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Natural Gas Combined Cycle Power Plant Integrated to Capture Plant

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ABSTRACT: A natural gas combined cycle (NGCC) power plant with capacity of about 430 MW integrated to a chemical solvent absorber/stripping capture plant is investigated. The capture ratio is 90%, and the captured CO_2 is compressed to 75 bar, liquefied, and finally pumped up to 110 bar. Both full load and partial load conditions are studied. The energy penalty for CO_2 capture is 398.4 kWhel/ton of CO_2, which causes a 7.5%-points reduction in the power plant net efficiency. From this energy penalty, 4.6%-points is related to the steam extraction and 2.9%-points is related to electricity consumption. The integration of the power plant with the compression section of the capture plant for preheating the water to the heat recovery steam generator (HRSG) will not improve the net plant efficiency. From the partial load investigation, the net efficiency of the variable IGVs gas turbine is shown to be about 6.2%-points higher than the efficiency of the constant IGVs gas turbine at 50% load. Also, the power plant with the throttled valve configuration for steam extraction has a better performance than the sliding configuration steam extraction.

1. INTRODUCTION

Fossil fuel-fired power plants are one of the largest sources of anthropogenic CO_2 emission. Fossil fuels are the main component of the world's energy resources at the moment, and they are increasing in the future.[1] Therefore, the amount of CO_2 emitted is expected to increase in the decades to come if nothing is done. For stabilizing the concentration of CO_2 in the atmosphere, carbon capture and storage (CCS) is necessary besides other actions such as increasing the efficiency of power production and use and increasing the nuclear and renewable energy share.

Natural gas is one of the main sources of energy today and in the future. The natural gas combined cycle (NGCC) is an advanced power generation technology that improves the fuel efficiency of natural gas. NGCC power plants have the highest efficiency among the fossil fuel power plants for electricity production.[2−4] In addition, the CO_2 production rate of an NGCC plant is less than half that of a coal-based power plant with the same power production.[3,4] Although the CO_2 emissions from a NGCC plant are lower than those for coal power plants, they should still be considered as big CO_2 emitters. Postcombustion capture and storage technologies based on chemical absorption/stripping are mature technologies and can be integrated with an NGCC power plant.

There are many studies on stand-alone CO_2 capture plants, but the number of studies on integrated capture and power plants is quite small. Also, most of these studies were done on coal power plants. Sanpasertparnich et al. investigated an 800 MW supercritical coal-fired power plant using process simulators. They investigated the energy consumption of a capture plant for different coals. In addition, the effects of different capture ratios and partial pressures of CO_2 were investigated.[5] Cifre et al. studied a 600 MW hard coal and a 1000 MW lignite power station integrated with a capture plant. They used the EBSILON software for their simulations and investigated the effect of different parameters such as column size, solvent mass flow rate, operating pressure, and temperature of the power plant cycle, and they could reduce the energy penalty by 1−3% by optimizing the operating conditions.[6] Aroonwilas and Veawab investigated a supercritical coal power plant. They used both a conventional and a split flow configuration with MEA and a MEA-MDEA blend for the CO_2 capture plant. They also investigated the effect of different capture ratios and partial flue gas capture on the energy efficiency.[7] Pfaff et al. used EBSILON software to model a 600 MW coal power plant in full load condition. They evaluated the adaptation of pressure levels in the water−steam cycle regarding the steam requirements of the CO_2 capture plant. They also investigated the heat integration of the condenser and compressor intercooler of CO_2 compression section in the capture plant to preheat the water in the power plant. This integration could increase the net efficiency by 0.31%-points for each case.[8] Liebenthal et al. investigated the quantity and quality of the heat duty needed for solvent regeneration on the energy penalty. They also quantified the energy penalty attributed to the additional cooling and power duty and correlated the impact of the heat, cooling, and electricity duty of postcombustion CO_2 capture processes on the net output of a steam power plant in a holistic approach.[9]

There are only a few publication for NGCC integrated to a CO_2 capture plant. Jonshagen et al. studied the effect of exhaust gas recirculation (EGR) to increase the CO_2 content of the flue gas for reducing the CO_2 capture energy penalty. They found that a 40% EGR ratio could increase the CO_2 concentration from 4 to 8 vol % and the flue gas flow rate decreased about 40%. In addition, the net efficiency is increased by using hot water as a part of the reboiler duty.[10]

In the mentioned studies, only full load conditions were investigated. In this work, we investigate the integrated NGCC at both full load and partial load, and the effect of capture plant on the power plant is investigated. Also, the efficiency change is investigated if the power plant does not operate at design

