (m <sup>3</sup> (ST)/m <sup>3</sup> )	78.99	88.88	81.24	61.27
O <sub>2</sub> Utilization (%)	98.33	85.21	95.11	98.93
(CO <sub>2</sub> +CO)/CO	8.23	9.68	15.18	8.09
Reacted O <sub>2</sub> forming Carbon Oxides (%)	68.7	57.7	63.5	68.3
Carbon consumed (kg/m <sup>3</sup> )	28.66	23.17	25.61	22.56
Fuel consumed $^{\star}$ (kg)	0.0542	0.0474	0.050	0.0422
Fuel requirement <sup>*</sup> (kg/m <sup>3</sup> )	33.11	28.97	30.76	25.79
O <sub>2</sub> /Fuel <sup>*</sup> (m <sup>3</sup> (ST)/kg)	2.39	3.07	2.64	2.38
Apparent H/C *	1.72	2.8	2.24	1.76

Approximate values due to nitrogen contamination in gas stream

Operating pressure and peak temperature differences between the runs seemed not to affect combustion parameters. Although the parameters varied slightly as pressure increased, it is likely that the low oil saturation and the helium leak which were present during all the Runs, improved the overall burning characteristics. The overall oxygen requirements vary from 61.27 to 88.88 m<sup>3</sup>(ST)/m<sup>3</sup> with the lowest value corresponding to Run 252 which was operated at the highest level of preheat (225°C) and, because of the helium leak, at the lowest oxygen partial pressure. The highest overall oxygen requirement and lowest oxygen utilization was for Run 250 which was operated at the highest oxygen partial pressure. The difference in the injected oxygen requirements for Runs 239, 250, and 251, (same preheat temperature of 90°C), is mainly due to the oxygen storage in the swept region.

Apparent atomic H/C ratio and percent reacted oxygen converted to carbon oxides are also presented in **Table 4.20**. These parameters are used as an indicator of the apparent oxidation kinetics during the combustion process. It can be seen that the nature of the oxidation reactions are sensitive to the oxygen partial pressure, with the highest apparent H/C ratio and lowest percent reacted oxygen conversion corresponding to the highest oxygen partial pressure run. The main cause of the variation for the current Runs is the oxygen stored in the swept volume of the core. In addition, the apparent H/C ratio was affected by the nitrogen contamination.

**Table 4.21** presents a summary of the stabilized parameters. Stabilized parameters are defined for the portion of each test where the combustion front

velocity and gas composition are stable. The parameters were evaluated from the average product gas analysis (**Table 4.22**). In view of the stability of Runs 239, 250, and 251, the stabilized injected oxygen requirement is considered to be representative of the stabilized operation.

TABLE 4.21	STABILIZE	COMBUS	TION PARAM	IETERS
Run	# 239	250	251	252
Front velocity (mm/h)	158	144	158	253
O <sub>2</sub> requirement (m <sup>3</sup> (ST)/m <sup>3</sup> )	78.99	86.60	79.70	49.50
O <sub>2</sub> Utilization (%)	99.20	98.80	99.58	99.56
(CO <sub>2</sub> +CO)/CO	8.05	9.04	11.62	8.41
Carbon consumed (kg/m <sup>3</sup> )	26.47	32.2	18.60	10.36
Fuel requirement <sup>*</sup> (kg/m <sup>3</sup> )	32.20	37.00	33.10	18.30
O <sub>2</sub> /Fuel <sup>*</sup> (m <sup>3</sup> (ST)/kg)	2.45	2.34	2.41	2.71
Apparent H/C *	2.03	1.54	1.78	3.20
(CO <sub>2</sub> +CO)/N <sub>2</sub> *	13.39	<sup>′</sup> 14.85	9.99	8.37

