KHAZAR UNIVERSITY

School: Graduate School of Science, Art and Technology

Department: Petroleum Engineering

Specialty: Development of Oil and Gas Fields

MASTER'S THESIS

Theme: Simulation of heavy oil recovery by using Computer Modelling Group (CMG)

Student: Babayev Masud Murad

Supervisor: Assoc. Prof. Dr. Grigorii Penkov

Baku – 2024

XƏZƏR UNİVERSİTETİ

Fakültə: Təbiət elmləri, Sənət və Texnologiya Yüksək Təhsil

Departament: Neft mühəndisliyi

İxtisas: Neft-qaz yataqlarının işlənməsi

MAGİSTR TEZİSİ

Mövzu: Kompüter modelləşdirmə qrup (CMG) proqramı vasitəsilə ağır neftlərin çıxarılmasının simulyasiyası

Magistrant: Babayev Məsud Murad oğlu

Elmi rəhbər: dosent Dr. Grigorii Penkov

Bakı - 2024

TABLE OF CONTENTS

INTRODUCTION

The relevance of the topic. As conventional oil supplies run out, the company depends increasingly on unconventional resources like heavy oil. Larger unconventional resources are frequently found, such as tight oil, shale gas, and oil sands. Unconventional resources can fill the gap between conventional and renewable energy sources. As the world is going to cleaner energy sources, conventional resources often produce more carbon emissions, thus unconventional resources can support this idea. Meanwhile, unconventional resources require cutting-edge technologies for the production of all these energy sources from the subsurface.

Exploration and exploitation of unconventional resources have to meet energy demand, which is driving up the cost of standard energy sources. Some types of unconventional resources include tight gas, tight oil, oil shale, gas shale, heavy oil, coalbed methane, gas hydrates, etc. One widespread type of unconventional reservoir is heavy oil, another word it is called oil sands. However, heavy oil reservoirs have complexity in terms of production due to their high viscosity and complicated nature. As a result, the petroleum industry continues to have serious concerns about the effective recovery of heavy oil.

Heavy oil reserves necessitate long-term planning and strategic decision-making due to their lower production rates and longer production durations. The petroleum sector may predict future production profiles more accurately, improve field development plans, and ultimately guarantee a consistent energy supply by investigating and implementing effective recovery solutions. It is crucial to remember that heavy oil deposits often need more sophisticated and powerful recovery methods than normal oil reserves. Oil prices, technical improvements, environmental concerns, the availability of infrastructure, and investment all have an impact on the development of heavy oil reservoirs.

The difficulty of extraction for heavy oil is all about the high viscosity of the oil. That is the reason advanced technologies are used to overcome and tackle these challenges. Methods used in production are qualified as thermal and non-thermal. One of the most popular thermal techniques has been steam injection, along with cyclic steam stimulation, steam-assisted gravity drainage which is called SAGD. The cyclic solvent process, vapor extraction, and cold flow with sand production are non-thermal techniques for recovering heavy oil. Thermal methods have advantages over non-thermal methods; however, it is not overwhelming.

The purpose of research. Due to the high risks of the application of SAGD and CSS, oil and gas companies started to use special software, such as Computer Modelling Group (CMG).

Before implementing both methods numerical simulation is required to predict the applicability of the methods. CMG has some modules that provide privileges to solve all these problems, such as the STARS module. This module aids in simulating the thermal motion of steam in the reservoir. That is why heat losses may be predicted and methods should be developed to tackle these kinds of problems, before implementing the most proper recovery techniques. In this research, sensitivity analysis has been conducted for both SAGD and CSS in a conceptual model. The main sensitivity parameters are steam quality, injection rate, and soaking time to analyze their effect on the performance of the methods. They have been assessed in terms of recovery factor, cumulative steam-oil ratio, and cumulative oil production.

The objective of research. Determining the optimal combination of parameters for maximizing oil recovery in SAGD and CSS operations is the main aim of this thesis. The following objectives were passed to complete this research:

1. To review all kinds of literature related to this topic.
2. To build reservoir models in the simulator for the specific heavy oil resource.
3. To model different operating scenarios and reservoir conditions for the SAGD and CSS recovery techniques.
4. To analyze and contrast SAGD and CSS's output regarding oil production, steam-oil ratio (SOR), and recovery factor (RF).
5. To optimize each recovery method based on simulation results.

CHAPTER 1. LITERATURE REVIEW

1.1. Literature of Unconventional Resources.

Although certain unconventional resources, such as heavy oil and oil sands, have been developed for some time, it has only recently proven practical to generate significant volumes of oil and gas from deep unconventional resources, such as shale gas and shale oil. The Barnett Shale in central Texas has created a new pathway for several other profitable shale plays in North America, including Fayetteville, Haynesville, Marcellus, Woodford, Eagle Ford, Montney, Niobrara, Wolfcamp, and Bakken (Liu et al., 2019). Although shale plays have dominated media coverage for the past ten years or so, unconventional resources are far more diversified. Analyzing and categorizing distinct hydrocarbon resources based on reservoir quality is beneficial.

Conventional reservoirs are usually found in porous, permeable subsurface rocks which are sealed by a cap rock to prevent hydrocarbon escape. These formations often do not need significant stimulation as hydrocarbons can be produced since migration paths connect the source rocks to the reservoir rocks. On the other hand, tight gas sands and oil shales among others are considered unconventional resources since they occur in tight formations with poor reservoir quality. Instead, the planet has an increased abundance of unconventional resources. This is shown in Fig. 1.1 as a triangle that represents conventional and unconventional resources in relative quantity terms. Examples of these include tight gas sands, gas shales, heavy oil sands, coalbed methane, oil shales, and gas hydrates. However, determining if a reservoir is conventional or unconventional may prove difficult due to the low permeability of tight basement formations containing oil or gas. While some studies classify tight gas sandstones as conventional; others consider gassy and oily shales, coal-bed methane, and gas hydrates to be examples of unconventional resources.

The term "conventional unconventional resources" or "non-source rock unconventional reservoirs" can be used to describe tight gas sandstone reservoirs (and possibly other tight formations as well) from the perspective of reservoir characterization methodology. Shale reservoirs can be called "deep unconventional resources" or "source-rock unconventional resources." The same uncertainty may be used to describe a particular reservoir; for example, a shale formation may contain oil and gas, or a hydrocarbon-bearing geological formation may contain a range of lithofacies, including shale and other coarser-grained lithologies. Most of the rocks in the Bakken oil-producing formations, for instance, are siltstones and other rocks with finer grain located between the upper and lower Bakken Shales (Thomas, S., 2008).

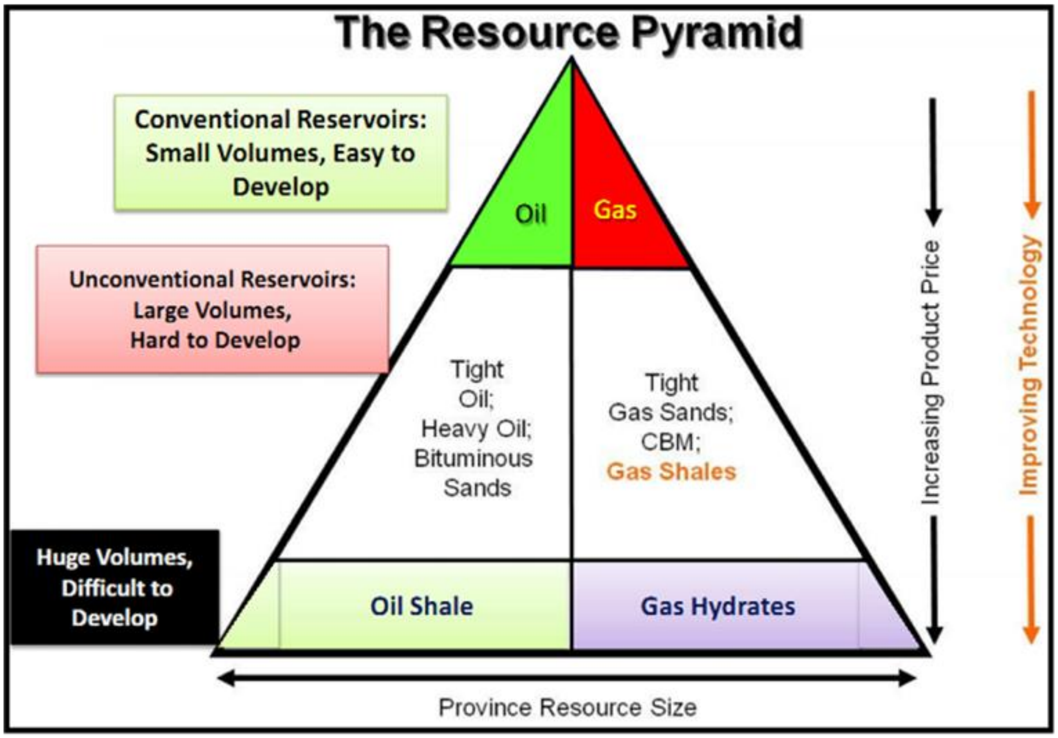


Figure 1.1. The resource pyramid includes petroleum reservoirs (Holditch et al., 2007)

Low to ultralow permeability and low to moderate porosity are two of the primary features of unconventional reservoirs. As a result, different extraction techniques than those needed for conventional resources are required for hydrocarbon production from these reservoirs. To extract commercial amounts of hydrocarbons, an unconventional reservoir has to be induced to produce them at a reasonable flow rate. The permeability of unconventional reservoirs is less than 0.1mD, this value is over 0.1mD for conventional reservoirs (That is applicable in the USA). The permeability of a reservoir is never a constant value, and both conventional and unconventional reservoirs often have large levels of permeability heterogeneity, therefore this is not always obvious in practice.

Under the ground, unconventional liquids make up a larger proportion of oil than conventional (see Figure 1.2). The planet is estimated to have 45,000 billion barrels of unconventional oil, and it is possible to produce 1000 billion barrels (Thakur & Rajput, 2011). Technically recoverable reserves for these three unconventional oils are estimated to be around 350 billion tons of oil, according to the latest estimations. About 60% of them are found in South and North America, while significant numbers are found in Eurasian regions, and the remaining portion is dispersed equally over the globe.

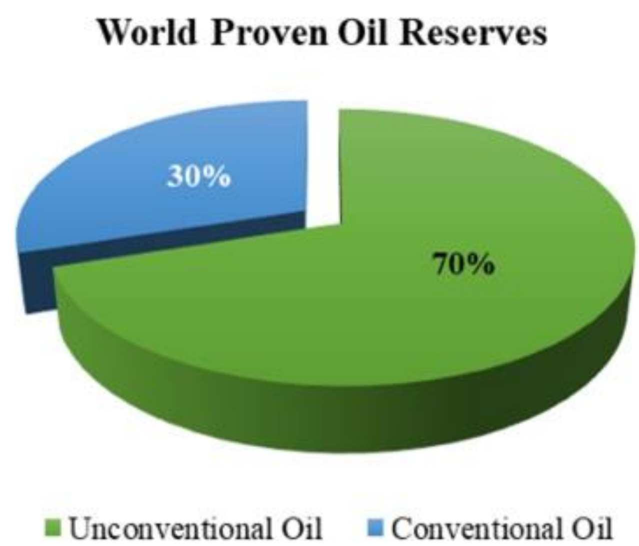


Figure 1.2. World Proven Oil Reserves (Theloy & Sonnenberg, 2013)

There will undoubtedly be a rise in the supply of unconventional liquids due to rising demand and consumption. Furthermore, the development of technology will result in the creation of more unusual liquids, increasing the global supply of liquid. Figure 1.3 shows the projected liquid supply through 2040. NGLs, deep water, tight oil, and oil sands are all seeing greater benefits. It is projected that the worldwide supply of tight oil and NGLs in liquid form will surpass thirty percent by 2040.

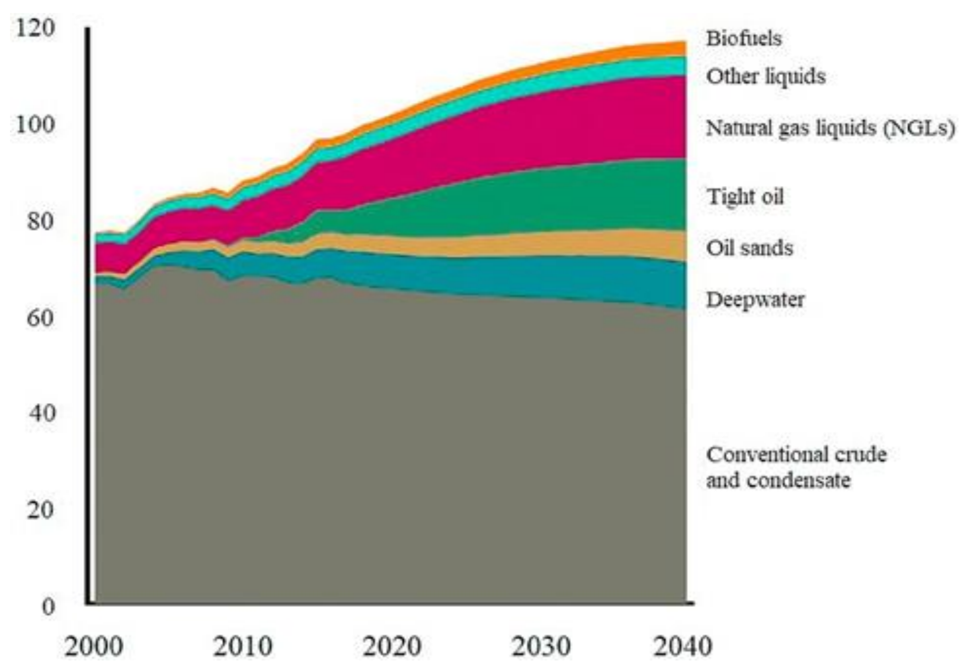


Figure 1.3. Liquid Supply Worldwide (MBDOE) (ExxonMobil, 2019).

Shale oil is a type of fracture-pore oil deposit whose source rock and reservoir are the same. It is defined as petroleum that is still present in source rocks and has not undergone migration. Thus far, OM, calcareous minerals, and silicate minerals have been abundant in the black mudstone and shale that contain these oil reserves. RO is typically 0.5% to 1.3% while TOC ranges from 1.0 to 20%. In terms of the accumulation space and fracture-pore system, shale gas and shale oil are comparable. Shale oil also requires specific geological settings and circumstances, such as high-quality source rocks, a fracture-pore system, and a fracture system with a high sealing capacity in layers of thick mudstone and shale (Zou, 2013).

In China, shale oil has been found in the Ordos, Songliao, and Bohai Bay Basins. Shale is thermally maturing at the condensate stage, which results in the formation of condensate oil in shale, contingent on flow and development. Shale oil and oil shale are not the same thing. Oil shale is an immature source rock with a high ash concentration and flammable organic matter. It can only use dry distillation and artificial heating to make liquid hydrocarbons. It will take advances in industrialized applications and in-situ mining technology to fully use oil shale deposits in the future. China possesses huge amounts of oil shale resources; in 2010, the country produced 55 × 104 t of oil (Zou, 2013).

Natural gas trapped in shale rocks is known as shale gas. Fine-grained sedimentary rocks known as shale can be rich reservoirs of natural gas and petroleum (Figure 1.4). This sedimentary rock contains pores that capture shale gas. In gas shales, gas is often stored in the following ways (Maiullari, 2011):

- Free gas is found in the pores in rocks and naturally occurring cracks.
- Adsorbed gas: Clay and organic materials absorb the gas.
- Dissolved gas: The organic compounds contain the dissolved gas.

Figure 1.4 An outcrop of shale gas that makes the stratified structure easy to see (Maiullari, 2011)

As can be seen in Figure 1.5, there is now a growing need for natural gas. The demand is expected to rise globally by 40% between 2016 and 2040. In order to meet global demand, more unconventional gas must be produced. Less than 15% of the natural gas resources that are currently recoverable have been produced. Approximately 45% of the remaining natural gas resources may be generated from tight gas, shale gas, and coalbed methane (see Figure 1.6) (ExxonMobil, 2019).

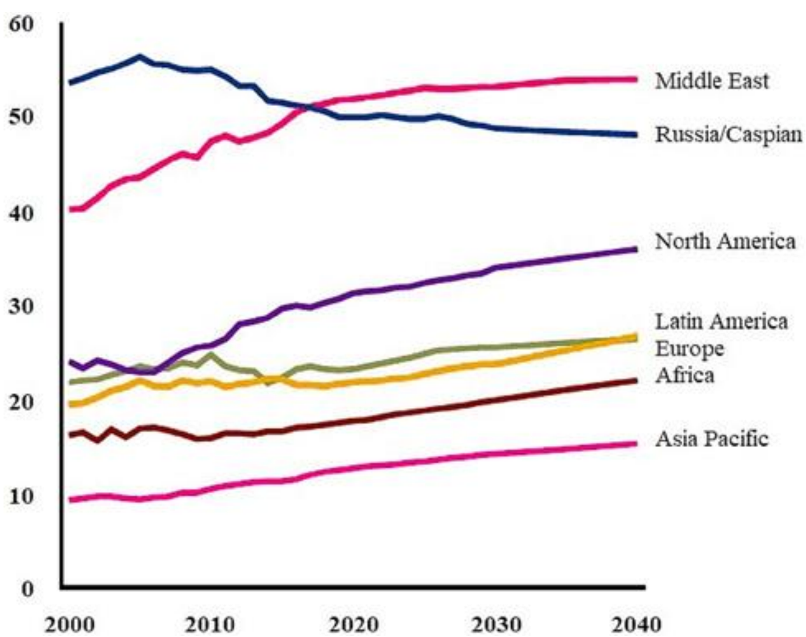


Figure 1.5. Energy demand (%) Forecast (ExxonMobil, 2019).

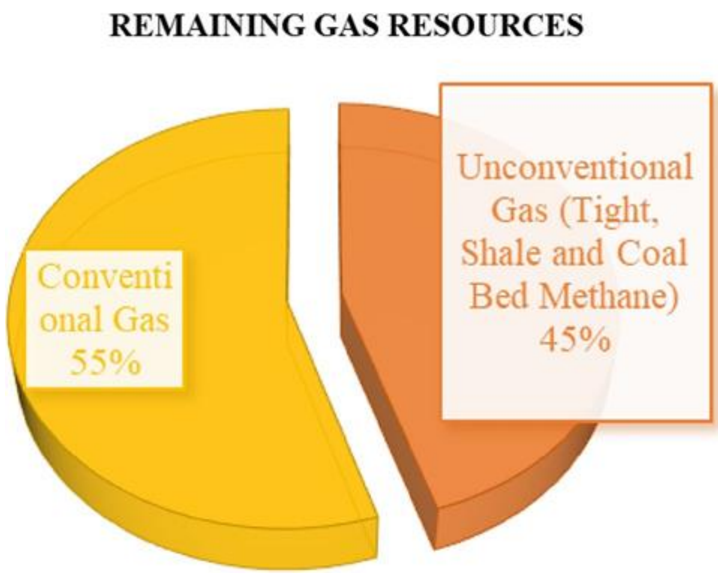


Figure 1.6. Remaining gas resources worldwide (ExxonMobil, 2019)

The primary nations with significant reserves of recoverable shale gas are shown in Table 1.1. Table 1.1 makes it evident that China is ranked top, ahead of Argentina, Algeria, the United States, and Canada.

Table 1.1: The Top 10 Shale Gas Resources That Can Be Recovered (U.S. Energy Information Administration, n.d.)

Rank	Country	Amount of Shale Gas (Trillion Cubic Feet)
1	China	1115
2	Argentina	802
3	Algeria	707
4	USA	665 (1161)
5	Canada	573
6	Mexico	545
7	Australia	437
8	South Africa	390
9	Russia	285
10	Brazil	245
	Total	7299 (7795)

Table 1.2 lists the world's proven and unproven shale gas reserves along with external resources for further information. The rise in total gas resources as a result of the discovery of shale gas is also shown in this table.

Table 1.2. Proved and Unproved Global Gas Resources (U.S. Energy Information Administration, n.d.)

USA	Amount of Wet Natural Gas (Trillion Cubic Feet)
Shale gas proved reserves	97
Shale gas unproved reserves	567
Other gas-proved resources	220
Other gas unproved reserves	1546
Total	2431
Increase in total gas resources due to shale gas	38%
Share of shale gas in total	27%
Outside the USA	
Shale gas unproved reserves	6634
Other gas-proved resources	6521
Other gas unproved reserves	7269
Total	20,451
Increase in total gas resources due to shale gas	48%
Share of shale gas in total	32%
Total World	
Shale gas proved reserves	97
Shale gas unproved reserves	7201
Other gas-proved resources	6741
Other gas unproved reserves	8842
Total	22,882
Increase in total gas resources due to shale gas	47%
Share of shale gas in total	32%

The exploration and extraction of unconventional shale gas resources in North America has significantly altered the region's energy environment in recent years. Now, this explosive growth is changing the world's energy supply. Leading the way in what some refer to as the "shale gas revolution" is the United States of America.

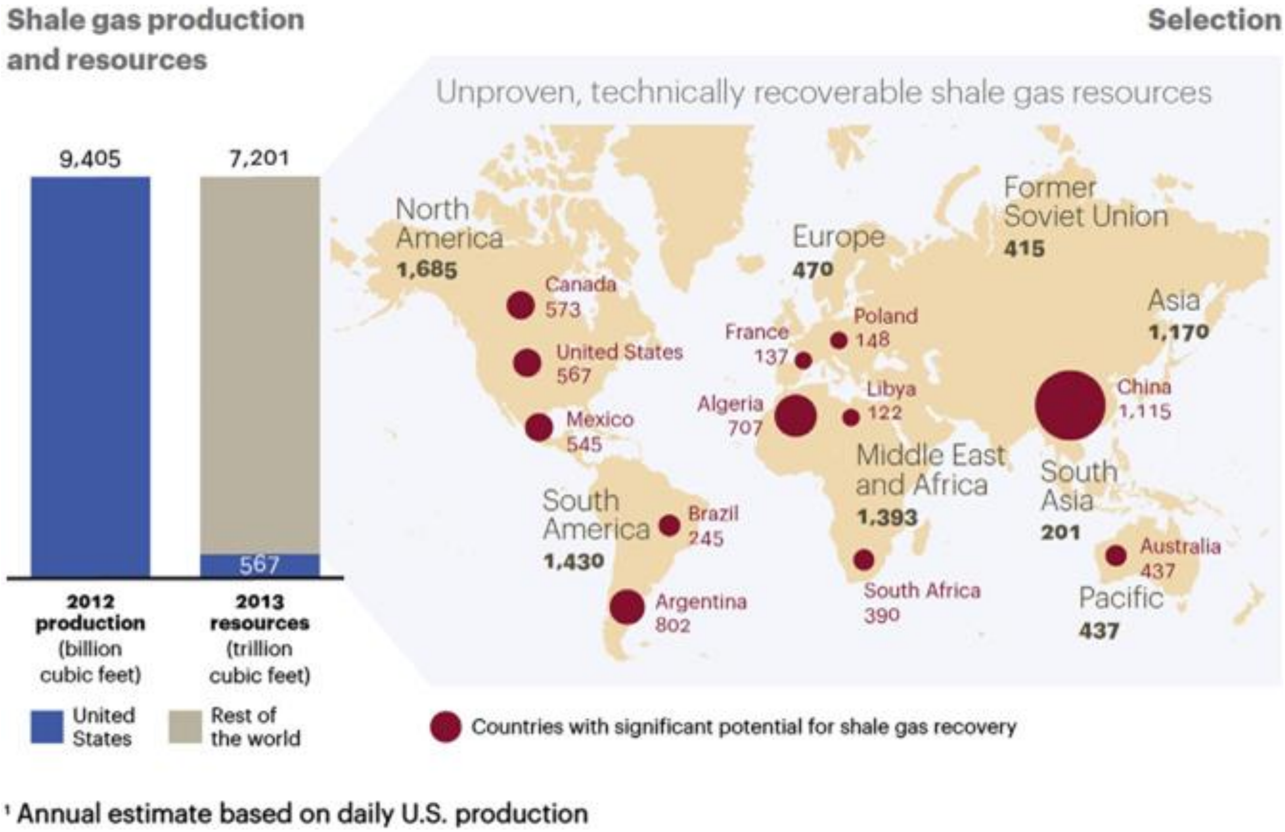


Figure 1.7: The respective contributions of regions and nations to the production and resources of shale gas (U.S. Energy Information Administration, n.d.). Study of 42 nations by the US Energy Information Administration; analysis by A.T. Kearney.

