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Performance and economic analysis of commercial-scale coal-fired power plant with post-combustion CO_2 capture

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Abstract−A performance and economic analysis of a commercial-scale coal-fired power plant with a post-combustion CO_2 capture process in South Korea was performed. Based on the KoSol Process for CO_2 Capture (KPCC) developed by the Korea Electric Power Company Research Institute, a power plant cost model coupled with a performance model was developed to evaluate the levelized cost of electricity and the cost of CO_2 avoided for power plants with CCS. A techno-economic evaluation result, based on the general guideline suggested by the IEA task force group and key performance data of the pilot-scale CO_2 capture test results showed that at the base case, the LCOE of a commercial-scale USC power plant with CCS in South Korea will increase from 47 USD/tCO_2 (without CCS) to 68 USD/tCO_2 (with CCS), and the cost of CO_2 avoided was calculated as 33 USD/tCO_2. Comparing this with various studies in other literature showed that the cost of CO_2 avoided for power plants in South Korea was much lower than that of the OECD average, which was mainly due to the relatively low capital expenditure (CAPEX) and operating expenditure (OPEX) of a power plant with/without CCS.

Keywords: CO_2 Capture, Chemical Absorption, Coal-fired Power Plant, Cost of CO_2 Avoided

INTRODUCTION

Capturing CO_2 from the flue gas of coal-fired power plants is of great concern due to its large quantity and its effects on the global environment. There are many research activities for the development of CO_2 capture technology. In 2012, Norway opened the world's largest center for testing CO_2 capture technology, which could treat about 100,000 tonCO_2/year from a natural gas combined heat and power plant and the refinery cracker [1], and Mitsubishi Heavy Industry, Ltd. and Southern Company have jointly constructed a CO_2 capture demonstration plant that captures 500 tonCO_2/day at an existing coal-fired thermal plant located in Alabama, USA [2]. In Canada, the construction of a CO_2 capture plant that will be able to treat million tons of CO_2 per year at SaskPower's Boundary Dam Power station is underway [3]. Along with these large-scale CO_2 capture test facilities, various studies on the techno-economic analysis of carbon capture and sequestration technology for the evaluation of the capital cost, cost of electricity and cost of CO_2 avoided have been conducted [4-6]. The International Energy Agency (IEA) published a summary of an economic evaluation study of post-combustion CO_2 capture technology performed by various organizations, including the Electric Power Research Institute (EPRI), the U.S. Department of Energy's National Technology Laboratory (DOE/NETL), the International Energy Agency Greenhouse Gas Programme (IEA GHG), and Global CCS Institute (GCCSI). It was shown that the average cost of electricity and the total overnight cost increased 63% and 75%, respectively. And the cost of CO_2 avoided was suggested to be from 40 to 78 USD/tCO_2 [7]. As summarized in the IEA research report [7], various techno-economic analyses of CCS technology based on data from Europe and the USA were suggested. However, few studies have reported on developing countries such as South Korea, China and India, countries in which greenhouse gas emissions are drastically increasing due to rapid commercialization. In particular, South Korea is the eighth-biggest greenhouse gas emitter in the world due to its phenomenal economic growth based on manufacturing, and it is ranked first among OECD members for the rate of increase in emissions. Thus, the government of South Korea has voluntarily presented a reduction target and demonstrated global leadership by proposing a Nationally Appropriate Mitigation Action Registry, which developing counties are able to participate in. Regarding this policy of the Korean government, KEPCO, the largest electric utility company in South Korea, began research in 2000 for post-combustion CO_2 capture technology to develop energy-efficient CO_2 capture processes, including amine-based CO_2 solvents. Based on this proprietary solvent (*KoSol*: Korea Solvent) and an extensive process design study, a CO_2 capture test pilot plant that could treat 2 tonCO_2/day (0.1 MWe equivalent) from the flue gas of a coal-fired power plant was constructed in 2010 and is being successfully operated. And based on this test pilot plant, the construction of a CO_2 capture pilot plant that could treat 200 tonCO_2/day (10 MWe equivalent) was recently finished (as shown in Fig. 1, [8]), and through various process optimizations, a long-run operation (1,000 hours) test using flue gas from a coal-fired power plant is in progress.

