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Demand and Supply Potential of Hydrogen Energy in East Asia – Phase 2

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Preface

Global energy trends indicate a shift from fossil fuels that contain carbon to variable renewable energy (vRE) with zero carbon. Solar photovoltaic (PV) and wind power, which are typical vRE sources, have been increasing due to their significant low costs and appropriate government policies, such as feed-in tariff and renewable portfolio standards. The rapid increase of the solar PV market surely contributes to the vRE's significant low costs. However, vRE still has negative aspects – intermittency, seasonality, and low capacity factor – which are big reasons for the smaller share of vRE especially in the ASEAN region. Hydropower is a better energy source than vRE but its seasonality due to the big gap in hydropower output between the dry and the wet seasons is still a negative factor. The early disruptions to the ecosystem and damage from dams also add to the negative image of hydropower.

Currently, hydrogen is highlighted as a future energy option because of clean and stable energy. There are two hydrogen sources: one is fossil fuels with carbon capture utilisation and storage and other is water electrolysis, which uses electricity from renewable energy. Thus, hydrogen will be abundant. In addition, the transport and storage of hydrogen are technically available, and their cost is lower than electricity transmission lines and electric storage.

Hydrogen demand will be wide and consumed for large-scale power generation, fuel cell electric vehicles as well as heating demand in the industry sector. Thus, the hydrogen demand potential in the future, such as 2030–2050, will be significant (please refer to the hydrogen phase 1 report). But a big issue is hydrogen's extremely high supply cost.

Therefore, the Economic Research Institute for ASEAN and East Asia continues to implement the hydrogen potential study phase 2. It covers hydrogen to be produced from unused brown coal applying the gasification process and transformed into liquefied hydrogen for long-distance transport. ERIA also established the hydrogen working group to discuss how to the East Asia Summit countries can shift to a hydrogen society.

Professor Hidetoshi Nishimura

President, Economic Research Institute for ASEAN and East Asia

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Special acknowledgement is also given to Ari Ugayama, Deputy Director, Fuel Cell and Hydrogen Strategic Office, New Energy System Section, Energy Efficiency and New Energy System Department, Ministry of Economic, Trade and Industry for his excellent contribution to this project through his useful comments and suggestions.

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Abbreviations and Acronyms

AHEAD	Advance Hydrogen Energy Chain Association for Technology Development
BAU	business-as-usual scenario
BOG	boil-off gas
CAPEX	capital expenditure
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCUS	carbon capture utilisation and storage
CO_2	carbon dioxide
EAS	East Asia Summit
FCB	fuel cell bus
FCEV	fuel cell electric vehicle
FCT	fuel cell train
FCV	fuel cell vehicle
GHG	greenhouse gas
H2	hydrogen
HRS	hydrogen refuelling station
HySTRA	Hydrogen Energy Supply-Chain Technology Research Association
IEA	International Energy Agency
KHI	Kawasaki Heavy Industries, Ltd
kWh	kilowatt-hour
LCA	life-cycle analysis
LCOE	levelised cost of electricity
LH2	liquefied hydrogen
LNG	liquefied natural gas
MCH	methylcyclohexane
MESTECC	Ministry of Energy, Science, Technology, Environment and Climate Change
METI	Ministry of Economy, Trade, and Industry, Japan
NEDO	New Energy and Industrial Technology Development Organization
NH3	ammonia
Nm3	normal cubic metre
OECD	Organisation for Economic Co-operation and Development
OPEX	operating expense
PEM	polymer electrode membrane
PFCV	passenger fuel cell vehicle
PV	photovoltaic/photovoltaics
PSA	Pressure Swing Adsorption

R&D	research and development
SOFC	solid oxide fuel cell
TCO	total cost of ownership
toe	tonnes of oil equivalent
TPES	total primary energy supply
US	United States
US$	United States dollar
vRE	variable renewable energy
WG	working group
WTW	well-to-wheel
¥	Japanese yen
ZEV	zero-emission vehicle

Executive Summary

The year 2019–2020 is a remarkable year for hydrogen because three hydrogen demonstration projects were started in Australia, Brunei Darussalam, and Japan with the support of the Government of Japan. For the Brunei project, hydrogen is produced as a by-product of gas generated under the liquefaction process from natural gas to liquefied natural gas (LNG). After hydrogen is produced, it is transformed to methylcyclohexane (MCH) by chemical reaction with toluene and transported from Brunei Darussalam to the Kawasaki coastal area in Japan. The hydrogen is then brought to a natural gas power plant site to be mixed with natural gas to generate electricity at an experimental stage. Hydrogen production is expected to reach a maximum of 210 tonnes per year. Another hydrogen project in Australia produces hydrogen from unused brown coal applying a gasification technology and carbon capture utilisation and storage (CCUS). The hydrogen is subsequently changed to liquefied hydrogen (LH2) for transporting from Victoria State in Australia to Kobe city in Japan by an LH2 tanker, which is similar to an LNG tanker. In Kobe city, the hydrogen is used to generate power (100% hydrogen fuel) as demonstration. Last but not least, Japan's hydrogen project in the Fukushima Prefecture produces hydrogen from water electrolysis using electricity generated by the solar PV system. The capacity of the solar PV system is 22 MW and the expected hydrogen production is 206 tonnes per year, which is consumed for power generation, fuel cell electric vehicles (FCEVs), and heat use in the industry sector.

Major hydrogen demand comprises fuel for power generation, direct burning at combine cycle gas turbine (CCGT), and FCEVs. For power generation, CCGT technology to burn hydrogen mixed with natural gas is already available, but there is a concern about the hydrogen mixing ratio. If the mixing rate is high, we need a hydrogen burner to replace a natural gas burner. Technically, a 100% hydrogen burner is possible. It is already being tested and will be commercially available in the near future if the price of hydrogen becomes affordable. The FCEV's price is extremely high due to the smaller market size and expensive hydrogen price as fuel. It will surely follow a learning curve (initially the high price will decrease due to market penetration, such as solar PV panel and lithium-ion battery) but it is still long way from becoming commercial. Anyway, the hydrogen demand potential for power generation and FECV will depend on the supply cost of hydrogen. And there will be many issues and challenges to reduce the cost, which are technical innovations to improve hydrogen supply efficiency and policy support to increase the hydrogen demand market.

Hydrogen supply cost is essential to enable a shift to a hydrogen society. Hydrogen supply cost consists of two parts: (i) production costs and (ii) transport and storage costs. Transport includes short, middle, and long distance. Hydrogen is basically produced from fossil fuels (coal, oil, and gas) and water electrolysis. For fossil fuel, unused fossil fuels such as flared gas at oil and gas fields and low-ranked coals (lignite and brown coal) should be sources of hydrogen. If we apply the CCUS system to treat CO_2 coming from the hydrogen production process based on fossil fuels, the hydrogen is classified as blue hydrogen. For water electrolysis, electricity with zero CO_2 emissions, such as renewable energy and hydroelectricity, should be used to produce hydrogen. We can expect a decrease in the cost of hydrogen production due to technology development, but an increase in market scale is more important. For a long-distance transport of hydrogen, such as Brunei Darussalam to Japan and Australia to Japan, this phase 2 study focuses on MCH and LH2. For MCH, direct MCH synthesis will be available in the future, which will directly produce MCH from toluene using renewable electricity. This will surely contribute to the reduction of hydrogen supply costs. For LH2, we can expect a similar development path as LNG, where large-scale LH2 transportation by a dedicated LH2 tanker will surely contribute to reducing the hydrogen supply cost.

Under the phase 2 study, two hydrogen workshops were held in Bangkok, Thailand and Bandar Seri Begawan, Brunei Darussalam. The workshops aimed to (i) increase and provide an accurate and common understanding of hydrogen in East Asia, (ii) introduce the ERIA hydrogen potential study phase 1, and (iii) share hydrogen policies amongst East Asia Summit (EAS) countries. ERIA collaborated with the Petroleum Institute of Thailand (PTIT) to hold the workshop in Bangkok and to publish ERIA's hydrogen potential study through the *PTIT Focus,* PTIT's monthly newsletter. For the hydrogen workshop in Brunei Darussalam, ERIA joined the ASEAN hydrogen workshop hosted by Brunei's Ministry of Energy and the International Policy Studies, Universiti Brunei Darussalam. After the presentation of ERIA experts, technology and engineering experts of ASEAN participated in the workshop to discuss the possibility of hydrogen use in the ASEAN region.

Hydrogen will be an energy option in the future due to its abundant source base, multiple production paths, and environmental friendliness. In addition, no negative aspects of variable renewable energy (vRE), such as intermittency and lower capacity factor, can be absorbed when it is transformed into hydrogen. Therefore, EAS countries should start discussing hydrogen amongst themselves because of their diversity; some are rich hydrogen-producing countries and others demand hydrogen. Thus, ERIA organised the First EAS Hydrogen Working Group Meeting in December 2019 participated in by hydrogen experts from China, India, Indonesia, Malaysia, New Zealand, and Thailand. After ERIA's presentations on its hydrogen potential study phase 1 and two hydrogen demonstration projects in Japan, participants discussed future hydrogen use in terms of national policy on hydrogen, the perspectives on the hydrogen demand–supply situation as well as hydrogen supply chain in the EAS region. Unfortunately, due to COVID-19, the Second Working Group meeting was postponed to Fiscal Year 2020–2021.

Hydrogen will be an important energy source in the future and will surely contribute to the reduction of CO_2 emissions; however, its high supply cost will be a major issue. Because of the immature technology of hydrogen production, government support for both supply and demand sides, such as through technology development and policy implications such as feed-in tariff for hydrogen, will be crucial for the EAS region to enjoy the benefits of a hydrogen society based on its robust supply chain.

Chapter 1

Review of Hydrogen Production and Supply Cost

This chapter reviews hydrogen production costs based on the study reports of the Advancement of Hydrogen Technologies and Utilization Project, which the New Energy and Industrial Technology Development Organization (NEDO), a government agency of Japan, has been conducting since 2014. There are two reports referred.

- ✔ Analysis and Development on Hydrogen as an Energy Carrier/Economical Evaluation and Characteristic Analyses for Energy Carrier Systems (2014–2015) (NEDO, 2014)
- ✔ Total System Introduction Scenario Research, Leading Technology Research and Development Project on Hydrogen Utilization (2016–2017) (NEDO, 2016)

These reports comprehensively studied the costs and energy inputs from hydrogen production to supply. However, the studies were conducted in FY2014 and FY2016[1] and, thus, do not reflect the latest technological trends.

The first NEDO report calculated the hydrogen supply chain cost in FY2014; however, it did not calculate the hydrogen production cost. In FY2016, the hydrogen production cost was calculated, and the hydrogen supply chain cost of FY2014 was combined to calculate the electricity generation cost and the supply cost to fuel cell vehicle (FCV). This chapter, therefore, reviews the cost of hydrogen according to the order of the NEDO reports.

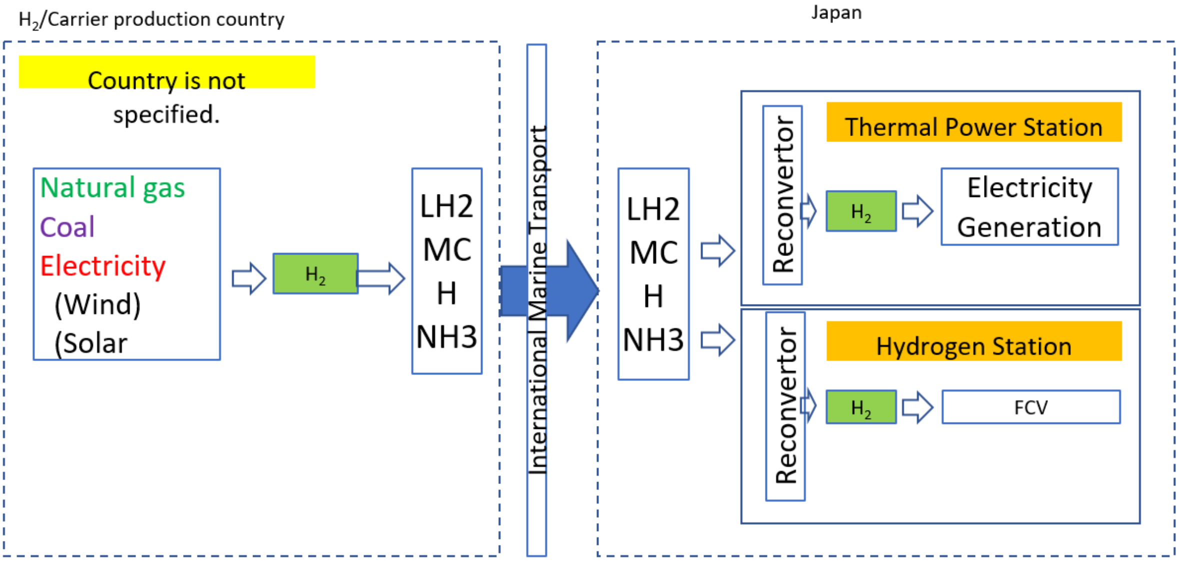
1. System Configuration

Figure 1.1 shows the outline of the NEDO study. This study aims to produce hydrogen in countries outside Japan, produce carriers for transporting hydrogen, import carriers into Japan by ship, and consume reconverted hydrogen in Japan.

Hydrogen production involves three processes: (i) natural gas steam reforming, (ii) coal gasification, and (iii) water electrolysis. The carriers for transporting hydrogen are liquified hydrogen (LH2), methylcyclohexane (MCH), and ammonia (NH3). Hydrogen is consumed at the hydrogen thermal electricity generation plant and FCV.

[1] Fiscal year of Japan: April–March.

Figure 1.1: System Configuration of the Study



Source: Author.

2. Hydrogen Supply for Electricity Generation

In this section, we review the hydrogen supply chain costs for hydrogen thermal electricity generation plants in different scenarios. First, we analyse the energy input to the supply chain, and then analyse the cost of the supply chain.

2.1. Scenario for hydrogen thermal electricity generation

The NEDO report (2014) created scenarios for a thermal power plant according to the scale of hydrogen imports and assumed an allowable imported hydrogen cost for the scenario to be realised. Allowable imported hydrogen cost includes hydrogen and carrier production costs, export terminal and loading costs, and shipping costs. Table 1.1 shows the allowable imported hydrogen cost for each scenario.

According to the NEDO report (2014), when the cost of imported hydrogen falls below ¥25–30/m^3, the utilisation of hydrogen will rapidly increase in the electricity generation sector; the total hydrogen demand, including from the industry and transport sectors, will increase significantly. If the imported hydrogen cost is ¥20/m^3, about 250 billion m^3 of hydrogen will be introduced.

Table 1.1: Scenario and Allowable Imported Hydrogen Cost

Scenario	Scale of Hydrogen Introduction	Allowable Imported Hydrogen Cost	
		2030	2050
Business-as-usual	No hydrogen import	–	–
Research and development (R&D)	Advances in R&D will lead to the introduction of fuel cell cogeneration, fuel cell vehicles (FCVs), and generation of hydrogen power.	¥40/m^3	¥30/m^3
Maximum introduction	The introduction and demand of fuel cell cogeneration, FCVs, and hydrogen power generation will be maximised. (Imported hydrogen accounts for about 15% of primary energy supply.)	¥30/m^3	¥20/m^3

Source: NEDO (2014).

2.2. Hydrogen supply cost for hydrogen thermal electricity generation plants

This section reviews the cost to supply hydrogen-to-hydrogen thermal electricity generation plants for each scenario based on the FY2014 NEDO report. The hydrogen supply chain consists of carrier production, hydrogen loading for exports, international marine transport, hydrogen unloading, regasification, dehydrogenation or ammonia decomposition, and domestic delivery for electricity generation plants by pipeline. In the FY2014 report, the hydrogen production cost for each process was not calculated. As mentioned earlier, the first NEDO report was studied in FY2014 and did not reflect the latest technological progress. Since the hydrogen production cost was studied in FY2016, the feedstock hydrogen cost in Table 1.2 is the allowable import cost minus the hydrogen supply cost outside Japan.

Table 1.2 and Figure 1.2 show the hydrogen supply cost for hydrogen thermal electricity generation.

LH2 has a high liquidation cost. In addition, loading and unloading costs are high because a dedicated freezing tank and loading and unloading equipment are required. On the other hand, regasification cost in Japan is unnecessary because sea water is used.

MCH has a high dehydrogenation cost. Ammonia (NH3) has a high ammonia synthesis cost and a decomposition cost.

Table 1.2: Hydrogen Supply Cost for Hydrogen Thermal Electricity Generation Plants

Unit: US cent/m^3

		Outside Japan							
Carrier	**Scenario**	**Hydrogen (Feedstock)**	**Carrier Production**		**Loading**		**International Marine Transport**		**(Subtotal)**
		CAPEX + OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	Import Cost
LH2	R&D 2030	9.1	8.5	4.0	5.0	0.4	4.2		(36.2)
	R&D 2050	9.1	6.1	3.2	4.8	0.4	3.6		(27.2)
	Max 2050	7.3	2.9	3.1	2.7	0.3	1.8		(18.1)
MCH	R&D 2030	9.9	1.2	4.1	0.4	0.01	1.5	2.1	(36.2)
	R&D 2050	9.1	1.0	4.0	0.4	0.01	1.5	2.1	(27.2)
	Max 2050	7.3	0.9	4.0	0.4	0.01	1.5	2.1	(18.1)
NH3	R&D 2030	9.1	3.7	7.6	0.3	0.003	1.7	1.2	(36.2)
	R&D 2050	9.9	3.7	5.6	0.3	0.003	1.7	1.2	(27.2)
	Max 2050	7.9	3.4	2.2	0.3	0.003	1.7	1.2	(18.1)

		Inside Japan						Total		
Carrier	**Scenario**	**Unloading**		**Dehydrogenation**		**Domestic Delivery**				
		CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX + OPEX
LH2	R&D 2030	7.1	0.2			0.5	0.7	25.2	5.3	39.6
	R&D 2050	6.7	0.2			0.5	0.7	21.6	4.4	35.2
	Max 2050	3.3	0.2			0.5	0.7	11.1	4.3	22.8
MCH	R&D 2030	1.3	0.02	3.6	11.6	0.5	0.7	8.4	19.0	36.8
	R&D 2050	1.3	0.02	3.3	8.3	0.5	0.7	7.9	15.2	32.2
	Max 2050	1.3	0.02	1.4	4.9	0.5	0.7	5.9	11.8	25.0
NH3	R&D 2030	1.7	0.02	2.4	5.6	0.5	0.7	10.3	15.2	34.6
	R&D 2050	1.7	0.02	2.4	5.6	0.5	0.7	10.3	13.2	33.3
	Max 2050	1.7	0.02	2.4	3.6	0.5	0.7	9.7	7.8	25.5

LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia, R&D = research and development.

Notes:

R&D 2030; R&D scenario 2030, allowable hydrogen import cost = ¥40/m^3

R&D 2050; R&D scenario 2030 and maximum introduction scenario 2030, allowable hydrogen import cost = ¥30/m^3

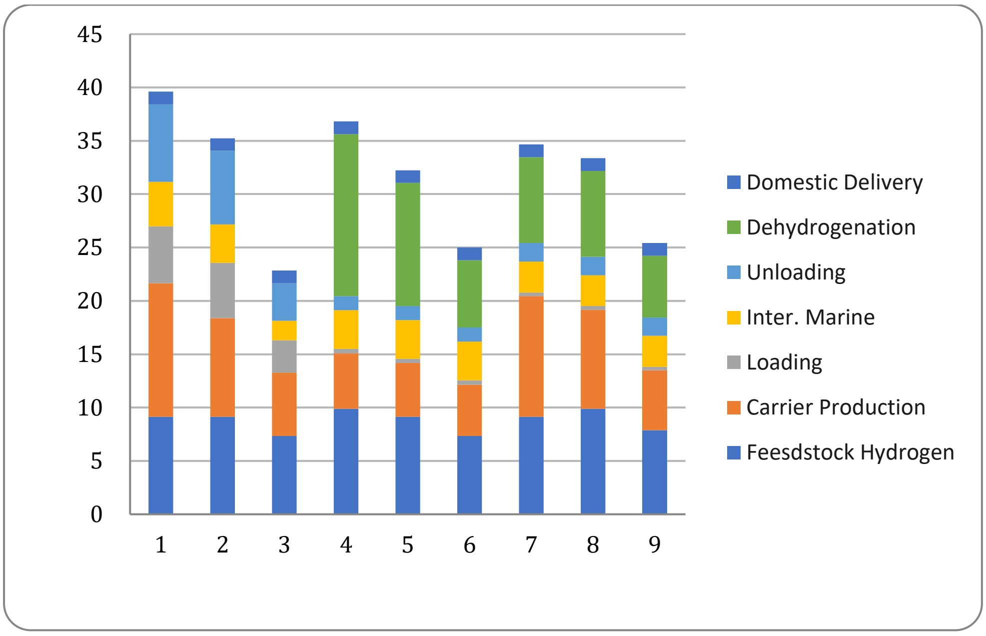
Max 2050; maximum introduction scenario 2050, allowable hydrogen import cost = ¥20/m^3

The same applies hereinafter.

Original currency is V. The cost is converted from V to US$ using the exchange rate, ¥110.4/US$ (average of 2018).

Source: NEDO (2014).

Figure 1.2: Hydrogen Supply Cost for Hydrogen Thermal Electricity Generation Plants



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia, R&D = research and development.
Source: NEDO (2014).

2.3. Cost of hydrogen production

This section reviews the hydrogen production cost based on the FY2016 report. The NEDO report assumed that hydrogen was produced overseas and imported to Japan, but the country of origin was not specified.

This section also analyses hydrogen production cost by natural gas steam reforming, coal gasification, and water electrolysis. Two types of electricity sources can be used in water electrolysis, solar PV and wind.

2.3.1. Assumptions of Hydrogen Production Cost

Table 1.3 shows the assumptions for the equipment for hydrogen production. The equipment will be constructed in countries other than Japan. Renewable energy–derived electricity input to water electrolysis is assumed to be supplied through the electricity grid and, hence, does not explicitly reflect the construction cost of renewable energy.