Mining oil shale can be either surface mining or in situ retorting. In surface mining the oil shale is transported to aboveground facilities. There the oil shale is crushed and loaded into a reactor known as a retort, where the temperature is increased to about 400–500°C to decompose the kerogen and release the shale oil. In situ-retorting heat is applied directly to the rocks underground and the shale oil obtained is extracted like petroleum extraction. Kerogen is a complex organic material that includes large hydrocarbon molecules containing nitrogen, oxygen, and sulfur.

An unconventional natural gas that can be discovered in coal seams or deposits is called coal bed methane (CBM). It is the main source of natural gas for clean energy. There are significant social and economic benefits to the development and application of CBM. Compressed natural gas, or CNG, is a fuel that burns cleanly and is suitable for both home and commercial usage.

Underground coal mine explosion risks are decreased by CNG extraction. A lot of methane (CH4) is frequently found around certain coal seams. Plant material is converted into coal during the coalization process, forming CBM (Tao et al., 2010).

A lot of methane (CH4) is frequently found around certain coal seams. Plant material is converted into coal during the coalification process, forming CBM. It is produced during coal formation by a thermal or microbiological process as a result of rising temperatures at deeper depths. Groundwater is frequently saturated in coal seams under high pressure. Drilling many wells down the coal seam allows for the recovery of CBM (Figure 1.8). Methane may be easily extracted by partially pumping water while lowering the water pressure. After traveling to the well, the gas is pumped to the surface. After compression, it is marketed. Drilling hundreds of wells with substantial infrastructure support facilities is part of the extraction process (Tao et al., 2010).

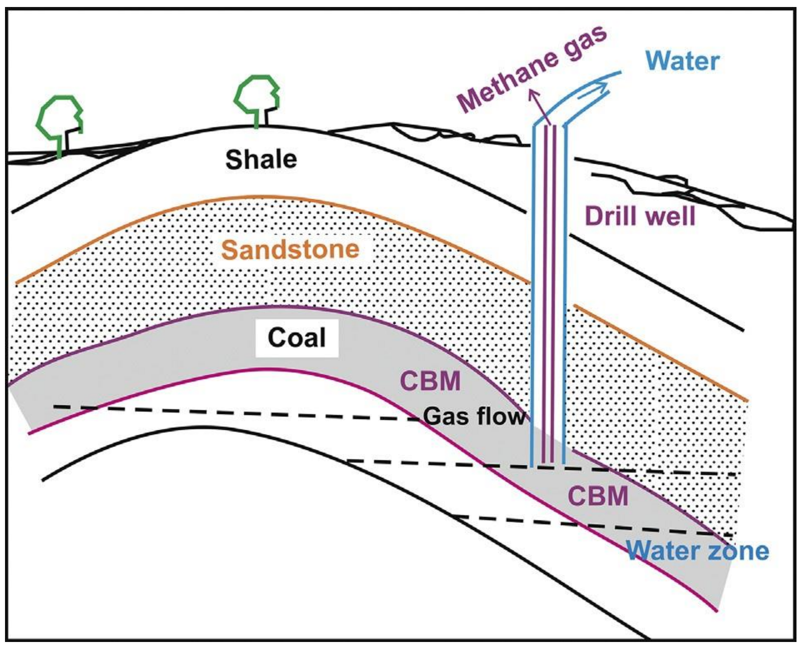


Figure 1.8. The process of mining coal bed methane is a common way to get clean compressed natural gas for usage in homes and businesses. Coal bed methane, or CBM (Tao et al., 2010).

Water and gas molecules combine to form crystalline, ice-like crystals known as gas hydrates. They occur when there is enough gas and water present, at high pressures and low temperatures. These requirements are met in deep lakes, permafrost areas, and the seafloor. Thus, gas hydrate is found all over the world. It can be found in polar sediments and permafrost areas, like the Canadian Arctic, Siberia, and the Qilian Mountain permafrost region at the Tibet plateau, as well as in oceanic sediments on the continental slopes along active and passive margins and regions with similar conditions, like the Black Sea or the Caspian Sea (Lyons & Plisga, 2011).

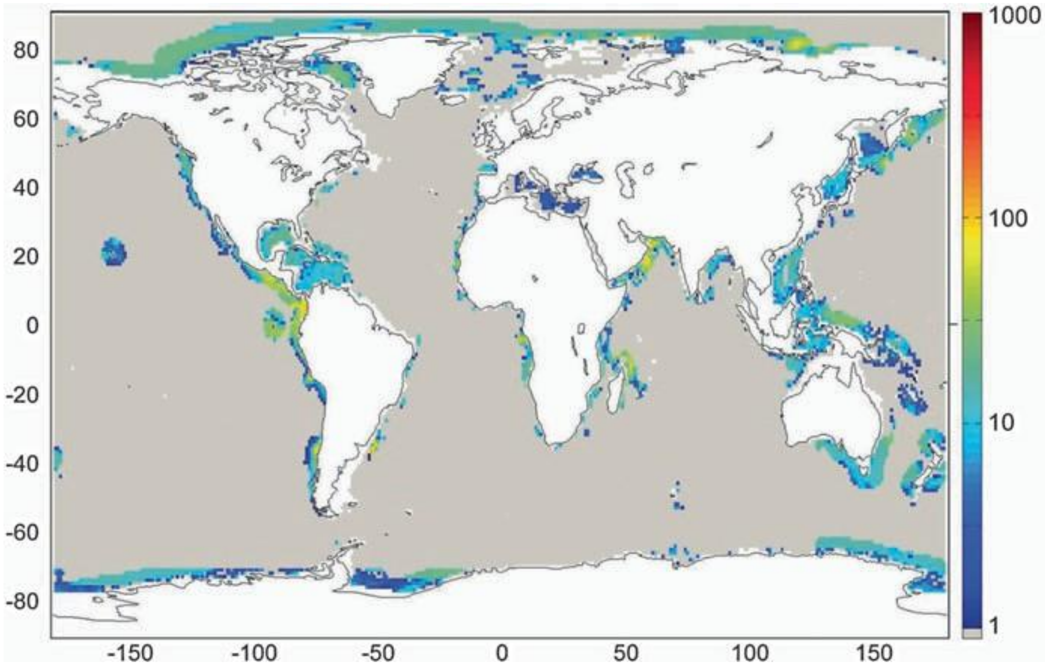


Figure 1.9. Global distribution of methane hydrate in marine sediments (Wallmann & Schicks, 2018). The color coding indicates depth-integrated hydrate inventories in kg C m^{-2}.

1.2. General information on heavy oil and production

The density (API Gravity) of several forms of crude oil, including heavy oil, extremely heavy oil, and bitumen, may be used to categorize them. The API Gravity values for the various crude oils are displayed in Table 1.3.

Table 1.3. Classification of crude oil (Gibson, 1982)

Crude oil type	API Gravity
Light	>31
Medium Heavy	21-31
Heavy	14-21
Extra Heavy	10-14
Bitumen	<10

The classic definition of heavy-oil recovery is "thermal stimulation of low-API-gravity oil," which can have an API of 4 to 20 (or 1.04 to 0.93 g/cm^3). When defining heavy oil, the API gravity must be at least 20° API [>0.93 g/cm^3] (Gibson, 1982). This gravitational term is also widely used in American law. The oil viscosity, rather than the API gravity, more accurately captures the flow characteristics of the crude oil (Greaves, 2000). For instance, certain crudes may be heavy (low gravity), but in comparison to some lighter crudes, have a comparatively low viscosity at reservoir temperature (Table 1.4).

Table 1.4. Typical Heavy-Oil Viscosities and Gravities (Gibson, 1982)

Field	Location	Gravity (API)	Reservoir viscosity(cp)
Bachaquero	Venezuela	13	150
Emlichheim	Germany	24.5	175
Lost Hills	California	14	400
Cold Lake	Canada	10 to 12	10,000 to 100,000

Heavy oils, or those requiring heat or other forms of stimulation, are suggested to be defined as crudes with viscosities > 100 cp [> 100 mPa s] at reservoir conditions. This is because the oil viscosity and its response to increased temperature control the flow rate under thermal stimulation, and the flow rate is a much more important factor in the economic exploitation of the reserve than the oil gravity. When the oil viscosity surpasses 100 cp [100 mPa s], the typical pumped cold-oil production rates will be less than 10 BID [1.6 m^3 /d].

Although it tends to refer to the heavier end of the heavy oil range, the term "bitumen" is often used interchangeably with the phrase "heavy oil." According to the United Nations Institute for Training and Research [**Error! Reference source not found.**], bitumen should be classified as having an API gravity > 10° [> 1 g/sm^3] and a viscosity > 10^4 cp [> 10^4 mPa's]. A naturally occurring viscous mixture mostly made up of hydrocarbons heavier than pentane, which may also contain sulfur compounds, and which, in its naturally occurring viscous condition, is not economically recoverable by a well, is another definition of bitumen. Such deposits are sometimes referred to as "tar sand" and are found in the Canadian Athabasca sands, which are shallower and can be produced by petroleum mining.

Most heavy oil resources are located in Venezuela and Canada, both of which have recoverable reserves equivalent to Saudi Arabia. Other countries with sizeable deposits include Mexico, Russia, China, Oman, California, Alaska, and Utah in the United States, Mexico, and Oman (Figure 1.10). Heavy oils are often found in older Cretaceous, Mississippian, and Devonian rocks as well as newer Pleistocene, Pliocene, and Miocene reservoirs. Because these reservoirs are often shallow, insufficient seals provide an environment favorable for producing heavy oil (Satinder & Larry, 2008).

Heavy oil is often easier to produce than bitumen, which needs higher levels of development. Around the world, there are several heavy oil resources, including China, which has a heavy oil reserve in the Shengli Liaohe and Xinjiang oil areas, where in-situ combustion is frequently employed. Cyclic Steam Stimulation (CSS) is frequently employed in Colombia's heavy oil belt, which is located west of Bogata in the southwest corner of the middle Magdelena basin. Egypt, where Huff & Puff is frequently practiced, Asran fields in the eastern desert.

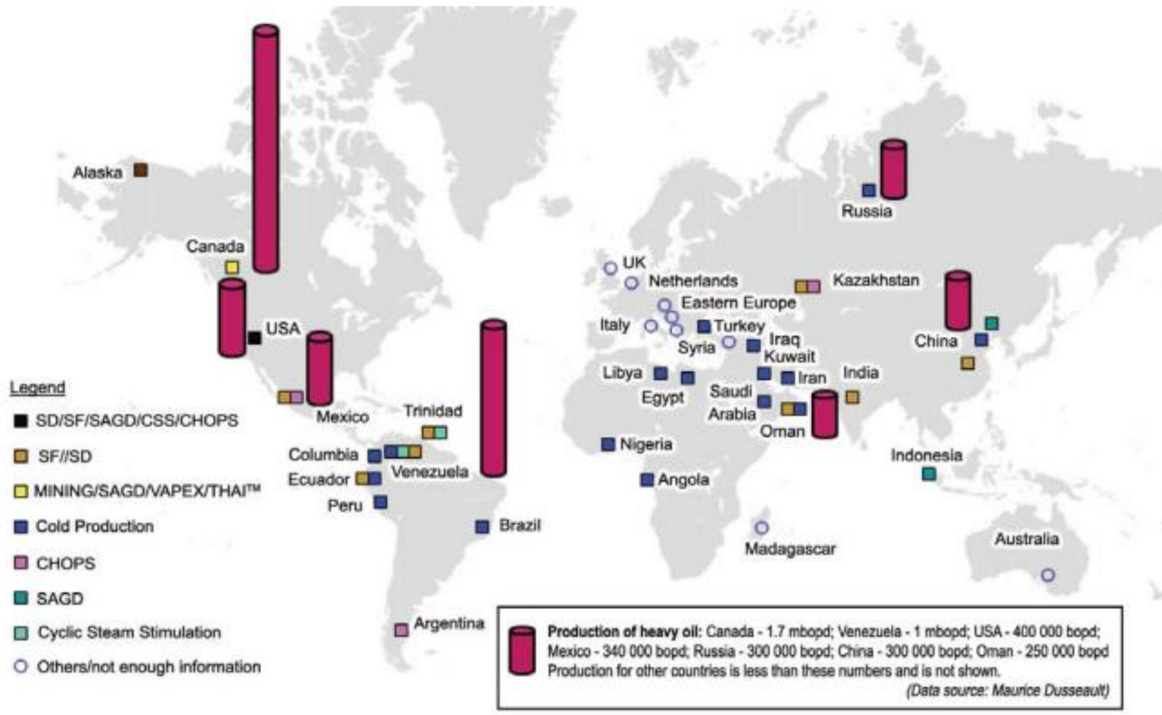
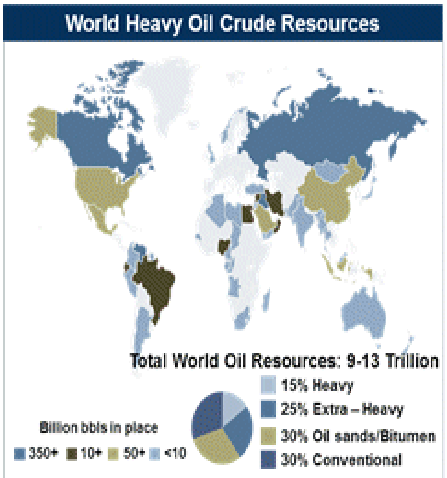


Figure 1.10 - Distribution of heavy oil around the world (Chopra & Lines, 2008b)

By 2030, the average annual growth rate of oil consumption is predicted to be 1.2%, with 105 million barrels per day (MMBD) being consumed. Since simple oil extraction is becoming increasingly difficult, the oil industry must constantly find new ways to meet the world's increasing energy demand. Significant oil resources exist in the form of bitumen and heavy oil, both of which must be extracted using cutting-edge technology. A little over 500 billion barrels of extra-heavy oil, including oil sands, are found worldwide; Canada holds half of these reserves, with the remaining portions being found in Venezuela, Nigeria, Brazil, and Russia.

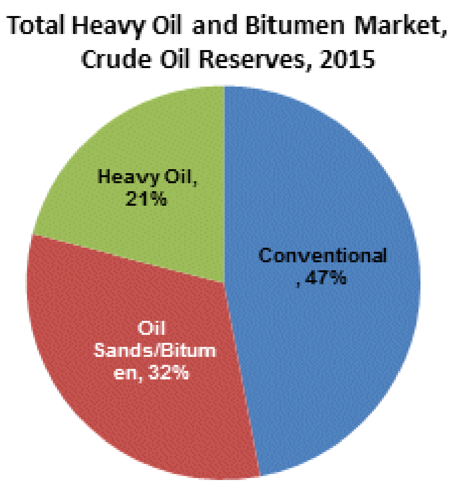


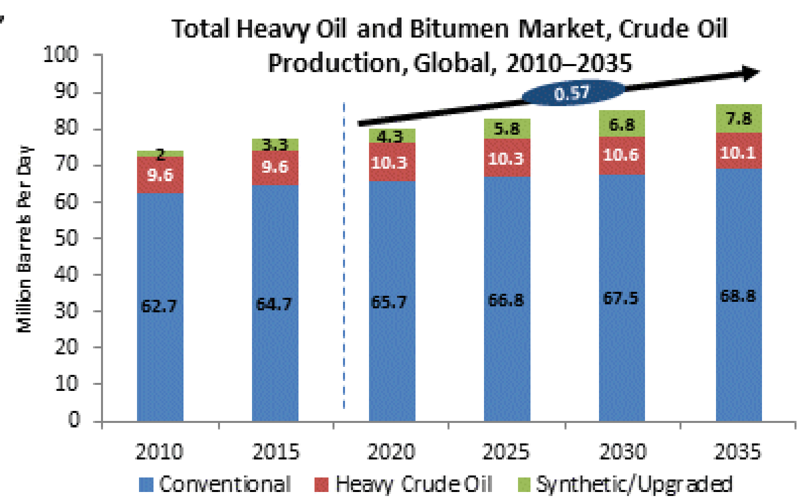
Geographic Distribution of Heavy Crude Oil – *Original Oil in Place*				
Region	Heavy Crude Oil (Billion bbls)	Natural Bitumen (Billion bbls)	Total (Billion bbls)	Percentage %
North America	651	2391	3042	34
South America	1127	2260	3387	38
Europe	75	17	92	1
Africa	83	46	129	1
Middle East	971	0	971	11
Russia	182	347	529	6
Asia-Pacific	306	444	750	8
Total	3396	5505	8901	100

Source: USGS 2007

Figure 1.11. Global Heavy Oil and Bitumen Reserves and Production (United States Geological Survey, 2007)

Between 2015 and 2035, the output of bitumen and heavy oil worldwide is predicted to rise from 13 to 18 MMBD. Canada has 170 billion barrels of known heavy oil and bitumen reserves in North America, mostly in the form of oil sand deposits in the southern portion of the province of Alberta. In 2015, Canada produced 2.7 million barrels of heavy oil annually, approximately 14% of the world's total production. Conventional oil production dropped somewhat (from 0.78 to 0.75 MMBD) during that same time frame.





Source: World Oil Outlook 2014 – OPEC; BP Statistical Review of World Energy 2015; USGS

Figure 1.12. Total oil market for 2010-2035 (BP, 2015)

After the primary and secondary recovery techniques, enhanced oil recovery (EOR) is used to produce the remaining oil that can be produced in the reservoir. The success of any EOR project depends on how much residual oil is.

There are two types of recovery methods, which are classified as thermal and non-thermal. Thermal methods mean they are used to increase the temperature, which will decrease the viscosity. The most effective methods for treating heavy oils are thermal ones, whereas non-thermal ones have only achieved limited success in actual field experiments. The reservoir is heated using thermal and electrical heating techniques. The viscosity of the oil has a relationship with temperature, when the temperature is increased, viscosity decreases in contrast.

Economic and technical factors must be considered when making decisions in terms of the selection of the most proper heavy oil recovery techniques.

Oil sands provide over 58% of Canada's total oil output. Bitumen is the term for the extremely heavy crude that is extracted from the oil sands deposit. One can generate oil sands in situ or by mining:

- Mined. Using conventional mining methods, the bitumen is removed from the surface and physically separated from the sand at a processing facility. Mined bitumen is either refined into Synthetic Crude Oil (SCO), a lighter form of crude oil, or it is mixed with light liquids, usually condensates, to make it suitable for pipeline transportation.
- In-situ. Uses steam at high pressure to extract bitumen from underground reserves. Steam-assisted gravity drainage (SAGD) is the most often used technique; cyclic steam stimulation (CSS) is the alternative.

The two primary kinds of in-situ recovery are thermal and non-thermal. Many different methods are now used under thermal recovery to extract heavy oil. Toe-to-heel air injection, cyclic steam stimulation (CSS), steam-assisted gravity drainage (SAGD), and in-situ combustion (ISC) are a few of these. Most of these highly developed techniques have been used in numerous heavy oil areas worldwide. Nevertheless, these methods have a significant detrimental influence on the ecosystem while having excellent recovery rates. They are therefore less favored in developed nations.

Examples of non-thermal methods include VAPEX, chemical extraction, miscible liquid extraction, cold heavy oil production using sand (CHOPS), and vapor extraction. Recovery rates with these methods are not as high as those using thermal methods. These, however, have less of an effect on the environment. As a result, wealthy nations like the US and Canada have greater use of these tactics.

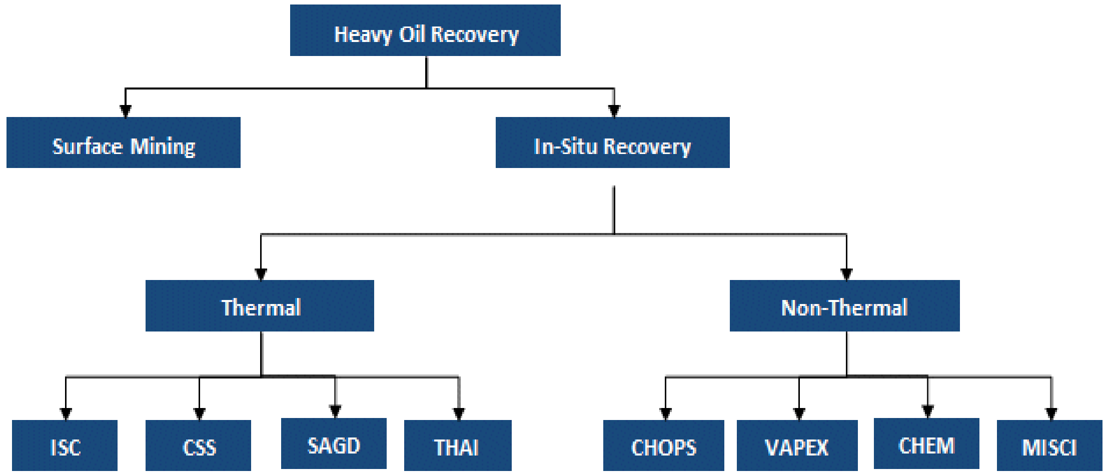


Figure 1.13. Heavy Oil Extraction Techniques (Valbuena et al., 2014)

1.3. Thermal methods

Thermal recovery is used to produce viscous, thick oils. These oils cannot flow unless they are heated, and their viscosity is reduced enough to allow flow toward producing wells. During thermal recovery, crude oil undergoes physical and chemical changes because of the effects of the heat supplied. Physical properties such as viscosity, specific gravity, and interfacial tension are altered. The chemical changes involve different reactions such as cracking, which is the destruction of carbon-carbon bonds to generate lower molecular weight compounds, and dehydrogenation, which is the rupture of carbon-hydrogen bonds. Hot fluid injection such as steam injection and hot waterflooding and in-situ combustion processes. There are main types of thermal methods: steam-assisted gravity drainage, steam flooding, cyclic steam stimulation, and in-situ combustion. Additionally, electrical heating can be considered a thermal method because it also increases the temperature.

1.3.1. Steam-Assisted Gravity Drainage

A modern thermal recovery method known as steam-assisted gravity drainage (SAGD) has received a lot of interest for its use in super-heavy oil (Butler, 2001). To increase the mobility of the high-viscosity crude oil between injection and production wells during the use of SAGD, the high-dryness steam was first injected by steam stimulation or circulation. Second, a steam chamber is created by injecting steam into the formation from an upper horizontal well, and heat exchange between the steam and oil takes place there. Then the heated oil and steam condensate fall downward due to gravity and are subsequently generated by the lower horizontal well (Liu, 2013). According to Zargar and Ali (2018), the SAGD process may be split into four stages: steam preheating, chamber rise, chamber lateral spreading, and chamber confinement. For thick super-heavy oil reservoirs around the world, a relatively mature SAGD technology has been developed through more than 30 years of field application, laboratory research, and numerical simulation analysis. This technology includes ultra-shallow double horizontal well drilling and completion, surface-efficient steam injection, and integration of aboveground and underground automatic monitoring, among other things.

However, as super-heavy oil has been exploited, an increasing number of thin-layer super-heavy oil reservoirs (thickness 15 m) have been found and require urgent development. For instance, the Canadian Lloydminster and Athabasca oil fields and the Chinese Wangzhuang, Shanjiasi, and Liuguanzhuang oil fields (Ganat, 2019). However, the heat loss to the overburden is significant and the sloping steam chamber is not fully formed when SAGD is employed in thin-layer super-heavy oil reservoirs (Wang et al., 2019). Therefore, advancements must be made to the SAGD technique for it to be effectively used to extract thin-layer super-heavy oil. First, based on the development histories of SAGD technology in China and the rest of the globe, the effect of reservoir physical features on the use of SAGD technology for thin-layer super-heavy oil reservoirs is analyzed. Second, the SAGD adjustment direction for the extraction of thin-layer super-heavy oil is demonstrated together with a systematic analysis of the benefits and limitations of the current SAGD technology. The application potential of the gas- and solvent-assisted SAGD technologies in thin-layer super-heavy oil reservoirs is then thoroughly examined.