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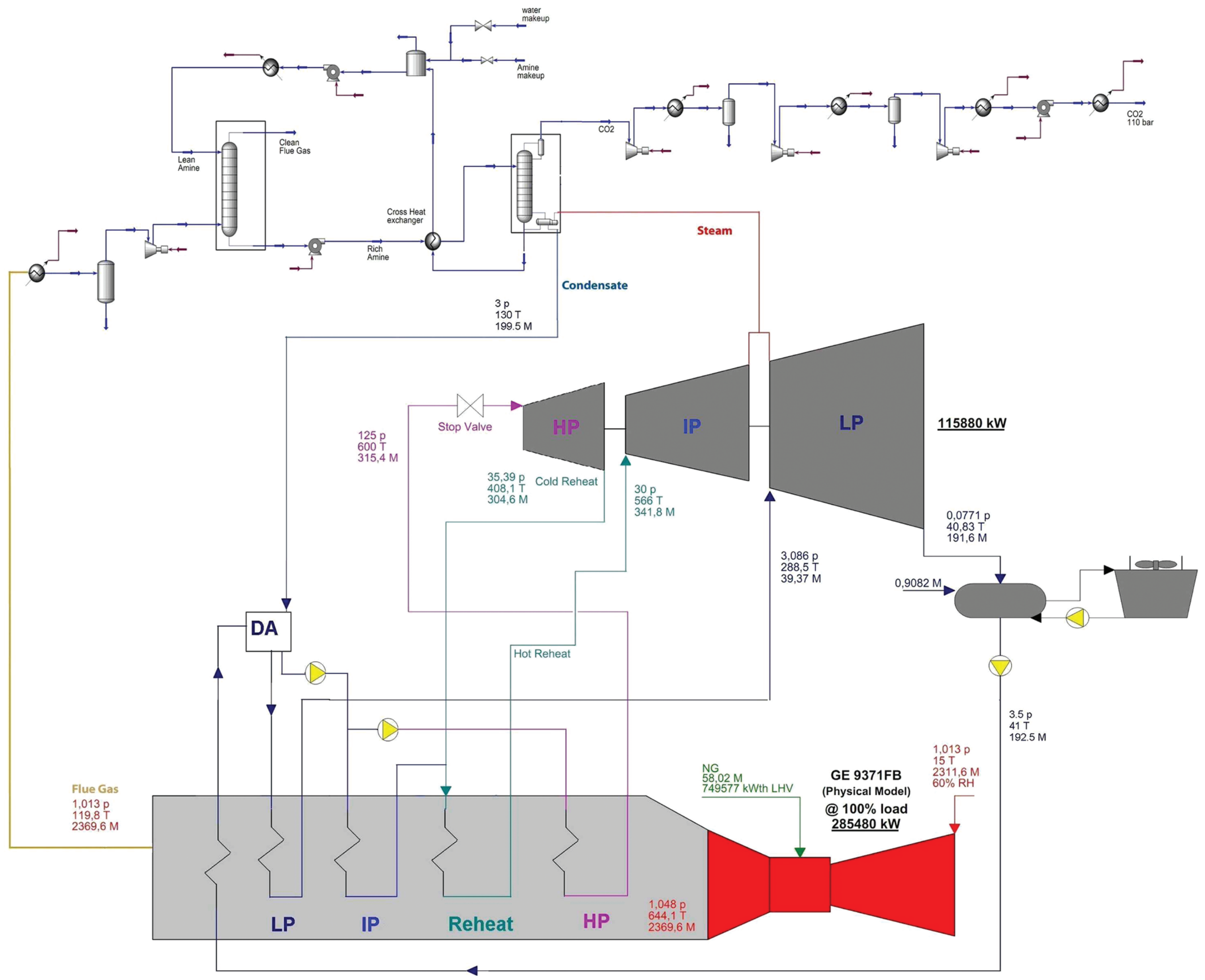

Figure 1. Schematic flow diagram of NGCC integrated to capture plant.

conditions. The possibility of heat integration of the power plant with the compression section of the capture plant is also studied.

In the partial load investigation, the performance of the power plant with constant inlet guide vanes (IGVs) is compared to the reference case. In another case study, throttled valve and sliding pressure steam extraction are compared. Figure 1 shows a schematic of the integrated NGCC with capture plant.

2. MODEL DESCRIPTION

The previous studies on CO_2 capture plant operation[11−13] were performed in Unisim Design, which is a general purpose commercial simulator. Simulating a power plant in this kind of software is not accurate enough, especially for partial load conditions. We, therefore, used GT PRO and GT MASTER by Thermoflow[14] in this work to model the combined cycle natural gas power plant at full load and partial load, respectively.

GT PRO automates the process of designing a combined cycle or gas turbine cogeneration plant. GT PRO is particularly effective for creating new designs and finding their optimal configuration and design parameters. The user inputs design criteria and assumptions, and the program computes heat and mass balances, system performance, and component sizing. GT PRO has over 3000 user-adjustable input parameters. Most key inputs are automatically created by intelligent design procedures that help the user identify the best design with minimal time and effort, while allowing the flexibility to make any changes or adjustments. It normally computes a heat balance and simultaneously designs the required equipment.[14]

GT MASTER simulates the expected performance of a given plant at different operating conditions, such as different ambient temperatures and loads. The roughly 2500 input parameters that define plant hardware and main control set-points can all be initialized for a plant by simply reading its GT PRO design file.[14]

To simulate an integrated power plant, we used Unisim Design (Honeywell) and GT PRO/GT MASTER (Thermoflow) simultaneously. The power plant is modeled and designed in GT PRO, and then, the model is exported to GT MASTER for the simulation in full load and partial load. The capture plant is simulated in Unisim Design. These two software programs cannot be connected together directly, and Microsoft Excel is used as an interconnection tool. Some

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macros are created in Excel in Visual Basic to connect Unisim Design and GT PRO/GT MASTER together.