Approximate values due to nitrogen contamination in gas stream

Stabilized apparent H/C ratios and oxygen parameters which are not dependent on the oxygen storage, are presented in **Table 4.21**. However, it was not possible to determine these parameters with any degree of certainty due to the problems with the nitrogen contamination. A comparison of the stabilized and overall combustion parameters shows agreement between the oxygen and fuel requirements for Runs 239, 250, and 251. This agreement is expected given the stable nature of the tests. Differences between the stabilized and overall combustion parameters for Run 252 reflect the period of high combustion front velocity for which the stabilized parameters were calculated. However, this run operated at two distinct front velocities. The low velocity for the first portion of the

<b>TABLE 4.22</b>	AVERAGE	PRODUCT	GAS ANAL	YSIS
Run #	239	250	251	252
Component		Mole Pe	ercent	
CO <sub>2</sub>	78.10	80.83	82.64	77.02
со	11.08	10.06	7.78	10.39
02	1.05	1.45	0.53	0.67
N <sub>2</sub>	6.66	6.12	9.05	10.45
H <sub>2</sub>	0.00	0.00	0.00	0.00
CH <sub>4</sub>	1.80	0.52	0.00	· 0.86
C <sub>2</sub> H <sub>4</sub>	0.17	0.14	0.00	0.04
С <sub>2</sub> Н <sub>6</sub>	0.56	0.42	0.00	0.22
C <sub>3</sub> H <sub>6</sub>	0.25	0.00	0.00	0.16
С <sub>3</sub> Н <sub>8</sub>	0.32	0.46	0.00	0.19
C <sub>4+</sub>	0.00	0.00	0.00	0.00
H <sub>2</sub> S	0.00	0.00	0.00	0.00
so <sub>2</sub>	0.00	0.00	0.00	0.00
COS	0.00	0.00	0.00	0.00

test indicates that the oxygen requirement was significantly higher before the front velocity changed (85.6 as compare to  $49.5 \text{ m}^3(\text{ST})/\text{m}^3$ ). Since the overall oxygen requirement for Run 252 is  $61.3 \text{ m}^3(\text{ST})/\text{m}^3$ , it appears that the oxygen consumed during the low velocity period was released during the high velocity portion of the

test. It is believed that the oxygen was stored in the form of an oxidized hydrocarbon rather than as a gas in the swept zone, due to oxygen consumption by low temperature oxidation reactions resulting from the lower ignition temperature. The releasing of this stored oxygen caused the velocities in the latter part of the run to be so high.

In addition to the standard gas analysis, "GasTec Detector Tubes" were used to measure the concentrations of trace sulphur components (Table 4.23-The specific components analyzed were: Hydrogen Sulphide (H<sub>2</sub>S), 4.26). Sulphur Dioxide (SO<sub>2</sub>), Carbon Disulphide (CS<sub>2</sub>), Methyl Mercaptan (CH<sub>3</sub>SH), Total Mercaptan (RSH), and Carbonyl Sulphide (COS). Some interesting trends can be noticed from these values. At low pressures (4.1 MPa, Run 239 and 252), the amount of H<sub>2</sub>S and mercaptan produced are dependent on the composition of the fuel burned. It was noted earlier that the burning characteristics of Run 252 were different due to the higher initial temperature causing an altered fuel. All runs presented varying amounts of carbon disulphide, and relatively small amounts of carbonyl sulphide. Run 251 performed at the highest operating pressure produced the largest amount of CS<sub>2</sub>. Also of interest is the low level of mercaptans which is the species which is most credited with being the source of the combustion odour. The dramatic reduction in the gas concentration after seven hours into Run 252 was due to the helium dilution.

	TABLE 4.23 SPECIALIZED GAS PHASE ANALYSIS (RUN 239)					
		"(	Gastec" Detec	tor Tubes	· .	
			All-Concenti	rations in ppr	1	
Time h	Hydrogen Sulphide H <sub>2</sub> S	Sulphur Dioxide SO <sub>2</sub>	Carbon Disulphide CS <sub>2</sub>	Methyl Mercaptan CH <sub>3</sub> SH	Total Mercaptan RSH	Carbonyi Sulphide COS
2.28	72	0	499	8	29	0.
3.75	22	ο.	512	11	8	2
4.73	t	0	256	0	2	0
5.70	0	0	366	0	0	16
6.72	35	0	344	t	t	0
7.77	72	0	1265	t	t	0

