ERIA Research Report FY2024, No. 33

Decarbonisation of Thermal Power Plants and CCS Business Feasibility Study in Indonesia

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ERIA Research Project Report FY2024 No. 33
Published in February 2025

This report is prepared for the Economic Research Institute for ASEAN and East Asia (ERIA) by Sumitomo Corporation.

Preface

After COP26, the world has shifted to carbon neutral by half of this century including Indonesia. Indonesia has announced its carbon neutrality until 2060. The dominant sectors of carbon dioxide (CO_2) emissions in Indonesia are the power sector, followed by the road transport sector. This is because Indonesia's power sector fully depends on thermal power generation such as coal and gas as well as most ICE vehicles in the road transport sector. In addition, most thermal power plants in Indonesia are relatively young (less than 10 years) and the rapid shutdown of thermal power plants does not make sense from an economic viewpoint. Then, how do we achieve carbon neutrality by keeping thermal power plants? One way is applying carbon capture and storage (CCS) technology in thermal power plants. However, the economics of CCS is an issue. This report then challenges the estimation of the CCS cost of existing facilities.

For thermal plants, we selected Units 5 and 6 of Tanjung Jati B (TJB 5&6) coal-fired power plant in Central Java as a source of CO_2 emissions, and Corridor gas field in South Sumatra as CO_2 storage site . We assumed two CO_2 transport ways between the TJB plant and the Corridor: one is a pipeline and the other requires ocean transport using a liquid CO_2 ship.

This study aims to estimate the cost of the whole CCS system, including CO_2 transportation ($ per CO_2 tonne) and the impact of the CCS system (LCOE: Levelized Cost of Electricity) to electricity price ($ cent/kWh). In this regard, the Economic Research for ASEAN and East Asia (ERIA) contracted the Sumitomo Corporation to conduct this study as an ERIA energy project in 2023–2024.

To supervise Sumitomo's Indonesian CCS study, ERIA requested Sumitomo corporation to formulate a working group which consists of Indonesian CCS stakeholders; Badan Riset dan Inovasi Nasional, Balai Besar Pengujian Minyak dan Gas Bumi LEMIGAS, the Ministry of Energy and Mineral Resources (MEMR), and Institut Teknologi Bandung.

On behalf of ERIA, I would like to express my thanks to the working group members for their useful and insightful comments and suggestions to this study in terms of methodologies and results.

This report includes an estimation of the cost of the Indonesian CCS project and the necessary regulations for the CCS business in Indonesia, after a review of the existing regulations on CCS and carbon capture, utilisation, and storage approved by the MEMR and the President of Indonesia.

I hope this report contributes to initiating the CCS business in Indonesia under appropriate regulations, government support, and regional collaboration frameworks.

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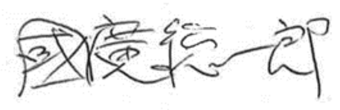
Acknowledgements

This project received tremendous support from Japan's Ministry of Economy, Trade and Industry and the Economic Research Institute for ASEAN and East Asia as well as the Indonesian Working Group – Ministry of Energy and Mineral Resources (MEMR), Badan Riset dan Inovasi Nasional, Institut Teknologi Bandung, and Balai Beasar Pengujian Minyak dan Gas Bumi LEMIGAS throughout the research project period. Invaluable advice and guidance from the Working Group members, especially at the kick-off meeting on 31 October 2023, encouraged the project members, enabled the smooth implementation of the project and the visualisation of the way forward in the near future. The project members would like also to extend the appreciation to the supporting members at ERIA for administrative and legal works.



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List of Abbreviations and Acronyms

APAC	Asia-Pacific
ASEAN	Association of Southeast Asian Nations
Bgi	initial formation volume factor
BPMA	Badan Pengelola Migas Aceh
CAPEX	capital expenditure
CCS	carbon capture and storage
CCUS	carbon capture, utilisation, and storage
Cf	cubic feet
CO_2	carbon dioxide
$DENCO_2$	Density of CO_2 at reservoir condition
EU	European Union
GHG	greenhouse gas
GIIP	gas initial in place
Gp	volume of ultimately recoverable gas
HP	high pressure
IDX	Indonesia Carbon Exchange
JETP	Just Energy Transition Partnership
kWh	kilowatt-hour
LCO_2	liquefied CO_2
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MEMR	Ministry of Energy and Mineral Resources
MRV	measurement, reporting, and verification
Mt	megatonne
MWh	megawatt-hour
OPEX	operating expenditure
PSC	production sharing contract
R&D	research and development

SC	super critical
SKK Migas	Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi
TJB	Tanjung Jati B
UK	United Kingdom
US	United States
USC	ultra-super critical
WT	wall thickness

Executive Summary

Indonesia has set a goal of achieving carbon neutrality by 2060 while relying on thermal power plants that heavily account for approximately 80% of power generation. Decarbonisation of thermal power plants is expected domestically and globally especially after COP28. To accomplish both stable electricity supply and economic growth, applying decarbonisation technology to thermal power plants such as carbon capture and storage (CCS) is desirable for large-scale purposes in the long term, if feasible and applicable enough. This study aims to contribute to the consideration of decarbonisation of thermal power plants through CCS from both technical and commercial perspectives. It does so by analysing the entire CCS value chain, from an operational coal-fired power plant to a potential CO_2 storage site in Indonesia, specifically for the purposes of this study.

Technical studies were conducted in this research project on two cases of CO_2 transport: a liquefied CO_2 vessel and a CO_2 pipeline. These studies revealed significant concerns regarding the feasibility of long-distance transport and operation throughout the value chain. However, the outcome was positive, indicating that the transport of CO_2 by liquefied CO_2 vessel would be preferable for long distances (over 1,000 kilometres) with a large-scale CO_2 volume (more than 10 million tonnes of CO_2 per year). The estimated transport costs are $17.5 per CO_2 tonnes by ship and $28.0 per CO_2 tonnes by pipeline. The estimated CCS cost is $63.7 per CO_2 tonnes in case of 13 million tonnes of CO_2 per year and ship transportation. If we convert this cost to a power generation basis, it is estimated at 7.42 cents per kilowatt-hour (kWh). These estimated costs are not accepted in Indonesia so far. To tackle such negative impact while achieving decarbonisation in parallel, the following measures are considered: (i) further technology development and cost reduction, (ii) scale-up of economic CCS business, (iii) acceptance of CO_2 from the operating business in Indonesia, and (iv) formulation of carbon price market, incentives from international institutes such as Asia Energy Transition Initiative, and carbon trade as credit.

While CCS and CCUS are expected to play a key role as a decarbonisation solution on a large scale over a longer time for project development, there are several other solutions such as biomass, ammonia, and hydrogen co-firing, amongst others, to achieve low CO_2 emissions at thermal power plants. These solutions would also need to be evaluated and pursued in parallel. Nowadays, renewable energy like solar and wind power are largely spread out in the global power sector. But the feasibility and affordability of such are subject to each region and each country considering energy availability and power generation stability, especially in Indonesia which heavily relies on coal-fired power plants. Sustainable power generation with decarbonisation solutions must be the promising key in the long term anyway. A regional supporting framework, including cross-border CO_2 transportation, is urgently expected in this regard.

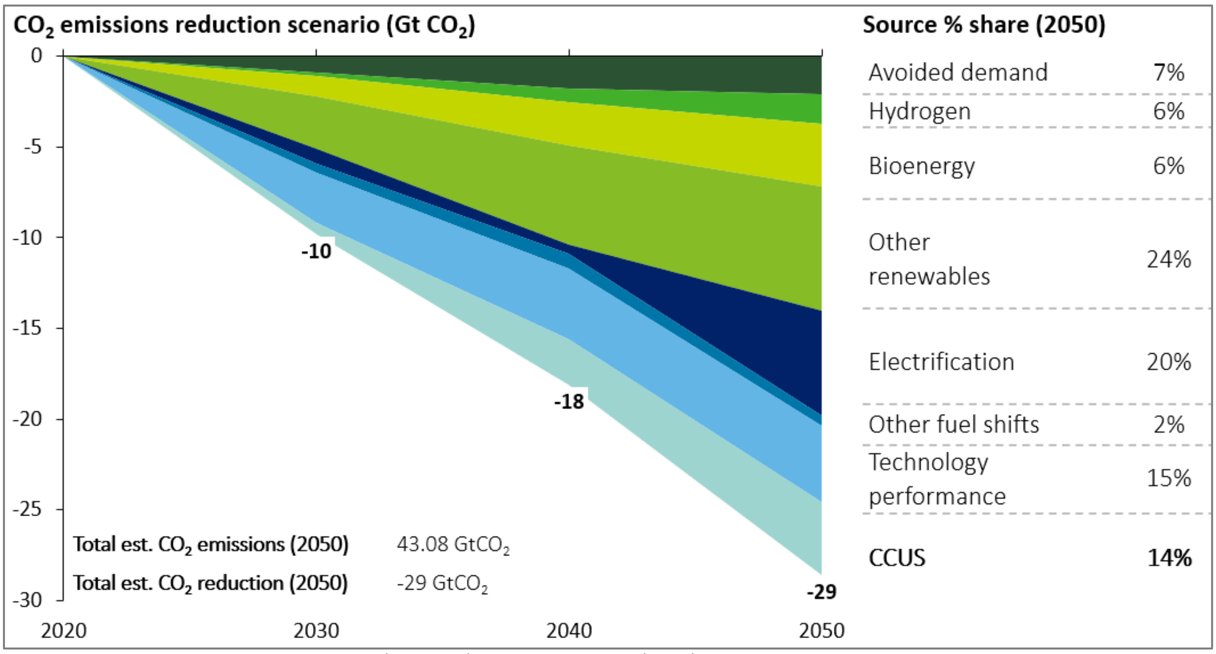
Chapter 1

Global Market Overview of Carbon Capture and Storage (CCS)

1. Global Market Overview

Carbon capture, utilisation, and storage (CCUS) will play a key role in abating up to 4.1 $GtCO_2$ of global CO_2 emissions by 2050. To achieve global net-zero emission targets by 2050, carbon reduction technologies, notably CCUS, will be critical for hard-to-abate sectors (e.g. steel, chemicals, fertiliser, oil and gas, electricity, and cement). Hard-to-abate industry emissions currently account for more than 25% of global greenhouse gas (GHG) emissions. As seen in Figure 1.1, CCUS usage is still low today. However, usage rates are expected to pick up rapidly due to the growth of the carbon capture segment, with CCUS accounting for approximately 14% of CO_2 emission reductions by 2050.

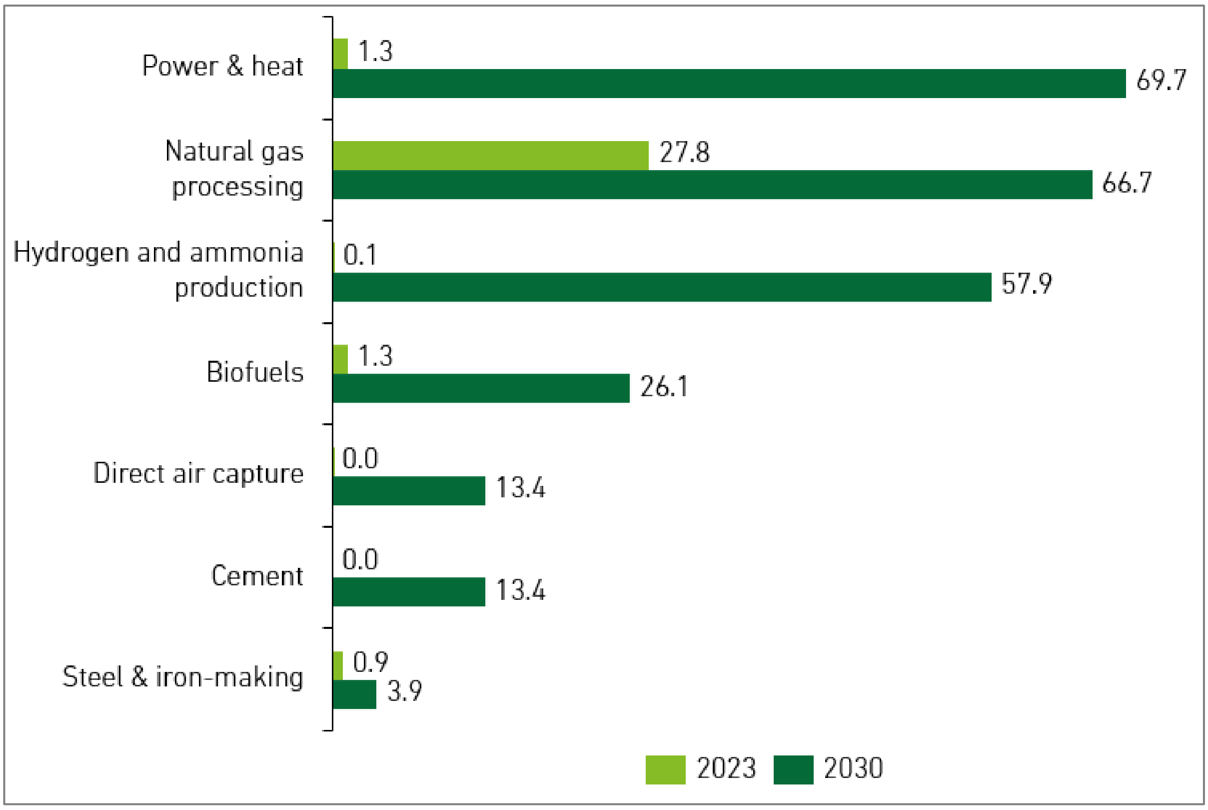
Figure 1.1. CO_2 Emissions Reduction (Gt CO_2) by Source (2020–2050)



Source: Authors based on IEA (2023a) and Statista (n.d.)

Looking forward, most of CCUS demand is expected to come from power generation, natural gas processing, hydrogen and ammonia production in that order, where CCUS has notable existing use cases. The power sector's contribution is expected to grow (i.e. fossil fuel power plants seeing persistent usage) in correlation with overall economic growth. The primary energy source of power generation is expected to continue to come from coal (e.g. China sources more than 60% of its energy from coal and the Asia-Pacific [APAC] region, as the global growing industry region, possesses an average power plant age of only 12 years). Coal-fired power plants are also expected to be retrofitted with large-scale CO_2 capture technologies. The second-largest application is expected to come from the natural gas processing industry at ~28Mt of CO_2 capacity annually. This is due to captured CO_2 being primarily used for enhanced oil recovery purpose.

Figure 1.2. Annual CO_2 Capacity (Mt CO_2) for CCUS Projects by Industry (2023 and 2030)



Source: Authors based on IEA (2023b).

Countries worldwide have adopted a considerable number of CCUS projects. The United States (US), which is focussed on enhanced oil recovery, leads by a considerable margin with 24 operational projects and an operational capture capacity of 27.2 Mtpa as of 2020.

Figure 1.3. CCS Projects by Leading Country (2020)

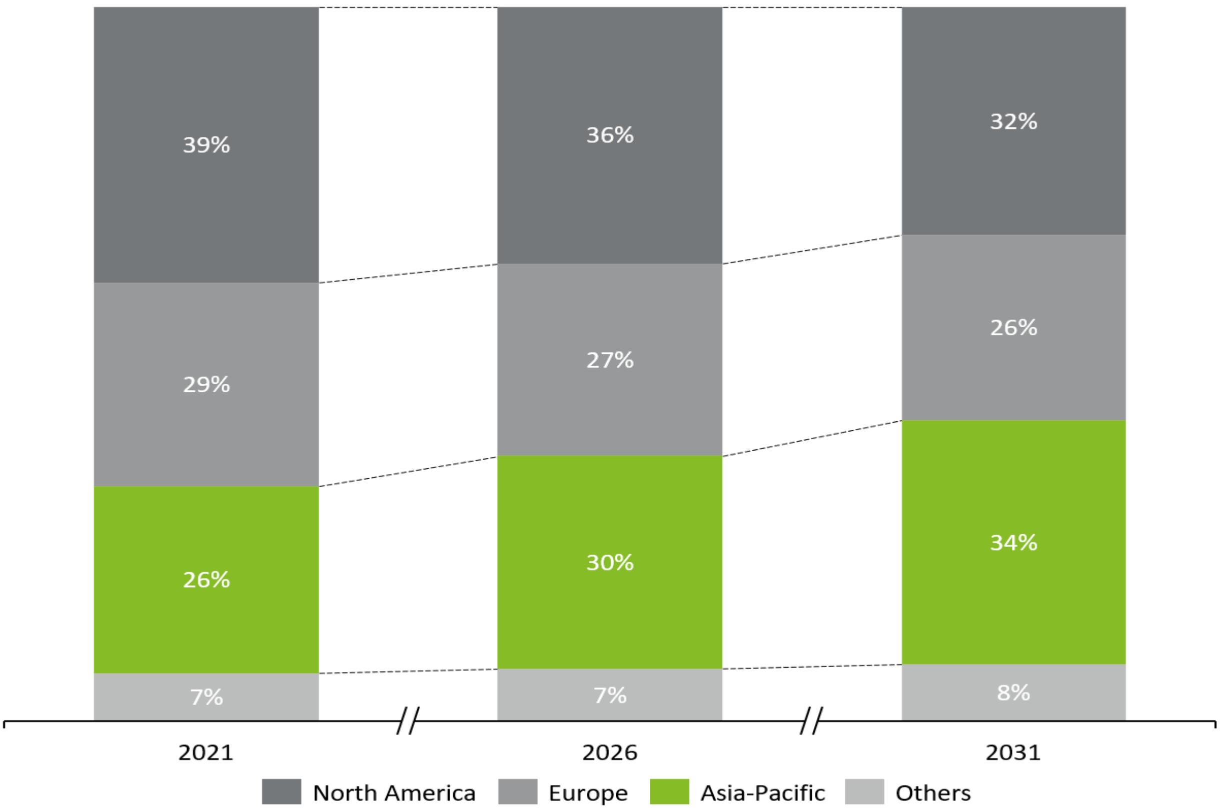
	Operational Capture Capacity (Mtpa)	No. of Operational Projects	End-Use (EOR / Geological Storage / Utilisation)
United States	27.2	24	EOR 95%, Geological Storage 4%
Australia	4.3	5	Geological Storage 93%, Utilisation 7%
Canada	4.3	8	EOR 72%, Geological Storage 28%
Brazil	3.0	1	EOR 100%
China	2.3	12	EOR 85%, Utilisation 15%
Norway	1.7	3	Geological Storage 100%
Saudi Arabia	1.3	2	EOR 100%
UAE	0.8	1	EOR 100%
Croatia	0.6	2	EOR 100%
Sweden	0.5	1	Geological Storage 100%
Others	N/A	9	Geological Storage 100%

Source: Authors based on GCSSI.

2. APAC Market Overview

Today, North America is still leading the global CCUS market with a market share of 39%. This can be mainly attributed to North America's huge natural gas market and increasingly supportive government policies. For example, the Inflation Reduction Act of 2022 increased tax credits, simplified requirements for the credits, and provided flexibility in monetising the credits for CCUS projects. Governments in North America have also provided significant funding support for CCUS and its research and development. North America has also been capitalising on partnerships with firms to develop new CCUS projects, hubs, and innovation.

Figure 1.4. Global CCUS Market Value by Region (%) (2021–2031)

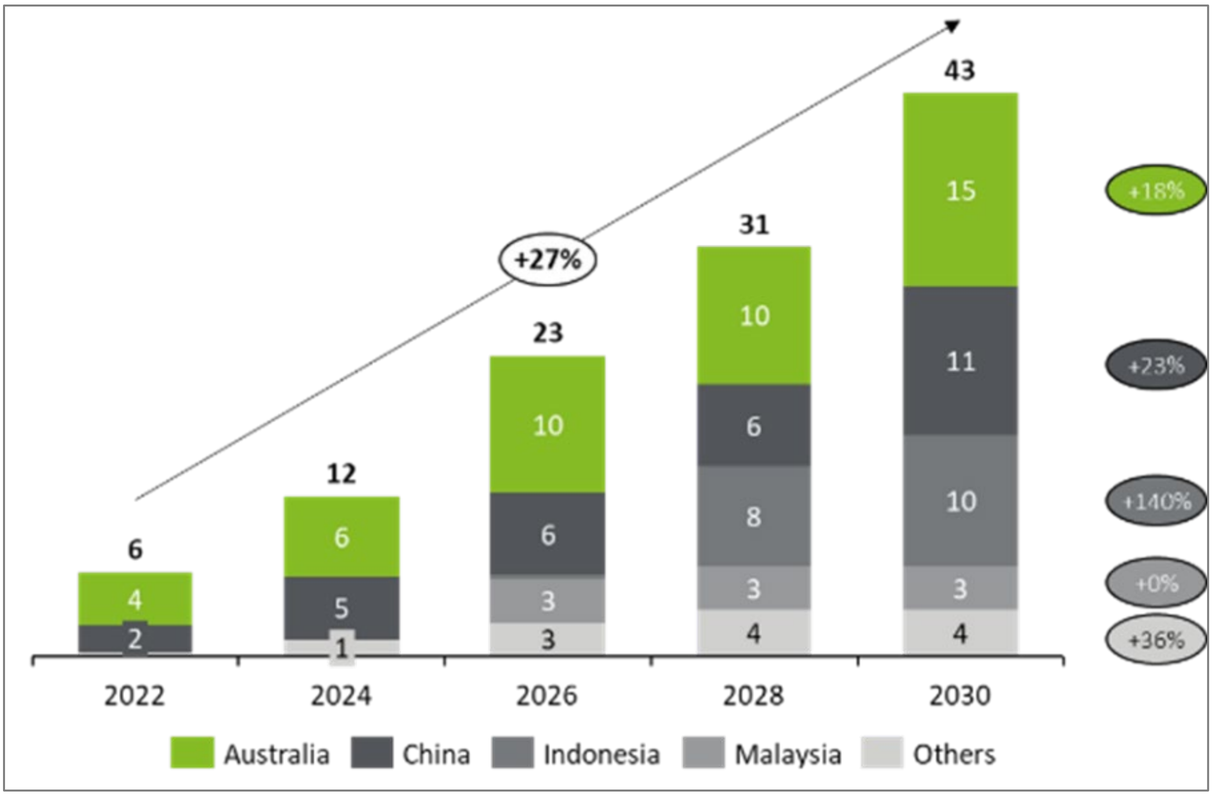


Source: Authors.

