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Review

Review of Formation Mechanisms, Localization Methods, and Enhanced Oil Recovery Technologies for Residual Oil in Terrigenous Reservoirs

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Abstract

Residual oil (RO) in terrigenous reservoirs formed after waterflooding can exceed 60% of the original oil in place; approximately 70% is trapped at the macro-scale in barriers and lenses, whereas about 30% remains at the micro-scale as film and capillary-held oil. This review aims to synthesize current knowledge of RO formation mechanisms, localization methods and chemical recovery technologies. It analyzes laboratory, numerical and field studies published from 1970 to 2025. The physical and technological factors governing RO distribution are systematized, and the effects of heterogeneities of various types, imperfections in pressure-maintenance (waterflood) systems and contrasts in oil–water properties are demonstrated. Instrumental monitoring techniques—vertical seismic profiling (VSP), well logging (WL), hydrodynamic well testing (WT) and geochemical well testing (GWT)—are discussed alongside indirect analytical approaches such as retrospective production-data analysis and neural-network forecasting. Industrial experience from more than 30,000 selective permeability-reduction operations, which have yielded over 50 Mt of additional oil, is consolidated. The advantages of gel systems of different chemistries are evaluated, and the prospects of employing waste products from agro-industrial, metallurgical and petroleum sectors as reagents are considered. The findings indicate that integrating multi-level neural-network techniques with instrumental monitoring and adaptive selection of chemical formulations is crucial for maximizing RO recovery.

Keywords: residual oil (RO); terrigenous reservoirs; reservoir heterogeneity; localization of reserves; polymer gel systems; physico-chemical enhanced oil recovery (EOR); optical well logging; neural-network forecasting

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1. Introduction

The development of oil fields inevitably leads to the formation of residual recoverable reserves (RRR). According to [1], the design oil recovery factor (ORF) amounts to 0.375 frac. units; consequently, up to 62.5% of unrecovered reserves remain in the subsurface after the end of production, which, on a national scale, amounts to billions of tons. The low ORF observed in Russian oil fields is a result of insufficient implementation of enhanced oil recovery methods, the application of which requires additional capital investment [2,3].

The largest portion of Russia's oil reserves is concentrated in the West Siberian, Volga-Ural, and Timan-Pechora petroleum provinces (PPs), with the majority of their unique fields

currently at the third and fourth stages of development. The final stage of development is characterized by a sharp increase in water cut, a consistently high decline in oil production rates, the decommissioning of a large number of wells, a drop in reservoir pressure, and an increase in the volume of hard-to-recover reserves [4,5].

The above-mentioned petroleum provinces are predominantly represented by terrigenous reservoirs composed of sandstones and siltstones. The oil- and gas-bearing formations are characterized by complex geological structure, heterogeneity in filtration and storage properties, and wide areal distribution [6–8]. Most fields are developed using waterflooding systems to involve a larger portion of reserves in production and to increase the ultimate oil recovery factor [9]. A common phenomenon during waterflooding is the uncontrolled increase in water cut due to water breakthrough along more permeable zones, which leads to the formation of undrained areas. These zones are of particular interest and require localization using modern approaches in order to implement the most effective geological and technical measures (GTMs) [10–12].

This topic has been addressed in the works of leading authors within the global scientific and technical community, such as Surguchev M.L. [13,14], Zheltov Yu.V. [14], Gazizov A.A. [15], Gazizov A.Sh. [16], Devlikamov V.V. [17], Kabirov M.M. [17], Khabibullin Z.A. [17], Craig F.F. [18], Willhite G.P. [19], Rose S.C. [20], Buckwalter J.F. [20], Woodhall R.J. [20], Lake L.W. [21], and others.

2. Classification and Formation of Residual Oil

Within the framework of this review, terrigenous reservoirs of continental origin are considered, where the processes of residual oil formation are most pronounced due to the high lithological and structural heterogeneity. There are various forms and quantitative distributions of residual reserves in oil reservoirs. As noted by the author, the causes may include a range of natural and technological factors.

The general concept of residual oil formation can be represented by three main categories of causes: geological, physico-chemical, and technological. Geological causes include reservoir heterogeneity in terms of filtration and storage properties, the presence of impermeable clay barriers, lack of lithological continuity, and lithological-facies heterogeneity. Physico-chemical causes involve capillary phenomena, interfacial tension at the oil–water boundary, hydrocarbon (HC) adsorption on the surface of rock grains, and end effects in reservoir pores [22]. Technological causes include the characteristics of the selected waterflooding system [20], the efficiency of the applied injection pattern, the distance between injection and production wells, the injection rate, and the resulting pressure gradient [23].

Based on the aforementioned causes, several types of residual recoverable reserves (RRR) are identified:

1. Dispersed oil, which includes capillary-trapped and film oil [14,24];
2. Oil remaining in interlayer low-permeability zones not affected by waterflooding;
3. Oil located in lenses isolated from the productive reservoir by impermeable barriers or baffles and not penetrated by wells;
4. Oil migrating into dead-end zones of homogeneous reservoirs.

According to the data presented in [25], the first type accounts for approximately 30%, the second—27%, the third—24%, and the fourth—19% of the total RRR volume.

Thus, after the primary development phase of the field is completed, two levels of residual recoverable reserves are formed. Residual oil at the microscale is represented by dispersed oil, which in turn consists of capillary-trapped oil (oil globules in water) and film oil (films wetting the surface of the solid rock). Macroscale residual oil, represented by lenses and pillars, accounts for approximately 70% of the total RRR volume, which largely determines the priority of its extraction among the various types of residual reserves.

2.1. Formation of RRR at the Microscale

The presence of dispersed oil in the reservoir is determined by two main factors: rock wettability and the geometry of the reservoir pore space [26,27]. Wettability is a property defined by the interaction between two immiscible phases—water and oil—with a solid surface and a liquid. Wettability is characterized by the contact angle, which indicates the hydrophilic or hydrophobic nature of the rock. A hydrophilic rock is coated with a water phase; in this case, the surface is said to be "wetted." Water is present as a hydrophilic film on the grain surfaces and as bound water located in dead-end pores. Hydrophobic rocks, on the contrary, are coated with oil; however, such rocks are unlikely to exist in practice, as it is generally accepted that all reservoir rocks formed in water-rich environments or were submerged shortly after sediment deposition. Most reservoirs are composed of rocks with mixed wettability.

The authors of [28], using experimental methods with X-ray computed tomography (CT scanner) and a core flooding system, established that residual oil is distributed within the capillary zones of the pore space: in hydrophilic reservoirs it remains in film form, whereas in hydrophobic ones it is retained in isolated droplets. In addition to the results of the study, it should be noted that, despite the high methodological rigor and the use of a modern experimental system (including X-ray computed tomography and controlled water saturation under specified pressure), the paper does not indicate compliance with any industry standards (such as [29–32]) that regulate the conditions of filtration experiments. Parameters such as core dimensions (diameter ~2.5 cm, length 3–5 cm), filtration rate (0.01 mL/min), and the viscosity of the working fluids (white oil with 2 mPa·s and NaI solution) were selected based on laboratory practice and are typical for well-controlled core-flooding studies. However, the lack of standardized reference points may complicate direct comparison of the results with other works, particularly when assessing residual oil saturation. As shown in specialized guidelines, the core size and filtration rate can significantly affect the degree of edge capillary effects and the structure of the displacement front, which, in turn, influences the quantitative value of residual oil. Therefore, when interpreting such results, it is advisable to consider applicable standards and recommendations for the unification of experimental conditions, which is especially important for comparative analysis or attempts to upscale the findings to reservoir conditions.

The geometry of pores also directly influences the formation of dispersed oil. Reservoir porosity is the result of sediment deposition and diagenesis. Depending on the pore size, the degree of pore connectivity, and the sorting of grains, the amount of dispersed oil varies. According to [33], experimental studies have shown that the geometry of the pore space affects the distribution of residual oil by increasing its retention in medium and small pores. In addition, the presence of clays can form dead-end zones and retain capillary-trapped oil. Experimental studies using SEM and XRD methods, conducted on low-permeability sandstone samples from the Daqing Oilfield (China), demonstrated that residual oil is retained in capillary traps formed by clay minerals, which leads to a reduction in permeability after water injection [34].

The distribution of dispersed oil in the reservoir is governed by three types of forces: capillary, viscous, and gravitational. In this case, capillary forces—which are also referred to as surface forces—are the dominant ones, as their magnitude can reach several MPa depending on the wettability of the rock and the size of the pore channels. Hydrodynamic resistance forces are negligible, as they are proportional to the filtration velocity. Gravitational forces exert a constant effect ranging from 0.1 to 10 kPa, which is caused by the density difference between the saturating fluids. Microscopic analysis of pore structure in [35] showed that in reservoirs with high heterogeneity, residual oil is distributed in the

form of films on grain surfaces and droplets in pore throats, indicating the significant role of capillary forces in oil displacement processes.

In fact, dispersed oil is regarded as immobile due to the high-pressure gradients generated by capillary forces. It should be noted that such oil is formed as a result of water flooding, which means it can be considered to be 'at the threshold of mobility' [13,14].

According to the study [36], after polymer flooding in sandstone reservoirs with varying permeability, residual oil is distributed as follows: In high-permeability reservoirs (>1100 mD), 50–51% of the oil remains in a bound state, primarily in the form of adsorbed films on particle surfaces, while 37% corresponds to free oil. In medium-permeability reservoirs (470–490 mD), the distribution of free and bound oil is approximately equal (49% and 32–49%, respectively). In low-permeability reservoirs (<180 mD), bound oil dominates (47–49%), and free oil accounts for only 20–38%, which is attributed to the low mobility of oil in small pore channels. Thus, the permeability of the pore space significantly affects both the form and volume of residual oil in the reservoir.

2.2. Formation of RRR at the Macroscale

The formation of residual oil at the macroscale is caused by the incomplete displacement of oil from the reservoir, which is associated with a number of factors. Formally, the resulting oil-saturated pillars can be classified into categories according to their formation mechanism [18].

