Pressure Drawdown Management Strategies for Multifractured Horizontal Wells in Shale Gas Reservoirs: A Review

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ABSTRACT: The flow capacity of shale gas reservoirs is easily impaired during the depletion process due to strong stress sensitivity. Thereby, an adequate production system, namely, the managed pressure drop method, has been widely introduced to the industrial practice application by decelerating the wellbore pressure drop rate and ultimately improving the long-term production process. This work presents a review of the pressure drawdown management mechanisms for shale gas formations. However, clarifying the water−shale interaction physical chemistry process and developing a mathematical model that accurately describes the water−shale interaction mechanism remain a challenge. Moreover, different classifications of the managed production simulation research approaches are discussed in detail. Each approach has its own merits and demerits. Among them, numerical simulations are commonly seen in cognizance of characterizing the managed pressure drawdown production period but are found to be relatively time-consuming and also computationally expensive. An optimized theoretical model is therefore essential because it can lead to a precise estimation of the ultimate long-term production and capture instantaneously the actual shale gas reservoir depletion phenomenon with various production systems compared to other available methods. The key influence of managed pressured production for single wells in shale reservoirs is elaborated as well. As observed from the current review, an accurate description of the pressure drop management mechanism is crucial for the theoretical model of the pressure control production process for shale gas wells. The influence of water−rock interaction on the managed pressure drawdown mechanism cannot be ignored. There have thus been works to improve and enhance it for use in theoretical models for shale formations. On the other hand, the advancement of theoretical models presents an opportunity for better representation of the managed pressure drop production process.

1. INTRODUCTION

Shale gas resources in the world are abundant, and their production has continued to grow rapidly. The U.S. Energy Information Administration (EIA)\(^1\) showed that the total global shale gas resource is \(456 \times 10^{12} \text{ m}^3\) and the technically recoverable reserve constitute \(220.69 \times 10^{12} \text{ m}^3\). By 2040, the global shale gas production is expected to reach \(1.1 \times 10^{12} \text{ m}^3\), and China may become the second largest shale gas development area after North America.\(^2\) The large-scale development of shale gas reservoirs has promoted the adjustment and change of the global energy structure, and it has become an important replacement resource to make up for the shortage of conventional energy.\(^3,4\)

Shale gas reservoirs are characterized as having low porosity and extremely low permeability. The reservoir permeability with a poor pore structure is between \(10^{-5}\) and \(10^{-3} \text{ mD}\).\(^5–7\) The large gas seepage resistance in reservoirs leads to no productivity under natural conditions. Generally, horizontal well technology and volumetric fracturing are used to make industrialized gas flow.\(^8\) The rapid decline in the production capacity of single wells can be attributed to the strong stress sensitivity of reservoirs. The increased effective stress on the formation and fractures will, thereby, make reservoir conductive medium systems compacted\(^8\) and shale gas flow channels deformed,\(^10\) resulting in flow capacity reduction.

During the production practice for shale gas formations, selecting a suitable production strategy is conducive to the production decline rate reduction and the optimal cumulative production of shale gas reservoirs. The outlet flow through nozzles is mainly adjusted to control the production pressure difference and alleviate the stress sensitivity damage to reservoirs.\(^11\) According to the bottom hole flow pressure
drawdown management approaches, the production behavior of shale gas wells can be divided into depressurization production and controlled pressure production. Among them, depressurization production means that there is no flow restriction at the wellhead, and the bottom hole flow pressure in the initial production stage is rapidly reduced to the constant pressure of the gas well. Improper adjustment of the flowback rate can cause proppant backflow, reduce fracture conductivity, and even lead to reservoir damage. Pressure drop management has attracted a lot of attention in recent years. Shale gas flow is generally restricted by setting different sizes of nozzles at the wellhead, which decreases the decline rate of wellhead pressure and sacrifices the initial high production to achieve long-term stable production. In the later period, production reversal may occur, and the stable production period of gas wells can be prolonged.

