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Article

Estimation of CO_2 Transport Costs in South Korea Using a Techno-Economic Model

Kwangu Kang [1], Youngkyun Seo [2], Daejun Chang [2], Seong-Gil Kang [1] and Cheol Huh [3,*]

[1] Offshore CCS Research Unit, Korea Research Institute of Ships and Ocean Engineering, 32 1312 Beon-gil, Yuseong-daero, Yuseong-gu, Daejeon 305-343, Korea; E-Mails: kgkang@kriso.re.kr (K.K.); kangsg@kriso.re.kr (S.-G.K.)

[2] Division of Ocean Systems Engineering, Korea Advanced Institute of Science and Technology, 291 Daehak-ro, Yuseong-gu, Daejeon 305-701, Korea; E-Mails: weeksky@kaist.ac.kr (Y.S.); djchang@kaist.edu (D.C.)

[3] Ocean Science & Technology School, Korea Maritime and Ocean University, 727 Taejong-ro, Youngdo-gu, Busan 606-791, Korea

* Author to whom correspondence should be addressed; E-Mail: cheolhuh@kmou.ac.kr; Tel.: +82-51-410-5247; Fax: +82-51-404-3985.

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Abstract: In this study, a techno–economic model was used to calculate the costs of CO_2 transport and specify the major equipment required for transport in order to demonstrate and implement CO_2 sequestration in the offshore sediments of South Korea. First, three different carbon capture and storage demonstration scenarios were set up involving the use of three CO_2 capture plants and one offshore storage site. Each transport scenario considered both the pipeline transport and ship transport options. The temperature and pressure conditions of CO_2 in each transport stage were determined from engineering and economic viewpoints, and the corresponding specifications and equipment costs were calculated. The transport costs for a 1 $MtCO_2$/year transport rate were estimated to be US\$33/tCO_2 and US\$28/tCO_2 for a pipeline transport of ~530 km and ship transport of ~724 km, respectively. Through the economies of scale effect, the pipeline and ship transport costs for a transport rate of 3 $MtCO_2$/year were reduced to approximately US\$21/tCO_2 and US\$23/tCO_2, respectively. A CO_2 hub terminal did not significantly reduce the cost because of the short distance from the hub to the storage site and the small number of captured sources.

Keywords: carbon capture and storage; CO_2 transport; cost; scale effect

1. Introduction

Because of the concerns over climate change in recent years, the need to mitigate CO_2 emissions is increasing. Carbon capture and storage (CCS) technology is an active carbon emission reduction method that can be used to capture CO_2 from large point sources such as fossil fuel power plants (PP) or steel and cement industries and store it in geological formations. CCS is expected to serve as intermediary technology for reducing CO_2 emissions before renewable energy technologies replace the fossil fuel-based energy portfolio. Many countries are planning on reducing their CO_2 emissions using CCS technology, and 65 large-scale integrated projects are currently in operation or are being planned [1].

In Korea, a total of 592.9 $MtCO_2$/year was emitted from fuel combustion in 2012, of which approximately 50% was from electricity generation [2]. The Korean government announced a plan to reduce the country's greenhouse gas emissions by 30% from the business as usual (BAU) level by 2020 [3]. The BAU level represents the CO_2 emissions that would occur without any efforts at reduction. Korea suggested using CCS as the key technology for reaching its mid-term greenhouse gas reduction goals [4]. According to the Korea CCS Plan [4], a CCS demonstration project will start at a scale of 1 $MtCO_2$/year in 2017. By 2020, the CCS project will be scaled up to 3 $MtCO_2$/year. By 2030, CCS in Korea will expand to 32 $MtCO_2$/year, which corresponds to 10% of the Korea CO_2 reduction goal. Therefore, many PPs based on fossil fuel in Korea are expected to adopt CCS to meet the CO_2 emission reduction goal. Because large amounts of financial resources and additional energy consumption are needed to build and operate a CCS project, an accurate estimation of the costs before the project launch is very important.

Many studies have been carried out on the CO_2 capture costs, which constitute more than 50% of the total CCS costs. According to recent reports [5–7], the capture costs per tonne of CO_2 for coal-fired power plants are US$50–81 for post-combustion, US$55–67 for pre-combustion and US$52–78 for oxy-fuel, respectively. For natural gas combined cycles, the costs are US$80–107 per tonne of CO_2. The CO_2 capture costs do not greatly differ for different countries or locations because they do not greatly depend on geological factors. However, the costs of transport and storage depend heavily on geographical and geological factors such as the transport distance, reservoir condition, and injection method. Therefore, it is very difficult to create general guidelines for CO_2 transportation and storage costs that can be applied to CCS projects in different countries. Important factors for the CO_2 transport costs include the transport methods, transport rates, storage sites (onshore vs. offshore), and distance. One issue of debate is whether or not ship transport is more expensive than pipeline transport. Important factors for storage costs are geological properties such as the storage capacity, injection depth, and storage sites (saline aquifer *vs*. oil field, onshore *vs*. offshore).

In Korea, two 10 MW-scale CO_2 capture plants are currently in the pilot test stage. The Boryeong PP is testing wet-type advanced amine technology, and the Hadong PP is testing dry-type regenerating sorbent technology [8]. After a 1 year pilot period, the final investment decision (FID) on the construction of >100 MW CO_2 capture plants will be made. It has not yet been determined if both or just one of the CO_2 capture technologies will be selected. The Boryeong PP will have the wet-type CO_2 capture plant, and the Hadong PP or Samcheok PP will have the dry type. The potential storage site is the Ulleung Basin, which has an estimated storage capacity of 5 $GtCO_2$ [9]. Only offshore storage sites are being considered as candidate storage sites because Korea is a densely populated country, and no large saline aquifer suitable for CO_2 storage has been found onshore. Figure 1 presents details on the locations of the three PPs and storage site. For the demonstration of the integrated CCS project, the CO_2 transport and storage systems should be set up before CO_2 capture is begun. Because the three PPs and one storage site are widely distributed around the Korean peninsula, various transport routes can be selected. Determining the optimal route is important to reaching an FID.

Figure 1. Locations of three CO_2 capture plants, CO_2 hub terminal, and storage site.

This study considered two different transport methods: a pipeline and ships. Recent studies [10–13] have reported that pipeline transport is suitable for short distances, and ship transport is suitable for long distances. The distance where ship transport becomes more cost-effective is around 200–1000 km. Because the distance from the Boryeong PP to the storage site is approximately 530 km, it is difficult to predict which method is more cost-effective. Therefore, a detailed and thorough comparison is required to determine the more cost-effective transport method. Generally, CO_2 is compressed to a level higher than the critical point for pipeline transport and is liquefied for ship transport. The costs of compression and liquefaction amount to approximately half of the total CO_2 transport costs; therefore, comparing the costs of compression and liquefaction is very critical. However, many previous studies on CO_2 transport costs did not consider the compression and liquefaction costs. Recent studies [11–14] have considered the cost of the liquefaction process, but these studies assumed that the CO_2 was already compressed to a pressure greater than 100 bar and only considered the additional liquefaction cost. To strictly compare the transport costs between pipeline transport and ship transport, the compression/liquefaction costs were considered in this study.

A techno–economic model was used to evaluate the CO_2 transport costs of various cases with different transportation routes and methods. First, three different CO_2 transport scenarios in Korea were set up based on the three PPs and one storage site. The pressure and temperature conditions at each stage of transport were assumed, and the lowest costs for the equipment were identified as the optimum values. The calculated costs were compared for different transport rates and methods to characterize the costs of CO_2 transport in Korea.

