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Study on role of simulation of possible leakage from geological CO_2 storage in sub-seabed for environmental impact assessment

Ryosuke Aoyagi[a1*], Osamu Kitamura[a], Kenshi Itaoka[a], Shuzo Igawa[b], Satoshi Suzuki[b]

[a]*Mizuho Information and Research Institute, Inc., 2-3 Kanda-Nishikicho, Chiyoda-ku, Tokyo 101-8443, Japan*
[b]*Japan NUS Co., Ltd., 7-5-25 Nishi-Shinjuku,Shinjuku-ku, Tokyo 160-0023, Japan*

Abstract

This paper summarizes the selection of short-term leakage scenarios and the results of numerical simulations based on the scenarios in order to assess the impact of CO_2 on the ocean environment. Two leakage scenarios are considered: either CO_2 migrates from an aquifer to the seafloor through two discontinuous faults, or it migrates through an abandoned well. The distribution and leakage amount of CO_2 are estimated for each scenario by using the multi-phase flow simulator TOUGH2. Then, sensitivity analyses for parameters corresponding to the permeability of the leakage path are conducted. The results suggest that differences of permeability significantly affect the total amount and time at which CO_2 leakage starts.

Keywords: CO_2 geological storage; leakage; numerical simulation; TOUGH2; environmental impact assessment

1. Introduction

In Japan, the Law Relating to the Prevention of Marine Pollution and Maritime Disaster was amended for the purpose of depositing the instrument of accession to the 1996 Protocol to the London Convention in October 2007. Therefore, for the sake of environmental preservation, there are now legal regulations on geological CO_2 storage in the sub-seabed.

Under this law, an operator who wishes to inject CO_2 into the sub-seabed is obliged to present an assessment report to the authorities. This report must state the location, range, and amount of leakage, as well as the methodology used for estimating the leakage of CO_2 into seawater.

The methods used for Environmental Impact Assessments (EIA) have been developed by the Ministry of the Environment of the Government of Japan to provide a precise, legal procedure for giving permission to operators of geological CO_2 storage in the sub-seabed.

In an EIA, it is necessary to assess the impact of CO_2 on the ocean environment. However, there is a small risk of impact on the ocean environment even if the site is properly selected. Therefore, this study examines scenarios when an event that is considered impossible actually happens.

The scope of this project includes:

(1) Selection of short-term leakage scenario
(2) Estimation of leakage by geological simulation
(3) Methodology of sea area simulation
(4) Prediction of CO_2 diffusion by sea area simulation

This paper examines the method and conclusion of (1) selection of short-term leakage scenario and the results of (2) estimation of leakage by geological simulation.

* Corresponding author. Tel.: +81-3-5281-5286; fax: +81-3-5281-5466.
E-mail address: ryosuke.aoyagi@mizuho-ir.co.jp.

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2. Leakage scenarios

Potential pathways from saline formations are shown in the IPCC's Special Report [1]; 1) through the pore system in low-permeability caprocks if the capillary entry pressure is exceeded, 2) through openings in the caprock or fractures and faults, 3) through poorly completed and/or abandoned wells, and 4) through aquifers where dissolved CO_2 migrates laterally. It would take more than 100,000 years for CO_2 to leak through the pore system in caprocks [2], and the flow in aquifers is estimated to be of the order of 1 mm/yr to 1 cm/yr [3]. This study focuses on leakage which can occur in just a few decades which operators can cope with, and considers two scenarios: leakage through faults, and leakage through injection wells and/or abandoned wells. In the latter scenario, leakage through injection wells is excluded because these can be monitored relatively easily by operators and action can be taken when a leak occurs.

2.1. Leakage through faults

The leakage scenario through faults is shown in Figure 1.

The main parameter which is considered to be a controlling factor in the case of leakage through faults is fault permeability. In Japan, fault permeability ranges from 1 mD to 100 D [4]. In the simulation to quantitatively estimate the leakage amount, it is important to conduct a sensitivity analysis of permeability and to understand the impact on leakage.