The shale gas production practice shows that the EUR per well by the pressure drop-controlled production strategy can generally increase by 28−30% compared to that by the depressurized production approach. Due to the high-pressure formation conditions and strong pressure-sensitivity effect, the Changning-Weiyuan and the Haynesville shale gas demonstration adopt controlled pressure production methods for enhancing the ultimate cumulative production. On the contrary, shale reservoirs with relatively low reservoir pressure coefficients such as the Fuling shale gas field and the Barnett and Marcellus shale reservoirs usually use depressurized production and the large differential pressure production method.

It is essential to design a reasonable controlled pressure production strategy to obtain ideal productivity for fractured shale gas reservoirs. The optimization design of the production system for shale gas reservoirs in China generally relies on production practice experience and field test knowledge from North America. Mature scientific theories on the dynamic production performance and pressure drop management optimization still need to be further explored and analyzed. The disagreement in the shale gas pressure drop controlled production mechanism, insufficient theoretical research on the control pressure production dynamic analysis, and the lack of the pressure control strategy optimization analysis are some of the scientific problems and technical difficulties encountered during the shale gas production process.

An accurate description of the pressure drop management mechanism is of theoretical importance for the simulation of a reasonable pressure control production process for shale gas wells. First, the shale gas pressure drop management mechanisms were systematically summarized. Moreover, the research approaches of control pressure production simulation for shale gas wells are investigated. Ultimately, the key control factors and influence mechanisms of pressure control production are presented, which aim to provide a scientific basis for the optimization of the shale reservoir production strategy.
2. RESULTS AND DISCUSSION

2.1. Shale Gas Pressure Drop Management Mechanism. The controlled pressure mechanism can essentially be explained by the geological reservoir stress. The diversity of pore structure scales in shale reservoirs makes the flow mechanism of shale gas complicated, covering from the molecular scale to the macro scale. The geo-mechanical properties also exist in the multiscale gas mass-transfer process, as shown in Figure 1. In the initial production stage, free gas in propped hydraulic fractures is transferred to the wellbore under the pressure drop near the wellbore, which can lead to a high initial fracturing fluid flowback rate and early gas breakthrough. The second period is the mass-transfer process of free gas in the secondary unpropped fracture network to the hydraulic fracture. The secondary fracture network is more sensitive than hydraulic fractures; thus, the porosity and permeability parameters are easier to decrease under the increasing effective stress conditions. The third stage is that the gas in the matrix flows into natural fractures or artificial fractures under the pressure difference between the matrix system and the fracture system. The decrease in the matrix pore pressure results in the matrix medium compaction, thereby affecting the ultimate cumulative production of shale gas wells. In summary, there are four controlled pressure production mechanisms: (1) artificial fracture conductivity loss; (2) microfracture stress sensitivity; (3) matrix stress sensitivity; and (4) proppant backflow theory.

2.1.1. Artificial Fracture Conductivity Loss. During the shale gas production process, the increase in effective net stress can cause the proppant inside the artificial fracture to be embedded, deformed, and ruptured in gas formations. Thus, the reduced effective flow channel width will cause the fracture conductivity loss.

Crespo et al. believed that under high pore pressure—high stress conditions, the proppant in hydraulic fractures may be squeezed, deformed, and damaged, which would seriously damage the conductivity of hydraulic fractures. The critical period for optimizing pressure drop management is considered to be the initial production stage of the well, and the mathematical relationship between the geological maximum horizontal stress and the bottom hole net pressure is proposed.

Weaver et al. adopted X-ray and scanning electron microscopy experiments to study the impact of proppant performance on hydraulic fracture conductivity. They found that the proppant application type usually depended on the compressive strength, availability, and cost of the proppant. The proppant material may chemically react with the reservoir, resulting in the loss of porosity and permeability.

Luo et al. proposed a new long-term proppant fracture conductivity model by considering the stress sensitivity of artificial fractures. The model results show that high effective stress in the reservoir leads to proppant fracture, fine formation migration, as well as fracturing fluid damage, and finally, the conductivity of supporting fractures will gradually decrease.

Gao et al. developed an analytical model of proppant embedding and deformation depending on net stress and believed that the proppant deformation, embedding process, and the reservoir’s effective stress are linearly related.

