RELATIVE PERMEABILITY DETERMINATION FOR STEAM INJECTION PROCESSES: AN ANALYTICAL APPROACH

A Thesis

by

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ABSTRACT

Due to the nature of bitumen and the inability to flow at reservoir conditions, it becomes necessary to alter the original state by imparting heat into the reservoir, thus lowering the viscosity to produce the fluid. The heat introduction is achieved through the utilization of steam assisted gravity drainage (SAGD) as well as solvent steam assisted gravity drainage (S-SAGD). However, the presence of three distinct fluid phases (oil, steam, and water) in the reservoir during steam injection has implications for the effective modeling of the complex fluid dynamics. Inherent complexity as a result of introducing a third phase (steam) in conjunction with temperature dependencies results in the inability to generate a comprehensive three phase relative permeability capable of adequately representing flow in the reservoir at all domains.

In this study, experimental oil recovery data for two SAGD experiments, three S-SAGD experiments and one hot water flood are empirically modelled by manipulating relative permeabilities. Addition of a solvent during the steam injection (S-SAGD) takes advantage of a miscibility component with the bitumen in conjunction with the thermal mechanism of enhanced oil recovery which results in incremental recovery of bitumen along with a minimization of the environmental footprint. The two SAGD experiments are differentiated by different types of clay content while the three S-SAGD experiments vary due to the different solvent and injection strategy utilized during the experiment. The analytical approach implemented allows for the representation of fluid flow in the reservoir by achieving a pseudo-two phase relative permeability that results in comparable

performance to the experiments. The assumption of a waterflood through the application of fractional flow theory allowed for the negation of the steam phase in the model and so two-phase flow was established. The sensitivity of the relative permeability curves to temperature change results in the inability to formulate a generic three-phase curve and so the pseudo-two phase curve is valuable for the analysis of the relative permeability behavior for different SAGD scenarios.

DEDICATION

I dedicate this to my parents who have supported me throughout my life and have encouraged me in my studies.

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NOMENCLATURE

f_w	Fractional Flow of Water
f_{wf}	Fractional Flow of Water at Flood Front Saturation
f_{iw}	Fractional Flow of Water at Interstitial Water Saturation
f'_{wf}	Slope of the Fractional Flow Curve
f_{w2}	Fractional Flow of Water at $x_D = 1$
k_{rw}	Permeability of Rock to Water
k_{ro}	Permeability of Rock to Oil
N_p	Stock Tank Oil Displaced, bbl
SAGD	Steam Assisted Gravity Drainage
S-SAGD	Solvent Steam Assisted Gravity Drainage
S_w	Water Saturation, Fraction
S_{wD}	Normalized Water Saturation
S_{iw}	Initial Water Saturation, Fraction
S_{or}	Residual Oil Saturation, Fraction
$\overline{S_w}$	Average Water Saturation in the Linear System
S_{w2}	Water Saturation at $x_D = 1$
t_{D2}	Dimensionless Time required to Propagate Saturation to the Outlet
μ_w	Viscosity of Water, cP
μ_o	Viscosity of Oil, cP

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1. INTRODUCTION

As petroleum engineers continue to pioneer into the frontier of unconventional reservoirs, the effective characterization of the flow dynamics correspondingly becomes more integral to success. Increasing demand of energy worldwide in conjunction with diminishing conventional resources corresponds to a necessity to identify viable sources of hydrocarbons that are capable of bolstering production (EIA 2015). Dependency on hydrocarbons as a source of energy will continue to grow parallel to the demand until renewable resources such as wind or solar power become a viable option. This dependency of worldwide energy generation on fossil fuels has been documented as has the increase in energy demand. The Organization of the Petroleum Exporting Countries world oil report in 2013 stated that the demand for energy will increase by 52% with a staggering 80% of that being supplied by fossil fuels even until the year 2035 (Abdul-Hamid 2013). Therefore, the efficient extraction of hydrocarbons from unconventional sources is essential to the future of the industry. The time of conventional reservoirs is primarily coming to an end in developed nations as we have preferentially produced and exhausted these resources and so the necessity to access the potential of unconventional resources continues to grow (Deffeyes 2004; Meyer and Attanasi 2003). The expansive potential of the unconventional reserves necessitates that more emphasis be placed on effectively producing this resource.

Reservoirs can be unconventional due to the fluid characteristics, rock properties, and the environmental conditions of the reservoir location. The transmission of fluid through rock is highly sensitive and dependent on the fluid properties and so heavy oil with low API gravity and high viscosity results in bitumen as an unconventional resource due to the very poor mobility (Schmoker and Klett 1999; Stabell 2005). Heavy oils and bitumen offer a vast source of reserves that could greatly bolster petroleum production as bitumen alone accounts for over 30% of the world's oil reserves with over 1.7 trillion barrels of that being contained in the Alberta, Canada reservoirs (Alboudwarej et al. 2006; Hein and Marsh 2008). The mobility of bitumen is very low due to high viscosity and so flow can only be attained by imparting energy in the form of heat or by diluting the fluid with lighter molecular solvents (Good et al. 1994; Nasr et al. 2003). Steam processes such as steam flooding or steam assisted gravity drainage (SAGD) are two of the most commonly applied and reliable thermal enhanced recovery methods to make the heavy oil economically viable. The fluid properties of heavy oil in the Peace River formation of Canada prevent the flow of hydrocarbons as the buoyant force is unable to overcome the viscous forces (Good et al. 1994). The steam assisted gravity drainage process accounts for this by imparting heat into the reservoir thereby lowering the viscosity. Two horizontal wells are drilled approximately five meters apart and are located at the bottom of the formation. The well located on top is continuously injecting steam into the reservoir so that a steam chamber is generated. This configuration of two horizontal wells in conjunction with continuous injection of steam maximize both the volume of steam in contact with the reservoir as well as the time of contact making SAGD a more effective method than steam flooding for bitumen reservoirs. The steam propagates both vertically and laterally until the steam reaches the overburden at which point the steam is forced in the lateral direction. The rising steam imparts heat to the reservoir and condenses at the boundary of the steam chamber where the now lighter oil and condensate can then flow into the production well located below the injector (Butler et al. 1981; Nasr et al. 2000). This is illustrated in **Fig 1** which depicts a cross sectional view of a SAGD well pair where the flow of fluid is shown with arrows.

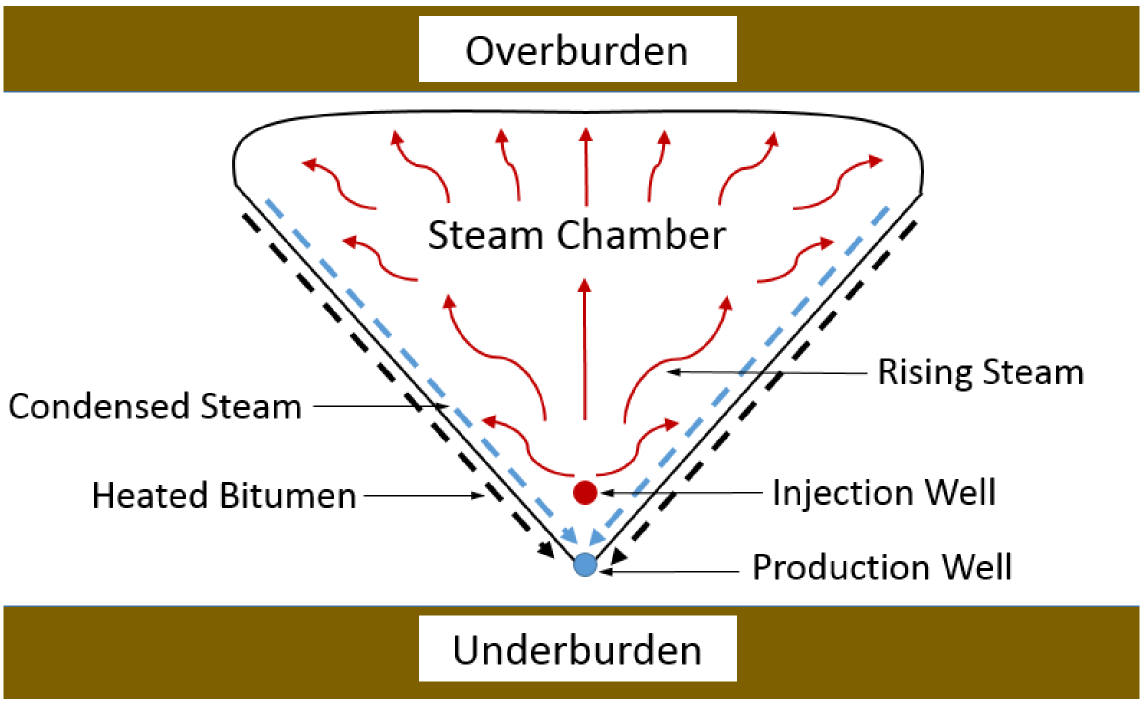


Figure 1- Schematic of the SAGD process

However, inherent to any enhanced oil recovery process that utilizes steam is a very low efficiency. Generation of steam at the surface results in SAGD being a very energy intensive technique that is accompanied by large CO_2 emissions. To increase effectiveness of the SAGD process and reduce the required steam, the solvent steam assisted gravity drainage (S-SAGD) technique was proposed (Nasr et al. 2003). Vast quantities of steam required to adequately heat the reservoir can diminish the economics of the project while simultaneously increasing the environmental impact and so solvents are injected along with the steam in solvent steam assisted gravity drainage (S-SAGD). By coupling the advantages of steam and the miscibility of solvents the quantity of steam generated on the surface can be minimized and bitumen recovery can be maximized. Incremental recovery of bitumen as a function of the utilization of steam assisted gravity drainage is associated with a very large environmental footprint with a ratio of approximately 85 kg CO_2 per barrel of oil produced achieved in Canada (ECCC 2013). Anthropogenic activities are anticipated to increase CO_2 production from 30 Gtons in 2010 to approximately 55 Gtons/year in 2050 and so conscious efforts to decrease the environmental footprint are currently being made as the industry becomes more aware of the detrimental impact and effect of greenhouse gases (Marchal et al. 2011). The process is very energy intensive as steam must be generated at the surface and so Canadian CO_2 emissions are projected to be .73 Gton in 2020 with Alberta being directly responsible for 37% of the total (Bachu 2016; ECCC 2013). Efficiency of the overall process is considerably lower than ideal which is addressed through the combination of thermal and miscibility techniques. By introducing a solvent to the steam, the quantity of water necessary to enhance recovery is diminished by diluting the bitumen with considerably lighter molecules. Solvent steam assisted gravity drainage (S-SAGD) encompasses both aspects of miscibility and heat dissipation and effectively resolves the inadequacies of the SAGD process. Therefore, S-SAGD offers a means of enhancing the bitumen recovery while negating the inefficiency and environmental footprint of the SAGD process.

The foundation of oil displacement specific to the SAGD process is the introduction of heat energy into the reservoir. The utilization of steam for enhanced oil recovery is associated with four different mechanisms of increasing the displacement of fluid which are thermal expansion, viscosity reduction, changes in wettability, and reduction of oil water interfacial tension (Prats 1982). Altering the state of the bitumen to more water wet allows for a relative increase in the capability of the fluid to flow when injecting steam which is gaseous water. Relative to the other two mechanisms identified, both the wettability and the viscosity reduction are the most significant when considering the overall bitumen displacement efficiency. Furthermore, as the density of the crude oil or bitumen increases, the impact of wettability and viscosity are observed even more significantly. This relationship is evidenced by the fact that viscosity variation as a function of temperature is governed by the power law and most of the fluids in the reservoir exhibit shear thinning behavior. Viscosity experiences an inverse and nonlinear relationship with temperature where an increase in temperature accordingly results in a decrease in viscosity.

Along with the degree of viscosity reduction experienced with the increase in temperature is a shift to a more water-wet state. Wettability describes the rocks affinity to preferentially retain a certain fluid and so a strongly-oil wet system would be expected to have a higher residual oil saturation. By manipulating the state of the reservoir to a more water-wet state the oil production can be maximized as the system retains water and allows for the oil to more readily flow (Sharma and Mohanty 2013; Yousef et al. 2011; Zendehboudi et al. 2011). Therefore, the temperature increase achieved through the SAGD process can help to counteract and reduce the impact of wettability as well as alter the wettability to a more water-wet state (Anderson 1987a, 1987b; Sola and Rashidi 2008; Squier et al. 1962). In high asphaltene composition reservoirs such as bitumen reservoirs, the precipitation and deposition of asphaltenes plays a vital role in wettability alteration (Kar et al. 2016). The polarity of asphaltenes has implications for the wettability as a result of their interaction with reservoir clays. Wettability alterations can be quantified through the utilization of contact angle measurements (Unal et al. 2015) but the adaptation of this information into a useful model is only possible through relative permeability measurements. Two-phase water-oil relative permeability curves are provided in **Fig 2** to highlight the important points affecting flow in porous media. The shape of the curve along with the endpoints govern the relative flow and transmission of fluids in the reservoir. Observing **Fig 2** and according to Anderson and Craig, a relative permeability curve can be diagnosed as water-wet when the blue circle falls between 20-25% water saturation along with an intersection represented by the red circle of more than 50% water saturation (Craig 1971).

