Tight and Shale Oil Exploration

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The exploration and development of West Siberian tight and shale oil reserves, drawing inspiration from North American shale experience is investigated. Emphasizing the advancement in enhanced recovery methods and integrated data-driven approaches. This analysis highlights the potential of multistage hydraulic fracturing while addressing the scarcity of dedicated enhanced oil recovery pilot studies for West Siberian shale formations.

Keywords: tight reservoir ; shale oil ; enhance oil recovery ; Bazhen formation ; Achimov formatoin

1. Introduction

Tight oil and shale reserves are characterized by ultra-low permeability of less than 0.1 mD [1][2]. This almost impermeable rock matrix restricts the flow of fluid and makes it difficult for the accumulated hydrocarbons to be retrieved. The ultra-low permeability characteristic of tight oil reservoirs limits the oil and gas flow area to only around a meter from the well, and the rest of the valuable fluids are trapped in the farther non-stimulated regions, which are hard to reach via the depletion regime. Thus, a small initial stimulated reservoir volume (SRV) is the main problem for shales [3]. A shale resource system can be defined as a continuous organic-rich source rock or rocks that serve dual purposes, functioning as both a source and a reservoir for petroleum (oil and gas) production or, alternatively, as a means to charge and seal petroleum in adjacent, continuous organic-lean intervals. This system involves primary migration processes, confined to movement solely within the source interval, as well as secondary migration, which extends into non-source horizons that are juxtaposed to the source rock(s) [4]. Although the deposits of tight and shale oil are enormous in West Siberia, they are still in the earliest stages of development. Most of the few ongoing projects include horizontal wells drilling and hydraulic fracturing in the fields of the Bazhenov formation (BF), which is a deep shale reservoir (2500–3000 m) characterized by high organic content (up to 40% of kerogen) and low permeability at the micro or nano Darcy scale. Kalmykov et al. [5] reported that West Siberian shales and tight oil reservoirs possess unique characteristics compared to Bakken formations. These characteristics include varying amounts of carbonates, feldspar, and pyrite. Additionally, the oil shale of the West Siberian formation can be described as sediments saturated with hydrocarbons and heteroatomic compounds, where organic matter plays a significant role in the composition of the rocks.

From the early 2000s, the exploration of tight oil and shale reservoirs increased dramatically due to the application of two advanced, improved oil recovery methods: horizontal well drilling and hydraulic fracturing (HF). While the drilling of horizontal wells increases the drainage area of the well, hydraulic fracturing is required to improve the flow of the accumulated fluids from the matrix towards the wellbore for recovery. Since then, the development of the world's shales and tight oil reservoirs has fundamentally included increasing the simulated reservoir volume (SRV) by creating a network of drainable fractures through hydraulic fracturing or multistage hydraulic fracturing (MSHF). The principle of hydraulic fracturing involves the injection of large amounts of prepared fluids into the well, providing increased reservoir pressure that exceeds the rock strength at certain positions, literally tearing the rock apart and creating fractures [6]. The creation of large SRV via multistage hydraulic fracturing is usually enough for the stable production of shale gas. However, even massive MSHF leads to the recovery of only up to 10% of shale oil, with a rapid decrease in the flow rate during the first few months of well exploitation. The main reason for that is the low relative permeability of the rock to oil and the depletion of the fracture net, which very slowly refills with the upcoming fluid [7]. Therefore, enhanced oil recovery (EOR) methods are implemented to achieve high shale oil recovery rates following one of these main scenarios: thermal treatment, gas injection, water injection, or chemical-based fluids.

