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Potential Utilisation of Fuel Ammonia in ASEAN Countries

Edited by

Yoshikazu Kobayashi

Potential Utilisation of Fuel Ammonia in ASEAN Countries

Economic Research Institute for ASEAN and East Asia (ERIA)
Sentral Senayan II 6th Floor
Jalan Asia Afrika No. 8, Gelora Bung Karno
Senayan, Jakarta Pusat 10270
Indonesia

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Foreword

In recent years, as the global attention towards the realisation of net zero emissions grows, some ASEAN countries have announced their carbon neutrality target by the middle of this century. Realising net zero emissions is never an easy task. Since ASEAN countries are still at the stage of economic development, they will need to pursue not only decarbonisation of their energy supply structure but also economic development to raise the living standard of their citizens.

Using fuel ammonia can be an effective solution to reconcile their twin goals: decarbonisation and economic development. Many ASEAN countries will utilise the existing fleet of coal-fired power generation because it is a stable power source in the energy mix, at least during the transition period towards carbon neutrality. Using co-fired ammonia as fuel in thermal power plants will help reduce carbon emissions, all the while requiring only minor modifications to their existing setups.

Building on the findings of last year's study, this study extends its analysis beyond the demand potential in ASEAN countries. It now includes the projected power supply costs and proposes policy measures to expedite the adoption of ammonia in their power sector. The study reviews the latest advancements in ammonia co-firing technologies (including co-firing with natural gas and ammonia single firing). It also investigates ongoing efforts in the development of the ammonia supply chain.

The report aims to support ASEAN countries in adopting fuel ammonia as an innovative decarbonisation solution. Its insights are expected to aid in the formulation of policies that will ease the integration of fuel ammonia into their energy mix in the coming years.

Yoshikazu Kobayashi
Project Leader
The Institute of Energy Economics, Japan

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Yoshikazu Kobayashi
Project Leader
The Institute of Energy Economics, Japan

List of Project Contributors

Mr. Yoshikazu Kobayashi (Leader)
Senior Economist, Manager, CCUS Group, Fossil Energies & International Cooperation Unit, The Institute of Energy Economics, Japan (IEEJ).

Mr. Kiminori Maekawa (Coordinator)
Senior Research Fellow and Manager, International Cooperation Group, IEEJ.

Mr. Keita Katayama (Working Group Member)
Senior Researcher, Climate Change Group, Climate Change and Energy Efficiency Unit, IEEJ.

Mr. Souji Koikari (Working Group Member)
Senior Researcher, CCUS Group, Fossil Energies & International Cooperation Unit, IEEJ.

Mr. Soichi Morimoto (Working Group Member)
Senior Researcher, Climate Change Group, Climate Change and Energy Efficiency Unit, IEEJ.

Mr. Koichi Sasaki (Working Group Member)
Assistant Director, Climate Change and Energy Efficiency Unit, IEEJ.

Mr. Kazuhisa Takemura (Working Group Member)
Researcher, Energy Efficiency Group, Climate Change and Energy Efficiency Unit, IEEJ

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List of Abbreviations and Acronyms

ASEAN	Association of Southeast Asian Nations
BAU	business as usual
BECCS	Bioenergy with Carbon Capture and Storage
BLCP	Banpu Power Public Company Limited
CCS	Carbon dioxide Capture and Storage
CCUS	Carbon dioxide Capture, Utilisation and Storage
CO_2	Carbon dioxide
COP	Conference of the Parties
EAS	East Asia Summit
EGAT	Electricity Generation Authority of Thailand
EGCO	Electric Generating Company Limited
ERIA	Economic Research Institute for ASEAN and East Asia
EV	Electric Vehicle
GDP	Gross Domestic Product
GHG	Greenhouse Gas
IEA	International Energy Agency
IEEJ	The Institute for Energy Economics, Japan
IFHE	Association of Indonesian Fuel Cell and Hydrogen Energy
METI	Ministry of Economy, Trade and Industry, Japan
NEDO	New Energy and Industrial Technology Development Organization, Japan
NDC	Nationally Determined Contribution
NH3	ammonia
NREs	New and renewable energies
PIHC	Pupuk Indonesia Holding Company
PTTEP	Petroleum Authority of Thailand Exploration and Production

SCG	Siam Cement Group
UN	The United Nations
UNFCCC	United Nations Framework Convention on Climate Change

Executive Summary

The objectives of this study are to update the demand potential of fuel ammonia for co-firing at coal-fired power plants in five ASEAN countries (Indonesia, Malaysia, the Philippines, Thailand, and Viet Nam), analyse cost analysis of ammonia production and electricity generated by co-firing operation, and to consider policy measures to adopt fuel ammonia in ASEAN.

There are four major findings in this study. First, the potential fuel ammonia demand for the five ASEAN countries combined is estimated at 27 to 52 million tons per annum as of 2050 depending on the adoption scenario. Though the assumption is made only for co-firing operation at coal-fired power plants, the size of demand is large, which exceeds the volume of globally traded ammonia as of today. Using fuel ammonia for co-firing at gas-fired power plants, implementing 100% ammonia single-firing, and adopting maritime fuel could significantly increase the demand.

Second, by 2030, ammonia production costs are projected to reach \$381/ton of ammonia (t-NH_3) for *blue ammonia* – ammonia from natural gas with carbon capture and storage (CCS) and \$489/t-NH_3 for *green ammonia* – ammonia produced from renewable sources. At the same time, the levelised cost of electricity (LCOE) through co-firing blue ammonia will be 11.41 US cents per kilowatt hour (kWh), while green ammonia co-firing will be 13.22 US cents/kWh. This is compared to 4.89 US cents/kWh in scenarios without co-firing arrangements. Since ammonia is not inherently a low-cost energy source, incorporating it into co-firing processes will inevitably increase electricity costs. The production of blue ammonia is a well-established technology, with limited potential for cost reduction. Conversely, the cost of green ammonia is expected to decrease in the future, particularly due to the expected rapid and significant decline in the cost of the electrolyser used to produce hydrogen. For ASEAN countries, the source of feedstock – whether natural gas or renewable energy – is less crucial if it contributes to reduce carbon emissions by substituting fossil fuel and affordable. Instead of limiting the possibility of ammonia to green ammonia a priori, ASEAN countries should pursue both ammonia projects.

Third, the development of the supply chain needs to be accelerated. Ammonia is a new energy source, and the supply chain, including transportation infrastructure, needs to be installed. In the early stages of its introduction, the existing supply chain of ammonia for fertiliser feedstock can be used. However, to expand its use as an energy source for power generation, it will be necessary to develop the entire supply chain from ammonia production to transportation, storage, and utilisation.

Fourth, government policy support is essential. Introducing fuel ammonia, which requires additional costs and infrastructure development, cannot be achieved simply by relying on market mechanism. Governments must provide incentives for companies to adopt it. Such incentives might include tax benefits and compensation for price gaps. The incentive mechanisms should be tailored to align with each country's existing systems and circumstances.

Chapter 1

Background and Objectives

1. Study Objectives

This study aims to address the following three items. First, it estimates the demand potential of fuel ammonia in five ASEAN countries: Indonesia, Malaysia, the Philippines, Thailand, and Viet Nam. This estimation will be in line with the power supply development plan of each country. In recent years, fuel ammonia has gained growing attention as a zero-emissions fuel. This is because fuel ammonia can be directly used as a fuel in existing boilers and turbines with minor modifications. Ammonia is also a 'carrier' of hydrogen at the lowest cost, where pipelines cannot be used for transportation. Ammonia liquefies at -33°C, being much easier to handle than transporting hydrogen in its original form. Moreover, since ammonia is already widely used as a feedstock for fertilisers, existing infrastructure can be repurposed during the initial stages of adoption.

While fuel ammonia is also considered maritime transportation and industrial fuel, its most promising application at this stage is in power generation, most likely first as a fuel for co-firing at existing coal-fired power plants. Due to its slower burn than hydrogen, controlling combustion is more manageable when ammonia is co-fired in coal-fired plants rather than in gas-fired power plants. This study assesses the prospective demand for fuel ammonia for co-firing in coal-fired power plants, considering the planned integration of coal-fired power in the latest power supply developments for each country.

Second, this study conducts a cost analysis of fuel ammonia supply and its use at a coal-fired power plant in the ASEAN region. In each ASEAN country, decarbonisation in power generation is undoubtedly a major policy issue for energy strategy. However, this pursuit must proceed judiciously, ensuring that it does not unduly burden current electricity costs. While addressing climate change is a vital objective, it is not the single supreme policy goal. The potential for excessively high energy costs raises concerns, as it could hinder stable energy access for households and undermine the competitiveness of electricity-intensive industries.

This study examines the economic impacts associated with co-firing ammonia in thermal power generation. Considering the two types of fuel ammonia production patterns, which include fossil fuels with CCS (blue ammonia) and hydrogen generated through electrolysis of water using renewable-energy sourced electricity (green ammonia), this study will examine the production costs of both variants.

Third, this study will summarise recent trends in fuel ammonia production, utilisation technology, and the advancements in the fuel ammonia supply chain. In addition to the current demonstration of 20% co-firing of fuel ammonia in an operational coal-fired power plant in Japan, this study also reviews the escalation of co-firing ratios and the emerging technology of 100% single-firing. Further, this study will provide an overview of the supply chain development activities concerning fuel ammonia by Japan, Korea, Europe, Australia, North America, and several other countries.

2. Significance of This Study

The study outcomes provide meaningful implications for future decarbonisation measures within ASEAN, addressing several key areas. First, the examination of the demand potential for fuel ammonia serves to outline the scale of investment necessary. By quantifying the potential demand for fuel ammonia, this analysis paints a clear picture of the required commitment. Also, presenting a concrete demand outlook for fuel ammonia in the coming decades enables the visualisation of potential CO_2 emission reductions attainable through its implementation. This includes a precise understanding of the extent to which infrastructure development is needed to incorporate it into both existing and newly built coal-fired power plants.

Second, the cost analysis of fuel ammonia can serve as a benchmark for comparing future decarbonisation options, offering a clear cost reference. Decarbonising the power generation sector encompasses several potential avenues. Prominent amongst these are variable renewable energy sources like solar photovoltaic (PV) and wind power. Co-firing with biomass, harnessing hydropower, and using geothermal energy could also be viable options in some countries. While a comprehensive exploration of all decarbonisation options in the power generation sector is beyond this study, specific cost figures will be important in deciding how much ammonia to use and the optimal timing for its implementation. These figures also play a crucial role in positioning ammonia co-firing relative to the spectrum of decarbonisation alternatives.

Recent developments in producing and using fuel ammonia, along with developments in its supply chain, can offer valuable insights for policymakers. In fuel ammonia production, new projects are on the horizon across different regions, including Australia, the Middle East, North America, and South America, introducing various supply possibilities. In terms of utilisation, Japan and the Republic of Korea (henceforth, Korea) have set numerical goals for adopting fuel ammonia by 2030. In Singapore is increasingly interested in fuel ammonia, mainly for maritime transport, and has plans to establish a hub for receiving and trading fuel ammonia. In Germany, efforts are underway to introduce ammonia in sectors that are difficult to decarbonise solely with renewable electricity, particularly in industries and shipping. The establishment of utilisation hubs for fuel ammonia worldwide is expected to foster a global and active trading market for this fuel, ultimately promoting its use within the ASEAN region.

3. Updates from the Preceding Study

A study of fuel ammonia utilisation was also conducted last year by ERIA. The primary focus of the previous study was to analyse demand potential. This was achieved by creating an outlook for a coal-fired power plant deployment based on the power supply development plan of each country. Additionally, the study developed another deployment outlook for coal -fired power plants using a database provided by Enerdata and estimated fuel ammonia demand under both scenarios.

However, the outlook in the earlier study assumed a larger installation of coal-fired power generation in ASEAN countries than their latest power development plan, reflecting the growing momentum for carbon neutrality in the region. The survey this year has addressed these shortcomings. We updated the outlook based on the latest Enerdata forecasts and gathered the latest power development plans through interviews with ASEAN government officials. For countries with available individual power plant data, this study has conducted a more precise analysis using this specific information.

In addition to enhancing and updating the demand analysis, this study provides an in-depth cost analysis of ammonia utilisation. The cost analysis breaks down various cost components, including capital, fuel, and other variable costs. Quantitative insights into the expected CO_2 emission reductions from the use of fuel ammonia are included. The cost analysis covers both types of fuel ammonia: blue ammonia and green ammonia. The assumption is that domestically produced fuel ammonia will predominantly serve ASEAN countries in the future. The analysis extends to the year 2030 and beyond, as this is when the introduction of fuel ammonia co-firing within ASEAN is realistically anticipated.

When fuel ammonia is employed as a co-firing fuel in coal-fired power generation, the electricity price will unavoidably rise. Consequently, implementing policy support is essential for the practical adoption of ammonia as a power generation fuel. Since several developed countries have already established dedicated policies to provide such support, this study includes details about these policy initiatives. This information will be very useful for policy makers within ASEAN governments.

4. Major findings of this study

The study unveils four major findings. First, the collective potential demand for fuel ammonia across five ASEAN countries reaches 27 to 52 million tons annually by 2050. Remarkably, this demand estimation solely considers co-firing in coal-fired power plants, yet it is substantial, surpassing current global ammonia trade volumes. If fuel ammonia extends to co-firing in gas-fired power plants and for maritime fuel applications, the demand can surge further.

Second, by 2030, the cost of producing blue ammonia (ammonia produced from natural gas with Carbon Capture and Storage (CCS)) is projected at \$381 per tonne of ammonia (t-NH_3), while green ammonia (ammonia produced from renewable energy) would cost \$489/t-NH_3. Co-firing blue and green ammonia in 2030 would translate to levelised cost of electricity (LCOE) of US cents 11.41/kWh and 13.22 US cents/kWh, respectively, compared to 4.89 US cents/kWh without co-firing arrangements. Given that ammonia is costly, co-firing elevates electricity cost. The production process for blue ammonia is a mature technology, there may be limited room for cost reduction, but green ammonia is expected to significantly reduce the cost of the electrolyser that produces hydrogen, offering significant potential for future cost reduction. For ASEAN countries, the source of the feedstock – natural gas or renewable energy – matters less than its cleanliness and affordability. Rather than favoring one type over the other, both 'clean' ammonia options and their utilisation should be pursued.

Third, the development of the supply chain needs to be accelerated. Ammonia is a new energy source, and the supply infrastructure needs to be established. In the early stages of its introduction, the existing supply chain of ammonia for fertiliser feedstock can be used, but to expand its use as an energy source for power generation, it will be necessary to develop the entire supply chain from ammonia production to transportation, storage, and utilisation.

Fourth, government policy support is essential. Introducing fuel ammonia, which requires additional costs and infrastructure development, cannot be achieved by solely relying on market forces. Governments must offer incentives to encourage company adoption. Such incentives may include tax benefits and compensation for price gaps. These incentives could encompass tax benefits and compensation for price disparities. These incentive mechanisms should be tailored to each country's existing systems and circumstances.

5. Methodology

This survey primarily employs a literature review. It involves examining analyses from relevant institutes available online and integrating them into the contents of this survey. In addition, whenever possible, media reports are also incorporated. Since fuel ammonia is still emerging, there's a scarcity of public information. However, within this limited scope, the survey strives to fully use objective and scientific information.

Further, the study conducted two workshops with government officials from ASEAN countries over the course of its duration. These workshops engaged government officials or national oil company officials from Indonesia, Malaysia, the Philippines, Thailand, and Viet Nam – countries focused on this study. They were invited to the workshops to receive their comments on the study's implementation strategies, analytical assumptions, key research questions, and research findings. This provided an opportunity to gather opinions from the field in each country, a perspective not easily attainable solely through publicly accessible information.

In addition, informal interviews were conducted with professionals from companies actively involved in the development of technology. These discussions primarily focused on current trends in technology development. Additionally, conversations were held with engineering companies, trading companies, heavy industry manufacturers, electric power companies, and other stakeholders involved in manufacturing, transportation, and utilisation activities. By engaging in dialogues with these companies and associated entities, this approach facilitated the collection and analysis of information pertinent to the actual business landscape.

6. Structure of This study

In Chapter 2, this study updates and examines the demand potential for fuel ammonia in the five ASEAN countries with newly obtained data. In Chapter 3, the study presents an analysis of the production cost of fuel ammonia in a hypothetical ASEAN country and the cost of generating electricity from co-firing ammonia at a coal-fired power plant. For ammonia production costs, both blue and green costs will be analysed. Scenario analysis will also be conducted for power generation costs. In Chapter 4, the study summarises the recent situation surrounding fuel ammonia, including the latest technological developments in the production and utilisation of fuel ammonia and the status of the fuel ammonia supply chain. Finally, in Chapter 5, the study concludes with policy implications to accelerate the adoption of fuel ammonia in the ASEAN region.

Chapter 2

Fuel Ammonia Demand Potential

1. Updates in the Power Development Plan

This section provides updates on power generation, power development plans, and decarbonisation initiatives within the five case countries: Indonesia, Malaysia, the Philippines, Thailand, and Viet Nam. These updates build upon the information presented in the previous year's study.

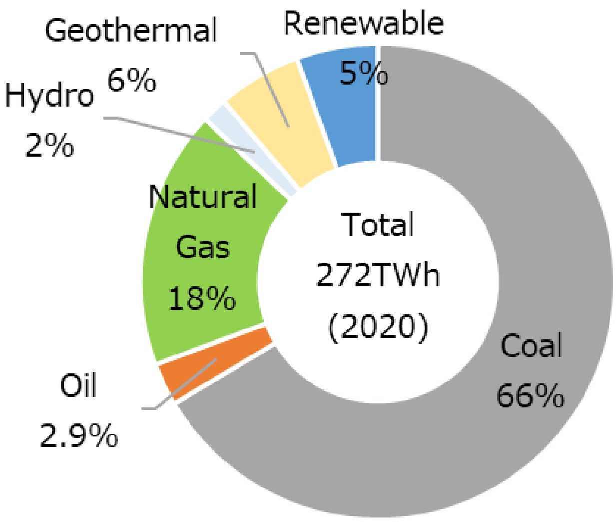
1.1. Indonesia

1.1.1. Power generation mix

Indonesia is the 4th and most populous nation in the ASEAN region. It has sustained robust economic growth in recent years, paralleled by an increase in energy demand. The nation's energy policy is clouded by a significant reliance on coal-fired power generation. This dependence gives rise to a critical concern, as Indonesia contributes approximately half of the total GHG emissions from ASEAN countries, posing a pressing challenge for the nation's ambition of sustainable economic growth. The current electricity generation mix in Indonesia is shown in the Figure 2.1. Coal-fired thermal power accounts for up to 66%, followed by natural gas-fired thermal power at 18%. The combined share of fossil energy reaches 87%. Mitigating emissions from the existing generation fleet is a major issue for the country's power development planning.

Figure 2.1. Current Power Supply Configuration in Indonesia, 2020

(%)



Source: International Energy Agency, 2022b.

1.1.2. Power development plan

To address the challenge of emissions reduction, Indonesia is actively deliberating a forthcoming power development plan. Aligned with this effort, the country's Nationally Determined Contribution (NDC), established in July 2021, states that it would comply with the National Energy Policy enacted in 2014 – Indonesia's latest energy policy document (President of the Republic of Indonesia, 2014). The National Energy Policy lists the following goals for clean energy sources in 2025 and 2050:

- Increase new and renewable energy (NRE) to 23% or more in 2025 and 31% or more in 2050.
- Decrease oil below 25% in 2025 and below 20% in 2050.
- Decrease coal below 30% in 2025 and below 25% in 2050.
- Decrease gas below 22% in 2025 and below 24% in 2050.

1.1.3. Coal outlook

As for coal development, a significant policy shift occurred in September 2022 when the Government of Indonesia issued Presidential Decree No. 112 (Presidential Regulation No. 112 of 2022 on Acceleration of the Development of Renewable Energy for Electrical Generation). It states that renewable energy will be expanded to achieve carbon neutrality by 2060. Notably, the decree establishes a principle that new coal-fired power plants will not be permitted in the future (The President of the Republic of Indonesia, 2022). However, there are two specified exceptions:

- Coal-fired power plants planned in the electricity supply plan before this presidential decree.
- Power plants that meet all the following conditions:
  - ✓ Classified as a national strategic project, making a significant contribution to employment and the national economy.
  - ✓ Reduce emission by 35% from the 2021 average emission of coal fired power generation within 10 years of operation.
  - ✓ Terminate operations by 2050.

In response to this, on November 15, 2022, Japan, the United States (US), and the European Union (EU) collaboratively issued a joint statement with Indonesia, unveiling the creation of a Just Energy Transition Partnership (Indonesia JETP). This partnership lends support to Indonesia with its endeavor to shift from coal-based energy to renewable sources (Joint Statement, 2022). A substantial agreement has been reached, involving the provision of a funding package totalling $20 billion to expedite the substitution of coal units with renewable energy units.

1.1.4. Recent movement towards decarbonisation

There are a few other notable developments towards decarbonisation in Indonesia. The first involves the Asian Development Bank (ADB) implementing the Energy Transition Mechanism (ETM). This was announced in November 2021 during the 26th meeting of the Conference of the Parties (COP 26), where Asian Development Bank (ADB), along with Indonesia and the Philippines, announced their partnership to create the ETM (Asia Development Bank, 2021a). The primary goal of the ETM is to expedite the closure of existing coal-fired power plants and replace them with cleaner power plants such as renewable energy sources. If fully implemented in Indonesia, the Philippines, and possibly Viet Nam, with the aim of stopping 50% of coal-fired power plant output – equivalent to roughly 30 giga-watts (GW) – over the next 10 to 15 years, it could reduce approximately 200 million tons of carbon dioxide emissions per year. The Government of Japan announced a $25 million grant to support this ETM partnership (Asian Development Bank, 2021b).

In November 2022, ADB also signed a Memorandum of Understanding with leading Indonesian companies, expressing their intention to suspend independent coal-fired power plants early (Asian Development Bank, 2022). This signing took place during the Group of Twenty (G20) Summit in Bali. Key figures, including the President of ADB, Darmawan Prasodjo, President Director of Perseroan Terbatas Perusahaan Listrik Negara (PT PLN), and representatives from Cirebon Electric Power, which is funded by JERA, Marubeni, and others, attended the ceremony and confirmed that they would use the ETM again to discuss ways to reduce greenhouse gas emissions in Cirebon 1.

The second notable development towards decarbonisation is the planning of ammonia co-firing adoption by Indonesia. Major projects agreed in recent years in this area are summarised in Table 2.1. Electric power companies and plant engineering companies are mainly working with Indonesian energy companies to carry out co-firing of ammonia in the thermal power sector and build supply chains. Amongst them, IHI Corporation is the first entity within ASEAN to carry out co-firing of fuel ammonia in commercial power plants, showcasing promising efforts.

