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Economical Considerations on CCS System for Geological Uncertainty and Injection Failure

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ABSTRACT: In this study, an operation research on the performances of Tomakomai CCS project has been carried out for investigating the permeability uncertainty and the failures on CO_2 operation and transportation. Firstly, economical effects of estimation error in aquifer permeability were investigated by using a reservoir block modeling based on numerical simulation results on CO_2 injection rate. Secondary, economic loss resulted from failure of CO_2 injection was evaluated by assuming periodical injection halts. It is clear that CO_2 buffers, such as sphere gas tanks, should be installed to store CO_2 on the CCS process which can temporarily store CO_2 after it is captured when a trouble on transportation or injection processes occurs. Without a buffer, releasing the captured CO_2 to the atmosphere due to system failure or trouble in injection will add to capture costs, or will result in carbon tax or opportunity loss on CCS. The larger size of CO_2 buffer volume can potentially withstand against long-term trouble, however the larger buffer volume needs larger cost for initial construction and maintenance. The study also present the optimum CO_2 buffer volume based on economical evaluations for a commercial CCS model based on several simulations performed with and without CO_2 buffer in the system.

Keywords: CCS; Uncertainty; Economic Evaluations; Permeability; CO_2 Buffer
JEL Classifications: Q35; Q41; Q55

1. Introduction

Carbon Capture and Storage (CCS) is expected to make an important contribution to the reduction of atmospheric CO_2which is a main cause of global climate change (Wei et al., 2011). During the past decade, interests in CCS technologies have been growing in public and private sectors, as it is an option to address the increased energy demand with the need to reduce atmospheric CO_2 (Yousefi-Sahzabi et al., 2011). The Japanese Government together with Japan CCS Co., Ltd. and private sectors are advancing toward CCS technology development, especially CO_2 storage into deep saline aquifer. Nevertheless, for designing a robust and feasible CCS system, several characteristics of geological, technical, economic, and policy uncertainties must be considered (Zhang et al., 2014). Typically, uncertainty estimations are made based on numerical modeling of the input parameters in order to determine the impacts on short-term results and long-term predictions (Holloway et al., 2006).

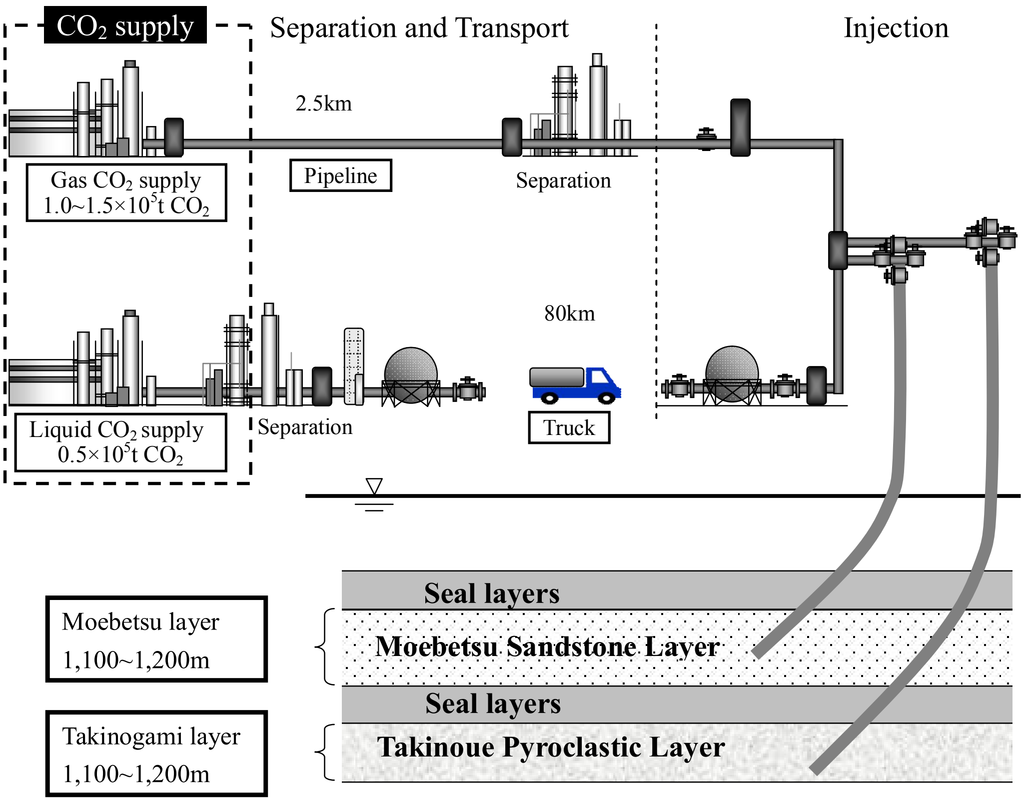
Among others, one important uncertainty is related to the reservoir permeability that is the difference between actual value and predicted value of permeability. The uncertain nature of permeability and other subsurface characteristics is an important matter of consideration in CCS research and development (Ginting et al., 2014). However the modeling of permeability uncertainly is difficult is some reservoirs. According to Orr Jr. et al. (2003) "simulating CO_2 flow behavior in geologic media is difficult because of the interplay between phase behavior, composition, reservoir heterogeneity, and the computational demands these aspects impose".

