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Techno-Economic Analysis of Hydrogen–Natural Gas Blended Fuels for 400 MW Combined Cycle Power Plants (CCPPs)

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Abstract: Various research and development activities are being conducted to use hydrogen, an environmentally friendly fuel, to achieve carbon neutrality. Using natural gas–hydrogen blends has advantages such as the usage of traditional combined cycle power plant (CCPP) technology and existing natural gas piping infrastructure. Therefore, we conducted CCPP process modeling and economic analysis based on natural gas–hydrogen blends. For process analysis, we developed a process model for a 400 MW natural gas CCPP using ASPEN HYSYS and confirmed an error within the 1% range through operation data validation. For economic analysis, we comparatively reviewed the levelized cost of electricity (LCOE) of CCPPs using hydrogen blended up to 0.5 mole fraction. For LCOE sensitivity analysis, we used fuel cost, capital expenditures, capacity factor, and power generation as variables. LCOE is 109.15 KRW/kWh when the hydrogen fuel price is 2000 KRW/kg and the hydrogen mole fraction is increased to 0.5, a 5% increase from the 103.9 KRW/kWh of CCPPs that use only natural gas. Economic feasibility at the level of 100% natural gas CCPPs is possible by reducing capital expenditures (CAPEX) by at least 20%, but net output should be increased by at least 5% (20.47 MW) when considering only performance improvement.

Keywords: hydrogen–natural gas blends; economic analysis; levelized cost of electricity; total revenue requirement; low-carbon fuels

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1. Introduction

The use of fossil energy in various industries generated 37.1 billion tons of CO_2 emissions worldwide in 2021, which has been causing environmental problems, such as global warming and ocean acidification [1]. Moreover, since CO_2 is a major cause of climate change, in February 2021, 124 countries pledged to make joint efforts to eliminate carbon using carbon reduction technologies to become carbon-neutral by 2050 or 2060 [2]. The plan is to continue to reduce CO_2 emissions through various kinds of research and development activities, but transition to environmentally friendly fuels is crucial at this point to achieve zero emissions. When hydrogen, which is a typical environmentally friendly fuel, is used as a fuel for power generation, only oxygen (O_2) is created as the by-product in the process, and hence it can be the ultimate solution to problems related to energy and the climate crisis. According to market research by the International Energy Agency (IEA), the global demand for hydrogen was 75 million tons in 2019, but it is expected to increase sharply to approximately 1200 million tons by 2070 as its application scope expands to industries, transport, and fuels. Moreover, using hydrogen or hydrogen-based fuels is expected to reduce CO_2 emissions by 8% per year, which is why it is necessary to use hydrogen for sustainable energy industries [3]. To use hydrogen in various industries, it is necessary to establish the entire process of production, storage, and supply. First, hydrogen is classified into three types according to the production method. Gray hydrogen is produced through steam methane reforming (SMR) of fossil fuels (coal, oil, or gas), blue hydrogen is produced by additionally applying carbon capture and storage (CCS) equipment, and green hydrogen produces hydrogen through renewable energy [4]. Of all the hydrogen produced worldwide, 48% is produced using natural gas, 30% using oil, and 18% using coal; only about 4% is produced using water electrolysis [5]. Moreover, less than 1% is produced using renewable energy, which suggests a need to increase production of green hydrogen through continuous R&D and demonstration [6]. Next, the storage and supply method of hydrogen is addressed. To use hydrogen as a fuel, countries with insufficient hydrogen production are considering phase-converting and storing gaseous hydrogen in a liquid state and then supplying it through transport. Liquid hydrogen has an extremely low melting point, 20 K, and it generates boil-off gas (BOG) even with a small heat input from the outside, which limits long-distance transport. Hence, continuous efforts are being made to establish a hydrogen ecosystem by developing technologies, such as slush hydrogen production for zero boil-off application [7,8] or methods to transport hydrogen using catalytic reactions of organic liquids, such as toluene/methylcyclohexane and ammonia (NH3) [9–11].

It Is difficult to ensure economic feasibility with existing technologies, considering the production, storage, and transport process of hydrogen, but it will be possible to produce grey hydrogen for USD 1.0–USD 2.1/kg, blue hydrogen for USD 1.5–USD 2.9/kg, and green hydrogen for USD 3.0–USD 7.5/kg [12]. As 7.5–8 kg of oxygen is generated per kg of hydrogen through electrolysis when a hydrogen electrolyzer is used, a plan has also been suggested to ensure economic feasibility by lowering the cost of produced oxygen to USD 2.98–USD 3.2/kg-H_2 in connection with biomass gas and the process [13]. Moreover, the method of blending natural gas and hydrogen has been receiving attention for using business infrastructure that is already established, and many studies are currently being conducted on this method [14]. Blending hydrogen into a natural gas pipeline network can reduce greenhouse gas emissions more than using just natural gas alone. An experiment proved that blending 20% hydrogen into natural gas for combustion can reduce CO_2 by up to 9.33% per year [15]. Other experiments have also confirmed that blending as much as 20% hydrogen into the engine using natural gas results in lower emissions such as hydrocarbon and carbon monoxide than recommended by European emission standards such as Euro-5 (Euro V) and Euro-6 (Euro VI) [16,17]. Furthermore, it is possible to ensure economic feasibility and increase supply by using the natural gas pipeline networks established in each country, and the demand and supply of hydrogen can be adjusted by gradually increasing the amount of blended hydrogen from 0.1% to 10%, until a large amount of hydrogen production is secured [18,19]. Countries such as the UK, Netherlands, and France have studied ways to blend 2–20% hydrogen into the existing natural gas pipelines and reviewed the applicability by changing the method of combustion control and reinforcing safety equipment [20–22]. However, an experiment regarding the effect of operating pressure on piping when blending natural gas and hydrogen proved that fatigue life rapidly decreased when the amount of hydrogen blended into high-pressure 12 MPa natural gas piping was increased up to 50%, which suggests the need for additional research on materials [23]. A combustor design to prevent flashbacks is important since hydrogen combusts faster than natural gas. Cameretti et al. suggested a method that does not cause flashbacks even when blending more than 10% hydrogen into natural gas using computational fluid dynamics (CFD) [24]. The well-known problem of flashback at higher hydrogen concentrations can be prevented by using water dilution [25]

Recently, gas turbines have been developed, such as the distributed electric and thermal energy generation to avoid any possible waste [26]. Combustor development is one of the key technologies of gas turbines, and the GE DLN-2.6 combustor is capable of 15% hydrogen cofiring, which is limited to 5% in actual operation. There is ongoing research and demonstration to apply high-concentration hydrogen of more than 50% [27]. Siemens is capable of up to 15% hydrogen blending without significantly changing the current natural gas combustor for natural gas–hydrogen cofiring and is currently validating the performance of the gas turbine combustor to apply up to 50% [28]. An examination of fuel characteristics and review of the performance of diaphragm gas meters to accurately measure the flow rate of blended gas revealed that the error is small when 0–15% hydrogen is blended into natural gas [29].

