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• Review •

A Review of Gas Injection and Energy Supplement for Shale Condensate Gas Reservoirs

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Abstract: Natural gas has become a core component of the global clean energy transition, and shale condensate gas reservoirs represent a high-value unconventional resource critical to improving national energy security, especially for countries with a coal-dominated energy mix like China. This paper reviews the current status of gas injection and energy supplement technologies for shale condensate gas reservoirs, focusing on key technical challenges and recent research advances. First, it outlines the unique hurdles of shale condensate gas development, including ultra-low reservoir porosity/permeability, complex nanopore-induced phase behavior alterations, compositional gradients with depth, and retrograde condensation damage during pressure depletion. Then, it systematically summarizes progress in four core research areas: (1) development methods such as gas injection huff-n-puff, which has been proven to boost condensate oil recovery by 15%–20% in field simulations; (2) the nano-confinement effect, which modifies fluid critical properties and diffusion coefficients (reducing effective diffusion by 10^2–10^4 times at low porosities) and enhances CO_2 miscibility in oil phases; (3) compositional gradient modeling, which is shown to prevent significant errors in reserve estimation (up to 54% overestimation of crude volume if ignored); and (4) fractured reservoir simulation, particularly the evolution from discrete fracture models (DFM) and embedded discrete fracture models (EDFM) to the projection-based embedded discrete fracture model (pEDFM), which addresses EDFM's limitations in handling low-permeability fractures. Finally, the paper proposes an innovative numerical simulation method integrating the general pEDFM with the commercial simulator CMG, which retains pEDFM's computational accuracy for complex fracture networks while avoiding the high cost of developing custom nonlinear solvers. This review provides a comprehensive theoretical framework for efficient and sustainable shale condensate gas reservoir development, supporting energy security and the global energy transition.
Keywords: Shale condensate gas reservoir; Component gradient; Nano-confinement effect; Projection-based embedded discrete fracture model (pEDFM); Gas injection and energy supplement

1 Introduction

In the global energy landscape, natural gas, as a relatively clean and efficient energy source, has become increasingly important. For a long time, China's energy structure has been dominated by coal, with relatively scarce oil and gas resources, resulting in a persistently high degree of external dependence on oil and gas. Energy security, as the cornerstone of national development, urgently requires improvement of this situation. With the maturity of horizontal well and large-scale hydraulic fracturing technologies, the production efficiency of shale gas has been significantly improved [1]. In 2023, U.S. shale gas production exceeded 830 billion cubic meters, accounting for 75% of its total natural gas output. China has also achieved remarkable results in shale gas development; by the end of 2023, the cumulative proven geological reserves of shale gas approached 30 trillion cubic meters, and the annual shale gas output reached 25 billion cubic meters, accounting for 11% of the country's total natural gas production [2-3]. As a valuable oil and gas resource, the effective development of shale condensate gas reservoirs can significantly increase domestic natural gas supply, gradually raise the proportion of natural gas in China's primary energy consumption structure, reduce excessive reliance on coal and imported oil and gas, and optimize the energy consumption structure. This has irreplaceable strategic significance for enhancing the stability and security of national energy supply and reducing risks brought about by fluctuations in the international energy market. Accelerating shale gas development is an important measure to reduce China's external dependence on oil and gas.

Compared with conventional gas reservoirs, the development of shale condensate gas reservoirs faces numerous severe challenges:

(1) Shale reservoirs have extremely low porosity and permeability. This tight characteristic makes fluid flow extremely difficult, and conventional mining methods are ineffective. Fracturing technology must be used to form artificial fractures to connect the reservoir with the wellbore and achieve effective natural gas production. In this context, accurate simulation of fluid flow in fractured reservoirs is crucial. Accurate simulation can deeply understand the flow laws of fluids in complex fracture networks, provide key basis for fracturing scheme design and productivity prediction, and is directly related to the economy and efficiency of shale gas development.

(2) The pore structure of shale reservoirs is extremely complex, with abundant nanopores widely distributed inside [4]. The existence of these nanoscale pores has greatly changed the phase behavior of reservoir fluids. Compared with general reservoirs, the interaction between fluid molecules and pore walls in shale reservoirs is more significant, which changes the phase transition conditions and diffusion properties of fluids, increases the difficulty of predicting fluid flow and phase state changes during gas reservoir development, and further affects the accuracy and rationality of development plans.

