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THERMAL OIL RECOVERY METHODS

Study Guide

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This study guide aligns with the modern curriculum of petroleum engineering and complements courses such as Thermal Oil Recovery Methods and Enhanced Oil Recovery Techniques. It offers a concise overview of key concepts, along with detailed explanations of essential terms and engineering principles. Designed for university students, graduate candidates, and educators, this resource aims to provide a solid foundation in the principles and applications of thermal oil recovery.

This study guide is intended for students in master's program 21.04.01 – Petroleum Engineering, discipline "Enhanced Oil Recovery Methods" and full-time bachelor's program 21.03.01 "Petroleum Engineering".

The book was developed and edited at the Department of Petroleum Engineering in collaboration with the PJSC Tatneft.

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1. Introduction

"Good prose is like an iceberg: "seven-eighths of it is underwater for every part that shows"

Ernest Miller Hemingway

Each technology is effective in specific geological and technological conditions. Each stage of field development or well operation is characterized by specific problems, the solution of which is the key to efficient field development where the main target is the selection of appropriate technologies and their integration.

The basic principle of integration is that the weaknesses of one (previous) technology should be compensated by the strengths of another (subsequent) technology.

By strategically combining various technologies, it is possible to address the diverse and complex issues that arise during different phases of field development. This integrated approach not only optimizes resource utilization but also maximizes the recovery of hydrocarbons, ensuring both economic and operational efficiency.

2. Enhanced Oil Recovery Methods: General Aspects and Classification

Depending on the producing life of a reservoir, oil recovery operations can be divided into three phases: primary, secondary, and tertiary [1]. Primary recovery is generally yielded by natural drive energy initially available in the reservoir, including rock and fluid expansion, solution gas, water influx, gas cap, and gravity drainage. In this stage, no injection of any extra fluids or heat is required. The displacement by these natural energies can recover only a limited amount of crude oil from the reservoir. Secondary recovery methods involve injecting external fluids, typically water or gas, to maintain reservoir pressure and enhance volumetric sweep efficiency. This stage follows primary recovery, which relies solely on natural reservoir energy. Subsequent recovery efforts beyond secondary recovery are termed tertiary recovery, or enhanced oil recovery (EOR). Tertiary recovery employs various techniques aimed at boosting oil production, including the injection of specialized fluids like chemicals, miscible gases, or thermal energy. These advanced methods help to mobilize the remaining oil, making it easier to extract and significantly increasing the overall recovery from the reservoir.

Enhanced oil recovery (EOR) techniques refer to the injection of gases, chemicals, thermal energy, or their combination into reservoir. Enhanced oil recovery (EOR) techniques are versatile and can be implemented at any stage of a reservoir's life cycle. Unlike primary recovery, which relies solely on the reservoir's natural energy to drive oil to the production wells, EOR methods introduce additional energy into the reservoir to facilitate oil extraction. This is particularly beneficial during the initial development phase of an oilfield when natural energy is insufficient to sustain oil flow, such as in the case of thermal flooding for heavy oil reservoirs. The primary goal of EOR is to boost oil production from reservoirs that are either in the early stages of development or have already undergone primary recovery, ensuring maximum extraction efficiency. It is worth noting that, following primary production, and sometimes even prior to it, various stimulation techniques like fracturing and acidizing can be employed to modify reservoir properties and enhance operating conditions. These treatments, however, do not introduce additional energy into the reservoir; they merely optimize the existing natural energy for better production. Consequently, such techniques do not fall under enhanced oil recovery (EOR) methods, except in certain debatable scenarios. Instead, these are typically classified as improved oil recovery (IOR) methods.

In the petroleum industry today, the term IOR is broadly accepted and encompasses a wide range of techniques aimed at boosting oil recovery, beyond the primary processes. EOR is considered a subset of IOR. IOR techniques include, but are not limited to, EOR processes, near-wellbore conformance control (such as profile control and water or gas shutoff), immiscible gas injection, water injection, cyclic water injection, and various well stimulation methods including acidizing and fracturing. Essentially, IOR represents any approach designed to improve oil recovery by enhancing the effectiveness of the natural reservoir energy, optimizing fluid flow, or improving reservoir management practices.

EOR techniques employ external forces and substances to modify the chemical and physical interactions within oil and gas reservoirs, creating conditions that enhance oil recovery. These methods have the potential to convert previously unrecoverable and contingent reserves into producible quantities, often surpassing the volumes of oil currently being extracted. This makes EOR a powerful tool for maximizing the output of existing reservoirs.

Over the past fifty years, numerous EOR methods have demonstrated their effectiveness in enhancing field development. Since 1959, nearly a thousand EOR projects have been initiated, yet their global application remains relatively limited. The adoption and expansion of any recovery technique on a broad scale hinge on the assurance of its success. This assurance can only be achieved through comprehensive and detailed analysis of existing EOR projects, which helps build the necessary confidence in their efficacy and reliability for potential stakeholders and operators.

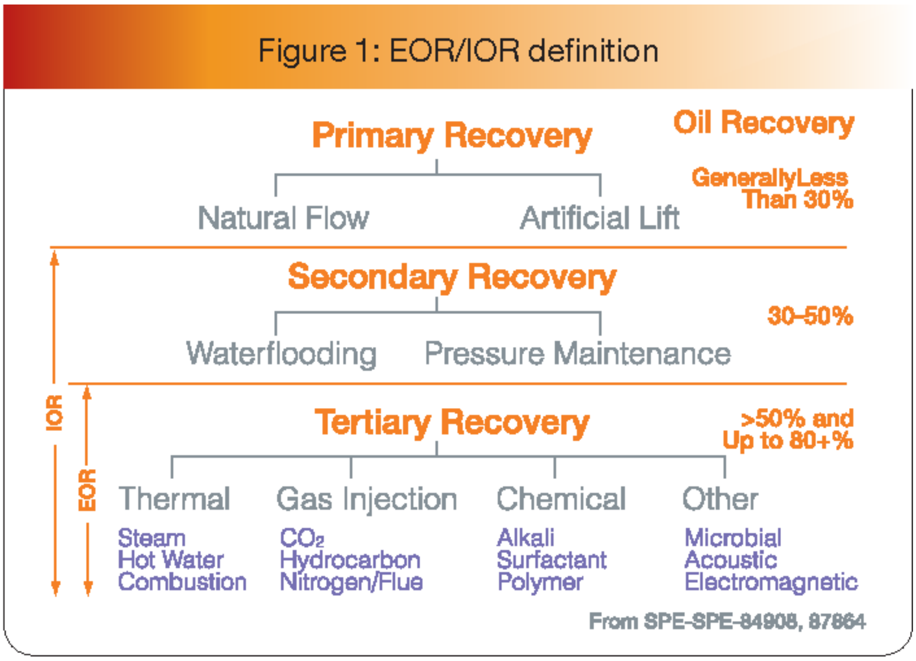


Fig. 1. General scheme of crude oil production stages.

Fig. 1 shows the connection between traditional production stages defined in the producing life of a reservoir and IOR/EOR. Here, EOR and IOR refer to those processes that are implemented for increasing the production in reservoirs in traditional production stage [1]. There are different classifications of EOR methods. One of the most common classifications divides them to four categories: gas, thermal, chemical and microbial. A brief description of all four categories is presented below.

Gas EOR Methods: Gas EOR methods include immiscible and miscible gas injection. Traditionally, only miscible gas injection is classified as EOR, whereas immiscible gas injection belongs to IOR. Recently, people use them loosely. Immiscible gas injection usually uses dry gas, CO_2, nitrogen, alternating or co-injection with water. While miscible gas injection generally uses CO_2, natural gas, LPG, nitrogen, flue gas, solvent, etc. In the case of immiscible gas flooding, the gas is injected below its minimum miscible pressure (MMP). This method improves the efficiency of macroscopic displacement by raising reservoir pressure, which in turn causes the oil to expand. In contrast, miscible gas flooding involves injecting gas at or above the minimum miscibility pressure (MMP) to achieve miscibility with the oil. The miscible gas injection process can be broadly divided into first-contact miscible (FCM) and multiple-contact miscible (MCM) methods.

FCM processes utilize a displacing fluid that becomes completely miscible with the oil upon first contact, ensuring uniform miscibility throughout the process. On the other hand, MCM processes involve a displacing fluid that does not immediately achieve complete miscibility with the oil. Instead, miscibility occurs progressively through repeated contacts. Achieving miscibility means that there is no interface between the oil and the displacing fluid, which eliminates capillary forces. This absence of capillary forces results in a substantial reduction of residual oil saturation, theoretically reducing it to zero. By effectively combining these techniques, miscible gas flooding can enhance oil recovery significantly by ensuring that a larger volume of oil is mobilized and produced from the reservoir. This approach is particularly beneficial in maximizing the extraction of oil from mature and complex reservoirs.

Thermal EOR methods: Generally thermal EOR methods include in situ combustion—forward: dry, wet, Toe-to-Heel Air Injection (THAI), and CAPRI (i.e., variation of THAI with a catalyst for in situ upgrading); in-situ combustion reverse, high-pressure air injection; cyclic steam stimulation or huff and puff; SAGD; VAPEX (solvent gas VAPor Exstraction), Expanding Solvent VAPEX (ES-VAPEX) or ES-SAGD; Steam And Gas Push (SAGP); hot water drive; electromagnetic heating, etc. All these methods elevate the temperature inside the reservoir to reduce oil viscosity. Among these methods, fours processes have evolved over the past 30 years to commercial application, and they are cyclic steam stimulation, steam drive, SAGD, and forward in-situ combustion. Steam injection is the most widely used EOR method for heavy oil recovery [2]. During steam injection process, beside the reduction of oil viscosity, the swelling of oils and increased reservoir pressure together with rock expansion aid in releasing oils from the reservoir rock. In addition, high temperature can also change the oil/water relative permeability, capillary pressure, and wettability of rock, etc. (especially during steam distillation). Therefore, thermal EOR like steam injection can effectively improve both macroscopic displacement efficiency and microscopic displacement efficiency by reducing interfacial tension. Recently, a new concept was proposed by Kazan Federal University and University of Calgary, that is using special catalysts for improving the efficiency of steam injection and in-situ combustion. Application of these methods helps not only to decrease viscosity directly in reservoir but also to achieve in-situ upgrading of heavy oil. Also, last decade some new thermal stimulation and EOR methods have been developed and tested in the field: electrical heating methods (ExxonMobil's Electrofrac™, Shell's In Situ Conversion Process) and injection of heat-producing binary mixtures.

Chemical EOR methods: Chemical methods for enhanced oil recovery (EOR) entail injecting various chemicals like polymers, cross-linked polymer gels, surfactants, alkalines, emulsions, foams, or combinations thereof into the reservoir. These methods aim to enhance either microscopic or macroscopic displacement efficiency, or both. In polymer flooding, polymers are introduced into the water to increase its viscosity, which helps achieve favorable mobility ratios. This adjustment enhances macroscopic displacement efficiency by promoting a more uniform and effective sweep of the oil. Surfactants, on the other hand, are added primarily to improve microscopic displacement efficiency. They achieve this by reducing the interfacial tension between oil and water, which aids in mobilizing trapped oil. Additionally, surfactants can alter the wettability of the rock, making it more water-wet, and can also generate emulsions that facilitate oil recovery. By carefully selecting and combining these chemicals, it is possible to tailor the EOR process to the specific characteristics of the reservoir, thereby maximizing oil recovery. Alkali can react with petroleum acid and in-situ produce oleate (surfactant) that reduces the interfacial tension proportionally based on the pH value, forms emulsion that can reduce the mobility ratio, and also alters the wettability of rock. Therefore, one can see that mechanism of alkali is similar to that of surfactant, therefore, generally alkali is added to water to minimize the use of surfactant. Polymer-based gels are used for conformance control to block high-permeability zones, diverting the displacing fluid to areas where oil has not been swept.

Microbial EOR methods: Microbial Enhanced Oil Recovery (MEOR) leverages microbes to enhance oil production. Under reservoir conditions, these microbes generate gases that increase reservoir pressure and reduce oil viscosity, thereby improving macroscopic displacement efficiency. Additionally, microbial activity can enhance absolute permeability through acidic dissolution of reservoir rocks. This increased permeability facilitates the flow of oil, further boosting recovery rates.

Alternatively, microbes can selectively block high-permeability zones, redirecting the flow of injection fluids and improving sweep efficiency across the reservoir. Moreover, microbes can produce bio-surfactants that lower the interfacial tension between oil and water, aiding in the mobilization of trapped oil. These bio-surfactants also alter the wettability of reservoir rocks, making them more water-wet, which enhances oil displacement. For example, certain microbes can reduce the population of sulfate-reducing bacteria, thereby favorably changing the wettability of the reservoir. By employing these various mechanisms, MEOR provides a versatile and environmentally friendly approach to maximizing oil recovery from reservoirs.

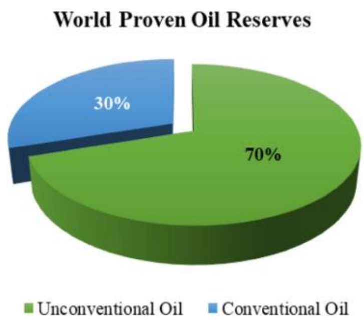


Fig. 2. World EOR project categories (1959–2010). Adapted from [3](2022)Licensed under Creative Commons Attribution 4.0. http://creativecommons.org/licenses/by/4.0/.

The analysis of EOR projects from 1959 to 2010 shows that the most widely used are thermal methods (Fig. 2). Practically half of them were carried out by heat stimulation. Gas injection is in the second place. The microbial EOR is less than 1 %. Microbial EOR has been proposed for many years, however, it is difficult to apply in the field due to the difficulty in controlling the conditions in reservoir for the growth of microbes.

According to the forecast, the application of EOR methods in near future will increase (Fig. 3) due to the increase in the share of mature oilfields and hard-to-recover hydrocarbons in overall crude oil reserves.

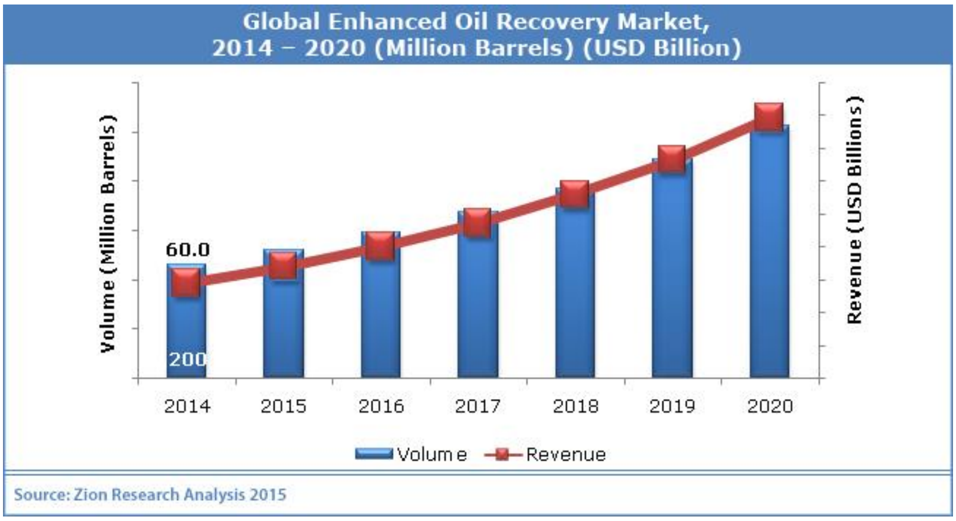


Fig. 3. Global Enhanced Oil Recovery Market 2014-2020.

Each EOR method has its own application criteria. In Fig. 4 the literature analysis of application of several EOR methods depending on the reservoir depth and oil viscosity is presented.

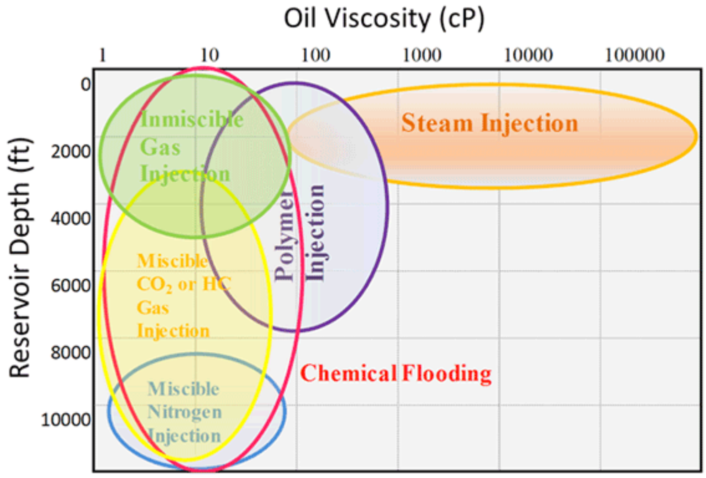


Fig. 4. General application criteria of EOR methods.

Accurate reservoir description is particularly critical in determining the applicability of any EOR process. Information about reservoir properties comes from a combination of sources that include geological studies, core analysis, logging, and pressure transient testing, as well as analysis of reservoir dynamic and production history.

3. Development of Ultra-Viscous Oil Reservoirs

There are many ways to develop the deposits of viscous and superviscous oils, and each of them has its own technological and economic characteristics. The applicability of a particular development technology is determined by the geological structure and conditions of the reservoir, the physicochemical properties of the reservoir fluid, the state and reserves of hydrocarbons, climatic and geographical conditions, etc. Conventionally, the technologies can be divided into two following groups: 1 - *Mining Methods*: Open Pit Development and Mine Development methods; 2 - *Thermal Methods* of Oilfield development.

3.1. Open Pit Development

In case of open pit development method (Fig. 5) a rock saturated with ultra-viscous oil (Fig. 6) is extracted at the daylight surface and, therefore, the possibility of applying this method is limited by the depth of reservoirs, which should be less than 50 meters. With this development method, capital and operating costs at the field are relatively small. However, after extracting the rock, additional works such as sand laundering using steam and solvent is required to obtain hydrocarbons from it. Finally, this method ensures a really high oil recovery ratio from 85 to 95-98%.

Fig. 5. Open Pit Development Method. Adapted from [4](2020). Licensed under Creative Commons Attribution 4.0. http://creativecommons.org/licenses/by/4.0/.

Fig. 6. Oil-saturated sandstone.

The Athabasca oil sands, also known as tar sands, are vast deposits of bitumen or extremely heavy crude oil situated in northeastern Alberta, Canada, near the boomtown of Fort McMurray (Fig. 7). These oil sands are predominantly found within the McMurray Formation and comprise a complex mixture of crude bitumen, silica sand, clay minerals, and water. The Athabasca deposit is recognized as the largest known reservoir of crude bitumen globally. It is one of Alberta's three major oil sands deposits, alongside the nearby Peace River and Cold Lake deposits, with the latter extending into Saskatchewan. The immense size and richness of the Athabasca oil sands make them a crucial source of bitumen, contributing significantly to Canada's oil production capabilities. These deposits play a vital role in the energy sector, providing substantial reserves of heavy crude oil for extraction and processing.

Fig. 7. Athabasca oil sands.

These oil sand deposits collectively span an area of 141,000 square kilometers

(54,000 square miles) across boreal forests and muskeg (peat bogs). They hold approximately 1.7 trillion barrels (270 billion cubic meters) of bitumen in place, a volume comparable to the world's total proven reserves of conventional petroleum. According to the International Energy Agency (IEA), as of 2007, the economically recoverable reserves—considering the price and modern unconventional oil production technology—are estimated at 178 billion barrels (28.3 billion cubic meters), representing about 10% of the total bitumen deposits. This substantial quantity positions Canada as the holder of the third-largest proven oil reserves globally, following Saudi Arabia and Venezuela's Orinoco Belt. These reserves significantly bolster Canada's status in the global energy market.

3.2. Mine Development Methods

Mine development can be carried out in two modification: Surface Mining, which includes the transportation of hydrocarbon-saturated rock to the surface (Fig. 8) and Mine-Borehole modification, which includes mining under the oil-saturated formations and drilling of vertical and inclined wells from these formations to the productive reservoirs already in the mines for oil recovery (Fig. 9). The most famous example of Mine-Wellbore Development of heavy oil deposits is the development of the Yarega field (Fig. 8).

Fig. 8. Method for thermoshaft oil production.

The surface mining method is applicable only to depths of 200 meters, but it has a higher oil recovery coefficient (up to 45%) as compared with wellbore methods. The large in-depth drilling into dry rock reduces the profitability of the method, which is currently cost-effective only if there are rare metals (in addition to hydrocarbons) in the rock. The mine-borehole development method is applicable at a deeper depth (up to 400 meters), but it has a relatively low oil recovery coefficient and requires a large amount of drilling through dry rocks. Thermal-steam formation treatment is used to increase the rate of high-viscosity oil and natural bitumen production and ensure high oil recovery ratio of the Mine-Wellbore method. The so-called thermo-mine method is applicable at depths of up to 800 meters, and has a high oil recovery factor (up to 60%), but is more difficult to manage compared to the Mine Development method and Mine-Wellbore Development methods.

3.3. Thermal Methods for Enhanced Oil Recovery

As mentioned before, thermal methods are most widely used in the world. Mostly, they have been applied to improve heavy oil production. It should be emphasized that thermal EOR methods have also high potential for tight oil reservoirs, oil shales, and mature conventional oilfields (for mature oilfields using high-pressure air injection). Fig. 9 shows the detailed classification of most widely used thermal EOR methods.

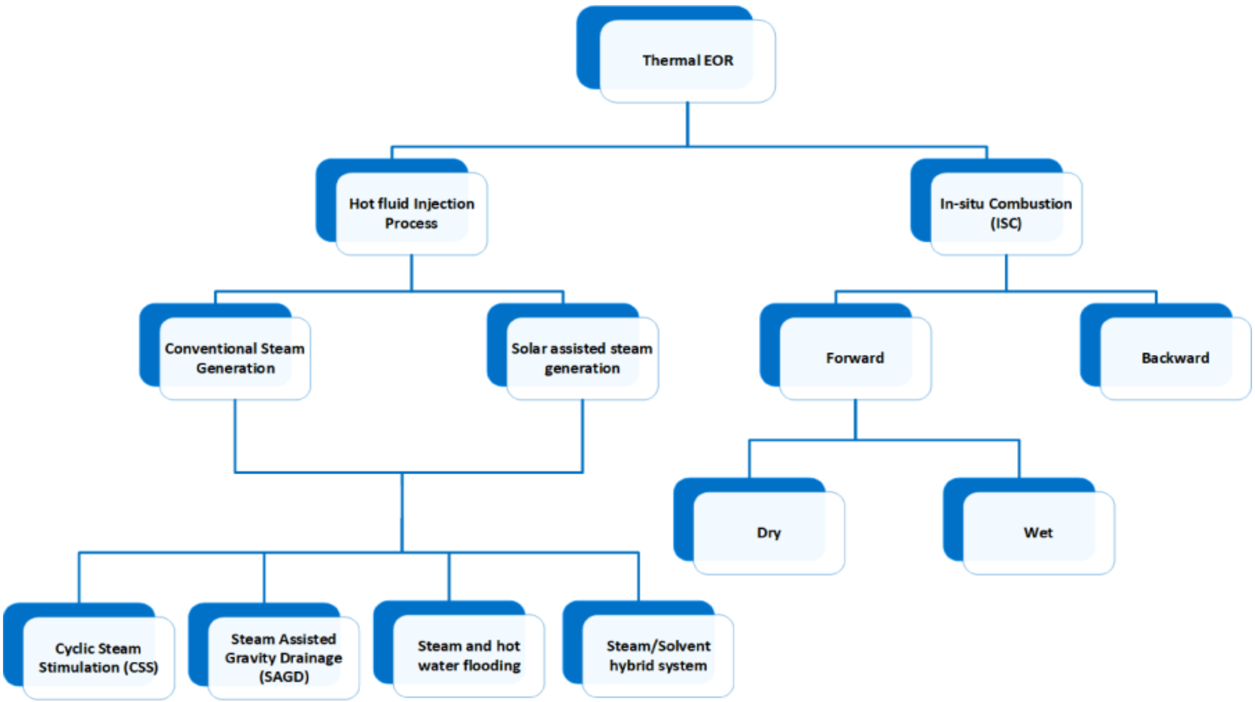


Fig. 9. Most widely used thermal EOR methods.

Among these EOR methods, processes such as cyclic steam stimulation (CSS), steam drive, steam assisted gravity drainage (SAGD), and hot water injection, in-situ combustion, etc. are the most prominent thermal EOR techniques. The other thermal EOR techniques, such as electric heating and electromagnetic heating, are rarely applicable until now due to technical constrains and environmental issues, subsequently, future work is required in order to make these methods more competitive.

3.3.1. In-situ combustion

In-Situ Combustion (ISC) holds significant promise for recovering a substantial percentage of the original oil in place. Field examples and laboratory studies have demonstrated that ISC can achieve one of the highest recovery factors among Enhanced Oil Recovery (EOR) methods, typically ranging between 70-80%. Despite its potential, ISC is challenging to control and optimize due to its inherent technical complexity. Consequently, many operators view ISC as a high-risk oil recovery process, largely because numerous early projects ended in failure. It is important to note that these failures often resulted from the application of the ISC process in unsuitable reservoirs or inappropriate prospects, rather than flaws in the process itself. Therefore, careful reservoir selection and detailed feasibility studies are crucial for the successful implementation of ISC projects.