Table 2.1. Ammonia Mixed Combustion in Indonesia by Japanese Companies

Date	Enterprise	Indonesian companies	Overview
May 2022	Toyo Engineering	Pupuk Indonesia Holding Company (PIHC)	Feasibility study on green ammonia production at a fertiliser plant
October 2022	IHI	PT PLN	Implementation of small-scale co-firing of ammonia in gas power generation facilities
October 2022 March 2023	TEPCO	PPI	Joint research and basic agreement on the development of green hydrogen and green ammonia (1) Co-firing of hydrogen at a natural gas power plant (2) Biomass co-firing, single-firing, and conversion to ammonia fuel at coal-fired power plants
November 2022	NEXI	PT PLN	Memorandum on financial support for decarbonisation
November 2022	Mitsubishi Heavy Industries	PT PLN Indonesia Power	Memorandum on investigation of mixed combustion of hydrogen, biomass, and ammonia in various parts of Indonesia
March 2023	Mitsubishi Heavy Industries	PT PLN Nusantara Power	Co-firing of hydrogen in a gas turbine and ammonia co-firing in a gas boiler were considered. Memorandum on biomass co-firing in coal-fired power plants
March 2023	Chiyoda Corporation	Pertamina	Joint study, solution proposal, and business agreement regarding CCU

Date	Enterprise	Indonesian companies	Overview
March 2023	IHI	PT PLN, IFHE	Memorandum on the construction of a power system utilising green energy for local production and consumption, and the study of ammonia and biomass co-firing and single-firing systems in existing thermal power plants
March 2023	IHI	Pupuk Indonesia (PIHC)	Memorandum on green ammonia production and co-firing at coal-fired power plants

CCU = Carbon Capture and Utilization; IFHE = Indonesia Fuel Cell and Hydrogen Energy; NEXI = Nippon Export and Investment Insurance; PPI = Pertamina Power Indonesia; TEPCO = Tokyo Electric Power Company.

Source: Toyo Engineering, 2022; IHI, 2022a; TEPCO, 2022; TEPCO 2023; NEXI, 2022, Mitsubishi Heavy Industries, 2022; Mitsubishi Heavy Industries, 2023; Chiyoda Corporation, 2023; IHI 2023a; IHI, 2023b.

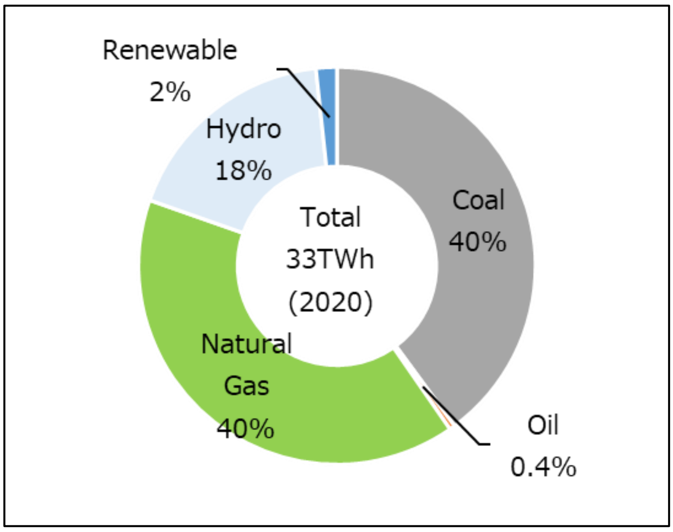
In addition, on 4 March 2023, the Ministerial Meeting of the Asia Zero Emission Community was held in Japan, during which Indonesia signed 12 memorandums of understanding (MOUs). Amongst them, six MOUs were for hydrogen co-firing in gas turbines and ammonia co-firing in coal-fired power plants (Agency for Natural Resource and Energy of Japan, 2023).[0]

1.2. Malaysia

1.2.1. Power generation mix

In the power generation mix of Malaysia, natural gas and coal take almost the same share (approximately 40%). Most of the remaining electricity supply comes from hydropower (approximately 18%) with a small supply from other renewable sources (Figure 2.2).

Figure 2.2. Current Power Supply configuration in Malaysia, 2020



Source: International Energy Agency, 2022b.

1.2.2. Power development plan

The Power Development Plan 2020, outlined in the 'Report on Peninsular Malaysia Generation Development Plan 2020, 2021–2039' issued by the Energy Commission, outlines a strategy (Energy Commission, 2021). It mandates the abandonment of that 2,100 mega-watts (MW) of coal-fired power plants by 2031, followed by an additional 1,400 MW in 2033. Meanwhile, two new coal power plant projects are scheduled for commission: 1,400 MW in 2031 and 700 MW in 2037. Contrary to these new build plans, however, the former prime minister, Ismail Sabri Yaakob, stated in his speech on the National Development Plan (Malaysia Plan) on September 27, 2021 that the government would no longer build new coal-fired power plants (Economic Planning Unit, 2021).Therefore, the new build plans might be reconsidered to align with the prime minister's statement. The estimated coal-fired power generation capacity as of 2040 will be 6.0 GW and all coal-fired power generation in Peninsula Malaysia will be phased out in 2044.[1]

As for natural gas-fired power plants, the plan outlines the addition of 1,200 MW of Liquefied Natural Gas (LNG)-based power plants (Combined-cycle Gas Turbine (CCGT)) by 2029, followed by the operation of an additional 2,800 MW LNG-based plant by 2030.

1.2.3. Coal outlook

Coal production in Malaysia has been increasing. The country's coal production started in Sarawak in 1988. Since then, the production grew to 392,000 tonnes in 2000, 2.7 million tonnes in 2010, and 3.49 million tonnes in 2021.[2] Coal consumption has also increased in accordance with the country's economic growth and the development of coal-fired power plants to the

[1] Comments obtained from the Malaysian participant in the second workshop held on May 29, 2023.
[2] Production for 2021 is predicted value.

energy need to sustain the economy. Correspondingly, coal consumption increased from 459,000 tonnes in 1988 to 4.1 million tonnes in 2000, 26.0 million tonnes in 2010, and 36.9 million tonnes in 2021. With domestic production insufficient, Malaysia imports coal, witnessing an increase from 459,000 tonnes in 1988 to 3.4 million tonnes in 2000, 23.2 million tonnes in 2010, and almost 33.6 million tonnes in 2021.[3] The Government of Malaysia plans to achieve 31% renewable energy supply in the energy mix by 2025 and decrease the coal-fired power plant installed capacity share from 37% in 2021 to 22% in 2039. This shift is expected to lead to a moderate decline in coal consumption.

1.2.4. Recent movement towards decarbonisation

The first notable development in Malaysia's decarbonisation efforts is its introduction of a carbon pricing system. Malaysia has initiated its first Voluntary Carbon Market (VCM) as a measure to achieve its carbon emissions reduction target by reducing carbon emissions by 45% in 2030 (lowering carbon intensity of GDP) and achieving carbon neutrality by 2050. With its extensive forest reserves, Malaysia has a large potential to generate carbon credits, although such activities are currently limited. Malaysian Investment Development Authority (MIDA) argues that operating the VCM is critical to ensure industrial competitiveness in the Malaysian economy. This becomes particularly significant if the EU enacts the carbon border adjustment mechanism (CBAM). If the CBAM comes into effect, products exported to the EU from countries lacking proper carbon pricing systems will incur a carbon border adjustment tax. The 'Pelan Kelestarian Alam Sekitar Malaysia 2020–2030' plan aims to introduce a carbon pricing system in Malaysia. According to MIDA 'Malaysian manufacturers must prepare for this wave as it benefits both the business and the environment. Failure to do so may cause Malaysian exporters to lose trade worth billions of Ringgit to European countries due to their failure to produce goods with greater GHG efficiency.' (Malaysian Investment Development Authority, unspecified year).

The second notable development is the establishment of the National Energy Policy 2022–2040 (NEP). Particularly important within the plan is the Low Carbon Nation Aspiration 2040, which identifies nine targets to be achieved by 2040 in comparison to the baseline of 2018:

- Increase public transportation usage rate from 20% to 50%.
- Increase electric vehicle (EV) penetration from less than 1% to 38%.
- Introduce B30 (30% blend of biofuel) in heavy-duty vehicles.
- Increase the usage rate of liquefied natural gas in maritime transport from 0% to 25%.
- Increase energy conservation percentage in the industrial sector from less than 1% to 11%.
- Increase energy conservation percentage in the housing sector from less than 1% to 10%.
- Increase total installed renewable energy capacity from 7,597 MW to 18,431 MW.
- Reduce coal share of installed capacity from 31.4% to 18.6%.

[3] Same as above Consumption and imports for 2021 are predicted values.

- Increase share of renewable energy in total primary energy supply from 7.2% to 17%.

These objectives contribute to reducing CO_2 emissions in the energy sector, aligning with the goal of the Long-Term Low Emissions Development Strategy (LT-LEDS) to reach net zero greenhouse gas emissions by 2050. The NEP outlines key measures and targets within short-term (2021–2025), medium-term (2026–2030), and long-term (2031–2040) perspectives to ensure effective implementation. Renewal of the NEP will occur every three years under the oversight of the National Energy Council, chaired by Prime Minister Ismail Sabri, in response to technological progress and energy demand.

The third important development involves initiatives to demonstrate ammonia utilisation. Malaysia is actively promoting ammonia use through several avenues. First, on October 7, 2021, IHI, a Japanese heavy industry manufacturer, announced collaboration with PETRONAS Gas & New Energy Sdn. Bhd. – a subsidiary of the Malaysian national oil and gas company Petroliam Nasional Bhd – and TNB Power Generation Sdn Bhd – a subsidiary of Tenaga Nasional Berhad (TNB), a major power company in Malaysia. Their goal is to reduce CO_2 emissions and conduct a feasibility study on mixed ammonia combustion technology in Malaysian coal-fired power plants. This includes assessing the entire supply chain's technological and economic aspects, encompassing green ammonia production from renewable energy sources and blue ammonia derived from natural gas (IHI, 2021). Second, on October 26, 2022, IHI Asia Pacific Pte. Ltd., the Singaporean subsidiary of IHI, signed a Memorandum of Understanding (MoU) with JERA Asia Pte. Ltd., a group company of JERA Co., Inc. – the largest power generation company in Japan. Their aim is to offer recommendations to stakeholders in Malaysia for introducing and expanding fuel ammonia utilisation to decarbonise thermal power plants (IHI, 2022b). Third, on April 25, 2022, ITOCHU Corporation and Malakoff Corporation Berhad signed an MoU at the first Asian Green Growth Partnership Ministerial Meeting (AGGPM) Public-Private Forum hosted by the Ministry of Economy, Trade and Industry, to jointly conduct a feasibility study on hydrogen and ammonia decarbonisation initiatives in Johor. The MoU aims to develop an ammonia receiving station in Johor and to decarbonise the coal-fired power plant owned by Malakoff through the development of a new gas turbine thermal power plant mixed with ammonia and hydrogen (ITOCHU, 2022).

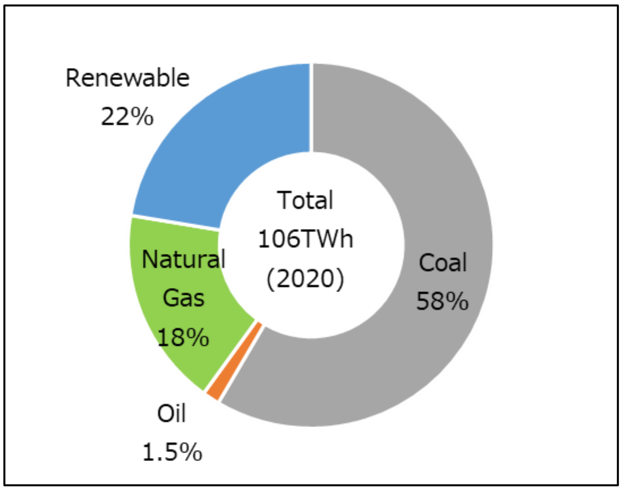
1.3. The Philippines

1.3.1. Power generation mix

In the Philippines, coal-fired power generation constitutes 58% of the power generation mix (based on generation capacity). Renewable energy (including hydro power generation) holds a 22% share, while natural gas-fired power generation contributes 18%. The combined share of fossil energies in the power generation mix is 78% (Figure 2.3).

Figure 2.3. Current Power Generation Capacity in the Philippines, 2021

(%)



Source: Department of Energy of the Philippines, 2023.

1.3.2. Recent movement towards decarbonisation

Several important developments in the country's decarbonisation efforts have been observed since the last study. The first is the ongoing temporary moratorium on construction approvals for coal-fired power plants. According to a local newspaper, the Secretary of the Department of Energy in the Philippines stated that the country, following the Marcos administration, would continue the suspension on new coal-fired power plant approvals introduced by the former Duterte administration in October 2020. This measure aims to promote the use of renewable energy. Under the current policy, new coal-fired power plants are allowed only if they have already obtained licenses and are in the stages of front-end engineering, material procurement, and securing financing.

The second is the pledge by Banco De Oro (BDO) Unibank, the largest bank in the Philippines, to cut its stake in coal-fired power plants. According to a local newspaper, BDO Unibank plans to reduce its medium and long-term loans to coal-related businesses by 50% from current levels by 2033 (Agcaoili, 2022). The bank also aims to have less than 2% of its total loans extended to coal-related businesses over the medium to long term by 2023. It will continue to provide short-term loans to companies to get out of coal. However, it is noted that the bank might reconsider lending to coal projects if, for example, the government introduces temporary emergency measures to address energy crisis.

The third development pertains to the decision on foreign ownership in the country's renewable energy sector. On November 15, 2022, the Department of Energy (DOE) issued Department Notice No. 2022-11-0034 ('DOE Notice'), amending Article 19 of the Enforcement Regulations of Republic Act No. 9513, which is also known as the Renewable Energy Act of 2008 ('RE Act IRR'). The amendment removed the ownership requirement for Philippine nationals in the exploration, development, and use (EDU) of solar, wind, hydro, marine, and tidal energy resources. This decision allows full ownership for foreigners in the country's renewable energy sector. Since the previous enforcement bylaws had set a cap of 40% on foreign ownership of renewable energy projects, this step is seen as a significant move to attract more investments to its renewable energy sector.

The fourth development involves a joint study on co-firing of ammonia in coal-fired power plants. On February 10, 2023, JERA Co., Inc. and Aboitiz Power Corporation, a subsidiary of Aboitiz Equity Ventures Inc., a major conglomerate group in the Philippines, signed an MoU in the presence of the Filipino President Ferdinand Marcos during his Japan visit. This MoU marks the start of a collaborative feasibility study of co-firing ammonia at Aboitiz Power's coal-fired power plants to advance their decarbonisation efforts (JERA, 2023).

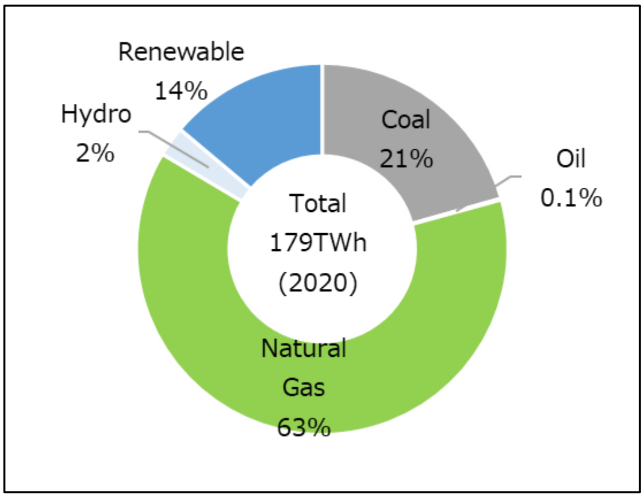
1.4. Thailand

1.4.1. Power Generation mix

In the power generation mix in Thailand, natural gas-fired power accounts for 63% of energy mix in Thailand, followed by coal fired power generation at 21% and renewable energy power (including hydropower) at 16% (Figure 2.4).

Figure 2.4. Current Power Supply configuration in Thailand, 2020

(%)



Source: International Energy Agency, 2022b.

1.4.2. Recent movement towards decarbonisation

In 2022, a notable decarbonisation effort emerged through the adoption of a carbon pricing scheme. Thailand introduced the Voluntary Emissions Trading System (V-ETS) in October 2014, piloting emissions trading in key sectors like cement, pulp and paper, steel, and petrochemicals.[4] A recent development involves the Ministry of Finance's announcement to introduce a carbon tax on industrial greenhouse gas emissions. The government targets 30% of its electric vehicle (EV) production by 2025 to counter declining fossil fuel excise tax revenues. As part of this, changes to EV excise tax rates are under consideration with a lower rate for EVs compared to fossil fuel vehicles.

The second action towards decarbonisation involves adopting fuel ammonia. Projects for co-firing ammonia are shown in Table 2.2. Collaborations between power generation, plant engineering, and trading companies, mainly from Japan, are planned with Thai counterparts for ammonia co-firing and supply chain development in thermal power sectors. In January 2023, four memorandums were signed, including ammonia co-firing in coal-fired power plants and considering CCU in cement plants. This movement is propelled by the Asia Energy Transition Initiative (AETI), which introduced a comprehensive aid package in May 2021, providing ASEAN nations with an energy transition roadmap, decarbonisation technical support, and financial support (Ministry of Economy, Trade, and Industry of Japan, 2021).

Table 2.2. Projects of Fuel Ammonia Utilisation in Thailand

Date	Enterprise	Thai Companies	Overview
April 2022	INPEX/JGC	PTTEP	Memorandum on cooperation for CCS project development in Thailand
November 2022	Mitsubishi Heavy Industries	EGAT	Memorandum on clean fuel generation, clean hydrogen and CCUS in Thailand
January 2023	JERA	EGCO	Memorandum on joint study on development of roadmap for decarbonisation and co-firing of ammonia
	JERA, Mitsubishi Heavy Industries, Mitsubishi Corp.	EGCO BLCP	Memorandum on the application of technology for co-firing of ammonia in BLCP coal-fired power plant, economic evaluation, and examination of CO_2 reduction plan
	Mitsubishi Corporation,	BLCP	Memorandum on the application of CO_2 separation, recovery, and utilisation

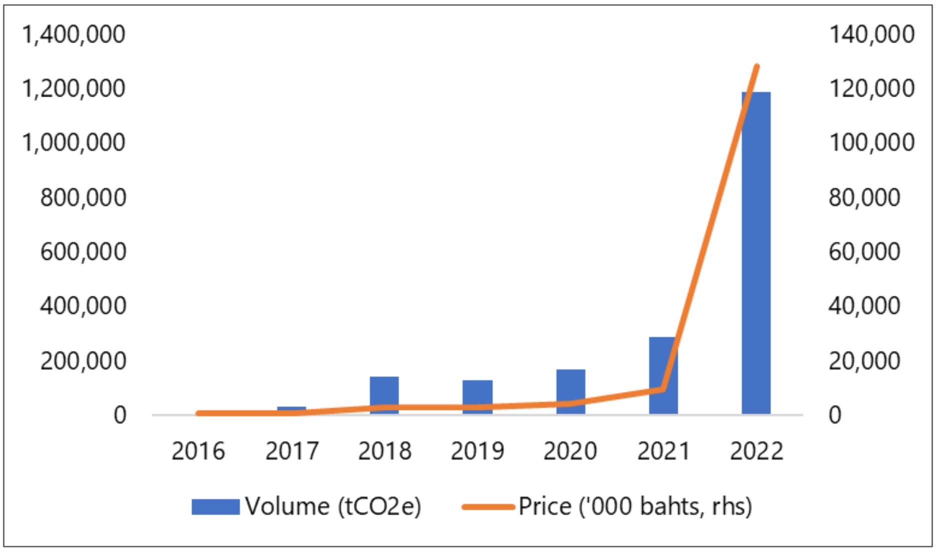
[4] The power sector also participated in the pilot project, but later left it.

Date	Enterprise	Thai Companies	Overview
	Chiyoda Corporation		technology in BLCP coal-fired power plant, economic evaluation, examination of CO_2 reduction plan, etc.
	Nippon Steel Engineering Thai Nippon Stel Engineering & Construction	Siam Cement Group (SCG)	Memorandum on cooperation to introduce technology for separating and recovering CO_2 from cement factory exhaust gas in Thailand and surrounding countries of Southeast Asia
March 2023	Mitsui O.S.K. Lines, Chiyoda Corporation, Mitsubishi Corporation LT (Thailand)	EGAT	Memorandum on building clean hydrogen and ammonia value chain in Thailand
	IHI	EGAT	Memorandum on decarbonisation (battery energy storage systems, etc.)

BLCP = Banpu Power Public Company Limited; CCUS = Carbon Capture, Utilisation, and Storage; EGAT = Electricity Generating Authority of Thailand; EGCO = Electricity Generating Public Company Limited; PTTEP = PTT Exploration and Production.
Source: Authors' survey.

The third notable development involves a surge of carbon credit transactions. In 2022, Thailand experienced a sharp increase in carbon credit transactions. The Thailand Greenhouse Gas Management Organization (TGO), an independent administrative agency supervised by the Natural Resources and the Ministry of the Environment, launched the Thailand Voluntary Emission Reduction Program (T-VER) in 2014. Companies seeking credits submit documents to TGO, which, upon certification by an external validation and verification body (VVB), issues the credits. Credits issued through T-VER lack international certification and are limited to domestic use. Figure 2.5 illustrates Thailand's carbon credit market transactions and prices from 2016 to 2022. Both trade volume and selling prices increased gradually until 2021, followed by a significant trade volume surge in 2022. Many credits, particularly related to renewable energy sources like solar and biomass power generation, along with forest conservation, were issued.

Figure 2.5. Trade Volume and Price of Carbon Credit in Thailand



Source: The Thailand Greenhouse Gas Management Organization, 2023.

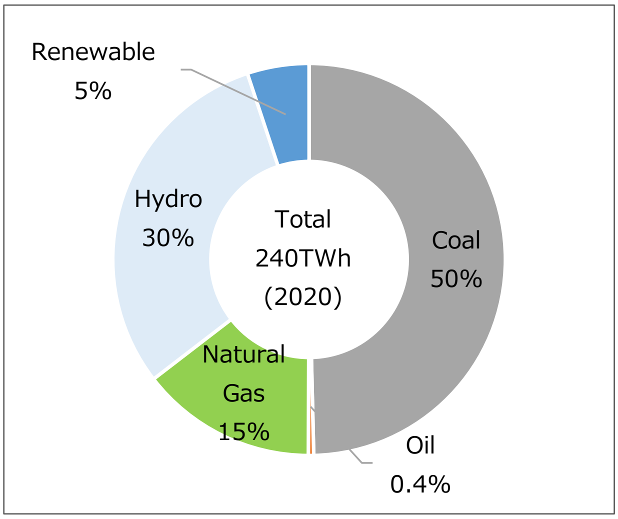
1.5. Viet Nam

1.5.1. Power generation mix

Viet Nam's power generation sector, like other ASEAN countries in this study, heavily depends on coal-fired power generation. Coal power contributes 50% of the Viet Nam's power generation, followed by hydropower at 30%, natural gas power at 15%, and renewable power like solar PV at 5% (Figure 2.6). The substantial coal power share is due to Viet Nam's abundant coal reserves. Making good use of domestic coal aligns naturally with Viet Nam's goals for energy security and cost competitiveness.