(3) Affected by factors such as geological structure and sedimentary environment, some shale condensate gas reservoirs exhibit obvious component gradient phenomena [5]. The fluid composition of reservoirs at different depths varies, which directly leads to different dynamic characteristics of reservoirs at various depth intervals during development. For example, deep reservoirs may have a higher content of heavy hydrocarbon components, making them more prone to phase state changes during pressure reduction mining, which has a unique impact on productivity and recovery rate. Therefore, accurately grasping the differences in development dynamics caused by such component gradients is one of the key links to achieve efficient development of shale condensate gas reservoirs.

(4) During the formation pressure depletion

of shale condensate gas reservoirs, a prominent problem is the precipitation of condensate liquid. As the formation pressure decreases, when the pressure is lower than the dew point pressure, condensate oil in the gas phase will gradually precipitate and accumulate in reservoir pores, which not only blocks gas flow channels but also reduces gas phase permeability, leading to a sharp decline in single-well productivity. Therefore, seeking effective ways to eliminate retrograde condensation pollution and restore and maintain gas well productivity has become an urgent problem to be solved in the development of shale condensate gas reservoirs.

In summary, clarifying and successfully solving these difficulties in the development of shale condensate gas reservoirs is the core prerequisite for realizing efficient and sustainable development of shale condensate gas reservoirs, and is of immeasurable significance for fully tapping the potential of such valuable oil and gas resources and improving China's energy security capacity.

2 Research Status

2.1 Development Methods of Shale Condensate Gas Reservoirs

Compared with conventional gas reservoirs, the development of shale condensate gas reservoirs mainly faces the following two situations. First, in the early stage of depletion development of shale condensate gas reservoirs, due to the bottom-hole flowing pressure being lower than the dew point pressure, condensate liquid precipitates in the formation near the wellbore, leading to a sharp decline in productivity [6-9]. In the later stage of development, due to the continuous decrease of reservoir pressure, retrograde condensation damage becomes more serious, and gas injection huff-n-puff is generally required to improve the recovery rate [10]. Meng et al. [11] confirmed through gas chromatography and numerical simulation that gas injection huff-n-puff is an effective way to improve condensate oil recovery, and its main mechanisms are twofold: first, when condensate liquid precipitates in the near-wellbore zone, the oil well is opened to discharge the condensate liquid through a large pressure difference; second, gas is injected to increase the formation pressure in the near-wellbore zone, reduce the dew point pressure of the fluid, vaporize the condensate liquid again, and then open the well to discharge the gas. Second, the reservoir has extremely low porosity and permeability, requiring horizontal well fracturing development [12]. In 2015, Yu et al. [13] used Local Grid Refinement (LGR) for huff-n-puff development simulation of Bakken shale oil. In 2016, Sheng et al. [14] proposed a huff-n-puff gas injection method to increase condensate oil production in Eagle Ford, USA. Ganjdanesh et al. [15] and Yu et al. [16] conducted huff-n-puff simulations on the Eagle Ford shale condensate gas reservoir in the United States, introducing the EDFM method for fracture simulation in the model. After 10 huff-n-puff developments of a single well, the cumulative oil production increased by 15%~20%.

