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Comparison of CSS and SAGD in Cold Lake

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Comparison of CSS and SAGD in Cold Lake

By

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ABSTRACT

Several methods are being used to recover buried heavy oil or bitumen deposits within oil-sands reservoirs. Cyclic Steam Stimulation (CSS) has been a commercial recovery process since the mid 1980's in the Cold Lake area in northeast Alberta. Also, Several Steam-Assisted Gravity Drainage (SAGD) projects are in operation in different types of reservoirs in the Cold Lake area. There is a debate over whether CSS is more efficient in the Cold Lake reservoirs or SAGD. It is very important for producers to know broadly about the performance and efficiency of the oil recovery process. This helps them to select the proper recovery process.

The main objective of this study was aimed to review and compare the performance and efficiency of the CSS and SAGD processes in Cold Lake area. In the current survey, the field data gathered since the start of the operation until almost the present time and the performance comparison were carried out based on the acquired data. Then two robust models were built using CMG-STARS for both CSS and SAGD processes. In both models, averaged reservoir properties that represent mean values of Cold Lake reservoir was incorporated. The production profile of both processes were history matched and the validity of the models confirmed through sensitivity studies. The performance indicators such as cumulative steam oil ratio, recovery factor and cumulative produced oil values were obtained from the models and compared. Finally, sensitivity scenarios were performed on both models to evaluate and compare the performance of each reservoir under different recovery mechanism.

AKNOWLEDGEMENTS

DEDICATION

This is dedicated to my dearest wife Narges for her endless love support and encouragement, to my wonderful daughter Tina and to my great friend Mohammad Tavallali.

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LIST OF SYMBOLS, ABBREVIATIONS AND NOMENCLATURE

Symbol	Definition
cP	Centipoises
cSOR	Cumulative Steam Oil Ratio
CNRL	Canadian Natural Resources Limited
CSS	Cyclic Steam Stimulation
ERCB	Energy Recourses and Conservation Board
h	height
k	Effective permeability to the flow of oil
k_{rw}	Water relative permeability
k_{row}	Oil relative permeability in the Oil-Water System
k_{rg}	Gas relative permeability
k_{rog}	Oil relative permeability in the Gas-Oil System
Kv1	First coefficient for Gas-Liquid K-Value correlation
Kv5	Fifth coefficient for Gas-Liquid K-Value correlation
L	Length of horizontal well
OOIP	Original Oil in Place
PVT	Pressure, Volume, Temperature
RF	Recovery Factor
SAGD	Steam Assisted Gravity Drainage
Sl	Liquid Saturation
S_{oi}	Initial Oil Saturation
Sgr	Residual gas saturation
Sw	Water saturation
TVD	True Vertical Depth
UTF	Underground Test Facility
ΔSo	Oil saturation change
fr	Residual Dilation Fraction
Pdila	Dilation Pressure

Greek Symbols

μ	Viscosity
φ_{max}	Maximum void porosity

CHAPTER 1 INTRODUCTION

The Province of Alberta in Western Canada hosts one of the world's largest petroleum accumulations. According to Alberta Energy Regulator (AER) report of 2005, the initial volume in-place of Alberta is approximately equal to 279 billion m^3 (1.7 trillion barrels); about 12% of the total known global oil reserves are hosted in the province of Alberta. This volume of petroleum resource puts Canada in the third position of countries with the largest total oil reserves in the world after Saudi Arabia and Venezuela.

In Alberta, crude extra heavy oil, also referred to as bitumen, resources are contained in both clastic (sand) and carbonate formations. The three designated Oil Sand Areas, displayed in Figure 1-1, in Alberta are the Athabasca, Peace River, and Cold Lake deposits. Within these oil sands areas, there are fifteen Oil Sand Deposits each with their own specific geological zones. The three largest oil sand accumulations are the Athabasca Wabiskaw-McMurray, Cold Lake Clearwater, and Peace River Bluesky-Gething deposits. Table 1-1 lists estimates for the initial crude bitumen volumes in place in Alberta.

Figure 1-1 Bitumen and heavy oil deposits of Alberta [1].

Table 1-1 Initial in-place volumes of crude bitumen in Alberta as of December 2013 [2].

Oil Sands Area	Initial Volume in-place (10^6 m³)
Athabasca	206,400
Cold Lake	31,900
Peace River	20,500

The key technical issue that confronts production from these deposits is the viscosity of the oil at original reservoir conditions. For many of these reservoirs, the original temperature is equal to about 10°C and the viscosity of the oil is of order of hundreds of thousands to millions of cP. Thus, this oil is largely immobile at original reservoir conditions.

1.1 Oil Sands

Oil sand is a mixture of clay, sand or other minerals with bitumen and water which exists by nature and without artificial aid. It is a tremendously viscous oil that cannot be used directly and must be treated to be usable as gasoline and diesel and other useful fuels [3].
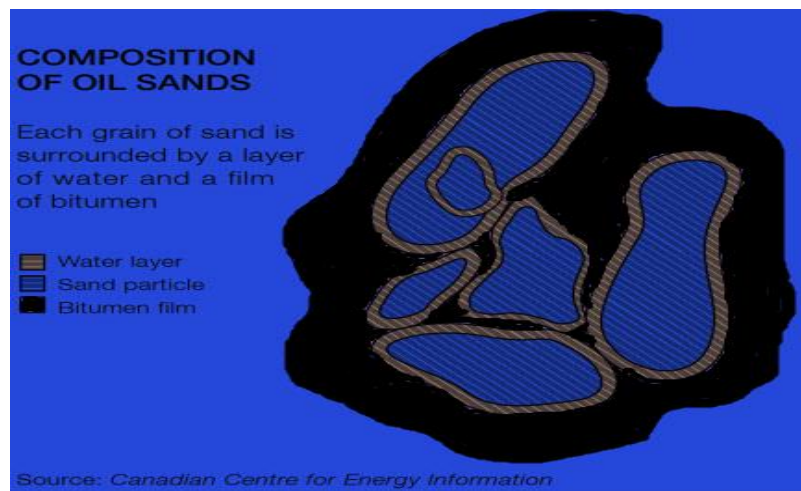
Figure 1-2 Composition of oil sands [3].

A typical oil-rich oil sand contains 80-85 mass percent sand and other minerals, 5-10 mass percent water, and 1-18 mass percent crude bitumen [4]. The oil sand is unconsolidated and if brought to room conditions, it falls apart – at reservoir conditions, which typically ranges from 5 to 15°C, the viscosity of the bitumen is in the hundreds of thousands to millions of cP and thus

the oil sand may act to some extent like a solid with the bitumen itself cementing the oil sand together [5].

1.2 Bitumen Production from Oil Sands Formations

In Alberta, conventional crude oil production in 2011 was equal to 77,900 m^3/day (490,000 bbl/day). In that year, Alberta produced 28.4 million m^3 (179 million barrels) of conventional crude oil. For oil sands production, in 2011, Alberta produced 101.2 million m^3 (637 million barrels) for an average of 277.2 thousand m^3/day (1.7 million bbl/day) of raw crude bitumen. Figure 1-3 shows the annual in situ bitumen production and the number of bitumen wells on production in Alberta since 1991. The data shows that bitumen production and number of producing oil sands wells in Alberta has increased dramatically over the past 20 years.
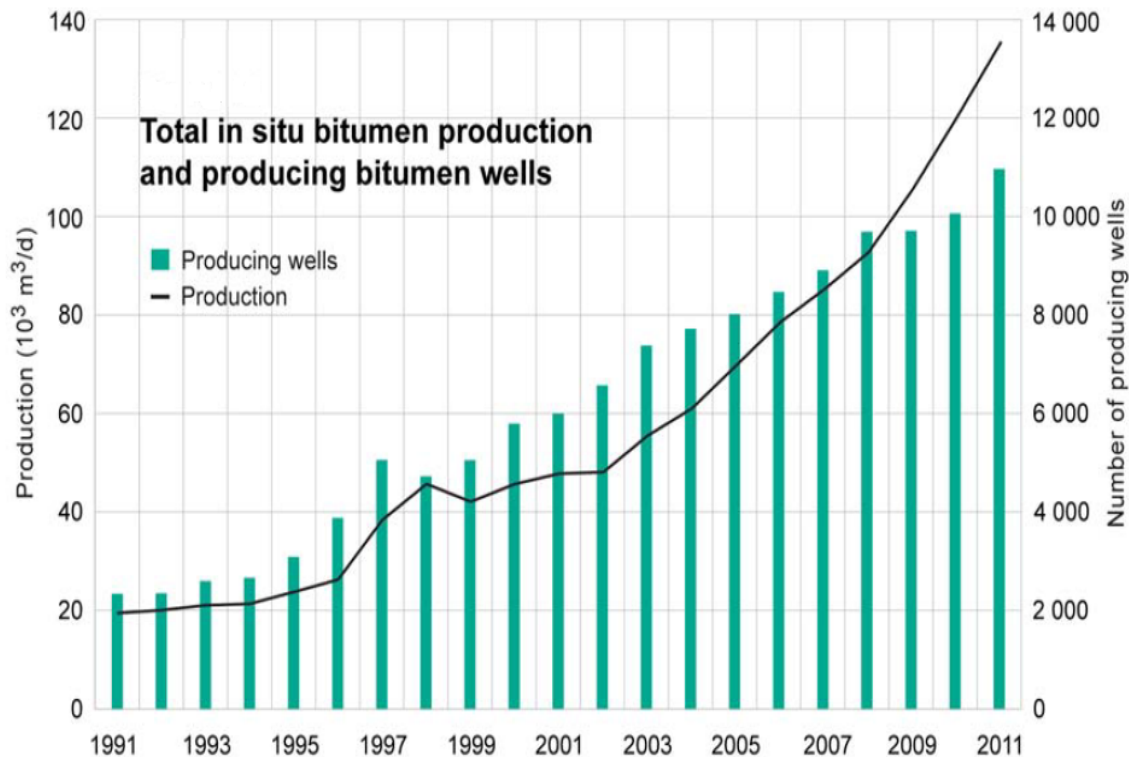
Figure 1-3 Evolution of Alberta bitumen production and number of production wells during 1991-2011 [6].

Historical in situ production from Alberta's oil sands is shown Figure 1.4. Athabasca, Cold Lake, and Peace River oil sands each produced 67.7x10^3 m^3/day 61.2x10^3 m^3/day, and 6.5x10^3 m^3/day, respectively in 2011. The annual production growth rates of production from the

Athabasca deposit were steeper than Cold Lake in 2011. In Figure 1-4, significant increases in production within the Athabasca area since 2002 are due to SAGD developments. Currently, there are three main methods for producing in situ bitumen: primary production, CSS, and SAGD. The In situ bitumen production recovery using different methods for the period of 2001-2011 has been shown in Figure 1-5. As it can be seen, in 2011, 31 per cent of in situ production was recovered by CSS, 44 per cent by SAGD, and 25 per cent by primary schemes. The trends suggest that major growth of oil sands production will occur from the Athabasca deposit.
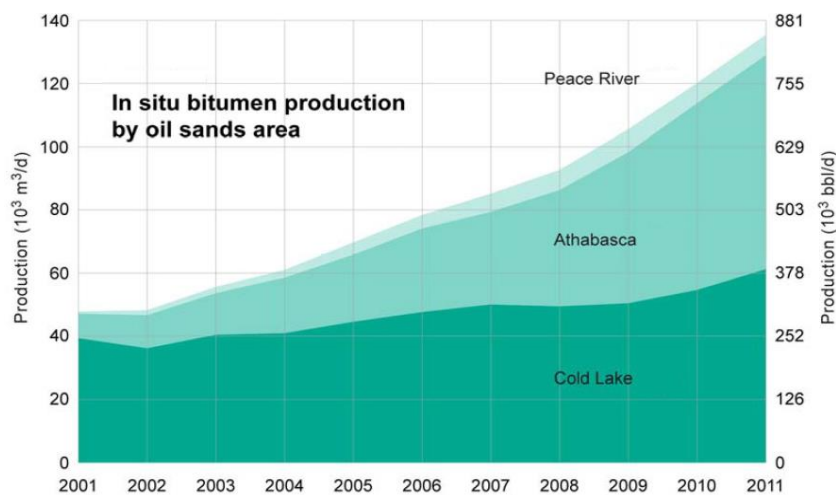
Figure 1-4 Historical in situ production from Alberta's oil sands (By Oil Sand Area) [6].
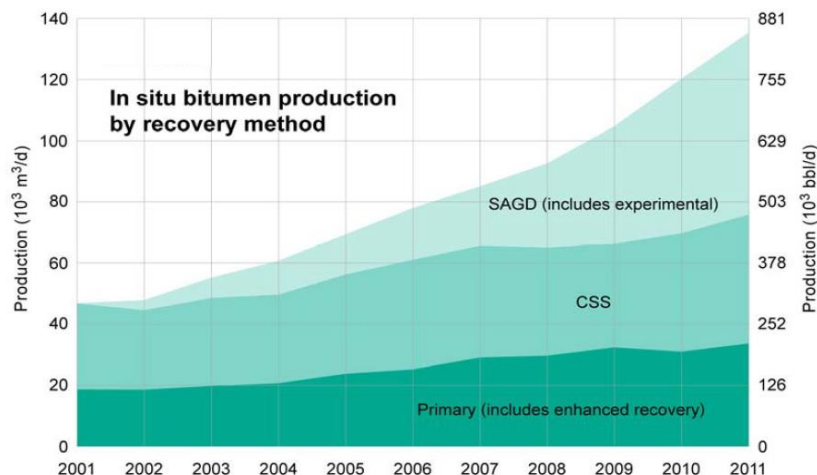
Figure 1-5 Historical in situ production from Alberta's oil sands (by recovery method) [6].

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1.3 Brief Geological Description of the Cold Lake Oil Sands Deposit

The Cold Lake oil sands deposit is located east of Alberta's capital, Edmonton, near Alberta's border with Saskatchewan. The Cold Lake deposit covers a surface are equal to about 6,500 km^2. Cold Lake is the second largest deposit of oil sand in Canada and contains 20×10^9 m^3 (125 billion barrels) of heavy oil in place. Most of the bitumen deposits in this area are found within the sands of the lower cretaceous Clearwater interval [7, 8].

The Cold Lake heavy oil and oil sands deposit is located in the Mannville Group and consists of the Grand Rapids, Clearwater and McMurray Formations. At Cold Lake, oil sands reserves mostly belong to the Grand Rapids and Clearwater Formations. The average thickness of Mannville Formation in this area is equal to about 210 m. The lower Mannville has an average thickness of 60 m and consists largely of the McMurray formation. The Clearwater Formation and the lower and upper Grand Rapids form the upper Mannville unit. The Clearwater Formation consists of highly saturated oil sand with the average thickness of about 50 m starting from a depth of 425-450 m below the surface. The Clearwater Formation is most abundant reservoir in this area and contains about half of the oil in place in the Cold Lake deposit.

The average thickness of the Lower Grand Rapids is 50 m. It is mostly comprised of thin shale sands. In comparison to the Clearwater Formation, the oil accumulation is more variable. The average thickness of Upper Grand Rapids is 50 m and like the Lower Grand Rapids, it contains interbedded thin shale sands but the oil content is even more variable than the Upper Grand Rapids Formation and the upper layer sand in some areas contains gas [9].

There are five types of reservoir in the Cold Lake deposit. Type 1 consists of a thin lentoid shaped oil sands layer along with a gas layer on top and a water layer on the bottom. Due to thinness of the oil layer and the existence of gas and water layers, this layer is not a good candidate for steam injection. Type 2 contains thin sheets of stacked oil sands with, in many cases, water zones below the oil sands. When there is no underlying water, this type of reservoir is more attractive than Type 1. In Type 3, there is a thick oil column, but there are significant amounts of water under the oil sand. The thick oil zone is a benefit but the large amount of water creates a heat sink which is detrimental for a steam based recovery process. Type 4 reservoirs typically consist of a thick continuous column of oil. In some parts there may be a bottom water zone. This type of reservoir is the best candidate for steam based recovery procedures. Areas

with a thick water layer create challenges for steam-based recovery methods. To evaluate the potential for in-situ processes, the thickness of the oil zone and the extent of water amount underneath the oil and the degree of vertical continuity and permeability should be considered. In Type 5 reservoirs, there exist thin oil sands intervals with limited areal extent with in some cases, bottom water zones. [10]

1.4 Brief Geological Description of the Athabasca Oil Sands Deposit

The Athabasca oil sands is a North-South ellipse shaped, centered around 15 km south of Ft. McMurray and is the largest accumulation of petroleum in the world. The physical reservoir characteristics such as porosity and permeability are dramatically heterogeneous. Most of the deposits are located in McMurray Formation. The thickness of this formation in some areas are up to 150 m and has consist of a layer of sandstone, shale, and oil-saturated sands formed during the Cretaceous period by river and ocean. McMurray Formation is located under the Clearwater Formation, and lies over a layer of shale and limestone. The Clearwater Formation is a layer of marine shale and sandstone and is located under the Grand Rapids Formation. [11].
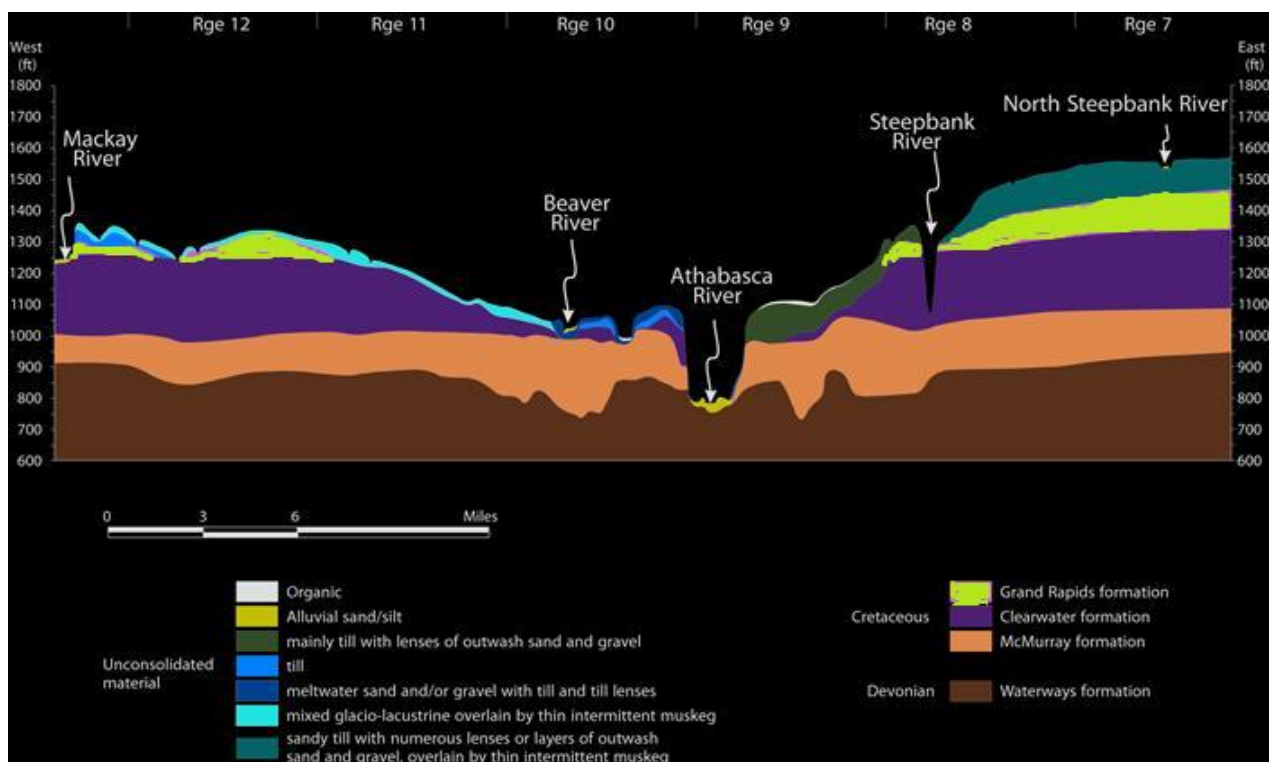
Figure 1-6 East-West geological cross-section of the Athabasca oil sands region [11].

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1.5 Comparison of Mineralogy and Rock Properties for Cold Lake and Athabasca

A comparison of the mineralogy between the Cold Lake and Athabasca oil sands deposits, listed in Table 1-2, demonstrates that they are different. Oil sands from the Athabasca deposit is dominated by quartz whereas the Cold Lake oil sand consists of nearly equal amounts of quartz, feldspar, volcanics, and chert.

Mineralogical analysis was conducted by a number of workers to assess in situ technologies for the recovery of bitumen from Cold Lake. As shown in Table 1-2, the porosities of the Cold Lake and Athabasca deposits are comparable but the horizontal permeabilities are quite different. In general, the permeability of the McMurray Formation is higher than that of the Clearwater Formation.

Table 1-2 Grain composition and rock properties [7, 12].

	Cold Lake Deposit, Clearwater Formation	Athabasca Deposit, McMurray Formation
Quartz	21	93
Feldspar	28	5
Volcanics	23	0
Chert	20	1
Argillite	3	0
Metasediments	5	1
Average Porosity	0.35	0.33
Average Permeability , Md	0.32	4

1.6 Fluid Properties

A comparison of the oil properties from the Clearwater and McMurray Formations is presented in Table 1-3.

Table 1-3 Fluid Properties of Clearwater and McMurray Formations [7, 12, and 13].

	Property	Cold Lake Clearwater Fm.	Athabasca McMurray Fm.
Formation Bitumen	Oil Saturation	0.70	0.80
	Water-oil interfacial tension, mN/m	27.1-29	2-12
	Average density, kg/m^3	998	970
	Viscosity @Reservoir Temp., cP	100,000	>100,000
	Viscosity @200°C, cP	10	12
	Pour Point, °C	10	--
	Percent Sulphur	4.5	4.41-5.44
Solution Gas	Gas-to-Oil Ratio, m^3/m^3	9.8	--
	Composition	>99% Methane	--
Formation Water	Average Salinity, ppm	15,500	4000-30000

1.7 Recovery Techniques

Extraction of crude oil from underground is called oil recovery. In situ recovery is the process of oil extraction from too deep buried deposits. In the Cold Lake area, most in situ bitumen production pertains to the deposits buried more than 400 meters below the surface. Currently two basic methods are used to produce oil in the oil sands area

- Primary recovery –Cold Heavy Oil Production with Sand (CHOPS) and Cold Heavy Oil production without sands.
- Thermal recovery methods:
    - Cyclic Steam Stimulation (CSS)
    - Steam-Assisted Gravity Drainage (SAGD)
    - Toe-to-Heal-Air-Injection (THAI) [14]

1.7.1 Primary Recovery

Conventional methods for heavy oil extraction is not very efficient. CHOPS technology with sand has proven to be very effective and ten times more oil can be obtained. In CHOPS, huge amounts of sand will be produced. If the separation process of oil, water and sand is done on the surface, heavy oil production is more costly and more pollutant will be released to air, water and soil. The problem can be solved by introducing the product to the salt covens below the

reservoir. By the density difference all the three components will be separated. Oil and water pump out separately.

In the late 1920's, heavy crude oil with high asphaltenes content was produced with the aid of reciprocating pumps. The normal production rate at that time was limited to 10-15 b/d and reservoir extraction efficiency was in the range of 5-8% Original Oil in Place (OOIP). Operators soon found out that wells that produce sand along with heavy oil tended to be better oil producers. They realized that they can separate the sand and most of the water before shipping. The operators spread the sand on local gravel roads.

The development of progressing cavity (PC) pumps in late 1980s along with the increasing oil price in the period 1973-1983 improved non-thermal heavy oil production process in Canada. The first generation of PC pumps was not cost effective but soon in the 1990s they were accepted globally because of longer life and less operating problems.

Currently, there are several primary recovery projects under operation in the southern parts of the Cold Lake and Athabasca (Wabasca) Oil Sands Areas. CHOPS is still developing rapidly. More improved methods with the aid of development of new technologies such as improved sand disposal methods and combination of improved recovery technologies along with CHOPS are being implemented [15].

1.7.2 Thermal Recovery

The viscous nature of the bitumen does not allow it to flow under normal reservoir pressure and temperature conditions. Numerous in situ technologies have been developed that are known as thermal methods. Thermal oil recovery, either by heat injection or internally generated heat through combustion, introduces heat into the reservoir to reduce the flow resistance by reduction of the bitumen viscosity with increased temperature. As a result, the heated oil can flow towards the well bore. Thermal methods include steam flooding, cyclic steam stimulation, in-situ combustion, electric heating, and steam assisted gravity drainage.

The most common thermal methods consist of steam injection into the oil sands deposit using either steam assisted gravity drainage (SAGD) or cyclic steam stimulation (CSS) recovery technology. Hot steam is injected into the oil sands zone through vertical, deviated or horizontal wells. Bitumen is heated and its viscosity reduces, and is able it to move toward producing wells where it can be brought to the surface using pumps, reservoir pressure or gas lift.

1.7.2.1 Cyclic Steam Stimulation (CSS)

Imperial Oil made a CSS pilot plant unit in 1965 and eventually in 1985, this process was used at commercial scale.

As shown in Figure 1-7, in CSS, high-pressure and high-temperature steam is injected into the well until the targeted volume of steam is injected into the reservoir. If the steam pressure is high enough, it fractures the reservoir. After the steam injection period is done, the well is shut in in what is referred to as the soak period. This permits further heating of the reservoir in the neighbourhood of the well. The heat transfers from the steam to neighboring layers and lowers the steam zone temperature. The soak period is usually limited to about one week to prevent steam zone temperature becoming too low. Finally, in the production phase the mobilized bitumen flows to the surface either under its own pressure or by pump. The cycle is repeated several times until the recovery falls below an economic limit.

The volume of the steam zone increases after each cycle and more heat is transferred to the oil zone which decreases the thermal efficiency of the process due to increased heat losses to the cap rock.

Normally, the cyclic steam injection process is capable to recover to up to a maximum of about 25% of the original oil-in-place (OOIP).

STAGE 3
PRODUCTION
Heated oil and water are pumped to the surface.

STAGE 2
SOAK PHASE
Steam and condensed water heat the viscous oil.
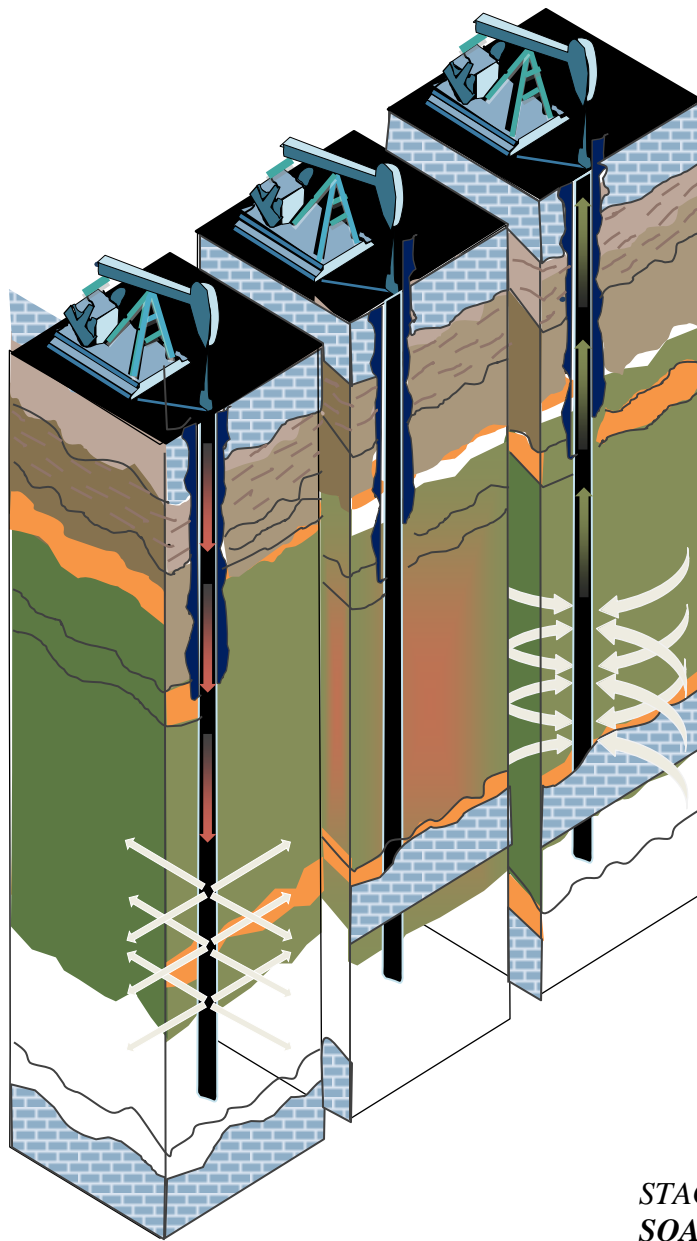
STAGE 1
STEAM INJECTION
Steam is injected into the reservoir.

Figure 1-7 Stages of a CSS process [16].

1.7.2.2 Steam-Assisted Gravity Drainage (SAGD)

In the late 1970s and early 1980s, the concept of application of continuous heating and production, was developed by Rodger Butler (1979). In this process, called Steam-Assisted Gravity Drainage (SAGD), depicted in Figure 1-8, two parallel horizontal oil wells are drilled in the formation. One of the wells is located about 4-6 meters above another one. Steam is injected from the upper well and the heated bitumen or crude oil is collected from the lower one. Along the lower well bitumen and water from condensation of injected steam are produced out of the formation. In this process the injected steam forms a steam chamber which grows horizontally and vertically within the reservoir. The viscosity of the bitumen is reduced due to heat transfer from steam to bitumen, which allows it to flow downward into the producer wellbore. The density of the steam and gases is lower than the density of bitumen, so they move upward and fill the void space created from the produced oil. The bitumen and condensed steam are recovered to the surface by progressive cavity pumps [17].
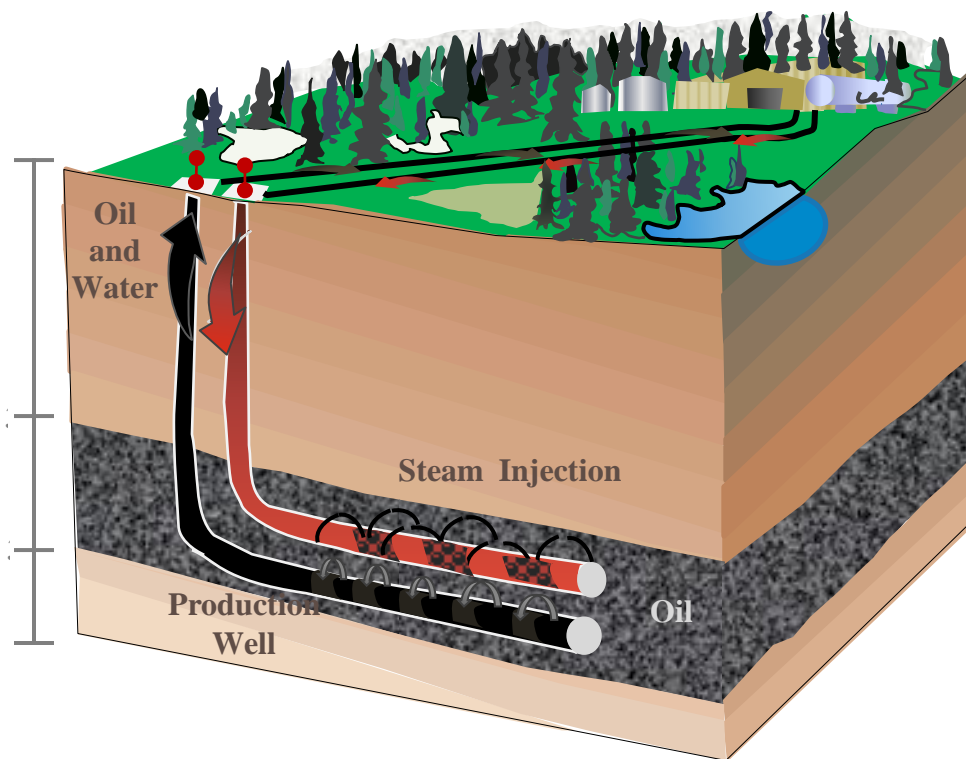
Figure 1-8 Schematic of a SAGD process [17].

1.7.2.3 Toe-to-Heel-Air-Injection (THAI)

THAI was been developed by Dr. Greaves at the Univeristy of Bath. This method, illustrated schematically in Figure 1-9, is a combustion process and uses a vertical air injection well along with a horizontal production well. At first steam is injected through the vertical injector for the first three months to heat the reservoir between the vertical and horizontal wells. Then air is injected in the vertical well and combustion is created and part of the oil in the reservoir is burned which generates heat. The heat release reduces the viscosity of the oil and allows it to flow by gravity to the horizontal producing well[18]. The combustion reaction creates hot gases which move from the injection well (toe) to the producing well (heel). The pressure of the injected air pushes the hot gases towards the heel of the horizontal well and causes more of the heavier oil component to burn. The produced heat lowers the viscosity of the oil which enables gravity drainage to the horizontal well. This technology potentially could use less energy partially upgraded oil product. In comparison with other in-situ methods, there is potential that the GHG emissions associated with THAI are about 50% less and water usage is relatively low compared to steam-based recovery processes such as CSS and SAGD [19].
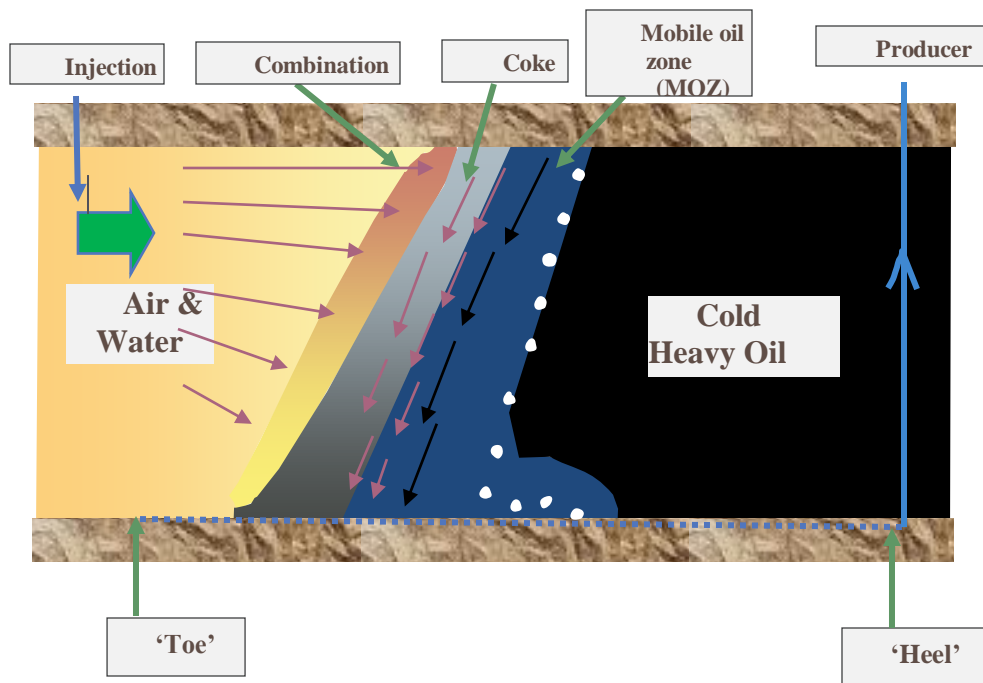
Figure 1-9 Schematic of a THAI process [18].

1.8 Research Questions

The research questions that are examined in the research documented in this thesis are as follows:

1. What is the performance of SAGD in Cold Lake relative to CSS?
2. What accounts, both mechanisms and reservoir features, for the difference of the performance between the two processes?
3. What process changes are required to enhance the performance of SAGD in Cold Lake compared to its performance in Athabasca deposits?

1.9 Thesis Outline

This thesis consists of four additional chapters which are described as follows:

Chapter Two: In the first part of this chapter, a literature review on past comparisons of CSS and SAGD in Cold Lake is described. In the second part, a summary of the most recent available data from Alberta oil sands, in particular the Cold Lake deposit, are reviewed. In addition, a review of the physics, geo-mechanics, three phase phenomena, field practice and well/completion design of both CSS and SAGD for the Clearwater Formation is presented.

Chapter Three: In this chapter, field CSS and SAGD data have been compared and analyzed in depth.

Chapter Four: In this chapter, simulation results for SAGD and CSS methods have been compared and analyzed to deduce the mechanistic differences between the two processes.

Chapter Five: The major conclusions and recommendations based on the research documented in the preceding chapters are listed.

CHAPTER 2 LITERATURE REVIEW

2.1 Literature review

Over time, many thermal processes such as steam flooding, Steam Assisted Gravity Drainage (SAGD). In-situ combustion, and Cyclic Steam Stimulation (CSS) have been field and laboratory tested and even field pilot experimented to establish the most economical method for bitumen extraction in Cold Lake area. Among them Cyclic Steam Stimulation has been found beneficial to be used as a commercial recovery process. This method has been used successfully since the mid 1980's in the Cold Lake area. Currently over 220,000 bbl/d bitumen is produced by this method in this area.

In more recent years, the Steam Assisted Gravity Drainage (SAGD) has passed successfully the field tests. It has been used commercially in the Cold Lake area.

Farouq Ali [44, 45] claimed that the application of SAGD in the heavy oil fields is problematic and is not economically viable – a view that has since been proven incorrect. Batycky [46] compared the performance of CSS and SAGD in the Clearwater formation in the Cold Lake area. He obtained the field data for a CSS well and also built a SAGD model. He used the physical properties of the CSS well in his model and then compared the results. The key performance indicators that he used were produced oil rate, steam to oil ratio and ultimate recovery factor. He concluded that CSS has a better performance in all aspects.

Scott [47] from Imperial Oil compared the performance of SAGD and CSS by calculating the required amount of gas for steam generation which was used to produce one cubic meter of bitumen. He used the field data to estimate the recovery factor of both SAGD and CSS processes. It was concluded that the recovery of bitumen using SAGD mechanism in the Clear water formation at Cold Lake area is usually uneconomic.

Donnelly [48] compared the two mechanisms by using available field data of CSS and the forecasted SAGD production. The compared parameters were produced water quality, projected recovery factors, electrical power, steam requirements, and production rates. He claimed that CSS is a proven economical process and SAGD might compete favourably with CSS in the future based on predictions.

Baker [49] compared the performance of Hilda Lake and Burnt Lake projects. These are two SAGD projects in the Clear Water Formation in the Cold Lake area. He concluded that Burnt

Lake project meets the expectations. Eddie [51] claimed that CSS in shallow reservoirs without thick capping shale is not very effective. SAGD is capable to be developed in oil sand resources with bottom water zones or with extensive top gas. He also mentioned that SAGD in the reservoir with higher saturations of oil is more effective.

Jiang [52] reported that the existing CSS projects in the Cold Lake area are utilizing the reservoirs with minimum tap gas and some of the existing SAGD projects in the Cold Lake area have been established on the reservoirs with thick bottom water zones.

2.2 Cyclic Steam Stimulation (CSS)

For the first time, utilizing steam injection in sand took place in Texas in 1931. The steam was injected continuously at a depth of 380 feet in sands of 18 feet thick. Duration of injection was for only 4 hours every day for 70 days. The next injection was recorded 20 years later; in the pilot steam injection in Yorba Linda, California. The first commercial projects were performed in Schoonebeek, Holland and Tia Juana, Venezuela. Since then, steam injection has been utilized successfully in heavy oil recovery projects worldwide. The process of cyclic steam stimulation (CSS) accidentally was discovered by Shell in Venezuela in 1959 [20].

The Cyclic Steam Stimulation process (CSS) is the key thermal recovery method employed commercially in the Cold Lake area. Currently the CSS operated by Imperial oil is the leading thermal project across Canada.

2.2.1 Physics of CSS

CSS consists of three steps: 1. steam injection, 2. soaking, and 3. production. To minimize heat loss, the wellbore is placed in the vicinity of the formation base and steam is injected into the formation, typically at pressure greater than the fracture pressure, and due to gravity segregation, steam penetrates into the reservoir. As a result, the region, i.e. rock, bitumen, and water, near the wellbore is heated. After that, the soak period starts when the well is shut in for a specific period of time which is approximately one to two weeks. In this period the volume of the rock around the wellbore reaches an increased temperature. At the end of the soak period, the viscosity of the heated oil is lowered to a few centipoises. At the same time thermal expansion of both oil and water occurs. Thermal expansion of oil is greater than that of the water. In the soak period, the oil saturation increases and free gas is forced to dissolve in oil as a result of

pressurization of the reservoir. At the end of the soak period, the sand contains low viscosity oil, water and steam.

In the production stage, the fluids are expelled into the wellbore by the help of one or more of the following driving forces. Reservoir pressure (if adequate) is the driving force that helps production. Pressure of the reservoir forces the hydrocarbons to move them toward the well and force them to move upward to the surface. Gravity drainage may significantly contribute in production from thick formations. However, it depends on existence of other driving mechanisms such as solution gas drive, water drive, etc. Due to gravity, the hot oil is able to flow to the wellbore and subsequently replenishment occurs and oil flows from colder formations.
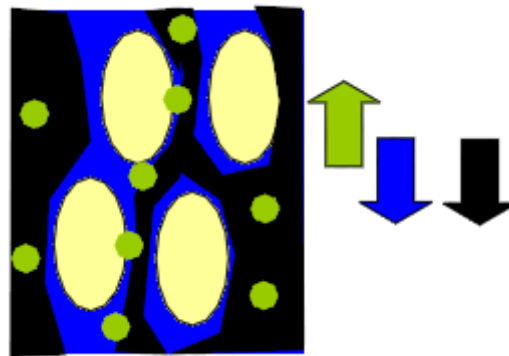
3

Figure 2-1 Gravity Drainage Mechanism [21] (Bitumen indicated as black, Water as blue, Gas as green and Sand as yellow).

As it can be seen from Figure 2-1, in gravity drainage, the gas rises and oil and water drain in the downwards direction. During production phase the reservoir pressure decreases and the dissolved natural gas in the oil expands which causes pushing additional oil to the wellbore and acts as a driving force to expel the oil from well.
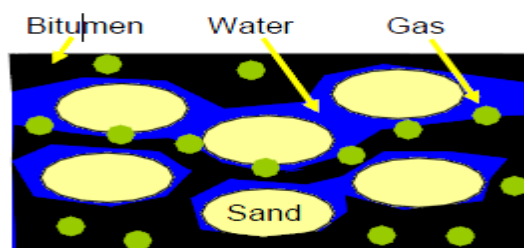
Figure 2-2 Solution gas drive mechanism [21] (Bitumen indicated as black, Water as blue, Gas as green and Sand as yellow).

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Due to injection of the steam, part of the high pressure water inside the reservoir and in the vicinity of the well bore, flashes to steam. This steam is distributed in the sand and could act as a driving force. Another mechanism is the expansion of the compressed formation fluids during steam injection. This process extremely depends on the compressibility of reservoir fluids. However, since both oil and water have small compressibility, the contribution of this mechanism to the final recovery factor is small. Another mechanism is the compaction of the reservoir rock. In recent years it has been found that reservoir compaction occurs in many reservoirs and it is a contributor towards recovery. In CSS operations surface subsidence occurs and helps as a driving force.
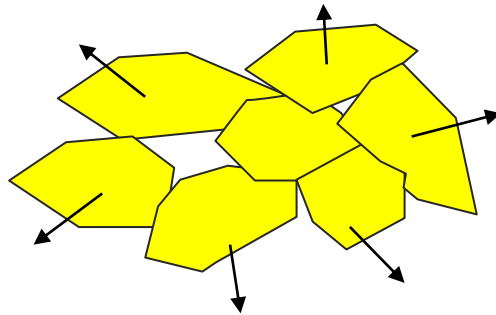
Figure 2-3 Compaction drive mechanism [21].

In an important paper, Denbina, Boberg and Rotter (1991) discussed the key drive mechanisms that occur in the CSS as operated in Cold Lake. Surprisingly, they found that formation compaction was by far the dominant producing mechanism, followed by solution gas drive. Fluid expansion was less important, and gravity drainage became important only in later cycles.

2.2.2 Geomechanics of CSS

In CSS, steam is injected in to the reservoir at high pressure ranging from 10 to 12 MPa which is usually higher than the reservoir fracture pressure. High injection pressure creates some fractures in the reservoir, and high temperature causes a substantial decrease in bitumen viscosity. Therefore a high mobility zone is formed around the wellbore and melted bitumen and condensate flows back toward the wellbore. The fracturing stage consists of dilation and re-compaction events. Beattie et al. (1991) defined a model for deformation which is presented in Figure 2-4 [22]. Every single cycle of a CSS process follows the entire deformation envelope.

The deformation model comprised of following stages: a) elastic expansion, b) dilation, c) elastic compaction, and d) re-compaction. Reservoir pressure increases with injecting of steam into the reservoir. The rock shows elastic behavior with changing pressure. The rock pore volume at the new pressure will be obtained based on the initial reservoir pressure, rock compressibility and initial porosity.
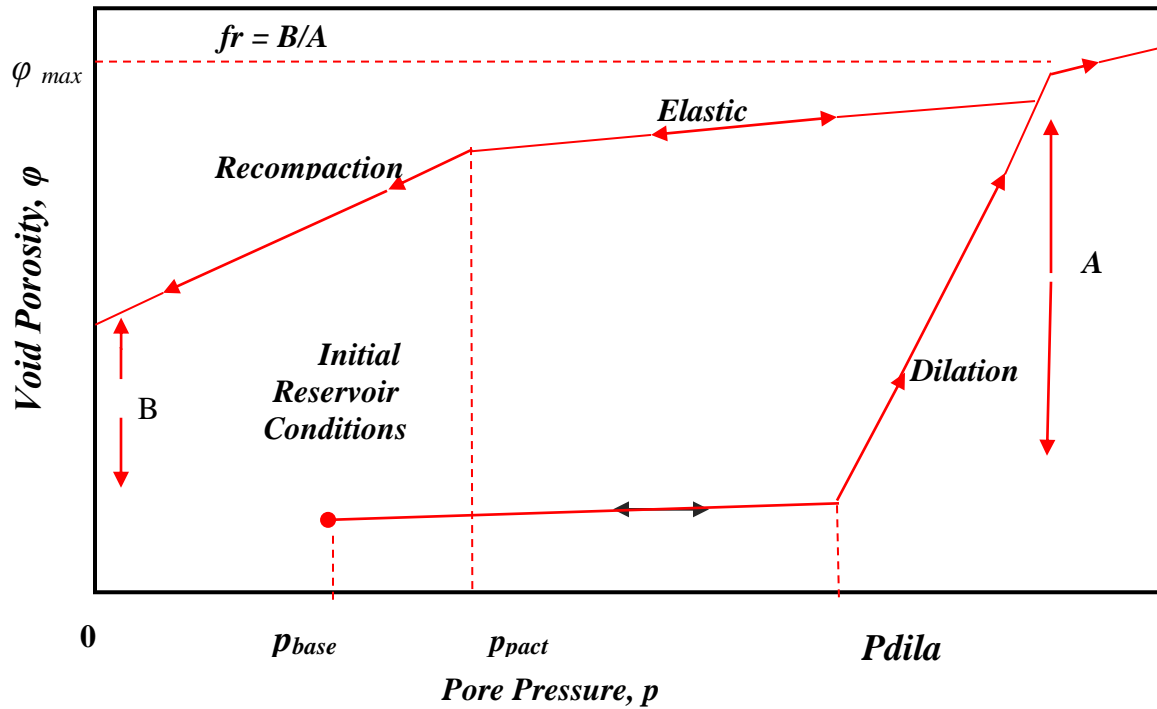
Figure 2-4 Reservoir deformation model [22].

If the reservoir pressure increases above the dilation pressure ($P_{dilation}$) in Figure 2-4, then the reservoir pore volume follows the dilation curve and is irreversible. In other words beyond the dilation pressure, the porosity increases rapidly with increasing the pressure. Steam injection is accompanied by significant dilation. Surface uplift exists in injection and surface down lift during production. Surface uplift can reach up to 45 cm during injection at Cold Lake [22]. This huge amount of uplift is too great to be considered as thermal expansion or fracture of formation due to tensile fracturing.

Re-compaction consists of two steps. In first step the change in porosity is elastic and almost no recovery of dilation happens. At this step the high-pressure steam lifts up the upper formations. In the second step the reservoir begins to recompact and pushes bitumen toward the

wellbore. The minimum porosity belongs to zero pressure. The shape of the deformation model in Figure 2-4 is consistent with the experimental observations.

Beyond φ_{max} further dilation is not possible and the compressibility value is low. Usually the dilation pressure is slightly lower than the fracture pressure. Field observation has shown that when the pressure commences to decline, re-compaction does not begin immediately.

2.2.3 Three phase phenomena in CSS

Flow regime characterization in cyclic steam stimulation operations reveals discrete and consecutive flow regimes during the production phase. Vittoratos (1991) categorized the CSS flow regimes into three distinctive steps. The first type (type I) consists of mostly free water. There might be a small amount of bitumen along with the free water. In the second type (type II) there are slugs of water in the emulsions of bitumen. In the third kind (type III) the flow is single phase comprising of water in bitumen emulsions.

In the few first cycles the mainstream of the production happens during type III flow while type II occurs slightly. With continuing production as the number of cycles rise and approaching to economic limits of the well, the amount of water in the emulsion increases and reaches to about 50% and the flow type changes to type II. Production according to type II yields declined OSR and increases WOR.

In early cycles the time allocated to flow types I and II are short and most of the cycles is type III. Water content of the emulsion is in the range of 15-25% in type III during early cycles. In cycle three, the flow regime of type II becomes longer and the water content is in the range of 40-50%. In cycles 6 to 8, the dominant regime is type I which might last to several months and the remainder of the cycle consists of flow type II and a small amount of type III [23].

2.2.4 Field practice

There are currently two commercial CSS projects in Cold Lake which are CNRL Primrose and Imperial Oil Cold Lake. AMOCO started CSS steaming operations in February 1995. Amoco used horizontal wells and slightly below fracture pressure steam injection. To enhance initial steam injectivity, the horizontal wells produced on primary for a period of up to six months. In 1999, CNRL acquired Primrose from Amoco. CNRL's Primrose project is located North of Imperial Oil's Cold Lake Primrose from Amoco. CNRL's Primrose project is located at North of Imperial Oil's

Cold Lake operation and obtains oil from the Clearwater formation. In 1998, Amoco commenced a single well in Primrose. Later in 2001, Amoco converted it to CSS. Reservoir and also fluid properties are similar to that of Imperial Oil's Cold Lake resource. The injection pressure is the fracture pressure of the reservoir and the wells are horizontals. In this area, the well lengths are in the range of 600-1200 meters and well spacing is from 60 to 188 meters.

The average Primrose Clearwater reservoir characteristics have been mentioned below [40]

Oil saturation: 0.6

Bitumen weight: 9%

Pay thickness: 11m

Porosity: 32%

Horizontal permeability: 3,000mD

Vertical permeability: 900mD

Viscosity: 100,000cP (at 15oC)

The average performance of Primrose has shown in Figure 2-5
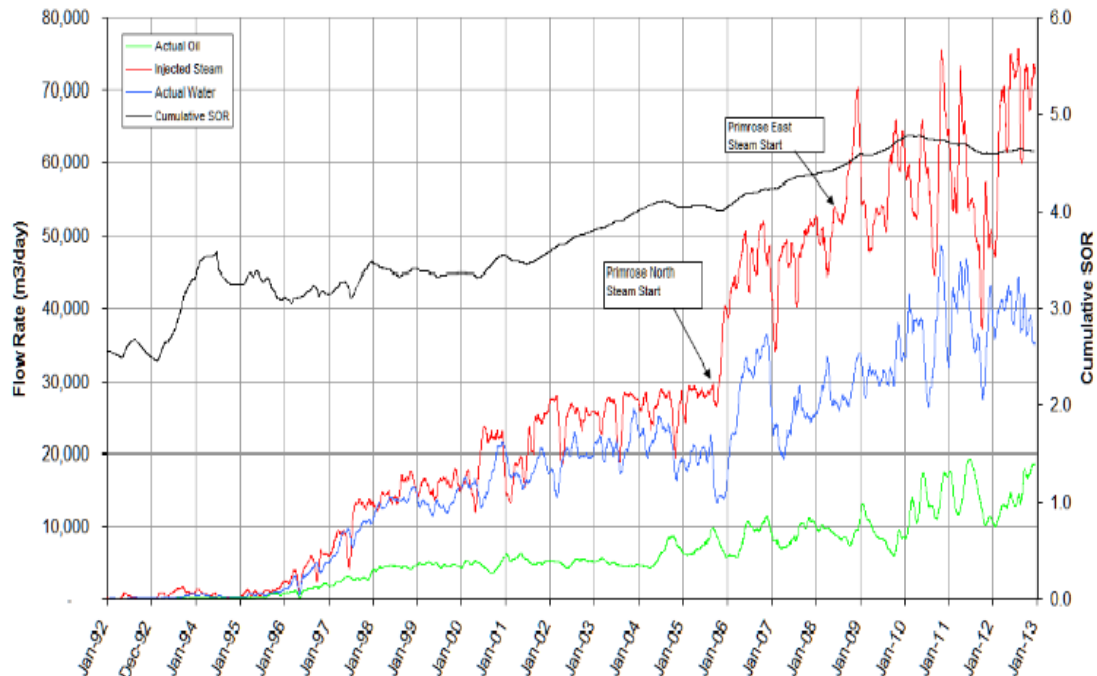
Figure 2-5 Average performance of Primrose field [40].

