https://doi.org/10.1051/e3sconf/202340703001

Enhancing Efficiency of Corncob-Fired Power Generation with Carbon Capture and Storage

George Victor Brigagão[1,*], *Matheus de Andrade* Cruz[1], *Ofélia de Queiroz Fernandes* Araújo[1], and *José Luiz* de Medeiros[1]

[1]Environmental Engineering Program, Escola Politécnica & Escola de Química, Universidade Federal do Rio de Janeiro, Av. Athos da Silveira Ramos 149, Rio de Janeiro, Brazil

Abstract. Bioenergy from biomass wastes with carbon capture and storage (CCS) is an important way to compensate for hard-to-abate emissions and collaborate with decarbonizing the energy industry. This work evaluates a corncob-fired power generation with CCS regarding overall energy efficiency in two process alternatives: (a) post-combustion CO_2 capture by an aqueous blend of methyl-diethanolamine and piperazine; and (b) oxy-combustion coupled to state-of-art air separation unit. The alternatives are simulated in Aspen HYSYS and compared with a conventional plant to evaluate the energy penalty of capturing CO_2. The lean solvent composition is optimized for the lowest regeneration heat demand (2.92 GJ/t_{CO2}). Post-combustion capture designed for 90% CO_2 abatement presents an efficiency penalty of 7.96%LHV. In contrast, Oxy-combustion has zero CO_2 emissions and outperforms Post-combustion with a lower penalty of 6.77%LHV, given a chance to have oxygen supplied at an energy cost of 139 kWh/tO_2. To render Post-combustion the most efficient route, it would be necessary to have its reboiler heat ratio reduced to 2.30 GJ/t_{CO2}.

1 Introduction

One of the main challenges of the century is to decarbonize the economy to limit global warming according to the Paris Agreement targets while meeting the increasing global energy demand. Energy transition towards Net-Zero Emissions (NZE) moves the energy industry toward a renewable-based matrix. Although noticeable advancements are in course, fossil fuel substitution is not occurring due to the steep expansion in energy demand and energy security concerns. Decarbonization of fossil energy is required while renewable energy supply and storage are not widely stablished, and the most attractive alternative is the use of carbon capture, utilization, and storage (CCUS). The concept can be applied to power generation with fossil fuels, allowing $\geq$90% CO_2 abatement, and to biomass-based processes, where net negative CO_2 emissions is achievable, by considering the life cycle of carbon [1]. The latter pathway is also known as bioenergy with carbon capture and storage (BECCS), considered by IPCC as an essential tool to compensate hard-to-abate emissions and thus allow limiting global temperature increase below 2°C [2].

---

[*] Corresponding author: george.victor@poli.ufrj.br

In the context of BECCS systems, using biomass wastes reduces environmental and social issues related to biomass cultivation for energy purposes [3]. Among possible waste biomass resources, corncob stands out with reduced mineral [4] and nitrogen contents [5], which favor its use for combustion [4], besides presenting large availability in many countries. The resource is not always well availed, left to decay in crop fields [5] when it is not used as fuel or crushed to serve as animal food. When it is consumed for heat and power generation, the current practice is to release the exhaust gas into the atmosphere. However, the process could be adapted to mitigate emissions through the BECCS concept, avoiding the return of biogenic CO_2 to the environment.

This work evaluates corncob-fired power generation as a waste-to-power BECCS system capable of carbon dioxide removal from the atmosphere. Post-combustion CO_2 capture with aqueous-blended amines is compared in terms of overall efficiency with oxy-combustion coupled to a standalone air separation unit (ASU). Heating demand sensitivity is evaluated for solvent composition and CO_2 mass fraction in lean amine for a given capture efficiency and minimum approach in the rich/lean-solvent heat exchanger.

