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Coal's Endgame:

Cost-Benefit Analysis (CBA) of Early Retirement Coal-Fired Power Plant (CFPP) versus CFPP with Carbon Capture and Storage (CCS)

Imprint

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Coal's endgame: Cost-benefit analysis (CBA) of early retirement coal-fired power plant (CFPP) versus CFPP with carbon capture and storage (CCS)

In the Context of CASE
The regional programme, "Clean, Affordable and Secure Energy for Southeast Asia" (CASE), is jointly implemented by GIZ, and international and local expert organisations in the area of sustainable energy transformation and climate change: Agora Energiewende and New Climate Institute (regional level), the Institute for Essential Services Reform (IESR) in Indonesia, the Institute for Climate and Sustainable Cities (ICSC) in the Philippines, the Energy Research Institute (ERI), and Thailand Development Research Institute (TDRI) in Thailand. These organisations have set the objective of changing the narrative for energy transition. In Indonesia, CASE is anchored to the Ministry of National Development Planning/National Development Planning Agency (Bappenas) –Directorate of Electricity, Telecommunications and Informatics, and jointly implemented by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH and the Institute for Essential Services Reform (IESR).

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Executive Summary

In its pursuit of limiting global temperature rise to 1.5°C, and its Net Zero Emission (NZE) target, Indonesia demonstrates its commitment by revising planning documents for the energy and power sector and fostering international partnerships and collaborations. Through the Just Energy Transition Partnership (JETP), Indonesia can secure funding to boost its energy transition, provided it develops a more ambitious energy transition roadmap. This requirement includes setting a peak emission target for the power sector at 290 $MtCO_2$ by 2030 while achieving NZE in the power sector by 2050. The disparity of power sector emission reduction between the current planning document and the JETP target and emission pathways aligned with the 1.5°C target underscores the urgency of expediting the decarbonisation of its coal-dependent power sector. Reports also suggest that the investment need for achieving NZE is tremendous, and the funding to-be-provided by JETP alone is without a doubt insufficient.

This study aims to identify the costs and benefits of different decarbonisation scenarios for a coal-fired power plant (CFPP), which include early retirement of the CFPP and retrofitting the CFPP with carbon capture and storage (CCS). These scenarios are compared with the reference scenario where the CFPP continues to operate until its natural operational lifetime ends. It is also assumed that the CFPP

will be replaced with battery-equipped solar power plant of similar generation capacity once they are retired, either early or naturally. The analysis is conducted at the plant level, with a case study focusing on the 1 GW Jawa-8 Ultra Supercritical (USC) CFPP due to its favourable characteristics for retrofitting CCS. The Discounted Cash Flow (DCF) method is used to estimate the present value of all future costs.

The results show that implementing either decarbonisation method would incur some additional cost compared to the reference scenario, with the CCS retrofit scenario having a significantly higher cost and reducing emissions to a smaller amount. Across different assumptions employed in the sensitivity analyses, even with a case study that favours retrofitting CCS, retrofitting CCS remains more expensive than the early retirement of the CFPP, highlighting its poor economic viability. Performing such analysis on other CFPPs with shorter operational lifetimes will further detriment the economics of retrofitting CCS while having the opposite effect on CFPPs' early retirement. This study also identifies the level of carbon pricing to monetise the carbon emission reduction that can offset the additional cost of implementing each decarbonisation method.

Based on the findings in this report, we recommend the following points:

- Selecting an optimal mix of different renewable energy technologies and coal-exit strategies to decarbonise the power sector calls for a well-informed decision-making process to design an evidence-based pathway. For the case of coal fleet retirement and CCS adoption in the energy sector, a staged approach for CFPPs retirement may prioritise more carbon intensive subcritical power plants in the short to medium term, whereas CCS adoption may follow for CFPPs with higher design efficiency. However, with a more economically viable alternative, as shown in this study, the use of CCS in the power sector shall be reconsidered and least-prioritised.
- Develop a national emission pathway to be aligned across ministries and agencies. This emission pathway will serve as the basis for developing a cohesive national CFPP retirement and energy transition roadmap aligned with other planning documents, including the JETP's Comprehensive Investment Policy Plan (CIPP). A transparent and clearly defined national CFPP retirement plan provides a better market signal for relevant stakeholders regarding the decarbonisation of the power sector.
- Internalise the social cost of carbon emission using carbon pricing as it is central to quantifying the social benefits of deploying low-carbon technologies. A stronger signal for more stringent carbon caps and a more suitable carbon price can disincentivise prolonged fossil fuel use and increase the feasibility of renewable energy investments.
- Utilise innovative financing mechanisms for the early retirement of CFPPs to limit the impact on the public budget. The costs associated with the implementation of decarbonisation methods, such as CFPPs early retirement and CCS retrofit, may strain the state budget for electricity, which is already heavily burdened by subsidy expenses. Therefore, the government should explore innovative funding mechanisms to make power sector decarbonisation efforts more affordable.
- Further studies should cover the cost and benefit of other decarbonisation methods, such as cofiring with biomass and ammonia. Additionally, other forms of renewable energy besides solar energy should be considered for replacing CFPPs with the objective of minimising costs. The inclusion of the benefits derived from job additions in the renewable energy supply chain can enhance the robustness of the analysis. Furthermore, the impact of CFPPs early retirement or CCS retrofit on the system level should also be explored.

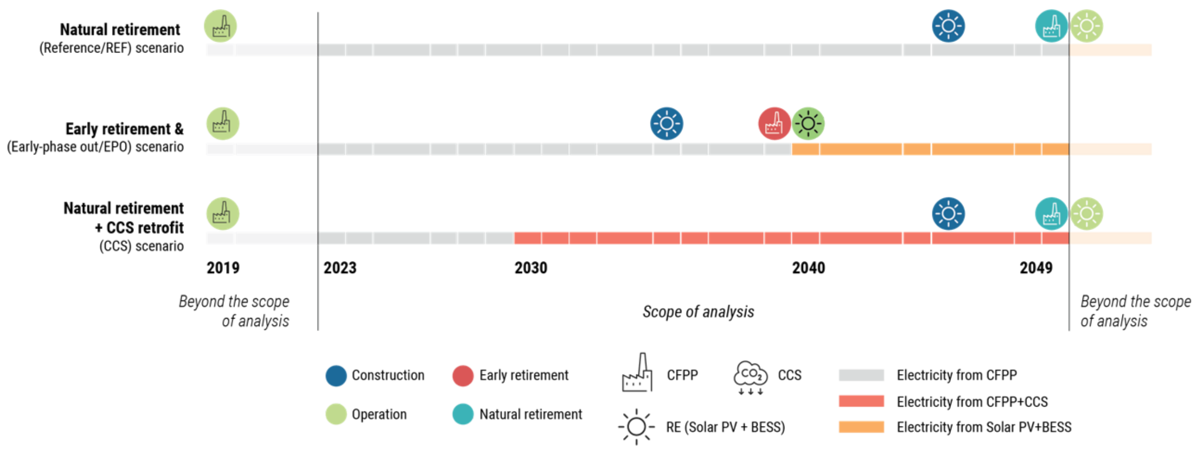

Figure ES 1: Detailed analysis scenarios. Solar power + BESS will replace the CFPP once they retire early or naturally. The investment for solar power + BESS is incurred a few years prior the end of CFPP operation considering its lead time.

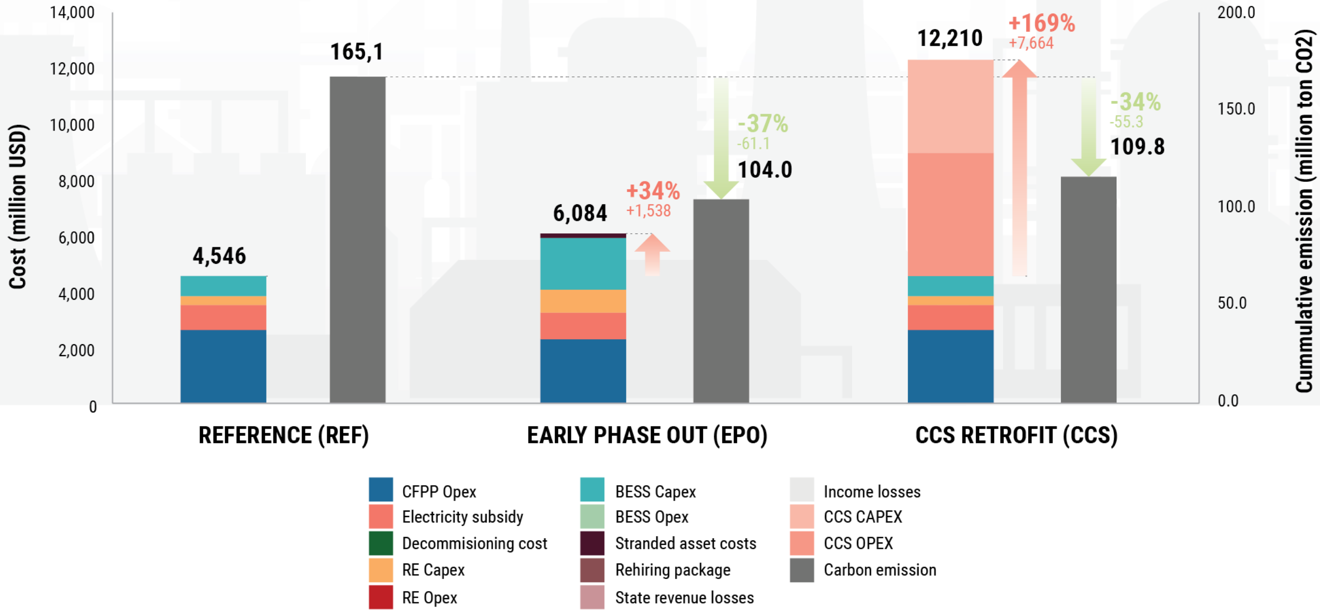

Figure ES 2: Analysis result shows the significantly higher cost of the CCS scenario compared to other scenarios.

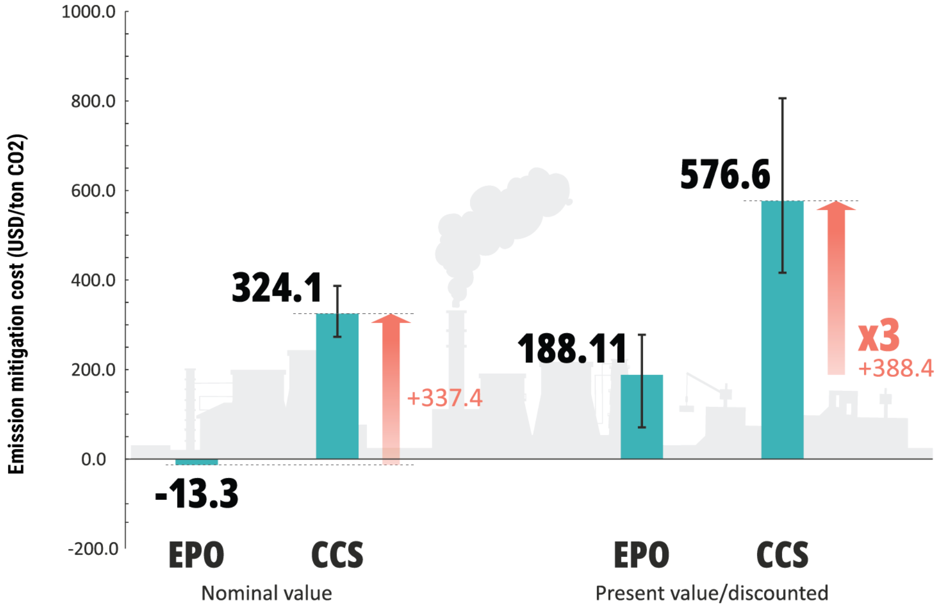

Figure ES 3: The higher cost and lower emission reduction leads to significantly higher emission mitigation cost of CCS retrofit compared to CFPP early retirement.

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Introduction

Decarbonizing Indonesia's Power Sector

In Indonesia, coal is a crucial energy source. It fuels the majority of installed electricity generation capacity in 2022—with 42.1 GW from CFPPs out of 81.2 GW, generating about 60% of the country's electricity (ESDM, 2023a). However, the country's reliance on coal has led to a range of environmental and health challenges, making CFPPs retirement a pressing issue.

Furthermore, in pursuit of limiting the global temperature rise at 1.5°C, Indonesia is committed to reducing its greenhouse gas emissions by up to 31.89% (unconditional) or up to 43.2% (conditional) by 2030, as stated in its Enhanced Nationally Determined Contribution (eNDC) under the Paris Agreement. This commitment includes emission reduction in the energy sector of 358 million tons of carbon dioxide equivalent ($MtCO_2e$) (unconditional) to 446 $MtCO_2e$ (conditional) or around 12-15% below its business-as-usual scenario. To achieve this target, shifting away from fossil fuels to cleaner and more sustainable energy sources is essential.

Leading up to the publication of Indonesia's eNDC, the country has released multiple energy plannings. A few notable developments for energy planning documents include the 10-year business plan[1] of the State Electricity Company (Perusahaan Listrik Negara/PLN) published in 2021, which states that more than 50% of the electricity generation capacity expansion until 2030 will be coming from renewables, indicating a commitment to sustainable and low-carbon energy planning (PLN, 2021b). In the same year, the government of Indonesia also published its Long-Term Strategy for Low Carbon and Climate Resilience 2050 (LTS-LCCR 2050), which aimed to align the climate goals and targets with national, sub-national, and international objectives. This document presents one of them: Indonesia's low carbon pathway scenario compatible with the Paris Agreement target (GoI, 2021a).

Indonesia made a commitment to achieving an economy-wide net-zero emissions (NZE) target by 2060 the following year. The commitment was intensified during the G20 Summit in November 2022—where it secured the JETP deal worth USD 20 billion in public and private financing. This financing takes the form of a mix of grants, concessional loans, market-rate loans, guarantees, and private investments (JETP, 2023). This partnership is designed to assist Indonesia in transitioning away from fossil fuels and sets specific emission reduction targets, aligning with the global carbon neutrality objective. The JETP aims to achieve peak power sector emissions by 2030. Furthermore, the power sector emission is capped at 290 megatons[2] of CO_2, down from the baseline of 357 megatons of CO_2 (JETP, 2023).

In parallel to the development of JETP's CIPP in 2023, the Ministry of Energy and Mineral Resources (MEMR) published the draft of the National Electricity Master Plan (Rencana Umum Ketenagalistrikan Nasional/RUKN) 2023-2060 that laid out the projections for the electricity generation required to achieve NZE 2060 (ESDM, 2023c). The RUKN draft employs several scenarios to project the future of Indonesia's power sector, including ZE Decommissioning. In this scenario, the addition of the CFPPs follows the list of CFPPs published in the PLN 10-year business plan and Presidential Regulation No. 112/2022, which allows for the addition of new CFPPs only if specific requirements are met. It also assumes natural retirement for all CFPPs.

Nonetheless, the emission reduction target required by JETP implies the need for a more progressive decarbonisation effort compared to the current planning in the RUKN draft. Part of the emission cuts are expected to come from the early retirement of CFPPs and curbing the development of captive CFPPs (JETP, 2023). JETP aims to attain NZE 10 years earlier than the previous target, by 2050, provided that at least 34% of all power generation comes from renewable energy sources by 2030[3], doubling the previous rate of deployment.

When comparing these climate and power-sector planning projections, discrepancies are evident both in terms of projection between all documents and their compatibility with the 1.5C target. The Paris

[1] Rencana Umum Penyediaan Tenaga Listrik (RUPTL) 2021-2030
[2] The 2023 JETP scenario envisions a maximum carbon emission of 250 megatons in 2030 for on-grid power sector
[3] The 2023 JETP scenario aims for a 44% share of RE for the on-grid power sector, of which, 14% comes from variable RE

Agreement-compatible scenario employed in the LTS LCCR follows the unconditional NDC trajectory until 2030 and proposes more ambitious efforts post-2030 until reaching NZE in 2060. However, the emission pathway in the power sector proposed in this study is higher than the JETP target, implying that the emission pathway in JETP complies with the 1.5°C target.

However, recent studies suggest otherwise, highlighting that these projections (JETP, RUKN, and LTS LCCR) are not enough to limit the temperature rise to 1.5°C. A study by IESR and the University of Maryland suggested that the trajectory aligned with achieving NZE by 2050 and the global 1.5°C target indicates a reduction of 11% in Indonesia's coal power generation by 2030, a decrease exceeding 90% by 2040 and a complete phase-out by 2045 (Cui et al., 2022a). Figure 1 shows the apparent gap of emission in the power sector between the projection stated in the RUKN draft, LTS-LCCR, which includes the current unconditional NDC target, the JETP target, and the study by IESR and UMD. This condition implies the risk of failing to secure JETP funding and limiting temperature rise.

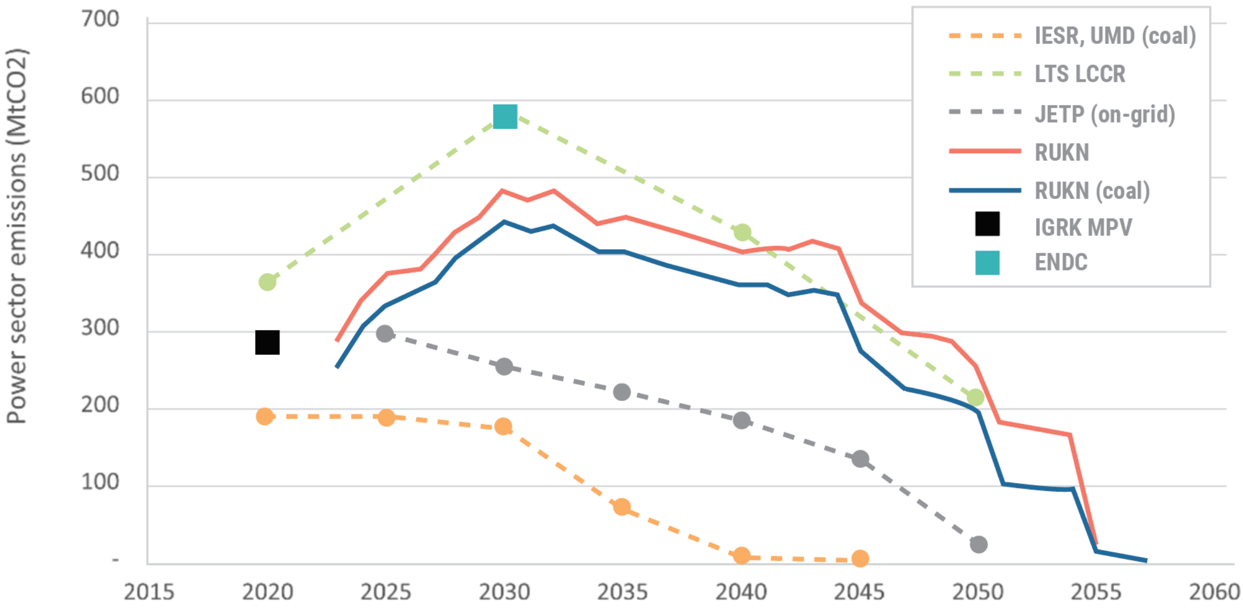


Figure 1: Carbon emission from the power sector and coal-fuelled power generation as projected by RUKN, LTS-LCCR, JETP, and study by IESR and UMD, as well as 2020 historical power sector emission (IGRK MPV). Solid lines represent data available each year, while dashed lines represent interpolation between known data *(dots)*(Cui et al., 2022a; ESDM, 2023c; GoI, 2021a; JETP, 2023).