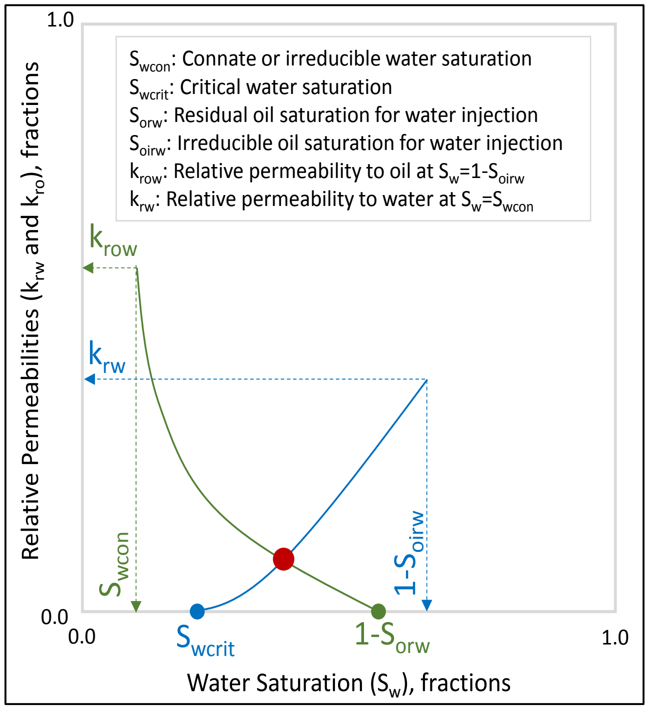


Figure 2 - Schematic representation of water-oil relative permeabilities (Morte and Hascakir 2016)

Temperature dependent three phase relative permeability curves are necessary for the adequate representation of the flow in the reservoir. However, the experimental relationship that has been identified is not well understood and the dependency of relative permeability on temperature is therefore hard to model (Kumar and Do 1990). Accordingly, three phase relative permeability models are exponentially more difficult which results in the inability to formulate a universally acceptable model of three phase permeability that is capable of effectively characterizing the fluid dynamics of all three phases (Ahmadloo et al. 2009). Both the end-points as well as the liquid-gas relative permeability curve contain a temperature dependency that must be accounted for in order to address all facets of flow in the reservoir at varying time intervals (Akhlaghinia et al.

2013; Closmann and Seba 1983; Denney 1999; Edmondson 1965; Maini and Okazawa 1987; Poston et al. 1970; Sinnokrot 1969; Weinbrandt et al. 1975). This temperature dependency necessitates a model capable of handling simulation parameters that vary with temperature which, intuitively, results in much more complicated models and flow dynamics so most simulation studies ignore their importance altogether by assuming two phase flow (Ahmadloo et al. 2009; Corey et al. 1956; Hascakir and Kovscek 2010; Leverett and Lewis 1941; Li and Horne 2003; Naar and Wygal 1961; Zhao et al. 2005).

Therefore, interpolation of two-phase data to account for three phase flow has gained notoriety in the petroleum experimentalist community as a means of negating the steam interaction (Dietrich and Bondor 1976; Svirsky et al. 2004). This simplification to purely an interpolation of two-phase data to account for three-phase flow has resulted in little success with a minimal degree of confidence (Ahmadloo et al. 2009). Various models are valid only in certain domains and no single available three-phase predictive models can be considered a reliable and comprehensive tool for accurate prediction of isoperms (Ahmadloo et al. 2009). Simulation studies have been conducted in an attempt to numerically and empirically formulate three phase relative permeability curves through the use of history matching (Deng et al. 2010; Khaledi et al. 2015; Lei et al. 2010; Wang 2010) but these studies don’t reflect the presence of asphaltenes deposition, clay migration, and temperature dependencies. The presence of steam in the reservoir affects both the oil-water and liquid-gas relative permeability curves as a function of temperature and movement of the solid phase, namely reservoir fines and asphaltenes (Al Bahlani and Babadagli 2008; Fatemi et al. 2012; Good et al. 1997; Hascakir and Kovscek 2010; Li and

Horne 2003; Zhao et al. 2005). Solvent co-injection with steam accordingly increases the complexity even more due to the potential interactions between asphaltenes causing precipitation, clay migration, and emulsion formation. Careless adoption of interpolated curves or relative permeability curves established from analogs can lead to erroneous production as a result of the inherent heterogeneity realized in any reservoir (Lei et al. 2010). Generic approaches to reservoir analysis would produce poor results due to the heterogeneity and so unique analysis is required for each reservoir.

Experimental procedures are useful in validating the viability of any process but an upscaling in the form of simulation is eventually required to characterize years of fluid flow. Evolution of any process for incremental oil recovery will eventually require utilization of simulation where decades of production can be realized on a manageable timescale (Mendoza et al. 1999). Introduction of heat to the reservoir through the SAGD process has been proven viable and effective and therefore optimization or forecasting is now required. Expansion of the SAGD performance to estimate future trends is dependent on the relative permeability curves which necessitate that the impact of temperature and three fluid phases be considered (Blunt 2002; Kumar and Do 1990; Lo and Mungan 1973; Nakornthap and Evans 1986). Fluid flow in the reservoir is a direct function of the relative permeability and the sensitivity of simulation to these curves requires high degree of confidence in their capability of representing flow (Kumar and Do 1990). To achieve any confidence in the simulation result the generated model inputs must be valid. Therefore, relative permeability curves are an integral component of any simulation but the complex interactions in the reservoir make formulating these curves difficult (Baker 1988; Sato and

Aziz 1987; Stone 1970; Wang 2010). The ability of one fluid to flow preferentially in regard to the other will play a major role in the production profile of the reservoir and so adequate characterization of relative permeability as a function of saturation is integral to successful simulation. Therefore, understanding and optimizing the ability of oil to flow relative to water enables more incremental recovery. Pertinent to any reservoir simulation is the idea of balancing the cost effectiveness of representing flow on a macroscopic proportion by analyzing the reservoir using the simplest method. Utilizing the simplest element size that produces results that are still representative of the overall flow would prevent the use of generic analogs as a means of formulating curves.

The simplest way to calculate relative permeability curves while remaining representative of overall fluid flow is through the fractional flow theory established by Buckley and Leverett (Buckley and Leverett 1942). Frontal advance theory is founded on the law of conservation of mass and essentially is an application of this concept. Flow through a finite volume element can be expressed in terms of a total flow rate. This flow rate can be mathematically defined as the summation of the flow rates of the individual phases in the reservoir assuming immiscibility. Denoting the total flow rate in terms of the fraction of water allows for the tracking of the accumulation of water per unit of time. Mass balance then dictates that the incremental water accumulation in the reservoir must correspond to the same oil production. Conventional analysis using this theory enables the calculation of the waterflooding performance in terms of cumulative recovery factor as a function of time by starting with known relative permeability curves. Also, reverse engineering can be applied where known cumulative oil recoveries are used to calculate the relative permeability ratios (Johnson et al. 1959; Jones and Roszelle 1978). Implementation and adaptation of this theory have allowed for the extension to other EOR techniques but the heat introduction associated with thermal EOR has prohibited any successful modification for thermal operations (Dholkawala et al. 2007; Pope 1980; Walsh and Lake 1989; Wangen 1993). Fractional flow theory is derived on the basis of linear displacement and isothermal conditions with no mass transfer between the fluids. Hence, many assumptions made in the derivation of this theory have to be relaxed through modification to enable the use of this theory specific to the SAGD and S-SAGD processes.

The overall oil displacement efficiency in any enhanced oil recovery (EOR) process is evaluated on the basis of both a macroscopic as well as a microscopic scale that when determined together form the foundation of the sweep efficiency (Green and Willhite 1998). The governing phenomenon of the microscopic displacement consists of capillary forces, viscous forces, phase trapping, and the mobilization of trapped phases and can be represented through a parameter defined as the capillary number (Melrose 1974). The capillary number is a ratio of the viscous force to the capillary force and describes the ability of the fluid to overcome capillary retention to flow oil. Capillary dominated flow results in a smaller capillary number as well as the relative inability to flow the fluid through the pore throat (Fulcher Jr et al. 1985; Pope et al. 2000). Capillary number can be examined and introduced to any performance evaluation in the form of relative permeability curves (Anderson 1986; Donaldson et al. 1969; Li and Horne 2003). Therefore, the relative permeability is an integral modeling parameter and highly affects the performance estimation of any recovery process (Sato and Aziz 1987; Stone 1970).

Fractional flow achieved in accordance with the utilization of a waterflood corresponds to the macroscopic component of the overall displacement efficiency. The macroscopic displacement will be characterized using the parameter of mobility ratio which represents the ability of the injected phase to flow relative to the in-situ phase. Ideally the mobility ratio will be around unity which would imply that the oil is equally capable of flowing in the reservoir in regards to the water so a piston-like displacement can be achieved.

In this study, the proposed analytical model consists of a pseudo two-phase relative permeability that utilizes both Buckley-Leverett and Corey functions along with waterflooding techniques to negate the temperature dependency as well as the liquid-gas relative permeability (Buckley and Leverett 1942; Corey 1954). By implementing a reverse engineering approach to the waterflood design the problem of simply interpolating two-phase flow data to generate three-phase flow is addressed as the relative permeability curves are manipulated according to laboratory data and not interpolated.

2. RESEARCH STATEMENT

Dependencies of three phase relative permeability on temperature associated with the introduction of heat energy to the reservoir prohibit the utilization of conventional three phase relative permeability curves. By introducing a pseudo two phase relative permeability curve that is capable of adequately representing overall bitumen flow the ability to forecast production is established. Assuming that all experiments are waterflooding projects allows for the regression of the three fluid phase relative permeability to a pseudo two phase. Modifications to conventional fractional flow theory address deviances from the original derivation and extend the applicability of this theory to both SAGD and S-SAGD processes. To establish a unique solution the generated pseudo two phase relative permeability simultaneously matches both the oil recovery attained in the laboratory as well as the breakthrough. Through the implementation of the reverse engineering approach of this study a pseudo two phase relative permeability is analytically generated that results in comparable recovery to the actual three phase fluid flow realized in the lab. Simplification allows for the analysis of very complex problems that have numerous different dependencies and all simplifications or assumptions made in this study are validated through the exemplary match of analytical and experimental cumulative bitumen production.

3. PROCEDURE

3.1 Analytical Model

The simplification of the flow to a pseudo-two phase model using waterflooding techniques has value in the ability to simulate complex flow while still being adequate in representing the overall fluid dynamics. Fractional flow theory is then applicable and the pseudo relative permeability curves can be manipulated in order to match experimental recovery. The theoretical recovery is a function of a waterflooding design and the mechanism of recovery is the sweep of the water front. At the foundation of fractional flow theory is the law of conservation of mass which dictates that any mass of injected fluid must equate to the same mass of fluid produced. Essentially, pore volumes of water are injected into the reservoir and replace the oil that is initially in the pores. The injected water propagates through the reservoir in a displacement front and effectively pushes the oil to the producing well. This is represented through the fractional flow model where the parameter Sw-av is used in order to account for the lack of a piston like displacement. An increase in average water saturation of the reservoir relative to the initial water saturation reflects a comparable volume of bitumen being mobilized from the pore space. By manipulating the relative permeability of oil and water, a model can be formulated that is able to effectively characterize the fluid dynamics in the reservoir as they pertain to cumulative recovery. All experiments are assumed to be waterflooding which enables the simplification of the relative permeabilities to a two phase thus negating the contribution of the liquid-gas relative permeability curve. This pseudo two phase relative permeability assumes that only water and oil are present in the reservoir but through this crucial simplification, the recovery of the oil can be simulated and validated.

The implementation of the waterflooding design for the purpose of establishing two phase flow requires that requisite and essential assumptions be made. In conventional waterflooding, the portion of the reservoir that experiences three phase flow is insignificant and the gas, if present, is dissolved in the water due to the pressure increase caused by the oil bank (Craig 1971; Leverett and Lewis 1941). This results in the ability to have a high degree of confidence in accounting for only two phase flow in the reservoir. By treating the steam processes as purely a waterflood, the reservoir can be simplified to a pseudo two phase problem (Spillette and Nielsen 1968). Derivations of the waterflooding techniques proposed by Buckley-Leverett were created on the foundation of one dimensional, incompressible and isothermal flow with no mass transfer between the phases (Buckley and Leverett 1942). The deviance of SAGD from the isothermal nature of the Buckley and Leverett model is addressed by extrapolating the viscosity into the domain of the experiment using the viscosity profile. The viscosity is then constant at the steam temperature and the model reflects a waterflood at a constant temperature associated with the steam. Immiscibility between all the phases allows for the enhanced oil recovery mechanism to be purely a function of the physical displacement by the piston-like waterfront that propagates through the reservoir. However, by definition with solvent steam assisted gravity drainage there is a component of miscibility that enables the dilution of the oil by lowering the relative amount of heavy hydrocarbons (Butler 1985; Gates 2007). The disparity is addressed through utilization of the bulk oil in the proposed model as well as in all of the conducted experiments. Any mass transfer will be contained within the bulk phase of the oil and so consistently reporting all parameters and recoveries in terms of bulk oil will normalize any miscibility issues. Therefore, adequate representation of the fluid flow is established as both the experiments and the analytical model will pertain to the bulk oil produced. Primary assumptions of incompressible flow are pivotal to the derivation of fractional flow theory as volumetric flow of the fluids is the foundation of the displacement (Craig 1971). The piston-like displacement is defined in terms of the volumetric displacement as the water essentially pushes the oil in the form of an oil bank in front of the water as it propagates through the reservoir (Willhite 1986). The compressible nature of the bitumen prohibits the use of purely a volumetric balance and a material balance must therefore be introduced. The Law of Conservation of mass states that matter is neither created or destroyed and so defining the material balance in terms of the mass of each produced and injected fluid enables the model to account for the compressibility of the bitumen. Implementation of a mass balance along with reporting all recoveries in terms of the bulk oil addresses deviances from the primary assumptions required to derive the theoretical model employed in this work. Relaxation of many of the assumptions made for the derivation of fractional flow theory enable the extension of the theory to the domain of the SAGD and S-SAGD techniques.