Yet another important uncertainty that has received less attention in CCS numerical studies is the possibility of temporal mismatch between CO_2 supply and transport/storage capacity. Normally an intermediate storage facility or buffer might be needed to address the mismatch problem by temporarily storing the CO_2 (Holloway et al., 2006) and absorbing intermittent peaks in gas flow (Scottish Enterprise, 2011). Assume that injection process stops a number of times during a given period due to a periodical inspection or system failure. In such circumstances, existence of an above ground or underground CO_2 buffer is necessary to ensure continues operation of the whole CCS system. In the absence of the buffer, the captured CO_2 may release to the atmosphere in case of injection failure. Installing a larger buffer with higher capacity means a longer period of sustained operation of the system in injection failures; however larger buffer requires higher initial capital cost for instruction of the tank as well as higher maintenance costs. As a result, a comparison between the additional costs of a larger buffer versus the saved cost of the longer time of smoothing out the supply and storage interruptions is necessary.

The current research is investigating the CO_2 storage capacity, the uncertainty of reservoir permeability, and the potential injection failures in a CCS system. In particular, numerical simulations of reservoir permeability and net cost evaluations of the size of CO_2 buffer were carried out. CMG GEM^{TM} simulator was used to study the uncertainty of permeability affecting CO_2 injection rate, and a simple operations research by considering the number of injection failure days was used to simulate the optimal size of CO_2 buffer volume.

Tomakomai Demonstration Project: On behalf of the Ministry of Economy, Trade and Industry (METI), the Japan CCS Co., Ltd. (JCCS) has started a large-scale CCS demonstration project at the Tomakomai Area in Hokkaido for the period of 2012-2020; in which the first four years are to be devoted for preparatory works and construction of the necessary facilities, while CO_2 injection is planned to start in 2015 (JCCS, 2012). The injection base will receive both gaseous and liquefied phase CO_2 from two different supply sources, which is an indication of a large-scale CCS operation (Yamanouchi et al., 2011). The two reservoirs that are considered for injection are Moebetsu Formation and Takinoue Formation, with estimated drilling length of 3,600m and 5,600m respectively (JCCS, 2012). Based on the already available geological and geophysical data from the past oil and gas explorations activities as well as the recently conducted 3-D seismic and drilling surveys, Tomakomai was identified as one of the best candidates for a comprehensive CCS demonstration project; not only for geological suitability, but for the availability of nearby CO_2 emission sources (Tanase et al., 2013). The area is located near the Tomakomai industrial port, a large-scale coastal industrial zone hosting a wide variety of industries such as automobile, oil refinery, and power generation. The gas supply for the project will be provided by CO_2 capture equipments installed in the hydrogen production facilities of the neighboring refinery industries (Yamanouchi et al., 2011). The objective of this project is to inject CO_2 into sub-seabed formations of Tomakomai offshore field (Figure 1). In order to meet the Government regulations regarding CO_2 storage in seabed, a marine environmental assessment prior to injection will be carried out (JCCS, 2013).

Figure 1. Tomakomai demonstration project schematic diagram (Japan CCS Co. Ltd)



2. Numerical Simulations of Geological Parameters

2.1. CO_2 Storage Capacity of Moebetsu Layer

It is necessary to identify how much CO_2 can be stored in a certain geological space or how much space we need to store a certain amount of CO_2 (van der Meer and Yavuz, 2009). Previous studies have attempted to assess CO_2 storage capacity using various approaches by considering diverse trapping mechanisms (Bachu et al., 2007). Some studies have already presented formulas for aquifer storage capacity calculations in Japan by systematic nationwide saline-aquifer capacity assessments (Nakanishi et al., 2009; Ogawa et al., 2011; Takagi, 2011). In this study, the numerical modeling using CMG-GEMTM was carried out to investigate the CO_2 injection capacity into Moebetsu layer of Tomakomai project. An equation suggested by Takagi (2011) was used to quantify the volume of numerical model as below:

$$V = \frac{Q}{S_f \times \varphi \times (1 - S_{wir}) \times \rho} \tag{1}$$

where Q is the total injected CO_2 (7.5×10^5 t in 3 years), S_f is storage factor (0.25 for strati graphical trapping), φ is Porosity (0.281 for Moebetsu layer of Tomakomai), Sg is the supercritical phase volume fraction in the injected CO_2 (assumed to be 0.50 from Nakanishi et al., 2009), and ρ is CO_2 density (0.62362 tCO_2/m^3) at reservoir condition of 11.45 MPa pressure and 45.6 ºC temperature. The numerical model volume calculated by equation 1 is 3.36×10^7 m^3.

Table 1 shows the numerical simulation conditions and reservoir parameters. The simulation result of cumulative CO_2 injection performed by this study has similar patterns with the results obtained by JCCC that approves the modeling reliability (Figure 2). The minor differences are due to the fact that JCCC has used closed boundary condition with larger numerical grid blocks in size and number, while current study has simplified the numerical model by using constant pressure and permeable flow at the reservoir boundary (open boundary condition) to be able to get the result in a reasonable calculation time. In the simulation modeling in order to set open boundary condition, 4 water producer wells were considered in each corner to discharge water when the reservoir's pressure increases by CO_2 injection.

In addition the permeability in the model is not the same with JCCS's model to adjust the size differences in the two models.

Table 1. Condition of numerical simulation and reservoir parameters

	Present Simulation	JCCS's Simulation
Size	0.58km × 0.58km × 100m	8km × 16km × 1500m
Total Number of Blocks	10000	97024
Boundary Condition	Open	Closed
Injection Rate, Period	2.5×10^5 ton CO_2/year, 3 years	
Max Bottom Hole Pressure	13.41 MPa	
ええPorosity	28.1 %	
Horizontal Permeability	25mD	17 mD
Vertical Permeability	2.5mD	1.7 mD

Distribution of CO_2 before and after injection is shown in Figures 3. It is evident from Figure 3(b) that CO_2 distribution is not happening around producer wells; indicating that only water will be produced by these wells in order to keep the reservoir pressure in constant conditions.

