INVESTIGATION OF HYBRID STEAM/SOLVENT INJECTION TO IMPROVE THE EFFICIENCY OF THE SAGD PROCESS

A Dissertation

by

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ABSTRACT

Steam assisted gravity drainage (SAGD) has been demonstrated as a proven technology to unlock heavy oil and bitumen in Canadian reservoirs. Given the large energy requirements and volumes of emitted greenhouse gases from SAGD processes, there is a strong motivation to develop enhanced oil recovery processes with lower energy and emission intensities.

In this study, the addition of solvents to steam has been examined to reduce the energy intensity of the SAGD process. Higher oil recovery, accelerated oil production rate, reduced steam-to-oil ratio, and more favorable economics are expected from the addition of suitable hydrocarbon additives to steam.

A systematic approach was used to develop an effective hybrid steam/solvent injection to improve the SAGD process. Initially, an extensive parametric simulation study was carried out to find the suitable hydrocarbon additives and injection strategies. Simulation studies aim to narrow down hybrid steam/solvent processes, design suitable solvent type and concentration, and explain the mechanism of solvent addition to steam. In the experimental phase, the most promising solvents (n-hexane and n-heptane) were used with different injection strategies. Steam and hydrocarbon additives were injected in continuous or alternating schemes. The results of the integrated experimental and simulation study were used to better understand the mechanism of hybrid steam/solvent processes.

Experimental and simulation results show that solvent co-injection with steam leads to a process with higher oil production, better oil recovery, and less energy

intensity with more favorable economy. Solvent choice for hybrid steam/solvent injection is not solely dependent on the mobility improvement capability of the solvents but also reservoir properties and operational conditions such as operating pressure and injection strategy.

Pure heated solvent injection requires significant quantities. A vaporized solvent chamber is not sustainable due to low latent heat of the solvents. Alternating steam and solvent injection provides heat for the solvent cycles and increases oil recovery. Co-injection of small volumes (5-15% by volume) of suitable solvents at the early times of the SAGD operation considerably improves the economics of the SAGD process.

DEDICATION

I wish to dedicate this dissertation to:

My mother, to whom I owe everything in my life,

My father, for believing in me,

My family for supporting me in every step I have taken in my life.

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1. INTRODUCTION

There are huge, well-known resources of heavy oil, extra-heavy oil, and bitumen in Canada, Venezuela, Russia, the USA, and many other countries. Over 90% of the world's heavy oil and bitumen (oil sands) are deposited in Canada and Venezuela. Alberta holds the world's largest reserves of bitumen with reserves of the same order of magnitude as reserves of conventional oil in Saudi Arabia. Up to 80% of estimated reserves could be recovered by in-situ thermal operations. Sophisticated technologies have been required to economically develop Canada's complex and varying oil fields (Nasr and Ayodele, 2005).

Heavy oil and bitumen can be profitably produced, but at a smaller profit margin than for conventional oil, because production and upgrading costs are higher and the market price for heavier crude oils is lower. A large number of technologies can have an impact, but there is no single silver bullet, because of the tremendous variety of heavy oil, extra-heavy oil, and bitumen resources (Clark et al., 2007).

Heavy oil recovery methods are divided into two main types according to temperature. This is because the key fluid property, viscosity, is highly temperature dependent; when heated, heavy oils become less viscous. Cold production methods do not require the addition of heat and can be used when heavy oil viscosity at reservoir conditions is low enough to allow economic rates. Thermally assisted methods are used when oil must be heated before it will flow (Alboudwarej et al., 2006).

Canada, Venezuela, and the United States are leading producers of heavy oil and bitumen. Various existing in-situ technologies such as hot-water injection, steamflooding, cyclic steaming, and combustion processes have been successfully applied in Venezuela and California. Most recently, advances made in directional drilling and measuring while drilling (MWD) technologies have facilitated development of new in-situ production technologies such as steam assisted gravity drainage (SAGD), expanding-solvent SAGD (ES-SAGD) and solvent vapor extraction (VAPEX) that have significantly improved wellbore/reservoir contact, sweep efficiencies, and produced-oil rates and reduced production costs. In Canada, open-pit mining of shallow oil sands provides approximately 50% of the nation's heavy oil production. In-situ production of heavy oil with sand and thermal production using injected steam provide the remainder of Canada's production. In particular, SAGD production is rapidly growing so that SAGD and its variants have become the dominant technologies to recover heavy oil and bitumen. Canada has played the leading role in development and application of the process (Nasr and Ayodele, 2005).

In SAGD, displayed in cross-section in Figure 1.1, steam injected into the reservoir through a horizontal well enters a depleted zone, called the steam chamber, which extends above and laterally away from the injection well as the process evolves. The steam transports convectively from the injection well through the chamber to its edge. Because no pressure gradient is imposed beyond that caused by gravity, at any given time the pressure and temperature are roughly constant throughout the chamber volume. At the edges of the depletion chamber, the steam releases its latent heat to the oil sand, and heat conducts into the cooler oil sand beyond the chamber. Also, at the chamber edges, hot fluids, consisting of bitumen and (steam) condensate, flow under the action of gravity to a horizontal production well positioned typically between 5 and 10 m below and substantially parallel to the injection well. In field practice, the production well is located close to the base of the oil pay (Butler, 1994; Butler, 1998).

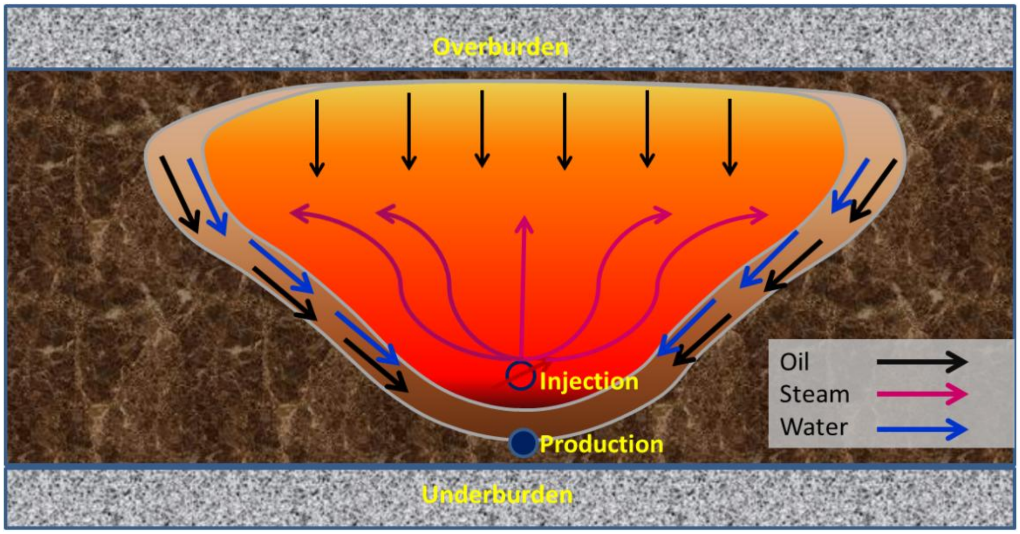


Figure 1.1. Schematics of a 2D cross-section of the SAGD process.

The advantage of the SAGD process is its high oil production rate. However, the high production rate is associated with intensive energy consumption and CO_2 emissions from burning natural gas to generate steam, and costly post-production water treatment (Deng et al., 2008).

Different attempts have been made to accelerate and improve the SAGD process, which can be mainly classified into two categories: chemical and geometrical. The chemical approach aims to directly improve heat efficiency and reduce interfacial tension to achieve higher production. The geometrical approach attempts to alternate pressure differential points related to well placement to achieve accelerated steam chamber growth (Bahlani and Babadagli, 2008).

One may capitalize on the advantages of both solvent-based and thermal processes by co-injecting a hydrocarbon additive with steam. The aim of hybrid steam solvent processes is to take advantage of the viscosity reduction capability of both heat and solvent and reduce the energy intensity of the SAGD process (Nasr et al., 2003). Higher oil production, lower steam-to-oil ratio (SOR), increased well productivity, and increased ultimate oil recovery have been expected from the addition of the solvent to steam. The challenges are the solvent type, solvent concentration, injection strategy, and operating pressure (Govind et al., 2008).

1.1. Research objectives

The role of a hydrocarbon additive in the steam chamber and its effect on the performance of the gravity drainage process are not clear. In fact, co-injecting a hydrocarbon additive with steam can improve or conversely deteriorate the energy efficiency or oil rate of SAGD via different mechanisms, depending on several variables. Operating pressure and temperature, phase behavior of the hydrocarbon additive, original reservoir fluid composition, and reservoir physical properties dictate the role that hydrocarbon can take in the steam chamber.

The main objective of the current study is to develop an efficient process using steam and the proper solvents to reduce the drawbacks of the SAGD process. There are several scenarios for combination of solvents and steam in terms of hybrid steam/solvent processes. Extensive simulation study was carried out to narrow down the range of applicable hybrid steam/solvent processes. The type of solvent, solvent concentration, and injection strategy were determined from a simulation study. Since the presence of solution gas seems to play an important role in steam and solvent processes governed by gravity drainage, a mechanistic study was performed to understand the role of solution gas and also to have better insight into the combination of heat and mass transfer in hybrid steam/solvent processes.

An experimental study was used to examine the selected hybrid steam/solvent injection processes. Experiments were conducted with different solvents and injection strategies to examine the effect of solvent co-injection with the steam. Oil production rate, steam consumption, oil recovery factor, steam chamber growth, and residual oil saturation were used to compare different experiments.

2. LITERATURE REVIEW

The major challenge in heavy oil and bitumen recovery is low mobility or immobility of the reservoir fluids at reservoir conditions. Steam and hydrocarbon additives are known to be the best sources to reduce the viscosity of heavy oil and bitumen. Many researchers have investigated the combination of heat and solvents to take advantage of both of them to efficiently produce heavy oil and bitumen. Various types of solvents with different concentrations have been tested to increase the performance of displacement mode processes. Ali and Abad (1976) and Hernandez and Ali (1972) investigated the bitumen recovery from oil sands by using solvent in conjunction with steam. They concluded that bitumen recovery is determined by the type of solvent, the steam/solvent volume ratio used, and the solvent placement. Redford and McKay (1980) and Redford (1982) experimented with co-injection of a variety of solvents including methane, ethane, propane, butane, pentane, naphtha, natural gasoline, great Canadian oil sands (GCOS) crude, CO_2, and combinations of some of the solvents with steam in displacement and drawdown modes. Shu et al. (1988) conducted a series of simulation studies to investigate the effect of solvent type and concentration. They categorized the solvents into light, medium, and heavy solvents according to their respective volatility (high, medium, and low) under reservoir conditions during thermal recovery. They concluded that lighter solvents promote earlier oil recovery and contribute to displacement drive, whereas medium solvents provide the greatest increase in total oil production. Heavy solvents improve recovery slightly, which is offset by solvent retention.

The combination of steam and solvent in gravity drainage processes has been a subject of discussion of many experimental and simulation papers since the successful field tests of the SAGD process. In recent years, several SAGD projects have been initiated. Every operator is coming across new learning almost every day, although most of the information is proprietary.

Although SAGD appears to be the most promising in-situ recovery for heavy oil and bitumen recovery, it suffers from high energy intensity and environmental impacts. The aim of hybrid steam-solvent processes is to take advantage of the viscosity reduction capability of both heat and solvent and to reduce the energy intensity of SAGD process (Nasr et al. 2003). Higher oil production, lower SOR, increased well productivity, and increased ultimate oil recovery have been expected from the addition of the solvent to steam.

Hybrid steam/solvent processes are different variants of SAGD process. They include steam-assisted gravity drainage (SAGD), vapor extraction (VAPEX) (Butler and Mokrys, 1991; Das, 1998), expanding-solvent SAGD (ES-SAGD) (Nasr and Ayodele, 2006; Nasr et al., 2002a; Nasr et al., 2003) and steam-alternating solvent (SAS) (Zhao, 2004). These techniques are similar in principle; the main different among them is the composition of the injected fluid and the injection strategy. They are all based on the combination of horizontal well technology and gravity drainage mechanism. In VAPEX, pure solvent is injected, while in SAGD, pure steam is injected.

Steam extraction requires heating about 8 kg of tar sand to a very high temperature (200 to 260ºC) to mobilize 1 kg of bitumen. Consequently, steam production requires combustion of enormous amounts of fuel (about 30% of the heating value of the bitumen) and creates substantial carbon dioxide emissions (Nenniger and Dunn, 2008).

Thermal processes such as SAGD cannot be applied to some problematic reservoirs such as thin formations or heavy oil in offshore and deep reservoirs. Butler and Mokrys (1991) described a new recovery concept similar to SAGD. The process was intended to be used in thin reservoirs, where the application of SAGD alone was uneconomical due to the high heat losses to the formations above and below the reservoir. The process, called VAPEX, involves injection of vaporized hydrocarbon solvents into heavy oil and bitumen reservoirs; the solvent-diluted oil drains by gravity to a horizontal production well. Later research showed that the process is highly energy efficient, environmentally friendly, causes in-situ upgrading, and requires low capital investment compared to its competitor, SAGD. The applicability of the VAPEX process may even surpass SAGD in thin reservoirs, reservoirs underlain by aquifers, offshore operations, etc (Das, 1998).

Numerous experimental and simulation studies exist in literature regarding the VAPEX process. These include work on solvent type and composition (Badamchizadeh et al., 2008; Derakhshanfar et al., 2009; Gul and Trivedi; Singhal et al., 2002; Talbi and Maini, 2004), upscaling (Yazdani and Maini, 2005), reservoir-parameter effects (Jiang and Butler, 1996; Thimm, 2007), asphaltene precipitation (Ardali et al., 2009; Haghighat and Maini, 2008).

The main concern about VAPEX has been the slow nature of mass diffusion. Several field pilot tests of VAPEX have been done, but most results are proprietary. Baytex has reported oil production rates of 5 m^3/day and EnCana reported oil rates of 1.5 m^3/day from their VAPEX pilot (Nenniger and Dunn, 2008) .

Addition of variable amounts of heat in different forms has been proposed by many researchers to accelerate and enhance the economics of VAPEX. In solvent-based processes, solvent is used as the main tool to reduce the viscosity of heavy oil and bitumen. Mass transfer is much slower than heat conduction. Addition of heat in different forms such as electrical heating, electromagnetic heating, and steam have been examined to accelerate solvent-based processes.

Nenniger and Dunn (2008) and Nenniger and Gunnewiek (2009) described a thermal solvent process, N-Solv, which does not use steam. Instead, it uses pure vapor propane, the same as the VAPEX process. With N-Solv, the VAPEX process is operated at elevated pressure and heat is added to the solvent to vaporize it. This means that the solvent is condensed to slightly heat the reservoir as the front expands. Nenniger et al. (2009) showed that the elevated temperatures greatly accelerate drainage rates compared with VAPEX, to a point exceeding SAGD rates. With high production rates at moderate temperatures N-Solv offers potential for dramatically reduced CAPEX and energy costs, no water consumption, reduced greenhouse gas emissions, and improved oil quality.

Nenniger and Dunn (2008) and Nenniger and Gunnewiek (2009) believed that the main problem of the VAPEX process was the high viscosity of the in-situ fluid and the poisoning effects of the noncondensable gas (NCG) in a conventional VAPEX process. If a stable vapor chamber with moderate temperatures of 40 to 50°C could be achieved, the oil rates could be on the order of the SAGD process.

N-Solv was designed to operate at solvent bubble point conditions rather than at the solvent dew point conditions, which are conventionally implemented in the VAPEX process. By attaining the bubble point conditions at the solvent-bitumen interface, the less-volatile components of the oil would also condense along with the solvent; therefore, the vulnerability of the VAPEX process to the presence of less-volatile components would be eliminated. Furthermore, the quality of the produced oil would also be enhanced as a result of in-situ upgrading through asphaltene precipitation (limited asphaltene precipitation in this process is expected to have insignificant role on oil recovery). Based on an empirical correlation derived for scaling the VAPEX process, N-Solv was estimated to produce considerably more oil than SAGD process, with significantly lower energy consumption. However, these predictions were based on extrapolating the lab-scale experiments, which brings uncertainty to the estimation results (Rezaei and Chatzis, 2007). No published experimental results and field applications are available, but many disadvantages are associated with the hypothesis. Considering that the heat capacity and saturation temperature of propane are much lower than steam, an accelerated production rate of this process over SAGD is under skepticism.

The most important disadvantage of N-Solv is the high dynamic retention of solvent that follows from using solvent to raise and maintain the temperature. Heat losses will ensure that condensing conditions will persist in most of the chamber until final blow-down, therefore, liquid solvent saturations in the depleted zone remain elevated above the oil phase residual (Edmunds et al., 2009).

Frauenfeld et al. (2005; 2007; 2006; 2008) and Ivory et al. (2006; 2007) from Alberta Research Council (ARC) conducted numerical and experimental studies of the addition of heat in different forms to the solvents. They described the process as thermal solvent reflux or thermal solvent recovery processes. The objective of these processes was to develop a solvent-based recovery mechanism to recover heavy oil from thick formations in the Cold Lake and Athabasca reservoirs. The thermal solvent recovery processes concept is to inject solvent and produce oil though horizontal wells and to heat the injection and production wells to reboil the in-situ solvent (solvent reflux or in-situ recycling of the solvent). Heat can also serve to initiate communication between an injection well and the producer, enabling solvent injection, or to speed the diffusion of solvent into the oil. This process involves one or more heated wellbores. Heat is at first used to establish communication between the injection and production wells, but later is used to vaporize solvent or to reflux solvent from the production well. Refluxing reduces the volume of solvent that must be pumped to the surface with the oil, and also reduces the volume of solvent to be separated, purified, stored, and re-injected from the surface.

Electrical or steam heat in the production well was capable of recycling ethane in situ. Methane, ethane, propone, butane and their mixtures were examined. Their results show much lower production rate and recovery factor than with steam injection. The main reasons are that the heat delivered by a solvent under non-condensing conditions is too small, and the solubility of the solvent in the bitumen is too low to significantly reduce the oil viscosity (Li and Mamora, 2010) .

There is a need to formulate pore-scale mechanisms during hybrid VAPEX, which, to date, have not been fully identified. Pore-scale mechanisms during VAPEX and warm and wet VAPEX were analyzed experimentally by Rezaei and Chatzis (2007; 2009). The role played by different mass transfer models (diffusion, convection) and heat transfer mechanisms need to be quantified to understand exactly how each process works and how to optimize operating conditions for maximum oil production at the lowest cost.

In the solvent-assisted SAGD process, different types of the solvents were used to reduce the drawbacks of SAGD. In these processes, steam is used as the main tool to reduce the viscosity of heavy oil and bitumen. Nasr et al. (2002b) developed expanding solvent SAGD (ES-SAGD) process, which is one of the modifications of the SAGD process combining the benefits of steam and solvents in the recovery of heavy oil and bitumen. The solvent is injected with steam in a vapor phase, and then the condensed solvent around the interface of the steam chamber dilutes the oil in conjunction with heat, and reduces its viscosity. Compared to conventional SAGD, this process can improve oil production rate and decrease SOR, energy and water requirements.

Several experimental studies were conducted at ARC by Nasr et al. (2003; 2006a) regarding solvent-assisted SAGD process, although most of their experimental results are not in the public domain yet. They have investigated the effect of solvent type and concentration. In their work, steam remains the main tool to reduce the viscosity. An initial screening of solvents was carried out by comparing the vaporization temperatures of a wide range of hydrocarbon solvents (C_3 to C_8 and a diluent) to that of steam temperature.

In the ES-SAGD process, a hydrocarbon additive at low concentration is co-injected with steam in a gravity-dominated process, similar to the SAGD process. The hydrocarbon additive is selected in such a way that it would evaporate and condense at the same conditions as the water phase. By selecting the hydrocarbon solvent in this manner, the solvent would condense, with condensed steam, at the boundary of the steam chamber. In the ES-SAGD process, the solvent is injected with steam in a vapor phase. Condensed solvent around the interface of the steam chamber dilutes the oil and in conjunction with heat, reduces its viscosity (Nasr et al., 2003).

Gupta et al. (2002) and Gupta and Gittins (2005) described a solvent aided process (SAP) that aims to combine the benefits of SAGD and VAPEX. In SAP, a small amount of hydrocarbon solvent is introduced as an additive to the injected steam during SAGD. While steam is intended to be the main heat-carrying agent, the solvent will dilute the oil to reduce its viscosity beyond what is accomplished by heating alone. The overall effect should be an improved oil-to-steam ratio (or reduced energy intensity). Cenovous Energy is currently undertaking a field scale pilot of the SAP process at Christina Lake (Orr, 2009) . In the SAP process, butane was co-injected with steam, and very promising results were obtained (62% decrease in SOR and 80% increase in oil production rate).

Liquid addition to steam for enhancing recovery (LASER) involves the injection of a liquid hydrocarbon (C_{5+}) as steam additive in the cyclic Steam Stimulation (CSS) mode of operations. It was first tested in laboratory with Cold Lake bitumen and was later field-tested by Imperial Oil Resources Canada at its Cold Lake Bitumen lease. Although the LASER process is in the CSS mode, in the late cycles of operation, the mechanism of oil recovery is dominated by gravity drainage. Hence, the injected solvent behaves in a similar way to the injected solvent in gravity-drainage-based processes such as ES-SAGD. The injection of the solvent is done at late cycles to be able to recover more solvent and reduce solvent retention. The pilot test involved co-injection of 6% by volume fraction of C_{5+} condensate during CSS cycle 7. The oil-to-steam ratio was improved by 33% in the pilot test (Leaute, 2002; Leaute and Carey, 2007).

Zhao (2004; 2007) proposed a new heavy oil recovery process called steam alternating solvent (SAS). The process is intended to combine the advantages of the SAGD and VAPEX to minimize the energy input per unit oil recovered. The SAS process involves injecting steam and solvent alternately, and the basic well configurations are the same as those in the SAGD process. Numerical simulations were conducted to assess the process performance under typical Cold Lake reservoir conditions. Based on preliminary estimation, the energy input per unit of oil recovered using SAS is 18% less than that using SAGD. In the experiments, steam and propane were injected. The experimental results were not encouraging but Zhao (2004) claimed that in the real field the results would be more promising because of higher diffusion and dispersion. The main problem with SAS process is the cooling of the system in propane injection cycles. In addition, a portion of propane gas stays in the chamber in steam-injection cycles. This prevents effective heat transfer by SAGD process.

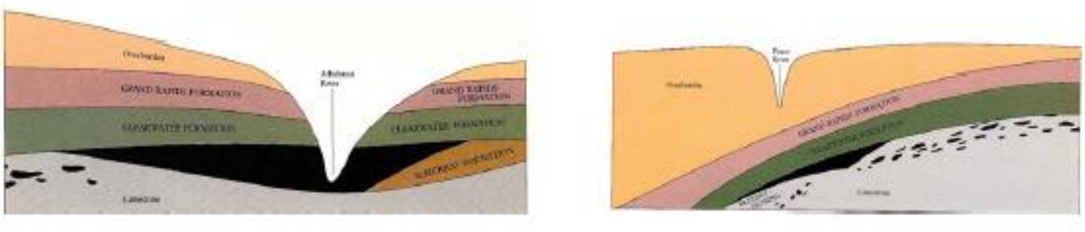
3. SIMULATION STUDY

3.1. Background

The Canadian bitumen deposits are almost entirely located in the province of Alberta. The three major deposits are defined as Athabasca, Cold Lake, and Peace River (Figure 3.1). The initial volumes of oil in place are 206.7 x 10^9, 31.9 x $10^{9,}$ and 20.5 x 10^9 m^3 for the three deposits respectively. Based on Alberta Energy and Utilities Board (AEUB) estimates, the total bitumen in place is around 259.1 x 10^9 m^3. This shows that Canada has the largest bitumen deposits in the world. Out of the total volume, 24 billion m^3 are available for surface mining. The remaining bitumen in place lies too deep to be surface mined and is exploitable by in-situ technologies (Nasr and Ayodele, 2005).

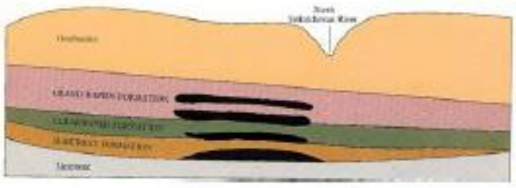
Figure 3.1. The geographic location of three major heavy oil and bitumen reserves in Canada. Initial oil in place for the three reservoirs is more than 259.1 billion m^3 (Nasr and Ayodele, 2005).

The average depth of Athabasca reservoir is around 300 m. The other two reservoirs are located deeper. The average depths are 400 m and 500 m for Cold Lake and Peace River respectively. The geological settings of these reservoirs are different, as shown in Figure 3.2. Most of the reserves in Athabasca are contained in the McMurray formation, which has a high average thickness that could be up to 40 to 60 m. The Cold Lake deposit contains inter-bedded shale layers, and the thickness of the reservoir is lower. The reservoir quality is more favorable in the Athabasca reservoir (Ivory et al., 2009).



Athabasca Deposit

Peace River Deposit



Cold Lake Deposit

Figure 3.2. Geological cross-section of the major Canadian heavy oil and bitumen reservoirs. Athabasca has the highest amount of recoverable bitumen and reservoir quality of the three reservoirs(Shin and Polikar, 2005).

SAGD has been demonstrated as a proven technology to unlock heavy oil and bitumen in Canadian reservoirs. One of the long-term concerns with the SAGD process is its high energy intensity and related environmental impacts. The addition of light hydrocarbon solvents to steam has long been regarded as the simplest and most important potential increase in SAGD performance. Higher oil recovery, accelerated oil production rate, reduced steam-to-oil ratio, and generally more favorable economics are expected from the addition of potential hydrocarbon additives to steam.

Any recovery process that involves solvents appears to be quite expensive. That is why it is very important to find the cheapest effective solvent with the lowest concentration. In this study, the additions of different type of solvents with different weight fractions have been tested for two different types of reservoirs, Athabasca and Cold Lake. The simulations are conducted with or without initial solution gas to investigate the effect of solution gas on SAGD and solvent-assisted SAGD processes.

The challenges for the addition of solvents to steam are the solvent type, solvent concentration, injection strategy, and operating pressure. The cost-effectiveness of the addition of hydrocarbon additives depends on the reservoir conditions such as initial pressure and operating strategy used to co-inject solvents with the steam. A detailed screening of reservoir conditions in which an appropriate solvent makes a contribution to the SAGD process is needed before co-injecting expensive solvent with the steam.

For the purpose of this study, CMG-STARS was used as the reservoir simulator. STARS is a three-phase multi-component thermal and steam additive simulator. It is an advanced-process reservoir simulator which includes options such as chemical/polymer flooding, thermal applications, steam injection, horizontal wells, dual porosity/permeability, directional permeabilities, and many more. STARS was developed to simulate steamflood, steam cycling, steam with additives, and dry and wet combustion, along with many types of chemical additive processes, using a wide range of grid and porosity models at both field and laboratory scale (CMG, 2011).

A step-by-step simulation procedure was employed to understand the main production mechanisms and obtain validated numerical models. The main objective of the simulation study was to examine the technical feasibility and economic viability of steam and solvent combination in gravity-dominated processes. In addition, the mechanism of hybrid steam/solvent processes was studied in detail.

3.2. Numerical model

Two-dimensional numerical simulations were performed with CMG-STARS using petrophysical properties typical of Athabasca- and Cold Lake-type reservoirs. Assuming no pressure drop and flow resistance along the horizontal wellbore, a 2D simulation model is sufficient for studying reservoir phase behavior reservoir and production performance of the SAGD process. The well pattern is symmetrical, so only half the well pattern is used for this study to reduce simulation time. Table 3.1 lists rock/fluid and fluid properties, heat loss parameters, and other key model parameters. There is no gas cap or bottom water zone in the reservoir model. Figure 3.3 shows the grid structure used to simulate SAGD and solvent-aided SAGD process in the Athabasca reservoir.

The numerical model for Athabasca was 51 x 1 x 30 gridblocks, while for Cold Lake the reservoir was 51 x 1 x 21 gridblocks. In some simulations, finer grids were used to better represent the gradients. The reservoir width (x direction) was assumed to be 5 times the reservoir thickness. The horizontal injection well was located 5 m above the horizontal production well, which in turn was positioned 1 m above the base of the reservoir pay. Each well is 750 m long.