2.2 Nano-confinement Effect and Phase State

A large number of nanopores develop in shale reservoirs, and the critical properties of reservoir fluids will shift due to changes in pore radius, which in turn affects productivity evaluation and enhanced oil recovery. The nano-confinement effect refers to the microscopic interactions and fluid states caused by pore sizes much smaller than molecular sizes. In 2011, Kuila and Prasad studied the pore size of shale and found that the shale matrix is mainly composed of micropores (pore diameter less than 2 nm) and mesopores (pore diameter 2-50 nm) [17]. In 1992, Brusllovsky studied the effect of capillary pressure on multi-component phase equilibrium, calculated the dew point and bubble point pressures under different pore radii, and pointed out that as the pore radius decreases, the bubble point pressure decreases and the dew point pressure increases. When the reservoir pressure is high, the influence of porous media on bubble point and dew point is small [18]. In 1996, Ping et al. proposed a theoretical model for calculating dew point pressure, which considered the effects of capillary pressure and adsorption in porous media. It was pointed out that capillary pressure and adsorption increase the dew point, and the increase range of dew point pressure increases with the decrease of permeability and porosity [19]. Morishige et al. first experimentally proved that the critical temperature of pure components is affected in nanopores [20, 21]. Zarragoicoechea et al. established a formula based on the van der Waals equation of state to characterize the degree of deviation of critical temperature and critical pressure [22]. In 2005, Ortiz et al. found that the critical temperature of methane adsorbed in carbon nanotubes decreases with the decrease of pore radius [23]. The confinement effect of shale reservoirs makes the oil and gas phase behavior characteristics in nanoporous media different from the bulk phase behavior characteristics, which in turn affects the judgment of oil and gas interfaces in shale condensate gas reservoirs [24]. In 2012, Devegowda plotted the phase diagram of condensate gas reservoir fluids under confined conditions, showing the influence of critical property deviation on the fluid phase diagram [25]. In 2012, Firincioglu calculated the bubble point pressure and fluid composition changes in gas and liquid phases of three different fluids under different pore radius conditions, and believed that compared with bulk phase fluids, the smaller the capillary radius, the more obvious the decrease of bubble point pressure, and the increase of light components and decrease of heavy components in the gas phase [26]. In 2013, Nojabaei and Johns considered capillary force in the simulation to characterize the confinement effect of shale nano-reservoirs. The study found that considering the influence of nanopores in the simulation can greatly promote history matching, making the dynamic prediction of oil wells and reserves evaluation more accurate. If this influence is not considered in shale reservoir development, it will seriously affect the final recovery rate and future oil and gas production estimates. The capillary force caused by nanopores will lead to a decrease in bubble point pressure, and the increase or decrease of dew point pressure depends on the position of the phase envelope. Capillary pressure mainly affects bubble point pressure [27]. In 2019, Wu et al. proposed a new phase equilibrium calculation model that considers critical property deviation, capillary force, and adsorption effect, and studied the mechanism of CO_2 enhanced oil recovery. It was believed that the nano-confinement effect helps to reduce the minimum miscibility pressure of the oil phase during CO_2 injection and increase the diffusion coefficient of CO_2 in the liquid phase [28]. In 2020, Du and Nojabaei calculated the diffusion coefficient of shale fluid in nanoscale shale from two aspects: 1. Considering both capillary force and critical property deviation to analyze their effects on fluid diffusion coefficient; 2. Combining rock porosity and curvature factor to calculate the diffusion coefficient of shale fluid in porous media. It was found that compared with bulk phase conditions, when the porosity changes from 0.1 to 0.03, the effective diffusion coefficient of shale decreases by 10^2-10^4 times [29]. In 2024, Song et al. verified the accuracy of simulating the nano-confinement effect using critical property deviation by comparing experimental data with critical properties. It was believed that critical property deviation makes it easier for molecules to enter large pores [30].

In 2018, Yu et al. conducted a CO_2 huff-n-puff simulation study considering the nano-confinement effect on the Eagle Ford shale reservoir in the United States, and the results showed that considering the nano-confinement effect helps to improve the huff-n-puff effect [31]. In 2023, Jia et al. considered the nano-confinement effect when using pEDFM to simulate gas injection in shale oil, and the results showed that the nano-confinement effect helps to increase the sweep range of CO_2 flooding, and has a significant impact on the fluid phase diagram and single-well cumulative oil production [32]. In 2024, Song et al. studied the mechanism of CO_2 enhanced oil recovery and storage in shale reservoirs, considering the nano-confinement effect and crude oil maturity in the simulation, and found that the nano-confinement effect has a significant impact on the bubble point pressure of high-maturity shale oil, and has a more obvious impact on the production of low-maturity shale oil [33].

2.3 Condensate Gas Reservoirs Considering Component Gradient

Due to the influence of gravity, thermal diffusion and other factors, the fluid in condensate gas reservoirs often shows the characteristic that the component composition changes with depth, that is, the component gradient characteristic [34-35], resulting in an obvious oil-gas interface. Usually, above the oil-gas interface is a condensate gas reservoir, and below the oil-gas interface is a volatile oil reservoir. Considering the component gradient distribution in the numerical simulation process is of positive significance for reservoir initialization, estimation of reservoir geological reserves, history matching, production dynamic prediction and enhanced oil recovery research [36, 37].

