

REDUCING THE ENVIRONMENTAL IMPACT OF BITUMEN EXTRACTION
WITH ES-SAGD PROCESS

A Thesis

by

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ABSTRACT

Steam Assisted Gravity Drainage (SAGD) is a proven enhanced oil recovery technique for oil sand extraction. However, the environmental and economic challenges associated with excessive greenhouse gas emissions due to the combustion of significant amount of natural gas and consumption of large amount of fresh water for steam generation limit the application of this technology. To address these issues, various SAGD modifications have been developed, among those, SAGD with solvent co-injection is one of the most prospective techniques.

In this experimental study, the effectiveness of base SAGD and Expanding Solvent SAGD (ES-SAGD) was tested on a Peace River bitumen. All experiments were conducted using a two-dimensional cylindrical physical model. In order to investigate the influence of in-situ asphaltene precipitation on the performance of ES-SAGD process, three different types of solvent were considered as hydrocarbon additives; asphaltene soluble (toluene), asphaltene insoluble (n-hexane), and solvent with intermediate solubility parameter (cyclohexane). Different strategies for solvent injection were examined.

In all experiments, temperature profiles at 47 different positions, produces oil and water were monitored continuously. Viscosity and API gravity of original and produced oil samples were measured. This study reveals that co-injection of hydrocarbon solvents with steam enhances the efficiency of SAGD process in terms of oil production, level of oil upgrading, steam to oil ratio and energy consumption. It was also concluded that

selection the solvent type and injection strategy are important parameters for the design of hybrid SAGD process.

DEDICATION

To my parents, Zulfiya and Rail, for their love and encouragement throughout my life.

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CHAPTER I

INTRODUCTION AND LITERATURE REVIEW

The growing global demand for energy and continuous decline of conventional oil reserves force the petroleum industry to get involved in the development of unconventional oil resources (Canadian Association of Petroleum Producers, 2013). The majority of these resources are constituted by heavy oil and bitumen. World resources of heavy oil and bitumen are estimated at 5.6 trillion barrels. The vast portion of these reserves is located in Canada, Venezuela, Russia, and USA (Hein, 2006). Canada holds the world's largest oil sand deposits, which are almost entirely located in three areas in the province of Alberta: Athabasca, Cold Lake, and Peace River (Hein and Marsh, 2008). These reserves are considered to be 1.7 trillion barrels of Original Oil In Place (OOIP), but only approximately 135 billion barrels can be recovered through in-situ processes, according to the current technologies (Bott, 2011).

The production of heavy oil and bitumen is challenging, due to extremely high viscosity at reservoir conditions. However, the bitumen viscosity is very sensitive to temperature: it becomes much less viscous with temperature increase. Therefore, thermal recovery techniques are known as the most effective methods for heavy oil and bitumen extraction (Butler, 1991).

Among a wide spectrum of thermal recovery methods, Steam Assisted Gravity Drainage (SAGD) is known as one of the promising Enhanced Oil Recovery (EOR) methods for heavy oil and bitumen extraction. SAGD process was proposed by Roger

Butler and his colleagues in the late 1970s (Butler et al., 1979). Figure 1 shows the concept of SAGD process. In this process, two horizontal wells are drilled one above another at the base of the reservoir. The upper well is used for steam injection, the lower – for oil production. The distance between the wells is approximately 5 meters. Injected steam creates a continuously growing steam chamber above the wells. Steam heats the bitumen and condenses at the interface of the steam chamber. As a result bitumen becomes less viscous and able to flow. Condensed steam and heated oil drain to the production well by gravity forces (Butler, 1982; Butler and Stephenes, 1981)

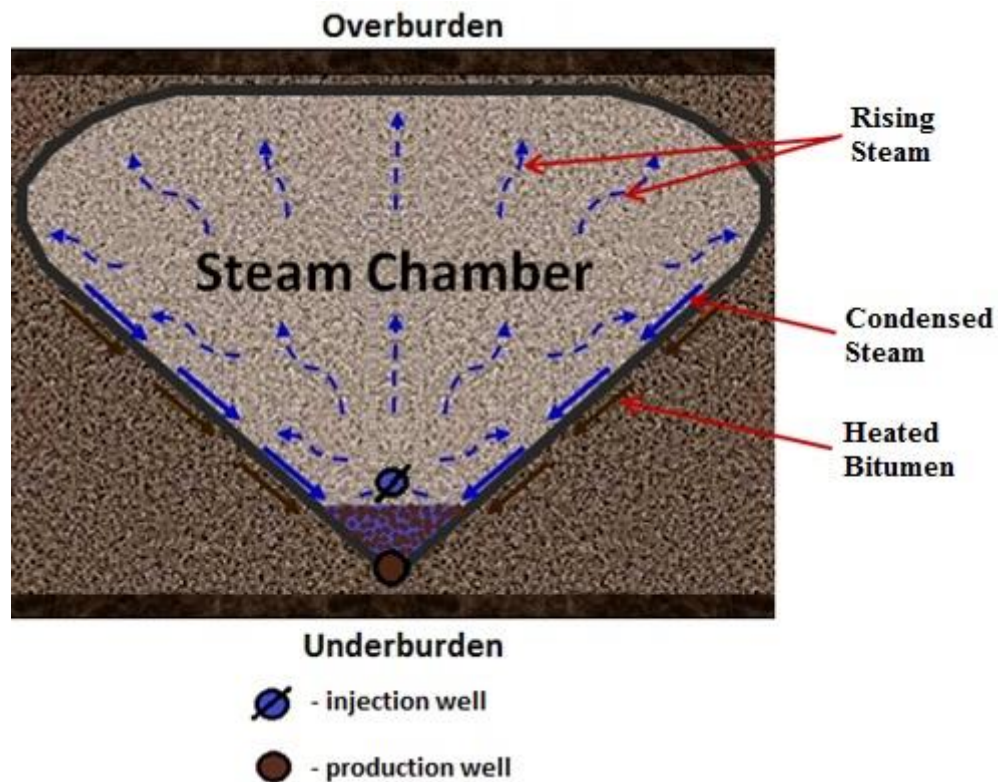


Figure 1. Concept of SAGD process. Adapted from Butler (1994)

SAGD has some advantages over conventional Steam Flooding (SF) process. Despite the fact that injection and production wells are close to each other and located at the bottom part of the reservoir, because steam chamber expands gradually above the injection well and spans a large area of the reservoir, sweep efficiency in SAGD process is higher than in SF. Additionally, the temperature inside the steam chamber is constant and equal to the steam temperature. Therefore, in SAGD the bitumen remains hot as it flows towards the production well, unlike the conventional SF where oil is cooling on its way to the production well (Butler, 1991).

To better understand the mechanism of SAGD process, numerous experimental and numerical studies have been performed for over 30 years. Chung and Butler (1988), Chan et al. (1997) and Canbolat et al. (2002) tested different well configurations in SAGD process. Nasr et al. (1996) investigated the effect of enthalpy control, wells pressure difference and capillary pressure on the SAGD performance. Kisman and Yeung (1995), Edmunds and Chhina (2001) and Collins (2007) tested the sensitivity of oil recovery performance to the operating pressure. Sasaki et al. (1996) and Sasaki et al. (2001) examined the influence of the well spacing, steam injection pressure and reservoir thickness on the SAGD efficiency. Yang and Butler (1992), Barillas et al. (2006) and Chen et al. (2007) studied the effect of reservoir heterogeneities on the SAGD process. SAGD pilot projects have proved this process as an efficient technology for heavy oil and bitumen extraction. The first pilot test was initiated in 1987 by the Alberta Oil Sands Technology & Research Authority at its underground test facility, which is located in Alberta, Canada (Edmunds et al., 1994). Butler in 2001 published the

summary of SAGD pilots conducted in Canada (Butler, 2001). Some SAGD pilot projects were being implemented in Venezuela (Mendoza et al., 1999), USA (Grills et al., 2002), Russia (Ibatullin et al., 2007), and China (Yang, 2007). Currently, SAGD is known as an effective, reliable, and easily to apply technique, which is characterized by high oil recovery rates and ultimate oil recovery factor of up to 70% of OOIP (Huc, 2011). In Canada, the number of commercial SAGD projects is implemented to produce bitumen from the oil sand deposits (Suggett et al., 2000; Huc, 2011).

Despite the successful commercial realization of SAGD process, it has some environmental and economic issues. Environmental concerns include consumption of large amount of fresh water that is used for steam generation, disposal and treatment of produced water (Ray and Engelhardt, 1992), and excessive greenhouse gas (GHG) emissions due to the combustion of significant amount of natural gas to generate steam. SAGD process with steam to oil ratio (SOR) equal to about 3.1 bbl/bbl, steam quality equal to 80 percent and steam temperature equal to 175 °C requires burning of about 1.02 thousand cubic feet of natural gas to produce one barrel of oil (McColl et al., 2008). Table 1 presents natural gas consumption and associating GHG emissions depending on oil recovery rate (for SOR equal to 3) (Bersak and Kadak, 2007).

Table 1. SAGD natural gas consumption and GHG emissions (SOR = 3.0)

Barrels of Bitumen per Day	Natural Gas for Steam production (MMBtu/day)	Resulting GHG emissions (Metric tons of CO ₂ /day)
30,000	40,053	2,603

Economic challenges also arise from high energy intensity of SAGD process. Steam generation cost is accounted for more than 50% of the total operating cost. (National Energy Board, 2000). Additionally, separation, treatment, and disposal of produced water are also cost-intensive processes (Deng, 2005).

To overcome these drawbacks and improve efficiency of conventional SAGD technology, various SAGD modifications have been developed. Butler (1999) and Jiang et al. (1998) developed Steam and Gas Push process, in which the non-condensable gases (NCG), such as methane and carbon dioxide, are used as a steam additive. They considered that accumulation of NCG on the top part of the reservoir reduces heat losses to the overburden and this way improves energy efficiency of SAGD process. Sasaki et al. (2002) and Bagci et al. (2004) investigated surfactant-SAGD process, in which surfactant is injected into the reservoir before starting the steam injection. Chen et al. (2010) proposed to use a foamed steam in SAGD process. This process was named foam-assisted SAGD process. Authors pointed that foam promotes creation of a uniform steam chamber in the heterogeneous reservoirs and helps to control the steam breakthrough from injection to production well. Nasr et al. (1991) and Mokrys and Butler (1993) commenced the study of the addition of hydrocarbon solvent to the steam in SAGD process in the early 90's. Nowadays, SAGD with solvent co-injection is one of the most prospective techniques, which comprises advantages of both steam and solvent in the bitumen viscosity reduction.

The combination of steam and solvent in steam drive process has been investigated since the 1970s. Farouq Ali and Abad (1976) conducted experimental study

of bitumen extraction, using three types of solvents (“Synthetic crude”, “Mobil solvent”, and “Naphtha”) in conjunction with steam. The results indicated that bitumen production is affected by the type of the solvent, its concentration and the type of the well (production or injection) in which solvent is injected. Redford and McKay (1980) tested the co-injection of hydrocarbon solvents at different molecular weights with steam to improve bitumen recovery from oil sands. They concluded that proper hydrocarbon additive during SF process enhances bitumen recovery. It was also shown that the use of higher molecular weight solvents results in higher ultimate oil production, but in this case solvent retention in the reservoir takes place, which impairs the economics of the process. Shu and Hartman (1988) studied numerically, the use of small amount of hydrocarbon solvent in SF process. They classified solvents into light, medium, and heavy. It was concluded that the light solvents induce earlier oil recovery and increased efficiency in terms of less solvent retention in the reservoir. The medium weight solvents promote the highest ultimate recovery factor, but solvent loss is higher in this case. The heavy solvents do not advance the oil recovery at all.

Experimental study of steam and solvent conjunction in SAGD process was first performed by Nasr et al. (1991). They co-injected 5 wt% and 10 wt% naphtha with steam. Both runs with naphtha showed improvement in the ultimate oil recovery in comparison with base SAGD run. However, ultimate oil recovery was greater in the experiment in which 5 wt% naphtha was used. The authors explained this by the fact that NCG accumulated on the edge of the steam chamber and reduced the upward and sideways heat transfer, thereby limited the steam chamber growth.

Mokrys and Butler (1993) conducted hybrid SAGD experiment with Lloydminster-type heavy oil. Steam and propane were injected simultaneously into the scaled model. Experimental results showed that hybrid SAGD process is more energy efficient in comparison with base SAGD. However, improvement in oil recovery has not been observed in the hybrid process.

Nasr and Isaacs (2001) patented Expanding Solvent SAGD (ES-SAGD) process. In ES-SAGD process, a solvent is chosen in such way that its thermodynamic behavior has to be close to that of water at reservoir conditions. Thus, water and solvent should condense almost simultaneously at the steam chamber boundary. Condensed solvent dilutes the oil, thereby further reduces its viscosity (Nasr et al., 2003). The solvent selection and the effectiveness of ES-SAGD process are determined by the operating conditions, bitumen viscosity, and reservoir characteristics (Hosseininejad Mohebati et al., 2009).

Nasr and Ayodele (2006) and Ayodele et al. (2010) performed 2D high pressure/high temperature SAGD and ES-SAGD experiments. They examined C₄-C₁₀ n-alkanes mixture and n-hexane as hydrocarbon additives. In both cases, ES-SAGD process showed improved recovery factor, oil production rate and lower residual oil saturation in comparison with conventional SAGD. Ayodele et al. (2009) compared low-pressure ES-SAGD experiment with high-pressure base SAGD experiment. Gas-condensate (multi-component diluents) at different concentrations was co-injected with steam. The main conclusion was that multi-component ES-SAGD at the low concentration is quite competitive with high pressure SAGD, while the energy intensity

of low pressure ES-SAGD much lower than the energy intensity of base SAGD. It demonstrates the environmental and economic advantages of ES-SAGD.

Ibatullin and Zolotukhin (2009) carried out simulation study of ES-SAGD process for Athabasca oil sands reservoir. Solvent concentration, fluid injection rate and production pressure were optimized for the co-injection of three different solvents: pentane, hexane, and heptane. Results indicated that in all runs, low SOR was obtained at low fluid injection rates because it prevents steam breakthrough from injector to producer. Pentane was found as the most suitable hydrocarbon additive for the considered reservoir conditions.

Li and Mamora (2010) performed a simulation study of Solvent-Aided SAGD (SA-SAGD) process using a 2D reservoir model with Athabasca rock and fluid properties. C₃, C₅, C₆, C₇, C₁₂, and mixture of C₆ and C₇ n-alkanes were examined as solvent additives. Simulation results indicated that oil recovery factor grows with the increase in the molecular weight of the solvent. Production performance of SAGD with propane co-injection was even worse than in the case of base SAGD. The heaviest solvent showed the highest recovery factor. But for this case authors pointed on economic inefficiency of the process since significant amount of injected solvent remains in the formation and C₁₂ has high boiling point, which complicates the recycling of the solvent from produced fluid.