The report by Climate Action Tracker suggests that Indonesia should lower its coal share in electricity generation to only 7-16% in 2030 and complete phase-out by 2040 to be compatible with the 1.5°C target. Furthermore, based on Indonesia's existing targets and policies, emissions are projected to increase and result in a warming of more than 4°C (CAT, 2023b). Meanwhile, despite the proposed reduction, the scenarios in RUKN, LTS-LCCR, and JETP employ a larger share of coal for electricity generation than what is needed to align with the 1.5°C target, as presented in Figure 2. This condition further signifies the need for decarbonizing the coal-dependent power sector.

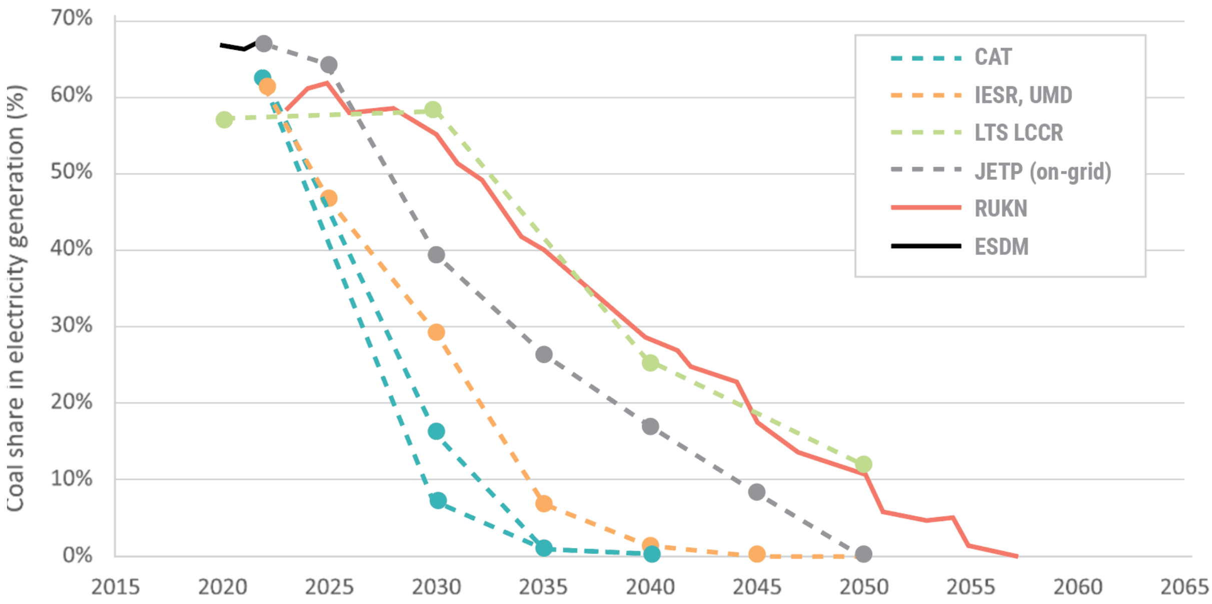


Figure 2: Coal share in electricity generation projections employed in different studies. Solid lines represent data that is available at each year, while dashed lines represent interpolation between known data *(dots)* (CAT, 2023a; Cui et al., 2022a; ESDM, 2023c; GoI, 2021a; JETP, 2023).

Indonesia must substantially ramp up its power sector investment to reach NZE earlier. According to the International Energy Agency (IEA), investments need to rise from approximately USD 20 billion per year during the 2016-2020 period to around USD 55 billion per year between 2026-2030. Beyond 2030, investment should increase to USD 100 billion annually from 2046 to 50 (IEA, 2022). The International Renewable Energy Agency (IRENA) estimates the investment requirements for NZE by 2050 at USD 1,436 billion over 2018-2050, roughly equivalent to USD 45 billion annually (IRENA, 2022a). This investment is intended for power generation, electricity networks, battery storage, and CCS projects (IEA, 2022; IRENA, 2022a). These reports highlight the enormous scale of funding needed compared to the funding provided by the JETP, thus emphasizing the funding shortage and the importance of effective and targeted limited-resource (time and money) spending. Amidst these financial demands and environmental targets, the adoption of CCS emerges as a potential strategy. This study assesses if the economics justify the envisioned role of CCS in Indonesia.

CCS Concept and Its Role in Energy Outlooks

CCS is a technology that captures carbon emissions from direct air or the combustion of fossil fuels and stores it underground in geological formations. One of the most mature post-combustion capture technologies suitable for power plant retrofit involves chemical absorption with amines, wherein a liquid solvent is utilised to separate CO_2 from flue gas (ERIA, 2022; Spigarelli & Kawatra, 2013; World Bank, 2015). Monoethanolamine (MEA) is the most common amine being used due to its low-cost relative to other amine solvents such as diethanolamine (DEA) and methyldiethanolamine (MDEA) (Spigarelli & Kawatra, 2013). The captured carbon is then separated from the solvent through heating, transported via pipelines or shipping, and stored in depleted oil and gas wells, leaving the lean solvent ready to be used again. When utilised in carbon capture, utilisation, and storage (CCUS), the injection of carbon can be utilised to enhance oil or gas recovery (EOR/EGR) in oil and gas production processes (BP, 2021; World Bank, 2015). Figure 3 presents the simplified carbon capture process in a CCS retrofit for CFPPs.

The MEMR, in cooperation with the IEA, launched a road map to NZE by 2060 for the energy sector in Indonesia (IEA, 2022). In this report, under the Announced Pledges Scenario (APS), CCUS, hydrogen, and ammonia co-firing are used to help many existing power plants become compatible with the NZE target, as presented in Figure 4. In detail, the report suggests that by 2040, around 2

GW of CFPPs should be equipped with CCUS, increasing to 7 GW by 2060. Additionally, for gas-fired power plants, the capacity with CCUS increases from 1 GW in 2040 to 3 GW in 2060.

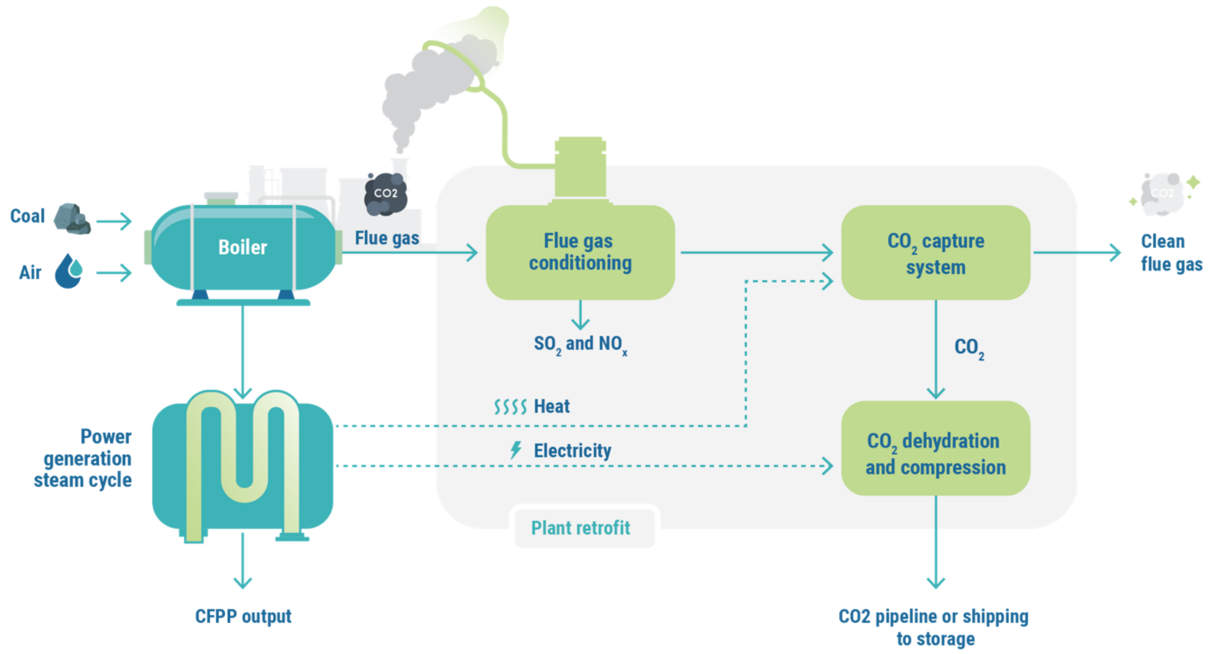


Figure 3: Simplified diagram of additional components for carbon capture retrofit into a CFPP (World Bank, 2015).

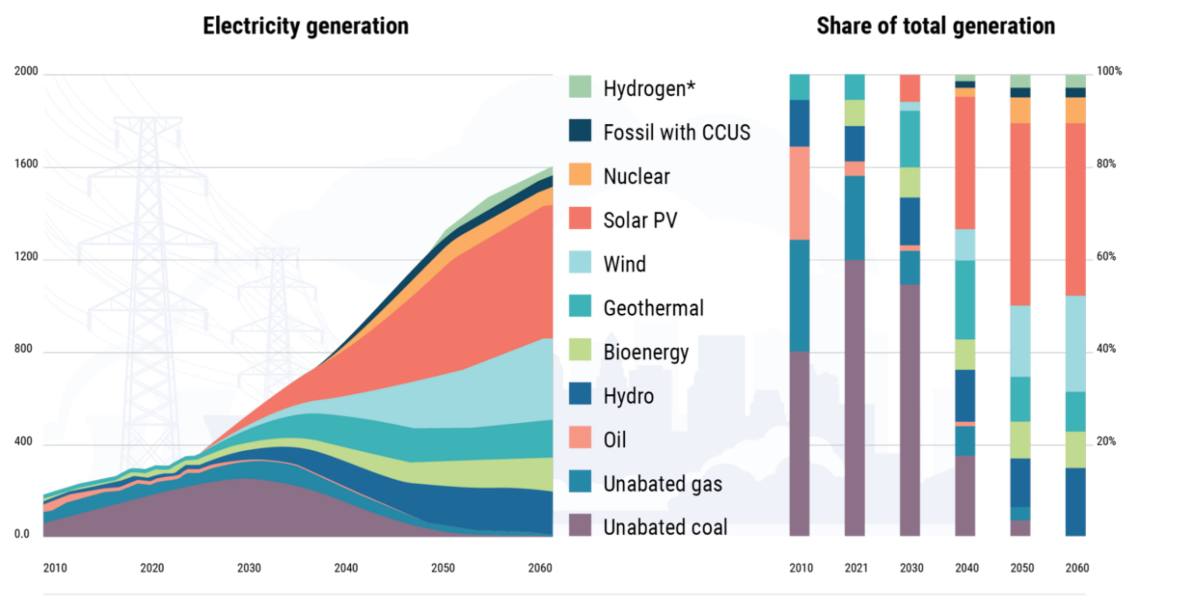


Figure 4: Electricity generation by type and share of total generation in Indonesia in the Announced Pledges Scenario, 2010–2060 (IEA, 2022).

The IEA's model aligns with the LTS-LCCR 2050 report, which Indonesia submitted to the United Nations Framework Convention on Climate Change (UNFCCC). According to this report, CCS/CCUS technology will be implemented in CFPPs to achieve decarbonisation in the energy sector (GoI, 2021a). Furthermore, a study conducted by Greig and Uden revealed that decarbonisation efforts to limit global warming below 2°C would be costly or infeasible without the use of CCUS (Greig & Uden, 2021).

In projected scenarios aiming for a 1.5°C temperature increase with limited or no overshoot, implementing CCS would enable gas to contribute to approximately 8% of global electricity generation by 2050 (IPCC, 2018). Therefore, it is evident that reports perceive CCS as a means to reduce emissions from fossil fuel generation, such as coal or gas.

While most are content with the inclusion of CCS in decarbonisation roadmaps, many debate its possible utilisation in the power sector. The Institute for Energy Economics and Financial Analysis (IEEFA) has pointed out that globally, 94% of captured CO_2 comes from gas processing plants and industrial applications, while only 6% comes from power generation (Robertson & Mousavian, 2022). Similarly, the database of global CCS facilities maintained by the Global CCS Institute indicates that out of the 30 operating CCS/CCUS facilities worldwide, only one is utilised in power generation, with the majority being employed in natural gas processing. The database also highlights that most of the CCS projects for power generation are still in the development phase (GCCSI, 2022). Meanwhile, an analysis of the CCS/CCUS database curated by the US National Energy Technology Laboratory reveals that around 90% of the proposed CCS capacity for the power sector was never actually constructed (Abdulla et al., 2021). These findings indicate the low maturity level of the CCS technology for power generation and underscore the need for careful consideration if Indonesia intends to incorporate CCS for fossil-fueled power plants in the future. On top of that, most of the carbon storage locations in Indonesia are in an active tectonic condition, posing a high risk of leakage of the stored carbon dioxide and implying that additional precautions must be taken when selecting the storage location (Amijaya, 2009).

Cost and Benefit of the Use of CCS in the Power Sector

Achieving NZE requires tapping into least-cost abatement technologies, one of them being CCS. According to estimates by the Global CCS Institute, retrofitting CCS to supercritical (SC) and ultra-supercritical (USC) CFPPs increases the total plant cost and variable operation and maintenance (O&M) cost by more than 70% and 80% respectively[4] (GCCSI, 2017).

To provide additional local context, we conducted a review of previous studies on the retrofitting of CCS on CFPPs in Indonesia. The World Bank conducted a study on the CCS retrofit of two USC CFPPs in West Java and a 600 MW SC CFPP in South Sumatera for the purpose of EOR. The study's findings indicate that the levelised cost of electricity (LCOE) may increase by up to 15.5 USD cents/kWh, more than double the baseline electricity provision cost without CCS (World Bank, 2015). The study on CCS retrofit to a 500 MW USC in Central Java by ERIA suggests an incremental capital cost estimate of 1,789.57 USD/kW (ERIA, 2022). This cost estimate is higher than the estimate provided by the Global CCS Institute (1,537 USD/kW for USC CFPP) (GCCSI, 2017).

On the other hand, the use of CCS can reduce the carbon emissions of coal-fired power plants by up to 90% (ERIA, 2022; World Bank, 2015). Emission reduction is a form of climate change mitigation that can provide indirect benefits such as reduced health costs, reduced damages to agricultural crops and human-built structures as well as preservation of wildlife habitat and human cultures. In the oil and gas industries, the captured carbon can also be utilised to enhance oil and gas production by injection into the oil and gas reservoir (Bergstrom & Ty, 2017).

However, it is important to note that these benefits provided by CCS are limited and constrained by its partial emission reduction, which still allows some greenhouse gas emissions to be released into the atmosphere. Thus, additional measures to offset the uncaptured emissions should also be considered on top of deploying CCS to achieve NZE. Furthermore, using CCUS to enhance the increased production of oil and gas will lead to additional carbon emissions due to the continued use of oil and gas. Considering that this undermines the efforts to reduce emissions and hinders progress toward reaching NZE, these scenarios provoke some intriguing questions. This study excludes the use of CCUS as a decarbonisation option and the necessity to complement CCS with carbon offsets.

To gain a better understanding of which approach to decarbonizing the power system is a valuable investment, it is necessary to compare the costs and benefits of retrofitting CFPPs with CCS with

[4] Total plant cost refers to the capital cost of the CFPP which include capital cost for equipment, materials, labour, and engineering services. Variable O&M (VOM) cost refers to the costs for operating the CFPP which include VOM for equipment, materials, and labour.

other decarbonisation methods for the power system, such as early retirement of CFPPs and their replacement with renewable power plants. Against this backdrop, CASE Indonesia intends to conduct research with the specific goal of answering the following question:

"Which method provides greater benefits for decarbonizing the power sector in Indonesia: retrofitting CFPPs with CCS or early retirement of CFPPs and their replacement with renewable power plants?"

To simplify the process of answering the research question, this research selects a case study CFPP and carries out plant-level analyses of the costs and benefits of retiring the CFPP early and replacing it with renewables. It then compares these costs and benefits with those of retrofitting the CFPP with CCS. The following sub-questions are identified:

1. What are the costs and benefits of retrofitting a CFPP with CCS?
2. What are the costs and benefits of retiring a CFPP early and replacing them with renewable power plants?
3. What are the implications of each scenario for the relevant stakeholders?

On top of conducting a plant-level analysis, other considerations were also taken to limit the scope of the study. The analysis will focus on a CFPP in Indonesia, but relevant international studies and experiences will also be considered. CCUS is not considered in this study due to its potential to produce additional emissions. The study also considers the potential for policy and regulatory changes to impact the costs and benefits of each option.

Methodology

The study is based on a comprehensive literature review, including academic research, government reports, and institutions publications. The cost-benefit analysis is done with the DCF methodology and will consider financial and non-financial costs and benefits, detailed in the following chapter.

Scenarios

The study will compare two scenarios taken on a plant-level, retrofitting a CFPP with CCS and CFPP early-retirement, to the reference scenario where the CFPP continues operating. The term early-retirement in this study refers to retiring the CFPP after an operational lifetime of 20 years, which is 10 years earlier than its 30-year normal operational lifetime (Cui et al., 2022b). The CCS retrofit scenario employed monoethanolamine (MEA) as the chemical absorption reagent due to its commercially proven process (ERIA, 2022; World Bank, 2015). MEA is technologically mature, where several commercial technologies are available and can achieve a high capture rate of up to 90%. Still, it has some drawbacks, such as high energy consumption, solvent degradation, corrosion, and hazardous waste (Spigarelli & Kawatra, 2013). Other capture methods such as pre-combustion (adsorption, membrane separation, and cryogenic distillation), post-combustion, and oxy-combustion technology are available but have a lower capture rate, higher energy consumption and cost, or lower maturity levels than MEA (Spigarelli & Kawatra, 2013). Therefore, this study chooses MEA as the baseline technology for CCS.

As this study explores the option of implementing CCS, the selection of the CFPP for the case study should consider the optimal criteria for CCS retrofit, such as the CFPP's capacity, the operational lifetime of the CFPP, and the availability of flue gas desulfurisation (FGD) system (Juangsa & Bairy, 2023). Therefore, it is important to note that this consideration leads to conservative results for the CCS retrofit scenario. At the same time, this consideration yields suboptimal conditions and results in the early-retirement scenario.

Typically, small-capacity CFPPs with less than 300 MW belong to the subcritical category, have higher emission intensity and require higher energy penalties. Higher energy penalties led to higher CCS costs, which is less favourable (Juangsa & Bairy, 2023). The term "energy penalty" refers to the energy fed from the CFPP to run the carbon capture process, which ultimately lowers the final output of the CFPP.

A longer operational lifetime also maximises CCS utilisation in carbon emission abatement. Thus, CFPPs that are less prioritised to be retired, such as USC CFPPs, have an advantage in this criterion due to their longer lifetime (ERIA, 2022). The carbon capture process also requires the FGD system to remove the SO_2 from the flue gas. CFPPs that are already equipped with FGD will require no additional cost for this system and less CSS capital cost. All 8 USC CFPPs in Indonesia, with five operating and three under construction, are designed with an FGD system (BPI, 2016; ESDM, 2015; Gandhawangi, 2019; Purba, 2020). With these considerations in mind, USC CFPP was chosen for the case study. The current USC CFPP projects in Indonesia are presented in Figure 5 and Table 1. All USC CFPPs in Indonesia are owned by private or independent power producers (IPPs). These CFPPs have the same heat rate of 8,272 Btu/kWh (GEM, 2023).

