

Steam Supply Evaluation for Carbon Capture and Storage in a Subcritical Coal-Fired Power Plant

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ABSTRACT

The aim of this study is to analyze the implementation of carbon capture and storage (CCS) in coal-fired power plants (CFPP) in Indonesia by determining the reboiler energy demand through steam source analysis. The study uses a representative 3×330 MW subcritical coal-fired power plant (CFPP), with an emission intensity of 1.02 tCO₂/MWh and flue gas CO₂ concentration of 13.8%. CCS modeling shows the reboiler requires about 2.9×10⁹ kJ/h energy, supplied by steam extracted from the plant's steam cycle. A steam cycle model was developed to evaluate the impact of steam extraction. Potential tapping points analyzed include main steam, cold reheat, intermediate-pressure (IP) extraction, low-pressure to intermediate-pressure LP-IP crossover, and low-pressure (LP) extraction. Main steam extraction with the highest energy content needs the lowest steam mass flow of 355 t/h but causes the highest energy penalty of 57% because of lost electricity production in HP and IP extraction. Cold reheat extraction requires moderate steam flow of 399 t/h and a penalty of 52% but risks overheating reheater tubes. The LP-IP crossover point needs the highest steam flow 414 t/h, yet achieves the lowest net energy penalty at 33.8% with minimal operational risk, making it the most favorable option for CCS integration.

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Keywords: CCS, CFPP, energy penalty, reboiler energy, steam tapping.

I. Introduction

Indonesia's power system remains heavily dependent on coal-fired power plants, which in 2022 accounted for approximately 42.1 GW of the total national installed capacity of 81.2 GW, generating around 60% of the country's total electricity consumption [1]. This reliance has resulted in high greenhouse gas (GHG) emissions from the power sector, posing significant challenges to achieving emission reduction targets in line with both national and international commitments, particularly those aimed at limiting global temperature rise to below 1.5°C [2]. In 2024, Indonesia's national power generation capacity is predominantly supplied by fossil-fuel-based power plants, which account for approximately 86 GW or about 85% of the total installed capacity. The largest share among these comes from coal-fired power plants (CFPP) contributing around 53% of the national total. On the other hand, power plants utilizing new and renewable energy contribute around 15% of the national total, equivalent to approximately 15 GW [3]. Under a business-as-usual scenario, CO₂ emissions are projected to increase and reach up to 900 MtCO_{2e}/year [4].

One of the strategic steps currently being developed is the implementation of carbon capture and storage (CCS) technology in existing coal-fired power plants. CCS is a



technology that enables the capture of carbon dioxide (CO₂) from power plant flue gases and its storage in underground geological formations to reduce CO₂ emissions into the atmosphere [5]. Indonesia has formulated the electricity energy mix in the 2025 National Electricity General Plan (RUKN 2025). The installed capacity of Indonesia's power generation system is projected to rise significantly by 2060, reaching around 443 GW, supporting an estimated annual electricity production of 1,947 TWh. The energy mix will undergo a substantial transformation, with renewable and new energy sources accounting for 73.6% of total production, comprising 24.1% from new energy such as nuclear, green hydrogen, and ammonia, and 49.5% from renewable sources including hydro, geothermal, biomass, wind, and solar. Within this mix, variable renewable energy (VRE) such as solar and wind equipped with energy storage systems will contribute approximately 20.7%, while stable renewable energy like hydro and geothermal will provide 28.8%. The remaining 26.4% of electricity will come from fossil-based plants integrated with CCS [3].

The implementation of CCS in Indonesia has great potential considering the vast carbon storage reserves, reaching 305 Mt CO₂ storage across Java-Sumatra [6]. However, the implementation of this technology faces various challenges, ranging from technical and economic aspects to policy issues, where the development costs of CCS can significantly increase electricity costs and require appropriate policy support and incentives [7]. In line with the spirit of a just and sustainable energy transition, the Indonesian Government, through the international partnership just energy transition partnership (JETP), has initiated a comprehensive investment and policy plan (CIPP) to support emission reductions in the power sector, targeting peak emissions by 2030 and achieving net-zero emissions by 2050 [8]. This plan includes accelerating renewable energy development, the gradual phase out of coal-fired power plants, and the utilization of low-carbon technologies such as CCS [9]. Achieving national emission reduction targets in power generation requires technical and economic assessments of CCS implementation in Indonesia's coal power plants, ensuring a balanced approach to availability, affordability, and acceptability.