Meanwhile, many studies anticipate several benefits from using natural gas–hydrogen blends, but there are several problems. Italy has a natural gas pipeline network of approximately 300,000 km, so economic benefits are expected from blending hydrogen. However, the lower heating value (LHV) per unit mass of hydrogen is 120.1 MJ/kg, which is higher than that of natural gas (49.3 MJ/kg), but the heating value per unit volume is 10.8 MJ/Nm^3, which is lower than that of natural gas (39.08 MJ/Nm^3). Hence, the volume of hydrogen should be at least 3.6 times that of natural gas to produce the same heating value [30]. Therefore, when using blended fuel, it is important to design the combustor according to the increase in volume. Moreover, various studies have been conducted on the levelized cost of hydrogen (LCOH) in which hydrogen is produced and stored using a hydrogen electrolyzer associated with renewable energy, but many studies are still needed to ensure economic feasibility at the level of USD 37.9–USD 52.9/kg when applying a 200–300 kW hydrogen electrolyzer [31]. Therefore, this study validated a process model for a combined cycle power plant (CCPP) using natural gas–hydrogen blends as fuels and examined the economic benefits of using natural gas–hydrogen blends through economic analysis. First, we validated the analytical model by comparing the simulation results of the existing CCPP process that uses 100% natural gas as fuel with actual operation data. Then, using the validated model, we calculated the change rate in power generation and temperature character depending on the amount of hydrogen blended. Therefore, we verified the fuel costs of adequate hydrogen by comparing the levelized cost of electricity (LCOE) expected from operating a 400 MW CCPP with natural gas–hydrogen blends. In addition, we proposed proper operation conditions to secure competitiveness with natural gas CCPPs by comparing LCOE according to changes in hydrogen fuel cost, capacity factor, and facilities investment cost, namely, capital expenditures (CAPEX).

2. Methodology

2.1. Process Model

2.1.1. Assumption of Combined Cycle Power Plant (CCPP)

The CCPP process generates power using natural gas as fuel, and it is a system that operates at more than 60% efficiency by generating power from a gas turbine while recovering the heat from the high-temperature exhaust gas discharged simultaneously, which is supplied to the steam turbine [32]. CCPPs mainly comprise a compressor, gas turbine, heat recovery steam generator, steam turbine, deaerator, condenser, boiler feedwater pump (BFP), and condensate extraction pump (CEP).

Figure 1 shows the schematic diagram for the performance review of a CCPP, which mostly comprises 1 gas turbine, 1 heat recovery steam generator, 1 steam turbine, and balance of plant (BOP) equipment. The net power output of the process is 393.58 MW, and the net power efficiency at higher heating value (HHV) and lower heating value (LHV) is 53.6% and 58.8%, respectively. Conditions such as ambient relative humidity of 60%, ambient dry bulb temperature of 15°C, and atmospheric pressure of 1.013 bar(a) were considered, and the HHV and LHV of the natural gas supplied were 54,136 kJ/kg and 49,300 kJ/kg, respectively [33]. In addition, the following conditions were set for process analysis.

- The flow is in a steady state.
- Air and combustion products are assumed as ideal gas.
- The gas turbine and steam turbine models are operated at a steady state.
- Heat transfer between the components of the plant and the environment is negligible.

We used ASPEN HYSYS V 12.0 for the CCPP process modeling and applied the Peng–Robinson (PR) equation of state (EOS) for analysis. The values provided by the HYSYS database were used for material properties. The composition of Natural gas is shown in Table 1.

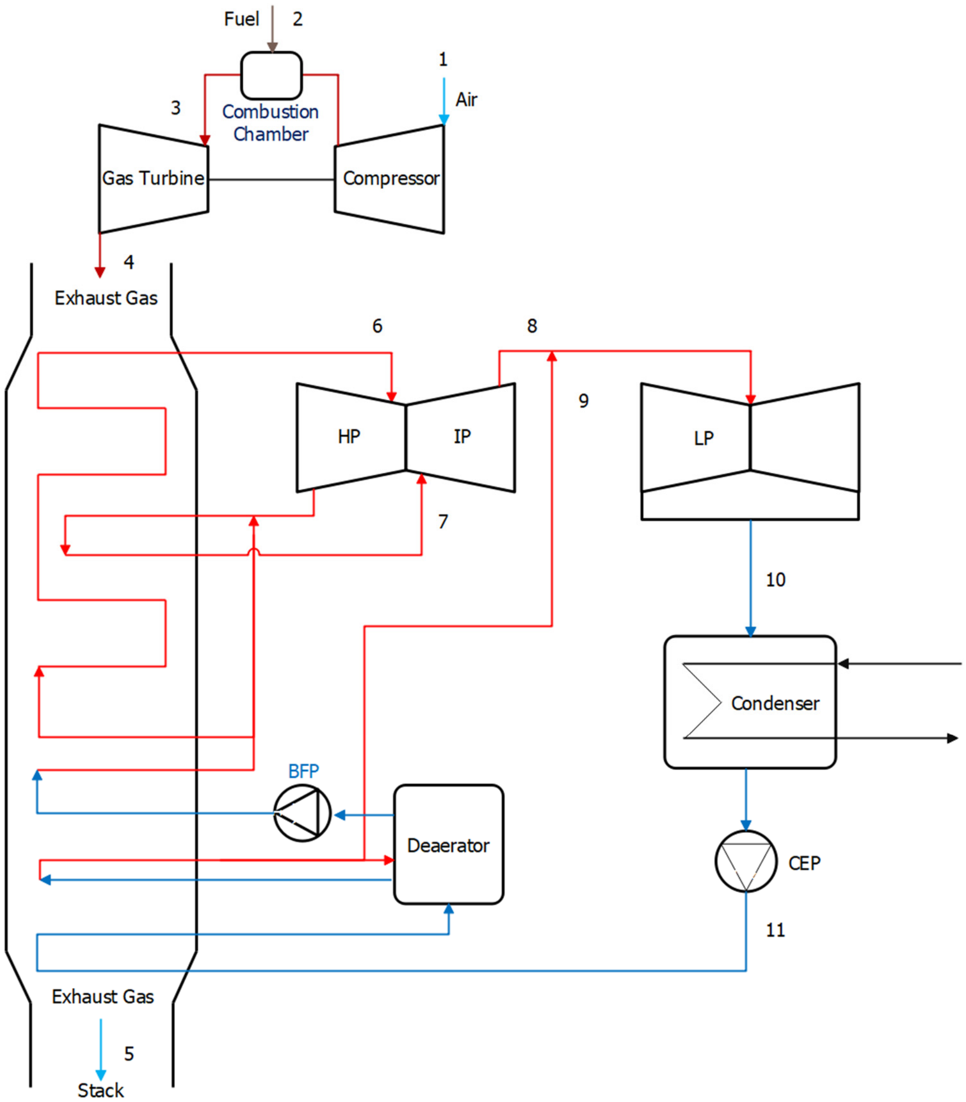

Figure 1. Schematic diagram of a combined cycle power plant.

Table 1. Natural gas fuel composition.

Gas	CH_4	C_2H_6	C_3H_8
Vol (%)	89.5	8.8	1.7

2.1.2. Model simulation

For CCPP process modeling, we used the 400 MW CCPP heat and mass balance diagram operated by Korea South-East Power Co., Ltd. (Jinju, Republic of Korea). To perform block modeling including the gas turbine, the combustion efficiency of the combustor was set at 100% and the heat loss that may occur in the combustion process was set at 3%. The efficiency of the gas turbine and compressor was set at 85% and 89.3%, respectively, and it was modeled so that 11% of the compressed air flow would be used for cooling the gas turbine. Required equations for the calculation of components of compressor and gas turbine are given below [34].