Li et al. (2011) also accomplished low-pressure (10 psig) SA-SAGD experiments with heptane (C₇) and mixture of C₇ and xylene. Both runs showed improved results over the base SAGD. However, the solvent mixture demonstrated the superior

performance in terms of ultimate recovery factor, SOR, and cumulative energy per oil ratio. Authors explained this by the fact that, in this case, the solvent presented inside the steam chamber was in both vapor (C_7) and liquid (xylene) phases. The solvent vapor phase alone may create a thick gas blanket that decreases the heat transfer from the steam to the cold bitumen.

Hosseininejad Mohebati et al. (2012) conducted 3D ES-SAGD with hexane experiments at different reservoir pressures. Experimental results indicated improved performance of ES-SAGD process at both low and high operating pressures in terms of oil recovery rate, oil recovery factor, and SOR. However, it was concluded that the effect of hexane on the steam chamber shape and residual oil saturation depends on the operating pressure.

Mohammadzadeh et al. (2010b, 2012) performed pore-level investigation of Athabasca bitumen recovery by SA-SAGD process. N-alkanes were used as solvent additives. In-situ asphaltene precipitation during the process was observed. Authors didn't study the influence of asphaltene precipitation on oil production performance and energy efficiency of the process.

By now, there is the limited number of hybrid SAGD pilot projects for the public access. Nexen conducted ES-SAGD field test in part of the Long Lake oil sands project (Orr, 2009; Orr et al., 2010). Jet B fuel (mix of petroleum fraction from C_7 to C_{12}) was chosen as a solvent. ES-SAGD test lasted for two months. Jet B was injected with steam at a concentration of 5%. The oil recovery rate during ES-SAGD test was compared with that during the base SAGD process. As at the end of the second month of ES-SAGD test,

the bitumen production enhancement was not observed, pilot test was terminated. Later, the investigation of three medium weight solvents (butane, hexane, and Keyera Condensate) in ES-SAGD process was initiated. Simulation study showed that hexane is supposed to be the most suitable solvent to improve ES-SAGD performance.

The Solvent Aided Process (SAP) was tested at EnCana's East Senlac and Christina Lake SAGD Projects in Canada. Gupta et al. (2003) studied SAP, which differs from ES-SAGD by solvent type. In SAP, small amounts of light hydrocarbon solvent (such as propane, butane, or pentane) are injected with steam. Well configuration is the same as in SAGD process. Numerical simulation indicated that after replacing 15% of steam to butane, oil recovery rate had increased twice. Field tests of SAP had shown encouraging results. The addition of butane into steam phase increased recovery rate, reduced SOR and energy consumption. It was noted that it is preferable to start solvent injection, after oil rates have reached the maximum in the implementation of the normal SAGD process. Also, oil upgrading was pointed out, which may indicate in-situ asphaltene precipitation (Boyle et al., 2003; Gupta and Gittins, 2006; Gupta et al., 2005).

It can be seen from the literature survey, that n-alkanes are the most commonly used solvents in the hybrid SAGD process. It is a well known fact that heavy oil and bitumen contain significant amount of asphaltenes (Huc, 2011). The asphaltene fraction of crude oil is defined as insoluble in n-alkanes, but soluble in aromatic and some other solvents (Yen et al., 1961). Thus, paraffinic solvents in hybrid SAGD process can cause asphaltene precipitation.

The effect of in-situ deasphalting of heavy oil and bitumen on efficiency of the process still remains unclear. On the one hand, asphaltene precipitation reduces the viscosity of heavy oil and bitumen, thereby improves quality of produced oil (Das and Butler, 1994). However, precipitated asphaltenes can plug the formation and reduce reservoir permeability. Moreover, undesirable asphaltene precipitation can occur either in the wellbore, surface or process facilities (Mansoori, 2010). However, as it was mentioned above, asphaltene fraction is soluble in some solvents, such as benzene and toluene.

This experimental study aims to investigate:

1. The performance of SAGD process for bitumen extraction.
2. The effect of clay on the effectiveness of SAGD process.
3. Enhancing the efficiency of SAGD process with continuous and cyclic solvent co-injection. Asphaltene soluble, asphaltene insoluble, and intermediate solvents are considered as hydrocarbon additives.
4. Reducing SOR and GHG emissions in SAGD process by solvent co-injection.

CHAPTER II
MATERIALS & METHODS

2.1 Sample Characterization

Experimental study was done on a Peace River bitumen. The Peace River oil sands deposit is one of the three major oil sands deposits in Canada. It is located in the Northwestern part of Alberta and contains around 65 billion barrels of OOIP at a depth of 460 to 760 meters (Energy Resources Conservation Board, 2012; Hein and Marsh, 2008). Peace River reservoir properties are given in Table 2 (Hamm and Ong, 1995).

Table 2. Properties of the Peace River reservoir

Parameter, unit	Value
Oil Gravity, °API	7.5
Reservoir temperature, °C	16.7
Reservoir pressure, psi	537
Reservoir thickness, m	26
Porosity, %	28
Initial oil saturation, %	84

Since 1970s some experimental and field-scale studies were performed to investigate the methods for Peace River bitumen production (Glandt and Malcolm, 1991). Prats (1977) conducted experimental study of bitumen extraction by steam drive

processes and identified the steam pressure cycling process as an optimal method for Peace River bitumen recovery. In 1979, Shell Canada Ltd. performed the first pilot project at the Peace River oil sands area, the Peace River In-Situ Project (PRISP). The pressure cycle steam drive process was tested in the frame of this pilot project (Lentz, 1991). The PRISP showed encouraging results and in 1986, Shell commenced the commercial Peace River Expansion Project (Thimm et al., 1993). Later, Shell initiated SAGD and Cyclic Steam Stimulation (CSS) projects at the Peace River oil sands area (Brissenden, 2005; Hamm and Ong, 1995).

As seen in the map (Figure 2) provided by Alberta Department of Energy (2013), currently, a number of primary and thermal recovery projects are being implemented on the Peace River oil sands area. Baytex Energy Corp. operates some primary and CSS projects (Baytex Energy Corp., 2012). Seal Main CSS pilot project is being accomplished by Penn West Petroleum Ltd (Alberta Government, 2013). Toe to heel air injection Dawson project is under construction and will be operated by Petrobank Energy and Resources Ltd (OGJ editors, 2010). SAGD Sawn Lake project, which is also currently under construction, will be managed by Andora Energy Corporation (Alberta Government, 2013).

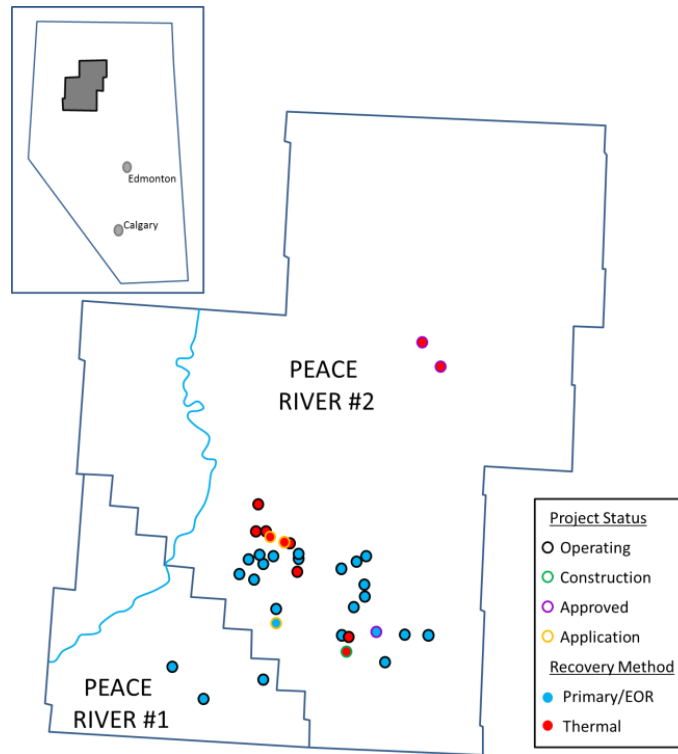


Figure 2. Peace River oil sands projects. Adapted from Alberta Department of Energy (2013)

2.2 Experimental Set-up

Schematic diagram of the experimental set-up is presented in Figure 3.

Experimental set-up basically consists of 4 elements:

- Fluid injection system;
- SAGD Physical model;
- Production system;
- Data acquisition system.

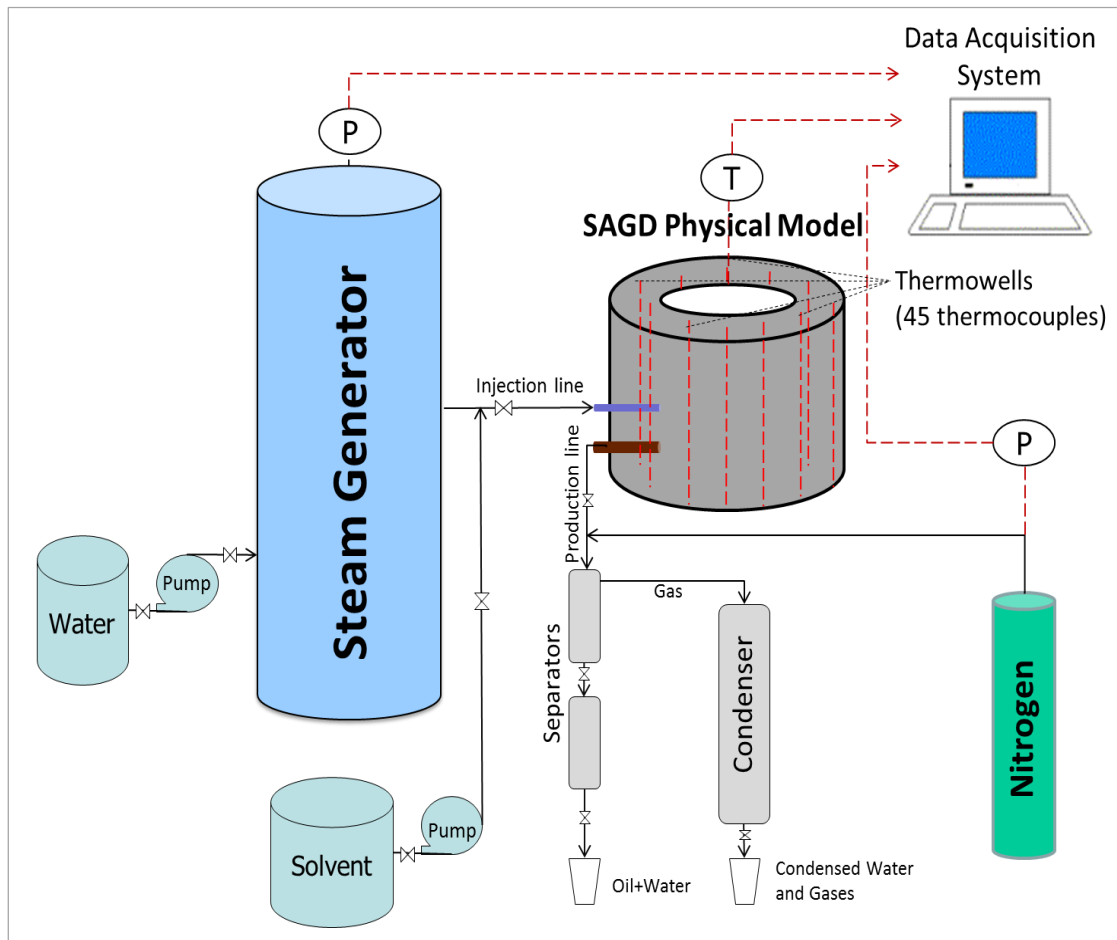


Figure 3. Schematic diagram of the experimental set-up

2.2.1 Fluid Injection System

Fluid injection system consists of:

- High pressure / high temperature steam generator (SG);
- Two syringe pumps for water injection with capacity of 1000 and 500 ml;
- One continuous pump for solvent injection;
- Water and solvent tanks.

Syringe pumps feed SG by distilled water at a certain injection rate. To minimize rate pulsations, the pump outlet pressure is maintained at 1000 psig by back pressure regulator. 1000 ml capacity pump is the main pump, 500 ml capacity pump - the supplementary pump. The water supply is switched from the main pump to the supplementary pump when it is necessary to refill the cylinder of the main pump. SG heats the water and injects hot water / steam into the physical model at the rate 18 ml/min. In the case of experiments with solvent co-injection, solvent is introduced in the steam generator outlet line, mixed with hot water / steam and this mixture is injected into the physical model.

2.2.2 SAGD Physical Model

SAGD physical model created previously by Ardali et al. (2012) was modified for this study. The model represents a stainless steel two-dimensional cylindrical model. Earlier, some Vapor Extraction (VAPEX) experiments proved 2D cylindrical model as good as rectangular model in terms of chamber development and oil production performance (Badamchi-Zadeh et al., 2008; Yazdani and Maini, 2005).

In this study, experiments were done with two different dimensions of the experimental model as it is shown on Figure 4.

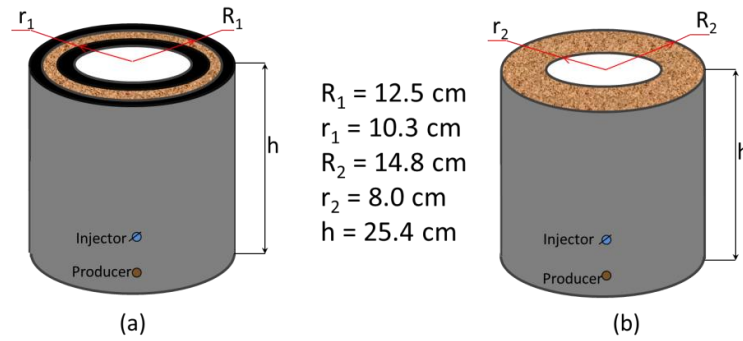


Figure 4. Dimensions of “Thin” (a) and “Thick” (b) physical models

To monitor the temperature distribution inside the physical model, 2 K-type thermocouples were placed in the production and injection wells and 45 J-type thermocouples were placed in 11 vertical thermowells, which were located throughout the model. Each thermowell contained 2 to 7 thermocouples at different positions. Figure 5 and Table 3 summarize positions of the thermowells and thermocouples inside the model.