2 Methods

Figure 1 presents an overview of the considered BECCS alternatives: (a) post-combustion CO_2 capture via chemical absorption with aqueous blended-amine solution (Fig. 1a); and (b) oxy-combustion CO_2 capture (Fig. 1b), where gaseous oxygen (GOX) is supplied by different alternatives of air separation unit. The conventional CO_2-emitting process is also simulated, comprising only the first block of Fig. 1a. In case (a), the lean (treated) flue gas from the absorption plant is released into the atmosphere containing 10% of generated CO_2 (90% capture efficiency), while pure CO_2 is sent to compression, dehydration, and pumping. In case (b), part of the flue gas is recycled to the burners to keep the combustion temperature the same as in air-blown case (a), and the remaining part is compressed, dehydrated, and pumped. No further purification is considered. In all cases, the CO_2-fluid is dehydrated by triethylene glycol (TEG) at 60 bar and exported with 150 ppm(mol) H_2O at 150 bar.

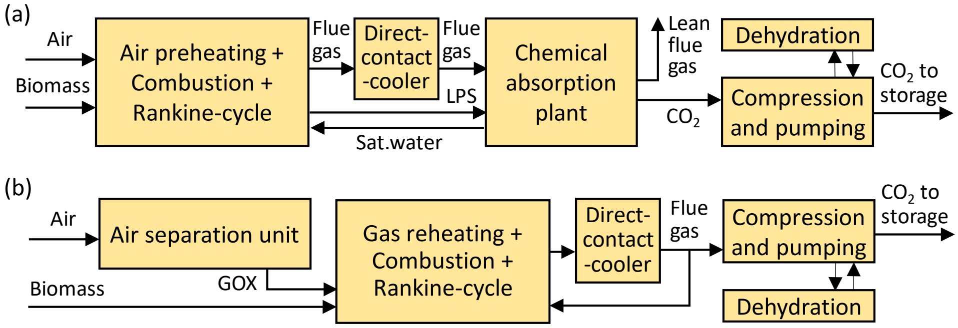
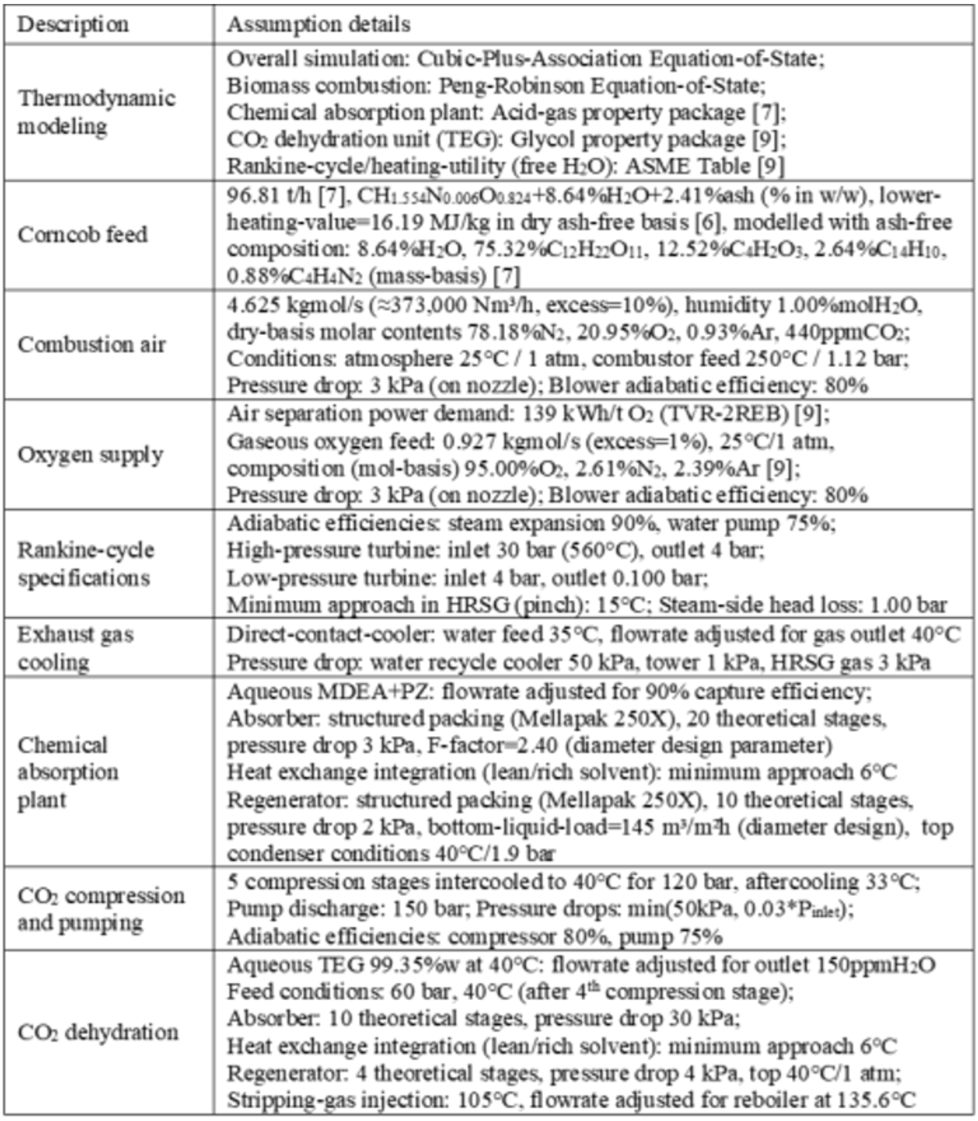


