Evaluation Method for Gas Injection and Production Capacity of PG2 Gas Storage

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Abstract: ***PG2 gas storage is a gas storage rebuilt from a volatile oil reservoir, and its injection-production capacity evaluation method has a certain guiding role for other gas storage of the same type. According to the gas reservoir characteristics of PG2 gas storage, the node analysis method is used to evaluate the injection and production capacity of PG2 gas storage. The critical liquid carrying flow rate and erosion flow rate are coupled to the inflow and outflow curve, and the reasonable injection and production gas volume of the gas well is ultimately determined through the coordination point and limit curve of the inflow and outflow curve. Research shows that PG2 gas storage is suitable for 4 ½ Size of tubing with a reasonable gas production rate of 40 × 10^4~ 70 × $10^4 m^3/d$, with a reasonable gas injection rate of 48 × 10^4 ~ 82 × $10^4 m^3/d$。 This study provides a reference for reasonably selecting completion tubing sizes and controlling wellhead pressure during multi cycle injection and production.***

Keywords: Node analysis; Critical liquid carrying flow rate; Erosion flow rate; Injection production capacity analysis chart

1. Foreword

PG2 Block is located in the Bohai Bay Rim and the Beijing-Tianjin-Hebei Integrated Collaborative Development Economic Circle. The structure of this block is an anticlinal structure complicated by faults, with large reservoir thickness and good physical properties. The overlying direct mudstone cap layer is thick, and it is a vertically connected block volatile oil reservoir. Currently, water injection development has achieved good results and is in the middle stage of water injection development, with a large residual potential. However, due to the impact of water injection, water invasion, and dissolved gas, the current distribution of oil, gas, and water is complex. Although the construction of domestic gas reservoirs has a history of more than 20 years, there is little experience in reservoir construction, and reservoir construction is far more complex than gas reservoirs. Therefore, how to achieve optimal multi cycle production and injection allocation is the key to the stable and efficient operation of gas storage[1-2].

2. Improved Nodal Analysis Method

The node analysis method was proposed by Gilbert in the mid-1950s, and is a comprehensive analysis method aimed at improving economic benefits. Among them, determining the bottom or wellhead as the solution node is the most commonly used analysis method. This solution node will divide the entire production system into inflow and outflow parts for solution. According to the relationship between the pressure and production at the upstream and downstream of the solution node, draw the relationship curve between the pressure and production at the upstream of the solution node and the relationship curve between the pressure and production at the downstream of the solution node in the same coordinate system, calculate the intersection point of the two curves (i.e., the coordination point of the inflow and outflow curves), and then compare them with the erosion flow rate, critical liquid carrying flow rate, and other limiting conditions to obtain appropriate values [3-5], The resulting node inflow and outflow curve is shown in Figure 1.

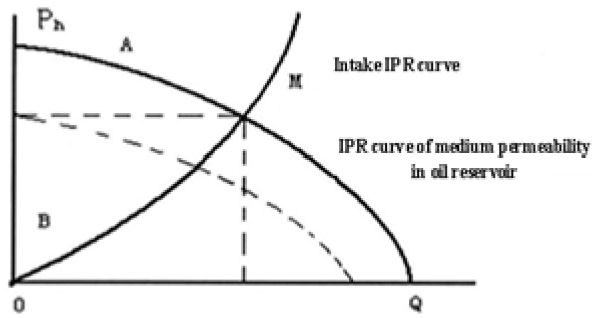

Figure 1: IPR and OPR curves

However, in order to reduce workload and improve the evaluation efficiency of gas storage injection and production capacity, constraints are coupled to inflow and outflow equations respectively, which can directly determine reasonable production and injection allocation, as shown in Figure 2.