In 1980, Schulte developed a component gradient calculation model considering gravity by introducing the P-R equation of state, and believed that gravity can make the molar fraction of components change with depth. The calculation results can well explain the variation law of bubble point and dew point of fluids at different depths in the Brent oilfield in the North Sea [38]. In 1994, Whitson and Belery proposed an isothermal reservoir component gradient calculation model [39]. In 1997, Padua proposed non-isothermal component gradient simulation, verified the model, and applied it to large deep-water oilfields in Brazil [40]. In 2000, Hoier and Whitson considered the influence of temperature gradient in the component gradient model, and further improved the component gradient model [41].

In 2001, Jaeamillo and Barrufet conducted research on near-critical fluids in the Cusiana oilfield in Colombia, and believed that component gradients have a significant impact on estimating oil and gas reserves and formulating reservoir development plans. For condensate gas reservoirs, without considering the influence of component gradients, the crude oil volume is overestimated by 54%, the natural gas volume is underestimated by 15.60%, and the crude oil recovery rate is overestimated by 135% [42]. In 2004, Luo and Barrufet conducted numerical simulation research on reservoirs with component gradients, and the results showed that reservoirs with obvious component gradients need to select an appropriate grid size in the vertical direction to obtain accurate simulation results, and component gradients have a significant impact on gas injection enhanced oil recovery [43]. In 2006, Pedersen and Hjermstad conducted phase state analysis on fluids from 6 different depths of an oil and gas reservoir in the North Sea, and found that the upper part of the reservoir structure is a condensate gas reservoir, the lower part is a volatile oil reservoir, and there is an obvious oil-gas interface between them [44]. In 2014, Mokhtari conducted scheme optimization research on gas injection development of reservoirs with component gradients, and determined the optimal gas injection depth. They believed that the miscibility pressure (MMP) of reservoir fluids increases with the increase of reservoir depth, thus increasing the difficulty of miscibility. Injecting CO_2 above the reservoir can achieve miscibility, improve recovery rate, and increase reservoir pressure, while miscibility cannot be achieved below the reservoir, resulting in low sweep efficiency [45]. In 2015, Xiong Yu et al. used the isothermal component gradient model to calculate the oil-gas interface of the condensate gas reservoir in Anyue Gasfield, and the results showed that the model can accurately predict the position of the oil-gas interface of a single well in the condensate gas reservoir. The molar content of light components decreases with the increase of depth, and the saturation pressure of reservoir fluid first increases and then decreases with depth [46]. In 2015, Wang et al. compared and studied the influence of component gradient effect on the recovery rate of volatile oil reservoirs under different development methods, and concluded that the influence of component gradient on crude oil recovery rate is much higher than other factors [47]. In 2019, Pourhadi and Fath conducted research on CO_2 injection development of reservoir fluids at different depths in the black oil reservoir in southwest Iran, and found that injecting CO_2 into the upper part of the reservoir can achieve better miscibility [48]. In 2020, Igwe et al. used the winprop and GEM modules in cmg software to compare the productivity differences between the model considering component gradient and the model not considering component gradient. It was believed that the influence of gravity, temperature gradient and thermal diffusion on reservoir component distribution should be fully considered during reservoir initialization, otherwise it will seriously affect the estimation of reservoir geological reserves and lead to wrong development prediction schemes, providing wrong guidance for oilfield sites [49].

2.4 Projection-based Embedded Discrete Fracture Model (pEDFM)

Dynamic simulation of gas injection and energy supplement in shale condensate gas reservoirs is of great significance for predicting energy supplement effects and designing energy supplement schemes. Its reservoir seepage model is a component model, and its seepage medium includes tight matrix and various fractures. In the development process, complex fracture networks need to be formed through fracturing operations. Therefore, the key to dynamic simulation of gas injection and energy supplement in shale condensate gas reservoirs lies in how to carry out seepage simulation in fractured reservoirs. At present, the commonly used numerical simulation frameworks for fractured reservoirs include: Discrete Fracture Model (DFM/DFN), Embedded Discrete Fracture Model (EDFM), and the Projection-based Embedded Discrete Fracture Model (pEDFM) developed in recent years. DFM reduces the dimension of fractures and generates matching unstructured grids to locate them at the interfaces between matrix grids [50-51]. Compared with the dual-medium model, DFM can more accurately describe the geometric characteristics of fractures and has higher calculation accuracy. However, due to the complex fracture network geometry formed by fractures, it is very difficult to generate corresponding matching grids, and it is inevitable to generate a large number of small-sized grids near fracture intersections and narrow areas between fractures, which significantly increases the calculation cost and convergence difficulty.

