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"NUMERICAL AND EXPERIMENTAL ANALYSIS OF THE SAGD METHOD FOR THE DEVELOPMENT OF HIGH-VISCOSITY OIL FIELDS"

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This article discusses the results of numerical modeling and laboratory experiments aimed at studying the processes of intensification of heavy oil production by steam injection into inhomogeneous porous media. Athabasca bitumen, widely distributed in the oil fields of Canada, was used as the object of the study. For the experiments, methods of measuring viscosity at various temperatures using a rotary viscometer, as well as analyses of the composition of bitumen and its components, were used. At the same time, a numerical simulation was developed simulating the injection of steam into a porous medium, taking into account the presence of layers with high permeability and shale barriers. The simulation was carried out using the CMG STARS program, which made it possible to assess the influence of temperature and steam quality, porosity, rock permeability and the presence of shale barriers on the oil extraction process.

The main results showed that the optimal steam injection temperature is 200 °C, which provides the most effective reduction in oil viscosity and an increase in the recovery coefficient. At the same time, the optimal steam quality was determined at the level of 85%. An increase in quality to 95% or higher led to a decrease in the efficiency of the process due to insufficient liquid content in steam, which limited heat exchange and increased residual oil in a porous medium. In addition, an analysis of the impact of shale barriers has shown that their presence can significantly limit the steam flow and reduce the oil recovery coefficient. The simulation also showed that minimizing the differences in permeability between high- and low-permeability zones helps to increase the efficiency of steam injection and increase oil production.

Thus, the results of this work can be useful for optimizing steam injection processes in the development of heavy oil fields, especially in conditions of heterogeneous geological structures, which will increase production efficiency and reduce the cost of thermal exposure.

KEYWORDS: *steam injection, heavy oil, numerical modeling, bitumen, porous medium, shale barriers, thermal effects.*

ЧИСЛЕННЫЙ И ЭКСПЕРИМЕНТАЛЬНЫЙ АНАЛИЗ МЕТОДА SAGD ДЛЯ РАЗРАБОТКИ МЕСТОРОЖДЕНИЙ ВЫСОКОВЯЗКОЙ НЕФТИ

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В данной статье рассматриваются результаты численного моделирования и лабораторных экспериментов, направленных на исследование процессов интенсификации добычи тяжелой нефти методом инъекции пара в неоднородные пористые среды. В качестве объекта исследования использовался битум Атабаски, широко распространенный в нефтяных месторождениях Канады. Для проведения экспериментов применялись методы измерения вязкости при различных температурах с использованием ротационного вискозиметра, а также анализы состава битума и его компонентов. Одновременно было разработано численное моделирование, имитирующее инъекцию пара в пористую среду с учетом наличия слоев с высокой проницаемостью и сланцевых барьеров. Моделирование проводилось с использованием программы CMG STARS, что позволило оценить влияние температуры и качества пара, пористости, проницаемости породы и наличия сланцевых барьеров на процесс извлечения нефти.

Основные результаты показали, что оптимальная температура инъекции пара составляет 200 °C, что обеспечивает наиболее эффективное снижение вязкости нефти и увеличение коэффициента извлечения. При этом оптимальное качество пара было определено на уровне 85%. Увеличение качества до 95% и выше приводило к снижению эффективности процесса из-за недостаточного содержания жидкости в паре, что ограничивало тепловой обмен и увеличивало остаточную нефть в пористой среде. Кроме того, анализ влияния сланцевых барьеров показал, что их наличие может существенно ограничивать поток пара и уменьшать коэффициент извлечения нефти. Моделирование также показало, что минимизация различий в проницаемости между высоко- и низкопроницаемыми зонами способствует повышению эффективности инъекции пара и увеличению добычи нефти.

Таким образом, результаты данной работы могут быть полезны для оптимизации процессов инъекции пара при разработке месторождений тяжелой нефти, особенно в условиях неоднородных геологических структур, что позволит повысить эффективность добычи и снизить затраты на тепловое воздействие.