As can be seen from Figure 2, during gas production, due to the impact of the critical liquid carrying flow rate and erosion flow rate, the range where the left and right ends of the outflow curves 1, 2, 3, and 4 lie outside the limit curve is not desirable. Taking Curve 4 as an example, under the conditions of satisfying Curves 5 and 6, the reasonable gas production corresponding to the intersection point is 170 × 10^4、197 × $10^4 m^3/d$, but there is no intersection with curves 7 and 8. The reasonable gas production is taken as 220 at the intersection of curve 4 and erosion flow × $10^4 m^3/d$。

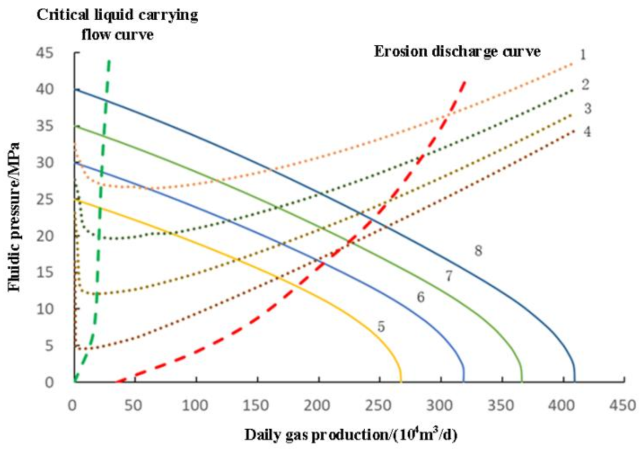

Figure 2: Injection production capacity analysis chart

1) Inflow and outflow performance of gas wells

Considering the geological characteristics of the gas storage in Block PG2, a single well inflow performance model is established, and the injection and production capacity of a single well is determined by combining the vertical pipe flow equation, erosion flow equation, and critical liquid carrying flow equation.

2) Formation inflow equation

Using the plane radial flow model and Darcy's quasi stable seepage formula, it is deduced that [6]:

$$Q_{Rl} = \frac{K_{rl}}{\mu_l} \cdot T \cdot \left(P_{ws} - P_{wf}\right) \tag{1}$$

Among

$$T = \frac{2\pi kh}{C_1\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + S\right]} \tag{2}$$

$$C_1 = \frac{14.7 \times 0.3048^2}{86400 \times 10^{-10}} \tag{3}$$

Where Q_{Rl} is the fluid flow rate under this phase condition, $10^4m^3/d$; l is the oil, water, or gas phase; K_{rl} is the relative permeability of oil, water, or gas, mD; μ_l is the viscosity of oil, water, or gas, mPa · s; P_{ws} is the reservoir pressure, MPa; P_{wf} is the bottom hole flow pressure, MPa; k is the reservoir permeability, mD; h is the effective thickness of the reservoir, m; r_e is the discharge radius, m; r_w is the wellbore radius, m; S is the skin factor.

For multiphase fluid outflows, the total inflow can be written as the sum of multiphase fluid outflows:

$$Q_R = Q_{RO} + Q_{RW} + Q_{RG} \tag{4}$$

Therefore, the total flow rate of multiphase fluid under this phase state condition is:

$$Q_R = \left(\frac{K_{rO}}{\mu_O} + \frac{K_{rW}}{\mu_W} + \frac{K_{rG}}{\mu_G}\right) \cdot T \cdot \left(P_{ws} - P_{wf}\right) \tag{5}$$

(1) For liquid flow (oil, water flow), the outflow flow is:

$$Q_L = \frac{Q_R}{B_L} = \frac{Q_{RO}}{B_L} + \frac{Q_{RW}}{B_L} = \frac{2\pi kh(p_{ws} - p_{wf})}{C_1\mu_L B_L\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + S\right]} \tag{6}$$

Where: Q_L is the liquid flow rate, $10^4m^3/d$; B_L is the liquid volume coefficient; μ_L is the liquid viscosity, mPa s.

(2) For gas flow, the volume coefficient of the gas can be expressed in terms of pressure and temperature:

$$B_G = \frac{V}{V_s} = \frac{ZRT}{P} \cdot \frac{P_s}{Z_s RT} \tag{7}$$

The formation pressure is taken as the average deep pressure in the formation:

$$P = \frac{p_{ws} + p_{wf}}{2} \tag{8}$$

Therefore, the outflow flow of gas is:

$$Q_G = \frac{Q_R}{B_G} = \frac{2\pi kh(p_{ws}^2 - p_{wf}^2)}{C_2\mu_G TZ\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + S\right]} \tag{9}$$

Among

$$C_2 = \frac{2C_1 Z_s P_s}{T_s} = 2\pi \cdot 1422 \tag{10}$$

Where: Q_G is the gas flow, $10^4m^3/d$; B_G is the volume coefficient of the gas; μ_G is the viscosity of the gas, mPa s;