Figure 2.6. Current Power Supply Structure in Viet Nam, 2020

(%)

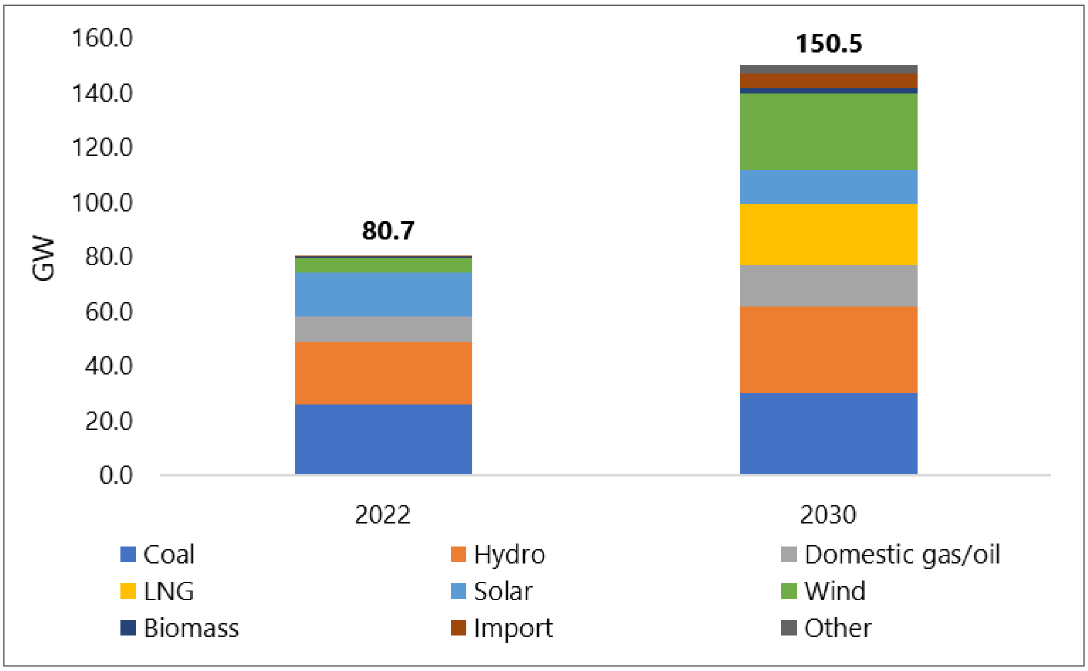


Source: International Energy Agency, 2022b.

1.5.2. Power development plan

On May 15, 2023, the eagerly anticipated Power Development Plan VIII (PDP8) was finally approved. According to the approved plan, the country's power generation capacity will expand from 81 GW in 2022 to 151 GW in 2030, with an estimated investment of $134.7 billion (Figure 2.7).

Figure 2.7. Power Generation Capacity Development Plan by PDP8



Source: Japan External Trade Organization (JETRO), 2023.

In terms of generation capacity, natural gas-fired power plant will account for 25% (including LNG) of the total generation capacity by 2030, increasing from 11% in 2022. While there are currently no operational LNG based power generation units, the PDP8 expects 22.4 GW capacity across 13 plants as by 2030. PetroVietnam Gas has already completed an LNG-fired power plant in Ba Ria Vung Tau, which will initially use domestic natural gas and transition to LNG later.

PDP8 places high importance on coal-fired power generation. Coal has played a major source of the country's power supply in the past and will continue to do so until 2030. The generation capacity of coal-fired power plant was 26.1 GW by the end of 2022, and this generation capacity will increase to 30.1 GW by 2030, which will account for 20% of the power generation mix.

As for renewable energy, PDP8 first aims to maximise the potential of hydroelectric resources. The hydro power capacity is expected to increase to 31.7 GW by 2030 from 23.0 GW in 2022. The plan envisions further growth to 36 GW by 2050. Wind power capacity will grow from 5.1 GW by the end of 2020 to 27.9GW by 2030, including 6 GW in offshore zones. Solar PV capacity will reach 12.8 GW by 2030, constituting 9% of the total generation capacity (Figure 2.7). The plan also advocates a target of 189 GW solar power generation capacity by 2050, leveraging both onshore and offshore potential, along with encouraging rooftop generation capacity (Vu and Guarascio, 2023).

1.5.3. Recent movements towards decarbonisation

According to JETRO, there is a plan to produce green hydrogen in Viet Nam (JETRO, 2022). In Ben Tre Province in southern Viet Nam, a local company, TGS Green Hydrogen, plans to start construction of a green hydrogen plant using German hydrogen production technology at the end of June 2022. The plant is scheduled to operate from the first quarter of 2024, as government public relations stated on May 25, 2022. Its annual output targets 26,900 tonnes of green hydrogen, 168,000 tonnes of ammonia, and 218,000 tonnes of oxygen. Future expansion aims to more than double the capacity to 67,000 tonnes per year for hydrogen, 420,000 tonnes for ammonia, and 549,000 tonnes for oxygen. The total investment amounts to 19.5 trillion Vietnamese dong (VND), equivalent to approximately $821 million. The factory is expected to increase revenue by 2 trillion VND annually and create jobs for 500 to 1,000 people. The produced hydrogen is intended for export to Japan or Australia.

2. Updates in Fuel Ammonia demand potential

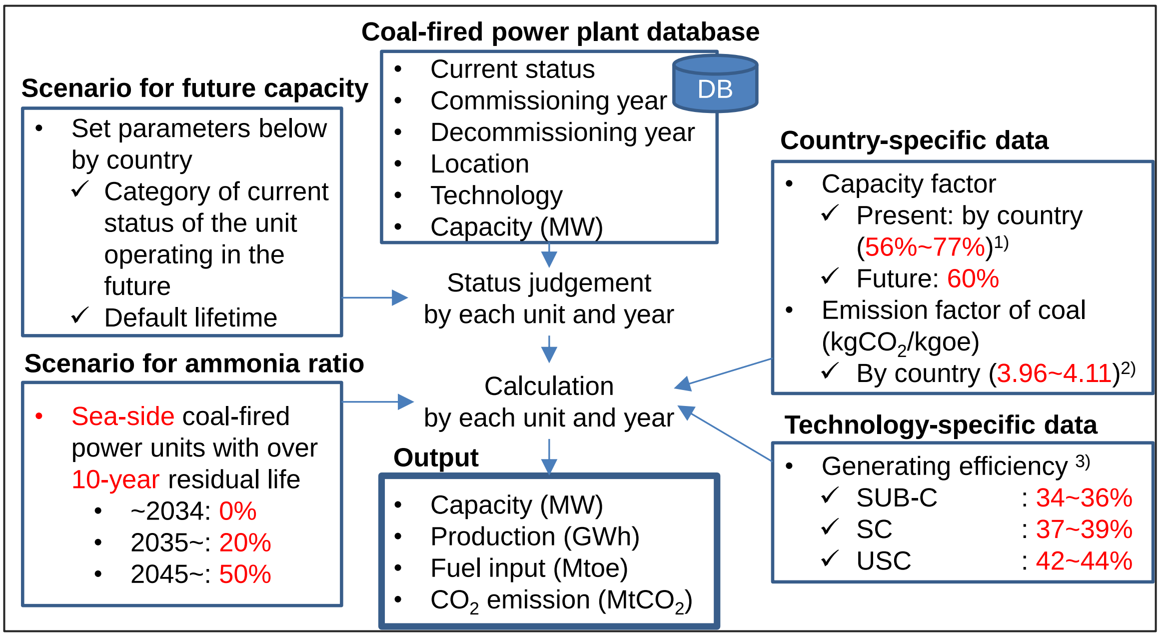
This section provides an estimate of the potential demand of fuel ammonia for co-firing at coal-fired power plants in five ASEAN countries: Indonesia, Malaysia, the Philippines, Thailand, and Viet Nam. The estimation approach aligns with the methodology of the previous study report with updates on the following three points (Economic Research Institute of ASEAN ,2022):

- The database of coal-fired power plants has been replaced with the latest version.
- Parameters for estimating future coal-fired power capacity have been adjusted for each country to align with their latest power development plans or outlooks.
- New considerations have been introduced regarding location constraints. Specifically, ammonia co-firing is assumed to be implemented only at plants situated along the coastline for ease of transporting fuel ammonia.

2.1. Methodology

The estimation method is based on last year’s report, combining the latest power plant database (Enerdata, 2023) developed by Enerdata with country-specific data (capacity factor and emission factor of coal) and technology-specific data (power generation efficiency) to estimate installed capacity of coal-fired power plants, power generation, fuel consumption, CO_2 emissions from present to 2050. The overview of the methodology is shown in Figure 2.8.

Figure 2.8. Overview of Methodology



DB = data base; GWh = gigawatt hour; $kgCO_2$ = kilograms of carbon dioxide; kgoe = kilograms of oil. equivalent; MW = megawatt; Mtoe = million tons of oil equivalent; $MtCO_2$ = million tons of carbon dioxide; SUB-C: sub critical; SC = super critical; USC = ultra super critical.

Notes:

1. Estimated with Enerdata, Power Plant Tracker, Country Dashboard, and International Energy Agency (IEA) Energy balances (values in 2020).
2. Estimated with IEA Energy balances and IEA Emission factors (values in 2020)
3. Technology data for the Indonesian power sector

Source: Author's calculations, 2023.

(1) Coal-fired power generation capacity

The projected coal-fired power generation capacity outlined by each government is shown in Table 2.3. To estimate the potential for ammonia co-firing, operating conditions were set by each country as shown in Table 2.4, which was prepared so that estimated coal-fired power capacity replicates the outlook by each government as much as possible. Categories of status in Table 2.4 is provided in Table 2.5.

Table 2.3. Outlook of Coal-Fired Power Capacity by Government

(GW)

Country	2030	2040	2050
Indonesia	65	58	29
Malaysia	-	Around 6.0	-
Philippines	13.6	13.6	-
Thailand	3.7	-	-
Viet Nam	30.1	-	-

Note: Excludes coal-fired power plants located in Lao People's Democratic Republic, small power producers (SPP), and very small power producers (VSPP).
Sources: Author's calculations, 2023; Department of Energy of the Philippines, 2021; Ministry of Energy of Thailand, 2019; Ministry of Industry and Trade of Vietnam, 2023.

Table 2.4. Parameters for Estimating Future Coal-fired Power Capacity

Parameter	Indonesia	Malaysia	Philippines
Category of current status of the unit operating in the future (Table)	1, 2, 3, 4, 5, 6	1, 2, 3, 4, 5, 6	1, 2, 3, 4, 5*
Lifetime of the unit with unknown DY (years)	30	25	40
Parameter	**Thailand**	**Viet Nam**	***Last year's report***
Category of current status of the unit operating in the future (Table)	1, 2, 3, 4, 5, 6	1, 2	*Low case**: 1, 2, 3* *High case**: 1, 2, 3, 4, 5, 6*
Lifetime of the unit with unknown DY (years)	40	40	*40*

Note: DY=Decommissioning Year: Refer to Table 2.5 for parameters.
* In line with committed power projects by DOE as of 30 November 2022. https://www.doe.gov.ph/private-sector-initiated-power-projects?withshield=1.
** The last year's study provided two demand cases: Low Case and High Case
Source: Author's categorisation, 2023.

Table 2.5. Category of Current Status

Category		Current Status
1	Operating	Operational, Mothballed
2	Under construction	Synchronised, Under construction
3		Suspended construction
4	Pre-construction	Authorised
5		Bidding process, PPA signed, FID
6		Announced
9	-	Cancelled, Frozen, Stopped

Source: Author's categorisations, 2023.

Indonesia and Viet Nam are active participants in the Just Energy Transition Partnership (JETP), exploring measures to reduce coal-fired power plants, including restrictions on new installations.[5] Specifically, for Viet Nam, adherence to the latest Power Development Plan VIII (PDP8) implies a limited addition of installed capacity to projects currently under construction. For all five countries, when the commissioning year of additional units is unclear, it is uniformly set to 2025 for ongoing projects and 2030 for pre-construction plants. In instances where the decommissioning year is unknown, a standard 40-year lifespan is applied. For Indonesia, to better align with the government's forecast, the lifespan is assumed to be 30 years.

Given that the Philippines has declared a moratorium on coal-fired power, the installed capacity to be added in the future was assumed to be limited to approved projects only. For Thailand and Malaysia, any restrictions are not assumed on the status of additional plants in the future, although new installation is limited for those countries. In Malaysia, the lifespan in case the decommissioning year is unknown was set at 25 years, reflecting the policy of Malaysia.

(2) Ammonia co-firing ratio

Regarding the co-firing ratio of ammonia, plants with more than a 10-year residual lifetime at the start of co-firing are assumed to introduce ammonia co-firing. This involves a 20% ammonia co-firing ratio from 2035 and 50% after 2045. This year's study incorporates location constraints for power plants. Specifically, from the viewpoint of transporting fuel ammonia, ammonia co-firing was assumed to be introduced only at seaside plants. For the location information of the plants, the latitude and longitude of the Enerdata's database were referenced. When the distance from the coastline was within five kilometres, plants were presumed to be seaside. Notably, due to a mechanical Geographic Information System (GIS) approach, exact plant

[5] A partnership in which donor countries work together to accelerate the early retirement of high-emission infrastructure in partner countries and provide supports for investment in renewable energy and related infrastructure.

location determination may vary. Additionally, plants with over 100 MW capacity, operational by 2030, were investigated for latitude and longitude details.[6] It should also be noted that, even if a plant is determined to be on inland, there may be a plant that can transport ammonia through pipeline or river barge, although this study does not consider such possibilities.

(3) Capacity factor

Similar to last year's report, the actual capacity factor by country was used. However, for future projections, a uniform 60% capacity factor was assumed for all plants.

(4) Generating efficiency

As in last year's report, the generating efficiency by technology is based on Indonesia's technology data (Danish Energy Agency, 2021). Efficiency improvements by 2050 are also being considered. Amongst the technical classifications in the Enerdata database, the efficiency of 'Steam' is assumed to be equal to sub-critical (SUB-C); 'Fluidized bed combustor (FBC)' equal to SUB-C, and 'Circulating fluidized bed gasifier (CFBG)' equal to super critical (SC), since temperature and pressure conditions are unknown. In addition, for plants with unknown technology, those in operation are assumed to be SUB-C, while the rest are categorised as ultra-super critical (USC). This study assumes that efficiency is not affected by the co-firing ratio of ammonia.

2.2. Results

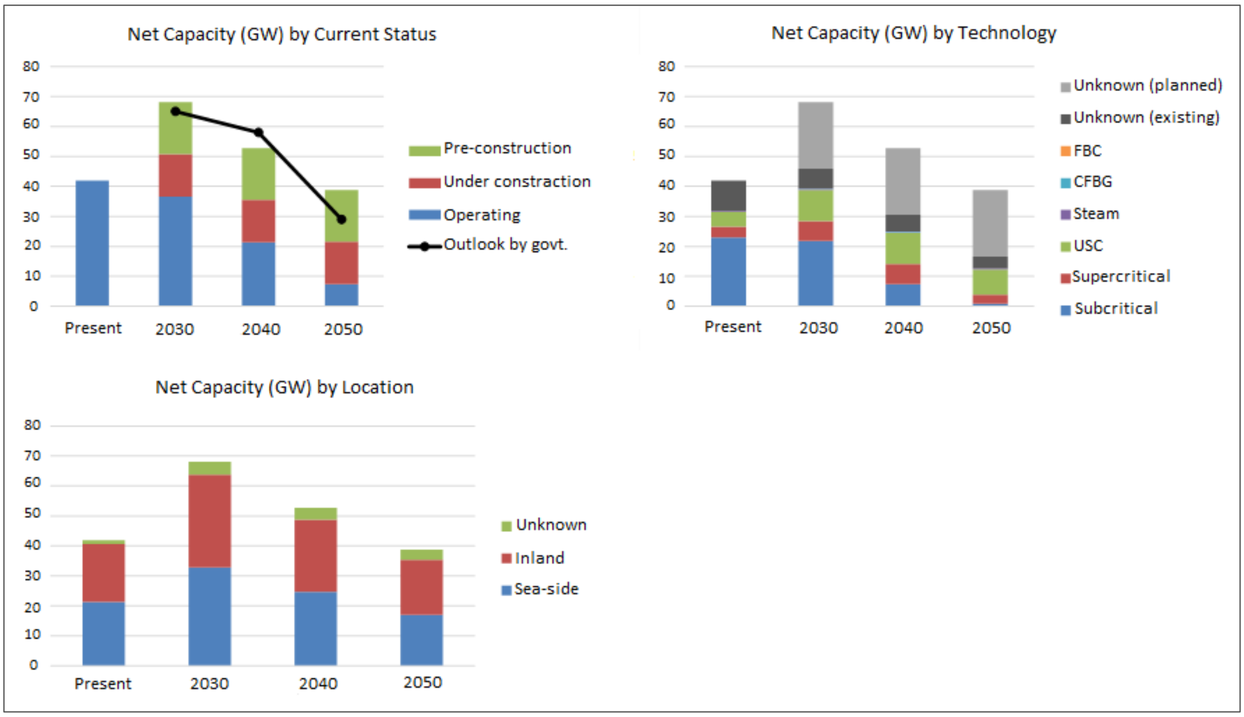
(1) Coal-fired power capacity

For Indonesia, the estimated installed capacity in 2030 is generally in line with the government's outlook by adding approved projects (Figure 2.9). The government's outlook shows significant retirement especially after 2040, with 7 GW expected to be retired from 2030 to 2040 and as much as 29 GW from 2040 to 2050. Although the estimated results were somewhat lower than the government outlook for 2040 and higher for 2050, a broad trend can be captured. The estimated installed capacity is 53 GW in 2040 and 39 GW in 2050, of which about 40% to 50% are seaside plants that can receive ammonia fuel by ship. For much of the newly installed fleet with unknown technology type, this study assumes an equivalence to USC.

[6] The location of some plants was corrected as well. The location information of the plant was referred to below. https://www.gem.wiki/Main_Page.

Figure 2.9. Coal-fired Power Capacity by 2050, Indonesia

(GW)

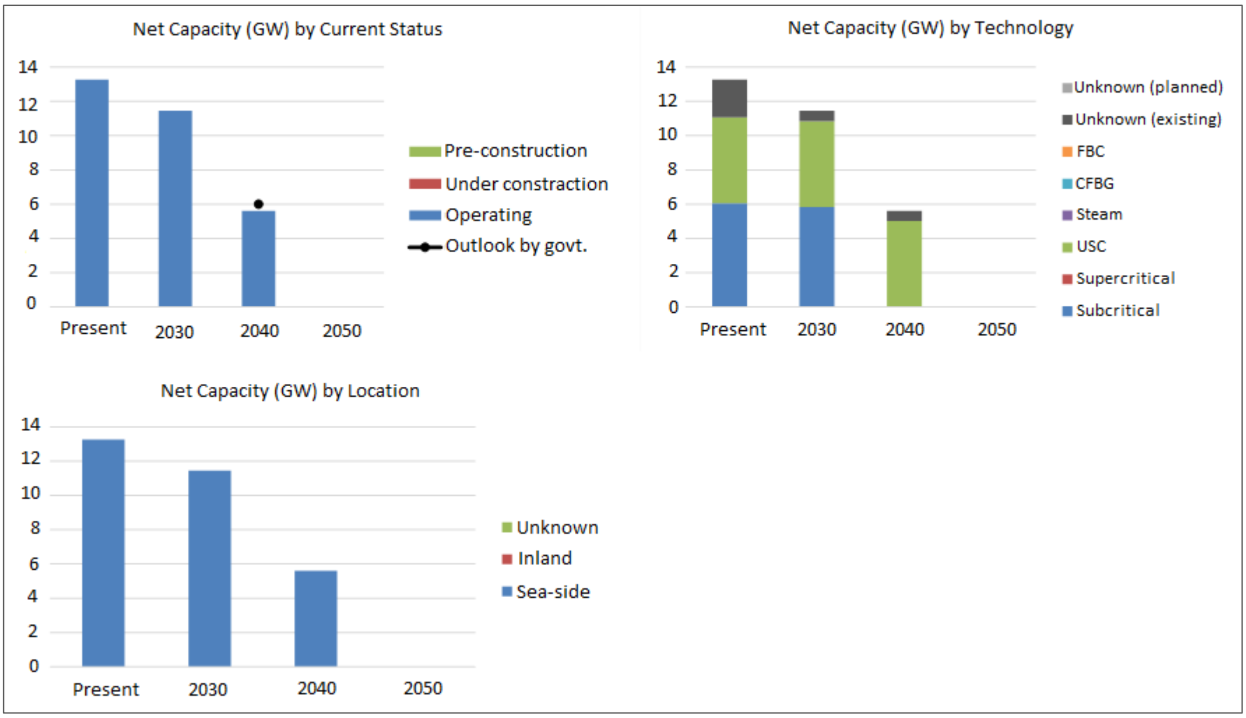


CFBG = Circulating fluidised bed gasifier; FBC = Fluidised bed combustion.
Source: Author's calculations, 2023.

For Malaysia, since the Enerdata database does not include any new projects, the installed capacity of coal-fired power will decrease from the current 13 GW to 6 GW by 2040 and to 0 GW by 2050 due to natural retirement (Figure 2.10). The estimated result is consistent with the government's outlook for 2040. The current power development plan for Peninsular Malaysia announced on March 2021 expects to add 2,800 MW of new capacity between 2031 and 2039 (Ministry of Natural Resources, Environment, and Climate Change, 2021). In his speech on the Malaysia Plan on September 27, 2021, meanwhile, former Prime Minister Ismail Sabri Yaakob stated that the government would not build new coal-fired power plants.