КЛЮЧЕВЫЕ СЛОВА: *инъекция пара, тяжелая нефть, численное моделирование, битум, пористая среда, сланцевые барьеры, тепловое воздействие.*

ТҰТҚЫРЛЫҒЫ ЖОҒАРЫ МҰНАЙ КЕН ОРЫНДАРЫН ИГЕРУГЕ АРНАЛҒАН SAGD ӘДІСІНІҢ САНДЫҚ ЖӘНЕ ЭКСПЕРИМЕНТТІК ТАЛДАУЫ

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Бұл мақалада гетерогенді кеуекті ортаға бу енгізу арқылы ауыр мұнай өндіруді интенсивтендіру процестерін зерттеуге бағытталған сандық модельдеу және зертханалық эксперименттердің нәтижелері қарастырылады. Зерттеу нысаны ретінде Канаданың мұнай кен орындарында кең таралған Атабаска битумы қолданылды. Эксперименттер жүргізу үшін айналмалы вискозиметрді қолдана отырып, әртүрлі температурада тұтқырлықты өлшеу әдістері, сондай-ақ битум құрамы мен оның компоненттерін талдау қолданылды. Сонымен қатар, өткізгіштігі жоғары қабаттар мен шифер кедергілерін ескере отырып, кеуекті ортаға бу инъекциясын имитациялайтын сандық модельдеу жасалды. Модельдеу CMG STARS бағдарламасын қолдана отырып жүргізілді, бұл будың температурасы мен сапасының, кеуектілігінің, тау жыныстарының өткізгіштігінің және тақтатас тосқауылдарының мұнай алу процесіне әсерін бағалауға мүмкіндік берді.

Негізгі нәтижелер бу инъекциясының оңтайлы температурасы 200 °C екенін көрсетті, бұл мұнай тұтқырлығының ең тиімді төмендеуін және экстракция коэффициентінің жоғарылауын қамтамасыз етеді. Бұл ретте будың оңтайлы сапасы 85% деңгейінде анықталды. Сапаның 95% - ға дейін және одан жоғары өсуі бу сұйықтығының жеткіліксіз болуына байланысты процестің тиімділігінің төмендеуіне әкелді, бұл жылу алмасуды шектеді және кеуекті ортадағы қалдық мұнайды арттырды. Сонымен қатар, тақтатас тосқауылдарының әсерін талдау олардың болуы бу ағынын айтарлықтай шектей алатынын және мұнай алу коэффициентін төмендететінін көрсетті. Модельдеу сонымен қатар жоғары және төмен өткізгіш аймақтар арасындағы өткізгіштік айырмашылықтарын азайту бу инъекциясының тиімділігін арттыруға және мұнай өндіруді арттыруға көмектесетінін көрсетті.

Осылайша, бұл жұмыстың нәтижелері ауыр мұнай кен орындарын игеру кезінде бу инъекциясы процестерін оңтайландыру үшін пайдалы болуы мүмкін, әсіресе гетерогенді геологиялық құрылымдар жағдайында, бұл өндіріс тиімділігін арттыруға және жылу әсерін азайтуға мүмкіндік береді.

Түйін сөздер: *бу инъекциясы, ауыр мұнай, сандық модельдеу, битум, кеуекті орта, шифер кедергілері, жылу әсері.*

Introduction. The development of heavy oil fields, particularly oil sands, presents a complex challenge in the oil and gas industry due to the high viscosity and low mobility of these resources. One of the most effective methods for enhancing the recovery of heavy oil is steam injection, which aims to reduce the oil's viscosity through thermal effects. The application of thermal methods, such as Steam Assisted Gravity Drainage (SAGD), significantly increases oil recovery by heating and liquefying heavy hydrocarbons, making them more fluid and therefore easier to extract from porous media.

However, despite the high efficiency of this method, its implementation faces several technical challenges. A major issue is the heterogeneity of porous media, which includes zones with varying permeability and porosity, as well as the presence of shale barriers. These heterogeneities can significantly impede the steam injection process by creating thermal and permeability barriers, reducing the efficiency of heat transfer and limiting steam flow into oil-saturated zones. As a result, a portion of hydrocarbons remains in the form of residual oil, which lowers overall recovery rates.

To address these problems, detailed studies on the influence of key steam injection parameters on the development of heavy oil fields in heterogeneous media are necessary. The most important parameters to consider when designing thermal recovery processes include steam temperature and quality, the porosity and permeability of the oil-bearing formation, and the configuration of shale barriers. Experimental and numerical studies in this area not only help to better understand the physics of the process but also optimize injection parameters to achieve maximum recovery efficiency with minimal energy costs.

The aim of this work is to conduct numerical simulations and laboratory experiments to investigate the effects of various steam injection parameters on the recovery of heavy oil from heterogeneous porous media. Special attention is given to studying the dependency of injection efficiency on steam temperature and quality, as well as the permeability and porosity of the formation and the presence of shale barriers. In the course of this work, a numerical model of steam injection was developed using the CMG STARS software to simulate the thermal effects on the heavy oil reservoir, enabling a sensitivity analysis of key parameters and the formulation of recommendations for process optimization.

