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# Thermodynamic Study on Decarbonization of Combined Cycle Power Plant

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**Abstract**

Integrating hydrogen firing and a carbon capture plant (CCP) into a natural gas combined cycle (NGCC) power plant is a promising strategy for reducing $CO_2$. In this study, process simulation in Aspen PLUS of hydrogen co-firing in a 40 MW turbine gas combined cycle power plant was done at an identical gas turbine inlet temperature from 0%.cal to 30%.cal. The evaluated cases were hydrogen co-firing with CCP (H2 Co-firing + CCP) and hydrogen co-firing without CCP (H2 Co-firing). The results showed a 6% $CO_2$ emission reduction per 5% increase in hydrogen, albeit with increased NOx emissions. H2 Co-firing experienced a decrease in net power with rising hydrogen co-firing, while H2 Co-firing + CCP saw an increase but remained below Case 2 due to the energy penalty from the carbon capture plant. The capital cost of H2 Co-firing + CCP exceeds that of H2 Co-firing due to CCP usage, impacting gross revenue. The sensitivity analysis indicated that the cost of hydrogen has higher sensitivity compared to the cost of CCP. Lowering hydrogen prices is recommended to effectively reduce $CO_2$ emissions in NGCC.

**Keywords:** *carbon capture; co-firing; combined cycle; hydrogen; natural gas.*

## Introduction

Concerns about climate change highlight the importance of a global transition to decrease greenhouse gas (GHG) emissions related to the energy industry [1]. In 2015, the Conference of the Parties 21 (COP21), also known as the Paris Agreement, expressed the worldwide reaction to climate change risks, resulting in a resolution to limit the rise in global temperature. COP7 was held in Egypt in 2022 to examine the implementation six years after COP21. The implementation of a decarbonized society is an essential and frequently discussed topic and the impetus to decarbonize is increasing in all fields, including the energy industry.

The energy sector is the most significant contributor to global GHG emissions [2]. Natural gas contributes a portion of 23% (Figure 1) for about 36.7% of total electricity generation, or 6346 TWh [3], [4]. Power generation has relatively lower difficulty in decarbonizing compared to other energy services, considering its significant contribution to global emissions [5]. Some approaches have been discussed, such as energy from municipal solid waste [6], tracking to increase solar panel power output [7], and optimization of solar energy, wind energy, and natural gas based on demand [8]. However, it is still necessary to retrofit existing fossil fuel power plants, such as natural gas combined cycle power plants by integrating co-firing with hydrogen.

Hydrogen offers several advantages over other non-carbon fuels, including high conversion efficiency, excellent combustion performance, and various production and utilization methods [9]-[11]. A novel hydrogen production method is by using a photocatalytic process [12]. At room temperature, hydrogen has a high gravimetric energy density with a heating value of 120 MJ/kg but a low volumetric energy density of 0.0108 MJ/L. Hydrogen must be stored effectively in several forms, including compressed, liquid, hydrides, adsorption, and liquid organic hydrogen carriers (LOHC).


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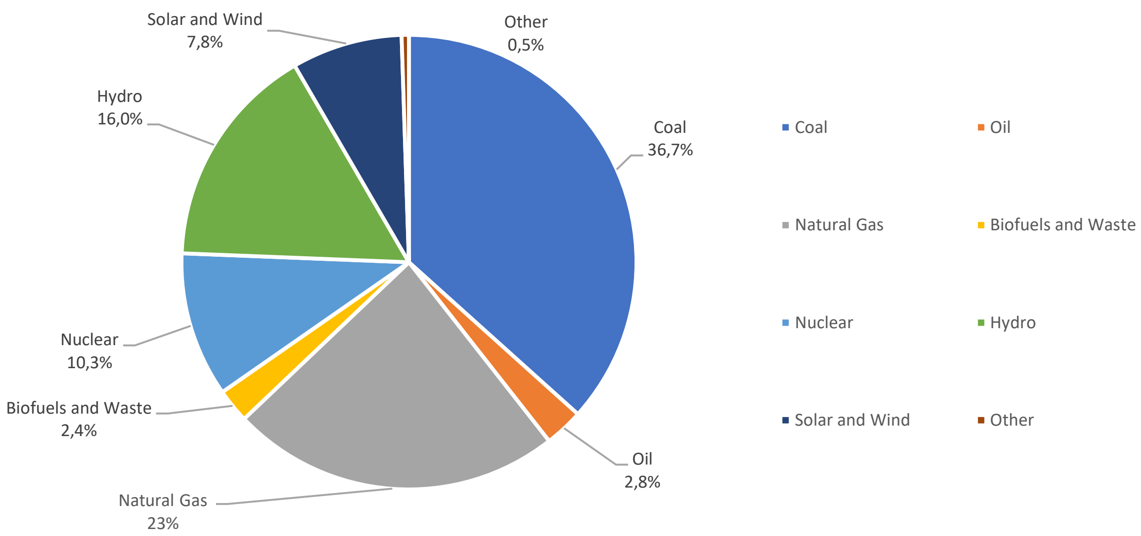


**Figure 1** Electricity production in the world [4].

Several studies on natural gas-hydrogen co-firing have been reported [13]. Mitsubishi found that gas turbine operation under a 30 vol% co-firing condition is possible [14]. The addition of hydrogen in the combustion chamber influences the process and results of combustion. Although hydrogen does not have nitrogen, increasing the hydrogen ratio in the natural gas mixture will increase NOx production. In this case, the NOx produced is of the thermal NOx type, which is produced due to the high combustion temperature [15]. The increased combustion rate will make the position of the flame in the combustion chamber rise upstream. However, this increase does not affect the combustion dynamics, such as the level of internal fluctuations or flashbacks in the combustion chamber. Based on this research, the changes in the process and combustion products due to addition of hydrogen in the combustion chamber are still acceptable [15]. Meanwhile, the optimization of the combustor design to reduce NOx and the demonstration of a 2 MW scale commercial gas turbine, namely IM270, have been reported in [16]. Stable operation of 20% co-firing with a combustion efficiency of approximately 99.87% has been reported. NOx can be controlled below the regulation limit with a de-NOx catalyst.