2. Experimental EOR Methods

Due to the fact that the application of hydraulic fracturing and horizontal wells increases the recovery factor of shale and tight oil reserves, enhanced oil recovery methods are very crucial in increasing the recovery factor for these types of reservoirs. Hence, many studies over the years have been dedicated to optimizing EOR methods applicable to conventional reservoirs for tight oil and shale formations. These studies include thermal enhanced oil recovery methods, gas enhanced oil recovery methods, chemical enhanced oil recovery methods, and hybrid methods. Depending on the geological and petrophysical characteristics of the formation, one method might be applicable, while other methods might not be applicable. There are numerous laboratory and numerical investigations conducted globally on shale and tight reservoirs. Some of these studies are pilot studies and commercial application of this technology. Hydraulic fracturing, thermal and gas-based EOR methods are the most popular methods experimented on at the field scale for shales and tight reservoirs.

Gas injection is a well-known technology employed by oil and gas companies globally across various types of formations, resulting in a significant increase in cumulative oil recovery [8]. Its applicability to shales and tight fields is a straightforward choice for EOR. Nevertheless, initial pilot tests of gas injection in shales unveiled several challenges, including early breakthroughs, inadequate sweep efficiency, and insignificant increase in the recovery factor. These field studies highlight the necessity for a customized approach to achieve successful gas EOR performance in shales. One of the most significant choices to make when designing a gas EOR method for field application is the choice of gas to inject. CO_2 and natural (hydrocarbon) gas are the most preferable and frequently used EOR gases in EOR for shales. Both carbon dioxide (CO_2) and natural gas are utilized as miscible agents, leading to enhanced oil recovery through favorable solubility, oil swelling, and diffusion. The injection of these gases has demonstrated efficiency in shales, with certain pilot cases reporting up to a 70% increase in oil recovery [9][10]. Even if, in some cases, other gases (e.g., ethane) might appear to be a more efficient option, it is usually a consequence of the gas source availability near the field. The economic profitability of the additional oil recovery from gas should not be compromised by its production and transportation to the field. In scenarios where the preferred gases are unavailable for various reasons, less miscible agents, such as lean gas or nitrogen, can be employed as EOR agents for shales, albeit resulting in lower oil recovery [11][12][13]. Only when gas injection is not a viable option do enterprises shift their focus towards less desirable water-based fluids.

Cyclic injection (or huff-n-puff mode) is considered to be a more efficient well operation regime for shales and low-permeable reservoirs than continuous flooding due to the poor fracture net connection between wells [11][14]. Huff-n-puff mode allows the injected solvent to propagate deep into the matrix and interact with the oil for a longer period of soaking. An example of successful implementation of the huff-n-puff mode is gas EOR projects on Eagle ford shales [15]. Gas and water-based liquid injections are extensively studied EOR technologies for shales, both in laboratory settings and, to some extent, in the field. Several comprehensive reviews have been conducted to summarize the global experience with gas EOR for shales [11][14][16]. In general, water-based fluids are not very useful in shales and tight formations, unlike conventional fluids. This is because of the ultra-low permeability of the reservoir rocks, clay swelling, and other effects that have already been described, which cause low injectivity, decreased permeability, and permanent damage to the near-wellbore zone [17][18]. For some reservoirs, the calculated economics could be positive if a water-based fluid such as surfactant is used as an EOR agent. Low costs of transportation, preparation, and injection and a slight production increase confirmed by a few field tests promise an optimistic scenario.

Another aspect of successful EOR performance in the field is the surface area for the treatment and the time of contact between oil and an EOR agent within the reservoir. The rock matrix in shales is almost impermeable, and the only way to effectively increase the contact area and provide pressure propagation is to create a large SRV zone by applying hydraulic fracturing, as stated above. A higher degree of fracture branching throughout the reservoir is anticipated to enhance the effectiveness of EOR, regardless of the chosen injected fluid. However, operational parameters, such as injection pressure, re-pressurization control, injection and soaking durations, production periods for huff-n-puff treatments, and the number of cycles, play a crucial role in establishing the necessary oil–fluid contact.