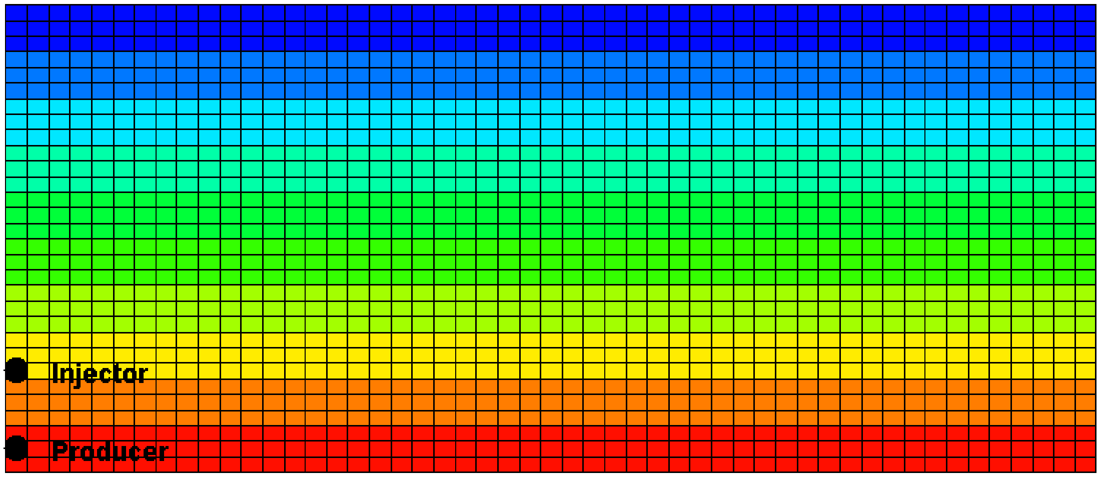


Figure 3.3. Gridding used to simulate SAGD and SA-SAGD processes in Athabasca and Cold Lake reservoirs.

To operate the process, at the injection well, the steam injection pressure was constrained to maximum bottomhole pressure equal to 2,100 kPa for Athabasca and 3400 kPa for Cold Lake with steam quality at the sandface equal to 0.95 for Athabasca and 0.9 for Cold Lake. At the production wells, to prevent steam losses from the chamber to the producer, a maximum steam flow rate equal to 1 m^3/day was imposed. This prevented excessive steam from being lost from the depletion chamber into the production well. This imposes a steam trap control for SAGD and solvent-aided SAGD operations. The reservoir simulations were run for 8 year of operation.

Preheating was applied to establish a hydrodynamical connection between horizontal injection and production wells using line heaters. The preheating period was 3 months for Athabasca because of its high initial viscosity and 2 months for Cold Lake reservoir, and the temperature supplied by the heaters was 240°C for both cases.

In the CMG-STARS simulator, the equilibrium K-values of a specific solvent were calculated using a modified version of the "Antoine Equation." In this study, a three-parameter K-value equation was used.

$$K_i = \frac{KV_{1\mathrm{i}}}{P} \exp\left(\frac{KV_{4\mathrm{i}}}{T - KV_{5i}}\right) \quad \text{...} (1)$$

where p is pressure, T is temperature, and $KV_{1\mathrm{i}}$, $KV_{4\mathrm{i}}$, and $KV_{5\mathrm{i}}$ are coefficients for specific solvents.

The STARS default logarithmic mixing rule was used to determine the oil phase viscosity:

$$\ln(\mu_{\mathrm{o}}) = \sum x_i \ln(\mu_i) \quad \text{...} (2)$$

where μ_i is the pseudo-viscosity of component i and x_i is the mole fraction of each component. Figure 3.4 shows the bitumen viscosity of typical Cold Lake and Athabasca reservoirs used in this simulation study. The best source for pseudo-liquid viscosities would be back-calculated experimental values. A Walther-type equation (Mehrotra, 1992) was used to obtain pseudo-viscosity at different temperatures.

$$\ln[ln(v_0 + 0.8)] = \ln[\ln(v + 0.8)] +$$

$$a_2 ln\left(\frac{T}{T_o}\right) \text{...} (3)$$

where v_0 and v are kinematic viscosity at T and T_0 and $a_2 = -3.7$.

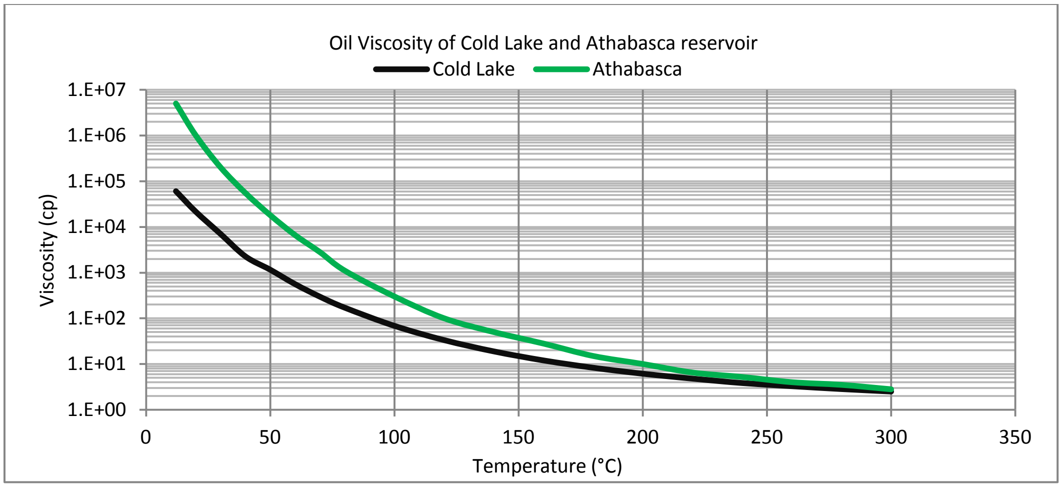


Figure 3.4.Viscosity of Athabasca and Cold Lake reservoir used in the study.

3.3. Results and discussion

There are numerous scenarios to combine steam and a type of solvent to enhance the SAGD process. Primarily, a simulation study can be used to narrow down the range of hybrid steam/solvent processes. The type of solvent and its ratio for co-injection with steam in SAGD at specific operating conditions can be selected. The combination of heat transfer and mass transport in hybrid-steam/solvent processes is complex. Also, the presence of a non-condensable gas in the steam chamber makes the process more complicated. Mechanistic studies were carried out to better understand the role of solvent additives in solvent-aided SAGD processes.

Steam-injection rate, oil-production rate, oil-recovery factor, solvent-retention rate, fluid-saturation distribution, and temperature distribution are the main variables to compare simulation results.

Table 3.1. Key simulation parameters used in this study

Reservoir Properties	**Athabasca Type**	**Cold Lake Type**
Initial reservoir temperature, °C	18	12
Initial reservoir pressure at injection well depth, kPa	1500	3100
Permeability (k_h), Darcy	4	2
k_v/k_h	0.5	0.5
Porosity	0.35	0.30
Oil saturation	0.85	0.75
Reservoir thickness, m	30	21
Well spacing , m	153	101
Fluid Properties		
Initial solution-gas/oil ratio for live oil, m^3/m^3	3.04	5.89
Initial solution-gas/oil ratio for live oil, mole fraction	0.06	0.11
Viscosity at 12°C, cp	5,000,000	60,590
Viscosity at steam-injection temperature (cp, T)	9.24 (217.3C)	3.82 (240 C)
K-values for the solvents	STARS default	STARS default
Operating Parameters		
Injection pressure, kPa	2100	3400
Steam quality	0.95	0.9
Saturation temperature, °C	217.3	240.0
Max live steam production, m^3/ day	1	1
Preheating period, days	90	60
Thermal Properties (STARS default)		
Rock heat capacity, $J/m^3.°C$	2.01E+06	
Rock thermal conductivity, J/m.day.°C	2.74E+05	
Oil thermal conductivity, J/m.day.°C	1.15E+04	
Water thermal conductivity, J/m.day.°C	5.35E+04	
Gas thermal conductivity, J/m.day.°C	2.50E+03	
Over/underburden volumetric heat capacity, J/m^3. °C	2.35E+06	
Over/underburden thermal conductivity, J/m^3. °C	1.50E+05	
Rock/Fluid Parameters		
S_{orw}	0.15	0.25
S_{wc}	0.15	0.2
S_{org}	0.005	
S_{gc}	0.05	
K_{rwro}	0.1	
k_{rocw}	0.992	
k_{rogc}	0.834	
$k_{rg(Sorg)}$	1.0	
Three-phase relative permeability model	Stone's Model 2	

3.3.1. Mechanistic study

It is difficult to study dynamic changes near the steam/oil interface in experiments and from field data. In this section, numerical simulations were used to investigate the mechanism of SA-SAGD processes and the role of a non-condensable gas. The gridding was refined to be able to capture the change of properties more accurately. Frontal property changes from the simulation study were used to understand the mechanism of the addition of hydrocarbon additives to the steam. In addition, the impact of initial solution gas on SAGD and SA-SAGD processes was also evaluated numerically.

In the mechanistic study, the change of different properties such as temperature, oil viscosity, and oil, water and solvent proportion in the oil phase near the steam/oil interface has been investigated for four different cases:

1. SAGD process without initial solution gas
2. SAGD process with initial solution gas (3.04 m^3/m^3)
3. Solvent-aided SAGD process (steam + 15% by volume n-hexane) without initial solution gas. Solvent proportion obtained at atmospheric conditions.
4. Solvent-aided SAGD process (steam + 15% by volume n-hexane) with initial solution gas (3.04 m^3/m^3)

The simulations in this section were performed using the reservoir and operating conditions of the Athabasca reservoir (Table 3.1). In all cases the injection pressure was limited to 2100 Kpa and the producer was limited by maximum live steam production (1 m^3/day). A simple approach has been used understand the dominant variables. Different zones were recognized along a cross-section of the reservoir. The classification of different zones might not be very precise, but was helpful to explain the mechanism.

3.3.1.1. SAGD process with no initial solution gas

Figures 3.5 and 3.6 summarize the results of SAGD at the Athabasca reservoir for 10 years. Figure 3.5 shows steam injection and oil production rate during SAGD operation. The life of a SAGD operation can be divided in three stages, ramp-up, plateau and decline. During ramp-up period steam injectivity and oil productivity increases and remains almost constant in plateau period. In decline period, the oil production decreases. The length of each period depends on reservoir properties (permeability and porosity and reservoir heterogeneities) and operational parameters (operating pressure mainly).

Figure 3.6 shows oil and water saturation and temperature distribution at different times for a cross-section of the reservoir perpendicular to the well axis. The shape and evolution of the steam chamber depended on reservoir properties such as horizontal permeability, vertical permeability, and heterogeneity of the reservoir. As expected, the steam chamber had a higher tendency to advance in the vertical direction when vertical permeability was significant, and later it advanced laterally.

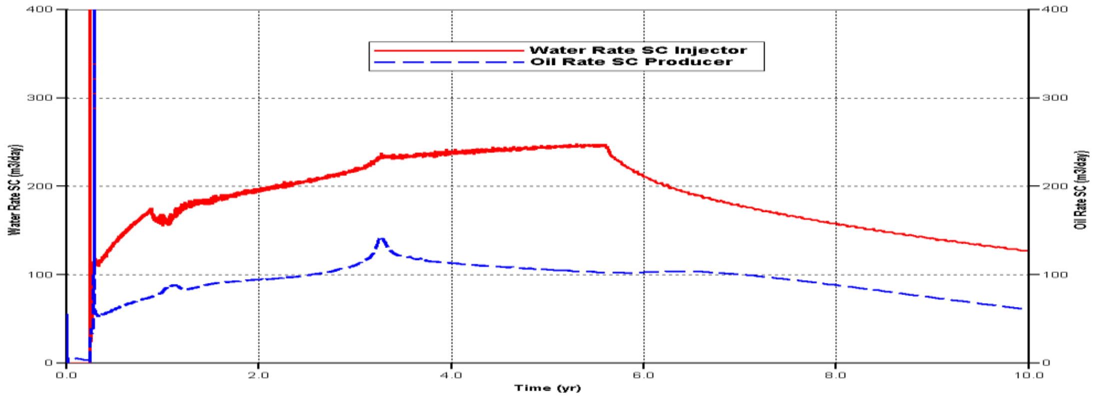


Figure 3.5. Steam injection (cold water equivalent) and oil production rate of SAGD process.

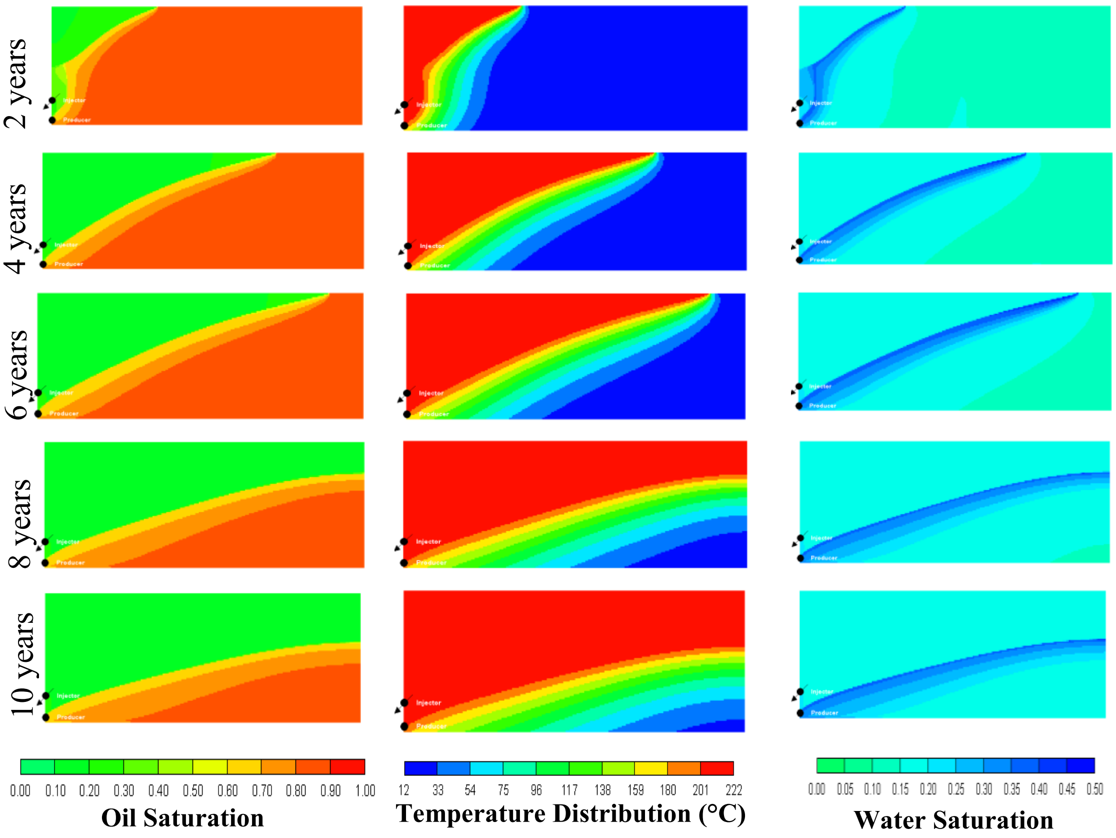


Figure 3.6. Oil saturation distribution, temperature distribution and water saturation profile progression in time for a typical SAGD process.

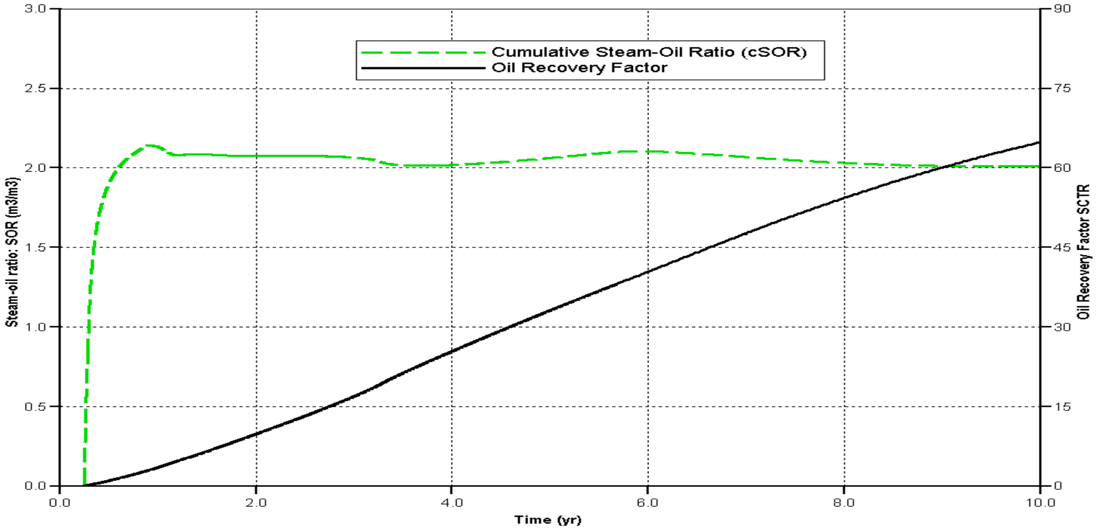


Figure 3.7. Steam/oil ratio and oil recovery factor are the main performance indicators of SAGD process.

Figure 3.7 shows the cumulative steam/oil ratio (cSOR) and oil recovery factor. CSOR is a reasonable economic indicator to analyze the energy intensity of thermal processes such as steamflooding and SAGD process. Based on the result of the simulations, cSOR is around 2.0 m^3/m^3. In field operations this value is between 2 and 4 m^3/m^3. Oil recovery obtained at the specific operating strategy in this study is 65% after 10 years.

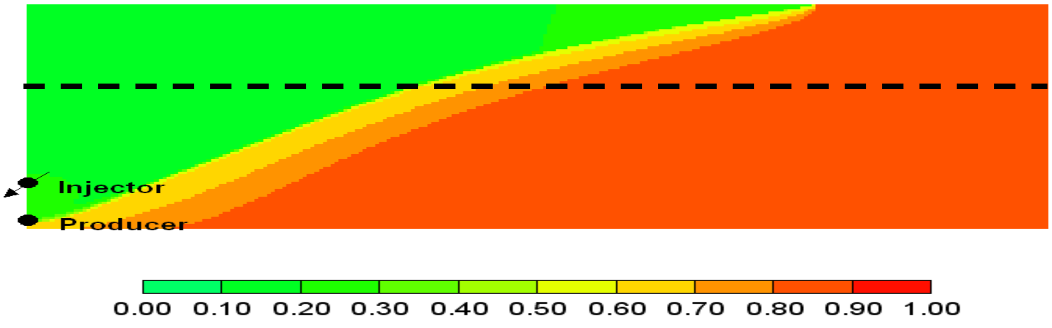
Figure 3.8.a shows the oil saturation profile of a SAGD process after 4 years of operation in an Athabasca type reservoir. The presence of initial solution gas has been ignored in this case. The dashed line shows the location where property changes have been studied. The line of study is located 10 m below the top of the net pay. The change of properties on this line is a good representation of overall interface changes. Figure 3.8.b shows a schematic representation of different zones recognized on this line.

1. The steam zone: this zone contains steam at saturation conditions, residual oil and connate water. The temperature and pressure throughout this zone are almost

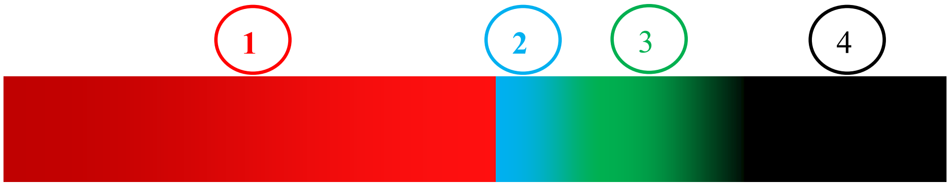
uniform.

2. Steam condensation zone: in this zone the steam is in contact with low-temperature bitumen and reservoir rock. As a result of the temperature difference, the latent heat of the steam is conducted to the cold zone and the steam is condensed. Accordingly, the steam saturation sharply decreases and water saturation increases. Sharp steam saturation reduction and water saturation buildup represent this zone.
3. Mobile oil zone: in this zone the oil viscosity is reduced by the heat action and the oil is mobile enough to be drained by gravity drainage. This zone is mainly represented by high oil phase mobility due to reduction in viscosity. In this zone the temperature changes from saturation temperature to reservoir temperature.
4. Immobile bitumen zone: in this zone the temperature is still low and bitumen is not heated enough to be drained.

In Figure 3.8.c, oil, water, and steam saturation, oil viscosity, and temperature variations have been shown along the line of study (This line is located is located 15 meters above the injector and it is extended along the reservoir extent (100 meters) to monitor property changes. The line is shown in magenta color on Figure 3.8.a). As can be seen, in the steam zone (0 to 32 m) residual oil, steam, and water saturation are 20%, 64%, and 16% respectively. The temperature and pressure in this region are at saturation conditions and the oil phase mobility is almost zero. In the steam condensation zone, steam saturation is reduced from 64% to zero. Water saturation increases as a result of steam condensation. In the mobile oil zone, the oil phase mobility is high due to viscosity reduction by the action of heat. In the immobile bitumen zone, water saturation returns to connate water saturation, oil saturation is almost equal to initial oil saturation, and temperature is low because not enough heat has been conducted and oil phase mobility is close to zero.

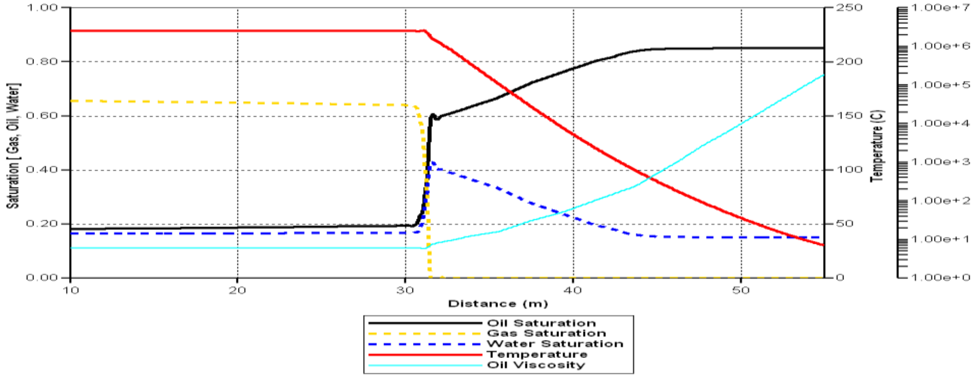


a. Oil saturation distribution after 4 years in Athabasca reservoir with no initial solution gas



1. Steam Zone, **2.** Steam Condensation Zone, **3.** Mobile Oil Zone, **4.**Immobile Oil Zone

b. Schematics of different zones present along the line of study



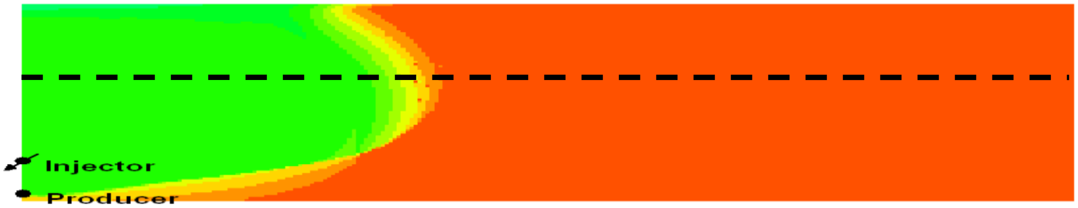
c. Profile indicating property variations (fluid saturations, temperature and oil viscosity) along the line of study

Figure 3.8. Oil saturation, schematics of different zones and property variation along the line of study for SAGD process after 4 years of operation.

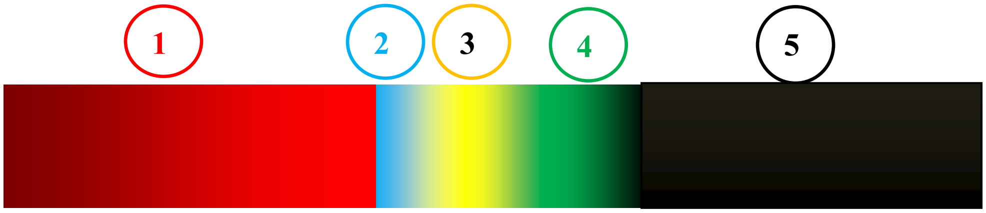
3.3.1.2. SAGD process with initial solution gas

Athabasca reservoir contains small amounts of initial solution gas which is negligible compared to conventional oil reservoirs. Even small amounts of solution gas might play an important role in thermal processes driven by gravity drainage. In SAGD process, the bitumen is heated by the injection of the steam. As a result of the temperature increase, solution gas exsolves from the bitumen. The solution gas contains volatile and mostly non-condensable components at the pressure and temperature of the steam chamber. A portion of the exsolved gas is produced by a process which is not very well understood (Edmunds, 2005; Edmunds, 2007). A part of the solution gas that remains in the steam chamber circulates near the edge of the steam/oil interface and can be problematic to heat transfer. As discussed in the literature (Yuan et al., 2006; Yuan et al., 2001), such a gas layer acts as an insulator and deteriorates the heat transfer from condensing steam to the cold bitumen. Reduced heat transfer creates poor opportunities for the steam chamber to grow deeper into the reservoir, and thermal sweep declines.

Numerical simulation of solution-gas behavior is quite difficult in SAGD. In this study, the solution gas parameters such as k-values were selected from the available literature (Yuan et al., 2003). The solution gas was considered to be methane for Athabasca. This assumption is realistic for Athabasca reservoir because methane dominates the solution gas composition in a severely biodegraded Athabasca bitumen.

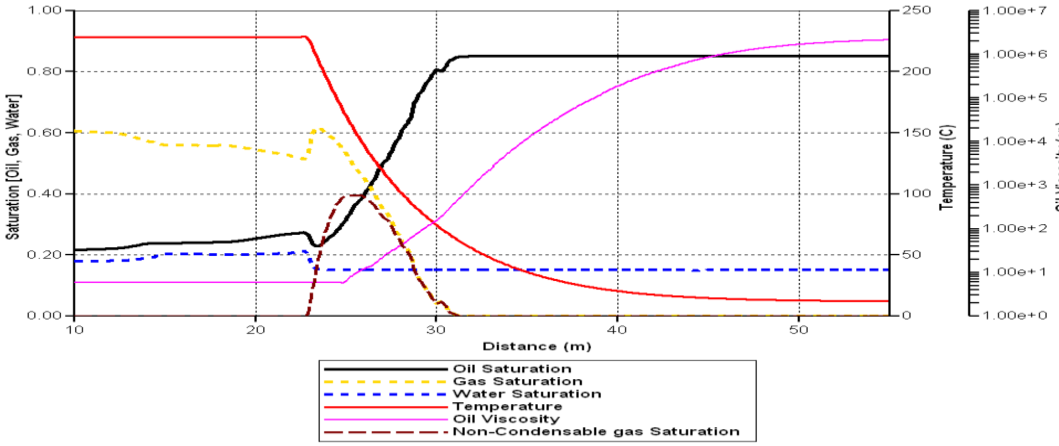


a. Oil saturation distribution after 4 years in the Athabasca reservoir with initial solution gas



b. Schematics of different zones present along the line of study

1. Steam Zone, **2.** Steam Condensation Zone, **3.**Non-Condensable Gas zone, **4.** Mobile Oil Zone, **5.** Immobile Oil Zone

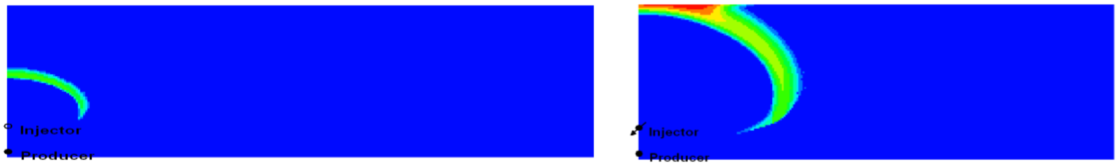


c. Property (fluid saturations, temperature, oil phase viscosity and non-condensable gas saturation) variations along the line of study.

Figure 3.9. Oil saturation distribution, schematics of different zones and property variation for a SAGD operation in a reservoir with initial solution gas (3.04 m^3/m^3)

Figure 3.9 shows the frontal properties analyzed for a SAGD process in which initial solution gas (3.04 m^3/m^3) was present in the reservoir. The description of the zones is similar to those mentioned previously for the SAGD process. Compared to

SAGD process in a dead oil reservoir, a gas zone lies between the water-condensation zone and the mobile oil zone, as shown in Figure 3.9.b. The thickness of this gas zone is variable, increasing toward the top of the reservoir. This non-condensable gas zone separates the steam condensation and mobile oil zone and severely delays the heat transfer to the bitumen and the rock. The evolution of liberated solution gas is shown in Figure 3.10. Non-condensable saturation is obtained by multiplying the gas mole fraction of methane in the gas phase by the gas saturation. As SAGD progresses, more solution gas is released. Non-condensable gas zone will grow as the SAGD process moves forward. The thickness of the gas zone depends on the operating pressure of the process and initial solution gas ratio. Numerical simulation results show that the major portion of non-condensable gas circulates near the steam/oil interface. The gas zone has the capability to reduce the efficiency of SAGD process. At later times, steam injectivity is dramatically reduced as a result of the presence of the gas buffer zone.



After 1 Year After 3 Years

After 5 Years After 7 Years

Figure 3.10. The evolution of non-condensable gas zone in the vertical cross section of the SAGD dual horizontal wells. As SAGD advances, more methane is released. A major portion of the methane remains in the steam chamber. At later times, steam chamber growth decreases dramatically because of the accumulated gas zone.