1. Oil-saturated pillars formed as a result of high heterogeneity of the reservoir in terms of geological and physical properties;
2. Oil-saturated pillars formed due to the manifestation of the viscoplastic properties of oil;
3. Oil-saturated pillars formed as a result of an imperfect well pattern or other technological factors.

The size and shape of such RRR formations in the subsurface may vary widely depending on the properties of the reservoir and the saturating fluids.

When designing a reservoir pressure maintenance (RPM) system, which is used in the development of most existing fields, an important stage is the assessment of the degree, nature, and direction of heterogeneity distribution within the production target [19], since this directly affects the completeness of oil displacement. Reservoir heterogeneity can take various forms, including:

1. The presence of multiple hydrocarbon-bearing interlayers composed of rocks with significantly different properties, such as sandstones interbedded with carbonates;
2. Variations in the continuity, interconnection, and areal distribution of porous and permeable layers within the reservoir;
3. The presence of a natural fracture system in the formation, resulting from regional tectonic stresses in the rock;
4. Directional development of permeability caused by depositional conditions or diagenetic alterations;
5. The presence of faults that affect the connectivity between parts of the reservoir and adjacent zones, either acting as barriers or enabling unrestricted fluid flow along the fault plane;
6. Interbedding of permeable and porous reservoir layers with nearly or completely impermeable layers of anhydrite, shale, or other minerals.

All of the above-mentioned types of heterogeneity, in one way or another, contribute to incomplete displacement, as high-permeability filtration channels are formed and mainly high-productivity zones are drained, while less permeable areas remain undeveloped. Another case leading to the formation of undrained zones containing RRR is the presence

of crossflows between two reservoirs with different filtration and storage properties. In such situations, the displacing agent follows the path of least resistance, leaving large portions of the reservoir undrained. A significant difference in the thermobaric conditions of fluid occurrence, particularly reservoir pressure, leads to uneven depletion of layers within a single production target. The mechanisms of oil-saturated pillar formation due to heterogeneity are discussed in detail in the following studies [37,38].

Another major reason for the formation of oil-saturated pillars in the reservoir is the physico-chemical difference between the properties of oil and the injected water. To analyze this cause of stagnant zone formation, it is useful to consider the reservoir in terms of a 2D projection [39,40], that is, as a thin, isotropic horizontal plane. Studying oil and water displacement under such conditions allows for the exclusion of several factors, such as reservoir heterogeneity in thickness, geological and physical properties, and filtration–storage characteristics. In the general case, only the interaction of the two fluids from the standpoint of their physical and chemical behavior remains.

An example of a model representing this type of interaction is the so-called "Hele-Shaw cell." The cell consists of two superimposed plates made of plexiglass, with a gap between them. This gap is considered to be infinitesimally small compared to the thickness of the plates [41]. This assumption allows the flow within the cell to be treated as two-dimensional, which simplifies the analysis of the effect and eliminates other influencing factors. The flow observed in the Hele-Shaw cell is referred to as Hele-Shaw flow and is described by the following Equation (1) [42]:

$$\vec{u} = -\frac{b^2}{12 \cdot \mu} \nabla p, \tag{1}$$

where:
$\vec{u}$—flow velocity (averaged over the gap thickness);
b—gap between the plates;
μ—fluid viscosity;
p—pressure.

Since the fluid is considered incompressible, the following condition also applies (2):

$$\nabla \cdot \vec{u} = 0 \; \nabla^2 p = 0, \tag{2}$$

That is, the pressure satisfies the Laplace equation.

Oil displacement by water in a Hele-Shaw cell proceeds with the formation of breakthrough fingers [43], which, from a geometrical point of view, are referred to as fractals. The primary cause of fractal formation is the difference in viscosity between the displacing and displaced fluids, as well as the wettability and interfacial tension at the water–oil boundary [44,45].

In study [46], the Hele-Shaw cell is used to investigate the influence of the mobility ratio between oil and the displacing fluid on the front behavior and the level of residual oil. The authors show that in the case of high oil viscosity and low water viscosity, pronounced fingering develops, leading to uneven sweep and increased residual oil saturation. Conversely, increasing the viscosity of the displacing fluid (by adding polymer) stabilizes the displacement front. Visualization in the Hele-Shaw cell convincingly demonstrated that the difference in viscosities—and consequently in phase mobilities—is the key factor responsible for the formation of residual oil zones under conditions where other influencing factors are absent.

Similar conclusions are presented in study [47], where a Hele-Shaw cell was used to analyze the effect of the displacing fluid's viscosity on the oil displacement behavior. The

authors demonstrated that increasing viscosity by adding cellulose nanoparticles leads to a more stable displacement front that maintains a uniform shape during propagation. Such displacement occurs evenly, without the development of unstable "fingers" or breakthrough channels. The article emphasizes that this effect is achieved only under a favorable mobility ratio between oil and the displacing phase, which is directly related to the viscosity properties of the system. This confirms the key role of viscosity and relative phase mobility in shaping the flow front and determining the volume of residual oil in the Hele-Shaw model.

In article [48], the Hele-Shaw cell is used to study the dynamics of fingering during the displacement of glycerin by water under conditions of complete mutual miscibility of the phases. The authors model displacement in a sealed cell and identify several characteristic flow regimes, including an initial slow front, rapid compression following breakthrough, and uniform expansion. The study emphasizes that even in the absence of porosity, the difference in viscosity between the displacing phase (water) and the displaced phase (glycerin) determines the shape and stability of the displacement front. Visualization made it possible to establish that increasing the viscosity contrast accelerates the transition from a diffusion-dominated to a convection-dominated regime and enhances front instability, increasing the volume of the residual, more viscous fluid.

Study [49] presents a review of micromodels, including Hele-Shaw cells, for analyzing wettability alteration and mobility changes in oil–water systems when using nanofluids and surfactants. Although the main focus of the article is on wettability modification, the authors emphasize that Hele-Shaw cells enable direct visualization of phase redistribution in response to changes in relative mobility and contact angles. Within the scope of this review, it is highlighted that even with fixed pore channel geometry, differences in viscosity and interfacial tension give rise to localized zones of residual oil. The Hele-Shaw cell is regarded as an important tool for isolating capillary and viscous effects in their pure form.

The pressure maintenance systems currently applied at oil fields are intended to ensure the most effective flooding of the entire reservoir. The systems described by the authors in [20] as the main and most widespread are most efficient in homogeneous reservoirs without any natural or artificial disturbances—an idealized scenario that rarely exists in reality. The ratio of production to injection wells depends on the expected volume of injected displacing agent and oil production. The distance between wells can be defined as a function of the expected oil recovery factor increment, oil production rate, reduction in operating costs, and minimization of drilling expenditures for additional wells [50]. The ORF increment, in turn, depends on the geological and physical characteristics and heterogeneity of the reservoir, including porosity, permeability, anisotropy of rock properties, and technological performance of the wells. In general, designing the most efficient development system plays a critical role in the rational exploitation of the field [51].

The main factors contributing to the formation of RRR as a result of development system design include the following:

1. Insufficient water injection—when the injection rate lags behind oil production, it leads to pressure decline, resulting in a reduced pressure gradient. According to Poiseuille's law [52], water begins to preferentially flow through the most permeable zones toward the nearest wells, bypassing distant areas and leaving them unswept. Prolonged exposure to such conditions results in the formation of stable streamlines from injection to production wells, leading to the development of so-called "dead zones."
2. High-intensity reservoir flooding—when the injection rate significantly exceeds the oil production rate. On the one hand, this causes water to push oil through high-permeability channels, forming dominant filtration pathways. On the other hand, it

may lead to the formation of auto-hydraulic fracturing (auto-HF) channels—high-permeability paths from the RPM well—into which the injected water escapes. It is important to note the difference in RRR formation in this case compared to point 1: here, the pressure is sufficient to reach remote zones of the reservoir, but water bypasses large volumes due to high filtration velocity. In other words, the reservoir's filtration capacity was not properly accounted for during RPM system design.

3. The presence of multiple productive horizons within a reservoir, differing in filtration and storage properties (FSP), penetrated by a common wellbore filter. When an impermeable barrier exists between them, water injection occurs predominantly into the most permeable intervals, leaving other layers almost or entirely unaffected. If there is some degree of hydrodynamic communication between the layers (i.e., crossflows), along with lateral variability in reservoir properties, situations may arise in which the injected water enters one formation and then flows into another, more permeable one, forming filtration channels and bypassing other portions of the reserves. For example, analysis of low-permeability formations in China has shown that after 20 years of waterflooding, approximately one-third of the layers in the section had never been swept by water; it is precisely in these layers that residual oil is concentrated [53]. The cause was the absence of an effective layer-by-layer RPM system during the early years of development. A similar issue is observed at mature fields: due to wear and damage of casing strings in old wells, it becomes difficult to implement proper zonal injection across the formations, which complicates the alignment of the water front.
4. The distance between injection and production wells, as well as the density of the well pattern, is another common cause of RRR formation. Large spacing between injection and production wells can lead to low sweep efficiency—the water front may not reach the production wells or may arrive in a weakened state. However, this relationship is most relevant for heterogeneous reservoirs with variable filtration and storage properties (FSP). It has been demonstrated repeatedly—mainly in fields in the western part of Texas, developed in carbonate reservoirs—that in isotropic formations with a high degree of continuity, reducing the spacing between wells did not lead to a significant increase in development efficiency and had little effect on the ultimate oil recovery factor. The optimal well pattern density depends on several factors, including permeability; for example, low-permeability reservoirs require denser well spacing. In practice, most fields started with sparse well patterns, gradually increasing density. At the Romashkinskoye field, well spacing was reduced in 1968, and the development system was switched from a linear to a block-pattern waterflood. In 1976, the grid was further densified by implementing a 3:1 well ratio. It should be noted that well pattern design is a complex task influenced by numerous factors [54].
5. Formation of zones with reduced pressure gradient between wells, where oil remains in an almost immobile state. During waterflooding, a specific pressure distribution is established in the inter-well space. The farther a given point is from the production well, the lower the filtration velocity in that zone, as it is directly proportional to the pressure gradient. High pressure gradients are established near the wellbore, while with increasing distance, the gradients decrease accordingly.
6. Another cause of RRR formation is design errors in the waterflooding system with respect to geological structures within the reservoir. For example, when there is strong hydrodynamic communication between the outer and near-boundary zones and an active aquifer, an improperly designed RPM system may lead to water bypassing into the near-boundary zone. This, in turn, promotes the formation of zones with unswept oil in the central part of the reservoir [55].

