Research Article

Investigation on the Relationship between Wellhead Injection Pressure and Injection Rate for Practical Injection Control in CO₂ Geological Storage Projects

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The existing investigations on the maximum allowable wellhead injection pressure have found the upper limit of wellhead injection pressure, which, however, cannot provide a practical operational designing scheme of wellhead injection parameters for CO₂ geological storage projects. Therefore, this work firstly proposes the complete constraint conditions of wellbore injection to realize the whole process of forward and inverse calculations of wellbore pressure and then applies it to explore the relationship between wellhead injection pressure and injection rate. The results show that the wellhead injection pressure and the injection rate are a pair of mutually constrained physical quantities. For a certain injection project, the allowable wellhead injection pressure and injection rate separately form a continuous interval. Change of one quantity within its allowable interval will also change the other within its interval, both jointly forming a closed region. Thus, controlling the wellhead injection parameters in this closed region can simultaneously ensure the effectiveness and safety of injection. Subsequently, this work further studies the factors of impacting the relationship between wellhead injection pressure and injection rate and finds that all the temperature of injected fluid, the parameters of saturation, and the characteristic parameters of reservoirs only change their upper and lower limits to some extent but have no essential effects on their relationship. Application of this theory and method in Shenhua CCS demonstration project obtained the relationship diagram of wellhead injection pressure and injection rate, which found that its actual injection parameters just fall into the closed region of the relationship diagram, effectively verifying the reliability of this work.

1. Introduction

In the China-US joint announcement on climate change, 2014, China intended to achieve the peaking of CO₂ emissions around 2030 and to make best efforts to peak early [1]. To achieve this goal, carbon capture and storage (CCS), as one of the most effective approaches for greatly reducing CO₂ level in the atmosphere [2–5], is expected to gradually advance from demonstration project to commercialization. The general procedure of CO₂ geological storage includes site selection, well drilling, injection, monitoring, and evaluation [6, 7], among which the most key step is CO₂ injection. Therefore, it is very important to control wellbore injection parameters [8, 9]. Due to the great burial depth of the storage sites (means high temperature and high pressure),

CO₂ injection (resulting complex two-phase flow in pores and cracks), and the complexity and uncertainty of geological conditions, a great challenge to the effectiveness and safety of CO₂ injection is induced [2, 10].

Currently, it is widely accepted by engineers that controlling the maximum bottom hole pressure is practical and reliable to avoid the strata fracturing [11–13]. Based on that, the more convenient method is to control the wellhead injection pressure [13], which has been verified sufficiently in In Salah [14] and Ketzin and Shenhua CCS projects [13, 15]. To obtain the maximum allowable wellhead injection pressure for CCS projects, Carroll and Lui [16] and Hashim and Maloka [17] analyzed the main influential factors of wellhead pressure, and Streit and Hillis [18], Rutqvist et al. [10], and Gapillou et al. [19] proposed some approximate

estimation methods and engineering experience. Subsequently, Bai et al. [8] developed a new fast explicit finite difference method (FEFDM) for calculating the wellhead pressure under assumption of single reservoir, and Wu et al. [20] presented a new estimation method of wellbore pressure from the perspective of engineering. However, many CCS projects still use the typical approach referring from the field of enhanced oil recovery (EOR) and sour gas reinjection for the advantages of simplicity and extensive application experience [21], although there are four obvious shortcomings [13]. Therefore, Bai et al. [13] developed a methodology for determining the maximum allowable wellhead injection pressure based on the precious work recently, which includes the control conditions for bottom hole safety, the inversion method of wellhead pressure, and the design coefficients on the basis of engineering experience and analogy. It is available for multireservoirs injection simultaneously. However, it is worthy to concern that the above investigations are mainly focused on the wellhead injection pressure, especially on the maximum allowable wellhead injection pressure, which ignores the wellhead injection rate. Although the injection rate is usually set as the project target, it is also a significant parameter of injection control. What is more, no investigation has addressed the relationship between wellhead injection pressure and injection rate.

Thus, as to a determined target injection flow, the above methods of designing wellhead injection pressure can only provide the maximum allowable wellhead injection pressure. However, the actual wellhead injection pressure must be less than its maximum value in consideration of safety, so how much should the applicable wellhead injection pressure be? Could any wellhead injection pressure bellowing the maximum allowable wellhead injection pressure ensure that the target injection flow will enter the reservoirs completely? Of course, the answer is no. That is to say, the applicable wellhead injection pressure not only has an upper limit but also has a lower limit. Only the pressure of ranging from the lower limit to the upper limit can ensure that the target injection flow will enter the reservoirs completely. Another question is how does the applicable wellhead injection pressure change when the target injection flow changes? It would be transferred to the schema of constant pressure controlling; thus the problem is how to determine the applicable target injection flow under knowing the wellhead injection pressure. Apparently, to answer these questions exactly, it is necessary to investigate the wellhead injection pressure and the injection rate simultaneously and to master the internal relationship between wellhead injection pressure and injection rate clearly. In addition, to facilitate the application in projects, it is worthy to study their influential factors.