Thermal treatment distinguishes itself from other EOR methods for shales, as it relies on increasing the temperature within the reservoir to convert solid organic matter into synthetic oil [19][20][21]. Thermal EOR techniques for shales can be classified into two distinct technologies: air injection, known as in situ combustion (ISC), or hot-fluid injection. Hot-fluid injection, such as hot-water injection (including overheated vapor and supercritical water) or other agent injections, involves preheating a specific fluid, typically water, to deliver heat into the formation. These methods have established efficacy in enhancing oil recovery in light, heavy, and viscous oil formations.

2.1. Advances in the Thermal Treatment of Shales and Tight Reservoirs

Thermal treatment of reservoirs is aimed at improving the mobility properties of the in situ oil [22]. It mainly involves the application of heat to the in situ oil, thereby decreasing its density and viscosity and consequently increasing its mobility. The application of thermal EOR methods to shales requires the consideration of all physical and chemical characteristics of the reservoir and the in situ fluids. Thermal treatment of shales and tight oil reservoirs can be categorized into four main groups, based on the source of heating—in situ combustion, hot-fluid injection, electrical heating, and electromagnetic heating methods. Considering the mode of injection and the source of heat, the thermal methods that have received the most extensive research attention encompass continuous steam injection, cyclic steam injection, steam-assisted gravity drainage (SAGD), vapor extractions (VAPEX), and in situ combustion [23]. The order of listing does not represent the importance or popularity of these thermal methods.

2.1.1. In Situ Combustion and Heating EOR

In situ combustion technologies have been reported to have been developed and actively implemented in the USA since 1916 and have since been tested for heavy oil, shales, and tight oil reservoirs [24]. Since then, numerous experiments and pilots have been reported. At the inception of the shale revolution, the application of in situ combustion to shale oil formation began to gain recognition. In situ combustion is a technology that involves the ignition of combustion in a reservoir and controlling the combustion front to generate heat and increase the mobility of trapped oil or shale oil [25]. The process involves the use of hydrocarbons as a fuel to heat up the reservoir and enhance or speed up chemo-physical processes in hydrocarbon-bearing zones. In situ combustion has become a popular in situ conversion process due to the possibility of generating the required heat needed for increasing the mobility of heavy oil, as well as converting kerogen into oil by burning coke [26][27]. While the application of in situ combustion to heavy oil and bitumen sands is well reported in literature, the complexity of the process required comprehensive research for its application to a specific shale and tight oil-bearing formation as compared to other enhanced oil recovery methods.

In situ combustion can be performed in two ways: forward or reverse, depending on the movement of the combustion front within the reservoir. Forward combustion occurs when air flows in the same direction as the combustion front, while reverse combustion happens when the airflow opposes the movement of the combustion front. The commonly preferred approach is forward combustion due to its stability. The reverse combustion can cause spontaneous ignition in the reservoir, which is unstable and difficult to control, rendering it more complex to be implemented for enhanced oil recovery [28]. Both forward and reverse combustion can be carried out in two modes: dry and wet. In the dry mode, only dry air is injected, whereas in wet combustion, a mixture of air and water are injected. In the process of in situ combustion, many reactions take place simultaneously—some at low temperatures and others at higher temperatures. In terms of implementation, there have been many reported techniques of in situ combustion. These include Top–Down ISC, Bottom–Up ISC, Toe-to-Heel Air Injection (THAI), Combustion Override Split-Production (COSP), and Combustion-Assisted Gravity Drainage (CAGD).

Most of the in situ combustion studies presented in the literature were performed for heavy oil and bitumen samples. The implementation of in situ combustion for shales is purposefully for the conversion of shale oil into light synthetic oil for production. Oil shale has low thermal conductivity and permeability, which makes it inefficient in transmitting the injected air and the propagation of heat. In in situ methods, the porosity and permeability of the shale within the geologic formation play a crucial role in enabling heat transfer. In shales and tight reservoirs, the heat propagation is enhanced by hydraulic fracturing and horizontal drilling to improve permeability and increase the reaction area.

