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Proceeding Paper

Decarbonization Challenges and Opportunities of Power Sector in Uzbekistan: A Simulation of Turakurgan Natural Gas-Fired Combined Cycle Power Plant with Exhaust Gas Recirculation †

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Abstract: Power generation dependency on natural gas in Uzbekistan is high, with more than 85% of electricity production coming from natural gas. Hence, natural gas-fired power plants constitute the largest proportion of greenhouse gas emissions of the country. Carbon capture, storage, and utilization (CCSU) play an essential role in reaching Uzbekistan's reduction targets for carbon dioxide (CO_2) emissions. In this study, one (450 MW) of the two identical blocks of a 900 MW Turakurgan natural gas-fired combined cycle power plant (NGCCPP) located in the Fergana valley in Uzbekistan is simulated using Aspen Plus® commercial software and validated with its open access project data prior to the evaluation of end-of-pipe CCSU unit integration. An optimal value of exhaust gas recirculation (EGR) is identified in order to further increase the CO_2 content in the flue gas while reducing the flue gas flow rate. In addition, according to the simulation results, more 2.16 Mt of annual CO_2 emissions can be avoided when the capture plant is set at a 90% CO_2 capture rate. Apart from that, the suitability of various CCSU integration methods such as absorption, adsorption, membrane separation, and CO_2 bio-fixation is discussed considering the power plant's site-specific conditions and the obtained flue gas stream characteristics.

Keywords: CO_2 capture; decarbonization; combined cycle power plant; Uzbekistan

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1. Introduction

Global climate change has become a major issue for the entire world in the 21st century. An increased amount of carbon dioxide (CO_2) in the atmosphere is considered to be the primary leading factor of global warming. The fossil fuel-dependent energy sector, principally driven by coal and natural gas (NG), is one of the main sources responsible for more than a third of the total global CO_2 emissions [1]. In this context, to meet the target of the Paris Agreement (2015) of limiting the temperature rise far below 2 °C, preferably 1.5 °C, above the pre-industrial level, the decarbonization of the fossil fuel-based electricity generation in line with the other large industrial point sources ought to be the priority by each country's policy.

The current state of power generation in the Republic of Uzbekistan (hereinafter referred to as Uzbekistan) is heavily dependent on thermal power plants (TPP) with more than 85% of the country's electricity coming from TPPs, mainly running on NG [2]. Uzbekistan's first target towards net zero emissions is to cut its greenhouse gas emissions by 35% by the end of 2020s. In this way, the country's main green economy policy includes the transition to solar, wind, and hydrogen energy reaching a minimum of 25% share of renewables by 2025 [3]. Although the transition from fossil fuel-based power sources to renewable energy is seen as the most feasible climate change mitigation strategy, it is uncertain, especially in the current growing urbanization and population situation, to meet the energy demand of the whole country by renewables as far as the period from now to 2050 is concerned. Therefore, the implementation and feasibility of other decarbonization alternatives such as Carbon Capture, Storage, and Utilization (CCSU) in Uzbekistan's condition should thoroughly be evaluated.

For the reliable assessment of CCSU integration possibilities in Uzbekistan, there is a necessity for developing a rigorous CCSU model to evaluate techno-economic, site-specific conditions with different scenarios. From this perspective, initially, a simulation with exhaust gas recirculation (EGR) analysis of one block of two identical 450 MW Turakurgan natural gas-fired combined cycle power plant (NGCCPP) is selected as an object of this investigation due to the following reasons:

- NG is the abundant and primary fuel for energy production in Uzbekistan;
- NG is cleaner emissions compared to coal, oil, and other heavier hydrocarbons;
- The majority of the TPPs operate in the combined cycle principle in Uzbekistan;
- NGCCPPs are not likely to be replaced by renewables in the near term;