The development and implementation of CCS in coal-fired power plants in Indonesia represent a crucial solution to support emission reduction targets while ensuring the reliability and availability of the national electricity supply during the energy transition period. This study aims to investigate the technical aspects of integrating CCS with existing coal-fired power plants in Indonesia by evaluating the steam energy requirements needed to support the post-combustion carbon capture process. The study models a comparison of steam tapping in a representative subcritical coal-fired power plant unit in Indonesia, analyzing its effects on steam mass flow requirements, energy penalty, gross power output, and the impact on the thermal efficiency of the power plant.

II. Material and Methods

This study involves the simulation modeling of the post-combustion carbon capture process and the modeling of a representative CFPP existing in Indonesia. The modeling was performed using Aspen Hysys V14 software. The simulation process requires operational data from the existing CFPP, including coal fuel characteristics, flue gas composition, CFPP emission intensity, and the mass and energy balance of the CFPP commissioning and operation system [10], [11]. Based on these data, process modeling of the capture unit and the CFPP unit was conducted, followed by validation using the net power output generated by the CFPP, energy penalty [12], the thermal efficiency of the CFPP, and the reboiler energy generated in the capture process [13], [14]. After validating the simulation results,

variations in the steam tapping points for supplying reboiler steam in the capture process were performed and further analyzed.

1. Carbon Capture Model

In the modeling of carbon capture, post-combustion carbon capture technology was employed, with amine absorption selected due to its proven application in retrofitting coal-fired power plants with CCS systems [15]. The amine solvent used was a mixture of MDEA and PZ at concentrations of 42% and 8%, respectively [16]. The capture process targeted a 90% capture rate, considering the existing power plant emission intensity of 1.02 tCO₂/MWh [11]. The coal fuel characteristics of the power plant utilized lignite coal, with the ultimate coal analysis results presented in Table 1 [10].

Table 1. Coal ultimate analysis

Compositions	Symbol	Unit	Design value
Lower heating value	LHV	kcal/kg	4200
Total moisture	M	%	30
Volatile matter (DAF)	VM	%	52.85
Ash	ASH	%	3.78
Carbon	C	%	47.65
Hydrogen	H	%	3.36
Oxygen	O	%	14.42
Nitrogen	N	%	1.21
Sulphur	S	%	0.23

The coal feed into the boiler combustion process produces flue gas, whose composition at the stack is shown in Table 2. The flue gas from three 330 MW units of the existing CFPP is combined into a single flue gas stream exiting the plant chimney. The flue gas still contains relatively high concentrations of SO_x and NO_x, which must be treated prior to further processing in the capture system [17]. NO_x reduction is achieved through burner modification in the boiler, while SO_x removal is performed by installing flue gas desulfurization (FGD) equipment [18].

Table 2. CFPP flue gas composition

Parameter	Value
Temperature	141.08 °C
CO ₂	13.8%
O ₂	2.16%
N ₂	70.08%
H ₂ O	13.3%
SO _x	844 mg/Nm ³
NO _x	164 mg/Nm ³

The flue gas temperature exiting the FGD is approximately 40°C and requires additional flue gas blowers to increase the pressure up to 1.2 bar in order to enhance the

driving force for CO₂ absorption in the amine solution [19]. Increasing the flue gas pressure raises the partial pressure of CO₂, which improves the capture process efficiency [20].

