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Comparative Analysis of Gasification and Adiabatic Digestion of Corn for Practical Implementation in Conventional Gas Turbines

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Abstract: Clean, more responsible energy production in gas turbine power plants is a challenge. Interestingly, various alternative sources could be found in agricultural locations with great potential of being transformed from agricultural waste to energy. Corn cob gasification gas could be successfully implemented in gas turbines through co-firing with natural gas. Concurrently, agricultural biogas could also be employed for such a purpose. The technology could be implemented in locations such as Vojvodina, Serbia, which is an agricultural region with great potential for producing biogas from agricultural waste. Therefore, this paper approaches the practical implementation of gas produced by adiabatic corn digestion with CO_2 recirculation. Five different cases were assessed. The results are compared to previous analyses that used co-firing of the corn cob gasification gas in representative gas turbine systems. Impacts of the fuel composition on the characteristics of combustion were analyzed using CHEMKIN PRO with GRI–Mech 3.0. Impacts of fuel quality on the power plant performance were analyzed through calculations with a numerical model based on a Brayton cycle of 3.9 MW power output. The application shows acceptable values during co-firing with natural gas without modification of the overall system, with better outlet parameters compared to pure corn gasification gas.

Keywords: gas turbine; gasification; adiabatic digestion; corn; bioenergy; simulation; biomass

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1. Introduction

The utilization of biomass as an energy source is inefficient in many developing agricultural regions that intend to use it as alternative energy source [1]. However, biomass can provide an economically sustainable energy source as long as it is recovered from either industrial or agricultural waste. Further, advantages can also be achieved through the local reduction of fossil-based sources, with great positive impact in countries with significant energy dependance on fossil imports.

Currently, biomass power cycles are showing high potential when implemented in gas turbine power plants [2–4]. Even though their significant potentials, combustors designs for these biogases have to overcome irregularities of combusting biogas blends with lower heating value (which is about 30% of that of natural gas) [5], combustion instabilities and corrosion effects. Operating irregularities could be solved by appropriate modifications followed by certain stability passive methodologies [6]. In cases where the heating value of the biogas is significantly different compared to natural gas, operation irregularities are solved by partial fuel substitution implementing co-firing of alternative gas with natural gas [7–9]. It is known that decreased methane amounts in biogases can cause off-design operation of turbine systems [10]; therefore, the practical implementation of these biogases can be only carried out through the proper acknowledgement of thermodynamic and operational impacts that could occur in such devices. These impacts can be predicted by mathematical models [11,12], which are highly flexible and have a wide range of stability parameters.

As shown in previous analyses [12], the practical implementation of biomass gasification is a promising way of implementing biomass as an alternative fuel in gas turbine facilities [1,13], with great potential of reduction of greenhouse gases (GHGs). Biomass obtained from waste such as corn cobs is also a growing trend in corn producing regions since corn represents one of the most produced agricultural products in the world. Despite its low heating value, it has been shown that up to 40% of the corn cob gasification gas could be co-fired with natural gas with promising outlet parameters [12]. Therefore, this source presents a path to development sustainable solutions with the improvement of the local environment.

On the other hand, gas from gasification has low methane content, hence it is a low calorific gas. With these characteristics, it is not suitable for its direct use in gas turbine plants. However, by changing the gas production path from gasification to adiabatic digestion, it is possible to obtain a product gas with significant increase of methane share (~60%) [14]. This trend has been demonstrated from other digestors, which usually produce product gases that contain 55% to 65% methane, 35% to 45% carbon dioxide and <1% nitrogen [15]. Therefore, such a biogas would be of medium calorific value, and it could be possible to obtain better outlet parameters during power production [16,17]. Therefore, anaerobic digestion of biomass is a promising and proven alternative treatment of biodegradable waste [18]. Further, anaerobic digestion gas production is a technology that supports energy-efficiency improvement and environment protection with significant advantages compared to other forms of bioenergy [19,20]. Moreover, fertilizers can also be a by-product of this gas production path; thus, digestion can produce fuel and fertilizers whilst increasing its sustainability appraisal [15].

Implementation of anaerobic digestion gas in the micro-gas turbine in combination with waste heat application in adiabatic digester has shown great potential for industrial power plants [21]. Mixing of the anaerobic digestion gas with natural gas in a combined heat and power (CHP) cycle showed exergy efficiency of 50.5% with 50% anaerobic digestion gas in the fuel mixture [22]. Energy, exergy, environmental and economic analyses showed that optimal ratio of anaerobic biogas and natural gas is 0.55 in a dual fuel gas turbine cycle would be the preferred option [23,24]. Similarly, a CHP facility that combines a 30 MW gas turbine cycle, steam generator and anaerobic digestor has delivered the exergy efficiency 46.94% with 100% biogas. This number can be compared to cases where pure natural gas was employed, giving exergy efficiencies of 50.64% [22,25]. Further, related studies that approach non-premixed combustion of natural gas and biogas in micro combustors have shown that despite a decrease in methane, the right combination of swirl number and fuel injector diameters can enable adequate performance comparable to natural gas cycles whilst delivering power at low NO emissions [26,27]. New ideas of implementing anaerobic digestion gas in the gas turbine cycle that are reflected in combining gas turbine cycles are also tangible whilst combining the gas turbine cycle with CO_2 recirculation and oxy-fuel combustion in two zone models with potential for carbon capture and storage (CCS) [28], micro turbine coupled with Permanent Magnet Synchronous Generators (PMSG) [29] and combined gas turbines that employ supercritical CO_2 with cooling at the inlet of the compressor [30]. All the above analyses show high possibility of implementation biomass anaerobic digestion gas fueling with great potential of decreasing both emissions and use of fossil fuels.