Figure 3.9.a shows that the oil saturation profile progresses slower, especially near the top of the reservoir, than the SAGD process in a dead oil reservoir. The shape of the steam chamber in this case is affected by the presence of the exsolved solution gas. Property changes along the line of study in Figure 3.9.c show that the water-saturation buildup in the steam condensation zone is separated from the mobile oil zone by the exsolved solution-gas layer. The latent heat of the steam mainly is released at a distance from the bitumen zone, and heat transfer is impaired where the gas zone is present. The mobile zone is thicker in SAGD process without initial solution gas than in the SAGD process in a live oil reservoir.

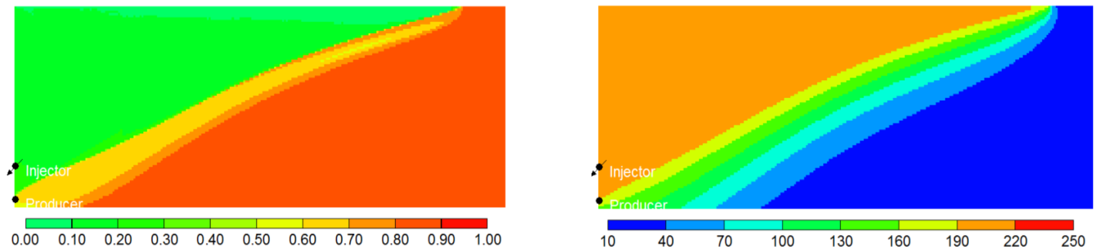
3.3.1.3. Solvent-aided SAGD without initial solution gas

Hydrocarbon additives can effectively reduce the viscosity of heavy oil and bitumen. The objective of adding solvents to steam in SAGD is to enhance the viscosity reduction capability from heat and from the solvent. SAGD is based on gravity drainage, and the co-injected solvent must satisfy the requirements of a gravity drainage process. In other words, an effective solvent should be fully vaporized in the injection well and steam chamber so that it could be transported to the edge of the steam chamber. If the solvent is condensed before reaching the steam/oil interface, it is directly produced in the production well and it is wasted. In addition, the hydrocarbon additive has to cooperate with the heat transfer mechanism when it approaches the interface. The presence of solvent in the gaseous and liquid phases should have only a slight impact on heat transfer because heat transfer is the main source of viscosity reduction.

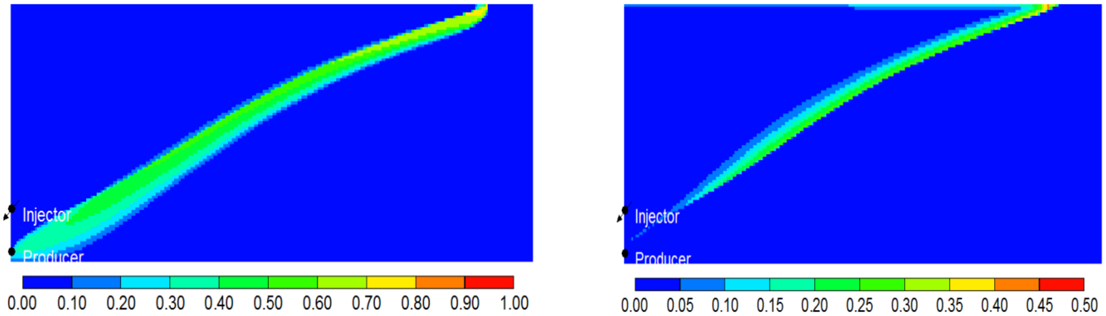
If the same volume percent of different hydrocarbon additives such as propane, butane, or heptanes is dissolved into a sample of bitumen the mixture, viscosity obtained at the same temperature and pressure is about the same for different type of solvents. The important points are how fast and how much solvent can be transferred and dissolved into bitumen. To better understand the role of the solvent near the steam/oil interface, the variation of properties over distance was studied. In this illustrative example 15% n-hexane by volume was co-injected with steam in Athabasca reservoir without initial solution gas.

Figure 3.11 shows oil saturation, temperature distribution, and n-hexane saturation in the oil and gas phases after 4 years of operation. As can be seen, a major portion of the n-hexane is dissolved into the oil phase, which contributes to viscosity reduction.

Figure 3.12.a shows the oil saturation distribution after 4 years. Compared to SAGD with no solvent co-injection, the depleted chamber has lower residual oil saturation, especially near the top of the reservoir. Different zones are illustrated in Figure. 3.12.b. The main difference with a pure steam injection process is the presence of a solvent-rich zone within the mobile oil zone. In this zone, the percentage of solvent dissolved in the bitumen is high and the oil phase mobility is higher than the mobile oil zone in a SAGD process.



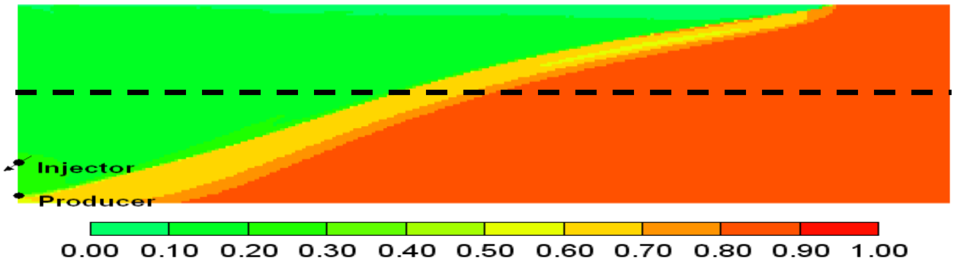
Oil Saturation **Temperature Distribution**



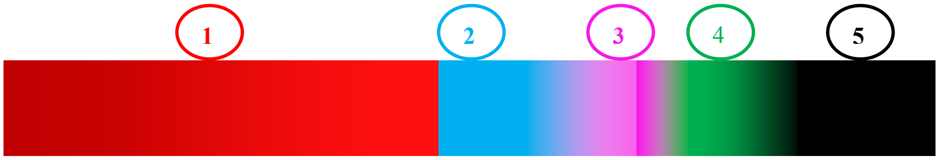
n-Hexane Saturation in oil phase **n-Hexane Saturation in gas phase**

Figure 3.11. Oil saturation, temperature distribution, and n-hexane saturation in the oil and gas phase after 4 years on the vertical cross section of SAGD wellbores. A major portion of the n-hexane is dissolved into the oil phase.

The steam zone contains steam and vaporized solvent at almost uniform temperature and pressure. Propane, butane, pentane, and n-hexane were fully vaporized in the steam chamber under the operating conditions of this study. Heavier solvents such as heptanes and octanes were partially vaporized. In the steam-condensation zone, solvent and steam condensed in line with their phase (PVT) behavior. Oil flowed in both the solvent-rich zone and the oil mobile zone. However, the dilution of the oil in the mobile oil zone was governed by heat transfer while viscosity reduction in the solvent-rich zone was governed by mass and heat transfer.

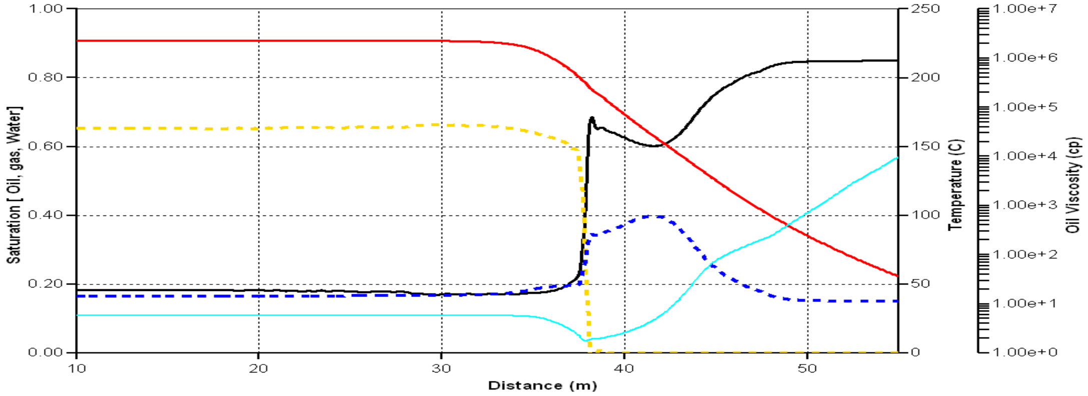


a. Oil saturation distribution after 4 years. 15% by volume n-hexane was co-injected with steam in a typical Athabasca reservoir with no initial solution gas.

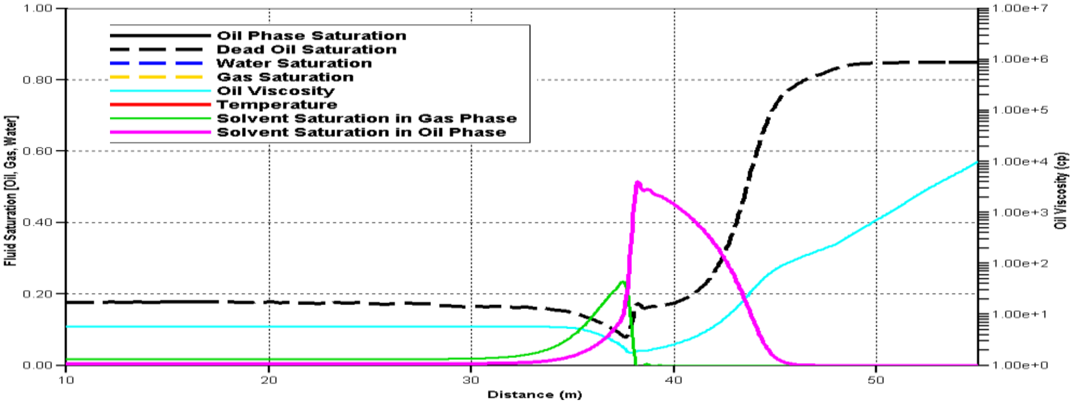


1.Steam zone, **2.** Steam condensation zone, **3.**Solvent-rich zone**, 4.** Mobile oil zone**, 5.** Immobile oil zone

b. Different zones along the line of study



c. Property (fluid saturations, oil phase viscosity and temperature) variations along the line of study



d. Property (n-hexane saturation in oil and gas phase, oil-phase viscosity, and dead oil saturation) variations along the line of study.

Figure 3.12. Oil saturation, schematics of different zones and property variation for a SAGD project enhanced by co-injection of 15% by volume n-C_6. Initial solution gas in this case is zero.

Figure 3.12.c and Figure 3.12.d show that in a narrow zone, the viscosity is noticeably lower due to the dissolution of the solvent in oil. As shown in Figure 3.12.d, solvent volume percent in the oil phase in this zone is up to 50%. As a result, oil phase mobility is considerably higher which leads to accelerated oil production. The increase in solvent volume in oil phase corresponds to water saturation build-up. This confirms the benefits of co-injection of a solvent with thermophysical properties close to those of water. Therefore, mass and heat transfer cooperate with each other and the presence of the solvent does not interfere with the heat transfer mechanism.

3.3.1.4. Solvent-aided SAGD process with initial solution gas

The mechanism of the addition of a solvent to a live oil reservoir is very complex as a result of the presence of a solvent and a non-condensable component near the steam/oil interface. In this section, we attempt to explain the mechanism of addition of solvents to steam in a reservoir with initial solution gas.

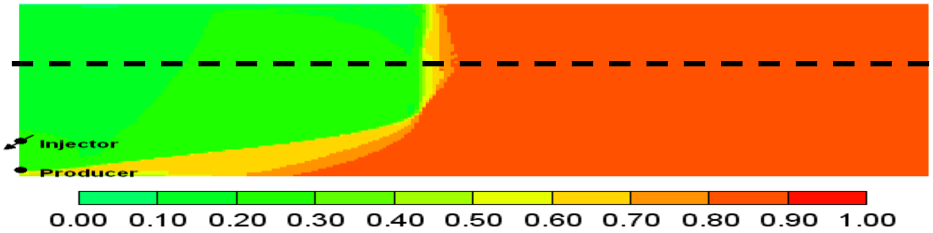
Co-injection of hydrocarbon additives has the potential to accelerate oil production and increase oil recovery in reservoirs with no initial solution gas. Simulation results show that the oil recovery by SAGD is lower when the reservoir contains high quantities of initial solution gas. It is important to understand the role solvents in reservoirs containing liberated solution gas.

Figure 3.13.a shows the oil saturation profile after 4 years in an Athabasca-type reservoir that initially contains 3.04 m^3/m^3 solution gas (methane). 15% by volume n-hexane was co-injected with the steam. The advancement of the chamber is delayed by

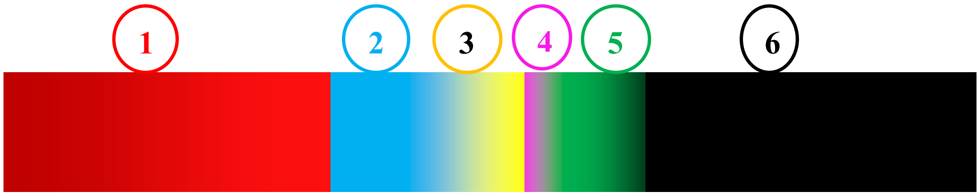
the presence of exsolved solution gas. Figure 3.13.b shows different zones created along the line of study. Two additional zones appear as compared to a pure SAGD process: a gas zone and a thin, solvent-rich zone.

The thickness of the gas zone is variable and increases toward the top of the reservoir. The gas zone mainly contains methane and vaporized solvent. As illustrated in Figure 3.13.b, the main condensation zone happens to be before this gas zone. Hydrocarbon additives and steam condense according to their vapor pressure. As a result, the mass and heat transfer are impaired because of early condensation, and part of the solvent is condensed before contacting the oil zone. Heavier solvents which are more effective in Athabasca reservoir would have poor opportunities to contact the bitumen zone and are unable to create an effective high oil-mobility zone.

Oil, steam, and water saturation, methane saturation in the gas phase, pentane saturation in gas phase and oil phase, and oil-phase mobility are shown in Figure 3.13.c. The important changes are magnified in Figure 3.13.d.The humps in methane and water saturation are representative of a gas zone and a condensation zone respectively. This plot clearly shows that the main condensation zone and the solvent-rich zone are separated from the mobile oil zone. The presence of a gas zone leads to early condensation of steam and the hydrocarbon additive (n-hexane). The additives have poor opportunities to contact the bitumen zone. As shown in Figure 3.12.d, the solvent-rich zone is much thinner than in Figure 3.13.d.

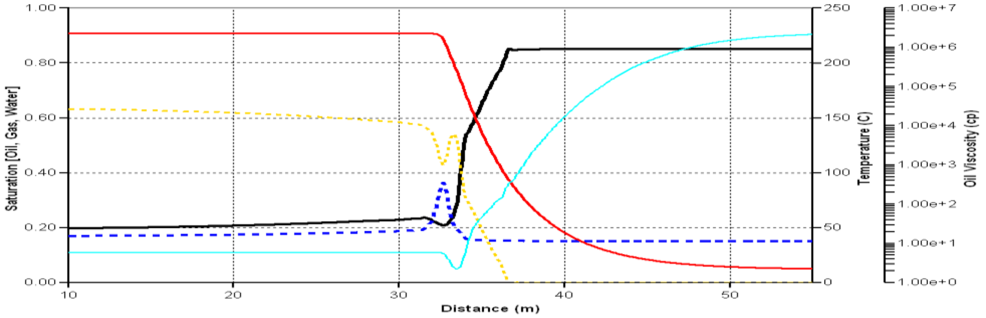


a. Oil saturation distribution after 4 years. 15% by volume n-hexane is co-injected with the steam in at typical Athabasca reservoir with initial solution gas

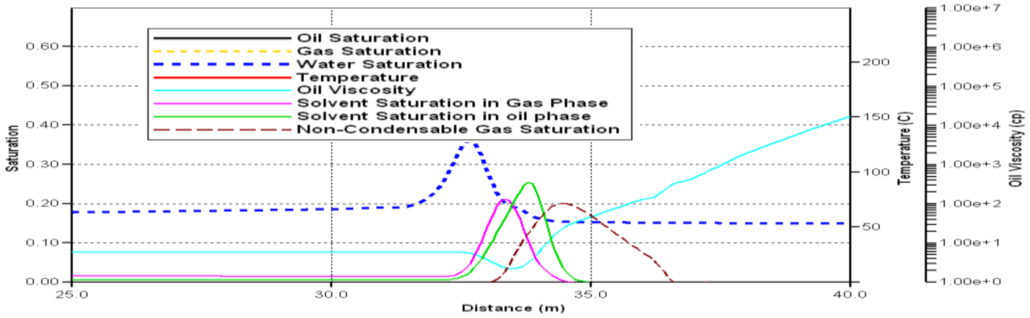


1. Steam zone, **2.** Steam condensation, **3.**Noncondensable gas, **4.** Solvent-rich, **5.** Mobile oil, **6.** Immobile oil

b. Schematics of different zones in the line of study



c. Property (fluid saturation, oil phase viscosity and temperature) variations along the line of study.



d. Water saturation, solvent saturation in oil and gas phase, noncondensable gas saturation, and oil-phase viscosity changes. Noncondensable gas zone separates the main steam condensation and solvent-rich zone from the mobile oil

Figure 3.13. Oil saturation, schematics of different zones and property variation in distance for SAGD operation enhanced by co-injection of 15% by volume of n-Hexane after 4 years. Initial solution gas is 3.04 m^3/m^3.

In conclusion, according to simulation results, the oil production and steam injectivity are reduced when a reservoir contains high amounts of solution gas. In these reservoirs, the addition of solvent to steam is not advantageous since a major portion of the solvent condenses early and does not contribute. Both mass and heat transfer are adversely affected by the presence of non-condensable gas near the steam/oil interface.

Figures 3.14 and 3.15 show steam injection rate and oil production for the four cases discussed earlier. As can be seen, the steam injectivity and oil production rate are considerably lower when non-condensable gas is present in the chamber (Cases 2 and 4). In these cases, non-condensable gas creates a buffer zone that deteriorates heat transfer and mass transfer. As a result, steam and injected additives have poor opportunities to contact heavy oil and bitumen directly.

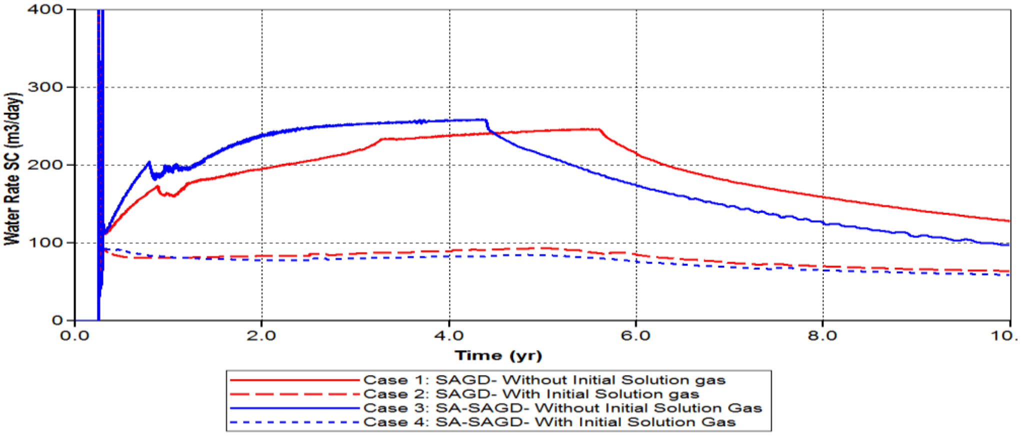


Figure 3.14. Steam injection rate of Cases 1 to 4. Steam injection rate is considerably lower when non-condensable gas is present in the steam chamber.

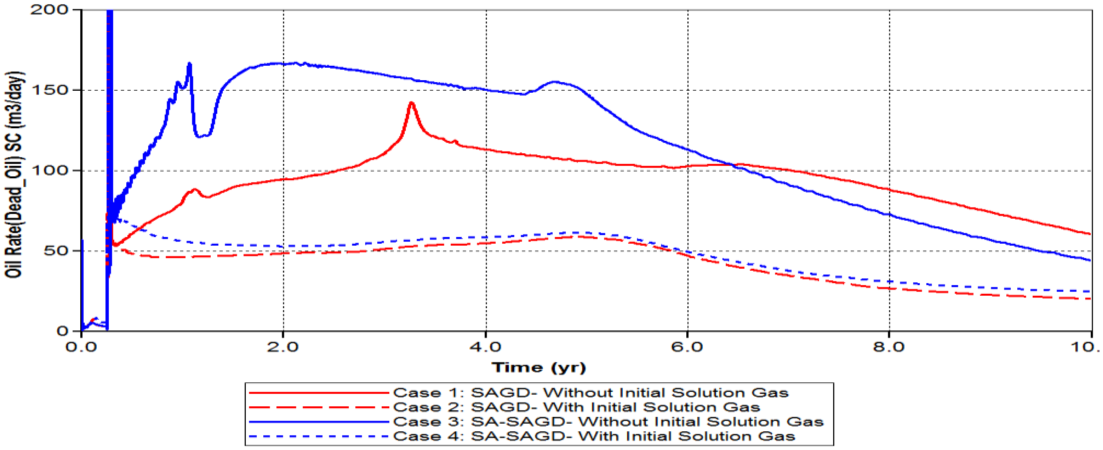


Figure 3.15. Oil production rate of Cases 1 to 4. Oil production rate is considerably lower when non-condensable gas is present in the steam chamber.

3.3.2. Solvent screening

Recovery processes that involve solvents are likely to be expensive. Thus, it is very important to find an effective and relatively cheap solvent and the optimum amount to be co-injected. An effective solvent has to yield higher oil recovery with lower energy consumption. Simulations were conducted for Cold Lake- and Athabasca-type reservoirs to investigate the effect of solvent type and concentration. Propane, butane, pentane, hexanes, and heptanes were co-injected with the steam. Solvents with different ratios from 1 to 20 wt% were co-injected to study the effect of solvent type and concentration. It has to be noted that initial solution gas is zero for both type of reservoirs in this section.

The results of simulations for dead oil Cold Lake and Athabasca reservoirs are summarized in Figures 3.16, 3.17, 3.18, and 3.19. Oil recovery factors are reported for a period of 8 years in all cases. Figure 3.17 and Figure 3.19 show average cumulative energy-to-oil ratio (cEOR) for different solvent types and concentrations for the two types of reservoirs. They include the enthalpy of stream (steam and solvent) injected into the reservoir. CEOR is the average cumulative energy-to-oil ratio over 8 years of operation. This value is a reasonable indicator for comparing the efficiency of the solvent-assisted SAGD processes.

Table 3.2. Solvent co-injected with steam in different cases

	Mole %				
Weight %	**C_3**	**n-C_4**	**n-C_5**	**n-C_6**	**n-C_7**
1	0.41	0.31	0.25	0.21	0.18
2	0.83	0.63	0.51	0.43	0.37
5	2.11	1.61	1.30	1.09	0.94
10	4.35	3.33	2.70	2.27	1.96
15	6.73	5.19	4.23	3.56	3.08
20	9.28	7.20	5.88	4.97	4.31

3.3.2.1. Athabasca type reservoir

SAGD process in the Athabasca reservoir is more energy efficient than in the Cold Lake reservoir. Simulation results show that on average, the cEOR in the Athabasca reservoir is about 4 to 5 GJ/m^3 while in the Cold Lake reservoir it varies between 8 and 9 GJ/m^3. Energy losses to the overburden and underburden in the Cold Lake reservoir are higher because of the lower thickness. Other reasons for lower energy intensity of the SAGD process in the Athabasca are higher permeability of the reservoir and lower operating pressure.

Co-injection of propane with steam drastically reduces the recovery of SAGD process in Athabasca. The recovery is reduced by 25% if 10% propane by weight is co-injected with steam (Figure 3.16). Propane at the pressure and temperature conditions near the edge of the steam chamber mainly remains in the gas phase, and very small amounts are diffused into the oil or condensed in the liquid phase. A gas zone is formed like the one described previously, which impairs heat transfer to the bitumen. Co-injection of propane reduces the energy intensity of the SAGD process mainly by reducing energy losses to the overburden and underburden formations. Also, the steam volume that can be injected into the chamber is lower when the gaseous propane zone has grown.

Small amounts of butane up to 5 wt% increase the oil recovery and energy efficiency of SAGD process (Figure 3.16 and Figure 3.17). Higher amounts seem not to be useful to SAGD process at these operating conditions because the solubility of butane is limited at the pressure and temperature near the steam/oil interface. Solvents heavier than butane such as pentane, hexanes, and heptanes are capable of increasing the recovery by more than 20% after 8 years. This group of solvents is the most promising for the Athabasca reservoir at the operating conditions of this study. This group of solvents has thermophysical behavior very close to water and can condense at almost the same pressure and temperature as water condenses. In other words, they fully satisfy gravity drainage mechanism requirements. They are vaporized at the steam temperature in the injection well, and they condense near the steam/oil interface. Solvent weight percentages on the order of 10 to 15 wt% seem to be the optimum solvent ratios for the Athabasca reservoir.

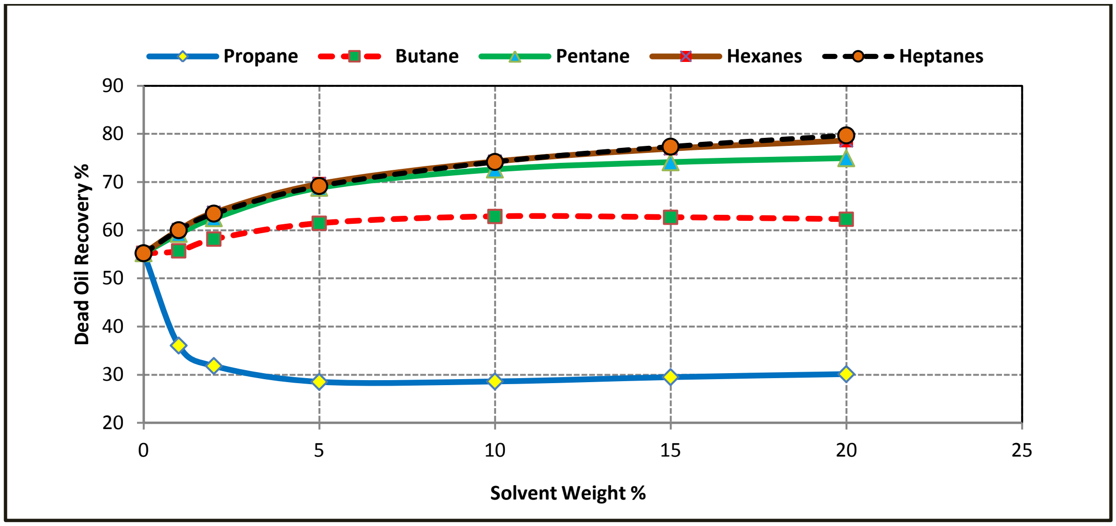


Figure 3.16. Oil recovery factor after 8 years in Athabasca reservoir with no initial solution gas. Different solvents from 1 to 20 wt% were co-injected with steam.

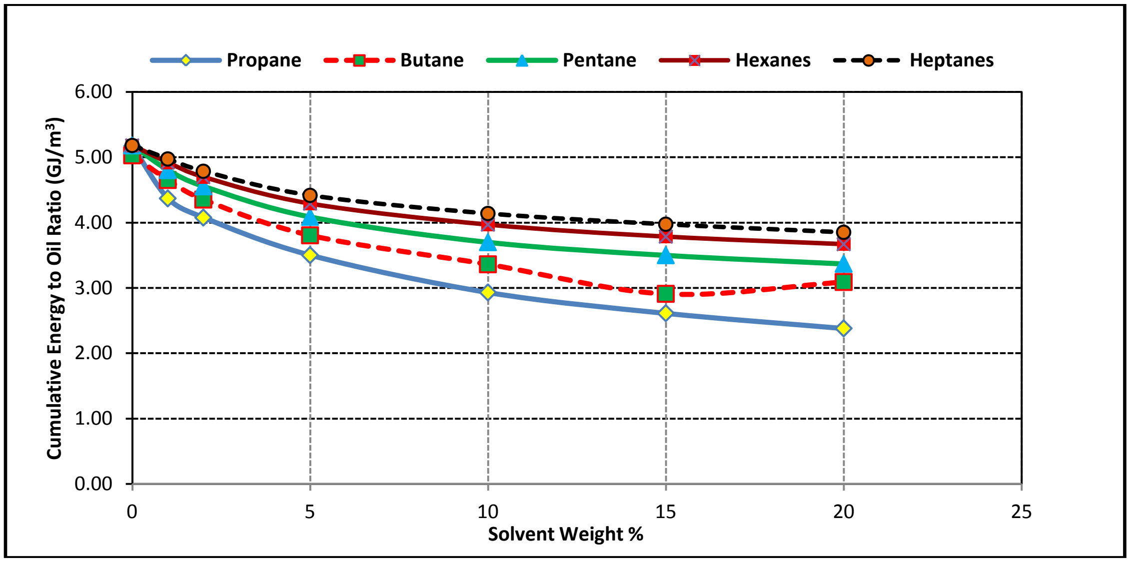


Figure 3.17. Average cumulative energy to oil ratio in Athabasca reservoir with no initial solution gas. Different solvents from 1 to 20 wt% were co-injected with steam.