However, the model has to be calibrated and tuned to encompass the novelty of the application to SAGD. Extremely high viscosity relative to the injected water during a waterflood will lead to poor sweep efficiency. Significant disparity between the viscosity of the displacing fluid and the displaced fluid illustrated by a poor mobility will result in preferential flow of the less viscous fluid to the producing well. Mobility ratios of larger than one will generate a non-uniform displacement profile that is associated with early water breakthrough. The channel created will allow for the water to cut through the bitumen filled porous media and bypass the intended sweeping of the oil. Once established, the channel will conduct the large majority of the water and there will be significant decrease in the cumulative production. So, the time of breakthrough of the experiments must also be matched simultaneously with the cumulative oil production to establish a more comprehensive and unique model. Time of breakthrough can be identified by analyzing the oil flow rate for each individual experiment. Finite flow area of the reservoir dictates that when water breakthrough is achieved, more flow area is being occupied by water and therefore less oil will be produced. By this logic, the time of breakthrough would be when the oil flow rate reaches a peak and begins to decrease as more water is being produced. Identifying the time of breakthrough is illustrated in **Fig 3** where the dashed red line denotes the maximum oil flow rate which directly precedes a substantial decrease in oil flow. The time of breakthrough can then be directly related to the water saturation at breakthrough as a function of a mass balance which accounts for the mass of water injected and the mass of produced oil. By simultaneously matching both the cumulative recovery factor of the bitumen and the time of breakthrough, any concerns of the model being non-unique are addressed. The relative permeability curves are unique as a function of matching two different parameters simultaneously.

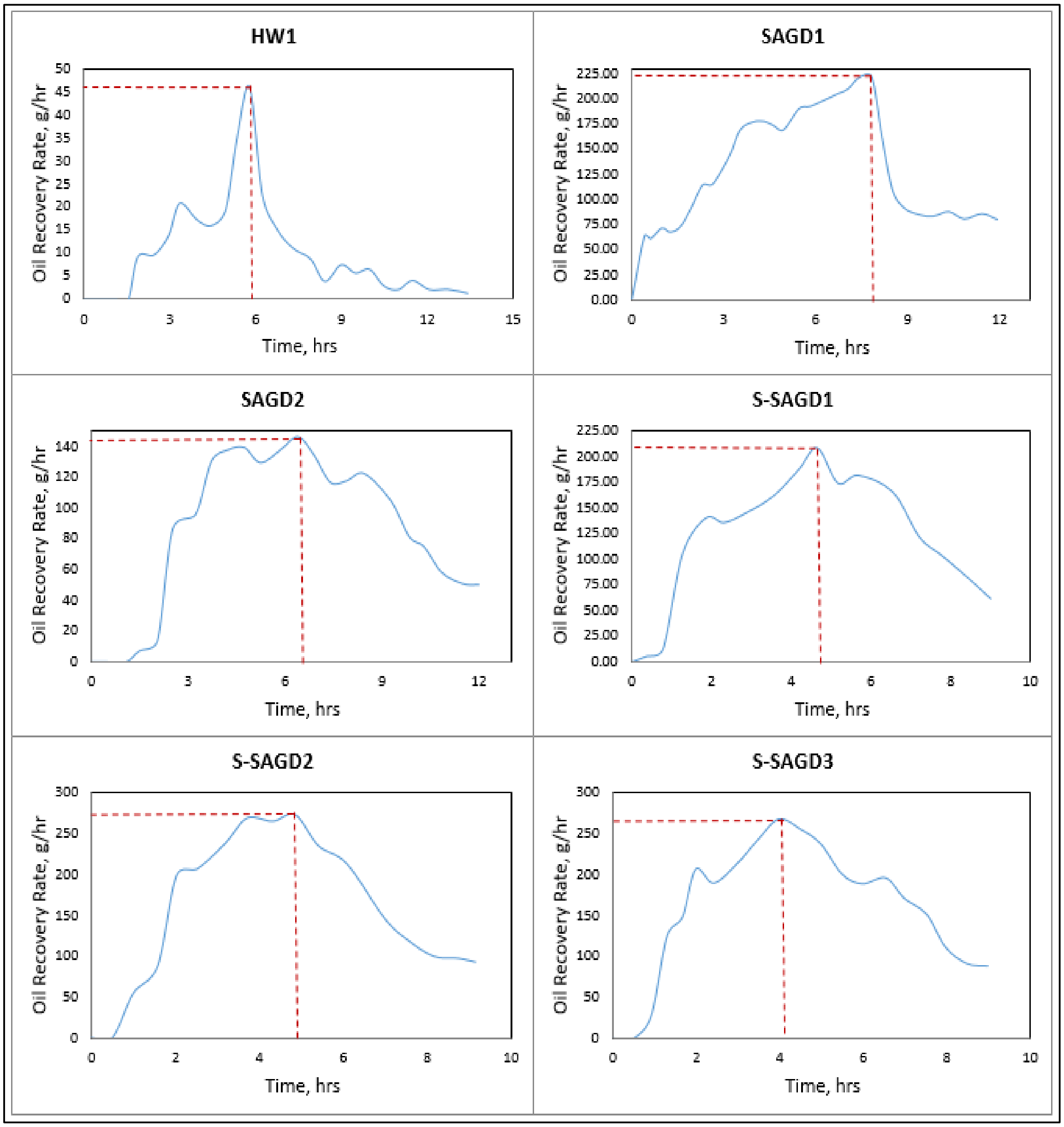


Figure 3 - Oil rate and cumulative oil recovery factor

Fractional flow theory requires that the water breakthrough be analytically matched in conjunction with the cumulative recovery in order to produce the same flow profile in the reservoir. Conservation of mass dictates that any injection of steam must equate to the same production of mass and so by keeping the injection rate constant the water saturation can be tracked as it propagates through the reservoir with respect to time. By calculating the pore volume associated with the reservoir which is modeled with an experimental cylinder, the saturation can be found as a function of the differential between injected water and produced oil. The chamber utilized to experimentally conduct the SAGD process is illustrated by **Fig 4** below.

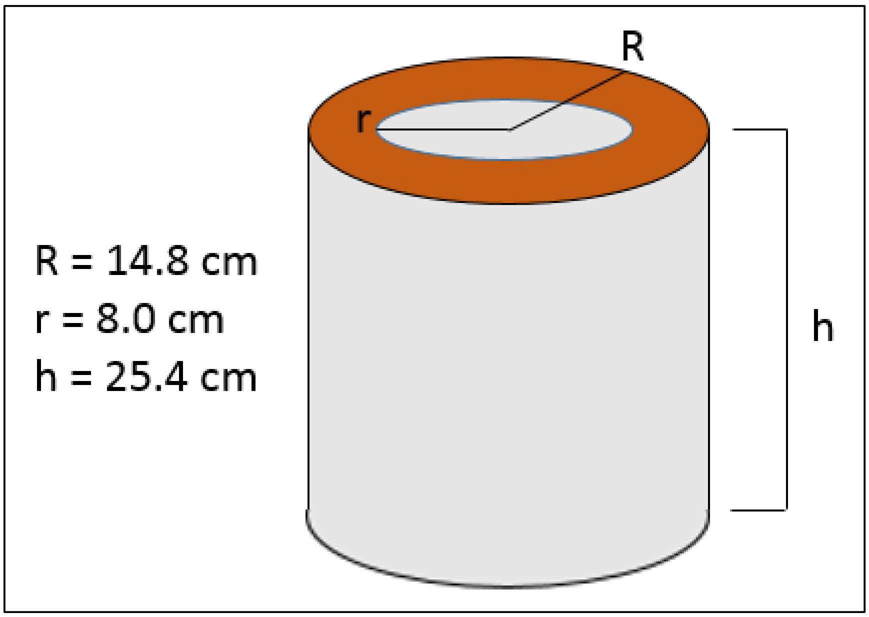


Figure 4 - Volumetric extent of the SAGD chamber

The volumetric extent of the chamber can be mathematically calculated and, with the knowledge of porosity, the pore volumes of water injected can be found. Tracking fluid injection and production with respect to pore volumes allows for the normalization of the mass balance and allows for the definition of the remaining fluid in the pore space. Both the initial water and oil saturation were experimentally defined and so the mass of the oil produced can be subtracted from the mass of the initial oil to define the residual oil saturation. As the water front essentially forces the oil to the production well with a piston-like displacement the pore volume must be replaced in order to maintain pressure and so the water saturation of the reservoir increases in accordance with increasing bitumen production. Knowledge of the pore volume as well as the initial oil saturation enables the calculation of the original oil in place. Oil is displaced from the pore space by the water and so the oil saturation decreases with time while the water saturation increases with time. To account for the compressibility of the oil, the differential of the mass of the produced bitumen and the injected mass of water are tracked which allows for the definition of water saturation at any time. Defining the mass of oil and water in the pore space accounts for the change in volume experienced while altering temperature.

As a function of injected pore volumes for the theoretical model, the cumulative recovery can be found and defined to be comparable to the experimental recovery. Minimizing the difference in theoretical and experimental recovery provides the best possible match and by extension a relative permeability curve that is capable of representing cumulative recovery. The generated relative permeability curve is unique to the reservoir in question which in the case of this study is the Peace River reservoir in Canada but the proposed methodology and model can serve as an analog. The characterization of the reservoir with the pseudo-two phase relative permeability allows for the simulation of cumulative recovery as a function of saturation and by extension time. However, the complicated fluid dynamics in the reservoir on a more localized scale are not represented with this model as, by definition with steam assisted gravity drainage, there is steam in the reservoir which would necessitate a three-phase model.

Conventional waterflooding models generate cumulative recovery as a function of time by starting with relative permeability curves but the reverse engineering model implemented in this study allows for the generation of relative permeability curves as a function of cumulative recovery. Inherent to three phase relative permeability curves is the inability to formulate a generic mathematical model that is viable. Therefore, the analytical model is repeated for all three different processes and the recovery is matched for each case. The reverse engineering approach utilized allows for a unique relative permeability curve to be analytically established for a specific reservoir and steam process by utilization of the Buckley-Leverett model based on fractional flow theory. (Willhite, 1986) The hyperbolic degree of the curve in conjunction with the starting point are analytically manipulated in order to minimize the difference between the experimental results and the theoretical results by use of a solver function. Good match between the analytical model and experimental results will be indicative of the fact that the formulated model is capable of effectively characterizing the fluid dynamics in the reservoir as they pertain to cumulative recovery. The overall sweep efficiency can then be characterized by defining both the mobility ratio which is representative of the macroscopic sweep as well as the capillary number which is representative of the microscopic sweep efficiency. Therefore, the model that is built is valid as a means of matching production and can be used to forecast production.

The governing equation for fractional flow or frontal advance theory is shown below as Eqn 1 where the location of the water saturation (x_{S_w}) is described on the basis of injection rate (q_t), the cross sectional area (A), the average porosity ($\emptyset$), and the fractional flow of water (f_w). The equation describes the velocity of the waterfront as it propagates through the reservoir.

$$\frac{dx_{S_w}}{dt} = \frac{q_t}{A\emptyset}\left(\frac{\partial f_w}{\partial S_w}\right)_{S=S_w} \text{.. Eqn. 1}$$

Conventional frontal advance theory describes the oil production as a function of time that would be achieved with known relative permeability curves. The reverse engineering waterflood implemented in this study is described below to empirically generate pseudo relative permeability curves. The first step involves calculating the dimensionless time of the experiments. Dimensionless time (t_D) is a parameter that is used to normalize the time (t) in terms of the injection rate (q_t) which allows for the direct comparison of all experiments and can be seen in Eqn 2. Dimensionless time at breakthrough is simply the reciprocal of the derivative of the fractional flow of water.

$$t_D = \frac{tq_t}{V_p} \text{.. Eqn. 2}$$

Incremental oil production is dictated by conservation of mass where any retention of water in the pore space corresponds to an equal amount of oil production. The pore space must be filled to maintain pressure so by replacing the pore volume that was initially filled with bitumen by water, the oil production is increased and the residual oil saturation is accordingly decreased. Eqn 3 mathematically represents this concept by relating the difference in average ($\overline{S_w}$) and initial water saturation (S_{iw}) and multiplying the delta function by the pore volume (V_p). Ideally, the fluid front would be completely piston-like and uniform but in reality the fractional flow of water is not 100%. Therefore, the water saturation at the point of breakthrough is a function of time and is referred to as average water saturation. The average water saturation accounts for the lack of an instantaneous and step-wise evolution of the displacement front and takes into consideration any retained water. A representative element approach enables the definition of a numerical value defined to be the water saturation as a function of the cumulative oil production (N_p) which was established by the bench-scale experiments conducted in the lab.