Although NGCCPPs have relatively low CO_2 emission factor compared to coal-fired power plants (CFPP) at 364 and 800 kgCO_2/MWh respectively [4], CO_2 concentration in the NGCCPP (4.0 vol%) flue gas is much less than those of CFPP (15 vol%) counterparts, which makes the capture unfeasible. Thus, recycling a part of the exiting flue gas as EGR in a combined cycle process has a significant impact on the CCSU process intensification. There are several research papers [5,6], which developed the NGCCPP model prior to CCSU integration and analyzed EGR integration for different types of gas turbines. However, the effect of EGR with different ratios on various parameters and the location of the plant is rarely considered. In this paper, a simulation of one block of Turakurgan TPP is developed and validated with the plant's preparatory project report data. Apart from that, the EGR effect on the power plant's performance and other main parameters is studied and discussed. Moreover, there is a brief discussion about the integration of different post-combustion CO_2 capture methods and their feasibility in the case of Turakurgan NGCCPP.

2. Model Development

2.1. Brief Process Description in the Base Case

Turakurgan TPP consists of two same (450 MW outputs) blocks with Mitsubishi-Hitachi M701F Series Gas Turbines (GT). The simulation of one block of 450 MW gas and steam turbine was developed and validated using the commercial software—Aspen Plus® (See Figure 1). In the power generation process, 664.5 kg/s of ambient air with a pressure of 0.944 bar is compressed up to 18 bar and is divided into two directions—one for the combustion reactor after mixing with 16.11 kg/s (lower calorific value (LCV)—46.750 kJ/kg) of natural gas, while another one is used for cool down the hot flue gas coming out of the combustion chamber right after the heating of the natural gas by the heat exchanger. Due to the metallurgical limitation on inlet temperature of up to 1300 °C of the F-type GTs, an extra amount of air of 34 kg/s is used to keep the GT inlet temperature at a permissible level (the exact amount of cooling air is not provided in the project report, so it is calculated by Aspen Plus in response to the GT inlet temperature limitations). GT outlet hot gas at 1 bar and 596 °C is fed to the Heat Recovery Steam Generator (HRSG) where the heat from the hot flue gas is absorbed by the heat exchangers generating even more power by three steam streams in high pressure at 127 bar, intermediate pressure at 27.5 bar, and low-pressure steam turbines (ST) at 4.5 bar. The flue gas exits the HRSG (14) at 104 °C and 0.981 bar.

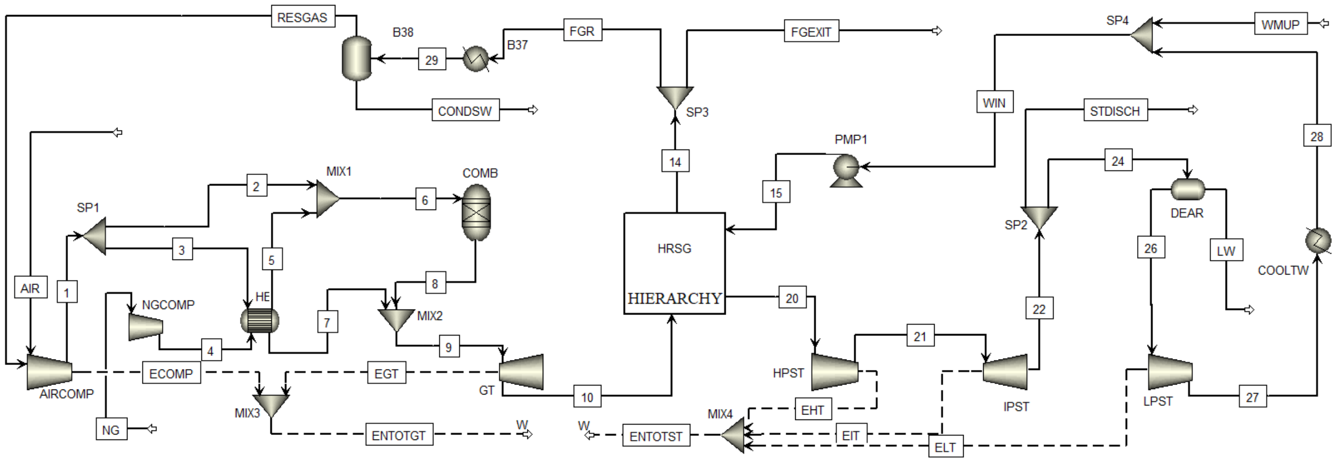

Figure 1. Simulation flowsheet of Turakurgan natural gas-fired combined cycle power plant with exhaust gas recirculation.