Since Butler et al. (2001) thoroughly explained the operation of the dual-horizontal well SAGD, SAGD technology has gradually been used to extract super-heavy oil. The first SAGD field pilot test ever was carried out underground in Canada's Fort McMurray (UTF) in 1987. This pilot has five stages, and the horizontal section length, gas-assisted SAGD, and field-supporting technologies have all undergone extensive testing. A mature SAGD technology was created with an oil recovery of 40%–60% (Bao et al., 2012), as a result of extensive application of the SAGD technology in super-heavy oil reservoirs in Canada and other nations (Chao et al., 2012). This technology is illustrated in Figure 1.14. The reservoir thickness in SAGD projects across the world (apart from China) is larger than 20 m, whereas the reservoir buried depth is often less than 300 m.

This is because the expenses are high when the reservoir thickness is modest (about 15 m), and these conditions are favorable for the development of steam chambers. However, SAGD may be effectively used in deep and thin-layer super-oil reservoirs, such as the Senlac oilfield in Canada, providing the oil viscosity is not extremely high (Delamaide, 2018).

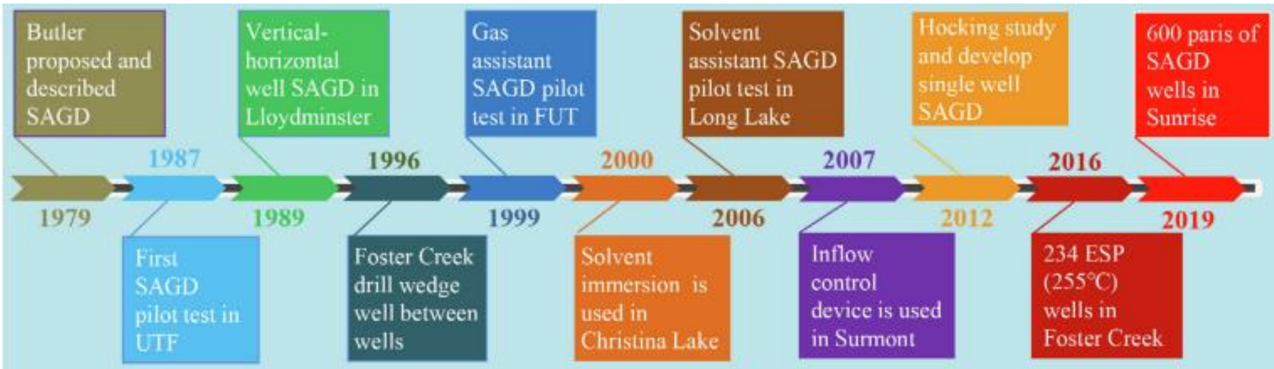


Figure 1.14. Development history of SAGD technology in the world (Bao et al., 2012)

Dual-horizontal and vertical-horizontal wells are the two most typical well patterns. According to Tian and Sun (2013) and Li et al. (2020), the dual-horizontal well plan consists of two parallel horizontal wells spaced 4-6 m apart, with the upper well used to inject steam and the lower well to produce oil. A lower horizontal well and a few vertical wells make up the vertical-horizontal well configuration. The vertical wells are used to inject steam, while the horizontal wells are utilized to generate oil. Although the vertical-horizontal well SAGD appears to have benefits for super-heavy oil reservoirs with thick layers and existing vertical wells, it is not appropriate for such reservoirs with thin layers. Due to the short steam chamber rise and limited gravity drainage, the typical dual-horizontal well SAGD is likewise not suited for thin heavy-layer super-heavy oil reservoirs. Shortening the vertical distance between injection and production wells is one of the effective methods to achieve the economically viable exploitation of thin-layer super-heavy oil utilizing dual horizontal well SAGD (Li et al., 2020). Increasing the horizontal spacing between injection and production wells, which can expand the steam chamber, is another practical solution. According to Tavallali et al. (2012), the ideal horizontal interval for a super-heavy oil reservoir with a 10 m thickness (Kisman & Lau, 1994) is 12 m. The cost of drilling and heat loss is reduced by the single horizontal well SAGD's utilization of a single well to perform the injection-production process (Hu, 2014; Jamali, 2014). The single horizontal well SAGD has to be optimized, but because oil production is hard to manage and produced at a low rate, associated supporting technologies still need to be developed.

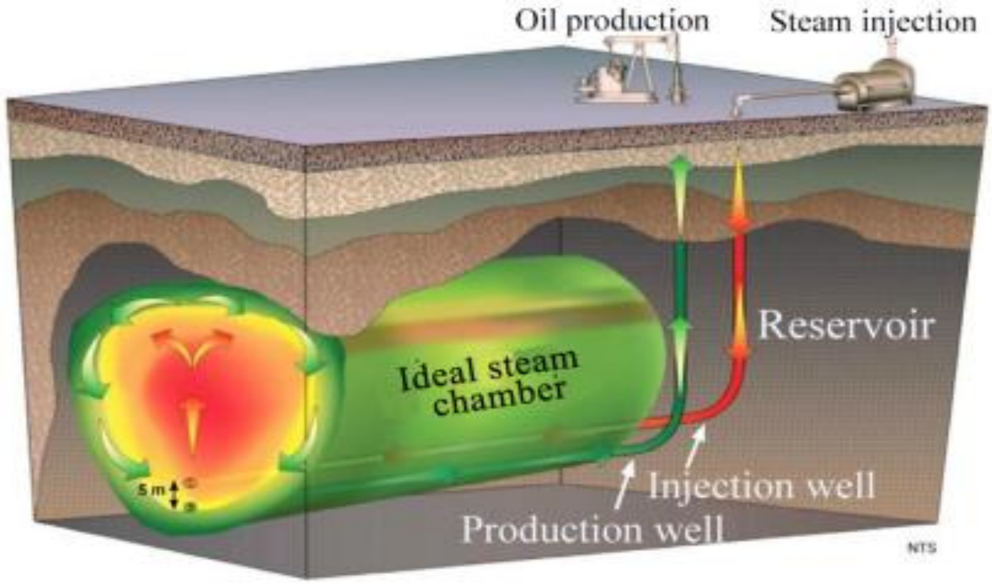


Figure 1.15. String structure and process flow of double-horizontal well SAGD (Singfield, 2016)

One of the main areas of future study for thin-layer super-heavy oil extraction is the optimization of well design to increase the steam chamber.

Although there are many different wellbore constructions for traditional SAGDs, a three-hole-in well is often developed (Huang et al., 2018), and the wire-wrapped screen liner or slotted sieve tube is used to manage sand. While the production well in SAGD typically employs two tubings, the injection well can use either a single long tubing or a pair of tubings to accomplish the injection-production process (Wang, 2018). A long tubing is used to inject steam and a packer is used to control the steam distribution along the horizontal section in the injection well, while a short tubing is used to produce the liquid in the production well, as shown in Figure 1.16 (Tao et al., 2010). When employing a dual horizontal well SAGD, the well's horizontal section should be expanded. The slotted sieve tube is advised to be used owing to its high strength to boost the production rate of thin-layer super-heavy oil (Bao et al., 2010). Although the wire-wrapped screen liner has a modest pressure drop, it has a low strength, so if it is used in the dual-horizontal well SAGD for the production of thin-layer super-heavy oil, the strength should be evaluated.

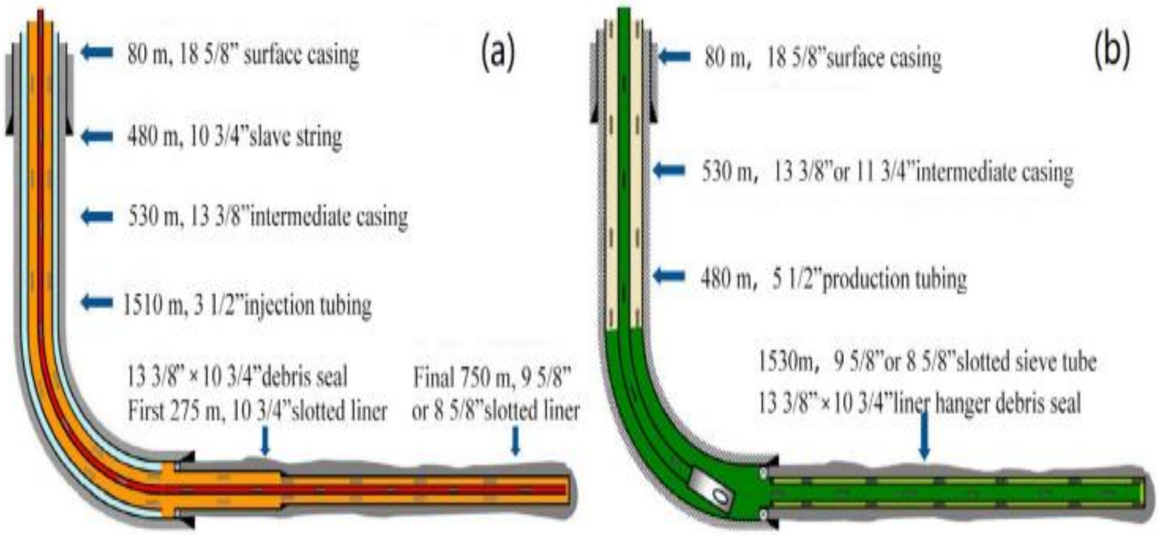


Figure 1.16. Wellbore structure of injection and production wells in the Firebag SAGD project. (a) Injection well. (b) Production well (Tao et al., 2010)

During the SAGP operation, a tiny quantity of non-condensable gas is co-injected into the reservoir together with steam. This has an impact on the lateral expansion of the steam chamber and improves the ultimate oil recovery. This occurs because the injected non-condensable gas collects at the top of the steam chamber and has poor thermal conductivity, high viscosity, and high oil solubility (Gao et al., 2009). The built-up gas can lessen heat loss and steam consumption, maintain steam chamber pressure, and speed up oil drainage (Butler, 2004). In particular, the co-injected nitrogen in SAGP acts as a heat insulator to increase the thermal efficiency overall, and the nitrogen fingering increases the capacity of the steam flow (Wang et al., 2019). After dissolving into the crude oil, the co-injected CO2 in SAGP lowers oil viscosity. The fractured water-in-oil emulsion also lowers oil-water interfacial tension, improving oil mobility (Zhang, 2014). Since CO2 and nitrogen are both present in the co-injected SAGP flue gas, both gases' processes are present, although CO2's influence on heat insulation is less than nitrogen.

Expanding-solvent SAGD (ES-SAGD), a technique that also employs a setup similar to traditional SAGD, involves the injection of steam and solvent together. However, in this instance, to increase the generation of heavy oil, a small amount of solvent is also added to the steam (Nasr & Isaacs, 2001). If the solvent is chosen properly, it will dilute the local oil and, when combined with steam, will lessen the viscosity of the heavy oil. While ES-SAGD operations often require longer operating times than traditional SAGD, they nonetheless have the same inefficiencies related to surface steam production since the solvent typically carries less energy than steam. Improved recovery and a decreased steam-to-oil ratio (SOR) have been attained using the ES-SAGD technique in various field trials (Dong et al., 2019).

The Solvent Thermal Resource Innovation Process (STRIP), developed by RII North America, Inc., a Calgary-based upstream oil business, is a more modern heavy oil extraction process. Using a specifically created burner, methane is burned in a combustion cavity within the pay zone to produce in situ steam and CO2 in the STRIP thermal EOR process. The oxygen-to-methane ratio for the STRIP burner is between 1.6 and 1.9, and it functions in an oxygen-starved (or sub-stoichiometric oxygen) atmosphere. While the combustion pressure is often adjusted to be somewhat greater than the reservoir pressure, the combustion temperature typically varies from 2800 to 3200 °C. Hydrogen, carbon monoxide, a small quantity of unreacted methane, carbon dioxide, steam, and minute amounts of unreacted oxygen are the main combustion byproducts in these circumstances (Dong et al., 2019).

1.3.2. Hot water injection

By transferring heat from hot water to the heavy oil, it is possible to inject hot water into the reservoir sand to improve oil output by reducing the viscosity of the heavy oil and allowing the flow. This method's reduced heat content as compared to other steam injection techniques is a limitation (Heidary et al., 2017).

The previous century has seen a sharp growth in the demand for oil due to the advancement of global development. The globe has been interested in heavy oils because of their large reserves and recent growth. In order to recover heavy reservoir oils, a variety of methods have been used, including thermal and cold production. Natural depletion, water flooding, and chemical flooding (polymer, surfactant, gas, etc.) are examples of cold production techniques. Injecting thermal fluid into reservoirs by techniques like steam flooding, cyclic steam stimulation, and steam-aided gravity drainage (SAGD) or producing heat inside the reservoir are examples of thermal production (Zhao & Gates, 2015).

Several interrelated criteria cause oil to shift from its original position in the reservoir toward the production well. The principal advantages are:

- by replacing voids, the reservoir pressure is maintained;

increased mobility ratio when the oil phase viscosity decreases with heat;

- increased efficiency in areal sweeps due to a reduction in viscous fingering as temperature rises;
- greater recovery factor because heat lessens residual oil saturation and interfacial tension;

- enhanced formation pressure recovery as a result of fluid and rock thermal expansion;
- increased effectiveness of the vertical sweep.

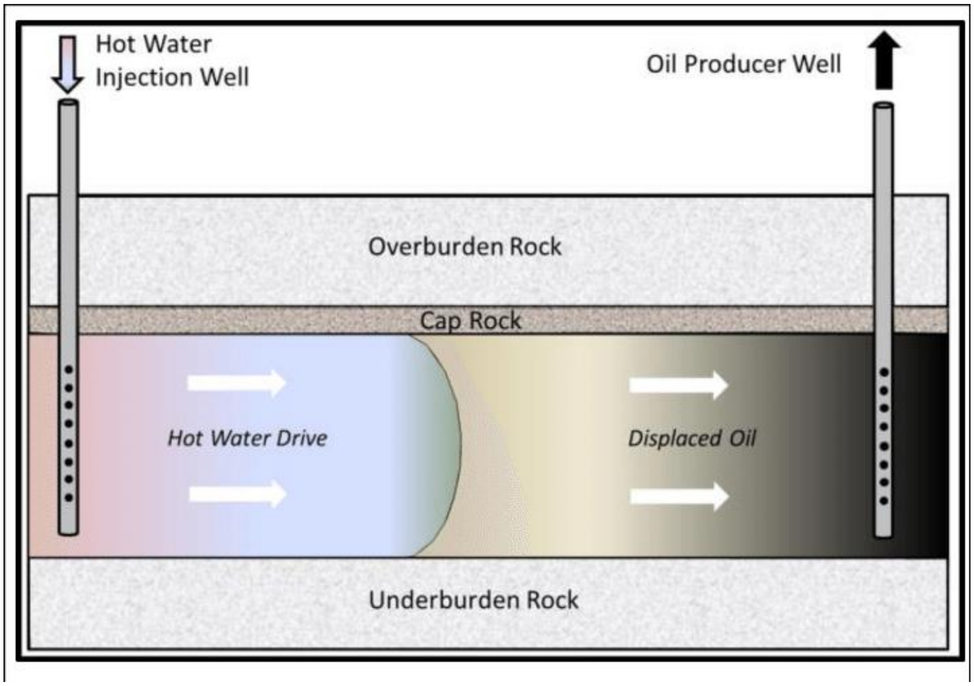


Figure 1.17. Hot water flooding process (Nmegbu & Pepple, 2017)

At the current reservoir pressure, water is heated to a temperature that is greater than the reservoir but lower than the water's boiling point. As shown in Figure 1.17, hot water is fed into an injection well that is dug parallel to the oil production well.

1.3.3. CYCLIC STEAM STIMULATION (CSS)

This technique is one of the most efficient thermal techniques for recovering heavy, extra-heavy oil and bitumen. This method, also known as "Huff and Puff," is illustrated in Figure 1.18. It involves injecting steam into the reservoir at high pressure and temperature for a prolonged period of up to a month and then ending the injection to allow the heat to be distributed along the formation and, as a result, reduce the viscosity of the oil. The well is then turned into a producer well. The negative aspect of this cycle-repeating process is the low recovery factor (RF), which is shown by the fact that it only achieves (20–40%) with a steam/oil ratio of 3 to 5. Despite this, it is more effective with lower emission levels than other thermal injection methods (Putra et al., 2011).

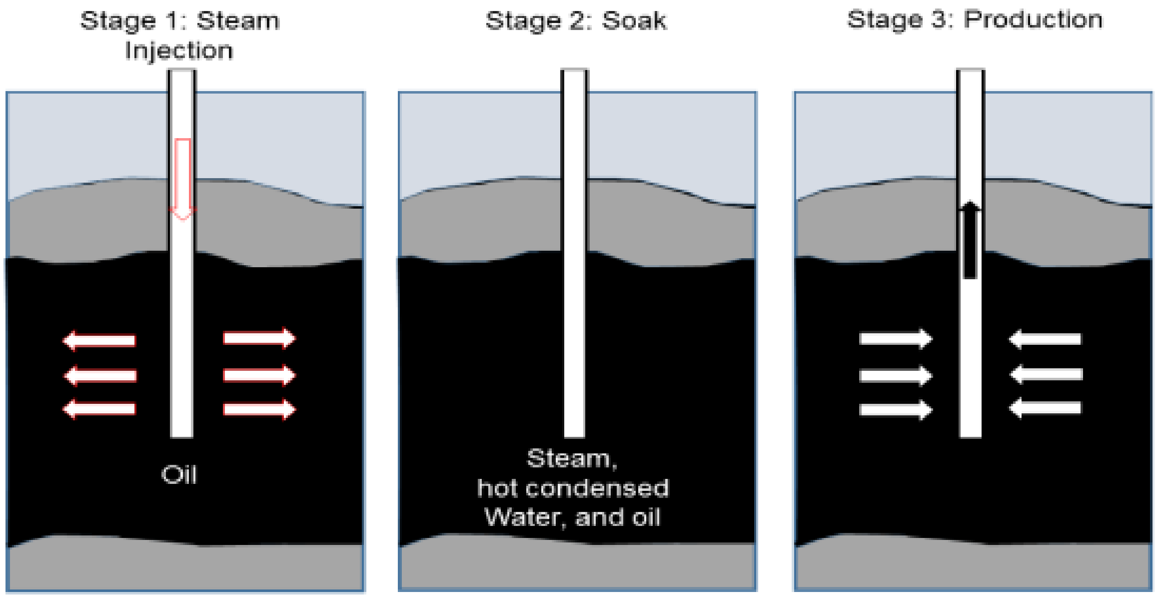


Figure 1.18. Cyclic Steam Stimulation Technique (Barillas et al., 2008)

In order to raise the temperature, steam is pumped into the reservoir during the steam injection step. Depending on the reservoir conditions, this stage typically lasts three to four weeks.

The well is sealed off to allow the steam to soak the rocks in the reservoir after the injection step. The viscosity of the heavy oil reduces, and the mobility of the crude oil rises as the steam diffuses and raises the temperature in the reservoir. This stage often lasts two to three weeks, depending on the state of the reservoir. Proper selection of this duration is important, as too short a duration may prevent steam from heating the formation, while too long a duration may induce heat loss to the formation and subsequent cooling of the reservoir (Arpaci, 2014).

The well is placed into production after the viscosity is lowered to the appropriate level. Production keeps going until it reaches a limit set by economic factors. The entire cycle of injection, soaking, and manufacturing may be repeated until it is deemed to be impractical once the production rate hits an economic limit (Arpaci, 2014). When the oil rate falls to an unprofitable level, cycles are repeated. As the number of cycles grows, so does the steam-oil ratio. Understanding the near wellbore is essential for both heat dispersion and heated/mobilized oil recovery in CSS. The rapid payout of CSS makes it very alluring, however the recovery factors are minimal (10–40% OIP). Figure 1.19 illustrates the CSS cycles.

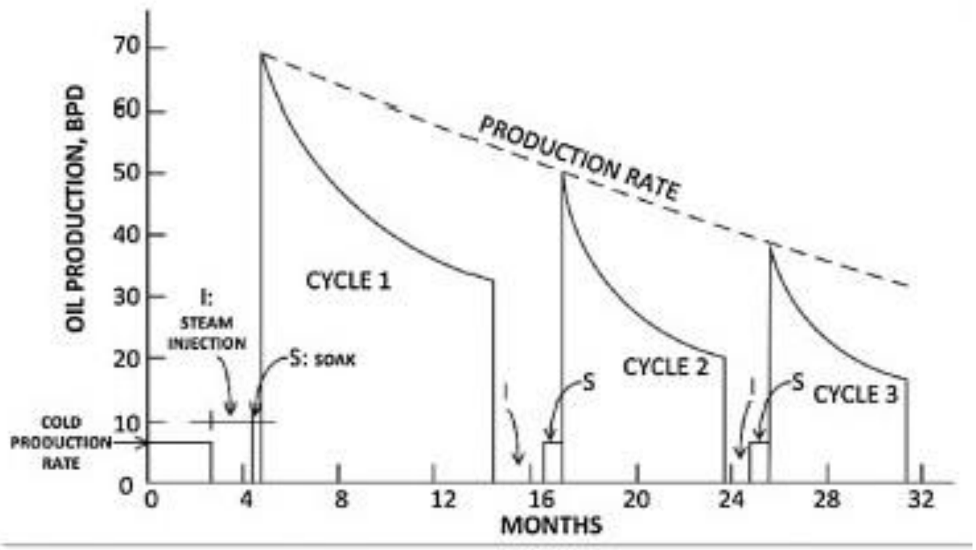


Figure 1.19. Cyclic Steam Injection with all Stages (Yalgın, 2017)

Here are the main mechanisms of this process: (United States Department of Energy, accessed 2021)

Heating reduces viscosity. As the viscosity-temperature chart illustrates, one notable property of heavy oil is how temperature affects its viscosity. The reservoir and crude oil are heated when high-temperature, high-pressure steam is injected into it. This raises the formation temperature within a given radius of the well zone. The high permeability zone is where the steam that is injected into the reservoir initially penetrates. Nevertheless, because steam has a low density, gravity causes the steam to rise to the top of the reservoir, unevenly heating it. However, when sufficient steam is injected, the heated zone progressively expands and the temperature in the steam zone stays at the bottom hole steam temperature (250 to 350°C) because of the actions of heat convection and heat conduction. Even when it slightly lowers, the temperature in the hot water zone—the steam condensation zone—remains quite high. In the ensuing heated belt, the viscosity of crude oil drops from thousands of mPa*S to around 10 mPa*S. In this manner, the flow coefficient (kh/μ) climbs orders of magnitude, the oil well production rate increases considerably, and the oil flow resistance is greatly decreased.

Thermal expansion. The heated crude oil expands in the reservoir when hot steam is introduced. The impact of solution gas drive will occur if there is even a tiny quantity of dissolved gas in the crude oil because it will escape from the crude oil. The reservoir's fluid and rock skeleton both experience thermal expansion at the same time that the pore volume shrinks, the fluid volume rises, and the elastic energy needed to sustain oil production rises. Crude oil's degree of thermal expansion is mostly determined by its composition. Light crude oil typically has a higher thermal expansion coefficient than heavy crude oil.

Gravity drive. The overlap phenomena develop during the steam injection process due to the difference in vapor and liquid densities, resulting in unequal reservoir heating throughout its length. But because of heat conduction, the reservoir's heated region grows, and its non-displacement portion gets heated. Gravity causes heated crude oil to flow down the hole. Gravity drainage becomes more significant in heavy oil reservoirs with substantial single-layer thickness.

Distillation by steam. The vaporization pressure of water and oil during the steam injection process rises as temperature rises. Steam distillation occurs when the light components of crude oil evaporate into the gas phase and the vaporization pressure of the oil and water mixture equals the reservoir's current pressure. The following factors primarily demonstrate how distillation affects heavy oil recovery: low gas phase viscosity, low flow resistance, solvent flooding at the displacement front, and the transfer of light components from dead-end rock pores to connected pores, which reduces viscosity and causes self-dilution.

Compaction of the formation. It is impossible to overlook the mechanism of oil displacement known as formation compaction. To extract the oil, the reservoir layer is compressed by the weight of the strata above it.

