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Accelerating Commercial Hydrogen and Carbon Capture and Storage Projects in Indonesia:

Building an Enabling Ecosystem

Economic Research Institute for ASEAN and East Asia

Accelerating Commercial Hydrogen and Carbon Capture and Storage Projects in Indonesia: Building and Enabling Ecosystem

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List of Abbreviations

ACCU	Australian Carbon Credit Unit
B2B	business-to-business
BECCS	bioenergy with carbon capture and storage
BEV	battery electric vehicle
BPS	*Badan Pusat Statistik* (Central Statistics Agency)
CAPEX	capital expenditure
CBAM	Carbon Border Adjustment Mechanism
CCS	carbon capture and storage
CCUS	carbon capture, utilisation, and storage
CDR	carbon dioxide removal
CO_2	carbon dioxide
EGR	enhanced gas recovery
EOR	enhanced oil recovery
ETS	emission trading scheme
EU	European Union
FCEV	fuel cell electric vehicle
FID	final investment decision
G2G	government-to-government
HRS	hydrogen refuelling station
IEA	International Energy Agency
IMO	International Maritime Organization
JCM	Joint Crediting Mechanism
KBLI	*Klasifikasi Baku Lapangan Usaha Indonesia* (Indonesian Standard Industrial Classification)
KEN	*Kebijakan Energi Nasional* (National Energy Policy)
kg	kilogram
ktpa	kilotonne per annum
LOHC	liquid organic hydrogen carrier
$MtCO_2$	million tonnes of carbon dioxide

MW	megawatt
NDC	nationally determined contribution
RUPTL	*Rencana Usaha Penyediaan Tenaga Listrik* (Electricity Supply Business Plan)
SIGHT	Strategic Interventions for Green Hydrogen Transition
SMR	steam methane reforming
SRN PPI	*Sistem Registri Nasional Pengendalian Perubahan Iklim* (National Registry System for Climate Change Control)
SRUK	*Sistem Registri Unit Karbon* (Carbon Unit Registry System)
tCO_2e	tonne of carbon dioxide equivalent
TOE	tonne of oil equivalent
US	United States

Executive Summary

Globally, the hydrogen and carbon capture and storage (CCS) sectors face a complex reality. Despite significant enthusiasm, commercial deployment of associated projects remains limited. Most operational hydrogen projects are small-scale, while CCS initiatives are largely confined to enhanced oil recovery (EOR).

Indonesia's experience reflects this global trend; the country possesses vast renewable energy potential and significant geological carbon dioxide (CO_2) storage capacity, yet initiatives remain largely within the feasibility study or memorandum of understanding stage. The primary barrier is not technical but rather the structural commercial hurdles facing the sector. Market forces alone cannot bridge the gap between high project costs and market willingness-to-pay. Unlocking this potential requires a supportive ecosystem built on a pragmatic, state-driven industrial strategy.

Commercialising hydrogen is also challenging due to the fundamental price disparity. Clean hydrogen costs US$4–8 per kilogram (kg), much higher than subsidised fossil alternatives like natural gas or diesel fuel (US$1/kg and US$3/kg, respectively). This is creating a cycle in which infrastructure investors delay building without demand, while industries defer switching without an affordable supply. Global experience confirms that active governmental intervention is required to close this gap.

This study proposes a pragmatic, phased timeline to commercialise hydrogen and CCS projects in Indonesia. In the short term, the focus should be on niche opportunities like industrial captive use and de-dieselisation in remote areas. In the mid-term, Indonesia can leverage global policy shifts, such as the European Union's Carbon Border Adjustment Mechanism (CBAM) and International Maritime Organization (IMO) shipping standards, to export green ammonia and methanol. This approach would utilise existing brownfield refinery and port infrastructure to minimise capital expenditure. Finally, the long-term decarbonisation of domestic heavy industries, such as fertiliser and steel, should proceed once technology costs fall and subsidy reforms occur.

As noted, governmental fiscal support is essential to enable this transition, but this requires strong economic justification beyond emission reduction – the narrative must shift towards national security. Hydrogen enables the next phase of industrial downstreaming (*hilirisasi*), transforming raw exports into high-value green products. Additionally, as domestic gas production declines, hydrogen will act as a strategic hedge to protect the fertiliser industry and national food security from liquefied natural gas import volatility. Considering the uncertainties surrounding the future of hydrogen, it is imperative that Indonesia adopt a 'no-regret' strategy.

Like hydrogen, CCS projects face financial bottlenecks. Only limited business models, such as EOR and enhanced gas recovery (EGR), have reached commercial scale; these models are supported by established regulations and clear revenue streams through additional hydrocarbon recovery. Expanding CCS beyond EOR and EGR transforms the business model into a cost centre. The total cost of CCS projects is estimated to range from US$23 to US$249 per tonne of CO_2 and varies widely depending on the emission source (capture cost), transport costs, and storage costs. Therefore, monetisation pathways to claim climate benefits from CCS operation must be available, such as the sale of carbon credits or a green premium product.

While the domestic carbon price is low, the mid-term strategy must therefore focus on CCS project models that generate revenue from overseas, which tend to have more stringent climate policies. This includes developing cross-border hubs that import CO_2 to generate storage service fees, producing blue ammonia for export, and monetising high-value CO_2 reduction markets such as bioenergy with CCS (BECCS). Long-term domestic industrial CCS will likely remain challenging until a domestic carbon-pricing mechanism is established and reaches a sufficiently high price.

Unlocking the potential of the hydrogen and CCS sectors in Indonesia requires a unified national agenda. First, the government should elevate hydrogen and CCS to the status of strategic investments essential for future-proofing Indonesia's economy. This consensus is vital to justify the necessary fiscal allocation. For example, hydrogen can be positioned as a future green export commodity, ensuring energy security. Meanwhile, Indonesia has potential as a regional CCS hub and may increase oil and gas lifting from EOR/EGR businesses.

Financial ecosystems must also be strengthened. For hydrogen, this involves designing tailored governmental support schemes and aligning the sector with national industrial priorities. For CCS, the government should facilitate carbon credit exports and design de-risking facilities to address long-term liability, thereby improving investor appetite. Finally, policymakers should continue building a 'no-regret' ecosystem, which includes refining regulatory frameworks, enhancing institutional co-ordination, and strengthening bilateral cooperation.

Chapter 1

Introduction

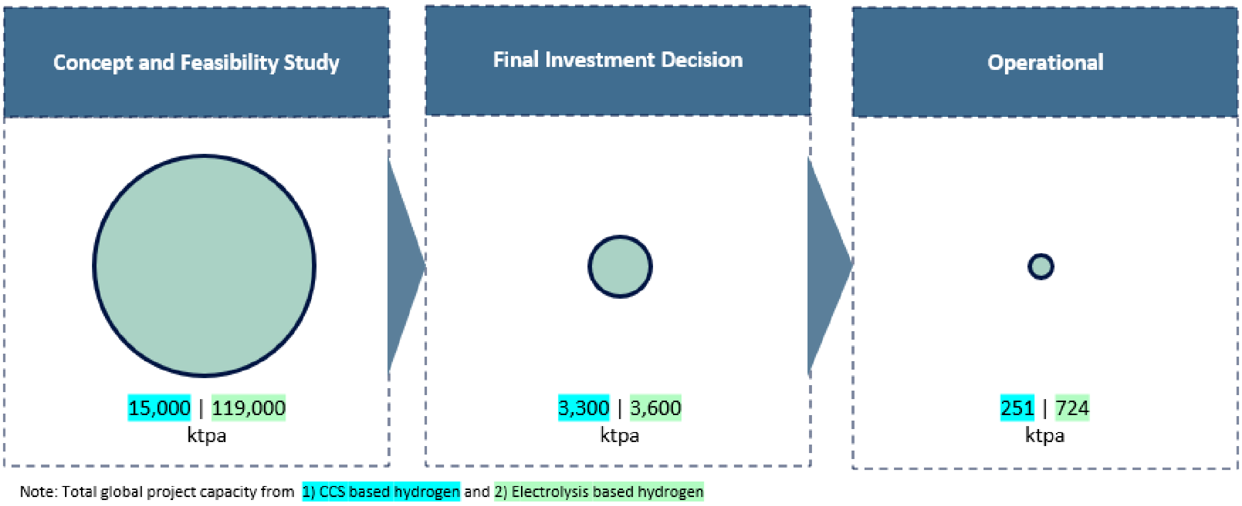
1. Gap between the Ambition and Commercial Reality of Hydrogen

1.1. Global Trends of Hydrogen Projects

Global momentum has positioned hydrogen as a future clean fuel and a key complement to renewable energy, which then accelerated the launch of large-scale hydrogen project announcements between 2021 and 2023. In 2024, global hydrogen demand reached nearly 100 million tonnes and is expected to exceed this in 2025, although most gigawatt-scale proposals remain far from commercial realisation (IEA, 2025b).

As indicated in Figure 0.1, since 2023, the sector has entered a more cautious phase, with multiple high-profile cancelled projects, including blue and green hydrogen projects in Australia, Europe, and the United States (US). According to the International Energy Agency, these delays and downward revisions have led to renewed questions about whether the hydrogen industry is entering another hype cycle, as only a small fraction of announced projects have reached final investment decision (FID) or operational status. Projects that do materialise tend to be modest in scale, often limited to pilot or demonstration phases.

Figure 0.1. Statistics of Global Hydrogen Projects
(kilotonnes per annum)



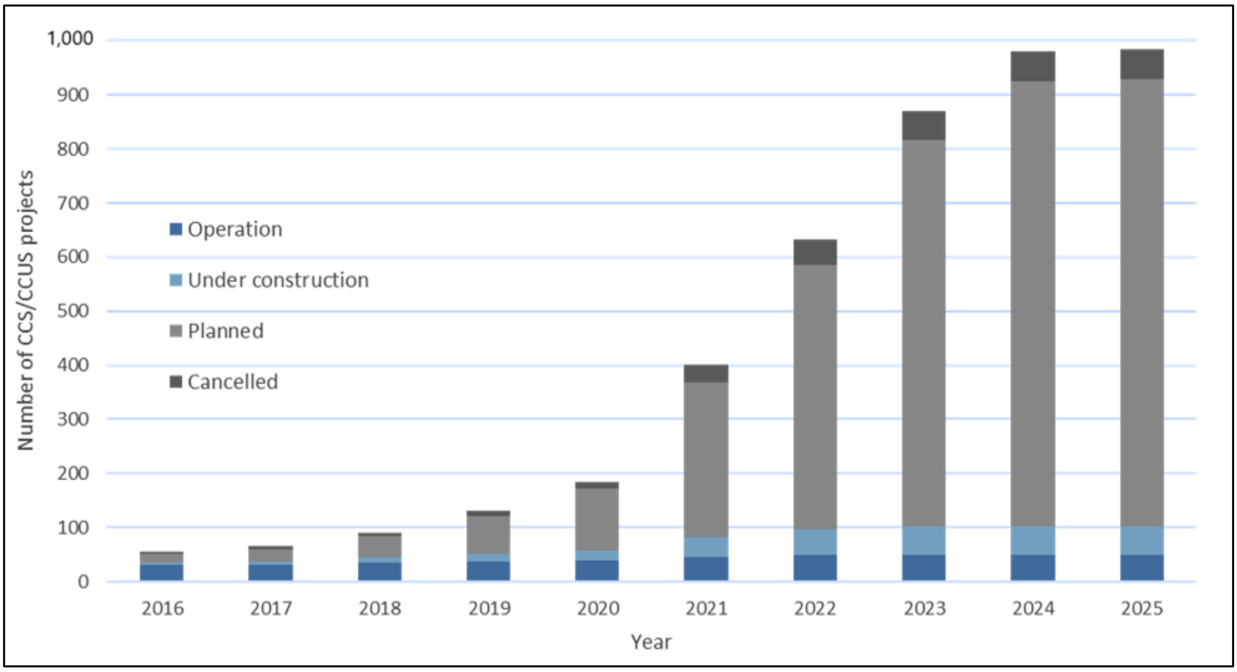
CCS = carbon capture and storage.
Source: IEA (2025b).

1.2. Global Trends of Carbon Capture and Storage and Carbon Capture, Utilisation, and Storage Projects

Carbon capture and storage (CCS) technology itself is not new; the Sleipner project in Norway, for example, has been injecting carbon dioxide (CO_2) into geological formations since 1996 (Skalmeraas, 2017). Interest in CCS accelerated after the Paris Agreement, particularly amongst oil and gas companies, which began exploring CCS as part of their decarbonisation strategies. Significant development of carbon capture, utilisation, and storage (CCUS) has also occurred in the US, where deployment increased notably after the introduction of the Section 45Q tax credit.[1]

Despite increasing project announcements globally, the number of CCS/CCUS projects in operation remains low (Figure 0.). Deployment progress has also been slow, with several major CCS projects recently cancelled or paused. Many projects – notably by major companies such as BP and Exxon – were cancelled due to economic feasibility concerns, safety issues, local opposition, and regulatory requirements (Green, 2025; Clark, 2025).

Figure 0.2. Global CCS/CCUS Projects



CCS = carbon capture and storage; CCUS = carbon capture, utilisation, and storage.
Source: Authors' calculations based on IEA (2026).

While flagship initiatives – such as the Northern Lights[2] project in Norway – have been operational since 2024, commercial cases outside of enhanced oil recovery (EOR) remain limited. Several operational projects have struggled to meet expectations; for instance,

[1] Officially established in 2008, enhanced in 2018, and expanded in the 2022 Inflation Reduction Act (Braun, 2025). It provides financial incentives for CO_2 storage, especially through enhanced oil recovery (EOR).

[2] Concept study in 2015, FID in 2020, drilling for injection well in 2022, operation of Phase 1 in 2024.

Australia's Gorgon CCS project has faced long-term underperformance relative to its targets, mainly due to reservoir pressure limitations that have restricted CO_2 injection rates (Robertson and Mousavian, 2022; Denis-Ryan and Morrison, 2024). These setbacks underscore the persistent uncertainty surrounding the commercial viability of CCS projects and highlights why – despite increasing interest and announcements – tangible progress towards large-scale project implementation remains limited.

1.3. Development of Projects in Indonesia

Indonesia is aiming to reduce greenhouse gas emissions by 31.89% unconditionally by 2030 and to reach net-zero emissions by 2060, as stated in its nationally determined contribution (NDC). Building on these national climate change goals, Government Regulation No. 40 of 2025 expands 'new energy' to include hydrogen, ammonia, and nuclear. It prioritises hydrogen and ammonia produced from renewable sources and permits continued use of non-renewable energy sources only where necessary. In parallel, the *National Hydrogen and Ammonia Roadmap* outlines the government's ambition to scale up clean hydrogen production after 2030 (ESDM, 2025a).

Over the few past years, many initiatives have taken the forms of memoranda of understanding, consortium announcements, feasibility studies, and pilot demonstrations. The government targeted 15 CCS/CCUS projects to be onstream by 2030 (ESDM, 2024a). Indeed, the *National Hydrogen and Ammonia Roadmap* lists 215 activities related to hydrogen, including studies and pilot projects involving collaboration between local and international organisations and private companies (ESDM, 2025a). Yet despite these announcements, only a small number of hydrogen and CCS projects in Indonesia have progressed beyond the feasibility or demonstration stage. This leads to two fundamental questions:

(i) Why are projects not moving forward, despite available resources and growing initiatives by the private sector?

(ii) What kind of ecosystem must be built to enable their commercialisation?

This document thus analyses the enabling ecosystem for hydrogen and CCS projects in Indonesia. By evaluating ongoing projects, it seeks to identify critical financial, regulatory, infrastructure, operational, and institutional dimensions necessary to accelerate deployment. It operates on the hypothesis that Indonesia's primary challenges are less about technological or resource limitations; instead, commercial scaling is stalled due to the absence of a robust, integrated ecosystem. Strengthening this framework is essential to move projects from the pilot phase to commercial viability.

2. Methodology

To understand why projects stall and what conditions are needed for commercialisation, this study applies a bifocal approach, four ecosystem layers, and overseas benchmarks.

The bifocal approach integrates business-to-business (B2B) and government-to-government (G2G) perspectives in hydrogen and CCS project commercialisation. The B2B element focusses on the needs of investors, manufacturers, and service partners and viable business models, risks, and commercial structures of the project development. The G2G element examines meaningful engagement from governmental stakeholders to address regulatory, institutional, and financial bottlenecks that hinder project implementation. Together, these two lenses create a continuous feedback loop that connects private sector realities with policy improvement, resulting in more effective guidelines and a stronger enabling environment for project deployment.

Indonesia's hydrogen and CCS project readiness is also assessed across four ecosystem layers:

(i) Regulatory layer. Covers the policies, technical standards, safety requirements, roadmaps, and market incentives that provide clarity and certainty for project developers.

(ii) Financial layer. Includes the mechanisms that determine project bankability, including approaches to risk allocation, options to monetise carbon reduction, and availability of financing or funding schemes.

(iii) Infrastructure and operational layer. Examines the readiness of CO_2 and hydrogen value-chain infrastructure, including transport; storage; operation and management capabilities; and measurement, reporting, and verification.

(iv) Institutional layer. Reflects the roles and co-ordination of organisations involved in project development, including contracting arrangements, off-taker readiness, and the presence of competent regulatory bodies.

While domestic initiatives face significant hurdles, successful commercial projects exist globally. This study thus analyses these international benchmarks to identify the specific factors driving their success, which will be critical lessons for potential adoption within the Indonesian hydrogen and CCS ecosystem.

Data for this study were collected through desk research, interviews with market players, and discussions with governmental stakeholders.

3. Scope and Applicability

This study focusses on the commercialisation pathways for hydrogen and CCS projects within Indonesia's current and planned energy transition. The analysis is grounded in the current landscape of projects, policies, and institutional capabilities in Indonesia. It aims to help projects commercialise by identifying project bottlenecks and providing recommendations for ecosystem development. The recommendations are designed to strengthen Indonesia's policy and ecosystem readiness. Some findings are closely tied to Indonesia's local context, particularly those related to regulatory design and institutional arrangements. However, many of the ecosystem requirements identified are also relevant across South-east Asia.

Chapter 2
Hydrogen Ecosystem Analysis

1. Hydrogen Value-chain Mapping

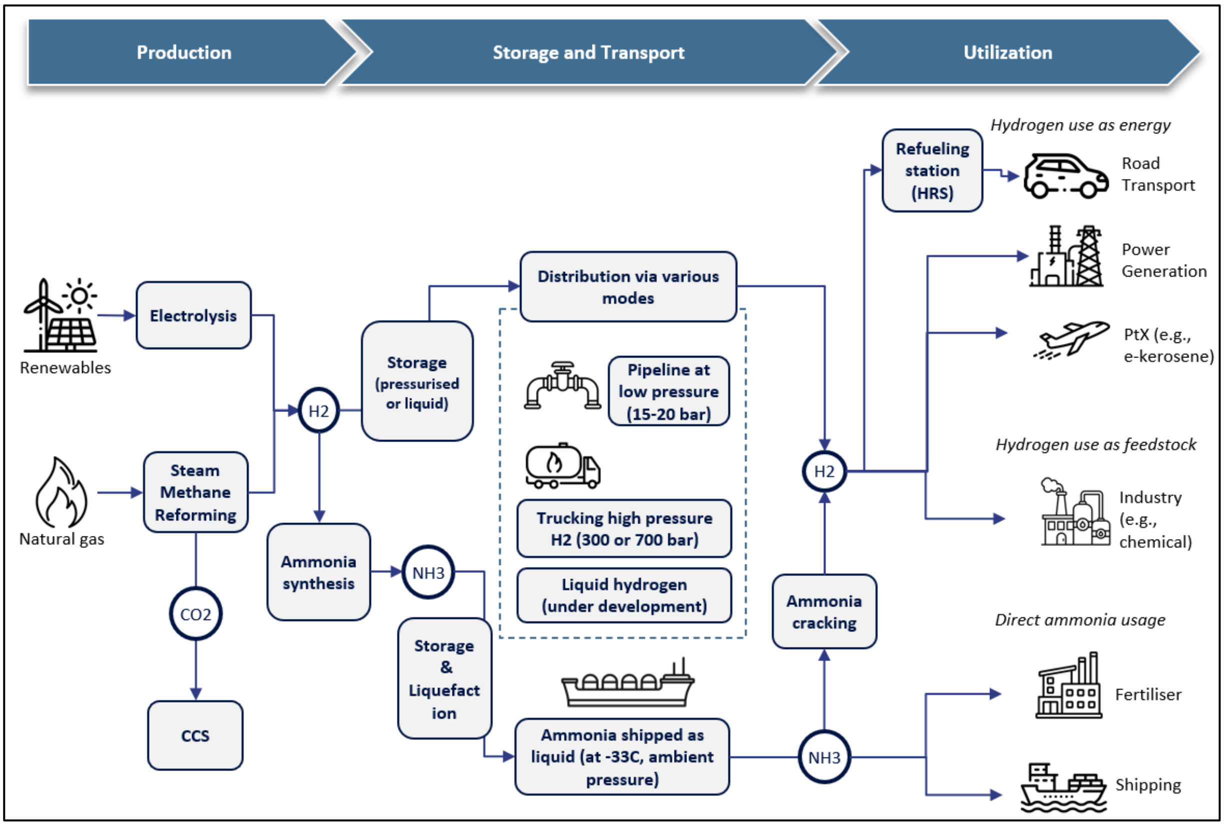
As illustrated in Figure 2., an end-to-end hydrogen ecosystem encompasses three key segments: production, transport and storage, and utilisation.

(i) **Production.** Hydrogen can be generated through various pathways. The primary method includes steam methane reforming (SMR), typically using natural gas or electrolysis, which uses electricity to split water. SMR produces grey hydrogen – or blue hydrogen when combined with CCS – while electrolysis produces green hydrogen when powered by renewable energy.

(ii) **Transport and storage.** Once produced, hydrogen must be transported. Common methods involve carrier technologies such as compressed gas, liquefied hydrogen, ammonia, or liquid organic hydrogen carriers (LOHC).

(iii) **Utilisation.** Finally, hydrogen is used as an energy carrier or feedstock in end-use sectors, including heavy industry, transport, and electricity generation.

Figure 2.1. Hydrogen Value Chain



CCS = carbon capture and storage, H_2 = hydrogen, NH_3 = ammonia.
Source: Authors.

Indonesia's low-carbon hydrogen value chain is in a nascent stage. Currently, the only segment operating at a commercial scale is the captive[3] production of grey hydrogen. This hydrogen, produced via SMR, is generated on site for immediate consumption as feedstock in industrial processes, primarily for fertiliser (ammonia) production and petroleum refining.[4]

Several companies are actively developing pilot and demonstration projects to establish a low-carbon hydrogen value chain in Indonesia (

Table). State-owned enterprises PT PLN and PT Pertamina, along with private sector companies like Toyota, are leading these efforts. As dedicated hydrogen transport infrastructure is not yet available, these demonstration projects currently rely on conventional trucking of compressed hydrogen gas for delivery.

Table 2.1. Hydrogen Projects along the Value Chain

Company	Project Description	Related Value Chain Segment
PLN	PLN has commissioned 22 green hydrogen plants across Indonesia, including a facility at the Kamojang Geothermal power plant.	Production via electrolysis
Pertamina	Pertamina Geothermal Energy held a groundbreaking ceremony for a green hydrogen pilot plant in the Ulubelu geothermal area.	Production via electrolysis
PLN	PLN is testing hydrogen co-firing in gas power plants (e.g. Pesanggrahan), ammonia co-firing in coal-fired power plants (e.g. Labuhan), and the use of hydrogen fuel cells in remote areas (e.g. Gili Ketapang).	Utilisation in electricity sector
PLN	PLN launched Indonesia's first hydrogen-refuelling station in Senayan, Jakarta.	Utilisation in transport sector
Pertamina	Pertamina held a groundbreaking ceremony for a hydrogen-refuelling station in Daan Mogot, Jakarta.	Utilisation in transport sector

[3] The majority of current hydrogen demand is for refineries and ammonia production. In these large plants, hydrogen is generated on site for internal use (i.e. captive). There is also minor demand from other industries, such as food, semiconductors, pharmaceutical manufacturing, and laboratories, which obtain the hydrogen produced by gas companies via tube trailer trucking.

[4] ASEAN's hydrogen consumption totalled 3.7 million metric tonnes in 2020 and is projected to reach 4.4 million metric tonnes by 2025. Current usage remains exclusively within the industrial sector as feedstock. The ammonia industry accounts for nearly 50% of this demand, followed by oil refining (30%), methanol production (12–14%), chemicals (3%), and steel production (1%) (Kimura et al., 2025).

Company	Project Description	Related Value Chain Segment
Toyota	Toyota established a hydrogen-refuelling station in Karawang, West Java.	Utilisation in transport sector

Note: Projects listed are limited to those under construction or in the operation phase; there are several studies occurring by other companies. Pupuk Indonesia is developing green and blue ammonia projects across its subsidiaries (e.g. Pupuk Iskandar Muda, Pupuk Kaltim, Petrokima Gresik). Panca Amara Utama plans to convert an existing plant into blue ammonia with CCS, injecting into the Donggi Senoro gas field. Krakatau Steel is conducting a study to build a blue/green hydrogen plant to support the decarbonisation of its steel production.
Sources: ESDM (2024a), PLN (2023), PGE (2025).

Indonesia possesses significant resources for large-scale hydrogen production. The country has vast, untapped renewable energy potential, which is crucial for green hydrogen produced via electrolysis. Furthermore, Indonesia holds substantial natural gas reserves and geological formations suitable for CCS. This combination creates an opportunity for blue hydrogen production from SMR with CCS. Indeed, Indonesia's green hydrogen production potential could reach 3,794 kilotonnes per annum (ktpa) by 2040 (Kimura et al., 2025).

2. Hydrogen Business Models

Clean hydrogen business models are determined by the specific segment of the value chain that a project addresses. Table 2.2 provides examples of business models.

Table 2.2. Hydrogen Business Models

Model	Description	Revenue Source
Self-consumption	An entity (e.g. mine, logistics depot, or remote island) installs its own renewable generation and electrolyser on site to produce hydrogen for its own use.	Operating expense savings. Avoiding the high cost of importing diesel or purchasing expensive grid power
Hydrogen gas utility	A large-scale infrastructure player produces or aggregates hydrogen centrally and distributes it via a pipeline network to a cluster of industrial offtakers (e.g. power plants, factories) within a zone.	Metered utility bill. Long-term contracts based on volume sales plus a fixed connection fee
Commodity trade	A global or regional player buys hydrogen/ammonia in bulk from low-cost producers (e.g. Australia) and sells it to high-demand markets on the spot market or via short-term	Arbitrage margin. The price difference (i.e. spread) between the buying price and the selling price, minus logistics costs

Model	Description	Revenue Source
	contracts, optimising supply and demand mismatches.	
Transport operator	A specialised logistics company owns the transport infrastructure (i.e. pipelines, ships, tube trailers). It generally does not own the hydrogen that its transports; it simply provides the service of moving it for others.	Tolling fees. A contracted fee based on capacity booking, regardless of commodity price fluctuations.
Retailer station	An operator of HRS networks sells hydrogen directly to end-users (e.g. trucks, cars, buses) alongside conventional fuels. This model focusses on location convenience and speed of service.	Fuel margin. The markup on every kilogram of hydrogen sold at the pump (i.e. retail price minus wholesale cost)
Power generation	A power company uses hydrogen to fuel gas turbines or cells to generate electricity back to the grid. In remote areas, a combination of solar PV–battery–hydrogen systems can power an off-grid system.	Electricity sales. Payments from the grid operator; selling electricity at very high prices during peak hours
Green products	A manufacturer (e.g. of steel, fertiliser, chemicals) integrates hydrogen production into its processes to replace fossil fuel feedstock (i.e. coal or gas). It does not sell the hydrogen; it uses it to create a decarbonised final product.	Green premium. Selling the final product (e.g. green steel, green ammonia) at a higher price than the conventional alternative Carbon tax savings. Avoiding penalties (e.g. CBAM) that would apply to high-carbon competitors.