There are some parameters from a power plant that affect the capture plant performance such as flue gas flow rate, temperature, and composition and extracted steam pressure and temperature. In addition, there are some other parameters from the capture plant that affect the power plant performance, such as the amount of steam extracted for solvent regeneration, de-superheated water flow, and condensed water flow, pressure, and temperature. The program starts by running the code in Excel. The input of this code is the gas turbine load. GT MASTER runs the power plant for the defined load. Later, the code opens and runs the Unisim file by entering the flue gas properties and extracted steam properties. After convergence of the Unisim file, the amounts of electricity needed for blower, pumps, and compressor are defined. In addition, the steam amount and condensed water flow, pressure, and temperature are exported to GT MASTER, and the power plant model is run again. Now, all the parameters of the integration of the power plant with the capture plant, such as power output, efficiencies, steam consumption, etc., are available. With this method, we can have all parameters of an integrated power plant with capture plant for any power plant load. Figure 2 shows a brief block diagram of the model for the integrated NGCC power plant with capture plant.

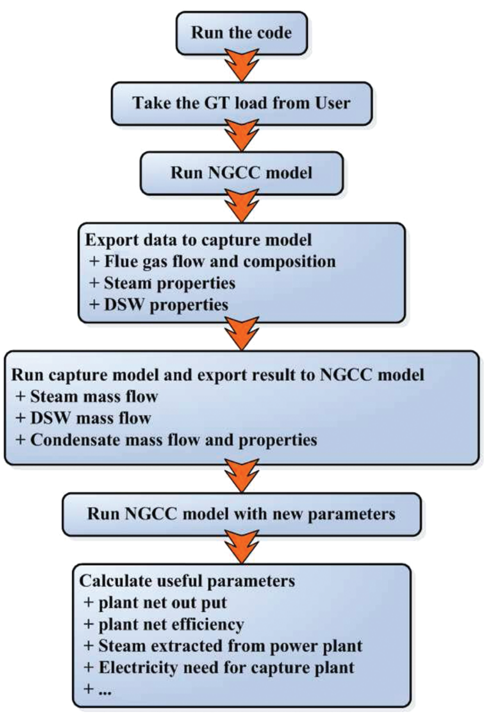

Figure 2. Brief block diagram of the model.

3. MODEL PARAMETERS

3.1. Power Plant. In this study, a natural gas combined cycle (NGCC) power plant is modeled in GT PRO. To model the power plant, we need to define some parameters. The supposed ambient parameters are as follows:

- Ambient temperature: 15 °C.
- Ambient pressure: 1.01 bar.
- Ambient relative humidity: 60%.
- Ambient wet bulb temperature: 11 °C.

In the GT PRO library, there are more than 420 types of gas turbine with different capacities, frequencies, and other specifications. The GE 9371FB gas turbine from General Electric was selected.[15] It has a dry low NO_x combustor, and the model deviation is less than 0.5%. It has variable inlet guide vanes (IGVs) for partial load. The specifications for this gas turbine are the following:[14]

- Pressure ratio: 18.2.
- 50 Hz engine, 3000 rpm.
- Power generation: 291 485 kW.
- LHV net efficiency: 38.3%.

The natural gas properties are shown in Table 1.

Table 1. Natural Gas Properties[15]

component	vol %
methane	89.00
ethane	7.00
propane	1.00
i-butane	0.05
n-butane	0.05
i-pentane	0.005
n-pentane	0.004
CO_2	2.00
N_2	0.89

The temperature and pressure of natural gas are assumed to be 15 °C and 70 bar, respectively.

The fuel gas should have a minimum temperature to prevent condensation in the injection nozzles. In addition, increasing the fuel temperature to more than the minimum temperature will increase the gas turbine efficiency by reducing the fuel consumption for a desired firing temperature. This temperature is usually increased to about 185 °C. The heating source is a stream from the heat recovery steam generator (HRSG) that should be taken from an optimum point, which is the intermediate-pressure boiler feedwater or intermediate-pressure economizer output.[16]

Three different pressure levels of steam are produced in an HRSG. Steam is reheated after the high-pressure (HP) steam turbine to prevent condensation in the low-pressure (LP) turbine.[15] The reheated steam is mixed with intermediate-pressure (IP) steam and enters the intermediate-pressure steam turbine. The steam properties for different pressure levels are as follows:[15]

- High-pressure steam: 125 bar, 600 °C.
- Intermediate-pressure steam: 30 bar, 566 °C.
- Low-pressure steam: 3.5 bar, 288 °C.

The amount of steam will be calculated by an energy balance between the hot flue gas and steam side. The minimum temperature approach is as follows:[15]

- $\Delta T_{\text{steam-gas}} = 25$ °C
- $\Delta T_{\text{gas-boiling liquid}} = 10$ °C
- $\Delta T_{\text{liquid-gas}} = 10$ °C
- $\Delta T_{\text{approch-ECO}} = 5$ °C

For a three-pressure level steam cycle, there are several possible steam extraction points. Steam can be extracted directly from the turbine inlet or outlet, the LP reboiler, the turbine casing, or the IP/LP crossover.[17] The steam extraction from the LP reboiler creates the minimum energy penalty, but the amount of steam is not enough for a CO_2 capture plant. In this study, the steam extracted from the IP/LP crossover is the optimum point, and there is enough steam.[17,18] The pressure at the extraction point is about 4 bar. The condensate from the capture plant is returned to a de-aerator and the water for de-superheating is extracted from the intermediate-pressure economizer.