Compressor

$$T_{out} = T_{in}\left(1 + \frac{1}{\eta_{AC}}\left(r_{AC}^{\frac{k-1}{k}} - 1\right)\right) \tag{1}$$

Gas turbine

$$T_{out} = T_{in}(1 - \eta_{GT}\left(1 - \left(\frac{P_{in}}{P_{out}}\right)^{\frac{k-1}{k}}\right) \quad (2)$$

The heat recovery steam generator of the steam turbine block was modeled by arranging 4 economizers, 3 evaporators, and 7 superheaters, and the minimum approach temperature was set at 5 K. We conducted a comparative review on temperature, pressure, and flow rate at the major points, and the differences between the actual heat and mass balance diagram and the simulation model are as shown in Table 2.

Table 2. Thermophysical property comparison of actual and simulation data.

Point	Stream	Temperature (°C)		Pressure (Bar)		Mass Flow Rate (t/h)	
		Actual	Simulation	Actual	Simulation	Actual	Simulation
1	Air	15	15	1.013	1.013	2,122	2132
2	Natural gas	200	200	39	39	48.83	48.83
3	Combustion gas	1500	1,514	39	39	2,170	2181
4	Exhaust gas	611.8	616.0	1.039	1.09	2,170	2181
5	Exhaust gas	83.0	83.6	1.013	1.07	2,170	2181
6	Steam	596.4	596.0	129.7	129.7	257.5	288.8
7	Steam	582.3	582.0	27.2	31.3	283.1	317.4
8	Steam	235.5	238.2	2.0	2.5	289.5	289.6
9	Steam	244.2	245	4.0	4.2	47.8	49.2
10	Steam	29.4	31.2	0.041	0.094	340.1	342
11	Water	29.5	29.5	9.5	9.5	340.8	345

The model analysis results revealed a difference in flow rate at certain points, and there were some errors in the process since the LP sealing steam and the steam fumed intermittently to the condenser. However, we confirmed that the maximum error was around 1% by similarly controlling the rates of fuel consumption and total power produced in the steam turbine and gas turbine blocks. The thermodynamic efficiency of the CCPP was evaluated by net efficiency ($\eta_{net,CCPP}$) based on the power produced, and it is defined as shown in Equation (3).

$$\eta_{net,\ CCPP} = \frac{P_{net,\ GT} + P_{net,\ ST}}{(\dot{m}_{NG}) \times LHV} \times 100 \quad (3)$$

Here, $P_{net,GT}$ is the net power of the gas turbine, excluding the auxiliary power generated in the compressor from the gross power produced in the gas turbine. $P_{net,ST}$ is the net power of the steam turbine, excluding power such as BFP and CEP from the gross power produced in the steam turbine, and $\dot{m}_{NG}$ is the fuel supply based on LHV.

We compared the change in the amount of hydrogen blended with natural gas by increasing the amount from 0 to 0.5 in mole fraction. Equation (4) shows the natural gas-hydrogen blend ratio in mole fraction [35], and the amount of natural gas–hydrogen blends injected is as shown in Table 3.

$$\text{Mole fraction}_{H2} = \frac{\chi_{H2}}{\chi_{H2} + \chi_{NG}} \times 100 \quad (4)$$

2.2. Economic Model

2.2.1. Methodology of Levelized Cost of Electricity (LCOE)

Connecting the processes or converting fuels can improve the efficiency of the CCPP system, but it generally involves a complicated system or reduces economic feasibility. Hence, a newly proposed process or a process altered by fuel conversion requires a comparative review between different power generation systems through economic evaluation.

The LCOE can quantitatively evaluate the economic feasibility of the source of power through the process of converting the costs required for constructing and operating the equipment in the CCPP into the present value and levelizing them. The total revenue requirement (TRR) methodology used by the US Electric Power Research Institute (EPRI) was applied to calculate the LCOE of the 400 MW natural gas–hydrogen CCPP [36].

Table 3. Flow rate of blended fuel based on mole fraction.

Fuel Composition			
H_2 Mole Fraction	**H_2 Flow Rate (t/h)**	**NG Mole Fraction**	**NG Flow Rate (t/h)**
0	0	1.0	48.83
0.1	0.662	0.9	47.38
0.2	1.435	0.8	45.68
0.3	2.352	0.7	43.67
0.4	3.455	0.6	41.24
0.5	4.808	0.5	38.26

The TRR calculates the cost of system construction and other expenditures with the cost that must be recovered annually by selling electric power. Hence, it requires the calculation of TCI (total capital investment), which consists of FCI (fixed capital investment) and OO (other outlay). FCI is divided into DC (direct cost) and IC (indirect cost) and is expressed as shown in Equation (5).

$$TCI = FCI + OO = DC + IC + OO \quad (5)$$

DC includes purchased equipment cost (PEC), piping, land, and service facilities, and IC includes engineering cost, construction cost, and contingency. OO includes startup cost, working capital, and allowance for funds used during construction.

Meanwhile, TRR is calculated as the sum of annual expense and CC (carrying charge) required for facility operation. Expenses comprise electricity cost (or fuel cost, FC) and O&M cost (OMC), and CC includes capital recovery, return on equity, return on debt, income taxes, other taxes, and insurance. Figure 2 shows the diagram for calculating TRR [37].

CR_j (capital recovery) is calculated as the sum of BD_j (book depreciation), $DITX_j$ (differed income taxes), and $RCEAF_j$ (recovery of common-equity AFUDC), as shown in Equation (6).

$$CR_j = BD_j + DITX_j + RCEAF_j \quad (6)$$

$DITX$ is the tax incurred owing to the difference between TXD (tax depreciation) and BD (book depreciation), and it is as shown in Equation (7), considering $f_{MARCS,\,j}$ (rate of depreciation), t (tax rate), and TL (taxation period).

$$\begin{array}{ll} TXD = TDI + f_{MARCS,\,j} & j = 1,\ \ldots,\ \mathrm{TL}\ +1 \\ TXD = 0 & j =\ \mathrm{TL}\ +2,\ \ldots,\ \mathrm{n} \\ DITX = (TXD - BD) \times t & j = 1,\ \ldots,\ \mathrm{TL}\ +1 \\ DITX = -\frac{\sum_{k=1}^{TL+1} DITX_k}{n-(TL-1)} & j =\ \mathrm{TL}\ +2,\ \ldots,\ \mathrm{n} \end{array} \quad (7)$$

Meanwhile, CC (carrying charge) is calculated as shown in Equation (8), using variables such as ROI (return on investment), BBY (balance beginning of year), f_x (funding ratio), ADJ (adjustment), and BD (book depreciation).

$$\begin{array}{ll} ROI = BBY_{j,x} \times i_x & x = \text{ d, ps, ce} \\ BBY = TCI \times f_x & x = \text{ d, ps, ce} \\ BBY_j = BBY_{j-1} - (BD_{j-1} + ADJ_{j-1}) & j = 2, \ldots, \text{n} \\ ADY_{j,d} = DITX_j \times f_x & j = 2, \ldots, \text{n, x = d, ps} \\ ADY_{j,d} = DITX_j \times f_{ce} + RCEAF_j & j = 1, \ldots, \text{n} \\ ITX = \frac{t}{1-t}\left(ROI_{ce} \times ROI_{ps} + RCEAF_j\right) - DITX & \\ CC = TCR + ROI_{ce} + ROI_{ps} + ROI_d + ITX + OXTI & \\ \text{Expense} = \text{FC} + \text{OMC} & \end{array} \quad (8)$$