A 40 MWe natural gas combined cycle (NGCC) power plant unit was chosen as the research project for this study to fulfill the stated objective. Modeling with the Aspen PLUS V12.1 software was used to conduct a simulation to understand and draw conclusions on the macro aspect of hydrogen co-firing in existing NGCC power plants. The co-firing was based on the calorific value (%.cal), with a constant turbine inlet temperature, comparing different cases, including hydrogen co-firing with and without carbon capture against a conventional natural gas base case. In addition, the economic feasibility was also evaluated. The aim was to weigh the benefits and drawbacks of incorporating these innovative approaches, considering their implications on the construction, operation, maintenance expenses, natural gas consumption, and $CO_2$ emissions. By conducting a thorough economic analysis, this study sought to ascertain the economic viability and sustainability of these advanced energy strategies in the evolving landscape of power generation. Key parameters, such as hydrogen and natural gas costs, capacity factors, carbon tax, and electricity prices, were considered in this comprehensive economic evaluation. In view of the cost variance of hydrogen [17], a sensitivity analysis was also performed.

## Configuration and Modeling

### General System

The general system is shown in Figure 2. Air is compressed and burned in the combustion chamber with natural gas and hydrogen. The flue gas after the turbine is utilized for heating the steam power plant. The $CO_2$ is captured in the CCP and compressed to be transported and injected into the reservoir or utilized as a mineral.

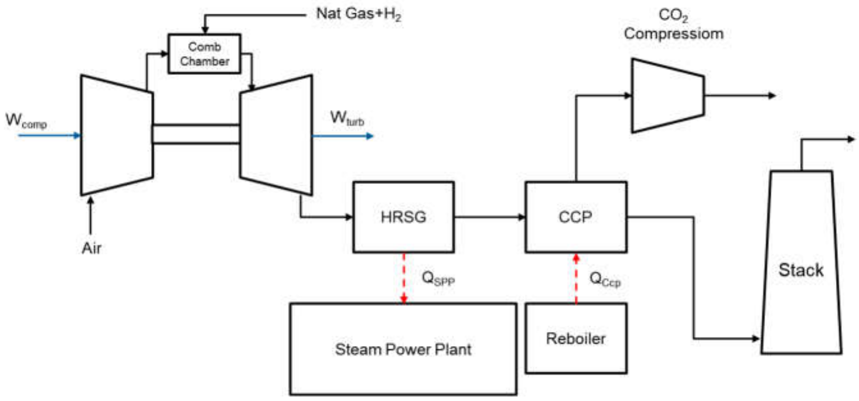


**Figure 2** General schematic of NGCC co-firing.

## NGCC Modeling

This section describes an NGCC-based system in detail based on the process flow diagram depicted in **Figure 3**. The system was analyzed using a theoretical computation and Aspen PLUS version 12.1 software modeling with identical turbine inlet temperature conditions. During the simulation, the following assumptions were used to build the system model:

1. The system of each component was analyzed at steady state.
2. Peng Robinson (PENGROB) was selected as base property for air, fuel, and exhaust gas, and ASME steam table for water and steam [18].
3. Changes in potential and kinetic energy in each system were neglected [19].
4. The mole percent of oxygen, water, carbon dioxide, nitrogen, and argon in the air was 20.33%, 2.98%, 0.03%, 75.75%, and 0.91%, respectively [20]
5. The isentropic efficiency of the turbine and compressor was 90% [21]
6. The mechanical losses and other losses were neglected [19].
7. The gas turbine power plant does not interfere with the combined cycle power plant.

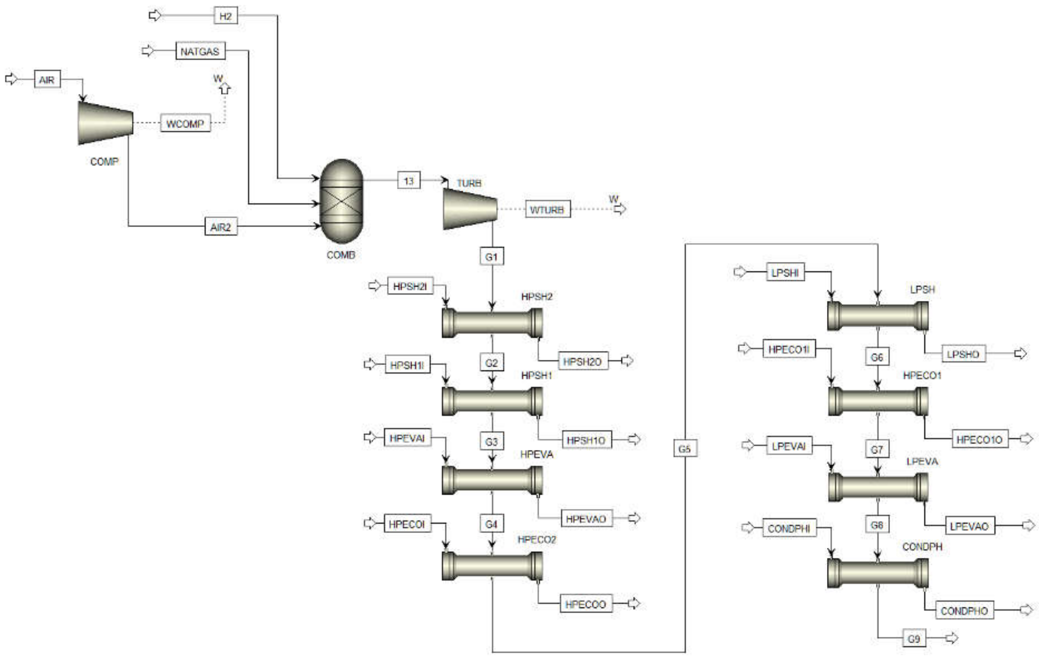

**Figure 3** Detailed NGCC system.

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The combustion of hydrogen and natural gas was performed by a COMB block (RGibbs). RGibbs is a reactor that minimizes the Gibbs free energy needed for combustion. The major natural gas and hydrogen combustion products are $H_2O$, $N_2$, $O_2$, $H_2$, CO, $CO_2$, $Cl_2$, NO, and $NO_2$. Several researchers have utilized an RGibbs reactor to predict NOx in numerous process simulations of the combustion of fuels, such as oxy-fuel combustion of coal [22], [23], combustion of syngas [24], combustion of ammonia [25], coal-ammonia combustion [26].