$$N_p = (\overline{S_w} - S_{iw}) * (V_p) \ldots\ldots\ldots\ldots\ldots\ldots \text{Eqn. 3}$$

Once both the dimensionless time (t_{D2}) and the average water saturation ($\overline{S_w}$) are known, the fractional flow of water (f_{w2}) can be calculated as is shown in Eqn 4. This parameter is indicative of the fraction of water flowing in the water front at a specified location in the reservoir and is utilized to characterize the piston-like quality of the displacement front.

$$\overline{S_w} = S_{w2} + t_{D2}(1 - f_{w2}) \ldots\ldots\ldots\ldots\ldots\ldots \text{Eqn.4}$$

Injection of steam, represented by water in this model, propagates throughout the reservoir is the form of a displacement front which effectively sweeps the oil from the inlet to the outlet or production well. Preferential flow of water established due to the much lower viscosity when compared to the oil will result in a non-uniform displacement front and water fingering. Water will bypass the more viscous oil and create a dominant flow channel that will deviate from the front behavior and flow directly to the outlet. The time at which injected water reaches the production well is referred to as water breakthrough and is associated with diminishing return as a result of the poor sweep of oil. The water will preferentially flow through the generated channel and the water front that is pushing the oil bank with a piston-like behavior will be abandoned. Breakthrough is mathematically equivalent to the tangent of the fractional flow of water as a function of saturation at initial conditions and breakthrough conditions which is evidenced by Eqn 5. By differentiating the fractional flow profile the dimensionless time at breakthrough can be determined as it is mathematically defined at the reciprocal of the parameter $f_{wf}{}'$.

$$f_{wf}{}' = \frac{f_{wf}-f_{iw}}{S_{wf}-S_{iw}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{Eqn. 5}$$

Fractional flow of the water can be described on the foundation of the continuity equation coupled with Darcy's Law which is the governing equation for fluid transmission through porous media (Bear 2013; Ingham and Pop 1998; Whitaker 1986). Derivation of the fractional flow equation of water shown as Eqn 6 requires the flow characteristics of the fluid which can be represented by the relative permeabilities and viscosities.

$$fw = \frac{\left(\frac{k_{rw}}{\mu_w}\right)}{\left(\frac{k_{ro}}{\mu_o}+\frac{k_{rw}}{\mu_w}\right)} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{Eqn. 6}$$

To conduct a theoretical waterflood it is necessary to normalize the water saturation to account for the residual oil as well as the interstitial water which is shown by Eqn 7. Normalization of the water saturation enables the tracking of the waterfront as it displaces the oil bank to the producing well and provides the means of comparing the performance of the different experiments.

$$S_{wD} = \frac{S_w-S_{iw}}{1-S_{or}-S_{iw}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{Eqn. 7}$$

Simulation of flow in the reservoir requires that the ability of the fluids to flow relative to each other by adequately defined. Complex dynamics and interactions as a function of temperature and pressure result in preferential fractional flow of one fluid in regard to the other and so the relative permeability is determined as a function of the normalized water saturation in conjunction with the Corey exponents and weighting factors. Eqn 8 is the mathematical definition of the oil relative permeability curve and Eqn 9 is for the flow of water relative to the oil. Parameters A and B are the weighting factors that establish the initial permeability to oil at the irreducible water saturation as well as the final permeability to water at the residual oil saturation and the parameters m and n are the Corey exponents indicative of the hyperbolic degree of the relative permeability curves. Manipulation of all four parameters simultaneously provides control of all aspects of the curve where both the slope and intercept of the exponential curve can be manipulated in order to match the experimental curve established.

$k_{ro} = A * (1 - S_{wD})^m$ .... Eqn. 8

$k_{rw} = B * (S_{wD})^n$ .... Eqn. 9

A flow chart of the reverse engineering waterflood is illustrated in **Fig 5** which summarizes the above process. The manipulation of the Corey exponents contains a nested loop as can be seen by the figure where both the breakthrough and the cumulative recovery have to be solved simultaneously. This nested loop essentially renders the process unique where only one solution can be obtained that satisfies both of the conditions.

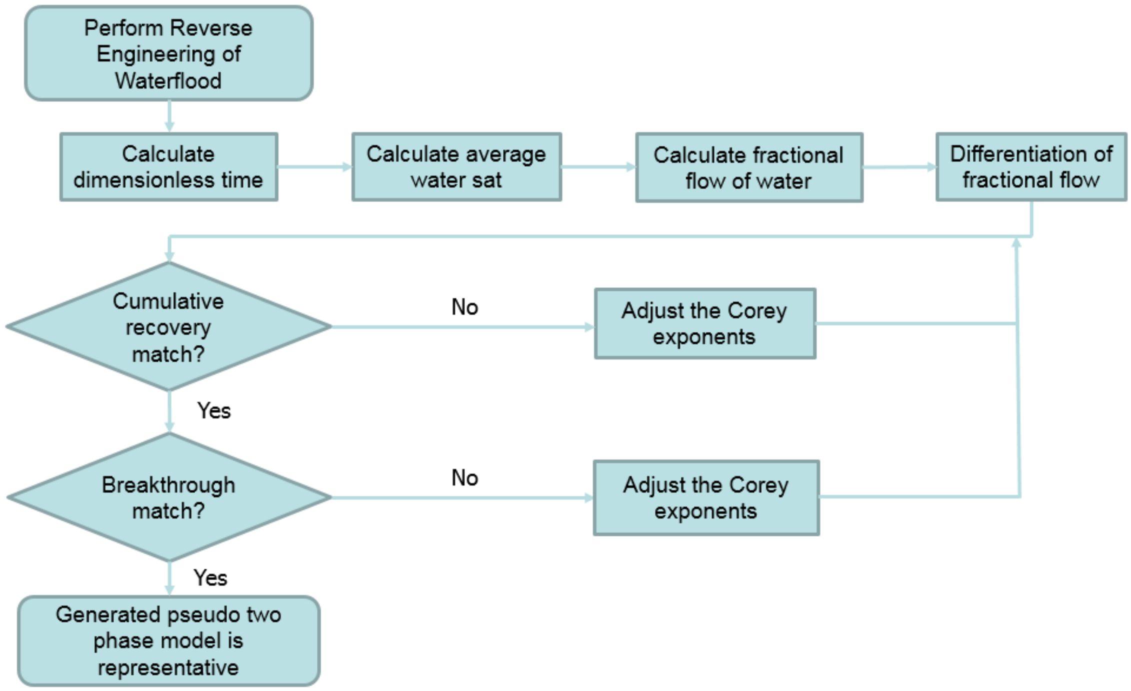


Figure 5 - Flow chart of the reverse engineering waterflood

3.2 Experimental Model

Characterization of any enhanced oil recovery process requires experimental work to establish the validity and viability of the technical aspects of the petroleum recovery (Closmann and Seba 1983; Maini and Okazawa 1987). Therefore, six experiments were previously conducted on a Peace River bitumen sample from Alberta, Canada to determine the enhanced bitumen production as a function of the introduction of heat to the reservoir (Morrow et al. 2014; Mukhametshina and Hascakir 2014; Mukhametshina et al. 2014). To formulate a representative sample the Peace River lithology was simulated by homogeneously mixing 15% by weight clay with 85% by weight Ottawa sand which resulted in a porosity of 32% (Bayliss and Levinson 1976; Hamm and Ong 1995). The pore space was then filled with 84% bitumen (8.8 °API and 54,000 cP) with the remaining volume being taken up by distilled water (Svrcek and Mehrotra 1989). The identified values of porosity and initial oil saturation were provided from literature as being representative of the reservoir properties in Peace River. The six experiments conducted consisted of a hot water flood (HW1), two steam assisted gravity drainage (SAGD), and three solvent steam assisted gravity drainage processes (S-SAGD). The various experiments were performed with the intention of adequately defining the cumulative recovery as a function of the introduction of heat into the reservoir.

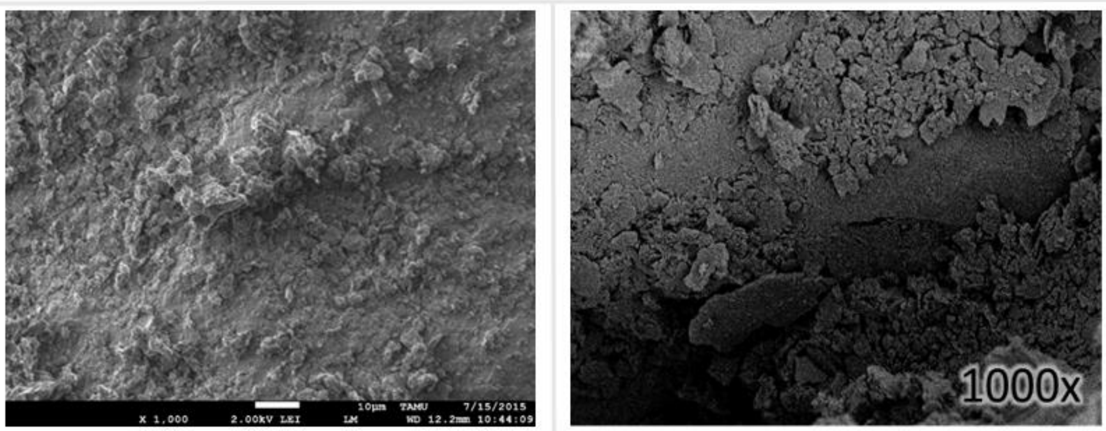
The HW1 experiment denoted E1 is differentiated from the SAGD experiments by the temperature. The SAGD experiments were performed at 165 °C at a constant pressure of 75 psig to ensure a steam quality of 100% was maintained while HW1 was performed at 155°C. Both experiments E2 and E3 were SAGD and are differentiated by the type of clay utilized. SAGD1 (E2) used only Kaolinite as the clay component while SAGD2 (E2) used a mixture of 90% Kaolinite and 10% illite. The last three experiments are S-SAGD1, S-SAGD2, and S-SAGD3 which are represented by E4, E5, and E6 respectively. The first S-SAGD experiment was performed with the solvent component being n-Hexane which is asphaltene insoluble. Experiment E5 was performed with co-injection of n-Hexane and Toluene where the presence of Toluene serves as an asphaltene soluble component (Badre et al. 2006). The last experiment utilized a cyclic injection of n-Hexane and Toluene as opposed to co-injection. Table 1 contains a summary of the important parameters associated with the experiments that were conducted along with the differentiating parameters involved in each. The cumulative oil recovery reported in Table 1 mimics the oil that the wellhead would see and thus contains both clay and water-in-oil emulsions. To make Buckley-Leverett valid and relax the assumption of no mass transfer between the phases, all bitumen recovery reported in the analytical model is in terms of bulk oil and so everything produced in the oil phase is attributed to the oil production. Important to recognize is the fact that production on a field scale with bitumen contains oil with clay and emulsions before going to the separator which is mirrored by presenting recoveries in bulk oil. The identified experiments will be used as a means of establishing fluid flow in the reservoir and will enable the generation of unique relative permeability curves capable of matching the bitumen recovery. The reservoir was considered to be pervasively filled with the bitumen at the saturation discussed above as a result of the homogenous mixing that was conducted.

Table 1 - Summary of the experimental conditions and results

Parameter, unit	**Experiments**					
	E1	**E2**	**E3**	**E4**	**E5**	**E6**
1. Type of Clay	Clay 1	Clay 1	Clay 2	Clay 2	Clay 2	Clay 2
2. Operating Pressure, psig	75	75	75	75	75	75
3. Operating Temp, °C	155	165	165	165	165	165
4. Hot water inj rate, g/min	18	-	-	-	-	-
5. Steam inj rate, g/min	-	18	18	18	18	18
6. Solvent inj rate, ml/min	-	-	-	2	1+1	2/2
7. Experimental time, hours	13.45	12	12	9	9	9
8. Cum Recovery wt%	12.5	46.5	31.5	35.6	44.4	44.9
9. Produced Oil Viscosity @ Room Temp (cP)	54,152	52,466	50,113	34,105	3,556	3,667

*Clay1 contains kaolinite and Clay2 contains kaolinite-illite mixture (Kar et al. 2015)

The vast difference and discrepancy in the recoveries of the two SAGD experiments as evidenced in Table 1 is a function of the different clay content in the experiments (Unal et al. 2015). The presence of purely kaolinite corresponded to a much greater and more efficient recovery relative to SAGD2 which contained both kaolinite and illite. Accordingly, the much lower residual oil fraction of SAGD2 can be attributed to the much more water-wet state achieved as a result of the absence of the pore bridging associated with the illite clay (Unal et al. 2015). The pore bridging effect realized as a result of the illite clay for SAGD2 is illustrated in **Fig 6** which definitively shows a decrease in permeability for the case of SAGD2. The presence of the illite component of the clay mixture interacted primarily with the oil phase which increased the oil-wetness and produced significantly less oil (Mukhametshina and Hascakir 2014; Unal et al. 2015).