2.2. EGR Integration Process

The exhaust gas (mainly Nitrogen (N_2), Oxygen (O_2), CO_2, and water vapor (H_2O)) exiting the power plant is split into two streams (FGEXIT and FGR) in the optimal ratio, one goes to the CO_2 capture plant while another one is recirculated back to the compressor after removing the part of H_2O content from the flue gas by directly cooling with cold water down to an average 10–20 °C (See in Figure 1). Required additional amount of water for cooling the recirculated stream is supplied by Grand Canal Namangan, an artificial irrigation channel made of concrete with an average water flowrate of 6.6 m^3/s [2]. The EGR effect on the additional water demand for the CO_2 capture process is very small due to the EGR advantage of flue gas flowrate decrease. Even if EGR is not applied, flue gas needs to be cooled down for the majority of CO_2 capture techniques including absorption, adsorption, and membrane separation. Cooled and partly dehydrated flue gas is mixed with ambient air reducing its flowrate coming into the compressor. Exact ambient air flowrate reduction is calculated in only the condition of GT inlet temperature (stream 9) at 179–180 °C in all different EGR ratio cases except EGR ratio at 0.6 because the EGR ratio at this point creates massive O_2 deficiency leading to the simulation errors.

3. Results and Discussion

3.1. Simulation Results and Validation

The summary of the comparison of project data and simulation results is given in Table 1. It is apparent from the table, in most cases, there is a good agreement between the simulation results and the power plant's project report data [2]. However, since the focus of this investigation is mainly on the flue gas flowrate and characteristics before the design of the CO_2 capture plant, the auxiliary power consumption of the plant is estimated as 3% of its net power output (it includes the pumps, compressors, water treatment plant, etc.). While calculating the annual CO_2 emission, the capacity factor is obtained from the project report as 86.8%. According to the CO_2 emission result, at least more than 2.16 Mt of CO_2 can be avoided when the capture rate is at 90% standard.

Table 1. 1 Unit Gas Turbine modeling tuning parameters and Aspen Plus simulation results.

Parameters	Project	Input	Parameters	Project	Results
Air inlet mass flow (kg/s)	664.5	664.5	Flue gas out pressure (bar)	1	1
Air temperature (°C)	13.7	13.7	CO_2 content in flue gas (mol%)	N/A	3.96
Air pressure (bar)	0.944	0.944	O_2 content in flue gas (mol%)	N/A	12.3
Compressor discharge pressure (bar)	18	18	Flue gas out temperature (°C)	100	104
Natural gas mass flow (kg/s)	16.11	16.11	GT power output (MW)	299.3	299.8
Natural gas inlet temperature (°C)	15	15	ST power output (MW)	134.5	132.8
Natural gas inlet pressure (bar)	14	14	Total power output (MW)	433.8	432.6
Circulation water mass flow (m^3/s)	138.5	138.5	Auxiliary power (MW)	12.6	12.6
Compressor efficiency	N/A	0.90	Net power output (MW)	421.2	420
GT efficiency	N/A	0.89	Net power efficiency (%)	55.9	55.76
Three steam turbines efficiencies	N/A	0.91	1 Unit CO_2 emission (t/year)	1,177,177	1,202,000
Cooling air kg/s	N/A	34	Total CO_2 emission (t/year)	2,354,355	2,404,000