Combustion of hydrogen and natural gas can be carefully controlled to maintain a consistent temperature during the co-firing process [27]. This approach is crucial for preserving the structural integrity and efficiency of the combustion chamber, turbine, and other components within an NGCC power plant. Eq. (1) allows for precise calculation of the hydrogen mass needed for co-firing, ensuring an optimal balance to achieve the desired heating value while mitigating potential challenges related to excessive temperatures. Moreover, this method aligns with the goal of maximizing the overall energy output and efficiency of the power plant by leveraging hydrogen's superior heating properties without compromising the stability of the combustion process. Ultimately, this simulation approach based on the heating value facilitates a more effective and efficient integration of hydrogen co-firing within an existing NGCC system.

$$\mathrm{m_{H2}\ (ton/hr)} = \frac{\dot{\mathrm{m}}_{\mathrm{NG\ base\ case}}\mathrm{(ton/h)}\times\mathrm{LHV_{NG}\ (MJ/kg)}}{\mathrm{LHV_{H2}}} \times \%\mathrm{co-firing} \tag{1}$$

## Carbon Capture Process Modeling

Post-combustion, pre-combustion, and oxy-combustion capture are the three carbon capture process (CCP) methods that are currently available. Post-combustion capture is the most advanced method and needs the least modifications to the existing power plant [28]. Several approaches exist for post-combustion $CO_2$ capture. MEA processes were employed in this study, since they are the most developed and widespread. At a 90% $CO_2$ collection rate, its thermal energy demand is 3.85 MJ/kg $CO_2$ and its electrical energy demand is 0.1397 MWh/ton $CO_2$ [29,30]. Eq. (2) and Eq. (3) were used to determine the electric power and thermal energy consumption, respectively.

$$\dot{\mathrm{Q}}_{\mathrm{CCP}}(\mathrm{MW_{th}})=\dot{\mathrm{m}}_{\mathrm{CO_2}}(\mathrm{kg/s})\times 3.85\ (\mathrm{MJ/kg}) \tag{2}$$

$$\dot{\mathrm{W}}_{\mathrm{CCP}}\ (\mathrm{MW_e})= \dot{\mathrm{m}}_{\mathrm{CO_2}}(\mathrm{ton/h})\times 0.1397\ (\mathrm{MWh/ton}) \tag{3}$$

Due to the low temperature of flue gas, a new boiler is needed. The reboiler of a CCP uses natural gas with an efficiency of 85.7% and an emission of 50.29 kg $CO_2$/TJ [31].

## Economic Modeling

The installation of CCP equipment and hydrogen co-firing increases construction and operation costs and maintenance (O&M) expenses but reduces natural gas consumption and $CO_2$ emissions. The purpose of the economic study was to evaluate the economic advantages of hydrogen co-firing with carbon capture relative to the basic case and decide which is economically superior. The economic possibility of adding hydrogen co-firing and carbon capture to the regular GTCC was thus evaluated. The case to be reviewed is depicted in Table 1.

**Table 1** Evaluated case.

| Case | Base Case | H2 co-firing++CCP | H2 co-firing |
|---|---|---|---|
| Description | 100% Natural Gas | Hydrogen Co-firing with CCP | Hydrogen Co-firing without CCP |

Some assumptions were used in this economic modeling. Blue hydrogen from natural gas was used due to being more economically feasible and producing less emissions than gray hydrogen. The cost of the blue hydrogen used was 1.9 USD/kg, while the cost of the natural gas was 6 USD/GJ [9]. An NGCC has a capacity factor of 85% or 7446 working hours per year [32]. The carbon tax is 2.1 USD/ton $CO_2$ [33]. The electricity price is based on PLN, i.e., 74.5 USD/MWh [34], and the selling price of electricity, operating and maintenance costs, and capacity factor were considered constant each year. The parameters for economic modeling are shown in Table 2. The unit capital cost of an NGCC was used for the cost of operation and maintenance (O&M) of the base case. The gas turbine has a modification or retrofit cost to accommodate hydrogen co-firing. The carbon capture plant (CPP) cost was assumed based on the regression graph in Pieri & Angelis-Dimaskis [35]. The regression graph was used to accommodate the change in $CO_2$ emissions when hydrogen is co-fired in an NGCC power plant. Meanwhile, the cost for the reboiler was evaluated based on IEA-ETSAP [31].

**Table 2** Parameter for economic modeling.

| Component | Parameter | Cost | Source |
|---|---|---|---|
| NGCC | Unit capital cost ($U_{NGCC}$) | 769.97 USD/kW | [37] |
| | Unit gas turbine capital cost ($U_{GT}$) | 218.4 USD/kW | [37] |
| | Unit gas turbine revision cost ($U_{RE}$) | 40% of $U_{GT}$ | [38] |
| | O&M Cost | 4% of $U_{NGCC}$ | [39] |
| CCP | Unit Capital Cost ($U_{CCP}$) | 137.4 [$CO_2$ Captured in $MtCO_2$/y]$^{2.263}$ M USD | [35] |
| | O&M Cost (in M$) | 9.276 $10^6$ [$CO_2$ Captured in $MtCO_2$/y]$^{1.419}$ M USD | [35] |
| Reboiler | Unit Capital Cost ($U_{RB}$) | 6000 USD+22.9 ($kW_{th}$-2620) | [31] |
| | O&M Cost | 1% of $U_{RB}$ | [31] |

Eqs. (4) and (5) were used to evaluate the capital cost needed and the operation and maintenance costs, respectively. Due to the higher hydrogen cost, the fuel cost will be higher when the hydrogen co-firing ratio is higher. The operation cost also depends on the net power, including the energy penalty due to the carbon capture and the hydrogen used in the NGCC. Meanwhile, the gross revenue was calculated based on Eq. (6). The capital cost was revised based on the CEPCI index in late 2021 (776.9) [36].

$$\text{Capital Cost} = U_{RE}+U_{CPP}+U_{RB} \tag{4}$$

$$\text{O\&M Cost} = O\&M_{NGCC}+O\&M_{CPP}+O\&M_{RB}+(H_2\ \text{Cost}\cdot \dot{m}_{H2}+\text{NG Cost}\cdot\dot{m}_{NG})\ 7466\ \text{hours}\cdot(\dot{W}_{net\ NGCC}-\dot{W}_{CCP}) \tag{5}$$

$$\text{Gross Revenue} = 7466\ \text{hours}\cdot(\dot{W}_{net\ NGCC}-\dot{W}_{CCP})\cdot\text{electricity price-O\&M Cost-Carbon Tax} \tag{6}$$

## Result and Discussion

### Simulation Model

Tables 3 and 4 were used to simulate the NGCC. An H-25 Turbine was used in the power plant. The compression ratio of the compressor was eight and the natural gas components consisted mainly of $CH_4$. The heat recovery steam generator (HRSG) had eight heat exchangers and was not modeled.