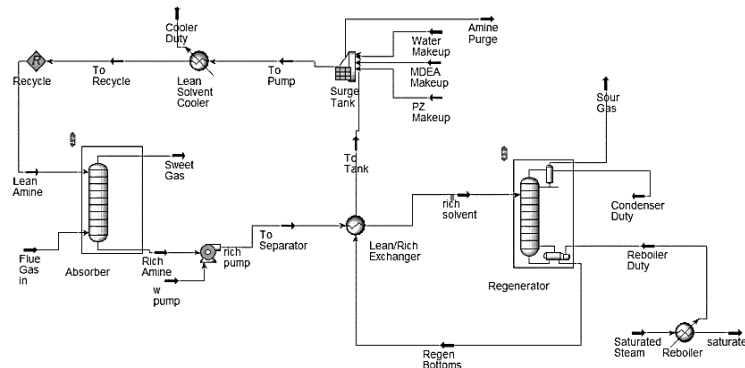


Fig. 1. Post-combustion capture modelling

The CO₂ capture process design is shown in Figure 1 and parameters using amine absorption are detailed in Table 3, with the reference [21], [22]. Flue gas at a pressure of 1.2 bar and a temperature of 40°C enters the absorption column, where the separation of flue gas and CO₂ takes place. Flue gas with a reduced CO₂ concentration exits the absorber column as the sweet gas stream. The rich solvent containing amine and absorbed CO₂ is separated in the regeneration column, where the reboiler energy required for regeneration must be supplied by steam extracted from the existing CFPP.

Table 3. Post-combustion capture parameters

Unit	Parameter	
Absorber	Type	: Bubble cap tray
	Number of stages	: 40 stages
	Diameter	: 22 m
	Absorber pressure	: 1.2 bar
	Flue gas temperature	: 40 °C
Regenerator	Type	: Bubble cap tray
	Number of stages	: 20 stages
	Diameter	: 15.8 m
	Regenerator pressure	: 1.8 bar
Loading	Rich loading	: 0.49 mole CO ₂ /mole <i>Amine</i>
	Heat exchanger	ΔT min : 10 °C
Duty	Regenerator duty	: 2.9e ⁹ kJ/h
Compressor	Compressor pressure	: 110 bar
	Stages	: 4 stages

The CO₂ separated from the flue gas undergoes a compression process up to supercritical CO₂ pressure. The compression system is designed with four stages to increase the CO₂ pressure to 110 bar, enabling further processing for transportation and injection into a saline aquifer or depleted oil and gas fields [23], [24]. The CO₂ compression design is illustrated in Figure 2.

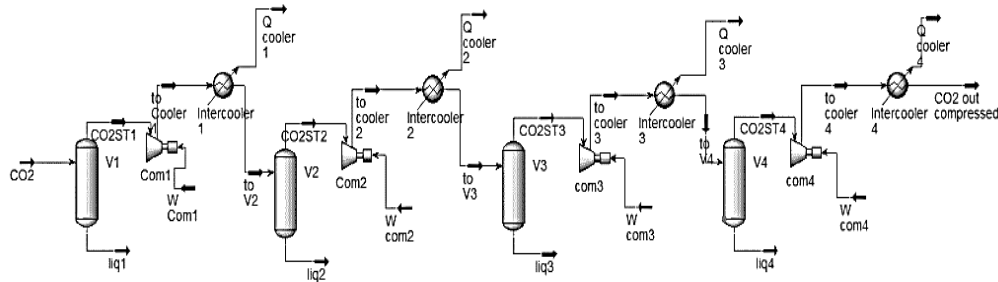


Fig. 2. CO₂ compression model

In the CCS modeling, the reboiler energy requirement supplied by the steam energy from the power plant was determined. Steam tapping points were identified and modeled within the CFPP using Aspen HYSYS, within Table 5. Subsequently, an analysis was conducted to evaluate the technical and operational effects on the CFPP. The calculation of the required steam mass flow can be expressed by Eq. (1) [24].

$$m = \frac{\alpha \cdot m_{CO2}}{(H_{steam} - H_{sat\ liquid})} \dots\dots\dots (1)$$

- m : Steam supply mass flow (ton/h)
- α : Reboiler duty (GJ/tCO₂)
- m_{CO₂} : CO₂ emission mass flow (t/h)
- H_{steam} : Enthalpy of steam (MJ/ton)
- H_{sat liq} : Enthalpy of saturated liquid exiting reboiler (MJ/ton)