Fig. 1. Overview of considered power generation alternatives with carbon capture and storage: (a) post-combustion with chemical absorption; (b) oxy-combustion coupled to air separation unit.

The process alternatives are simulated with Aspen HYSYS v12.1. The main simulation premises are summarized in Table 1. Cubic-Plus-Association Equation-of-State is utilized for thermodynamic modeling, except in the following special cases: biomass combustion, free H_2O systems, chemical absorption plant, and CO_2 dehydration unit, where Peng-Robinson, ASME Table, Acid-gas and Glycol property package are utilized, respectively. The thermodynamic packages are employed with the binary interaction parameters available from the software database.

The same biomass feed of 96.81 t/h of grinded corncobs is applied to all processes, of which 8.64%w is moisture and 2.41%w is ash [6]. To represent the biochemical composition of corncobs, the same procedure described in [7] is availed, with a basis on the lower heating value and elemental composition of biomass from [6]. It is assumed that the particle size distribution of input biomass is suitable for complete conversion in the boiler, which is approached with 10% of combustion air excess. A simple Rankine cycle is adopted, with superheated steam generation at 560°C and 30 bar. The high-pressure turbine discharge is at 4 bar, and a part of this steam is utilized as a heating utility in the plant, supplying reboiler heat duties in amine and TEG regeneration. CO_2 absorption by an aqueous solution of methyl-diethanolamine (MDEA) blended with piperazine (PZ) in different proportions is considered, given the relatively high CO_2 content in the flue gas and the better stability in the presence of O_2 and SO_2 comparatively to monoethanolamine (MEA) [8].

Table 1. Simulation premises.