Therefore, this analysis presents predictions of several parameters and practical implementation of corn cob digestion gas as a substitute of natural gas for gas turbine power plants. Results provide valuable information for implementation of this alternative source. The study is complemented by a comparison with previous studies that addressed the use of gasification, thus denoting the implications of using different product gases from the same agricultural feedstock. Through this study, it is shown that corn cob adiabatic digestion gas could be applied in a conventional energy production system with appropriate combination of minimal fuel system and gas turbine modifications for the high share of CCADG in the fuel and with significant outlet power and efficiency values.

2. Materials and Methods

2.1. Numerical Model of a Physical Cycle

In previous analyses, a bespoke model of an industrial gas turbine was employed to recognize and understand the possible changes in gas turbine cycle performance when different gas blends of corn gasification are employed [12]. The developed numerical model was calibrated and validated in previous studies against industrial systems with errors no greater than 2% [31,32]. The model is based on an integral cycle approach, considering a non-adiabatic expansion and inter-cooling across the turbine [33]. Development of the model, calibration and validation are presented elsewhere [12,34].

2.2. Gas Combustion Modeling

For determination of the composition of the combustion gases for their application in the numerical model, Table 1, analyses were done via CHEMKIN–PRO and the reaction chemical model GRI–Mech 3.0 [35–37]. Results were used in the numerical simulation of a gas turbine fed with corn gasification gas [12], and corn adiabatic digestion gas, Table 1.

Table 1. Gas composition obtained by simulation of downdraft CCGG [1] and CCADG [14,18].

	Dry CCGG	Wet CCGG	CCADG
N_2 [vol%]	43.01	47.09	0–5
CO_2 [vol%]	10.42	11.41	15–60
CO [vol%]	19.40	21.24	-
H_2 [vol%]	16.67	18.26	Traces
CH_4 * [vol%]	1.83	2.00	40–75
H_2O [vol%]	8.70	-	1–5%
H_2S [vol%]	-	-	-
O_2 [vol%]	-	-	<2
LHV [MJ/m^3]	4.90	5.37	21.48
LHV [MJ/kg]	5.26	5.77	30.00

* Fixed methane share in the gas.

Combustion simulations were performed using a hybrid of Perfectly Stirred Reactors-Plug Flow Reactor (PSR-PFR). This network assumes adequate mixing and flow characteristics representative of swirling gas turbine combustors [38]. PSR–PFR consists of two clusters; the first section is comprised of three distinct zones, namely a mixing zone for partial premixing of fuel, a flame region directly connected to the former and the central recirculation zone (CRZ) for combustion products recirculation [31,32]. Recirculation rates in PSR are approximated to 20% of the combustion products [39–41]. The second cluster is a PFR (Plug Flow Reactor) for post-flame operation along a 0.1 m duct [42], Figure 1.

2.3. Fuel Selection

For this work, two types of corn gases were considered: (1) gas from corn cob gasification (CCGG) obtained experimentally [1], and (2) corn adiabatic digestion gas (CCADG) whose composition is based on an approximation of mean values from facilities where corn adiabatic digestion gas has been produced CCADG [14,18]. The corn cob gasified gas has a low share of methane (~2%) and, therefore, low calorific value, Table 1. Further, analyses were done using dry conditions. Simultaneously, the analyzed adiabatic digestion gas was considered with a high methane share (60%) and 40% of carbon dioxide, Table 1 CCADG.