	TABLE 4.24 SPECIALIZED GAS PHASE ANALYSIS (RUN 250)					
		**(	Gastec" Detect	tor Tubes		
			All Concenti	rations in ppm		
Time h	Hydrogen Sulphide H <sub>2</sub> S	Sulphur Dioxide SO <sub>2</sub>	Carbon Disulphide CS <sub>2</sub>	Methyl Mercaptan CH <sub>3</sub> SH	Total Mercaptan RSH	Carbonyl Sulphide COS
3.67	0	0	71	0	0	0
4.78	0	0	252	0	0	0
5.43	0	0	1117	0	0	12
6.07	0	0	0	0	0	7
8.63	0	0	ND	0	0	0
9.20	0	0	ND	0	0	0

TABLE 4.25   SPECIALIZED GAS PHASE ANALYSIS (RUN 251)     "Operator"   Detector						
	1		Gaslec Dele		_	
	-		All Concen	trations in ppr	11	
Time h	Hydrogen Sulphide H <sub>2</sub> S	Sulphur Dioxide SO <sub>2</sub>	Carbon Disulphide CS <sub>2</sub>	Methyl Mercaptan CH <sup>3</sup> SH	Total Mercaptan RSH	Carbonyi Sulphide COS
2.90	118	0	356	0	0	0
4.15	0	0	936	0	ND	0
5.47	0	0	518	0	ND	130
6.67	3239	0	1295	0	NĎ	0
7.30	606	0	1528	0	ND	ο.
7.93	0	0	t	0	ND	0
8.58	. 0	0	t	0	ND	0

TABLE 4.26 SPECIALIZED GAS PHASE ANALYSIS (RUN 252)						
"Gastec" Detector Tubes						
			All Concen	trations in ppr	n	
Time h	Hydrogen Sulphide H <sub>2</sub> S	Sulphur Dioxide SO <sub>2</sub>	Carbon Disulphide CS <sub>2</sub>	Methyl Mercaptan CH <sub>3</sub> SH	Total Mercaptan RSH	Carbonyl Sulphide COS
2.20	4655	0	t	47	47	0
3.73	3389	0	850	16 <sub>.</sub>	42	0
4.40	3747	0	681	28	45	102
5.07	3280	0	693	22	35	43
5.88	1804	0	649	36	72	0
6.57	t	0	370	19	28	0
7.70	0	0	0	0	0	0
t = trace ND = Not Determined						

In conclusion, the distinct values obtained for the four tests are accredited to the diverse and complex reactions occurring during the combustion process even for the same type of oil.

### 4.5 General Discussion

The following discussion highlights the enhancement obtained by combining steamflooding with the *in-situ* combustion recovery process. The insights obtained from this laboratory work and a general overview of the future applications will be presented.

Thermal recovery process stability is affected by increased pressure. During steamflooding, higher pressures usually mean lower enthalpy of vaporization and greater heat losses which slow down the condensation front and reduce the quality of the steam injected. Oil recovery is then lower, suggesting that the above effects overshadows the benefits of an increased saturation temperature. An increase in pressure also affects the more energy efficient combustion process. The pressure effects are known to be much greater for enriched air processes than for normal air injection processes (Moore et al. 1990); however, a weak dependence of process stability and combustion parameters on pressure was observed during the combustion of a steamflooded core. A lower oxygen partial pressure, due to the presence of an inert gas (helium), combined with a highly mobile low oil saturation downstream of the combustion front enhanced the stability of the process.

Low initial oil saturation seems not to affect combustion temperature and performance. In fact, low initial saturation levels facilitated an exceptionally stable performance throughout the process. Ignition was successfully attained in zones were the oil saturation was believe to be about 15%. Furthermore, the propagation of the combustion front was achieved at high steady velocities, which accelerated the oil production. This behaviour confirms that combustion will operate well in the low oil saturated channels induced by steam stimulation; however, the low amount of oil contained in these channels might not justify the use of *in-situ* combustion alone.