2.1.2. Hot-Fluid Injection (HFI)

The injection of fluid has been applied to many conventional reservoirs, with reported success in its implementation. Hot-fluid injections are mainly applied to heavy oil reservoirs, with the aim of increasing the fluid mobility in such reservoirs. The injection of hot fluid consists of mainly injection steam into the reservoir to heat up the formation and the in situ fluid to increase the fluid mobility. Some studies have reported the application of hot fluids for shale and tight oil reservoirs [29][30][31]. With respect to shales, the thermal EOR methods applied must be capable of providing the adequate heat required to convert the kerogen mobile hydrocarbons. Hence, not all the thermal methods that are applicable to a conventional reservoir could be applied to shale and tight formations [32][33][34][35]. For generation of hydrocarbons, a temperature above 300 °C is required. The temperature for pyrolysis lies between 300 °C and 500 °C. Initially, the kerogen is converted into bitumen and, later, converted into lighter hydrocarbons [36].

A high yield of liquid hydrocarbons has been reported from other studies where subcritical water was injected into oil shales [37][38][39][40]. Sun et al. [40] emphasized that it takes a long duration for the kerogen to be completely transformed into bitumen. The optimal extraction time was recorded to be approximately 250 h. Other researchers have used thermal treatment coupled with other techniques to enhance the oil generation from kerogen. Washburn et al. [41] presented hydropyrolysis in the presence of overburden formation by using a novel uniaxial confinement clamp. The experiment was conducted on Woodford shale samples. During the artificial maturation process, experiments conducted under confined stress produced more fractures than the unconfined pores. By mimicking the overburden pressure in the reservoirs with the confining pressure, one should expect a higher increase in porosity and permeability during hydropyrolysis in the reservoir.

2.1.3. State-of-the-Art of the Application of Thermal EOR Methods to West Siberian Shale and Tight Reservoirs

With respect to in situ combustion, on the one hand, very low formation permeability of shales and tight reservoirs may reduce the well injectivity of air (injected gas) [32][42]. On the other hand, a huge surface area of the grains due to low permeability will enhance the reactivity of oil with the injected gas. Furthermore, low reservoir porosity of shales and tight reservoirs could result in considerable thermal losses from heating the rock matrix, hence, interfering with the development of a high-temperature combustion front required for the conversion of kerogen to oil. On the brighter side, the high clay concentrations of the West Siberian formation serve as a catalyst for the combustion by decreasing activation energy. The in situ combustion process provides the optimal heat ideal for thermal breakdown of kerogen, which will aid in the production of substantial unconventional hydrocarbon reserves [32][42].

2.2. Gas Treatment of Shale and Tight Reservoirs

Gas-enhanced oil recovery methods involve the process of injecting gas into oil-bearing formations with the aim of improving the physical properties of the oil and increasing its mobility in the pore space. A wide range of mechanisms have been reported to control the recovery process of gas injection in tight oil formations. These mechanisms include displacement (gas drive) due to depressurization, change in the physical characteristics of the oil due to gas–oil interactions (diffusion, oil swelling, viscosity change, IFT reduction), and changes in the physical properties of the reservoirs (wettability alternation, permeability changes, and porosity change) [43][44][45][46][47][48].

N_2, CO_2, lean gas, and rich gas are among the gases investigated to improve oil recovery from tight and shale formations. Both miscible and immiscible displacements have been recorded for shale formations. At injection pressures lower than the minimum miscibility pressure (MMP), the oil recovery is controlled by the gas drive (displacement) mechanism, while at pressures above the MMP, the process is controlled by both gas drive and diffusion [49][50]. One other important factor from the experimental investigation of shale is the noticeable variation in results with the oil and gas contact surface area. Li and Sheng [51] reported that the higher the surface area of the cores is, the higher the recovery factor. This trend is attributed to the higher contact area between the in situ oil and the injected gas [52][53][54].