Figure 2. Present numerical simulation result compared with JCCS's simulation result

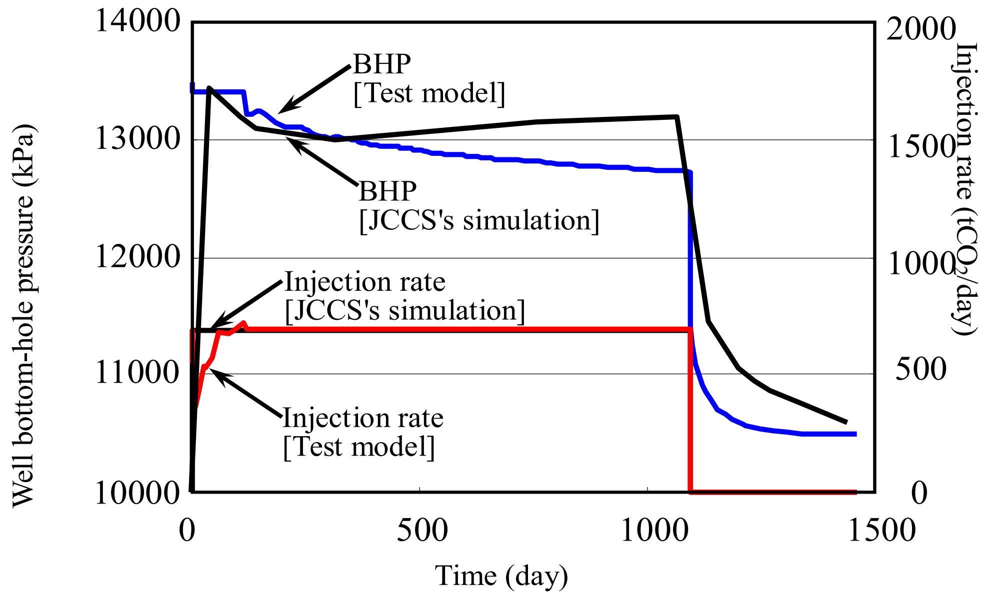
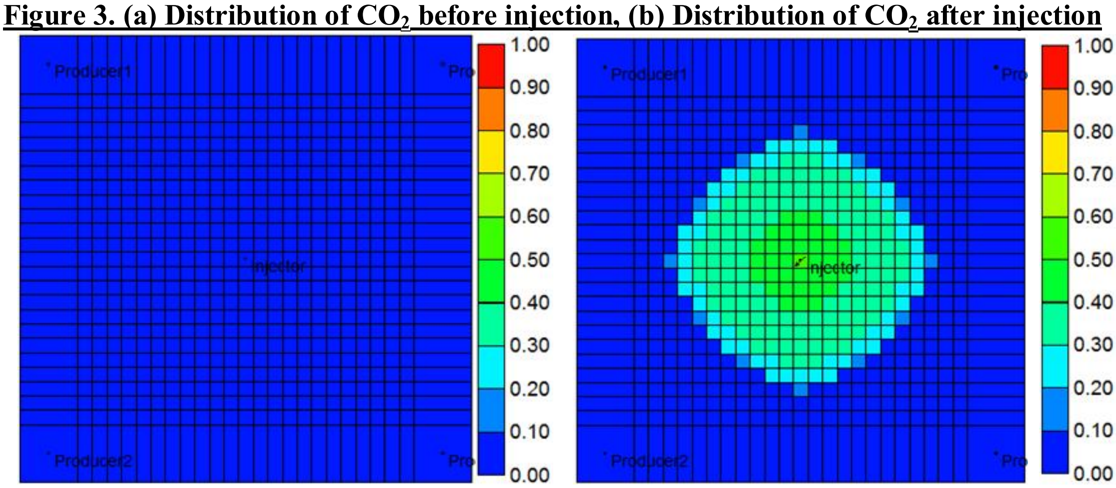


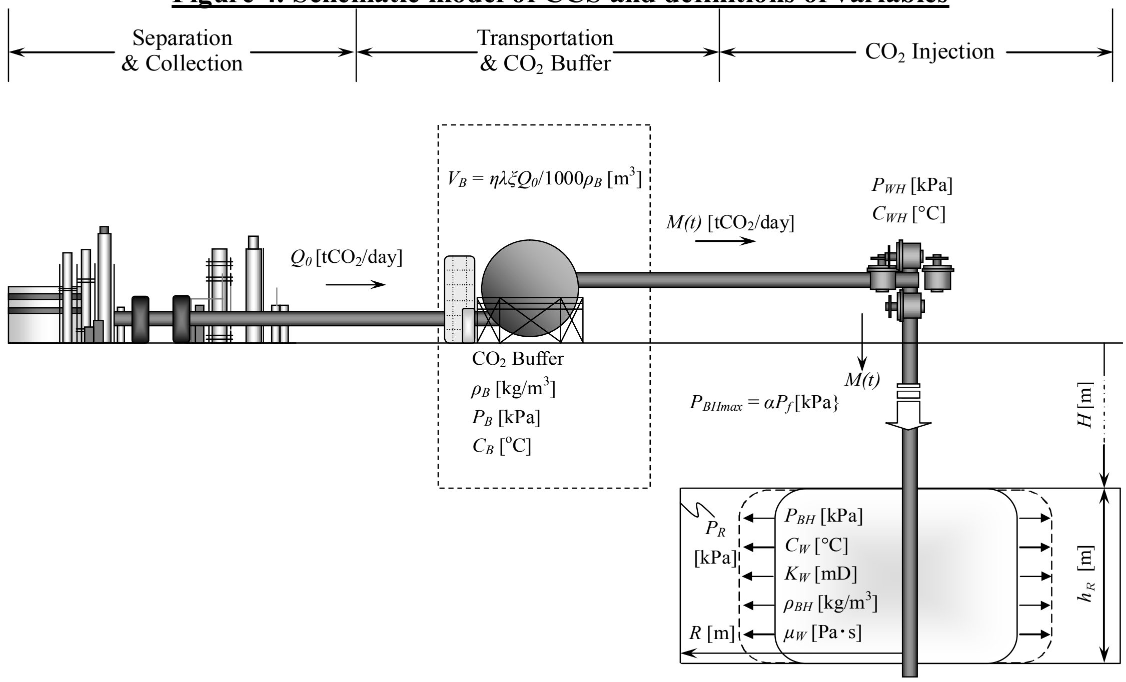
Figure 3. (a) Distribution of CO_2 before injection, (b) Distribution of CO_2 after injection