The gas storage in Block PG2 is a massive volatile oil reservoir, and there was no relevant gas seepage test in the early stage of reconstruction, lacking corresponding test data. The natural gas productivity equation obtained using

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the above model:

$$q_g = \frac{kh(p_{ws}^2 - p_{wf}^2)}{1422\mu_g TZ\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + S\right]} \quad (11)$$

Where: q_g refers to natural gas production, $10^4 m^3/d$; k is the effective permeability of the reservoir, mD; p_{ws} is the average reservoir pressure, MPa; p_{wf} is the bottom hole flow pressure, MPa; r_e is the supply boundary radius, m; r_w is the radius of the drilled hole, m; Z is the gas deviation coefficient; μ_g is the gas viscosity, MPa; T is the reservoir temperature.

3) Vertical pipe flow equation

The outflow performance of a gas production well is determined by the vertical pipe flow equation [7]:

$$p_{wf}^2 = p_{wh}^2 e^{2s} + 1.3243\lambda q_g^2 T_{av}^2 Z_{av}^2 (e^{2s} - 1)/d^5 \quad (12)$$

Inflow performance equation of injection wells:

$$p_{wf}^2 = p_{wh}^2 e^{2s} - 1.3243\lambda q_g^2 T_{av}^2 Z_{av}^2 (e^{2s} - 1)/d^5 \quad (13)$$

Among, $s = 0.03415\frac{\gamma_g D}{T_{av} Z_{av}}$;

Where: p_{wf} is the wellhead pressure of the tubing, MPa; p_{wh} is the tubing wellhead pressure, MPa; q_g refers to natural gas production, 104m3/d; T_{av} is the average temperature of the dynamic gas column in the wellbore, K; Z_{av} is the average deviation coefficient of the dynamic gas column in the wellbore; d is the inner diameter of the tubing, cm; γ_g is the relative density of natural gas; D is the depth in the middle of the gas layer, m; λ is the tubing resistance coefficient; S is the skin factor.

In Equations 12 and 13, since Z_{av} is a function of T_{av} and p_{av}, and p_{av} depends on p_{wh} and p_{wf}, the calculation requires repeated iterations.

4) In-pipe erosion flow equation

Erosion refers to the abrasion and destruction of the pipe body by acidic substances such as CO_2 and H_2S carried by the gas and solid particles. Too high a gas flow rate can cause erosion of the pipe string, so it is necessary to control the gas flow rate below a certain range to reduce or avoid erosion. Currently, in the evaluation of the injection-production capacity of gas reservoirs, the calculation of erosion flow is mainly based on the APIRP14E recommended formula [8]:

$$q_e = 3.3\times10^{-4} Cd^2 \left(\frac{p}{ZT\gamma_g}\right)^{0.5} \quad (14)$$

Where:; q_e refers to erosion gas production, $10^4 m^3/d$, and d refers to inner diameter of oil pipe, m; C is the empirical coefficient, with a value of 100 for continuous, non corrosive, and non solid systems; p is wellbore pressure, MPa; Z is the average deviation coefficient of the dynamic gas column in the wellbore; T is the average temperature of the dynamic gas column in the wellbore, K; γ_g is the relative density of natural gas.

5) Critical liquid carrying flow equation

Minimum liquid carrying gas production using Turner formula [9]:

$$q_{sc} = 2.5\times10^4 \times \frac{p_{wf} V_g A}{ZT} \quad (15)$$

Where: q_{sc} refers to erosion gas production, $10^4 m^3/d$; $A = \pi d^2/4$ is the internal cross-sectional area of the tubing, m2; P_{wf} is the bottom hole flow pressure, MPa.

$$V_g = 1.25\times\left[\frac{\sigma(\rho_L - \rho_g)}{\rho_g^2}\right]^{0.25} \quad (16)$$

Where: V_g is the critical velocity of gas carrying liquid, m/s; ρ_L is the liquid density, kg/m3, taking

$\rho_w = 1074kg/m^3$ for water and $\rho_o = 894kg/m^3$ for crude oil; σ is the interfacial tension, taking $\sigma_w = 60mN/m$ for water and σ=20mN/m for crude oil.

$$\rho_g = 3.4844 \times 10^3 \frac{\gamma_g p_{wf}}{ZT} \tag{17}$$

Where: ρ_g is the gas density, kg/m^3; T is the air flow temperature, K.