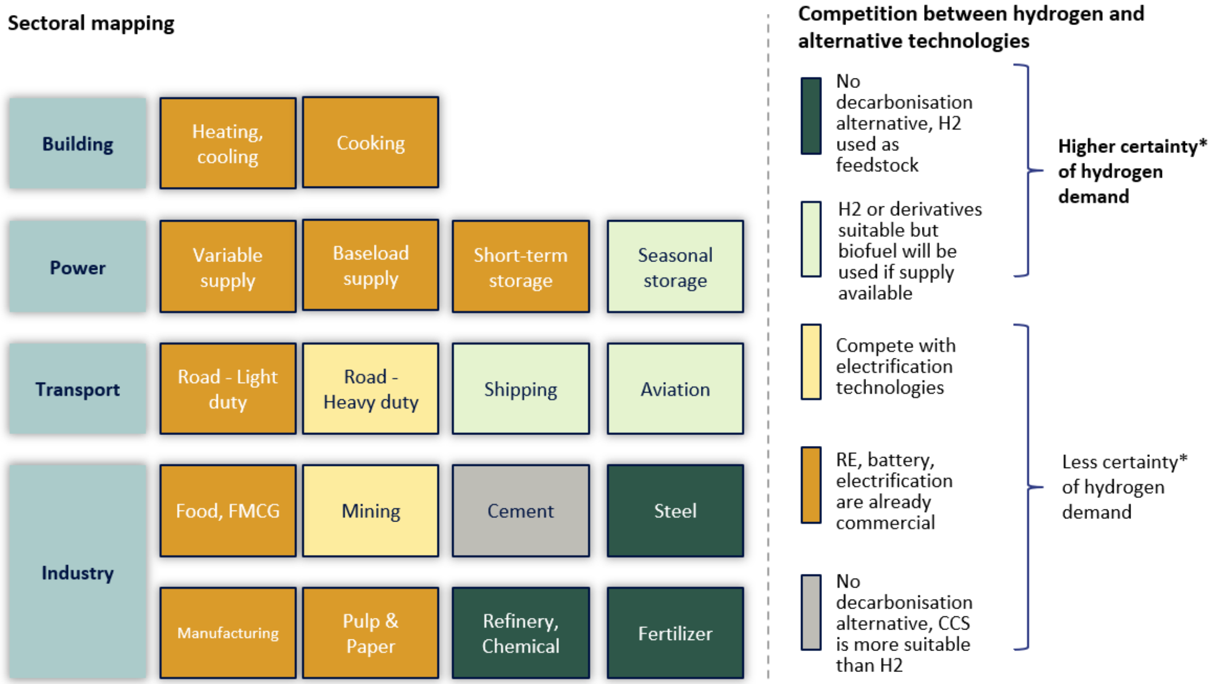
CBAM = Carbon Border Adjustment Mechanism, HRS = hydrogen refuelling station, PV = photovoltaic.
Notes:
1. Business model variations will also depend on regulatory frameworks.
2. For more information on green steel, see Gestamp (2025).
Source: Authors.

3. Sector Competition and Market Feasibility

While hydrogen is, theoretically, a versatile energy carrier with diverse applications, its strategic deployment must be assessed based on commercial viability and its effectiveness in achieving decarbonisation. Prioritising hydrogen uses in sectors where it offers the clearest competitive advantage over alternative – and often more mature – decarbonisation technologies is essential to establish market certainty. The sectoral mapping of hydrogen competitiveness is in

Figure , while hydrogen technology readiness is presented in the appendix.

Figure 2.2. Sectoral Mapping of Hydrogen Competitiveness



CCS = carbon capture and storage, FMCG = fast-moving consumer good, H_2 = hydrogen, RE = renewable energy.

*There is a nuanced difference between the certainty of demand and short-term feasibility. For example, certain demand from fertiliser may take a while to materialise due to the nature of the sector, which subsidises its products for farmers. However, it can be very well viable in the short term if a premium market (e.g. exported clean fertiliser) arises.

Sources: Agora Industry, ICCT, RAP (2025); Energy Transitions Commission (2021), Purwanto and Rusli (2024).

3.1. Residential Sector

The use of hydrogen for domestic applications, such as building heating and cooking, is technically feasible as a replacement for natural gas. However, direct electrification via technologies like high-efficiency heat pumps and electric cooking stoves presents a more energy-efficient and commercially viable pathway for decarbonising this sector.

3.2. Electricity Generation

The demand for hydrogen in power generation, through hydrogen-firing turbines or ammonia-firing boilers, depends on regional renewable energy resource availability. Regions with sufficient, stable renewable energy sources (e.g. hydro, geothermal, and biomass) may have a limited need for hydrogen to meet baseload power demands.

While battery energy storage systems are continuously improving to balance variable renewable energy sources like solar and wind, hydrogen may play a critical role in providing seasonal or long-term storage. This application is particularly relevant for regions facing several windless and cloudy days during winter,[5] while large-scale alternatives, such as pumped hydropower storage, are geographically limited.

3.3. Transport Sector

The transport sector presents varied opportunities and competitive[6] dynamics:

(i) Light-duty road transport. Battery electric vehicles (BEV) currently dominate the light-duty segment due to their superior energy efficiency, lower operating costs, and mature technology.

(ii) Heavy-duty road transport. This segment is characterised by strong competition (Figure 2.3). While current battery technology may limit the range and load capacity of heavy-duty trucks, continued advancements could significantly restrict the market for hydrogen fuel cell electric vehicles (FCEV) (Berglas et al., 2023). Furthermore, Indonesia's commitment to biofuels (e.g. B100) makes them an immediate alternative for decarbonisation in this sector.

(iii) Shipping and aviation. Due to the limited energy density of batteries, direct electrification is generally unsuitable for long-haul shipping and aviation. These sectors will continue to require liquid fuels. Hydrogen derivatives, such as ammonia, methanol,[7] and e-sustainable aviation fuel, are essential pathways for deep decarbonisation.

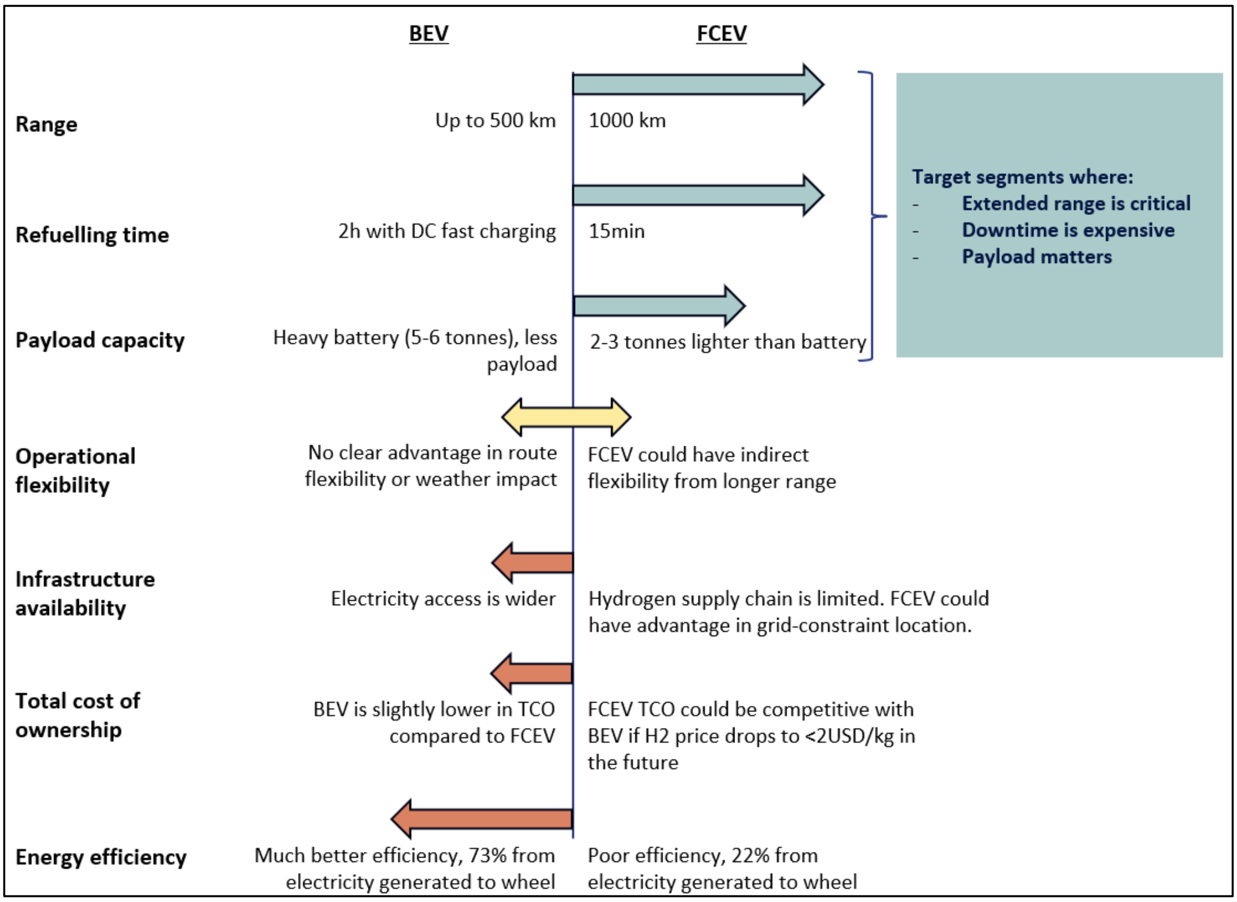
Biofuels, including biomethane and bio-derived sustainable aviation fuels, represent a near-term, commercially available decarbonisation option. However, their long-term scalability may be constrained by land-use limitations. Clean hydrogen, when combined with sustainable carbon sources (e.g. biomass and recycled plastics), will be necessary to complement the limited supply of these products.

[5] Known as *Dunkelflaute.*

[6] Assuming the use of clean hydrogen. Grey hydrogen has a lower cost but is not competitive compared to diesel fuel due to its expensive logistics cost. It has a higher cost than compressed natural gas, which is commonly used as an alternative to diesel fuel. Hydrogen by-products from industry can be competitive but are limited in supply.

[7] Marine fuels supported by the International Maritime Organization (IMO).

Figure 0.1. Comparison of Battery and Fuel Cell Electric Vehicles for Heavy-duty Transport



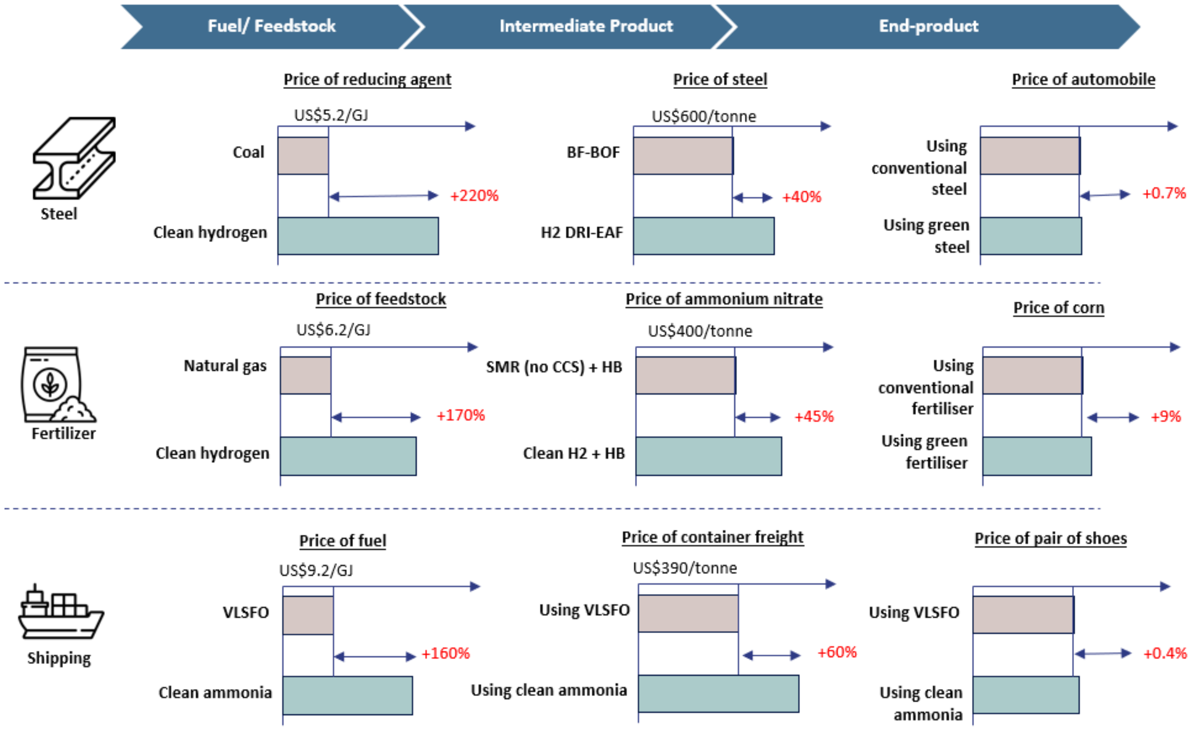
BEV = battery electric vehicle, FCEV = fuel cell electric vehicle, h = hour, kg = kilogram, km = kilometre, TCO = total cost of ownership.

Source: Authors.

3.4. Industrial Sector

The industrial sector offers the most certain and high-value applications for hydrogen, specifically in processes where effective decarbonisation alternatives are lacking or cost-prohibitive. The price premium of clean hydrogen for different sectors is shown in Figure .

Figure 2.4. Price Premium of Clean Hydrogen



BF-BOF = blast furnace-basic oxygen furnace, CCS = carbon capture and storage, DRI-EAF = direct reduced iron-electric arc furnace, GJ = gigajoule, HB = Haber-Bosch, SMR = steam methane reforming, VLSFO = very low sulphur fuel oil.

Note: Based on the assumption of several prices: clean hydrogen at US$2.0/kilogram, coal at US$100.0/tonne, natural gas at US$6.5/MMBTU, VLSFO at US$390.0/tonne. The clean hydrogen price assumption is optimistic, while the current cost may reach above US$5.0/kilogram. The resulting price is sensitive to these assumptions.

Source: Energy Transitions Commission (2021).

For low-temperature heat requirements – such as processes in food and beverages, fast-moving consumer goods, and pulp and paper manufacturing (up to 200ºC) – direct electrification via heat pumps is a competitive and cost-effective pathway. Similarly, industry can meet medium-temperature heat needs (up to 500ºC) using electric boilers (Fraunhofer ISI, 2024). However, the problem of process emissions remains. Industries, like cement, release non-combustion CO_2 during chemical reactions; therefore, hydrogen use alone does not eliminate these emissions. Addressing this challenge requires two main strategies: the adoption of innovative, low-greenhouse gas production processes or the transitional deployment of CCS.

Consequently, the most strategic and certain applications for hydrogen are those that demand very high temperatures (i.e. above 500ºC) where electrification is impractical, or where hydrogen is required as a chemical feedstock rather than merely as a heat source. These are the 'no-regret' sectors for deep decarbonisation, which include fertiliser and ammonia production, refining, the chemical industry, and steel[8] production.

[8] Specifically, via the direct reduced iron route.

3.5. Niche and Feasibility Considerations

It is important to distinguish between the certainty of demand and short-term feasibility. For example, the fertiliser sector has a certain demand, but this may be slow due to market subsidies.[9] As shown in Figure 2.4, shifting to clean hydrogen significantly increases the price of ammonium nitrate. However, this may change if a premium export market arises for clean ammonia or fertiliser.

Specific niche markets may exist where the local economics favour hydrogen. This includes the 'de-dieselisation' of remote islands and utilising hydrogen industrial by-products for forklift or tractor facilities in port. In these specific contexts, hydrogen systems may compete favourably against the high logistical costs of transported diesel fuel and offer better performance under specific conditions than local renewable energy or electrification alternatives.

4. Findings from Selected Projects

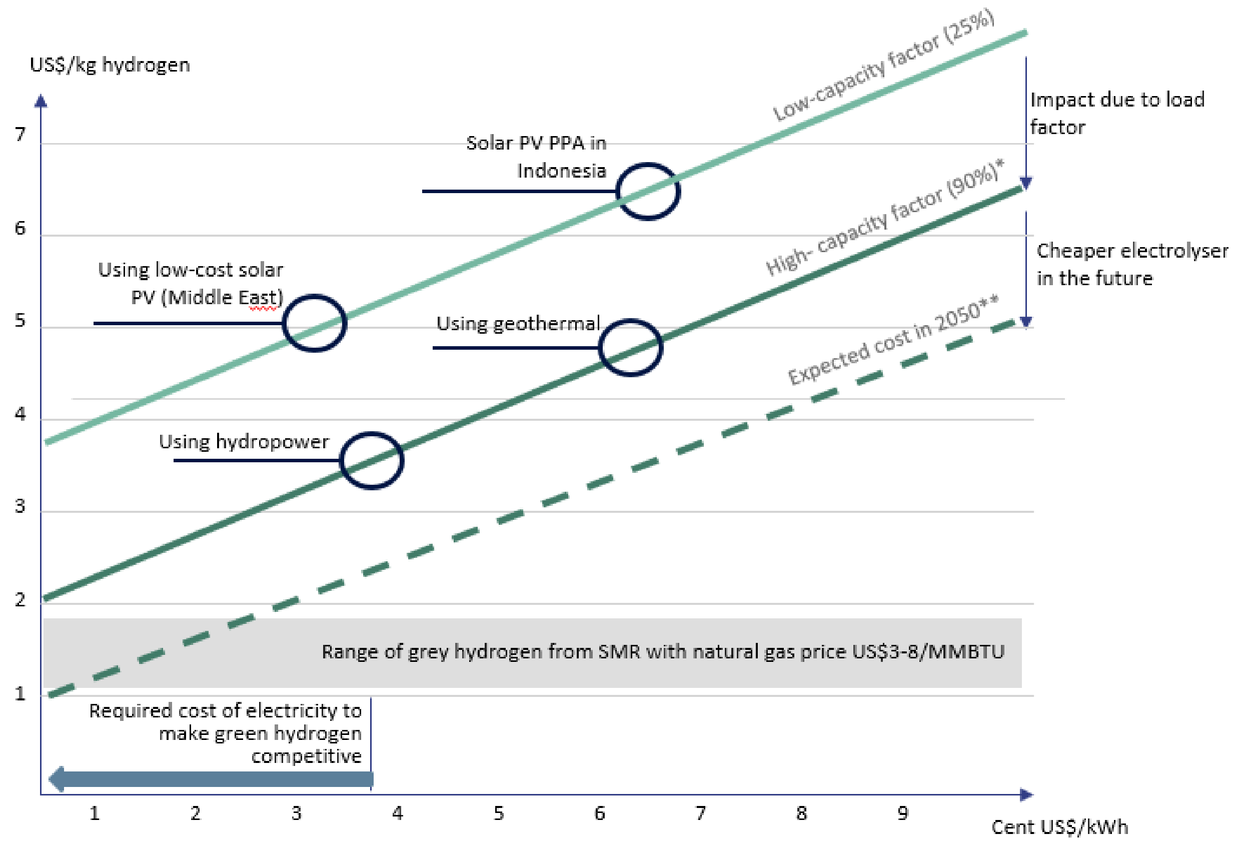
This analysis examines two typical hydrogen projects, green hydrogen production and hydrogen refuelling stations (HRS). The two projects represent the challenges facing both the hydrogen production and utilisation value chain segments, respectively.

4.1. Green Hydrogen Production

This project focusses on hydrogen production using electrolysis. Developers must secure a supply of renewable electricity, either through direct procurement or on-site generation. Depending on the specific scheme, the project scope may include transporting the hydrogen to an end-user. Revenue is generated through sales to committed offtakers. In Indonesia, major state-owned enterprises – including Pertamina, PLN, and Pupuk Indonesia – have launched initiatives in this space, although no project has yet reached commercial scale.

[9] The Government of Indonesia has implemented a regulated gas price policy set at US$6.5–7.0/MMBTU for fertiliser and six other industries since 2020 (ESDM, 2025c). Moreover, it provides fertiliser subsidies to eligible farmers for nine main commodities to support national food security (Sekretariat Kabinet, 2024).

Figure 0.2. Sensitivity of Green Hydrogen Cost on Electricity Input Price
(US$/kilogram)



kg = kilogram, PPA = power purchase agreement, PV = photovoltaic.
*Cost in 2020, based on electrolyser cost of US$650/kilowatt.
**Electrolyser cost drops to US$130/kilowatt after 5-terawatt installed capacity.
Notes:
1. The Indonesian geothermal electricity price is US$0.06–0.13/kilowatt-hour.
2. The Indonesian subsidised natural gas price is US$6.5/MMBTU.
Source: Authors based on IEA (2019).

The primary challenges for this project stem from unfavourable economics and complex logistics:

(i) The small capacity – typically in hundreds of kilowatts up to a few megawatts (MW) – results in a high unit cost for the produced hydrogen, underscoring that hydrogen production is capital-intensive and requires significant scale-up to reduce unit product cost. The share of capital expenditures drops from 90% for 1-MW to 60% for 10-MW and to only 40% for 100-MW system capacity (Agora Industry and Umlaut, 2023).

(ii) Renewable energy resources are sometimes located in remote areas, or hydrogen demand is unavailable near the production plant. Such a project's remote location necessitates heavy infrastructure investment for sea transport, including port construction and shipping costs, adding considerable capital risk.

(iii) Such a project often lacks clear offtake certainty. Without securing a committed, long-term buyer, it can remain unbankable.

(iv) Low-cost electricity must be sourced to generate a competitive hydrogen cost. As illustrated in

Figure 0.2, the electricity price is a strong determinant of the resulting hydrogen cost.

4.1. Hydrogen Refuelling Stations

HRS involve designing, constructing, and operating facilities that supply hydrogen fuel to vehicles. These projects typically include sub-systems for hydrogen storage, compression, and dispensing. The operator must manage hydrogen delivery, whether from on-site production or from external sources. Several companies are developing such projects, including Pertamina (Rahayu and Djumena, 2024), PLN, and Toyota.

These projects illustrate a critical demand-side bottleneck for the transport sector, however. The demand from the light-duty passenger car segment is unclear, as BEV are rapidly gaining traction. Moreover, the anticipated high dispensed hydrogen price[10] would make the total cost of ownership[11] for FCEV considerably higher than both internal combustion engine vehicles and BEV.

Regulatory immaturity exacerbates the situation. Projects are hindered by the absence of specific guidelines (e.g. FCEV roadworthiness permits, high-pressure tank safety, necessary business licence classification, and specific safety regulations for co-locating HRS infrastructure within existing fuel stations). While demonstration HRS facilities exist (e.g. PLN's in Senayan and Toyota's in Karawang), they function primarily for public education, not commercial business (Kurniawan and Ferdian, 2025).

4.3. Similarities with Other Hydrogen Projects

The findings from both project models represent the commercial bottlenecks of other hydrogen initiatives. Investors are hesitant to make financing decisions due to various uncertainties. Both models are struggling to secure a guaranteed, long-term offtaker willing to pay a premium for clean hydrogen, as most potential buyers currently rely on cheaper, mature alternatives. The combination of this financial barrier and the currently developing regulatory framework represents the largest hurdle to hydrogen projects in Indonesia.

5. Key Commercial Barriers

The challenges observed in the above projects reflect broader systemic issues facing Indonesia's hydrogen economy. Challenges across four critical ecosystem layers – financial, infrastructure, regulatory, and institutional – are described below.

5.1. Financial Barriers

[10] A gas company stated that the delivered price of grey hydrogen is US$7.0–10.0/kilogram, while green hydrogen is US$21.0–36.0/kilogram.

[11] This includes the vehicle purchase price and operational costs such as fuel, maintenance, insurance, and labour.

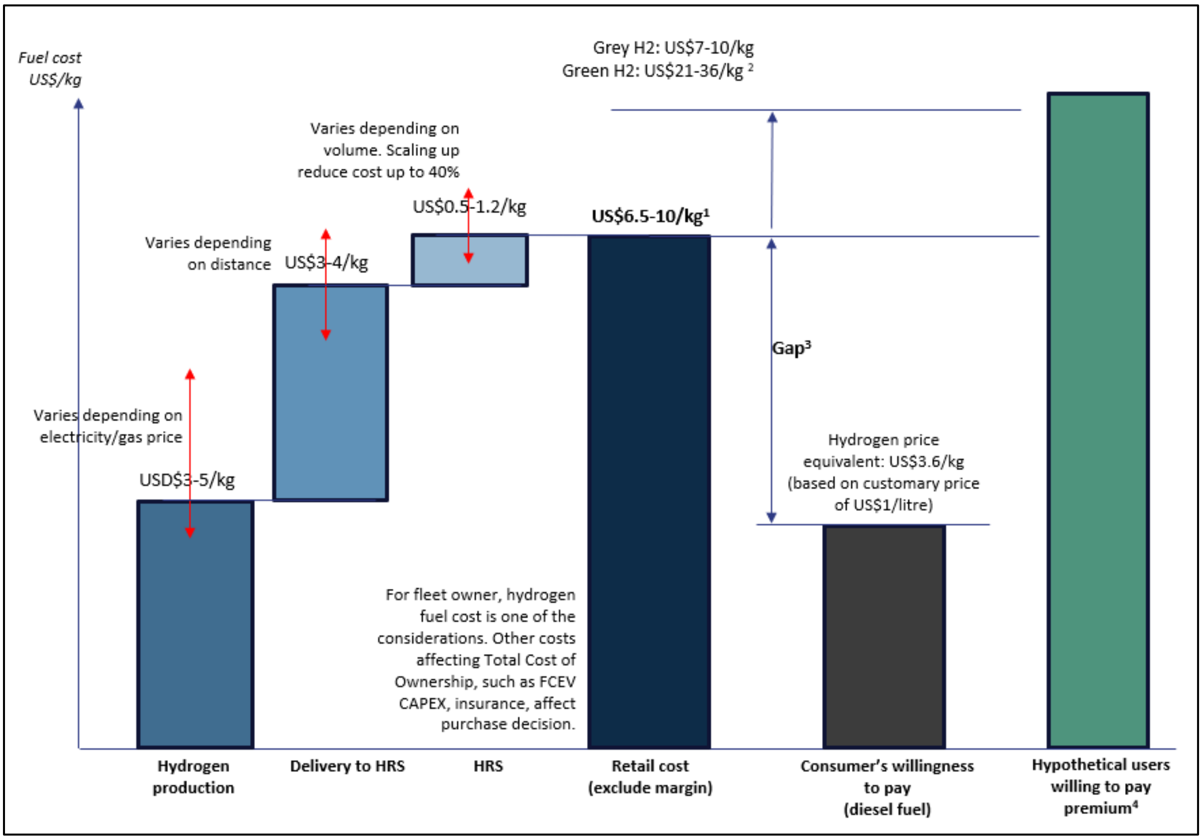
Most hydrogen projects globally struggle to secure guaranteed, long-term offtakers. Potential buyers continue to rely on mature, lower-cost energy alternatives rather than paying a premium for clean hydrogen. A significant price gap (Figure 0.3) drives this hesitation. Market estimates place clean hydrogen costs between US$4.0 and US$8.0/kg, contrasting sharply with subsidised or price-controlled alternatives:

(i) **Grey hydrogen.** Costs US$1.0–2.0/kg, depending on natural gas price as feedstock.

(ii) **Natural gas.** At the government-mandated price of US$6.5–7.0/MMBTU, the energy equivalent is about US$1.0/kg of hydrogen.

(iii) **Diesel fuel.** At US$1.0/litre, the energy equivalent is about US$3.0/kg of hydrogen.

Figure 0.3. Hydrogen Retail Prices Remain above Consumer Willingness-to-Pay



CAPEX = capital expenditure, FCEV = fuel cell electric vehicle, HRS = hydrogen refuelling station, kg = kilogram.

[1]Overseas figure.

[2]Indonesia figure, from a gas company

[3]The hydrogen price dispensed at HRS is still high. Scaling-up will reduce the cost, but this may still be higher than the willingness to pay. A form of economic incentive is needed.

[4]Such users may be less concerned by economics, or their adoption to FCEV is not sensitive to their overall operation costs.

Sources: Basma and Rodríguez (2023); Bracci, Koleva, Chung (2024); Eißler et al. (2024).

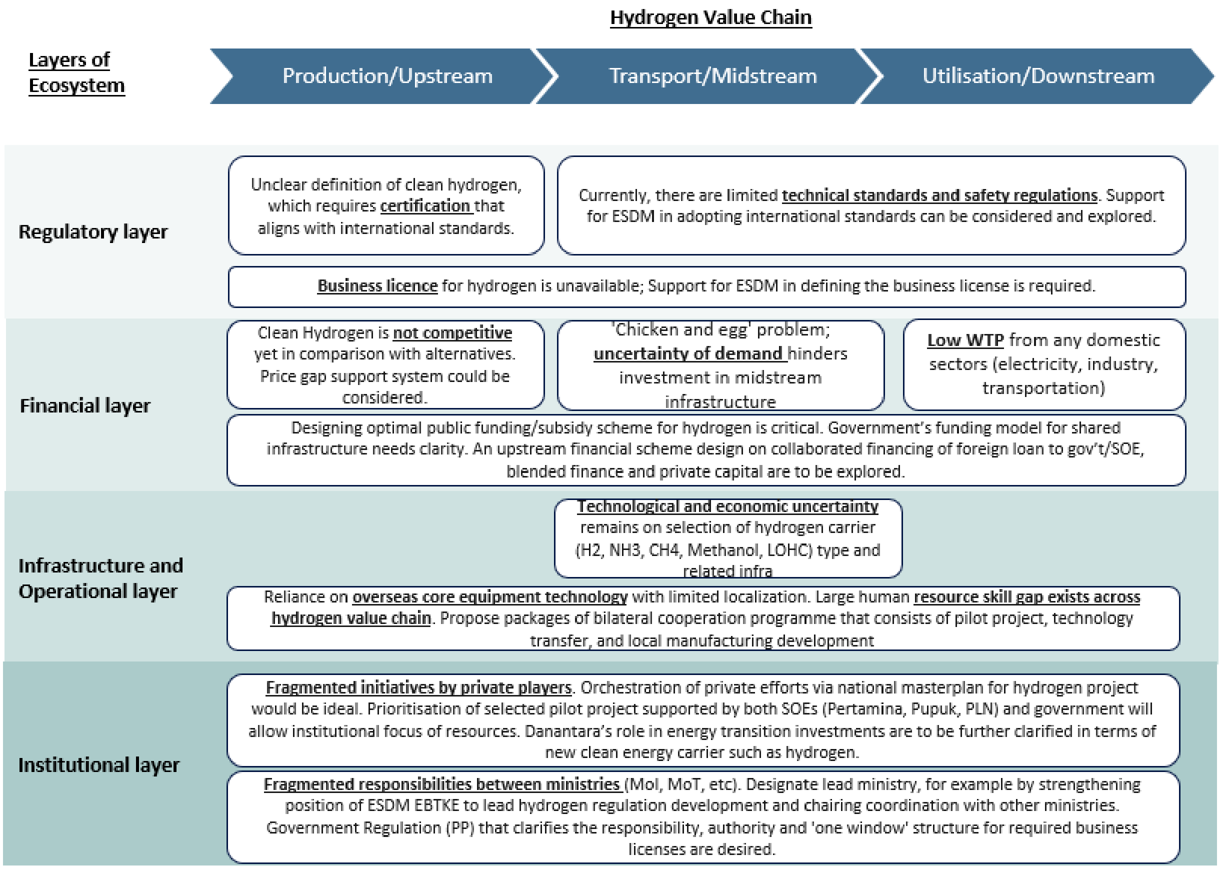
5.2. Infrastructure Barriers

The lack of demand creates an infrastructure 'chicken-and-egg' problem. Developing essential assets such as ports, pipelines, and widespread HRS is capital-intensive. Private investors will not finance this infrastructure without commercially viable, large-scale domestic demand. Conversely, demand cannot grow without the necessary infrastructure in place.