2. CO_2 Transport Scenarios

Table 1 gives the three CO_2 transport scenarios set up with different combinations of the three capture plants. Figure 2 shows the detailed transport routes of each scenario.

Table 1. CO_2 transport scenarios.

	Transportation method	Capture plant (annual volume)
Scenario 1	Boryeong power plant $\xrightarrow[\text{ship}]{\text{pipeline}}$ Storage site	Boryeong only (1, 2, 3, 4, 6 $MtCO_2$)
Scenario 2	Boryeong power plant $\xrightarrow[\text{ship}]{\text{pipeline}}$ Hadong power plant $\xrightarrow[\text{ship}]{\text{pipeline}}$ Storage site	Boryeong (1, 3 $MtCO_2$), Hadong (1, 3 $MtCO_2$)
Scenario 3	Boryeong power plant $\xrightarrow{\text{pipeline}}$ Terminal; Samcheok power plant $\xrightarrow{\text{pipeline}}$ Terminal; Terminal $\xrightarrow{\text{pipeline}}$ Storage site	Boryeong (1 $MtCO_2$), Samcheok (1 $MtCO_2$)
	Boryeong power plant $\xrightarrow{\text{ship}}$ Terminal; Samcheok power plant $\xrightarrow{\text{ship}}$ Terminal; Terminal $\xrightarrow{\text{pipeline}}$ Storage site	
	Boryeong power plant $\xrightarrow{\text{ship}}$ Terminal; Samcheok power plant $\xrightarrow{\text{pipeline}}$ Terminal; Terminal $\xrightarrow{\text{pipeline}}$ Storage site	

As noted in the introduction, the wet-type and dry-type CO_2 capture technologies are competitors in Korea, and it has not yet been determined whether one or both types will be selected in the FID. Because the wet-type capture is verified and mature technology, the Boryeong PP using it was included in all scenarios. The Hadong PP and Samcheok PP, which are based on dry-type technology, were included in Scenarios 2 and 3, respectively. In summary, Scenario 1 has only one capture plant (Boryeong), Scenario 2 has two capture plants (Boryeong on the west coast and Hadong in the southern part of the Korean Peninsula), and Scenario 3 has two capture plants (Boryeong and Samcheok on the east coast). The Ulleung Basin served as the fixed storage site in all of the scenarios. Scenario 3 includes the hub terminal at Ulsan, but Scenarios 1 and 2 do not.

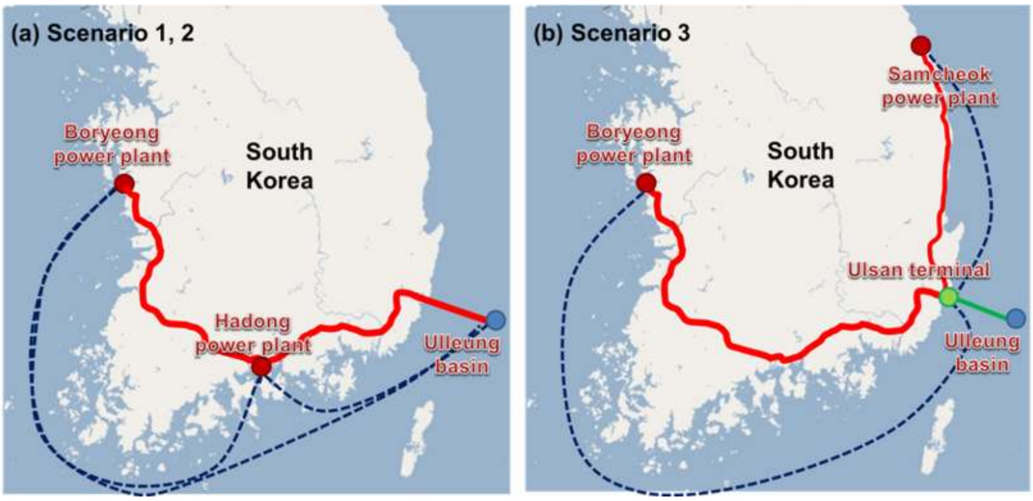

Figure 2. CO_2 transport scenarios in Korea: (**a**) Scenarios 1 and 2 and (**b**) Scenario 3. Scenario 1 has one capture plant at Boryeong, Scenario 2 has two capture plants at Boryeong and Hadong, and Scenario 3 has two capture plants at Boryeong and Samcheok. The CO_2 storage site is fixed at the Ulleung Basin. Scenario 3 has a hub terminal at Ulsan, but Scenarios 1 and 2 do not. The solid red lines, solid green line, and dotted blue lines represent the onshore pipeline transport routes, offshore pipeline transport route, and ship transport routes, respectively.

The CO_2 transport volume was varied in the range of 1–6 $MtCO_2$/year to determine its effect; the values are summarized in Table 1. Table 2 lists the details of the transport distances. For the pipeline transport in Scenario 1, the transport route from the Boryeong PP to the storage site is not the shortest route but follows the plains around the coastline to avoid the high mountains in the center of the Korean peninsula, as shown in Figure 2a. Because the Hadong PP in Scenario 2 is located on the route of Scenario 1, the pipeline transport routes of Scenario 2 are the same as the route of Scenario 1. However, in Scenario 2, CO_2 is added from the Hadong PP. In Scenario 3, the Boryeong and Samcheok PPs are included; because they are located on the west and east coasts, respectively, of the Korean peninsula (Figure 1), the hub terminal was assumed to be set up in Ulsan harbor, which is the nearest harbor to the storage site. Scenario 3 has three different transport methods: pipeline transport for both the Boryeong PP–Ulsan Harbor and Samcheomk–Ulsan Harbor routes, ship transport on both routes, and both transport methods on both routes (*i.e.*, ship transport for the Boryeong PP–Ulsan Harbor route and pipeline transport for the Samcheok–Ulsan Harbor routes). Ship transport is understood to be more economical than pipeline transport for long distances. Therefore, ship transport was adopted for the longer Boryeong PP–Ulsan terminal route, and pipeline transport was adopted for the shorter Samcheok PP–Ulsan terminal route in Scenario 3, as shown in Figure 2b. The transport method between the hub and storage site was fixed to an offshore pipeline.

Table 2. Distances from PP (Power Plant) to PP, PPs to storage site, PPs to hub terminal, and hub terminal to storage site.

Departure/Destination	Pipeline (km)	Ship (km)
Boryeong PP to Hadong PP	280	617
Hadong PP to Ulsan terminal	190	N/A
Ulsan terminal to Ulleung Basin	60	60
Boryeong PP to Ulleung Basin	530	724
Boryeong PP to Ulsan terminal	470	726
Hadong PP to Ulleung Basin	250	270
Samcheok PP to Ulsan terminal	250	282

3. CO_2 Transport Cost Calculation Method

Table 3 presents the major CO_2 transport cost elements considered in this study, which are divided into three categories: pipeline, ship, and hub terminal. In a pipeline, the cost elements are the compression in the capture plant, onshore and offshore pipelines, and booster. The cost elements for ship transport are the liquefaction process in the capture plant, carrier, and pumping process for injection. For a terminal, the major cost elements include the storage tank and pressurization process of ship-transported CO_2 for offshore pipeline transport.

Table 3. List of major cost elements in CO_2 transportation.