3.3.2.2. Cold Lake-type reservoir

Propane has a similar effect in a Cold Lake reservoir as in Athabasca, but the effect is not as severe as in the Athabasca. The main reason can be related to the difference in initial viscosity of different reservoirs. In the Cold Lake reservoir, even an impaired heat transfer can reduce the viscosity of the bitumen to be drained, while in the Athabasca more heat is needed to reduce the viscosity of bitumen enough.

The oil recoveries obtained by butane, pentane, hexane and heptanes are very close. The cEOR is lower in the case of butane, indicating the higher ability of butane to increase the thermal efficiency of the SAGD process. Butane increases the viscosity reduction rate at the steam/oil interface and reduces the heat losses to over/underburden formations. The optimum solvent ratio based on the simulation results for Cold Lake reservoir is around 10% by weight (Figures 3.18 and 3.19). At this ratio, butane is capable of reducing the energy intensity of the SAGD process by almost half (from 9 GJ/m^3 to 5 GJ/m^3). Considering the cost of solvents, butane seems to be the optimum solvent at operating conditions in this study for the Cold Lake reservoir.

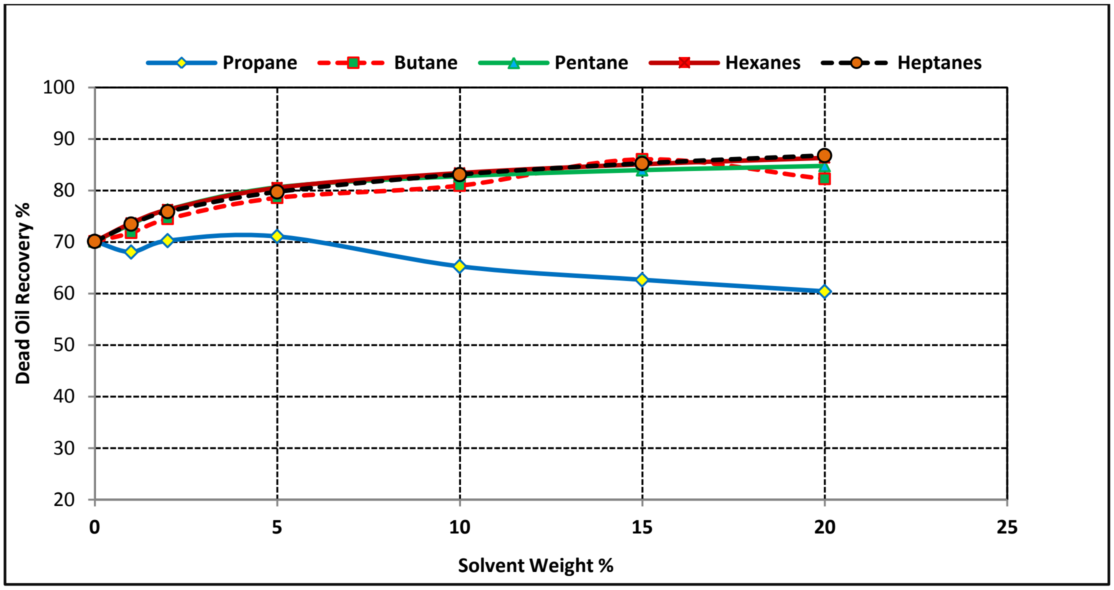


Figure 3.18. Oil recovery factor after 8 years in the Cold Lake reservoir with no initial solution gas. Different solvents from 1 to 20 wt% were co-injected with steam.

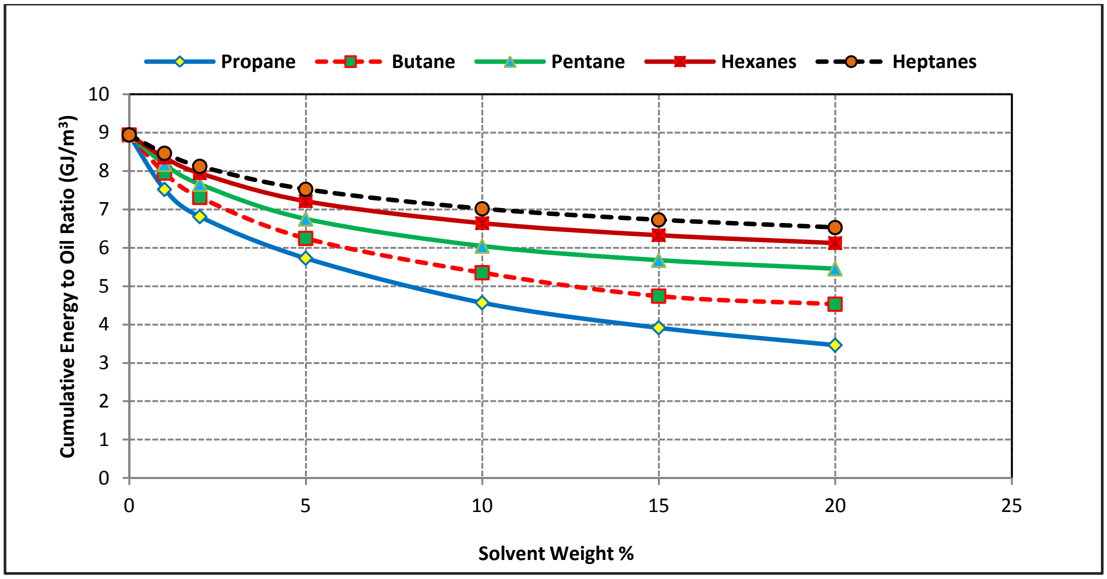


Figure 3.19. Average cumulative energy-to-oil ratio in the Cold Lake reservoir with no initial solution gas. Different solvents from 1to 20 wt% were co-injected with steam.

3.3.3. Detailed analysis

The results of the simulations were further analyzed to compare the performances of different solvents in solvent-aided SAGD processes. Different solvents (C_3, C_4, n-C_5, n-C_6 and n-C_7) were co-injected at 10 wt% with steam in an Athabasca reservoir prototype in these sector simulations. The effects of solvent co-injection on different variables such as steam injection, oil production, solvent dynamic retention, and energy requirements of SAGD were investigated.

Figure 3.20 shows cumulative steam injection for different simulation runs. Injected steam pore volume fraction of different cases is compared in Figure 3.21. The injection well is controlled by a maximum injection pressure (2100 Kpa). The production well is limited by maximum live steam production (1.0 m^3/day) and also minimum bottomhole pressure (1400 Kpa). The steam chamber remains at constant pressure and temperature corresponding to the injection pressure and temperature. Steam rate is mainly controlled by the voidage created by the production of the liquid (oil and water). As can be seen, steam injectivity is dramatically reduced when propane is injected. At low operating pressure, most of the injected propane remains in the gaseous phase due to the low solubility of propane in the oil phase. In addition, at the pressure and temperature conditions near the steam/oil interface, propane cannot be condensed. The presence of propane in the gaseous phase deteriorates heat transfer and reduces the steam injection volume. When heavier solvents are co-injected with steam, steam intake capacity of the SAGD is enhanced. As can be seen in Figure 3.21, in SAGD process at the operating conditions of this study almost 1.0 pore volume of steam is injected after

10 years. When heavier solvents are injected steam pore volume can be increased by 20%.

Table 3.3. Composition of injected solvent (and water) in the reservoir for different cases.

Solvent	C_3	n-C_4	n-C_5	n-C_6	n-C_7
Mole %	4.35	3.33	2.70	2.27	1.96
Weight %	10	10	10	10	10

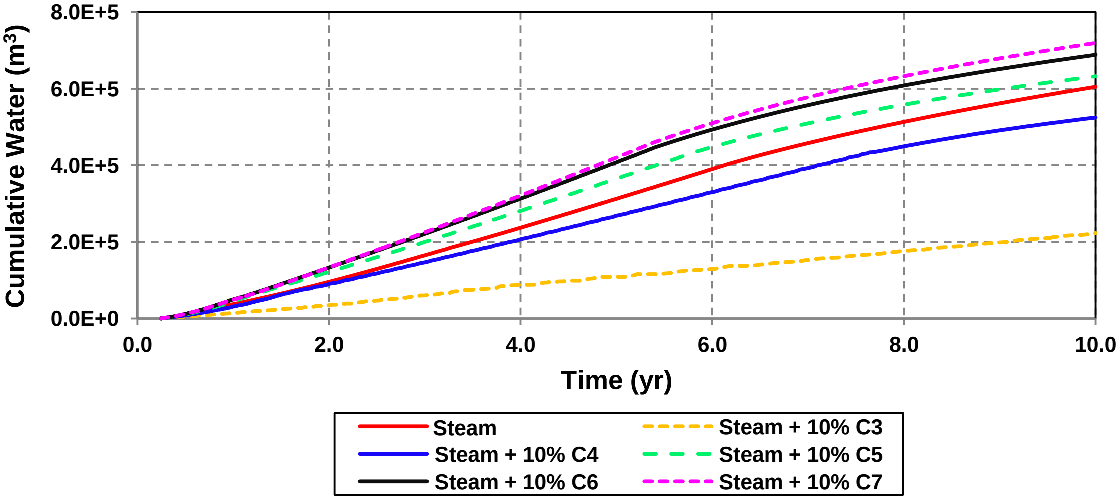


Figure 3.20. Cumulative steam injected in different cases is compared. Steam injection pressure is set to 2100 Kpa and 217.3 °C. Steam intake capacity can be enhanced by co-injecting a proper solvent.

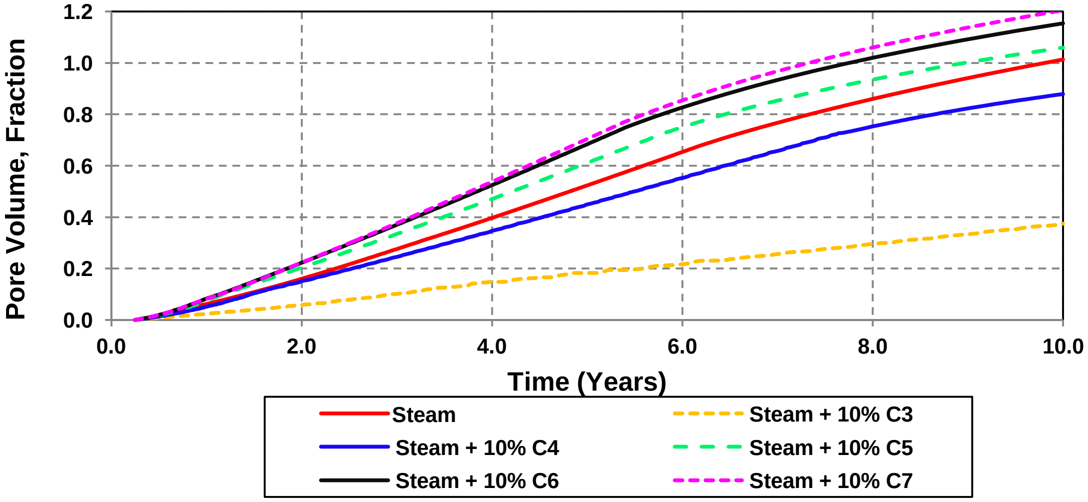


Figure 3.21. Injected steam pore volume of different cases compared with the SAGD process.

Figure 3.22 compares the oil recovery factor of different cases to the SAGD process in Athabasca. It has to be noted that the reported oil recovery excludes the dissolved solvent from the oil. In most cases, oil production is enhanced when solvent is co-injected with steam. When propane is co-injected with steam, the oil recovery factor is reduced by 30% compared to SAGD process. As discussed earlier, propane co-injection with steam reduces the steam intake in the reservoir, and therefore oil recovery factor rate is reduced. Ultimate oil recovery factor is increased by 10 to 15% compared to SAGD process when heavier solvents are injected. Majority of incremental oil recovery by addition of the solvent to steam is obtained during SAGD ramp-up and plateau period.

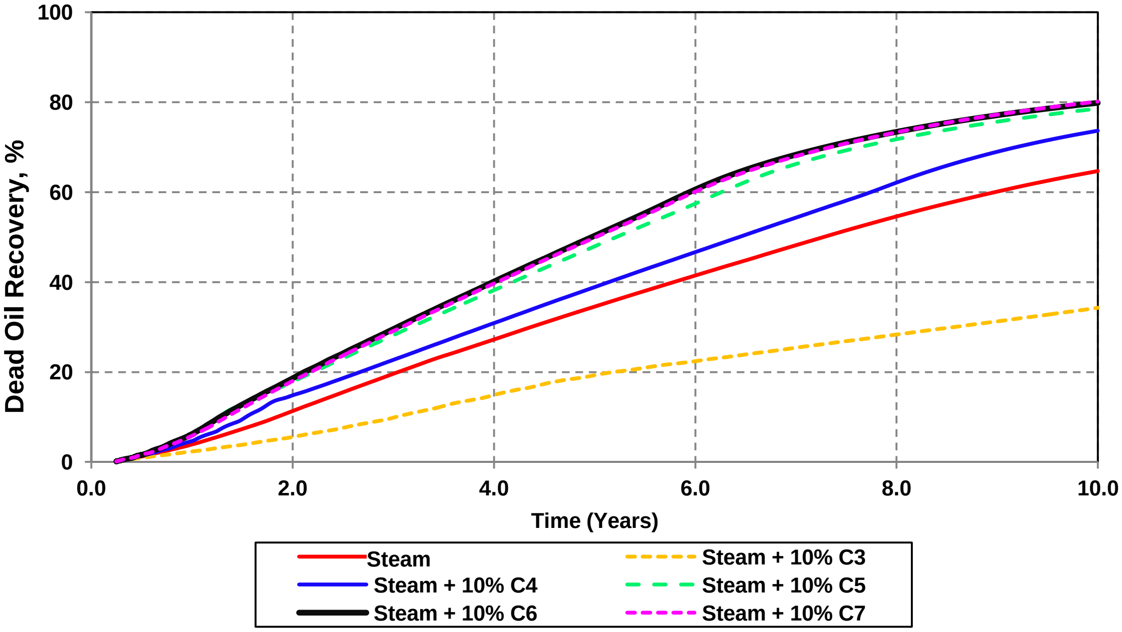


Figure 3.22. Oil recovery factor is enhanced when heavier solvents are co-injected with steam. Oil recovery is reduced when light solvents such as propane are co-injected with steam.

Cumulative steam/oil ratio (SOR) is compared for different cases in Figure 3.23. The average SOR for the SAGD process is almost 2.0 m^3/m^3. This value is considerably reduced when a solvent is co-injected with the steam. It has to be noted that steam/oil ratio in simulation models is relatively low compared to field cases. The simulation models in this study are limited to homogeneous sector models. In field cases, the heterogeneity of the reservoir, shale barriers, steam losses and operational inefficiencies lead to higher steam/oil ratio. Figure 3.24 shows steam/oil ratio versus oil recovery factor.

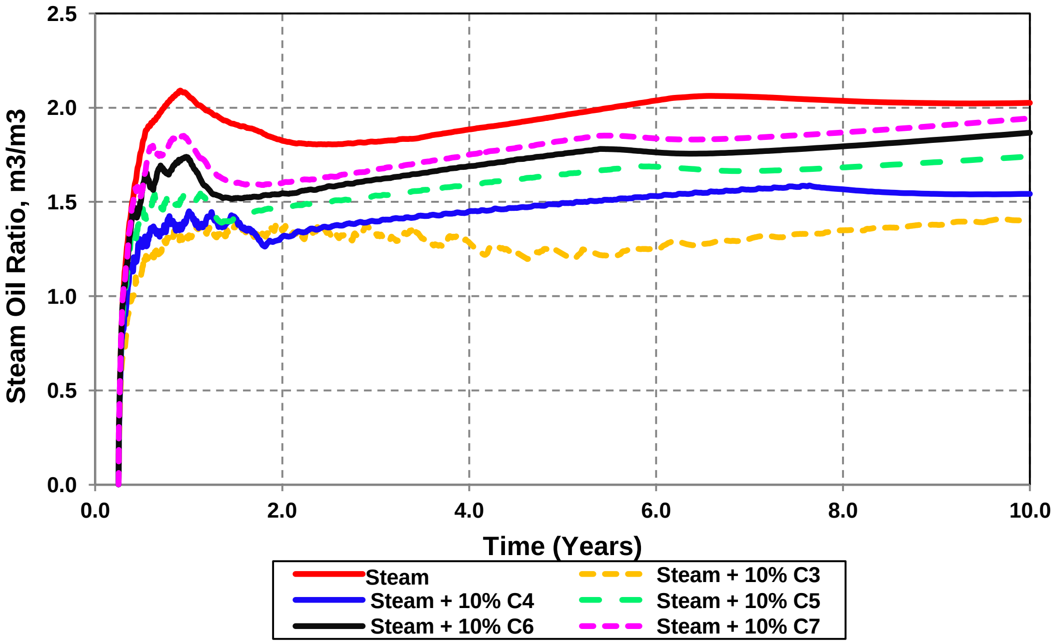


Figure 3.23. Steam consumption is considerably reduced when solvents are co-injected with steam.

The injected fluid contains hydrocarbon additives. To better compare the energy intensity of different cases, cumulative energy to oil ratios of different cases were compared with the SAGD process. As can be seen in Figure 3.25, the energy intensity of

SAGD can be reduced by around 20 to 40% when different solvents are co-injected with the steam. The energy intensity is the lowest when propane is co-injected. The presence of propane in the gaseous phase reduces heat losses to the overburden. In addition, injected energy (steam and propane) is much lower than in the other cases. Lower energy intensity solely does not lead to a favorable process. It has to be coupled with accelerated recovery to lead a better process than SAGD process.

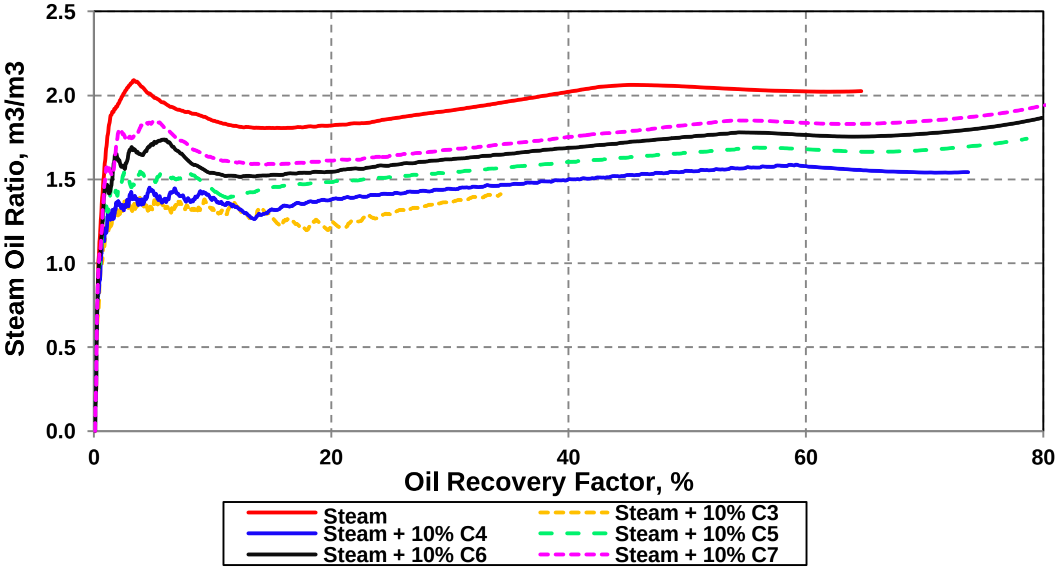


Figure 3.24. Steam oil ratio versus dead oil recovery for different cases (Solvent assisted and pure steam)

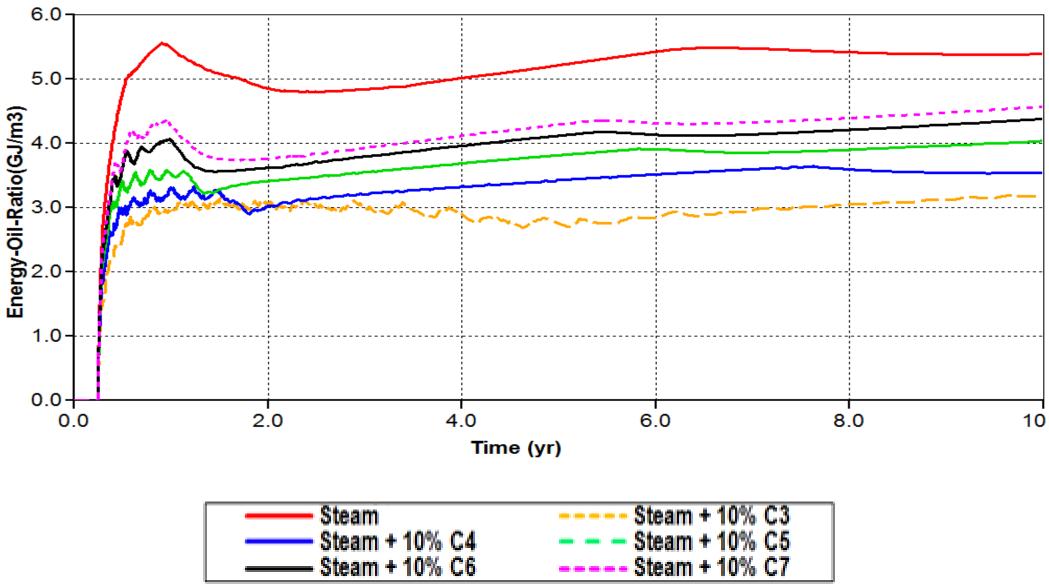


Figure 3.25. Energy/oil ratio is reduced when solvents are co-injected with steam.

In the simulation cases above, 10 wt% solvent was co-injected with steam. Due to high solvent cost, it is very important to recover the maximum amount of solvent from the reservoir. Solvent retention depends on the reservoir properties such as permeability and heterogeneity. Solvent retention in the reservoir also depends on type of the solvent. Figure 3.26 shows the amount of solvent (in wt%) dynamically retained in the reservoir. Cumulative solvent produced is subtracted from cumulative solvent injected and is divided by the cumulative injected solvent. An appreciable amount of the solvent is retained in the reservoir in all cases. The highest retention happens when propane is co-injected with steam. The heavier the solvent, the lower the amount of the solvent retained in the reservoir. Most of the remaining solvent can be recovered by blowdown at the end of process operation. However, dynamic retention might adversely affect the economics of solvent assisted SAGD processes. A large portion of the injected solvent is produced with diluted oil and water. The presence of the solvent with the oil in the wellbore is useful for transporting producing fluid. Figure 3.27 shows the weight percentage of different solvents in the produced fluids (mole percent values are closer to each other for different solvents). The heavier the solvent, the higher the percentage in the produced fluid would be. Solvent content in the produced fluid increases with time due to lower oil production.

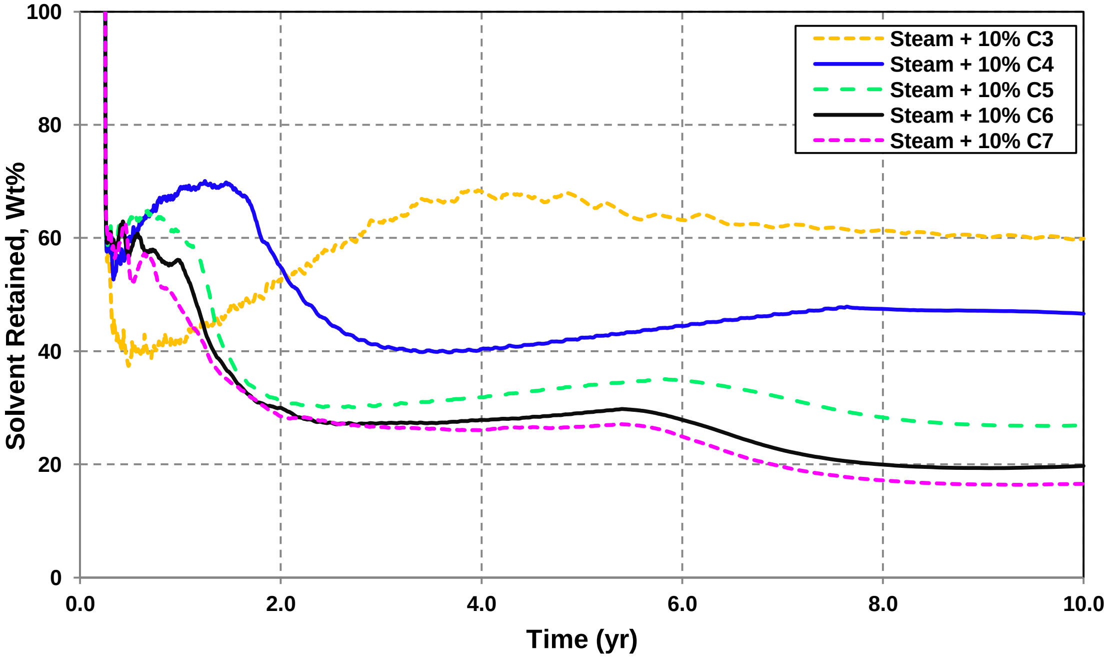


Figure 3.26. Net solvent retained in the reservoir. The heavier the solvent, the lower the rate of solvent retention in the reservoir.

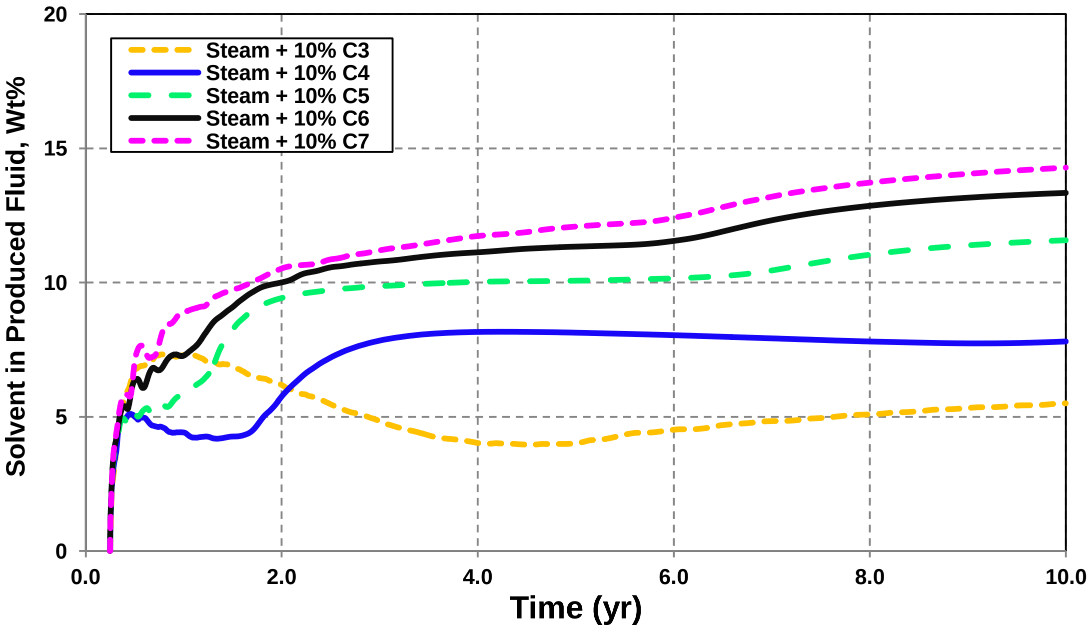


Figure 3.27. Solvent content in the produced oil phase. The presence of solvent aids transportation of the heavy oil and bitumen in the wellbore.

4. EXPERIMENTAL STUDY

4.1. Description of the equipment

The experimental setup mainly consisted of four components: a scaled 2D physical model, a fluid injection system, a fluid production system, and data acquisition. Figure 4.1 shows the schematics of the experimental setup. The details of each component are discussed in this chapter.