5.3. Regulatory and Institutional Barriers

As noted previously, the regulatory framework for safety and licensing is under development in Indonesia. The production of hydrogen also requires the certification of clean hydrogen, which is currently not available. Institutionally, the sector has the opportunity to co-ordinate, but private-sector initiatives currently operate in isolation. While the Ministry of Energy and Mineral Resources (ESDM) leads hydrogen policy, effective policy implementation requires alignment with multiple governmental bodies.

Figure 2.7. Matrix of Issues across Hydrogen Ecosystem Layers



CH_4 = methane, EBTKE = Directorate General of Renewable Energy and Energy Conservation, ESDM = Ministry of Energy and Mineral Resources, H_2 = hydrogen, LOHC = liquid organic hydrogen carrier, NH_3 = ammonia, SOE = state-owned enterprise, WTP = willingness to pay.
Source: Authors.

The development of safety and technical regulations for FCEV use illustrates Indonesia's institutional complexity. The high-pressure storage tanks required for FCEV (e.g. 350- and 700-bar) fall under the jurisdiction of the Ministry of Manpower and remain unregulated. Simultaneously, vehicle registration and roadworthiness require separate approvals from the Ministry of Transport and the National Transportation Safety Committee. In addition to these challenges, business licences (KBLI) for hydrogen are not available.[12] The issuance of KBLI requires co-ordination with the Central Bureau of Statistics (BPS). ESDM is said to be forming an interministerial team to accelerate regulatory and technical preparations needed for FCEV operation on public roads, however.

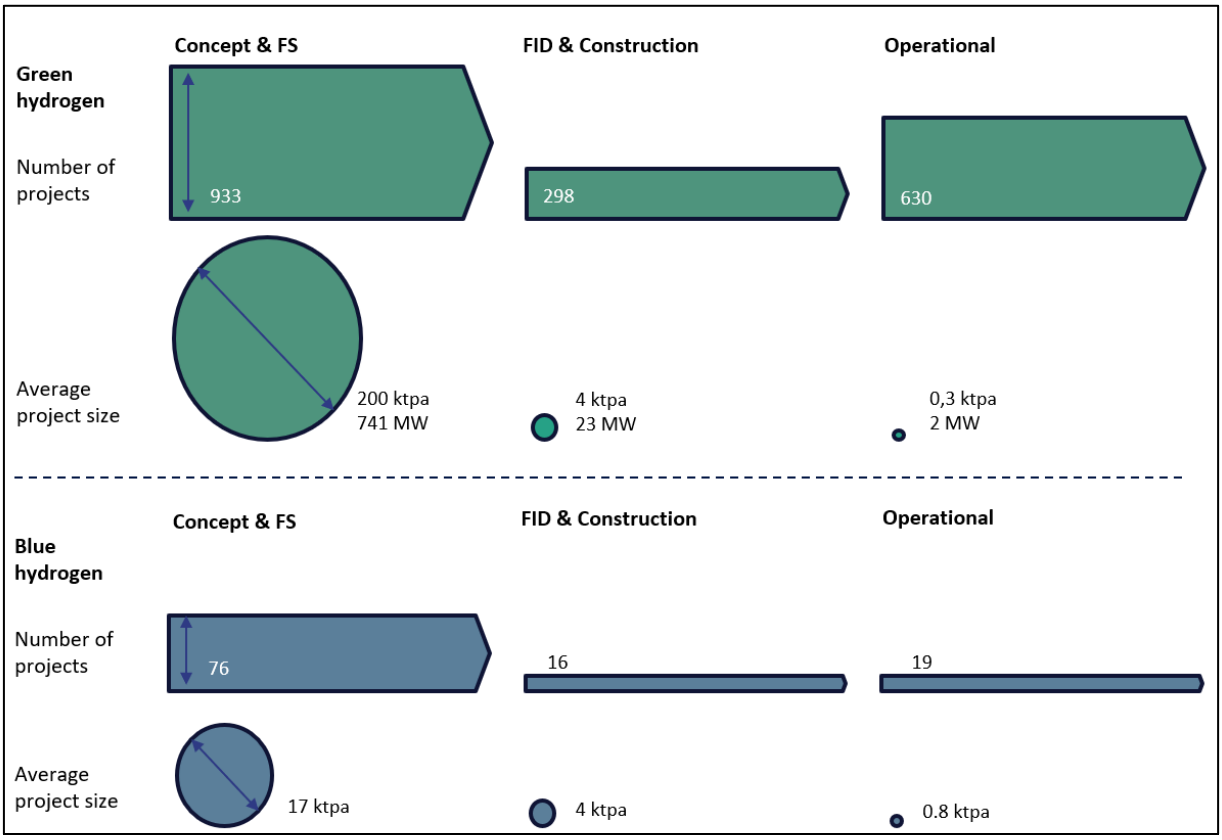
6. Lessons from Successful Overseas Cases

Indonesia's commercialisation hurdles reflect a global reality, where only a limited number of small-capacity projects are currently in operation (Figure). Yet even in developed nations, projects frequently stall due to the same price gap and lack of bankable offtake agreements found domestically. Implementation in developing countries is more challenging considering the fiscal constraints and low willingness-to-pay of domestic industries.

Some specific large-scale projects are advancing, however. Notable examples include green ammonia exportation from Kakinada (India), green steel production in Boden (Sweden), green methanol in Inner Mongolia (China), and the construction of hydrogen truck corridors across major industrial zones (e.g. Beijing–Tianjin and Chengdu–Chongqing) (China).

[12] Recently, BPS issued new a KBLI list under BPS Regulation No. 7/2025 on 17 December 2025, which lists hydrogen business activities along the value chain. Other new activities were also added, such as carbon credit trading in the agriculture, forestry, and energy sectors; CCS; and the operation of electric vehicle-charging stations.

Figure 2.8. Global Hydrogen Project Status



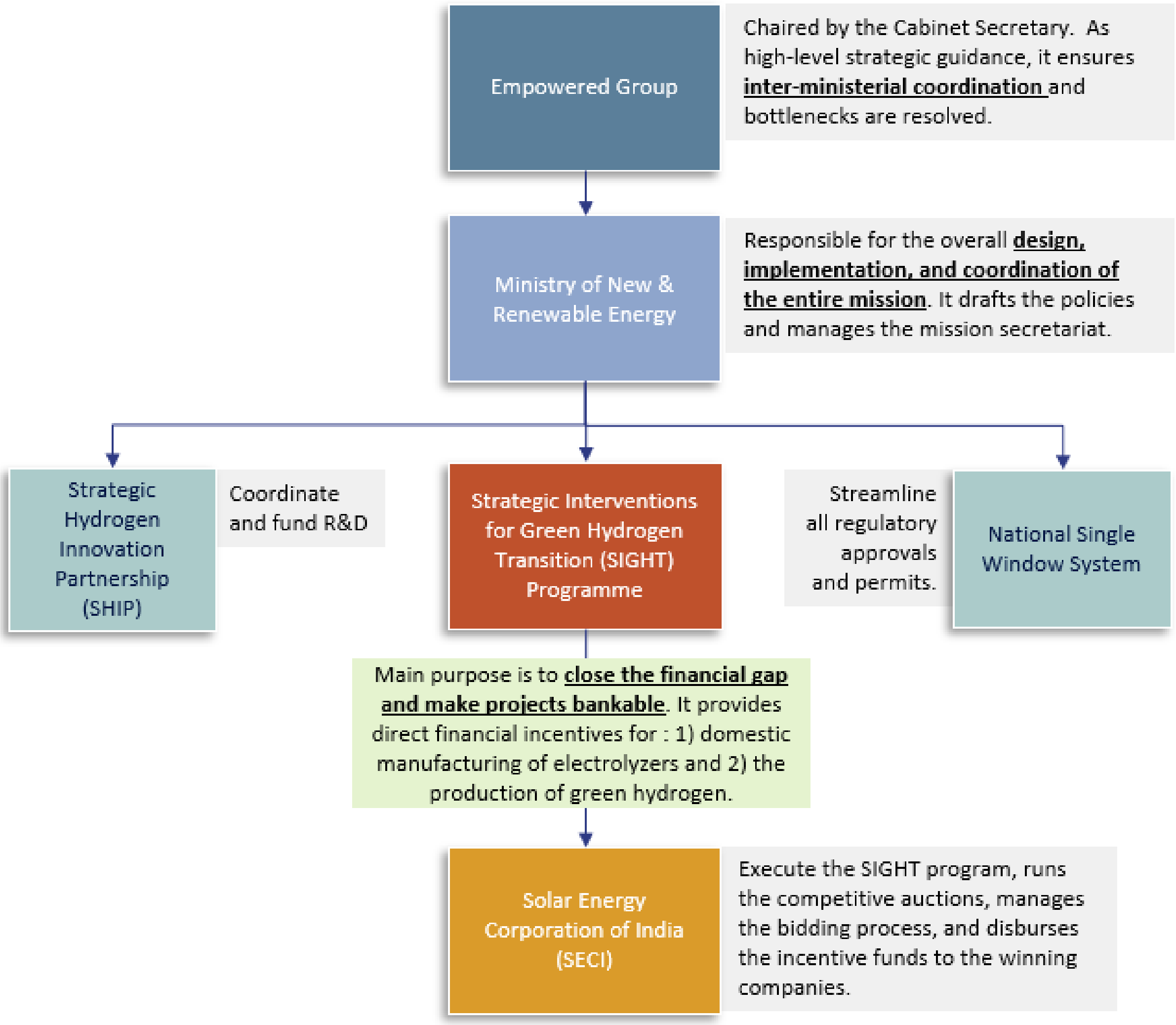
FID = final investment decision, FS = feasibility study, ktpa = kilotonnes per annum, MW = megawatt.
Source: IEA (2025b).

6.1. Role of National Industrial Strategies

A strong national agenda – extending beyond climate goals – drives these success stories. Governments are justifying these projects through industrial strategy, energy security, or technological leadership rather than emission reduction goals alone.

India provides a clear example of a robust institutional framework for hydrogen development (Figure 2.9). Despite being a developing economy, the government offers significant hydrogen subsidies, aiming to reduce the nation's heavy reliance on imported fossil fuels and fertilisers. It aligns with the *Atmanirbhar Bharat Abhiyan* (Self-Reliant India) vision championed by Prime Minister Narendra Modi, which seeks to strengthen local production capabilities and economic self-sufficiency.

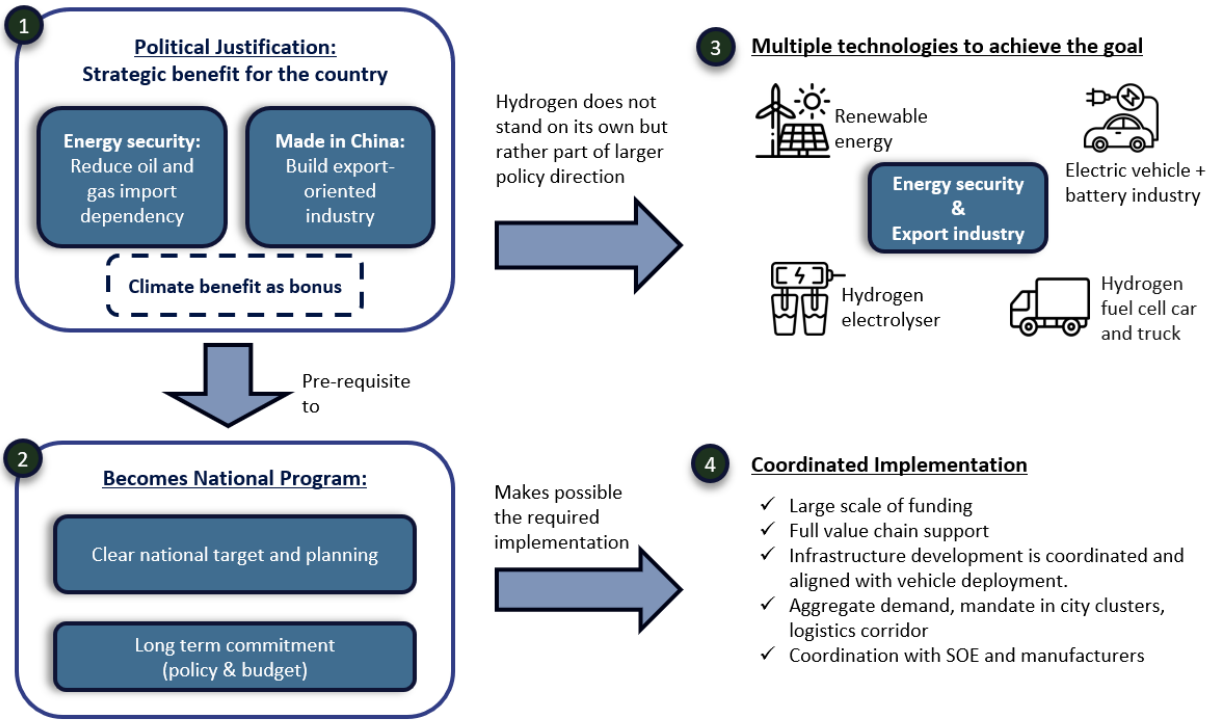
Figure 2.9. Institutional Setup for Hydrogen in India



R&D = research and development.
Source: MNRE (2023a).

China is following a similar strategic stance (Figure). The government subsidises a wide range of non-fossil technologies, including FCEV and electrolysers. Like India, China seeks to escape energy import dependence and to support its 'Made in China 2025' policy, positioning the nation as the global factory for new energy technologies to boost economic growth and the country's geopolitical standing.

Figure 2.10. China's Policy Framework for Energy Transition



SOE = state-owned enterprise.
Sources: Brown and Grünberg (2022), NOW (2020).

6.2. State-driven Commercialisation

These powerful mandates provide the political will to enact direct financial interventions for projects. These appear as 'push' mechanisms (e.g. subsidies in India and China) or 'pull' mechanisms (e.g. carbon pricing like the European Union [EU] Carbon Border Adjustment Mechanism [CBAM]). The lesson is clear – current commercialisation patterns result from an active, state-driven industrial strategy, not a passive market event. As illustrated in Figure , strong state support justified by national priorities is common criteria for successful projects overseas.

Governmental financial support is also reducing the price gap between green and grey hydrogen. India serves as an example, as the government provides direct production subsidies through a 3-year sliding scale: INR50/kg in the first year, INR40/kg in the second, and INR30/kg in the third (Fuel Cells Works, 2025). Beyond direct subsidies, India grants green hydrogen projects critical fiscal waivers, including exemptions from the goods and services tax and transmission and distribution charges. While these waivers appear modest, their cumulative impact is substantial. These combined interventions are expected to lower green hydrogen costs from US$5.50–5.90/kg to US$3.20–3.70/kg (NITI Aayog, 2022).

Figure 2.11. Summary of Key Success Factors of Overseas Commercial Projects

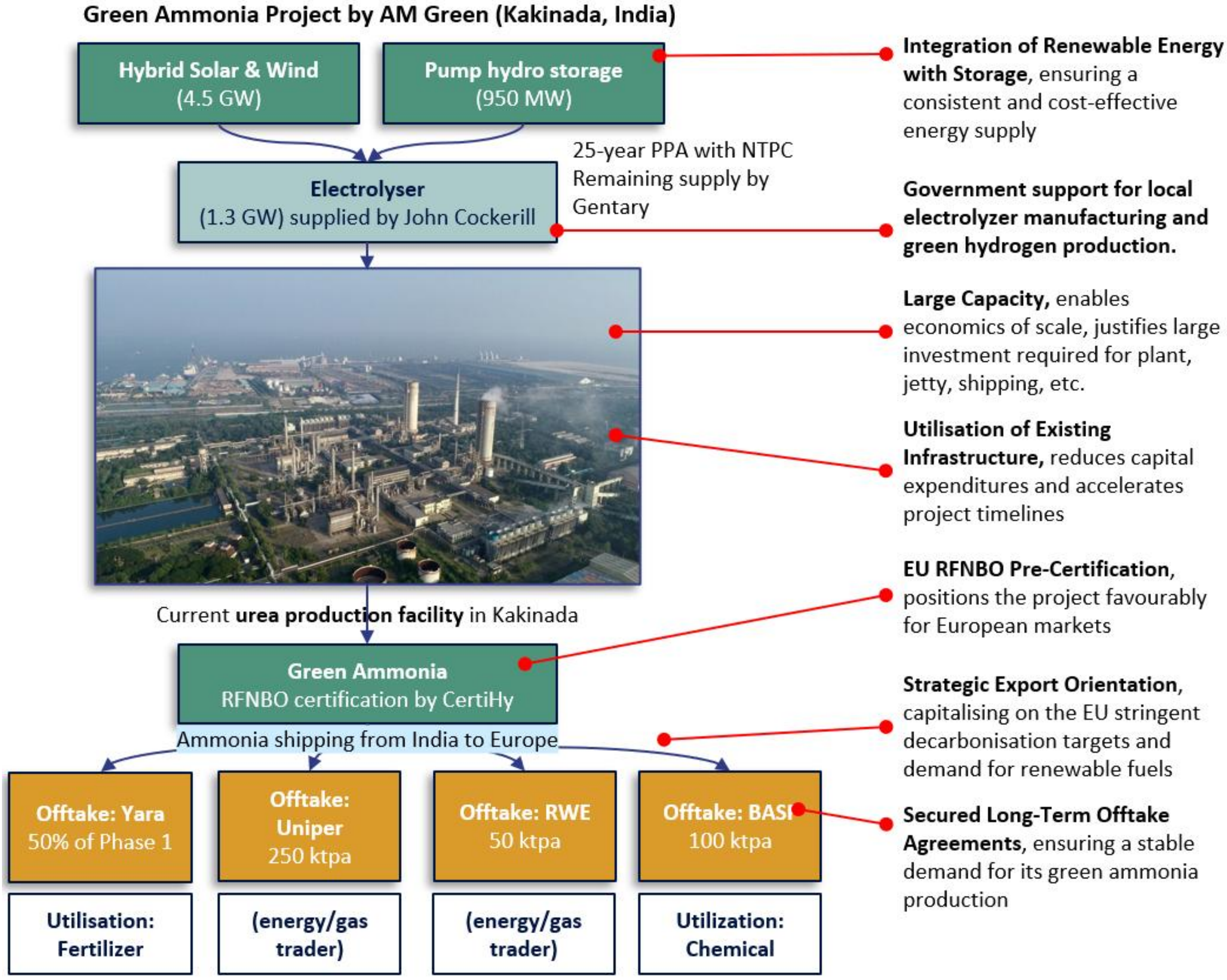
	National Priority	Ecosystem Enablers		Business Model Success Factor
Overseas projects	**Country's strategic benefit**	**Government supports / subsidies**	**Pressure from emission regulation**	**Sector suitability**
[India - Kakinada] Green Ammonia Export	India is currently importing ammonia (and oil & gas in general) and plans to become future exporter of green hydrogen	Through SIGHT programme, government subsidise electrolyser manufacturing and green hydrogen production	Offtakers (BASF, Yara, RWE) are from Europe, assumed under pressure of high carbon price	Fertiliser and chemical needs hydrogen for feedstock
[Sweden - Boden] Direct Reduced Iron (DRI) Steel Production Using Green Hydrogen	Historically, steel has been important sector for Sweden	€200 loan backed by a guarantee from the European Commission under the InvestEU programme	High carbon price (average EU ETS price is 70 USD/tonne CO_2e in 2024)	Beside CCS, DRI pathway is the only option to decarbonize steel industry
[China – Inner Mongolia] Green Methanol Production	Green hydrogen for chemical industry reduces China's dependence on gas import	Inner Mongolia government secured CNY 4.7 bill in subsidies for RE prices	Government is strictly controlling coal to chemical projects	Methanol needs hydrogen for feedstock
[China] Hydrogen Corridors for FC Trucks (Beijing-Tianjin, Chengdu-Chongqing, Shanghai-Jiaxing-Ningbo, Jinan-Qingdao and Wuhan-Yichang)	China is both improving energy security and advancing FC technology	Under NEV policy, national and local governments subsidise purchase of FCEV and HRS construction	Increasingly stringent emission and fuel consumption standards for vehicles	Competing with battery truck, but FC has advantages for heavy-duty truck class

CCS = carbon capture and storage, FC = fuel cell, FCEV = fuel cell electric vehicle, HRS = hydrogen refuelling station, NEV = new energy vehicle, RE = renewable energy, tCO_2e = tonne of carbon dioxide equivalent.
Sources: Liu and Mao (2024); NIB (2024); *Viet Nam News* (2024); Liqiang, Hu, Yuan (2023); *Reuters* (2023).

Project viability requires a package of contributing factors, not just financial support. The AM Green ammonia project in India illustrates this (Figure). A combination of governmental support, large-scale stable renewable energy supply, and low-carbon certification[13] lowered project costs and secured overseas offtakers.

[13] For exportation to the EU, renewable fuels of non-biological origin (RFNBO) certification is needed to comply with its Renewable Energy Directive.

Figure 2.12. AM Green Ammonia Project in India



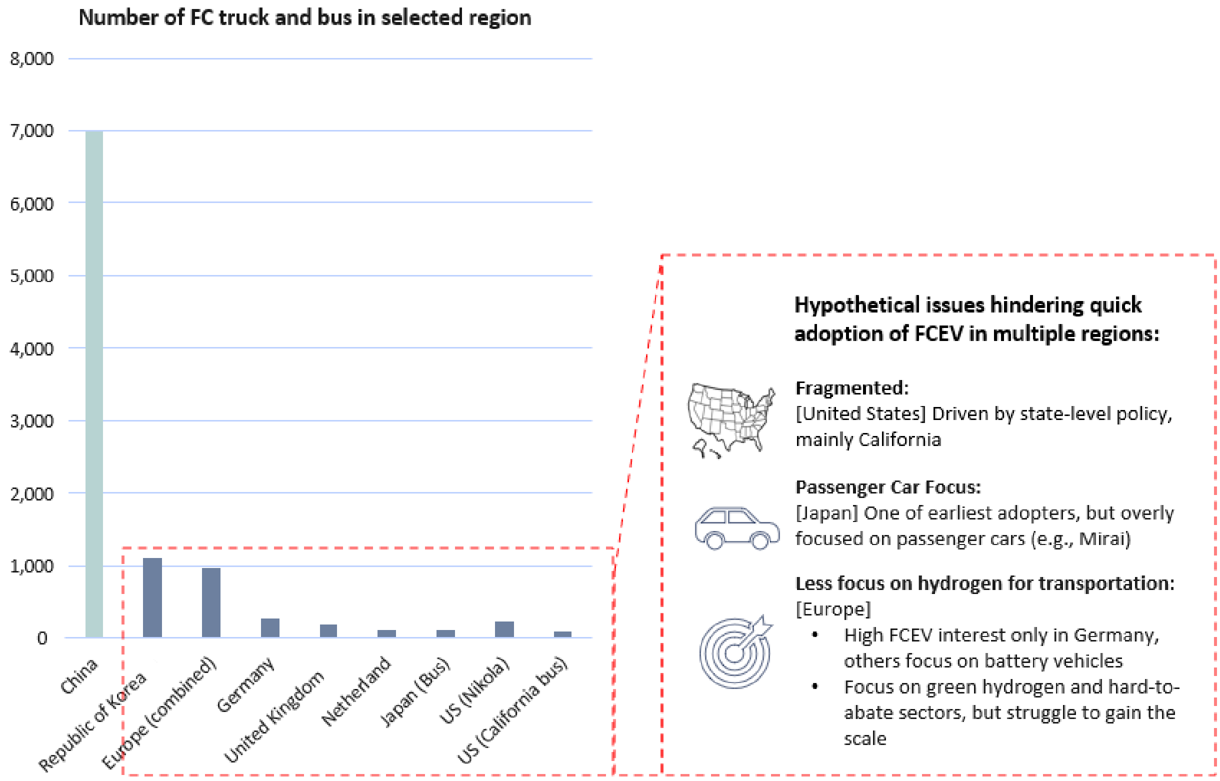
EU = European Union, ktpa = kilotonne per annum, GW = gigawatt, MW = megawatt, PPA = power purchase agreement, RFNBO = renewable fuel of non-biological origin.
Sources: Atchison (2024), RWE (2024), BASF (2024).

6.3. Complexity of Market Adoption

Counterintuitively, the availability of governmental support does not guarantee commercial adoption, as demonstrated by heavy-duty FCEV development in several regions. In 2024, China registered only 7,000 FCEV buses and trucks, while other countries had significantly fewer (

Figure). Although developed nations provided robust policy support – including roadmaps and research and development funding – heavy-duty FCEV growth still lags due to strategic misalignment. In the US, for example, development remains fragmented and driven by state-level policies, primarily in California. In Japan, early adoption focussed excessively on passenger cars rather than on the more suitable commercial transport sector.

Figure 2.13. Global Fuel Cell Electric Vehicle Sales Statistics, Selected Countries, 2024



FCEV = fuel cell electric vehicle, US = United States.
Sources: Mao and Rodríguez (2025), Zhu (2024), Hydrogen Fuel Cell Partnership (2025), European Hydrogen Observatory, Hydrogen Fuel Cell Electric Vehicles, https://observatory.clean-hydrogen.europa.eu/index.php/hydrogen-landscape/end-use/hydrogen-fuel-cell-electric-vehicles.

Chapter 3

Policy Actions for a Hydrogen Ecosystem

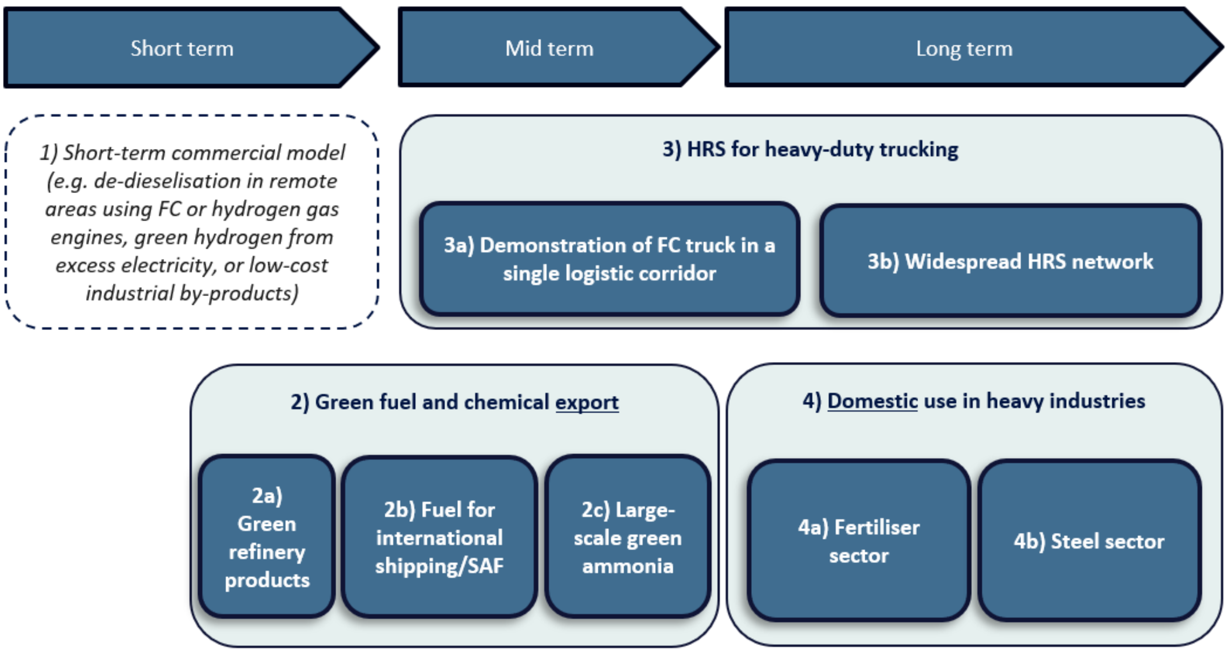
1. Pragmatic Commercial Timeline

A pragmatic commercial timeline for a project must follow a sequence based on technology readiness, infrastructure requirements, and market willingness-to-pay. First, technologies with higher maturity will commercialise faster. For instance, marine transport of ammonia is an established practice, whereas liquid hydrogen, LOHC, and metal hydrides are less-mature technologies. Second, infrastructure complexity will dictate implementation speed. Projects that require widespread distribution networks and complex supply chains will require more time. Conversely, models that leverage existing plants and require minimal logistics can launch quickly.