Description	Assumption details
Thermodynamic modeling	Overall simulation: Cubic-Plus-Association Equation-of-State; Biomass combustion: Peng-Robinson Equation-of-State; Chemical absorption plant: Acid-gas property package [7]; CO_2 dehydration unit (TEG): Glycol property package [9]; Rankine-cycle/heating-utility (free H_2O): ASME Table [9]
Corncob feed	96.81 t/h [7], $CH_{1.554}N_{0.006}O_{0.824}$+8.64%$H_2O$+2.41%ash (% in w/w), lower-heating-value=16.19 MJ/kg in dry ash-free basis [6], modelled with ash-free composition: 8.64%H_2O, 75.32%$C_{12}H_{22}O_{11}$, 12.52%$C_4H_2O_3$, 2.64%$C_{14}H_{10}$, 0.88%$C_4H_4N_2$ (mass-basis) [7]
Combustion air	4.625 kgmol/s (≈373,000 Nm^3/h, excess=10%), humidity 1.00%molH_2O, dry-basis molar contents 78.18%N_2, 20.95%O_2, 0.93%Ar, 440ppmCO_2; Conditions: atmosphere 25°C / 1 atm, combustor feed 250°C / 1.12 bar; Pressure drop: 3 kPa (on nozzle); Blower adiabatic efficiency: 80%
Oxygen supply	Air separation power demand: 139 kWh/t O_2 (TVR-2REB) [9]; Gaseous oxygen feed: 0.927 kgmol/s (excess=1%), 25°C/1 atm, composition (mol-basis) 95.00%O_2, 2.61%N_2, 2.39%Ar [9]; Pressure drop: 3 kPa (on nozzle); Blower adiabatic efficiency: 80%
Rankine-cycle specifications	Adiabatic efficiencies: steam expansion 90%, water pump 75%; High-pressure turbine: inlet 30 bar (560°C), outlet 4 bar; Low-pressure turbine: inlet 4 bar, outlet 0.100 bar; Minimum approach in HRSG (pinch): 15°C; Steam-side head loss: 1.00 bar
Exhaust gas cooling	Direct-contact-cooler: water feed 35°C, flowrate adjusted for gas outlet 40°C Pressure drop: water recycle cooler 50 kPa, tower 1 kPa, HRSG gas 3 kPa
Chemical absorption plant	Aqueous MDEA+PZ: flowrate adjusted for 90% capture efficiency; Absorber: structured packing (Mellapak 250X), 20 theoretical stages, pressure drop 3 kPa, F-factor=2.40 (diameter design parameter) Heat exchange integration (lean/rich solvent): minimum approach 6°C Regenerator: structured packing (Mellapak 250X), 10 theoretical stages, pressure drop 2 kPa, bottom-liquid-load=145 m^3/m^2h (diameter design), top condenser conditions 40°C/1.9 bar
CO_2 compression and pumping	5 compression stages intercooled to 40°C for 120 bar, aftercooling 33°C; Pump discharge: 150 bar; Pressure drops: min(50kPa, 0.03*P_{inlet}); Adiabatic efficiencies: compressor 80%, pump 75%
CO_2 dehydration	Aqueous TEG 99.35%w at 40°C: flowrate adjusted for outlet 150ppmH_2O Feed conditions: 60 bar, 40°C (after 4th compression stage); Absorber: 10 theoretical stages, pressure drop 30 kPa; Heat exchange integration (lean/rich solvent): minimum approach 6°C Regenerator: 4 theoretical stages, pressure drop 4 kPa, top 40°C/1 atm; Stripping-gas injection: 105°C, flowrate adjusted for reboiler at 135.6°C

*HRSG≡Heat-recovery-steam-generator

3 Results and Discussion

Table 2 presents the composition of selected process streams, and Table 3 summarizes the main results from the process simulation. The flue gas leaving the HRSG to the direct-contact-cooler (DCC) in the Post-combustion case has the same composition and flowrate as its counterpart in the Conventional process since the only upstream modifications for CO_2 capture are applied in the configuration of the steam cycle for the supply of steam to the solvent regeneration reboilers. The chemical absorption plant receives cooled gas from the DCC and produces lean gas with ≈90% less CO_2 for atmospheric emission. The captured CO_2 is compressed, dehydrated, and pumped, resulting in 127.7 t/h of exported CO_2-fluid (99.9%mol). In contrast, the oxy-combustion case has zero emission to the atmosphere and a less pure exported CO_2-fluid (93.9%mol), as CO_2 end-purification is not included. Since GOX feed is assumed at 95%mol purity with slight excess of 1% and gas recycle is utilized for combustion temperature abatement, as usually prescribed for oxyfuel conditions, the flue gas is constituted mainly by CO_2 (70.9%mol) and H_2O (24.5%mol), with air species present in minor but relevant contents. These latter are due to 1% excess and use of impure GOX 95%mol, which originates ≈90% of the N_2 in exported CO_2-fluid. Utilization of GOX at higher purities can be considered for a greater CO_2 purity and improved performance if N_2-free cryogenic separation of O_2/Ar species is avoided due to close boiling points and significantly higher power consumption above 97%mol O_2 [9-11].

Table 2. Molar composition of process streams.

