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## Research Article

**Keywords:** CO<sub>2</sub> storage, Saline aquifer, Observation well, Pressure response, CO<sub>2</sub> saturation

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# Analysis of Pressure Response at an Observation Well against Pressure Build-Up by Early Stage of CO<sub>2</sub> Geological Storage Project

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## Abstract

To ensure a safe and stable CO<sub>2</sub> storage, pressure responses at an observation well is expected to be an important and useful field monitoring items to estimate the CO<sub>2</sub> storage behaviors and the aquifer parameters during and after injecting CO<sub>2</sub>, because it can detect whether the injected CO<sub>2</sub> leaks to the ground surface or the bottom of the sea. In this study, pressure responses were simulated to present design factors such as well location and pressure transmitter of the observation well. Numerical simulations on the pressure response and the time-delay from pressure build-up after CO<sub>2</sub> injection were conducted by considering aquifer parameters and distance from the CO<sub>2</sub> injection well to an observation well. The measurement resolution of a pressure transmitter installed in the observation well was presented based on numerical simulation results of the pressure response against pressure build-up at the injection well and CO<sub>2</sub> plume front propagations. Furthermore, the pressure response at an observation well was estimated by comparing the numerical simulation results with the curve of CO<sub>2</sub> saturation and relative permeability. It was also suggested that the analytical solution can be used for the analysis of the pressure response tendency using pressure build-up and dimensionless parameters of hydraulic diffusivity. Thus, a criterion was established for selecting a pressure transducer installed at an observation well to monitor the pressure responses with sufficient accuracy and resolution, considering the distance from the injection well and the pressure build-up at the injection well, for future CCS projects.

**Keywords** CO<sub>2</sub> storage; Saline aquifer; Observation well; Pressure response; CO<sub>2</sub> saturation

## Introduction

The average atmospheric CO<sub>2</sub> concentration had increased from 280 ppm in industrial era to 411 ppm in May 2019 (Dlugokencky and Tans, 2019; Lake and Lomax, 2019). The average CO<sub>2</sub> concentration is increasing continuously by more than 2 ppm/year (Metz et al., 2005). With this growth rate, it will exceed 450 ppm within the next 20 years (Li et al., 2019), and the mean global temperature will increase by over 2 °C. To mitigate the increasing rate, many intergovernmental organizations have assessed climate change and exchange technology for reducing the anthropogenic CO<sub>2</sub> emissions (IEACHG, 2010; Metz et al., 2005; Shackley et al., 2005). In 2017, a possible framework to reduce CO<sub>2</sub> emissions into the atmosphere had been agreed upon countries that joined COP23 (Obergassel et al., 2018).

CO<sub>2</sub> capture and geological storage is a promising way to mitigate CO<sub>2</sub> emissions into the atmosphere by capturing CO<sub>2</sub> gases from relatively large industrial sources, such as power plants, and then transporting and injecting them into porous and permeable storage reservoirs. A suitable reservoir should be covered by sealing layers with very low permeability to prevent CO<sub>2</sub> leakage from storage reservoirs to the ground surface or sea bottom. Three main

underground storage reservoirs have been identified: saline aquifers, depleted oil and gas reservoirs, and unminable coal seams (Yang et al., 2010). Deep saline aquifers at depths over -800 m have been considered ideal because of their large storage capacity and broad distribution worldwide. The saline aquifers are geologic layers of permeable layers located 1,000 to 3,000 m deep and can store injected CO<sub>2</sub> in a supercritical state under reservoir conditions.

The International Energy Agency (IEA) has estimated the potential contribution of CCS in mitigating global CO<sub>2</sub> emission to be as high as 20 % of the global emissions in 2050, which follows the most important contribution by improvement in energy efficiency (Lipponen et al., 2011). The Blue Map reduction plan has been considered necessary to continue annual geological storage of 9.5 Gt-CO<sub>2</sub> by CCS for 45 years. Several ongoing pilots and commercial CCS projects have suggested that CO<sub>2</sub> geological storage in deep sedimentary formations is technologically feasible (Eiken et al., 2011; Hansen et al., 2013; Tanaka et al., 2014). To make a significant contribution to the mitigations of climate change, many CCS projects with larger CO<sub>2</sub> injection rates from an injection well need to be planned and implemented. However, the CO<sub>2</sub> reduction rate by CCS projects is currently limited because sufficient CCS projects have not been implemented owing to economic issues as well as social acceptance issues related to storage safety and stability.

CO<sub>2</sub> injections induce a pressure increase in the reservoir from its original geomechanical pressure. A large CO<sub>2</sub> injection rate can easily cause considerable pressure build-up in the bottom hole and its surrounding region in the reservoir, where activated faults through the upper sealing layers may lead to CO<sub>2</sub> leakage (Rutqvist, 2012). Therefore, the management of the bottom hole pressure (BHP) as an induced pressure build-up will be a critical factor in the safe operation of CO<sub>2</sub> storage. For instance, the In Salah CCS project in Algeria has shown significant geomechanical changes because of the injection pressure and site-specific geomechanical conditions. Although the injection rate of the In Salah CCS project was 1 Mt/year, the project was still shut down because of concerns about the integrity of the seal layers (Eiken et al., 2011; Goertz-Allmann et al., 2014). In the Tubaen Formation in the Snøhvit field (offshore Norway), Statoil successfully injected 1.6 Mt of CO<sub>2</sub> from April 2008 to April 2011. However, the CO<sub>2</sub> injection had to be stopped owing to an increase in pore pressure before reaching the full storage capacity of the Tubaen Formation (Hansen et al., 2013).

Generally, to confirm that the injected and stored CO<sub>2</sub> is in a safe and stable condition, it is necessary to grasp the behavior of CO<sub>2</sub> in the reservoir and to detect whether there is leakage of CO<sub>2</sub> out of the reservoirs or not. In the Tomakomai CCS demonstration project (hereinafter Tomakomai CCS project) (Tanaka et al., 2014), five continuous monitoring items and three periodic monitoring items were operated for two aquifers at different average depths of 1,150 and 2,700 m. The continuous monitoring items are temperature and pressure in two injection wells, temperature, and pressure changes in two remote observation wells, and seismic monitoring at the ocean bottom and onshore. In contrast, the periodic monitoring items are marine environmental observations (sea water, bottom mud, and sea lives) and 2D and 3D seismic surveys. Specifically, two observation wells were drilled from onshore to the Moebetsu Formation (1,100–1,200 m in deep) and the Takinoue Formation (2,400–3,000 m in deep) to record continuous passive changes in aquifer pressure and temperature as well as CO<sub>2</sub> saturation in each formation water. The monitoring data recorded in the observation wells can be used to detect the movement of the CO<sub>2</sub> plume and judge the stability of stored CO<sub>2</sub> based on comparisons with the numerical simulation results using aquifer models.

In the Tomakomai CCS project, CO<sub>2</sub> was injected into the Moebetsu Formation in short cycles between April 6 and May 24, 2016, at an injection rate of 180 to 600 t-CO<sub>2</sub>/day and 7,163 t-CO<sub>2</sub> were stored in cumulative amount (Sato and Horne, 2018). The original pressure of the Moebetsu Formation at the injection well was 9.3 MPa and the maximum BHP in the injection well that was recorded during the test injection was 10 MPa at an injection rate of 600

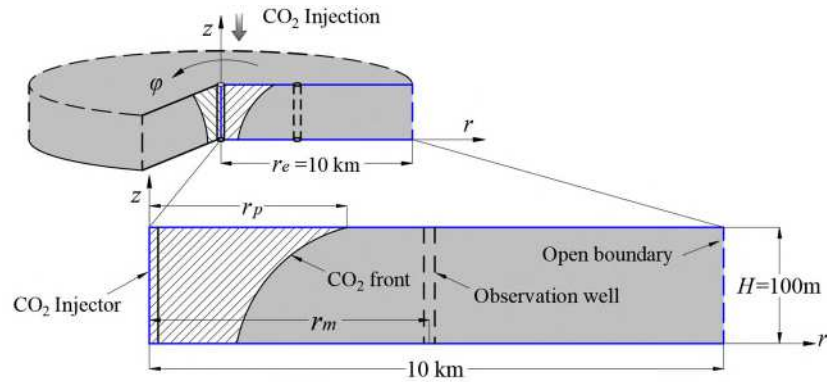
t-CO<sub>2</sub>/day, the cumulative CO<sub>2</sub> injection was around 0.3 Mt-CO<sub>2</sub> during the four years (Sawada et al., 2018; Tanaka et al., 2014). However, there is no pressure response was recorded in the observation well OB-2 (Tanaka et al., 2014) which was drilled about 3,000 m from the injection well in the Moebetsu Formation with installing pressure and temperature sensors. The reason for the lack of pressure response at the observation well was explained as the sensitivity of the pressure transducer is not sufficient to detect the pressure propagation from the injection well to the observation well.

Drilling a new observation well requires an additional budget and may create a new potential pathway for CO<sub>2</sub> leakage to the surface. Therefore, the observation well and installed sensors for measuring parameters, such as distance from the CO<sub>2</sub> injection well and the sensor sensitivity, should be suitably designed before drilling an observation well. In this study, we numerically investigated the pressure response at an observation well, induced by CO<sub>2</sub> injection in the early stage of CO<sub>2</sub> geological storage in a deep saline aquifer. The results can be used as reference data for designing an observation well and determining the location for installing sensors (or transmitters).

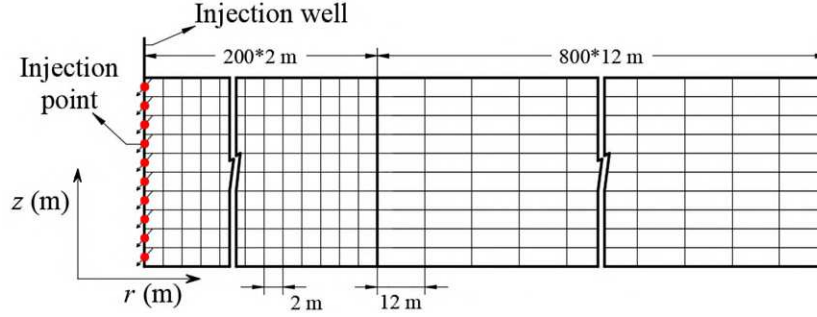
### Aquifer model for CO<sub>2</sub> injection and storage

As shown in Fig. 1, a cylindrical grid system with  $(r, \phi, z)$  coordinates was used to construct the reservoir model. The pressure and CO<sub>2</sub> saturation distributions were simulated by injecting CO<sub>2</sub> from an injection well located at  $r=0$  m into an aquifer with radius  $r_w$ . It was assumed that the aquifer had uniform porosity and permeability in horizontal and vertical directions. Its outer boundary at  $r=r_e$  is defined as an open boundary that the pressure is equal to the initial pressure. There is no-flow across the top and bottom boundaries. A typical aquifer model was simulated by setting  $r_w=0.1$  m and  $r_e=10$  km.

The meshing of the aquifer in the  $r$  and  $z$  directions is shown in Fig. 2. The grid blocks consist of  $1,000 \times 1 \times 10$  grid cells in the  $(r, \phi, z)$  directions, of which 200 grid-cells were set between  $r=0.1-400$  m, and 800 grid-cells between  $r=400-10,000$  m. The reservoir consists of 10 layers with a constant spacing of 10 m in the vertical direction. CO<sub>2</sub> was injected from the injector into horizontal layers connecting to the aquifer by three types of perforations. The radial distance from the observation well to the injection well,  $r_m$ , was assumed to be in the range of 1,000 to 5,000 m. The pressure changes in the aquifer blocks connected to the aquifer at  $r=r_m$  were considered as the pressure responses at the bottom of the observation well connected to the aquifer. Numerical simulations were conducted using the compositional reservoir simulator CMG-STARSTM.



**Fig. 1** Schematic aquifer model



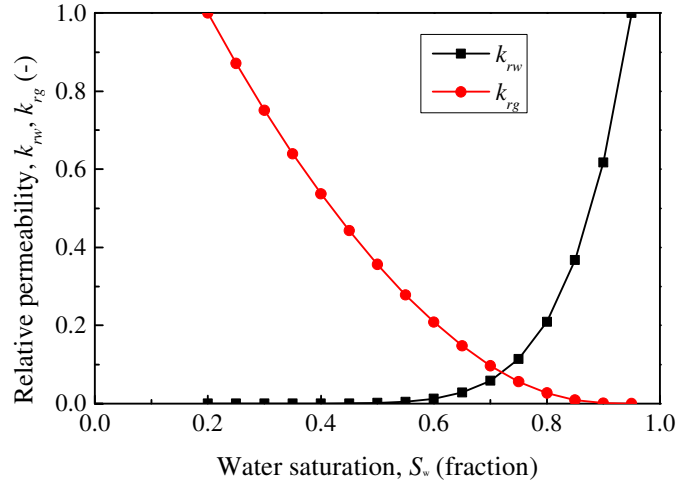
**Fig. 2** Schematic diagram of meshing in the vertical section

The simulation parameters set for the base model are listed in Table 1. In the case of the Moebetsu Formation in the Tomakomai CCS project, the range of horizontal permeability was estimated as  $k=0.98\times10^{-15}$ – $980\times10^{-15}$  m<sup>2</sup> (=1–1,000 md) from the geophysical measurements, and  $k=363\times10^{-15}$  m<sup>2</sup> (=370 md) based on the fall-off test using the injection well after drilling. In addition, the porosity was measured as  $\phi=0.20$ – $0.40$  by a laboratory core test and the excavation result was  $\phi=0.12$ – $0.42$  (Tanaka et al., 2014). In this simulation, the uniform permeability in the horizontal direction was also set as  $k=363\times10^{-15}$  m<sup>2</sup>, and the ratio of vertical permeability ( $k_v$ ) to horizontal permeability ( $k$ ) was  $k_v/k=0.1$ . The porosity  $\phi=0.30$  was used for the base simulations. In the present simulations, assuming the ground surface temperature was 15 °C and geothermal gradient as 2.5–2.75 °C/100 m, the targeted aquifer temperature was 40–42.5 °C, and the CO<sub>2</sub> injection temperature was specified as 40 °C. Therefore, the injected CO<sub>2</sub> was similar to the isothermal process. No geochemical reactions or mineralization were considered because a short period of fewer than 200 day was considered for simulation.

**Table 1** Aquifer parameters and CO<sub>2</sub> injection well set in the base model (Garimella et al., 2019; Sawada et al., 2018; Tanaka et al., 2017)

Parameter	Present Simulation	Tomakomai CCS Project	Unit (SI)
Aquifer upper level	-1,000	-1,000 – -1,200	m
Aquifer thickness, $H$	100	100–200	m
Outer boundary radius, $r_e$	10,000		m
Initial aquifer pressure, $p_0$	10	9.3	Mpa
Initial water saturation	1		-
CO <sub>2</sub> injection temperature	40		°C
CO <sub>2</sub> injection pressure, $p_0+p_i$	<14		Mpa
CO <sub>2</sub> injection well radius, $r_w$	0.1		m
Porosity, $\phi$	0.30	0.10–0.42	-
Horizontal permeability, $k$	$363\times10^{-15}$	$363\times10^{-15}$	m <sup>2</sup>
Vertical permeability, $k_v$	$36.3\times10^{-15}$	$36.3\times10^{-15}$	m <sup>2</sup>
Rock compressibility, $C_r$	$9.0\times10^{-10}$		Pa <sup>-1</sup>
Brine water compressibility, $C_w$	$1.0\times10^{-10}$		Pa <sup>-1</sup>
scCO <sub>2</sub> <sup>1</sup> compressibility, $C_c$	$4.0\times10^{-10}$		Pa <sup>-1</sup>
Hydraulic diffusivity, $\eta$	2.26		m <sup>2</sup> /s

Note: <sup>1</sup> <sub>sc</sub>CO<sub>2</sub> denotes CO<sub>2</sub> in supercritical phase.



**Fig. 3** Relative permeability curves used in present simulations (Brooks-Corey-Burdine Model) (Garimella et al., 2019)

Relative permeability was modeled based on the Brooks–Corey–Burdine model (Garimella et al., 2019) and is expressed by following Eqs. (1) to (3), as follows:

$$k_{rw} = S_e^{\frac{2+3\lambda}{\lambda}} \quad (1)$$

$$k_{rg} = \left(1 - S_e^{\frac{2+\lambda}{\lambda}}\right) (1 - S_e)^2 \quad (2)$$

$$S_e = \frac{(S_w - S_{wr})}{(1 - S_{wr} - S_{gr})} \quad (3)$$

where  $S_e$  is the effective saturation;  $k_{rw}$  and  $k_{rg}$  are the aqueous and gas phase relative permeability respectively;  $S_l$  is the aqueous phase saturation;  $S_{lr}$  and  $S_{gr}$  are the aqueous and gas phase residual saturations respectively, and  $\lambda$  (-) is the pore size distribution index. In the present simulations,  $S_{wr}=20$  %,  $S_{gr}=5$  %, and  $\lambda=0.5$ . The relative permeability curves are shown in Fig. 3. Based on the curves, the remaining water saturation after displacement of CO<sub>2</sub> gas is almost  $S_w \approx 65$  %, which means that the CO<sub>2</sub> gas saturation becomes  $S_g \approx 35$  % in an aquifer except near the well.

## Theoretical analysis

### Linearized radial flow equation and estimation solution

Assuming porous media is viscous-dominated and there is no turbulent flow, the flow in porous media can be described by Darcy's law for a single incompressible fluid phase that is shown in Eq. (4) (Hubbert, 1953):

$$\mathbf{q} = -\frac{k}{\mu} (\nabla p - \rho g \nabla z) \quad (4)$$

where  $\mathbf{q}$  is the vector of the volumetric flow rate;  $k$  (m<sup>2</sup>) is permeability;  $\mu$  (Pa·s) and  $\rho$  (kg/m<sup>3</sup>) are the viscosity and density of the reservoir fluid;  $g$  is the gravitational acceleration vector directed downwards;  $\nabla p$  is the hydraulic gradient.

Without considering gravity in the vicinity of an injection well, the governing equation on pressure  $p$  (Pa) for one-dimensional radial linearized flow, assuming a constant compressibility in the aquifer is given as (Wu and Pan, 2005):

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \frac{\partial p}{\partial r} = \frac{1}{\eta} \frac{\partial p}{\partial t}; \quad \eta = \frac{k}{\phi C_i \mu} \quad (5)$$

where  $\eta$  (m<sup>2</sup>/s) is hydraulic diffusivity;  $\phi$  is reservoir porosity;  $\mu$  (Pa·s) is reservoir fluid viscosity;  $C_i = C_r + C_f$  (Pa<sup>-1</sup>) is the total value of rock compressibility ( $C_r$ ) and reservoir fluid compressibility ( $C_f$ ), and  $t$  (s) is elapsed time from the start of CO<sub>2</sub> injection. The hydraulic diffusivity,  $\eta$ , is a hydraulic parameter that controls the unsteady pressure transient.

The pressure build-up in an injection well, defined as  $p_i$ , under the general steady-state radial flow is proportional to the fluid injection rate  $q$  (m<sup>3</sup>/s), while it is inversely proportional to the transmissivity (or permeability-thickness product)  $K = k \cdot H$  (m<sup>3</sup>), which is product of the horizontal permeability  $k$  and the reservoir thickness  $H$ (m) (Dietz, 1965). The transmissivity  $K$  expresses the flow capacity and ability in aquifers and reservoirs. The radial flow solution for the steady-state ( $\partial p / \partial t = 0$ ) in Eq. (6) is given by the following equation (IEACHG, 2010; Van Everdingen and Hurst, 1949):

$$p_i = \frac{\mu q}{2\pi k H} \ln \left( \frac{r_e}{r_w} \right) \quad (6)$$

where  $r_e$  (m) is the effective reservoir radius, which is the extent from the injection well to the reservoir boundary where the pressure is equal to the initial hydrostatic pressure; and  $r_w$  (m) is the injection well radius.

Assuming that the reservoir fluid is uniform and incompressible ( $C_f = 0$  and  $\rho = \text{const.}$ ), a typical solution of radial transient flow can be expressed as (Goode and Thambynayagam, 1987):

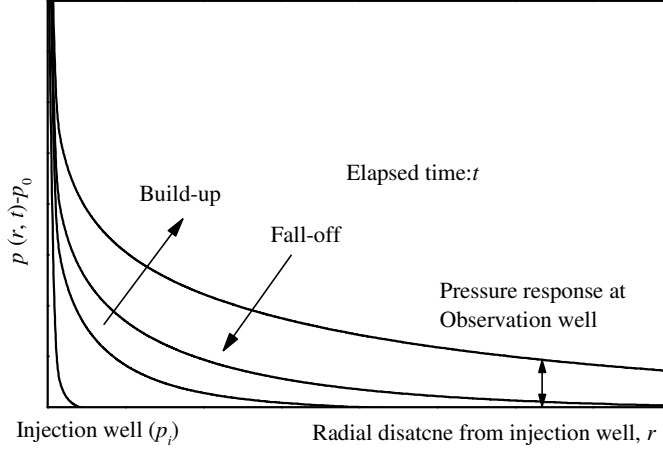
$$p(r, t) - p_0 = \frac{\mu q}{4\pi H k} \left( \ln \frac{kt}{\phi \mu C_i r^2} + 0.809 \right) \quad (7)$$

where  $p_0$  is the initial or outer boundary pressure of the aquifer, and  $q\mu/(4\pi k H)$  is a constant for a constant if the injection rate  $q$  is set as a constant without considering skin factors. This solution shows the reservoir pressure build-up at different injection periods and different radial distances from the injection well. The transient pressure changes in the aquifer at the elapsed time from the start of injection are expressed by the transient flow equation and are shown in Fig. 4.

The pressure response at the observation well at  $r = r_m$ ,  $\Delta p$  (Pa) can be estimated by:

$$\Delta p(t) = p(r_m, t) - p_0 \quad (8)$$

The pressure calculated by Eq. (8) is roughly equal to the pressure changes between build-up and fall-off at  $r = r_m$ . The transient condition is applicable only if the pressure response in the aquifer is assumed to be not affected by the presence of the outer boundary; thus, the reservoir appears infinite in extent. In this study, a constant pressure boundary was assumed to be close to an aquifer with enough radius. Therefore, it is possible to use this equation to estimate the rough pressure response at the observation well.



**Fig. 4** Schematic solution showing transient pressure for pressure build-up at an injection well

The distance from the CO<sub>2</sub> injection well to the observation well ( $r=r_m$ ) is the critical parameter that controls the magnitude of the pressure response at the observation well, which is affected by the CO<sub>2</sub> injection rate and amount from the injection well and the aquifer parameters. According to Eq. (7), the magnitude of the response pressure is directly proportional to the injection rate,  $q$ , and injection period, while the transmission delay time is inversely proportional to the hydraulic diffusivity of the aquifer. The pressure response is almost inversely proportional to distance  $r_m$ .