As part of the research, laboratory experiments were also conducted to determine the viscosity characteristics of Athabasca bitumen at various temperatures. This provided experimental data that were used to calibrate the numerical model. Further studies will help to improve the understanding of the thermal recovery process in oil reservoirs and develop efficient steam injection techniques to increase heavy oil recovery in complex geological structures. [2]

Materials and methods. Several laboratory tests were conducted to determine the necessary flow properties of bitumen for numerical simulation purposes. The tests are outlined below. Detailed experimental results, such as bitumen viscosity, required for typical thermal simulation studies are presented in more depth, while other parameters, like interfacial tension measurements, are only briefly mentioned. A comprehensive analysis report is available elsewhere.

The viscosity-temperature relationship of Athabasca bitumen was assessed using a computerized rotational viscometer capable of measuring fluid viscosity from room temperature up to 300°C. The test, based on the SAGD method, utilized samples from the Athabasca oil sands. [1] Condensates produced with the bitumen were expelled at high temperatures, and the samples were not treated with any solvents. *Figure 1* compares our measured viscosities to those reported for bitumen by Mehrotra and Svrcek in their 1986 study. [2]

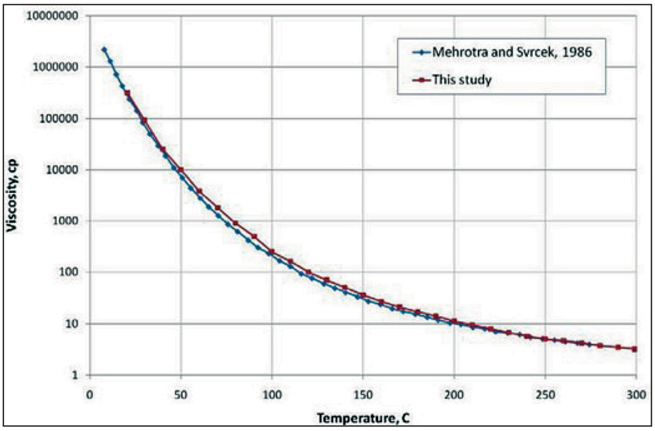

Figure 1 – **Viscosity of Athabasca bitumen versus temperature**

One of those correlations is shown below:

$$\ln\ln(\mu) = C_1 \ln T + C_2; \quad (1)$$

In this equation, the kinematic viscosity of the heavy oil sample is expressed at atmospheric pressure and temperature T(K). Experimental data from each sample can be used to determine the empirical constants C_1 and C_2. These constants can be estimated using the least-squares method. *Figure 2* shows a graph of the logarithms of viscosity and temperature. For four different bitumen samples, as described by Khan et al. (1984), this figure compares the viscosity data measured in the laboratory during this study with the viscosity relationship fitted according to Equation 1.[3] The evaluation for Equation 1 was consistently applied, and the viscosity data for the four bitumen samples were fitted as shown in the legend of *Figure 2*.

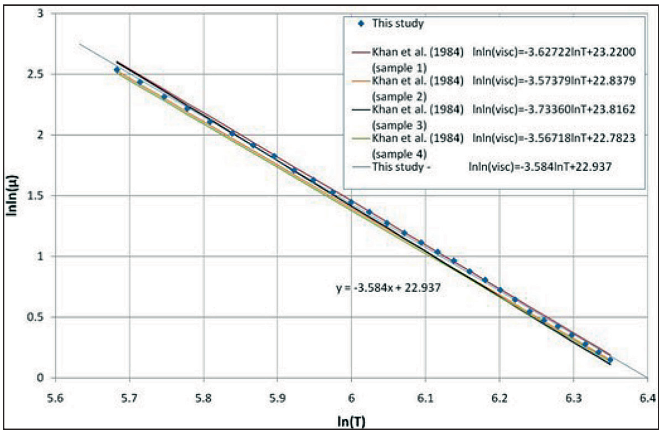

Figure 2 – **Bitumen viscosity correlation – double logarithm of viscosity shows straight line behavior versus logarithm of temperature**