2.2. Permeability Uncertainty in Commercial Scale Injection

Reliable characterization of the subsurface is one of the most challenging tasks in underground flow simulations (Ginting et al., 2014). Among important factors that affect CO_2 storage performance is the spatial heterogeneity of the reservoir properties such as permeability (Hou et al., 2013). Such properties can be simulated by sophisticated computer modeling programs to improve the predictability of reservoir quality for commercial CCS purposes. Tomakomai project is still in demonstration stage, however commercial scale injection for this project can be modeled by using underground simulators. In this study, a numerical model was developed to simulate injection and storage of 10^7 ton CO_2 in a period of 10 years in Tomakomai project by employing the data from Moebetsu layer. The objective was to model CO_2 injection rate against permeability uncertainty and the uncertainty of formation fracture pressure in order to quantify the required margins on the transportation and injection processes. The schematic presentation of the model is illustrated in Figure 4. Reservoir parameters and numerical characteristics of the numerical simulation are shown in Table 2.

Figure 4. Schematic model of CCS and definitions of variables



Q_0 : Collection rate of CO_2 [tCO_2/day]	*$M(t)$: Injection rate at time t [tCO_2/day]*	*V_B : Buffer volume [m^3]*	*η : Coefficient of buffer*
λ : Cycle of trouble [day]	*ξ : Ratio of trouble in each cycle*	*ρ_B : CO_2 density of buffer[kg/m^3]*	*ρ_{BH} : CO_2 density at bottom hole [kg/m^3]*
P_B : Pressure at buffer [kPa]	*P_{WH} : Pressure at well head [kPa]*	*P_{BH} : Pressure at bottom hole [kPa]*	*P_R : Pressure at boundary of reservoir [kPa]*
P_f : Formation fracture pressure [kPa]	*P_{BHmax} : Maximum bottom hole pressure [kPa]*	*K_W : Reservoir permeability [mD]*	*μ_W : Viscosity of reservoir [Pa·s]*
C_B : Temperature at buffer [°C]	*C_{WH} : Temperature at well head [°C]*	*C_{BH} : Temperature at bottom hole [°C]*	
H : Depth of reservoir [m]	*h_R : Height of reservoir [m]*	*R : Radius of reservoir [m]*	

Table 2. Condition of numerical simulation and reservoir parameters for a commercial CO_2 storage

Size	2.1 km × 2.1 km × 100m
Injection Rate	1.0×10^{6} ton CO_2/year
Injection Period	10 years
Horizontal Permeability	20.0~27.5 mD
Vertical Permeability	2.00~2.75 mD
Reservoir Pressure	11.45 MPa
Reservoir Temperature	45.56 °C

Reservoir permeability is expected to have a direct relation with storage capacity, because higher permeability is important for a sufficient flow rate (Morgan, 2003). The quality of such relationship by considering the possible permeability changes of the reservoir rock was modeled for the case of Tomakomai project for a range of permeability values. The result of numerical simulation on the cumulative amount of injected CO_2 (1.0×10^{7}ton) against time (10 years) for various values of permeability is presented in Figure 5. The figure indicates that bigger cumulative amount of injection could be achieved when permeability is higher. Sasaki et al. (2000) have shown that at time $t = 0$ the reservoir permeability and the average injection rate have proportional relationship as is shown in Equation 2.

$$M(0) = K_w h_R \rho_{BH} \frac{P_{BH}(0) - P_R}{\frac{\mu_w}{2\pi} \cdot \ln\left(\frac{R}{r_w}\right)} \tag{2}$$

where $M(0)$ is the initial CO_2 injection rate (equal to initial CO_2 mass flow rate), $\rho(x,t)$ is CO_2 density in the tubing pipe, $\rho_{BH} = \rho(H,t)$ is CO_2 density in the bottom hole, g is gravity acceleration, r_w the bottom hole outer radius, K_w is permeability, P_{WH} is pressures at well head, P_{BH} is pressure at bottom hole and P_R is pressures at outer boundary (reservoir initial pressure), μ_w is reservoir water viscosity, and H is the length of injection well (vertical well) (Sasaki et al., 2000).