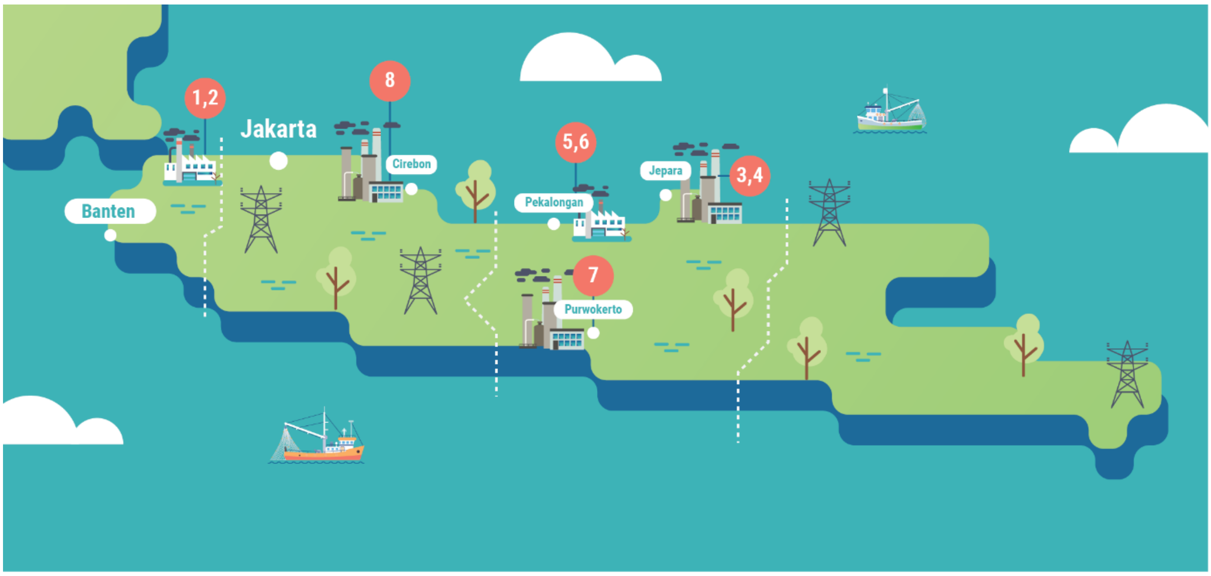


Figure 5: USC CFPP locations in Indonesia (GEM, 2023).

Table 1: USC CFPP Details per January 2023 (GEM, 2023; PLN, 2023a).

No	Province	Plant	Unit Name	Capacity (MW)	Status[a]	Period[a]	Remaining Operational Lifetime
1	Banten	Banten Suralaya Power Station	Jawa-9, Unit 9	1,000	Construction	2024-2049	25 years
2	Banten	Banten Suralaya Power Station	Jawa-10, Unit 10	1,000	Construction	2024-2049	25 years
3	Central Java	Tanjung Jati B Power Station	Jawa-4, Unit 5	1,000	Operating	2022-2047	24 years
4	Central Java	Tanjung Jati B Power Station	Jawa-4, Unit 6	1,000	Operating	2022-2047	24 years
5	Central Java	Central Java Power Project	Jawa Tengah 1, Unit 1	950	Operating	2022-2047	24 years
6	Central Java	Central Java Power Project	Jawa Tengah 1, Unit 2	950	Operating	2022-2047	24 years
7	Central Java	Cilacap Sumber Segara Primadaya Power Station	Jawa-8	1,000	Operating	2019-2049	26 years
8	West Java	Cirebon power station	Jawa-1	924	Construction	2023-2048	25 years

[a](PLN, 2023a)

This study takes Cilacap Sumber Segara Primadaya Power Station, also known as Jawa-8 CFPP, as the case study due to its longest remaining operational lifetime among all USC CFPPs, 26 years before its power purchase agreement (PPA) termination in 2049. Newer CFPPs are granted a 25-year PPA. Moreover, it is important to note that the operational lifetime of CCS is further shortened by its lead time of around 7 years. This lead time includes the time for early development, design and construction phase of the CCS (GCCSI, 2020b). Thus, retrofitting CCS in Jawa-8 CFPP results in higher CCS utilisation and abated CO_2 amount as compared to other USC CFPPs. Vice versa, choosing other USC CFPPs as the case study may not reflect the highest benefit, in the form of CCS utilisation and CO_2 abatement amount, that can be generated from retrofitting CCS for the same setup.

The President Regulation No. 112/2022 prohibits building new CFPPs, except those listed in the PLN's Electricity Supply Business Plan. An exemption also applies to CFPPs that meet three requirements: a) intended for National Strategic Projects; b) committed to reducing its emissions by at least 35% compared to the average emissions of CFPPs in Indonesia in 2021 after 10 years of operation; and c) operate only until 2050 (GoI, 2022b). Given the short remaining timeframe between the end year of the PPA period (Table 1) and considering the constraint of having no new CFPPs built or no new CFPP PPAs arranged by 2050, the replacement of CFPPs with renewable power plants assumed in this study is a logical step. This is due to the fact that it is needed not only to comply with the mandate, but also to achieve Indonesia's energy mix target in the future, as stated in its NDC target as well as the objective set by JETP of 34% by 2030 (PLN, 2022b).

The selection of solar power for this study is based on its enormous potential in Indonesia, estimated at around 3,294 GW, making it the largest among renewable energy sources. Based on the estimate of Veldhuis and Reinders, this potential corresponds to around 4,941 TWh annually (Veldhuis & Reinders, 2013). However, its current utilisation is still minuscule, at only 0.32 GW (ESDM, 2023g). The solar power plant considered in this study is sized to have a similar annual electricity generation with the replaced CFPP, as expressed in Equation 1 (Castañer et al., 2012).

Equation 1

Jawa-8 CFPP is built with a capacity of 1,000 MW, of which 55 MW is self-used to run the machinery, and 945 MW is the net output of the CFPP that supplies the demand. CF is the capacity factor of the CFPP, which is equal to 80% for the case study and is the daily energy demand that must be filled with solar power once the CFPP is retired. For the case study CFPP, equals to 18,144 MWh. refers to the average daily Peak Sun Hour (PSH), which is approximately 4 hours for the case study in Cilacap, Central Java (GSA, n.d.). With these assumptions, the capacity of the solar power plant is 4,536 MW.

An addition of a solar power plant unit at this scale would result in the biggest solar plant in the world to date. Hence, the study assumes that the added solar capacity is not limited to a single power plant unit; it can be distributed across multiple solar power plants as long as their combined capacity equals 4,536 MW and they are located within or connected to the grid where the CFPP-to-be-replaced is situated, which, in this case, is the Java-Bali system. This capacity addition is also within the technical potential limit for solar power in the Java-Bali grid system, which is around 652-658 GW (ESDM, 2023d; IESR, 2021). Therefore, the solar power plant that replaces the CFPP will be spread into several units so that the capacity of each unit is smaller than 4,536 MW.

Furthermore, the solar power plant is equipped with a utility battery energy storage system (BESS), which is sized to store excess power during the day and meet the demand during the night. For this purpose, BESS with 10-hour lithium-ion batteries (lithium iron phosphate) are chosen due to its lowest levelised cost of storage (LCOS) (IESR, 2023a). The capacity of the battery is then calculated with Equation 2 (Andam et al., 2023).

Equation 2

Since solar power is only available during the day, a portion of the needs to be supplied by the battery, with its value represented by . This value can be determined by inspecting the solar power generation profile, presented in Figure 6, provided by the Global Solar Atlas (GSA, n.d.). The area below the blue line represents , intersected by the solar power generation represented by the area beneath the orange curve. By subtracting the solar power generation from , is obtained, which amounts to 58.3% of for the provided graph.

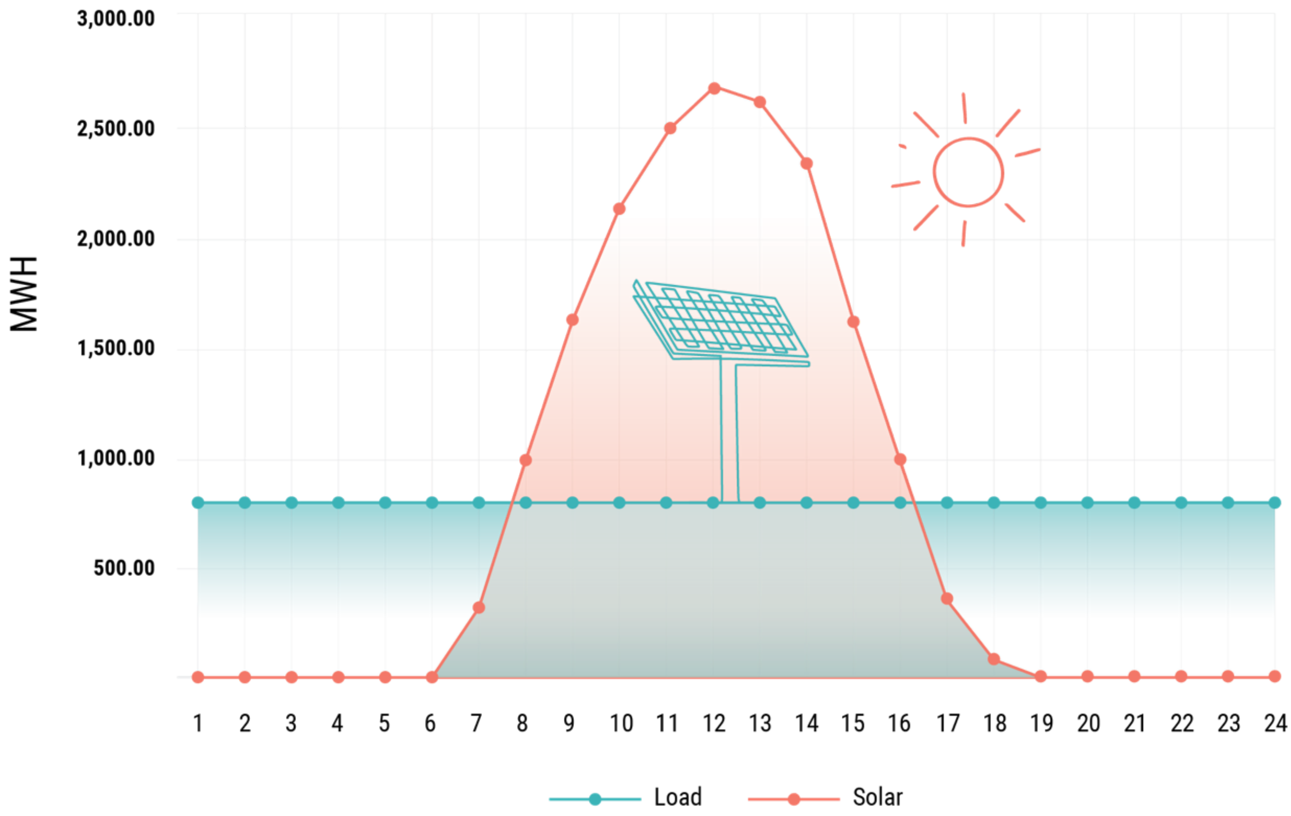


Figure 6: Solar power generation and load profile in Cilacap (GSA, n.d.).

represents the autonomy days, which signifies the number of days the system should be able to sustain in autonomy. In this study, it is set to 1. This is because the BESS is not off-grid, and there is reserve capacity available in the Java-Bali power system in case of low solar power generation (PLN, 2023b). DoD represents the depth of discharge, and RTE stands for the round-trip efficiency of the battery, which are assumed at 80% and 86%, respectively (IESR, 2023a). Following these assumptions, the 10-hour BESS capacity suited for this study is 1,537.4 MW. Again, following the assumption used for the solar power, the BESS capacity is distributed into multiple BESS with a total capacity equal to 1,537.4 MW.

The typical lead time for constructing a solar power plant is 1 year (DJEBTKE & UNDP, 2021; IFC, 2015). Meanwhile, a few examples of o complete its construction (ESDM, 2023e, 2023i; GoI, 2020). An upcoming and larger solar power project in Indonesia is a 2.2 GW floating solar power in Batam, which require 4 years lead time for permit and construction (Saturi, 2021). As explained earlier where the solar power plant is assumed to be spread into several units, the construction of each unit can be done in parallel to shorten the lead time. This study takes 5 years lead time given its significantly higher capacity.

The detailed assumptions for the case study CFPP and solar power are presented in Table 2. The capacity and capacity factor of Java-8 CFPP are taken from PLN's financial report (PLN, 2023a). The GCPT database also provides the value for these parameters but the data from PLN is used due to higher credibility. The annual CO_2 emission and coal consumption are approximated from the official emission report 2022 for Java-8 CFPP. The report stated that the annual emission factor and coal consumption rate is at 0.554 ton of coal per MWh and 0.873 ton of carbon dioxide equivalent (tCO_2e)

(S2P, 2023). Table 3 summarizes the scenarios analysed in this study as explained in the previous paragraphs.

Table 2 Detailed assumptions on case study.

		Reference
CFPP type	USC	(PLN, 2023b)
Capacity (MW)	1,000	
Net capacity (MW)	945	
Capacity factor (%)	80%	
Annual net energy production (AEP) (MWh)	6,622,560.00	
Coal consumption rate (tCoal/MWh)	0.554	(S2P, 2023)
Emission factor (tCO_2e /MWh)	0.873	
Boiler efficiency (%)	79.26	(Fachruddin, 2023)
Coal calorific value (kcal/kg)	4,280	(Lesmono, 2022)
Coal price (USD/tCoal)	52.2	
Annual coal (MtCoal)	3.883	
Annual emission ($MtCO_2e$)	6.115	
Average PSH (hours)	4	(GSA, n.d.)
Solar power capacity (MW)	4,536	Equation 1
BESS capacity (MW/MWh)	1,537.4/ 15,374.04	Equation 2

Table 3 detailed scenarios of the analysis.

Parameter	Scenario		
	Reference	CCS retrofit	CFPP Early retirement
Operational period	30 years	30 years	20 years [a]
Retire year	2049	2049	2039
CCS installation year	-	2023	-
CCS lead time	-	7 years [b]	-
CCS operation start year	-	2030	-
Solar power + BESS installation year	2044	2044	2035
Solar power + BESS lead time	5 years	5 years	5 years
Solar power + BESS operation start year	-	-	2040

[a](Cui et al., 2022b), [b](GCCSI, 2020b)

Cost and Benefit Structure

CCS Costs

The cost structure for CCS is taken from the studies conducted by ERIA (ERIA, 2022) and is presented in Table 4. The CCS cost structure consists of three components: capture, transport, and storage. In this study, only transport by ship is considered when calculating the CCS transport cost, as all USC CFPPs in Indonesia are located near the shore, and offshore storage in the form of depleted oil and gas wells is assumed. Since the potential storage location has not been pinpointed yet due to the lack of publicly available information, we utilise multiple cost estimates in CCS transport and storage to represent the maximum range of possible costs. A lower transport cost implies a closer distance between the CFPP and storage location, while a lower storage cost indicates a storage location at a lesser depth, influencing the requirement for drilling. The details on the transport range and storage depth are presented in Table 9: Summary of Sensitivity Analyses. The analysis employs the upper-cost values, while the lower cost values are used in the sensitivity analysis.

Table 4: CCS Cost Structure

CCS capture		
CAPEX (MUSD/MtCO2)		(ERIA, 2022)
Supporting boiler	142.81	
Higher desulphurisation	15.84	
Other equipment	75.72	
OPEX (MUSD/MtCO2/year)		
Operation of supporting boiler		
Energy demand (GJ/tCO2)	4.5	(World Bank, 2015)
Other variable costs	2.52	(ERIA, 2022)
Absorbent	3.93	
Desulphurisation	0.98	
Labour	28.12	
CCS transport – shipping		
Capacity (MtCO2/year)	2.50	(ERIA, 2022)
CAPEX (MUSD) (lower, upper)	259.10	
	399.25	
OPEX (MUSD/y) (lower, upper)	62.91	
	92.45	
Range (km) (lower, upper)	180.00	
	1,500.00	
CCS storage – offshore well		
Well capacity (ktCO2/year)	500.00	(ERIA, 2022)
CAPEX (MUSD/well)		
Drilling cost (lower, upper)	40.50	
	76.40	
Pre-exploration of site	7.76	
Compressor station	12	
OPEX (MUSD/well/year)		
Monitoring	4.42	

The operation of CCS requires a stream of low-pressure steam for processing the amine solvent in the capture unit, which consumes 1.5 GJ/tCO_2 (World Bank, 2015). The low-pressure steam can be extracted from the CFPP steam cycle with the consequence this reduces the amount of steam for power generation and the net output capacity of the CFPP. This condition is also known as 'energy penalty'. A study conducted by the World Bank showed that this reduction may reach up to 27.5% of the total CFPP capacity for a 2x1,000 MW USC CFPP (World Bank, 2015). For capturing the CO_2 emission of the case study CFPP, the required energy equals to 7.64 TWh annually–larger than the electricity generated by the CFPP in a year.

Alternatively, additional steam demand can be provided by supporting boilers, thus not hampering the electricity generation output of the CFPP. The additional coal demand for producing this steam is estimated to be around 1.93 MtCoal annually, calculated with Equation 3 (BEE, 2015).

Equation 3

CV is the calorific value of the coal, 4,280 kcal/kg, and is the boiler efficiency at 79.62%. In consequence, the additional consumption of coal of this scale also increases the carbon emission by 3.04 $MtCO_2$ per year when it is calculated using the emission factor and coal consumption rate of the CFPP boiler presented in Table 4. This additional emission corresponds to 49.74% of the annual carbon emission of Java-8 CFPP at 6,115 $MtCO_2$. Therefore, the final CFPP carbon emission after retrofitting with CCS is at 59.74% of its initial emission value, with 10% coming from the unabated CFPP carbon emission.

CFPP Early Retirement Cost

The cost structure for CFPP early retirement is adapted from the study by IESR, which comprises four components: stranded asset, state coal revenue losses, rehiring package, and income losses.

Stranded Asset

Stranded asset value is estimated by calculating the remaining value of the prematurely retired plants assuming linear cost depreciation, as presented by Equation 4 below (Cui et al., 2022c).

Equation 4

OCC indicates the overnight capital cost of the power plant, Cap indicates capacity, L indicates expected lifetime, and R indicates the retirement age of the plant. For the case study of Jawa-8 CFPP, the L and R values are 30 and 10 years, respectively. The OCC of Jawa-8 CFPP is estimated at USD 1.4 billion (ESDM, 2023h; PLN, 2020).

Annual State Coal Revenue Loss

Annual state coal revenue loss refers to the loss incurred due to lower sales of coal. This loss is calculated by multiplying the coal price by the percentage of state revenue gain for each ton of coal sales, which is rated at 5.565%. This value is generated from the average royalty value for the reduced coal sales due to CFPP's early phase-out, as stated in the study by IESR (Cui et al., 2022b). The Government of Indonesia (GoI) receives royalties for coal sales, ranging from 4 to 13.5% of its price based on the calorific value and the price stated in Government Regulation No. 26/2022 (GoI, 2022a).

This study also assumes that international demand for coal will be shrinking as countries, including the main importers of Indonesian coal, such as India, China, and other Asian countries, pledge to reach their NZE target (IESR, 2023b). The domestic and international demand for Indonesian coal will decline more rapidly in a scenario where more ambitious climate action is taken to align with the Paris Agreement. Projections indicate that it will drop by 20% by 2030, 60% by 2040, and 90% by 2050 when compared to the levels observed in 2020 (IESR, 2022). Thus, shifting coal sales from the domestic market to the international market is assumed to be not a viable option in this study.