The Embedded Discrete Fracture Model (EDFM) can avoid the limitations of the Discrete Fracture Model (DFM). Usually, it divides the matrix part into structured grids and embeds discrete fractures into the matrix grids. Fractures are treated as source or sink terms in the matrix grid. In 2006, Lee and Li [52] first applied the embedded discrete fracture model to the matrix grid. In 2019, Hui et al. [53] proposed a multi-scale embedded discrete fracture workflow for simulating large-scale fractured reservoirs. In the same year, Xu et al. [54] extended the embedded discrete fracture model to make it suitable for corner-point grids. In 2013, Moinfar et al. [55] first applied the embedded discrete fracture model to the three-dimensional (3D) component model. In 2020, Rao et al. [56] proposed a multi-layer virtual grid embedded discrete fracture model to more accurately capture the transient flow characteristics between the matrix and fractures. For this reason, in 2022, Olorode and Rashid [57] proposed an analytical expression of matrix-fracture (m-f) conductivity considering transient flow of matrix-fracture (m-f). In 2022, Rao et al. [58] proposed the first meshless embedded discrete fracture model (MFDFM), which further enhanced the ability to handle complex computational domains.

At present, the embedded discrete fracture model has been widely used in the numerical simulation of fractured reservoirs. For example, in 2018, Shakiba et al. [59] used the embedded discrete fracture model to calibrate the numerical simulation of complex hydraulic fracture networks in microseismic monitoring. In 2019, Cao et al. [60] adopted the embedded discrete fracture model in the simulation of anisotropic reservoirs. In 2019, Rao et al. [61] improved the embedded discrete fracture model to simulate the effect of water blocking on the cyclic development process of tight oil reservoirs. In 2020, Li et al. [62] applied the embedded discrete fracture model to fractured geothermal reservoirs to simulate the heat and mass exchange of reservoir fluids. In 2022, Zhao et al. [63] used the embedded discrete fracture model to numerically simulate the development of fractured shale gas reservoirs, and analyzed the effects of different pressure reduction schemes and fracture parameters on productivity. In 2021, Shi et al. [64] extended the application of the embedded discrete fracture model to non-isothermal flow simulation. In 2023, Zheng et al. [65] combined the embedded discrete fracture model with the Parallel Reservoir Simulator (PRS) to achieve accurate and rapid simulation of three-dimensional flow in hydraulic fractures and natural fractures. In 2023, Xu et al. [66] combined the StoSAG and EnOpt optimization algorithms with the embedded discrete fracture model to realize the workflow of development optimization for naturally fractured reservoirs. In 2024, Rao et al. [67] proposed a streamline method for fractured reservoirs based on the embedded discrete fracture model.

However, in 2017, Tene et al. [68] pointed out that the Embedded Discrete Fracture Model (EDFM) cannot effectively handle the case where the permeability of the fracture grid is lower than that of the matrix grid. They first proposed the Projection-based Embedded Discrete Fracture Model (pEDFM) to solve this problem. The model projects the fracture grid embedded in the matrix grid onto the interface of the matrix grid, adds additional matrix-fracture (m-f) connections, and weakens the original connections between adjacent matrix grids. In 2017, Jiang and Younis [69] pointed out that the traditional embedded discrete fracture model may lead to significant errors when simulating multiphase flow across high-conductivity fractures, because it cannot accurately describe the correct flux distribution. They found that the Projection-based Embedded Discrete Fracture Model (pEDFM) can solve this problem and improved some technical details of the Projection-based Embedded Discrete Fracture Model. In 2020, Rao et al. [70] pointed out that the Projection-based Embedded Discrete Fracture Model (pEDFM) still produces significant errors when simulating a class of flow scenarios, solved this problem by adding a new type of fracture-fracture (f-f) connection, and proposed a "micro-translation method" for determining the fracture projection configuration to construct an improved projection-based embedded discrete fracture model. HosseiniMehr et al. [71] and Wang et al. [72] proposed a multi-scale method to improve the computational efficiency of the Projection-based Embedded Discrete Fracture Model (pEDFM) when dealing with a large number of grids in actual reservoir models. In 2022, HosseiniMehr et al. [73] extended the projection-based embedded discrete fracture model to corner-point grids. In 2023, Li et al. [74] used the projection-based embedded discrete fracture model to simulate the geomechanical effects during hydraulic fracturing. In 2020, Liu et al. [75] used the projection-based embedded discrete fracture model to simulate carbon dioxide storage in shale gas reservoirs under complex boundary conditions, and compared the simulation results with those of commercial software CMG to verify the accuracy of the simulation. In 2022, Rao and Liu [76] proposed a necessary condition from a topological perspective, that is, the fracture projection configuration must be topologically homeomorphic to the original fracture topology to conform to physical reality. In 2022, Wu et al. [77] used semi-analytical matrix-fracture conductivity in the projection-based embedded discrete fracture model to perform fluid-solid coupling simulation of fractured reservoirs. In 2023, Rao [78] proposed the first general projection-based embedded discrete fracture model, which maintains the computational advantages over the Embedded Discrete Fracture Model (EDFM) in any flow scenario, laying the algorithm foundation for the commercial application of the projection-based embedded discrete fracture model. Subsequently, in 2024, Rao [79] extended the general projection-based embedded discrete fracture model to non-K-orthogonal grids by using the mixed flux approximation method. However, when applying the general projection-based embedded discrete fracture model to complex component models (multi-component and flash calculations will lead to verification nonlinearity), the cost of developing high-performance solvers is high.