The fundamental principle of In-Situ Combustion (ISC) involves burning the heavier, less mobile components of oil to generate heat, thereby lowering the viscosity of heavy oils and altering their composition. ISC is typically applied to heavy oil reservoirs that are too deep, have excessively high pressure, or feature pay zones too thin for effective steam flooding. During the ISC process, air is injected into the reservoir, and a portion of the oil in place is ignited. Once ignition occurs, continuous air injection sustains the combustion, creating a high-temperature combustion front. This front self-propagates forward, driven by the continuous air supply, and displaces the downstream oil towards production wells. This technique effectively mobilizes heavy oils, making them easier to extract, especially in challenging reservoir conditions. Generally, there is a variety of in-situ combustion methods, including reverse combustion, forward combustion (dry and wet), Toe-to-Heel Air Injection (THAI), high-pressure air injection, etc. Each of them has certain advantages and drawbacks. Reverse combustion has been found difficult to apply and economically unattractive. The most widely recognized form of in-situ combustion (ISC) is forward dry combustion, where the combustion front moves in the same direction as the injected air. This method typically requires a minimum of two wells or uses a pattern similar to those designed for water flooding techniques (Fig. 10). The key distinction between dry and wet combustion lies in the injection of water in wet combustion, which generates steam, enhancing the oil recovery process. This additional steam aids in further reducing the viscosity of the oil, thereby improving its mobility and overall extraction efficiency.

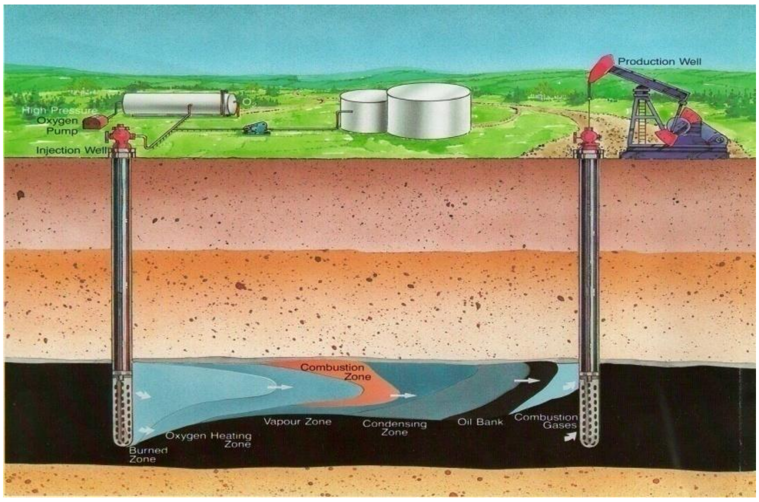


Fig. 10. Standard scheme of forward ISC process.

The initial phase of forward combustion involves igniting the oil. Occasionally, auto-ignition (self-ignition) can occur when air injection starts, provided the reservoir temperature is sufficiently high (typically above 60-70°C) and the oil is highly reactive. Ignition can also be deliberately initiated using methods such as downhole gas burners, electrical heaters, or the injection of heat-generating chemical agents or steam. Once ignition is achieved, the combustion front is maintained and advanced by a continuous supply of air, which sustains the combustion process and facilitates the displacement of oil towards the production wells. Fig. 11 shows electrical heater for ignition of combustion process.

Fig. 11. Electrical heater for ignition of combustion process.

Rather than an underground fire, the front is propagated as a glow similar to the hot zone of a burning cigarette. As the front progresses into the reservoir, several zones exist between injector and producer as a result of heat and mass transport and the chemical reactions. In Fig. 12, an idealized representation of the various zones and the resulting temperature and fluid-saturation distributions. In the field, there are transitions between zones; however, the concepts illustrated provide insight on the combustion process (Fig. 12).

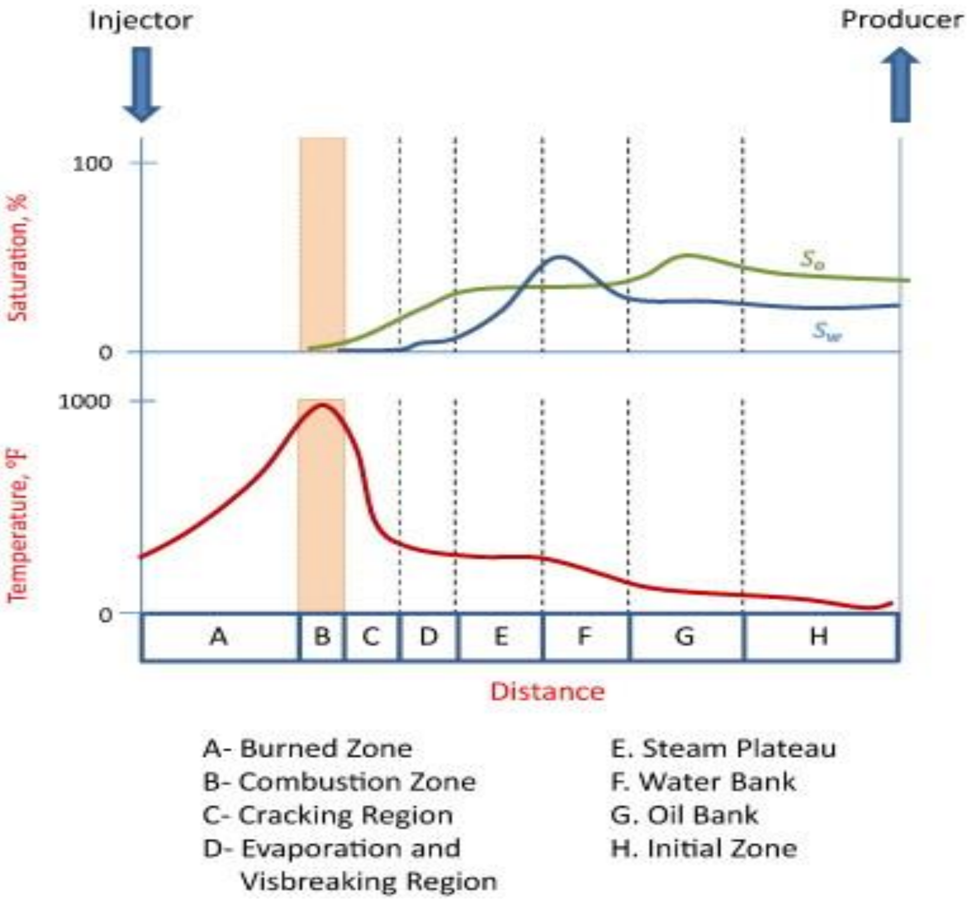


Fig. 12. Characterization of in-situ combustion zones with the temperature and fluid saturation profiles.

The area adjacent to the injection well is known as the burned zone (Zone A), which is where combustion has already occurred. In typical field conditions, combustion is rarely complete, so this zone often contains residual unburned organic solids, commonly referred to as coke in the oil industry. Due to prolonged exposure to the highest temperatures, this zone usually exhibits significant mineral alteration.

Just ahead of the burned zone lies the combustion zone (Zone B). This is where the reaction between oxygen and fuel generates heat. The combustion zone is very narrow, usually only a few centimeters thick, and it is here that high-temperature oxidation (the burning of coke) occurs, producing primarily water and combustion gases such as carbon dioxide (CO2) and carbon monoxide (CO). The primary fuel in this zone is coke, which forms in the thermal cracking zone located just before the combustion zone.

The temperature within the combustion zone can reach between 600-700°C, depending on the nature and quantity of fuel consumed per unit volume of rock. The intensity of the heat generated and the efficiency of the combustion process are influenced by these factors. This high-temperature environment plays a critical role in the in-situ combustion (ISC) process, facilitating the effective displacement of oil by reducing its viscosity and enabling its movement towards the production wells. The overall success of ISC operations hinges on the careful management and understanding of these zones and their interactions. Just downstream of the combustion zone lies the cracking/vaporization zone (C). In this zone, the high temperature generated by the combustion process causes the lighter components of the crude to vaporize and the heavier components to pyrolyze (thermal cracking). The vaporized light ends are transported downstream by combustion gases and are condensed and mixed with native crude. The pyrolysis of the heavier end results in the production of CO_2, hydrocarbon and organic gases and solid organic residues. The residue, commonly referred to as coke, is deposited on the rock and serves as the primary fuel source for the combustion process. Adjacent to the cracking zone is the condensation-evaporation and visbreaking zone (Zone D). Due to the typically low pressure gradient in this area, the temperature remains relatively stable and is influenced by the partial pressure of water vapor. In this zone, some hydrocarbon vapors condense and dissolve into the crude oil. Depending on the temperature, the oil may undergo visbreaking—a mild form of thermal cracking—which reduces its viscosity.

This region contains a mixture of steam, oil, water, and flue gases, all of which move towards the production well. Adjacent to this zone is the steam plateau (Zone E). Field tests indicate that the steam plateau extends from 10 to 30 feet ahead of the combustion front. At the leading edge of the steam plateau, where the temperature drops below the condensation point of steam, a hot water bank (Zone F) forms. This hot water bank is characterized by a water saturation level higher than the original saturation.

In front of the hot water bank is the oil bank (Zone G), which contains all the oil displaced from the upstream zones. This zone acts as a buffer, accumulating oil as it moves towards the production well. Beyond the oil bank lies the undisturbed zone, which has not yet been affected by the combustion process. This area remains mostly unchanged except for a potential increase in gas saturation due to the flow of combustion gases such as carbon dioxide (CO2), carbon monoxide (CO), and nitrogen (N2). Understanding these distinct zones and their interactions is crucial for effectively managing the in-situ combustion (ISC) process. Each zone plays a specific role in the overall dynamics of oil displacement, and careful monitoring and control can optimize recovery efficiency.

According to the Burguer et al, the temperature and saturation profiles for dry and wet combustion processes are different. In wet combustion a steam front is observed, which helps to improve production.

The chemical reactions involved in in-situ combustion (ISC) are numerous and complex, occurring across a broad temperature range. Researchers typically categorize these reactions into three classes based on ascending temperature ranges. The first set of reactions, known as low-temperature oxidation (LTO), involves heterogeneous gas/liquid reactions that produce partially oxygenated compounds and a small amount of carbon oxides.

During the early stages of LTO, oxygen addition reactions form hydroperoxides. As the process progresses, these hydroperoxides undergo isomerization and decomposition, resulting in oxygen-rich products such as carboxylic acids, ketones, and alcohols, along with small amounts of CO_2, CO, and H_2O. The oxygen-rich products remaining after LTO are commonly referred to as LTO residues. In heavy oil reservoirs (API<20°), LTO is more pronounced when oxygen, rather than air, is injected into the reservoir. The second stage of reactions, known as fuel deposition (FD), involves the cracking and pyrolysis of LTO residues to form fuel. Fuel deposition occurs at intermediate temperatures following the LTO reactions and is critical for the feasibility and economic success of a combustion project. The rate and extent of these reactions depend on the type and chemical structure of the oil. Additionally, catalytic effects from the reservoir matrix or injected metal solutions can influence the type and quantity of fuel produced. These initial reactions lay the groundwork for the high-temperature oxidation that follows, ultimately driving the in-situ combustion process. Understanding these stages and their respective chemical pathways is essential for optimizing ISC operations, as each stage plays a pivotal role in determining the overall efficiency and effectiveness of the oil recovery process. Third stage is high temperature oxidation (HTO) - heterogeneous H/C bond breaking reactions- in which the fuel reacts with oxygen to form carbon dioxide, carbon monoxide, and water. HTO are heterogeneous (gas-fluid and gas-solid) reactions and are described by utilization of the majority of the oxygen in the gas phase.

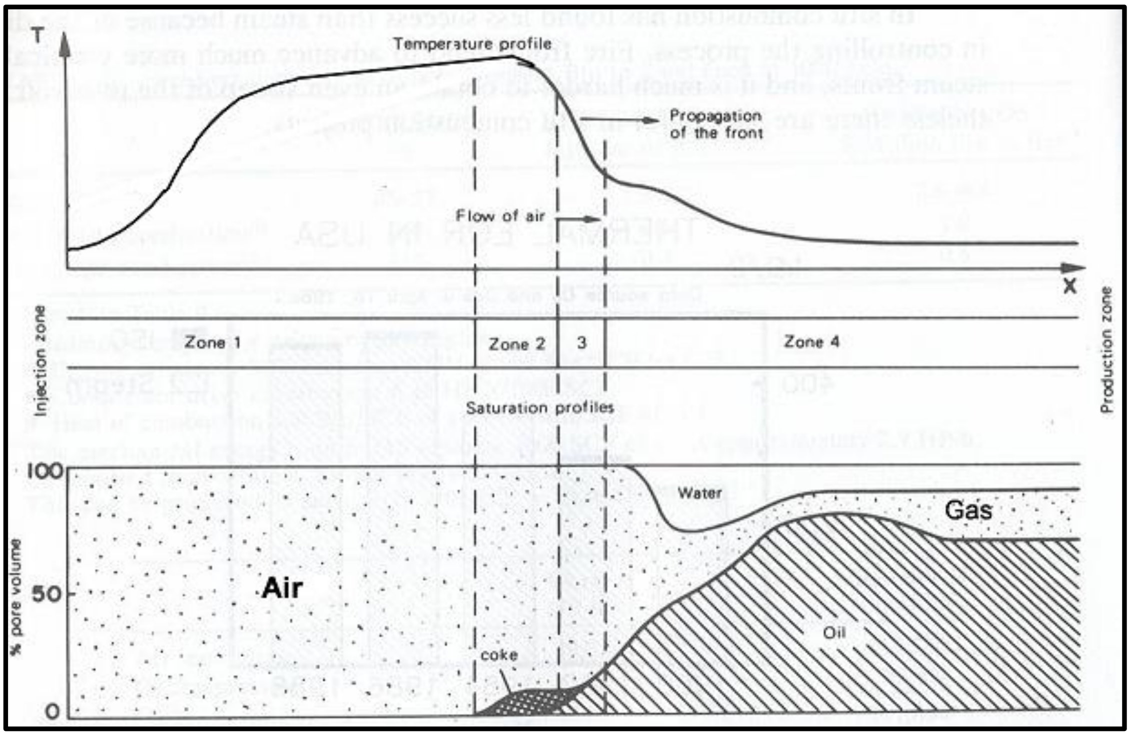


Fig. 13. Temperature and saturation profiles during **dry** ISC process.

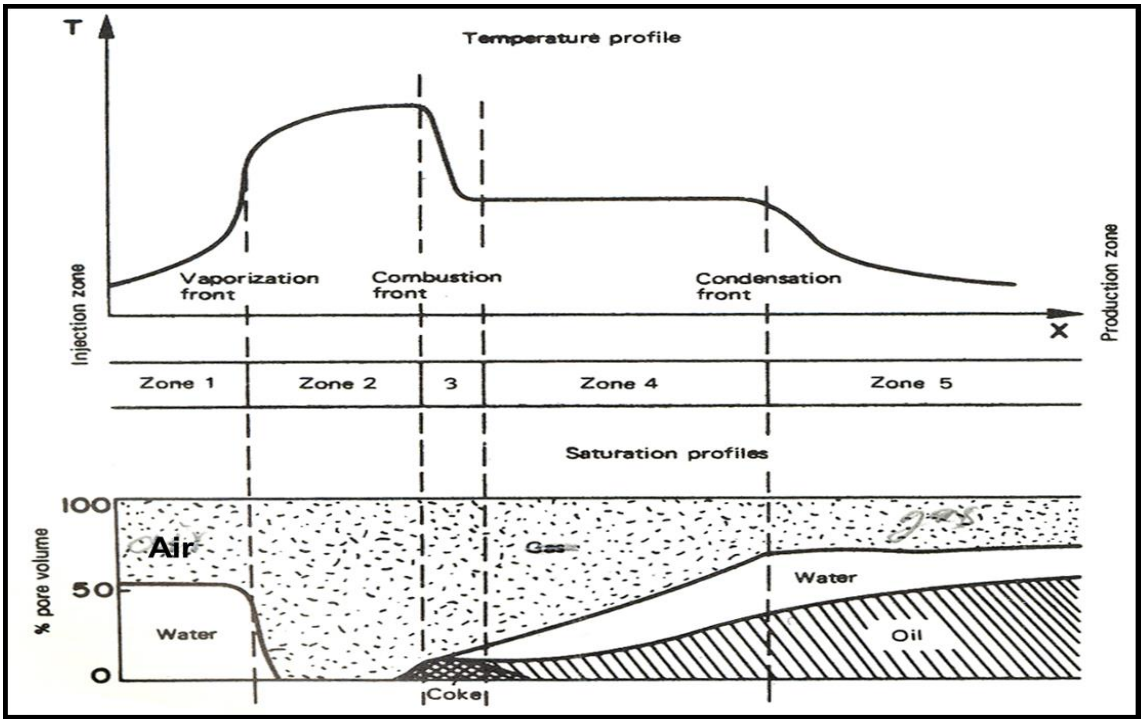


Fig. 14. Temperature and saturation profiles during **wet** ISC process.

One of the most important parameters of ISC method is kinetics of chemical reactions. The kinetics of combustion reactions describe the speed at which these chemical reactions take place and the extent to which the oil is affected.

Understanding kinetics is crucial for several reasons: it helps characterize the reactivity of the oil, determine the conditions necessary for ignition, and provide insights into the nature of the fuel and its combustion characteristics. Additionally, kinetic parameters are essential for the numerical simulation of the combustion process. Various experimental techniques can be employed in the laboratory to study the kinetics of crude oil combustion, including differential scanning calorimetry, thermogravimetry, accelerating rate calorimetry, and ramped temperature oxidation cells. These methods allow researchers to analyze the thermal and oxidative behavior of crude oil under controlled conditions, providing valuable data for optimizing in-situ combustion processes and improving overall oil recovery efficiency.

Fig. 15 provides a comprehensive illustration of the key zones involved in the in-situ combustion process of an oil-saturated sandstone core. The upper images display the actual experimental setup, showcasing the combustion tube apparatus with the core sample inside. The clear illustration of the key zones of the combustion fronts (visualization of combustion zones) was taken in the laboratory by a senior researcher Kamil Gamirovich Sadikov at Kazan Federal University, visibly show the combustion stages with clear demarcations of the combustion zones as well as temperature gradients along the combustion tube. The lower diagrams complement this by detailing the temperature distribution and fluid dynamics within the combustion front. The left schematic breaks down the zones: post-combustion, combustion, coking, steam, light oil, and crude oil zones. The right diagram expands on this, highlighting the injection of air and water into the combustion zone, the formation of coke, and the progression of the combustion front, eventually leading to the mobilization and production of crude oil. Together, these images and diagrams elucidate the complex interactions and stages in the in-situ combustion process, emphasizing the thermal and chemical transformations occurring within the reservoir.

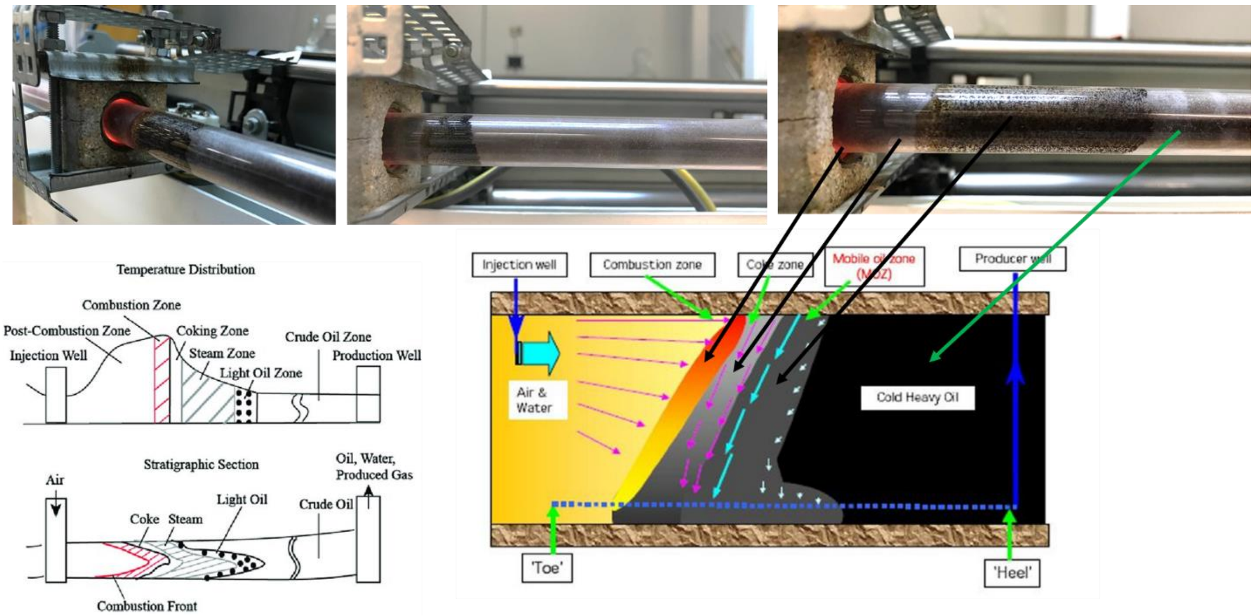


Fig. 15. Schematic and Visualization of Combustion Zones During In-Situ Combustion of Oil-Saturated Sandstone Core.

Combustion tubes are essential tools used in laboratory settings to study the behavior of in-situ combustion (ISC) processes. When properly designed and operated, combustion tube tests can yield valuable information about the combustion characteristics of a rock/oil system. This data is crucial for making accurate engineering and economic projections for field tests. Therefore, laboratory combustion tube studies are a fundamental first step in the design and implementation of an ISC project.

These tests simulate the nature of the propagating combustion front and the dynamic chemical reactions that occur under conditions closely resembling those in a reservoir. Despite their usefulness, a significant limitation of combustion tube tests is their lack of scalability. The results obtained from these tests cannot be directly scaled up to predict reservoir performance accurately. The correlation between combustion tube results and actual reservoir conditions is, at best, tenuous. However, experience has demonstrated that when tests are conducted using actual reservoir rock and oil under appropriate operating conditions, the chemical reactions and reaction stoichiometry observed in the tube are consistent with those occurring in the reservoir. This consistency is because the stoichiometry of the reactions is governed by the temperature, pressure, and chemical characteristics of the oil.

By ensuring that combustion tube tests closely mimic reservoir conditions, researchers can gain insights into the combustion process's fundamental aspects, such as reaction kinetics and heat generation. These insights are invaluable for designing effective ISC strategies and optimizing oil recovery in the field. Although direct scaling may not be possible, the qualitative understanding and quantitative data obtained from combustion tube tests play a critical role in the successful application of in-situ combustion technologies.

Fig. 16. Combustion tube device in Kazan Federal University.

The information that can be obtained from combustion tube experiment includes: fuel burned; air required to burn a unit volume of reservoir; atomic H/C ratio of burned fuel; excess air and oxygen utilization; oxygen-fuel ratio (OFR); air/fuel ratio; apparent fuel consumption; oil recovery from the swept zone; optimization of water/air ratio in wet combustion; composition of produced fluids; and front temperature and stability.

Among all the thermal EOR methods, ISC has the widest application criteria. Until now, about one hundred projects have been implemented in the field based on different air injection techniques. Most of in-situ combustion have been applied for heavy oil recovery. The field trials showed that ISC helps to improve significantly the production and additionally to upgrade the heavy oil in the reservoir. Also, ISC was successfully applied for development of light oil reserves, especially for low permeability reservoirs. There are several examples of application of air injection in shale oil reservoirs. It can be perspective nowadays for mature oilfields on the last stage of development to recover the residual oil.

Based on the available literature information the ranges of reservoir parameters where ISC was tested were collected and data are presented below:

Depth: 100 – 3500 meters

API gravity of oil: 10.0 – 40.0

Permeability: 1 – 4000 mD

Porosity: 10-36 %

Viscosity: 1.4 – 100000 cp

Reservoir temperature: 17.8 – 110 ^{0}C

It can be concluded that the ranges are very wide.

Several factors must be taken into consideration when evaluating candidate reservoirs for in-situ combustion application. These include site geology, reservoir rock and fluid properties, crude oil characteristics, and reservoir geometries.

Geological Characterization: Reservoir geological characteristics played a major role in the outcome of many past ISC projects. Examination of the reservoir characteristics of the California, Oklahoma, and Texas in-situ combustion projects indicate that the structure, lateral continuity, and physical characteristics of the individual sand layers within the reservoir as well as the reservoir heterogeneities played a significant role in the performance of these projects. The key geological parameters to be considered when selecting a site for an in-situ combustion project include:

- the degree and extent of lateral and vertical reservoir continuity,

- depth,
- thickness,
- structural attitude and dip,
- overburden competence,
- reservoir heterogeneities, and
- presence of gas cap and aquifer.