Table 1.3: Assumptions of Natural Gas Reforming Facility

Item	Description
Hydrogen production capacity	2.5 billion Nm3/y
Hydrogen production per hour	317,098 Nm3/h
Capacity factor	90%
Natural gas consumption (feedstock)	73.35 tonne/h
Natural gas consumption (fuel)	14.67 tonne/h
Electricity consumption	33,682.40 kWh/h
Cooling water	1,585 tonne/h
Pure water	379.90 tonne/h
Reforming	2 stages (3.0 MPa – 650℃, 3.0 MPa – 250℃)
Hydrogen gas treatment process	Moisture condensation + CO_2 recovery (rate of CO_2 recovery: 90%) + PSA (rate of hydrogen recovery: 85%)
Hydrogen output pressure	2.62 Mpa
CO_2 output pressure	15.3 Mpa
Natural gas specification	Das Island, UAE (C1: 75%, C2: 23%, C3: 2%)
Natural gas price	US$5/MMbtu
Electricity price (country of production)	¥5.6/kWh
Electricity price (Japan)	¥12.5/kWh

MPa = Megapascal, PSA = pressure swing absorption, UAE = United Arab Emirates.
Source: NEDO (2016).

Table 1.4: Assumptions of Coal Gasification Facility

Item	Description
Hydrogen production capacity	2.5 billion Nm^3/y
Hydrogen production per hour	317,098 Nm^3/h
Gasification process	Fluidised bed coal gasifier (5.6 MPa; 1,300℃)
Capacity factor	90%
Coal consumption (feedstock)	481.2 tonne/h
Electricity consumption	216,286 kWh/h
Reforming	2 stages (5.5 MPa – 650℃, 5.4 MPa – 250℃)
Hydrogen gas treatment process	Acid gas removal + PSA
Hydrogen output pressure	6.8 MPa
CO_2 recovery process	Exhaust gas desulphurisation + Decarboxylation (Amine method) + Dehydration + Compression
CO_2 output pressure	14.9 MPa

MPa = Megapascal, PSA = pressure swing absorption.
Note: Details of coal are not disclosed.
Source: NEDO (2016).

Table 1.5: Assumptions of Water Electrolysis Facility

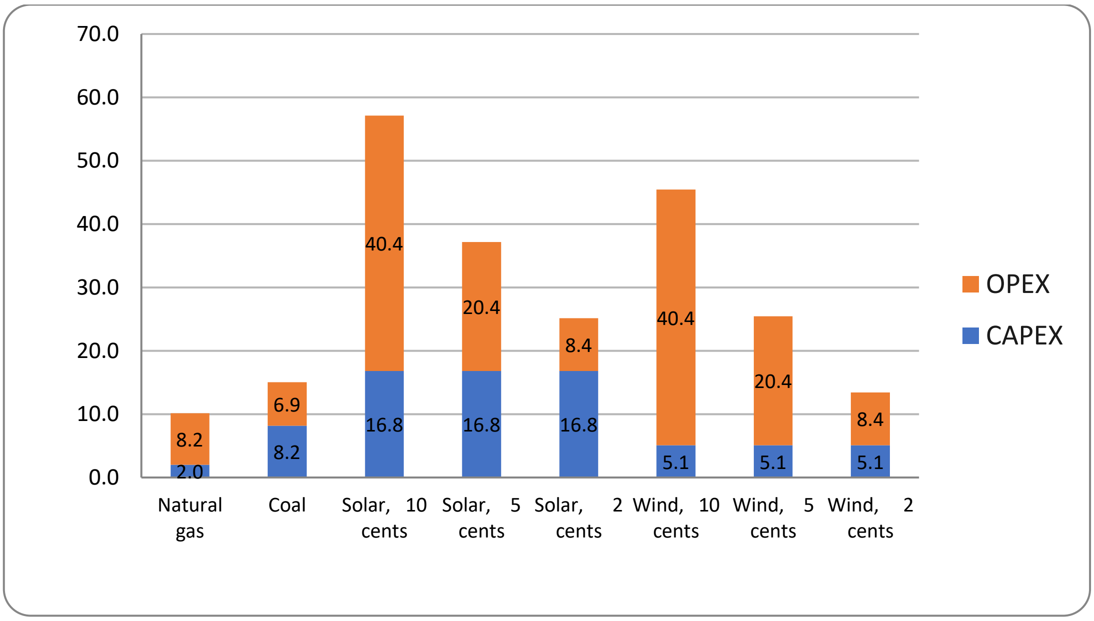
Item	Description
Process	Not specified
Unit electricity consumption	4 kWh/Nm^3-H_2
Unit water consumption	900 g/Nm^3-H_2
Unit equipment cost	¥200,000/Nm^3-H_2
Unit converter cost	¥60,000/Nm^3-H_2
Pure water cost	¥438.9/tonne
Unit pure water cost	¥0.4/m^3
Capacity factor (solar)	15%
Capacity factor (wind)	50%
Electricity price (renewable energy, feedstock)	US cents 10/m^3 US cents 5/m^3 US cents 2/m^3

Note: The construction cost of renewable generation plants is not included.
Source: NEDO (2016), Author.

2.3.2. Cost of hydrogen production

Figure 1.3 shows the cost of hydrogen production for each process. For water electrolysis, three cases of feedstock electricity price are assumed, i.e. US cents 10/kWh, US cents 5/kWh, and US cents 2/kWh.

Figure 1.3: Cost of Hydrogen Production, by Process



CAPEX = capital expenditure, Coal = coal gasification, Natural gas = natural gas steam reforming,
OPEX = operating expense, Solar 10 cents = water electrolysis from solar power, electricity price is US cents 10/kWh, the same applies hereinafter.
Note: Original currency is ¥. The cost is converted from ¥ to US$ using the exchange rate ¥110.4/US$ (average of 2018).
Source: NEDO (2016), Author.

The cost of hydrogen production through natural gas steam reforming is US cents 10.1/m^3 and coal gasification is US cents 15.0/m^3. Due to 15% low capacity factor, solar-based water electrolysis costs US cents 25.19/m^3 even if we assume US cents 2/kWh of the feedstock electricity price. On the other hand, wind-based water electrolysis, which has a higher capacity factor of 50%, can expect US cents 13.4/m^3 when the feedstock electricity price is US cents 2/kWh. It is lower than the production cost adopting coal gasification.

2.4. Electricity generation cost

This section reviews the generation cost of hydrogen thermal electricity by adding the result of '1.2.2 Hydrogen supply cost for hydrogen thermal electricity generation plants' to '1.2.3 'Cost of hydrogen production'.

Table 1.6 shows the assumption of a thermal electricity generation plant.

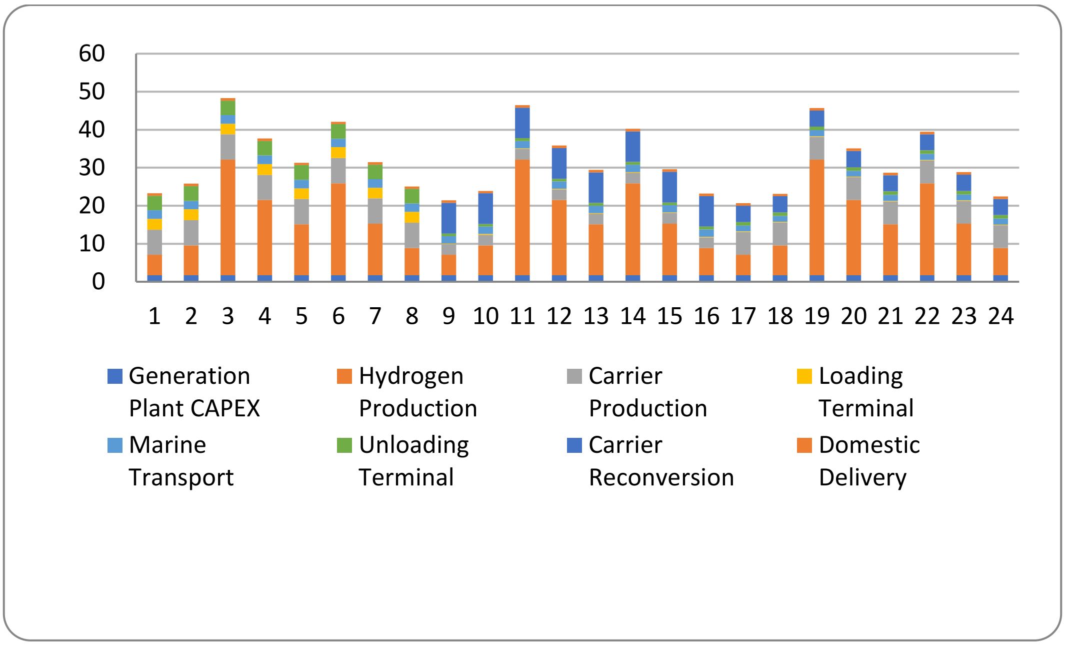
Table 1.6: Assumptions of a Hydrogen Thermal Electricity Generation Station

Item	Description
Capacity	720 MW
Unit construction cost	¥120,000/kW
Construction cost	¥86.4 billion
Thermal efficiency	63.0% at LHV
Rate of own use	2.0%
Hydrogen consumption	2.5 billion Nm3-H2/y (27.0 PJ/y)
Capacity factor	76.5%
Plant output electricity	4.7 TWh/y (16.9 PJ/y)

LHV = lower heating value.
Source: NEDO (2016).

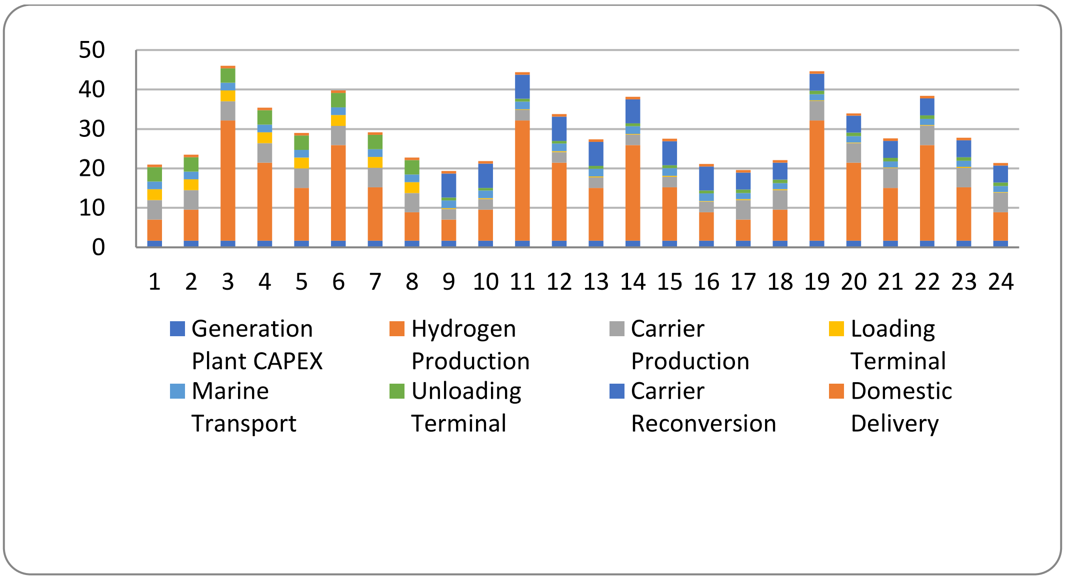
Figure 1.4 and Figure 1.5 show the electricity generation cost by carrier and hydrogen production process.

Figure 1.4: Electricity Generation Cost (R&D 2030 Scenario)



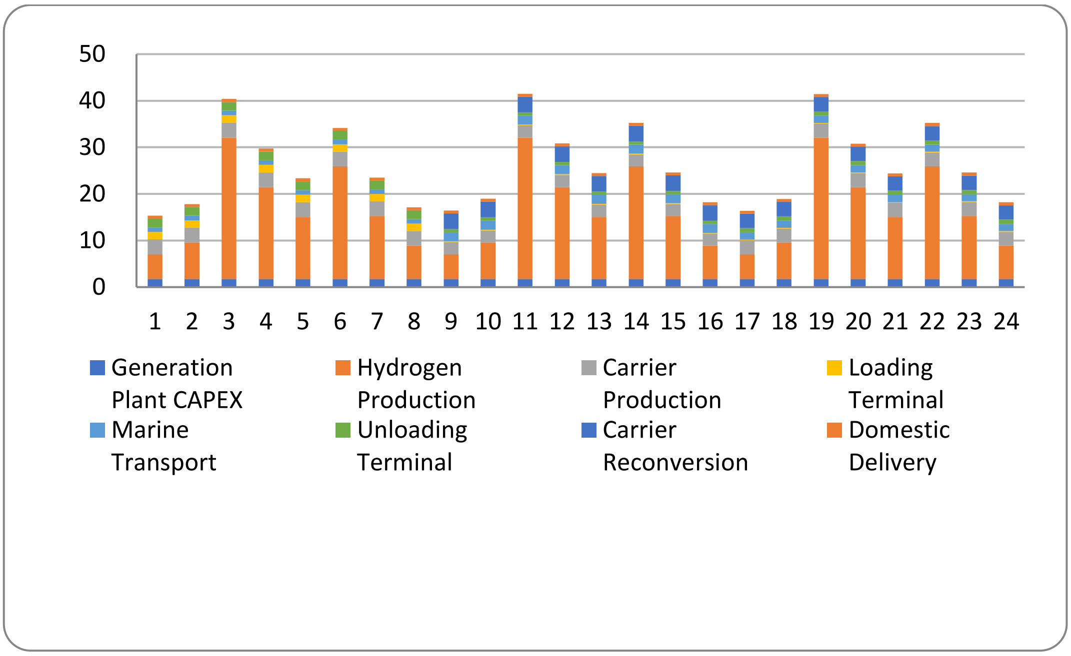
LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

Figure 1.5: Electricity Generation Cost (R&D 2050/Max 2030 Scenario)



LH2 = liquified hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

Figure 1.6: Electricity Generation Cost (Max 2050 Scenario)



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

2.5. Input fuel for hydrogen supply chain

This section reviews the outline of the hydrogen supply chain and the fuel input into each carrier.

2.5.1. Liquefied Hydrogen

Table 1.7 shows the supply chain of LH2 and the fuel to be inputted. Feedstock hydrogen is cooled to a liquefaction temperature or lower by the liquefaction machine and is transported to the dedicated LH2 tanks. At the loading site, LH2 is stored in tanks before shipment and delivered to tankers. The hydrogen boiled off in the loading tank is compressed by the boil-off gas (BOG) compressor, returned to the liquefier, and re-liquefied. LH2 is transported by dedicated tankers. It is assumed that BOG is used as fuel for LH2 tankers. After unloading and storage at the unloading site, reconverted gaseous hydrogen is pressurised by the compressor and then transported to the power plant by pipelines.

Table 1.7: Fuel Input for Hydrogen Supply Chain (LH2)

Source of Hydrogen	Fuel	Hydrogen Production	Liquefaction	Loading Storage	International Marine	Unloading	Vaporisation	Domestic Delivery
Natural gas	Electricity (Grid)	✓	✓	✓		✓		✓
	Natural gas	✓						
Coal	Electricity (Grid)	✓	✓	✓		✓		✓
	Coal	✓						
Water electrolysis	Electricity (Grid)		✓	✓		✓		✓
	Electricity (Res.)	✓						

Source: NEDO (2016).

2.5.2. Methylcyclohexane (MCH)

Table 1.8 shows the supply chain of MCH and the fuel to be inputted. The toluene/MCH system consists of hydrogenation equipment, storage equipment, international marine transportation, storage equipment at landing sites, dehydrogenation equipment (including hydrogen treatment), and domestic transportation. What differs from other systems is that after dehydrogenation, toluene (carrier) is loaded back into the hydrogen production country.

Table 1.8: Fuel Input for Hydrogen Supply Chain (MCH)

Source of Hydrogen	Fuel	Hydrogen Production	Hydrogenation	Loading Terminal	International Marine	Unloading Terminal	Dehydrogenation	Domestic Delivery
Natural gas	Electricity (Grid)	✓	✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas	✓	✓					
	Fuel oil				✓			
Coal	Electricity (Grid)	✓	✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas		✓					
	Fuel oil				✓			
	Coal	✓						
Water electrolysis	Electricity (Grid)		✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas		✓					
	Fuel oil				✓			
	Electricity (Res.)	✓						

MCH = methylcyclohexane.
Source: NEDO (2016).

2.5.3. Ammonia (NH3)

Table 1.9 shows the supply chain of NH3 and the fuel to be inputted. The NH3 system consists of nitrogen production equipment (air separator), NH3 synthesis, NH3 storage equipment, international marine transportation, storage equipment at unloading sites, NH3 decomposition equipment (including hydrogen treatment), and domestic transportation.

Table 1.9: Fuel Input for Hydrogen Supply Chain (NH3)

Source of Hydrogen	Fuel	Hydrogen Production	Ammonia Synthesis	Loading Terminal	International Marine	Unloading Terminal	Ammonia Decomposition	Domestic Delivery
Natural gas	Electricity (Grid)	✓	✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas	✓	✓					
	Fuel oil				✓			
Coal	Electricity (Grid)	✓	✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas		✓					
	Fuel oil				✓			
	Coal	✓						
Water electrolysis	Electricity (Grid)		✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas		✓					
	Fuel oil				✓			
	Electricity (Res.)	✓						

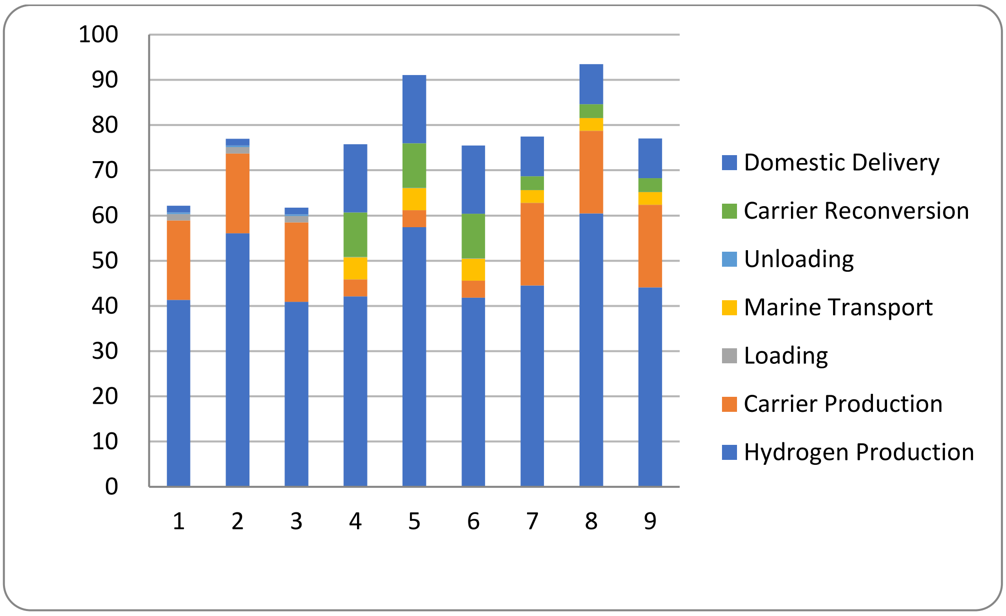
NH3 = ammonia.
Source: NEDO (2016).

2.6. Energy input for hydrogen supply chain

This section reviews the energy input to the hydrogen supply chain analysed in the NEDO report. However, since the NEDO report was done in FY2016, it did not reflect the latest technological progress.

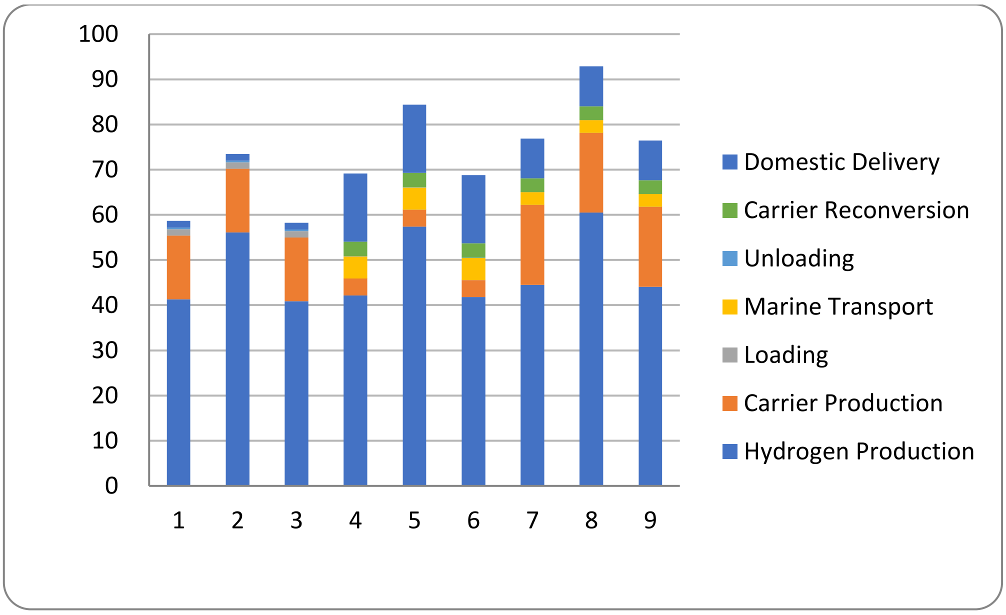
Figure 1.7 shows the required energy to supply 2.5 billion m^3 per year of hydrogen to hydrogen thermal electricity plants by scenario. LH2 requires a large amount of energy for carrier production (liquefaction). Unlike LH2 and NH3, MCH does not require a large amount of energy for carrier production; however, it requires a large amount for dehydrogenation and domestic delivery in Japan. Like LH2, NH3 requires a large amount of energy for carrier production (NH3 synthesis) and for domestic delivery.