Reactive gases could also be injected, with the purpose of reacting with the rock minerals to increase the porosity and permeability of the rock matrix [48]. Similar effects can be observed during long-term EOR operations with those gases or CO_2 sequestration projects. At the same time, adsorption on the pore surface is a primary physical trapping mechanism for shale and tight reservoirs. Thus, the CO_2 storage capacity of shales largely depends on their geochemical and mineral composition; the amount of clay minerals and kerogen, which are the main adsorption sites for CO_2; and pore size distribution [55].

Laboratory investigation by Luo et al. [48] showed that the injection of supercritical CO_2 could transform the pore shape of shales. The experiment was conducted on cores from Qaidam and Ordos Basins at a pressure of 10 MPa and a temperature of 50 °C. The results show that the dissolution of clay and carbonate minerals due to the reaction between the supercritical CO_2 ($ScCO_2$) and shale led to the increase in the micropore structure of the shales.

In addition, the number of micro- and mesopores with a diameter of 0.3–20 nm of the marine samples were reduced significantly after exposure to supercritical CO_2. In contrast, the number of the mesopores increased after exposure to supercritical CO_2. This increased the overall permeability and porosity of the shales. However, it was also recorded that the opposite variation trend was observed for the terrestrial shale samples.

Mineral matrix and pore size alteration together lead to great changes in geomechanical properties, e.g., significant reduction of Young’s modulus [56][57] or Brazilian splitting strength [58], which makes geomechanics one of the most important parameters while planning any CO_2 projects in shales or any other reservoirs. Higher temperature and pressure conditions of the reservoir also influence the level of changes in the mineral matrix and pore size, hence, geomechanical properties [55].

It is a widely agreed phenomenon in both experiments and field pilots that gas injected above the minimum miscibility pressure produced a higher recovery factor as compared to gas injection below the minimum miscibility pressure [48]. Different studies have presented various methodologies of obtaining the minimum miscibility pressure for a given injected gas and respective reservoir oil. The traditional MMP measurement involves the use of cores from the reservoirs through a flooding system at different pressures until a recovery factor close to 100% is recorded. In recent times, microfluidics technology has been adopted to simplify the filtration process by creating a microfluidic analogue to be used.

Pilot studies have also shown that for tight and shale reservoirs with very high heterogeneity, the process of continuous flooding could lead to short circuiting, which is the principle when the injected fluid flows through a preferred relatively higher permeability, hence leading to fingering. While many studies have shown that the huff-n-puff method of injection reduces the probability of the occurrence of short circuits, this technique still requires a long waiting time for the injected solvent to interact with the oil due to the low permeability of the tight oil and shale reservoirs. In addition, the recovery in the huff-n-puff method decreases with the number of cycles [15][17][59].

3. Numerical Modeling of Shale and Tight Reservoirs

3.1. Core Reservoir Scale: Hydrodynamic Modeling

Numerical modeling of core-scale experiment serves as the bridge between laboratory experiments and up-scaling a model to the reservoir scale. The core-scale simulations allow the validation of the model parameters on laboratory experimental data through history matching. These parameters include the effective permeability and the relative permeability of oil, water, and gas phases, and the diffusion coefficient of the injected solvents. Matched parameters could be readily incorporated into up-scaled reservoir models for field simulations. Likewise, the reservoir-scale model is vital for the designing of production methods to be implemented in field pilots or field-scale productions.

The study concluded that the injection of heated agents was the most effective method due to the ability to successfully reduce the oil viscosity, desorption of heavier and lighter hydrocarbons, and increase in the matrix permeability and thermal cracking of kerogen. Shilov et al. [50] presented a core-scale simulation of West Siberian shale samples. The numerical model was developed using a radial grid, a similar method to that of Alharthy et al. [60] and Li et al. [61]. The model showed that the re-injection of associated gas is an effective method of increasing the recovery factor of tight reservoirs. Numerical modeling of gas injection into other tight and shale geological formations has demonstrated that CO_2 is a very efficient agent for increasing the recovery factors of such fields [62]. One of the underlying parameters to increase the oil recovery during gas injection is the minimum miscibility pressure [63].