Lateral and Vertical Extent of Reservoirs:

The continuity of individual sand layers within the production formation is crucial for the successful operation of the in-situ combustion (ISC) process, particularly in thin, lenticular sands. This continuity affects the efficiency and effectiveness of the ISC method. ISC demands significantly higher capital investment per unit of production compared to water flooding due to the expensive equipment required, such as air compressors, which also incur high operating costs. Consequently, the volume of oil in place per unit area must exceed a certain minimum threshold to ensure the economic viability of the project. In thin reservoirs, the total volume of oil in place is influenced by factors such as porosity, oil saturation, and the areal extent of the reservoir. Ensuring these factors are favorable is essential to justify the higher costs associated with ISC and to achieve a successful and economically feasible oil recovery operation.

Vertical Depth:

The depth of the reservoir does not hinder the implementation of the in-situ combustion (ISC) process. However, depth influences factors such as temperature, pressure, and well costs. At shallow depths (less than 200 feet), the air injection pressure is severely limited, which can restrict the effectiveness of the ISC process. As the depth increases, the required air injection pressure also rises, leading to higher compression costs due to the need for larger compressors. Additionally, deeper reservoirs tend to be hotter, making spontaneous ignition of in-situ hydrocarbons more likely upon air injection. These considerations are crucial for the successful and cost-effective deployment of ISC.

Reservoir Thickness:

Sand thickness plays a critical role in the efficiency of the in-situ combustion (ISC) process. A significant density difference between air and reservoir fluids often causes air to override the oil column, potentially bypassing much of the oil if the reservoir is too thick. However, in thinner oil sands, this override tendency is mitigated, promoting a more uniform displacement and vertical sweep of the oil. In thin heavy oil reservoirs, heat can be transferred rapidly to the bottom, allowing the combustion front to advance more quickly compared to thicker sands.

For successful ignition in these reservoirs, it is essential to heat the near well-bore area to a high temperature to initiate the combustion process. In very thick formations (>50 ft.), the amount of heat required to elevate the well-bore vicinity above the oil's auto-ignition temperature can be substantial and costly. Despite these challenges, artificial ignition techniques have successfully ignited formations up to 60 feet thick. Therefore, understanding and managing sand thickness is crucial for optimizing ISC operations, ensuring effective ignition, and maintaining an efficient combustion front propagation.

Structural Attitude and Dip:

Structural attitude and dip are important consideration in the location of wells for an ISC project. Injected air and combustion front movement will be more rapid toward high-dip wells than toward low-dip wells on the structure if air injectors at downdip and producers at updip. However, in reservoirs with high dip angle, it is advisable more often to locate the air injectors at updip and production wells at downdip of structure to compensate for the expected flow of air towards updip and to take advantage of gravity in the recovery of hot mobile crude affected by combustion.

Overburden Competence:

The producing formation at the project site must have sufficient and competent overburden so as to confine the injected air within the pay zone. Gaps in oil sand overburden or leaky interzonal seals in stratified reservoirs can allow fluid 'leaks' into overlying strata.

Reservoir Heterogeneities:

Reservoir heterogeneities significantly influence recovery performance in the in-situ combustion (ISC) process. These heterogeneities include permeability barriers to lateral and vertical flow, natural fractures, high permeability zones, and directional permeability. Permeability barriers can affect the ISC process both positively and negatively. On the positive side, vertical permeability barriers can segment a thick reservoir into smaller units, which may be more suitable for the ISC process. They can also serve as seals, preventing the upward migration of injected air, leading to more uniform combustion in relatively thick reservoirs.

Conversely, horizontal permeability barriers can disrupt reservoir continuity and hinder recovery efforts. Fractures and joints, as secondary properties, can create preferential flow channels that impact the recovery process. Additionally, a thin, high-permeability zone at the top of the reservoir extending from one well to another can pose a threat to the combustion front by diverting air and depriving the process of the necessary oxygen.

These heterogeneities must be carefully managed to optimize the ISC process. Effective management can enhance the combustion front's stability and uniformity, ensuring better oil recovery. Understanding the complex interplay of these factors is crucial for designing and implementing successful ISC projects, thereby maximizing hydrocarbon recovery from heterogeneous reservoirs.

Rock Properties:

The key rock properties of interest to an engineer evaluating a prospect for the application of ISC process are: sand texture, permeability and its distribution, porosity, and composition of rock matrix. In many air injection projects, especially those implemented in oil not favorable for the formation of coke (like heavy oil with high saturation but low resins and asphaltenes), rock composition is very import in determining the amount of fuel available for combustion.

Sand Uniformity and Texture:

Oil sands often vary considerably in the characteristics both vertically and laterally. Grain size and grading, shape of grains, and character and amount of cementing material determine the physical characteristics and properties of the reservoir. The size, shape and sorting of the grains determine the porosity and permeability of rock. Coarse, well-sorted and rounded sand grains result in a high porosity, high permeability reservoir.

Permeability:

The value of permeability has very little effect on the mechanics of combustion process. Economically successful ISC process have been implemented in carbonate light oil reservoirs with permeability of less than 10 mD. The only requirement for permeability is that it must be adequate to permit air injection at a pressure compatible with overburden at an acceptable compression cost. In viscous heavy oil reservoirs too, low permeability may fail to provide the minimum air flux needed for sustained combustion. Low permeability also increases air injection pressure requirements and compression costs, and prolongs the operation. Low permeability in a viscous (> 100 cp.) shallow reservoir can limit the injectivity and promote low temperature oxidation. In such reservoirs a permeability greater than 100 mD would be necessary.

Porosity:

High porosity in a reservoir is advantageous as it indicates a greater capacity for holding hydrocarbons. In the United States, successful in-situ combustion (ISC) projects have been implemented in reservoirs with porosity ranging from 0.16 to 0.38. As porosity decreases, the amount of heat stored in the rock increases. However, in wet combustion processes, lower porosity does not significantly affect overall energy utilization since some of the stored heat is recovered during scavenging operations. The primary impact of porosity is on the oil content within the reservoir. The economic success of an ISC process is more dependent on oil saturation than on porosity alone. For instance, porosity values lower than 0.2 are still acceptable if the oil saturation exceeds 0.45. Thus, while high porosity is generally desirable, sufficient oil saturation is crucial for ensuring the economic viability of ISC projects. This balance between porosity and oil saturation plays a critical role in determining the effectiveness and profitability of ISC operations.

Oil Saturation:

A minimum oil content, determined by the product of oil saturation and porosity, is essential to compensate for the oil consumed as fuel in an in-situ combustion (ISC) process. In the industry, a commonly accepted guideline is that if the 'oil saturation-porosity product' is less than 0.09 or 700 barrels per acre-foot, dry combustion should not be considered. This threshold indicates that the reservoir must contain sufficient recoverable oil to meet the energy demands of the process and provide additional production to ensure economic viability.

For wet combustion, where the fuel consumption is lower, reservoirs with somewhat lower oil saturation can still be acceptable. Essentially, this guideline ensures that the reservoir can support the ISC process without depleting its resources excessively and still yield profitable results. Therefore, assessing the oil saturation and porosity is crucial in determining the feasibility and economic attractiveness of implementing ISC techniques in a given reservoir.

Composition of Reservoir Matrix:

The economics and feasibility of an in-situ combustion (ISC) process within a reservoir are heavily influenced by the nature and quantity of fuel generated in the reservoir. Adequate fuel deposition is crucial; insufficient fuel will prevent the combustion front from being self-sustaining. On the other hand, excessive fuel deposition can lead to unfavorable economic outcomes due to high air requirements, increased power costs, and reduced oil recovery rates. Both laboratory studies and field evidence suggest that the mineralogical composition of the reservoir rock and the chemical composition of the crude oil significantly impact the amount of fuel available for sustaining combustion. These factors must be carefully considered to optimize the ISC process. Properly balancing fuel generation ensures that the combustion front remains effective and economically viable, leading to higher efficiency and better recovery rates in the field. Therefore, understanding the interactions between rock mineralogy, crude oil chemistry, and fuel deposition is essential for the successful implementation of ISC techniques.

Effect of Well Spacing:

Determining the appropriate well spacing in an in-situ combustion (ISC) process is crucial to avoid operational issues. If wells are spaced too closely, the combustion front may encounter early gas breakthrough, which can disrupt the process. Conversely, if the spacing is too wide, the oil production rate will be slow, extending the project's duration and reducing its economic viability. Therefore, achieving an optimal well spacing is essential to maximize oil recovery and ensure the economic success of the project. Balancing these factors helps maintain a steady and efficient combustion front, leading to more effective and profitable oil extraction.

Screening Criteria:

Oil: - Viscosity: Preferably less than 5,000 cp at reservoir condition.

- Gravity: 10-40 API

- Composition: low heavy metal content crude. Heavy metal (Va, Ni, etc.) should be preferably less than 50 ppm.

Water: - Connate water properties are not critical.

Lithology: heavy oil reservoir: low clay content; low in minerals that promote increased fuel formation such as pyrite, calcite, and siderite as well low in heavy metals; light oil reservoirs: lithology that tends to promote fuel deposition is preferred.

Reservoir:

- Depth: 300 - 12500 ft.
- Thickness: 5- 50 ft.
- Permeability: Not critical
- Porosity: > 0.1 8
- Oil concentration: 700 bbl/ac-ft, fSo > 0.09
- Transmissibility: 20 mdft/cp

Favorable Factors:

1. High reservoir temperature
2. Low vertical permeability
3. Good lateral continuity
4. Multiple thin sand layers
5. Good overburden competence
6. High dip
7. Uniform permeability profile

Engineering of an in-situ combustion project

Several variables affect the performance of an ISC process. The most important parameters are:

-fuel deposit,

-air requirement,

-air flux,

-air injection rate,

-air-oil ratio,

-injection pressure,

-oil recovery rate.

Fuel Deposit:

The quantity and type of fuel deposited within the reservoir is a crucial variable, typically measured in pounds of fuel per cubic foot of formation. This metric influences the amount of heat generated, the volume of air required, the advancement rate of the burning front, the oil recovery rate, and the overall project duration. Fuel deposition depends on several factors, including the properties of the crude oil, oil saturation levels, formation permeability, and the temperature within the combustion zone. Understanding these factors is essential for optimizing the in-situ combustion (ISC) process and ensuring efficient and effective oil recovery.

Air Requirements:

The volume of air needed to burn a unit volume of the reservoir is determined through a stoichiometric analysis of the combustion gases produced in the combustion tube. This air requirement is crucial as it dictates the compression capacity necessary for the process, significantly impacting the overall project economics. The amount of air required to burn a unit mass of fuel depends on the carbon and hydrogen content of the fuel and the ratio of carbon dioxide (CO_2) to carbon monoxide (CO) produced during combustion. Typically, the hydrogen-to-carbon ratio of the fuel deposited in an in-situ combustion (ISC) process ranges from 0.1 to 0.15. Understanding and accurately calculating these air requirements are essential for ensuring the efficiency and economic viability of ISC operations. This involves balancing the chemical composition of the fuel and optimizing the air compression capacity to achieve effective combustion and maximize oil recovery.

Air Flux:

The combustion front progresses at a rate determined by the air supply necessary to consume the deposited fuel, as all the fuel must be burned for the process to continue. Laboratory tests have shown that with relatively high air fluxes, combustion is vigorous, achieving temperatures around 540°C for a typical fuel deposition of 1.5 lb/ft^3. Conversely, lower air fluxes result in lower combustion temperatures. If the air flux is reduced too much, the process reaches a point where heat losses surpass heat generation, causing the combustion front to extinguish. Therefore, the minimum air flux needed to sustain the combustion front is dependent on both the fuel deposition and heat losses. In practical field conditions, the required air flux to maintain combustion increases with higher oil gravity and decreases with thinner pay zones. This balance ensures that enough heat is generated to sustain the combustion process, optimizing oil recovery while maintaining efficient air use.

Air-Oil Ratio:

The air-oil ratio (AOR) is a critical economic parameter in the in-situ combustion (ISC) process, representing the amount of air needed to produce one barrel of oil. This ratio, combined with the unit air cost, helps determine the total air injection cost per barrel of oil produced. The AOR depends on the amount of oil in place and the quantity of fuel burned during the process.

The theoretical air-oil ratio is calculated as the volume of air injected per barrel of oil displaced from the burned volume, where the displaced oil equals the initial oil in place minus the oil consumed as fuel. On the other hand, the actual produced air-oil ratio is based on an air requirement of 180 standard cubic feet (scf) per pound of fuel burned. This distinction is essential for accurately estimating the air supply needs and associated costs, ensuring the economic feasibility and efficiency of the ISC operation. Understanding and optimizing the AOR is key to maximizing oil recovery while minimizing operational costs.

Injection Pressure:

One of the significant costs in a combustion project is the expense of compressing air. The size and capacity of the compressor are determined by the necessary air injection rate and the required discharge pressure. The air injection pressure is primarily influenced by factors such as the permeability of the formation, the rate of air injection, well spacing, and the depth of the formation. The best approach to determine the needed air injection pressure is to conduct actual air injection tests in the field. For design purposes, the pressure values obtained from these tests should be increased by a reasonable margin, typically around 30%, to account for any unexpected pressure increases during the combustion operation. This precaution ensures that the system can handle variations and maintain efficient performance throughout the process.

Oil Recovery Rate:

In laboratory settings, oil recovery rates for in-situ combustion (ISC) programs typically range from 60% to 90% of the oil in place. These high recovery rates are generally achieved by burning mobile crudes within high-porosity sand packs that have a high initial oil saturation. However, field oil recovery rates are significantly lower than those observed in the laboratory. This discrepancy is primarily due to reduced horizontal and vertical sweep efficiencies in actual reservoir conditions, which impact the overall effectiveness of the ISC process in the field.

Current major commercial operations:

- Suplacu de Barcau Project, Romania (approx 7,000 bbl/day); duration over 45 years;
- Balol and Santhal Projects in India; combined production over 10,000 bbl/day; for over 18 years;
- Commercial operations in several Chinese Oil Fields;
- Bellevue, Louisiana, USA - 900 bbl/day; very old exploitation (over 50 years).

General AOR – 2,000-3,500 sm3/m3.

One of the most renowned field applications of in-situ combustion (ISC) is the **Suplacu de Barcau Project** in Romania. Despite the Suplacu reservoir possessing excellent production parameters, initial forecasts for the high-density and viscous oil suggested a recovery rate of only 9% over more than 80 years under primary depletion. However, theoretical and laboratory studies conducted between 1961 and 1964 concluded that thermal recovery methods, specifically in-situ combustion (ISC) and steam drive (SD), could significantly boost oil production and greatly enhance the recovery factor while dramatically shortening the exploitation period.

Field pilot tests carried out from 1964 to 1970 demonstrated that both ISC and SD methods were commercially viable. These tests indicated an additional recovery of 10-15%, leading to the decision to proceed with in-situ combustion. Subsequent field results largely validated these forecasts, although some factors were not fully understood or were overlooked during the initial development phases. Despite achieving an impressive recovery rate close to 60%, the ISC process at Suplacu de Barcau still holds potential for further improvements. These include water injection behind the combustion front, optimization of the air injection rate, and better control of the combustion front.

As of January 1, 2006, the project involved around 800 production wells, yielding an average daily production of 1200 tons of oil. Air injection rates were approximately 2000 thousand standard cubic meters per day through 90 wells, and steam injection rates were about 1300 tons per day through 24 wells. The cumulative recovery factor at that time was 45.3%. These results highlight the significant potential of ISC in enhancing oil recovery and improving the efficiency of oil production in high-density and viscous oil reservoirs.

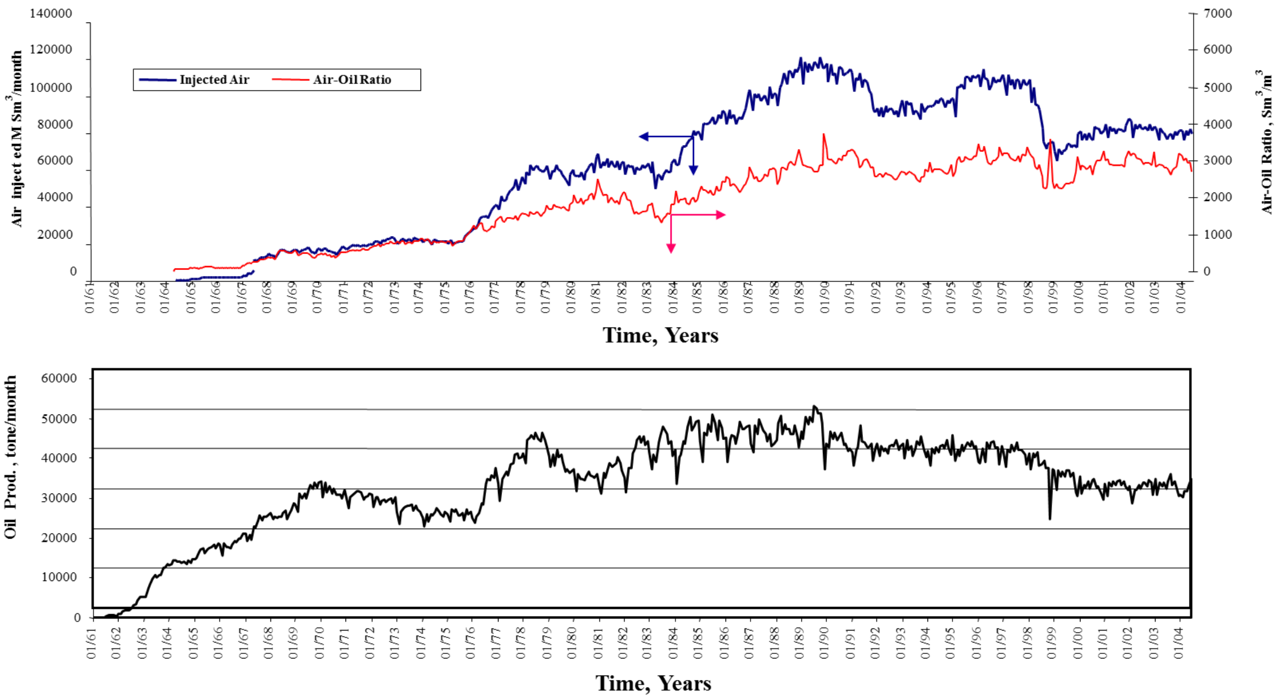


Fig. 17. The performance of the commercial ISC project in Suplacu de Barcau Project, Romania.

The good example of application of ISC after steam injection is **Xinjiang oilfield project** in China. Steam injection production for 8 years from 1991 gave accumulated oil production 81.7 thousand tons and the recovery degree 28.9%. After that the production declined significantly and operations were stopped on ten years from 1999 to 2009. In 2009, first field tests of in-situ combustion started on the area of 0.28 km^2 with 13 air injectors and 42 producers (well space: 70 m; areal well pattern at early stage, converting to linear well pattern later). The first results showed significant improvement of production (about 40 t/day in test area), significant upgrading of recovered oil, high decrease and stabilization of water cut (from 98 % to 72%). The accumulated air oil ratio equal to 2245 m^3/m^3 confirms economic efficiency of the project.

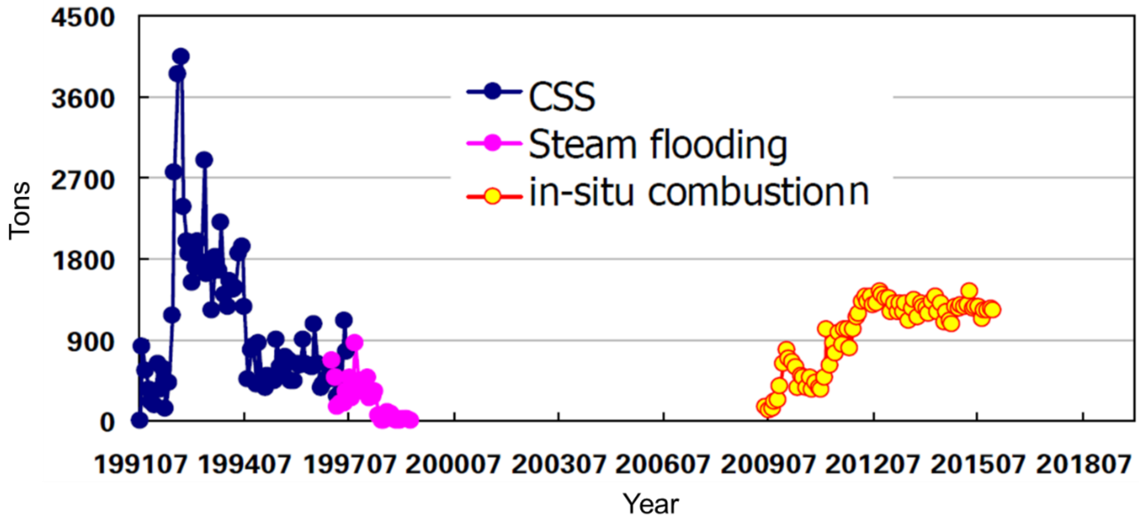


Fig.18. The performance of the pilot ISC project in Xinjiang oilfield (China) after steam injection.

New ISC Technologies: THAI Process

THAI, or "Toe-to-Heel" Air Injection, is an air injection process that leverages advanced horizontal well technology to achieve potentially high recovery rates of heavy oil. This method integrates the in-situ combustion (ISC) process with horizontal wells in what is known as a Short Distance Oil Displacement (SDOD) process, similar to Steam Assisted Gravity Drainage (SAGD). Consequently, THAI is classified as an SDOD process. A distinctive feature of THAI is its ability to facilitate significant in-situ upgrading through thermal cracking, allowing for upgraded oil to be produced at the surface. The process operates in a gravity-stabilized manner by confining drainage to a narrow mobile zone, directing the flow of mobilized fluids directly into the exposed section of a horizontal production well.

THAI can be implemented as a primary production technology, as a follow-up to existing methods, or as a co-process where high thermal efficiency is advantageous. This is accomplished by focusing the energy needed for oil mobilization, recovery, and thermal upgrading within the reservoir. By doing so, THAI enhances the overall efficiency and effectiveness of heavy oil recovery, making it a versatile and promising technique in the field of enhanced oil recovery.

The main phases of the THAI process: 1) Initiate a quasi-linear, ISC front perpendicular to the horizontal producer trajectory. This is achieved in the start-up region between the shoe of injection well and horizontal producer. 2) ISC front is anchored at the toe of horizontal well; then, the front propagated from the toe towards the heel.

In a bird's-eye view of the process, a notable aspect is the strategic placement of the vertical injector near the toe of the horizontal producer. A significant advantage of this setup is its self-healing capability, particularly in terms of complete oxygen consumption. This self-healing feature is attributed to the presence of a coke-plug at the intersection where the in-situ combustion (ISC) front meets the horizontal section of the horizontal producer. The coke-plug plays a crucial role in ensuring that oxygen is fully consumed, thereby enhancing the efficiency and safety of the process. This design element helps maintain continuous and effective operation, addressing potential issues related to oxygen management in the reservoir.

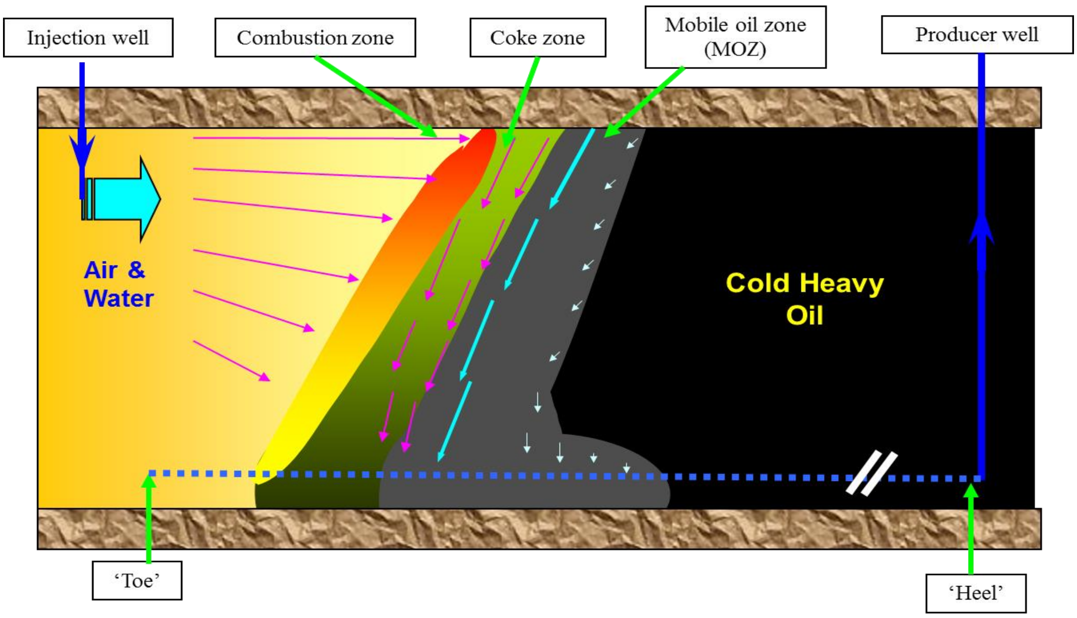


Fig. 19. THAI (Toe-to-Heel Air Injection) Scheme.