Figure 1.7: Energy Input for Hydrogen Supply Chain (R&D 2030 Scenario)



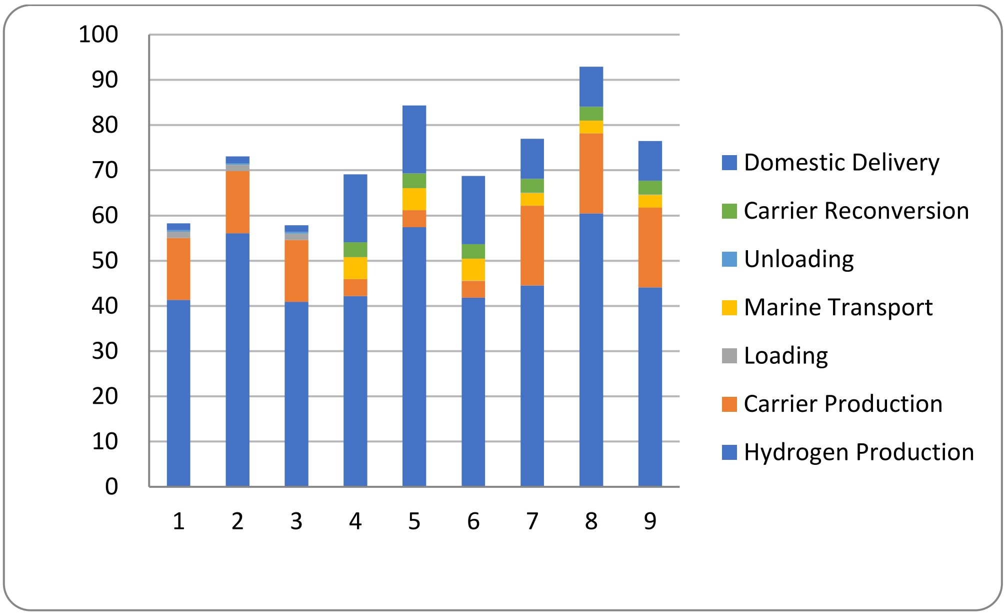
LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016).

Figure 1.8: Energy Input for Hydrogen Supply Chain (R&D 2050/Max 2030 Scenario)



LH2 = liquified hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016).

Figure 1.9: Energy Input for Hydrogen Supply Chain (Max 2050 Scenario)



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016).

2.7. Energy efficiency of delivered hydrogen and generated electricity

Table 1.6 presents the assumptions of a thermal plant.

The calculation for hydrogen efficiency and electricity efficiency is as follows:

$$Energy\ efficiency\ of\ delivered\ hydrogen\ = Delivered\ hydrogen\ (2.5\ billion\ m3, 27\ TJ) / Energy\ input\ for\ hydrogen\ supply\ chain$$

$$Energy\ efficiency\ of\ generated\ electricity = Generated\ electricity\ (17\ TJ)/Energy\ input\ for\ hydrogen\ supply\ chain$$

Table 1.10 shows the energy efficiency of hydrogen and electricity for each carrier and scenario. However, the calculation did not reflect the latest technological progress as it was done in FY2016.

For carriers, LH2 has the highest energy efficiency, followed by MCH and NH3. Looking at the feedstock of hydrogen production, natural gas and electricity from renewable source (solar and wind) have the highest energy efficiency, followed by coal.

Table 1.10: Energy Efficiency of Delivered Hydrogen and Generated Electricity, %

Carrier	Process	Scenario					
		R&D 2030		R&D 2050/Max 2030		Max 2050	
		Hydrogen	Electricity	Hydrogen	Electricity	Hydrogen	Electricity
LH2	Natural gas	43	27	46	29	46	29
	Coal	35	22	37	19	37	23
	Renewables	44	27	46	29	47	29
MCH	Natural gas	36	22	39	24	39	24
	Coal	30	19	32	20	32	20
	Renewables	36	22	39	25	39	25
NH3	Natural gas	35	22	35	22	35	22
	Coal	29	18	29	18	29	18
	Renewables	35	22	35	22	35	22

LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016).

3. Hydrogen Supply for FCVs

This section reviews hydrogen supply for FCVs. From hydrogen production to unloading hydrogen carrier in Japan, the supply chain is the same as electricity generation, and the difference is domestic delivery.

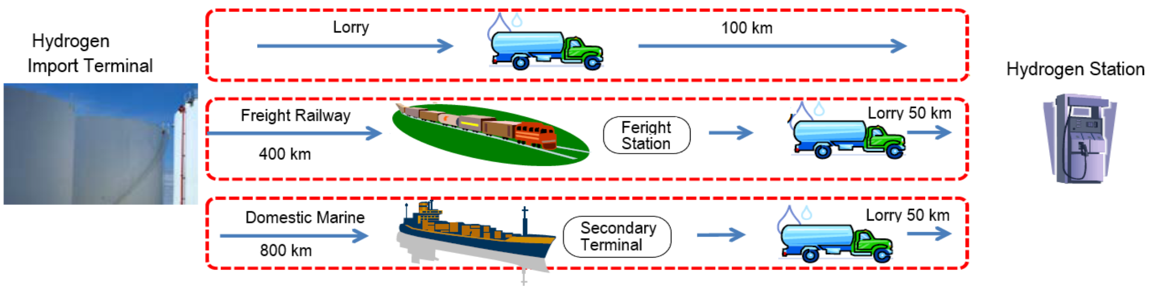
3.1. Hydrogen supply chain for FCVs

Domestic delivery for the FCV system is assumed as follows. The hydrogen carrier is transported from the hydrogen import terminal to the hydrogen station and stored. The hydrogen carrier is reconverted to gaseous hydrogen at the station. Gaseous hydrogen is compressed and supplied to the FCVs.

Figure 1.10 shows how hydrogen is transported from the hydrogen import terminal to the hydrogen station. The following three transport modes are assumed.

Mode 1: Lorry 100 km
Mode 2: Rail 400 km + Lorry 50 km
Mode 3: Domestic marine 800 km + Lorry 50 km

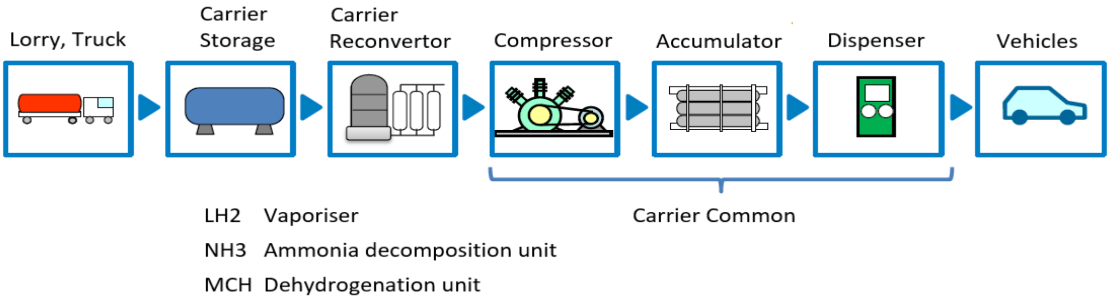
Figure 1.10: From Hydrogen Import Terminal to Hydrogen Station



Source: NEDO (2014).

Figure 1.11 shows the image of the hydrogen station. The hydrogen station consists of equipment that receives and stores hydrogen carriers, equipment that reproduces hydrogen from carriers, compressor, accumulator, and dispenser (including pre-cooling). The equipment of carrier storage and carrier re-converter differ, depending on the carrier. Compressor, accumulator, and dispenser are common equipment for carriers.

Figure 1.11: Equipment of Hydrogen Station



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016).

3.2. Hydrogen supply cost for FCVs

Hydrogen stations are expected to have three sizes (Table 1.11).

Table 1.11: Scenario of Scale of Hydrogen Station

	Scenario		
	Small	**Medium**	**Large**
Hydrogen sales	300 Nm^3/h	Ave. 830 Nm^3/h Max. 1,200 Nm^3/h	Ave. 1,240 Nm^3/h Max. 2,400 Nm^3/h
(Gasoline sales equivalent)	(100 KL/month)	(200 KL/month)	(300 KL/month)
Number of visitors (Peak hour)	8 vehicles/h 2 dispensers	15 vehicles/h 3 dispensers	22 vehicles/h 4 dispensers
Number of visitors (Monthly)	4,000 vehicles	8,000 vehicles	12,000 vehicles

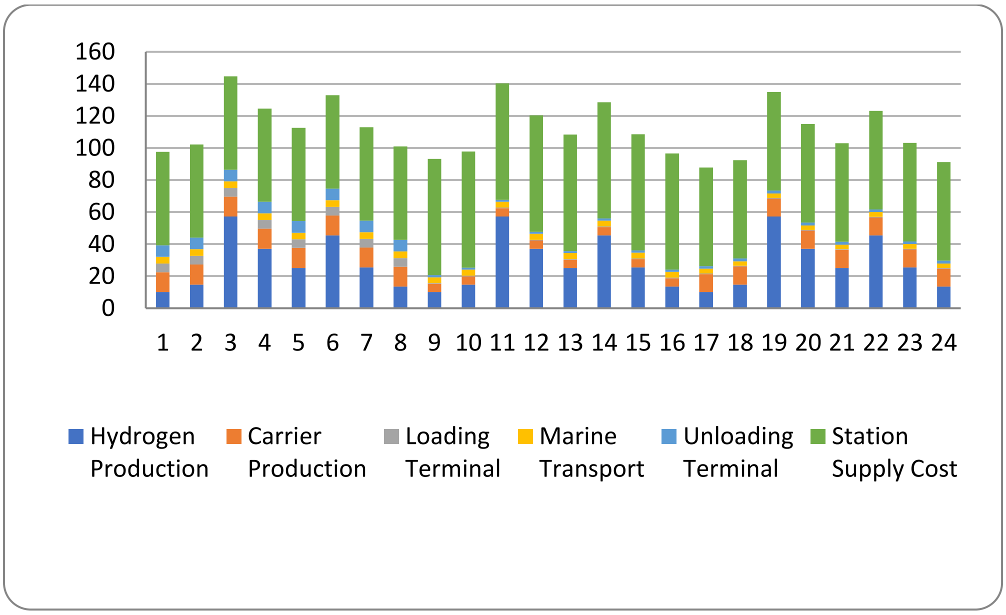
Source: NEDO (2016).

Figure 1.12 shows the hydrogen supply cost (up to dispenser) for FCVs. Hydrogen production and supply costs (up to unloading) are the same as electricity generation. The comparison of the scenario names for electricity generation and for FCVs is as follows:

For Electricity Generation		For FCVs
R&D 2030	→	Small
R&D 2050/Max 2030	→	Medium
Max 2050	→	Large

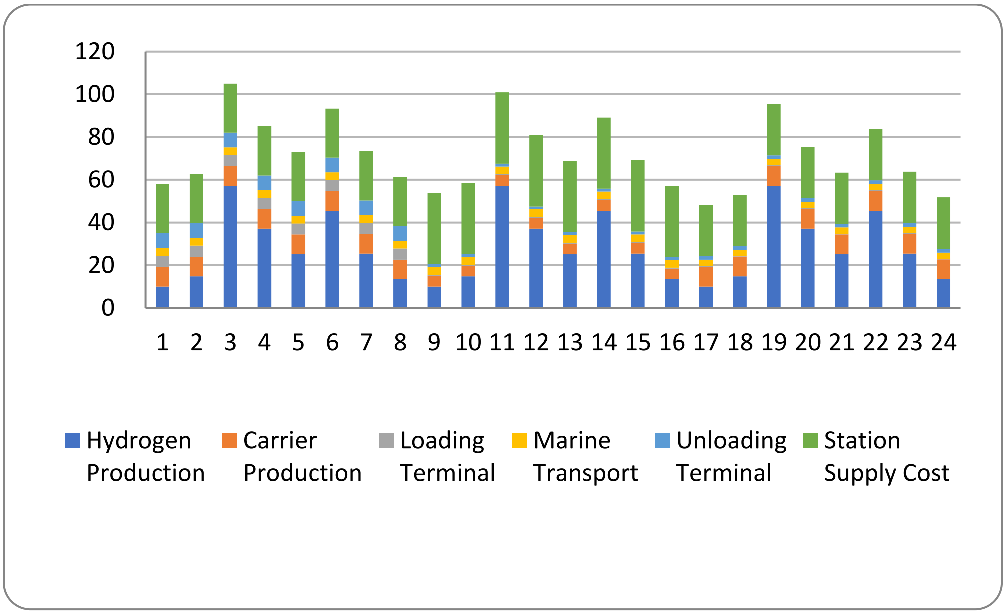
Figure 1.13 shows the hydrogen supply cost at a dispenser when the transport mode is 'Lorry 100 km'. In the figure, station supply cost is the sum of transporting hydrogen carrier from the hydrogen import terminal to the hydrogen station, storing it, reproducing hydrogen from the carrier, and sending it to the dispenser.

Figure 1.12: Hydrogen Supply Cost at a Dispenser (Small Scale)



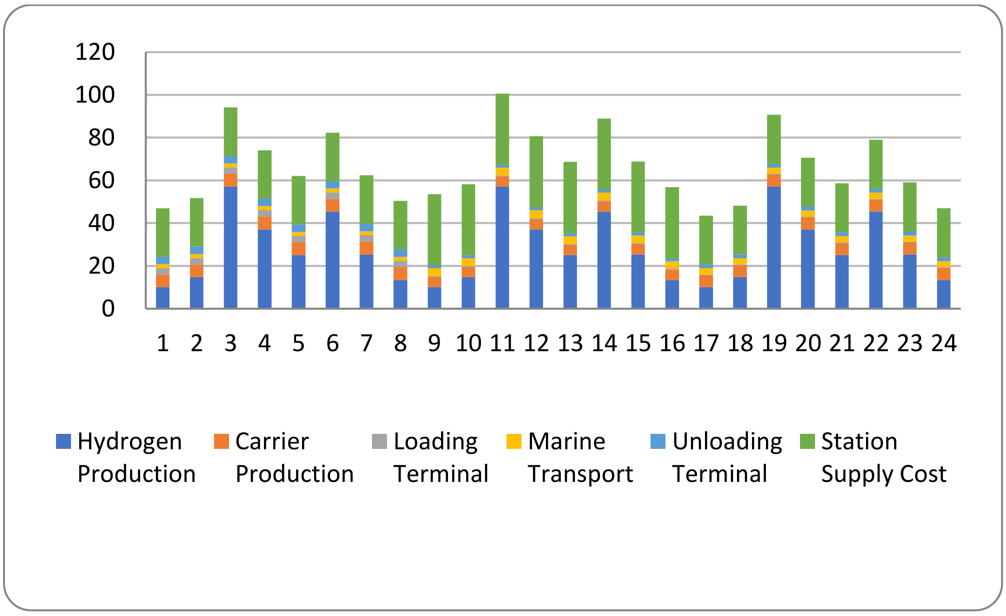
LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

Figure 1.13: Hydrogen Supply Cost at a Dispenser (Medium Scale)



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

Figure 1.14: Hydrogen Supply Cost at a Dispenser (Large Scale)



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

4. Price Comparison

This section compares the electricity generation cost shown in subsection 1.2.4 on electricity generation cost and the supply cost to FCVs shown in subsection 1.3.2 on hydrogen supply cost for FCVs with the existing system.

4.1. Electricity generation

Table 1.12 shows the assumptions for estimating the levelised cost of electricity generation (LCOE) for different technologies and fuel.

Table 1.12: Assumptions of Hydrogen Price Comparison for Electricity Generation (LCOE)

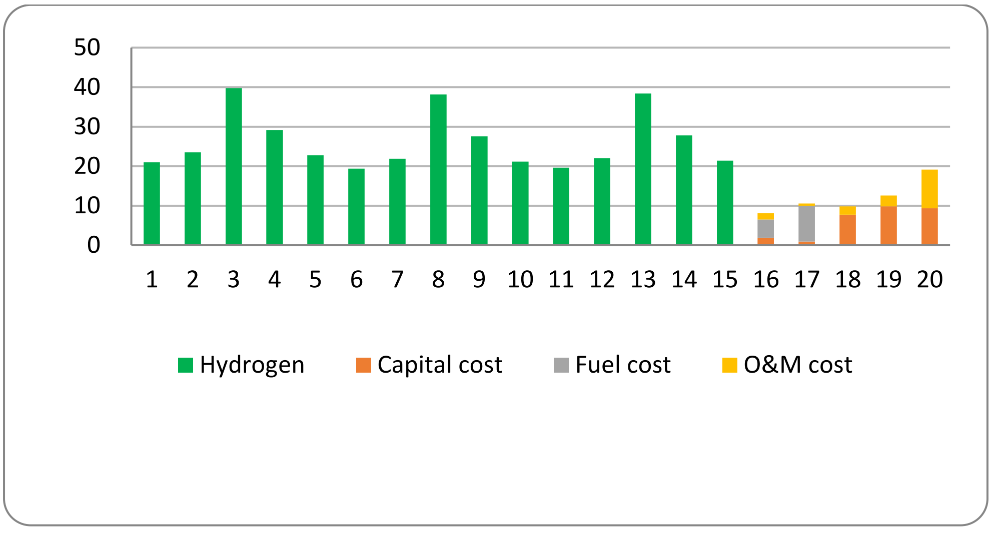
Item	Description
Plant site	Japan
Hydrogen production process	Natural gas steam reforming Coal gasification Water electrolysis (wind)
Thermal (Coal)	Capacity: 800 MW, Capacity factor: 70% Thermal efficiency (2030): 48% at HHV Construction cost: ¥250,000/kW Operation years: 40 years Coal price (2030): US$133.45/tonne
Thermal (Natural gas)	Capacity: 1,400 MW, Capacity factor: 70% Thermal efficiency (2030): 57% at HHV Construction cost: ¥120,000/kW Operation years: 40 years Natural gas (LNG) price (2030): US$751.22/ton (US$14.1/MMBtu)
Conventional Hydro	Capacity: 12 MW, Capacity factor: 45% Construction cost: ¥640,000/kW Operation years: 40 years
Wind (Onshore)	Capacity: 20 MW, Capacity factor: 20% Construction cost: ¥252,000/kW Operation years: 20 years
Solar (Commercial scale)	Capacity: 2 MW, Capacity factor: 14% Construction cost: ¥222,000/kW Operation years: 30 years

HHV = higher heating value, LCO = levelised cost of electricity.

Source: Electricity Generation Cost Verification Working Group, METI, May 2015.

Figure 1.15 compares the LCOE of hydrogen thermal power generation in the R&D 2050/Max 2030 scenario and conventional technologies.

Figure 1.15: Comparison of LCOE



LCOE = levelised cost of electricity, LH2 = liquified hydrogen, MCH = methylcyclohexane, NH3 = ammonia, O&M = operations and maintenance.
Note: Scenario = R&D 2050/Max 2030.
Source: NEDO (2016), Author.

4.2. Hydrogen supply for FCVs

This section compares hydrogen prices to fuel FCVs with regular gasoline prices (for conventional gasoline engine vehicles) and electricity prices (for battery electric vehicles). Since hydrogen (gaseous), gasoline (liquid), and electricity have different units, we will compare the consumption amount for 100 km driving. Comparison is made only for fuel costs, excluding vehicle costs and taxes.

Table 1.13 shows the assumptions for prices and vehicles for comparison.

Table 1.13: Assumptions of Hydrogen Price Comparison for Fuel Cell Vehicles

Item	Description
Location	Japan
Hydrogen production process	Natural gas steam reforming
Hydrogen carrier	Liquified hydrogen (LH2)
Transport mode	Lorry 100 km
Types of vehicle	Fuel cell vehicle Conventional gasoline-engine vehicle Battery electric vehicle
Hydrogen price at dispenser	Hydrogen supply cost + ¥5/m^3 of station charge
Regular gasoline price	¥80.0/L (Japan, 2018, tax is excluded)
Electricity price for household	¥24.059/kWh (Japan, 2018, tax is excluded) (Battery is assumed to be charged at the driver's house.)

Source: IEA (2019).

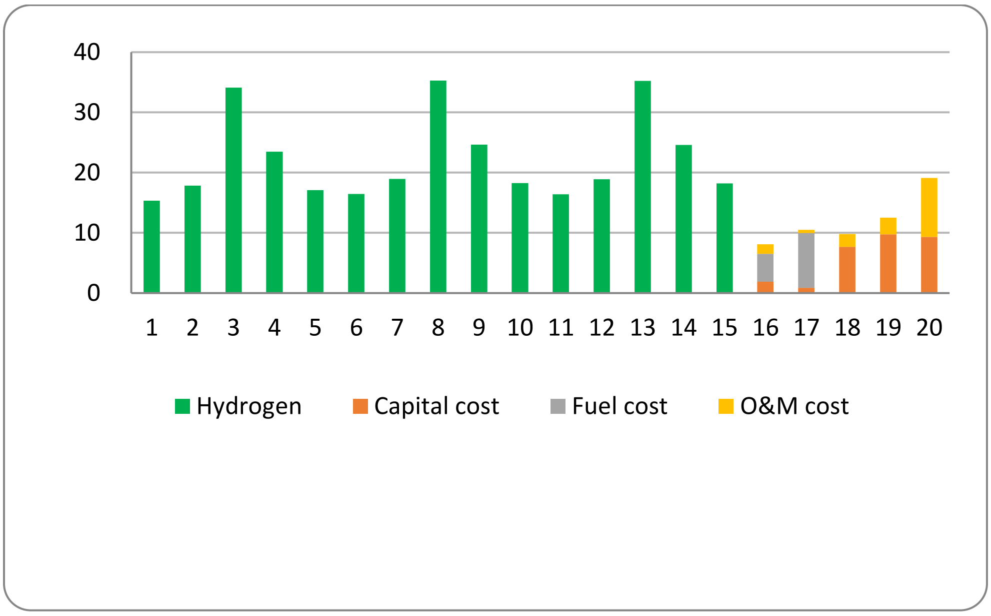
4.2.1.Selected Vehicles

Type	Vehicle	Fuel Mileage	Fuel Consumption (100 km driving)
FCV	Toyota Mirai	7.59 km/m^3 (JC08)	13.2 m^3
Gasoline	Toyota Land Cruiser	6.7 km/L (JC08)	14.9 L
	Toyota Crown 2.0L	12.8 km/L (JC08)	7.8 L
	Toyota Corolla 1.8 L CVT	14.6 km/L (WLTC)	6.8 L
	Toyota Vitz 1.0 L	20.8 km/L	4.8 L
	Toyota Vitz Hybrid 1.5 L + motor	34.4 km/L	2.9 L
BEV	Nissan Leaf 62 kWh	458 km (WLTC)	13.5 kWh
	Nissan Leaf 40 kWh	322 km (WLTC)	12.4 kWh
	Tesla Model 3 55 kWh	409 km (WLTP)	13.4 kWh
	Tesla Model 3 75 kWh	499 km (WLTP)	15.0 kWh
	Tesla Model S 100 kWh	610 km (WLTP)	16.4 kWh

BEV = battery electric vehicle, FCV = fuel cell vehicle, JC08 = one of the methods in Japan to calculate the fuel economy of vehicles, WLTC = worldwide harmonised light vehicles test cycle.
Source: Manufacturers' website.

Figure 1.16 compares the fuel costs for 100 km driving. Other costs, such as vehicle costs and taxes, are excluded.