Figure 2.10. Coal-Fired Power Capacity by 2050, Malaysia

(GW)

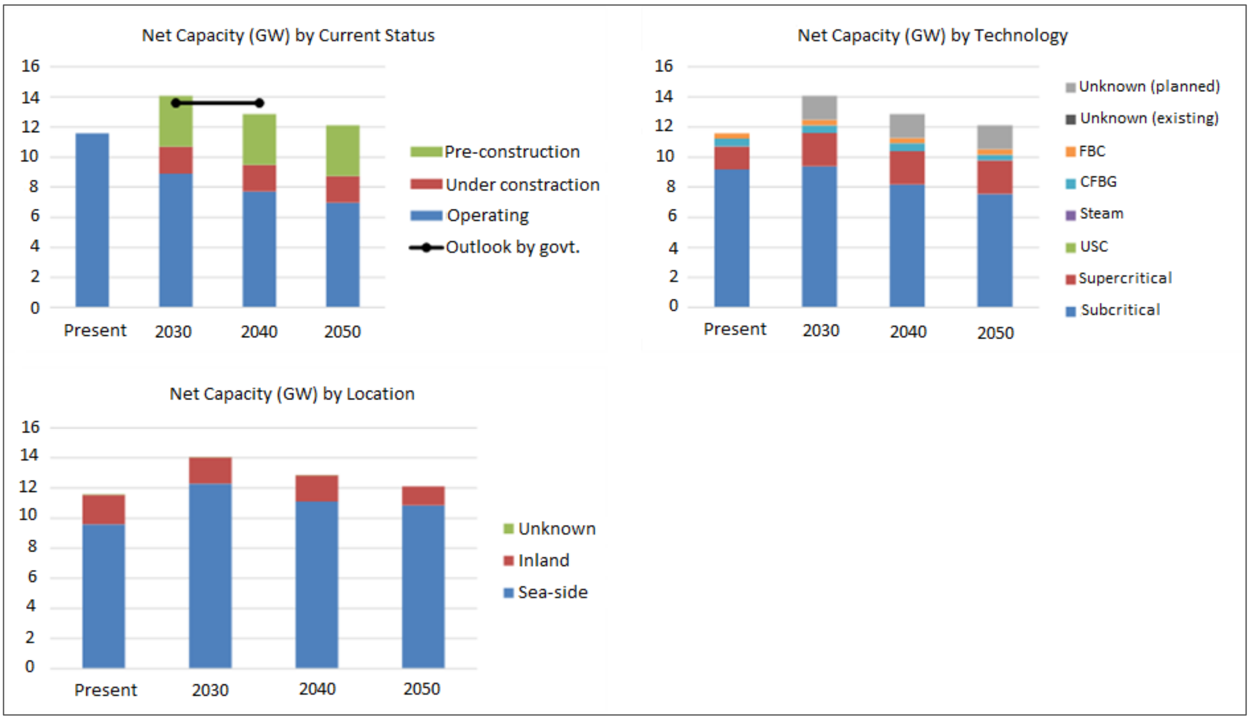


Source: Author's calculations, 2023.

For the Philippines, the government's outlook for installed capacity is 13.6 GW from 2030 to 2040, and the estimates are generally consistent with the outlook by assuming that approved projects will be added (Figure 2.11). If the plants with unknown decommissioning year have the lifetime of 40 years, 12 GW of coal-fired power will remain in operation even in 2050. Considering that a large number of plants are located on the seaside, there exists a big potential for ammonia co-firing in the Philippines.

Figure 2.11. Coal-fired Power Capacity by 2050, Philippines

(GW)

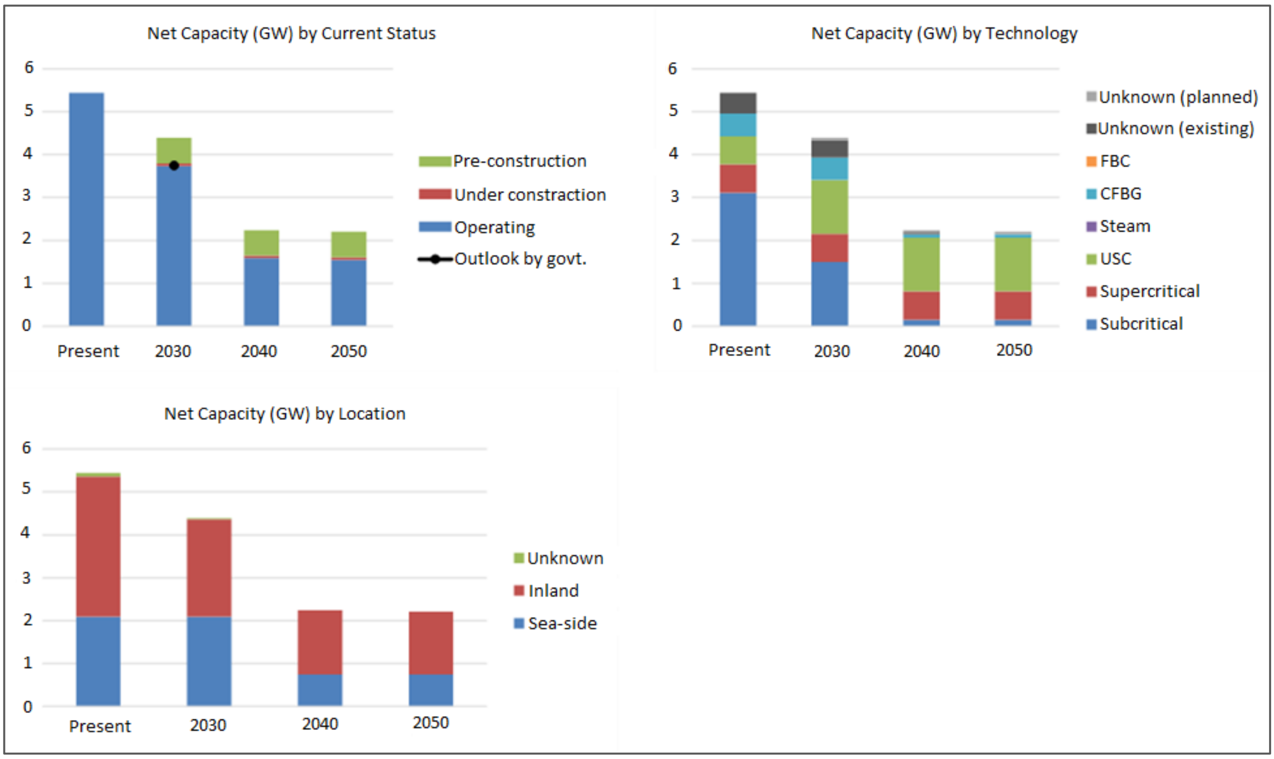


Source: Author's calculations, 2023.

For Thailand, since the database expects almost only replacement for the new projects (a replacement of Mae Moh 8-9), the coal-fired power capacity will decrease significantly to 2.2 GW by 2040 due to natural retirement (Figure 2.12). Although Thailand's power development plan also includes coal-fired power located in Lao People's Democratic Republic (Lao PDR), the government's outlook of 3.7 GW in 2030 excludes the plants in Lao PDR since this study only covers plants in Thailand. The estimated result is higher than the government's outlook for 2030 excluding import from Lao PDR. This is because the database includes small power plants that are excluded in the power development plan.

Figure 2.12. Coal-fired Power Capacity by 2050, Thailand

(GW)

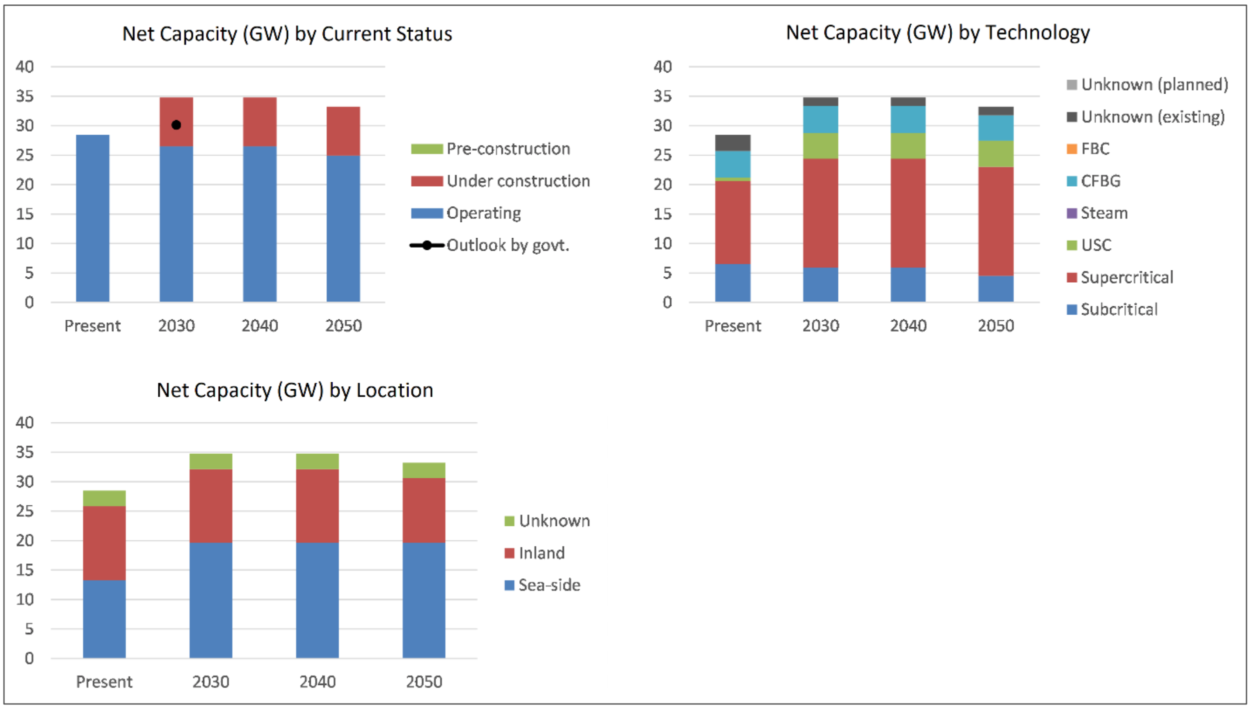


Source: Author's calculations, 2023.

For Viet Nam, if only plants under construction are added, the estimated installed capacity for 2030 is 35 GW, slightly larger than the recently approved PDP8 (30.1 GW) as shown in. Figure 2.13. The installed capacity is projected to remain almost constant after 2030, estimated at 33 GW even by 2050, if plants with unknown decommissioning years have a lifespan of 40 years. Although the latest PDP8 expects zero coal-fired power generation by 2050, achieved through a complete shift to biomass or ammonia, this study evaluates the potential of coal-ammonia co-firing through 2050. According to the database, the newly installed capacity is between supercritical (SC) and ultra-supercritical (USC) technologies. After 2040, it is estimated that more than half of the installed capacity will be situated on the seaside.

Figure 2.13. Coal-fired Power Capacity by 2050, Viet Nam

(GW)



Source: Author's calculations, 2023.

(2) Fuel input and CO_2 emission

Figure 2.14 shows ammonia demand and CO_2 emissions reduction volume. As a reference, the figure also shows the trend of installed capacity in the five countries. The collective ammonia demand in the five countries is estimated to reach 27 Mt in 2040 and 52 Mt in 2050.

Figure 2.14. Ammonia Demand and Reduced Carbon Dioxide by Coal Ammonia Co-firing by 2050

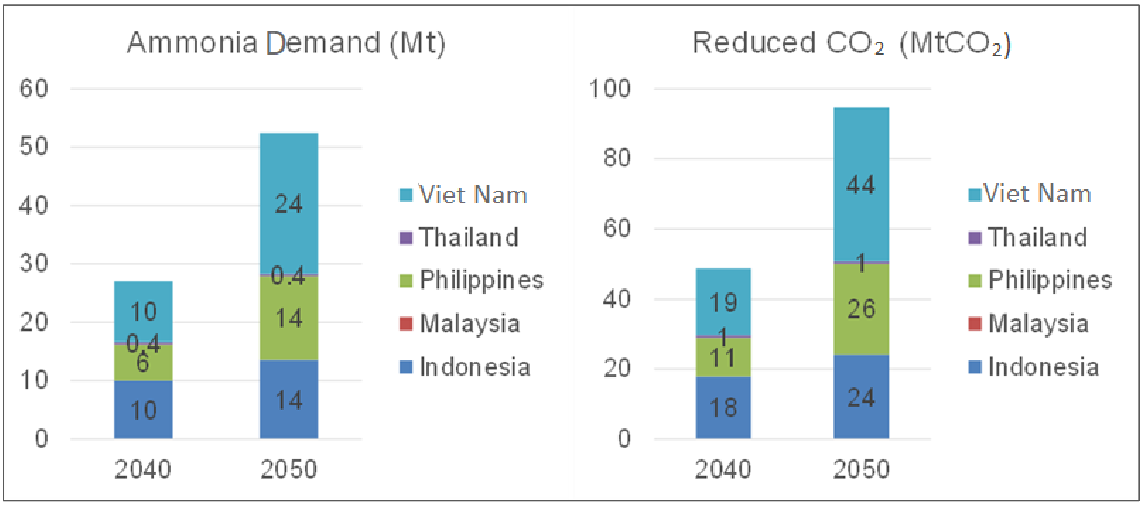
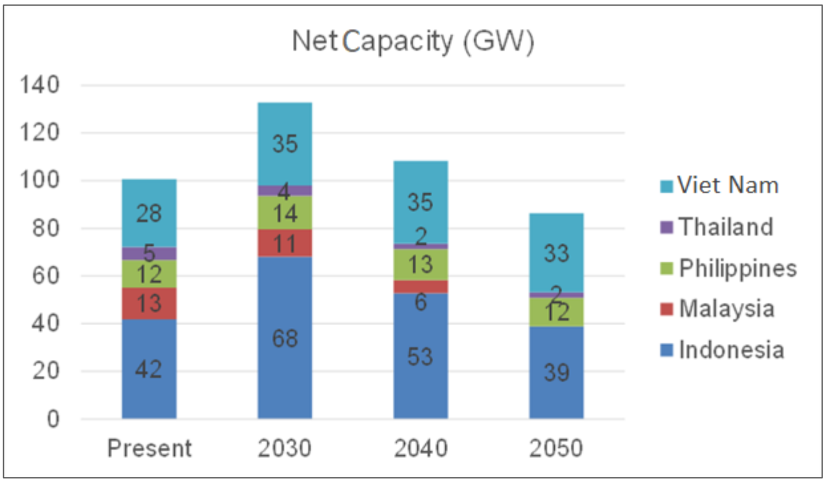


Figure 2.14. *Continued*



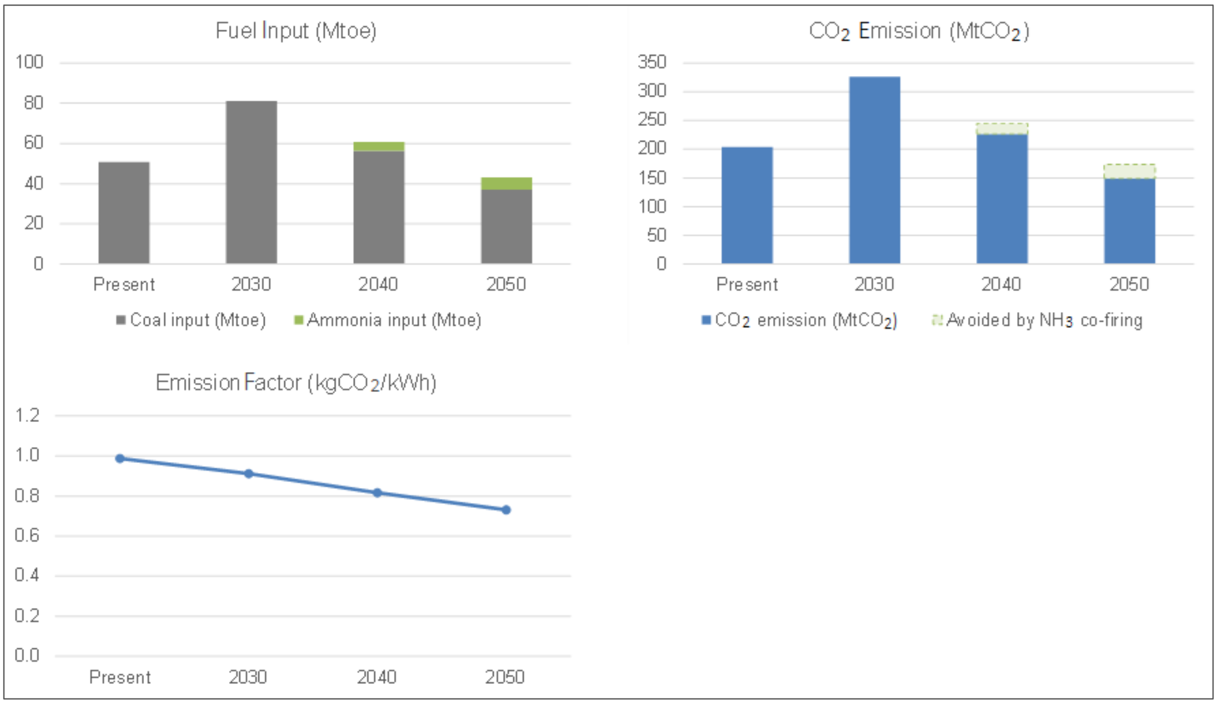
Source: Author's calculations, 2023.

The previous year's report estimated ammonia demand in 2050 at 83 Mt under the 'Low' scenario and 160 Mt under the 'High' scenario. The current study's estimate, about 60% of the Low scenario, is influenced by the restriction of ammonia co-firing to seaside plants. Despite more realistic assumptions leading to a downward revision of potential fuel ammonia demand, the estimated demand is still large (about one-fourth of current international ammonia trading volume by 2050). The increase in ammonia demand from 2040 to 2050 mainly stems from Viet Nam and the Philippines, where installed capacity is largely maintained after 2030. In Indonesia, a slight increase in ammonia demand is expected due to a decrease in installed capacity coupled with an increase in co-firing ratio. It should be noted that early adoption of coal-ammonia co-firing technologies and evolving technologies for co-firing at gas-fired power plants and single-firing will further expand opportunities for ammonia utilisation in power generation within ASEAN.

The amount of CO_2 emissions reduction, which is calculated by multiplying ammonia demand by emission factor of coal, was estimated at 49 million tonnes of carbon dioxide ($MtCO_2$) in 2040 (7% of CO_2 emissions in 2019) and 95 Mt-CO_2 in 2050 (15% of CO_2 emissions in 2019) for the five countries combined. For reference, fuel input, CO_2 emissions, and emission factors for coal-fired power generation by country are shown in Figures 2.15 to 2.19.[7]

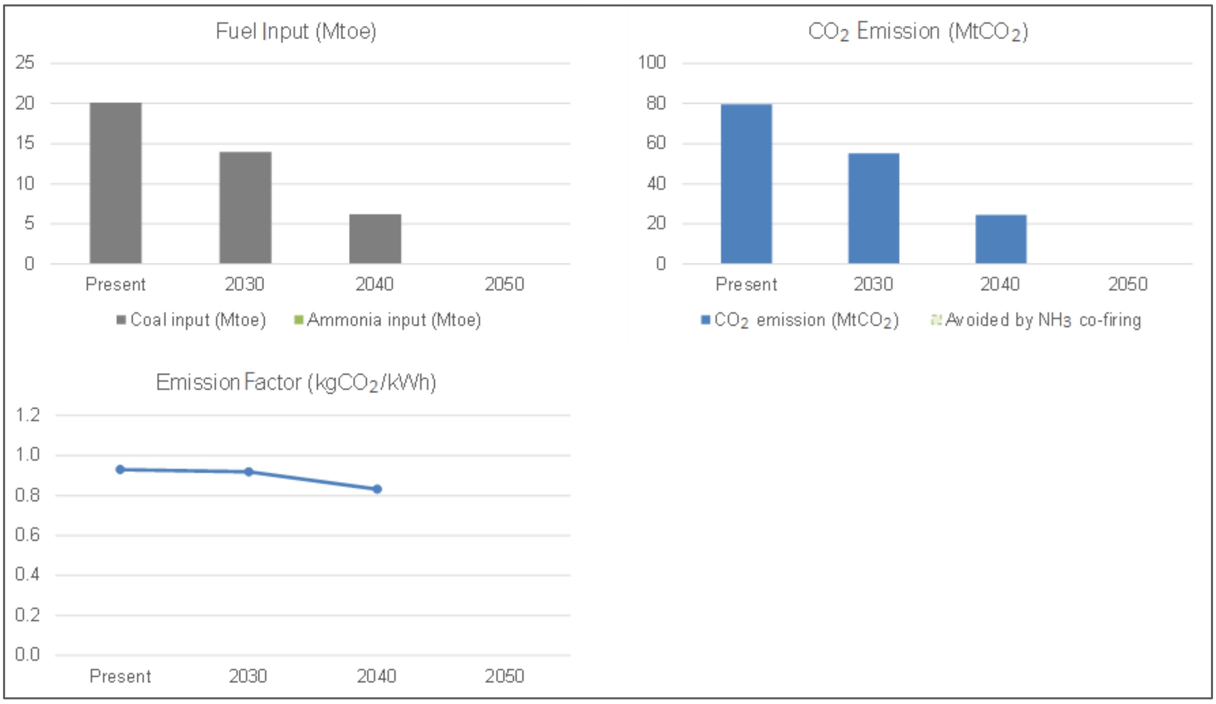
[7] Since the Indonesian technology catalog is referred for the efficiency of the plant by technology, the current efficiency may not match the value calculated from the country-specific statistics.

Figure 2.15. Fuel Input and Carbon Dioxide Emission by 2050, Indonesia



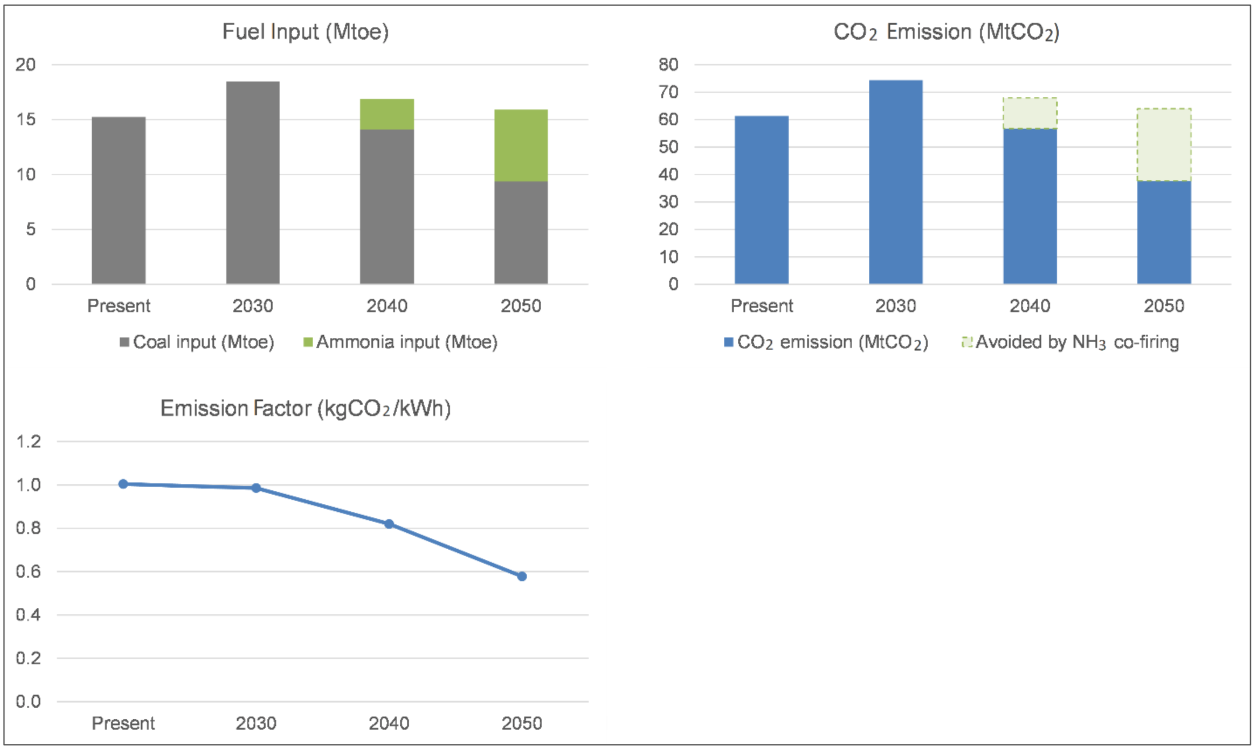
CO_2 = carbon dioxide; $kgCO_2$ = kilograms of carbon dioxide; kWh = kilowatt-hour; Mtoe = million tonnes of oil equivalent; Mt-CO_2 = million tonnes of carbon dioxide.
Source: Author's calculations, 2023.