Therefore, this work will firstly improve the constraint conditions of wellbore injection from the perspective of flow rate to realize the whole process of forward and inverse calculations of wellbore pressure and then explore the relationship between wellhead injection pressure and injection rate and its influential factors. Finally, we apply this method to Shenhua CCS demonstration project to find the feasible ranges of wellhead injection pressure and injection rate and to verify the reliability of this work simultaneously.

FIGURE 1: Schematic of the injection well and its related reservoirs.

2. Theory and Method

2.1. Constraint Conditions of Wellbore Injection. Figure 1 shows the schematic of injection wellbore and its related reservoirs. There is one injection well and N layers of reservoir-caprock combination units from top to bottom. The wellbore is divided into N segments by the reservoir-caprock unit. The reservoir-caprock units, reservoirs, caprocks, and well segments are numbered as $1, 2, \dots, N$ from top to bottom. In the following, the subscript i denotes the corresponding physical quantities of the i th reservoir-caprock unit, the superscript r indicates the physical quantities within the reservoir, and the superscript w marks the physical quantities within the well segments.

As described in Bai et al. [13], when CO_2 is injected at a given wellhead injection pressure P_{WH} [Pa] into the injection well, the flow not only should satisfy its related fluid dynamics equations but also should not damage the stratum. Moreover, the injection rate C_{WH} [kg/s] should reach the preset target injection flow. These are enough for the inverse calculation of wellhead injection parameters based on the bottom hole conditions, whereas for the forward calculation of wellbore pressure and flow rate distribution on the basis of wellhead injection parameters, they are not enough because the forward calculation is unable to ensure that the injected fluid will enter reservoirs completely only from the perspective of pressure. Therefore, to realize the process of forward calculation, C_{WH} must be less than the total available capacity of all the reservoirs and the actual flow rate of each reservoir also must be below its available capacity; then the effectiveness and safety of injection can be ensured.

Hence, the complete constraint conditions of wellbore injection are

$$\begin{aligned} P_{0i} + P_{bi} &< P_{ki} \leq [P_{ki}] \\ M_0 &\leq C_{\text{WH}} = \sum C_i \leq \sum [C_i] \\ C_i &\leq [C_i], \end{aligned} \quad (1)$$

where P_0 is the formation pressure (Pa), P_b is the capillary pressure (Pa), P_k is the pressure on the interface of wellbore and reservoir (Pa), $[P_k]$ is the maximum allowable pressure of reservoir (Pa), M_0 is the target injection flow rate (kg/s), C denotes the actual flow rate of the reservoir (kg/s), and $[C]$ denotes the available capacity of reservoir (kg/s).

The first inequality of (1) is the constraint condition about pressure. The maximum allowable pressure is a reduced value of fracturing pressure [22]; details can be found in Bai et al. [13]. The other two inequalities represent the constraint conditions about flow rate. And the second one is focused on the total flow rate, which requires the injection rate to be higher than the design target but lower than the total available capacity of all the reservoirs. The third one requires the actual flow rate of each reservoir to be within its available capacity. Obviously, when the third inequality is satisfied, the right half of the second one is met naturally, while the left half of the second one could be confirmed in the feasibility study of project. Therefore, the constraint conditions about flow rate are equivalent to the third inequality in essence. Furthermore, in the actual calculations, only the available capacity of the bottom reservoir needs to be checked because the capacity of the other reservoirs is just equal to their actual flow rate, which is calculated by the following calculation method. Therefore, they always satisfy (1). It should be noted that the above constraint conditions did not involve the caprocks, which are beyond our discussion.

2.2. Calculation Method. As mentioned above, inverting wellhead parameters based on the bottom hole conditions only can find their maximum value, which, however, can only be used as the upper limit of injection control. Therefore, in practical operation, it is necessary to directly calculate the wellbore pressure and flow rate distribution according to the given wellhead injection parameters and then to judge whether the injection is safe and effective. It is a forward calculation process. The fast explicit finite difference model (EFDM) from wellhead to bottom can be derived based on the continuity equation of steady flow, the motion equation of vertical wellbore, and the state equation of fluid [8, 9] as follows:

$$P_{j+1} = P_j + \frac{(\Delta x g (P_j^3 M / RT_j Z_j) - (\Delta x \gamma \bar{C}_j^2 RT_j / 2D) (Z_j P_j / M))}{(P_j^2 - (\bar{C}_j^2 RT_j / M) Z_j)}, \quad (2)$$

where P is the wellbore pressure (Pa); $\bar{C}$ is the mass flow rate of wellbore cross section (kg/m²/s); Δx is the differential element (m); g is the acceleration of gravity (m/s²); D is the interior diameter of injection tube (m); M is the molar mass of gas (kg/mol); R is the universal gas constant; γ is the friction coefficient; Z is the compression factor; and T is the temperature (K). The subscript j is the number of differential elements within a certain well segment.