Here, for the first time in South Korea, we propose a techno-economic study of a commercial-scale coal-fired power plant with

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(a) 0.1 MW-scale CO_2 capture plant

(b) 10 MW-scale CO_2 capture plant

Fig. 1. Pictures of wet-scrubbing post-combustion CO_2 capture plants located at the Boryeong power station of Korea Midland Power Co., Ltd.

post-combustion CO_2 capture in South Korea to evaluate the cost of electricity and the cost of CO_2 avoided. For the cost evaluation, a power plant performance model considering the CO_2 capture test coupled with process simulation was developed. An in-house cost model guided by the IEA report [9] was used to evaluate the cost of electricity with and without CCS.

1. Methodology for the Techno-economic Evaluation of a Power Plant with/without CCS

The overall methodology for the techno-economic evaluation of a coal-fired power plant with CCS is suggested as follows.

1-1. Plant Specifications

A reference coal-fired power plant without CCS and a plant with CCS of the same general type and design are assumed. The net power generations of power plants with and without CCS are also considered to be the same (1,000 MW). This means that a plant with CCS has a higher fuel feed rate and a lower net power output. As for the CO_2 capture process, the KoSol Process for CO_2 Capture (KPCC^{TM}), developed by the KEPCO Research Institute, was considered. KPCC^{TM} is an amine-based CO_2 capture process using chemical absorption that is commercially available and most suitable for existing thermal power plants. For the techno-economic evaluation, key parameters are guided by the IEA report [7].

The costs of CO_2 transport and storage were not considered in this study. The plant construction period was assumed to be four years, and the total operating period as 30 years. The remaining key financial parameters, such as the carbon tax and discount rate, are summarized in Table 1.

1-2. CO_2 Capture Technology: KPCC^{TM}

As mentioned above, for the techno-economic evaluation of a coal-fired power plant with CCS, we considered the KPCC^{TM} developed by the KEPCO Research Institute.

KPCC^{TM} is a CO_2 capture process that uses KEPCO's proprietary chemical solvent. In 2010, KEPCO constructed a 0.1 MW CO_2 capture test bed capable of treating 2 tons of CO_2 per day at the Boryeong power station of Korea Midland Power Co., Ltd., and started operation in 2010. This CO_2 capture test bed consists of an absorber (diameter=0.4 m, total height=23.5 m) and a stripper (diameter=0.35 m, total height=17 m) with structured packing material to increase the retention time and surface area for effective contact between the flue gas and solvent [11].

From April 2 to May 14, 2011, long-term, nonstop continuous operation for 1,000 hours was done for the first time in Korea. Through this long-run operation, the KPCC^{TM} process captured more than 90% of the CO_2 from the slipstream of the power plant at a purity of more than 99%, and the average regeneration energy from this test was evaluated as between 3.1 and 3.3 GJ/tCO_2, which is about 20% lower than that of the conventional solvent monoethanolamine.

In 2012, using KoSol-4, which is an advanced version of KoSol-3, five different campaigns were performed, changing the various operating conditions including varying solvent flow rate and stripper pressure. The overall results of these campaigns showed that the CO_2 removal rate met the technical guideline (CO_2 removal rate: 90%) suggested by IEA-GHG and that the regeneration energy of the KoSol-4 showed about 3.0~3.2 GJ/tCO_2 which was, compared to that of the commercial solvent monoethanolamine, a reduction of regeneration energy of approximately 25% [12].

After these campaigns, the long-run operation of a CO_2 capture pilot plant that can treat 200 tonCO_2/day (10 MWe equivalent) using KoSol-4 has been in progress from April, 2014.

1-3. Plant Performance Model

For the evaluation of the cost of electricity of a power plant with CCS and the cost of CO_2 avoided, the energy penalty of a power plant with CCS should be calculated to estimate the coal feed rate and the CO_2 emissions of the plant with CCS.