Case	Item	CO_2	N_2	O_2	Ar	H_2O
Conventional (no CCS)	Flue gas to stack	0.164	0.654	0.016	0.008	0.158
Post-combustion	Flue gas to DCC	0.164	0.654	0.016	0.008	0.158
Post-combustion	Cooled gas to absorber	0.180	0.722	0.018	0.009	0.071
Post-combustion	Exported CO_2-fluid	0.999	0.000	0.000	0.000	0.000
Post-combustion	Lean gas to stack	0.022	0.883	0.022	0.010	0.063
Oxy-combustion	Flue gas to DCC	0.709	0.021	0.007	0.018	0.245
Oxy-combustion	Cooled gas for recycle	0.870	0.026	0.008	0.022	0.073
Oxy-combustion	Exported CO_2-fluid	0.939	0.028	0.009	0.023	0.000

3.1. Post-combustion

Table 3 reveals a major reduction of turbines' output power in the Post-Combustion case comparatively to the conventional process. This results from extracting a significant portion of low-pressure steam (LPS) from the Rankine cycle to meet solvent regeneration requirements, totaling 103.5 MW, of which only ≈0.1 MW is for TEG, due to the low purification service of the dehydration unit. The high requirement of the amine system is compatible with large CO_2 flow to the chemical absorption plant, as revealed by the relatively high CO_2 content of 18.0%mol for flue gas. The value is compatible with a heat ratio of 2.92 GJ/t for recovering 127.6 t/h CO_2 (90% of absorber inlet CO_2). This ratio was obtained after optimization of lean amine composition. To illustrate the heat ratio response to this composition, Figs. 2a-d present a sensitivity analysis to CO_2 and PZ mass percentages for 4 levels of H_2O content.

Table 3. Summary of main simulation results.

Item	Conventional	Post-combustion	Oxy-combustion	Unit
Biomass lower-heating-value	377.8	377.8	377.8	MW
Gross power (steam turbine)	119.7	103.2	123.4	MW
Net power (overall plant)	118.0	87.12	92.46	MW
Power demand for GOX supply	–	–	14.30	MW
Heating demand (Amine+TEG)	–	106.3	0.12	MW
Export gas mass flowrate	–	127.7	148.4	t/h
CO_2 content in export gas	–	99.95	95.33	%w
CO_2 total emission	141.8	13.58	0.02	t/h
Specific CO_2 emission	1.201	0.161	0.000	t/MWh
Overall efficiency	31.24	23.28	24.47	%LHV

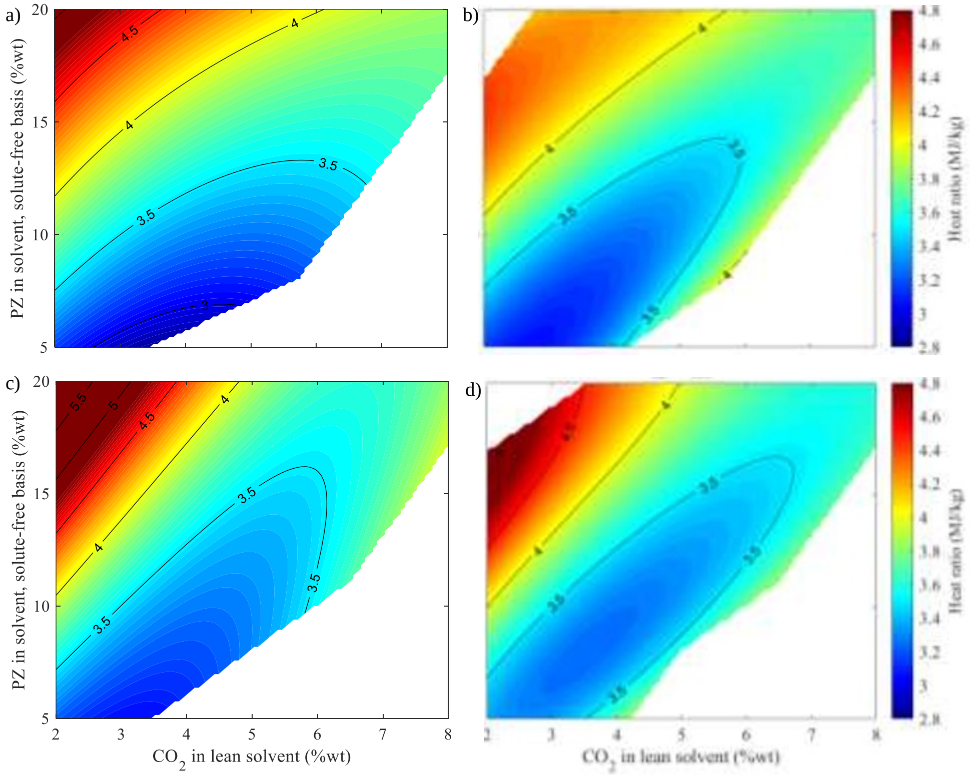


Fig. 2. Heat ratio sensitivity (MJ/kg CO_2 captured) to variations in CO_2 content in lean solvent, piperazine and water weight percentages: (a) 45%wH_2O; (b) 50%wH_2O; (c) 55%wH_2O; (d) 60%wH_2O (solute-free basis).