Pipeline	Capture site	Compression
	Pipe	Material, Labor, Right of way, Miscellaneous
	Booster	Onshore, Entrance of offshore pipeline
Ship	Capture site	Liquefaction, Temporary storage tank
	Ship	Ship, Pumping for injection
Terminal	Terminal	Storage tank
	Terminal to offshore pipeline	Pressurization

Figure 3 illustrates a system block diagram of CO_2 transport. The dotted rectangles represent the system boundary of this study's cost calculations. Because this study only focused on the transport cost, the capture and storage costs were excluded from the system boundary, but the compression and liquefaction systems were included in the pipe transport and ship transport, respectively.

3.1. Design and Cost Estimation of Pipeline Transport

In this study, the pipeline transport method was divided into four modules: the compression system, pumping system, onshore pipeline, and offshore pipeline, as shown in Figure 3a. The captured CO_2 at the capture system is compressed to the supercritical or liquid dense phase by pressure and then pumped at approximately 150 bar. The compressed CO_2 is transported through the onshore pipeline to the booster station at the entrance of the offshore pipeline. When the pressure in the onshore pipeline drops below 86 bar, an additional booster is required. The CO_2 is pumped at the booster station at the entrance of the offshore pipeline to meet the injection well head pressure conditions and is then transported through the offshore pipeline. In this study, the pumping cost to reach the required injection well head pressure condition was included, but the injection cost itself was excluded.

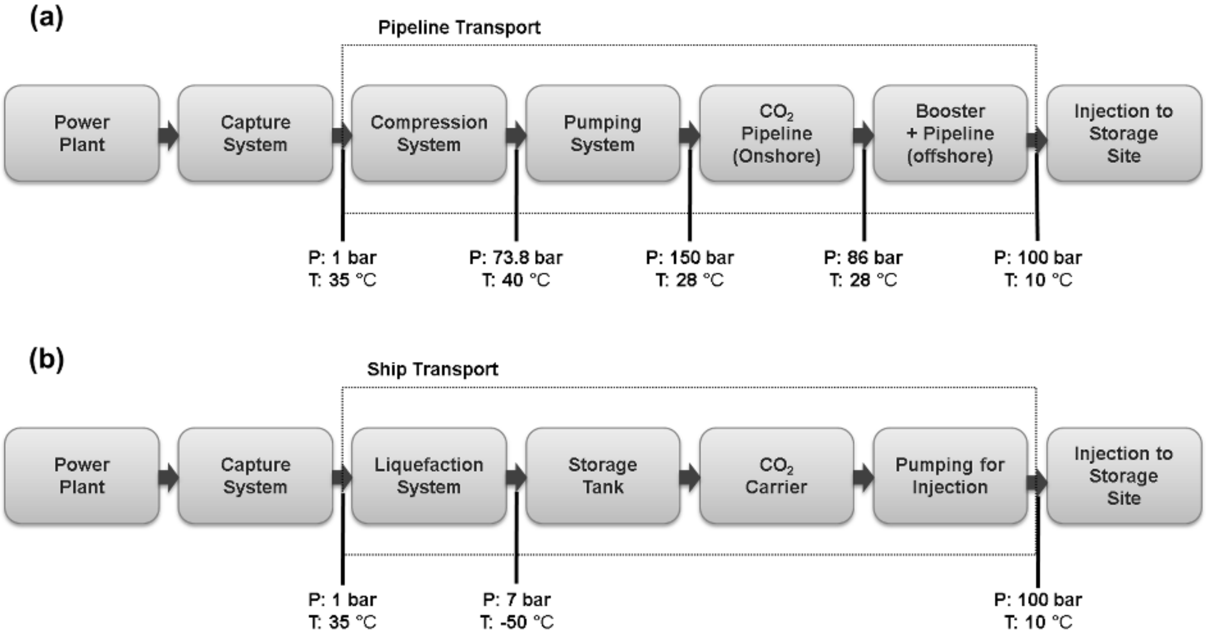

Figure 3. Block diagram of CO_2 transport. The dotted rectangles represent the system boundary of this study's cost calculations. The assumed pressures (P) and temperatures (T) at different stages are indicated for (**a**) pipeline transport and (**b**) ship transport.

3.1.1. Design of Pipeline Transport

In large-scale pipeline transport, CO_2 is mostly in a liquid or supercritical phase [15,16]. Therefore, it should be compressed to a pressure higher than the critical pressure of 7.38 MPa to change the phase to a liquid or supercritical state. In this study, the minimum pressure in the pipeline was set not to the critical pressure but to 8.6 MPa to avoid abrupt changes in the compressibility of CO_2 [10,15]. The maximum pressure was set to 15 MPa to avoid exceeding the maximum allowable operating pressure of ASME-ANSI 900# flanges [15]. Therefore, the maximum operating pressure difference (*i.e.*, difference between the maximum and minimum pressures) was 6.4 MPa. If the pressure in the pipeline is less than the minimum pressure of 8.6 MPa, a booster station needs to be installed. For the offshore pipeline transport, a booster station was assumed to be installed at the entrance of the offshore pipeline. This booster station maintained the pressure at the injection head at much higher than 100 bar. Because the specific storage depth and other conditions at the storage site have not yet been determined, the required pressure in the well head was assumed to be 100 bar. The onshore pipelines were also assumed to be buried 1 m underground [10]. The temperature of CO_2 in the onshore pipeline was assumed to be 28 °C, which is the maximum temperature in the summer 1 m underground in Korea [17].

The most important design parameter in the cost calculations of CO_2 pipeline transport is the pipe diameter because it has a very significant effect on the pipeline material and construction costs. Therefore, many pipeline diameter calculation equations have been proposed [18]. Most of these equations require the pressure difference to be a given value, but this is given arbitrarily without any optimization process [18,19]. In other words, once the pressure difference is determined, the pipe diameter is also determined automatically. A higher pressure difference requires more pumping power, but a smaller diameter pipe is available. The opposite holds true for smaller pressure differences. Therefore, using an arbitrary pressure difference does not allow the pipeline diameter to be optimized. The thickness of the pipeline is also important to the calculation of the pipeline material costs. Using pipeline materials with a high yield strength can decrease the pipe thickness but increase the unit cost. Therefore, to optimize the CO_2 pipeline thickness, both the class and cost of the materials need to be considered.

In this study, instead of determining the pipe diameter from a user-given pressure difference, the pipeline transport cost with all of the standard pipe diameters between Nominal Pipe Size (NPS) 6 and NPS 20 was calculated because standard pipe diameters are used for CO_2 transport. The pressure differences were conversely determined from each pipe diameter and used to calculate the number of boosters. For the calculation of the pipeline transport cost with each pipe diameter, the material costs of pipelines fabricated from all API 5X grade materials in Table 4 were calculated along with the material cost of the corresponding minimum standard pipe thickness to determine the least-cost pipeline materials. In other words, for a fixed transport rate, the transport costs of 64 cases were calculated to determine the least-cost pipe diameter, material, thickness, number of booster stations, and pressure difference. These cases involved eight standard pipe diameters and eight pipe materials. Through this approach, the least-cost pipeline diameters, material class, pipe thickness, and number of boosters could be determined simultaneously. This optimization exercise was performed in one of our previous studies [20].

Table 4. Minimum specified yield strengths and prices of API 5LX grade carbon steels. The price is roughly determined from internet survey [21,22].