For this purpose, a plant performance model was developed based on pilot-scale CO_2 capture test results combined with a CO_2 capture process simulation using a simulator (Aspen Plus software, Aspen Technology, Inc.) In this study, instead of an extensive thermodynamic calculation of the CO_2 capture process integrated with a power block for the calculation of the energy penalty of a plant with CCS, the method developed by Bolland et al. and Lee et al. was adopted [13,14]. They calculated the overall energy penalty of the power plant based on the total energy loss for the operation of the CO_2 capture system. Total energy loss was estimated by sum-

Table 1. Basic assumptions for the calculation of CCS cost

Information	Figure	Comments/References
Power plants without CO_2 capture (reference/base line plants)		
Battery limits		
Fuel type	Black (Hard) coal	
Reference heating value (GJ/ton)	25.0	
Carbon wt%	70.0	
Power plant type	Ultra Super Critical (USC)	
Plant location type	South Korea	·
Plant net capacity (MWe)	1,000	
Electric efficiency	44.1%	
Construction period (year)	4	
Year and currency of cost estimate	2014	
CO_2 transport and storage		
Overall net cost per ton of CO_2 stored (USD/tCO_2)	Not considered	
Cost of electricity		
Method	Constant money value	
Discount rate	7%	
Inflation	Constant money value	
Carbon tax	0	
Economic lifetime (year)	30	
Capacity (load) factor	85%	· IEA report [7]
Fuel prices (USD/GJ)	3.60	

ming the energy loss caused by the steam extraction for the solvent regeneration at the stripper and mechanical work required in order to operate the CO_2 compression and auxiliary equipment, respectively.

1-4. Process Simulation Model Definition

For the calculation of the total energy loss of the CO_2 capture plant, a process simulation was performed using the Aspen Plus software package version 7.1. As mentioned above, instead of modeling the whole power block, the CO_2 capture process with CO_2 compression (from 0.1 MPa to 11 MPa as guided by the IEA GHG [10]) was modeled to calculate the total energy loss of the CO_2 capture plant and the energy penalty of a plant with CCS. In Fig. 2, the Aspen

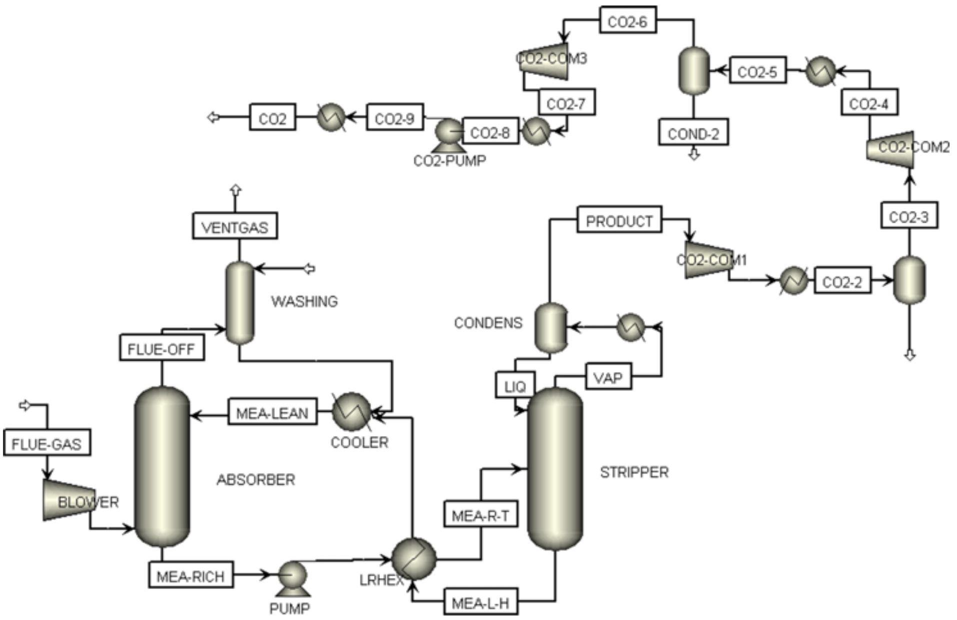

Fig. 2. The CO_2 capture process including CO_2 compression (Aspen Plus).

plus CO_2 capture process model evaluated in this study is shown.

