# Post-combustion $CO_2$ capture for coal power plants: a viable solution for decarbonization of the power industry?

Branimir Tramošljika, Paolo Blecich, Igor Bonefačić
University of Rijeka, Faculty of Engineering
Vukovarska 58, HR-51000 Rijeka, Croatia
paolo.blecich@riteh.hr

***Abstract:*** *This paper investigates the performance of post-combustion carbon capture and storage (PCCS) for pulverized coal-fired power plants. The PCCS units comprises $CO_2$ absorption by 30 wt% monoethanolamine (MEA) solution and $CO_2$ compression at 150 bar for permanent storage or enhanced oil recovery. The specific $CO_2$ emissions per unit of generated electricity is 733 $kg_{CO2}$/MWh in the reference power plant without PCCS while the power plant with integrated PCCS achieve specific emissions lower than 100 $kg_{CO2}$/MWh, assuming a carbon capture rate of 90%. However, PCCS technology needs substantial amounts of thermal energy for absorbent regeneration and electricity for carbon capture, $CO_2$ compression as well as for the operation of other parasitic electricity consumers. The PCCS energy requirements vastly affect the overall power plant performance. The reference coal-fired supercritical power plant (without PCCS) achieves a net efficiency of 45.1%. On the other hand, the PCCS integrated power plant achieves a net efficiency of 34.6%, a 10.5%-pts net efficiency loss over the reference scenario, when the PCCS specific energy demand is 3.5 $MJ_{th}/kg_{CO2}$ for absorbent regeneration, 0.35 $MJ_{el}/kg_{CO2}$ for $CO_2$ compression and 0.15 $MJ_{el}/kg_{CO2}$ for carbon capture and cooling water pumps. The corresponding electricity output penalty caused by the PCCS unit is 352 $kWh_{el}/kg_{CO2}$. PCCS technology shows promising potential for decarbonization of the power industry, but further development is necessary to improve its reliability, cost-effectiveness and to diminish its impact on the power plant performance.*

***Keywords****: POST-COMBUSTION CARBON CAPTURE, $CO_2$ EMISSIONS REDUCTION, COAL-FIRED POWER PLANT, ELECTRICITY OUTPUT PENALTY, NET EFFICIENCY LOSS,*

## *1. Introduction*

In 2019, the total global anthropogenic greenhouse gases (GHG) emissions reached 51.8 $GtCO_{2eq}$ [1]. Figure 1 shows the GHG emissions by economic sectors in 2019. The largest sources of GHG involve: 1) fuel combustion (coal, natural gas and oil) for electricity and heat generation (25%), 2) fuel consumption for chemical, metallurgical and mineral transformation processes in various industries (21%) not associated with electricity or heat generation, 3) agriculture, forestry, deforestation, land use for crop cultivation and livestock (24%), 4) fuel consumption for road, rail, air and marine transport, where the majority of GHG is from the use of petroleum based fuels, mainly gasoline and diesel (14%), 5) fuel combustion in residential and commercial buildings, for heating and cooking, excluding electricity use (6%), 6) other energy related GHG emissions such as fuel extraction, refining, processing and transport, not directly associated with electricity or heat generation (10%). Energy related GHG emissions (fuel combustion & fuel fugitive emissions) represent 76% of the total global GHG emissions. Carbon dioxide ($CO_2$) is the largest contributor to GHG emissions since 90% of all energy-related emissions are originated from carbon oxidation. $CO_2$ alone represents two-thirds of the total GHG emission, or 35 Gt in 2019 [1]. The remaining one-third of the GHG emissions is due to: 1) methane ($CH_4$) emitted during fossil fuels extraction and production, and from agriculture, livestock and organic waste decay, 2) nitrous oxides (NOx) generated from fossil fuel combustion, agricultural activities and waste management, 3) man-made gases (CFCs, HFCs, PFCs, $SF_6$) used in air-conditioning and refrigeration systems and for industrial processes.