2. Coal Fired Power Plant Model

The modeling of the CFPP was conducted based on the existing mass and energy balance data as shown in Figure 3. The plant operates with subcritical technology and utilizes a pulverized coal boiler type. It consists of three units, each capable of producing a maximum gross power output of 330 MW, with a plant heat rate of 2241 kcal/kWh as shown in Table 4. The power plant features a three-stage turbine system, comprising high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP) turbines with a single reheat cycle. The boiler is designed to use lignite coal with a calorific value of 4200 kcal/kg, as shown in Table 1. The flue gas characteristics presented in Table 2 are derived from measurements by the CEMS installed at the plant unit. The flue gas contains 13.8% CO₂, with the power plant’s emission intensity measured at 1.02 tCO₂/MWh.

Table 4. CFPP 330 MW parameters

Parameter	Value
Gross power output	330 MW
Net plant heat rate	2241 kcal/kWh
Boiler efficiency	92.7%
Aux power consumption	22.3 MW
Emission intensity	1.02 tCO ₂ /MWh

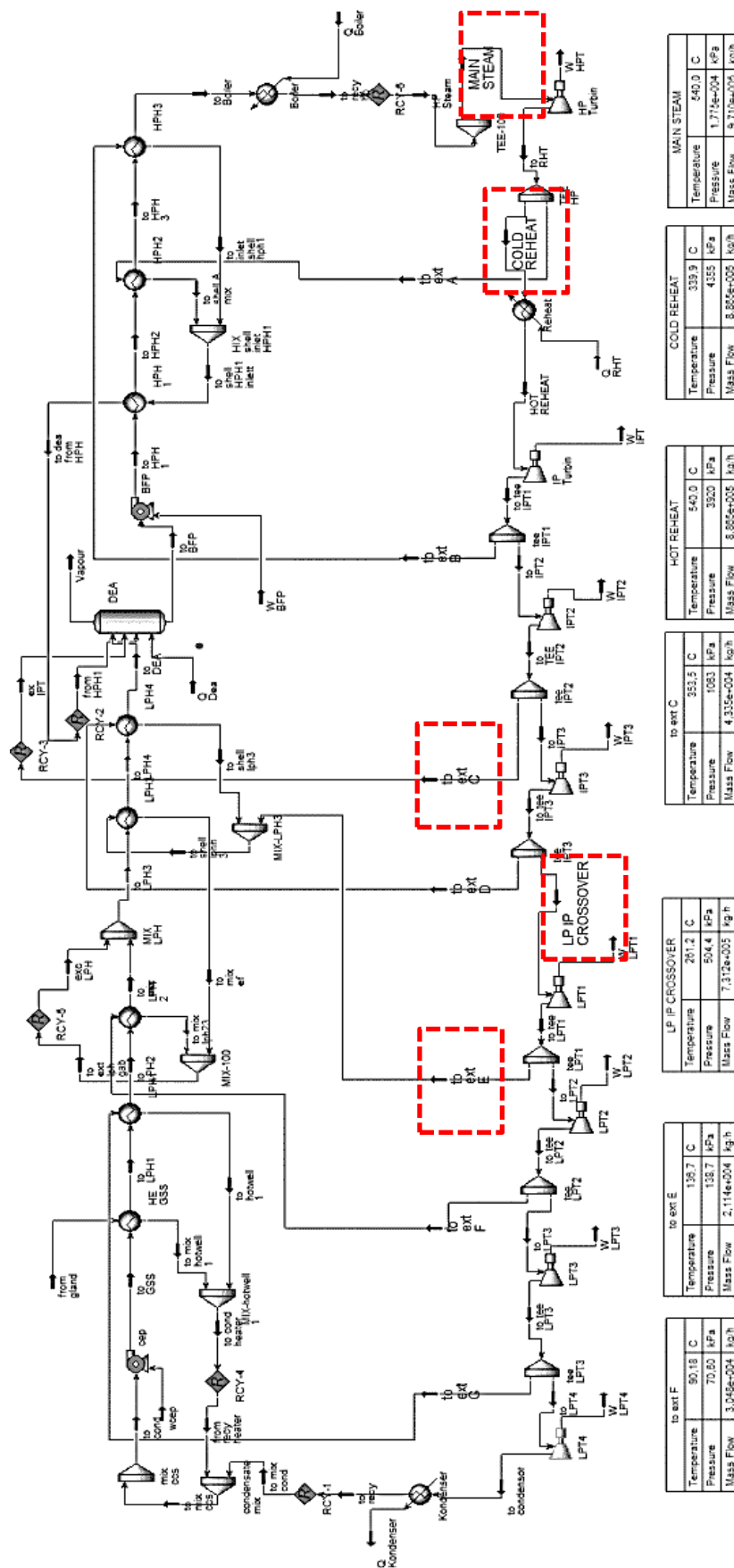


Fig. 3. 330 MW CFPP modeling

Table 5. Mass and energy balance of 330MW CFPP

Equipment		Mass flow (ton/h)	Temperature (°C)	Pressure (bar)
HP turbine (HPT)	Inlet HPT	969	540	177
	Outlet HPT	884	339	43.5
Reheat	Inlet reheat	884	339	43.5
	Outlet reheat	884	540	39.2
IP turbine (IPT1, 2, 3)	Inlet IPT 1	884	540	39.2
	Outlet IPT 2	731	261	5.04
LP turbine (LPT 1, 2, 3, 4)	Inlet LPT 1	731	261	5.04
	Outlet LPT 4	657	42.7	0.08
Condenser	Inlet condenser	657	42.7	0.08
	Outlet condenser	679	42.9	0.09
Condensate pump	Inlet CEP	679	42.9	0.09
	Outlet CEP	680	43.1	12.0
LPH1	Inlet LPH1	680	43.1	11.8
	Outlet LPH1	680	61.5	11.5