### Analysis method

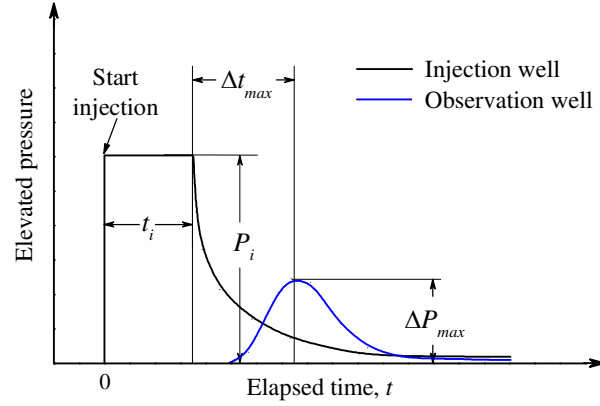
The initial pressure of the aquifer was set as  $p_0=10$  MPa in the present simulations. The BHP in the injection well is equal to  $p_0+p_i$ . The pressure response and distribution of CO<sub>2</sub> saturation in the aquifer were simulated for a constant CO<sub>2</sub> mass injection rate  $q_m$  (t-CO<sub>2</sub>/day) as shown in Fig. 5.

When the injection well is shut-in after the CO<sub>2</sub> injection for a period,  $t_i$ , the pressure response of the observation well changes and has a peak value  $\Delta p_{max}$ , which is recorded after the delay time,  $\Delta t_{max}$  from the shut-in of the injection well. A pressure response  $\Delta p_{max}$  is sensitive to the magnitude of pressure build-up  $p_i$ . Therefore, it is expected that the ratio of both pressures defined as:

$$R = \frac{\Delta p_{max}}{p_i} \quad (9)$$

is not sensitive to injection rate  $q$ . Simulations were carried out to investigate the pressure response and the delay time of the peak pressure in the observation well by comparing the CO<sub>2</sub> plume front position extending to the outer ward. In the present simulations, the CO<sub>2</sub> injection rate  $q$  was controlled according to the BHP, which must be less than the threshold capillary pressure and sufficiently less than the fracture pressure of the caprock or upper sealing layer. The maximum BHP has been set as 90% of the threshold capillary pressure (12.6 MPa=14.0 MPa×0.9) measured for the Moebetsu Formation (Osipov, 2017). In the base model, the CO<sub>2</sub> mass injection rate was set as  $q_m=600$  t-CO<sub>2</sub>/day ( $q=3.744$  m<sup>3</sup>-std/s,  $\rho_{CO_2}=1.855$  kg/m<sup>3</sup> at the surface condition). The injection period in the base model was assumed to be  $t_i=100$  day, and the distributions of the pressure response and CO<sub>2</sub> saturation were simulated until  $t=1,000$  day from the start of CO<sub>2</sub> injection.



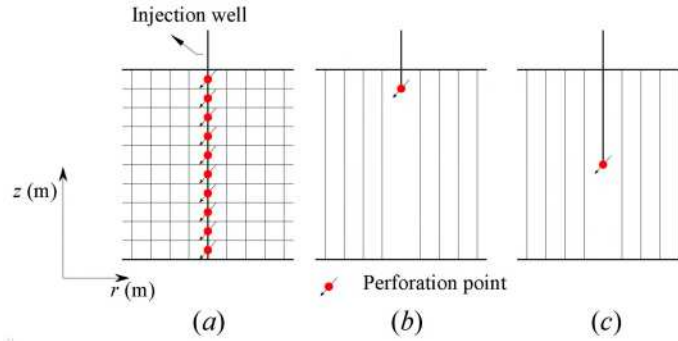


**Fig. 5** Schematic diagram of defined variables

## Pressure build-up at the injection well and pressure response at the observation well

### Effect of perforation scheme for injecting CO<sub>2</sub>

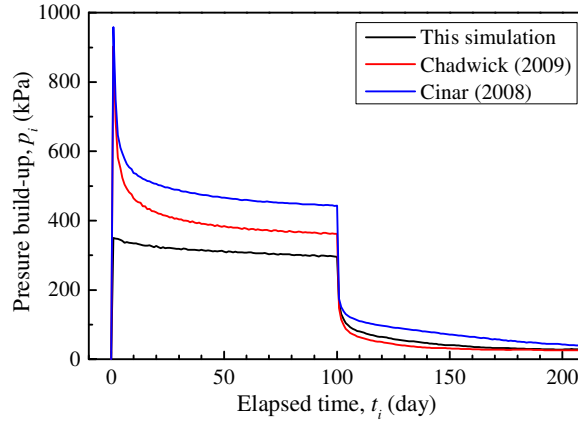
The CO<sub>2</sub> injection well was assumed to be a vertical well. As different perforation schemes will lead to a difference in pressure build-up at the well, the effects of the perforation scheme on the CO<sub>2</sub> injectivity were discussed. As shown in Fig. 6, some previous studies used different simulation models with several perforation points and locations for CO<sub>2</sub> injection (Chadwick et al., 2009; Cinar et al., 2008). In this study, the multiple perforation scheme using 10 holes perforated in the center of each layer (Fig. 6 (a)) was used. Chadwick (2009) (Chadwick et al., 2009) Chadwick et al used the scheme with an injection point located 10 m below the aquifer ceiling (Fig. 6 (b)) to study the pressure build-up at the injection well and pressure distribution in the aquifer. Cinar et al. (2008) (Cinar et al., 2008) used the scheme with the injection point located in the middle of the reservoir (Fig. 6 (c)).



**Fig. 6** Injection well perforation schemes used in previous studies; (a) multiple perforations, (b) single perforation hole at the top used by Chadwick (2009) (Chadwick et al., 2009), (c) single perforation hole at a position used by Cinar et al (2008) (Cinar et al., 2008)

Figure 7 shows the pressure build-up at the injection well with different perforation schemes for CO<sub>2</sub> injection using the same injection rate. It can be seen that the injection with one perforation point will lead to a significant pressure build-up in the first hour of injection, which is more than twice that of all the perforations (Fig. 6 (a)). In the multiple perforation scheme, a larger contact area with the reservoir results in a smaller pressure build-up and less stress on the sealing layer for the same injection rate. Furthermore, only one block in the vertical direction may not be rigorous to study the pressure build-up. If the pressure gradient of the reservoir is not considered, the calculated BHP may be

overestimated. Therefore, in this study, a multiple perforation scheme was used in the simulations to ensure a safe injection with a smaller pressure build-up at the well.

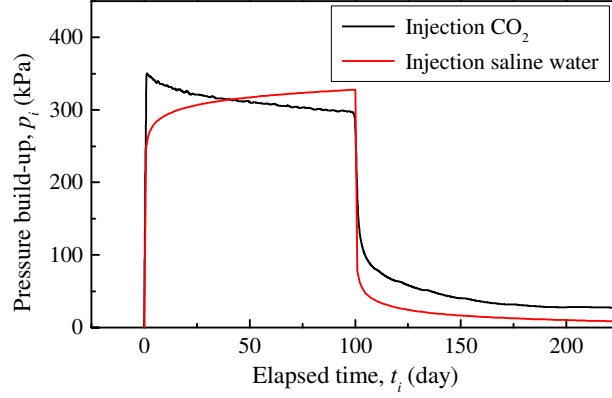


**Fig. 7** Numerical simulation results on pressure build-up of the injection well obtained with different perforation methods of the CO<sub>2</sub> injection well using CMG-STARSTM

### Pressure build-up and bottom-hole pressure

To study the pressure build-up at the CO<sub>2</sub> injection well, an injection scheme based on the base model for injection rate  $q_m=600$  t-CO<sub>2</sub>/day and continuous injection for 100 day ( $t_i=100$  day) was simulated compared with the case of injecting saline water that is the same with the reservoir fluid. The injection rates of injecting CO<sub>2</sub> and saline water were the same in the reservoir condition.

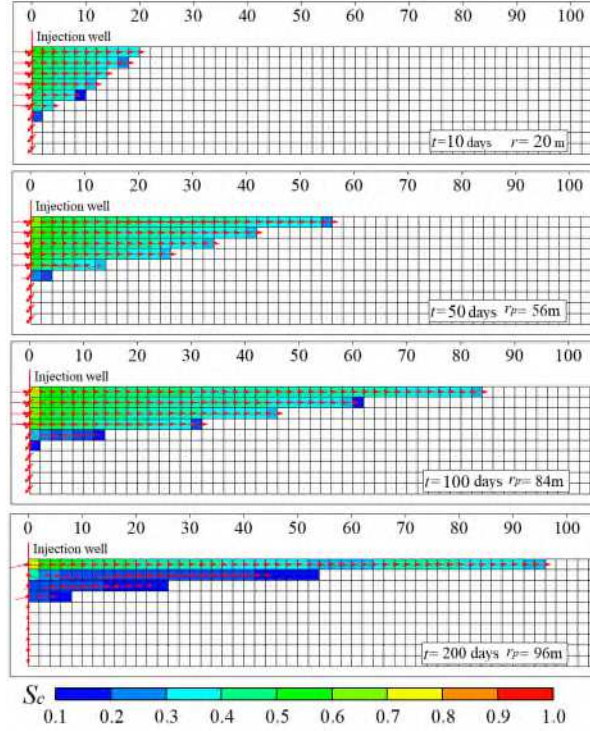
After the start of injecting CO<sub>2</sub> into the aquifer, CO<sub>2</sub> saturation around the injection well increased with replacing saline water. Therefore, with increasing CO<sub>2</sub> saturation, the viscosity  $\mu$  of the aquifer fluid, especially around the injection well, gradually changed from the viscosity of saline-water ( $\mu_{brine} \approx 6 \times 10^{-10}$  Pa·s) to that of supercritical-CO<sub>2</sub> viscosity ( $\mu_{CO_2} \approx 0.429 \times 10^{-10}$  Pa·s). As shown in Fig. 8, a decrease in the transient pressure after a pressure build-up of 350 kPa was observed during CO<sub>2</sub> injection at a constant injection rate, while the pressure build-up during saline water injection gradually increased. However, in the early stage of CO<sub>2</sub> geological storage, the magnitude of pressure build-up ( $\approx 350$  kPa) is similar even if different fluids are injected, because the CO<sub>2</sub> storage area is limited around the well; moreover, CO<sub>2</sub> saturation is also limited to less than 35 %, based on the relative permeability curves shown in Fig. 3, when CO<sub>2</sub> dissolution into saline water is neglected. Therefore, the pressure change ( $\approx 50$  kPa) during the CO<sub>2</sub> injection period (100 day) is not proportional to the fluid viscosity, even if the viscosity of CO<sub>2</sub> is less than 10 % of the viscosity of saline water. Thus, using the viscosity of saline water in Eq. (6) instead of that of CO<sub>2</sub> shows a more realistic estimation of the pressure build-up in the aquifer at the initial injection stage. However, the pressure build-up estimated by Eq. (6) using the viscosity of saline water is slightly overestimated than that of CO<sub>2</sub>. This difference can also be explained by the equation presented by Cinar et al. (Cinar et al., 2008; IEACHG, 2010). They modified Eq. (6). by introducing the relative permeability of CO<sub>2</sub>. However, introducing CO<sub>2</sub> relative permeability is another complicated question as CO<sub>2</sub> relative permeability changes with continuous injection, adding more uncertain variables. In this study, the viscosity of saline water is used to estimate the rough pressure build-up using Eq. (6).



**Fig. 8** Pressure build-up by injecting CO<sub>2</sub> and saline water vs. elapsed times for the base model

In the present simulations, the radial flow consisting of saline water and CO<sub>2</sub> was calculated considering the relative permeability curves for each fraction. Therefore, physical property changes in the blocks including multi-phase flow were simulated automatically in the present simulations using CMG-STARSTM.

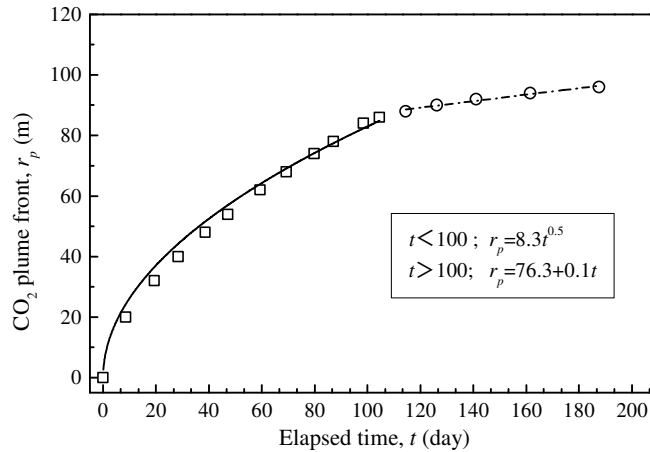
Figure 9 shows the cross-sectional simulation results for the  $r$  and  $z$  axes of CO<sub>2</sub> saturation and CO<sub>2</sub> plume flux vectors at  $t=10, 50, 100$ , and  $200$  day after the start of CO<sub>2</sub> injection. The CO<sub>2</sub> plume expands mainly as a radial flow, because the horizontal permeability,  $k$ , or hydraulic diffusivity,  $\eta$ , is 10 times larger than that of the vertical value. The buoyancy force on unit CO<sub>2</sub> volume (roughly 4,000 kN/CO<sub>2</sub>-m<sup>3</sup>) induces vertical CO<sub>2</sub> convection flow, because of the density difference between injected supercritical CO<sub>2</sub> ( $\approx 600$  kg/m<sup>3</sup>) and saline water ( $=1,030$  kg/m<sup>3</sup>) in the aquifer. Therefore, the top layer of the aquifer shows the largest expanding CO<sub>2</sub> seepage flow velocity with the farthest CO<sub>2</sub> plume front. The red arrows in Fig. 9 show the flow velocity vectors. It is clear that the CO<sub>2</sub> plume diffuses mainly in the radial direction during the CO<sub>2</sub> injection period, while the convection in the vertical direction is much slower. After the injection well was shut-in, the driving pressure in the horizontal direction gradually vanished with fall-off pressure, and the vertical buoyancy flow becomes prominent.



**Fig. 9** Cross-sectional on  $r$  and,  $z$  axes of CO<sub>2</sub> saturation and CO<sub>2</sub> plume flux vectors at  $t=10, 50, 100$ , and  $200$  day for the base model

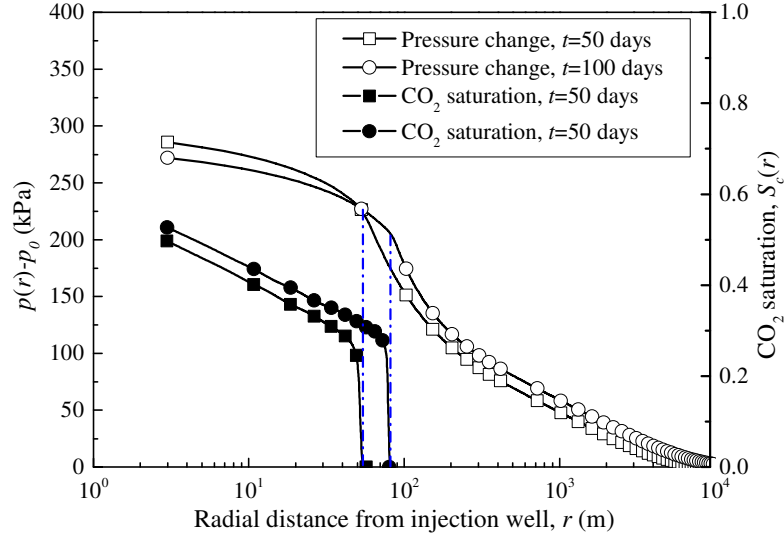
At the end of CO<sub>2</sub> injection, the CO<sub>2</sub> saturation around the injection well is about 70 %–80 %, and it decreases with the distance from the injection well, with a sharp decrease to 0 % around the plume front. After the injection is stopped, the CO<sub>2</sub> pattern continues to expand, and the CO<sub>2</sub> saturation next to the injection well decreases over time. When  $t=100$  day, the CO<sub>2</sub> saturation around the injection well decreases to approximately  $S_c=50$  %–60 % at  $t=200$  day.

We defined the CO<sub>2</sub> plume front position at the top layer,  $r_p$ , where the CO<sub>2</sub> saturation is  $S_c=10$  %. As shown in Fig. 10, the plume front is observed at  $r_p=84$  m on the 100<sup>th</sup> day. Figure 10 shows the CO<sub>2</sub> plume front position,  $r_p$ , before and after stopping CO<sub>2</sub> injection at  $t=100$  day ( $=t_i$ ). The CO<sub>2</sub> plume front position,  $r_p$ , expands almost proportionally to  $t^{0.5}$  for  $0 < t < 100$  day. After the injection well was shut-in at  $t > 100$  day, the CO<sub>2</sub> front slowly expands proportionally to  $0.1t$  by buoyancy force on the CO<sub>2</sub> plume.



**Fig. 10** CO<sub>2</sub> saturation front distribution over time

The numerical simulation results of the base model for the distributions of the reservoir pressure change from the initial aquifer pressure ( $p(r)-p_0$ ) and CO<sub>2</sub> saturation ( $S_c(r)$ ) at  $t=50$  and 100 day are shown in Fig. 11.

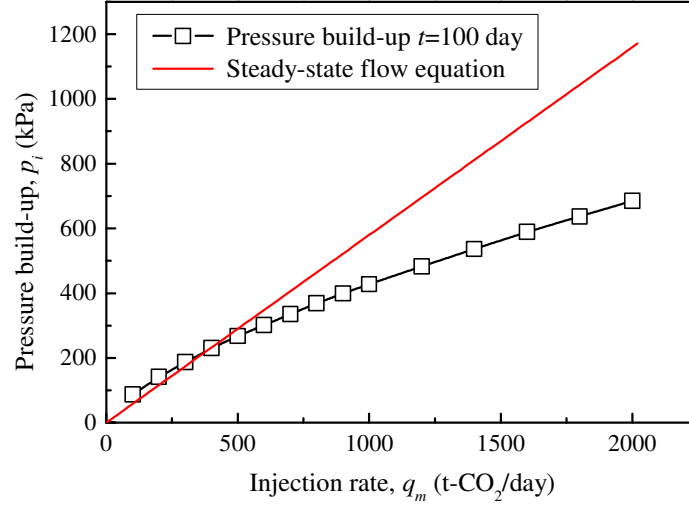


**Fig. 11** Numerical simulation results of pressure response vs. CO<sub>2</sub> saturation at different distances from the injection well

It can be seen that pressure changes and CO<sub>2</sub> saturation distributions are correlated in the region of CO<sub>2</sub> saturation  $S_c > 35\%$ , while only a pressure change is observed in the region ( $r > 100$  m) with a CO<sub>2</sub> saturation  $S_c \approx 0$ . Assuming the position of the CO<sub>2</sub> plume front defined by  $S_c = 10\%$ , the pressure transmitting speed is two orders of magnitude higher than that of the CO<sub>2</sub> plume front, because the pressure change is observed without CO<sub>2</sub> saturation change.

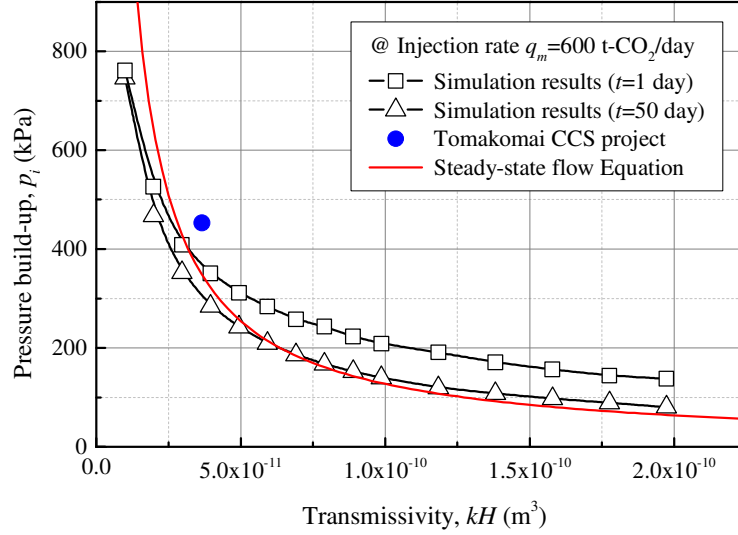
### Effect of CO<sub>2</sub> injection rate and aquifer transmissivity on pressure build-up

Figure 12 shows the simulation results of pressure build-up,  $p_i$  at the CO<sub>2</sub> injection well for injection rate,  $q_m$ , compared with the estimated line calculated using Eq. (6) by assuming the viscosity of saline water, as discussed in the previous section. The pressure build-up does not show a significant linear relationship with injection rate. As discussed previously, this can be explained by the changing CO<sub>2</sub> saturation around the injection well, since the relative permeability changes with CO<sub>2</sub> saturation. The simulation results show that the linearity between  $p_i$  and  $q_m$  is better and closer to the values estimated by Eq. (6) with a low injection rate  $q_m < 600$  t-CO<sub>2</sub>/day than that with a large injection rate  $q_m > 1,500$  t-CO<sub>2</sub>/day. This is because the higher injection rate results in a faster change in CO<sub>2</sub> saturation around the injection well.



**Fig. 12** Numerical simulation results of pressure build-up  $p_i$  vs. CO<sub>2</sub> mass injection rate  $q_m$

We confirmed that the pressure build-up can be correctly estimated using saline water viscosity can be corrected by using the viscosity of saline water to be 65 % because the CO<sub>2</sub> saturation around the injection well is close to 35 %. CO<sub>2</sub> injection into the Moebetsu Formation was conducted and the maximum pressure build-up of the injection well (IW-2) was recorded around  $p_i=450$  MPa at the injection rate  $q_m=600$  t-CO<sub>2</sub>/day and injection time  $t_i=50$  day. The thickness of the Moebetsu Formation is approximately 100 to 200 m which is uncertain and different from the base model set. Simulations were run, and the pressure build-up against different transmissivities of the aquifer was studied. According to the simulation results shown in Fig. 11, the transmissivity of the Moebetsu Formation is approximately  $K=2.7 \times 10^{-11}$  m<sup>3</sup>, and the permeability of the Moebetsu Formation was calculated as  $135 \times 10^{-15}$ – $270 \times 10^{-15}$  m<sup>2</sup>, which is different from our base model setting  $k=363 \times 10^{-15}$  m<sup>2</sup> that is overestimated according to a comparison between the field pressure data and simulation results. Owing to the short injection period, the fluid flow around the injection well is in an unsteady state. In Fig. 13, the pressure build-up at the injection well after  $t=1$  and 50 day, with respect to aquifer transmissivity  $K$ , were compared with those in the steady-state flow (Eq. (6)). As in the early stage of injection, there is a transient effect of pressure build-up at the injection well, and the pressure build-up of the injection well on the 50<sup>th</sup> day is closer to the steady-state flow than with that on the 1<sup>st</sup> day. A higher transmissivity aquifer is getting closer to the calculated pressure build-up,  $p_i$  of steady-state flow.