CO₂ is injected from wellhead through wellbore into the reservoirs; due to the presence of brine in the reservoir pores, the flow changes into two-phase flow [23–25]. In accordance

with the two-phase flow theory, the fluid-rock characters determine the relative permeability of each phase [26–29]. The functional relationship of the flow rate flowing into the i th reservoir and the pressure can be obtained under the assumption of steady flow [27], or

$$C_i^r = 2\pi k_i B_i \rho_i^w \cdot \frac{P_{ki} - P_{0i}}{(1/\lambda_{ci}) \ln(R_{ci}/r_0) + (1/\lambda_{wi} - 1/\lambda_{ci}) + (1/\lambda_{wi}) \ln(R_{0i}/R_{maxi})}, \quad (3)$$

where R_0 is the maximum influence radius of flow in the reservoir (m); R_c and R_{max} are the maximum radii of CO₂ plume at the bottom and top of the reservoir (m), respectively; r_0 is the tubing radius (m); k is the absolute permeability of the reservoir (m²); B is the thickness of the reservoir (m); φ is the porosity of the reservoir; ρ is the density of CO₂ (kg/m³); λ_c is the mobility of CO₂ (m·s/kg); and λ_w is the mobility of brine (m·s/kg).

On the basis of (2) and (3), to realize the multireservoir injection simultaneously, the equilibrium condition of flow at the reservoir node is still required. It could be simplified into the flow rate allocation under the condition of constant pressure because all junctions of reservoirs and wellbore are regarded as the equivalent nodes of flow rate allocation and the wellbore pressure between the top and bottom of the reservoir is assumed to be a constant in this work. Hence, the equilibrium condition of flow of the i th equivalent node is that the inflow amount of CO₂ equals the sum of outflow to the next well segment and inflow into the i th reservoir. Then, combined with (3), the flow rate allocation relationship at the equivalent node can be deduced as follows [13]:

$$\bar{C}_i^w = \frac{2k_i B_i \rho_i^w}{r_0^2} \cdot \frac{P_{ki} - P_{0i}}{(1/\lambda_{ci}) \ln(R_{ci}/r_0) + (1/\lambda_{wi} - 1/\lambda_{ci}) + (1/\lambda_{wi}) \ln(R_{0i}/R_{maxi})} + \frac{\rho_i^w}{\rho_{i+1}^w} \bar{C}_{i+1}^w. \quad (4)$$

When (4) is applied to the N th reservoir (the bottom reservoir), due to the absence of outflow, the second term of right hand should be considered as zero. Then, according to (4), the available capacity of the bottom reservoir can be determined. And the actual flow rate of the bottom reservoir is obtained by (4) with $i = N - 1$. So that when the latter is not more than the former, the constraint conditions about flow rate are satisfied.

2.3. Calculation Procedure. There are two basic control models on fluid injection, namely, the constant pressure and the constant flow rate. For constant pressure, the allowable interval of flow rate should be solved; and as for constant flow rate, the problem is how to obtain the allowable interval of pressure. However, the results under different control models are the same. Therefore, this work chooses the control model of constant pressure as an example to explore the relationship between wellhead injection pressure and injection rate. The calculation procedures of forward calculation process are listed as follows:

TABLE 1: The parameters of reservoir-caprock combination units.

Reservoir number	Reservoir thickness (m)	Caprock thickness (m)	Reservoir permeability ($\times 10^{-3} \mu\text{m}^2$)	Reservoir porosity (%)	Fracturing pressure (MPa)	Formation pressure (MPa)
1	10	1400	6	12	35	15
2	10	200	5	11	38	17
3	10	200	4	10	41	19
4	10	200	3	9	44	21

TABLE 2: The simulation injection design schemes.

Injection design schemes	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
P_{WH} (MPa)	15	14.49	14	13	6	5	4.83	4.5
C_{WH} (kg/s)	0~9	0~9	0~9	0~9	0~2.5	0~2.5	0~1.1	0~2.5

Notes. The calculation step of C_{WH} in (a), (b), (c), and (d) is 0.1 kg/s; for (g) it is 0.02 kg/s; for (e), (f), and (h) it is 0.05 kg/s.

- (1) Set P_{WH} .
- (2) Set the initial C_{WH} .
- (3) Compute the wellbore pressure according to (2); compute the flow rate of flow into the reservoir according to (3) and renew the flow rate of flow to the next well segment according to (4) when the calculation reaches to the reservoir.
- (4) Judge whether the computed results at the equivalent node meet the constraint condition of (1). If “Yes,” execute the subsequent calculation; if “No,” go to Step (5). After finishing all calculation process, if the calculated results meet all the corresponding inequality conditions in (1), the corresponding P_{WH} and C_{WH} are the feasible wellhead injection parameters.
- (5) Renew C_{WH} ; repeat Step (3) to Step (4) until both the upper and lower limits of feasible C_{WH} under the condition of P_{WH} are found; if there is no feasible C_{WH} (indicating that P_{WH} cannot achieve injection), go to Step (6).
- (6) Renew P_{WH} ; repeat Step (2) to Step (5) to find the upper and lower limits of feasible P_{WH} .
- (7) Plot the relationship diagram between P_{WH} and C_{WH} according to the results.