Therefore, this paper is committed to constructing the first numerical simulation method for shale condensate gas reservoir development that combines the general projection-based embedded discrete fracture model (pEDFM) with the commercial simulator CMG. This method uses the connection table composed of inter-grid connections and corresponding conductivities obtained from the general projection-based embedded discrete fracture model to call the nonlinear solver in CMG to simulate component flow in shale condensate gas reservoir development. This method not only has the advantages of the general projection-based embedded discrete fracture model over the Embedded Discrete Fracture Model (EDFM) and Discrete Fracture Model (DFM) in calculation accuracy and handling complex fracture networks, but also avoids the difficulty of developing additional high-performance nonlinear solvers. It provides a theoretically optimal numerical simulation tool for the development of fractured shale condensate gas reservoirs.

3 Conclusions

Shale condensate gas reservoirs are strategic resources for optimizing energy structures and enhancing national energy security, but their development is hindered by multiple technical bottlenecks including ultra-low porosity/permeability, nano-confinement-induced phase behavior anomalies, compositional gradients, and retrograde condensation damage. This paper comprehensively reviews the latest research progress in shale condensate gas reservoir gas injection and energy supplement technologies, and draws the following key conclusions:

3.1 Development methods:

Gas injection huff-n-puff is a proven effective technology for mitigating retrograde condensation damage and improving condensate oil recovery, with field simulations showing a 15%–20% increase in cumulative oil production after multiple cycles, and its coupling with horizontal well fracturing is the core technical approach for developing ultra-low permeability shale condensate gas reservoirs.

3.2 Nano-confinement effect:

The nanopore structure of shale significantly alters fluid critical properties and diffusion behaviors, reducing the effective diffusion coefficient by 10^2–10^4 times at low porosities and lowering the minimum miscibility pressure of CO_2, which is a key factor that must be considered in productivity evaluation and enhanced oil recovery scheme design.

3.3 Compositional gradient modeling:

Neglecting compositional gradients leads to severe errors in reservoir reserve estimation and development plan formulation (e.g., 54% overestimation of crude oil volume), and models integrating gravity and temperature gradients can accurately predict oil-gas interface positions and guide optimal gas injection depth selection, with upper-reservoir CO_2 injection achieving better miscibility and sweep efficiency.

3.4 Fracture simulation models:

The projection-based embedded discrete fracture model (pEDFM) overcomes the limitations of traditional DFM and EDFM, addressing issues such as low fracture permeability and inaccurate flux distribution in high-conductivity fracture multiphase flow simulations; the integration of general pEDFM with commercial simulator CMG provides a high-precision, low-cost numerical tool for dynamic simulation of shale condensate gas reservoir gas injection and energy supplement.

Future research should focus on optimizing the coupling of pEDFM with multi-component phase behavior models, verifying the proposed simulation method through field pilot tests, and exploring the synergistic effects of nano-confinement and compositional gradients on gas injection efficiency, to further promote the efficient and sustainable development of shale condensate gas resources.

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Author Contributions

The author confirms sole responsibility for the following: study conception and design, data-collection, analysis and interpretation of results, and manuscript preparation.

Availability of Data and Materials

None.

Conflicts of Interest

The authors declare that they have no conflicts of interest to report regarding the present study.

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