Emulsion displacement. The disturbance effect is caused by the condensing and heat-releasing steam near the leading edge of the steam chamber during the steam injection process, which has a high steam flow rate and specific volume. Emulsification takes place to create an oil-in-water or water-in-oil emulsion. These viscous emulsions restrict the highly permeable bands in heterogeneous reservoirs, decreasing steam pointing in the condensing zone and boosting sweep volume.

High temperatures enhance oil phase permeability. When a heterogeneous reservoir is heated by wet steam injection, the colloidal oil film on the surface of the sand grain is destroyed, changing the reservoir's wettability from being oil-wet or strong oil-wet to water-wet or strong water-wet. This causes the reservoir's relative permeability to oil and water to change at high temperatures. The permeability of water drops, the permeability of oil rises, and the permeability of bound water increases with the same water saturation. Additionally, the replacement oil enters the percolation channels, and the hot water is pulled into the low-permeability reservoir, boosting the flow of moveable oil to the wellbore.

There are also surface facilities that should be provided to apply this process. All these facilities have been shown below: (Sheng, 2013)

Water supply: Seawater - Water tank - Seawater desalination equipment - Water treatment equipment - High-pressure piston pump - Steam generator;

Fuel supply: Fuel - Oil Tank - Oil pump room - Steam generator – Well;

The nitrogen system: Air compressor - Membrane separation - Supercharger - Oil well annulus.

The steam generator is the main piece of equipment among them. Following purification, the water goes into the steam generator, which creates a lot of steam that is constantly pumped into the oil well.

Since various CSS projects account for 75% of China's heavy oil output, CSS is regarded as the primary method for producing heavy oil in that country (Liu, 2013). According to Nehring et al., 41 pools in the United States are selected for the CSS procedure (Dong et al., 2019).

In Athabasca, Cold Lake, Peace River, and Grosmont in Alberta, Canada, CSS was established more than 45 years ago (Farouq Ali, 1994; Novak et al., 2007). Canadian Natural Resources has been using it since the 1980s in Primrose and Wolf Lake, and Shell Canada has been using it at Peace River (Novak et al., 2007; Edmunds et al., 2009).

A CSS began in China in the 1960s in the Karamay oilfield (CNPC, Xinjiang). The technology was first used in a pilot test before being used in the Liaohe, Shengli, and Henan oil fields (Dong et al., 2019). In Russia (Xia & Greaves, 2002; Shandrygin & Lutfullin, 2008) Indonesia, Colombia (Xia & Greaves, 2002; Valbuena et al., 2014), Oman, and Mexico (Xia & Greaves, 2002; Alvarez & Han, 2013), many initiatives have been implemented.

1.3.4. Steam Flooding

Steam is produced at the surface and pumped into the reservoir via the injection wells in a process known as steam injection, also known as steam drive or continuous steam injection (Figure 1.20). After the injection, the steam warms the crude oil in the reservoir and lowers its viscosity (Ezekwe, 2010).

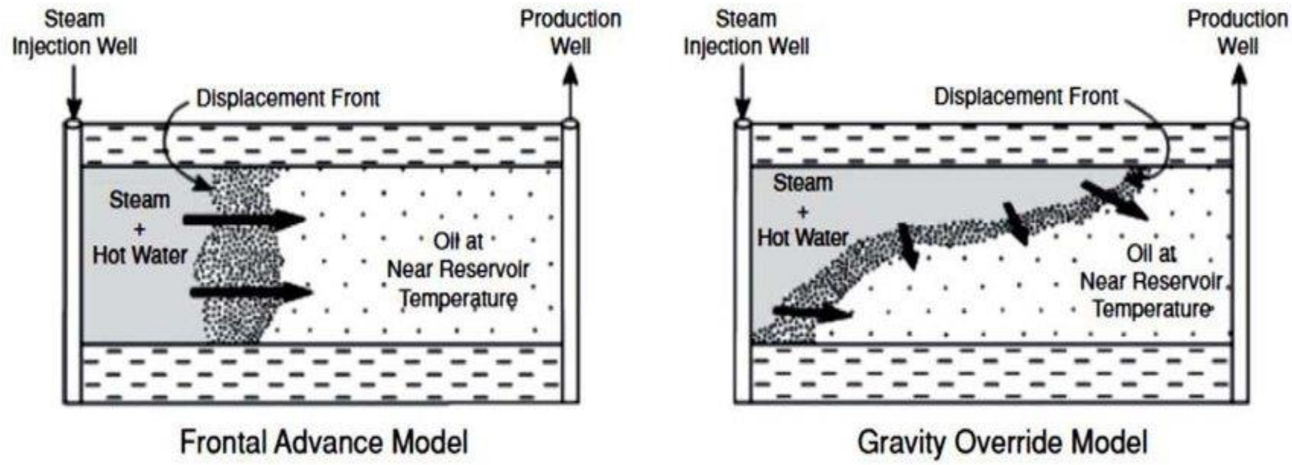


Figure 1.20. Schematic of steam flooding (Ezekwe, 2010).

Steam flooding is related to two primary phenomena. The first is steam override, also known as gravity segregation, which happens when liquids and steam have different densities in porous media. Steam tends to climb to the top of the reservoir and creates a steam channel that leads to the production well because it is less dense than water and oil. The second problem, which arises from the formation's heterogeneity, is steam channeling. For example, when steam channeling happens, the steam moves into the formation's greater permeability zones. Separately, the following elements are necessary for steam flooding to be successful (Lyons & Plisga, 2011):

1. The pay zone of the reservoir needs to be thicker than 20 feet and the oil saturation needs to be high (40–50% PV) to minimize heat losses to adjacent formations.
2. The shallowest achievable steam-flooded reservoir should reduce the amount of heat lost in the wellbore.
3. High porosity, high permeability, viscous oil, and unconsolidated sand are the main materials that can benefit from steam flooding.
4. If water flooding does not work on lighter, less viscous crude oils, steam flooding can be used.
5. The cost per incremental barrel of oil is significant since about one-third of the extra oil recovered is used to produce the necessary steam.

Optimizing steam flooding performance has gained more attention in both academic research and field applications as steam flooding methods for heavy oil recovery have advanced (Aguilar et al., 2014; Dong et al., 2019). According to Kirmani et al., the main goals of steam flooding optimization are to increase oil production economically, optimize heat efficiency, improve sweep efficiency, and postpone steam breakthrough time. According to Huang et al., this necessitates adjusting several technical aspects at every stage of the process, from late field development to pilot design. Several strategies for optimizing steam injection parameters depending on reservoir conditions have been explored in recent research (Sheng, 2013). In order to attain greater oil rates than normal pressure, Dong et al. (2019) adjusted the temperature and quality of high-pressure steam injection for a deep reservoir. Sun et al. (2017) balanced oil output and heat efficiency by optimizing the injection rate.

Distributed temperature sensing (DTS) and other monitoring technologies have made real-time injection control and optimization possible. A closed-loop method to continually adjust the steam rate has been developed using simulator forecasts and DTS data. The problem of steam override has been addressed by modifying the injector-producer spacing depending on monitoring. These methods have been successful in cutting down on steam loss and improving sweep efficiency.

Applications of steam flooding are prohibited (limited) for the following (Lyons & Plisga, 2011):

1. To reduce heat losses to nearby formations, the pay zone needs to be more than 20 feet thick, and the oil saturation level needs to be rather high.
2. If lighter, less viscous crude oils do not react to a water flood, they may be steam-flooded.
3. Viscous oil in large, high-permeability sandstone or unconsolidated sands is the main application for steam flooding.
4. Because of the high heat losses in the wellbore, steam-flooded reservoirs should be as shallow as feasible, provided that pressure can be maintained for adequate injection rates.
5. Carbonate reservoirs are not often subjected to steam flooding.
6. Since around one-third of the extra oil recovered is used to produce the necessary steam, the cost per incremental barrel of oil is considerable.
7. For optimum injectivity, a low proportion of clays that are sensitive to water is preferred.

1.3.5. IN-SITU COMBUSTION (ISC)

This thermal technique aims to heat and mobilize some of the oil by downhole combustion. Through a central vertical well, air "gas containing oxygen" is pumped into the reservoir. When this gas is exposed to the oil, it ignites, causing a combustion front to move through the reservoir as seen in Figure 1.21. Oil is extracted using several producing wells after its viscosity is decreased by heating and increases in API from 2 to 6 (Greaves, 2000; Tao et al., 2010).

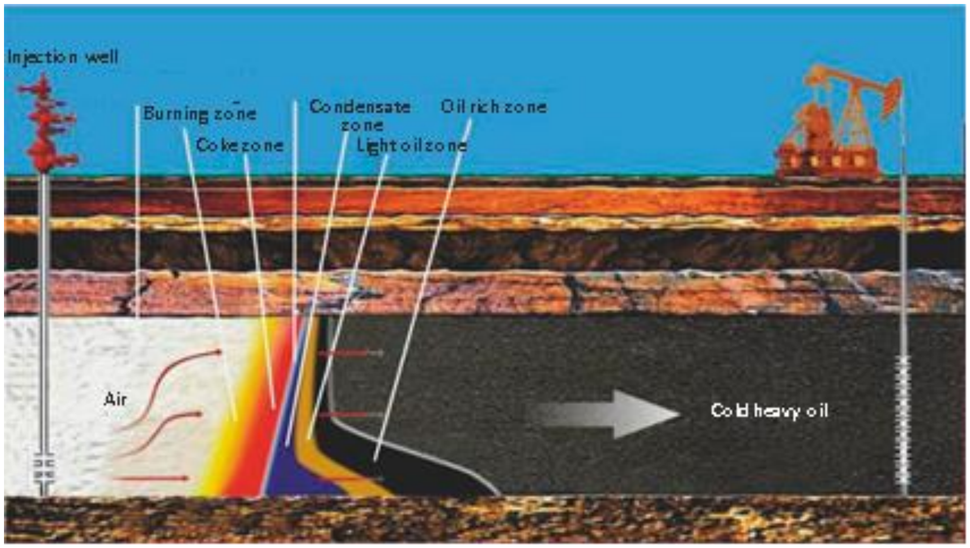


Figure 1.21. In situ combustion process schematic (Dong et al., 2019)

The methods for in-situ combustion come in several varieties. Both dry and wet forward combustion, as well as reverse combustion, are included.

Forward combustion begins with the air injection in the injector well and is known as dry combustion because the combustion front travels from the injector well in the same direction as the airflow. Wet combustion is a technique in which a small amount of water is mixed with the gas. Since the combustion zone is established at the production well and is highly effective in the low permeability reservoirs, reverse combustion occurs when the combustion front goes in the opposite direction of the injected air (Xia & Greaves, 2002; Liu et al., 2020; Card et al., 2014).

Reverse combustion has undergone substantial laboratory research and field testing. The theory is that it may be a practical method of creating highly viscous, heavy oils. It has not been economically successful for two main reasons, to put it briefly:

1. The hot generated fluids from combustion that began at the producer frequently contain unreacted oxygen. Special, expensive tubulars are needed in these situations to guard against corrosion and high temperatures. Operating an in-situ combustion project is more expensive since more oxygen is needed to propagate the front than in forward combustion.

2. The burnt area of the reservoir will include unreacted heavy ends that resemble coke. The coke will eventually begin to burn, returning the process to forward combustion with significant heat creation but minimal oil production. Even in closely monitored laboratory studies, this has happened.

The combustion front extends from the toe-to-the heel of the horizontal well, called THAI, generating a flowing oil zone and aiding in the thermal cracking of the heavy oil, in this method (Xue et al., 2022) illustrated in Figure 1.22. For traditional in-situ combustion, the horizontal well aids in reducing the displacement distance (Barillas et al., 2008).

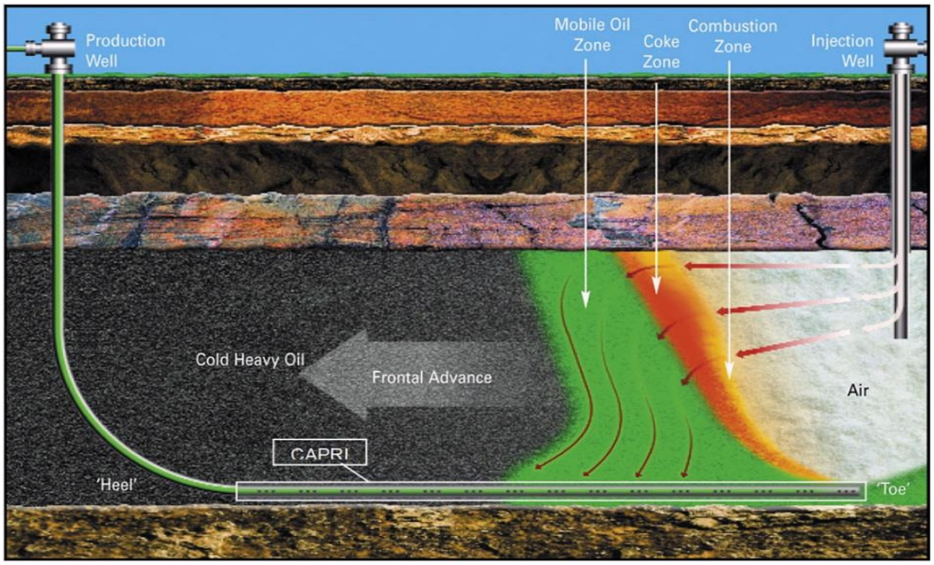


Figure 1.22. The toe-to-heel air injection method (Tao et al., 2010)

The production of heavy oil from the horizontal well depends on employing lateral wells (Xue et al., 2022; Kirmani et al., 2021) to pump the running gas out of the reservoir. In the heat-affected zone, crude oil viscosity decreases below the combustion front (Liu, 2013).

Similar to the SAGD method but used for in-situ combustion, two horizontal wells are employed at the top and close to the bottom of the formation (Patarroyo et al., 2014).

Numerous reservoirs can be used with in-situ combustion. Several recommended standards for screening include (Santos et al., 2014):

Nature of the formation: As long as the oil/matrix system is sufficiently reactive to support burning, the kind of rock doesn't matter. High-permeability streaks are bad for any driving process. Clays that swell might be an issue in the steam-plateau region.

Depth: The reservoir needs to be sufficiently deep to guarantee that the air that is pumped into it is contained. Other than the possibility that it will alter the injection pressure, there is no depth limit.

Pressure: This does not affect the technical elements of combustion, but it will have an impact on the process's economics.

Reservoir thickness: In order to prevent excessive heat loss to nearby formations, the thickness of the reservoir must be more than 4 m (15 ft). Gravity override can pose issues with sweep efficiency in thick formations.

Permeability: This needs to be adequate to permit air injection at the intended air flux. In particular, air injectivity matters for heavy-oil reservoirs. Good conditions occur when kh/μ exceeds 5md m/cp3.

Oil saturation and porosity must be sufficiently large for profitable oil recovery. To be economically viable, the product needs to be more than around 0.08.

Oil gravity: This is not a crucial element. Small enough in-situ viscosity is required to permit air injection and the consequent generation of oil at the design rate.

Oil nature: Under reservoir and rock matrix circumstances, heavy oil projects should have easily oxidizable oil. Laboratory investigations must be conducted to ascertain this link. The quantity of air required to burn a specific reservoir capacity may also be found using the same laboratory tests. This is crucial to the process's profitability.

1.4. NON-THERMAL METHODS

With several trillion barrels of oil reserves, heavy oil deposits are a valuable resource in the United States, Canada, Venezuela, and other nations. Over 2,000 heavy oil reserves are found in 1500 locations throughout 26 states in the United States alone. An estimated 106.8 billion barrels are in the overall resource, of which 45.9 billion barrels might be recovered by thermal oil recovery techniques. The remaining 60.9 billion barrels are found in areas that are unsuitable for the use of thermal techniques like in situ combustion and steam injection. The current conditions include things like thin formations (less than 30 feet), excessive depths (greater than 3,000 feet), low formation permeability (less than a darcy), too low an oil viscosity (50–200 cp), low oil saturation, possibly in conjunction with low porosity and large formation thickness, etc., and factors that prevent high enough injection rates from being achieved. It might be feasible to use a nonthermal oil recovery technique in these circumstances, which could be adjusted for an oil with a moderate viscosity.

1.4.1. VAPOR EXTRACTION (VAPEX)

If SAGD is not proper, vapor extraction (VAPEX) is a process used to produce heavy oil and bitumen. Propane, butane, or a combination of these solvents (in the form of light hydrocarbon vapors) must be injected into the upper well of two horizontal wells. As indicated in Figure 1.24

(Atia & Mohammedi, 2018), it will aid in diluting the oil deposit in the higher formation and will be dropped by gravity to be generated by the bottom well. Due to the minimal pore space, fracture appearance, and high water saturation, the VAPEX approach can be employed in reservoirs that are not suited for thermal treatments (Georgie & Smith, 2012). Due to its impact on reducing viscosity and increasing density, CO2 has recently been utilized in place of solvents and produces positive results (Atia & Mohammedi, 2018).

Lateral well spacing was shown to have a significant impact on oil output by Butler (1998) when he investigated the impact of various factors on the VAPEX performance.

Choosing the ideal solvent concentration is difficult when using this procedure because asphaltene may deposit and precipitate if this value exceeds the critical threshold (Butler, 1998).

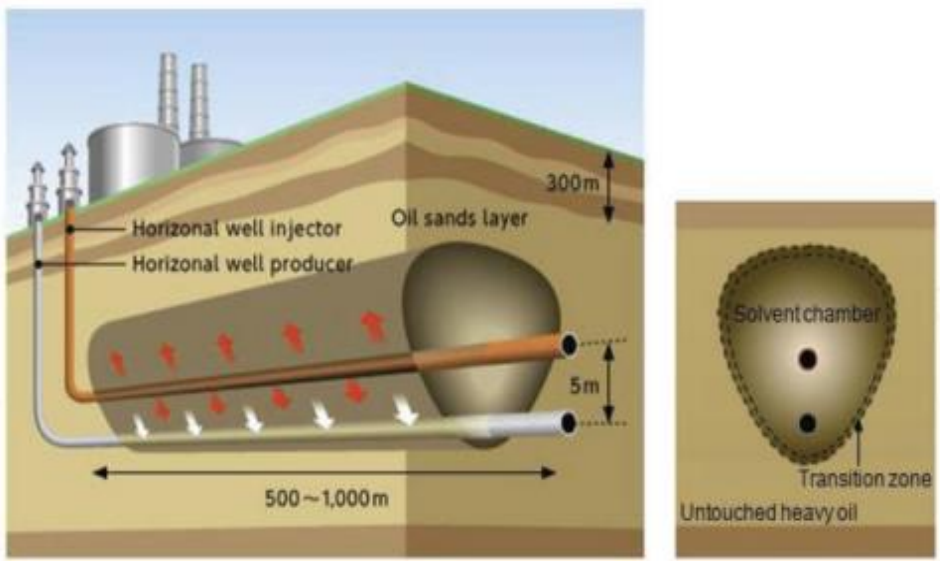


Figure 1.24. The VAPEX heavy oil recovery process (Atia & Mohammedi, 2018)

The reservoir pressure should be lower than the solvent's vapor pressure due to the significance of reservoir pressure and temperature in the solvent selection and to prevent any liquefaction at any location in the reservoir (Das, 1998).

The two categories of physical qualities in general are transport and thermodynamic properties. Although several metrics have been recorded, there is a lack of consistency in their associations. As was previously indicated, one major challenge in describing the chemistry and molecular weight distribution of the constituents in heavy oil is that adequate weighting of the physical attributes is still up for discussion. One characteristic of heavy oil is that each and every molecule has a big molecular weight. This is similar to the situation in polymers, where there is a molecular weight distribution, yet each individual molecule is enormous. Additionally, polymer molecules may differ chemically in ways like chain branching. It was demonstrated by Flory (1953) that the thermodynamic characteristics of polymer solutions should be described in terms of volume fractions rather than mole fractions. When it comes to crude oils, the unique chemical composition of the oil is combined with the name of the oil field where it was produced. Flory struggled to have his point of view acknowledged, and one editor declined our article for evaluation, stating that they only looked at materials with completely defined chemistry. The same volume-based methods may be used to comprehend the transport qualities, as will be covered later.

1.4.2. COLD HEAVY OIL PRODUCTION WITH SAND (CHOPS)

Nonthermal heavy-oil production without sand is known as cold production. Utilizing the extensive drainage area of long horizontal wells with slotted liners allows for the achievement of economical rates. Economic success with oils less viscous than about 1500 cp is typical in Canada, even though OOIP recovery is less than 10% and production rates might decline by 40% annually. Multilateral branches are added to the well drainage area in the Venezuelan Faja del Orinoco, where this technique has found widespread use (Rodriguez Hernandez et al., 2016).

The discovery that sand ingress may increase the oil rate in heavy-oil UCSS by an order of magnitude or more is exploited by cold heavy-oil production with sand or CHOPS. In heavy-oil fields using CHOPS, pressure-pulsing technology (PPT) was used to improve the flow rate between 1999 and 2001 (Dusseault et al., 2000). The method entails repeatedly applying precise pressure pulses to the liquid phase, and it may be used in any porous media that is saturated with liquid. This has the effect of bypassing capillary barriers, decreasing pore-throat obstruction, and suppressing advective instabilities such as viscous fingering or permeability channeling.

A new and quickly evolving manufacturing technology is called CHOPS. The fields of ideal workover plans, sand disposal procedures, and enhanced recovery techniques (such as pressure pulsing and floods) are developing swiftly. There is a lot of interest in using CHOPS as a major production technique because of its low operating costs and lack of requirement for thermal energy. Refinery upgrading capacity was the sole significant impediment to the amount of oil produced by CHOPS in the heavy-oil belt in 2002. Because heavy oil is high in sulfur, heavy metals, and carbon, it cannot be used as feedstock by traditional refineries. Coking and hydrogenation are used in specialized, expensive refineries known as upgraders to create synthetic crude oil, which may then be processed in a traditional refinery.

There are significant differences in the production histories of CHOPS wells. Several following variables influence the production of CHOPS:

- The first significant influx of sand into a newly built well is 10–40% of the volume of the produced liquids and solids (which are gas-free);
- Depending on the oil viscosity, the sand rate progressively decreases over a few days to many months to a steady-state inflow rate (0.5 to 10%);
- After turning the well on, the rate of oil production rises to a maximum for many months or longer before gradually declining as the consequences of reservoir depletion take over.
- Significant gas production occurs with every CHOPS output, and GOR levels often hold steady over several years.
- The rates of short-term sand inflow and oil production oscillate erratically around the mean value.

1.4.3. Chemical Viscosity Reduction Development Technique.

With the goal of lowering the viscosity, this approach requires injecting a chemical viscosity reduction system into a heavy oil reservoir. Heating is not used with the chemical viscosity reduction method. Unlike polymer flooding, it primarily affects the oil phase and enhances the development effect by altering the crude oil's fluidity. The Shengli Oil Field developed and tested the heavy oil chemical viscosity-reducing cold recovery process in response to the decline in crude oil prices and the tightening of environmental protection regulations in recent years. The primary development strategies are flooding to increase the sweep coefficient and in situ emulsification to increase the crude oil's capacity for percolation and emulsion control (Allenson et al., 2011). The Shengli Oil Field has been tested and promoted in the Jin 8 and Shang 2 blocks, including sensitive reservoirs, heavy oil reservoirs, low-efficiency water drive heavy oil reservoirs, and deep low-permeability heavy oil reservoirs, due to its low investment requirements and green environmental protection features. The development of oil reservoirs, particularly heavy oil reservoirs with edge and bottom water, has advanced significantly. The world's largest heavy oil viscosity reduction cold recovery development base has been built, 384,000 tons of oil have been amassed since 2018, and technical advancements are continuing to grow in scope.