Specification	Minimum Specified Yield Strength, psi (MPa)	Price ($/ton)
API 5LX Grade X42	42,000 (289.59)	650
API 5LX Grade X46	46,000 (317.17)	700
API 5LX Grade X52	52,000 (358.54)	750
API 5LX Grade X56	56,000 (386.1)	770
API 5LX Grade X60	60,000 (413.7)	800
API 5LX Grade X65	65,000 (448.175)	900
API 5LX Grade X70	70,000 (482.65)	960
API 5LX Grade X80	80,000 (551.6)	1000
API 5LX Grade X90	90,000 (620.53)	N/A

The pressure difference of a given standard pipe diameter can be determined using the following equation [19]:

$$\Delta P = \frac{8 f Q_m^2 L}{\rho_{CO2} \pi^2 D_i^5} + \rho_{CO2} g \Delta z \tag{1}$$

where P (Pa) is the pressure, f is the friction factor, Q_m (kg/s) is the mass flow rate, L (m) is the pipeline length, ρ_{CO2} (kg/m^3) is the density of CO_2, D_i (m) is the inner diameter, g (m/s^2) is the gravitational acceleration, and z (m) is the height. Because the capture plants and hub terminal are all on the shoreline, $\Delta z = 0$ was assumed for onshore pipeline transport. The depth of the sea at the storage site was 150 m, so $\Delta z = -150$ m was assumed for offshore pipeline transport.

3.1.2. Cost Calculation Methods of Compressor, Pump, and Booster

The pressure and temperature of CO_2 from the capture system to the compressor were assumed to be 1 bar and 35 °C, respectively. The CO_2 is compressed to the critical pressure of 7.38 MPa by the compressor and then to approximately 15 MPa by the pump [23]. The compressor of this study was assumed to have five stages with a compression ratio of 2.36. The discharge and suction temperatures of the compressor were assumed to be 140 and 40 °C, respectively.

The capital costs of the CO_2 compressor can be obtained using the following equation [24]:

$$C_{comp} = m_{train} N_{train} \left[\left(0.13\times10^{6}\right)\left(m_{train}\right)^{-0.71} + \left(1.40\times10^{6}\right)\left(m_{train}\right)^{-0.60} \ln\left(\frac{P_{cut-off}}{P_{initial}}\right) \right] \tag{2}$$

where C_{comp} (US$) is the capital cost of the CO_2 compressor, m_{train} (kg/s) is the CO_2 mass flow rate through the compressor train, N_{train} is the number of compressor trains, $P_{cut\text{-}off}$ (Pa) is the target pressure, and $P_{initial}$ (Pa) is the initial pressure. When the total compression power requirement exceeded 40,000 kW, the flow rate was split into N_{train} parallel compressor trains [25].

The capital costs of the CO_2 pump and booster were calculated using the following equations [25]:

$$C_{pump} = \left(1.11\times10^{6}\right)\times\left(\frac{W_p}{1000}\right) + 0.07\times10^{6} \tag{3}$$

and:

$$C_{booster} = \left(7.82\times10^{6}\right)\times\left(\frac{W_p}{1000}\right) + 0.46\times10^{6} \tag{4}$$

where C_{pump} (US$) and $C_{booster}$ (US$) are the capital costs of the CO_2 pump and CO_2 booster, respectively, and W_p (kW) is the electric power required. The annual operating expenditure comprises the total electric power cost [23,25] and maintenance costs. The maintenance cost was assumed to be 0.04 of the capital cost. In this study, the electricity cost was assumed to be 0.07 US$/kWh.

3.1.3. Cost Calculation Method of Pipeline

Usually, the capital expenditure (CAPEX) of the CO_2 pipeline cost is divided into four different categories: materials, labor, right of way, and miscellaneous. Among the various CO_2 pipeline cost models [18], the Parker model [23,26] was adopted in this study excluding the material cost because its results were most similar to the costs of natural gas pipelines in Korea. The applicability of the Parker model to CO_2 pipeline transport was verified in a recent study [27]. The material cost can be directly calculated by multiplying the pipeline weight by the price per ton. Table 4 lists the prices of 5LX grade carbon steels. The pipeline weight can be determined using the following equation [28] based on the pipe diameter and thickness:

$$W_s = \pi L \rho_{steel} t\left(D_i + t\right) \tag{5}$$

where W_s (kg) is the pipeline weight, ρ_{steel} (kg/m^3) is the density of carbon steel, and t (m) is the pipe thickness. The pipe thickness is determined from the CO_2 pressure in the pipe and the material's yield strength. A detailed equation with these quantities is given as follows [28]:

$$t = \frac{P_{design} \cdot D_0}{2S \cdot F \cdot L_f \cdot J \cdot T} \tag{6}$$

where D_o (m) is the outer diameter, P_{design} (Pa) is the maximum pressure in the pipeline, S (Pa) is the minimum yield strength of the pipe, F is the design factor, L_f is the location factor, J is the joint factor, and T is the temperature factor. In this study, F, L_f, J, and T were assumed to be 0.8, 0.9, 1, and 1, respectively. The closest standard pipe thickness greater than the thickness from Equation (6) was determined to find the optimum thickness. In this study, the operational expenditure (OPEX) of the pipeline was assumed to be 4% of the CAPEX.

3.2. Design and Cost Estimation of Ship Transport

3.2.1. Design of Ship Transport

Figure 3b illustrates a system block diagram of a ship-based CCS chain. In this study, the range of ship transport was limited to from the liquefaction system to the injection system. Ship transport can be divided into four modules: the liquefaction system, storage tank, CO_2 ship, and injection system. The captured CO_2 at the capture system is liquefied by the liquefaction system. The liquefied CO_2 is preserved in the temporary storage tank until the CO_2 ship comes for loading. The stored CO_2 is unloaded into the CO_2 ship, and the CO_2 ship navigates to the offshore storage site. Finally, the CO_2 is injected into the storage well by the injection system.

Because a high-pressure carrier is more expensive than a low-temperature carrier, the CO_2 in the cargo tank of the CO_2 carrier was assumed to be in a dense liquid phase. A pressure and temperature of 7 bar and −50 °C, respectively, which are near the triple point, were selected as the liquefaction point. Liquefied CO_2 takes up about 1/500 of the volume of gaseous CO_2, so CO_2 should be liquefied for economical transportation. Because CO_2 can be liquefied between the triple point (5.18 bar, −56.5 °C) and critical point (73.8 bar, 31.1 °C), a single point should be determined. In this study, the pressure near the triple point was selected because of the high density of CO_2 at this point.

A closed cycle was employed for the liquefaction. Two kinds of liquefaction cycles are available for CO_2 liquefaction: open and closed. In the open cycle, CO_2 is compressed and expanded with itself acting as the refrigerant. In a closed cycle, CO_2 is liquefied by external refrigerants. Although the open cycle is simpler than the closed cycle, it is less efficient [29]. Efficiency is an important economic factor; thus, the closed cycle was selected in this study. Figure 4 shows the cascade cycle using propane-ethane, which was assumed to be the liquefaction system. The cascade cycle using propane-ethane was found to exhibit the highest efficiency of the various closed cycles [30,31].

A cylindrical pressure vessel was applied as the cargo tank for liquefied CO_2. A pressure vessel is necessary to preserve liquefied CO_2 because its pressure is higher than the atmospheric pressure. Cylindrical and spherical pressure vessels can withstand high-pressure fluids. The cylindrical type was selected in this study because of its easier manufacture. The cylindrical pressure vessel was designed to satisfy the ASME and IGC codes [32,33].