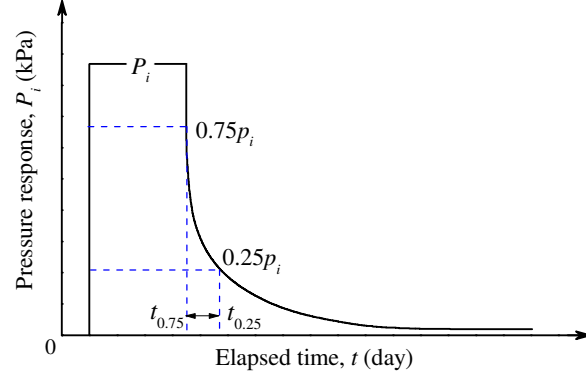
**Fig. 13** Pressure build-up,  $p_i$  (kPa) vs. aquifer transmissivity,  $kH$  ( $m^3$ )

### Pressure fall-off at the CO<sub>2</sub> injection well

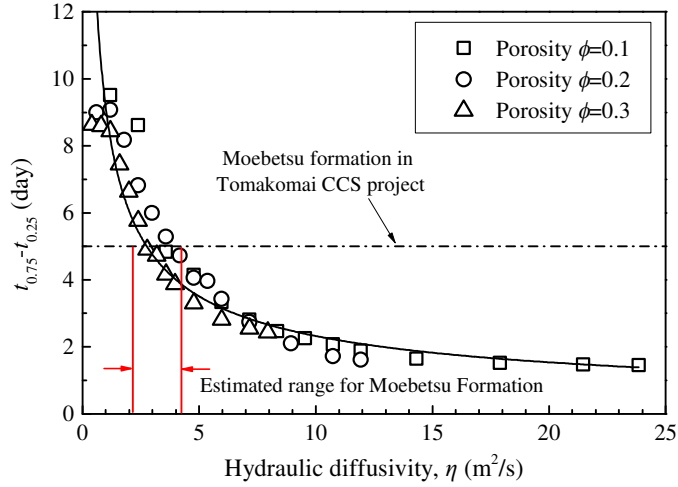
Opening or shutting off a well causes pressure changes in the CO<sub>2</sub> injection well. The CCS projects including fall-off data after shut-in can be used to study the aquifer state (Escobar and Montealegre, 2008). When the BHP vs. time plots are measured with sufficient precision after the well shut-in, the aquifer *in-situ* permeability and well skin factor can be estimated by analyzing the data. This is similar to the well-testing method widely used in petroleum reservoir engineering. Without considering the skin factor the pressure fall-off function in the injection well is expressed by the radial transient flow equation (Eq. (7)). The pressure  $p_0$  should be modified to the instantaneous BHP when the injection well is shut in. Because  $q\mu/(4\pi kH)$  can be treated as a constant if the injection rate  $q$  is constant, the hydraulic diffusivity  $\eta$  can be considered the main parameter controlling the fall-off curve.

In contrast to the traditional method of analyzing pressure fall-off lines, the pressure fall-off time is defined in this study to analyze reservoir conditions and pressure transients. As shown in Fig. 14,  $t_{0.75}$  and  $t_{0.25}$  are defined as the elapsed times to reach 75% and 25% pressure reductions from the build-up pressure after the well shut-in. The pressure fall-off time is defined as  $(t_{0.75}-t_{0.25})$ , which shows the period the pressure falls off 50% of the built-up pressure.

In the case of CO<sub>2</sub> injection in the Moebetsu Formation, Tomakomai CCS project, some pressure fall-off data were recorded after shutting the well, and the fall-off time  $(t_{0.75}-t_{0.25})$  was analyzed at about 5 day based on the BHP data. The numerical simulation results for the fall-off time  $(t_{0.75}-t_{0.25})$  vs. hydraulic diffusivity  $\eta$  for the base model are shown in Fig. 15, which includes the results of different porosities (0.1, 0.2, and 0.3) and permeabilities  $k$  ( $=98\times 10^{-15}$ – $1,960\times 10^{-15}$   $m^2$ ). As the fall-off time for the Moebetsu Formation (dotted line in Fig. 15) was 5 day, the hydraulic diffusivity range of the Moebetsu Formation can be estimated as  $\eta=2$ – $4$   $m^2/s$  from the simulation results of  $(t_{0.75}-t_{0.25})$  and hydraulic diffusivity. As the transmissivity of the Moebetsu Formation was matched as  $K=2.7\times 10^{-11}$   $m^3$  in the last section, and the thickness is between  $H=100$ – $200$  m, porosity  $\phi=0.2$ – $0.4$ ; therefore, the matrix rock compressibility of the Moebetsu Formation is estimated as  $C_r=0.14\times 10^{-9}$ – $1.11\times 10^{-9}$   $Pa^{-1}$ . This means that the rock compressibility set as  $C_r=0.9\times 10^{-9}$   $Pa^{-1}$  is within the reasonable range compared with the Moebetsu Formation.



**Fig. 14** Definition of pressure fall-off time after pressure build-up

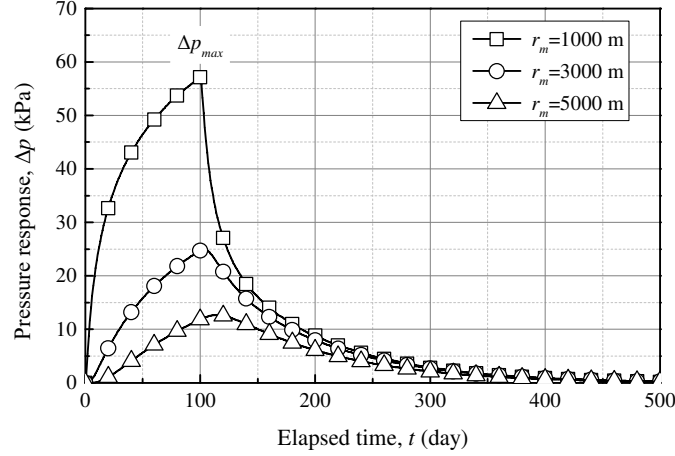


**Fig. 15** Numerical simulation results of fall-off time ( $t_{0.75}-t_{0.25}$ ) vs. hydraulic diffusivity  $\eta$  compared with the fall-off time of the Moebetsu Formation (5 day)

### Pressure response at observation wells

In this section, the pressure responses at a hypothetical observation well located at a range of radial distance  $r_m=1,000$ – $5,000$  m from the injection well are discussed based on the simulation results by comparing the values estimated using Eq. (8). The maximum value of pressure response is defined as  $\Delta p_{max}$ , which is recorded at the observation well ( $r=r_m$ ) after continuous  $\text{CO}_2$  injection for  $t_i=100$  day in each injection scheme. Figure 16 shows the numerical simulation results of the pressure response at the observation well located at  $r_m=1,000$ ,  $3,000$  and  $5,000$  m against the  $\text{CO}_2$  injection  $q_m=600$  t- $\text{CO}_2$ /day for  $t_i=100$  day (base model). The pressure of the observation well increases gradually during the injection period, which is different from the pressure build-up of the injection well. This is because the pressure build-up in the vicinity of the injection well (less than  $r=100$  m) is influenced by both  $\text{CO}_2$  and saline water flows, while the pressure disturbance around the observation well far from the injection well is not influenced by the difference in viscosities of  $\text{CO}_2$  and saline water. After the injection well is shut-in ( $t>t_i$ ), the observation well pressure draws a curve similar to the pressure fall-off of the injection well. It can also be seen that there is a time delay between the injection well shut-in to the peak pressure response of the observation well, and this delay time becomes larger as the distance from the injection well increases. The peak value of the pressure response,  $\Delta p_{max}$  becomes smaller and broader, and the peak time recorded at the observation well,  $\Delta t_{max}$ , increases with increasing distance from the injection well,  $r_m$ . For example,  $\Delta p_{max}=57$  kPa at  $r_m=1,000$  m becomes more than twice ( $\Delta p_{max}=25$  kPa) at  $r_m=3,000$  m.



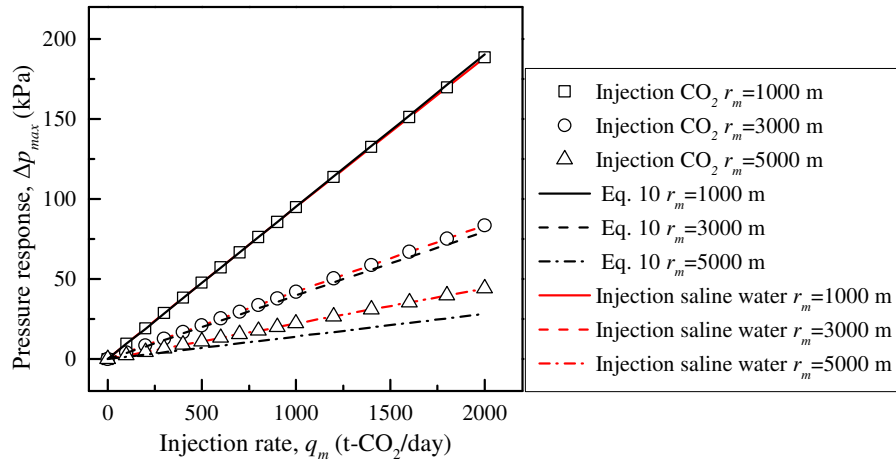


**Fig. 16** Typical simulation results of the pressure response at the observation wells located at  $r_m=1,000$ ,  $3,000$ , and  $5,000$  m

As is shown in Fig. 17, the simulation results of  $\Delta p_{max}$  have a linear relationship with the  $\text{CO}_2$  mass injection rate  $q_m$  and are consistent with the numerical simulation results for injecting saline water. The analytical equation assuming a transient radial flow expressed as:

$$\Delta p_{max} = p(r_m, t_{max}) - p_0 \quad (10)$$

The analytical solution obtained with Eq. (10) is less than the simulation results. The difference between the results increases as the radial distance between the injection well and observation wells increase, because the value estimated by Eq. (10) can only be applied for a rough estimation. In this simulation study, the injection period was assumed to be  $t_i=100$  day, and the peak pressure response at the observation well can be detected after dozens of days.



**Fig. 17** Numerical simulation results of the pressure response at the observation wells vs.  $\text{CO}_2$  mass injection rate  $q_m$  ( $\text{t-CO}_2/\text{day}$ )

## The pressure ratio of the injection well and observation well

### Single $\text{CO}_2$ injection with pressure build-up and fall-off

To avoid the error in the absolute magnitude of the pressure response at the observation well, we introduced the parameter  $R$ , which is the ratio of the pressure build-up (BHP)  $p_i$  and the maximum value of pressure response  $\Delta p_{max}$ .

Both the pressure build-up at the injection well and the pressure response at the observation wells have almost linear relationships with the injection rate,  $q_m < 600$  t-CO<sub>2</sub>/day. This ratio can be used for determining the pressure response at the observation wells based on the pressure build-up, because the ratio  $R = \Delta p_{max}/p_i$  is not sensitive to the mass injection rate,  $q_m$ . In addition, the term  $q\mu_w/(4\pi kH)$  in Eq. (7) can be treated as a constant if the mass injection rate  $q_m$  is a constant. Therefore, the value of  $R$  is proportional to the injection period and hydraulic diffusivity but inversely proportional to the square of the radial distance from the well, while it is not as sensitive to the CO<sub>2</sub> mass injection rate  $q_m$ . The rough value of  $R$  can be estimated by the following equation where hydraulic diffusivity,  $\eta$ , is defined by Eq. (5).

$$R = \frac{1}{2 \ln(r_e/r_w)} \left( \ln \eta \frac{t_i}{r_m^2} + 0.809 \right) = 0.0434 \cdot \left( \ln \eta \frac{t_i}{r_m^2} + 0.809 \right) \quad (11)$$

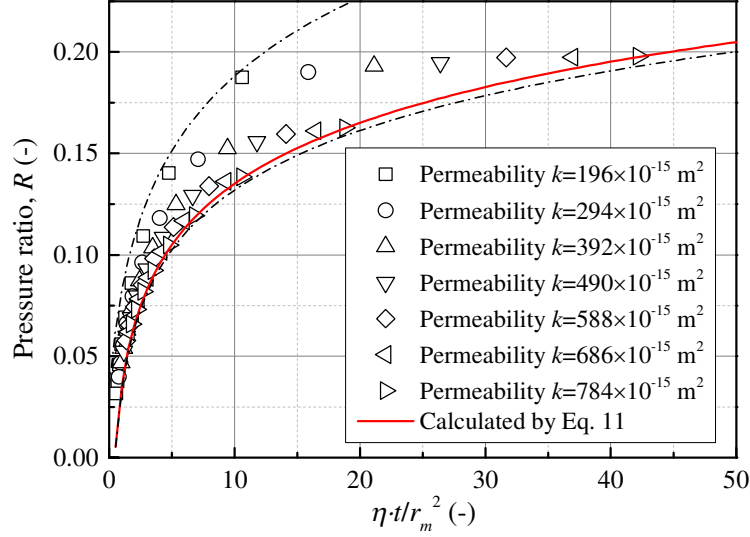
where  $C_i$  is equal to rock compressibility because fluid is assumed to be incompressible ( $C_f=0$ );  $r_e=10,000$  m is the effective reservoir radius, and  $r_w=0.1$  m is the radius of the injection well. Equation (11) shows that  $R$  consists of a logarithmic function of time  $t$ , aquifer area up to the inner area of the observation well radius ( $\pi r_m^2$ ), and hydraulic diffusivity,  $\eta$ . Assuming that the observation well response to the peak pressure value occurs at the moment the injection well is shut-in, the time  $t$  in Eq. (11) is replaced with  $t_i$ .

The numerical simulations of  $R$  using CMG-STARST<sup>TM</sup> were performed for the base model with the horizontal permeability range from  $k=196 \times 10^{-15}$ – $784 \times 10^{-15}$  m<sup>2</sup> (=200–800 md), the observation well location  $r_m=1,000$ – $5,000$  m, and different injection periods  $t_i=50$ – $300$  day; the porosity and compressibility of the porous media were considered constant ( $\phi=0.30$  and  $C_i=1.4 \times 10^{-9}$  Pa<sup>-1</sup>). A sensitive study of hydraulic diffusivity  $\eta$  was also carried out by setting the constant injection rate  $q_m=600$  t-CO<sub>2</sub>/day. The simulation results of  $R$  compared with values calculated by Eq. (11) are shown in Fig. 18. It can be seen that the pressure ratio  $R$  shows an almost logarithmic function of  $\eta t/r_m^2$ . However, there is a slight difference between the values of  $R$  for different permeabilities, especially when  $\eta t/r_m^2 > 10$ . Because there is a time delay between the injection well shut-in and the observation well response to the peak pressure value, the time  $t$  of the simulation results shown in Fig. 18 was considered as  $t=t_i+\Delta t_{max}$ .  $\Delta t_{max}$  is defined as the time delay from the shut-in time at the injection well to the time observation well attains the peak pressure (Fig. 5). Thus, the pressure response at the observation well calculated by Eq. (11) is underestimated compared with the numerical simulation; however, both plots of  $R$  vs.  $\eta t/r_m^2$  have a similar relationship expressed by the logarithmic function. It can also be seen that Eq. (11) is more suitable for a high-permeability aquifer as an aquifer with a larger permeability has a shorter time delay, and the simulation results of  $R$  will be closer to the value calculated by Eq. (11). This logarithmic function can help us deduce an evolution of the pressure at the observation well at different distances  $r_m$ , at different times according to the injection well pressure build-up of field data. The hydraulic diffusivity  $\eta$  was evaluated by the pressure fall-off lines after the shut-in. Therefore, the observation well location can be designed at an appropriate location, and a pressure transmitter with suitable pressure resolution can be selected for pressure monitoring.

An empirical equation based on the simulation results in Fig. 18 was summarized without considering the time delay  $\Delta t_{max}$ , and it is given by:

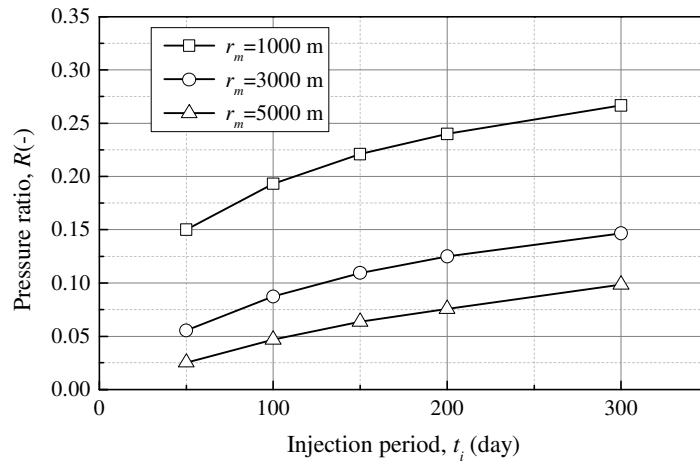
$$R = \frac{\Delta p_{max}}{p_i} = (0.0425-0.06) \cdot \left( \ln \eta \frac{t_i}{r_m^2} + 0.809 \right) \quad (12)$$

The pressure ratio at an observation will have a big variation at different permeability aquifer conditions. Eq. (12) can be applied to the Tomakomai CCS project, and it can also be applied to other CCS projects with the pressure ratio  $\eta t/r_m^2 < 10$ . In addition, a specific analysis of the pressure ratios against different variables can be performed to make a relatively more accurate assessment for a planned CCS project in the future.



**Fig. 18** Numerical simulation results of pressure ratio  $R$  for different permeabilities ( $q=600$  t- $\text{CO}_2/\text{day}$ ,  $t_i=100$  day,  $k=196\times 10^{-15}$ – $784\times 10^{-15}$   $\text{m}^2$ )

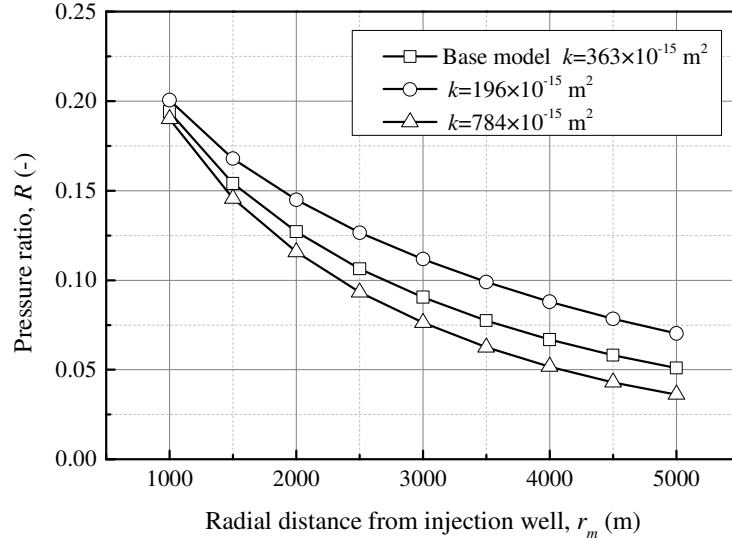
According to the simulation results of pressure build-up at the  $\text{CO}_2$  injection well and pressure response at the observation well, it is expected that the pressure ratio  $R$  increases with increasing injection period because the pressure build-up at the injection well  $p_i$  decreases with increasing  $\text{CO}_2$  injection period  $t_i$ . In contrast, the response pressure at the observation well  $\Delta p_{\max}$  becomes higher. Figure 19 shows the numerical simulation results of the pressure ratio  $R$  for different injection periods from  $t_i=50$ – $300$  day. The higher response pressure can be monitored by increasing the injection period because  $R$  increases with  $t_i$ .



**Fig. 19** Effect of injection period,  $t_i$  on pressure ratio,  $R$

The pressure ratios at different distances from the injection well for the base model ( $k=363\times 10^{-15}$   $\text{m}^2$ ) compared with the pressure ratio in an aquifer with permeability  $k=196\times 10^{-15}$  and  $784\times 10^{-15}$   $\text{m}^2$  (=200 and 800 md) are shown in Fig.

20. The pressure fluctuates with the permeability of the aquifer. As shown in Fig. 18, there is a small difference between the values of  $R$  for different permeabilities, especially when  $\eta t/r_m^2 > 10$ . Figure 20 more intuitively reflects the pressure ratio change with the increasing radial distance from the injection well. The pressure ratio,  $R$ , changes faster when the radial distance from the injection well is larger. However, as the upper limit pressure response at the observation well is small, it is easy to estimate the pressure for choosing an effective pressure sensor. In the Tomakomai CCS project, the observation well OB-2 was drilled at  $r_m \approx 3,000$  m from the injection well to monitor the pressure change caused by  $\text{CO}_2$  injection. The present simulation result for  $q_m = 600$  t- $\text{CO}_2$ /day and  $t_i = 100$  day shows that  $R = 0.09$  at  $r_m = 3,000$  m.

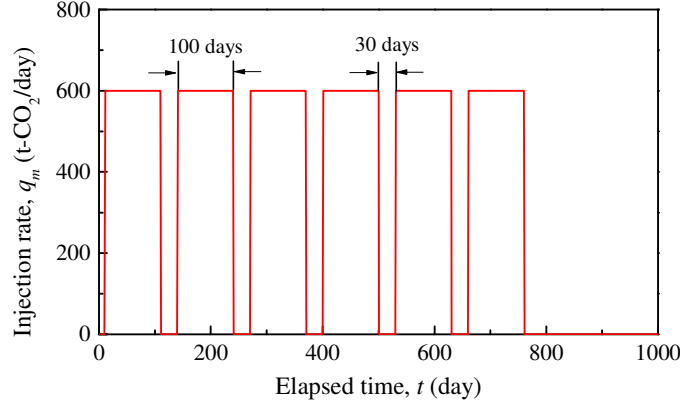


**Fig. 20** Pressure ratio vs radial distance from the injection well ( $t_i = 100$  day) for the base model

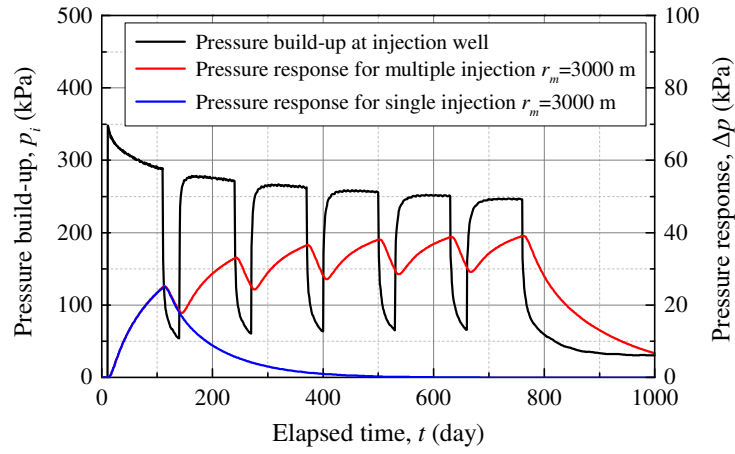
### A case of multiple $\text{CO}_2$ injections

For the Tomakomai CCS project, the  $\text{CO}_2$  injection pattern in the early stage of the project comprised a series of injections with multiple pressure build-ups and fall-offs. The  $\text{CO}_2$  injection status was tested to check the pressure build-up against the injection rate in the early stage of  $\text{CO}_2$  injection. A model case used to investigate the pressure response by multiple  $\text{CO}_2$  injections is shown in Fig. 21. The multiple injection model includes six cycles with  $t_i = 100$  day as injection period and  $t_s = 30$  day as shut-in period based on the Tomakomai CCS project (Singh, 2018). The parameters set in the numerical simulation were the same as those for the single injection model (Table 1).

