Research and Application of Shale Gas Reservoir-Wellbore Integrated Model Coupling Method

Silin Yan, Mingzhong Li*, Chenwei Liu, Haojia Li, Sen Lv

School of Petroleum Engineering, China University of Petroleum (East China), Qingdao, Shandong 266580, China

Abstract. As a representative of emerging unconventional energy, shale gas has the characteristics of large reserves, long production cycle, and environmental protection. However, due to the complex geological characteristics of shale gas reservoirs, the economic development of shale gas reservoirs is difficult. In this paper, on the basis of a full investigation of relevant literature, according to the permeability mechanism of shale gas reservoirs, the productivity of horizontal wells in low-permeability gas reservoirs is studied, and an integrated dynamic simulation model of gas reservoir wellbore is established. And the historical fitting and dynamic forecasting are carried out, and the results are in good agreement with the actual situation.

1 Research on coupling method of shale gas reservoir-wellbore integrated model

The flow of the shale gas well production system includes the flow from the shale gas reservoir to the bottom of the shale gas well and the flow from the perforated section of the shale gas well to the wellhead. Formation seepage and wellbore pipe flow follow different flow laws and need to be simulated with different models.

The traditional processing methods are mainly to simplify the wellbore pipe flow with accurate formation seepage and the simplified formation seepage with accurate wellbore pipe flow. There are problems in the current shale gas numerical simulator. When the precise formation seepage simplifies the wellbore pipe flow, it cannot deal with the unsteady state change of the wellbore. The impact on the actual production, the storage and discharge of the wellbore will interfere with the production of the wellhead, especially in the early and late stages of production, there is a risk that the design plan cannot be realized during actual construction. When accurate wellbore flow simplifies formation seepage, the static productivity model cannot predict dynamic productivity changes, and has great limitations in the optimization design of drainage and gas recovery, which requires accurate prediction of future production changes.

This method is based on wellbore multiphase flow simulation, evaluates the production system of shale gas reservoirs, conducts reservoir-wellbore integration model coupling research according to different wellbore flow states and production systems, combined with shale gas reservoir numerical simulation software, Obtain cumulative gas production, water production, predict future formation pressure change trends, and provide design basis for integrated drainage and production throughout the life cycle of gas wells. The basic process is shown in Figure 1.1.

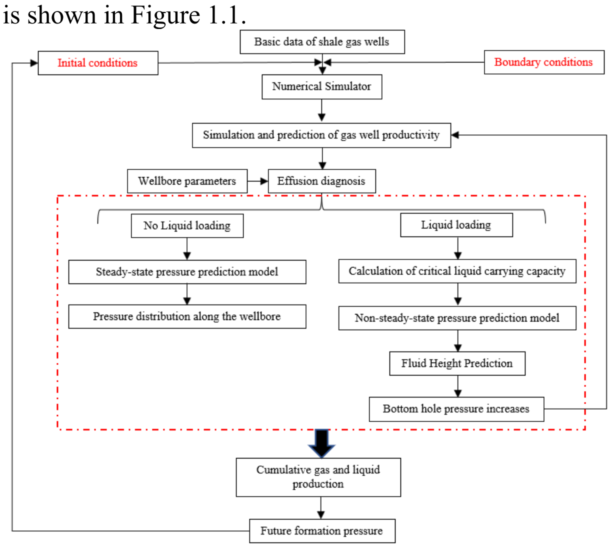

Fig. 1.1 Coupling process of reservoir-wellbore integration model

When there is no liquid accumulation in the wellbore, the pressure distribution is solved according to the conventional steady-state pressure model. When the wellbore is liquid-loaded, the fluid accumulation rate is quantified in combination with the gas reservoir productivity, and the bottom hole flow pressure and gas well productivity changes are predicted, as follows:

Firstly, the pressure field coupling between wellbore variable mass flow and reservoir seepage is considered, and the pressure field in the reservoir and wellbore is coupled through water production and gas production models. The calculation method is as follows:

$$m_g = \rho_g \cdot J_g \cdot \Delta p \tag{1.1}$$

* Corresponding author: 18834174701@163.com

$$m_w = \rho_w \cdot J_w \cdot \Delta p \quad (1.2)$$

Secondly, the wellbore and the reservoir are discretely divided, as shown in Fig. 1.2.