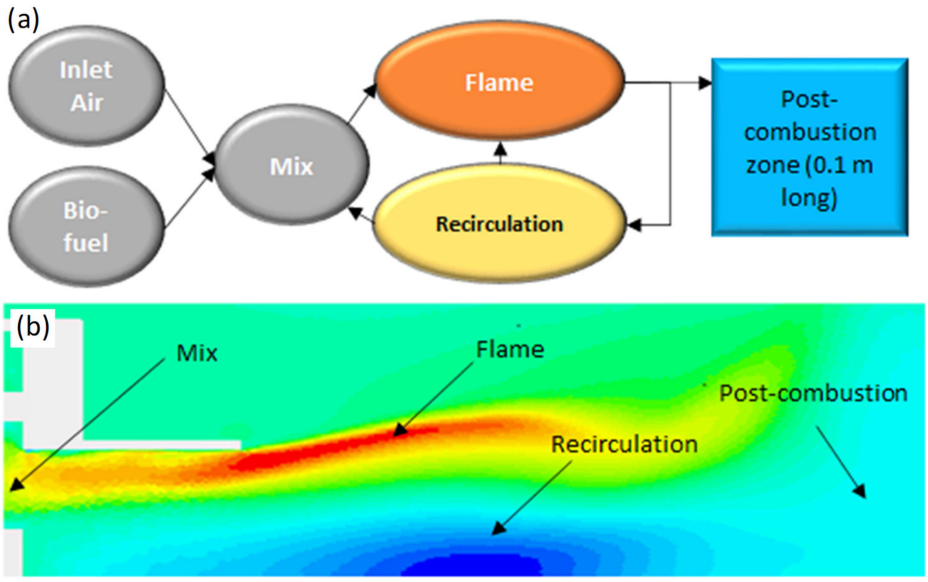


Figure 1. (**a**) PSR-PFR Schematic; (**b**) Model flame.

The CCGG gas delivers a Wobbe Index (WI) difference of 80% when compared to natural gas, while for CCADG, this difference is only 44%. For cases where the WI difference is above 50%, these gases can only be used in conventional gas turbine cycles only through co-firing with natural gas [43]. In previous analyses [12], CCGG was co-fired with natural gas. Analyses were done for fuel blends with different CCGG ratios from 0% to 40% of CCGG in co-firing modes with natural gas. Results from that study are compared to the performance of corn adiabatic digestion gas in the same conventional gas turbine [12]. Five fuel blends with different gas ratios were also defined with increments of 10% between cases. The selected fuel blends are presented in Tables 2 and 3, respectively.

Table 2. The selected fuel blends composition (CCGG and natural gas).

Composition [Molar Fraction]	0% CCGG	10% CCGG	20% CCGG	30% CCGG	40% CCGG
CH_4	0.9247	0.8342	0.7438	0.6533	0.5628
C_2H_6	0.0350	0.0315	0.0280	0.0245	0.0210
C_3H_8	0.0132	0.0119	0.0106	0.0092	0.0079
C_4H_{10}	0.0022	0.0019	0.0018	0.0015	0.0013
C_5H_{12}	0.0006	0.0005	0.0006	0.0004	0.0004
N_2	0.0175	0.0588	0.1000	0.1413	0.1825
H_2	0.0000	0.0167	0.0333	0.0500	0.0667
CO	0.0000	0.0194	0.0388	0.0582	0.0776
H_2O	0.0000	0.0087	0.0174	0.0261	0.0348
CO_2	0.0068	0.0165	0.0263	0.0360	0.0458

Table 3. The selected fuel blends composition (CCADG and natural gas).

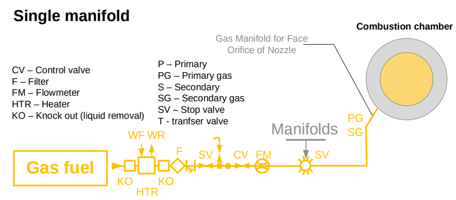
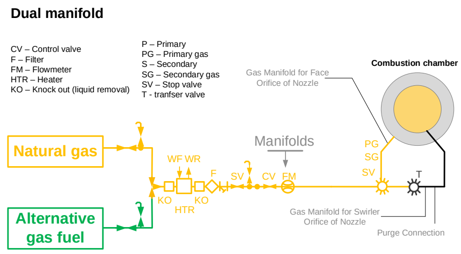
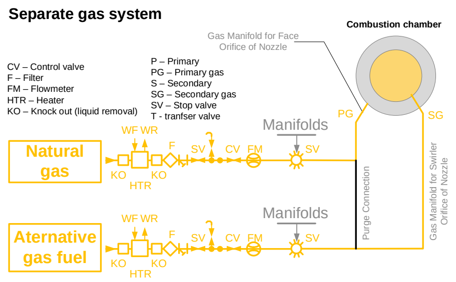
Composition [Molar Fraction]	0% CCADG	10% CCADG	20% CCADG	30% CCADG	40% CCADG
CH_4	0.9247	0.8922	0.8598	0.8273	0.7948
C_2H_6	0.0350	0.0315	0.0280	0.0245	0.0210
C_3H_8	0.0132	0.0119	0.0106	0.0092	0.0079
C_4H_{10}	0.0022	0.0019	0.0018	0.0015	0.0013
C_5H_{12}	0.0006	0.0005	0.0005	0.0004	0.0004
N_2	0.0175	0.0158	0.0140	0.0123	0.0105
CO_2	0.0068	0.0461	0.0854	0.1248	0.1641

The results from CHEMKIN-PRO were used in a gas turbine cycle simulation for prediction of the thermodynamic parameters of all cases The matrix of the corn cob combustion tests is given in Table 4, while the results for corn adiabatic digestion gas are presented in Table 5.

Table 4. Parameters at the combustion chamber inlet.