Figure 1.16: Fuel Cost for 100 Km Driving



Note: Cost other than fuel expenditure is excluded.
Source: Author.

Chapter 2

Hydrogen Demand Potential (Phase 2)

Future hydrogen demand potential is difficult to estimate due to many uncertainties, including promotion policies. In the phase 1 study in FY2018, based on ERIA's energy outlook, the working group (WG) created assumptions and scenarios to estimate the hydrogen demand potential. In this phase 2, we conducted a hearing on hydrogen power generation amongst experts from Mitsubishi Hitachi Power Systems and on fuel cell vehicles (FCVs) from Toyota Motor Corporation to revise the scenarios.

First, we reviewed the assumptions and scenarios for the calculation of the hydrogen demand potential in phase 1. Next, we re-estimated the hydrogen demand potential based on the revised assumptions and scenarios and compared it with that of the phase 1 study.

1. Review of Hydrogen Demand Potential in Phase 1

This section reviews the hydrogen demand potential in phase 1.

1.1. Basic assumptions (Phase 1)

Table 2.1 shows the basic assumptions of the phase 1 study, which were also applied to phase 2.

Table 2.1: Basic Assumptions for Estimating Hydrogen Demand Potential (Phase 1)

The national hydrogen pipeline, as well as refuelling stations, will only be partially established in 2040.
Hydrogen demand for chemicals and hydrogen carriers, e.g. ammonia or methanol, is excluded.[a]
Hydrogen utilisation technologies to be fully commercialised in 2040: ● Utility scale gas turbine fuelled by a mixture of hydrogen and natural gas ● Commercial scale boiler fuelled by a mixture of hydrogen and natural gas ● Passenger fuel cell vehicle ● Fuel cell bus ● Fuel cell train
Technologies that need to be developed by 2040: ● Utility scale fuel cell ● Heavy-duty fuel cell vehicle ● Fuel cell ship Technically available, but international and domestic refuelling infrastructures will only be partially established in 2040.
Hydrogen demand for stationary fuel cell is not included in this study because we assumed that hydrogen for stationary fuel cell would be produced from on-site natural gas reforming, which can be categorised as natural gas demand.

[a] Currently, most ammonia production is for nitrogen fertiliser. If ammonia were to be used for energy, its demand would be one or two times greater than its current level, thus affecting its global supply/demand balance (IEEJ, 2015).
Source: ERIA (2018).

1.2. Other assumptions and conversion factors (Phase 1)

Table 2.2 shows the assumptions and conversion factors used in the phase 1 study, which were applied to phase 2.

Table 2.2: Other Assumptions and Conversion Factors (Phase 1)

Carbon content	Coal: 25.8 kg-C/GJ (=3.961 tonne-CO_2/toe-input) Natural gas: 15.3 kg-C/GJ (=2.349 tonne-CO_2/toe-input) Gasoline: 18.9 kg-C/GJ (=2.902 tonne-CO_2/toe) (=2.269 tonne-CO_2/KL)	Source: IEA (2018)
Net calorific value	Other bituminous coal (Australian export coal) 0.6138 toe/tonne	Source: IEA, World Energy Balances 2018 database
H2 specification	Gas density: 0.0835 kg/m^3 NCV: 10,780 kJ/m^3 = 2,575 kcal/m^3 = 30,834 kcal/kg = 3,884 m^3/toe	Source: Iwatani Corporation
Thermal efficiency (Electricity generation)	Coal: 55% Natural gas: 63% H_2: 63%	Source: METI–ANRE (2017)
Conversion factor	1 GJ = 0.02388 toe 1 cal = 4.187 J 1 Gcal = 0.1 toe 1 MWh = 0.086 toe 1 MMBtu = 0.0252 toe	–

ANRE = Agency for Natural Resources and Energy; IEA = International Energy Agency; METI = Ministry of Economy, Trade, and Industry, Japan.
Source: ERIA (2018).

1.3. Summary of scenarios (Phase 1)

Table 2.3 summarises the scenarios to calculate hydrogen demand potential in the phase 1 study.

Table 2.3: Summary of Scenarios (Phase 1)

Sector	Fuel		Scenario 1	Scenario 2	Scenario 3
			H2 concentration of mixed fuel		
Electricity generation	Coal	20% of new coal-fired electricity generation will be converted to natural gas and H2 mixed fuel–fired generation	H2: 10% Natural gas: 90%	H2: 20% Natural gas: 80%	H2: 30% Natural gas: 70%
	Natural gas	20% of new natural gas–fired electricity generation will be converted to natural gas and H2 mixed fuel–fired generation			
Industry	Natural gas	20% of natural gas consumption for industrial purposes will be replaced by natural gas and H2 mixed fuel			
			Share of H2/gasoline for passenger cars		
Transport	Gasoline	Passenger fuel cell vehicle: Gasoline demand will be converted to H2	OECD H2: 2.0% Gasoline: 98% Non-OECD H2: 1.0% Gasoline: 99%	OECD H2: 10% Gasoline: 90% Non-OECD H2: 5% Gasoline: 95%	OECD H2: 20% Gasoline: 80% Non-OECD H2: 10% Gasoline: 90%
			Share of H_2/diesel for buses		
	Diesel	Fuel cell bus: Diesel demand will be converted to H2	Japan H_2: 0.05% Gasoline: 99.95% Other countries H2: 0.025% Gasoline: 99.975%	Japan H_2: 0.1% Gasoline: 99.9% Other countries H2: 0.05% Gasoline: 99.95%	Japan H_2: 0.2% Gasoline: 99.8% Other countries H2: 0.1% Gasoline: 99.9%
			Share of H_2/diesel for rail transport		
	Diesel	Fuel cell train: Diesel consumption for rail transport will be converted to H2	H2: 5% Diesel: 95%	H2: 10% Diesel: 90%	H2: 20% Diesel: 80%

OECD = Organisation for Economic Co-operation and Development.
Source: ERIA (2018).

2. Hydrogen Demand Potential (Phase 2)

This section re-analyses the hydrogen demand potential. The phase 2 study revised the scenarios for calculating hydrogen demand potential; more precisely, the study introduced a new idea to classify countries. Basic assumptions, other assumptions, and conversion factors in the phase 1 study were applied to phase 2.

2.1. Classification of East Asia Summit countries

Future hydrogen demand in a country is likely to be greatly affected by the balance between the hydrogen supply cost and the income level of a country. For instance, a resource-rich country could enjoy cheap hydrogen price whilst a resource-scarce country will accept a higher price that reflects the additional cost of import. In terms of income level, a high-income country can afford to pay for a higher price in exchange for environmental benefits whilst a low-income country cannot. In this way, the balance between the hydrogen supply price and the acceptable energy price range – in other words, the economic competitiveness or affordability of hydrogen – differs from country to country. And these facts would greatly affect the magnitude of market penetration of hydrogen in the future. Therefore, this study categorised the East Asia Summit (EAS) countries, excluding the United States (US), in two axes and four quadrants (Table 2.4).

Table 2.4: Classification of EAS Countries, excluding the United States

		Hydrogen Supply Cost	
		Cheap	**Expensive**
Income Level	**High**	**A** The hydrogen supply costs are low, and the income levels are high. **The most widespread use of hydrogen can be expected.** Australia Brunei Darussalam Indonesia Malaysia (Sabah and Sarawak) New Zealand	**B** The hydrogen supply costs are high, and the income levels are high as well. **The use of hydrogen can be expected through a hydrogen promotion policy.** China Japan Korea, Republic of Malaysia (Peninsula) Singapore Thailand
	Low	**C** The hydrogen supply costs are low, and the income levels are low as well. **The use of hydrogen is limited. Becomes a hydrogen exporter.** India Lao People's Democratic Republic Myanmar	**D** The hydrogen supply cost is high, and the income level is low. **Hydrogen demand is unlikely to be expected.** Cambodia Philippines Viet Nam

Source: Author.

2.2. Summary of Revised Scenarios (Phase 2)

Table 2.5 shows the revised assumptions and scenarios for calculating the hydrogen demand potential. The conversion ratio from conventional energy to hydrogen differs depending on the quadrant. Each quadrant has one conversion ratio to avoid evaluation complexity.

Table 2.5: Assumptions and Scenarios for Calculating Hydrogen Demand Potential (Phase 2)

Quadrant A

Sector	Assumption	Conversion Ratio
Electricity generation	Full-scale hydrogen use will begin in 2030 (Assume that 10 years will be required to build a large-scale hydrogen production plant, domestic supply infrastructure, and hydrogen-fired CCGT.) Hydrogen will be supplied to the power plant through newly constructed hydrogen pipelines.	The ratio of conversion to hydrogen and natural gas mixed fuel or pure hydrogen. 50%
	Existing natural gas power generation (TWh) as of 2030 will be partially converted to the 30% hydrogen and 70% natural gas mixed fuel by replacing the combustors.	
	New natural gas power generation (TWh) after 2030 will be partially converted to the 100% hydrogen fuel.	
Transport	Assume a certain share of the zero-emission vehicle (ZEV) in the registered passenger cars in 2040. Fuel cell vehicle (FCV) share in ZEV: 20%	The ratio of ZEV; 50%

CCGT = combined cycle gas turbine.

Quadrant B

Sector	Assumption	Conversion Ratio
Electricity generation (Existing generation)	Full-scale hydrogen use will begin in 2030 (Assume that 10 years will be required to build a large-scale hydrogen production plant, domestic supply infrastructure, and hydrogen-fired CCGT.) Japan, the Republic of Korea, Malaysia (Peninsula), Singapore, and Thailand are assumed to construct hydrogen import terminals adjacent to liquefied natural gas (LNG) import terminals for power generation. Other than Singapore, existing gas pipelines will be used to distribute hydrogen in a country. If gas power plants are connected to the same gas pipeline network, they will be converted to hydrogen at once	The ratio of conversion to hydrogen and natural gas mixed fuel or pure hydrogen
	Existing natural gas power generation (TWh) as of 2030 will be partially converted to the 30% hydrogen and 70% natural gas mixed fuel by replacing the combustors.	
	Malaysia (Peninsula) Imported hydrogen.	50%
	Thailand Gas power plants connected to LNG import terminals will be converted. The gas power plants in the following two areas are not subject to conversion: – The south-eastern area that receives natural gas from the JDA with Malaysia, – The north-western area that natural gas is imported from Myanmar.	50%
	China China will have a mix of domestic fossil–fuel reformed hydrogen and imported hydrogen.	50%
	Japan Imported hydrogen	50%
	Republic of Korea The KOGAS high-pressure gas pipeline connected to the gas-fired plants is looped.	100%
	Singapore The country is small. It is assumed that a new hydrogen pipeline will be constructed. The number	100%

	of gas-fired plants may be very small.	
Electricity generation (New generation)	New natural gas power generation (TWh) after 2030 will be partially converted to the 100% hydrogen fuel. Japan, the Republic of Korea Singapore, and Thailand are assumed to construct new 100% hydrogen thermal power adjacent to the hydrogen import terminals, which will not be connected to the existing natural gas pipelines. China will have a mix of domestic fossil fuel–reformed hydrogen and imported hydrogen.	
	Malaysia (Peninsula) **Thailand** **China** **Japan** **Republic of Korea**	50%
	Singapore The number of gas-fired plants may be very small.	100%
Transport	Assume a certain share of the zero-emission vehicle (ZEV) in the registered passenger cars in 2040. FCV share in ZEV: 10%	The ratio of ZEV 30%

CCGT = combined cycle gas turbine, JDA = joint development area of offshore hydrocarbon field, LNG = liquefied natural gas.

Quadrant C

Sector	Assumption	Conversion Ratio
Electricity generation	Full-scale hydrogen use will begin in 2040 (assume it will take 20 years to improve income levels) Hydrogen is supplied to the power plant through newly constructed hydrogen pipelines.	The ratio of conversion to mixed fuel
	Existing natural gas–fired electricity generation (TWh) as of 2030 will be partially converted to the 30% hydrogen and 70% natural gas–mixed fuel by replacing the combustors except for the Lao PDR that has no plan of introducing natural gas–fired plant.	30%
	A new 100% hydrogen-fired plant will be operated in 2040 except for the Lao PDR. The generation capacity is assumed to be 200 MW.	One 200 MW plant
Transport	Assume a certain share of the zero-emission vehicle (ZEV) in the registered passenger cars in 2040. FCV share in ZEV: 10%	The ratio of ZEV 30%

Quadrant D

Sector	Assumption	Conversion Ratio
Electricity generation	Full-scale hydrogen use will begin in 2040 (Assume it will take 20 years to improve income levels). As of 2040, a pilot project or first plant will be introduced. Assume that a hydrogen import terminal will be constructed adjacent to the liquefied natural gas (LNG) terminal that is expected to be developed in the future. Cambodia will also consider importing hydrogen from the Lao PDR through pipelines.	
(Existing generation)	Existing natural gas power generation (TWh) as of 2030 will be partially converted to the 30% hydrogen and 70% natural gas mixed fuel by replacing the combustors.	
	Viet Nam	30%
	Cambodia Philippines The number of gas-fired plants may be very small.	100%
(New generation)	No new 100% hydrogen-fired plant will be operated in 2040.	–
Transport	Assume a certain share of the zero-emission vehicle (ZEV) in the registered passenger cars in 2040. FCV share in ZEV: 5%	The ratio of ZEV 30%

Source: Author.

Table 2.6, Figure 2.1, and Figure 2.2 show the major differences of scenarios between phases 1 and 2.

In the electricity generation sector, coal electricity generation is excluded because the gradual phase-out of the coal electricity generation scenario was already included in the ERIA energy outlook 2019. The conversion ratio from natural gas electricity generation to hydrogen is increased. In phase 1, only new power generation was the subject of fuel switch to hydrogen but, in phase 2, existing power generation was also targeted to use hydrogen. In addition, after 2030, we assumed that pure hydrogen thermal electricity generation would start operation considering recent developments in technology.

Meanwhile, hydrogen consumption in the industry sector is excluded. We thought it would be premature to build pure hydrogen pipeline infrastructures for industrial boilers before 2040. This is because of a smaller demand per plant compared to electricity generation, which makes feasibility of a pure hydrogen pipeline low.

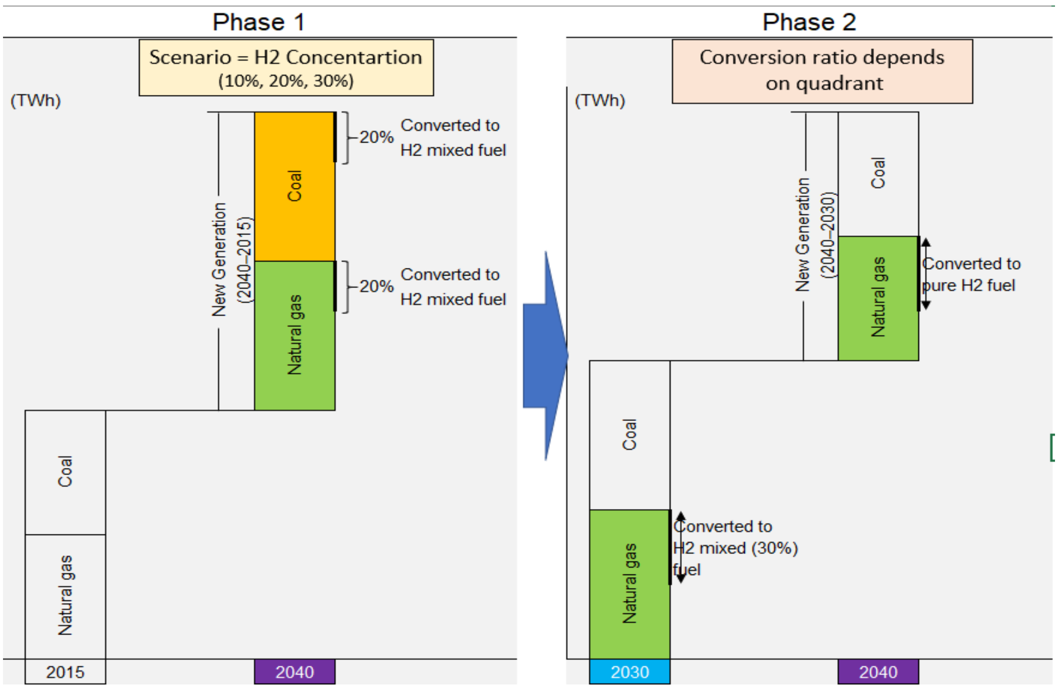
In the transport sector, diesel was excluded because calculated hydrogen demand to substitute for diesel engine was very small in phase 1. The transport sector's scenarios in phase 2 are not progressive compared to phase 1.

Table 2.6: Major Differences of Scenarios between Phases 1 and 2

Sector	Item	Phase 1	Phase 2
Electricity generation	Subject of fuel switch	Natural gas Coal	Natural gas
	Scenario (Factors of change)	Fuel for electricity generation: The hydrogen concentration in natural gas and hydrogen mixed fuel	Generated electricity: The conversion ratio of generated electricity to hydrogen/natural gas mixed fuel or pure hydrogen
Industry	Subject of fuel switch	Natural gas	Excluded
Transport	Mode	Passenger fuel cell vehicle (gasoline) Fuel cell bus (diesel) Fuel cell train (diesel)	Passenger fuel cell vehicle (gasoline)
	Scenario	Conversion ratio of gasoline/diesel	The ratio of zero-emission vehicle

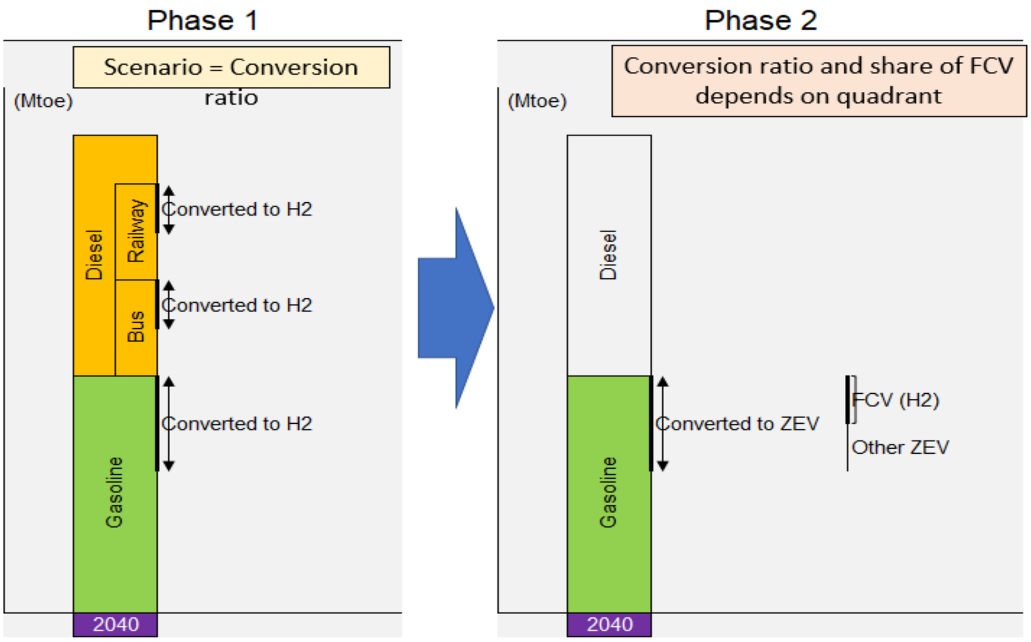
Source: Author.

Figure 2.1: Hydrogen Demand Calculation Method of the Electricity Generation Sector



Note: Scale is not accurate.
Source: Author.

Figure 2.2: Hydrogen Demand Calculation Method of the Transport Sector



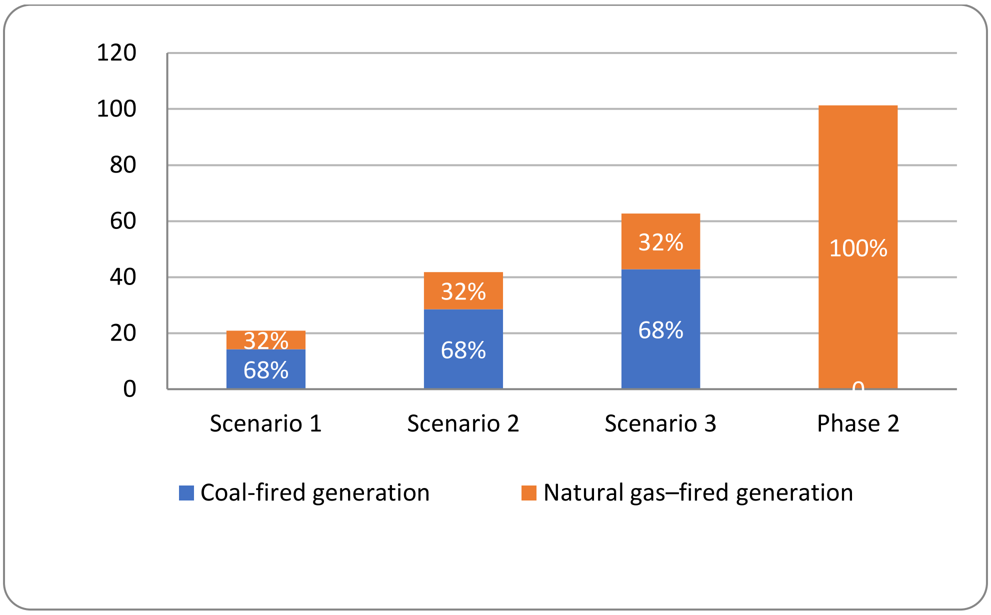
FCV = fuel cell vehicle, ZEV = zero-emission vehicle.
Note: Scale is not accurate.
Source: Author.

2.3. Hydrogen demand potential by sector and by country (Phase 2)

2.3.1. Electricity generation sector

Figure 2.3 shows the hydrogen demand potential of the electricity generation sector of the EAS in 2040. In the phase 2 study, hydrogen demand potential will reach 101 Mtoe. Compared to phase 1, hydrogen demand potential will increase 80 Mtoe from scenario 1, 59 Mtoe from scenario 2, and 38 Mtoe from scenario 3, despite coal-fired electricity generation being excluded in phase 2.

Figure 2.3: Hydrogen Demand Potential of the Electricity Generation Sector in the EAS in 2040



Source: Author.

Table 2.7 compares the scenarios of the electricity generation sector between the two study phases.