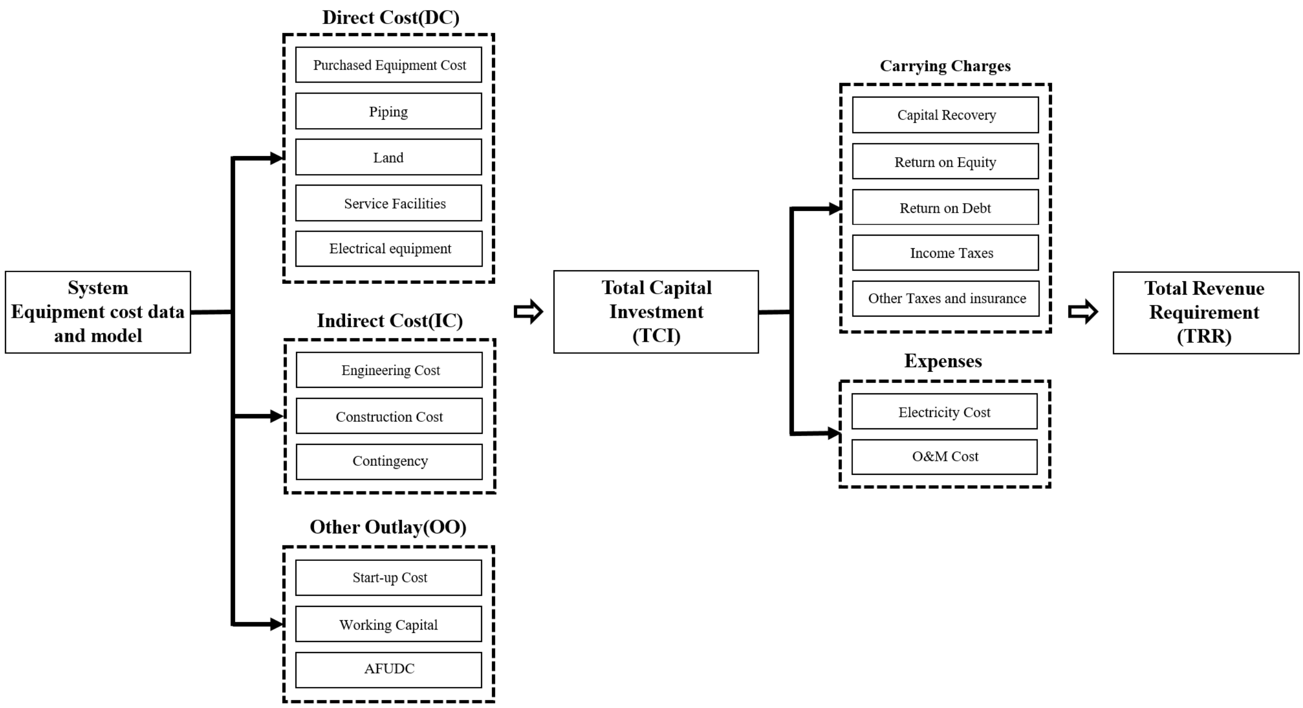

Figure 2. The concept of the TRR method for a CCPP.

Then, to levelize TRR, i.e., the sum of CC and expense, the constant escalation levelization factor (CELF) is applied to the cost incurred for overall system operation, as shown in Equation (9).

$$\begin{array}{c} CC_L = CRF \times \sum_1^n \frac{CC_j}{\left(1+i_{eff}\right)^j} \\ CRF = \frac{i_{eff}\left(1+i_{eff}\right)^n}{\left(1+i_{eff}\right)^n - 1} \\ FC_L = FC_O \times CELF_{FC} \\ CELF_{FC} = \frac{k_{FC}\left(1-k_{FC}^n\right)}{1-k_{FC}} \times CRF,\ k_{FC} = \frac{1+r_{FC}}{1+i_{eff}} \\ OMC_L = OMC_O \times\ CELF_{OMC} \\ CELF_{OMC} = \frac{k_{OMC}\left(1-k_{OMC}^n\right)}{1-k_{OMC}} \times CRF,\ k_{OMC} = \frac{1+r_{OMC}}{1+i_{eff}} \\ TRR_L = CC_L + FC_L + OMC_L \end{array} \quad (9)$$

The LCOE is calculated by subtracting BPV (by-product value) from TRR and dividing the result by annual power, as shown in Equation (10) [38].

$$LCOE\ [\$/MWh] = \frac{TRR_L - BPV}{Annual\ \ Power} \quad (10)$$

2.2.2. Capital Cost Calculation

To calculate the LCOE of a natural gas–hydrogen CCPP, a levelization process is required to prepare cash flows, calculate annual costs to be recovered, and convert them into present values. Hence, a few necessary conditions for economic analysis were assumed, as shown in Table 4. For the annual inflation rate, nominal inflation rate, and exchange rate, 1.5%, 1.5%, and KRW 1100 were applied, respectively, with the consideration of the means from 2012 to 2020 for each [39,40]. The first and second FPI supply refer to the facilities investment cost of each year, assuming that the construction period is two years, and this is randomly assumed to convert the interest incurred during the construction period into allowance for funds used during construction. Total income tax rate was set as 22%, and other tax rate as 2.0%, which is 10% of total income tax rate [41]. Since the lifetime of a turbine, which is a major facility, is generally about 30 years, plant life was set as 30 years and tax years, as 20 years [42]. In addition, capacity factor was set as 28.6% based on the actual utilization rate, and for fuel cost, the actual fuel cost of the CCPP operated by Korea South-East Power Co., Ltd. was applied. Regarding the combustor replacement cost for natural gas–hydrogen cofiring, we used the data provided by a gas turbine company in Korea. The results obtained from the experiment and analysis of CFD can be used to adjust the amount of hydrogen blended or replace the combustor for application to the existing CCPP system [43].

Table 4. Economic assumptions and index input for economic analysis.

Contents			Unit	Value
Overall economic index	Annual inflation rate [39]		%	1.5
	Nominal inflation rate [39]		%	1.5
	Fuel escalation		%	1.0
	Levelized interest rate		%	4.7
	First FPI supply		%	40.0
	Second FPI supply		%	60.0
	Won–dollar exchange rate [40]		KRW	1100
System financing	Plant design start year		year	2020
	Plant construction start year		year	2020
	Plant operation start year		year	2022
	Common equity	Financing fraction	%	50.7
		Required annual return	%	7.0
	Preferred stock	Financing fraction	%	0.0
		Required annual return	%	8.0
	Debt	Financing fraction	%	49.3
		Required annual return	%	2.4
	Resulting average cost of money		%	4.7
	Total income tax rate [41]		%	22.0
	Other tax income rate [41]		%	2.0
Plant operation index	Plant life [42]		year	30
	Tax life		year	20
	Capacity factor (or plant operation rate)		%/year	28.6
	Power plant net power		kW	406,211
	Fuel cost	Natural gas unit price	USD/MJ	20,488
		Hydrogen unit price	USD/t	7273
	Combustor	Number of combustors	ea.	14
		Unit cost per combustor	USD/ea.	272,727
		Lifetime of combustor	h	25,000
		Total combustor cost for repair	USD	26,757,818.2
		Total combustor cost for repair per year	USD/year	1,337,891

Meanwhile, for the total facilities investment cost, land cost, and other utility costs of the natural gas CCPP, we used the data provided by Korea South-East Power Co., Ltd., and other main equipment manufacturers to calculate DC, IC, and OO. Table 5 summarizes the total net outlay and total facilities investment cost that is not depreciated from the total investment cost calculated.