The process consists of an absorber and a stripper with other auxiliary equipment such as pumps, condensers, and exchangers. Each tower is assumed to be filled with packing material to enhance the gas (flue gas)-liquid (chemical solvent) reaction. The flue gas from the pre-treatment process is introduced to the absorber. Then, the CO_2 in the flue gas reacts counter-currently with the CO_2-lean solution. The gases that do not react with the chemical solvent are emitted from the top of the absorber. The CO_2-rich solution from the bottom of the absorber is transferred to the stripper via a lean/rich heat exchanger in which the CO_2-rich solution is heated to between 80 and 90 °C, and the CO_2-lean discharged from the bottom of the stripper is simultaneously cooled.

In the stripper, the CO_2 and solutions are separated from the CO_2-rich amine solution by heating at elevated temperatures. The heat used to transform the CO_2-rich amine solution to a CO_2-lean amine solution is extracted from the turbine of the power plant. The captured CO_2 stream from the stripper moves into the compression section, where the CO_2 is compressed from near-atmospheric pressure to 11 MPa for storage. In this part, most of the water in the flue gas is also removed to avoid gas hydrates, water freezing, and pipeline corrosion during transportation and storage [14].

For the process simulation, the absorber and the stripper were simulated using five and eight equilibrium stages using the RadFrac model. The thermodynamic and transport properties were modeled using an ELECNRTL property method, which could handle both aqueous and polar reactions such as sour gas treating processes. In the ELECNRTL calculation, the NRTL method is used to calculate the liquid-phase activity coefficient, and the Redlich-Kwong method is used for the vapor-phase fugacity coefficient calculation [14].

1-5. Plant Cost Model

Using the plant performance data derived from the performance model suggested above, an in-house spreadsheet model for the cost evaluation of a power plant with CCS, the cost of electricity and the cost of CO_2 avoided was developed. The cost model used in this study is a spreadsheet model according to a set of basic assumptions, and is easy to use to generate the LCOE and the cost of CO_2 avoided. Those values are useful cost metrics for comparing the cost of power plants with different technological options and can be defined as follows [15]:

LCOE (Levelized Cost of Electricity)

$$=\sum_t \frac{(\text{Capital Expenditure})_t + \text{O\&M}_t + \text{Fuel}_t}{(1+r)^t} \Big/ \sum_t \frac{(\text{Electricity Sold})_t}{(1+r)^t} \tag{1}$$

where capital expenditure=the expenditure in year t associated with construction of the plant, electricity sold=the net electricity produced and sold in year t, $O\&M_t$=the total non-fuel operating and maintenance costs in year t, r=the discount rate. And the cost of CO_2 avoided can be defined as follows [15]:

Cost of CO_2 Avoided ($/t$CO_2$)

$$=\frac{(\text{LCOE})_{CCS}-(\text{LCOE})_{ref}}{(\text{tCO}_2/\text{MWh})_{ref}-(\text{tCO}_2/\text{MWh})_{CCS}} \tag{2}$$

where LCOE=the levelized cost of electricity generation ($/MWh), tCO_2/MWh=the CO_2 mass emission rate to the atmosphere in tons per MWh (based on the net capacity of each power plant), and the subscript "ccs" and "ref" refer to plants with and without CCS, respectively.

1-6. Capital Expenditure (CAPEX) and Operating Expenditure (OPEX) Estimation

For the calculation of the LCOE of the reference power plant (power plant without CCS), the total capital expenditure and operating expenditure should be evaluated first. Referring to the total capital expenditure, the total plant cost is the sum of the bare erected cost and the engineering, procurement and construction cost. The overnight cost is the sum of the total plant cost to which the owner's cost and the cost of other site-specific items is added. Lastly, the total capital requirement is the sum of the total plant cost to which interest during construction and cost escalations during construction are added [9], and OPEX is the operation and maintenance cost, including operating labor, maintenance labor, administrative & support labor, maintenance materials, etc.