To optimize the CO_2 ship transportation, the transportation time was estimated based on the distance from the capture plant to the storage site or hub terminal. Here, the ship speed was assumed to be 15 knot. The loading and unloading times were assumed to be 20 h each, and the times to enter and leave the port were assumed to be 2 h each. For direct injection of CO_2 from the ship in Scenarios 1 and 2, the injection was assumed to be continuous, and the injection rate was assumed to be ~2800 kg/s, which corresponds to 1 MtCO2/year. For the continuous injection from the ship, the number of ships was fixed to three. Based on this information, the optimum capacity of the CO_2 ship can be determined. A detailed exercise for this optimization was performed in one of our previous studies [34].

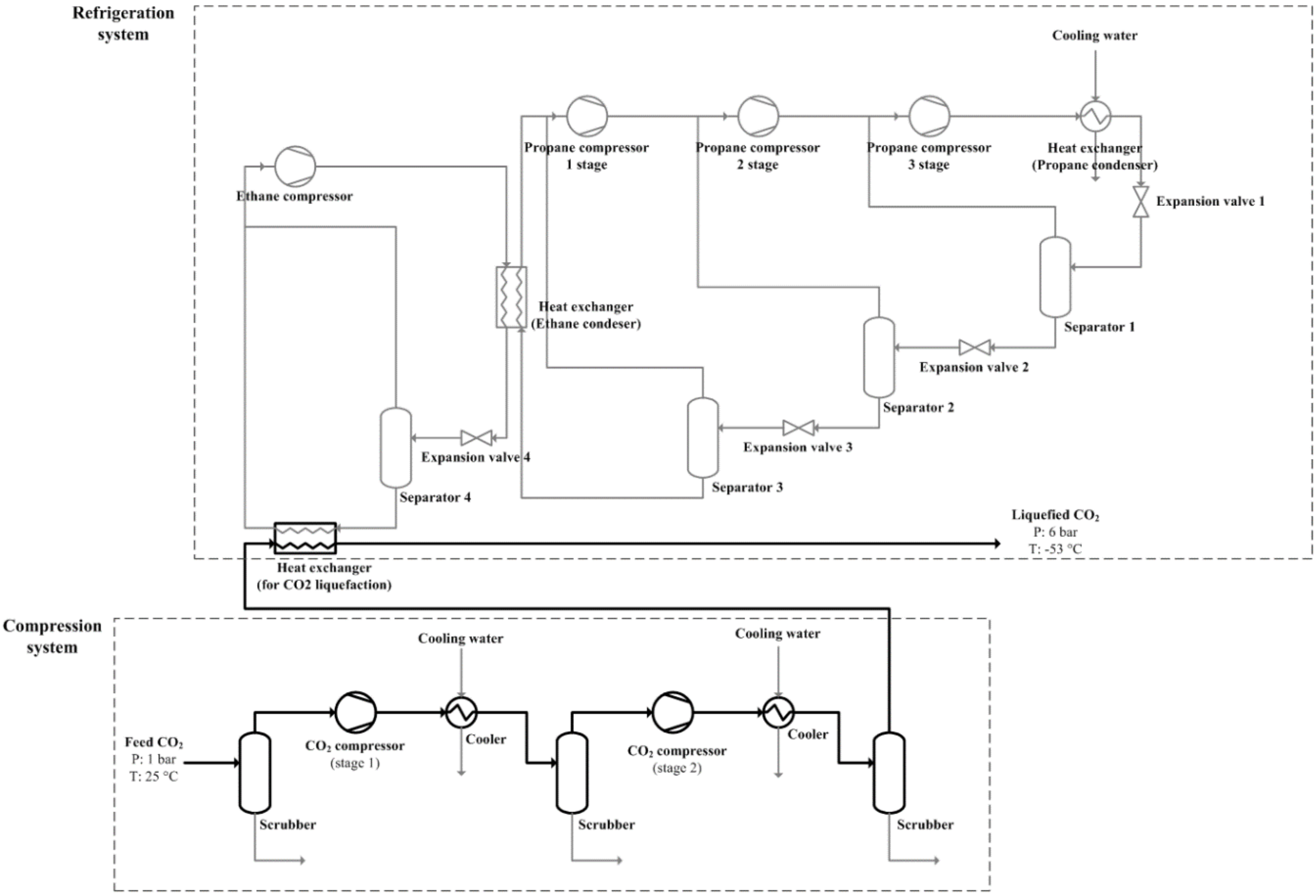

Figure 4. Cascade cycle using propane–ethane for CO_2 liquefaction.

The pumping system for injection consists of a pump and heat exchanger. The pump increases the pressure of the liquefied CO_2 to overcome the well pressure. The heat exchanger increases the CO_2 temperature to prevent hydrate formation and freezing because the CO_2 may meet formation water in the reservoir [35,36].

3.2.2. Cost Estimation of Ship Transport

To the best of our knowledge, empirical relations for the cost calculation liquefaction system have not yet been published. In this study, therefore, the cost of the liquefaction system was calculated by using the Aspen HYSYS Economic Evaluation [37]. The CAPEX of the liquefaction system is calculated from the "percentage of delivered equipment cost" [38]. This methodology estimates various costs in the CAPEX from the equipment cost. The equipment cost is estimated with the Aspen HYSYS Economic Evaluation [37]. The items in the OPEX are estimated using the CAPEX and a process simulator [39]. The cost of energy consumption, especially the electricity cost, is estimated using the process simulator. The electric power obtained by the process simulator is converted to the energy consumption cost by referring to the unit electricity cost. More detailed results are given in one of our previous papers [40].

The calculated liquefaction costs from the Aspen HYSYS Economic Evaluation showed a large reduction in cost as the amount of liquefied CO_2 increased because of the economies of scale effect. For the compression costs in Equation (2), there is no scale effect because this equation is based on parallel compressor trains. The liquefaction system has to be based on parallel liquefaction trains, similar to the compression system, because there is no equipment that meets the requirements for a large-scale liquefaction system. Therefore, this study assumed that the CAPEX and OPEX of the liquefaction system were 1.6 and 1.7 times higher than the CAPEX and OPEX, respectively, of a compression system based on the Aspen HYSYS results and Equation (2). The assumed cost ratio of the liquefaction system to the compression system was within the range of the ratios in Yang *et al.* [41].

The CAPEX of the storage tank was estimated from aggregating the manufacturing and material costs. The manufacturing and material costs are dominant for the storage tank. The required amount of material for a given pressure was calculated using the formula indicated in the *Pressure Vessel Handbook* [42]. The material cost was estimated from the product of the required amount of material and the unit price of steel. The manufacturing cost was assumed to be 45% of the total storage tank [43]. Thus, the cost of the storage tank was calculated to ~280 US$/m^3. The annual OPEX, especially the maintenance and repair costs, was assumed to be 5% of the CAPEX.

A CO_2 carrier consists of a hull and cargo tank. An oil tanker cost was used to estimate the hull cost. Although there are differences between a CO_2 carrier and oil tanker, the dominant cost factors continue to be the material and manufacturing costs. If the sizes of the CO_2 carrier and oil tanker are identical, then the costs are similar. The bulk ship cost was estimated using Clarkson's new building prices [44]. The cost of the cargo tank was estimated in a manner analogous to that of the storage tank. The annual OPEX of the CO_2 carrier was assumed to be the sum of 5% of the CAPEX [43] and the fuel consumption cost. This fuel consumption cost, depending on the cruising range, was calculated from the fuel consumption rate of the oil tanker. In this study, a fuel price of 850 US$/ton was assumed.