Third, economic viability will drive adoption. Sectors where the price gap between clean hydrogen and alternative fuel is the smallest will lead market adoption. Similarly, products in which hydrogen represent a small fraction of the total cost will require a lower price premium to compete with incumbent alternatives. The proposed timeline for hydrogen projects based on market segmentation is indicated in

Figure .

Figure 3.1. Hydrogen Project Timeline Based on Market Segmentation



FC = fuel cell, HRS = hydrogen refuelling station.
Source: Authors.

1.1. Short-term Projects

ESDM's *National Hydrogen and Ammonia Roadmap* indicates that pilot and demonstration projects[14] will dominate the sector until 2034 (ESDM, 2025a). The National Energy Policy, as regulated in Government Regulation No. 40/2025, states that hydrogen and ammonia usage will be relatively minor[15] in 2030 (ESDM, 2023b). Therefore, the near-term focus should target 'low-hanging fruit' projects, such as:

(i) Remote power generation. Replace high-cost diesel generators in off-grid areas (i.e. de-dieselisation projects) through hybrid solar PV–battery–hydrogen systems, which avoid large-capacity batteries, to cover days without sunlight. However, the economics of such systems are subject to the future evolution of battery cost and electrolyser/fuel cell system costs.

(ii) Captive logistics. Utilise industrial by-product hydrogen (e.g. chlor-alkali plants [electrolysing brine to produce chlorine and hydrogen], steel manufacturing [from waste gases], and petrochemical facilities [hydrogen is a by-product of various processes like reforming]). However, these supplies are typically already absorbed by gas merchants or other nearby industries to lower costs for in-port or logistics activities that demand 24/7 reliable operation.[16]

(iii) Captive feedstock. Generate hydrogen on site to replace trucked hydrogen. PLN has already proven this concept by producing green hydrogen for internal power plant generator cooling. It has operationalised 21 small-scale green hydrogen plants, aggregating 0.2 ktpa (PLN, 2023).

3.1.2. Mid-term Projects

Green fuel and chemical exportation to markets with high willingness-to-pay could become commercialised projects in the mid-term. While domestic demand may remain weak, global policy shifts are creating a premium market for low-carbon products.

(i) CBAM. This policy incentivises the import of low-carbon industrial goods (i.e. iron, steel, aluminium, cement, and fertilisers). Its purpose is to prevent carbon leakage

[14] Transport sector (3,000 pilot FCEV), electricity sector (demonstration hydrogen gas turbines up to 10% co-firing rate), and industry sector (initiation in steel and refineries).

[15] Hydrogen in 2030 will equal 700–1,400 tonnes of oil equivalent (TOE), while ammonia in 2030 will equal 2,400–2,900 TOE. Note that 1.0 TOE equals 11.6 megawatt-hours, which is around the annual electricity consumption of one household in developed countries.

[16] Sinopec, however, has launched China's first cross-regional hydrogen trucking corridor, spanning 1,150 kilometres from Chongqing to Qinzhou Port. The initial hydrogen supply will come from industrial by-product hydrogen, since more than 400 ktpa is produced in these areas. Sinopec has built another six cross-regional hydrogen corridors: Beijing–Shanghai, Beijing–Tianjin, Chengdu–Chongqing, Shanghai–Jiayong, Jinan–Qingdao, and the Hanyi Expressway (Martin, 2025; Chen, 2023).

where production shifts outside the EU to avoid climate policies and to create a level playing field between EU and non-EU producers.[17]

(ii) International Maritime Organization (IMO) standards. These new fuel standards will drive demand for clean ammonia and methanol in shipping (IMO, 2025).

(iii) Aviation policies. Various airline decarbonisation goals and governmental mandates will increase the demand for sustainable aviation fuel[18] (Department for Transport, 2024).

Indonesia can capture these markets by leveraging its existing refineries; this brownfield approach minimises capital expenditures (CAPEX). Indeed, the major cost contributor of grey ammonia production is fuel (57%), followed by CAPEX (29%) (Cloete et al., 2020). Since refineries already produce ammonia and methanol, investment would focus mainly on decarbonising the feedstock – via electrolysis or CCS – rather than building new processing plants. Furthermore, these export-oriented projects would utilise existing port infrastructure, avoiding the need to build a costly domestic distribution network.

Indonesia's competitiveness here also relies on specific natural advantages. Large-scale hydropower[19] can provide the low-cost, stable electricity required for efficient electrolysis. Additionally, vast geological storage capacity enables the production of blue hydrogen.

1.3. Long-term Projects

FCEV technology is mature and commercially available in Indonesia (e.g. the Toyota Mirai and Hyundai Xcient). Moreover, the cost gap between clean hydrogen and diesel fuel is smaller than that with coal or gas. These factors have led to the expectation that FCEV will be the first adopters of clean hydrogen, but consumers are hesitating due to the lack of refuelling infrastructure and high vehicle costs. FCEV face stiff competition from BEV, which are rapidly improving. Moreover, biofuels offer a 'drop-in' solution without major vehicle or infrastructure changes.

Consequently, commercialisation of FCEV for heavy-duty road transport will take time. It will likely start to develop through a single transport corridor (e.g. connecting ports to industrial zones) before expanding into a national network. Buses represent a potential hydrogen market, but for standard urban routes, BEV are superior in both operating cost

[17] The mechanism has a transitional phase from 1 October 2023 to the end of 2025, after which the definitive regime takes effect in 2026. See EPA, EU Carbon Border Adjustment Mechanism, https://www.epa.ie/our-services/licensing/climate-change/eu-carbon-border-adjustment-mechanism/

[18] However, note that hydrogen-based e-sustainable aviation fuel will compete with currently available bio-based options.

[19] Indonesia does not have the best solar and wind resources. Unless coupled with storage, solar and wind there produce low-capacity factor electricity that makes the unit cost of produced hydrogen more expensive.
Large-scale hydropower, however, produces low cost and high-capacity factor electricity.

and energy efficiency. Indeed, sales data from European cities confirm a strong preference for BEV in urban areas (Molliere, 2025).

FCEV may have advantages in specific cases (e.g. long-distance intercity routes and high-frequency corridors). In these scenarios, the rapid refuelling of hydrogen may outperform the long charging windows required by BEV. This viability remains heavily dependent on low-cost hydrogen, however, which currently requires governmental subsidies. In Malaysia, Sarawak Metro launched a hydrogen bus trial operation in 2020. In 2024, it procured 55 hydrogen feeder buses (Full Cells Works, 2024). Low-cost green hydrogen production using excess hydropower contributed to the feasibility of this project (Soong and Yoong, 2022).

Commercial hydrogen projects for the domestic fertiliser and steel industries will also take time to develop. These industries currently rely on subsidised fossil fuel feedstocks, making clean hydrogen uncompetitive. Decarbonisation in these sectors will become commercially viable only after hydrogen production costs fall significantly and the governmental reforms the subsidy framework or implements stringent carbon pricing.

Finally, hydrogen is expected to play a complementary role in the power generation sector as various renewable alternatives become more available. Based on the *Roadmap of Energy Transition in Electricity Sector,* which was ratified in ESDM Regulation No. 10/2025, electricity across the country in 2060 will be generated 6.5% by hydrogen and 3.1% by ammonia. The electricity price will be regulated while introducing clean hydrogen, as fuel impacts the electricity price.[20] A low co-firing rate of hydrogen or ammonia is occurring, but the technology for a higher firing rate is still being developed.

1.4. Optimising Project Design

To accelerate the commercialisation of projects across these phases, developers should prioritise designs that minimise project costs by focussing on

(i) Economy of scale. Design large-scale projects to lower unit costs.

(ii) On-site integration. Co-locate renewable generation with production to eliminate expensive logistics.

(iii) Brownfield development. Utilise existing plants and infrastructure to minimise CAPEX.

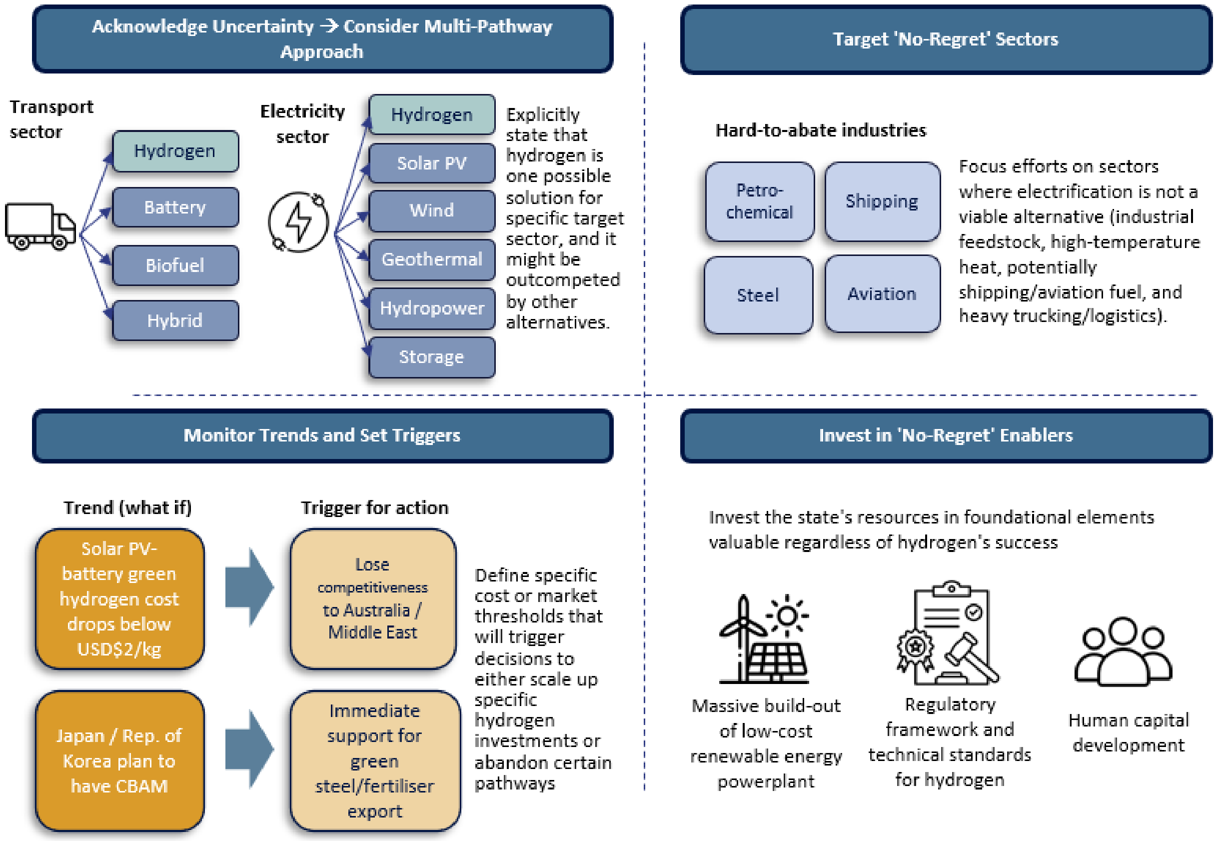
2. Strategies under Uncertainty

Both governments and the private sector operate in a context of uncertainty regarding future technology costs and global carbon policies. Given the unpredictability of competition and demand, stakeholders should adopt various strategies for uncertainty

[20] The cost of electricity for gas turbines built in 2024 and converted from natural gas to hydrogen in 2035 ranges EUR0.204–0.356/kilowatt-hour (Kost, 2025).

(Figure). This consists of both engaging in 'no-regret' action items while closely monitoring the sector for a reversal or changes in trends.

Figure 3.2. Approaches for Strategies for Uncertainty



CBAM = Carbon Border Adjustment Mechanism, kg = kilogram.
Source: Authors.

To navigate for uncertainty, four approaches are recommended.

(i) Take a multi-pathway approach. Policymakers must explicitly state that hydrogen is one possible solution amongst many alternatives, with differing degrees of suitability depending on the use case. For instance, the decarbonisation of heavy-duty road transport may begin with biofuels and eventually transform into a competition between BEV and FCEV. A multi-pathway strategy avoids locking in capital on a technology that may be quickly outcompeted.

(ii) Prioritise no-regret utilisation patterns. Long-term efforts should focus on areas where hydrogen has no viable alternative. These 'no-regret' sectors include petrochemicals, steel, shipping, and aviation, where direct electrification is physically or economically impractical.

(iii) Monitor trends and set triggers. An adaptive approach is more effective than a rigid road map. This strategy consists of defining a specific metric (e.g. cost or market thresholds) that would trigger decisions to scale up or to abandon various pathways. A policy trigger could be that if a key trade partner (e.g. China, Republic of Korea, or

Japan) implements a CBAM policy, the government will activate specific fiscal support for Indonesia's green export industry.

(iv) Invest in 'no-regret' enablers. While waiting for market clarity, the government should invest in foundational actions that create value regardless of the eventual level of hydrogen adoption in the market. These 'no-regret' enablers include a massive build-out of low-cost renewable power plants necessary for both direct electrification and green hydrogen production and the establishment of hydrogen technical standards and safety regulations.

Box 3.1. Example Monitoring Framework for the Heavy-duty Transport Sector

While hydrogen mobility is currently commercially unviable, market conditions remain dynamic. Policymakers and investors must monitor specific sectoral trends to determine if and when investment can be accelerated. This framework focusses on two areas: the evolution of competing technologies and the maturity of hydrogen solutions themselves.

Battery electric heavy-duty vehicles

- Fast charging capability. Can megawatt charging allow under-1-hour charging for Class 8 trucks?
- Energy density improvement. Does gravimetric energy density improve (target 400–500 watt-hour/kilogram), reducing battery weight?
- Range capability. Can electric heavy-duty vehicles reliably reach the 800–1,000 kilometre range with a full load?
- Battery cost trends. Will battery prices continue to decline (e.g. below US$100/kilowatt-hour)?
- Grid infrastructure. Can grid upgrades support highway megawatt charging networks?

Biodiesel/renewable diesel

- Feedstock scalability. Can non-food crops or waste-based feedstock scale sustainably for regional demand?
- Land-use trade-offs. Will environmental or food security concerns limit future expansion?
- Sectoral competition. Are airlines, shipping, and industry absorbing the limited biofuel supply?
- Policy preferences. Will governments prioritise biofuels for aviation/shipping, which is harder to electrify, over road transport?

Hydrogen production

- Electrolyser cost trends. Can capital expenditure fall below US$200–300/kilowatt? Are new low-cost technologies maturing?
- Renewable electricity availability. Is clean, cheap, dedicated power available at scale?
- Hydrogen cost trajectory. Will hydrogen (green or blue) approach diesel price parity (US$3/kilogram or lower)?
- Blue hydrogen acceptance. Is fossil-based hydrogen with carbon capture and storage (CCS) accepted as clean? Are life-cycle emissions and leakage tolerable?
- CCS viability. Are carbon capture costs, infrastructure, and storage sites proven and scalable?

Hydrogen transport

- Transport cost. Can the high cost of hydrogen logistics be reduced (e.g. via novel liquid hydrogen, liquid organic hydrogen carriers such as methylcyclohexane, or metal hydride technologies)?

Fuel cell electric vehicles (FCEV)

- Vehicle price convergence. Can FCEV become cost-competitive with battery electric vehicles or clean diesel alternatives at mass production?
- Durability and reliability. Does stack lifetime meet or exceed the diesel equivalent (more than 500,000 kilometres)?
- Total cost of ownership. Is the total cost of ownership acceptable for fleet operators?
- Original equipment manufacturer commitment. Are major automakers scaling up FCEV production or pulling it back?

Source: Authors.

3. Building a National Priority Narrative beyond Emission Reduction

Closing the financial gap for hydrogen commercialisation requires governmental support. If the Ministry of Finance allocates fiscal resources, justification beyond emission reduction arguments is necessary.

Currently, hydrogen is viewed primarily as a tool for decarbonisation and reducing oil imports. While valid, these benefits alone may not justify dedicated fiscal allocations, as there are alternatives like renewable energy, electric vehicles, and electric cooking. Such options also deliver emission and energy import reductions and require less subsidy per unit of impact.[21] Thus, to secure fiscal support, hydrogen must align with broader national priorities and demonstrate larger economic benefits. A consensus on positioning hydrogen within the national agenda is essential as well. Two strategic narratives may offer strong justification:

(i) Protecting domestic industries. This argument is anchored in the reality of Indonesia's stagnant natural gas production and declining exports. If domestic gas reserves deplete,[22] Indonesia faces the risk of relying on volatile imported liquefied natural gas. Developing a green hydrogen ecosystem would serve as a strategic hedge against future gas supply shocks. This narrative also addresses global economic shifts; future demand for Indonesia's coal is projected to decline, particularly as China – Indonesia's largest export destination – accelerates its own energy transition.

(ii) Next 'downstreaming' industry. Simultaneously, key export industries like steel and fertiliser may face new trade barriers. The CBAM is the first green tariff targeting carbon-intensive imports; major trading partners such as Japan and the Republic of Korea, which account for approximately 36% of Indonesia's ammonia exports, may implement similar policies.[23] Hydrogen enables the 'green downstreaming' of these sectors. Transforming raw commodity exports into high-value green products (e.g. green steel or green ammonia) aligns with national policy.[24] This shifts the economy from raw material exportation to the production of high-value finished goods, ensuring industrial competitiveness in a carbon-constrained global market. Yet to capture this opportunity, Indonesia must move quickly. Regional peers like Australia and India have already established robust regulatory frameworks and financial incentives to capture the hydrogen export market.[25] Malaysia, particularly Sarawak, is also preparing its hydrogen ecosystem.[26]

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21 It can be quantitatively compared using marginal abatement costs, which is the cost of reducing one additional unit of pollution (e.g. 1 tonne of carbon dioxide equivalent [tCO_2e]). Hydrogen utilisation often falls above US$100/ tCO_2e, which is much higher than renewable energy and BEV (Della Vigna, E. et al., 2022).

22 ESDM statistics indicate stagnant natural gas production while exports are declining (ESDM, 2024c).

23 OEC, Indonesia, https://oec.world/en/profile/country/idn

24 Indonesia's downstreaming policy aims to increase the added value of commodities by processing them domestically before exportation, rather than selling them raw. This policy involves various sectors such as mining (e.g. nickel, bauxite, copper), agriculture, fisheries, and forestry to process natural resources into high value-added products. This is ultimately expected to create jobs, increase state revenue, and drive Indonesia's economic transformation from a consumer to a productive nation.

25 Australia's AUD2 billion Hydrogen Headstart programme provides direct production credits, and a new AUD2/kg Hydrogen Production Tax Incentive is being implemented to compete with the US. India's US$2.4 billion funding of the Strategic Interventions for Green Hydrogen Transition (SIGHT) programme is providing direct financial incentives for both hydrogen production and electrolyser manufacturing.

26 A state-owned enterprise, SEDC Energy, is providing land and infrastructure, and an amendment to a gas bill includes hydrogen.

4. Governmental Financial Support

A 'one-size-fits-all' subsidy approach is ineffective for the diverse hydrogen value chain in Indonesia. Instead, financial support must be tailored to specific business models and their unique commercial barriers. Thus, a structured evaluation process is recommended to determine the appropriate level of state intervention:

(i) Evaluate the economic internal rate of return. Assess the project's broader economic benefits. If the economic internal rate of return is high, the project will likely deliver significant public value and may justify treatment as public infrastructure.

(ii) Assess the financial internal rate of return. If this is high, the project is commercially viable and should proceed as a standard B2B investment without governmental support. If it is medium, the project may require partial de-risking. The government can facilitate blended finance, combining private capital with concessional loans or guarantees to improve project profitability. If the financial internal rate of return is low, the government could combine direct public financing with private investment, potentially by segregating non-profitable scopes (e.g. shared infrastructure) for public funding while leaving commercial assets to the private sector. As a start, the government's role in the short term could be to facilitate grants and concessional finance from international organisations to de-risk initial pilot projects.

Specific sectors require distinct intervention mechanisms as indicated in Table.

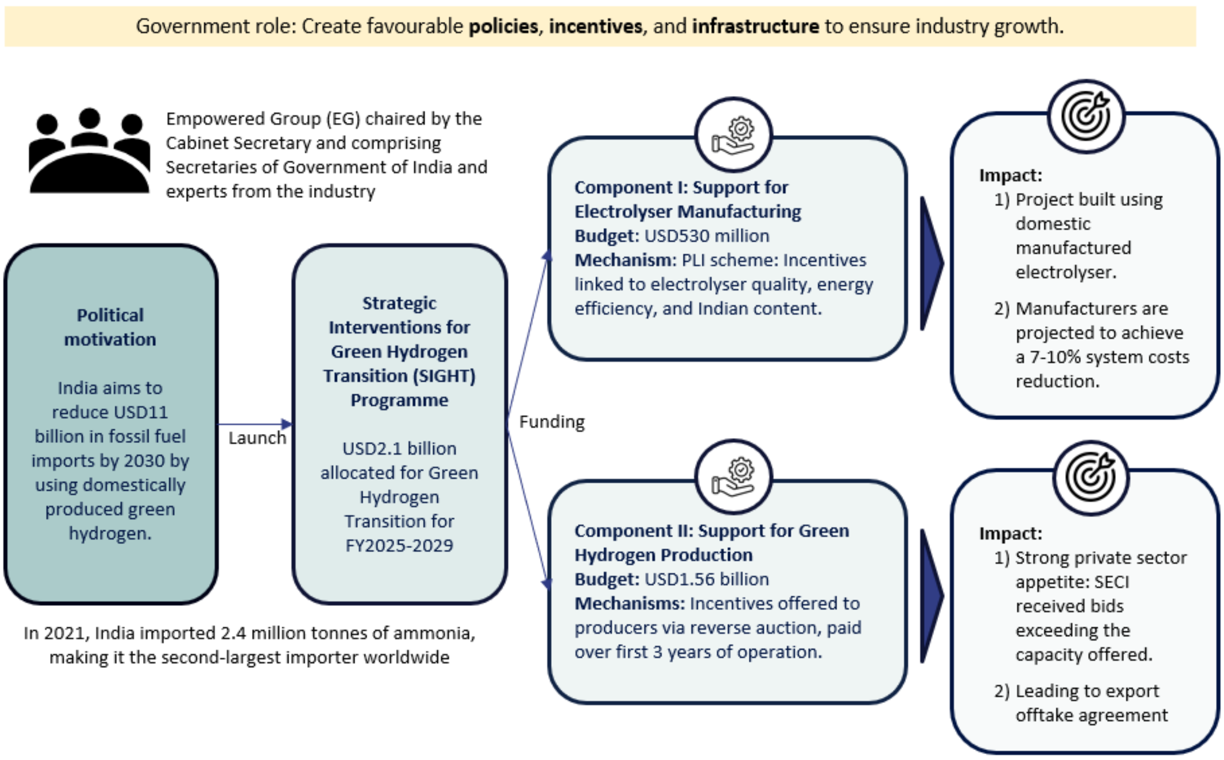
Table 3.1. Governmental Financial Support for Hydrogen Projects

Project Type	Example of Potential Governmental Financial Support
Green fuel and chemical exportation	• Designation of special economic zones for green product manufacturing (e.g. tax holidays and import duty exemptions for electrolysers). • If fiscal capacity allows, consider production incentives directly linked to export volumes.
Hydrogen refuelling stations	• The government should fund high capital expenditure assets, such as port storage and pipelines, treating them as shared utilities. • Providing tax incentives for fuel cell electric vehicle purchases will lower the barrier to entry for logistics operators.
Clean hydrogen for heavy industries	• The government should evaluate implementing a contracts-for-difference scheme. By guaranteeing a stable strike price for green hydrogen, this mechanism covers the gap between production costs and market prices, making projects bankable for private investors.

Project Type	Example of Potential Governmental Financial Support
	• With green public procurement, the government can create guaranteed demand through state budgets. For example, infrastructure projects could mandate a specific quota for green steel procurement, providing a secure anchor market for domestic producers.

Notes:
1. Operational expenditure support includes direct power purchase agreements/power wheeling, transmission fee exemption, special retail tariffs for hydrogen, contracts for differences, tax credits for the supply or demand side, and carbon credits.
2. Capital expenditure support includes land and public–private partnerships for ports, transmission lines, pipelines, and seawater desalination.
Source: Authors.

Figure 3.3. India's Strategic Interventions for Green Hydrogen Transition (SIGHT) Programme



SECI = Solar Energy Corporation of India.
Sources: Ministry of New and Renewable Energy (2023); Gulia et al. (2024); Rathi (2024); Raizada (2025).

5. 'No-regret' Ecosystem Development

While decisions on governmental financial support may take time, the government could meanwhile execute the following low-cost, high-impact, 'no-regret' actions to build foundational investor confidence.

(i) Support a regulatory framework. Immediate priorities include establishing technical standards, safety regulations, and business licensing for the entire value chain (i.e. production, transport, storage, and dispensing [specifically 350- and 700-bar standards]). In the long term, the government should implement stringent domestic carbon policies, such as via an emission trading scheme or carbon tax.[27] Emission trading scheme implementation – including penalties for non-compliance – in energy-intensive industries, aviation, and maritime will incentivise adoption of clean hydrogen.

(ii) Ensure institutional clarity. Clear ministerial roles and authority are essential. If hydrogen becomes a national priority, the government should establish a National Hydrogen Task Force, responsible for developing strategy, co-ordinating across ministries, monitoring progress, and de-bottlenecking pilot projects.

(iii) Seek bilateral cooperation. International partnerships are critical for scaling up. The government should secure bilateral agreements with key markets like Japan, the Republic of Korea, and the EU to guarantee long-term offtake for green exports such as ammonia and methanol. Additionally, these agreements should target technology transfer, local supply chain development, and funding for supporting infrastructure.

[27] A carbon tax of Rp30/kg of CO_2 is planned based on Law No. 7/2021. However, as of December 2025, it has not been implemented.

Chapter 4

Carbon Capture and Storage and Carbon Capture, Utilisation, and Storage Ecosystem Analysis

1. Value-chain Mapping

The CCS/CCUS ecosystem consists of three main segments:

(i) Capture. CO_2 sources can originate from various facilities, such as liquefied natural gas production sites, industrial processes, and fossil fuel-based power plants. CO_2 can be captured through several methods, including post-combustion capture using chemical solvents, pre-combustion capture through syngas processing, and industrial process capture from high-purity CO_2 streams.

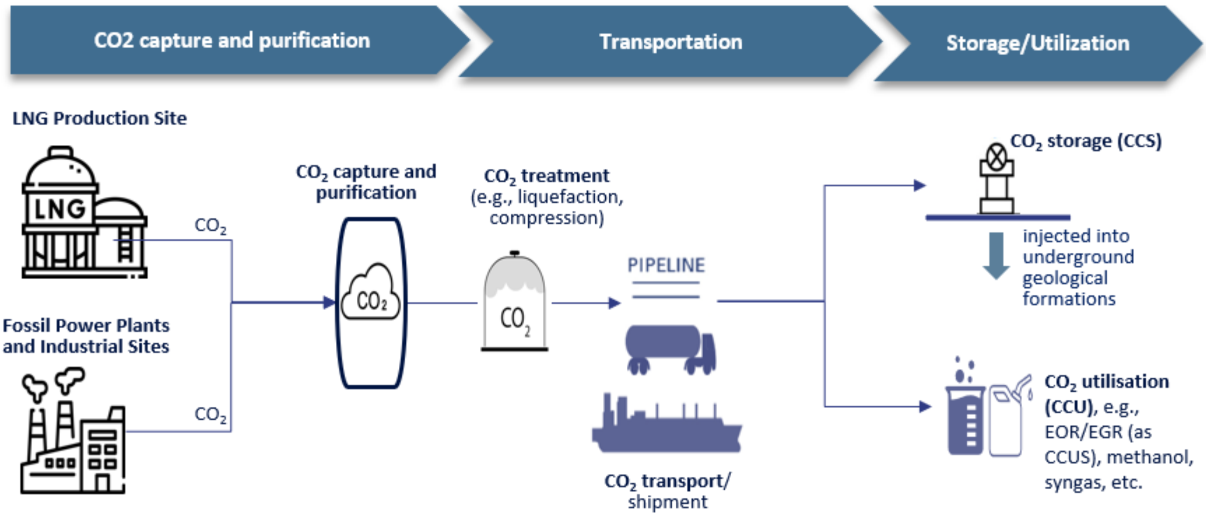
(ii) Treatment and transport. Once captured, CO_2 undergoes treatment to remove impurities and water to prevent corrosion and to ensure safety during transport. The treated CO_2 is then compressed into a supercritical state (i.e. liquefied or compressed into a dense phase) for transport, by shipping or pipeline.

(iii) Storage and/or utilisation. The captured CO_2 can be stored underground (e.g. in depleted oil or gas reservoirs or deep saline aquifers) or utilised to produce valuable products (e.g. methanol or syngas). Additionally, CO_2 can be applied in EOR or enhanced gas recovery (EGR) to boost production. Besides underground storage, CO_2 can be used as product feedstocks.[28]

A reference to CCS technology readiness is presented in the appendix.