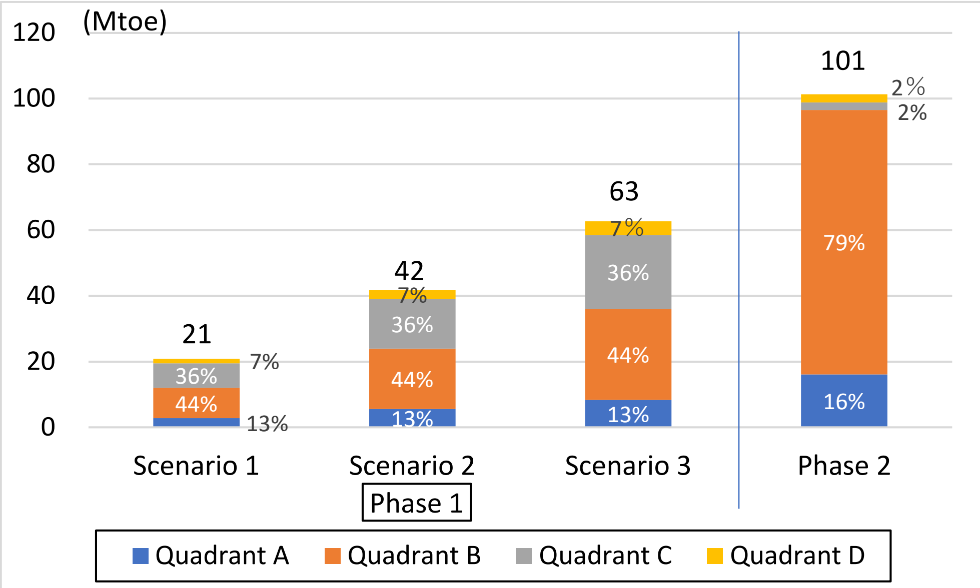
Table 2.7: Comparison of Scenarios in the Electricity Generation Sector

Item	Phase 1	Phase 2
Converted electricity generation (Natural gas)	New	Existing and new
Conversion ratio	20%	30%, 50%, 100% (Depends on the quadrant)
Hydrogen content in the mixed fuel	Three scenarios (10%, 20%, 30%)	Existing 30% New 100%

Source: Author.

Figure 2.4 shows the hydrogen demand potential of the electricity generation sector in 2040, by quadrant. Compared to the phase 1 study, hydrogen demand potential increases in quadrants A and B. However, it decreases in quadrants C and D. The difference comes from a different expectation for natural electricity generation. In quadrants A and B, countries are expected to generate a large capacity of natural gas electricity. Meanwhile in quadrants C and D, countries are expected to generate a larger capacity of coal electricity rather than natural gas.

Figure 2.4: Hydrogen Demand Potential of the Electricity Generation Sector in the EAS, by Quadrant



EAS = East Asia Summit.
Source: Author.

Table 2.8 shows electricity generation from coal and natural gas, which is the basis of the calculation of hydrogen demand potential, and their share to total electricity generation. The latter is a reference to make comparison easier.

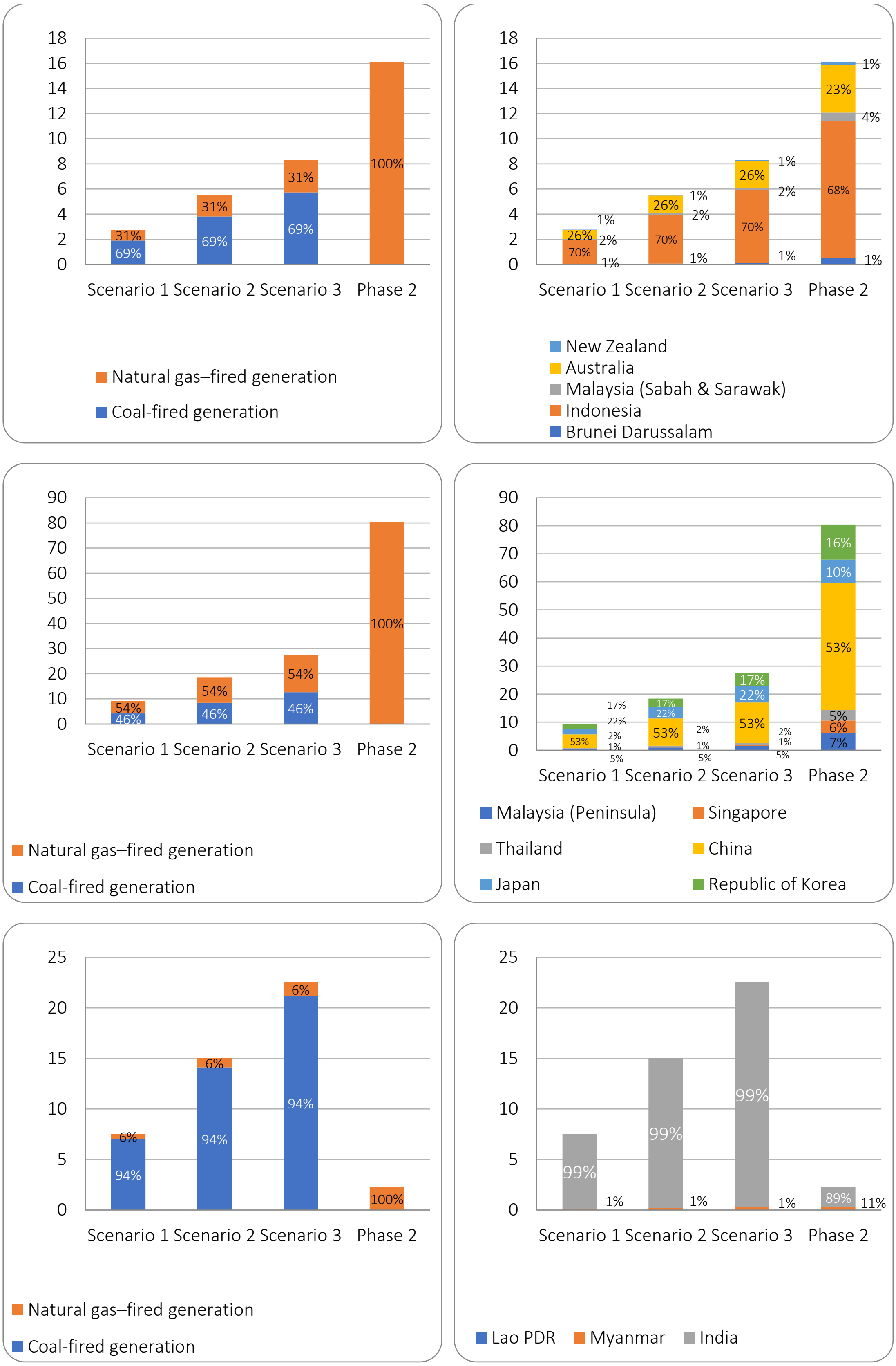
Table 2.8: Electricity Generation from Coal and Natural Gas, by Country

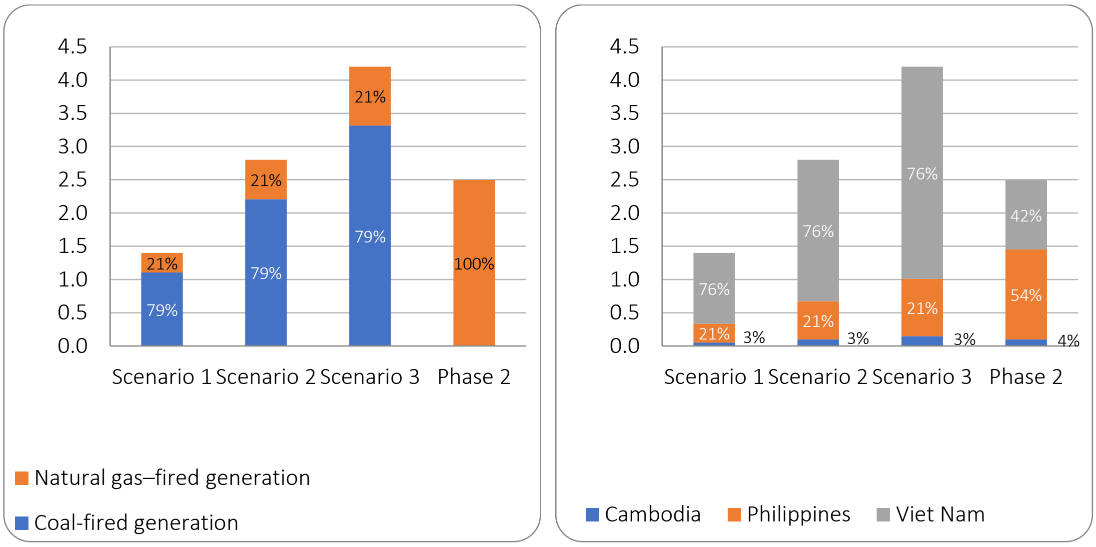
Country	Electricity Generation (TWh)				Share, %			
	Phase 1		Phase 2		Coal		Natural Gas	
	Coal	Natural Gas	Natural Gas	Natural Gas				
	New	New	Existing	New	2015	2040	2015	2040
Brunei Darussalam	4	10	9	5	–	21	99	79
Indonesia	551	161	86	134	56	70	25	23
Malaysia (Sabah and Sarawak)	4	12	13	6	10	10	24	26
Australia	141	119	90	28	63	38	21	32
New Zealand	0	10	10	1	4	0	16	18
Quadrant A	700	312	208	174	52	56	23	26
Malaysia (Peninsula)	78	109	121	52	50	47	52	58
Singapore	1	38	74	11	1	1	95	91
Thailand	39	44	151	10	20	24	71	55
China	780	994	683	456	70	49	2	11
Japan	337	390	381	9	33	29	40	34
Republic of Korea	309	256	181	74	43	42	22	34
Quadrant B	1,544	1,831	1,591	613	62	45	12	17
Lao PDR	43	–	–	–	13	63	0	0
Myanmar	27	7	9	4	0	42	41	22
India	2,557	162	154	77	75	75	5	5
Quadrant C	2,627	169	163	81	74	74	5	5
Cambodia	11	7	2	5	48	34	0	18
Philippines	68	37	33	23	45	49	23	26
Viet Nam	325	65	85	25	32	69	28	20
Quadrant D	405	109	120	52	36	62	26	22
Total	5,275	2,421	2,083	920	62	54	12	15

Note: Malaysia is divided by generation capacity.
The definition of 'New generation' is different between phases 1 and 2 of the study.
Source: Author.

Figure 2.5 shows the hydrogen demand potential in 2040 by generation fuel and by country.

Figure 2.5: Hydrogen Demand Potential of the Electricity Generation Sector, by Country



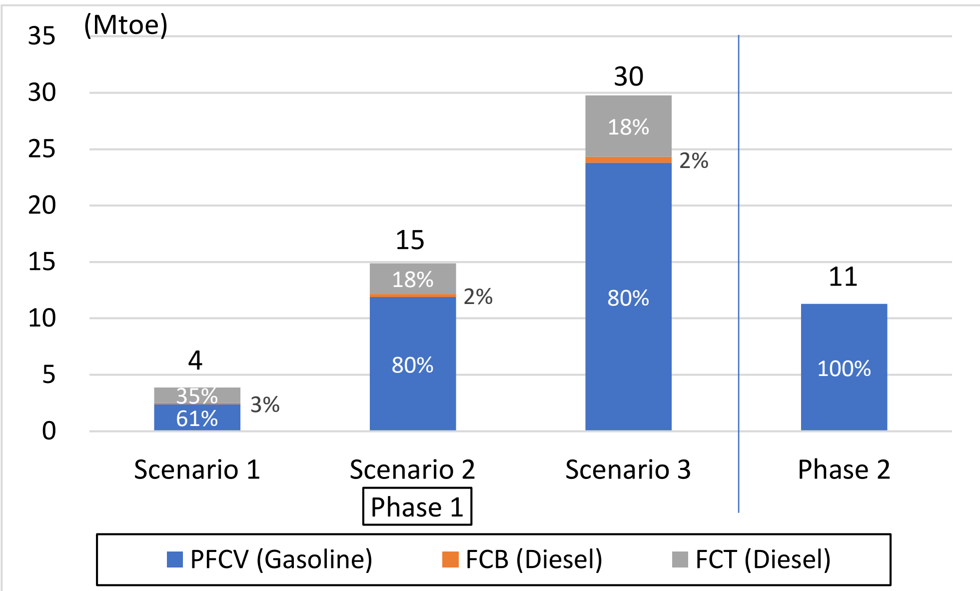


Note: Malaysia is divided by natural gas generation capacity.
Source: Author.

2.3.1. Transport sector

Figure 2.6 shows the hydrogen demand potential of the transport sector of the EAS in 2040. In the phase 2 study, hydrogen demand potential will reach 11 Mtoe. Compared to phase 1, hydrogen demand potential will increase 7 Mtoe from scenario 1 but will decrease 4 Mtoe from scenario 2 and 19 Mtoe from scenario 3.

Figure 2.6: Hydrogen Demand Potential of the Transport Sector in the EAS in 2040



Note: PFCV = passenger fuel cell vehicle, FCB = fuel cell bus, FCT = fuel cell train.
Source: Author.

Table 2.9 compares the scenarios in the transport sector between the two study phases.

Table 2.9: Comparison of Scenarios in the Transport Sector

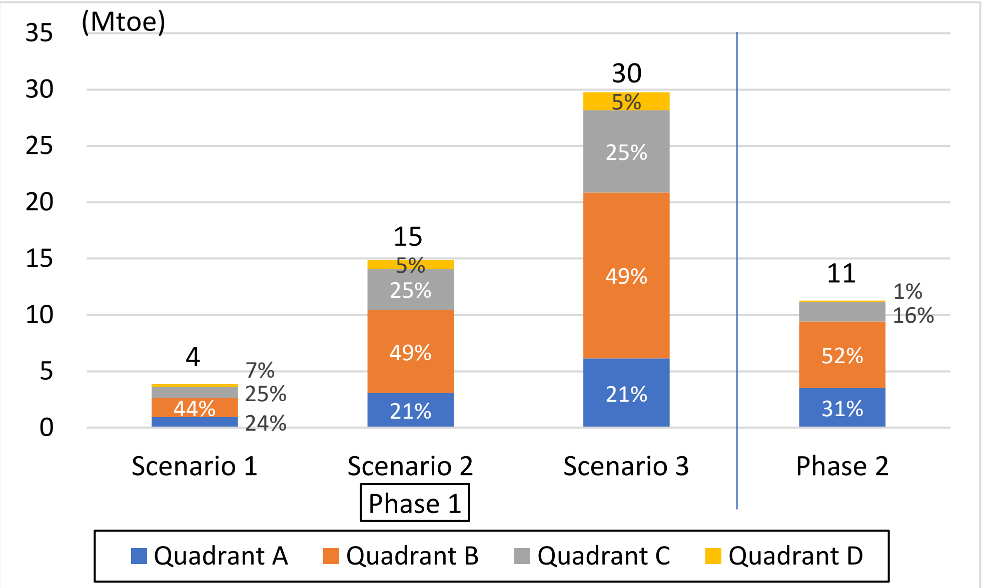
Item	Phase 1	Phase 2
Mode	Passenger vehicle Bus Railway	Passenger vehicle
Conversion ratio	Ratio: Depends on country Passenger: From 1% to 20% Bus: From 0.025% to 0.2% Railway: From 5% to 20%	1.5%, 3%, 10% (Depends on quadrant)

Source: Author.

Figure 2.7 shows the hydrogen demand potential of the transport sector in 2040, by quadrant.

Compared to the phase 1 study, hydrogen demand in quadrant A countries will increase 2.6 Mtoe from scenario 1, 0.4 Mtoe from scenario 2, but will decrease 2.6 Mtoe from scenario 3. Quadrant B will increase 4.2 Mtoe from scenario 1 but will decrease 1.4 Mtoe from scenario 2 and 8.8 Mtoe from scenario 3. Quadrant C will increase 0.8 Mtoe from scenario 1 but will decrease 1.9 Mtoe from scenario 2 and 5.6 Mtoe from scenario 3. Quadrant D will decrease 0.2 Mtoe from scenario 1, 0.7 Mtoe from scenario 2, and 1.5 Mtoe from scenario 3.

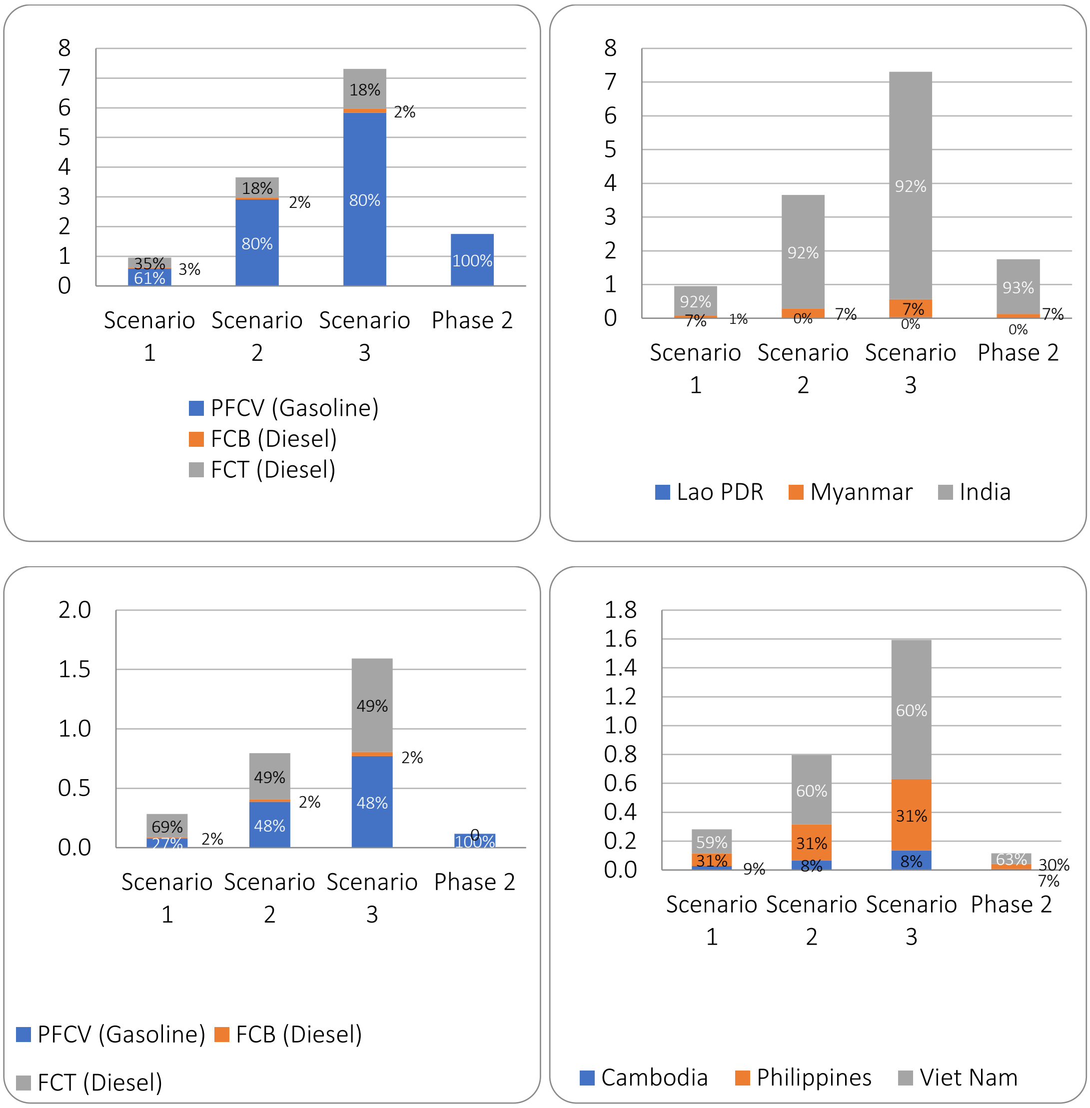
Figure 2.7: Hydrogen Demand Potential of the Transport Sector in the EAS, by Quadrant



EAS = East Asia Summit.
Source: Author.

Figure 2.8 shows the hydrogen demand potential in 2040 by transport mode and by country.

Figure 2.8: Hydrogen Demand Potential of the Transport Sector, by Country and Transport Mode



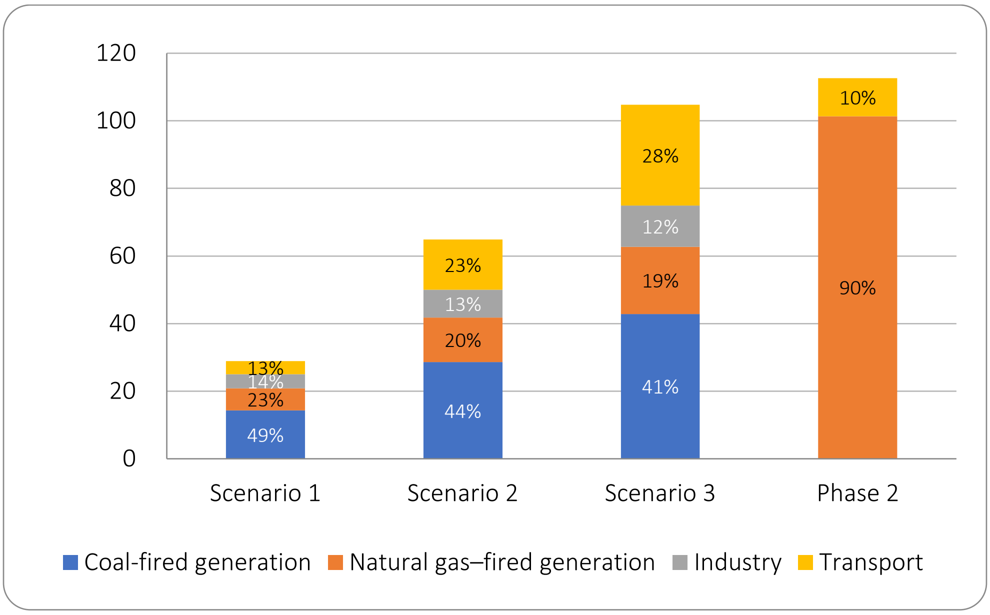
PFCV = passenger fuel cell vehicle, FCB = fuel cell bus, FCT = fuel cell train.
Note: Malaysia is divided by state GDP in 2018.
Source: Author.