Since 2018, Indonesia's power sector has benefited from a lower coal price cap at 70 USD/tCoal thanks to the Domestic Market Obligation (DMO) pricing regulated in the Decree of the Minister for Energy and Mineral Resources (ESDM, 2018). This price is intended for coal with a calorific value of 6,322 kcal/kg, total moisture 8%, total sulphur 0.8% and ash content 15%. Coal with lower specifications, such as the one used in Jawa-8 CFPP, costs lower.

Future coal prices are estimated using the projection by IEA, which provides price estimates for 2030, 2040, and 2050 across different regions. The price between known years is linearly interpolated. In this study, future coal prices for Coastal China are used as the reference due to their geographical proximity to the case study and are assumed to provide a better approximation (IEA, 2021). Fuel prices are expected to decrease due to reduced demand as countries shift away from fossil fuels to cleaner energy to reach their NZE targets. The advancement in technology in clean power generation leads to lower LCOE compared to those from coal, further driving the transition away fro m coal (Roser, 2023).

This study assumes that DMO pricing will continue to prevail until future coal prices reach levels lower than USD 70/tCoal. Beyond this point, it is assumed that the domestic price will equal the projected price, and the lower-calorific coal price will adjust accordingly. Figure 7 presents the historical and future coal price projections.

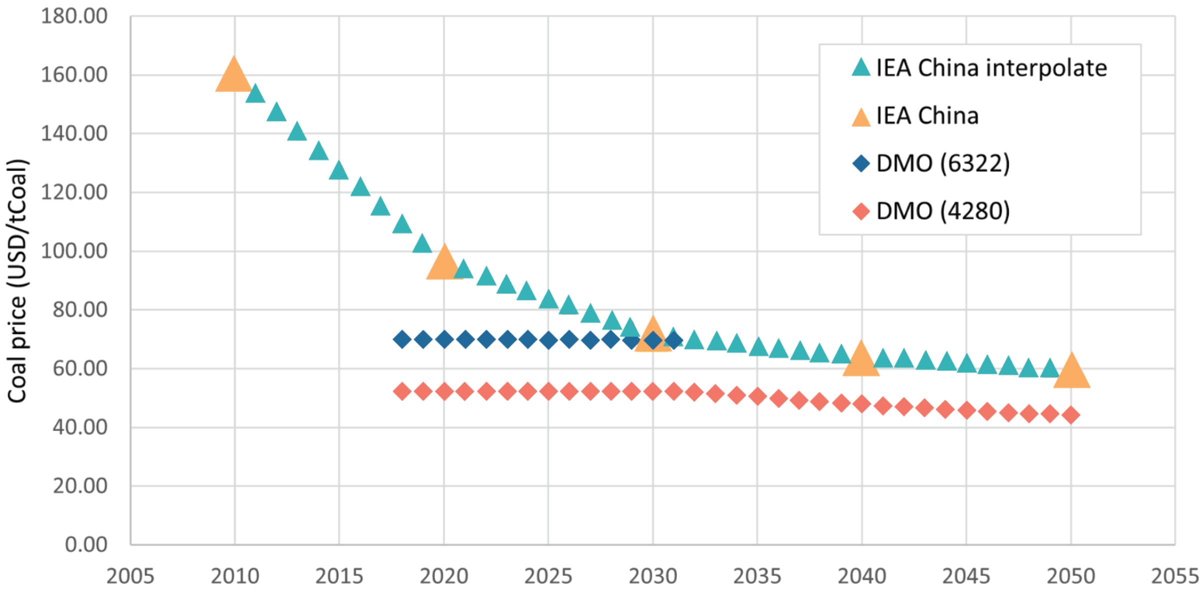


Figure 7: Coal price historical data and projection (IEA, 2021).

Rehiring Package

Fiscal support in the form of rehiring packages includes providing company funds to hire former coal workers, offering relocation support, and providing retraining funds. Transitioning such aspects is important to achieve a just transition, which can be supported by international financing such as through a JETP. The total cost incurred to cover this financing is a function of the support package amount per worker and the number of workers operating the CFPP.

The number of workers estimated for Jawa-8 CFPP is provided by CELIOS at 0.22 workers per MW, or around 220 workers (CELIOS, 2023). The fiscal support amount is approximated from support packages available in other countries, grouped into lower, middle, and higher estimates as presented in Table 5 (Cui et al., 2022b). The middle-value estimate is used in the analysis.

Table 5: Rehiring Package for Displaced CFPP Workers (Cui et al., 2022b).

	Lower	Middle	Higher
Amount per worker (USD)	9,882.00	20,392.00	39,727.00

Job and Income Losses

The income losses for CFPP are calculated by multiplying the number of workers displaced due to the early retirement of the CFPP by the average annual income for such workers. The reduction of coal demand downstream in the coal supply chain (due to the CFPP phase-out and employees' income reduction) will exert pressure upstream on the coal mining industry. The loss of income (LoI) in the coal mining industry is calculated by Equation 5 (Cui et al., 2022b).

Equation 5

Coal reduction is the amount of coal sales reduced due to CFPP early retirement, which equals the annual coal consumption of the Jawa-8 CFPP. The annual salary per worker in the mining industry sector in Indonesia was approximately 3,930 USD in 2020 (BPS, 2021). Data for annual salaries is taken from 2020, as the latest available data for the number of workers in the coal mining industry is from that particular year, estimated at 250,000 people (IESR, 2022). Coal production in 2020 is 561 MtCoal (ESDM, 2023f). This results in an estimate of 1.75 million USD per million.

Other Costs

Other costs refer to the expenses applicable to all scenarios, including CFPP operational costs, decommissioning costs, electricity subsidies, social costs of carbon (SCC), and capital and operational costs of utility-scale solar power plants and utility-scale BESS.

CFPP Operational Costs

CFPP operational costs mainly consist of fixed operation and maintenance (FOM) costs, variable operation and maintenance (VOM) costs, and fuel costs(Nalbandian-Sugden, 2016). Annual FOM and VOM for USC CFPP in Indonesia are estimated at 56,600 USD/MW and 0.11 USD/MWh (ESDM, 2021). The coal cost estimates for coal with a calorific value of 4280 kcal/kg are presented in Figure 6.

Decommissioning Costs

Due to the lack of in-country CFPP decommissioning experience, a decommissioning example of NTPC 1,000 MW Badarpur Power in India is taken. The decommissioning cost is estimated at 58.11 MUSD/1,000 MW, with the breakdown presented in Table 6 (Cui et al., 2022b; Shrimali & Jindal, 2021).

Table 6: Cost Breakdown of CFPP Decommissioning (Shrimali & Jindal, 2021).

Cost Component	Cost (MUSD/1000 MW)
Employee cost	7.11
Stations overheads	24.14
O&M expenses	3.90
Pre-demolition cost: environmental regulation (asbestos removal)	0.09
Demolition cost	4.05
Cost combustion residuals (ash pond)	15.72
Coal storage area cleanup	3.10
Total	**58.11**

Electricity Subsidies

Electricity in Indonesia is still subsidised by the GoI due to the cost of supply (Biaya Pokok Penyediaan/BPP) being above the average electricity tariff paid by consumers (PLN, 2022a). A subsidy involves the allocation of funds from the government to businesses to lower the price of subsidised goods or services. On the other hand, as the GoI determines electricity prices, compensation refers to payments made by the government to businesses when there is a revenue shortfall resulting from such pricing policies (MoF, 2022). The budget for electricity subsidy in Indonesia is driven by several factors, including, among others, oil price (Indonesian Crude Price/ICP), currency conversion rate, electricity tariff, and the number of subsidy recipients. ICP and currency conversion rates affect the BPP because PLN uses non-subsidised diesel fuel for its operation (Setiawan, 2022). Equation 6 presents the calculation for the electricity subsidies per unit of generated electricity, expressed in USD/kWh.

Equation 6

The historical electricity subsidy per kWh data from 2017-2022 is calculated from PLN's statistics (PLN, 2022a). RUPTL provides projections for this parameter between 2023-2030 (PLN, 2021a). Indonesia aims to eliminate poverty by 2045, which is the centenary of Indonesia's independence (Bappenas, 2019). On top of that, the GoI also aims to decrease its GHG partially through energy subsidy reductions (Bappenas, 2019). Therefore, it can be assumed that the subsidy for electricity for periods beyond 2030 will be declining until it diminishes to zero in 2045 due to receding recipients. Due to the lack of future policy on electricity subsidy, the electricity subsidy during this period is estimated using linear interpolation between the values in 2030 and 2045, as presented in Figure 8.

The coal in the electricity generation mix is then used to calculate the subsidy dedicated for electricity generated from CFPP (Cui et al., 2022b). The coal share in electricity generation historical data (2017-2022) is obtained from MEMR (ESDM, 2023b). Meanwhile, the projection data for coal share from 2023 and beyond is taken from the RUKN draft (ESDM, 2023d). Figure 2 presents the share of coal in the electricity generation mix, which is gradually decreasing.

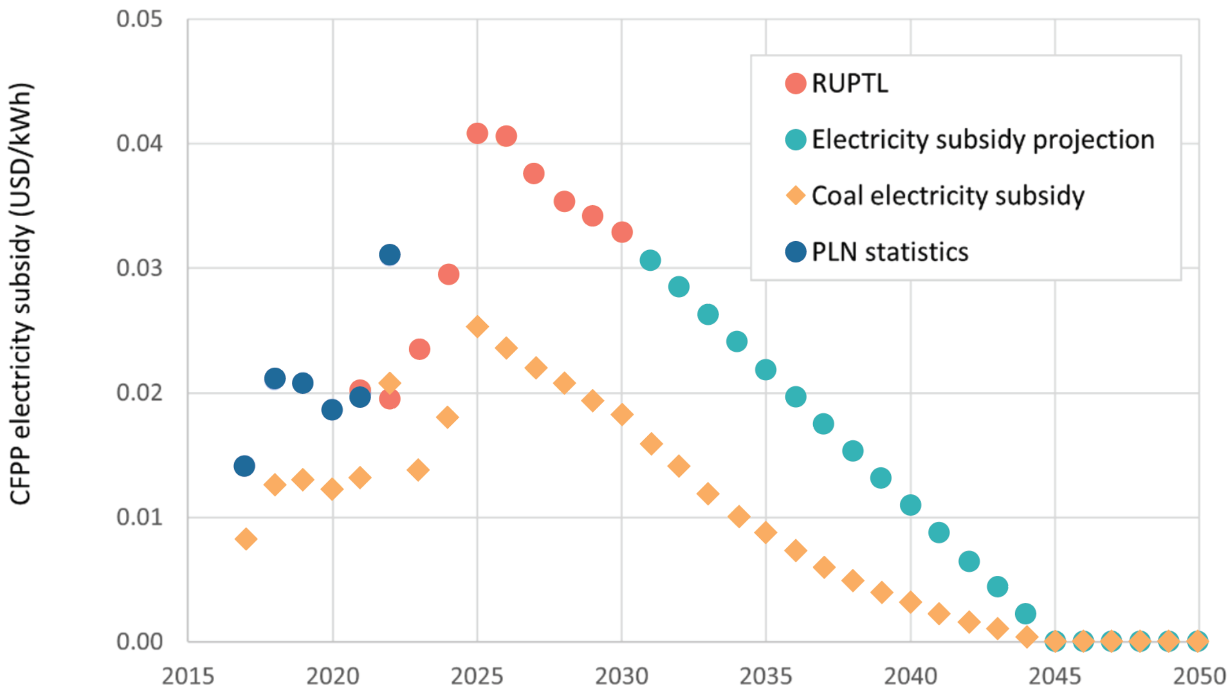


Figure 8: Electricity subsidy historical data and projection

Utility Scale Solar Power Plant and BESS

The IESR report provides the capital and operational costs for utility-scale solar power plants in the years 2023, 2030, and 2050, which is used as the basis for the analysis in this study. The costs for other years are estimated using linear interpolation based on available data. The same report also provides the capital and operational costs for utility-scale BESS. Table 7 presents the cost assumptions for solar power plant and BESS (IESR, 2023a).

Table 7: Utility-Scale Solar Power Cost and BESS (IESR, 2023a)

	202	2030	2050

	3		
CAPEX solar power (USD/kW)	790	560	410
OPEX solar power (USD/kW/year)	14.4	10	8
CAPEX BESS (LFP) (USD/kW)		3,767	
Fixed OPEX BESS (LFP) (USD/kW/year)		9.87	
Variable OPEX BESS (LFP) (USD/MWh)		0.51	

Social Cost of Carbon

The Social Cost of Carbon (SCC) or carbon pricing is a valuable tool for measuring the impact of CO_2 changes on the climate. SCC internalises the cost incurred due to climate change damages and includes changes in net agricultural productivity, human health, property damages from increased flood risk, and changes in energy system costs, such as reduced heating costs and increased air conditioning costs(EPA, 2016). Internalizing the SCC results in an additional cost in the operation of CFPP as it produces carbon emissions. Vice versa, reducing the emission results in the benefit of SCC reductions.

Carbon pricing mechanism in Indonesia is still in the early implementation phase. The currently enacted law sets the minimum price at 2 USD/tCO_2 (GoI, 2021c). The carbon price in the recently inaugurated national carbon exchange is around 4.85 USD/tCO_2 (Puspaningtyas, 2023). This study aims to find the carbon pricing level whose benefit equals the additional cost for implementing the EPO and CCS scenario by assigning specific numbers for the carbon pricing in each scenario.

The SCC can also be expressed in terms of the price per unit of electricity generated to provide an illustration of when SCC is internalised into the electricity pricing scheme in Indonesia. Considering that electricity tariffs in Indonesia are still subsidised by the government, internalizing SCC into electricity prices can also be interpreted as an additional burden on government subsidies for electricity provision

Overview of cost distribution

Table 8 presents an overview of costs that occur during the timeframe of our analysis for each scenario, spanning from 2023 (year 0) to 2049 (year 26). The table also indicates the duration for which each corresponding cost occurs. The benefit in the CCS retrofit scenario (CCS) and the early phase-out scenario (EPO) is measured as a cost reduction when compared to the reference scenario (REF).

In the CCS retrofit scenario, the CCS is assumed to be immediately implemented in this study; hence, the CCS capital expenditure (CAPEX) cost is incurred in year 0. The CCS operational expenditure (OPEX) is incurred once the CCS starts operating, from year 7 until the end of CFPP's natural operational lifetime in the year 2049, accounting for the 7-year CCS lead time (GCCSI, 2020b).

The stranded asset and rehiring package costs are incurred as some form of compensation to the CFPP and the workers (Cui et al., 2022b). Hence, it is assumed that it comes in a one-time payment due when the CFPP is retired earlier than its expected operational lifetime. Meanwhile, the loss of income and state revenue is incurred due to the reduced CFPP capacity from early retirement and the reduced coal production in the coal mining industries responding to the reduced CFPP capacity. Therefore, these costs are incurred annually in the early phase-out scenario from the early retirement year of the CFPP until the year when its intended operational lifetime ends.

Other costs, such as solar power and BESS CAPEX, and decommissioning costs apply to all scenarios but at different times for the early phase-out scenario. The solar power and BESS CAPEX are incurred 2 years prior to the end of the CFPP's operational lifetime due to their lead time. Therefore, these CAPEX are incurred in year 25 for the reference and CCS retrofit scenarios, and year 15 for the early phase-out scenario. Consequently, the decommissioning costs for the early retirement scenario are incurred 10 years earlier than in other scenarios. Solar power and BESS OPEX are incurred annually when the solar power is online, which is from year 17 onwards to year 26.

In the sensitivity analysis that employs SCC, the SCC is incurred annually as long as the CFPP operates. Consequently, it becomes zero when the CFPP is retired, either naturally or early. When CCS is in operation, the SCC will decrease due to emission reduction.

Table 8: Cost Component and Its Year of Occurrence for Each Scenario

Cost (year)	REF	CCS	EPO
CCS CAPEX	No	Yes	No
CCS OPEX	No	Yes (7-26)	No
Stranded asset	No	No	Yes (16)
Rehiring package	No	No	Yes (16)
Income losses	No	No	Yes (17-26)
State revenue losses	No	No	Yes (17-26)
Decommissioning cost	Yes (26)	Yes (26)	Yes (16)
Solar power CAPEX	Yes (22)	Yes (22)	Yes (12)
Solar power OPEX	No	No	Yes (17-26)
BESS CAPEX	Yes (22)	Yes (22)	Yes (12)
BESS OPEX	No	No	Yes (17-26)
Social Cost of Carbon*	Yes (0-26)	Yes (0-26)	Yes (0-16)
Electricity subsidy	Yes (0-26)	Yes (0-26)	Yes (0-16)

*Only in the sensitivity analysis

Net Present Value of the Costs

This study uses the Net Present Value (NPV) analysis to measure the present value of all costs incurred during the project lifetime, calculated with Equation 8 (Asad et al., 2022). For this study, T equals 26 years (2023-2049) of the analysis timeframe, represents the discount rate and d_i is the discount factor at year *i* (EPA, 2010).

The investment guidelines for renewable power plants by MEMR suggest a discount rate of 10% for solar, wind, hydro, and mini-hydro power plants (DJEBTKE & UNDP, 2021). IEA suggest a range of discount rates at 3%, 7%, and 10% for calculating the LCOE (IEA, 2020). The discount rate can also be approximated from the weighted average cost of capital (WACC), where a 10% WACC is considered moderate and commonly used for analysis (Alvarez & Zhang, 2021; IESR, 2023a; IRENA, 2022b). This study employs a 10% discount rate, as similar studies involving financial analysis for investments in the power sector within Indonesia use this value. Sensitivity analysis includes 7% and 13% discount rates to capture the results of the analysis at different risk levels.

 is the initial investment occurred at year 0 and is other cash flow occurred at year . Initial investment is also taken from the overnight cost of capital (OCC). The use of OCC for financial analysis is a simplification approach to conduct the financial analysis, as in practice, capital recovery charges are used to allocate the capital cost across its operational lifetime (DJEBTKE & UNDP, 2021). When capital recovery charges are used, the initial investment is annuitised to an equal amount over the power plant's lifetime using a capital recovery factor. Despite the change in the cost distribution over time, both approaches would result in the same present value (HOMER Energy, 2018).

$$NPV = -C_0 + \sum_{i=0}^{T} d_i C_i$$ *Equation 8*

$$d_i = \frac{1}{(1+r)^i}$$ *Equation 9*

NPV analysis takes into account the risk involved when expecting future benefits or cash inflows by discounting the value of those future benefits. The greater the uncertainty surrounding the realisation of these benefits, the higher the discount rate applied to the future value (Arnold, 2015). Likewise, costs incurred in the future will be discounted, leading to a lower present value of costs. In other words, delaying costs to the future provides an opportunity for investment and profit generation through interest before the need to pay those costs in the future arises.

As previously mentioned, in this study, benefits are considered as cost reductions. Therefore, the objective of this study is to identify the scenario with the lowest present value of costs.

Sensitivity Analysis

This study includes four sensitivity analyses to better understand the impact of changes in input parameters on the output, summarised in Table 9. Sensitivity analyses are also conducted to incorporate different input estimates for the same parameter from different sources. These analyses involve internalisation of SCC, variations in the transport and storage cost for the CCS retrofit scenario, extended operational lifetime, and variations of the discount rate.