A- SAGD1 (1000X) | B- SAGD2 (1000X)

Figure 6 - Images of the two clay types used in the previously conducted experiments

The inability of bitumen to readily flow in the natural state of the reservoir is due to the incredibly high viscosity which is defined as the ability of the fluid to resist flow (Chen and Ito 2012; Evans 1937; Islam and Chakma 1989). Viscosity is directly dependent on the temperature of the sample where an increase in temperature corresponds to an exponential decrease in viscosity. Effective and comprehensive experimental characterization of the bitumen sample required viscosity profiles with varying temperature which can offer insight into the flow capability of the oil at certain time as a byproduct of the advancement of the steam chamber. Energy is introduced into the reservoir and the steam chamber propagates throughout the reservoir so the viscosity is altered as a function of temperature and by extension time. The identified relationship is illustrated in **Fig 7** and is useful in the ability to extrapolate the viscosity into the temperature domain associated with steam processes. The mathematical formula given as Eqn 10 describes the original bitumen and is defined using an exponential curve which is corroborated by the literature (Evans 1937). The SAGD experiments generated slightly different viscosity profiles which are attributed to the injection of steam instead of hot water which is evidenced by Eqn 11 and Eqn 12.

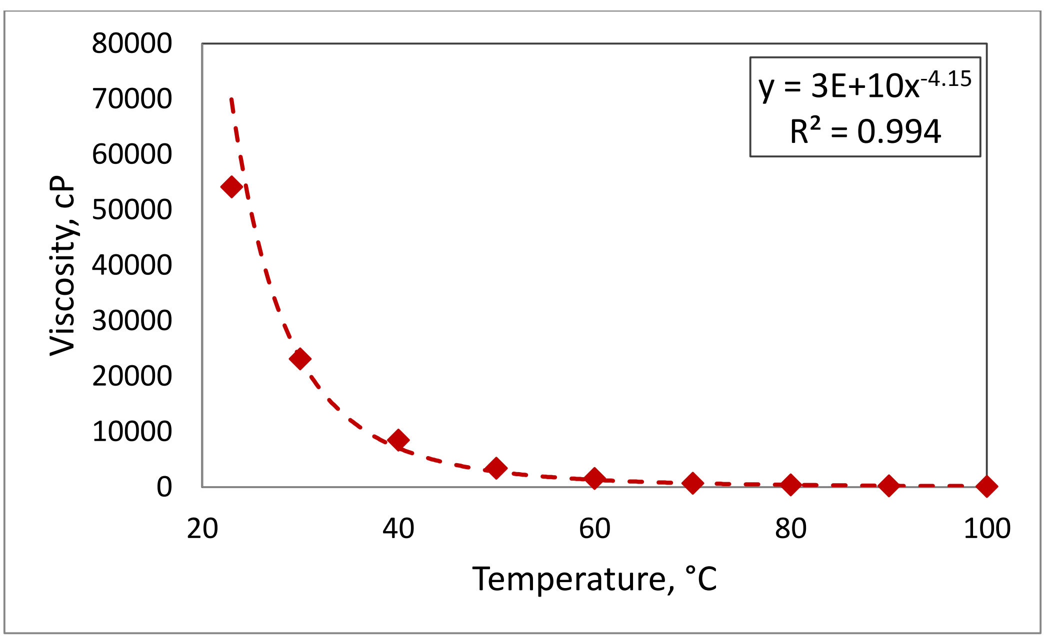


Figure 7 - Viscosity variation as a function of temperature for the original bitumen

$$\mu = (3 * 10^{10}) * T^{-4.15} \quad \text{Eqn. 10}$$

$$\mu = (3 * 10^{10}) * T^{-4.14} \quad \text{Eqn. 11}$$

$$\mu = (3 * 10^{10}) * T^{-4.152} \quad \text{Eqn. 12}$$

The dissipation of heat energy to the reservoir and the direct dependency on time were accounted for by manipulating the original bitumen viscosity of 54,000 cP at reservoir conditions by considering the established correlations described in Eqn 10, Eqn 11, and Eqn 12 (Mukhametshina et al. 2014). Associated with the addition of the solvent component into the steam is a much different viscosity profile as the exponential decrease is not solely a function of temperature but also the miscibility of the solvent. **Fig 8** shown below definitively illustrates two curves where S-SAGD2 contains toluene and S-SAGD1 only contains hexane. The solubility power of toluene is much greater relative to hexane as it is capable of dissolving asphaltenes which are defined as being soluble in aromatics. Asphaltene precipitation increases the viscosity as the particles aggregate and flocculate into large clusters and so the increased solubility power of toluene intuitively results in much greater viscosity reduction. The relationship of viscosity and temperature as a function of the introduction of the solvents can be seen in Eqn 13, Eqn 14, and Eqn 15 where there is a marked difference in the viscosity of the experiments that utilize toluene. The miscibility obtained with the presence of toluene creates a much more favorable mobility ratio and an enhanced flow capability.

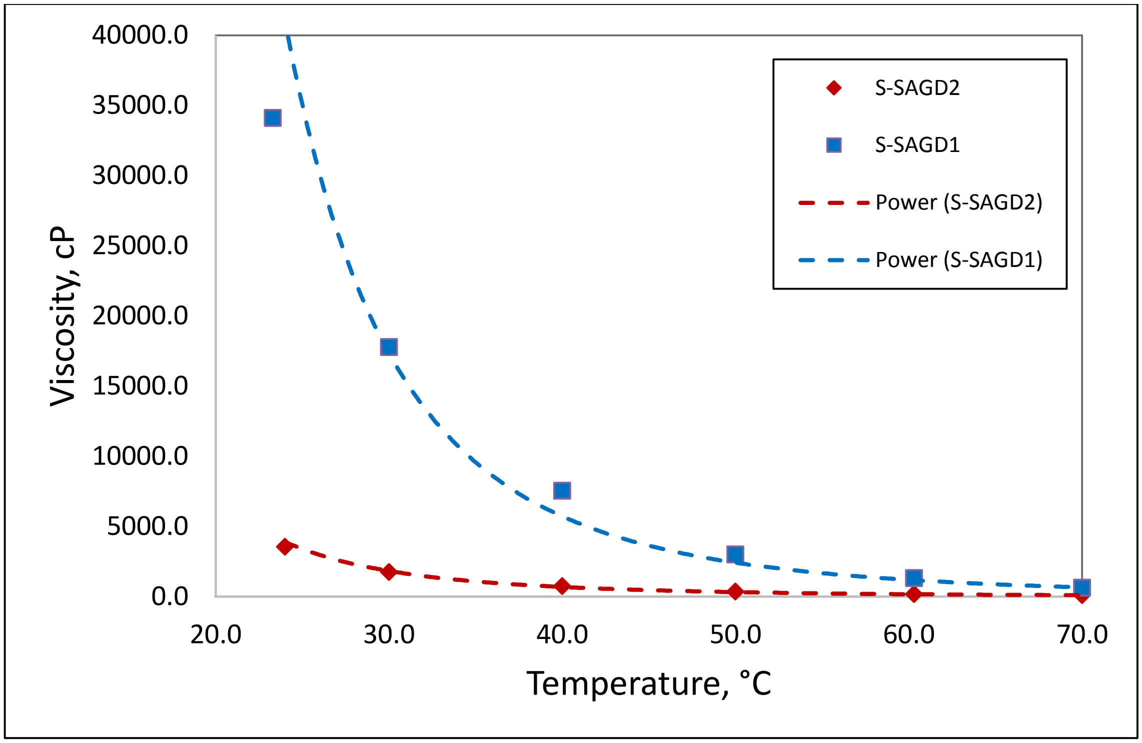


Figure 8 - Viscosity profile of the S-SAGD experiments

$$\mu = (9 * 10^9) * T^{-3.856} \quad \text{Eqn. 13}$$

$$\mu = (2 * 10^8) * T^{-3.39} \quad \text{Eqn. 14}$$

$$\mu = (1 * 10^8) * T^{-3.281} \quad \text{Eqn. 15}$$

4. RESULTS & DISCUSSION

Sound reservoir management practices include and revolve around the concept of extending the life of the reservoir while maintaining profitability. Maximizing the economics of any project require consideration of the time value of money where incentive might be given to produce more oil sooner at the expense of the overall recovery. However, increasing initial recovery may have implications in regard to pressure depletion and decrease in the expected cumulative recovery. Therefore, it becomes necessary and vital to accurately determine the production decline of any reservoir to optimize the economics and formulate the most logical production strategy. The model generated in this study is capable of representing three phase flow in the reservoir through a pseudo two phase waterflood enabling production forecasting of any reservoir that undergoes enhanced oil recovery with steam processes. Simplification of any process while still being representative of the overall flow is necessary to maximize efficiency as well as to model complex problems. The experiments themselves experience three phase fluid flow and all concerns that are associated with three phase fluid flow and so by matching this bitumen recovery, the analytical model essentially addresses any issues or concerns by extension.

Localized flow and fluid transmission through the porous medium consists of three phases where oil, liquid water, and steam are flowing simultaneously but by assuming that fractional flow is valid and treating the experiment as a waterflood the steam phase is negated. Inherent complexity associated with the effective simulation of the SAGD process requires that simplifications be made that enable representation of flow instead of a direct physical model. This study essentially is a means of greatly simplifying the flow of bitumen in the reservoir experiencing three phase flow to a much more manageable scale. The viability and validity of the model is not a function of any physical model presented but rather the great match of cumulative bitumen production versus time of the analytical and experimental model. Simulation of very complex processes through simplification is valid and this study is an attempt at achieving that same idea specific to the SAGD process. Therefore, the proposed model is not capable of modeling the complex interactions of the local flow phenomenon and retention but the overall flow established by the pseudo two-phase relative permeability results in comparable oil production as a function of time. The scope of the analytical model encompasses only the cumulative recovery of the bitumen but this is a pivotal component of any sound reservoir management strategy. Project evaluation is an integral component of petroleum engineering and so this model is valuable in characterizing the reservoir in terms of a decline curve through forecasting. Experimental cumulative recovery and the dependency on time is required for this model due to the nature of the history match and so a core from the reservoir in question is required so that the steam assisted gravity drainage process can be conducted in the lab.

As is illustrated in **Fig 9**, the pseudo two phase relative permeabilities that were generated are more than adequate at matching experimental recovery for the SAGD experiments (Morte and Hascakir 2016). The comparable recovery realized with the waterflooding technique results in a high degree of confidence in the efficacy of the permeability model. The generated relative permeability is unique to the Peace River formation but the applicability of the model can be extended to any reservoir where three phases are present. The viability of simplifying the technique to a waterflood with a pseudo two phase relative permeability is evident in **Fig 9** which definitively shows that the experimental recovery and the analytical recovery are the same (Morte and Hascakir 2016). Also, the dependency on time was able to be adequately represented which results in the ability to confidently estimate cumulative recovery at all time. The red curve which illustrates SAGD1 achieved the largest recovery due to the presence of purely kaolinite clay which can be credited for the more water wet state achieved relative to SAGD2. The hot water flood experienced substantially less bitumen production because, by definition, the fluid injected was not steam but only water and the heat exchange capacity of the water is much less than steam. Immiscibility between the water and the oil in conjunction with the lesser heat exchange capacity is recognized as the contributing factor to the large disparity between bitumen recoveries. For all six scenarios identified the fit of cumulative recovery as a function of time are exact matches which is indicative of an effective relative permeability model. The comparable production established results in the ability to confidently estimate the cumulative recovery for these steam processes in a Peace River reservoir.

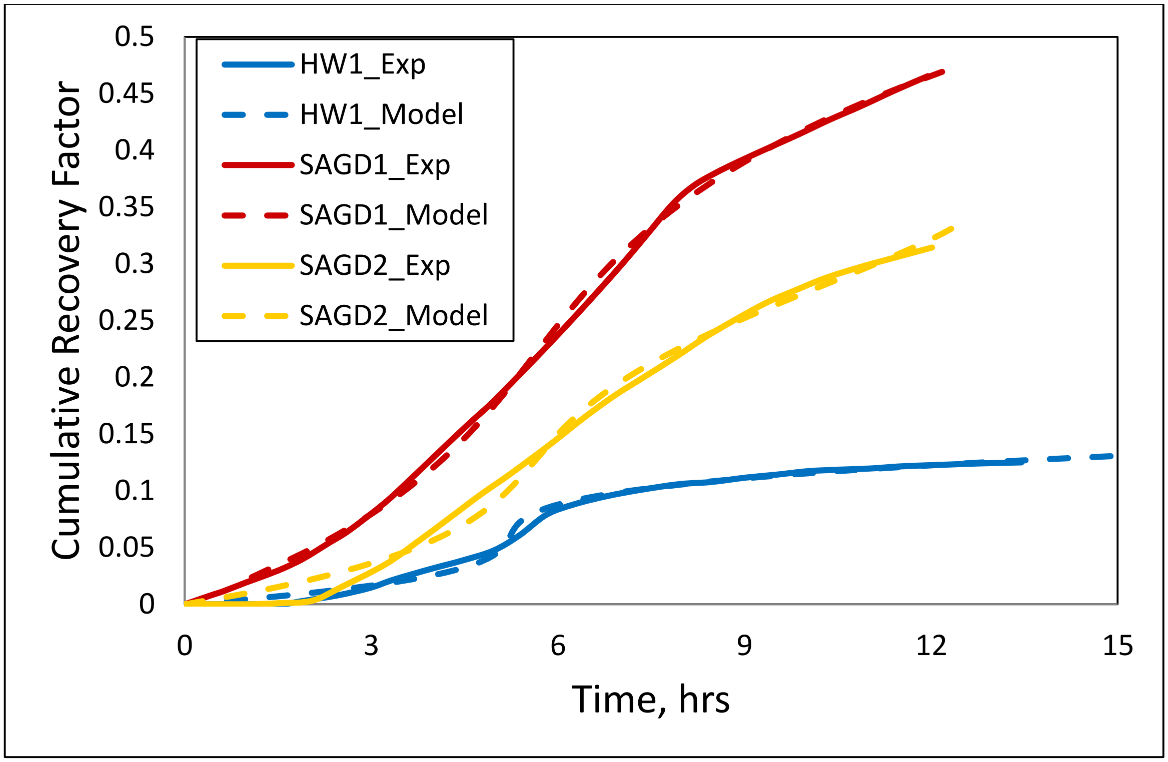


Figure 9 - Cumulative recovery factor match of SAGD experiments by the analytical model (Morte and Hascakir 2016)

Comparison of the base SAGD case which contained the illite component of clay and the S-SAGD experiments offers significant discrepancy in cumulative oil recovery. Miscibility of the solvent and the oil generated an increase in flow potential of the bitumen where an incremental recovery of approximately eight weight percent for S-SAGD1 and thirteen weight percent for the other two S-SAGD experiments was realized. The presence of toluene in both S-SAGD2 and S-SAGD3 increased the cumulative oil recovery as a result of the increase in solubility power and the much greater viscosity reduction. The model proposed in this study was performed on the S-SAGD experiments to bolster the scope and potential influence of the model to include solvent steam processes and results can be seen in **Fig 10** below (Morte and Hascakir 2016). Good match between the analytical and experimental model is once again indicative of a representative pseudo two phase relative permeability curve that is capable of establishing comparable production. Therefore, the applicability of the model can be extended to include the solvent steam assisted gravity drainage process which encompasses miscibility and mass transfer between phases.