By 2031, the APAC region is projected to surpass North America and become the largest CCUS market with a market share of 34%. There is a growing project pipeline in the APAC region with cumulative capacity forecast to be more than 90 Mt by 2030. APAC's growing market share can be attributed to its economically effective value chain, a strong engineering, procurement, and construction ecosystem and high partnership potential (cross-industries and cross-border). However, APAC still lacks regulatory support and commercial attractiveness for CCS projects. Australia and China have made some progress on commercial attractiveness, but in Indonesia, Malaysia, Thailand, and Viet Nam, commerciality is largely under development.

Within APAC, Australia is expected to continue its leading market position with a projected growth of 18% in capture capacity from 2022 to 2030. Indonesia is expected to be the fastest-growing market in terms of capture capacity.

Figure 1.5. APAC Capture Capacity (2022–2030)

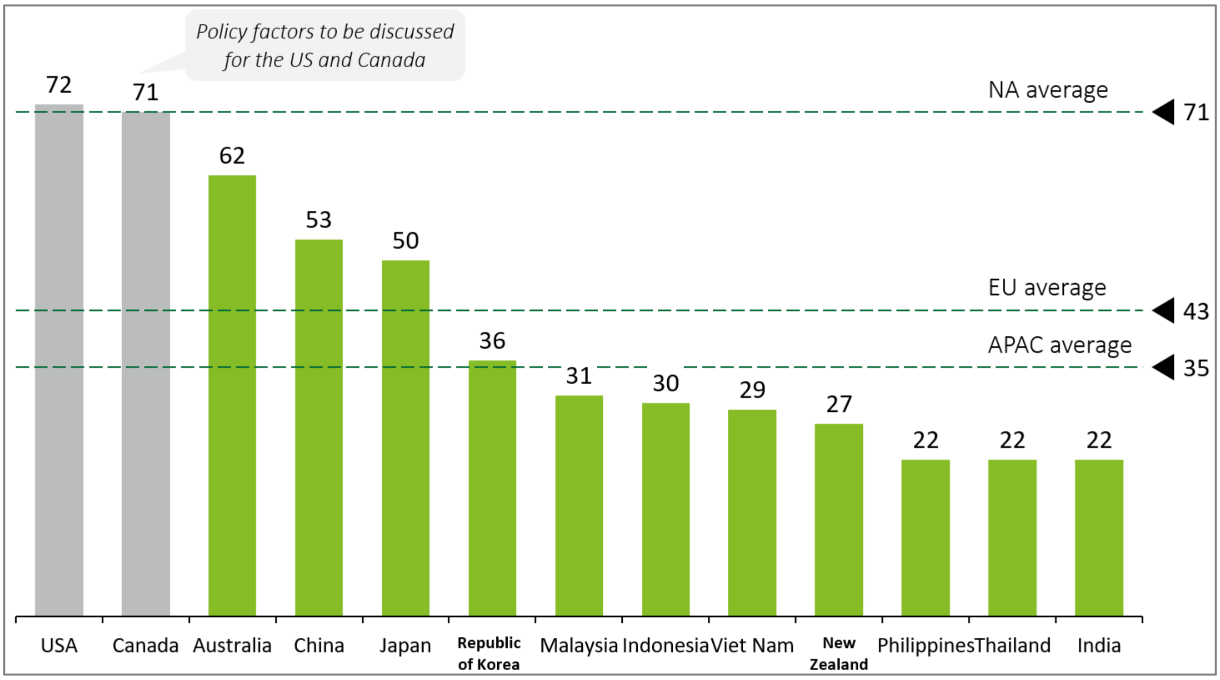


Source: Authors based on IEA (2023b).

Australia has several competitive advantages for CCS, having well-established and stable geological storage basins that can accommodate the injection of up to 300 Mtpa for at least 100 years[7]. The government has also demonstrated support to CCS and the development of CCS technologies through many funding programmes. Other competitive advantages of Australia include its advanced legal and regulatory framework in the CCS market and its strategic location which positions it in proximity to high-emitting countries with limited carbon capacity.

Further scaling of CCS remains a big challenge in APAC due to limited available value chain between emitters and storages, regulations, technical issues, and bankability. Limited access to suitable geographical locations for CO_2 storage and finding viable sequestration sinks can be also challenging. Policies are being progressed in countries like Australia., while many other countries are still under development. There are insufficient technical demonstration projects as the region lacks a deep pool of pilot projects and operational proof points. Since CCS/CCUS requires significant amounts of investment, emitters are reluctant to contribute to CCS/CCUS goals so far. This is exacerbated by carbon pricing regulations that are still considered insignificant to make CCS/CCUS projects commercially feasible.

Figure 1.6. APAC CCS Readiness, by Location, Index (100 = ready)



Notes: (1) CCS readiness in each location is evaluated individually across (i) storage readiness (geological and technical aspects affecting the ability to store), (ii) legal and regulatory frameworks, (iii) policy measures and implicit support (i.e. carbon pricing) (2) Most recent readiness data is based on the 2021 index.
Source: Authors based on Global CCS Institute (2023).

3. Summary of Global and APAC Markets Overview

The key learnings from this initial global and APAC market overview are summarised in the following four topics:

Outlook:

- CCUS is positioned to play a key role in global net-zero emission roadmaps, especially in hard-to-abate sectors.
- APAC is positioned to become the largest CCS market, with Australia as the market leader and Indonesia as the fastest-growing player.
- Despite its readiness, the APAC region must endeavour to optimise its cost advantage and operational capabilities within a partnership ecosystem.

Market landscape:

- The CCS market has been dominated by some established players, primarily due to financial and technological resource advantage.
- It is a common practice amongst players to collaborate across the CCS value chain.
- Economic feasibility remains a challenge due to the significant gap in expected total cost against global carbon pricing.

Policies:

- Australia stands out in the APAC region in terms of policy development, while it is still under development for many other APAC countries.
- CCS is not expected to be economically feasible unless the government supports it in the form of subsidies and other financial incentives (i.e. tax credits).
- Support from the government will be crucial in countries with limited commercial attractiveness.

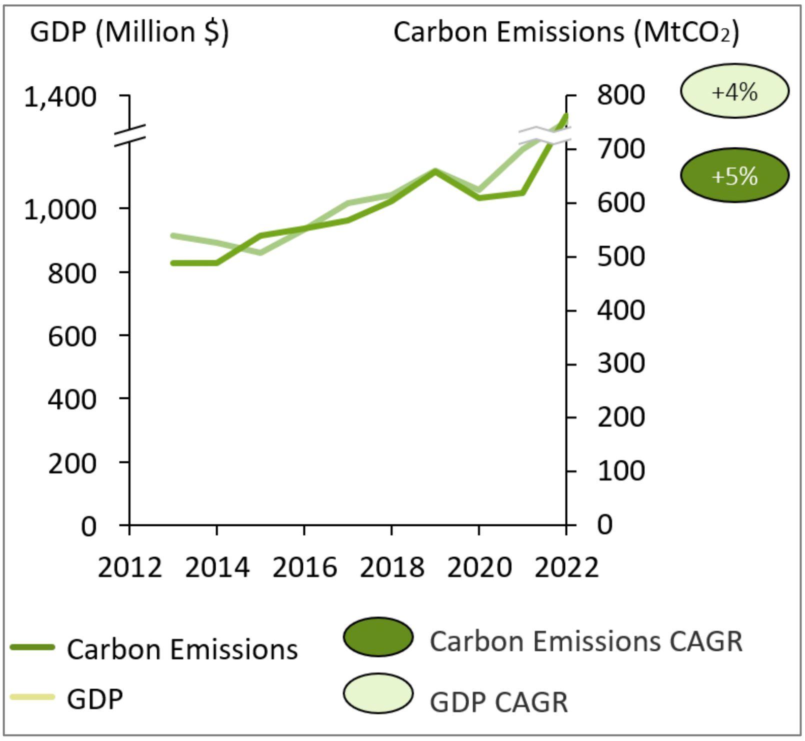
Chapter 2

Indonesia Market Overview of CCS

1. Overview

Indonesia's economic growth exhibits strong parallel to its fuel consumption, and the growth is expected to continue. This growth trajectory is a typical characteristic of similar countries in emerging markets.

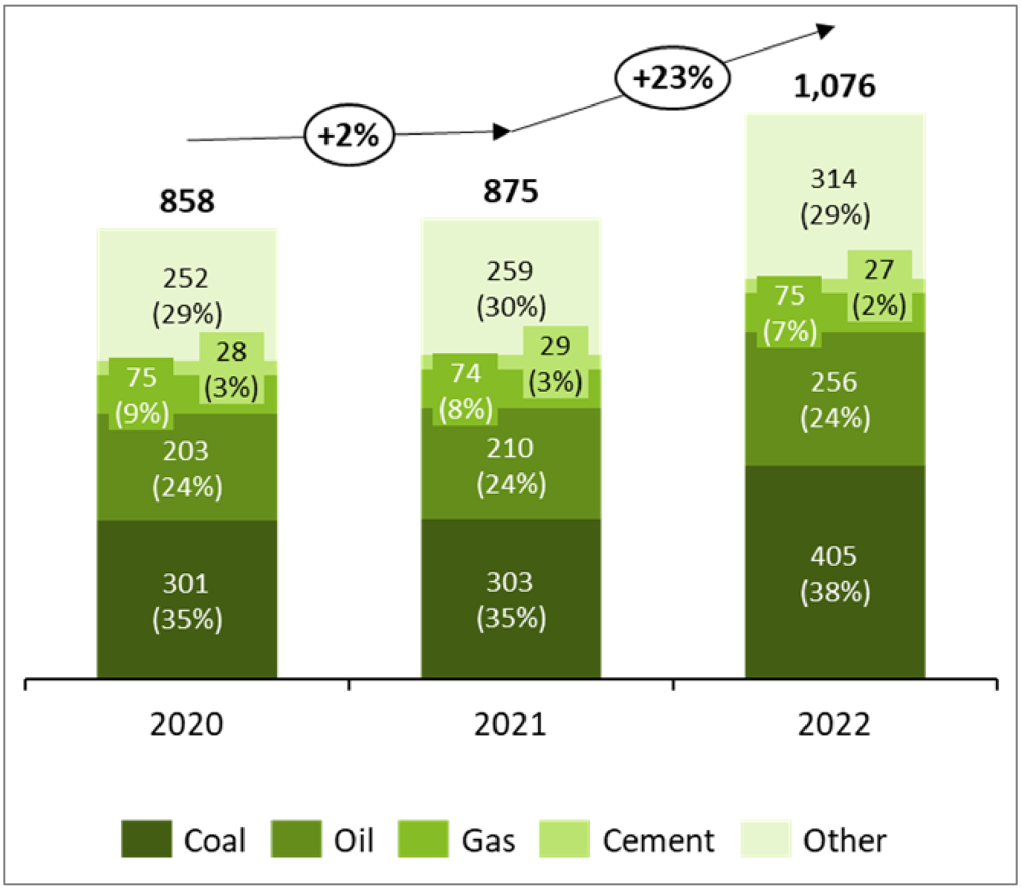
Figure 2.1. Historical Economic and Emission Growth



CAGR = compound annual growth rate, GDP = gross domestic product.
Source: Authors based on World Bank (2023).

Indonesia has historically been a major global supplier of coal, and we expect a similar trajectory to continue assuming similar patterns in key buyer markets such as India and China. Coal consumption reached its highest in 2022 and is expected to reach its peak around 2029 due to the establishment of new coal-fired power plants and ongoing construction and expansion of the nickel downstream industry. Coal shipments to Europe reached its peak in 2022, surging to five times the amount recorded in 2021 due to a consumption shift in response to high gas prices caused by the conflict in Ukraine.

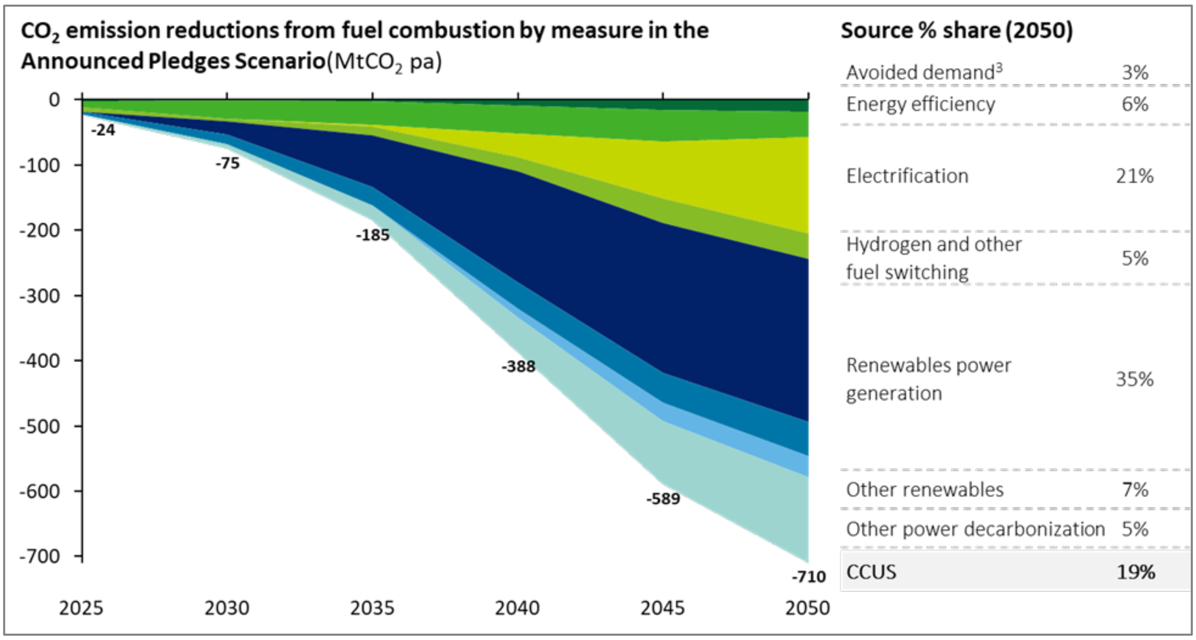
Figure 2.2. Carbon Emissions by Energy Source in Indonesia ($MtCO_2$)



Source: Authors based on IEA (2023c).

In line with the global landscape, CCS/CCUS is expected to play a key role in Indonesia's CO_2 reduction effort, contributing up to 135 Mtpa by 2050. Such a significant role is due to the Indonesian economy's reliance on crucial sectors such as manufacturing, steel, petrochemical, fertiliser, and cement. The most promising role for CCUS to play in Indonesia is to reduce emissions from industry manufacturing and the power generation sector. Indonesia can serve as a storage hub for countries with large manufacturing operations that emit significant CO_2 emissions but lack storage capacity in their home geographies such as Japan and the Republic of Korea (henceforth, Korea).

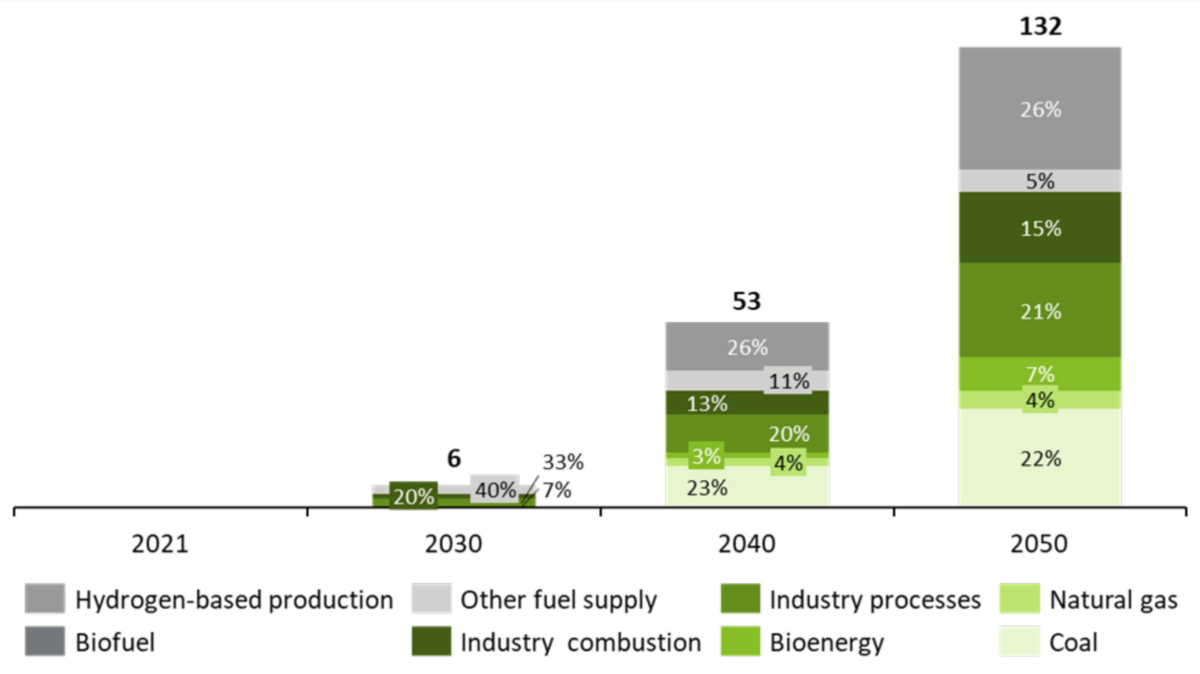
Figure 2.3. CO_2 Emission Reduction from Fuel Combustion by Measure in the Announced Pledges Scenario ($MtCO_2$ pa) and Share of Source



Source: Authors based on IEA (2023d).

CCUS is expected to be applied predominantly within the fuel supply industry, and power generation sectors. For hydrogen-based production, ammonia is one of the most cost-effective options. In this case, 5 $MtCO_2$ has already been utilised for urea production through an ongoing collaboration between Indonesia and Japan. CCUS will also be crucial in reducing emissions from industry manufacturing processes due to its cost effectiveness (for example, CCUS-based technologies cost 19%–37% less than a non-CCUS low-carbon technology) and scalability (for example, 33% of 30 emission sites in Java and Sumatra that emit 1 $MtCO_2$ in Indonesia are cement plants, totalling 26.7 $MtCO_2$ as of 2021). In the power generation sector (bioenergy, natural gas, and coal), CCUS deployment is expected to be crucial in coal, specifically for supercritical (SC) and ultra-supercritical (USC) coal-fired power plants due to its design efficiency. Indonesia plans to increase these plants by 20%–30%.