Figure 5. Result of numerical simulation for a commercial CO_2 storage model with different permeability (k_v, k_h) unit in mD

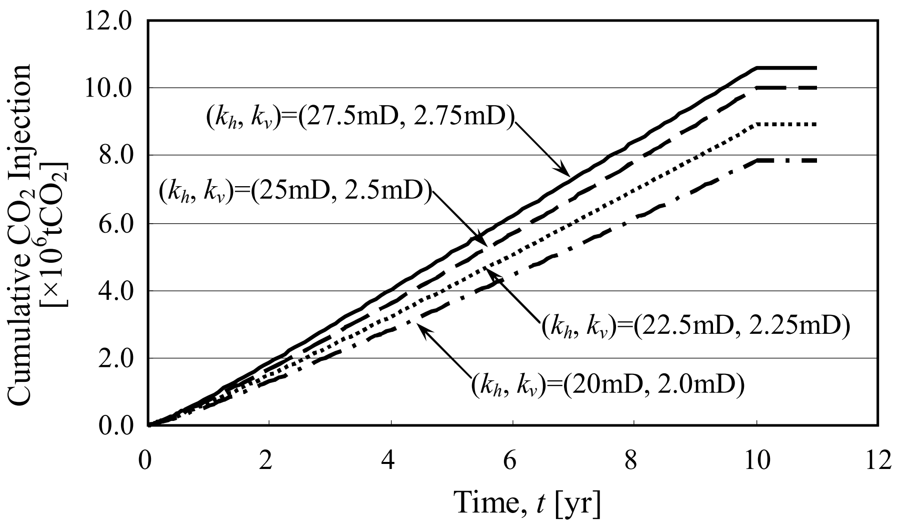
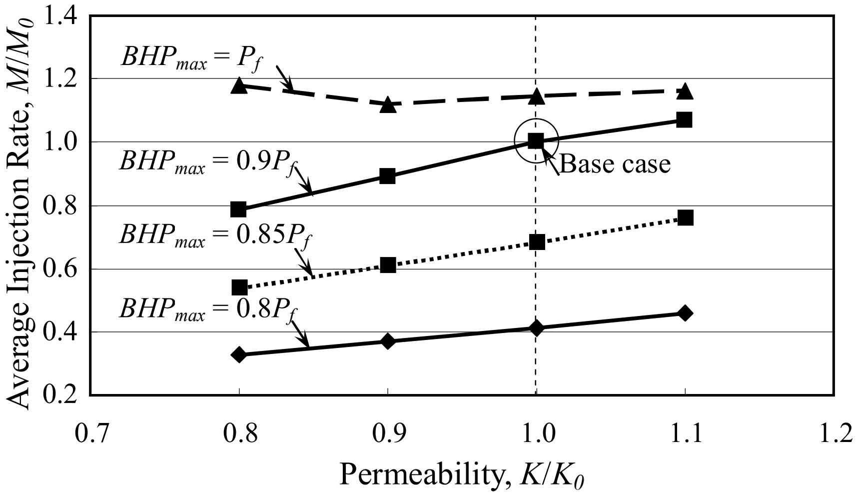


Figure 6 shows the relationship between average injection rate and permeability (for different cases of maximum bottom hole pressure). In order to prevent the destruction of cap layer, the maximum bottom hole pressure must be lower than formation fracture pressure. For the feasibility testof Tomakomai project,the maximum bottom hole pressure is equal to 90% of the formation fracture pressure. Therefore the base case is Figure 6 is a case in which K is equal to K_0 and P_{BHmax} is equal to 90% of formation fracture pressure. Average injection rate is shown in a broken line in the figure which is bigger than M_0. The figure also reveals that in each level of permeability, the average injection rate proportionally increases with the value of maximum bottom hole pressure. In addition, it can be seen that a higher permeability results in a bigger average injection rate for each value of the maximum bottom hole pressure (Suzuki et al., 2013).

Figure 6. Average injection rate for different permeability on different maximum bottom hole pressure- *P_f :Formation fracture pressure, P_{BHmax} : Maximum bottom hole pressure, K_0 : Predicted permeability (k_v, k_h) = (45.0, 4.5) [mD]), K : Actual permeability, M_0 : Average injection rate (base case), M : Average injection rate (other cases)*



3. Economic Evaluations and Analysis

3.1. Economic Analysis on Permeability Uncertainty

The geological simulation results of this study showed that when permeability was set to lower values, the cumulative amount of injected CO_2 wasalso decreased. In such case the extra CO_2 may release to the atmosphere rather than being injected in the reservoir. Suppose the project can get revenue from the Government or a company for the injected amounts of CO_2 through a carbon tax or trade system. Then an opportunity cost (benefit lost) may occur by decreased amount of injected CO_2 as a consequence of permeability estimation errors. On the other hand the cost spent for capturing those non-injected CO_2 will be lost. Economic evaluations were performed in order to calculate the net cost of injecting 10^7ton-CO_2in Tomakomai project for different values of permeability. The evaluation was based on a value method comprised calculating the revenue from injecting 10^7ton-CO_2 in present value (interest rate is 4 %), calculating the cost of the total system, and finally calculating the net cost by subtracting cost from revenues.

Calculation of the cost of the total system is composed of the initial and operating costs in present value. It also includes the costs of installation and operation of a CO_2 buffer tank. As discussed earlier, the system can benefit from inclusion of a CO_2 buffer when an injection failure happens. In order to avoid benefit lost in injection failures, the buffer can be considered for temporary storing the captured CO_2until the failure is resolved. The components of the total cost calculation are shown in Table 3.