3. Relationship between Wellhead Injection Pressure and Injection Rate

3.1. Parameters and Injection Schemes. In the following, this work supposed an analysis case to explore the relationship between P_{WH} and C_{WH} . There are four reservoirs and one injection well with a depth of 2000 meters in this case. Table 1 lists the reservoir-caprock combination units and the characteristic parameters of the reservoirs. The values of thickness, permeability, and porosity of reservoirs are determined by engineering experience, which represent the typical characteristic (small thickness, low porosity, and low permeability) of reservoirs in China. They could be updated for research.

FIGURE 2: Distribution of wellbore pressure at different injection rates.

First, it is necessary to present the wellbore pressure distribution for a determined P_{WH} under different C_{WH} to analyze the characteristics of the wellbore pressure distribution, as shown in Figure 2. Here P_{WH} is given as 13 MPa, while C_{WH} are 0.1, 1, and 6 kg/s.

It is clear from Figure 2 that (1) the wellbore pressure increases approximately linearly with the well depth; the bigger C_{WH} is, the more obviously the pressure increases; when C_{WH} enlarges to a certain value, the wellbore pressure above the reservoirs barely changes with C_{WH} ; (2) the wellbore pressure distribution changes linearly and continuously with C_{WH} , showing no inflection point; thus it is appropriate to use the variation trend of wellbore pressure at one point to represent the variation trend of pressure in the whole wellbore. Therefore, in the following, the change in pressure on the interface of wellbore and reservoir is adopted to replace that of the whole wellbore.

Table 2 shows the simulation injection schemes. When P_{WH} is great enough, the lower limit of the constraint conditions about pressure expressed by the left part of the

first inequality in (1) is clearly met, so the four injection schemes (a), (b), (c), and (d) in Table 2 are adopted to study the variation rule of pressure on the interface of wellbore and reservoir with C_{WH} in the condition of no reservoir fracturing. The calculation results are shown in Figures 3(a)–3(d). Subsequently, with P_{WH} reducing, the constraint condition about pressure to prevent the reservoir from fracturing can be naturally satisfied and the lower limit of the constraint conditions about pressure should be considered. The four injection schemes (e), (f), (g), and (h) in Table 2 are adopted for that and the calculation results are shown in Figures 3(e)–3(h).

3.2. Results Analysis. There are two types of curves shown in Figures 3(a), 3(b), 3(c), and 3(d): the pressure curves and the flow rate curves. The former are used to analyze whether the calculated results meet the upper limit of the constraint conditions about pressure, and the latter are used to analyze whether the calculated results meet the constraint conditions about flow rate. The specific analyses are shown below.

(1) The dense data segments in the figure result from one-tenth of calculation step, which verified that no oscillation singularities existed in the calculations. It aims to accurately find the intersection and its corresponding C_{WH} .

(2) In Figures 3(a), 3(b), and 3(c), with C_{WH} changing, there is an interval that $P_{k1} > [P_{k1}]$; as for the other reservoirs, the similar intervals basically disappear or are included in the interval of the first reservoir, which indicates that the critical reservoir [13, 30] is the first one under the above described injection conditions. Hence, only the intersections of the curve P_{k1} and the curve $[P_{k1}]$ are shown in Figures 3(a)–3(d) as the basis for the following discussions.

(3) With C_{WH} changing, all the pressure curves P_{ki} show the same varying trend of upward convex parabola with obvious peak. Based on the above analysis and with Figure 3(a) as an example, the intersections P1 and P2 of the curve P_{k1} and the curve $[P_{k1}]$ divide C_{WH} into three intervals. It looks like C_{WH} smaller than P1 or greater than P2 would meet the upper limit of the constraint conditions about pressure. However, in fact, this is not true, because the calculations are based on the assumption that the flow in the wellbore reaches to steady state at 10 days after CO₂ injection; if greatly expanding the time, even a tiny C_{WH} will make the wellbore pressure exceed the allowable pressure at some points. Therefore, as for P_{WH} whose P1 is located before the peak point, C_{WH} less than P1 could not be used as the design scheme of the gas injection projects. Moreover, whether C_{WH} higher than P2 can be used as the design scheme still needs to be determined by the constraint conditions about flow rate, which can be judged by the flow rate curves of the last reservoir. Apparently, C_{WH} at the left side of intersection F1 of the flow rate curves meet this condition, while C_{WH} at the right side does not. Therefore, for determined P_{WH} , its corresponding C_{WH} that can be used as the design scheme of gas injection must belong to the interval of $[P2, F1]$. Among the above schemes, in Figure 3(a), F1 is smaller than P2, indicating that there is no feasible C_{WH} under this P_{WH} ; that is, this P_{WH} has exceeded the maximum allowable