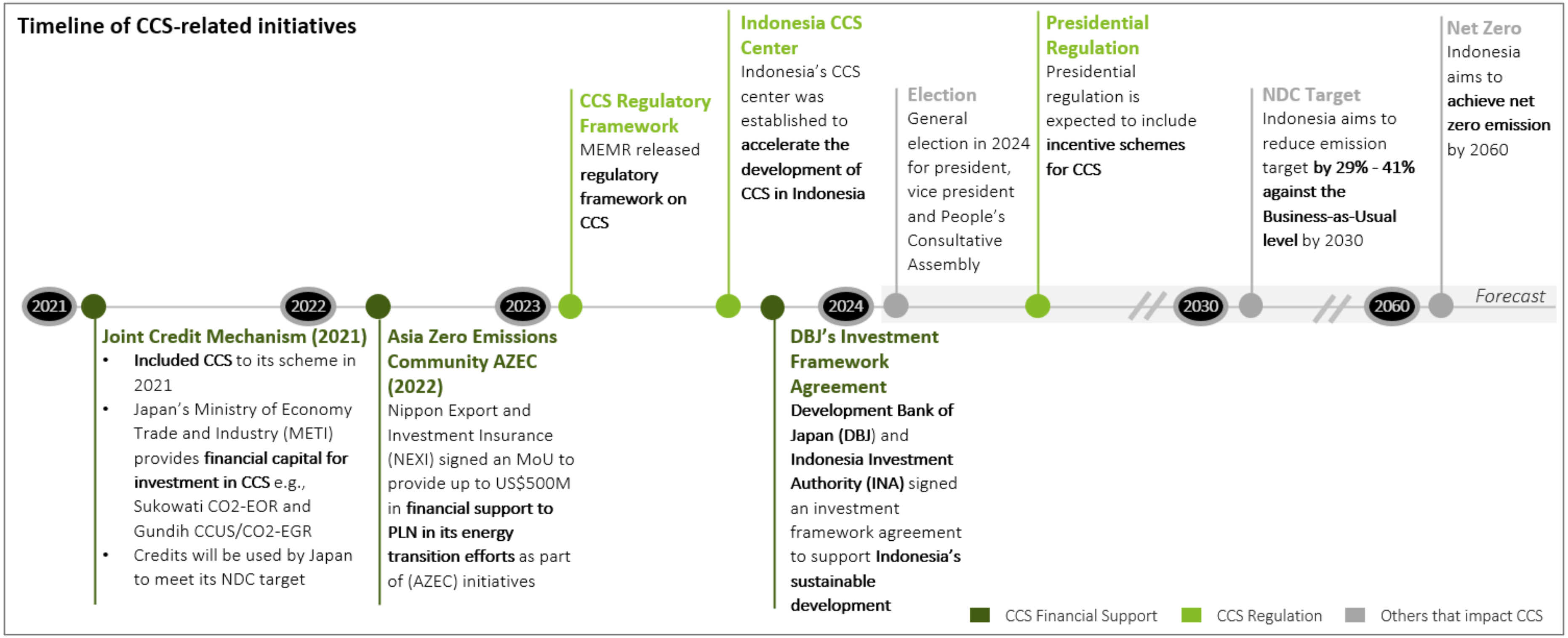
Figure 2.4. CCUS Deployment in Indonesia in the Announced Pledges Scenario (2020–2050) ($MtCO_2$ pa)



Source: Authors based on IEA (2023e).

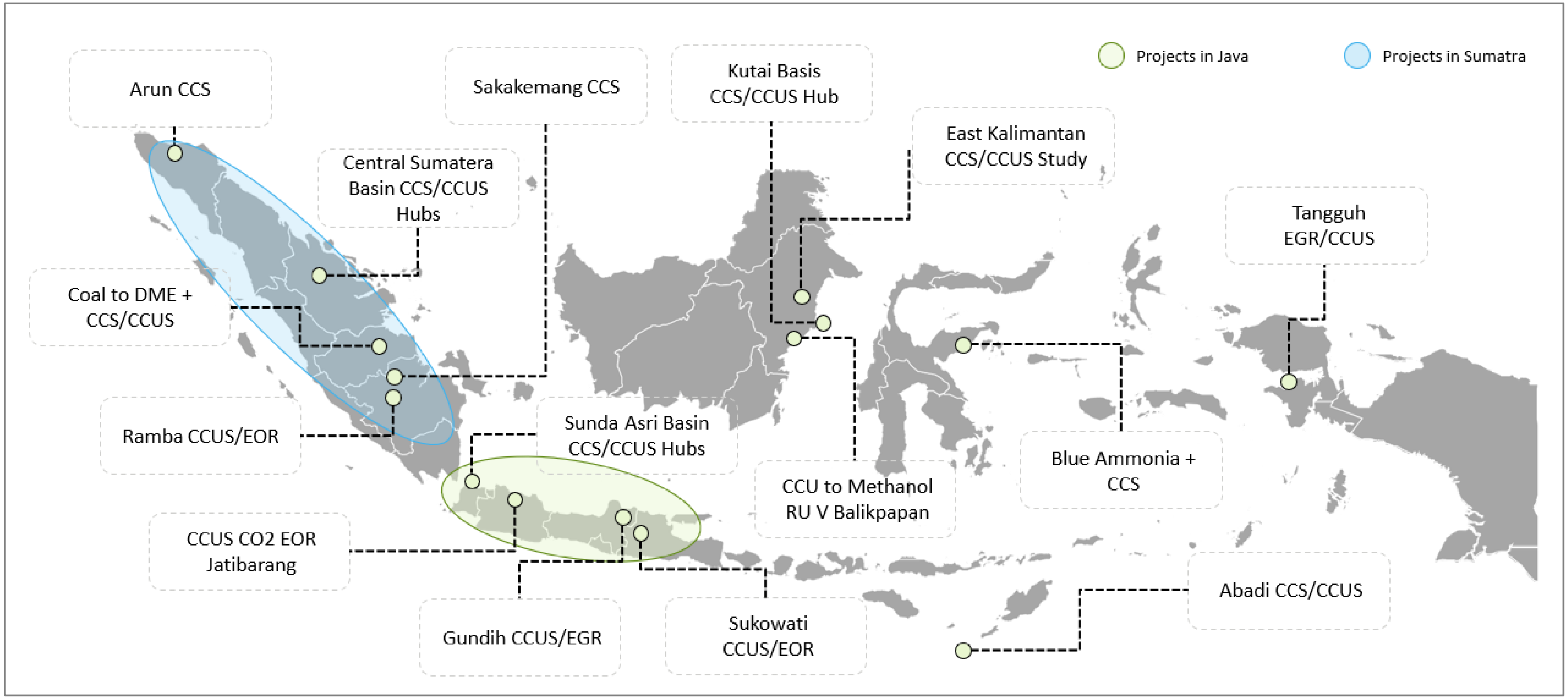
Market support is building up as we see notable traction towards CCS market development and commercialisation. There have been initiatives by both domestic and international organisations that support CCS development in Indonesia.

Figure 2.5. Timeline of CCS-related Initiatives in Indonesia



Source: Authors based on Government of Japan (2021), Ministry of Foreign Affairs of Japan (2022), Ministry of Energy and Mineral Resources Indonesia (2023), ICCSC (n.d.), Development Bank of Japan (2023), The Jakarta Post (2024), Syaifudin (2023).

Figure 2.6. CCS and CCUS Projects in Indonesia



Source: Authors based on Directorate General of Oil and Gas (2022).

Fifteen CCS and CCUS projects in the study and preparation stage are targeted to be on-stream by 2030 with the majority (~67%) concentrated in Sumatra and Java. While no commercial CCS project is available at this moment, such big trend of CCS implementation is coming soon.

Chapter 3
Indonesia Regulatory and Policy Overview

1. CCUS Regulatory Framework

1.1. Implementation of CCS/CCUS

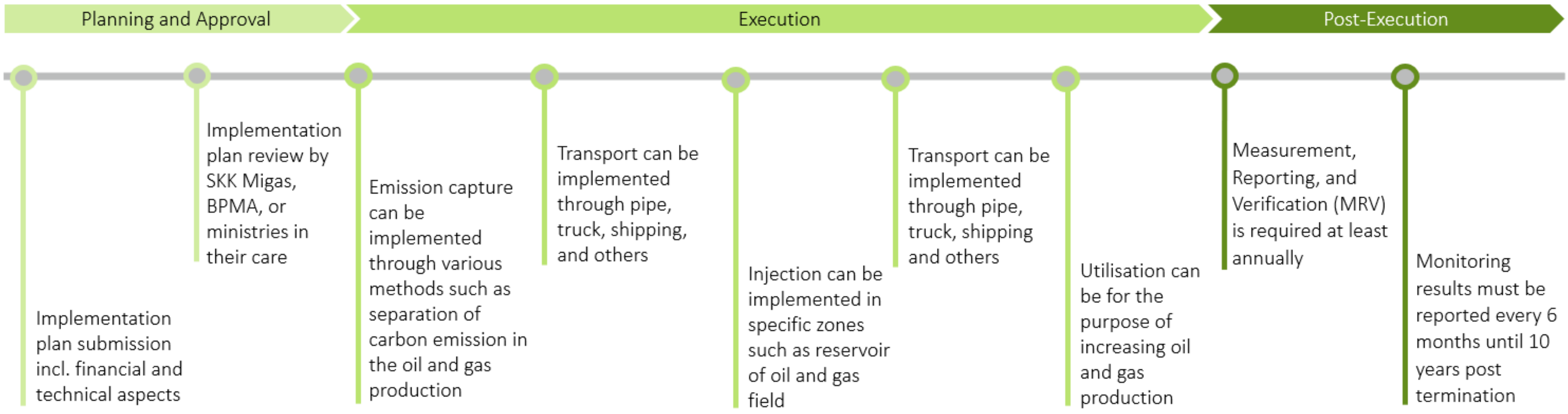
Regulation No. 2/2023 of the Ministry of Energy and Mineral Resources (MEMR), released in March 2023, is Indonesia's first regulatory framework on CCS/CCUS for oil and gas upstream businesses and the first of its kind in Southeast Asia. The framework covers general guidelines from planning to post-execution phases and financial schemes of CCS/CCUS in Indonesia, within the limitation of the oil and gas industry as MEMR's specific jurisdiction.

The regulation provides incentives with CCS/CCUS within the existing accounting system for the oil and gas industry. CCS/CCUS from carbon emissions of oil and gas upstream businesses becomes part of oil operations under the contract of each site. For carbon emissions from non-oil and gas upstream businesses, CCUS can commence from the contractor's site in accordance with agreements between the contractor and third parties. CCS/CCUS costs from oil operations can be considered as operation costs. Thus, CCS/CCUS contractors are supposed to receive tax incentives applicable to oil and gas upstream businesses.

Contractors can also utilise financing from other parties for the study stage, facility development and certification of GHG emission reduction. Financing schemes include project financing, grant, and other schemes according to the applicable laws and regulations. Monetisation can be considered in the form of carbon trading and operational costs for oil and gas upstream businesses arising from injection and storage services for non-oil and gas upstream businesses, which must follow applicable laws and regulations.

Later, Presidential Regulation No. 14/2024 was released in January 2024, expanding regulatory framework on CCS/CCUS to permit various industries to implement CCS not just in oil and gas upstream businesses, allow contractors or storage permit holders to allocate up to 30% of their total carbon storage capacities to carbon storage for oversea emission, and so forth.

Figure 3.1. Overview of CCS/CCUS Regulations



Source: Authors based on The Audit Board of Indonesia (2023).

The carbon storage area is divided into the working area within the Indonesian mining jurisdiction and carbon storage permit rea. In the former, contractors who signed a cooperation contract such as a production sharing contract can conduct with an operating cost recovery mechanism. Additionally, contractors operating under a gross split production sharing contract can carry out CCS as part of their petroleum operations. In the latter case, holders of an exploration licence or a storage operation permit can conduct CCS projects.

To conduct CCS/CCUS projects in Indonesia, the implementation plan must be submitted to the Special Task Force for Oil and Gas (SKK Migas) and Aceh Oil and Gas Management Agency (BPMA) as the regulators in this area. The contractor, defined as an entity or permanent establishment to perform exploration and exploitation for a site under contract with SKK Migas or BPMA, must propose an implementation plan for the site during exploration and exploitation. Implementation plans should include aspects covering at a minimum technical, economic, operational, safety and health issues, and termination. Analysis should include at least a geological, geophysics, reservoir, operation of transport; storage and injection including utilisation for CCS/CCUS implementation; economics, technical review, risk evaluation and mitigation, and Monitoring, Reporting, and Verification (MRV). The implementation plan is then submitted to the minister in the care of SKK Migas or BPMA for first field development plan and SKK Migas or BPMA for further field development plans. Further changes and next field development plans can be submitted through proposals. Contractors can only proceed with CCS/CCUS implementation when the plan is approved. Approval from SKK Migas and BPMA is required in the case of third-party injection or storage emissions for the contractor.

1.2. Guidelines for CCS/CCUS Value Chain

The CCS/CCUS regulatory framework contains guidelines for each step of the value chain: capture, transport, injection, storage, and utilisation. Carbon emissions captured shall be from various sources, including upstream oil and gas facilities, refineries at oil and gas business activities, power generation activities, industrial activities, and so on. Transportation of the carbon captured can be carried out based on the carbon transport permit through pipeline, truck, shipping, and/or other prevailing methods. Injection is handled by a contractor into an injection target zone, which refers to depleted reservoirs, saline aquifers, or coal deposits for coal bed methane. Storage can be performed by the storage operation licence holder that obtained ministerial and environmental approval. Emissions produced by the third party can be injected and stored by the contractor.

Carbon storage capacity is prioritised for carbon from domestic industries. Contractors and storage operation permit holders must reserve 70% of the total carbon storage for domestic carbon storage and are allowed to allocate up to 30% of the total carbon storage for carbon from overseas. For cross-border carbon transport and storage, bilateral cooperation agreement between Indonesia and the country where the carbon was captured is essential. In the event of leakage during the transport, the leakage is not added to Indonesia's GHG inventory.

MRV should be conducted regularly. Monitoring is required to ensure worker safety, installation and equipment security, and environmental and/or general safety according to the approved CCS/CCUS plan. Monitoring results must be submitted every 6 months through to 10 years after termination, and budget must be reserved. Ten years of monitoring is relatively short compared to other countries' regulatory framework such as the US Underground Injection Control program (50 years), Norway's Storage Regulation and Petroleum Regulation (20 years), UK's Energy Act 2008 (20 years), and so on. Plans should use direct or indirect methods to identify the risk potential of leakage, underground water contamination, buffer zone deposit integrity, tight zone deposits, and geological traps to estimate other risks associated with carbon emission injection. The contractor shall perform the MRV annually in accordance with laws and regulations. The MRV report should include both general data, comprising contractor identity as the entity in-charge and responsible for CCS/CCUS, the title and type of activities, the appointed mechanism of CCS/CCUS and the economic value of carbon, technology transfer, capacity increase, budget, technical data stating at least the GHG emission baseline assessment, reference period determination for the GHG emission baseline, carbon emission reduction assessment method, activity monitoring data, including the measurement, location, and period of CCS/CCUS, value of reduction target and/or carbon emission absorbance, and managerial system descriptions and the systems built to monitor and collect the activity data in relation to CCS/CCUS and NEK. An independent institution might be appointed to examine the reported data and submit the results to the ministry in care.

Closure is carried out when the carbon storage capacity is full, carbon can no longer be injected, the storage operation licence expires and is not renewed. Through SKK Migas or the storage operation licence holder, the contractor submits such CCS closure plan to the minister. The plan must contain information of at the injection target zone, equipment, facilities and the closed well, total carbon storage amount, cost estimates, closure timeline, post-closure monitoring plan, and the plan to prevent damage to the environment, human resources, equipment, facilities, and so on. With ministerial approval, the contractor or storage operation licence holder can close CCS activity in accordance with the approved closure plan.

1.3. Costing and Funding Mechanisms

Costing and funding mechanisms are covered in the regulation that includes topics on economics, financing, monetisation, and incentives to ensure project feasibility. CCS/CCUS from carbon emissions of oil and gas upstream businesses may become part of oil operations under the contract of each site. For carbon emissions from non-oil and gas upstream businesses, CCUS can commence from the contractor's site in accordance with agreements between the contractor and third parties. CCS/CCUS costs from oil operations can be considered operation costs. The contractor can utilise financing from other parties for the study stage, facility development, and certification of GHG emission reduction. Financing schemes include project financing, grant, and other schemes according to the applicable laws and regulations. Monetisation can be in the form of storage fee and other forms such as carbon trading. Contractors may receive tax or non-tax incentives to support CCS/CCUS implementation.

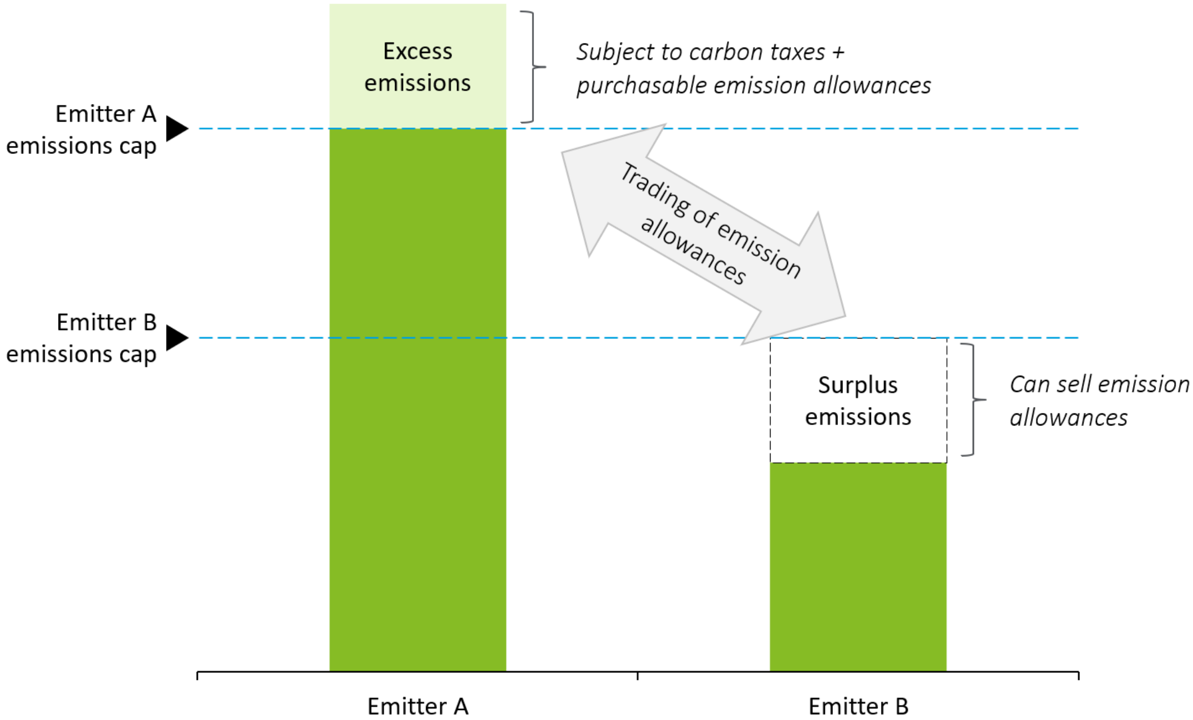
2. Market Pricing, Incentives, and Funding Support

Several regulations that explain carbon trading and carbon tax mechanisms include Presidential Regulation No. 98/2021, MEMR 16/2022, MEMR Decree No. 14K/TL04/MEM.L/2023, Ministry of Environment and Forestry 21/2021, and Ministry of Finance 7/2021.

Indonesia's government intends to implement a hybrid model for a carbon trading scheme, including cap-and-trade, GHG emission reduction certificates on the Indonesia Stock Exchange (IDX), and a carbon tax. Currently, only the cap-and trade mechanism and GHG emissions reduction have been launched.

The government has established a cap on the emissions for each emitter, any excess emissions will be taxed. While carbon tax has not been implemented, it was proposed to be approximately $2/t$CO_2$ in 2021. It must not be less than the domestic carbon market price, and the scheme should perform as a vehicle to accommodate the gradual development of Indonesia's carbon market. Indonesia has offered allowable tax deductions in the form of purchasing carbon market allowances from another emitter's unused allowances. Emitters acquire tax deductions by utilising offset certificates obtained through investment in voluntary reduction projects.

Figure 3.2. Carbon Trading Scheme in Indonesia



Source: Authors based on Andriansyah and Hong (2023), The Audit Board of Indonesia (BPK) (2021 and 2022a),

The four key regulatory provisions governing carbon pricing and trading include Presidential Regulation No. 98/2021, MEMR No. 21/2022, MEMR No. 16/2922, and MEMR No.14.k/TL04/MEM.L/2023.

Figure 3.3. Primary Regulations Governing Carbon Pricing and Trading

	Presidential Regulation No. 98 of 2021	**Ministry of Environment and Forestry Regulation No. 21 of 2022**	**Ministry of Energy & Mineral Resources Regulation No. 16 of 2022**	**Ministry of Energy & Mineral Resources Decree No. 14.K/TL.04/MEM.L/2023**
Overview of regulation	Implementation of Carbon Pricing for the purpose of achieving Indonesia's Nationally Determined Contribution and the control of greenhouse gas emissions in national development	Guidelines for the implementation of Carbon Pricing	Procedures for the implementation of Carbon Pricing within the power plant subsector	Emissions cap for coal-fired power plants connected to PLN's network
Date of enactment	*29 October 2021*	*20 October 2022*	*27 December 2022*	*13 January 2023*

Source: Authors based on Oentong Suria & Partners (2022), The Audit Board of Indonesia (BPK) (2021,2022a, 2022b, 2023), JDIH (2023).