The best lean amine composition has 2.85%w CO_2 in MDEA/PZ/H_2O solvent with mass proportion 50/5/45, which results in 2.92 GJ/t. For the sake of heat ratio comparison with a conventional solvent, aqueous monoethanolamine (MEA) was also simulated for current assumptions, and after optimization of lean amine composition for treating cooled gas leaving DCC (composition shown in Table 2) for the minimum heat ratio, 3.53 GJ/t was found for 35%wMEA (solute-free basis) with loading of 0.397 molCO_2/molMEA. The relatively high loading is mostly explained by the high CO_2 content in flue gas, which facilitates separation and allows the lean gas to leave the absorber at a proportionally higher CO_2 content. With some modifications in the amine process configuration, a lower heat ratio is likely achievable, as Zhou et al. investigated [12]. Their work indicated a higher PZ content for optimum efficiency, probably due to a lower CO_2 content in their flue gas. It should yet be noted that all results of sensitivity analysis and optimization of lean amine composition relies on Aspen HYSYS v12.1 data and its updated version of Acid-Gas property package. For a future work in determination of optimum amine blend composition, the operation pressure of regeneration column could also be subject of optimization, for the highest overall efficiency [13].

3.2. Oxy-Combustion

Table 3 evinces significantly greater overall efficiency of the oxyfuel mode compared to post-combustion case. The result would not be possible with a 2-column air separation unit and is an outcome of adopting a state-of-the-art GOX production plant, which demands 139 kWh/t O_2 (1 atm) [9-10]. Out of 14.30 MW shown for GOX supply, 14.11 MW is derived from air separation, and the balance is due to equivalent compression. Although GOX is likely to be supplied directly in the required pressure, 1 atm is assumed to comply with a common standard basis for expressing air separation power requirement [9-10].

Unlike the usual 2-column and 3-column processes, the selected air separation unit (TVR-2REB) is based on single-column near-atmospheric distillation with cryogenic top vapor recompression. Currently, most cryogenic plants for GOX production employ additional pressurized columns to generate liquid-nitrogen reflux to the main fractionation tower. The TVR-2REB solution avoids unnecessary compression of O_2 in air without nitrogen compression at near-ambient temperature. The distillation column has an intermediate reboiler, where partial vaporization of O_2-rich liquid is driven by condensation of compressed nitrogen. The bottom reboiler is heated by the liquefaction of pressurized air, which is then subcooled and fed to the column. According to [9], the separation power demand is significantly lower than other known standalone plants for either 95% and 99.5%mol O_2 purity standards. For instance, for atmospheric GOX 95%, while TVR-2REB demands 139 kWh/tO_2, 2-column and 3-column designs are known to require 200 [10] and 158 kWh/tO_2 [14], respectively. The product stream leaves the process at a pressure slightly above 1 atm, but the equivalent compression power is discounted.

In this application to the corncob BECCS system, if TVR-2REB is considered for GOX supply, it would be necessary to reduce the post-combustion heat ratio to 2.30 GJ/t to make its overall efficiency greater than Oxy-combustion. If a 3-column plant [14] were applied, air separation demand would be 1.93 MW higher, implying 0.51%LHV lower efficiency (23.96%LHV). The corresponding break-even heat ratio for an equal efficiency via chemical absorption would be 2.60 GJ/t, which is more easily achievable with advanced amine blends and process configurations. Although the development of TVR-2REB process allows a significant reduction in power requirement for oxygen production, there is still a wide opportunity for further enhancements. Air separation technology can make oxy-combustion even more efficient, since from a Thermodynamic theoretical viewpoint it is possible to reduce GOX specific power down to 50 kWh/t O_2 [15].