Table 5. Capital cost calculation summary.

Contents				Cost (USD)
Fixed capital investment	Direct cost	Onsite costs	Purchased equipment cost	209,090,909
		Offsite costs	Land cost	20,909,901
			Civil, structural and supervision	118,181,818
		Total cost		348,181,818
	Indirect cost	Engineering and supervision		27,854,545
		Construction cost		52,227,273
		Contingency		64,239,545
		Total cost		144,321,364
	Total cost			492,503,182
Other outlay	Startup cost	Fuel and O&M for startup		9,543,459
		Escalated startup cost		288,451
		Total cost		9,831,910
	Working capital	Working capital cost		23,233,479
		Escalated working capital cost		1,061,267
		Total cost		24,294,746
	AFUDC	Allowance for funds used during construction		30,372,455
		Total AFUDC after 2 years		34,883,398
Total capital investment (TCI)	Total net outlay		Land cost	20,909,091
			Plant facilities investment	490,220,655
			Startup cost	9,831,910
			Working capital	24,294,746
			Total net outlay	545,256,402
			Total cost	580,139,800
Total depreciable capital Investment	Total net capital investment		Total capital investment	580,139,800
			Total cost	580,139,800
	Total nondepreciable capital investment		Land cost	20,909,091
			Working capital	24,294,746
			Common equity AFUDC	25,948,579
			Total cost	71,152,416
			Total depreciable capital investment	508,987,384

2.2.3. Model Development

Before calculating the LCOE of the 400 MW natural gas–hydrogen CCPP system, it is necessary to validate the TRR model. Hence, validation was conducted to determine whether the same level of LCOE is calculated by applying the actual facilities investment cost of Bundang CCPP Unit 2, which has been in operation since 1997. Table 6 summarizes the variables applied for validation. The results showed that the LCOE calculated using the suggested TRR method was 96.5 KRW/kWh, indicating a 1.4% difference from that of Bundang CCPP Unit 2 (95.16 KRW/kWh), which confirmed that the proposed model has sufficient reliability.

Table 6. Evaluation of TRR method model.

Contents	Unit	Bundang CCPP-2	TRR Method Simulation
Total capital investment	KRW	162,900,000,000	162,900,000,000
Common equity financing fraction	%	50.73	50.73
Cost of equity capital	%	7.02	7.02
Debt financing fraction	%	49.27	49.27
Cost of debt capital	%	2.36	2.36
Weighted average cost of capital	%	4.7	4.7
Income tax rate	%	22	22
Plant lifetime	Year	30	30
Capacity factor	%	28.6	28.6
Plant net power	MW	368	368
Fuel cost/year, only NG	KRW	80,200,000,000	80,200,000,000
Levelized cost of electricity	KRW/kWh	95.16	96.5

3. Analysis Results

3.1. Process Simulation Results

Based on the model that has been validated using actual CCPP data, we checked for a change in performance according to the natural gas–hydrogen blend ratio. For performance comparison, we applied the same condition by setting the heat energy of the natural gas–hydrogen blend supplied to the gas turbine at 743.3 MW and consistently supplying air at a flow rate of 2132 t/h by replacing only the combustor in the existing gas turbine. Moreover, the amount of air required according to the increase in hydrogen cofiring rate increased gradually when the hydrogen volume was 80% or higher, but the ratio was around 0.5%, proving that there was almost no change in the characteristics of the compressor [33]. Table 7 shows the comparison of the process analysis results and efficiency.

Table 7. Results of the thermodynamic analysis.

Contents		Unit	Actual	Simulation	Error (%)
Gas turbine block	NG flow rate	t/h	48.83	48.83	-
	Air flow rate	t/h	2122	2132	0.46
	GT inlet temperature	°C	1500	1500	-
	GT outlet temperature	°C	611.8	616	0.65
	GT exhaust gas flow rate	t/h	2170	2181	0.46
	Net power	kW	263,180	263,197	0.01
Steam turbine block	BFP flow rate	t/h	340	345	1.47
	HRSG inlet temperature	°C	83	83.6	0.72
	Net power	kW	130,400	130,968	0.43
Total net power generation		kW	393,580	394,165	0.14
$\eta_{net.CCPP}$ (LHV)		%	58.86	58.94	0.13

An increase in the ratio of hydrogen blended into the fuel led to an increase in the output of the gas and steam turbines. At 0.5 mole fraction, the gas turbine block generated 271.17 MW of power, showing that power generation increased by 3.03%, while the steam turbine block generated 135.36 MW, showing that power generation increased by approximately 3.1%. Thus, a total of 406.53 MW was generated. Figure 3 shows the characteristics of the increase in an enthalpy change and output due to the increase in the partial pressure of water as the hydrogen blend ratio increased.

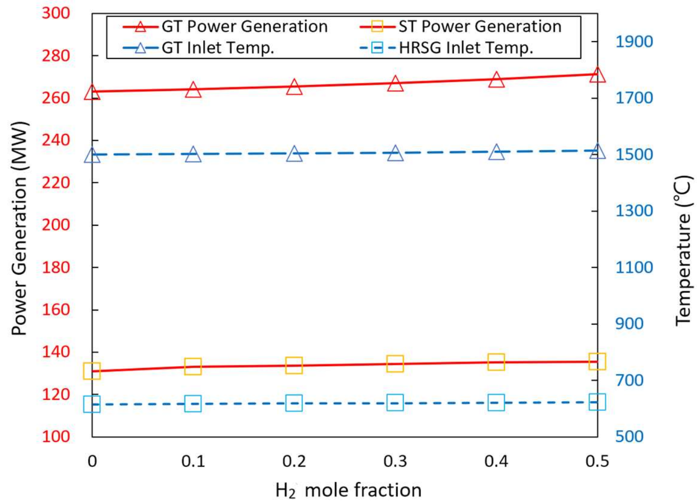

Figure 3. The performance results of the CCPP based on blended fuels.

Figure 4 shows that when the mole fraction of hydrogen in the fuel increases to 0.5, the net efficiency improves by 1.86% from 58.94% to 60.8%, proving that fuel supply in mass decreases by 11.8%. This is because the per unit mass LHV of hydrogen is 2.43 times greater than that of LNG, but the analysis was conducted assuming the heating value of the fuel supplied to the CCPP is the same. Therefore, higher efficiency can be expected by increasing the hydrogen blend ratio in the fuel. The inlet volume flow increased by 63.9% from that when supplying 100% natural gas. This proves that combustor design is important for using hydrogen fuel blends.