Sensitivity Analysis (SA) 1 internalises the SCC with the aim to identify the level of carbon pricing required to have the benefit of SCC reduction offset the additional cost in each scenario. SA 2 analyses the study case with a closer shipping range and shallower storage location, aiming to capture the lower cost estimate of the CCS retrofit scenario since the exact location of carbon storage is not yet pinpointed. SA 3 analyses the scenario where the capture unit is only functioning 60% of the time due to technical faults and maintenance. This number is taken from the performance report of the first two commercial CCS projects, Boundary Dam and Petra Nova, that can only capture 52.5% and 60.6% of their carbon emission, respectively (DOE, 2020; Schlissel, 2021; S&P Global, 2022). SA 4 analyses a case study in which the operational lifetimes of all scenarios are extended by 10 years. SA 5 employs variations in the discount rate to assess the results at different risk levels.

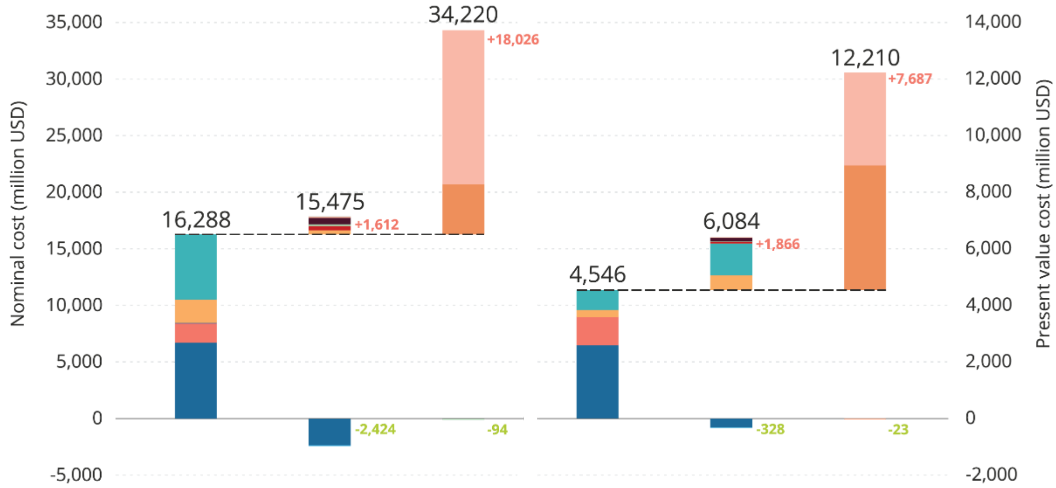
Table 9: Summary of Sensitivity Analyses

No	Parameter		Unit	Main Analysis	Sensitivity Analysis	Reference
SA 1	SCC			No	Yes	
SA 2	CCS transport	Shipping range	km	1,500	180	(ERIA, 2022)
	CCS storage	Distance from coast	km	70	20	
		Water depth	m	150	30	
		Drilling depth	m	3,000	1,000	
SA 3	Capture unit capacity factor		%	100	60	
SA 4	Extended CFPP operational lifetime		year	30	40	
SA 5	Discount rate		%	10	5, 7, 13	

Results

Main Result

The results reveal the present value of costs for each scenario: REF, EPO, and CCS. Figure 9 displays the present value of the REF scenario costs alongside the present value of the EPO and CCS scenario costs relative to the REF scenario. This presentation not only captures the magnitude of each cost component but also the incremental cost or benefit of implementing the EPO and CCS scenarios. The benefits are shown as negative incremental costs highlighted with green shades.



	Nominal cost	Nominal cost, relative to REF		Present value cost	Present value cost, relative to REF	
	REF	EPO	CCS	REF	EPO	CCS
CCS OPEX	0	0	13,623	0	0	3,284
CCS CAPEX	0	0	4,403	0	0	4,403
Income losses	0	74	0	0	10	0
State revenue losses	0	100	-94	0	13	-23
Rehiring package	0	4	0	0	1	0
Stranded asset cost	0	554	0	0	121	0
BESS Opex	0	152	0	0	20	0
RE Opex	0	388	0	0	52	0
BESS Capex	5,791	0	0	711	1,134	0
RE Capex	2,030	340	0	249	506	0
Decommisioning cost	68	0	0	6	9	0
Electricity subsidy	1,673	-57	0	984	-10	0
CFPP Opex	6,725	-2,367	0	2,596	-318	0

Cost Benefit

Figure 9: Present values of cost for REF scenario and costs of EPO and CCS relative to REF

The result shows that keeping the Jawa-8 CFPP operating until 2049 would result in a total cost of USD 4.66 billion while producing emissions of as much as 165.1 million tons of carbon dioxide equivalent ($MtCO_2e$), as shown in Figure 12. More than half of this cost comes from the CFPP OPEX. Additionally, the operation of CFPP would result in electricity subsidy spending of USD 984 million.

The CAPEX for the solar power plant and BESS, as well as decommissioning costs, are incurred at a later date close to the CFPP’s end of operational lifetime. As a result, they are heavily discounted, and their share of the present value of the total cost is smaller than other cost components such as CFPP OPEX and electricity subsidy. This condition can be observed in Figure 10 and Figure 11, where the cumulative nominal and discounted cost of different scenarios across the observed time horizon 2023-2049 is illustrated. When not considering the time value of money, the REF scenario has a higher undiscounted/nominal cost than the EPO scenario.

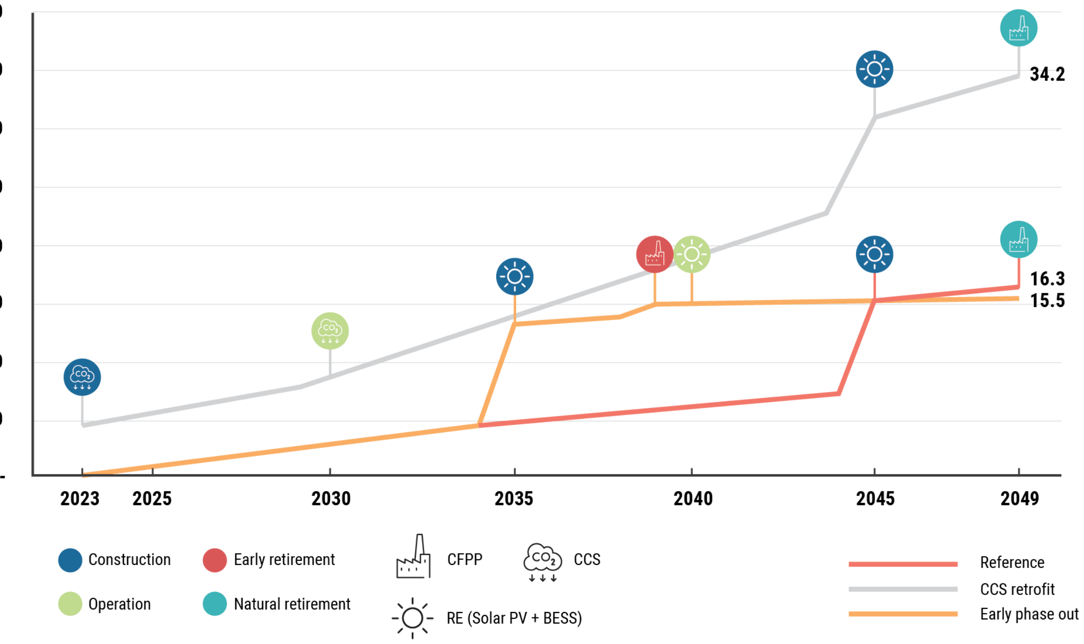


Figure 10: Undiscounted cost for REF, EPO, and CCS scenarios

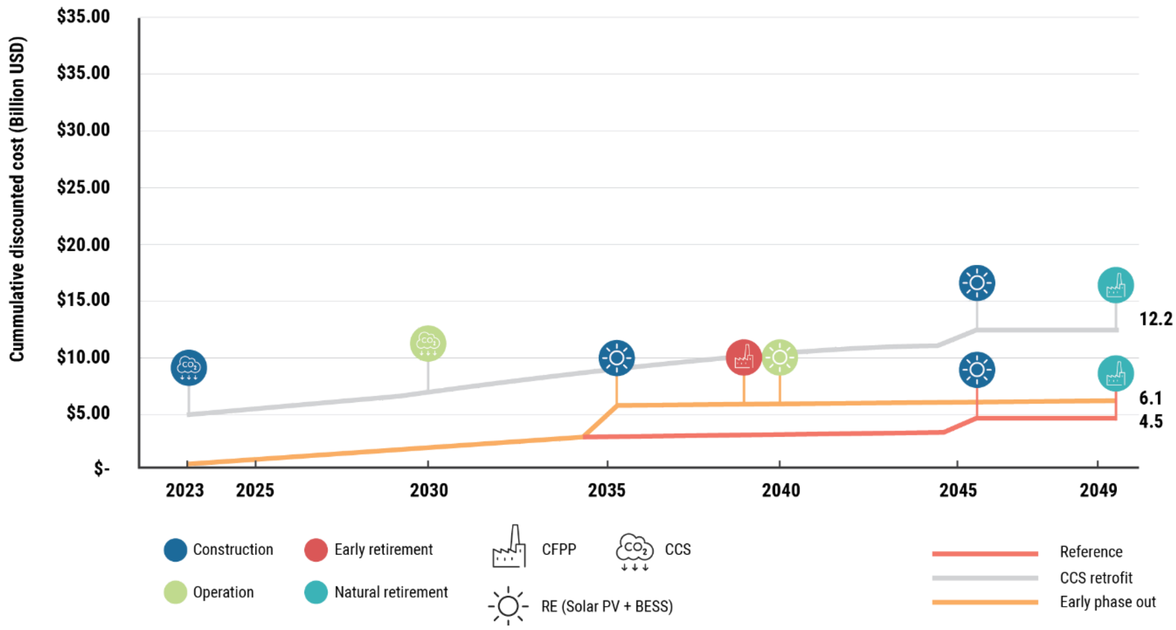


Figure 11: Discounted cost (10%) for REF, EPO, and CCS scenarios

The result for the EPO scenario shows its ability to reduce the amount of carbon emissions by 61.15 $MtCO_2e$, corresponding to a 37% decrease in the CFPP emission, with a total present value of incremental cost at USD 1.54 billion. The incremental cost is the additional cost required to implement scenario EPO and CCS relative to the REF scenario. This incremental cost can also be expressed as a cost per ton of carbon emission reduced at 25.2 USD/tCO_2e. Carrying out the EPO scenario would yield a reduction in CFPP OPEX and electricity subsidy due to the CFPP shutdown.

The results also reveal that the CAPEX for solar power and BESS is USD 1.64 billion higher than that of the REF scenario, constituting most of the incremental cost for the EPO scenario. It's important to note that the higher value for this cost component does not result from a larger solar power plant capacity, but it is partially due to the solar power and BESS earlier implementation compared to the REF scenario, making it less discounted. Another reason for the cost reduction is the advancement of solar power technology, which reduces installation costs at a later date. The solar power CAPEX reduction due to technological advancement is around 15% for the 10-year gap between the installation of solar power in the EPO and REF scenarios. The substantial increase in cost in 2035 and 2045, as observed in Figure 10 and Figure 11, is attributed to the solar power and BESS CAPEX. While the magnitude of the cost increase in these particular years is nearly identical in Figure 10, the difference is more apparent in Figure 11, where the cost increase in 2045 appears less significant due to being discounted at a higher rate.

Interestingly, the present value of costs related to CFPP's early phasing out is relatively small compared to other cost components, such as the cost of running the CFPP for another 10 years and the CAPEX for solar power and BESS, totalling USD 153.9 million. This result highlights the less significant share of costs related to phasing out the CFPP earlier. It also implies that in the pursuit of increasing the renewables in the energy mix, where the capacity of solar power is targeted to grow by multiple gigawatts and investment in renewable energy is a must, the cost for early phasing out the CFPP is less of an issue.

The result for the CCS retrofit scenario shows a poor outcome–yielding a lower reduction in carbon emissions than the EPO scenario, at 55.3 MtCO_2e or 34% reduction, with a significantly higher total incremental cost of USD 7.73 billion. Despite its ability to reduce CFPP's emission by 90%, a lower carbon emission reduction is expected as the carbon capture process requires a huge amount of energy–more energy than the electricity the CFPP generates–which adds 45% carbon emission on top of the reduction. When expressed as a cost per ton of carbon emission reduction, this amounts to USD 324.14/tCO_2. The CAPEX and OPEX of CCS constitute a major part of the cost for this scenario, at USD 4.4 billion and USD 3.35 billion, respectively. The high value of this cost component arises from the assumption that the CAPEX of CCS occurs at the beginning of the present value analysis; thus, it is not subject to any discount.

The operation of CCS would entail an increase in cost for electricity provision cost expressed in USD/kWh. This cost equals USD 0.045/kWh or equivalent to an increase in PLN's BPP in 2022 by 45.4%. Meanwhile, the additional cost of electricity provision for EPO is at 0.01 USD/kWh or only 9% of PLN's BPP in 2022.

The present value of cost for the REF scenario is the lowest when compared to the present value of cost for EPO and CCS. However, it is important to note that the case study condition favours early retirement less and CCS retrofit more. Hence, it can be expected that the result for early retirement for Jawa-8 CFPP does not support the initiative. As for the CCS retrofit scenario, it becomes evident that even under favourable conditions, the result shows suboptimal economic viability.

Therefore, the decision on whether to retire the Jawa-8 early depends on the need for emission reduction. The natural retirement of Jawa-8 will still comply with the 2050 CFPP operational limit. However, the emission profile of the power sector between the peak in 2030 and zero in 2050 is not yet defined. This trajectory could follow a linear path, decrease gradually before speeding up, or vice versa. Identifying this emission profile between 2030 and 2050 will be crucial in determining whether early retirement for the Jawa-8 CFPP is necessary.

Figure 12 further shows the cumulative carbon emissions over the analysis timeframe of 2023-2049 and explains how the emission reductions mentioned above are achieved. In the REF scenario, CFPP continues to operate and constantly emits carbon emissions. In the EPO scenario, CFPP is phased out in 2039 and completely removes any additional carbon emissions post-2039. Meanwhile, the operation of CCS partially reduced carbon emissions, leaving a lower annual carbon emission addition from 2030 to 2049.

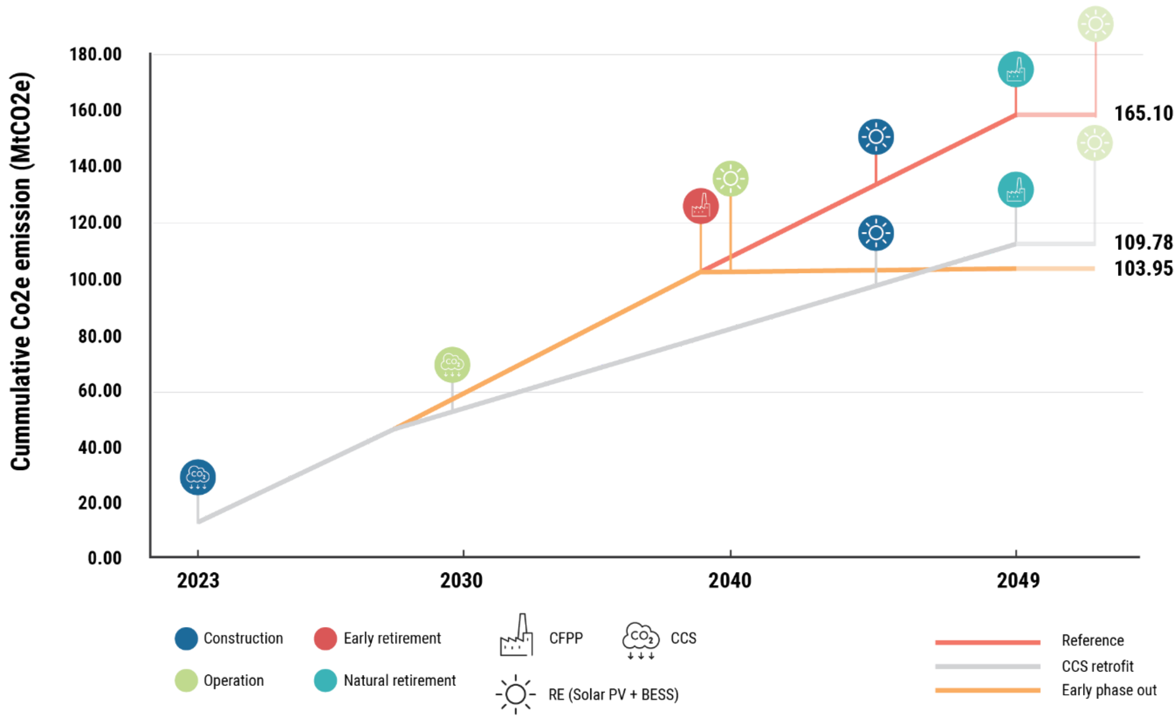
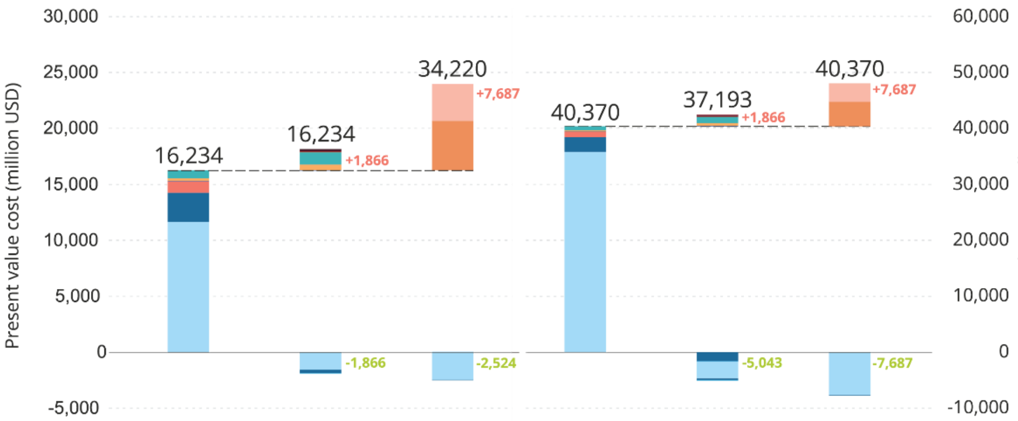


Figure 12: Cumulative carbon emissions per scenario

Sensitivity Analysis 1: Social Cost of Carbon

In this analysis, all cost components remain constant, except for the social cost of carbon emissions. As presented in Figure 13, the benefit from SCC reduction can offset the incremental cost of the EPO scenario when the carbon pricing is set at 188.11 USD/tCO_2. Meanwhile, for the CCS scenario, a significantly higher carbon pricing, at 653.65 USD/tCO_2, is required for the benefit to offset the incremental cost. The results show that the current carbon pricing set by the law and market is tiny compared to what is required to make the least economic sense of both decarbonisation efforts. In other words, it also implies that the current SCC cost estimate is not sufficiently high to discourage the continuation of the status quo of conventional CFPP operation. With an emission factor of 0.873 tCO_2/MWh, these carbon prices translate to an additional electricity cost of provision at 16.4 and 57 USD cents/kWh. With the average electricity tariff at 9.9 USD cent/kWh in 2022, this additional cost corresponds to an increase of 166% and 576%.