A pumping system for the injection is required to pressurize the CO_2 at a pressure and temperature of 7 bar and −50 °C, respectively, in the CO_2 carrier to 100 bar and 10 °C to match the conditions of the pipeline and ship transports at the end of the system boundary. The Aspen HYSYS Economic Evaluation [37] was used to evaluate the pumping and heat exchanger systems and their costs.

3.3. Specifications and Cost of CO_2 Hub Terminal

Because Scenario 3 includes the hub terminal at Ulsan, the CAPEX and OPEX of the hub terminal needed to be included in the CO_2 transport cost calculations. Table 3 lists the major cost factors for the hub terminal. The injection and discharge costs into/from the storage tanks were not included in the cost calculations. The specifications and cost of the storage tank at the hub terminal were calculated using the same method used to calculate the cost of the storage tank at the PP as given in Section 3.2.2. The pressurization costs of the ship-transported CO_2 were calculated using the Aspen HYSYS Economic Evaluation. An additional buffer storage tank for the pipeline-transported CO_2 was assumed in this study. Usually, no buffer storage is needed for pipeline transport because the pipeline itself works as a storage buffer. However, in this study, ship- and pipeline-transported CO_2 were mixed in the hub, so a 2-h buffer storage tank for the pipeline-transported CO_2 was assumed. Because of the high pressure of the pipeline-transported CO_2 (>8.6 MPa), the storage tank was assumed to be bundles of parallel pipes.

4. Results

Figures 5–7 show the normalized cost of each scenario for the different transport methods and transport rates. The capital recovery factor in the normalized cost was 0.08 with a repayment period of 20 years and interest rate of 5%. In the figures, the notations "Emitter", "Onshore", "Offshore", "Carrier", "Injection", and "Hub" represent the compression or liquefaction costs in the capture plant, onshore pipeline, offshore pipeline, CO_2 carrier, pumping for injection to the storage site, and hub terminal, respectively.

On the x-axis, the letters "B", "H", and "S" represent the Boryeong, Hadong, and Samcheok PPs, respectively. The numbers after the letters are the transport rates ($MtCO_2$/year). For example, "B1 + H3" denotes the capture plants at the Boyeong PP with a captured amount of 1 $MtCO_2$/year and Hadong PP with a captured amount of 3 $MtCO_2$/year.

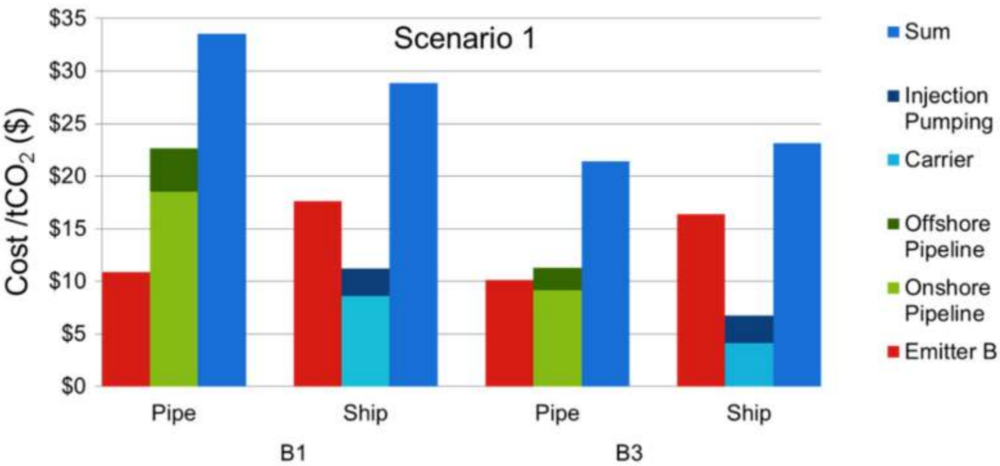

Figure 5. CO_2 transport costs per unit tCO_2 in Scenario 1.

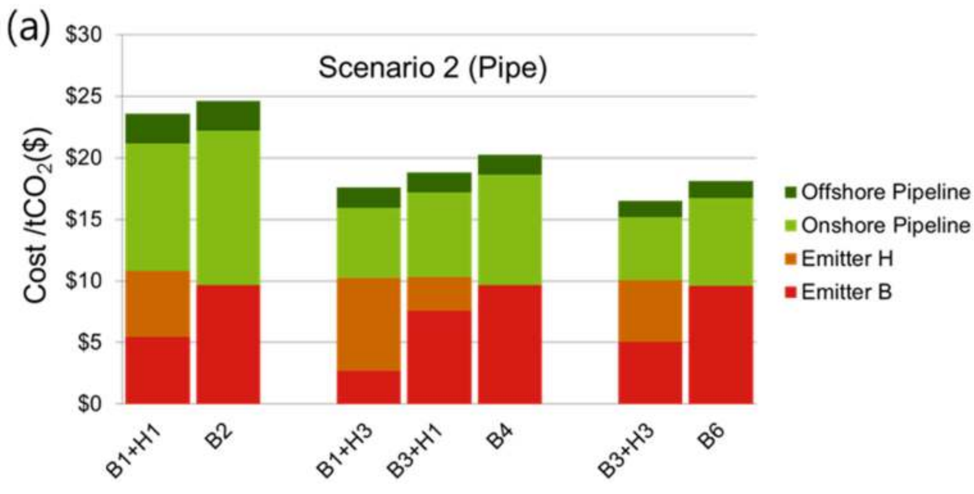

Figure 6. *Cont.*

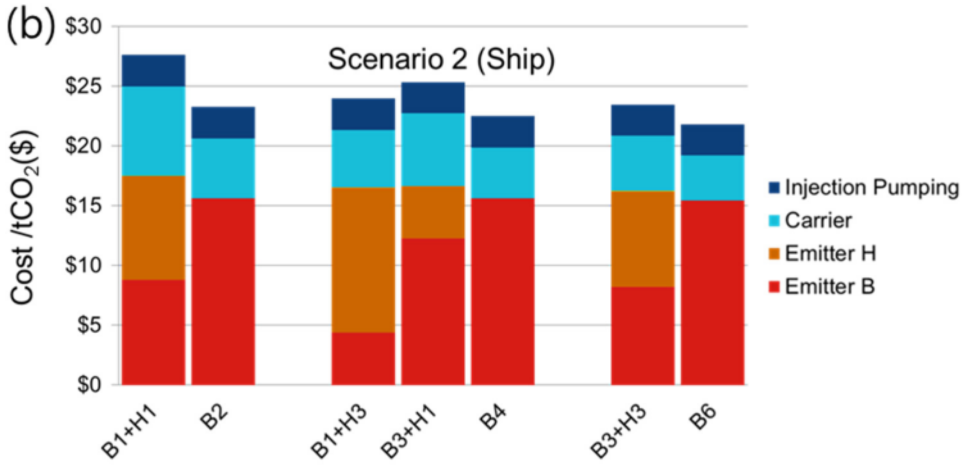

Figure 6. CO_2 transport costs per unit tCO_2 in Scenario 2: (**a**) pipeline transport, (**b**) ship transport.