The Imperial Oil Cold Lake Production Phase (CLPP) project began steaming operations of phases 1 and 2 in 1985. The expansion of phases 3 and 4 of the CLPP project were carried out in 1985. The next expansion project happened in 1986 for Phases 5 and 6. Phases 7 to 10 expanded in 1988, and in 2002 Phases 11 to 13 (Mahkeses) expanded [24]. Imperial Oil operates one of the largest in-situ projects, the development history of cold lake is summarized as below:

Lease acquisition small scale research pilots   60's-70's

10 kbd commercial pilot   1975

Phase 1-10 (Maskwa and Mahihkan)   '85-'94

Phase 11-13 Mahkeses (Cogeneration facility)   2002

Approval area expanded (Nabiye, Mahihkan North)   2004

Fig 2-6 shows developed pad of CSS in Cold Lake area.
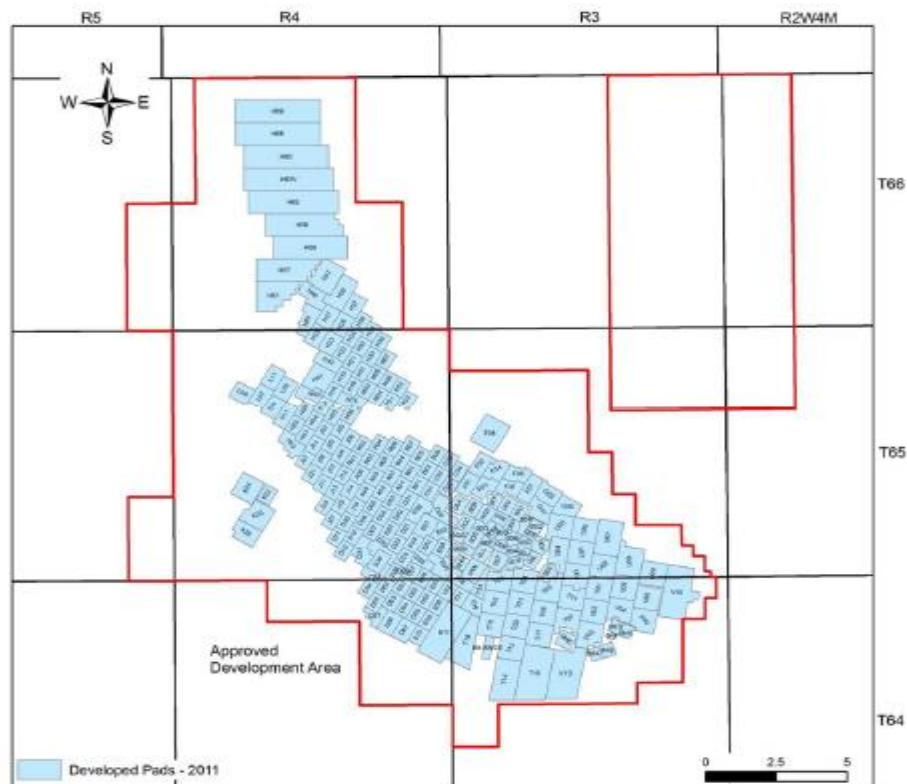
Figure 2-6 Developed CSS pads in Imperial Oil's Cold Lake project [24].

Average reservoir properties for Imperial Oil Cold Lake has been mentioned below. [24]

Depth: Clearwater @ 400m

Sands: Unconsolidated, reactive, clay clasts

Diagenetic Cements: Mixed-layer clays

Bitumen API Gravity: 10.2

Bitumen Viscosity: 100,000 cp @ 13 C

    8 cp @ 200C

Bitumen Saturation: 70% (Average)

Porosity: 27 - 35 % (Range), 32% (Average)

Permeability: 1 - 4 Darcies (Range), 1.5 Darcies (Average)

Bitumen Wt.: % 6 - 14 % (Range) 10.5% (Average)

Total Net Pay: 12 - 60m (Range) 30m (Average)

Cold Lake Imperial Oil production performance has been shown in Figure 2-7
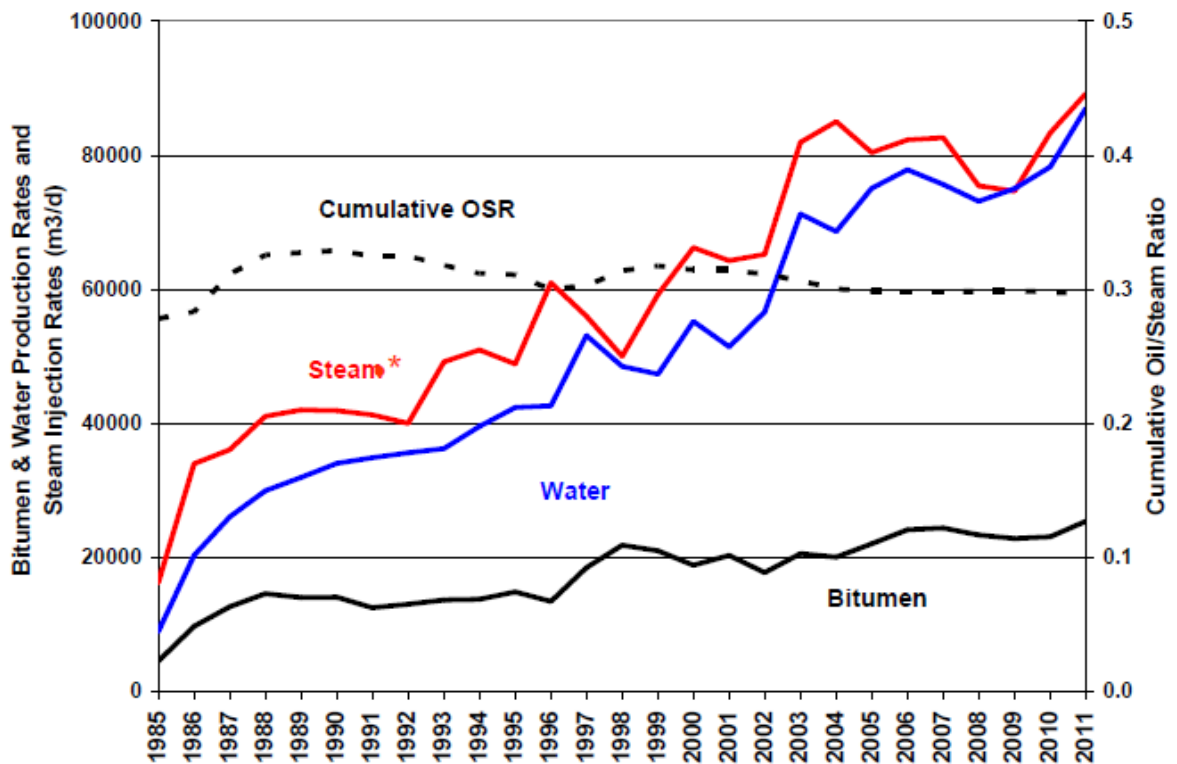
Figure 2-7 Cold Lake Imperial Oil production performance [24].

Due to the improved development economics and increased operational efficiencies, completion of the wells has been done directionally from central lease location. Original pad design consisted of 20 wells on 4 acre spacing, but current pad design could be up to 35 wells on 4 or 8 acre spacing. Also combination of deviated and horizontal wells is being completed.

At Cold Lake currently 150,000 bbl/d of 100,000 cP oil is produced using 4,000 wells by CSS procedure. At injection stage the steam pressure is high enough to facilitate the penetration into the reservoir and also to be able to heat the bitumen. In production stage, the heated oil is being produced as a result of increased reservoir pressure. However, as time proceeds, the reservoir pressure drops and oil has to be produced with the help of rod pumps.

At Cold Lake a typical cycle consists of 10% calendar days for steam injection, 10% for soak and 80% for production stage. This process is repeated multiple times.

For large scale commercial CSS projects highly ordered steam strategy is used. In dealing with a single well process, it would be immaterial which steaming strategy was adopted. However, from operation point of view such as the steam generation capacity and the steam distribution system layout, the use of ordered patterns is more energy efficient and also more convenient. Well servicing and also steam scheduling are simplified. Therefore, there is a tendency to perform the operations toward certain ordered steaming patterns. At Cold Lake an overlapping row steaming pattern is used and this procedure is a key innovation in the CSS operations. By this procedure steam is allowed to sweep across the field. [25]
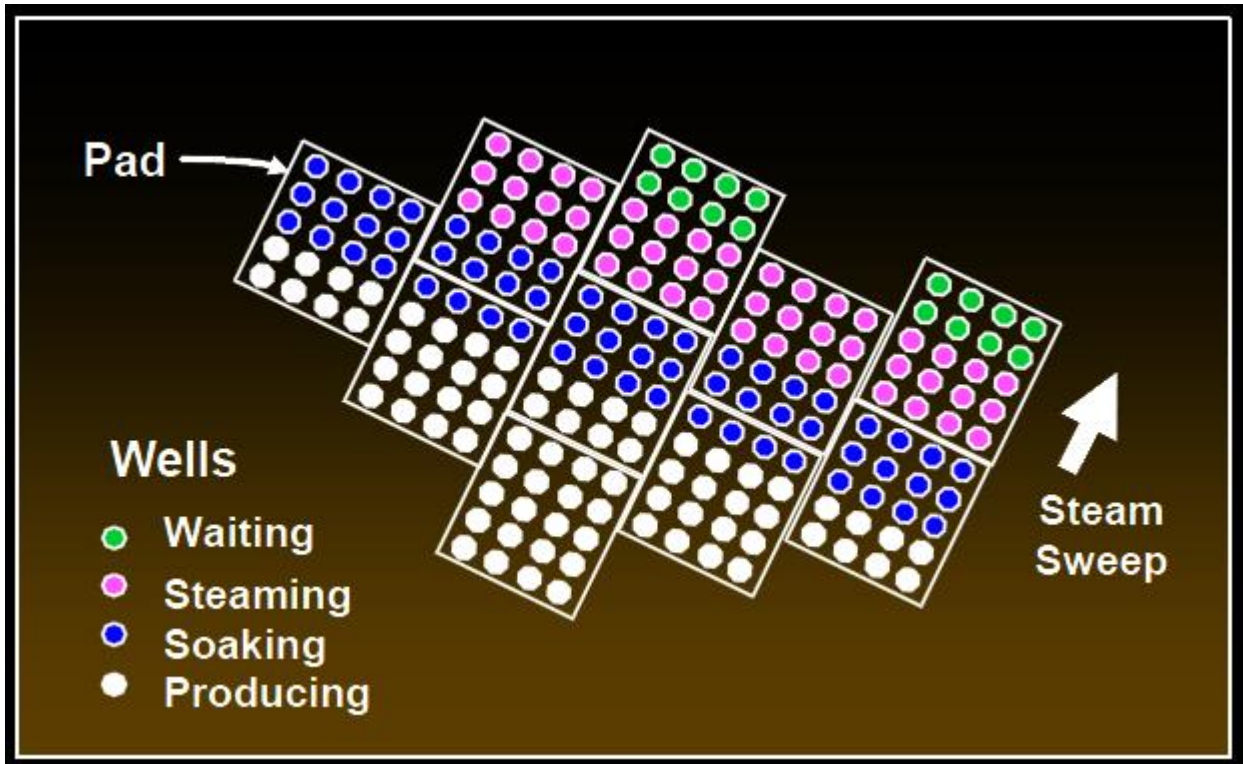
Figure 2-8 Overlapping row steam pattern in Cold Lake [26].

2.2.5 Well/Completion Design

The process of making a well ready for injection or production is called well completion. Effective completion design improves production rate and at the same time reduces the energy consumption. A number of steps should be carried out to complete a well which are well casing installation, well head installation and lifting equipment installation.

Drilling of wells in Cold Lake is usually done near the base of the Clear Water. A 7" casing is cemented up to surface. In well completion in Cold Lake, casing in the lower Clear Water is perforated. The perforated part of the casing is around 12-15 m. In order to control the sand production, a 5" slotted liner with the length of 60 m is installed inside the perforated casing. Usually in Cold Lake sand problem is minimal and a gravel pack is not required. A 3" tubing is located close to bottom. A bottom hole insert pump has been connected to the pump unit at surface. Steam is injected with the pressure up to 2000 psi inside the annulus by the bottom hole pump unseated and the polished rod clamped and sealed at surface [27].

In cyclic steam stimulation operation, working above and below the yield point causes fatigue issues and could lead to yield failures. The expansion of annulus fluid during steam injection can exacerbate these problems. By applying insulation on tubing, the temperature variation of the casing can be reduced. All of these issues require heat transfer reduction. The high temperature also causes more stress on the tubing and facing.

2.3 SAGD

In 1978, Dr. Roger Butler presented the concept of Steam Assisted Gravity Drainage (SAGD). The Alberta Oil Sand Technology and Research Authority (AOSTRA), and government held SAGD as a talented innovation in oil sands extraction technology quickly.

In 1984, the Underground Test Facility (UTF) was started by AOSTRA. The UTF site is located approximately 60km North West of Fort McMurray, Alberta, Canada. UTF operations had multiple phases. Phase A performed to confirm only the physical process of SAGD and the result was successful. A number of issues were considered during the test: Start up, sand control, steam trap control, reservoir heterogeneities, effect of solution gas, and numerical simulation. In phase B the SAGD process was investigated on a commercial scale. The result was beyond the expectations. Horizontal drilling from the surface and operation of SAGD from the surface was

the aim of phase D study. Currently Steam assisted gravity drainage is one of the most popular enhanced oil recovery methods of producing heavy oil and bitumen.

2.3.1 Physics of SAGD

Figure 2-9 displays a vertical cross-section of the SAGD process.
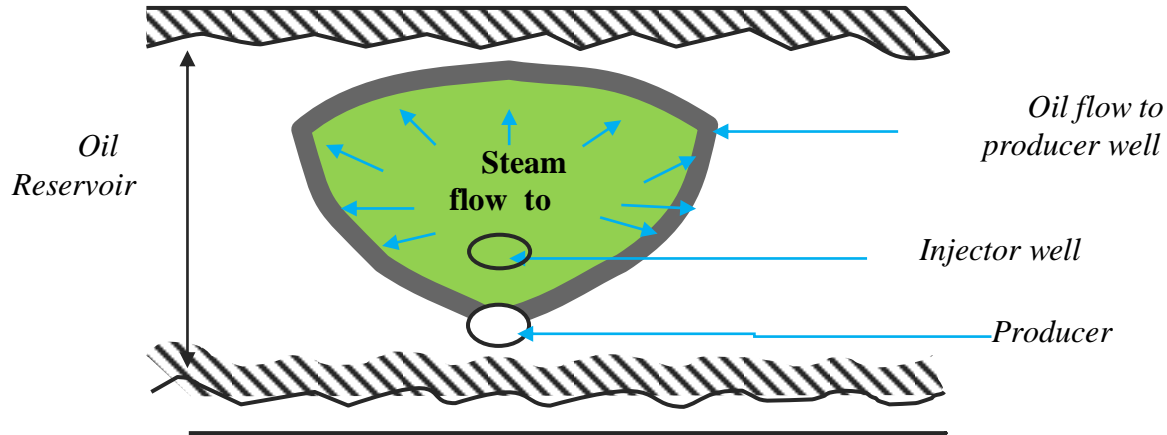
Figure 2-9 Schematic of SAGD.

In the SAGD operation, two parallel horizontal wells are placed at the base of the formation. This configuration enhances the contact area between the reservoir and the wellbore. One well is injector and another one is producer. The producer is located several meters below the injector and as low as possible in the reservoir. The bitumen viscosity is reduced due to the injection of steam. Steam heats the bitumen and condenses. The condensed steam flows down by gravity force toward the producer. There are two basic SAGD mechanisms which are ceiling drainage and slope drainage. The ceiling drainage happens when steam chamber is rising and expanding in upward direction. At this stage the injected steam rises to the ceiling and heated bitumen along with condensed water flow downward into the producer. The flow pattern in counter current. The rate of the steam rise is an important factor and is a function of vertical permeability and steam temperature. The ceiling drainage has a dominant role during the early stages of the process. The slope drainage occurs when the steam chamber is expanding sideways horizontally. During this stage the condensed steam and hot bitumen flow toward the producer from steam chamber perimeter. It is important in the late stages of SAGD process. [28]

The horizontal well offers several advantages, such as; higher sweep efficiency, augmented reserves, amplified steam injectivity, and reduced number of wells needed for reservoir development which leads to fewer pumps, less piping, and lower operation and maintenance

costs. In the SAGD well-pair, one well is located above the other well. The upper well is the steam injector and the bottom well is the oil producer. The vertical distance between the injector and the producer is typically 4-10 m. The producer is usually placed a few meters above the base of formation. The SAGD process comprises of three phases which are Start-up, Injection of steam and oil production, and finally wind down stage.

The start-up period is essential for a high efficiency SAGD process to reduce the viscosity of the bitumen between two wells. In this phase, the steam is circulated in both wellbores for about 3-4 months in order to heat the section between the wells. The heat transfer mechanism is conduction. In this phase heat communication between two wellbores is established. The hot and mobilized bitumen starts flowing down from the injector to the producer as a result of gravity drainage and the small pressure gradient between wellbores and the wells behaves as hot fingers in the reservoir.

The normal SAGD operation can start once the heat communication between injector and producer is established. As the steam enters continuously to the reservoir a steam chamber is formed. During the normal SAGD phase, two distinct stages can be realized which are called Ramp-up and Plateau. The initial growth of the steam chamber happens in upward direction. This growth occurs much faster than the lateral growth. Meanwhile the injection and production rates increase. This stage is called Ramp-Up. As soon as the chamber reaches the formation top, the growth of the steam chamber continuous but in lateral direction. In this period, the oil production rate reaches a maximum (and slowly declines subsequently) and the water percentage is minimum. This period is called Plateau.

The steam chamber continues to growth laterally as operation continues. As a result, inclination of the steam chamber interface changes continuously. The exposed area of the steam chamber to cap-rock is increasing during Plateau stage. The distance between the oil at interface and production well increases constantly and oil has to travel more distance to reach the production well. As a result the oil production rate decreases and the SOR increases. The ultimate recovery factor in SAGD is usually higher than 50%. Finally the SOR becomes unreasonably high and the steam chamber becomes "mature." The Wind-Down stage begins at this point. [29]

2.3.2 Geomechanics of SAGD

Geo-mechanical behavior affects the production performance of the SAGD process. The reason is that geo-mechanical behavior can modify reservoir parameters, such as permeability and porosity which are key parameters associated to fluid flow in the reservoir. Only by including the interaction of SAGD and geo-mechanics we can achieve more complete understanding of the process and optimize well placement and facility design for several quarter billion dollar SAGD projects in western Canada.

Typically, the SAGD process is used in unconsolidated sandstone reservoirs with very heavy oil or bitumen. These bituminous unconsolidated sandstones or oil sands are solid under virgin conditions and are not loosely packed beach sands. Instead they have a dense interlocked structure. They have no cementation and their strength is entirely dependent upon grain-to-grain contacts, which are considerable in their undisturbed state. These contacts are maintained by the effective confining stress. Since the SAGD process increase the formation fluid pressure, it reduces the effective stress and weakens the oil sand density. Once the individual sand grains rotate, bulk volume increases and dilation increases due to increase in porosity. The associated increase in absolute permeability can be a factor of 10. It is this remarkable behavior of oil sands that makes geo-mechanics so important to SAGD.

Due to injection of steam, reservoir pressure and temperature are raised. Due to the increase in temperature, thermal expansion, horizontal stress and transient vertical stress increases. As a result of the increase in pressure, shear dilation is created. Shear dilation is the result of increasing effective horizontal stresses induced by inhomogeneous thermal expansion. Shear dilation is irreversible and in quartzose sand leads to porosity, permeability and compatibility increases. Hence, shear dilation has been considered a major and positive geo-mechanic factor in thermal enhanced oil recovery. In other words, shear dilation occurs when there is low effective stress and shear failure. In other words the benefits of shear dilation is permeability and porosity enhancement. Perm enhancement is directional and thin vertical flow barriers can be broken enhancing vertical drainage. It should be mentioned that due to the increase in pressure, effective shear stress decreases. Effective Stress is a force that keeps a collection of particles rigid. Also we have volumetric expansion, increase in horizontal stress and also increase in transient vertical stress.

2.3.3 Three phase phenomena in SAGD

The shape of the steam chamber has been studied by Butler. With performing sand pack laboratory experiments he realized that during the rise of steam chamber there are ragged and separated steam fingers at the top and it is not a flat front shape. He mentioned that the steam chamber at the rising stage is as a dome-shaped structure with steam fingers jutting out from its upper surface while sideways and downside movement of interface is in a more stable trend. Figure 2-10 presents the steam chamber growth model presented by Butler.

Heated oil drainage around chamber

Steam inside chamber and fingers
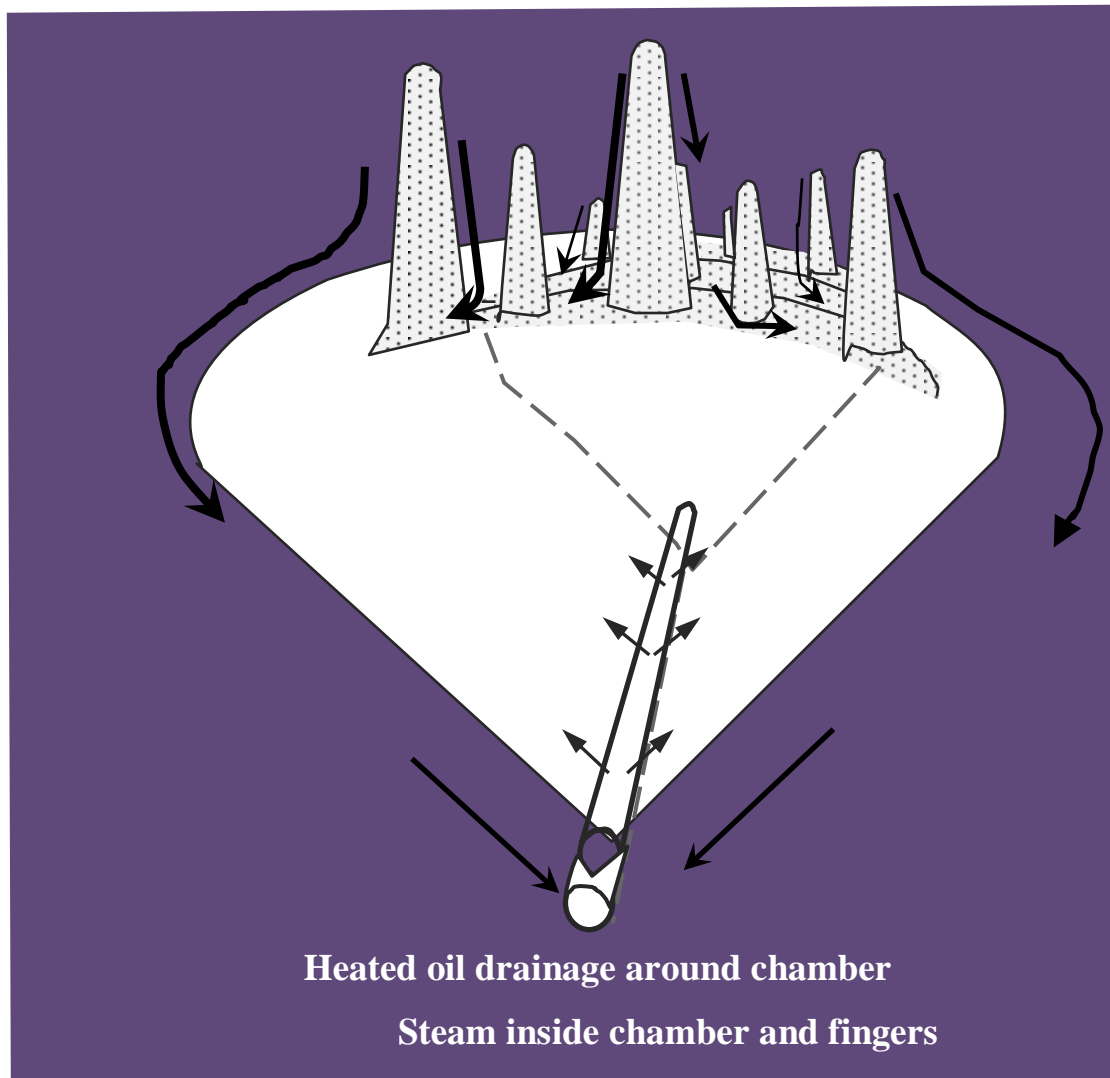
Figure 2-10 Growth of steam chamber.

He believed the existence of these fingers is due to instability caused by rising lighter steam below heavy oil. In describing his steam fingering theory, Butler (1994) mentioned that steam flows into these fingers and condenses on their surface, and heats up the oil around the fingers. The hot oil drains down side around the perimeter of the fingers into the steam chamber where it meanders in counter-current flow against the steam. With a two-dimensional visual model, Sasaki et al. (2001) showed images of steam fingering during the rise of the steam chamber. They also reported increasing instability of the steam chamber interface near its ceiling, i.e., steam fingering, with intermittent steam injection from the lower horizontal well. Ito and Ipek

31

(2005) examined the steam fingering phenomenon with the measured field data from UTF Phase A, Phase B, Hangingstone and Surmount SAGD projects. They expanded Butler's steam fingering theory and concluded that many observations in those field projects are clearly explained by the steam fingering concept.

Steam flows in upside direction within the lower boundary and affords heat into the reservoir. The reservoir oil receives the heat and its mobility increases at the same time the steam condenses around the perimeter of the chamber and condensate and heated oil flow around and through the chamber towards the producer. Meanwhile, steam moves upward at a higher velocity than the chamber. At the very top of the chamber steam fingers move into the relatively cold reservoir. Heat is transferred by conduction from these fingers to the reservoir material and the oil drains in down side direction around and between the fingers as it becomes mobile. The oil moves downward because gravity allows the steam to rise. The steam and oil flow within the chamber is counter current.

During the chamber development stage, a steam-saturated zone is formed above the producer which spreads from injector to the overburden. The injected steam flows inside the chamber where it contacts cold bitumen located at the surrounding of the chamber. At the boundary of the chamber the steam condenses and releases its latent heat of vaporization, which applies to heat the bitumen. This heat transfer occurs by both convection and conduction. The heated and mobilized bitumen, drains by gravity and the steam condensates to the production well. The pressure remains constant within the chamber and a counter current flow between draining fluid and steam occurs. With producing bitumen, the empty space will be filled by steam. The chamber grows longitudinally and laterally.

According to Butler research, the steam fingers expand up to several meters in heavy oil. The rise rate estimated by his theory is considerably smaller than the actual data. Butler believed that the maximum rise velocity does not happen at the centerline of the steam finger. Gotawala and Gates [30] in their research concluded that the rise velocity at the centerline is maximum and the rise rate is directly related to the density difference of oil and gas and also it is directly proportional to the mobility of the gas phase, but inversely related to the steam to oil ratio of the finger and also inversely related to the content per unit reservoir rock volume. The results reveal that the steam fingers does not enter several meters into the oil. Also if there is no mobile water the leading heat transfer mechanism at the edge of the steam chamber is conductive heating.

2.3.4 Field Practice

Many SAGD pilots have been tested successfully in the Athabasca-McMurray Formation field. The effective results has led companies to develop several commercial projects in this area. Figure 2-11 shows an overview of SAGD projects in Athabasca. As it can be seen the number of active SAGD pilot and commercial projects in Athabasca is quite large.

AOSTRA initiated the first successful SAGD field test project which was called Underground Test Facility (UTF). It was located at 40 km northwest of Fort McMurray. The test comprised of multiple phases. The purpose of "Phase A" was to perform a case study to validate the SAGD physical process. In "Phase B" the commercial feasibility of SAGD process was investigated. During "Phase D" operation the horizontal drilling from surface was tested and was not completely successful. The pilot was continued to operation until 2004 with the ultimate recovery of approximately 65% and cSOR of 2.4 m^3/m^3. From that time SAGD has been applied in multiple pilot and commercial projects in Athabasca. [31]

The largest commercial SAGD project in Canada is currently being run by CENOVUS (Encana). In 1997, the Foster Creek project started as a pilot by deploying 4 well pairs and then the project expanded to 28 well-pairs in 2001. At present it consists of over 160 well pairs and is producing over 100,000 bbl/d. The location of the pay zone is at 450 m depth and the target formation is Wabiskaw-McMurray .The Injection pressure is 2800 kPa.

Reservoir characteristics have been mentioned in table 2-1

Table 2-1 Reservoir Characteristics of Foster Creek [32].

Reservoir Characteristics	Values
Depth (m Subsea)	180-225
Thickness (m)	Up to 30+
Porosity (%)	32-34 %
Horizontal Permeability (D)	Up to 10 D
Vertical Permeability (D)	Up to 8 D
Oil Saturation	0.85
Water Saturation	0.15
Original Pressure (kpa)	2700
Original Temperature (℃)	12

Two SAGD well pairs were completed by JACOS in Hangingstone in 1999. The primary pilot operation was successful and the project was expanded to 17 well pairs in 2008. Currently 10,000 bbl/d is being produced by JACOS. The project produces from the Wabiskaw-MacMurray Formation which is 280-310 m depth. Recoverable bitumen is estimated to be 6.4 million m^3. In 2006, cSOR was 3.17. [34].

Suncor is operating one of the best existing SAGD projects with respect to its cSOR in the MacKay River area. The average amount of cumulative SOR is 2.5 m^3/m^3. The company started the project with completion of 25 well pairs in 2002. The steam circulation operation started in September 2002 and the production initiated in November 2002. In 2005/2006, 16 additional well pairs were added. This project uses the Wabiskaw-McMurray formation which is located 150 m below the surface [31, 35]. Performance summary has been shown in Table 2-2

Table 2-2 Performance summary of Suncor Mackay River Project [35].

	OBIP (e^{3}m^3)	Cum.Oil (e^{3}m^3)	Recovery (Aug. 013)	cSOR (m^3/m^3)	iSOR (m^3/m^3)	Ultimate Recovery (%)
Total	37,960	16,249	42.8	2.4	2.6	65

Phase-1 of the Christina Lake project started by completion of 6 well-pairs pilot SAGD by Encana (now CENOVUS) in 2002/2003. The lowest cSOR belongs to Christina Lake project and is equal to 2.1 m^3/m^3. At present MEG Energy is also performing SAGD at Christina Lake. The net pay is Wabiskaw-McMurray and is located at ~ 400m depth. Typical operating pressure is in the range of 1800-3000 kpa. [31, 36].

Reservoir Properties have mentioned below:

Average SAGD pay: 23 m

Average Porosity (%): 33

Average Oil Saturation (%): 80

Rock Volume: 1,778 x 10^6 m^3

ConocoPhillips commenced their SAGD operation with completion of 3-well-pairs pilot project at Surmont in 2004. One of the wells contains a 700 m long slotted liner and two other well pairs contain 350 m long slotted liners. The steam injection started in June 2007 for commercial SAGD at Surmont and oil production began in October. At present, Surmont is

being operated by ConocoPhillips Canada on behalf of its 50% partner Total E&P Canada. The depth of reservoir is ~400 m and the formation is Wabiskaw-McMurray [31].

REF NO.	OPERATOR - PROJECT NAME	PROJECT TYPE	STAGE
	Athabasca Oil Sands Area		
1	E-T Energy - Poplar Creek OSFT2009	Experimental	Producing
2	Laricina Energy - Saleski SAGD Pilot	Experimental	Producing
3	Petrobank - Whitesands	Experimental	Producing
4	CNRL - Horizon	Mining	Producing
5	Shell - Jackpine Mine	Mining	Producing
6	Shell - Muskeg River Mine	Mining	Producing
7	Suncor - Suncor Oil Sands	Mining	Producing
8	Syncrude - Syncrude Mine	Mining	Producing
9	Cenovus - Pelican Lake III	Primary/EOR	Producing
10	CNRL - Brintnell	Primary/EOR	Producing
11	CNRL - South Brintnell	Primary/EOR	Producing
12	CNRL - Wabasca North	Primary/EOR	Producing
13	Husky - McMullen Primary/EOR Heavy Oil	Primary/EOR	Producing
14	Cenovus - Christina Lake Thermal	Thermal	Producing
15	Cenovus - Foster Creek	Thermal	Producing
16	Connacher - Algar	Thermal	Producing
17	Connacher - Great Divide	Thermal	Producing
18	Conoco Phillips - Surmont	Thermal	Producing
19	Devon - Jackfish SAGD Thermal	Thermal	Producing
20	JACOS - Hangingstone	Thermal	Producing
21	MEG Energy - Christina Lake Regional	Thermal	Producing
22	Nexen - Long Lake	Thermal	Producing
23	Statoil - Leismer	Thermal	Producing
24	Suncor - MacKay River	Thermal	Producing
25	Suncor - Suncor Firebag	Thermal	Producing
26	Sunshine Oilsands - Harper	Thermal	Producing
27	Imperial Oil - Kearl	Mining	Construction
28	Black Pearl Resources - BlackRod SAGD Pilot	Thermal	Construction
29	CNRL - Kirby Commercial	Thermal	Construction
30	Devon - Jackfish 2	Thermal	Construction
31	Husky - McMullen Thermal Conduction Pilot	Thermal	Construction
32	Harvest Energy - BlackGold	Thermal	Construction
33	Husky - Sunrise Thermal	Thermal	Construction
34	Laricina Energy - Germain	Thermal	Construction

Figure 2-11 Athabasca Oil Sand's Projects.

One of the leaders in SAGD operations is Suncor. This company is running the Firebag, with 40 well-pairs, and also the MacKay River project mentioned earlier. The first steam injection in the Firebag project started in September 2003 and the oil production was initiated in January 2004. At present the average daily bitumen production rate is 48,400 bbl/day and the cSOR is 3.14 m^3/m^3 with the current capacity of 95,000 bbl/d. Average reservoir properties has been mentioned below [37] :

Initial reservoir pressure: 800kPa

Initial reservoir temperature: 8˚C

Average gross pay = 46.4 m

Average net pay = 39.7 m

Average porosity = 0.322

Average oil saturation = 0.85

Effective horizontal permeability: 3 to 4 D

Effective vertical permeability: 2 to 3 D

Viscosity: ~ 11cp @ 215°C

In North Athabasca the shallowest SAGD operation had 90-100 m depth. The Joslyn pilot project commenced with a well-pair and steam circulation in April 2004. While the Phase II of the project was ongoing, a well blowout happened in May 2006. At present time there is no injection-production in that area.

Nexen and OPTI Canada (now CNOOC Canada) established a 65/35 joint venture and started the phase 1 of the Long Lake Project. This is the most unique SAGD project in Athabasca area. This project is associated with an on-site upgrader. The project has three horizontal well pairs at different lengths from 800-1000 m and 150 m well spacing. Phase 1 of the project is operating with a full capacity of 70,000 b/d and will extract crude oil from 81 SAGD well-pairs and converts it into premium synthetic crude oil. Steam injection pressure is 2200-2800 kPa and temperature 220-232°C [38].

The Jackfish SAGD project in Athabasca was initiated by Devon. In this project 24 well-pairs in 4 pads were completed in 2006 at a depth of 350 m. The Wabiskaw-McMurray formation was targeted. First steam injection started in 2007. The designed capacity of the project was 35,000 bbl/d. Presently the average cSOR is 2.4 m^3/m^3. The construction of the second phase of this project was started in 2008 and it is similar to the first phase of Jackfish 1. Average reservoir property has been mentioned below [31, 39]:

Depth: ~415m TVD

Pay Thickness: >18m

Porosity: >25%

Permeability: 2-10 Darcies

Oil Saturation: >50%

Original Pressure: 2,700-2,900 kPag

Original Temperature: 12° C

The Wolf Lake project was the first SAGD pilot at Cold Lake area. Amoco started this project in 1993 by drilling one 825 m horizontal well pair in Clearwater formation. Production result for the first three years of production was high cSOR and low RF, Therefore Amoco had to change the project into a CSS process.

Suncor offered Burnt Lake SAGD project in the Clearwater Formation of Cold Lake in 1990 and the operation was commenced in 1996 and then later in 2000; Canadian Natural Resources Limited (CNRL) picked up the operation of Burnt Lake in 2000. This project consists of three well-pairs of 700-1000m well length. The amounts cSOR and RF till end of 2009 were 3.9 m^3/m^3 and 47.9% respectively .The 2012 performance has been summarized in Table 2-3. [40]

Table 2-3 Performance of Burnt Lake SAGD Project [40].

BURNT LAKE SAGD PILOT PRODUCTION SUMMARY	
Active Well Pairs	3
2012 Bitumen Production (m3)	36,827
2012 Average SOR	4.8
Cumulative Bitumen Production (m3)	837,413
Cumulative SOR	4.0
OBIP (m3)	1,493,013
Recovery Factor (%)	56.1

The Performance of Burnt Lake SAGD Project is shown in Figure 2-12
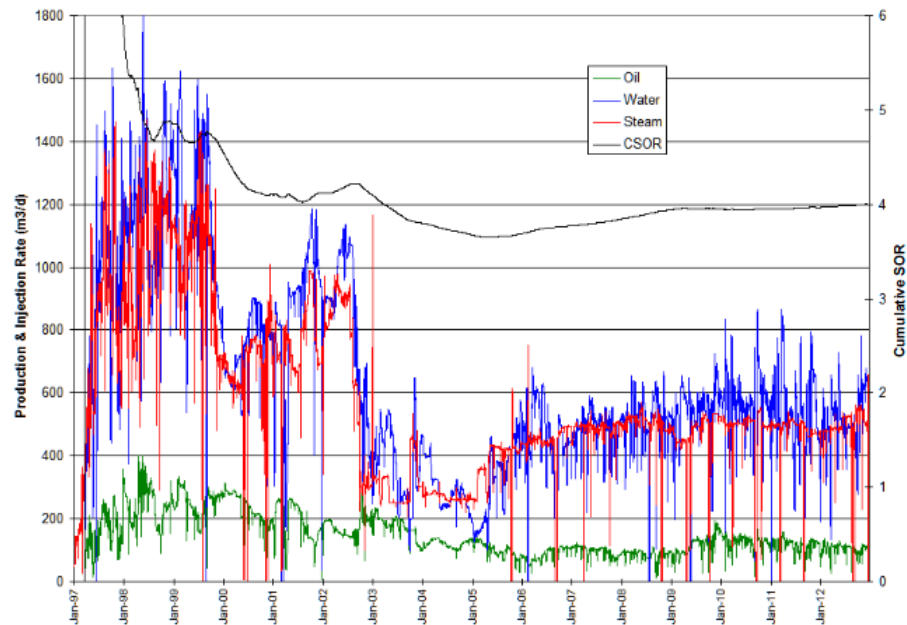
Figure 2-12 Performance of Burnt Lake SAGD Project [40].

Black Rock started the Hilda Lake pilot SAGD project in 1997. In the Clearwater Formation, two 1000 m well-pairs were drilled. The operation was continued by Shell in 2007. The cSOR and RF at the end of 2009 were 3.5 m^3/m^3 and 35% [31].

The second SAGD pilot project of Amoco in Cold Lake area was started in 1998. The pilot comprised of one well pair of 600 m length which was completed in the Clearwater Formation. The Pilot operation continued for two years and because of high cSOR and low RF of the project was changed into a CSS process.

Orion is a commercial project located in Cold Lake area which produces from Clearwater Formations. Shell has drilled total of 22 well pairs with an average well length of 750 m. However, only 21 of them are on steam. The first steam injection commenced in 2008. The cSOR is high due to early time of the project, and the reported RF is 6-7%

Property ranges are:

Reservoir Property Ranges:

Horizontal Permeability 100 – 5000 mD

Vertical Permeability 80 – 4000 mD

Viscosity: 30,000 – 3,000,000 cSt

Production injection history has been shown in the following graph.
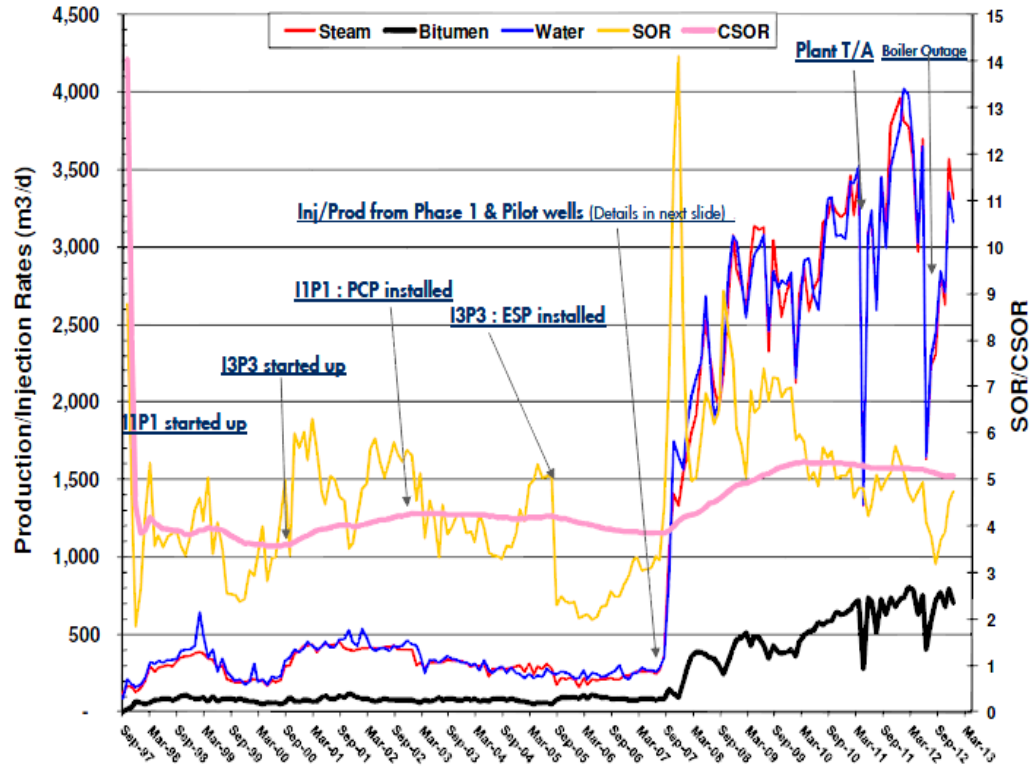
Figure 2-13 Performance of Hilda Lake Project [41].

The commercial SAGD plant of Husky was established in second half of 2006 at Cold Lake. At this project 32 well-pairs were completed. Length of these well-pairs are approximately 700 m. The goal of the Tucker project was to produce from Clearwater Formation with a depth of ~400 m. In November 2006 the first steam injection was initiated. Eight more well-pairs were added to the project in 2010. The cSOR by the end of May 2010 was above 10 m^3/m^3 while the RF is below 5% [42]. Average reservoir characteristics have been listed in Table 2-4:

Table 2-4 Average reservoir characteristics for Tucker thermal project [42].

Formation	Thickness (m)	Average Porosity	Average Oil Saturation
Clearwater	45	0.31	0.57
Lower Grand Rapids	30	0.29	0.55
Colony	10	0.30	0.79

Production and Injection history for Tucker thermal project is shown in Figure 2-14
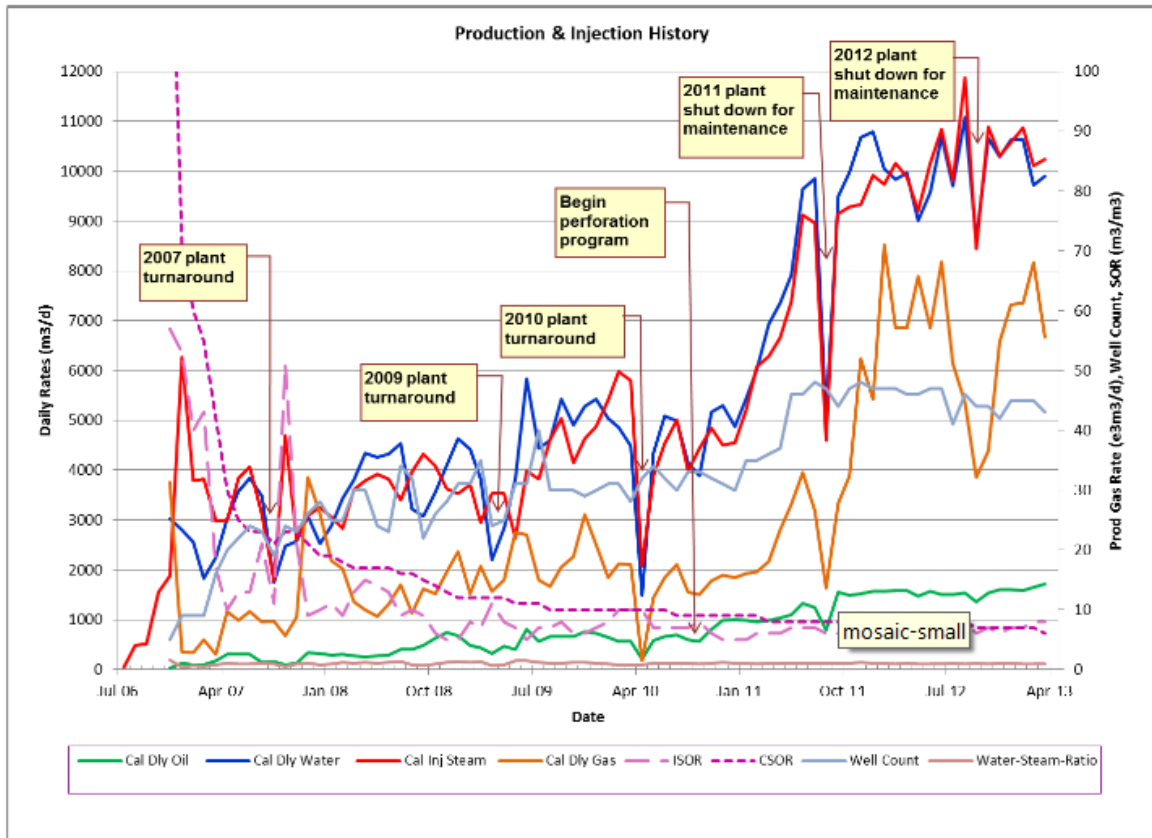
Figure 2-14 Production and Injection history for Tucker thermal project [42].

Although SAGD has been verified to be economically viable and technically successful, more studies should be carried out to answer the questions remain regarding SAGD performance compared to CSS and more comprehensive understanding of the parameters affecting SAGD performance in the Cold Lake area is required.

2.3.5 Well/completion design in SAGD

The SAGD drilling process involves the drilling and development of two horizontal wells. These wells are drilled in a manner where one is placed above the other in the reservoir. The design and drilling of each type of well bore is dependent upon reservoir quality, Sand particle size, porosity and depth. The steam injector is generally drilled with a larger diameter bore size than that of the production well bore size. A drilling rig is used to drill from the surface, down through the subsurface and into the oil bearing reservoir. The drilling process uses drilling muds

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that contain additives to help reduce friction, accretion and to stabilize the drilled section of hole unit so a slotted liner can be inserted. A horizontal well is usually drilled in three distinct sections, surface, intermediate and horizontal. The surface section is drilled vertically or near a vertical orientation through the subsurface geology to a pre-determined depth where surface casing is installed to protect potable water aquifers from cross contamination. The intermediate section is drilled below the surface section and is the portion of the well that starts to build toward a horizontal orientation. The build section is crucial as it is desired to gradually turn near 90 degrees to land the bore hole at pre-determined point in the reservoir.

Drilling technology evolution is a key factor in the commercial implementation of SAGD. In 1993, the technology to drill parallel horizontal wells was developed. The first well pair for SAGD was drilled using magnetic-ranging /guidance technology. This is done by measuring the relative position of one well with respect to another. The orientation and the distance from injector well to the producer well is being determined. SAGD wells must be able to withstand the harsh environment of the process. As it can be seen in Figure 2-13 the casing which is located in the intermediate section of the casing is the main barrier for isolation of the bottom hole SAGD environment from the surface. Production liner must be integrated to avoid sand production.

An example of a SAGD completion has been shown in Figure 2-15

If possible, insulation to minimise heat loss for both injection and production

Steam rises and disperses horizontally below cap rock; oil viscosity reduces

Possible pump to increase rates and minimise steam condensation in the reservoir

Producer set near base of reservoir

Slotted liner in horizontal wells
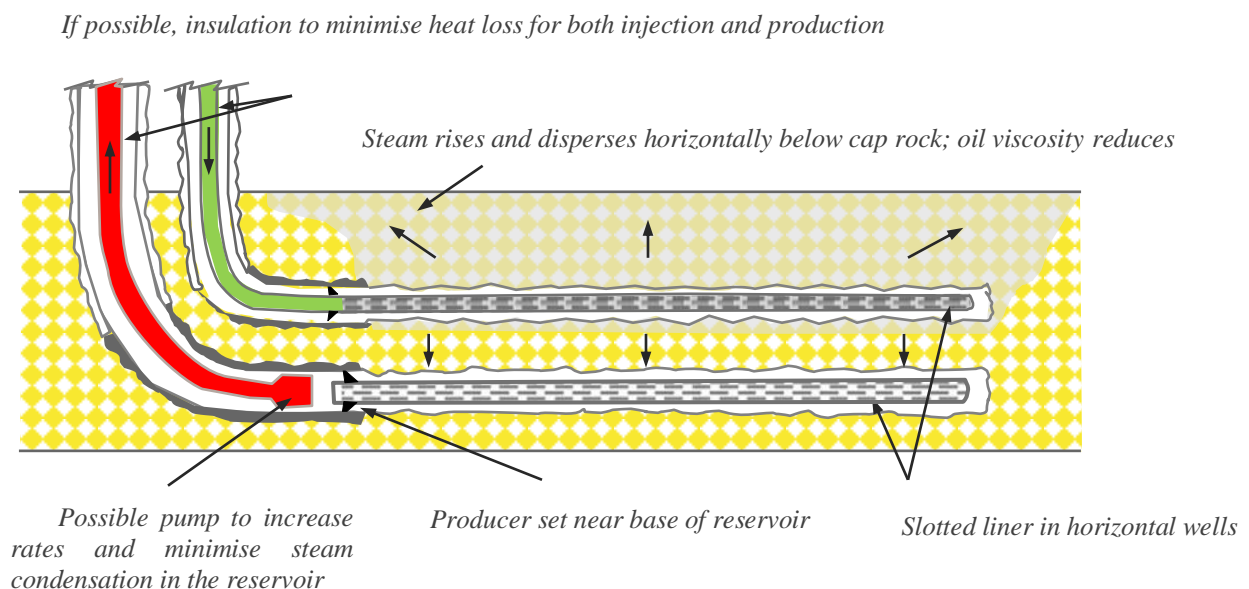
Figure 2-15 SAGD well completion [43].

Therefore it is critical to select adequate thermal conditions and appropriate thermal casing design. SAGD Well completion is still in evolution and diverse completion configurations are being implemented. The general leaning is to allow for bitumen production or steam injection at two or more points along the horizontal well bore.

Sand control in SAGD operations in both wells is required due to the unconsolidated nature of sandstones. Most widely used sand control method is using slotted liners. Injection wells of SAGD typically are completed with dual strings in a slotted liner. The end of one string is located at the heel, and the other ends at the toe. Steam is injected independently into either of these strings, but only at two points—the heel and the toe. Proper well completion design can impact the uniformity of the steam chamber.

2.4 What is missing in the literature?

All of the previous investigations about the comparison of CSS and SAGD mentioned in section 2.1 have been performed either based on the field data of the past history or for the long term predictions based on the field data. It should be mentioned that for some SAGD operations the long term prediction of trends of performance indicators is very uncertain. This is due to the fact that unlike the CSS, some SAGD operation is still in the early years. Performance review based on the field data for a newly developed SAGD operation could be misleading.

It is worth mentioning that all the preceding surveys that mentioned before were performed at least a decade ago. Nowadays, steam chambers are more mature and the level of understanding of the behavior of the SAGD reservoir has increased. Therefore it is expected that the performance of some SAGD operation is much better when compared with the SAGD operation ten years ago.