From the standpoint of mobility, residual oil can be divided into movable and immovable parts. At present, the scientific literature devoted to the classification of residual oil does not provide a definitive answer to whether it should be considered movable or immovable. Hypothetically, any oil can be regarded as movable if there are technologies capable of altering the physicochemical conditions within the reservoir. In practice, the movable portion of residual oil is defined as that which retains hydrodynamic connectivity with the main drainage zones and can be recovered by modifying pressure gradients, mobility ratio, wettability, or interfacial tension. The immovable oil, on the other hand, is defined as the oil that is difficult to affect due to technological limitations; it is typically localized within capillaries and dead-end pores and exists in the form of thin films as a result of dominant adhesive and capillary retention forces. Furthermore, part of the oil existing on the macroscopic scale can also be considered immovable if it is hydrodynamically isolated from the drainage zones or if pressure gradients are absent, precluding its movement.

The analysis results are presented in the form of a conceptual diagram (Figure 1) illustrating the structure, hierarchy, and main factors governing the formation of residual recoverable oil reserves (RRO) in terrigenous reservoirs. The diagram demonstrates the relationship between microscopic (≈30%) and macroscopic (≈70%) forms of residual oil, as well as the physical and technological processes controlling their distribution.

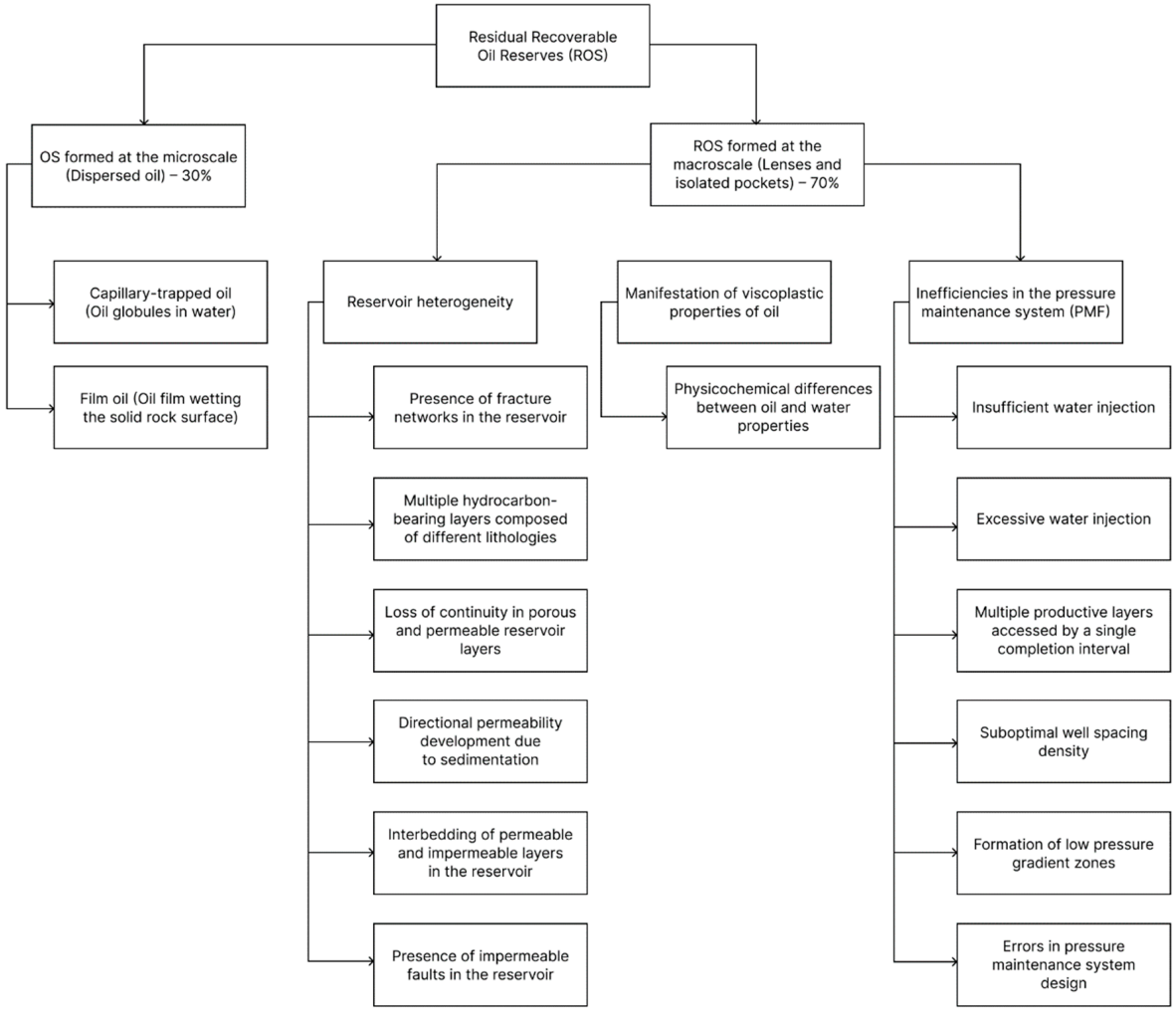

Figure 1. Generalized block diagram of RRR classification [compiled by the authors].

Microscopic forms (capillary-trapped and film oil) are formed within the pore space under the influence of capillary and adhesive forces, which depend on wettability, pore geometry, and the surface characteristics of mineral grains.

Macroscopic forms (lensed and isolated accumulations) are determined by reservoir heterogeneity, gravitational redistribution of fluids, and imperfections in the pressure-maintenance system (PMS). Their formation is associated with the presence of fracturing, interbedding of rocks with differing permeabilities, and uneven water injection within the PMS.

3. Methods for Localizing Residual Recoverable Reserves

The RRR types classified above represent a source of additional oil production. Accordingly, the identification and targeted development of such reserves can significantly increase the ultimate oil recovery factor (ORF) at oil fields by utilizing existing infrastructure. Various methods are used for localization, which are conventionally divided into two groups: direct (instrument-based) methods and indirect methods.

Instrument-based methods include a number of investigations, among which are:

1. Seismic technologies, such as Vertical Seismic Profiling. This is a high-resolution seismic exploration method in which geophones are placed along the wellbore, while the seismic source is located on the surface—or vice versa. VSP provides higher accuracy compared to conventional 3D surface seismic surveys. It is used both in single-well mode for detailed examination of a local zone and in multi-offset mode (e.g., walkaway VSP, where the seismic source is moved along a profile) [56,57].

This method allows for predicting hydrocarbon saturation near the wellbore and for identifying poorly drained zones where oil accumulates in the form of isolated pockets. Its high vertical resolution enables detailed evaluation of reservoir intervals adjacent to the well, while the recording of multicomponent P- and S-waves allows differentiation of fluid types and qualitative assessment of their migration and volume. The method is widely used at modern oil fields; however, it should be noted that each VSP session covers only the vicinity of a specific well. Therefore, assessing the entire field requires

2. Well Logging. This group of instrument-based methods includes both open-hole logging, i.e., conducted during drilling, and cased-hole logging. The fundamental difference lies in the objectives of these investigations. Open-hole logging is aimed at recording the initial parameters of the wellbore. Cased-hole logging—commonly referred to in modern literature as production geophysical investigations —is considered a separate category and focuses on recording parameters during field development.

In the context of residual recoverable reserve localization, production geophysical investigations include pulsed neutron logging and carbon–oxygen (C/O) logging. The operating principle of neutron-based methods is based on the generation of neutrons by a source placed in the wellbore and the subsequent detection of thermal or epithermal neutrons, or gamma rays. The emitted neutron undergoes changes as a result of interactions with the surrounding formation material. Neutron logging responses primarily depend on the hydrogen and chlorine content in the vicinity of the well. C/O logging is one of the few methods that allows for the evaluation of reservoir fluid saturation independently of formation water salinity [58]. C/O logging directly measures the ratio of carbon to oxygen concentrations in the rock: a high C/O ratio indicates the presence of oil (carbon), whereas when oil is replaced by water, the oxygen content increases and the ratio decreases [59].

These methods are routinely used by major oil companies for reservoir development monitoring. The ability to determine the current oil saturation of the reservoir around the wellbore without prolonged well shutdown, along with the possibility of repeated measurements to track dynamic changes, is a clear advantage. However, the sensitivity of these methods decreases in low-porosity formations, in the presence of thin productive layers, and—specifically for neutron logging—in cases of low formation water salinity, since low-salinity water produces signals similar to those of oil. The investigation radius of these methods typically spans several tens of centimeters from the wellbore.

Well thermometry, noise logging, flowmetry, moisture logging, and densitometry are also noteworthy methods widely used for development monitoring and assessment of current oil saturation. These methods help answer the question of which fluids, and in what quantities, are entering the wellbore from each penetrated reservoir interval. Accordingly, they allow detection of oil–water contact (OWC) movement, behind-casing flow (BCF), and interlayer crossflows, which result in the formation of stagnant oil zones [60].