Figure 2.16. Fuel Input and Carbon Dioxide Emission by 2050, Malaysia



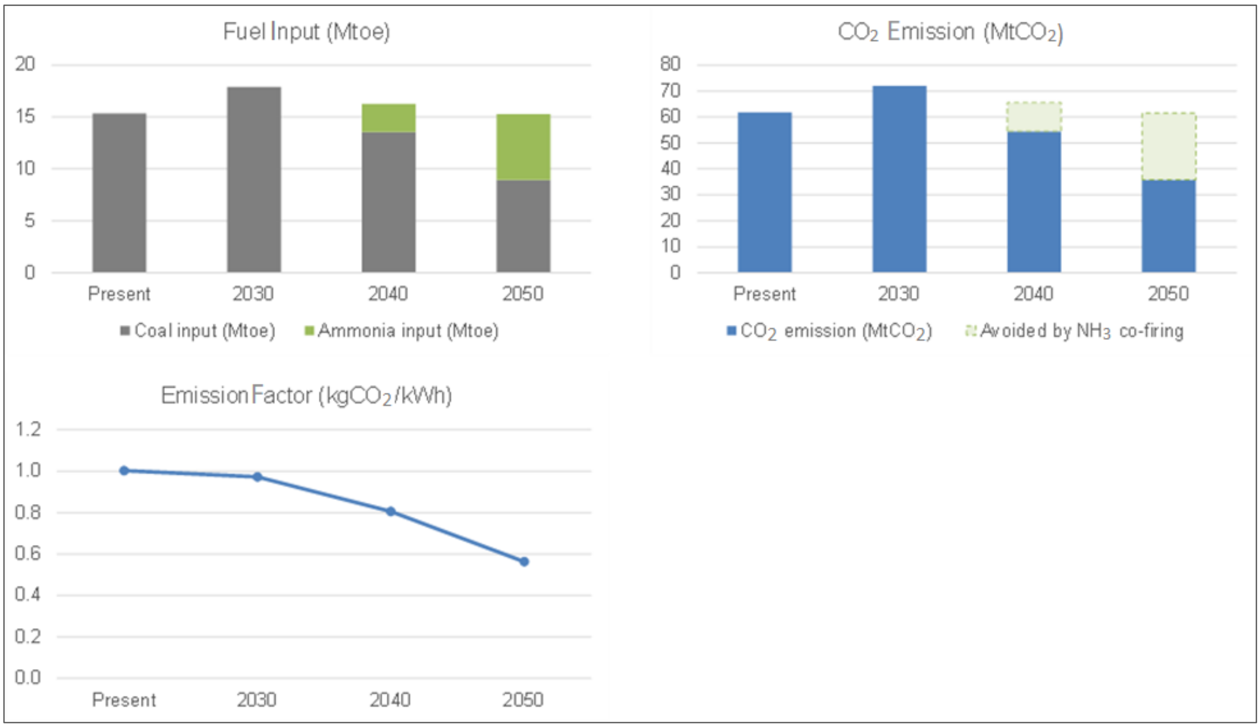
Source: Author's calculations, 2023.

Figure 2.17. Fuel Input and Carbon Dioxide Emission by 2050, Philippines



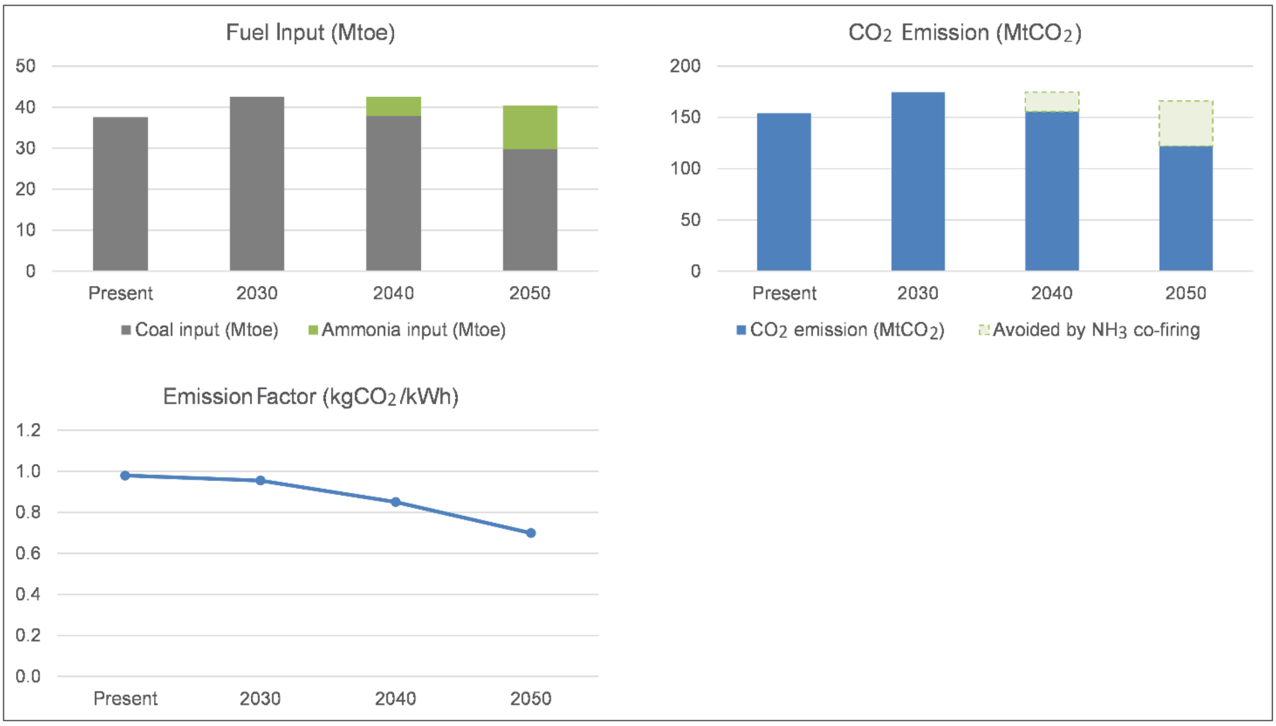
Source: Author's calculations, 2023.

Figure 2.18. Fuel Input and Carbon Dioxide Emission by 2050, Thailand



Source: Author's calculations, 2023.

Figure 2.19. Fuel Input and Carbon Dioxide Emission by 2050, Viet Nam



Source: Author's calculations, 2023.

2.3. Sensitivity Analysis (More Aggressive phase-down from Coal)

Ammonia co-firing potential will be greatly influenced by the installed capacity of future coal-fired power generation. This study conducted a sensitivity analysis, assuming that

only coal-fired power plants currently under construction will be realised;

SUB-C units will be decommissioned in 20 years; and

SC and USC in 30 years for the plants with unknown decommissioning year (Table 2.6).

Table 2.6. Parameters for estimating future Coal-fired Power Capacity (More Aggressive Phase-down from Coal)

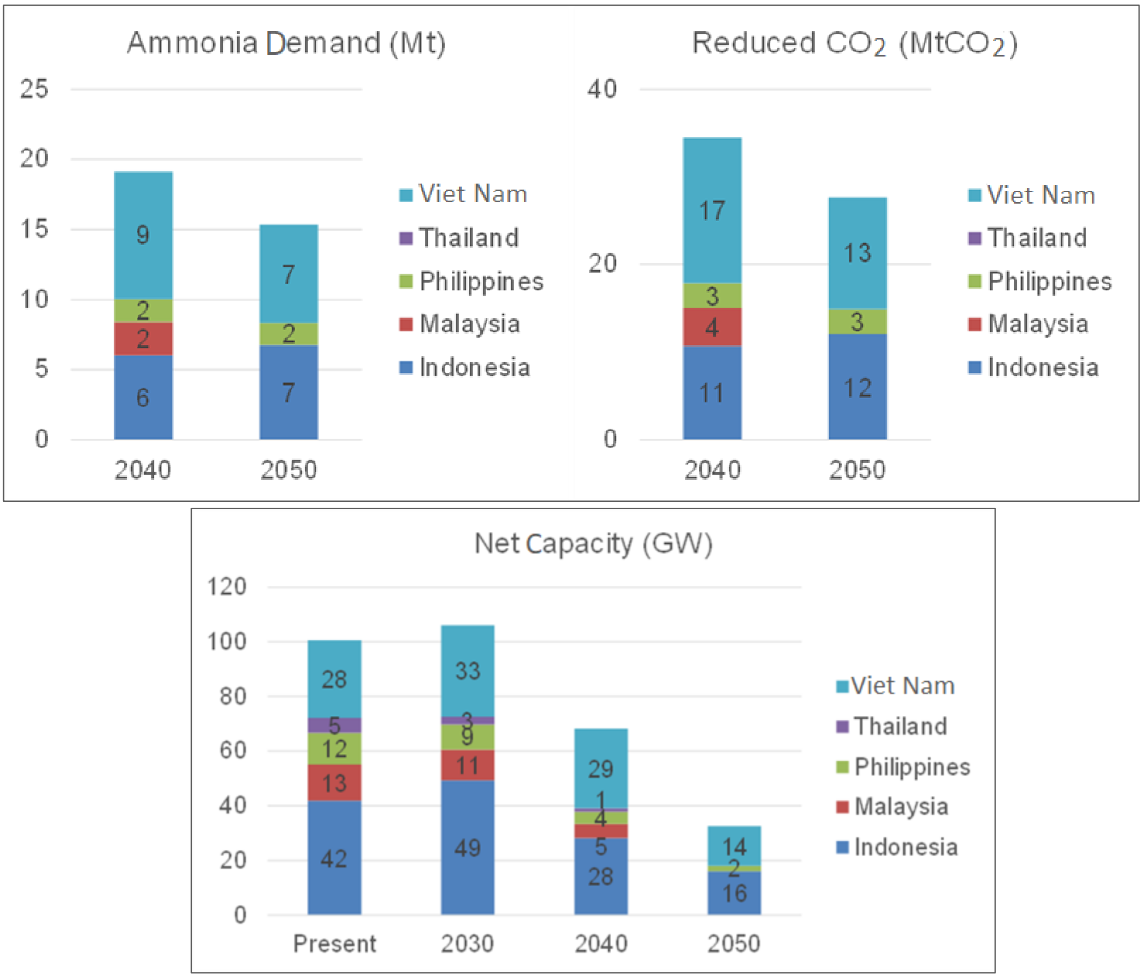
Parameter	All Countries
Category of current status of the unit operating in the future (Table 2.5)	1-2
Lifetime of the unit with unknown decommissioning Year (years)	SC, USC: 30 SUB-C: 20

Source: Author's assumptions, 2023.

Despite a substantial reduction in coal-fired power generation in this strengthened phase-down scenario, approximately 68 GW of coal-fired power capacity is projected for 2040, decreasing to

33 GW in 2050 across the five countries collectively. Consequently, the anticipated ammonia demand is estimated to reach 19 Mt in 2040 and 15 Mt in 2050 (Figure 2.20). In this scenario, coal-fired power will remain mainly in Viet Nam and Indonesia after 2040, with ammonia demand also concentrated in these two countries. Thus, this scenario underscores the potential of fuel ammonia for co-firing. On the other hand, since electricity demand is expected to grow with economic growth and electrification, this scenario requires a more rapid increase in investment in clean power sources to cover the rapid decline in coal-fired power generation.

Figure 2.20. Ammonia Demand and Reduced Carbon Dioxide by Coal Ammonia Co-Firing by 2050 (More Aggressive Phase-down from Coal)



MT = Million tons.
Source: Author's calculations, 2023.

Chapter 3

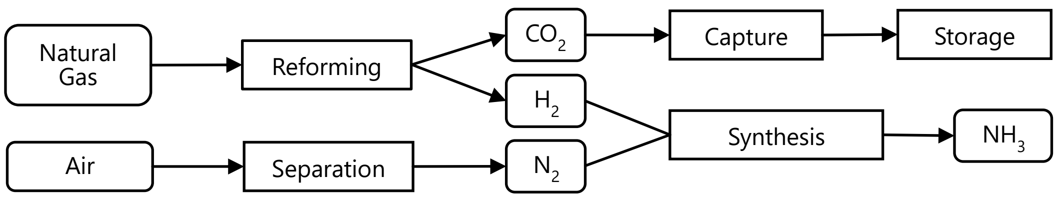
Cost Analysis of Fuel Ammonia Supply

1. Cost Analysis of Fuel Ammonia Supply in ASEAN

1.1. Assumptions for Production Cost of Blue Ammonia (Assumptions)

Figure 3.1 outlines the standard process for producing blue ammonia. In this process, Hydrogen (H_2) obtained by reforming natural gas and nitrogen (N_2) separated from air are synthesised to yield ammonia (NH_3). This ammonia can be regarded as blue ammonia the if CO_2 emitted from the reforming is sequestered and stored.

Figure 3.1. Assumed Flow Diagram of Blue Ammonia Production



H_2 = Hydrogen; N_2 = Nitrogen.
Source: Author.

The cost estimate in this section is based on the Assumptions Annex of the IEA's report (International Energy Agency, 2020)[0] and a spreadsheet in METI's report (Ministry of Economy, Trade, and Industry of Japan, 2022), which calculates the overall cost of producing blue ammonia from the Oceania region.[8] The IEA report's data is used to estimate the cost of ammonia production, including natural gas reforming and carbon dioxide capture, while the METI report is used to compute the cost of CO_2 storage. Table 3.1 shows all assumptions in this calculation. The plant is assumed to operate for 25 years with an availability of approximately 91% (8,000 hours/year) and a production capacity of one million tonnes per a year (1MTPA). The plant's projected location is within an ASEAN country. The assumed price of natural gas is $6.0/million British thermal unit (MMbtu), or $311/tonne of natural gas (t-NG), referencing the domestic selling price for fertiliser producers in Indonesia.[9] It is considered that 70% of the CO_2 emitted during natural gas reforming is captured and sequestered, with the cost of CO_2 storage assumed

[8] Because there is no reliable information of the assumptions for ASEAN countries, this study referred to the information of Oceania region in the above-cited reference.
[9] Suggestion from the participant in the workshop meeting held on 29 May 2023.

to be \$40.0/t-CO_2. Labor and electricity costs are also considered.

Table 3.1. Assumptions for Estimating Blue Ammonia Cost

Item	Value	Unit	Item	Value	Unit
Capacity	1.00	MTPA (NH_3)	Natural gas demand	38.30	GJ/t-NH_3
Life time	25	Year	Natural gas price	6.00	USD/MMBTU
Availability	91.32%	-	Unit conversion	1.05506	GJ/MMBTU
Unit CAPEX	1,260.00	USD/t-NH_3	Higher heat value	54.10	MJ/kg-NG
Owner's cost	5.00%	-	Electricity demand	1.30	GJ/t-NH_3
Captured CO_2	1.32495	MTPA (CO_2)	Electricity price	3.10	Cent/kWh
CO_2 storage unit cost	40.00	USD/t-CO_2	Emission factor	0.00	t-CO_2/t-NH_3
Relative annual OPEX	2.50%	-			

CAPEX = Capital expenditure; OPEX; Operating expenses.
Source: Author's estimates, 2023.

1.2. Result of Production Cost Estimate of Blue Ammonia

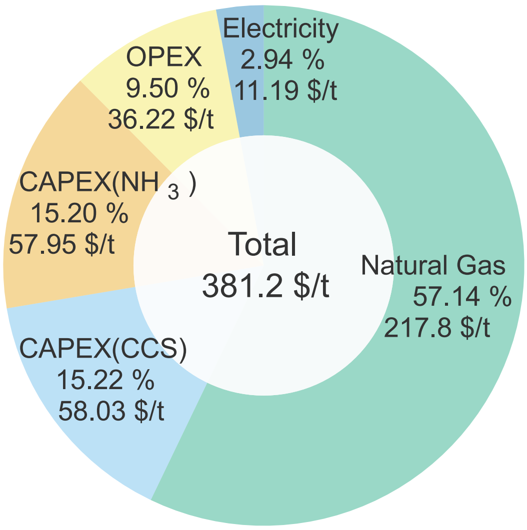
The result of cost estimation for blue NH_3 production, under the assumptions of Table 3.1, is shown in Table 3.2. The breakdown of the computed cost is depicted in Figure 3.2. The production cost consists of CAPEX, OPEX, the purchase cost of natural gas, CCS cost, and others. The summation of all these costs divided by the amount of produced ammonia provides the cost estimate per unit mass, and it is found to be \$381/t-NH_3. This value is used as the price of ammonia in the subsequent calculation of the levelised cost of electricity (LCOE) for a coal-fired plant with ammonia co-firing. In this context, all expenditures in Table 3.2 are considered as fuel cost in the LCOE calculation. From the breakdown of the cost shown in Figure 3.2, the purchase cost of natural gas is more than 50% of the total cost, which means that variation of natural gas price greatly affects the cost of blue ammonia production.

Table 3.2. Estimated Cost of Blue Ammonia

Item	Value	Unit	Item	Value	Unit
Total production	22.83	Million t-NH_3	Total cost of natural gas	4,972.79	Million USD
CAPEX	1,323.00	Million USD	Total amount of electricity	29,680.37	TJ
CO_2 storage cost	1,324.95	Million USD	Total cost of electricity	255.58	Million USD
Annual OPEX	33.08	Million USD	Total amount of emission	0.00	Million t-CO_2
Total OPEX	826.88	Million USD	Total cost	8,703.20	Million USD
Cost of natural gas	307.66	USD/t-NG			
Amount of natural gas	16.16	Million t-NG	**Blue ammonia price**	**381.20**	**USD/t-NH_3**

TJ = Terra Joules.
Source: Author's estimates, 2023.

Figure 3.2. Breakdown of Blue Ammonia Price

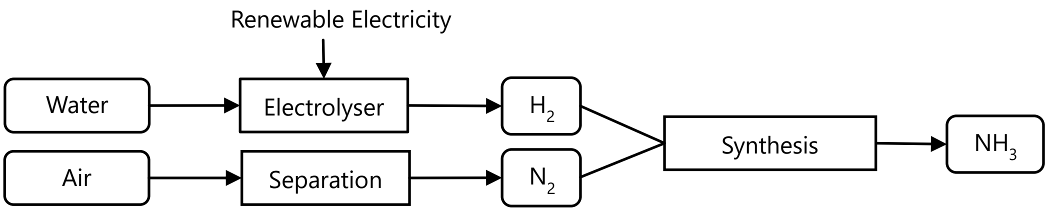


Note: The unit, $/t, in the figure means USD/t-NH_3.
Source: Author's calculations, 2023.

1.3. Assumptions for Production Cost of Green Ammonia

Figure 3.3 depicts a simplified flow diagram of green ammonia production. The process involves synthesising hydrogen produced from water and nitrogen separated from air to create ammonia. This product qualifies as green ammonia since the electricity used by the electrolyser for water splitting is provided by renewable energy sources. It is assumed here that electricity required in other processes, such as air separation and ammonia synthesis, is also provided by renewable sources.

Figure 3.3. Assumed Flow Diagram of Green Ammonia Production



Source: Author.

The cost of green ammonia production is estimated based on IEA's assumption of projected 2030 values for all capital expenditures (CAPEX), except power generation, and required amount of electricity. Since the 2030 price for renewable electricity is unavailable, the long-term Australian price (3.1 US cent/kWh) is adopted, encompassing power generation expenses, including CAPEX. The cost of water, used as NH_3 production feedstock, is also considered. The required amount of water is determined by reaction formulas, $2H_2O \rightarrow 2H_2 + O_2$ and $N_2 + 3H_2 \rightarrow 2NH_3$. All assumptions for this cost estimate are shown in Table 3.3.

Table 3.3. Assumptions for Estimating Green Ammonia Cost

Item	Value	Unit	Item	Value	Unit
Capacity	1	MTPA	Electricity demand	35.30	GJ/t-NH_3
Life time	25	Year	Electricity price	31.00	USD/MWh
Availability	26.5%	of life time	Molar mass (NH_3)	17.03	g/mol
Unit CAPEX	885	USD/t-NH_3	Molar mass (H_2O)	18.02	g/mol
Annual OPEX	1.5%	of CAPEX	Water price	0.60	USD/t-H_2O

Note: The unit CAPEX is currently 1,160 USD/t-NH_3, and its long-term expectation is 575 USD/t-NH_3. The required amount of electricity is currently 37.8 GJ/t-NH_3, and it is expected to be 33.2 GJ/t-NH_3 in the long term.
Source: Author's estimates, 2023.

1.4. Result of Production Cost Estimate of Green Ammonia

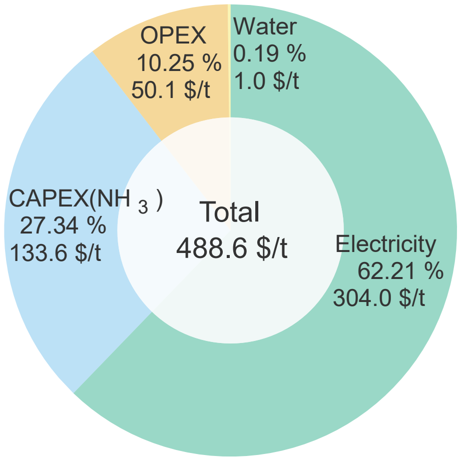
The estimated cost of green ammonia production based on the assumptions of Table 3.3 is found in Table 3.4, and its breakdown is shown in Figure 3.4. As in the case of blue ammonia, all required costs divided by the amount of ammonia gives the estimated cost per unit mass of green ammonia, and it is \$489/t-NH_3. This is regarded as the price of fuel ammonia being purchased by a co-firing plant, and it is used in the LCOE computation of the plant. Discounting is also considered in the LCOE estimation. The breakdown of the cost in Figure 3.4 shows that the cost of renewable electricity is more than 60% of the whole expenditure. It is seen that the cost of green ammonia production strongly depends on the price of renewable electricity.

Table 3.4. Estimated Green Ammonia Price

Item	Value	Unit	Item	Value	Unit
Total production	6.62	Million tonne	Electricity cost	2,013.47	Million USD
CAPEX	885.00	Million USD	Amount of water	10.51	Million tonne
Annual OPEX	13.28	Million USD	Total cost of water	6.31	Million USD
Total OPEX	331.88	Millioin USD	Total cost	3,236.65	Million USD
Total electricity	64,950.61	GWh	**NH_3 price**	**488.64**	**USD/t-NH_3**

Source: Author's calculations, 2023.