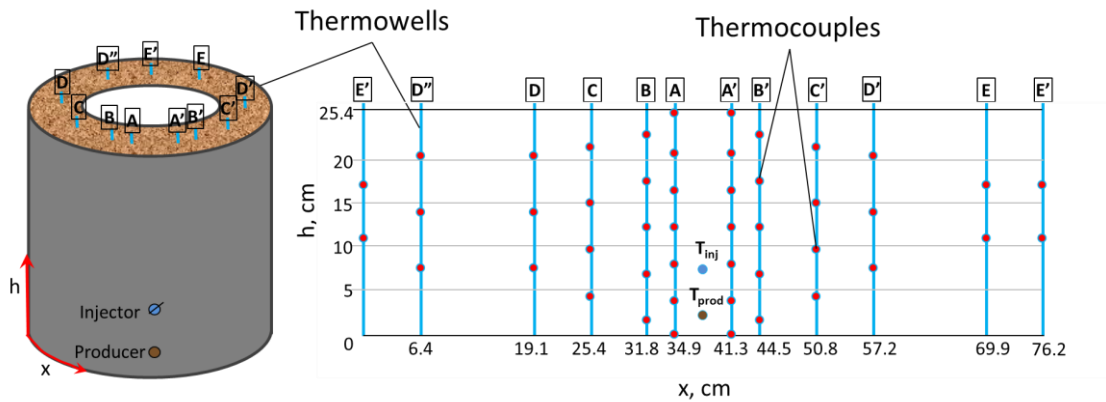


Figure 5. Thermowell (blue lines) and thermocouple (red dots) locations

Table 3. Thermocouple positions from the bottom of physical model

Thermowell Number									
A & A'		B & B'		C & C'		D & D' & D''		E & E'	
Thermo-couple Number	h, cm	Thermo-couple Number	h, cm	Thermo-couple Number	h, cm	Thermocouple Number	h, cm	Thermo-couple Number	h, cm
1 & 8	0	15 & 20	2	25 & 29	4.6	33 & 36 & 39	17	42 & 44	11.1
2 & 9	4.1	16 & 21	7.1	26 & 30	9.8	34 & 37 & 40	7.8	43 & 45	17
3 & 10	8.2	17 & 22	12.3	27 & 31	15	35 & 38 & 41	14		
4 & 11	12.3	18 & 23	17.4	28 & 32	21.2				
5 & 12	16.4	19 & 24	22.6						
6 & 13	20.5								
7 & 14	25.4								

The pair of horizontal wells was inserted into the model. The production well is situated 1 inch above the bottom. The injection well is located 2 inches above the producer. Production and injection wells are 1/2 and 1/4 inches perforated stainless steel pipes, respectively. Both wells were wrapped with screen to avoid sand production.

The fiber glass and perlite were used as a thermal insulation for the experimental set-up to reduce the heat losses to the surroundings during the experiment.

2.2.3 Production System

Production system consists of two-stage separator, condenser, which was placed into cold water bath, and the nitrogen cylinder for maintaining pressure in the production line. Produced water and oil were sampled during the experiment from the separator. Steam and gases followed from the separator to the condenser. Steam and condensable

gases were condensed, and the rest of the produced gases were vented to the outlet of the system, which is at atmospheric conditions.

2.2.4 Data Acquisition System

Data acquisition system is constituted by personal computer and data logger. All thermocouples were connected to the data logger and temperatures were monitored during the entire experiments and recorded in a pre-selected excel file by Labview software.

A list of the equipment used in this study is given in Table 4.

Table 4. Experimental equipment used in this study

Equipment	Brand	Model
Steam Generator	Custom Made	Max. pressure/temperature 2000 psig/ 1200 F
SG temperature Controller	Eurotherm Digital Controller	808
1000 ml Syringe pump (for water injection)	TELEDYNE ISCO	1000D
500 ml Syringe pump (for water injection)	TELEDYNE ISCO	LC-5000
Continuous pump (for solvent injection)	BECKMAN	100A
Back-pressure regulator	Tescom Corporation	26-1724-24
Data Logger	Hewlett Packard	3497 A
Rheometer	Brookfield	DV III Ultra
Density Meter	Anton Paar	DMA 4100
pH meter	Cole Parmer	5941-00

2.3 Experimental Procedure

In total, eight 2D experiments were performed on a Peace River bitumen. The effect of physical model dimensions, rate of injected steam, clay type, total experimental time, and three different solvents have been investigated on SAGD.

All experiments were conducted at 75 psig. Table 5 summarizes experimental conditions for all experiments. Throughout thesis, Table 5 will be referred for the experiments' names.

Table 5. Conditions of all experiments

Parameter, unit	Experiments							
	E1	E2	E3	E4	E5	E6	E7	E8
	1st HAGD	2 nd HAGD	1 st SAGD	2 nd SAGD	SAGD + n-Hexane	SAGD + n-Hexane + Toluene	SAGD + n-Hexane + Cyclohexane	SAGD + n-Hexane + Toluene (Cyclic injection)
Physical model size	Thin	Thick	Thick	Thick	Thick	Thick	Thick	Thick
Type of Clay	Clay 1	Clay 1	Clay 1	Clay 2	Clay 2	Clay 2	Clay 2	Clay 2
Operating Pressure, psig	75	75	75	75	75	75	75	75
Operating Temperature, °C	155	155	165	165	165	165	165	165
Hot water injection rate, g/min	8	18	-	-	-	-	-	-
Steam Injection rate, g/min	-	-	18	18	18	18	18	18
Solvent injection rate, ml/min	-	-	-	-	2	1+1	1+1	2/2
Experimental time, hours	13.45	8.6	12	12	9	9	2.8	9

E1 and E2 are Hot water Assisted Gravity Drainage (HAGD) experiments, which differ by the experimental model size and hot water injection rate.

E3 and E4 are base SAGD experiments at 100% steam quality. They differ by the type of clay, used for sample preparation.

E5 through E8 are SAGD experiments with solvent co-injection. N-hexane, toluene, and cyclohexane were tested as hydrocarbon additives in these runs. In all hybrid SAGD runs, 10 vol.% of solvent was co-injected with steam. In E5, n-hexane alone was added to the steam stream. In E6 and E7, n-hexane-toluene and n-hexane-cyclohexane mixtures (in a volume ratio 1 to 1), respectively, were continuously co-injected with steam, while in E8, n-hexane and toluene were injected alternately: 1 hour – 10 vol.% of n-hexane co-injection, 1 hour – 10 vol.% of toluene co-injection.

Solvent selection was made according to the phase diagram of each solvent and their state under experimental pressure and temperature of the injected steam. While n-hexane and cyclohexane are in the gaseous phase at experimental pressure and temperature (75 psig and 165 °C, respectively), toluene - in liquid phase (Figure 6). Another categorization has also been considered during solvent selection; while n-hexane is asphaltene insoluble solvent, toluene is asphaltene soluble and cyclohexane has intermediate solubility parameter (Cosultchi et al., 2003; Gray, 1994 ; Yarranton, 1997).

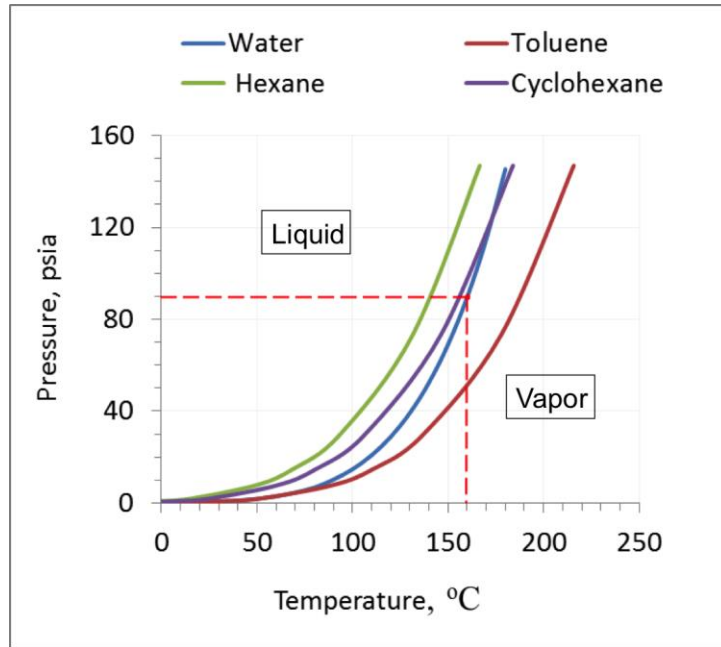


Figure 6. Phase diagrams of water and hydrocarbon solvents. Adapted from CHERIC (2013)

Experimental procedure of all experiments was the same and includes the steps listed below.

2.3.1 Sample Preparation

To simulate the Peace River bitumen reservoir conditions in the laboratory, the following rock composition and fluid saturations have been used:

- According to Bayliss and Levinson (1976), reservoir rock was composed 85 wt% sand and 15 wt% clay. 20-40 mesh size Ottawa sand was used. Two different types of clay (Clay 1 and Clay 2) were selected, in this study. To determine clays' mineralogy, X-ray diffraction (XRD) analysis was conducted on clay samples by the

Department of Geology & Geophysics, Texas A&M University. XRD results are given in Figures 7 and 8. Red curves in both XRD results represent our clay samples, gray, blue, and green curves are reference curves for kaolinite, quartz, and illite, respectively. It can be seen from these figures, that while Clay 1 has mainly kaolinite, Clay 2 contains around 10-20% of illite and 90-80% kaolinite.

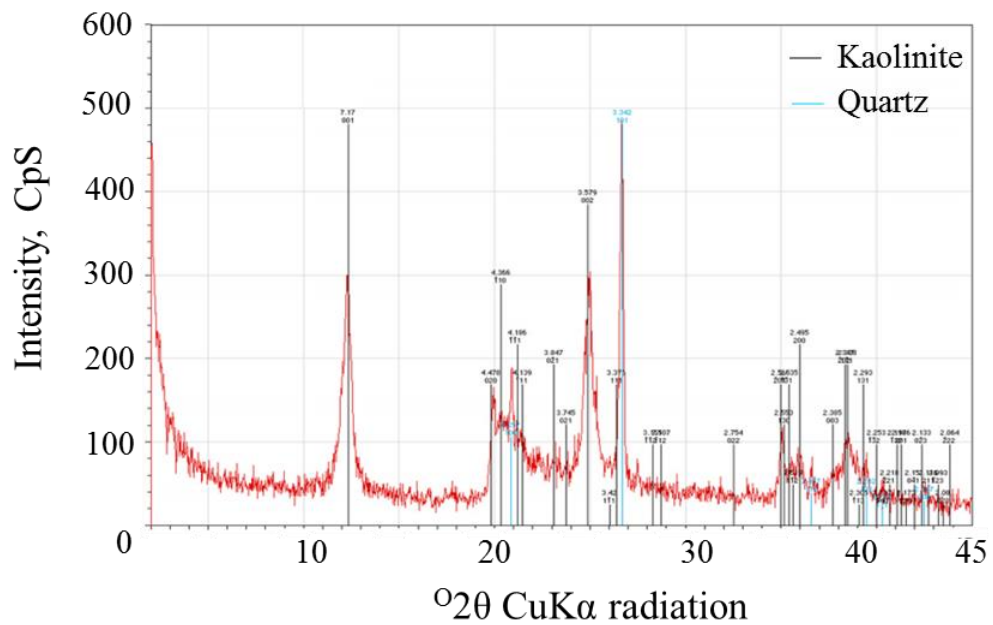


Figure 7. XRD analysis of Clay 1

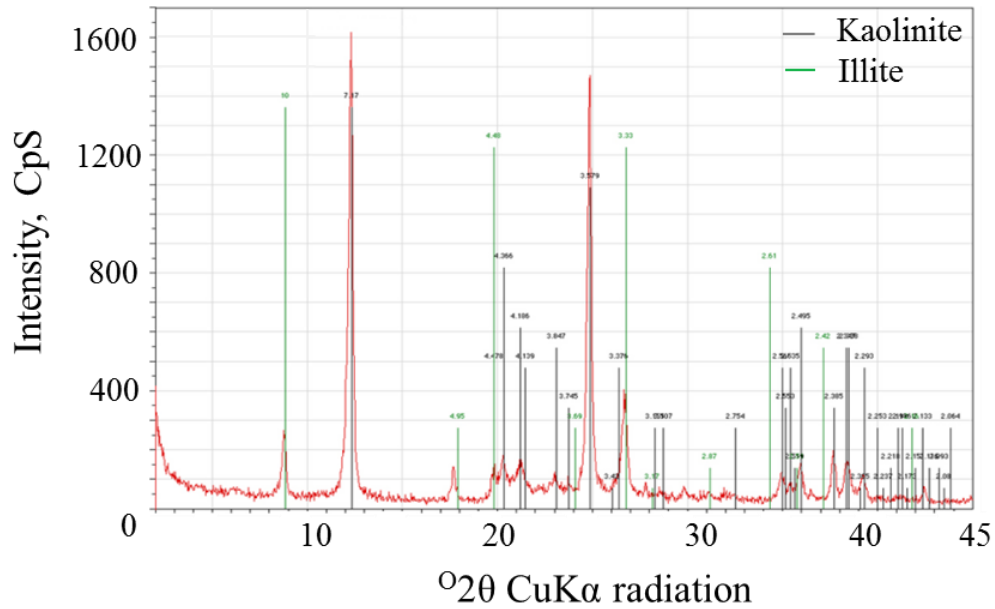


Figure 8. XRD analysis of Clay 2

- The resulting porosity of the sand-clay mixture was measured 32%. The porous media was saturated with Peace River bitumen and distilled water in 84 and 16 volume percentages, respectively (Hamm and Ong, 1995). The viscosity and gravity of used Peace River bitumen at room temperature are equal to 54,152 cP and 8.8 °API, respectively. Figure 9 shows the variations of the bitumen viscosity and gravity with temperature.

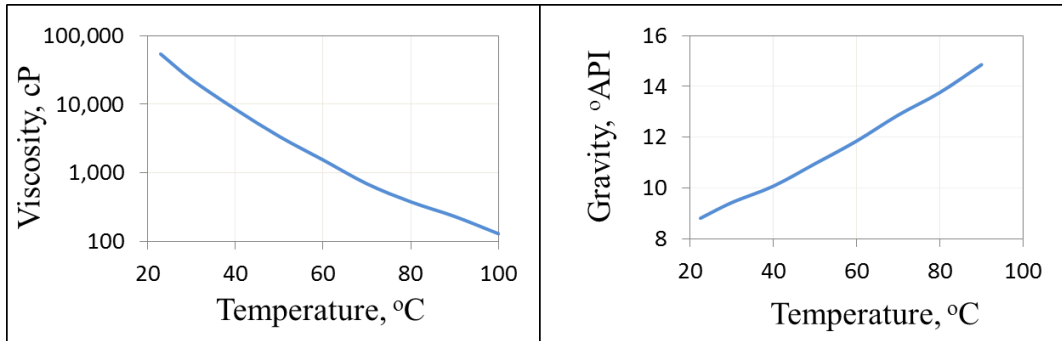


Figure 9. Viscosity and Gravity variation with temperature for Peace River bitumen

2.3.2 Sample Packing & Entire System Assembling

Prepared oil sand mixture was packed inside 2D cylindrical model. The model then was covered with a cap and 11 thermowells with 45 thermocouples were inserted into the packed model. Extra two thermocouples were used; one to monitor injected steam temperature and the other to monitor production fluid temperature continuously. Once the model has been sealed properly, leak test was performed by nitrogen injection at 80 psig. Further, the injection well was connected to the SG outlet and production well – to the production line. Thermocouples were connected to the data logger via extension cables.