Gas chromatography (GC) and compositional analysis of an Athabasca bitumen sample were carried out. Detailed descriptions of these analyses can be found elsewhere. In this section, only the compositional analysis of the bitumen samples is presented in Table 1. No conventional alkanes lighter than C10 were detected. The samples are classified into pseudo-components, as shown in *Table 3*. The weight percentages in *Table 3* are accurate to two decimal places. The mole fractions presented in this table are based on weight percentages, generalized Katz-Firoozabadi properties, cryogenically determined molar masses (discussed later in the paper), and densitometric data derived from the oil's density (also described later in the paper).[4]

The molar mass of oil tests is decided by solidifying point discouragement (solidifying strategy) utilizing benzene as dissolvable. Comes about demonstrate that the molar mass of Athabasca bitumen is 534 ± 2 g/gmol.[5]

Oil thickness was measured employing a high-temperature high-pressure densitometer cell calibrated at the specified temperature with nitrogen gas and unadulterated water. Thickness estimations were performed at standard temperature of 15.56 °C and lifted weights of 5, 10, 15, 20 and 25 bar. Extrapolation of the straight relationship between oil thickness and weight yielded an oil thickness of 1.0129 g/cm3 at standard conditions (SC) of 1.01325 bar and 15.56 °C. Oil thickness was moreover measured at raised temperatures of 120°C, 140°C, 160°C, 180°C and 195°C for each weight, giving solid oil densities for the temperature and weight extend of 0.90 - 0.95 g/cm^3.[6]

Bulk tests were performed to decide the weight percent of asphaltenes accelerated when certain solvents were blended with Athabasca overwhelming oil. The reason of the test was to explore whether there is a relationship between the dissolvable mole division and the sum of asphaltenes accelerated. Solvents utilized in this test were n-pentane, n-hexane, and n-heptane. Different sums of dissolvable were included to the oil and the oil was warmed to 60°C to guarantee ease. The mixture was blended and cleared out at room temperature for around 20 hours.[7]

Table 1 – **Compositional analysis of Athabasca bitumen**

Pseudo-component Mass fraction (%)	Mole fraction (%)	Molar mass (g/gmol)	Density (g/cm^3)	
C10	0.211	0.842	134.0	0.7780
C11 – C12	0.948	3.286	154.0	0.7945
C13 – C14	1.976	5.782	182.5	0.8165
C15 – C16	3.006	7.501	214.0	0.8355
C17 – C18	3.731	8.166	244.0	0.8495
C19 – C20	4.068	8.075	269.0	0.8595
C21 – C22	3.959	7.094	298.0	0.8695
C23 – C24	3.759	6.186	324.5	0.8790
C25 – C26	3.594	5.453	352.0	0.8870
C27 – C28	3.602	5.048	381.0	0.8945
C29 – C30	3.437	4.487	409.0	0.9005
C31 – C32	3.265	3.989	437.0	0.9075
C33 – C34	2.577	2.959	465.0	0.9130
C35 – C36	2.599	2.815	493.0	0.9180
C37 – C38	2.309	2.366	521.0	0.9230
C39+	56.960	25.950	1172.1	1.1474
Total / Average	100.000	100.000	534.0	1.0129

The blend was at that point sifted with a vacuum pump and the accelerate was weighed. The comes about are appeared in *Figure 3*. Tests have appeared that lighter n-alkanes accelerate more emphatically from overwhelming fuel oil than heavier n-alkanes. Besides, as the dissolvable mole division increments, the precipitation of solids increments. Precipitation starts at a mole division of ~85% for n-pentane, ~86% for n-hexane and 87% for n-heptane. Dissolvable mole divisions ought to be kept underneath these levels to maintain a strategic distance from issues such as arrangement harm from asphalting. Minuscule figure of asphaltene particles is appeared in *Figure 4*.

Numerical reenactments were performed for heterogeneous centers to ponder the usability of steam injection. Different arrangements of shale boundaries have been examined to decide the impacts of these non-fluidized layers. Considering the heterogeneous framework, the affectability examination centered on the impacts of infusion