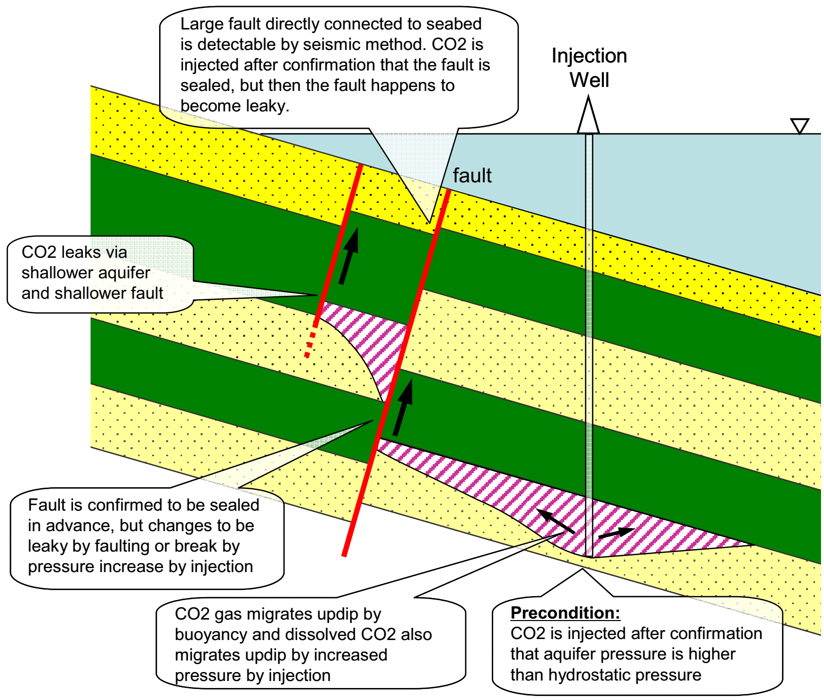

Figure 1 Leakage scenario through faults

2.2. Leakage through abandoned wells

Abandoned wells are possible pathways if they are poorly treated, whether the wells have been detected or not. The scenario of leakage through abandoned wells is shown in Figure 2. Because permeability is assumed to be a controlling factor in the case of leakage through abandoned wells as in the case of leakage through faults, a sensitivity analysis of parameters corresponding to borehole permeability is needed.

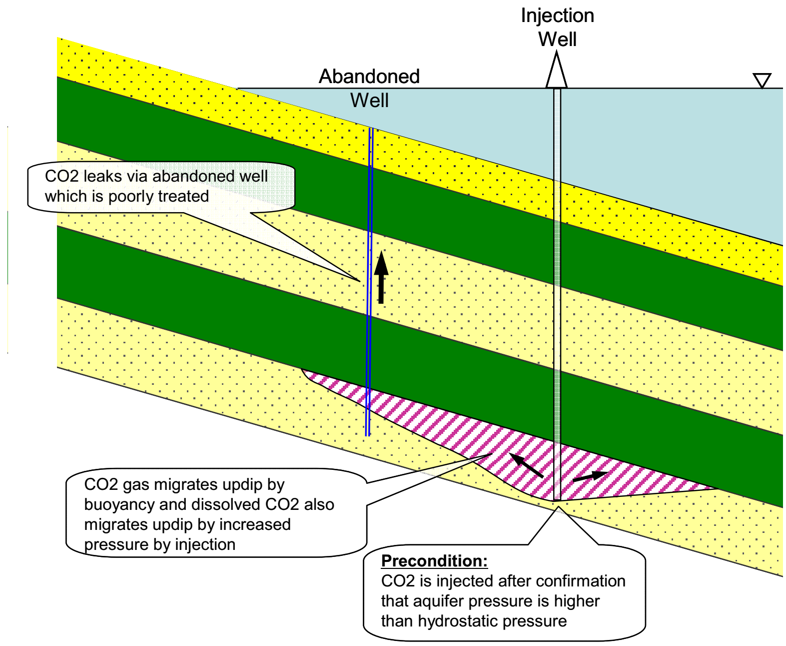

Figure 2 Leakage scenario through abandoned wells

3. Leak simulation

A leak simulation is conducted to quantitatively estimate the leakage. TOUGH2/ECO2N [5][6] is used as the simulator because it is readily available and has been widely used. CO_2 distribution, flux to seabed, and leak area on the seabed are estimated for each of the two scenarios, then a sensitivity analysis for permeability is conducted.

3.1. Leakage through faults

3.1.1. Lithofacies

Figure 3 shows a stratigraphy and a cross section of the simulation domain. The surface layer just under the seafloor is 200 m-thick sandstone. Below the surface layer, there are alternating layers of 100 m-thick sandstone and mudstone. The bottom layer below 1,000 m is 400 m-thick mudstone.