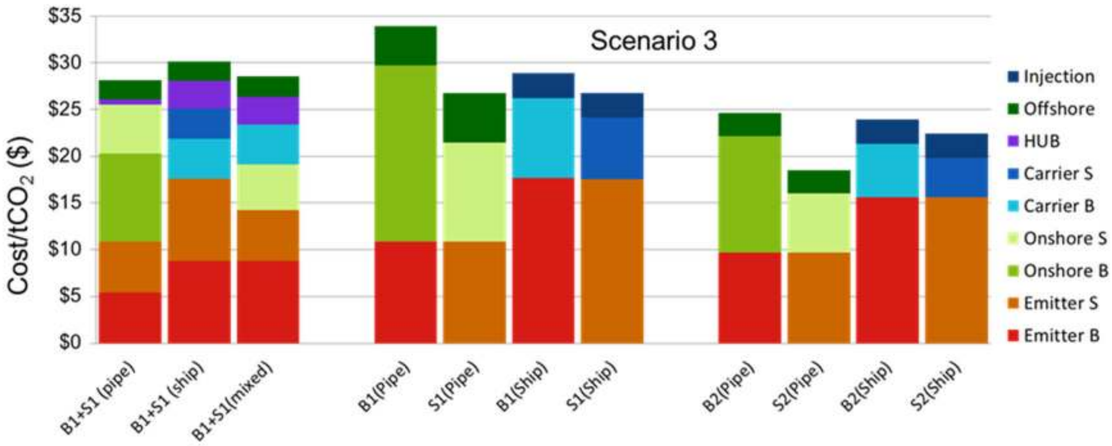

Figure 7. CO_2 transport costs per unit tCO_2 in Scenario 3.

4.1. Scenario 1

Figure 5 shows the transport cost of Scenario 1. The costs of pipeline transport at the two transport rates of 1 and 3 $MtCO_2$/year were compared. The compression costs of Emitter B at 1 and 3 $MtCO_2$/year were both approximately US$10/$tCO_2$ and showed little difference. The almost constant compression cost per ton of CO_2 was due to two reasons. First, an increase in the transport rate did not mean an increase in the equipment size but in the number of trains. Because the CAPEX of the compression/liquefaction costs in the emitter was proportional to the number of trains in parallel, an economies of scale effect produced by the increased capture rate was difficult to expect. Second, the most dominant factor for the emitter cost was the electric power, but the unit electric power consumption for CO_2 compression was not heavily affected by the amount of CO_2. In contrast, the costs of the onshore and offshore pipeline significantly decreased as the transport rate increased. As shown in Figure 5, the costs of the onshore and offshore pipelines at 1 $MtCO_2$/year were US$18/$tCO_2$ and US$5/$tCO_2$, respectively. The costs of the onshore and offshore pipelines at 3 $MtCO_2$/year were about twice the costs at 1 $MtCO_2$/year. Unlike the emitter cost, the CAPEX was the dominant factor for the pipeline cost, and a large-diameter pipeline was cost-effective per ton of CO_2. Despite the almost constant emitter cost, the overall economies of scale effect on the pipeline cost was high because of the significant effect on the onshore and offshore pipeline costs. For example, the estimated pipeline cost at 1 $MtCO_2$/year of US$33/$tCO_2$ was reduced to US$21/$tCO_2$ at 3 $MtCO_2$/year.

When the costs of ship transport at the transportation rates of 1 and 3 $MtCO_2$/year were compared, the emitter costs were found to remain almost constant with an increased transport rate, while the carrier costs were greatly reduced, similar to the pipeline cost. Note that the liquefaction cost was assumed to be proportional to the compression cost, and the characteristics of the emitter cost for the ship and pipeline transport methods were similar. The economies of scale effect on the carrier cost was so strong that the carrier costs at 3 $MtCO_2$/year were around half the costs at 1 $MtCO_2$/year. The cost of injection pumping heavily depended on the electric power consumption while being independent of the transportation rate, similar to the emitter costs.

Because the emitter costs accounted for 30%–70% of the total transport cost, the difference in emitter costs between the compression and liquefaction processes could determine which of the pipeline transport and ship transport provides the least cost. Without including the emitter costs, the ship transport method was less costly than the pipeline method at both 1 and 3 $MtCO_2$/year. At 1 $MtCO_2$/year without the emitter cost, the pipeline transport cost was approximately US$23/$tCO_2$, while the ship transport cost was approximately US$11/$tCO_2$. Because the emitter costs were independent of the transport distances and rates, the difference in emitter cost of approximately US$7/$tCO_2$ between liquefaction and compression was fixed. Therefore, for the ship transport cost to be more cost-effective than the pipeline transport cost, the sum of the carrier and injection pumping costs had to be approximately US$7/$tCO_2$ less than the sum of the onshore and offshore pipeline costs. At 1 $MtCO_2$/year, the ship transport with the emitter cost was still more cost-effective than the pipeline transport. At 3 $MtCO_2$/year, the pipeline transport with the emitter cost became more cost-effective than the ship transport. This implies that, for the strict comparison of pipeline and ship transport methods, the costs of compression/liquefaction must be included in the transport costs.

4.2. Scenario 2

Scenario 2 is an extended version of Scenario 1 that includes an additional load of CO_2 on the route. Figure 6 shows the calculated costs of Scenario 2. As shown in Figure 2, Scenario 2 has a similar route to Scenario 1 that starts at the Boryeong PP and ends at the Ulleung Basin; however, there is an additional CO_2 load at the Hadong PP. The effect of the additional CO_2 on the route was studied by comparing Scenarios 1 and 2. In other words, each case of Scenario 2 was compared with the case of Scenario 1, where the transport rate was the same as the sum of the captured CO_2 at the Boryeong and Handong PPs.

For pipeline transport, the distance from the Boryeong PP to the Hadong PP was 280 km, which corresponded to approximately 53% of the total distance. Because the transport rate in the Boryeong–Hadong section was less than that in the other section because of the addition of CO_2 at the Hadong PP, a large reduction in cost was expected compared to Scenario 1. However, the cost reduction in Scenario 2 was not as large as expected, as shown in Figure 6a. There are two reasons for the small cost reduction. First, the cost reduction in the onshore pipeline induced by the lower transport rate in the Boryeong–Hadong section was ~30% because of the well-known economies of scale effect with regard to mass flows [45]. For example, the cost of the onshore pipeline at B1 + H1 was approximately US$10/$tCO_2$, which corresponded to 80% of the onshore pipeline at B2, as shown in Figure 6a. The cost of the onshore pipeline at B1 + H3 showed the largest cost reduction compared to the corresponding Scenario 1 because the difference in the transport rate between the Boryeong–Hadong section and the other section was as high as 3 $MtCO_2$/year. Second, the increased emitter costs from the two PPs compared to the emitter cost from the single PP in Scenario 1 offset the cost reduction in the onshore pipeline. For B1 + H1, the sum of Emitters B and H was approximately US$11/$tCO_2$, which was approximately US$1.5/$tCO_2$ higher than that of Emitter B in the B2 case. The cost of the offshore pipeline did not change between Scenarios 1 and 2 because the transport rate and other conditions were the same.