Table 2. Data on electricity generating cost of coal-fired power plants [9]

Country	Technology	Net capacity	Electrical conversion efficiency	Overnight cost	Fuel cost	OPEX	LCOE[a]
		MWe	%	USD/kWe	USD/kWe	USD/kWe	USD/MWh
Japan	Black	800	41	2,719	31.61	10.06	88.08
United States	Black PCC	600	39	2,108	19.60	8.76	72.49
Mexico	Black PCC	1,312	40	1,961	26.71	6.51	74.39
China	Black PCC	932	46	656	23.06	1.64	29.99
	Black SC	1,119	46	602	23.06	1.51	29.42
	Black SC	559	46	672	23.06	1.68	30.16
Russia	Black USC PCC	627	47	2,362	20.41	10.96	50.44
	Black USC PCC	541	37	4,864	26.10	21.58	86.82
	Black SC PCC	314	42	2,198	22.83	10.20	50.77
Korea	Black PCC	767	41	895	31.53	4.25	68.41

[a]Calculation is based on a discount rate of 5%

Comparing the total overnight cost and OPEX of the power plants of various countries summarized in the report [9], the total overnight cost of coal-fired power plants in South Korea is quite different. For example, as suggested in Table 2, the total overnight cost of the Black PCC_767 MW in South Korea is reported as 895 USD/kWe, and this figure amounts to almost half of that of the USA (2,108 USD/kWe for Black PCC_600 MW) and Japan (2,749 USD/kWe for Black PCC_800 MW), and slightly higher than that of China (672 USD/kWe for Black PSC_559 MW), while the fuel price is a little bit higher than that of other nations, which leads to an increase in LCOE.

For an evaluation of the LCOE, the exact values of the CAPEX of the reference power plant are inevitable. However, it is very challenging to accurately evaluate the total capital requirements of power plants with/without CCS mainly due to the uncertain circumstances. In this study, for the evaluation of the total capital requirements of a reference power plant in South Korea, we used the historical data of a coal-fired power plant published in KPX from 1989 to 2011. After summarizing the capital cost of the each coal-fired power plant constructed in South Korea, the regression equation regarding the capital cost of the coal-fired power plant was evaluated as shown in Fig. 3, and using this equation, the total capital requirements of the reference coal-fired power plant was evaluated (1,223 USD/kW for year 2014).

For the evaluation of the total capital requirements of a power plant with CCS, a cost evaluation model such as ICARUS of ASPEN plus could be used. However, this approach could lead to a big difference between actual capital costs due to the different nationwide economic conditions. Therefore, in this study, due to the difficulty of estimating the total capital requirements of a coal-fired power plant with CCS, we used a sensitivity analysis with a range of capital cost increases for OECD nations (66-95%).

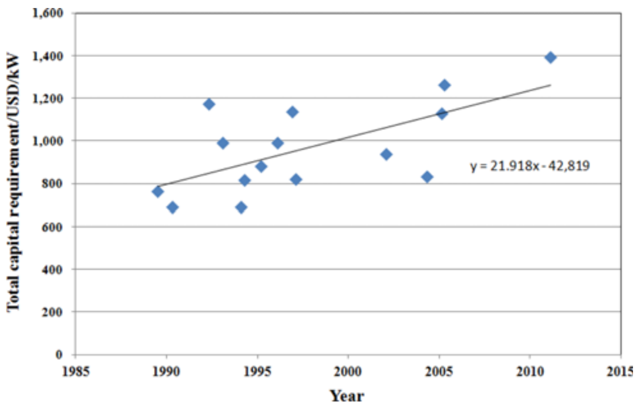

Fig. 3. Total capital requirement of reference coal-fired power plant in South Korea [16].

For the evaluation of the OPEX of power plants with/without CCS in South Korea, the literature data from various studies was used; the OPEX of a reference power plant without CCS is from an IEA report published in 2010 [7]. And the incremental of OPEX compared to a reference power plant without CCS (51% for PCC) reported in the DOE/NETL 2007 report [6] was used for the OPEX of a plant with CCS (as shown in Table 3). Using these key values, the LCOE of power plants with and without CCS was calculated based on the spreadsheet model as noted above.