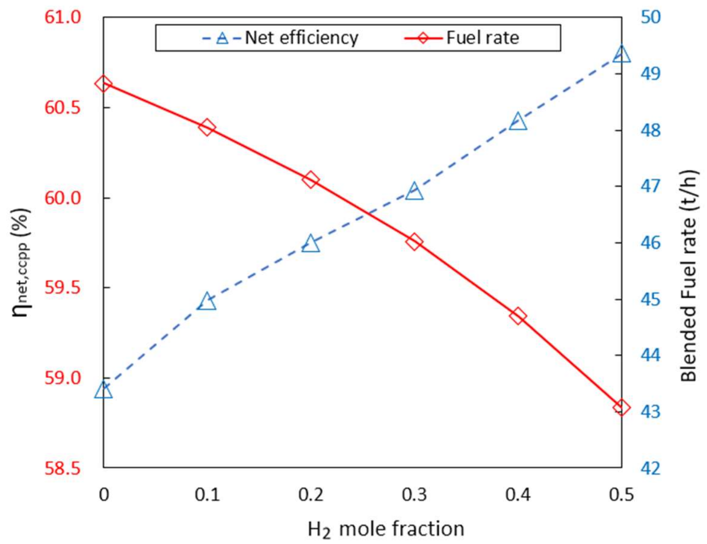

Figure 4. Correlation of net efficiency with fuel consumption based on blended fuels.

3.2. LCOE of Natural Gas–Hydrogen CCPP

We reviewed the expected LCOE in case a natural gas–hydrogen CCPP is operated by changing or replacing the existing combustor in the LCOE model based on the TRR method. The target hydrogen supply price was 6000 KRW/kg in 2022 according to the Korean government's Hydrogen Economy Roadmap, but as the distribution was 7000–8800 KRW/kg in 2022, the hydrogen fuel supply price was set as 8000 KRW/kg [44]. Moreover, we calculated the combustor replacement cost and TCI based on the expected cost of constructing a 400 MW

CCPP provided by a turbine manufacturer and used the values listed in Table 6 for other variables. The LCOE when only natural gas is used versus when natural gas–hydrogen blends are used is as shown in Table 8.

Table 8. Index input for LCOE of a natural gas–hydrogen CCPP.

	Unit	Natural Gas	Natural Gas and Hydrogen
Total capital investment	KRW	360,000,000,000	360,000,000,000
Hydrogen mole fraction	-	0	0.5
Plant lifetime	Year	20	20
Plant operating rate	%	28.6	28.6
Plant net power	MW	394.165	406.53
Combustor repair cost	KRW/year	-	1,470,000,000
Fuel cost/year	KRW	72,000,000,000	152,800,000,000
Levelized cost of electricity	KRW/kWh	103.9	180.67

For the natural gas CCPP, fuel and maintenance costs play a bigger role than capital expenditures (CAPEX) when calculating LCOE. Consequently, it was found that the cost increased up to 180.67 KRW/kWh when operating a natural gas–hydrogen CCPP owing to hydrogen fuel cost.

3.3. Sensitivity Analysis of LCOE

The key variables that affect the LCOE calculation of the CCPP include fuel cost, capacity factor, CAPEX, and power generation. Hence, we reviewed ways to achieve price competitiveness by conducting a sensitivity analysis of the variables that affect LCOE.

The IEA has predicted that the price of hydrogen in China will decrease to USD 2–USD 5/kg by 2030, and the price of hydrogen in the global market is expected to be USD 1.5–USD 2.5/kg [45]. For fuel cost, since LCOE may fluctuate greatly depending on hydrogen supply price, LCOE was reviewed at the price range of 2000–8000 KRW/kg (USD 1.8–USD 7.2/kg). Figure 5 shows the analysis results based on a hydrogen fuel supply of up to 50% in terms of mole fraction. The range of LCOE when using 50% blends is 109.15–180.67 KRW/kWh, and when the supply fuel is converted 100% to hydrogen, the expected LCOE could be 432.08 KRW/kWh (8000 KRW/kg), 280.20 KRW/kWh (5000 KRW/kg), or 128.32 KRW/kWh (2000 KRW/kg).

Capacity factor, which is the utilization rate of the natural gas–hydrogen CCPP, can also be a key variable. Increasing the capacity factor from 28.6% to 35% or more can lower the LCOE to 103.76 KRW/kWh, down to the LCOE level (103.9 KRW/kWh) of a CCPP using only natural gas. Here, hydrogen fuel price must be lowered to 2000 KRW/kg, and the results of the economic analysis on hydrogen supply price and capacity factor are as shown in Figure 6.

The investment cost associated with hydrogen production is expected to be reduced by approximately 30% by 2050 with a learning rate of 17–23% due to technology development and learning effects [46,47]. Even in the case of combustors and related equipment for using hydrogen fuel, it is necessary to review LCOE according to an approximately 30% change in CAPEX, considering a case in which CAPEX decreases owing to technology development or the cost increases owing to increased technical difficulty. Figure 7 shows the change in LCOE according to the increase and decrease in CAPEX. Even when CAPEX decreases by up to 30%, the LCOE changes only by around 5%. When the hydrogen supply price is 8000 KRW/kg, the LCOE is 171 KRW/kWh even when CAPEX is reduced by 30%. However, it is 2000 KRW/kg, the LCOE is 118.17 KRW/kWh even when CAPEX is increased by 30%, which is significantly lower. Therefore, a change in fuel price is much more important than a change in CAPEX.

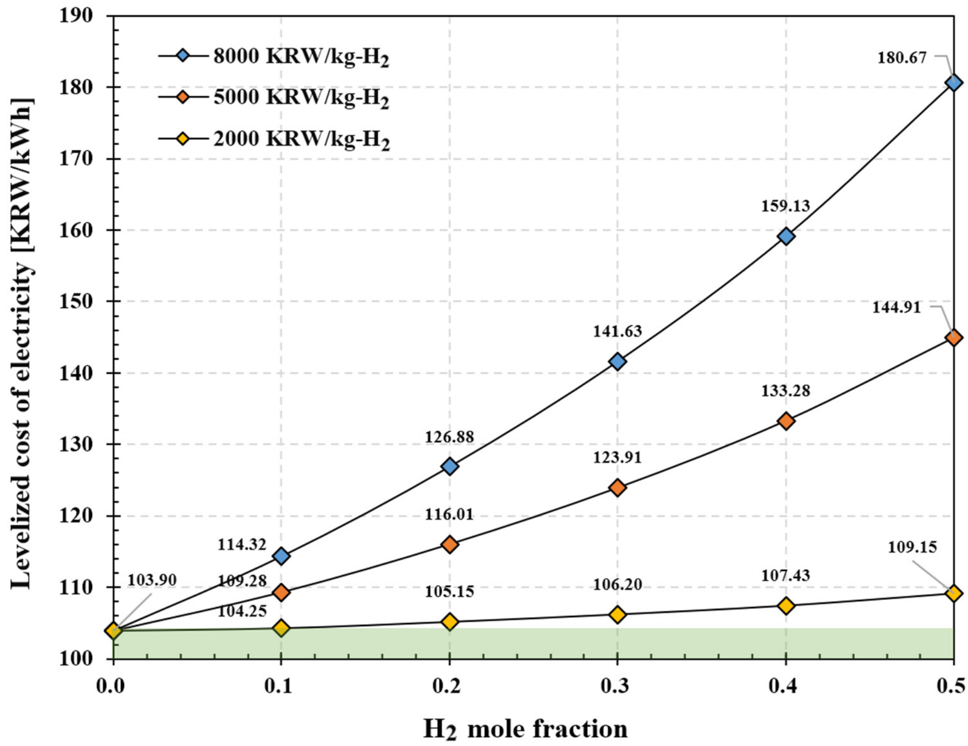

Figure 5. LCOE analysis results considering fuel blend.