The low-pressure steam turbine is connected to a water cooled steam condenser. Cooling water is supplied by a natural draft cooling tower.

3.2. Capture Plant. An absorption/stripping aqueous MEA technology is used for the capture plant. The capture plant includes absorber, stripper, cross heat exchanger, cooler, flue gas blower, and CO_2 compression section. The following parameters have been considered for the CO_2 capture model:

- 30 wt % MEA is used for the capture plant. The specific heat requirement is about 3.6 GJ/ton of CO_2 that is calculated by the capture model.
- The captured CO_2 is compressed to 75 bar, liquefied, and pumped up to 110 bar.
- The cross heat exchanger temperature approach at the cold end side is 10 °C. In the previous study,[12] we showed that 10 °C is more economical than 5 °C for most of stripper configurations.
- The lean amine temperature to the absorber is 45 °C.
- The steam is de-superheated at 3 bar (133.6 °C) for the reboiler, and the condensate temperature is 130 °C. With this temperature, there is a temperature approach of about 10 °C at the reboiler.

The investigation was done with the mentioned specifications for the power and capture plants.

4. FULL LOAD INVESTIGATION

For a power plant integrated to capture plant, the following opportunities are possible:

- When a power plant is designed with CO_2 capture, a portion of steam is extracted for solvent regeneration in the capture plant and the steam turbine is designed on the basis of the remaining steam. If there is no CO_2 capture from the power plant for some reason, for example, peak hours, all the produced steam is used for power production and the operating conditions are not the same as the design conditions.
- The retrofit case is when the capture plant is added to an existing power plant. In this case, the power plant has been designed on the basis of the total steam that is produced in HRSG for power production. When CO_2 is captured from the power plant, a portion of the steam is extracted for solvent regeneration and the operating conditions are not the same as the design conditions.

In the following, the mentioned cases will be investigated with and without CO_2 capture and the plants performance are compared.

4.1. Power Plant Design Based on CO_2 Capture in the No Capture Condition. In this case study, we assume a power plant has been designed based on CO_2 capture. This means that the steam extraction is from a steam turbine and the steam turbine has been designed on the basis of the remaining steam after extraction in the low-pressure part. Now, we investigate the performance of this power plant, but without CO_2 capture, and compare it with a power plant that has been designed without CO_2 capture. The different parameters of the two power plants are shown in Table 2.

Table 2. Performance Comparison of Two Power Plants without CO_2 Capture

item	design with capture	design without capture
power plant net efficiency (%)	55.51	57.12
steam turbine net efficiency (%)	29.93	32.74
HRSG efficiency (%)	82.25	88.49
HP steam (bar, °C, ton/h)	126.2, 597, 318.3	125.2, 598, 316.9
IP steam (bar, °C, ton/h)[a]	31.9, 562, 349.9	30.1, 561, 342.8
LP steam (bar, °C, ton/h)	6.4, 322, 11.5	3.1, 288, 46.1
condenser (bar, °C)	0.19, 59	0.08, 41
flue gas temp. from HRSG (°C)	129	87

[a]The mass flow is the IP steam production + HP steam from HP turbine that is mixed with IP steam and reheated to enter to the IP turbine.

The results show that the plant designed for CO_2 capture will have a lower net efficiency when run without CO_2 capture compared to the power plant designed without CO_2 capture. The efficiency is reduced because the LP turbine is not large enough to convert all the steam energy to mechanical work. When the capture plant is not on-line, the steam is not extracted from the steam turbine and all the steam should pass through the LP turbine. Therefore, the pressure of the steam turbine increases, especially in the LP part. Consequently, the power production will decrease. The flue gas exhaust temperature from the HRSG is higher for the plant designed based on CO_2 capture. This means that a smaller fraction of the flue gas heat is utilized for steam production and power generation. This happens because the condenser has been designed for a small steam flow rate. When the steam flow rate increases, the condenser is not able to cool the condensate and warmer water returns to the HRSG. In addition, the operating conditions (pressure and temperature) in the HRSG deviate from the optimum design conditions.

4.2. Adding a Capture Plant to an Existing Power Plant. Here, we want to investigate the performance of an existing power plant when a capture plant is added to it and compare it with a power plant has been designed based on CO_2 capture. A comparison of different parameters of two power plants is shown in Table 3.

Table 3. Performance Comparison of Two Power Plants with CO_2 Capture

item	design with capture	design without capture
power plant net efficiency (%)	49.62	49.53
steam turbine net efficiency (%)	25.07	25.13
HRSG efficiency (%)	83.63	85.15
HP steam (bar, °C, ton/h)	125.1, 598, 316	125.1, 598, 316.7
IP steam (bar, °C, ton/h)[a]	30.1, 564, 343.2	29.9, 562, 340.9
LP steam (bar, °C, ton/h)	3.1, 289, 38.1	1.5, 285, 47.3
condenser (bar, °C)	0.08, 41	0.04, 30
flue gas temp. from HRSG (°C)	120	110

[a]The mass flow is the IP steam production + HP steam from HP turbine that is mixed with IP steam and reheated to enter to the IP turbine.