In the current survey, the field data has been gathered since the start of the operation until almost the present time and the performance comparison has been carried out based on the acquired data. Then the robust models for both CSS and SAGD processes have been established. In creation of the models the physical properties of real wells have been deployed. In the next step the results of the simulations have been confirmed with field data. Finally, forecasts based on the models have led us to perform a better performance evaluation.

CHAPTER 3 ANALYSIS OF FIELD DATA

3.1 Introduction

Diverse methods are used in the recovery of buried heavy oil or bitumen deposits within oil-sands reservoirs. In-situ recovery processes consist of increasing the mobility of the oil and then driving the fluids to a production well. Cyclic Steam Stimulation (CSS) has been a commercial recovery process since the mid 1980's in the Cold Lake area in northeast Alberta. Also, Several SAGD projects are in operation in different types of reservoirs in the Cold Lake area.

In this chapter, performance review was conducted based on the available data in Accumap for various CSS and SAGD projects in the Cold Lake area.

3.2 Cold Lake In situ Projects in the Clearwater Formation

The most important in situ projects in the Cold Lake area are:

- CNRL-CSS
- Imperial Oil Limited-CSS
- CNRL-Burnt Lake-SAGD
- HUSKY-Tucker Lake-SAGD
- OSUM-SAGD

3.3 Production Data

The following parameters were extracted from Accumap (Accumap, 2014) :

- Oil production profile
- Water production profile
- Steam injection profile

The production data were used to calculate the following parameters:

- Normalized oil rate
- Normalized water rate
- Normalized steam rate
- Cumulative Steam Oil Ratio
- Instantaneous Steam Oil Ratio

3.3.1 CNRL-CSS

Production data has been extracted in the period from 1998/12/01 to 2014/08/31. The number of wells is equal to 1015. The maximum amount of the average daily oil production is

approximately 23,600 m³/day. The daily volume of production was very limited before 1995 and steadily increased for the years beyond 1995. The cumulative oil produced in this time period was roughly 60,000 x 10^3m³. The daily oil production per well or normalized rate shows some fluctuations but the average value is around 14 m³/day. After 1995, the normalized cumulative oil increased with almost constant slope. This amount was equal to 133.9 x 10^3m³ in August 2014. The maximum of the average daily produced water was over 50,000 m³/day and cumulative water produced at the end of the period was nearly 180,000 x 10^3m³ with almost a constant slope after 1995. The average normalized daily water was around 47 m³/day and normalized cumulative water is 439 e³m³ by the end of the August 2014. Cumulative injected steam was equal to 362,000 x 10^3m³. The slope of the normalized cumulative injected steam after 1995 is almost constant. Cumulative and instantaneous steam oil ratio are almost constant with an average value of around 6 and 6.3 respectively for the years after 1995. Figures 3-1 to 3-7 show the different performance curves for CNRL-CSS
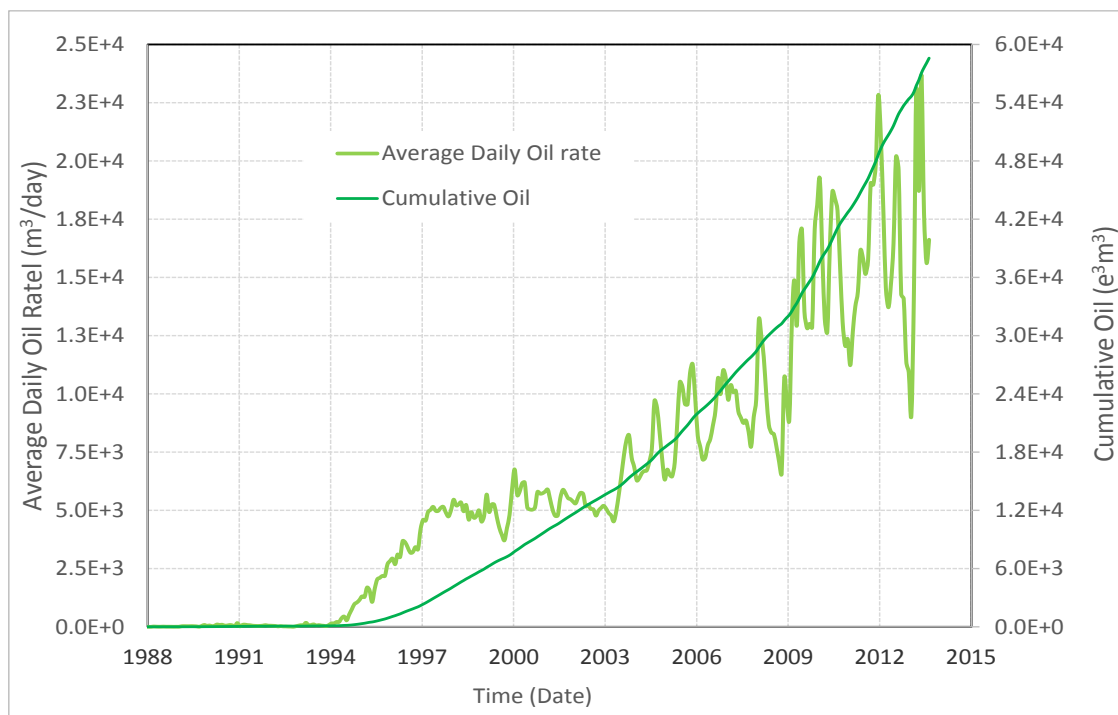
Figure 3-1 Average daily oil and cumulative oil versus production date for CNRL-CSS.
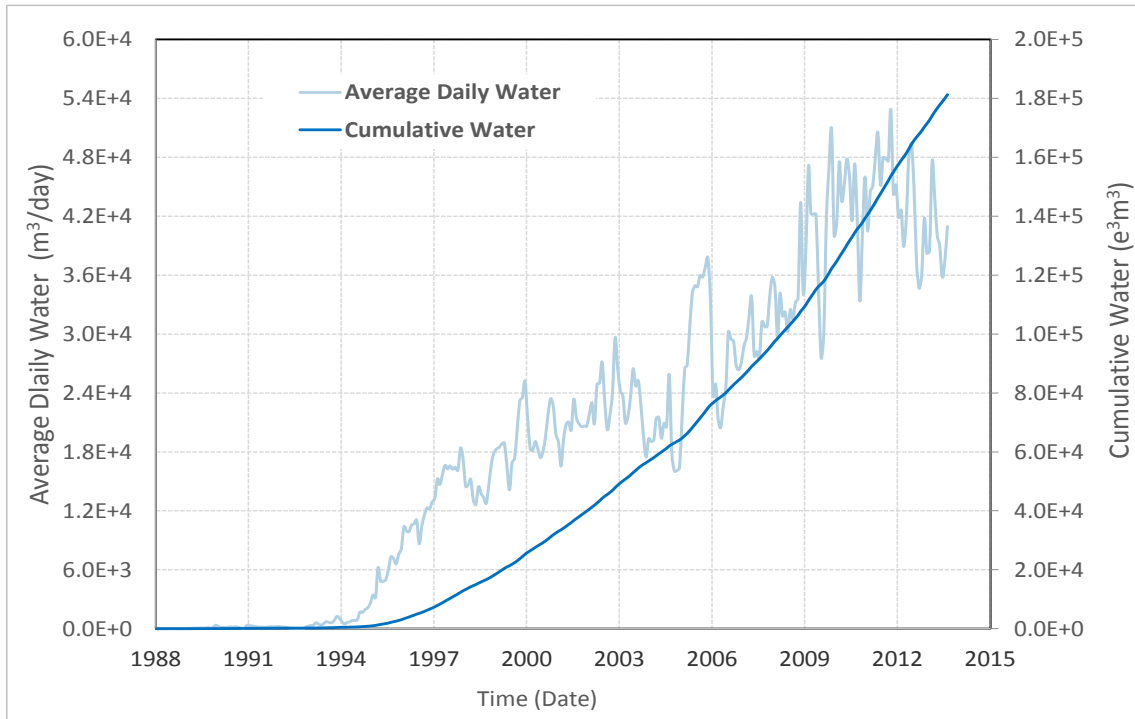
Figure 3-2 Average daily water and cumulative water versus production date for CNRL-CSS.

Figure 3-3 Average injected steam and cumulative injected steam versus production date for CNRL-CSS.

Figure 3-4 Normalized oil rate and normalized cumulative oil versus production date for CNRL-CSS.

Figure 3-5 Normalized water rate and normalized cumulative water versus production date for CNRL-CSS.

Figure 3-6 Normalized injected steam and normalized cumulative injected steam versus production date for CNRL-CSS.
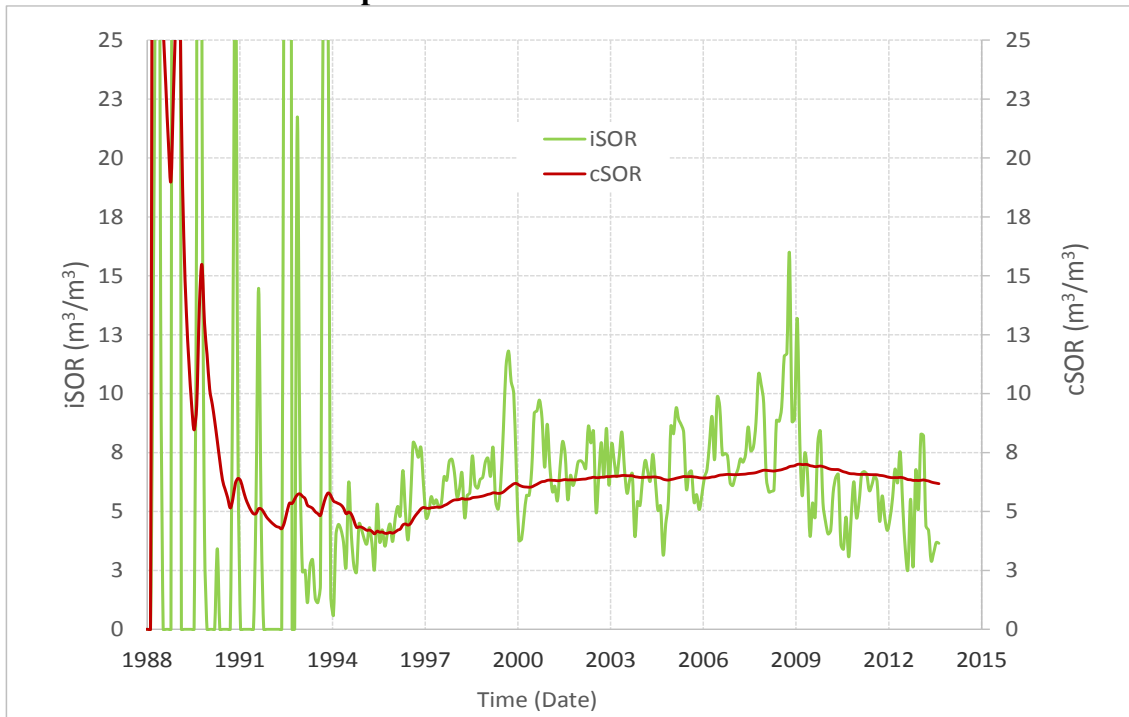
Figure 3-7 Instantaneous steam oil ratio and cumulative steam oil ratio versus production date for CNRL-CSS.

3.3.2 Imperial Oil Limited-CSS

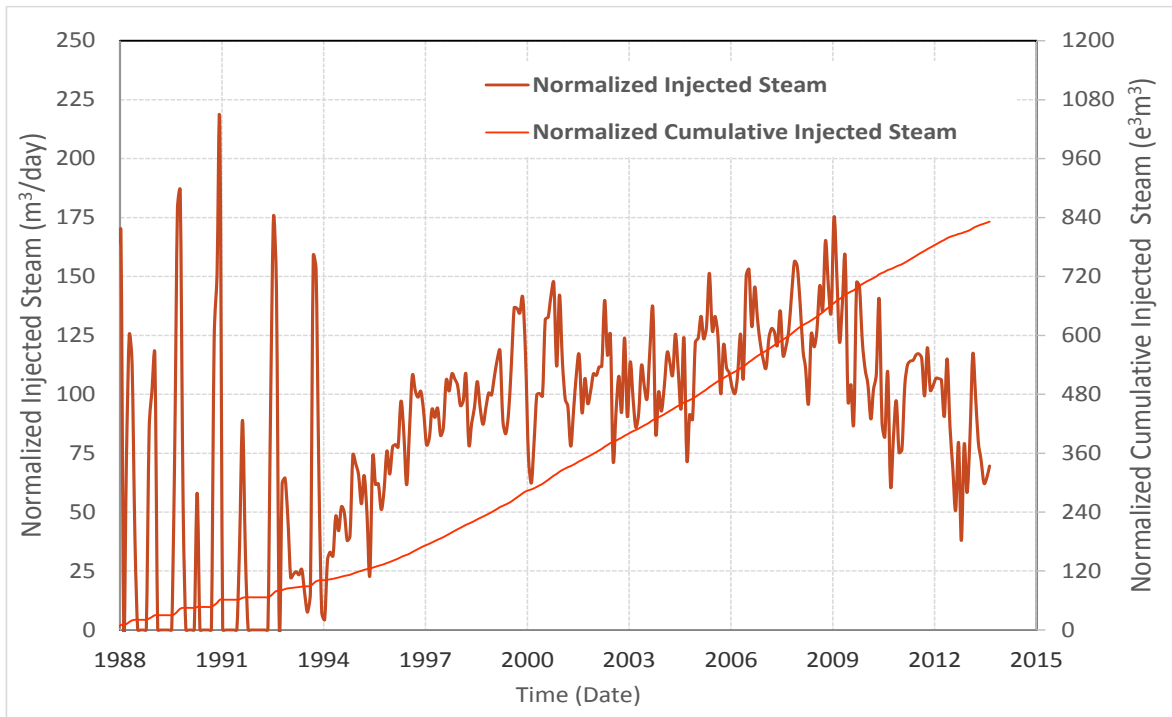Production data has been obtained in the periods of 1964/11/01 to 2014/08/31. The maximum number of wells was equal to 4040. The maximum of the average daily oil production is nearly 29,000 m^3/day. The daily amount of production was very limited before 1985 and increased with almost a constant slope after 1985. The total amount of oil produced in this time period was approximately 230,000 x $10^3 m^3$. The normalized rate was almost constant and average value is around 8.6 m^3/day. After 1995, the normalized cum oil increased with a constant slope. This amount is equal to 157 x $10^3 m^3$ in August 2014. The maximum of the average daily produced water is over 120,000 m^3/day and cumulative water produced at the end of the period is around 750,000 x $10^3 m^3$ with almost a constant slope after 1985. The average normalized daily produced water was around 25 m^3/day. Normalized cumulative water was 500 x $10^3 m^3$ by the end of the August 2014. Cumulative injected steam was over 1,000,000 x $10^3 m^3$.The slope of the normalized cumulative injected steam after 1972 was almost constant. Cumulative and instantaneous steam oil ratios were almost constant with average value of around 4.4 for the years after 1985. Figures 3-8 to 3-14 show the different performance curves for Imperial Oil Limited-CSS.
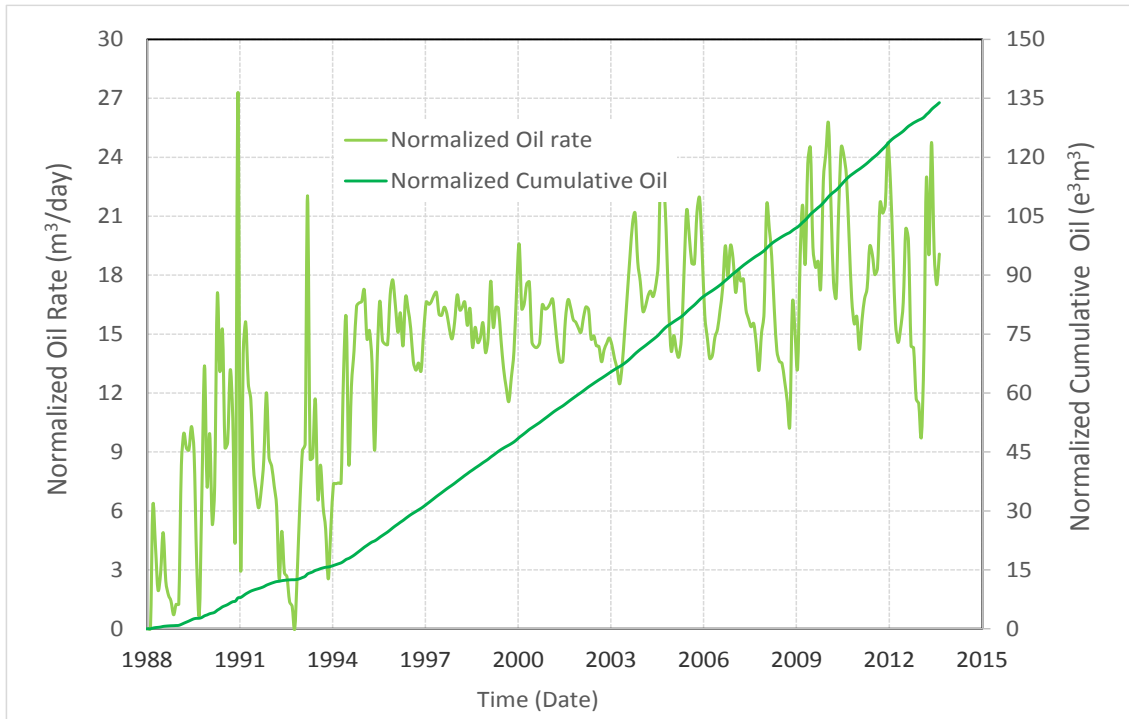

Figure 3-8 Average daily oil and cumulative oil versus production date for Imperial Oil Limited-CSS.
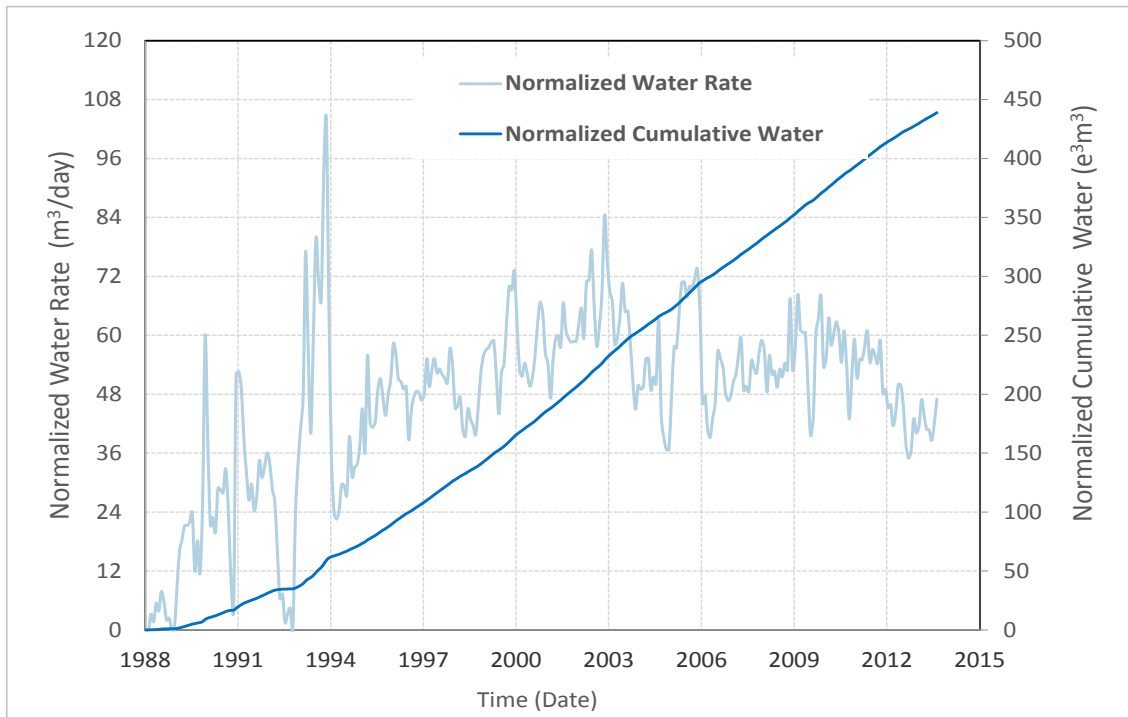
Figure 3-9 Average daily water and cumulative water versus production date for Imperial Oil Limited-CSS.
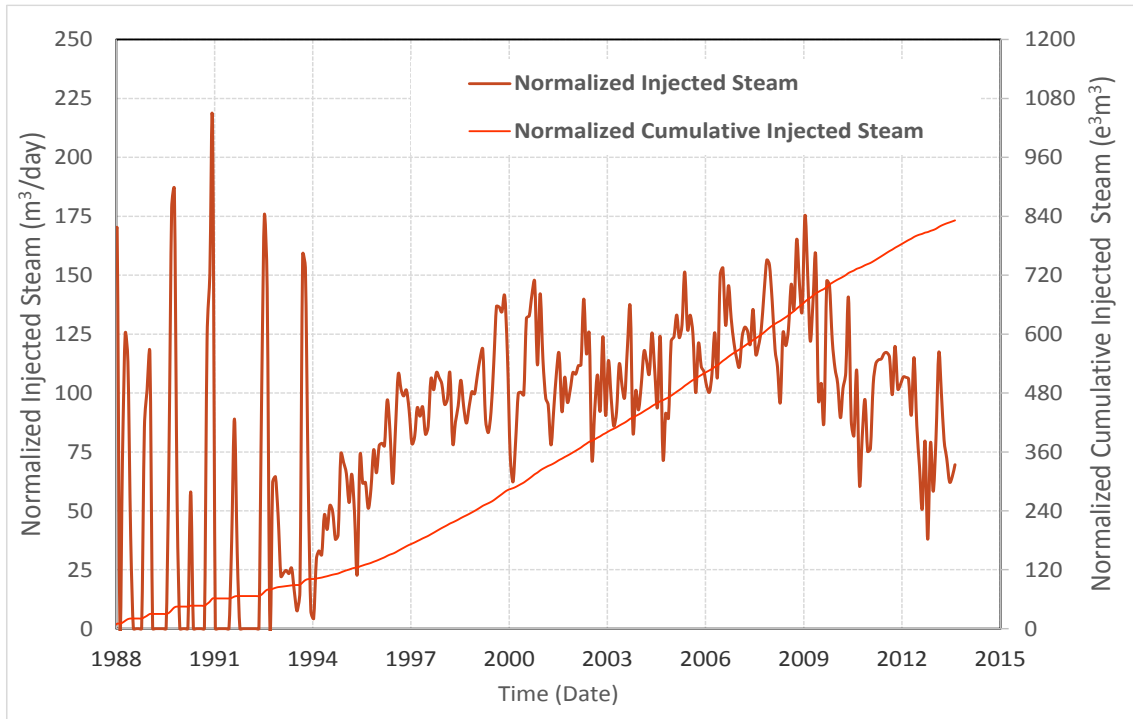

Figure 3-10 Average injected steam and cumulative injected steam versus production date for Imperial Oil Limited-CSS.

Figure 3-11 Normalized oil rate and normalized cumulative oil versus production date for Imperial Oil Limited-CSS.

Figure 3-12 Normalized water rate and normalized cumulative water versus production date for Imperial Oil Limited-CSS.

Figure 3-13 Normalized injected steam and normalized cumulative injected steam versus production date for Imperial Oil Limited-CSS.
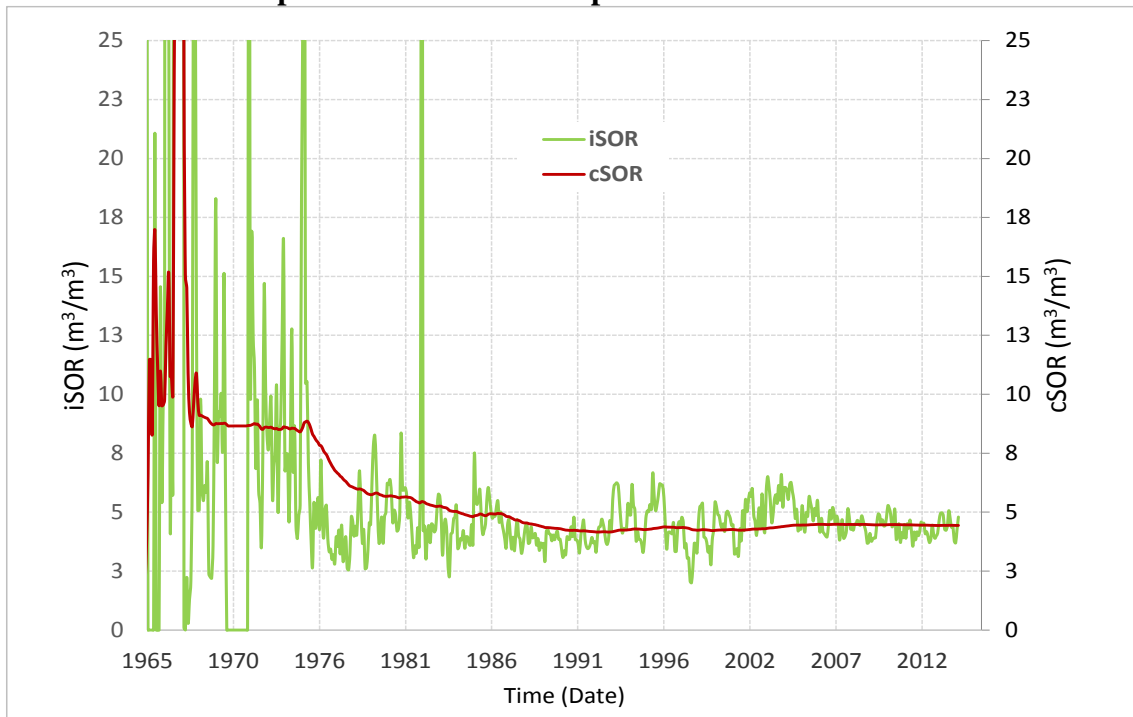
Figure 3-14 Instantaneous steam oil ratio and cumulative steam oil ratio versus production date for Imperial Oil Limited-CSS.

3.3.3 CNRL-Burnt Lake-SAGD

Production data in the period of 1997/01/01 to 2014/08/01 shows that there are three well pairs in this area. The maximum average daily oil production was roughly 290 m^3/day. The cumulative oil produced in this time period was approximately 950 x 10^3 m^3. The value for the normalized oil production rate has some fluctuations but the average value was around 14 m^3/day. After 1995, the normalized cum oil rises with constant slope. This amount was equal to 133.9 x 10^3 m^3 in August 2014. The maximum value of the average daily produced water was over 290 m^3/day and cumulative water produced at the end of the period was around 4200 x 10^3 m^3. Average normalized daily water was around 47 m^3/day. Normalized cumulative water production was 1400 x 10^{3}m^3 by the end of August 2014. Cumulative injected steam was around 3500 x 10^3 m^3. The values of normalized injected steam after 2006 was almost constant with the average value of 160 m^3/day. The cumulative steam oil ratio was almost constant after 2002 with average value of around 4.2. Figures 3-15 to 3-21 show the different performance curves for CNRL-Burnt Lake-SAGD.

Figure 3-15 Average daily oil and cumulative oil versus production date for CNRL-SAGD.
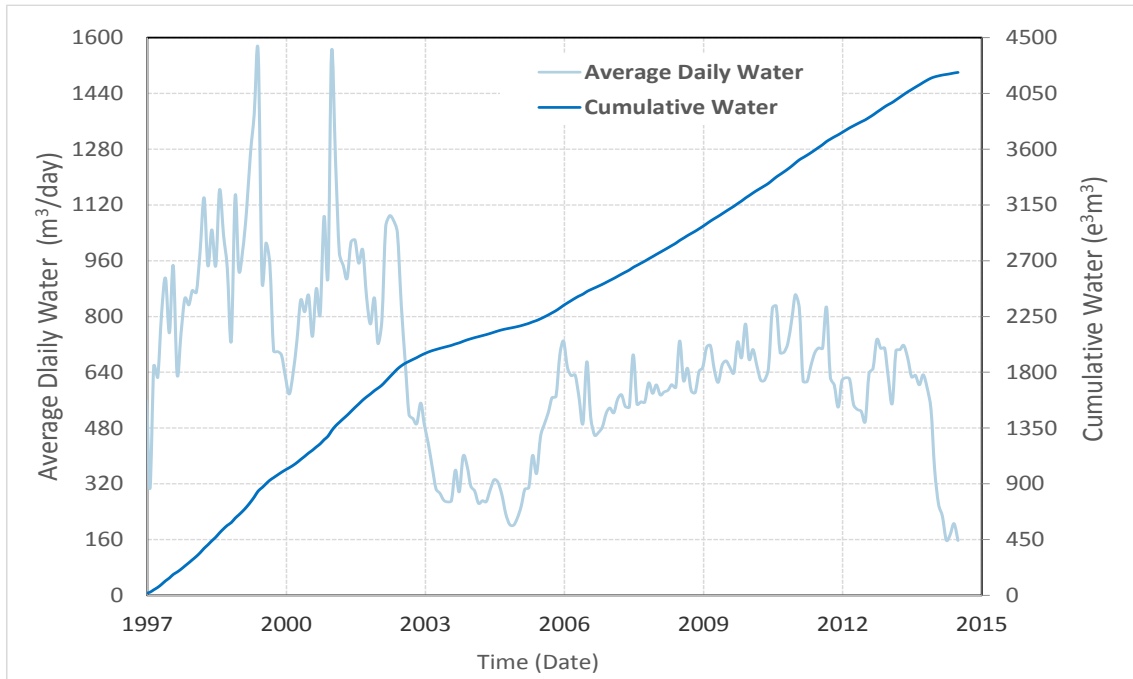
Figure 3-16 Average daily water and cumulative water versus production date for CNRL-SAGD.
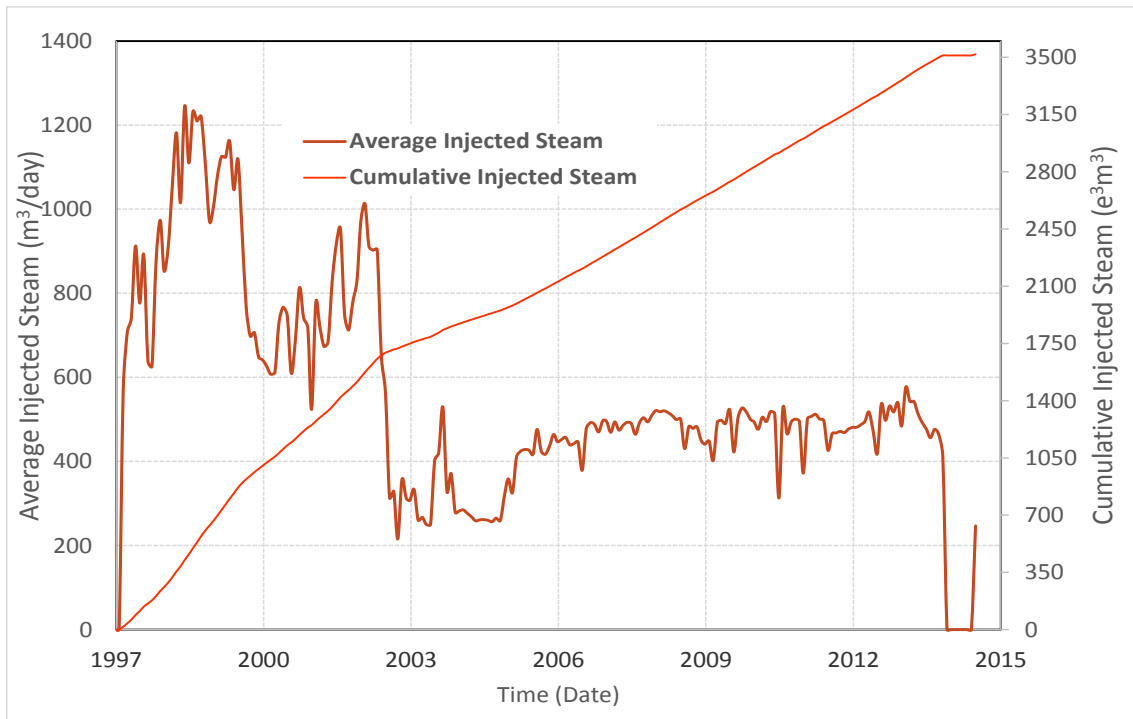
**Figure 3-17 Average injected steam and cumulative injected steam versus production date for CNRL-SAGD.**

Figure 3-18 Normalized oil rate and normalized cumulative oil versus production date for CNRL-SAGD.

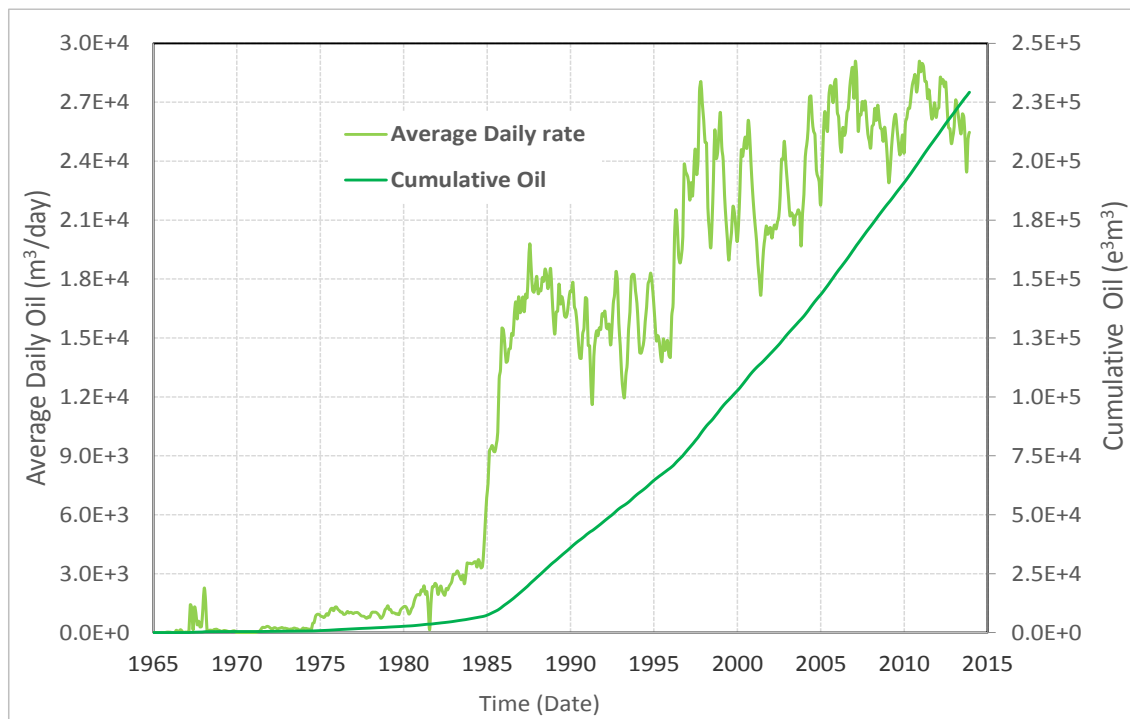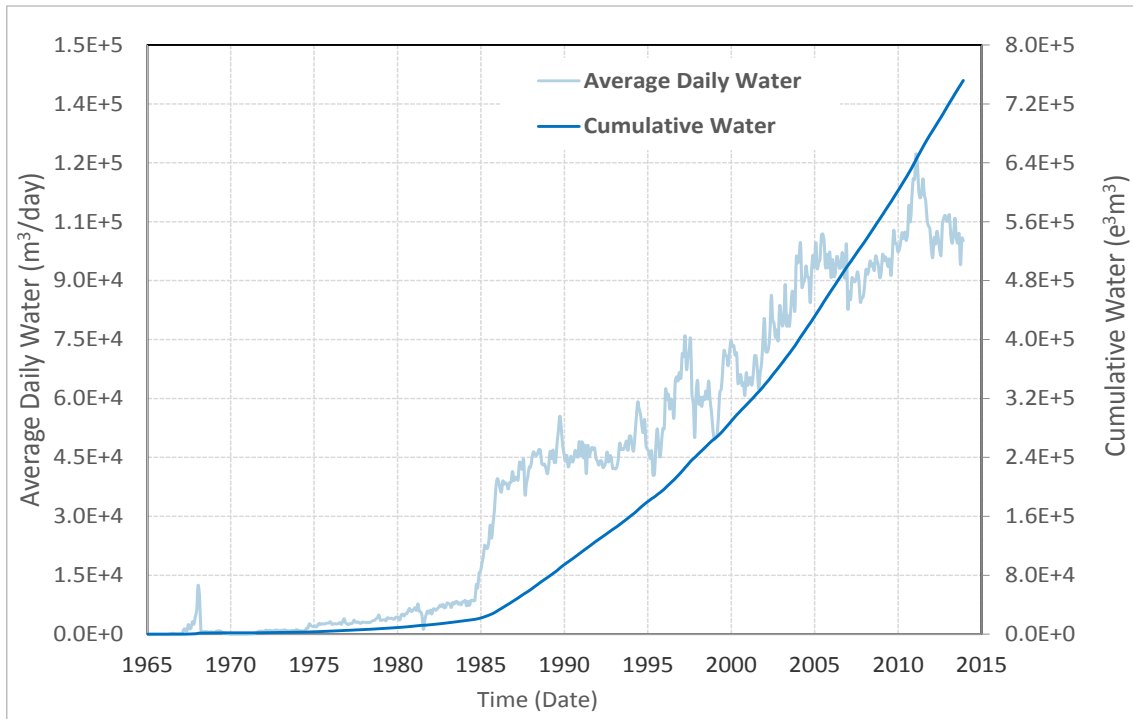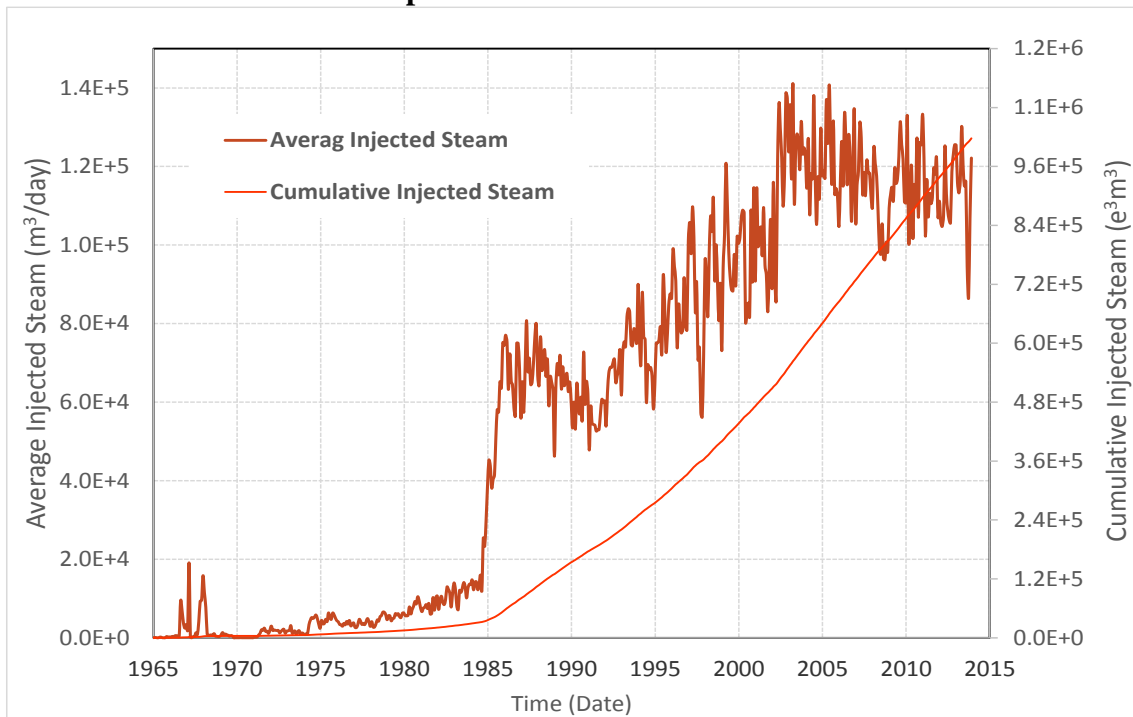**Figure 3-19 Normalized water rate and normalized cumulative water versus production date for CNRL-SAGD.**

Figure 3-20 Normalized injected steam and normalized cumulative injected steam versus production date for CNRL-SAGD.
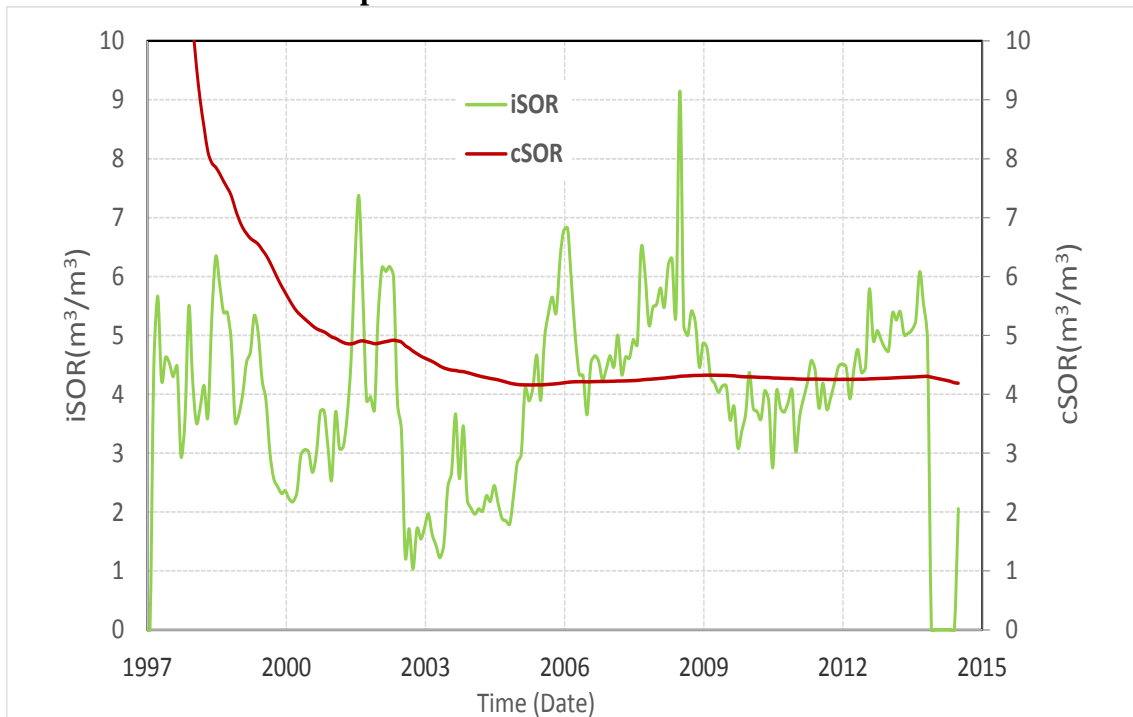
Figure 3-21 Instantaneous steam oil ratio and cumulative steam oil ratio versus production date for CNRL-SAGD.

3.3.4 HUSKY-Tucker Lake-SAGD

In the period of 2006/08/01 to 2014/08/01, production data reveals that the maximum average daily oil production was roughly 1900 m^3/day for a maximum number of 63 well pairs. Cumulative oil produced is 3000 x 10^3 m^3. Normalized oil production rate has some fluctuations but the average value was around 25 m^3/day from 2009 to 2014. Normalized cumulative oil increased with constant slope in 2011-2014 and the maximum value was 60 x 10^3 m^3 in 2014. The maximum amount of the average daily produced water was over 29,000 m^3/day and cumulative water produced at the end of the period was around 33,000 x 10^3 m^3 with almost a constant slope during production period. Average normalized daily water production was around 250 m^3/day. Normalized cumulative water was 700 x $10^3 m^3$ by the end of August 2014. In August 2014, the cumulative injected steam was 24,000 x $10^3 m^3$. Injected steam after 2007 was 315 x 10^3 m^3. And the slope after 2007 was almost constant. The cumulative steam oil ratio curve had a decreasing trend with time and the minimum value was 7.9. Figures 3-22 to 3-28 show the different performance curves for HUSKY-Tucker Lake-SAGD

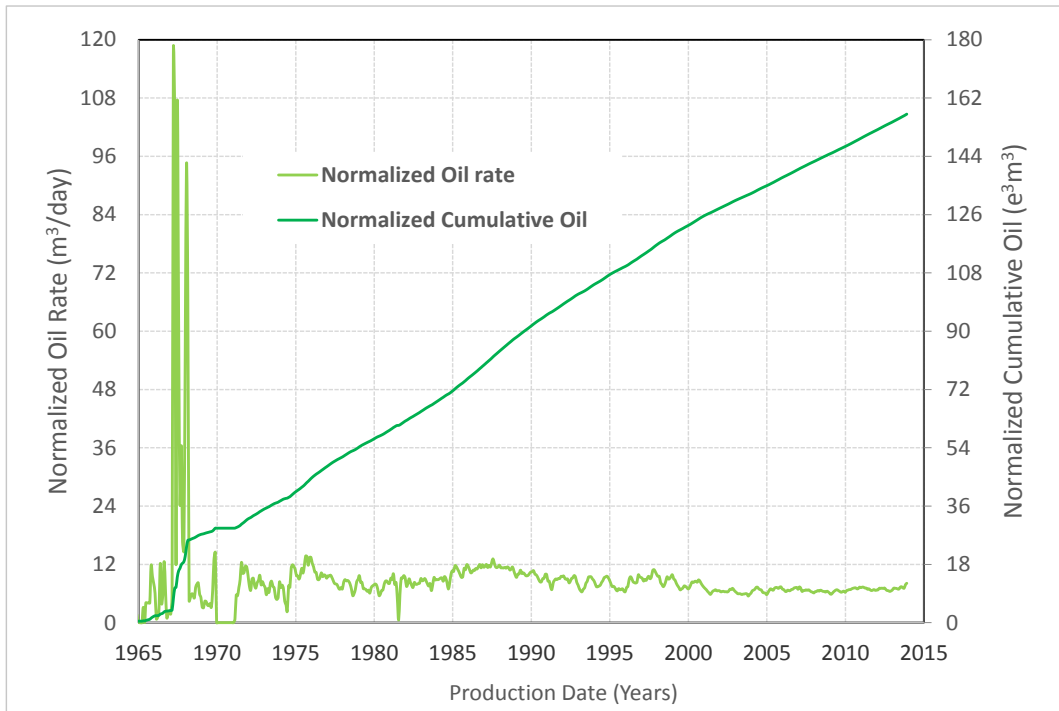**Figure 3-22 Average daily oil and cumulative oil versus production date for HUSKY-SAGD.**
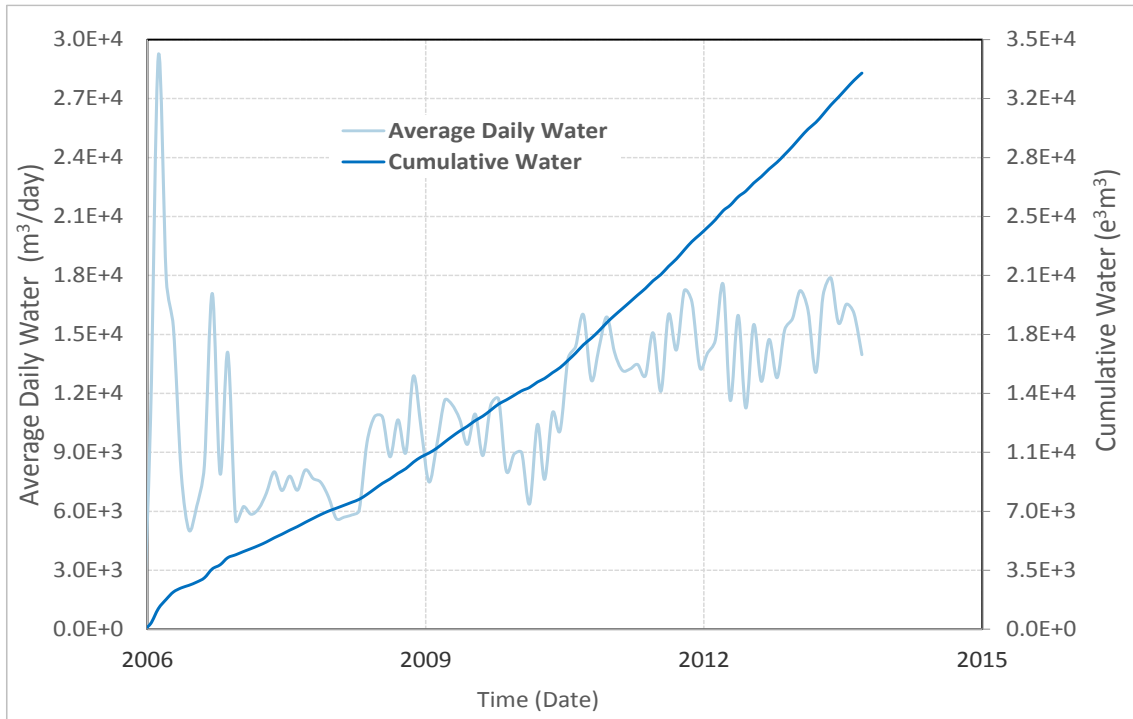
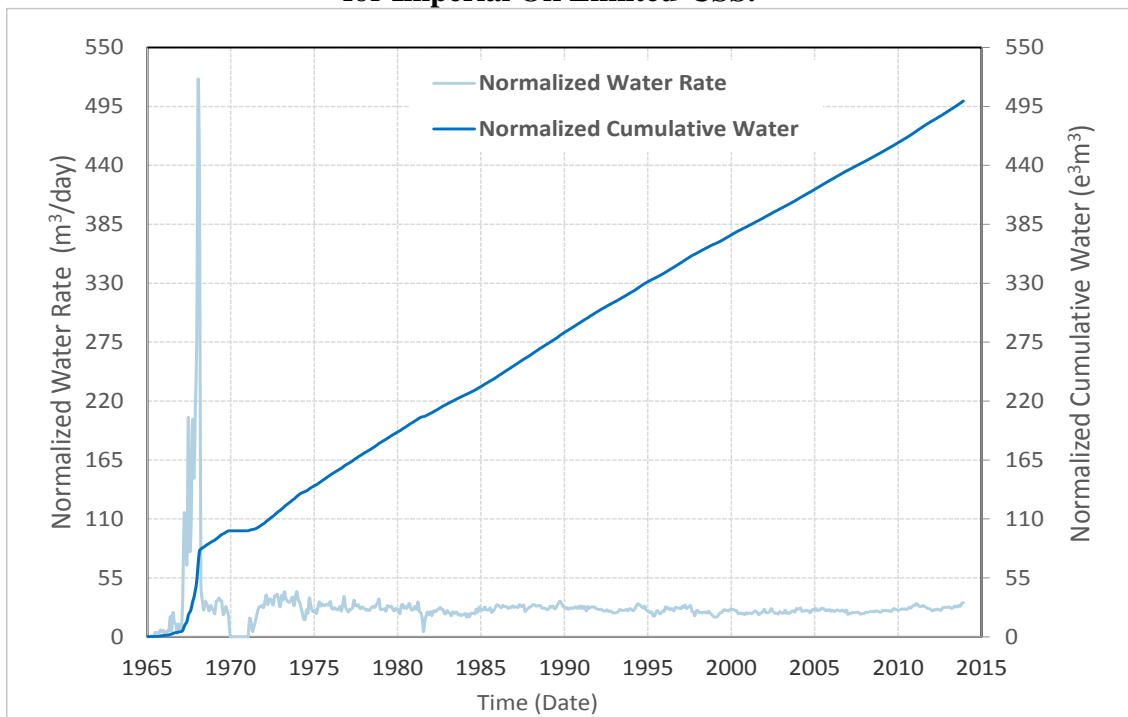**Figure 3-23 Average daily water and cumulative water versus production date for HUSKY-SAGD.**
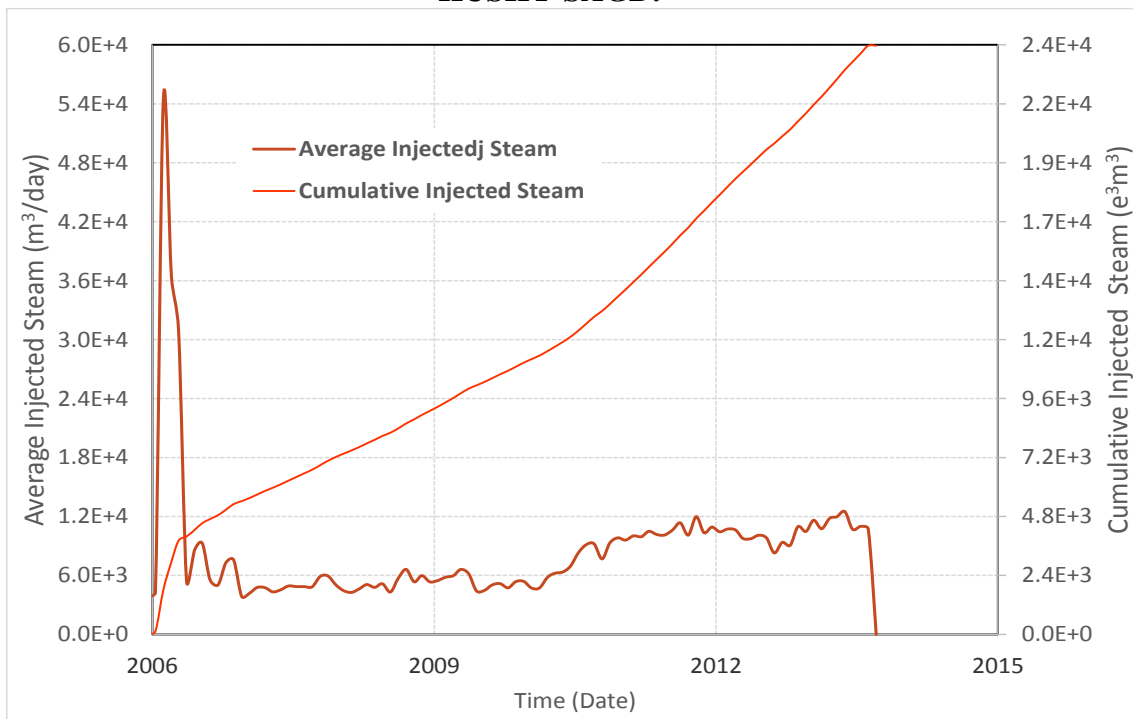
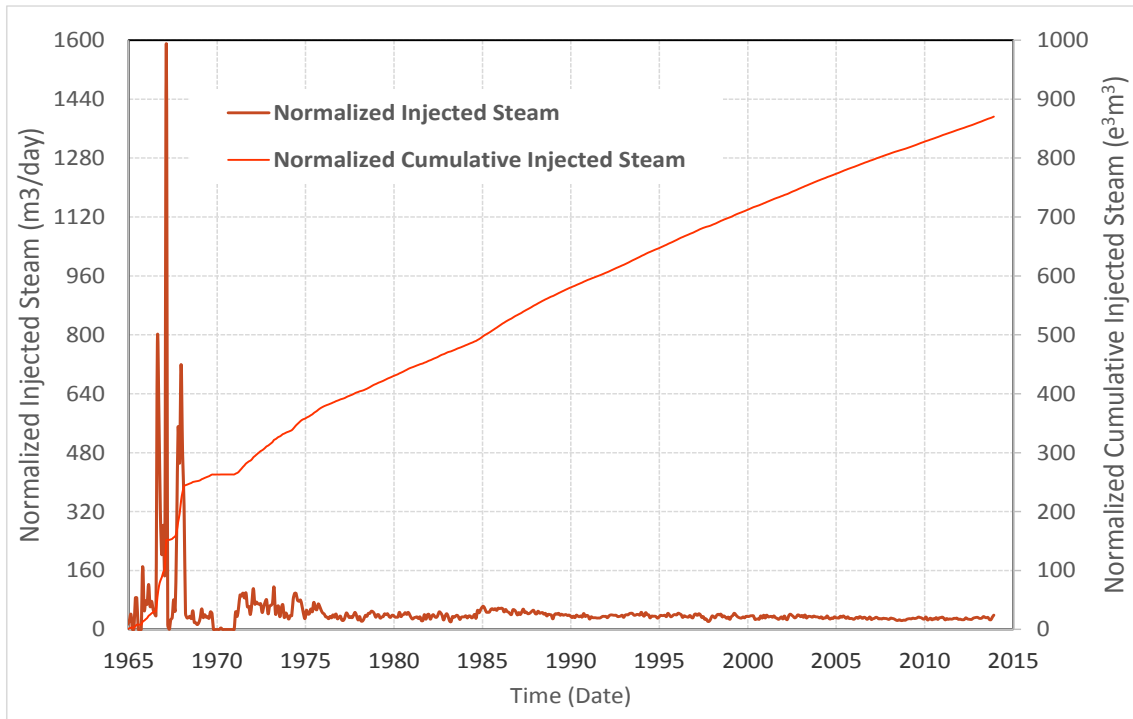**Figure 3-24 Average injected steam and cumulative injected steam versus production date for HUSKY-SAGD.**

