

An explicit integral solution for pressure build-up during CO₂ injection into infinite saline aquifers

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Abstract: The increase of fluid injection projects with large burial depths, such as CO₂ geological storage, poses a new challenge for the change law of pressure in reservoirs. To obtain the pressure of anywhere at anytime conveniently and then evaluate the injectivity and safety of reservoirs, a Darcy formulation suited for two-phase flow of displacement is put forward in this paper. A convenient and practical explicit integral (analytical) solution of pressure build-up for two-phase flow under a constant injection rate of CO₂, based on an infinite reservoir with a constant pressure boundary whose location is a function of time is then derived. Subsequently, this work compared the results of the explicit integral solution with the results of Nordbotten's approximate solution and the simulated results of TOUGH2/ECO2N for an analysis case of CO₂ injection, which demonstrated a good consistency, verifying the correctness and the reliability of the explicit integral solution. Furthermore, the sensitivity analysis of S_{ic} (the saturation of brine in the CO₂ domain) and S_{lw1} (the saturation of brine in the brine domain 1) showed that they both have a great impact on the pressure profiles in reservoirs, and the pressure is more sensitive to S_{lw1} than S_{ic} . Therefore, the determination of S_{ic} and S_{lw1} should be careful and based on the actual project in applications. Generally speaking, the explicit integral solution is simple, convenient, and practical compared with numerical simulators and other analytical solutions with similar assumptions. © 2016 Society of Chemical Industry and John Wiley & Sons, Ltd

Keywords: CO₂ geological storage; constant pressure boundary; explicit integral (analytical) solution; pressure build-up; two-phase flow

Introduction

Currently, to relieve the global energy crisis and reverse the trend of environmental deterioration, many projects related to fluid injection or production have been implemented, such as shale gas extraction, CO₂-ECBM (enhanced coal-bed methane), acid gas reinjection, hazardous waste disposal, CO₂ geological storage, geothermal resource exploitation, and more.¹⁻⁵ Because the pores

and cracks of the target strata are typically filled with much brine, the pressure in the porous medium will be increased by fluid injection.⁶ To prevent the strata from fracturing, the fluid pressure should be controlled to a certain extent. Therefore, we must understand the evolution of pressure induced by fluid injection to confirm the safety and efficiency of a project.^{7,8} When the injected fluid is completely miscible with brine, the fluid migration in the porous medium can still be regarded as single-phase flow; thus, the analytical

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solution of fluid pressure evolution can be directly obtained by applying Darcy's law in consideration with the influence of high temperature and high pressure.^{7,9} When the injected fluid is immiscible or partially miscible with brine, the fluid migration turns into a complex two-phase flow or multi-phase flow instead of a single-phase flow, and the single-phase Darcy's law is not suitable.⁹

To meet the needs of numerous projects several numerical multi-phase flow simulators, such as TOUGH2,¹⁰ OpenGeoSys,¹¹ and FEHM,¹² have been used to simulate the process of fluid injection, especially for CO₂ injection into brine aquifers. However, such simulators can be expensive to acquire and computationally intensive to run.^{13,14} Therefore, a series of simple analytical and semi-analytical methods have been developed simultaneously.^{6,9,13–31} The earliest Buckley-Leverett displacement, regarded as the origin of two-phase flow, was proposed by Buckley and Leverett¹⁵ under assumptions of incompressible flow, immiscible flow and no capillary pressure. Furthermore, Nordbotten *et al.*⁹ presented a governing equation for the composite fluid based on similar assumptions and without the vertical pressure gradient and developed a corresponding approximate solution and analytical solution. However, because the analytical solution was not integrated, numerical integration is necessary for practical applications of the solution. Consequently, Bachu *et al.*¹⁷ simplified the governing equation,⁹ directly applied Darcy's law in the CO₂ domain and the brine domain, and obtained a simple equation. However, the integrality and uniformity (the inseparability of the composite fluid composed by some pure fluids, i.e., the composite fluid cannot be regarded as the simple accumulation of pure fluids and the physical properties of them are different) of two-phase flow were neglected, which caused the integrated solution to not exist, depending on numerical methods. Moreover, this problem is still exists in the later works of Nordbotten *et al.*^{19,20} and Celia *et al.*^{21,22} Subsequently, Mathias *et al.*²⁶ followed Nordbotten's governing equation⁹ and developed an approximate solution for pressure build-up within formations of infinite radial extent during CO₂ injection by using the method of matched asymptotic expansions. Wiese *et al.*²⁷ extended the Mathias solution²⁶ to consider the relative permeability of CO₂ and residual brine saturation. Mathias *et al.*²⁸ further extended the Mathias solution²⁶ to address closed formations of finite radial extent and Mathias *et al.*¹³ extended the

Mathias solution²⁶ to consider the effect of partial miscibility, both in open and closed brine aquifers. However, the Mathias solution and the improved Mathias solutions are all based on the method of matched asymptotic expansions which is a type of infinite approximation with a complex mathematical expression, which generates some difficulties in actual application. Recently, Azizi and Cinar^{14,30} presented a new approximate analytical solution for pressure build-up applied under three types of outer boundary conditions of the formation: closed boundary, constant pressure boundary, and infinite-acting formation, while it is also an approximate solution and relatively complex. Doster *et al.*³¹ proposed an implicit pressure explicit mass finite volume method (ImPEM), which can be applied to multi-phase multi-component flow, including capillary pressure and buoyancy, but is still a numerical solution. Therefore, it is regrettable that the analytical solutions for two-phase flow mentioned above cannot acquire the explicit equation for pressure by direct integration, and can only obtain approximate solutions or numerical solutions. At the same time, these solutions are not convenient to practical project applications, though they are accurate enough. Thus, the analytical solution for two or multi-phase flow in porous media still needs further investigation.

This work aims to extend Darcy's law to two-phase flow based on Nordbotten's governing equation⁹ and to deduce an explicit integral (analytical) solution of pressure build-up for two-phase flow. Then, this paper's explicit integral solution is compared with Nordbotten's approximate solution⁹ and TOUGH2/ECO2N,³² for an analysis case of CO₂ injection, to verify the correctness and the reliability of the explicit integral solution. At last, this work investigates the sensitivity of some key parameters to obtain the appropriate value of them.