In Table 3, the power plant net efficiency is higher for the plant that has been designed based on CO_2 capture, in spite of lower steam turbine efficiency. When a capture plant is added to the existing plant, the equipment after the steam extraction is overdesigned for the new condition. Consequently, it can utilize more energy from the steam. The higher HRSG efficiency and lower condenser temperature and pressure confirm this (Table 3). On the other hand, the overdesigned equipment will consume more energy, and the new situation is not optimized from an energy consumption point of view. This extra energy consumption in the power plant causes a decrease in the net power plant efficiency. The main consumer of energy after the steam extraction point is the condenser cooling water pump. Decreasing the flow rate of the cooling water does not improve the net efficiency of the plant because, by decreasing the flow, the cooling water pump is far from the optimum condition and pump efficiency decreases. In this situation, the HRSG and steam turbine efficiencies will decrease; however, the consumption does not decrease very much, and the net power plant efficiency will decrease more.

4.3. Power Plant with and without CO_2 Capture. Here, we want to compare a stand-alone power plant with a power plant integrated with a CO_2 capture plant. In this section, both plants are working at their design conditions. The plant parameters are shown in Table 4.

Table 4. Power Plant with and without CO_2 Capture

item	with CO_2 capture[a]	without CO_2 capture
power plant net efficiency (%)	49.62	57.12
net power plant output (MW)	372.0	428.2
power plant auxiliary (MW)	7.64	8.63
CO_2 capture electricity consumption (MW)	21.75	
steam required for solvent regeneration (ton/h)	199.5	
de-superheated water (ton/h)	28.96	
CO_2 emission (ton/h)	15.67	156.8
flue gas temp. from HRSG (°C)	120	87

[a]Based on 90% CO_2 capture and CO_2 compression to 110 bar

With CO_2 capture from the proposed power plant, the power plant net efficiency decreases 7.5%-points. From this energy penalty, 4.6%-points is related to steam extraction and 2.9%-points is related to electricity consumption in the flue gas blower, different pumps in the capture plant, and the increase in the CO_2 pressure up to 110 bar. The power plant with CO_2 capture has a lower auxiliary consumption because the steam flow rate in the condenser is less than that in the stand-alone power plant and less circulating cooling water is needed for steam condensation. The exhaust flue gas from the HRSG has a higher temperature because the amount of steam extracted for the capture plant is returned to the de-aerator of the power plant after condensation at 130 °C. This condensate is therefore not used for heat utilization from the flue gas in the last stage of the HRSG. This hot flue gas must be cooled before the capture plant and will increase the energy consumption of capture plant.

4.4. Power Plant Integration with the CO_2 Compression Section. In the combined cycle power plant, steam passes through the steam turbine and is condensed in the condenser at about 40 °C. This water returns to the HRSG to produce steam again. Here, we want to investigate the effect of using some of this water for intercooling between the compressor stages. For this investigation, the water is taken from the water tank before the HRSG and sent to the intercooler of the CO_2 compressor. The water temperature increases about 100 °C, and it is returned to the de-aerator of the power plant. Because the water flow rate is not high enough, the integration is done for only two compressor stages. The third stage and the CO_2 condenser are operated by using cooling water. The temperature approach of the intercooler is 5 °C in the simulation. The results are shown in Table 5.

Table 5. Integration Results with CO_2 Compression Section

item	base case	integrated case
power plant net efficiency (%)	49.62	49.47
net power plant output (MW)	372.0	370.8
water flow for integration (ton/h)		129
CO_2 capture electricity consumption (MW)	21.75	22.42
flue gas temp. from HRSG (°C)	120	137

The results show that the net efficiency decreases by this integration. This kind of integration can increase the power production efficiency in a coal power plant.[8] One of the reasons can be the water flow rate in the steam cycle. The water flow rate in coal power plant is much more than the NGCC plant. In the coal power plant, some steam is extracted for preheating the water; this means that the flue gas heat is not enough to heat the water. By heat integration with the compression section in coal power plant, the amount of steam that is extracted for water preheating decreased and was used for more power production.

This decrease of efficiency has two reasons. First, when the water from the power plant is used instead of cooling water, the CO_2 temperature between the compressor stages increases (45.3 °C instead of 30 °C) because the water that is used for cooling is 40.3 °C. Therefore, the energy requirement for CO_2 compression increases. Second, in the integrated case, a portion of water is used for heat integration, the water flow for cooling the flue gas decreases, and the flue gas goes to capture plant with a higher temperature (last row of Table 5). This hot flue gas must be cooled before entering the absorber, and thus, more energy is required for flue gas cooling.

5. PARTIAL LOAD INVESTIGATION

In this section, the power plant integrated with capture plant is investigated at different power plant loads. Here, the efficiency variation, steam properties and consumption changes, effect of inlet guide vanes (IGVs), and throttle valve effect on the extracted steam properties are investigated. The degree of partial load is based on the gas turbine load and is not calculated on the basis of the total power plant output.