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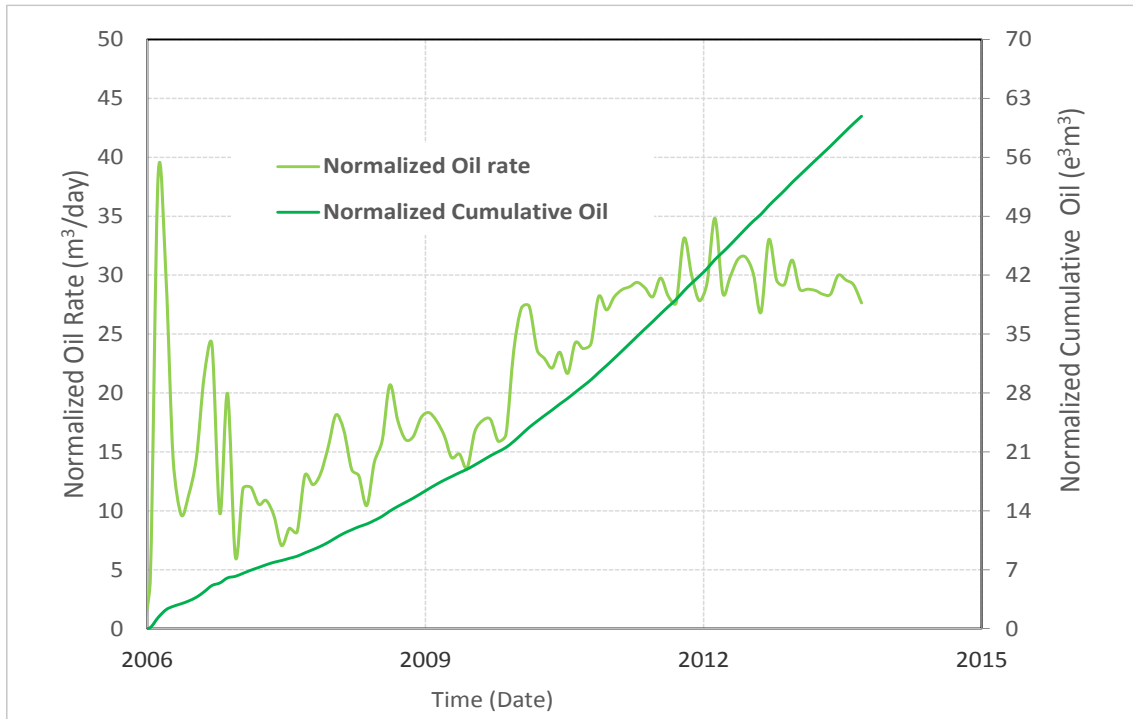
Figure 3-25 Normalized oil rate and normalized cumulative oil versus production date for HUSKY-SAGD.
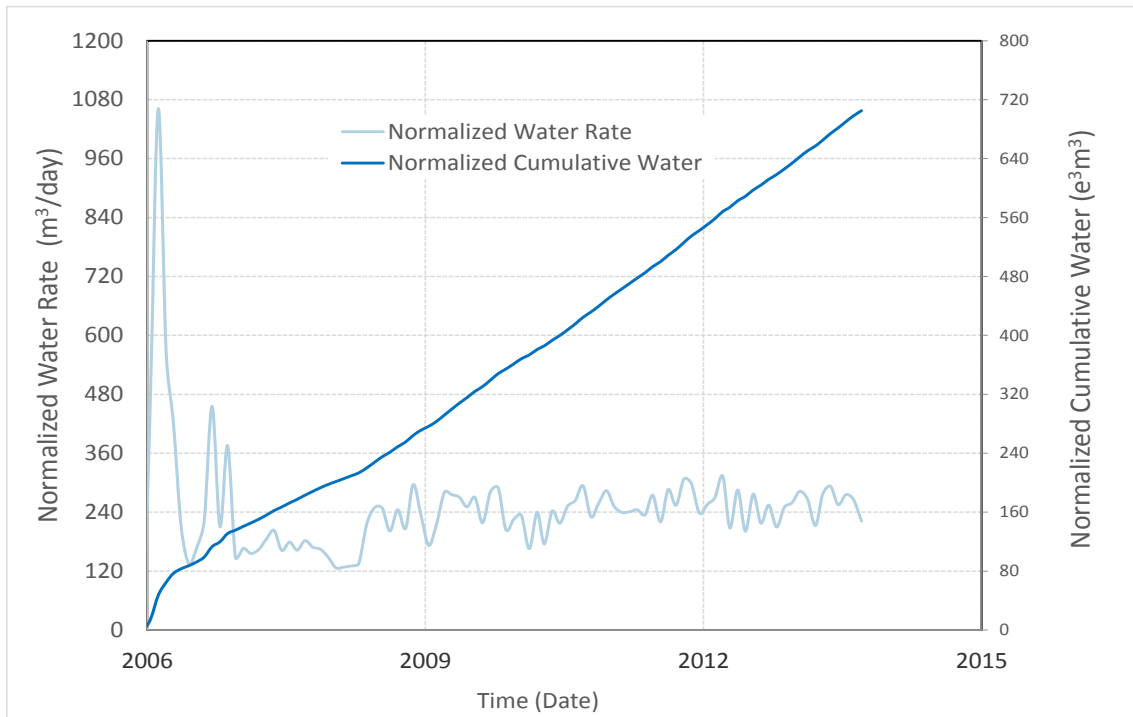
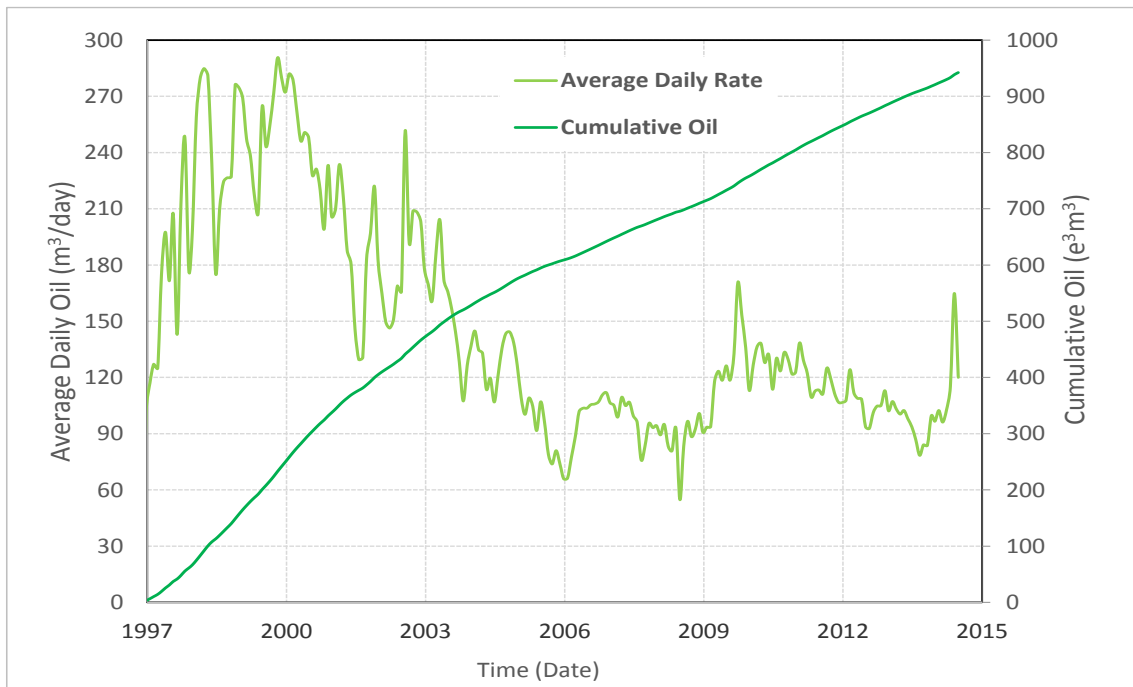**Figure 3-26 Normalized water rate and normalized cumulative water versus production date for HUSKY-SAGD.**
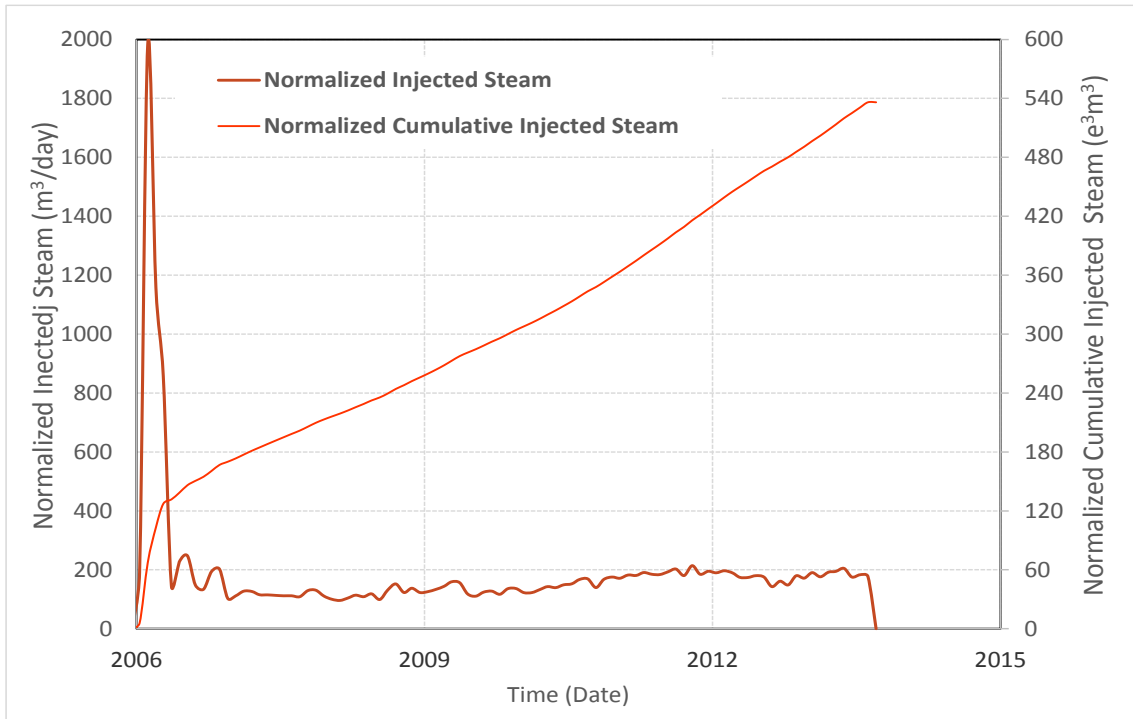
Figure 3-27 Normalized injected steam and normalized cumulative injected steam versus production date for HUSKY-SAGD.
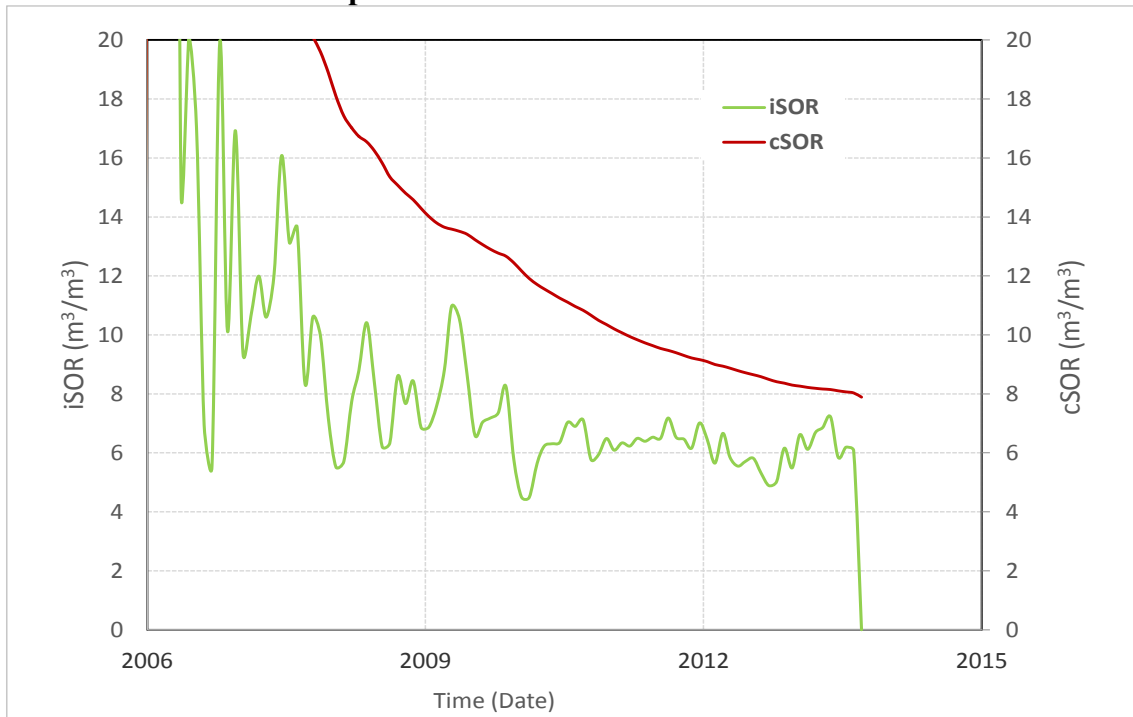
Figure 3-28 Instantaneous steam oil ratio and cumulative steam oil ratio versus production date for HUSKY-SAGD.

3.3.5 OSUM-SAGD

Production data has been gathered in the period of 1997/08/01 to 2014/08/01. The maximum number of well pairs was 24. The maximum value for the average daily oil was roughly 1,400 m^3/day. The average daily oil production was nearly constant up to 2007 and then increased sharply to a maximum value of around 1400 m^3/day. The cumulative oil produced in this time period was roughly 2,000 x 10^3 m^3. The maximum value of the normalized production rate is 22 m^3/day. The average daily water production rate increased rapidly 10^3 m^3after around 2007. Normalized cumulative oil production increased with constant slope. This amount was equal to 140 x 10^3 m^3 in August 2014. The maximum value for the average daily produced water was over 4,400 m^3/day and cumulative water produced at the end of the period was around 100,000 x 10^3 m^3. After around 2007 the amount of produced water increased rapidly. Average normalized daily water production was around 108 m^3/day. Normalized cumulative water was 679 x 10^3 m^3 by the end of the August 2014. At the end of the period, the cumulative injected steam was 8,800 x 10^3 m^3. The slope of the normalized cumulative injected steam increases sharply after 2007. The average values of cumulative and instantaneous steam oil ratio were 4.2 and 4.1 respectively. Figures 3-29 to 3-35 show the different performance curves for OSUM-SAGD.
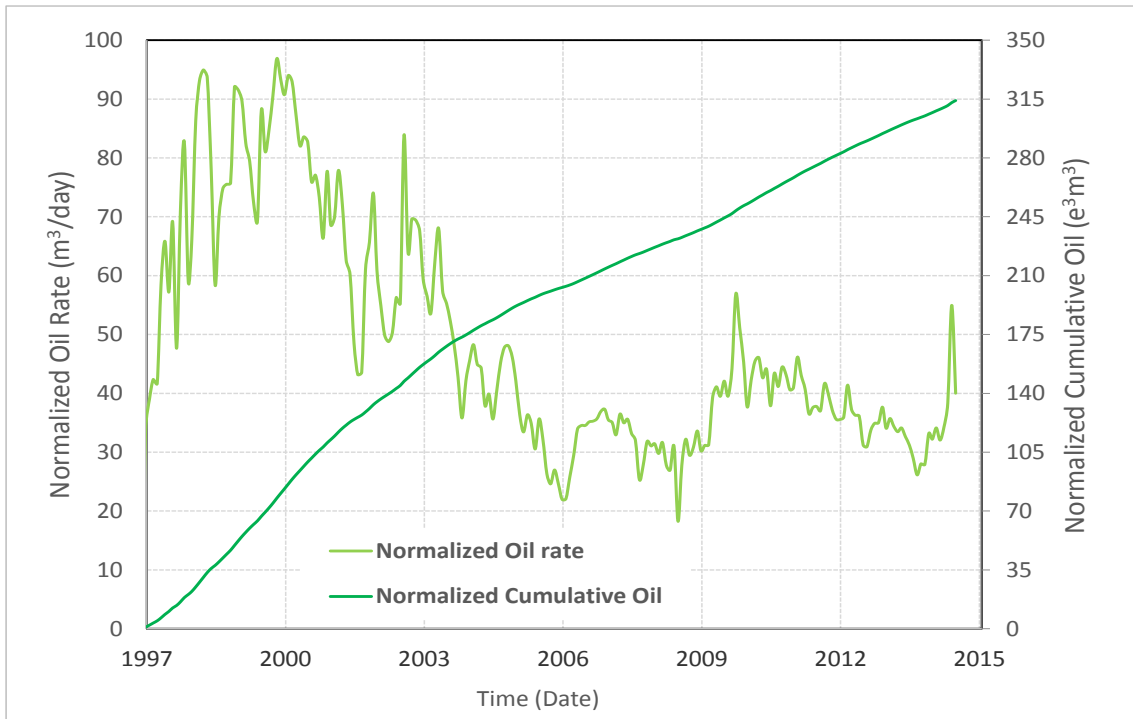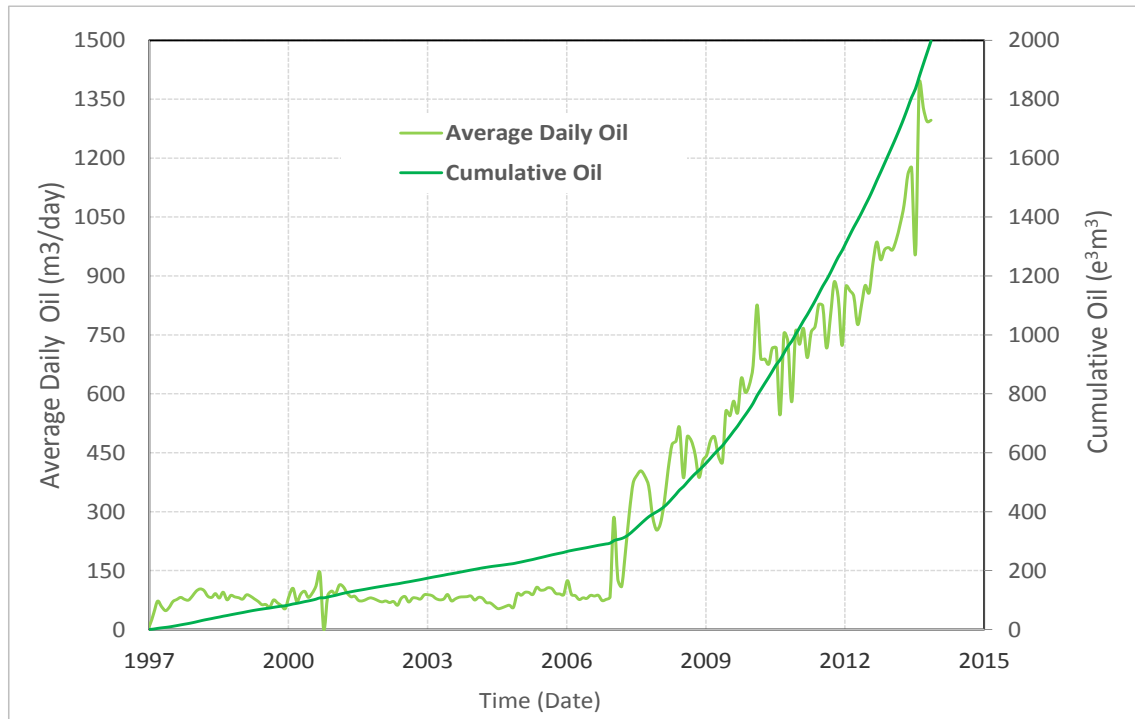

Figure 3-29 Average daily oil and cumulative oil versus production date for OSUM-SAGD.
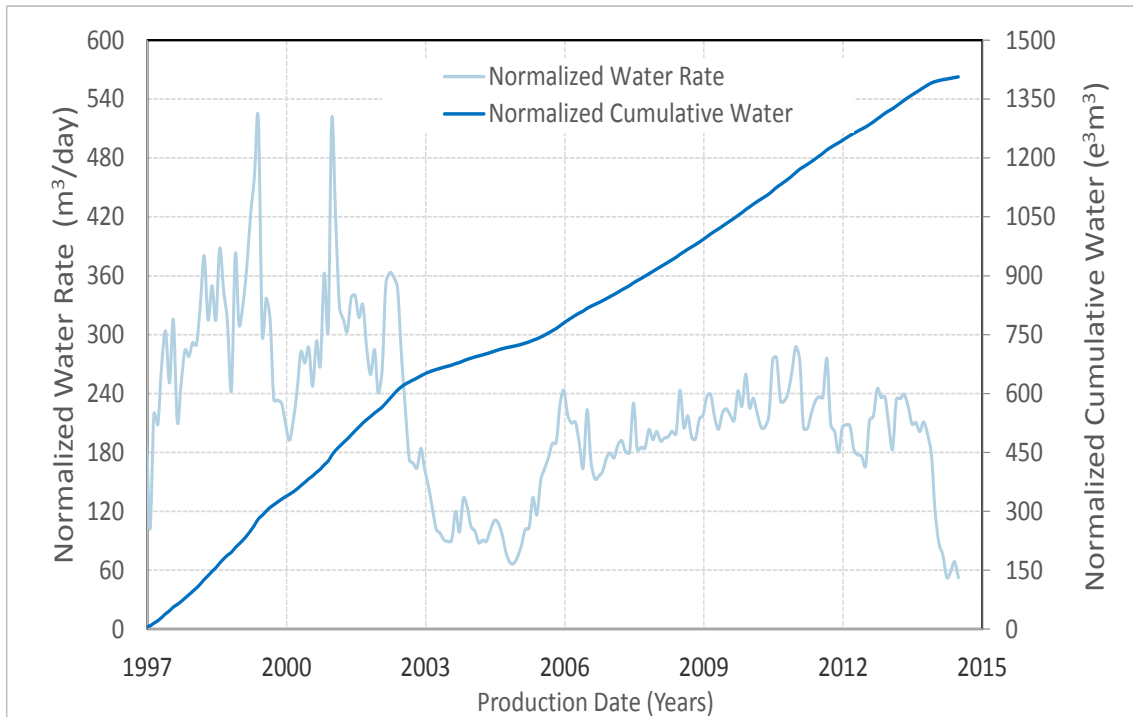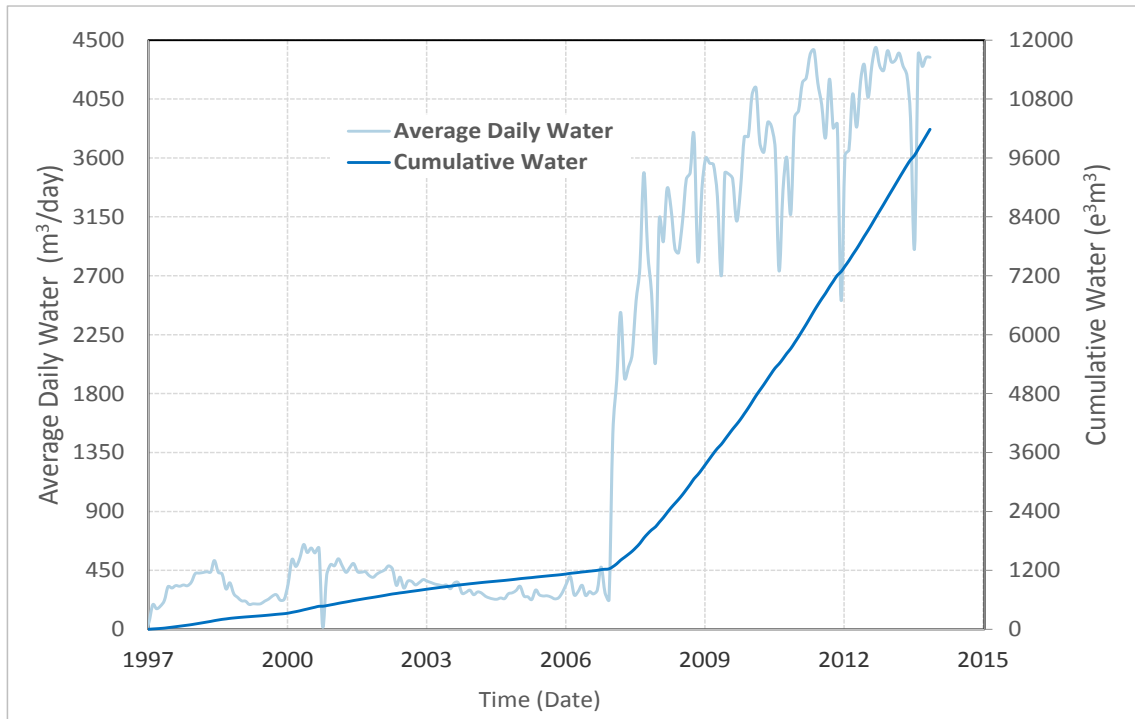
Figure 3-30 Average daily water and cumulative water versus production date for OSUM-SAGD.
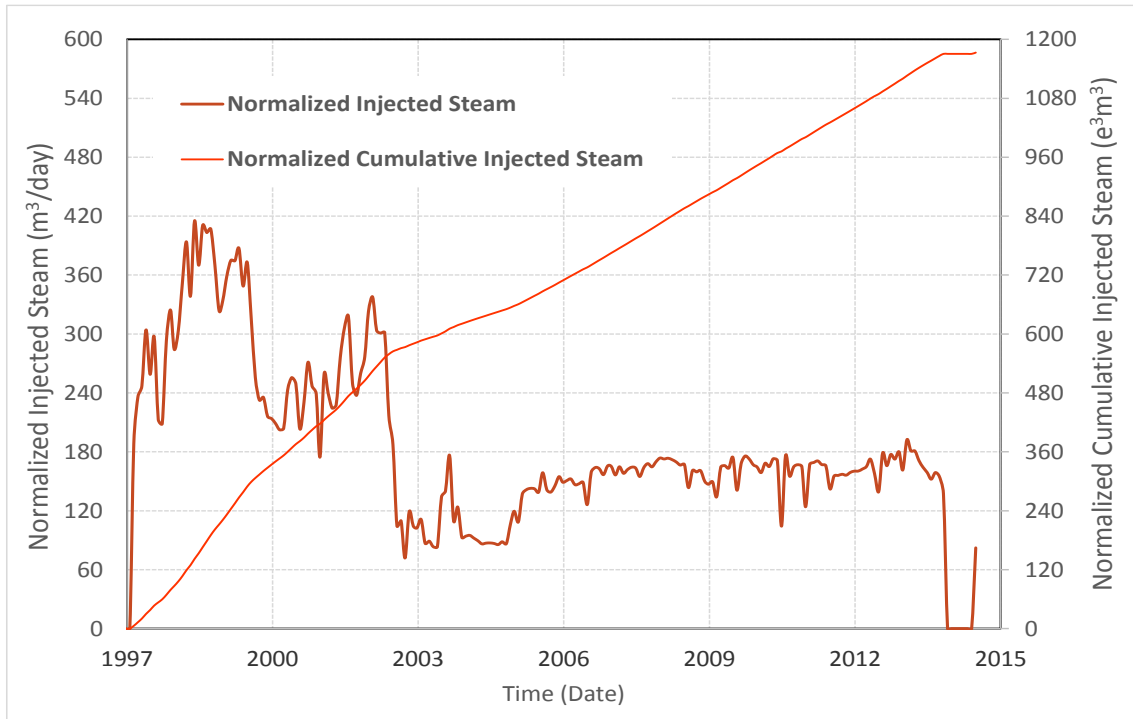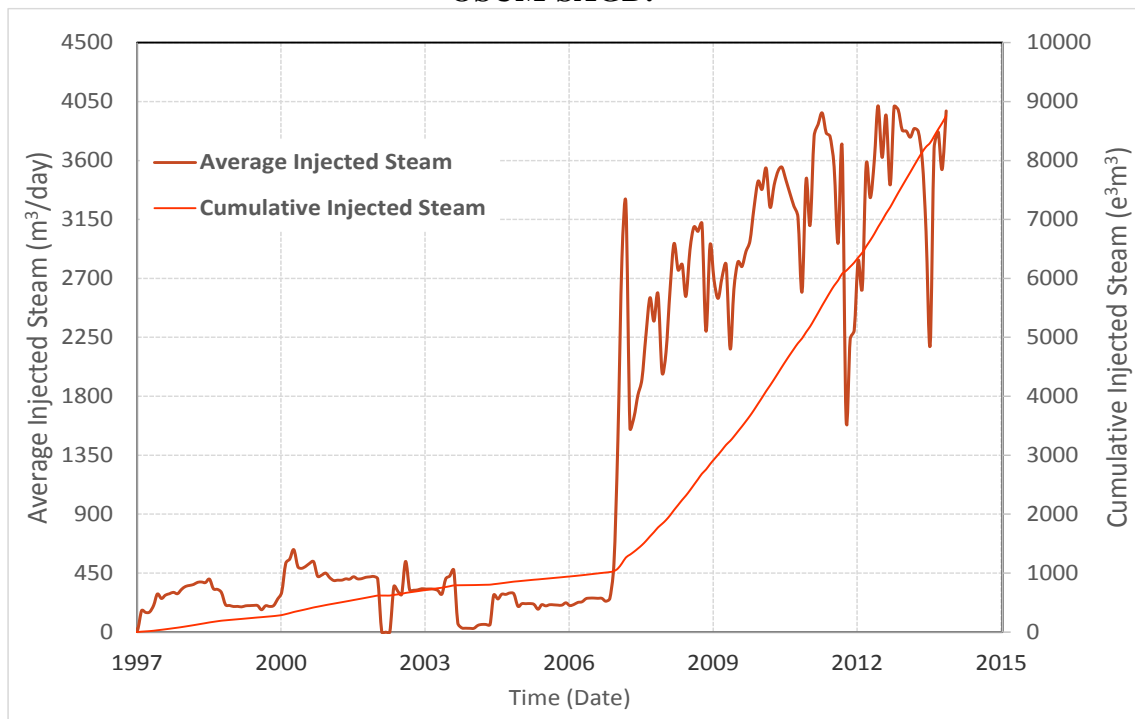

Figure 3-31 Average injected steam and cumulative injected steam versus production date for OSUM-SAGD.
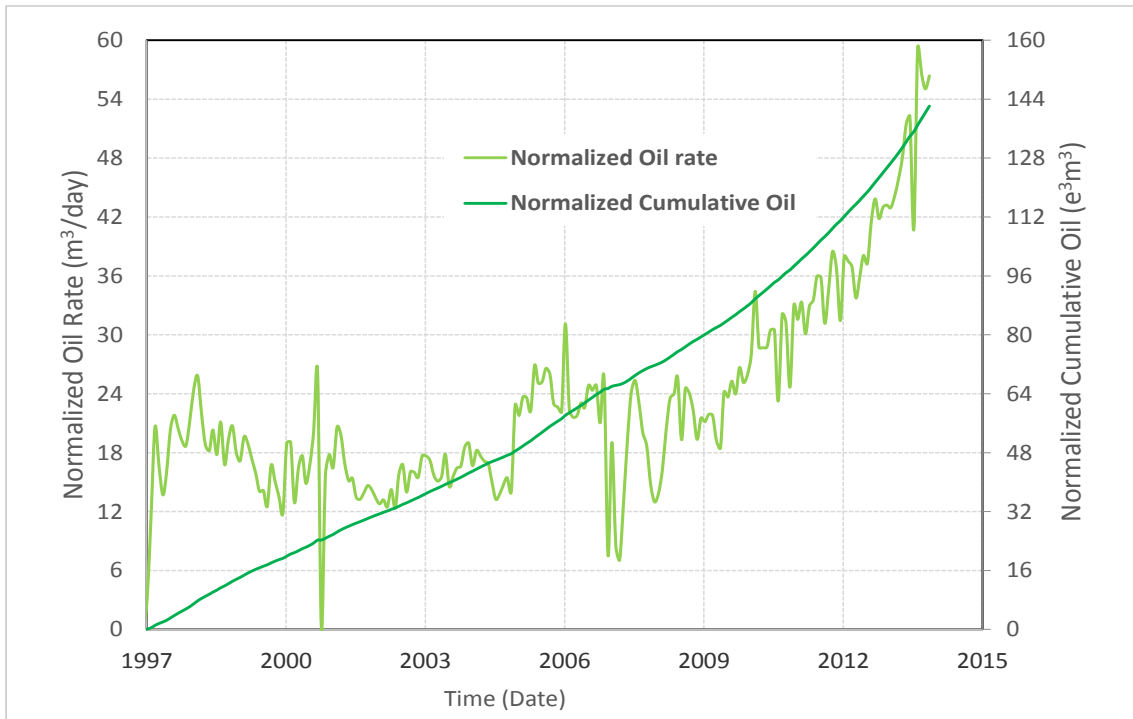
Figure 3-32 Normalized oil rate and normalized cumulative oil versus production date for OSUM-SAGD.
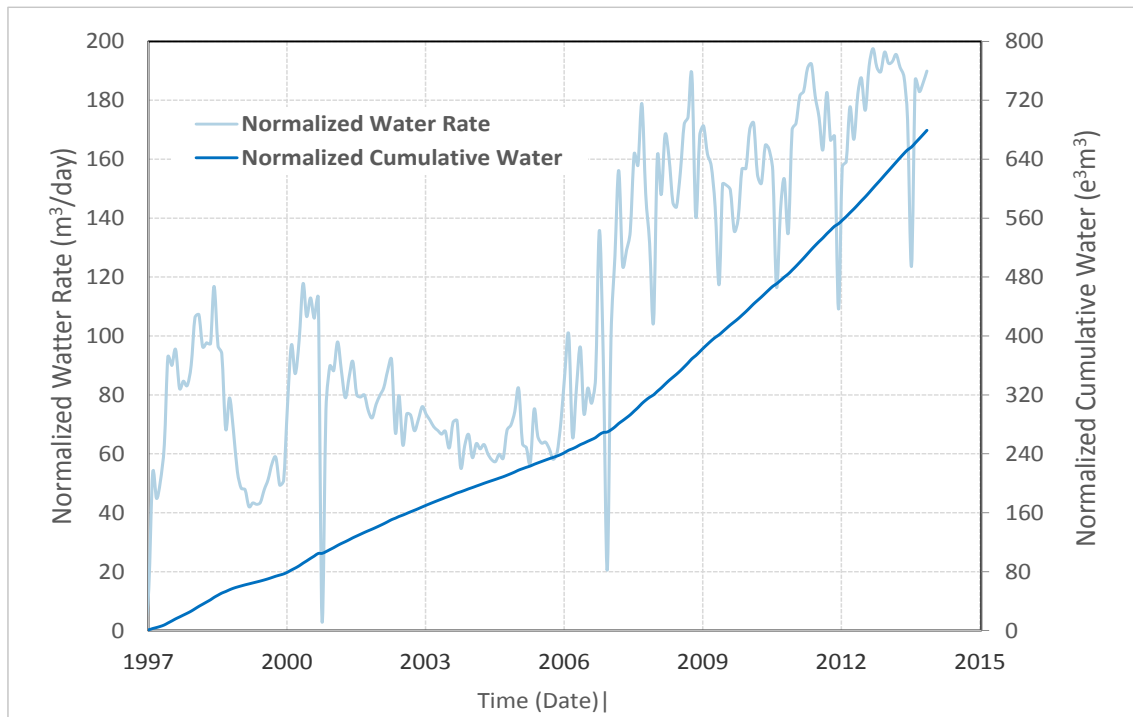
Figure 3-33 Normalized water rate and normalized cumulative water versus production date for OSUM-SAGD.
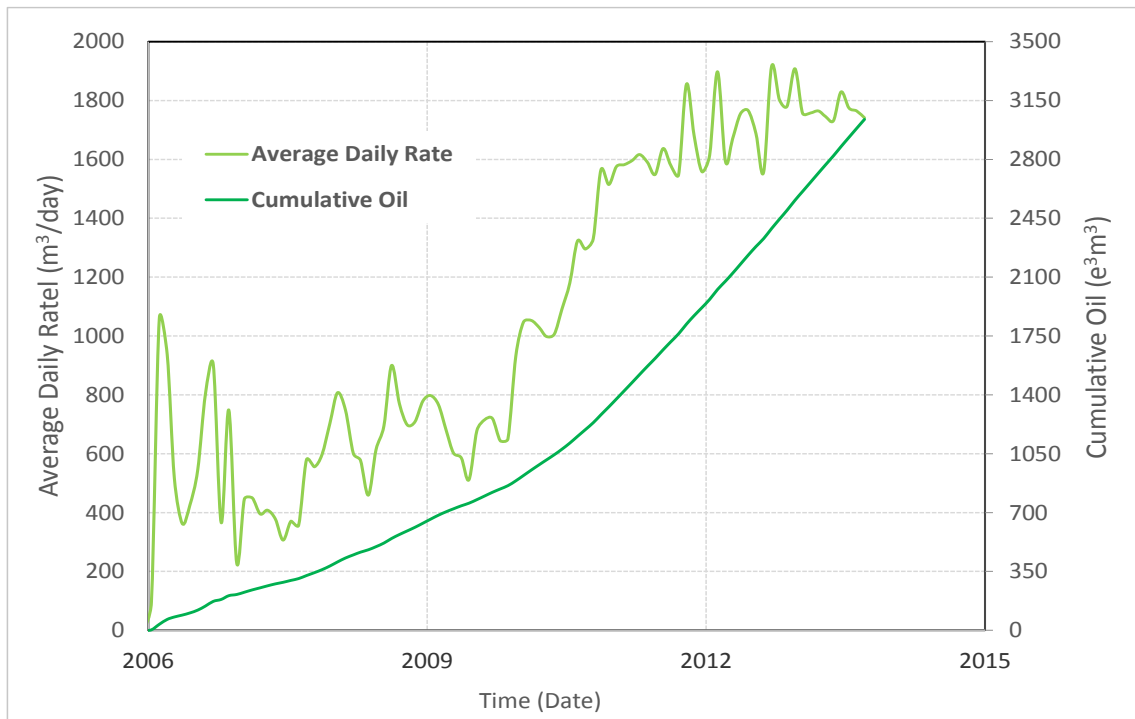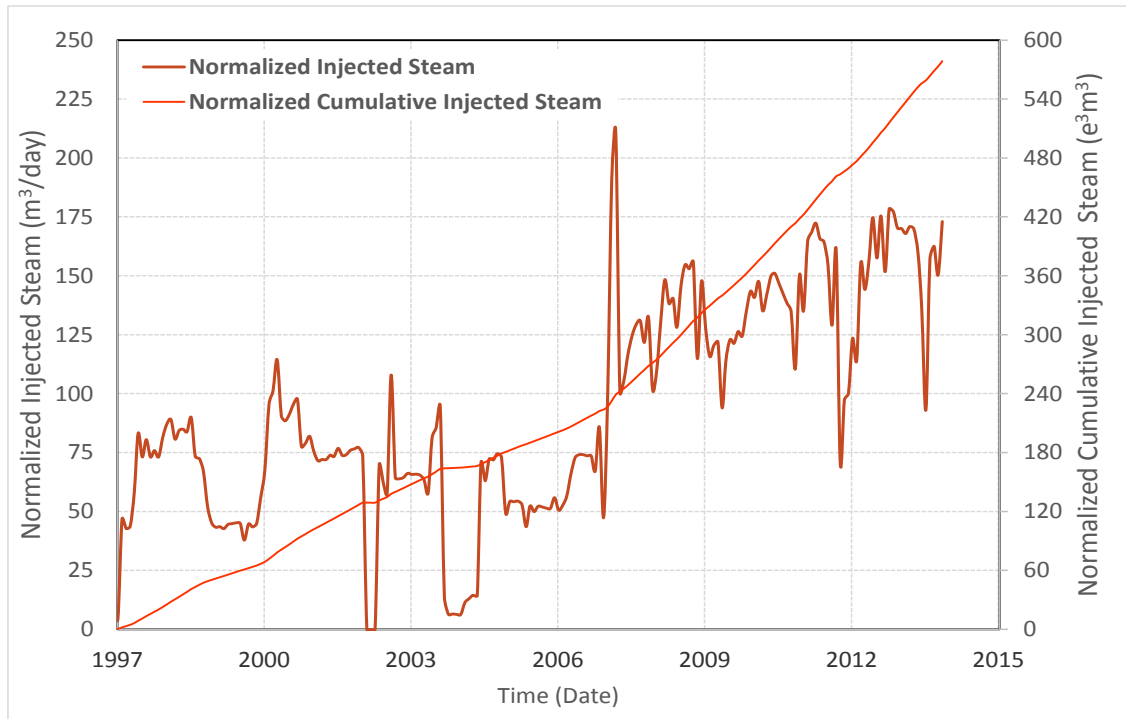
Figure 3-34 Normalized injected steam and normalized cumulative injected steam versus production date for OSUM-SAGD.
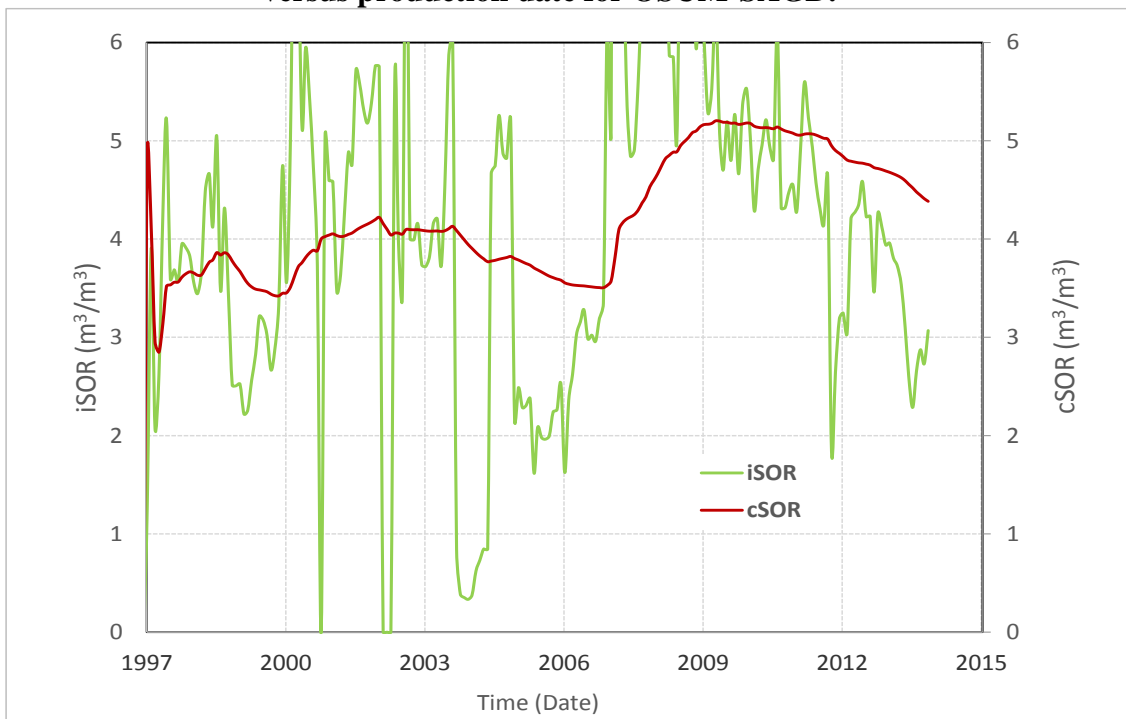

Figure 3-35 Instantaneous steam oil ratio and cumulative steam oil ratio versus production date for OSUM-SAGD.

3.4 Performance Comparison

Figures 3-36 to 3-42 compare the performance of the various fields.
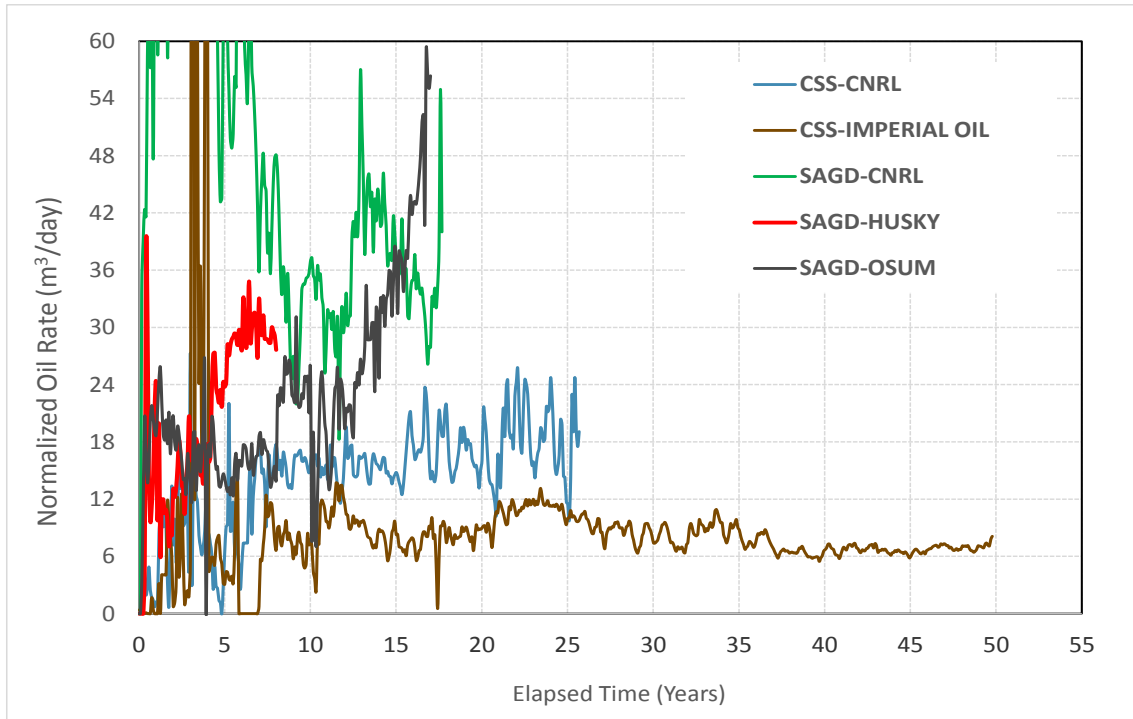
Figure 3-36 Normalized oil rate versus elapsed time for various fields.