[28] CCS involves capturing and permanently storing CO_2 underground; CCUS includes both using and storing captured CO_2, such as EOR/EGR.

Figure 4.1. CCS/CCUS Value Chain



CCS = carbon capture and storage; CCU = carbon capture and utilisation; CCUS = carbon capture, utilisation, and storage; CO_2 = carbon dioxide; EGR = enhanced gas recovery; EOR = enhanced oil recovery; LNG = liquefied natural gas.
Source: Authors.

In Indonesia, CCS/CCUS development remains in the early stages, with several projects still in the study or pilot phase. However, certain projects – most notably the Tangguh CCUS project – have progressed to the investment and development stage, having reached FID (ESDM, 2025b). The ongoing and planned initiatives across the CCS/CCUS value chain are summarised in Table .

Table 4.1. CCS/CCUS Projects in Indonesia

Project Name and Location	Companies Involved	Description	Related Value Chain Segment
Tangguh CCUS, West Papua	Pertamina, BP (as operator), Mitsubishi, INPEX, JX Nippon Oil and Gas Exploration Corporation, MITSUI and Co, LNG JAPAN Corporation, Japan Organization for Metals and Energy Security (JOGMEC)	Captures CO_2 produced during LNG processing and re-injects it into the Vorwata reservoir for enhanced gas recovery. It is the most advanced large-scale project in Indonesia (FID approved 2021, under construction).	Entire value chain

Project Name and Location	Companies Involved	Description	Related Value Chain Segment
Sukowati CCUS, East Java	Pertamina EP, Japan Petroleum Exploration (JAPEX)	Captures CO_2 from a nearby gas field (Jambaran Tiung Biru), moving towards large-scale implementation (Phase 2).	Entire value chain
Jatibarang CCUS, West Java	Pertamina, JOGMEC	Proved the technical feasibility of CO_2 EOR in the field; first implemented CO_2 injection pilot (huff and puff method) in 2022.	Entire value chain
Gundih CCS, Central Java	Pertamina, JGC, Janus, J-Power	Captures CO_2 from the Gundih gas plant and injects it into a nearby aquifer/reservoir.	Entire value chain
Abadi CCS, Masela Block, Arafura Sea	Inpex (Operator), Pertamina, Petronas	Includes CCS to capture CO_2 from the offshore gas field and to re-inject it into the Abadi reservoir.	Entire value chain
Sakakemang CCS, South Sumatra	Repsol, Pertamina, Mitsui Energy Development	Plans to capture CO_2 and to re-inject it into depleted fields nearby to enable gas sales; the Kaliberau field has a high CO_2 content (around 26%).	Entire value chain
South Sumatra BECCS	Pertamina, Marubeni	Involves capturing CO_2 from biomass boiler of a pulp mill and storing it in synclinal aquifers in the northern Limau oil field, which is operated by Pertamina.	Entire value chain
Sunda Asri CCS Hub, offshore of West Java	Pertamina, ExxonMobil	Targets depleted oil/gas fields and saline aquifers with massive capacity (3 gigatonnes). It aims to serve industries in Java and potentially import CO_2 from the region (Singapore).	Transport and storage
Kutai Basin CCS Hub, East Kalimantan	Chevron, Pertamina	Evaluates a CCS hub utilising depleted fields in the prolific Kutai Basin to serve local industries (LNG, fertiliser).	Transport and storage
Arun CCS Hub, Aceh	PEMA, Carbon Aceh	Utilises the massive, depleted Arun gas reservoir near the Malacca Strait, positioning it as a	Storage

Project Name and Location	Companies Involved	Description	Related Value Chain Segment
		prime candidate for receiving shipped CO_2 from overseas.	
Fossil fuel power plants + CCS	PLN Enjiniring	Plans to add 2 GW of power plants with CCS by 2040, as part of a larger plan to use CCS/CCUS in about 19 GW of capacity by 2060. This plan is still being studied for PLTU Suralaya, PLTU Indramayu, PLTU Tanjung Jati, PLTGU Tambak Lorok.	Capture

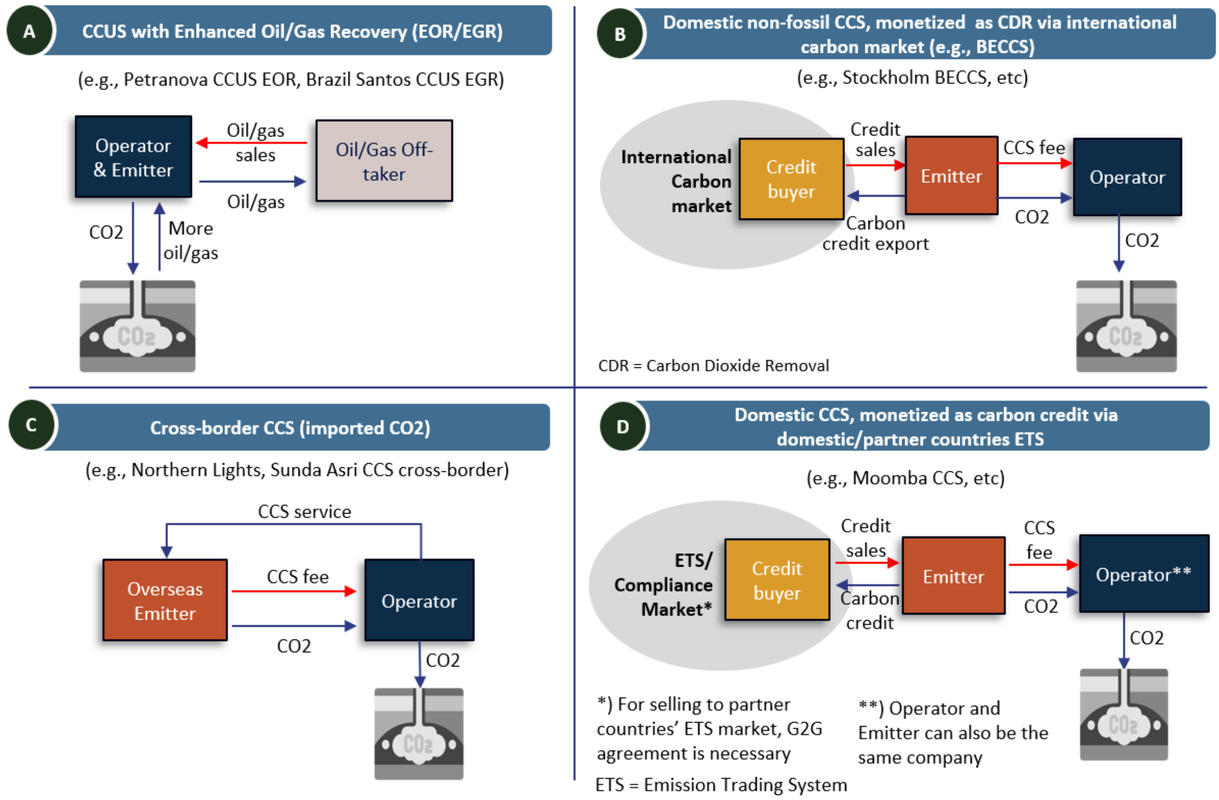
CCS = carbon capture and storage; CCUS = carbon capture, utilisation, and storage; CO_2 = carbon dioxide; EOR = enhanced oil recovery; GW = gigawatt; LNG = liquefied natural gas.
Sources: BP (2024), JAPEX (2023), JOGMEC (2022), J-Power (2021), ESDM (2023c), Petromindo.com (2025), Siahaan (2025), Hendriawan (2025).

In addition, CCS/CCUS is reflected in Indonesia's broader energy planning frameworks, including the *Electricity Supply Business Plan* (RUPTL) and the *National Energy Policy* (KEN). The RUPTL states that coal-fired power plants reaching the end of their techno-economic lifetime or the expiration of their power purchase agreements may have their operating periods extended, provided that they adopt emission reduction technologies such as CCS/CCUS (ESDM, 2025b). As an initial step towards CCS deployment, PLN plans to implement a CCS pilot project at a coal-fired power plant with a capacity of up to 1 gigawatt by 2030. PLN is also evaluating the potential use of integrated gasification combined-cycle and CCS technologies to achieve further reductions in greenhouse gas emissions, although actual deployment will depend on the commercial maturity of these technologies. Meanwhile, KEN, as stipulated in Government Regulation No. 40/2025 (Article 58), permits the development of non-renewable energy resources using low-carbon technologies, including CCS and CCUS (ESDM, 2023b).

2. CCS/CCUS Business Models

For this study, four business models were defined based on the primary sources of revenue (**Error! Reference source not found.**): (i) CCUS with EOR/EGR; (ii) domestic non-fossil CCS, monetised as carbon dioxide removal (CDR) via international carbon markets (e.g. bioenergy with carbon capture and storage [BECCS]); (iii) cross-border CCS (i.e. imported CO_2); and (iv) domestic CCS, monetised as carbon credits via domestic or partner countries' emission trading systems (ETS). These models were selected based on findings from international benchmarks of operating or developing CCS projects, as well as their relevance to the pilot projects assessed in this study. The classification was made for simplicity based on the main revenue sources. In practice, a single project may generate revenue from multiple sources simultaneously or due to a combination of multiple business models.[29]

Figure 4.2. CCS/CCUS Business Models



BECCS = bioenergy with carbon capture and storage; CCS = carbon capture and storage; CCUS = carbon capture, utilisation, and storage; CO_2 = carbon dioxide; EGR = enhanced gas recovery; EOR = enhanced oil recovery; ETS = emission trading system; LNG = liquefied natural gas.

Notes:

1. For simplicity, the project schemes are categorised by their primary revenue sources (i.e. CCS service fees for cross-border projects, carbon credit sales, and oil/gas sales from EOR/EGR). In practice, a single project may generate revenue from multiple sources simultaneously.
2. It is assumed that the operator and the storage owner are the same entity.

Source: Authors.

2.1. CCUS with EOR/EGR

In this model, CO_2 – typically from oil or gas production – is injected into the same or nearby reservoir to enhance oil and gas recovery. The emitter often serves as the CCS operator. Revenue is generated from the additional oil or gas produced through the EOR/EGR process. Examples include the Petra Nova CCUS project in the US and the Santos Basin CCUS project in Brazil. Several CCUS projects with EOR/EGR around the world are already

[29] For example, the Tangguh CCUS project may generate revenue from the additional gas produced from the EGR process and potentially from monetising carbon credits through the Joint Crediting Mechanism (JCM).

operating on a commercial basis, requiring little to no governmental support. In Indonesia, the Tangguh CCUS–EGR project has already reached its FID.

2.2. Domestic Non-fossil CCS

This model captures CO_2 from non-fossil or carbon-neutral sources, such as biomass power plants. When CCS is applied, the overall process can achieve net-negative emissions, enabling the generation of premium carbon credits, referred to as CDR credits. These credits can be sold on international carbon markets at higher prices, typically around US$200–300/tonne (CDR.fyi, 2023). In this arrangement, emitters transfer captured CO_2 to a CCS operator for transport and storage, paying service fees for the process. An example is the BECCS Stockholm project in Sweden.

2.3. Cross-Border CCS

In this scheme, CO_2 emissions are transported from overseas emitters to domestic storage sites. The emitters may include industries seeking to reduce their emissions, such as cement, steel, petrochemicals, refining, and fertiliser production; industries aiming to produce low-carbon products like blue ammonia or hydrogen; as well as fossil fuel-based power plants, natural-gas processing facilities, and other sectors with significant CO_2 footprints. The CCS operator's main revenue comes from transport and storage service fees paid by foreign emitters. Examples include the Northern Lights CCS project in Norway and the Sunda Asri CCS initiative.

2.4. Domestic CCS

This model is similar to domestic non-fossil CCS, but the CO_2 sources may include both fossil and non-fossil emitters. The emitters may also include industries seeking to reduce their emissions, such as cement, steel, petrochemicals, and fertiliser; industries aiming to produce low-carbon products like blue ammonia or hydrogen; as well as fossil fuel-based power plants and other sectors. The resulting carbon credits are classified as standard (i.e. non-premium) credits, which can be traded in compliance carbon markets or ETS, either domestically or through partner countries. Cross-border ETS participation requires G2G agreements. The viability of this model depends on the maturity and stability of the domestic or partner country's compliance carbon market ecosystem. An example is the Moomba CCS project in Australia.

2.5. Potential Revenue Streams

Beyond the four business models described, CCS/CCUS projects can access a wider range of potential revenue streams depending on applicable market mechanisms, such as carbon taxes, ETS, voluntary carbon markets, IMO regulations, CBAM policies, and the oil and gas market. Some of these mechanisms can generate direct revenue (e.g. through the sale of carbon credits or increased oil and gas production). Others do not provide direct revenue but create compliance pressures that encourage CCS/CCUS adoption (e.g. carbon taxes, carbon prices, or penalties associated with high-emission fuels or products under IMO or CBAM policies). The summary of potential market mechanisms for CCS/CCUS projects are listed in

Table.

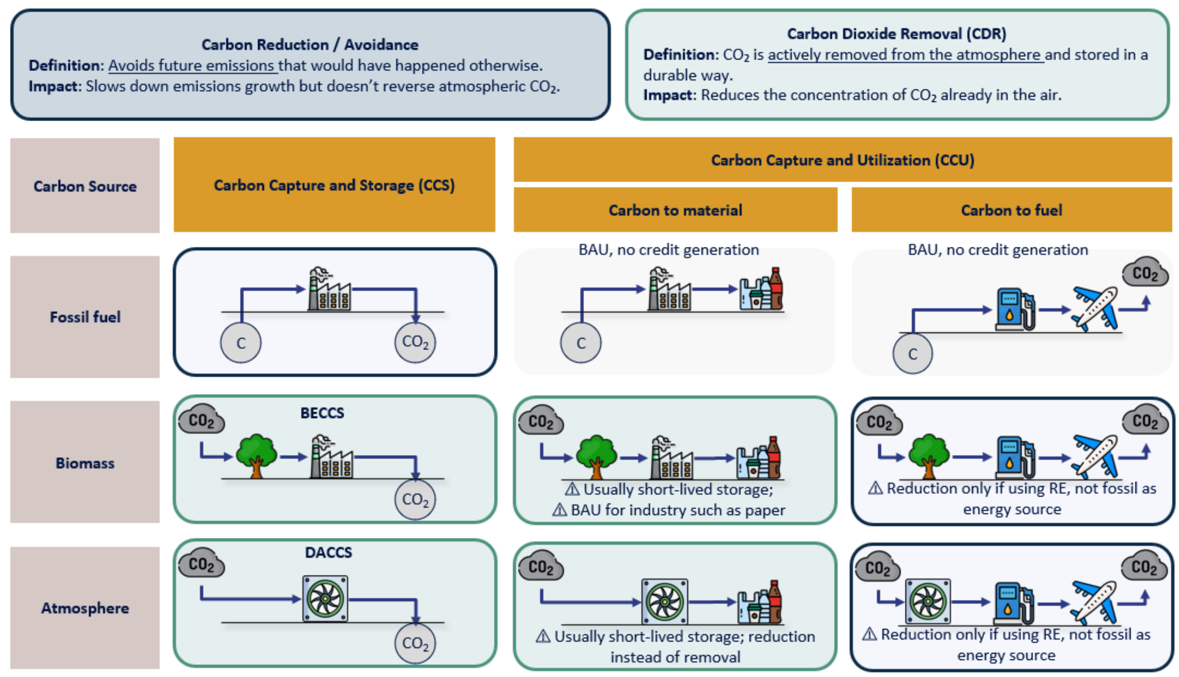
Table 4.2. Potential CCS Market Mechanisms

Available Market Mechanisms	Possible Revenue/Commercial Pressure
Carbon tax	Avoidance of carbon tax liabilities
ETS	Avoidance of carbon price or revenue from selling ETS allowances
Voluntary carbon market	Revenue from selling carbon credits
Voluntary CDR market	Revenue from selling CDR credits
International Maritime Organization policy	Premium pricing for low-carbon shipping fuels
Cross-border Adjustment Mechanism policy	Ability to maintain competitiveness in export markets through low-carbon products; potential premium for cleaner products
Oil and gas market	Revenue from increase in oil and gas sales enabled by CCUS EOR/EGR

CCUS = carbon capture, utilisation, and trading; CDR = carbon dioxide removal; EGR = enhanced gas recovery; EOR = enhanced oil recovery; ETS = emission trading system.
Source: Authors.

Box 4.1. Carbon Reduction Credit versus Carbon Dioxide Removal Credit

Carbon capture and storage (CCS) projects can generate either carbon-reduction credits or carbon dioxide removal (CDR) credits, depending on the source of the carbon dioxide (CO_2) being captured**Error! Reference source not found.**. Carbon reduction aims to avoid future emissions that would otherwise occur (e.g. capturing CO_2 from burning fossil fuels in a power plant prevents those emissions from being released into the atmosphere). CDR goes further by actively taking CO_2 out of the atmosphere and storing it in a durable form, either through natural processes such as reforestation or through technological solutions like bioenergy with carbon capture and storage (BECCS) and direct air capture. In BECCS, CO_2 is first absorbed by plants as they grow; the biomass is then burned to produce energy, and the resulting CO_2 emissions are captured and permanently stored or utilised. This process achieves net-negative emissions because it removes atmospheric CO_2. While both approaches support climate-mitigation goals, carbon reduction slows the growth of new emissions, whereas CDR removes existing atmospheric CO_2, making it crucial for achieving net-zero and eventually net-negative emissions targets.

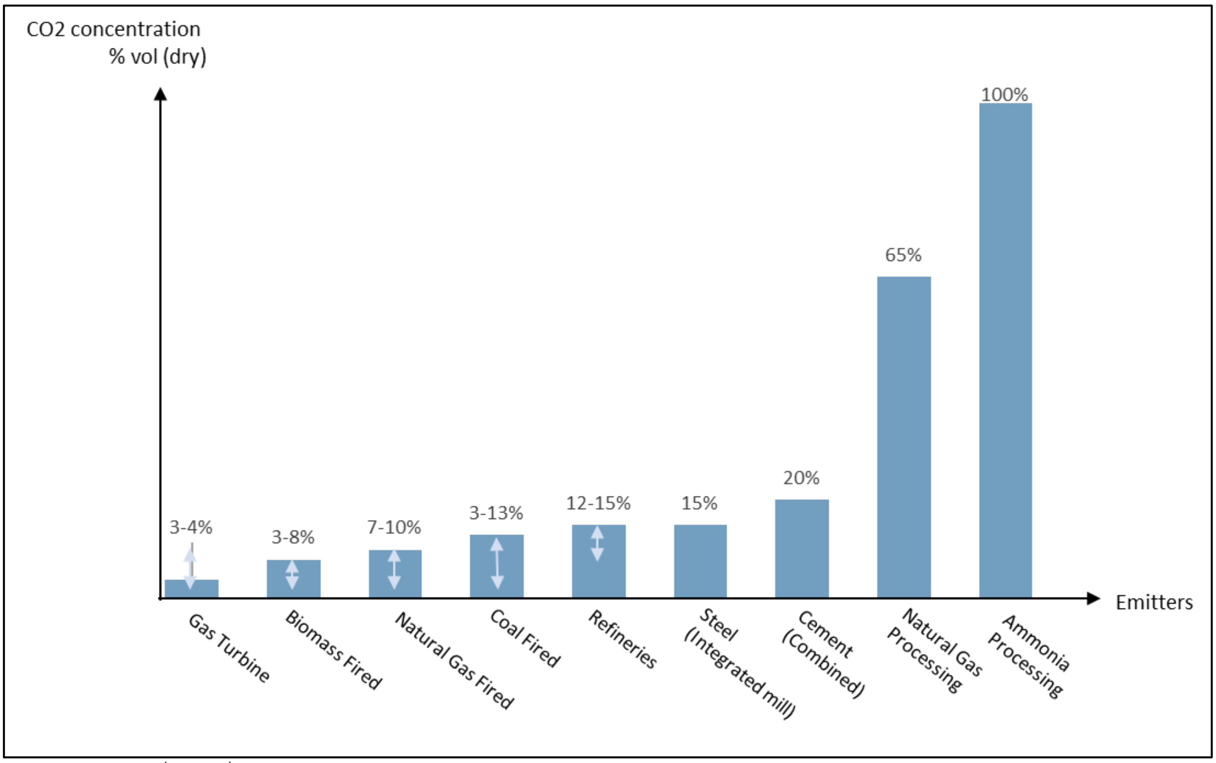


BAU = business as usual, BECCS = bioenergy with carbon capture and storage, CO_2 = carbon dioxide, DACCS = direct air carbon capture and storage, RE = renewable energy.
Source: South Pole (2023).

Furthermore, CCS/CCUS project configurations can vary significantly.[30] Key differentiating factors include the structure of the value chain, jurisdiction in which the CO_2 is captured, and whether the CO_2 is geologically stored or utilised as an industrial feedstock.

[30] See a further explanation of various CCS/CCUS business models in the appendix.

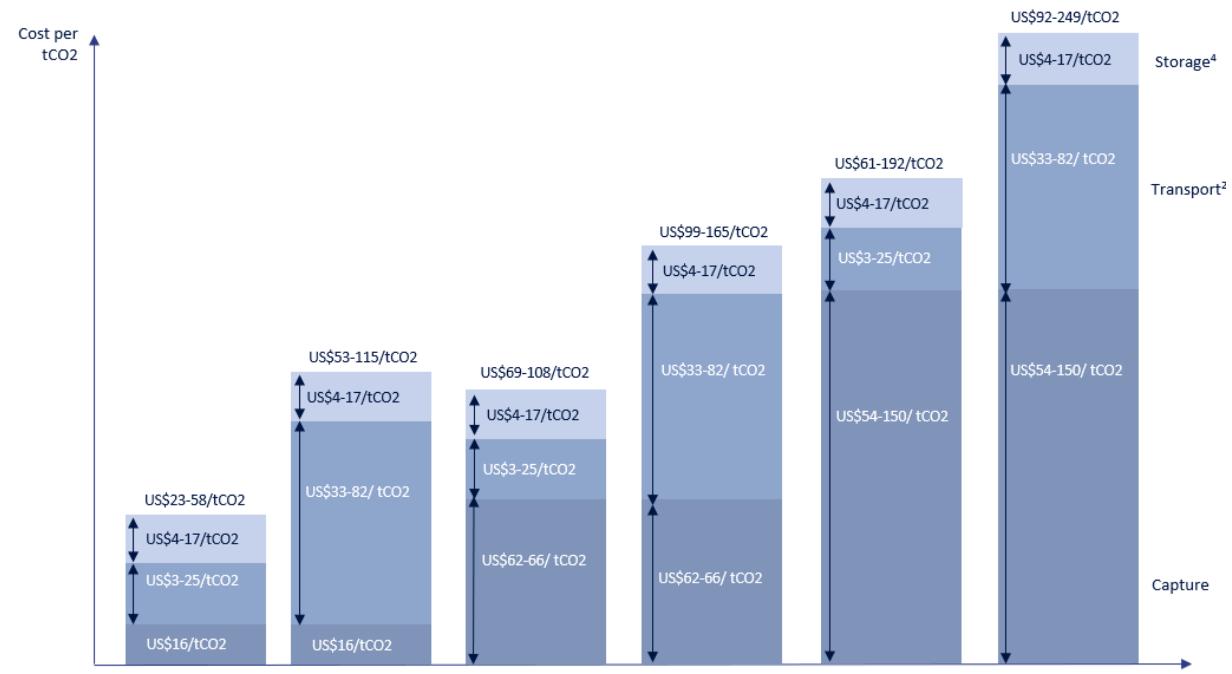
Figure 4.3. Typical CO_2 Concentrations across Various Potential Emitters



Source: IPCC (2005).

The characteristics of the CO_2 source influence capture costs, which are one of the major components of total CCS/CCUS project costs. Different CO_2 sources have different properties, such as CO_2 concentration levels (i.e. partial pressure), capture efficiency rates (i.e. the proportion of CO_2 per unit volume that is captured), energy required to capture the CO_2 (and to regenerate solvents/sorbents where necessary), scale of the plant, and minimum capture rate. Figure 4.3 provides an overview of typical CO_2 concentrations across various sources; in general, higher CO_2 concentration leads to lower energy requirements and therefore lower capture costs. The variety of total estimated CCS costs for different CO_2 source and transport scenarios are summarised in Figure 4.4.

Figure 4.4. Variety of Whole Value Chain CCS Cost



	Segment 1	Segment 2	Segment 3	Segment 4	Segment 5	Segment 6
CO2 source	Gas processing plant[1]	Gas processing plant[1]	Hard-to-abate industries	Hard-to-abate industries	CFPP	CFPP
Transport	Pipeline (<500km)	Shipping (>500km)	Pipeline (<500km)	Shipping (>500km)	Pipeline (<500km)	Shipping (>500km)

CCS = carbon capture and storage, CFPP = coal-fired power plant, km = kilometre, tCO_2 = tonne of carbon dioxide.
[1]The capture cost for the gas-processing plant is only for compression, intercooling, and related activities.
[2]The pipeline transport cost is assumed for dense phase at 1 million tonnes per annum with a distance of 100–500 km (i.e. US$0.05/tonne/kilometre). The shorter the pipeline, the cheaper the transport cost.
[3]The shipping transport cost is assumed using both low and medium pressure with a volume of 10,000–50,000 tonnes. Low-pressure CO_2 shipping contributes to a lower shipping cost.
[4]Storage cost is assumed for both saline aquifer and depleted oil/gas reservoir with and without existing wells. The cheapest cost is for onshore depleted oil/gas reservoir with existing wells.
Source: Authors' calculations based on ERIA and Indonesia National Energy Council (2025), Hughes and Zoelle (2022), GCCSI (2025), CESGS (2025), Muzakki (2025), Quantum (2025), Estes Consultancy (2025).

3. Findings from Selected Projects

Two typical CCS project models are further analysed in this study – dedicated CCS and BECCS projects.

3.1. Dedicated CCS Projects

This project is typically developed by an oil and gas company to capture CO_2 emitted from its operations, such as natural gas-processing plants. CO_2 is then injected into a nearby oil and gas reservoir for permanent storage. Since it does not produce additional oil or gas recovery, its only revenue stream comes from the sale of carbon credits. The project can be registered to an accrediting programme,[31] such as the Joint Crediting Mechanism (JCM). In the JCM, the generated credits can be sold into Japan's upcoming ETS market.[32]

Such projects face several key challenges, however, including an unavailable implementation framework for carbon credit exportation, unavailable specific methodology[33] on CCS in the accrediting programme, a significant gap between project cost and carbon prices under current conditions, and uncertain demand for carbon credits generated from CCS or related to fossil fuels.

3.2. BECCS Projects

BECCS projects capture CO_2 emissions from a biomass boiler/power plant that supplies electricity and/or steam to grid or industrial facilities. The captured CO_2 is transported and stored in an underground reservoir, ideally near the plants. BECCS projects result in negative emissions, thus having the potential to generate CDR credits, which can be sold at higher prices than conventional carbon credits.

Interviews with relevant stakeholders identified several key implementation challenges, however. Although Presidential Regulation No. 110/2025 allows carbon credit exports, detailed implementing regulations have not yet been developed. The implementing regulations are expected to provide further clarity, including procedures for registering voluntary carbon market projects under the newly established National Registry System for Climate Change Control (SRN PPI) and Carbon Unit Registry System (SRUK) systems[34] as well as guidance on the applicability of international standards in relation to national regulatory requirements. In addition, BECCS methodologies are available through several accreditation programmes, but they have not yet been established under SRN PPI,[35] requiring further development and alignment with international standards. Finally, CDR credits are sold in voluntary carbon markets, but projects relying on voluntary carbon markets may face bankability and financing challenges due to demand uncertainty and price volatility.

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[31] Major carbon credit accreditation/registries include American Carbon Registry, Climate Action Reserve, Global Carbon Council, Gold Standard, Plan Vivo, Puro.earth, and Verra.

[32] Japan's ETS, known as GX-ETS, is transitioning from a voluntary phase to a mandatory one, starting in April 2026. The mandatory phase will cover 300-400 large emitters (i.e. above 100,000 tonnes of CO_2 annually) and establish a cap-and-trade system with emission quotas.

[33] A carbon credit methodology is a standardised set of rules and parameters used to calculate and to verify the greenhouse gas emission reduction or removal from a specific climate project.

[34] The SRN PPI functions as Indonesia's national system for monitoring progress on emission reduction and adaptation commitments under the NDC, whereas SRUK serves as the official registry for issuing, managing, transferring, and retiring carbon units.

[35] Under Presidential Regulation No. 110/2025, project owners seeking to issue carbon credits are required to prepare a mitigation action plan document and project design document, which must include the methodology applied in the project. However, it remains unclear whether the methodology must refer to those listed under SRN PPI or whether international accreditation standards may also be used.

4. Key Commercial Barriers

Based on the findings from the pilot projects, there are several key challenges in CCS/CCUS project development.

4.1. Underdeveloped Implementation Regulations and Unclear Mechanisms for Carbon Credit Export

There are several pathways for monetising carbon credits which can generally be grouped into two categories: governmental registry accreditation and private registry accreditation (Figure 4.5).