For the capacity factor of the power plant, while the base conditions are assumed to be 85%, the sensitivity analysis was done from a range of 70% to 95%, reflecting the relatively high capacity factor in South Korea (the average capacity factor suggested by the KPX is: 2010: 93.9%, 2011: 94.5%, 2012: 92.7%). For the discount rate, 7% was assumed as a base condition. And the sensitivity analysis was done in a range from 5.5% to 8%, reflecting the guideline of the Korea Development Institute [17].

TESTS AND RESULTS

1. CO_2 Capture Test

The operating conditions of a 10 MW-scale post combustion CO_2 capture plant are shown in Table 4. A slipstream of flue gas generated from the combustion of coal was treated for CO_2 removal. In the absorber, the flue gas flow rate was 36,500 m^3N/h and the solvent flow rate was 83 ton/h. During 500 hours of continuous operation starting from April 2014, the average regeneration energy and the CO_2 purity remained at 2.8 GJ/t-CO_2 and over 99% at a CO_2 removal efficiency of 91%. In addition, low corrosion and degradation of the solvent was also confirmed. As was mentioned, 3.1-3.3, 3.0-3.2 GJ/tCO_2 of stripper regeneration energy was obtained from the 0.1 MW class test bed, while the 10 MW class plant operations showed an average of 2.8 GJ/tCO_2. A few process improvement plans are proposed; one of them involves maximizing the performance of the lean/rich heat exchanger.

2. Energy Penalty Calculation

Based on the performance data of the CO_2 capture pilot plant

Table 3. CAPEX and OPEX estimation

Information	Cases	
	Without CCS	With CCS
CAPEX		
Total capital requirement (USD/kWe)	1,223	Base case: 2,140
- Reference	KPX	Relative increase 75%
OPEX (excluding CO_2 transport and storage)		
OPEX excluding fuel costs (USD/MWh)	4.25	6.41
- Reference	IEA report [7]	Average increment of OPEX from DOE/NETL [6]

Table 4. Operating conditions of a 10 MW-scale post-combustion CO_2 capture plant

Operating conditions	Unit	Figures
Flue gas flow rate	Sm^3/h	36,500
Flue gas temperature	°C	34
Amount of CO_2 captured	Ton/d	200.0
CO_2 concentration in the flue gas	%	15%
Solvent flow rate	Ton/hr	83
Lean amine feed temperature	°C	40.0

as suggested above, the power plant performance analysis with CCS was evaluated through a CO_2 capture process simulation. As mentioned in the introduction, instead of using an extensive thermodynamic calculation of the CO_2 capture system integrated with a power block, a convenient method originally developed by Bolland et al. and Lee et al. was adopted [13,14] for the evaluation of the energy penalty for a power plant with CCS. A detailed explanation of the evaluation of power plant performance with CCS was suggested as follows.

2-1. Process Simulation

An amine-based CO_2 capture plant, including CO_2 compression that could treat all the flue gas from a power plant), was considered for the process simulation of an entire power plant with CCS. Based on the design conditions of the flue gas from the power plant of Boryeong Power Station, the energy and steam consumption of the CO_2 capture with CO_2 compression (from 0.1 MPa to 11 MPa as guided by the IEA GHG [9]) was estimated using a pro-

Table 5. Results from the overall analysis of energy performance with and without CCS

Case	Item	Figure	Comments
Power plant without CCS	Net power output (MWe)	1,000	
	Fuel feed rate (MW)	2,267	
	Net efficiency (%)	44.1	
	CO_2 emission ($tonCO_2/MWh$)	0.712	
Power plant with CCS	Net power output (MWe)	1,000	Based on CO_2 capture pilot plant results
	Fuel feed rate (MW)	2,867	
	CO_2 removal rate (%)	90	
	Regeneration energy ($GJ/tonCO_2$)	2.8	
	Net efficiency (%)	34.9	
	CO_2 emission ($tonCO_2/MWh$)	0.09	