3. Regulatory Issues

3.1. The Lack of Incentives

Indonesia set its first CCS regulatory in 2023 and established detailed guidelines for CCS in a presidential regulation in 2024. The latter also made CCS more applicable by enabling various emission sources for CCS. However, CCS is still not feasible due to the lack of incentive schemes and funding support.

In general, CCS business can be feasible, as of today, based on government funding for the capital expenditure (CAPEX) and operating expenditure (OPEX) of CCS-related facility, carbon pricing, or even the combination of both. For example, the US adopted the Inflation Reduction Act of 2022 that provides a tax credit of \$85/CO_2t captured and stored to enhance CCS implementation. Another example is the Emissions Trading System of the European Union (EU ETS), a cap-and-trade system for carbon reduction, with the highest carbon price of €200/CO_2t. The EU ETS affects emitters' choice of decarbonisation method, and CCS can be a competitively priced method compared to a high carbon price. On the other hand, in Indonesia, the CCS regulatory framework is now in place and IDX, an official carbon exchange established in 2023, handles carbon allowance (PTBAE-PU). However, the track record of carbon exchange is limited, and carbon market price is relatively low.

Besides, the carbon tax has yet to be implemented. Generally, the carbon tax is a source of funds to enhance decarbonisation as well as to serve as a negative incentive for emissions. Without carbon tax, government fails to secure sufficient funding for industrial decarbonisation. CCS remains an expensive method for decarbonisation.

3.3.2. The Uncertainty of Liability for Hub and Cluster Model

Although Presidential Regulation No. 14/2024 mentions that the contractor or permit holder must monitor and is liable for leakage, underground water contamination, and so forth, the responsibility is not clear when the hub and cluster business has multiple sources of emission. Such uncertainty makes it hard to evaluate the business risk of CCS, which can lead to disinclination of investors and emitters to implement CCS.

Chapter 4
Technical Study on CCS Value Chain

1. Background and Assumptions of CCS Value Chain

To achieve net-zero GHG emissions and sustainable growth in Indonesia by 2060 by realising a stable power supply and economic efficiency, it is necessary to economically achieve the transition to decarbonisation while effectively using existing coal-fired power plants.

The Central and East Java–Sumatra regions are rich in oil and gas, have many coal-fired power plants, and have a lot of potential for the application of efficient decarbonisation technologies and the realisation of CCS commercialisation.

In this report, we will study decarbonisation by capturing CO_2 from the state-of-the-art TJB 5&6 coal-fired power plant in the island of Java, transporting it to the Corridor PSC on Sumatra Island, and storing it.

Since CO_2 transport from Central Java to southern Sumatra is quite long, more than 1,000 km away, it is not practical for actual project development. However, in anticipation of future CCS value chains in Indonesia and the ASEAN region, long-distance CO_2 transport is expected for regional decarbonisation and therefore incorporated herewith as a part of the study. Both ocean transport by LCO_2 ships and the pipeline transport are studied in this regard for comparison.

At the implementation stage of the actual project development, it will be surely realistic to store the CO_2 captured by TJB in nearby oil and gas fields or aquifer as close as possible. Also, CO_2 storage in the Corridor PSC will be an effective study for receiving CO_2 from surrounding emission sources such as nearby thermal power plants, or for realising a value chain through cross-border CCS from neighbouring ASEAN countries, Japan, and Korea.

In these aspects, this study is expected to contribute towards future decarbonisation for Indonesia and regional countries.

1.1. Outline of the CCS Value Chain

In this CCUS value chain study, TJB 5&6, 2 x 1,000 MW ultra-supercritical coal-fired plant in Central Java, were selected as CO_2 emission sources. Unit 5 started commercial operation in March 2022, and Unit 6 in September 2022. Figure 4.1 shows the major feature of TJB 5&6.

Figure 4.1. Basic Features of TJB 5&6, Location, Site Panorama

	TJB 5&6
Project Company	PT Bhumi Jati Power
Sponsors	50% Sumitomo Corporation 25% The Kansai Electric Power Co. Inc. 25% PT United Tractors Tbk
Off-taker	PT PLN (Persero)
Project scheme	Build-Own-Operate-Transfer (BOOT)
Term	25 years
Project cost	$4 billion
Plant capacity	1,000 MW x 2
Plant technology	Ultra-supercritical
- Turbine/generator	Toshiba
- Boiler	MHI
Coal (HHV)	4,000–5,250 kcal/kg
COD	Unit 5: Mar 2022 Unit 6: Sep 2022

Source: Authors.

For storage site, Corridor PSC in South Sumatra was selected as a potential area.

Corridor PSC is operated by Medco, and is believed to have significant potential to storing CO_2 by depleted gas reservoir (Figure 4.2)

There are several gas fields in Corridor PSC with the Indonesian government's long-term plan), and each end-of-field life varies from 2023 to 2038.

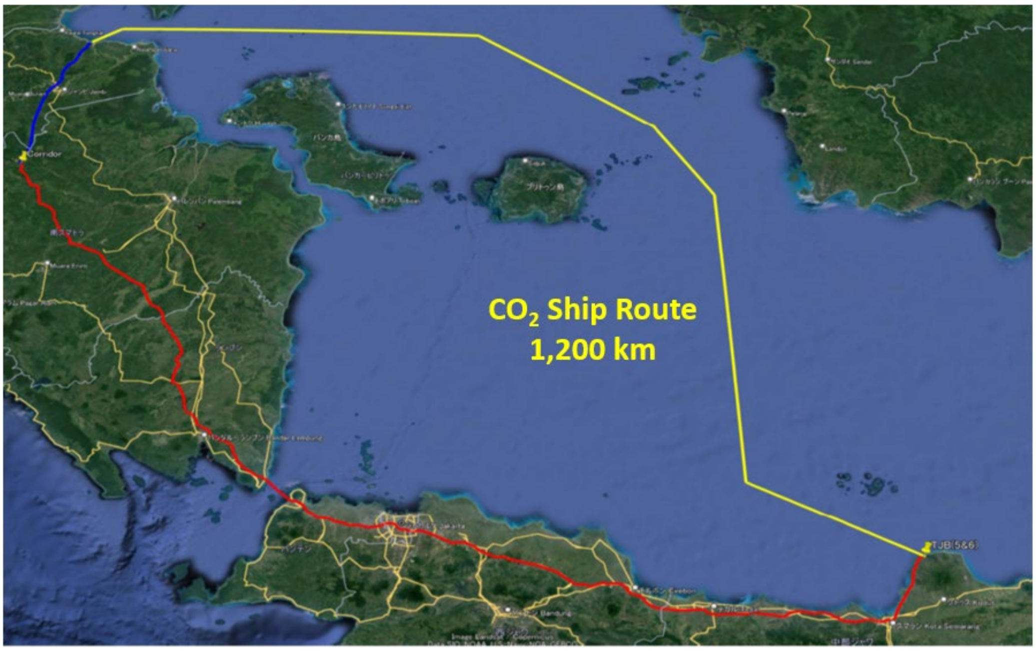
Suban field is the largest matured gas field in Corridor PSC with a capacity of approximately 400 Mt CO_2.

Figure 4.2. Corridor PSC

Source: Provided by Medco (2023).

As previously stated, captured CO_2 from TJB 5&6 were assumed to be transported to the storage site in Corridor PSC. Two options for CO_2 transport were studied for two different CO_2 capacities corresponding to one unit (TJB 5 or 6) and both units (TJB 5&6).

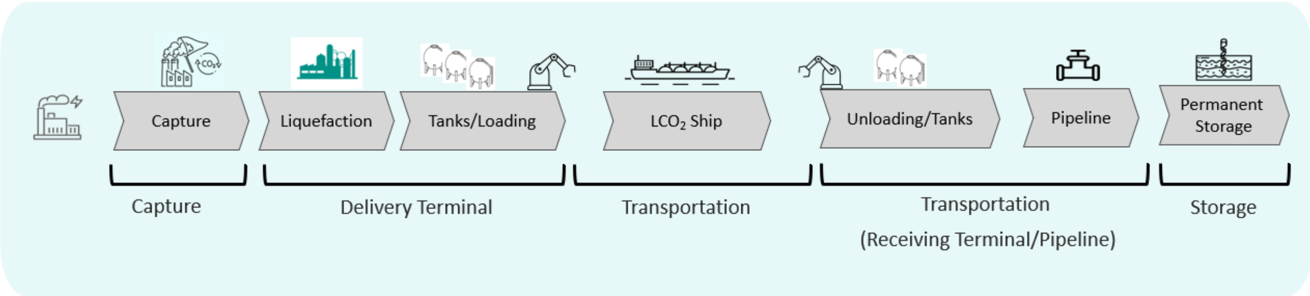
Figure 4.3. CO_2 Transport Route



Case A: Ocean transport - yellow and blue; Case B: Pipeline transport - red
Source: Authors based on Google Earth.

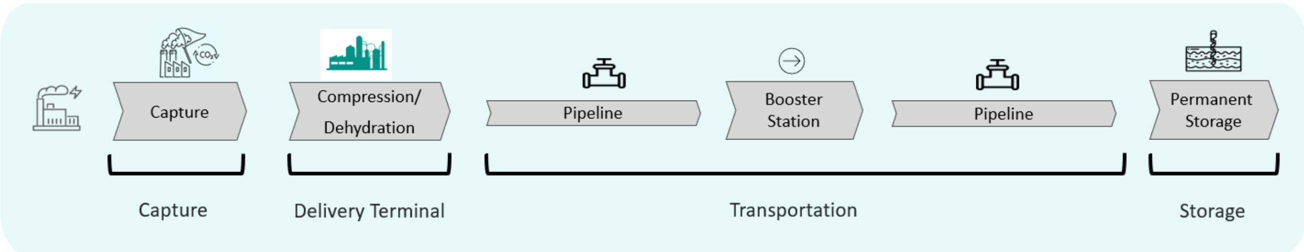
Each transport option consists of equipment and facility shown in Figures 4.4. and 4.5, and study and cost estimations were determined based on these categories.

Figure 4.4. Configuration of Case A (Ocean Transport)



Source: Authors.

Figure 4.5. Configuration of Case B (Pipeline Transport)



Source: Authors.

1.2. CO_2 Emission Source and CO_2 Amount of the CCS Value Chain

In this study, TJB 5&6, 2 x 1,000 MW ultra-supercritical coal-fired plant, were selected as CO_2 emission sources. Both units are operating in good condition and the capacity factor is almost close to 90% when an outage is not carried out. Table 4.1 shows the generating amount, coal consumption, and CO_2 emissions from October 2022 to September 2023.

Table 4.1. TJB 5&6 Operating Data (1 October 2022–30 September 2023)

	Unit	Unit 5	Unit 6	Total
Rated Capacity (NET)	MW	1,000	1,000	2 x 1,000
COD		Mar '2022	Sep '2022	
Power Generation	GWh	6,748	7,546	14,294
Capacity Factor	%	77 *1	86	-
Coal Consumption	M ton	-	-	6.7
CO_2 Emission	M ton	5.8	6.4	12.2

Note: Unit 5 was shut down in May–June 2023.
Source: Authors.

To define the capacity of the CO_2 capture facility, CO_2 emission at the rated operating condition (1,000 MW) was picked up and averaged. The actual CO_2 emission data in September 2023 was corrected by the continuous emission monitoring system, and it was 19,832 tonnes/day per one unit.

The advanced amine technology will be employed to capture CO_2 from TJB 5&6 coal-fired units. The 95% capture rate is achievable by the recent CO_2 capture technology.

The capacity of the capture facility for 1 unit (1,000 MW) was defined as follows:

19,832 x 1.1 (Margin)*2 x 0.95 (capture rate) = 20,724.4 ⇒ 20,724 tonnes/day

*2: 10% margin is assumed for overload operation or future improvement of the capture rate, etc.

To calculate the annual CO_2 amount, a capacity factor of 0.86 was applied:

20,724 tonnes/day x 365 days x 0.86 (capacity factor) = 6,505,264 ⇒ 6.5 M tonnes/year

2 x 6.5 M tonnes/year = 13.0 M tonnes/year (for 2 units)

For the study of CCS value chain, the above annual figure was applied.

As for the capture rate(efficiency), a couple of options were available to select the partial capture rate, such as 30%, 50%, etc. However, in this study, the maximum capture rate (95%), was selected to determine the maximum CO_2 amount case of the CCS value chain and to evaluate cost competitiveness by the scale factor.

At the implementation stage of the real project, of course it will be good practice to start a lower capture rate and expand it accordingly.

1.3. Assumptions

Table 4.2 summarises the assumptions for this study.

Table 4.2. Assumptions for the Study

Category	Unit	Case A Ocean Transport		Case B Pipeline Transport	
CO_2 amount	Mt-CO_2/year	6.5 Mt/y	13.0 Mt/y	6.5 Mt/y	13.0 Mt/y
Generation Capacity	MW	1,000	2 x 1,000	1,000	2 x 1,000
Type of Power Plant		USC Coal-Fired Power Plant			
Capacity Factor		86%			
Capture Rate		95%			
Project Lifespan	Years	25			
Total CO_2 amount	Mt-CO_2	162.5	325	162.5	325
Ship	Ships x tonne	6 x 28,000	7 x 48,000	-	-
Pipeline	From to	Receiving Port in Sumatra to Corridor		TJB to Corridor	
Pipeline	inch	24	34	28	38
	km	183	183	1,148	1,148
Injection well	Number	9	17	9	17
	Depth (m)	2,000	2,000	2,000	2,000

Source: Authors.

1.4. Method of Study

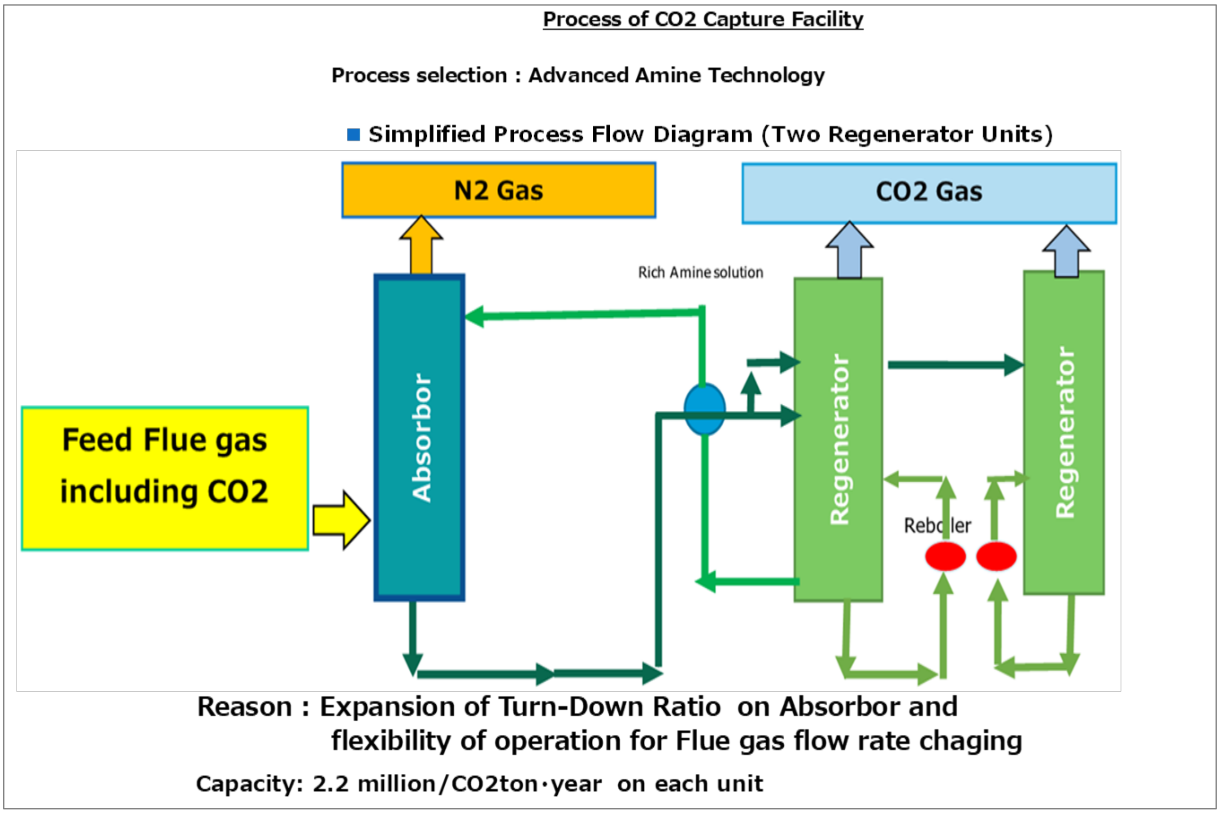
Since there is no track record with large-capacity CO_2 separation, capture, liquefaction, tanks and shipping transport like this project scale at present, some referential studies in the oil and gas sector having liquefied natural gas (LNG) and liquefied petroleum gas (LPG) facilities, etc. that have sufficient records for liquefaction, tanks and transport were referred to implement this project. However, there are some views and arguments on the feasibility for large-scale specifications and capacities especially of liquefaction and storage tanks, etc. Further detailed studies would, therefore, be required in this area and described in Chapter 8 as issues to be considered in the future.

2. CO_2 Capture

There are various CO_2 capture methods, including chemical absorption, physical absorption, adsorption, and membrane separation, but the chemical absorption method using a new type of aqueous amine solution is the most suitable CO_2 capture system for a large-scale coal-fired power plant such as TJB 5&6. This type of equipment has been tested in Japan and overseas since 2010 and is already a commercial product. However, the commercialised track record is a maximum annual treatment capacity of 1 million tonnes per train, so the conventional two-tower system (absorption and regeneration towers) has limited facility capacity for large-volume recovery treatment. This study proposes the process shown in Figure 4.6 as a system consisting of one absorption tower and two regeneration towers to increase throughput.

After 2030, the technology for commercialisation of this method is feasible, and that it is possible to increase the throughput of a single train. In this study, the system shown in Figure 4.6 comprises three trains for one unit (6.5 million tonnes/year). Therefore, for one unit of TJB 5 or 6 (6.5 million tonnes/year), a three-train configuration with one absorption tower and two regeneration towers is assumed, and for two units (13 million tonnes/year), a six-train configuration.

Figure 4.6. Equipment Configuration of Three-column Chemical Absorption Method



Source: Authors.

3. Delivery Terminal

3.1. Case A (Ocean Transport)

3.1.1. Liquefaction

In this study, costs were examined assuming a low-pressure, low-temperature (7 Barg, -55°C) CO_2 transport system.

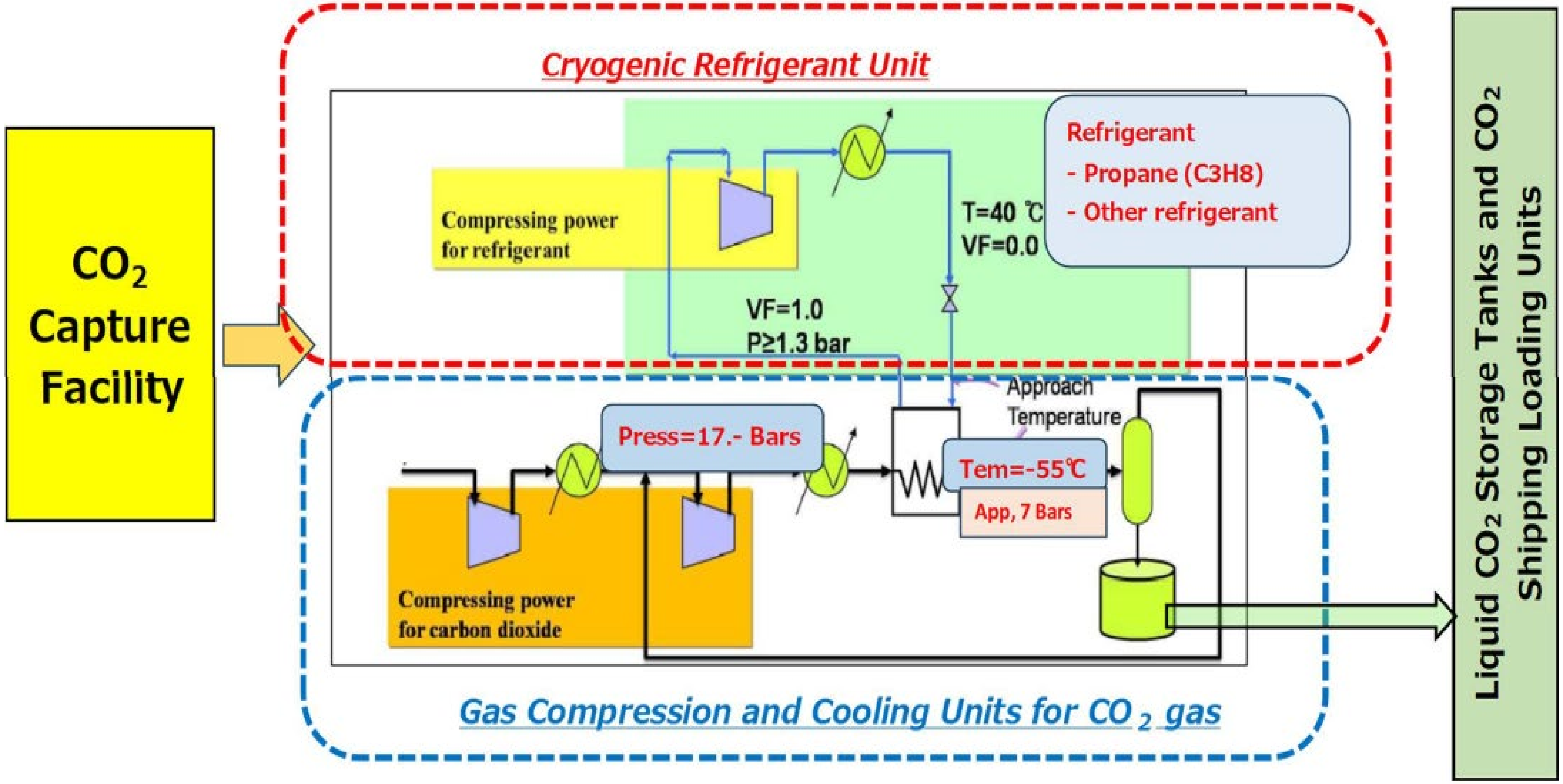
The CO_2 marine vessel transport in the initial CCS project (the transport method for the small-scale CCS demonstration test) used a medium pressure and low temperature (20 Barg, -20°C) process method for CO_2 transport conditions, and the scale of the CO_2 ships was about several thousand tonnes. The -20°C liquefaction facility has a proven track record and is already a commercial technology.