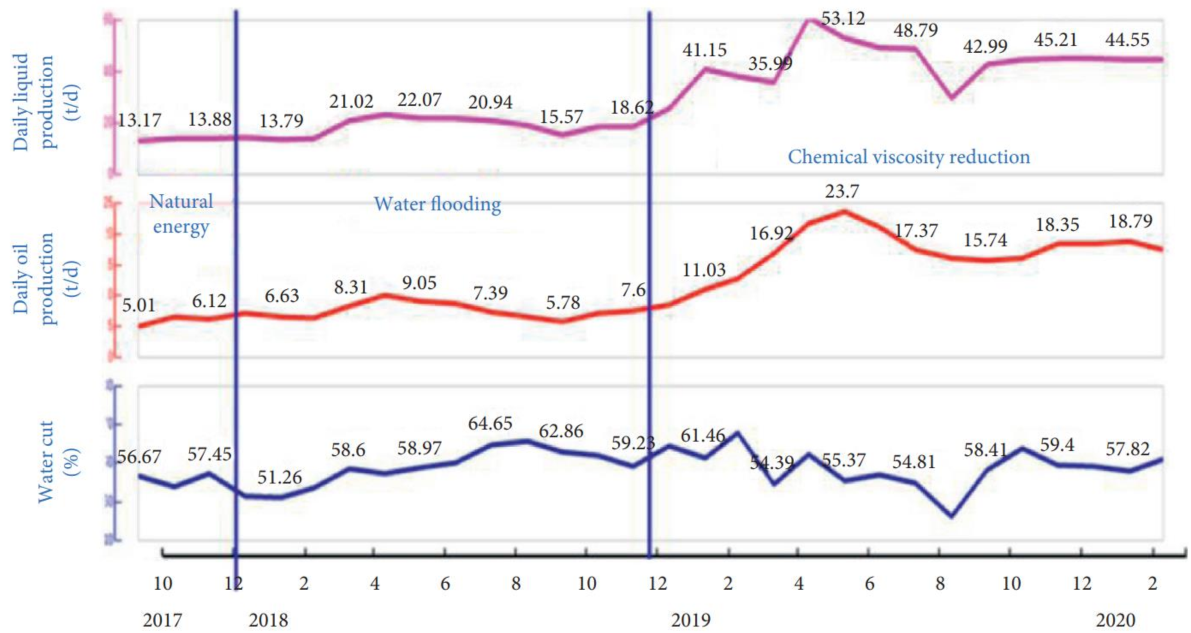


Figure 1.25. Production curve of the chemical viscosity-reducing development of the test well group in the Jin 8 block (Xue et al., 2022)

1.4.4. Miscible flooding

The mobilization of the oil's light components, the decrease of interfacial tension, the vaporization and swelling of the oil, and the reduction of oil viscosity are all necessary for miscible flooding (Thomas, 2008). The minimum miscibility pressure (MMP) is defined as the pressure at which more than 80% of the original oil-in-place (OOIP) is recovered at CO2 breakthrough and is determined experimentally through slim-tube tests or mathematical correlations (Zou, 2013), the injected CO2 completely dissolves through crude oil (Barillas et al., 2008). On the other hand, an oil recovery of at least 90% at 1.2 pore volume of injected CO2 is generally employed as a guideline for determining MMP in the industrial setting. Miscibility between CO2 and reservoir oil is achieved when the reservoir pressure is above the MMP. This is known as multiple-contact or dynamic miscibility, in which part of the injected CO2 dissolves into the oil (condensed gas-drive process) and the intermediate and higher molecular weight hydrocarbons from the reservoir oil vaporize into the CO2 (vaporized gas-drive process). This mass transfer between CO2 and oil serves to form a transition zone that is miscible with CO2 and oil and enables the two phases to become fully miscible without any contact. One first contact, vaporizing gas drive, and condensing gas drive are the components of CO2 miscible flooding (Mansour, 2022):

First contact: during this stage, all of the reservoir oil's components combine with miscible solvents, but the mixture stays in one phase. through one or more connections, with the outcome being significantly better oil recovery.

The vaporizing gas-drive procedure (also known as a high-pressure gas drive): this method produces dynamic miscibility by injecting lean gases or CO2B into the reservoir oil to cause the intermediate-molecular-weight hydrocarbons to evaporate in situ.

The enriched gas drive method, also known as the condensing gas-drive process, transfers intermediate molecular weight hydrocarbons from a rich solvent to a lean reservoir oil in situ to provide dynamic miscibility.

1.4.5. ELECTRICAL HEATING METHODS

These techniques have lower oil recovery than thermal techniques and are not commercially viable.

A heat transfer system via an electrode will flow an electric current from the electricity generator to the reservoir formations and flow back to the surface in the electrical heating technique, as shown in Figure 1.23 (Xue et al., 2022). Depending on the pace of production, different amounts of electric current are needed. If too much energy is utilized, the reservoir will be exposed to damage (Vinsome et al., 1994).

As a result, heating effectively reduces oil viscosity (McGee et al., 1996). The benefits of electrical heating include the ability to produce while heating without the need for fluids, which reduces heat loss. Volumetric sweeping is thought to be more effective than thermal injection because electric current may easily pass through poor permeability zones (Xue et al., 2022).

China experimented using catalysts and hydrogen donors in 20 CSS wells in 2005, and output increased with the elimination of excessive sulfur and asphaltene levels (Ovalles et al., 2015; Wang et al., 2019). Alkyl ester sulfonate copper (0.1–0.3 wt.%) was also tested in 2012, and it had positive results for the elimination of asphaltene and sulfur, leading to a rise in API gravities (Ovalles et al., 2015; Chao et al., 2012).

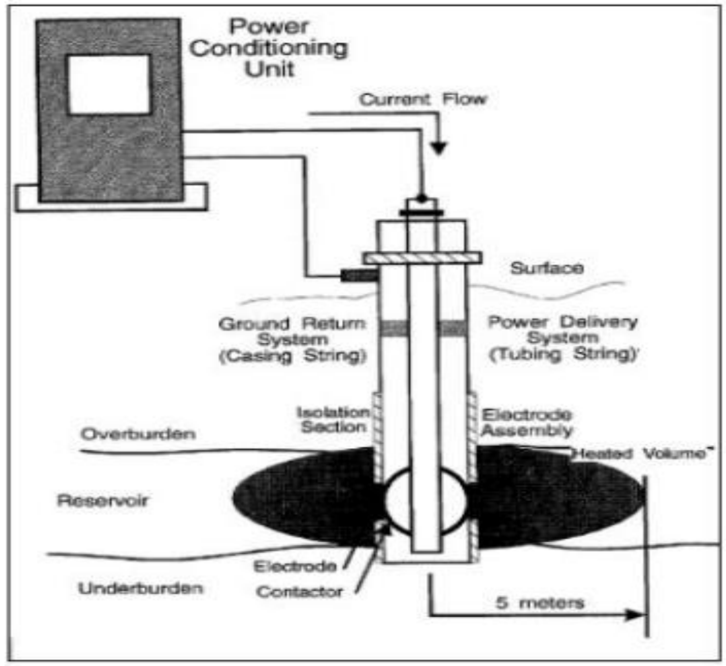


Figure 1.23. Electrical heating single wellbore configuration (Xue et al., 2022)

The Orinoco oil belt in Venezuela is an example of a heavy oil reservoir where this approach is favored since the temperature is too low and the oil viscosity is not too high.

According to the frequency of the electrical current employed, there are three different types of electrical heating techniques. They categorized it as high-frequency (radio frequency or microwave) electromagnetic heating, medium-frequency electromagnetic (EM) induction heating, and low-frequency electric resistive (ohmic) heating (Xia & Greeves, 2002).

CHAPTER 2. METHODOLOGY

2.1. General information about numerical modelling

For simulating dynamic conditions of Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) processes, this study is conducted using CMG STARS. It aims to examine how the performance of a reservoir would change because of variations in steam quality, injection rate, and soaking time. It is achieved by creating elaborate models that represent different sections of the reservoir within CMG STARS software; these models take into account geological parameters such as porosity or permeability alongside petrophysical data relevant specifically to SAGD and CSS operations so as also integrate fluid properties like viscosity etc. In order to carry out thermal and multiphase flow analyses under such conditions, several simulation scenarios are defined. Furthermore, changes brought about by altering the steam quality, injection rate, or soaking duration are looked at through sensitivity tests whose results show what impact they have on recovery processes among others like RF, SOR, or COP.

This research examines the performance of Steam-Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) techniques for recovering heavy oil from one reservoir. SAGD is a Category 1 method that employs two parallel horizontal wells. The first well delivers steam at high temperatures into the reservoir while the second produces condensed steam and oil; on the other hand, CSS which is categorized as number 2 involves sporadic injection of pulses of steam into the reservoir.

In simulating and evaluating each recovery phase, this study adopts CMG's STARS software. Employing this computer-based methodology, it is possible to make an extensive evaluation of such technical performance indicators as Oil Recovery Factor (RF) and Steam-Oil Ratio (SOR); thus, making it easier to compare them against each other in terms of their feasibility and efficiency for heavy oil recovery.

This research adopts a Cartesian grid to identify and understand the reservoir structure. The reservoir is divided into i×j×k directions that form a 25x15x10 discretized grid. This allows for the investigation of fluid flow and distribution within the reservoir domain with a grid-based method, which leads to deeper knowledge about recovery processes.

2.2. Input data

Furthermore, a range of input parameters are used in order to accurately reproduce heavy oil behavior within the reservoir. These variables are used to characterize the physical and chemical properties of both the reservoir itself and its fluids, including component as well as rock-fluid properties. Specific input parameters for Oilfield Alpha can be found in Table 2.1 where they have been compiled from Oilfield Review (Cenovus Energy, 2016).

It is possible to efficiently estimate and assess the effectiveness of recovery techniques like Cyclic Steam Stimulation (CSS) and Steam-Assisted Gravity Drainage (SAGD) by including these input parameters in the numerical simulation framework. This thorough process guarantees that our simulation results faithfully represent Oilfield Alpha's actual circumstances, improving the validity and relevance of our conclusions.

Table 2.1. Input parameters and values for the model.

Input parameter	Value
Grid type	Cartesian
Number of Grid Blocks	25 x 15 x 10
Grid Block Dimensions	1000 ft x 300 ft x 90 ft
Grid top	1300 ft
Reference depth	1300 ft
OWC depth	1380 ft
Initial pressure	650 psi
Reservoir temperature	110 F
Porosity	0.308 or 30,8 %
Horizontal permeability	1700 mD
Vertical permeability	1400 mD
Initial oil saturation	0.8 or 80 %
Oil Gravity	9.8 API
Oil Viscosity	15780 cp

Regarding the model we are working with, it is necessary to take into account some parameters more carefully if there is no gas phase involved, especially those that show a direct proportionality with pressure. It is worth mentioning that these figures demonstrate interesting changes in basic properties such as oil formation volume factor (Bo), density of oil, and viscosity of oil at different pressures within the reservoir.

In Figure 2.1, we can see how Bo changes as well as the density of oils when exposed to various pressure gradients; this plot not only shows the dependence on Bo and density but also emphasizes its importance in controlling fluid behavior at different points in the reservoir.
Similarly, Figure 2.2 gives us an overview of what happens with viscosity under different levels of pressure applied to it. What this illustration does is enable people to comprehend better how the dynamic relationship between them exists which leads to further knowledge concerning characteristics of fluid flow and possible operation consequences for recovery methods.

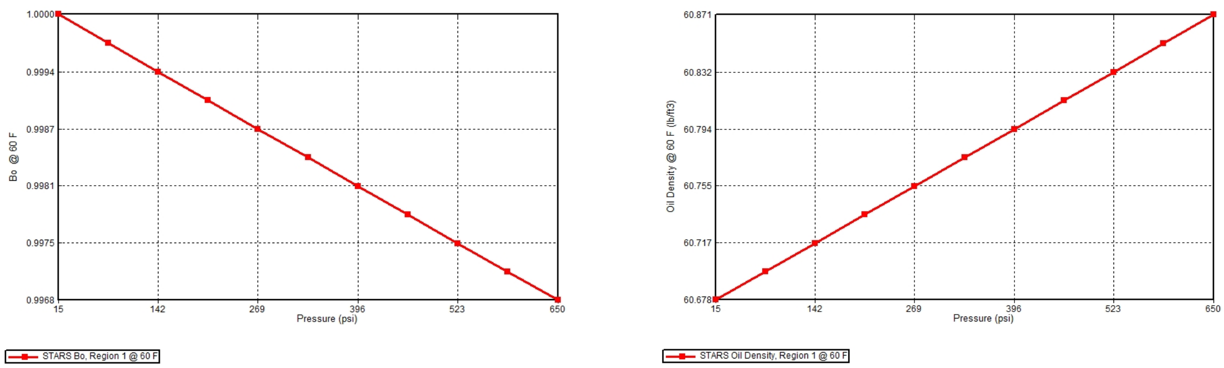


Figure 2.1. B_o (left) and density (right) change with the pressure.

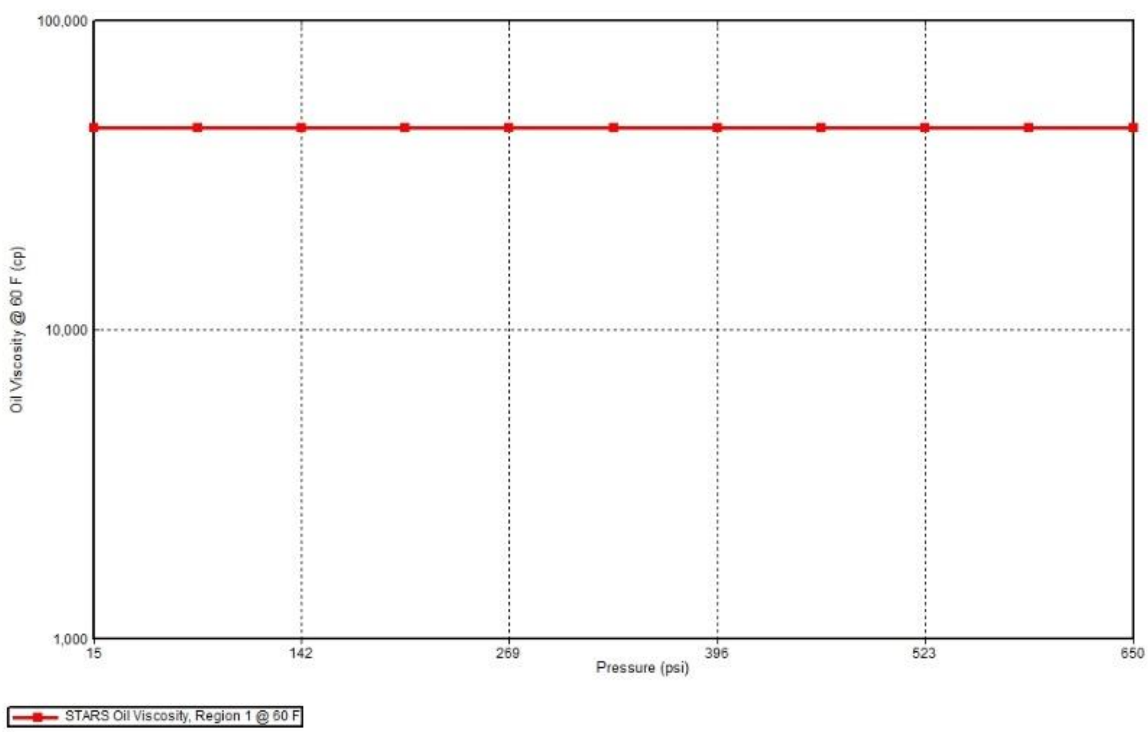


Figure 2.2 The dependence of oil viscosity on the pressure

Heavy oil production faces a major obstacle in the form of its high viscosity, which makes efficient recovery difficult. Thermal techniques like Steam-Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) seem like viable options as they help decrease viscosity by increasing temperatures and enhancing fluid mobility within the reservoir.

Figure 2.3 visually represents the relationship between viscosity reduction and heavy oil composition. The illustration highlights that the magnitude of viscosity reduction is dependent on the composition of heavy oil, thus different techniques should be employed for each type in the course of thermal recovery operations as per empirical observation and experimental. data.

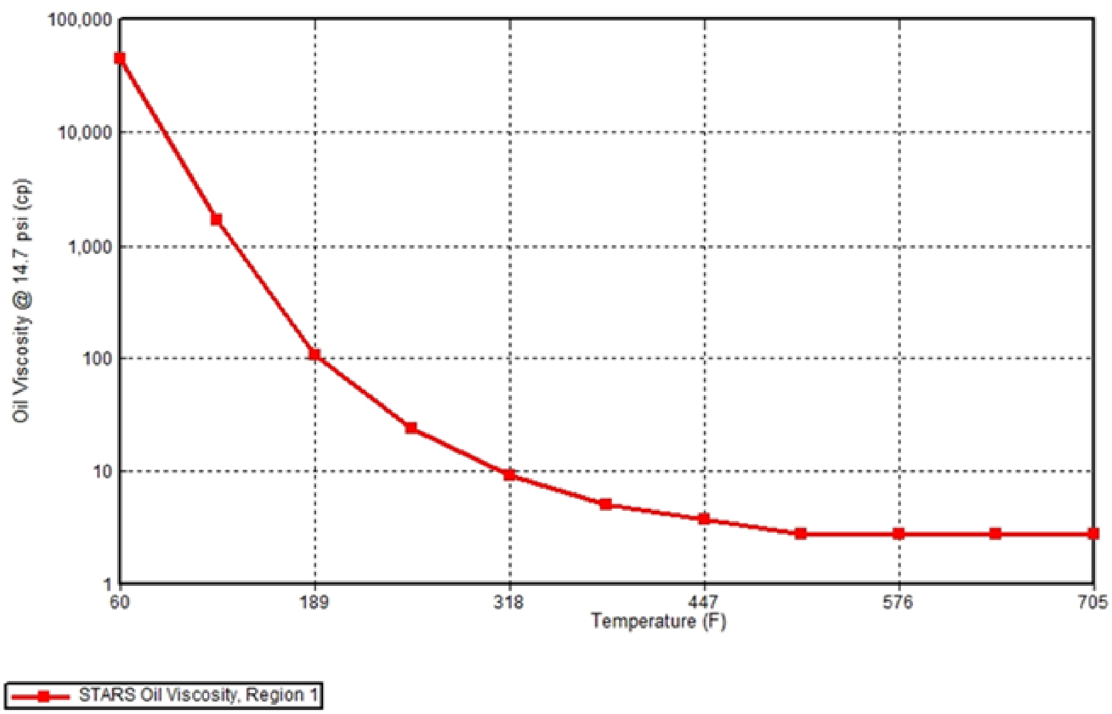


Figure 2.3 The dependence of oil viscosity on the temperature

Rock-fluid information is very important in the modeling of reservoirs as it provides useful knowledge about how fluids behave within the confines of these structures. One of the things that we find particularly interesting for this research is that there is no presence of a gas phase; this, therefore, implies that we have to carefully study fluid flow dynamics.

A key illustration is shown in Figure 3.4 which shows water-oil relative permeability curves. These curves describe relationships between water and oil relative permeabilities and can give us some idea of what type(s) of fluids may be flowing through different parts of our model at any given time. This graph also helps us understand where liquids like petroleum or natural gas might move within reservoir rocks based upon their saturation levels concerning each other as well as how they are affected by them at various points during production history periods such as those induced by pumping operations conducted at pumps installed along wells drilled into formations containing said reserves – among other factors too numerous mention here individually suffice it say that all these things contribute significantly towards making accurate predictions concerning preferential flow paths and saturation dependent fluid displacement mechanisms in reservoirs.

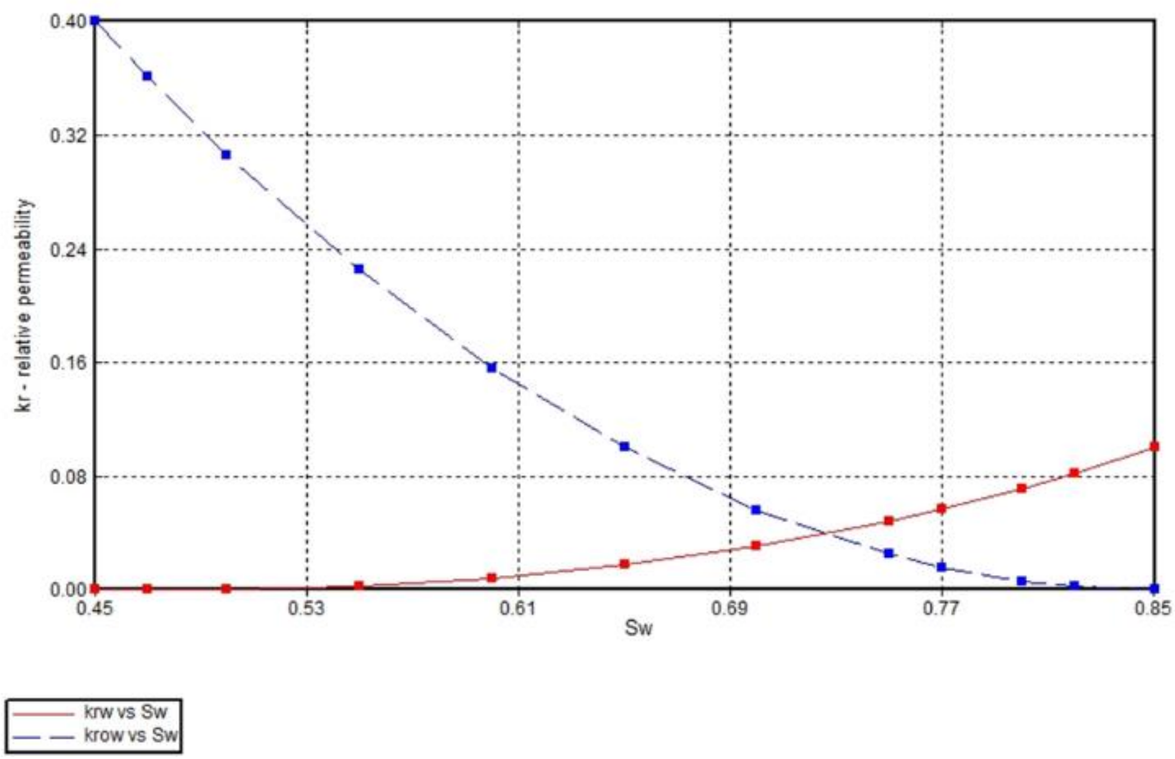


Figure 2.4 Water-oil relative permeability curves

After specifying all the input parameters of the reservoir system, the reservoir simulation software CMG STARS was used for constructing and characterizing the conceptual model shown in Figure 2.5. In this conceptual model, the grid arrangement and depth distribution within the reservoir domain are represented visually which lays the foundation for subsequent numerical simulation and analysis.

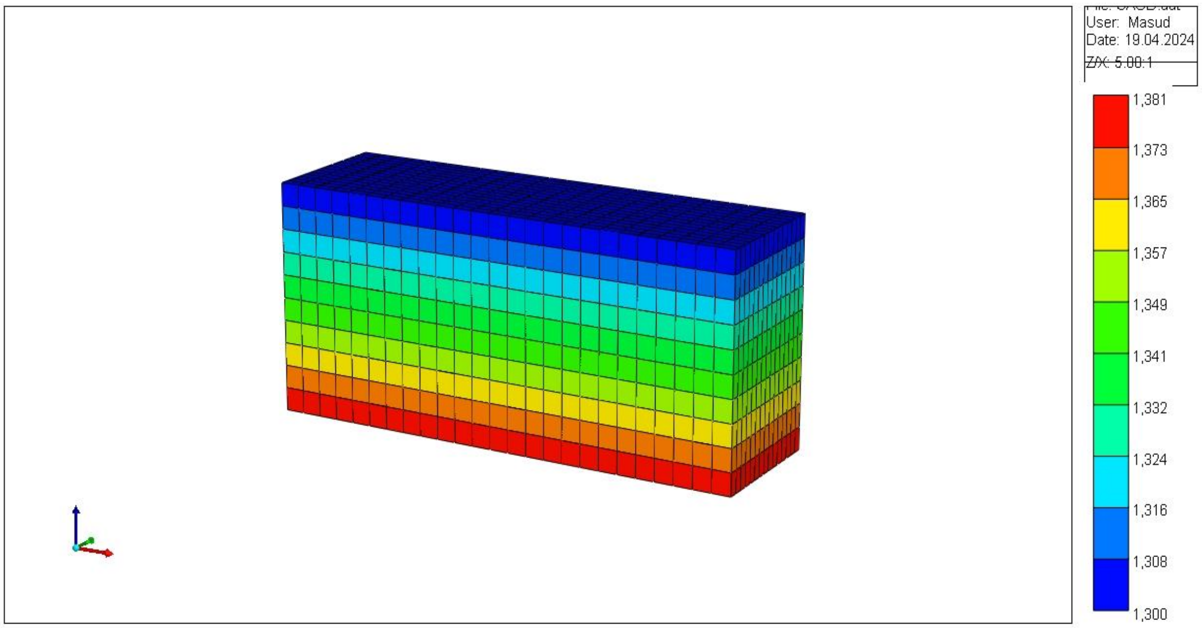


Figure 2.5. 3D view of the conceptual model

This research focuses only on two popular techniques that are used to extract heavy oil, namely Steam-Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS). It examines them in light of their importance to the recovery of heavy crude oils, creating sophisticated numerical models for both processes coupled with advanced simulations.