As can be seen in Figure 3-36, CSS-IMPERIAL OIL has the lowest normalized oil production rate and CNRL-SAGD has the highest. Also it was realized that all SAGD projects have higher values when compared with CSS. As can be expected, the cumulative production curves follow the same trend as the curves in Figure 3-36 as shown in Figure 3-37. As shown in Figure 3-38, the normalized injected steam for CSS is lower than that of the SAGD operations in the steady section of the curves. As it can be seen in Figure 3-39, the normalized cumulative steam of CSS has the lower values. In Figure 3-40, normalized produced water for SAGD projects are higher than for CSS projects. The trend for normalized cumulative water curves (Figure 3-41) is the same as for Figure 3-40.
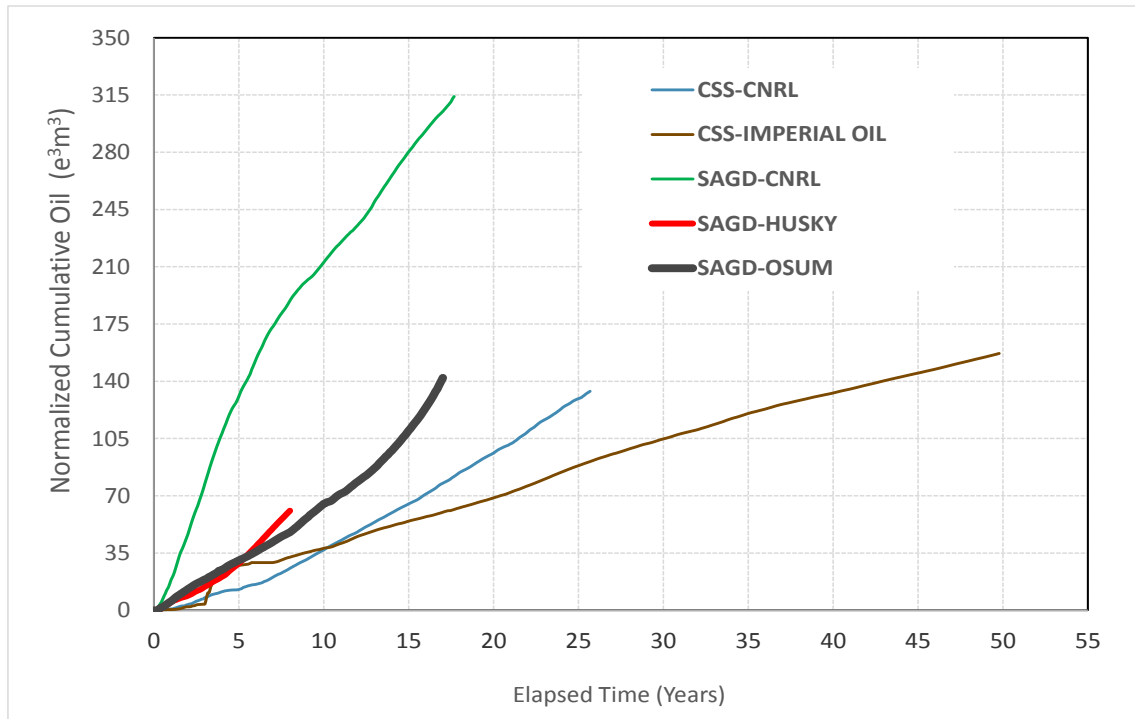
Figure 3-37 Normalized cumulative oil versus elapsed time for various fields.
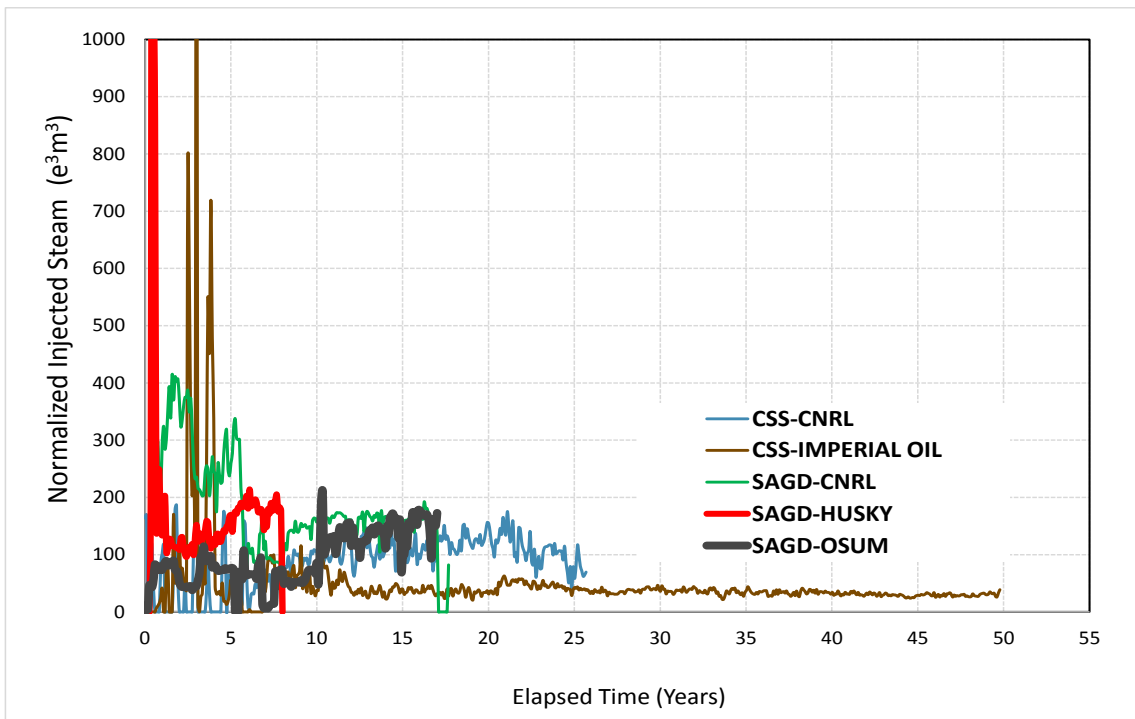
Figure 3-38: Normalized injected steam versus elapsed time for various fields.
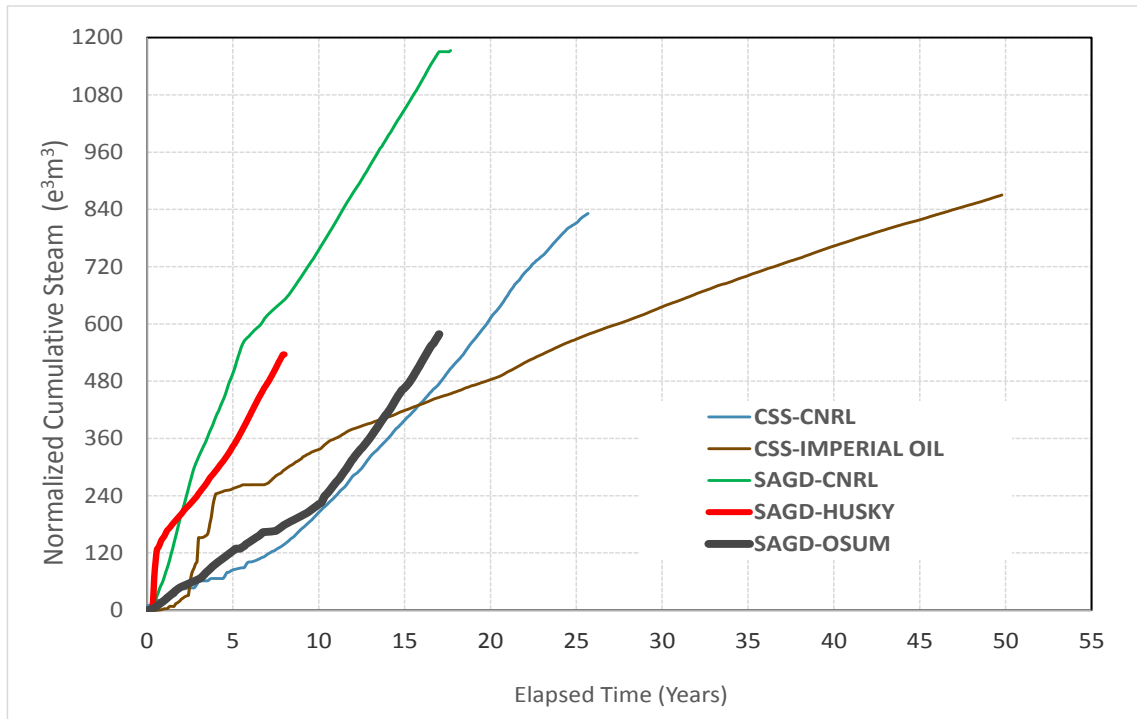
Figure 3-39 Normalized cumulative steam versus elapsed time for various fields.
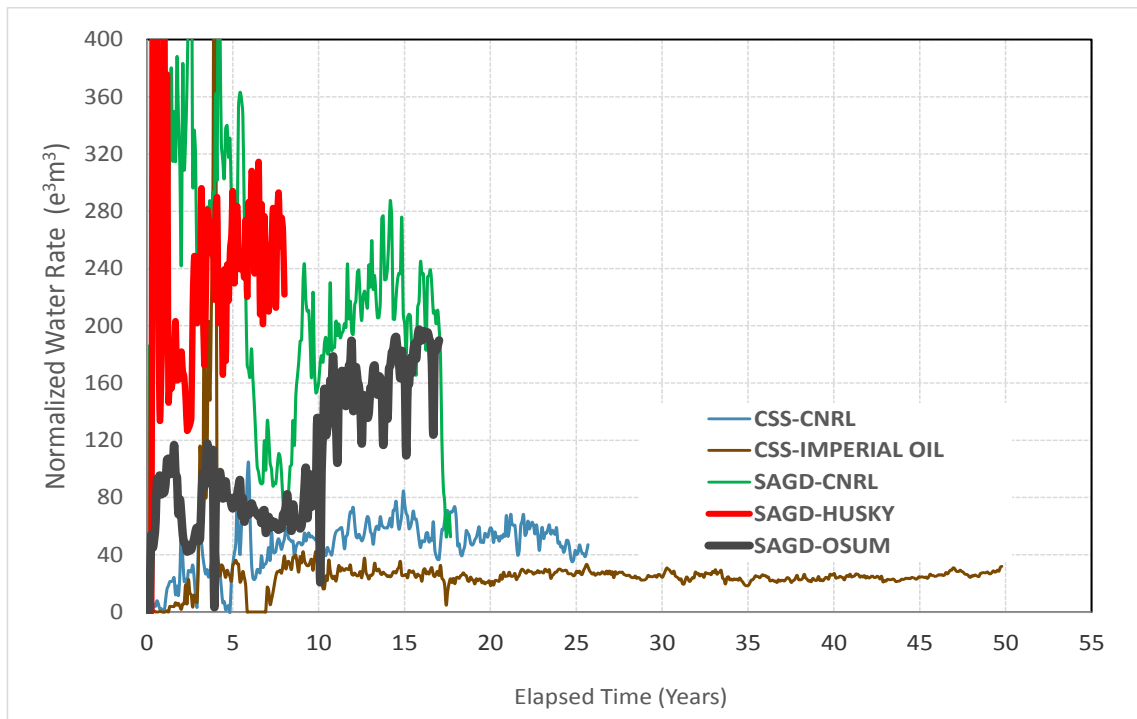
Figure 3-40 Normalized water rate versus elapsed time for various fields.
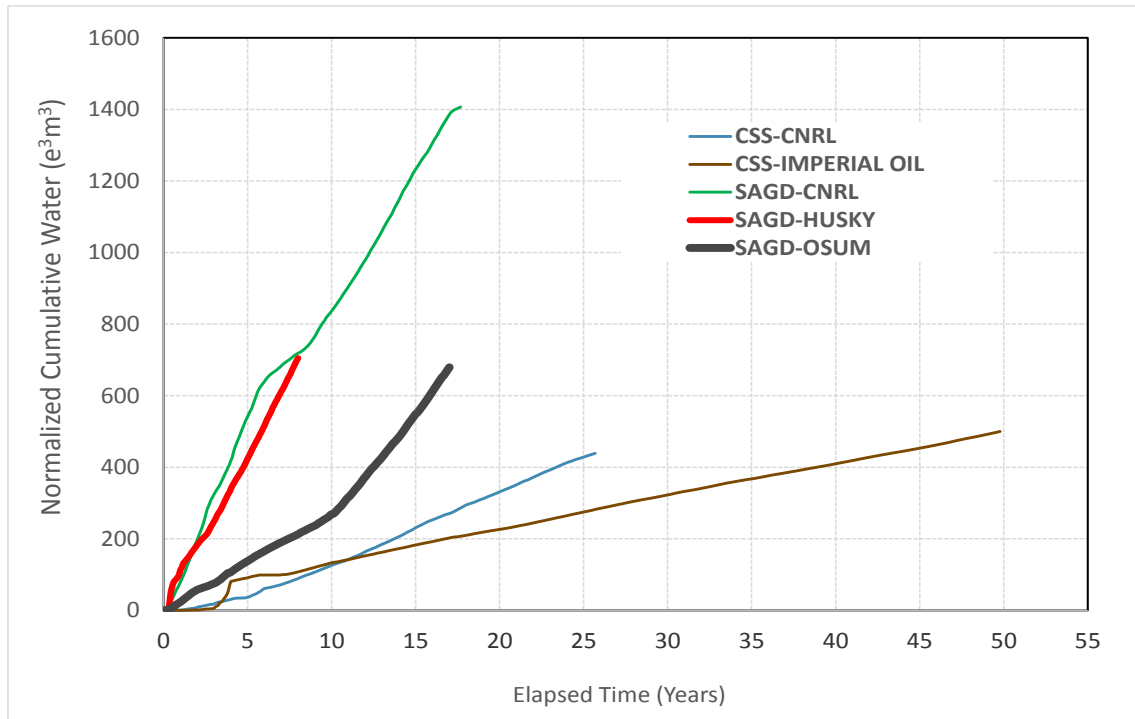
Figure 3-41 Normalized cumulative water versus elapsed time for various fields.
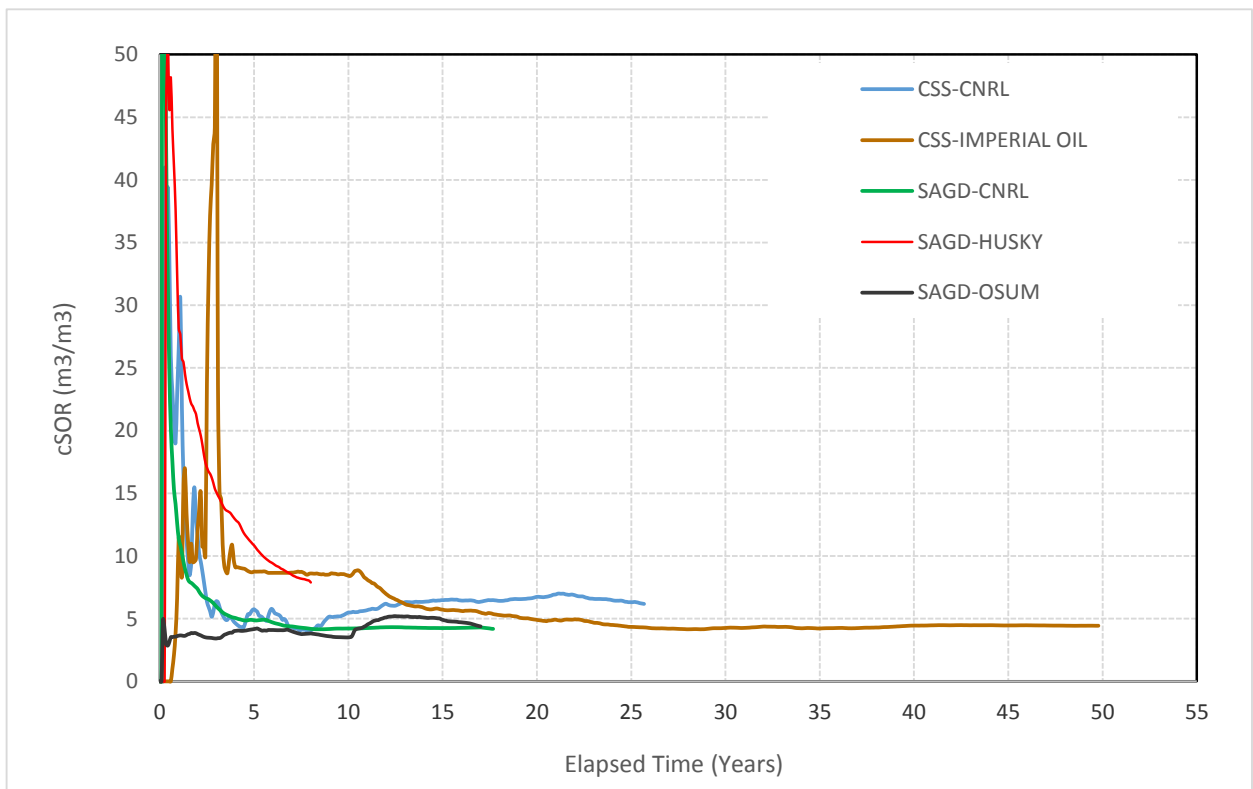
Figure 3-42 Cumulative steam oil ratio versus elapsed time for various fields.

It can be observed from Figure 3-42, the cSOR for SAGD-CNRL and SAGD-OSUM have lower values when compared to CSS. In the case of SAGD-HUSKY, more time is required to be able to be compared with the other curves. For the first eight years of production, SAGD-HUSKY shows higher cSOR values than other fields, but if the cSOR decline continues, it may drop below values observed in other fields.

3.5 Discussion

Most literature compared the performance of mature CSS with fledgling SAGD. The comparison was mostly against SAGD. It was concluded that the recovery of bitumen using SAGD mechanism in the Clearwater formation at Cold Lake area is usually uneconomic while CSS is a proven economical process and SAGD might compete favourably with CSS in the future based on predictions.

Unlike most of the previous literature surveys in this regard, analysis of field data shows better performance of SAGD over CSS. This is due to the fact that preceding surveys were performed over a decade ago. Currently the steam chambers are more mature and SAGD operators are more experienced than ten years ago. Therefore it is expected that the performance of some SAGD operation is much better when compared with the SAGD operation in ten years ago.

Comparison of the performance indicators such as cumulative oil production and cSOR show that all SAGD projects have higher normalized cumulative produced oil. Among the current thermal projects at Cold Lake, SAGD-CNRL has the lowest cSOR. CSS-IMPERIAL OIL and SAGD-CNRL reveal close performance. Due to high values of cSOR of CSS-CNRL, it is not considered to be as efficient as CSS-IMPERIAL OIL and SAGD-CNRL. Evaluation of the exact behaviour of SAGD-OSUM and SAGD-HUSKY require more time to be mature and stabilize.

CHAPTER 4 RESERVOIR SIMULATION STUDY

This chapter explains the numerical simulation studies for Steam-Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) to forecast and compare the efficiencies of these processes at Cold Lake area. Geological description and PVT data have been described first and then the explanation about the simulation models and the results of simulation studies are presented and discussed.

4.1 RESERVOIR DESCRIPTION

High quality bitumen pay exists in the Clearwater Formation in the Cold Lake area. The sands of Clearwater formation are unconsolidated and thick. The top of the Clearwater Formation at Cold Lake is located at 400-450 m total vertical depth (TVD) and the cumulative net pay is between 10 and 40 m, the range of porosity is from 28 to 35%, and the average bitumen saturation is 10.5% by weight. The viscosity of bitumen at reservoir temperature of 15°C is about 100,000 cP [47]. However, when the bitumen is raised to above 200°C, its viscosity drops to less than 10 cP and it is sufficiently mobile enough to be produced from the reservoir.

4.2 FLUID PROPERTIES

For the reservoir simulation models constructed in this research, three fluid components were considered. These are bitumen, water, and methane. The existing phases in the model are aqueous, oleic and gas. The aqueous phase is water – in the model, the solution gas is not soluble in the aqueous phase. The gas phase includes both steam and methane. Bitumen and methane or both comprise the oleic phase.

The internal properties database in the CMG STARS^{TM} thermal reservoir simulator was used for the properties of water in both gas and aqueous phase. This includes water and steam properties (density and viscosity versus temperature and pressure) as well as thermal properties such as phase enthalpies and latent heat, and heat capacity. It is assumed that the bitumen cannot evaporate. The properties of the bitumen are as follows [54]:

Oil viscosity @ 15°C = 100,000 cP

Bitumen density @ 15°C = 1130 kg/m^3

Bitumen molecular mass = 620.0 g/mole

The solubility of the methane in the oil phase is expressed by a K-value correlation given by:

$$K - Value = \frac{Kv_1}{P} \exp^{\frac{Kv_4}{T + Kv_5}}$$

Where K-value = y/x is the ratio of the gas phase methane mole fraction and the oil phase methane mole fraction, P is the total pressure, T is the temperature, and Kv_1, Kv_4, Kv_5 are correlation coefficients for methane given by 5.4547×10^5 kPa, -879.84 °K, and 7.16 °K for Kv_1, Kv_4 and Kv_4 respectively for methane (CMG, 2006). With these correlation coefficients, the unit of pressure is kPa and temperature is °C.

For the viscosity of bitumen, the Mehrota and Svrcek [55] viscosity versus temperature correlation has been used [55]:

$$\ln \ln(\mu) = A + B \ln(T)$$

where μ is the oil viscosity and T is temperature. Figure 4-1 shows the viscosity vs temperature curve for Cold Lake bitumen. The data reveals that the temperature of the oil drops by over 5 orders of magnitude when the temperature is raised from the original reservoir temperature to that of steam temperatures used in bitumen recovery processes, typically between 200 and 300°C.
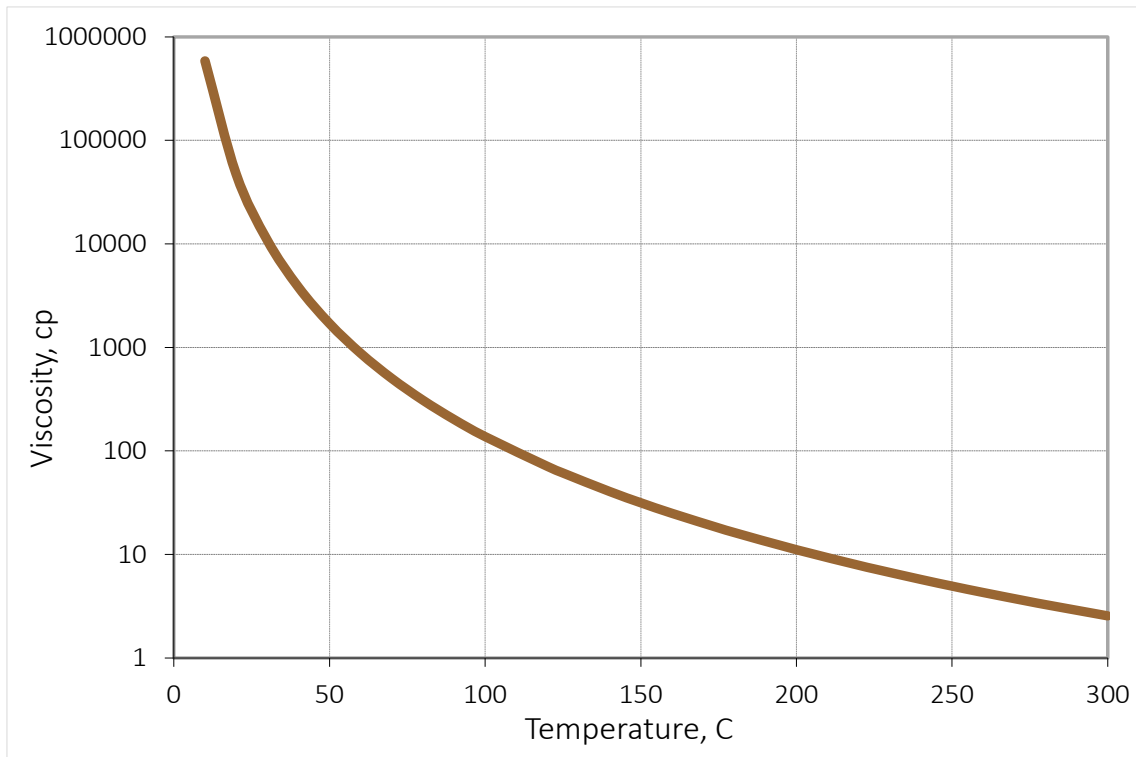
Figure 4-1: Viscosity of bitumen versus temperature in the Cold Lake area (Mehrotra and Svrcek, 1986).

4.3 ROCK-FLUID PROPERTIES

Figures 4-2 and 4-3 display the water-oil and gas-oil relative permeabilities used in the reservoir simulation models constructed here.
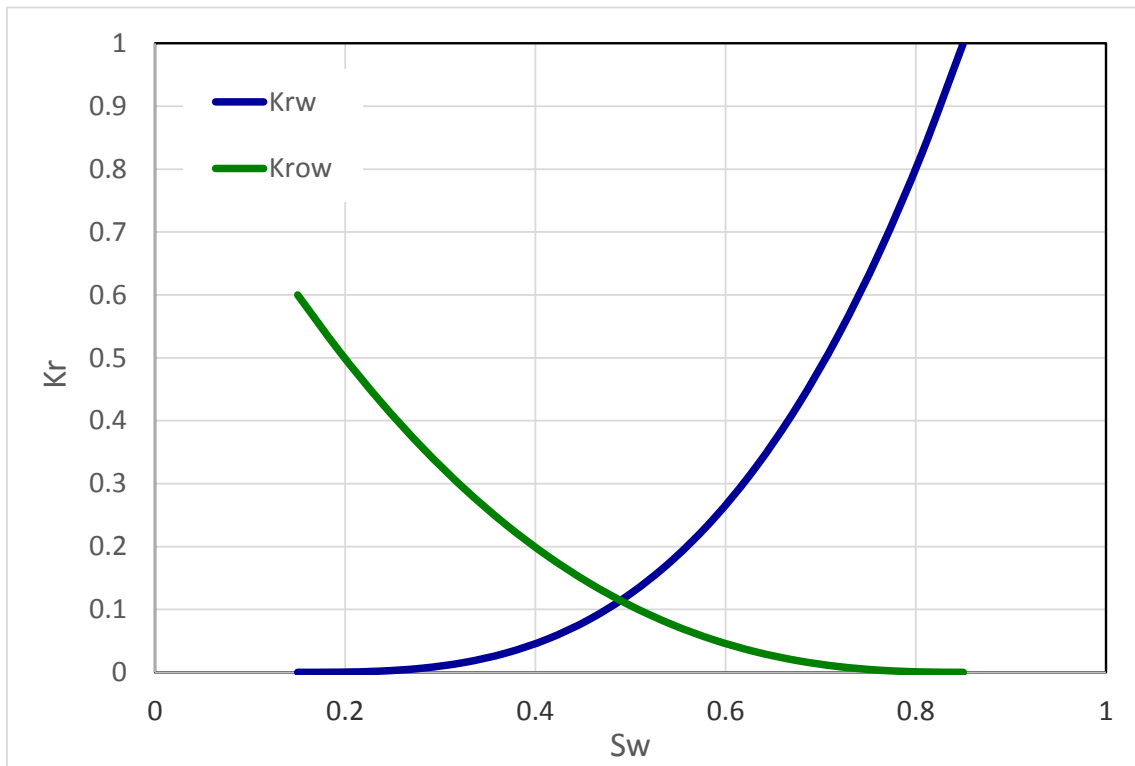
Figure 4-2: Water-Oil relative permeability curves.
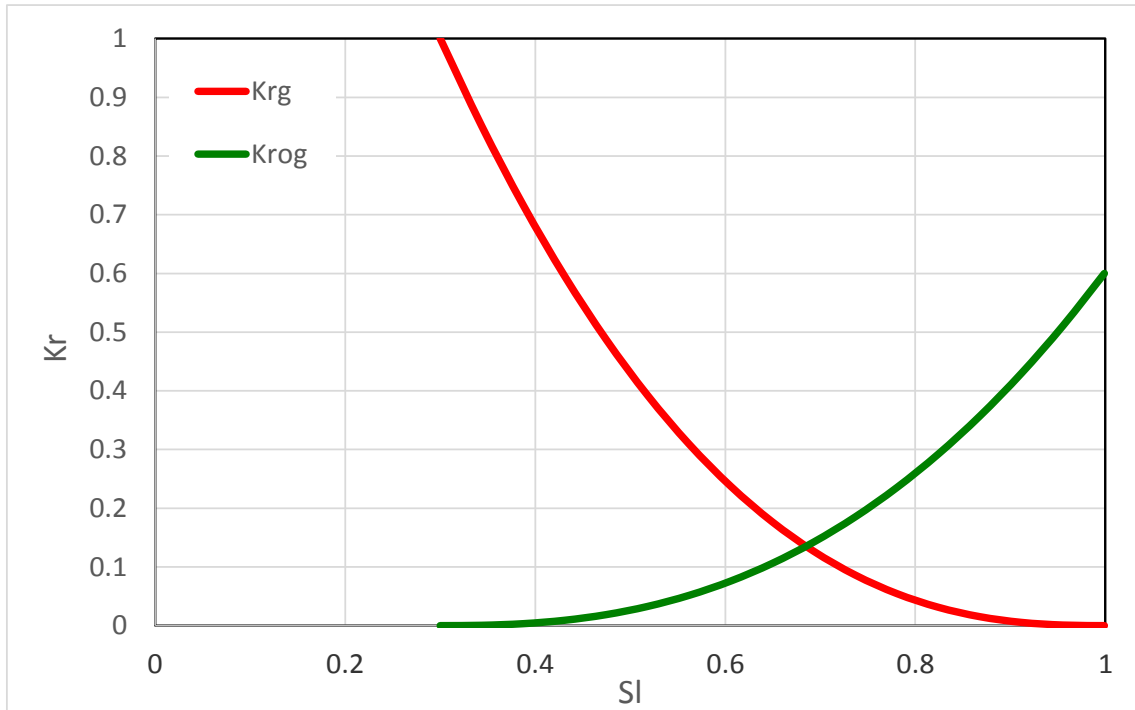
Figure 4-3: Gas-Oil relative permeability curves.

Due to lack of experimental data, the Stone II model was used for three-phase relative permeability curves in both CSS and SAGD models. This is most used three-phase model for oil sands systems. According to this model, the relative permeabilities of water and gas in three phase systems are equal to the relative permeabilities of the water-oil and gas-oil curves, respectively and the oil relative permeability depends on the saturations of all three phases.

4.4 RESERVOIR MODELLING

Numerical modeling of the SAGD and CSS recovery processes was carried out by using the Computer Modeling Group (CMG) STARSTM (version 2006.10) thermal reservoir simulator. In this simulator, the geological domain is tessellated into grid blocks over which the mass and energy balances are discretized by using the finite volume method (CMG, 2006). The material balances are combined with Darcy's law which relates flow rate and pressure via the phase mobility. An additional set of equations that are solved simultaneously are the phase equilibrium equations (by using the K-value correlation described above) within each grid block at each time step.

4.4.1 Steam-Assisted Gravity Drainage (SAGD) in Burnt Lake, Clearwater Formation

A reservoir simulation model was prepared for a well pair from the CNRL Burnt Lake SAGD operation. The well pair was selected based on the comparison of the produced oil and water and the cSOR values of the well pair. The universal well identifier of the selected well pair is as follows:

Producer: 100/10-23-067-03W4/0

Injector: 102/10-23-067-03W4/0

The average properties for the fluid and reservoir to the selected well pair is obtained from the CNRL annual submission to the Alberta Energy Regulator (AER). Table 4-2 summarizes the reservoir properties [53]. The vertical-to-horizontal permeability ratio was taken to be equal to 0.4 which is typical of values used for the Clearwater Formation. The spacing is the average lateral distance between the SAGD well pairs.

Table 4-1: The average fluid and reservoir properties for base case SAGD.

Property	Value	Unit
Oil Saturation	70	%
Pay Thickness	35	m
Porosity	37	%
Horizontal Permeability	2500	mD
Vertical Permeability	1000	mD
Initial Viscosity	100,000	cP
Spacing	80	m
Measured depth	1400	m

The core data that were available in the vicinity of the selected well pair were extracted and a permeability versus porosity cross plot was generated for the Clearwater Formation. As presented in Figure 4-4, the data are scattered which does not allow a reasonable correlation to be developed for this region. In general, the trend suggests that the greater the porosity, the higher the permeability. Therefore, an initial values of the porosity and permeability were taken from Table 4-1. These values are compared against measured values in Figure 4-4 which reveals that they are within the permeability-porosity data scatter and thus provide a reasonable first order estimate of the permeability and porosity of the reservoir.
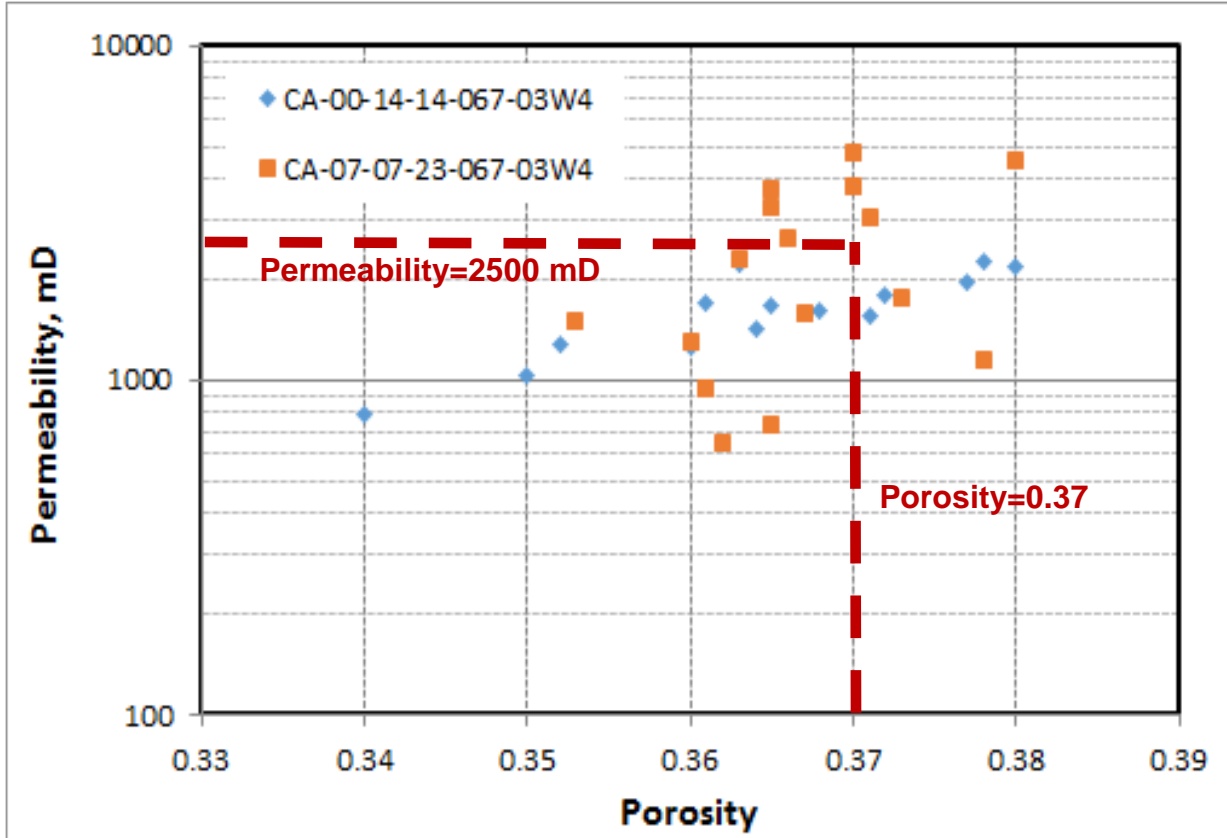
Figure 4-4: Cross plot of porosity and permeability obtained from core data in the vicinity of the CNRL well pair.

To simplify the reservoir simulation model and reduce its computational time, the model was assumed symmetric in the plane of the SAGD well pair. Therefore, the simulation model was created for half of the chamber and then the results were doubled to obtain the full field rates. The size of the sub-model is equal to forty 1 m dimension grid blocks in the down well direction, one hundred 1 m dimension grid blocks in the cross well direction, and thirty five 1 m dimension grid blocks in the vertical direction. Figure 4-5 displays a three-dimensional (3D) view of the reservoir model. The distance between the injector and producer is equal to 5 m. The producer is positioned 1.5 m above the bottom of the pay zone. The producer and injector wellbores were approximated as sink and source wells, respectively. In other words, wellbore hydraulics were assumed to play a minor role in the process dynamics and were not evaluated by the model.
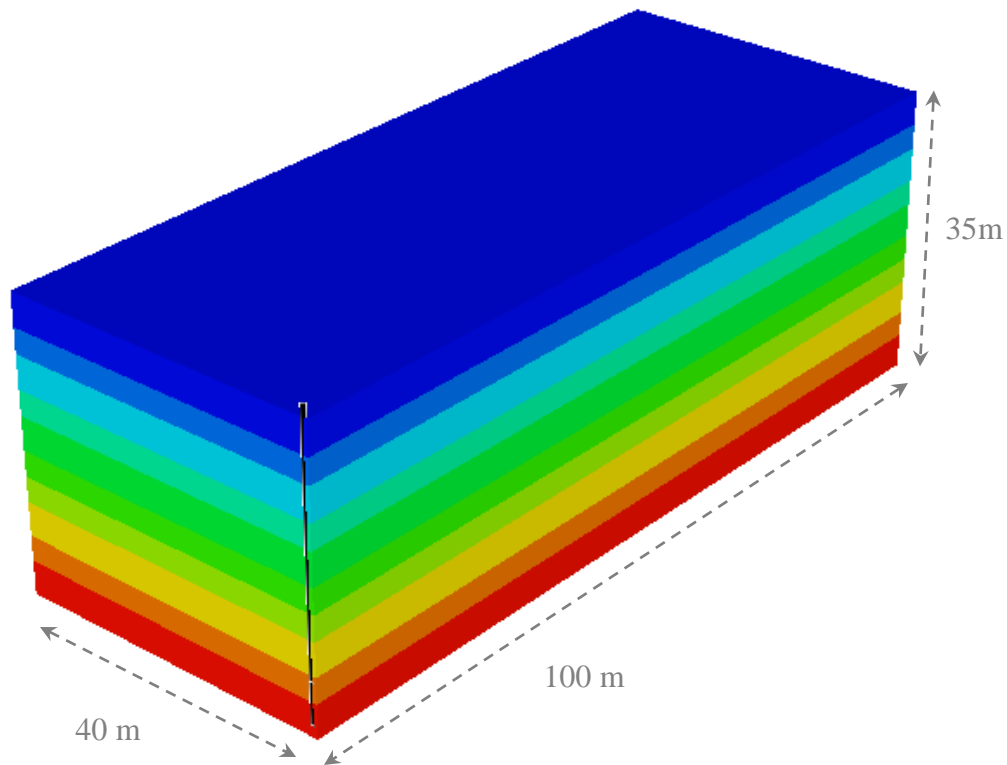
Figure 4-5: 3D schematic of SAGD Cold Lake reservoir model.

4.4.1.1 Calibration of SAGD model

The steam circulation period (also referred to as the pre-heating period) is modeled by using temporary heaters in the location of the injector and producer. After the preheat period is complete, the temporary heaters are removed from the model. The preheat period lasted 20 days whereas the main production period, referred to as SAGD mode, lasted approximately 17 years.

The historical steam injection rate is used as injector constraint. The production well is assumed to produce within minimum bottom-hole pressure and steam trap of 15°C. The steam trap control is normally used as an operational control to reduce or prevent steam withdrawal from the steam zone in the reservoir.

The relative permeability end points and the producer bottom hole pressure (BHP) of the model were the calibration parameters to history match the field operation. The final relative permeability data set which led to a reasonable match of production history is presented in

Figures 4-2 and 4-3, above. From the history match, the BHP on the producer that yielded the best match of the simulation with the field data was 3000 kPa.

Figures 4-6 to 4-8 represent the results of the simulation and history match for the selected SAGD well pair. Comparisons of the produced oil and water, both the rates and the cumulative volumes, from the reservoir simulation model and that of the field data reveal that the history matched reservoir model provides a reasonable representation of the behaviour of the reservoir.
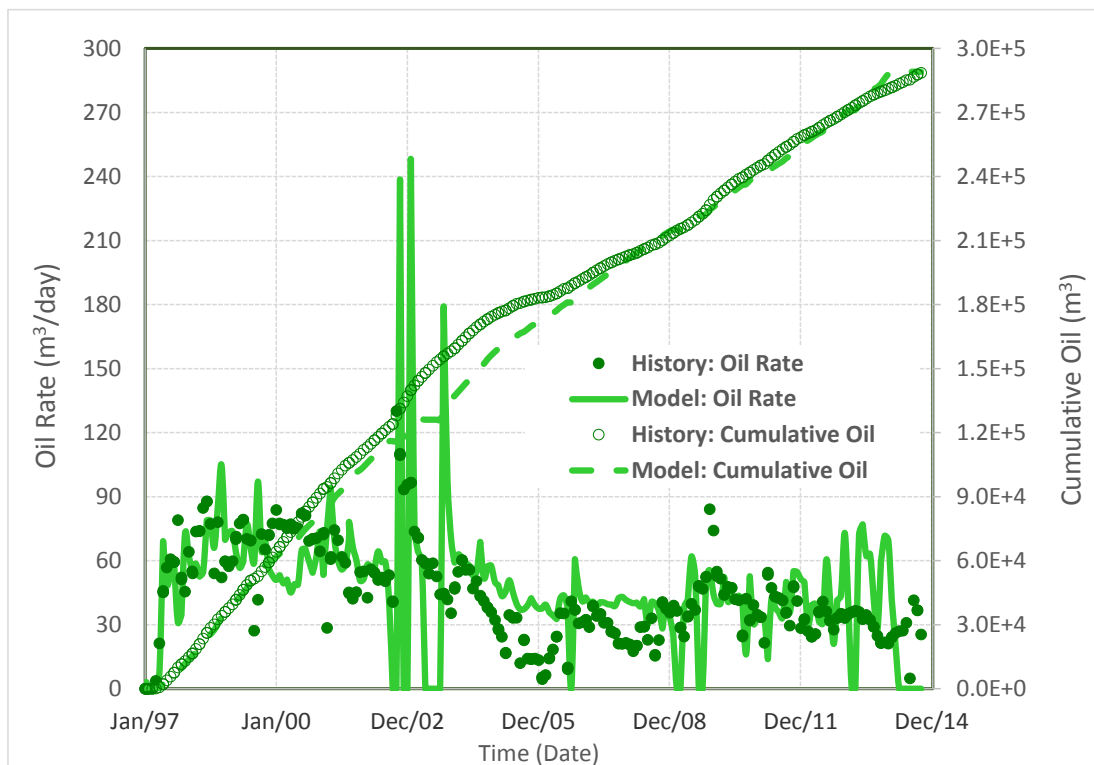
Figure 4-6: Oil rate and cumulative oil for base case SAGD.
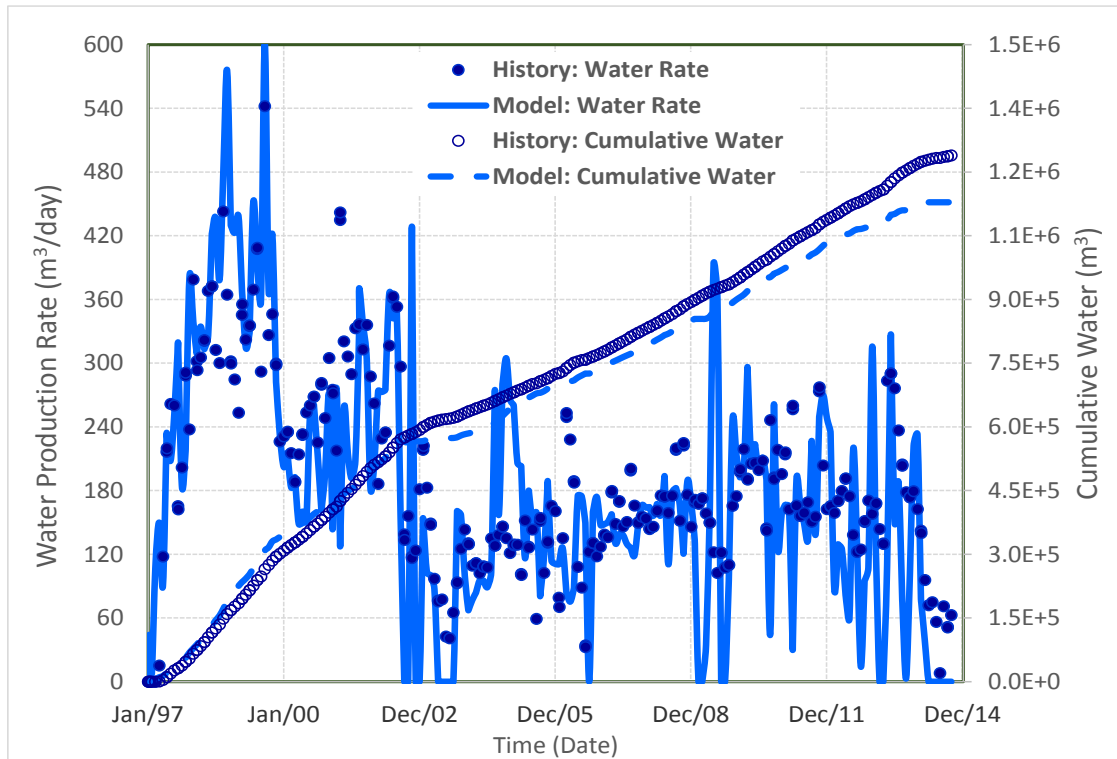
Figure 4-7: Produced water rate and cumulative water for the base case SAGD.
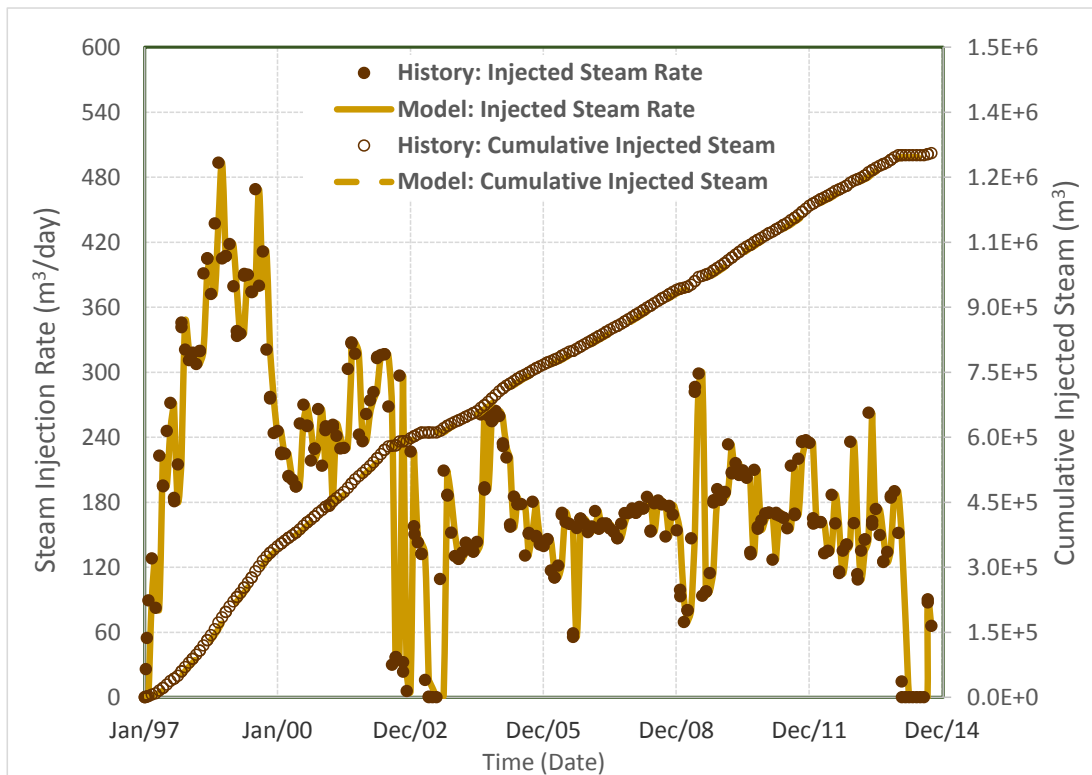
Figure 4-8: Injected steam rate and cumulative Injected steam for the base case SAGD.

