Optimization of pressure drop model for shale gas wells in area X based on correlation coefficient method

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Abstract: The bottom hole pressure is an important parameter in the production process of a gas well, and it is of great significance to many aspects such as gas well productivity evaluation, dynamic analysis and production allocation. A large number of shale gas wells in area X were lack of the bottom hole pressure data. In order to solve this problem, based on extensive research in many articles, this paper selected eight kinds of calculation models as candidate objects, such as Hagadorn-Brown and Beggs-Brill. Different models were used to calculate the bottom hole pressure of only two shale gas wells with measured pressure data in this area, and the calculated results were compared with the measured data to select the best model for calculating the bottom hole pressure of shale gas wells in area X. In the optimization analysis, it was found that the conventional average relative error comparison method or the graph comparison method could not reflect the application situation of the calculation models well in this area. Therefore, on the basis of the two comparison methods, the correlation coefficient method was introduced to quantify the overall difference between the calculated pressure and the measured pressure. The results showed that the calculated result of Orkiszewski model fitted the measured pressure best.

1.Introduction

The flow mechanism of shale gas reservoirs in area X was complex. At present, a large number of shale gas wells in this area were lack of bottom hole pressure parameters, which brought difficulties for gas well productivity evaluation. In order to solve the problem of pressure loss, this paper used the theory and calculation method of multiphase pipe flow to solve the problem. According to the analysis of articles at home and abroad, many scholars have done a lot of research work to solve the bottom hole pressure. For example, for the problem of vertical pipe flow, the Hagedorn-Brown model can be used to calculate the bottom hole pressure. For the problem of inclined pipe flow, the Beggs-Brill model can be used to calculate the pressure drop of pipe flow with different inclined angles. Due to the different pressure drop models proposed to solve the actual problems, their focus was also different, resulting in different model calculation results. In order to determine which model was most suitable for solving the pressure of gas wells in area X, this paper analyzed and compared the eight models, and selected the best model for area X. Solved the problem of lack of bottom hole pressure of gas wells in this area.

2.Study on calculation model of multiphase pipe flow
(1)Hagadorn-Brown model
The main feature of Hagedorn Brown model was that there was no need to divide the flow regime. The model was a pressure drop model based on the experimental data of two-phase flow in small diameter. The liquid holdup was obtained by a large number of field experiments, and the friction coefficient was modified. The model was suitable for water producing gas wells\textsuperscript{[1]}.

(2) Beggs-Brill model

Based on the experimental analysis and theoretical derivation of the flow characteristics of air and water in an inclined polypropylene pipe, Beggs & Brill proposed the Beggs-Brill model. The model studied the influence of inclined pipe inclination on liquid holdup and pressure drop, and established the correlation between liquid holdup and friction coefficient, which was suitable for pressure drop calculation of pipe flow with different inclination\textsuperscript{[2]}.

(3) Mukherjee-Brill model

Mukherjee- Brill model was a further study of Beggs-Brill model. This model proposed a friction coefficient correlation considering liquid holdup and non slip friction coefficient for annular fog flow. In the lower layer flow, it assumed smooth interface and calculated pressure drop gradient through two-phase momentum balance\textsuperscript{[3]}.

(4) Gray model

One of the characteristics of the Gray model was that there was no need to divide the flow regime. This model was proposed on the basis of the actual data analysis of more than one hundred wells on site, and was mainly suitable for condensate gas wells. It was found that for the data with low gas-liquid ratio, the Gray model calculation results were often small\textsuperscript{[4]}.

(5) Orkiszewski model

Orkiszewski model was suitable for the calculation of two-phase pressure drop in a wide range of well conditions. This model was a further study of Griffith & wallisll method. In this method, the liquid holdup comes from the observed physical phenomena, which made the results more objective and reasonable. At the same time, it was pointed out that the pressure drop gradient was related to the distribution of flow pattern. And 148 measured pressure drop were used to verify the model. It was found that the calculation accuracy of the model was about ten percent. The model was suitable for vertical well section\textsuperscript{[5]}.

(6) Duns-Ros model

The Duns-Ros model was a model based on the analysis and fitting of a large number of experimental data. The model needed to consider both flow pattern and slippage, which was suitable for the pressure drop calculation of condensate gas wells. The model had better applicability for short pipe sections, and it must be calculated by sections for deep wells\textsuperscript{[6,7]}.

(7) Aziz-Govier-Fogarasi model

The Aziz-Govier-Fogarasi model was a pressure drop calculation method based on mechanics, and the proposed method was more consistent with the flow mechanism. The model was modified on the basis of the flow pattern diagram of Govier et al, which made the boundaries of each flow pattern clear and easy to identify, and it was suitable for programming calculation\textsuperscript{[8]}.

(8) Ansari model

The Ansari model was composed of a prediction model and a set of mechanism models, which could predict the pressure drop of bubble flow, annulus flow, etc. The rationality of the model was verified by analyzing the measured data of 1712 wells. It was mainly used in vertical oil and gas wells, and generally used in gas wells\textsuperscript{[9, 10]}.