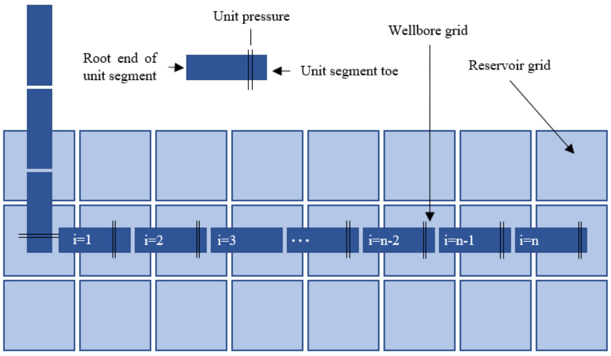

Fig. 1.2 Schematic diagram of discrete division of wellbore and reservoir

Flow pressure drop of unit segment i=2,3,…,n:

When there is no liquid accumulation in the wellbore, the solution method is to first estimate the wellbore pressure distribution in the horizontal section, obtain the productivity of each formation, and then combine the wellbore steady-state variable-mass multiphase flow model to predict the wellbore pressure distribution and compare it to carry out iterative solution.

When the wellbore is liquid-loaded, the solution method is to predict the liquid-carrying amount based on the wellbore pressure and liquid-loaded height at a certain moment, and iteratively calculate the pressure distribution along the wellbore and the liquid and gas production profiles in the horizontal section in combination with the wellbore structure of the gas well, and carry out the next step. Solve the relevant parameters at a time.

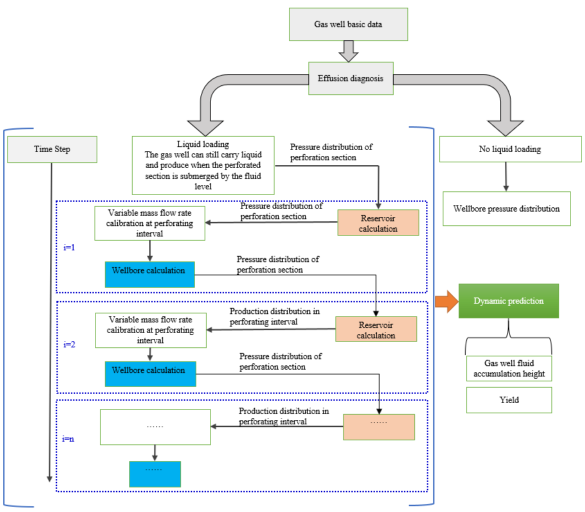

Figure 1.3 Shale gas reservoir-wellbore integration process

Figure 1.3 shows the calculation process of the shale gas reservoir-wellbore integration model coupling method under the condition of fluid accumulation and the condition of no fluid accumulation.

2 Application of shale gas reservoir-wellbore integration model coupling method

2.1 Geological modeling

Apply this method to the dynamic analysis of WH1 platform production.

Geological modeling: Import the geological model established by Petrel software into the history matching module to complete the geological modeling.