Mathematical model

Basic assumption

As already described, as the brine is displaced by CO₂ the actual flow in reservoirs turns into a two-phase flow. Thus, it is necessary to meet the basic law of two-phase flow.^{7,8} According to the seepage theory of two-phase flow, the driving force comes from the pressure differential between the two types of fluid. The relative permeability of fluid depends on its saturation.⁷ As shown in Fig. 1, it is clear that with increasing radial distance, the saturation of CO₂ in reservoirs after CO₂

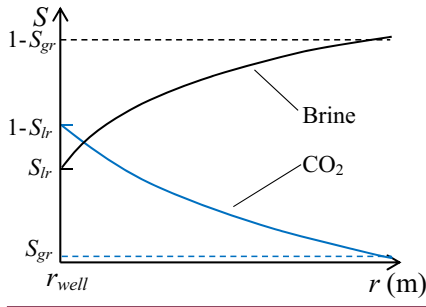


Figure 1. Schematic diagram of saturation of CO₂ and brine vs radial distance in the reservoir after CO₂ injection for a certain time (r_{well} is the radius of injection well (m), S_{lr} and S_{gr} are the residual saturation of brine and CO₂, respectively).

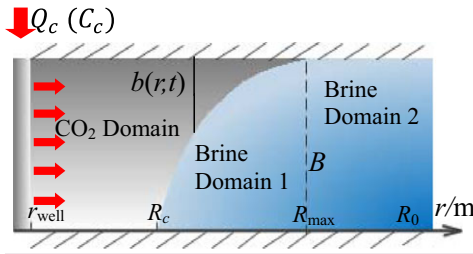


Figure 2. Schematic profile of CO₂ & brine flow in the reservoir (R_c and R_{max} are the maximum radius (m) of the CO₂ plume at the bottom and top of the reservoir after injecting CO₂ for a certain time, and R_0 is the maximum radius (m) that flow influences in the reservoir, which occurs at the outer boundary).

injection for a certain time decreases to the residual saturation S_{gr} gradually, before finally becoming equal to zero (where the CO₂ plume has not reached yet and the only fluid present is brine); while the saturation of brine is increasing gradually, it is the residual saturation S_{lr} on wellface of the injection well, and then increases to one.³² However, if completely considering the actual situation of fluid saturation in the reservoir, the work on analytical solutions is too difficult and needs to be simplified. Therefore, Nordbotten *et al.*⁹ assumed that the CO₂ and brine were divided into two zones by a sharp interface and that the CO₂ and brine are completely saturated at the two sides of the interface, as shown in Fig. 2. This means that the saturation of brine in the CO₂ domain is zero, i.e., $S_{lc} = 0$, and the saturation of brine in the brine domain

is one, i.e., $S_{lw} = 1$, without consideration of the capillary pressure. This assumption is very useful for the research of analytical solutions, and has been applied by other scholars.^{17,25–28} However, it neglects the effect of the residual saturation, which will induce a deviation to the calculation. Consequently, Nordbotten *et al.*^{19,20} and Celia *et al.*^{21,22} developed this assumption by replacing the one interface with two fronts (drying front and wetting front) of CO₂ plume to consider the residual saturation of brine. Whereas, this assumption delineates that the residual brine only exist in the region between the drying front and the wetting front, and the invading CO₂ in brine domain is ignored. In addition, which will brings a bigger difficulty of calculation than the assumption of one interface.

Therefore, to make the simplified case closer to the actual situation and easy to calculate simultaneously, this paper only follows the assumption of a sharp interface between CO₂ and brine at the range of $[r_{well}, R_{max}]$, as showed in Fig. 2, and the saturation of brine on the two sides of the sharp interface are only assumed to be constants but not zero and one because the CO₂ and brine are partial miscible,^{13,14,28} i.e., $S_{lc} = \text{constant} > 0$ because the residual brine exists in here^{13,19–22,28} and $S_{lw1} = \text{constant} < 1$ because partial CO₂ invades (dissolves) into brine domain 1²⁸ (S_{lw1} denotes the saturation of brine in the brine domain 1), respectively. The saturation of brine is equal to one at the range of $[R_{max}, R_0]$ (brine domain 2), i.e., $S_{lw2} = 1$.

With received the saturation of each fluid phase in reservoirs, the relative permeability of each fluid phase can be calculated according to the Van Genuchten-Mualem Model³³ as Eqns (1)–(4) show.

$$k_{rw} = \begin{cases} \sqrt{S_*} [1 - (1 - S_*^{1/\eta})^\eta]^2, & S_{lx} < S_{ls} \\ 1, & S_{lx} \geq S_{ls} \end{cases} \quad (1)$$

$$k_{rc} = \begin{cases} 1 - k_{rw}, & S_{gr} = 0 \\ (1 - S_{\#})^2 (1 - S_{\#}^2), & S_{gr} > 0 \end{cases} \quad (2)$$

where

$$S_* = (S_{lx} - S_{lr}) / (S_{ls} - S_{lr}) \quad (3)$$

$$S_{\#} = (S_{lx} - S_{lr}) / (1 - S_{lr} - S_{gr}) \quad (4)$$

where k_{rw} and k_{rc} denote the relative permeability of brine and CO₂, respectively; S_{lx} is the actual saturation

of brine, where subscript x identifies different domain, with $x = c$ for CO₂ domain and $x = wi$ for brine domains, $i = 1$ and 2 denote brine domain 1 and brine domain 2, respectively; S_{ls} is the volume saturation of the fluids in the porous medium, i.e., the ratio of the fluids volume to the pore volume, when the pore volume of the porous medium are occupied by the fluids completely, S_{ls} is equal to one; S_{lr} and S_{gr} are the residual saturation of brine and CO₂, respectively; η is the shape function.

Other assumptions include the following. (i) The homogeneous and isotropic reservoir extends infinitely in the horizontal direction and is overlain and underlain by thick impervious rocks, so that the outer boundary, whose location is function of time, is regarded as constant pressure, which is consistent with formation pressure. (ii) The vertical pressure gradient in the reservoir is neglected, and the CO₂ plume has radial symmetry. (iii) The injection rate is assumed to be a constant and does not consider the change of temperature in the reservoir. (iv) The fluids are incompressible, and gravity, capillary pressure and chemical reactions are neglected.