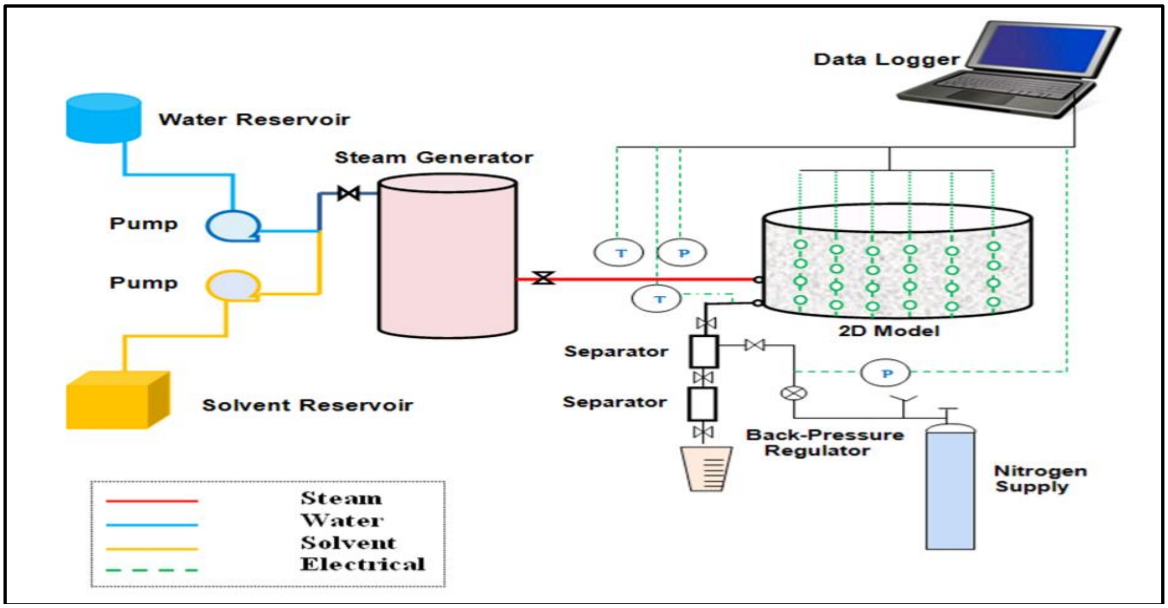


Figure 4.1. Experimental setup schematics

4.1.1. 2D physical model

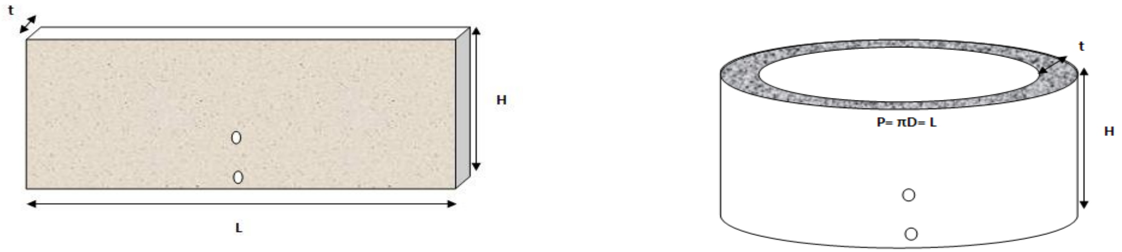
In order to conduct hybrid steam/solvent experiments at medium pressure, a 2D scaled physical model was designed and constructed. A 2D model is representative of a vertical cross-section of the dual horizontal wells in SAGD process.

Due to lab constraints and pressure requirements, the 2D planar model was replaced by a 2D annular model. This type of geometry has been used to conduct vapor extraction (VAPEX) experiments previously (Badamchizadeh et al., 2008; Yazdani and Maini, 2005). The main mechanisms in a VAPEX and an SAGD experiment are similar. Both processes use the same well configuration (dual horizontal wells) and they are governed by gravity drainage mechanisms. The major difference is that in SAGD, steam reduces the viscosity, while in VAPEX, vaporized solvents are used to dilute in-situ heavy oil and bitumen.

Design of the scaled experimental model was done in three phases: identification of the field data and operating conditions, selection of the most appropriate scaling approach, and design of the scaled model (Kimber and Ali, 1989**.** Canadian heavy oil reservoir conditions were identified and selected for the experimental study. Several scaling methods are available in the literature. In this study, the Pujol and Boberg (1972) scaling theory was used. This scaling theory is similar to Kimber and Ali (1989) and Butler (1994) if experiments are conducted at high pressure. This set of scaling criteria matched the ratios of gravity, viscous forces, and conductive and convective heat transfer, at the expense of incorrectly scaling pressure drop and capillary forces. Moreover, this scaling theory was used by Nasr et al (2002b) to carry out the solvent-assisted SAGD process at the Alberta Research Council (ARC).

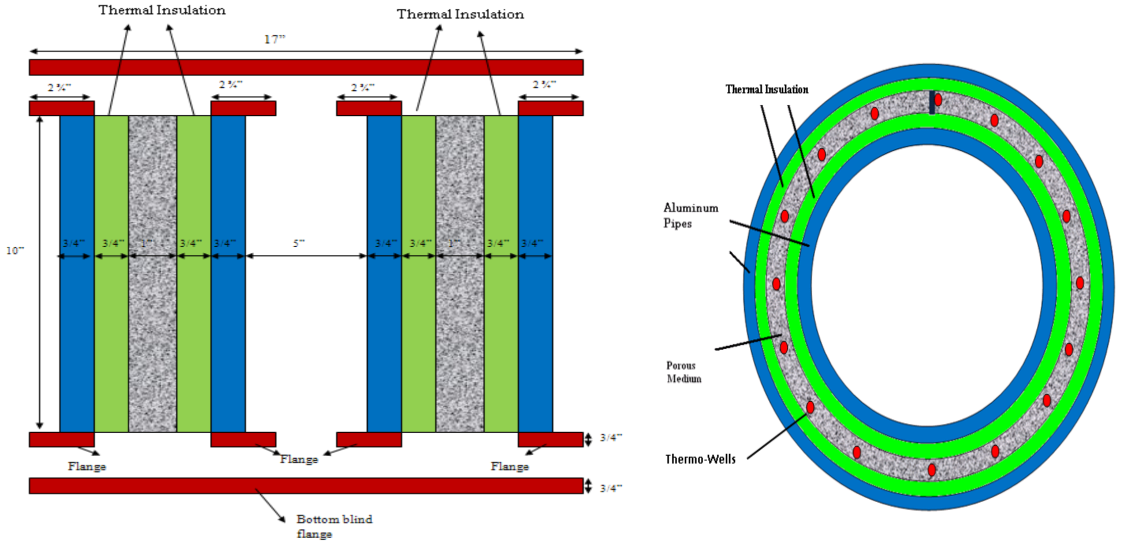
The scaling factor (experimental model to field model) was calculated to be 1:118.2. In laboratory conditions, one hour represents about 1.60 years at field scale. The resulting internal dimensions of the cell were 28 in. long by 10 in. wide by 1.25 in. thick with well spacing between injector and producer 2 in. and the location of the producer 1 in. from the bottom of the cell.

Due to laboratory constraints, the planar 2D model was converted to an annular model. Figure 4.2 shows the schematics of the 2D cell. In order to verify the feasibility of this model, a laboratory-scale simulation modeling was carried out. The results of the lab-scale SAGD experiments in Cartesian and annular geometry were compared. Oil recovery factor, oil production rate, SOR, and steam chamber growth were compared. The match between the results of Cartesian model and annular model was perfect (Figure 4.3).



a. 2D Scaled Planar Model

b. 2D Scaled Planar Model

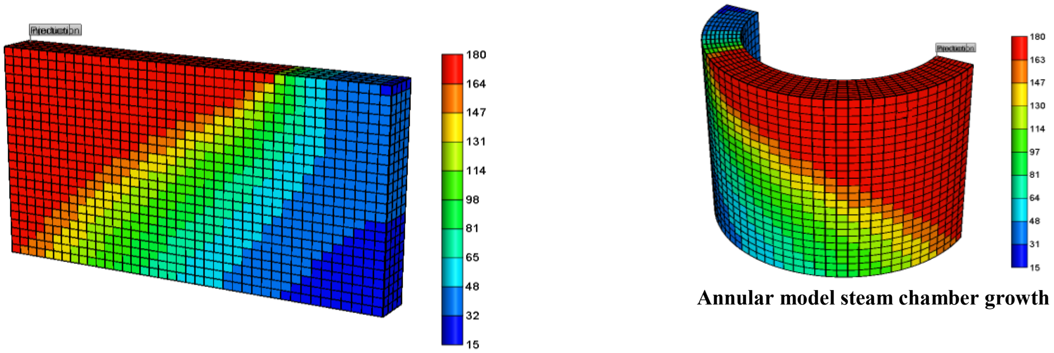


c. Cross section of the physical model. The annular cavity is wrapped with inner insulation

d. Top View of the annular model. The model is equipped with 45 thermocouples to monitor the temperature front

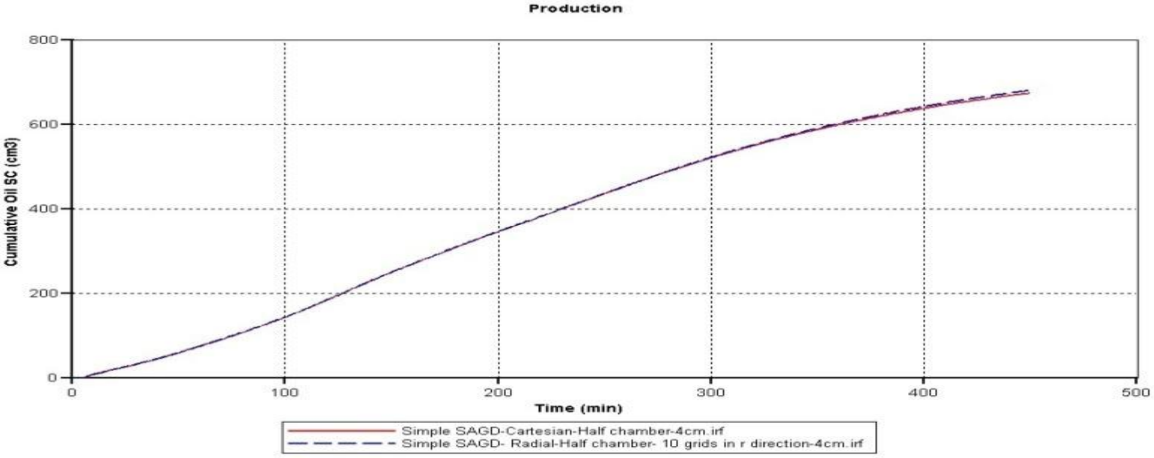
Figure 4.2. Schematics of 2D physical model designed for hybrid steam/solvent injection.

Heat loss to the surroundings is a major concern in thermal recovery experiments such as steamflooding, cyclic steam stimulation, and SAGD. It is practically impossible to prevent heat losses in physical models. However, heat losses at no-flow boundaries of the physical models have to be minimized.



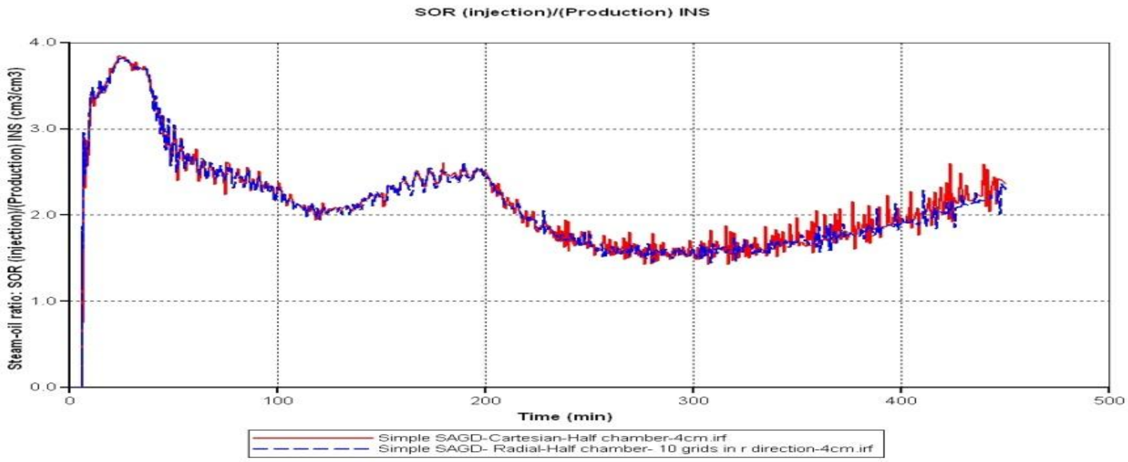
Annular model steam chamber growth

Rectangular model steam chamber growth



a. Cumulative oil production is almost the same by two geometries.

Figure 4.3 Numerical simulation is used to verify the annular geometry for solvent-assisted SAGD processes. Both geometries show the same results in terms of steam chamber growth, cumulative oil production, and SOR.

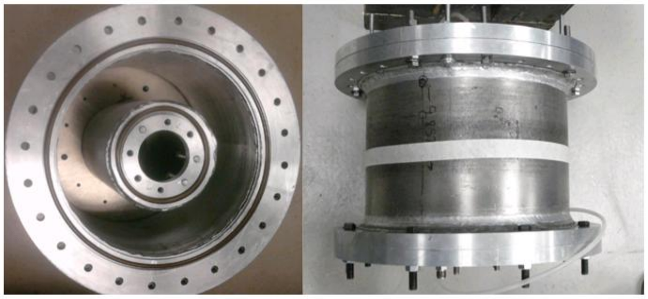


b. SOR ratio is almost the same by two geometries

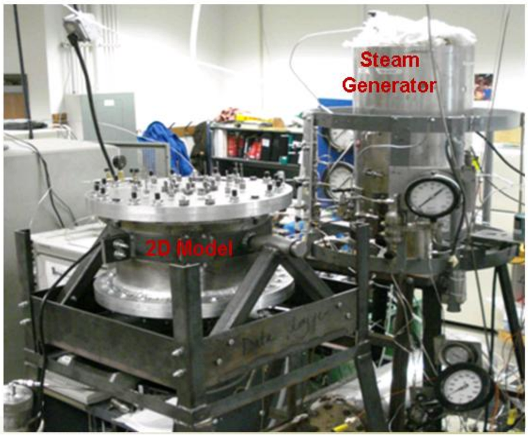
Figure 4.3. Continued.

To have proper heat distribution in the physical model, it was decided to use a suitable inner insulation. Installing an inner insulator was quite challenging, since the inner insulator was exposed to oil, water, and steam at high pressure and temperature during the experiments. Most thermal insulators are not stable if exposed to steam and hydrocarbons. In addition, the inner thermal insulator had to withstand sufficient pressure. Foamglas, Viton, and PTFE (Teflon) were among the options. Foamglas HLB 1600 was selected because of its lowest thermal conductivity and highest compatibility with steam and hydrocarbons, although it might lose its stability if exposed to steam and oil for a long time. Therefore, the Foamglas insulation was covered with Viton sheets. Viton acts as a barrier between the annular reservoir and the inner insulators. Both Viton and Foamglas HLB 1600 are good thermal insulators. Viton o-rings were used to seal the model because they are capable of withstanding the expected pressure and temperature of the experiments.

Figure 4.4 shows different parts of the physical model, which was relatively heavy. To facilitate the experiments, the whole model was mounted on a tall stand. All the stages of the experiments such as cleaning, assembling, packing, and fluid saturation were done on the stand. The dimensions of the stand were selected precisely. Using the stand, it was possible to locate the model as close as possible to the steam generator. This enabled us to feed the model with very high-quality steam during the experiments.



Top and side view of the model



2D Physical Model Connected to the steam Generator

The Physical Model is Mounted on a tall Standing to Reduce the Length of Injection Line and Minimize Heat Losses

Figure 4.4. Different parts of the experimental setup.

For injection and production well tubing, 1/4-in. and 1/2 in. tubings were used. The production and injection well tubing were perforated for uniform fluid injection and production and wrapped with screens to avoid sand production.

K-type thermocouples were placed at different locations both inside and outside the injection line to monitor the temperature of the injected steam. During the experiments, the injection line was wrapped with electrical band heaters and appropriate insulation to compensate for heat losses and supply superheated steam into the model. To trace the temperature front and steam chamber growth in the reservoir, 45 J-type thermocouples were located in the model. These thermocouples were placed in 11 thermo-wells and were inserted into the model. The majority of thermo-wells are located close to injection and production ports. Figure 4.5 shows the location of thermocouples inside the physical model.

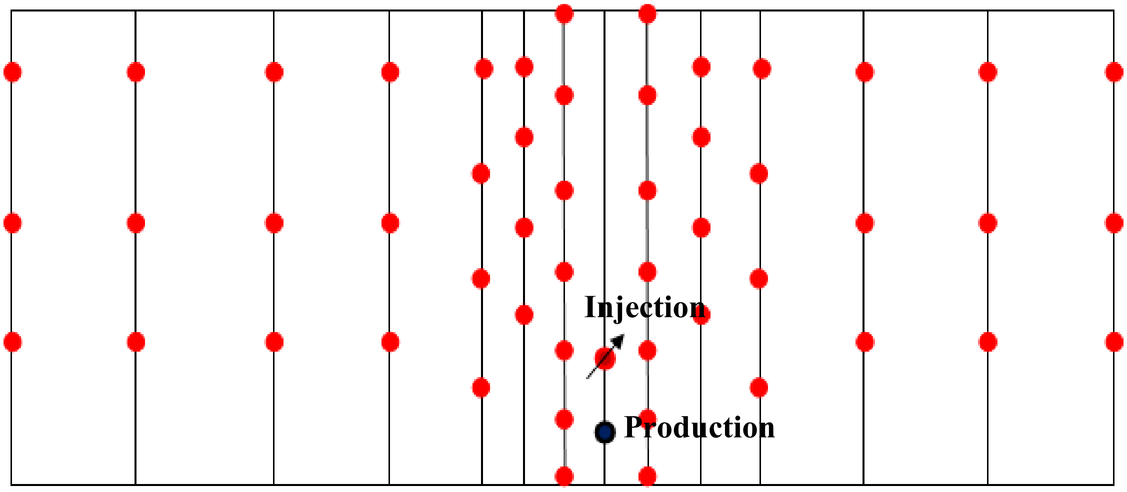


Figure 4.5. The location of J-type thermocouples inside the physical model. Most of the thermocouples were placed close to the injection and production well.

4.1.2. Fluid injection system

The injection system consisted of a steam generator, one high-pressure liquid chromatography (HPLC) pump to inject cold water into the steam generator, and one positive displacement Teledyne pump to inject the solvent. The steam generator had the capacity to supply high-pressure steam (up to 2000 psia) with high quality. For the experiments involving the co-injection of the solvent, water and solvent were injected into the steam generator at a certain ratio.

The pumps (HLPC and Teledyne, Figure 4.6) received a constant supply of distilled water and solvent from the reservoir and pumped it into the steam generator. The pumps were set at a desired rate and were monitored by a mass flow meter whose readings were directly fed into the data logger system.

Figure 4.6. The positive displacement pumps used to inject solvent and water into the steam generator.

An 11,000-W steam generator (Figure 4.7) was used to produce superheated steam (356ºC and 80 psig). A series of computer-controlled flexible heaters wrapped around the injection line were used to compensate for heat losses and maintain the superheated conditions of the injected steam. Just upstream of the injection well, two pressure transducers (Figure 4.8) were installed to record the injection and production pressure as close as possible to the cell. A thermocouple was also placed inside the injection line to register the steam temperature at the injection well. The length of the injection fluid injection line is short (less than 1 ft). This enabled us to deliver high-quality steam during the experiments.

Figure 4.7. Steam generator used to prepare the injection fluid.

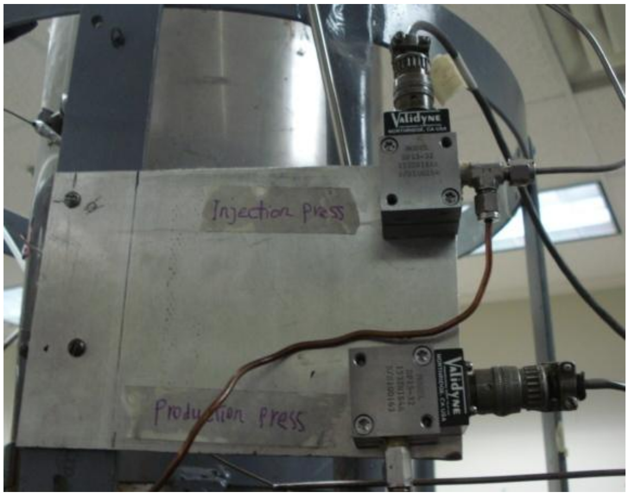


Figure 4.8. Two pressure transducers were used to record the pressure at the injection and production points.

4.1.3. Fluid production system

Produced oil, water, and solvent were collected by the production system and later analyzed. The fluid production system consisted of:

1) Two high-pressure separators with a capacity of 1 liter (Figure 4.9). The large volume of separators reduced the number of sampling times and decreased the irregularities in injection and production pressure.
2) A cooling system (PolyScience Model 9000) was used to cool down the produced fluid.
3) The backpressure system consisted of a backpressure regulator and N_2 cylinder. The whole production system resembled a natural piston-like cylinder. The production pressure, which was supplied by the N_2 cylinder and backpressure regulator, controlled the pressure of the whole system.

Liquid samples were typically collected at the bottom of the second separator in graduated tubes. Any liquid carryover in the gas stream was collected from the third separator. Produced samples were analyzed to obtain fluid rates and recovery. The results were plotted and compared to obtain the performance of each experiment. The results of the experiments were compared to evaluate the effect of solvent co-injection.

Figure 4.9. Two large separators were used to collect produced fluids.

4.1.4. Data acquisition system

The physical model was equipped with 45 internal J-type thermocouples to monitor the temperature inside the reservoir, two K-type thermocouples to monitor the temperature of overburden, and three K-type thermocouples to view and control the temperature inside the injection and production line. The temperature points and production and injection pressure were recorded using HP data loggers and were transferred using Labview. Labview provides real-time changes in pressure and temperature of the system and helps to conduct a more stable experiment. The data recording system consisted of a data logger and a personal computer (Figure 4.10). The parameters were recorded every 30 seconds into a pre-selected data file.

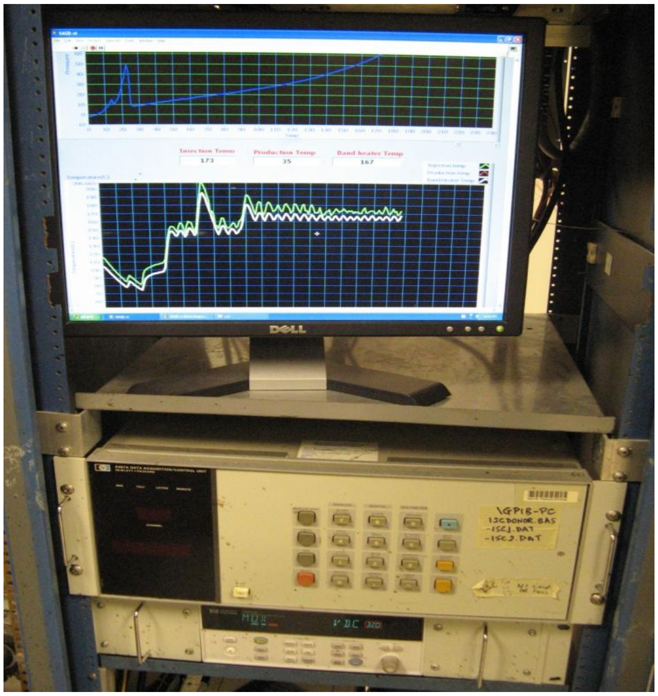


Figure 4.10. HP data logger connected to the computer.

4.1.5. Testing procedure

To conduct the experiment, the following steps were done in all experiments, and we tried to make sure that all the experiments had the same reservoir and fluid properties.

1. Different parts of the model were cleaned and assembled. A leakage test was performed to make sure there was no leakage in the system. Four Viton o-rings were used to insulate the model. They provided a perfect insulation and withstood the temperature range of the experiments. The physical model was tested for pressure range up to 200 psig to assure that model would not have any leakage problem during the experiment. Figure 4.11 shows the model during a leakage test.

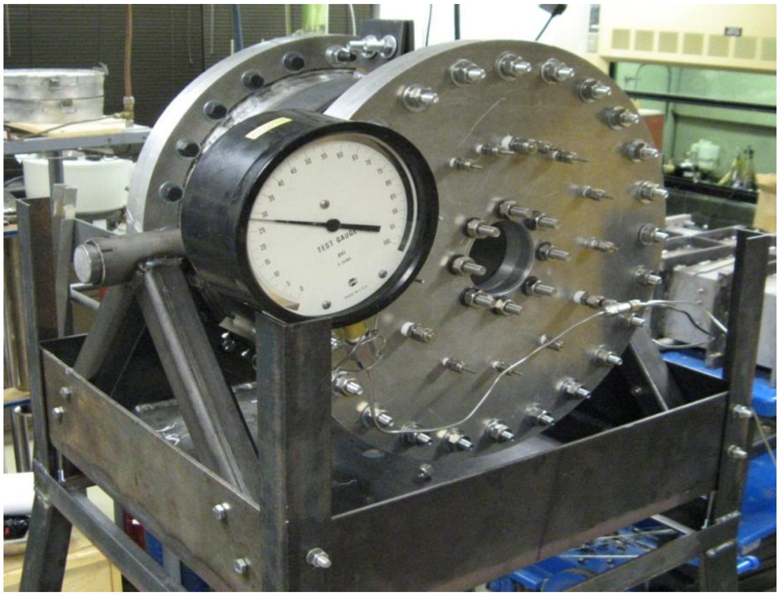


Figure 4.11. The physical model was tested for leakage before packing the system with sand in each experiment.

2. The model was packed with 20/40 silica sand (Average size = 630 µm). During packing the whole system was vibrated using two strong shakers to provide a homogeneous porous medium. Figure 4.12 shows the model during packing. An approximate value for the porosity of the system could be obtained from the mass of silica sand in the system.

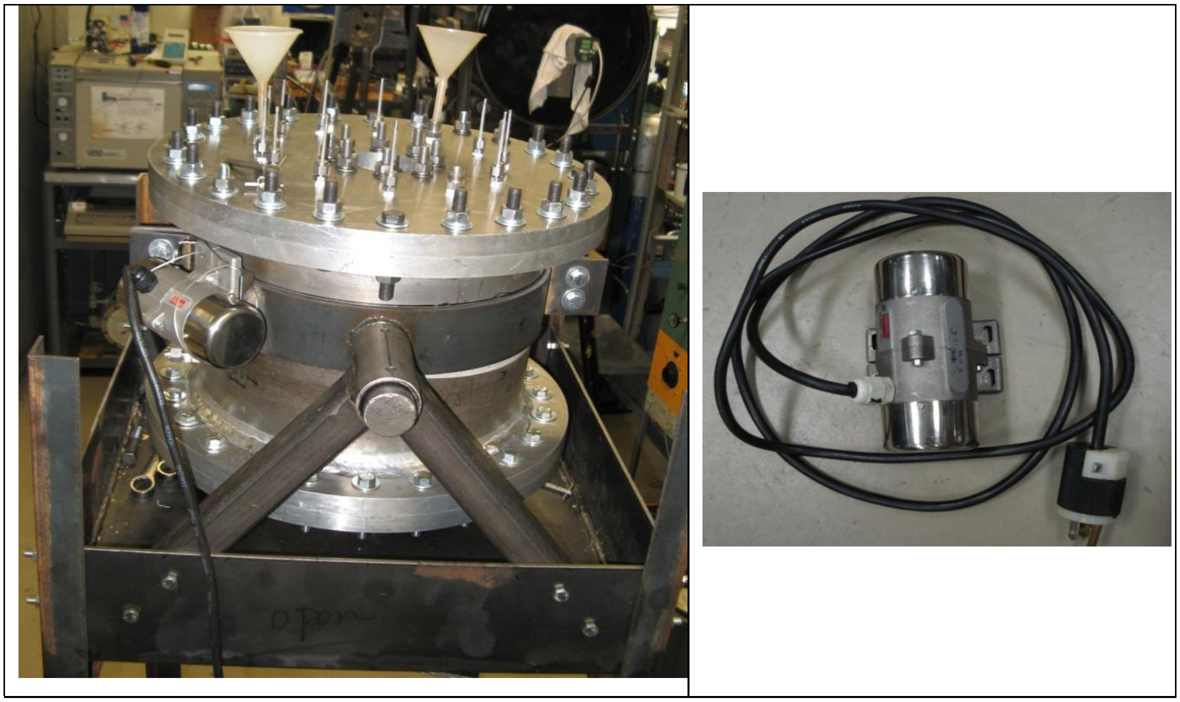


Figure 4.12. 2D physical model was equipped with two vibrators to fill the reservoir with homogeneous sand.

3. The model was vacuumed to remove the air from the system. The system was saturated with distilled water using a positive displacement pump. The porosity of the system was obtained from the injected volume of distilled water.
4. The model was saturated with oil. The oil sample was contained in a piston cylinder and pushed into the system using the Teledyne positive displacement

pump. For saturating the model, we heated the oil cylinder, the lines, and the physical model to a certain temperature to assure the piston-like movement of oil into the system. Figure 4.13 is schematics of the components of the system during oil saturation. The oil sample was located in a cylinder. All lines were wrapped by band heater to assure the mobility of oil in the lines. The oil sample was gradually pushed into the system using a positive displacement pump. The saturation of oil and water in the system were calculated using the volume of the oil and water in the system.