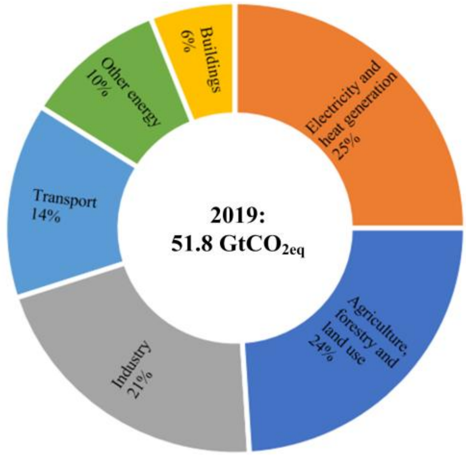


***Fig. 1.*** *Global GHG emissions by sectors in 2019*

More than half of the total global GHG emissions are point sources GHG emissions originated from fuel combustion for electricity and heat generation, industry transformation processes and buildings. For example, electricity generations is still dominantly fossil-fuel generated, whereas coal, natural gas and oil supplied 63.5% of the worldwide electricity in 2019 [2]. Specifically, coal generated 9945 TWh (36.8%), natural gas 6376 TWh (23.6%) and oil 835 TWh (3.1%) to the worldwide electricity of 27005 TWh [1]. Fossil fuel electricity generation is encumbered by high GHG emissions into the atmosphere. The largest part of the GHG emissions is from $CO_2$, but NOx, SOx, soot and fly ash are also emitted from fossil fuel combustion. The specific $CO_2$ emission for electricity generations are in the range between 877 and 1130 kg/MWh for coal and between 422 and 548 kg/MWh for natural gas power plants. For comparison, lifecycle $CO_2$ emissions from renewable sources are estimated at 8–20 kg/MWh for wind power, 20–57 kg/MWh for geothermal power and 29–80 kg/MWh for solar PV [3].

The IEA sustainable development scenario [2] estimates that, for limiting the long-term global temperature increase within 1.5 °C, energy-related $CO_2$ emission should be reduced to 27 Gt by 2030 and further down to 15 Gt by 2050, from the present value of 35 Gt. On the other side, the business-as-usual scenario would result in a 20% increase of energy-related $CO_2$ emissions by 2035, which would lock the long-term temperature increase at 3.6 °C. In order to achieve this substantial $CO_2$ reduction, natural gas should replace coal as the principal source of combustion energy. However, natural gas could reduce $CO_2$ emissions by 50% while further reduction could be obtained by alternative gaseous fuels such as biogas, renewable and low-carbon hydrogen, synthetic natural gas and new technologies such as carbon capture, utilization and storage (CCS).