An additional advantage of combining the two processes is the resulting increased oil mobility. Critical to the success of *in-situ* combustion, oil mobility must be ensured ahead of the front. Steam pre-heating of the reservoir provides the necessary energy to reduce the oil viscosity inducing oil mobility. In Canadian reservoirs, where oil mobility is very poor due to low initial temperatures and high viscosities; steam can be used to create an initial mobility in order to improve *in-situ* combustion performance.

Steam stimulation and flooding prior to combustion not only ensures sufficient oil mobility but also successful gas injectivity. As the saturation of the steam increases around the injection well, the relative permeability to the displacing fluid increases. This higher permeability results in ease of gas injection. This is extremely important for the later combustion stage as a high injectivity will ensure that oxygen can be injected at a sufficient flux so as to maintain the oxidation reaction in a mode which provides effective oil mobilization. A high oxygen flux will result in efficient burning and high front velocity, resulting in reduced heat losses due to a lower residence time.

Future application of this approach for the recovery of heavy oil can be of great utility in reservoirs that have been steamflooded and are close to their economic limit, in reservoirs where low initial oil mobility makes it impossible to the combustion process at economic rates, and in reservoirs were steamflooding alone proves not to be efficient. However, enhancements to the process are needed in order to access the colder oil not contacted by the steam in order to economically justify the process. In addition, gravity effects with steam and gas overriding are important in the reservoir and should be taken into account in field applications.

In-situ combustion can also operate very efficiently in high water saturated zones underlying oil formations. A process similar to the one developed by **Shell Canada** in the Peace River reservoir, (Dillabough and Prats, 1974), could be implemented. This process will have the advantage of using combustion as the prime energy generation mechanism.

Field piloting of this combined approach, in addition to laboratory research, should continue to bear new insights into the development of new and more effective ways to recover the vast reserves of heavy oil and bitumen.

#### **CHAPTER FIVE**

#### CONCLUSIONS

The commercial use of thermal recovery methods has been practised for over thirty-five years. Steam injection and *in-situ* combustion stand as the two dominant processes used for heavy oil and bitumen recovery. These processes have followed an established procedure of initial laboratory research, based on theoretical consideration, followed by numerical modelling and, finally, appropriate designed pilot tests in the field.

The combination of the two enhanced oil recovery methods of steam injection and *in-situ* combustion within a laboratory study was investigated and the most important findings follow:

 Water injection through a heavy oil saturated core at 90°C proved to be very inefficient recovery process, yielding recoveries of only 2 - 13% of the oil in place.
Oil production was accompanied by large volumes of water.

2. The injection of steam effectively mobilizes viscous oil from the core and enhances oil recovery by reducing oil viscosity and producing gas, (water vapour), and water drive effects.

3. Pressure affects the steam displacement efficiency in the following ways:

i) The steam front rate of advancement decreased as the pressure increased, retarding the production of oil.

ii) At high pressures larger volumes of steam, measured as cold water equivalent, are required to produce the same amount of oil. iii) Time required for steam to breakthrough became extensively long during the 6.2 and 10.3 MPa runs, affecting the cumulative oil recovered. The low pressure runs presented a shorter time for steam breakthrough, and significant oil production both before and after steam breakthrough.

4. The combined waterflood and steamflood phases of the experiments produced a total oil recovery (based on the initial oil in the core) of:

Run 239 (4.1 MPa)	69%
Run 250 (6.2 MPa)	48%
Run 251 (10.3 MPa)	43%
Run 252 (4.1 MPa)	65%

The differences reflect both pressure and volume of steam injected.

5. The oil production rate, steam front velocity, and steam saturation temperature were affected by the presence of a helium leak during the progression of Run 252. Both the oil production rate and steam front velocity were increased while a lower steam saturation temperature was observed.