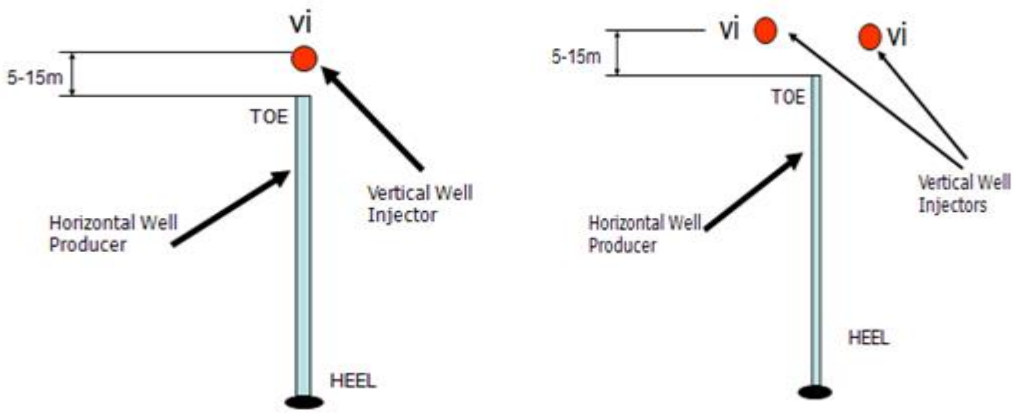


Fig. 20. Schematic of Toe-To-Heel Air Injection in a Direct and a Staggered Line Drive Configuration. Bird's Eye View.

Field application of THAI process (in all projects the direct line drive (DLD) configuration was tested (except the test in India):

1) Whitesands Experimental Project, Conklin, Alberta, Canada

   3 experimental well pairs; duration 5.5 years

   March 2006 – October 2011

2) Kerrobert Project, Saskatchewan, Canada

   2 experimental well pairs followed by semi-commercial operation of 12 pairs (2+10); duration 7.5 years

   September 2009 – Present (on-going project)

3) Two Experimental Projects in China (one is ongoing)
4) One pilot in India (started in Dec 2016) - ongoing

Whitesands Experimental Project results:

- Confirmed the possibility to recover an upgraded oil with oil rates up to 30-40m^3/day/well; average oil rate per well was around 20 m^3/day.
- The THAI^{TM} Pilot produced a cumulative of oil of approx. 29,000 m^3. According to literature data, except SAGD and CSS (which produce commercially) no other method tested in Athabasca oil sands has produced more.

- The pilot demonstrated the technical feasibility of THAI™ process, which, at this time, is the only EOR process showing consistent upgrading of the produced oil.
- The technical validity of THAI is demonstrated, but the full economic validity is not demonstrated yet (AOR was too high! Oil rate much less than that of SAGD!).
- Some operational problems: -sand influx (solved); some oil lifting problems; horizontal producers re-drilled.

Kerrobert Project results:

- Conventional heavy oil reservoir underlain by bottom water.
- No sand problems and, in general, less operating problems.
- Substantial upgrading of the produced oil (maximum 7 API degrees)
- Semi-commercial project consisted in the extension to 12 pairs (24 wells). It started at the end of 2011, beginning of 2012
- The pilot (first 2 years): oil rate per well up to 22 m^3/day; average oil rate per well was around 10 m^3/day; AOR=1500 m^3/m^3
- The performance of large-scale operation has been much lower than that of the pilot in its first two years
- The first project in the world to try a large-scale operation in the presence of **b**ottom **w**ater (BW).

New ISC Technologies: CAPRI Process

In CAPRI (catalytic upgrading process in situ), the horizontal section of the THAI horizontal producer is surrounded by a catalyst-activated gravel packing (Picture-5). Therefore, CAPRI is a catalytic THAI process.

All the phenomena (thermal, hydrodynamic, etc.) are the same for THAI and CAPRI; the only difference is the second upgrading occurring when oil is flowing into the bottom-hole of the horizontal producer. In laboratory testing, the process was able to achieve an upgrading of up to 14 API degrees. Compared to THAI, CAPRI is much less investigated and developed. In addition, there are many challenges in the simulation of the process; at this time it is difficult to reflect the upgrading process in its entirety. Short history: CAPRI was discovered by Dr. Conrad Ayasse and Dr. Alex Turta, formerly of the Petroleum Recovery Institute (PRI), with PRI later incorporated in Alberta Innovates-Technology Futures, Calgary, Canada, and Prof. Malcolm Greaves of University of Bath, UK. Current status: CAPRI has not been extensively piloted in the field. The field testing of CAPRI should be considered only after more intense laboratory investigations to clarify the main mechanisms and optimize the use of catalysts in less controllable, underground conditions are performed. Also, the relationship between oil upgrading and hydrogen production has to be investigated.

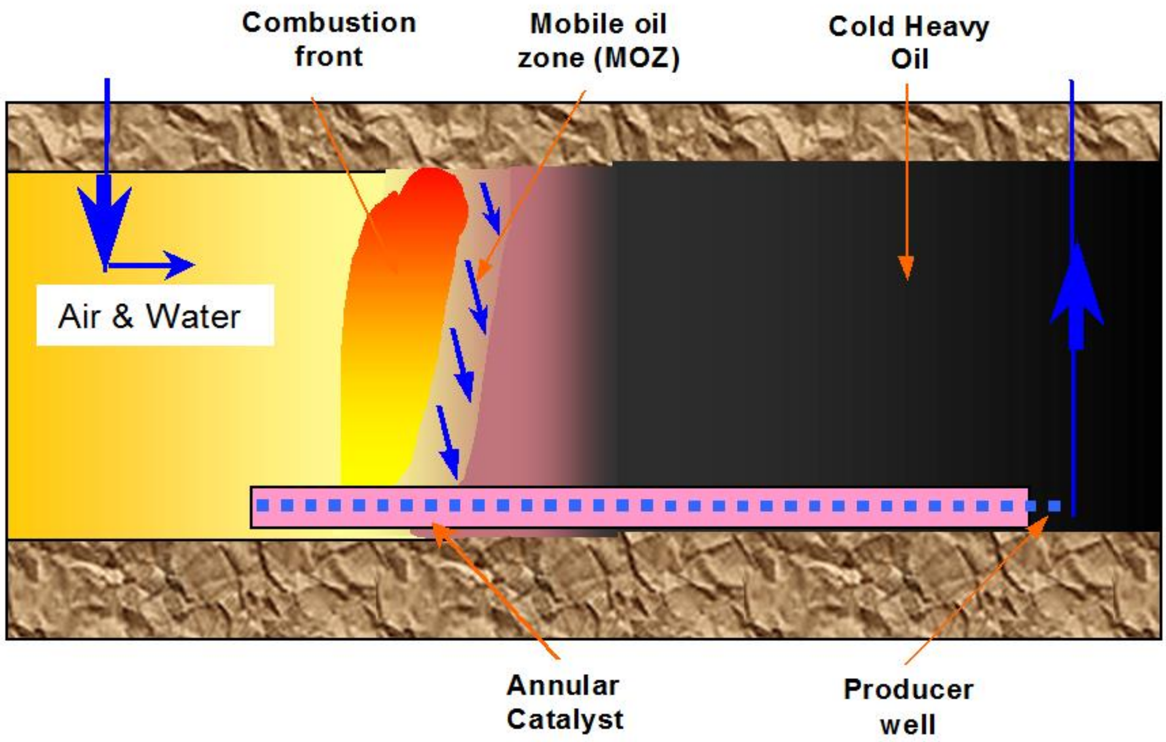


Fig. 21. CAPRI Scheme.

Physical Modeling of the in-situ combustion process Under Laboratory Conditions

Description of a unique scientific installation and methodology for conducting physical and chemical modeling of the in-situ combustion process

This chapter presents the developed methodology based on Industry Standard (I-S) 39-195-86, intended to determine the dynamics of change in the oil displacement coefficient, temperature profile, pressures at the entrance and exit of the reservoir model under thermal impact. In this case, the oil displacement conditions are maximally close to reservoir ones due to the use of reservoir or model fluids with the obligatory creation and maintenance of reservoir temperature and pressure.

The oil displacement coefficient is one of the most important characteristics of the reservoir. The oil displacement coefficient is taken into account in the formula when calculating the oil recovery coefficient. It is also an efficiency criterion when selecting oil displacement technology.

The essence of the method is to filter the injection agent (cold, hot water, steam, air) through oil-saturated rock on a unique scientific installation (registration number 2083849) for physical and chemical modeling of the process of in-situ combustion and steam-thermal drainage (photo shown in Fig. 22).

Fig. 22. Photo of a unique scientific installation for conducting physical modeling of the in-situ combustion process.

The unique scientific installation consists of an agent supply system, a high-pressure chamber for creating a confining (rock) pressure, and a fluid collection system (gas, oil, water). The installation diagram is shown in Fig. 23.

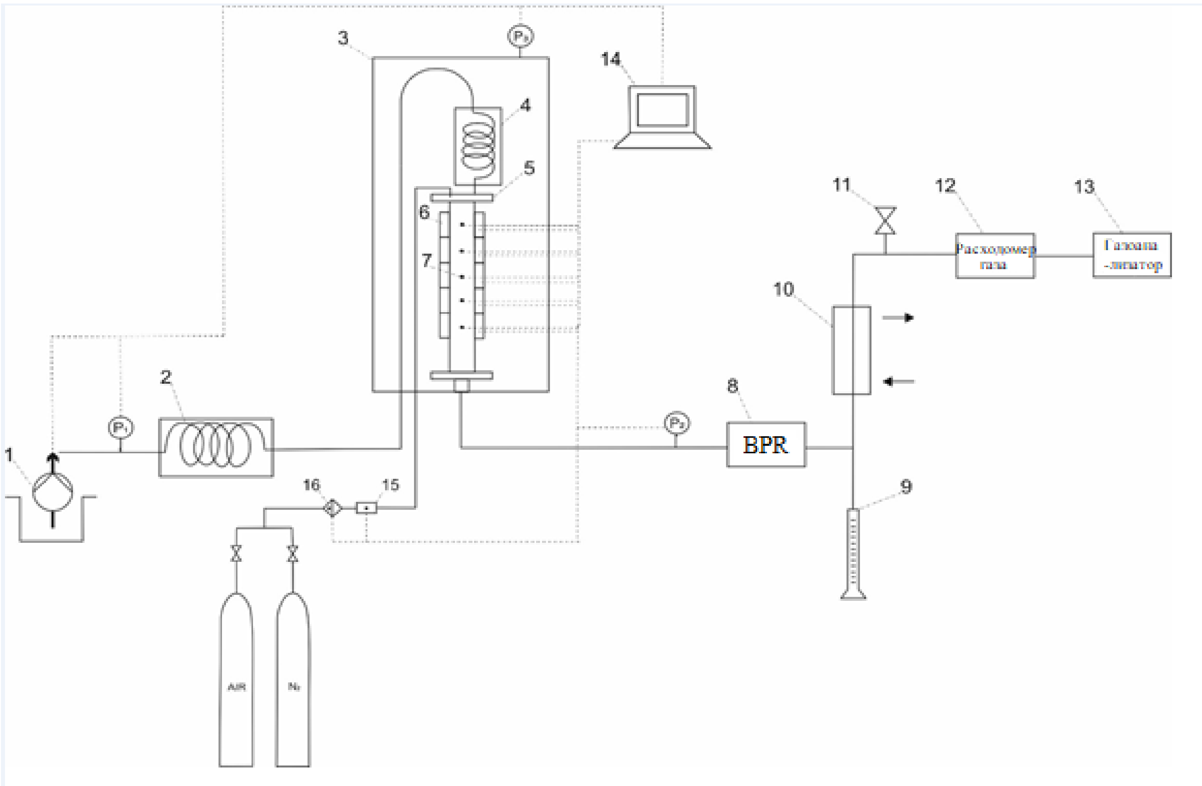


Fig. 23. Schematic diagram of a unique scientific installation for conducting physical modeling of the in-situ combustion process.

The injection agent feed system consists of a high-pressure plunger pump with piston containers (1) dosing water and reagents at a constant rate to the input of an external steam generator (2) and an internal steam generator (4), or directly through a system of connecting tubes to a core holder (5). The high-pressure chamber (3) includes an internal steam generator (4), a core holder (5) with a formation model, ceramic electric heaters (6) and thermocouples (7).

The model can be positioned both vertically and horizontally due to the rotary mechanism. The fluid collection system consists of a back pressure regulator (8), which maintains formation pressure in the model and discharges fluid into a receiving burette (9), in which the fluid is separated under standard conditions into liquid and gas. The separated gas is fed to a Ritter gas flow meter, then to a gas analyzer (13) to determine the gas composition. Optionally, gas samples can be taken in front of the gas flow meter (11) for analysis by gas chromatography. A Bronkhorst model F-231M Mass Flow Controllers gas flow regulator (15) is installed to supply air.

Pressure sensors are installed at the inlet and outlet of the formation model and reflect the pressure change in real time. Thermocouples (7) are installed on the core holder every 5 cm in the formation model, recording the movement of the thermal front in real time. Annular ceramic heaters for maintaining the adiabatic regime are installed along the core holder (5) to prevent heat loss during the experiment. The control system of the electric heaters (6) is configured to turn them on when the temperature inside the formation model increases by 5°C from the temperature of the formation model.

Methodology for conducting an in-situ combustion experiment

When creating a bulk model in experiments, sand or ground core (fractions 0.1÷1 mm) was used as rock. When conducting research on a composite model, the core is positioned in the center of the core holder and compacted (using a press) with ground rock (fraction less than 0.1 mm) to a permeability corresponding to the reservoir properties of cylindrical samples.

The core holder for the experiment is a steel pipe with a flange mount and mounting holes for thermocouples (Fig. 24). The thermocouples are located in the center of the model at a distance of 5 or 9 cm from each other. Thermocouple calibration is carried out before each experiment. A copper high-temperature gasket was used to seal the flanges; the flanges were assembled using high-strength bolts (strength class 10.9).

The core holder is positioned vertically to minimize gravity effects, allowing the combustion front and associated chemical reactions to propagate under near reservoir conditions.

During the experiment, temperature, pressure, air flow and the composition of the exhaust gases are recorded. Injection usually continues until the combustion temperature in the extreme temperature zone of the core holder decreases. However, for safety reasons, during the in-situ combustion experiments, the combustion front was not brought to the lower flange, but stopped approximately 5-7 cm before it by feeding nitrogen.

The data on the characteristics of the reservoir model during the in-situ combustion experiments are presented in Appendix B.

The oil displacement coefficient is calculated using formula special formula. The oil displacement coefficient is calculated based on the material balance using the following formula:

Recovery factor = m (mass of the recovered oil)/m (maas of the initial crude oil in the model)

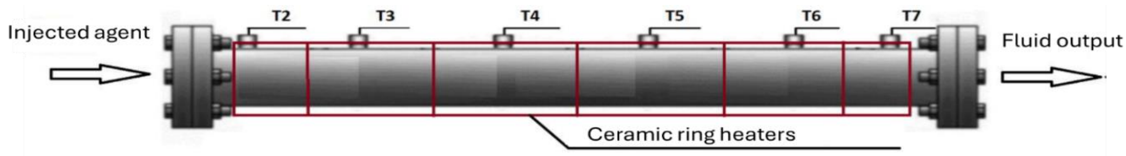


Fig. 24. Diagram of a core holder with designation of temperature heating zones

3.3.2. Steam Based Enhanced Oil Recovery Methods

Steam injection is an increasingly common method for extracting heavy crude oil. It is the most widely used thermal enhanced oil recovery (EOR) method. There are several different forms of the technology, including cyclic steam stimulation (CSS), steam flooding, and steam-assisted gravity drainage (SAGD), etc. CSS and steam flooding are two widely used processes, mainly in those reservoirs that are relatively shallow and contain very viscous crude at reservoir temperature. Steam injection is widely used in the San Joaquin Valley of California (USA), the Lake Maracaibo area of Venezuela, the oil sands of northern Alberta (Canada), and Ashalchinskoe ultra-viscous oilfield (Russia).

Fundamentals of steam based thermal EOR methods-Thermodynamic properties of water vapor

When water is heated at constant pressure after reaching the boiling point or vaporization, it begins to boil, and some of the hot water turns into steam. If heating is continued, then all the water will be evaporated over time. At the same time, the temperature remains constant (Fig. 25).

The **latent heat of vaporization of a liquid** is the amount of heat in kJ required to evaporate 1 kg of liquid at the boiling point.

The **latent heat of vapor condensation** is the amount of heat in kJ releasing during condensation of 1 kg of water vapor.

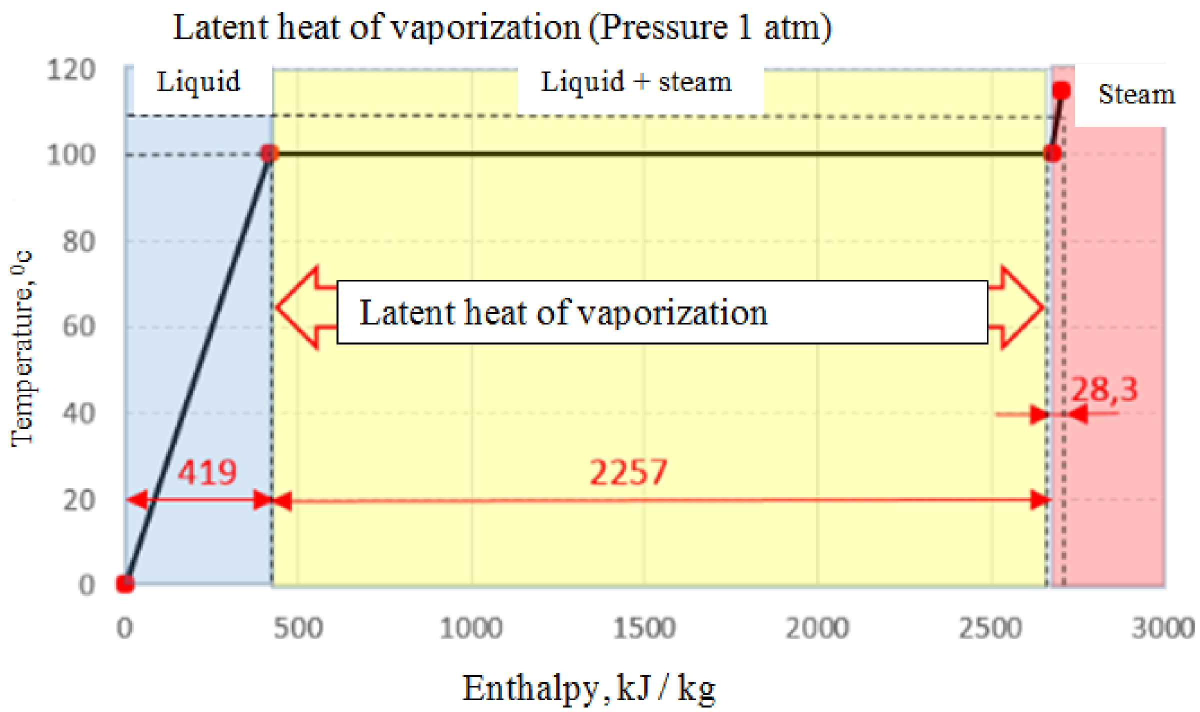


Fig. 25. Energy distribution during vaporization.

A mixture of steam and condensate (water) forms ***wet steam***. The share of steam in the total mass of wet steam is called the degree of **steam dryness**.

If the dry steam continues to be heated (energy transfer), it turns into superheated steam with a temperature above the temperature of vaporization. At the same time, the vaporization temperature depends on the pressure and increases with the increase in the latter (Fig. 26).

P, atm	T, °C	specific volume, sm3/g		Heat energy J/g	
		water	steam	water	steam
1	99,09	1,043	1725	415	2674
3	132,88	1,073	616,9	559	2724
5	151,11	1,092	318,9	637	2747
8	169,61	1,11	230	718	2768
10	179,4	1,126	198	759	2777
12	187,08	1,137	166,3	795	2783
14	194,13	1,148	143,4	826	2789
16	200,43	1,157	126,1	854	2793
18	206,14	1,166	112,5	882	2796
20	211,38	1,178	101,6	904	2799
22	216,23	1,183	92,44	926	2800
24	220,75	1,191	84,86	952	2801
26	225	1,199	78,28	967	2802
28	228,98	1,207	72,82	985	2802
30	232,8	1,214	67,98	1003	2803

Fig. 26. Thermodynamic properties of water and steam along the vaporization line.

Thus, all other things being equal, steam has a greater quantity of heat than hot water of the same mass. Consequently, by pumping steam into the reservoir, we are able to transfer a greater amount of heat to the reservoir than when pumping hot water of the same mass.

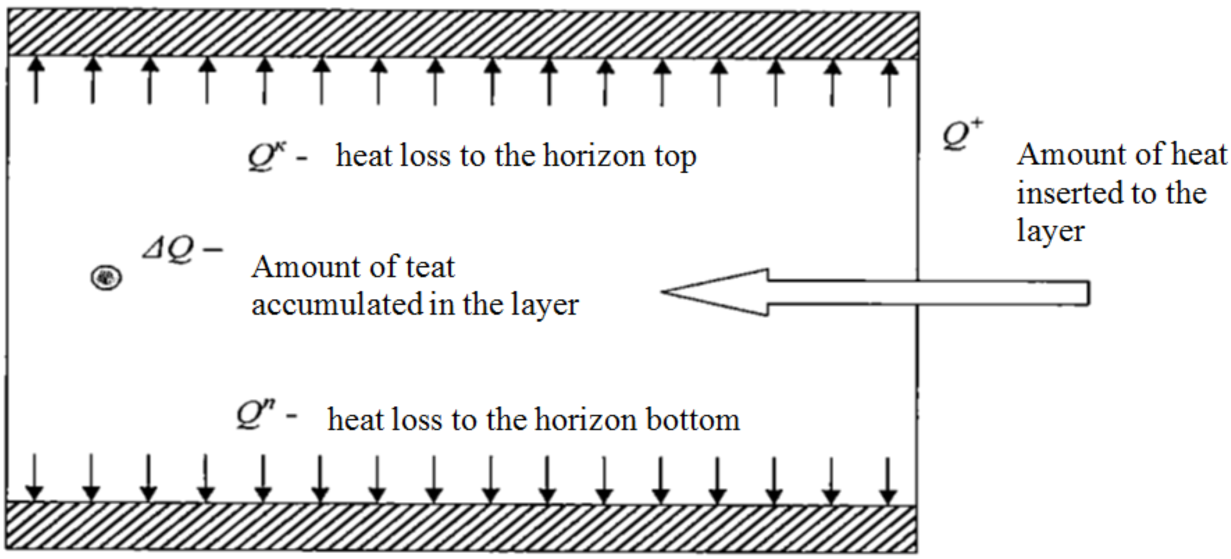


Fig. 27. Energy balance in the reservoir

Heat transferred to the reservoir is spent on heating rocks around the wellbore and the oil-saturated formation interval. Partially heat is dissipated through the top and the bottom of the formation (Fig. 27).

Within the oil-saturated interval of the reservoir, the **main share** of thermal energy is spent on heating the rock (Fig. 20).

Favorable factors for the use of steam injection are depths of up to 600-900m, the net saturated thickness of more than 6 m.

The large number of permeable intervals of the reservoir and low porosity of the reservoir act as negative factors in the implementation of the steam injection technology.

Example:

With a porosity of m = 20%, oil saturation So = 75%, approximately 2352 kJ/deg will be required to heat 1 m^3 *of the reservoir rock. The distribution of the amount of heat for heating the rock, oil + water will be approximately 79% and 21%, respectively (Fig 28).*

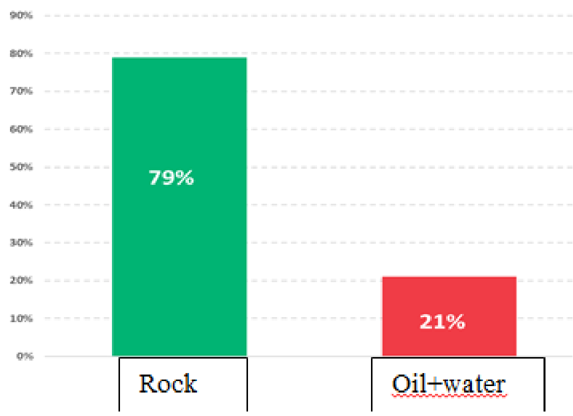


Fig. 28. Distribution of the delivered energy during the productive formation heating.

When steam is injected, the formation is heated primarily due to the latent heat of vaporization (condensation). As steam moves through the reservoir, the degree of steam dryness gradually decreases to complete condensation. Furthermore, heating of the rock and the fluids saturated inside it occurs due to the heat of hot water, followed by a decrease and equalization of temperature to the initial temperature of the reservoir.