Because of the overdesign of the steam cycle in the partial load condition, the steam cycle power does not decrease as much as the gas turbine power, and the total power plant load will be higher than gas turbine partial load in most of the cases. The gas turbine load will be changed from 50 to 100% for this investigation. In the following, when we mention a stand-alone power plant, it means that the power plant has been designed without CO_2 capture, and when we mention an integrated power plant with CO_2 capture, it means that the power plant has been designed on the basis of CO_2 capture. Therefore, both plants are working at their design condition at 100% load. The power plant efficiency will decrease when it is not working at design condition, as was discussed in sections 4.1 and 4.2.

The equipment, such as turbines, pumps, blower, and compressor, have specific characteristics. These are usually designed to have the highest efficiency at the design capacity. The efficiency drops both above and below the design capacity. To have more accurate results, the equipment efficiencies vary on the basis of their specific characteristic and will decrease at partial load.

In the following, three different cases are investigated. The first case, the reference case, uses the gas turbine model for partial load and a throttle valve at the steam extraction point to extract steam at 4 bar for the CO_2 capture plant. In the second case study, the gas turbine performance with constant IGVs is compared to the reference case. In the third case study, the effect of steam extraction without a throttle valve is investigated.

5.1. Case Study 1: Reference Case. Here, the power plant performance at partial load with and without CO_2 capture is investigated. The capture ratio is 90% for all the cases, and the product CO_2 pressure is 110 bar. Different parameters of the power and capture plants are shown in Table 6.

Table 6. Reference Plant Different Parameters at Different Loads

item	gas turbine load (%)					
	100	90	80	70	60	50
plant load based on net output	100	91.62	83.14	74.59	65.93	57.15
fuel consumption (ton/h)	58.03	53.85	49.63	45.37	41.06	36.68
flue gas flow (ton/h)	2 370	2 236	2 100	1 962	1 822	1 678
flue gas temp. to HRSG (°C)	644.1	644.8	645.5	646.2	646.9	647.6
plant net output (MW)	428.2	392.3	356.0	319.4	282.3	244.7
plant net output with CO_2 capture (MW)	372.0	339.9	307.4	274.5	241.3	207.5
plant net efficiency (%)	57.12	56.40	55.52	54.49	53.22	51.63
plant net efficiency with CO_2 capture (%)	49.62	48.87	47.95	46.84	45.49	43.80
CO_2 emission (kg CO_2/kWh)	0.366	0.371	0.377	0.384	0.393	0.405
CO_2 emission with CO_2 capture (kg CO_2/kWh)	0.042	0.043	0.044	0.045	0.046	0.048
electricity consumption of CO_2 capture (MW)	21.75	20.43	19.16	17.91	16.67	15.44
steam extraction for CO_2 capture (ton/h)	199.5	184.3	169.3	154.3	139.0	123.7
extracted steam temp. (°C)	292.4	299.0	304.6	310.9	318.1	326.1
extracted steam pressure (bar)	4	4	4	4	4	4
de-superheated water (ton/h)	28.96	27. 90	26.53	25.10	23.57	21.91
de-superheated temp. (°C)	140.2	140.3	140.4	140.5	140.6	140.7
de-superheated pressure (bar)	35.21	33.41	31.61	29.75	27.84	25.87
specific heat req. (kJ/kg CO_2)	3 564	3 567	3 571	3 576	3 582	3 589
lean amine circ. rate (m^3/h)	2 437	2 264	2 090	1 915	1 737	1 556

The most important parameter for power production is the plant net efficiency. The results show that the plant net efficiency, as expected, drops when the load decreases. For a stand-alone power plant, the efficiency drops from 57.12% at full load to 51.63% at 50% load, that is, a 5.49%-points efficiency reduction. For the power plant integrated with a capture plant, the efficiencies are 49.62% and 43.80% for full load and 50% load, respectively, that is, a 5.82%-points efficiency reduction. This is 0.33%-points more than the efficiency reduction in the stand-alone power plant, and it may be concluded that the energy penalty at partial load does not increase significantly in the case of CO_2 capture included.

5.2. Case Study 2: Power Plant Performance with Constant and Variable IGVs. Inlet guide vanes (IGVs) guide the air flow to the first stage of the compressor. The compressor of the gas turbine can have fixed or variable IGVs. The exhaust gas temperature to the gas turbine is an important parameter that affects the NGCC power plant performance and efficiency. Usually, this temperature should be the maximum allowable temperature imposed by the turbine blade materials. The variations of the temperature of the exhaust gas entering the HRSG will affect the efficiency of the steam turbine power production. The exit gas temperature of the gas turbine must be maintained at the optimal value at any load to have the maximum efficiency. In the constant IGVs gas turbines, the air flow for different loads is the same. Consequently, the turbine exhaust temperature decreases from the optimum value. The variable IGVs at the compressor inlet regulate the incoming air flow. To maintain constant outlet temperature, it is necessary to adjust the air flow as the fuel flow changes. At the partial load condition the IGVs remain partially closed, to maintain the exhaust temperature at the target level. However, as the gas turbine operating point approaches full load, the IGVs are in the fully open position, and air flow cannot be increased any more.[19] Most of the industrial gas turbines have variable IGVs to improve the gas turbine performance at partial load.