wellhead injection pressure; in Figure 3(b), F1 is equal to P2, indicating that this P_{WH} is the maximum allowable wellhead injection pressure; in Figure 3(c), F1 is greater than P2, corresponding to the general cases; in Figure 3(d), only F1 exists but there is no intersection of pressure curves, revealing that no matter how C_{WH} changes, the constraint conditions about pressure will be always met under this P_{WH} ; therefore the corresponding interval of flow rate is $(0, F1]$. It is predictable that the feasible interval of C_{WH} remains $(0, F1]$ with continuous reduction of P_{WH} , although F1 will decrease with P_{WH} declining.

Figures 3(e)–3(h) are basically consistent with Figures 3(a)–3(d) except that the pressure curves in Figures 3(e)–3(h) show the lower limit of the constraint conditions about pressure. According to Figures 3(e)–3(h), (1) as for each injection scheme, the intersections of curve P_{k1} and curve P_{01} correspond to the minimum C_{WH} , indicating that the injection to the first reservoir is most easily realized. Therefore, the lower limit of the constraint conditions about pressure can be transferred into that as long as $P_{k1} > P_{01}$; the injection is achievable. (2) Similarly, conclusion (1) is only focused on the constraint conditions about pressure, and the constraint conditions about flow rate still need to be met. In summary, the feasible interval of C_{WH} is $[0, F1]$ in Figure 3(e), $[F1, F2]$ in Figure 3(f), and $F1$ in Figure 3(g) and does not exist in Figure 3(h), revealing that P_{WH} in Figure 3(g) is corresponding to the minimum achievable wellhead injection pressure. It is predictable that gradually increasing P_{WH} from the minimum achievable wellhead injection pressure will expand the feasible range of C_{WH} , which is consistent with the relationship between P_{WH} and C_{WH} in the consideration of no reservoir fracturing. In the process of one increasing with the other decreasing, they will coincide eventually.

The two above-mentioned types of injection schemes represent two limit zones in the relationship diagram between P_{WH} and C_{WH} , respectively. Similarly, the middle P_{WH} and C_{WH} can also be obtained, plotting them in one figure, that is, the relationship diagram between P_{WH} and C_{WH} , as shown in Figure 4, where the red and blue lines represent the upper and lower limits of the interval of flow rate under constant pressure injection, respectively; both of them jointly form a closed region. And the closed region forms the wellhead injection parameters domain of simultaneously meeting the constraint conditions about pressure and flow rate. Hence theoretically, as long as controlling the wellhead injection parameters falling in the closed region, the safe and effective injection can be achieved. In addition, the left intersection of curves represents the lower limit of constraint conditions about pressure, where the CO₂ fluid is just able to be injected into the reservoir completely. And the right one represents the upper limit of constraint conditions about pressure, in which just no reservoir would fracture. The feasible flow rate corresponding to these two intersections is unique and determined. Therefore, the wellhead injection parameters should be away from the intersections and close to the middle region as much as possible when designing the injection schemes, which will bring a greater allowable interval for pressure and flow rate, and then the projects will be safer.

FIGURE 3: Continued.

FIGURE 3: Curves of pressure and flow rate on the interface of wellbore and reservoir along with injection rate.

FIGURE 4: Relationship diagram between wellhead injection pressure and injection rate.

4. Influential Factors of Wellhead Injection Pressure and Injection Rate

4.1. Overview. The influential factors can be classified into two parts: the human-controllable factors and the engineering geological factors, as shown in Figure 5. The former mainly refer to the temperature of injected fluid T_0 determined by the engineers, and the latter include the factors of impacting wellbore heat transfer, impacting reservoir

capacity, and determining constraint conditions about pressure. And the last five in Figure 5 also can be considered as the characteristic parameters of reservoirs.

As for the geothermal gradient, it was studied by Lui et al. [31] in consideration of the single reservoir and they found that it affects the wellbore pressure distribution by impacting the wellbore heat transfer and only has slight effect when C_{WH} is small. Obviously, the impact of earth's surface temperature is weaker. Since the wellbore heat transfer has nothing to do with the number of reservoirs, it is acceptable that the effect of geothermal parameters on the wellbore pressure distribution can be neglected. Thereafter, the analysis case in Section 3.1 is used to study the effect of the other above-mentioned factors.

4.2. Temperature of Injected Fluid. Take the situation of $T_0 = -5^\circ\text{C}$ as the standard case, compared with the cases of $T_0 = -10, 0, 10,$ and 20°C , respectively, to study the influence of T_0 on the relationship of P_{WH} and C_{WH} with other parameters unchanged. Figure 6 shows the calculated results.