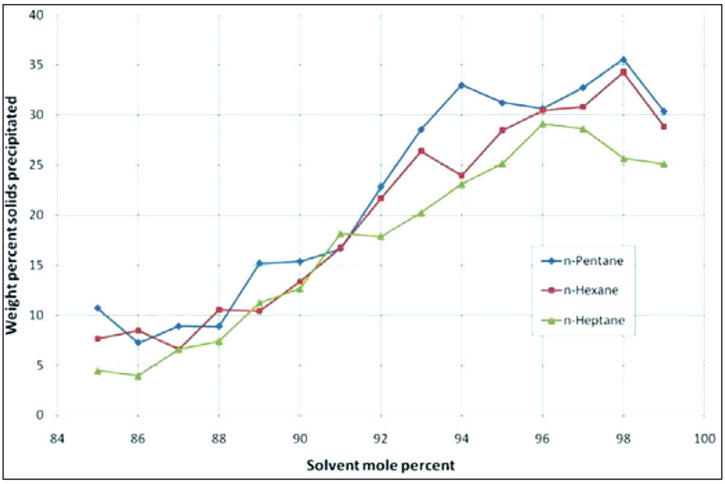

Figure 3 – **Asphaltene precipitation versus different solvent loadings**

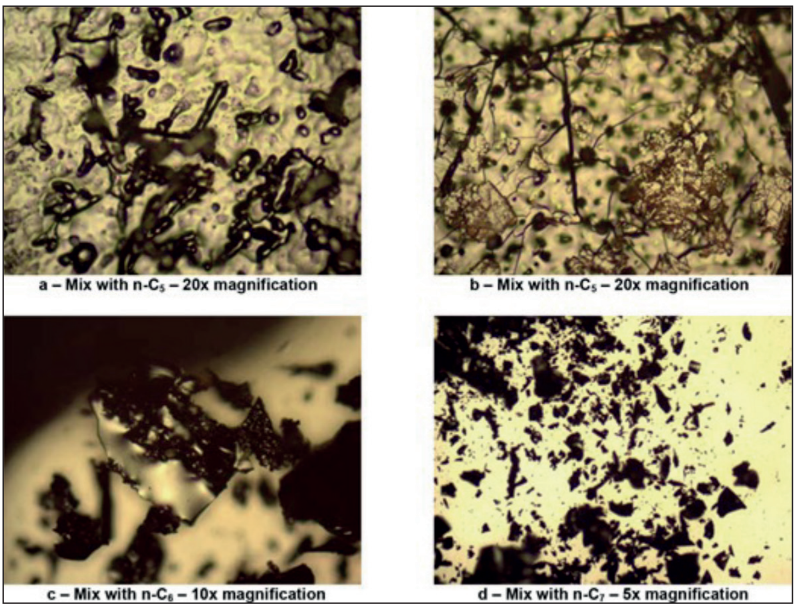

Figure 4 – **Microscopic images of asphaltene particles precipitated after mixing with different solvents**

rate, porosity, porousness differentiates and thickness of the high-permeability zone. Different steam temperature and quality cases were moreover examined amid center flooding tests on this framework.[8]

The center comprises of sandstone with a measured penetrability of 640 mD and contains a little flat exceedingly permeable and penetrable layer within the center of the demonstrate. Recreation ponders were performed utilizing the CMG STARS warm test system, ordinary supply properties of the Athabasca oil sand store, and a few laboratory-measured liquid properties.

A Cartesian facilitate framework is utilized, so the square cross-sectional zone of the cubical show is rise to the cross-sectional region of the center. *Figure 5* appears the numerical show considered.

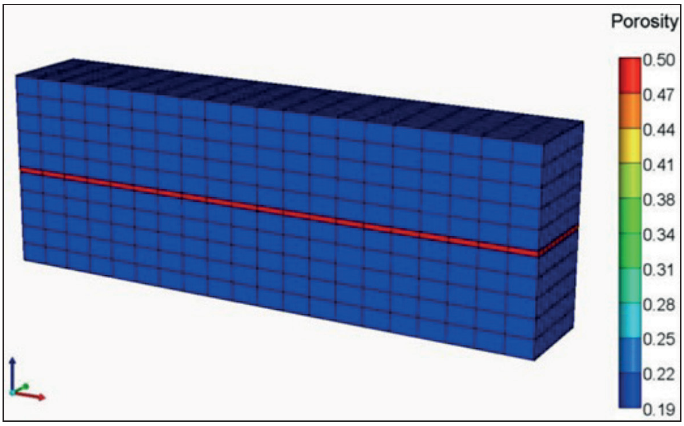

Figure 5 – **Numerical model**

It may be a square show of 20 x 10 x 11 squares. The length of the network piece is 1 cm within the x course and 0.33588 within the y and z headings. A little 1 mm wide even layer within the center is considered an exceedingly penetrable channel. This layer is accepted to have a porosity of 0.5 and a penetrability of 5 Darcy. The show, supply, and liquid properties utilized are appeared in *Table 2*. Relative porousness information was gotten from Coats et al. Evacuated from a steam-immersed case.[9]