3. Evaluation of reasonable gas injection and production capacity

3.1 Evaluation of formation seepage capacity

The porosity of the PG2 block reservoir is 15%; The effective permeability of the reservoir is 18.9mD. From the phase permeability curve obtained after multiple rounds of injection and production, it is determined that the maximum phase permeability of residual oil to gas after multiple rounds of injection and production is 0.59 [10] on average, and based on this calculation, the effective permeability of gas is 11.15mD; The temperature is 157 ℃; The relative density of natural gas is 0.615; The average thickness of the oil layer is 36.4m. Using formation inflow equation (11), the productivity curves of vertical wells under different formation pressures are calculated, as shown in Figure 3.

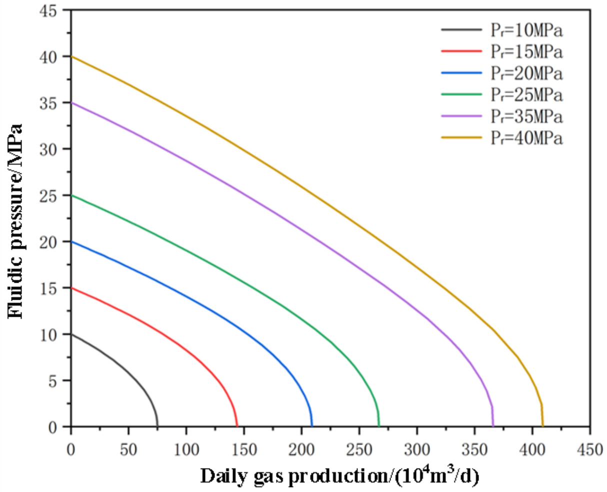
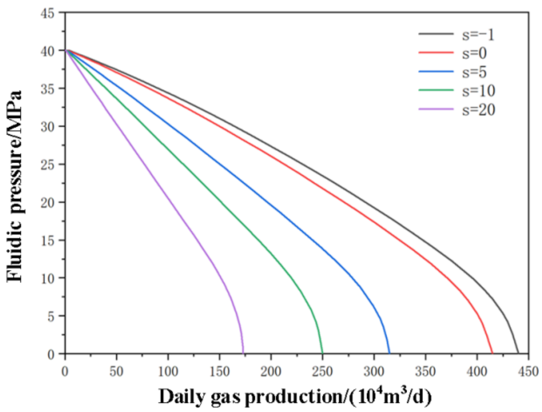


Figure 3: Productivity curves of vertical wells under different formation pressures

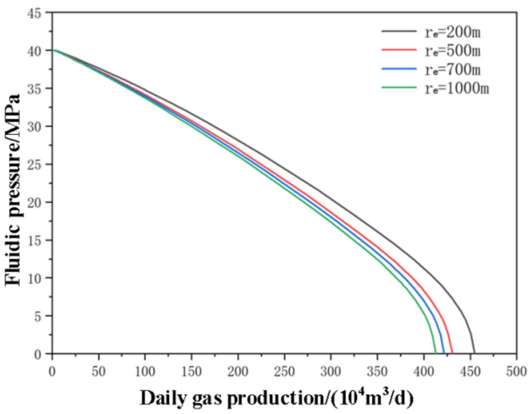
From Figure 3, it can be seen that the PG2 reservoir has a strong seepage capacity after construction. When the formation pressure is 40MPa, its open flow rate is 410× 10^{4}m^3/d。

Based on the fact that the construction of the PG2 block reservoir is in the early evaluation stage and some parameters are not yet available, sensitivity analysis has been conducted on the factors affecting productivity. The productivity curves of vertical wells with skin coefficients of - 1, 0, 5, 10, and 20 and formation pressure of 40 MPa are calculated, as shown in Figure 4a. It can be seen that the skin has a significant impact on the productivity of gas wells. When the skin factor is 20, the open flow rate is 170× 10^{4}m^3/d。 In addition, consider the impact of different discharge radii (200, 500, 700, and 1000 m respectively) on the productivity of gas wells, as shown in Figure 4b. It can be seen from the figure that the larger the discharge radius, the smaller the open flow rate, but the open flow rate is all above 400 × 10^{4}m^3/d.