3.2. Pore-Scale Digital Rock Physics

Pore-scale simulations have become increasingly popular in the oil and gas industry due to the coupled improvement in both imaging techniques and simulation tools [64]. The digital analogues of pore networks are generated from reconstructed images generated by either Computer Tomography (CT) scans or a Focused Ion Beam–Scanning Electron Microscope (FIB-SEM). Furthermore, the images are then processed to obtain the final digital pore network. The method of obtaining digital pore networks is known as Digital Image Processing (DIP). The complete workflow of DIP is presented in [65]. While the imaging techniques are reliable for generating pore networks for conventional reservoirs, there is a drawback when applied to unconventional reservoirs, which are mainly characterized by submicron pores. With respect to the modeling of fluid flow, the main methods reported in the literature are Direct Numerical simulations (DNSs), Molecular-Scale simulation-Lattice Boltzmann (LBM), and Pore-Network simulations (PNMs). While the flow equations for the modeling of fluid flow in submicron pores are improving, there is still a drawback in the process of generation of a reliable geometry for the simulation. Currently, both FIB-SEM and CT scans have limitations due to resolution; hence, the pore networks generated do not account for the pores below the set resolution.

Orlov et al. [66] presented a comparative analysis on the different methods of numerical computation of the absolute permeability on digitally generated pore networks. In this research, two comparative analyses were made. First, three different methods of generating digital pore networks were analyzed (Manual DIP, Cross-Laboratory Control DIP, and Automated DIP). Secondly, different numerical methods of computing the relative permeability were applied (PNM, LB, and direct methods). The results show that when different numerical methods are applied on the same DIP, the standard deviation is approximately 0.71 mD. Higher variation was reported for the PNM as compared to the direct simulation methods. This is because the direct simulation methods generate robust geometry from the actual digital pore network, while the PNM is based on approximation of the pores.

To eliminate the disadvantages of individual methods, most researchers have implemented multi-scale modeling techniques by coupling the different methods of simulations. Multi-scale digital rock imaging and modeling methods are applied to highly heterogeneous rocks to account for the contribution of the submicron pores to the flow process. A multi-scale approach by Soulaine et al. [67] based on the micro-continuum approach accounts for bulk flow and the mechanism that controls the fluid flow in nanopores (slip flow, adsorption, surface diffusion).

3.3. Data-Driven Modeling Approaches

Artificial intelligence has gained wide application in various disciplines across the petroleum industry. The application of machine learning and artificial intelligence involves several stages: data collection, data preparation, choosing the machine learning model, training, and testing of the model and validation [68]. Different researchers have applied artificial intelligence methods to predict geological [69], petrophysical [70], and geomechanical properties [71] and production and enhanced oil recovery methods' efficiency for shale and tight reservoirs [72][73]. A systematic review of the application of artificial intelligence by Syed et al. [74] has shown an exponential increase in the publication of artificial intelligence applications to shale and tight reservoirs. The application of data-driven approaches for the study of West Siberian shales was dedicated mostly to the characterization of geological and petrophysical properties of tight oil reservoirs. With respect to improved and enhanced oil recovery methods, most of the research was dedicated to optimization of hydraulic fracturing techniques [75][76][77][78].