Table 2 – **Numerical simulation parameters used in this study: Rock properties and fluid properties are cited from the literature, except for the molar mass and density of bitumen, which have been measured in the laboratory**

Model properties		Thermal properties	
Width	3.3588 cm	Formation heat capacity	2.39E+06 J/ (m^3. °C)
Height	3.3588 cm	Rock thermal conductivity	1.469E+05 J/(m.day. °C)
Permeability	20 cm	Water thermal conductivity	5.35E+04 J/(m.day.°C)
Porosity	0.19	Oil thermal conductivity	1.34E+04 J/(m.day.°C)
Initial temperature	21 °C	Gas thermal conductivity	2.60E+03 J/(m.day.°C)
Oil saturation	0.95	Water´s first coefficient of thermal expansion	2.657E-04 $°C^{-1}$
Water saturation	0.05	Bitumen´s first coefficient of thermal expansion	7.85E-04 $°C^{-1}$

Results and discussion. Various steam injection conditions were investigated in this heterogeneous core model, with the primary parameters being steam temperature and quality.[10] Increasing the injected steam temperature raises the energy input to the system, which enhances viscosity reduction and improves overall oil production. As shown in Figure 6, the total recovery increases as the steam temperature rises from 180°C to 221°C. However, the difference in recovery between 200°C (91.35%) and 221°C (91.86%) is relatively small. Given that higher steam temperatures result in increased generation costs and energy consumption, it is reasonable to conclude that 200°C is the optimal temperature. Operating above this temperature is not recommended, as it only slightly improves oil recovery while significantly increasing energy use.

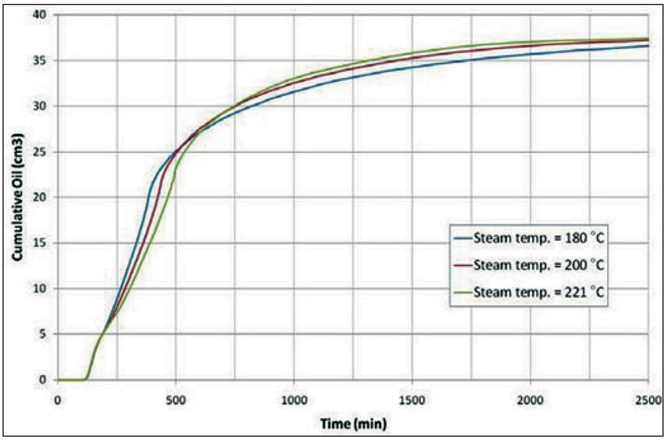

Figure 6 – **Cumulative oil production at various steam injection temperatures at 85% steam quality**

A steam injection temperature of 200°C was selected for the remaining simulation runs to assess the effect of different steam qualities on final oil production. Steam qualities of 50%, 75%, 85%, 95%, and 100% were tested. [13] The cumulative oil production curves are shown in *Figure 7*. Higher quality steam introduces more heat into the porous medium, resulting in a more efficient process and increased overall production, which is evident during the early stages of production in *Figure 7*. However, a closer examination of later production stages, as shown in *Figure 8*, reveals a different trend. Up to a steam quality of 85%, increasing the steam quality improves oil recovery. However, when the steam quality is further increased to 95% and 100%, the positive effect diminishes, and a decline in final oil production is observed. A similar trend was noted during steam injection at different steam temperatures.

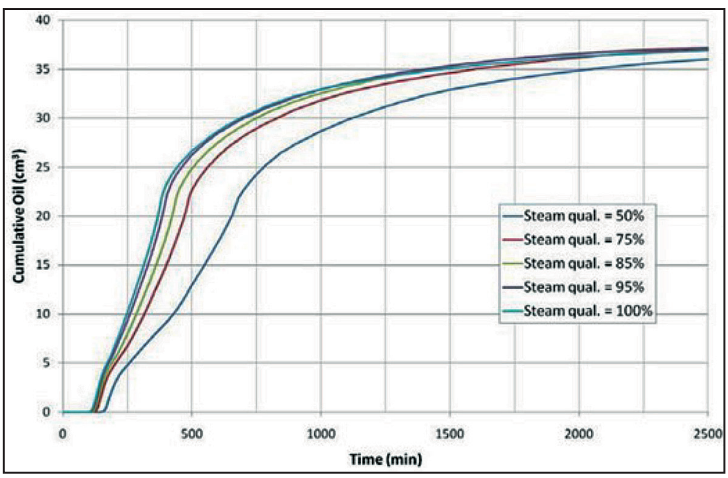

Figure 7 – **Cumulative oil production at various steam qualities (200 °C steam temperature)**