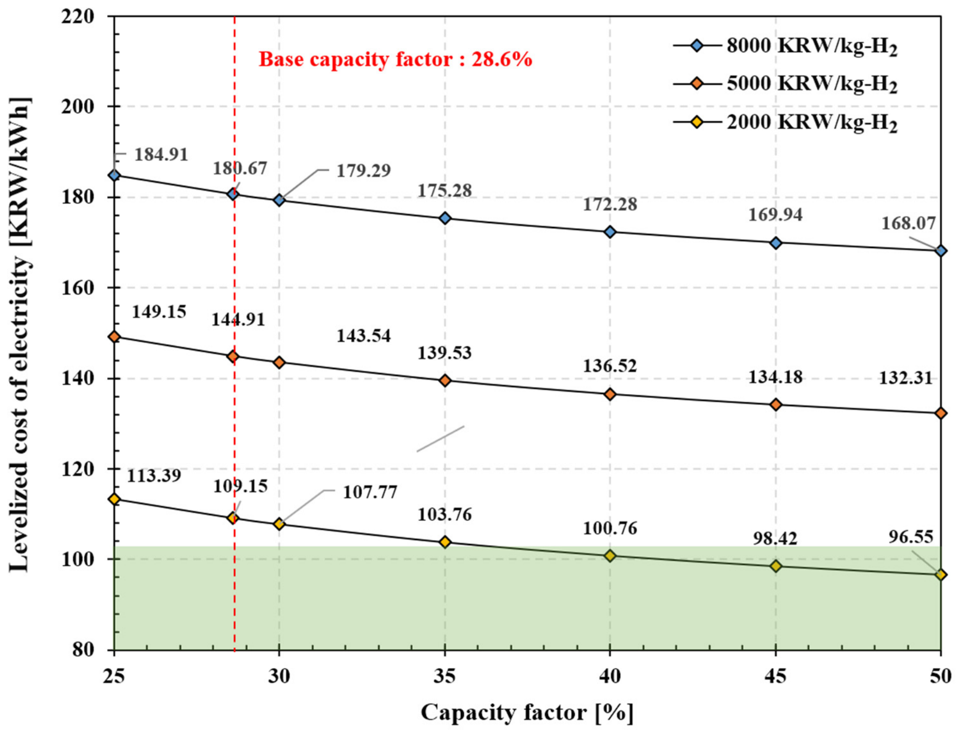

Figure 6. LCOE analysis results considering capacity factor.

Finally, Figure 8 shows the power generation required for a natural gas–hydrogen CCPP to achieve competitiveness with a CCPP that uses only natural gas as fuel. If the output of a CCPP using 2000 KRW/kg hydrogen blended in 0.5 mole fraction is 427 MW or more, it achieves competitiveness with a CCPP that only uses natural gas. The results of the process analysis conducted earlier show that the output (power generation) of a natural gas–hydrogen CCPP is 406.53 MW. If the output is increased by at least 20.47 MW by optimizing the process and improving performance, it will be possible to achieve a similar level of LCOE as a natural gas CCPP.

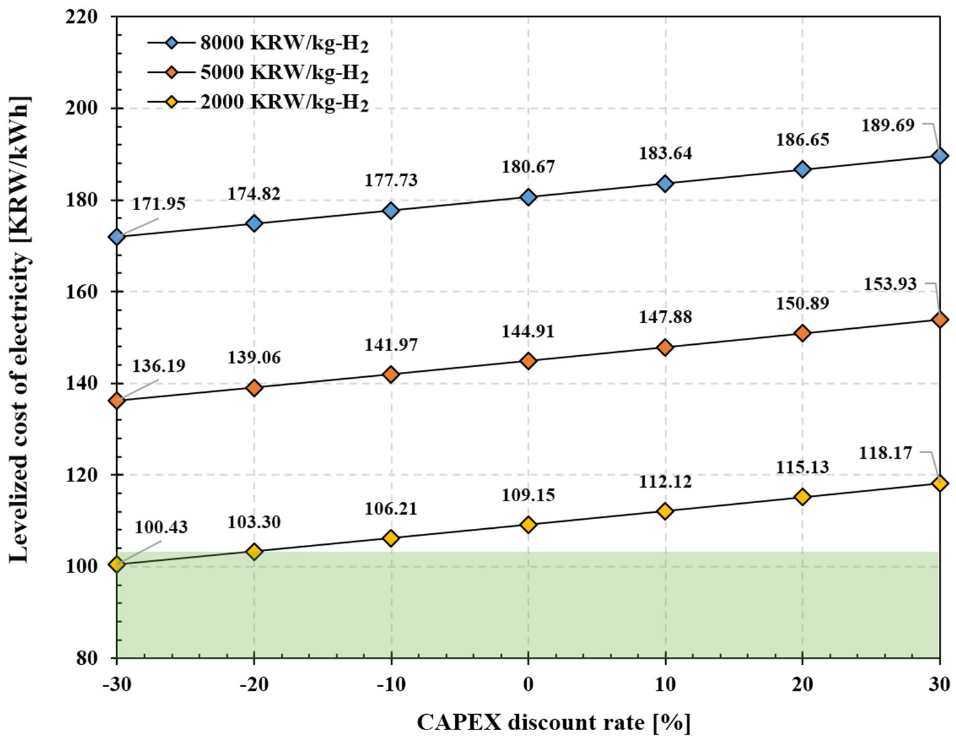

Figure 7. LCOE analysis results considering CAPEX discount rate.

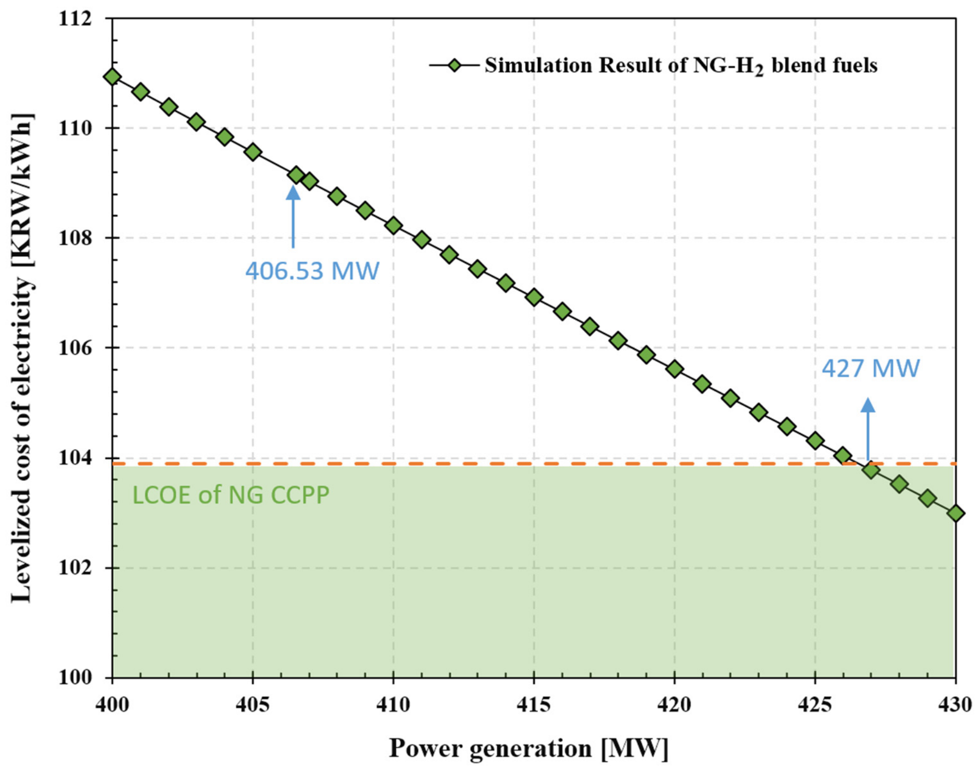

Figure 8. LCOE analysis results considering power generation.