The simulation results of pressure build-up at the injection well and pressure response at the observation well are shown in Fig. 22. The pressure responses of the observation wells located 3,000 m away from the injection well are shown in Fig. 22. The first  $\text{CO}_2$  injection cycle is the same as the single injection case (base case) until the second cycle starts. It can be seen that each injection causes a pressure response peak at the observation well and draws down in the injection well, similar to the pressure fall-off in the case of single build-up and fall-off. The BHP in the injection well shows a slight drop due to the changing  $\text{CO}_2$  saturation and fluid viscosity around the injection well as discussed for the single build-up and fall-off case. The pressure build-up in each injection decreases, while the pressure response  $\Delta p_{max}$  in each corresponding injection at the observation well gradually increases.

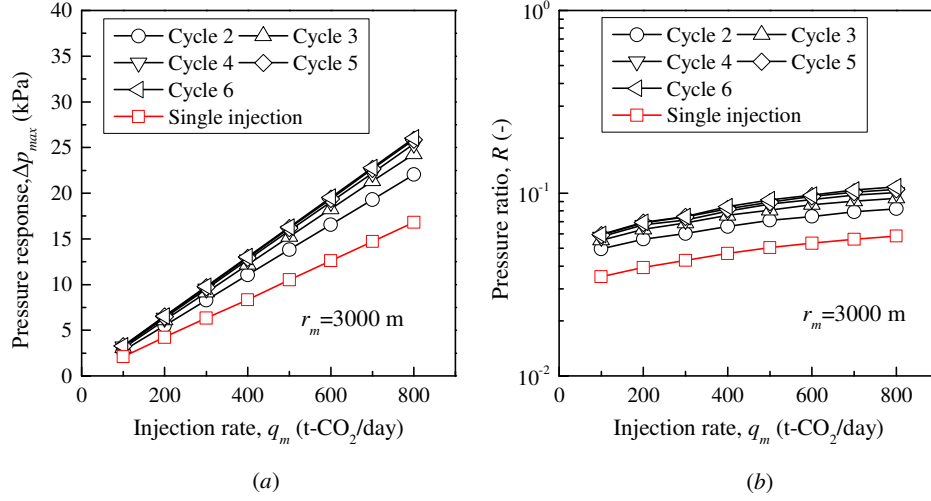


**Fig. 21** A model case of CO<sub>2</sub> multiple injections consists of six injection cycles with  $t_i=100$  day as injection period and  $t_s=30$  day as shut-in period



**Fig. 22** Pressure build-up of the injection well and pressure response in multiple-injection and single injection cases for the observation well at  $r_m=3,000$  m

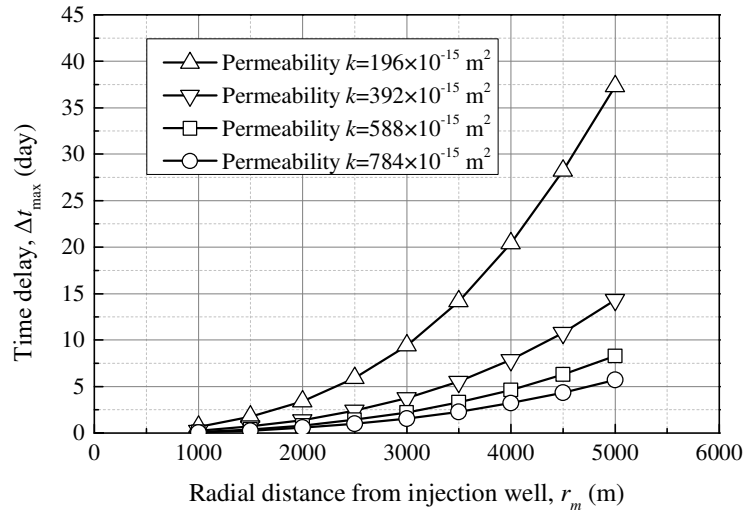
The reservoir flow around the injection well turns to a steady state after injecting a large amount of CO<sub>2</sub> into the reservoir in a single cycle. As is shown in Fig. 22, the case of multiple CO<sub>2</sub> injections shows a broader pressure response. Figure 23 shows the pressure response at the observation wells and the pressure ratio for the distance  $r_m=3,000$  m from the injection well. The peak pressure value at the observation well turns to be a stable value, which is similar to the pressure build-up at an injection well. Thus, the pressure ratio also approaches to a stable value. This is more convenient for determining a reliable pressure ratio in the simulation study.



**Fig. 23** Pressure response and pressure ratio  $R$  in the observation well at  $r_m=3,000$  m for the multiple-injections model compared with the single injection model (base case) vs. injection rate  $q_m$ ; (a) Pressure response (b) Pressure ratio  $R$ .

### Delay time of the pressure response at the observation well

Even if the injection well is shut-in and returns to the initial pressure, the pressure transmitted in the aquifer continues moving to the outer ward with depleting its amplitude. Figure 24 shows the numerical simulation results of time delay  $\Delta t_{max}$  in the aquifer with the horizontal permeability range from  $k=196 \times 10^{-15}$ – $784 \times 10^{-15}$  m<sup>2</sup> ( $=200$ – $800$  md) at the observation wells with different radial distances ( $r_m=1,000$  to  $5,000$  m) from the injection well. As discussed above, fluid flow transmits faster in a high-permeability aquifer, and the pressure transmitting speed is two orders of magnitude higher than that of the CO<sub>2</sub> plume. The time delay  $\Delta t_{max}$  is proportional to the distance from the injection well and inversely proportional to the aquifer permeability. The time delay  $\Delta t_{max}$  increases exponentially with increasing radial distance  $r_m$ . For example, the time delay value for an observation well located at the radial distance  $r_m=1,000$  m occurs the peak pressure value on the day of shut-in of the injection well, while it takes about  $t=37$  day to detect a peak pressure response from an observation well located at a radial distance  $r_m=5,000$  m for a reservoir with permeability  $k=196 \times 10^{-15}$  m<sup>2</sup>.



**Fig. 24** Numerical simulation results of time delay  $\Delta t_{max}$  of the pressure response peak for the observation wells

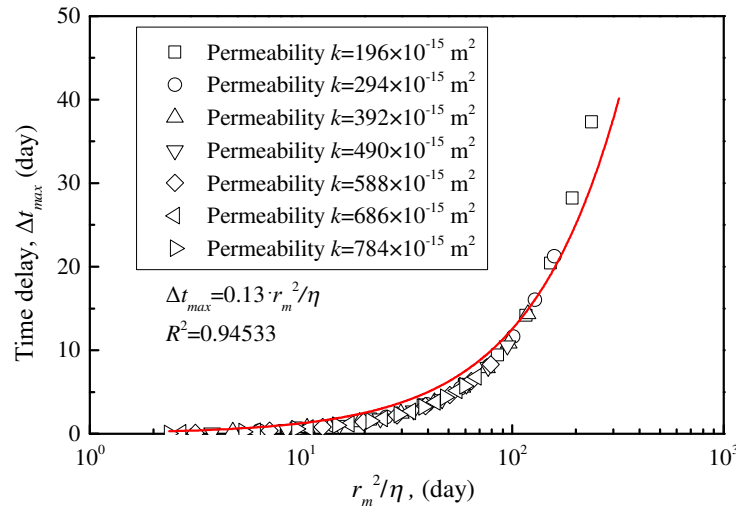
located at the radial distance  $r_m$  (Base model, injection period  $t_i=100$  day)

The pressure response at the observation well shows a pressure peak that is almost proportional to the pressure build-up at the injection well. The delay time,  $\Delta t_{max}$ , as defined in Fig. 5, was found to be the peak value on the curve of  $p(r_m)$  vs.  $t$  for  $r_m=1,000\text{--}5,000$  m and permeability  $k=196\times 10^{-15}\text{--}784\times 10^{-15}$  ( $\approx 200\text{--}800$  md).

The simulation results of  $\Delta t_{max}$  vs.  $r_m^2/\eta$  are summarized in Fig. 25. It can be seen that the time delay  $\Delta t_{max}$  is almost linearly proportional to  $r_m^2/\eta$ , which is inversely proportional to the horizontal permeability,  $k$ . The relationship can be summarized as follows:

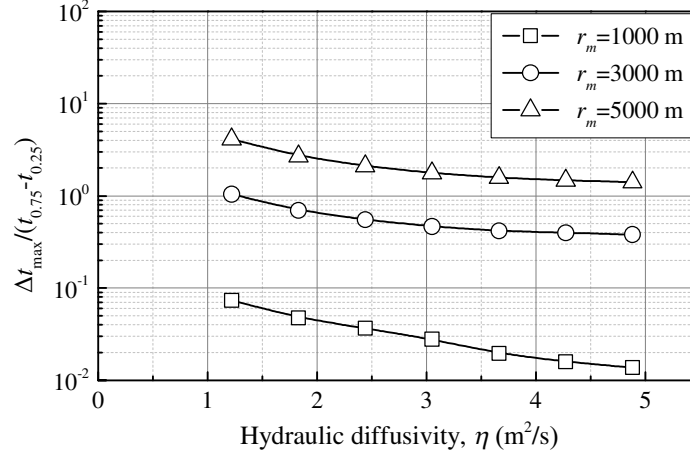
$$\Delta t_{max} = 0.13 \cdot \frac{r_m^2}{\eta} = 0.13 \cdot \frac{\phi C_t r_m^2 \mu}{k} \quad (13)$$

The time delay  $\Delta t_{max}$  can be used as a reference parameter to assess the hydraulic transmission capacity of aquifers.



**Fig. 25** Time delay of the observation wells with  $r_m=1,000\text{--}5,000$  m for different permeabilities

As discussed above, both the time delay  $\Delta t_{max}$  and the pressure fall-off time ( $t_{0.75}-t_{0.25}$ ) can be used as important parameters to evaluate the hydraulic diffusivity  $\eta$  of an aquifer. Figure 26 shows the numerical simulation results of the relationship between the hydraulic diffusivity  $\eta$  and time ratio  $\Delta t_{max}/(t_{0.75}-t_{0.25})$ . Both time delay and fall-off time are inversely proportional to the hydraulic diffusivity, and the time ratio is inversely proportional to the hydraulic diffusivity. The approximate magnitude of the time ratio in different hydraulic diffusivity aquifers was estimated. It is convenient to estimate the time delay of peak pressure using the time ratio when the fall-off time is measured. For example, for  $r_m=3,000$  m,  $\Delta t_{max}$  is equal to  $(0.4\text{--}0.7) \times (t_{0.75}-t_{0.25})$  for  $\eta=2\text{--}4$  m<sup>2</sup>/s corresponding to the range of the Tomakomai CCS project.



**Fig. 26** Numerical simulation results of time ratio against hydraulic diffusivity  $\eta$  (m²/s)

### Design of observation wells for CO<sub>2</sub> geological storage

Observation wells are drilled to observe the aquifer with CO<sub>2</sub> storage. It is assumed that temperature and pressure gauges are installed in the bottom hole for continuous monitoring of the aquifer. They are used to detect the CO<sub>2</sub> plume front development and verify that the injected CO<sub>2</sub> had not leaked into shallower strata (Metz et al., 2005). Most of the observation wells are used to monitor the CO<sub>2</sub> plume front position (Hu et al., 2015; Mathieson et al., 2011). The In Salah CCS program used an observation well KB-5 (Durucan et al., 2011) with a distance of 1.3 km from the injection well KB-502 and analyzed the gas tracer injected together with CO<sub>2</sub> to examine the CO<sub>2</sub> plume development. The observation well KB-5 was used for detecting the CO<sub>2</sub> plume position, not for the pressure analysis, and it was an abandoned gas production well drilled in 1980, which was not well designed for the CCS program. In Germany, a Ketzin pilot CCS program used two observation wells (Ktzi 200 and Ktzi 202) to determine the pressure evolution during injection operation with a distance of 50 m and 112 m from the injection well Ktzi 201 (Max. injection rate 78 t-CO<sub>2</sub>/day) respectively (Liebscher et al., 2013). If the distance between the observation wells and the injection well is extremely small, it can detect the CO<sub>2</sub> plume front development. However, according to some *in situ* experience, the greatest risk of CO<sub>2</sub> leakage for any geological storage project is associated with old wells and observation wells. Thus, an observation well located at a small distance from the injection well also creates a new potential pathway for CO<sub>2</sub> leakage to the sublayers, limiting the CO<sub>2</sub> injectivity.

In this section, pressure responses at an observation well are analyzed to discuss the effect of the radial distance from the injection well ( $r_m > 1,000$  m) and the pressure sensor resolution installed in it.

Table 2 shows the simulation results of the pressure at the observation well range with different radial distances from the injection well. For example, in the case of the observation well distance is equal to  $r_m = 3,000$  m, the minimum sensitivity of the pressure transmitter needs approximately 1 kPa order under the absolute pressure (or pressure resistance) of 10 to 11 MPa to obtain an accuracy of 2 digits. However, in the case of the minimum sensitivity is 10 kPa order, the well distance required should be lesser than  $r_m = 1,000$  m.

The pressure build-up of the Tomakomai CCS project is about 450 kPa, and the observation well OB-2 is drilled with a distance  $r_m = 3,000$  m from the injection well, according to the calculation, the maximum pressure value might be  $\Delta p_{\max} = 27$  and 35 kPa is expected after  $t = 50$  and 100 day injection respectively. The specific resolution of the pressure



transmitter installed in the observation well at  $r_m=3,000$  m is required to be less than 1 kPa that is a tough specification under absolute pressure 10 to 11 MPa to analyze aquifer permeability characteristics.

**Table 2** Resolution required for pressure measurement at the observation wells ( $r_m=1,000$ – $5,000$  m  $p_i=1,000$  kPa)

Radial distance $r_m$ (m)	$t_i=50$ day		$t_i=100$ day	
	Pressure response $\Delta p_{\max}$ (kPa)	Spec. resolution (kPa)	Pressure response $\Delta p_{\max}$ (kPa)	Spec. resolution (kPa)
1,000	144–156	5	190–200	5
2,000	73–100	5	116–145	5
3,000	41–70	1	76–112	1
4,000	25–51	1	52–88	1
5,000	18–38	1	36–70	1

## Conclusion

In this study, numerical simulations on pressure responses at injection and observation wells for CO<sub>2</sub> geological storage in a deep saline aquifer were done for CO<sub>2</sub> injection rate and aquifer characteristics, such as permeability or transmissibility and hydronic diffusivity. The pressure responses and their time delay at the observation well become base data to check whether the aquifer model is enough reasonable to simulate the CO<sub>2</sub> storage. If the pressure measurement result at the observation well in the early stage of the CO<sub>2</sub> storage project matches the numerical prediction result using the aquifer simulation model, it can be one of the data proofing accuracies of the simulation model. Especially, the pressure ratio of the pressure response at the observation against a pressure build-up and fall-off at the injection well has been predicted as the judgment index of pressure change that is mainly related to the distance between injection and observation wells, but not sensitive to the injection rate. Therefore, it is essential to determine the location of the observation well and select a pressure transmitter with a reasonable resolution to measure the pressure response induced by the pressure build-up. The comparison of the simulation results and the actual measured results at the observation well provides whether the wide-area aquifer modeling used for the simulation is enough to correct or not. The results can be summarized as follows:

1. The pressure build-up  $p_i$  is proportional to  $q/K$  ( $q$ : CO<sub>2</sub> injection rate,  $K$ : transmissivity), and gradually tends to be saturated and maintains a slight dropping rate with increasing CO<sub>2</sub> saturation around the injection well due to decreasing reservoir fluids viscosity. The equation (6) for steady-state flow can be used for a rough estimation of the pressure build-up of the injection well by assuming saline water saturated in the aquifer.
2. The numerical simulation results of pressure build-up, and fall-off at the injection well were analyzed by comparing the field data of the Tomakomai CCS project, the transmissivity of the Moebetsu Formation targeted in the project was estimated roughly as  $K=2.7 \times 10^{-11}$  m<sup>3</sup> and the hydraulic diffusivity of the reservoir is  $\eta=2$ – $4$  m<sup>2</sup>/s. Therefore, assuming that the permeability of the Moebetsu Formation is  $k=135 \times 10^{-15}$ – $270 \times 10^{-15}$  m<sup>2</sup> and the porosity is  $\phi=0.20$ – $0.40$ , and the rock matrix compressibility of the Moebetsu Formation is estimated as  $C_r=0.14 \times 10^{-9}$ – $1.11 \times 10^{-9}$  Pa<sup>-1</sup>.

3. The radius of the CO<sub>2</sub> plume top front expands approximately proportionally to  $t^{1/2}$  before  $t < t_i = 100$  day, and after shut-in of the injection well at  $t = t_i$ , the top front is slowly expanding with proportionality to  $0.1t$  due to buoyancy force on the CO<sub>2</sub> plume.

The numerical simulation results on the pressure ratio  $R$  defined as the corresponding response pressure peak at the observation well ( $\Delta p_{\max}$ ) overpressure build-up in the injection well ( $p_i$ ) were analyzed, and a rough estimation value of  $R$  at the observation well location ( $r = r_m$ ) has been presented as

$$R = \frac{\Delta p_{\max}}{p_i} = (0.0425 - 0.06) \cdot \left( \ln \eta \frac{t_i}{r_m^2} + 0.809 \right)$$

4. In the case of six cycles of CO<sub>2</sub> injections of 100 day injection and 30 day shut-in,  $R$  for each response pressure peak at the observation well shows an almost same value as that of the single injection case.
5. The time of  $\Delta t_{\max}$  from shut-in to the time observing the response pressure peak at the observation well is directly proportional to the radial distance from the injection well ( $r_m$ ) and inversely proportional to the hydraulic diffusivity of the aquifer ( $\eta$ ), but it is not sensitive to the injection rate ( $q$ ).
6. The peak value of pressure response at the observation well at a radial distance from the injection well of  $r_m = 3,000$  m was simulated as 27–35 kPa for the pressure build-up of 0.45 MPa at the injection well. The specific resolution of the pressure transmitter set in the observation well at  $r_m = 3,000$  m must be less than 1 kPa to get two or more valid digits.

## Declarations

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## Compliance with ethical standards

The authors declare that they have no conflict of interest.

## Availability of data and material

Not applicable

## Code availability

Not applicable

## Author Contribution Statement

Dr. Sun and Prof. Sasaki are responsible for conceptualization, methodology and parametric analysis, software, preparation of figures and editing manuscript. The contribution of Prof. Yuichi Sugai, Dr. Ronald Nguele and Prof. Xiaoming Zhang includes conducting derivation, editing manuscript and improving manuscript writing.