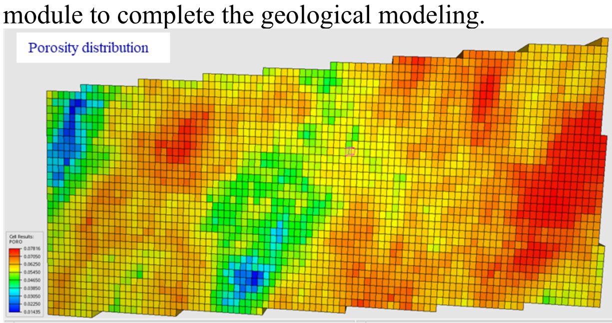

Figure 2.1 Porosity distribution

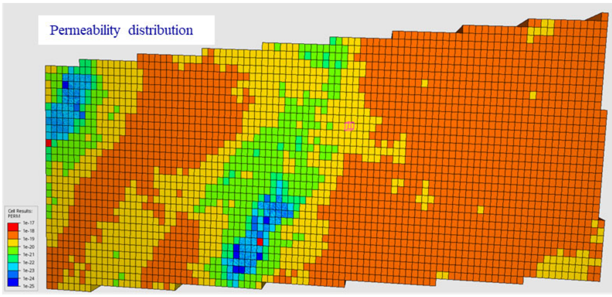

Figure 2.2 Permeability distribution

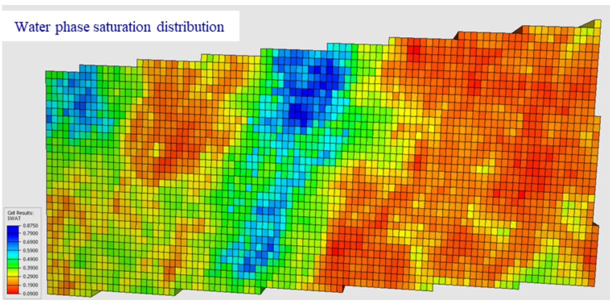

Figure 2.3 Water phase saturation distribution

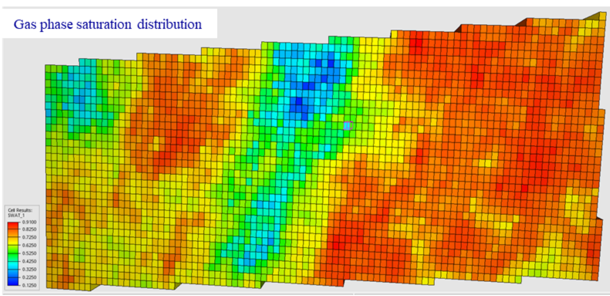

Figure 2.4 Gas phase saturation distribution

2.2 History Fitting

Calculate the bottom hole flow pressure based on the wellhead casing pressure or oil pressure and gas and water production data; use the flow pressure as the production condition to fit the daily gas production and daily water production of the gas well.

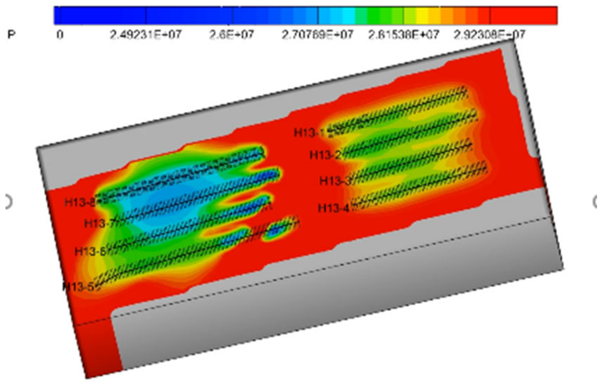

Figure 2.5 Changes in the pressure field distribution of the H1 platform

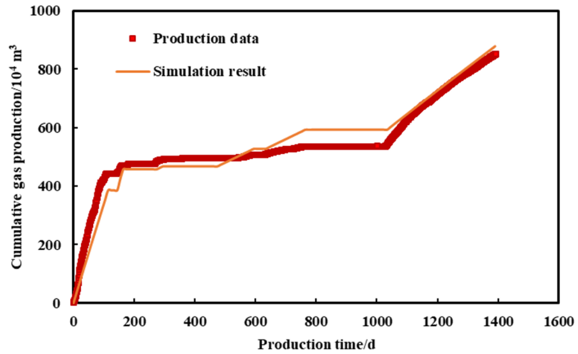

Fig. 2.6 Fitting of cumulative gas production of WH1-1

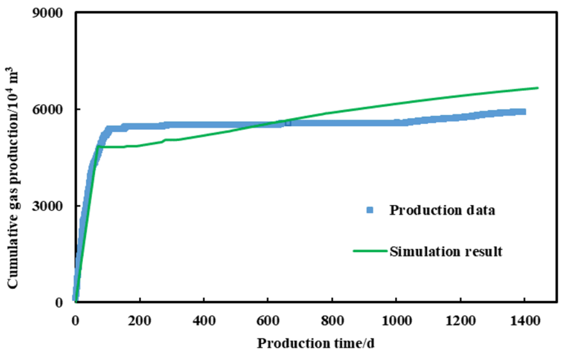

Figure 2.7 Fitting of cumulative water production in WH1-1

2.3 Production Forecast

Production prediction: This method is used to predict the production performance of the gas well 30 days after liquid accumulation, and compare it with the actual production.