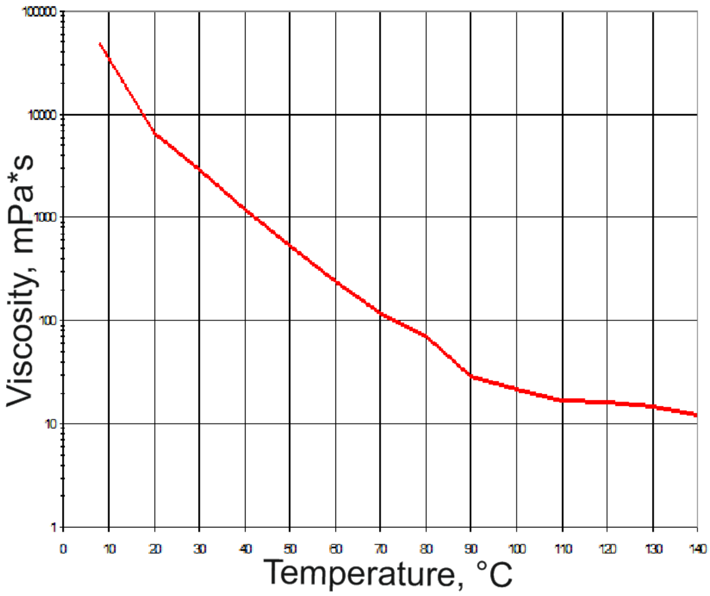
Evaluation of the technological efficiency of thermal impact on the reservoir is expressed by the specific steam consumption for the production of 1 ton of oil, or as it is called the ***steam-oil ratio (SOR)***.

NB. Burning of 1 ton of oil in a steam generator produces 13-15 tons of steam;

therefore, in order to get cost-effective technologies, the specific steam consumption per ton of oil, taking into account the costs of steam preparation and steam pumping, the PNO is considered to be no more than 3-4 tons of steam per 1 ton of oil.

Fundamentals of steam based thermal EOR methods-Properties of oil when assessing the applicability of thermal-stream methods (Results of laboratory studies)

Numerous laboratory studies of various authors have shown the expected behavior: oil viscosity decreases with increasing temperature. Considering the example of the Ashalchinskoe UVO field, (Fig. 29), at a reservoir temperature of 8 °C, the viscosity of the oil reaches 17,000-20,000 mPa·s. At the same time, an increase in temperature from 8 ºC (reservoir temperature) to 120 ºC causes a decrease in oil viscosity by three orders of magnitude (Fig. 29 b). At this temperature, the viscosity of the ultra-viscous oil is close to the viscosity of standard oil, which is a favorable factor for the application of thermal EOR methods.



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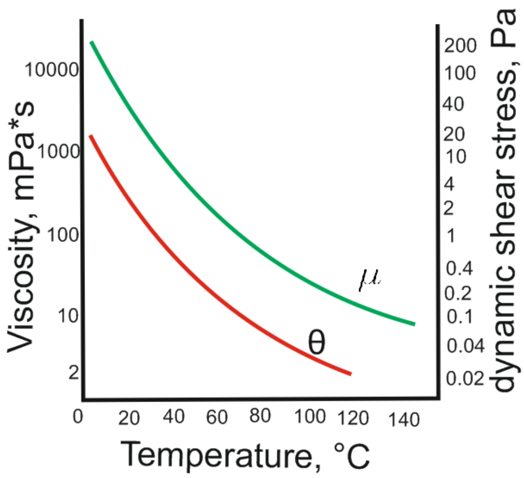


b

Fig. 29. Oil viscosity – temperature relationship in Ashalchinskoe oilfield.

Rheological curves analysis (Fig. 30), obtained as a result of laboratory studies shows that with the same values of depression, productivity increases by 3-4 orders of magnitude at the increased temperatures. The result also suggests a possible application of thermal EOR methods for the development of ultra-viscous oils.

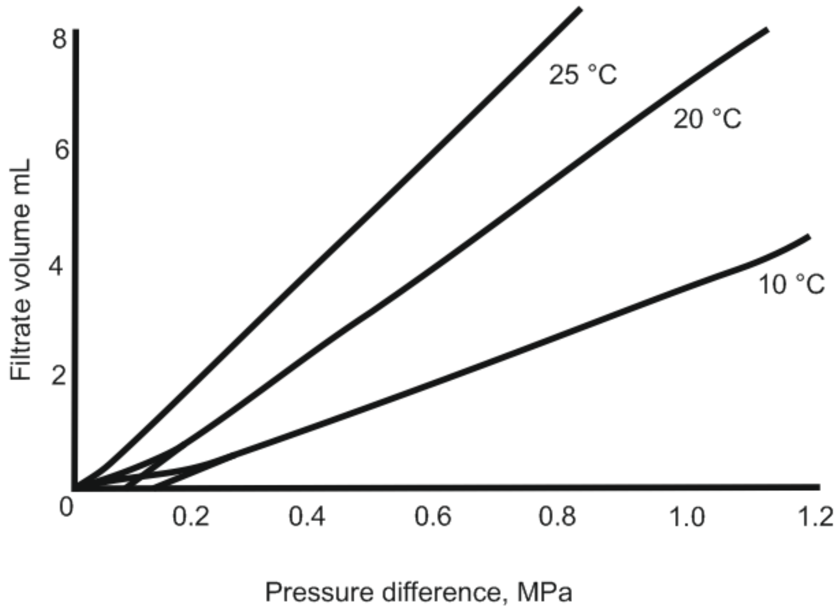


Fig. 30. Rheological lines in the ultra-viscous oil filtration through loose sandstone.

Cyclic Steam Stimulation (CSS)

This method, also known as the Huff and Puff, consists of three stages: injection, soaking, and production. CSS yields a recovery of approximately 20% of the Original Oil in Place (OOIP), which is relatively low compared to that of SAGD (has been reported to recover over 50% of OOIP). Nevertheless, it is quite common for wells to be produced in using CSS for a few cycles before the implementation of steam drive. Fig. 31 shows the stage and sequence of the Cyclic Steam Stimulation (CSS) [5].

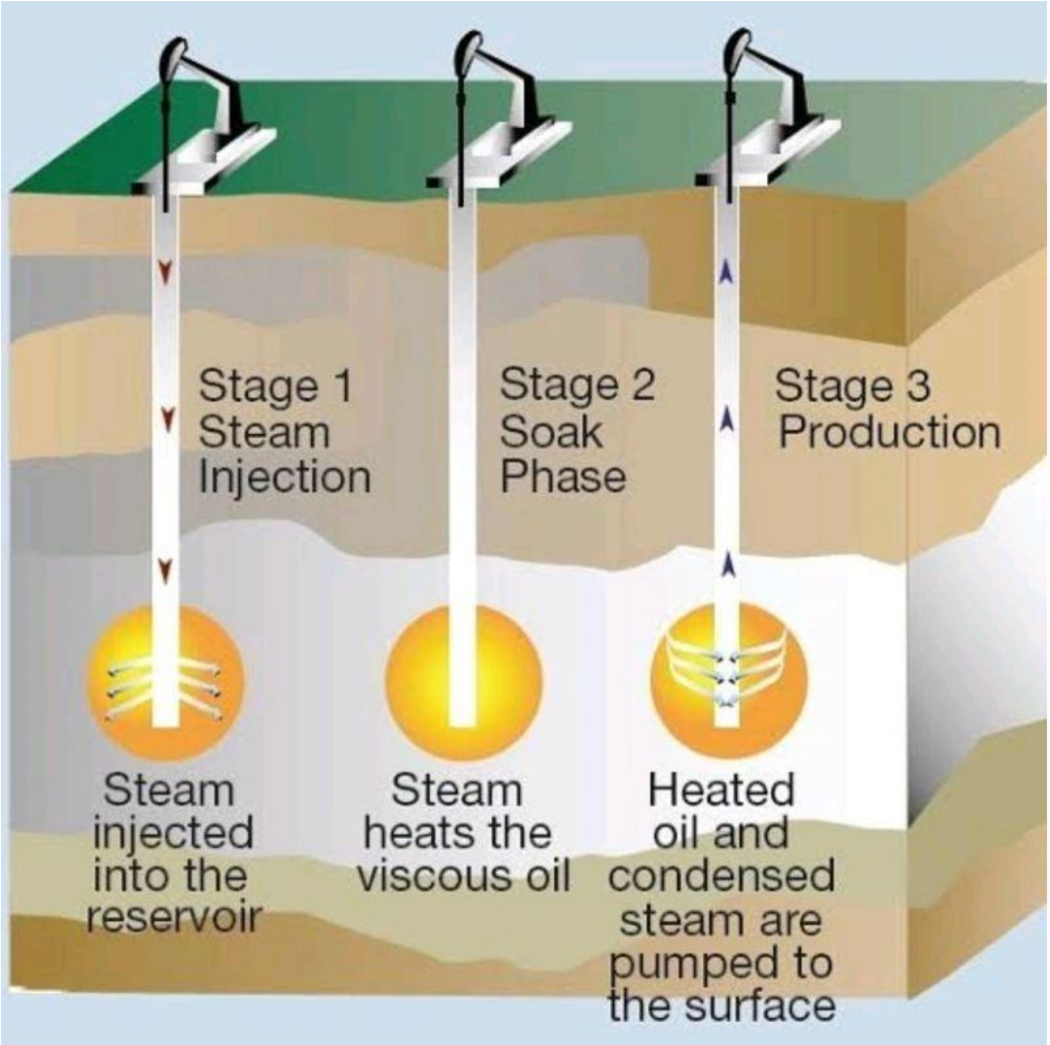


Fig. 31. Main stages of the Cyclic Steam Stimulation (CSS) process.

In a CSS process, first, steam is injected into a well at a temperature of 300 to 340 °C for a period of weeks to months. Next, the well should be shut down for days to weeks to allow heat to be soaked into the formation. Finally, the hot oil is pumped out of the well for a period of weeks or months. Once oil production rates fall below a critical threshold due to the cooling of the reservoir, the well is put through another cycle of injection, soak and production. This process is repeated until the cost of steam injection becomes higher than the money made from producing oil. Usually, the CSS method has the recovery factor of around 20 to 25% and it is easy to be implemented. But the cost for steam injection is high. Canadian Natural Resources use “cyclic steam stimulation” or "huff and puff" technology to develop bitumen resources.

High pressure cyclic steam stimulation (HPCSS)

High Pressure Cyclic Steam Stimulation (HPCSS) accounts for approximately 35% of all in situ oil sands production in Alberta. This technique involves two main phases. Initially, steam is injected into an underground oil sands deposit at high pressures, which fractures and heats the formation, softening the bitumen much like conventional Cyclic Steam Stimulation (CSS), but with the added benefit of higher pressures. After the steam injection phase, the process shifts to production. During this phase, the heated bitumen, mixed with steam to form a "bitumen emulsion," is pumped to the surface through the same well. This production continues until the pressure drop slows down extraction to an uneconomical rate, at which point the cycle is repeated multiple times.

The Alberta Energy Regulator (AER) explains that HPCSS differs from Steam Assisted Gravity Drainage (SAGD) in several key ways. While HPCSS uses high-pressure steam to create fractures and facilitate bitumen flow, SAGD involves continuous steam injection at lower pressures without fracturing the reservoir, relying primarily on gravity drainage for recovery. HPCSS has been utilized in Alberta for over 30 years, indicating its long-term viability and effectiveness in oil recovery.

In the Clearwater Formation near Cold Lake, Alberta, HPCSS employs both horizontal and vertical wells. Steam injection is performed at fracture pressure, with horizontal wells spaced 60 to 180 meters apart and vertical wells spaced at 2 to 8 acres. The technique is effective even in formations with as little as 7 meters of net pay and is typically used in areas with minimal to no bottom water or top gas. The Cyclic Steam-Oil Ratio (CSOR) for HPCSS ranges from 3.3 to 4.5, and the ultimate recovery is estimated to be between 15% and 35%.

SAGD is also used in the Clearwater and Lower Grand Rapids Formations, employing horizontal well pairs spaced 700 to 1000 meters apart, with an operating pressure of 3 to 5 MPa. The Burnt Lake SAGD project initially operated at a higher pressure close to the dilation pressure, with well spacings of 75 to 120 meters. This method is applicable in areas with or without bottom water and achieves a CSOR of 2.8 to 4.0, with a predicted ultimate recovery of about 45% to 55%.

Canadian Natural Resources Limited's (CNRL) Primrose and Wolf Lake in situ oil sands project, located near Cold Lake in the Clearwater Formation and operated by CNRL subsidiary Horizon Oil Sands, employs HPCSS. This project exemplifies the practical application and effectiveness of HPCSS in enhancing bitumen recovery from challenging reservoirs.

Overall, HPCSS has proven to be a robust method for enhancing oil recovery in Alberta's oil sands, particularly in formations where high-pressure steam can effectively fracture the reservoir and facilitate bitumen extraction. By leveraging the strengths of HPCSS, operators can achieve significant recovery rates, making it a cornerstone technique in the region's oil production strategy. The dual-phase approach of HPCSS, involving high-pressure steam injection followed by production, ensures sustained bitumen flow and maximizes the economic viability of oil sands projects.

Steam Flooding

For a steam flooding process (also called as steam drive), steam is injection from injection wells, and the oil is produced from production wells. There are two main mechanisms for improving oil recovery. The first is to heat the oil to higher temperatures and thereby to decrease its viscosity so that it can flow more easily through the formation toward the production wells. A second mechanism is the physical displacement similar to water flooding, i.e. oil is meant to be pushed to the production wells. More steam is needed for this method than for the cyclic method, but it is typically more effective at recovering a larger portion of the oil. Fig. 32. illustrates the diagram showing a steam flood operation [6].

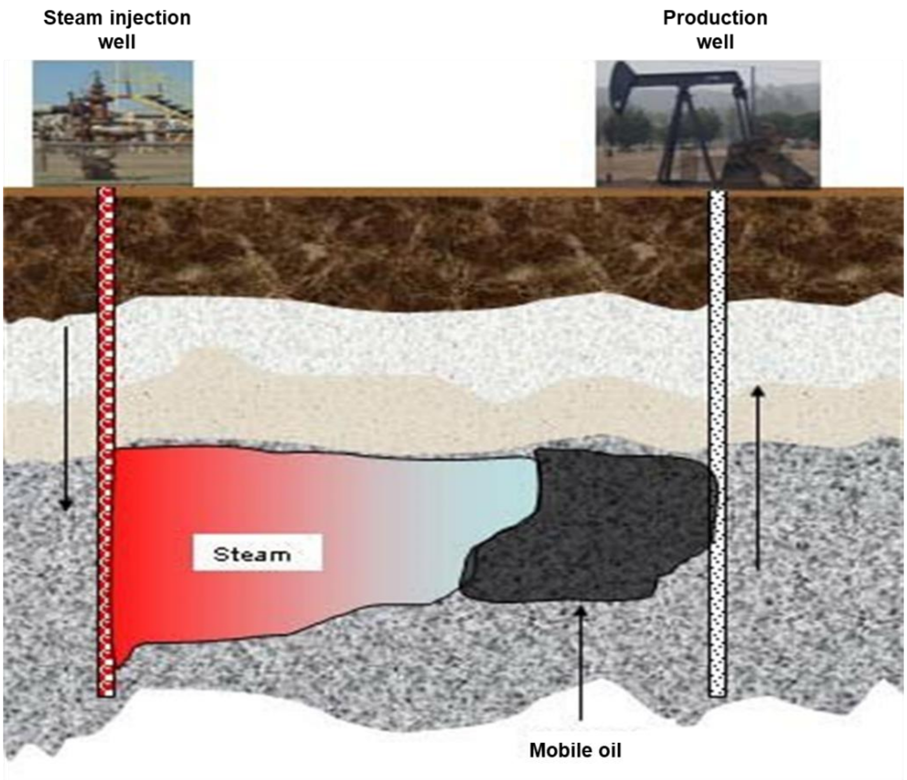


Fig. 32. Diagram showing a steam flood operation.

Steam-assisted gravity drainage (SAGD)

Another widely used steam injection technique in the Alberta oil sands is Steam Assisted Gravity Drainage (SAGD). In this process, two horizontal wells are drilled in parallel within the formation, with the upper well positioned about 4 to 6 meters above the lower one. The upper well is responsible for injecting steam, while the lower well collects the heated crude oil or bitumen that flows down due to gravity, along with the condensed water from the steam.

The core principle of the SAGD process is to establish thermal connectivity with the reservoir so that the injected steam creates a "steam chamber." This heat significantly lowers the viscosity of the heavy crude oil or bitumen, allowing it to flow downwards into the lower well. The steam and gases rise because they are less dense than the oil beneath, ensuring that steam does not enter the lower production well directly. Instead, they fill the space left by the displaced oil, creating an insulating "blanket" of associated gases above and around the steam chamber, which helps retain heat within the system. Oil and water flow is by a countercurrent, gravity driven drainage into the lower well bore. The flow of oil and water occurs through a countercurrent, gravity-driven process into the lower wellbore. The condensed water, along with the crude oil or bitumen, is then brought to the surface using pumps, such as progressive cavity pumps, which are particularly effective for handling high-viscosity fluids containing suspended solids.

The idea of gravity drainage was initially proposed by Dr. Roger Butler, an engineer at Imperial Oil, during the 1970s. In 1975, Butler was transferred from Sarnia, Ontario, to Calgary, Alberta, by Imperial Oil to spearhead their heavy oil research efforts. By 1980, he had put the concept into practice through a pilot project at Cold Lake, using one of the industry's earliest horizontal wells combined with vertical injectors. In 1983, Butler took on the role of director of technical programs at the Alberta Oil Sands Technology and Research Authority (AOSTRA), a government organization founded by Alberta Premier Peter Lougheed to support the development of innovative technologies for oil sands and heavy crude production. Seeing the promise in Butler’s approach, AOSTRA soon endorsed Steam-Assisted Gravity Drainage (SAGD) as a revolutionary method for extracting oil sands.

Under Butler's leadership and AOSTRA's support, SAGD was developed into a highly effective method for heavy oil recovery. This technique has since become a cornerstone of oil sands extraction, demonstrating significant improvements in efficiency and production rates. The collaboration between Butler and AOSTRA played a pivotal role in the evolution of SAGD, highlighting the importance of innovative research and development in the energy sector.

Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) are two primary thermal recovery techniques commercially utilized in the oil sands. These methods are applied within specific geological formation sub-units, such as the Grand Rapids Formation, Clearwater Formation, McMurray Formation, General Petroleum Sand, and Lloydminster Sand of the Mannville Group, which is part of the Western Canadian Sedimentary Basin's stratigraphic range. These formations are key targets for extracting heavy oil and bitumen using thermal methods due to their favorable geological characteristics.

Canada has become the largest supplier of imported oil to the United States, providing over 35% of US oil imports, significantly more than Saudi Arabia, Venezuela, or all OPEC countries combined. This increase in supply primarily comes from Alberta's extensive oil sands deposits. There are two main methods of recovering oil from these sands: strip mining and steam-assisted gravity drainage (SAGD). Strip mining is well-known but limited to shallow bitumen deposits. SAGD, however, is more effective for the deeper and more extensive deposits surrounding the shallow ones and is expected to drive much of the future growth in Canadian oil sands production.

In the Clearwater Formation near Cold Lake, Alberta, High Pressure Cyclic Steam Stimulation (HPCSS) is employed. This technique uses both horizontal and vertical wells, with steam injected at fracture pressure. Horizontal wells are spaced 60 to 180 meters apart, while vertical wells are spaced 2 to 8 acres apart. HPCSS is effective even in formations with as little as 7 meters of net pay and is used in areas with minimal to no bottom water or top gas. The Cyclic Steam-Oil Ratio (CSOR) for HPCSS ranges from 3.3 to 4.5, with ultimate recovery rates predicted to be between 15% and 35%.

SAGD is also utilized in the Clearwater and Lower Grand Rapids Formations, involving horizontal well pairs spaced 700 to 1000 meters apart and operating at pressures of 3 to 5 MPa. The Burnt Lake SAGD project, for instance, started with higher operating pressures near the dilation pressure, with well spacings of 75 to 120 meters. This method can be applied in areas with or without bottom water and achieves a CSOR of 2.8 to 4.0, with an ultimate recovery rate of approximately 45% to 55%.

Canadian Natural Resources Limited’s (CNRL) Primrose and Wolf Lake in situ oil sands project near Cold Lake, Alberta, within the Clearwater Formation, also employs HPCSS. This project, operated by CNRL subsidiary Horizon Oil Sands, exemplifies the effective use of HPCSS in enhancing bitumen recovery from challenging reservoirs.

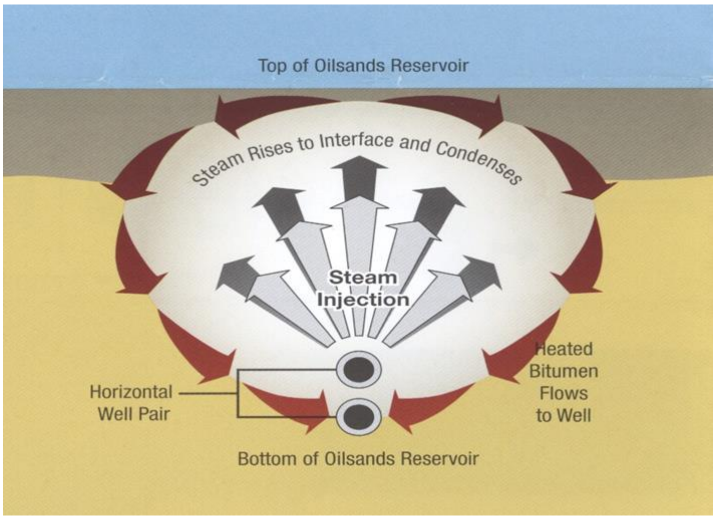


Fig. 33. Steam-assisted gravity drainage (SAGD).

Steam-Assisted Gravity Drainage (SAGD) is an advanced method for extracting heavy oil or bitumen, building on earlier steam injection techniques originally developed for heavy oil production in California's Kern River Oil Field. The basic concept behind steam flooding processes is to apply heat to the oil reservoir, which lowers the viscosity of the heavy oil. This reduction in viscosity enables the oil to flow more freely toward the production well, enhancing recovery efficiency.

Cyclic Steam Stimulation (CSS) was originally developed for heavy oil fields in California and had some success in parts of Alberta’s oil sands, including the Cold Lake region. However, CSS proved less effective for extracting bitumen from the deeper and heavier deposits found in the Athabasca and Peace River oil sands, which make up the majority of Alberta’s reserves. To overcome the challenges presented by these larger and more complex deposits, the Steam-Assisted Gravity Drainage (SAGD) process was developed as a more suitable solution.

The SAGD technique was initially developed by Dr. Roger Butler of Imperial Oil, with contributions from the Alberta Oil Sands Technology and Research Authority and several industry collaborators. According to estimates by the National Energy Board, SAGD becomes financially feasible when oil prices reach at least

US$30 to $35 per barrel. This technique marks a major breakthrough in the recovery of heavy oil and bitumen, enhancing the extraction efficiency from Alberta's extensive oil sands. SAGD's capability to extract oil from challenging reserves, where other techniques have struggled, highlights its significance in the industry. By effectively delivering heat to the reservoir and lowering the viscosity of the oil, SAGD enables the movement of oil towards production wells, thereby playing a vital role in optimizing oil recovery from Alberta's oil sands deposits.

Vapor extraction (VAPEX) is a promising gas-based method for recovering heavy oils and bitumen, particularly in reservoirs where thermal methods like steam-assisted gravity drainage (SAGD) are unsuitable (Fig. 34). In the VAPEX process, a pair of horizontal wells is used: one for injection and the other for production. A gaseous hydrocarbon solvent, such as propane, butane, or a mixture of these gases, is injected through the top well. This solvent dilutes the heavy oil, which then drains downward by gravity to the lower production well.

Recently, a novel approach utilizing carbon dioxide (CO2) as the solvent in the VAPEX process has been developed. The high solubility and significant viscosity reduction potential of CO2 can enhance the efficiency of the VAPEX process. Additionally, using CO2 offers the added benefit of carbon sequestration, addressing environmental concerns by reducing greenhouse gas emissions. This innovative use of CO2 not only improves the recovery of heavy oils and bitumen but also contributes to more sustainable oil extraction practices.