Table 3. Cost of each section to dispose 1.0×1010 tCO_2 in 10 years

	Initial Cost [JPY]	Operation & Maintenance Cost [JPY/yr]
Collection and Separation	9.6×10^9	2.4×10^{10}
Transportation (Pipeline)	7.8×10^9	3.0×10^9
Buffer	$1.20\times10^5\times V_B\times\rho_B$	$1.20\times10^4\times V_B\times\rho_B$
Injection	4.0×10^9	$8.62\times10^5\times M(t)$

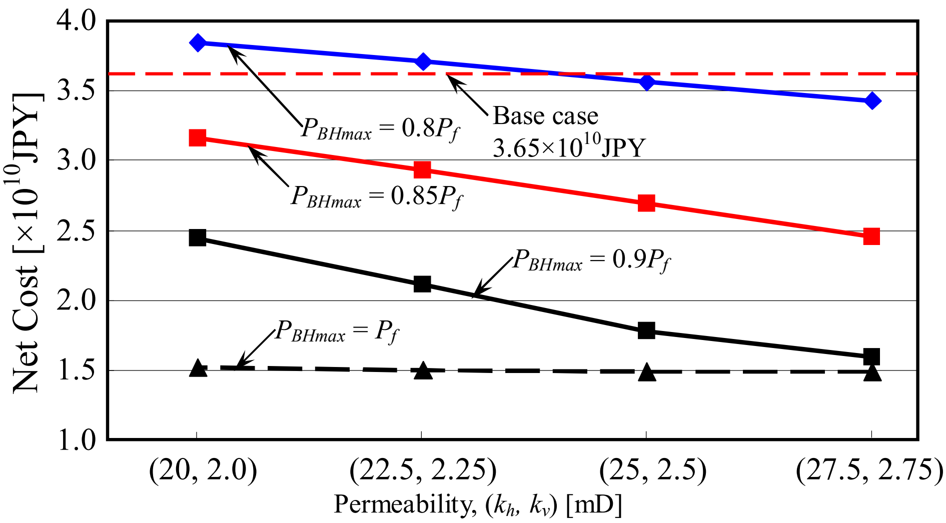
The calculated amount of injected CO_2 and the net cost of injection for various permeability values are shown in Table 4 and Figure 7, respectively. As it can be seen in the Table 4, the injection amount in business model is considered 10% higher than the actual maximum injection amount in order to deal with the possible accident in injection processes.

The "Base case" in Figure 7 is a case without CCS in which the produced CO_2 is released to the atmosphere. The value shown in base case represents the total cost of purchasing carbon credit from outside, instead of carbon injection. The figure indicates that the net injection cost is higher than the cost of the base case; and therefore CCS system could have economic advantages under an appropriate carbon trade system.

Table 4. Injection amount in different permeability

Permeability (k_v, k_h) [mD]	Injection amount (business model) [$\times 10^6 tCO_2$]	Injection amount (actual) [$\times 10^6 tCO_2$]
(27.5, 2.75)	10.6	9.54
(25.0, 2.50)	10.0	9.00
(22.5, 2.25)	8.92	8.02
(20.0, 2.00)	7.84	7.06

Figure 7. Net cost evaluations of for each reservoir permeability



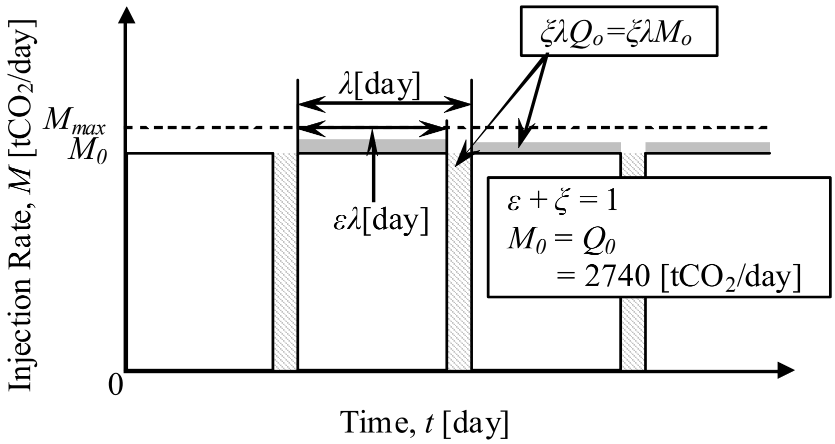
3.2. Injection Failures and CO_2 Buffer Volume

Dealing with injection failures requires additional costs, because at any event of failure a certain amount of captured CO_2 may be released to the atmosphere instead of being injected. In one hand the cost spent for capturing of non-injected CO_2 will be lost, and on the other hand a benefit lost will be happened in the form of revenue lost through the carbon tax/trade system. However, as indicated earlier, CO_2 can be stored temporarily in a buffer while resolving the failure. The time period during which the captured CO_2 can be stored in the buffer depends on the buffer volume. The volume has a direct relation with the amount of initial investment for construction of the buffer tank. Economic evaluations was carried out by considering some possible troubles in the system in order to measure how CO_2 buffer volume can affect the net cost of CCS. In the commercial scale CCS investigated in this research, CO_2 is assumed to be continuously captured from the hydrogen separation unit of an oil refinery with a constant rate regardless of any possible trouble in transportation and injection of CO_2. Therefore any halt in transportation or injection is expected to have a meaningful effect on the net cost.