Case	Inlet Data—Mass Flows and ER				Pressure		
	m_{fuel} [kg/s]	m_{air} [kg/s]	ER CCGG [-]	ER CCADG [-]	p_{fuel} [bar]	p_{air} [bar]	$p_{combustion}$ [bar]
1	0.29	14.47	0.89	0.89	11.22	9.69	9.69
2	0.29	14.47	0.78	0.81	11.22	9.69	9.69
3	0.29	14.47	0.68	0.73	11.22	9.69	9.69
4	0.29	14.47	0.58	0.67	11.22	9.69	9.69
5	0.29	14.47	0.49	0.61	11.22	9.69	9.69

Table 5. Types of manifold injection systems.

Type	ΔWI	Field of Application	Graphical Scheme
Single manifold fuel system	~5%	one type of fuel	
Dual manifold fuel system	5% (or 10%) to 25%	two types of fuels	
Separate gas fuel systems	greater than 50%	two types of fuels	

2.4. Types of Manifold Injection

Various manifold injection systems were considered for this analysis, i.e., single manifold, dual manifold and separate gas system [12]. In this analysis, all three systems were analyzed for the purpose of co-firing the alternative gas, either CCGG or CCADG, in a conventional gas turbine. Each of them has different purposes for various flow rate applications, Table 5.

For cases with a WI difference in a range from 25% to 50%, both the dual manifold fuel system and separate gas systems could be employed [43]. However, other limitation criteria need to be analyzed before final selection, for example, the fuel propulsion, the maximum fuel velocity value (20 m/s), etc. [44].

3. Results and Discussion

3.1. Reaction Modeling

Increase of CCGG share in the fuel blend decreases the adiabatic temperature ~7% for every 10% of the CCGG share, while an increase of CCADG share in the fuel mixture decreases the adiabatic temperature ~5% for every 10% of the CCADG share, Figure 2.

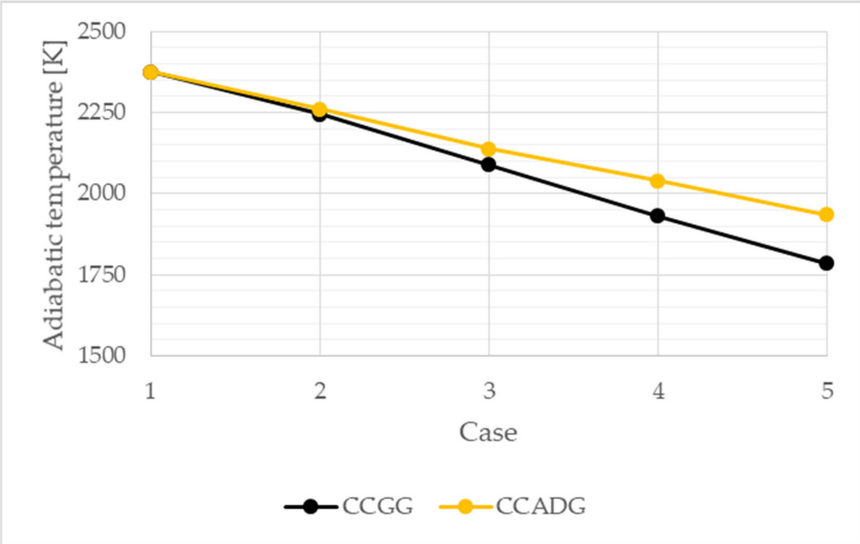


Figure 2. Change of adiabatic combustion temperature through composition change of fuel blend for the considered cases for corn cob gasification gas and corn adiabatic digestion gas.

In order to track the impacts of fuel quality changes, and therefore the gases in the combustion products, the following species were analyzed: oxygen, water vapor, carbon dioxide and nitrogen, Figures 7–10. All the analyses were done using the combustion products' specific heats [34].

By increasing of the share of the alternative gas in the fuel blend, in both fuel types, the oxygen share in the combustion products has increased, with a change in ~30% for every 10% of the CCGG share and ~26% for every 10% of the CCADG share, Figure 3. The higher increase of the oxygen in the combustion products with CCGG is due to higher amounts of oxygen in such a fuel. In the case of the water vapor, there is a decrease in both cases with an increase of alternative gas share, Figure 4, with ~14% for every 10% of the CCGG share and ~9% for every 10% of the CCADG share. This is caused due to the lower number of hydrocarbons in the reactants. Higher content of water vapor in the combustion products of CCADG is due to the higher amount of the hydrocarbons in such a gas compared to CCGG.

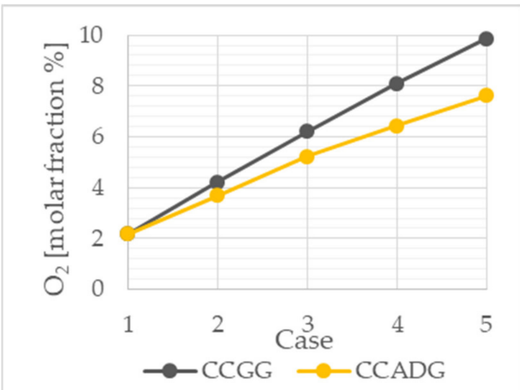


Figure 3. Change of oxygen content.