Detailed reservoir simulations are used to model these methods taking into account complex characteristics of such formations and fluid dynamics peculiar to reservoirs with high viscosity hydrocarbons.

2.3. Wells and Recurrent

In executing Steam-Assisted Gravity Drainage (SAGD), a dual-well configuration shown in Figure 2.6 is used. This involves drilling horizontal wells spaced 20 feet apart. Steam at high temperatures is injected into the reservoir through the upper well to create a conducive environment for hydrocarbon recovery from the lower well hence ensuring maximum utilization of the reservoir's potential.

Implementation of SAGD in CMG STARS is needed to write some algorithm that covers all properties of SAGD such as injection pressure, steam quality, and perforation clusters as well. The code system below is taken from cEDIT which is another tool of CMG software for our SAGD case.

```
WELL  'Injector-1'
INJECTOR MOBWEIGHT EXPLICIT 'Injector-1'
INCOMP  WATER  1.0  0.0
TINJW  500.0
QUAL  0.8
OPERATE  MAX  BHP  950.0  CONT REPEAT
OPERATE  MAX  STF  700.0  CONT REPEAT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.25  0.249  1.0  0.0
PERF      GEOA  'Injector-1'
** UBA            ff         Status  Connection
5 8 6         1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
6 8 6         1.0  OPEN    FLOW-FROM  1
7 8 6         1.0  OPEN    FLOW-FROM  2
8 8 6         1.0  OPEN    FLOW-FROM  3
9 8 6         1.0  OPEN    FLOW-FROM  4
10 8 6        1.0  OPEN    FLOW-FROM  5
11 8 6        1.0  OPEN    FLOW-FROM  6
12 8 6        1.0  OPEN    FLOW-FROM  7
13 8 6        1.0  OPEN    FLOW-FROM  8
14 8 6        1.0  OPEN    FLOW-FROM  9
15 8 6        1.0  OPEN    FLOW-FROM  10
16 8 6        1.0  OPEN    FLOW-FROM  11
17 8 6        1.0  OPEN    FLOW-FROM  12
18 8 6        1.0  OPEN    FLOW-FROM  13
19 8 6        1.0  OPEN    FLOW-FROM  14
20 8 6        1.0  OPEN    FLOW-FROM  15
WELL  'Producer - 1'
PRODUCER 'Producer - 1'
OPERATE  MIN  BHP  500.0  CONT REPEAT
OPERATE  MAX  STW  500.0  CONT REPEAT
**          rad  geofac  wfrac  skin
```

```
GEOMETRY  K  0.25  0.249  1.0  0.0
PERF      GEOA  'Producer - 1'
** UBA           ff        Status  Connection
5 8 8        1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
6 8 8        1.0  OPEN    FLOW-TO  1
7 8 8        1.0  OPEN    FLOW-TO  2
8 8 8        1.0  OPEN    FLOW-TO  3
9 8 8        1.0  OPEN    FLOW-TO  4
10 8 8        1.0  OPEN    FLOW-TO  5
11 8 8        1.0  OPEN    FLOW-TO  6
12 8 8        1.0  OPEN    FLOW-TO  7
13 8 8        1.0  OPEN    FLOW-TO  8
14 8 8        1.0  OPEN    FLOW-TO  9
15 8 8        1.0  OPEN    FLOW-TO  10
16 8 8        1.0  OPEN    FLOW-TO  11
17 8 8        1.0  OPEN    FLOW-TO  12
18 8 8        1.0  OPEN    FLOW-TO  13
19 8 8        1.0  OPEN    FLOW-TO  14
20 8 8        1.0  OPEN    FLOW-TO  15
```

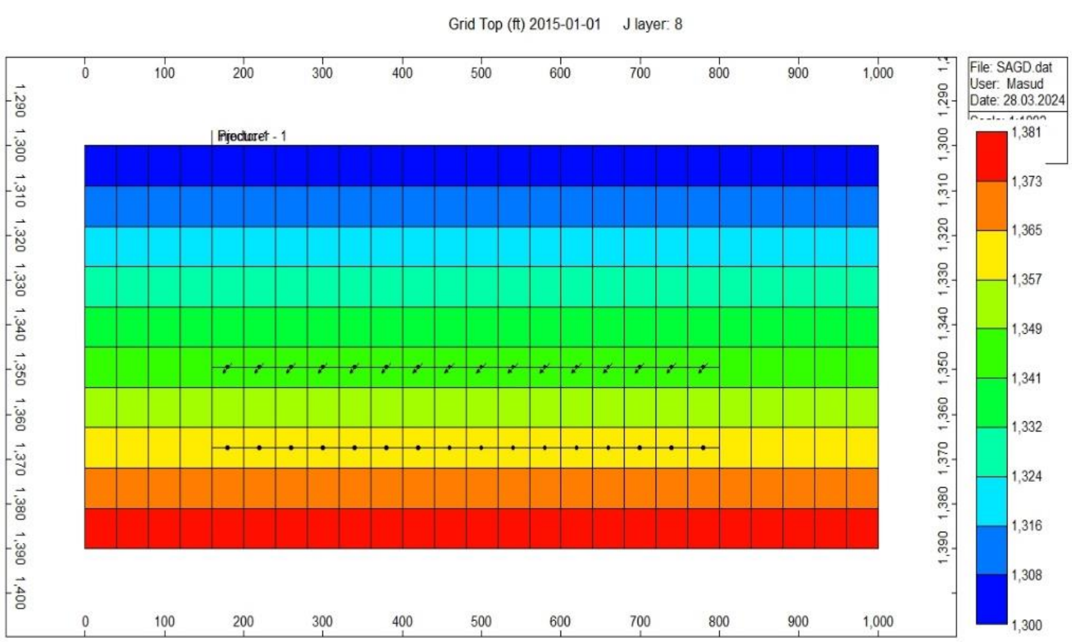


Figure 2.6. X-sec view of SAGD

In the CSS model, the producer and injector have common perforations located in the middle of the reservoir, which is the mean of this method. The perforation clusters of CSS wells are presented in Figure 2.7. The codes for CSS:

WELL 'Injector 1'

```
INJECTOR MOBWEIGHT EXPLICIT 'Injector 1'
INCOMP  WATER  1.0  0.0
TINJW  500.0
QUAL  0.8
OPERATE  MAX  BHP  1100.0  CONT REPEAT
OPERATE  MAX  STW  1000.0  CONT REPEAT
**         rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
PERF     GEOA  'Injector 1'
** UBA           ff        Status  Connection
13 8 2        1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
13 8 3        1.0  OPEN    FLOW-FROM  1
13 8 4        1.0  OPEN    FLOW-FROM  2
13 8 5        1.0  OPEN    FLOW-FROM  3
13 8 6        1.0  OPEN    FLOW-FROM  4
13 8 7        1.0  OPEN    FLOW-FROM  5
13 8 8        1.0  OPEN    FLOW-FROM  6
13 8 9        1.0  OPEN    FLOW-FROM  7
OPEN 'Injector 1'
```

WELL 'Producer 1'

```
PRODUCER 'Producer 1'
OPERATE  MIN  BHP  20.0  CONT REPEAT
OPERATE  MAX  STW  600.0  CONT REPEAT
**         rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
PERF     GEOA  'Producer 1'
** UBA           ff        Status  Connection
13 8 2        1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
```

13 8 3 1.0 OPEN FLOW-TO 1
13 8 4 1.0 OPEN FLOW-TO 2
13 8 5 1.0 OPEN FLOW-TO 3
13 8 6 1.0 OPEN FLOW-TO 4
13 8 7 1.0 OPEN FLOW-TO 5
13 8 8 1.0 OPEN FLOW-TO 6
13 8 9 1.0 OPEN FLOW-TO 7

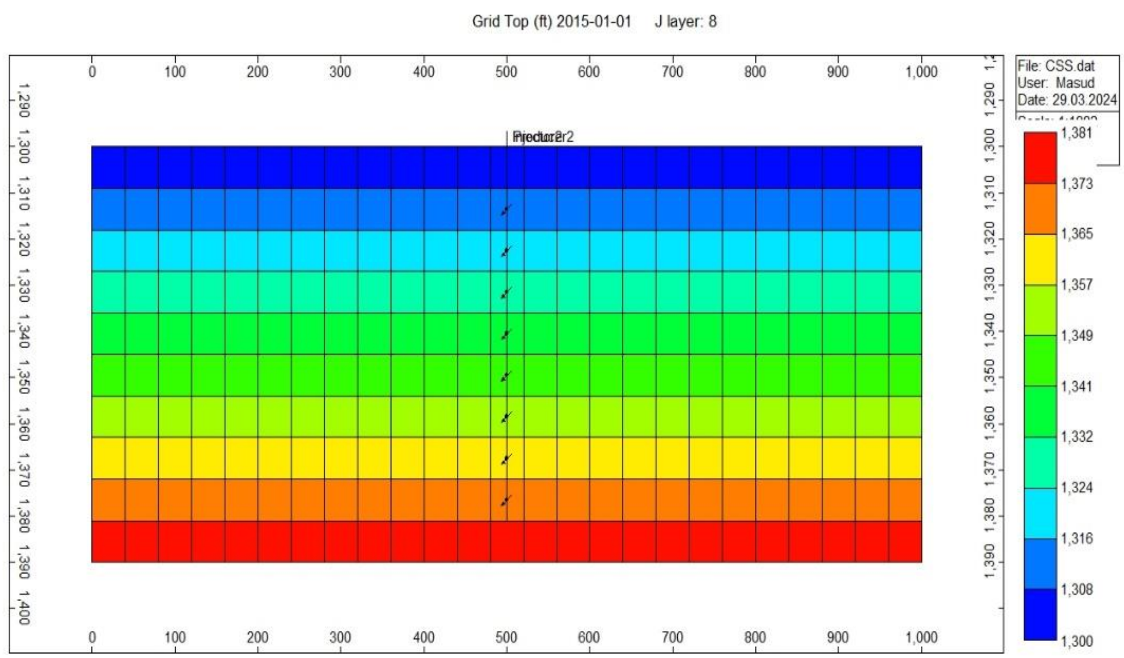


Figure 2.7. X-sec view of CSS

In CSS, two wells are simulated at the same perforation grids; also, here it is needed to add the codes for creating a cycling period. The code system below shows one of the scenarios simulated.

** Cycle No. 1 - Injection
*SHUTIN 'Producer 1' ** Shut in producer
OUTSRF GRID REMOVE SO
*TIME 20 – This time shows how many days steam is injected.
*DTWELL 1
** Cycle No. 1 - Soak
*SHUTIN 'Injector 1' ** Shut in injector

OUTSRF GRID SG TEMP

*TIME 26 – After 20 days injection, 6 days for soaking, that is the reason of being 26.

*DTWELL 1

** Cycle No. 1 - Production

*OPEN 'Producer 1' ** Turn on producer

OUTSRF GRID PRES

*TIME 86 - 26 + 60 days production = 86

*DTWELL .01

** Cycle No. 2 - Injection

*SHUTIN 'Producer 1' ** Shut in producer

*OPEN 'Injector 1' ** Turn on injector

OUTSRF GRID NONE

*TIME 106

*DTWELL 1

** Cycle No. 2 - Soak

*SHUTIN 'Injector 1' ** Shut in injector

*TIME 112

*DTWELL .5

** Cycle No. 2 - Production

*OPEN 'Producer 1' ** Turn on producer

*TIME 172

*DTWELL .002

** Cycle No. 3 - Injection

*SHUTIN 'Producer 1' ** Shut in producer

*OPEN 'Injector 1' ** Turn on injector

OUTSRF GRID SG TEMP

*TIME 192

*DTWELL 1

** Cycle No. 3 - Soak

*SHUTIN 'Injector 1' ** Shut in injector

OUTSRF GRID REMOVE

*TIME 198

```
*DTWELL 1
** Cycle No. 3  -  Production
*OPEN 'Producer 1'    *** Turn on producer
OUTSRF GRID SO
TIME 258
STOP
```

According to the terms of the plan, restrictions should be put on wells before they start producing hydrocarbons or injecting any substance. These limitations which contain various important elements are to control the performance of the system and optimize reservoir management. Table 3.2 highlights the full scope of such limits showing key values necessary for efficient and reliable operations within a borehole.

Category	Recovery Method	Injector Constraint	Producer Constraint
1	SAGD	max BHP-950 psi max STF - 400 bbl/day	min BHP-500 psi max STW - 500 bbl/day
2	CSS	max BHP-1100 psi max STW - 1000 bbl/day	min BHP-20 psi max STW - 300 bbl/day

Table 2.2. Well Constraints

The methodology section of this study was carefully constructed with invaluable help obtained from the comprehensive resources given in the CMG STARS Manual (Computer Modelling Group Ltd., 2021).

CHAPTER 3. RESULTS AND DISCUSSION

After the first run of simulations, calculating initial reserves is a crucial part of evaluating how much oil and water a field may hold. In Table 4.1, you can see exactly what these figures are—both for each phase individually (oil or water) and combined together within the entire area where rock contains hydrocarbons is located—with no mention whatsoever about gas being taken into account throughout this process which highlights further that there is none present other than liquid ones.

Table 3.1. Reserve calculation results by reservoir simulation.

Volume	Unit	Value
Gross formation	ft^3	$2.70 \cdot 10^7$
Formation pore	ft^3	$8.316 \cdot 10^6$
Aqueous phase	ft^3	$1.6632 \cdot 10^6$
Oil phase	ft^3	$6.6528 \cdot 10^6$
Gaseous phase	ft^3	0

3.1. Category 1 – SAGD

This study aims to carry out a comprehensive analysis of Category 1 with particular reference to the utilization of two horizontal wells in the context of Steam Assisted Gravity Drainage (SAGD). In SAGD, steam quality is central to its success, hence this necessitates investigation of variations in steam quality as the focal point for sensitivity analysis.

The current sensitivity review is aimed at establishing how closely linked are different characteristics of steam are to performance indicators of SAGD. The most important among these indicators are recovery factor (RF) and steam-oil ratio which give insight into operational success and reservoir behavior respectively.

The research investigates the influence of steam quality incongruities at 0.6, 0.7, and 0.8 proportions on SAGD operations effectiveness. A relative evaluation of steam properties and major performance indicators – namely recovery factor (RF) and steam-oil ratio – is shown in Figure 3.1 by using information obtained from CMG STARS.

The goal of this study is to clarify the complex connection between changes in steam quality during the Steam-Assisted Gravity Drainage (SAGD) process and changes in subsequent recovery performance. Accordingly, it is desired the inquiry to identify how changing steam quality influences retrieval benchmarks that in turn affect the efficacy of SAGD.

Of major importance are the recovery factor and steam-oil ratio as indicators of SAGD operation effectiveness and invaluable insights into reservoir behavior plus operational optimization strategies. The recovery factor indicates a fraction of recoverable hydrocarbons produced from a reservoir and helps in quantifying successes regarding operational efficiency and resource utilization. Similarly, the steam-oil ratio indicates energy consumption as well as process efficiency by showing the quantity of oil produced versus the amount of injected steam.

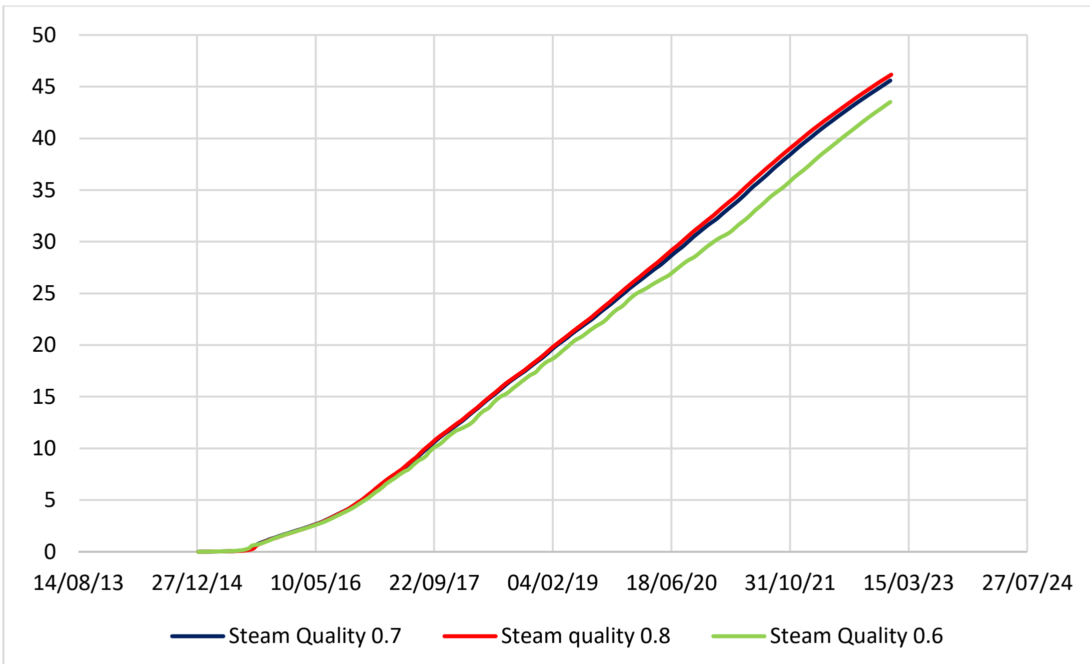


Figure 3.1. Recovery factor for different steam qualities.

As illustrated in the graph, the red line exhibits a superior recovery factor, corresponding to a steam quality of 0.8. Thus, a higher steam quality correlates with an increased recovery factor. Conversely, a contrasting trend is observed in the steam-oil ratio, where higher steam quality corresponds to a lower steam-oil ratio. This phenomenon occurs due to the greater oil production potential under conditions of higher steam quality, as depicted in Figure 3.2.

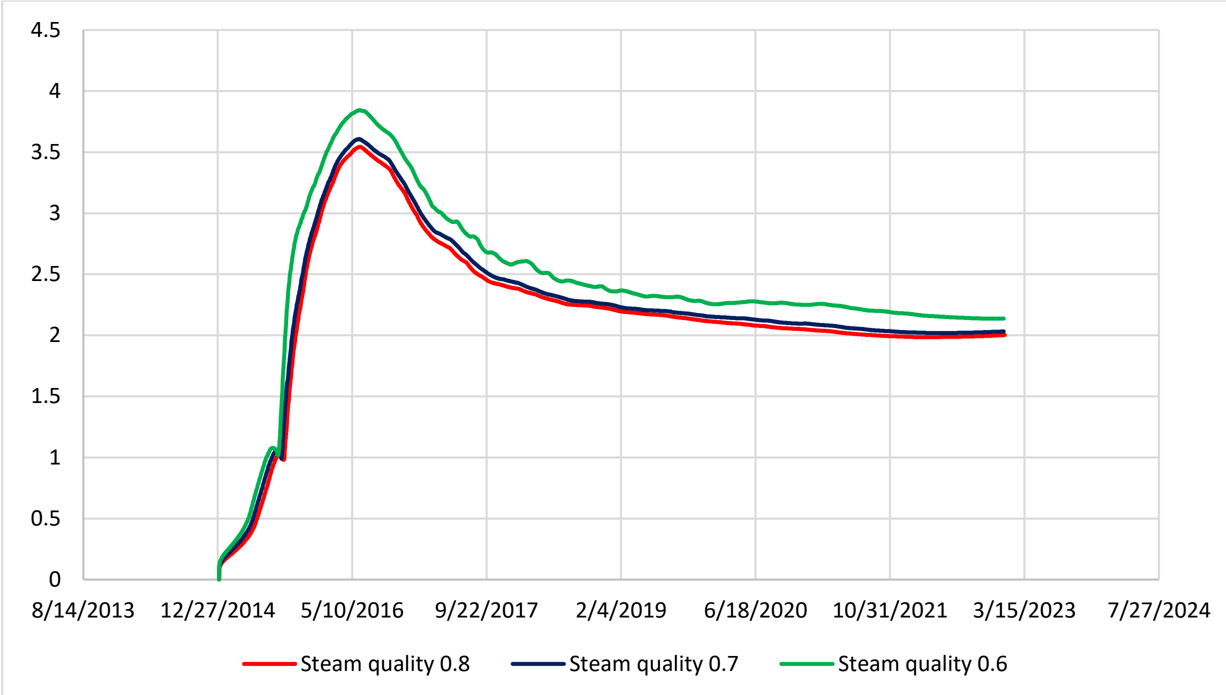


Figure 3.2. The steam-oil ratio for different steam qualities.

To ensure a thorough analysis of the gaps in simulation results, final values obtained from simulations are illustrated in Table 3.2. This table extensively compares some important performance indices across several cases, which can be used to understand the disparity in process recovery due to steam quality changes in SAGD.

Table 3.2. RF, CSOR, and Cumulative Oil Production for different steam qualities

Steam Quality	Final Recovery Factor	Final Cum. Steam-Oil Ratio	Cum. Oil Production, bbl
0.8	**46.16**	**2.003**	**538457.12**
0.7	45.65	2.032	532477.12
0.6	43.58	2.137	508422.03

After establishing the optimal steam quality (0.8), it is imperative to elucidate the maximum injection rate. While theoretically, higher injection rates may result in increased production, it is essential to consider the associated steam consumption. Injecting 400, 500, 600, and 700 barrels per day (bbl/day) of water (maximum constraint) is evaluated, with steam generation adjusted accordingly based on the designated steam quality value. Figures 3.3 and 3.4 show which one is more versatile, of course, more injection led to optimization.

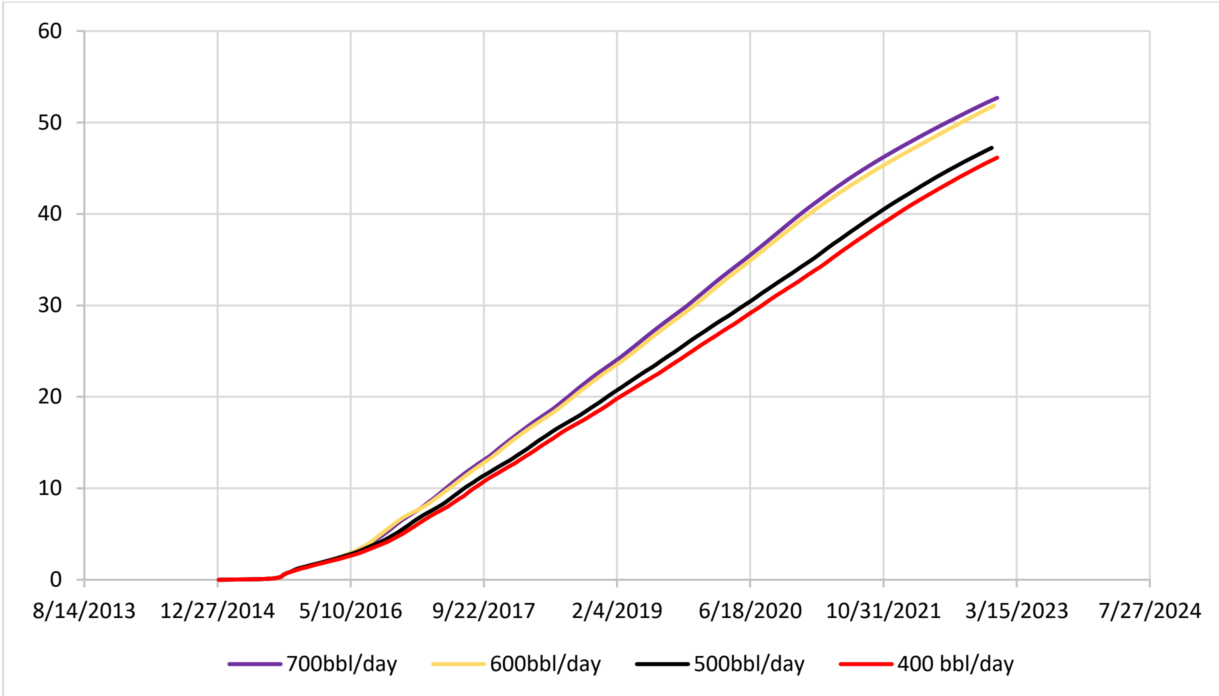


Figure 3.3. Recovery factor for different injection rates.