Explicit integral solution for two-phase flow: CO₂ and brine

Following the assumptions described and with the conclusion in Nordbotten *et al.*,⁹ we can obtain the following equation that governs flow of the composite fluid over the entire thickness of the formation,

$$-kB\nabla \cdot (\lambda \nabla P) = Q_c \delta(r - r_{well}) \quad (5)$$

where, Nordbotten *et al.*⁹ developed the expression of some parameters based on minimization of energy principles

$$\lambda = \frac{b(r, t)}{B} \lambda_c + \frac{(B - b(r, t))}{B} \lambda_w \quad (6)$$

$$b(r, t) = \frac{B}{\lambda_c - \lambda_w} \left(\sqrt{\frac{\lambda_c \lambda_w V_c(t)}{\phi \pi B r^2}} - \lambda_w \right) \quad (7)$$

$$V_c(t) = \int_0^t Q_c dt \quad (8)$$

where Q_c is the volumetric injection flow (m³/s), k is the absolute permeability of the reservoir (m²), B is the reservoir thickness (m), P is the pressure that governs flow of the composite fluid (Pa), λ is the total mobility

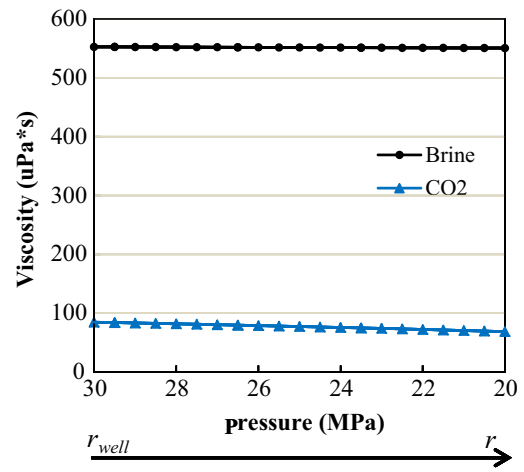


Figure 3. Curves of viscosity of CO₂ and brine along with pressure.

of the fluid ($m \cdot s/kg$), r is the radial distance far from the center of the wellbore (m), t is the injection time (s), $b(r, t)$ is the thickness (m) of CO₂ plume at the position of r in the reservoir at time t , $V_c(t)$ is the total flow into the reservoir (m³); ϕ is the reservoir porosity. The individual phase mobility is defined as the ratio of relative permeability to fluid viscosity $\lambda_\alpha = k_{r\alpha}/\mu_\alpha$, where subscript α identifies each fluid, with $\alpha = c$ for CO₂ and $\alpha = w$ for brine.

As for the viscosity of each fluid phase, which depends on the fluid type and its state, a supposed fluid temperature of 50°C and a range of pressure from approximately 20 to 30 MPa are assumed. Curves of viscosity of CO₂ and brine along with pressure can be acquired from the NIST (National Institute of Standards and Technology, USA) Chemistry WebBook,³⁴ as shown in Fig. 3. Based on Fig. 3, the effect of pressure on the viscosity of fluids is very small, especially for brine. Therefore, the viscosity of each fluid phase is regarded as constant in this paper. Consequently, it is logical to consider the mobility of each phase fluid at each domain as constant.

It is worth noting that the governing Eqn (5) is always valid whether the partial miscibility is considered or not, but the validity of Eqn (6) and Eqn (7) for solving parameters is need to be discussed further, because there is moving brine in the CO₂ domain and there is also moving CO₂ in the brine domain 1 since considering the partial miscibility. Therefore, according to the assumption of saturation, the completely total mobility should be expressed as Eqn (9):

$$\lambda = \begin{cases} \lambda_c + \lambda_w & , \quad r_{well} \leq r < R_c \\ \frac{b(r, t)}{B} (\lambda_c + \lambda_w) + \frac{(B - b(r, t))}{B} (\lambda_{c1} + \lambda_{w1}), & R_c \leq r < R_{max} \\ \lambda_{w2} & , \quad R_{max} \leq r \leq R_0 \end{cases} \quad (9)$$

where, since the flow field is divided into three domains and the saturation of brine at each domain is different, hereinafter, we use λ_w , λ_{w1} and λ_{w2} denote the mobility of brine in CO₂ domain, brine domain 1 and brine domain 2, respectively; and use λ_c and λ_{c1} denote the mobility of CO₂ in CO₂ domain and brine domain 1, respectively.

brine in the CO₂ domain and the relative permeability of CO₂ in the brine domain 1 both are nearly close to zero based on Fig. 4, which means that λ_w and λ_{c1} can be regarded as zero. Hence, Eqn (6) and Eqn (7) are also valid in this case, Eqn (9) can be simplified into Eqn (10) which is the equivalent form of Eqn (6):

$$\lambda = \begin{cases} \lambda_c & , \quad r_{well} \leq r < R_c \\ \frac{b(r, t)}{B} \lambda_c + \frac{(B - b(r, t))}{B} \lambda_{w1} = \frac{b(r, t)}{B} (\lambda_c - \lambda_{w1}) + \lambda_{w1} = \sqrt{\frac{\lambda_c \lambda_{w1} V_c(t)}{\phi \pi B r^2}} & , \quad R_c \leq r < R_{max} \\ \lambda_{w2} & , \quad R_{max} \leq r \leq R_0 \end{cases} \quad (10)$$

Actually, the difference between Eqn (9) and Eqn (6) is whether λ_w and λ_{c1} are equal to zero. We have known the viscosity of each fluid phase can be regarded as constant, thus, whether λ_w and λ_{c1} are equal to zero or not that depends on the relative permeability. Consequently, according to Eqns (1)–(4), curves of relative permeability of CO₂ and brine along with saturation of brine were presented in Fig. 4. Generally, the S_{lc} is between S_{lr} and 0.7 (or 0.6), and the S_{lw1} is between $1 - S_{gr}$ and 1, thus, the relative permeability of

As mentioned in the introduction, two different approaches are presented to solve the differential Eqn (5) in Nordbotten *et al.*⁹ The first is a type of approximate solution, dividing the sharp interface of CO₂ and brine into N layers, and then directly applying Darcy’s formula within each layer; the second uses the calculus of variations, based on minimization of energy principles, to obtain an analytical solution described in integral form. However, this analytical solution cannot be integrated because the object function of integrand cannot be found; thus, it is cannot be calculated directly by integration. Therefore, this approach just verifies the existence of an analytical solution in theory, while the specific calculation still relies on the numerical integration, which has a large limitation in practical application. Consequently, it is necessary to find other methods. Bachu *et al.*¹⁷ simplified Eqn (5) into a Darcy’s formula by directly introducing the individual phase mobility into Darcy’s law, as shown in Eqn (11),