## Consent for publication

Not applicable

## Consent to participate

Not applicable

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Figures

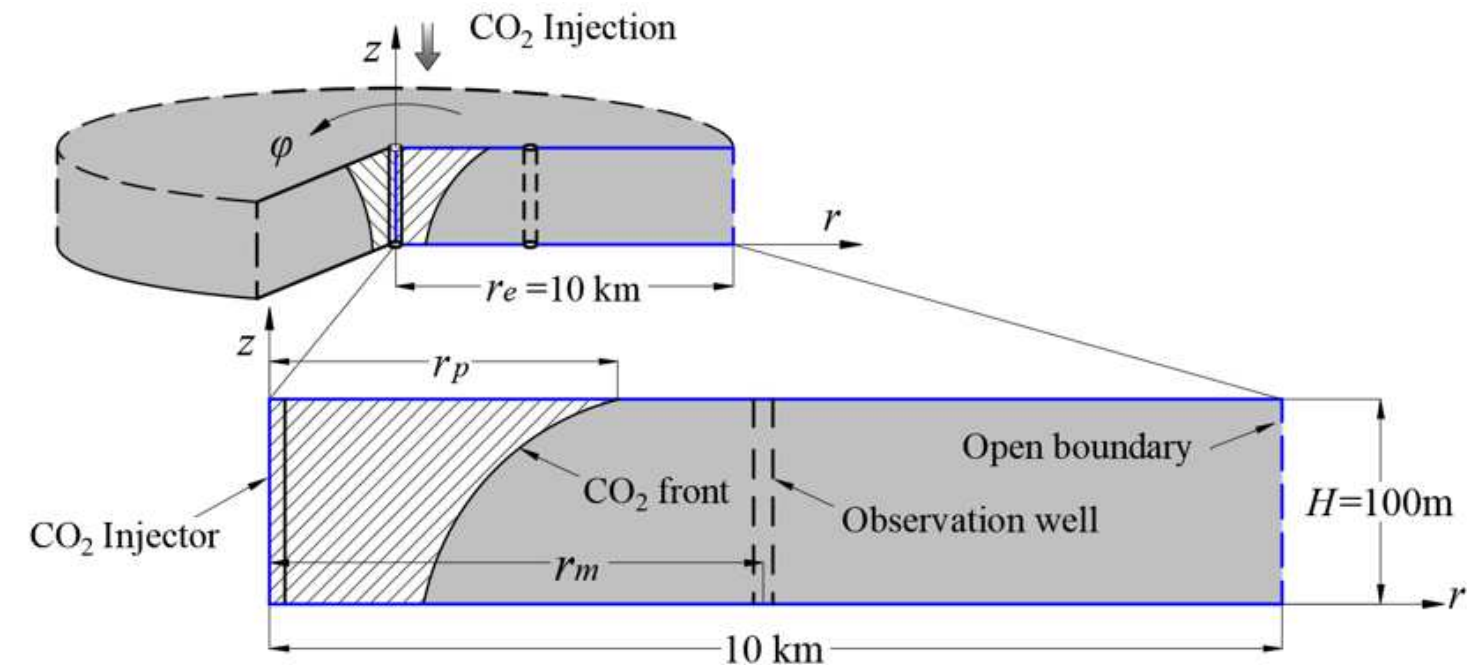


Figure 1

Schematic aquifer model

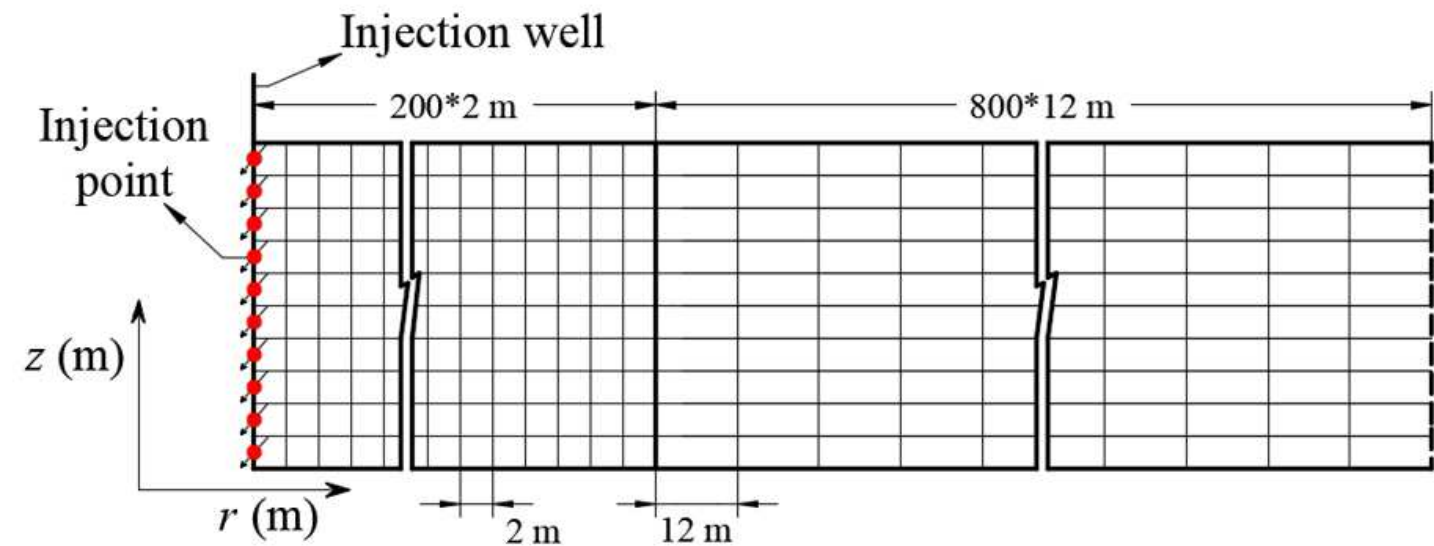
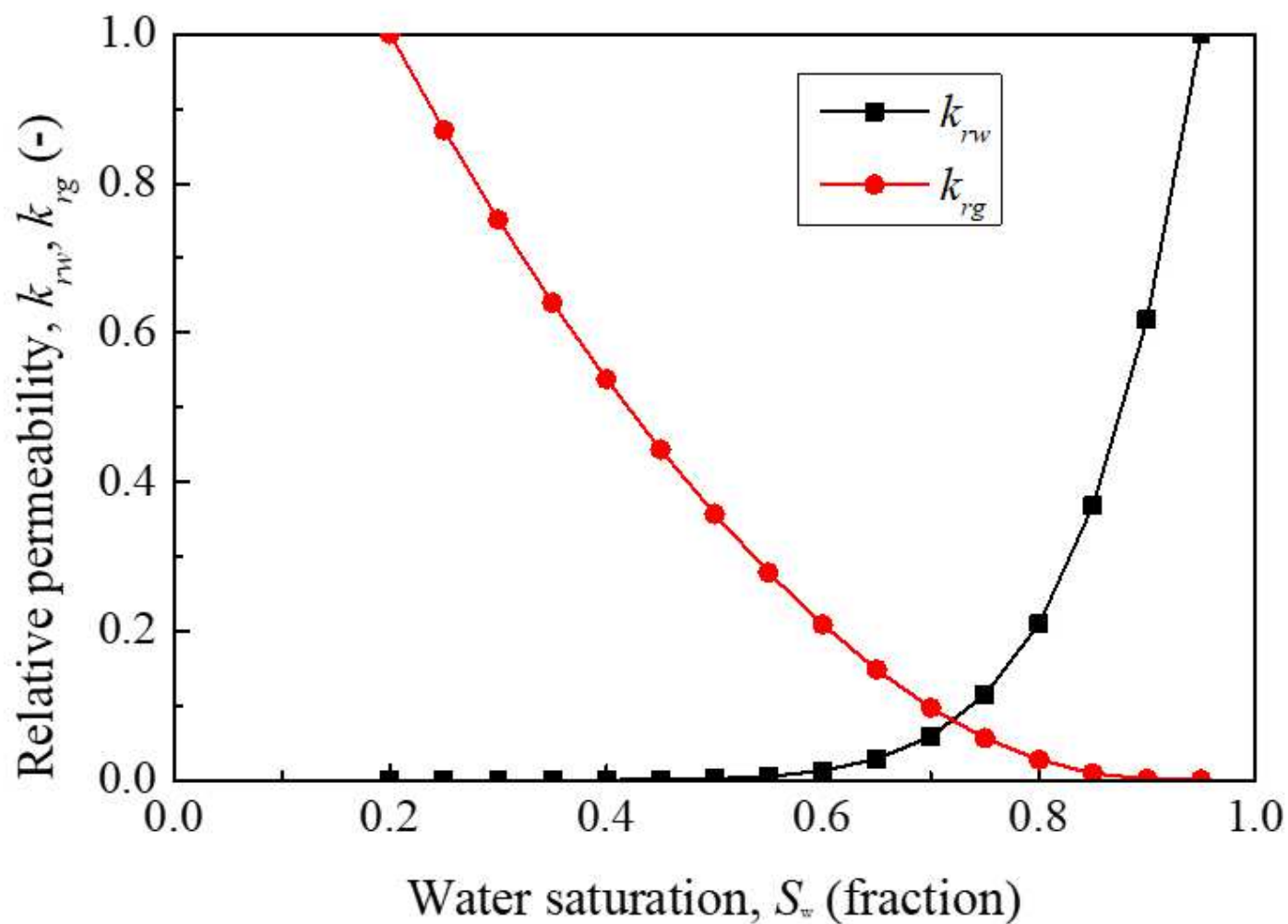


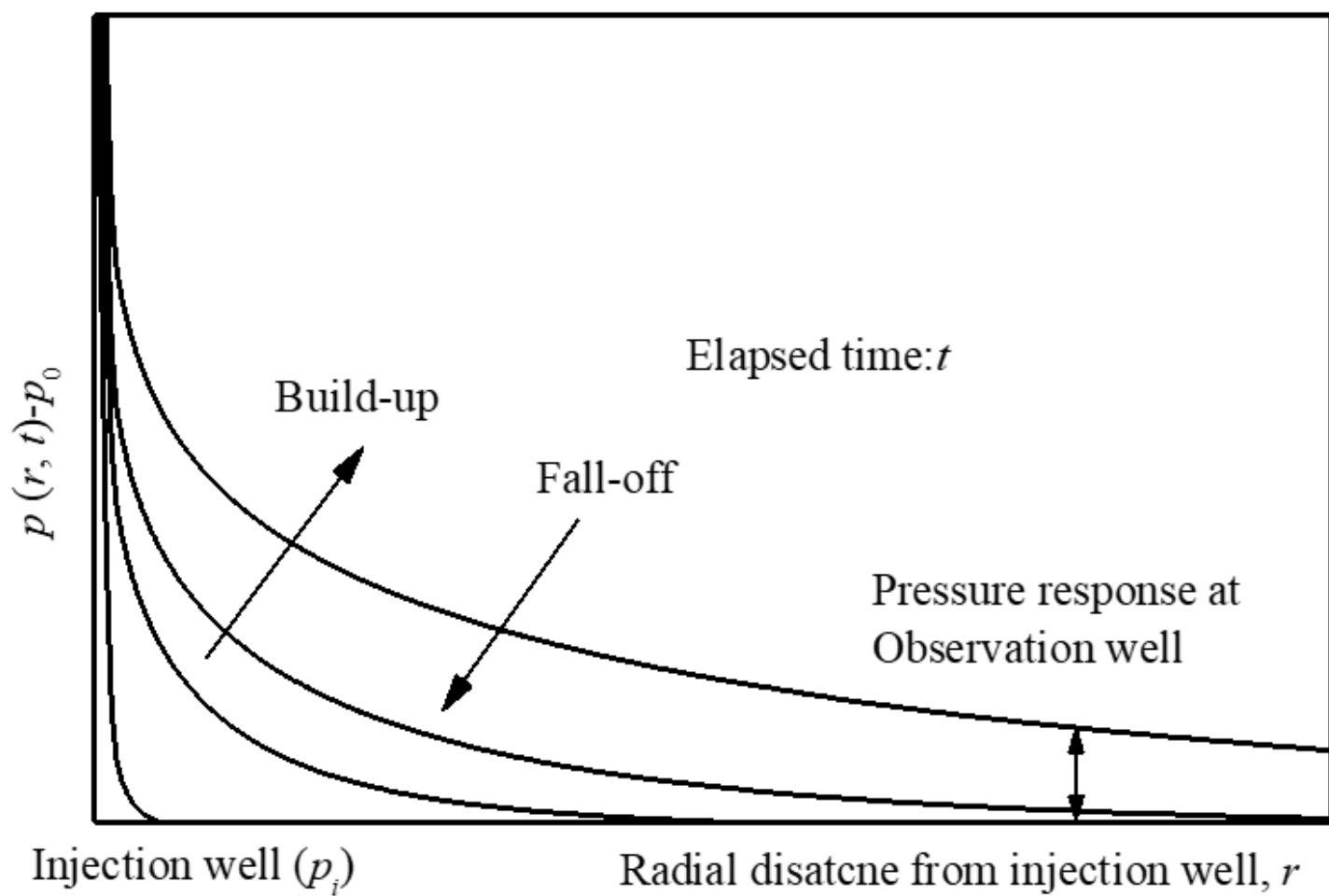
Figure 2

Schematic diagram of meshing in the vertical section



**Figure 3**

Relative permeability curves used in present simulations (Brooks-Corey-Burdine Model) (Garimella et al., 2019)



**Figure 4**

Schematic solution showing transient pressure for pressure build-up at an injection well



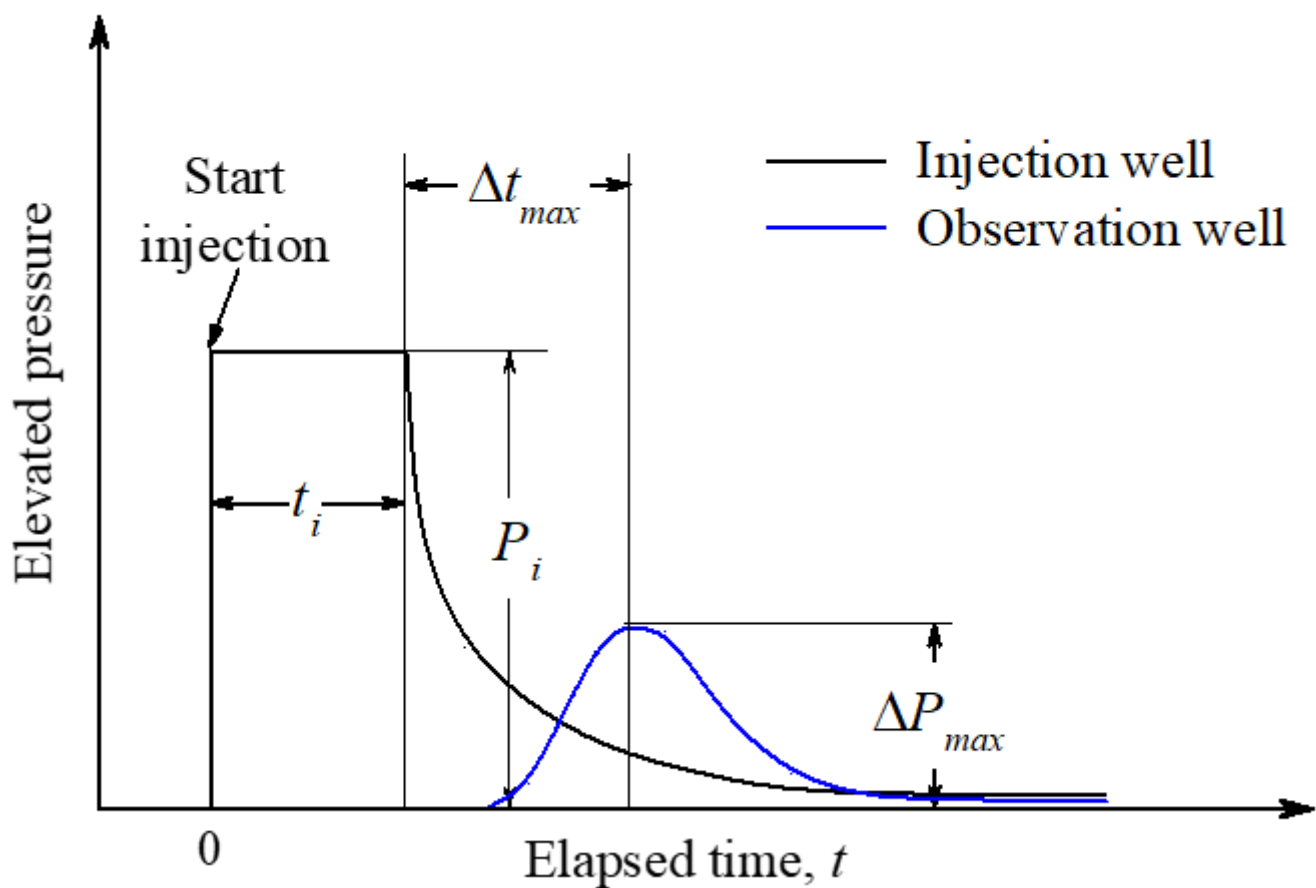


Figure 5

Schematic diagram of defined variables

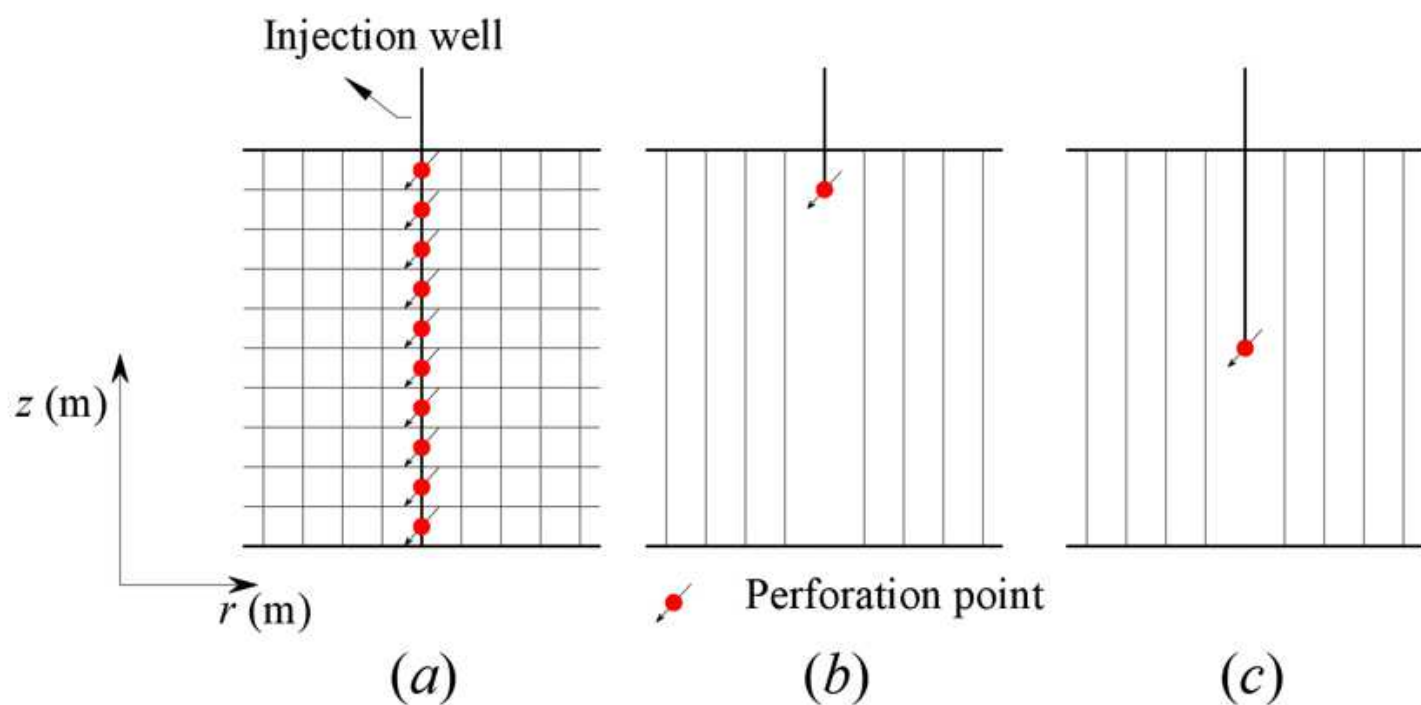
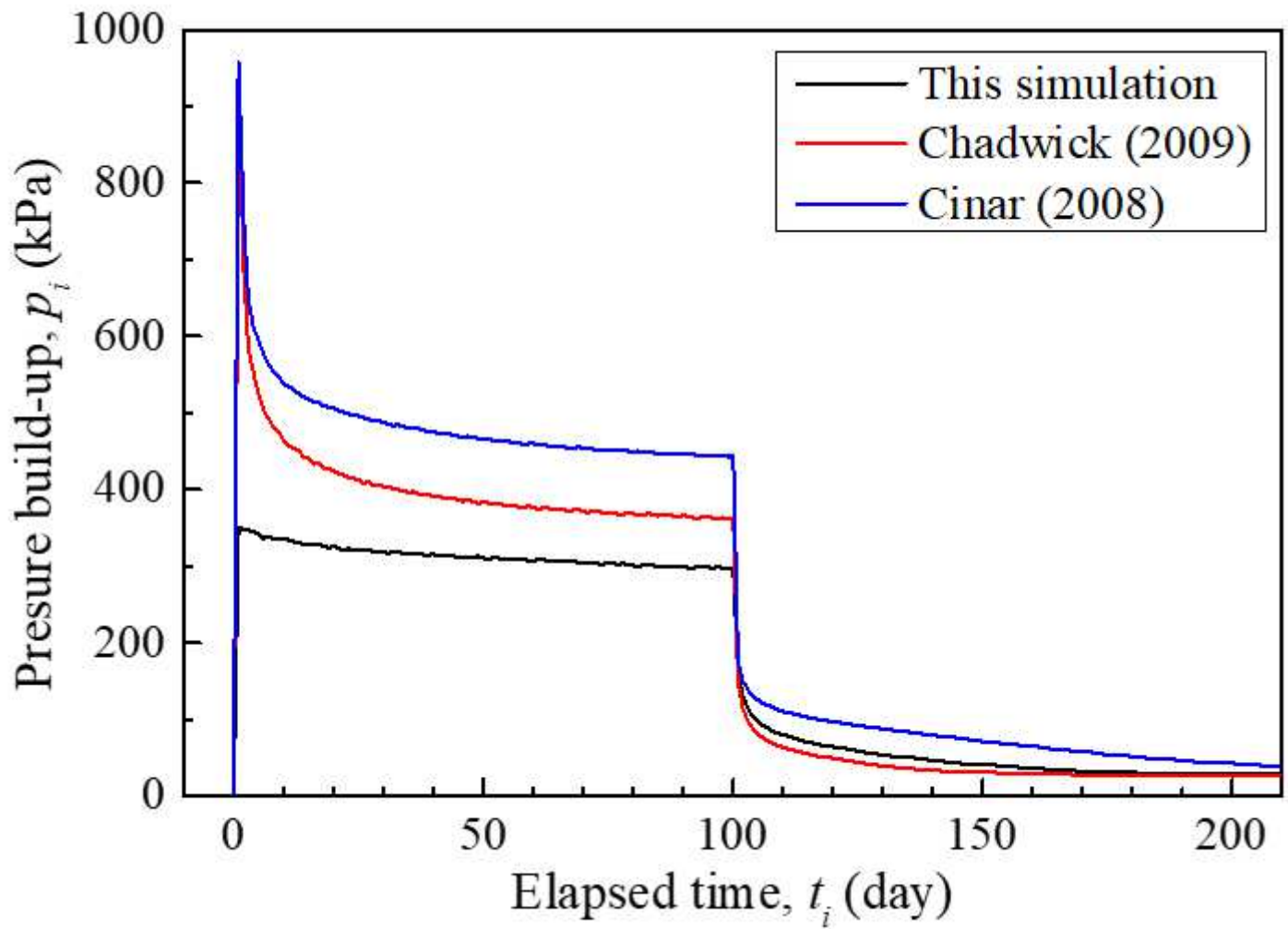


Figure 6

Injection well perforation schemes used in previous studies; (a) multiple perforations, (b) single perforation hole at the top used by Chadwick (2009) (Chadwick et al., 2009), (c) single perforation hole at a position used by Cinar et al (2008) (Cinar et al., 2008)



**Figure 7**

Numerical simulation results on pressure build-up of the injection well obtained with different perforation methods of the CO<sub>2</sub> injection well using CMG-STARSTM