3. Calculation model analysis of two wells in area X

At present, only two wells in area X have been tested for bottom hole pressure. For these two wells, the bottom hole pressure were calculated by using the above eight calculation models\textsuperscript{[11-15]}. The results were shown in Table 1, Table 2 and Figure 1 and Figure 2.
Table 1 Measured pressure and model calculated pressure of X-1 (unit: MPa)

| $q_{sc}$ 10^4 m³/d | Measured pressure | H-B | B-B | M-B | Gray | Orkiszewski | Duns-Ros | Aziz-Govier-Fogarasi | Ansari |
|---------------------|-------------------|-----|-----|-----|------|------------|---------|----------------------|-------|
| 4.70                | 26.65             | 25.26 | 32.74 | 28.98 | 30.24 | 29.99 | 30.27 | 25.73 | 29.03 |
| 5.84                | 24.57             | 18.81 | 31.79 | 24.08 | 26.74 | 26.92 | 27.41 | 19.66 | 25.08 |
| 7.37                | 22.52             | 20.78 | 29.34 | 25.09 | 25.38 | 25.47 | 26.02 | 21.29 | 24.41 |
| 9.23                | 21.47             | 16.12 | 29.37 | 20.89 | 23.98 | 24.04 | 24.61 | 16.78 | 21.53 |
| 9.55                | 19.35             | 17.76 | 27.4  | 22.09 | 22.06 | 22.18 | 22.99 | 17.97 | 20.59 |

Table 2 Measured pressure and model calculated pressure of X-2 (unit: MPa)

| $q_{sc}$ 10^4 m³/d | Measured pressure | H-B | B-B | M-B | Gray | Orkiszewski | Duns-Ros | Aziz-Govier-Fogarasi | Ansari |
|---------------------|-------------------|-----|-----|-----|------|------------|---------|----------------------|-------|
| 4.99                | 22.61             | 18.44 | 26.25 | 21.56 | 26.06 | 26.06 | 27.06 | 19.21 | 24.46 |
| 6.98                | 22.13             | 16.09 | 23.08 | 18.68 | 22.3  | 22.36 | 23.64 | 16.58 | 20.02 |
| 8.81                | 20.52             | 14.32 | 20.6  | 16.44 | 19.17 | 19.06 | 20.74 | 14.62 | 17.32 |
| 11.65               | 18.77             | 12.09 | 17.46 | 13.59 | 15.11 | 14.74 | 17.02 | 12.17 | 14.08 |

Figure 1 Comparison of measured pressure and calculated pressure of each model in X-1

Figure 2 Comparison of measured pressure and calculated pressure of each model in X-2

From the analysis of Fig. 1 and Fig. 2, it could be found that for the two wells in area X, the pressure values were different when using different calculation models, but they all fluctuate near the measured pressure. It indicated that all kinds of calculation models have certain credibility in this area.
Therefore, for area X, when the gas well production data was short, a certain calculation model could be used to calculate the pressure to meet the needs of the site. In order to better compare which model is more suitable for the pressure calculation in the area X, further research is needed.

4. Optimization of calculation model for area X

The most commonly used method for the optimization of the calculation model is the average relative error comparison method or the graph comparison method[16-18].

In this paper, the relative error was represented the absolute value of the difference between the calculated pressure and the measured pressure, and then expressed in percentage form. Assuming that the calculated pressure of the model is \(a\) and the measured pressure is \(b\), the relative error can be expressed as

\[
\delta = \left| \frac{a - b}{b} \right| \times 100\% (1)
\]

The graph comparison method is to draw the measured pressure and the calculated pressure of each model into a graph, and judge the most suitable calculation model by observing the distribution of data points of each model.

However, in the process of model optimization, it was found that these two methods would have some problems in the model optimization of area X. The specific analysis results of each calculation model were shown in Table 3, Table 4 and Figure 3, Figure 4.

Table 3 Analysis of relative error between model calculated pressure and measured pressure of X-1

| \(q_{sc} \times 10^4\)m³/d | H-B | B-B | M-B | Gray | Orkiszewski | DunsRos | AzizGovier-Fogarasi | Ansari |
|-----------------------------|-----|-----|-----|------|-------------|--------|---------------------|-------|
| 4.70                        | 5.22% | 22.85% | 8.74% | 13.48% | 12.53% | 13.61% | 3.43% | 8.93% |
| 5.84                        | 22.76% | 32.24% | 0.17% | 11.23% | 11.98% | 14.02% | 18.22% | 4.33% |
| 7.37                        | 7.72% | 30.31% | 11.42% | 12.70% | 13.11% | 15.57% | 5.45% | 8.42% |
| 9.23                        | 24.91% | 36.82% | 2.70% | 11.71% | 12.01% | 14.63% | 21.80% | 0.29% |
| 9.55                        | 8.25% | 41.60% | 14.16% | 14% | 14.60% | 18.81% | 7.13% | 6.37% |
| Average relative error      | 13.77% | 32.76% | 7.44% | 12.62% | 12.85% | 15.33% | 11.21% | 5.67% |