On the other hand, for large-scale CCS projects with more than several million tonnes of CO_2 per year such as in this study, low-pressure and low-temperature (7 Barg, -55°C) transport systems are planned to reduce the cost of dedicated CO_2 ships. Although we expect that commercialisation-based plans will be realised after 2025, presently there are no such low-temperature liquefaction facilities for CCS project applications in the world. After 2030, a low-temperature system is assumed to be selected for large-scale storage CCS projects.

The liquefaction process technology is an established refrigerant technology as well as LNG and cryogenic LPG transport business. This project will use this technology to liquefy CO_2 gas, and propane gas refrigerant will be used in this method. The process concept of the liquefaction facility is shown in Figure 4.7.

One train of the facility will have a capacity of 6.5 million tonnes/year of CO_2, and one train and two trains will be installed for 6.5 million t/y and 13 million t/y cases, respectively.

Figure 4.7. Process Conceptual Diagram of Liquefaction Equipment



Source: Authors.

3.1.2. Tanks

The method used to study the specifications of CO_2 storage tanks was to examine the reasonable CO_2 storage capacity, applicable tank system, and number of tanks in accordance with the operation plan for dedicated CO_2 ships (detailed in Section 4.1) (Table 4.3).

The number of tanks was determined based on the shipping operation and plant capacity utilisation of the CO_2 ship operation plan. However, the minimum number of tanks was set here considering the low cost, so that the tanks could store a volume of CO_2 for 5 days.

The tank system uses the dome-roof type or the spherical type. Both types of existing technology are applied to low-temperature LPG tanks. Although there is no tank for CO_2 at -55^{0}C employing this method, it is expected to be developed and commercialised after 2030. Table 4.3 shows the equipment specification based on the study results.

Table 4.3. Equipment Specifications of CO_2 Storage Tanks

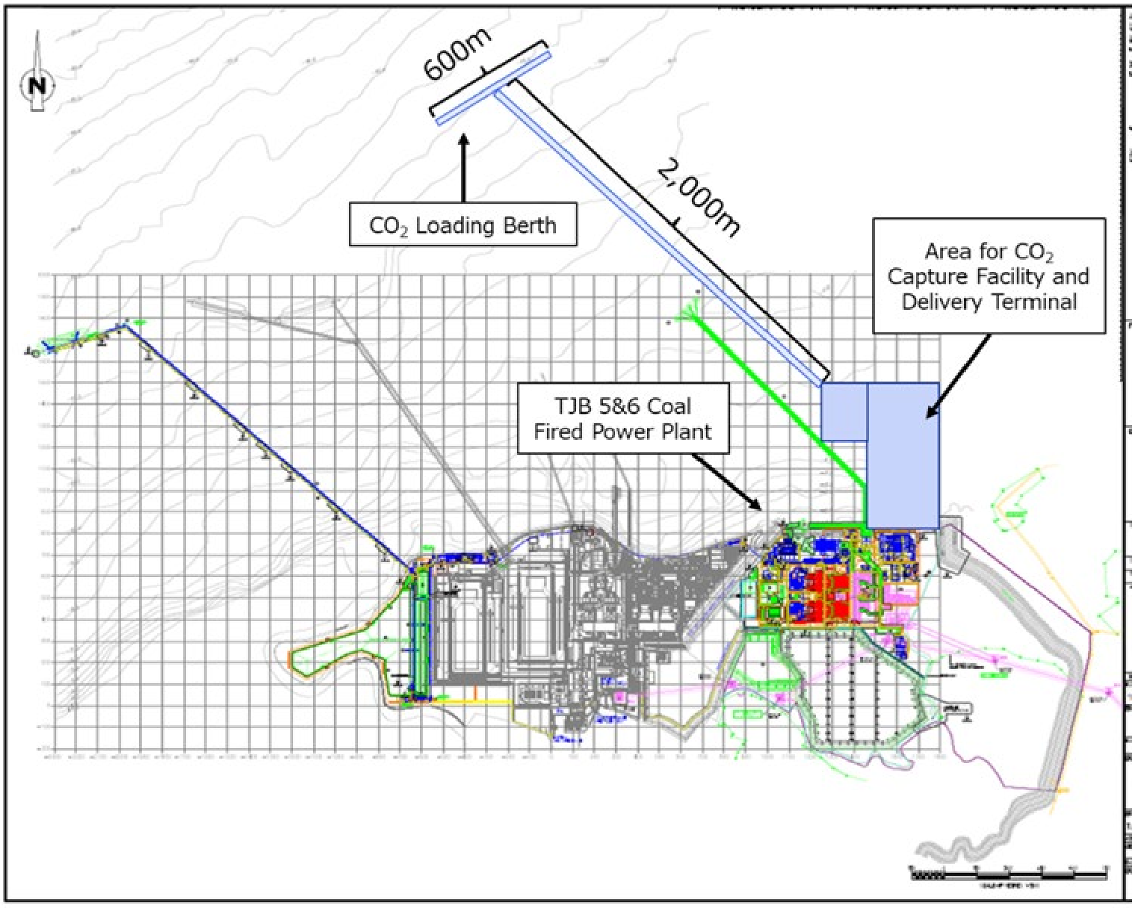
Tank Specification	6.5 Million Tonnes/Year	13.0 Million Tonnes/Year
Place of Tank Yard	TJB Delivery Terminal	
CO_2 Storage Capacity (days)	5	5
CO2 Tank Yard Storage Capacity (tonnes)	90,000	180,000
Type of Tank	Dome type/Spherical type	Dome type/Spherical type
Tank Capacity (tonnes)	18,000 / 12,000	30,000 / 12,000
Numbers of Tanks (minimum)	5/8	6/15
Operating Conditions	7.0 Bars/-55℃	7.0 Bars/-55℃

Source: Authors.

3.1.3. Loading Facility

The shipping transfer technology for low-temperature liquefied fluid is a method that has been commercialised in low-temperature LPG/LNG terminals. The same shipping method (simultaneous gas and liquid transfer) was adopted in this study. The loading arm facility for CO_2 loading to be employed in this study has two trains with three units (two for liquid and one for gas) to reduce CO_2 loading time. In the marine jetty system to be adopted for the loading arm, an offshore jetty capable of simultaneously mooring and shipping two CO_2 ships in series at a point about 2 km off the coast of the delivery terminal will be installed to minimise environmental impact, such as changes in coastal ocean currents. Figure 4.8 shows the layout of the marine jetty system.

Figure 4.8. Marine Jetty System for CO_2 Loading



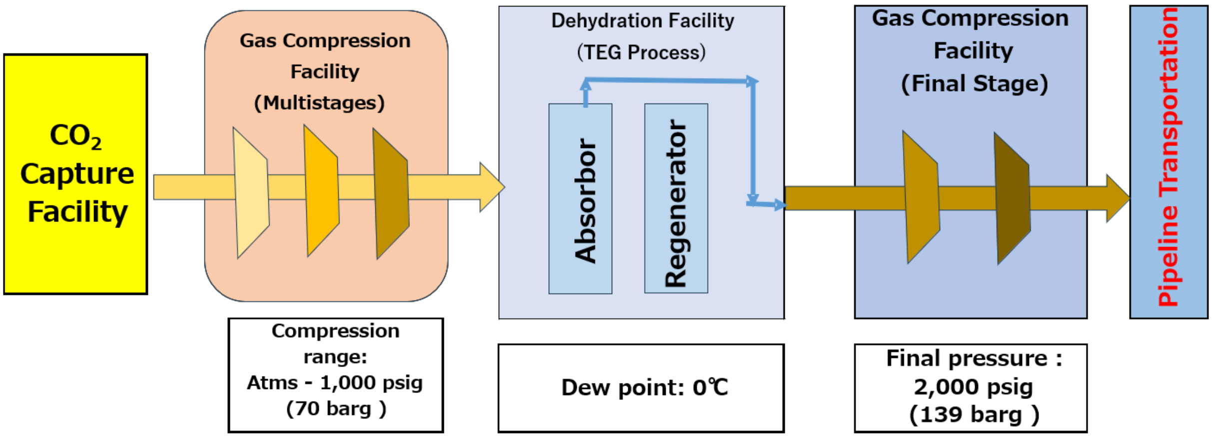
Source: Authors.

3.2. Case B (Pipeline Transport)

3.2.1. Compression

To obtain sufficient condition for pipeline transport, the multistage gas compression system with dehydration facility was selected. Discharge pressure was defined at 2,000 psig (139 barg) like the Weyburn Project in Canada. Figure 4.9 shows the gas compression and dehydration facilities.

Figure 4.9. CO_2 Compression and Pump Delivery Facilities



Source: Authors.

3.2.2. Dehydration

If CO_2 contains water, ice (CO_2 hydrate) precipitates in the CO_2 pipeline, and the risk of pipeline blockage failure and corrosion exists. Therefore, saturated water in the CO_2 gas collected by the CO_2 capture system should be removed. This technology has already been commercialised as a moisture removal system in the natural gas industry. The challenge was to determine the operating pressure of this dehydration facility and make it a low-cost, high-efficiency facility. Therefore, a process study was conducted to determine the specifications of the facility.

In this study, the triethylene glycol process, with one absorber and one regenerator, will be adopted. This device will be installed between the gas compression facilities as shown in Figure 4.9.

4. CO_2 Transport

4.1. Case A (Ocean Transport)

4.1.1. LCO_2 Ship

In considering CO_2 ships, we collected the latest information regarding the construction scale and cost of low-temperature liquefaction ships. The survey results revealed that the CO_2 ships to be built and delivered by Hyundai Shipyard in Korea in the second half of 2025 will be the largest, low-temperature, low-pressure ship (-50℃, 7.5 barg) (25,300 tonnes of CO_2 loaded).

It is assumed that 50,000 tonnes of CO_2 ship Will be available after 2030.

Table 4.4 summarises the general specifications of the special ships considered in this study.

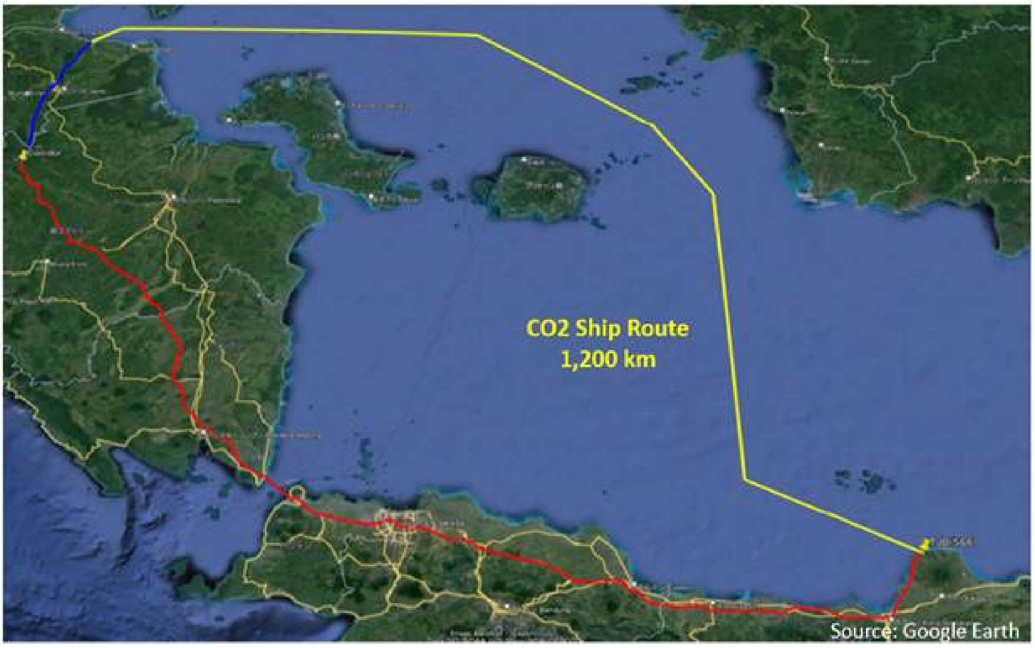
Table 4.4. General Specifications of CO_2 Ships and Required Numbers

Ship Specifications	6.5 Million Tonnes/Year	13.0 Million Tonnes/Year
CO_2 Mounted Volume (tonnes)	28,000	48,000
CO_2 Tank Capacity (tonnes)	7,000 X 4	9,000 X 6
Vessel Length (metres)	Approx. 170	Approx. 240
Vessel Width (metres)	Approx. 35	Approx. 40
Vessel Depth (metres)	Approx. 18	Approx. 21
Vessel Draft (metres)	Approx. 10	Approx. 11
Numbers of Tanker	6 Ships	7 Ships

Source: Authors.

The navigation route for the CO_2 ship in Figure 4.10 was determined considering a safe route and formulating a navigation plan. Figure 4.10 shows the planned route. The voyage distance will be approximately 1,200 km.

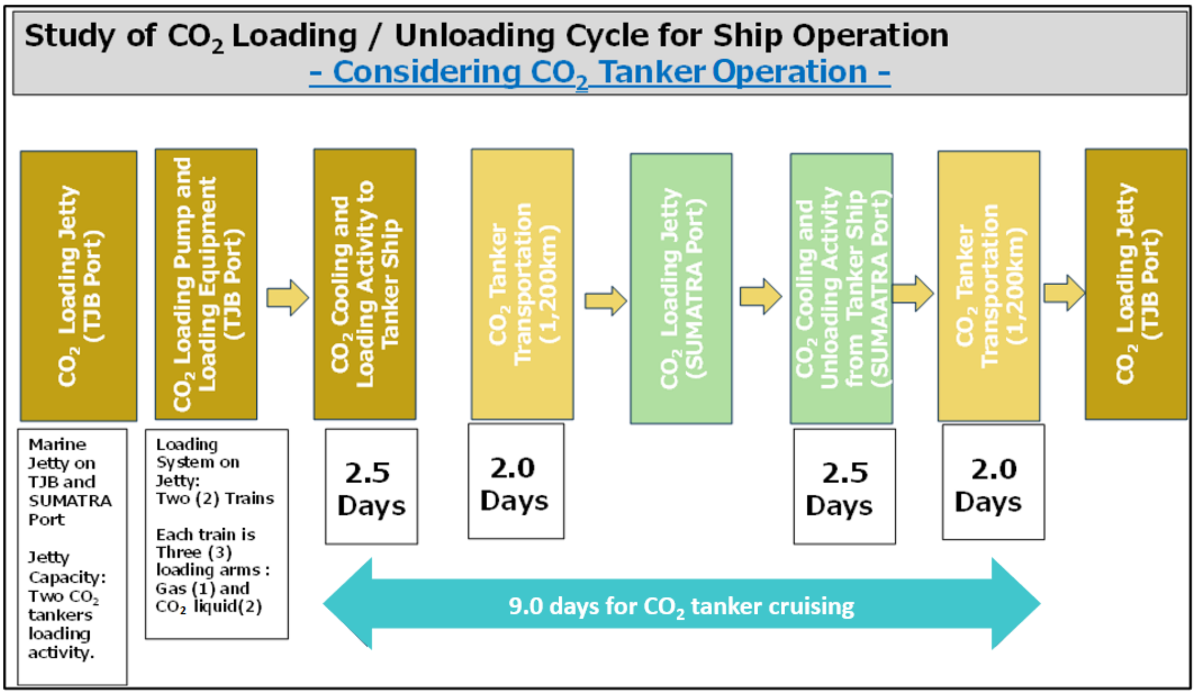
Figure 4.10. CO_2 Ship Planned Navigation Route



Source: Authors based on Google Earth.

In accordance with the basic study conditions, we assumed the CO_2 loading and unloading (including cooling work) of the CO_2 ship and the number of sailing days of the dedicated ship. Figure 4.11 outlines the process.

Figure 4.11. Operation Flow Diagram of CO_2 Ship



Source: Authors.

4.1.2. Receiving Terminal

The receiving terminal has facilities for receiving and storing low-temperature CO_2 and transporting CO_2 to Corridor PSC. The transportation of CO_2 to Corridor PSC at the terminal will be operated 24 hours a day and will occur annually. The equipment configuration includes an unloading arm and related piping for receiving low-temperature CO_2, CO_2 storage tanks, CO_2 transport equipment (to boost the pressure and raise the temperature of low-temperature CO_2), and other necessary related equipment. Offshore jetty and unloading arms similar to TJB delivery terminal will be considered. Receiving tanks were also studied (Table 4.5.)

Table 4.5. Equipment Specifications for CO_2 Tanks at the Receiving Terminal in Sumatra

Tank Specifications	6.5 Million Tonnes/Year	13.0 Million Tonnes/Year
Place of Tank Yard	Sumatra Receiving Terminal	
CO_2 Storage Capacity (days)	5	6
CO_2 Tank Yard Storage Capacity (tonnes)	90,000	180,000
Type of Tank	Dome type/Spherical type	Dome type/Spherical type
Tank Capacity (tonnes)	18,000/12,000	30,000/12,000
Numbers of Tanks (minimum)	5/8	6/15
Operating Conditions	9.5 Bars/-49℃	9.5 Bars/-49℃

Source: Authors.

4.1.3. CO_2 Pressure Rising and Temperature Rising Equipment

Liquid CO_2 is stored in the CO_2 storage tank at 0.6 MPaG and -55°C. To transport this CO_2 through a pipeline, the pressure and temperature are increased to 2,000 psig and 5°C by CO_2 pump and heater. Based on the above settings, the HYSYS simulation software was used to model and determine the specifications of the CO_2 pump and heater. Table 4.6 shows the equipment specifications based on the HYSYS model.

Table 4.6. Specifications of CO_2 Pressure and Temperature Rising Equipment

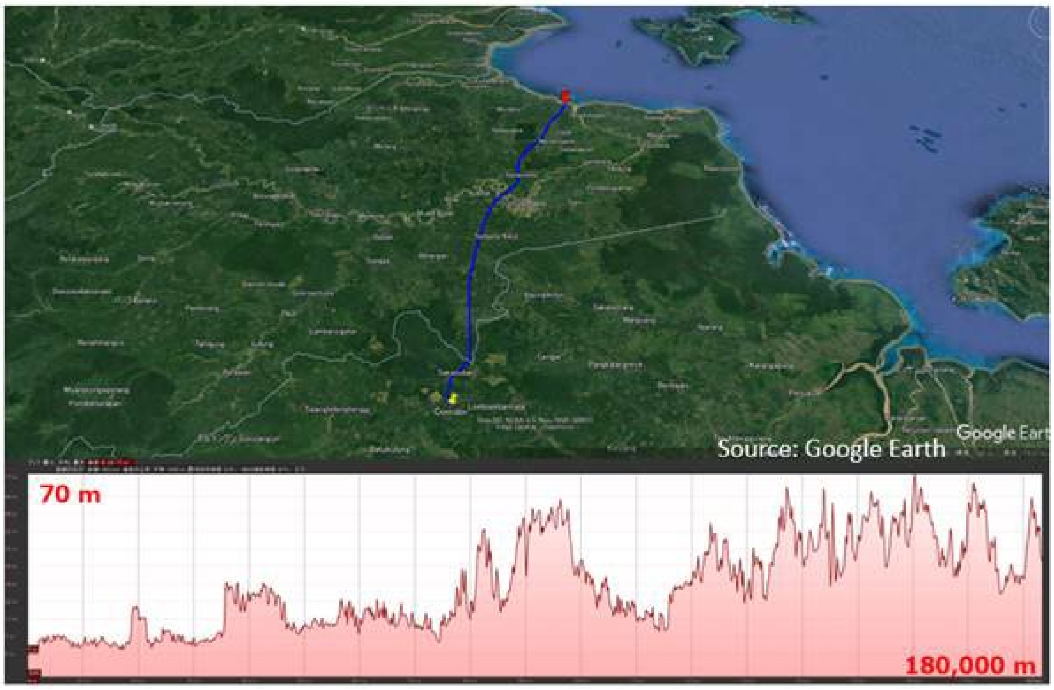
Case	Flow Rate (t/d)	Pump (HP)	Heat Exchanger (HP)
6.5 million tonnes/year	17,808	4,540	28,698
13 million tonnes/year	35,616	9,081	57,397

Source: Authors.