3.1.2. Simulation domain

The simulation domain measures 10.1x10.1 km horizontally and 1.4 km vertically. The injection element is set at the center of the deep aquifer, namely at (X,Y,Z) = (5050 m, 5050 m, -975 m). The element width in the horizontal direction is 100 m for the central 3x3 km area to be analyzed in detail and 200 m for the outside. The element thickness in the vertical direction is 50 m, except near the boundary. “Fault 1” elements are set 500 m away from the injection element and “fault 2” elements are further away from fault 1. The width of fault elements is 50 m.

3.1.3. Rock properties

The rock properties used in the simulation are shown in Table 1. The densities of sandstone and mudstone are the average of samples included in the rock property database in Japan [7]. The porosity of sandstone is 0.2 and that of mudstone is 0.1. The density and porosity of fault rock are the same as those of sandstone. The permeability of sandstone is 100 mD in the horizontal direction and 10 mD in the vertical direction, while those of mudstone are 500 nD and 50 nD, respectively. These values are based on the value of 50.5 nD, which is the average permeability measured by triaxial tests for fine-grained sedimentary rocks in the deep subsurface [8].

The permeability of Fault 1 in the direction parallel to the fault plane is 100 mD and that in the perpendicular direction is 10 mD, while those of Fault 2 are 200 mD and 20 mD, respectively.

Corey’s curves [9] are used for the relative permeability model. Model parameters are based on [10], as listed in Table 2.

The van Genuchten function [11] is used for the capillary pressure model. Model parameters are based on [10], except for the strength coefficient, which differs between sandstone and mudstone based on [6] (see Table 3).

3.1.4. Initial and boundary conditions

The initial conditions in the domain include a hydrostatic pressure distribution and a geothermal temperature distribution. The geothermal gradient is assumed to be 0.03 K/m and the initial temperature at the seafloor (0 m depth) is 10ºC and that at the bottom (1400 m depth) is 52ºC. The initial salinity of brine is 3% with no CO_2 gas saturation. The bottom and lateral boundary conditions are no-flow Neumann conditions and the top is the Dirichlet condition equal to the initial condition. The top and bottom boundaries are no-flow boundaries. The isothermal condition is assumed in the entire simulation.

CO_2 is injected at a constant rate of 500 kt-CO_2/yr over a period of 30 years. The total simulation time is 100 years.

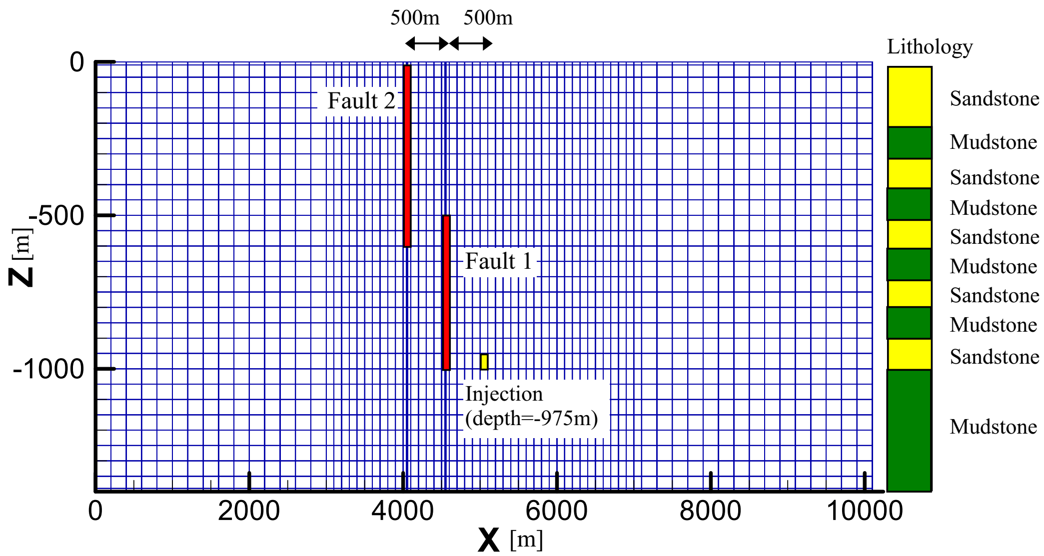

Figure 3 Cross section

Table 1 Rock properties

Parameter	Sandstone	Mudstone	Fault1	Fault2
Density	2640 kg/m^3	2445 kg/m^3	2640 kg/m^3	2640 kg/m^3
Porosity	0.2	0.1	0.2	0.2
Permeability (direction)	100 mD (X, Y)	500 nD (X, Y)	10 mD (X)	20 mD (X)
	10 mD (Z)	50 nD (Z)	100 mD (Y, Z)	200 mD (Y, Z)