Chang et al. and Sone et al. showed that the linear elastic deformation of hydraulic fracture proppants began to fail and proposed that the dynamic deformation of proppants can be characterized by creep.
Tian et al. proposed a shale gas trilinear flow productivity model and then established a dimensionless production decline chart by coupling slippage, adsorption, natural fracture stress sensitivity, as well as the non-Darcy flow of artificial fractures. The results show that if the stress sensitivity of natural fractures is ignored, it will lead to errors in the prediction of shale gas production capacity.

Han et al. proposed a semianalytical model for staged fractured horizontal wells in shale gas formations by considering shale gas adsorption and desorption, unsteady diffusion, and stress sensitivity. The calculation results show that the dimensionless bottom hole pressure drop considering stress sensitivity is several times that of not considering stress sensitivity, and the ignored influence of stress sensitivity in the model analysis will produce larger errors in the calculation results.

Zhu et al. adopted the Langmuir isotherm adsorption equation to describe the adsorption and desorption, the permeability decay index model to present stress sensitivity, and the Forschermeier equation to analyze the non-Darcy process based on the dual model and the discrete fracture hybrid model. The well test model focuses on the influence analysis of nonlinear factors on pressure response. It is believed that the influence of fracture stress sensitivity gradually increases with the production time.

2.1.3. Matrix Stress Sensitivity. Unconventional low-permeability reservoirs are obviously susceptible to suffering from elastoplastic deformation of the rock pore structure when the gas reservoir pressure reduces and the effective stress on the rock skeleton of the reservoir increases, impairing matrix permeability, porosity, and rock physical properties. Proper controlled pressure production will reduce the shrinkage rate of the rock pore volume and improve the connectivity between effective pores.

Zhang et al. used the core pulse method to analyze the stress sensitivity mechanism of a shale core sample based on the permeability stress sensitivity mechanism of capillary, flat fracture, and dual-porosity media. It shows that the existence of microfractures, nanoscale flat pores, and clay minerals in shale results in the shale pore compressibility being much greater than that of sandstone.

Li et al. found that when the temperature is constant, the permeability of coal rocks first decreases and then increases during the depressurization process. When the pore pressure is constant, the permeability of coal rocks first decreases and then increases during the heating process. The matrix shrinkage strain increases with the decrease in pore pressure in the coal gas desorption.

Akande and Spivey believed that the pore stress sensitivity is less influenced in the production period with a higher initial net stress, but the pore stress sensitivity is greater when the initial net stress is low.

Based on the traditional Hooke’s law, Liu et al. proposed a dual-strain Hooke model, referred to as the TPHM model. Taking into account the reservoir heterogeneity, the rock in the model is conceptualized into two different parts (the “hard” part and the “soft” part). The soft part corresponds to the pores and microcracks in the rock that can undergo relatively large deformation, and the remaining part is considered the hard part. The matrix permeability varies with the effective stress, and different permeability models are proposed.

Zheng et al. established a TPHM numerical model by the comsol numerical simulator to study the relationship between the seepage rate of different lithologies and the effective stress, and thereby, dynamic change in permeability of the soft part in the matrix was characterized by a stress-sensitivity exponential model.

Based on the Beskok–Karniandakis model, Guo et al. derived a shale apparent permeability model considering stress sensitivity and adsorption. When the shale pore radius is greater than 5 nm, the impact of stress sensitivity on apparent permeability is dominant.

2.1.4. Proppant Flowback Theory. Proppants with excellent performance can maintain high conductivity of fractures, strengthen communications between the reservoir and the wellbore, as well as maintain long-term production of the shale gas well. The aggressive pressure drop strategy can greatly promote the proppant flowback in the reservoir, leading to fracture closure in the farthest part of the wellbore and productivity loss of gas wells.

Van Batenburg et al. designed the RCS approach to increase the proppant flowback viscosity, reduce the probability of proppant flowback, and increase the shale gas seepage capacity in reservoirs.

Nguyen et al. injected a curable resin or surfactant into the proppant and succeeded in reducing the amount of proppant flowback.

Jiao et al. established an optimized design model for controlling proppant backflow by considering the sand volume, sand addition ratio, construction displacement, and fracturing net present value.