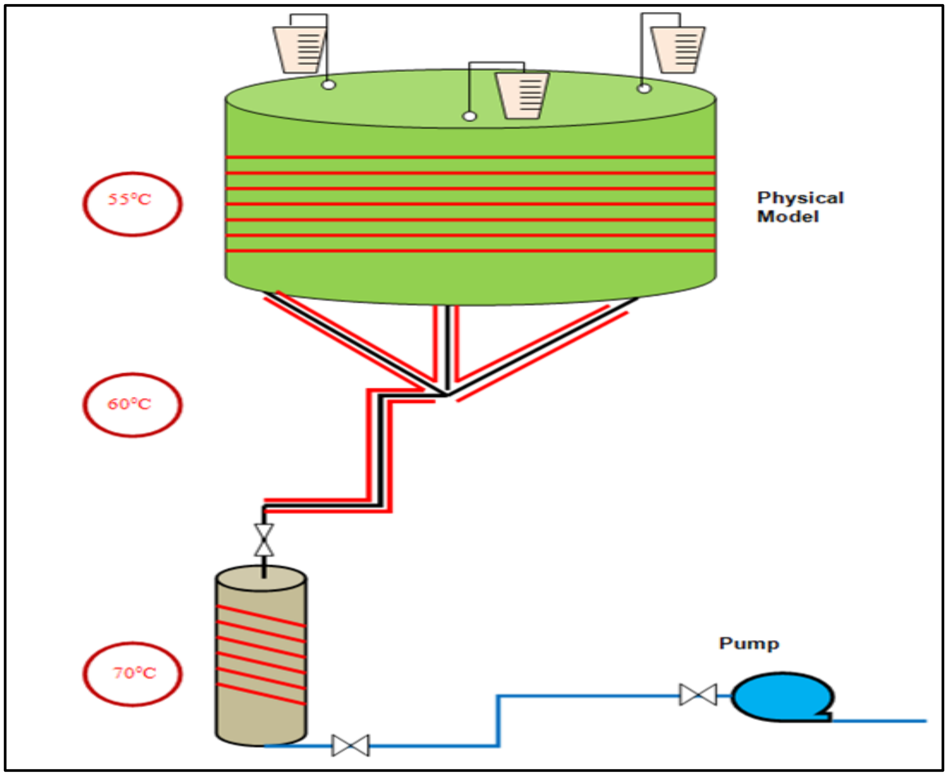


Figure 4.13. Different components of the system were preheated before saturating the system with oil.

5. The physical system was connected to the steam generator. At this point the model had been filled with measured amounts of sand, oil, and water. The initial

oil and water in place were determined, and a pressure test was performed to make sure that the steam generator and the whole system were leakage free.

6. The steam generator was conditioned for a couple of hours to make sure that it could supply steam at high quality without fluctuations in steam pressure and temperature. The injection lines were wrapped with the band-heaters and outer insulation to minimize the heat losses.
7. The whole pressure of the system was controlled by the backpressure regulator and N_2 cylinder.
8. The injection and production wellbores were heated using the band heaters for 10 minutes to provide the communication between the injection and production wellbores.
9. Steam was injected into the model at a specified rate and the experiment was initiated. In the experiments that involved the co-injection of the solvent, solvent was co-injected using a positive displacement pump running at constant volumetric rate to the steam generator. Pressure and temperature at the injection and production points were monitored during the experiments.
10. Produced volumes (a mixture of oil, water, and solvent) were collected and passed through an intermediate condenser. The fluids were analyzed for oil, water, and solvent content. In addition, temperature, pressure, and injection rates were recorded each 30 seconds.

4.2. Preliminary experiments

Individual parts of the new apparatus (the 2D physical model) were tested to assure their reliability and safety at high pressure and temperature during the experiments. A steam generator was examined to make sure that it operated for the long duration of each experiment (12 hours without interruption). Different parts of the system were tested to assure they were leakage-free at high temperature and pressure. The data recording system (HP data logger) and pressure transducers were also calibrated before each experiment.

A number of preliminary experiments were conducted to verify the stability of the steam-injection experiments. The objective was to carry out a SAGD experiment with a continuous steam chamber evolution for an experiment's duration (longer than 12 hours). In order to have a stable steam chamber in the SAGD process as depicted in Figure 1.1, the injection pressure and temperature and also production pressure needed to be almost constant. In a number of experiments, we observed temperature and pressure fluctuations. The system was diagnosed and the production system's separators and backpressure system were modified to assure stable experiments. Most of the preliminary experiments were conducted using West Sak oil from Alaska. The viscosity of the oil samples was not as high as Canadian heavy oil or bitumen and the operation of the experiments was easier. In addition, Canadian oil samples (Peace River bitumen) were not abundant in the laboratory. Once a successful SAGD experiment was conducted, the main hybrid steam/solvent processes were initiated.

4.3. Main experiments

The results of four main successful experiments were used to evaluate the effectiveness of the various scenarios to inject solvents and steam hybrid steam. Prior to conducting the experiments, an extensive simulation study was conducted to select only the most promising fluid-injection scenarios. (Chapter 3 provides the results from the simulation study.) Table 4.1 shows the main reservoir and operational parameters for four different experiments. A brief description of each run is given below:

Table 4.1. Main Reservoir and Operational Properties of Runs 1 Through 4

Experiments	**Run 1: Steam**	**Run 2: Steam + 15% C_6**	**Run 3: Steam + 15% C_7**	**Run 4:Pure C_6+ Cyclic**
Porosity	34.4%	35.6%	36.1%	36.3%
Sand type	Silica Sand	Silica Sand	Silica Sand	Silica Sand
Sand Size	20-40	20-40	20-40	20-40
Initial Oil Saturation	92.3%	91.2%	90.8%	91.5%
Oil type	Peace River	Peace River	Peace River	Peace River
Solvent Type	-	n-Hexane	n-Heptane	n-Hexane
Water Injection rate, cc/min	8.0	8.0	8.0	8.0 - cyclic
Solvent Injection Rate	0	1.42	1.40	6.5 – cyclic
Solvent Volume Ratio	0	15%	~15%	-
Average Steam Pressure, psig	80	80	80	80
Average Steam Temperature	162	162	162	162

Run 1: In this run, only steam was injected for 12 hours at a constant rate of 8 cc/min. This experiment was the base SAGD experiment.

Run 2: Steam and n-hexane were co-injected to improve the performance of the SAGD experiments and clarify the role of solvent addition to steam. The steam and solvent injection rates were 8 cc/min and 1.42 cc/min respectively. The n-hexane injection ratio was 15 vol%, 10.45 mass%, and 2.38 mole%.

Run 3: Steam and n-heptane were co-injected to improve the performance of the SAGD experiments and clarify the role of solvent addition to steam. Moreover, the thermophysical properties of hexane and n-heptane are different. The results of n-hexane and n-heptane co-injection were compared later. Steam and solvent injection rates were 8 cc/min and 1.40 cc/min respectively. The n-hexane injection ratio was 14.9 vol%, 10.62 wt%, 2.09 mole %.

Run 4: In this experiment, n-hexane was injected in different injection strategies to examine the idea of pure heated solvent injection. Initially, n-hexane was injected (with the rate of 6.5 cc/min), followed by steam and solvent cycles with different periods (solvent cycle rate is 6.5 cc/min and steam cycle rate is 8 cc/min).

4.3.1. Solvent co-injection with steam

The results of the first three experiments (Runs 1, 2, and 3) were compared first to evaluate the effectiveness of different hydrocarbon additives and operating conditions. Oil recovery factors, temperature distribution, and SOR were the main comparison parameters in this section. Later, the experimental results of the last run (Run 4) were analyzed. Finally, the results of different experiments were compared using an economic indicator.

Figure 4.14 shows the steam injection pressure profile for the first three experiments. To compare the experimental results quantitatively, steam injection pressure needed to be almost identical for the experiments. Steam injection pressure and temperature determine the value of energy input into the reservoir model. As can be seen in Figure 4.14, the injection pressure for all three experiments was almost equal, with some slight fluctuations during oil and water sampling. At first, produced fluid sampling was done in 30-minute time periods. Later, the sampling time was increased to one-hour periods because of lower fluid production rates. These small fluctuations usually lasted for less than a minute and did not impact the experimental results. The production system including separators and backpressure system were diagnosed and modified in the preliminary experiments. As a result, in the main experiments pressure profiles were stable.

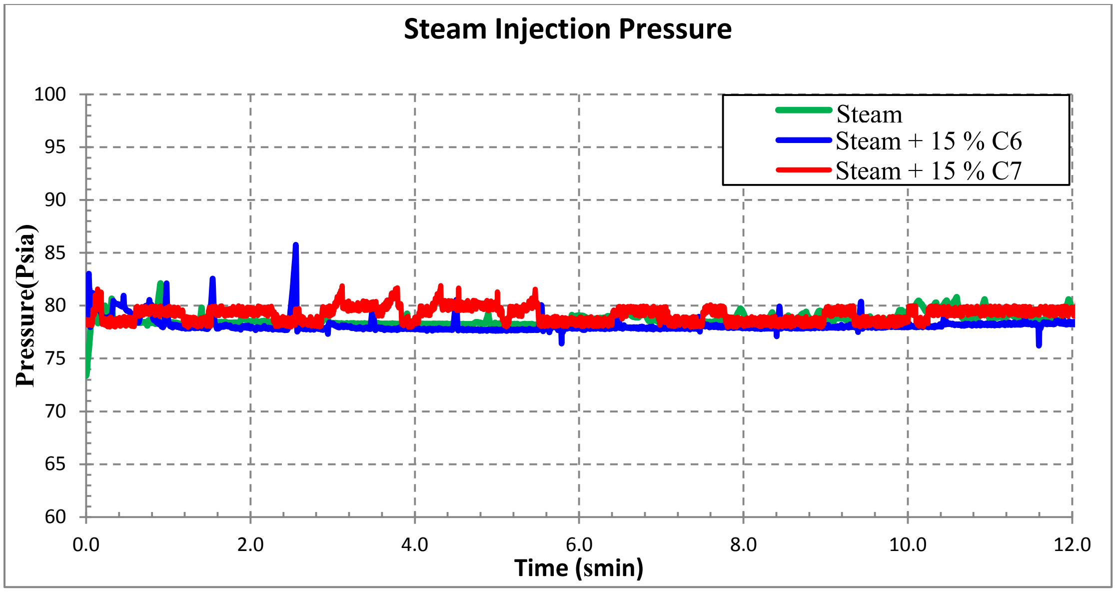


Figure 4.14. Injection pressure history for different runs. Injection pressure and temperature are almost equal for different experiments.

Produced oil, water, and solvent were sampled at 30-minute or one-hour intervals. The samples were carefully analyzed to obtain water, solvent, and oil ratios. The separation of oil, water, and solvent was based on the difference between the boiling point and the density of oil, water, and solvents. The normal boiling point of the solvents was less than that of water. The produced fluid was placed in a temperature-controlled vessel to separate solvent from the oil. This process might take 3 days to one week to completely separate solvent from oil. Sometimes, the produced fluid was placed in the refrigerator to make the oil viscous and remove the water from the sampling bottle.

The description of each run is given at the beginning of this session. Solvent co-injection with steam was considered the most effective method to enhance the performance of SAGD process. Among the available solvents n-hexane and n-heptane were selected. Based on the results of the simulations the lighter solvents such as propane reduce the efficiency of SAGD process. Propane and lighter hydrocarbons accumulate in the steam chamber (mainly at the top) and circulate near the steam-oil interface. At the temperature and pressure conditions near the steam-oil interface propane solubility and diffusivity is limited. Moreover, propane does not condense at the pressure and temperature of steam chamber. As a result, it creates a barrier for heat transfer and reduces the thermal efficiency. Butane is an intermediate solvent. It has partial condensation near the steam-oil interface. Heavier solvents such as n-hexane and n-heptane mainly condense at the temperature and pressure near the steam-oil interface. As a result, the solvents dissolve and mix with the heavy oil and bitumen and increase the viscosity reduction rate. Heavier solvents do not deteriorate the heat transfer by conduction at the interface.

The oil production rate was compared for Runs 1, 2, and 3 in Figure 4.15. As can be seen, the oil rate for Run 2 (with n-hexane) and Run 3 (with n-heptane) is substantially higher than the Run 1 (pure-steam injection) process, particularly at earlier times. Addition of the solvents to steam accelerated the oil production by increasing the viscosity-reduction rate.

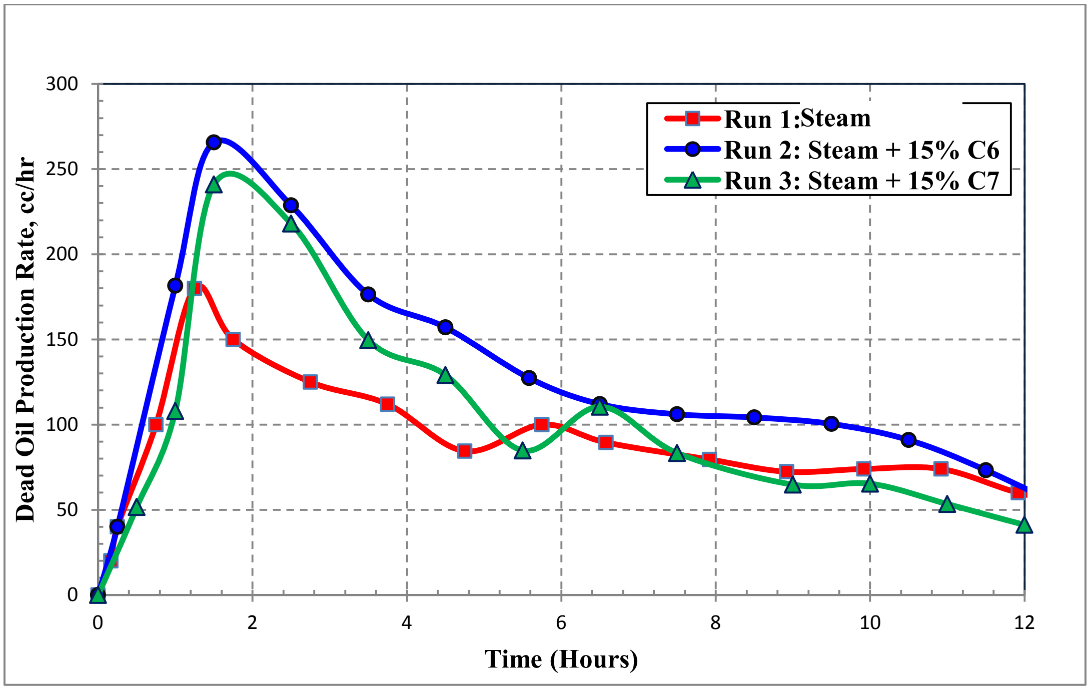


Figure 4.15. Dead Oil production rate of Runs 1-3. Dead oil production rate was significantly higher when solvent was co-injected with the steam.

Figure 4.16 shows oil recovery factor for these three experiments. The oil recovery factor was clearly higher for Runs 2 and 3 than for Run 1. The oil recovery factor was the highest in Run 2, when n-hexane was added to steam. Additional oil recovery under co-injection of steam and solvent was significant. However, an economic model needed to be used to justify the cost of the co-injected solvent. Additional oil recovery in Runs 2 and 3 can be related the solvent's capability to further reduce the viscosity. The details of the solvent addition mechanism were investigated in detail in Chapter 3. As described, solvents created a high mobility zone near the steam/oil interface and increased the oil production rate and oil recovery factor. In addition, residual oil saturation in the steam chamber was lower when a solvent was co-injected. Condensed solvent near the steam/oil interface also created a miscible process. Consequently, residual oil saturation will be lower and ultimate oil recovery factor will be higher under similar conditions.

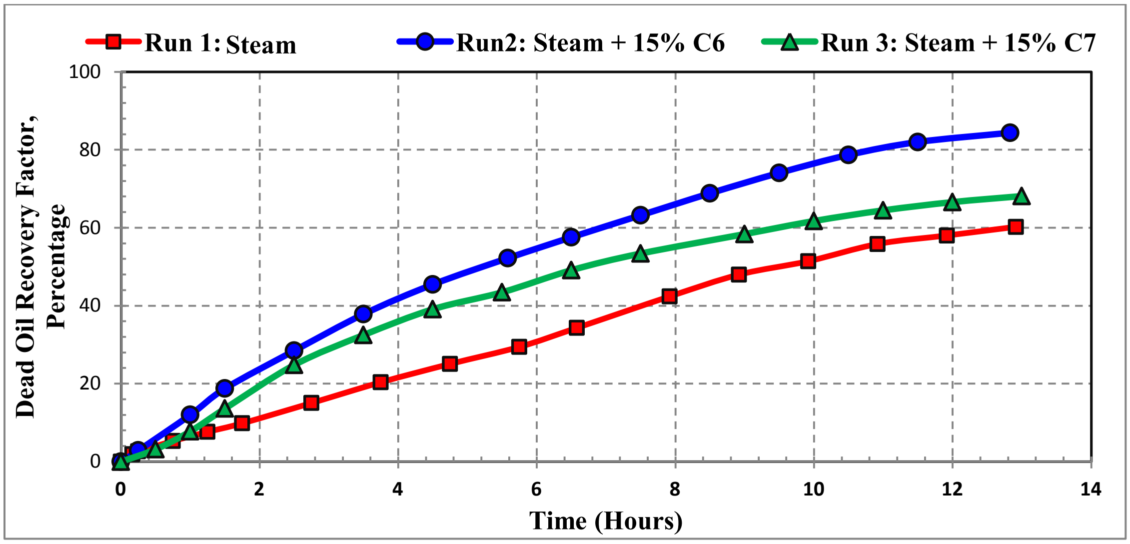


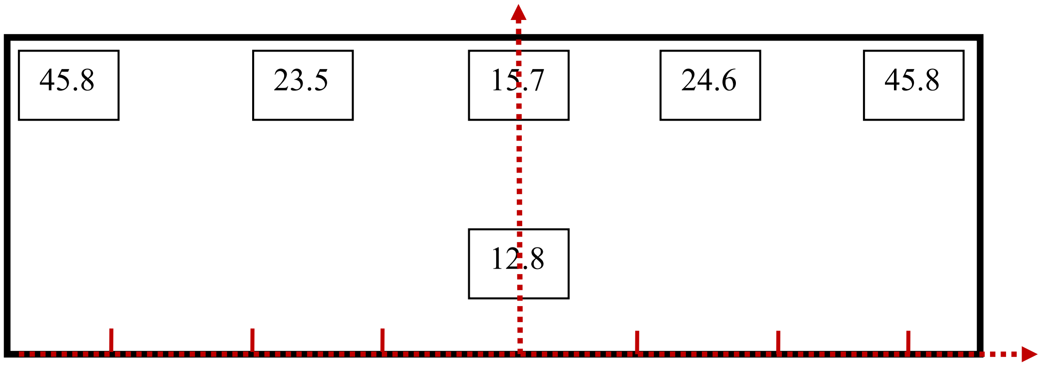
Figure 4.16. Oil recovery factor of Runs 1 to 3. Oil recovery was considerably higher when solvents were co-injected with steam.

Addition of solvents (n-hexane and n-heptane) increased the oil recovery factor significantly at earlier times. At later times the effect of solvent co-injection was not as substantial. At early times the steam chamber volume was not very high. A major portion of the solvent was transported in the gaseous phase towards the interface. At the steam/oil interface, the solvents tended to condense due to decreasing temperature. At later times, a part of the injected solvent sometimes condensed before reaching the steam/oil interface. Partial condensation of the solvent in a region other than the steam/oil interface reduced the advantage of solvent addition. Partial condensation of the solvents might have occurred because of severe heat losses to the under/overburden or the steam-chamber surroundings. This is the main reason for the laboratory tests' results. In the real field, reservoir heterogeneities also tend to increase solvent condensation. As a result, the addition of heavier solvents at early time is useful.

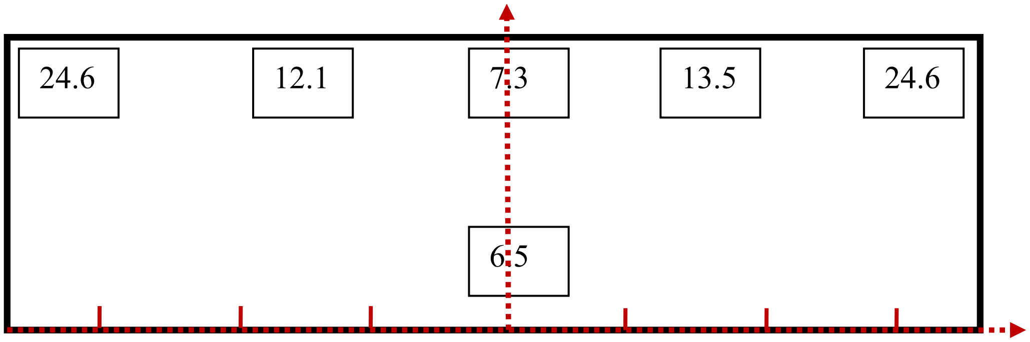
The addition of the solvent has two main advantages. It accelerates the oil production (Figure 4.15) and also increases the ultimate oil recovery (Figure 4.16). Residual oil saturation obtained using a simple material balance (Dean Stark analysis) was measured for a number of points in the physical model. Five samples were taken from different locations in the model. The samples were located in the oven to vaporize the water and the solvents. The remaining oil volume was measured and oil saturation was obtained. These numbers are subject to experimental error, but they provide a good qualitative basis for comparison. In addition, the sand pack removed from the reservoir model looked much brighter in Run 2 and 3 than in Run 1.

Figure 4.17 shows the oil saturation at the end of the experiment for Runs 1, 2, and 3. As can be seen, the residual oil saturation was lower when solvent was co-injected with steam. Solvent addition created miscibility near the steam/oil interface and reduced the oil saturation compared to pure steam injection. Therefore, solvent co-injection with steam has the potential to lead to higher ultimate oil recovery. The residual oil saturation data also can be used to modify the relative permeability curve endpoints in the simulations.

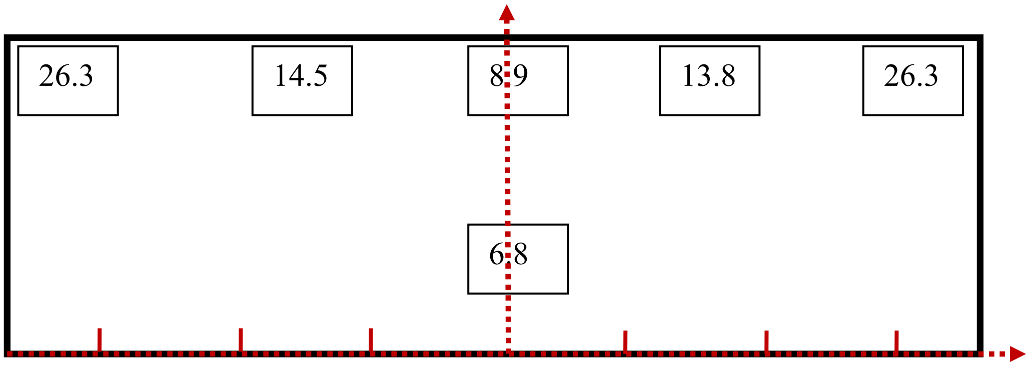
Temperature and pressure data at the injection and production points and inside the model were recorded. Temperature data inside the reservoir model were gathered by 45 J-type thermocouples. At injection and production locations, K-type thermocouples were used. Pressures at the injection and production points were recorded by pressure transducers. Pressure gauges also were used to monitor the pressure and temperature during the experiments. All the temperature and pressure data were gathered by HP data logger. Labview provides the possibility of monitoring real-time temperature and steam-chamber progression during the experiments. Temperature data inside the cylindrical model was interpreted and compared for different experiments. Tecplot 360 was used to interpolate the temperature data for the locations in which thermocouples did not exist. Temperature visualization by Tecplot was useful to control the steam-chamber stability during the experiment. The size of the steam chamber cannot be directly calculated from this data. Nevertheless, these data helped provide a qualitative comparison between the experiments.



Residual oil saturation at the end of Run 1



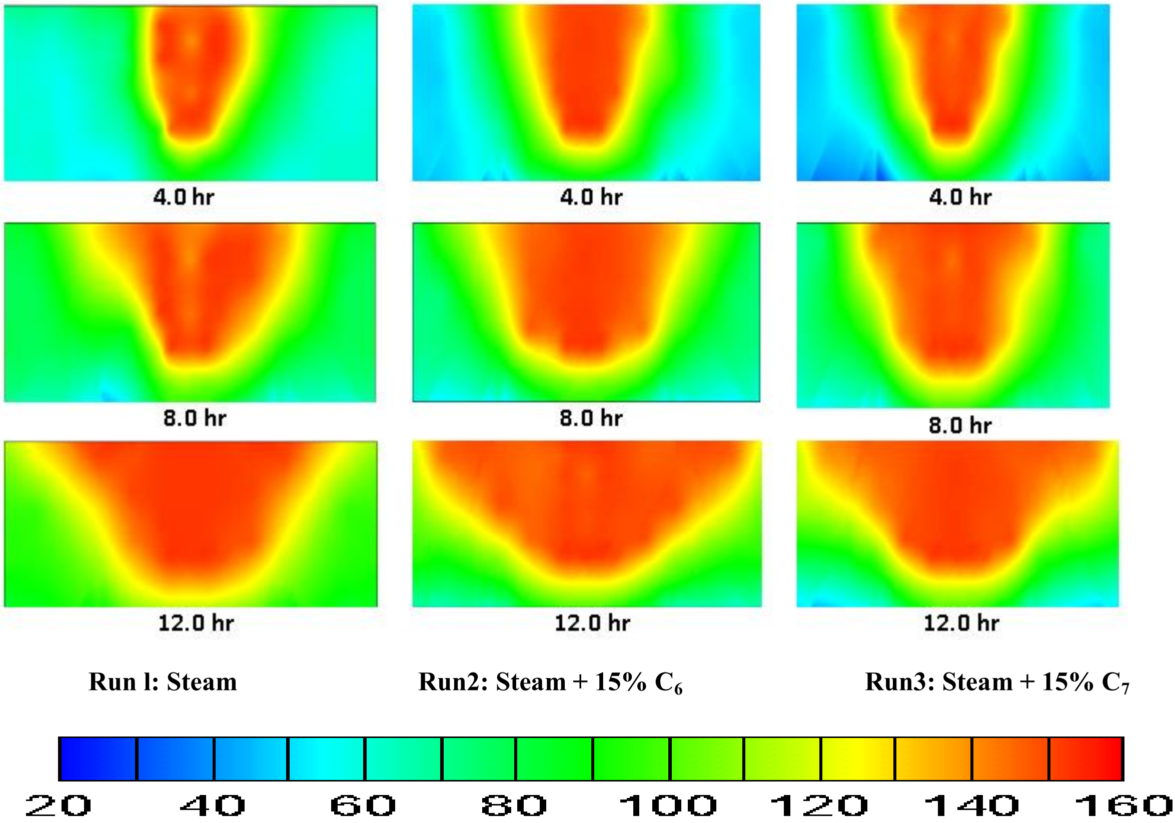
Residual oil saturation at the end of Run 2



Residual oil saturation at the end of Run 3

Figure 4.17. Residual oil saturation at the end of Runs 1, 2, and 3. Residual oil saturation in the chamber is significantly lower for Runs 1 and 2 than for Run 1.

Figure 4.18 shows the steam chamber zone for three different experiments (Runs 1, 2, and 3). Steam chamber zones were captured at 4, 8, and 12 hours and compared. The size of the steam chamber at different times was bigger when solvent was co-injected with the steam and when the solvent was n-hexane. The bigger the volume of the steam chamber, the higher the oil recovery factor. The results of oil recovery comparison (Figure 4.16) and steam chamber growth comparison (Figure 4.18) are in agreement, indicating the effectiveness of solvent co-injection with steam.



Run l: Steam **Run2: Steam + 15% C_6** **Run3: Steam + 15% C_7**

Figure 4.18. Steam chamber progression at different times for Runs 1, 2, and 3.

Figures 4.20, 4.21, and 4.22 show the temperature profile for three thermocouples (T1, T2, and T3) inside the reservoir for three experiments. The location of the thermocouples is shown in Figure 4.19. The temperature was low at the beginning, close to reservoir temperature (T2 and T3). Later, the temperature increased due to heat conduction. At the end, the temperature reached a maximum point and stayed constant afterwards. Constant temperature indicates the presence of steam and heating by convection. This constant temperature corresponds to the saturation temperature of the pressure at the injection point since the pressure is almost constant in the steam chamber.

As can be seen, the temperature profile advanced faster much faster in Run 2 than in Runs 1 and 3.