LPH2	Inlet LPH2	680	61.5	11.5
	Outlet LPH2	792	86.9	11.3
LPH3	Inlet LPH3	792	86.9	11.3
	Outlet LPH3	792	104	11.0
LPH4	Inlet LPH4	792	104	11.0
	Outlet LPH4	792	149	10.3
Deaerator	Inlet deaerator	798	149	10.3
	Inlet HPH	133	192	21.6
	Inlet IPT	43.3	353	10.6
	Outlet deaerator	969	181	10.3
BFP pump	Inlet BFP	969	181	10.3
	Outlet BFP	969	184	188
HPH1	Inlet HPH1	969	184	188
	Outlet HPH1	969	211	187
HPH2	Inlet HPH2	969	211	187
	Outlet HPH2	969	252	187
HPH3	Inlet HPH3	969	252	187
	Outlet HPH3	969	256	186
Boiler	Inlet boiler	969	256	186
	Outlet boiler	969	540	177

III. Results and Discussions

CFPP modeling was carried out with mass and energy balance constraints based on the power plant's manual book [11], with the gross power output of the CFPP as the output variable. The mass and energy balance model of the CFPP was validated against the CFPP gross output, net output, and thermal efficiency [11], [10]. The validation results serve as the baseline for determining the steam tapping points to be extracted and for analyzing the CFPP operational aspects.

The steam supply option identified in Table 6 requires pressure adjustment to 5 bar or below before being used as energy supply for the reboiler with letdown valve [25]. The reboiler utilizes the latent heat from the steam condensation process. The steam is in a superheated phase, providing additional heat from the steam's sensible heat [24]. After the steam changes phase to saturated liquid, a condensate pump is needed to pump the water to the feedwater outlet LPH4 or the inlet feedwater deaerator with steam parameters close to

the operational conditions of the power plant. Figure 4 illustrates the steam supply process and the recirculation of feedwater back into the steam cycle.