**Table 3** Natural gas and NGCC parameters.

| Natural Gas Component | Mole Fraction | Cycle Parameter | Value |
|---|---|---|---|
| $CH_4$ | 77.37% | Natural Gas Mass Flow Rate [ton/h] | 7.24 |
| $C_2H_6$ | 8.01% | Natural Gas Temperature [°C] | 27 |
| $C_3H_8$ | 4.75% | Natural Gas Pressure [bar] | 8 |
| $C_4H_{10}$ | 2.21% | Air Mass Flow Rate [ton/h] | 333.1 |
| $C_5H_{12}$ | 0.88% | Air Temperature [°C] | 27 |
| $C_6H_{14}$ | 0.50% | Air Pressure [bar] | 1 |
| C | 0.94% | Compression Ratio | 8 |
| $N_2$ | 0.51% | | |
| $CO_2$ | 4.84% | | |

**Table 4** HRSG parameters.

| HRSG | $\dot{m}$ [ton/h] | Inlet | | Outlet | |
|---|---|---|---|---|---|
| | | T [°C] | p [bar] | T [°C] | p [bar] |
| HP Superheater 2 | 43.9 | 358.41 | 57.53 | 511.4 | 51.75 |
| HP Superheater 1 | 43.63 | 272.9 | 57.53 | 436.93 | 57.53 |
| HP Evaporator | 43.63 | 272.9 | 57.53 | 272.9 | 57.53 |
| HP Economizer 2 | 43.63 | 194.58 | 57.53 | 257.9 | 57.53 |
| LP Superheater | 8.84 | 150 | 4.76 | 220.4 | 4.76 |
| HP Economizer 1 | 43.63 | 150 | 57.53 | 239.68 | 57.53 |
| LP Evaporator | 8.84 | 150 | 4.76 | 150 | 4.76 |
| Condensate Preheater | 65.52 | 60.1 | 4.76 | 137.7 | 4.76 |

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Table 5 shows the simulation result at 100% natural gas combustion. After the compressor, the temperature of the air becomes 303.78 °C, and the combustion temperature is 1079.18 °C. The result of the process simulation of the selected NGCC power plant was compared to its design value to validate the simulation approach. Table 6 includes the LHV of natural gas, the net power of the gas turbine, the temperature of flue gas flowing to the HP Superheater 2, and the temperature of the flue gas to stack for the natural gas combined cycle power plant analyzed.

**Table 5** Simulation results at 100% natural gas.

| Parameter | AIR2 | G0 | G1 | G9 |
|---|---|---|---|---|
| T (°C) | 303.78 | 1079.18 | 605.02 | 109.94 |
| p (Bar) | 8 | 8 | 1 | 1 |
| | Mass flow (kg/s) | Mass flow (kg/s) | Mass flow (kg/s) | Mass flow (kg/s) |
| CH4 | 0.00 | 0.00 | 0.00 | 0.00 |
| O2 | 20.46 | 13.49 | 13.49 | 13.49 |
| H2O | 1.69 | 5.33 | 5.33 | 5.33 |
| CO2 | 0.04 | 5.34 | 5.34 | 5.34 |
| N2 | 66.73 | 66.73 | 66.73 | 66.73 |
| AR | 1.14 | 1.14 | 1.14 | 1.14 |
| C2H6 | 0 | 0 | 0 | 0 |
| C3H8 | 0 | 0 | 0 | 0 |
| C | 0 | 0 | 0 | 0 |
| BUTANE | 0 | 0 | 0 | 0 |
| PENTANE | 0 | 0 | 0 | 0 |
| HEXANE | 0 | 0 | 0 | 0 |
| NO | 0 | 4.42e-2 | 4.42e-2 | 4.42e-2 |
| NO2 | 0 | 1.27e-3 | 1.27e-3 | 1.27e-3 |
| CO | 0 | 1.39e-6 | 1.39e-6 | 1.39e-6 |
| H2 | 0 | 0 | 0 | 0 |
| Total mass flow (kg/s) | 90.07 | 92.08 | 92.08 | 92.08 |
| Volume flow (cum/s) | 18.90 | 45.76 | 237.42 | 103.51 |

The largest relative error was found in the flue gas temperature flowing to the HP Superheater (2.65%). These deviations were caused by the gas turbine's heat loss assumption. Significant flue gas property parameter variances were all within the permitted range, showing that the modeling method and simulation process accurately replicated the NGCC system's actual process.

**Table 6** Comparison of parameters from the simulation results and the design.

| Parameter | Simulation | Design | Relative Error |
|---|---|---|---|
| LHV NG [MJ/kg] | 43.74 | 43.67 | 0.16% |
| $W_{net}$ Gas Turbine [kW] | 28195 | 27920 | 0.98% |
| Flue gas to HP Superheater 2 temperature [°C] | 605. | 568 | 6.52% |
| Flue gas flowing to stack temperature [°C] | 110 | 107.1 | 2.65% |

## Thermodynamic Analysis

The net power decreases in Case 2 (H2 Co-firing), while it increased in Case 1 (H2 Co-firing + CCP), as depicted in Figure 4. The net power decreases from 41.5 MW in H2 co-firing only due to less total mass flows into the turbine, as shown in Table 7. Hydrogen combustion requires less oxygen; therefore, less air is supplied to maintain the furnace temperature. The constant temperature of combustion gas with a smaller mass flow rate and constant GT exhaust temperature results in a decreasing power output of GT. This finding aligns with Shih et al. [40], that when the hydrogen percentage increases, there is a reduction of the high temperature region in the primary zone due to the lower heat release. However, the net power in the H2 Co-firing + CCP case increases due to the decrease of the energy penalty, which is much higher than the decrease of the turbine power because of less flue gas being used. However, the total energy produced in the H2 Co-firing + CCP is case still lower than in the base case. This result is not in line with previous research, which highlighted that the injection of hydrogen can enhance power generation in co-firing scenarios [27],[41]. This is due to the different method of co-firing than in this research, where the co-firing was based on the calorific value, while co-firing in [27] and [41] was based on mass rate.