According to Figure 6, it is clear that the relationship diagrams of P_{WH} and C_{WH} under different T_0 are accordant in shape and the areas of different closed region are roughly equal. With T_0 increasing, the closed region only shows a tendency of uniformly shifting to the right. Therefore, it could be concluded that T_0 has no substantial impact on the relationship of P_{WH} and C_{WH} . Furthermore, with T_0 increasing, the allowable C_{WH} exhibits a linearly decreasing trend, and the allowable P_{WH} shows a linearly increasing trend. The reason is that a rise in T_0 causes the wellbore pressure to reduce, therefore leading to an increase in the allowable P_{WH} . Subsequently all the constraint conditions about pressure and flow rate changed, especially for the upper limit of constraint condition about pressure.

4.3. Saturation Parameters S_{lw} and S_{lc} . In the above cases, the saturation parameters S_{lc} and S_{lw} are set as 0.55 and 0.999,

FIGURE 5: The influential factors of the relationship between wellhead injection pressure and injection rate.

FIGURE 6: Relationship diagram between wellhead injection pressure and injection rate at different temperature of injected fluid.

FIGURE 7: Relationship diagram between wellhead injection pressure and injection rate at different S_{lw} .

respectively. To analyze their impact on the relationship between P_{WH} and C_{WH} , firstly it is necessary to design different values of S_{lc} and S_{lw} . Here, the Van Genuchten-Mualem Model [32] was adopted to inversely derive the parameters S_{lc} and S_{lw} . Table 3 lists the design values of S_{lc} and S_{lw} and Figures 7 and 8 show the calculation results.

Figures 7 and 8 show that (1) the parameters S_{lc} and S_{lw} just change the ranges of allowable P_{WH} and C_{WH} to some extent and have no substantial effects on the relationship between P_{WH} and C_{WH} , which is similar to T_0 . (2) With the decrease of S_{lw} , the allowable P_{WH} and C_{WH} gradually reduce, the upper limit of C_{WH} gradually closes to its lower

limit, and the effects of S_{lc} are just contrary to those of S_{lw} because the CO_2 domain and brine domain of two-phase flow are mutually restrictive. (3) The changes of the right intersection of the upper and lower limits of C_{WH} in Figures 7 and 8 have a common feature; that is, the intersection moves strictly along the track of lower limit of C_{WH} with the variable changing. And it differs slightly from that of the left intersection, which suggested that the change of S_{lc} and S_{lw} just alters the constraint conditions about the flow rate and the lower limit of pressure; however, it has no impact on the constraint conditions about the upper limit of pressure.

TABLE 3: The values of parameters S_{lw} and S_{lc} .

	A	B	C	D	E	F	G	H	I	J
S_{lc}	0.55	0.55	0.55	0.55	0.55	0.40	0.50	0.55	0.60	0.70
S_{lw}	0.9999	0.999	0.99	0.97	0.95	0.999	0.999	0.999	0.999	0.999

FIGURE 8: Relationship diagram between wellhead injection pressure and injection rate at different S_{lc} .

FIGURE 9: Relationship diagram between wellhead injection pressure and injection rate at different reservoir thickness.

4.4. Thickness, Permeability, and Porosity of Reservoirs. The thickness, permeability, and porosity of reservoirs as their inherent characteristic parameters are invariant for a given storage site, but they directly determine the capacity of the reservoir. Thus their influence that aims to generalize the above obtained conclusions to other projects is analyzed. Secondly, with CO_2 injected into the reservoir, this will cause a series of physical and chemical reactions. However, a change in load and chemical reactions with minerals will generally cause changes in the permeability and porosity of reservoirs [33–35]. Limited by the existing testing technology, the impacts of thickness, permeability, and porosity have not been taken into consideration. Tables 4–6 list the different design parameters of reservoirs, and the corresponding calculation results are shown in Figures 9–11.

On the basis of Figures 9 and 10, (1) the impacts of reservoir thickness and permeability on the relationship between P_{WH} and C_{WH} have common features: both only affect the range rather than the essence of P_{WH} and C_{WH} . With the thickness or permeability increasing, the allowable P_{WH} and C_{WH} increase at similar ratio, ascribed to their similar status in (3). (2) Of course, there are also some differences about the impact of reservoir thickness and permeability: curves B and C in the figures are not exactly the same, because the value of R_0 is also affected by the thickness but not by the permeability. (3) Curves B and C in Figure 9 do not overlap,

revealing that increase in thickness of the upper reservoir has greater effect on enlarging the allowable P_{WH} and C_{WH} in the multireservoir injection simultaneously, compared with increasing the thickness of the lower reservoir. It indicates that the injected fluid majorly enters the upper reservoirs, which is consistent with the conclusions of Rutqvist and Tsang [36], Liu et al. [31], and Xie et al. [37, 38] based on TOUGH2. Furthermore, as described above, the critical reservoir in this case is the first reservoir, which means that increase in thickness of the critical reservoir is most effective for the increase of total available capacity of the entire storage site. (4) The effect of reservoir porosity on P_{WH} and C_{WH} is limited and could be ignored according to Figure 11. (5) The traces of intersections of upper and lower limit of C_{WH} in Figures 9, 10, and 11 are in agreement with those in Figures 7 and 8, indicating that the changes caused by these five parameters are similar in essence; that is, they all indirectly change the constraint conditions about flow rate by changing the capacity of reservoirs.