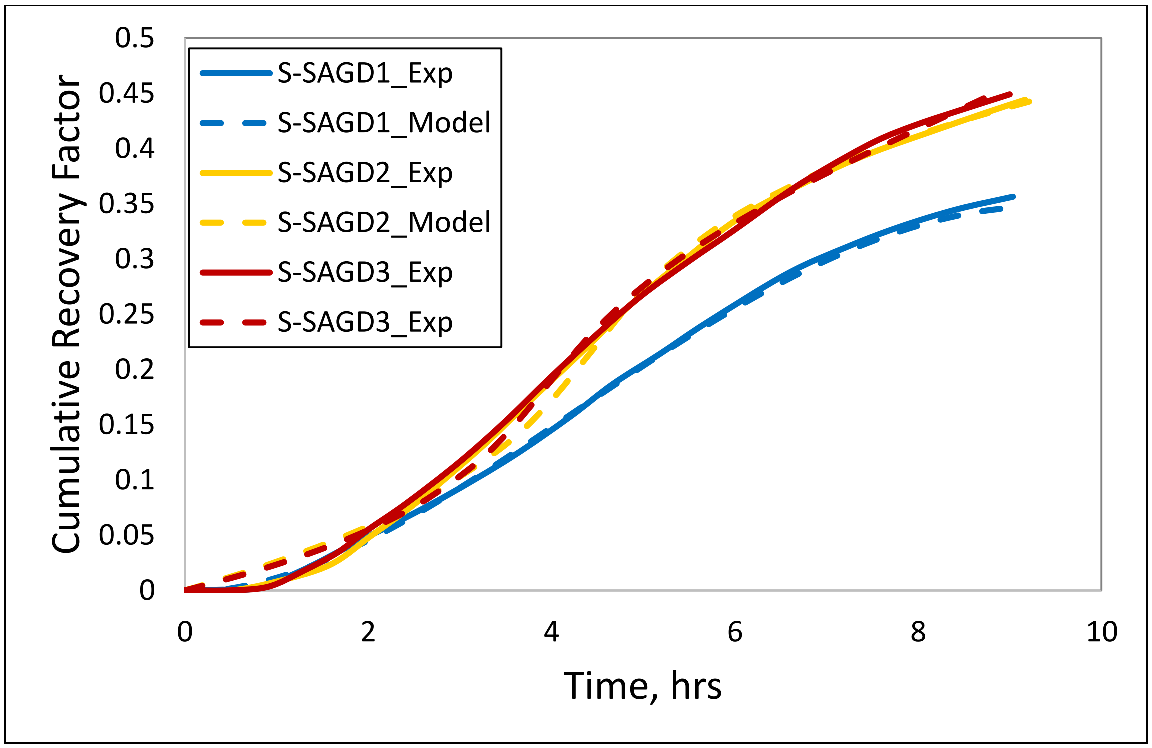


Figure 10 - Cumulative recovery factor match S-SAGD experiments by the analytical model (Morte and Hascakir 2016)

The hyperbolic nature of relative permeability curves inherent to any reservoir that has been identified in research is also evident in the generated curves in **Fig 11** and **Fig 12** for all six steam processes (Juanes and Patzek 2004; Morte and Hascakir 2016). Therefore, the pseudo-two phase relative permeability is governed by a similar empirical relationship as the conventional relative permeability curves. The relationship in regard to the overall shape of the curves is equivalent to what would be anticipated by curves established for a regular waterflood. However, the slope of the curve changes as a function of the increase in recovery relative to each specific process. The impartation of heat to the oil corresponds to a lesser hyperbolic degree where oil is able to flow at higher water saturations which can be definitively seen in **Fig 11** (Morte and Hascakir 2016). Also, upon inspection of the generated curves, there is an incremental increase in the initial permeability to oil that corresponds to an increase in overall recovery factor. Intuitively this makes sense as there would be an increase in recovery associated with an enhanced capability of oil to flow at the outset of the experiment. By maximizing the relative permeability to oil at the beginning of the experiment, the decline to zero relative permeability to oil with respect to the continuous injection of water can be delayed enabling more oil to flow at higher water saturations. SAGD1 had the highest cumulative recovery along with the lowest slope of the oil curve which effectively delays the preferential flow of water until a higher water saturation was reached. The change in wettability in conjunction with the decrease in viscosity associated with the introduction of heat into the reservoir decreases the slope of the oil curve and increases the initial oil permeability. The worst experiment in terms of cumulative recovery was HW1 which experienced the largest slope and lowest initial oil permeability where the flow of water to oil occurred much more quickly. Accordingly, the SAGD experiments were conducted at a much higher temperature and correspondingly achieved an increase in permeability of oil to water illustrated in **Fig 11** (Morte and Hascakir 2016).

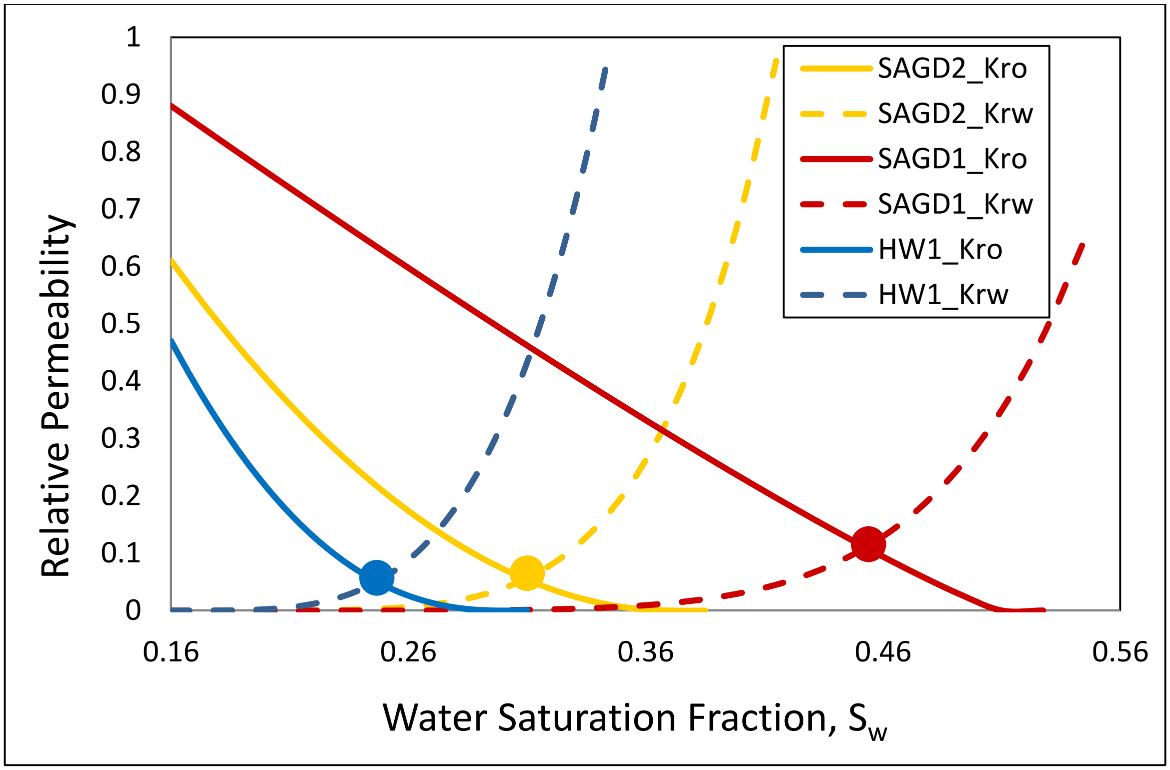


Figure 11 - Empirically generated relative permeability curves for HW1, SAGD1, and SAGD2 (Morte and Hascakir 2016)

The intersection of the water and oil curves can offer insight into the nature of the wettability type of the reservoir and therefore has an effect on the flow capability of the sample. According to Craig's rule of thumb, the sample can be considered to be water-wet when the intersection occurs at a water saturation of greater than 50% (Craig 1971). Alternatively, the sample can be classified as oil wet in nature when the intersection is less than a value of 50% water saturation. **Fig 11** depicts the identified intersection as a blue, yellow, and red dot which represent the HW1, SAGD2, and SAGD1 experiments respectively. All samples are shown to be oil wet in nature which is corroborated by the experimental findings but the red dot, SAGD1, is shown to favor a more water wet state than the blue and yellow dots (Kar et al. 2016; Mukhametshina and Hascakir 2014). The

k_{ro} value is highest for SAGD1 which is indicative of better overall performance by SAGD1 and describes the enhanced ability of bitumen to flow during this experiment at the initial water saturation. The wettability is reflected in the cumulative recovery of each experiments where a more water wet nature is associated with an incremental increase in recovery. The relative permeability at the endpoints for each of the processes can be seen in Table 2 and represents the ability of each fluid to flow at the residual oil saturation and the initial water saturation. Also provided in Table 2 are the Corey exponents that were utilized to produce the pseudo two phase relative permeability curves as seen in both **Fig 11** and **Fig 12** (Morte and Hascakir 2016). The parameters m and n account for the hyperbolic slope of the curve while the parameters A and B account for the end points so that all facets of flow are described by the parameters which can be seen in Eqn 8 and Eqn 9. The ability of oil to flow at the beginning of the experiment is predicated on the reduction of the viscosity and the initial displacement of the injected water. The relationship identified shows a distinct increase in k_{ro} with respect to increasing cumulative recovery for every experiment except S-SAGD3 where the discrepancy was a result of the cyclic injection of solvents.

Table 2 - Endpoints of the generated relative permeabilities for all six experiments

EXP	**k_{row} @ S_w = S_{iw}**	**k_{rw} @ S_w = 1-S_{oirw}**	**S_w @ Intersection**	**A**	**B**	**m**	**n**
HW1	0.47	0.97	0.245	0.47	0.33	2.31	3.92
SAGD1	0.88	0.65	0.458	0.88	0.35	1.15	6.46
SAGD2	0..61	0.92	0.325	0.61	0.34	1.94	5.34
S-SAGD1	0.67	0.61	0.372	0.67	0.41	1.72	5.56
S-SAGD2	0.81	0.93	0.395	0.81	0.78	1.43	5.72
S-SAGD3	0.52	1	0.331	0.52	0.94	2.3	3.7

Upon inspection of the S-SAGD curves illustrated in **Fig 12** it is evident that there is some disparity in the established trends (Morte and Hascakir 2016). Discrepancy in the wettability of S-SAGD3 is attributed to the nature of the injection of the steam and solvent. Unique to this experiment was a cyclic injection of the solvent while simultaneously injecting steam. Switching between the toluene and the n-Hexane produced a viscosity profile that consisted of essentially an average of the two curves identified earlier with S-SAGD1 and S-SAGD2. The model was incapable of adequately capturing the cyclic nature of the experiment as there would be a different relative permeability associated with each individual injection of solvent. The proposed relative permeability curve for S-SAGD3 illustrated in **Fig 12** is able to represent the overall oil recovery as was evident in **Fig 10** but at the expense of the identified trends when compared to the other experiments (Morte and Hascakir 2016). However, the comparable recovery between the analytical model and the experimental model still results in a high degree of confidence in the generated curve as the discrepancy is attributed and explained by the cyclic injection of the solvents.