Table 6. Steam supply options

Steam tapping	Pressure (bar)	Temperature (°C)	Mass flow (ton/h)
LP/IP crossover (3)	5.04	261	731
Cold reheat (2)	43.5	339	880
Main steam (1)	177	540	969
IP ext steam (C)	10.6	353	43.3
LP extraction (E)	1.38	136	23.1

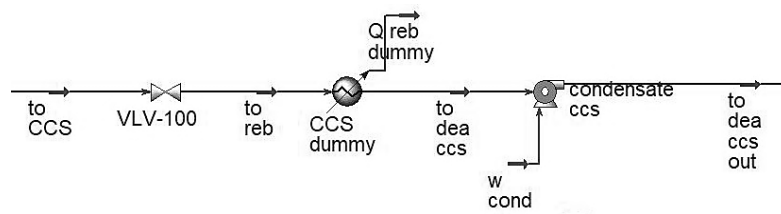


Fig. 4. Steam supply design

In the CCS modeling, the reboiler energy requirement was found to be approximately 2.9×10^9 kJ/h, which must be compensated by steam energy availability from the host coal-fired power plant, as summarized in Table 6. This corresponds to a specific reboiler duty of 3.46 MJ/kgCO₂, aligning with solvent-based post-combustion capture performance benchmarks from a previous study [26]. The adequacy of steam supply and thermal matching to the reboiler duty remains a critical consideration for the overall feasibility and efficiency of the integrated capture system. This table allows a comparison of the differences in steam quality parameters, illustrated in Figure 5. The highest energy is at the main steam tapping point, with an enthalpy value of 3392 kJ/kg and a steam mass flow of 969 tons/hour, while the lowest is at the LP extraction point, with an enthalpy of 2745 kJ/kg.

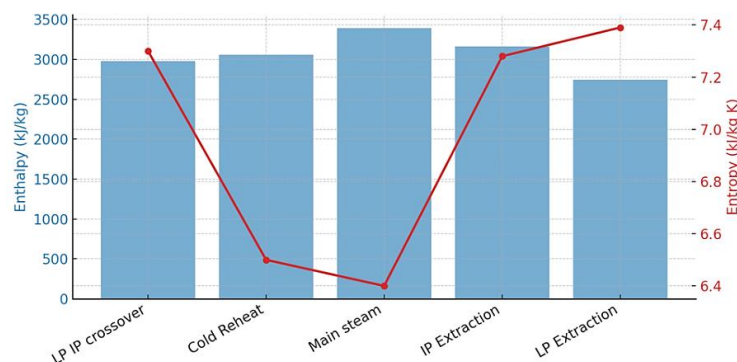


Fig. 5. Steam quality comparison

1. Main Steam Tapping

Steam is taken directly from the main steam tapping point, where the steam properties of high pressure and temperature are thermodynamically advantageous for solvent regeneration because it requires a smaller steam mass flow to meet the heat demand. However, this extraction significantly reduces the mass flow to the high-pressure turbine,

Since the boiler heat input (Q) and the reheat tube geometry remain unchanged, a lower mass flow of reheated steam increases the wall temperature of the tubes. This raises the risk of localized overheating, especially in the reboiler and reheater sections, potentially exceeding material design limits. Such thermal excursions can elevate the equivalent forced outage rate (EFOR) and reduce the equivalent availability factor (EAF), thereby impairing the long-term operational reliability of the plant [27]. Additionally, increased thermal stress may accelerate creep and fatigue damage [28], leading to more frequent maintenance interventions and higher O&M costs.

3. LP IP Crossover Tapping

The selected steam tapping point operates at a moderate pressure of 5.04 bar and a temperature of 261 °C, which are considerably lower than typical extraction points in supercritical cycles. These conditions require the highest steam mass flow rate of 414.3 ton/h to satisfy the thermal duty of the reboiler in the post-combustion CO₂ capture system. Despite the elevated steam flow demand, this configuration results in the lowest energy penalty among the evaluated cases, measured at 33.8%, and achieves the highest gross power output of 270.2 MW. This is primarily due to the minimal thermal and mechanical disturbance imparted to the upstream turbine stages, thereby preserving the cycle's enthalpy gradient and maintaining optimal turbine efficiency. Consequently, the net power output reaches a maximum of 216.3 MW, indicating that the efficiency gains from reduced turbine disruption outweigh the additional steam extraction burden. From an operational perspective, this steam tapping strategy offers a low risk of plant instability, as it effectively balances energy penalty reduction with system reliability and integration simplicity. Here is a tabulated comparison of the case studies presented in Table 7.