## *2. Carbon capture and storage technology*

Nowadays, the CCS technology is shifting from pilot plant to large-scale demonstration projects, not only in the power generation sector but also in other sectors. The Global Status of CCS 2020 [4] reports 26 commercial CCS facilities currently in operation with a total carbon capture and storage capacity of 40.7 million tonnes of $CO_2$ per year (Mtpa). CCS units are being used in the following industries: natural gas processing (30.5 Mtpa), power generation (2.4 Mtpa), hydrogen production (2.2 Mtpa), fertilizer production (1.8 Mtpa), methanol and ethanol production (1.6 Mtpa), oil refining (1.4 Mtpa), iron and steel production (0.8 Mtpa). The two dominant carbon storage practices are enhanced oil recovery (30.7 Mtpa) and storage in dedicated geological formations (10 Mtpa). The estimated costs of CCS projects for fossil fuel power plants span over wide ranges of values, as reported in the relevant literature [5-7]. The costs of CCS depend on the fuel type, the costs of labor, materials, operation and maintenance, the carbon capture technology, the costs of transport and storage, and the type of project (greenfield or retrofit). The levelized cost of electricity (LCOE) is between 61 and 87 US$/MWh in power plants without CCS and between 94 and 163 US$/MWh for power plants with CCS. The LCOE can be reduced to between 61 and 139 US$/MWh if the captured $CO_2$ is sold to enhanced oil recovery projects instead of simply storing it in geological formations. The cost of captured $CO_2$ is between 33 and 58 US$/$t_{CO2}$, while the cost of avoided $CO_2$ (including compression, transport, and storage) is between 44 and 86 US$/$t_{CO2}$ [5, 6]. Post-combustion CCS for combined cycle natural gas turbines (CCGT) or supercritical coal power plants with oxy-fuel combustion are predicted to operate with similar costs. Slightly higher costs were estimated for coal-based integrated gasification combined cycles (IGCC) with pre-combustion CCS [7]. The specific costs of $CO_2$ transport are between 2 and 15 US$/$t_{CO2}$, depending on pipeline capacity, type (onshore or offshore), and length. The specific costs of $CO_2$ storage are estimated between 1 and 18 US$/$t_{CO2}$, depending on the storage type (depleted oil/gas field, geological formation, or ocean storage) and the potential of using EOR credits. The worldwide $CO_2$ storage capacity is 400 billion tonnes of discovered capacities in oil and gas fields (depleted or for EOR projects) and 12,000 billion tonnes in potential (estimated) storage capacities in geological (saline) formations [4]. The $CO_2$ storage capacities are such that exceeds the global net-zero emission scenario. It is estimated that the CCS industry could be cost-effective with carbon prices between 40 and 80 US$/t$CO_2$ [4].

At the moment, two carbon capture demonstration projects are up and running in the power generation sector: The Boundary Dam power plant and the Petra Nova power plant [5]. The estimated annual carbon capture capacities are 1 Mtpa at the Boundary Dam power plant and 1.4 Mtpa at the Petra Nova power plant. Both are using amine-based post-combustion capture, applied on one coal-fired unit each, and the captured carbon is transported via pipelines for usage in enhanced oil recovery (EOR) projects. Usually, an extra two to three barrels of oil can be recovered for every tonne of $CO_2$ injected into the mature oil field. According to the IEA, EOR results in a net $CO_2$ emissions reduction, which means that the amount of permanently stored $CO_2$ is generally greater than the $CO_2$ emitted from the production and consumption of the recovered oil. Other studies found that $CO_2$ EOR projects generate negative emissions in the first part of the oil field lifecycle but positive emissions in the second part. In the Boundary Dam power plant, the non-CCS units generate electricity from lignite coal with a cost of 60 US$/MWh while the CCS-refurbished unit operates at a cost of 120 US$/MWh after selling $CO_2$ to an EOR field at a price of 25 US$ per tonne. The unit is able to absorb and capture $CO_2$ at a rate of 90% reducing emissions to 150 kg/MWh. The economic viability of both the Boundary Dam and the Petra Nova carbon capture facilities are affected by electricity and oil prices. Carbon capture for enhanced oil recovery projects tend to be unfeasible when crude oil prices are under 100 US$ per barrel. Three carbon capture technologies have been developed up to the stage of large-scale demonstration plants. These are pre-combustion carbon capture, oxyfuel combustion carbon capture and post-combustion carbon capture. Several more technologies exist at the prototype stage: chemical looping combustion, membrane separation, cryogenic separation, calcium looping. The CCS sector is envisioned to grow up to a total global capacity of 5600 Mtpa of $CO_2$ by 2050 [4].