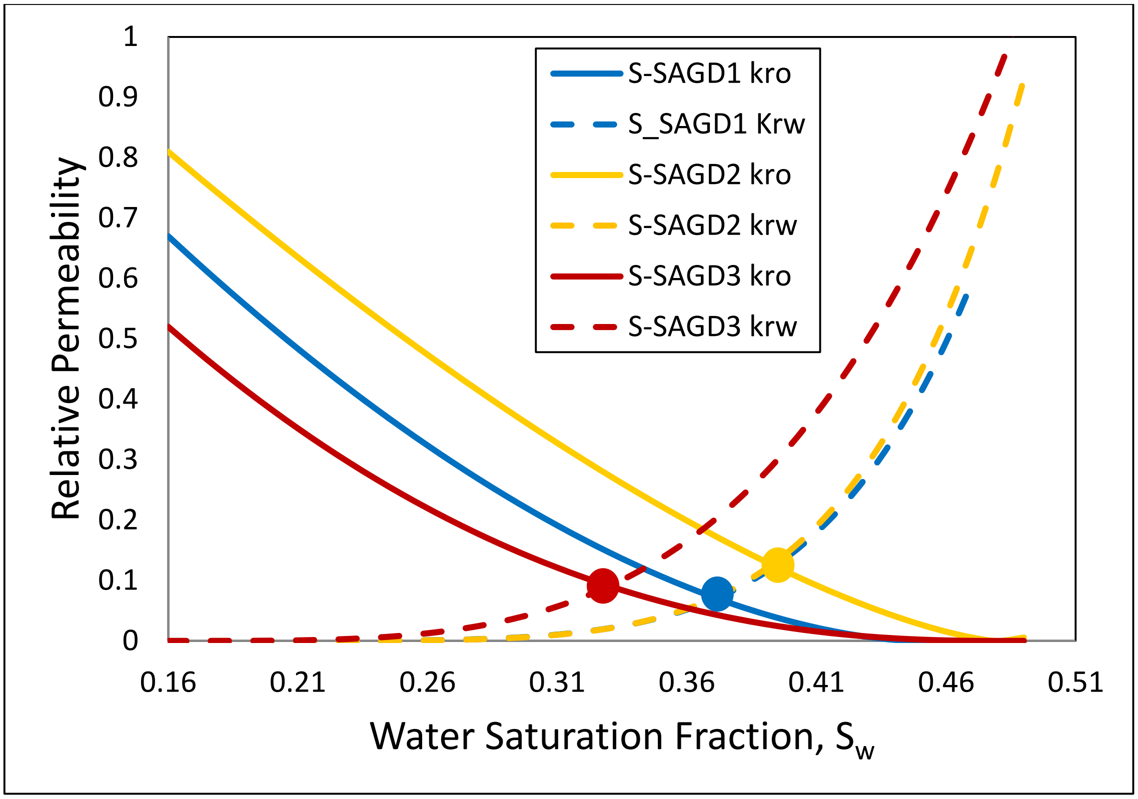


Figure 12 - Empirically generated relative permeability curves for the S-SAGD experiments (Morte and Hascakir 2016)

The increase in cumulative recovery realized by the SAGD experiments is a function of both impartation of energy in the form of heat along with a delayed breakthrough. SAGD1 experienced a water breakthrough at a saturation fraction much higher than the other two experiments which can be seen in Table 3. Table 3 summarizes the important results of the analytical model proposed in this study. The parameter S_{wf} represents the water saturation at breakthrough and the displacement of oil by water was intuitively more effective if the saturation of water is higher. The higher water saturation of SAGD1 means that more oil was displaced and produced. The parameter f_{wf} in Table 3 represents the fraction of water of the displacement front. Ideally, the value would be one where a uniform and piston like displacement is achieved. Therefore, the closer f_{wf} is to one the more optimum the displacement front will be. The introduction of heat and the temperature dependency of the steam processes is accounted for by the change in viscosity of 54,000 cP at reservoir conditions to the domain of the specific steam process. The manipulation of viscosity allows for the negation of the liquid-gas relative permeability and essentially is required to enable the utilization of the pseudo-two phase relative permeability. The presence of the toluene is evident in viscosity values that are approximately four times lower than the viscosity achieved with the SAGD experiments. The mass balance allows for the definition and calculation of the residual oil recovery of the analytical models and the assumption of only two phases in the pore space dictates that the remaining volume be pervasively filled with water. Establishing the density of the bitumen enables the definition of the remaining bitumen in the pore space in terms of volume instead of mass at steam temperatures. The water saturation is then the difference between one and the residual oil fraction. The table also contains the fractional flow parameters of f_{wf} and S_{wf} which summarize the fractional flow of all of the experiments. The two parameters define the piston-like displacement of the front at breakthrough as well as the water saturation at breakthrough.

Table 3 - Summary of the analytical model results

Experiments	Cumulative Oil Recovery, wt %	Oil Viscosity @ Exp. Cond., cP	Residual oil, fraction	Residual water, fraction	f_{wf}	S_{wf}
HW1	12.5	24.4	0.7	0.3	0.85	0.225
SAGD1	46.5	19.8	0.49	0.51	0.92	0.44
SAGD2	31.4	18.6	0.63	0.37	0.89	0.3
S-SAGD1	35.6	25.3	0.55	0.45	0.86	0.34
S-SAGD2	44.4	6.1	0.52	0.48	0.84	0.39
S-SAGD3	44.9	5.3	0.52	0.48	0.81	0.325

Due to the finite flow area, any increase in water production necessitates a decrease in oil production and so the delay of water breakthrough results in higher cumulative recovery for SAGD1. This is illustrated in **Fig 13** where the higher values of S_{wf} and f_{wf} are indicative of later breakthrough (Morte and Hascakir 2016). The less than ideal mobility ratio evidenced by the relatively early breakthrough for HW1 is attributed to the much lower recovery and is shown by the far left position of the curve in **Fig 13** (Morte and Hascakir 2016). The parameter S_{wf} denotes the water saturation at breakthrough and so a higher water saturation at breakthrough is directly related to more bitumen produced as cumulative recovery is a function of the difference in water saturations at any location behind the water front. The parameter f_{wf} describes the fraction of pore space occupied by water at the time of breakthrough of the displacement front where increasing values correspond to more piston-like displacement.

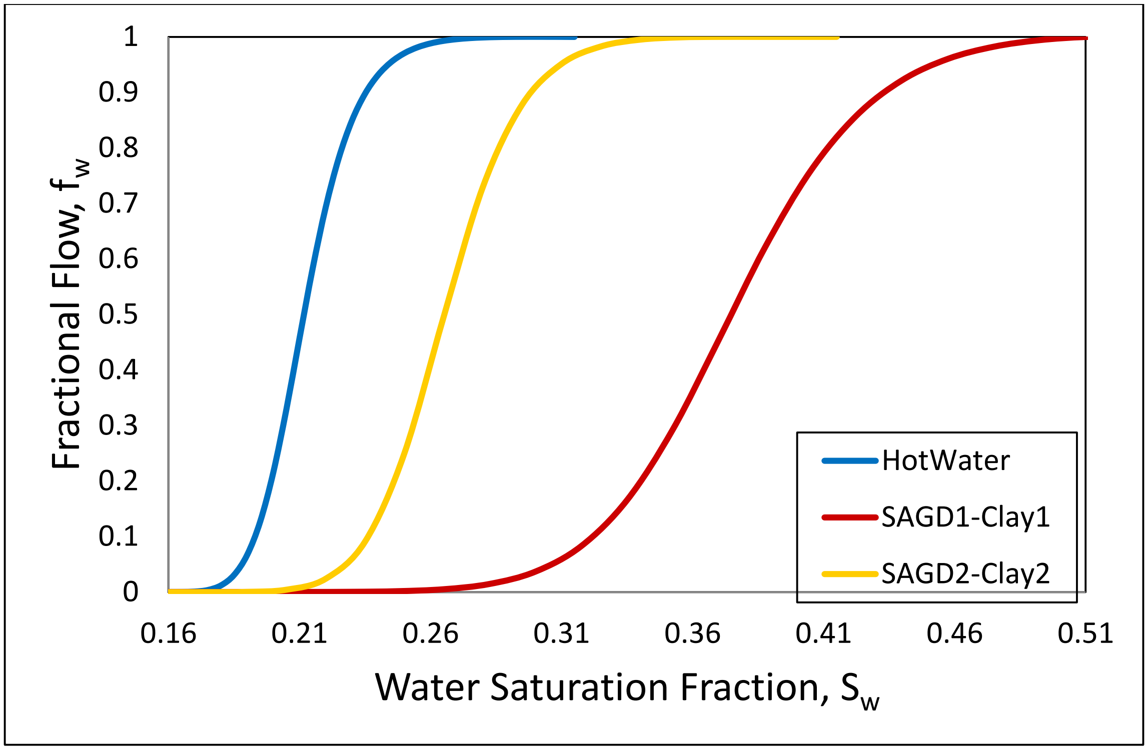


Figure 13 - Fractional flow curve of the HW1, SAGD1, and SAGD2 experiments
(Morte and Hascakir 2016)

Also, the same methodology was applied to the solvent steam assisted gravity drainage experiments where the fractional flow is depicted in **Fig 14**. The results identify a similar trend as was identified above where the greater recovery corresponds to a shift in the fractional flow curve to the left. However, the experiment S-SAGD3 once again strays from the identified trend due to the cyclic injection of the solvents. The fractional flow of S-SAGD3 experiences a different shape with a decrease in the slope of the curve relative to the other two S-SAGD experiments. The good fit that was depicted in **Fig 10** necessitates that this fractional flow be representative of the actual flow and **Fig 14** allows for the extension of the model to encompass the fractional flow of solvent steam processes as well (Morte and Hascakir 2016).

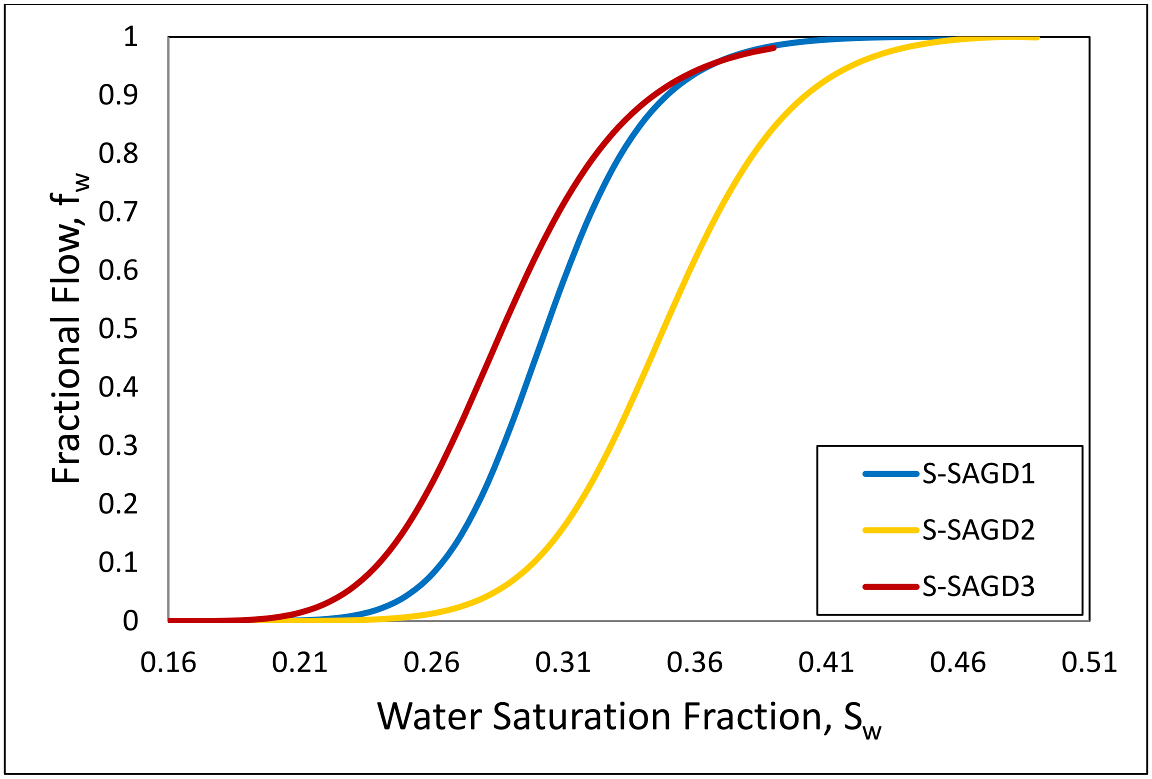


Figure 14 - Fractional flow curve of the S-SAGD experiments (Morte and Hascakir 2016)

Macroscopic sweep of the bitumen by the propagation of the steam is the governing phenomenon behind the incremental increase in recovery. This volumetric displacement is represented by the mobility ratio which describes the ability of the displacing fluid to effectively push the displaced fluid and can be seen in Eqn 16.

$$M = \frac{\mu_o k_{rw}}{\mu_w k_{ro}} \quad \text{Eqn. 16}$$

By taking into consideration the viscosity of the fluids and relating them in terms of a ratio the mobility ratio is able to characterize the relative ability to flow. A ratio of one is ideal where the viscosity of the fluids are the same and so there will be little bypassing of the displaced fluid and a more uniform front will be established. **Fig 15** illustrates the identified relationship where the cumulative recovery is shown to increase with a decreasing mobility ratio (Dyes et al. 1954; Morte and Hascakir 2016). The viscosity of the bitumen is much greater than the viscosity of the water and so the mobility ratio for all six experiments is greater than one but the trend identified definitively shows the increase in production corresponding to the reduction in mobility ratio. Characterizing the recovery in terms of the mobility ratio is a means of illustrating the volumetric sweep capability of all of the experiments and shows a distinct correlation. Macroscopic displacement efficiency increases as heat is introduced and viscosity is lowered and the cumulative recovery accordingly increases.