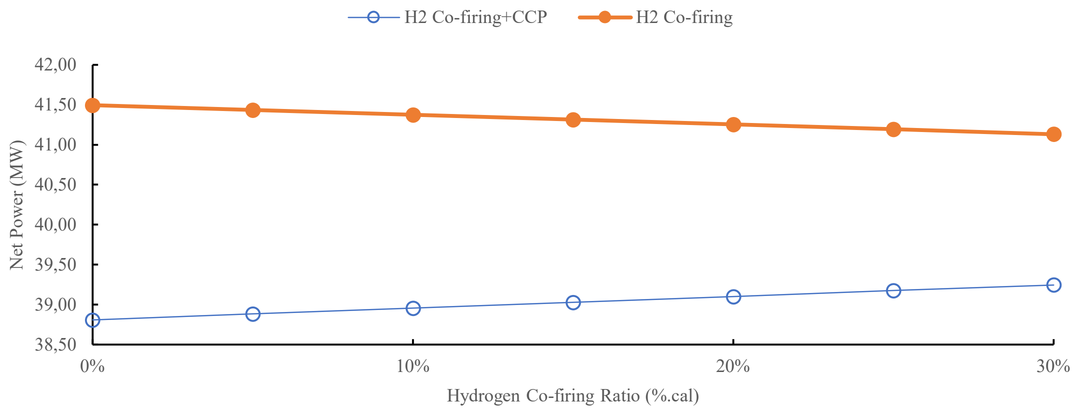


**Figure 4** Net power comparison for each case.

$CO_2$ emission decreases by about 6% per 5%.cal, as shown in Figure 5a. This is because of the reduced carbon carrier gas, i.e., natural gas. With a CCP, the $CO_2$ is reduced to 90%. The primary concern associated with hydrogen combustion is the emission of nitrogen oxides (NOx), primarily in the form of thermal NOx generated through the Zeldovich mechanism. NO is the dominant constituent of NOx emissions, with minimal proportions of $NO_2$ and $N_2O$. The sensitivity analysis highlighted that NO formation is driven by the interaction of O and OH radicals. It is concluded that the main component of NOx emission is NO, while $NO_2$ and $N_2O$ exist only at small fractions [42]. The $NO_x$ emission increases by about 6.2 ppm per 1%.cal of hydrogen from 461.7 ppm. As depicted in Figure 5b, the relative NOx increases remain minimal. Emphasizing relative NOx is essential, as RGibbs does not account for combustion chamber dimensions or inlet conditions. Notably, modern advancements in combustion technologies, such as premixed and staged combustion, typically maintain NOx concentrations below 25 ppm. With a similar furnace temperature, the NOx increases due to the larger concentration of OH radicals existing when the hydrogen fraction in the fuel is higher [43]-[45]. In addition, the excess $O_2$ increases along the hydrogen co-firing ratio. Higher excess oxygen provides more opportunities for nitrogen and oxygen to form NOx. However, in terms of NOx emission per net power in gr/kwh, hydrogen co-firing only has a lower value due to the higher net power.

**Table 1** Some main parameters of the simulation.

| Parameter | Hydrogen co-firing ratio (%.cal) | | | | | | |
|---|---|---|---|---|---|---|---|
| | 0% | 5% | 10% | 15% | 20% | 25% | 30% |
| Natural Gas Mass Flow [ton/hr] | 7.24 | 6.88 | 6.52 | 6.15 | 5.79 | 5.43 | 5.07 |
| Hydrogen Mass Flow [ton/hr] | 0 | 0.12 | 0.25 | 0.37 | 0.49 | 0.62 | 0.74 |
| Air Mass Flow [ton/hr] | 324.24 | 322.92 | 321.61 | 320.29 | 318.97 | 317.66 | 316.34 |
| Total Mass Flow [ton/hr] | 331.48 | 329.92 | 328.37 | 326.81 | 325.25 | 323.71 | 322.15 |
| Excess $O_2$ [%] | 12.97 | 13.00 | 13.03 | 13.06 | 13.10 | 13.13 | 13.16 |
| Furnace Temperature [°C] | 1079.2 | 1079.2 | 1079.2 | 1079.2 | 1079.2 | 1079.2 | 1079.2 |
| Stack Temperature [°C] | 109.9 | 108.0 | 105.9 | 103.9 | 101.9 | 99.9 | 97.8 |
| Compressor Power [MW[ | 25.96 | 25.86 | 25.75 | 25.65 | 25.54 | 25.44 | 25.33 |
| Gas Turbine Power [MW] | 54.16 | 53.99 | 53.83 | 53.66 | 53.49 | 53.33 | 53.16 |
| Steam Turbine Power [MW] | 13.30 | 13.30 | 13.30 | 13.30 | 13.30 | 13.30 | 13.30 |
| Energy Penalty [MW] | 2.69 | 2.55 | 2.42 | 2.29 | 2.15 | 2.02 | 1.89 |
| Net Power H2 Co-firing [MW] | 41.49 | 41.43 | 41.37 | 41.31 | 41.25 | 41.19 | 41.13 |
| Efficiency H2 Co-firing [%] | 42.77 | 42.70 | 42.64 | 42.58 | 42.52 | 42.46 | 42.39 |
| Net Power H2 Co-firing + CCP [MW] | 38.81 | 38.88 | 38.95 | 39.03 | 39.10 | 39.17 | 39.25 |
| Efficiency H2 Co-firing + CCP [%] | 40.00 | 40.07 | 40.15 | 40.22 | 40.30 | 40.37 | 40.45 |