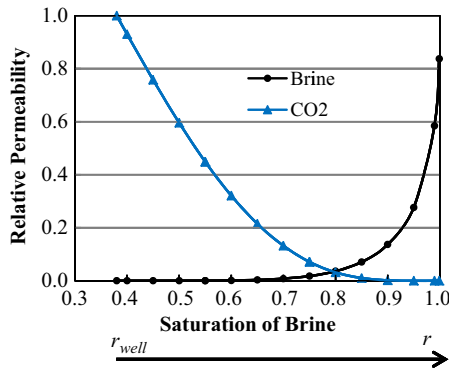


Figure 4. Curves of relative permeability of CO₂ and brine along with saturation of brine (The parameter values of Eqns (1)–(4) are $\eta = 0.44$, $S_{ls} = 1$, $S_{lr} = 0.38$, $S_{gr} = 0.05$).

$$Q_\alpha = -2\pi r k b_\alpha(r, t) \lambda_\alpha \frac{\partial P_\alpha}{\partial r} \quad (11)$$

for a fixed time, Eqn (11) can be further described as

$$dP_\alpha = -\frac{Q_\alpha}{2\pi k b_\alpha(r, t) \lambda_\alpha r} dr \quad (12)$$

supposed the pressure at the point of R_{max} in the reservoir is P_c , integrating Eqn (12) in CO₂ domain,

$$\int_{P_k}^{P_c} dP_c = \int_{r_{well}}^{R_{max}} \frac{-Q_c}{2\pi k b_c(r, t) \lambda_c} \frac{1}{r} dr \quad (13)$$

we can obtain

$$\begin{aligned} P_k - P_c &= \frac{Q_c}{2\pi k \lambda_c} \left[\int_{r_{well}}^{R_c} \frac{1}{Br} dr + \int_{R_c}^{R_{max}} \frac{1}{b_c(r, t)r} dr \right] \\ &= \frac{Q_c}{2\pi k \lambda_c} \left[\frac{1}{B} \ln \frac{R_c}{r_{well}} + \int_{R_c}^{R_{max}} \frac{1}{\frac{B}{\lambda_c - \lambda_{w1}} \left(\sqrt{\frac{\lambda_c \lambda_{w1} V_c(t)}{\phi \pi B}} \frac{1}{r} - \lambda_{w1} \right)} dr \right] \\ &= \frac{Q_c}{2\pi kB} \left[\frac{1}{\lambda_c} \ln \frac{R_c}{r_{well}} + \frac{\lambda_c - \lambda_{w1}}{\lambda_c} \int_{R_c}^{R_{max}} \frac{1}{\sqrt{\frac{\lambda_c \lambda_{w1} V_c(t)}{\phi \pi B}} - \lambda_{w1} r} dr \right] \\ &= \frac{Q_c}{2\pi kB} \left[\frac{1}{\lambda_c} \ln \frac{R_c}{r_{well}} + \frac{\lambda_c - \lambda_{w1}}{\lambda_c} \frac{-1}{\lambda_{w1}} \ln \left(\sqrt{\frac{\lambda_c \lambda_{w1} V_c(t)}{\phi \pi B}} - \lambda_{w1} r \right) \Big|_{R_c}^{R_{max}} \right] \\ &= \frac{Q_c}{2\pi kB} \left[\frac{1}{\lambda_c} \ln \frac{R_c}{r_{well}} + \left(\frac{1}{\lambda_c} - \frac{1}{\lambda_{w1}} \right) \ln \frac{0 \cdot \lambda_c}{\lambda_c - \lambda_{w1}} \right] \end{aligned} \quad (14)$$

where

$$R_c = \sqrt{\frac{\lambda_{w1} V_c(t)}{\lambda_c \phi \pi B}}, \quad R_{max} = \sqrt{\frac{\lambda_c V_c(t)}{\lambda_{w1} \phi \pi B}} \quad (15)$$

where P_k is the injection pressure (Pa) on the wellface in the reservoir.

Because the integral result described as Eqn (14) does not exist, Eqn (11) still cannot be integrated, although Eqn (11) represents much progress in comparison with Eqn (5). Noting that the essential difference between Eqn (11) and Eqn (5) is that the injected CO₂ and the brine in the reservoir are described separately in Eqn (11) to obtain the relationship between the injection flow and the pressure gradient, while they are regarded as one entity in Eqn (5). With the integrated solution non-existent, Eqn (11) needs to be modified. To utilize the integrability of Darcy's formula and avoid the problem of Eqn (11), this paper directly introduces the total mobility instead of the individual phase mobility into the Darcy's formula to maintain the uniformity of

the composite fluid, and then obtains the displacement formula of two-phase flow, as shown in Eqn (16).

$$Q_c = -2\pi r k B \lambda \frac{\partial P}{\partial r} \quad (16)$$

Compared with Eqn (5), Eqn (16) not only states the essence of two-phase flow but also has more practical value and can be applied directly in engineering to evaluate the project capacity and design the wellbore pressure, while Eqn (5) just illustrates a physical truth and has a high level in fundamental researches. Thus Eqn (16) can be regarded as an inheritance (in aspect of physical truth) and development (in aspect of mathematical expression) of Eqn (5). Besides, Eqn (16) is a displacement formula of two-phase flow described by volumetric injection flow. In an actual project application, to coordinate with the calculation of wellbore pressure, the injection flow is generally described by mass flow.³⁵ Therefore, it is necessary to take Eqn (16) into a form of mass flow, as shown in Eqn (17), then execute the following deduction, which is convenient to apply the conclusion of this paper into the project of fluid injection.

$$C_c = -2\pi r k B \lambda \frac{\partial P}{\partial r} \cdot \rho_0 \quad (17)$$

where C_c is the mass flow of CO₂ fluid (kg/s); ρ_0 is the density (kg/m³) of CO₂ fluid in the injection well at the depth of the reservoir. It can be calculated by the Peng-Robinson state equation in the wellbore.³⁵ Because there is no calculation of wellbore pressure in this paper, the value of ρ_0 is acquired directly according to the NIST Chemistry WebBook.³⁴

Subsequently, to obtain the pressure on the well face of the reservoir, we integrate Eqn (17) in the range of $[r_{well}, R_0]$

$$\int_{P_k}^{P_0} dP = \int_{r_{well}}^{R_0} \frac{-C_c}{2\pi kB\lambda\rho_0} \frac{1}{r} dr \quad (18)$$

where P_0 is the initial formation pressure in the reservoir.