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4.4.1.2 Validation of Calibrated Model

The validity of the history matched model was tested to forecast the performance of the adjacent SAGD well pairs. These well-pairs are:

Pair 1) Producer: 102/07-23-067-03W4/0, Injector: 103/07-23-067-03W4/0

Pair 2) Producer: 105/07-23-067-03W4/0, Injector: 103/10-23-067-03W4/0

To test the validity of the history matched model, the injection rates of the injectors of each pair were incorporated into the model and the subsequent produced oil and water rates were obtained. The results were compared with the production data of each pair. These results are presented in Figures 4-9 to 4-11 for Pair 1, and Figures 4-12 to 4-14 for Pair 2.
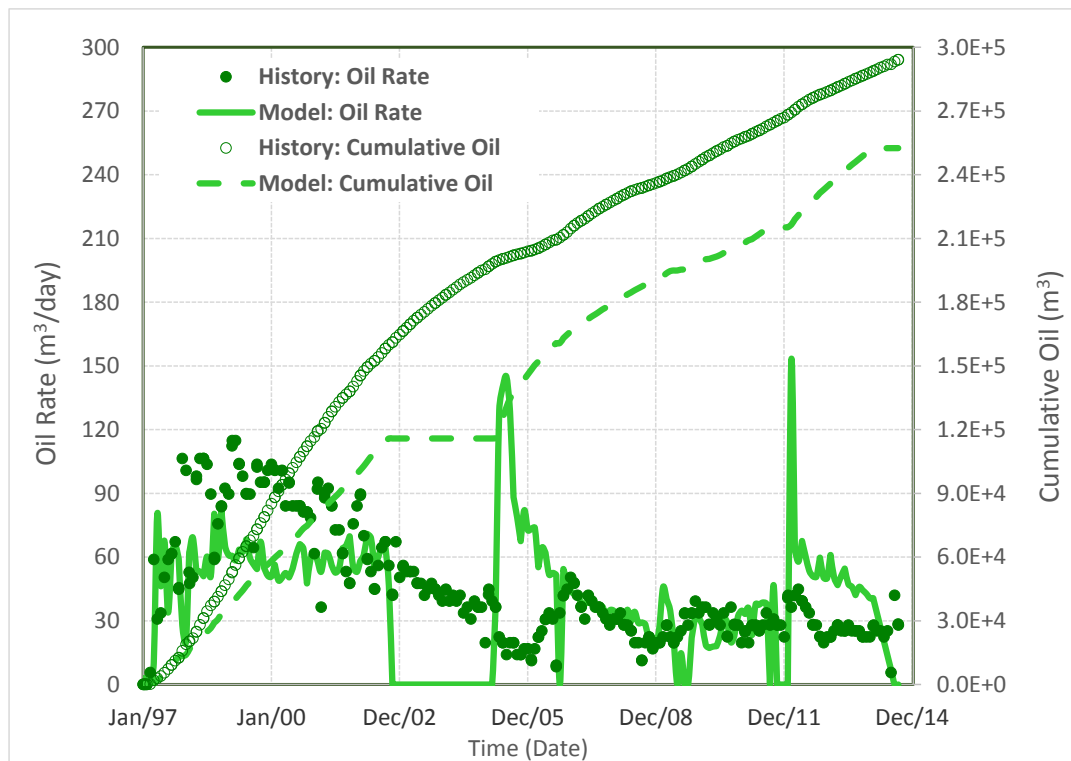
Figure 4-9: Pair 1) Oil rate and cumulative oil.
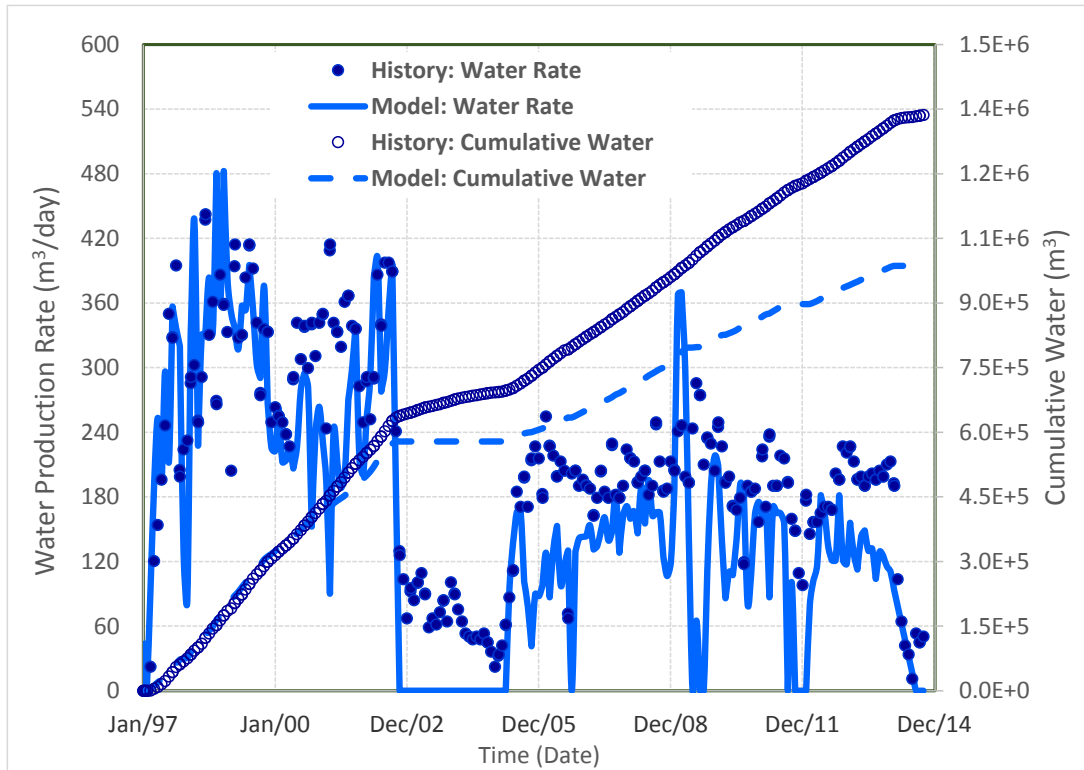
Figure 4-10: Pair 1) Produced water rate and cumulative water.
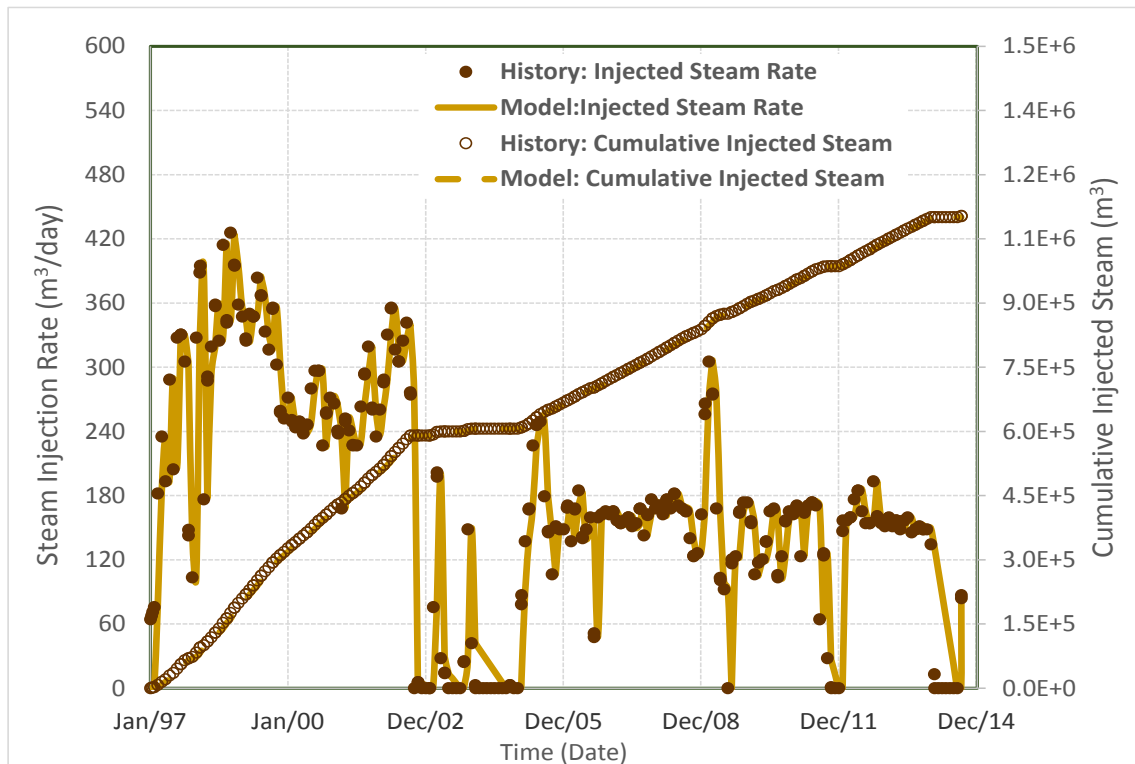
Figure 4-11: Pair 1) Injected steam rate and cumulative injected steam.
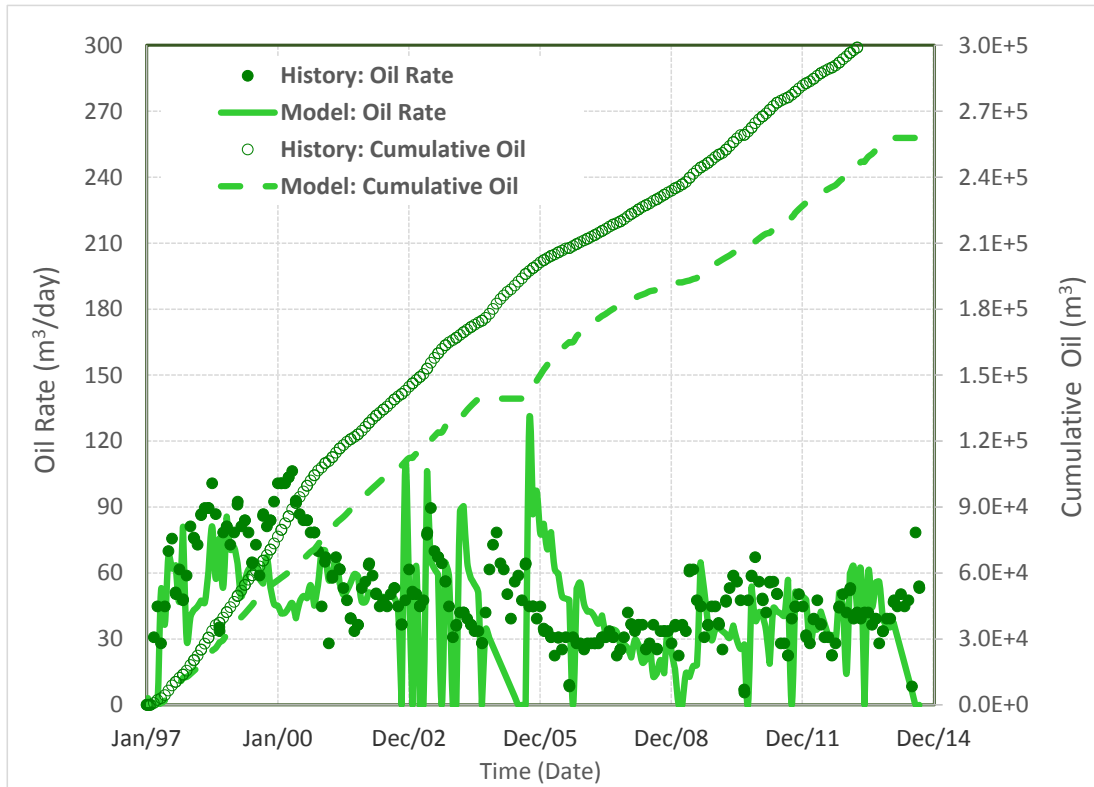
Figure 4-12: Pair 2) Oil rate and cumulative oil.
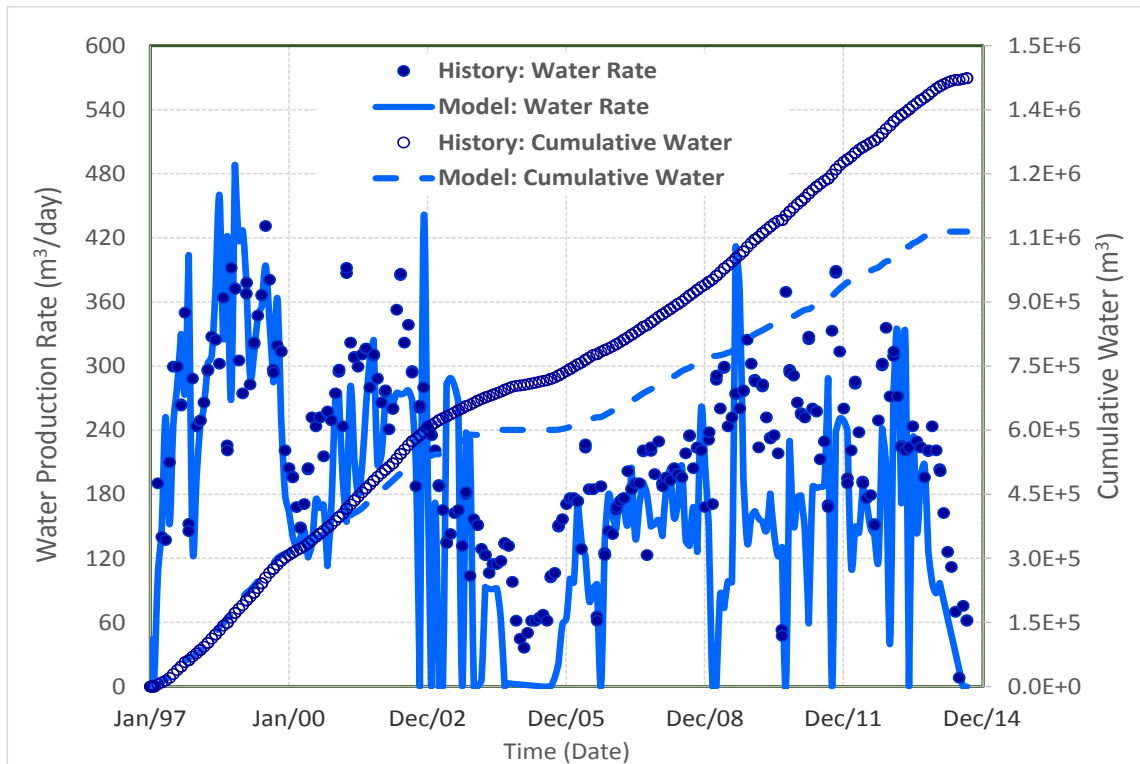
Figure 4-13: Pair 2) Produced water rate and cumulative water.

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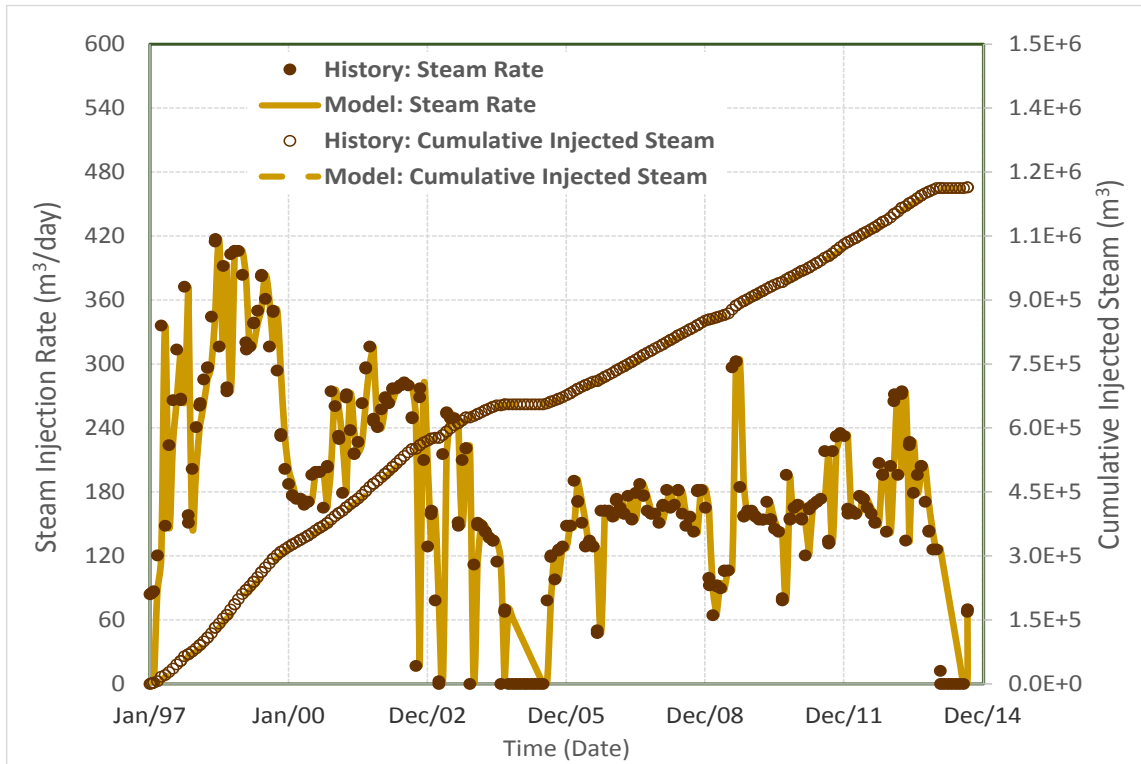
Figure 4-14: Pair 2) Injected steam rate and cumulative injected steam.

The results demonstrate that the history matched model can forecast the performance of the adjacent wells within close proximity with the actual field data. Thus, the calibrated reservoir simulation model provides reasonable predictions of the performance of steam injection based reservoir recovery processes.

4.4.2 Cyclic Steam Stimulation (CSS) in Primrose, Clearwater Formation

Well 102/12-01-068-04W4/0 is a good candidate for analysis of CSS in the Clearwater Formation. This well is operated by CNRL in the Cold Lake area. The average properties for the fluid and reservoir was obtained from CNRL's annual submission to the AER. Table 4-3 lists the reservoir properties [53].

Table 4-2: The average fluid and reservoir properties for base case CSS.

Property	Value	Unit
Oil Saturation	76	%
Pay Thickness	23	m
Porosity	32	%
Horizontal Permeability	3400	mD
Vertical Permeability	1500	mD
Initial Viscosity	100,000	cP
Spacing	60	m
Measured depth	1500	m

The core data that were available in the vicinity of the selected well pair were extracted and a permeability versus porosity cross plot was generated for the area of the Clearwater Formation near the CSS well. As presented in Figure 4-15 and similar to the core data used for the SAGD well pair, the data are scattered which does not allow a reasonable correlation to be developed for this region. Therefore, the values of the porosity and permeability were taken from Table 4-2 which are in the mid-range of the ranges of the porosity and permeability. These values are compared against measured values in Figure 4-15. The vertical-to-horizontal permeability ratio is equal to 0.44 which is slightly higher than that of the area near the SAGD well pair described above.
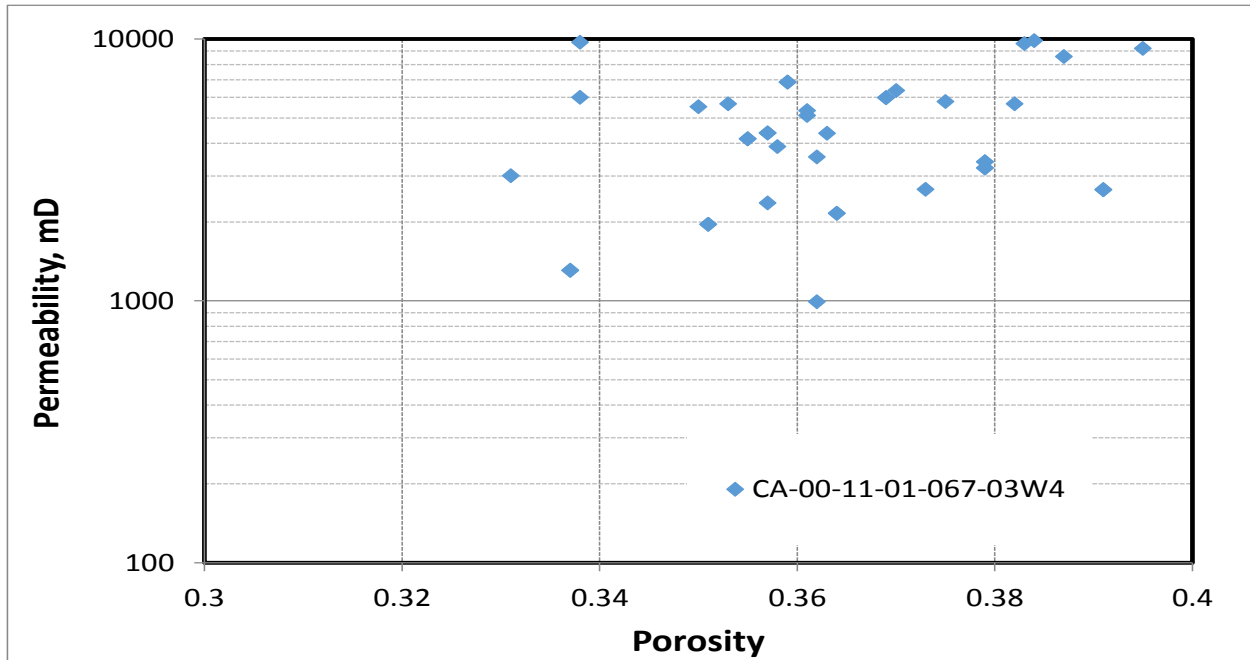
Figure 4-15: Cross plot of the porosity and permeability data obtained from core samples in the neighborhood of the CSS well.

The reservoir domain was discretized into thirty 1 m dimension grid blocks in the cross well direction, two 50 m dimension grid blocks in the down well direction, and twenty three 1 m dimension grid blocks in the vertical direction. Figure 5-15 displays a 3D view of the reservoir model.

To model the injection and production periods of the CSS process, two horizontal wellbores, injector and producer, are introduced at the same location. During the steam injection period, the injector is used and the producer is shut in. During the production period, the injector is shut in and the producer is used. During soak periods, both the injector and producer are shut in. For both wells, the source/sink well model is used. Both wells are positioned 1.5 m above the bottom of the pay zone.
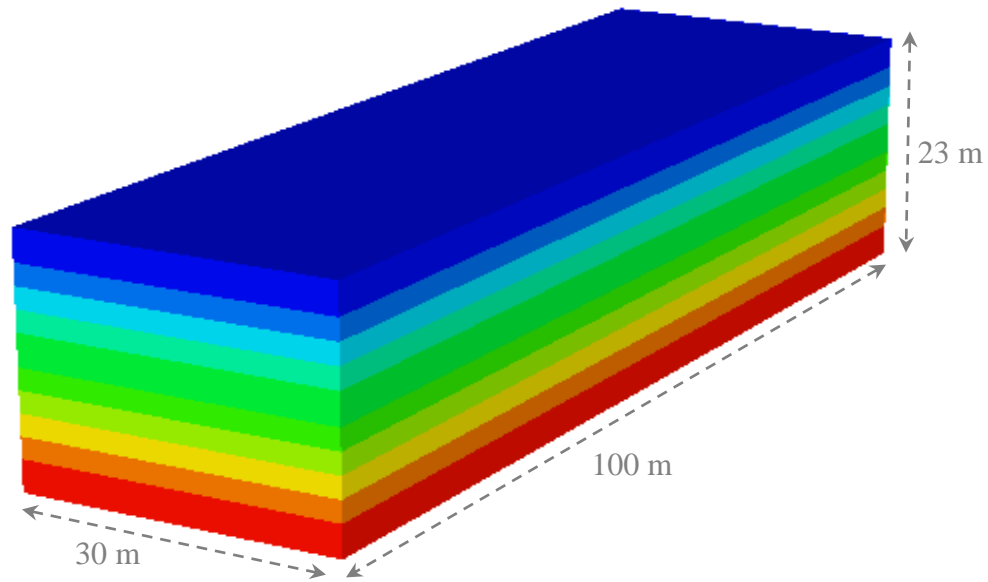
Figure 4-16: 3-D schematic of CSS Cold Lake reservoir model.

4.4.2.1 Calibration of CSS Model

Since steam fracturing occurs in the CSS process, this must be modeled. Here it is modeled by using the quad geomechanical model as described by Beattie et al. (1991). The entire deformation envelope was followed by every single cycle of a CSS process. The quad model input parameters are listed in Table 4-4 [22].

The first CSS cycle was started with steam injection at a maximum pressure of 11,000 kPa which lasted for 30 days. Then 10 days of soaking were done. After the soak period, approximately five months of production occurred. The next cycle started with the same steam injection pressure but now for a longer period following the CSS control strategy as dictated by CNRL's field data. A total of 6 cycles exists in the current well.

To calibrate the reservoir simulation model to that of the field data, the adjustable parameters were the relative permeability end points and the production BHP. The final relative permeability data set which led to a reasonable match of production history is presented in Figures 4-2 and 4-3. The BHP that led to the best history match was found to be equal to 1350 kPa.

Table 4-3 Dilation-compaction properties for CSS model.

Pressure at which dilation (fracturing) occurs	7,300	kPa
Pressure at which oil sands re-compacts	5,000	kPa
Maximum growth of the porosity, φ_{max}	1.25 φ_i	
Maximum amount of dilation that can persist after re-compaction	0.45	
Dilation compressibility	1.0 E-4	1/kPa

Figures 4-17 to 4-19 represent the result of simulation and history data. The proximity of the history matched simulation based curves and field data for the oil, water and steam profiles shows that the calibrated model provides a reasonable representation of the reservoir performance.
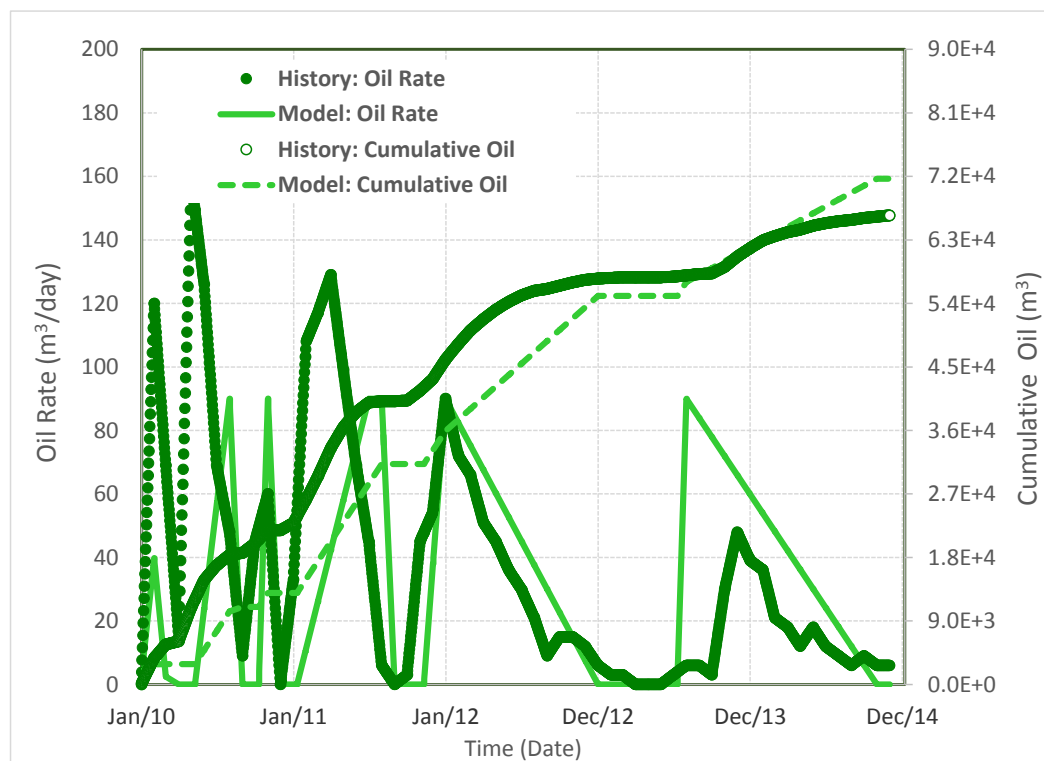
Figure 4-17: Oil rate and cumulative oil for CSS.
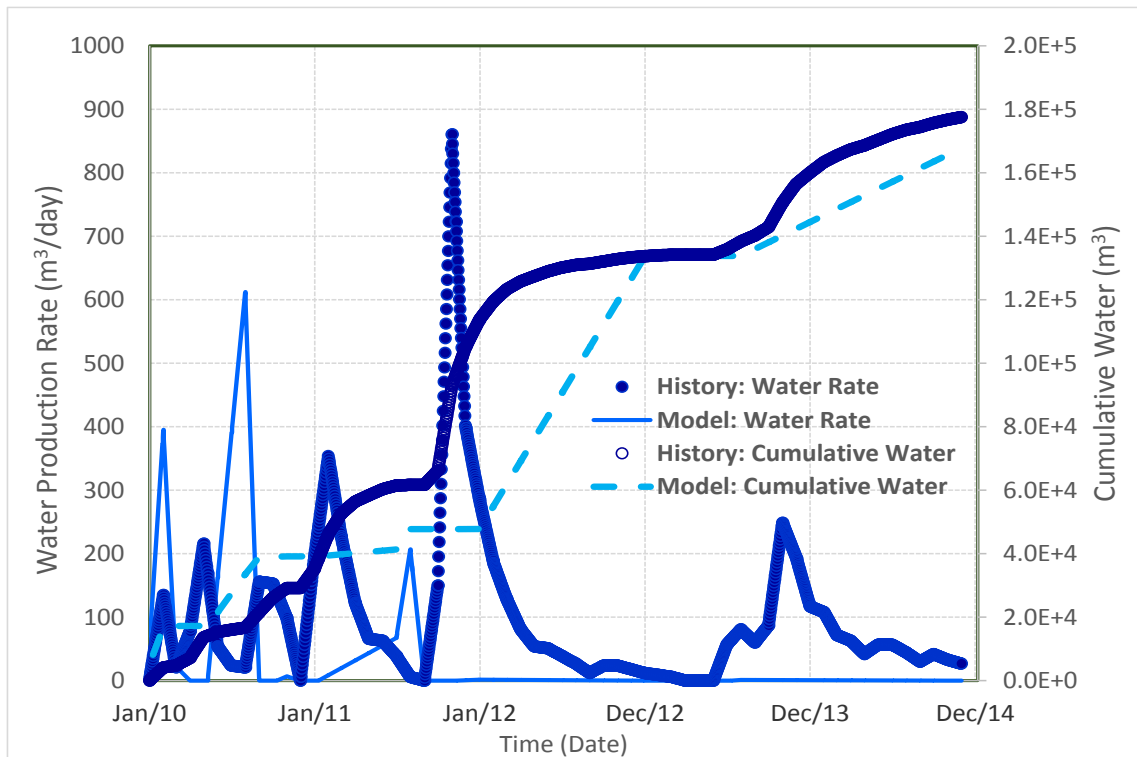
Figure 4-18: Produced water rate and cumulative water for CSS.
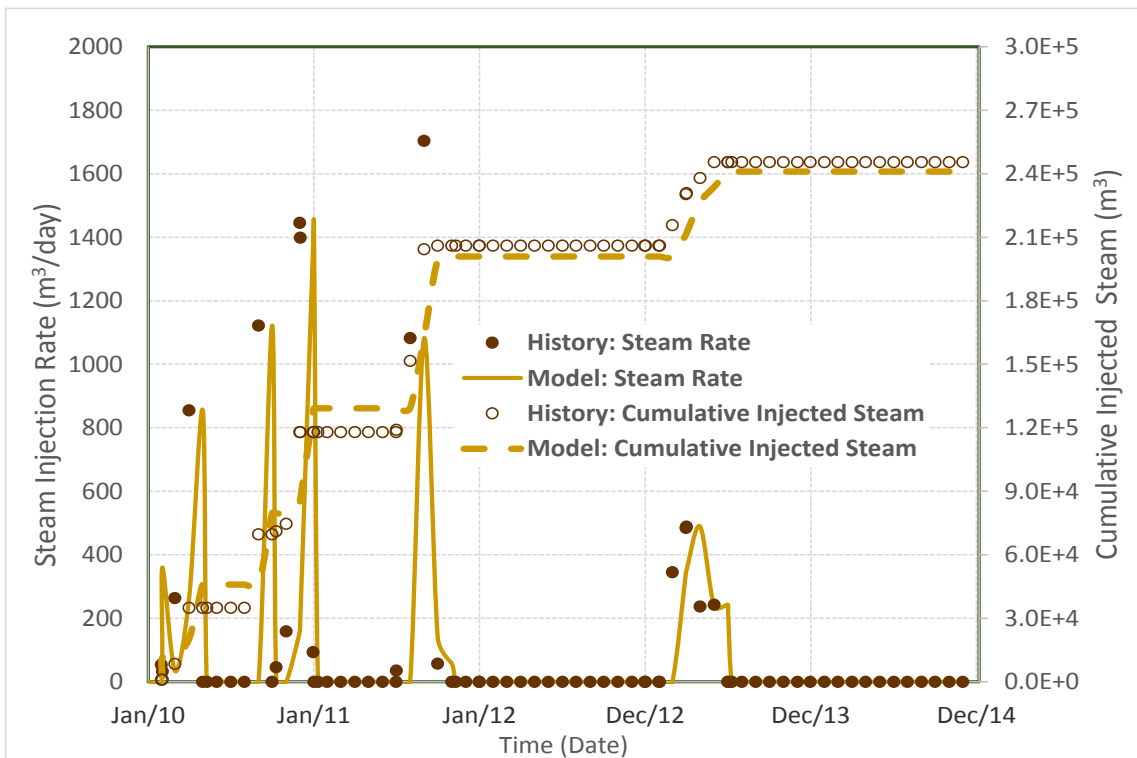
Figure 4-19: Injected steam rate and cumulative steam for CSS.

4.5 SENSITIVITY STUDY

To explore the efficiency of CSS and SAGD in the Cold Lake area, their performance needs to be compared through several sensitivity cases. These sensitivity scenarios will be built by using the calibrated CSS and SAGD models. For this purpose, six different scenarios were constructed. In two cases, the petrophysical properties of SAGD and CSS were switched. In other cases the permeability and net pay effects were studied. Table 4.4 summarizes the properties of different sensitivity scenarios.

Table 4.4: Properties of different sensitivity scenarios.

Case	Net Pay (m)	Porosity (%)	K_h (mD)	K_v (mD)	So (%)
Base SAGD in Burnt Lake Reservoir	35	37	2,500	1,000	70
Base CSS in Primrose Reservoir	23	32	3,400	1,500	76
A: SAGD in Primrose Reservoir	23	32	3,400	1,500	76
B: CSS in Burnt Lake Reservoir	35	37	2,500	1,000	70
C: SAGD in Reduced Permeability Primrose Reservoir	23	32	2,000	880	76
D: CSS in Reduced Permeability Primrose Reservoir	23	32	2,000	880	76
E: SAGD in thin Primrose Reservoir	11	32	3,400	1,500	76
F:CSS in thin Primrose Reservoir	11	32	3,400	1,500	76

4.5.1 Comparison of SAGD in Burnt Lake (base SAGD) and SAGD in Primrose (Case A)

The properties in Table 4-3 were incorporated into the SAGD model described in Figure 4.4.1 Figures 4-17 to 4-19 represent the results of simulation and history data. 4.4.1 and cumulative oil, cumulative produced water, cSOR and recovery factor were compared with the associated values for SAGD model. Figures 4-20 to 4-23 compare the performances of SAGD and Case A.
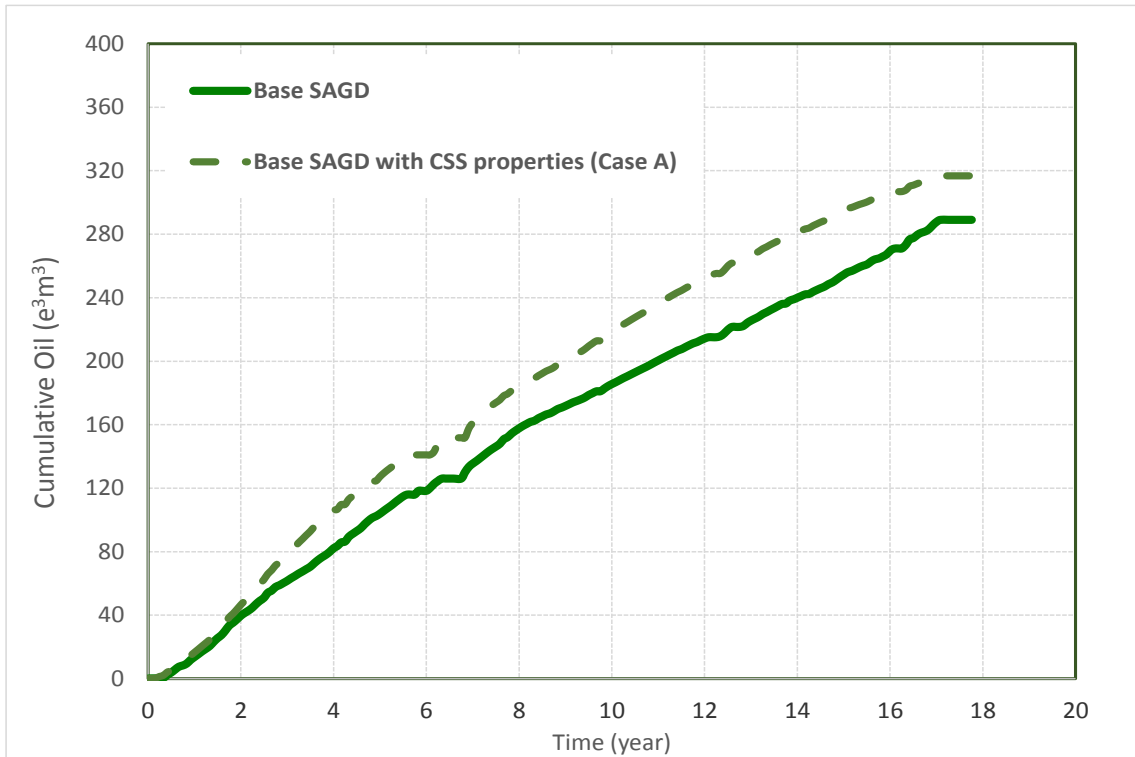
Figure 4-20: Cumulative oil for SAGD and Case A.
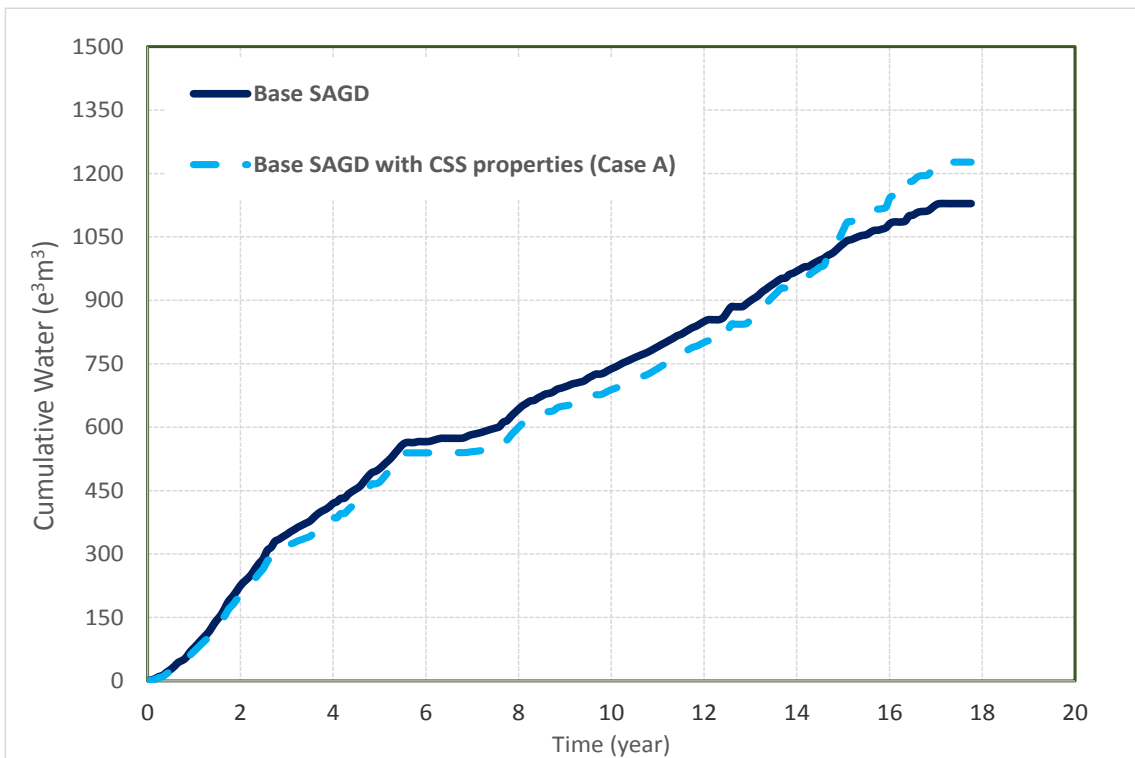
Figure 4-21: Cumulative water for SAGD and Case A.
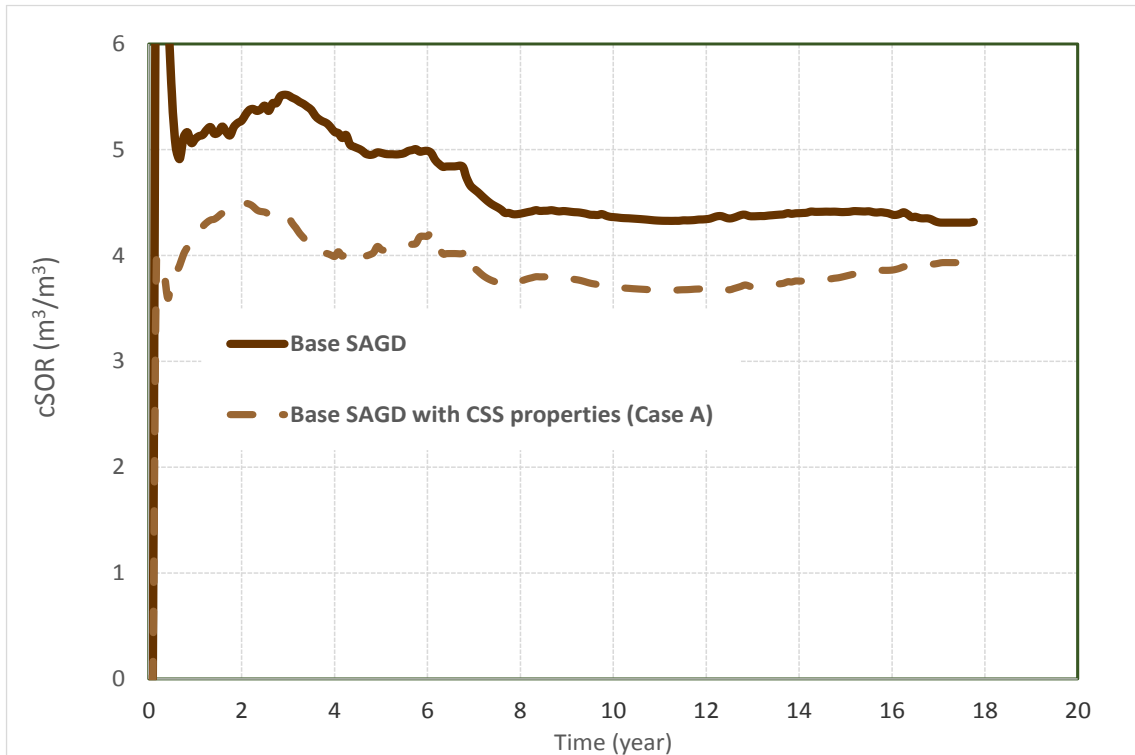
Figure 4-22: cSOR for SAGD and Case A.
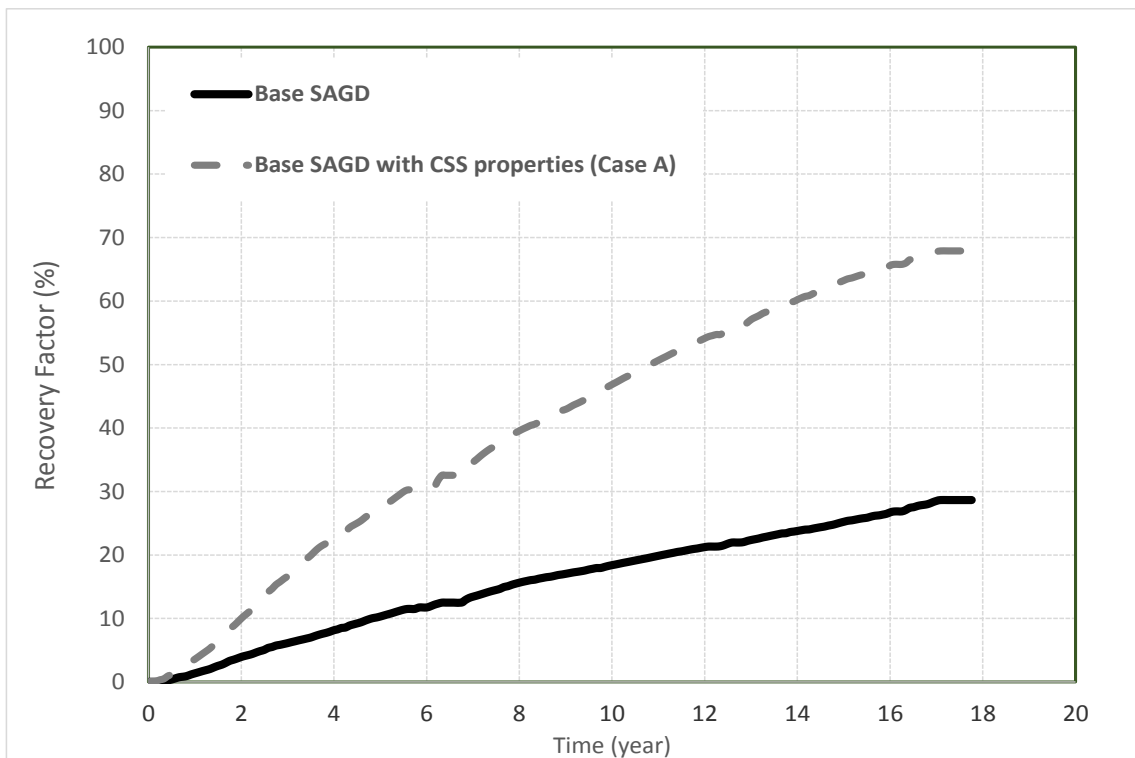
Figure 4-23: Recovery Factor for SAGD and Case A.

Comparison of SAGD in Burnt Lake (base SAGD) and Primrose (Case A) reservoirs revealed that the cumulative produced oil increased from 290,000 m^3 in SAGD model to almost 316,000 m^3 in Case A. A comparison of the cumulative produced water for base SAGD model and Case A showed that the cumulative produced water slightly increased from 1,113,000 m^3 in SAGD model to almost 1,210,000 m^3 in Case A. Figure 4-22 shows the cumulative steam-to-oil ratio, cSOR (steam expressed as cold water equivalent, CWE), for Case A was almost constant and equal to nearly 3.9 m^3/m^3 whereas the value for SAGD was around 4.3 m^3/m^3. A comparison of the recovery factors for the two cases indicated that the recovery factor for Case A was over twice that of the SAGD case. In conclusion, better performance is observed when the physical properties of CSS model are allocated to SAGD operation. In other words in the specific reservoir that currently has CSS operation, if we shift to SAGD operation and compare the results with SAGD operation in its main reservoir, then better performance is experienced in the shifted to SAGD operation case. Physically, this is because the horizontal and vertical permeabilities and oil saturation are greater in the original CSS geology model.

4.5.2 Comparison of SAGD in Burnt Lake (base SAGD) and CSS in Burnt Lake (Case B)

The properties listed in Table 4-3 were incorporated in CSS model in Section 4.4.2 and cumulative oil, cumulative produced water, cSOR and recovery factors were compared with the associated values for base SAGD model. Figures 4-24 to 4-27 show the performances of SAGD and case B. Evaluation of the cumulative produced oil for SAGD model and Case B reveals that the cumulative produced oil decreased from around 105,000 m^3 in SAGD model to almost 38,000 m^3 in Case B. Assessment of the values of the cumulative produced water for SAGD model and Case B showed that the cumulative produced water decreased from around 500,000 m^3 in SAGD model to almost half that in Case B. As shown in Figure 4-26 the cSOR for SAGD model was almost constant after the first year of production and equal to 4.9 m^3/m^3 while this value for Case B had fluctuations and the best value was around 5.5 m^3/m^3. A comparison of the recovery factors for the two cases showed that the recovery factor of the SAGD case was over twice of the recovery factor of the Case B. In conclusion, within our specific reservoir with SAGD operation there appears to be no benefits if we shift the operation to CSS.
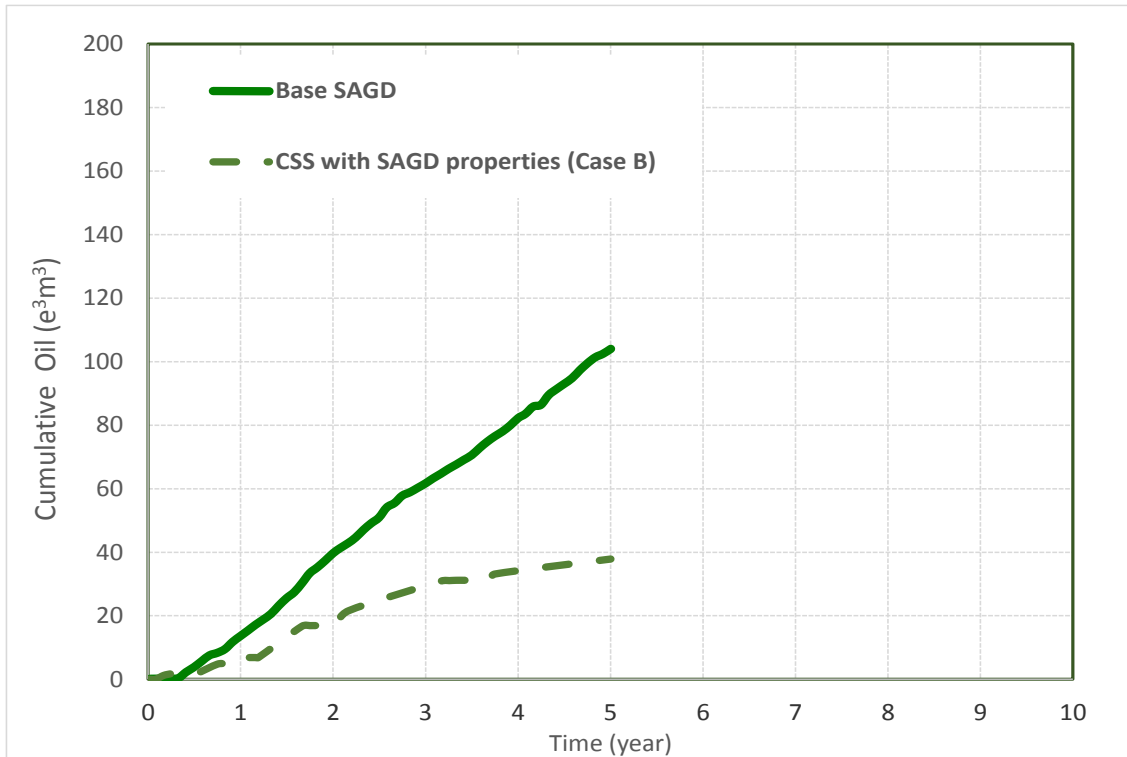
Figure 4-24: Cumulative oil for SAGD and Case B.
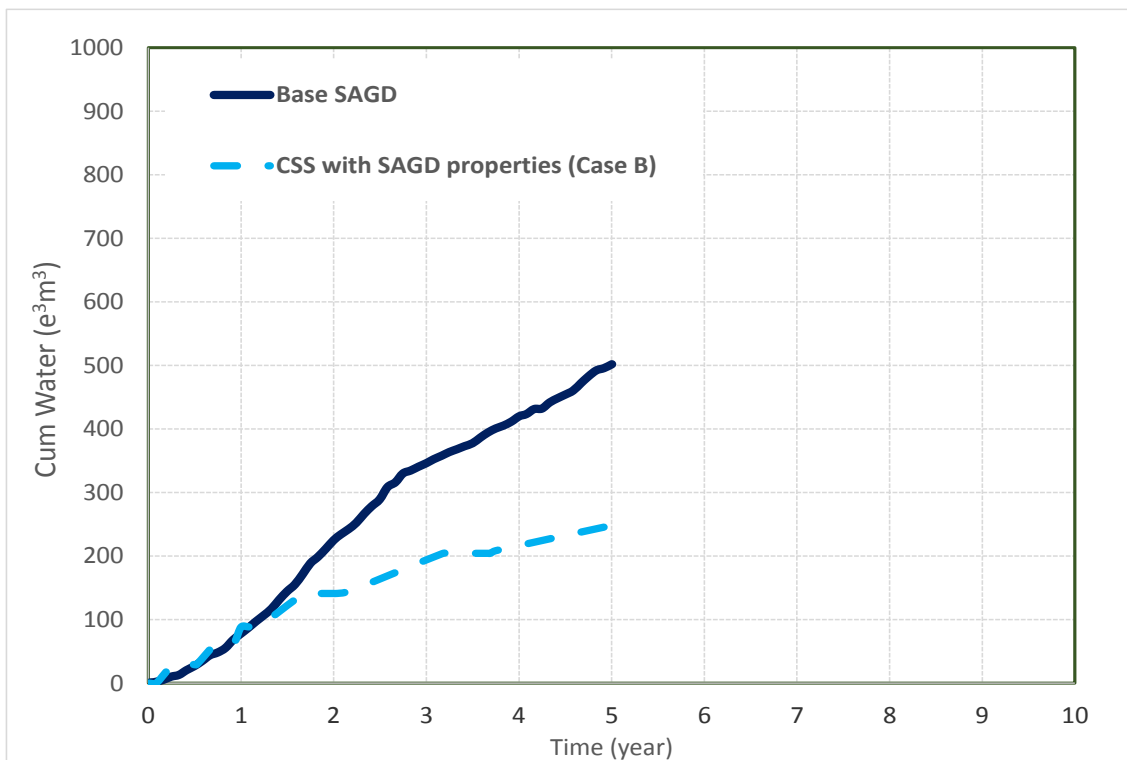
Figure 4-25: Cumulative water for SAGD and Case B.
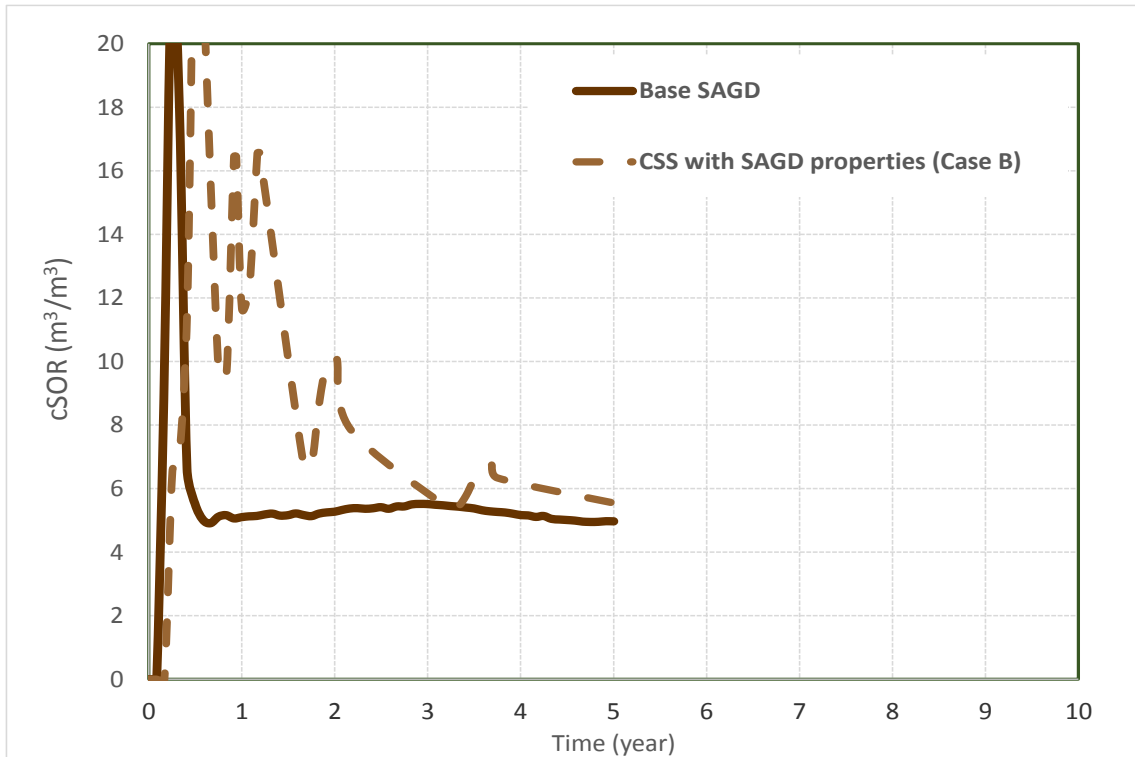
Figure 4-26: cSOR for SAGD and Case B.
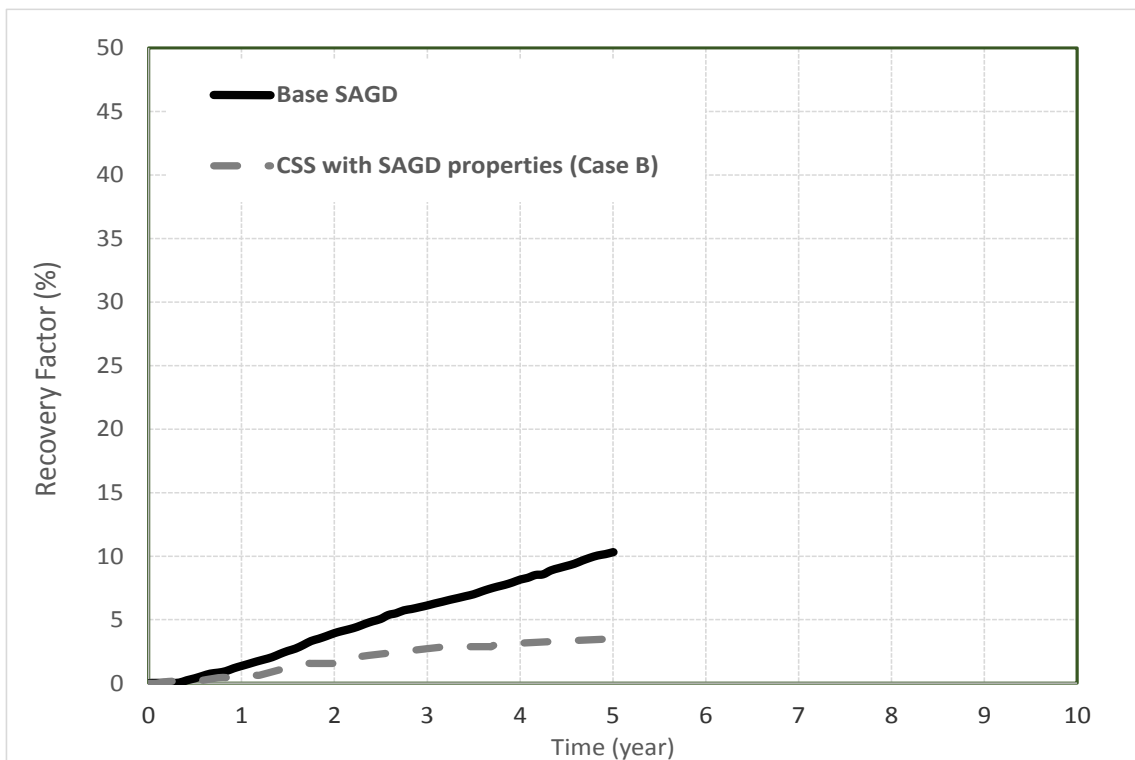
Figure 4-27: Recovery Factor for SAGD and Case B.