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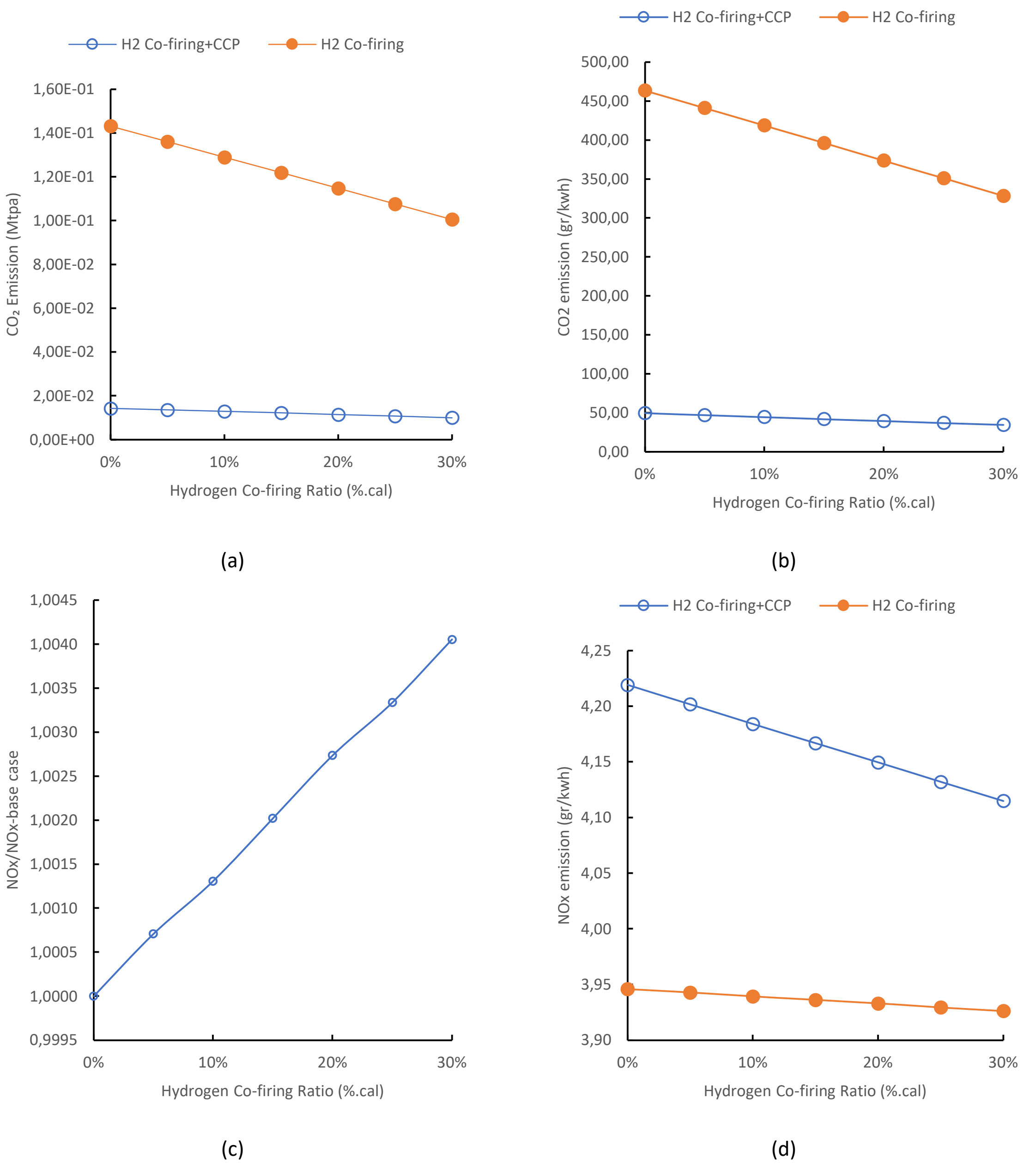


**Figure 5** Emissions for Case 1 and Case 2. (a) CO2 emission in Mtpa (million ton per annum); (b) $CO_2$ emission in gr/kwh; (c) relative NOx emission; (d) NOx emission in gr/kwh.

The change in flue gas temperature will also influence the heat exchange in the HRSG. One of the parameters that can be discussed is each heat exchanger's log mean temperature difference (LMTD). With an assumption of the counterflow heat exchanger, it was found that the LMTD of HRSG decreases with an increase of the hydrogen co-firing ratio, as shown in Figure 6. The result shows that the heat exchange would decrease, leading to a decrease in the steam outlet temperature. Modification of the HRSG heat exchanger may be needed to keep the energy output of the steam cycle.

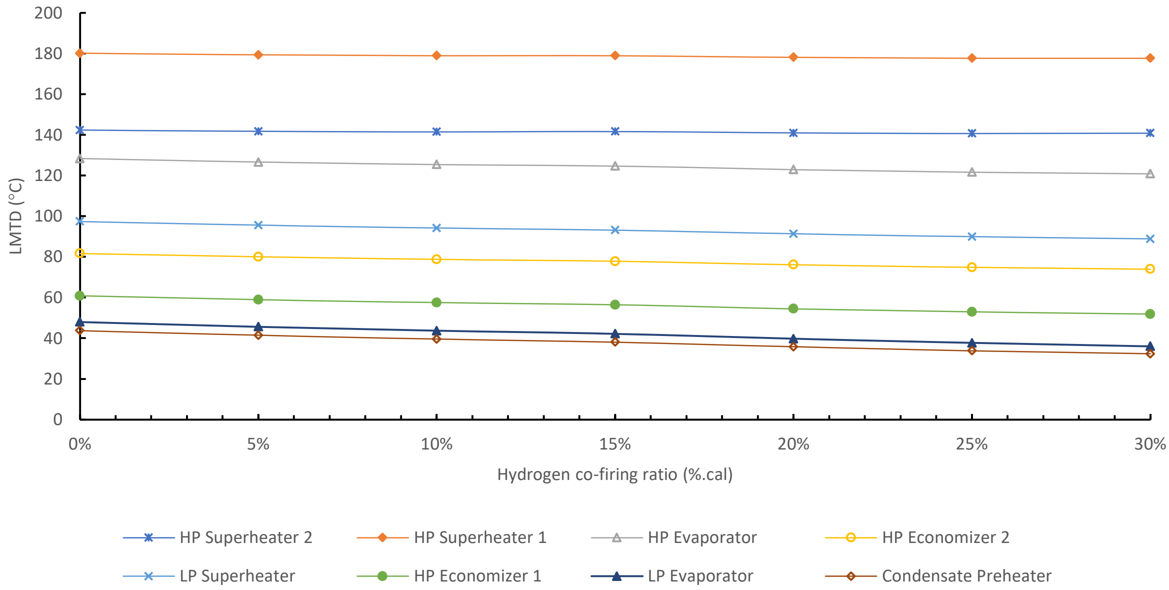


**Figure 6** Logarithmic mean temperature difference of each heat exchanger in the HRSG.

## Economic Analysis

The capital costs for Case 1 and Case 2 are shown in Figure 7. Case 2 has a much lower capital cost than Case 1 because there is only a gas turbine revision cost. Meanwhile, for Case 1, the cost will be lower with an increase in hydrogen co-firing due to the smaller carbon capture plant and the smaller reboiler. Figure 7 also shows that the carbon capture plant still has higher cost to implement than hydrogen co-firing.