In comprehensive consideration, the construction of reservoir in PG2 block has a strong seepage capacity of the reservoir. When analyzing the injection and production capacity of a gas well, it is only necessary to consider the optimization of the injection and production gas string.



a. Different skin factors



b. Different discharge radii

Figure 4: Sensitivity analysis

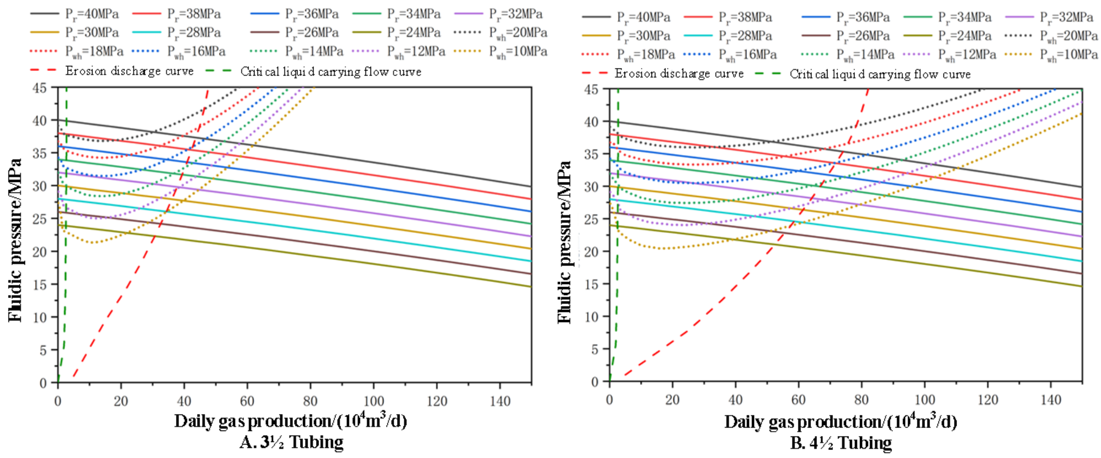
3.2 Reasonable gas production

During the gas production process, consider the bottom hole as a node and use equation set (18) to solve the reasonable gas production under different formation pressures, wellhead pressures, and tubing sizes, as shown in Figure 5.

$$\begin{cases} q_{g(i)} = \dfrac{kh(p_{ws(i)}^2 - p_{wf(i)}^2)}{1422\mu_G TZ\left[\ln\left(\dfrac{r_e}{r_w}\right) - \dfrac{3}{4} + S\right]} \\ p_{wf(i)}^2 = p_{wh(i)}^2 e^{2s} + 1.3243\lambda q_{g(i)}^2 T_{av}^2 Z_{av}^2 (e^{2s} - 1)/d^5 \\ q_{rg(i)} \le q_{e(i)} \\ q_{rg(i)} \ge q_{sc(i)} \end{cases} \tag{18}$$

Where: $q_{g(i)}$ is the daily gas production, $10^4 m^3/d$; $p_{ws(i)}$ is the formation pressure, MPa; $p_{wf(i)}$ is the bottom hole flow pressure, MPa; $q_{rg(i)}$ is the reasonable gas production, $10^4 m^3/d$; $q_{e(i)}$ is erosion flow, $10^4 m^3/d$; $q_{sc(i)}$ is the critical liquid carrying flow rate, $10^4 m^3/d$.

As shown in Figure 5, the range of inflow and outflow performance curves obtained by using the node analysis method with the bottom hole as a node is affected by the critical liquid carrying flow rate and erosion flow rate, and cannot be obtained beyond the limit flow rate. The intersection of the inflow and outflow curves is the reasonable gas production rate under certain tubing size, wellhead pressure, and formation pressure conditions.