4. Field-Scale Shale and Tight Oil Recovery

One of the greatest projects was conducted from 2017 to 2021, revealing an industry-scale experiment at the shale technology test site in West Siberia. The project was aimed at a comprehensive study of the Bazhenov shale oil formation, assessment of key production and economic drivers, and development of a high-tech oil service market. Following the specific design of the experiment, the company drilled more than 30 horizontal wells and performed more than 620 stages of hydraulic fracturing, while pumping about 70,000 tons of proppant and 650,000 m^3 of fracturing fluid. The most technologically advanced solution became horizontal wells with a cemented liner 1500 m long; a pump down plug-and-perf system with dissolvable frac plugs; an engineered completion of 30 stages, with four perforation clusters per stage; and a proppant mass of 150 tons per stage of clean fracturing fluid, with a flow rate of up to 16 m^3/min. The average cumulative well production for 180 days for this group of wells reached up to 89,000 bbl, which is comparable to North American analogues with a longer length of wells and greater number of stages. As a result of the experiment, the development cost for Bazhenov shale was reduced by 72%—from 57 to 16 USD/bbl [79]. One of the most significant contributions to the result was the implementation of a unique research program, including covering the entire site with wide-azimuth 3D seismic and controlled source electromagnetic surveys, and acquiring a large set of spatially distributed well data (core, logs, PVT, etc.). This program made it possible to create a digital twin of the most complex reservoir system and move to a new level in the field development management [80]. The progress achieved allowed for starting the commercial development of shale oil as early as 2023. For the full-scale multi-basin production, the company conducts exploration studies in the promising areas in West Siberia (Bazhenov formation) and the Volga-Ural region (Domanik formation) [81][82].

Sredne-Nazym shale field is also a great example of HF application: in the period 2020–2021, an oil company significantly increased the drilling of horizontal wells—21 wells against 8 wells in 2018–2019. Wells in 2018 were characterized by a length of up to 1000 m; an openhole completion system with controllable frac ports, from 6 to 10 zones; and a standard hydraulic fracturing design with 30 tons of proppant per stage.

The effective temperature for thermal cracking of solid organic matter in shales is higher than the one needed for viscous oil. Furthermore, shales have a substantially higher heat conductivity (hence, greater heat loss) than that of a conventional formation [83] caused by low porosity, making it harder to reach the high temperature required for kerogen transformation. This brings thermal EOR methods up to a whole new level of field development and well construction.

The main risks during hot-water injection are associated with well materials and heat losses. Most of the standard well materials are not stable enough to withstand the temperatures of hot water (>350 °C) and the corrosion caused by it [84][85]. Even the temperature of produced fluids, which might exceed 150 °C, is a problem for some operational parts, e.g., the electric pump. Moreover, the well materials should not only be heat-resistant, but also should prevent heat losses, which can be achieved by using thermal insulation [86][87][88].

Air (or oxygen) injection in shales reveals not much positive state-of-the-art, the base of field tests is still extremely poor, and no commercial projects exist worldwide. The risks of air injection are mainly caused by corrosion [83], which can be prevented by suitable well completion, and explosiveness, which can be avoided by careful selection of the injection regime and development scenario using numerical simulation and laboratory tests. On the other hand, due to the inexpensive cost and widespread availability of air, it is anticipated that this EOR technique is more appropriate for the economics of field development.

5. Conclusions

Thermal EOR methods, particularly in situ oil thermal synthesis technologies, like HPAI, combustion, and supercritical-water injection, show promise for recovering shale and tight oil fields, in West Siberia in particular. However, implementing these methods is challenging due to the complexity, high costs, and extensive experimental phases required, including precise determination of kinetics, thermal rock properties, and fluid behavior. Deviations in the recovery factor from field pilots and modeling data have made in situ combustion less attractive, despite its reported advantages.

Each shale and tight oil field has unique characteristics, necessitating a specialized approach for exploration and EOR. There is no universally applicable EOR scenario for all reservoirs; hence, an individualized approach with detailed reservoir characterization, lab testing, numerical simulations, and field trials is essential to develop economically viable and successful projects.

To bridge the gap between lab-recorded recovery factors and pilot studies, improved techniques like the 3D laboratory combustion chamber are crucial. However, specialized equipment and thermal insulation capable of reaching high temperatures are needed. The existing literature provides valuable statistical evidence to enhance this technology.

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