Figure 8 shows an image of injection failure where λ is injection failure interval, ε is continuous injection interval (interval of injection without trouble), ξ is ratio of injection failure in each interval, M_0 is CO_2 injection rate at the plant (equal to collection rate Q_0), M_{max} is maximum injection rate, ρ_B is density of CO_2 in buffer, and V_i is the ideal volume of the buffer. The CO_2 preserved in the buffer is equal to the amount of injected CO_2 in the next injection period. V_i can be obtained from the following equation.

$$V_i = \frac{\xi \lambda Q_0}{1000 \rho_B} \tag{4}$$

Figure 8. Interval of injection failure



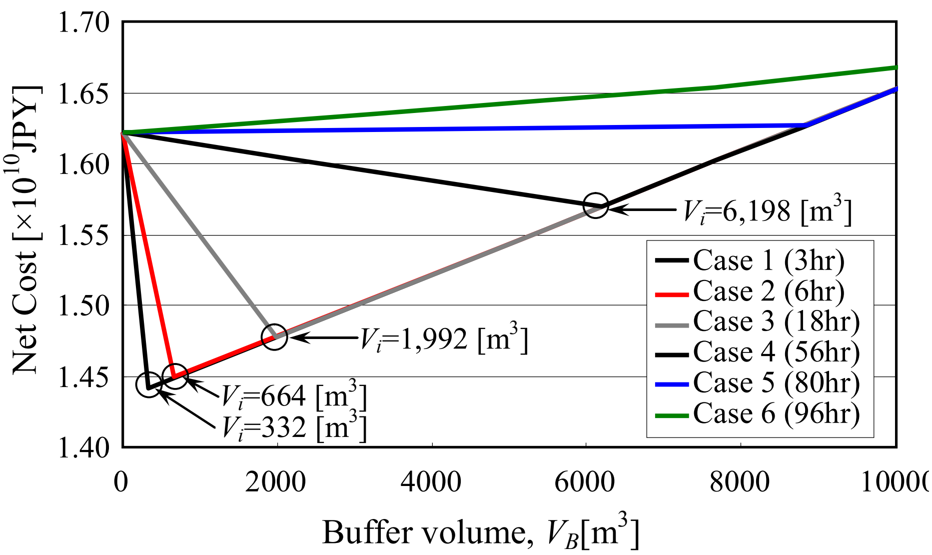
3.2.1. Case Study

In order to examine the potential effects of injection failure, a case study has been carried out comprising of six cases with assuming that each cases has an injection failure resulting in a total of 200 days injection halt in 10 years (Table 5). Then, the injection net cost was calculated for each failure case with a different assumed buffer volume (V_B) as is shown in Figure 9.

Table 5. Assumed cases for economical evaluation

	Termination Period $\xi(24\times\lambda)$ [hour]	Interval of Termination λ [day]
Case 1	3	2.3
Case 2	6	4.6
Case 3	18	13.7
Case 4	56	42.6
Case 5	80	60.8
Case 6	96	73.0

Figure 9. CO_2 buffer volume against the net cost of CCS



Calculation result shows that for cases 1 to 4 installing CO_2 buffer makes economic sense because for these cases, the net cost is less than that of no-buffer scenario i.e. $V_B = 0$ (1.52×10^{10} JPY). However, for the cases 5 and 6, the net cost of no-buffer scenario is the cheapest; therefore installing a buffer does not make economic sense. A longer injection stop event is positively correlated with a larger optimum buffer volume until a turning point (break-even point in Figure 10) in which a larger volume is no longer economic, because the net cost turns out to be more than that of the no-buffer case ($V_B = 0$). This turning point for the current case study is equal to 77.60 hours of injection halt.

The costs indicated in Table 3 can be classified in two groups of *fixed* and *variable* costs. The total cost for each group can be obtained from the following equations:

$$TFC = IC_{Col} + IC_{Tran} + IC_{Inj} + OC_{Col} + OC_{Tran} \quad (5)$$

$$TVC = IC_{Buf} + OC_{Inj} + OC_{Buf} + RV_{Lost} \quad (6)$$

where IC is initial cost, OC is operation and maintenance cost, RV is revenue, RV_{Lost} is lost revenue and RV_0 is original revenue (no injection failure case). A range of buffer volume in which TVC is lower than the cost of no-buffer case can be seen in Figure 10. Installing CO_2 buffer beyond this range has not economic value. Such a condition that buffer volume goes beyond the break-even point is shown in Figure 11.

Figure 10. The case in which CO_2 buffer should be installed

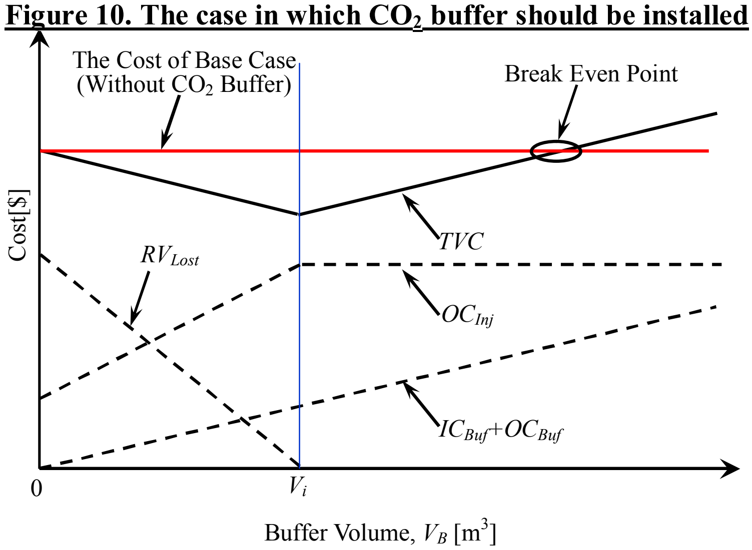
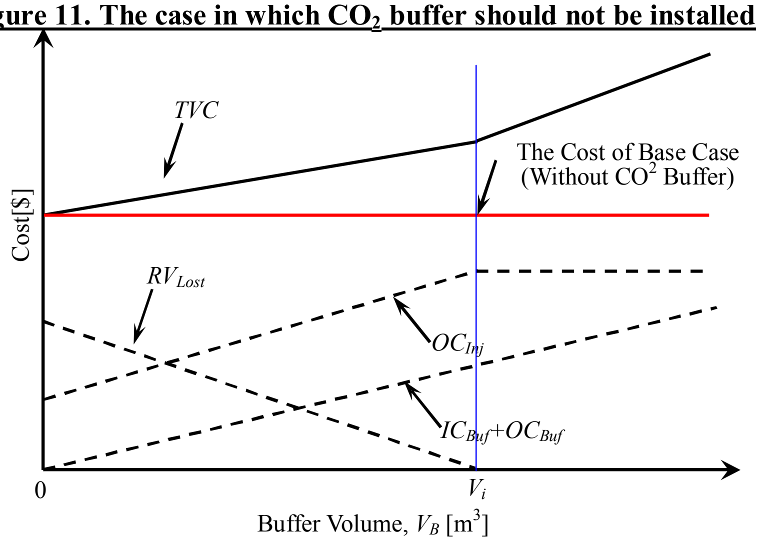