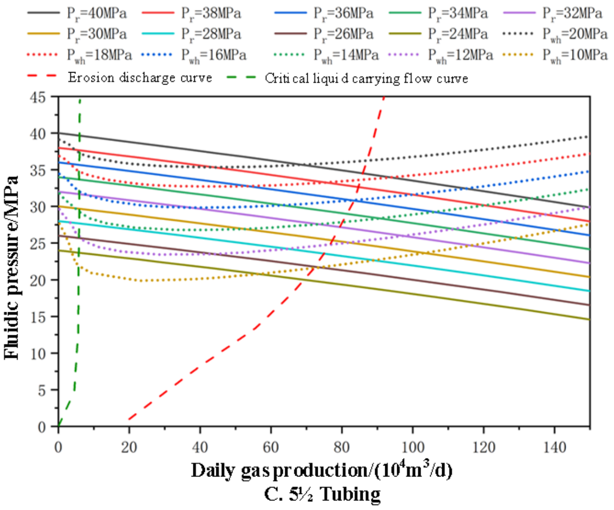


Figure 5: Analysis of Gas Production Nodes with Different Tubing Sizes

3.3 Reasonable gas injection rate

The method of injection allocation is similar to production allocation, and the flow process of gas injection can be considered as the reverse flow of gas production. During gas injection, consider the bottom hole as a node, and use equation set (19) to solve the reasonable gas injection amount under different formation pressures, wellhead pressures, and tubing sizes, as shown in Figure 6.

$$\begin{cases} q_{g(j)} = \dfrac{kh(p_{wf(j)}^2 - p_{ws(j)}^2)}{1422\mu_G TZ\left[\ln\left(\dfrac{r_e}{r_w}\right) - \dfrac{3}{4} + S\right]} \\ p_{wf(j)}^2 = p_{wh(j)}^2 e^{2s} - 1.3243\lambda q_{g(j)}^2 T_{av}^2 Z_{av}^2 (e^{2s} - 1)/d^5 \\ q_{rg(j)} \le q_{e(j)} \end{cases} \tag{19}$$

Where: $q_{g(j)}$ is the daily gas production, $10^4 m^3/d$; $p_{wf(j)}$ is the bottom hole flow pressure, MPa; $p_{ws(j)}$ is the formation pressure, MPa; $q_{rg(j)}$ is the reasonable gas

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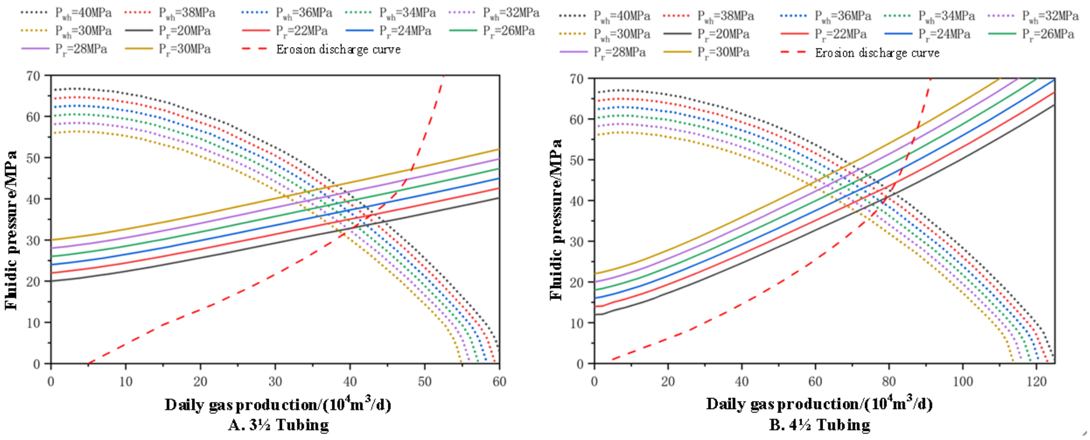
production, $10^4m^3/d$; $q_{e(j)}$ is erosion flow, $10^4m^3/d$;

It can be seen from Figure 6 that due to the restriction of erosion flow, the inflow and outflow performance curve with the bottom hole as a node cannot exceed the erosion flow, where the intersection of the inflow flow curve is the reasonable gas injection rate under certain tubing size, wellhead pressure, and formation pressure conditions.