2.3.3 Experiment

To establish the communication between injection and production wells, at start-up they were heated till reaching 100 °C by the band heaters for 10 minutes. After this, the band heaters were turned off and fluid injection into the set-up was started. Depending on the type of the experiment, the injectant was hot water, pure steam, or

steam with solvent (Table 5). Produced fluids were collected every 20-30 minutes and analyzed later. Experiments were terminated when significant decline in oil production was observed.

2.3.4 Post-experimental Work

At the end of each experiment, the oil sand from the model was extracted for visual examination. Postmortem sample and produced liquids were weighed for material balance. Additionally, produced bitumen viscosity and gravity and produced water pH values were measured.

CHAPTER III

EXPERIMENTAL RESULTS & DISCUSSION

Four sets of experiments were performed to investigate:

1. The effect of HAGD for different physical model size & water injection rate (E1 & E2);
2. The effectiveness of SAGD over HAGD (E3 & E2, respectively);
3. The influence of clay mineralogy on the performance of SAGD process, in particular, on the in-situ precipitations of bitumen residues (E3 & E4);
4. The potency of SAGD with hydrocarbon solvent continuous and cyclic injection (E4 through E8).

Sensitivity analysis has been run for the viscosity variation of bitumen by the addition of three solvents at three separate doses. In Figure 10, the viscosity change with temperature is given for original bitumen (blue curve), and for the mixtures of the bitumen with n-hexane (green curve), toluene (red curve), and cyclohexane (purple curve) at three concentrations; 5 vol.% (Figure 10A), 7 vol.% (Figure 10B), and 10 vol.% (Figure 10C). As it can be observed from the figure, the greatest viscosity reduction was acquired with toluene at 10 vol.% concentration. Cyclohexane showed an intermediate degree of viscosity reduction, while n-hexane – the lowest viscosity reduction.

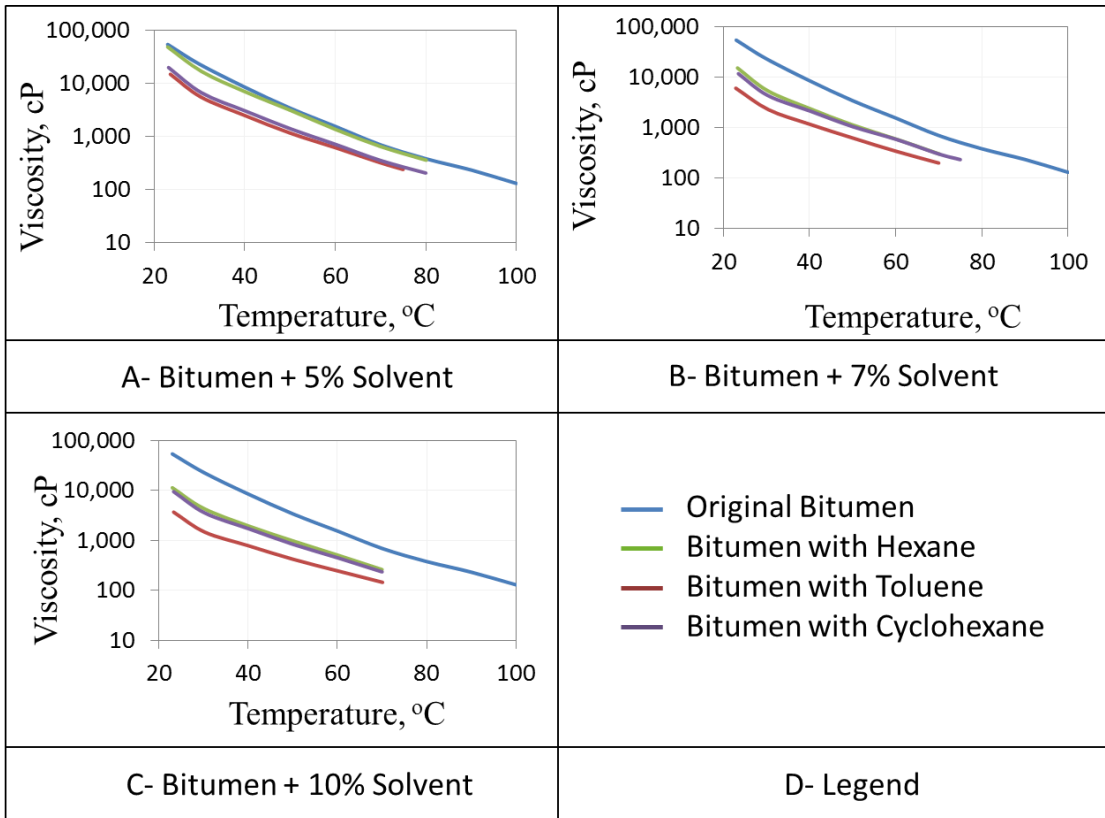


Figure 10. Bitumen viscosity variation with solvent dose for increasing temperatures

All experimental runs, except run E7, were discussed in terms of temperature distributions at 47 different positions, oil, water, and gas production, and level of oil upgrading. For run E7, due to oil leak, only temperature profiles and postmortem pictures results could be recorded.

Experiment E7 was terminated at the end of 2.8 hours due to the plugging in production lines. After the termination, pressure in the experimental system could not be decreased, therefore, it was decided to disconnect the production line to release the pressure. As a result, oil leak was occurred. Even though production well, in this

experiment was wrapped with screen as well as in all other experiments, plug-in of the production line was happened. To understand the reason of the plug-in, the production line was disassembled and all connections were examined. It was found that line was plugged by the mixture of small amount of sand and significant amount of bitumen residues (most probably asphaltenes) (Figure 11). Cyclohexane as a solvent with an intermediate solubility parameter dissolved some part of asphaltenes under steam temperature. Further, when bitumen-solvent-water mixture went through the production line, temperature drastically decreased from steam temperature to room temperature. Changes in temperature caused asphaltene destabilization and its precipitation (Mullins et al., 2007). Picture of the line plug-in is presented in Figure 11. Probably, higher cyclohexane concentration would help to avoid the line plug-in.



Figure 11. Plug-in of the production line during E7

For the rest of the hybrid SAGD experiments, the production line plug-in was not observed. For the experiments conducted with toluene, E6 and E8, asphaltene destabilization was reduced, since toluene is asphaltene soluble solvent (Gray, 1994). In

the case of n-hexane co-injection (E5), n-hexane, as a low boiling n-alkane, induced in-situ asphaltene precipitation, thereby reduced asphaltene content in the produced bitumen and prevented its precipitation in the production line (Firoozabadi, 1999). However, asphaltenes were precipitated in-situ.

3.1 Temperature Profiles

Figures 12 and 13 present the temperature distributions inside the model over time for all experiments. On these figures “h” represents the height of the physical model and “x” is a circumference of the model. The height and the circumference were the same in all experiments. Injection and production points were located in the lower center part of the experimental model. Thickness of the model in E1 was 2.2 cm (“thin” model), in all other runs – 6.8 cm (“thick” model). Temperature measurements were taken in the same position for all experiments; 11 vertical thermowells were located at the center part of the model thickness as shown in Figure 5.

3.1.1. 1st Set of Experiments

Temperature profiles for the 1st set of experiments are given in Figures 12A and 12B. These runs were performed with hot water injection at pressure and temperature equal to 75 psig and 155°C, respectively. Hot water injection rates were 8 g/min and 18 g/min for E1 and E2, respectively. Despite the fact that in E1 additional inner thermal insulation was used, temperature propagation was better in E2. In E1, hot water chamber stopped growing after 12 hours and swept only 25-30 vol. % of the physical model. This is the result of doubled hot water injection rate in E2. Higher hot water injection rate in

E2 provided higher heat injection rate and as a result better temperature propagation within the model.

3.1.2. 2nd Set of Experiments

Figures 12B and 12C present temperature profiles for the 2nd set of experiments. Water rate and system pressure were kept constant in E2 and E3; 18 g/min and 75 psig, respectively. However, in E3 injection temperature was increased to 165 °C which is corresponds to steam temperature at experimental pressure. Thus, E2 represented HAGD experiment, while E3 – SAGD. A better temperature propagation was found for E3 and steam chamber could be developed successfully by the end of 12 hours of experimental time (Figure 12C). The effect of latent heat of vaporization can be easily observed by comparing Figure 12B with Figure 12C in which hot water and steam were injected, respectively. Therefore, with one unit mass of steam much higher heat content was introduced to the system than with one mass unit of hot water. As a result, steam reduces bitumen viscosity more effectively and improves heat propagation inside the reservoir (William et al., 1961). Therefore, SAGD had better temperature distribution than HAGD.

3.1.3. 3rd Set of Experiments

Figures 12C and 12D give temperature distributions for the 3rd set of experiments. Although E3 and E4 runs were SAGD experiments conducted at the same pressure-temperature conditions, samples were prepared in each experiment with two different clays, which were discussed in Chapter 2. While Clay 1 used in E3 mostly

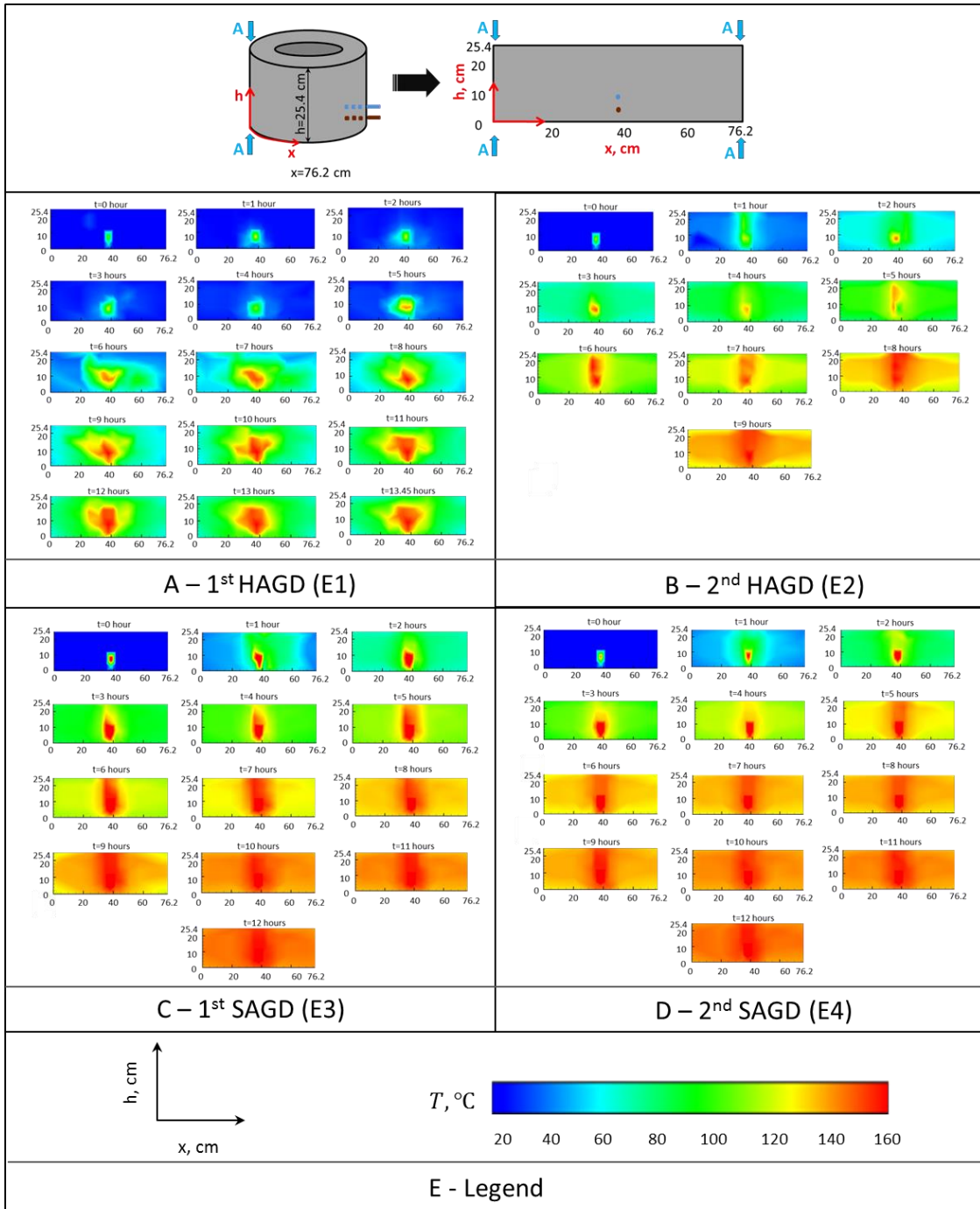


Figure 12. Temperature profiles for experiments E1-E4

contains kaolinite, Clay 2 used in E4 has 80-90% kaolinite and 10-20% illite. The temperature profiles did not indicate significant difference for the first three hours of E3 & E4 (Figures 12C and 12D, respectively). However, better temperature propagation was observed for E4 after three hours until nine hours. During the last three hours of the experiments, similar temperature profiles were observed within the model for both, E3 and E4.

3.1.4. 4th Set of Experiments

Figure 13 shows the temperature profiles for the 4th set of experiments. In this set, five experiments; a base SAGD (E4) and four SAGD with solvent co-injection (E5 through E8), were conducted. As seen in the figure, the temperature propagation was better in the hybrid SAGD experiments, in comparison with the base SAGD experiment. This proves the ability of hydrocarbon additives to improve the efficiency of SAGD process. In hybrid SAGD processes, solvent diluted the bitumen inside the reservoir (Nasr et al., 2003). Thereby in SAGD with solvent co-injection experiments, bitumen viscosity was reduced due to the heating by the steam and diluting by the hydrocarbon additives (Gates, 2007). As a result, the solvent enhanced the steam chamber development and the temperature within the model increased at a faster rate in hybrid SAGD experiments than in the base SAGD experiment. You et al. (2012) compared steam chamber development in 2D SAGD and ES-SAGD with hexane co-injection experiments and also reported improvement of the steam chamber development in ES-SAGD experiment.