Ai et al. developed a theoretical model for simulating fracturing fluid velocity distribution during the early flowback process. The flowback rate of a fracturing fluid gradually decreases with the flowback process, and it is considered that proppant flowback is an important factor in evaluating the fracturing effect.

Emmanouil et al. established a wellbore choke optimization quantitative model to avoid excessive proppant backflow in the early stage of production, resulting in fracture closure, wellbore damage, and final productivity reduction in the near-well area. It is believed that the best pressure drop method can be achieved by controlling the pressure drop time.

Cai et al. believed that avoiding proppant backflow is the key to controlled pressure production and developed a geo-mechanical-fluid flow coupling model for early flowback in shale reservoirs. Numerical calculation results show that fracture closure is often uneven during the flowback process, but excessive pressure drop may destroy the connectivity between the fractures and the wellbore. It is emphasized that throttling/pressure drop management can be used to affect fluid recovery and even maintain a relatively high fracture conductivity.

Tabatabaei et al. designed an experiment to analyze the proppant wetting performance to improve the proppant flowback rate.

The common pressure drop management mechanisms can be summarized in four points: artificial fracture conductivity loss, microfracture stress sensitivity, matrix stress sensitivity, and proppant backflow. The above understanding mostly came from gas-bearing reservoirs. However, during the early depletion process, long-term invasion of fracturing fluids into reservoirs could cause significant damage to mechanical properties as well as reservoir conductivity. Thus, it is crucial...
to clarify the water–shale interaction physical chemistry process and develop a mathematical model that can accurately describe the water–shale interaction mechanism. Besides, research on the pressure drop mechanism is mainly based on numerical simulation, lacking the support and verification of experimental research and theoretical models.

2.2. Shale Gas Pressure Drop Production Simulation.

The research methods of pressure drop production simulation were investigated to analyze the dynamic performance of shale gas controlled pressure production, including field tests, physical simulation, and numerical simulation.

2.2.1. Field Tests. Carrying out mine experiments can clarify the design principles of field engineering and intuitively help understand the experimental results, which can be used to guide and deepen physical experimental research to obtain qualitative research in the field and to obtain better feedback on on-site engineering work.

In North America, the pressure drop management and gas production rate are achieved by controlling the nozzle size. Generally, the initial production nozzles are relatively small, starting with 3.18 mm, and then, the nozzle sizes are gradually increased in the production process, finally ranging from 6.35 or 7.94 mm. Table 1 shows a comparison of BP’s shale gas well nozzle refined management system.

Small nozzles of sizes 8.7 and 5.6 mm are mainly adopted for controlled pressure production in the Haynesville shale gas block. It was found that the production capacity of gas wells with large nozzles was significantly higher than that with small-nozzle gas wells in the early stage of production, but when gas wells with small nozzles were produced for about 3 years, the cumulative gas production began to exceed the cumulative gas production of wells with large nozzles, resulting in a “production reversal phenomenon”. The cumulative gas production of gas wells with small nozzles for three years was higher than that with large-nozzle production wells by more than 30%. To avoid damage to the wellbore and reservoirs in the near-well area, operators’ production practices have shifted to controlling pressure drop or limiting production. Belyadi et al. defined linear flow parameters based on IHS RTA numerical simulation. The larger the linear flow parameter, the more conservative the pressure drop, and the slower the bottom hole pressure drop. The EUR of the four controlled pressure production wells can be increased by about 30% compared with that of the depressurization production wells. Taitel et al. evaluated the impact of stress-dependent permeability on the production performance of shale gas reservoirs and found that when the overall production began decreasing, there was a sudden change in the bottom hole flow pressure and daily production near 2011. It can be seen that there were indeed changes in the production system around 2011, and it was speculated that its production system was transformed into “controlled pressure production”.

In North America, multiple field experiments on controlled pressure production for shale gas wells have been carried out, which can accurately reflect the production system for gas wells and the production mode conversion, truly present controlled pressure dynamic production changes in shale gas wells, as well as provide reliable technical reference to clearly formulate reasonable controlled pressure production methods. However, due to the strong regionality and high research costs in minefield test research, most of them are adopted in large-scale fields to provide engineering practice knowledge for theoretical scientific research and physical simulation work.