Table 2 Relative permeability parameters

Parameter	Value
Irreducible liquid saturation	0.3
Residual CO_2 saturation	0.05

Table 3 Capillary pressure parameters

Parameter	Sandstone	Mudstone
Irreducible liquid saturation	0.29	
Exponent	0.457	
Strength coefficient	1.87 kPa	59.10 kPa

3.1.5. Sensitivity analysis

A sensitivity analysis for fault permeability is conducted. The case with parameters as listed in Table 1 is called the base case (A1); that with fault permeability ten times the base case is the high permeability case (A2); and that with fault permeability one-tenth of the base case is the low permeability case (A3).

3.1.6. Simulation results

The simulation results are summarized in Table 4. The distributions of CO_2 saturation at 30 years and 100 years are shown in Figure 4. The change in amount of CO_2 leakage over time is shown in Figure 5.

In the base case A1, leakage begins at 53 years and continues at 100 years, the end of the simulation. The amount of CO_2 leakage per unit time reaches a peak at 59 years, at 6 kt-CO_2/yr, corresponding to 1.2% of the injection rate. The total amount of leakage during the 100 years is 159 kt-CO_2, corresponding to 1.1% of the total CO_2 injected.

In the high permeability case A2, leakage begins at 26 years and ends at 70 years. The amount of CO_2 leakage per unit time reaches a peak at 31 years, at 69 kt-CO_2/yr, corresponding to 14% of the injection rate. The total amount of leakage during the 100 years is 645 kt-CO_2, corresponding to 4.3% of the total CO_2 injected.

In the low permeability case A3, CO_2 migrates up to the top of Fault 1, but there is no leakage from the seafloor.

It is reasonable that CO_2 reaches the seafloor earlier and the leakage amount is larger in case A2 than in case A1. Leakage from the seafloor terminates earlier in case A2 than in case A1 because the aquifer pressure and driving force for CO_2 migration decrease due to the leakage.

3.2. Leakage through abandoned wells

3.2.1. Simulation methodology

The deliverability model built into TOUGH2 is used to simulate leakage through a well-bore. The amount of CO_2 flowing into the bottom of the well-bore from the aquifer is regarded as leakage. The amount of CO_2 leakage is expressed by Eq. 1 [5],

$$q_\beta = \frac{k_{r\beta}}{\mu_\beta} \rho_\beta PI \left(P_\beta - P_{wb} \right) \tag{1}$$

where q_β is the leakage amount of component β per time, $k_{r\beta}$ is the relative permeability of component β, μ_β is the viscosity of component β, and P_β is the component β partial pressure of formation. Those parameters are calculated. PI is the original productivity index of the production well and is related to the skin factor, which is an index of production difficulty. P_{wb} is well-bore bottom pressure and is assumed to be 1.1 times hydrostatic pressure in consideration of partial cementing in the well-bore.

3.2.2. Simulation domain

Figure 6 shows a cross section of the simulation domain. The simulation geometry and lithology are the same as the simulation for the fault leakage scenario but without fault elements. The borehole element is set 500 m from the injection element in the aquifer.

3.2.3. Rock properties

The rock properties are the same as those used for the simulation for the fault leakage scenario. The same values as given in Table 1 are used for the density and porosity of sandstone and mudstone. The parameters for relative permeability model and capillary pressure model are also the same as those used for the fault simulation. The values of Tables 2 and 3 are used.

The initial conditions, boundary conditions, and injection scenario are also the same as those used for the fault simulation.

3.2.4. Sensitivity analysis

The sensitivity analysis for productivity index is conducted for the three cases: PI = 1×10^{-12} m^3 for the base case (B1), 6×10^{-12} m^3 for the high-PI case (B2), and 3×10^{-13} m^3 for the low-PI case (B3).