Bringing Eqn (10) into Eqn (18), we can obtain

$$\begin{aligned} P_k - P_0 &= \frac{C_c}{2\pi kB\rho_0} \left(\int_{r_{well}}^{R_c} \frac{1}{\lambda_c r} dr + \int_{R_c}^{R_{max}} \frac{1}{\lambda r} dr + \int_{R_{max}}^{R_0} \frac{1}{\lambda_{w2} r} dr \right) \\ &= \frac{C_c}{2\pi kB\rho_0} \left(\frac{1}{\lambda_c} \ln \frac{R_c}{r_{well}} + \int_{R_c}^{R_{max}} \sqrt{\frac{\phi\pi B}{\lambda_c \lambda_{w1} V_c(t)}} dr + \frac{1}{\lambda_{w2}} \ln \frac{R_0}{R_{max}} \right) \\ &= \frac{C_c}{2\pi kB\rho_0} \left[\frac{1}{\lambda_c} \ln \frac{R_c}{r_{well}} + \left(\frac{1}{\lambda_{w1}} - \frac{1}{\lambda_c} \right) + \frac{1}{\lambda_{w2}} \ln \frac{R_0}{R_{max}} \right] \end{aligned} \quad (19)$$

Hence, the pressure of any position at anytime is,

$$P(r, t) = P_0 + \begin{cases} \frac{C_c}{2\pi kB\rho_0} \left[\frac{1}{\lambda_c} \ln \frac{R_c}{r} + \left(\frac{1}{\lambda_{w1}} - \frac{1}{\lambda_c} \right) + \frac{1}{\lambda_{w2}} \ln \frac{R_0}{R_{max}} \right], & r_{well} \leq r < R_c \\ \frac{C_c}{2\pi kB\rho_0} \left[\left(\frac{1}{\lambda_{w1}} - \sqrt{\frac{\phi\pi B}{\lambda_c \lambda_{w1} V_c(t)}} \cdot r \right) + \frac{1}{\lambda_{w2}} \ln \frac{R_0}{R_{max}} \right], & R_c \leq r < R_{max} \\ \frac{C_c}{2\pi kB\rho_0} \left(\frac{1}{\lambda_{w2}} \ln \frac{R_0}{r} \right), & R_{max} \leq r < R_0 \end{cases} \quad (20)$$

Equation (20) is the explicit integral solution of pressure build-up of two-phase flow between CO₂ and brine in the reservoir. Thus, the pressure of any location at anytime in the reservoir can be calculated directly according to Eqn (20) under the condition of a given mass flow.

For the R_0 of Eqn (20), the well function $W(u)^7$ is applied in this paper,

$$W(u) = -0.5772 - \ln u + u - \frac{u^2}{2 * 2!} + \frac{u^3}{3 * 3!} - \dots \quad (21)$$

$$u = \frac{r^2 u^*}{4Tt} \quad (22)$$

where

$$u^* = u_s B = \rho g (\alpha + \phi \beta_w) \approx \rho g \phi (\alpha_p + \beta_w) \quad (23)$$

$$T = KB = \frac{\rho g}{\mu_w} k \quad (24)$$

where u^* is the storage coefficient of the porous medium; T is the transmissivity of the porous medium (m²/s); u_s is the specific storativity of the porous

When u is sufficiently small, such as 0.01, Eqn (21) is dominated by the first two terms on the right side.⁷ Based on that, according to the approach of Nordbotten *et al.*³⁶ when $W(u) = 0$, $u_0 = 0.56$ can be acquired. While this is considerably larger than 0.01, we choose $u_0 = 0.56$ to calculate R_0 . Thus, on the basis of Eqns (22)~(24), we have

$$R_0 = \sqrt{\frac{4Ttu_0}{u^*}} + R_{\max} = \sqrt{\frac{4u_0kt}{\mu_w\varphi(\alpha_p + \beta_w)}} + R_{\max} \quad (25)$$

Noting that Eqn (21) is only valid for the single-phase fluid outside the maximum radius of the CO₂ plume; thus, the value of the maximum radius of CO₂ plume should be added in the calculation.

Verification

Comparison with the approximate solution of J.M. Nordbotten

As described, as for Eqn (5), Nordbotten *et al.*⁹ presented a simple approximate solution. When the reservoir is divided into two layers, i.e., $N = 2$, the expression of the approximate solution as shown in Eqn (26) is

$$P(r, t) = P_0 + \begin{cases} \frac{-Q_c}{2\pi kB} \left[\frac{1}{\lambda_c} \ln \frac{r}{a_2} + \frac{B}{b_1\lambda_c + (B - b_1)\lambda_{w1}} \ln \frac{a_2}{a_1} + \frac{1}{\lambda_{w2}} \ln \frac{a_1}{R_0} \right], & r_{well} \leq r < a_2 \\ \frac{-Q_c}{2\pi kB} \left[\frac{B}{b_1\lambda_c + (B - b_1)\lambda_{w1}} \ln \frac{r}{a_1} + \frac{1}{\lambda_{w2}} \ln \frac{a_1}{R_0} \right], & a_2 \leq r < a_1 \\ \frac{-Q_c}{2\pi kB} \left(\frac{1}{\lambda_{w2}} \ln \frac{r}{R_0} \right), & a_1 \leq r < R_0 \end{cases} \quad (26)$$

where

$$a_1 = \sqrt{\frac{\lambda_c Q_c t}{\varphi\pi(b_1\lambda_c + (B - b_1)\lambda_{w1})}} \quad (27)$$

$$a_2 = \sqrt{\frac{\lambda_{w1} Q_c t}{\varphi\pi(b_1\lambda_c + (B - b_1)\lambda_{w1})}} \quad (28)$$

where $b_1 = B/2$.

Table 1. Calculation parameters.

Parameter	Value	Parameter	Value
r_{well} (m)	0.2	η	0.44
B (m)	10	S_{ls}	1
k (m ²)	6×10^{-15}	S_{lr}	0.38
P_0 (MPa)	20	S_{gr}	0.05
φ	0.15	S_{lc}	0.5
α_p (m ² /N)	4.5×10^{-10}	S_{lw1}	0.999
β_w (m ² /N)	4.5×10^{-10}	S_{lw2}	1
C_c (kg/s)	2	μ_c (kg/m/s)	88
ρ_0 (kg/m ³)	900	μ_w (kg/m/s)	552

When $N > 2$, a similar expression can be obtained and we have,

$$a_i = \sqrt{\frac{\lambda_c \lambda_{w1} Q_c t}{\varphi\pi(b_{i-1}\lambda_c + (B - b_{i-1})\lambda_{w1})(b_i\lambda_c + (B - b_i)\lambda_{w1})}} \quad (29)$$

where $b_i = i * B/N$.

The expressions of Eqn (26) and Eqn (20) are very similar; however, there is an essential difference. Although they are derived from the same governing equation, the former is an approximate solution and

the latter is an exact explicit integral solution obtained directly by integration. To verify the correctness and the reliability of the explicit integral solution presented in this paper, a comparison between the explicit integral solution and the approximate solution is implemented for the same simulation, applying a control model of constant flow injection, and 1000 d of continuous CO₂ injection. The values of the parameters chosen are shown in Table 1, and the calculation results are shown in Figs 5 and 6.