Even so, the SCCs suggested in this result are not to reflect the actual SCC incurred to compensate for the damage from carbon emission but rather to identify the minimum SCC level required before each decarbonisation approach can be considered. Therefore, the accuracy of SCC estimates that reflect the actual damage is crucial in this matter. While the EPO scenario reduces more carbon emissions than the CCS scenario, its SCC reduction is smaller than that of the CCS scenario. This is because the SCC reduction occurs later and is subject to a greater discount, similar to what can be observed in Figure 11



	Present value cost	Present value cost, relative to REF		Present value cost	Present value cost, relative to REF	
	REF	EPO	CCS	REF	EPO	CCS
CCS OPEX	0	0	3,284	0	0	3,284
CCS CAPEX	0	0	4,403	0	0	4,403
Income losses	0	10	0	0	10	0
State revenue losses	0	13	-23	0	13	-23
Rehiring package	0	1	0	0	1	0
Stranded asset cost	0	121	0	0	121	0
BESS Opex	0	20	0	0	20	0
RE Opex	0	52	0	0	52	0
BESS Capex	711	1,134	0	711	1,134	0
RE Capex	249	506	0	249	506	0
Decommisioning cost	6	9	0	6	9	0
Electricity subsidy	984	-10	0	984	-10	0
CFPP Opex	2,596	-318	0	2,596	-318	0
Social cost of carbon	11,688	-1,538	-2,501	35,823	-4,715	-7,664

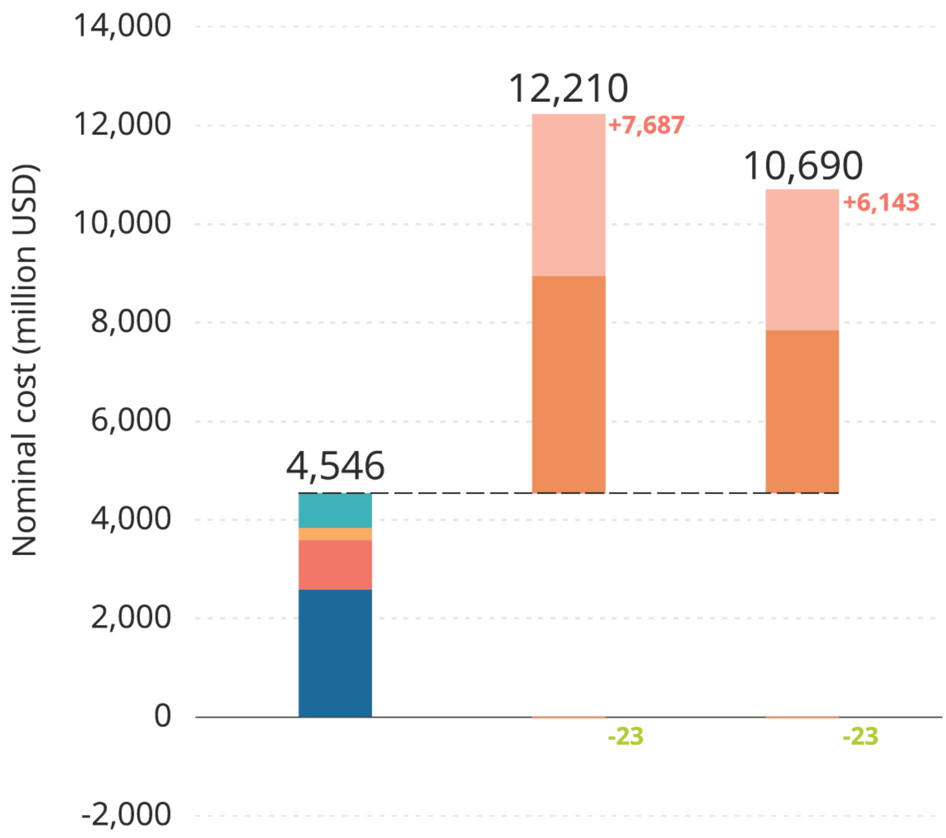
Cost Benefit

Figure 13: Present values of cost for REF scenario and costs of EPO and CCS relative to REF with internalised SCC

Since the SCC depends on the amount of carbon emissions, it can be understood that measures leading to higher emission reductions result in greater social benefits from SCC reduction. Given that JETP emphasises a just perspective on energy transition, the allocation of provided funds should prioritise energy transition projects that have the greatest impact on the net social benefit. In this context, the result indicates that CCS retrofit for CFPP is a less favourable option compared to CFPP early retirement.

Sensitivity Analysis 2: Lower CCS Investment Requirement

This sensitivity analysis aims to capture the range of CCS costs for carbon storage located in depleted offshore oil and gas wells that are closer and shallower than the assumption employed in the main analysis, while maintaining the same capture capacity. The results indicate that costs can be reduced by 19.6% or USD 1.53 billion, as shown in Figure 14. This result also suggests that storage location designation is important to accurately estimate the cost and the economics of CCS retrofit on CFPPs. Despite this reduction, the total present value for the CCS scenario cost remains significantly higher than that of the REF and EPO scenarios. This result implies the less effective use of funds to abate the carbon emissions and decarbonise the power sector when it is spent on CCS retrofit compared to early retirement of CFPP. Consequently, the reduction of CCS cost also reduces the additional cost for electricity provision cost, which is now equal to USD 0.036/kWh or equivalent to an increase in PLN's BPP in 2022 by 36.4%.



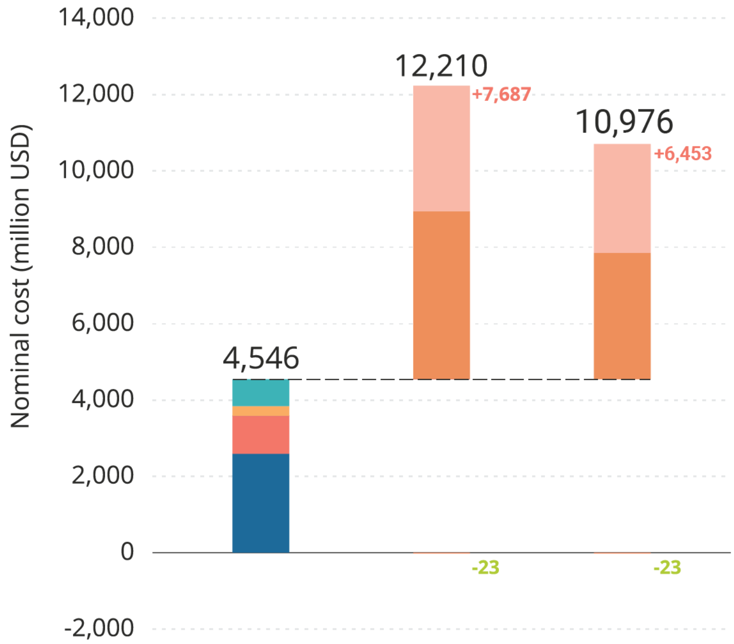
	Present value cost	Present value cost, relative to REF	
	REF	**CCS**	**CCS** Lower investment
CCS OPEX	0	3,284	2,856
CCS CAPEX	0	4,403	3,311
Income losses	0	0	0
State revenue losses	0	-23	-23
Rehiring package	0	0	0
Stranded asset cost	0	0	0
BESS Opex	0	0	0
RE Opex	0	0	0
BESS Capex	711	0	0
RE Capex	249	0	0
Decommisioning cost	6	0	0
Electricity subsidy	984	0	0
CFPP Opex	2,596	0	0

Cost Benefit

Figure 14: Present values of cost for REF scenario and costs of CCS and low investment CCS scenario relative to REF

Sensitivity Analysis 3: Low Capacity Factor Capture Unit

The lower capacity factor of the capture unit due to maintenance would result in the idle capacity of the CCS, which lowers the CCS OPEX. Other than that, all cost components remain constant in this analysis, including the CCS CAPEX. Figure 15 presents the result, where the CCS OPEX is reduced by 37.8% or USD 1.26 billion. The reduction of CCS cost also reduces the additional cost for electricity provision cost, which now equals USD 0.038/kWh or equivalent to an increase in PLN's BPP in 2022 by 38%. Consequently, the low-capacity factor of the capture unit further lowers the amount of captured carbon emission to 29.54 $MtCO_2$, or only 18% of the CFPP emission (see Figure 16). This finding underscores the investment risk associated with utilizing the same CCS technology without resolving its inherent shortcomings, should the CCS scenario encounter similar challenges to existing systems.



	Present value cost	Present value cost, relative to REF	
	REF	CCS	CCS Lower CF
CCS OPEX	0	3,284	2,050
CCS CAPEX	0	4,403	4,403
Income losses	0	0	0
State revenue losses	0	-23	-23
Rehiring package	0	0	0
Stranded asset cost	0	0	0
BESS Opex	0	0	0
RE Opex	0	0	0
BESS Capex	711	0	0
RE Capex	249	0	0
Decommisioning cost	6	0	0
Electricity subsidy	984	0	0
CFPP Opex	2,596	0	0

Cost Benefit

Figure 15: Present values of cost for REF scenario and costs of CCS and CCS with lower capture rate scenario relative to REF

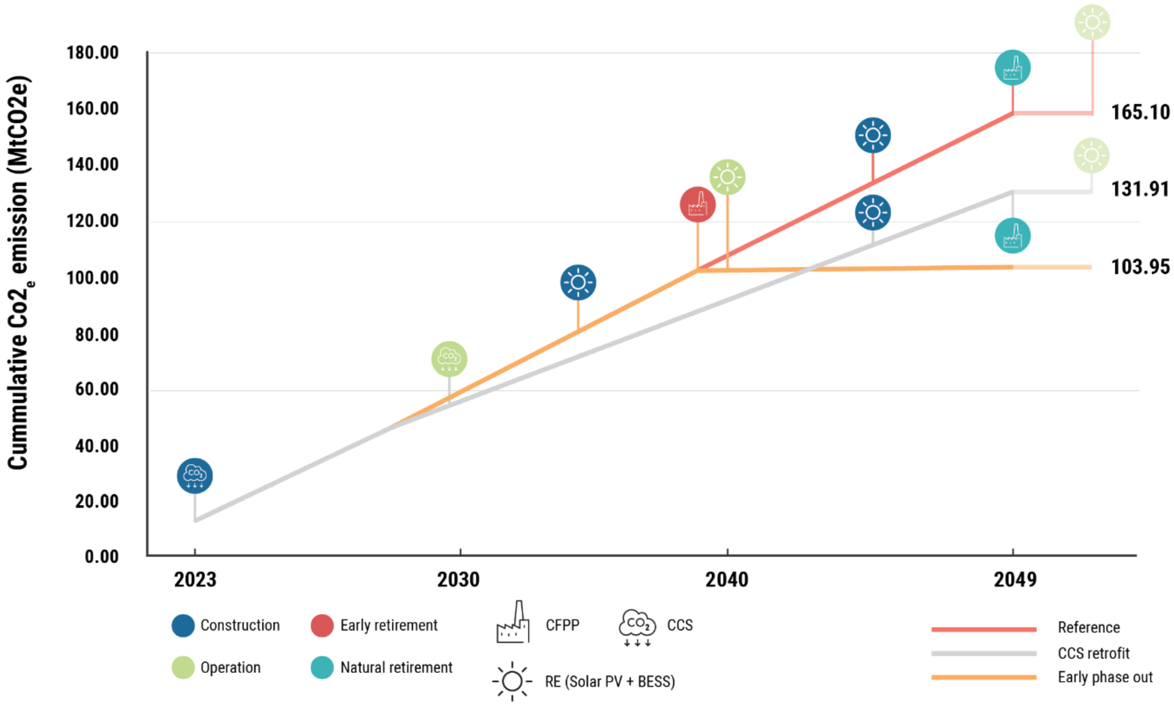
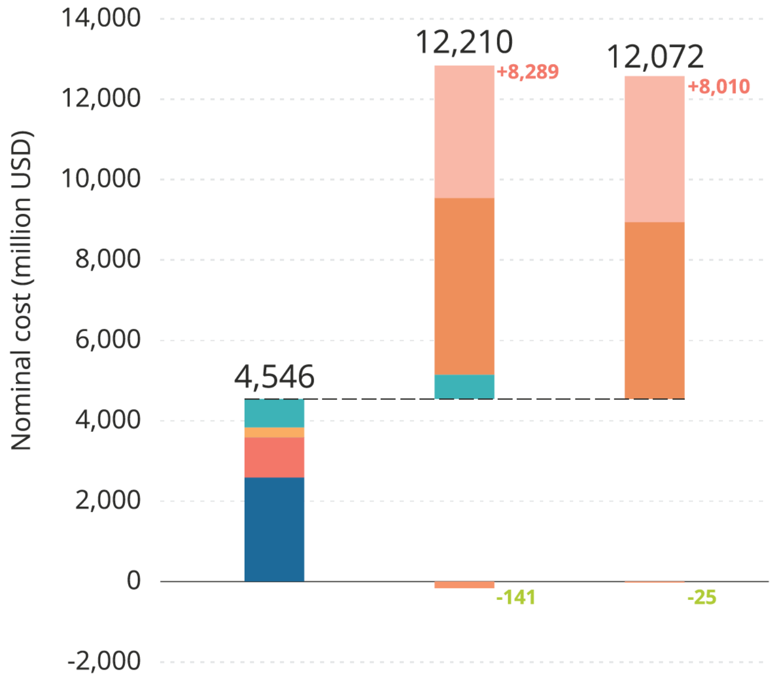


Figure 16: Cumulative carbon emissions per scenario with lower capture rate CCS

Sensitivity Analysis 4: Extended Operational Lifetime

While President Regulation No. 112/2022 explicitly imposes restrictions on the construction of new CFPPs unless they meet specific criteria, it does not regulate the closure of CFPPs already in operation before the enactment of this regulation. Such closures may be further addressed in derivative regulations. The case study, Jawa-8 CFPP, began its operation in 2019 and may not be classified as a 'new' CFPP mentioned in President Regulation. Therefore, this sensitivity analysis aims to explore the scenario in which the case study CFPP is not subject to the 2050 operational lifetime limit, and its PPA can be extended by another 10 years to 2059. Studies from IEA, IRENA, and the draft of RUKN also suggest that there may be a small remaining amount of CFPP capacity in the power sector post-2050 if equipped with CCS.

The results shown in Figure 17 indicate that by prolonging the lifetime of the CFPP, the present value of costs for all scenarios is lower than their normal operational lifetime counterpart. This result is primarily due to the shift of significant investments–such as solar and BESS CAPEX, decommissioning costs, and costs related to the early retirement of the CFPP–to later dates. Thus, these costs will then be subjected to a higher rate of discount. The present value of the incremental cost for EPO is reduced to only USD 555 million. Meanwhile, the continued operation of CCS increases the CCS OPEX by 10.6%. The incremental cost for CCS is also increased to USD 8.1 billion. Consequently, the longer operation of CCS retrofit enables a higher amount of carbon to be captured and stored, totalling 73.9 $MtCO_2e$ (Figure 18). The additional electricity provision cost for the EPO and CCS scenario in this sensitivity analysis is 0.034 USD/kWh and 0.003 USD/kWh, corresponding to a 34.3% and 3.3% increase in electricity provision cost, respectively.



	Present value cost	Present value cost, relative to REF	
	REF Extended Operation	CCS	CCS Extended Operation
CCS OPEX	0	3,284	3,632
CCS CAPEX	0	4,403	3,311
Income losses	0	0	0
State revenue losses	0	-23	-25
Rehiring package	0	0	0
Stranded asset cost	0	0	0
BESS Opex	0	0	0
RE Opex	0	0	0
BESS Capex	274	437	0
RE Capex	88	161	0
Decommissioning cost	2	4	0
Electricity subsidy	984	0	0
CFPP Opex	2,714	-118	0

Cost Benefit

Figure 17: Present values of cost for REF scenario and costs of EPO and CCS relative to REF with extended operational lifetime

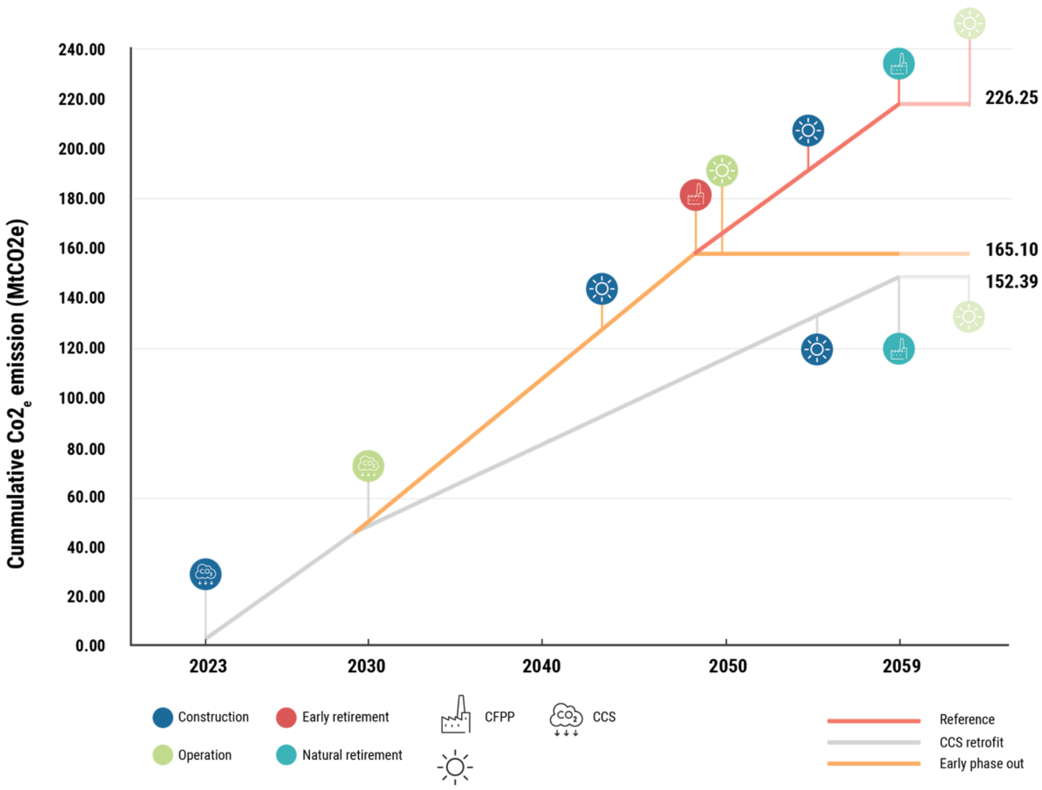
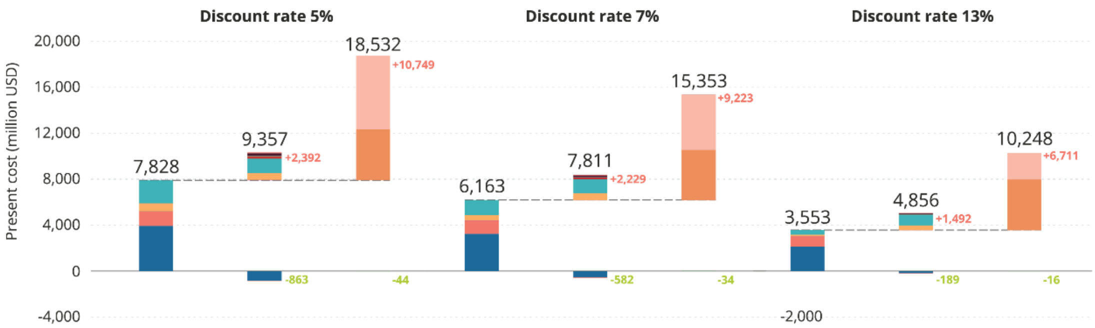


Figure 18: Cumulative carbon emissions per scenario with extended operational lifetime

Sensitivity Analysis 5: Discount Rate Variation

This sensitivity analysis aims to identify costs that are sensitive to changes in the discount rate, both positively and negatively. A lower discount rate results in higher present values of costs incurred in the future. Costs that are incurred later, close to the end of the analysis timeframe, as presented in Table 8, such as decommissioning costs, solar power CAPEX, BESS CAPEX for the REF and CCS scenarios, and solar power OPEX, BESS OPEX, state revenue losses, and income losses for the EPO scenario, are heavily impacted by the decrease in the discount rate.