The optimum turbine exhaust temperature at partial load is different for different gas turbines from the different manufactures. Figure 3 shows the relative exhaust temperature for four industrial gas turbines from different manufacturers.

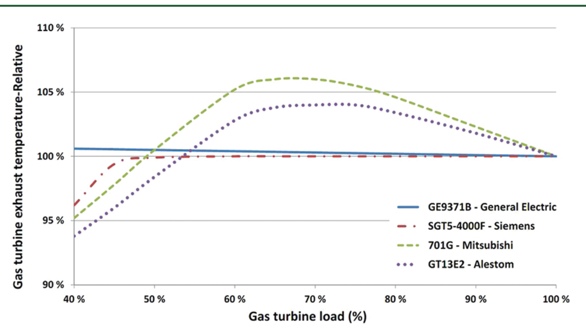

Figure 3. Turbine exhaust gas temperature at different loads.

As shown in Figure 3, the exhaust gas temperature is constant or even increases for more than 50% load and for loads less than 50% the temperature is less than its value at full load. For the GE9371B turbine that is used for this study, the exhaust temperature is a little higher at 50% load than it is at full load. With the constant IGVs the exhaust temperature decreases when the turbine works at partial load. In the following, the gas turbine is modeled with the constant IGVs and the performance is compared to the reference case.

Now we can compare the plant performance with constant IGVs with the reference case by comparing the data in Tables 6 and 7. For the constant IGVs case, the plant efficiency decreases more than the reference case at partial load. The results show that the efficiency for the constant IGVs is about 6.2%-points lower than for the reference case at 50% load. The plant load based on net output is higher than the gas turbine load in reference case, but for the constant IGVs case, it is vice versa. This means that both the HRSG efficiency and the steam turbine efficiency are higher for the reference case than for the constant IGVs case. The reason is that the turbine exhaust gas temperature decreases in partial loads for this case and this affects the steam production. The fuel gas consumption is smaller because the mass flow to the gas turbine is higher for the second case, but the net efficiency of the plant that shows the fuel consumption per power production is lower than that for the reference case. In this case, the flue gas has lower concentration of CO_2 and it will increase energy penalty related to CO_2 capture. Because the flue gas flow rate does not change very much for this case, the energy consumption of compressing and cooling of the flue gas for the absorption process does not change very much at partial load.

Table 7. Power Plant Performance at Different Loads with the Constant IGVs Gas Turbine

item	gas turbine load (%)					
	100	90	80	70	60	50
plant load based on net output	100	88.53	77.23	66.39	55.84	45.80
fuel consumption (ton/h)	58.03	52.66	47.44	42.49	37.83	33.43
flue gas flow (ton/h)	2370	2364	2359	2354	2349	2345
flue gas temp. to HRSG (°C)	644.1	595.6	548.7	504.8	465.2	428.0
plant net output (MW)	428.2	379.1	330.9	284.3	239.1	196.1
plant net output with CO_2 capture (MW)	372.0	327.5	283.8	241.3	200.7	162.3
plant net efficiency (%)	57.12	55.72	54.00	51.79	48.93	45.42
plant net efficiency with CO_2 capture (%)	49.62	48.15	46.30	43.95	41.06	37.58
CO_2 emission (kg CO_2/kWh)	0.366	0.376	0.388	0.405	0.429	0.463
CO_2 emission with CO_2 capture (kg CO_2/kWh)	0.042	0.044	0.045	0.048	0.051	0.056
electricity consumption of CO_2 capture (MW)	21.75	20.55	19.45	18.45	17.52	16.65
steam extraction for CO_2 capture (ton/h)	199.5	184.1	168.6	153.8	139.4	125.4
extracted steam temp. (°C)	292.4	280.7	269.7	259.1	250.6	243.7
extracted steam pressure (bar)	4	4	4	4	4	4
de-superheated water (ton/h)	28.96	24. 69	20.90	17.55	14.80	12.51
de-superheated temp. (°C)	140.2	140.3	140.5	140.6	140.8	141.1
de-superheated pressure (bar)	35.21	32.97	32.86	33.44	33.73	33.70
specific heat req. (kJ/kg CO_2)	3564	3586	3611	3642	3676	3715
lean amine circ. rate (m^3/h)	2437	2232	2032	1842	1664	1492

5.3. Case Study 3: Effect of Using Throttle Valve at the Steam Extraction Point. An important interface of the power plant and capture plant is the steam extraction from the turbine as a heat supply for solvent regeneration. Because of the temperature level required for solvent regeneration, the heat could be provided by low-pressure steam. As mentioned before, because of the large amount of steam, it cannot be supplied from the low-pressure steam cycle. For this reason, the crossover pipe between the intermediate-pressure (IP) and low-pressure (LP) steam turbine sections is considered as the most suitable extraction point.[17,18] The steam must have a minimum pressure (here, we assume 4 bar) at any load of the power plant. The pressure decreases in the steam cycle of the NGCC at partial load. Some manufacturers utilize LP crossover throttle valves to regulate the extraction steam pressure. An LP crossover extraction valve can adjust the extraction pressure, which allows for more efficient operation in part-load conditions.[20]

If a throttle valve is not used, it is called a sliding pressure configuration. This means that the pressure of the extracted steam decreases at partial load. Therefore, the steam needs to be extracted at the higher pressure level at full load conditions to be sure that the pressure is high enough for solvent regeneration also at partial load conditions. Figure 4 shows the comparison of extracted steam pressure for the sliding and throttled configurations. As shown, the crossover pressure decreases from 5 to 4 bar when the gas turbine load changes from 100% to 30%.