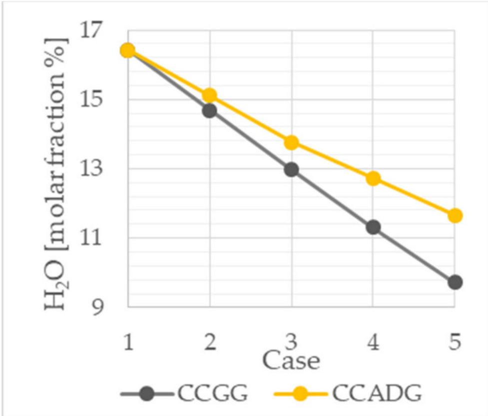


Figure 4. Change of water vapor content.

The carbon dioxide content in the combustion products was lower with an increase of the alternative gas share, with ~11% for every 10% of the CCGG share and ~4% for every 10% of the CCADG share. Regarding CO_2 emissions, CCGG combustion showed a higher CO_2 decrease due to its higher share of oxygen and lower share of methane, Figure 5. Finally, the nitrogen share content was higher with ~1% for every 10% of the CCGG share and ~0.5% for every 10% of the CCADG share. As expected, the nitrogen increases in the combustion products with the higher share of the CCGG in the fuel and is almost double the value compared to the CCADG case, which is a consequence of the significantly high amount of nitrogen in the CCGG, Figure 6.

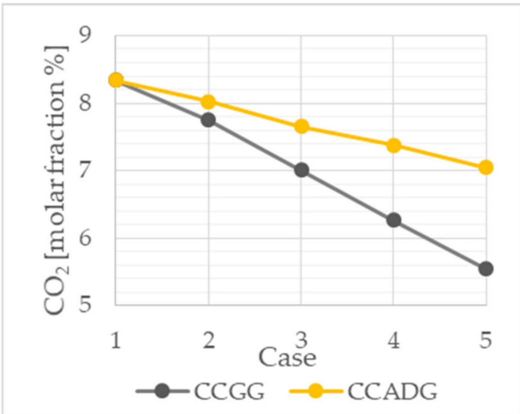


Figure 5. Change of carbon dioxide content.

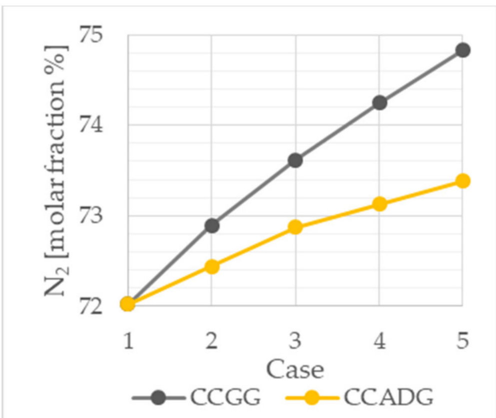
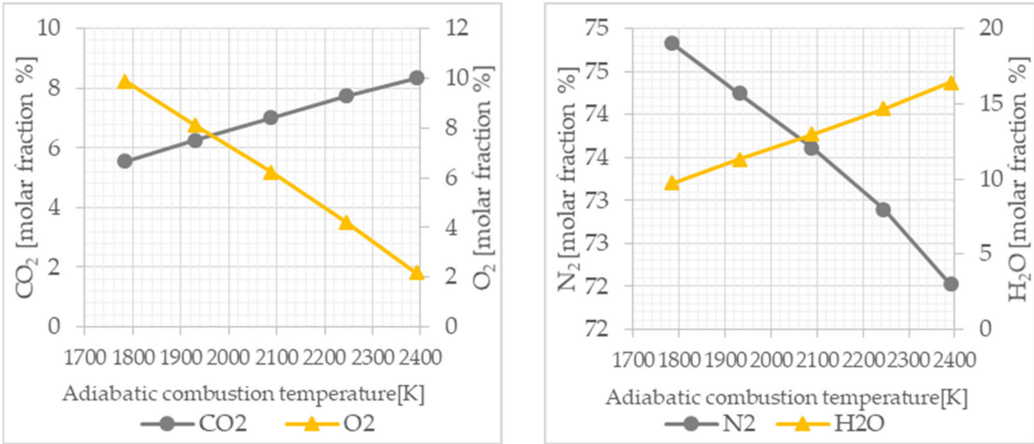