2.2.2. Physical Simulation. Physical simulation is a research method that reproduces the controlled pressure production process of shale gas wells based on the principle of similarity criteria. It is feasible to conduct the matrix-fracture coupled multilcore controlled pressure production indoor simulation to acquire a qualitative understanding of the pressure control production process and key controlled pressure production influencing factors.

Sang et al. illustrated that the staged pressure drop and the linear pressure drop can reduce the stress sensitivity of the shale matrix and increase the final productivity of gas wells through experiments. Zhu et al. conducted a full-core experimental study of the Longmaxi Formation in Sichuan by X-ray diffraction and high-pressure mercury test methods and found that stress sensitivity had a non-negligible impact on reservoir production. Thus, it is necessary to reasonably control the pressure difference to avoid causing damage to reservoirs. Subsequently, Zhu et al. used electron microscopy technology to describe the microscopic pore characteristics and adopted the cross-plotting method to measure the effective stress coefficient of shale samples and finally concluded that the existing area of microfractures is greatly affected by stress.

Because the experimental scale, experimental conditions, and experimental parameters cannot accurately restore the complex deep reservoir depletion on-site, indoor physical simulation experiments can be used as effective auxiliary means for minefield tests and theoretical model research, which can provide the experimental qualitative knowledge or experimental parameters of the research object for carrying out the mining area test and designing numerical simulation analysis.

2.2.3. Numerical Simulation. With the continuous innovation of numerical calculation methods and the development of oil and gas numerical simulation software, numerical simulation has developed into an important tool for analyzing the shale gas reservoir depletion process, including numerical simulation software and the theoretical mathematical model.

Wang et al. established a dynamic prediction model for shale gas controlled pressure production and believed that a long-term pressure control method can achieve higher cumulative gas production.

Adopting numerical simulations considering reservoir physical properties and rock mechanical properties, Crespo

Table 1. Comparison of BP’s Shale Gas Well Nozzle Refined Management System

| stages                  | nozzle size, mm | lasting time, h | permitted minimum wellhead pressure, MPa | permitted maximum wellhead pressure, drop |
|-------------------------|-----------------|-----------------|------------------------------------------|------------------------------------------|
| initial stage           | 2               | 24–48           | 47                                       | 2, 0.08                                  |
| gradual- increase stage | 3–8             | 48–72           | 34                                       | 2, 0.08                                  |
| refined adjustment stage| 9–14            | 72–             | keep the nozzle size fixed until further decision by the project               |

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et al.\textsuperscript{21} fitted the completion casing pressure and production data and then established the relationship chart of the effective stress versus production time based on the heterogeneous pore elastic equation. The proppant change was obtained, and the pressure drop strategy optimization analysis was carried out.

Wilson et al.\textsuperscript{66} developed an analytical model to quickly evaluate the effective stress changes in the reservoir and dynamically monitor the effective stress on the fracture network in real time, which is conducive to clarifying the bottom hole pressure drop plan, alleviating fracture damage, and increasing EUR (estimated ultimate recovery).

Okouma Mangha et al.\textsuperscript{57} comprehensively considered the productivity loss mechanisms, including stress sensitivity of permeability, proppant embedding, and man-made operation problems, and proposed a multifractured geo-mechanical reservoir model under different pressure drop schemes. The research results showed that the aggressive scheme leads to productivity reduction in the near-well area and the fracture system.

To achieve optimal economic benefits of the Vaca Muerta block, Alejandro Lerza\textsuperscript{65} proposed a geo-mechanical reservoir model by coupling the uncertainties of reservoir parameters and proppant performance parameters and designed a DOE method to detect the reliability of the production method under the deterministic parameter conditions.

Wilson et al.\textsuperscript{66} adopted the transient flow (RTA) analysis method to derive the reservoir utilization area, which basically matched the calculation result of the reservoir geo-mechanical model. The RTA method was used to quickly evaluate and determine the optimal pressure drop.

Rojas et al.\textsuperscript{66} developed RTA numerical simulators to perform history matching and production prediction on the production data of multiple shale gas wells and carried out an economic benefit evaluation to determine the optimal pressure drop scheme.