## *3. Post-combustion carbon capture*

In *precombustion capture*, the $CO_2$ is captured before combustion. The fossil fuel (coal, oil or gas) is fed to the gasifier along with oxygen from the air separation unit. The resulting syngas (a mixture of $CO_2$, CO, $H_2O$ and $H_2$) is blown into the desulfurization and particle precipitation units and thereafter shifted to $CO_2$ and $H_2$ in the water-gas shift reactor ($CO + H_2O \rightarrow CO_2 + H_2$). $CO_2$ is separated in an absorption based stripper while $H_2$ is used for electricity generation in turbines and fuel cells or in hydrogen powered vehicles. Alternatively, $CO_2$ and $H_2$ can be used for synthetic natural gas production using $CO_2$ methanation ($CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$). Pre-combustion carbon capture is generally used for integrated gasification combined cycle (IGCC) power plants. For example, the 580 MW Kemper power plant (Mississippi, USA) generates syngas from lignite coal and captures 65% of the $CO_2$ using the Selexol absorption process. The annual carbon capture capacity of the Kemper power plant is estimated at 3 Mtpa. In *oxyfuel combustion capture*, coal is burned in a mixture of oxygen and recycled flue gases because coal firing in pure oxygen from the air separation unit would result in excessive flame temperatures. The nitrogen-free flue gases from oxyfuel combustion consists primarily of $CO_2$ and $H_2O$. The carbon capture unit is installed in the flue gases treatment line, after the desulfurization and electrostatic precipitation.

*Post-combustion carbon capture (PCC)* is a mature technology that can be integrated in new power plants or existing power plants for retrofit or upgrade projects. $CO_2$ is separated from flue gases after the combustion process. The flue gases are dominated by high concentrations of nitrogen gas, which increases the energy requirements for carbon capture. Flue gases from natural gas combustion typically contain only 4% of $CO_2$ while flue gases from coal combustion contain between 12 and 15% of $CO_2$ per volume. *Absorption-based* carbon capture involves chemical or physical processes for the absorption of $CO_2$ into liquid solutions containing the absorbent. The absorbent is regenerated by increasing the solution temperature up to the point of breaking the $CO_2$-absorbent bond. Amine-based absorbents have been used for many years in the oil and gas processing industry and can remove up to 90% of the $CO_2$ from flue gases. After the desorber column, the CO2 is filtered dehydrated and compressed for industrial utilization, enhanced oil recovery projects or permanent storage. *Adsorption-based* carbon capture involves chemical or physical processes for the adsorption of $CO_2$ using solid sorbents. Solid sorbents are less preferred than liquid absorbents as they achieve lower $CO_2$ capture rates although the energy demand for thermal regeneration is also reduced [8-9].

Figure 2 shows the typical amine absorption post-combustion carbon capture unit, installed in the flue gases treatment line after the DeNOx unit, the electrostatic precipitators (EP) and the flue gases desulfurization (DeSOx). After the first stage treatment, flue gases are directed into the absorber column, where the cold amine solution forms a rich solution by absorbing $CO_2$. The carbon-free flue gases are discharged into the atmosphere through the stack. The energy efficiency of the carbon capture unit is increased by installing a heat exchanger which preheats the rich amine solution and precools the lean amine solution. Inside the stripper (desorber, regenerator), the rich amine solution is separated into lean solution and wet $CO_2$. The heating demand necessary for amine regeneration is supplied to the reboiler by low-pressure steam extracted from the power plant steam cycle or steam generated in separate boiler. The lean amine solution is pumped back to the absorber through the heat exchanger. On the other side, wet $CO_2$ is having moisture removed in the overhead condenser. Dry $CO_2$ is compressed in a multi-stage compression process. Generally, intercooling between compression stages is used to lower the $CO_2$ temperature and decrease the $CO_2$ compression power duty. High-pressure $CO_2$ is fed into the pipeline and transported to permanent storage, enhanced oil recovery projects or industrial usage.