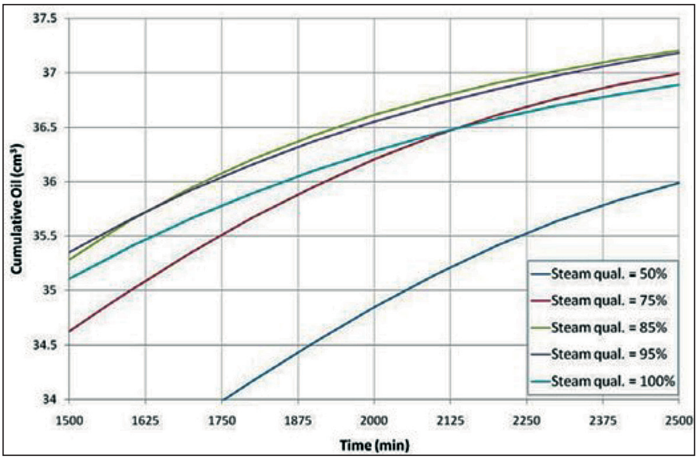

Figure 8 – **Cumulative oil production at various steam qualities (200 °C steam temperature)**

A snapshot of the saturation distribution within the core illustrates the effects of injecting steam at very high quality. A later snapshot of the core, showing oil and water saturation, is provided in *Figure 9*. The left column of the figure displays the distribution when steam was injected at 85% quality, while the right column shows the distribution at 100% quality. Injecting steam at 100% quality results in limited liquid water saturation, especially near the core channel surface. This occurs due to the low fluid content in the injected vapor, which can even cause some of the pore water at the injection face to evaporate. As a result, the water saturation becomes lower than the initial level, leading to higher residual oil saturation in those grid blocks compared to others. [14]

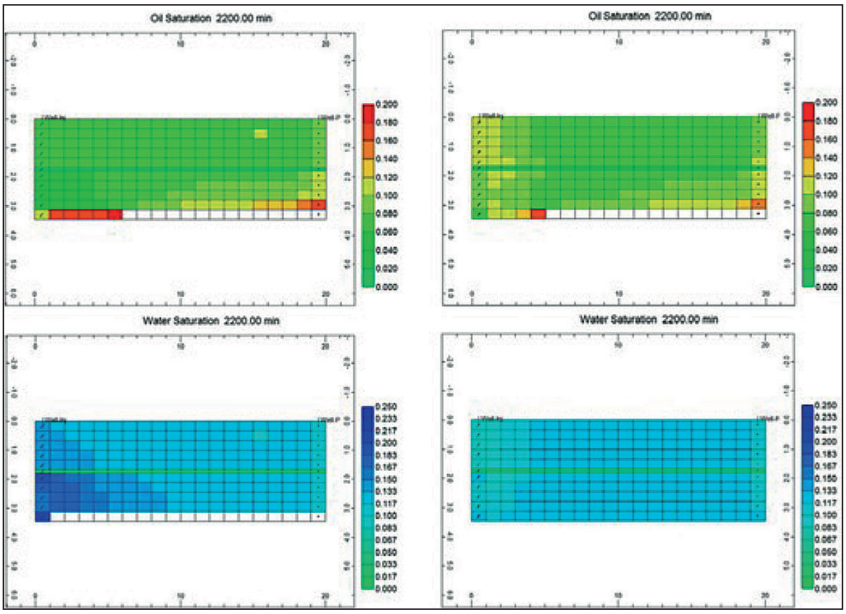

Figure 9 – **Saturation distribution and different steam qualities at 2200 minutes of steam injection at 200 °C (left column 85% steam quality, right column 100% steam quality)**

The observed behavior varies in intensity depending on the relative permeability of each system. The distribution of saturation shows that dry steam injection leads to very limited water saturation at the inlet. The key takeaway is that steam injection should not use excessively high steam quality. The optimal steam quality in this case is around 85%.