3.2. The Effect of EGR on the Plant's Performance and Different Parameters

EGR is considered as a feasible approach to avoid the huge energy penalty of CO_2 capture plants due to the relatively low concentration of CO_2 and high amount of flue gas flowrate which makes CO_2 separation costly. EGR can easily be integrated without making a significant change to the existing plant. For instance, by EGR integration, in the case of CO_2 capture with absorption method, it can be possible to reduce the flue gas flowrate enabling the capital cost reduction in response to using smaller dimensions of the absorber and stripper towers. Increased CO_2 content, on the one side, provides a better mass transfer rate which results in lower solvent pumping requirement. On the other side, risks of oxidative degradation in presence of O_2 can also be reduced with decreased O_2 content in the flue gas since O_2 is usually regarded as an impurity in the CO_2 capture process. Figure 2 indicates the effect of EGR ratios from 0 to 0.6 with 0.05 step on the molar concentration of O_2, CO_2, and combustor outlet O_2 as well as the exiting flue gas mass flowrate.

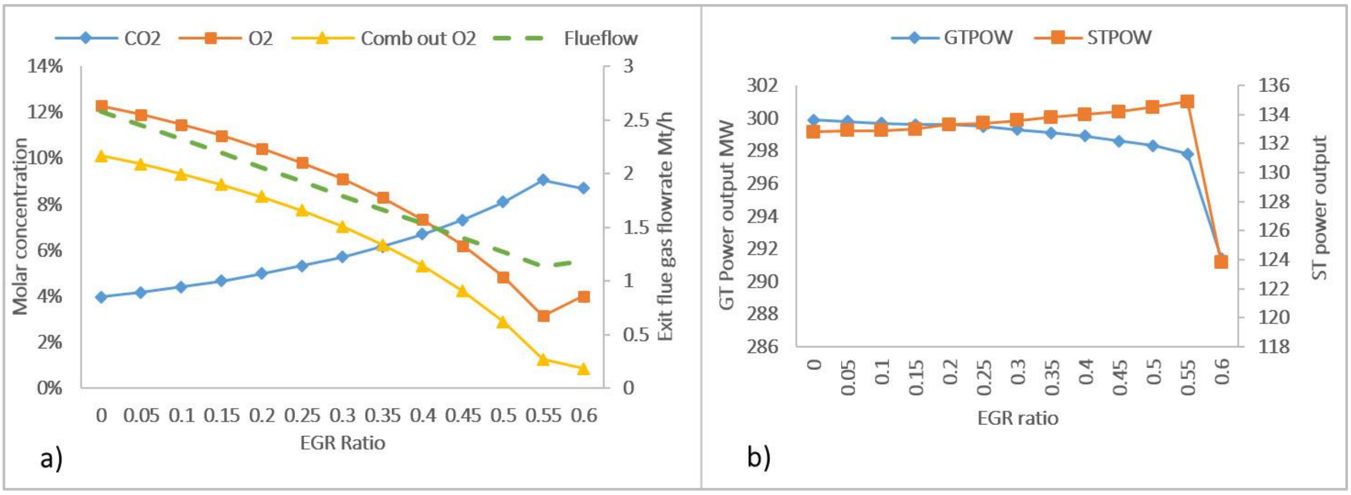

Figure 2. The effect of exhaust gas recirculation in different ratios on the exiting flue gas mass flowrate and the molar concentration of different compounds (**a**); The effect of exhaust gas recirculation on the power output of the gas turbine and steam turbines (**b**).

It can be observed from the Figure 2a that, at first glance, nearly all variables are reaching their optimal value when the EGR ratio is 0.55. After this point, the amount of ambient air cannot be reduced even though the amount of recirculated flue gas increases due to O_2 deficiency in the combustor and a significant quantity of carbon monoxide (CO) generation. However, for the combustion reaction to occur stable and for the conversion of all hydrocarbons completely, O_2 content in the combustor outlet flue gas should be between 3–4 mol%. In terms of the EGR effect on GT and ST power output, the result shows that as the EGR ratio is increased GT power output is decreasing while ST generates more power (See Figure 2b). GT power generation efficiency decrease can be explained by the fact that the flowrate of air and gas mixture coming into the compressor is slightly higher than without EGR case so as to keep the GT inlet temperature at 179–180 °C in each EGR ratio test resulting in the compressor more power consumption. For instance, the flowrate of the compressor inlet mixture gas is higher by about 1.15 kg/s at 0.05 EGR ratio and by 10.1 kg/s at 0.5 EGR ratio than the value without EGR. In the case of a positive effect of EGR on steam turbines is explained that as the EGR ratio increases the GT outlet temperature also increases resulting in more steam generation and so as the power output increase. Steam cycle power output at 0.45 of EGR ratio generates 1.05% more electricity than that without EGR.