4.5. Formation Pressure and Fracturing Pressure. The formation pressure in essence also affects the capacity of reservoirs; therefore it has some similarity to the five above-mentioned parameters. However, it is also different from

FIGURE 10: Relationship diagram between wellhead injection pressure and injection rate at different reservoir permeability.

FIGURE 11: Relationship diagram between wellhead injection pressure and injection rate at different reservoir porosity.

them because it also determines the lower limit of constraint conditions about pressure. Thus, it is discussed together with the fracturing pressure. Table 7 lists the different pressure conditions and Figure 12 shows the corresponding calculation results.

Comparison of curves A, B, and C shows that, with the formation pressure increasing, both allowable P_{WH} and C_{WH} decline, and the right intersection of upper and lower limits of C_{WH} still moves along the lower limit of C_{WH} . It

TABLE 4: The values of reservoir thickness.

Reservoir number	Reservoir thickness (m)			
	A	B	C	D
1	10	10	20	20
2	10	13	16	20
3	10	16	13	20
4	10	20	10	20

TABLE 5: The values of reservoir permeability.

Reservoir number	Reservoir permeability ($\times 10^{-3} \mu\text{m}^2$)			
	A	B	C	D
1	6	6	8	8
2	5	5	7	7
3	4	6	4	6
4	3	5	3	5

TABLE 6: The values of reservoir porosity.

Reservoir number	Reservoir porosity (%)		
	A	B	C
1	12	17	22
2	11	16	21
3	10	15	20
4	9	14	19

TABLE 7: The values of formation pressure and fracturing pressure.

Reservoir number	Formation pressure (MPa)			Fracturing pressure (MPa)	
	A	B	C	D	E
1	15	15.5	16	35.5	36
2	17	17.5	18	38.5	39
3	19	19.5	20	41.5	42
4	21	21.5	22	44.5	45

indicates that the formation pressure also indirectly changes the constraint conditions about flow rate by affecting the capacity of reservoirs, so there is a same feature with the five aforementioned parameters with similar characteristics. Moreover, the left part of closed region shifts toward the right when the formation pressure increases, which embodies the fact that the formation pressure directly determines the lower limit of constraint conditions about pressure. Obviously, a rise in the lower limit of pressure will naturally increase the allowable P_{WH} . Comparison of curves A, D, and E shows that, with the fracturing pressure increasing, both allowable P_{WH} and C_{WH} will increase, and only the right boundary with the initial trend and shape extends to the right. It suggests that the fracturing pressure only changes the upper limit of constraint conditions about pressure and does not affect the other conditions and parameters.

TABLE 8: The parameters of reservoir-caprock combination units in Shenhua CCS project [13].

Reservoir number	Reservoir thickness (m)	Caprock thickness (m)	Logging permeability ($\times 10^{-3} \mu\text{m}^2$)	Logging porosity (%)	Fracturing pressure (MPa)	Formation pressure (MPa)
1	9	1699	2.81	10.6	35.29	17.45
2	5	57	5.47	12.4	37.53	17.89
3	40	191	1.431	9.7	38.95	20.15
4	8	43	6.58	12.9	42.60	21.43
5	4	119	5.99	12.6	47.00	22.94
6	26	114	2.738	12.5	43.47	23.1
7	8	52	5.1	11.9	46.03	23.84
8	12	178	0.039	5.2	45.68	22.75

FIGURE 12: Relationship diagram between wellhead injection pressure and injection rate at different formation pressure and fracturing pressure.

5. Case Study: Shenhua CCS Demonstration Project

In Section 3, the relationship diagram between P_{WH} and C_{WH} was obtained through an analysis case; in Section 4, relevant factors affecting the relationship and their influential rules were found. All these indicate that the theory and method presented in this paper are scientific and effective in solving engineering problems. As follows, this work will apply the theory and method in Shenhua CCS demonstration project to obtain the ranges of P_{WH} and C_{WH} which simultaneously meet the constraint conditions of pressure and flow rate in the actual project.

The calculation parameters of the reservoir-caprock combination units in Shenhua CCS demonstration project are listed in Table 8, including 8 reservoir-caprock combination units from top to bottom and one injection well with a depth of 2450 meters. The parameters are mainly determined by

FIGURE 13: Relationship diagram between wellhead injection pressure and injection rate in Shenhua CCS project.

the logging interpretation data [13]. As mentioned above, the reservoirs are a kind of formation with small thickness, low porosity, and low permeability. The reservoirs are simplified into homogeneous and isotropous formation because we applied an analytical solution to describe the CO_2 -brine flow in the reservoirs, although the actual reservoirs have strong heterogeneity.