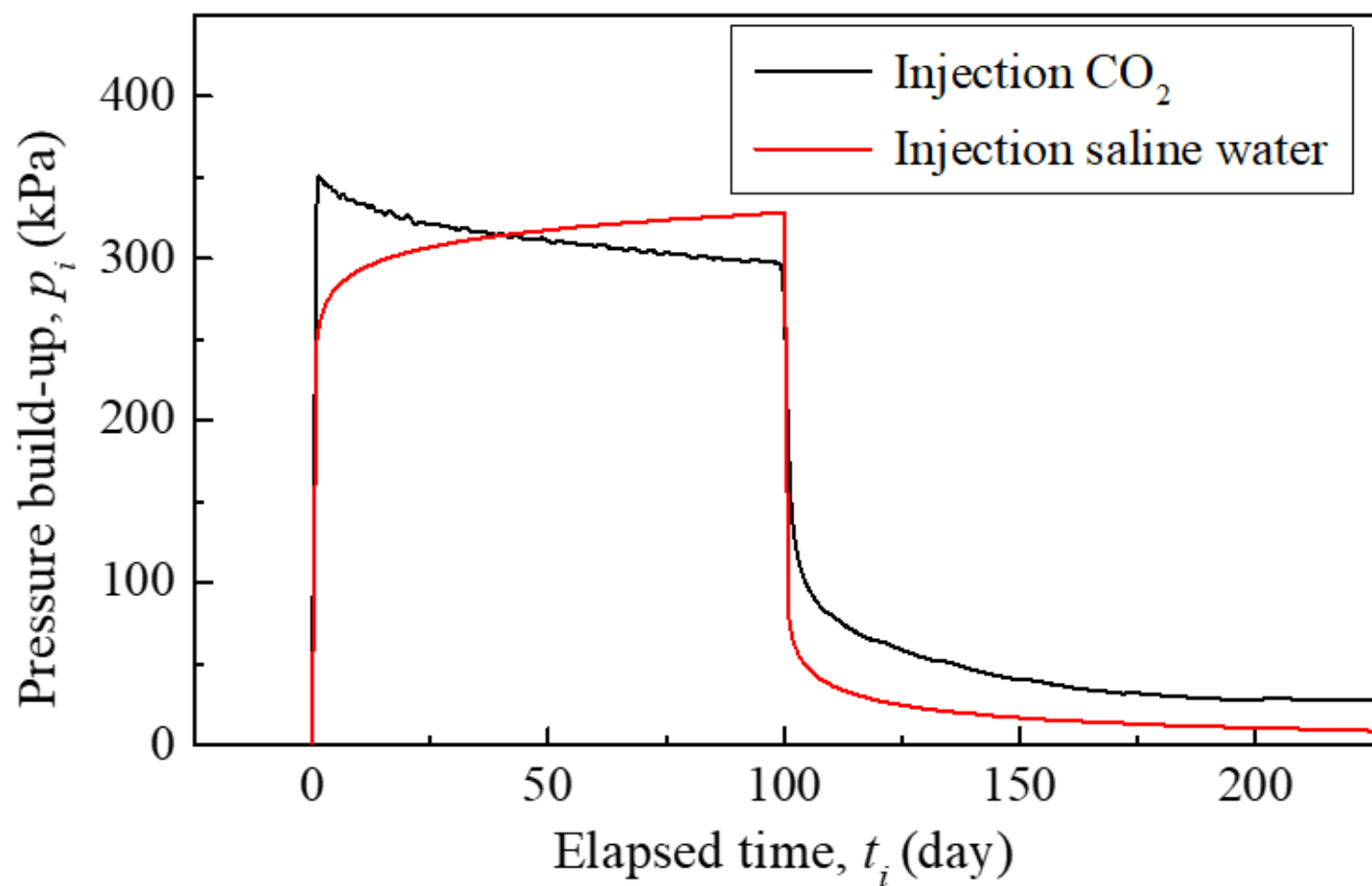
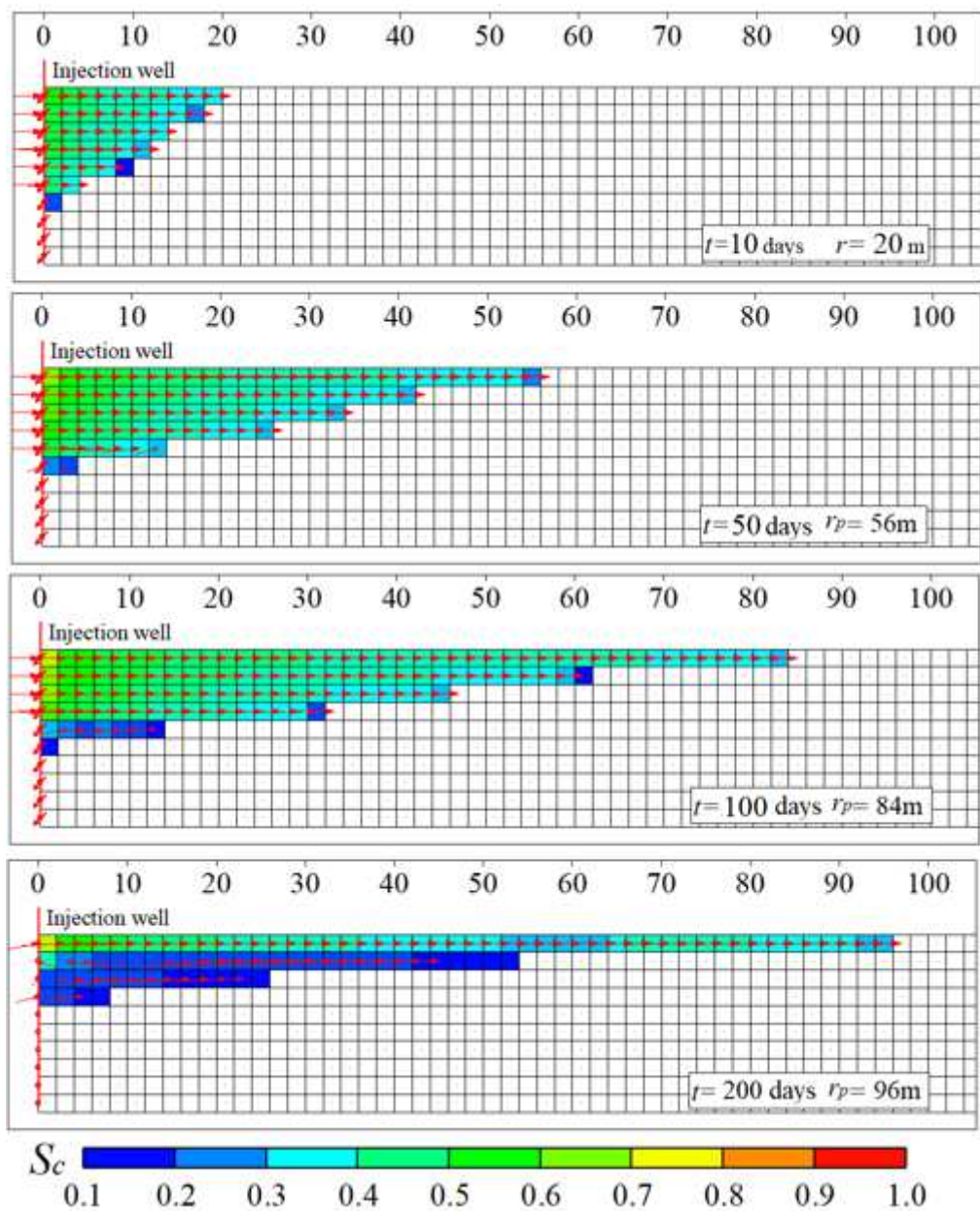


Figure 8

Pressure build-up by injecting CO<sub>2</sub> and saline water vs. elapsed times for the base model



**Figure 9**

Cross-sectional on  $r$  and,  $z$  axes of CO<sub>2</sub> saturation and CO<sub>2</sub> plume flux vectors at  $t=10, 50, 100$ , and  $200$  day for the base model

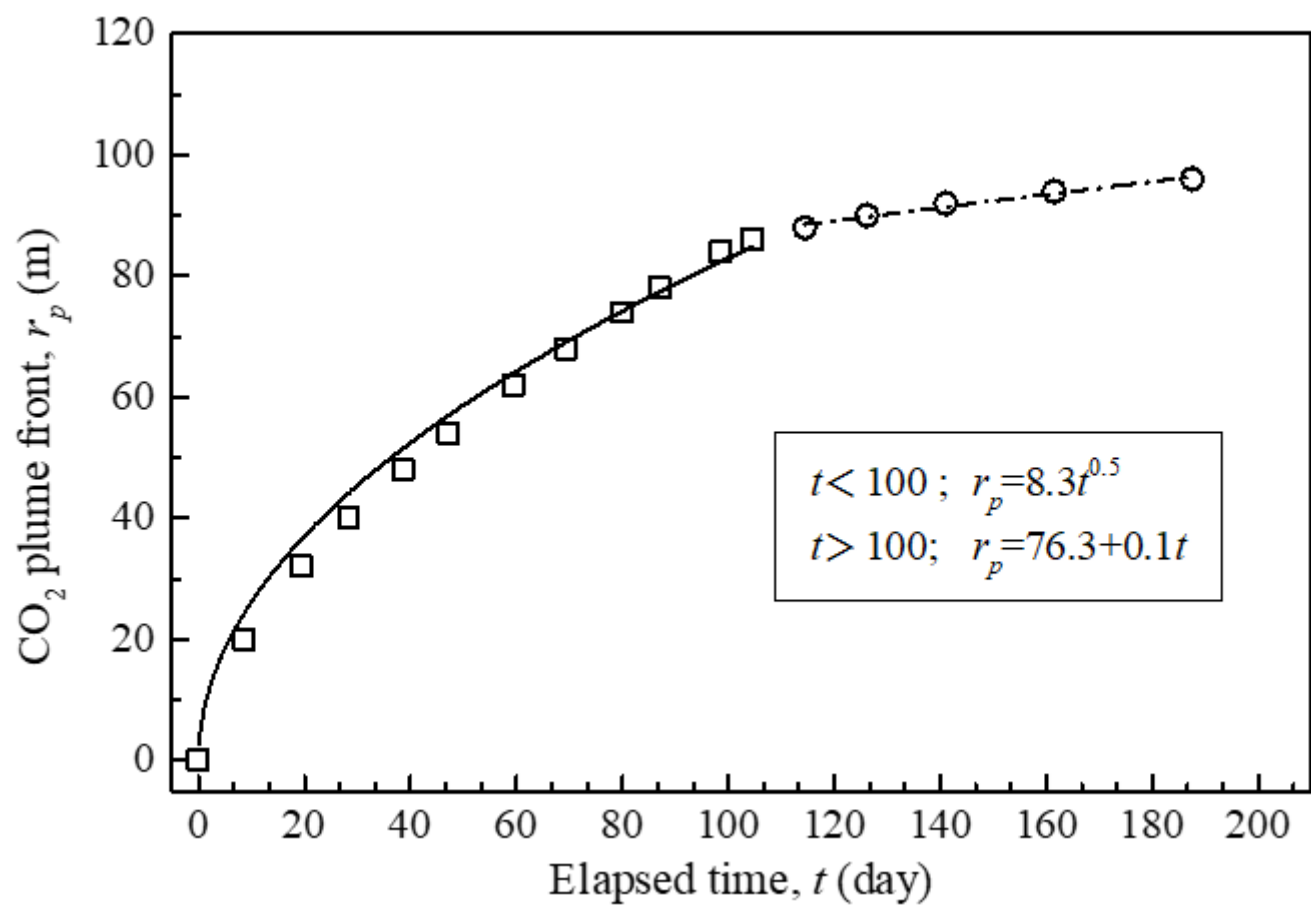
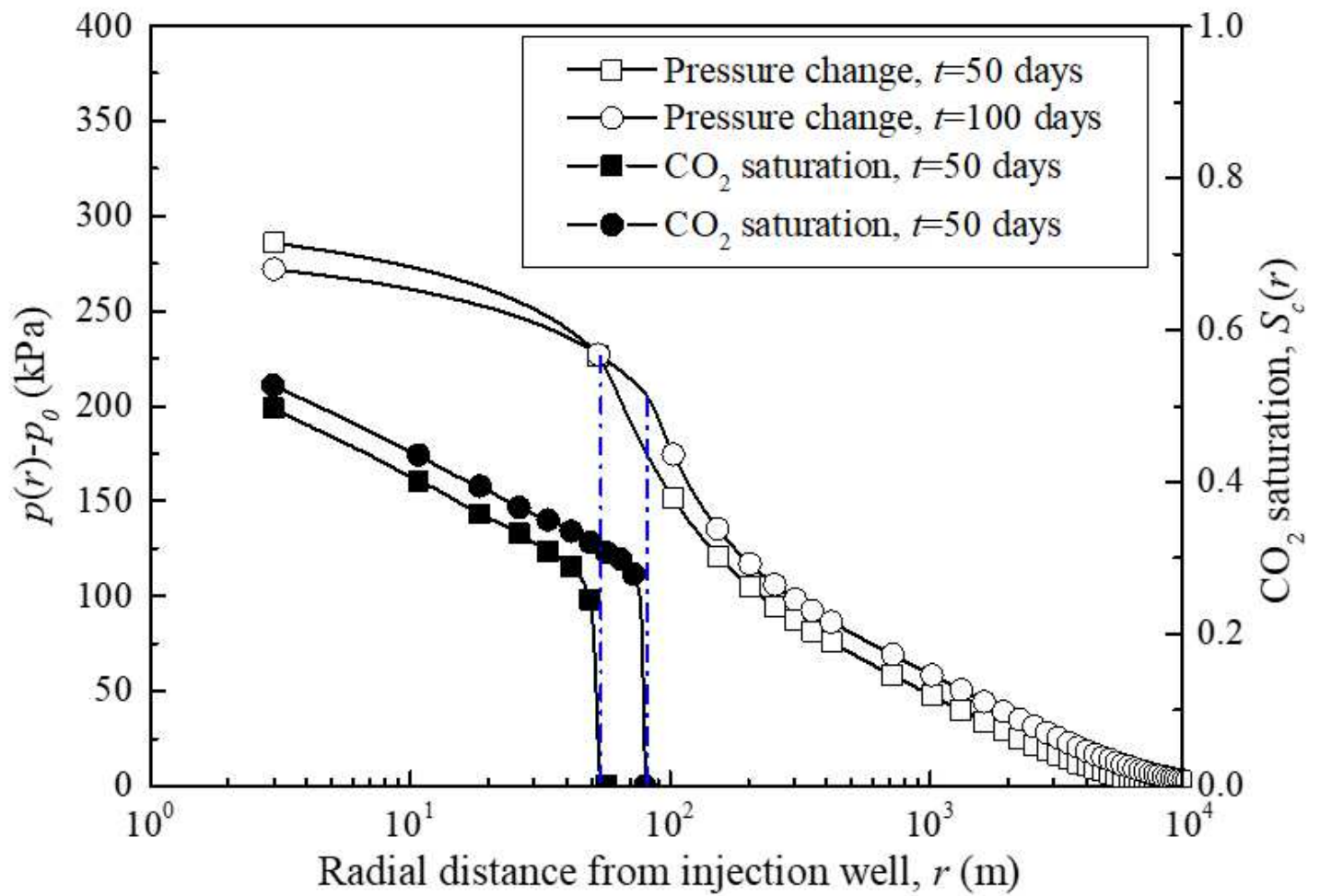


Figure 10

CO<sub>2</sub> saturation front distribution over time



**Figure 11**

Numerical simulation results of pressure response vs. CO<sub>2</sub> saturation at different distances from the injection well

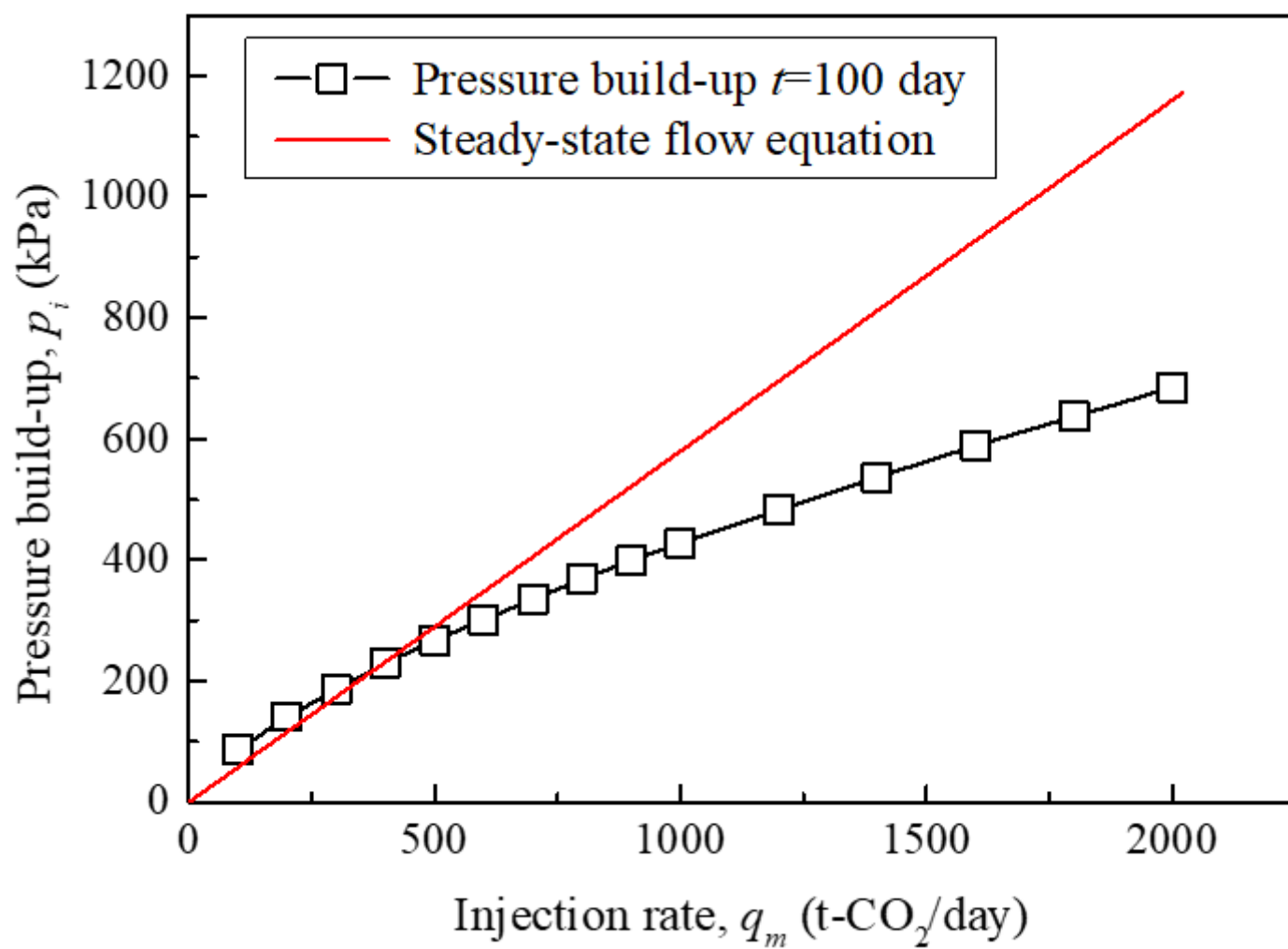


Figure 12

Numerical simulation results of pressure build-up  $p_i$  vs. CO<sub>2</sub> mass injection rate  $q_m$

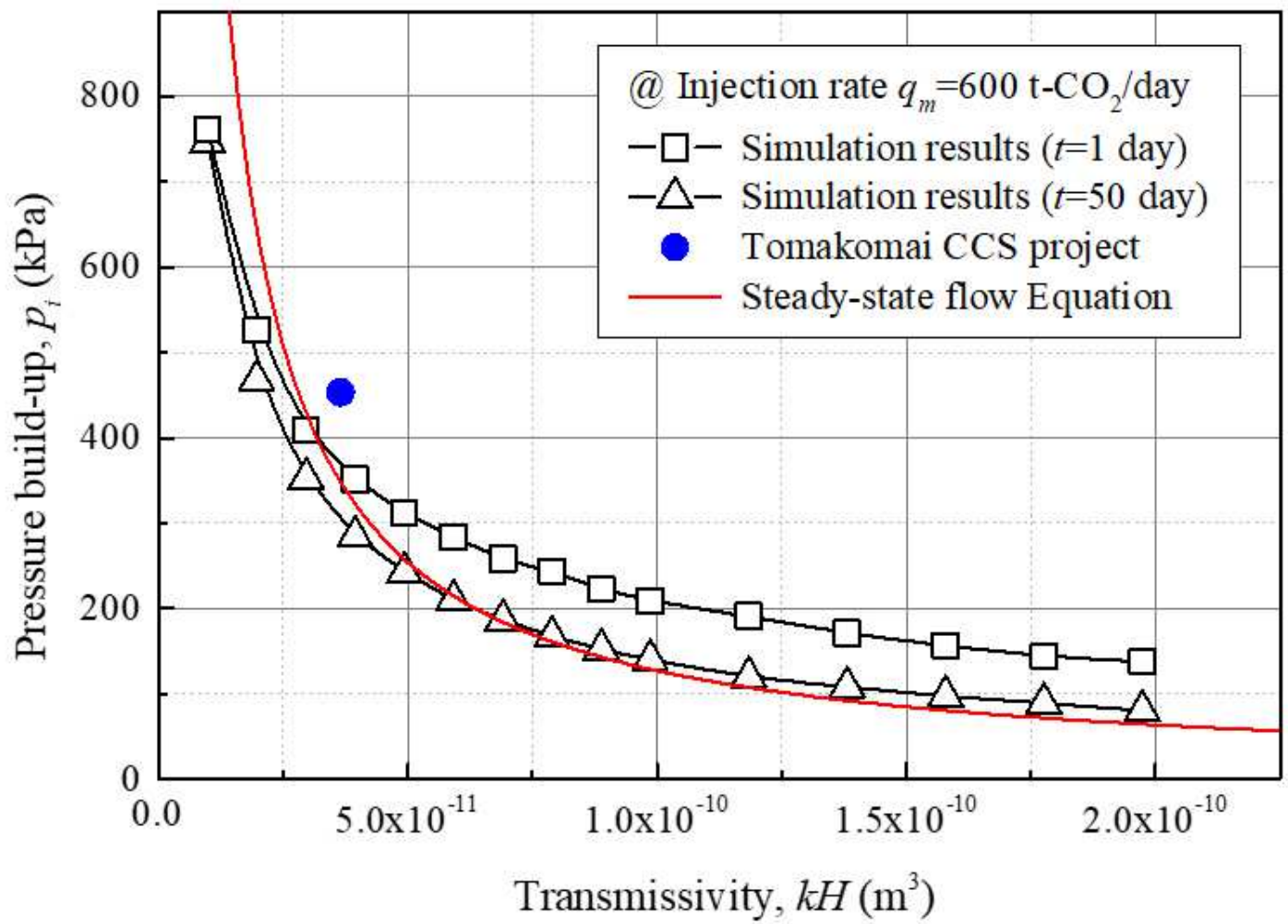


Figure 13

Pressure build-up,  $p_i$  (kPa) vs. aquifer transmissivity,  $kH$  ( $m^3$ )