Figure 3.4. Breakdown of Green Ammonia Price



Note: The unit, $/t, in the figure means USD/t-NH_3.
Source: Author's calculations, 2023.

1.5. Transportation Cost of Ammonia

Ammonia is assumed to be transported via a pipeline from the production plant to a power plant. The transportation cost is estimated using previous assumptions and calculation shown in Table 3.5. The CAPEX for constructing 1 km of pipeline, divided by the transported amount of ammonia for 40 years, provides an estimated transportation cost per unit mass of $0.0764/t-$NH_3$. Although this cost is included in the ammonia price and considered in LCOE calculation, it has limited impact on the total cost of power generation due to its relatively small size compared to the production cost of ammonia.

Table 3.5. Transportation Cost of Ammonia through Pipeline

Item	Value	Unit	Item	Value	Unit
Life time	40	Year	Distance	1	km
Capacity	240	kt-NH_3/y	CAPEX	0.55	Million USD
Unit CAPEX	0.55	Million USD/km	Throughput	180	kt-NH_3/y
Utilization	75%	-	Total amount	7,200	kt-NH_3
			Unit cost	**0.0764**	**USD/t-NH_3**

Source: Author's calculations, 2023.

2. Cost Analysis of Ammonia Co-firing

2.1. Assumptions for Levelised Cost of Electricity and Carbon Dioxide Intensity of Ammonia Co-firing

In this estimate, Levelised Cost of Electricity (LCOE) and CO_2 intensity are calculated for a new coal-fired plant that will be operated for 40 years from 2025. The following three cases are considered:

- Thermal electricity is provided solely by coal throughout the operation period.
- No NH_3 co-firing is introduced in the first 5 years, 20% of thermal energy is provided by blue NH_3 in the next 5 years, and the ratio is 50% thereafter.
- The same plan as (2) is adopted except green ammonia is used instead of blue.

Assumptions in this estimate are summarised in Table 3.6. It is assumed here that the CAPEX for coal-fired power generation and for ammonia co-firing are proportional to capacity [kW] and co-firing ratio [%], respectively. The CAPEX for each kW of capacity is $1,400/kW, while the CAPEX per one percent of co-firing ratio is $10.8 million/% for a power plant with 700 MW capacity. The performance (heat efficiency) of each equipment and the overall power generation efficiency remain constant without deterioration. It is important to note that CO_2 emissions in the NH_3 production stage are not included in this estimate.

Table 3.6. Assumptions for Estimating Levelised Cost of Electricity and Carbon Dioxide Intensity of Co-fired Plant

Item	Value	Unit	Item	Value	Unit
Discount rate	4.5%	-	Efficiency reduction	0.0%	-
Generation capacity	700	MW	Calorific value (coal)	24.8	MJ/kg (LHV)
Capacity factor	70%	-	Fuel cost (coal)	44.0	USD/t-coal
Internal use	5.5%	-	Calorific value (NH_3)	14.1	MJ/Nm^3 (LHV)
Heat efficiency (LHV)	40.0%	-	NH_3 Density	0.772	kg/Nm^3
Unit CAPEX (coal)	1400	USD/kW	Fuel-related expenses	0.057	Cent/MJ
Decomission (coal)	5%	of CAPEX	Unit CAPEX (co-firing)	10.8	Million USD/%
Labor cost	3.26	Million USD	Decommision (NH_3)	5%	-
Maintenance	2.4%	of CAPEX	CO_2 intensity (coal)	93.72	g-CO_2/MJ
Other expenses	2.2%	of CAPEX	CO_2 intensity (blue NH_3)	0.00	g-CO_2/MJ
G&A expenses	12.2%	of direct expenses	CO_2 intensity (green NH_3)	0.00	g-CO_2/MJ

Source: Author's calculations, 2023.

As for the calculation of fuel cost, the coal price in Indonesia is chosen, and the values estimated in this report are used for ammonia. The cost per unit mass of fuel is assumed to be constant for both coal and ammonia throughout the operation period of the plant. The yearly fuel purchase cost is weighted by a factor derived from the discount rate before computing the total cost over the whole plant life. The lower heat value (LHV) is used when thermal energy obtained by a given amount of fuel is necessary. For example, as the amount of CO_2 emission from coal per 1 MJ of thermal energy, the value, 93.7 g-CO_2/MJ, based on LHV is used instead of the Higher Heating Value (HHV) based value, 89.0 g-CO_2/MJ.

2.2. Result of LCOE and CO_2 Intensity of NH_3 Co-firing

The estimated cost of power generation and CO_2 emissions are shown in Table 3.7 to Table 3.9 and Figure 3.5 to Figure 3.6. Table 3.7 displays the whole cost including CAPEX, OPEX, and the other expenses. Information about total amount electricity generation and CO_2 emissions are in Table 3.8. The LCOE and its breakdown are in Table 3.9 and illustrated in Figure 3.6 for the three scenarios: (1) no co-firing, (2) blue co-firing, and (3) green co-firing. The estimated CO_2 intensity is 0.893 for case (1) and 0.604 [kg-CO_2/kWh] for case (2) and (3) (Table 3.8 and Figure 3.5). The corresponding LCOE values are (1) 4.89, (2) 11.41, and (3) 13.22 [Cent/kWh] for each case (Table 3.9 and Figure 3.6).

Table 3.7. CAPEX, OPEX, and Fuel Cost for Power Generation

($ million)

Cost	Coal	Blue	Green	Cost	Coal	Blue	Green
CAPEX(coal)	980	980	980	Fuel cost (coal)	1,261	854	854
CAPEX(co-fire)	0	469	469	Fuel cost (NH_3)	0	4,798	6,149
Decommission	8	13	13	Fuel related cost	405	405	405
Total OPEX	998	998	998	**Total**	**3,653**	**8,517**	**9,869**

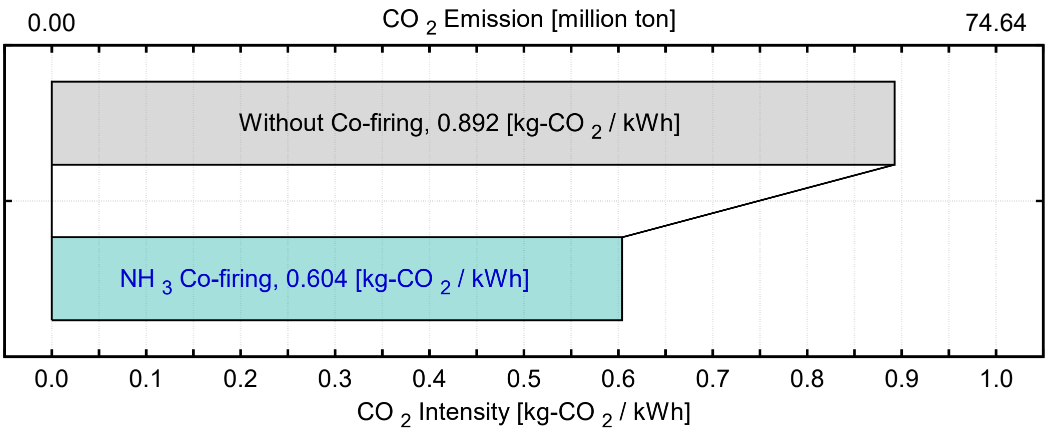
Source: Author's calculations, 2023.

Table 3.8. Total Electricity and Carbon Dioxide Emission

	Coal	Blue or green	Unit
Total electricity	74.64	74.64	TWh
CO_2 emission	66.62	45.09	Million tonne
CO_2 intensity	0.8926	0.6040	kg-CO_2/kWh

Note: Total electricity and CO_2 emission are discounted separately.
Source: Author's calculations, 2023.

Figure 3.5. Reduction of Carbon Dioxide Emission by Co-firing



Source: Author's calculation, 2023.

Table 3.9. Levelised Cost of Electricity

(US cents/kWh)

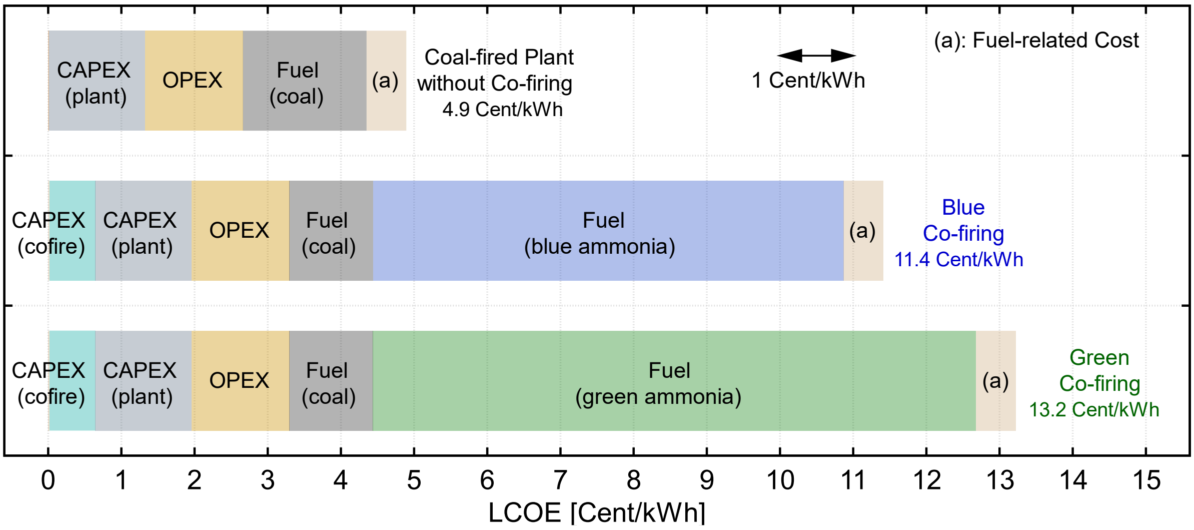
LCOE	Coal	Blue	Green	LCOE	Coal	Blue	Green
CAPEX(coal)	1.313	1.313	1.313	Fuel cost (coal)	1.690	1.143	1.143
CAPEX(co-fire)	0.000	0.628	0.628	Fuel cost (NH_3)	0.000	6.427	8.239
Decommission	0.011	0.018	0.018	Fuel related cost	0.543	0.543	0.543
Total OPEX	1.337	1.337	1.337	**Total**	**4.894**	**11.410**	**13.221**

Source: Author's calculations, 2023.

The variation in CO_2 emissions between the plans with and without co-firing comes from the difference in coal consumption for power generation. The LCOE of each co-firing plan depends mainly on the fuel cost as shown in Figure 3.6. The fuel-related expenses in Table 3.9 and Figure 3.6 remain consistent across co-firing ratios, as they are tied to the thermal energy required to generate equivalent electricity with the same efficiency.

Figure 3.6. Breakdown of Levelised Cost of Electricity for Coal Fired and Ammonia Co-Fired Plant

(US cents/kWh)



LCOE = levelised cost of electricity.
Source: Author's calculations, 2023.

3. Sensitivity Analysis

Sensitivity analysis is a method for measuring the degree to which the overall economic outlook is influenced by changes in assumptions that could potentially exert significant impact on the overall economics. The computed supply cost of fuel ammonia, as established in the previous section, is contingent on assumptions, many of which may be variable and uncertain. Therefore, in considering the economics of fuel ammonia in the ASEAN region, it is important to understand how the final cost of supply would change if these assumptions were to vary, so that a rough understanding of the range of possible cost variations can be obtained.

To investigate how the LCOE of the co-fired power plant depends on the fuel and capital cost, the LCOE of the following four cases are computed in the same way as the previous paragraphs.

- The price of natural gas rises by $1/MMBTU.
- The availability of the plant for green ammonia production falls by 10%.
- CAPEX for ammonia production increases by 10%.

- The price of renewable electricity rises by 1 US cent/kWh.

The LCOE of each co-firing plan that is affected by the variation of the parameters is shown in Table 3.10 with its purchase cost of NH_3. The columns named 'Base Case' store the results before the variation. The blue ammonia co-firing is included in case (d), because renewable electricity is assumed to be utilised in the blue ammonia production.

Table 3.10. Results of Sensitivity Analysis

	Base case		Case(a)	Case(b)	Case(c)		Case(d)		Unit
	Blue	**Green**	**Blue**	**Green**	**Blue**	**Green**	**Blue**	**Green**	
NH_3 price	381.2	488.6	417.5	600.0	390.6	507.0	384.8	586.7	USD/t-NH_3
(difference)	(0.0)	(0.0)	(36.3)	(111.4)	(9.4)	(18.4)	(3.6)	(98.1)	
NH_3 cost	6.43	8.24	7.04	10.12	6.59	8.55	6.49	9.89	Cent/kWh
(difference)	(0.00)	(0.00)	(0.61)	(1.88)	(0.16)	(0.31)	(0.06)	(1.65)	
LCOE	11.41	13.22	12.02	15.10	11.57	13.53	11.47	14.87	Cent/kWh
(difference)	(0.00)	(0.00)	(0.61)	(1.88)	(0.16)	(0.31)	(0.06)	(1.65)	

LCOE = Levelised Cost of Electricity; NH_3 = Ammonia.
Note: Differences from the base case are shown in round brackets.
Source: Author's calculations, 2023.

Table 3.11 outlines the variation rate of the parameters denoted as 'x' in the table, the computed increase rate of LCOE ('y' in the table), and their ratio, y/x. In case (a), (c), and (d), the increase rate of LCOE is divided by the specified rate of change of the natural gas price, CAPEX for NH_3 production, and the renewable electricity price, respectively. On the other hand, in case (b), the increase rate of LCOE is divided by that of CAPEX equivalent to the specified decrease of availability of the green ammonia plant. From Table 3.11, it is seen that the ratio, y/x, has larger values for the blue ammonia co-firing in case (a) and the green ammonia co-firing in case (d). This means that the price of natural gas and renewable electricity has a stronger effect on LCOE than CAPEX does.

Table 3.11. Ratio of LCOE Increase to Cost Variation

	Case (a)	Case (b)	Case (c)		Case (d)	
	Blue	**Green**	**Blue**	**Green**	**Blue**	**Green**
Cost increase (=x)	16.67%	60.61%	10.00%	10.00%	32.26%	32.26%
LCOE increase (=y)	5.36%	14.20%	1.39%	2.34%	0.53%	12.50%
Ratio (y/x)	**0.322**	**0.234**	**0.139**	**0.234**	**0.017**	**0.388**

Source: Author's calculations, 2023.

An additional sensitivity analysis was conducted to assess the impact of a higher discount rate.[10] In this scenario, a discount rate of 10% was assumed. The outcome of this analysis is presented in Table 3.12 and Figure 3.7. Notably, under the influence of a higher discount rate, the estimated generation cost declines for both blue and green ammonia scenarios, while maintaining their relative balance.

Table 3.12. Levelised Cost of Electricity

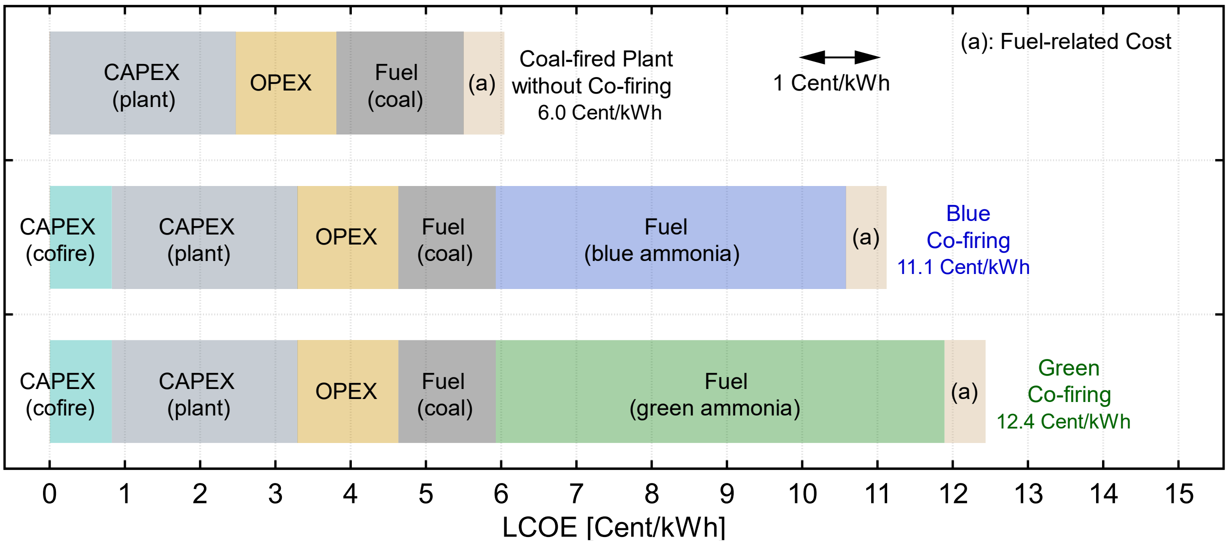
(US cents/kWh)

LCOE	Coal	Blue	Green	LCOE	Coal	Blue	Green
CAPEX(coal)	2.471	2.471	2.471	Fuel cost (coal)	1.690	1.294	1.294
CAPEX(co-fire)	0.000	0.822	0.822	Fuel cost (NH_3)	0.000	4.652	5.962
Decommission	0.002	0.004	0.004	Fuel related cost	0.543	0.543	0.543
Total OPEX	1.337	1.337	1.337	**Total**	**6.043**	**11.123**	**12.434**

Source: Author's calculations, 2023.

Figure 3.7. Breakdown of Levelised Cost of Electricity for Coal Fired and Ammonia Co-Fired Plant

(US cents/kWh)



Source: Author's calculations, 2023.

[10] This question was raised at the second workshop for this study held in May 2023.

Chapter 4

Recent Development Fuel Ammonia Technologies and Supply Chain Development

1. Hydrogen production

Fuel ammonia production uses hydrogen produced from natural gas or renewable energy sources as a feedstock. Ammonia is produced by reacting nitrogen recovered from the atmosphere with hydrogen. This process of reacting nitrogen and hydrogen to produce ammonia is known as the Haber-Bosch process, a technology with a long history that was developed by German chemists Fritz Haber and Carl Bosch in 1906. The Haber-Bosch process is a mature technology as its long history indicates, and it is not likely that dramatic improvements in efficiency or cost reductions will occur in this production method in the future. Therefore, future innovations in fuel ammonia are expected to be mainly in the hydrogen production part.

Currently, except for those produced as a by-product, hydrogen is primarily produced from fossil fuels such as natural gas, oil, and coal. The steam methane reforming (SMR) process is commonly used in the production of hydrogen from fossil fuels. In this method, carbon monoxide and hydrogen are first produced by reacting fossil fuels with water (steam reforming), and then hydrogen and carbon dioxide are further produced by reacting the carbon monoxide with water (shift reaction) (Figure 4.1 and 4.2). Since SMR is an endothermic reaction, it requires constant external heating to cause this reaction. The CO_2 produced in steam reforming reacts with the latter water gas shift reaction. This reaction is especially important not only for hydrogen production, but also for removing toxic carbon monoxide.

Figure 4.1. Hydrogen Production by Steam Methane Reforming

$CH_4+H_2O \rightarrow CO+3H_2$ … (Steam reforming)

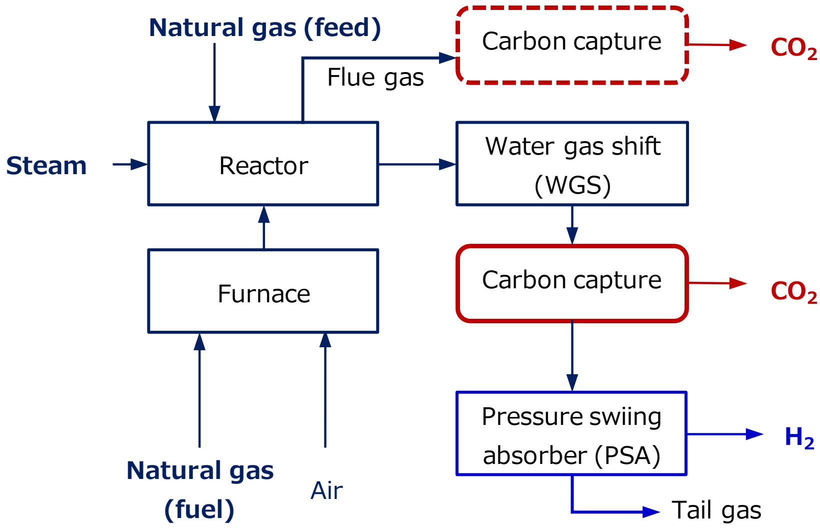
$CO+H_2O \rightarrow H_2+CO_2$ … (Water gas shift reaction)

Source: Authors.

Steam methane reforming (SMR) is also a well-known process with a long history and has very low technological risk. On the other hand, the challenge of this process is that it produces carbon dioxide as a byproduct for hydrogen produced. In the SMR, CO_2 is generated in two stages: the production of heat for the reaction and the production of hydrogen from syngas and water

(Figure 4.2). Of these, the latter has a high concentration of CO_2 in the emitted gas, so its recovery can be done at relatively low cost, but the CO_2 generated in the production of heat has a low concentration in its flue gas, so its recovery cost is high. In the future, when hydrogen and fuel ammonia are utilised in decarbonisation to achieve carbon neutrality, CO_2 emissions during their production must also be strictly controlled. When SMR is utilised, the major issue for the future is how much CO_2 emitted from the heat production sector can be recovered and at what cost.

Figure 4.2. Process of Steam Methane Reforming



Source: Authors.

In addition to SMR, a production method called autothermal reforming (ATR) has gained much interest in recent years as a method for producing the hydrogen needed for fuel ammonia. This method combines SMR and the partial oxidation processes. The partial oxidation method is a process that recovers oxygen from the atmosphere and utilises it in the hydrogen production reaction. The recovered oxygen is reacted (oxidised) with methane to produce syngas containing carbon monoxide and hydrogen, and the carbon monoxide is further used to produce hydrogen through a water gas shift reaction like in the steam methane reforming method (Figures 4.3 and 4.4). The major difference between the hydrogen production process in the partial oxidation method and the steam methane reforming method is that the reaction is exothermic rather than endothermic. Therefore, the heat produced during the production of hydrogen can be utilised in the overall process, and the problem of CO_2 recovery during the production of heat, which is an issue in the steam reforming method, can be eased. As the CO_2 recovery rate during hydrogen production is required to be increased, it is likely that this autothermal reforming method will be used as one of the major fuel ammonia production processes in addition to the currently dominant steam reforming method. Some companies have reported that the autothermal reforming method can recover 99% of CO_2 at the time of production, and the development and diffusion of this technology is greatly anticipated in the future (Air Liquide, 2023).