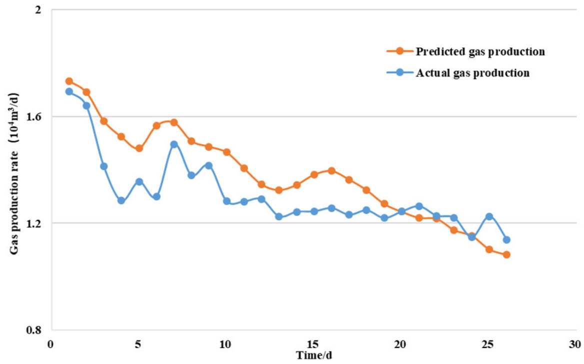

Figure 2.8 Comparison of predicted and actual production of Well WH1-2

Well WH1-2: On January 5, 2020, 16,928 m^3 of gas was produced, and it was diagnosed as fluid accumulation. After 26 days of production, the well was shut down on January 30 due to high transmission pressure and pressure control. The average error of forecasting gas production within 26 days is 5.79%.

Table 2.1 Summary of comparison between actual production and prediction of liquid-loaded wells on WH1 platform

	Forecast start date	Forecast end date	Forecast days	Forecast mean error	Take measures
WH1-1	2019.8.27	2019.9.8	13	9.82%	intermittent production
WH1-2	2020.1.5	2020.1.30	26	5.79%	Well shut-in and pressure control
WH1-4	2022.5.8	2022.5.31	24	6.14%	Drainage and rebirth
WH1-5	2020.12.28	2020.1.26	30	6.06%	Effusion production
WH1-6	2020.3.27	2020.4.7	11	-4.87%	intermittent production
WH1-7	2020.6.7	2020.6.26	20	9.86	intermittent production

As shown in Table 2.1, this method is used to predict the production dynamics of 6 wells on the WH1 platform after liquid accumulation, and compare with the actual production. The average error of gas production prediction is 7.1%, and the prediction coincidence rate is 92.9%.

3 Conclusion

In this paper, on the basis of a full investigation of relevant literature, according to the permeability mechanism of shale gas reservoirs, the productivity of horizontal wells in low-permeability gas reservoirs is studied, and an integrated dynamic simulation model of gas reservoir wellbore is established. And the historical fitting and dynamic forecasting are carried out, and the results are in good agreement with the actual situation. this method is used to predict the production dynamics of 6 wells on the WH1 platform after liquid accumulation, and compare with the actual production. The average error of gas production prediction is 7.1%, and the prediction coincidence rate is 92.9%.

https://doi.org/10.1051/e3sconf/202341601003

References

1. Clossman P J. An Aquifer Model for Fissured Reservoirs[J]. Society of Petroleum Engineers Journal. 1975, 15(05): 385-398.
2. Abdassah D, Ershaghi I. Triple-Porosity Systems for Representing Naturally Fractured Reservoirs[J]. SPE Formation Evaluation. 1986, 1(02): 113-127.
3. Zhang M, Yao J, Sun H, et al. Triple-continuum modeling of shale gas reservoirs considering the effect of kerogen[J]. Journal of Natural Gas Science and Engineering. 2015, 24.
4. Azom P N, Javadpour F. Dual-Continuum Modeling of Shale and Tight Gas Reservoirs[C]. 2012.
5. Ozkan E, Raghavan R, Apaydin O G. Modeling of Fluid Transfer from Shale Matrix to Fracture Network[C]. 2010.
6. Watson A T, Gatens J M I, Lee W J, et al. An Analytical Model for History Matching Naturally Fractured Reser
7. voir Production Data[J]. SPE Reservoir Engineering. 1990, 5(03): 384-388.
8. Kucuk F, Sawyer W K. Transient Flow In Naturally Fractured Reservoirs And Its Application To Devonian Gas Shales[C]. 1980.
9. Kazemi H. Pressure Transient Analysis of Naturally Fractured Reservoirs with Uniform Fracture Distribution[J]. Society of Petroleum Engineers Journal. 1969, 9(04): 451-462.
10. Barenblatt G, Zheltov, Kochina I N. Basic Concepts in the Theory of Seepage of Homogeneous Liquids in Fissured Rocks[J]. PMMM. 1960, 24: 5-1303.