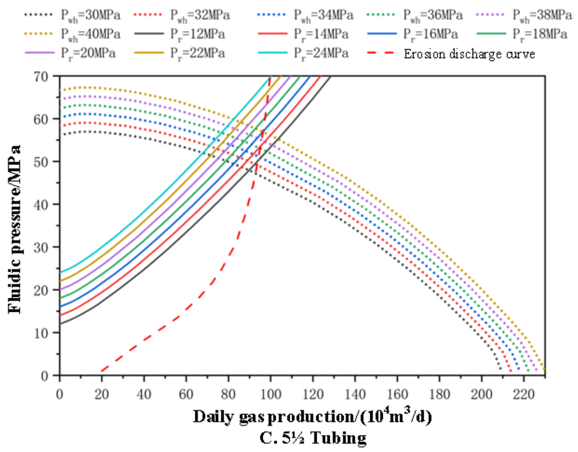


Figure 6: Analysis of Gas Injection Nodes with Different Tubing Sizes

3.4 Optimization of tubing size

The reasonable gas injection and production volumes under different conditions are determined using an improved nodal analysis method to obtain a reasonable gas injection and production volume versus tubing size and wellhead pressure change curve, as shown in Figure 7. As can be seen from Figure 7a, when the tubing size remains unchanged, the reasonable gas production rate increases with the increase in wellhead pressure; When the wellhead pressure is constant, the reasonable gas production rate increases with the increase of tubing size, but 5 ½ Size of tubing heel 4 ½ The increase in size of tubing is relatively small. As can be seen from Figure 7b, when the tubing size remains unchanged, the reasonable gas injection rate increases with the increase in wellhead pressure, but the increase is small; When the wellhead pressure is constant, the reasonable gas injection rate increases with the increase of tubing size, but 5 ½ Size of oil pipe is smaller than 4 ½ The increase in tubing size is small.

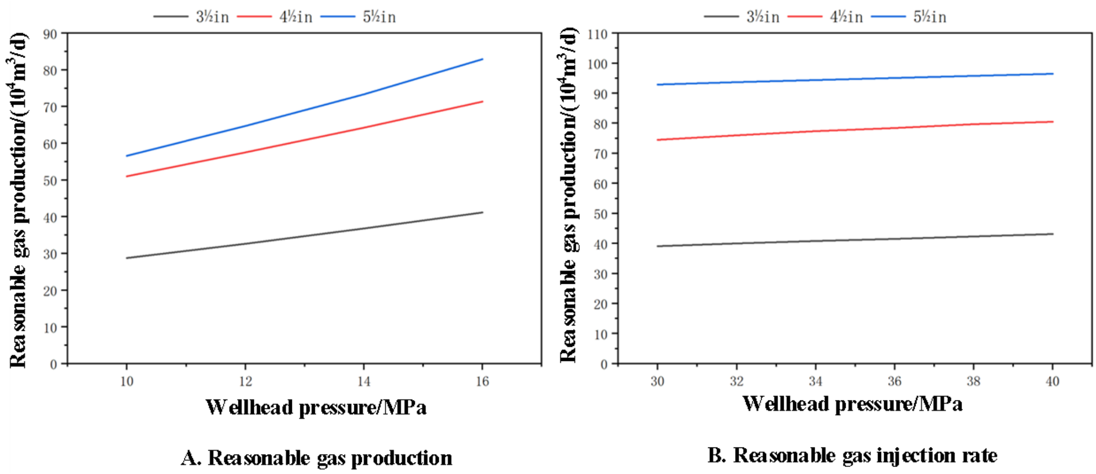


Figure 7: Reasonable gas injection and production volume varying with wellhead pressure under different pipe diameters

Through analysis, it can be seen that the larger the tubing size, the stronger the gas production capacity, and the fewer wells required under the same peak shaving capacity. However, the corresponding difficulty of drilling technology also increases, and the cost of completing a single well increases. Therefore, in order to achieve the working gas volume of the gas storage, achieve greater production capacity at low pressure, and have higher liquid carrying capacity, it is determined that the injection and production gas wells of the gas storage should adopt 4 ½ Size of tubing with a reasonable gas production rate of 40×10^4 ~ $70\times10^4 m^3/d$, with a reasonable gas injection rate of 48×10^4 ~ $82\times10^4 m^3/d$[11]-[13]]。

4. Conclusion

1) By further improving the conventional nodal analysis method, limiting conditions (critical liquid carrying flow rate and erosion flow rate) are coupled into the inflow and outflow curves analyzed by the nodal analysis method, and a set of injection and production capacity analysis charts for PG2 gas storage are established.
2) By deriving the multiphase seepage productivity equation and coupling the vertical pipe flow equation and limiting conditions, an injection production model for PG2 gas storage is obtained. By analyzing the drawn injection production capacity chart, it is determined that PG2 gas storage is suitable for using 4 ½ Size of tubing with a reasonable gas production rate of 40×10^4 ~ $70\times10^4 m^3/d$, with a reasonable gas injection rate of 48×10^4 ~ $82\times10^4 m^3/d$。

Acknowledgement

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