In terms of economic considerations, the assessment extends beyond the recovery factor alone. With increased consumption leading to a higher steam-oil ratio, operational success is compromised. Figure 3.4 illustrates that the injection rate of 400 bbl/day yields a lower steam-oil ratio. A steam-oil ratio of 3 or lower is deemed acceptable for operational success. While for all rates, this value surpasses 3 annually, it decreases below 3, particularly for the 700 bbl/day scenario during 2015-2017. Hence, the injection rate of 700 bbl/day may be deemed viable, as evidenced by the consistent steam-oil ratio performance compared to the 600 bbl/day rate. Moreover, 700 bbl/day offers the additional advantage of maintaining a lower steam-oil ratio compared to the 600 bbl/day rate.

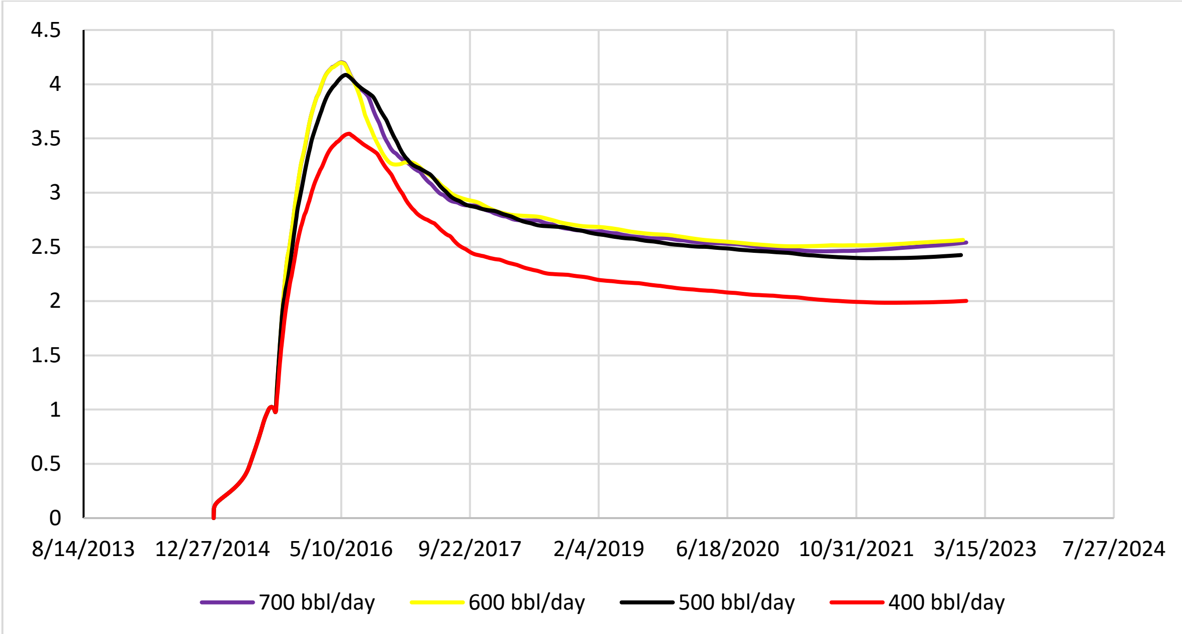


Figure 3.4. Cumulative steam-oil ratio for different injection rates.

Table 3.3. RF and CSOR for different injection rates.

Steam Quality	Injection rate (bbl/day)	Oil Recovery Factor (%)	Cum. Steam-Oil Ratio (bbl/bbl)	Cum. Oil Production, bbl
0.8	400	46.159	2.002	538457.12
	500	47.514	2.428	554441.62
	600	52.015	2.566	606867.43
	700	**52.691**	**2.541**	**614627.5**

Table 3.3 shows how sensitive Steam Assisted Gravity Drainage (SAGD) operations are to variations in both steam quality and injection rate. The first situation had a combination of steam quality and injection rate values that produced a 46.159% recovery factor (RF). Then, there was a significant improvement in SAGD performance as evidenced by the RF increasing from the previous scenario to 52.691% due to systematic changes in steam quality and injection rate parameters.

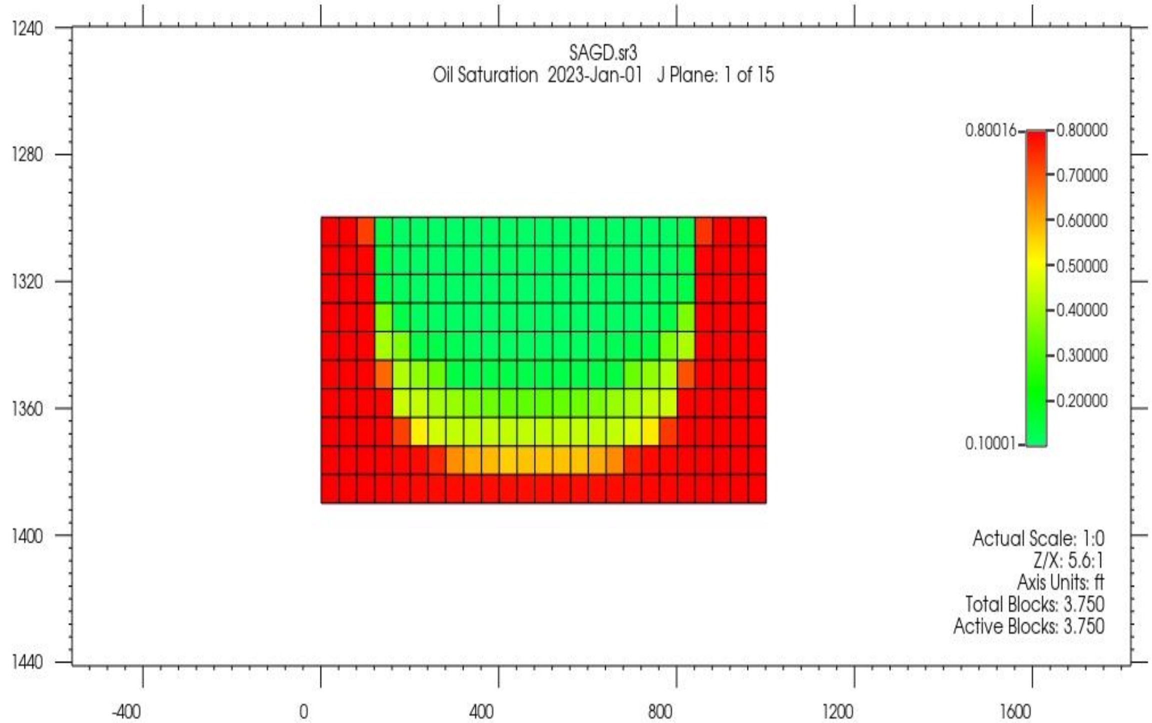


Figure 3.5. Oil saturation at the end of the simulation for steam quality 0.8.

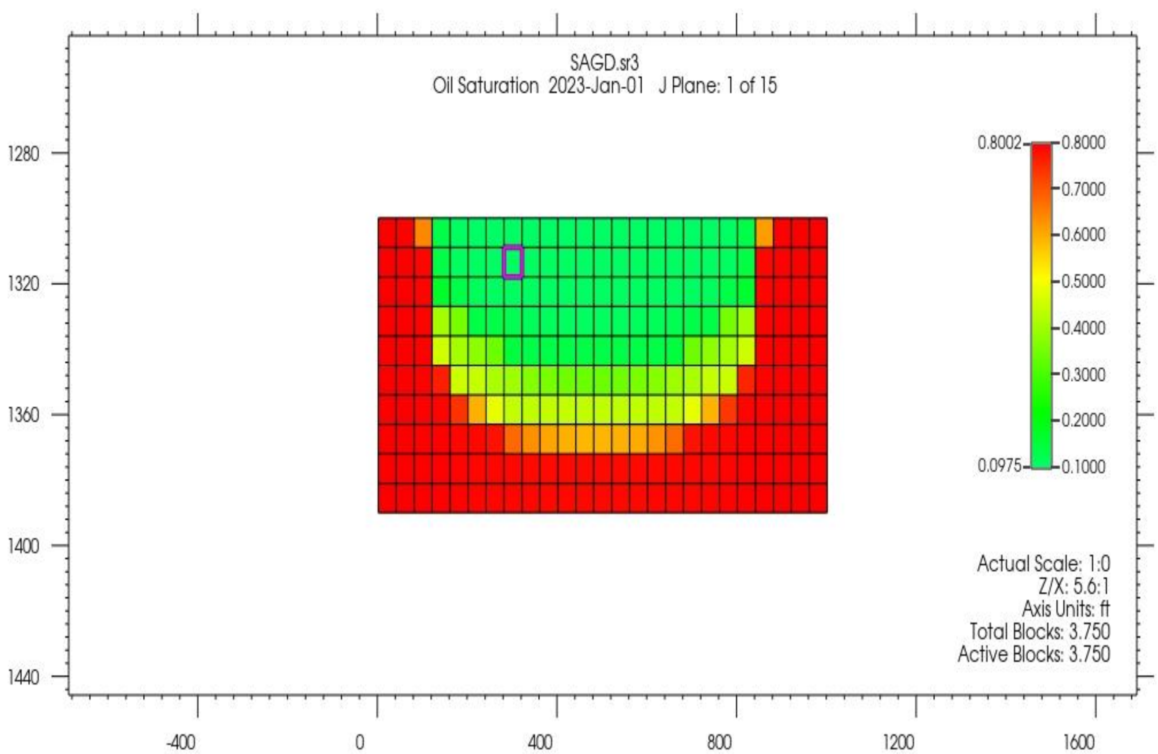


Figure 3.6. Oil saturation at the end of the simulation for steam quality 0.6.

The effects of different steam qualities say 0.8 or 0.6, on the reservoir's surface area, are magnificently shown in Figures 3.5 and 3.6. A higher drainage area corresponds with a high steam quality ratio which is the case in Figure 3.5 while a lower steam quality ratio results in a drainage area of a relatively smaller size illustrated in Figure 4.6.

The need for steam quality in the performance of steam-assisted gravity drainage methods like SAGD can be enhanced because it is significant because of its influence on the size of the drainage area. A higher ratio of steam quality shows that there will be better development of the steam chamber and hence increased heat transfer efficiency within the reservoir thus leading to larger drainage areas where oil can be recovered faster than normal rates would allow for. On the other hand, if this value is less than one then not enough thermal energy will be transferred during the process and also little expansion of the steam chamber occurs thereby limiting both these things together and may restrict drainage area consequently slowing down production levels.

3.2. Category 2 – CSS

In Category 2, attention turns to the second parameter: the soaking period - a period during which the reservoir is allowed to absorb the injected steam before commencing the production phase; this interval is crucial for thermal energy to penetrate deeper into the reservoir to promote the mobilization of heavy oil and facilitate its flow towards production wells.

The initial time cycle for CSS operations in the context of this study consists of a 40-day injection period followed by a 6-day soaking period and culminating in a 60-day production phase, which is then repeated thrice to thoroughly analyze the impacts of different steam qualities on CSS productivity levels.

That can be achieved by varying systematically between different soaking periods and observing their effect on production rates as well as overall recovery efficiencies; from here they can make out what would be considered optimal operational parameters for CSS operations. It is through such detailed analysis that strategies for improving reservoir performance leading to maximum heavy oil recovery should be identified.

Like Category 1, steam quality values of 0.6, 0.7, and 0.8 were assessed to determine the optimal system for this analysis. In this category, permeability type 1 and 2 values are also examined to determine whether CSS is applicable for both higher and lower permeability ranges. Permeability type 1 corresponds to the same model used in SAGD.

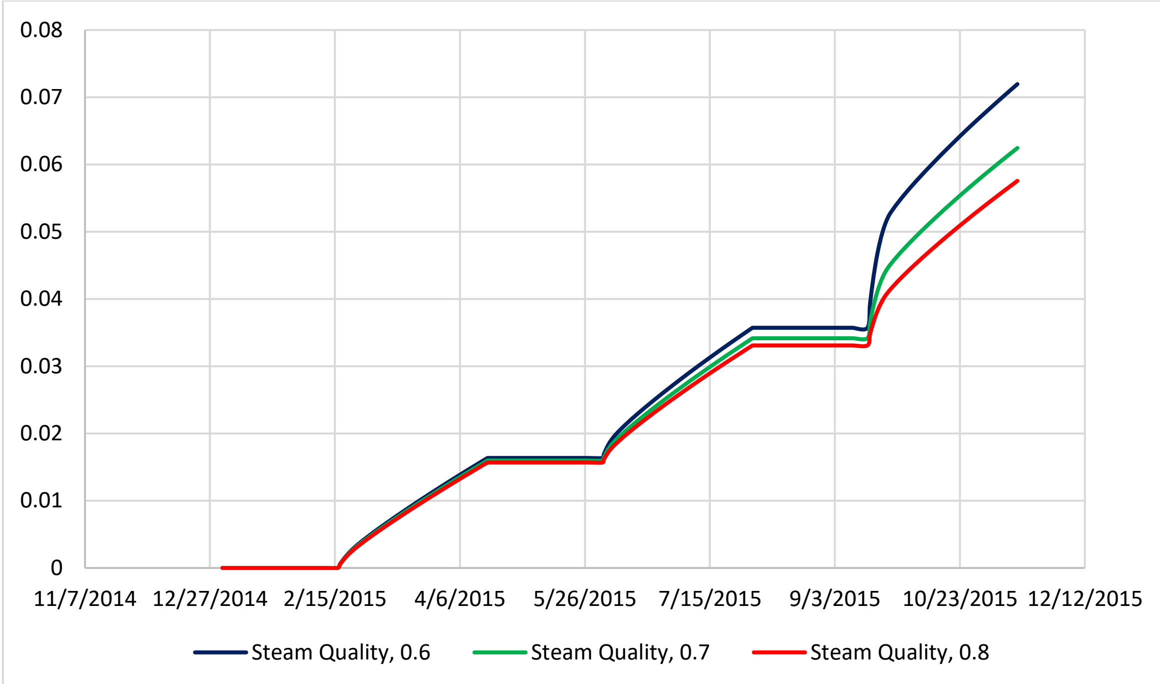


Figure 3.7. Recovery factor for different steam quality ratios.

Figure 3.7 illustrates that higher steam quality does not consistently lead to improved oil recovery. This phenomenon can be attributed to higher oil viscosity ranges, where lower steam quality results in higher water content in the steam-water mixture, consequently leading to enhanced recovery rates in such scenarios.

To ensure favorable performance, cyclic steam stimulation (CSS) is often used in reservoirs with lower viscosity ranges at 5780cp compared to 15780cp. The purpose of this study was to see whether CSS could be applied under these circumstances by changing the viscosity level deliberately. It is because fluids move easily while transferring heat when their viscosities are low thus increasing chances of success during CSS operations.

The experiment involved three consecutive cycles where each cycle consisted of 20 days injection phase followed by 7 soaking period then 60 days production stage which was repeated thrice. This cyclic method enables a comprehensive evaluation of how well CSS works when tried repeatedly under different reservoir conditions.

Simulation results show that CSS is successful under decreased viscosity environments where it can be used in reservoirs with low viscosities. The study noted that an increase in the quality of the steam led to higher levels of oil recovery thus emphasizing its link to the performance of CSS operations.

Two main performance indicators that are necessary for assessing how well a particular kind of CSS system works include Cumulative Oil Production (COP)and Steam-Oil Ratio (SOR). These need to be considered when trying to come up with an effective as well as efficient way to recover crude from well-drilled areas known as reservoirs. It is therefore important that one optimizes the level of steam quality to achieve maximum production at minimum cost through reduced consumption rates.

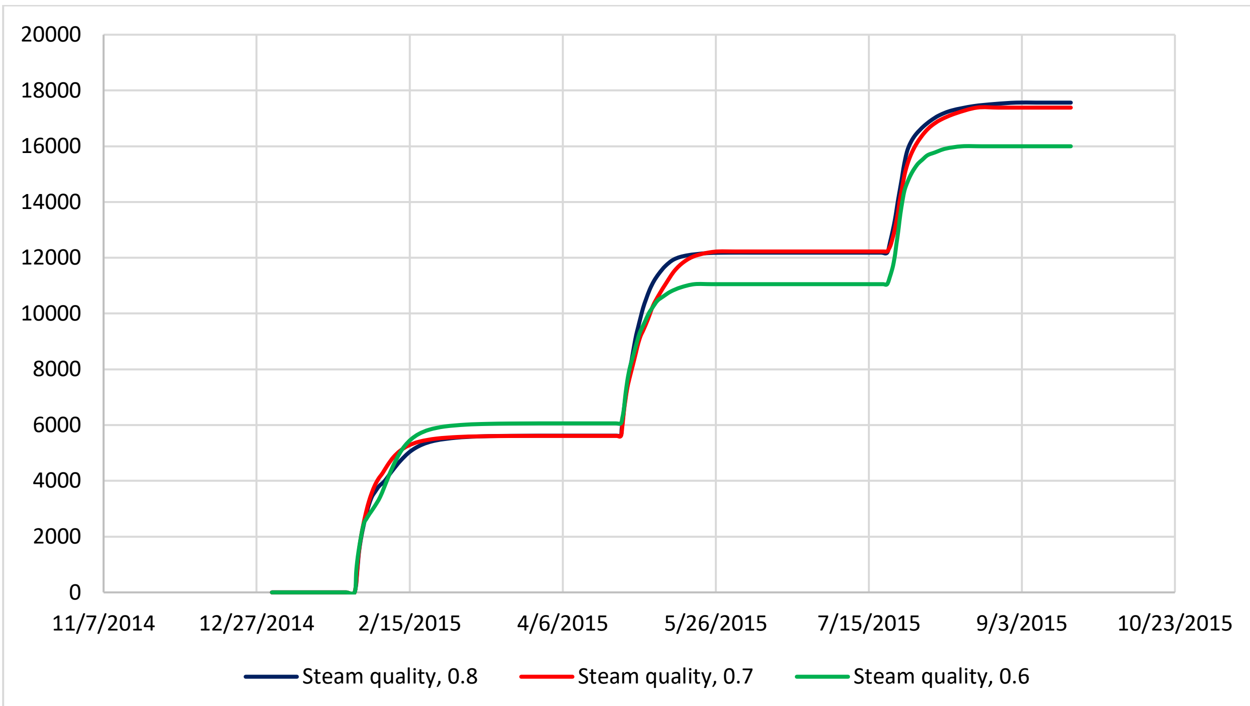


Figure 3.8. Cumulative oil production for different steam quality ratios.

Table 3.4. CSOR and Cumulative Oil Production for different steam qualities

Steam Quality	**Final Cum. Steam-Oil Ratio**	**Cum. Oil Production, bbl**
0.8	**0.794**	**17564.55**
0.7	0.845	17385.36
0.6	0.845	15998.71

Both Figure 3.8 and Table 3.4 make it clear that steam quality is essential when trying to get the most out of oil production during our analysis. They show without a doubt that the highest oil production levels achieved in this study were linked with an optimal steam quality set at 0.8.

The subsequent phase after recognizing the finest steam quality is finding the best soaking duration to increase the effectiveness of oil recovery in methods using heat in the likes of CSS. The periods required for soaking have been tested between 4 and 7 days.

The shorter the duration for soaking theoretically, the higher the rates of oil recovery. The origin of this thought is that lower time periods heat reservoirs for a short while thus reducing their cooling effects allowing continued transfer of thermal energy at substantial rates because mass action which leads to oil movement is sustained. Hence temperatures within operational limits should also be maintained towards which end they should be made constant throughout those periods during which soakings occur so as to keep fluids mobile thereby guaranteeing improved recovery rates for oils.

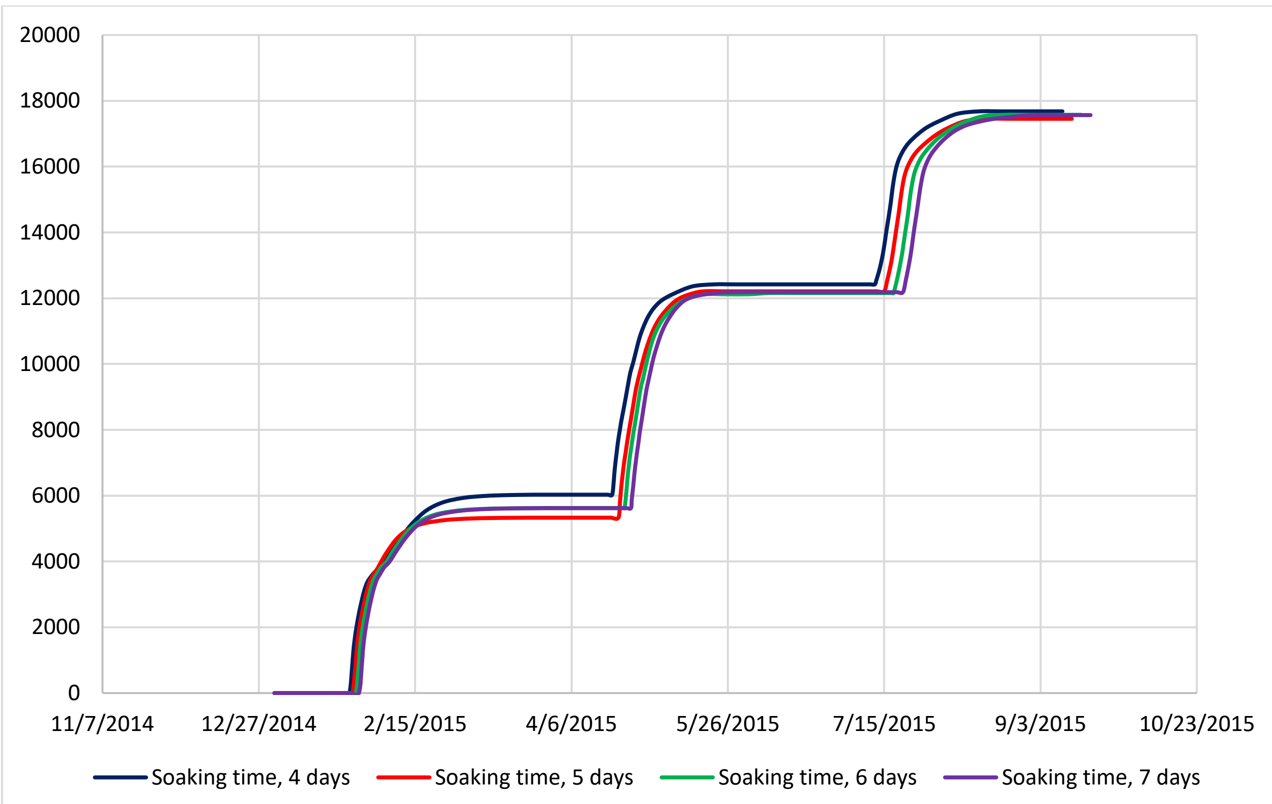


Figure 3.9. Cumulative oil production for different soaking times.

Table 3.5. CSOR and Cumulative Oil Production for different soaking times.

Steam Quality	Soaking time (day)	Cum. Oil Production, bbl	Final CSOR (bbl/bbl)
0.8	**4**	**17678.91**	**0.782**
	5	17452.86	0.799
	6	17573.42	0.793
	7	17564.56	0.794

Figure 3.9 and Table 3.5 illustrate that shorter soaking times generally lead to higher oil recovery and lower steam-oil ratios for CSS applications. However, it is noteworthy that a soaking time of 5 days appears to have a contrasting effect, deviating from this trend.