Table 4 Simulation results

ID	Fault permeability	Leakage during the 100 years [kt-CO_2]	Max. leakage flow rate [kt-CO_2/yr]	Time at max. leakage flow rate [yr]	Arrival time [yr]
A1	Base	159	6	59	53
A2	High	645	79	31	26
A3	Low	0	0	-	-

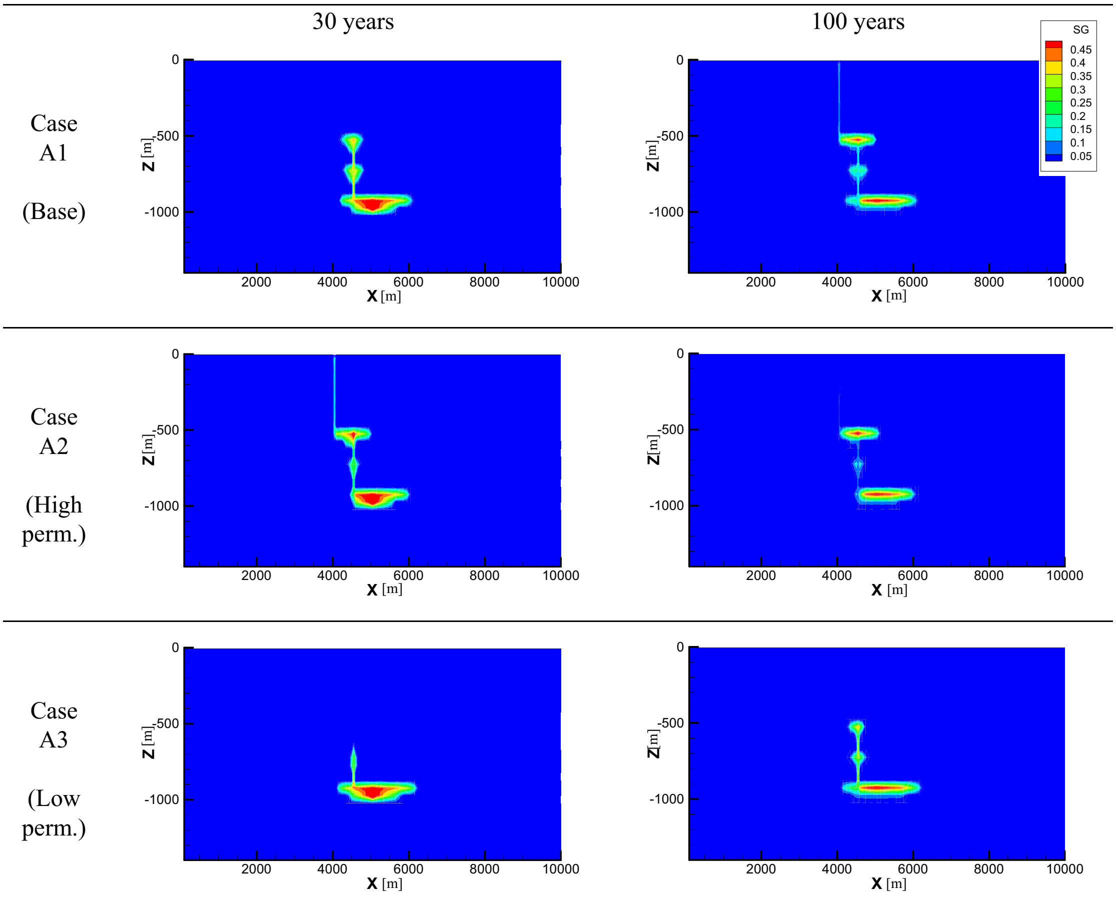

Figure 4 Distributions of CO_2 saturation

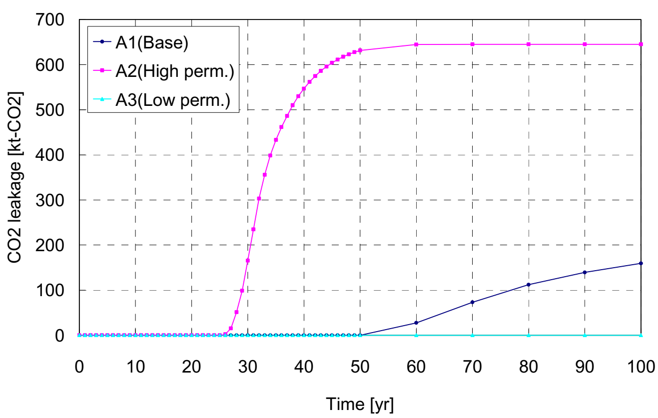

Figure 5 Total amount of CO_2 leakage over time

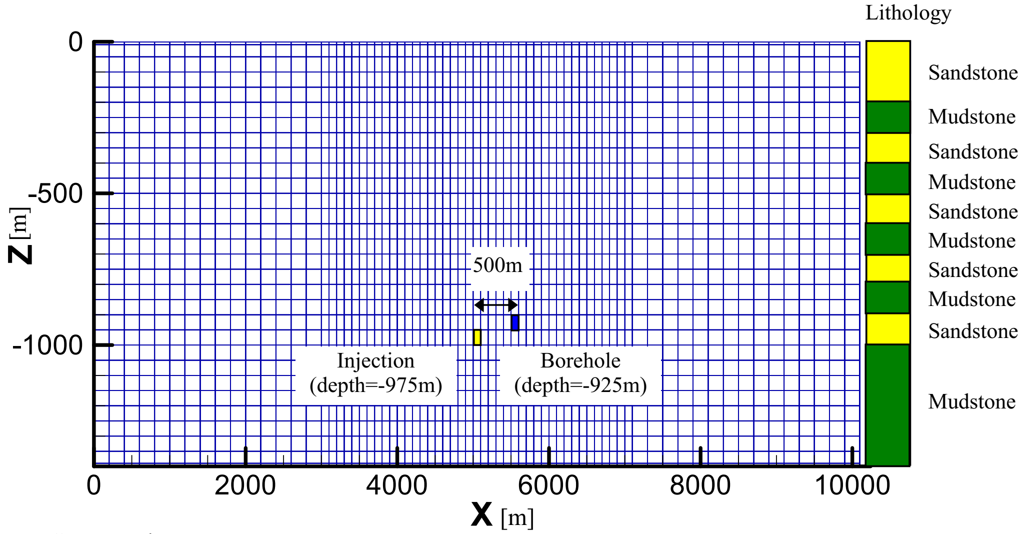

Figure 6 Cross section

3.2.5. Simulation results

The simulation results are summarized in Table 5. The change in amount of CO_2 leakage over time is shown in Figure 7.

In the base case B1, leakage begins at 12 years. The maximum CO_2 leakage per unit time reaches 76 kt-CO_2/yr, corresponding to 15% of the injection rate. The total amount of leakage during the 100 years is 2410 kt-CO_2, corresponding to 16.1% of the total CO_2 injected.

In the high-PI case B2, the total leakage is 1.6 times as large as in case B1. In the low-PI case B3, the total leakage is approximately half as large as in case B1. In all cases, CO_2 begins to leak at the same time of 12 years. This is because the time when CO_2 begins to leak does not depend on PI, as shown by Eq. 1; leakage begins only after the aquifer pressure has exceeded the well-bore bottom pressure. In all cases, the leakage flow rate reaches a peak at 30 years. CO_2 is still flowing out at 100 years, though leakage is just about to end because the flow rate has passed its peak and the pressure difference between the aquifer and well-bore bottom has decreased.