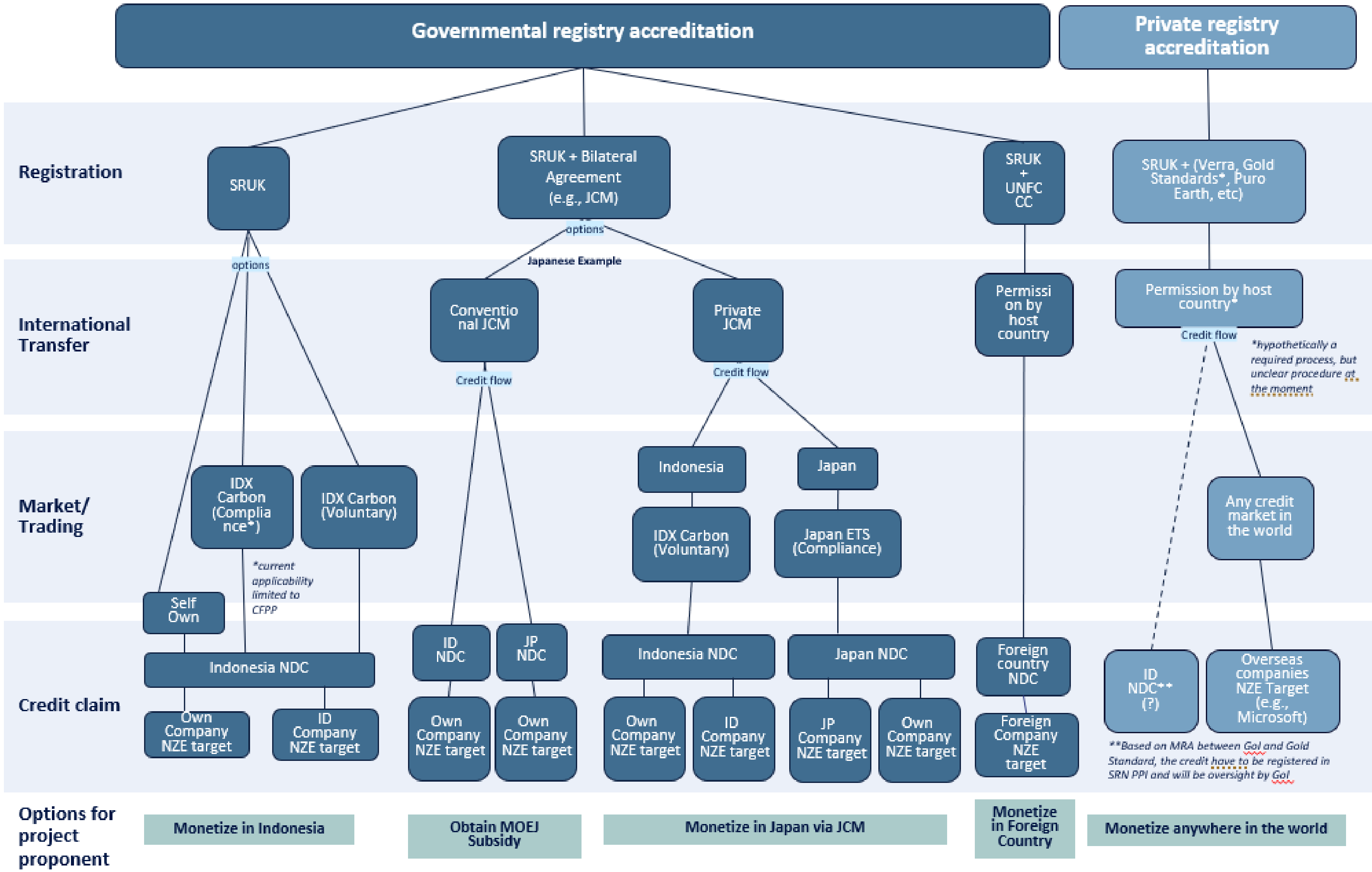
Governmental registry accreditation is typically used when carbon credits are sold on (i) the domestic market, (ii) a partner country's compliance market under a bilateral cooperation framework (e.g. the JCM under Paris Agreement Article 6.2), or (iii) international markets under Article 6.4 of the United Nations Framework Convention on Climate Change.

For monetisation under bilateral G2G arrangements, countries usually require a mutual recognition agreement along with detailed implementing guidelines that specify procedures, standards, and verification rules. In the JCM, projects may utilise either the conventional JCM scheme or private JCM scheme. However, the conventional JCM – which provides financial support – has a funding cap of around US$10 million, making it insufficient for capital-intensive CCS projects. Therefore, to maximise its monetisation potential, larger projects can use the private JCM mechanism, which allocates all carbon credits to the project developer and allows the selling of the credits on Japan's ETS.

Indonesia's Ministry of Environment and Forestry and Japan's Ministry of the Environment signed a mutual recognition agreement for the JCM in October 2024 (Ministry of the Environment, 2024). Nevertheless, operational-level implementing guidelines – covering procedures, methodologies, verification standards, and registries – have not yet been issued. As of December 2025, the ministries formed a joint task force to accelerate preparation of these guidelines.

Private registry accreditation applies when carbon credits are intended for the voluntary carbon market. Alignment is required between Indonesia's national standards and those of international private standards such as Gold Standard, Puro.earth, and Verra. In addition, exporting credits to voluntary carbon market platforms typically requires host-country authorisation, a procedure that remains undefined in Indonesia.

Figure 4.5. Pathways of Carbon Credit Monetisation



ETS = emissions trading system, JCM = Joint Crediting Mechanism, JP = Japan, ID = Indonesia, IDX = Indonesia Stock Exchange, NDC = nationally determined contribution, NZE = net-zero emissions, MRA= Mutual Recognition Agreement, SRUK = *Sistem Registri Unit Karbon*, UNFCCC = United Nations Framework Convention on Climate Change.

Source: Authors.

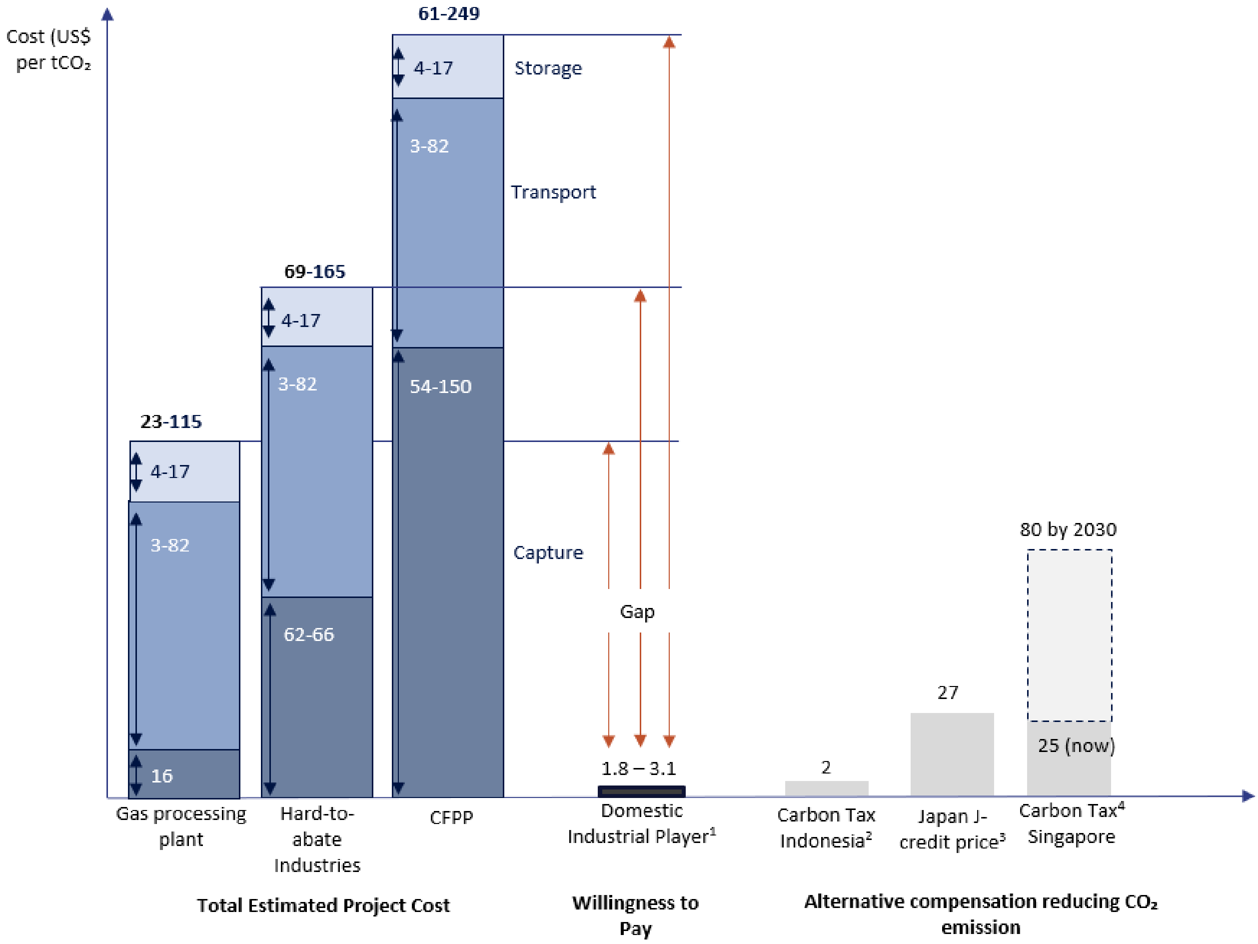
4.2. Significant Price Gap between Project Cost and Offtaker Willingness-to-Pay

Based on a global survey, CCS costs vary depending on the emission source, as different types of flue gas require different capture technologies. The higher the CO_2 concentration in the gas stream, the lower the capture cost. For example, capturing CO_2 from gas-processing plants is significantly cheaper than capturing them from coal-fired power plants.

However, even for project configurations with lower capture costs, the overall CCS cost remains higher than current market willingness-to-pay, as reflected in existing carbon prices (Figure 4.6). Total CCS project costs vary, ranging from US$23 to US$249 per tonne of CO_2. Meanwhile, carbon pricing remains low, as indicated by Indonesia's carbon tax (US$2/tonne) and Singapore's carbon tax (US$25/tonne). Although these prices are expected to rise,[36] these levels are still insufficient to make most CCS projects commercially viable. Therefore, the significant price gap between CCS costs and existing or expected carbon prices remains a major barrier to investment and deployment.

[36] Singapore's tax is increasing to US$80/tonne by 2030, and Japan's ETS price is expected to align with Japan's J-credit price of around US$27/tonne.

Figure 4.6. CCS Total Project Cost versus Offtaker Willingness to Pay



CFPP = coal-fired power plant, tCO_2 = tonne of carbon dioxide.

Note: Total project costs are estimated based on data from published documents as mentioned in the sources. Calculation was done with several assumptions as follows:

(i) The capture cost for gas-processing plants is only for compression, intercooling, and related activities. The capture cost is for hard-to-abate industries, including for cement and iron/steel.

(ii) Transport costs are assumed for various modes, including pipelines for distances below 500 kilometres (km) and shipping for distances above 500 km. The pipeline transport cost is assumed for a dense phase at 1 million tonnes per annum with distances of 100–500 km (i.e. US$0.05/tonne/km). The shorter the pipeline, the cheaper the transport cost. The shipping transport cost is assumed using both low and medium pressures with a volume of 10,000–50,000 tonnes. Low-pressure CO_2 shipping contributes to lower shipping costs.

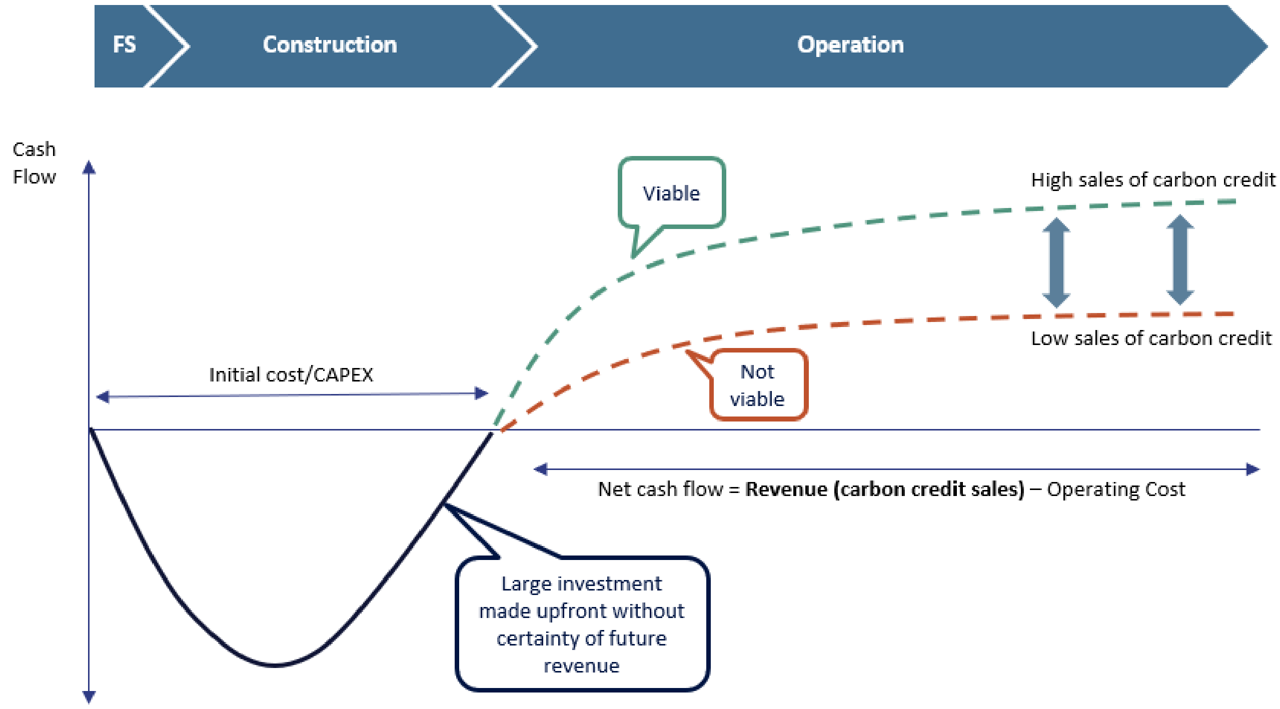
(iii) The storage cost is assumed for both saline aquifers and depleted oil/gas reservoirs with and without existing wells. The cheapest cost is for onshore depleted oil/gas reservoirs with existing wells.

Source: ERIA and Indonesia National Energy Council (2025), Hughes and Zoelle (2022), GCCSI (2025), CESGS (2025), Muzakki (2025), Quantum (2025), Estes Consultancy (2025).

4.3. Revenue Uncertainties Due to Uncertain Demand and Price

CCS projects require substantial upfront investment, yet future revenue streams are often uncertain, particularly when projects rely on carbon credit sales (Figure .7). In many cases, there is no guarantee that the generated credits will be purchased, which is a significant revenue risk. This high level of uncertainty can discourage private investors from committing large amounts of capital at the early stages of project development. In addition, due to carbon price volatility, CCS asset owners increasingly expect higher carbon credit prices and shorter payback periods to justify investment.

Figure 4.7. Demand Risk of CCS Projects

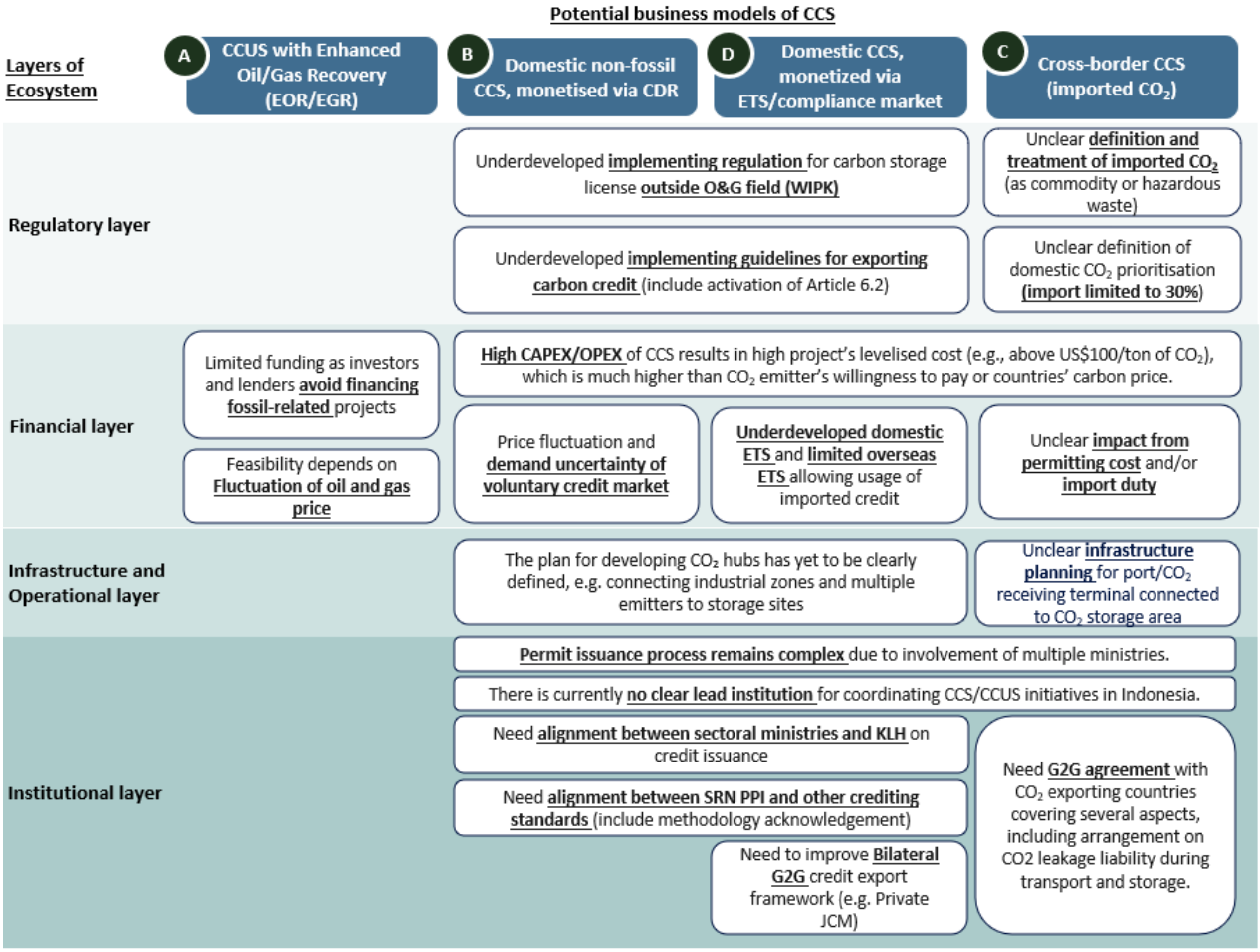


CAPEX = capital expenditure, CCS = carbon capture and storage.
Source: Authors.

In addition to these challenges, there are issues across the broader ecosystem layers, including regulatory, financial, infrastructure, and operational, as well as institutional aspects (

Figure).

Figure 4.8. CCS/CCUS Issues across Ecosystem Layers



CAPEX = capital expenditure; CCS = carbon capture and storage; CCUS = carbon capture, utilisation, and storage; CDR = carbon dioxide removal; CO_2 = carbon dioxide; EGR = enhanced gas recovery; EOR = enhanced oil recovery; ETS = Emission Trading System; G2G = government-to-government; JCM = Joint Crediting Mechanism; O&G = oil and gas; OPEX = operating expenditure; SRN PPI = *Sistem Registri Nasional Pengendalian Perubahan Iklim*.

Source: Authors.

5. Lessons from Successful Overseas Cases

Several operational CCS/CCUS projects overseas were studied. The key findings are as follows (Figure 4.9):

(i) These international cases demonstrate a clear linkage to national priorities or strategic benefits, which are essential to justify strong governmental support for project implementation. For instance, countries with established oil and gas industries (e.g. Australia, Brazil, and Norway) have positioned CCS as a national priority, given its role in supporting and sustaining key industrial sectors. These countries also benefit from existing tangible assets (e.g. extensive geological CO_2 storage potential and existing oil and gas infrastructure) and intangible assets (e.g. domestic technical expertise and established networks with emitter countries).

(ii) The presence of an enabling ecosystem – particularly through the enforcement of emission regulations such as emission caps, carbon taxes, or ETS – is critical to ensuring demand certainty for carbon credits or allowances and to expanding market potential.

(iii) In most of the overseas projects analysed, governments provide financial support or subsidies to cover part of the CAPEX and/or operating expenditures, thereby improving financial viability. This is also consistent with earlier findings, which show that global experience demonstrates the need for substantial public finance to mobilise private investment and to accelerate CCS deployment (GCCSI, 2024).

Figure 4.9. Lessons Learned from Overseas CCS/CCUS Cases

		National Priority	Ecosystem Enabler		Business Model Success Factor	
	Overseas projects	National benefit	Pressure/Drive from emission regulation	Government supports / subsidies	Additional Revenue/ Cost avoidance	Large Injection Volume (Design)
A CCUS EOR/ EGR	[US] Petranova CCUS-EOR Project*	• Decarbonise heavy industry • Maintain jobs in O&G sectors • Become tech leaders	N/A	• Tax credit 45Q** for each tonne CO2 stored • CAPEX support from Department of Energy of US	Increased oil sales	1.4 Million tonnes CO2/year
	[Brazil] Santos Basin CCUS-EOR project	• Support its LNG industry	• Potential implementation of Brazil ETS (not implemented yet) • No carbon tax	N/A	• Avoiding high operating costs from high CO_2 content • Increased oil sales	>10 Million tonnes CO2/year
B CCS CDR	[Sweden] Stockholm BECCS project	• Achieve negative emission after 2045 • Being leader for carbon removal market	• Future potential for trading negative emissions in EU ETS • Carbon tax in Sweden is EUR134 (USD155)/tonne in 2025	• CAPEX Support from EU Innovation Fund • OPEX Support from Sweden Gov't in the form of Base revenue support for each tonne credit generated	• Sales of Carbon Dioxide Removal (CDR) credit to overseas private buyers (Voluntary Carbon Market) • CDR average price in 2023 is USD300/tonne****	0.8 Million tonnes CO2/year
C Cross Border CCS	[Norway] Northern Light CCS project	• Provide CO2 storage service to EU • Utilise off-shore asset and expertise	• Driven by EU ETS regulation (emission cap for industries) • Carbon tax in Norway is EUR124 (USD143)/tonne in 2025	• 80% subsidy for project cost	• CO2 transport and storage fee	1.5 Million tonnes CO2/year
D CCS Carbon credit via ETS	[Australia] Moomba*** CCS Projects	• Support its LNG industry • Use its vast storage site to be a Regional CO_2 Hub	• Implementation of Australia's Safeguard Mechanism (emission cap for high emitters, including O&G sector) • No carbon tax • Carbon credit can be sold to other emitters or interested buyers	• CAPEX support from Australian Gov't	• Avoidance of carbon offset purchase • Sales of Australian Carbon Credit Units (ACCUs) in ETS (Safeguard Mechanism) or domestic Voluntary Carbon Market • ACCU is traded at AUD30-35 (USD22)/tonne in 2024*****	1.7 Million tonnes CO2/year

BECCS = bioenergy carbon capture and storage; CAPEX = capital expenditure; CCS = carbon capture and storage; CCUS = carbon capture, utilisation, and storage; CDR = carbon dioxide removal; CO_2 = carbon dioxide; EOR = enhanced oil recovery; ETS = Emission Trading System; EU = European Union; G2G = government-to-government; LNG = liquefied natural gas; Mtonne = million tonnes; O&G = oil and gas; OPEX = operating expenditure.

Source: Authors.

*Operations were suspended in 2020 due to the oil price downturn and resumed in 2023. **The US 45Q tax credit is a federal incentive administered by the Internal Revenue Service, providing per-tonne tax credits for the capture and secure storage or utilisation of carbon dioxide. ***The Moomba CCS project was developed to comply with Australia's Safeguard Mechanism; any surplus carbon credits may be sold as an additional revenue stream.

****The exact CDR price for the Stockholm BECCS project is not publicly disclosed; the value shown represents the global average BECCS CDR price.

*****The exact ACCU price for the Moomba CCS project is not publicly disclosed; the value shown represents the average ACCU price in Australia in 2024 across all projects.
Sources: Wellborn (2017), EIA (2017), Denis-Ryan and Morrison (2025), Taylor (2021), SeaWanderer (2025), Höglund (2024), EC (2022), NIB (2024), Clean Energy Regulator (2024; 2025), CDR.fyi (2023), BECCS Stockholm, https://beccs.se/news/stockholm-exergis-beccs-project-receives-180-million-eur-in-eu-funding/

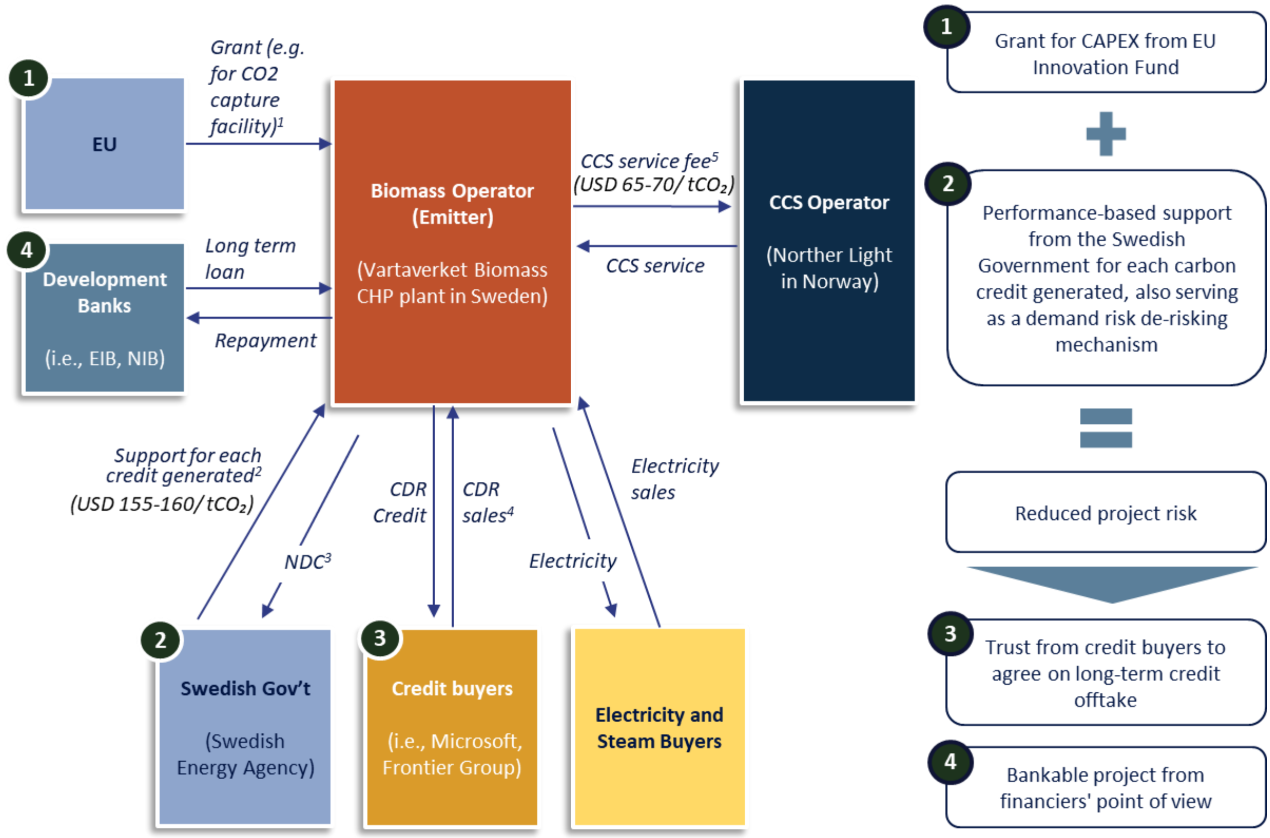
5.1. BECCS Stockholm, Sweden

The BECCS Stockholm project began construction in mid-2025 and is expected to become operational in 2028 (Enerdata, 2025). It will store 800,000 tonnes CO_2 per year. This project benefits from strong public support, including a EUR180 million grant from the EU's Innovation Fund and additional support awarded by Government of Sweden through the Swedish Energy Agency's BECCS reverse auction.[37] This setup helps de-risk the project and gives buyers confidence for long-term offtake agreements. With this support secured, the project reportedly signed major offtake agreements with large corporate buyers such as Microsoft (Segal, 2025) and frontier carbon firms.[38] Because the financing is backed by public grants, EU funds, and credible long-term credit buyers, the project was considered bankable and attracted long-term financing from financial institutions, like the Nordic Investment Bank and European Investment Bank (EIB, 2025; NIB, 2025). The overall business model for the BECCS Stockholm project is in Figure 4.10.