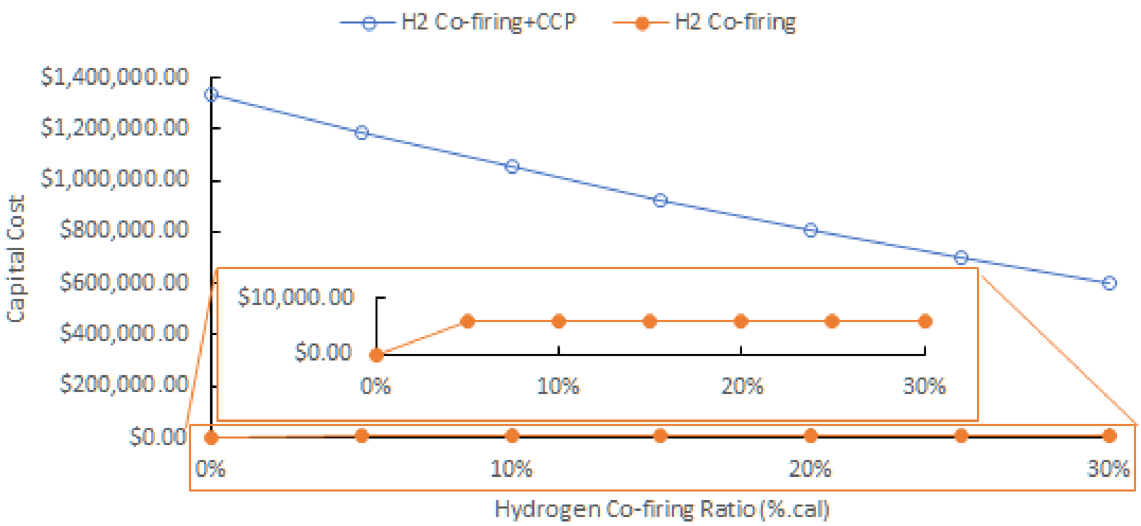


**Figure 7** Capital cost estimation.

The operation and maintenance (O&M) cost increases in both cases, as shown in Figure 8. This is because most of the O&M cost comes from fuel costs. Hydrogen prices are still high. Therefore, the fuel cost increases with the increase of the hydrogen co-firing ratio.

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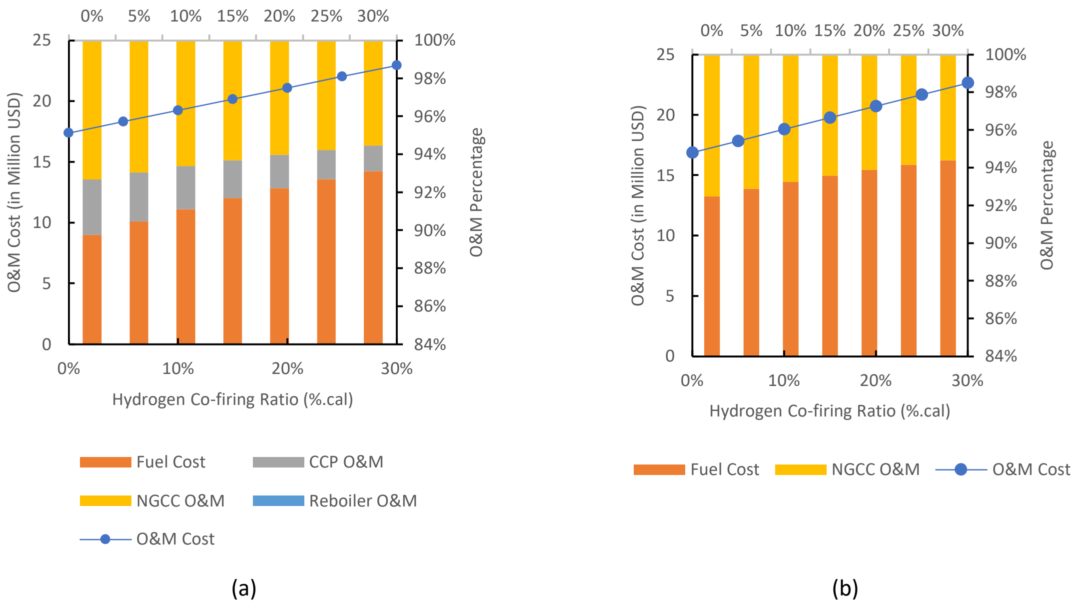


**Figure 8** Operation and maintenance cost: (a) H2 Co-firing + CCP (b) H2 Co-firing.

From the gross revenue point of view, Case 2 was found to be better than Case 1, as shown in Figure 9. With no carbon capture, gross revenue decreases about 17.7 million USD per 1%.cal of hydrogen. Meanwhile, with carbon capture, the gross revenue decreases about 19.6 million USD per 1%.cal of hydrogen.

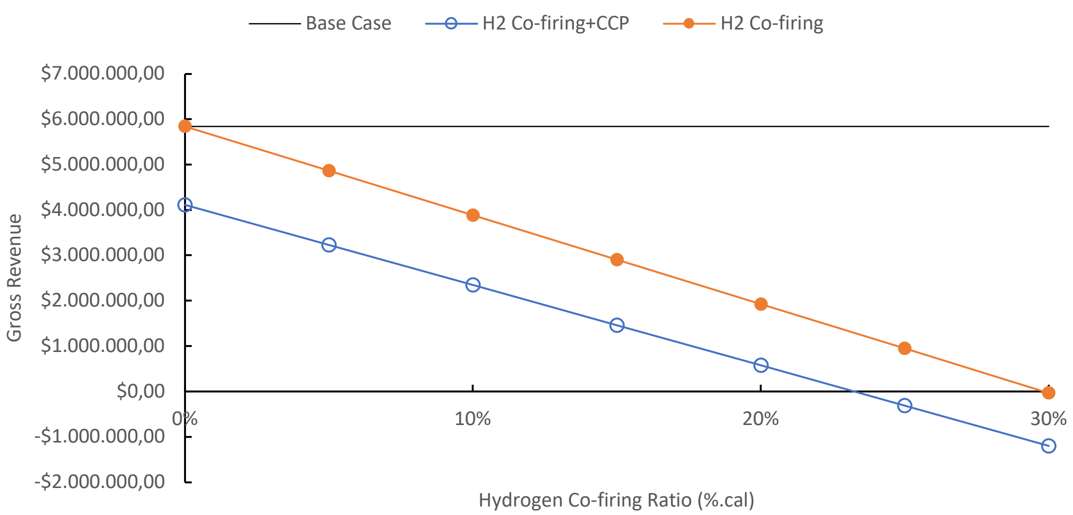


**Figure 9** Gross revenue.

A sensitivity analysis of hydrogen, natural gas, and CCP costs was done for 10%.cal of hydrogen. The result is shown in Figure 10. At a low hydrogen co-firing ratio, natural gas has the most influence on gross revenue, followed by hydrogen cost and carbon capture plant operation and maintenance cost. It was concluded that reducing carbon capture is not enough to increase the gross revenue, but the reduction of CCP will significantly influence the capital cost.