3. Hydrodynamic well testing is another group of instrument-based investigation method. Special attention should be given to the modern impulse-coded hydrodynamic listening (ICHL) method and tracer studies. ICHL is an advanced version of inter-well hydrodynamic listening. Instead of continuous excitation, it uses a series of short pulses delivered into one or several excitation wells. The reception of the coded signal in the observation well eliminates the need to shut down surrounding wells, making the method highly resistant to various types of interference. The method allows for the identification of stagnant oil zones based on the intensity of the received signal.

Tracer studies involve injecting a labeled fluid—chemically inert with respect to reservoir oil and rock—into an injection well and detecting it in a production well after a certain time interval. This method makes it possible to evaluate inter-well hydrodynamic connectivity, filtration heterogeneity, and the filtration and storage properties (FSP) of the reservoir. When combined with other methods, tracer studies provide a comprehensive picture of RRR formation in the reservoir [61]. The main advantage of this method lies in its simplicity of application, which allows its use at any stage of field development [62,63].

4. Geochemical well investigations, when applied to the task of localization, represent a group of methods based on the detection of anomalies and deviations from natural background values during oil field development. Methods that are actively used in practice include sampling of formation water and gas, determination of the component composition of formation gas, determination of the physico-chemical properties of formation fluids, optical studies (in the UV–visible–NIR spectral range), infrared (IR) spectral analysis, and luminescent-bituminological analysis of cuttings and core samples. Unlike the previous groups of methods, this group is less labor-intensive and does not require the suspension of production well operations.

Special attention should be given to optical studies of oil, as numerous studies have demonstrated that the optical properties of oil are highly sensitive to changes in its chemical composition during field development. The method is based on measuring the optical density of oil across different spectral ranges and subsequently correlating these values with the amount of residual oil in the reservoir. In other words, the analysis evaluates how strongly oil absorbs light at specific wavelengths, and this data is used as an indicator of whether the oil sample originates from a “depleted” or “unaffected” part of the reservoir.

Optical studies are based on the Bouguer–Lambert–Beer law (3) [64]:

$$K_{ac} = \frac{D}{0.4343 \cdot C \cdot l}, \quad (3)$$

where:

K_{ac}—absorption coefficient,
D—optical density of the analyzed solution,
C—concentration of the solution,
l—path length (thickness of the solution layer).

The physical basis of the method lies in the observation that the composition and optical properties of oil change as the reservoir is depleted. During displacement processes, lighter oil fractions are extracted first, while heavier oil—rich in asphaltenes and resins—remains in stagnant zones. Such heavy oil has higher optical density and a greater absorption coefficient.

The advantages of the method include its relative simplicity and the speed of optical density analysis in laboratory conditions. However, it should be noted that during transportation, samples undergo chemical changes due to the adsorption of natural surfactants and the evaporation of light oil fractions. Another benefit of the method is its complementarity with other techniques—optical studies can fill gaps where other methods, such as well logging, are limited or infeasible. Moreover, the method's high sensitivity to resin and asphaltene content—which is directly associated with the accumulation of RRR—offers strong potential for its further development in localization technologies. It is important to emphasize that the method characterizes the oil entering a specific well. If the well receives a mixture of oil from multiple zones, the optical response becomes averaged, making it difficult to attribute the signal to specific intervals. This requires either selective sampling from wells that penetrate only a specific zone or the combined use of optical data with interval-resolved well logging results. It is also evident that the presence of mechanical impurities, additional water inflow, and other indirect factors can distort the final results.

In study [11], a method for localizing residual oil reserves was proposed based on measuring the light absorption coefficient of wellhead samples. The method was tested on 50 wells of the Minnibayevo section of the Romashkinskoye field and demonstrated comparability with the results of geological modeling. The authors note the need for further validation of the method when adapting it to various geological conditions, and they emphasize the influence of laboratory factors as well as the importance of automating measurements for field-scale application.

Indirect methods include approaches that involve the analysis and processing of large datasets obtained from sensors and instruments installed at the wellhead or downhole. These instruments may be stationary or handheld/mobile operator tools. This group includes sensors from thermobarometric systems (TMS), downhole thermometers, pressure gauges, the "SUDOS Automat 2" device, optical sensors, various types of flowmeters, and other wellbore instrumentation.

1. Methods based on neural network algorithms represent a rapidly developing set of approaches for localizing residual recoverable reserves. Neural network algorithms apply machine learning (ML) techniques to analyze large volumes of heterogeneous field data and generate distribution forecasts. The main objective of using neural networks is to identify hidden nonlinear relationships that are not detectable through manual analysis. A key advantage of these methods lies in their ability to automatically account for massive datasets, including development history, well logging, hydrodynamic studies, and geochemical investigations. It is important to emphasize that neural network models are most effective at fields with a large, accumulated

data base and a sufficient number of examples for training. For example, in a large producing field where RRR has been assessed in several pilot zones, a neural network can be trained on those data and then applied to the rest of the area [65,66]. The application of neural network algorithms is especially justified in multilayered and highly heterogeneous systems, where traditional methods struggle to generalize information—neural networks can independently uncover complex dependencies. They are also well suited for real-time forecast updates as new data become available: the model can be retrained using fresh inputs. In small or poorly studied fields, neural network methods are less reliable due to the scarcity of training data; in such cases, they are more appropriate when combined with physical models—as part of history matching or for hypothesis validation. Thus, the application of neural network algorithms can be viewed as an integration of data from all types of investigations into a unified base for further analysis and pattern discovery. The authors further propose to explore the combined use of ML and optical oil analysis for RRR localization.

One of the most comprehensive and technologically advanced examples of integrating machine learning methods into residual oil exploration is presented in study [67]. The authors developed a unique architecture for forecasting residual oil saturation based on convolutional neural networks (CNNs), in which spatially normalized tensors are used as input data. These tensors reflect the dynamics of cumulative oil production, water injection, porosity, permeability, oil saturation, and results from geochemical investigations. Particular attention is given to chemical indicators—such as the ratio of light to heavy n-alkanes in associated gas—which allow for model prediction validation and the identification of unswept zones that are inaccessible to conventional hydrodynamic simulators. The methodology incorporates a stochastic analog of a hydrodynamic model based on the Kalman filter, which ensures high adaptability when working with real field data. Implementation of this technology enabled not only the accurate localization of residual reserves but also the automation of geological and technical measure (GTM) selection at mature fields.

2. Retrospective analysis is a method for identifying undeveloped or poorly developed reservoir zones based on the analysis of field development over the entire production history. Essentially, it is a search for missed oil-bearing intervals using development data. Within this approach, all available information is collected: initial reserves, inflow profiles for each reservoir object, well logging results, monthly production reports (MPR), workover histories, well reassignments to other horizons, and so on. Then, using a decision-making algorithm, potential zones containing RRR are identified, along with applicable geological and technical measures for their recovery.

Based on a proprietary RRR classification algorithm developed by the authors and implemented within the retrospective analysis of data from 2605 wells at one of the Romashkinskoye field sites, large-scale localization of previously unswept intervals was performed. More than 96% of the identified RRR were classified as Category 1—zones with high residual oil saturation that had not been previously affected during field development. The main localization zones included inter-injection-well rows, central rows in three-row patterns, areas near formation junctions, pinch-out zones, and oil–water contact regions. The study proposed GTM selection algorithms tailored to each RRR category. Their effectiveness was confirmed during field trials—in particular, additional perforation in wells No. 16 and No. 6 led to actual oil inflow. The authors emphasize that the method is still being refined, including optimization of production forecasting and adaptation of the algorithm to other areas of the field, taking into account geological characteristics and well stock condition [10].

3. Voronoi diagrams, or analysis of specific production reserves by well. This method is based on dividing the field area into so-called Voronoi polygons—filtration zones in the form of polygons that are closer to a given well than to any other. Each such polygon is considered the "zone of responsibility" of the corresponding well, from which it is expected to extract oil. The initial oil reserves within each polygon are then compared with the actual cumulative production. The difference is considered the residual reserve associated with the well. The method is simple and visually intuitive; however, it relies on a simplified model of streamlines, assuming that the entire selected area is hydraulically connected to a single well—an assumption that often does not reflect reality. The method requires highly reliable input data, as errors in the initial reserves map will directly affect the accuracy of residual reserve estimates. The approach is compatible with retrospective analysis—in fact, the Voronoi diagram method is a formalized version of well-by-well retrospective analysis. It also integrates well with categorical classification, allowing polygons to be classified as fully depleted or underdeveloped.

From the standpoint of applicability ranges, the research methods span a scale from 10^{-2} m to several kilometers. Thus, static core analysis methods allow for refinement at a scale of 10^{-2}–10^{-1} m, depending on the core sample size. It should be noted that the data obtained vary significantly with the selected core size: researchers from TatNIPIneft have reported permeability variations by an order of magnitude when transitioning from small to full-size core samples. Routine well-logging methods provide data with a resolution on the order of 10^{-1}–10^{0} m, establishing a link between laboratory investigations and reservoir-scale measurements. Hydrodynamic well testing (HWT) methods interpret filtration processes over a range from 10 to 10^{3} m, enabling analysis of inter-well connectivity and reservoir permeability. Field geochemical methods are applicable within the range of 10^{0}–10 m, providing additional information on flow directions and fluid composition. Tracer studies, which combine geochemical and hydrodynamic approaches, offer comparable resolution—from 1 to 10^{3} m—and make it possible to identify active flow zones and stagnant regions. Finally, seismic profiling covers the range of 10^{0}–10^{4} m, providing insights into the large-scale structure and heterogeneity of the reservoir.

The accuracy and applicability ranges of localization methods belonging to the class of indirect approaches are entirely dependent on the results obtained through instrumental measurements. Their reliability decreases as the analysis extends beyond the applicability range of the instrumental techniques. However, within the limits of field-scale investigations, indirect approaches make it possible to refine data in areas where instrumental interpretation was ambiguous.

Summarizing the above, it should be noted that there is no universal method for the localization and evaluation of residual recoverable reserves; no single method is perfect or self-sufficient. In practice, the highest efficiency is achieved through the integrated application of multiple approaches. A consolidated classification of RRR localization and evaluation methods is presented in Figure 2.