Table 5 Simulation Results

ID	Productivity Index	Leakage during the 100 years [kt-CO_2]	Max. leakage flow rate [kt-CO_2/yr]	Time at max. leakage flow rate [yr]	Arrival time [yr]
B1	Base	2,410	76	30	12
B2	High	3,880	200	30	12
B3	Low	1,220	27	30	12

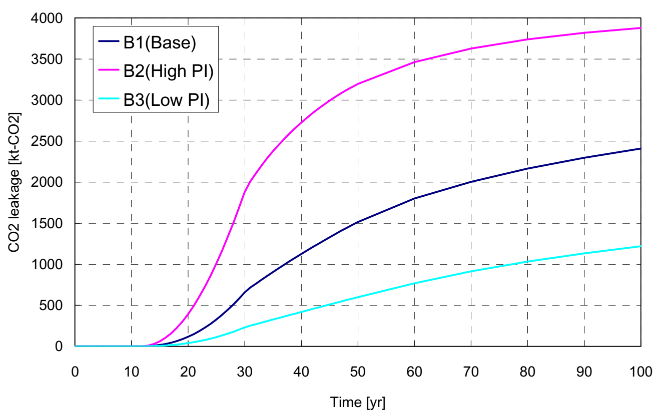

Figure 7 Total amount of CO_2 leakage over time

4. Conclusion

We selected various leakage scenarios for geological CO_2 storage in the sub-seabed, assuming that an impossible event actually happens. We conducted numerical simulations based on two scenarios: the pathways are permeable faults or abandoned well-bores. CO_2 migration in the geological formation and leakage from the seafloor over time were obtained by simulation over 100 years, including an injection period of 30 years. Then, we conducted sensitivity analyses for parameters that govern CO_2 migration such as fault permeability and productivity index, and showed that those parameters significantly affect the leakage. We hope that the results of this study will help to create a methodology for interpreting the results of environmental impact assessments required for CO_2 storage in the future.

Acknowledgment

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