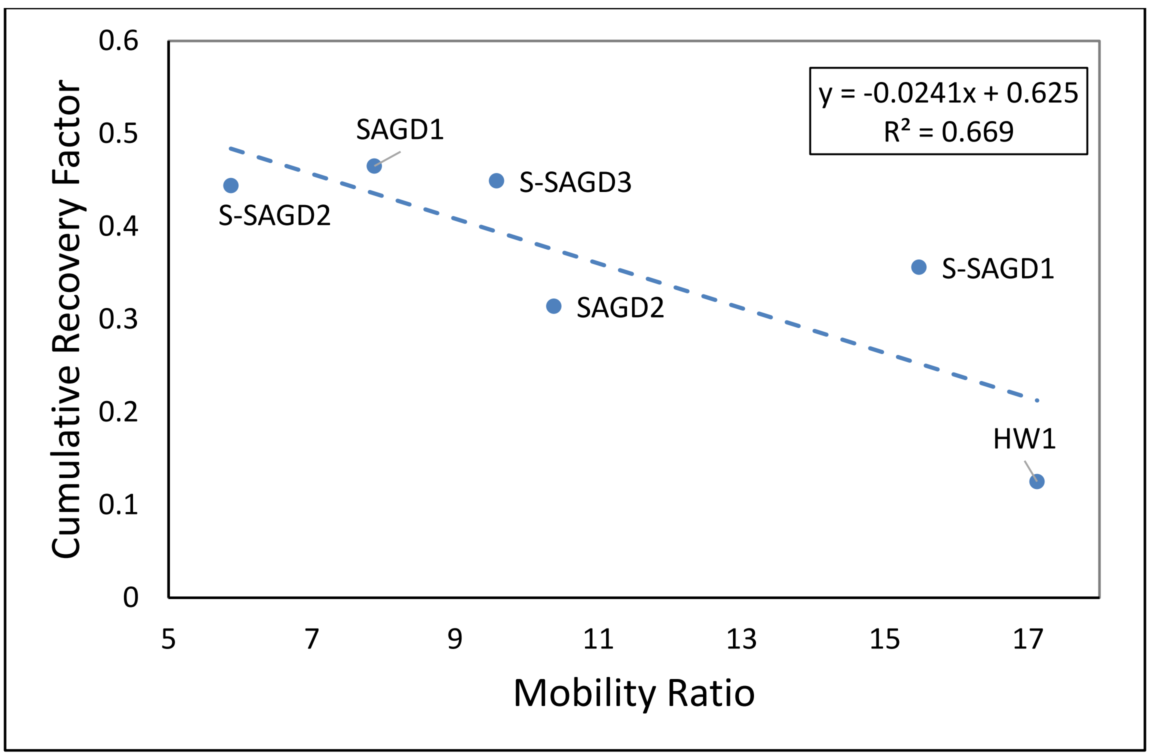


Figure 15 - Mobility ratio vs cumulative recovery factor for all experiments (Morte and Hascakir 2016)

Incremental recovery of bitumen is attributed to the viscosity reduction achieved by the impartation of heat but an extenuation of that is the delayed breakthrough. The parameter S_{wf} denotes the water saturation at the time of breakthrough and **Fig 16** definitely shows a direct corollary between this parameter and cumulative recovery factor. As the mobility ratio decreases, there is less viscous fingering and less bypassing of oil and so the displacement front is more uniform and piston-like. The lack of channeling due to preferential flow of the less viscous water is evident in the identified figure. The pore space is filled with only bitumen and water in this model and so the higher water saturation at the time of breakthrough must directly equate to a higher produced quantity of bitumen. The water essentially replaces the bitumen in the pore space as continuous injection is performed and the mass of water injected must be equal to the mass of the oil produced until breakthrough. At which point, the water will begin to flow preferentially to the producer as a function of the lower viscosity and bypass the unswept region of the bitumen. Therefore, by delaying breakthrough the experiment effectively delays the preferential production of water and maximizes the quantity of oil produced as a result of the mass balance of injected water.

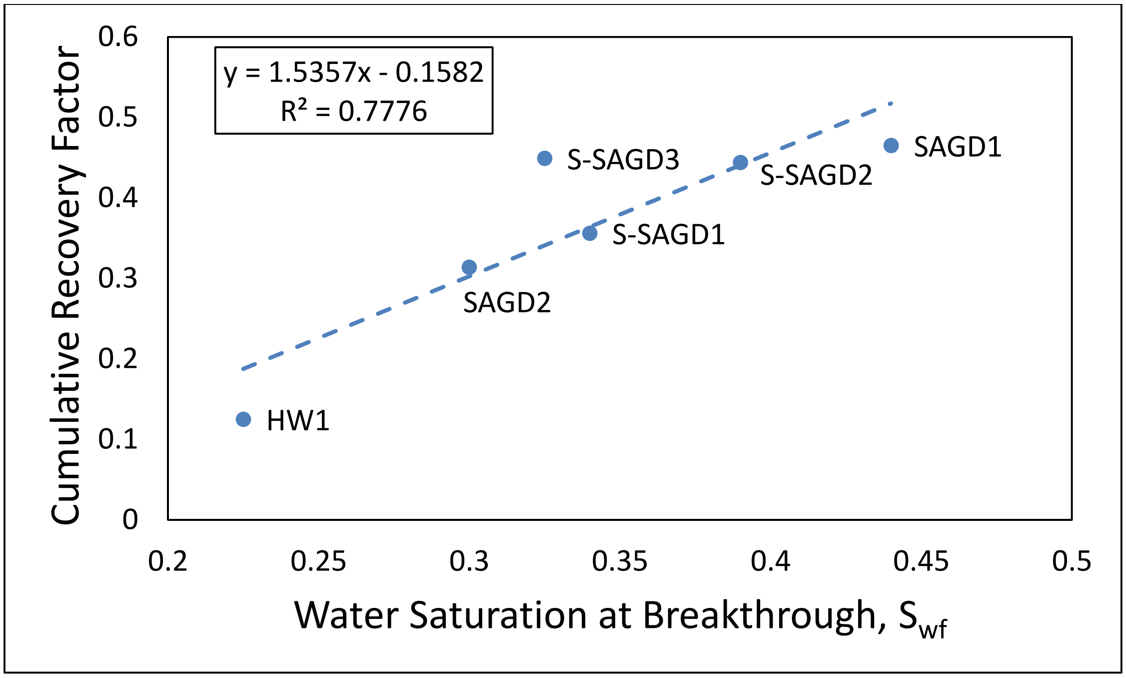


Figure 16 - Water saturation at breakthrough vs cumulative recovery factor for all experiments

To effectively characterize all facets of flow in the reservoir, it becomes necessary to represent the pore scale displacement. The modified capillary number is a quantitative measurement of the ability of the viscous forces to overcome the capillary force and can be seen in Eqn 17. Modified capillary where v is the interstitial velocity, μ_w is the viscosity of the water, μ_o is the viscosity of the oil, S_{oi} is the initial oil saturation, S_{or} is the residual oil saturation, σ_{ow} is the interfacial tension between the oil and water, and θ is the contact angle is utilized to show the efficacy of the experiments in mobilizing bitumen on a pore scale as opposed to the macroscopic scale.

$$N'_{ca} = \frac{v\mu_w}{(S_{oi}-S_{or})\sigma_{ow}\cos(\theta)} * \left(\frac{\mu_w}{\mu_o}\right)^{.4} \quad \text{Eqn. 17}$$

Dominating capillary force will result in trapping of the bitumen by the Jamin effect and this retention of bitumen will reduce the overall recovery (Hao et al. 2008; Li et al. 1999). Therefore, we would expect to see an increase in capillary number correlating to an increase in the cumulative bitumen recovery which is depicted in **Fig 17** (Morte and Hascakir 2016). As the capillary force decreases relative to the viscous forces by the introduction of heat, the bitumen flows more readily and the capillary retention is minimized. The microscopic displacement efficiency increases due to the introduction of heat which changes the wettability but also due to changes in interfacial tension as a result of the injection of solvents.

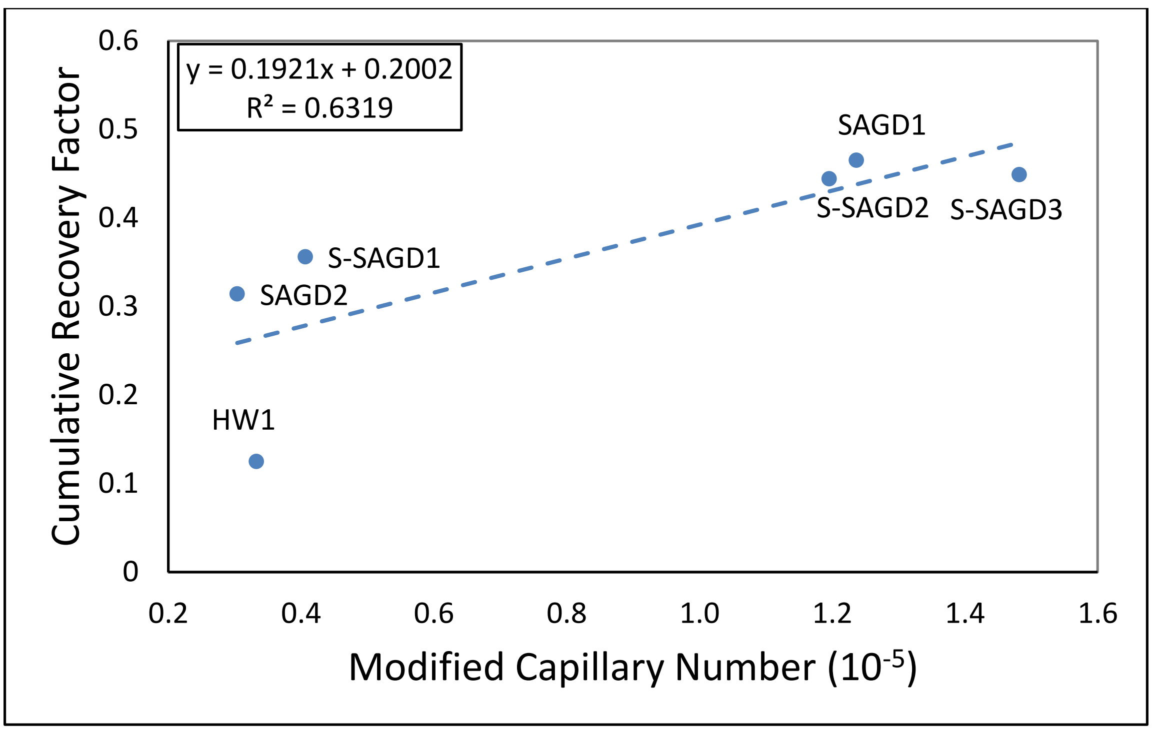


Figure 17 - Modified capillary number vs cumulative recovery factor for all experiments (Morte and Hascakir 2016)

5. CONCLUSIONS

An analytical approach was utilized to empirically obtain pseudo two phase relative permeability curves for HW, SAGD, and S-SAGD experiments. Six bench-scale experiments conducted in lab were used as a means of establishing a cumulative recovery profile that was matched by the analytical model. Utilization of fractional flow theory and considering the experiments as waterflooding negates the steam phase and the temperature dependency associated with it. By implementing a linear waterflood as the mechanism of recovery the three phase relative permeability is regressed to a pseudo two phase. Modifications to the original fractional flow theory allow for the relaxation of primary assumptions thereby extending the applicability to SAGD and S-SAGD. By manipulating the viscosity into the domain of the SAGD process, the waterflood reflects an isothermal displacement at the steam temperature. The temperature dependency is therefore introduced in the manipulation of viscosity for all six of the experiments. The match of recoveries results in confidence in the model and establishes that the empirically generated pseudo two phase relative permeabilities are capable of representing overall fluid flow in terms of bitumen. By extension, the model is then able to forecast bitumen production which is an invaluable tool to any project management decision.

The generated relative permeability curves are effectively able to match a large range of bitumen recoveries which renders this a resilient model. Corresponding to an increase in the cumulative recovery factor is a relative decrease in the hyperbolic slope of relative permeability to oil with a simultaneous increase in the slope of the relative permeability to water. This relationship allows for the flow of oil at higher water saturations and accordingly a greater recovery factor. Delayed water breakthrough as a result of the increase in the fractional flow of water along with a more piston like displacement front corresponded to better performance. Overall displacement efficiency consists of both a microscopic and macroscopic displacement which was represented by modified capillary number and mobility ratio respectively. Both facets of flow in the reservoir correlated well with expected trends from published data which suggests a comprehensive model.

The novelty of the research is the capability of forecasting production generated by the implementation of steam assisted gravity drainage or solvent steam assisted gravity drainage while negating the dependency of temperature for the relative permeability curves. Dependencies of three phase relative permeability on temperature associated with the introduction of heat energy to the reservoir prohibit the utilization of conventional three phase relative permeability curves. By introducing a pseudo two phase relative permeability curve that is capable of adequately representing overall bitumen flow we establish the ability to forecast production. Project selection is a major component of any sound reservoir management strategy and so knowing future production is necessary to maximize economics. Through the implementation of the reverse engineering approach of this research we analytically generate a pseudo two phase relative permeability that results in comparable recovery to the actual three phase fluid flow realized in the lab.

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