[37] This support amounts to more than SEK20 billion and will be disbursed on a performance basis for up to 15 years, from the commencement of geological storage. From these data, the implied support level is estimated at US$155–160/tonnes of CO_2. See BECCS Stockholm, https://beccs.se/news/stockholm-exergis-beccs-project-receives-180-million-eur-in-eu-funding/

[38] Microsoft signed a 10-year offtake agreement for 5.08 million tonnes of CDR from the BECCS project; however, the contract price has not been publicly disclosed. See BECCS Stockholm, https://beccs.se/news/stockholm-exergis-beccs-project-receives-180-million-eur-in-eu-funding/

Figure 4.10. Overseas Benchmark of the BECCS Stockholm Project



BECCS = bioenergy carbon capture and storage, CAPEX = capital expenditure, CDR = carbon dioxide removal, CHP = combined heat and power, CCS = carbon capture and storage, EIB = European Investment Bank, EU = European Union, NDC = nationally determined contribution, NIB = Nordic Investment Bank, tCO_2 = tonnes of carbon dioxide.

[1]The grant is provided by the EU Innovation Fund, financed through the EU Emissions Trading System (ETS).

[2]The project won a reverse auction by the Swedish Energy Agency and is eligible to receive SEK20 billion in support, disbursed over 15 years. Assuming annual CO_2 removal of 800,000 tonnes, the implied support level is estimated at US\$155–160/tCO_2.

[3]The Government of Sweden's support does not prohibit companies from using the credits for corporate climate claims. However, it requires that credit buyers acknowledge that their purchases contribute to Sweden's national climate targets and cannot be used to fulfil other country's NDCs.

[4]No public data are available for the CDR price between BECCS Stockholm and the buyers.

[5]No public data are available for the CCS service fee paid by BECCS Stockholm to Northern Lights. Based on estimates from other Northern Lights users, transport and storage costs are around €60 per tCO_2.

Sources: EC (2022), EIB (2025), Barnard (2025), BECCS Stockholm, https://beccs.se/news/stockholm-exergis-beccs-project-receives-180-million-eur-in-eu-funding/

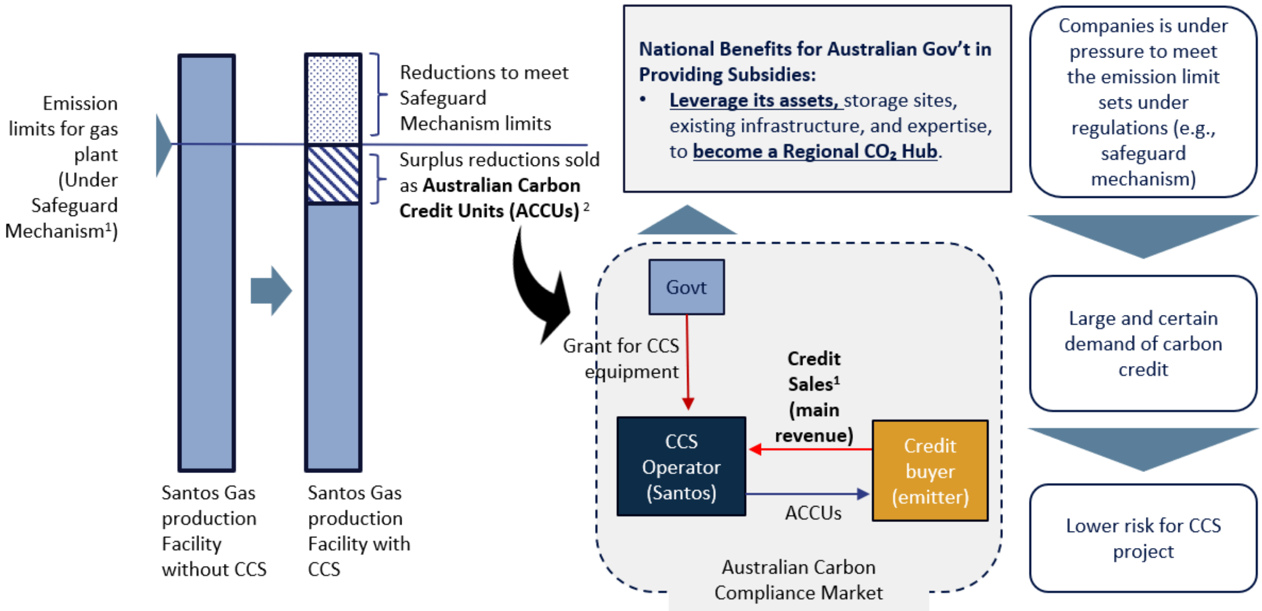
This project exemplifies the importance of governmental support to reduce risks and to enhance project bankability. It also shows alignment with a national strategy. By leveraging its abundant forest resources, Sweden aims to position itself as a global leader in BECCS. The initiative will help achieve its climate targets and advance its negative-emission ambitions beyond 2045.

5.2. CCS Moomba, Australia

The CCS Moomba project is operated by Santos in Australia. It seeks to capture CO_2 from natural gas-processing facilities. It is designed to store up to 1.7 million tonnes of CO_2 per year and is estimated to operate at a life-cycle cost below US$30/tonne (Figure 4.11).[39]

Australia has a compliance carbon market structured around the Safeguard Mechanism (Clean Energy Regulator, 2025). Under the Safeguard Mechanism, large emitters must limit their emissions. If they exceed the baseline, they are required to purchase Australian Carbon Credit Units (ACCU) to offset excess emissions.

Figure 4.11. Overseas Benchmarks for CCS Projects



CCS = carbon capture and storage, CO_2 = carbon dioxide.
Notes:
1. The Safeguard Mechanism sets emissions limits ('baselines') for large industrial facilities that emit more than 100,000 tonnes of CO_2-equivalent per year. This drives the implementation of CCS in gas production facilities and allows them to sell the remaining credit in the compliance carbon market.
2. The Moomba CCS project is registered under Carbon Farming Initiative project and is eligible to generate ACCUs. Revenue from ACCUs is a key component for the project's financial viability. The spot price for ACCUs in 2024 was reported to be AUD30–35/tonne of CO_2.
Source: Santos (2025).

According to the Clean Energy Regulator, the Moomba CCS project is formally registered under the approved CCS method and is eligible to generate ACCU under the Safeguard Mechanism. In November 2025, Santos received 614,133 ACCU for the project's first 6 months of operation (September 2024–March 2025), the single largest ACCU issuance at the time (Santos, 2025). These ACCU can be used by Santos to meet its safeguard obligations, while any surplus may be sold on the market.

[39] Santos, Moomba Carbon Capture and Storage, https://www.santos.com/moombaccs/

The project also received an AUD15 million capital grant from the Government of Australia's Carbon Capture, Use and Storage Development Fund (Santos, 2021). The government views that CCS projects have a key role in reducing emissions, supporting new economic opportunities, and spurring job creation (Taylor, 2021).

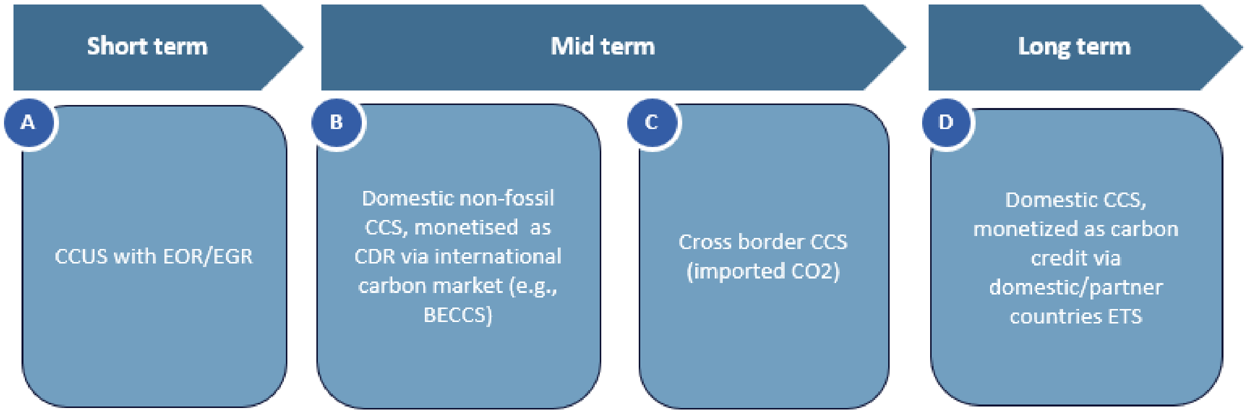
Chapter 5

Policy Actions for the CCS/CCUS Ecosystem in Indonesia

1. Pragmatic Commercial Timeline

To illustrate the expected commercialisation of future CCS/CCUS projects in Indonesia, a pragmatic timeline is proposed in Figure . Three key aspects are considered when prioritising the project – the need for governmental financial support, mandatory regulatory enablers, and bilateral agreement for transactions.

Figure 5.1. CCS/CCUS Business Model Commercial Timeline



BECCS = bioenergy carbon capture and storage; CCS = carbon capture and storage; CCUS = carbon capture, utilisation, and storage; CDR = carbon dioxide reduction; CO_2 = carbon dioxide; EGR = enhanced gas recovery; EOR = enhanced oil recovery; ETS = Emissions Trading System.
Source: Authors.

(i) Short-term – CCUS EOR/EGR. These are considered commercial projects. Regulations for CO_2 injection on oil and gas fields have been established. Several projects under this model have already been successfully implemented, demonstrating technical and commercial feasibility. For example, the CCUS EGR Tangguh project has already achieved FID.

(ii) Mid-term – CCS with CDR credits. On the mid-term horizon, CCS projects using non-fossil CO_2 sources that can generate CDR credits may become feasible due to the high price of CDR credits. These projects can generally operate on a B2B basis. However, this model may require minimal-to-moderate governmental financial support. As noted in previous section, such mechanisms can also serve as foundational revenue for other projects. Although Indonesia has allowed for the possibility of carbon credit exportation under Presidential Regulation No. 110/2025, detailed implementation guidelines are still needed to further clarify the carbon credit exportation process.

(iii) Mid-term – cross-border CCS. Japan, the Republic of Korea, and Singapore are actively seeking overseas storage options. Industries in those countries have a higher willingness-to-pay threshold compared to domestic industries. Indonesia, with its large geological storage capacity, could capture this opportunity. Bilateral agreement is required, particularly for CO_2 leakage liability arrangements during transport and storage. On the domestic side, regulations for CO_2 imports may take time to be developed.

(iv) Long-term – CCS relying on domestic ETS. Domestic CCS projects monetised through carbon credits/allowances under domestic or partner-country ETS are more likely to materialise in the long term. Although transactions occur on a B2B basis, compliance markets depend heavily on governmental regulation, making progress depending on governmental readiness and policy maturity. Implementing a compliance market requires setting emission caps for specific sectors, which will have broader macroeconomic impacts. Carbon price levels in developing countries are expected to stay low in the foreseeable future.

2. Building a National Priority Narrative beyond Emission Reduction

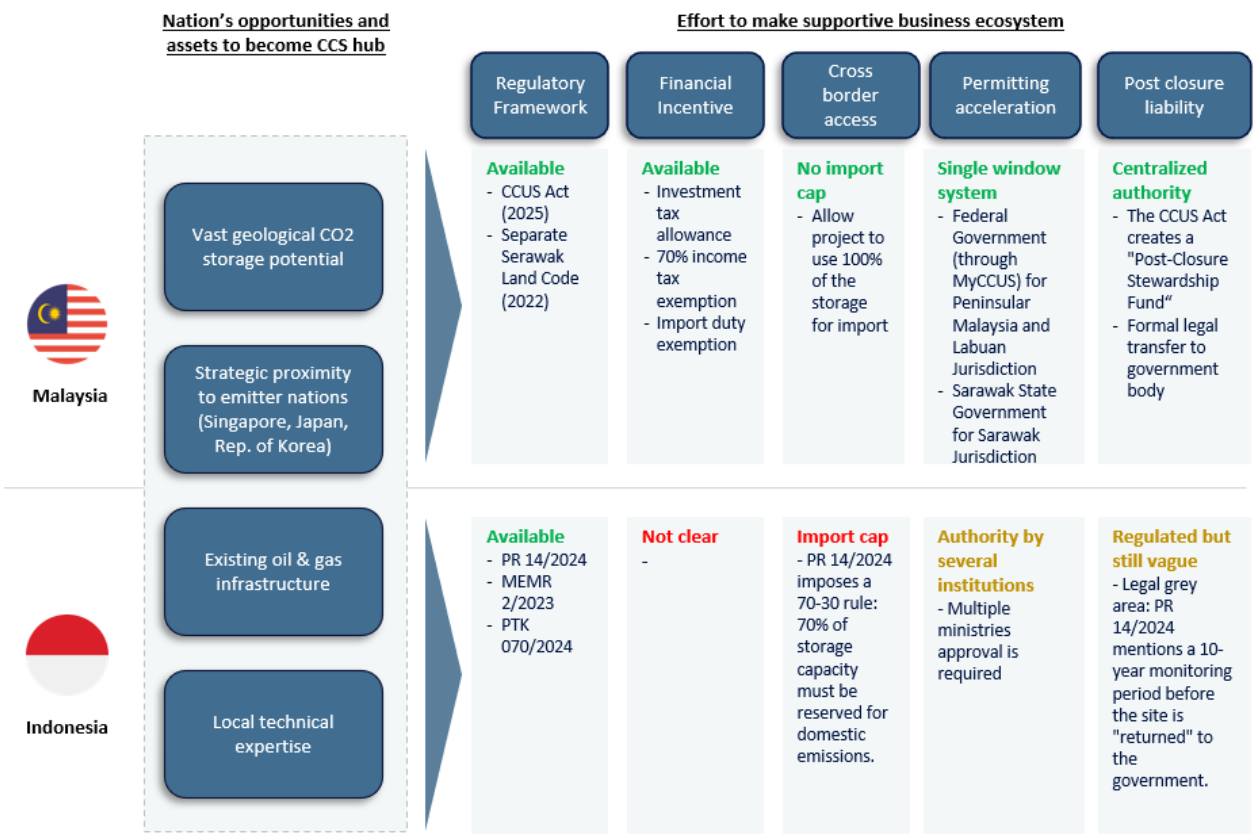
Overseas benchmarks show that governments typically require strong national-level justification before providing financial support to CCS/CCUS projects. While emission reduction and decarbonisation targets are justified as a national priority, these arguments alone are often insufficient, particularly because alternative mitigation options exist. For example, in the power sector, renewable energy is available, and in industrial sectors, hydrogen, energy efficiency, and renewable-based processes present viable alternatives.

In several countries, stronger justifications are framed around strategic national priorities with direct economic benefits, such as capturing regional economic opportunities through carbon storage services and compensating for declining state revenues from the oil and gas sector. These narratives are more compelling for governments because they align CCS/CCUS development with long-term economic and industrial strategies – not only climate goals. Indonesia's context aligns well with this narrative. With its extensive CO_2 storage capacity, Indonesia is amongst Asia's largest potential CCS hubs, offering significant opportunities to provide regional carbon storage services to countries such as Japan, the Republic of Korea, and Singapore. However, Indonesia must compete with other emerging hubs, notably Malaysia.

In addition, the Government of Indonesia, through President Prabowo Subianto's *Asta Cita*, aims to achieve national energy sovereignty. In line with this vision, the government has set a target to increase oil production to 1 million barrels per day by 2029. To do so, in the short to mid-term, one of the key strategies is the application of EOR technologies (ESDM, 2025c). This could be a strong justification to implement CCUS in Indonesia.

Indonesia and Malaysia share similar advantages for developing into regional CCS hubs, including vast geological storage potential, proximity to major emitter countries, existing oil and gas infrastructure, and strong local technical expertise. However, Malaysia has progressed more rapidly in building its CCS business ecosystem (Figure 5.2) It has established clear enabling conditions, such as financial incentives (including investment tax allowances, income tax exemptions, and import duty exemptions); a centralised CCUS authority that acts as a single-window agency for permitting and co-ordination; a well-defined post-closure liability framework supported by the Post-closure Stewardship Fund and formal transfer of responsibility to the government; and absence of a CO_2 import cap, allowing unlimited cross-border CO_2 storage.

Figure 5.2. Comparison of CCS/CCUS Ecosystems, Indonesia and Malaysia



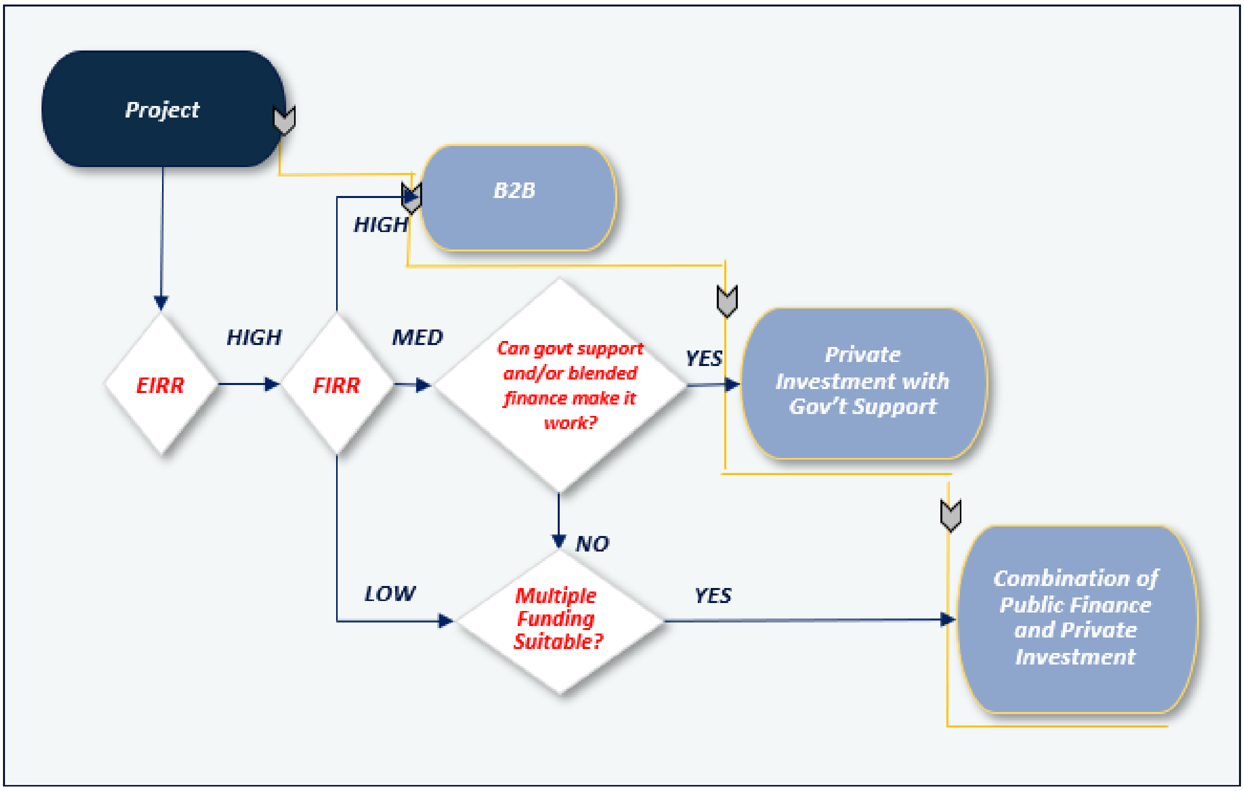
CCS = carbon capture and storage; CCUS = carbon capture, utilisation, and storage; CO_2 = carbon dioxide.
Source: Authors.

3. Governmental Financial Support Mechanisms

Once national benefits are clearly established, the government may consider providing financial and infrastructure support to accelerate the commercialisation of CCS/CCUS projects. This study proposes a framework for selecting appropriate financial schemes based on project viability in

Figure .

Figure 5.3. Framework for Designing Financial Schemes for CCS/CCUS Projects



B2B = business-to-business; CCS = carbon capture and storage; CCUS = carbon capture, utilisation, and storage.
Source: Authors.

The potential financing patterns can be grouped into three categories:

(i) B2B schemes. Projects with high commercial viability can be developed through a B2B scheme. An example is CCUS with EOR/EGR, which has existing commercial precedents globally. Although such projects can proceed on a B2B basis, targeted governmental incentives, such as favourable tax treatment or adjustments to oil and gas revenue-sharing obligations under profit-sharing contracts, may improve the viability of some projects.

(ii) Private investment with governmental support. For projects with medium viability, governmental support or blended finance may be required to improve their financial viability. Governmental support can take various forms; for instance, in BECCS projects, performance-based subsidies for each carbon credit generated can help mitigate demand risk, an uncertainty that private developers cannot fully manage, thereby encouraging private sector participation.

(iii) Combination of public finance and private investment. Projects with lower viability may require a combination of public and private financing. In such cases, the project can be segmented; each segment can be financed differently according to the nature of its assets. For cross-border CCS projects, for example, the development of CO_2 reception facilities – such as ship unloading terminals, pipelines, and related infrastructure – may be funded by the government. These assets can be considered public infrastructure if serving multiple emitters. By funding strategic infrastructure, the government can reduce upfront costs and risks, enabling private investors to focus on components that generate revenue through long-term operations.

4. 'No-regret' Ecosystem Development

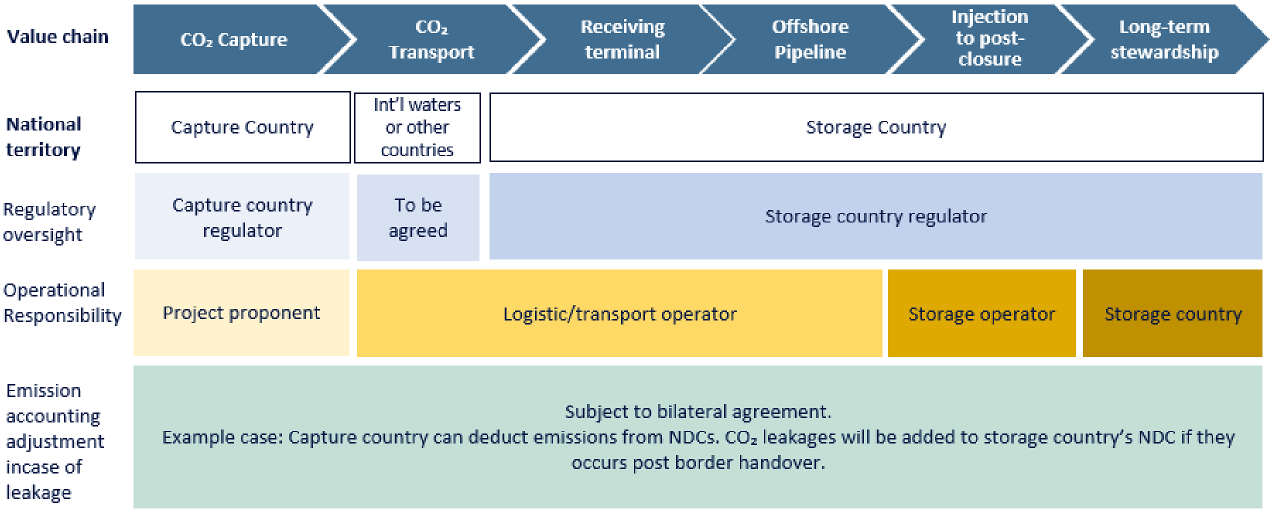
Governmental fiscal decisions may take time. Yet in parallel, Indonesia can begin 'no-regret' ecosystem development that requires minimal fiscal contribution, focussing on regulatory preparation, institutional strengthening, risk-sharing arrangements, and G2G cooperation. Several ecosystem elements have been identified as essential for CCS/CCUS development. Some are general requirements applicable to all business models, while others are model-specific.

(i) General ecosystem – institutional arrangements. ESDM's Directorate General of Oil and Gas is responsible for CCS projects located in oil and gas fields. Specifically, for CCUS with EOR/EGR, SKK Migas is involved due to implications for the profit-sharing contract. For other CCS projects, ESDM is the key regulator. However, involvement of other ministries will be needed (e.g. Ministry of Industry and Ministry of Environment) for complex CCS projects such as cross-border CCS. A co-ordinating ministry may accelerate cross-ministerial discussions, develop national priorities, and drive CCS development. In addition, creating a single-window agency for permits and approvals would streamline administrative processes that currently involve multiple stakeholders and lengthy procedures, increasing investor confidence and reducing project lead times.

(ii) General ecosystem – risk-sharing mechanisms. Leakage of CO_2 may occur at various points along the CCS value chain, and the allocation of liability for these risks must be clearly defined. In cross-border CCS projects, leakage risks can arise during CO_2 capture, transport, unloading at the receiving terminal, offshore pipeline transfer, injection, post-closure monitoring, and long-term stewardship. Liability at each stage should be assigned to the party best positioned to manage and control the associated risks (

Figure). Malaysia provides an example, where the government assumes post-closure liability through the Post-closure Stewardship Fund, offering strong assurance to investors. Establishing a similar framework in Indonesia would strengthen competitiveness and help attract international CO_2 storage demand. Clear allocation of liabilities across the entire CCS life cycle is essential to avoid future disputes. Additionally, agreed-upon emission accounting rules must be established to address potential leakage. These rules should be defined through bilateral arrangements. For example, the capture country may deduct the captured emissions from its NDC, while any CO_2 leakage occurring after cross-border transfer would be accounted for under the storage country's NDC.

Figure 5.4. Example of CO_2 Liability Framework for Cross-border CCS



CCS = carbon capture and storage, CO2 = carbon dioxide, NDC = nationally determined contribution.
Source: Asia Natural Gas and Energy Association, Accelerating Cross-border CCS in Asia Pacific, https://angeassociation.com/policy-areas/cross-border-ccs-for-asia-pacific/

(iii) **General ecosystem – planning and long-term strategy**. Developing a national CCS roadmap is also recommended. The roadmap should align potential CO_2 source clusters with nearby storage locations (ERIA and Indonesia National Energy Council, 2025). In addition, sectors can be prioritised where CCS is essential for decarbonisation, such as cement and certain industrial processes. Preparing this roadmap early will help guide investment decisions and infrastructure planning. Table provides examples of countries that have already developed CCS roadmaps.

Table 5.1. CCS Roadmaps in Selected Countries

Country	Roadmap	Key Features
United Kingdom	*CCUS Net Zero Investment Roadmap*	Sets out how government and industry will mobilise CCUS investment, targeting 20–30 $MtCO_2$ captured per year by 2030 across four clusters.
United Kingdom	*CCUS Supply Chains: A Roadmap to Maximise the UK's Potential*	Focusses on building CCUS supply chain capabilities: skills, innovation, finance, and industrial capacity.
European Union	*CCUS Roadmap to 2030*	Identifies research, innovation, policy, and infrastructure actions needed across Europe for CCUS development through 2030.
Malaysia	National CCUS Roadmap (under development)	

CCUS = carbon capture, utilisation, and storage; $MTCO_2$ = million tonnes of carbon dioxide.
Sources: Government of UK (2021; 2023), CCUS SET-PLAN (2022), MEF (2025).

(iv) **Model-specific ecosystem – regulatory frameworks.** Projects relying on carbon credits need clear guidelines on carbon credit exportation. To facilitate trading in compliance markets, the government must strengthen regulations by expanding sectoral coverage and establishing strict emission caps. Additionally, cross-border CCS requires specific regulations defining the treatment and allowable limits for CO_2 imports.

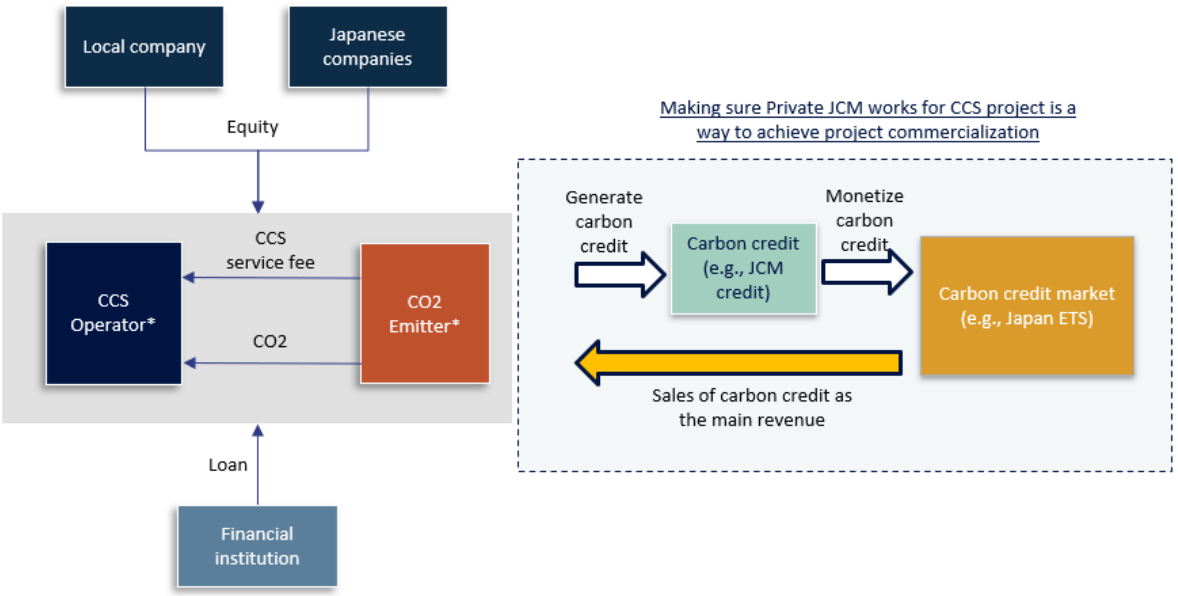
(v) **Model-specific ecosystem – institutional alignment.** Institutional clarity on carbon credit issuance and exportation procedures is needed. This will involve alignment between the Ministry of Environment and relevant sectoral ministries. NDC achievement will be the responsibility of sectoral ministries; moreover, it is assumed that sectoral ministries will be responsible for the approval of carbon credit exportation as it may affect NDC achievement.