To confirm the impact of shale barriers within the core experiment, different scenarios with various shale barrier configurations were modeled in this heterogeneous core test. The scenarios included two horizontal shale barriers, two vertical shale barriers, and one randomly placed shale barrier. [15] These configurations are illustrated in *Figure 10*. In Scenario 1 (HS-1), the horizontal shale barrier extends across the core from the injection area to the production zone. However, in Scenario 2 (HS-2), the horizontal shale layer is located within the core and does not reach the outer surface. The randomly placed shale barrier configuration combines both horizontal and vertical shale barriers.

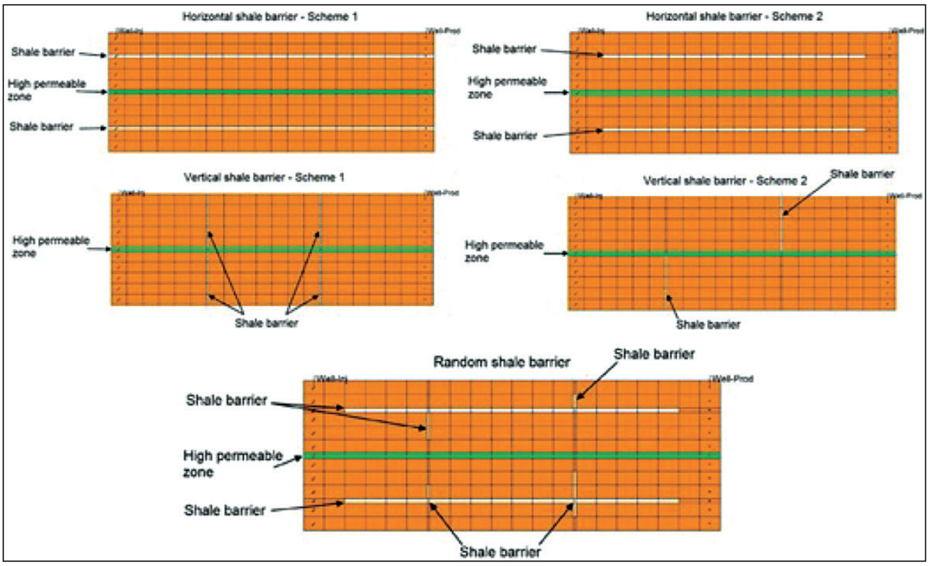

Figure 10 - **Schematic representations of different shale barrier schemes**

Conclusion. This study explored the efficiency of steam injection in heterogeneous porous media to enhance the recovery of heavy oil, specifically focusing on key parameters such as steam temperature, steam quality, permeability variations, and the presence of shale barriers. Through both numerical modeling and laboratory experiments, valuable insights were gained into how these factors influence the overall recovery process.

The findings revealed that a steam injection temperature of 200°C is optimal for effectively reducing the viscosity of heavy oil, leading to a significant improvement in the recovery rate. Temperatures higher than 200°C did not provide a substantial additional benefit in terms of oil recovery, but they increased the energy and operational costs. Therefore, operating at 200°C is the most energy-efficient and cost-effective solution.

Regarding steam quality, the study found that an optimal steam quality of 85% is the most efficient for maximizing oil recovery. Steam qualities higher than 85%, such as 95% or 100%, caused a reduction in performance due to limited water content in the injected steam, which restricted the heat transfer within the porous medium and led to higher residual oil saturation. This suggests that maintaining a balance between vapor and liquid phases in the steam is crucial for the effective thermal mobilization of heavy oil.

The presence of shale barriers in the porous medium had a significant impact on the efficiency of steam injection. These barriers restricted the flow of steam and limited the thermal exchange between steam and oil, resulting in lower oil recovery. The study highlighted that optimizing the distribution of permeability in the reservoir is essential to enhance steam flow and heat distribution. By minimizing the permeability contrast between high- and low-permeability zones, the efficiency of steam injection can be improved, leading to better oil recovery.

In addition to steam quality and temperature, the study demonstrated the importance of understanding the reservoir's geological characteristics, particularly the distribution and configuration of shale barriers. This understanding is crucial for optimizing steam injection strategies and ensuring that the injected steam reaches oil-rich zones effectively, thereby minimizing the amount of residual oil left in the formation.

Overall, the results of this study provide important guidelines for optimizing steam injection processes in the development of heavy oil fields, particularly in complex and heterogeneous geological formations. These findings can help improve the efficiency of oil production while reducing the costs and energy consumption associated with thermal recovery techniques. The insights gained from this research can also contribute to better management and planning of enhanced oil recovery projects, ensuring more sustainable and economically viable extraction of heavy oil reserves.

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