4 Conclusions

Corncob-fired power generation is evaluated for three process alternatives, aiming the reduction of the energy-efficiency penalty for carbon capture and storage: (i) conventional CO_2-emitting process; (ii) post-combustion CO_2 capture by chemical absorption with mixed amine (MDEA+PZ); and (iii) oxy-combustion with flue gas total compression to storage and GOX supply from state-of-the-art air separation unit. The conventional process exhibits overall efficiency of 31.24%LHV, emitting 1.20 kg/kWh of biogenic CO_2. Post-combustion is designed for 90% CO_2 capture, presenting net efficiency of 23.28%LHV and specific emission of 0.161 kg/kWh, if the lean solvent composition is optimized for the lowest regeneration heat, which results in 2.92 GJ/tCO_2 for the adopted premises. Without CO_2 end-purification, Oxy-combustion has no emissions and outperforms Post-combustion with higher efficiency of 24.47%LHV if only 139 kWh/tO_2 is required for GOX production. To make Post-combustion the most efficient alternative, reducing its heat ratio of regeneration to 2.30 GJ/t of captured CO_2 is needed, requiring a more efficient solvent formulation and advanced process configurations. Regardless of the chosen alternative, the concept configures a BECCS solution and can remove carbon dioxide from the atmosphere, given the occurrence of CO_2 biofixation in the crops.

References

1. S. Fuss, J. Canadell, G. Peters, M. Tavoni, R.M. Andrew, P. Ciais, et al. Nat. Clim. Change **4**, 850–853 (2014) https://doi.org/10.1038/nclimate2392
2. IPCC. Climate Change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, UK (2022) https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_FullReport.pdf
3. N. Pour, P.A. Webley, P.J. Cook. Appl. Energy **224**, 615–635 (2018) https://doi.org/10.1016/j.apenergy.2018.04.117
4. N. Kalyian, R.V. Morey. Fuel Process. Technol. **91**, 559–565 (2010) https://doi.org/10.1016/j.fuproc.2010.01.001
5. C. Jansen, T. Lübberstedt. Bioenerg. Res. **5**, 20–31 (2012) https://doi.org/10.1007/s12155-011-9158-y
6. H. Zhang, R. Xiao, D. Wang, G. He, S. Shao, J. Zhang, Z. Zhong. Bioresour. Technol. **102**, 4258–4264 (2011) https://doi.org/10.1016/j.biortech.2010.12.075
7. G.V. Brigagão, O.Q.F. Araújo, J.L. De Medeiros, H. Mikulcic, N. Duic. Fuel Process. Technol. **193**, 102–113 (2019) https://doi.org/10.1016/j.fuproc.2019.05.011
8. M. Wang, A. Lawal, P. Stephenson, J. Sidders, C. Ramshaw. Chem. Eng. Res. Des. **89**, 1609–1624 (2011) https://doi.org/10.1016/j.cherd.2010.11.005
9. G.V. Brigagão, J.L. De Medeiros, O.Q.F. Araújo. Energy Convers. Manag. **189**, 202–214 (2019) https://doi.org/10.1016/j.enconman.2019.03.088
10. A. Darde, R. Prabhakar, J.P. Tranier, N. Perrin. Energy Procedia **1**, 527–534 (2009) https://doi.org/10.1016/j.egypro.2009.01.070
11. R. Soundararajan, T. Gundersen, M. Ditaranto. Chem. Eng. Trans. **39**, 229–234 (2014) https://doi.org/10.3303/cet1439039
12. B. Zhao, F. Liu, Z. Cui, C. Liu, H. Yue, S. Tang, Y. Liu, H. Lu, B. Liang. Appl. Energy **185**, 362–375 (2017) https://doi.org/10.1016/j.apenergy.2016.11.009
13. S.S. Warudkar, K.R. Cox, M.S. Wong, G.J. Hirasaki. Int. J. Greenh. Gas Control **16**, 342–350 (2013) https://doi.org/10.1016/j.ijggc.2013.01.050
14. P. Higginbotham, V. White, K. Fogash, G. Guvelioglu. Int. J. Greenh. Gas Control **5S**, S194–203 (2011) https://doi.org/10.1016/j.ijggc.2011.03.007
15. C. Fu, T. Gundersen. Energy **44**, 60-68 (2012) https://doi.org/10.1016/j.energy.2012.01.065