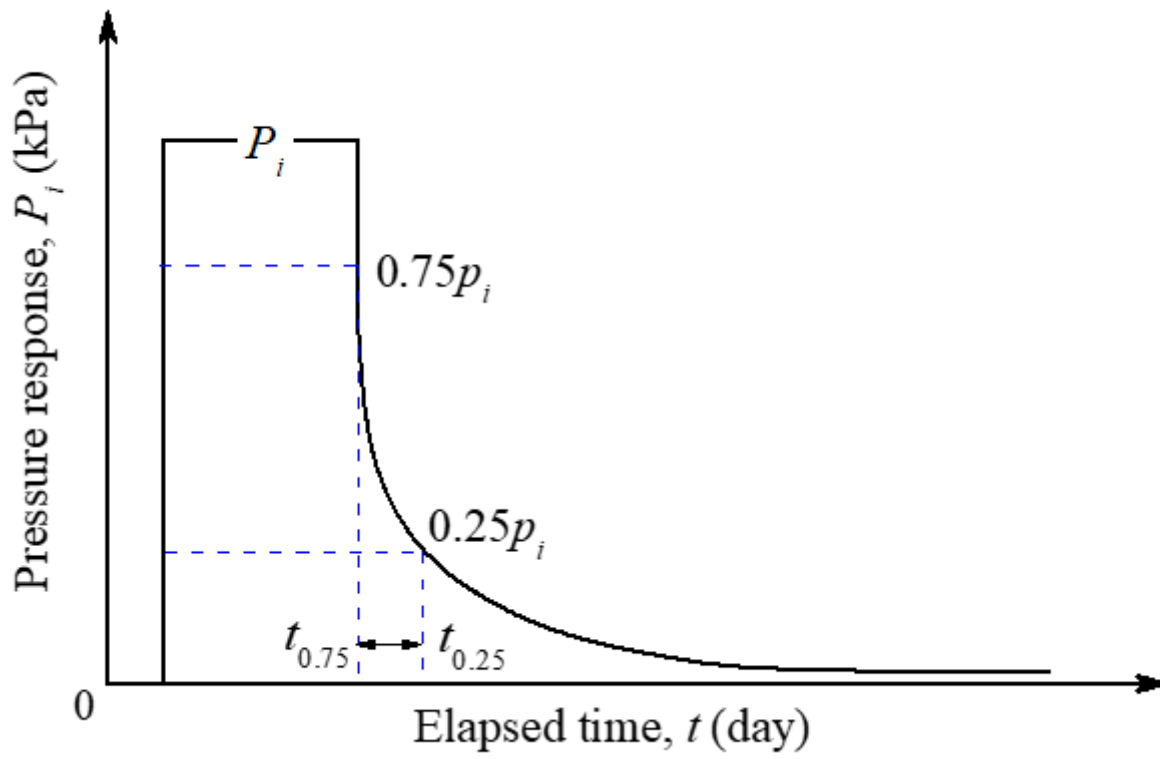
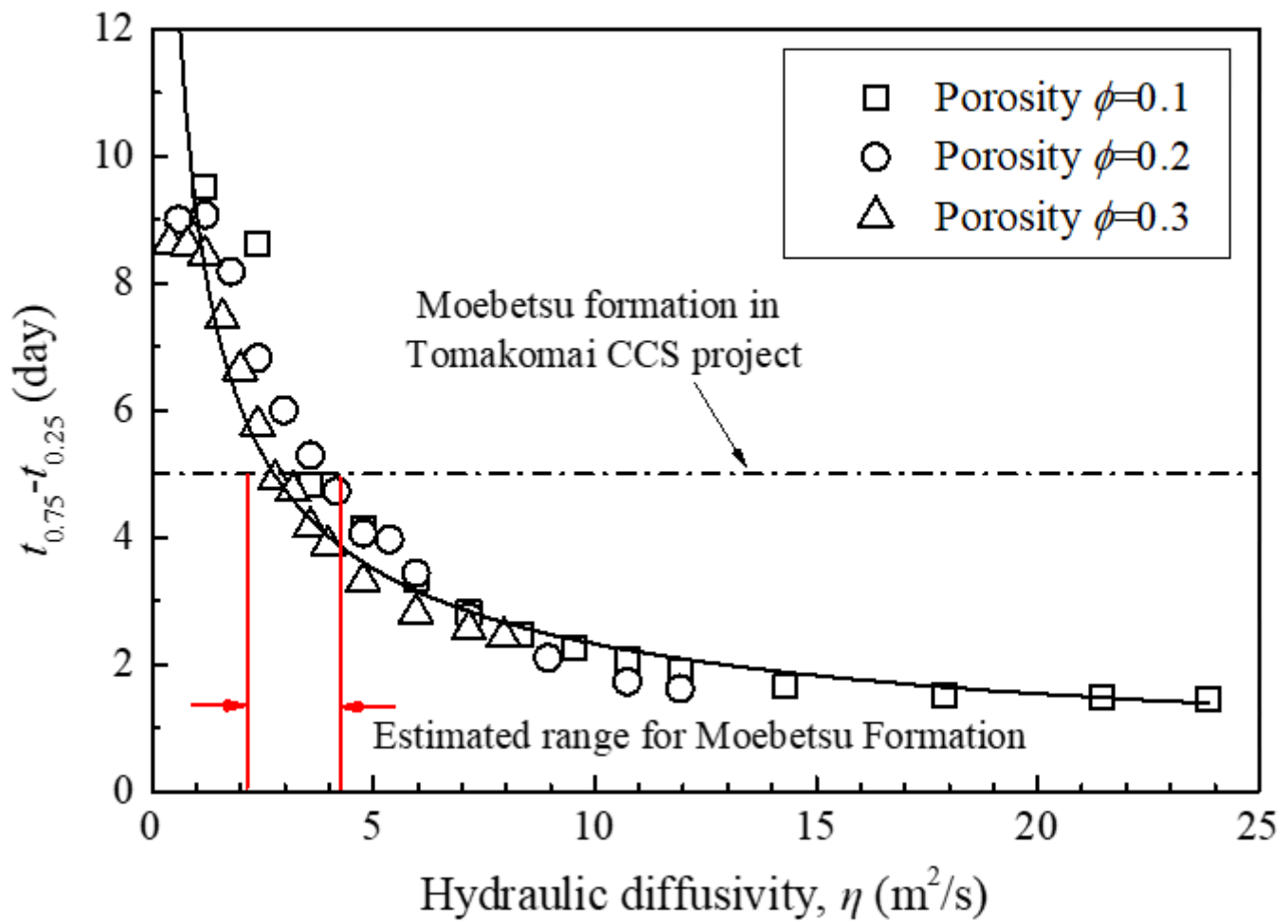


Figure 14

Definition of pressure fall-off time after pressure build-up



**Figure 15**

Numerical simulation results of fall-off time ( $t_{0.75}-t_{0.25}$ ) vs. hydraulic diffusivity  $\eta$  compared with the fall-off time of the Moebetsu Formation (5 day)

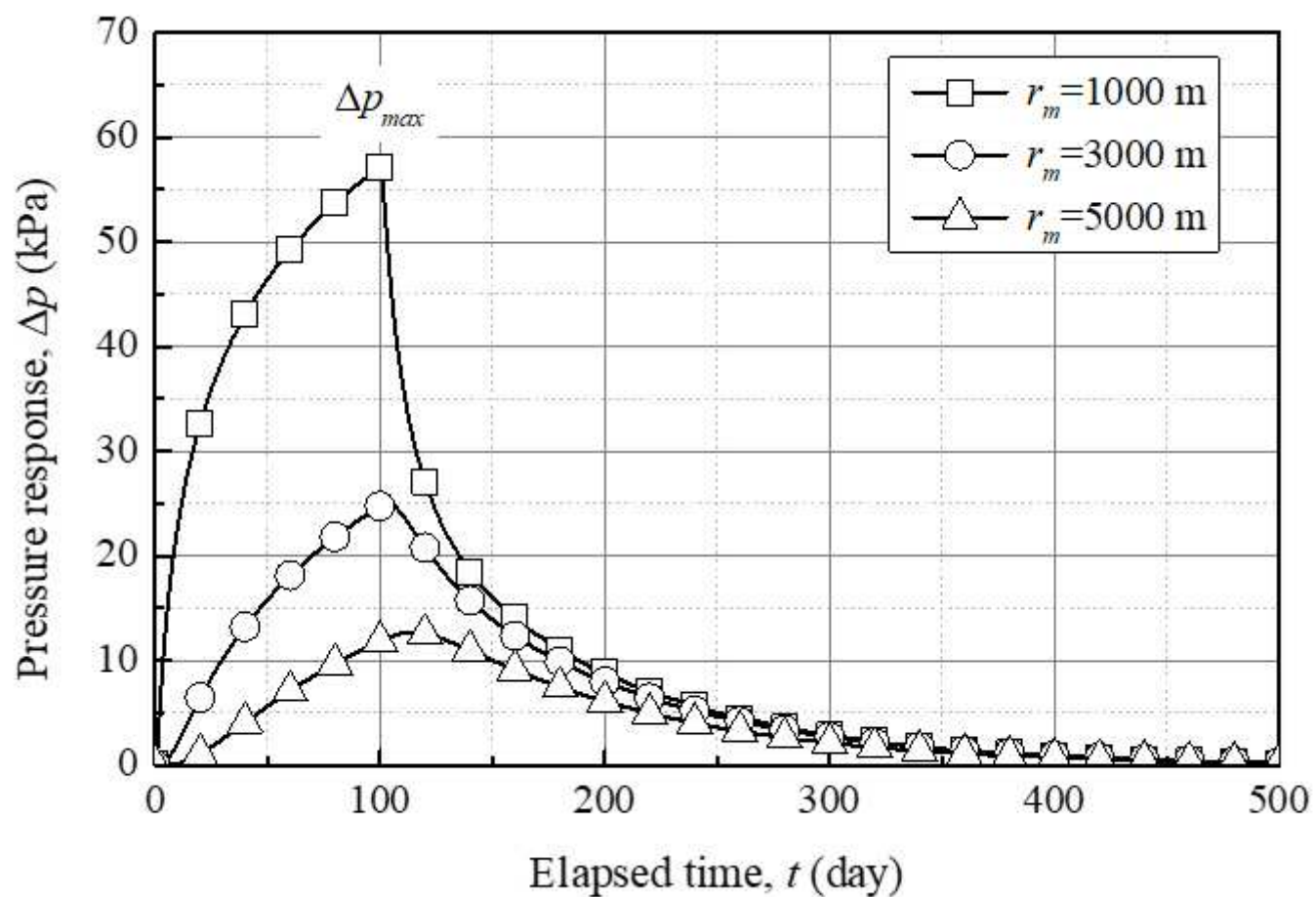
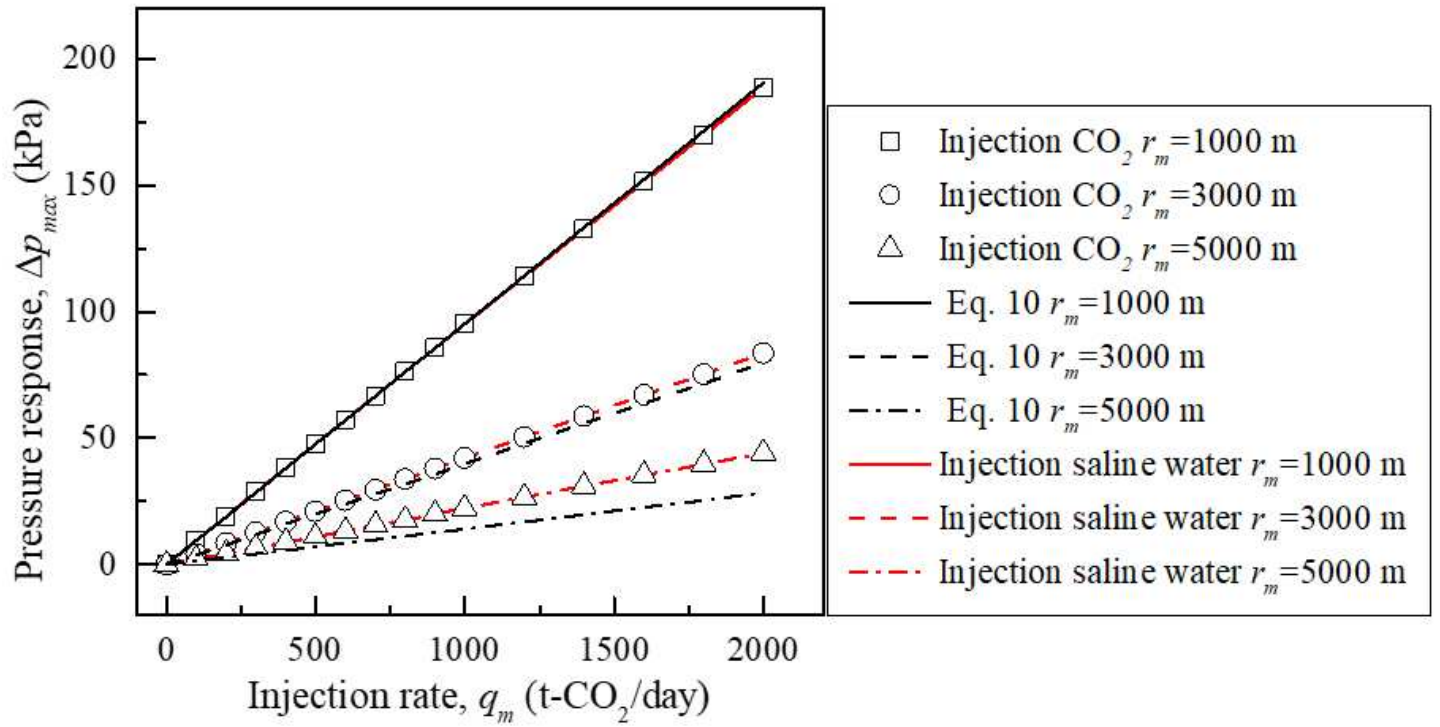


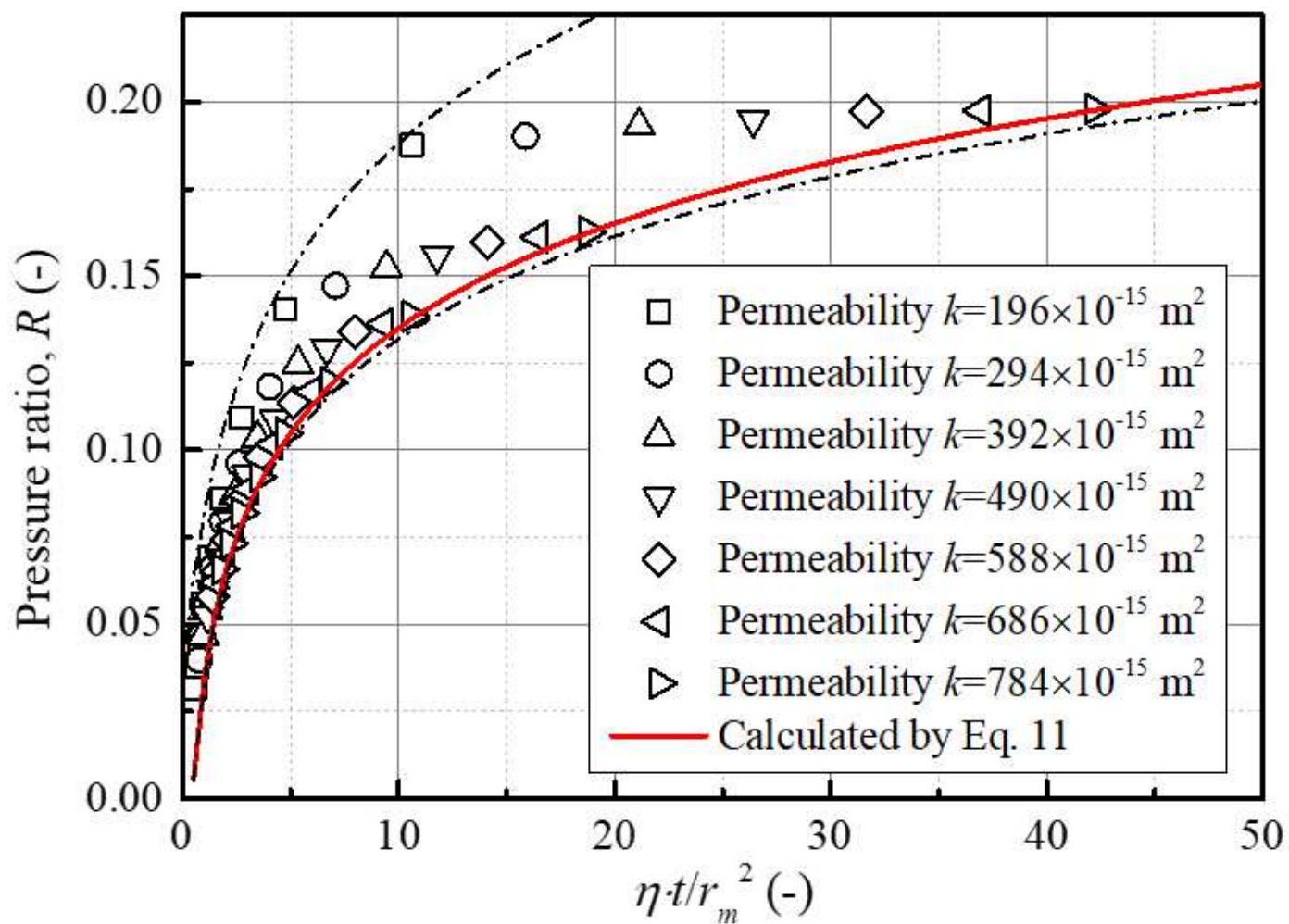
Figure 16

Typical simulation results of the pressure response at the observation wells located at  $r_m=1,000$ ,  $3,000$ , and  $5,000$  m



**Figure 17**

Numerical simulation results of the pressure response at the observation wells vs. CO<sub>2</sub> mass injection rate  $q_m$  (t-CO<sub>2</sub>/day)



**Figure 18**

Numerical simulation results of pressure ratio  $R$  for different permeabilities ( $q=600 \text{ t-CO}_2/\text{day}$ ,  $t_i=100 \text{ day}$ ,  $k=196 \times 10^{-15} - 784 \times 10^{-15} \text{ m}^2$ )

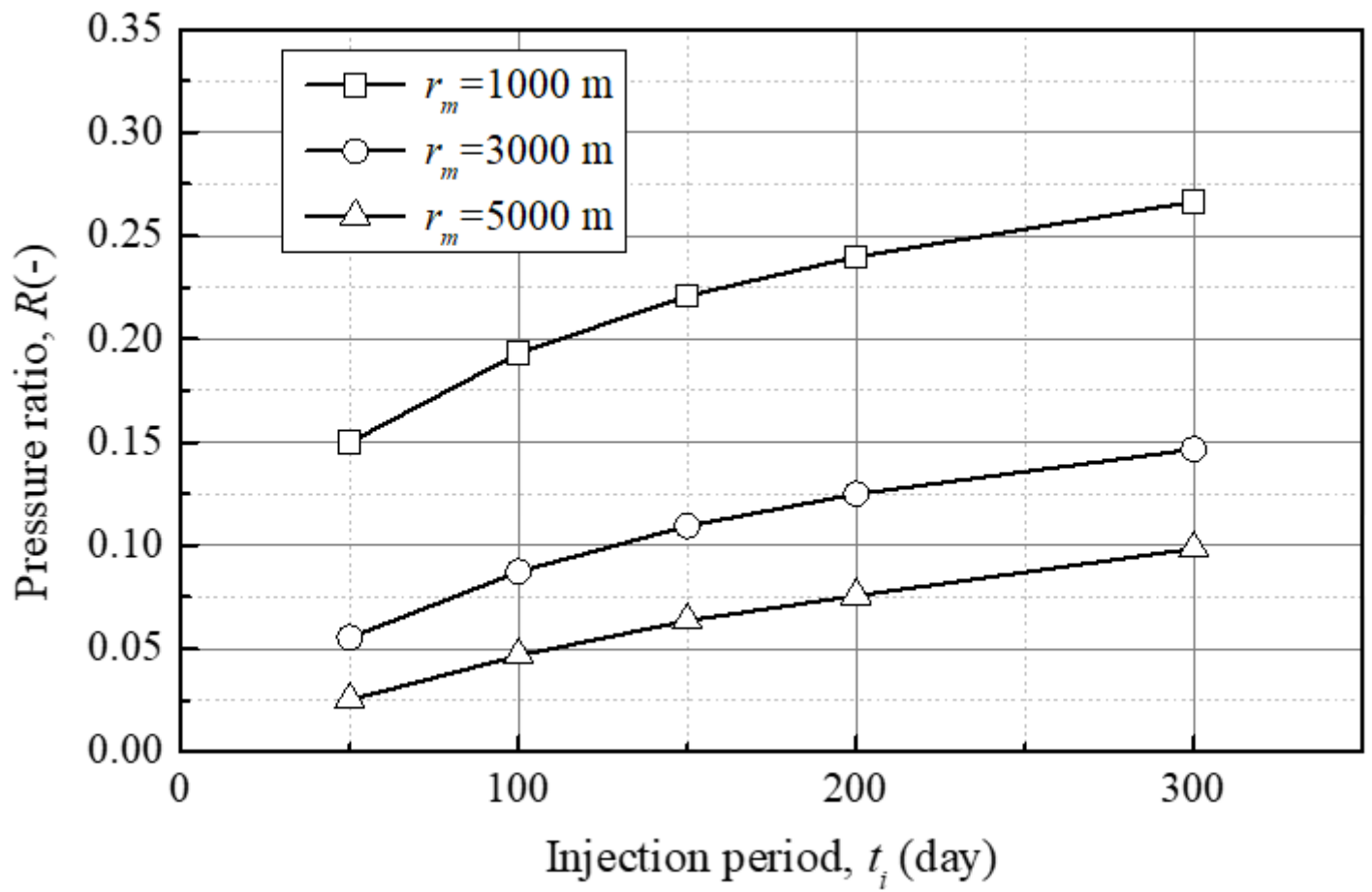


Figure 19

Effect of injection period,  $t_i$  on pressure ratio,  $R$

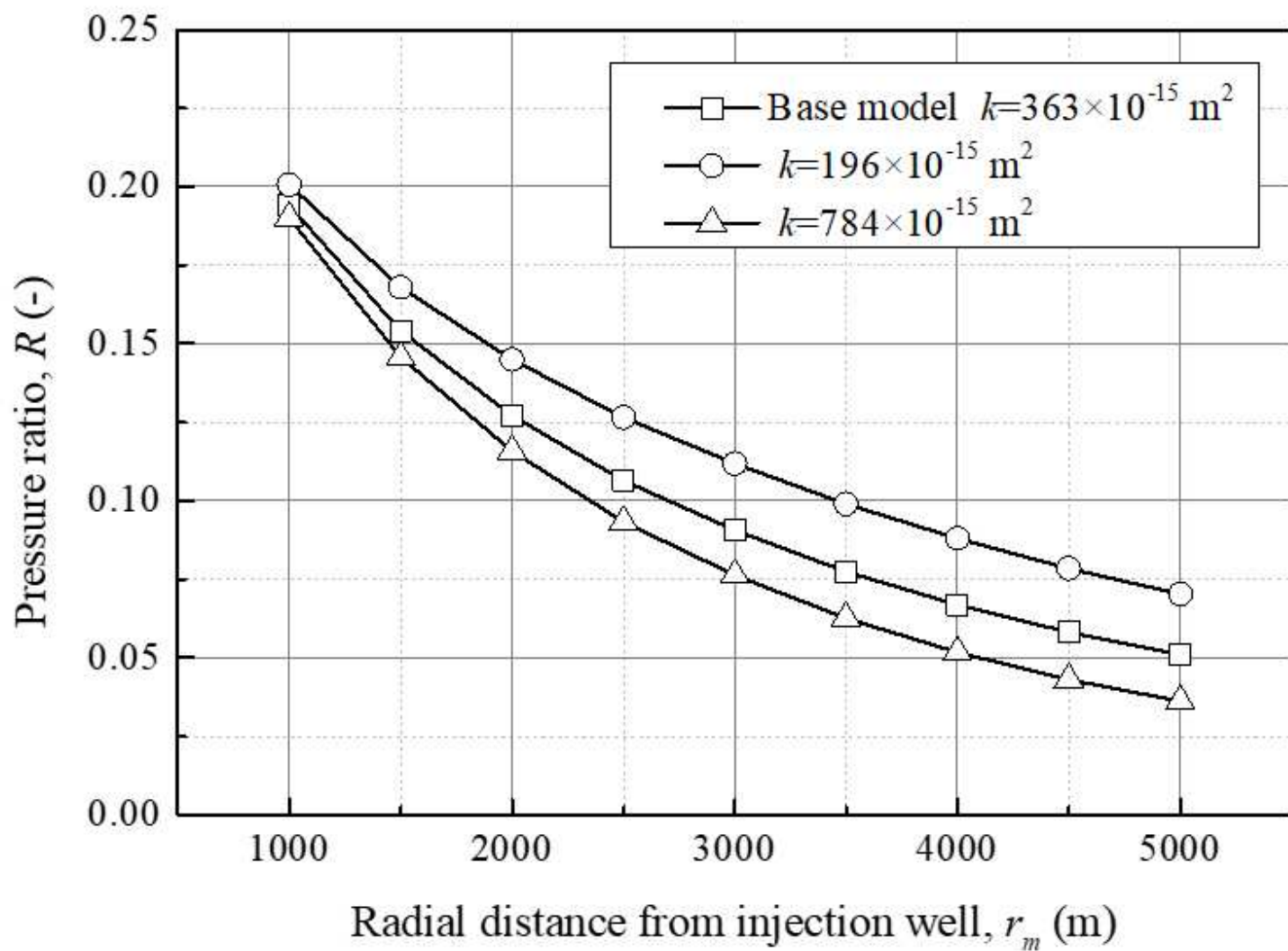


Figure 20

Pressure ratio vs radial distance from the injection well ( $t_i=100$  day) for the base model