Tobey et al.\textsuperscript{68} emphasized that the flowback operation process of gas wells in the Eagle Ford block can affect the short-term and long-term production performances of gas wells. The RTA method was used to process the flowback data of gas wells at the initial stage of production, optimize the pressure drop plan, and improve the recovery rate of gas wells.

Numerical simulation has the advantages of low cost, high efficiency, advanced simulation, and powerful data systematic processing, which can well guide the efficient shale gas reservoir development. Considering that the setting parameters are affected by the simulation software level and the built-in mechanisms are relatively simple, there is no unified standard for the selection of software and parameter determination, which are left to be solved in practical applications.

Quantitative research on the pressure drop management production process of shale gas reservoirs mostly relies on numerical simulation software. However, due to the limitations of computing capability and overly ideal assumptions, more research still needs to be done to develop new theoretical methods and physical simulation to interpret the controlled pressure production process and enhance the estimation accuracy of the ultimate cumulative production in shale.

2.3. Key Factors Affecting Shale Gas Pressure Drop-Controlled Production. It is an engineering reference value to clarify the key influencing production factors of shale gas wells with different production strategies and establish the multiproduction controlling factor chart.

The factors affecting the final cumulative gas production with pressure drop management are mostly classified into three types: reservoir geological background, fracturing conditions, and pressure drop strategy. The reservoir geological background includes reservoir pressure, matrix permeability, porosity, matrix stress sensitivity, and microfracture existence; the fracturing parameter conditions include supported fracture conductivity, stress sensitivity of unsupported fractures, filtrate intrusion, fracturing network scale, and proppant performance; and the pressure drop strategy parameters include the pressure control duration (pressure drop rate) and the pressure drop path.

2.3.1. Reservoir Geological Background. Shale gas reservoirs in China and North America with a depth of more than 3500 m have the geological characteristics of abnormally high pressure.\textsuperscript{69,70} Reservoir pressure is an important factor affecting the gas content and high production of shale gas. During the shale gas accumulation stage, a relatively closed environment\textsuperscript{71} formed by the abnormally high-pressured shale reservoir can slow down the natural gas loss within the reservoir.\textsuperscript{71−73} Due to the low Young’s modulus and high brittleness of abnormally high-pressured reservoirs, lots of nanopore structures and microfractures can be induced in the shale gas generation period and migration stage, providing much storage space for the adsorbed gas and free gas. Moreover, microfractures in abnormally high-pressured reservoirs are conducive to the realization of artificial reservoir reconstruction\textsuperscript{76} and improve the reserve production. Abnormally high-pressured reservoirs are more susceptible to stress sensitivity if the bottom hole pressure drop rate is too fast or the production allocation is too high, resulting in shale gas single wells with a high initial production, large decline rate, and extremely low later-stage production. Reasonable production pressure difference is an important way to promote high shale gas production for abnormally high-pressured reservoirs.\textsuperscript{61}

The poor connectivity of pore structures in shale gas reservoirs leads to low seepage performance and strong seepage resistance. Therefore, the fracture network system has become the main fluid permeability channel.\textsuperscript{77} Matrix permeability is the main factor that affects the gas supply capacity from the matrix to the fractures. Since the reservoir permeability is much smaller than fracture permeability, the shale gas mass-transfer channel is dominated by a fracture network composed of natural fractures and fracture-induced fractures.\textsuperscript{78} Matrix permeability is conducive to improving the shale matrix utilization, enhancing the contribution of remote well reservoirs to gas production,\textsuperscript{79} and determining the amount of gas production in the later stage of gas wells.\textsuperscript{80} In the late stage of production, the matrix permeability decreases obviously due to the matrix stress sensitivity. The strength of matrix stress sensitivity is related to the effective stress loading speed,\textsuperscript{81} shale clay mineral content,\textsuperscript{62} pore radius,\textsuperscript{83} Poisson’s ratio of the reservoir, and Young’s modulus.\textsuperscript{84} Therefore, the flow production pressure difference should be adjusted reasonably to effectively promote gas desorption in the matrix and avoid the matrix pore shrinkage effect caused by the increase of effective stress.