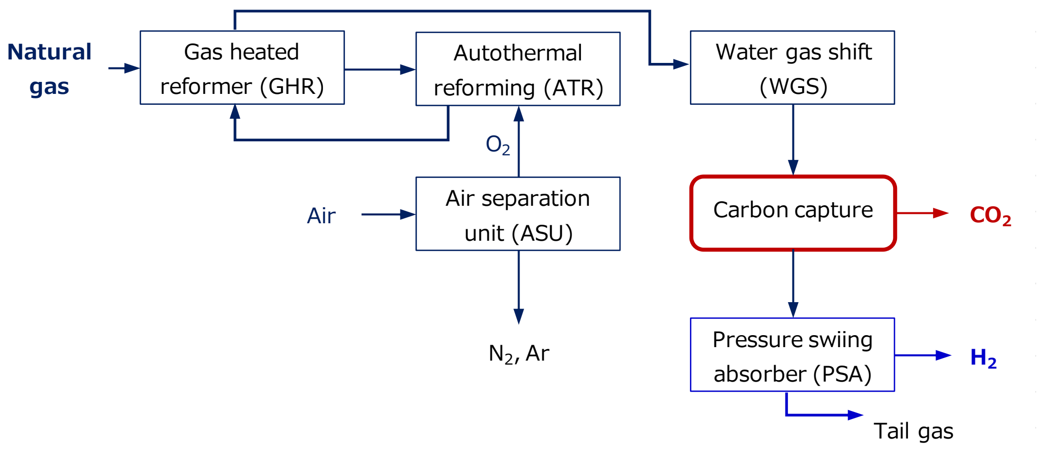
Figure 4.3. Hydrogen Production by Partial Oxidisation Process

$CH_4+1/2O_2 \rightarrow CO+2H_2$ … (Partial oxidisation)

$CO+H_2O \rightarrow H_2+CO_2$ … (Water gas shift reaction)

Source: Authors.

Figure 4.4. Autothermal Reforming Process

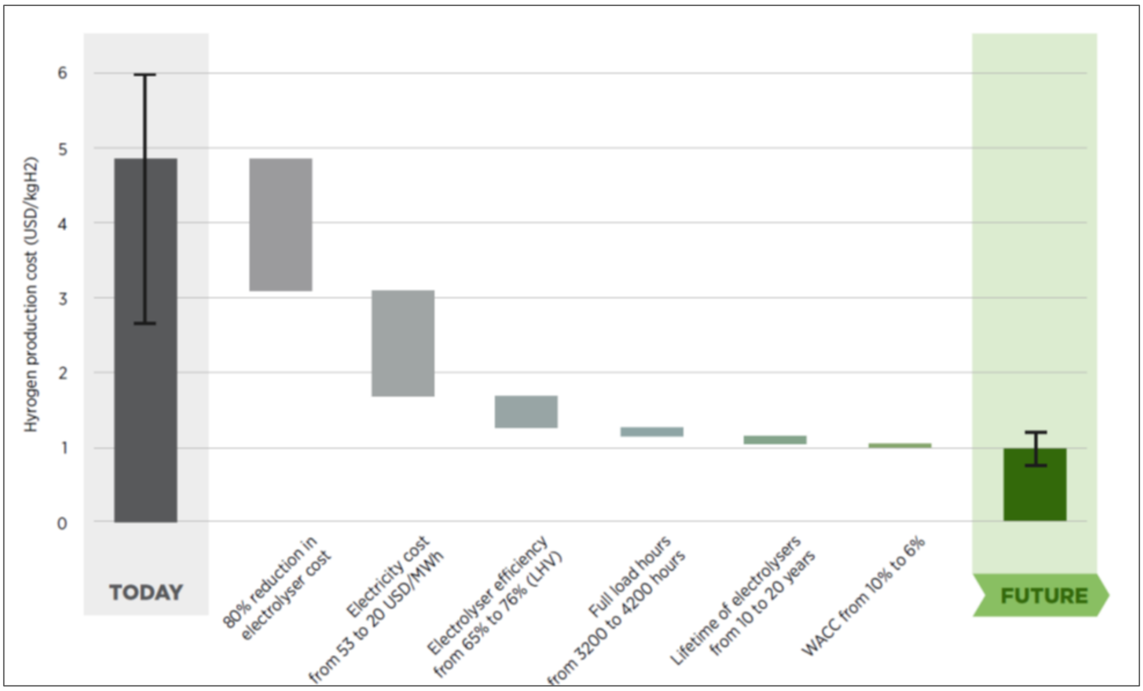


Source: Authors.

On the other hand, a process that is expected to dramatically reduce costs in the future is the electrolysis of water using electricity from renewable energy sources. As of today, the cost of electricity from renewable energy sources for water electrolysis has been high, and the process has not been sufficiently technologically developed. Therefore, future technological development is expected to dramatically reduce the cost of this process. The International Renewable Energy Agency, for example, estimates that the cost of water electrolysis equipment will drop by 80% from current levels in the future, which will enable the cost of hydrogen production cost to reach almost as low as $1/kg (Figure 4.5).

Figure 4.5. Expected Cost Reduction of Green Hydrogen Production

($\$/kgH_2$)



LHV = Lower Heating Value; WACC = Weighted Average Cost of Capital.
Source: International Renewable Energy Agency, 2020 *Green Hydrogen Cost Reduction*, p10.

While there are several types of water electrolysis processes, the two main types that are currently considered for adoption are the alkaline type and the proton exchange membrane (PEM) type. The alkaline type of water electrolyses uses a strong alkaline solution called potassium hydroxide. The concentration of potassium hydroxide is kept at 20% to 30%, and iron or nickel-based alloys are used as electrodes for electrolysis process. As the water used decreases as hydrogen is produced, it is replenished with pure water to maintain the potassium hydroxide concentration at a constant level. The temperature of operation of the water electrolyser is also maintained at around 70°C to 90°C, and the electricity intensity required to produce 1 m3 of hydrogen is 4.2 to 5.9 kWh. In this production method, the distance between the diaphragm and both electrodes are set as narrow as possible to reduce the resistance of the liquid. The efficiency is reduced at low electricity supply because the generated oxygen and hydrogen easily recombine and mix. In addition, the electrodes are easily degraded by the reverse current when the electrolyser is shut down. Thus, the alkaline-type electrolysis is less suitable for hydrogen production with unstable electricity supply such as wind and solar power.

The PEM type of electrolysis uses a fluoropolymer-based proton exchange membrane as a diaphragm membrane, and only pure water is used as the raw material. Since the proton exchange membrane is highly acidic, and the electrolysis reaction also takes place in an acidic atmosphere, iron and nickel materials cannot be used as electrodes. Platinum, which has excellent durability and activity, is desirable as electrodes to promote the reaction, although it is more costly than iron or nickel. The operating temperature needs to be maintained about 80°C, about the same level as the alkaline type, and the electricity consumption rate for hydrogen production is 4.2 to 5.6 kWh/Nm^3, which is also similar to that of the alkaline-type process.

Compared to the alkaline type, the hydrogen production system itself has an advantage of being compact because the current density can be increased. In addition, since only pure water is used, the electrical resistance is large and problems such as reverse current are unlikely to occur. Therefore, compared to the alkaline type, it is more resistant to output fluctuations and more suitable to hydrogen production with intermittent electricity supply such as renewable power sources.

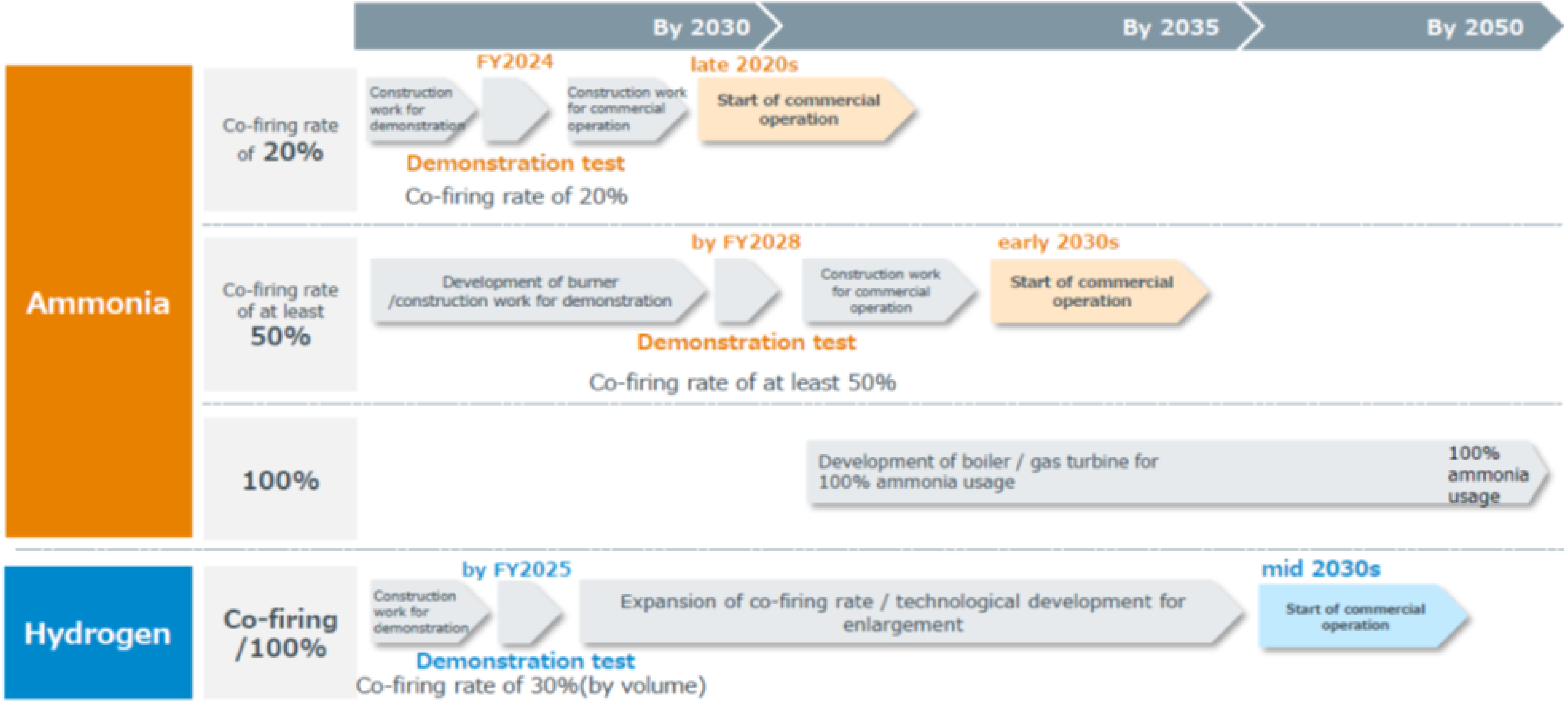
In addition to these two types, there is also the solid oxide type water electrolysis (SOEC) process, but this is still in the research and development stage.

A crucial consideration in hydrogen production using renewable energy sources is ensuring that the use of renewable electricity used for hydrogen production does not lead to increased fossil fuel consumption for electricity generation. In other words, the electricity used to produce green hydrogen must be renewable electricity that is additionally generated for hydrogen production, instead of taking it from the ongoing power generation operations. There are discussions in Europe and the United States on whether this 'additionality' requirement should be applied and monitored on an hourly basis or whether it should be allowed as long as renewable electricity is provided on a daily basis. In this report, Chapter 3 analyses the cost of hydrogen production from renewable energy sources, but this is conditional on the stable supply of the renewable power needed for hydrogen production as expected.

2. Combustion Technology

Ammonia is being considered for utilisation in power generation through three distinct approaches: (i) co-firing at boiler of coal-fired power plant; (ii) co-firing at gas turbine of gas-fired power plant; and iii) single-firing at gas turbine. Of these, JERA, a Japanese power producer, is currently conducting a demonstration test of co-firing with coal-fired power plants at its commercially operated Hekinan Thermal Power Plant in Japan. At the Hekinan Power Plant, IHI, a Japanese heavy industry company, is in the process of replacing the fuel injection system in the existing thermal power generation system with a co-firing system. The demonstration test itself is scheduled to be completed by 2025. After the demonstration test, JERA plans to start using 20% of the fuel at the No. 4 unit of the plant in March 2025. The ratio of co-firing is then scheduled to be raised to 50% on a commercial scale in early 2030. The first approach involves 100% ammonia firing, which entails the independent development of both boiler and gas turbine technologies for ammonia combustion. This method is anticipated to become commercially operational by the mid-2030s (Figure 4.6).

Figure 4.6. Fuel Ammonia Adoption Road Map by JERA



Source: JERA, 2022.

Co-firing technology at a coal-fired power plant has already been established on a pilot plant basis, and the rate of co-firing up to 60% is reportedly feasible. If a coal-fired power plant can increase the co-firing ratio to 50% or higher, the carbon intensity of the coal-fired power plant's operations can be significantly reduced to an equivalent level as a gas-fired power plants. Achieving such a substantial reduction in carbon intensity would be very effective and significant in terms of carbon emissions reduction. However, to promote the use of such a high co-firing ratio at power plants, a large and stable supply chain of fuel ammonia needs to be established. In addition, increasing the co-firing ratio in coal-fired power plants that use inexpensive fuels such as coal will require policy incentives for power producers. This is because the increase in fuel cost will be substantial, resulting in higher generation costs compared to existing 100% coal-fired power plants.

Fuel ammonia can also be co-fired at gas-fired power plants. In this case, ammonia is co-fired with natural gas when the fuel is injected into the gas turbine. There are two types of ammonia co-firing: one is to co-fire ammonia as is and the other is to 'crack' ammonia into hydrogen before co-firing. The former, in which ammonia is directly sprayed into the gas turbine, has the advantage of simplifying the fuel supply system from the storage tank to the gas turbine because the cracking process of ammonia to hydrogen can be omitted. On the other hand, since ammonia has low combustibility, when the co-firing rate is increased, nitrous oxide (N_2O), a greenhouse gas that is about 300 times more potent than CO_2, is generated. Against this challenge, IHI has succeeded in a demonstration test to reduce GHG emissions by 99% while maintaining the co-firing ratio at 70% or more.

The latter technology, in which ammonia is cracked into hydrogen and then co-fired in a natural gas-fired power plant, is being developed by Mitsubishi Heavy Industries, another Japanese heavy industry company, which is developing co-firing technology as well as hydrogen-fired gas turbine technology.

Currently, achieving co-firing levels of more than 70% ammonia at gas-fired power plants is challenging at present because it is difficult to control N_2O emissions. However, if technological advancements make 70% co-firing feasible for gas-fired power plants, the journey towards carbon neutrality in thermal power generation would significantly advance.

The 100% ammonia single-firing technology is currently in the demonstration and research phase. The IHI is developing an ammonia gas turbine which combusts ammonia without cracking. Adopting this approach, a cracking facility does not need to be installed and facilities can be simplified. Mitsubishi Heavy Industry, meanwhile, is developing both direct ammonia injection and cracked hydrogen from ammonia technologies Expected commercialisation for these technologies will be in the mid-2020s (Table 4.1).

Table 4.1. Major Research Development for Ammonia Gas Turbine

Company	Country	Capacity (MW)	Outline of research
IHI	Japan	2	Name of turbine: IM270 Efficiency: 27.4% Expected commercialisation: 2023 Joint development with GE for large-scale ammonia gas turbine
Mitsubishi Heavy Industry	Japan	28-574	Name of turbine: H-25 Expected commercialisation: around 2025 Different type of fuel system: Ammonia direct injection for smaller-scale turbine; Cracked hydrogen from ammonia injection for larger-scale gas-turbine Research and development activities in Indonesia and Singapore
GE Gas Power	US	34-571	Agreed IHI to jointly develop ammonia gas turbine in June 2021.
Doosan Enerbility	Korea	5/ 90/ 380	Plans to develop a gas turbine using hydrogen cracked from ammonia. Cooperation agreement was formed with Korea Electric Power Company.

MW = megawatt.
Source: Institute of Applied Energy, 2022.

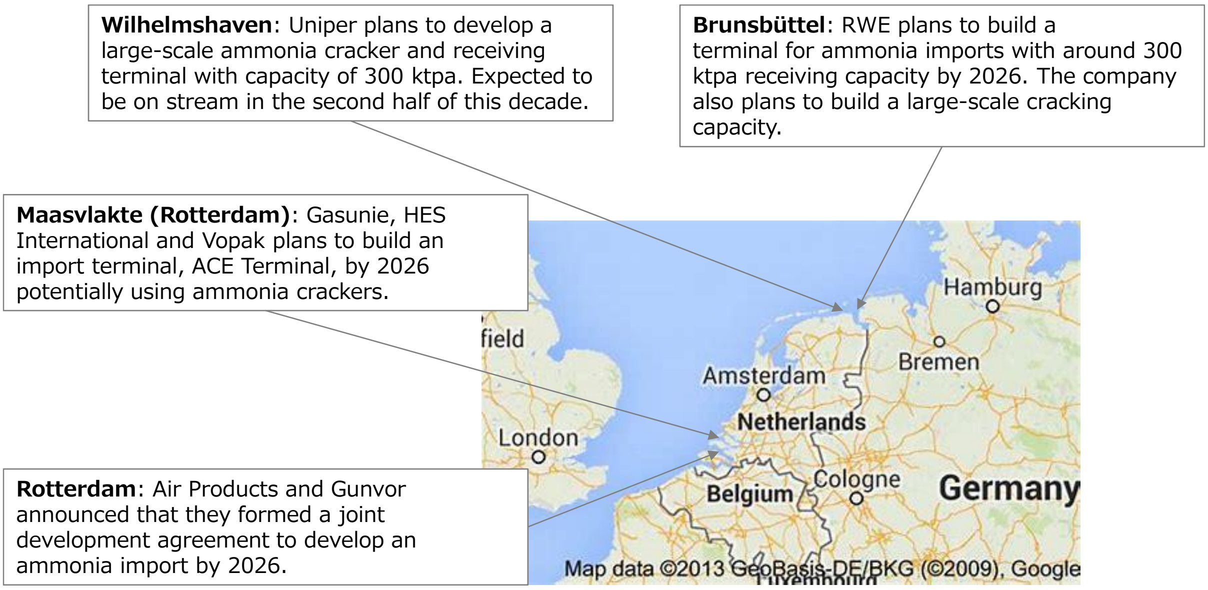
There are still many issues to be solved in using ammonia for single firing in power generation, especially in reducing NO_x emissions during combustion and reducing unburned ammonia in exhaust gas and treating it to render it harmless. The US Department of Energy (DOE) has announced $24.9 million in funding for six research and development projects to support the advancement of technologies for using ammonia in gas turbines. Noteworthy projects included Gas Technology Institute's exploration of ammonia-hydrogen fuel mixtures in gas turbines and Raytheon Technologies Research Center's investigation into ammonia combustion with gas turbine combustors that yield low nitrous oxide (N_2O) emissions (US Department of Energy, 2022).

3. Receiving Infrastructure

The second challenge is to develop receiving infrastructure. Globally, efforts are underway to develop a 'hub' for the acceptance and use of fuel ammonia, aiming to create supply centers for the surrounding regions. In Shunan, Japan, there is an ongoing project to convert an existing port into a carbon neutral port, with the acceptance and utilisation of fuel ammonia as a central pillar of the project. Under this concept, existing LPG receiving tanks and cargo handling facilities will be converted to fuel ammonia receiving facilities, and the ammonia will be used as a clean fuel for nearby chemical product manufacturing plants. To use such a large amount of fuel ammonia, it is necessary to expand the scale of receiving capacities and storage tanks. For the time being, existing LPG tanks can be repurposed. In the long term, the design and construction of a large-scale storage tank will be considered.

A study with a similar concept has been done at the port of Rotterdam in the Netherlands (Figure 4.7). The European port plans to adopt four million tons of hydrogen by 2030 and examines various means of hydrogen import. Fluor, an American engineering firm, suggests that the European port can accommodate more than 7 million tons of ammonia import that is cracked into one million tons of hydrogen supply. The cracked hydrogen will be utilised at industrial sites at Rotterdam port. A more detailed study is to be carried out with other partner firms such as BP, Shell Saudi Aramco, Uniper, Gasunie, and Vopak (Vopak, 2022).

Figure 4.7. Fuel Ammonia Receiving Port Developments in Europe



Source: Author, 2023.

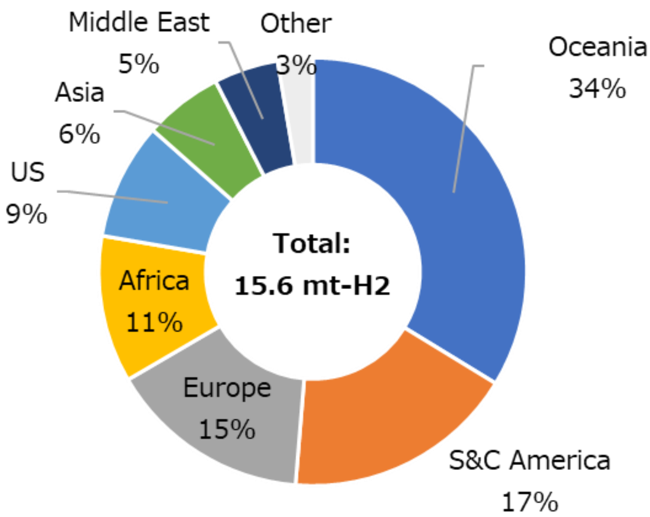
Fuel ammonia may not be utilised in some locations due to odor and safety concerns. Further, sufficient land for its receiving base may not be available. An Ammonia Floating Storage and Regasification Barge (A-FSRB) is being developed as a solution to address such issues. An A-FSRB is a fuel ammonia version of the LNG Floating Storage and Regasification Unit (FSRU) that has greatly contributed to the global expansion of LNG use. As in the case of FSRUs, A-FSRB requires less time to be constructed and installed compared to conventional onshore receiving facilities. An A-FSRB would also be an effective receiving means when there is limited land available for a receiving facility. At this point, the project to develop an A-FSRB is still in the design stage and the timing for commercialisation has not yet been determined. Regardless, the hurdles to commercialisation are not high because the individual elemental technologies will utilise existing technologies.

4. Supply Chain Development

Projects to produce both green and blue ammonia are being considered around the world. A total of 15.6 million tons-H_2 equivalent (about 90 million tons-NH_3) of fuel ammonia production projects are currently planned around the world according to the database compiled by the International Energy Agency (International Energy Agency, 2022b). By region, Oceania accounts for about one-third of the total, followed by Latin America, Africa, and Europe (Figure 4.8). In Southeast Asia, new ammonia production projects are being considered in Indonesia and Malaysia. In other parts of the Eastern Hemisphere, new projects are being considered in the Middle East. Together, about half of the world's projects are being considered in the Eastern Hemisphere, which will play a vital role in meeting the expected growth in demand in the Asian region.