2.3.3. Total hydrogen demand potential

Figure 2.9 shows the total hydrogen demand potential of the EAS in 2040. In the phase 1 study, hydrogen demand potential in the industry sector was included, which are 4 Mtoe in scenario 1, 8 Mtoe in scenario 2, and 12 Mtoe in scenario 3. However, it was excluded in phase 2.

In phase 2, total hydrogen demand potential will reach 113 Mtoe. Compared to phase 1, total hydrogen demand potential will increase by 84 Mtoe from scenario 1, 48 Mtoe from scenario 2, and 8 Mtoe from scenario 3.

Figure 2.9: Total Hydrogen Demand Potential in the EAS in 2040

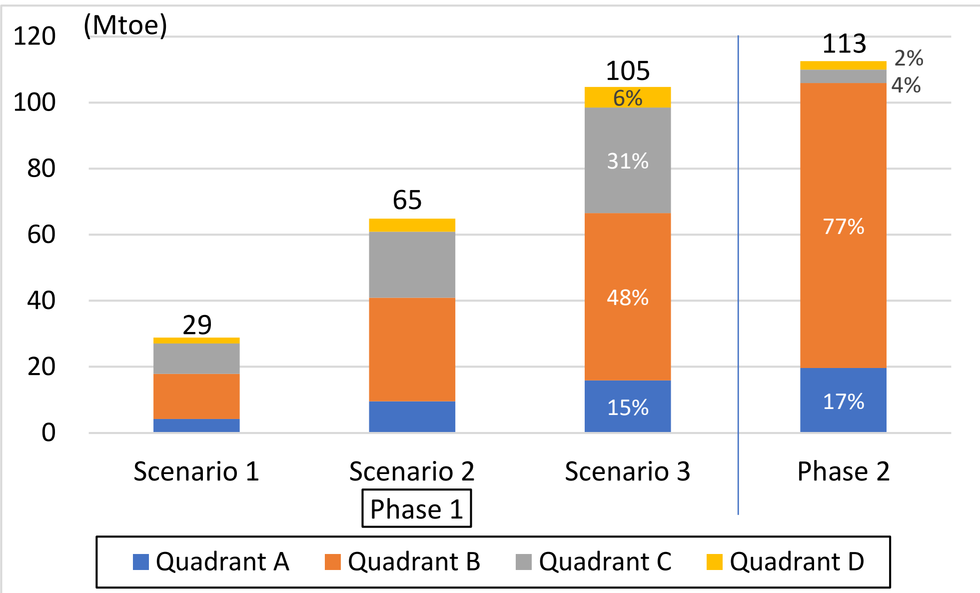


Source: Author.

Figure 2.10 shows the total hydrogen demand potential in 2040 by quadrant.

Compared to the phase 1 study, quadrant A will increase 15 Mtoe from scenario 1, 10 Mtoe from scenario 2, and 4 Mtoe from scenario 3. Quadrant B will increase 73 Mtoe from scenario 1, 55 Mtoe from scenario 2, and 36 Mtoe from scenario 3. Quadrant C will decrease 5 Mtoe from scenario 1, 16 Mtoe from scenario 2, and 28 Mtoe from scenario 3. Quadrant D will decrease 1 Mtoe from scenario 1 but will decrease 1 Mtoe from scenario 2 and 4 Mtoe from scenario 3.

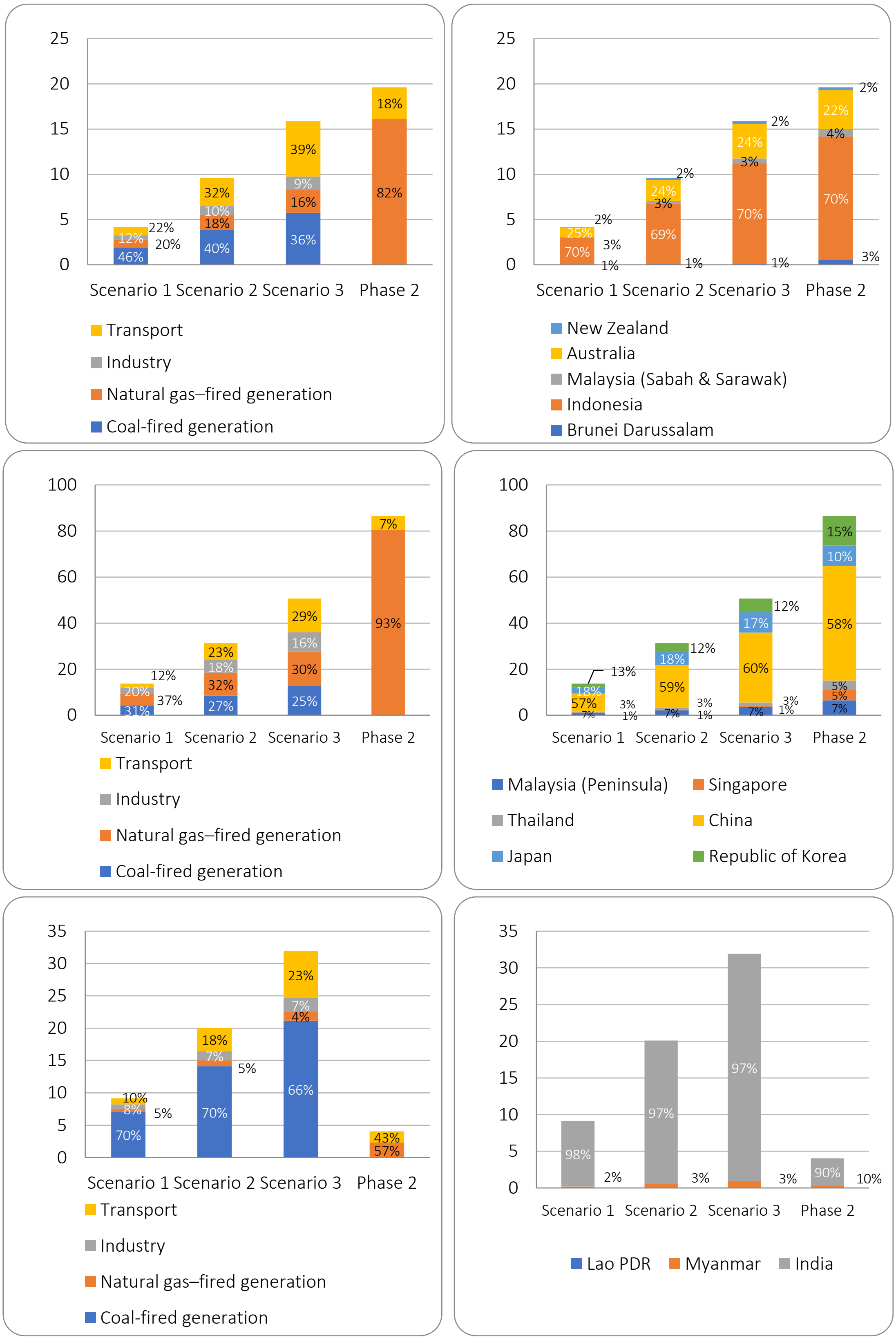
Figure 2.10: Total Hydrogen Demand Potential in the EAS in 2040, by Quadrant

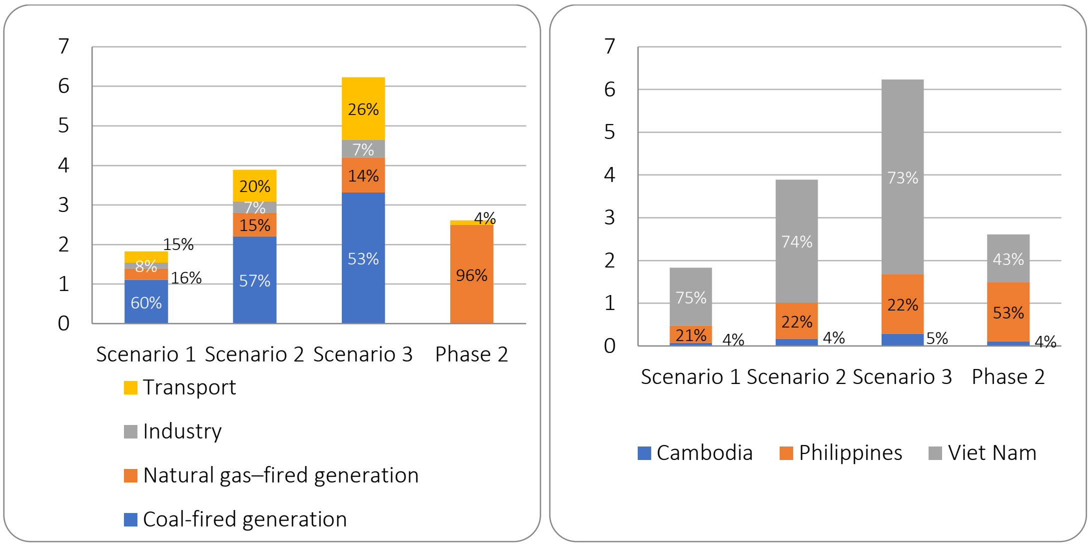


Source: Author.

Figure 2.11 shows the total hydrogen demand potential in 2040 by sector and by country.

Figure 2.11: Total Hydrogen Demand Potential, by Country and Sector





Gen = generation.
Source: Author.

2.4. Replaced energy

Table 2.10 shows the electricity generation sector's replaced energy by hydrogen in 2040. In the phase 1 study, net natural gas demand increased in many countries because it assumed 20% of coal-fired electricity generation to be replaced by natural gas and hydrogen mixed fuel-fired electricity generation.

Table 2.10: Replaced Energy by Hydrogen in the Electricity Generation Sector in 2040

Unit: Mtoe

	Phase 1												Phase 2
Generation	Coal Fired				Natural Gas Fired			Coal Fired + Natural Gas Fired					Natural Gas Fired
Fuel	Replaced coal	New natural gas demand			Replaced natural gas			Replaced coal	Net natural gas increase			Replaced natural gas	
Scenario	S1, S2, S3	S1	S2	S3	S1	S2	S3	S1, S2, S3	S1	S2	S3	-	
Brunei Darussalam	-0.1	0.1	0.1	0.1	-0.0	-0.1	-0.1	-0.1	0.1	0.0	-0.0	-0.5	
Indonesia	-9.5	13.5	12.0	10.5	-0.4	-0.9	-1.3	-9.5	13.1	11.2	9.2	-10.9	
Malaysia	-0.1	0.1	0.1	0.1	-0.0	-0.1	-0.1	-0.1	0.1	0.0	-0.0	-0.7	
Australia	-2.4	3.5	3.1	2.7	-0.3	-0.6	-1.0	-2.4	3.2	2.4	1.7	-3.8	
New Zealand	0.0	0.0	0.0	0.0	-0.0	-0.1	-0.1	0.0	-0.0	-0.1	-0.1	-0.2	
Quadrant A	-12.0	17.2	15.3	13.4	-0.9	-1.7	-2.6	-12.0	16.3	13.6	10.8	-16.1	
Malaysia	-1.3	1.9	1.7	1.5	-0.3	-0.6	-0.9	-1.3	1.6	1.1	0.6	-6.0	
Singapore	-0.0	0.0	0.0	0.0	-0.1	-0.2	-0.3	-0.0	-0.1	-0.2	-0.3	-4.6	
Thailand	-0.7	1.0	0.8	0.7	-0.1	-0.2	-0.4	-0.7	0.8	0.6	0.4	-3.8	
China	-13.4	19.2	17.0	14.9	-2.7	-5.4	-8.1	-13.4	16.5	11.6	6.8	-45.1	
Japan	-5.8	8.3	7.4	6.4	-1.1	-2.1	-3.2	-5.8	7.2	5.2	3.3	-8.4	
Republic of Korea	-5.3	7.6	6.7	5.9	-0.7	-1.4	-2.1	-5.3	6.9	5.3	3.8	-12.5	
Quadrant B	-26.6	37.9	33.7	29.5	-5.0	-10.0	-15.0	-26.6	32.9	23.7	14.5	-80.4	
Lao PDR	-	-	-	-	-	-	-	-	-	-	-	-	
Myanmar	-0.5	0.7	0.6	0.5	-0.0	-0.0	-0.1	-0.5	0.6	0.5	0.4	-0.3	
India	-44.0	62.8	55.9	48.9	-0.4	-0.9	-1.3	-44.0	62.4	55.0	47.5	-2.0	
Quadrant C	-44.4	63.5	56.4	49.4	-0.5	-0.5	-0.5	-44.4	63.0	55.5	48.0	-2.3	
Cambodia	-0.2	0.3	0.2	0.2	-0.0	-0.0	-0.1	-0.2	0.2	0.2	0.2	-0.1	
Philippines	-1.2	1.7	1.5	1.3	-0.1	-0.2	-0.3	-1.2	1.6	1.3	1.0	-1.4	
Viet Nam	-5.6	8.0	7.1	6.2	-0.2	-0.4	-0.5	-5.6	7.8	6.8	5.7	-1.0	
Quadrant D	-7.0	9.9	8.8	7.7	-0.3	-0.3	-0.3	-7.0	9.6	8.2	6.8	-2.5	
Total	-90.0	128.6	114.3	100.0	-6.6	-12.5	-18.3	-90.0	122.0	101.1	80.2	-101.3	

Notes: S1 = scenario 1, S2 = scenario 2, S3 = scenario 3; Negative number = decrease of demand, Positive number = increase of demand; Malaysia is divided by generation capacity.
Source: Author.

Table 2.11 shows the industry sector's replaced energy by hydrogen in 2040. In the phase 2 study, the industry sector was not included to calculate hydrogen demand potential.

Table 2.11: Replaced Energy by Hydrogen in the Industry Sector in 2040

Unit: Mtoe

	Phase 1			Phase 2
Fuel	**Replaced Natural Gas**			**-**
Scenario	Scenario 1	Scenario 2	Scenario 3	-
Brunei Darussalam	-	-	-	-
Indonesia	-0.3	-0.5	-0.8	-
Malaysia (Sabah & Sarawak)	-0.0	-0.1	-0.1	-
Australia	-0.2	-0.3	-0.5	-
New Zealand	-0.0	-0.0	-0.1	-
Quadrant A	-0.5	-1.0	-1.5	-
Malaysia (Peninsula)	-0.2	-0.4	-0.7	-
Singapore	-0.0	-0.1	-0.1	-
Thailand	-0.2	-0.4	-0.6	-
China	-1.8	-3.6	-5.4	-
Japan	-0.3	-0.6	-0.9	-
Republic of Korea	-0.2	-0.4	-0.7	-
Quadrant B	-2.8	-5.5	-8.3	-
Lao PDR	-	-	-	-
Myanmar	-0.0	-0.1	-0.1	-
India	-0.7	-1.3	-2.0	-
Quadrant C	-0.7	-1.4	-2.1	-
Cambodia	-	-	-	-
Philippines	-0.0	-0.0	-0.0	-
Viet Nam	-0.1	-0.3	-0.4	-
Quadrant D	-0.1	-0.3	-0.4	-
Total	**-4.1**	**-8.2**	**-12.3**	**-**

Note: Malaysia is divided by state GDP in 2018.
Source: Author.

Table 2.12 shows the transport sector’s replaced energy by hydrogen in 2040. In the phase 2 study, diesel demand (bus and railway) was not included to calculate hydrogen demand potential.

The fuel economy of FCVs was assumed to be 2.7 times better than gasoline vehicles. (Please see the phase 1 study.)

Table 2.12: Replaced Energy by Hydrogen in the Transport Sector in 2040

Unit: Mtoe

	Phase 1						Phase 2
Replaced Fuel	**Gasoline**			**Diesel**			**Gasoline**
Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3	-
Brunei Darussalam	-0.0	-0.0	-0.1	-0.0	-0.0	-0.0	-0.1
Indonesia	-0.7	-3.7	-7.4	-0.4	-0.9	-1.8	-7.4
Malaysia (Sabah & Sarawak	-0.0	-0.2	-0.5	-0.0	-0.0	-0.1	-0.5
Australia	-0.3	-1.3	-2.6	-0.1	-0.1	-0.2	-1.3
New Zealand	-0.0	-0.2	-0.4	-0.0	-0.0	-0.0	-0.2
Quadrant A	-1.1	-5.5	-11.0	-0.5	-1.0	-2.1	-9.4
Malaysia (Peninsula)	-0.2	-1.2	-2.5	-0.1	-0.2	-0.3	-1.2
Singapore	-0.0	-0.0	-0.1	-0.0	-0.0	-0.0	-0.0
Thailand	-0.1	-0.4	-0.9	-0.0	-0.0	-0.0	-0.4
China	-2.5	-12.5	-25.0	-0.3	-0.6	-1.1	-12.5
Japan	-0.5	-2.6	-5.2	-0.0	-0.0	-0.1	-1.3
Republic of Korea	-0.2	-0.9	-1.7	-0.0	-0.0	-0.0	-0.4
Quadrant B	-3.5	-17.7	-35.4	-0.4	-0.8	-1.6	-16.0
Lao PDR	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0
Myanmar	-0.1	-0.6	-1.1	-0.0	-0.1	-0.1	-0.3
India	-1.5	-7.3	-14.6	-0.3	-0.7	-1.4	-4.4
Quadrant C	-1.6	-7.9	-15.8	-0.4	-0.7	-1.5	-4.7
Cambodia	-0.0	-0.1	-0.1	-0.0	-0.0	-0.1	-0.0
Philippines	-0.1	-0.3	-0.6	-0.1	-0.1	-0.3	-0.1
Viet Nam	-0.1	-0.7	-1.3	-0.1	-0.2	-0.5	-0.2
Quadrant D	-0.2	-1.0	-2.1	-0.2	-0.4	-0.8	-0.3
Total	**-6.4**	**-32.1**	**-64.2**	**-1.5**	**-3.0**	**-6.0**	**-30.5**

Note: Malaysia is divided by state GDP in 2018.

Source: Author.

Table 2.13 shows the total replaced energy by hydrogen in 2040.

Table 2.13: Total Replaced Energy by Hydrogen in 2040

Unit: Mtoe

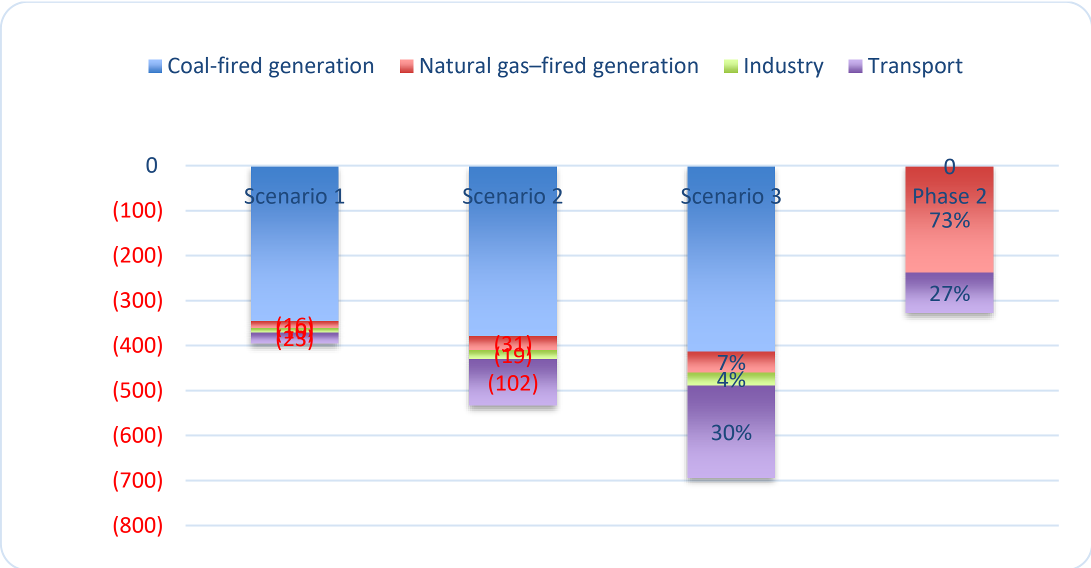
	Phase 1										Phase 2	
Replaced Fuel	**Coal**	**Natural Gas**			**Gasoline**			**Diesel**			**Natural Gas**	**Gasoline**
Scenario	S1, S2, S3	S1	S2	S3	S1	S2	S3	S1	S2	S3	-	-
Brunei Darussalam	-0.1	0.1	0.0	-0.0	-0.0	-0.0	-0.1	-0.0	-0.0	-0.0	-0.5	-0.1
Indonesia	-9.5	12.8	10.6	8.4	-0.7	-3.7	-7.4	-0.4	-0.9	-1.8	-10.9	-7.4
Malaysia	-0.1	0.0	-0.1	-0.2	-0.0	-0.2	-0.5	-0.0	-0.0	-0.1	-0.7	-0.5
Australia	-2.4	3.0	2.1	1.2	-0.3	-1.3	-2.6	-0.1	-0.1	-0.2	-3.8	-1.3
New Zealand	0.0	-0.1	-0.1	-0.2	-0.0	-0.2	-0.4	-0.0	-0.0	-0.0	-0.2	-0.2
Quadrant A	-12.0	15.9	12.6	9.4	-1.1	-5.5	-11.0	-0.5	-1.0	-2.1	-16.1	-9.4
Malaysia	-1.3	1.4	0.7	-0.1	-0.2	-1.2	-2.5	-0.1	-0.2	-0.3	-6.0	-1.2
Singapore	-0.0	-0.1	-0.3	-0.4	-0.0	-0.0	-0.1	-0.0	-0.0	-0.0	-4.6	-0.0
Thailand	-0.7	0.6	0.2	-0.2	-0.1	-0.4	-0.9	-0.0	-0.0	-0.0	-3.8	-0.4
China	-13.4	14.7	8.0	1.4	-2.5	-12.5	-25.0	-0.3	-0.6	-1.1	-45.1	-12.5
Japan	-5.8	6.9	4.6	2.3	-0.5	-2.6	-5.2	-0.0	-0.0	-0.1	-8.4	-1.3
Republic of Korea	-5.3	6.7	4.9	3.1	-0.2	-0.9	-1.7	-0.0	-0.0	-0.0	-12.5	-0.4
Quadrant B	-26.6	30.2	18.2	6.2	-3.5	-17.7	-35.4	-0.4	-0.8	-1.6	-80.4	-16.0
Lao PDR	-	-	-	-	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0	-	-0.0
Myanmar	-0.5	0.6	0.5	0.3	-0.1	-0.6	-1.1	-0.0	-0.1	-0.1	-0.3	-0.3
India	-44.0	61.7	53.6	45.6	-1.5	-7.3	-14.6	-0.3	-0.7	-1.4	-2.0	-4.4
Quadrant C	-44.4	62.3	54.1	45.9	-1.6	-7.9	-15.8	-0.4	-0.7	-1.5	-2.3	-4.7
Cambodia	-0.2	0.2	0.2	0.2	-0.0	-0.1	-0.1	-0.0	-0.0	-0.1	-0.1	-0.0
Philippines	-1.2	1.6	1.3	1.0	-0.1	-0.3	-0.6	-0.1	-0.1	-0.3	-1.4	-0.1
Viet Nam	-5.6	7.7	6.5	5.3	-0.1	-0.7	-1.3	-0.1	-0.2	-0.5	-1.0	-0.2
Quadrant D	-7.0	9.5	8.0	6.4	-0.2	-1.0	-2.1	-0.2	-0.4	-0.8	-2.5	-0.3
Total	**-90.0**	**117.9**	**92.9**	**67.9**	**-6.4**	**-32.1**	**-64.2**	**-1.5**	**-3.0**	**-6.0**	**-101.3**	**-30.5**

Notes: S1 = scenario 1, S2 = scenario 2, S3 = scenario 3, Negative number = decrease of demand, Positive number = increase of demand.
Source: Author.