Table 7. Result comparison for each case

Tapping	Steam requirement (ton/h)	Gross out (MW)	Gross penalty (%)	Net power (MW)	Thermal efficiency (%)
Main steam	355.6	191.2	57.9	137.4	18.5
Cold reheat	399.0	210.6	52.0	156.7	21.4
LP IP cross	414.3	270.1	33.7	216.3	27.4

In study [12], an energy penalty of 35% was required when using the LP-IP crossover configuration in a 660 MW CFPP. The results of this analysis are consistent with previous studies that recommended steam extraction from the low-pressure turbine stage rather than from earlier stages [29]. In those studies [30], utilizing the LP-IP crossover for steam extraction resulted in an energy penalty of approximately 30%, depending on the CFPP technology applied. Among various technologies, ultra-supercritical CFPP exhibit the lowest energy penalty compared to subcritical units, owing to their higher thermal efficiency refer to Table 8.

At other steam extraction points, such as the IPT extraction, there is a potential risk to equipment like the deaerator, boiler feed water pump (BFPT), or other auxiliary needs. Meanwhile, for LP extraction steam points E, F, and G, the extraction mass flow is insufficient to meet the CCS reboiler requirements and significant modifications are necessary to fulfill the reboiler's mass flow demand. Figure 8 provides a detailed explanation of the effects of existing steam extraction cuts on the power output generated by each turbine

stage. Therefore, the selection of tapping points in the existing CFPP for supplying reboiler energy at 120°C for CCS needs become crucial in relation to the resulting electricity output and the thermal efficiency of the plant. A tapping point with the lowest possible energy penalty will lead to higher thermal efficiency and reduce the significance of the increase in retrofit LCoE.

Table 8. Comparison of the energy penalty for each CFPP technology and capacity using LP-IP crossover steam tapping [30]

Parameter	300 MW supercritical	660 MW subcritical	600 MW subcritical	1,000 MW USC
Energy penalty (%)	33.5 %	32.4 %	35.7 %	30.5 %
CEI before (tCO ₂ /MWh)	0.933	0.935	0.937	0.838
CEI after CCS (tCO ₂ /MWh)	0.131	0.16	0.137	0.118
Reboiler duty (MJ/kgCO ₂)	2.96	2.92	2.93	3.01