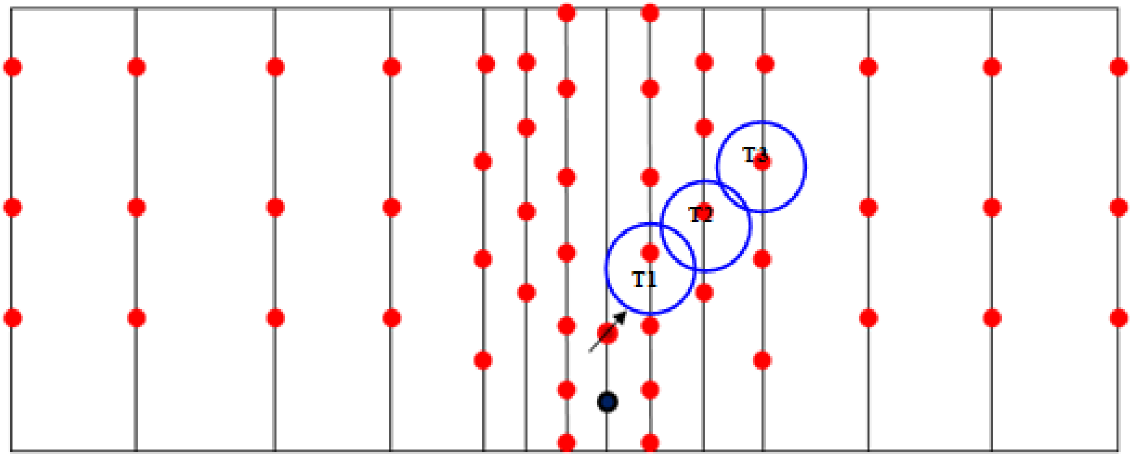


Figure 4.19. The location of three thermocouples (T1, T2 and T3). The temperature profiles for these three points for each experiment are shown in Figures 4.20, 4.21, and 4.22.

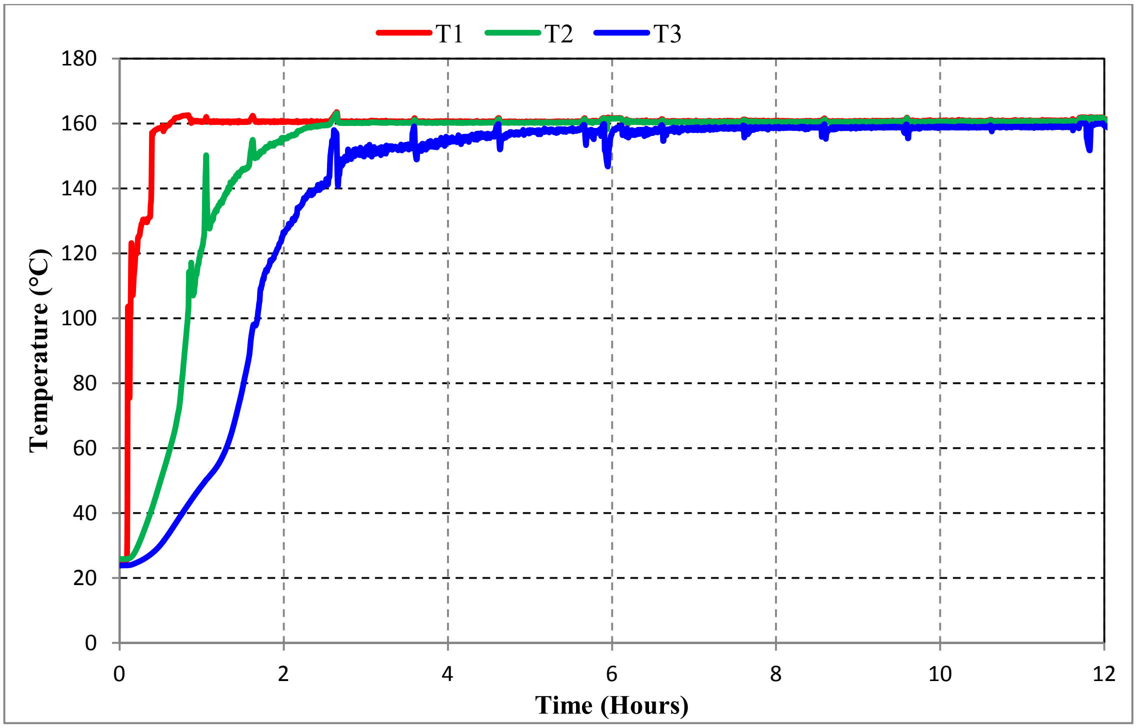


Figure 4.20. Temperature profile for thermocouples T1, T2, and T3 of Run 1.

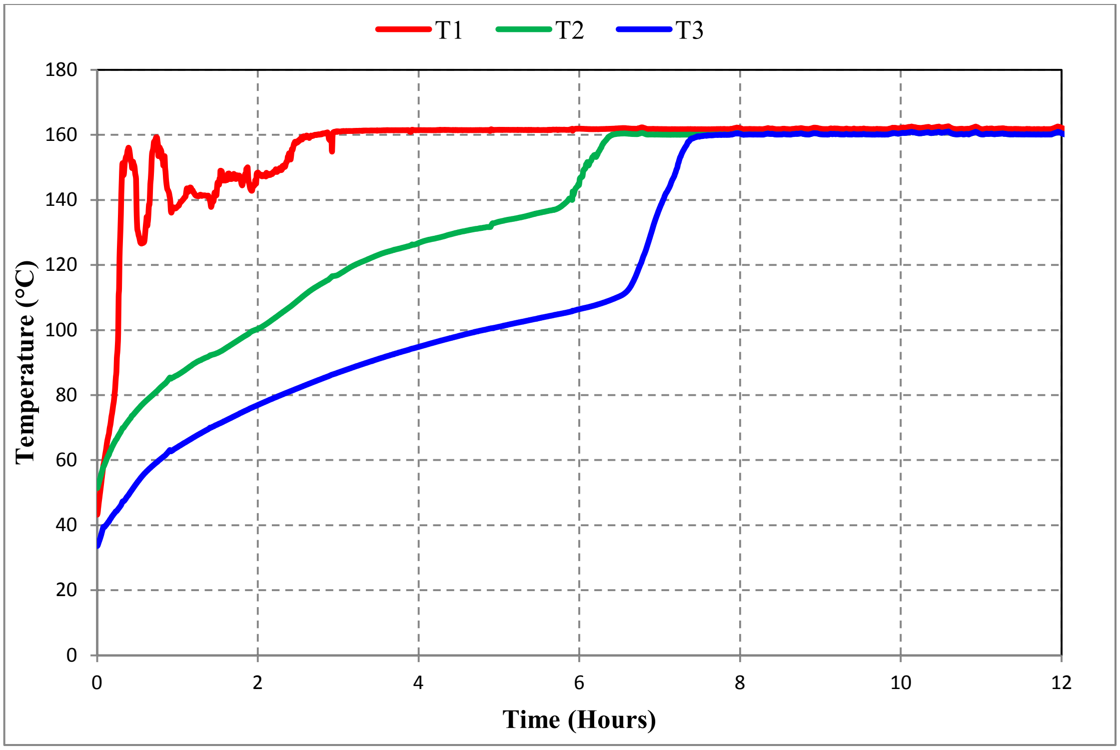


Figure 4.21.Temperature profile for thermocouples T1, T2, and T3 of Run 2.

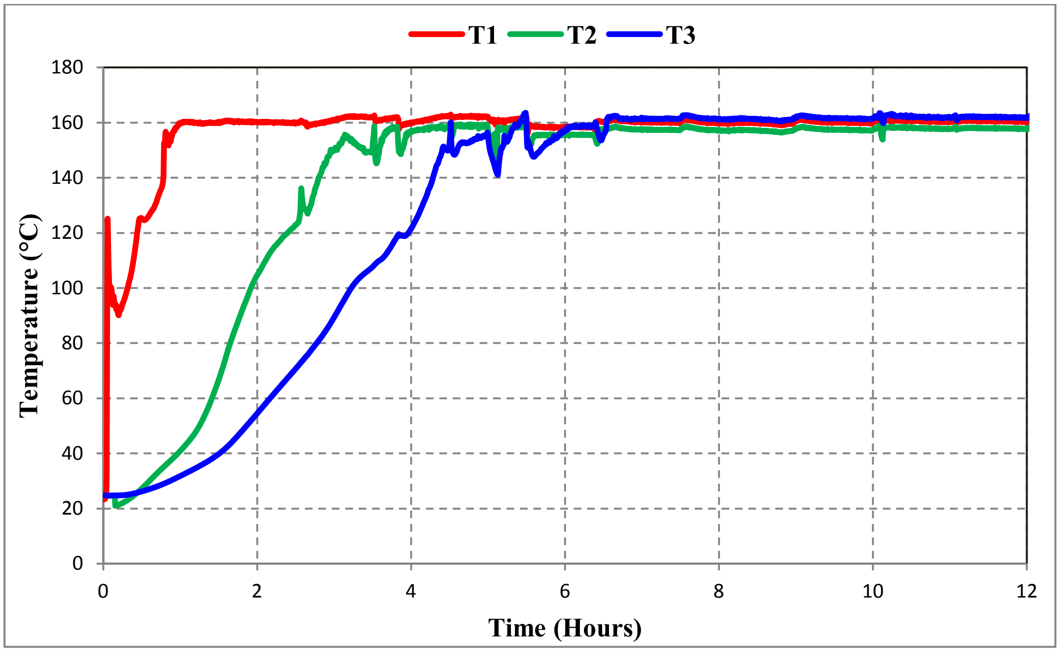


Figure 4.22. Temperature profile for thermocouples T1, T2, and T3 of Run 3.

Based on the experimental results above (oil production rate, oil recovery factor, and steam-chamber progress) n-hexane co-injection has better performance in terms of oil recovery than n-heptane co-injection. The thermophysical properties of n-hexane and n-heptane were compared at the operation temperature and pressure of the experiments. The nature of these two hydrocarbons and their interaction with the oil is slightly different. Slight differences in solvent (n-hexane and n-heptane) diffusivity and solubility in oil would not lead to the significant difference in oil recovery. After careful analysis of the experimental data, the main reason for the discrepancy in oil recovery was attributed to the difference in the vapor pressure behavior of the solvents. Saturation conditions for these two hydrocarbons were compared with water. Figure 4.23 shows the vapor pressure behavior of water, n-hexane, and n-heptane Point 1 on this plot shows the temperature and pressure set at the steam generator for the experiments. The temperature in the steam generator was set to a temperature of 180^{0}C to assure the complete vaporization of the injected fluid components (n-hexane, n-heptane, and water). Point 2 on the plot shows the estimation of average steam chamber temperature during the experiments. The temperature in the steam chamber corresponds to the saturation temperature of the injected fluid. At the operating pressure and the temperature of the experiment, n-heptane could condense because of the heat losses. The saturation temperature of n-heptane is higher than that of water at the operating pressure of the experiments and also at operating conditions for fields in Canadian reservoirs (70 psig to 500 psig).

On the other hand, the saturation temperature of n-hexane is lower than that of water for the current experiment and field conditions. If the injected fluid contains some percentage of n-heptane, partial condensation of n-heptane might occur in the steam chamber. As discussed earlier, this could be related to heat losses to over/underburden. However, if n-hexane is co-injected with the steam at different proportions, there is a much lower chance for early condensation of the solvent. Therefore, a portion of the n-heptane was condensed early, before reaching the steam/oil interface. As a result, the increase in oil recovery is not as significant as n-hexane co-injection.

We conclude that the solvent selection for co-injection with steam depends on the operating conditions of the experiment and field conditions. In real field conditions, a diluent is usually co-injected with steam. It is critical to assure the compatibility of the operating conditions with the thermophysical behavior of the injected hydrocarbon additive.

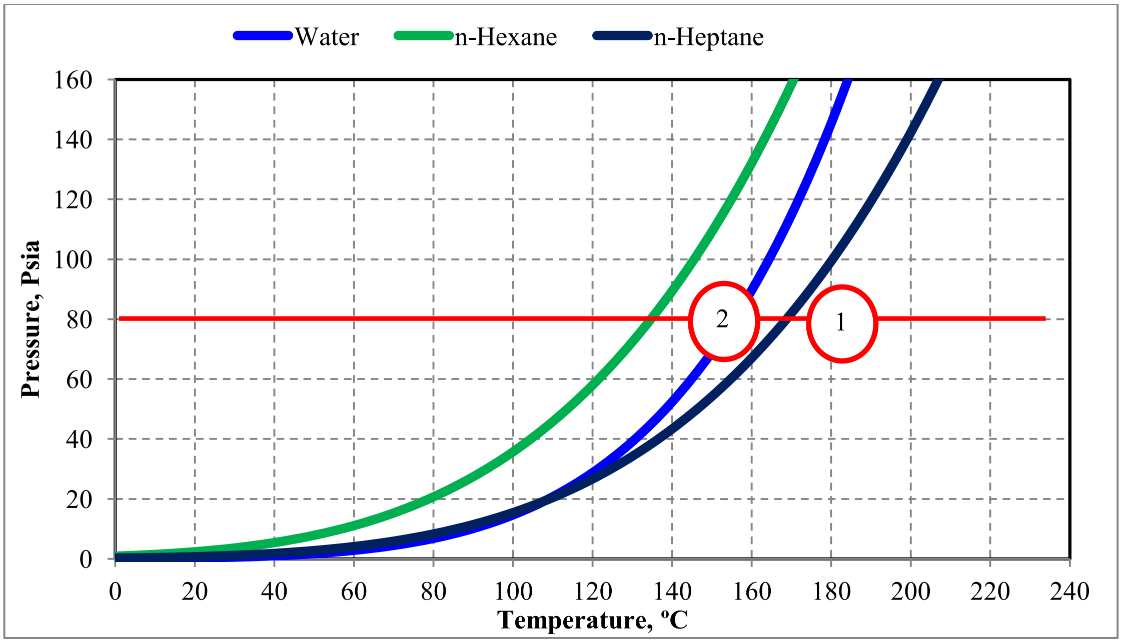


Figure 4.23. Comparison of vapor pressure of water, n-Hexane and n-Heptane.

There are some basic requirements for fluid injection in hybrid-solvent process governed by gravity drainage. The most important of all is that the major portion of the injected fluid should be vaporized in the steam chamber. Once the injected fluid reaches the chamber edge, the fluid including water and solvents will be condensed or diffused in the oil phase. Water is a perfect injection fluid since it is fully compatible with gravity-drainage based processes. Light solvents will easily vaporize and rise in the steam chamber. However, light solvent diffusion is much slower than heat conduction. Lighter solvents also do not condense at temperature and pressure conditions near the steam/oil interface. As a result a major portion of light solvents remain in gaseous phase. The accumulation and circulation of lighter solvents reduces the performance of the SAGD process.

A solvent with similar thermophysical properties as water is the most suitable hydrocarbon additive. The solvent will be vaporized with water and transported to the edge of the steam chamber; the condensation of water and solvent takes place at the steam chamber edge. The solvent dissolves into the oil phase depending on the solubility at the temperature and pressure. Most of the solvent will be in the liquid phase and does not interfere with heat transfer mechanisms.

In real field conditions, usually a diluent is co-injected with the steam. Thermophysical and PVT properties of the hydrocarbon-additive have to be carefully analyzed at the operating conditions of the SAGD process to assure compatibly with the gravity-drainage mechanism.

SOR is a reasonable economic indicator to compare the energy intensity of thermal processes involving steam injection. This value is used by engineers in the field for processes such as steamflooding, cyclic steam injection, and SAGD processes. The lower the value of SOR, the better the economics of the process would be.

In these experiments, the produced fluids were analyzed to obtain water, solvent, and oil ratios. The mass values were converted to a volumetric basis having the density of oil and water at standard laboratory conditions. Figure 4.24 shows SOR for Runs 1, 2, and 3. The average SOR value for Run 1 (pure steam injection) is the highest. This fairly high value reflects heat losses in the experimental model. The energy requirements for SAGD processes were reduced by the addition of solvents (n-hexane in Run 2 and n-heptane in Run 3). SOR reduction in Runs 2 and 3 was significant, and it considerably reduced the energy intensity of the SAGD process. However, in Runs 2 and 3 a valuable solvent was injected along with the steam.

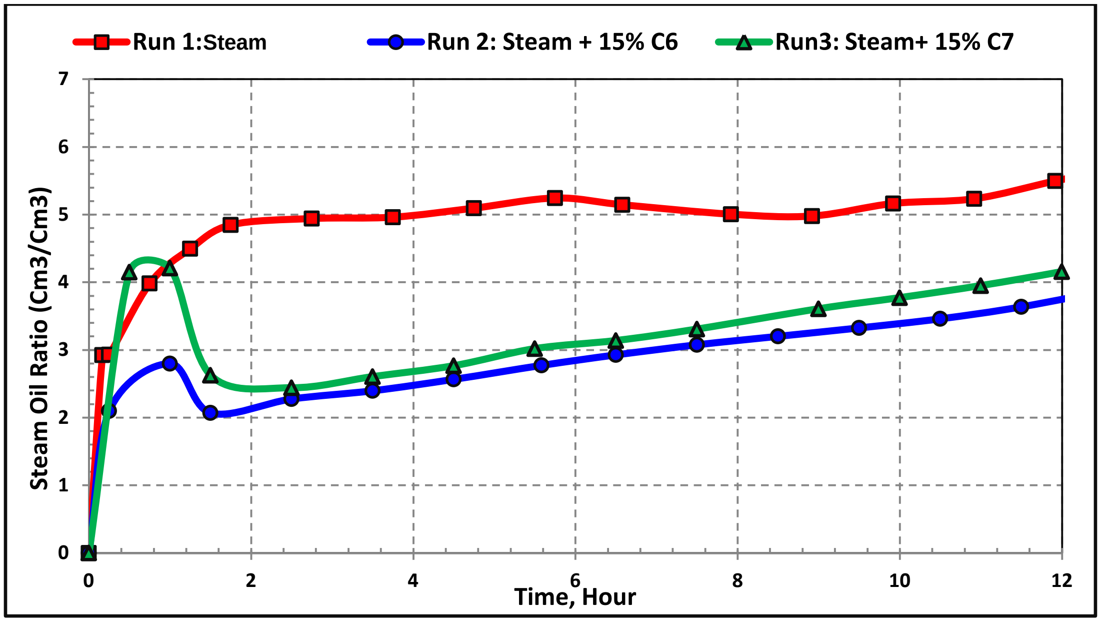


Figure 4.24. Steam/oil ratio comparison for Runs 1, 2, and 3. The energy intensity of the SAGD process was significantly reduced by the addition of solvents to steam.

4.3.2. Pure solvent co-injection

One way to reduce the viscosity of heavy oil and bitumen is to use solvents instead of steam. VAPEX is a solvent analogue of the SAGD process which was proposed by Butler and Mokrys (1991). A vaporized solvent is injected into the upper horizontal well. A vapor chamber similar to a steam chamber is formed by the injection of the solvent. Near the solvent/oil interface, the solvent is diffused into the heavy oil and bitumen. The diluted oil is produced by gravity drainage to the horizontal production well. Solvent diffusion is considerably slower than heat conduction. As a result, the VAPEX process does not meet economical requirements because of the low oil production and the high cost of the solvent.

A combination of solvent injection and a form of heating might enhance solvent-based processes such as VAPEX. Several researchers have proposed combined thermal/solvent recovery to boost the solvent-based gravity drainage process. The main objective of heat addition is to assist viscosity reduction. Besides, a vaporized solvent is required for these processes. Addition of heat vaporizes a number of solvents and aids transportation of the gaseous solvent towards the steam/oil interface. In thermal solvent recovery processes the main tool to reduce the viscosity is supplied by the solvents.

Various solvents are available for thermal solvent recovery processes. The application of light solvents (propane and butane) has been discussed in literature (Frauenfeld et al., 2005; Nenniger and Dunn, 2008). However, the use of heavier solvents such as pentane and heavier has not been discussed. Diluents, which are commercially available in the industry, are used for the transportation of the heavy oil. The main idea is to inject the heated diluent into the reservoir. The heated solvent reduces the viscosity in the reservoir and later helps the transportation of the heavy oil and bitumen. It can be recovered partially on the surface and re-injected into the reservoir.

This idea of hot diluent injection was discussed by Li and Mamora (2010). The latent heat of the hydrocarbon additives is significantly lower than that of water. Injected heated solvent might condense before reaching the interface. Single solvent injection and alternating heated solvent and steam injection were examined in Run 4.

Figure 4.25 shows the injection rate of the solvent and steam in Run 4. At the beginning of the experiment, steam was injected for less than half an hour to create communication between the injection and production wells. Afterwards, solvent was injected for 3.5 hours. Later, heated solvent and water were injected in alternating mode. The length of solvent and water injection periods was varied. The rate of steam injection was 8.0 cc/min and the rate of solvent was 6.5 cc/min in cycles.

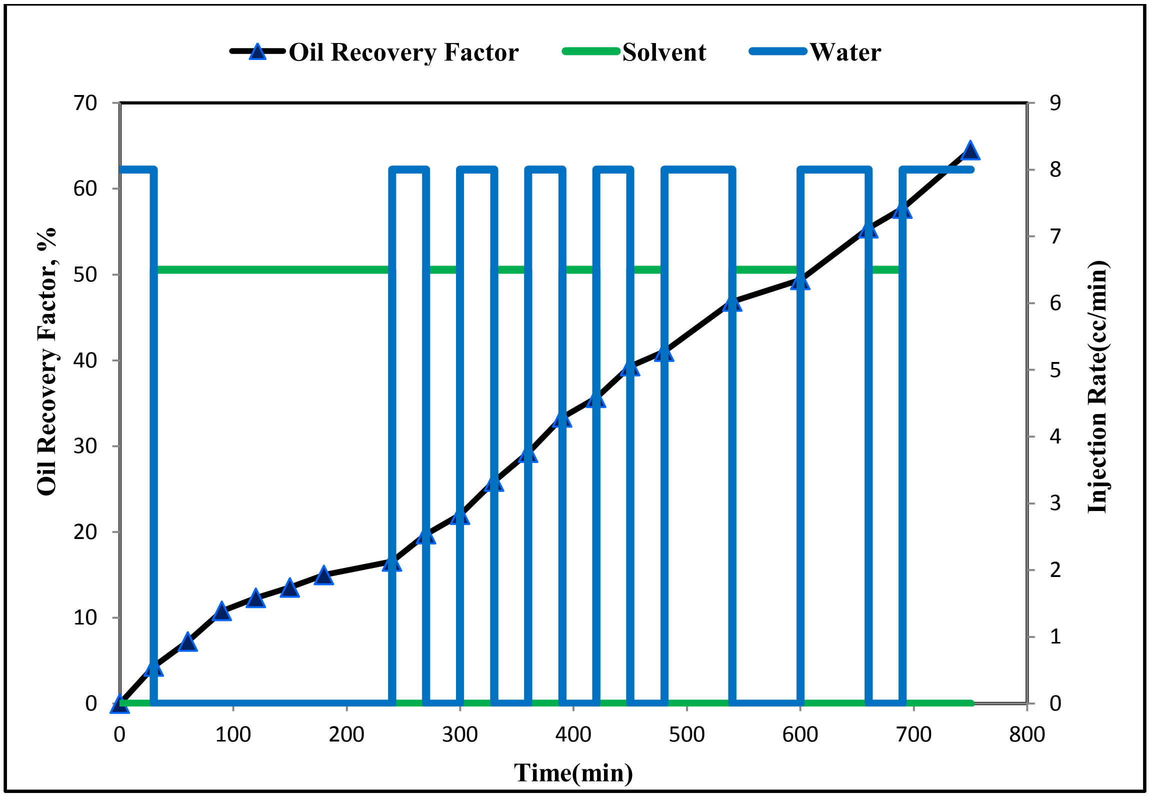


Figure 4.25. Oil recovery factor imposed on fluid injection profile for Run 4. Oil recovery by pure solvent injection cannot be sustained for a long time. Alternating solvent and steam injection with longer cycles of steam injected is more promising.

Oil recovery factor was superimposed on the injection rate of solvent and water to interpret the results. As can be seen from Figure 4.25, solvent injection oil recovery is high at the beginning but it is reduced after 1or 2 hours. The oil recovery by solvent injection reaches 16 to 18% and stays almost constant. Although solvent is injected at the rate of 6.5 cc/min, additional oil recovery is negligible; suggesting that the solvent chamber heat cannot be sustained for a long time. Most of the injected solvent condensed due to heat losses and low latent heat of the solvent. The condensed solvent was directly produced. We conclude that the heated diluent cannot be properly placed near the edge of vapor chamber.

To add more heat to the system, steam and heated solvent were injected alternately. The main objective was to use the residual heat left in the chamber by steam in steam injection cycles to reduce the condensation of the solvent. Therefore, it might be possible to sustain the solvent chamber for a longer time.

As can be seen from Figure 4.25, alternating solvent and water injection was more promising than single solvent injection. The lengths of the steam and solvent injection cycles were changed a number of times. Initial alternating cycles were half an hour. Later alternating steam cycles were around one hour. Based on the oil recovery results, alternating steam and solvent injection with longer cycles of steam injection and shorter cycles of pure heated solvent injection was more successful.

Oil recovery factor for different runs is shown in Figure 4.26 to compare Run 4 with other experiments (Runs 1, 2, and 3). As can be seen from this graph, the oil recovery from pure heated solvent injection and alternating solvent and steam injection in Run 4 was reasonably close to the SAGD process. However, in the SAGD experiment (Run 1), steam was injected, while in Run 4 a valuable solvent was injected. The results of the experiments were compared using a suitable economic indicator (see the next section) to compare their energy intensity and economic viability.

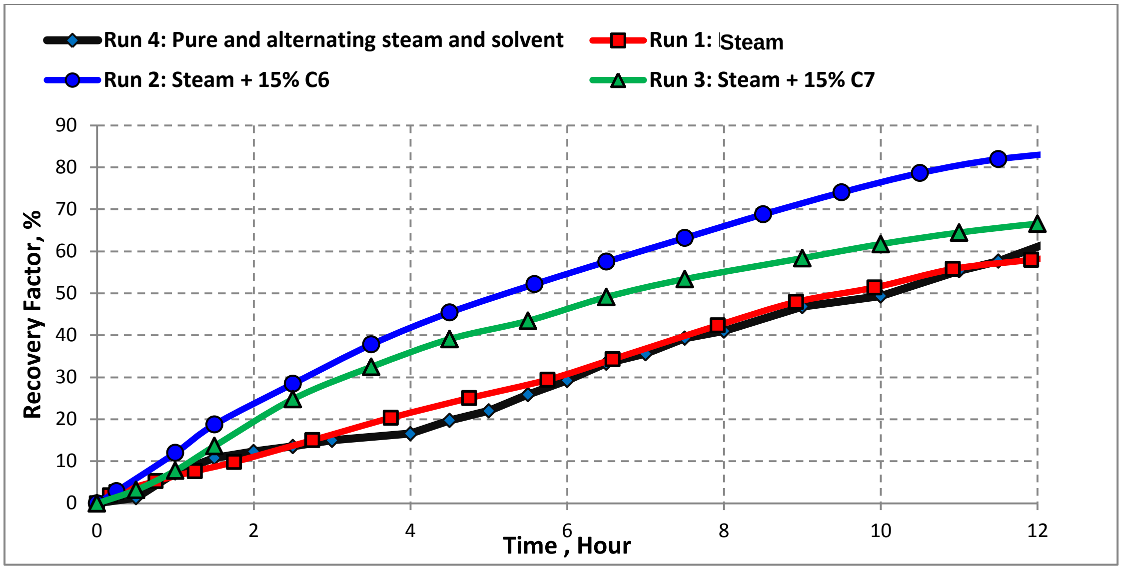


Figure 4.26. Oil recovery comparison for Runs 1 to 4. Oil recovery by pure solvent and alternating steam and solvent (Run 4) is close to pure steam injection recovery (Run 1).

Figure 4.27 shows the temperature profile for three thermocouples in the model (T1, T2, and T3 locations in Figure 4.19). As can be seen, the temperature of the chamber corresponds to the saturation temperature of the fluid present in the chamber. Figure 4.28 shows the temperature distribution of Run 4 at different times. In less than half an hour, a hot vapor chamber was formed by the initial steam injection. When pure solvent was injected, the vapor chamber's temperature was reduced significantly.

The steam chamber was replaced by a vaporized solvent chamber and the temperature changed from steam's saturation temperature to n-hexane's saturation temperature at 80 psig. As can be seen, the vapor chamber progression is not significant until 4 hours. The size of the solvent chamber does not change significantly from 1 hour to 4 hours. As a result, the solvent and steam were injected in alternating mode. The temperature of the chamber corresponds to the saturation temperature of the fluid present in the chamber. The vapor chamber progression is limited by condensation of the solvents by heat loss. Injection of the pure heated solvent (n-hexane) at later stages was not advantageous. At later times the distance between the injection point and the interface was high, and a major portion of the solvent was condensed and directly produced.