It is clear that from Figs 5 and 6: (i) The predicted pressures at different positions/time show the same

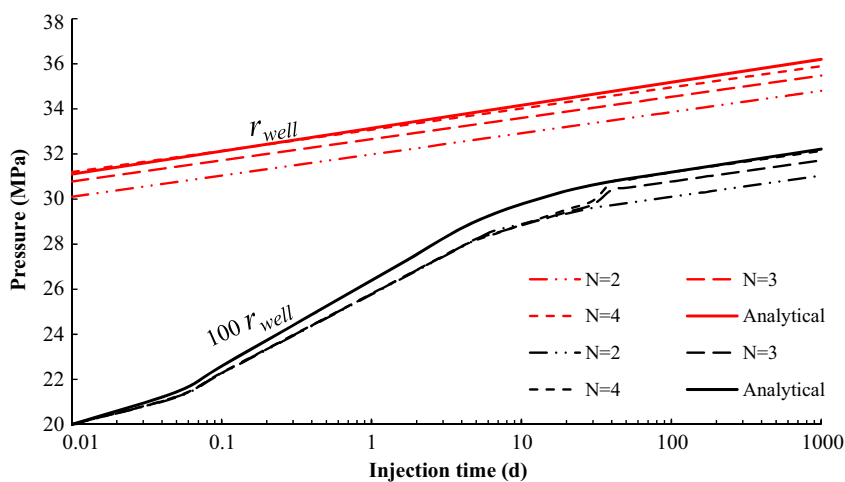


Figure 5. Comparison of predicted $P(r = r_{well}, t)$ and $P(r = 100r_{well}, t)$ profiles in the reservoir between the explicit integral (analytical) solution and the approximate solution.

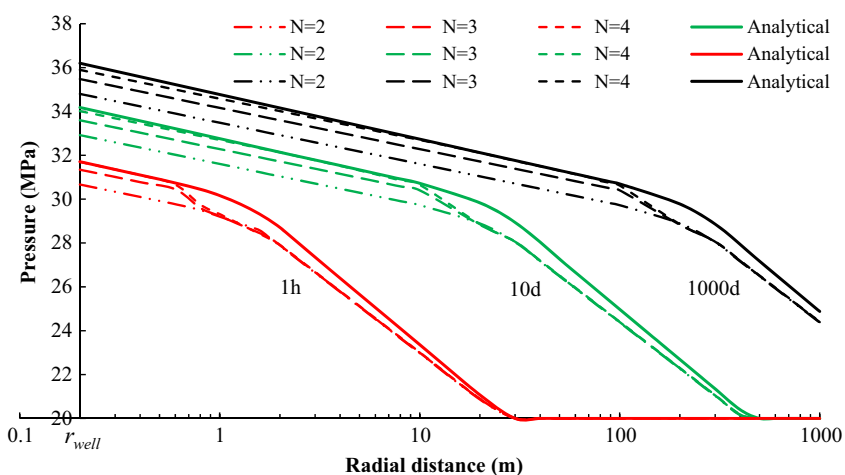


Figure 6. Comparison of predicted $P(r, t = 1h)$, $P(r, t = 10d)$ and $P(r, t = 1000d)$ profiles in the reservoir between the explicit integral (analytical) solution and the approximate solution.

changing trend. The results of the approximate solution gradually approach the explicit integral solution as the layer number N is increased, verifying the correctness and the reliability of the explicit integral solution presented in this paper. (ii) Generally speaking, the pressure in the reservoir increases in the form of logarithm along with increased injection time, meanwhile, it decreases in the form of negative logarithm along with the increase of radial distance. (iii) The comparison between the results at the point r_{well} and the results at the point 100 times r_{well} in Fig. 5 showed that, for the same layer number N , the results of the approximate solution are closer to the results of

explicit integral solution at increased radial distance, which means the deviation of the approximate solution is mainly produced in the CO₂ domain. (iv) There is a sudden drop in the approximate solution result with the increase of the layer number N , and the longer the injection time is, the farther the position of the sudden drop is according to Fig. 6. The reason is that as the CO₂ plume spreads to a position where the CO₂ plume in the interlayer is changed suddenly with increasing the layer number N in the approximate solution, therefore, the parameters (saturation and relative permeability) of this position also change suddenly, which introduces a sudden drop in the results.

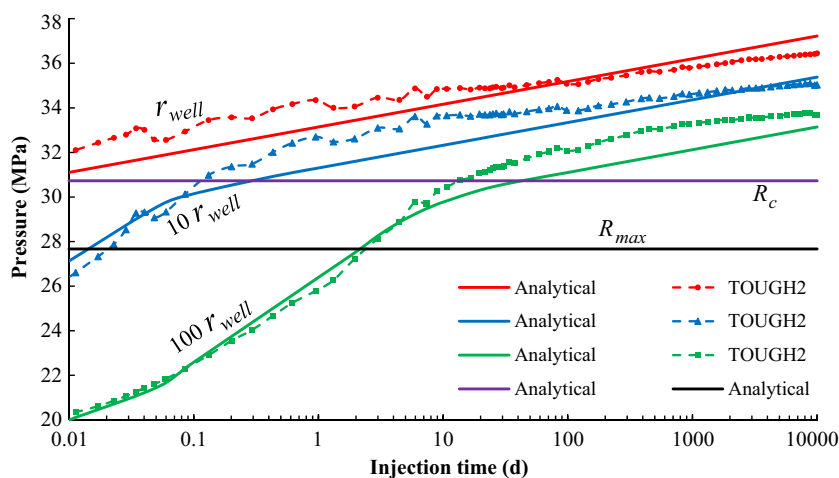


Figure 7. Comparison of predicted $P(r = r_{well}, t)$, $P(r = 10r_{well}, t)$ and $P(r = 100r_{well}, t)$ profiles in the reservoir between the explicit integral (analytical) solution and TOUGH2/ECO2N.