The shale rock pores can be divided into primary pores and secondary pores according to the evolution history; according to pore size, they can also be divided into micropores (pore size <2 nm), mesopores (2 nm < pore size <50 nm), and macropores (pore size >50 nm). Nanoscale pores have been
developed in the matrix organic matter, and the main pore size distribution of microfractures is concentrated in mesopores and macropores.85 Shales mostly show low porosity (<10%), of which the effective porosity is only 1−5%.86 The free gas is mainly distributed in the fractures and matrix pores, while the adsorbed gas mainly exists on the surface of the matrix organic particles. The free gas content is closely related to the size of the pore volume.87 Generally speaking, a larger pore volume leads to a large amount of free gas, affecting the high initial production of the gas well. The rock structure with great porosity can easily suffer from the high possibility of compaction, and thus, it is difficult for shale gas in the pores to be recovered.

Reservoirs with microfractures are more easily affected by stress change than those with matrix and propped fractures. The roughness, dislocation, and geometry, as well as rock mechanical properties of fractures,68−83 have a huge impact on microfracture conductivity. However, the stress sensitivity of hydraulic fractures has little effect on the final productivity. The fracture stress sensitivity mainly affects the production pressure difference required for stable production and has a small effect on the stable production of shale gas wells.89

2.3.2. Shale Gas Fracturing Conditions. Artificial fractures and equivalent fracture networks are important flow channels for the mass-transfer process of shale gas from reservoirs to the wellbore. Therefore, studying the conductivity and stress sensitivity of fracture networks under effective stress has become the key to improving the effect of reservoir production.

Hydraulic fractures can maintain sufficient conductivity under the action of proppants such as quartz sand and ceramsite,94 which is controlled by the proppant sand concentration, paving method, and proppant mechanical properties. Zhu et al.95 experimentally analyzed the influence of proppant type, particle size, closure pressure, and paving concentration on the proppant fracture conductivity of shale reservoirs. Research shows that the conductivity of embedding ceramsite is lower than that of quartz sand.96 In the case of a lower closure pressure, the high sand concentration and large proppant particle size can contribute to the high conductivity.97 The proppant embedding and fragmentation increase with the closure pressure increasing, and thus, the proppant conductivity gradually decreases.95 When the proppant in the hydraulic fractures is embedded, broken, and slipped, the fracture conductivity drops rapidly and the stress-sensitive effect of artificial shale fractures with stronger plasticity is stronger.98

Yang99 believed that there are huge differences in the physical conditions of shale reservoirs and fractures; thus, the impact of stress sensitivity on productivity should be considered differently. The stress sensitivity laboratory experiment was designed by Duan et al.,100 and the stress sensitivity of the matrix, unpropped microfractures, and propped fractures were compared and analyzed. The study showed that the stress sensitivity of microfractures was significantly higher than that of the matrix area. The fracture surface roughness and proppant can reduce the stress sensitivity, and the fracture slip is better in reducing the stress sensitivity than the fracture proppant.

In the hydraulic fracturing process, when the net hydraulic fracture pressure is greater than the horizontal principal stress difference, branch fractures will be induced at the side ends of the hydraulic fractures, forming a complex volume fracturing zone with induced branch fractures, hydraulic fractures, and open microfractures interlaced.101 Large-scale fracturing must be used to obtain considerable industrial gas flow. There is still a large amount of fracturing fluid remaining in the formation after the flowback stage of shale wells.102,103 The scale of the fracturing network, matrix porosity, and water saturation will affect the flowback of the fracturing fluid from shale gas reservoirs.102 Water retention has an impact on the flow capacity of shale gas and the cumulative gas production of a single well.103 The infiltration of fracturing fluids may cause fluid damage to shale reservoirs near the well. Studies have shown that the infiltration of fracturing fluids on the surface of shale fractures causes changes in the physical and chemical properties of reservoir rocks, reduces the surface strength of shale fractures,104 and enhances the stress sensitivity of unsupported fractures.105 Meanwhile, there would be a “water lock effect” due to the gas-water capillary force in the micropores, which causes fracturing fluids to block the pore below, resulting in mineral components absorbing the water and expanding106 and reducing the width of fractures107 by adsorbing on the surface of the flow space, and finally reducing the shale conductivity.108,109

2.3.3. Shale Gas Pressure Drop Strategy. The pressure drop strategy indicators specifically include the gas well pressure control duration (pressure drop rate), the type of pressure drop path, and other factors, such as the production allocation.