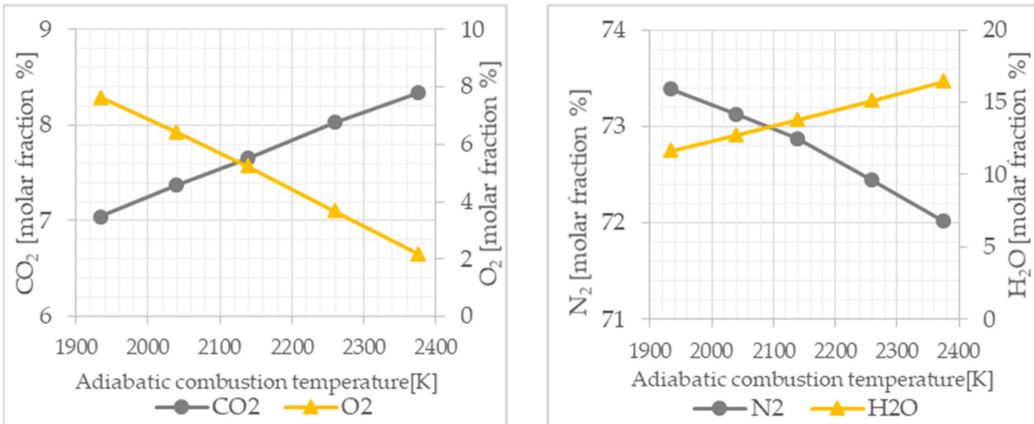
Figure 6. Change of nitrogen content.

The variations of species such as of oxygen, water vapor, carbon dioxide and nitrogen were also assessed with respect to the adiabatic combustion temperature, Figures 7 and 8.



(**a**) (**b**)

Figure 7. Composition change of the combustion products (**a**) carbon dioxide and oxygen and (**b**) nitrogen and water vapor as a function of adiabatic combustion temperature for CCGG combustion.



(**a**) (**b**)

Figure 8. Composition change of the combustion products (**a**) carbon dioxide and oxygen and (**b**) nitrogen and water vapor as a function of adiabatic combustion temperature for CCADG combustion.

3.2. Gas Turbine Simulation

Further, the five different cases were analyzed for modeling purposes. The fuel flows in both scenarios, i.e., CCGG and CCADG, were calculated on the basis of the case with pure natural gas. The analyzed indicators of the gas turbine cycle were supplied heat, power, gas turbine plant efficiency and turbine outlet temperature. With higher content of the alternative gas in fuel mixture, there is a decrease of the specific heat value due to a decrease of heating value of the fuel, Figure 9. Simultaneously, the decrease of supplied heat is lower in the CCGG scenario due to lower heating values of CCGG compared to CCADG. For example, in case 5, the supplied heat value of CCADG is about 11% higher than CCGG.

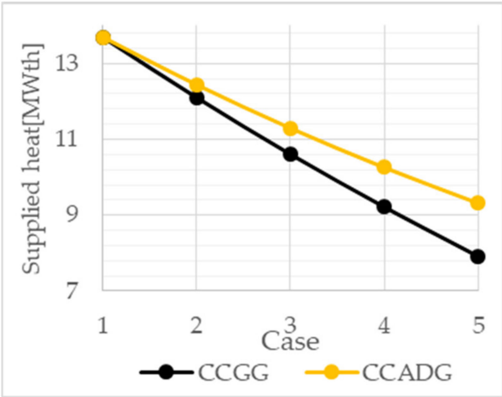


Figure 9. Change of supplied heat as a function of fuel composition for the considered scenarios with CCGG and CCADG, respectively.

Concurrently, a high share of alternative gas in the fuel mixture leads to lower power as a consequence of the lower fuel heating value, Figure 10. A decrease in power is also lower in the CCADG scenario, especially for cases with higher content of alternative gas share in the fuel blend. For example, in case 4, the produced power in the CCADG scenario is ~8% higher than in the scenario with CCGG, while for case 5, the difference between both scenarios is ~15%.

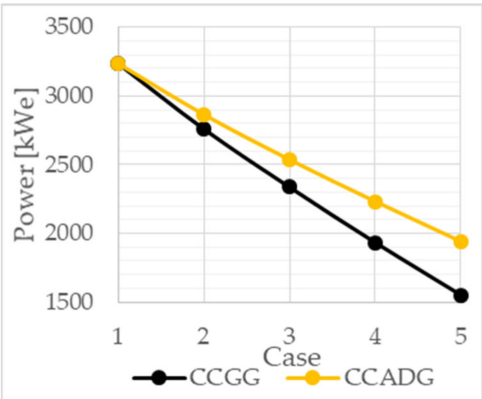


Figure 10. Change of produced power as a function of fuel composition for the considered scenarios with CCGG and CCADG, respectively.

The efficiency of the gas turbine cycle differs significantly in the cases with higher alternative gas content. As shown in Figure 11, with every 10% increase of the CCGG share in the fuel blend, the efficiency is lower for ~4% or 0.9 percent points, while for CCADG, the gas turbine plant efficiency decreases ~ 3% or 0.7 percent points. The main reason for the lower efficiency value is the lower fuel energy content and the change of the combustion product's density.

Similarly, the supplied heat decreases by increasing the alternative gas content in the fuel mixture, causing a decrease of the combustion products temperature at the end of the combustion chamber. Variation of the temperature at the turbine inlet will cause a decrease of temperature at the turbine outlet, Figure 12. Temperature decreases as a function of fuel composition with lower temperatures for the CCGG scenario, as shown in Figure 12.