2.5. Reduction in CO_2 emission

Figure 2.12 shows the reduction in CO_2 emission, which can be attained by switching fuel from fossil fuel to hydrogen. In the phase 2 study, CO_2 emission will be reduced to 327 million tonnes-CO_2 in 2040. Compared to the phase 1 study, CO_2 emission will decrease by 68 million tonnes-CO_2 from scenario 1, 206 million tonnes-CO_2 from scenario 2, and 367 million tonnes-CO_2 from scenario 3. The main reason for reduced CO_2 emission is that coal-fired electricity generation was not included in calculating hydrogen demand potential in the phase 2 study.

Figure 2.12: CO_2 Emission Reduction in the EAS in 2040

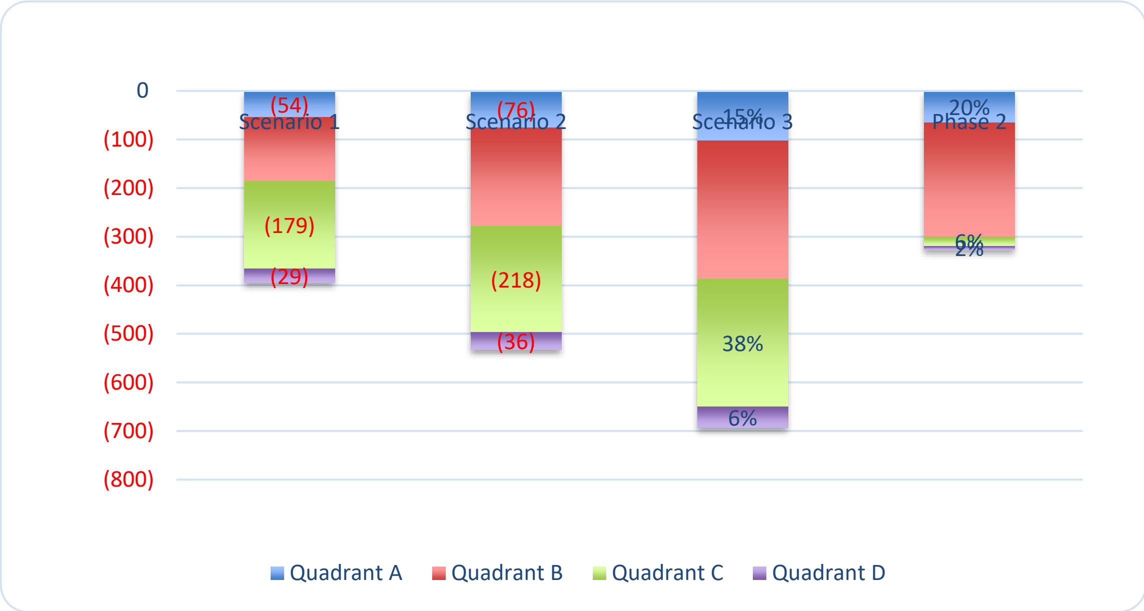


Source: Author.

Figure 2.13 shows the reduction in CO_2 emission in 2040 by quadrant.

Compared to the phase 1 study, quadrant A countries will increase CO_2 emission by 11 million tonnes-CO_2 from scenario 1 but will decrease 11 million tonnes-CO_2 from scenario 2 and 38 million tonnes-CO_2 from scenario 3. Quadrant B will increase 103 million tonnes-CO_2 from scenario 1 and 33 million tonnes-CO_2 from scenario 2 but will decrease 49 million tonnes-CO_2 from scenario 3. Quadrant C will decrease 160 million tonnes-CO_2 from scenario 1, 199 million tonnes-CO_2 from scenario 2, and 243 million tonnes-CO_2 from scenario 3. Quadrant D will decrease 22 million tonnes-CO_2 from scenario 1, 29 million tonnes-CO_2 from scenario 2, and 37 million tonnes-CO_2 from scenario 3.

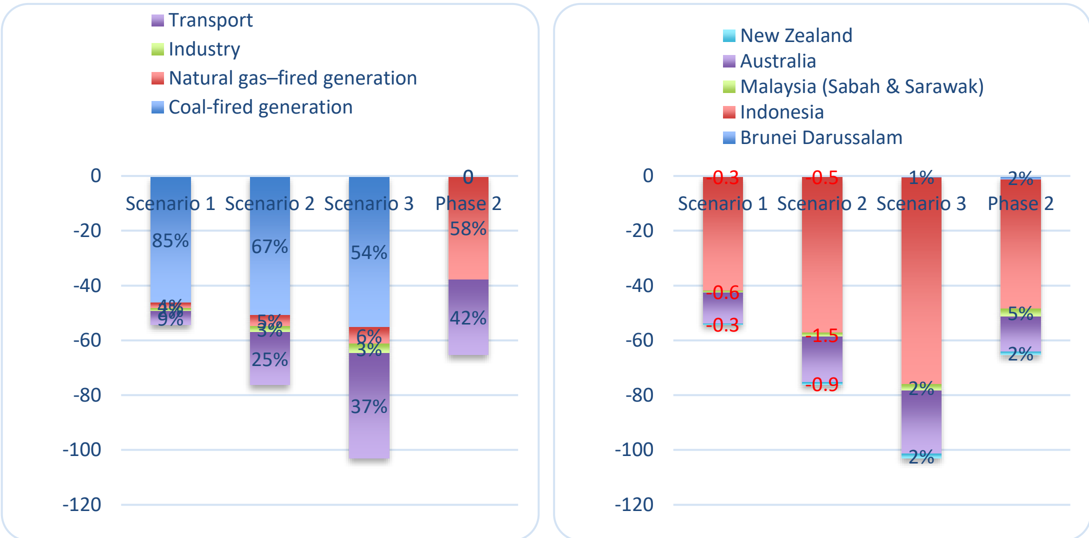
Figure 2.13: CO_2 Emission Reduction in 2040, by Quadrant

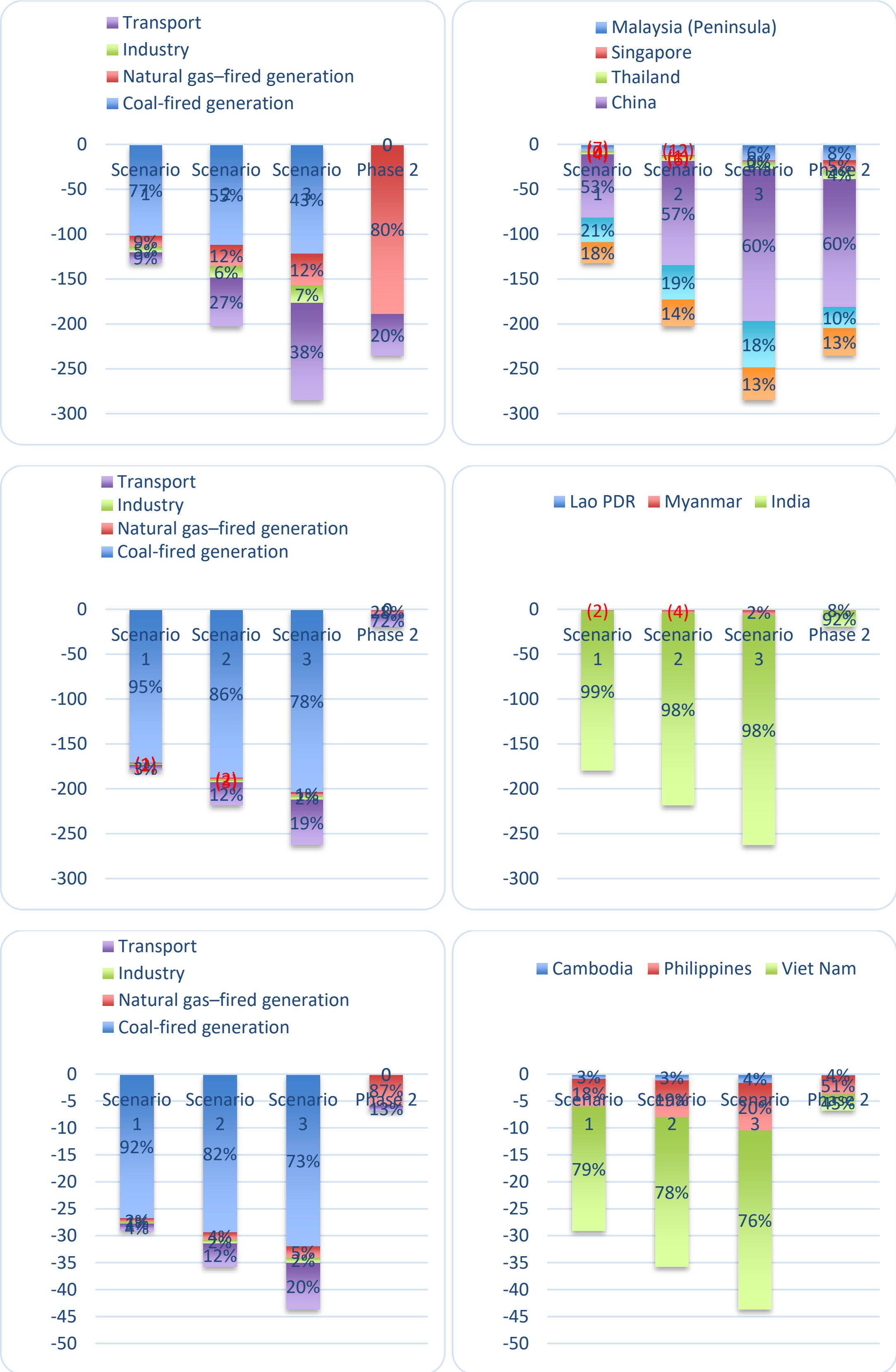


Source: Author.

Figure 2.14 shows the CO_2 emission reduction in 2040 by sector and by country.

Figure 2.14: CO_2 Emission Reduction in 2040, by Country and Sector





Source: Author.

3. Summary of Hydrogen Demand Potential

3.1. Hydrogen demand potential under the revised scenario

The scenarios estimating the hydrogen demand potential were revised from the phase 1 study by considering recent development of relevant technologies.

1) *Electricity generation sector*

At present, 30% hydrogen mix natural gas combustion in combined cycle gas turbine (CCGT) is already commercially available. Further, commercial-scale pure hydrogen CCGT is being tested. Considering these developments, the phase 2 study excluded coal electricity generation, and adopted a more ambitious target, i.e. pure hydrogen CCGT to be commercialised after 2030, and fuel switch from natural gas electricity generation. With these changes, hydrogen demand potential was greater than in the phase 1 study.

2) *Industry sector*

The industry sector was excluded in the phase 2 study.

3) *Transport sector*

Competition amongst vehicle technologies is tougher. Development and deployment of battery electric vehicles are going forward, whilst FCVs are slow due to higher technology cost. Therefore, the study team decided to revise the expectation of future deployment of FCVs. Besides, the phase 2 study excluded diesel demand for bus and railway from the subject of estimation as their hydrogen potential is negligible.

Table 2.14 shows the estimated hydrogen demand potential under the new scenarios.

Table 2.14: EAS Hydrogen Demand Potential, by Sector (Summary)

Unit: Mtoe

Sector	Phase 1			Phase 2
	Scenario 1	Scenario 2	Scenario 3	
Coal-fired generation	14	29	43	–
Natural gas–fired generation	7	13	20	101
Industry	4	8	12	–
Transport	4	15	30	11
Total	29	65	105	113

Note: Due to rounding, the sum of the sectors does not match the total.
Source: Author.

3.2. Hydrogen demand potential by country group

In phase 2, analysis was made by applying different scenarios, unique fuel switch rate, for each country group. EAS countries are classified according to their hydrogen supply cost and income level.

Table 2.15: Classification of EAS Countries, Excluding the United States (Summary)

<table>
<tr><td></td><td></td><td colspan="2">Hydrogen Supply Cost</td></tr>
<tr><td></td><td></td><td>Cheap</td><td>Expensive</td></tr>
<tr><td rowspan="2">Income Level</td><td>High</td><td>A
Brunei Darussalam
Indonesia
Malaysia (Sabah and Sarawak)
Australia
New Zealand</td><td>B
Malaysia (Peninsula)
Singapore
Thailand
China
Japan
Republic of Korea</td></tr>
<tr><td>Low</td><td>C
Lao PDR
Myanmar
India</td><td>D
Cambodia
Philippines
Viet Nam</td></tr>
</table>

EAS = East Asia Summit.
Source: Author.

The estimated result is shown in Table 2.16. It shows a large hydrogen demand potential in quadrants A and B, whilst it is small in quadrants C and D. The results come from different perspectives for future power generation mix. The hydrogen demand potential is larger for countries where a large increase of natural gas electricity generation is expected, i.e. quadrants A and B countries. In contrast, countries where increase of natural gas electricity generation is small, those in quadrants C and D have a smaller hydrogen demand potential.

Table 2.16: EAS Hydrogen Demand Potential, by Quadrant (Summary)

Unit:Mtoe

Quadrant	Phase 1			Phase 2
	Scenario 1	Scenario 2	Scenario 3	
A	4	10	16	20
B	14	31	51	86
C	9	20	32	4
D	2	4	6	3
Total	**29**	**65**	**105**	**113**

EAS = East Asia Summit.
Source: Author.

3.3. Reduction in CO_2 emission

Fuel switch to hydrogen can anticipate a reduction in CO_2 emission. Table 2.17 shows the estimates. The estimated amount of CO_2 is smaller in the phase 2 study because fuel switch from carbon-intensive coal to hydrogen, which was included in the phase 1 study, was not included in phase 2.

Table 2.17: CO_2 Emission Reduction in the EAS, by Sector (Summary)

Unit: Million tonnes-CO_2

Sector	Phase 1			Phase 2
	Scenario 1	Scenario 2	Scenario 3	
Coal-fired generation	–346	–380	–413	–
Natural gas–fired generation	–16	–31	–47	–238
Industry	–10	–19	–29	–
Transport	–23	–102	–205	–88
Total	**–395**	**–533**	**–694**	**–327**

EAS = East Asia Summit.
Note: Due to rounding, the sum of sectors does not match the total.
Source: Author.

Likewise, in the estimation results of hydrogen demand potential, reduction in CO_2 emission is larger in quadrants A and B, and smaller in quadrants C and D.

Table 2.18: Comparison CO_2 Emission Reduction in the EAS (Summary)

Unit: Million tonnes–CO_2

Quadrant	Phase 1			Phase 2
	Scenario 1	Scenario 2	Scenario 3	
A	–54	–76	–103	–65
B	–132	–202	–284	–235
C	–179	–218	–263	–19
D	–29	–36	–44	–7
Total	–395	–533	–694	–327

EAS = East Asia Summit.
Note: Due to rounding, the sum of sectors does not match the total.
Source: Author.

Chapter 3

Review of Hydrogen Transport Cost and its Perspective (Liquid Organic Hydrogen Carrier)

This chapter discusses hydrogen production and transportation cost in the global hydrogen supply chain utilising the liquid organic hydrogen carrier (LOHC) system.

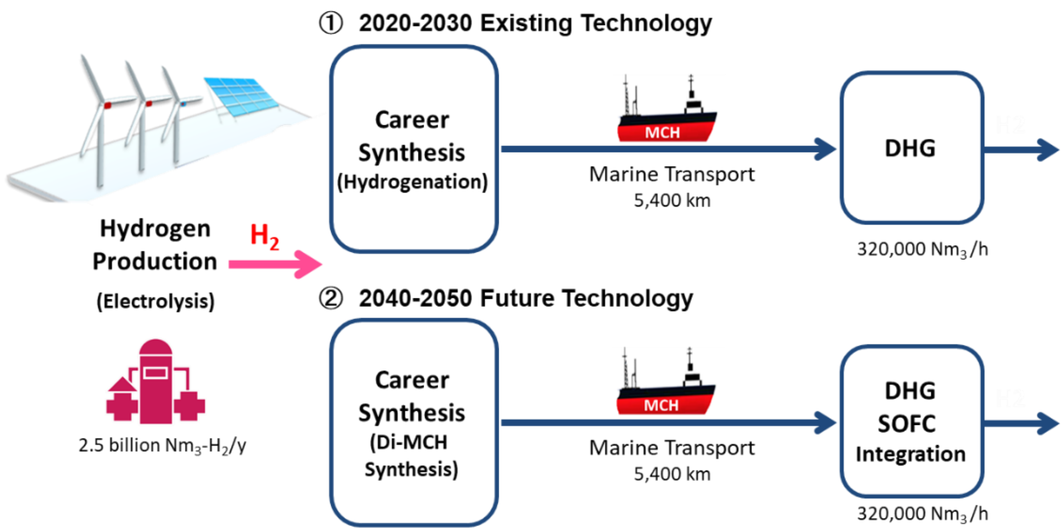
Various kinds of hydrogen carriers have been studied in LOHC system development activities so far, and this study focuses on methylcyclohexane (MCH) as a hydrogen carrier. In the MCH LOHC system, at the present status of technology, the resource hydrogen is chemically fixed to toluene in the hydrogenation reaction and converted into MCH. Then the MCH is stored and transported to hydrogen–demand countries in conventional chemical tanks and tankers in an ambient temperature and pressure, where hydrogen is extracted in dehydrogenation reaction for various uses in the industry, transport, commercial, and household sectors. This method is the combination of already proven existing technologies.

This study discusses the potential of reducing the cost of the MCH liquid organic hydrogen carrier system through future technology improvements and its impact on the overall supply chain cost.

1. Models of Global Hydrogen Supply Chain

Two global hydrogen supply chain models are proposed to compare the hydrogen costs: 2020–2030 Existing Technology model (Existing model) utilising existing technologies, and 2040–2050 Future Technology model (Future model) utilising future advanced technologies (Figure 3.1).

Figure 3.1: Models of Global Hydrogen Supply Chain



DHG = dehydrogenation, Di-MCH Synthesis = direct methylcyclohexane synthesis, SOFC = solid oxide fuel cell.
Source: Author.

The chain starts from the renewable energy power to produce resource hydrogen. The hydrogen capacity is set at 320,000 Nm3/h H2, which corresponds to 2.5 billion Nm3/y H2; transportation distance is assumed to be 5,400 km in both models. The advanced technologies employed for the Future model are listed as follows.

Future technologies:

- ✓ Process simplification, such as MCH direct synthesis (Tokyo University, 2019), employed as a substitute for the combination of electrolysis and hydrogenation (HGN)
- ✓ Transportation efficiency Improvement utilising Super Eco Ship (NYK)
- ✓ Energy efficiency improvement of dehydrogenation by catalyst performance increase
- ✓ Heat integration optimisation using SOFC exhaust gas to dehydrogenation heat

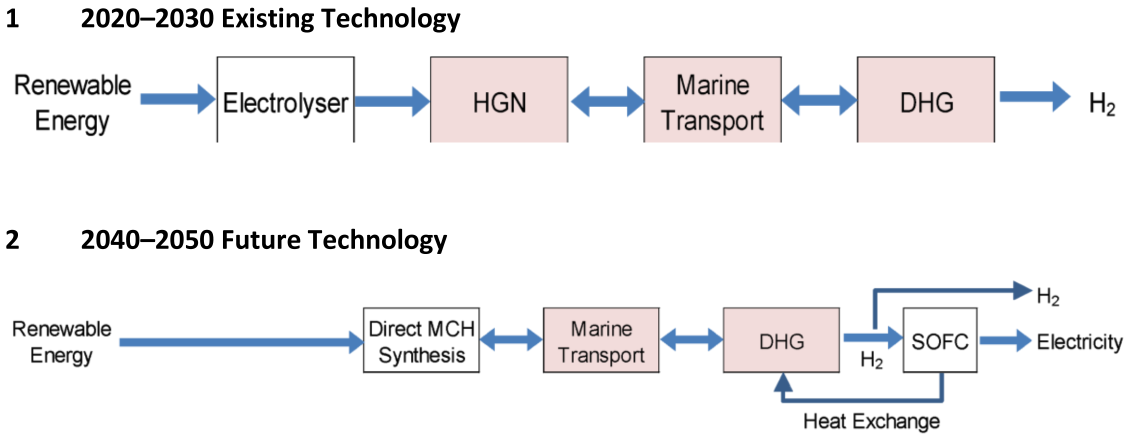
2. Key Assumptions

The block flows of two supply chain models are illustrated in Figure 3.2 and the key assumptions are shown in Table 3.1 to estimate the hydrogen supply chain cost in both models.

In the 2020–2030 Existing Technology model (Existing model), hydrogen is produced from renewable power by polymer electrode membrane (PEM) electrolysis and chemically fixed to toluene in the hydrogenation reaction. Then the produced MCH is transported by sea through conventional chemical tankers to hydrogen-demand countries. The hydrogen is extracted from the MCH by dehydrogenation reaction.

In the 2040–2050 Future Technology model (Future model), renewable power will directly synthesise MCH from toluene and water and MCH will be transported by the Super Eco Ships to hydrogen-demand countries, where hydrogen will be extracted in the dehydrogenation reaction to be fuelled for solid oxide fuel cell (SOFC) power generation. SOFC exhaust heat will also be used for dehydrogenation reaction to further reduce costs.