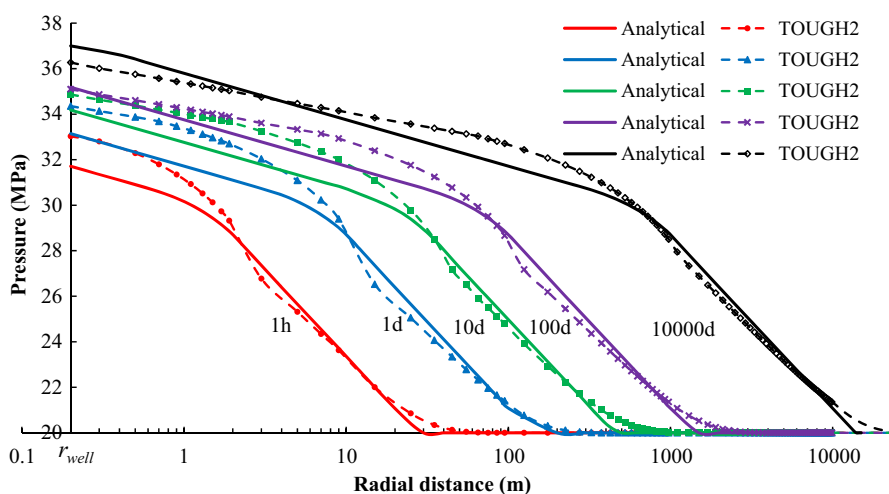


Figure 8. Comparison of predicted $P(r, t = 1h, 1d, 10d, 100d, 10000d)$ profiles in the reservoir between the explicit integral (analytical) solution and TOUGH2/ECO2N.

Comparison with TOUGH2/ECO2N

TOUGH2 is a professional numerical simulator for multiphase fluid and heat flow,^{10,33} and ECO2N is a corresponding fluid property module for mixtures of water, NaCl, and CO₂.³² To further verify the reliability of the explicit integral solution presented in this paper, a comparison between the explicit integral solution and TOUGH2/ECO2N will be implemented. The value of parameters are shown in Table 1, the outer boundary condition is regarded as constant pressure at 30 km distance from the injection well. Because the saturation is a function of time and position in TOUGH2, to avoid the influence of time, 10 000 d of continuous CO₂ injection, as a long-term continuous injection, is

applied. The calculation results are shown in Figs 7 and 8.

Observing Figs 7 and 8: (i) The calculation results of the explicit integral solution are consistent with the simulation results of TOUGH2 / ECO2N, which again verifies the reliability of the explicit integral solution. (ii) The pressure calculated by TOUGH2 / ECO2N is higher than the results of the explicit integral solution, then approach to the explicit integral solution gradually before falling below the explicit integral solution with increasing injection time or radial distance. This change rule is caused mainly by the difference of saturation because the flow is an unsteady state whose saturation gradually changes with time and position in

Table 2. The values of S_{lc} .

Parameter	value					
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
S_{lc}	0.38	0.40	0.45	0.50	0.55	0.60

Table 3. The values of S_{lw1} .

Parameter	value					
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
S_{lw1}	0.95	0.96	0.97	0.98	0.99	0.999

TOUGH2/ECO2N, while it is a steady state with a constant saturation in the explicit integral solution. Objectively speaking, the simulation results with good flexibility are more accurate than the explicit integral solution which is based on some ideal assumptions, but the explicit integral solution is simpler, more convenient, and easily visualized. (iii) According to the change rule described in (ii), a further conclusion that the flow field away-from/near the injection well is a quasi steady state at the early/late injection stage in practical flow can be obtained, i.e., only the flow field near the front of CO₂ plume is unsteady. (iv) The results of the explicit integral solution at R_c and R_{max} are both presented in Fig. 7. Since the two points change along with the injection time, the results cannot be acquired directly by numerical simulation, but it is easy to obtain the explicit integral solution. This is a big advantage and the results show that the pressure does not change with injection time at the two points, but only depends on the parameters of the fluids.

Sensitivity analysis of parameters

Analyzing Table 1, the most of parameters are depend on the actual project and the specific literature, while the S_{lc} and S_{lw1} are exceptions, which are determined only by experience with a great uncertainties and arbitrariness. Therefore, to obtain the appropriate value of S_{lc} and S_{lw1} , it is necessary to investigate the impact of the S_{lc} and S_{lw1} on the pressure in the reservoir, respectively. Taking the case of Table 1 as the standard case, when investigating the sensitivity of S_{lc} , the values of S_{lc} are shown in Table 2 (according to the experience as mentioned in the section *Explicit integral solution for two-phase flow: CO₂ and brine*), and the S_{lw1} is consistent with the standard case, while investigating the sensitivity of S_{lw1} , the values of S_{lw1} are shown in Table 3 (according to the experience as mentioned in

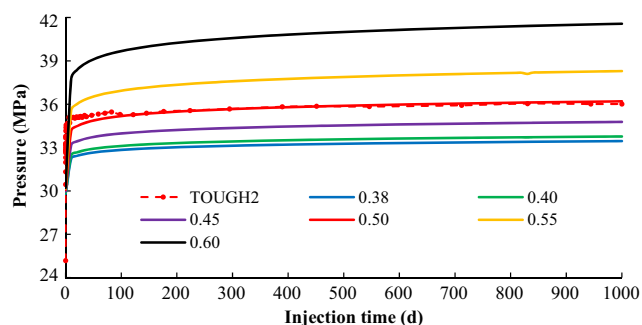


Figure 9. Comparison of predicted $P(r = r_{well}, t)$ profiles in the reservoir between TOUGH2/ECO2N and the explicit integral solution with different S_{lc} after 1000d of continuous CO₂ injection.

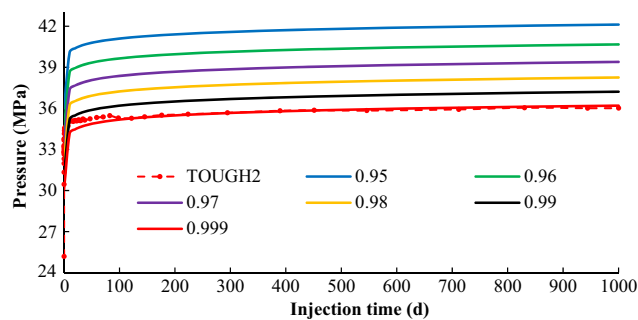


Figure 10. Comparison of predicted $P(r = r_{well}, t)$ profiles in the reservoir between TOUGH2/ECO2N and the explicit integral solution with different S_{lw1} after 1000d of continuous CO₂ injection.

section *Explicit integral solution for two-phase flow: CO₂ and brine*), and the S_{lc} is consistent with the standard case. The other parameters are still consistent with the standard case. The calculation results of injection pressure on the wellface in the reservoir are shown in Figs 9 and 10.