The biggest technical hurdle of the carbon capture technology is the high energy demand. Specifically, the heating duty for absorbent regeneration is between 2.0 and 5.0 $MJ_{th}/kg_{CO2}$ [8], depending on the absorbent type, flue gases composition, the carbon capture technology and absorption rates. The cooling duty necessary for moisture separation, flue gases cooling, lean amine cooling, and $CO_2$ compression intercooling, is between 2.0 and 6.0 $MJ_{th}/kg_{CO2}$ [8]. The auxiliary power duty for $CO_2$ compression is in the range between 0.30 and 0.40 $MJ_{el}/kg_{CO2}$, depending on the required pressure rise. Additional auxiliary power duty, for the operation of cooling water pumps, flue gases fans and solvent pumps, is between 0.07 and 0.21 $MJ_{el}/kg_{CO2}$ [10].

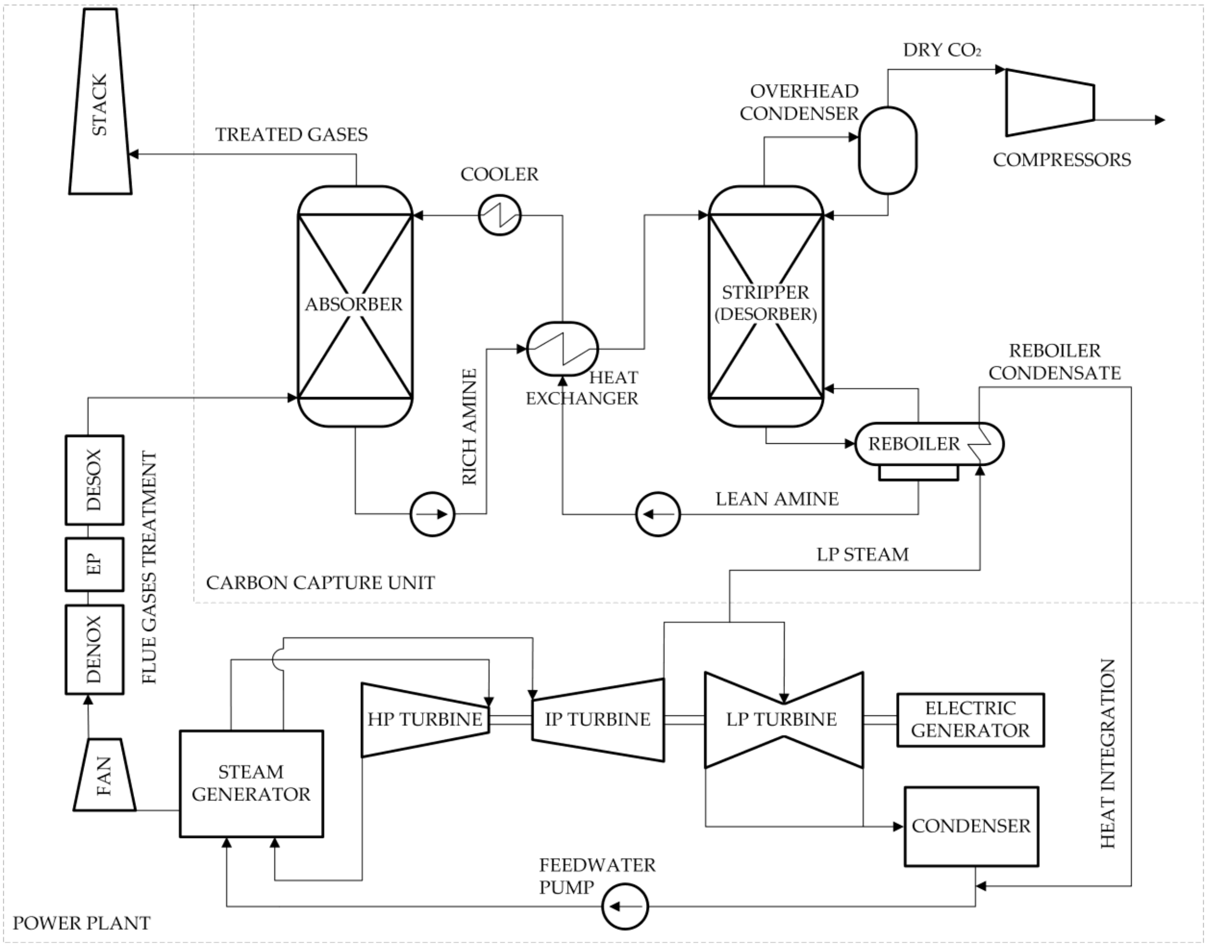


***Fig. 2.*** *Post-combustion carbon capture with amine absorption for a coal-fired power plant*

## *4. Thermal efficiency and electricity output penalty*

This section presents the methodology for assessing the impact of post-combustion carbon capture and storage (PCCS) technology on the performance of a coal-fired supercritical power plant. The reference power plant comprises a single-stage reheat and eight feedwater heaters (FWH). The electric generator is powered by one high pressure (HP) turbine, one intermediate pressure (IP) turbine and two double-flow low pressure (LP) turbines. Superheated steam enters the HP turbine with a temperature and pressure of 600 °C and 300 bar. Reheated steam enters the IP turbine with 610 °C and 60 bar. The steam generator efficiency is assumed $\eta_{sg} = 0.95$ while the turbine isentropic efficiencies are 0.90 for HP turbine, 0.94 for IP turbine, and 0.885 for LP turbines [11]. The net electric power of the reference power plant (without PCCS) is 500 MW. The gross electric power in the reference power plant ($\dot{P}_{el,gross,ref}$) is obtained adding auxiliary power ($\dot{P}_{el,aux,ref}$) to the net electric power.

$$\dot{P}_{el,gross,ref} = \dot{P}_{el,net,ref} + \dot{P}_{el,aux,ref} \quad (1)$$