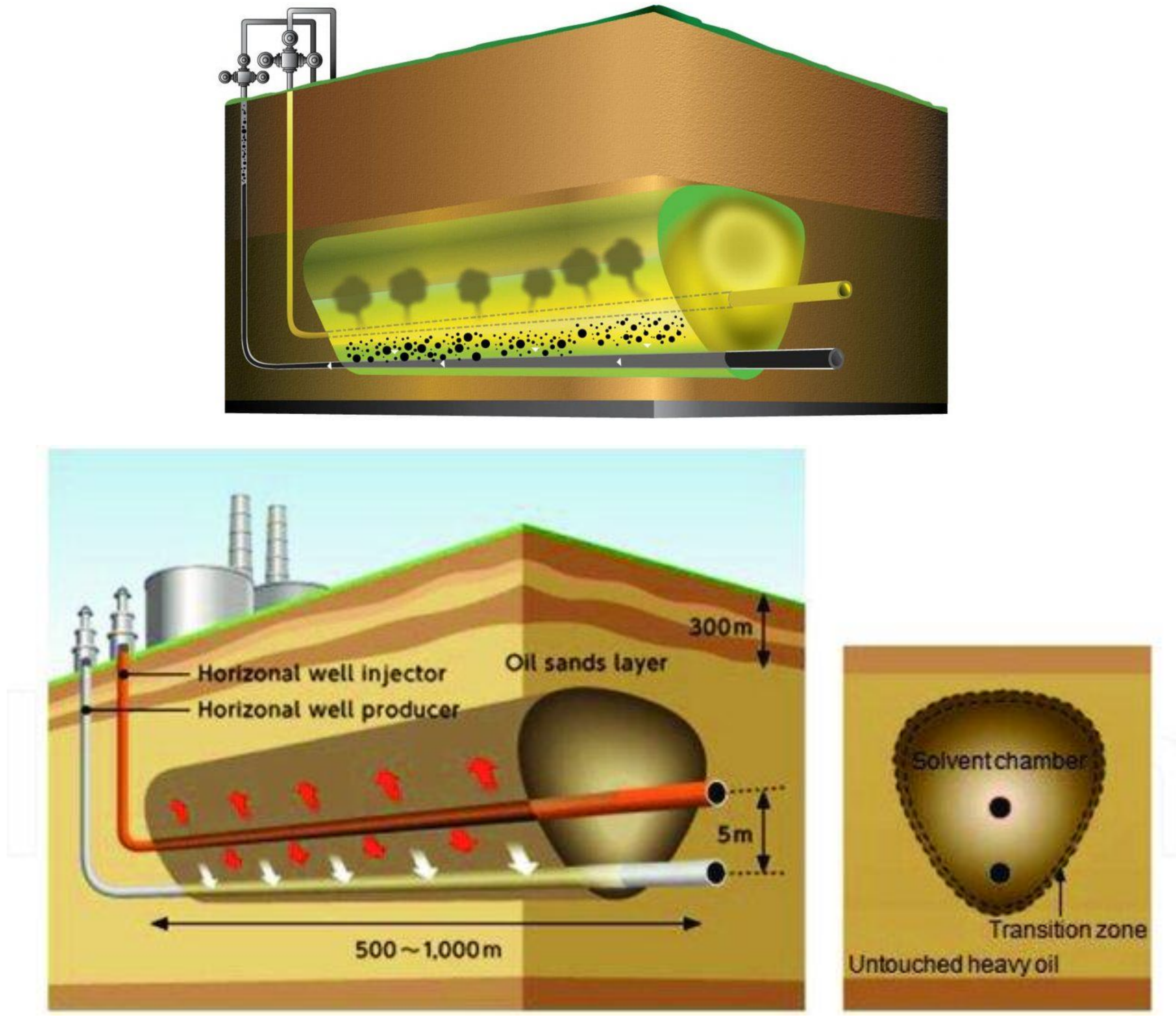


Fig. 34. The VAPEX heavy oil recovery process.

Sub-cool is defined as the difference between the saturation temperature (boiling point) of water at the producer's pressure and the actual temperature at that point. In simple terms, when the liquid level above the producer is higher, the temperature decreases, leading to an increase in sub-cool. Achieving a consistent sub-cool across the entire horizontal length of a well is often difficult because of the natural heterogeneity found in real-life reservoirs. To manage uneven steam chamber development, operators sometimes allow a controlled amount of steam to enter the producer. This strategy helps maintain the temperature along the wellbore, ensuring the bitumen remains warm, which reduces its viscosity and promotes the transfer of heat to cooler sections of the reservoir. This method improves overall efficiency and performance, even with sub-cool variations.

Another approach, known as Partial SAGD (Steam-Assisted Gravity Drainage), involves intentionally circulating steam in the producer after a prolonged shut-in period or during startup. This method helps to reheat the bitumen, keeping it mobile and easier to extract. While a high sub-cool is generally preferred for thermal efficiency, as it usually allows for reduced steam injection rates, it may also result in a slight decline in production. This happens because lower temperatures increase bitumen viscosity, reducing its mobility. One major downside of maintaining an excessively high sub-cool is that the steam pressure may become insufficient to sustain the development of the steam chamber above the injector. This can cause the steam chamber to collapse, with condensed steam flooding the injector and hindering further chamber expansion. Therefore, managing sub-cool levels is a delicate process; if it is too low, it can lead to uneven steam distribution and ineffective heating, but if it is too high, it can destabilize the steam chamber and negatively impact production efficiency. Operators must carefully monitor and adjust the sub-cool to optimize the thermal efficiency and productivity of the SAGD process. Ensuring that the steam chamber remains robust and that heat is effectively distributed throughout the reservoir is critical for maximizing bitumen recovery. Techniques like allowing controlled steam entry into the producer or using Partial SAGD can mitigate some of the challenges associated with maintaining an ideal sub-cool, helping to ensure consistent and efficient bitumen extraction.

Overall, sub-cool management is a critical aspect of thermal enhanced oil recovery techniques, such as SAGD. By carefully controlling the temperature and pressure conditions within the reservoir, operators can optimize the recovery of bitumen while maintaining the stability and efficiency of the steam chambers. This balance is essential for achieving the best possible outcomes in terms of both production rates and thermal efficiency.

Continuous operation of the injection and production wells at approximately reservoir pressure addresses the instability issues common to high-pressure and cyclic steam processes. Steam-Assisted Gravity Drainage (SAGD) offers smooth, consistent production, achieving recovery rates as high as 70% to 80% of oil in place in suitable reservoirs. This process is relatively unaffected by shale streaks and other vertical barriers because the heating of the rock induces differential thermal expansion, allowing steam and fluids to gravity flow to the production well. Consequently, even formations with numerous thin shale barriers can achieve recovery rates of 60% to 70% of the oil in place.

Thermally, SAGD is about twice as efficient as the older cyclic steam stimulation (CSS) process. This increased efficiency results in fewer wells being damaged due to the high pressures associated with CSS. Furthermore, the higher oil recovery rates make SAGD significantly more economical than cyclic steam processes, especially in reasonably thick reservoirs. The ability to maintain consistent pressure and avoid the pitfalls of high-pressure cycles underscores the operational advantages of SAGD, making it a preferred method for maximizing oil recovery while minimizing reservoir damage and operational costs.

Catalytic in-situ heavy oil upgrading

Steam injection is the most common EOR method for heavy oils production in the world. It is actively used in Latin America, USA, Canada, China, and in Russia. Injection of steam at high temperatures allows a significant reduction in the oil viscosity in reservoir conditions and, as a result, an increase of the oil recovery factor. However, the application of this method requires large energy inputs and leads to high water cut. Recovered oil is still heavy on surface, which causes difficulties with transportation. Also, it contains sulfur and other toxic compounds. After some period of oil recovery by steam injection, we can get high steam-oil ratio, which consequently will lead to poor economic parameters of heavy oil production and high-level of CO_2 emissions (steam produced by the combustion of gas mainly). In recent years, a new technology based on the joint application of steam and specially developed catalysts was proposed for in-situ oil upgrading. Application of this technology can help to produce light fractions from high molecular weight components of heavy oil, to irreversibly reduce viscosity, and to increase the production volume and facilitate oil transportation. In addition, catalytic processes can reduce sulphur content in the oil produced.

In the 1980s, Hyne and colleagues discovered that steam injection not only physically reduces the viscosity of heavy oil through temperature increase but also induces chemical reactions with some oil components, leading to beneficial changes in the oil's properties and composition. They termed this reaction "aquathermolysis." Further studies by these researchers highlighted that these chemical changes are reversible because heteroatoms such as sulfur (S), nitrogen (N), and oxygen (O) interact with other molecules via van der Waals forces, causing polymerization and a recurrence of high viscosity. The use of proper catalysts can significantly enhance these chemical reactions, leading to effective and irreversible viscosity reduction. This process of in-situ catalysis opens new possibilities for underground upgrading and enhanced oil recovery. Current research is focused on developing active, stable, and reliable catalysts at both laboratory and field scales. Catalysts reported for enhancing the recovery of heavy oil and bitumen are generally classified into six categories: (1) water-soluble catalysts, (2) oil-soluble catalysts, (3) amphiphilic catalysts, (4) minerals and zeolites, (5) solid superacids, and (6) dispersed nanoparticles.

Experiments typically simulate reservoir conditions by using a reactor that contains an oil sample, water, and a catalyst at various reaction temperatures, pressures, and durations. These setups have consistently shown that viscosity reduction is readily achieved in the reactor. This ongoing research aims to identify the most effective catalysts that can facilitate the chemical reactions necessary for reducing viscosity, thus making the recovery process more efficient and economically viable.

In summary, the discovery of aquathermolysis and the development of catalytic methods for enhancing this process represent significant advancements in the field of heavy oil recovery. By employing catalysts to facilitate chemical reactions, it is possible to achieve substantial and permanent reductions in oil viscosity, enabling more efficient extraction and in-situ upgrading of heavy oil resources.

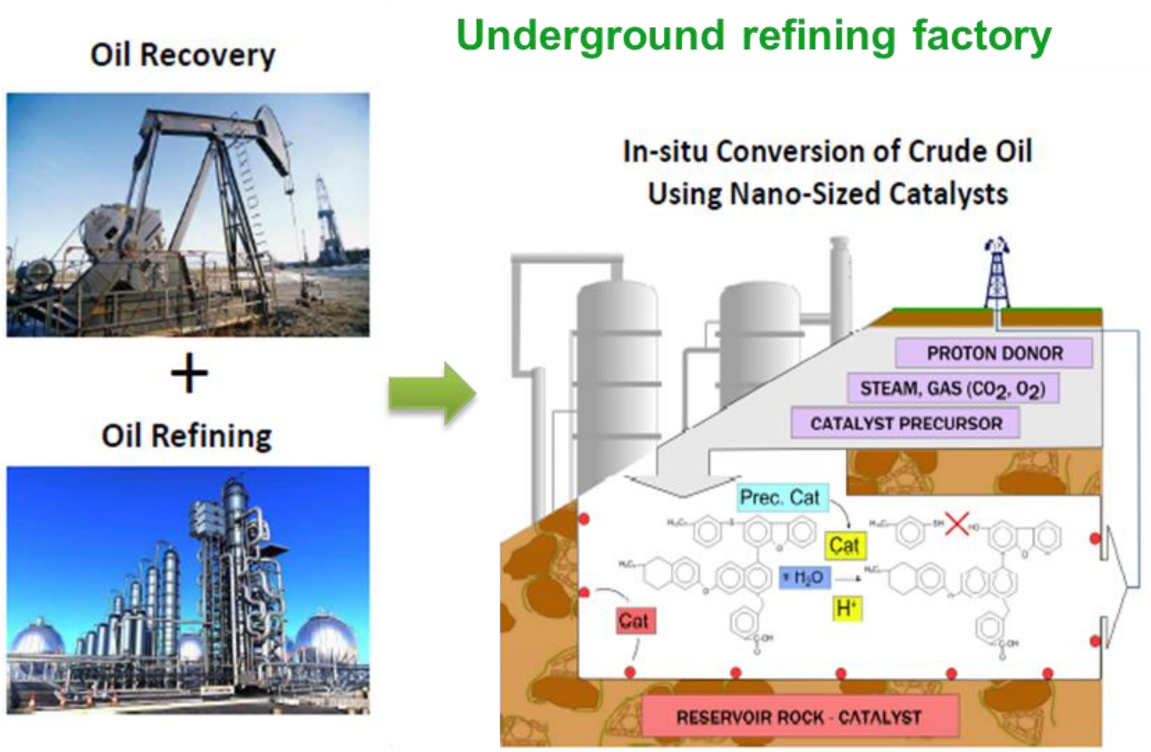


Fig. 35. In-situ catalytic heavy oil upgrading.

Nowadays, few pilot tests of this technology were carried out in Russia and China. In 2019, additional tests are under consideration in Canada, Mexico, Cuba, India and etc.

The results of field tests show that the application of catalysts in CSS technology after several cycles results in the improvement of production by 40-45 % and decreasing of viscosity by several times. Also, the reduction of asphaltenes occurred in produced fluid.

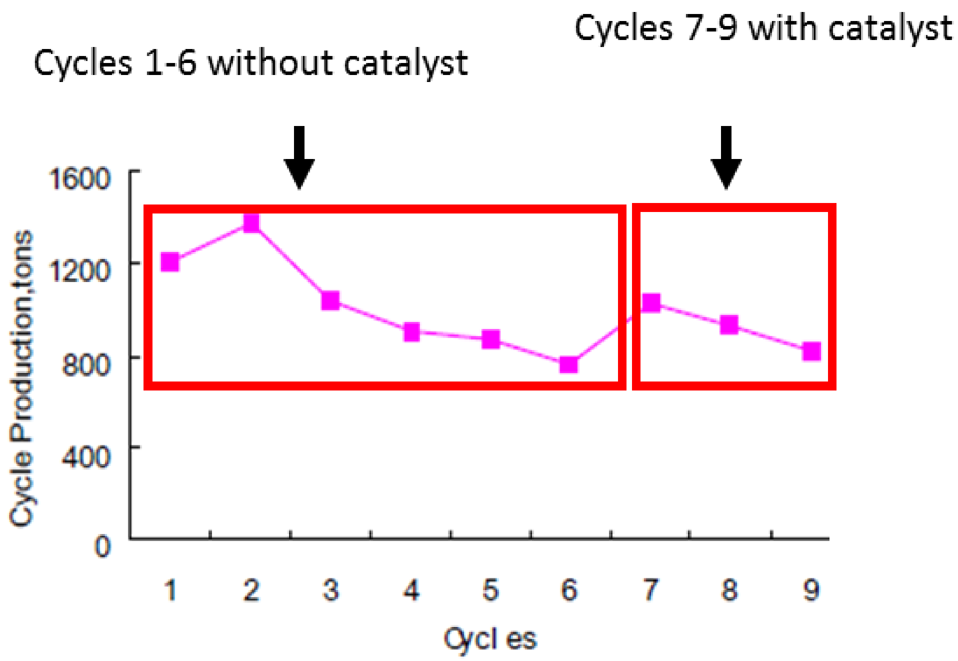


Fig. 36. Effect of catalyst of production in CSS method.

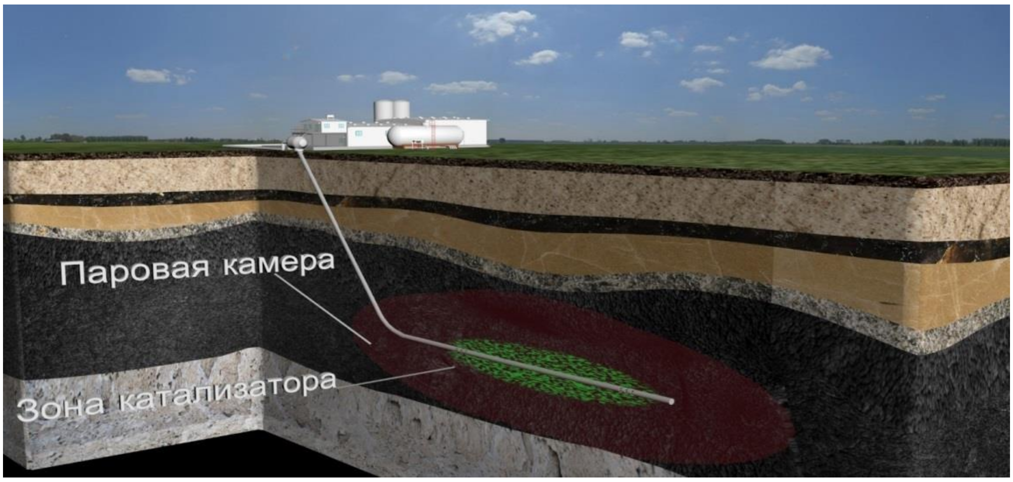


Fig. 37. Distribution of catalyst in CSS method.

Physical Modeling of the Steam Stimulation Under Laboratory Conditions

In this section, we present the schematic diagram and apparatus used for physical modeling of ultra-viscous oil displacement under laboratory conditions. Figures 37 and 38 illustrate the setup and the "Esso" device employed in these experiments. The objective is to evaluate the efficiency of thermal-steam enhanced oil recovery (EOR) methods by simulating reservoir conditions. Experimental results indicate that the oil displacement coefficient varies significantly, ranging from 12% to 70%, with steam flow rates reaching up to 30 pore volumes. Temperature distribution profiles, shown in Figure 25, reveal distinct zones, highlighting the complexity and dynamics of the steam injection process. A Schematic diagram for carrying out physical modeling is presented in Fig. 23.

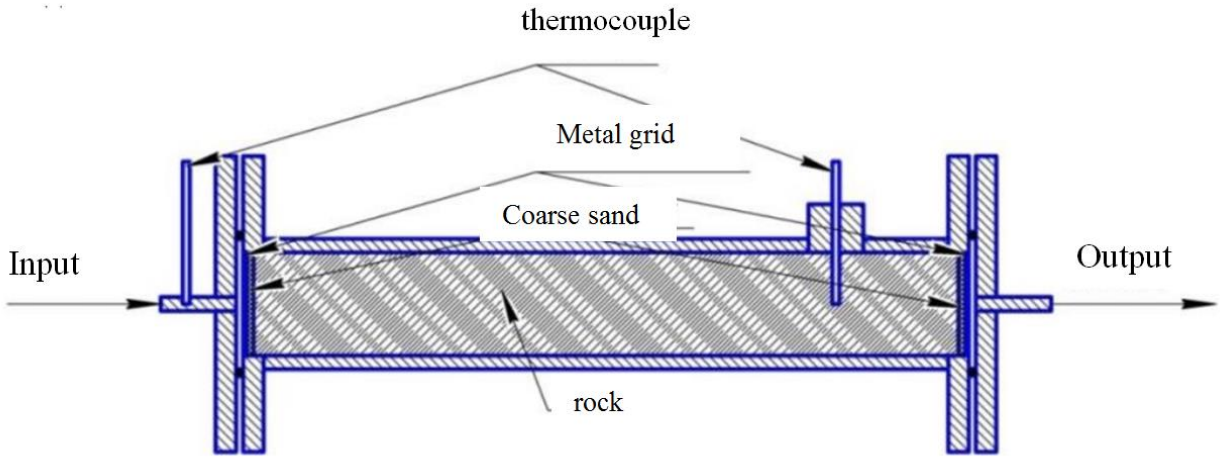


Fig. 38. Schematic diagram for physical modeling.

An example of a device for carrying out physical modeling of the processes of ultra-viscous oil displacement is presented in Fig. 39.

Fig. 39. “Esso” device for conducting physical modeling.

Experiments on the displacement of super-viscous oil from the bulk model of the reservoir with steam can indicate the relative efficiency of thermal-steam EOR methods. Here, oil displacement coefficient for 14 experiments ranged from 12 to 70 %. In the experiments, steam flow rate varied in wide ranges and reached up to 30 pore volumes.

The temperature distribution along the model at different points in time is shown in Fig. 40. The graph clearly identifies the following characteristic zones: cold water displacement zone, hot water zone, and steam and condensate zone. It should be noted that the vapor front moved along the length of the sample only after a sufficiently long-time steam injection ($V_{injection}$ = 1.64 - 1.88).

In all the experiments, the produced fluid before the breakthrough of the condensate was characterized by anhydrous oil, and after the breakthrough of the condensate it was characterized by free water and water-in-oil emulsion of various concentrations. The emulsion concentration and the water content of the produced fluid gradually increase and reach a maximum when the steam breaks out at the outlet of the model. After the steam breaks out, the model produces an oil-in-water emulsion, and the water content reaches 98-99 %.

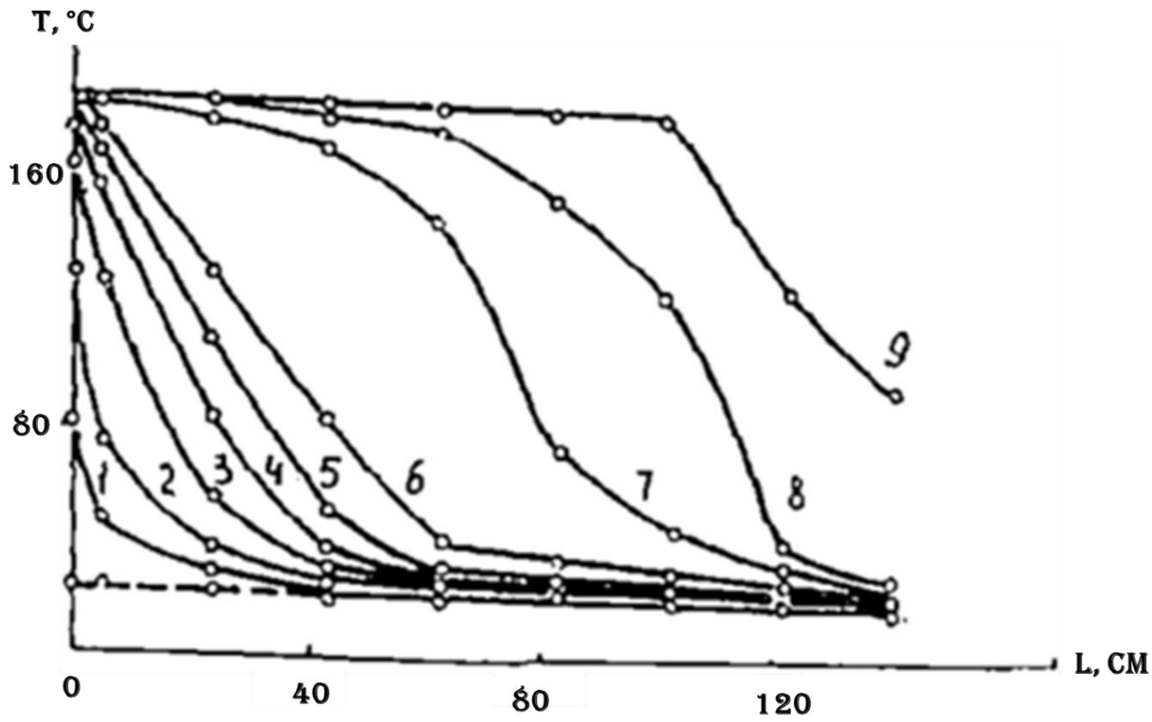


Fig. 40. Temperature distribution at different times along the length of the model in the process of steam injection. $V_{injection}$: 1 – 0.18; 2 – 0.37; 3 – 0.56; 4 – 0.73; 5 – 0.90; 6 – 1.2; 7 – 1.64; 8 – 1.88; 9 – 2.32.

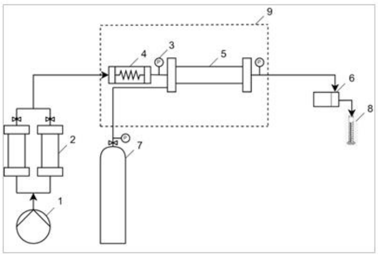
One of the most interesting experiments is the simulation of steam injection into the aquifer carried out by TatNIPIneft. When the generated steam was injected into the model, the produced fluid was characterized by water with a film of bitumen. As the rock was heated, the oil content increased and reached a maximum value of 60%, and decreased after the breakthrough of steam.

In the process of horizontal steam distribution, the heat gradually warms up the oil-saturated part of the reservoir. Due to thermal expansion, part of the oil enters the aquifer layer and at the same time increasing capillary impregnation and direct displacement of oil by steam. Injection of steam in this experiment has led to the fact that oil from the heated section, moving through a highly permeable aquifer interlayer, reduces phase permeability for condensate and decreases heat inflow into the heated zone, which eventually leads to the blockage of both pore channels and filtration. At the same time, the volume of steam injection exceeded by two orders of magnitude the volume of steam injection by other experiments, and the oil recovery factor was two orders of magnitude lower.

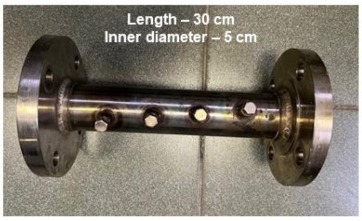
The methodology and laboratory equipment of the steam tube

The primary objective of physical modeling in the laboratory is to determine the dynamics of changes in the oil displacement coefficient (K_{dis}), the temperature profile, and the pressures at the inlet and outlet of the reservoir model during steam exposure. By using reservoir or model fluids and maintaining reservoir temperature and pressure conditions, the modeling closely mimics actual reservoir conditions.

The objective of this method is to inject an agent, such as hot water or steam, through oil-saturated rock to facilitate fluid filtration. This is carried out using specialized equipment designed for physicochemical modeling of the steam-assisted gravity drainage (SAGD) process (Fig. 41). By employing this technique, the behavior and efficiency of steam stimulation process including steam flooding as well as steam-assisted gravity drainage can be simulated under controlled laboratory conditions, providing valuable insights into the process dynamics and potential optimization strategies for enhanced oil recovery in real-world reservoirs [7,8].



1 – High-pressure plunger pump brand LN-400;
2 – ISCO Pumps (piston containers);
3 – Precision pressure sensors;
4 – Steam generator;
5 – Core holder;
6 – Back pressure regulator;
7 – Nitrogen cylinder;
8 – Graduated cylinder;
9 – Thermal cabinet



- High-temperature/pressure core holders (steam tubes)

Fig. 41. External view & schematic diagram of the steam injection unit.