Figure 13 shows the calculation results. P_{WH} and C_{WH} of right intersection are 13.16 MPa and 10.31 kg/s, respectively. If the annual injection time is 300 days, the annual injection mass flow will reach 270,000 tons. Obviously, the preset annual injection of 100,000 tons for Shenhua project is achievable. The actual injection started in March 2011 and stopped in April 2015. Figure 14 shows the monitoring records of wellhead injection pressure during the formal injection

stage from March 2011 to April 2014, during which time CO_2 was injected at a constant injection rate about 4.0 kg/s. Inputting the actual injection parameters into Figure 13 finds that they all fall into the closed region except the records of initial loading process and the other two monitoring records. However, the other two abnormal pressures were induced by some unexpected circumstances, which was controlled by engineers immediately and returned to normal. Hence, it is convincing that the theory and method established by this work can withstand the practice test and are scientifically reliable. Moreover, it is necessary to note that the actual injection is very close to the upper limit curve of C_{WH} at the later period of formal injection. Although it improves the utilization efficiency of cost, any improper operation or uncontrollable factor could possibly lead to an abortive injection and subsequently a series of chain consequences. Therefore, according to the current preset annual injection target, this work recommends to control its P_{WH} at 5~7 MPa in the subsequent injection process.

In addition, according to the conclusions of Section 4 and considering the changes of relevant parameters with time, it is necessary to pay attention to the following points for the actual injection control of Shenhua CCS project. (1) T_0 is real-time measurable in the injection process. Thus if T_0 rises, it is necessary to properly reduce C_{WH} or increase P_{WH} ; if T_0 declines, it is necessary to increase C_{WH} or decrease P_{WH} . (2) Because the parameters of saturation and permeability and fracturing pressure are difficult to measure in operation, it is worthy to investigate the rules that they change with time by laboratorial experiments. Then the wellhead injection parameters should be modified based on the conclusions of experiments. (3) For a given project, the thickness of reservoirs generally does not change over time and the effect of the porosity is small enough and ignorable. As to the impacts of formation pressure, it is unnecessary to consider that because the distant boundary condition is constant pressure in this work.

6. Conclusions

To improve the control theory of the wellhead injection parameters, this work firstly developed the complete constraint conditions of wellbore injection and then studied the relationship and its influential factors between P_{WH} and C_{WH} by applying the EFDM in the vertical well segment and the analytical solution of two-phase flow in the horizontal reservoir and obtained the following conclusions.

(1) P_{WH} and C_{WH} are a pair of mutual constraint physical quantities. For a given injection project, the allowable P_{WH} and C_{WH} individually form a continuous interval. When one changes within its allowable range, the other correspondingly alters within its allowable range; both of them jointly form a closed region. Thus, controlling the wellhead injection parameters within this closed region can simultaneously ensure the effectiveness and safety of CO_2 injection.

(2) Analysis of the factors that affect the relationship between P_{WH} and C_{WH} found that all of them only change their allowable upper and lower limits to some extent but not the essence of their relationship. With the fracturing

FIGURE 14: The monitoring records of wellhead injection pressure.

pressure increasing, their allowable upper limits increase and their lower limits remain unchanged. With the formation pressure increasing, the lower limit of P_{WH} increases and its upper limit remains unchanged; in contrast, the upper limit of C_{WH} decreases. With reservoir thickness and permeability increasing, the allowable upper limits of P_{WH} and C_{WH} significantly increase, and the lower limit of P_{WH} slightly decreases. As S_{lc} enlarges or S_{lw} reduces, the impacts on P_{WH} and C_{WH} are in agreement with that of reservoir thickness decreasing. The impact of reservoir porosity is ignorable. With T_0 increasing, the allowable upper and lower limits of P_{WH} enlarge, and those of C_{WH} reduce.

(3) Application of the above theory and method in Shenhua CCS demonstration project obtained the relationship diagram of P_{WH} and C_{WH} and found that its actual injection parameters are just located in the closed region, effectively verifying the reliability of the previous conclusions. Accordingly, it is recommended that if Shenhua project keeps the current annual target injection flow rate invariant, P_{WH} would better be controlled within 5~7 MPa in the subsequent injection process.

(4) Although this work only studies the relationship between P_{WH} and C_{WH} of the injection well, the above theory and method can be generalized to study the production well, which can obtain the similar relationship between wellbore pressure and production flow, and to further explore the effects of above-mentioned influential factors on the relationship.

(5) The constraint conditions of this paper do not involve the caprocks, so when including the caprocks, the entry pressure may have a strong impact on the maximum allowable pressure of reservoirs. Then the constraint conditions may change. Therefore, further study needs to address this occasion.

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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