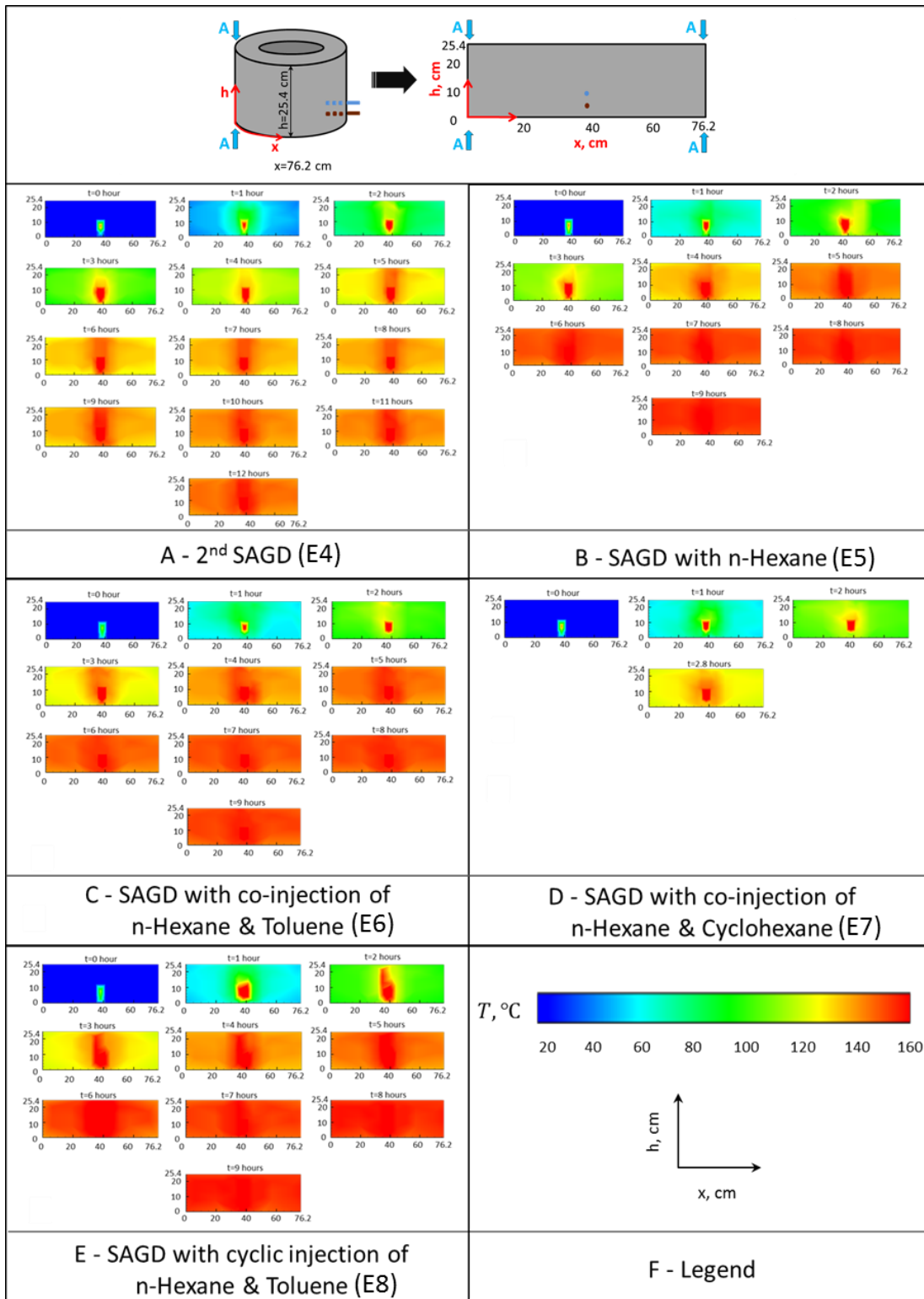


Figure 13. Temperature profiles for experiments E4-E8

In E7, steam chamber was not formed fully, as it was terminated at the end of 2.8 hour due to plug-in occurred during the experiment. However, temperature propagation in this run was similar to that in the first 3 hours of E6, but slightly worse.

Among the three SAGD with solvent co-injection runs (E5, E6, and E8), the steam chamber grew most rapidly for E8 during the first four hours, however, starting at the fifth hour of the experimental time, the temperature distributions became similar and after 6 hours the steam chamber was completely formed in all three runs. Note that in E8, n-hexane and toluene were injected alternately every next hour. In other words, during the first, third, fifth, seventh, and ninth hours n-hexane was injected continuously and during the second, fourth, sixth and eighth hours of the experiment toluene was injected. Even though the first hour of E5 and E8 represents n-hexane injection, temperature profiles showed variations due to pump failure during E5. Moreover, in E8, due to some problems with sealing of thermowell “A” (Figure 5), before the experiment start, thermowell was pulled out from the packed model and inserted back again. It created an easy pathway for injected steam and, as a result, better temperature propagation in E8 (Figure 13E). The effect of this pathway can be seen in Figure 13E with two hours ($t = 2$ hours) image. The temperature increase is more significant for the left hand side portion of the injection point than the right hand side of it. This place representing the place of replaced thermowell (Figure 5- Thermowell A).

3.2 Oil Production Performance

All oil production results are given together in Figure 14. The first column in the table gives the name of the experiments, second column represents oil recovery rate in

gram per hour in time, and third column shows the recovery factor in weight percentage in time. Oil recovery rate graphs for all experiments demonstrate a similar trend by initially rising until some maximum point and then declining. However, maximum oil production rate and production decline start time differs in each experiment. For a better presentation, the maximum oil recovery rates are compared to the production decline start time in Figure 15.

3.2.1. 1st Set of Experiments

Figures 14A and 14B show oil production results for the 1st set of experiments. As the size of the experimental model and water injection rate were different in E1 and E2; E2, with larger volume of sample and higher water injection rate, yielded higher oil recovery rate. However, as seen in the figure, production decline start time of the oil recovery rate was nearly the same in both runs and was about 5.8 hours (Figure 15). Cumulative oil recovery as a weight percentage of the OOIP in E1 and E2 was found to be 12 wt% and 33 wt%, respectively. The low oil production in E1 was due to the poor temperature propagation within the model in this run, as discussed earlier (Figure 12A). In the 1st set of experiments, higher oil recovery factor was obtained in E2 experiment, which is characterized by the larger size of the experimental model and greater hot water injection rate.

3.2.2. 2nd Set of Experiments

Figures 14B and 14C demonstrate oil production results for the 2nd set of experiments, in which the effectiveness of steam injection was investigated over hot

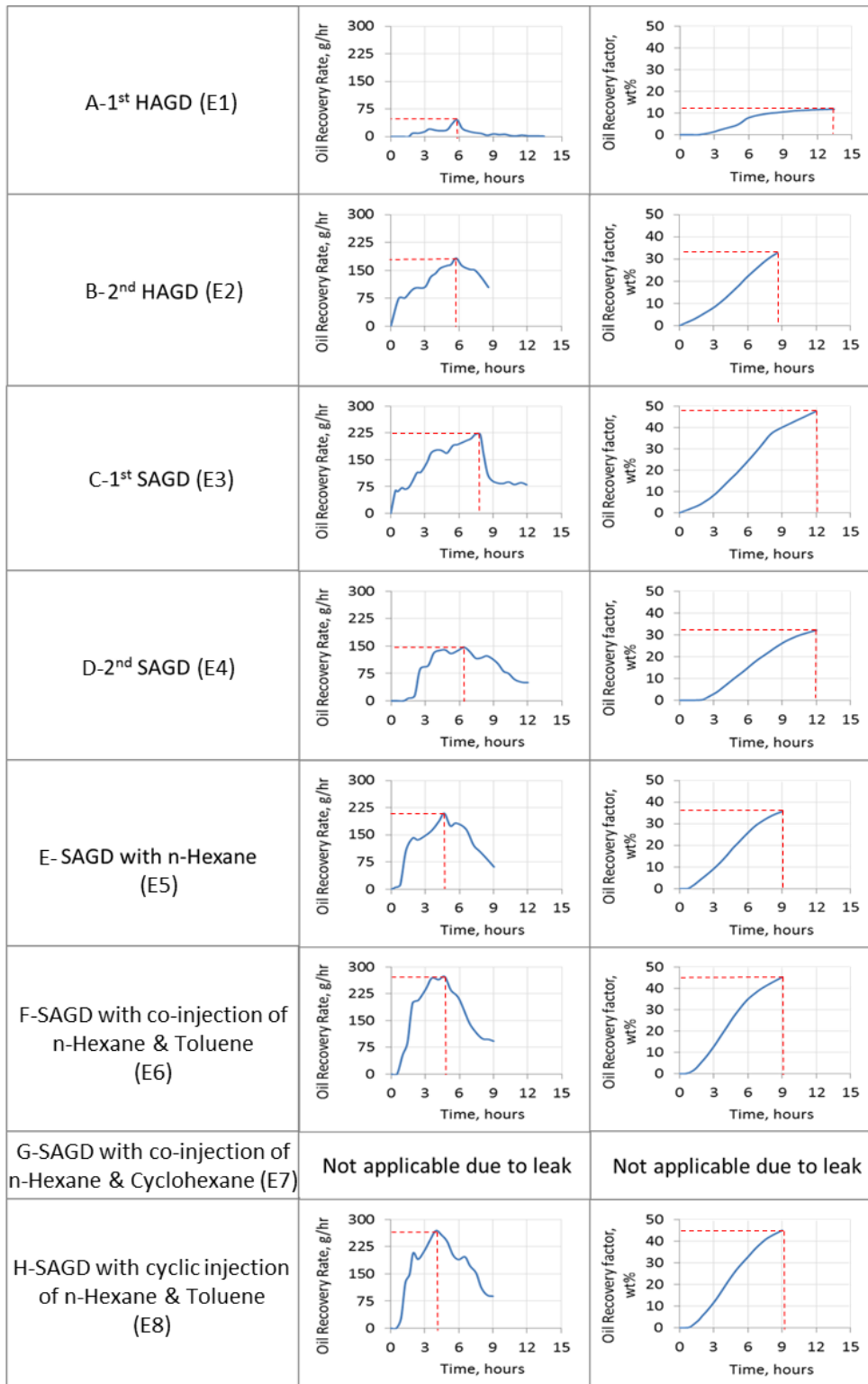


Figure 14. Oil recovery rate and cumulative recovery factor

water injection. As observed in Figures 15, in this set of experiments maximum oil recovery rate was achieved for E3; around 221 g/hr, which was obtained by the end of 7.85 hour of experimental time. It should be noted that oil recovery rate in E2 was nearly the same as that in E3 during the first 5.75 hours. However, after 5.75 hours oil production in E2 began to decline sharply, while oil production in E3 kept rising. As a result, cumulative oil recovery in E3 was found higher in comparison with E2; 47 wt% and 33 wt%, respectively (Figures 14B and 14C). Higher oil production rates in E3 was obtained due to better temperature propagation inside the model in this experiment (Figures 12B and 12C). Since steam has higher heat capacity than hot water (Prats, 1982), steam chamber expands faster than hot water chamber. As a result, in E3, steam chamber swept larger area and more oil was extracted.

3.2.3. 3rd Set of Experiments

In Figures 14C and 14D, oil recovery rate and cumulative oil recovery graphs for the 3rd set of experiments are shown. From Figure 14C, it is seen that E3 was characterized by higher values of oil recovery rate and ultimate oil recovery in comparison with E4. In E4, the first oil sample was obtained at the end of 1.5 hours of experimental time, while in E3 oil production started as the experiment start time. In this set of experiments, the effect of two separate clays was investigated. The experiment prepared with Clay 2 (E4) which contains 10-20% of illite yielded less oil than the experiment prepared with Clay1 (E3) which does not contain any illite. The maximum oil recovery rate was also less for E4 as it observed from Figure 15. Moreover, even though in E4, a delay was observed for oil production, recovery rate started to decline

earlier in this experiment (Figure 15). In order to explain the effect of clay better, further analysis should be conducted which is not the scope of this thesis and will be achieved in the future by different researchers. However, there is some literature knowledge which can help us to understand this concept. In E4, illite-kaolinite mixture could synthesize smectite through water/rock interaction (Boon and Hitchon, 1983; Gunter et al., 1994). Smectite, as a swelling clay, caused reservoir permeability impairment (Civan, 2007), that could reduce oil production rate (Xiao et al., 2005). Moreover, Schembre and Kovsek (2004) pointed that illite has more negative zeta potential than kaolinite and quartz-illite system is more sensitive to temperature variations. Therefore, the quartz-illite system is more addicted to detachment than the quartz-kaolinite. It means that illite tends to migrate more easily and could cause additional reservoir damage in E4. Also, wettability alteration from water-wet to oil wet and some clay reactions that occur under steam processes can lead to increase of residual oil saturation and, furthermore, to in-situ asphaltene precipitation (Pang et al., 2010; Bennion et al., 1995).

3.2.4. 4th Set of Experiments

Figures 14D through 14H demonstrate oil production results for the 4th set of experiments. As it was mentioned earlier, due to the plug-in occurred during E7, for this run, there was no oil recovery data. In all other ES-SAGD experiments (E5, E6, and E8), like to base SAGD experiment (E4), a delay was observed for the oil production. However, while in E4, the first oil sample was produced after 1.5 hours from the beginning of the experiment, in E5, E6, and E8, the first oil samples were recovered by the end of the first hour of the experiments. It means that in ES-SAGD

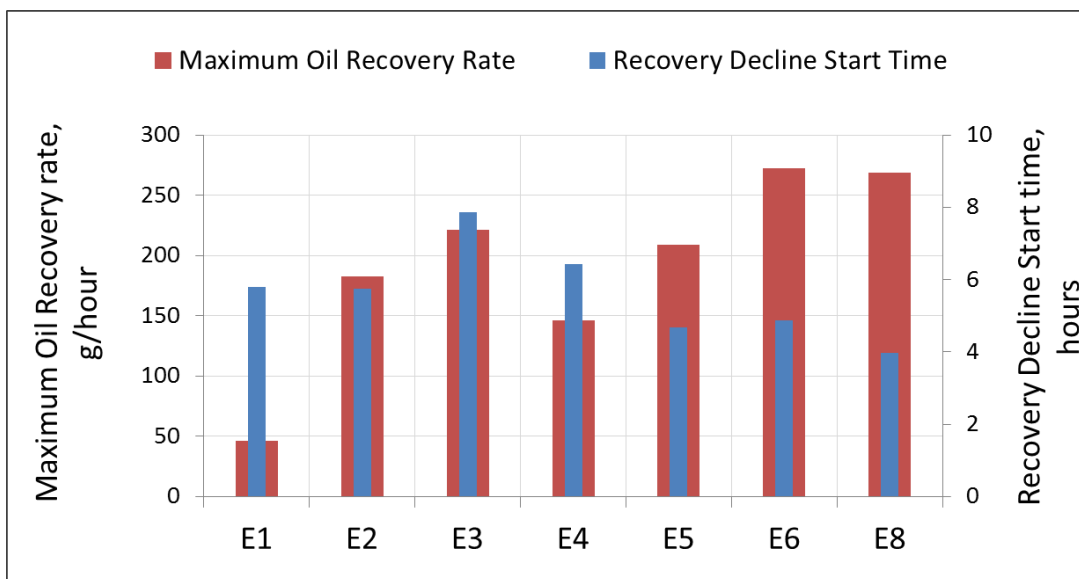


Figure 15. Maximum oil recovery rate and production decline start time for E1-E6 and E8

runs, hydrocarbon additives induced earlier oil production compared with the base SAGD run. The base SAGD run (E4) was characterized by the lowest oil recovery (33 wt%) when compare to ES-SAGD runs (E5 through E8). SAGD with the addition of n-hexane (E5) showed results that were better than the base SAGD run, but worse than SAGD with toluene-hexane co-injection runs (E6 and E8) performance. Cumulative oil recovery was equal to 37 wt%, 45 wt%, and 45 wt% in E5, E6, and E8, respectively. Moreover, SAGD with solvent co-injection runs showed higher maximum oil recovery rate and earlier oil production decline start time (Figure 15). Thus, addition of n-hexane slightly improved efficiency of SAGD process, while SAGD with n-hexane and toluene experiments showed considerable improvement in oil production. Thereby, cyclic

injection of n-hexane with toluene enhanced the oil production in ES-SAGD process, which can be explained by the fact that n-hexane as asphaltene insoluble solvent caused in-situ asphaltene precipitation during the process (Mohammadzadeh et al., 2010a). Asphaltene depositions plugged some pore channels and reduced reservoir permeability. In cases when toluene was added, toluene, as the asphaltene soluble solvent, dissolved the precipitated asphaltenes, thereby cleaned pores and improved oil production. Haghghat and Maini (2010) obtained the similar results during VAPEX process. They conducted VAPEX experiments with injection of n-alkane alone and the mixture of n-alkane with toluene and obtained higher oil recovery rate in the second case.