Figure 11. The case in which CO_2 buffer should not be installed



In break-even point the TVC of the CCS system with buffer will be equal to the TVC of no-buffer case:

$$TVC_{VB=Vi} = TVC_{VB=0} \tag{7}$$

Injection halt interval at break-even point, λ_{BEP}, could be calculated as:

$$\lambda_{BEP} = Const \times (price_{CO_2} - 291.3) \tag{8}$$

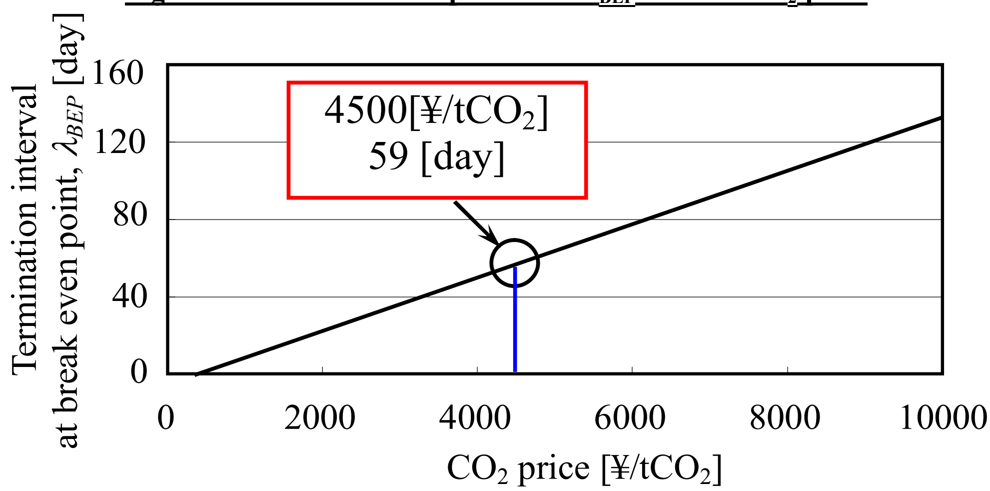
$$Const = \frac{365 \times (P/A, 4\%, 10)}{12 \times 10^5 \times \left(1 + \frac{(P/A, 4\%, 10)}{10}\right)} \tag{9}$$

λ_{BEP} and CO_2 price are proportional. The relationship between λ_{BEP} and CO_2 price is shown in Figure 12. The optimum CO_2 buffer volume (V_{opt}) can be identified by having the λ_{BEP} value:

- if $\lambda < \lambda_{BEP}$ then $V_{opt} = V_i$
- if $\lambda > \lambda_{BEP}$ then $V_{opt} = 0[m^3]$

Therefore, if as example CO_2 price is 4500 yen/tonCO_2, λ_{BEP} would be 59[day]; and if λ is 10[day], V_{opt} would be 1455[m^3]; and if λ is 80[day], V_{opt} would be to 0[m^3].

Figure 12. The relationship between λ_{BEP} and the CO_2 price



4. Conclusion

In this research the geological uncertainty and injection failure analysis with economical considerations were carried out to investigate uncertainty in aquifer's permeability and failures in CO_2 operation and transportation at the Tomakomai CCS project. Analyzing geological parameters using CMG-GEMTM model indicated that CO_2 injection capacity into Moebetsu layer of Tomakomai can be amounted to 3.36×107 m^3. However the uncertainty in capacity estimation is an issue because of the changeable nature of some reservoir parameters such as permeability. Such uncertainties may have economic consequences and in long-run can result is benefit lost. Therefore the reservoir block modeling for simulation of CO_2 injection rate was used to examine the economical consequences of estimated errors in aquifer permeability. On the other hand, since injection halt and temporary failures can potentially impose additional costs to the project, the economic loss resulted from failure of CO_2 injection was evaluated by assuming periodical injection halts. In order to minimize the economic effects of injection halts, installation of CO_2 buffers such as sphere gas tanks was considered to store CO_2 on the CCS process after its capture when a trouble on transportation or injection processes occurs. The larger size of CO_2 buffer volume can longer withstand against trouble, however the larger buffer volume needs larger cost for initial construction and maintenance. The optimum CO_2 buffer volume has been presented based on economical evaluations based on several simulations conducted on the system performance of commercial scale project with and without CO_2 buffer. The economic analysis indicated that a longer injection halt is positively correlated with a larger optimum buffer volume until reaching a turning pointin which a larger buffer volume is no longer economic.

Acknowledgments

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