One of the analyzed criteria for these alternative gas applications was gas turbine propulsion. Analyses show that the combustion products' flow rates for all cases are at their maximum possible flow rate, Figure 13.

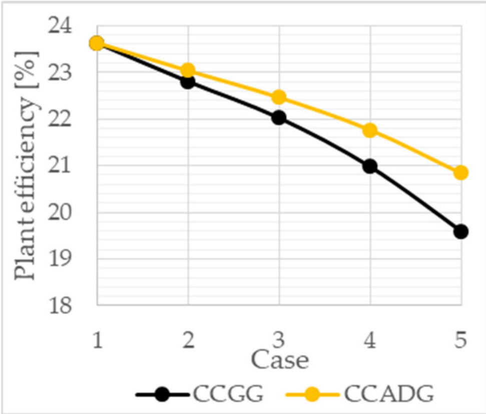


Figure 11. Change of gas turbine plant efficiency as a function of fuel composition for the considered scenarios with CCGG and CCADG, respectively.

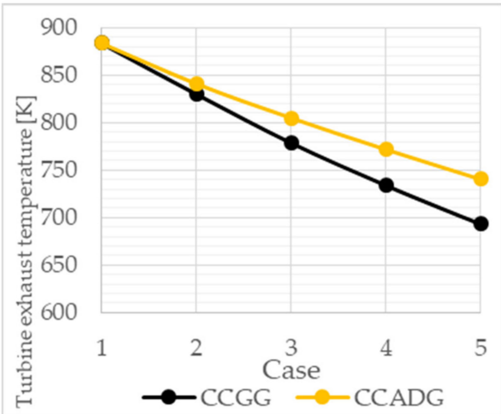


Figure 12. Change of turbine exhaust temperature as a function of fuel composition for the considered scenarios with CCGG and CCADG, respectively.

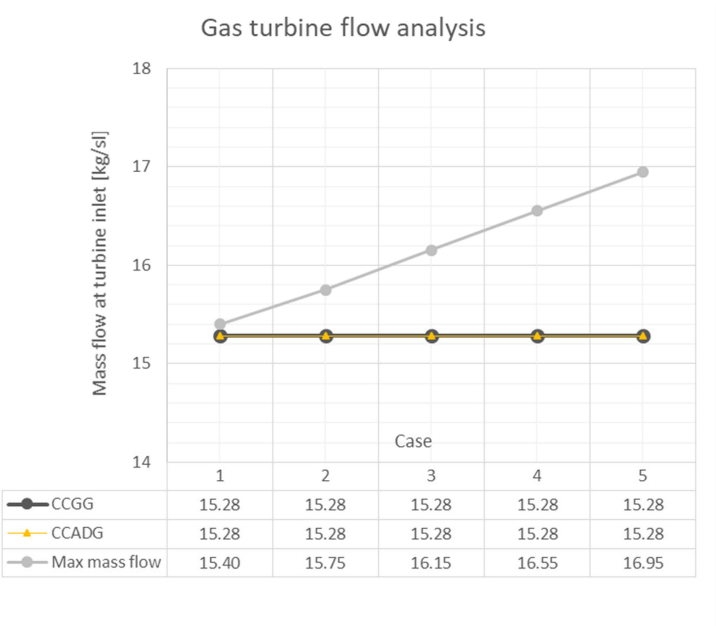


Figure 13. Maximum possible flow rates through the gas turbine, for CCGG and CCADG, respectively, compared to the maximum mass flows through the gas turbine calculated for natural gas.

Considering the Wobbe Index differences, seen in Figure 14, a standard single manifold fuel system without modifications can be employed for cases 1 and 2 for both CCGG and CCADG, since WI differences are less than 10% [44]. For cases 3, 4 and 5, WI differences are greater than 10% and lower than 50%; therefore, it is necessary to modify the fuel system to a dual manifold system [43].

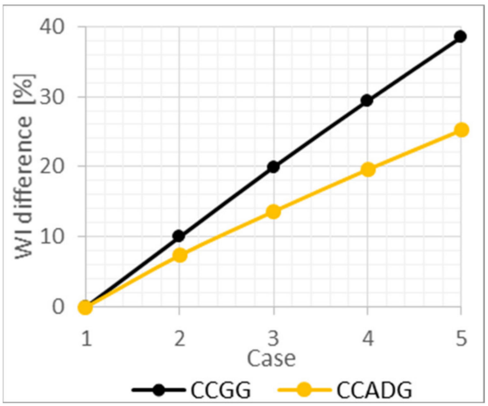


Figure 14. Change of WI difference.

Regarding the fuel propulsion, analyses show that fuel velocity for all cases is at their maximum permissible value of 20 m/s [45], Figure 15; therefore, is not necessary to modify the fuel system to separate fuel entries [46].