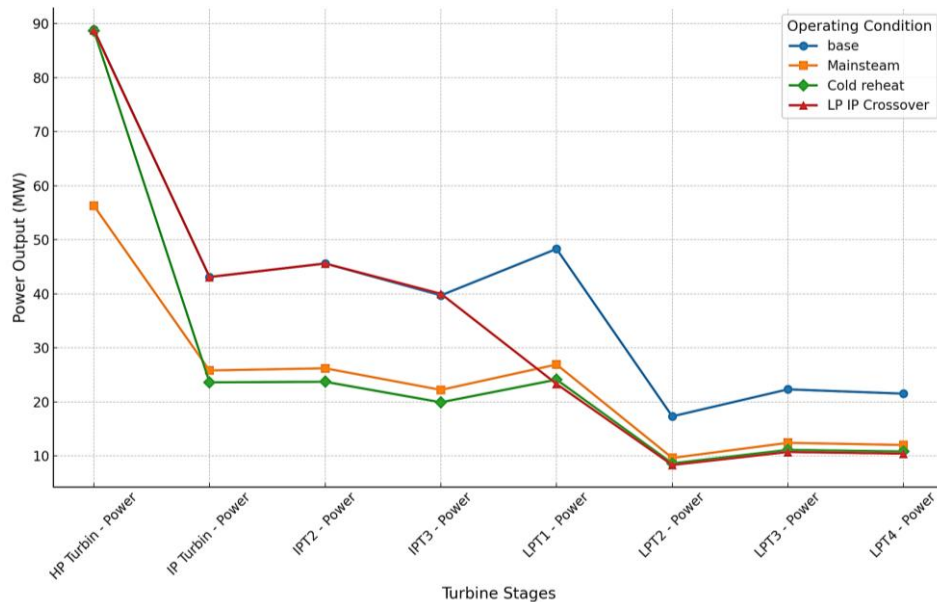


Fig. 8. Effect on turbine stage power output

The net power analysis of the power plant is conducted by accounting for the additional electrical load required for the CCS system. For the three units of the power plant, additional energy is needed for the flue gas blower (24 MW), CO₂ compressor (68 MW), and solvent pump (3 MW) as shown in Figure 9. Furthermore, the existing plant's auxiliary electrical energy demand must be recalculated at 22.3 MW in each CFPP. The largest component of the energy penalty is the steam energy requirement, which must be compensated by a significant reduction in the turbine's equivalent power output.

The selection of the steam tapping method is crucial, as it directly affects the energy penalty imposed on the CFPP, the overall plant efficiency, as well as the CO₂ capture cost and the levelized cost of electricity (LCoE) of the CFPP after CCS retrofit.

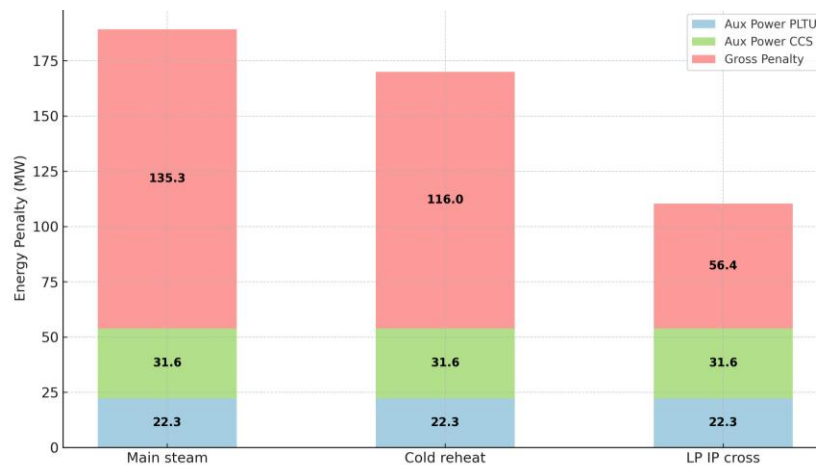


Fig. 9. Energy penalty breakdown (1x330 MW)

IV. Conclusions

In this study, a further analysis was conducted on the implementation of carbon capture and storage (CCS) in coal-fired power plants (CFPP) in Indonesia. The analysis used a representative 3×330 MW subcritical CFPP configuration, characterized by an emission intensity of 1.02 tCO₂/MWh and a flue gas CO₂ concentration of 13.8%. The CCS modeling indicated a reboiler energy demand of 2.9×10⁹ kJ/h, which must be supplied by steam extracted from the power plant. The impact of steam tapping on the plant's energy performance was assessed through steam cycle modeling. Several potential steam tapping points were identified, including main steam, cold reheat, intermediate-pressure (IP) extraction, low-pressure to intermediate-pressure (LP-IP) crossover, and low-pressure (LP) extraction. The findings reveal that main steam, with its high energy properties, requires the lowest steam mass flow for CCS at 355 t/h but incurs the highest energy penalty of 57%. Cold reheat results in a moderate steam mass flow and penalty at 399 t/h and 52%, respectively, but poses operational risks due to potential overheating of reheater tubes in the boiler. The LP-IP crossover tapping point requires the highest steam mass flow of 414 t/h, yet delivers the lowest net energy penalty at 33.8%, with minimal operational risks.

In this study, the mass and energy balance were conducted under full-load conditions of the CFPP, assuming steady-state operation. Future research opportunities remain widely open, particularly regarding the evaluation of dynamic load variations and the economic assessment of costs associated with the modification process. Apart from steam tapping selection conducted in this study, further energy optimization can be carried out, such as heat integration to utilize waste heat from CFPP and CCS Units.

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