Table 6. Comparison of LCOE and cost of CO_2 avoided

Regional focus	Unit	OECD				Average (OECD)	China	This study
Year of cost data		2007	2007	2009	2009		2009	2014
Year of publication		2009	2010	2009	2009		2009	2014
Organization		MIT	NETL	GCCSI	GHG IA		NZEC	KEPCO
Original data as published								
Region		US	US	US	EU		China	South Korea
Specific flue gas		Bit coal	Bit coal	Bit coal	Bit+10% Biomass		Bit coal	Bit coal
Power plant type		SCPC	Sub-PC	SCPC	SCPC			USC
Net power output w/o CCS	MW	500	550	550	519	582	824	1,000
Net power output w/ CCS	MW	500	550	550	399	545	622	1,000
Net efficiency w/o CCS	%	40.4	38.6	41.4	44.8	41.4	43.9	44.1
Net efficiency w/ CCS	%	30.7	27.5	29.7	34.5	30.9	33.1	34.9
CO_2 emission w/o CCS	kg/MWh	830	856	804	754	820	797	712
CO_2 emission w/ CCS	kg/MWh	109	121	112	73	111	106	90
Relative decrease in net efficiency	%	24	29	28	23	25	25	21
Reevaluated data		**Reevaluated data (2010)**						
LCOE W/o CCS	USD/MWh	70	66	70	78	66	51	47
LCOE W/CCS	USD/MWh	112	117	121	118	107	80	68
Cost of CO_2 avoided	USD/tCO_2	58	69	74	59	58	42	33
Relative increase in overnight cost		72%	93%	86%	74%	75%	96%	75%
Relative increase in LCOE		60%	77%	73%	52%	63%	57%	43%

cess simulator. The specifications of the flue gas stream from the power plant are evaluated from the downstream of the selective catalytic reduction process at the maximum guaranteed rating conditions of the Boryeong Power Station Unit #8 operating in South Korea [18].

The selective catalytic reduction process is one of the various desulfurization processes aimed at eliminating large quantities of SOx included in the flue gas; the SOx generated in several hundred PPM from the coal combustion process in a thermal power plant is reduced down to less than dozens of PPM while undergoing the desulfurization process. As the 10 MW class CO_2 capture plant, which is the subject of analysis in this paper, works for the flue gas after SCR, it can minimize the quantity of SOx fed into the CO_2 capture process. Normally, the amount of SOx fed into the CO_2 capture process causes the degradation of the amine solvent, which is undesirable; however, in this research, a considerable amount of SOx is removed through the desulfurization process, thus significantly increasing the long-term stability of the amine solvent.

In addition, the flue gas conditions generated by a power plant vary according to the design parameters for boiler operation, with major parameters such as best maximum continuous rating and maximum guaranteed rating being primarily utilized. Of these, we obtained the data on the flue gas flow rate and gas composition under the maximum guaranteed rating condition representing the maximum assured capacity of a boiler, and conducted process simulations based on it.

The key performance data of a previous pilot-scale CO_2 capture test from a 10 MW CO_2 capture plant, such as solvent regeneration energy, CO_2 purity and the CO_2 removal rate, was considered for the evaluation of the energy consumption of the CO_2 capture plant. For the evaluation of the energy loss for the extraction of low-pressure steam, the thermal energy used for the regeneration of the chemical solvent expressed in GJ/ton CO_2 was translated to the equivalent energy loss in kWh using a power factor developed by Bolland et al. [13]. Through the analysis of the heat and mass flow of the CO_2 capture process, including CO_2 compression, the total efficiency penalty of a power plant with CCS was evaluated, as shown in Table 5. The net energy penalty was reduced from 44.1% (without CCS) to 34.9% (with CCS) and the thermal energy required to regenerate the solvent reduced efficiency by 4.84%; the energy required to compress the CO_2 from 0.1 MPa to 11 MPa was the next-largest factor, reducing the efficiency by 2.69%; the other energy requirements amounted to 0.85%. Based on this analysis, it could be calculated that the fuel feed rate of a power plant with CCS should be increased from 2,267 MW to 2,867 MW to keep the constant net power output (1,000 MW) after CCS.

2-2. Economic Evaluation of Power Plants with/without CCS

Based on the evaluation of plant performance with CCS as suggested above, we did an economic evaluation using a cost model to calculate the LCOE and the cost of CO_2 avoided for a power plant with CCS as shown in Table 6. The results show that at the base case, the LCOE of a commercial-scale USC power plant with CCS in South Korea will increase by around 43% (47 to 68 USD/tCO_2), and the cost of CO_2 avoided was calculated as 33 USD/tCO_2.