Thus, the LCOE sensitivity analysis showed that, for a natural gas–hydrogen CCPP to secure competitiveness, it is more effective to reduce the hydrogen fuel supply price than

CAPEX and increase utilization rate. Furthermore, performance must be improved by at least 5% (20.47 MW) to secure an LCOE at the level of a natural gas CCPP.

4. Discussion

Various R&D and demonstration projects are underway to build a hydrogen ecosystem within the energy industry, from hydrogen production and storage to its transport and use. This study economically evaluated the gradual increase in hydrogen use as well as the use of natural gas–hydrogen blends that can be linked to natural gas-based CCPPs, which are used as a key power source in various countries. First, we simulated the natural gas CCPP process with 400 MW of output using ASPEN HYSYS to evaluate the benefits of using hydrogen fuel. The simulated model showed an error of around 1% by comparing the material properties of the key points of actual operation data, thereby confirming the excellence of the validation and implementation model.

Based on the validated process model, we reviewed ways to secure the economic feasibility of natural gas–hydrogen CCPPs compared with natural gas CCPPs. We completed the validation of the LCOE calculation model based on the TRR method using the commercialization costs of the operational Bundang CCPP-2. A sensitivity analysis was conducted with fuel cost, capacity factor, CAPEX, and power generation as the variables to evaluate the LCOE of natural gas–hydrogen CCPPs. The results showed that the change in LCOE was most significant according to hydrogen fuel prices, revealing that when hydrogen supply price decreases to 2000 KRW/kg, the LCOE does not change much even if hydrogen is blended into the fuel by up to 0.5 mole fraction. Hence, it will be possible to obtain an LCOE at a similar level as that of natural gas CCPPs by optimizing the process and improving performance while gradually increasing the ratio of hydrogen fuel. The capacity factor is expected to gradually increase more than 28.6% as the ratio of coal-fired power plants decreases and that of natural gas CCPPs increases within the power system in Korea. Hence, using natural gas–hydrogen blends will help to improve economic feasibility. Finally, regarding CAPEX, according to the use of hydrogen fuel, a reduction in cost is expected owing to the expansion of hydrogen-related industries and continuous technology development. Consequently, even if the amount of blended hydrogen is increased by up to 50%, natural gas–hydrogen CCPPs will be able to achieve sufficient competitiveness owing to technology development and green energy policies.

This study has a few limitations. First, the process model was validated using the operation data of natural gas CCPPs, but there is no operation data of the CCPP model using natural gas–hydrogen blends. Therefore, it is necessary to validate the reliability of the model through actual operation and experimental data in the future. Next, LCOE was analyzed by limiting the scope of variables used in economic analysis to certain values, but it is necessary to consider additional variables based on the ones confirmed in this study. Finally, it was assumed that hydrogen is blended into natural gas in certain ratios, but it is necessary to also consider specific hydrogen supply plans for future economic analysis.

Despite several limitations, this study suggested a method to secure economic feasibility of CCPP by using natural gas–hydrogen blended fuels instead of using only natural gas. In further research, we intend to analyze the probabilistic effects using methodologies such as Monte Carlo simulation for extensive economic analysis while connecting variables such as CAPEX, and capacity factor with learning rate. The cumulative probability curve using Monte Carlo will show the optimal LCOE conditions by reflecting price fluctuations in the equipment and electricity costs.

5. Conclusions

This study examined ways to secure the economic feasibility of using hydrogen fuel by simulating the process of a CCPP that uses natural gas–hydrogen blends and calculating LCOE. We increased the ratio of hydrogen in natural gas from 0 to 0.5 mole fraction and analyzed LCOE according to changes in the values of variables, such as fuel cost, capacity factor, CAPEX, and power generation. The results are as follows.

- We developed a process model for natural gasbased CCPPs and compared the material properties of each key point with operation data, which revealed an error range of around 1%, thereby completing the validation of the process model.
- When hydrogen fuel is supplied at 2000–8000 KRW/kg, the LCOE is 103.9–180.67 KRW/kWh. When it is supplied at under 2000 KRW/kg, the LCOE is 109.15 KRW/kWh even if the ratio of hydrogen blending is increased to 50%, showing a 5.0% increase from the LCOE of existing natural gas CCPPs (103.9 KRW/kWh).
- When the capacity factor of the CCPP is increased from 28.6% to at least 35% after blending 50% hydrogen at the price of 2000 KRW/kg with natural gas, the LCOE falls under 103.76 KRW/kWh, thereby ensuring price competitiveness over CCPPs using only natural gas.
- Even when CAPEX is reduced by up to 30%, the LCOE is reduced by only around 5%, not showing much of a reduction effect. However, when it is reduced by 20%, the LCOE is 103.3 KRW/kWh, which is lower than that of a CCPP that uses only natural gas.
- The process analysis showed that blending 50% hydrogen is expected to result in power generation of 406.53 MW and an LCOE of 109.15 KRW/kWh, suggesting that the same LCOE as that of existing natural gas CCPPs can be secured when net power generation is increased by 20.47 MW by optimizing the process and improving efficiency.

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Nomenclature

ADJ	Adjustment
AFUDC	Allowance for funds used during construction
BBY	Balance beginning of year
BD	Book depreciation
BFP	Boiler feedwater pump
BPV	Byproduct value
CC	Carrying charge
CCPP	Combined cycle power plant
CEP	Condensate extraction pump
CP	Cumulative probability
CRF	Capital recovery factor
DC	Direct cost
DITX	Differed income taxes
ESS	Energy storage system
FCI	Fixed capital investment
FOM	Fixed operating and maintenance
IC	Indirect cost
LCOE	Levelized cost of electricity

MACRS	Modified accelerated cost recovery system
OO	Other outlay
OTXI	Other taxes and insurance
PEC	Purchased equipment cost
PEI	Plant facilities investment
RCEAF	Recovery of common-equity AFUDC
ROI	Return of investment
SRHF	Standing reserve hourly fee
SRP	Standing reserve payment
SRSC	Standing reserve scheduled capacity
TCI	Total capital investment
TCR	Total capital recovery
TDI	Total depreciable investment
TRR	Total revenue requirement
TRRL	Total revenue requirement levelized
TXD	Tax depreciation
Subscript	
a	Annualized
ce	Common equity
d	Debt
FC	Fuel cost
j	J th year
k	Ratio of specific heats
L	Levelized
η	Net efficiency
n	Operating year
OMC	Operating and maintenance cost
ps	Preferred stock
R	Replacement
r	Pressure ratio
t	Tax rate

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