Unlike the pipeline costs of Scenario 2, the ship transport costs of Scenario 2 were higher than those of Scenario 1. In all cases of the ship transport costs, as shown in Figure 6b, the emitter and carrier costs of Scenario 2 were higher than the costs of the corresponding cases in Scenario 1. Because the CO_2 in Scenario 2 was captured at the two PPs, the emitter costs of Scenario 2 were higher than those of Scenario 1, where CO_2 was captured at only one PP. In contrast to the pipeline costs of Scenario 2, the ship transport distances of Scenario 2 were much greater than those of Scenario 1. In Scenario 1, the ship transport distance from the Boryeong PP to the Ulleung Basin was 724 km. However, the transport distance of Scenario 2 comprised two routes from the Boryeong PP to the Hadong PP and from the Hadong PP to the Ulleung Basin. The total distance of the two routes was 877 km, which was 22% longer than the routes of Scenario 1. This increased distance in Scenario 2 increased the carrier costs compared to Scenario 1. For example, the carrier cost of B1 + H1 in Figure 6b was approximately US$7.50/$tCO_2$, which was US$2.50/tCO_2 higher than the corresponding Scenario 1 case of B2. When the B2 costs for the pipeline transport method, as shown in Figure 6a, and ship transport method, as shown in Figure 6b, were compared, the latter was more cost-effective. However, when the B1 + H1 costs of the two transport methods were compared, the pipeline transport method was found to be more cost-effective. The different characteristics of the ship and pipeline transports in Scenario 2 indicated that the CO_2 transport cost is very sensitive to geological factors and transport conditions, which makes it difficult to set up general rules.

4.3. Scenario 3

The main difference between Scenario 3 and Scenarios 1 and 2 is the presence of the hub at Ulsan Harbor and the lack of overlapping between the two transport routes. The Boryeong and Samcheok PPs were assumed to be the CO_2 capture plants in Scenario 3, as shown in Figure 2. Unlike Scenarios 1 and 2, the capture rate at each PP in Scenario 3 was fixed to 1 $MtCO_2$/year.

The costs of Scenario 3 were compared with the cases with only one capture site using both transport methods, as shown in Figure 7. The left three columns show the costs of Scenario 3 for the different transport methods. The pipeline method showed the least cost of approximately US$28/$tCO_2$, but the difference in costs among the three methods was small. The costs of the hub in Figure 7 consisted of the storage tanks and pressurization of the carrier-transported CO_2 in the offshore pipeline. The pressurization costs of the ship-transported CO_2 accounted for the largest proportion. The hub cost of the pipeline transport was very small because no pressurization process was required, so only the storage tank cost was included in this case.

The four columns on the right in Figure 7 show the transport cost for one capture plant with no hub terminal at 2 $MtCO_2$/year. The transport cost of the four right columns with one capture plant and no hub terminal was much smaller than that of the three left columns with two capture plants and the hub terminal. The B1 + S1 case had two fundamental disadvantages compared to the B2 (pipe) and S2 (pipe) cases. The first was the longer transport distance. For example, the transport distances of B2 (pipe) and S2 (pipe) from the PPs to Ulsan were 470 and 250 km, respectively. However, the transport distance of B1 + S1 (pipe) from the PPs to Ulsan was the sum of 470 and 250 km. This much greater transport distance induced a higher cost for B1 + S1 (pipe) that was higher than the cost of B2 (pipe) or S2 (pipe), even though the transport rate for each route of B1 + S1 (pipe) was half the rate of B2 (pipe) or S2 (pipe). The second reason was the additional hub cost for B1 + S1.

The results of Scenario 3 are especially useful when a CO_2 transport route is added to an existing transport route. For example, assume that S1 (pipe) is already in operation, and the capture of CO_2 at the Boryeong PP is planned and needed to setup a CO_2 transport route with the same storage site as S1 (pipe). In this case, four choices are possible: (1) an extra pipeline route without a hub, (2) an extra ship route without a hub, (3) an additional pipeline route with a hub, and (4) an additional ship route with a hub. For choice 1, the cost of B1 (pipe) in Figure 7 would additionally be required, and the total cost (per MtCO2/year) would be the average of S1 (pipe) and B1 (pipe). For choice 2, the cost of B1 (ship) would be additionally added, and the total cost (per MtCO2/year) would be the average of S1 (pipe) and B1 (ship). For choices 3 and 4, the costs would be B1 + S1 (pipe) and B1 + S1 (mixed), respectively. Choices 1 and 3 are the same in that the pipeline transport method is adopted, but they differ in the sharing of the offshore pipeline and presence of a hub. Therefore, with B1 + S1 (pipe), the sharing of the offshore pipeline and small storage tank make the cost of B1 + S1 (pipe) smaller than the average cost of B1 (pipe) and S1 (pipe). Similarly, choices 2 and 4 both adopt the ship transport method from the capture plants, but they differ in that choice 4 shares the offshore pipeline. In choice 2, the ship- and pipeline-transported CO_2 are separately transported to the storage site. Except for the temporary storage cost at the hub with choice 4, the other costs do not greatly differ. Therefore, choice 4 shows slightly higher overall costs than choice 2. However, the complexity of choice 2 with the injection may offset the hub cost of choice 4.

The hub is economically advantageous when the hub gathers CO_2 from several routes and the distances from the hub to the storage site are long enough to produce the economies of scale effect. Overall, the incorporation of a hub in Scenario 3 did not result in high efficiency because of the relatively short distance from the hub to the storage site (approximately 60 km) and small number of gathered CO_2 routes.

5. Conclusions

In this study, the CO_2 transport costs in Korea were calculated using the techno-economic method. Three scenarios were developed that depended on the locations of the CO_2 capture plants, and each scenario included both the pipeline and ship transport methods. The compression/liquefaction costs constituted a large portion of the total transport cost. The economies of scale effect was significant on both the carrier cost and costs of the onshore and offshore pipelines, but it was negligible on the compression/liquefaction costs. Scenario 1 had only one capture plant and one storage site.

The transport costs of Scenario 1 were approximately US\$33/tCO_2 and US\$28/tCO_2 at 1 MtCO_2/year for a pipeline transport of approximately 530 km and ship transport of 724 km, respectively. At 3 MtCO_2/year, the costs decreased to approximately US\$21/tCO_2 and US\$23/tCO_2 for the pipeline and ship transports, respectively, because of the economies of scale effect. Scenario 2 had a route similar to that of Scenario 1 but had additional capture plants midway in the route. The pipeline costs of Scenario 2 were slightly lower than the costs of Scenario 1. However, the ship costs of Scenario 2 were higher than those of Scenario 1 because of the extended transport distance. Scenario 3 had two capture plants, one hub terminal, and one storage site. Because of the short distance from the hub terminal to the storage site and only two routes to the hub terminal, utilizing the hub terminal was not economical compared to Scenarios 1 and 2.

The implications of this study can be summarized as follows. (1) For a strict economic comparison of pipeline and ship transport methods, the cost of compression/liquefaction must be included in the transport costs. (2) In many previous CCS cost studies, the cost of CO_2 transport was included as part of the storage costs. However, in the case of long transport routes like the routes considered in this study, the transport cost may occupy more than 20% of the total CCS costs. Therefore, the transport costs should be separated from the storage costs in the case of long transport routes. (3) Because the economies of scale effect on the pipeline and ship transport costs is very strong, it is economically advantageous to implement a transport system with a high transport rate that can accommodate additional CO_2 transport in the future.

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Author Contributions

Kwangu Kang, Cheol Huh, and Seong-Gil Kang conceived the CO_2 transport scenarios; Kwangu Kang and Youngkyun Seo designed the cost calculation methods; Kwangu Kang calculated the pipeline transport costs; Youngkyun Seo and Daejun Chang calculated the ship transport costs; Kwangu Kang and Cheol Huh analyzed the data; and Kwangu Kang and Youngkyun Seo wrote the paper.

Conflicts of Interest

The authors declare no conflict of interest.

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