4.1.4. Onshore Pipeline (Sumatra)

The pipeline route from the receiving terminal to the corridor was determined based on location and elevation information from Google Earth. Basically, we selected a route that follows major roads with minimal elevation differences. Figure 4.12. shows the pipeline route from the receiving terminal to the corridor. The entire route was divided into multiple pipeline segments to model the pipeline distance and elevation difference similar to 4.4.2.1. The size of the CO_2 pipeline was determined using HYSYS simulation software. Tables 4.7 and 4.8 show the results of the study.

Figure 4.12. CO_2 Pipeline Route (Receiving Terminal to Corridor)



Source: Authors based on Google Earth.

Table 4.7. CO_2 Pipeline Specifications (Receiving Terminal to Corridor)

Item	Specifications
Length	183 km
Operating Pressure	Max. 2,000 psig (Weyburn Project, Canada)
Design Pressure	2,200 psig (110% of operating pressure)
Re-boosting at Booster Station	2,000 psig
Criteria for Re-boosting	No less than 1,300 psig
Criteria for CO_2 Flow Velocity	Approx 1–2m

Source: Authors.

Table 4.8. CO_2 Pipeline Size and Weight (Receiving Terminal to Corridor)

Case	Size	Pipeline Weight	Booster Station
6.5mmt/y case	OD 24 in, ID 22.624 in, WT 0.688 in	47,000ton	None
13mmt/y case	OD 34 in, ID 32.25 in, WT 0.875 in	84,000ton	None

Source: Authors.

4.2. Case-B (Pipeline Transport)

4.2.1. Pipeline

The pipeline route from TJB to the corridor was determined based on location and elevation information from Google Earth. We selected a route that follows major roads with minimal elevation differences.

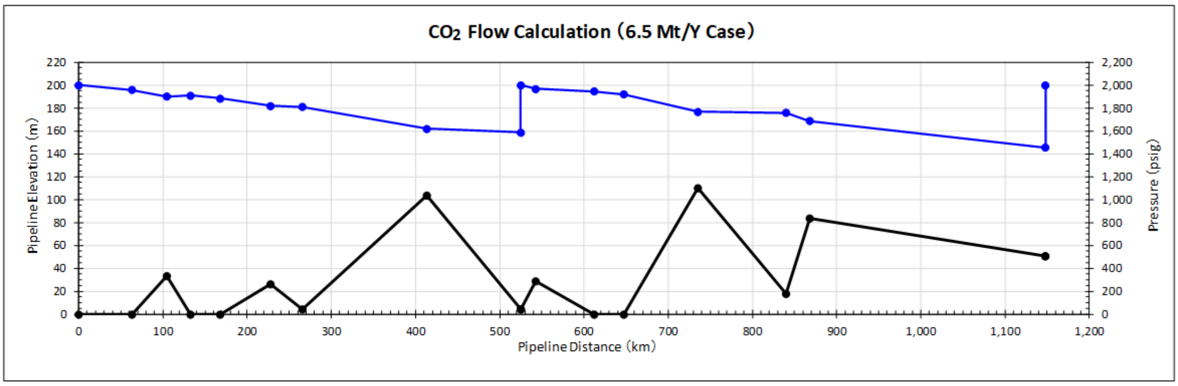
Figure 4.13. CO_2 Pipeline Route (TJB to Corridor)

Source: Authors based on Google Earth.

The entire route was divided into multiple pipeline segments to model the pipeline distance and elevation difference mentioned above. Figures 4.14 and 4.15 show information for each segment and calculation result for 6.5 Mt/y and 13.0 Mt/y cases.

Figure 4.14. CO_2 Pipeline Flow Calculation Results (TJB to Corridor, 6.5 Mt/year Case)

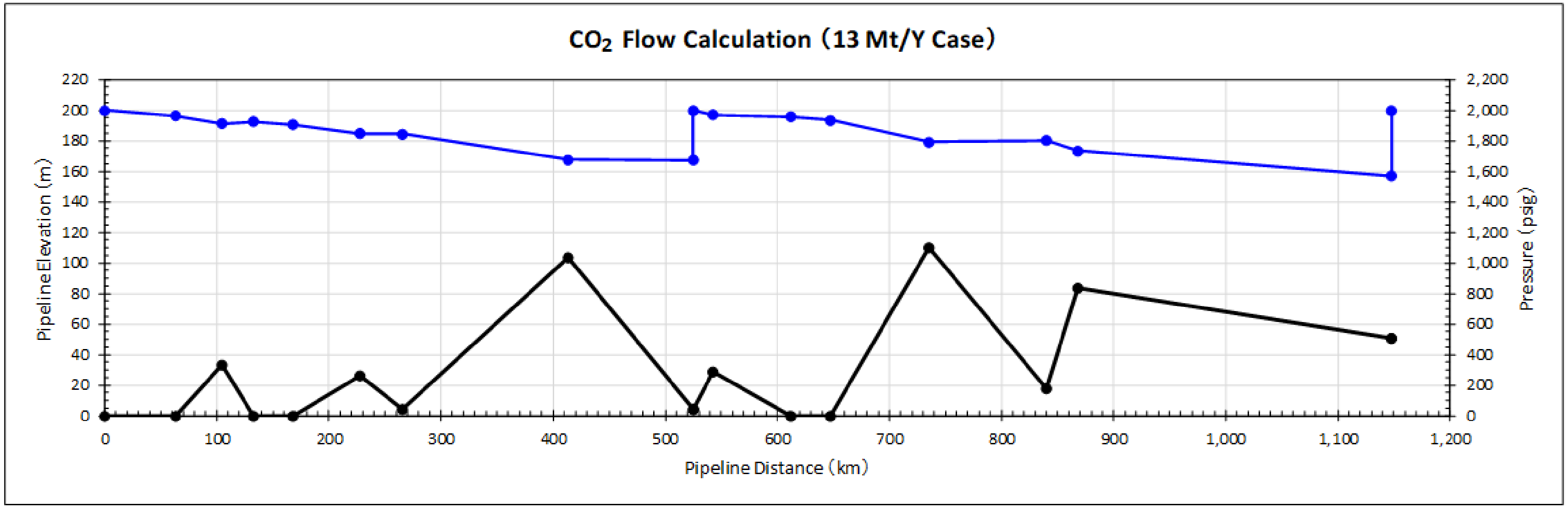
Distance	(km)	0	63	105	133	168	228	266	413	525	525	543	613	648	735	840	868	1,148	1,148
Section Distance	(km)	0	63	42	28	35	60	39	147	112	0	18	70	35	88	105	28	280	0
Elevation	(m)	0	0	33	0	0	26	4	103	4	4	29	0	0	110	18	84	51	51
Pressure	(psig)	2,000	1,957	1,900	1,908	1,883	1,819	1,808	1,618	1,587	2,000	1,968	1,945	1,920	1,767	1,758	1,687	1,454	2,000
CO_2 Density	(kg/m^3)	618	607	591	593	586	566	562	482	466	494	609	603	597	547	544	515	385	427
Velocity	(m/s)	0.94	0.95	0.98	0.98	0.99	1.02	1.03	1.20	1.24	1.17	0.95	0.96	0.97	1.06	1.06	1.13	1.51	1.38
											Booster								Injection



Source: Authors.

Figure 4.15. CO_2 Pipeline Flow Calculation Results (TJB to Corridor, 13 Mt/year Case)

Distance	(km)	0	63	105	133	168	228	266	413	525	525	543	613	648	735	840	868	1,148	1,148
Section Distance	(km)	0	63	42	28	35	60	39	147	112	0	18	70	35	88	105	28	280	0
Elevation	(m)	0	0	33	0	0	26	4	103	4	4	29	0	0	110	18	84	51	51
Pressure	(psig)	2,000	1,965	1,913	1,925	1,905	1,849	1,844	1,676	1,674	2,000	1,970	1,956	1,936	1,794	1,804	1,735	1,569	2,000
CO_2 Density	(kg/m^3)	618	609	595	598	592	575	574	510	509	530	610	606	601	557	560	535	455	485
Velocity	(m/s)	1.02	1.03	1.05	1.05	1.06	1.09	1.09	1.23	1.23	1.18	1.03	1.03	1.04	1.13	1.12	1.17	1.38	1.31
											Booster								Injection



Source: Authors.

Based on the above settings, the size of the CO_2 pipeline was determined by modelling using the HYSYS simulation software. Figures 4.14. and 4.15 show the results of the study for both 6.5 Mt/y and 13 Mt/y cases.

Table 4.9. CO_2 Pipeline Specification

Item	Specifications
Length	1,148 km
Operating Pressure	Max. 2,000 psig (Weyburn Project, Canada)
Design Pressure	2,200 psig (110% of operating pressure)
Re-boosting at Booster Station	2,000 psig
Criteria for Re-boosting	No less than 1,300 psig
Criteria for CO_2 Flow Velocity	Approx 1–2m

Source: Authors.

Table 4.10. CO_2 Pipeline Size and Weight (TJB to Corridor)

Case	Size	Pipeline Weight	Booster Station	Pump Power (HP)
6.5 Mt/y	OD 28 in, ID 26.5 in, WT 0.75 in	373,000 tonnes	1	2,256
13 Mt/y	OD 38 in, ID 36 in, WT 1.0 in	676,000 tonnes	1	3,258

Source: Authors.

A booster station was set up at a point 525 km from TJB based on process considerations. The facility was equipped with equipment that considered boost pumps, control equipment, offices, buildings, and other equipment.

5. CO_2 Storage

5.1. CO_2 Storage Capacity Calculation Methodology

The potential CO_2 storage capacity for depleted oil and gas fields was calculated using the following formula, assuming that the capacity is proportional to the volume of produced gas under subsurface reservoir conditions.

$$GCO_2t = Gp \times Bgi \times DENCO_2 \times E$$

GCO_2t: CO_2 storage capacity (tonnes)

Gp: Volume of ultimately recoverable gas (scf)

Bgi: Initial formation volume factor (rcf/scf)

$DENCO_2$: Density of CO_2 at reservoir condition (tonne/rcf)

E: Storage capacity efficiency (depending on aquifer, fracture, etc.)

5.2. Site selection

As a result of a literature survey through the Indonesian Petroleum Association and the Society of Petroleum Engineers, 17 fields are identified as oil and gas fields in Corridor PSC. These fields are categorised (Table 4.11) depending on the type of oil and gas field, size of reserves, and data availability.

Table 4.11. Field Selection

Search by IPA/SPE, etc.	Gas Fields	Large Fields	Fields with Available Data
17	10	7	3

IPA = Indonesian Petroleum Association, SPE = Society of Petroleum Engineers.
Source: Authors.

Based on the criteria above, Suban, Sumpal, and Dayung were selected as potential storage sites. Table 4.12 shows the ultimate recoverable reserves of these three gas fields. It also shows the volume of gas initial in place (GIIP). The ultimate recoverable reserve is calculated in this study using the general recovery factor of gas field (0.8).

Table 4.12. Reserves of Suban, Sumpal, and Dayung

Field	GIIP	Recovery Factor	Ultimate Recoverable Reserves
	(Tscf)		(Tscf)
Suban	6.9	0.8	5.5
Sumpal	1.6	0.8	1.28
Dayung	1.45	0.8	1.16
Total	9.95	-	7.96

Source: Authors.

Compared with in-house data of Corridor PSC's entire recoverable reserves, the recoverable gas reserves of Suban, Sumpal, and Dayung shown in Table 4.12 account for approximately 80%–90% of Corridor PSC's entire recoverable reserves. Therefore, this study assumes that these three gas fields also account for 80%–90% of the CO_2 storage capacity of the entire Corridor PSC.

5.3. Storage Capacity Calculation

Suban

Suban's CO_2 storage capacity is estimated to be 292 million tonnes using the following formula:

$GCO_2t = Gp \times Bgi \times DENCO_2 \times E1 \times E2$

Ultimate recoverable reserves (GP): 5.52 Tscf, assuming a recovery factor of 80%

Initial gas composition: Modified Dayung's gas composition to account for Suban's CGR value

Initial formation volume factor (Bgi): Estimated to be 0.00478 rf/scf from the initial gas formation pressure, temperature, and gas composition

CO_2 density ($DENCO_2$): Estimated to be 30.2 lb/cf based on the initial gas formation pressure and temperature.

CO_2 storage efficiency (E1): 0.9, considering the depletion drive pressure regime

CO_2 storage efficiency (E2): 0.9 as a risk factor for fractured reservoirs

Dayung

Dayung's CO_2 storage capacity is estimated to be 54 million tonnes using the following formula.

$$GCO_2t = Gp \times Bgi \times DENCO2 \times E1 \times E2$$

Ultimate recoverable reserves (GP): 1.16 Tscf, assuming a recovery factor of 80%

Initial gas composition: Methane (65.5%), CO_2 (30.7%), others (3.8%)

Initial formation volume factor (Bgi): Estimated to be 0.00714 rf/scf from the initial gas formation pressure, temperature, and gas composition

CO_2 density ($DENCO_2$): Estimated to be 19.9 lb/cf, calculated from the initial gas formation pressure and temperature

CO_2 storage efficiency (E1): 0.8, considering the weak water drive pressure regime

CO_2 storage efficiency (E2): 0.9 as a risk factor for fractured reservoirs

Sumpal

Sumpal's CO_2 storage capacity is estimated to be 62 million tonnes using the following formula:

$GCO_2t = Gp \times Bgi \times DENCO_2 \times E1 \text{ x } E2$

Ultimate recoverable reserves (GP): 1.28 Tscf, assuming a recovery factor of 80%

Initial gas composition: Assumed to be the same as Dayung

Initial formation volume factor (Bgi): Estimated to be 0.00543 rf/scf from the initial gas formation pressure, temperature, and gas composition

CO_2 density ($DENCO_2$): Estimated to be 27.4 lb/cf based on the initial gas formation pressure and temperature

CO_2 storage efficiency (E1): 0.8, assuming weak water drive pressure regime since it is adjacent to Dayung

CO_2 storage efficiency (E2): 0.9 as a risk factor for fractured reservoirs.

Table 4.13. CO_2 Storage Capacity Calculation

Field	GIIP	Recoverable Gas Reserves	Formation Volume Factor	CO_2 Density	CO_2 Storage Efficiency		CO_2 Storage Capacity
					Pressure Regime	Fracture Effect	
	(Tscf)	(Tscf)	(rcf/scf)	(lb/cf)			(million tonnes)
Suban	6.9	5.52	0.00478	30.2	0.9	0.9	**292**
Dayung	1.45	1.16	0.00714	19.9	0.8	0.9	**54**
Sumpal	1.6	1.28	0.00543	27.4	0.8	0.9	**62**
Total	9.95	7.96	-	-	-	-	**408**

GIIP = gas initial in place.
Source: Authors.

5.4. Number of Injection Wells

The number of injection wells is calculated so that overall target injection rate is achieved, while injection rate per well is lower than the threshold, which to be determined considering the leakage risk from the potential fracture of seal formation due to high CO_2 injection pressure.

This study assumes that the injection rate should be calculated based on the actual production rate. The number of injection wells was determined using the following procedure.

- The maximum CO_2 injection rate per well is calculated so that the injection rate is same as natural gas production rate per well during the plateau period of each gas field. Safety factor is also applied.
- Allocation of the CO_2 injection rate between three fields – Suban, Dayung, and Sumpal – is determined based on the maximum storage capacity of each field.
- The number of CO_2 injection wells is calculated by dividing the target injection rate for each gas field by the CO_2 injection rate per well.

The production rate per well during the production plateau period for each gas field was estimated by dividing the plateau rate by the number of wells (Table 4.14).

In this study, CO_2 injection rate per well is assumed to be 80% of the plateau production rate.

Table 4.14. Production and Injection Rate of Each Field

Field	Plateau Rate (MMscf/d)	Number of Production Wells	Production Rate/ Well (MMscf/d)	Injection Rate/ Well (MMscf/d)
Suban	800	8～13	60～100	64
Dayung	250	8	30	24
Sumpal	Assuming it is the same as Dayung as the production history is unknown		30	24

Source: Authors.

The target CO_2 injection rate (cases of 13 million tonnes/year and 6.5 million tonnes/year) was allocated based on the ratio of the maximum CO_2 storage capacity of the gas fields (Suban, Dayung, and Sumpal) to calculate the target injection rate for each gas field The number of CO_2 injection wells was calculated by dividing the target injection rate for each gas field by the CO_2 injection rate per well. Table 4.15 shows the number of injection wells for each gas field.

Table 4.15. 13 mmt/y Injection Case

13 mmt/y Case				
Field	**Storage Capacity**	**Target Injection Rate**	**Injection Rate per Well**	**Number of Injection Wells**
	mmt	**mmt/y**	**MMscf/d**	
Suban	292	9.3	64	8
Dayung	54	1.72	24	4
Sumpal	62	1.98	24	5
Total	**408**	**13**	**-**	**17**

mmt = million tonnes.
Source: Authors.

Table 4.16. 6.5 million tonnes (mmt)/y Case

6.5 mmt/y Case				
Field	Storage Capacity	Target Injection Rate	Injection Rate per Well	Number of Injection Wells
	mmt	mmt/y	MMscf/d	
Suban	292	4.65	64	4
Dayung	54	0.86	24	2
Sumpal	62	0.99	24	3
Total	**408**	**6.5**	**-**	**9**

Source: Authors.

6. Further Consideration

6.1. Energy Source for CCS Value Chain

The required energy amount for CCS (compression, transport, etc.) is not minimal and how to feed the energy is an important subject.

This study assumed that the required electric power for TJB Power Station (capture, liquefaction, compression, and loading) would be supplied from outside of the units.

It means that the electrical power will be supplied from the. n Listrik Negara's grid through switch yard of TJB 5&6. The cost of modification of the switch yard is included in CAPEX. The required electricity cost during CCS operation was assumed in OPEX as a proportional ratio of CAPEX.

The associated CO_2 emissions, due to additional energy usage, are also an important point to be improved to increase the carbon reduction potential of the CCS value chain. The detailed study shall be carried out in the next step of the feasibility study. The following alternatives for electrical power source shall be studied with the energy penalty.

- Alternative 1: Independent cogeneration unit
  (e.g. gas turbine generator with heat recovery boiler)
- Alternative 2: To supply from own generating unit
  (To feed electricity from TJB 5&6 as house load and to feed extraction steam from steam turbine)

Table 4.17 describes each energy source option and energy penalty.

Table 4.17. Concept of the Energy Supply Plan and Energy Penalty for CCS Value Chain

Case	Title	Description	Energy Penalty
Base	From Outside the Unit	- Electric power will be supplied from the grid system through the switch yard of TJB 5&6. Facility modification cost will be estimated as CAPEX. OPEX will be determined based on the proportional ratio of CAPEX. - Thermal energy will be assumed to be supplied from the excess steam source from the existing units (e.g. TJB 1 to 6) or the additional auxiliary boiler, etc. CAPEX of thermal energy will be studied at the next stage.	- CO_2 amount to generate the required electric power for carbon capture, (transportation and storage). (Calculated based on the grid emission factor: tCO_2/MWh) - CO_2 amount to generate the steam for capture - CO_2 amount from LCO_2 ship
Alt.-1	Independent Cogeneration Unit (gas turbine generator + heat recovery steam generator)	- Electric power will be supplied from the newly installed gas turbine generator for each unit (TJB 5&6) - 95% of CO_2 emission from gas turbine will be captured by the main CO_2 capture plant - Thermal energy will be supplied from the heat recovery boiler. - CAPEX and OPEX of this case will be studied at the next stage.	- 5% of CO_2 emission from the gas turbine - CO_2 amount to generate the required electric power for transportation and storage. (Calculated based on the grid emission factor: tCO_2/MWh) - CO_2 amount from LCO_2 ship
Alt.-2	From Own Unit (TJB 5&6)	- Both electric power and thermal energy will be supplied from the main units. (TJB 5&6) Net output of TJB 5&6 shall be	- CO_2 amount to generate the required electric power for

Case	Title	Description	Energy Penalty
		reduced, and the power purchase agreement needs to be adjusted and re-contracted subject to concerned stakeholders. - CAPEX and OPEX, and the effect of the NET output will be studied at the next stage.	Transportation &Storage. (Calculated based on the grid emission factor : tCO_2/MWh) - CO_2 amount from LCO_2 ship.