6. Even though the tube assembly is designed to control heat losses, it was not possible to maintain true adiabatic conditions during any of the experiments. For runs 250-252, superheated steam was injected through the core; however steam quality along the core was reduced by the loss of energy from the tube. Within Run 239, the injection of superheated steam was limited due to operational problems. Further modifications to the steam generator and a lower temperature differential for the heater control system of the tube apparatus may help maintain true adiabatic conditions through the progression of experimental Runs.

7. In-situ combustion process in steamflooded cores proved to be a successful and stable process as indicated from the temperature profiles, gas compositions, oil production and post-test analysis for each run. Low oil saturation, high oil mobility, low oxygen partial pressure, and high gas flux promoted the stability of the process. The latter two effects were due to the helium leak presented during the progression of the Runs.

8. Low initial oil saturation and high oil mobility enhanced the combustion process of Primrose oil. Ignition was successfully attained in zones were the oil saturation was as low as 15%, and the propagation of the combustion front was achieved at high velocities. Steamflooding ensured sufficient oil mobility and increased gas injectivity, both of which are critical to the success of *in-situ* combustion.

9. The injection of oxygen, combined with high levels of an inert gas, such as helium, can produce stable burning characteristics within a reservoir. The helium leak presented during the combustion phase of the Runs was found to decrease the effective oxygen concentration and increase the total injection flux, promoting stable burning characteristics. Oxygen concentrations as low as 11% maintained stable combustion at an absolute pressure of 10.3 MPa.

10. Combustion can produce incremental oil after steamflooding. The oil recovery data points out that an upgraded oil was produced. This oil presented a lower viscosity and density.

11. A 100% sweep efficiency was obtained during the combustion phase of the experiments. An analysis of the post-burned core showed no oil concentration in the burned zones and low coke concentrations. The sweep efficiency of this process applied in the field will be lower due to gravity override of the lighter fluids. 12. The burning characteristics of steamed cores confirm that combustion will operate well in the lower oil saturated steam channels; however, the low amount of oil contained in these steam channels requires the use of in-situ combustion in combination with other methods in order to simultaneously access the heated and unheated portion of the reservoir. The injection of water alternatively with the oxygen containing gas might enhance the distribution of thermal energy in the reservoir.

13. For the majority of the Runs, very small concentration of sulphur containing gases were produced. Run 252, which was ignited at a lower temperature and showed signs of low temperature oxidation reactions, presented the higher concentrations of mercaptan and hydrogen sulphide.

14. The laboratory combustion tube experiments performed on heavy oil cores presented in this report has given promising results and encouragement into the application of this combined process for the recovery of the vast reserves of heavy oil and bitumen.

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#### APPENDIX

## Stoichiometry of In-Situ Combustion

*In-situ* combustion is a complex process where a number of different oxidation reactions can occur over the temperature range of the process. While it is recognized that all of the reacted oxygen may not be consumed by high temperature combustion reactions, it is convenient to assume that the global reactions can be represented by the equations for the high temperature combustion.

The following calculations are based on the stoichiometric equation which describes high-temperature combustion. The assumed basic stoichiometric relationships used are:

$$C_{x}H_{y} + aO_{2} + (R)aN_{2} \rightarrow bCO_{2} + dCO + fO_{2} + jH_{2}O + (R)aN_{2} \qquad A.1$$

Where

$$R = \frac{N_2 \text{ mole fraction}}{O_2 \text{ mole fraction}}$$
A.2

in the feed gas.

Performing an element balance:

[Carbon - <i>C</i> ]	x = b + d
[Oxygen - <i>O</i> <sub>2</sub> ]	a = b + d/2 + f + j/2
[Hydrogen - <i>H</i> ]	y`= 2*j

The apparent atomic H/C ratio is expressed as y/x

$$H/C = \frac{4[a-b-d/2-f]}{[b+d]}$$
 A.3

The oxygen to fuel ratio, expressed in  $m^3(ST)/kg$ , is equal to *a* moles of oxygen over moles of fuel (molecular mass of fuel = [12.011\*x + 1.008\*y])

$$\frac{O_2}{fuel} = \frac{23.64 * a}{[12.011x + 1.008y]}$$
A.4

Furthermore, the air to fuel ratio is equal to

$$\frac{Air}{Fuel} = \frac{23.6 [1 + R] * a}{[12.011x + 1.008y]}$$
A.5

and the percent reacted oxygen converted to carbon oxides is defined as

$$f_{O_2(R)} = \frac{[b + d/2]}{[a - f]}$$
 A.6

To evaluate the coefficients from an instantaneous or stabilized product gas composition, a normalized (for hydrocarbon content) dry basis analysis of produced gas is assumed. The numerical values for a, b, d, and f are:
where [] signifies normalized composition in mole percent.