In the present study, the auxiliary power is assumed 5% of the net electric capacity, i.e. 25 MW. The fuel heat input (LHV) necessary for the production of superheated and reheated steam is

$$\dot{Q}_{fuel} = \frac{\dot{m}_{steam}\Delta h_{superheat} + \dot{m}_{steam}\left(1-\sum\varepsilon_i\right)\Delta h_{reheat}}{\eta_{sg}} \quad (2)$$

The power generated in the turbines is determined by the general expression taking into account the steam extractions, the isentropic enthalpy drops and the turbines isentropic efficiencies

$$\dot{P}_T = \dot{m}_{steam}\left[\sum\left(1-\sum\varepsilon_i\right)\Delta h_i\right]\eta_T \quad (3)$$

The reference power plant net efficiency $\eta_{gross}$

$$\eta_{net,ref} = \frac{\dot{P}_{el,net,ref}}{\dot{Q}_{fuel}} = \frac{\left(\dot{P}_{T,HP} + \dot{P}_{T,IP} + \dot{P}_{T,LP}\right)\eta_{gm} - \dot{P}_{el,aux,ref}}{\dot{Q}_{fuel}} \quad (4)$$

The PCCS unit uses LP steam for amine absorbent regeneration through the reboiler. Therefore, the gross electric power of the PCCS-integrated power plant ($\dot{P}_{el,gross,PCCS}$) is less than the gross electric power of the reference power plant ($\dot{P}_{el,gross,ref}$) since low pressure steam is extracted from the IP/LP crossover pipe

$$\dot{P}_{el,gross,PCCS} = \dot{P}_{el,gross,ref} - \Delta\dot{P}_{el,PCCS} \quad (5)$$

The IP/LP steam extraction reduces the mass flow rate through the LP turbine. The corresponding power loss is the difference between the LP turbine power in the reference power plant and the LP turbine power in the PCSS power plant. Part of the turbine power loss is compensated by heat integration (HI) of reboiler condensate into the low-pressure feedwater preheating train. The net electric power of the PCSS integrated power plant is further reduced as result of the auxiliary power duty in the coal-fired power plant itself and the auxiliary power duty in the carbon capture unit

$$\dot{P}_{el,net,PCCS} = \dot{P}_{el,gross,PCCS} - \dot{P}_{el,aux,ref} - \dot{P}_{el,aux,PCCS} \quad (6)$$