It should be noted that E6 and E8 differed by the strategy of hexane and toluene co-injection. In E6, toluene and hexane were mixed together before the experiment in 1:1 volume ratio and this mixture then was continuously co-injected with steam at a concentration of 10 vol. %. In E8, there were separate n-hexane and toluene containers; n-hexane and toluene were co-injected with steam alternately at a concentration of 10 vol. % (1 hour-1 hour), starting with n-hexane. However, as it can be concluded from the Figures 14F and 14H, this different strategy in solvent co-injection did not have an effect on oil production performance. As it is seen from Figure 15, the maximum oil recovery rates were nearly the same for E6 and E8. However, cyclic injection of n-hexane with toluene slightly reduced the time to reach maximum oil recovery rate: from 4.9 hours (E6) to 4.0 hours (E8). Moreover, in E8, less amount of toluene (480 ml instead of 540 ml) and greater amount of n-hexane (600 ml instead of 540 ml) were used. Toluene is known as more toxic and less environmentally friendly hydrocarbon solvent in

comparison with n-hexane (Schefflan and Jacobs, 1953). In this way, for this experimental study alternate co-injection of n-hexane and toluene yields an earlier achievement of maximum oil recovery rate and causes less environmental impact in comparison with continuous n-hexane and toluene co-injection. Although, for laboratory-scale study insignificant changes in production decline start time and amount of used solvents were observed between E6 and E8, for field-scale application, these changes will be considerable.

3.3 Postmortem Analysis

At the end of each experiment, visual inspection has been performed on unpacked samples (postmortem sample). Figure 16 shows the pictures of the postmortems for all experimental runs.

3.3.1. 1st Set of Experiments

Figures 16A and 16B present postmortem pictures for the first set of the experiments in which the effect of physical model size and the water injection rate on HAGD process were investigated. It is seen that in general oil sand samples extracted after both HAGD experiments, E1 and E2, were very similar. They had similar texture and color. Both samples contain light area that spreads from the center part of the model where hot water was injected to the periphery which has some darker areas on the sides of the model (Figures 16A and 16B). Light areas corresponded to swept zones by the hot water that contain lower residual oil saturation, while dark areas are less touched zones with high residual oil saturation values.

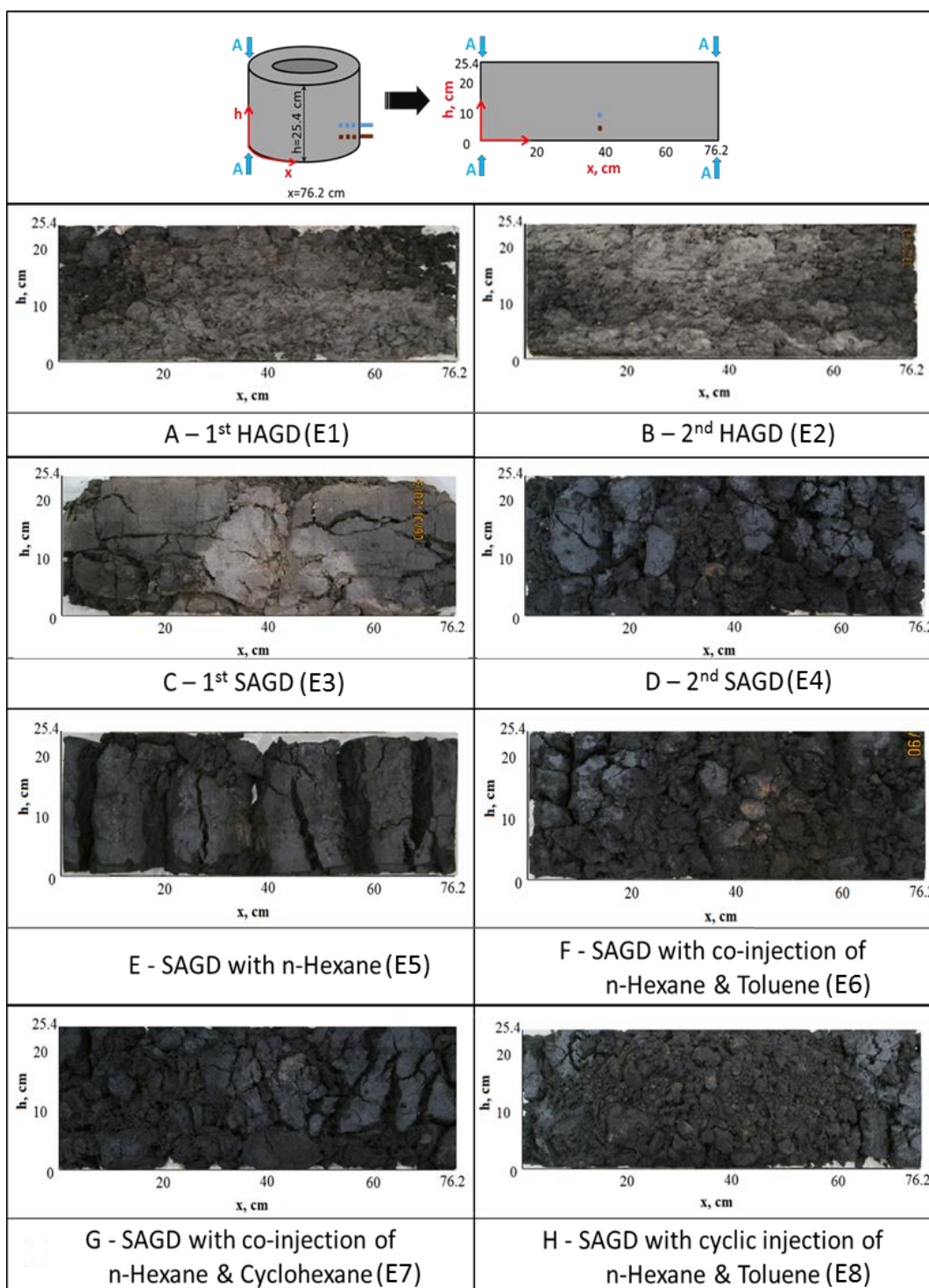


Figure 16. Postmortem pictures

3.3.2. *2nd Set of Experiments*

Figures 16B and 16C demonstrate postmortem pictures for the 2nd set of experiments. Like the previous set, in this set postmortems of both runs have lighter and darker areas. It can be concluded from the postmortem pictures, that sweep efficiency of both processes is a quite good. In SAGD postmortem picture, we can observe more sharp edge between light and dark areas. This edge represents the boundary of the steam chamber at the end of the experiment.

3.3.3. *3rd Set of Experiments*

Postmortem pictures for the 3rd set of experiments are given in Figures 16C and 16D. Despite the fact that both E3 and E4 were base SAGD experiments, the color of the samples after the experiment is very different. From the Figure 16D, we can observe much darker color of the sample than in Figure 16C. Dark color of the postmortem sample for E4 cannot be referred to untouched zone by the steam because temperature distribution picture (Figure 12D) demonstrates that the steam chamber was fully developed within the model during E4. It was also observed that postmortem sample after E4 was more consolidated and darker in comparison with the original oil sand sample. It means that some heavy compounds of the bitumen were precipitated during E4. Precipitated residues could plug pore channels and deteriorate the reservoir permeability, thereby reducing oil recovery rate (Compare Figure 14C with 14D).

E3 and E4 experiments were differed just by the clay compositions, which was used during the sample preparation. As it was mentioned before, in E3, clay was

constituted mostly by the kaolinite, while in E4 – by 80-90% kaolinite and 10-20% illite. Accordingly, illite caused some bitumen residues precipitation that made oil sand sample at the end of the experiment darker and more consolidated than original sample. Headen et al. (2007) proved that some clays enhance asphaltene aggregation. Although, illite is regarded as a clay with hydrophilic character, which does not tend to induce asphaltene aggregation (Bantignies et al., 1997), in some cases illite can reverse its wettability and become oil-wet clay (Durand and Rosenberg, 1996). Such wettability reversion increases amount of in-situ immobile bitumen (Pang et al., 2010) and, as a result, reduces cumulative oil recovery.

3.3.4. 4th Set of Experiments

Figures 16D through 16H represent postmortem pictures for the 4th set of experiments in which the effectiveness of solvent injection to enhance the performance of SAGD process was investigated. As in E4 through E8, Clay 2 (Figure 8) was used during sample preparation, all postmortem samples were characterized by the dark colored and consolidated structure when compared to the experiment conducted with Clay1; E1 through E3. Also, all postmortem samples contained small lighter areas around the injection and production points. In E6 and E8, these areas were slightly in larger size than in E4, E5, and E7. Because toluene has higher solubility parameter than n-hexane and cyclohexane (Smallwood, 2002), it reduces bitumen viscosity more efficiently (Figure 10) and resulted in more swept areas in postmortems (Figure 16). The degree of sand consolidation was different among the runs. Thus, the most consolidated sample was found in E5 in which n-hexane alone was co-injected with steam. In this

experiment, in addition to the residues precipitation due to illite, n-hexane as an asphaltene insoluble solvent induced asphaltene precipitation (Mohammadzadeh, 2012). Figure 17 shows small part of the postmortem sample from E5 which is highly consolidated due to asphaltene precipitation. Luo et al. (2008) reported about similar consolidated sand which was obtained after VAPEX experiment with butane mixture (70 mol.% n-butane and 30 mol.% iso-butane) and propane as the injectants.



Figure 17. Consolidated oil sand sample extracted after E5

In E7, the degree of sand consolidation was observed almost the same as in E4. The reason can be the short duration of the experimental time in E7 due to the plug-in; 2.8 hours. The least consolidation was found in E8, in which toluene was injected with n-hexane cyclically. In E6, the degree of sand consolidation was found higher than in E8, but lower than in E4 and E7. In E6 and E8, unconsolidated zones were swept by toluene zones. As it was mentioned in Chapter 2, at experimental pressure and temperature toluene was in liquid phase, while n-hexane and cyclohexane – in gaseous

phase. As a result, n-hexane and cyclohexane spread through the whole model, while toluene touched just part of the physical model.

Thus, postmortem analysis confirmed that co-injection with steam of n-hexane alone causes in-situ asphaltene precipitation (Mohammadzadeh et al., 2010a) and addition of toluene enhances the efficiency of ES-SAGD process by dissolution of asphaltenes.

3.4 Material Balance

After postmortem analysis, material balance calculations were done. Tables 6 and 7 summarize material balance for all experimental runs in lab and field units, respectively. The amount of produced oil and water in time can be found in section 2 of this chapter and Appendix A, respectively.

In Table 6, the amount of produced gases were found using the following equation:

$$m_{rg} = (m_{sp} + m_{wi} + m_{si}) - (m_{lr} + m_{pr}),$$

where: m_{rg} – mass of recovered gases, g;

m_{sp} – mass of packed oil sand sample, g;

m_{wi} – mass of injected water, g;

m_{si} – mass of injected solvent (applicable for E5-E8), g;

m_{lr} – mass of recovered liquid, g;

m_{pr} – mass of postmortem sample, g;

It can be seen from Table 6 that all experimental runs are characterized by the small amount of produced gases.

Table 6. Material balance for all experiments (lab units)

Experiment Number	Sample Packed, g					Injected Water, g	Injected Solvent, g	Produced Oil, g	Produced Water, g	Post-mortem, g	Produced Gas, g
	Sand	Clay	Oil	Water	Total						
E1	5747.3	1013.8	1161.6	217.8	8140.6	5834	-	136.9	5353.8	8426.9	57.02
E2	16604.3	2929	3355.9	633.5	23522.7	9266.4	-	1098	8250.7	23389.1	51.33
E3	16439.9	2900	3322.7	623.3	23285.9	12906	-	1575.4	11504.6	23029	82.90
E4	16523.9	2914.1	3312.1	626.54	23376.7	12960	-	1063.8	12625.5	22588.5	58.90
E5	16374.1	2888.4	3288.5	620.8	23171.8	9756	512	1108.5	10161.5	22062	77.85
E6	16615.4	2931	3330.5	629.94	23506.8	9720	821.7	1503.8	9894	22562	76.03
E7	16597.3	2927.9	3327	629.3	23481.5	3024	240.8	N/A*		22986	N/A*
E8	16590.3	2926.5	3325.4	629	23471.2	9666	809	1493.4	9802.2	22596.2	67.17

* N/A: Not applicable due to experimental error

Table 7. Material balance for all experiments (field units)

Case Number	Reservoir weight / volume ratio, <i>tone/acre-ft reservoir</i>	Injected Water, <i>bbl/acre-ft*day</i>	Injected Solvent, <i>bbl/acre-ft*day</i>	Produced Oil, <i>bbl/acre-ft*day</i>	Produced Water, <i>bbl/acre-ft*day</i>
E1	2510.0	20041.3	-	462.5	5353.8
E2	2346.5	15960.5	-	1965.1	8250.7
E3	2322.8	16259.7	-	1965.1	11504.6
E4	2331.9	16259.7	-	1326.7	12625.5
E5	2311.5	16259.7	1306.8	1845.4	10161.5
E6	2344.9	16259.7	1807.0	2493.8	9894.0
E7	2342.3	16259.7	1895.3	N/A	
E8	2341.3	16958.0	1807.0	24938.2	9802.2

* N/A: Not applicable due to experimental error

3.5 Oil Upgrading

To investigate the degree of bitumen upgrading for HAGD, SAGD, and ES-SAGD processes, viscosity and gravity of original and produced oil were measured (Figure 18).