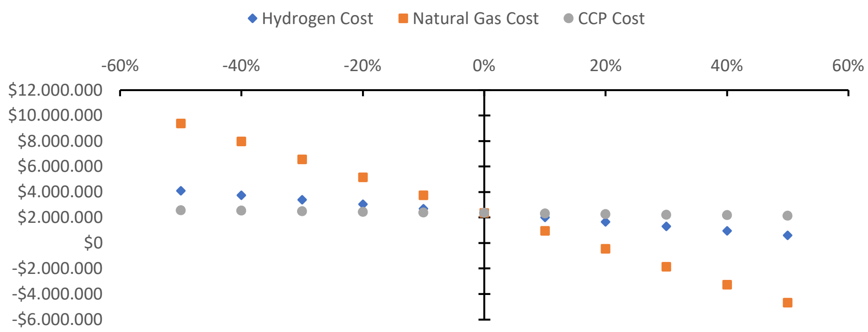


**Figure 10** Sensitivity analysis of gross revenue for 10%.cal of hydrogen.

The sensitivity analysis of natural gas cost and hydrogen cost for Case 1 for 10%.cal of hydrogen with gross revenue is shown in Figure 11. In this sensitivity analysis, green hydrogen was used, which has a projection of reduced cost in the future [9]. It was shown that a competitive hydrogen cost is 0.9 USD/kg when the natural gas cost is above 6 USD/GJ.

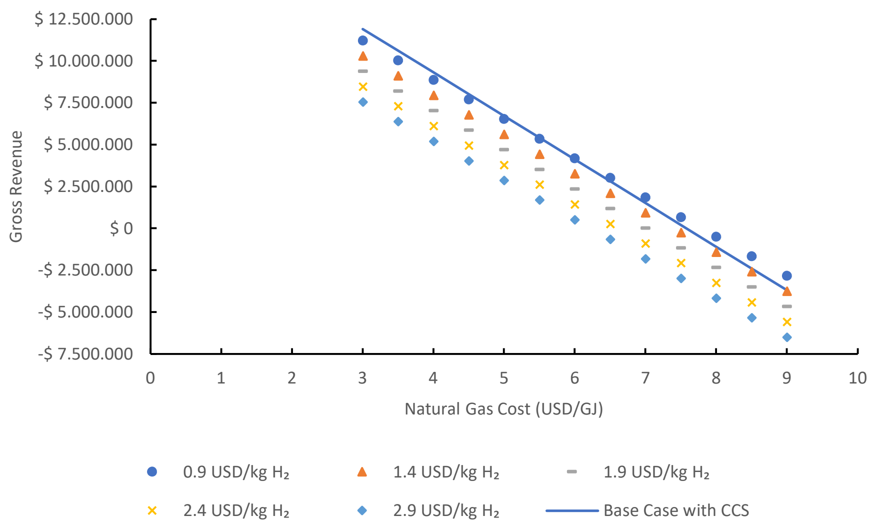


**Figure 11** Sensitivity analysis of natural gas and hydrogen costs on gross revenue for 10%.cal of hydrogen.

## Conclusion

The process simulation of natural gas and hydrogen co-firing showed that hydrogen co-firing in a natural gas combined cycle power plant can reduce $CO_2$ emissions. The net power will increase for hydrogen co-firing with CCP but stays below the base case due to the energy penalty. Meanwhile, the net power will decrease without carbon capture by 1.2 MW per 1%.cal of hydrogen. The NOx emission will increase by around 6.2 ppm per 1%.cal of hydrogen. There is a decrease in the log mean temperature difference in the heat recovery steam generator (HRSG). Therefore, modification of the HRSG may be needed. The capital and operation-maintenance costs of hydrogen co-firing with a CCP are higher than hydrogen co-firing only. The maximum co-firing rate from an economic viewpoint is around 24% for hydrogen co-firing with a CCP. Meanwhile, hydrogen co-firing has a maximum rate of only 30%. The hydrogen cost is more sensitive than the carbon capture cost. Therefore, lowering the cost of hydrogen is recommended to make the decarbonization of combined-cycle power plants more feasible.

A more detailed investigation may be pursued, incorporating computational fluid dynamics (CFD) to delve deeper into the mechanisms at play. Notably, the levels of NOx emissions observed are notably higher than what

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is typically seen with current gas turbine technology. This disparity can be attributed to one key factor: the current modeling approach, as observed in the work of the RGibbs reactor, does not adequately consider the dimensions and inlet locations of the fuel and air within the combustion process.

To enhance accuracy, it is imperative to account for critical aspects like the laminar burning velocity and combustion stability in the modeling. These elements are pivotal in comprehending the intricacies of hydrogen co-firing and its interplay with the NGCC system. Addressing challenges related to combustion stability, flame stability, and control mechanisms needs to be done, especially at different co-firing ratios and operating conditions to ensure reliable and safe operations. By incorporating these factors into our modeling and simulation, we can gain deeper insight into the combustion dynamics and NOx formation, providing a more nuanced understanding of the system's behavior and enabling more precise predictions.

Moreover, it is imperative to meticulously assess, and devise retrofitting strategies aimed at modifying prevailing natural gas infrastructure and power facilities to seamlessly accommodate hydrogen co-firing, carefully accounting for material compatibility and component integration. Equally crucial is a comprehensive examination of the hydrogen supply chain, encompassing robust infrastructure development for hydrogen storage, transportation, and distribution. Addressing potential hurdles related to hydrogen embrittlement and identifying optimal storage solutions is vital in ensuring the safety and effectiveness of the supply chain. Furthermore, investigating sustainable and economically viable approaches for hydrogen production, including the generation of green hydrogen from renewable energy sources, is essential to establish a dependable and eco-friendly hydrogen supply.

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