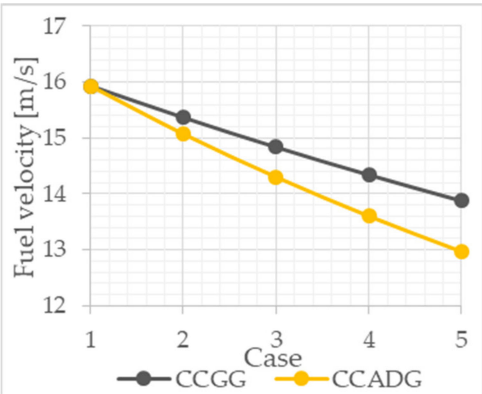


Figure 15. Fuel velocity change.

Overall, results show that conventional fuel systems without any modifications could be applied for cases 1 and 2, in both considered scenarios, while, for cases 3, 4 and 5, it is recommended to upgrade the fuel system to a dual manifold system [43].

3.3. NOx Emissions

The analysis of the NOx emission has been performed to investigate the effect of fuel composition changes. In this analysis, NO and NO_2 were considered for all five cases of both CCGG and CCADG, from pure natural gas to 40% alternative gas in the fuel mixture. CHEMKIN-PRO results of the combustion products are presented in Figures 16 and 17. The results show a decrease of both NO and NO_2 values with an increase of alternative gas in the fuel blend. For every 10% increase of alternative gas in the fuel blend, NO values decrease ~75% with CCGG and about 61% with CCADG. NO_2 values decrease ~61% with CCGG and about 37% with CCADG for every 10% increase of alternative gas share in the fuel blend. Considering the NOx emissions, the corn cob gasification gas has shown significant advantage compared to corn adiabatic digestion gas, especially in those cases of co-firing of fuel blends with higher shares of alternative gas. The phenomenon is related to the lower temperatures of combustion, hence lower Zeldovich NO emissions. Simultaneously, the reduced oxygen content leads to lower NO_2 for the CCG gas, whereas the CADG blend produces a higher concentration, which is linked to the presence of higher fuel oxygen in the blend that post-reacts with NO formed at the flame front.

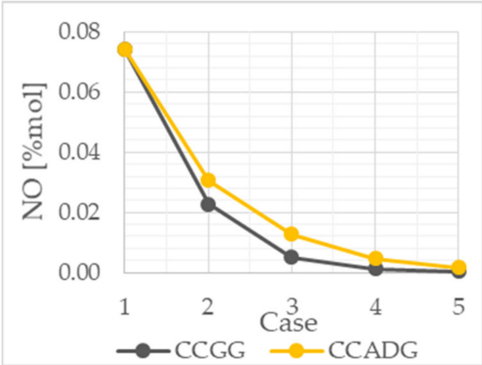


Figure 16. Change of NO.

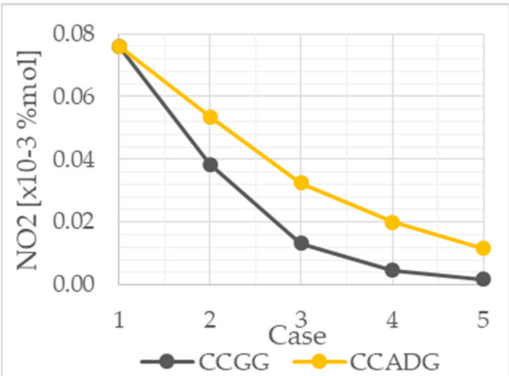


Figure 17. Change of NO_2.

4. Conclusions

The present concept investigates possibilities of practical implementation of gases that originate from biomass. The main advantage of biomass gas implementation in conventional energy production systems is tangible via the substitution of fossil fuels by alternative fuels. For this analysis, corn cob gasification gas and corn adiabatic digestion gas were investigated to determine the impacts of the fuel quality on a conventional gas turbine cycle. The analyzed alternative gases cannot be implemented in a gas turbine plant by themselves. Therefore, for the implementation of the analyzed alternative gases co-firing with natural gas is required. Two scenarios were numerically simulated: the implementation of corn cob gasification gas and corn adiabatic digestion gas. Various fuel mixtures with different alternative gas ratios were analyzed. Reaction modeling results show a lower value of the adiabatic temperature: ~7% per 10% CCGG share and 5% per 10% CCADG. The amount of the O_2 and N_2 is higher, while water vapor and CO_2 are lower with the addition of the alternative gas in the fuel mixture of both scenarios. The results also show that the analyzed parameters of power, temperature, heat and efficiency are significantly lower with the higher amounts of alternative gas in the fuel mixture, with better potential when using CCADG. In addition, cases with 10% alternative gas share can operate with conventional fuel systems designed for natural gas. On the other hand, alternative gas shares of 20% to 40% require a dual manifold system. Finally, NOx emissions tend to decrease tenfold as the share of biogas increases. Further analyses should be performed to increase the share of corn adiabatic digestion gas in the fuel mixture up to the possible 70% according to the Wobbe index differences. Therefore, the obtained results for CCADG are of great value for agricultural regions such as Serbia with great potential for adiabatic digestion gas production and implementation of the CCADG in electricity production in gas turbine facilities.

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