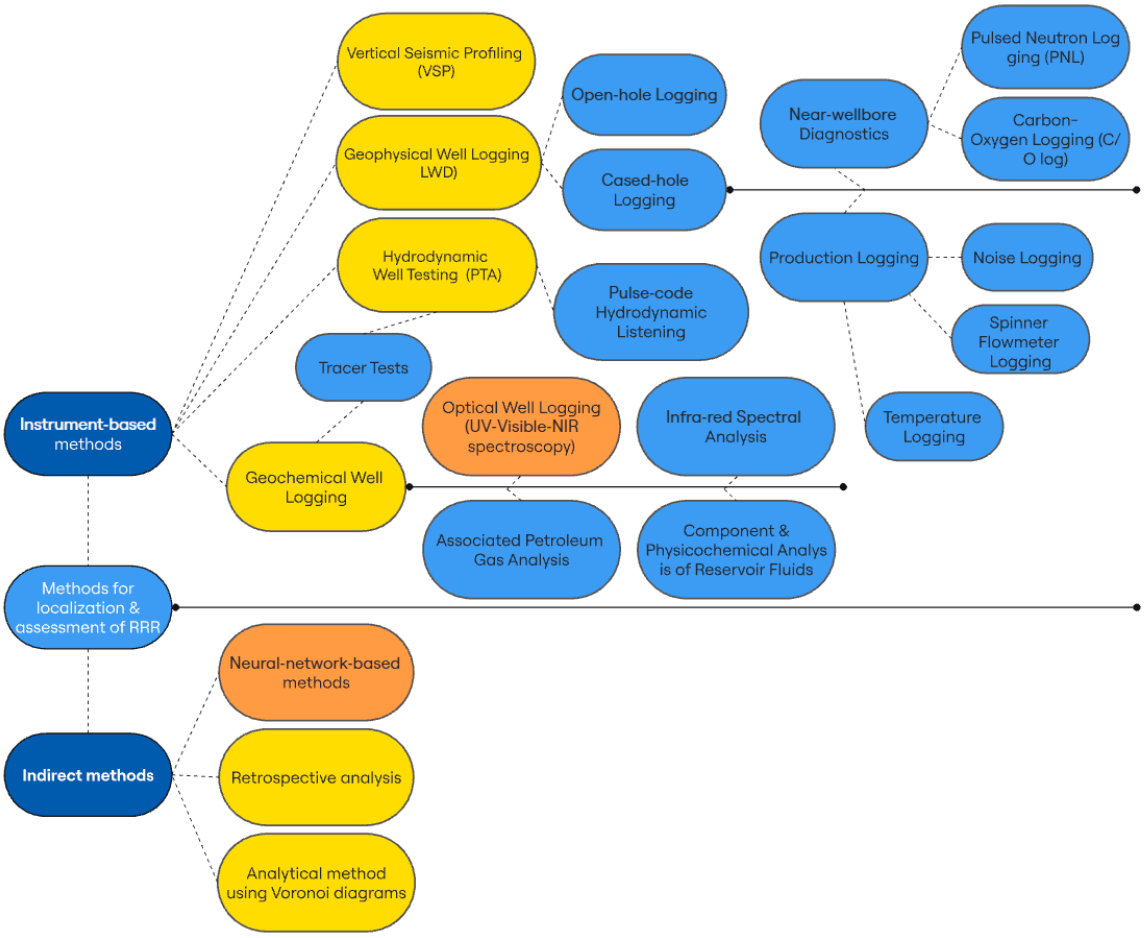

Figure 2. Block diagram of the classification of RRR localization and evaluation methods [compiled by the authors].

4. Chemical Methods for Enhanced Oil Recovery at the Macroscale

As previously noted, a significant portion of oil reserves remains in the reservoir after the primary development phase. In practice, regulation of the development process through methods such as increased injection pressure, cyclic injection, intensified fluid withdrawal, isolation of reservoir intervals into separate production objects based on their properties, and well pattern densification have proven effective under conditions of high geological heterogeneity. However, these methods lack universality and are insufficiently effective in formations where extensive waterflooding has already occurred. This fact explains the stabilization of oil recovery factors in modern waterflooding projects at the level of 0.3–0.5 of the geological reserves [15]. In this context, a key condition for further improving oil recovery is the restriction of water movement through high-permeability channels with established streamlines within the existing field development system.

Selective permeability reduction (SPR) methods, also known as water shutoff treatments (WST), are gaining increasing popularity today. According to their target technological effect, SPR methods can be classified into flow-diverting technologies, injectivity profile modification, and water inflow restriction. The essence of SPR technologies lies in selectively increasing the filtration resistance in water-swept, high-permeability zones of the reservoir, which leads to the redistribution of filtration flows within the formation. A water-blocking barrier is created in the water-flooded interval, which prevents further water movement and redirects it into oil-saturated, low-permeability layers. As a result, the sweep efficiency and the oil recovery factor (ORF) are increased.

Experience with the implementation of SPR technologies shows that their primary targets are predominantly terrigenous multilayer reservoirs characterized by a high degree of geological and physical heterogeneity, where permeability can vary by several orders of magnitude both vertically and laterally [68]. In particular, several sources describe the application of SPR methods in the northern Gulf of Mexico [69], in sandy reservoirs of Indonesia [70], in China's Daqing Oilfield, and at the Samotlor, Romashkinskoye, Vankor, and Novo-Elkhovskoye fields in Russia.

Flow-diverting technologies (FDT) have gained widespread application both in Russia and abroad. According to recent reviews [71], more than 100 different FDTs are currently known. In Russia, over the period from 2010 to 2020, more than 30,000 operations were carried out, resulting in a cumulative increase in oil production of 53 million tons. A confirmed example of the successful implementation of a flow-diverting technology using polymer systems is provided by the pilot field operations conducted at the Romashkinskoye field (reservoir D_0 of the Kynov horizon). In 2015, approximately 700 m^3 of a polymer–microgel composition (polymer + crosslinker + surfactant) was injected into an injection well. Following the treatment, a decrease in the water cut of producing wells from approximately 80% to 66% and an increase in oil production from about 500 to 700 tons per month were recorded. The achieved effect is attributed to selective permeability reduction. In 2020 alone, approximately 9000 SPR operations were performed, with additional oil production ranging from 0.3 to 1.6 thousand tons per well. The total contribution of FDTs to additional oil production across the country in 2020 is estimated at around 9.5 million tons, or approximately 8% of the total incremental production attributable to enhanced oil recovery methods. These figures emphasize the high effectiveness of selective permeability reduction technologies in addressing the growing problem of watercut and in localizing residual oil reserves at mature Russian oil fields [72].

To ensure an objective comparison of the effectiveness of various gel formulations used in chemical flooding technologies, real field application cases are summarized in the table below. Table 1, compiled by the authors, presents the key parameters: reservoir type and residual oil characteristics, the achieved effect—including production increase and water cut reduction—as well as the limitations under which the formulations can be applied, such as temperature, salt tolerance, rock sensitivity, and other conditions.

The technological approaches of flow-diverting technologies are classified into several main categories based on the mechanism by which the blocking barrier is formed. These include polymer gel-forming and viscoelastic systems, precipitate-forming compositions, surfactant-based foam systems, and curable (setting) systems. In real field applications, it is common to combine several mechanisms within a single treatment. For example, there are complex formulations that combine gel-forming and dispersed-phase components, which are injected sequentially to affect both the near-wellbore zone and deep reservoir intervals.

Table 1. Comparative characteristics of gel systems applied for residual oil recovery. [compiled by the authors].

Gel Type	Reservoir Type	Residual Oil	Effect	Limitations	Country of Application
Cr(III)–carboxylate/ acrylamide gel	Sandstone, 2 D	RO zones with 100% water cut	Oil production increased from 9.2 to 20 m^3/day; water cut decreased to 60–70%	Applicable up to ~80–90 °C; sensitive to hard water (Ca^{2+}/Mg^{2+}); possible rock adsorption; requires gelation control using retarders (malonate, glycolates). Gelation accelerates at higher temperatures. Suitable for low- to medium-temperature reservoirs.	China
Al(III)–crosslinked gel	Carbonate, moderate T	RO in water-bearing intervals	Moderate water cut reduction; production rate increase (limited data)	Thermal stability up to 90 °C; sensitive to salt ions; difficult to control gelation time without retarders; crosslinking may occur too rapidly. Limited use under high-temperature conditions. Less toxic than Cr-based gels.	Iran
Organically crosslinked gel	Carbonate, 2–3 mD	RO in fractured zones	Water cut decreased by 42%; gas rate increased by 7.7 times.	Stable at T > 120 °C due to covalent bonds; thermally resistant up to 150 °C; effective in fractured and tight reservoirs. Requires shut-in period for gelation; inhibitors needed at high T. Chemically complex and costly.	China
Biopolymer gel	Sandstone, heterogeneous	RO in swept zones	Oil increase ≈ 3 t/day; water cut ↓	Thermal stability up to ~90 °C; insensitive to Ca^{2+}/Mg^{2+}; biodegradable (biocides required); high viscosity; stable under pH and salinity variations. Applicable in fresh and saline waters; environmentally friendly and low-corrosive.	Russia

Table 1. *Cont.*

Gel Type	Reservoir Type	Residual Oil	Effect	Limitations	Country of Application
Monomer-based gel	Various, high permeability	RO in deep zones	Historical success; increased oil recovery	Highly sensitive to temperature and oxygen; difficult to control free-radical polymerization. Acrylamide is toxic and requires degassing. Thermal stability up to 93 °C with composition modification. Largely replaced by pre-crosslinked gels.	USA
Synthetic polymer gel (PPG)	Sandstone/carbonate, >0.5 D	RO between interbeds	Oil rate increase up to 10 t/day; water cut reduction by 5–10%	Operable up to 140 °C; requires sufficient pore or fracture width (>0.1 mm); unsuitable for fine-pore rocks. Applicable in highly heterogeneous formations. Provides long-term effect; available in various particle sizes.	USA, China
Inorganic (silicate) gel	Carbonate, fractures >1 D	RO in matrix zones	Significant water reduction; oil production increase	Temperature range 20–120 °C; high salinity resistance; inexpensive and readily available; non-selective—may block oil-saturated zones. Brittle; possible breakthrough under pressure variation. Requires precise placement.	Russia

4.1. Gel-Forming Systems

Gels are gel-forming substances produced by the coagulation of a colloidal solution into a semi-solid phase. In modern petroleum engineering literature, the term "gel" encompasses elastic and semi-solid materials formed through the chemical crosslinking of water-soluble polymers in an aqueous solution.