As explained in Subchapter 3, a lower discount rate implies a lower interest rate for an investment made today that would result in the same amount of value to cover the cost in the future, thus highlighting the need for interest rate risk management. Moreover, costs that are more distributed over time and incurred closer to the beginning of the timeframe of the analysis, such as CFPP OPEX and electricity subsidy costs, are less affected by the increase or decrease of the discount rate. Vice versa, a higher discount rate results in lower present values of costs. Figure 19 displays the present value of costs for the REF scenario at various discount rates, along with the relative present value costs for the EPO and CCS scenarios compared to REF. The REF scenario consistently maintains the lowest overall present value of costs.



	Present value cost	Present value cost, relative to REF		Present value cost	Present value cost, relative to REF		Present value cost	Present value cost, relative to REF	
	REF	EPO	CCS	REF	EPO	CCS	REF	EPO	CCS
CCS OPEX	0	0	6,345	0	0	4,820	0	0	2,308
CCS CAPEX	0	0	4,403	0	0	4,403	0	0	4,403
Income losses	0	26	0	0	18	0	0	6	0
State revenue losses	0	35	-44	0	24	-34	0	8	-16
Rehiring package	0	2	0	0	2	0	0	1	0
Stranded asset cost	0	254	0	0	188	0	0	78	0
BESS Opex	0	54	0	0	36	0	0	12	0
RE Opex	0	138	0	0	93	0	0	30	0
BESS Capex	1,980	1,245	0	1,307	1,264	0	394	943	0
RE Capex	694	626	0	458	594	0	138	409	0
Decommisioning cost	19	12	0	12	11	0	3	7	0
Electricity subsidy	1,249	-23	0	1,129	-17	0	870	-6	0
CFPP Opex	3,886	-839	0	3,257	-565	0	2,148	-183	0

Cost Benefit

Figure 19: Present values of cost for REF scenario and costs of EPO and CCS relative to REF at different discount rates

Figure 20 illustrates the sensitivity of increasing and decreasing the discount rate to the present value of costs for each scenario. The 5% discount rate is employed to simulate projects funded with low-interest-rate loans, resulting in a 50% increase in the present value of costs for the REF and CCS scenarios, and a 34% increase for the EPO scenario. It is also observed that increasing the discount rate by 3% has a smaller impact than decreasing it by the same percentage. Decreasing the discount rate by 3% increases the cost by 25% for the REF and CCS scenario and 18% for the EPO scenario compared to the main result. Meanwhile, increasing the discount rate by the same amount decreases the cost by 17% for the REF and CCS scenario and 14% for the EPO scenario. This outcome stems from the inherent nature of the discount factor itself, where the difference between the discount factors at 7% and 10% is more significant than that between 10% and 13%. This phenomenon becomes evident when applying this range of discount rates to Equation 9.

Furthermore, Figure 20 reveals that CCS OPEX, BESS CAPEX, and SCC are the cost components that drive the changes in present value when subjected to different discount rates. This observation is unsurprising, given that these components represent the majority share of costs in various scenarios, as depicted in Figure 10. This result implies the need for risk management for these cost components. Therefore, while the use of different discount rates has significant implications for the cost-effectiveness of each scenario, other factors, such as the timing of expenditures and the magnitude of initial costs, also play crucial roles.

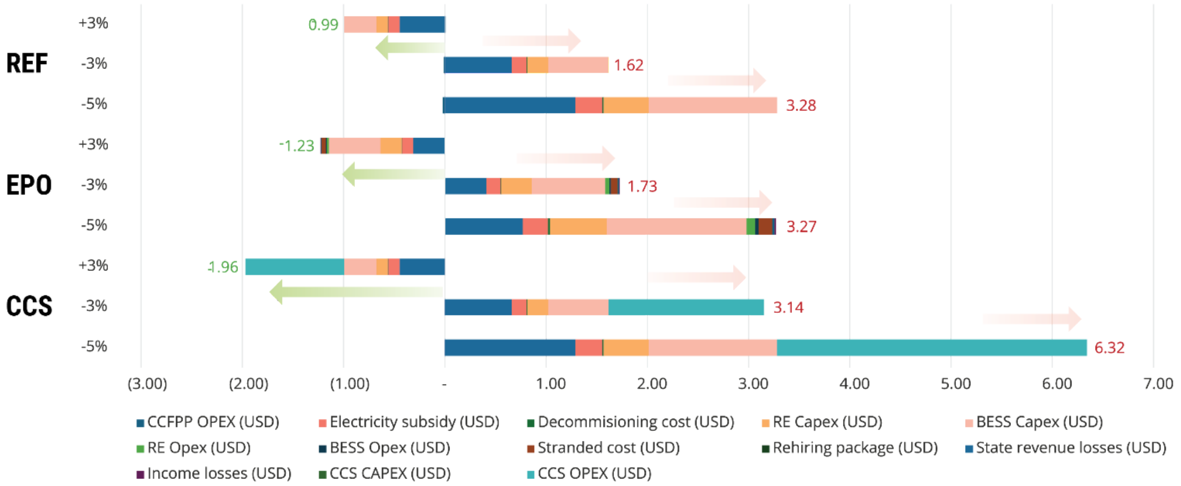


Figure 20: Present values of cost difference for REF, EPO and CCS scenarios with 5%, 7% and 13% discount rates.

Emission Mitigation Cost

As stated earlier, the discounted emission mitigation cost for retrofitting CCS on CFPP and early retiring the CFPP by 10 years are 576.56 USD/tCO_2e and 188.11 USD/tCO_2e, respectively. The emission mitigation cost for CCS retrofit is greatly reduced when its operation time is extended, or the transport and storage investment requirement is lower. The emission mitigation cost for CCS can be pushed down to 462.15 USD/tCO_2 and 544.15 USD/tCO_2 for lower CCS investment and extended operation.

However, under no scenario can the emission mitigation cost of CCS retrofit be lower than that achieved by the early retirement of CFPP. As such, even under the condition when the emission mitigation cost for CCS is the lowest, which is with a 5% discount rate, the EPO scenario can achieve an emission mitigation cost at 70.68 USD/tCO_2 or 1/6 that of what CCS can achieve. The emission mitigation cost for the lower capacity factor of the capture unit yields an even higher value, at 806.15 USD/tCO_2–further emphasizing the economic disadvantage of retrofitting CCS on CFPP. The emission mitigation cost is zero for the cases where the SCCs at the level suggested in this study are employed, as the additional cost is offset by the SCC reduction of each scenario.

The results also suggest that the CCS project poses more risk than EPO, as indicated by the greater change in emission mitigation costs with exposure to different discount rates. The implementation of the specific SCC value suggested by the study will eliminate the emission mitigation cost as the incremental cost is offset by the benefit of SCC reduction. Figure 21 presents the emission mitigation costs for different sensitivity analyses. When considering the undiscounted emission mitigation cost, EPO scenario has negative value due to its total undiscounted cost being lower than the reference scenario.

Having said that, it is important to note that a higher SCC is preferred and has a better economic impact on decarbonisation efforts, such as early CFPP retirement or retrofitting it with CCS. When an SCC lower than what has been suggested in this study is employed, as is the current condition in Indonesia where the case study is located, emission mitigation costs would rise. Until then, the benefits that may arise from decarbonisation approaches will be severely underestimated and pose no economic viability.

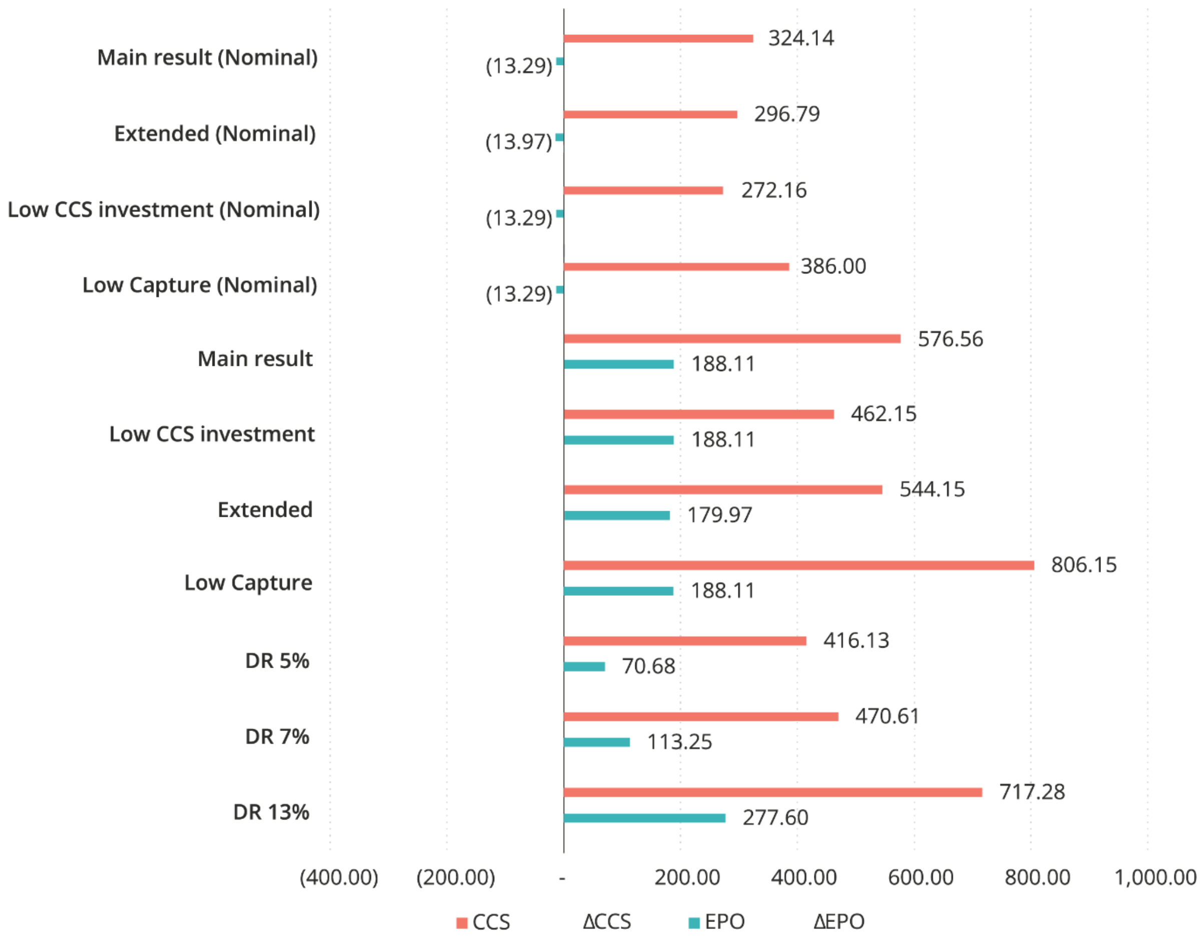


Figure 21: Emission mitigation cost for the main result and all sensitivity analyses, expressed in USD/tCO_2e

Discussion

CCS and Early Retirement Cost

One of the main findings of this study is that the cost of CCS retrofit scenarios is significantly higher compared to the reference and early phase-out scenarios. To better understand if this result is consistent with other studies, it is helpful to examine the emission mitigation cost expressed in USD per tCO_2e and the additional cost for electricity provision, expressed in USD/kWh. Table 10 presents the comparison of the emission mitigation of CCS on CFPP. This comparison uses the undiscounted emission mitigation cost from this study as other studies use this parameter.

Table 10: Emission Mitigation Cost of CCS from the Result and Other Published Studies

	Emission mitigation cost
Main result	324.1
Lower CCS investment	272.2
Extended operational lifetime	296.8
(World Bank, 2015)	101-128
(ERIA, 2022)	62
(GCCSI, 2017)	74
(GCCSI, 2020a)	70-110

Table 10 shows that in the reference scenario, the emission mitigation cost is USD 324.1 per tCO_2e, higher than the estimate of other studies due to several assumptions. It is important to note that the CCS cost resulting from the reference scenario employs higher estimates for transport (the longest transport range) and storage (the deepest storage location). Additionally, it operates for 20 years instead of the full length of the CFPP operational lifetime it retrofits due to lead time and the already operating CFPP. Thus, it should be noted that this emission mitigation cost leans more towards the higher end of the mitigation cost range for CCS retrofit. When lower CCS transport and storage investments and an extended operational lifetime are considered, the emission mitigation cost can be lowered to 22% of the emission mitigation cost of this study main result, resulting in an emission mitigation cost of around 251.4 USD/tCO_2.

On top of that, this study also considered the additional emissions from the capture process, derived from the assumption that the energy for this process comes from coal. These additional emissions hamper the emission reduction that can be achieved by retrofitting CCS on CFPP, from 90% to only 45%. The lower emission reduction increases the emission mitigation cost in this study. Not considering this potential for additional emissions may overestimate the carbon emission reduction of retrofitting CCS on CFPP and underestimate the emission mitigation cost. If the additional emission is neglected and assuming lower investment for CCS transport and storage, and an extended operational lifetime, the emission mitigation cost can be lowered to 61% of the emission mitigation cost of this study main result, resulting in an emission mitigation cost of around 126.4 USD/tCO_2, which is not too far off from other studies.

Furthermore, the GCCSI estimates that the additional cost for electricity provision for CCS at supercritical CFPP in the USA is around USD 49 to 56 per MWh, resulting in a 60-70% increase in the LCOE (GCCSI, 2017). World Bank estimates that the cost of electricity will double with the retrofit of CCS. The results from the CCS scenario indicate an increase in electricity costs of 0.088 USD/kWh, representing a 103% increase from the basic provision cost of electricity in 2022. These cost agreements should support the validity of the result obtained from this study despite being significantly higher than other scenarios.

Meanwhile, the nominal cost for retiring early the 1,000 MW Jawa-8 CFPP is USD 731.9 million, of which USD 553.7 million is cost incurred due to stranded assets. This value is higher than the reference cited as IESR stated that retiring 21.7 GW CFPP between 2031-2040 costs USD 13.3 billion, or around USD 613 million per GW (Cui et al., 2022b). While this study employs higher early retirement costs than the reference, the total cost of the EPO scenario remains significantly lower than the CCS scenario. This result clearly indicates the economic advantage of retiring CFPP earlier than retrofitting it with CCS. Therefore, the allocation of the budget for emission mitigation efforts should avoid wasteful spending on the poor economic viability of CCS retrofit on CFPP.

Impact on Stakeholders

The results for the reference scenario highlight a significant additional cost in electricity generation, multiplied by almost three to seven times when considering the social cost of carbon emissions at the level suggested in this study. The actual increase in cost will depend on the actual cost of carbon, which may be lower than what is employed in this study. Nevertheless, currently, there is little to no government support to address this negative impact. This cost reflects the indirect expenses borne by society and the environment, in addition to the electricity tariff paid by consumers. According to an IMF report, the social cost of fossil fuels in Indonesia amounted to USD 392 billion in 2020, equivalent to 37% of Indonesia's GDP (Sumarno & Sanchez, 2021).

In contrast, the government's allocated budget for addressing climate change is relatively small compared to the losses on health and environmental degradation incurred due to air pollution and climate change. The budget allocated for climate change in 2018 and 2019 was USD 8.47 billion and 5.61 billion, respectively (BKF, 2020). To mitigate these costs, it is necessary for the government to provide support and allocate additional funds for climate change initiatives. If the government decides not to increase the electricity tariff, this will involve adding to the existing electricity subsidy budget. Nonetheless, the current energy subsidy scheme needs to be revamped for better reach and budget allocation while reflecting the true cost of fossil fuel consumption. At a minimum, the recipients of the energy subsidy scheme should be based on national social welfare data rather than consumer groups, as both categories may not always be correlated. Other financing instruments should be pursued with the goal of alleviating the costs borne by society and the environment and shifting them to the emitter.

The implementation of early phase-out and CCS retrofit reduces the social cost incurred by society and the environment. However, as mentioned in the previous chapter, there will be an additional cost on top of the electricity provision cost for the CCS retrofit scenario. This cost can have one of two effects: it can either increase the electricity tariff or increase the budget for electricity subsidies when supported by the government. In the early phase-out scenario, the costs associated with the early retirement of the CFPP, such as stranded costs, rehiring packages, state revenue losses, and income losses, will be borne by both the owner of the CFPP and the government. The government may choose to support the CFPP by providing subsidies and compensation for the costs incurred during the implementation of the early phase-out. The extent to which the government bears the cost burden depends on its decision to provide financial assistance.

Moreover, the results also suggest that the internalisation of appropriate social costs is key to realising the financial benefits from CFPP early retirement or CCS retrofit. The current pricing policy for carbon in Indonesia, at USD 2 per tCO_2e, is significantly lower than the SCC estimates identified in this study, thus risking the economics of such decarbonisation efforts. Nevertheless, it is imperative to implement the internalisation of SCC that reflects the true cost of the damage borne by society and the environment due to carbon emissions, which is interesting to be explored in future research.

Study Limitations

There are several limitations employed in this study on top of those mentioned in the methodology chapter, which will be elaborated in this section.

In calculating the early phase-out scenario, the reduction of coal use imposes certain costs due to its entrenched role in Indonesia's economy. However, the shift towards renewable energy, such as solar energy, is expected to bring benefits to the economy. One of these benefits is the growth of the domestic industry in the renewable energy sector, which is not considered in this study due to the lack of supporting data. The development of utility-scale solar power plants can lead to the creation of numerous job opportunities, both in the construction phase and in the long-term operation and maintenance phase. This includes jobs in the installation of solar panels, grid integration, and other related sectors. Moreover, the establishment of solar power plants can stimulate the growth of supporting industries, such as the production of solar panels, inverters, and other components, which require critical metals. That said, the study did not account for the effects on the upstream industries, including public revenues generated from the royalties of the mining activities for these metals. Therefore, future studies should consider including this benefit to increase the robustness of the study.

Another limitation of this study is that the replacement of a 1 GW CFPP with a 4.5 GW solar power plant in all simulated scenarios does not consider the space required for the solar power plant. This analysis assumes that there is sufficient space available for the placement of the solar power plant, and its location is not constrained to the former site of the retired CFPP. Solar power is implemented in several utility-scale centralised solar power plants as well as in a distributed manner, as long as the cumulative capacity is 4.5 GW. With a power density of around 70 MWp/km^2, the 4.5 GW solar power requires land with an area of at least 64 km^2 (IRENA, 2014). This requirement is tiny compared to the available land for solar power installation in the Java-Bali system at 4,844.30 km^2 (IESR, 2021).

Solar power plants may require a larger land area, as indicated by previous studies. Lovering et al. estimated that the land-use intensity of solar power is twice that of coal (Lovering et al., 2022). A life-cycle assessment, which considers not only the land use of the power plant itself but also the land use for mining materials used in its construction, fuel inputs, and waste handling, shows that the land use per unit of electricity (MWh) for coal and solar power with silicon photovoltaic panels is 15 m^2 and 19 m^2, respectively. It is also stated that most of the land use for coal comes from the mining sites for fuel, so the land use for the power plant itself may be smaller (Ritchie, 2022).

Integrating 4.5 GW of solar power, which is a variable renewable energy (VRE) source, may result in grid disturbances due to intermittency and require some additional cost to handle. The study assumed the use of a BESS that is large enough to store all of the excesses of the generated solar power after meeting the demand. BESS can effectively mitigate the challenges posed by the variable nature of renewables, ensuring a stable electricity supply, and obviating the need for additional measures aimed at addressing intermittency. Hence, this study does not consider the additional cost that may be incurred by the impact of integrating a solar power plant of this capacity.