4.5.3 Comparison of CSS in Primrose (base CSS) and CSS in Burnt Lake (Case B)

The properties in Table 4-2 were incorporated in CSS model in Section 4.4.2 and cumulative oil, cumulative produced water, cSOR and recovery factors were compared with the associated values for CSS model. The performance comparison of the base CSS and Case B are shown in Figures 4-28 to 4-31. Comparison of the cumulative produced oil for the base CSS model and Case B showed that the it was reduced from around 70,000 m^3 in the base CSS model to almost 38,000 m^3 in Case B. Assessment of the values of the cumulative produced water for CSS model and Case B showed that it was increased from around 175,000 m^3 in the base CSS model to almost 240,000 m^3 in Case B. As shown in Figure 4-30 the cSOR for base CSS model was around 3.4 m^3/m^3 in year five of the production while this value for Case B had fluctuations and the best value was around 5.5 m^3/m^3. Assessment of the recovery factor for the two cases showed that the recovery factor of the base CSS was over three times higher than the recovery factor of the Case B. It can be concluded that better performance is not observed when the physical properties of Burnt Lake reservoir is used with a CSS operation. In other words, in the specific reservoir that currently has SAGD operation, if we shift to CSS operation and compare the results with CSS operation in its main reservoir, then better performance is not experienced with CSS.
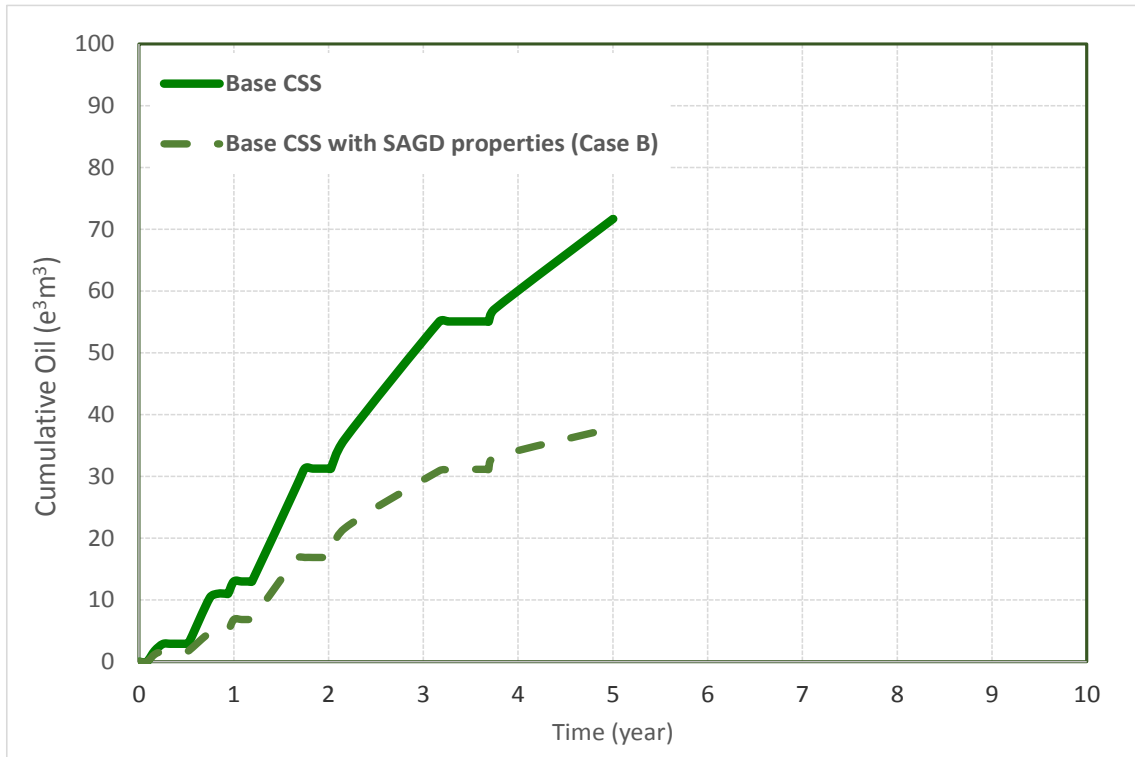
Figure 4-28: Cumulative oil for base CSS and Case B.
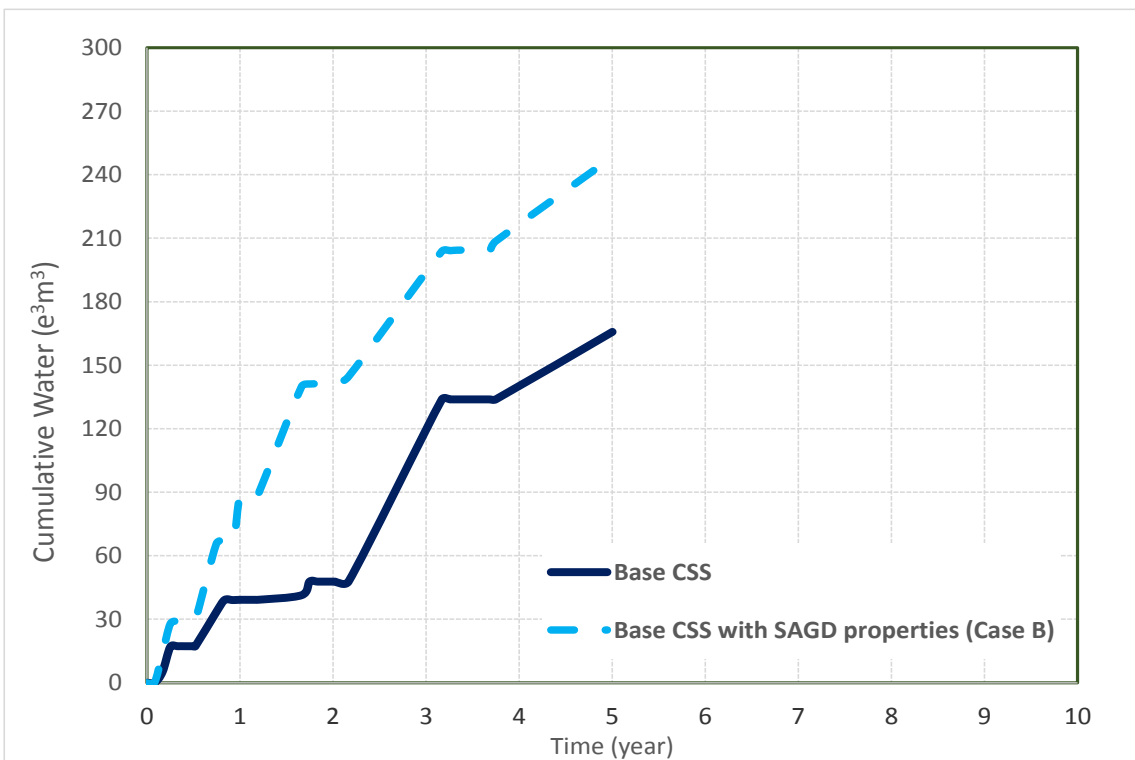
Figure 4-29: Cumulative water for base CSS and Case B.
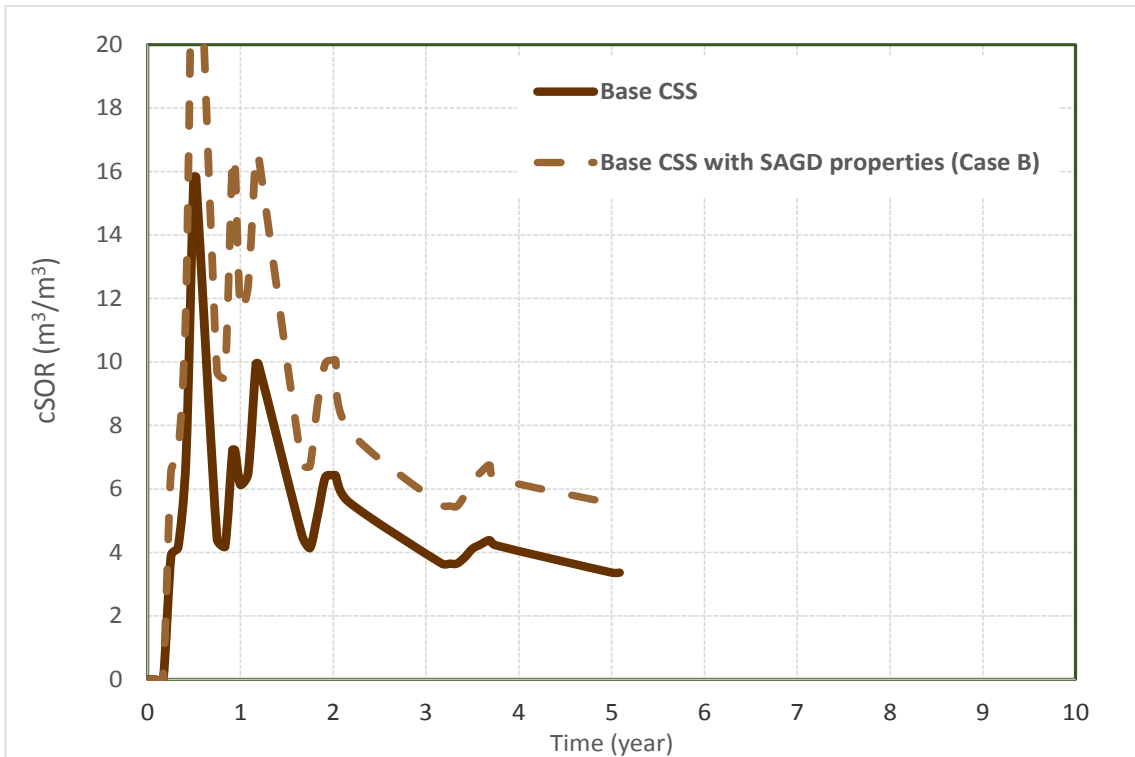
Figure 4-30: cSOR for base CSS and Case B.
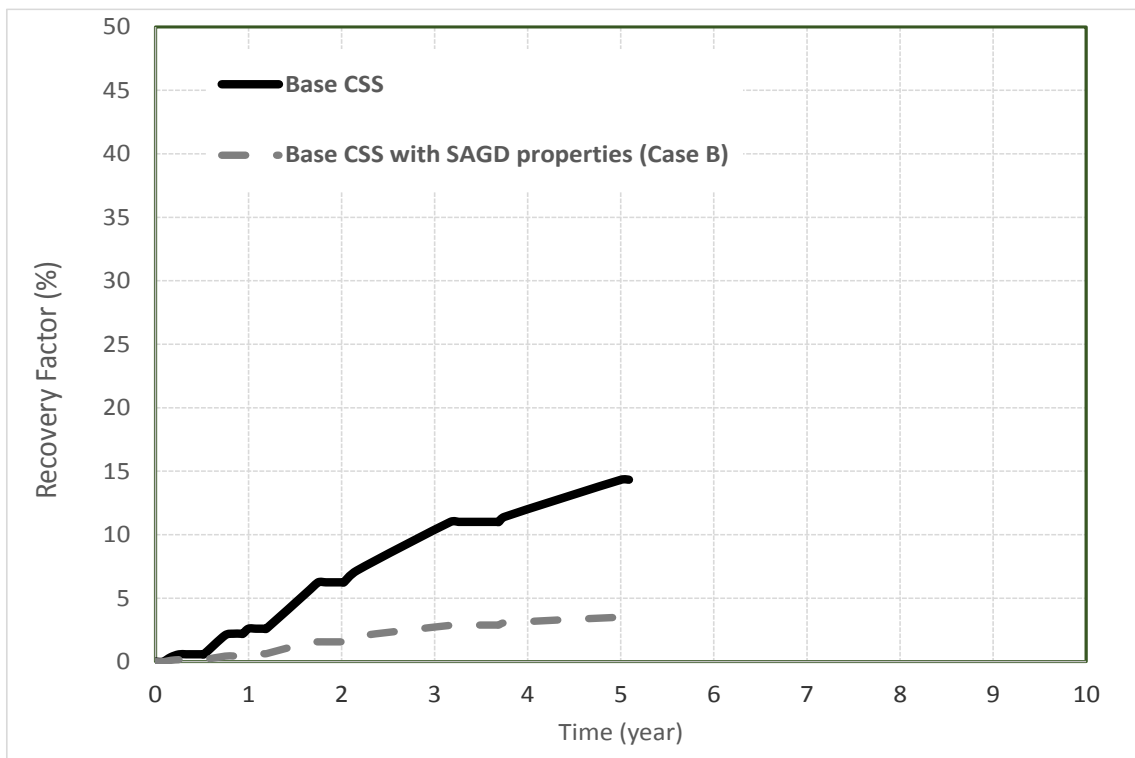
Figure 4-31: Recovery Factor for base CSS and Case B.

4.5.4 Comparison of CSS in Primrose (base CSS) and SAGD in Primrose (Case A)

The properties listed in Table 4-3 were incorporated in the SAGD model in Section 4.4.1 and cumulative oil, cumulative produced water, cSOR and recovery factors were obtained and compared with the associated values for base CSS model. Figures 4-32 to 4-35 show the performances of the base CSS case and Case A.

Figure 4-32 shows the cumulative produced oil for base CSS model and Case A. It can be seen that the cumulative produced oil increased from around 70,000 m^3 in the base CSS model to almost 130,000 m^3 in Case A. A comparison of the values of the cumulative produced water for the base CSS model and Case A showed that the cumulative produced water increased from around 165,000 m^3 in CSS model to almost 465,000 m^3 in Case A. As shown in Figure 4-34 the cSOR for Case A was almost constant and equal to 4 m^3/m^3 while this value for CSS had fluctuations and the best value was around 3.4 m^3/m^3 in year 5 of the production. Assessment of the recovery factor for the two cases showed that the recovery factor of the base CSS model around 14.4% whereas the recovery factor of the Case A was around 27% in year five of the production. We can conclude that if SAGD is operated in the Primrose reservoir, then there is performance improvement if we shift the operation from CSS to SAGD.
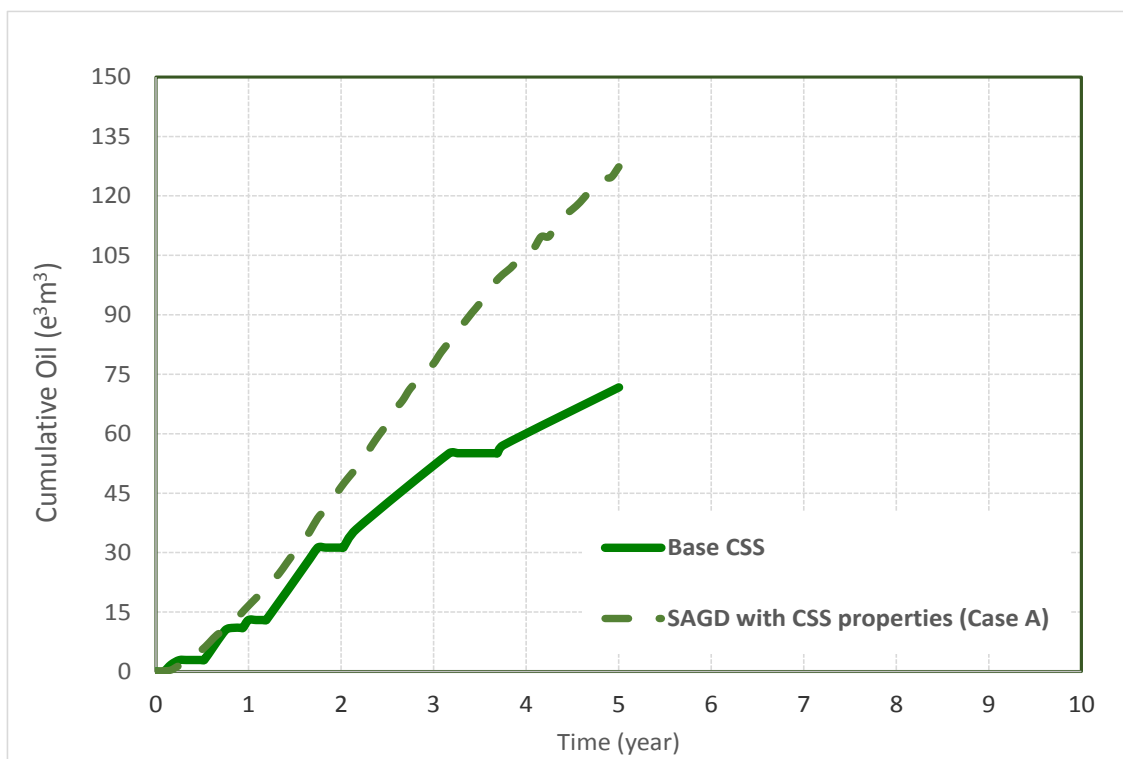
Figure 4-32: Cumulative oil for base CSS and Case A.
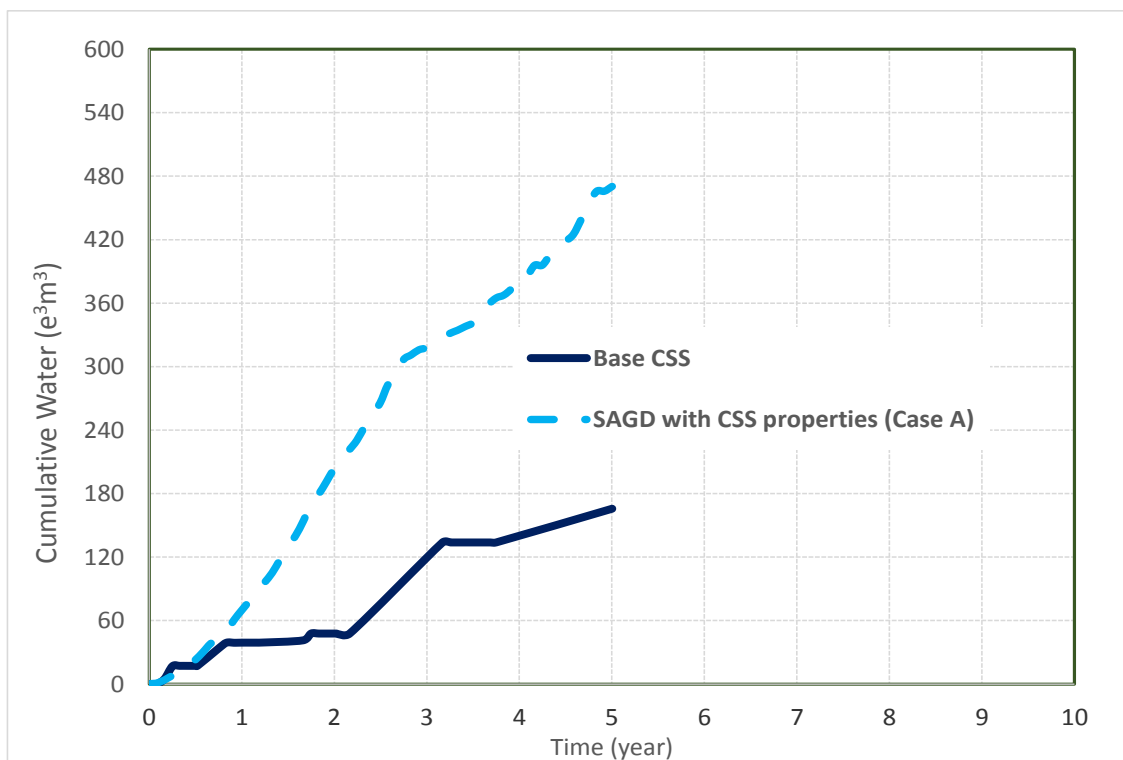
Figure 4-33: Cumulative water for base CSS and Case A.
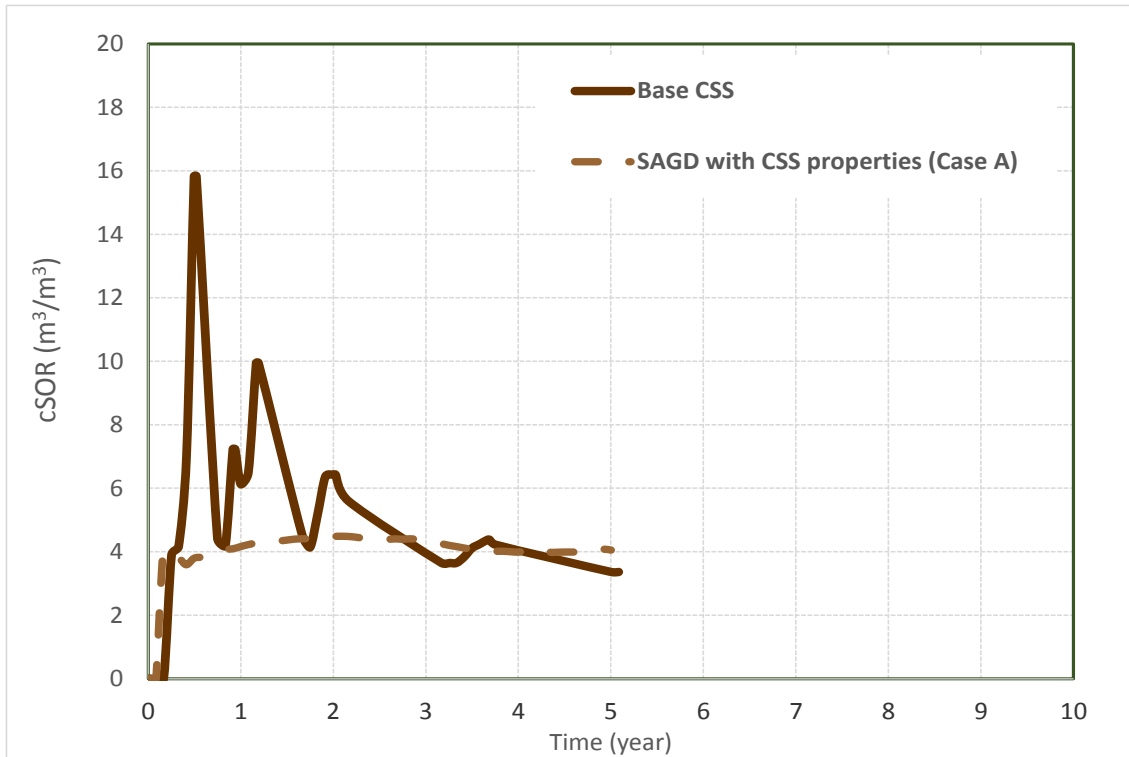
Figure 4-34: cSOR for base CSS and Case A.
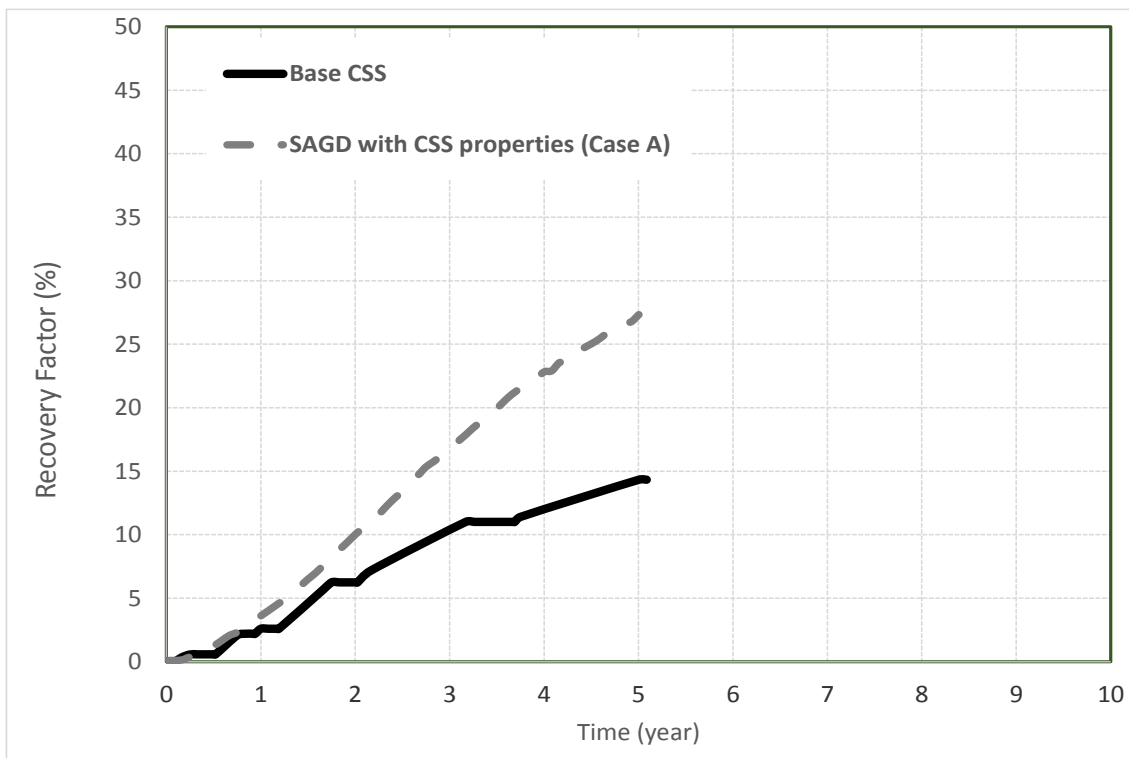
Figure 4-35: Recovery Factor of the base CSS and Case A.

4.5.5 Comparison of Cases C (SAGD in reduced permeability Primrose reservoir) and D (CSS in reduced permeability Primrose reservoir)

The properties listed in Tables 4-3 and 4-2 with the value of K_h equal to 2000 mD were incorporated in SAGD and CSS models in Sections 4.4.1 and 4.4.2, respectively and cumulative oil, cumulative produced water, cSOR and recovery factors were obtained and compared. Figures 4-36 to 4-39 compare the performance of two cases.

Figure 4-36 shows that the cumulative produced oil for Cases C and D. It can be seen that the cumulative produced oil increased from around 63,000 m^3 in Case D to almost 112,000 m^3 in Case C. A comparison of the values of the cumulative produced water for two cases showed that the cumulative produced water increased from 170,000 m^3 in Case D to almost 500,000 m^3 in Case C. As shown in Figure 4-40, the cSOR for Case C was almost constant and equal to 4.9 m^3/m^3 whereas this value for Case C had fluctuations and the best value was around 3.7 m^3/m^3 in year 5 of the production. Assessment of the recovery factor for the two cases showed that the recovery factor of Case D was around 12.6% while the recovery factor of the Case C was around 24% in year five of the production.

In Section 4.6.4, it was concluded that, within the Primrose reservoir with CSS operation there is performance improvement, if we shift the operation to SAGD. In the current comparison with horizontal permeability reduced to 2000 mD for both cases, although the performance of both operations suffers in the reduced permeability reservoir, the overall same conclusion is maintained with better performance from SAGD than that of CSS.
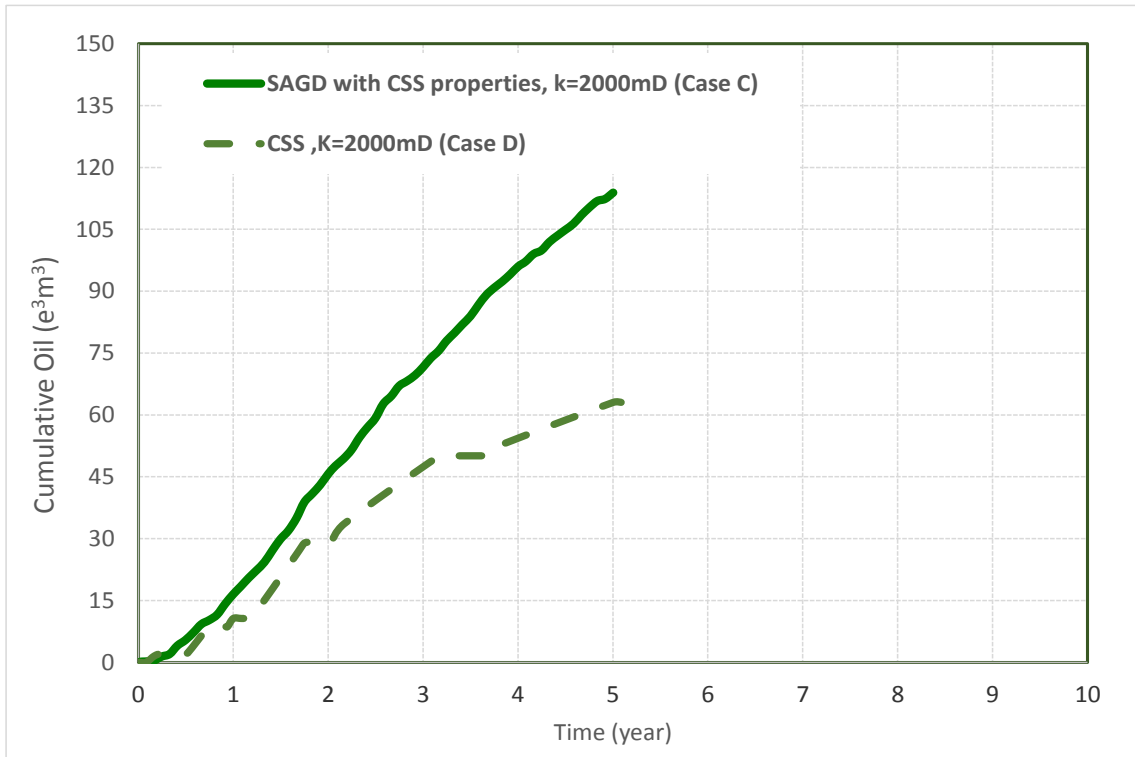
Figure 4-36: Cumulative oil for Cases C and D.
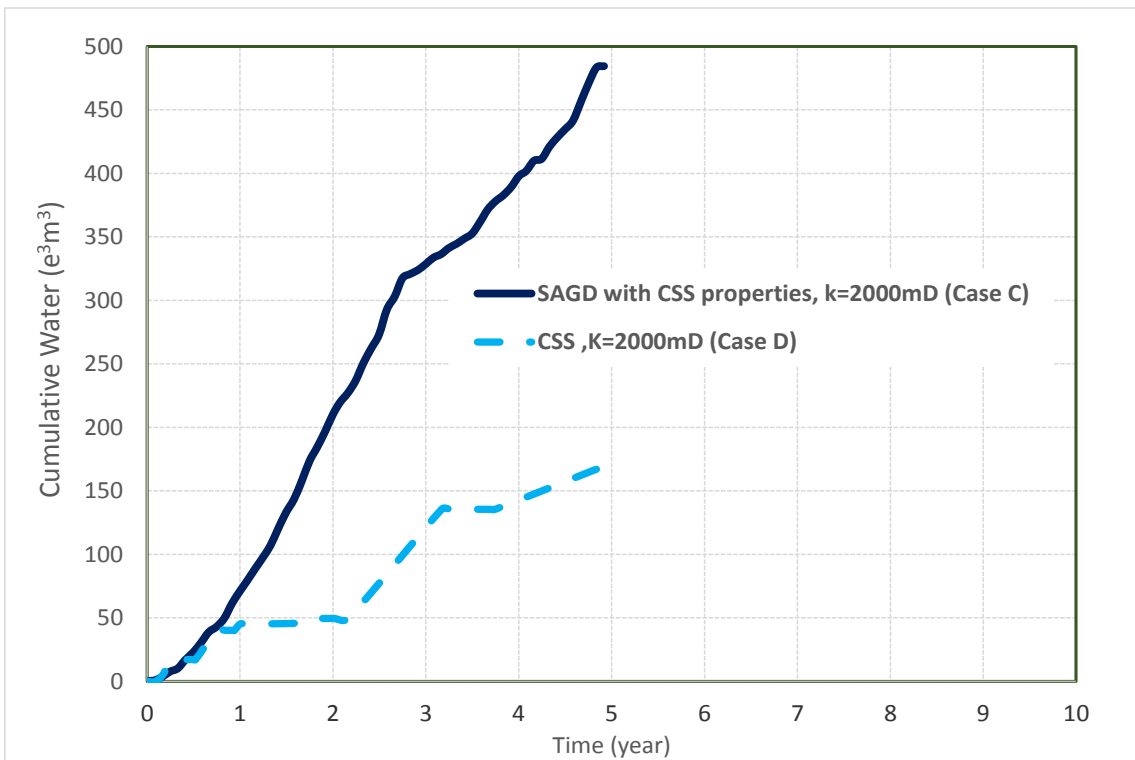
Figure 4-37: Cumulative water for Cases C and D.
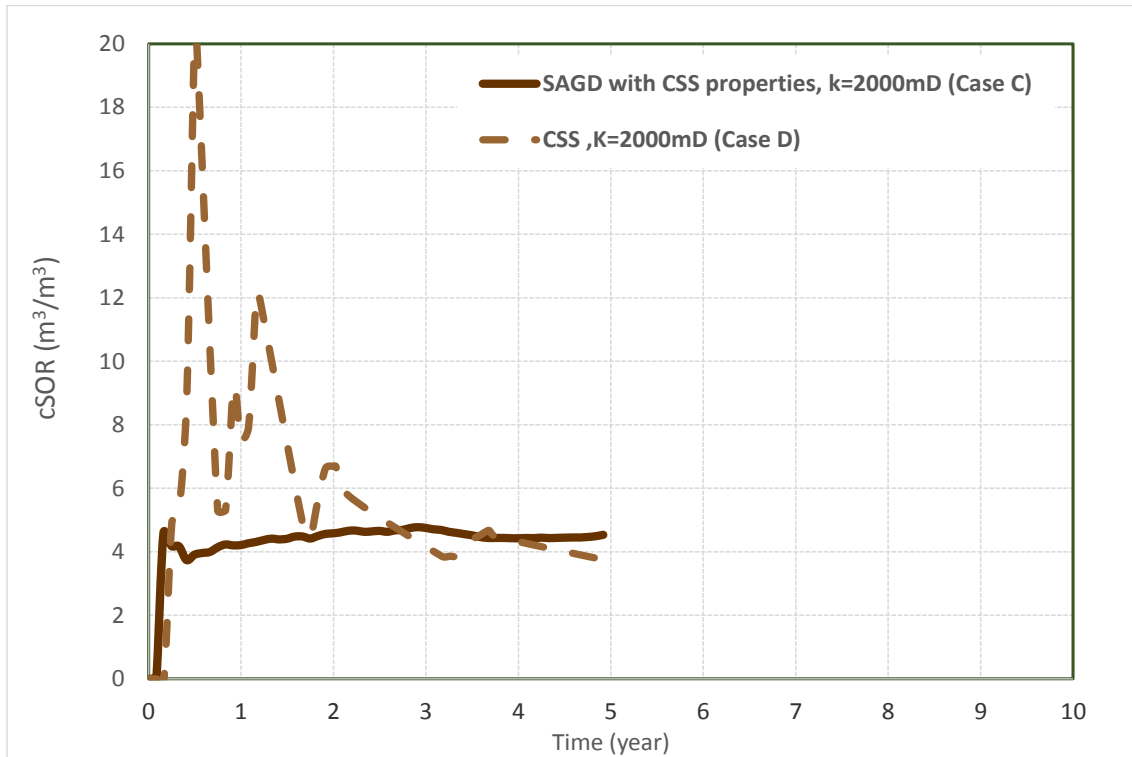
Figure 4-38: cSOR for Cases C and D.
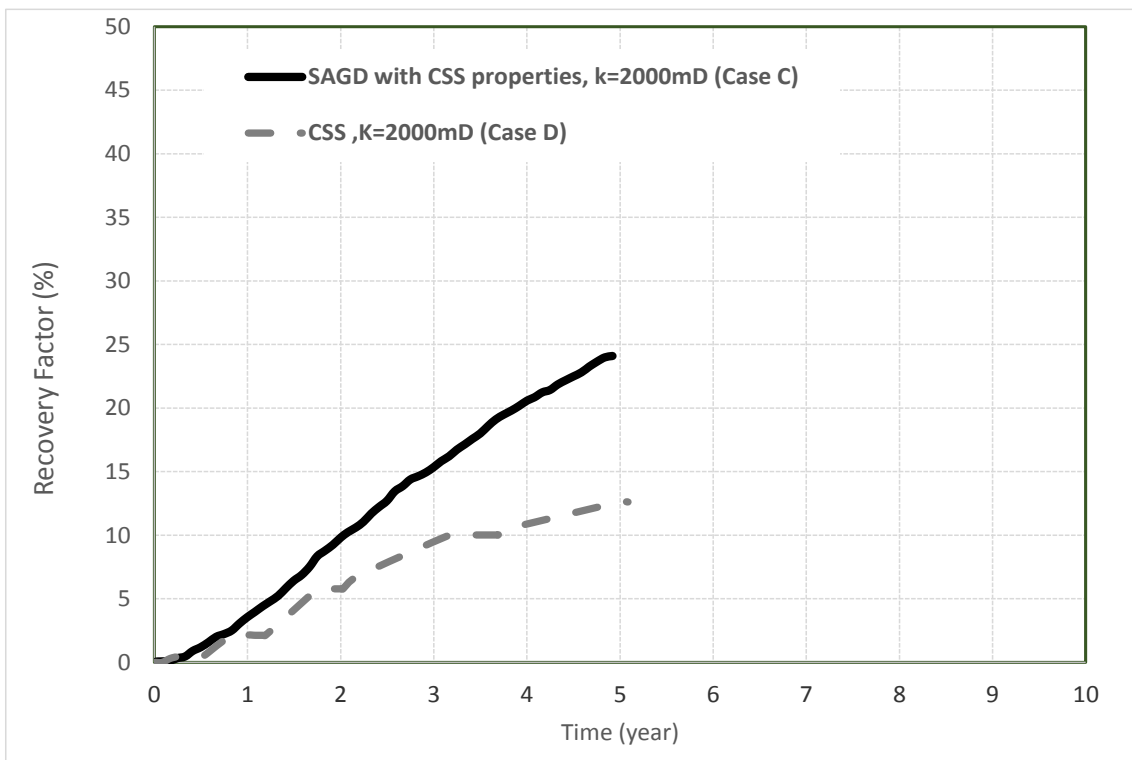
Figure 4-39: Recovery Factor for Cases C and D.

4.5.6 Comparison of Case E (SAGD in thin Primrose reservoir) and Case F (CSS in thin Primrose reservoir)

The properties listed in Tables 4-3 and 4-2 with the value of net pay equal to 11 m were incorporated in SAGD and CSS models described in Sections 4.4.1 and 4.4.2 respectively and cumulative oil, cumulative produced water, cSOR and recovery factors were obtained and compared. Figures 4-40 to 4-43 compare the performance of two cases.

Figure 4-40 displays the cumulative produced oil for Cases E and F. The results show that the cumulative produced oil increased from around 42,000 m^3 in Case F to almost double of its value in Case E. Evaluation of the values of the cumulative produced water for the two cases showed that it enlarged from around 169,000 m^3 in Case F to around 505,000 m^3 in Case E. As shown in Figure 4-42, the cSOR for Case E has increasing trend and the final value is equal to about 6 m^3/m^3 while this value for the other case is equal to 5 m^3/m^3 in year 5 of the production. Assessment of the recovery factor for the two cases showed that the recovery factor of Case F was around 18% while the recovery factor of the Case E was around 40% in year five of the production. In Section 4.6.4 it was concluded that the SAGD operation had better performance when applied to the Primrose reservoir versus that of the CSS operation. In the current comparison when the net pay dropped to 11 m for both cases, economical analysis is required to find out which process has better performance.
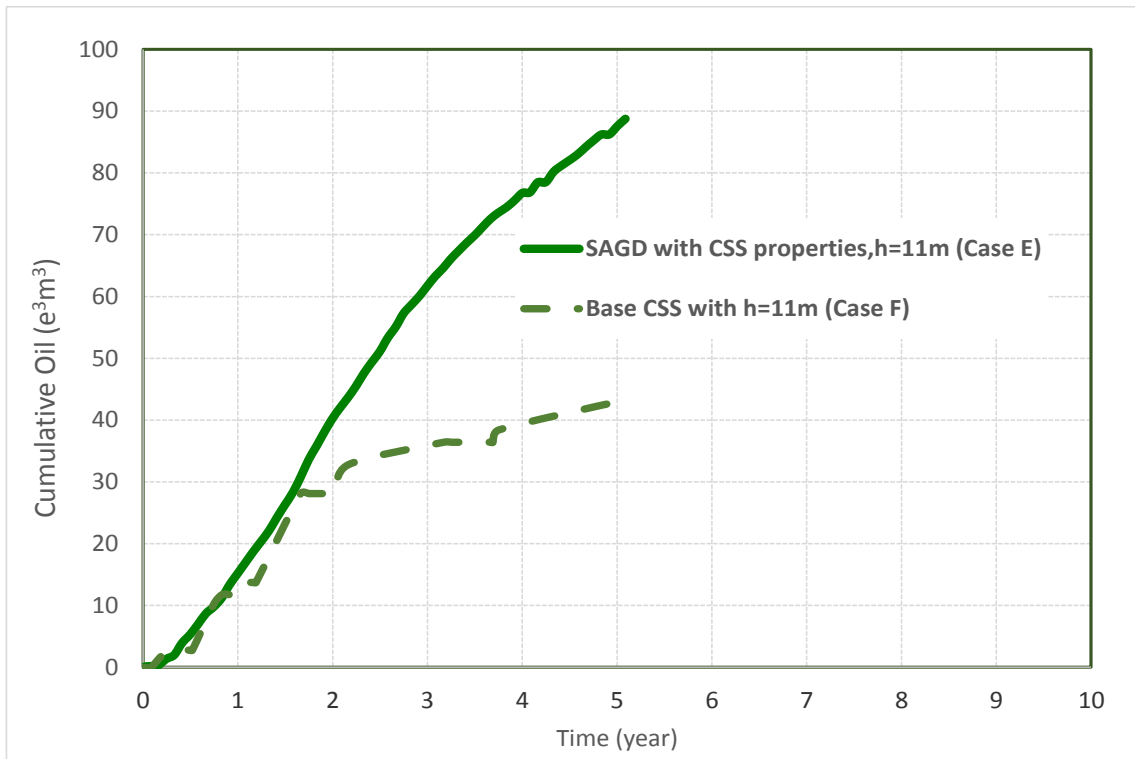
Figure 4-40: Cumulative oil for Cases E and F.
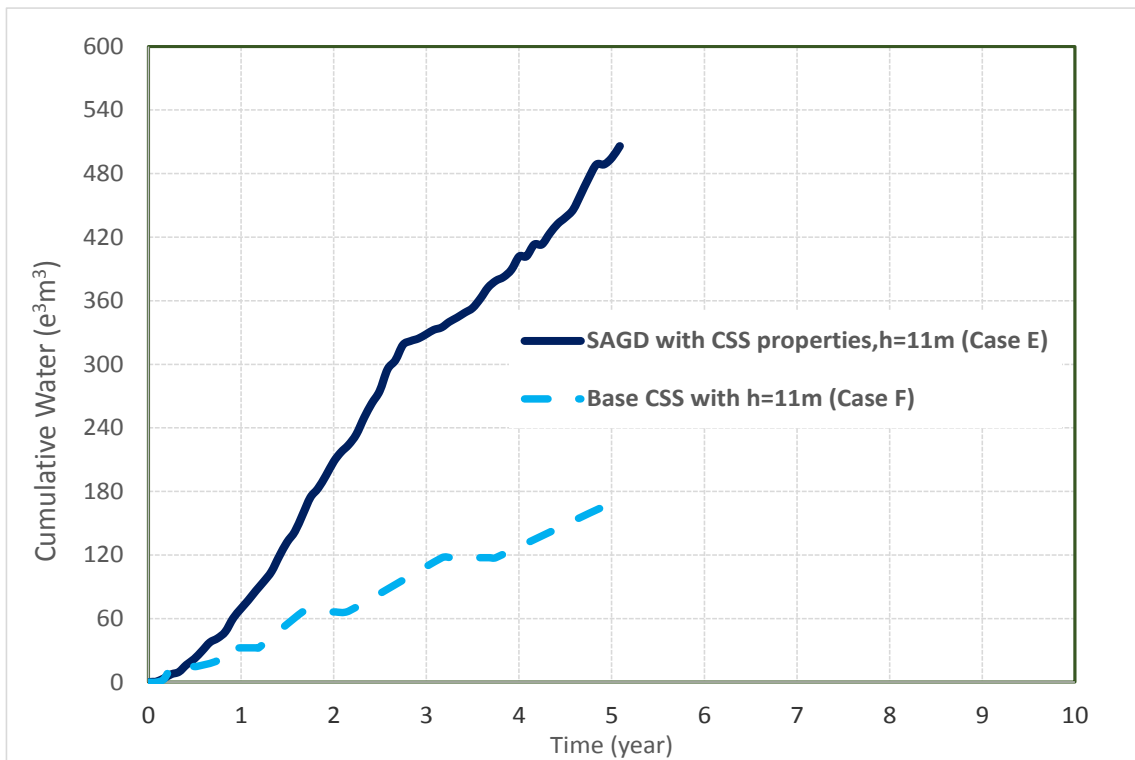
Figure 4-41: Cumulative water for Cases E and F.
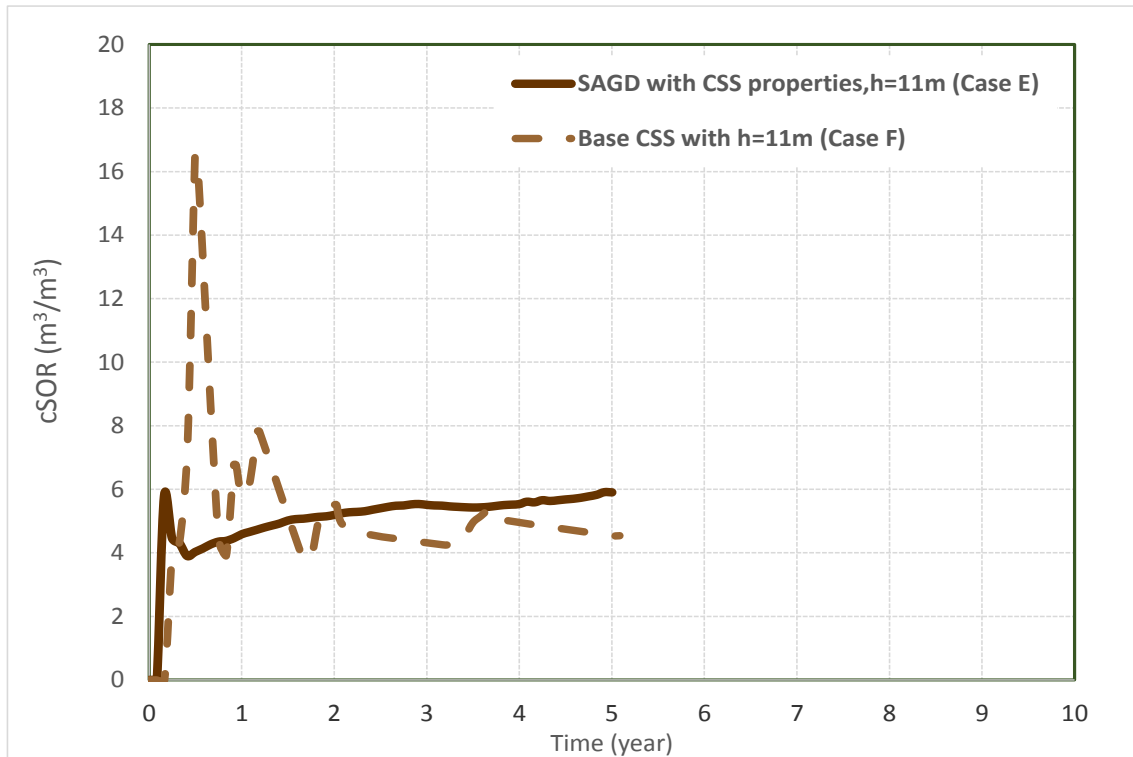
Figure 4-42: cSOR profiles for Cases E and F.
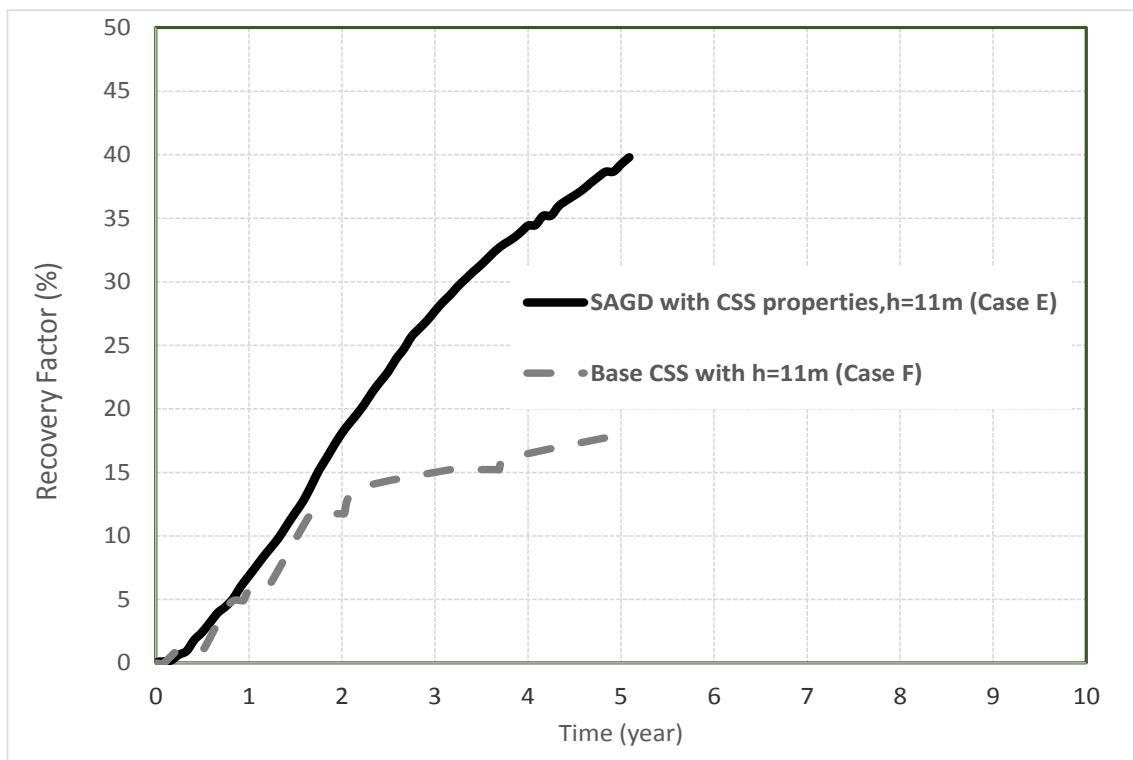
Figure 4-43: Recovery Factor cSOR for Cases E and F.

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4.6 Conclusions

Comparison of the performance indicators for CSS and SAGD reveals that SAGD represent better performance over CSS. In other words CSS has higher value of cSOR, lower normalized oil rate. Lower normalized cumulative oil and lower recovery factor. The obtained results are in complete agreement with the analysis of field data in Chapter 3.

The overall conclusion from conducting the comparison cases in Section 4.5 is that in the selected reservoirs, if the net pay is greater than a critical value, then the performance of SAGD is better in all aspects including cumulative oil production, cSOR, and recovery factor. On the other hand CSS has higher performance if the operation is carried out below the critical value. In one of the cases of this study, the net pay for CSS lowered from 23 m to 11 m. This value seems to be in the low side of the critical value for |SAGD process which showed a better performance for CSS process. However, the exact critical value can be obtained by performing more sensitivity runs. In the current study the selected reservoir with CSS operation in the primrose area had a net pay beyond the critical value and better results would be observed with SAGD operation in that reservoir. The Burnt Lake reservoir with a SAGD operation had a suitable net pay and shifting the operation to CSS is not beneficial.