An ideal gel injection technology for improving sweep efficiency should be applicable to both production and injection wells, for the purposes of displacement enhancement, inflow restriction, and flow control treatments. The technology must include a simple and effective gelation chemical system that can be used across a wide range of reservoir conditions, such as temperature, porosity, permeability, pressure, and others. The system should be stable over extended periods, provide sufficient gel strength across a broad range of conditions, and enable controlled and predictable thickening behavior. The gel should be formulated using relatively inexpensive and readily available chemical reagents, based on low-concentration compositions.

Field-applied gel systems for improving sweep efficiency exist in various forms and encompass a wide range of chemical compositions [73]. Below is a classification of gel systems most frequently referenced in contemporary literature.

Chromium(III) carboxylate/acrylamide-polymer gels are aqueous solutions of acrylamide-based polymer gels in which the chemical crosslinking agent is a carboxylate complex of Cr(III) [74]. These gels possess exceptionally stable chemical structures and are highly inert to surrounding environmental conditions. They are applicable across a wide pH range, making them suitable for use in both acidic and alkaline environments when properly formulated. Chromium triacetate, $Cr(CH_3COO)_3$, is often preferred as the crosslinking agent. To retard the gelation reaction, either low-molecular-weight hydrolyzed polyacrylamide is used, or strong carboxylate ligands are added, such as lactate ester or malonate ester [61].

Cr(IV) in redox reactions with acrylamide polymers represents one of the earliest technologies for creating blocking systems. Today, this technology is no longer used due to the high toxicity and carcinogenicity of Cr(IV), as well as the complexity of the crosslinking chemical reaction [75].

Aluminum(III)-crosslinked gels. There are numerous technologies that incorporate aluminum as a crosslinking agent; however, the most widespread involves the use of aluminum in combination with citric acid ester. According to several studies, gels based on high-molecular-weight hydrolyzed polyacrylamide encounter difficulties—and in some cases become completely immobile—in low-permeability reservoirs, although they exhibit good mobility in fractured formations. It is also noted that crosslinking with aluminum is a slow reaction, typically occurring over the course of several hours, and the viscosity of such systems does not exceed the viscosity of water-based polymer solutions without a crosslinking agent [76].

Polyacrylamide gels crosslinked with aluminum and acetic acid esters have recently gained popularity. These are referred to as colloidal dispersion gels and are primarily used in porous reservoirs. These systems are of particular interest, as crosslinking occurs via aluminum acetate, which provides thermal and chemical stability of the gel across a pH range of 3.5 to 8.5, as well as high stability in salinity levels up to 50 g/L [77].

An interesting direction is the use of aluminum alkoxides for modifying ethylene-vinyl acetate (EVA) copolymers, where transesterification reactions lead to the formation of three-dimensional crosslinked structures [78]. As a result of the interaction between the hydroxyl groups of the aluminum compounds and the acetate fragments of the polymer, a significant increase in viscosity is observed, along with the formation of a spatially crosslinked gel structure [79].

Gels crosslinked with other multivalent metal ions, such as Cu^{2+}, Zr^{4+}, Ni^{2+}, and Co^{2+}, are also being investigated. For example, the use of Zr^{4+} in gel systems significantly enhances their thermal stability and effectiveness when injected into high-temperature reservoirs. Modern modifications of such gels utilizing biocompatible components demonstrate stable behavior at temperatures up to 130 °C and effectively reduce permeability in high-permeability reservoir intervals, providing a reliable flow-diverting effect [80].

As part of the search for environmentally safe alternatives to toxic Cr^{3+} crosslinkers, gels based on divalent metals, particularly Co^{2+}, Ni^{2+}, and Cu^{2+}, are actively being studied. Research has shown that cobalt acetate forms strong and stable gels suitable for use at temperatures up to 150 °C and under high salinity conditions of formation water. Gel systems based on Ni^{2+} and Cu^{2+} have also demonstrated satisfactory stability and operational feasibility, effectively reducing water saturation and redistributing flow in heterogeneous reservoirs [81].

Gels crosslinked with organic crosslinking agents. This group of gels was originally developed in pursuit of strong and stable polymer gels that would eliminate the need for metallic crosslinkers. Most of the organic-crosslinked gels developed to date are based on the chemical properties of phenol and formaldehyde or their derivatives. However, phenol and formaldehyde are known to be highly toxic. In this regard, one of the modern solutions is the use of the amino acid L-lysine as a crosslinking agent for polyacrylamide. Gels developed on this basis demonstrate stable structure formation at temperatures up to 130 °C, high resistance to formation water salinity, and the ability to effectively reduce permeability in water-bearing zones [80].

Another actively researched direction involves organic gel systems based on hydroquinone and hexamethylenetetramine. These formulations allow for precise control of gelation time, which is critically important for the controlled placement of the gel within the pore space of the reservoir. Gels formed using these components exhibit high resistance to salinity and elevated temperatures, and are also effective in limiting water inflow in fractured formations.

Biopolymer gels are gels based on the crosslinking of biopolymers with either organic or inorganic crosslinking agents. One of the most established technologies in this category involves xanthan-based formulations crosslinked with inorganic Cr(III). In recent years, active attention has been given to the development of gels based on natural polysaccharides such as guar gum, scleroglucan, diutan-gamma, pectins, and gum arabic, owing to their biocompatibility, resistance to high salinity, and thermal stability. These polysaccharides act as the gel base, while crosslinking is achieved using agents such as Cr^{3+}, Zr^{3+}, and organoborate compounds, which effectively crosslink the hydroxyl groups of polysaccharides under alkaline pH conditions [82,83].

Guar gum is one of the most commonly used biopolymer bases for gels, especially under hydraulic fracturing conditions, due to its ability to form stable gel structures at low concentrations in the presence of organoborate crosslinkers. Scleroglucan and diutan-gamma are used under conditions of high temperature and high salinity, including in systems crosslinked with Cr^{3+} and Zr^{4+} ions [84].

Pectins, due to their carboxyl group content, interact with divalent cations (e.g., Ca^{2+}) to form ionic gels suitable for moderate temperature conditions [85].

Gum arabic, although it has limited gelation capability on its own, can enhance the solubility and thermal stability of other polysaccharides in mixed systems. It exhibits resistance to saline environments and maintains viscosity in the presence of Na^{+} and Ca^{2+} ions [86].

A promising direction is also the use of cellulose-based biopolymers, such as carboxymethyl cellulose (CMC) and hydroxyethyl cellulose, which have high water solubility and the ability to form gel-like structures. According to [87], such biopolymers are effectively used in environmentally friendly gel-forming systems aimed at enhancing oil recovery and controlling water inflow. Furthermore, experimental studies have shown that gelation of CMC may involve coordination crosslinking with multivalent cations, and the viscoelastic properties of such gels depend on both concentration and environmental conditions [88,89].

Another rapidly developing direction is the use of lignin as a natural biopolymer characterized by high chemical stability and environmental compatibility. Due to its polyfunctional structure, lignin can participate in the formation of gel-like networks, either as a base material or as a functional additive. Experimental studies have shown that lignin exhibits a high degree of adsorption on rock surfaces even under high salinity conditions, making it an effective flow-diverting material [90]. Moreover, combinations of lignin with inorganic components such as aluminum soaps allow the creation of durable gel-like materials with pronounced sorption and structural–mechanical properties, suitable for water-bearing zone isolation and enhanced oil recovery [91]. Additionally, hybrid gels based on lignin-containing nanocellulose have been developed, demonstrating thermal stability up to 150 °C and resistance to salinity levels up to 200,000 mg/L [92].

Monomeric gels are gels formed through the localized polymerization of organic monomers, with or without the inclusion of crosslinking monomers. The earliest developments in this area were based on the in situ polymerization of acrylamide monomer. However, due to its high toxicity, this method is now rarely used. Preference is currently given to the localized polymerization of less toxic monomers, such as acrylates. A key advantage of this type of gel is the low viscosity of the gel-forming solution, which facilitates injection. The main disadvantage is its high sensitivity to reservoir properties, which can limit the applicability of the method.

A promising direction is the use of multifunctional monomeric systems containing N,N-dimethylacrylamide, AMPSNa, and N-vinylpyrrolidone, which are polymerized in situ to enhance the thermochemical stability of gels under reservoir conditions [93]. In addition, technologies for controlled delayed polymerization are actively being developed. These are aimed at achieving deep flow diversion and uniform distribution of the gel front within the reservoir [94].

Gels based on synthetic organic polymers are gel-forming systems in which the primary component is a pre-synthesized polymer, such as polyacrylamide (PAM) and its copolymers. Unlike monomeric gels, which are formed in situ, these systems are injected into the reservoir in ready-to-use form, often in combination with crosslinking agents to stabilize the gel structure. A typical example is the PAM/PEI gel, which has demonstrated high efficiency at temperatures up to 120 °C, increasing the oil recovery factor by 24% in laboratory conditions [95]. To improve placement selectivity and blocking stability, such gels can be modified with inorganic nanoparticles, such as Fe_3O_4, without altering the organic nature of the base polymer. In particular, one study developed a magnetically responsive PAM gel modified with Fe_3O_4, capable of directed placement in porous media and thermal stability under reservoir conditions [96]. Synthetic organic polymers also serve as the basis for preformed particle gels (PPGs) in the micron size range [97]. The advantages of synthetic organic polymers include high salinity resistance, adaptability to various reservoir conditions, and a wide range of crosslinker options. However, limitations include increased viscosity prior to gelation and the potentially reduced depth of penetration compared to monomeric systems.