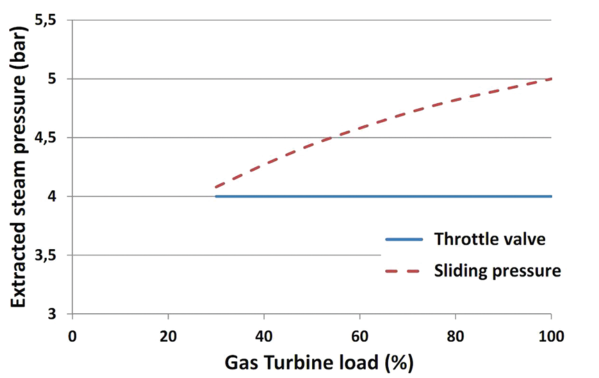

Figure 4. Comparison of extracted steam pressure for sliding and throttled configuration.

In sliding configuration, the extracted steam has higher quality (higher pressure and temperature) than is needed for solvent regeneration at loads higher than the minimum partial load considered. Consequently, the loss through steam extraction will be higher for the sliding pressure configuration.

When we compare the sliding configuration with the reference case, we can see that there is a small loss when there is no CO_2 capture. This loss is because of the throttle valve pressure drop. However, with the integrated power and capture plant, the net power output and the net electricity production efficiency is lower than in the reference case (Tables 6 and 8). The specific heat requirement is the same as the reference case because the flue gas properties are the same and the extracted steam is de-superheated at 3 bar for both cases. The maximum loss for the sliding configuration is at full load

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Table 8. Power Plant Performance with Sliding Configuration at Different Loads

item	gas turbine load (%)					
	100	90	80	70	60	50
plant load based on net output	100	91.78	83.43	74.98	66.41	57.73
plant net output (MW)	428.5	393.3	357.5	321.3	284.6	247.4
plant net output with CO_2 capture (MW)	370.0	338.4	306.2	273.6	240.7	207.3
plant net efficiency (%)	57.16	56.54	55.77	54.82	53.66	52.21
plant net efficiency with CO_2 capture (%)	49.36	48.64	47.76	46.68	45.38	43.75
CO_2 emission (kg CO_2/kWh)	0.366	0.370	0.377	0.384	0.393	0.405
CO_2 emission with CO_2 capture (kg CO_2/kWh)	0.043	0.043	0.044	0.045	0.046	0.048
steam extraction for CO_2 capture (ton/h)	195.2	180.6	166.3	151.7	137.0	122.2
extracted steam temp. (°C)	319.4	324.5	328.2	333.7	336.6	341.5
extracted steam pressure (bar)	5	4.91	4.82	4.71	4.59	4.44
de-superheated water (ton/h)	33.30	31. 56	29.65	27.66	25.58	23.41
specific heat req. (kJ/kg CO_2)	3 564	3 567	3 571	3 576	3 582	3 589

conditions because the steam quality is higher than needed for solvent regeneration. During partial load conditions, the extracted steam quality is closer to what is needed for the capture plant and the loss decreases. The most important advantage of the throttled valve case is that the extracted pressure is near the steam properties needed for capture plant at all partial load conditions.

6. CONCLUSIONS

Here, a NGCC power plant with capacity of about 430 MW integrated with an amine based absorption/stripping CO_2 capture plant is investigated based on simulation models. The capture ratio is 90%, and the captured CO_2 is compressed to 75 bar, liquefied, and finally pumped up to 110 bar. Both full and partial load conditions are investigated. The energy penalty for CO_2 capture is 398.4 kWhel/ton CO_2, which causes 7.5%-points reduction in the power plant net efficiency. From this energy penalty, 4.6%-points is related to the steam extraction and 2.9%-points is related to electricity consumption. The results show that the net efficiency of a power plant designed with CO_2 capture is a little higher than an existing power plant where the CO_2 capture plant is integrated at a later stage (49.62% compared to 49.53%). In the case where the power plant is designed with CO_2 capture and operated without CO_2 capture, the net efficiency deviates more from a stand-alone power plant (55.51% compared to 57.12%). The integration of the power plant with the compression section of the capture plant for preheating the water to the HRSG was found not to improve the net plant efficiency.

In the partial load investigation, results show that the net efficiency of the variable IGVs gas turbine is about 6.2%-points higher than the efficiency of the constant IGVs gas turbine at 50% load. Also, the power plant with a throttled valve configuration for steam extraction has a better performance than the sliding pressure configuration steam extraction.

At the end, we should mention that this investigation has been done for 30 wt % MEA in the conventional configuration with the specific heat consumption about 3.6 GJ/ton CO_2. For other improved configurations for CO_2 capture, there is a possibility to reduce the energy penalty. In addition, there is a possibility of penalty reduction if we can extract the steam with lower quality by changing the solvent.

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Notes

The authors declare no competing financial interest.

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