Table 4 Analysis of relative error between model calculated pressure and measured pressure of X-2

| \(q_{sc} \times 10^4\)m³/d | H-B | B-B | M-B | Gray | Orkiszewski | DunsRos | AzizGovier-Fogarasi | Ansari |
|-----------------------------|-----|-----|-----|------|-------------|--------|---------------------|-------|
| 4.99                        | 18.43% | 16.08% | 4.65% | 15.26% | 15.28% | 19.69% | 15.06% | 8.16% |
| 6.98                        | 27.29% | 4.31% | 15.61% | 0.76% | 10.4% | 6.80% | 25.06% | 9.55% |
| 8.81                        | 30.19% | 0.41% | 19.88% | 6.59% | 7.10% | 1.08% | 28.75% | 15.59% |
| 11.65                       | 35.57% | 6.99% | 27.62% | 19.48% | 21.48% | 9.31% | 35.14% | 25.01% |
| Average relative error      | 27.87% | 6.95% | 16.94% | 10.52% | 11.23% | 9.22% | 26% | 14.58% |

Analyzing Table 3 and Table 4, it could be found that for a certain calculation model, the average relative error comparison method was less effective in judging the degree of difference between the calculated pressure of the model and the measured pressure. The result showed that in the actual operation process, due to the influence of environmental conditions and human factors, the proportion of each work system could not reach the same condition, and the average relative error could not show the differences caused by these factors.
From the analysis of Fig. 3 and Fig. 4, it could be found that the applicability of a certain calculation model could be roughly judged from a macro perspective by drawing and analyzing the measured pressure and the calculated pressure of each model. However, this method required a high level of professional knowledge of analysts themselves, so that the most suitable calculation model could be judged by combining graphics and comprehensive factors. Therefore, the method was greatly influenced by human factors, and the final judgment results of different analysts may be quite different. This method did not quantitatively analyze the difference between the calculated data of various models and the measured data.

Therefore, in order to further described the difference between the calculated pressure and the measured pressure of each model, the correlation coefficient method was introduced to study the most suitable calculation model in area X\cite{19,20}. The correlation coefficient ($r$) expressed the degree of correlation between different variables. In this paper, the correlation coefficient method was to analyze the linear correlation degree between calculated pressure ($A$) and measured pressure ($B$) of different models. The formula could be expressed as

$$r(A, B) = \frac{\text{Cov}(A, B)}{\sqrt{\text{Var}(A)\text{Var}(B)}}$$  \hspace{1cm} (2)$$

where $\text{Cov}(A, B)$ is the covariance of $A$ and $B$; $\text{Var}(A)$ is the variance of $A$; $\text{Var}(B)$ is the variance of $B$. 

![Figure 3 Comparison of measured pressure and model calculated pressure of X-1](image)

![Figure 4 Comparison of measured pressure and model calculated pressure of X-2](image)
The correlation coefficient method was used to analyze the correlation coefficient between the calculated data of each model and the measured data of two wells in area X. The specific analysis results were shown in Table 5.

Table 5 Correlation coefficient comparison of two wells in area X

|       | X-1          |          | X-2          |          |
|-------|--------------|----------|--------------|----------|
|       | Correlation coefficient | Correlation coefficient |
| Measured pressure | 1 | Measured pressure | 1 |
| Orkiszewski     | 0.9929       | Orkiszewski     | 0.9784       |
| Duns-Ros        | 0.9922       | Duns-Ros        | 0.9749       |
| Gray            | 0.9886       | Gray            | 0.9743       |
| B-B             | 0.9844       | B-B             | 0.9699       |
| Ansari          | 0.9655       | M-B             | 0.9695       |
| M-B             | 0.8420       | H-B             | 0.9670       |
| Aziz-Govier-Fogarasi | 0.8210   | Aziz-Govier-Fogarasi | 0.9662   |
| H-B             | 0.7831       | Ansari          | 0.9480       |

Quantitative analysis of two wells in area X showed that, for X-1, the Orkiszewski model, the Duns-Ros model, the Gray model had a higher degree of correlation with the measured data; for X-2, the Orkiszewski model, the Duns-Ros model and the Gray model were highly correlated with measured data. Through the analysis of the relative error results of each model, graph comparison results and correlation coefficient comparison results of the two wells, it was considered that the Orkiszewski model had a better calculation result of bottom hole pressure in area X.

5. Conclusion

(1) On the basis of Database analysis, this paper analyzed eight kinds of pipe flow calculation models, and used these models to calculate the bottom hole pressure of two gas wells in shale gas reservoir of area X. The results showed that each model could reflect the bottom hole pressure to a certain extent, but the difference between the calculated pressure and the measured pressure was not clear;

(2) The average relative error method and the graph comparison method could not quantitatively and compare the difference between the measured bottom hole pressure data and the model calculation data under different production systems of gas wells in area X. These two methods had certain limitations;

(3) The correlation coefficient method was used to optimize the correlation degree between each model data and the measured data, and the Orkiszewski model was determined to be the most suitable model for calculating the bottom hole pressure of gas wells in shale gas reservoirs in area X.

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