(vi) **Model-specific ecosystem – international cooperation**. Bilateral agreement and international alignment are crucial for projects involving overseas partners. For CCS projects targeting voluntary carbon markets, co-ordination between the Ministry of Environment and international crediting standards will be needed. Similarly, for CCS projects intending to export credits under bilateral mechanisms, such as the JCM scheme, a clear bilateral framework must be established. For cross-border CCS projects, Indonesia requires bilateral agreements with potential CO_2-exporting countries to secure market access.

Box 5.1. Recommendations for Private Joint Crediting Mechanism Framework Improvement

Several carbon capture and storage (CCS) projects may rely on carbon-credit monetisation via private Joint Crediting Mechanism (JCM) schemes. Ensuring this scheme functions effectively is vital for commercialisation. Private JCM allows a project developer to sell carbon credits into Japan's upcoming emission trading system. This market attracts private players by offering predictable demand and potentially attractive carbon pricing compared to voluntary markets.

Private Joint Crediting Mechanism

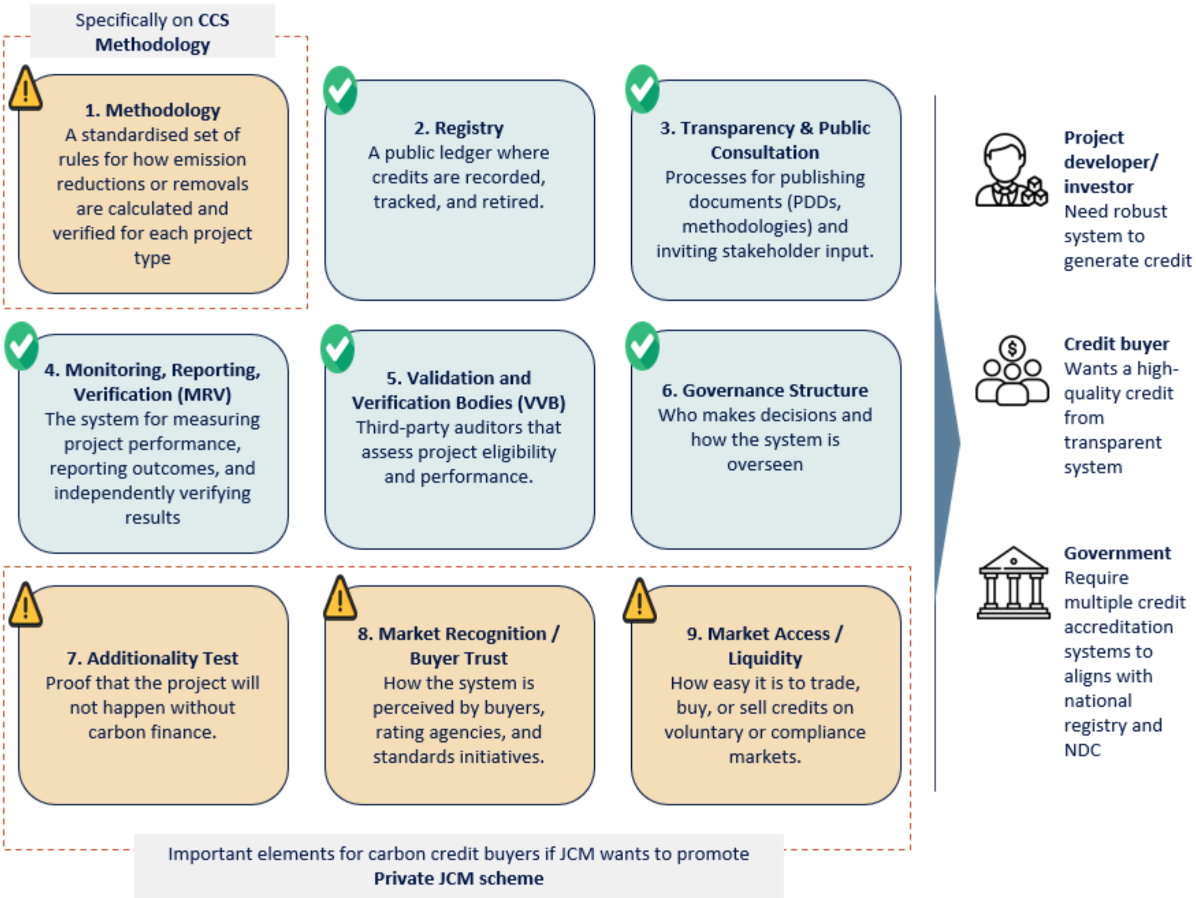


CCS = carbon capture and storage, CO_2 = carbon dioxide, ETS = Emissions Trading System, JCM = Joint Crediting Mechanism.
Note: In some cases, the CCS operator and CO_2 emitter can be the same company.
Source: Authors.

Comparative analysis with international markets, like Gold Standard and Verra, highlights specific areas for improvement for a private JCM framework. Confidence that credits will be recognised by international buyers is essential to reduce uncertainty and to improve project bankability. Second, credit buyers seek high-quality credits generated through a transparent process to ensure environmental integrity and to minimise reputational risk. Moreover, the government requires a system that accommodates multiple mechanisms while aligning with the national registry and the nationally determined contribution. This ensures consistent emission accounting and prevents double-counting.

Box 5.1. *Continued*

Proposed Areas of Improvement for a Private Joint Crediting Mechanism

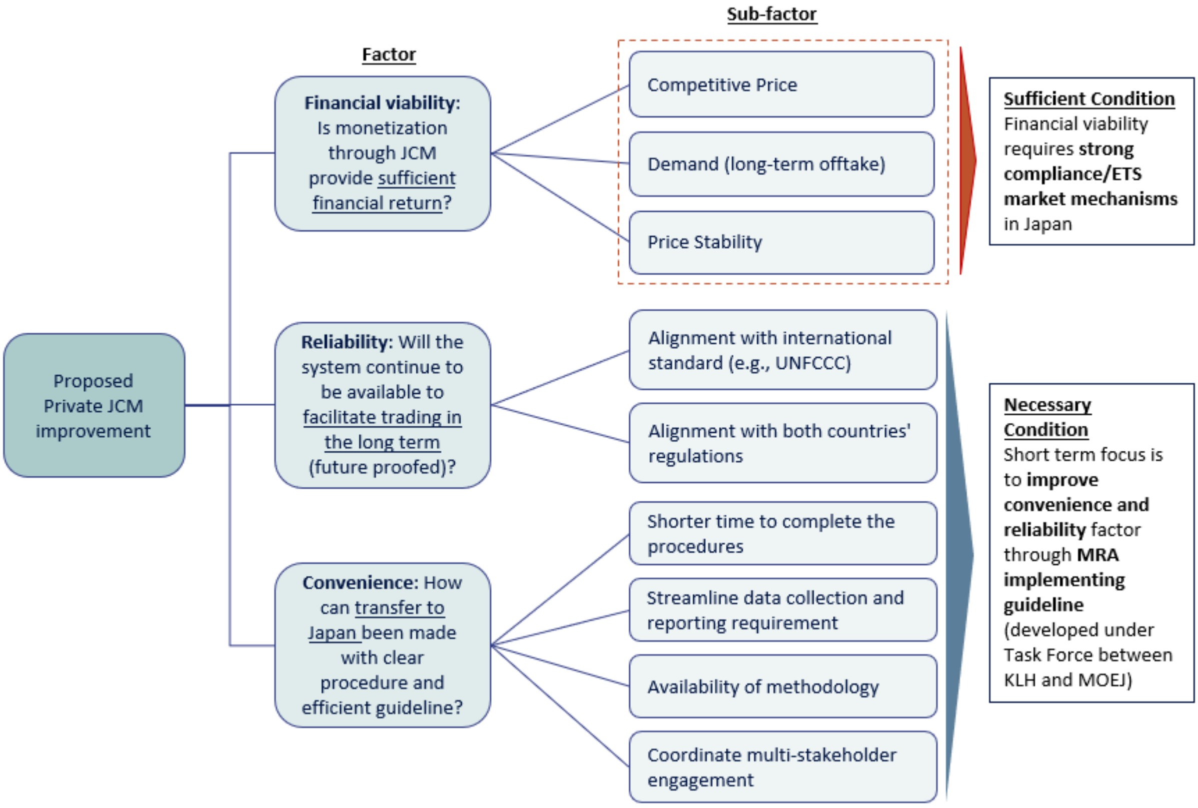


CCS = carbon capture and storage, NDC = nationally determined contribution, PDD = project design document.
Source: Authors

To increase participation, the framework must be attractive to the private sector. Three key factors drive this – financial viability, reliability, and convenience. While financial viability is crucial, it depends on the long-term maturation of Japan's compliance market. Therefore, short-term efforts should focus on improving the necessary conditions of reliability and convenience.

Box 5.1. *Continued*

Proposed Conditions for Improving Private Joint Crediting Mechanism Attractiveness



JCM = Joint Crediting Mechanism, ETS = emission trading system, UNFCCC = United Nations Framework Convention on Climate Change.
Source: Authors.

The system must be trusted for long-term trading. This requires alignment with international standards and harmonisation with the regulatory frameworks of both Japan and Indonesia. For convenience, the priority is to establish a clear, efficient, and predictable process for transferring credits from Indonesia to Japan. Key improvements include reducing procedural timelines, streamlining data collection, ensuring the availability of approved methodologies, and strengthening multi-stakeholder co-ordination. These improvements should be incorporated into the mutual recognition agreement's implementing guidelines, which are currently under development.

Chapter 6
Priority Action Plan

A robust supporting ecosystem is essential to transition hydrogen and CCS projects from the pilot phase to a commercial scale in Indonesia. Policymakers should prioritise the following actions to accelerate ecosystem development for both hydrogen and CCS projects in Indonesia.

(i) Further enhance the regulatory framework. Accelerate the completion of hydrogen governance regulations, such as those on hydrogen governance, business licences, high-pressure tank safety, low-carbon hydrogen certification, and technical standards. Actively solicit input from market players to identify and to bridge gaps in technical standards and safety protocols.

(ii) Elevate project plans to a national strategic priority programme. Build stakeholder consensus to position hydrogen as a key national agenda item. Align it with the downstreaming (*hilirisasi*) policy and energy security goals. Policymakers must identify and quantify economic benefits beyond greenhouse gas emission reduction to justify fiscal support.

(iii) Establish centralised co-ordination. If the priority elevates, designate a clear authority to accelerate, monitor, and de-bottleneck strategic hydrogen projects. Leverage an existing institution that manages national strategic projects; its authority could be clarified in the upcoming government regulation on hydrogen.

(iv) Design financial support schemes. Develop a tailored financial support framework. Benchmark effective incentive schemes used globally, and assess them for local adoption. Utilise blended finance structures to optimise capital efficiency.

(v) Support niche market initiatives. While large-scale commercialisation takes time, the government can provide non-fiscal support to immediate, private-sector initiatives in niche markets. These smaller, commercially viable projects serve as essential proofs of concept and build the initial supply chain.

(vi) Adopt adaptive planning. Acknowledge the inherent uncertainty of the sector. Treat current road maps as indicative, subject to adjustment. Implement a multi-pathway strategy that positions hydrogen as one of several decarbonisation options. Monitor sectoral trends, and establish 'trigger points' to adjust policy and investment strategies dynamically.

(vii) Strengthen bilateral cooperation. Expand international partnerships focussed on tangible outcomes – securing long-term offtake agreements, accessing low-cost financing, facilitating technology transfer, and upskilling the local workforce.

(viii) Expand regulatory scope. Expand implementing regulations for CCS outside of oil and gas. This includes guidelines for carbon hubs, cross-border CO_2 imports, and specific rules for industrial and power sector emitters.

(ix) Operationalise carbon monetisation. Clarify the export mechanism for carbon credits to improve project economics. Accelerate cooperation with international registries to align standards with the National Carbon Registry System and to ensure robust methodologies for monitoring, reporting, and validation.

(x) Develop de-risking instruments. Design insurance and guarantee schemes to improve investor appetite. These instruments may focus on critical risks, including CO_2 leakage and storage permanence, through clear technical, financial, and contractual frameworks.

(xi) Draft a national CCS road map. Update national planning to include precise mapping of CO_2 reservoirs and priority industrial clusters. The strategy should leverage existing commercial CCUS projects as future hubs. Crucially, the road map must prioritise CCS application in hard-to-abate sectors with process emissions (e.g. cement, petrochemicals) where renewable or electrification alternatives are limited.

(xii) Strengthen bilateral cooperation. Formalise bilateral cooperation to address cross-border CO_2 liability, financing, technology transfer, and local equipment manufacturing capabilities.

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Appendix 1
Hydrogen Technology Readiness

The following technology readiness information was obtained from the International Energy Agency's ETP Clean Energy Technology Guide.[40]

Table A1.1. International Energy Agency's Technology Readiness Levels

Classification	Level	Description
Concept	1	Initial idea; basic principles defined
	2	Application formulated; concept and application of the solution defined
	3	Concept needs validation; solution needs to be prototyped and applied.
Small prototype	4	Early prototype proven in test conditions (e.g. laboratory environment)
Large prototype	5	Large prototype; components proven in conditions to be deployed.
	6	Full prototype at scale; proven at scale in condition to be deployed
Demonstration	7	Pre-commercial demonstration; prototype working in expected real-world conditions
	8	First-of-a-kind commercial; full-scale deployment in final form
Market update	9	Commercial operation in a relevant environment; technology is available but needs incremental improvements to stay competitive.
	10	Integration needed at scale; the solution is commercial and competitive but requires further integration efforts into the wider energy system.
Mature	11	Proof of stability reached; predictable growth and widespread adoption

Source: IEA, ETP Clean Energy Technology Guide, https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide [accessed 2 April 2025]

[40] IEA, ETP Clean Energy Technology Guide, https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide [accessed 2 April 2025]

Table A1.2. Hydrogen Technology Readiness

Technology	TRL	Description	Status
Hydrogen production			
Alkaline electrolyser	9	Mature technology using a liquid alkaline electrolyte solution (KOH) to split water	Market Uptake: Fully commercial technology being deployed at gigawatt scale globally
Polymer electrolyte membrane electrolyser	9	Uses a solid polymer membrane (electrolyte) and noble metal catalysts to split water with high flexibility	Market Uptake: Commercial and rapidly scaling; leading technology for coupling with variable renewables
Anion exchange membrane electrolyser	6–7	Hybrid technology using a solid membrane compatible with alkaline (non-noble) electrode materials	Demonstration: Commercially available at small scale, but mass manufacturing and large stacks are still in the demonstration phase.
Solid oxide electrolyser cell	6–7	High-temperature electrolysis using steam; offers higher efficiency if waste heat is available	Demonstration: Moving from large prototypes to multi-MW demonstration projects (e.g. for industrial heat integration)
Steam methane reforming with CCS (partial capture)	9	Conventional natural gas reforming coupled with carbon capture on the concentrated process stream	Early Adoption: Commercially operating in large-scale facilities (e.g., for ammonia or refining) with capture rates of ~60%
Autothermal reforming with CCS	TRL 5	Reforming process using oxygen and steam; produces a purer CO_2 stream easier to capture (>95%)	Large Prototype: Individual components are proven, but full integrated demonstration at commercial scale is still needed.
Biomass-waste gasification with CCUS	TRL 6–7	Gasification of biomass/waste to produce hydrogen/syngas, coupled with carbon capture for negative emissions	Demonstration: Pilot and demonstration plants exist; requires integration of complex feedstock handling with capture infrastructure.
Plasma thermal	TRL 3–4	Uses thermal plasma to split methane into hydrogen and solid	Concept/small Prototype: Gaining momentum in R&D with pilot tests

Technology	TRL	Description	Status
decomposition (methane)		carbon (pyrolysis) without CO_2 emissions	but widely considered an early-stage technology.
Hydrogen storage and transport			
Ammonia storage	11	Storage of liquid ammonia in insulated tanks at ambient pressure (-33°C) or pressurised vessels	Mature: Standard industrial technology used globally for decades in the fertiliser/chemical industry.
Liquid hydrogen storage tank	8–9	Cryogenic storage vessels maintaining hydrogen at -253°C for transport or stationary use	Market Uptake: Commercially available for industry/space; scaling up for massive energy-terminal sizes is in demonstration.
Pressure vessel hydrogen storage	9–10	Compressed gas storage in Type I (steel) to Type IV (composite) cylinders (350–700 bar)	Integration: Mature technology widely used in vehicles and refuelling stations; focus is now on cost reduction.
Salt cavern hydrogen storage	8–9	Large-scale underground storage of pure hydrogen in solution-mined salt caverns	Early Adoption: Proven innovation; operational sites exist but fast-cycling usage is still being tested (TRL 6).
Ammonia cracking	6–7	Process to decompose ammonia back into nitrogen and hydrogen at the point of use (import terminal)	Demonstration: Several large pilot plants are operating; commercial-scale crackers are in the design/engineering phase.
Hydrogen liquefaction	9	Industrial process to cool hydrogen gas to liquid state (-253°C) for density increase	Market Uptake: Mature for small/medium scale; innovation needed for large-scale, high-efficiency trains for export.
Liquid organic hydrogen carriers	6–7	Chemical bonding of hydrogen to organic liquids (like toluene) for safe transport and release	Demonstration: Commercial pilots exist (e.g. shipping hydrogen to Japan), but widespread commercial chains are not yet established.
Hydrogen blending in gas grid	7–8	Mixing hydrogen (typically <20%) into existing natural gas pipeline networks	Demonstration: Numerous pilot projects worldwide are testing safety and appliance compatibility for blends up to 20%.

Technology	TRL	Description	Status
New hydrogen pipelines	9	Dedicated steel or composite pipelines designed specifically for 100% hydrogen transport	Market Uptake: Technically mature (used in industry corridors); major long-distance transmission networks are now entering planning/construction.
Hydrogen Truck transport (Fuel Cell)	8	Heavy-duty trucks using fuel cells and compressed hydrogen tanks for long-haul freight	First-of-a-kind Commercial: Manufacturers (e.g., Hyundai, Daimler) are delivering fleets, but widespread infrastructure (TRL 10) is lacking.
Ammonia tanker	11	Ships designed to transport liquid ammonia as cargo (often refrigerated LPG carriers)	Mature: Hundreds of vessels currently trade ammonia globally for the fertiliser industry.
Liquefied hydrogen tanker	4–5	Specialised ships with vacuum-insulated tanks to transport bulk liquid hydrogen at -253°C	Large Prototype: Only one pilot vessel (Suiso Frontier) has successfully demonstrated long-distance transport (Australia to Japan).
Hydrogen utilisation			
Power generation using solid oxide fuel cell	8–9	High-efficiency electrochemical conversion of hydrogen (or carriers) to electricity at high temperatures	Market Uptake: Commercial units exist (e.g. Bloom Energy), mostly running on natural gas; pure hydrogen operation is in early commercial phase.
Power generation using hydrogen fired gas turbine	5–6	Gas turbines modified to burn 100% pure hydrogen for grid-scale power generation	Large Prototype: Turbines running on 100% H2 are being successfully tested (e.g. Hyflexpower project); commercial units currently limited to ~50% blends.
Steel DRI based on 100% electrolytic hydrogen	6–7	Direct reduction of iron ore using pure hydrogen instead of natural gas/coal to remove oxygen	Demonstration: Major pilot plants (e.g. HYBRIT in Sweden) are producing fossil-free steel; full industrial-scale plants are under construction.
Steel DRI with high levels of hydrogen blending	7–8	Blending electrolytic hydrogen into existing natural gas-based DRI	Pre-commercial Demonstration: technically feasible in existing reactors; testing focuses on

Technology	TRL	Description	Status
		shafts to lower carbon intensity	optimising gas mixtures without reducing output quality.
High-temperature industrial boilers using hydrogen	7	Boilers designed to burn 100% hydrogen to generate high-grade steam/heat for industry	Demonstration: Prototype burners are available and being tested in chemical/industrial parks, but widespread retrofit packages are not yet off-the-shelf.
Cement kiln partial use of hydrogen	5	Injecting hydrogen into the main cement kiln burner to replace a portion of fossil fuels	Large Prototype: Trials have achieved partial substitution (~50%), but heat transfer issues (flame shape/emissivity) prevent 100% usage currently.
Hydrogen fuel cell truck	8	Heavy-duty freight vehicles using PEM fuel cells and compressed hydrogen	First-of-a-kind Commercial: Fleets are operating commercially (e.g. Switzerland, China, California) but rely on subsidised projects/infrastructure.
Hydrogen fuel cell passenger car	9	Passenger vehicles using fuel cells for long-range, zero-emission personal transport	Market Uptake: Fully commercial models (Toyota Mirai, Hyundai Nexo) are available, though sales are limited by infrastructure, not technology.
Ammonia-fuelled ship engine	5–6	Internal combustion engines modified to burn liquid ammonia for maritime propulsion	Large Prototype: Major manufacturers (MAN, Wärtsilä) are testing full-scale engines; the first commercial vessels have been ordered but are not yet sailing.
Methanol-fuelled ship engine	9	Dual-fuel maritime engines capable of running on methanol (grey or green) and diesel	Market Uptake: Fully commercial technology; large fleets (e.g. Maersk) are currently operating on international trade routes.

CCS = carbon capture and storage; CCUS = carbon capture, utilisation, and storage; CO_2 = carbon dioxide; DRI = direct reduced iron; PEM = proton-exchange membrane; TRL = technology readiness level.
Source: Authors.

Appendix 2

CCS/CCUS/CCU Technology Readiness

Technology	TRL	Description	Status
Carbon Capture			
CO_2 capture via chemical absorption	9–10	Separation of CO_2 using amine solvents in a packed column; requires heat for regeneration.	Market Uptake: The standard technology for gas processing and the basis for most operational CCS plants today
CO_2 capture via physical absorption	9	Uses solvents (e.g. Selexol, Rectisol) to absorb CO2 at high pressure without chemical bonding	Market Uptake: Mature and widely used in coal gasification, hydrogen production, and natural gas processing
CO_2 capture via physical adsorption	5–7	Uses solid sorbents (zeolites, activated carbon) to bond CO_2 to a surface; released by pressure/temperature swing	Demonstration: Proven for hydrogen purification (TRL 9) but still in pilot/demo phase for large-scale post-combustion flue gas
CO_2 capture via solid direct air capture	6	Fans move ambient air over solid filters that chemically bind CO_2, which is released using low-grade heat	Large Prototype: Commercial pilots (e.g. Climeworks Orca) are operating, but large-scale megatonne plants are still in development
Cement-chemical absorption (full capture)	7–8	Application of amine-based capture to the flue gas of a cement kiln to capture ~90%+ of emissions	Demonstration: The first full-scale commercial project (Brevik, Norway) is under construction; pilot testing is complete.

Technology	TRL	Description	Status
Cement-calcium looping	5	Uses calcium oxide (lime) as a sorbent to capture CO_2 at high temperatures within the cement process loop	Large Prototype: Pilot projects (e.g. CLEANKER) have demonstrated the concept, but continuous long-term industrial operation is pending.
Steel-chemical absorption at blast furnace	6–7	Retrofitting blast furnaces with amine scrubbers to capture CO_2 from the top gas	Demonstration: Several pilots (e.g. in Japan and Europe) have successfully captured CO2, but full-scale integration remains expensive.
Steel-process gas hydrogen enrichment and CO_2 removal	5–6	Technologies like sorption enhanced water gas shift that convert waste gas to hydrogen and capture CO_2 simultaneously	Large Prototype: Validated in industrial pilots (e.g., STEPWISE project), offering a pathway to lower energy penalties than standard capture
Transport			
CO_2 transport via pipeline	11	Transport of compressed CO_2 gas or supercritical fluid through steel pipes	Mature: Thousands of kilometres of CO_2 pipelines have operated in North America for decades (mostly for EOR).
CO_2 transport via shipping	9	Transport of liquid CO_2 in semi-refrigerated tanks on dedicated vessels	Market Uptake: Small food-grade CO_2 ships are mature; large-scale CCS carriers (e.g. Northern Lights) are being built now.

Technology	TRL	Description	Status
Storage and utilisation			
CO_2 storage for enhanced oil recovery (EOR)	11	Injection of CO_2 into declining oil fields to increase pressure and oil output, trapping CO_2 in the process	Mature: The most common form of CO_2 storage historically; fully commercial and profitable without subsidies in many regions
CO_2 storage at depleted oil and gas reservoir	9	Injection of CO_2 into exhausted hydrocarbon reservoirs for permanent storage	Market Uptake: Proven technology (e.g. Porthos in Netherlands); leverages existing data and geology to reduce risk
CO_2 storage at saline formation	9	Injection of CO_2 into deep porous rock formations filled with saltwater (brine)	Market Uptake: Successfully operating at megatonne scale since 1996 (Sleipner project); offers the largest global storage potential.
CO_2 sequestration in inert carbonate materials	3–4	Mineralisation: Reacting CO_2 with rocks (like basalt or olivine) to form solid stable minerals	Concept/small Prototype: Rapidly advancing (e.g. Carbfix in Iceland) but currently limited to specific geologies and small scales.

CCS = carbon capture and storage; CCU = carbon capture and utilisation; CCUS = carbon capture, utilisation, and storage; CO_2 = carbon dioxide; EOR = enhanced oil recovery; TRL = technology readiness level.

Source: Authors.

Appendix 3

Variations of CCS/CCUS Business Models

There are variations of carbon capture and storage (CCS) and carbon capture, utilisation, and storage (CCUS) business models, depending on how the project is configured. The following categorisation is not exhaustive but provides options to explore.

Combination of value chain: (i) project comprising end-to-end value chain from capture to storage (e.g. CCUS enhanced oil recovery [EOR] operated by the oil field operator, joint venture of emitter and CCS operator); project comprising a subset of the value chain (e.g. operator of CCS hub).

Type of emitter: (i) oil and gas operation, (ii) hydrogen/ammonia production, (iii) power plant, and (iv) direct air capture.

Jurisdiction of carbon dioxide (CO_2) source: (i) domestic, (ii) international (cross border), and (iii) mix of above.

Transport method: (i) pipeline onshore, (ii) pipeline offshore, (iii) shipping, (iv) trucking, and (v) combination.

Utilisation of CO_2: (i) stored underground, (ii) stored underground for oil or gas recovery, (iii) stored underground for coal bed methane recovery, and (iv) utilised as industrial feedstock (e.g. concrete curing, synthetic fuels).

Underground storage location: (i) depleted oil and gas reservoirs, (ii) deep saline aquifers, (iii) unmineable coal seams/beds, and (iv) basalt formations.

This report focusses on revenue models, which are strong determinants for project financial viability. Categorisation based on revenue models is generic for variations of project configuration mentioned above. It is assumed that a project comprises end-to-end value chains for simplicity. The CCS operator together, with the emitter, should find a monetisation way for its CCS business activity.

Revenue model: (i) oil and gas recovery, (ii) environmental claim (e.g. carbon credit, which can be monetised in various markets, registered in various standards, labelled as emission reduction or carbon dioxide reduction), (iii) compliance (e.g. pressure from Emissions Trading System or government mandate), and (iv) combination of above.

For projects comprising a sub-set of a value chain, there will be different business models depending on the value chain section. However, it can be generalised that

(i) the emitter needs to pay the entire CCS cost and find profitable revenue sources to compensate the CCS cost;

(ii) the storage operator may receive revenue, in the form of fees, from the emitter; and

(iii) the transport operator may receive revenue, in the form of fees, from the emitter or integrated with the storage operator.

Note that CCS cross-border or CCS hub involves fee payment from the emitter to CCS operator; it is a business model that splits the value chain.

Appendix 4

KBLI List for Hydrogen Business Activities

No.	Specific Hydrogen Business Activity	Parent Business Activity	KBLI Code
1	Natural hydrogen mining	Natural gas mining	6201
2	Production of hydrogen as a chemical feedstock	Gas industry	20112
3	Production of hydrogen as fuel*	Production of natural and man-made gas	35201
4	Hydrogen power generation	Electricity generation from non-renewable sources that do not produce emissions	35112
5	Hydrogen distribution	Distribution of natural and man-made gas via networks	35202
6	Hydrogen trading	Wholesale of chemical materials and goods	46751
7	Hydrogen retail sales for cars and motorcycles	Retail trade of automotive fuel	4730
8	Hydrogen refuelling station	Retail trade of fuel at filling stations	47301
9	Hydrogen transport via train	Freight rail transport	49120
10	Hydrogen transport by motor vehicle	Road transport for special goods	49232
11	Hydrogen transport via pipeline	Transport via pipeline	49300
12	Hydrogen transport via ship	Domestic sea freight for special goods and international sea freight for special goods	50122 50126
13	Hydrogen storage	Oil and natural gas storage	52104
14	Hydrogen safety certification services	Technical certification services	71201
15	Research and development in hydrogen technology	Research and development in engineering and technology	72102

KBLI = *Klasifikasi Baku Lapangan Usaha Indonesia*.
*Produced via electrolysis, photolysis, thermochemistry, biological, geological, and other methods, utilising new/renewable energy or fossil energy sources.
Source: BPS Regulation No. 7/2025.