The PCCS auxiliary power duty includes $CO_2$ compression power duty and the parasitic power duty for cooling water pumps, solvent pumps and flue gases fans. An eight-stage $CO_2$ compression process with the following parameters is assumed: compression efficiency 0.80, intercooling temperature 30 °C, final pressure 150 bar, carbon capture rate 0.90. The parasitic power duty in the PCCS unit is 0.15 $MJ_{el}/kg_{CO2}$ [12]. The net efficiency penalty caused by PCCS is

$$\Delta\eta_{net} = \eta_{net,ref} - \eta_{net,PCCS} = \frac{\dot{P}_{el,net,ref} - \dot{P}_{el,net,PCCS}}{\dot{Q}_{fuel}} \quad (7)$$

The electricity output penalty (EOP) measures the performance loss caused by the PCCS unit. It is the ratio between the net electric power loss and the mass flow rate of captured and compressed $CO_2$

$$\mathrm{EOP} = \frac{\dot{P}_{el,net,ref} - \dot{P}_{el,net,PCCS}}{\dot{m}_{CO_2}} \quad (8)$$

## 5. Results and discussion

The net electric power of the reference coal fired power plant is 500 MW. The total gross electric power output from the turbines is 535.7 MW: 166.1 MW from the HP turbine, 208.6 MW from the IP turbine and 161.0 MW from the LP turbine. The gross electric (generator) output is 525 MW, which against a gross fuel heat input of 1107.7 MW, yields a power plant gross efficiency of 47.39%. The auxiliary power duty is assumed at 25 MW, which return a net electric power output of 500 MW and a net efficiency of 45.14%. In the reference power plant, the total $CO_2$ emissions are 366.7 t/h while the specific $CO_2$ emissions per unit of generated electricity are 733.4 $kg_{CO2}/MWh_{el}$. The PCCS integrated power plant employs absorption-based carbon capture using 30 wt% monoethanolamine (MEA) solution. The fraction of $CO_2$ in flue gases is 21.2% on mass basis or 14.4% on volume basis. The $CO_2$ is absorbed by MEA aqueous solution, at a capture rate of 90% in the absorber column.

***Table 1:*** *Comparison between the reference power plant and the PCCS integrated power plant*

| Quantity | | Reference | PCCS |
|---|---|---|---|
| Gross fuel heat input, $MW_{th}$ | | 1107.7 | 1107.7 |
| Steam generator net heat input, $MW_{th}$ | | 1052.4 | 1052.4 |
| Live steam mass flow rate, kg/s | | 389.4 | 389.4 |
| Turbines gross power, $MW_{el}$ | | 535.7 | 463.6 |
| HP turbine power, $MW_{el}$ | | 166.1 | 166.1 |
| IP turbine power, $MW_{el}$ | | 208.6 | 208.6 |
| LP turbines power, $MW_{el}$ | | 161.0 | 88.9 |
| Total thermal discharge, $MW_{th}$ | | 572.0 | 743.9 |
| Steam generator heat losses, $MW_{th}$ | | 55.3 | 55.3 |
| Condenser thermal discharge, $MW_{th}$ | | 516.7 | 267.9 |
| PCCS thermal discharge, $MW_{th}$ | | - | 420.8 |
| Feedwater pump turbine power, $MW_{el}$ | | 17.8 | 17.8 |
| Power plant auxiliary power duty, $MW_{el}$ | | 25.0 | 25.0 |
| PCCS heating/ cooling duty | heating, $MW_{th}$ | - | 320.9 |
| | cooling, $MW_{th}$ | - | 420.8 |
| PCCS auxiliary power duty | total, $MW_{el}$ | - | 45.8 |
| | $CO_2$ compression, $MW_{el}$ | - | 31.7 |
| | cooling pumps, $MW_{el}$ | - | 13.9 |
| Gross electric (generator) power, $MW_{el}$ | | 525.0 | 454.3 |
| Net electric (power plant) power, $MW_{el}$ | | 500.0 | 383.5 |
| Flue gases mass flow rate, t/h | | 1728.0 | 1398.0 |
| $CO_2$ capture, t/h | | - | 330.0 |
| $CO_2$ emissions, t/h | | 366.7 | 36.7 |
| $CO_2$ emissions, $kg_{CO2}/MWh_{el}$ | | 733.4 | 73.4 |
| Electricity output penalty, $kWh_{el}/kg_{CO2}$ | | - | 352.9 |
| Power plant gross efficiency, % | | 47.39 | 41.01 |
| Power plant net efficiency, % | | 45.14 | 34.62 |
| Net efficiency penalty, %-pts | | - | 10.52 |