Figure 4.8. World Clean Ammonia Projects by Region

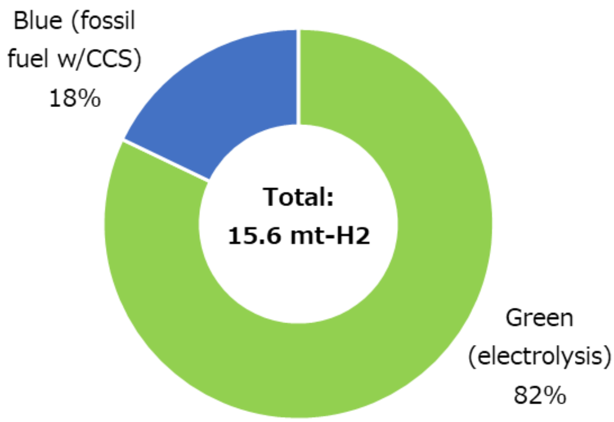
(%)



Source: International Energy Agency, 2022a.

In terms of the number of projects, there are a larger number of green fuel ammonia projects compared to blue ammonia. About 80% of the fuel ammonia projects currently in consideration are green ammonia, while the remaining 20% are blue ammonia projects (Figure 4.9). But, in terms of production capacity of each individual project, the average size of production capacity per project is slightly larger for blue ammonia, averaging 175 thousand tons-H_2 (1.0 million tons-NH_3) per year, while green ammonia production capacity is 135 thousand tons-H_2 (810 thousand tons-NH_3).

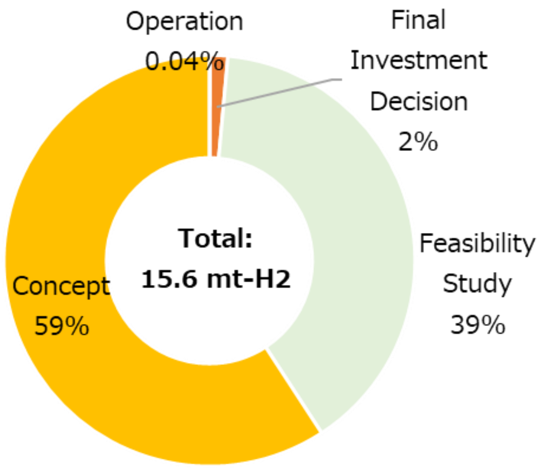
Figure 4.9. World Clean Fuel Ammonia Project by Source of Feedstock



mt-H_2 = million tons of hydrogen.
Source: International Energy Agency, 2022a.

While there are many fuel ammonia production projects, it is important to note that many of these projects are still at conceptual or feasibility study stage. Approximately 60% of all projects are still in the conceptual stage and almost 40% in the feasibility study stage (Figure 4.10). Only 2% of the projects are in operation and investment decisions have been made. A major reason for such a deferred investment decision is that the stable demand for fuel ammonia has yet to be seen. Investment decisions remain pending as the off takers have not been decided.

Figure 4.10. World Clean Ammonia Projects by Status



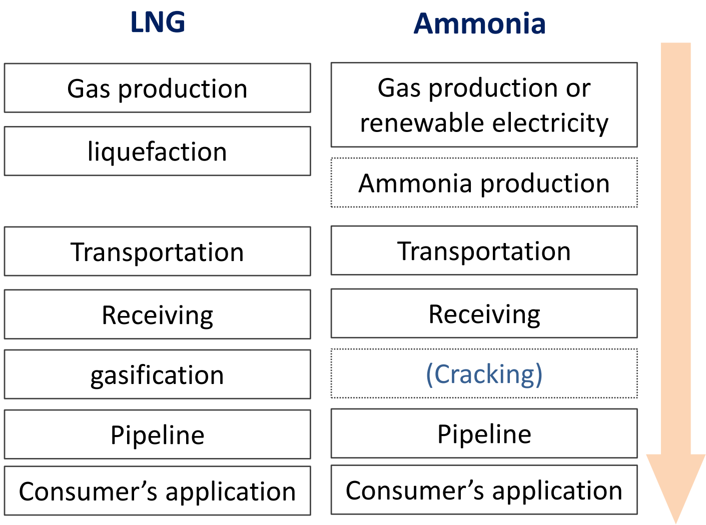
Source: International Energy Agency, 2022a.

There are two implications for ASEAN that can be extracted from these trends in clean ammonia production projects. First, from a regional perspective, ASEAN has an advantage in procuring fuel ammonia. Most of the clean ammonia to be used in the ASEAN region in the future will likely be produced domestically. However, if domestic production alone is not sufficient to meet future fuel ammonia demand, imports from overseas may be brought in, as was the case with LNG in the past. In that case, since the largest number of planned projects are in Oceania in terms of region, the ASEAN countries, which are geographically close to Oceania, are well positioned to procure ammonia from overseas.

Second, it is essential to develop a system on the demand side of fuel ammonia. Of the clean ammonia production projects currently being planned, less than 10% of them have made investment decisions and are in the construction stage. The projects face uncertainty in progressing to the investment stage due to the lack of clarity regarding demand-side offtake agreements, even though feedstock and renewable electricity to produce ammonia already exist. As will be discussed in the next chapter, Japan, the United Kingdom, the United States, and other countries are currently studying the development of a policy system for the demand side. It is important to prepare for the development of a policy system for the actual use of ammonia as a fuel for power generation in the ASEAN region based on such precedents.

The supply chain of fuel ammonia is similar to that of LNG. In both cases, natural gas is used as feedstock to produce the product, which is then transported to the final consumption point for use. Along the way, storage facilities, cargo handling facilities, pipelines, transport vessels, and other means of transportation must be in place (Figure 4.11). It is essential to minimise the gap between each of these value chains while expanding production capacity and consumption. This requires forming close partnerships amongst producers, users, and transporters.

Figure 4.11. Supply Chain of Fuel Ammonia and LNG



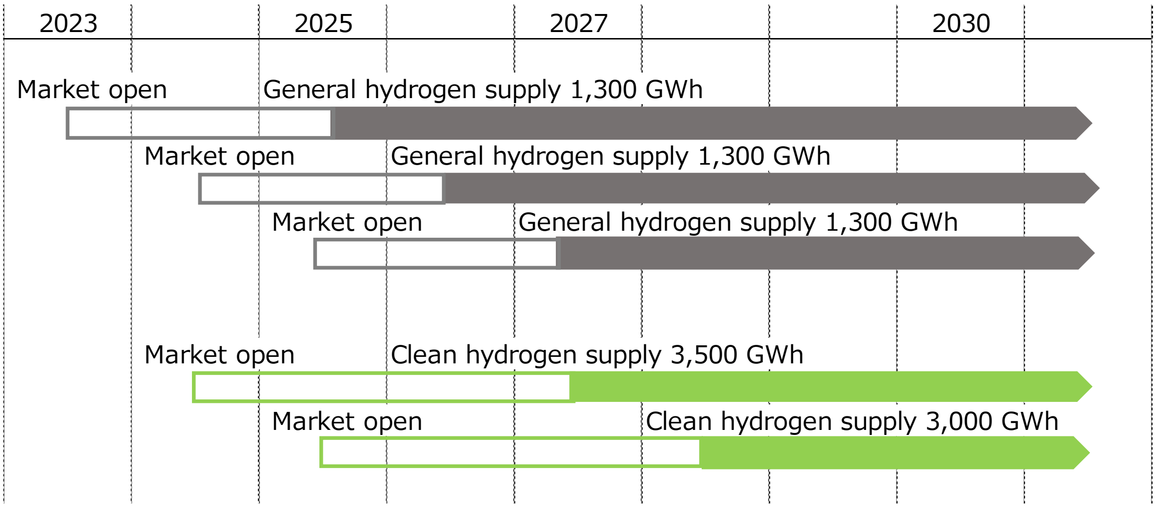
Source: Authors, 2023.

Against this backdrop, JERA announced that it would conduct the world’s first bidding for a long-term fuel ammonia contract in February 2022. The company has already sent a request for proposal (RFP) to some 30 companies. The terms of the contract are expected to be for 10 years or longer, from 2027 into the 2040s, with a maximum annual volume of 500,000 tons under free on board (FOB) delivery conditions. In principle, the fuel ammonia to be delivered is limited to ammonia that does not generate CO_2 at the time of production, or where CO_2 generated is recovered and stored. The presence or absence of equity participation by JERA in the fuel ammonia production business will also be considered in determining the final award.

In Germany, H2Global, a joint procurement organisation consisting of private companies with the support of the Government of Germany, launched an international hydrogen tender in December 2022. The organisation in considered to be reviewing the received offer as of September 2023. In addition to ammonia, the bidding process encompasses methanol, a derivative of hydrogen, and sustainable aviation fuel (SAF) based on hydrogen. The contract period for the procured hydrogen spans 10 years, with a specification that only green hydrogen produced from renewable energy sources will be employed in ammonia production. H2Global intends to distribute the acquired hydrogen within the domestic market through a bidding system employing short-term contracts of one year. It is likely that the selling price will be lower than the procurement price. The German government compensates for the price difference that is expected to occur (H2 Global Stifung, unspecified year).[0]

Other bidding for hydrogen procurement has also been under consideration in South Korea, where hydrogen is positioned as an essential piece of the decarbonisation of its power generation sector. The Korean announced its intention to launch a tender for ‘general hydrogen’ to be supplied in 2025. The planned volume of hydrogen-based power generation is 1,300 GWh, and the contract period extends over 10 years. 1,300 GWh of general hydrogen will be procured both from 2026 and from 2027. This 'general hydrogen' includes grey hydrogen produced by the existing production process. In addition to general hydrogen, Korea will procure 'clean hydrogen' in 2027. The bidding for 3,500 GWh clean hydrogen will be launched in 2024 and the actual supply will start in 2027. Another 3,000 GWh of clean hydrogen will also be supplied by 2028. The Korean government intends to provide up to 20% ammonia co-firing for coal-fired power plants and up to 50% hydrogen co-firing for gas-fired power plants (Collins, 2023).

Figure 4.12. South Korean Hydrogen Power Generation Procurement Plan

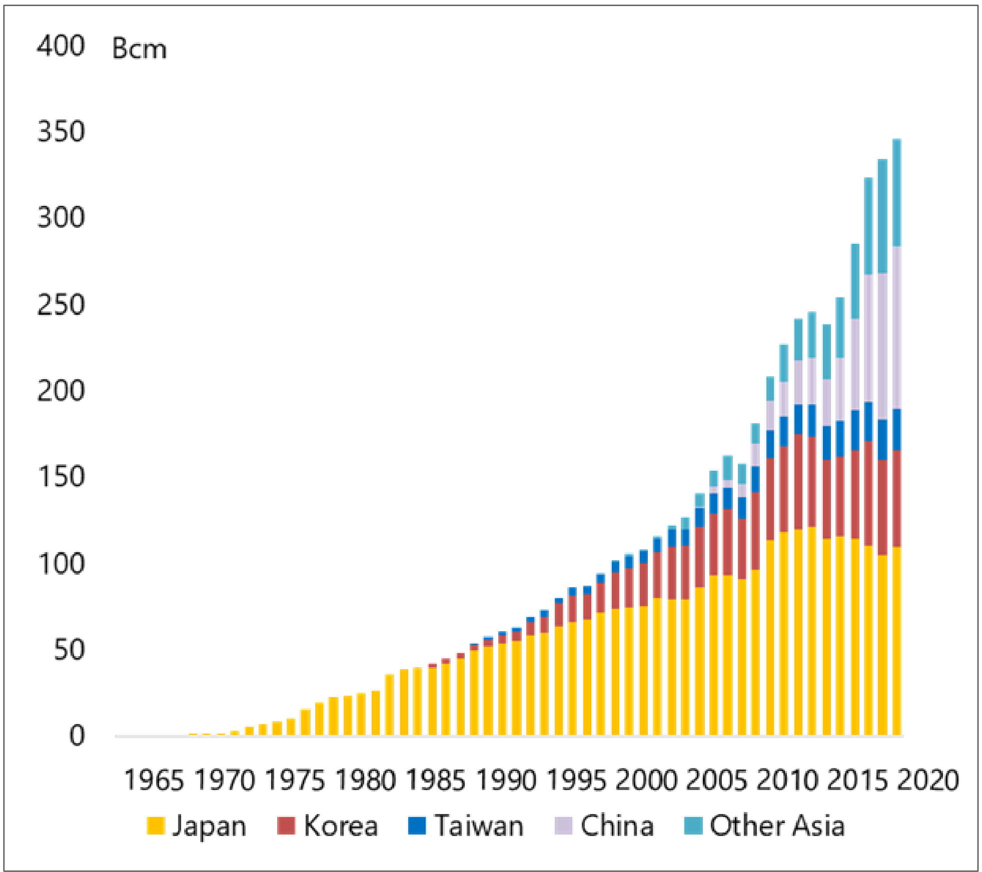


Source: Authors, 2023.

Fuel ammonia benefits from existing ammonia production equipment and transportation infrastructure during its initial phase. However, as demand for ammonia as a power generation fuel intensifies, dedicated production and transportation facilities must be established. The surge in fuel ammonia demand could impact the existing ammonia market for fertiliser production, potentially affecting fertiliser and food prices.

The separation of the ammonia market from the fertiliser feedstock ammonia market is a major issue. However, it will be challenging to completely distinguish between the two markets, and it is important to expand supply capacity in line with demand trends to prevent excessive instability in supply and demand. At an initial stage, fuel ammonia may be transacted only in a long-term contract at a pre-determined fixed price or by other fixed pricing formula. It is important to expand supply capacity in line with demand trends to prevent excessive instability in supply and demand.

Figure 4.13. Evolution of Liquefied Natural Gas Market in Asia, 1965–2020



Source: BP, various years.

Liquefied natural gas (LNG) is now an international commodity produced in 19 countries and consumed by 44 markets (GIIGNL, 2022). However, over the past 50 years, LNG has evolved into a leading global commodity. In Asia, Japan was initially the main importer, followed by Korea and Taiwan. In recent years, LNG has become widely and commonly used in China, India, and many Southeast Asian countries (Figure 4.13). In the future, fuel ammonia is expected to evolve into an international commodity, following a trajectory similar to LNG. However, unlike LNG, the development of the fuel ammonia supply chain must occur within a shorter timeframe to achieve carbon neutrality by mid-century.

5. Ammonia as a Maritime Fuel

To encourage supply chain growth, it is essential to explore non-power demand avenues. One promising avenue is using ammonia as maritime shipping fuel, which has garnered attention in recent years. In 2018, the International Maritime Organization set a goal to reduce CO_2 emissions intensity in global shipping by 70% and halve total emissions by 2050, in accordance with the Paris Agreement. This goal may be strengthened in the future to a carbon neutral goal as of 2050, as the international aviation sector has already done.

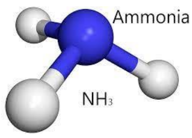
Ammonia is not the only solution to decarbonise maritime transportation fuels. Alternatives include methanol, hydrogen, synthetic fuels, and onboard carbon capture and storage (CCS). However, challenges like CO_2 sourcing for methanol and synthetic fuels and storage for captured CO2 in onboard CCS make fuel ammonia a currently more promising option for achieving decarbonisation in this sector.

In Germany, MAN Energy Solutions is developing ammonia-fueled engines for ships. The company started ammonia combustion tests in 2019 and plans to commercialise ammonia-based two-stroke engines for large ocean-going vessels by 2024. In addition, the company plans to offer a conversion package that will enable existing vessels to sail on ammonia fuel by 2025. Following the development of the two-stroke engine, the company also started a project to develop a four-stroke engine in April 2023. The technical challenges include the need to ensure a high level of safety since toxic ammonia is used in the limited space of a ship near the crew's living quarters, and the need to establish combustion control technology to control the generation of NO_X, especially nitrous oxide (N_2O), which has a large greenhouse effect. With the support of the Government of Japan through the Green Innovation Fund, Nippon Yusen Kaisha (NYK) and other companies in Japan are developing ammonia-fueled tugboats, which they plan to commercialise by 2025.

6. Comparison with Biomass Co-firing

In addition to ammonia, biomass fuel may be another option for co-firing fuel in coal-fired power generation. Many countries in the ASEAN region are rich in biomass resources, and biomass-based fuel can contribute significantly to decarbonising existing coal-fired power plants. There are several types of biomasses. Amongst them, black pellets can be co-fired with coal without additional investment in existing coal-fired power generation facilities. Biomass can be produced at a lower cost than ammonia and does not require the construction of a separate storage tank as ammonia does. On the other hand, the production of biomass fuel tends to be unstable compared to ammonia, which can be produced industrially. Also, it is often uncertain whether a stable supply of resources can be secured for decades. Therefore, while biomass co-firing can contribute to the decarbonisation of coal-fired power plants at a relatively early stage, ammonia has an advantage in terms of long-term supply and stability.

Table 4.2. Comparison between Biomass and Ammonia Co-Firing

	Ammonia co-firing	Biomass co-firing
		
Fuel supply reliability	Blue ammonia can be supplied in stable manner Can be produced from various feedstock (blue, green, pink, etc.)	Subject to forest resources; less certain to secure feedstock in the long-term
Boiler modification	Modification is required.	No additional investment is required if black pellet is used, and the co-firing ratio is low.
Storage facility	Storage tank is required.	No storage facility is required.
Scalability	High. 100% ammonia single-firing is feasible.	Subject to feedstock supply
Generation cost	Relatively high	Relatively Low

Source: Authors, 2023.

7. Operational Safety

The last and the most important issue that should be touched upon pertaining to fuel ammonia is operational safety. Ammonia can be harmful to the human body if inhaled in large quantities. Such safety concerns may lead to public acceptance issues, such as opposition to the use of ammonia by residents living near infrastructure where fuel ammonia is loaded, transported, or used. In this regard, the energy industry has tackled a similar issue in the past to minimise potential problems such as leakage. Based on the existing procedures for the distribution and the use of such energy products, it is necessary to develop sufficient infrastructure and operational procedures to prevent leakage, especially at sites where the products are used near residential areas.

Although not widely known, ammonia itself is one of the most widely traded chemical products in the world. The loading, unloading, and utilisation of ammonia is already taking place in many countries and regions. The existing chemical and fertiliser industries have already established appropriate procedures for the safe loading, transport, and use of ammonia. By adopting such established procedures, the energy industry can address potential safety issues satisfactorily. In addition, many thermal power plants have utilised ammonia in the denitration process of flue gas emitted from the power plant. Existing power utilities are familiar with the handling of ammonia. While the use of ammonia as fuel will substantially increase its handling volume, existing ammonia handling procedures can still be adapted to facilitate its smooth integration by power producers.

Chapter 5

Conclusions

To conclude the study, this chapter provides policy implications obtained from the analysis in Chapter 4.

1. Clear Target Setting for Ammonia Adoption

The first policy implication is the need to establish clear targets to adopt ammonia. As countries seek to become carbon neutral by mid-century, they will need to review their existing power supply development plans. The most prioritised action in decarbonising the power generation mix will be on integrating renewable energy sources such as wind and solar. Ammonia co-firing will play an increasingly vital role in the future, as it can decarbonise power generation while maintaining the existing thermal power plant's adjustment capacity to the entire power supply system.

To accelerate promote ammonia co-firing, the first step should involve the explicit inclusion of ammonia co-firing in national power development plans, coupled with setting precise numerical goals for the co-firing ratio or the quantity of fuel ammonia to be integrated by specific year. Clearly defined targets communicated to national and international stakeholders (governments, businesses, financial institutions, and local communities) will help to secure the various resources, understand implementation challenges, and advance the technology. The recent commitment by the Government of Viet Nam to transition coal-fired power units to ammonia or biomass beyond 2050 within their latest Power Development Plan represents a significant advancement in the direction.

2. Infrastructure Development

In the initial stages of fuel ammonia adoption, existing supply infrastructure, especially in the production, can be leveraged. However, as the volume of ammonia used for energy applications grows, large-scale development of new infrastructure will be required. Given the innovative nature of ammonia as an energy source, there are inherent investment risks, underscoring the need for government support in infrastructure development. In recent years, governments of developed countries, such as those in the United States and the United Kingdom, announced their public support package for such infrastructure development of hydrogen supply. While such support hinges on fiscal conditions and isn't universally applicable, government could commit to ammonia procurement for a defined period or offer administrative, regulatory, and tax incentives to facilitate domestic infrastructure creation. This public support could extend to domestic ammonia producers, greatly fostering the growth of domestic ammonia utilisation infrastructure.

3. Incentive Mechanisms to Utilise Ammonia

The introduction of fuel ammonia cannot proceed only through market mechanisms because the cost of fuel ammonia is higher than the price of existing fossil fuels. Therefore, policies are needed to induce power companies to adopt fuel ammonia as its decarbonisation effort. To promote the introduction of ammonia in ASEAN, some kind of policy framework is needed. Some ASEAN countries have introduced feed-in tariffs for the introduction of renewable energy with success. The introduction of a similar policy for fuel ammonia should be considered if the introduction of fuel ammonia is to be accelerated.

4. Carbon Pricing System

Another institutional tool to promote the use of fuel ammonia in ASEAN is carbon pricing. Since the cost of fuel ammonia will be higher than the cost of existing fossil fuel supplies, at least in the short term, some institutional incentives to firms are needed. One such option is a carbon pricing system that imposes a policy-based economic cost on CO2 emissions. By imposing a carbon price, or disincentive, on the use of fossil fuels, companies can be encouraged to shift from conventional fossil fuels to decarbonised energy sources that do not emit CO2, such as fuel ammonia.

There are various options for carbon pricing, including carbon taxes and emissions trading. A carbon pricing system to encourage the use of fuel ammonia would need to set the carbon price at a level where the investment required to use or convert to fuel ammonia is economically justified in the long run. In other words, companies will not invest in such facilities unless the additional cost of continued use of fossil fuels by carbon price exceeds the investment required to use fuel ammonia. Therefore, for a carbon pricing system to promote the use of fuel ammonia, the level of the carbon price must be set at a sufficient and stable level over the long term. A carbon tax system may be a preferable option to an emissions trading system due to its stable carbon price, which can mitigate significant fluctuations. This approach could effectively encourage the adoption of fuel ammonia.

Depending on how the carbon price system is set up, it could be applied not only to the power generation sector but also to various other sectors. Depending on how the system is designed, it may have a significant impact on energy costs and usage patterns in sectors other than the power generation sector, so great care must be taken in designing the system.

5. Capacity Development for the Government and the Industry

Since fuel ammonia is a new energy source, a capacity development system for its handling must be in place. Since ammonia is a toxic substance, operators at the loading/unloading and utilisation sites need to have ample knowledge of the properties of ammonia and the procedures for its safe transport and combustion. Such capacity building needs to be done not only for industry but also for government administrators. To achieve this, leveraging international cooperation platforms such as the East Asia Summit is crucial to absorb expertise and knowledge from countries experienced in the handling of ammonia.

6. Market Design

Finally, to introduce ammonia on a full-scale basis, a market design for ammonia will be necessary in the long term. A pricing scheme for ammonia needs to be defined, and when procuring ammonia from overseas, the form and duration of ammonia procurement contracts must also be considered. Further, it is necessary to address demarcation from the existing ammonia market for fertiliser feedstock. While immediate action might not be necessary, addressing these aspects will demand long-term policy responses.

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