Inorganic gels. Throughout the study of inorganic gels, a wide variety of formulations have been examined and applied. These systems typically utilize gels based on silicates or aluminum ions, as well as gels formed from iron and magnesium hydroxides. Silicate gel is formed when an aqueous solution with a relatively high pH, containing a sufficient amount of monomeric orthosilicic acid ester or oligomers of orthosilicic acid, undergoes pH reduction or is exposed to hardness cations. Silicate gels may form under the influence of either an external or internal catalyst. An internal catalyst is typically an acid-generating compound that spontaneously lowers the pH after injection into the reservoir. Silicate gel formation via external catalysis occurs when the monomeric orthosilicic acid or oligomer solution comes into contact with formation water containing hardness cations, such as Ca^{2+}.

Such systems demonstrate high thermal stability and resistance to saline environments, as confirmed by numerous studies. In particular, interactions with Ca^{2+} and Mg^{2+} ions lead to the formation of strong CSH (calcium silicate hydrate) and MSH (magnesium silicate hydrate) gels, which maintain stability at temperatures up to 140 °C and provide an increase in oil recovery factor of up to 23.87% [98]. A similar approach was implemented in an earlier study, where a silicate gel was used for flow diversion and demonstrated high efficiency in selective water shutoff in permeable zones, while maintaining stability under reservoir temperature and salinity conditions [99]. More recent developments have shown that the use of inorganic reagents can achieve high residual resistance factors (RRF > 180) and confirm the promising potential of such systems for injection profile control, without the need for complex organic components [100]. Despite their advantages, the main limitations of inorganic gels include limited controllability of gelation time and possible instability under varying reservoir pH and water composition.

Subsequently, Table 2 presents a summary of laboratory studies and pilot field trials of various gel-forming compositions.

Table 2. Summary of studies on various gel-forming formulations. [compiled by the authors].

Gel Type	Composition	Country	Reservoir Type	Temperature, °C	Pressure, MPa	Permeability, mD	Water Salinity, g/L	Application Effect	Source
Cr(III)-carboxylate/PAM gel	Partially hydrolyzed polyacrylamide (PHPA) + Cr(III) acetate	USA Field (multiple applications)	Fractured formation	up to 124 (H_2S-resistant)	Not available	Not available	High (salt-tolerant)	Widely implemented: ~700 treatments, reduced water cut, increased oil recovery	[101,102]
Al(III)-crosslinked gel	PAM + Al(III)-citrate complex (molar ratio ~2:1)	Not specified Laboratory tests	Porous (low-permeability)	~60–90 (moderate)	Not available	Not available	Depends on salinity (citrate selection at higher mineralization)	Effectively gels and blocks water at moderate temps	[103]
Organically crosslinked gel	PHPA (or AM/AMPS copolymer) + organic crosslinker (e.g., PEI)	Saudi Arabia (lab) Laboratory (core flooding)	Porous (sandstone)	up to 130 (stable $\geq$ 8 weeks)	3	Not available	Stable in salts/acids (no ionic precipitates)	At 90 °C and ΔP = 6.89 MPa, complete water shutoff for 3 weeks	[104]
Biopolymer gel	Polysaccharide (xanthan) + Cr(III) crosslinker + nano-silica	Iran (lab) Laboratory (bottle and core tests	Porous (sandstone)	60 (tested); stable at 80 (with 170 g/L salinity)	Not available	42.6	6.8 (simulated formation water); high salt tolerance	~72% water cut reduction after gel injection; high water selectivity	[102,105]
Monomer-based gel	In situ free-radical polymerization of acrylamide/acrylate monomers (initiator + crosslinker)	China	Matrix (perforated intervals)	up to ~93 (controlled gelation); at 149 (stable for a year)	Not available	Not available	Insensitive (inorganic monomers)	Forms rigid gel-plug	[106]

Table 2. *Cont.*

Gel Type	Composition	Country	Reservoir Type	Temperature, °C	Pressure, MPa	Permeability, mD	Water Salinity, g/L	Application Effect	Source
Synthetic polymer gel	Pre-crosslinked gel (PPG) based on PHPA, particles 1.5–5 mm	China (Daqing, field) Field (pilot injections)	Porous (heterogeneous sandstone)	~37	~10 (est.)	up to ~1200 mD	~6.8 (low salinity)	In pilot: oil recovery ↑ by ~8% (after polymer flooding), water cut ↓	[107,108]
Inorganic gel	Water glass (Na_2SiO_3) + Cr(III) salt (e.g., alum) + polyol (glycerin)	Russia (lab) Laboratory (fracture simulation)	Fractured/ fractured-porous	≥100 (thermally stable)	Not specified (thermo-barostable)	Not available	Insensitive to salinity (no organics)	In core: RRF_water ≈ 180, RRF_oil ≈ 1.2—high water selectivity (>150)	[109]

4.2. Other Methods for Selective Permeability Reduction

Other technologies exist that are based on different mechanisms of barrier formation. For example, precipitate-forming systems are also effective tools under field conditions. These systems consist of chemical reagent compositions that rely on the precipitation of amphoteric or crystalline solids. An example of such a technology includes sodium carbonate and calcium chloride solutions. Other known approaches involve sulfate–sodium mixtures with calcium chloride, or sodium silicate injected together with inorganic acids. Injection is typically performed by displacing chemical slugs into the reservoir. Precipitation-based technologies were widely used in the past, and field experience has shown them to be both effective and economically accessible. The technology was actively applied by Surgutneftegaz, with over 250 wells treated between 2012 and 2014. However, field results indicated that the method was effective mainly during the second and third stages of field development, when reserve depletion was still relatively low. This limited applicability is likely due to the insufficient mobility of the precipitate barriers within the reservoir, as well as significant sensitivity to formation water salinity and pH conditions [103].

Curable systems, most commonly represented by resins, are also used in selective permeability reduction. The application of resins is currently proposed by a limited number of modern companies, yet several types are distinguished: epoxy resins, phenolic resins, furan resins, and crosslinked styrene–butadiene block copolymers [110,111]. The advantages of this technology include high mechanical strength, adhesion, thermal stability, and chemical resistance of the resins. Among the disadvantages, a key limitation is the short treatment radius from the wellbore due to the high viscosity of resin solutions. Additionally, the systems are chemically complex, which requires especially careful injection modeling. Resins are also expensive per unit volume, which often leads to the use of resin-transported dispersed phases to reduce consumption [112]. Field applications include: Furan resin treatments in production wells at the Kern River and San Ardo fields in California; Phenolic resin treatments at the Midway-Sunset field; Epoxy resin treatments at the Green Canyon field in the Gulf of Mexico.

Surfactant–foam systems currently have three main applications in oil production:

1. Mobility control agent during steam injection into the reservoir;
2. Mobility control agent during CO_2 injection;
3. Gas-blocking agent around production wells.

Despite their potential, foam systems have not seen widespread use, primarily because the injection process is technically complex and labor-intensive. Gel-based systems are generally preferred due to their greater operational simplicity and reliability.

Based on the information presented above regarding selective permeability reduction (SPR) compositions, as well as practical experience described in recent publications, a large number of modifications of various systems have been developed—many of which have now evolved into distinct classes of formulations. The main modifications that enhance the performance of flow-diverting technologies include:

1. Thermal stabilizers—chemical additives that prevent the degradation of chemical systems under high-temperature conditions;
2. Catalysts—substances that accelerate chemical reactions within the reservoir, for example, external and internal catalysts used in inorganic gel systems;
3. Stabilizers—compounds that ensure the integrity and functional performance of gel systems over time by providing resistance to salinity, pH fluctuations, shear stress, and filtration effects;
4. Fillers—solid particles introduced into the dispersed phase to increase mechanical strength and plugging capability. They enhance the mechanical properties of the

system and may provide additional filtration resistance. For instance, the combined addition of wood flour and clay powder significantly increases resistance to flow in water-swept zones: wood flour swells on contact with water, while clay flocculates with the polymer, forming a strong structural framework. Another example is the use of rubber crumb, where shredded recycled rubber is mixed with sodium silicate or bitumen; the crumb swells, blocking fractures and flow channels.

Thus, new subclasses of flow-diverting compositions are being developed, including thermotropic systems, polymer–dispersed systems, fiber–dispersed systems, gel–precipitate-forming systems, and others.

As previously noted, one of the criteria for an ideal flow-diverting system is the use of the most effective and relatively low-cost components. Under current conditions, a particularly relevant area of focus is the identification and implementation of industrial waste products as reagents for FDT applications. Such materials may include sludges from oil refineries, byproducts of metallurgical processes, and components from the pulp and paper or agricultural industries. Data from several projects involving the application of recycled materials have been summarized in Table 3.

Table 3. Case studies on the use of recycled products for profile control and water shutoff (PCWS). [compiled by the authors].