The experimental setup for physical modeling of ultra-viscous oil displacement includes several key components: a high-pressure plunger pump (LN-400) (1), which ensures precise control of fluid injection; ISCO pumps (piston containers) (2) for accurate fluid dispensing; and precision pressure sensors (3) for monitoring pressure changes. The system also includes a steam generator (4) for producing the steam required for displacement experiments, a core holder (5) to securely contain the core samples, and a back pressure regulator (6) to maintain consistent pressure throughout the system. Additionally, a nitrogen cylinder (7) is used to pressurize the system, a graduated cylinder (8) measures fluid volumes, and a thermal cabinet (9) maintains the necessary temperature conditions for the experiments.

Preparation of sample and liquids for testing

For the experiment, either formation water or brine prepared according to a known component composition can be utilized. Formation water should be thoroughly mixed in a storage vessel and filtered through "filter paper" before use. Depending on the requirements of the experiment, stable degassed oil or isoviscous sample oil can be employed. To determine the oil displacement factor, a composite core model assembled from individual cylindrical samples or a bulk core model crushed to a fraction of 0.1-1 mm can be used. When preparing a reservoir model, two approaches can be applied to account for the rock's wettability during laboratory core studies: 1) the method of preserving wettability (studies on unextracted core); 2) the method for restoring the rock's wettability (extraction, oil saturation, and “core aging”) [4].

When assembling core samples, it is crucial to ensure that a cylindrical core is fixed inside the core holder in thermal effect experiments to prevent steam and hot water overflow through the sealing material between the steel wall of the core holder and the core. Overcoming the temperature barrier of 400°C for core sealing material, ensuring good adhesion to both the core and steel, and avoiding the "wall effect" for accurate determination of the oil displacement coefficient is critical. The use of fluorinated rubber (Viton type) for overburden pressure is usually limited to a temperature of +250°C, and epoxy resins to +300°C. Therefore, in experiments exceeding 300°C, a cylindrical core sample should be installed inside the core holder to assemble a cylindrical core seal. A centering ring is placed at the end of the core holder, and the gap between the inner cylindrical surface of the core holder and the compacted outer surface of the core is filled with thermally expanded graphite, crushed to a fraction of less than 3 mm. The thermally expanded graphite is then compacted. The detailed assembly procedure is provided in [5].

In the case of using a bulk model of the formation, core material with a fraction size of 0.1-1 mm is loaded and compacted into the core holder, and, if necessary, pressed using a press. The permeability of the reservoir model is determined using nitrogen under reservoir conditions. To prevent sand grains from entering and clogging the discharge tubes, perforated metal disks with screens are utilized.

In conducting the experiment, the use of formation water or brine is essential, each prepared to replicate the component composition accurately. Thorough mixing in a storage vessel is necessary for formation water, followed by filtration through "filter paper" to ensure purity before application. Depending on the specific requirements, stable degassed or isoviscous sample oil can be selected. For determining the oil displacement factor, researchers can choose between a composite core model composed of individual cylindrical samples or a bulk core model ground to a fraction of 0.1-1 mm. Two approaches can be adopted to address the wettability of the rock in laboratory core studies: preserving the wettability through studies on unextracted core or restoring the wettability through processes such as extraction, oil saturation, and “core aging” [4].

When assembling core samples for thermal effect experiments, it is vital to securely fix a cylindrical core inside the core holder to prevent any overflow of steam and hot water through the sealing material between the core holder's steel wall and the core. Achieving a temperature barrier of 400°C for the core sealing material, maintaining strong adhesion to both the core and steel, and avoiding the "wall effect" are decisive factors for accurately determining the oil displacement coefficient. The limitations of fluorinated rubber (Viton type) to +250°C and epoxy resins to +300°C necessitate specific assembly techniques for higher temperatures. For experiments exceeding 300°C, a cylindrical core sample is installed within the core holder, and a centering ring is placed at the core holder's end. The gap between the inner cylindrical surface of the core holder and the core's compacted outer surface is filled with thermally expanded graphite, crushed to a fraction of less than 3 mm, and then compacted. This assembly procedure is elaborated in [5].

For experiments using a bulk formation model, core material ground to a fraction size of 0.1-1 mm is loaded and compacted into the core holder, and pressed if necessary. The permeability of the reservoir model is measured using nitrogen under reservoir conditions. Perforated metal disks with screens are employed to prevent sand grains from entering and clogging the discharge tubes.

In these experimental setups, whether using formation water or brine, ensuring accurate replication of reservoir conditions is paramount. Proper preparation and filtration of formation water, combined with the selection of suitable oil samples, allow for precise determination of oil displacement factors. The use of composite or bulk core models provides flexibility in experimental design. Addressing the rock's wettability through preservation or restoration methods enhances the reliability of the results.

The assembly of core samples, especially for thermal effect experiments, requires meticulous attention to prevent overflow and ensure accurate measurements. Overcoming temperature barriers and maintaining proper adhesion between materials are critical for the success of these experiments. The specific techniques for high-temperature experiments, including the use of thermally expanded graphite, are vital for maintaining the integrity of the core assembly.

For bulk formation models, careful loading and compaction of core material, along with the use of perforated metal disks, ensure accurate permeability measurements and prevent equipment clogging. These detailed procedures and considerations are essential for conducting reliable and replicable oil displacement experiments in the laboratory.

Methodology:

The core holder used for experiments with bulk and composite core models of a reservoir is designed as a steel pipe, featuring welded flanges at both ends. Thermocouples are strategically positioned in the core holder's center to accurately measure temperature variations. When assembling a composite model, these thermocouples are placed between cylindrical core samples. To maintain capillary contact between the end surfaces of the cylindrical samples, a thin layer of crushed rock, less than 0.3 mm thick, is utilized. This setup ensures precise thermal measurements and effective simulation of reservoir conditions. The detailed arrangement is illustrated in Fig. 42, demonstrating the careful placement of components to replicate the reservoir environment accurately. This configuration allows for comprehensive monitoring and analysis of thermal and fluid flow behaviors within the core holder, facilitating a deeper understanding of the steam-assisted gravity drainage (SAGD) process and other enhanced oil recovery techniques.

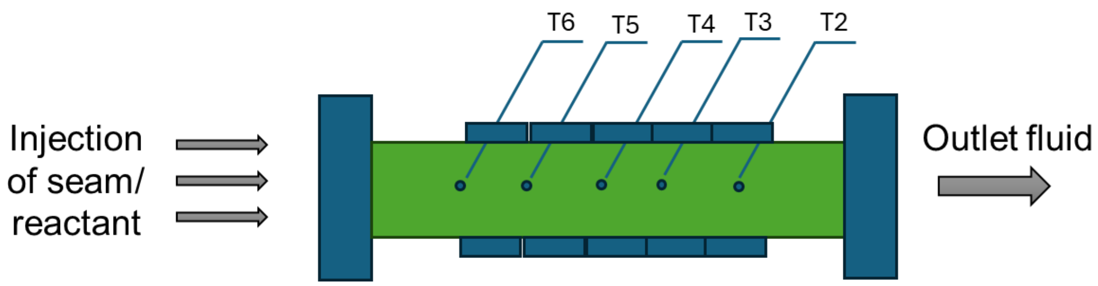


Fig. 42. Schematic of the core holder (steam tube).

At the start of the experiment, reservoir pressure is established by injecting nitrogen into the core holder. The overburden pressure is also generated using nitrogen, calculated as $P_{ovb} = 1.2 \times P_r$ to ensure appropriate conditions. The system is heated to the operating temperature using an electric heater positioned at the model's entrance. To minimize the temperature gradient between the core holder and its surroundings, ceramic ring heaters are employed around the core holder, maintaining adiabatic conditions. The temperature for steam injection is then selected based on the corresponding pressure values outlined in Table 1. This precise control of temperature and pressure is crucial for accurately simulating reservoir conditions and understanding the thermal behaviors during the experiment.

Table 1 - Boiling points of water from 0 to 100 bar.

Saturated steam pressure	Boiling temperature	Saturated steam pressure	Boiling temperature	Saturated steam pressure	Boiling temperature
bar	°C	bar	°C	bar	°C
0.02	17.51	11	184.06	58	273.36
0.03	24.10	12	187.96	59	274.47
0.04	28.98	13	191.60	60	275.56
0.05	32.90	14	195.04	61	276.64
0.06	36.18	15	198.28	62	277.71
0.07	39.02	16	201.37	63	278.76
0.08	41.53	17	204.30	64	279.80
0.09	43.79	18	207.11	65	280.83
0.1	45.83	19	209.79	66	281.85
0.2	60.09	20	212.37	67	282.85
0.3	69.13	21	214.85	68	283.85
0.4	75.89	22	217.24	69	284.83
0.5	81.35	23	219.55	70	285.80
0.6	85.95	24	221.78	71	286.76
0.7	89.96	25	223.94	72	287.71
0.8	93.51	26	226.03	73	288.65
0.9	96.71	27	228.06	74	289.59
1	99.63	28	230.04	75	290.51
1.1	102.32	29	231.96	76	291.42
1.2	104.81	30	233.84	77	292.32
1.3	107.13	30	233.84	78	293.22
1.4	109.32	31	235.66	79	294.10
1.5	111.37	32	237.44	80	294.98
1.5	111.37	33	239.18	81	295.85
1.6	113.32	34	240.88	82	296.71
1.7	115.17	35	242.54	83	297.56
1.8	116.93	36	244.16	84	298.40
1.9	118.62	37	245.75	85	299.24
2	120.23	38	247.31	86	300.07
2.2	123.27	39	248.84	87	300.89

2.4	126.09	40	250.33	88	301.71
2.6	128.73	41	251.80	89	302.51
2.8	131.20	42	253.24	90	303.31
3	133.54	43	254.66	91	304.11
3.5	138.87	44	256.05	92	304.89
4	143.63	45	257.41	93	305.67
4.5	147.92	46	258.76	94	306.45
5	151.85	47	260.08	95	307.22
5.5	155.47	48	261.38	96	307.98
6	158.84	49	262.66	97	308.73
6.5	161.99	50	263.92	98	309.48
7	164.96	51	265.16	99	310.22
7.5	167.76	52	266.38	100	310.96
8	170.42	53	267.58		
8.5	172.94	54	268.77		
9	175.36	55	269.94		
9.5	177.67	56	271.09		
10	179.88	57	272.23		

Throughout the experiment, data on temperatures, pressures, steam flow (measured by water), and the composition of exhaust gases are meticulously recorded. The injection process is sustained until the oil flow to the separation burette stops. Only students who have successfully completed safety training, as mandated by Kazan Federal University (KFU) [10], are permitted to conduct these laboratory tests. This ensures a safe and controlled environment for carrying out the experiments, allowing students to gain hands-on experience while adhering to strict safety protocols.

Processing the results

Upon completion of the experiment, the results are systematically documented in Tables 2 and 3. Additionally, a graph illustrating the filtration dynamics is constructed, showcasing variations in the oil displacement coefficient ($Kdis$), the pressure drawdown across the model, and the temperature profile. This comprehensive presentation of data helps in analyzing the experiment's outcomes and understanding the underlying processes.

Table 2. Reservoir model data

№ sample	Diameter of sample, cm	Length of sample, cm	Porosity, %	Permeability by nitrogen, 10^{-3} μm^2	Initial oil saturation, %
-	-	-	-	-	-

Table 3. Data for processing experimental results

Time, min	The volume of the injection*	T_1, °C	T_2, °C	T_n, °C	P_{inlet}, MPa	P_{outlet}, MPa	V_{liquid}, cm^3
-	-	-	-	-	-	-	-

* *The volume of the injection agent V_{inj} is determined by the formula (3)*

The oil displacement factor ($Kdis$) by steam is determined for composite samples, which include residual water volumes that match the conditions found in the reservoir. This calculation is performed using the specified formula, ensuring that the water content accurately reflects the natural state of the reservoir, thereby providing a realistic measure of the steam's effectiveness in displacing oil.

$$K_{dis} = \frac{Vo}{Voi} \quad (1)$$

where V_o - the volume of oil displaced from the sample under test conditions (reservoir) cm^3;

V_{oi} - the volume of oil originally contained in the sample under test conditions (reservoir).

The volume of oil displaced from the sample is determined by:

$$V_o = b * V_d \quad (2)$$

где V_d – the volume of degassed oil in the separation burette, cm^3;

b – formation volume factor.

By employing a bulk extracted model saturated by mixing with formation water and stabilized oil breakdown, the oil volume change coefficient, denoted as b, should not be considered. Conversely, if the sample is saturated with oil under reservoir conditions, the calculation of the original oil volume (Vo) requires the determination of coefficient b. This coefficient is experimentally obtained by observing the change in oil volume within a piston-cylinder setup at elevated pressures, maintaining isothermal conditions throughout the process. This experimental approach ensures that the volume change coefficient accurately reflects the behavior of the oil under the specific conditions of the reservoir, providing a more precise and reliable calculation for the oil displacement factor.

The agent injection volume is calculated:

$$V_{inj} = t \times q / v_p \tag{3}$$

where V_{inj} – the volume of agent injected into the model (in water equivalent)

t – agent exposure time, min

q – flow rate, cm3/min

Vp – pore volume of the model, cm3

Drawdown is calculated on the ΔP model by the formula:

$$\Delta P = P_{inlet} - P_{outlet}, \tag{4}$$

where P_{outlet} – model outlet pressure, MPa

P_{inlet} – inlet pressure, MPa

The oil-steam ratio is calculated:

$$OSR = V_{inj}/V_o \tag{5}$$

Where,

OSR– oil-steam ratio, cm^3/cm^3

V_{inj} – the volume of the injected agent (hot water, steam), cm^3

V_o – the volume of oil displaced from the model, cm^3

The calculated data are entered in a table and graphs are built (Table 4):

Table 4. Main characteristics of the experiment.

The volume of the injected agent, p.v.	K_{dis}, %	ΔP_{inlet}, MPa	*OSR*, cm^3/cm^3
-	-	-	-

Practical part:

Laboratory work is conducted in teams organized by the head of the laboratory after the theoretical material has been thoroughly mastered. Each team receives a technical task from the laboratory head, which outlines the experiment to be performed and serves as the core component of the educational practice. The research conducted during this lab work is documented and presented in the form of a report and a presentation.

Technical Task Example

Filtration Studies to Evaluate the Effectiveness of Thermal Methods of Oil Displacement

1. Purpose of the Experiment: Determination of the oil displacement coefficient (K_{dis}).

2. Sequence of the Experiment:

2.1. Selection of Steam Injection Temperature: Choose the appropriate steam injection temperature based on the given reservoir pressure.

2.2. Model Preparation: Prepare the core model for the experiment.

2.3. Determination of Initial Oil Saturation: Measure the initial oil saturation of the core sample.

2.4. Assembling the Model in the Core Holder: Properly assemble the core model within the core holder.

2.5. Permeability Determination: Measure the permeability using nitrogen both before and after the steam injection.

2.6. Observation During Experiment: Monitor and record the volumes of oil, water, and gas produced, as well as any changes in temperature and pressure during the experiment.

2.7. Pressing Out the Model: Conduct the pressing out of the model at the conclusion of the experiment.

2.8. Calculation: Calculate the oil displacement coefficient ($Kdis$), pressure drop (ΔP), and oil saturation ratio (OSR).

This structured approach ensures that students not only learn the theoretical aspects of thermal methods of oil displacement but also gain hands-on experience in conducting and analyzing these methods in a laboratory setting.

Table 5. Parameters of the experiment.

<table>
<tr><th rowspan="2">№</th><th rowspan="2">Experiment Stage</th><th colspan="5">Parameters</th></tr>
<tr><th>Temperature, °C</th><th>Fluid supply, cm3/min</th><th>Pressure, MPa</th><th>Duration</th><th>Note</th></tr>
<tr><td rowspan="3">1</td><td>Coldwater</td><td>23</td><td rowspan="3">-</td><td rowspan="3">-</td><td>-</td><td></td></tr>
<tr><td>Hot water</td><td>100</td><td>-</td><td></td></tr>
<tr><td>Steam</td><td>120</td><td>-</td><td></td></tr>
</table>

3. Processing Results:

3.1. Build a graph of the dynamics of fluid filtration at water and steam injection.

3.2. Create a report in Microsoft Word.

3.3. Preparing a presentation in Microsoft PowerPoint and defending it.

3.3.3. Vapor Extraction (Vapex)

Vapor Assisted Petroleum Extraction (VAPEX) is an innovative thermal enhanced oil recovery (EOR) method developed to extract heavy oil and bitumen more efficiently and economically. Invented by Dr. Butler, VAPEX is a gravity-drainage process that uses vaporized solvents instead of steam to mobilize and extract heavy oil from the reservoir. This technique significantly reduces the viscosity of the oil, enabling it to flow more easily towards production wells.

Principle and Mechanism

The fundamental principle of VAPEX involves the injection of a vaporized solvent, such as propane, butane, or other light hydrocarbons, into the oil reservoir. The solvent vapor is injected through an injection well, typically placed above a horizontal production well. As the vaporized solvent comes into contact with the heavy oil or bitumen, it diffuses into the oil, reducing its viscosity and making it more mobile. This mixture of solvent and heavy oil then drains by gravity towards the production well, from where it is subsequently pumped to the surface. Fig. 43 illustrates the schematic diagram of the VAPEX process [9].

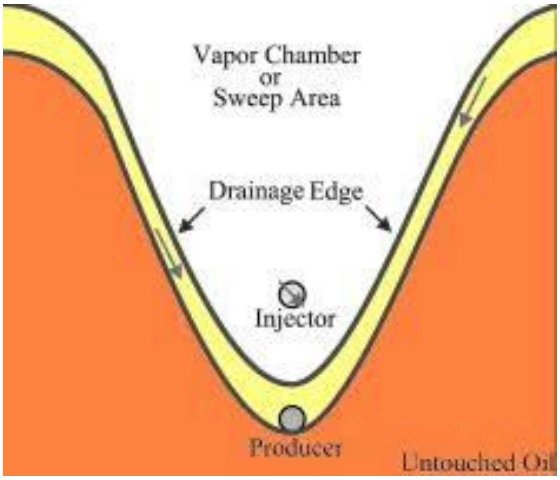


Fig. 43. Schematic diagram of the VAPEX process.

Process Overview

1. Injection of Solvent Vapor: The process begins with the injection of vaporized solvents into the reservoir through an injection well. These solvents are selected based on their ability to effectively reduce the viscosity of the heavy oil and their compatibility with reservoir conditions.

2. Diffusion and Viscosity Reduction: As the vaporized solvent spreads through the reservoir, it diffuses into the heavy oil, causing a significant reduction in viscosity. This diffusion process is essential for mobilizing the heavy oil and enabling its flow towards the production well.

3. Gravity Drainage: The now mobile mixture of solvent and heavy oil flows downward due to gravity. This movement is facilitated by the placement of the horizontal production well below the injection well, creating a natural drainage path.

4. Production and Recovery: The solvent-oil mixture is collected in the horizontal production well and pumped to the surface. Once at the surface, the solvent can be separated from the oil and potentially recycled for further use in the process [10].

Pourabdollah et al. [11] analyzed the viscosity distribution pattern in the VAPEX cell using experimental SARA (Saturates, Aromatics, Resins, and Asphaltenes) tests combined with CMG (Computer Modelling Group) simulator.

They calculated the viscosity of bitumen and the volume fraction of particles employing modified versions of Pedersen's and Gillespie's equations. Fig. 44 illustrates the distribution pattern of oil viscosity within the swept zone and bitumen chamber of the VAPEX cell. The findings indicated that the volume fraction of colloidal particles needs to be categorized into asphaltenes, resins, and metal chelates. Moreover, the upgrading process of the tested bitumen showed that the composition consisted of approximately one-third of each of these components: asphaltenes, resins, and metal chelates. This detailed breakdown provides a clearer understanding of the changes in bitumen properties during the VAPEX process [9].

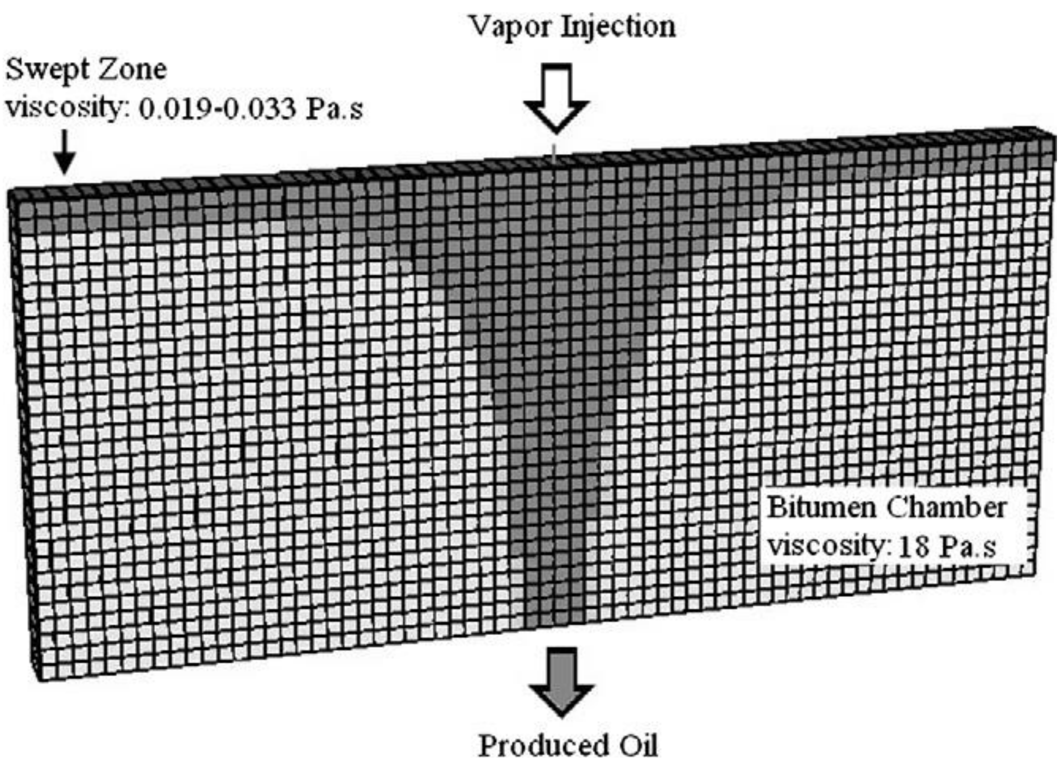


Fig. 44. Distribution pattern of oil viscosity in the conventional VAPEX model.

Advantages of VAPEX

1. Energy Efficiency: Unlike steam-based methods, VAPEX does not require the generation and injection of large volumes of steam, making it a more energy-

efficient process. This reduction in energy usage translates to lower operational costs and a smaller environmental footprint.

2. Lower Water Usage: VAPEX eliminates the need for water, which is a significant advantage in regions where water resources are scarce or where water management and disposal are costly and environmentally challenging.

3. Reduced Greenhouse Gas Emissions: The absence of steam generation in VAPEX reduces greenhouse gas emissions associated with fuel combustion for steam production. This makes VAPEX a more environmentally friendly option compared to traditional thermal EOR methods.

4. Enhanced Oil Recovery: VAPEX can achieve high oil recovery rates by efficiently reducing the viscosity of heavy oil, facilitating its flow towards production wells. This method is particularly effective in reservoirs with thin pay zones where steam injection may be less effective [9].

Challenges and Considerations

1. Solvent Management: One of the primary challenges of VAPEX is the management and recycling of solvents. Efficient separation and recycling of solvents are crucial for the economic viability of the process. Loss of solvents to the reservoir can increase operational costs.

2. Reservoir Conditions: The effectiveness of VAPEX is highly dependent on reservoir conditions, including temperature, pressure, and the properties of the heavy oil. Accurate characterization of the reservoir is essential for designing an effective VAPEX operation.

3. Solvent Costs: The cost of solvents can be a significant factor in the overall economics of VAPEX. Fluctuations in solvent prices can impact the feasibility of the process.

4. Operational Complexity: Implementing VAPEX requires precise control over injection and production operations. Ensuring uniform distribution of the

solvent and managing the gravity drainage process can be complex and may require advanced monitoring and control systems.

Field Applications and Future Prospects

VAPEX has shown promising results in pilot projects and small-scale field applications, particularly in Canada’s oil sands. The method is still under continuous development and optimization to address its challenges and improve its efficiency and cost-effectiveness. Ongoing research focuses on enhancing solvent recovery techniques, improving reservoir characterization, and developing more cost-effective solvent mixtures.

In conclusion, Vapor Assisted Petroleum Extraction (VAPEX) presents a viable alternative to steam-based EOR methods for heavy oil and bitumen recovery. Its energy efficiency reduced environmental impact, and potential for high recovery rates make it an attractive option for the petroleum industry. As technology advances and operational challenges are addressed, VAPEX is likely to play a more significant role in the future of enhanced oil recovery.

3.3.4. Electromagnetic Heating Methods

Electromagnetic Heating (EM) for heavy oil recovery was first proposed by Ritchey in his 1956 patent titled “Radiation Heating for Heavy Oil Recovery.” EM heating methods are categorized into three main types based on the frequency of the electrical current used. At low frequencies, ohmic heating or resistive heating occurs, where current flows through the medium, generating heat due to resistance. At medium frequencies, induction heating is employed. Here, alternating current flows through a conductor, creating a magnetic field around it. This varying magnetic field induces a secondary current within the medium, which then produces heat. For high frequencies, including radio frequency (RF) and microwave heating, the process involves the formation of molecular dipoles that align with the electric field. The movement and reorientation of these dipoles generate heat within the reservoir.