According to Figs 9 and 10, there is a large deviation along with the variation of S_{lc} and S_{lw1} , which means that the pressure profiles in reservoirs are sensitive to the variation of S_{lc} and S_{lw1} . The pressure increases with the increase of S_{lc} , and the rate of growth also increases gradually. The main reason is that increasing the value of S_{lc} (from S_{lr} to 0.6) will have an intense impact on the relative permeability of CO₂ by fast decreasing its value from Fig. 4, while the relative permeability of brine is near to zero all the time, thus the CO₂ displacement will be hindered and lowering the migration rate of the fluids in CO₂ domain, which resulting the increase of the pressure, under a constant injection rate of CO₂. On the contrary, the pressure decreases with the increase of S_{lw1} , and the rate of

decreasing is constant basically. Because increasing the value of S_{lw1} (from $1 - S_{gr}$ to 1) will rapidly increase the relative permeability of brine in brine domain 1 according to Fig. 4, hence promoting the CO₂ displacement and the dissipation (decrease) of the pressure. Furthermore, comparing the curves between case 1 and case 2 of Fig. 9 and case 1 and case 3 of Fig. 10, the pressure difference of the later is more than the former, though the absolute variation equality of S_{lc} is equal to S_{lw1} 's, which demonstrates the pressure profiles are more sensitive to the variation of S_{lw1} than the variation of S_{lc} . In conclusion, the determination of S_{lc} and S_{lw1} should be careful and based on the actual project in the application. From the calculation result of TOUGH2/ECO2N and the explicit integral solution, the values of standard case in this work are relatively appropriate, which can be regarded as a analogy in the project application to determinate the values of S_{lc} and S_{lw1} in consideration of injection condition and the engineering geological characters of reservoirs.

Discussion

Finding the analytical solution of pressure build-up with time and space in the reservoir after CO₂ injection is not a new story. The explicit integral (analytical) solution of pressure build-up proposed in this paper, expressed by Eqn (20), is derived directly by integrating Darcy's formula in consideration of two-phase flow, and the process of derivation is relative simple and easy to follow. The biggest advantage of this solution is its convenience and simplicity compared with other analytical solutions and semi-analytical solutions.

As mentioned in the introduction, firstly, Nordbotten *et al.*⁹ presented an analytical solution without considering the residual saturation for the governing equation (Eqn (5)). At later, Nordbotten *et al.*^{19–22} and Celia *et al.*^{21,22} developed the similarity solution and semi-analytical solution to include the residual saturation of brine while the invading CO₂ in brine domain is ignored. Moreover, the derivation of them is very complex, requiring a high mathematical ability, and the final expression is not integrated and must depend on numerical integration in practical applications. Therefore, it is difficult for engineers to understand and apply. In recently, Baù *et al.*³⁷ proposed an iterative global pressure solution (IGPS) for the semi-analytical solution of Nordbotten and Celia, and González-Nicolás *et al.*³⁸ discussed the stochastic and sensitivity of the residual saturation of brine by using

the iterative global pressure solution. However, the iterative global pressure solution is a numerical arithmetic whose results rely on numerical iteration, which introduced the problem of accuracy, convergence and stability.

Other similar solutions are the approximate solutions developed by Mathias *et al.*^{13,26,28} based on the method of matched asymptotic expansions, and the approximate analytical solution proposed by Azizi and Cinar^{14,30} based on the Laplace transform. Nevertheless, some problems in Nordbotten's solution are still appear that make them inconvenient for application, though the partial miscibility has been considered in Mathias *et al.*¹³ and Azizi and Cinar.^{14,30} The work of this paper is focused on overcoming the difficulty and inconvenience in practical application, which is very meaningful.

Conclusions

This work put forward a Darcy's formula for two-phase flow of displacement by directly introducing the total mobility of two-phase flow into Darcy's law and then deduced a convenient and practical explicit integral (analytical) solution of pressure build-up for two-phase flow during constant-rate injection of CO₂.

To verify the correctness and reliability of the explicit integral solution, the results of the explicit integral solution are compared with Nordbotten's approximate solution for a case of CO₂ injection. The results demonstrated good consistency. A further comparison between the explicit integral solution and a numerical solution of TOUGH2 / ECO2N further verified the reliability of the explicit integral solution. Meanwhile, the results showed that the pressure increases in the form of logarithm along with increasing injection time while it decreases in the form of negative logarithm along with the increase of radial distance, and only the flow field near the front of CO₂ plume is unsteady.

A sensitivity analysis of S_{lc} and S_{lw1} was implemented, which showed that the S_{lc} and S_{lw1} both have a great impact on the pressure profiles in the reservoir. The larger the value of S_{lc} is, the lower the relative permeability of CO₂ in CO₂ domain is, thus the CO₂ displacement will be hindered and the pressure will be increased. On the contrary, the larger the value of S_{lw1} is, the higher the relative permeability of brine in brine domain 1 is, which promoting the CO₂ displacement and decreasing the pressure. Moreover, the pressure is more sensitive to the variation of S_{lw1} than the

variation of S_{lc} . Therefore, the determination of S_{lc} and S_{lwl} should be careful and based on the actual project in the application. As for CCS projects, the values of standard case in this paper are worth to reference, which can be regarded as a analogy in consideration of injection condition and the engineering geological characters of reservoirs.

The greatest advantage of the explicit integral solution is that it is simple, convenient, and practical compared with the numerical simulators and other analytical solutions at similar condition and with similar assumptions. Hence the evaluation of capacity, the design of wellbore pressure and the safety assessment of projects will be more convenient and efficient by applying the explicit integral solution of pressure build-up.

The explicit integral solution of this paper is also valid for other two-phase flow. Although it is derived based on the two-phase flow of CO₂ and brine, as long as the density of the displaced fluid is greater than the injected fluid's, the solution will apply.

The explicit integral solution is based on the assumptions that the reservoir is homogeneous, isotropic, and infinite with a constant pressure boundary condition, and neglects the effects of the fluid compressibility, gravity, capillary pressure and chemical reactions; therefore, it needs further investigation to apply for more general cases.

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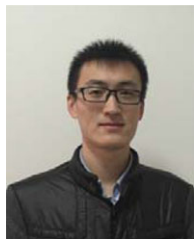
recovery. Representative achievements include the design methodology of CO₂ redline wellhead injection pressure of China Shenhua CCS pilot project. He is also the secretary of Theme 6, U.S-China Clean Energy Research Center on Advanced Coal Technology Consortium (CERC-ACTC 1.0).



Xiaochun Li

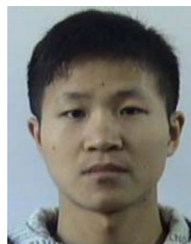
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