Compared to the other literature data summarized in Table 6, the cost of CO_2 avoided for a USC power plant in South Korea was relatively low compared to that of the OECD average, which was mainly due to the relatively low CAPEX and OPEX of power plants with/without CCS.

2-3. Sensitivity Analysis

As suggested in the introduction, a sensitivity analysis of the major influencing factors was performed. The factors considered for the sensitivity analysis were capacity factor, discount rate and increase of the total capital requirements of a power plant with CCS. The detailed conditions and the results are as shown in Fig. 4.

CONCLUSIONS

We did a performance and economic analysis of a commercial-scale coal-fired power plant with a post-combustion CO_2 capture process in South Korea. Based on the good performance of CO_2 capture technology from a pilot plant (treating capacity: 200 ton CO_2/day) developed by the Korea Electric Power Company Research Institute, a power plant cost model coupled with a performance model was developed to evaluate the LCOE and cost of CO_2 avoided

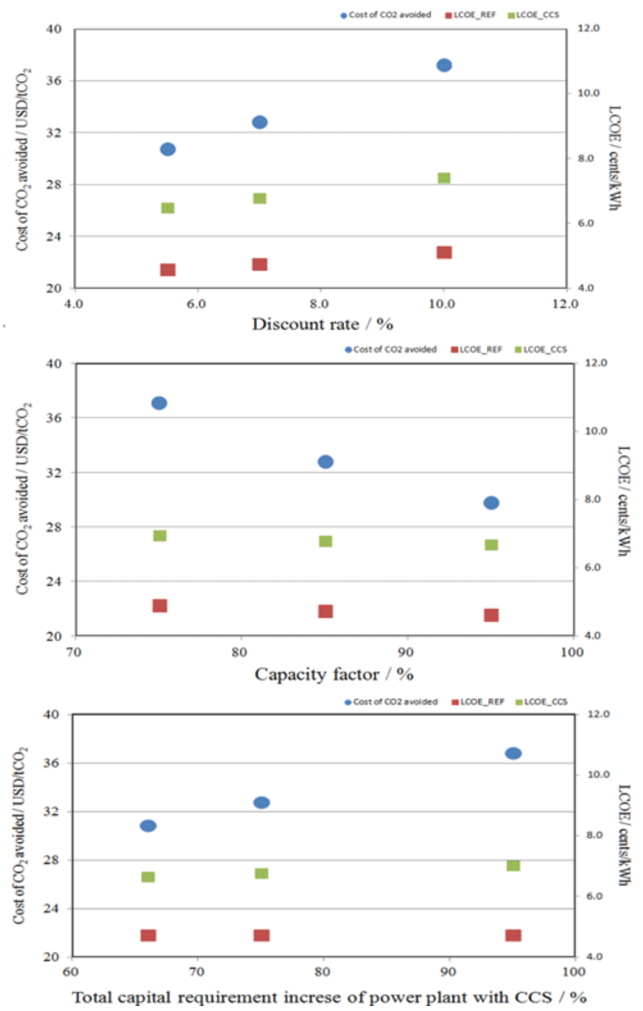

Fig. 4. The results of the sensitivity analysis, base case values: discount rate 7%, capacity factor 85%, TCR increase of power plant with CCS 75%.

the cost of CO_2 avoided from various studies was conducted. The results show that the LCOE of a commercial-scale USC power plant with CCS in South Korea will increase by around 43% (47 to 68 USD/tCO_2), and the cost of CO_2 avoided was calculated as 33 USD/tCO_2. Comparing the other literature data reported in the IEA report [7], the cost of CO_2 avoided for a USC power plant in South Korea was relatively low compared to that of the OECD average, which was mainly due to the relatively low CAPEX and OPEX of power plants with/without CCS. Based on these studies, work to obtain a more accurate evaluation of the CAPEX and OPEX cost of the reference plant with CCS in the future is recommended.

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