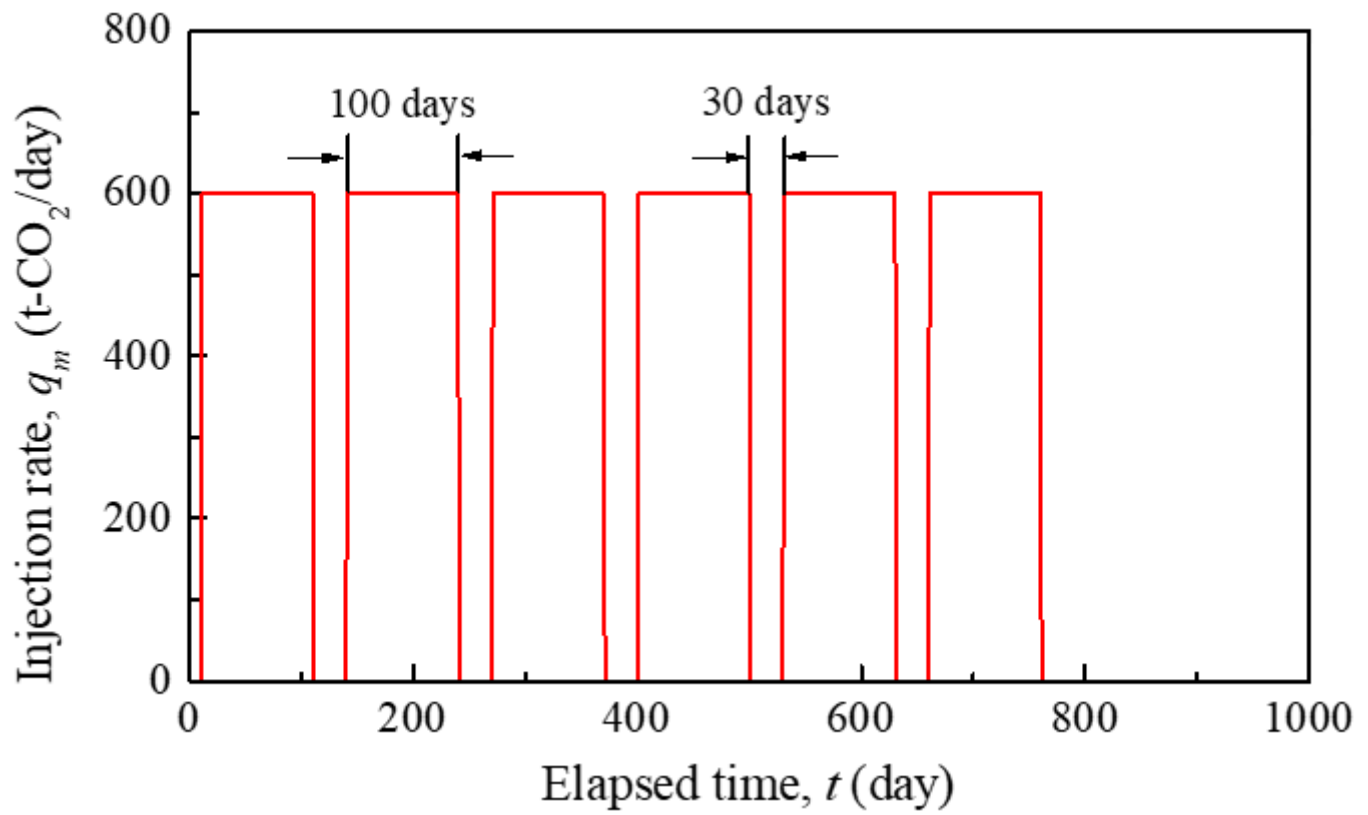


Figure 21

A model case of CO<sub>2</sub> multiple injections consists of six injection cycles with  $t_i=100$  day as injection period and  $t_s=30$  day as shut-in period



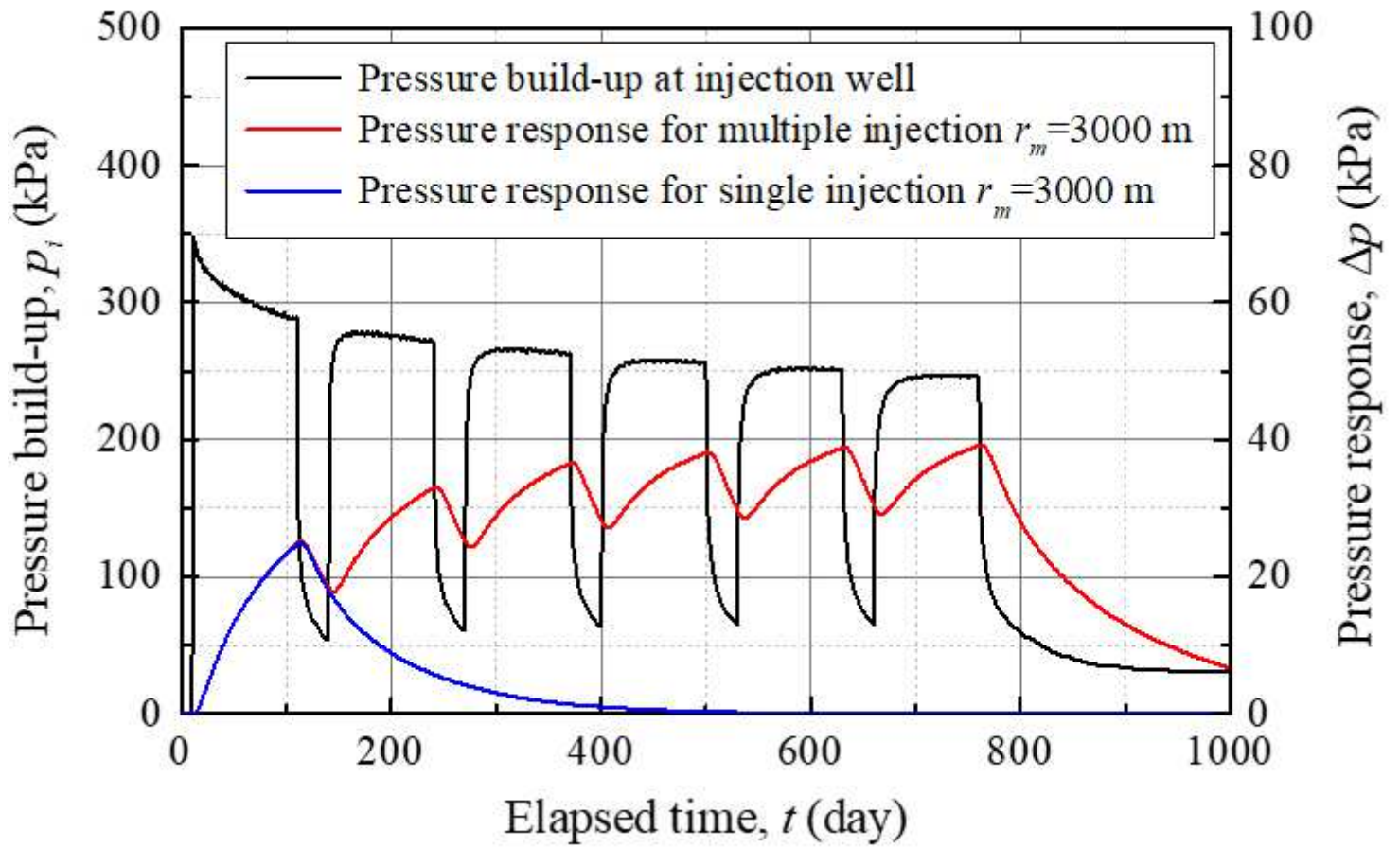
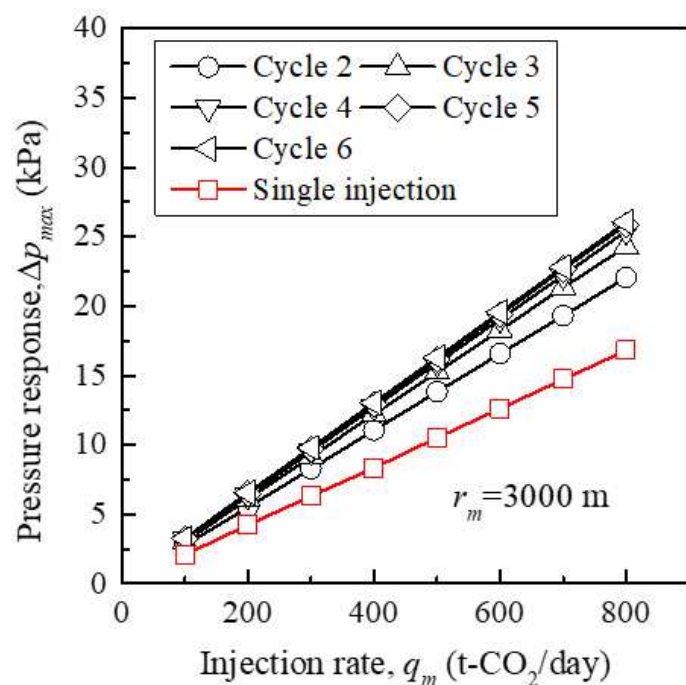
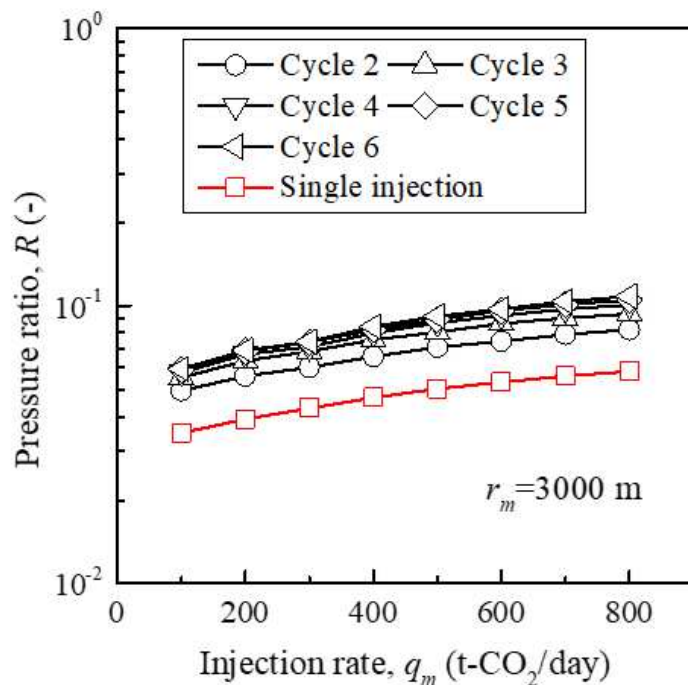


Figure 22

Pressure build-up of the injection well and pressure response in multiple-injection and single injection cases for the observation well at  $r_m = 3000$  m



(a)



(b)

**Figure 23**

Pressure response and pressure ratio  $R$  in the observation well at  $r_m=3,000$  m for the multiple-injections model compared with the single injection model (base case) vs. injection rate  $q_m$ ; (a) Pressure response (b) Pressure ratio  $R$ .

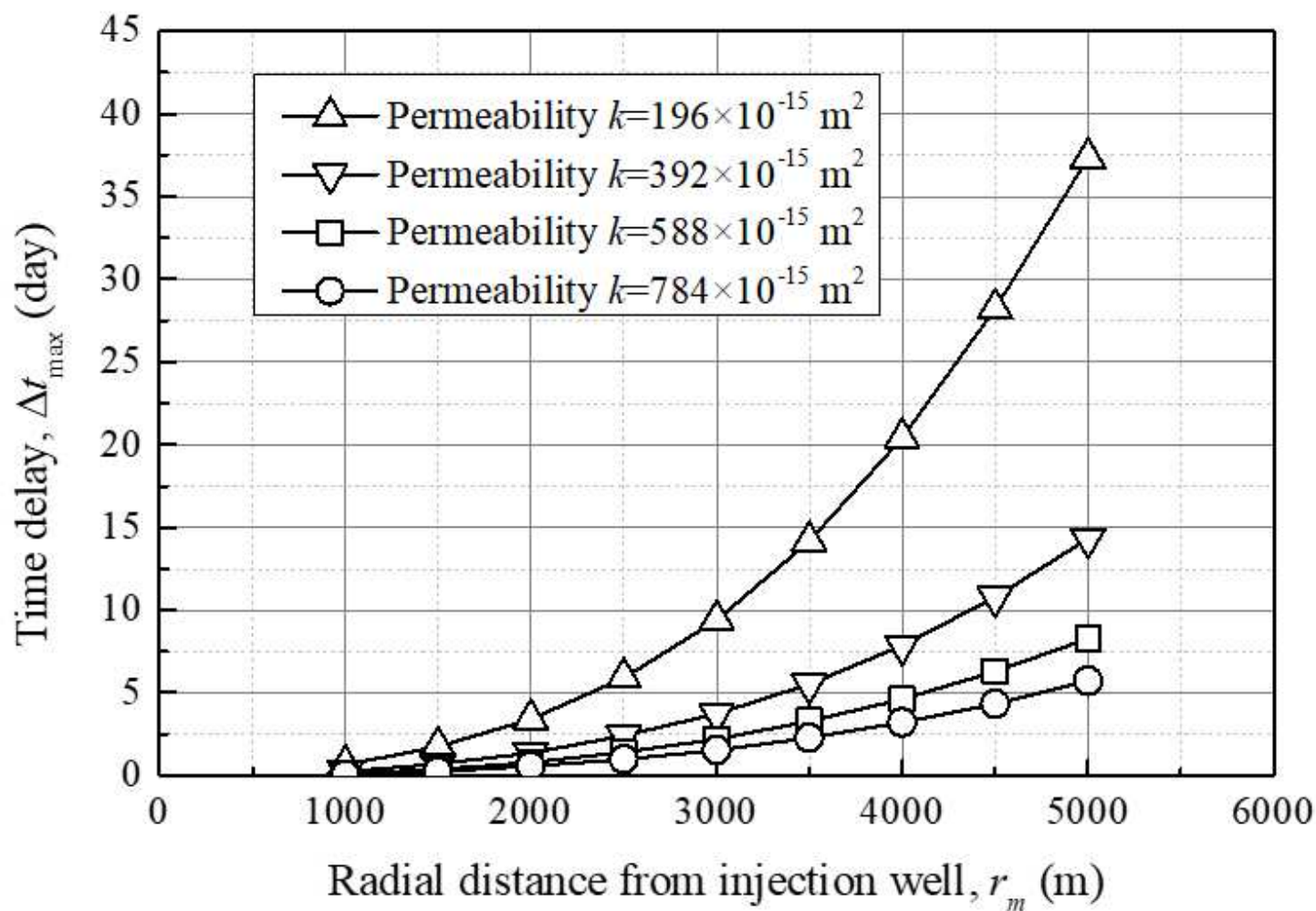


Figure 24

Numerical simulation results of time delay  $\Delta t_{\max}$  of the pressure response peak for the observation wells located at the radial distance  $r_m$  (Base model, injection period  $t_i=100$  day)

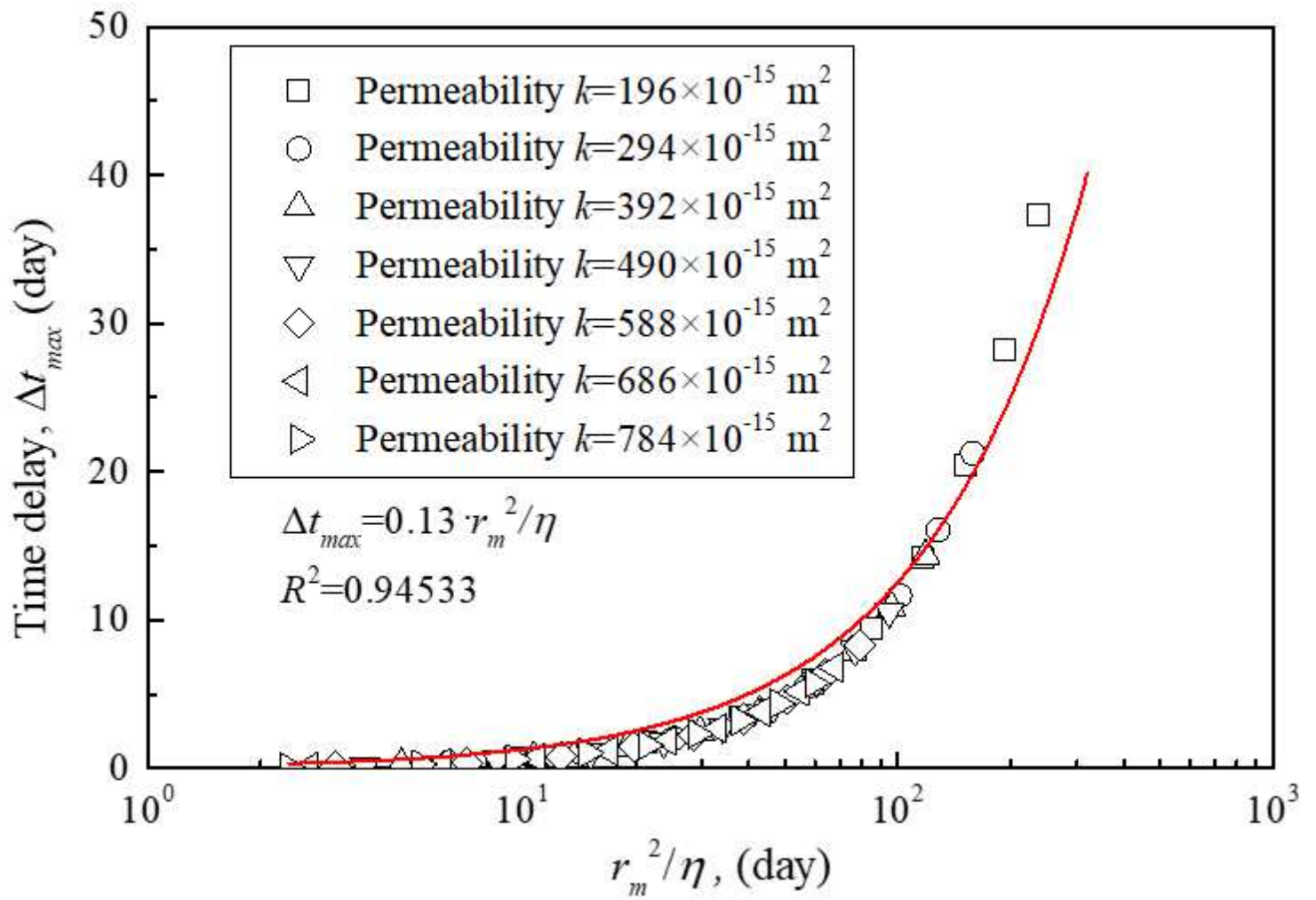


Figure 25

Time delay of the observation wells with  $r_m=1,000-5,000$  m for different permeabilities

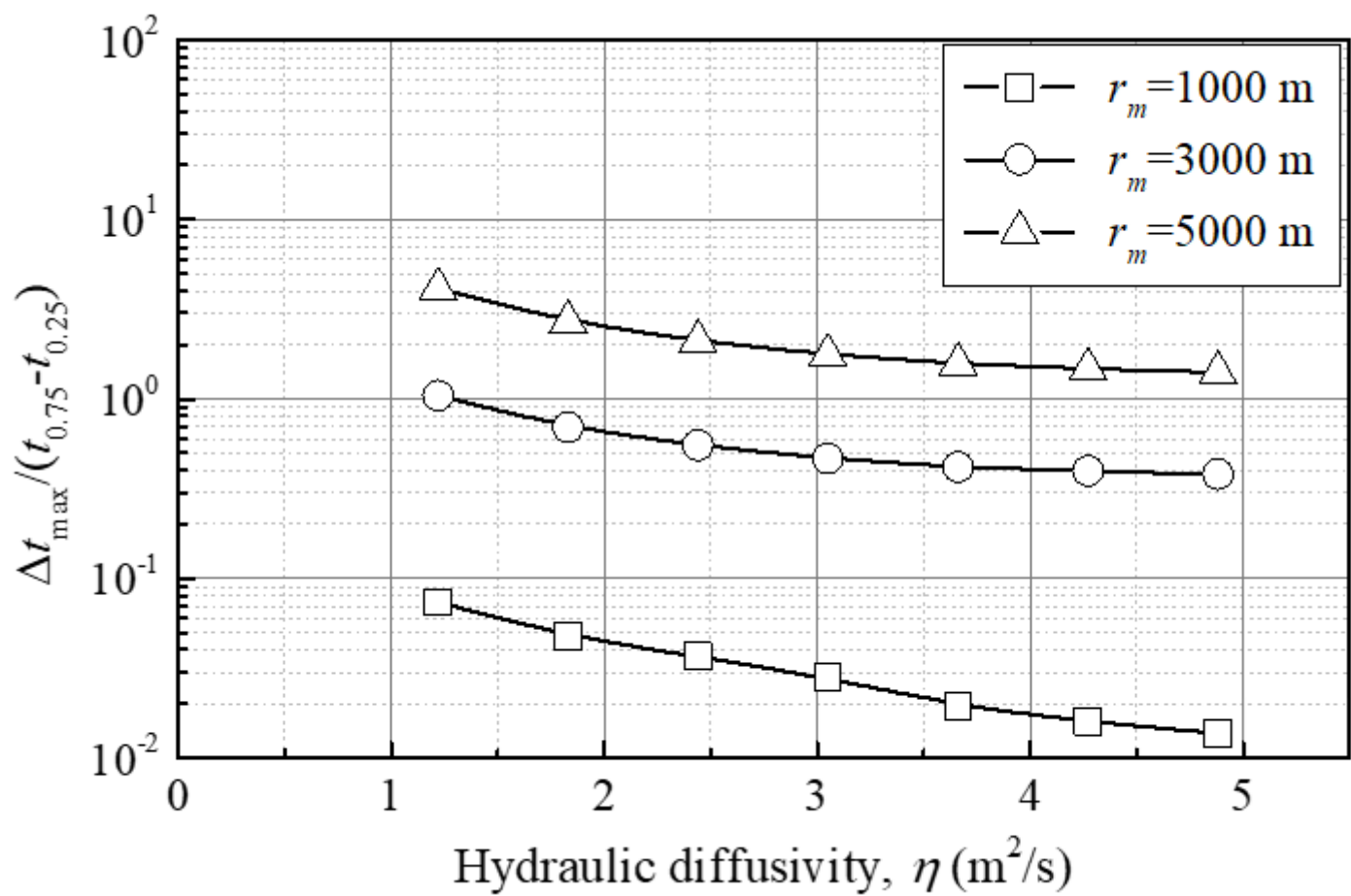


Figure 26

Numerical simulation results of time ratio against hydraulic diffusivity  $\eta$  ( $\text{m}^2/\text{s}$ )