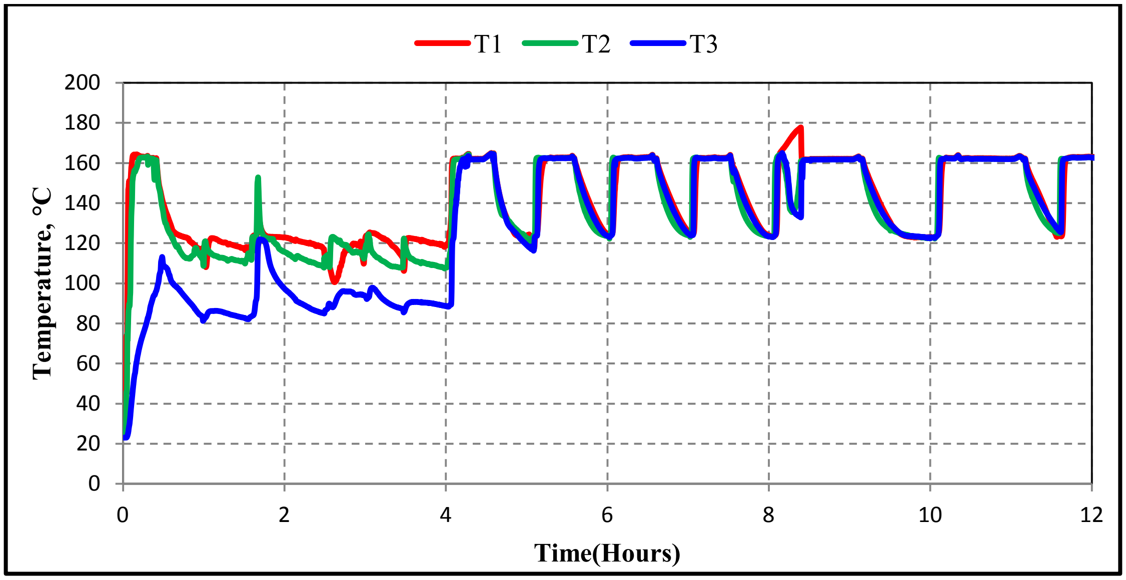


Figure 4.27. Temperature profile for the thermocouples (T1, T2 and T3) inside the model in Run 4.

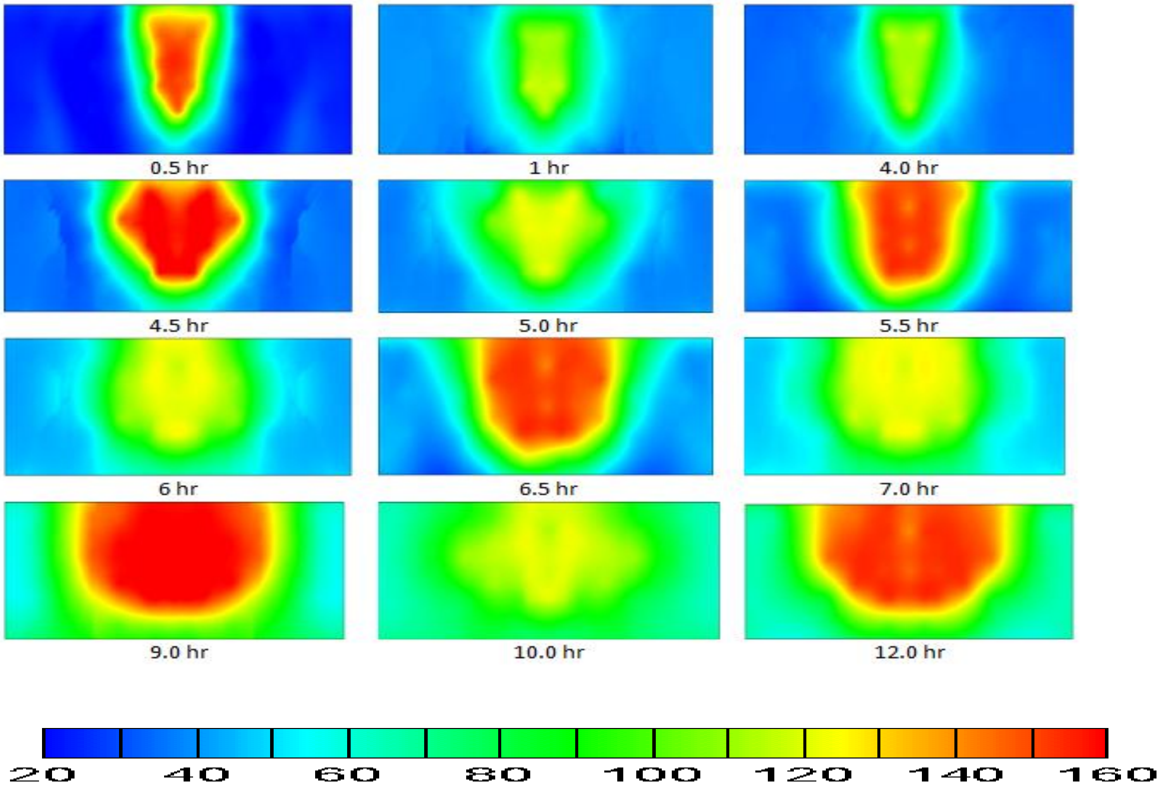


Figure 4.28. Temperature distribution at different times for Run 4. The chamber's temperature corresponds to the saturation temperature of fluid present in the model.

4.3.3. Economic evaluation

The injected fluid in the experiments was a mixture of steam and hydrocarbon additives. SOR was used previously to compare the energy intensity of different processes, but another performance indicator was required for a suitable comparison of the experimental results. Net cumulative oil production for sale (NCOPS) is defined as the cumulative oil production minus the oil used as fuel to generate the heat required for the process (Gonzalez et al., 2009). Net recovery factor is NCOPS divided by the initial oil in place. This variable is dimensionless and can be used to compare the process performance of reservoirs of different sizes and operating strategies.

This assumes that only the lease oil is used to generate the fluid injection. In the experiments conducted, the injected fluid contains steam and hydrocarbon additives. The injected fluid is converted to equivalent oil required to generate steam and solvent at the operating conditions of the experiments. The injected solvent can be converted to equivalent oil based on the energy balance or the price of the solvent. In the former case, it is assumed that solvent is burnt and steam is generated. In the latter case, solvents were converted to barrels of oil using a price basis. The second approach is used to calculate net recovery factor in this study. Net recovery factor can be simply defined as:

$$\text{Net Recovery Factor} = \frac{(\text{Cumulative Oil Produced} - \text{Amount of Oil Equivalent to the Injected Fluid})}{\text{Initial Oil in place}}$$

This value was used as a simple economic indicator to evaluate the process based on the amount of the energy injected and produced from the reservoir. To calculate the oil consumption as fuel it was assumed that the energy liberation from burning of this heavy oil is approximately equivalent to 6.2 MMBTU/bbl (GJ/m3). The water input into the system was assumed to be at 15.5 ^{o}C and the outlet steam at 80 psig at saturated conditions. However, not all the energy liberated is transferred to water. Part of it is lost to the atmosphere and the adjacent elements within the system. For this study, it is assumed that the efficiency of the steam generator was 95%. As a result, 1 bbl of oil is capable of producing almost 13.0 bbl of steam at operating pressure and temperature of the experiments (80 Psi, 324 °F) . In addition, one barrel of n-hexane and n-heptane were considered to be equivalent to 2.15 and 2.30 bbls of oil or 28.0 and 30 bbls of steam.

To understand the concept of net recovery factor, total and net recovery factor for Run 1 are compared in Figure 4.29. The total recovery factor is around 60% after 12 hours. However, net recovery factor is considerably lower due to the cost of steam generation. Net recovery factor is about 30% after 10 hours, and it remains almost constant afterwards due to low oil production compared to steam injection rate.

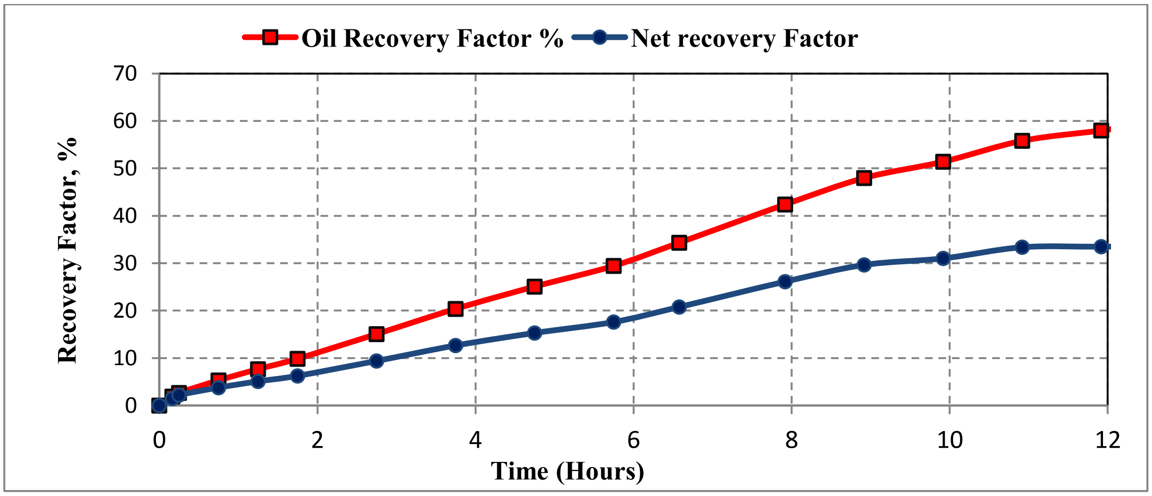


Figure 4.29. Total and net recovery factor comparison for Run 1. Net recovery factor is considerably lower than total recovery factor due to the high cost of steam generation.

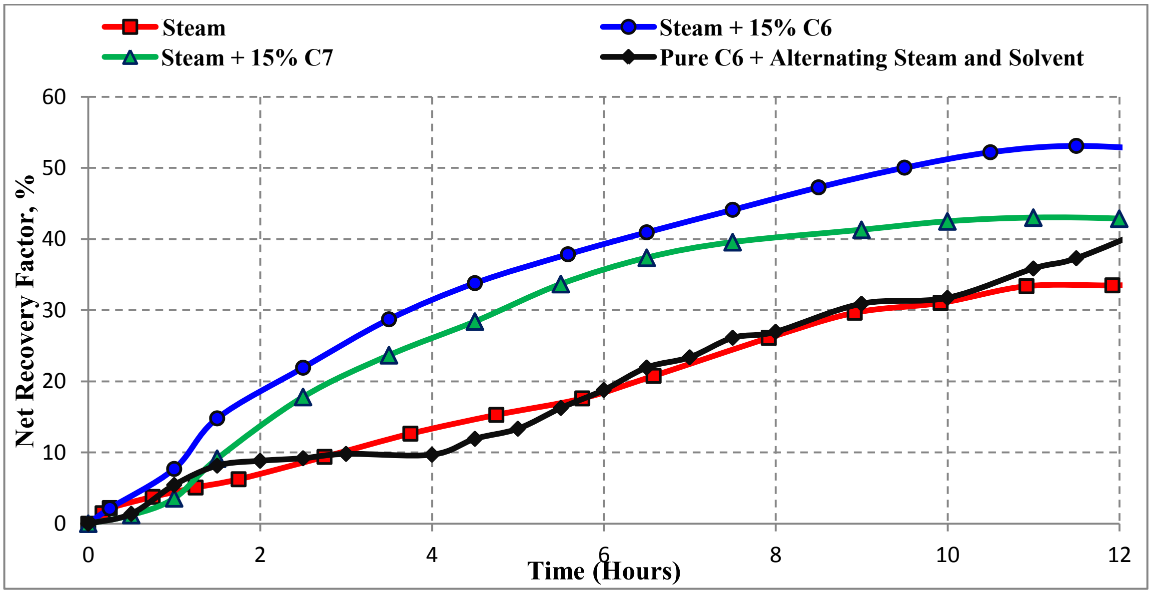


Figure 4.30. Comparison of net recovery factor of different Runs. Net recovery was significantly raised by addition of solvents. The economics of pure heated solvent injection was less favorable.

Figure 4.30 shows the net recovery factor for four runs. We assumed the solvent recovery factor was around 70%. Only 30% of the injected solvent was consumed and 70% was recovered and reinjected into the reservoir. The net recovery factor of steam injection SAGD process was increased by almost 20% and 10% if n-hexane and n-heptane are co-injected with steam (Run 2 and Run 3). The increase in net recovery factor was more significant at early times since addition of the solvents boosted oil production.

As can be seen from Figure 4.30, Run 1 and Run 4 have the least favorable economy. In Run 4, pure solvent was injected initially for 4 hours. During this time, even the net recovery factor was reduced due to unsustainability of the vapor chamber and low oil production rate. Alternating solvent and steam injection increased the economic performance of the process.

5. CONCLUSIONS AND RECOMMENDATIONS

5.1. Conclusions

Integrated experimental and simulation work was performed to assess the effectiveness of hybrid steam and solvent injection to improve SAGD processes. Different solvent proportions (propane, n-butane, n-pentane, n-hexane and n-heptane) were injected into two different types of reservoirs (Athabasca and Cold Lake) with different operating conditions in the simulation study.

It has to be noted that of the experimental and simulation results are valid for reservoir properties and operational parameters specific to this study. The following conclusions were drawn from this study:

- Addition of heavier solvents to steam increases the fluid injectivity up to 20%. Light solvents such as propane reduce the injectivity by 50%. Oil productivity in the plateau period of SAGD can be increased by more than 50% when an appropriate solvent is injected.
- Simulation studies indicate that solvents heavier than butane (with wt% < 20%) have the potential to enhance the oil recovery and thermal efficiency of SAGD processes in the Athabasca reservoir. These hydrocarbon additives create a high-oil-phase-mobility zone which accelerates the oil production in the SAGD process. Addition of the solvents at 10% by weight in the Athabasca reservoir reduces the energy intensity of the SAGD process by almost 40% or higher.
- According to simulation studies, butane appears to be the most effective solvent for

Cold Lake-type reservoirs at the operating conditions of this study. The optimum butane concentration is around 10 to 15 wt%; higher amounts lead to small incremental oil recovery due to limited solubility at the operating conditions of this study.

- Solvent retention in the reservoir is lower for heavier solvents than for lighter solvents. This is expected since their solubility in oil is larger. For heavier solvents at the operating conditions of this study, solvent retention at early stages is high, but it reduces to less than 10% by weight at the end of the SAGD project in 10 years.
- According to simulations study, a major portion of the solvents is dissolved in the in-situ oil and produced, which aids heavy oil transport in the wellbore and surface pipelines. The percentage of solvent in the produced fluid depends on the type of the solvent co-injected with the steam and its proportion.
- Mechanistic simulation studies show that in the presence of high initial solution/gas ratio, hydrocarbon additives are not as effective. Exsolved solution gas causes early condensation of steam and additives. Additives have poor opportunities to contact bitumen and are unable to create a high-oil-phase-mobility zone.
- Experimental results are in agreement with the simulation study and show that solvent co-injection with steam leads to a process with higher oil production, better oil recovery, and less energy intensity with more favorable economy.
- The solvent choice for hybrid steam/solvent injection is not solely dependent on the mobility improvement capability of the solvents but also on reservoir properties and operational conditions.

- Heated solvent injection requires appreciable amounts. The vaporized solvent chamber is not sustainable due to the low latent heat of the solvents. Alternating steam and solvent injection provides heat for the solvent cycles and increases oil recovery. Nevertheless, pure heated solvent injection and alternating steam/solvent injection has less favorable economy than steam/solvent co-injection

5.2. Recommendations

- Addition of solvents to steam has been shown to be effective at the reservoir level by experimental and simulation studies. However, the economics of these processes has to be investigated by integrating reservoir, wellbore, and surface facilities.
- Numerical models reasonably predict the performance of hybrid steam/solvent processes. However, simulation studies should be calibrated with reliable field data. A number of pilot tests have been conducted in Canada which can be used upon availability (list of Pilot tests can be found in literature (Ardali et al., 2012; Orr, 2009).
- The interaction of noncondensable gases, solvent, steam, and heavy oil is complex, and commercial simulators oversimplify these interactions. A detailed PVT analysis of solvents, steam, and noncondensable gases such as swelling test can aid better understanding of hybrid steam/solvent processes.

NOMENCLATURE

2D	Two Dimensional
3D	Three Dimensional
cEOR	Cumulative Energy/Oil Ratio
CSOR	Cumulative Steam Oil Ratio
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
EOR	Energy/Oil Ratio
ES-SAGD	Expanding-Solvent Steam-Assisted Gravity Drainage
LASER	Liquid addition to steam for enhancing recovery
NCG	Non-Condensable Gas
P-T	Pressure-Temperature
SAGD	Steam-Assisted Gravity Drainage
SAP	Solvent-Aided Processes
SAS	Steam Alternating Solvent
SA-SAGD	Solvent-Assisted Steam-Assisted Gravity Drainage
SC	Standard Conditions
SOR	Steam/Oil Ratio

VAPEX	Vapor Extraction
wt	Weight Percent

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APPENDIX A: SIMULATION CODE TEMPLATE

(** indicates comments, * or none indicates the code)

```
** Hybrid Steam/solvent Process template
** In this example 10% by weight of N-Hexane is co-injected
**with steam to enhance SAGD process
RESULTS SIMULATOR STARS 200900
*INUNIT *SI   *except 6 1    ** darcy instead of md
*OUTUNIT *SI  *except 6 1    ** darcy instead of md
*outprn *grid *all
*outprn *well *wellcomp
*outprn *iter *newton        ** Summary of Each Newton Iteration
OUTSRF GRID ENCONDRAT ENCONVRAT ENINPLRAT ENREACRAT PRES SG
SO SW TEMP VELOCRC X
        Y
OUTPRN ITER NEWTON
OUTSRF GRID ALL
OUTSRF SPECIAL SOR  'Injector' 'Producer' INST
OUTSRF SPECIAL SOR  'Injector' 'Producer' CUM
          WELLENERGY  'Injector' CUM
OUTSRF SPECIAL WELLENERGY  'Injector' RATE
OUTSRF SPECIAL OBHLOSSCUM
OUTSRF SPECIAL OBHLOSSRATE
OUTSRF SPECIAL CCHLOSSCUM
OUTSRF SPECIAL CCHLOSSRATE
OUTSRF GRID FLUXRC FLUXSC STRMLN VELOCRC VELOCSC
OUTSRF WELL DOWNHOLE
OUTSRF WELL LAYER ALL
OUTSRF WELL DOWNHOLE
```

```
OUTSRF WELL LAYER ALL
OUTSRF WELL MASS COMPONENT ALL
OUTSRF WELL MOLE COMPONENT ALL
OUTSRF WELL DOWNHOLE
OUTSRF WELL LAYER ALL

*wprn *grid time
*wprn *iter 1
*prntorien 2 0         ** I rows, K columns, J plane
**$================================================================
===============
**$================================================================
===============
**$ ********************************************************************
******
**$ CARTESIAN GRIDING
**$ ********************************************************************
******
**$================================================================
===============
**$================================================================
===============
** Reservoir Thickness = 30 m

*GRID *CART 51 1 30    ** Total gridblock number = 1530
*KDIR *DOWN            ** K = 1 at top of reservoir

*DI *IVAR 51*1.5
*DJ *JVAR 750.0
```

```
*DK *KVAR 30*1.0

*VAMOD 2 0.5 1.0 0.5 0.5 1.0 0.5 0.5 *9p 1.0 1.0
*VATYPE *CON          1
       *MOD  1 1 1:30 = 2



*DEPTH 1 1 1 302.0

NULL CON           1
**$ Property: Porosity  Max: 0.35 Min: 0.35
POR CON         0.35
**$ Property: Permeability I (d)   Max: 4000  Min: 4000
PERMI CON         4
**$ Property: Permeability J (d)   Max: 4000  Min: 4000
PERMJ CON         4
**$ Property: Permeability K (d)   Max: 2000  Min: 2000
PERMK CON         2

**$ Property: Trans Multiplier I  Max: 1  Min: 1
TRANSI CON           1.00000
**$ Property: Low Side Trans  Multiplier I  Max: 1  Min: 1
TRANLI CON           1.00000
**$ Property: Pinchout Array  Max: 1  Min: 1
**$  0 = pinched block, 1 = active block
PINCHOUTARRAY CON          1
*end-grid
```

```
**$=============================================================
==============
**$ ********************************************************************
******
**$ROCK THERMAL PROPERTIES
**$ ********************************************************************
******
**$=============================================================
==============

ROCKTYPE 1
PRPOR 1300
CPOR 1e-6
***DILATION PBASE 2000 PDILA 2100 PPACT 2050 CRD 1e-5 FR .9
PORRATMAX 1.3

ROCKCP 2.01198e+006 0
THCONMIX SIMPLE
THCONANTAB
**$      Temp    Rock-I     Rock-J     Rock-K      Water-I   Water-J   Water-K     Oil-I
Oil-J     Oil-K     Gas-I     Gas-J     Gas-K
        10    2.74e+005  2.74e+005   2.74e+005    5.35e+04   5.35e+04  5.35e+04
1.15e+04  1.15e+04  1.15e+04   2500  2500      2500
        300   2.74e+005   2.74e+005   2.74e+005    5.35e+04  5.35e+04  5.35e+04
1.15e+04  1.15e+04  1.15e+04   2500  2500      2500

HLOSSPROP OVERBUR 2.34731e+006 149535
        UNDERBUR 2.34731e+006 149535
   ** === THERMAL ROCK TYPE DESIGNATION ===
```

```
**$ Property: Thermal/rock Set Num  Max: 1  Min: 1
THTYPE CON            1
**================= FLUID DEFINITIONS ===================
**$ Model and number of components
MODEL 4 4 4 1
COMPNAME 'Water' 'Dead_Oil' 'Soln_Gas' 'C6H14'
CMM
0 0.5 0.0179614 0.086178
PCRIT
0 0 4598.86 2969
TCRIT
0 0 -81.9746 234.25
KV1
0 0 5.4547e+5 1.0062e+6
KV2
0 0 0 0
KV3
0 0 0 0
KV4
0 0 -879.84 -2697.55
KV5
0 0 -265.99 -224.37
PRSR 101.3
TEMR 10
PSURF 101.3
TSURF 20
**$ Surface conditions
SURFLASH SEGREGATED
```

```
MASSDEN
0 980 315 725
CP
0 4.35113e-006 4.35113e-006 4.35113e-006
CT1
0 0.000729241 0.000729241 0.000729241
VISCTABLE
**$     temp
       12.0        0   5000000    22.566411     78.79
       20.0        0   1000000  14.79060914     49.68
       30.0        0    200000  9.328655728     30.07
       40.0        0     55000   6.25868813     19.49
       50.0        0     18000  4.417352534     13.36
       60.0        0      6600  3.251013783      9.59
       70.0        0      2800  2.477358147      7.16
       80.0        0      1100  1.943636751      5.51
      100.0        0       240  1.283226255      3.54
      120.0        0       106   0.91062343      2.46
      140.0        0        50  0.682146432      1.81
      160.0        0        30  0.532784188      1.39
      180.0        0        16  0.430121219      1.11
      200.0        0        12  0.356681281      0.91
      220.0        0         8  0.302420723      0.77
      240.0        0         4  0.261253337      0.66
      260.0        0         3  0.229323308      0.57
      280.0        0         2  0.204093951      0.51
      300.0        0       1.5   0.18384167      0.46
***AVISC
***0 0.000012 0.003
```

```
***BVISC
***0 7275 3460
VSMIXCOMP 'Soln_Gas'
VSMIXENDP 0 0.07
VSMIXFUNC 0 0.00697852 0.0140717 0.021142 0.0281885 0.0352112 0.0422107
0.04919 0.0561462 0.0630832 0.07

** ==================== ROCK-FLUID DATA ================== **
ROCKFLUID
RPT 1 WATWET
SWT
**$      Sw        krw       krow
       0.15          0      0.834
   0.190625  0.000390625    0.733008
    0.23125    0.0015625    0.638531
   0.271875   0.00351562     0.55057
     0.3125      0.00625    0.469125
   0.353125   0.00976563    0.394195
    0.39375    0.0140625    0.325781
   0.434375    0.0191406    0.263883
      0.475        0.025    0.2085
   0.515625    0.0316406    0.159633
    0.55625    0.0390625    0.117281
   0.596875    0.0472656   0.0814453
     0.6375      0.05625    0.052125
   0.678125    0.0660156   0.0293203
    0.71875    0.0765625   0.0130313
   0.759375    0.0878906  0.00325781
        0.8          0.1          0
```

```
SLT
**$        Sl       krg        krog
       0.155     0.992           0
    0.207813  0.871875  0.00325781
    0.260625    0.7595   0.0130312
    0.313438  0.654875   0.0293203
     0.36625     0.558    0.052125
    0.419063  0.468875   0.0814453
    0.471875    0.3875    0.117281
    0.524687  0.313875    0.159633
      0.5775     0.248      0.2085
    0.630313  0.189875    0.263883
    0.683125    0.1395    0.325781
    0.735938  0.096875    0.394195
     0.78875     0.062    0.469125
    0.841562  0.034875     0.55057
    0.894375    0.0155    0.638531
    0.947187  0.003875    0.733008
           1         0       0.834
KRTEMTAB SORG SORW
**$      TEMP      SORG      SORW
          10      0.22       0.5
         200      0.06       0.2
** ==== RELATIVE PERMEABILITY TYPE DESIGNATION ====
**$ Property: Rel Perm Set Number  Max: 1  Min: 1
KRTYPE CON           1
**$ Property: Oil Effective Molecular Diffusion Coef. I(C6H14) ((m*m)/day)   Max:
8.64e-006  Min: 8.64e-006
DIFFI_OIL 'C6H14' CON    8.64E-006
```

```
**$ Property: Oil Effective Molecular Diffusion Coef. J(C6H14) ((m*m)/day)   Max: 8.64e-006  Min: 8.64e-006
DIFFJ_OIL 'C6H14' CON    8.64E-006
**$ Property: Oil Effective Molecular Diffusion Coef. K(C6H14) ((m*m)/day)   Max: 8.64e-006  Min: 8.64e-006
DIFFK_OIL 'C6H14' CON    8.64E-006
*TORTU *NOPORSAT
MOLDIFF_DEP 'C6H14' *OIL *TDEP 293.15 *VISDEP 1000000 0.545
** =================  INITIAL CONDITIONS  ==================== **

INITIAL
VERTICAL DEPTH_AVE

INITREGION 1
REFPRES 1500
REFDEPTH 325
**$ Property: Temperature (C)   Max: 12  Min: 12
TEMP CON           12

*sg *con 0.0
**$ Property: Oil Mole Fraction(Dead_Oil)  Max:1  Min: 1
MFRAC_OIL 'Dead_Oil' CON     1
**$ Property: Oil Mole Fraction(Soln_Gas)  Max: 0 Min: 0
MFRAC_OIL 'Soln_Gas' CON    0
**$ Property: Oil Mole Fraction(C6H14)  Max: 0  Min: 0
MFRAC_OIL 'C6H14' CON            0
```

```
** =================== NUMERICAL CONTROL ========================
**
*NUMERICAL
NORM PRESS 500 SATUR 0.4 TEMP 10 Y 0.4 X 0.4 W 0.4
CONVERGE PRESS 50 SATUR 0.1 TEMP 1
CONVERGE TOTRES NORMAL
NEWTONCYC 20
UPSTREAM KLEVEL
NORTH 200
ITERMAX 200
NCUTS 20
UPSTREAM KLEVEL

*run

**  ================  RECURRENT DATA  ========================

*time 0.0

  *dtwell 1.0e-4
**
**    *well 1 'Injector'    *frac 0.5
**$
WELL  'Injector'  FRAC  0.5
                              ** max. steam injection rate = 500 m3/d CWE (full well)
INJECTOR MOBWEIGHT EXPLICIT 'Injector'
INCOMP  WATER  0.977272727     0.  0.  0.022727273

TINJW  217.
```

```
QUAL  0.95
OPERATE  MAX  BHP  2100.  CONT REPEAT

**    *well 2 'Producer'    *frac 0.5      ** 900 m standard SAGD wells
**$
WELL  'Producer'  FRAC  0.5
PRODUCER 'Producer'
OPERATE  MIN  BHP  1400.  CONT REPEAT
OPERATE  MAX  STEAM  1.  CONT REPEAT
                              ** well diameter = 8.7"
              **   i   j   k  ff
                                ** injector 21.5 m from bottom of reservoir
**$         rad  geofac  wfrac  skin
GEOMETRY  J  0.11  0.249  1.  0.
PERF  GEO  'Injector'
**$ UBA     ff  Status  Connection
   1 1 24  1.  OPEN    FLOW-FROM  'SURFACE'
                             ** producer 2 kept open for release of fluid while heating the
SAGD pair
SHUTIN 'Injector'

  *uhtr   *ijk  1:1 1:1 24  1.95e9
  *tmpset *ijk  1:1 1:1 24  240
                             ** well diameter = 8.7"
              **   i   j   k   ff
                                ** producer 26.5 from bottom of reservoir
**$         rad  geofac  wfrac  skin
GEOMETRY  J  0.11  0.249  1.  0.
PERF  GEO  'Producer'
```

```
**$ UBA     ff  Status  Connection
   1 1 29  1.  OPEN    FLOW-TO  'SURFACE'

  *uhtr   *ijk  1:1 1:1 29  1.95e9
  *tmpset *ijk  1:1 1:1 29  240

*time 90

  *dtwell 1.0e-3              ** Standard SAGD Started
OPEN 'Injector'
  *uhtr *con 0.0                     ** turn heater off after startup period of 52 days

TIME  120
TIME  150
TIME  180
TIME  210
TIME  240
TIME  365
TIME  545
TIME  730
TIME  910
TIME  1095
TIME  1275
TIME  1460
TIME  1640
TIME  1825
TIME  2005
TIME  2190
TIME  2370
```

```
TIME  2555
TIME  2735
TIME  2920
TIME  3100
TIME  3285
TIME  3465
TIME  3650

*stop
```