Figures 18A, 18B, and 18C show oil viscosity variation with temperature and sampling time, and oil API gravity variation with temperature graphs, respectively. There were no measurement results for the 1st HAGD experiment (E1), because the amount of produced oil for this run was not enough for the measurements. Figures 18A and 18C demonstrate the similar behavior of viscosity and gravity variation with temperature for all runs; viscosity reduction and gravity increase at elevated temperature. Viscosity change with sampling time was not observed for all runs (Figure 18B). So, the produced oil quality has not been changed in time.

The average values of viscosity and API gravity of produced oil at room temperature are shown in Figure 19.

From this diagram, we can observe that in E2 through E4, the bitumen upgrading was achieved insignificantly; viscosity and API gravity of produced oil were found nearly equal to those of the original bitumen. This confirms that at temperature range 155-165 °C in-situ bitumen visbreaking does not occur (Henderson and Weber, 1965).

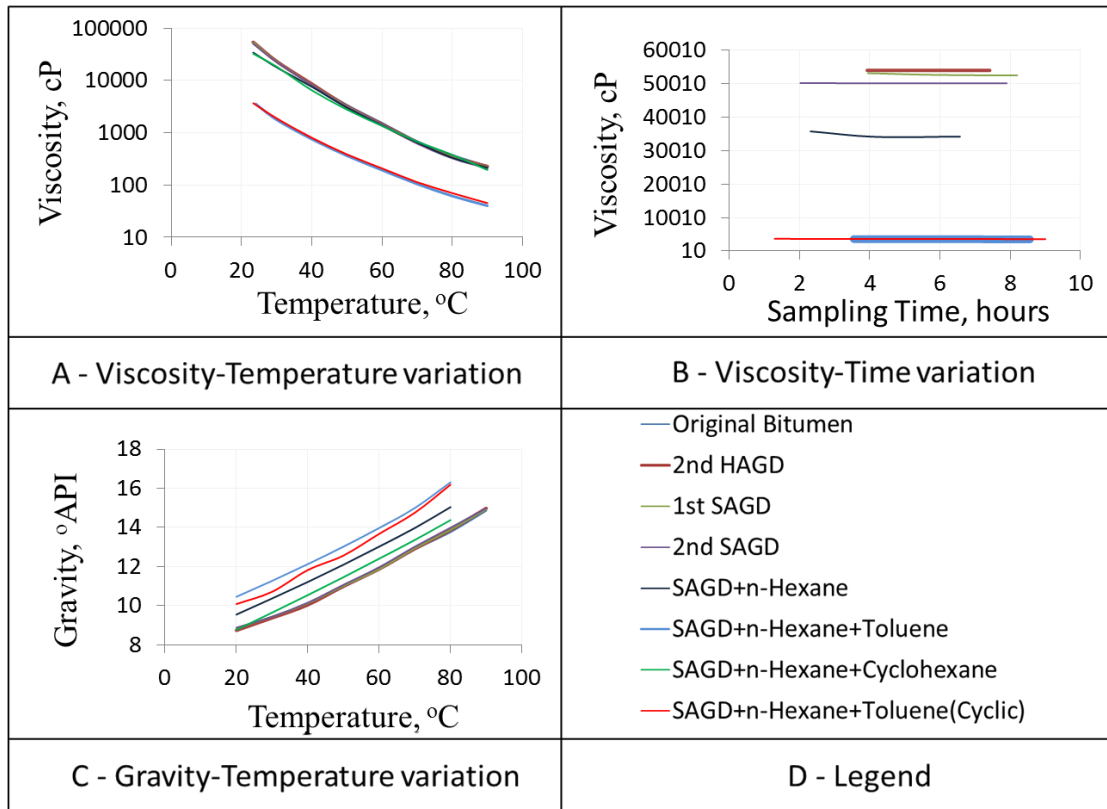


Figure 18. Variation of produced oil viscosity and gravity with temperature and time

Among ES-SAGD experiments (E5 through E8), the maximum level of oil upgrading was obtained in E6 and E8, in which n-hexane and toluene were simultaneously and alternately co-injected with steam, respectively. In these experiments, oil viscosity was found 15 times less than that of the original bitumen and API gravity was enhanced from 8.8 °API (original bitumen) to 10.4 °API (in E6) and 10 °API (in E8). E5 demonstrated reduction of oil viscosity in 1.5 times. API gravity was increased from 8.8 to 9.5 °API. In E7, improvement in oil gravity was not observed, but viscosity was reduced in 1.6 times.

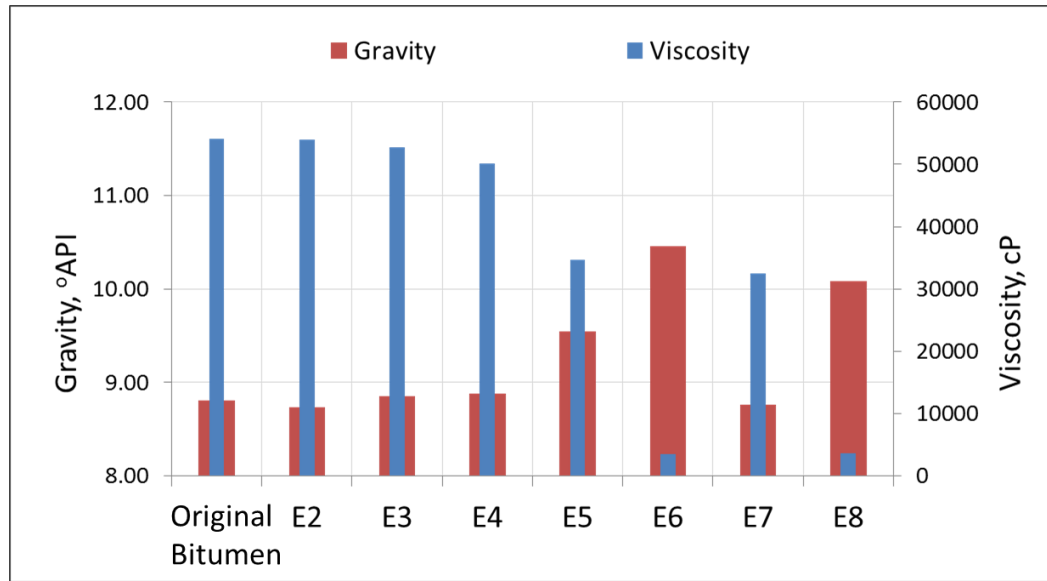


Figure 19. Average values of viscosity and gravity of original and produced oil

It should be noted that after each ES-SAGD experiment (E5 through E8), solvents were removed from produced oil samples by evaporation. However, 100% solvent removal could not be accomplished which can be observed with the comparison of produced oil gravities after base SAGD with ES-SAGD. To investigate the amount of solvent remained in the oil samples, gravity of the bitumen-solvent mixture versus solvent concentration graphs were obtained from literature (Saryazdi et al., 2013) (Figure 20). It has been calculated that 1.3 wt%, 4.6 wt%, and 4.4 wt% of solvent were remained in E5, E6, and E8, respectively. For E7, the gravity reduction was not observed, which indicates that all injected solvent was removed from the produced oil.

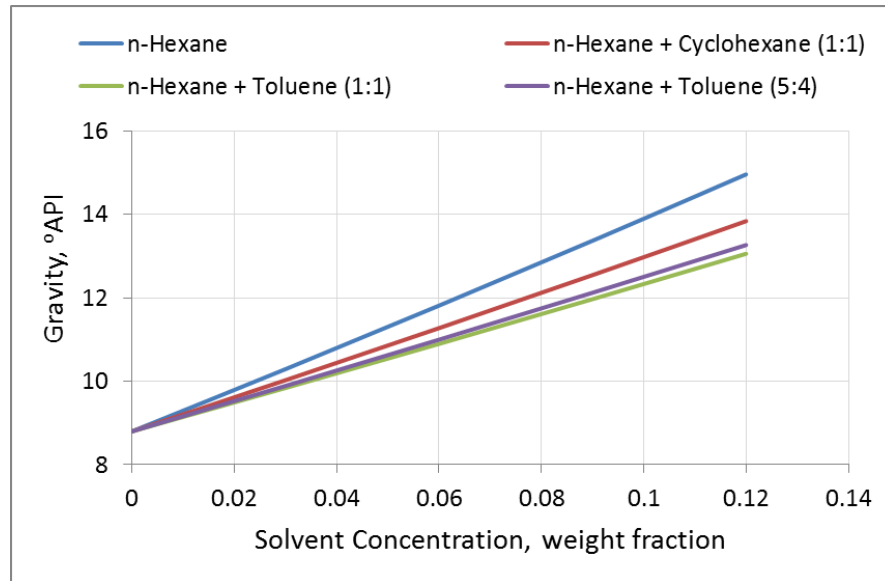


Figure 20. Variation of API gravity of bitumen-solvent mixture with solvent concentration

Bitumen viscosity variation with solvent dose is presented in Figure 21. It can be observed that reduction in oil viscosities from E5 through E8 were achieved not only the presence of solvent but also due to steam distillation which is one of the mechanisms taken place during steam injection processes.

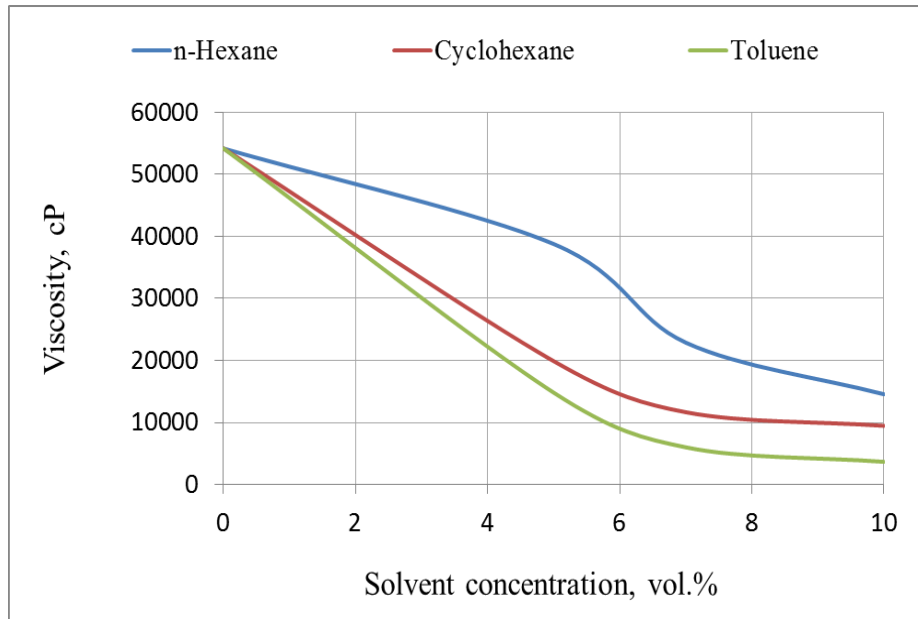


Figure 21. Bitumen viscosity variation with the addition of solvent at different solvent dose

3.6 pH Measurement

Figure 22 presents results of the measurement of produced water pH values. It is seen that the average pH values of produced water were found around 6.7. It proves that acid gases which can be in solution in water and form acid water were not produced during the experiments. Despite the fact that during steam injection processes in-situ bitumen visbreaking (Shu and Hartman, 1986) and production of hydrogen sulfide and carbon dioxide (Akstinat, 1983) can take place, hot water and steam temperatures in this experimental study were not high enough to cause these processes (Henderson and Weber, 1965) as discussed earlier.

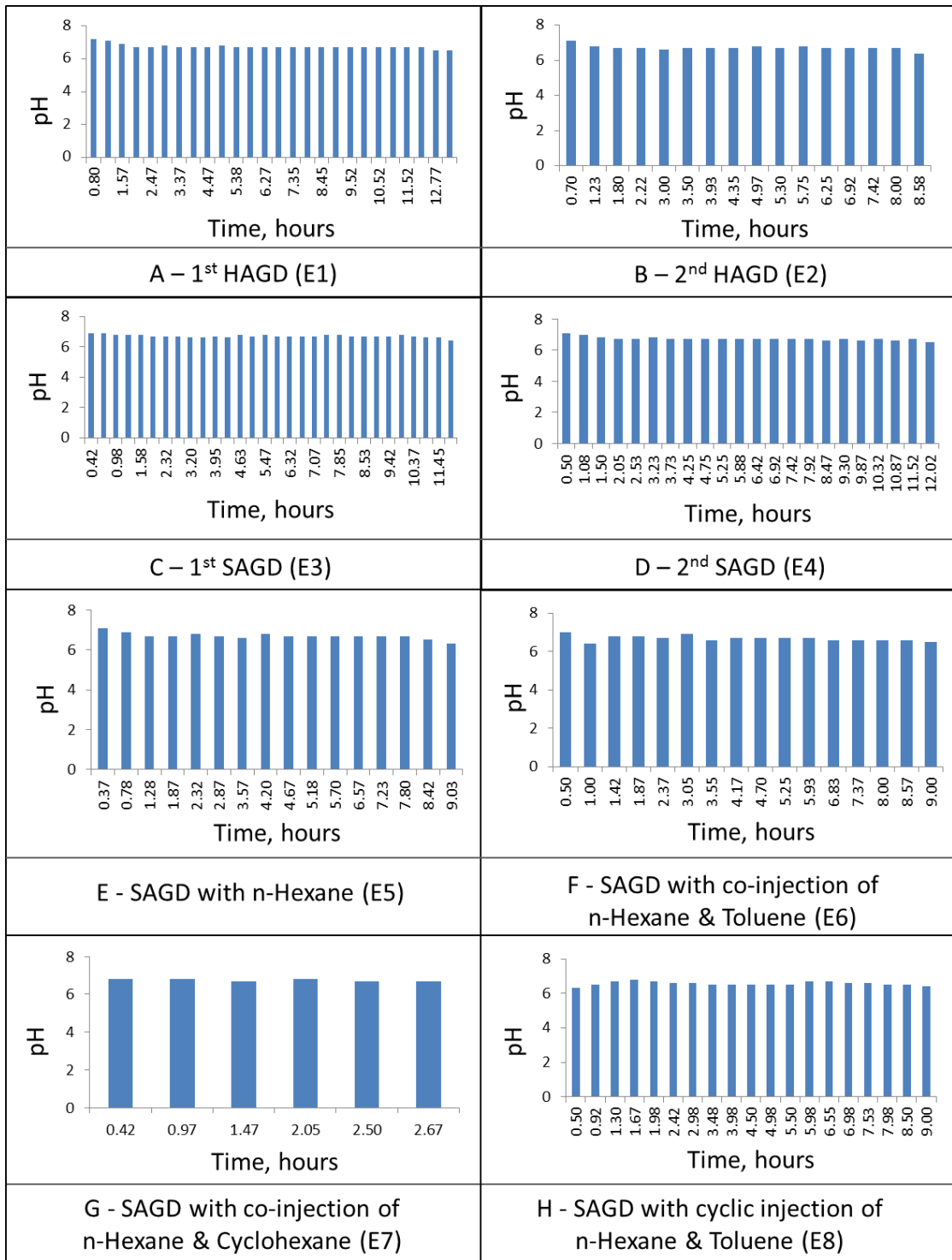


Figure 22. pH values of produce water

It should be mentioned, that produced liquid samples were in form of oil-water emulsion for E1 through E4. However, for E5 through E8 addition of the solvents helped to avoid creation of emulsion as solvents diluted bitumen, making it lighter than water. So, diluted bitumen and water could separate more easily and oil-water emulsions were not created in hybrid SAGD runs

3.7 Economic Evaluation

In section 2 of this chapter, oil production performance was discussed. However, economic efficiency of hot water/steam injection processes is more sensitive to water to oil ratio (WOR) than to the oil recovery rate (Edmunds and Chhina, 2001). WOR indicates how many barrels of hot water or steam in cold water equivalent were used to produce one barrel of oil (Butler, 1991). Energy consumption for water heating/steam generation processes also influences on the economics. Lower values of WOR and energy consumption correspond to higher economic efficiency of the process. In addition, for ES-SAGD experiments, solvent cost also influences on the economic efficiency of the process.