The coefficients are then calculated using the following equations:

$$\frac{H}{C} = \frac{4\{\frac{[N_2]}{R} - [CO_2] - \frac{[CO]}{2} - [O_2]\}}{[CO_2] + [CO]}$$
A.7



$$\frac{Air}{Fuel} = \frac{23.64*[1+R]*\frac{[N_2]}{R}}{12.001\{ [CO_2]+[CO]\} + 4.032\{ \frac{[N_2]}{R} - [CO_2] - \frac{[CO]}{2} - [O_2] \}} A.9$$

$$f_{O_2(R)} = \frac{[CO_2] + \frac{[CO]}{2}}{\frac{[N_2]}{R} - [O_2]}$$
 A.10

Fraction of oxygen utilized

$$Y = \frac{\frac{[N_2]}{R} - [O_2]}{\frac{[N_2]}{R}}$$
 A.11

and

Excess 
$$O_2 = \frac{(1-Y)}{Y}$$
 A.12

The overall combustion parameters are evaluated from the cumulative produced volumes of the individual components and the burned volume of the core.

The experimental data obtained from the laboratory tube combustion tests are:

V<sub>O2i</sub>

Volume of gas, dry basis  $(m^{3}(ST))$ :

Composition of injected air:

Nitrogen volume V <sub>N</sub>	<b>2i</b>
--------------------------------	-----------

Oxygen volume

Composition of produced gas:

Nitrogen volume	V <sub>N2</sub>
Oxygen volume	V <sub>02</sub>
Carbon Dioxide volume	V <sub>CO2</sub>
Carbon Monoxide volume	V <sub>CO</sub>

Assuming the same combustion reaction as A.1 and that the nitrogen is completely inert in the reaction, the following quantities can be calculated. Mass of carbon in fuel, (kg)

$$M_{c} = \{ (V_{CO_{2}}) + (V_{CO}) \} * \frac{12.011}{23.64}$$
 A.13

mass of water formed by combustion, (kg)

$$M_{w} = 2\left\{\frac{(V_{N_{2}})}{R} - (V_{O_{2}}) - (V_{CO_{2}}) - \frac{(V_{CO})}{2}\right\} * \frac{18.015}{23.64}$$
A.14

mass of hydrogen in fuel, (kg).

$$M_{h} = 2\left\{\frac{(V_{N_{2}})}{R} - (V_{O_{2}}) - (V_{CO_{2}}) - \frac{(V_{CO})}{2}\right\} * \frac{2.016}{23.64}$$
A.15

The total mass of fuel burned is

$$M_{fiel} = M_c + M_h \tag{A.16}$$

and the total fuel burned (or fuel requirement) in (kg/m<sup>3</sup>) is given by

Total volume of air injected (m<sup>3</sup>(ST))

$$V_{air} = \{(V_{N_2}) + \frac{(V_{N_2})}{R}\}$$
 A.18

and

is the air to fuel ratio in  $m^3(ST)/kg$ .

The total air requirement per volume of sand burned will be given in  $m^{3}(ST))/m^{3}$  by:

A.20

The apparent atomic H/C ratio can then be calculated.

$$\frac{H}{C} = \frac{2(M_w/18.015)}{(M_c/12.011)}$$
 A.21

An effective gas composition, which accounts for the enriched-air feed, contamination due to the helium leak, and for the nitrogen and oxygen initially in the system is used for the overall calculations. The reference conditions are 101.325 kPa and 15°C.