Regarding the above-mentioned conditions, the EGR ratio at 0.45 is selected as an optimal case for this process in order to keep the flame stable in the combustor. Above this EGR ratio, there is less than 3 mol% O_2 at the combustor outlet that can impact negatively the burner and combustion process. In this selected optimal case, CO_2 content in the flue gas can be increased from 3.96 mol% to 7.32 mol% while O_2 concentration reduces from 12.28 mol% to 6.2 mol%. Flue gas mass flowrate leaving the power plant decreases by 45.8% equivalent to roughly 389 kg/s. Although the power output of GT reduces by 1.3 MW, it is compensated by the additional power generation of ST by 1.4 MW compared to the non-EGR case. Overall, EGR integration can be implemented prior to the CO_2 capture plant integration without deteriorating the plant's performance.

3.3. Suitability of Different CO_2 Capture Techniques in the Case of Turakurgan TPP

When it comes to evaluating the suitability of different CO_2 capture technologies for Turakurgan TPP, the site-specific conditions and resource availability factors of the power plant are the most essential part of the research. Another important factor that has to be taken into consideration is the characterization of the flue gas which will further be treated in a CO_2 capture plant.

Table 2. 1 Flue gas stream characteristics leaving the power plant.

Parameters	Results	Flue Gas Composition	Results (mol%)
Flue gas exit mass flowrate (kg/s)	389	N_2	0.770
		O_2	0.062
Flue gas exit temperature (°C)	103	CO_2	0.073
		H_2O	0.085
Flue gas exit pressure (bar)	0.981	Argon (Ar)	0.009
		Nitric oxide (NO)	0.001

Since the concentration of CO_2 in the flue gas is directly proportional to the capture cost [7], the CO_2 concentration of Turakurgan TPP's flue gas (7.3 mol%) after implementing 0.45 EGR ratio still remains low to integrate the adsorption method cost-effectively, while the flowrate of flue gas is also still high for successful membrane separation application. The CO_2 bio-fixation method, on the one hand, can be seen as the most feasible option for the flue gases even with very low CO_2 contents without the need for flue gas pre-treatment and captured CO_2 storage issue. On the other hand, this technique requires a huge amount of water or wastewater resources which are nearly impossible to find around the plant location. Apart from that, CO_2 bio-fixation has not reached its maturity level and the installation cost of a large number of photobioreactors is also problematic [7,8]. In this context, the only option that can be implemented is conventional chemical absorption technology with an appropriate solvent. Membrane separation is also applicable in the hybrid form with chemical absorption by partially removing CO_2 from the flue gas resulting an increase in the concentration of CO_2 and a flue gas flowrate decrease so as the reduction of huge absorption and stripper columns dimensions. However, both applicable approaches need to be thoroughly studied in all aspects including techno-economic and life cycle analysis based on site-specific conditions and available resources.

4. Conclusions

The simulation of one block of 450 MW gas and steam turbine was developed and validated using the commercial software—Aspen Plus®. According to the results, there is a good agreement between the simulation results and the power plant's project report data. An EGR ratio of 0.45 is selected as an optimal case and analyzed its effect on different parameters. Overall, based on the plant's location and resource existence, absorption with an appropriate solvent and hybrid membrane-absorption approaches are recommended to further study the possible integration and their techno-economic, life cycle analysis.

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