Scalability

As suggested by previous studies, CCS retrofit would benefit from a longer duration, allowing it more time to maximise its function in reducing carbon emissions (Juangsa & Bairy, 2023). This criterion led to the selection of USC CFPP as the case study for CCS retrofit, as it is currently the most advanced technology and, therefore, least prioritised for phase-out. Sensitivity 4 further supports this criterion, showing that hypothetically extending the lifetime of CCS operation can significantly reduce its carbon reduction cost and enhance the project's economy. Among all USC CFPPs in Indonesia, Jawa-8 CFPP was chosen as the case study due to its longest remaining operational lifetime, even longer than those CFPPs starting to operate at a later date. Thus, it can be expected that retrofitting CCS to other USC CFPPs would be less economical, as they will operate for a shorter duration and capture less carbon emissions.

Newer CFPPs will also be subject to limitations imposed by President Regulation No. 112/2022, which allows them to operate only until 2050, leaving only 27 years remaining for the utilisation of CCS on CFPPs. Even for newer CFPPs that have reduced their emission by 35%, they are still subject to the 2050 operation limit as there is no regulation yet that excludes them from this restriction. The advancement of CCS technology that could reduce costs will be constrained by this timeframe. The longer it takes to make such advancements, the less time will be available for retrofitting CCS to CFPPs, increasing the economic risks of such projects.

Moreover, this study only considers solar power with BESS to replace the CFPP, which requires bulk capacity and significant investment. Other renewable energy sources may be available locally for other CFPPs that are more cost-effective and may require a lower BESS capacity. Thus, the costs of all scenarios can still be optimised when taking this into consideration.

Policy Implications

As of October 2023, several national-level decarbonisation roadmaps have provided varying pathways to decarbonizing the energy sector, including the use of CCS/CCUS and early retirement. Most notably, a) the LTS-LCCR 2050 (GoI, 2021a); b) PLN's accelerated decarbonisation roadmap (PLN, 2023c); c) Final draft of the National Electricity Plan (RUKN) 2023-2060 (ESDM, 2023d); d) Final draft of the National Long-Term Development Plan (RPJPN) 2025-2045 (Bappenas, 2023); as well as other studies published by institutions like IRENA's Indonesia Energy Transition Outlook 2023 (IRENA, 2022a) and IEA's Energy Sector Roadmap to Net-Zero Emission Indonesia (IEA, 2022). Amidst the vastness of decarbonisation strategies offered by these documents, this analysis aims to provide an in-depth look to help decision-makers consider the economical feasibility of adopting such technology.

Selecting an optimal power sector decarbonisation strategy calls for evidence-based decision-making

When designing a pathway for decarbonisation, decision-makers shall be well-informed of the total costs and benefits of deploying a certain technology to determine its feasibility and spatial and temporal suitability. Several studies have argued that a phased approach for either early retirement or CCS adoption would result in emission reductions while ensuring energy security. It is commonly agreed that more carbon-intensive subcritical power plants shall be prioritised for early retirement, whereas CCS adoption may follow for CFPPs that have higher design efficiency[5]. On top of considering the type of boilers, CCS deployment shall also consider the proximity of the plant to

[5] Currently, only 20% of Indonesia's coal plants are supercritical or ultra-supercritical, with additional capacity foreseen in the coming years, raising the share to around 30%.

carbon storage sites to minimise transportation costs and make CCS a viable option to reduce power generation emissions.

Even so, this study argues that with the most optimum scenario for CCS deployment analysed, where it is adopted at a USC power plant located in close proximity to a relatively shallow carbon storage site, the total present value still remains higher than both the reference and the early phase out scenarios (see Sensitivity Analysis 2). With a more economically viable alternative, the use of CCS in the power sector shall be reconsidered to achieve an economy-wide net zero.

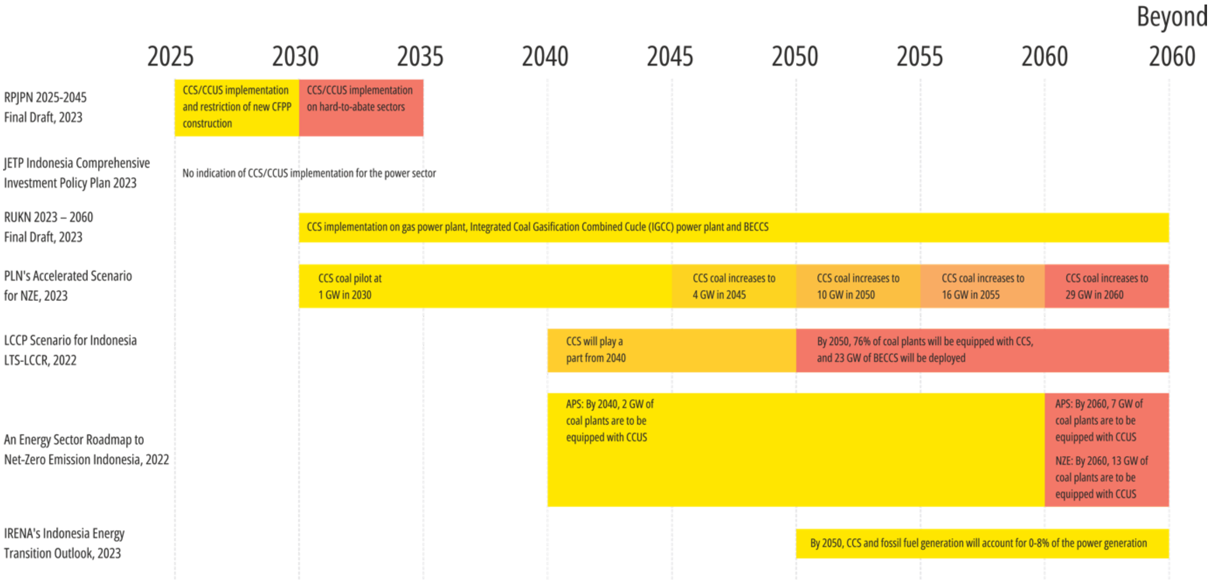


Figure 22 Current Trajectory on CCS Adoption from Published Documents

Considering that CCS is foreseen to be adopted as soon as 2025-2030, it is apparent that Indonesia remains optimistic about CCS adoption (Figure *22*). However, as of August 2022, there were only 15 planned CCUS projects at various stages of development, mostly utilised for Enhanced Gas Recovery (EGR) and Enhanced Oil Recovery (EOR), with the earliest onstream target scheduled for 2026. Information on detailed CCS projects for power generation remains lacking.

However, this study limits itself to a case study of one power plant and does not quantify the overall impact of this transformation on energy systems. Further studies shall also be developed to provide more thorough coal-exit alternatives (i.e. biomass co-firing and ammonia co-firing) and more renewable options (i.e. hydropower, wind, and geothermal), integrating social costs and benefits (i.e., health impacts, work support packages, and social safety programmes), to ensure the policies developed by the government would yield in positive net social benefits. Furthermore, in the journey of complementing existing studies, data transparency and accessibility shall be increased to ease the process of quantifying costs and benefits and produce a more democratic and accurate prediction for the decision-making process.

Integrate CFPP retirement into planning documents to ensure coherence with the energy transition pathway and alignment with the 1.5°C target

The result of the study indicates the need for a transparent and clearly defined national CFPP retirement plan to meet the emission reduction requirements of the power sector, including the target set by JETP. The primary rationale for adopting a coal-exit strategy, including CFPP retirement, is to mitigate emissions within the power system necessary for maintaining global temperature rise below 1.5°C. Consequently, the initial step involves establishing an emission reduction target that aligns with the temperature target. The GoI has undertaken such endeavours through the LTS-LCCR 2050, which is claimed to conform to the 1.5°C target. However, this claim falls short, as indicated by the findings from studies by IESR, UMD and CAT.

It is of the utmost importance to align the emission cap pathway across different regulations and medium and long-term plans such as LTS-LCCR, NDC, National Energy Policy (Kebijakan Energi Nasional/KEN), National Energy General Plan (Rencana Umum Energi Nasional/RUEN), RUKN, Long-Term National Development Plan (Rencana Pembangunan Jangka Panjang Nasional/RPJPN), and Medium-Term National Development Plan (Rencana Pembangunan Jangka Menengah Nasional /RPJMN), with the emission level as close as possible to the 1.5°C target. Having this defined and agreed across ministries and stakeholders will also assist in determining the retirement plan for each CFPP and assessing the financial impact of the retirement. Giasven that several regulations are currently under development, it is important to integrate the retirement plan to ensure coherence among different regulatory products (Figure 23).

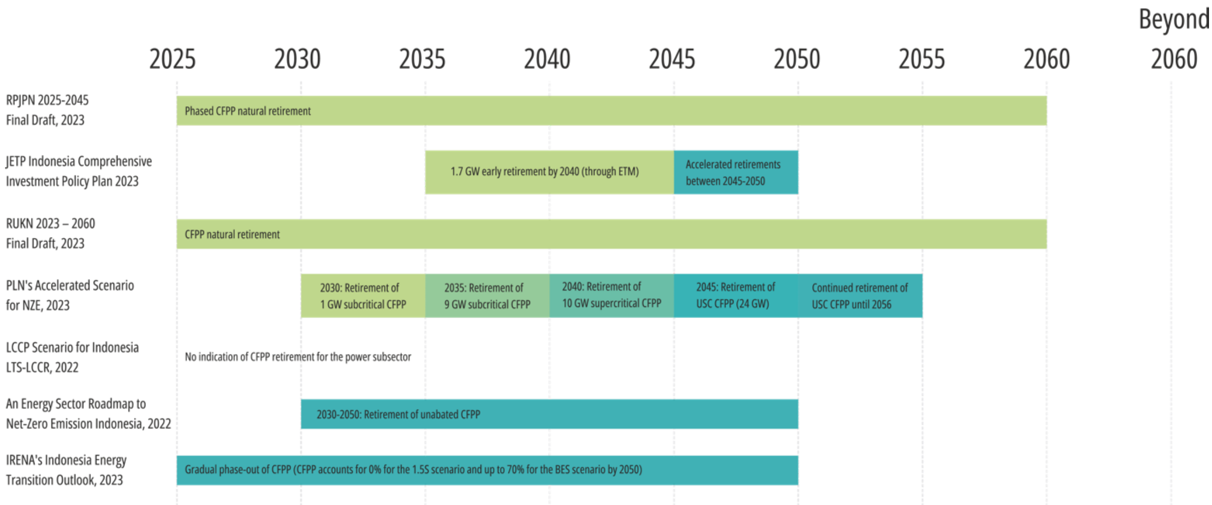


Figure 23 Current Trajectory on CFPP Retirement from Published Documents

It is evident that the government had incorporated its goal to achieve NZE through CFPP retirement and translated it into legal products—one of which is Presidential Regulation Number 112 of 2022. This regulation mandated that the Minister of Energy and Mineral Resources—after consolidating with the Minister of State-Owned Enterprises and the Minister of Finance—develop an early retirement roadmap for CFPPs, which will then be established in the sectoral development planning document—or the RUKN for the electricity sector.

The development of the early retirement roadmap is currently underway, with various energy planning documents also being revised, such as the KEN, which in turn will be a reference to the RUEN and, consequently, RUKN. Concurrently, Bappenas is developing Indonesia's RPJPN, which will serve as the corridor for the nation's development for the next 20 years. Considering that the early retirement plan spans well beyond the 2030s, integrating it into the long-term planning documents would be crucial to provide clarity and certainty for power producers on the retirement plan, as well as which technology to deploy to support the government in reaching its emission reduction and renewable energy targets.

With the current dynamics, a strong coordination between the MEMR with other ministries/governmental agencies, such as with the National Energy Council (DEN) for KEN, with Bappenas for RPJPN, or Ministry of Environment and Forestry for Indonesia's upcoming Second NDC is crucial to ensure policy coherence.

Appropriate carbon pricing can disincentivise the prolonged use of fossil fuels and enable national power sector decarbonization effort

Decarbonisation would require the cost internalisation of carbon emission to realise its economic viability. This study identifies the minimum level of carbon pricing to realise the economics of early retirement and CCS retrofit for the case study, which is significantly higher compared to the current carbon price. In this study, the effect of the currently enacted carbon pricing policy in Indonesia was not thoroughly examined. However, it strived to internalise the social cost of carbon to provide a more comprehensive analysis of the net social gains and losses, much like to simulate the effect of implementing carbon pricing. The result indicates that CFPP early retirement requires lower carbon pricing to start making a profit compared to the carbon pricing required for CCS retrofit.

With the carbon pricing implementation being underway starting from early 2023, CFPPs that are connected to PT PLN's transmission grid can trade their verified carbon allowances and sell them if there is any remainder. For 2023, the allowance is fully allocated freely, while the allowance for the subsequent years would reflect on the trade performance of the previous year. Looking into the carbon trading mechanism in the power sector as regulated in the Minister of Energy and Mineral Resources Regulation No. 16 of 2022, the USC CFPP, taken as a case study in this analysis, may technically profit from the carbon trading mechanism under the current emission cap of 0.91 tCO_2/MWh since its emission intensity is lower[6]. An emission cap based on capacity alone, regardless of the power plant technology, would rather incentivise a more efficient power plant to either emit more, or benefit from its lack of additionality.

Since Indonesia is in the early stages of carbon market development, it is understandable that its goal for the first few years is to develop the capacity of power plant operators to familiarise themselves with the carbon trading mechanism and systems, hence the less stringent emission cap. The resulting first phase of the carbon market implementation is unlikely to be significant in reducing the country's overall emissions, but with a clear roadmap for stricter cap and allowance allocation, the government can set the signal to invest in a long-term and more permanent carbon abatement.

The carbon pricing roadmap is also important to guarantee that the carbon price will increase as emission caps lower. The monetary value of carbon emissions plays a great role in quantifying how much cost will be borne by society due to the damages of carbon emissions. A carbon price that is set too low will undermine the benefits of deploying an impactful mitigation measure and vice versa. The carbon price for Indonesia's carbon trading is yet to be observed since the trading period will only begin in early 2024, but the 2023 trading price in the carbon exchange is roughly Rp 70,000 or USD 4 per ton of CO_2. Another reference would be the proposed carbon tax of USD 2/tCO_2 as elucidated in Law No. 7 of 2021 on Tax Harmonisation Law. Comparing these prices with the carbon prices calculated in this case study, it can be inferred that Indonesia's carbon price has yet to achieve the necessary carbon price that would make early retirement and CCS adoption as competitive as natural retirement—which should be at USD 188.11 and 576.56 per tCO_2, respectively.

Notwithstanding the carbon abatement potential of CCS, decarbonisation technologies deployed for carbon trading would need to provide certainty and permanence of emission reduction, thus granting stability to the carbon market and ensuring the climate crisis is averted. A thorough consideration of risk management measures should be made by the government, given the low maturity of the CCS technology and leakage-prone storage sites in Indonesia, to mitigate overshooting emission reduction targets if power sector decarbonisation will heavily rely on CCS.

Utilise innovative financing mechanisms for the early retirement of CFPPs to limit the impact on the public budget

The result of the study identifies the costs for pursuing CFPP early retirement and CCS retrofit, which result in some additional cost compared to the reference scenario–the scenario where the government decided to make no intervention in the operation of the CFPP. The additional cost may increase the burden of the state budget for providing the already subsidised electricity. As the result suggests, the cost increase will be significantly higher if the government considers retrofitting their CFPP fleet with CCS. Therefore, financing through mechanisms other than the state budget is essential for pursuing a just transition.

Considering that USC power plants are now seen as being the least prioritised for an early retirement, where it will be complemented with CCS and will only be retired starting from 2045, this study shows that an early retirement of CFPP would result in a significantly lower carbon abatement costs compared to implementing CCS technologies and retiring it post-2040. While the low-hanging fruits for early retirement remain to be Indonesia's less efficient subcritical power plants, the government should reconsider its plans to invest in CCS technologies and redirect public funding to ensure a faster early phase-out and rapid deployment of renewable energy.

[6] With the current cap for the case study's CFPP at 0.911 $tonCO_2e$/MWh, its emission factor of 0.873 $tonCO_2e$/MWh, and its historical annual emission of 6,115,000 ton CO_2e; the power plant would have an allowance of 6,381,174 ton CO_2e.

The Indonesian government should proactively leverage international financing mechanisms to expedite the retirement of its coal fleet, thereby alleviating the strain on the public budget. This is also mandated in Presidential Regulation No. 112/2022 Article 3(9) and Article 3(10), where the Ministry of Finance would have to provide fiscal support, including through blended finance, to accelerate the energy transition. There are several financial mechanisms that can be used to finance decarbonization efforts in the electricity sector. The Asian Development Bank's Energy Transition Mechanism (ETM) scheme offers a scheme that allows for the acquisition of partial ownership of coal-fired power plants (CFPPs) to the ETM in exchange for loans dedicated to emission reduction projects at the plant. The UNFCCC Clean Development Mechanism (CDM) and its successor, the Joint Crediting Mechanism (JCM), provide market-based opportunities to generate carbon credits from emission reductions achieved through decarbonization efforts such as large-scale renewable energy deployment and CCS. The Global Environment Facility (GEF) can also be explored as a potential source of international financing through co-financing programs.

One alternative that can be utilised is the JETP, which shall encompass investment portfolios to retire CFPPs early and mitigate the risks. The government can thus include risk mitigation strategies within the JETP investment plan that can finance rehiring packages and social protection programmes to absorb the impacts of income losses experienced by affected workers. On top of using it to address negative impacts, JETP-designated projects shall also prioritise options that yield the most net social benefit while ensuring efficient use of the funds for carbon abatement. By efficiently leveraging this partnership, Indonesia can accelerate its shift towards cleaner energy sources while simultaneously safeguarding the welfare of its people.

Conclusion

Pursuing a low-carbon power system has led countries, including Indonesia, to consider options such as early retirement of the CFPPs and retrofitting CFPPs with CCS. This study explores and identifies the costs associated with each option and compares it with the cost in case no option is taken with a 1 GW USC CFPP in Central Java as the case study.

The results indicate that both early retirement of CFPPs (10 years ahead of their intended operational lifespan) and retrofitting CFPPs with CCS can reduce carbon emissions, albeit with some additional cost. Early retirement shows better results than CCS retrofit as it requires lower additional cost requirement while reducing more carbon emissions. While the present value of the total cost for the CFPP early retirement scenario is higher than the reference scenario, the cost related to retiring the CFPP 10 years earlier is smaller than the cost incurred for running the CFPP for another 10 years.

Retrofitting the CFPP with CCS generates the greatest incremental cost that potentially escalates the electricity tariff by 45% or increases the state budget allocated for electricity subsidies. Despite its ability to capture 90% of the carbon dioxide from the CFPP's flue gas, the lower emission reduction of CCS retrofit resulted from the need for additional energy for its carbon capture unit. This energy need is immense, larger than the electricity generated by the CFPP, consumes coal, and produces unabated emissions.

This study puts emphasis on the financial consequences that may arise from each coal mitigation option where the implementation of the appropriate level of carbon pricing identified in this study plays a vital role. Given the time and funding constraints, it is encouraged that the government opts for least-cost measures. This study shows that, for the discussed case study, CCS may not be one of them. Future research should consider the limitations identified in this study to enhance the robustness of the findings and reinforce the conclusions drawn. We hope these insights will guide decision-makers towards sustainable and economically viable strategies for carbon emission reduction for CFPP while inciting the interest of fellow researchers to expand the study.

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