CONCLUSION

Based on the simulations conducted in CMG STARS, it's evident that various parameters, including steam quality, injection rates, and soaking time, play crucial roles in the effectiveness of steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) methods.

1. Steam Quality. Higher steam quality leads to higher oil recovery and lower steam-oil ratios for both models. This suggests that increasing steam quality can generally be utilized to optimize these methods. In Category 1, the reservoir exhibits higher viscosity rendering the CSS model ineffective. Therefore, increasing steam quality may not yield significant benefits. However, the main objective is to modify these parameters to analyze the sensitivity of CSS to steam quality and soaking time. 0.6, 0.7, and 0.8 ratios of steam quality are assessed, and the results showed that the 0.8 ratio is the best option among them.

2. Injection rate also plays a crucial role, as a higher injection rate correlates with a higher recovery factor. This is because more steam injected into the reservoir affects a larger area. Notably, at 700 bbl/day, the maximum ratio under 950 psi, a significant increase in oil production was observed.

3. Soaking time is a critical factor in CSS feasibility for the reservoir. Lower soaking times generally result in higher oil production. In the evaluation conducted using soaking times of 4, 5, 6, and 7 days in the software, the results align with theoretical expectations.

Numerical simulation also shows that SAGD is more applicable for this kind of reservoir. Because CSS is limited in this reservoir. In the CSS method, injection is conducted in a periodic way which is the reason 1100 psi is not enough to inject sufficient steam into the reservoir.

REFERENCES

1. Adam S. (2016). Breakthrough Solvent Tech Promises Benefits for Oil Sands. Retrieved from https://www.vistaprojects.com/solvent-technology-promises-oil-sands-benefits/
2. Ado, M. R., Greaves, M., & Rigby, S. P. (2018). Effect of pre-ignition heating cycle method, air injection flux, and reservoir viscosity on the THAI heavy oil recovery process. Journal of Petroleum Science and Engineering, 166, 94–103.
3. Aguilar, M. G., Mares, E., Cabra, C. M., & Peralta, O. O. (2014). CSS Performance in Sands of Samaria Tertiary Field, Mexico. Paper presented at the SPE Heavy and Extra Heavy Oil Conference: Latin America, Medellín, Colombia.
4. Ali, S. M. C. S. (1994). Canada's super strategy for oil sands. J Can Pet Technol, 33(9), 16-19.
5. Allenson, S.J., Yen, A.T., Lang, F. (2011). Application of emulsion viscosity reducers to lower produced fluid viscosity. Offshore Technology Conference, vol. 22443.
6. Alvarez, J., & Han, S. (2013). Current overview of cyclic steam injection process. Journal of Petroleum Science and Research, 2. Retrieved from https://www.academia.edu/26208229/Current_Overview_of_Cyclic_Steam_Injection_Process.
7. Arpaci, B. (2014). Development of an Artificial Neural Network for Cyclic Steam Stimulation Method in Naturally Fractured Reservoirs (Electronic thesis and dissertations for Graduate School).
8. Athabasca Oil Corporation. (2020). Athabasca Oil Corporation AER Hanging Stone Project Update.
9. Atia, A., & Mohammedi, K. (2018b). A Review on the Application of Enhanced Oil/Gas Recovery through CO2 Sequestration. InTech eBooks. https://doi.org/10.5772/intechopen.79278
10. Bagci, S., & Aybak, T. (1998). A Laboratory Study of Combustion Override Split-split-production Horizontal Well (COSH) Process. In Annual Technical Meeting. Petroleum Society of Canada.
11. Bao, Y., Wang, J., & Gates, I. D. (2012). History match of the Liaohe oilfield SAGD operation vertical-horizontal well reservoir production machine. In SPE Heavy Oil Conference Canada. Calgary.

12. Barillas, J. L. M., Dutra Jr., T. V., & Mata, W. (2008). Improved Oil Recovery Process for Heavy Oil: A Review. Brazilian Journal of Petroleum and Gas, 2(1), 45-54.

13. Bettembourg, S., Holyoak, S., Alwazeer, A., Manhali, M., Rawahi, M., & Habsi, A. (2016). Key learnings from the first 2 years of a full field CSS development in Oman. Paper presented at the SPE EOR Conference at Oil and Gas West Asia, Muscat, Oman.

14. Blevins, T. R., & Billingsley, R. H. (1975). The ten-pattern steam flood, Kern River Field, California. Journal of Petroleum Technology, 27(12), 1505–1514.

15. BP. (2015). Statistical Review of World Energy 2015.

16. Butler, R. M. (2001). Some Recent Developments in SAGD. Journal of Canadian Petroleum Technology, 40(1), 18–22. DOI: 10.2118/01-01-DAS.

17. Butler, R. M. (2004). The behavior of non-condensable gas in SAGD-A rationalization. Journal of Canadian Petroleum Technology, 43(01), 28–34.

18. Butler, R. M., & Jiang, Q. (2000). Improved Recovery of Heavy Oil by Vapex with Widely Spaced Horizontal Injectors and Producers. Petroleum Society of Canada. DOI: 10.2118/00-01-04.

19. Card, C. C., Kumar, A., Close, J. C., Kjosavik, A., Agustsson, H., & Picone, M. M. (2014). A new and practical workflow for large multipad SAGD Simulation—An Oil-Sands case Study. Journal of Canadian Petroleum Technology, 53(01), 14–31. https://doi.org/10.2118/165511-pa

20. Cenovus Energy. (2016). Cenovus Foster Creek in-situ oil sands scheme (8623) update for 2015.

21. Chao, K., Chen, Y., Liu, H., Zhang, X., & Li, J. (2012). Laboratory Experiments and Field Test of a Difunctional Catalyst for Catalytic Aquathermolysis of Heavy Oil. Energy Fuels, 26, 1152−1159.

22. Chopra, S., & Lines, L. (2008). Introduction to this special section: heavy oil. The Leading Edge, 27(9), 1104–1106. DOI: 10.1190/1.2978971.

23. CMG STARS Manual. (2021). Computer Modelling Group Ltd.

24. Das, S. K. (1998). Vapex: An Efficient Process for the Recovery of Heavy Oil and Bitumen. Society of Petroleum Engineers. DOI: 10.2118/50941-PA.

25. Delamaide, E. (2018). Senlac, the Forgotten SAGD Project. SPE J., 21(03), 789–805. DOI: 10.2118/183721-PA.

26. Dong, X., Liu, H., Chen, Z., Wu, K., Lu, N., & Zhang, Q. (2019). Enhanced oil recovery techniques for heavy oil and oilsands reservoirs after steam injection. Applied Energy, 239, 1190–1211. DOI: 10.1016/j.apenergy.2019.01.244.

27. Doraiah, A., Ray, S., & Gupta, P. (2007). In-situ combustion technique to enhance heavy oil recovery at Mehsana. ONGC-a success story SPE, vol. 105248.

28. Dusseault, M., Davidson, B., & Spanos, T. (2000). Pressure Pulsing: The Ups and Downs of Starting a New Technology. J Can Pet Technol, 39(4). PETSOC-00-04-TB. DOI: http://dx.doi.org/10.2118/00-04-tb.

29. Edmunds, N., Barrett, K., Solanki, S., & Cimolai, M. (2009). Prospects for commercial bitumen recovery from the Grosmont carbonate, Alberta. J Can Petrol Technol, 48(9), 26–32.

30. ExxonMobil. (2018). 2018 Outlook for Energy: A View to 2040.

31. ExxonMobil. (2019). 2019 Outlook for Energy: A Perspective to 2040.

32. Ezekwe, N. (2010). Petroleum reservoir engineering practice. Pearson Education.

33. Flory, P. J. (1953). Principles of Polymer Chemistry. Ithaca: Cornell University Press.

34. Ganat, Tarek. (2019). Pumping System of Heavy Oil Production. In Processing of Heavy Crude Oils -Challenges and Opportunities, Ramasamy Marappa Gounder (Ed.). IntechOpen. DOI: 10.5772/intechopen.87077. Available from: https://www.intechopen.com/books/processing-of-heavy-crude-oils-challenges-and-opportunities/pumping-system-of-heavy-oil-production.

35. Gao, Y.R., Liu, S.Q., Shen, D.H., & Guo, E.P. (2009). Optimization of N2 injection technology during steam-assisted gravity drainage process. Acta Petroleum Sinica, 30(5), 717–721. (in Chinese with English abstract)

36. Georgie, W. J., & Smith, P. C. (2012). The Challenges in Processing Heavy Oil. Society of Petroleum Engineers. DOI:10.2118/157894-MS.

37. Gibson, B.J. (1982). Methods of Classifying Heavy Crude Oils Using the UNIT AR Viscosity Based Definition. Proc., Second Intel. UNIT AR Future of Heavy Crude and Tar Sands Conference, Caracas (pp. 17-21).

38. Greaves M. (2000). Upgrading Athabasca tar sand using toe-to-heel air injection. In: SPE/CIM International Conference on Horizontal Well Technology. Society of Petroleum Engineers.

39. hakur, N. K., & Rajput, S. (2011). World’s oil and natural gas scenario. In the exploration of gas hydrates. Springer, Berlin, Heidelberg.

40. Haldar, Swapan Kumar. (2018). Chapter 12 - Elements of Mining. In Swapan Kumar Haldar (Ed.), Mineral Exploration (Second Edition), Elsevier, 229-258. https://doi.org/10.1016/B978-0-12-814022-2.00012-5.

41. Hasibuan MY et al. (2020). Electrical Heating for Heavy Oil: Past, Current, and Future Prospect. DOI:10.20944/preprints202001.0115.v1.

42. Heidary S, Dehghan AA, Mahdavi S. (2017). Feasibility study on the application of the recent enhanced heavy oil recovery methods (VAPEX, SAGD, CAGD, and THAI) in an Iranian heavy oil reservoir. Pet Sci Technol, 35(21), 2059–2065.

43. Hinkle, A., Batzle, M. (2006). Heavy oils: A worldwide overview. The Leading Edge, 25: 742-749. https://doi.org/10.1190/1.2210073;

44. Hocking, G., Cavender, T. W., & Person, J. (2011). Single-Well SAGD: Overcoming Permeable Lean Zones and Barriers. In Canadian Unconventional Resources Conference, Calgary, 15-17 November 2011. DOI:10.2118/148832-MS.

45. Hoffman L. (2014). The anatomy of cyclic steaming. [Internet]. Available from: https://www.independent.com/news/2014/jun/26/anatomy-cyclic-steaming/;

46. Hu, L.M. (2014). Drilling and Completion Technology in Double Horizontal Wells of SAGD in Fengcheng heavy oil [PhD thesis, Southwest Petroleum University]. (in Chinese with English abstract)

47. Huang, S., Chen, X., Liu, H., Jiang, J., Cao, M., & Xia, Y. (2018). Experimental and numerical study of solvent optimization during horizontal-well solvent-enhanced steam flooding in thin heavy-oil reservoirs. Fuel, 228, 379–389. doi:10.1016/j.fuel.2018.05.001

48. Xia, T. X., & Greaves, M. (2002). Upgrading Athabasca tar sand using toe-to-heel air injection. J Can Pet Technol, 41(08).

49. Xiaohu Dong, Huiqing Liu, Zhangxin Chen, Keliu Wu, Ning Lu, Qichen Zhang. (2019). Enhanced oil recovery techniques for heavy oil and oilsands reservoirs after steam injection. Applied Energy, Volume 239. https://doi.org/10.1016/j.apenergy.2019.01.244

50. Xue, Liang, Liu, Pengcheng, & Zhang, Yun. (2022). Development and Research Status of Heavy Oil Enhanced Oil Recovery. Geofluids, 2022, 1-13. https://doi.org/10.1155/2022/5015045.

51. Imperial Oil. (2014). Cold Lake Approvals 8558 and 4510. 2014 Annual Performance Review.

52. Jamali, A. (2014). Unconsolidated Oil Sands: Vertical Single Well SAGD Optimization [Ph.D. thesis, Texas Tech University].

53. Kasraie, M., Singhal, A. K., & Ito, Y. (1997). Screening and design criteria for Tangle flags type reservoirs. In International Thermal Operations and Heavy Oil Symposium, Bakersfield, California, 10-12 February 1997. doi:10.2118/37571-MS.

54. Kirmani, F. U. D., Raza, A., Gholami, R., Haidar, M. Z., & Fareed, C. S. (2021). Analyzing the effect of steam quality and injection temperature on the performance of steam flooding. Energy Geosci., 2, 83–86. doi:10.1016/j.engeos.2020.11.002

55. Kisman, K. E., & Lau, E. C. (1994). A new combustion process utilizing horizontal wells and gravity drainage. J Can Pet Technol., 33(03).

56. Lau, E. C., & Kisman, K. E. (1994). Attractive control features of the Combustion Override Split Production Horizontal Well process in a heavy oil reservoir. In: Annual Technical Meeting. Petroleum Society of Canada.

57. Li, H.Z., Xiong, B., Zhang, H., & Gong, X.Y. (2017). Technical review on the development of single-well SAGD in foreign heavy oil reservoirs. Nat. Gas and Oil, 35(1), 84–88. (in Chinese with English abstract)

58. Li, L. (2014). The applicability study for SAGD in the thin super heavy oil reservoir [PhD thesis, China University of Petroleum (East China)]. (in Chinese with English abstract)

59. Li, R., Chen, Z.X., Wu, K.L., Dong, X.H. (2020). Review on the effective recovery of SAGD production for extra and super heavy oil reservoirs. Sci. Sinica Technol. 50(6), 729–741.

60. Liu, H.Q. (2013). Principle and design of thermal oil recovery processes. Petroleum Industry Press.

61. Liu, X., Flemings, P.B. (2015). Capillary effects on hydrate stability in marine sediments. J Geophs Res 116: B07102.

62. Liu, S., Bao, L., Ma, D. (1999). New Technology Study for the Development of a SuperHeavy Oil Reservoir in Liaohe Oil Field. Pet Explore Dev. 26, 80–81.

63. Lyons, W.C., Plisga, G.J. (2011). Standard handbook of petroleum and natural gas engineering. Elsevier.

64. Maiullari, G. (2011). Gas shale reservoir: characterization and modeling play shale scenario on wells database. ENI Corporate University.

65. Mansour, E. M. I. (2022). Carbon Dioxide-Oil Minimum Miscibility Pressure Methods Overview. In IntechOpen eBooks. https://doi.org/10.5772/intechopen.106637

66. McGee, B.C.W., Vermeulen, F.E., Yu, C.L. (1996). Electrical Heating with Horizontal and Vertical Wells. Annual Technical Meeting.

67. Nasr, A., Isaacs, E.E. (2001). Oil phase viscosity behavior in Expanding-Solvent Steam-Assisted Gravity Drainage.

68. Nehring, R., Hess, R., Kamionski, M. (1983). The heavy oil resources of the United States. Research Report R-2946-DOE, The U.S. Department of Energy.

69. Nmegbu, C.G.J., Pepple, D.D. (2017). 2-Dimensional Modeling of Hot Water Injection Application in Thermal Recovery Processes, (A Frontal Advance Approach)

70. Novak, J., Edmunds, N., Cimolai, M. (2007). A history match of CSS Recovery in the Grosmont. Paper presented at the Canadian International Petroleum Conference, Calgary, Alberta, June 12–14, 2007.

71. Ovalles, C., Rivero, V., Salazar, A. (2015). Downhole Upgrading of Orinoco Basin Extra-Heavy Crude Oil Using Hydrogen Donors under Steam Injection Conditions. Effect of the Presence of Iron Nanocatalysts. Catalysts, 5, 286-297.

72. Patarroyo, M., Carvajal, G., Milena, Q., Urdaneta, J., Gomez, A., Pacheco, J. (2014). New art of building horizontal and highly deviated wells help maximize recovery and production from heavy oil fields in Colombia. SPE 170009 presented at the SPE heavy oil conference-Canada, Calgary, Alberta, Canada, 10–12 June.

73. Putra, E. A. P., Rachman, Y. A., Firmanto, T., Arsyadanie, R., & Hafizh, G. (2011). Case Study: Cyclic Steam Stimulation in Sihapas Formation. SPE Asia Pacific Oil and Gas Conference and Exhibition.

74. Rahnema, H., Barrufet, M., Mamora, D.D. (2017). Combustion-assisted gravity drainage–Experimental and simulation results of a promising in-situ combustion technology to recover extra-heavy oil. J Pet Sci Eng. 154:513–520.

75. Ratner, M., Tiemann, M.E. (2014). An Overview of Unconventional Oil and Natural Gas: Resources and Federal Actions.

76. Rodriguez Hernandez, I., Velazquez, R., Hernandez, E., Salazar, L., Terán, Y., Martínez, R., Correa Chacon, D., Korabelnikov, A., Gobert, K. (2016). Reservoir Characterization of Morichal Member in the Cerro Negro Field. Challenges and Opportunities in an Extra Heavy Oil Field in the Orinoco Oil Belt, Venezuela. Calgary, Canada. WHOC16-426.

77. Santos, R.G., Loh, W., Bannwart, A.C., Trevisan, O.V. (2014). An overview of heavy oil properties and its recovery and transportation methods. Brazilian J. Chem. Eng., 31(3), 571–590.

78. Sarathi, P. (2009). In-Situ Combustion Handbook Principles and Practices. Report DOE/PC/91008-0374, OSTI ID 3175 (January).

79. Satinder, Larry. (2008). Heavy Oils: Reservoir Characterization and Production Monitoring.

80. Shandrygin, Al., Lutfullin, A. (2008). Current status of enhanced recovery techniques in the fields of Russia. SPE 115712 presented at the SPE annual technical conference and exhibition, Denver, Colorado, USA, September 21–24.

81. Sheng, J. (2013). Enhanced oil recovery field case studies. Waltham, Mass.: Elsevier.

82. Shin, H., & Polikar, M. (2007). Review of reservoir parameters to optimize SAGD and Fast-SAGD operating conditions. J. Can. Petroleum Technol. 46. doi:10.2118/07-01-04

83. Speight, James G. (2013). Heavy oil production processes. Gulf Publishing Company.

84. Stinson, D. L., Carpenter, H. C., & Cegielski Jr, J. M. (1976). Power recovery from in-situ combustion exhaust gases. J. Pet. Technol., 28(06), 645–650.

85. Sun, F., Yao, Y., Chen, M., Li, X., Zhao, L., Meng, Y., et al. (2017). Performance analysis of superheated steam injection for heavy oil recovery and modeling of wellbore heat efficiency. Energy, 125, 795–804. doi:10.1016/j.energy.2017.02.114

86. Suncor. (2018). Suncor MacKay River Project 2017 AER Performance Presentation. 24 October 2018.

87. Tao, L., Li, Z. M., Bi, Y. Q., Li, B., Zhang, J. (2010). Multi-combination exploiting the technique of ultra-heavy oil reservoirs with deep and thin layers in Shengli Oilfield. Pet. Explore. Dev. 37(6), 732–736.

88. Tavallali, M., Maini, B. B., Harding, T. G., Busahmin, B. (2012). Assessment of SAGD Well Configuration Optimization in Lloydminster Heavy Oil Reserve, in SPE/EAGE European Unconventional Resources Conference and Exhibition, Vienna, 20-22 March 2012. doi:10.2118/153128-MS.

89. Theloy, Cosima, & Sonnenberg, Stephen A. (2013). Integrating Geology and Engineering: Implications for Production in the Bakken Play, Williston Basin.

90. Thomas, S. (2008). Enhanced oil recovery—An overview. Oil & Gas Science and Technology-Revue de l'IFP, 63(1), 9-19.

91. Tian, H. Z., & Sun, Y. (2013). Operation parameters optimization of steam flooding with the combination of vertical and horizontal wells. Lithol. Reserv., 25(3), 127–130. (in Chinese with English abstract)

92. U.S. Energy Information Administration. (n.d.). Analysis & Projections. Retrieved from http://www.eia.gov/analysis/studies/worldshalegas/.

93. United States Department of Energy. Cyclic steam stimulation production process. USDOE, Washington, DC (accessed 2021).

94. USGS. (2007). Global Heavy Oil and Bitumen Reserves and Production.

95. Valbuena, O. H., Bernal, M. E., Ramon, J. C., Tian, X. (2014). First extra-heavy-oil development in Caguan-Putumayo Basin, Colombia, Capella Field. SPE 171077 presented at the SPE heavy and extra heavy oil conference: Latin America, Medellín, Colombia, September 24–26.

96. Vinsome, K., McGee, B. C. W., Vermeulen, F. E., & Chute, F. S. (1994). Electrical heating. J. Can. Pet. Technol., 33(04).

97. Voskov, D. (2016). Heavy oil recovery efficiency using SAGD, SAGD with propane co-injection, and STRIP-SAGD. Volume 88, 8(5), 115-125.

98. Wallmann, K., & Schicks, J. M. (2018). Gas Hydrates as an Unconventional Hydrocarbon Resource. In H. Wilkes (Ed.), Hydrocarbons, Oils and Lipids: Diversity, Origin, Chemistry and Fate. Handbook of Hydrocarbon and Lipid Microbiology. Springer, Cham. https://doi.org/10.1007/978-3-319-54529-5_20-1

99. Wallmann, K., Pinero, E., Burwicz, E., Haeckel, M., Hensen, C., Dale, A., & Ruepke, L. (2012). The global inventory of methane hydrate in marine sediments: a theoretical approach. Energies, 5, 2449–2498.

100. Wang, J. H. (2018). Homogeneous Steam Injection Technology in Horizontal Wells. PhD thesis. China University of Petroleum (Beijing), 76 pp. (in Chinese with English abstract).

101. Wang, Y. Y., Zhang, L., Deng, J. Y., Wang, Y. T., Ren, S. R., & Hu, C. H. (2017). An innovative air-assisted cyclic steam stimulation technique for enhanced heavy oil recovery. J. Pet. Sci. Eng., 151, 254–263.

102. Wang, Y., Wang, X., Xing, Y., Xue, J., & Wang, D. (2017). Three-dimensional numerical simulation of enhancing shale gas desorption by electrical heating with horizontal wells. J. Nat. Gas Sci. Eng., 38, 94–106.

103. Wang, Z. Z., Li, Z. M., Lu, T., Yang, J. P., & Wang, H. Y. (2019). Visualization and mechanism analysis of the flue gas action in the steam chamber. Spec. Oil Gas Reservoirs, 26(2), 136–140.

104. Wen, S., Zhao, Y., & Liu, Y. (2007). A Study on Catalytic Aquathermolysis of Heavy Crude Oil during Steam Stimulation. Presented at 2007 SPE International Symposium Oilfield Chemistry, Houston, TX, USA, 28 February–2 March 2007.

105. Williams, L. L., Fong, W. S., & Mridul, K. (2001). Effects of discontinuous shales on multizone steam flood performance in the Kern River Field. SPE Reservoir Eval Eng, 4(5), 350–7.

106. Yalgın, G. (2017). Development of a screening model for the cyclic steam injection (CSI) process [Master's thesis, Middle East Technical University].

107. Yao, J., Li, G., & Wu, J. (2018). Application of In-situ combustion for heavy oil production in China: A Review. J Oil Gas Petrochem Sci., 1(3), 69–72. DOI: 10.30881/jogps.00014.

108. Zargar, Z., & Ali, S. M. F. (2018). Analytical modeling of steam chamber rises stage of Steam-Assisted Gravity Drainage (SAGD) process. Fuel, 233, 732–742.

109. Zhang, M. B. (2014). Research on SAGP Technology Development for Super Heavy Oil in Guontao reservoir of Block 8. Ph.D. thesis. Northeast Petroleum University (in Chinese with English abstract).

110. Zhao, David W., & Gates, Ian D. (2015). On hot water flooding strategies for thin heavy oil reservoirs. Fuel, 153, 559-568.

111. Zou, C. (2013). Unconventional Continuous Petroleum Accumulation. In C. Zou (Ed.), Unconventional Petroleum Geology. Elsevier, 27-60. DOI: 10.1016/B978-0-12-397162-3.00002-5.