Alt. = Alternative.
Source: Authors.

6.2. Technical Verification of the Liquefied CO_2 Facilities

This study assumes that CO_2 liquefaction facilities, storage tanks, LCO_2 ships, etc. have low temperature and low-pressure conditions in consideration of large-scale transportation. However, liquefied CO_2 facilities of this scale do not actually exist currently. For this reason, when considering and evaluating facilities, we refer to existing LNG and LPG liquefaction technologies and incorporate them on the premise that future technological development will be realised for liquefied CO_2 facilities.

In the future, the specifications of large-capacity CO_2 liquefaction facilities, storage tanks, and LCO_2 ships will need to be reflected in the detailed design after reviewing technological development trends and updating them as appropriate.

6.3. Site Expansion for CO_2 Capture, Compression and Liquefaction Facilities, and Storage Tanks

The installation of CO_2 capture facilities, compression and liquefaction facilities, and storage tanks requires a site area equivalent to that of an existing power plant. If the installation area is limited, it is necessary to secure the necessary construction area through reclamation or other means.

As a rough study result, an additional site of about 27 ha in Case A and about 14 ha in Case B is required for the TJB coal-fired power plant. Although the costs of landfill and reclamation are not included in this study, they should be considered as evaluation items in the next step.

Chapter 5

Commercial Study on CCS Value Chain

1. Background and Assumption for the CCS Value Chain

To achieve net-zero GHG emissions in Indonesia by 2060 as well as sustainable growth by realising a stable power supply and economic efficiency, it is necessary to economically achieve the transition to decarbonisation while making effective use of existing coal-fired power plants.

The Central and East Java-Sumatra regions are rich in oil and gas, have many coal-fired power plants, and have a lot of potential for the application of efficient decarbonisation technologies and the realisation of CCS commercialisation.

In this report, we will study decarbonisation by capturing CO_2 from the state-of-the-art TJB 5&6 coal-fired power plant on the island of Java, transporting it to Corridor PSC in Sumatra Island, and storing it.

Since CO_2 transport from Central Java to southern Sumatra is quite long, more than 1,000 km, it is not practical for actual project development. However, in anticipation of the future CCS value chain in Indonesia and the ASEAN region, long-distance CO_2 transport is expected for regional decarbonisation and, therefore, incorporated as a part of the study. Ocean transport by LCO_2 ships and pipeline transport is studied for comparison purposes.

At the implementation stage of actual project development, it will be realistic to store the CO_2 captured by TJB in nearby oil and gas fields or aquifer as close as possible. Also, CO_2 storage in Corridor PSC will be an effective study for receiving CO_2 from surrounding emission sources such as nearby thermal power plants, or for realising a value chain through cross-border CCS from neighbouring ASEAN countries, Japan, and Korea.

In these aspects, this study is expected to contribute towards future decarbonisation not only for Indonesia but also in countries in the region.

As a reference, similar model case studies had been conducted by ERIA as a side event under the Energy Transition Working Group G20 2022. Further to the previous ERIA study, this research aims to evaluate the cost tendency due to the scale up of the CCS amount by selecting a real project site for both capturing and storage.

1.1. Calculation Method of CAPEX

Regarding the investment amount, injection facilities, pipelines, and shipping costs are calculated based on latest literature (reports) and in-house data reference. The costs for liquefaction and low-temperature CO_2 storage terminal and others are calculated based on facility and equipment cost indicators ($/t-$CO_2$) shown in public literature.

Based on the above equipment cost information, the equipment scale is estimated according to the equipment capacity in each case, and the scale-up method is calculated using the law of similarity (0.6 rule).

The accuracy of the above cost shall be Association of Advanced Cost Engineers Level 4 (Study of Engineering).

The cost reliability accuracy is in the range of L: -15% to -30%, H: +20% to +50%.

1.2. Calculation Method of OPEX

OPEX comprises utility costs, personnel costs, maintenance costs, etc.

When examining the FS level of study, it is common to estimate OPEX using the CAPEX ratio. Thus, we applied this method to estimate OPEX over a 25-year period.

The ratio was set based on 'Shipping CO_2 - UK cost estimation study, Final report for Business, Energy & Industrial Strategy Department, No. 2018.

In calculating OPEX, the following ratios in Tables 5.1.1 and 5.1.2 were applied for each type of equipment and system.

Table 5.1. OPEX Ratio (Case A)

No.	Plant Name	Site	OPEX Ratio (%)
1.	CO_2 Capture	TJB	6%
2.	CO_2 Liquification	TJB	10%
3.	CO_2 Storage Tanks	TJB	3%
4.	CO_2 Loading Equipment with Pipeline	TJB	6%
5.	JETTY	TJB	3%
6.	CO_2 Ship	TJB-Sumatra Port	13%
7.	Port on Unloading Equipment with Piping	Sumatra Port	6%
8.	CO_2 Storage Tanks	Sumatra Port	3%
9.	Jetty	Sumatra Port	3%
10.	CO_2 Pump Delivery	Sumatra Port	6%
11.	CO_2 Heater	Sumatra Port	6%
12.	Onshore Pipeline	Port-Corridor CCS	3%
13.	CCS Facility	Corridor CCS Site	3%
14.	Injection Pump	CCS Site	6%
15.	Drilling Cost	CCS Site	3%

Source: Authors.

Table 5.2. OPEX Ratio (Case B)

No.	Plant Name	Site	OPEX Ratio (%)
1.	CO_2 Capture	TJB	6%
2.	CO_2 Compression	TJB	6%
3.	CO_2 Dehydration	TJB	6%
4.1	Onshore Pipeline	TJB-Booster Pump Station	3%
4.2	Pipeline Control System	SCADA System	3%
4.3	Control Room and Building	SCADA Control Building	3%
4.4	Gate and Parking	Paving, Fence, Parking Area	3%
5.	Booster Pump Station	Booster Pump Station (BPS)	6%
6.	Onshore Pipeline	BPS-Sunda Subsea	3%
7.	Marine Pipeline	Sunda Subsea	3%
8.	Onshore Pipeline	Sunda Subsea-Corridor CCS	3%
9.	CCS Facility	Corridor CCS Site	3%
10.	Injection Pump	CCS Site	6%
11.	Drilling Cost	CCS Site	3%

Source: Authors.

OPEX does not include costs such as CO_2 leakage monitoring and aquifer analysis during operation.

1.3. Exclusion

The following items are excluded in this study when estimating equipment costs.

1) Cost of site purchase and land lease

2) Cost of special land clearing work for the site

3) Cost of soil improvement for unstable base and offshore facility ground

4) Cost of electricity, portable water, and industrial water for base utilities

5) Cost of coastal reclamation to secure land for both TJB extended area and ports in South Sumatra

6) Cost of abnormal seabed soil removal and navigation channel maintenance

7) Cost of removal and monitoring after project completion

2. Capture Costs

The cost analysis was split into three categories of the capture facility: Capture, Electrical System Modification, and Others (boil-off gas processing, etc.).

As for capture facility, (i) the previous ERIA data, (ii) the public report of Petra Nova Project which is the largest commercial capture facility in the US, and (iii) the manufacturer's data were referenced to evaluate the cost.

As for electrical system modification, power feed line from the switch yard of TJB 5&6 and required equipment, such as transformers, bus ducts, etc., were assumed.

For boil-off gas processing, the steam pipeline from TJB 1 – 6 to the capture facility was assumed.

Table 5.3 shows the CAPEX and OPEX of the capture facility for both Cases A and B.

Table 5.3. Capture Facility Costs

Unit: $ million

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year
CAPEX	Capture	871.5	1,568.7
	Electrical System Modification	54.0	108.0
	Others (BOP, etc.)	15.0	30.0
Subtotal		940.5	1,706.7
OPEX	Capture	4,509.0	8,116.2
	Electrical System Modification	40.5	81.0
	Others (BOP, etc.)	11.3	22.5
Subtotal		4,560.8	8,219.7
Total CAPEX and OPEX		5,501.3	9,926.4

Source: Authors.

3. Delivery Terminal Costs

3.1. Case A (Ocean Transport)

The cost analysis was split into the four categories of TJB delivery terminal facility: Liquefaction, Storage Tanks, Loading Equipment with Pipeline, and Jetty.

There are currently no large-capacity low-temperature liquefaction facilities for CCS projects. Here, the cost was evaluated based on references from the data of LNG liquefaction facilities of similar capacity.

The tank was evaluated on the premise of the dome roof type, which is applied to low-temperature LPG tanks with existing technology.

The shipping equipment for low-temperature liquefied fluids is a method that has been commercially used at low-temperature LPG and LNG terminals. In this study, the cost was evaluated with reference to the same method (simultaneous transfer of gases and liquids).

In addition, the approximate cost of the jetty was evaluated on the assumption that two berths would be installed at 2 km offshore, similar to the TJB coal jetty.

Table 5.4 shows the CAPEX and OPEX of the delivery terminal for Case A.

Table 5.4. Delivery Terminal Costs (Case A)

Unit: $ million

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year
CAPEX	Liquefaction	351.0	702.0
	Storage Tanks & Yard	144.0	229.6
	Loading Equipment with Pipeline	166.5	199.5
	Jetty	84.0	134.4
Subtotal		745.5	1,265.5
OPEX	Liquefaction	877.5	1,755.0
	Storage Tanks & Yard	108.0	172.2
	Loading Equipment with Pipeline	249.7	299.2
	Jetty	63.0	100.8
Subtotal		1,298.2	2,327.2
Total CAPEX and OPEX		2,043.7	3,592.7

Source: Authors.

3.2. Case B (Pipeline Transport)

For pipeline transport, the cost of compression equipment and dehydration equipment was calculated.

The cost of compression equipment was evaluated based on the pump specifications in Chapter 4 and based on the unit price index of pump power.

The cost of the dehydration equipment was evaluated based on the data from the water removal device in natural gas industry that has been put into practical use.

Table 5.5 shows the CAPEX and OPEX of the delivery terminal for Case B.

Table 5.5. Delivery Terminal Costs (Case B)

Unit: $ million

ategory		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year
CAPEX	Compression	458.1	916.2
	Dehydration	146.5	293.1
Subtotal		604.6	1,209.3
OPEX	Compression	687.2	1,374.3
	Dehydration	219.8	439.6
Subtotal		906.9	1,813.9
Total CAPEX and OPEX		1,511.6	3,023.2

Source: Authors.

4. Transport Costs

Both Ocean Transport and Pipeline Transport from TJB to Corridor PSC were analysed.

4.1. Case A (Ocean Transport)

The cost analysis was split into the four categories of the ocean transport case: LCO_2 Ship, Jetty, Unloading Facility, Tanks, Pump, Heater, and Onshore Pipeline.

As for liquefied CO_2 ships, we referred to data from low-temperature and low-pressure ships (-50°C, 7.5 barg) scheduled to be built and delivered by the Korea Hyundai Shipyard in 2025. The ship price cost corresponding to the CO_2 loading capacity examined in Chapter 4 was calculated using the plant similarity law (0.6 power rule). In addition, the number of ships required was calculated based on the operation plan shown in Chapter 4 and the cost was evaluated.

The receiving terminal, pier, unloading facilities, etc. on the Sumatra side are assessed at cost in the same way as TJB shipping terminal in Section 3.1. For pumps and piping from the receiving terminal to Corridor PSC, the cost of pumps and piping is evaluated using the HYSYS model (Chapter 4).

Table 5.6 shows the CAPEX and OPEX of the Transport for Case A.

Table 5.6. Transport Costs (Case A)

Unit: $ million

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year
CAPEX	LCO_2 Ship	539.3	869.4
	Jetty/Unloading Facility	198.5	300.9
	Tanks/Pump/Heater	102.1	186.2
	Onshore Pipeline	498.1	564.5
Subtotal		1,338.0	1,921.0
OPEX	LCO_2 Ship	1,617.8	2,825.6
	Jetty/Unloading Facility	234.7	350.5
	Tanks/Pump/Heater	92.5	171.4
	Onshore Pipeline	373.5	423.3
Subtotal		2,318.6	3,770.8
Total CAPEX and OPEX		3,656.5	5,691.8

Source: Authors.

4.2. Case B (Pipeline Transport)

In addition to the pipeline, the cost assessment also includes the evaluation of booster stations. The booster station includes equipment such as booster pumps and control equipment, offices, and buildings.

In addition, the cost of piping is evaluated for both onshore piping and subsea piping using the HYSYS model shown in Chapter 4.

Table 5.7 shows the CAPEX and OPEX of transport for Case B.

Table 5.7. Transport Costs (Case B)

Unit: $ million

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year
CAPEX	Onshore Pipeline (TJB - Booster St.)	1,667.0	2,104.0
	Booster Pump, Control System, etc.	28.3	31.9
	Marine Pipeline	493.9	623.4
	Onshore Pipeline (Booster St. - Corridor)	1,929.1	2,434.8
Subtotal		4,118.3	5,194.1
OPEX	Onshore Pipeline (TJB - Booster St.)	1,250.2	1,578.0
	Booster Pump, Control System, etc.	28.6	34.0
	Marine Pipeline	370.4	467.5
	Onshore Pipeline (Booster St. - Corridor)	1,446.8	1,826.1
Subtotal		3,096.1	3,905.6
Total CAPEX and OPEX		7,214.4	9,099.7

Source: Authors.

5. Storage Costs

Storage cost is calculated under the following assumptions:

- Injection wells are vertical injection wells. Well design is based on the US Environmental Protection Agency Class VI Well permit.
- Drilling takes 40 days/well with rig rate of $200,000/day.
- The following equipment are included in calculating costs:
  - Injection pump
  - Temporary storage tank
  - Flowline
  - Injection wells
  - Management office

Table 5.8 shows the CAPEX and OPEX of storage.

Table 5.8. Storage Costs

Unit: $ million

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year
CAPEX	Drilling Cost	378.0	714.0
	CCS Facility/Injection Pump	92.4	129.6
Subtotal		470.4	843.6
OPEX	Drilling Cost	283.5	535.5
	CCS Facility/Injection Pump	69.3	97.2
Subtotal		352.8	632.7
Total CAPEX and OPEX		823.2	1,476.3

Source: Authors.

6. Summary of Cost Estimation

Per Chapter 4, technical studies on two cases of CO_2 transports – liquefied CO_2 vessel and CO_2 pipeline – were conducted. While the long distance throughout the transport value chain is a hurdle, there are some positive outcomes as follows:

- 2 units case with 13 million CO_2-tonnes would be referable than 1 unit case with 6.5 million CO_2-tonnes in terms of unit cost, although CAPEX and OPEX would surely increase accordingly.
- A big volume of around 10 mil CO_2-tonne/year of capturing unit cost would lead to a positive result due to scale merit and some technical reasons like capturing plant efficiency etc.
- CO_2 transport by liquefied CO_2 vessel would be preferable than CO_2 pipeline in case of long distance of around 1,000 km with a large-scale CO_2 volume, as shown in Section 6.3 on comparison of unit costs.
- Liquefaction cost is needed to transport CO_2 by vessel, which is an additional cost factor compared to CO_2 pipeline case.
- Due to the reservoir characteristics, gas production rate especially in Suban gas field is believed to be as high as 60–100 mmscf/d/well. In this study, the CO_2 injection rate is calculated based on this high gas flow rate. Therefore, the CO_2 injection rate is assumed to be as high as 64 mmscf/d/well in the Suban field. As a result, the number of wells required to achieve target injection rate is relatively low.
- Due to the significant gas reserves, the Suban, Sumpal, and Dayung fields are assumed to have a CO_2 storage capacity of as large as 408 mmt in total. Due to economies of scale, the unit cost for CO_2 storage is relatively low.

6.1. Case A (Ocean Transport)

Table 5.9. Summary of Cost Estimation (Case A)

Unit: $ million

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year
CAPEX	Capture	940.5	1706.7
	Liquefaction/Tanks/Loading	745.5	1,265.5
	Transportation	1,338.0	1,921.0
	Storage	470.4	843.6
Subtotal		3,494.4	5,736.8
OPEX	Capture	4,560.8	8,219.7
	Liquefaction/Tanks/Loading	1,298.2	2,327.2
	Transportation	2,318.6	3,770.8
	Storage	352.8	632.7
Subtotal		8,530.3	14,950.4
Total CAPEX and OPEX		12,024.7	20,687.2

Source: Authors.

6.2. Case B (Pipeline Transport)

Table 5.10. Summary of Cost Estimation (Case B)

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year
CAPEX	Capture	940.5	1706.7
	Compression/Dehydration	604.6	1,209.3
	Transportation	4,118.3	5,194.1
	Storage	470.4	843.6
Subtotal		6,133.8	8,953.6
OPEX	Capture	4,560.8	8,219.7
	Compression/Dehydration	906.9	1,813.9
	Transportation	3,096.1	3,905.6
	Storage	352.8	632.7
Subtotal		8,916.6	14,571.9
Total CAPEX and OPEX		15,050.4	23,525.5

Source: Authors.

6.3. Unit Cost

Table 5.11. Unit Cost (Case A)

Unit : $/t-$CO_2$

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year	2022 ERIA *1
Unit Cost	Capture	33.9	30.5	45.9
	Liquefaction/Tanks/Loading	12.6	11.1	-
	Transportation	22.5	17.5	0.95
	Storage	5.1	4.5	15.9
Total Unit Cost		74.0	63.7	62.8

Source: Authors.

Table 5.12. Unit Cost (Case B)

Unit : $/t-$CO_2$

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year	2022 ERIA *1
Unit Cost	Capture	33.9	30.5	45.9
	Compression/Dehydration	9.3	9.3	-
	Transportation	44.4	28.0	0.95
	Storage	5.1	4.5	15.9
Total Unit Cost		92.6	72.4	62.8

Source: Authors.

7. Levelized Cost per kWh for CCS

In addition to the above commercial study, we tried to calculate the levelized cost per kWh at TJB 5&6 for CCS using the following formula to see how much needs to be recovered from its electricity tariff if we invest in this CCS project at this point.

Figure 5.1. Formula

$$\underset{\textbf{(\$/kWh)}}{\text{Levelized Cost of CCS}} = \frac{\text{NPV of CAPEX and OPEX for CCS } \textbf{(\$)}}{\text{Total Production of Electricity during 25 years } \textbf{(kWh)}}$$

Source: Authors.

We used the following assumptions for this calculation.

Table 5.13. Assumptions

Item	Assumptions
lCapacity	1,000MW x 2 units
lAverage Capacity Factor	86%
lElectricity Production Period	25 Years
lCAPEX and OPEX	Received Estimate
lDiscount Factor	10%
lEscalation, Tax, or other factors	Unconsidered

Source: Authors.

Table 5.14 shows that at Case A (Ocean Transport), the total unit cost per kWh is 8.77 US$ cents/kWh for capture, transport, and storage of 6.5 M CO_2 tonne/year, and 7.42 US$ cents/ kWh for 13 M CO_2 tonne/year.

Meanwhile, the total unit cost at Case B (Pipeline Transportation) is 42% (6.5 M tonnes) or 28% (13 M tonnes) higher than Case A because of the larger transportation cost, resulting in 12.46 US$ cents/kWh for 6.5 M CO_2 tonnes, 9.47 US$ cents/kWh for 13 M CO_2 tonnes.

These unit costs must have a significant impact on the generation and operational costs of power producers and could also affect the viability of their businesses. Therefore, mechanisms to absorb these costs, such as broad support from Indonesia or international organisations, or transferring them to electricity selling prices, may be necessary.

Table 5.14. Unit Cost per kWh for Cases A and B

Case A (Ocean Transport)

Category		Unit	1 unit 6.5 M tonnes	2 units 13 M tonnes
Unit Cost	Capture	US$ cent/kWh	3.45	3.12
	Liquification/Tank	US$ cent/kWh	1.62	1.40
	Transport	US$ cent/kWh	2.90	2.19
	Storage	US$ cent/kWh	0.80	0.71
Total Unit Cost		US$ cent/kWh	**8.77**	**7.42**

Case B (Pipeline Transport)

Category		Unit	1 unit 6.5 M tonnes	2 units 13 M tonnes
Unit Cost	Capture	US$ cent/kWh	3.45	3.12
	Compression/ Dehydration	US$ cent/kWh	1.24	1.24
	Transport	US$ cent/kWh	6.97	4.40
	Storage	US$ cent/kWh	0.80	0.71
Total Unit Cost		US$ cent/kWh	**12.46**	**9.47**

Source: Authors.

Chapter 6
Approach to Potential Business Model

1. Approach for Hub and Cluster Model

This section explores business development initiatives such as the Hub and Cluster Model in general. Potential business model by leveraging such hub and cluster demand opportunities (e.g. from industrial sources surrounding huge storage fields) will be recommended to be pursued further. Positive economic outcomes would be expected by scale merit in this regard (i.e. bigger CO_2 volume makes more economical outcome than small CO_2 volume). Also, infrastructure development by a phased approach may expand business opportunities.