According to the decreasing speed of bottom hole flowing pressure, the pressure drop control strategy is divided into the conservative type, standard type, and aggressive type.57,65,67 Studies have shown that there is an optimal pressure drop management time for bottom hole flowing pressure.28 Whether the pressure drops too fast or too slowly, the long-term EUR of the production well can be reduced. When the initial reservoir pressure and final bottom hole pressure of the gas well keep constant, and the pressure control time increases, the average pressure drop rate of the gas well becomes smaller, and the initial production of the gas well gradually decreases. The cumulative production of gas wells with a high pressure control duration exceeds that of gas wells with a low pressure control duration, that is, productivity reversal occurs.67

According to the shape of the bottom hole pressure drop curve, the pressure drop path can be divided into linear decline, concave decline, convex decline, and stepwise decline.60,110 Experimental results and numerical simulation analysis show that linear decline and stepwise decline can delay the permeability loss of reservoir seepage media compared with the depressurization production strategy and obtain a more ideal single-well production effect. When the convex decline effect is dominant, the gas well is produced at a more conservative method, which is not conducive to increasing the long-term production of shale gas reservoirs. The obvious concave decline effect can result in serious productivity loss of near-well fractured reservoirs, which will weaken the production of reserves in boundary reservoirs.110

Excessive production allocation or production pressure difference will cause proppant migration and stress-sensitive effects in reservoirs and fractures, thereby reducing the fractures and matrix conductivity; if the allocated production or production pressure difference is too low, the gas desorption rate can be reduced and the outlet production rate of the matrix can be weakened, as well as the ultimate cumulative gas production can be reduced.111
The reservoir utilization is highly correlated with these factors, including reservoir geological parameters, fracturing parameters, and wellbore pressure drop strategy. Determining the operation unit with better geological background and optimal engineering construction conditions is the prerequisite for controlled pressure production; reasonable fracturing plans can induce stimulated formation of high seepage capacity and a wide gas leakage area. Besides, formulating an appropriate production system is the key to protecting the seepage capacity of shale gas reservoirs and improving the long-term stable production of a single well. The dynamic controlled pressure production influencing factor analysis is mainly conducted by single-factor comparison; the main control influencing factors on controlled pressure production are further clarified to study the impact of multifactor coupling on controlled pressure production and to develop the mathematical model of long-term and short-term gas production versus multiple main control influencing factors.

3. CONCLUSIONS

In this paper, we reviewed the managed pressure drop strategies for multifractured horizontal wells in shale gas formations. Specifically, an accurate description of pressure drawdown management mechanisms is crucial for theoretical support of the entire controlled pressure production evaluation analysis. We discuss how different pressure drawdown management mechanisms impact the ultimate production of single wells. Managed pressure drawdown production behavior in gas shale formation is affected by factors like artificial fracture conductivity loss, microfracture stress sensitivity, and matrix stress sensitivity, as well as proppant backflow. The influence of water–rock interaction on the managed pressure drawdown mechanism cannot be ignored. Clarifying the influence of water–shale interaction on the reservoir flow capacity and developing a mathematical model that accurately describes the water–shale interaction mechanism remain to be analyzed. Considerable progress has been made in research approaches of managed pressure drawdown production analysis. Due to the limitations of computing capability and overly ideal assumptions, more research still needs to be done to develop new theoretical methods and physical simulation to interpret the controlled-pressure-production process and enhance the estimation accuracy of the ultimate cumulative production in shale. The reservoir utilization is highly correlated with these factors, including reservoir geological parameters, fracturing parameters, and wellbore pressure drop strategy. The scope for future work is to reveal the mechanisms of multifactor coupling on the controlled pressure production and establish the mathematical equation of long-term and short-term gas production versus multiple main control influencing factors.

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