CHAPTER 5 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The Steam-Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) field data from main producers in the Cold Lake area collected and analyzed. To provide consistent basis for comparison purpose, the production profile of all thermal projects are normalized. The following conclusions were observed by comparing cumulative steam-to-oil ratio (cSOR), normalized produced oil and normalized produced water.

- The analysis of the field operation results suggest that the SAGD process yields to a higher normalized produced oil and lower cSOR than that of CSS process in the Cold Lake area.
- Numerical reservoir simulation models for both SAGD and CSS operations at Cold Lake area were conducted. For each of these processes, a typical injection/production profile was selected from CNRL's SAGD and CSS operations at Cold Lake. Both models are homogenous with representative averaged reservoir properties. Both models were history matched and then sensitivity scenarios were conducted to evaluate the effectiveness of each process at Cold Lake area. The following conclusions were obtained:
  1. According to simulation results, SAGD demonstrate better performance than CSS in a reservoir with Cold Lake properties. The reservoir simulation results are consistent with the conclusions of the data analysis of the field data.
  2. In a Cold Lake reservoir with reduced permeability, SAGD still demonstrated better performance than that of CSS.
  3. In a Cold Lake reservoir with thin oil column thickness (equal to 11 m), Both Recovery economic analysis is required to find out which process has better performance.

5.2 Recommendations

The recommendations derived rom the results of the research documented in this thesis are as follows.

- In the current research two different values for net pay were examined. It seems that. here is a critical value of net pay where the performances of the two processes are equal. If the net pay is greater than a critical value, then it is possible that the performance of SAGD is better in all aspects including cumulative oil production, cSOR, and recovery factor. On the other hand CSS has higher performance if the operation is carried out below the critical value. Therefore finding the critical value of net pay is recommended.
- In this study, homogeneous reservoir simulation models with averaged properties were constructed. It is known that recovery process performance is affected by heterogeneity of the reservoir. Therefore it is essential to investigate the validity of the numerical reservoir simulation results in real heterogeneous reservoir models.
- The availability of thief zones, for example bottom water, top gas and water zones, will have detrimental effects on the performance of the thermal recovery processes. Investigation on the validity of the results of the current research with the existence of thief zones is recommended.

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APPENDIX A: DATA FILE OF THE SAGD MODEL

```
RESULTS SIMULATOR STARS 200600

*INTERRUPT *STOP

*TITLE1 'Heating with ciculating wells'
*TITLE2 'SAGD Cold Lake reservoir'

*INUNIT *SI
DIM MDICLU 4000000
MAXERROR 1
WSRF GRID TIME
WSRF SECTOR TIME
WSRF WELL TIME
OUTPRN GRID OBHLOSS PRES SG SO SW VISO
OUTPRN WELL ALL
OUTPRN ITER NEWTON
OUTSRF GRID PRES QUALBLK SG SO STEAMQUAL SW TEMP
OUTSRF WELL MASS COMPONENT ALL

WPRN GRID 0
**$  Distance units: m
RESULTS XOFFSET          0.0000
RESULTS YOFFSET          0.0000
RESULTS ROTATION          0.0000  **$  (DEGREES)
**$
************************************************************************
*
**$ Definition of fundamental cartesian grid
**$
************************************************************************
*
GRID VARI 40 2 35
KDIR DOWN
DI IVAR
 40*1
DJ JVAR
 2*50
DK KVAR
 35*1
DTOP
 80*475
**$ Property: NULL Blocks  Max: 1  Min: 1
**$  0 = null block, 1 = active block
NULL CON          1
              **porosity =33%
**$ Property: Porosity  Max: 0.36 Min: 0.36
POR CON       0.37
                **permeability in i direction= 5000 milidarci
**$ Property: Permeability I (md)   Max: 3200  Min: 3200
```

```
PERMI CON          2500
PERMJ EQUALSI
**$ Property: Permeability K (md)   Max: 2500  Min: 2500
PERMK CON          1000
**$ Property: Pinchout Array  Max: 1  Min: 1
**$  0 = pinched block, 1 = active block
PINCHOUTARRAY CON           1


END-GRID

PRPOR    3200
ROCKTYPE 1
    CPOR 2.9E-06                        ** Effective formation (pore)
compressibility (1/kPa)
    ROCKCP 2.35E+06                     ** Rock heat capacity (J/m3-C)
    THCONR 6.6E+05                      ** Thermal conductivity of rock
(J/m-day-C)
    THCONW 5.35E+04                     ** Thermal conductivity of water
phase (J/m-day-C)
    THCONO 1.25E+04                     ** Thermal conductivity of oil
phase (J/m-day-C)
    THCONG 3200                         ** Thermal conductivity of gas
phase (J/m-day-C)
    THCONMIX COMPLEX
HLOSSPROP OVERBUR 2.35E+06 1.45E+05
         UNDERBUR 2.35E+06 1.45E+05
**$ Property: Thermal/rock Set Num  Max: 1  Min: 1
THTYPE CON           1




** ==================  COMPONENT PROPERTIES  ==============

*MODEL 3 3 3 1

** COMPONENT TYPES AND NAMES

*COMPNAME  'WATER'    'BITUMEN' 'CH4'
**   ------    ---------  --------
*CMM       0.E+00     0.620     0.01690    **molecular mass[kg/gmol]
*PCRIT     2.2048E+4 1.1149E+3  4.624E+3
*TCRIT     3.7420E+2  4.9780E+2 -8.400E+1

*MOLDEN    0.0E+0     1.825E+3   1.02160E+4   **liquid mol
density[kmol/m3]
*CP        0.0E+0     6.84E-7    6.84E-7    **liquid compressibility[1/kPa]

*CT1       0.0E+0     8.0E-4     8.0E-4     **thermal expansion coef.[1/C]
*CT2       0.0E+0     0.0E+0     0.0E+0

cpg1         0        -20 19.251    **1st coef.of gas heat cap.[J/gmol-C]
```

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```
cpg2             0        1.9  5.213e-2    **2nd coef.of gas heat cap.[J/gmol-
C^2]
cpg3             0        -1e-3       1.197e-5    **3st coef.of gas heat
cap.[J/gmol-C^3]
cpg4             0        3e-7        -1.132e-8   **4th coef.of gas heat
cap.[J/gmol-C^4]
hvr              0        1500.       1556.       **vaporization enthalpy correl
[J/gmol-C]
                                                  **ev=0.38
default


** K-VALUE CORRELATION DATA

*KV1         0.E+00  0.E+00      5.4547E+05      **1st coef.of
gas/liq.K_value[kPa]
*KV4         0.E+00  0.E+00      -8.80E+02   **4th coef.of gas/liq.K_value[C]
*KV5         0.E+00  0.E+00      -2.66E+02   **5th coef.of gas/liq.K_value[C]


*VISCTABLE
10  0 187949.00 407.03
20  0 67942.24 216.33
30  0 15934.19 46.080
40  0 5209.420 30.230
50  0 2957.280 13.760
60  0 1391.390 8.1600
70  0 636.6700 4.8000
80  0 317.1300 4.0300
90  0 169.3500 3.7150
100 0 93.52000 3.4400
120 0 40.21000 2.9100
125 0 34.37000 2.8060
140 0 21.95000 2.5300
150 0 17.05000 2.3280
160 0 13.40000 2.1500
175 0 9.910000 1.9180
180 0 9.000000 1.8500
200 0 6.590000 1.4500
220 0 5.270000 1.1600
225 0 5.010000 1.1020
240 0 4.350000 0.9500
250 0 3.910000 0.8648
260 0 3.520000 0.7900
275 0 3.100000 0.7052
280 0 2.970000 0.6800
300 0 2.540000 0.5500
2000 0 2.440000 0.5400


** Reference conditions
*PRSR  3200
*TEMR  15
*PSURF 101.3
*TSURF 15.5
```

```
** ==================== ROCK-FLUID DATA  ==============


*ROCKFLUID
** MATRIX
RPT 1 STONE2 WATWET
**  Water-oil relative permeabilities
**   Sw          Krw             Krow
**  ------       --------        --------
SWT
**$       Sw            krw             krow
        0.15            0               0.6
       0.19375   0.000244141        0.510598
       0.2375    0.00195313         0.429706
       0.28125   0.0065918          0.357034
        0.325    0.015625           0.292284
       0.36875   0.0305176          0.235144
        0.4125   0.0527344          0.18529
       0.45625   0.0837402          0.142383
          0.5    0.125              0.106066
       0.54375   0.177979           0.075962
        0.5875   0.244141           0.0516689
       0.63125   0.324951           0.0327549
        0.675    0.421875           0.01875
       0.71875   0.536377           0.00913386
        0.7625   0.669922           0.00331456
       0.80625   0.823975           0.000585937
         0.85    1                  0
**  Liquid-gas relative permeabilities
**   Sl          Krg             Krog
**  ------       --------        --------
SLT
**$       Sl            krg             krog
         0.3            1                0
       0.343688   0.850997        0.000585937
       0.387375   0.716177        0.00331456
       0.431063   0.595057        0.00913386
        0.47475   0.487139        0.01875
       0.518438   0.391906        0.0327549
       0.562125   0.308816        0.0516689
       0.605813   0.237305        0.075962
        0.6495    0.176777        0.106066
       0.693188   0.126603        0.142383
       0.736875   0.0861149       0.18529
       0.780563   0.0545915       0.235144
        0.82425   0.03125         0.292284
       0.867938   0.0152231       0.357034
       0.911625   0.00552427      0.429706
       0.955313   0.000976563     0.510598
         0.999     0               0.6




** =================  INITIAL CONDITIONS  ====================
```

116

```
INITIAL
VERTICAL DEPTH_AVE
INITREGION 1
REFPRES 3200.0
REFDEPTH 475.0        **initial reservoir pressure of 2670 in depth 475 m
                **constant temp=15
**$ Property: Temperature (C)   Max: 15  Min: 15
TEMP CON          15
**$ Property: Water Saturation  Max: 0.25  Min: 0.25
SW CON        0.3
**$ Property: Oil Saturation  Max: 0.75  Min: 0.75
SO CON        0.7
                                **composition of oil
**$ Property: Oil Mole Fraction(BITUMEN)  Max: 0.94  Min: 0.94
MFRAC_OIL 'BITUMEN' CON        0.95
**$ Property: Oil Mole Fraction(CH4)  Max: 0.06  Min: 0.06
MFRAC_OIL 'CH4' CON        0.05


** ================= NUMERICAL CONTROL  =====================

NUMERICAL
NORTH 100
ITERMAX 100
NCUTS 10



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

RUN

DATE 1997 1 1     **start of operation
** 0.001 day start running
DTWELL 0.0001

WELL  'TBG-INJ-INJECTOR' *Frac 0.5        **symmytry of the model
INJECTOR MOBWEIGHT EXPLICIT 'TBG-INJ-INJECTOR'
INCOMP  WATER  1.  0.  0.
TINJW  237.5
QUAL  0.8
*OPERATE  MAX  STW  1.  CONT REPEAT
*OPERATE  MAX  BHP  3300.  CONT REPEAT
                                                **the
location of perforation in the injector  .i,j,k
                                **from the surface to the
lenght of the injector
**$          rad  geofac  wfrac  skin
GEOMETRY  J  0.14  0.229  0.5  0.
PERF  GEO  'TBG-INJ-INJECTOR'
**$ UBA      ff  Status  Connection
   1 1 29  1.  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   1 2 29  1.  OPEN    FLOW-FROM  1

*HEAD-METHOD 'TBG-INJ-INJECTOR' GRAV-FRIC-HLOS
```

```
SHUTIN 'TBG-INJ-INJECTOR'


 WELL  'ANNAL-PRD-INJECTOR'  *Frac 0.5
 PRODUCER 'ANNAL-PRD-INJECTOR'
 *OPERATE  MAX  STL  30.  CONT REPEAT        **maximum flow of liquid=400
m3/d
 *OPERATE  MIN  BHP  3200.  CONT REPEAT       **constraint :minimum
BHP=3170 kpa
                                                    **from 10 to
surface
**$          rad  geofac  wfrac  skin
GEOMETRY  J  0.14  0.229  0.5  0.
PERF  GEO  'ANNAL-PRD-INJECTOR'
**$ UBA      ff  Status  Connection
    1 1 29  1.  OPEN    FLOW-TO 'SURFACE'  REFLAYER
    1 2 29  1.  OPEN    FLOW-TO  1


*HEAD-METHOD 'ANNAL-PRD-INJECTOR' GRAV-FRIC-HLOS      **hlos=heat loss


WELL  'TBG-INJ-PRODUCER'  *Frac 0.5
INJECTOR MOBWEIGHT IMPLICIT 'TBG-INJ-PRODUCER'
INCOMP  WATER  1.  0.  0.
TINJW  237.5
QUAL  0.8
*OPERATE  MAX  BHP  3300.  CONT REPEAT
*OPERATE  MAX  STW  30.  CONT REPEAT
                                                  **14m+5m=19 m
**$          rad  geofac  wfrac  skin
GEOMETRY  J  0.14  0.229  0.5  0.
PERF  GEO  'TBG-INJ-PRODUCER'
**$ UBA      ff  Status  Connection
    1 1 34  1.  OPEN    FLOW-FROM 'SURFACE'  REFLAYER
    1 2 34  1.  OPEN    FLOW-FROM  1


*HEAD-METHOD 'TBG-INJ-PRODUCER' GRAV-FRIC-HLOS


 WELL  'ANNAL-PRD-PRODUCER' *Frac 0.5
 PRODUCER 'ANNAL-PRD-PRODUCER'
  *OPERATE  MAX  STL 30.  CONT REPEAT
 *OPERATE  MIN  BHP  3200.  CONT REPEAT
**$          rad  geofac  wfrac  skin
GEOMETRY  J  0.14  0.229  0.5  0.
PERF  GEO  'ANNAL-PRD-PRODUCER'
**$ UBA      ff  Status  Connection
    1 1 34  1.  OPEN    FLOW-TO 'SURFACE'  REFLAYER
    1 2 34  1.  OPEN    FLOW-TO  1


*HEAD-METHOD 'ANNAL-PRD-PRODUCER' GRAV-FRIC-HLOS


HEATR CON             0
*MOD
```

118

```
   1  1:2    29 = 9.0e9
   1  1:2    34 = 9.0e9


TMPSET CON          15
*MOD
   1  1:2    29 = 150
   1  1:2    34 = 150


UHTR  CON           0
*MOD
   1  1:2    29 = 5.0e9
   1  1:2    34 = 5.0e9


AUTOHEATER   ON  1  1:2  29
AUTOHEATER   ON  1  1:2  34


SHUTIN  'TBG-INJ-PRODUCER'

DATE 1997 1 10
DATE 1997 1 20



HEATR CON           0
UHTR CON          0
TMPSET CON          15
AUTOHEATER  Off  1  1:2  29
AUTOHEATER  off  1  1:2  34


DTWELL 0.001

**SHUTIN  'ANNAL-PRD-INJECTOR'
PRODUCER 'ANNAL-PRD-PRODUCER'
OPERATE  MIN BHP 3000.  CONT REPEAT
OPERATE  STEAMTRAP 10       **reduce temperature 10 c from saturation
temp to form condensate




DATE 1997 2 01

INJECTOR MOBWEIGHT EXPLICIT 'TBG-INJ-INJECTOR'
INCOMP  WATER  1.  0.  0.
TINJW  237.5
QUAL  0.75
*OPERATE  MAX  STW  6.38  CONT REPEAT
*OPERATE  MAX  BHP  3250  CONT REPEAT



DATE 1997 3 1
ALTER 'TBG-INJ-INJECTOR'
    9.16
```

```
DATE 1997 4 1
ALTER 'TBG-INJ-INJECTOR'
    5.9

DATE 1997 5 1
ALTER 'TBG-INJ-INJECTOR'
    15.92
DATE 1997 5 31
ALTER 'TBG-INJ-INJECTOR'
    13.9
DATE 1997 7 1


ALTER 'TBG-INJ-INJECTOR'
    17.56
DATE 1997 8 1

ALTER 'TBG-INJ-INJECTOR'
    19.41
DATE 1997 8 31
ALTER 'TBG-INJ-INJECTOR'
    12.93
DATE 1997 10 1
ALTER 'TBG-INJ-INJECTOR'
    15.35
DATE 1997 10 31

ALTER 'TBG-INJ-INJECTOR'
    24.7
DATE 1997 12 1

ALTER 'TBG-INJ-INJECTOR'
    22.92
DATE 1998 1 1
ALTER 'TBG-INJ-INJECTOR'
    22.22

DATE 1998 1 29

ALTER 'TBG-INJ-INJECTOR'
    22.71
DATE 1998 3 1


ALTER 'TBG-INJ-INJECTOR'
    21.97
DATE 1998 3 31
ALTER 'TBG-INJ-INJECTOR'
    22.84


DATE 1998 5 1
```

```
ALTER 'TBG-INJ-INJECTOR'
    27.94

DATE 1998 5 31

ALTER 'TBG-INJ-INJECTOR'
    28.95
DATE 1998 7 1

ALTER 'TBG-INJ-INJECTOR'
    26.58

DATE 1998 8 1

ALTER 'TBG-INJ-INJECTOR'
    31.23
DATE 1998 9 1

ALTER 'TBG-INJ-INJECTOR'
    35.24

DATE 1998 10 1

ALTER 'TBG-INJ-INJECTOR'
    28.93
DATE 1998 10 31
ALTER 'TBG-INJ-INJECTOR'
    29.08

DATE 1998 12 1
ALTER 'TBG-INJ-INJECTOR'
    29.87
DATE 1999 1 1

ALTER 'TBG-INJ-INJECTOR'
    27.09
DATE 1999 1 29


ALTER 'TBG-INJ-INJECTOR'
    23.82

DATE 1999 3 1
ALTER 'TBG-INJ-INJECTOR'
    23.97
DATE 1999 3 31

ALTER 'TBG-INJ-INJECTOR'
   27.91

DATE 1999 5 1

ALTER 'TBG-INJ-INJECTOR'
    27.85
```

```
DATE 1999 5 31


ALTER 'TBG-INJ-INJECTOR'
    26.7
DATE 1999 7 1

ALTER 'TBG-INJ-INJECTOR'
    33.49


DATE 1999 8 1

ALTER 'TBG-INJ-INJECTOR'
    27.13


DATE 1999 9 1


ALTER 'TBG-INJ-INJECTOR'
    29.39
DATE 1999 10 1

ALTER 'TBG-INJ-INJECTOR'
    22.92
DATE 1999 10 31

ALTER 'TBG-INJ-INJECTOR'
    19.7

DATE 1999 12 1

ALTER 'TBG-INJ-INJECTOR'
    17.42

DATE 2000 1 1

ALTER 'TBG-INJ-INJECTOR'
    17.56

DATE 2000 1 30

ALTER 'TBG-INJ-INJECTOR'
    16.03

DATE 2000 3 1

ALTER 'TBG-INJ-INJECTOR'
```

```
     16.07

DATE 2000 3 31

ALTER 'TBG-INJ-INJECTOR'
     14.53

DATE 2000 5 1


ALTER 'TBG-INJ-INJECTOR'
     14.35
DATE 2000 5 31

ALTER 'TBG-INJ-INJECTOR'
     13.89
DATE 2000 7 1

ALTER 'TBG-INJ-INJECTOR'
     18.05
DATE 2000 8 1

ALTER 'TBG-INJ-INJECTOR'
     19.28

DATE 2000 8 31

ALTER 'TBG-INJ-INJECTOR'
     17.87

DATE 2000 10 1

ALTER 'TBG-INJ-INJECTOR'
     15.6
DATE 2000 10 31
ALTER 'TBG-INJ-INJECTOR'
     16.4
DATE 2000 12 1
ALTER 'TBG-INJ-INJECTOR'
     19.
DATE 2001 1 1

ALTER 'TBG-INJ-INJECTOR'
     15.26
DATE 2001 1 29
ALTER 'TBG-INJ-INJECTOR'
     17.86
DATE 2001 3 1

ALTER 'TBG-INJ-INJECTOR'
     12.61
DATE 2001 3 31

ALTER 'TBG-INJ-INJECTOR'
```

```
    17.96
DATE 2001 5 1


ALTER 'TBG-INJ-INJECTOR'
    17.24

DATE 2001 6 1
ALTER 'TBG-INJ-INJECTOR'
    16.4

DATE 2001 7 1
ALTER 'TBG-INJ-INJECTOR'
    16.44


DATE 2001 8 1

ALTER 'TBG-INJ-INJECTOR'
    21.65

DATE 2001 8 31

ALTER 'TBG-INJ-INJECTOR'
    23.39

DATE 2001 9 1


DATE 2001 10 1


ALTER 'TBG-INJ-INJECTOR'
    22.65
DATE 2001 11 1


ALTER 'TBG-INJ-INJECTOR'
    17.31
DATE 2001 12 1
ALTER 'TBG-INJ-INJECTOR'
    16.87
DATE 2002 1 1

ALTER 'TBG-INJ-INJECTOR'
    18.68
DATE 2002 2 1


ALTER 'TBG-INJ-INJECTOR'
    19.58
DATE 2002 3 1

ALTER 'TBG-INJ-INJECTOR'
```

```
    20.12
DATE 2002 3 31

ALTER 'TBG-INJ-INJECTOR'
    22.44
DATE 2002 5 1


ALTER 'TBG-INJ-INJECTOR'
    22.56


DATE 2002 5 31
ALTER 'TBG-INJ-INJECTOR'
    22.62

DATE 2002 7 1
ALTER 'TBG-INJ-INJECTOR'
    19.16


DATE 2002 8 1
ALTER 'TBG-INJ-INJECTOR'
    2.15
DATE 2002 8 31

ALTER 'TBG-INJ-INJECTOR'
    2.65

DATE 2002 10 1

ALTER 'TBG-INJ-INJECTOR'
    21.21
DATE 2002 10 31

ALTER 'TBG-INJ-INJECTOR'
    1.69

DATE 2002 12 1


ALTER 'TBG-INJ-INJECTOR'
    0.41

PRODUCER 'ANNAL-PRD-PRODUCER'


DATE 2003 1 1


ALTER 'TBG-INJ-INJECTOR'
    16.19
```

```
DATE 2003 1 29
ALTER 'TBG-INJ-INJECTOR'
    10.75

DATE 2003 3 1
ALTER 'TBG-INJ-INJECTOR'
    10.21
DATE 2003 3 31
ALTER 'TBG-INJ-INJECTOR'
    9.44



DATE 2003 5 1


ALTER 'TBG-INJ-INJECTOR'
    1.14


DATE 2003 5 31

ALTER 'TBG-INJ-INJECTOR'
    0.1


DATE 2003 8 1
ALTER 'TBG-INJ-INJECTOR'
    0.1



DATE 2003 10 1


ALTER 'TBG-INJ-INJECTOR'
    14.94


DATE 2003 10 31
ALTER 'TBG-INJ-INJECTOR'
    13.29


DATE 2003 12 1


ALTER 'TBG-INJ-INJECTOR'
    10.85

DATE 2004 1 1
```

```
ALTER 'TBG-INJ-INJECTOR'
     9.31

DATE 2004 1 30
ALTER 'TBG-INJ-INJECTOR'
     9.12
DATE 2004 3 1
ALTER 'TBG-INJ-INJECTOR'
     9.55

DATE 2004 3 31
ALTER 'TBG-INJ-INJECTOR'
     10.19



DATE 2004 5 1

ALTER 'TBG-INJ-INJECTOR'
     9.92

DATE 2004 5 31
ALTER 'TBG-INJ-INJECTOR'
     9.6
DATE 2004 7 1


ALTER 'TBG-INJ-INJECTOR'
     10.24
DATE 2004 8 1

ALTER 'TBG-INJ-INJECTOR'
     18.64



DATE 2004 8 31
ALTER 'TBG-INJ-INJECTOR'
     13.68



DATE 2004 10 1
ALTER 'TBG-INJ-INJECTOR'
     18.57



DATE 2004 10 31
ALTER 'TBG-INJ-INJECTOR'
     18.2
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DATE 2004 12 1

ALTER 'TBG-INJ-INJECTOR'
    18.88
DATE 2005 1 1
ALTER 'TBG-INJ-INJECTOR'
    18.54



DATE 2005 1 29
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DATE 2005 3 1

ALTER 'TBG-INJ-INJECTOR'
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DATE 2005 3 31
ALTER 'TBG-INJ-INJECTOR'
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DATE 2005 5 1
ALTER 'TBG-INJ-INJECTOR'
    13.22


DATE 2005 5 31
ALTER 'TBG-INJ-INJECTOR'
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DATE 2005 7 1
ALTER 'TBG-INJ-INJECTOR'
    12.73

DATE 2005 8 1

ALTER 'TBG-INJ-INJECTOR'
    9.34
DATE 2005 8 31

ALTER 'TBG-INJ-INJECTOR'
    10.83
DATE 2005 10 1



ALTER 'TBG-INJ-INJECTOR'
    12.88
DATE 2005 10 31
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ALTER 'TBG-INJ-INJECTOR'
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DATE 2005 12 1
ALTER 'TBG-INJ-INJECTOR'
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DATE 2006 1 1

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DATE 2006 1 29
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DATE 2006 3 1
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DATE 2006 3 31

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DATE 2006 5 1


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DATE 2006 5 31
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DATE 2006 8 1


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DATE 2006 8 31
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DATE 2006 10 1
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DATE 2006 10 31
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DATE 2006 12 1
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DATE 2007 1 1
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DATE 2007 3 1
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DATE 2007 3 31
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DATE 2007 5 1
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DATE 2007 5 31

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DATE 2007 7 1

ALTER 'TBG-INJ-INJECTOR'
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DATE 2007 8 1
ALTER 'TBG-INJ-INJECTOR'
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DATE 2007 8 31
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DATE 2007 10 1


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DATE 2007 10 31
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DATE 2007 12 1
ALTER 'TBG-INJ-INJECTOR'
    12.14
DATE 2008 1 1
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DATE 2008 1 30
ALTER 'TBG-INJ-INJECTOR'
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DATE 2008 3 1

ALTER 'TBG-INJ-INJECTOR'
    12.55
```

```
DATE 2008 3 31
ALTER 'TBG-INJ-INJECTOR'
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DATE 2008 5 1
ALTER 'TBG-INJ-INJECTOR'
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DATE 2008 5 31
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DATE 2008 7 1
ALTER 'TBG-INJ-INJECTOR'
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DATE 2008 8 1
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DATE 2008 8 31
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DATE 2009 3 1

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DATE 2009 3 31
ALTER 'TBG-INJ-INJECTOR'
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DATE 2009 5 1
ALTER 'TBG-INJ-INJECTOR'
    10.47
DATE 2009 5 31


ALTER 'TBG-INJ-INJECTOR'
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DATE 2009 7 1
ALTER 'TBG-INJ-INJECTOR'
    21.34
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DATE 2009 8 1
ALTER 'TBG-INJ-INJECTOR'
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DATE 2009 8 31

ALTER 'TBG-INJ-INJECTOR'
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DATE 2009 10 1
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DATE 2009 10 31
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DATE 2009 12 1
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DATE 2010 1 1
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DATE 2010 3 1

ALTER 'TBG-INJ-INJECTOR'
    16.68
DATE 2010 3 31
ALTER 'TBG-INJ-INJECTOR'
    14.76
DATE 2010 5 1

ALTER 'TBG-INJ-INJECTOR'
    15.43

DATE 2010 5 31
ALTER 'TBG-INJ-INJECTOR'
    14.65
DATE 2010 7 1

ALTER 'TBG-INJ-INJECTOR'
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DATE 2010 8 1
ALTER 'TBG-INJ-INJECTOR'
    14.46

DATE 2010 8 31
ALTER 'TBG-INJ-INJECTOR'
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DATE 2010 10 1
ALTER 'TBG-INJ-INJECTOR'
    14.99
DATE 2010 10 31
```

```
ALTER 'TBG-INJ-INJECTOR'
     11.11
DATE 2010 12 1
ALTER 'TBG-INJ-INJECTOR'
     11.67
DATE 2011 1 1
ALTER 'TBG-INJ-INJECTOR'
     12.12
DATE 2011 1 29
ALTER 'TBG-INJ-INJECTOR'
     12.17
DATE 2011 3 1

ALTER 'TBG-INJ-INJECTOR'
     9.07
DATE 2011 3 31
ALTER 'TBG-INJ-INJECTOR'
     12.16
DATE 2011 5 1
ALTER 'TBG-INJ-INJECTOR'
     11.95
DATE 2011 5 31
ALTER 'TBG-INJ-INJECTOR'
     11.83
DATE 2011 7 1
ALTER 'TBG-INJ-INJECTOR'
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DATE 2011 8 1
ALTER 'TBG-INJ-INJECTOR'
     15.26

DATE 2011 8 31
ALTER 'TBG-INJ-INJECTOR'
     12.
DATE 2011 10 1
ALTER 'TBG-INJ-INJECTOR'
     15.73

DATE 2011 10 31
ALTER 'TBG-INJ-INJECTOR'
     16.87
DATE 2011 12 1
ALTER 'TBG-INJ-INJECTOR'
     16.95

DATE 2012 1 1
ALTER 'TBG-INJ-INJECTOR'
     16.78
DATE 2012 1 30
ALTER 'TBG-INJ-INJECTOR'
     11.45
DATE 2012 3 1

ALTER 'TBG-INJ-INJECTOR'
```

```
     11.55
DATE 2012 3 31
ALTER 'TBG-INJ-INJECTOR'
     11.54
DATE 2012 5 1

ALTER 'TBG-INJ-INJECTOR'
     9.49
DATE 2012 5 31
ALTER 'TBG-INJ-INJECTOR'
     9.65
DATE 2012 7 1
ALTER 'TBG-INJ-INJECTOR'
     13.35
DATE 2012 8 1
ALTER 'TBG-INJ-INJECTOR'
     11.46
DATE 2012 8 31
ALTER 'TBG-INJ-INJECTOR'
     8.18
DATE 2012 10 1

ALTER 'TBG-INJ-INJECTOR'
     9.66
DATE 2012 10 31
ALTER 'TBG-INJ-INJECTOR'
     10.07
DATE 2012 12 1
ALTER 'TBG-INJ-INJECTOR'
     16.85
DATE 2013 1 1
ALTER 'TBG-INJ-INJECTOR'
     11.48
DATE 2013 1 29
ALTER 'TBG-INJ-INJECTOR'
     7.76
DATE 2013 3 1
ALTER 'TBG-INJ-INJECTOR'
     9.66
DATE 2013 3 31
ALTER 'TBG-INJ-INJECTOR'
     10.41

DATE 2013 5 1
ALTER 'TBG-INJ-INJECTOR'
     18.76
DATE 2013 5 31
ALTER 'TBG-INJ-INJECTOR'
     11.37
DATE 2013 7 1
ALTER 'TBG-INJ-INJECTOR'
     12.42
DATE 2013 8 1
ALTER 'TBG-INJ-INJECTOR'
```

```
    10.7
DATE 2013 8 31
ALTER 'TBG-INJ-INJECTOR'
    8.91
DATE 2013 10 1
ALTER 'TBG-INJ-INJECTOR'
    9.57
DATE 2013 10 31
ALTER 'TBG-INJ-INJECTOR'
    13.28
DATE 2013 12 1
ALTER 'TBG-INJ-INJECTOR'
    13.58


DATE 2014 1 1
ALTER 'TBG-INJ-INJECTOR'
    10.83
DATE 2014 1 29
ALTER 'TBG-INJ-INJECTOR'
    0.
DATE 2014 4 1


DATE 2014 7 1



ALTER 'TBG-INJ-INJECTOR'
    0.
DATE 2014 8 31


ALTER 'TBG-INJ-INJECTOR'
    6.46
DATE 2014 9 1
ALTER 'TBG-INJ-INJECTOR'
    4.7


DATE 2014 10 1
STOP

RESULTS PDW FILENAME 'C:\Thesis-29-Oct\Simulation\CNRL-SAGD\CNRL-SAGD-
Submodel-injection.prd'
RESULTS PDW FILETYPE 0
RESULTS PDW COMMAUSE 0
RESULTS PDW FIELDTYPE 1
RESULTS PDW WISUFFIX 'iw'
RESULTS PDW GISUFFIX 'ig'
RESULTS PDW SISUFFIX 'is'
RESULTS PDW WELLNAMEROW 0
RESULTS PDW DATAROW 3
RESULTS PDW CONSECUTIVE 1
RESULTS PDW SEMICOLON 1
RESULTS PDW SPACE 1
RESULTS PDW TAB 1
RESULTS PDW OTHERCHAR
RESULTS PDW NUMCOLS 4
```

```
RESULTS PDW COLSELS 1 ' ' ' ' 'Date/ Time ' 'day ' 'Time(eg. 730 ) '
RESULTS PDW COLSELS 2 ' ' 'Irregular ' 'Water Injected ' 'm3/day '
'Producing daily rate '
RESULTS PDW WELLNAMEINCOL 0
RESULTS PDW APPLYDATA 0
RESULTS PDW RATETOL 0
RESULTS PDW END
RESULTS RELPERMCORR NUMROCKTYPE 1
RESULTS RELPERMCORR CORRVALS 0.15 0.15 0.15 0.15 0.15 0.15 0.001 0.001
RESULTS RELPERMCORR CORRVALS 0.6 1 1 -99999 3 2.5 2.5 2.5
RESULTS RELPERMCORR CORRVALS_HONARPOUR -99999 -99999 -99999 -99999 -99999
-99999 -99999 -99999
RESULTS RELPERMCORR STOP

RESULTS SPEC 'Permeability J'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 0
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC EQUALSI 0 1
RESULTS SPEC STOP

RESULTS WPD WELLNAME 'TBG-INJ-INJECTOR'
RESULTS WPD PROPNAME 'Water Rate SC'
RESULTS WPD PRIMARYCONSTRAINT
RESULTS WPD STARTTIME 19961201.0
RESULTS WPD TIMEUNIT 0
RESULTS WPD VALUE 0 0 31 0 59 6.38 90 9.16 120 5.9 151 15.92 181 13.9 212
17.56 243 19.41 273 12.93 304 15.35 334 24.7 365 22.92 396 22.22 424 22.71
455 21.97 485 22.84 516 27.94 546 28.95 577 26.58 608 31.23 638 35.24 669
28.93 699 29.08 730 29.87 761 27.09 789 23.82 820 23.97 850 27.91 881
27.85 911 26.7 942 33.49 973 27.13 1003 29.39 1034 22.92 1064 19.7 1095
17.42 1126 17.56 1155 16.03 1186 16.07 1216 14.53 1247 14.35 1277 13.89
1308 18.05 1339 19.28 1369 17.87 1400 15.6 1430 16.4 1461 19 1492 15.26
1520 17.86 1551 12.61 1581 17.96 1612 17.24 1642 16.4 1673 16.44 1704
21.65 1734 23.39 1765 22.65 1795 17.31 1826 16.87 1857 18.68 1885 19.58
1916 20.12 1946 22.44 1977 22.56 2007 22.62 2038 19.16 2069 2.15 2099 2.65
2130 21.21 2160 1.69 2191 0.41 2222 16.19 2250 10.75 2281 10.21 2311 9.44
2342 1.14 2372 0 2403 0 2434 0 2464 7.8 2495 14.94 2525 13.29 2556 10.85
2587 9.31 2616 9.12 2647 9.55 2677 10.19 2708 9.92 2738 9.6 2769 10.24
2800 18.64 2830 13.68 2861 18.57 2891 18.2 2922 18.88 2953 18.54 2981
16.55 3012 15.8
RESULTS WPD VALUE 3042 11.24 3073 13.22 3103 12.71 3134 12.73 3165 9.34
3195 10.83 3226 12.88 3256 10.56 3287 10.07 3318 9.97 3346 10.42 3377 8.36
3407 7.89 3438 8.67 3468 12.15 3499 11.54 3530 11.43 3560 3.98 3591 11.16
3621 11.78 3652 11.47 3683 10.88 3711 11.25 3742 12.28 3772 11.11 3803
11.47 3833 11.45 3864 11.12 3895 10.9 3925 10.48 3956 11.44 3986 12.14
4017 12.14 4048 12.45 4077 12.16 4108 12.55 4138 12.45 4169 13.21 4199
10.92 4230 12.79 4261 12.98 4291 12.72 4322 10.59 4352 12.62 4383 12.04
4414 11 4442 6.66 4473 4.96 4503 5.75 4534 10.47 4564 20.45 4595 21.34
4626 6.7 4656 6.98 4687 8.19 4717 12.99 4748 13.72 4779 13.01 4807 13.53
4838 16.68 4868 14.76 4899 15.43 4929 14.65 4960 14.95 4991 14.46 5021
9.42 5052 14.99 5082 11.11 5113 11.67 5144 12.12 5172 12.17 5203 9.07 5233
```

12.16 5264 11.95 5294 11.83 5325 11.14 5356 15.26 5386 12 5417 15.73 5447
16.87 5478 16.95 5509 16.78 5538 11.45 5569 11.55 5599 11.54 5630 9.49
5660 9.65 5691 13.35 5722 11.46 5752 8.18 5783 9.66 5813 10.07 5844 16.85
5875 11.48
RESULTS WPD VALUE 5903 7.76 5934 9.66 5964 10.41 5995 18.76 6025 11.37
6056 12.42 6087 10.7 6117 8.91 6148 9.57 6178 13.28 6209 13.58 6240 10.83
6268 0 6299 0 6329 0 6360 0 6390 0 6421 0 6452 0 6482 6.46 6483 4.7
RESULTS WPD END

APPENDIX B: DATA FILE OF THE CSS MODEL

```
RESULTS SIMULATOR STARS 201401

*INTERRUPT *STOP

*TITLE1 'Heating with ciculating wells'
*TITLE2 'SAGD Cold Lake reservoir'

*INUNIT *SI
DIM MDICLU 4000000
MAXERROR 1
WSRF GRID TIME
WSRF SECTOR TIME
WSRF WELL TIME
OUTPRN GRID OBHLOSS PRES SG SO SW VISO
OUTPRN WELL ALL
OUTPRN ITER NEWTON
OUTSRF GRID PRES QUALBLK SG SO STEAMQUAL SW TEMP
OUTSRF WELL MASS COMPONENT ALL


WPRN GRID 0
**$  Distance units: m
RESULTS XOFFSET            0.0000
RESULTS YOFFSET            0.0000
RESULTS ROTATION             0.0000  **$  (DEGREES)
**$
************************************************************************
*
**$ Definition of fundamental cartesian grid
**$
************************************************************************
*
GRID VARI 30 2 23
KDIR DOWN
DI IVAR
 30*1
DJ JVAR
 2*50
DK KVAR
 23*1
DTOP
 60*489
**$ Property: NULL Blocks  Max: 1  Min: 1
**$  0 = null block, 1 = active block
NULL CON          1
                **porosity =33%
**$ Property: Porosity  Max: 0.36 Min: 0.36
POR CON        0.32
                 **permeability in i direction= 5000 milidarci
**$ Property: Permeability I (md)   Max: 3200  Min: 3200
PERMI CON         3400
```

```
PERMJ EQUALSI
**$ Property: Permeability K (md)   Max: 2500  Min: 2500
PERMK CON         1500
**$ Property: Pinchout Array  Max: 1  Min: 1
**$  0 = pinched block, 1 = active block
PINCHOUTARRAY CON           1

END-GRID

PRPOR    3300
ROCKTYPE 1
   CPOR 2.9E-06                         ** Effective formation (pore)
compressibility (1/kPa)
   ROCKCP 2.35E+06                      ** Rock heat capacity (J/m3-C)
   THCONR 6.6E+05                       ** Thermal conductivity of rock
(J/m-day-C)
   THCONW 5.35E+04                      ** Thermal conductivity of water
phase (J/m-day-C)
   THCONO 1.25E+04                      ** Thermal conductivity of oil
phase (J/m-day-C)
   THCONG 3200                          ** Thermal conductivity of gas
phase (J/m-day-C)
   THCONMIX COMPLEX
HLOSSPROP OVERBUR 2.35E+06 1.45E+05
        UNDERBUR 2.35E+06 1.45E+05
**$ Property: Thermal/rock Set Num  Max: 1  Min: 1

*DILATION
*PBASE 3300.
*PDILA 7300.
*PPACT 5000.
*CRD 100E-06
*FR 0.45
*PORRATMAX 1.25

*PERMULI con 7.0

*PERMULJ con 7.0

*PERMULK con 7.0

THTYPE CON              1

** =================== COMPONENT PROPERTIES  ==============

*MODEL 3 3 3 1

** COMPONENT TYPES AND NAMES

*COMPNAME  'WATER'   'BITUMEN' 'CH4'
**    ------    ---------  --------
*CMM      0.E+00     0.620      0.01690    **molecular mass[kg/gmol]
*PCRIT    2.2048E+4  1.1149E+3  4.624E+3
*TCRIT    3.7420E+2  4.9780E+2 -8.400E+1
```
139

```
*MOLDEN     0.0E+0      1.825E+3   1.02160E+4   **liquid mol
density[kmol/m3]
*CP         0.0E+0      6.84E-7    6.84E-7    **liquid compressibility[1/kPa]


*CT1        0.0E+0      8.0E-4     8.0E-4     **thermal expansion coef.[1/C]
*CT2        0.0E+0      0.0E+0     0.0E+0

cpg1        0          -20  19.251    **1st coef.of gas heat cap.[J/gmol-C]
cpg2        0          1.9  5.213e-2   **2nd coef.of gas heat cap.[J/gmol-
C^2]
cpg3        0          -1e-3      1.197e-5   **3st coef.of gas heat
cap.[J/gmol-C^3]
cpg4        0          3e-7       -1.132e-8  **4th coef.of gas heat
cap.[J/gmol-C^4]
hvr         0          1500.      1556.       **vaporization enthalpy correl
[J/gmol-C]
                                                  **ev=0.38
default

** K-VALUE CORRELATION DATA

*KV1        0.E+00  0.E+00      5.4547E+05      **1st coef.of
gas/liq.K_value[kPa]
*KV4        0.E+00  0.E+00      -8.80E+02   **4th coef.of gas/liq.K_value[C]
*KV5        0.E+00  0.E+00      -2.66E+02   **5th coef.of gas/liq.K_value[C]


*VISCTABLE
10  0 187949.00  407.03
20  0 67942.24 216.33
30  0 15934.19 46.080
40  0 5209.420 30.230
50  0 2957.280 13.760
60  0 1391.390 8.1600
70  0 636.6700 4.8000
80  0 317.1300 4.0300
90  0 169.3500 3.7150
100 0 93.52000 3.4400
120 0 40.21000 2.9100
125 0 34.37000 2.8060
140 0 21.95000 2.5300
150 0 17.05000 2.3280
160 0 13.40000 2.1500
175 0 9.910000 1.9180
180 0 9.000000 1.8500
200 0 6.590000 1.4500
220 0 5.270000 1.1600
225 0 5.010000 1.1020
240 0 4.350000 0.9500
250 0 3.910000 0.8648
260 0 3.520000 0.7900
275 0 3.100000 0.7052
280 0 2.970000 0.6800
```

```
300 0 2.540000 0.5500
2000  0 2.440000 0.5400


** Reference conditions
*PRSR  3300
*TEMR  15
*PSURF 101.3
*TSURF 15.5

** ==================  ROCK-FLUID DATA  ==============

*ROCKFLUID
** MATRIX
RPT 1 STONE2 WATWET
**   Water-oil relative permeabilities
**    Sw          Krw             Krow
**   ------      --------        --------
SWT
**$       Sw           krw           krow
        0.15            0             0.6
      0.19375   0.000244141       0.510598
       0.2375   0.00195313        0.429706
      0.28125   0.0065918         0.357034
        0.325   0.015625          0.292284
      0.36875   0.0305176         0.235144
       0.4125   0.0527344          0.18529
      0.45625   0.0837402         0.142383
          0.5     0.125           0.106066
      0.54375   0.177979          0.075962
       0.5875   0.244141          0.0516689
      0.63125   0.324951          0.0327549
        0.675   0.421875           0.01875
      0.71875   0.536377          0.00913386
       0.7625   0.669922          0.00331456
      0.80625   0.823975         0.000585937
         0.85       1                 0
**   Liquid-gas relative permeabilities
**    Sl          Krg             Krog
**   ------      --------        --------
SLT
**$       Sl           krg           krog
          0.3           1                 0
     0.343688    0.850997      0.000585937
     0.387375    0.716177       0.00331456
     0.431063    0.595057       0.00913386
      0.47475    0.487139          0.01875
     0.518438    0.391906        0.0327549
     0.562125    0.308816        0.0516689
     0.605813    0.237305         0.075962
       0.6495    0.176777         0.106066
     0.693188    0.126603         0.142383
     0.736875    0.0861149         0.18529
     0.780563    0.0545915        0.235144
```

```
     0.82425      0.03125       0.292284
     0.867938    0.0152231      0.357034
     0.911625    0.00552427     0.429706
     0.955313    0.000976563    0.510598
         0.999            0          0.6


** ================ INITIAL CONDITIONS  ===================

INITIAL
VERTICAL DEPTH_AVE
INITREGION 1
REFPRES 3300.0
REFDEPTH 489.0       **initial reservoir pressure of 2670 in depth 475 m
             **constant temp=15
**$ Property: Temperature (C)   Max: 15  Min: 15
TEMP CON          15
**$ Property: Water Saturation  Max: 0.25  Min: 0.25
SW CON         0.24
**$ Property: Oil Saturation  Max: 0.75  Min: 0.75
SO CON         0.76
                                **composition of oil
**$ Property: Oil Mole Fraction(BITUMEN)  Max: 0.94  Min: 0.94
MFRAC_OIL 'BITUMEN' CON          0.95
**$ Property: Oil Mole Fraction(CH4)  Max: 0.06  Min: 0.06
MFRAC_OIL 'CH4' CON          0.05

** ================ NUMERICAL CONTROL  =====================

NUMERICAL
**CONVERGE TOTRES TIGHT
NORTH 100
ITERMAX 100
NCUTS 20


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

RUN

Date 2009 11 1
** 0.001 day start running
DTWELL 0.0001


HEATR CON          0
*MOD

   1  1:2   22 = 9.0e9


TMPSET CON          15
*MOD
   1  1:2   22 = 310
```

```
UHTR   CON           0
*MOD
    1  1:2   22 = 8.0e9


AUTOHEATER   ON  1  1:2  22

WELL  'PRODUCER' *Frac 1.0

Date 2009 12 1


 PRODUCER 'PRODUCER'
 *OPERATE  MIN  BHP  1350  CONT REPEAT
 *OPERATE  MAX STO 3.0  CONT REPEAT
**$         rad  geofac  wfrac  skin
GEOMETRY  J  0.14  0.229  0.5  0.
PERF  GEO  'PRODUCER'
**$ UBA      ff  Status  Connection
    1 1 22  1.  OPEN    FLOW-TO 'SURFACE'  REFLAYER
    1 2 22  1.  OPEN    FLOW-TO 1

*HEAD-METHOD 'PRODUCER' GRAV-FRIC-HLOS

Date 2010 1 1

WELL  'INJECTOR' *Frac 1.0          **symmytry of the model
INJECTOR MOBWEIGHT EXPLICIT 'INJECTOR'
INCOMP  WATER  1.  0.  0.
TINJW  311.
QUAL  0.8
OPERATE  MAX  STW  12  CONT
OPERATE  MAX  BHP  11000  CONT
**the location of perforation in the injector  .i,j,k
                                     **from the surface to the
lenght of the injector
**$         rad  geofac  wfrac  skin
GEOMETRY  J  0.14  0.229  0.5  0.
PERF  GEO  'INJECTOR'
**$ UBA      ff  Status  Connection
    1 1 22  1.  OPEN    FLOW-FROM 'SURFACE'  REFLAYER
    1 2 22  1.  OPEN    FLOW-FROM 1

*HEAD-METHOD 'INJECTOR' GRAV-FRIC-HLOS


DATE 2010 2 1

HEATR CON           0
UHTR CON          0
TMPSET CON         15
AUTOHEATER  Off  1  1:2  22
```

```
ALTER 'INJECTOR'
    1.1

DATE 2010 3 1

SHUTIN 'PRODUCER'


ALTER 'INJECTOR'
    8.8
DATE 2010 4 1
ALTER 'INJECTOR'
    28.5

DATE 2010 5 1
ALTER 'INJECTOR'
    0.


DATE 2010 5 10

OPEN 'PRODUCER'

DATE 2010 8 1
ALTER 'INJECTOR'
    0.
DATE 2010 9 1

SHUTIN 'PRODUCER'

ALTER 'INJECTOR'
    37.4

DATE 2010 10 1
ALTER 'INJECTOR'
    0.

DATE 2010 10 10

OPEN 'PRODUCER'
DATE 2010 11 1

SHUTIN 'PRODUCER'

ALTER 'INJECTOR'
    5.3
DATE 2010 12 1
ALTER 'INJECTOR'
    48.2

DATE 2011 1 1

ALTER 'INJECTOR'
```

```
     0.

DATE 2011 1 10

OPEN 'PRODUCER'


DATE 2011 7 1
ALTER 'INJECTOR'
     0.
DATE 2011 8 1

SHUTIN 'PRODUCER'


ALTER 'INJECTOR'
    36.1
DATE 2011 9 1
ALTER 'INJECTOR'
    56.8
DATE 2011 10 1
ALTER 'INJECTOR'
     1.9

DATE 2011 11 1

ALTER 'INJECTOR'
     0.

DATE 2011 11 10

OPEN 'PRODUCER'


DATE 2012 1 1

DATE 2013 1 1


DATE 2013 2 1



ALTER 'INJECTOR'
     0.
DATE 2013 3 1

SHUTIN 'PRODUCER'

ALTER 'INJECTOR'
    11.5
DATE 2013 3 31
```

```
ALTER 'INJECTOR'
    16.3
DATE 2013 5 1
ALTER 'INJECTOR'
    7.9
DATE 2013 6 1
ALTER 'INJECTOR'
    8.1
DATE 2013 7 1


ALTER 'INJECTOR'
    0.

DATE 2013 7 10

OPEN 'PRODUCER'

DATE 2013 08 1

DATE 2014 11 1


DATE 2014 12 1
STOP
RESULTS PDW FILENAME 'C:\Thesis-29-Oct\Simulation\CNRL-CSS\CNRL-CSS-
Submodel-Half Chamber.prd'
RESULTS PDW FILETYPE 0
RESULTS PDW COMMAUSE 0
RESULTS PDW FIELDTYPE 1
RESULTS PDW WISUFFIX 'iw'
RESULTS PDW GISUFFIX 'ig'
RESULTS PDW SISUFFIX 'is'
RESULTS PDW WELLNAMEROW 2
RESULTS PDW DATAROW 4
RESULTS PDW CONSECUTIVE 1
RESULTS PDW SEMICOLON 1
RESULTS PDW SPACE 1
RESULTS PDW TAB 1
RESULTS PDW OTHERCHAR
RESULTS PDW NUMCOLS 4
RESULTS PDW COLSELS 1 ' ' ' ' 'Date/ Time ' 'day ' 'Time(eg. 730 ) '
RESULTS PDW COLSELS 3 ' ' 'Irregular ' 'Water Injected ' 'm3/day '
'Producing daily rate '
RESULTS PDW WELLNAMEINCOL 0
RESULTS PDW APPLYDATA 0
RESULTS PDW RATETOL 0
RESULTS PDW END
RESULTS RELPERMCORR NUMROCKTYPE 1
RESULTS RELPERMCORR CORRVALS 0.25 0.25 0.15 0.15 0.15 0.15 0.001 0.001
RESULTS RELPERMCORR CORRVALS 1 0.8 1 -99999 4.5 2.5 2.5 2.5
```

```
RESULTS RELPERMCORR CORRVALS_HONARPOUR -99999 -99999 -99999 -99999 -99999
-99999 -99999 -99999
RESULTS RELPERMCORR STOP

RESULTS SPEC 'Permeability J'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 0
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC EQUALSI 0 1
RESULTS SPEC STOP

RESULTS WPD WELLNAME 'INJECTOR'
RESULTS WPD PROPNAME 'Water Rate SC'
RESULTS WPD PRIMARYCONSTRAINT
RESULTS WPD STARTTIME 20100101.0
RESULTS WPD TIMEUNIT 0
RESULTS WPD VALUE 0 0 28 1.1 59 8.8 89 28.5 120 0 150 0 181 0 212 0 242
37.4 273 0 303 5.3 334 48.2 365 0 393 0 424 0 454 0 485 0 515 0 546 0 577
36.1 607 56.8 638 1.9 668 0 699 0 730 0 759 0 790 0 820 0 851 0 881 0 912
0 943 0 973 0 1004 0 1034 0 1065 0 1096 0 1124 0 1155 11.5 1185 16.3 1216
7.9 1246 8.1 1277 0 1308 0 1338 0 1369 0 1399 0 1430 0 1461 0 1489 0 1520
0 1550 0 1581 0 1611 0 1642 0 1673 0 1703 0 1734 0 1764 0 1765 0
RESULTS WPD END
```