Figure 23 summarizes oil recovery data, WOR (E2)/ SOR (E3-E6 and E8), and energy consumption for heating water (E2)/ steam generation (E3-E6 and E8) processes.

Energy consumption was calculated on the basis of the heaters' power for steam generation, total experimental time and cumulative oil recovery. The following equation was used for calculation of energy consumption:

$$E = \frac{P_1 \cdot n \cdot t \cdot 10^{-9}}{Q},$$

where: E – energy consumption due to water heating/steam generation processes

per barrel of produced oil, GJ/bbl;

P_1 – power of the steam generator heater, W;

n – the number of heaters;

t – total experimental time, s;

Q – cumulative oil recovery, bbl.

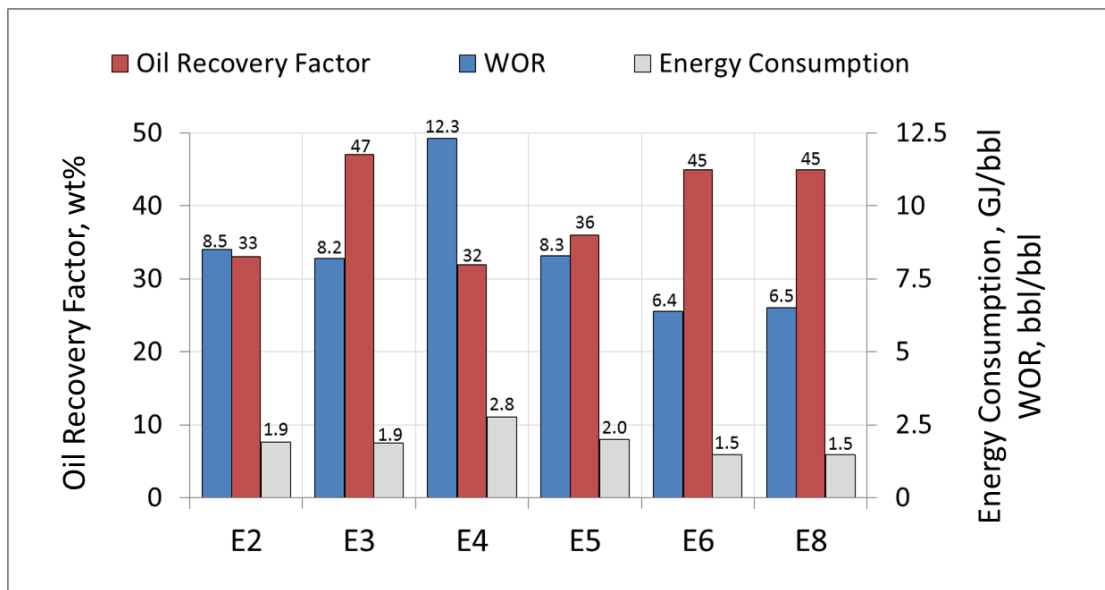


Figure 23. Summary of oil recovery, WOR, and energy consumption for E2-E6 and E8

The results for E1 were not included in the chart due to their significant contrast with the results for E2-E6 and E8 that made the comparison the results for E2-E6 and E8 inconvenient. In E1, energy consumption, WOR, and oil recovery factor were equal to 24.1 GJ/bbl, 43, and 12 wt%, respectively. If to compare these results with those for E2

presented in Figure 23, in E2, energy consumption was 12.7 times less, WOR was 5 times less, and cumulative oil recovery factor was 2.7 times greater in comparison with E1. So, E2 showed better performance than E1 in terms of WOR, energy consumption, and cumulative oil recovery, even though they are both representing hot water injection cases with different dimensions. Higher volume of reservoir results in better performance for hot water injection.

From the comparison results for E2 and E3 it is seen that these runs are characterized by the nearly the same values of WOR and energy consumption. However, for E3, ultimate oil recovery factor was found 1.4 times greater. So, we can concluded that despite the similarity in energy and water consumption for HAGD and SAGD experiment, SAGD process is characterized by higher cumulative oil recovery that once again proves the higher efficiency of steam injection processes over hot water injection processes.

Between E3 and E4, E3 demonstrated better performance in terms of WOR, cumulative oil recovery and energy consumption. So, the experiment in which kaolinite without any illite was used yielded higher oil recovery with lower energy and water consumption. This proves the importance of reservoir lithology, especially, importance of clay composition on SAGD performance.

Among E4 through E6 and E8, E6 and E8 showed the lowest WOR and energy consumption with the highest cumulative oil recovery, while E4 – the highest WOR and energy consumption with the lowest cumulative oil recovery. E5 showed intermediate values for WOR, energy consumption, and cumulative oil recovery factor. These results

prove the ability of hydrocarbon additives to improve energy and economic efficiency of SAGD process. Moreover, it can be concluded, that addition of toluene to n-alkanes enhances performance of ES-SAGD process.

Furthermore, total solvent cost for each experiment was calculated. E5 showed the greatest cost and E6, the lowest. However, the higher cost of the solvent for E8 than for E6 can be compensated by the less toxicity and environmental impact of the solvent for E8 that was discussed in section 2 of this chapter. For E5, E6, and E8, the cost of consumed solvents per barrel of produced oil per day were calculated 112.3 USD/bbl*day, 98.7 USD/bbl*day, and 105.8 USD/bbl*day, respectively (Grainger Industrial Supply; Alfa Aesar - A Johnson Matthey Company). Taking into account that typically over 70% of solvent is recovered and re-injected again (Orr, 2009), the cost intensity of the solvent can be assumed equal to 33.7 USD/bbl*day, 29.6 USD/bbl*day, and 31.7 USD/bbl*day for E5, E6, and E8, respectively. Performed solvent price estimation is fair for retail prices. However, for field-scale projects solvents are purchased wholesale. So, the solvent prices for real ES-SAGD projects will be lower if compared to ones accomplished in this study.

CHAPTER IV

CONCLUSIONS

Experimental studies were performed on an oil sand sample to investigate (1) the effectiveness of SAGD process over HAGD, (2) the influence of clay composition on SAGD performance, and (3) the potency of different hydrocarbon additives to improve efficiency of SAGD process.

The following conclusions were made on the basis of the experimental study:

SAGD experiment showed the better temperature propagation within the model and higher cumulative oil recovery than HAGD that is in agreement with the previous studies and once again proves the advantage of the steam injection processes over the hot water injection processes for in-situ bitumen extraction.

Depending on the clay mineralogy some unfavorable in-situ processes, such as clay minerals swelling, migration of clay particles, wettability reversion, and bitumen residues deposition can occur. These processes can lead to impairment of the efficiency of SAGD process. Therefore, prior to implementation of any steam process, it is essential to know the reservoir lithology and the respond of the steam process to that lithology.

Co-injection of hydrocarbon solvents with steam improves the performance of SAGD process in terms of oil production, energy and water consumption, and oil upgrading. Experimental results indicates that ES-SAGD process has environmental and economic benefits over base SAGD.

Co-injection of n-hexane alone induced in-situ asphaltene precipitation that was observed from the postmortem sample. However, asphaltene deposition did not cause deterioration in oil production rate. Moreover, in comparison with base SAGD, slight improvement of oil recovery factor and reduction of energy consumption were observed.

Conjunction of n-hexane and toluene demonstrated superiorly efficiency in comparison with co-injection of n-hexane alone. It should be also mentioned, that continuous and cyclic co-injection of n-hexane and toluene showed nearly the same performance in terms of oil production, WOR, and energy consumption. But cyclic solvents co-injection process was determined as a less toxic and more environmentally friendly technique.

However, some solvents can cause undesirable effects due to the asphaltene destabilization and precipitation in production line or transportation facility. It confirms the importance of the proper selection of the solvent type, solvent concentration and solvent injection strategy for ES-SAGD process.

NOMENCLATURE

OOIP	Original Oil In Place
SAGD	Steam Assisted Gravity Drainage
EOR	Enhanced Oil Recovery
SF	Steam Flooding
SOR	Steam to Oil Ratio
GHG	Greenhouse Gas
NCG	Non-Condensable Gases
ES-SAGD	Expanding Solvent SAGD
SA-SAGD	Solvent-Aided SAGD
SAP	Solvent Aided Process
PRISP	Peace River In Situ Project
SG	Steam Generator
CSS	Cyclic Steam Stimulation
VAPEX	Vapor Extraction
HAGD	Hot water Assisted Gravity Drainage
XRD	X-Ray Diffraction
WOR	Water to Oil Ratio
m_{rg}	mass of recovered gases, g
m_{sp}	mass of packed oil sand sample, g
m_{wi}	mass of injected water, g

m_{si}	mass of injected solvent (applicable for E5-E8), g
m_{lr}	mass of recovered liquid, g
m_{pr}	mass of postmortem sample, g
E	energy consumption due to water heating/steam generation processes per barrel of produced oil, GJ/bbl
P_I	power of the steam generator heater, W
n	the number of heaters
t	total experimental time, s
Q	cumulative oil recovery, bbl

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APPENDIX A

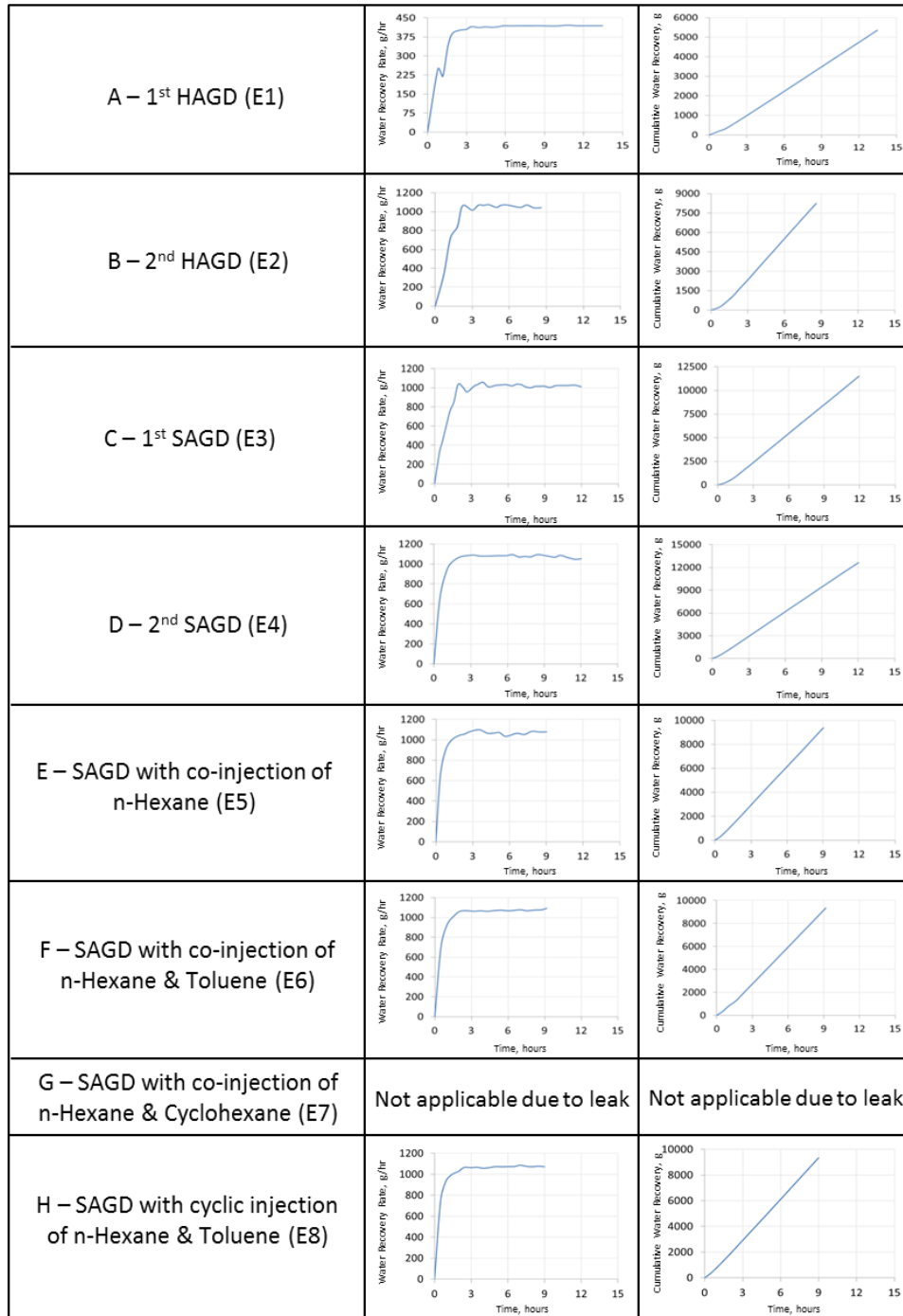


Figure 24. Water recovery performance