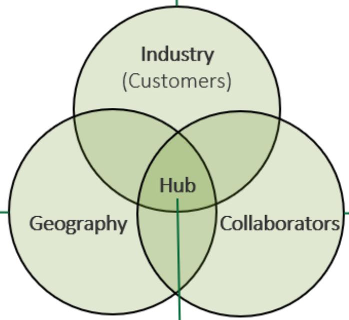
2. Hub and Cluster Analysis

The hub and cluster concept incorporates various aspects of development factors such as industry clustering, geographical proximity, and availability of market collaborators.

Figure 6.1. Hub and Cluster Concept

- Bounded industrial regions (or close proximity) with characteristics that enable decarbonisation pathway
- Availability of supply and demand
- **Example:** Houston Industrial Center

- Bounded by a specific region, representing a sizeable level of aggregated point-source emission
- **Example:** UK East Coast Cluster



- Provides capacity to maximize value within a hub, for instance, by forming novel business models, engaging in advocacy, granting/increasing market access, etc.
- **Example:** Partnership between companies, and public private partnership (PPP)

- Hubs are **high-potential geographic areas that contain a combination and critical mass of industry players and collaborators that maximize value**
- **Example:** Northern light hub (*see slide 70 for details*)

Source: Authors based on Deloitte (2023) and The CCUS Hub (n.d.).

To identify the optimal implementation of hubs, archetypes and operating models should be well defined and considered across the value chain. Hub archetypes can be categorised into supply-led and demand-led hubs. A supply-led hub leverages a diverse supplier network to attract high-demand customer areas. An asset-led hub focuses on leveraging and acquiring specific assets such as pipelines and a product-led hub focuses on producing a specific product such as hydrogen. A demand-led hub delivers lower emission solutions within a specific industry to create a sizeable market demand for the reduction of CO_2 emissions. An off-loader-led hub is driven by high emitting industries looking to off-load captured CO_2, increasing demand for capture and sequestration services. An off-taker-led hub is for industries looking to utilise clean hydrogen and captured CO_2 to decarbonise operations and products.

3. Recommendations

Three crucial areas to increase the likelihood of success for a potential business model such as the Hub and Cluster Model are recommended as follows:

Regional supports including governments and international organisations:

- Financial incentives: introduction of government subsidies, grants, tax incentives, overseas funds permissibility, and push towards green product premiums.
- Carbon pricing: carbon tax pricing to increase from $2/tonne to $50/tonne or above in the future.
- Policy expansion: inclusion of all relevant industries for CCS, legal liability regulatory associated with CO_2 sequestration and working Hub and Clusters Model.
- Roadmap: strategic roadmap with the inclusion of power plants with CCS as a key government initiative.

Technical implementation

- Storage feasibility: availability of proven studies for reliability and safety of CO_2 sequestration sites (depleted oil and gas reservoirs and/or saline aquifers).
- Technology advancement: successful technology applications at scale across the CCS value chain (capture – transport – storage).
- Capabilities readiness: workforce re/up-skilling of CCS research and development (R&D) and implementation across relevant sectors.

Partnership and Financing Ability

- Strategic partnerships: successful tie-up amongst developers, potential technical and financial partners

- Portfolio-based financing: CCS inclusion into broader risk assessment (e.g. bundling power plant projects with CCS), allowing for risk profiles to be assessed at a portfolio-level, hence, lower borrowing costs.
- Funding innovation: availability of 'energy transition' financial products to ensure acceptable risk and returns for investors and CCS players.

Chapter 7
Regional CCS Regulatory Overview in ASEAN

1. Overview

Since ASEAN countries such as Malaysia, Singapore, and Viet Nam are also expected to be future CCUS markets, the regulatory overviews are investigated.

2. Malaysia

2.1. Key Summary Notes of Malaysia Regulatory Overview

Malaysia has the largest CCS potential due to in-country emission sources, storage proximity, concrete government support, and implementation roadmap. Malaysia possesses Southeast Asia's second-largest storage capacity up to 3,000 Mt-CO_2 with ambitious carbon tax plan in the medium to long term. Even though the comprehensive regulatory framework is still in development, Malaysia shows the most significant stakeholder support with tax incentives and launch of voluntary carbon market, followed by Singapore, which aims to become Asia's carbon trading hub.

2.2. Regulatory Overview – Malaysia

Malaysia does not have a CCUS regulatory framework in place. However, the government has formulated its preliminary CCUS strategy and launched supportive policies and incentives. The Malaysian government aspires to build 80 mpta of storage capacity and develop multiple CCUS hubs by 2050. It has built strategic partnerships with global companies throughout the value chain and developed a CCUS roadmap strategy in 2023, accelerating its CCUS implementation.

With the regulatory framework being developed, the ongoing projects are regulated in accordance with the London Protocol and EU CCS Directive for transboundary transport and storage of CO_2. Besides, the government passed the Land Code Amendment bill in 2022 to issue licences for land and offshore sites in Sarawak. The bill enables the continental shelf within Sarawak state boundaries to store carbon.

To support industry to utilise CCUS, the CCUS tax incentive was introduced in 2023. It includes the following:

- Tax allowance of 100% for 10 years and exemption on import duty and sales tax for the equipment of CCS from 2023 to 2027

- Tax deduction for pre-commencement expenses within 5 years from the start of operations
- Tax exemption of 70% on statutory income for 10 years and a tax deduction for services fees incurred.

Malaysia's carbon pricing expectation is quite aggressive with expectations to impact mostly the power generation sectors. Although Malaysia does not charge carbon prices, the government will likely introduce hybrid carbon pricing policy with a mix of domestic emissions–trading schemes and carbon taxes. Based on the recommendation of the International Monetary Fund, Malaysia might impose a carbon tax rate of \$25/t-CO_2, which will gradually increase to \$30 by 2030. Bursa Malaysia, the Malaysian stock exchange, has launched a voluntary carbon market exchange enabling companies to purchase carbon credits.

3. Singapore

3.1. Key Summary Notes of Singapore Regulatory Overview

Singapore leans toward hard-to-abate industries decarbonisation and carbon export on the back of its established trading ecosystem and capabilities and geographical factors. Singapore does not state a sizeable storage capacity in its roadmap. However, Singapore has imposed a carbon tax across industries, with marginal scale to CCS-expected implementation cost. Comprehensive regulatory framework is still in development.

3.2. Regulatory Overview – Singapore

Singapore's CCUS regulatory framework is currently in the R&D stage, with no clear guidelines on carbon capture, transport, and storage. The government has started funding R&D projects and partnerships to accelerate CCUS.

Construction and chemical industries are the priority areas for the government. Twelve R&D projects on low-carbon energy technology solutions were awarded with \$41 million, including CO_2 utilisation for construction purposes and CO_2 capture technologies. The government also accelerates partnerships with Asian countries, such as Australia and Malaysia, to build end-to-end decarbonisation capabilities, especially on carbon capture and transport.

Singapore has implemented a carbon tax with further significant rise expected in the future. The carbon tax introduced in 2019 covers 80% of domestic emissions, including manufacturing, power, waste, and water sectors. In 2023, the carbon tax act was amended to

- provide transitory allowances to emissions-intensive industries,
- set up a carbon credits framework, and
- include nitrogen trifluoride starting in 2024.

Negative profitability is still expected for CCS in Singapore in the next ~5 years due to the gap between carbon price and CCS cost with current carbon tax rate of \$3.7/CO_2e, which is expected to be \$18.7 in 2024–2025, and \$37.5–\$60 in 2028. Overall, Singapore presents a local decarbonisation effort focus with carbon market trading hub as its future focus.

4. Viet Nam

4.1. Key Summary Notes of Viet Nam Regulatory Overview

Viet Nam is still in the nascent phase of developing CCUS and supporting carbon market regulations. Currently, a comprehensive regulatory framework is still being developed. Aspiring to put the regulatory framework related to carbon market in place and implement CCUS, the government passed a regulatory order and signed Just Energy Transition Partnership (JETP) in 2022. The government is improving the legal framework to attract funding and collaborating with international investors to accelerate CCUS development.

4.2. Regulatory Overview – Viet Nam

Viet Nam is currently in the R&D phase of establishing the CCUS regulatory framework under Environmental Protection Law 2020. The government passed a regulatory order in 2022, which set two phases for developing its carbon market, scheduled to undergo a pilot phase from 2025 to 2027, and become fully operational in 2028. In a pilot phase (Phase 1), Viet Nam will focus on developing regulations on carbon credit management, quote exchange activities and carbon credit trading floors. In Phase 2, Viet Nam will launch the carbon credit trading floor, facilitating the integration of domestic carbon market with the global market.

To realise net-zero emissions by 2050, the government positions CCUS as one of its key focus areas as well as transition from coal to natural gas. In May 2023, the government adopted its Power Development Plan 8 (PDP8) and laid out a comprehensive plan for CCUS expansion and attain a storage capacity of 1 MtCO_2 by 2040 with an eye towards achieving 3–6 MtCO_2 by 2050. The PDP8 mentions a total investment of \$135 billion for green growth funding.

The participation in the JETP, an agreement for energy transition with G7 countries, has also affected investment in CCUS. In December 2022, under the JETP, the Canadian government helped in raising $15.5 billion to accelerate the development and application of CCUS.

Overall, Viet Nam is still in the early development phase for CCUS and carbon market implementation. The government needs to establish a regulatory framework for CCUS and develop a carbon trading system achieve its net-zero emission target by 2050.

Chapter 8

Conclusion and Recommendations

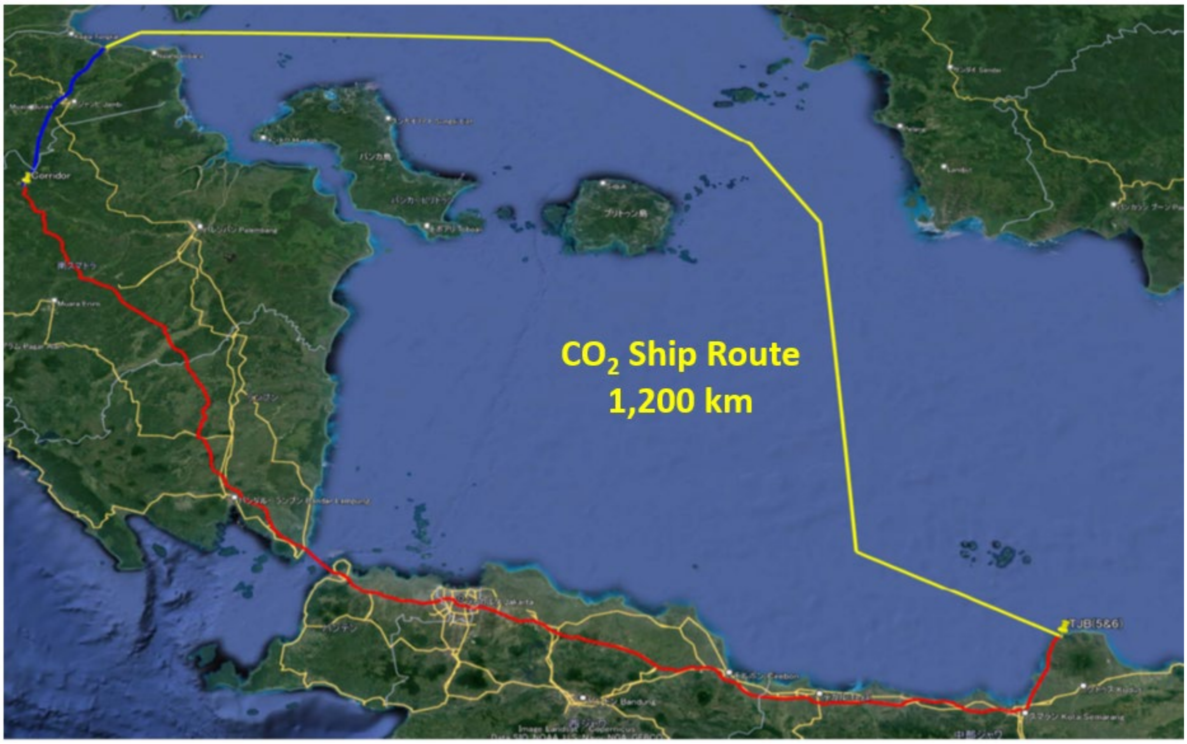
1. Conclusion

Conducted at the start of this study is a market research on the overview of global CCS market (Chapter 1), the Indonesian CCS market (Chapter 2), and the legal framework of Indonesia's CCS market including its regulatory and policy overview (Chapter 3).

Technical and commercial studies on CCS value chain in Indonesia were conducted, detailed in Chapters 4 and 5, respectively. These studies analysed and evaluated the whole value chain of a full-scale CCS solution from the existing coal-fired power plant – TJB 5&6, 2 x 1,000 MW ultra-super critical coal-fired power plant in Central Java – to Corridor PSC in South Sumatra.

Chapter 4 studied two cases of CO_2 transport : Case A for ocean transport in yellow and blue below and Case B for pipeline transport in red (Figure 8.1).

Figure 8.1. CO_2 Ship Route



Source: Authors based on Google Earth.

The technical specifications and conditions are summarised as follows.

Table 8.1. Technical Specifications and Conditions

Category	Unit	Case A Ocean Transport		Case B Pipeline Transport	
CO_2 amount	Mt-CO_2/year	6.5 Mt/y	13.0 Mt/y	6.5 Mt/y	13.0 Mt/y
Generation Capacity	MW	1,000	2 x 1,000	1,000	2 x 1,000
Type of Power Plant		USC Coal-fired Power Plant			
Capacity Factor		86%			
Capture Rate		95%			
Project Lifespan	Years	25			
Total CO_2 Amount	Mt-CO_2	162.5	325	162.5	325
Ship	Ships x tonnes	6 x 28,000	7 x 48,000	-	-
Pipeline	From to	Receiving Port in Sumatra to Corridor		TJB to Corridor	
Pipeline	inch	24	34	28	38
	km	183	183	1,148	1,148
Injection Well	Number	9	17	9	17
	Depth (m)	2,000	2,000	2,000	2,000

Source: Authors (2023).

Similarly, in Chapter 5, two options of CO_2 transport were studied. Table 8.2 summarises the cost estimation outcome.

Table 8.2. Summary of Cost Estimation (Case A)

Unit : $ million

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year
CAPEX	Capture	940.5	1706.7
	Liquefaction/Tanks/Loading	745.5	1,265.5
	Transportation	1,338.0	1,921.0
	Storage	470.4	843.6
Subtotal		3,494.4	5,736.8
OPEX	Capture	4,560.8	8,219.7
	Liquefaction/Tanks/Loading	1,298.2	2,327.2
	Transportation	2,318.6	3,770.8
	Storage	352.8	632.7
Subtotal		8,530.3	14,950.4
Total CAPEX and OPEX		12,024.7	20,687.2

Source: Authors (2023).

Table 8.3. Summary of Cost Estimation (Case B)

Unit : $ million

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year
CAPEX	Capture	940.5	1706.7
	Compression/Dehydration	604.6	1,209.3
	Transportation	4,118.3	5,194.1
	Storage	470.4	843.6
Subtotal		6,133.8	8,953.6
OPEX	Capture	4,560.8	8,219.7
	Compression/Dehydration	906.9	1,813.9
	Transportation	3,096.1	3,905.6
	Storage	352.8	632.7
Subtotal		8,916.6	14,571.9
Total CAPEX and OPEX		15,050.4	23,525.5

Source: Authors (2023).

Table 8.4. Unit Cost (Case A)

Unit : $/t-$CO_2$

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year	2022 ERIA *1
Unit Cost	Capture	33.9	30.5	45.9
	Liquefaction/Tanks/Loading	12.6	11.1	-
	Transportation	22.5	17.5	0.95
	Storage	5.1	4.5	15.9
Total Unit Cost		74.0	63.7	62.8

Source: Authors (2023).

Table 8.5. Unit Cost (Case B)

Unit : $/t-$CO_2$

Category		1 Unit 6.5 M tonnes/year	2 Units 13.0 M tonnes/year	2022 ERIA *1
Unit Cost	Capture	33.9	30.5	45.9
	Compression/Dehydration	9.3	9.3	-
	Transportation	44.4	28.0	0.95
	Storage	5.1	4.5	15.9
Total Unit Cost		92.6	72.4	62.8

Source: Authors (2023).

In addition, the levelized cost per kWh at TJB 5&6 was estimated to evaluate the impact if such CCS solution is applied, which is expected to be recovered by additional electricity tariff as a cost pass-through basis in principle.

Table 8.6. Unit Cost per kWh for Cases A and B

Case A (Ocean Transport)

Category		Unit	1 Unit 6.5 M tonnes	2 Units 13 M tonnes
Unit Cost	Capture	US$ cent/kWh	3.45	3.12
	Liquefaction/Tank	US$ cent/kWh	1.62	1.40
	Transport	US$ cent/kWh	2.90	2.19
	Storage	US$ cent/kWh	0.80	0.71
Total Unit Cost		US$ cent/kWh	8.77	7.42

Table 8.6. *Continued*

Case B (Pipeline Transport)

Category		Unit	1 Unit 6.5 M tonnes	2 Units 13 M tonnes
Unit Cost	Capture	US$ cent/kWh	3.45	3.12
	Compression/Dehydration	US$ cent/kWh	1.24	1.24
	Transport	US$ cent/kWh	6.97	4.40
	Storage	US$ cent/kWh	0.80	0.71
Total Unit Cost		**Cent US$/kWh**	US$ cent/kWh	**9.47**

Source: Authors (2023).

Throughout the technical and commercial studies in Chapters 4 and 5, various hurdles have been revealed, which need to be settled from now on to apply the CCS solution for decarbonising thermal power plants, requiring big challenges in every aspect. Additionally, Chapter 6 suggests a considerable approach to potential business creation like hub and cluster opportunities, which needs to be investigated further. Chapter 7 on legal framework also reviews other countries.

2. Recommendations

According to the CCS feasibility study on capturing CO_2 at TJB 5&6 in central Java, the costs of transporting CO_2 by ship or pipeline and storing it in the Corridor gas field in South Sumatra are estimated at $63.7/$CO_2$-tonne and $72.4 per CO_2-tonne by pipeline. Also, CO_2 storage in the depleted field is better than saline aquifers due to its cost competitiveness, utilisation of existing facilities, development timeline, etc. CCS definitely contributes to reducing emissions at around 13 million tonnes of CO_2 per year, but its cost is an issue. The cost is expected to decrease in the future due to technology development and the scaling up of the CCS business. However, at the initial stage, public finance will be important in implementing CCS pilot projects in the Asian region. In parallel, carbon pricing mechanism will be studied and promoted in the region. Incentives supporting CCS is also expected much. In addition, a legal and regulation framework will be indispensable in the region. Technical studies on two cases of CO_2 transport – liquefied CO_2 vessel and CO_2 pipeline – were conducted and revealed growing concerns on such feasibility because of the long distance and the operation throughout the value chain. However, this resulted in a positive outcome: CO_2 transportation by liquefied CO_2 vessel would be preferable in case of long distance (more than 1,000 km) with a large-scale CO_2 volume (more than 10 million tonnes of CO_2

per year). CO_2 capturing of such a large volume amounting to around 10 million CO_2-tonnes per year is also an epoch-making challenge due to the lack of a track record so far in the world. Such large amount would hopefully lower the CO_2 capturing unit cost. However, it would cause other hurdles not only in the affordability of CAPEX and OPEX but also in technical aspects, such as plant construction and utilities for plant operation. One of the biggest concerns is how such cost could be considered and managed by power plants for decarbonisation purposes. They would rather be expected to be passed through to the electricity tariff accordingly, which might cause social problems due to inflations, etc. To tackle such negative impact while achieving decarbonisation in parallel, many kinds of support are surely required in the long term, especially from the financial aspect. Energy transition finance would be supportive enough as an example, if available domestically, regionally, and internationally. Other considerable measures would be (i) further technology development and cost reduction, (ii) scale-up of economic CCS business, (iii) acceptance of CO_2 from the operating business in Indonesia, and (iv) formulation of the carbon price market, incentives from international institutes such as Asia Energy Transition Initiative, and carbon trade as credit.

CCS/CCUS is expected to play a key role as one of the large-scale decarbonisation solutions although it will take more time for project. At the same time, there are other solutions such as ammonia and hydrogen-cofiring to achieve low CO_2 emissions in thermal power plants. Those also need to be evaluated and pursued in parallel with many kinds of challenges such as cost and procurement issues, amongst others. Those would require long steps to commercialise the thermal power market and therefore need to be further investigated as the next steps. Sustainable power generation with decarbonisation solutions must be the promising key in the long term. A regional supporting framework to realise carbon neutrality societies is urgently expected in this regard.

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