Waste Type	Composition	Country	Project Status	Reservoir Type	Reservoir Temperature, °C	Result	Source
Oil sludge (bottom sediment from oil storage tanks)	~40% oil, ~7% water, ~52% solids (silt, sand, etc.)	China	Field (injection into 15 injection wells)	Porous (sandstone, multilayered)	Not specified (effective at high temps)	Positive: after treatment, injection pressure increased, injection profile redistributed (absorption share in high-perm layer decreased from 71.3% to 44.5%; increased in low-perm layer from 9.7% to 45.5%). Additional oil recovery: ~12,186 tons from 15 wells; oil recovery factor increased by ~4.1%.	[113,114]
Wood flour (finely ground sawdust; pulp and paper industry waste)	Cellulose and hemicellulose fibers, high lignin content (typical lignocellulosic material); possible additives (clay, reagents)	Russia	Field (pilot field trials)	Not specified (used in heterogeneous reservoir)	Not specified	Positive: field trials of wood flour-based system showed improved oil recovery and isolation of formation water influx	[115]
Cellulose flour (from agricultural waste, e.g., straw)	~40–58% microcellulose (from annual plants), ~40–60% fine hydromuscovite (clay filler), 1.5–5% thermally and salt-resistant polymer	Russia	Laboratory (patented formulation, tested on samples)	Not specified	Not specified (formulation stable at high temperatures)	Positive: the composition increases oil production and reduces water cut by selectively blocking water-bearing layers	[116]
Metallurgical sludge + ash and slag waste (blast furnace slag and thermal power plant ash in plugging formulation)	Mixture of powdered solid waste: granulated blast furnace slag, fly ash, clay component, perlite (total 50–85 wt.%); binder—phenol-formaldehyde resin (~10–45%); hardener—hexamethylenetetramine + benzoic acid (0.5–5%)	China	Laboratory (development and testing, patented)	Not specified	Not specified	Positive: composition is easy to prepare, reliably solidifies in formation, forms a durable long-term blocking barrier; low cost	[117]

Table 3. *Cont.*

Waste Type	Composition	Country	Project Status	Reservoir Type	Reservoir Temperature, °C	Result	Source
Blast furnace slag (metallurgical slag containing aluminum)	CaO (~39–41%), SiO_2 (~36%), Al_2O_3 (~10–13%)	China	Field	Fractured	High (≈80–150 °C)	Formation of a strong sealing structure; effective blocking of water-bearing fractures/channels (100% success in trials)	[118]
Oil sludge (from separators at TPPs, heavy oil)	~60–70% water, 10–15% oil, 15–30% solids (sand/clay; d ≈ 10–50 μm)	China	Laboratory + field (150 wells)	Porous	Not specified	After injection and solidification, sludge cemented large pores, redirecting flow to fine-pore zones; cumulative effect: +10,756 tons of additional oil recovered	[119]
Ground fly ash (coal)	Mainly SiO_2 (~92%) and Al_2O_3 (mullite ~8%)	China	Laboratory (patented)	Porous	Not specified	Mechanical “bridging” of pore channels; strong adhesion in pores, high thickening strength, low cost, long-term effect	[120]

The efficiency of gel-forming and flow-diverting compositions based on industrial waste is determined by their granulometric and chemical composition. Modified fly ash and blast furnace slag represent inorganic matrices with particle sizes of 5–50 μm and a predominance of SiO_2, Al_2O_3, and CaO. Activation with alkaline agents (NaOH 0.3–2%) and the use of borax or $CaCl_2$ as curing regulators enhance polymer adsorption and promote the formation of a dense silicate–polymer structure with a compressive strength of 0.8–1.5 MPa and thermal stability up to 300 °C [118].

Systems based on oily sludge contain both mineral and organic phases (10–25 wt.%), which determine the gelation kinetics. Finely dispersed particles (<20 μm) increase gel strength, while a moderate organic content imparts elasticity and hydrophobicity. When the organic phase is excessive, crosslinking slows down, reducing long-term stability. Optimization of the phase ratio allows regulation of the gelation time within 3–300 h, achieving sealing efficiency above 85% and thermal stability up to 350 °C [119].

Cellulose-based compositions [116] include microfibrous fillers and hydromicas, which provide reinforcement and salt tolerance at mineralization levels up to 200 g/L and temperatures of 120–150 °C. Natural biodegradable materials also exhibit selective water shutoff properties with minimal environmental impact, offering a sustainable alternative to synthetic systems.

Based on the analysis of available sources, several examples of industrial waste utilization as components for selective permeability reduction in reservoirs have been identified. Most case studies demonstrate a positive effect from implementation, and the diversity of waste products offers a wide range of chemical compositions, allowing their use in various modifications of base FDT systems. Bauxite residues deserve special mention, as they contain significant amounts of metal cation impurities, including Fe_2O_3, Al_2O_3, SiO_2, TiO_2, and Na_2O. In addition to their high content of reactive components, this byproduct is also highly alkaline due to the specifics of its processing. Other types of waste also contain multivalent metals, which, in turn, determine the direction of the authors' future research.

5. Results and Discussion

The current pace of field development inevitably leads to the formation of residual oil reserves. After the completion of primary recovery, up to 62.5% of oil reserves may remain unproduced in the reservoir. As noted by several authors, the low oil recovery factor observed at many Russian fields is a result of insufficient application of enhanced oil recovery methods, the implementation of which requires significant capital investment, as well as the lack of technologies capable of targeting the underlying causes of incomplete reservoir depletion [121].

Residual reserves in terrigenous reservoirs are formed at both the microscale, which accounts for approximately 30% of residual oil, and the macroscale, which accounts for about 70%. In the first case, as noted in fundamental sources, the primary cause of such accumulation is reservoir rock wettability, with oil existing in the form of films and dispersed droplets. In the second case, oil is present as accumulations—so-called pockets and lenses—formed due to reservoir heterogeneity, the viscoplastic properties of oil, and technological factors associated with the imperfections of the development system. There is no doubt that targeting oil reserves formed at the macroscale is a more universal and effective approach compared to attempting to recover capillary- and film-trapped oil. The predominance of macroscale residual reserves, as well as the availability of effective methods to act upon them, determines the authors' research focus on improving oil field development efficiency by involving previously undrained zones containing RRR.

At present, there are numerous field-proven methods for monitoring oil field development, many of which have long become routine practice for operating companies. Based

on an analysis of modern advancements in this area, the authors have classified these monitoring methods into two groups: instrument-based methods and indirect (analytical) methods. The fundamental difference lies in how information is obtained regarding the current state of the development object. The instrumental methods group includes Vertical Seismic Profiling, well logging, well testing, and geochemical investigations. Each of these classes is actively evolving and, under current conditions, constitutes an essential part of field monitoring. Indirect or analytical methods refer to approaches for localizing and evaluating residual recoverable reserves. These include retrospective analysis, Voronoi diagram analysis, and the use of neural network algorithms, which—given the ongoing digital transformation of the industry—represent a promising direction. Among instrumental methods, the authors emphasize geochemical investigations, particularly the optical method for well analysis in the UV–visible–NIR spectrum. The optical properties of oil are extremely sensitive to changes in chemical composition during production, which, when properly implemented, can be effectively used as a tool for identifying and localizing zones containing RRR. Going forward, the authors plan to implement neural network approaches in combination with optical oil analysis to localize RRR zones—an approach that has the potential to become a highly effective technological solution.

The formation of dominant water-swept zones within the reservoir is an inevitable consequence of current field development systems, due to a number of factors. Although technological methods based on adjusting well operating parameters are effective tools for enhancing oil recovery, their application does not sufficiently enable the involvement of previously undrained reservoir zones. In this regard, given the substantial volumes of residual recoverable reserves at Russian oil fields, physicochemical enhanced oil recovery methods based on selective permeability reduction have proven highly effective. Injectivity profile control aimed at improving sweep efficiency, isolation of water-swept intervals, and redistribution of flow paths in the reservoir via the creation of remote blocking barriers are all recognized as efficient tools widely applied at oil fields around the world. Chemical systems for such applications can be classified by the physicochemical mechanism used to create the blocking barrier, namely into gel-forming systems, precipitate-forming systems, curable (setting) systems, and surfactant–foam systems.

Through source analysis, the authors have identified gel-forming systems as the most extensive, rapidly developing, and highly tunable group among selective permeability reduction technologies. Among gel systems, the most frequently applied are those based on Cr(III) and Al(III) crosslinked gels, biopolymer gels, inorganic gels based on sodium silicate, and gels based on synthetic organic polymers. Various modifications of these gels are also known, including the use of thermal stabilizers, catalysts, and the addition of dispersed fillers into the gel framework. Field applications have demonstrated the high efficiency of these compositions both in Russia and internationally. Under current technological and economic conditions, systems incorporating industrial waste products are gaining popularity. Numerous industrial sectors generate chemical components that can either serve as crosslinkers, form the base of a gel, or act as modifiers. Examples include byproducts from the pulp and paper, agricultural, metallurgical, and oil refining industries. Due to the presence of multivalent metals and natural polymers in production sludges, the authors propose this area as a promising direction for future research.

6. Conclusions

The present study outlines the principles of residual oil reserve formation at both the micro- and macroscale during oil field development, along with the methods for evaluation and localization of residual recoverable reserves and physicochemical enhanced oil recovery methods, specifically selective permeability reduction techniques, which represent one of

the most promising directions in this field. Based on the results of this study, the following conclusions can be drawn:

1. At large oil fields in Russia, up to 62.5% of oil reserves remain unrecovered in the reservoir, of which 30% correspond to oil retained at the microscale and 70% to oil accumulated at the macroscale.
2. The formation of macroscale residual oil is caused by various types of reservoir heterogeneity, differences in oil and water properties, and imperfections in the pressure maintenance system.
3. A wide range of monitoring methods is used in the field to control reservoir development. These include both instrumental and indirect (analytical) methods. The key distinction between them lies in the manner of acquiring information about the reservoir.
4. A promising direction is the integration of optical well investigation methods in the UV–visible–NIR spectrum with neural network algorithms operating in situ. The combined implementation of these methods will improve mapping by enabling the localization of residual oil that differs significantly in its optical properties. However, the question of the feasibility and necessity of large-scale pilot projects for integrating neural network algorithms in field operations remains relevant.
5. Chemical methods for residual oil recovery based on selective permeability reduction have proven effective. These include gel-forming, precipitate-forming, curable, and surfactant–foam systems for creating blocking barriers. Gel systems, in particular, offer the highest degree of tunability.
6. A promising direction in the field of flow-diverting technologies is the use of waste products from various industries, including pulp and paper, agricultural, metallurgical, and petroleum refining sectors. These recycled materials may contain useful components such as crosslinking agents, gel-forming substances, and thermal stabilizers.

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