The disadvantage of the MEA absorption process is the large energy consumption. The present study assumes that the specific heating duty of the capture process is 3.5 $MJ_{th}/kg_{CO2}$. This heating duty is supplied by LP steam from the IP/LP crossover pipe. Consequently, the LP turbines power is reduced to 88.9 MW, and the total turbine gross power is 463.6 MW. The gross electric power of the PCCS integrated power plant is 454.3 MW, which returns 41.01% of gross efficiency. However, fraction of the generated electric output is supplied to the PCCS unit, a total of 45.8 MW for auxiliary power, 31.7 MW for $CO_2$ compression and 13.9 MW for cooling pumps and other equipment. By combining the power plant internal duty and the PCCS unit auxiliary power duty, the total auxiliary power is 70.8 MW. The net electric power is 383.5 MW, a 23.3% reduction over the 500 MW in the reference power plant. The net efficiency is 34.62%, a net efficiency loss of 10.52%-pts over the reference value of 45.14%. The electricity output penalty per unit of captured $CO_2$ is 352.9 $kWh_{el}/kg_{CO2}$.

## 6. Conclusions

Absorption-based post-combustion carbon capture is a well-developed technology that can be successfully integrated into fossil fuel power plants. PCCS can reduce $CO_2$ emissions by up to 90%, but at the cost of efficiency and electricity penalties. The net electric power of the power plant without PCCS is 500 MW, while the PCCS integrated power plant achieves 383.5 MW. The reduction in the power output (116.5 MW) comprises the following components: LP turbine power output loss 70.9 MW (60.9%), $CO_2$ compression 31.7 MW (27.2%) and PCCS auxiliary consumers such as capture unit and cooling pumps 13.9 MW (11.9%). The net efficiency of the reference coal-fired power plant with supercritical steam cycle is 45.14%, whereas the net efficiency of the same coal-fired power plant with PCCS technology is 34.62%, an efficiency loss of 10.52%-pts. The resulting electricity output penalty per unit of captured and stored $CO_2$ is calculated at 352.9 $kWh_{el}/kg_{CO2}$. The disadvantages of the PCCS unit are the large energy requirements that cause substantial efficiency and electricity output losses. However, the advantage of the PCCS-integrated power plant is the reduction in $CO_2$ emissions, which can be up to 90% relatively to reference power plants without PCCS technology. In the present study, the reference power plant generates electricity with specific $CO_2$ emissions of 733.4 $kg_{CO2}/MWh_{el}$, whereas the PCCS integrated power plant operates at $CO_2$ emissions as low as 73.4 $kg_{CO2}/MWh_{el}$. Lifecycle $CO_2$ emissions, including upstream emissions from coal mining and transport, are higher, estimated at 100 $kg_{CO2}/MW_{el}$. Future PCCS technology should achieve even higher carbon absorption rates but at lower electricity output penalties. Improved absorbent chemistry, advanced $CO_2$ capture process strategies and efficient $CO_2$ compression and storage are among the possible solutions. PCCS technology is ready for large-scale integration and inevitable for full decarbonization of the power industry.

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