These various methods allow for targeted heating of heavy oil reservoirs, improving the flow and recovery of bitumen. The choice of frequency depends on the specific conditions and characteristics of the reservoir being targeted. Each method utilizes the principles of electromagnetic induction and molecular agitation to efficiently generate heat and facilitate oil recovery. Canadian Natural Resources Limited's (CNRL) Primrose and Wolf Lake in situ oil sands project near Cold Lake, Alberta, within the Clearwater Formation, exemplifies the effective application of these advanced recovery techniques. Operated by CNRL subsidiary Horizon Oil Sands, this project uses high-pressure cyclic steam stimulation (HPCSS) to enhance bitumen recovery, showcasing the integration of innovative methods in modern oil extraction.

In oil production, the primary goal of electromagnetic (EM) heating is to raise the reservoir temperature using either an RF antenna or an induction coil placed in the injector well. As the reservoir heats up, the viscosity of the oil decreases, allowing it to flow more easily towards the production well. The recommended practice for EM heating involves using two horizontal wells, similar to the SAGD process. The upper horizontal well is equipped with the RF antenna or induction coil, which heats the surrounding area. The resulting melted oil then flows down to the lower horizontal production well, as illustrated in Fig. 45. Additionally, it is worth noting that both cyclic RF heating and continuous RF heating processes have been proposed for vertical wells to enhance heavy oil recovery. These methods offer a controlled way to efficiently reduce oil viscosity and improve the overall recovery rates from the reservoir, making EM heating a valuable technique in the field of enhanced oil recovery (EOR).

Generally, no water is injected into the wells during RF heating, thus avoiding the creation of steam or hot water injection conditions; this approach is often referred to as "non-aqueous heating" for heavy oil recovery. However, EM heating can be combined with solvent injection. When a solvent is used alongside EM heating, it enhances the dilution of the oil, significantly reducing its viscosity. This combination allows the oil to flow more easily towards the production well, improving the efficiency and effectiveness of the recovery process. This method leverages the benefits of both thermal and chemical processes to optimize oil extraction.

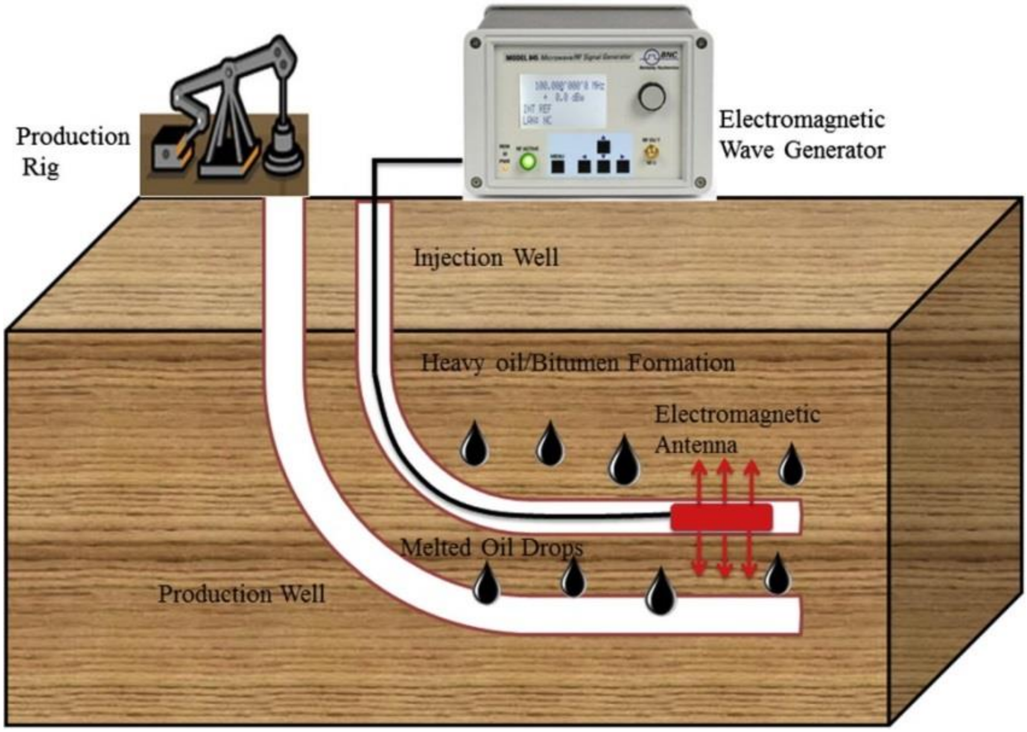


Fig. 45. EM heating method for heavy oil production (SAGD-like design).

The advantages of the electrical methods are as follows:

1. The EM heating method is more energetically efficient than other aqueous thermal heating methods.

2. It is also efficient to work in shallow wells where other aqueous thermal methods like steam injection cannot work.

3. This method does not require huge amount of water supply like steam stimulation method.

4. It can also work in heterogeneous reservoirs even in the high permeability zones or fractured area.

5. The production of EM heating does not depend on the application of electrical power.

6. It is a time-saving process (within shorter time compared to other heating

processes) wherein it can increase the temperature and therefore enhances the production rate.

7. Heat loss can be reduced by controlled use of EM heating process.

8. In EM heating, less amounts of greenhouse gas is emitted compared to other steam-based methods. Therefore it is environmentally accepted.

On the other hand, in addition to some environmental issue, this method has some disadvantages including:

1. This method is only applicable for near-well bore heating, typically in vertical wells.

2. Electrodes or antenna might suffer from corrosion problem in case of high salt concentration reservoir. As a result, the cost of the technique would not be feasible. Even conducting a field trial for this method is more expensive than the other electrical methods. Therefore, it cannot meet the economic feasibility criteria for pilot scale application for heavy oil recovery.

3. In the case of high frequency radiation, the penetration depth is low. Therefore heating area in the reservoir will be reduced.

4. EM heating method also suffers from few environmental issues.

The primary drawbacks of the EM technique are its economic and environmental impacts. Large-scale field applications of electromagnetic heating are notably limited. Historical reports of such applications date back to the 1980s, with only a handful of field trials conducted for heavy oil recovery. These trials have taken place in the USA (specifically in California and Utah), Canada (in Alberta and Saskatchewan), and Russia (in the regions of Bashkortostan and Tatarstan). Despite its potential, the EM technique has yet to achieve widespread commercial viability due to these challenges.

Electrical Heating Methods

One example of electrical methods for oil recovery is the in-situ upgrading process (IUP) developed by Shell. This technology involves drilling two levels of horizontal wells: the lower level for electrical heaters and the upper level for production wells. The IUP process is conducted in several stages:

1. The heater wells gradually increase the subsurface temperature.
2. The elevated temperature upgrades heavy oil into lighter fractions.
3. The process results in high recovery rates of light hydrocarbon products, leaving coke in the reservoir.

Pilot tests of the IUP method have demonstrated a notable recovery factor. Moreover, the oil produced through this process has a significantly higher API gravity compared to the initial bitumen. This means that the IUP not only enhances recovery rates but also improves the quality of the extracted oil, making it a valuable technique for heavy oil recovery and upgrading in situ.

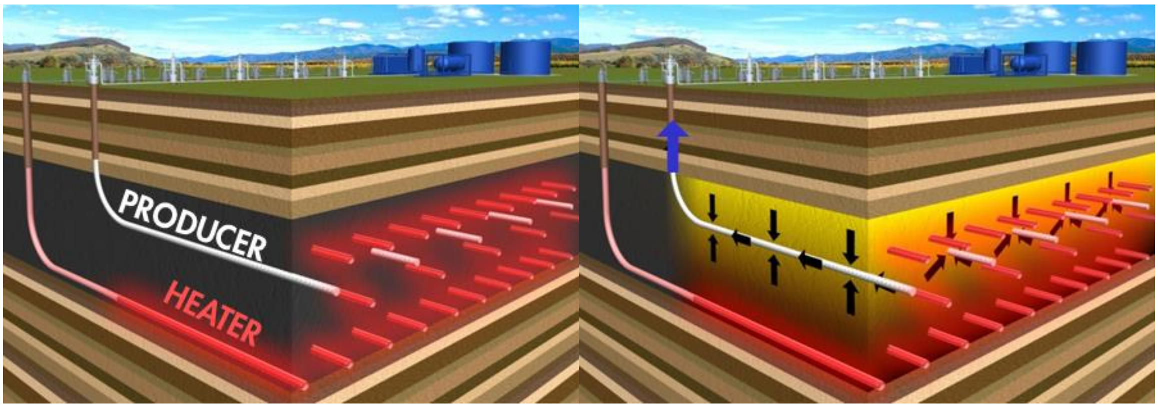


Fig. 46. In-situ upgrading process by Shell.

In recent decades, additional reservoir heating technologies have been developed, such as heat-producing binary mixtures, ExxonMobil's Electrofrac, and Chevron CRUSH. Some of these methods have undergone field testing, but they have not yet reached the stage of full commercial application. While promising, these innovative techniques still require further development and validation before they can be widely implemented in the oil recovery industry.

3.3.5. Practical conclusions

Any technology has its criteria and limitations on applicability. There are no universal technologies that allow putting a well (field) into operation, continue its operation at a profitable level and complete its operation. Take the cyclic steam stimulation technology as an example (Fig. 47), it can be seen that each subsequent cycle requires a greater consumption of steam, and is accompanied by an increase in the steam-oil ratio. In the third cycle, the steam-oil ratio is already 26.9 % higher than that in the first cycle. Each subsequent steam injection cycle should be made taking into account the technological, and, more importantly, economic efficiency.

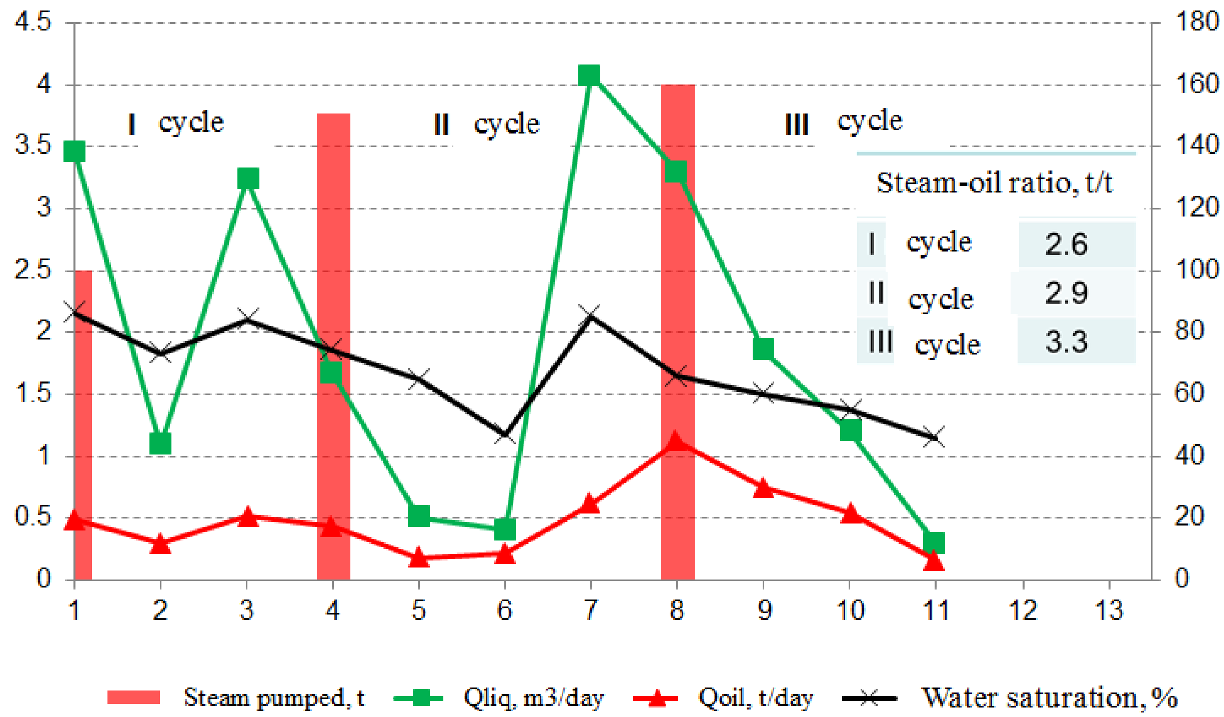


Fig. 47. CSS well operation dynamics.

Each development stage is characterized by its own problems, so the chosen technology must correspond to the problems to be solved for a particular case. Thus, during the development and putting well into operation, the main problem will be the lack of injection capacity, and the corresponding task here is to create a hydrodynamic connection in the reservoir-well system. So, an attempt to drain a well with steam-cyclic treatments will lead to an increase in the development time of the well and to the inefficient use of steam. As shown by laboratory and field tests, one of the solutions for putting a well into operation may be the use of thermo-solvent treatments.

In addition, the use of thermo-solvent treatments during operation shows its effectiveness (Fig. 48).

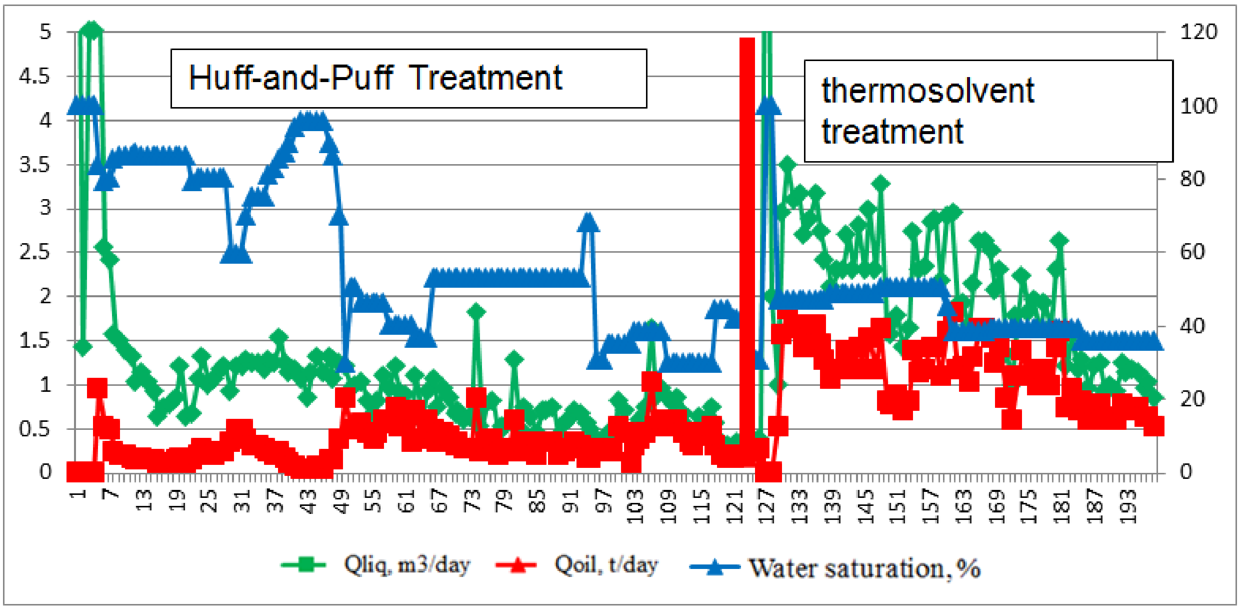


Fig. 48. Comparative analysis between CSS and thermo-solvent treatments.

A comparative analysis between CSS and thermo-solvent treatments showed that at half of the effect time (cycle), production amounted to 180% of the cumulative production from the previous steam treatment cycle. At the same time, the volume of steam injection was equal during Huff-and-Puff and thermo-solvent treatments. This in turn leads to a decrease in the steam-oil ratio, an increase in the efficiency of steam use - an improvement in the project's efficiency indicators.

Another key problem in the implementation of thermal-steam technologies (including the steam and gravity drainage) is the formation heterogeneity and uneven development of thermal chamber. This problem in practice leads to steam breakthroughs from an injection well to a producing well, which leads to inefficient consumption of thermal energy, failure of downhole pumping equipment due to high product temperatures, and other related problems. The main directions for solving these tasks are the well operation monitoring, such as temperature profile monitoring along the wellbore and well production monitoring (flow rate, water cut, chemical composition of oil and water).

Temperature control during the implementation of the steam and gravity drainage technology is carried out using a fiber optic cable that is lowered into the interval of the filter (Fig. 49). Timely monitoring of the temperature profile allows the following corrective measures to equalize the temperature profile: regulation of steam injection and production volumes, adjustment of steam supply, and production points.

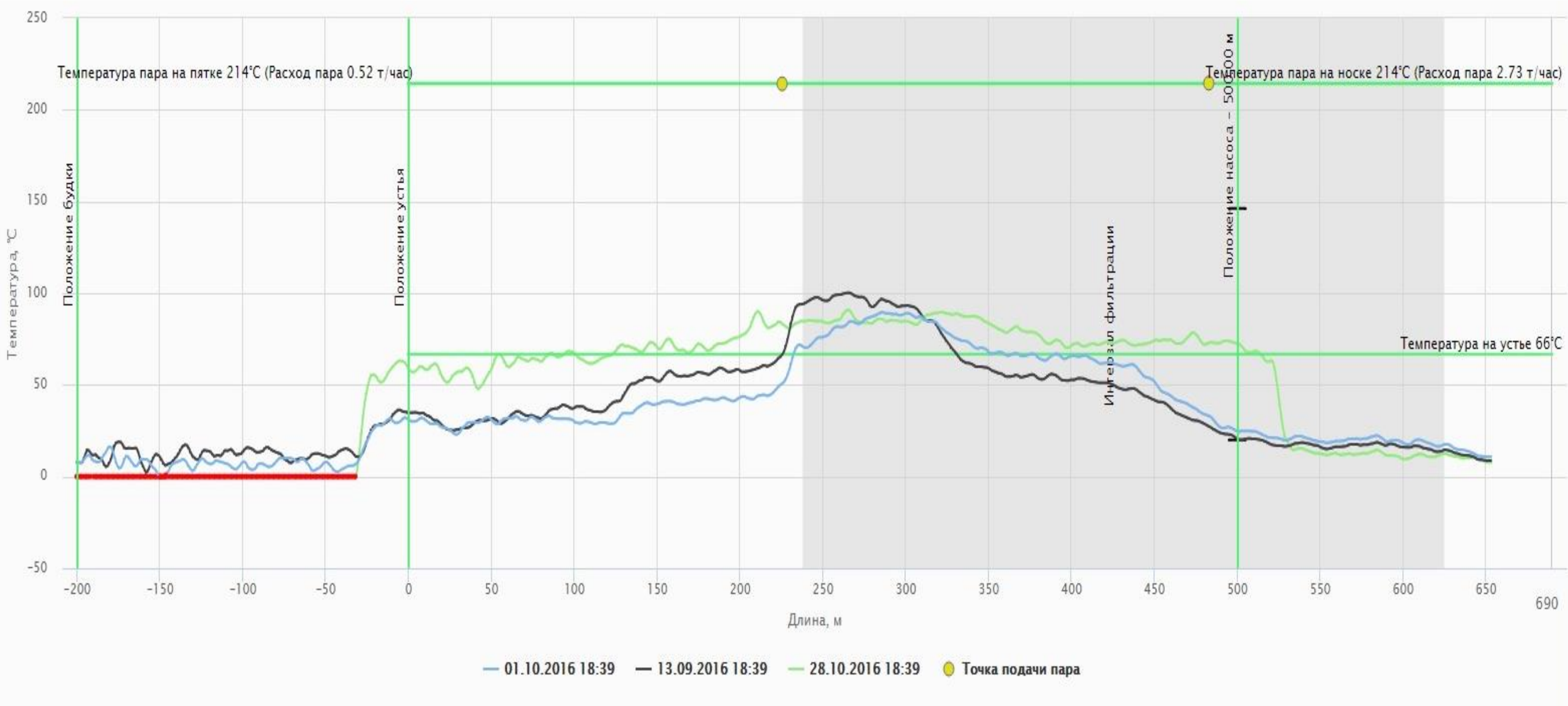


Fig. 49. Temperature profile of the well during the implementation of SAGD technology.

Monitoring over the produced fluid composition allows determining the sources of water in the product such as condensate or formation water.

The above methods for monitoring and controlling well operations are related to reactive methods. As a proactive monitoring method, it is possible to use a special system for well completion including production and injection flow control devices (Fig. 50). The equipment presented on the market allows both autonomous adjustment of steam injection volumes and production profile adjustment, as well as adjusting them in “manual” mode. However, the use of such methods of well completion is expensive and has several limitations on the specific reservoir productivity.

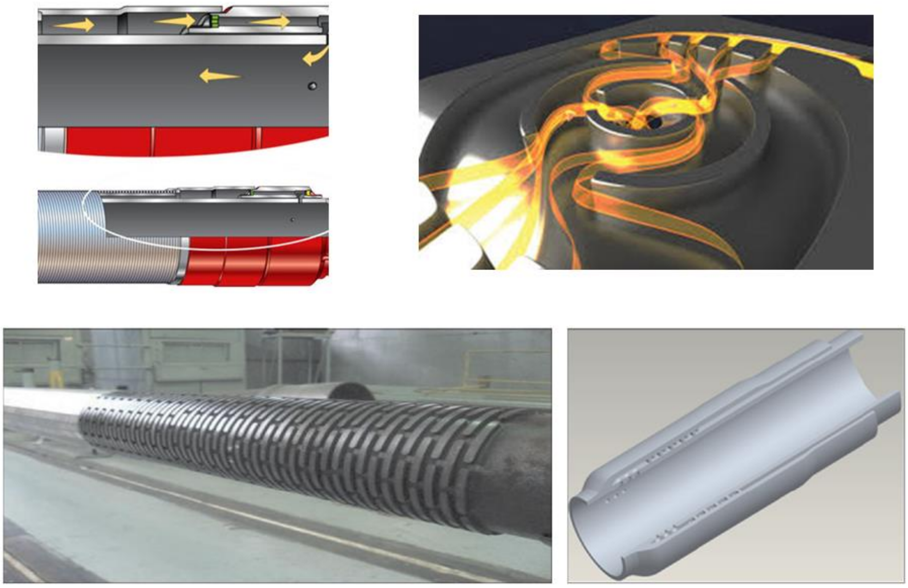


Fig. 50. Inflow control devices.

The principle of flow control device operation is based on the creation of additional hydrodynamic resistances to the fluid flow (choke restriction, increasing the flow path of the fluid, separation), thereby leveling out the reservoir heterogeneity and ensuring uniform agent injection or production.

In the process of well construction, a well completion layout is calculated based on well logging (dividing into sections using swellable packers, including flow control devices in the layout) followed by lowering the casings and equipment into the well.

4. Conclusion

Based on the foregoing discussions, we formulate the following conclusions:

1. Technology Effectiveness:

- Each technology is effective under specific geological and technological conditions.

- Different stages of field development or well operation present unique challenges requiring tailored solutions.

2. Integration of Technologies:

- The principle of integration is fundamental, where the weaknesses of one technology are compensated by the strengths of another.

- Effective field development hinges on the careful selection and integration of appropriate technologies.

3. Diversity in Thermal EOR Methods:

- Thermal enhanced oil recovery (EOR) encompasses a wide range of methods and technologies.

- Each method is designed to address specific conditions, as explored throughout this study guide.

4. Optimization and Resource Utilization:

- Integration allows for the optimization of resource utilization and maximization of hydrocarbon recovery.

- Techniques like cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) are effective in different contexts, and understanding their advantages and limitations is crucial.

5. Addressing Specific Challenges:

- Each development stage of an oil field presents unique problems that must be addressed by the chosen technology.

- Thermal EOR methods, such as in-situ combustion (ISC) and steam flooding, have shown high recovery factors in both laboratory and field applications.

6. Technical Challenges and Monitoring:

- Implementation of thermal EOR methods is often complicated by technical challenges like reservoir heterogeneity and the need for precise temperature and pressure control.

- Advanced monitoring techniques, including temperature profile monitoring with fiber optic cables and production monitoring, are essential for optimizing these processes.

7. Vapor Extraction (VAPEX):

- VAPEX offers a promising alternative to steam-based methods, with benefits like reduced energy consumption and lower greenhouse gas emissions.

- The effectiveness of VAPEX depends on factors such as solvent management, reservoir conditions, and operational complexity.

- Ongoing research and field trials are necessary to refine VAPEX and other emerging EOR technologies.

8. Comprehensive Understanding and Future Role:

- Successful application of thermal EOR methods requires a comprehensive understanding of reservoir geological and technical conditions, integration of multiple technologies, and adoption of advanced monitoring and control systems.

- As the petroleum industry evolves, enhanced recovery techniques will be crucial in meeting global energy demands while minimizing environmental impact.

- This study guide aims to equip students and professionals with the necessary knowledge and skills to navigate the complexities of thermal EOR and contribute to the advancement of this vital field.

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