Figure 3.2. Block Flows for Two Supply Chain Models



HGN = hydrogenation, DHG = dehydrogenation, SOFC = solid oxide fuel cell.
Source: Author.

Table 3.1: Key Assumptions for Cost Calculation

Contents	① Existing Technology	② Future Technology
Renewable energy	Capacity factor 70% (Hybrid of wind and solar power + battery) (Steggel et al., 2018)	
Hydrogen capacity	2.5 billion Nm3 /y Hydrogen	
Hydrogen production	PEM water electrolysis Efficiency: 5.0 kWh/Nm3 (Element energy 2018)	—
Carrier synthesis	Hydrogenation	Direct MCH synthesis
Marine transport	5,400 km Chemical tanker	5,400 km Super Eco Ship (NYK)
Hydrogen extraction	Dehydrogenation	
Heat integration	—	SOFC exhaust gas for dehydrogenation SOFC efficiency: 50% (Mizutani, 2019)
Commercial conditions	Project period: 20 years Full equity base	

MCH = methylcyclohexane, PEM = polymer electrode membrane, SOFC = solid oxide fuel cell.
Source: Author.

3. Global Hydrogen Supply Chain Cost

The global hydrogen supply chain costs are compared between the Existing and Future models.

Because of improvements in catalyst performance, such as impurity reduction and longevity extension, and heat integration of SOFC exhaust gas to dehydrogenation reaction, the cost of dehydrogenation could be reduced by nearly 40% in 2040–2050.

The use of the Super Eco Ship (NYK) could also contribute to reduce the cost of marine transport by nearly 10%.

The cost reduction effect of the simplification process in carrier synthesis and employment of MCH direct synthesis to substitute for electrolysis and hydrogenation will vary depending on electricity prices.

3.1. Hydrogen cost comparison (electricity US$0.05/kWh)

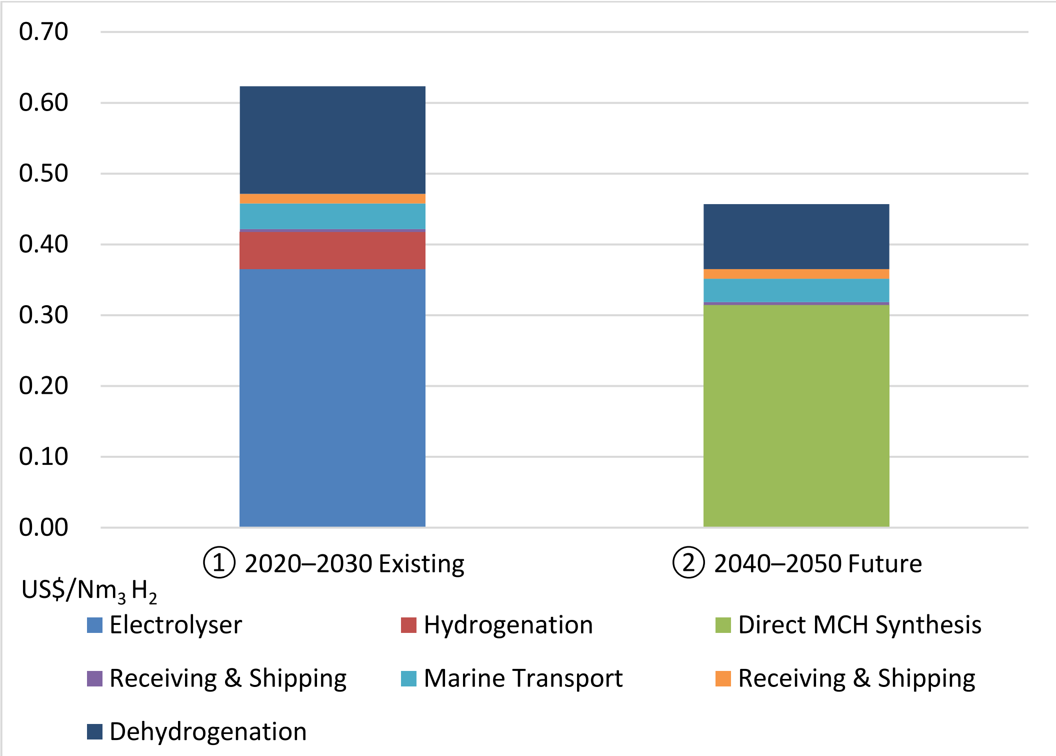
The cost projection results between the Existing and Future models were compared. At the electricity price of US$0.05/kWh, the hydrogen price in 2040–2050 is estimated to be reduced by around 25%, compared to US$0.62/Nm3 in 2020–2030.

Due to the high electricity price for electrolysis, carrier synthesis, PEM electrolysis plus hydrogenation or direct MCH synthesis account for nearly 70% of the hydrogen costs in both models.

In the Future model, the cost of direct MCH synthesis accounts for around 70% of the total, followed by dehydrogenation at 20%, and marine transportation, 7%.

The cost of carrier synthesis is projected to be reduced by 25% in the Future model, compared to the Existing model.

Figure 3.3: Hydrogen Cost Comparison (Distance: 5,400 km; Electricity US$0.05/kWh)



Note: The data ① were customised based on Institute of Applied Energy (2016).
Source: Authors' analysis based on Institute of Applied Energy (IAE) Report.

3.2. Hydrogen cost comparison (electricity US$0.03/kWh)

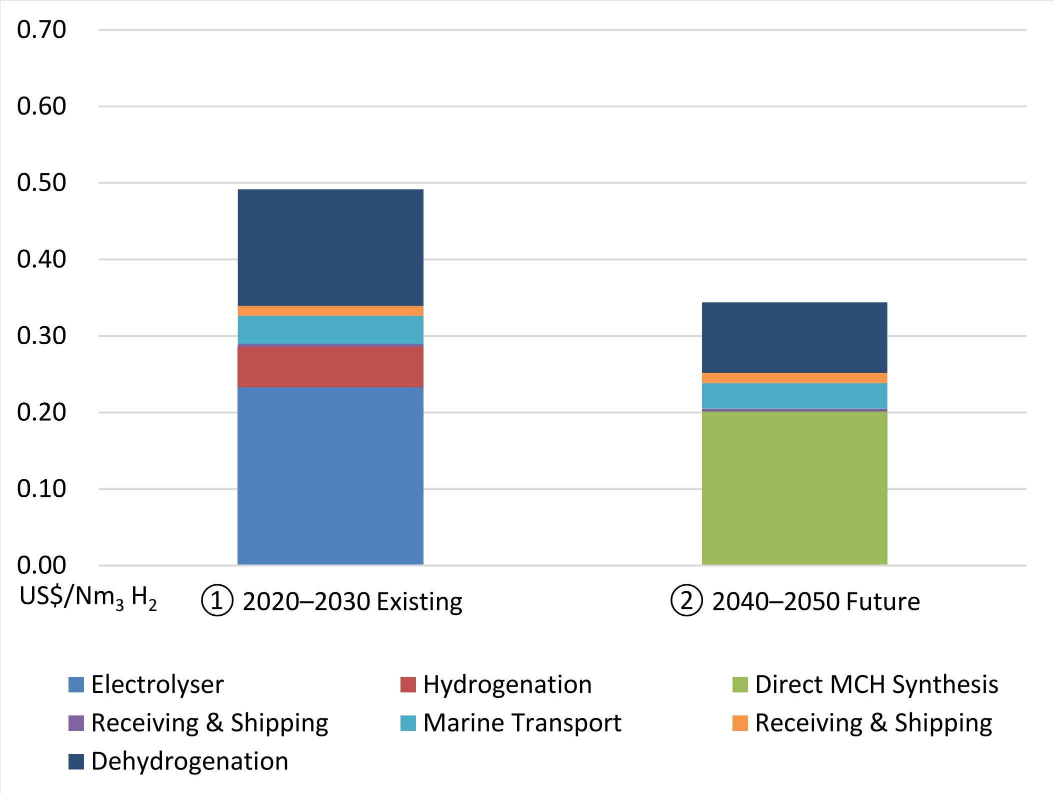
At the electricity price of US$0.03/kWh, the hydrogen price is projected to be reduced by nearly 30% by 2040–2050 compared to US$0.49/Nm3 in 2020–2030.

Carrier synthesis, PEM electrolysis + hydrogenation or direct MCH synthesis, account for nearly 60% of the hydrogen costs in both models.

The same as the electricity price of US$0.05/kWh case, direct MCH synthesis shares the largest part of the supply chain costs, accounting for around 60%, followed by dehydrogenation at 27%, and marine transport at 10% in the Future model.

The cost of carrier synthesis is projected to be reduced by around 70% in 2040–2050, compared to that of the Existing model.

Figure 3.4: Hydrogen Cost Comparison (Distance: 5,400 km; Electricity US$0.03/kWh)



Note: The data ① were customised based on Institute of Applied Energy (2016).
Source: Authors' analysis based on Institute of Applied Energy (IAE) Report.

3.3. Hydrogen cost comparison (electricity at US$0.01/kWh)

At the electricity price of US$0.01/kWh, the hydrogen cost will be significantly reduced due to the low electricity prices in both models.

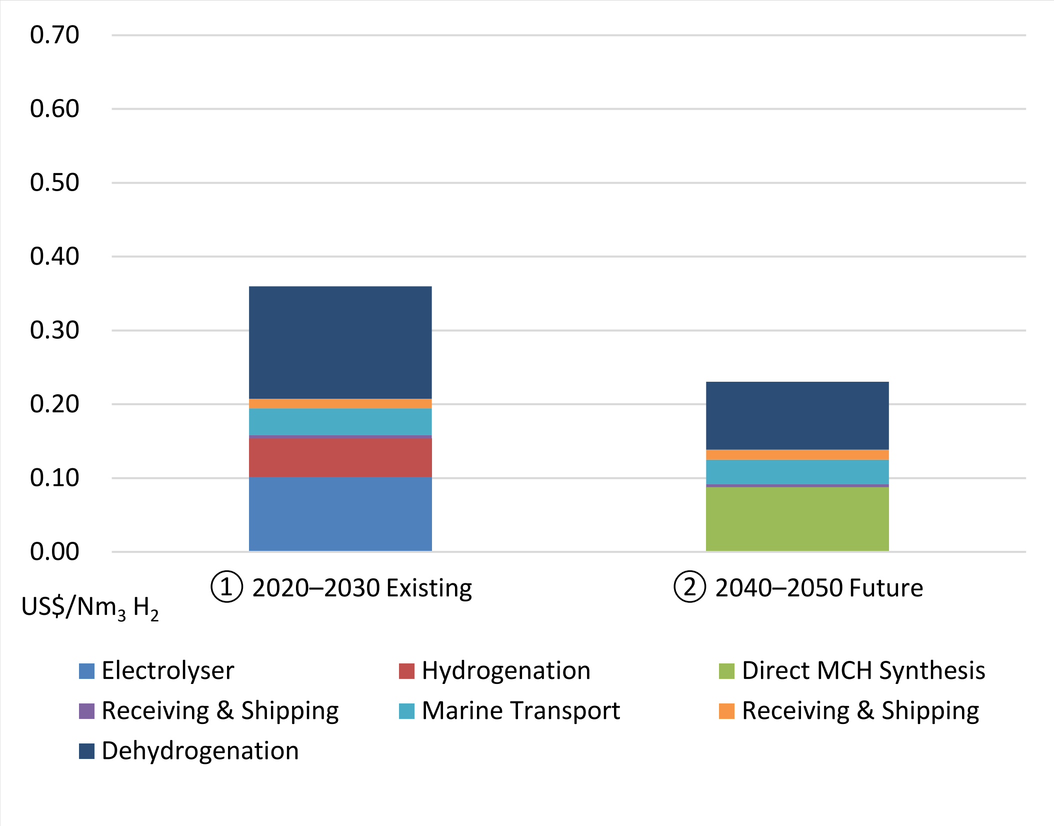
In the Future model, the supply chain cost could be reduced to around US$0.23/Nm3, nearly a 35% reduction from that of the Existing model.

Thanks to the low electricity prices, cost sharing of carrier synthesis in the total supply chain costs will be largely reduced in both models in this electricity price level, accounting for around 40%.

In the Future model, unlike the previous two electricity price cases, dehydrogenation shares the largest portion of the costs, accounting for 40%, followed by direct MCH synthesis at 38%, and marine transport at 14%.

The cost of carrier synthesis will be reduced by around 40% in 2040–2050 compared to that of the Existing model.

Figure 3.5: Hydrogen Cost Comparison (Distance: 5,400 km; Electricity at US$0.01/kWh)



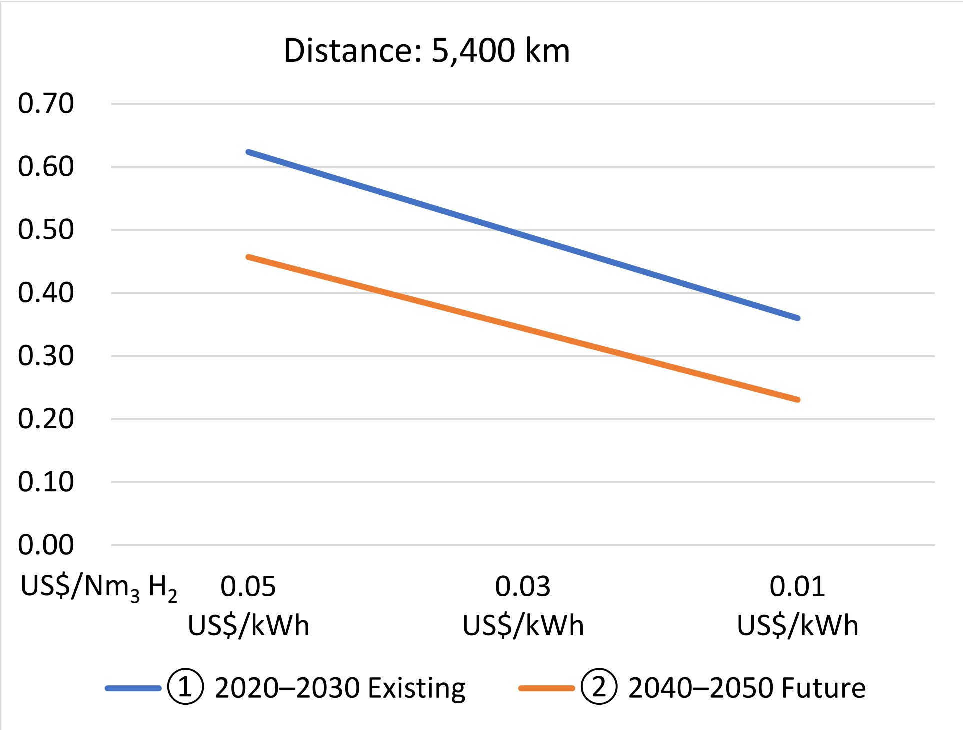
Note: The data ① were customised based on Institute of Applied Energy (2016).
Source: Authors' analysis based on Institute of Applied Energy (IAE) Report.

3.4. Sensitivity analysis

Sensitivity analysis is performed on hydrogen supply chain cost based on electricity prices. As illustrated so far, the hydrogen costs will be highly dependent on electricity prices. As the electricity prices decrease from US$0.05/kWh to US$0.01/kWh, the hydrogen costs are reduced by around 50% in both models.

The hydrogen cost is estimated to reach around US$0.62/Nm3 at US$0.05/kWh in the Existing model at its highest, and US$0.23/Nm3 at US$0.01/kWh in the Future model at its lowest. It shows an almost 60% reduction of the overall supply chain cost.

Figure 3.6: Sensitivity to Electricity Prices



Note: The data ① were customised based on Institute of Applied Energy (2016).
Source: Author (2020).

4. Conclusion

This section investigated the global hydrogen supply chain cost of two models, the 2020–2030 Existing Technology model (Existing model) and the 2040–2050 Future Technology model (Future model).

The study showed that the total hydrogen supply chain cost could be reduced by around 20%–30% broadly owing to future technology improvements, like MCH direct synthesis, catalyst performance upgrades, and heat integration of SOFC exhaust gas to dehydrogenation reaction.

At the electricity price of US$0.01/kWh in the Future model, hydrogen supply cost will be most competitive at US$0.24/Nm3. At the electricity price of US$0.05/kWh in the Existing model, hydrogen supply cost is highest at US$0.60/Nm3.

From the study, we can conclude that, starting from renewable power–derived hydrogen, the hydrogen supply chain cost is highly dependent on electricity prices in hydrogen-supplier countries. Electricity prices directly influence the cost of carrier synthesis in both models, the PEM electrolysis plus hydrogenation in the Existing model, or direct MCH synthesis in the Future model, and the prices significantly impact the overall supply chain costs.

Chapter 4

Review of Hydrogen Transport Cost and its Perspective (Liquefied Hydrogen)

1. Introduction

In Japan, CO_2-free hydrogen energy has been gaining momentum since the endorsement of the government's 4th Strategic Energy Plan in 2014, which identified hydrogen as an important energy solution of the future.

Kawasaki Heavy Industries, Ltd. is developing world-leading technologies to realise the hydrogen society. These include the liquefier, the storage tank, the supply systems, the liquefied hydrogen carrier ships, and the hydrogen gas turbines. Kawasaki can contribute to decarbonisation by promoting international hydrogen supply chains through hydrogen-related technologies.

2. Liquefied Hydrogen Supply Chain for Decarbonisation

2.1. The concept of liquefied hydrogen supply chain

The conceptual diagram of the liquefied hydrogen energy supply chain by Kawasaki is shown in Figure 4.1. Kawasaki plans to produce hydrogen overseas from affordable resources and bring liquefied hydrogen to Japan. This scheme of hydrogen supply chain is very similar to that of the liquefied natural gas (LNG) supply chain.

Due to the method of producing hydrogen, we can promote a CO_2-free hydrogen supply chain worldwide. We are looking for a suitable place to produce hydrogen reasonably from fossil fuel with carbon capture utilisation and storage (CCUS) and renewable energy such as solar, wind, or hydropower (Figure 4.2.).

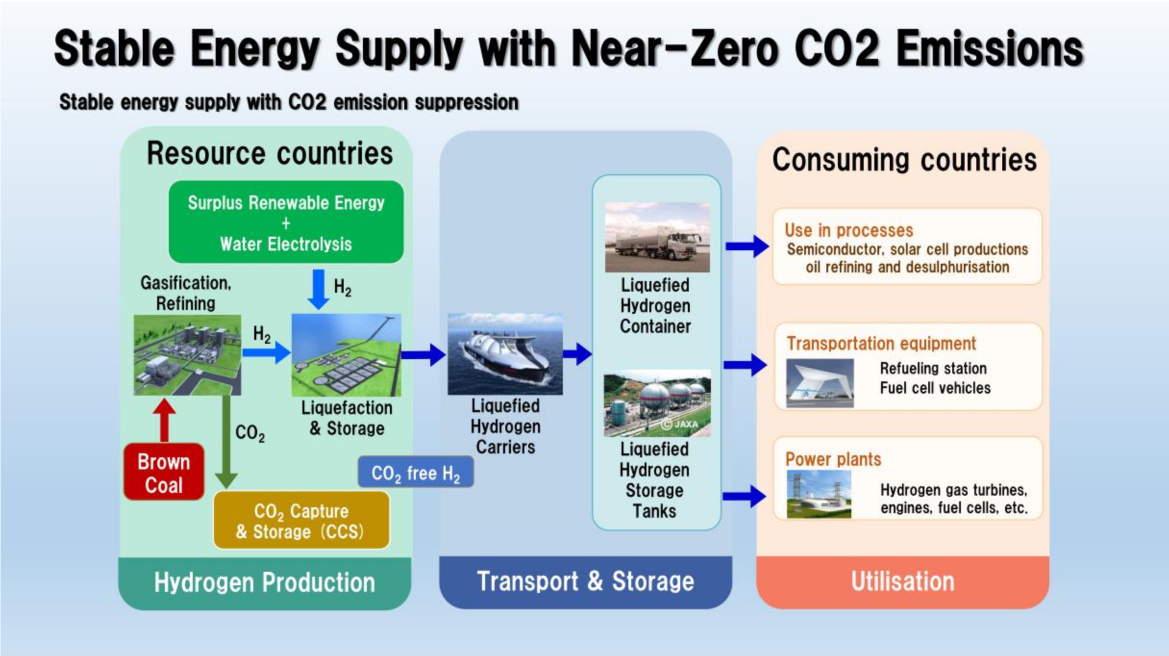
To transport and store hydrogen efficiently, the produced hydrogen gas will be liquefied. The liquefied hydrogen will then be loaded in special liquid hydrogen carrier ships and transported to Japan.

Hydrogen is used for various purposes like feedstock, fuel cell vehicles (FCVs), distributed power and heat generation, and large utility power generation. Regarding the amount of consumption, a hydrogen power station with a capacity of approximately 1 GW consumes 220,000 tonnes of hydrogen in a year. This is equivalent to the total annual fuel for 3 million FCVs.

By realising a large-scale CO_2-free hydrogen supply chain, hydrogen cost will decrease and become competitive. This can promote the deployment of FCVs, hydrogen stations, and other hydrogen-energised equipment. We believe this large-scale supply chain will accelerate the realisation of the hydrogen economy and sustainable future.

Figure 4.1: Conceptual Diagram of the Hydrogen Energy Supply Chain

by Kawasaki Heavy Industries, Ltd



Source: Author.

Figure 4.2: Expected CO_2-Free H2 Supply Chain

Source: Author.

2.2. Advantages of liquefied hydrogen carriers

The advantages of liquefied hydrogen carriers are shown in Figure 4.3. The volume of liquefied hydrogen is 1/800 that of gaseous hydrogen. Therefore, liquefied hydrogen is suitable for transporting a large amount of hydrogen overseas with high efficiency.

Liquefied hydrogen has a purity of 99.999% or higher and can be directly supplied to fuel cells only by evaporating it without refining, which needs domestic energy.

When hydrogen is burned, only water, and not CO_2, is emitted. Therefore, the use of hydrogen can contribute to environmental measures.

Hydrogen is also not toxic and has no greenhouse effect; thus, an excellent substance in terms of health and safety.

The scheme of liquid hydrogen supply chain is like that of the supply chain of liquefied natural gas (LNG). LNG, which is currently distributed all over the world, was once very expensive. However, as years pass and the volume of distribution increases, it has become relatively affordable energy. Therefore, hydrogen can potentially and significantly decrease the cost in the future. Those are the reasons we chose liquid hydrogen as a carrier.

Figure 4.3: Advantages of Liquefied Hydrogen Carrier

Source: Author.

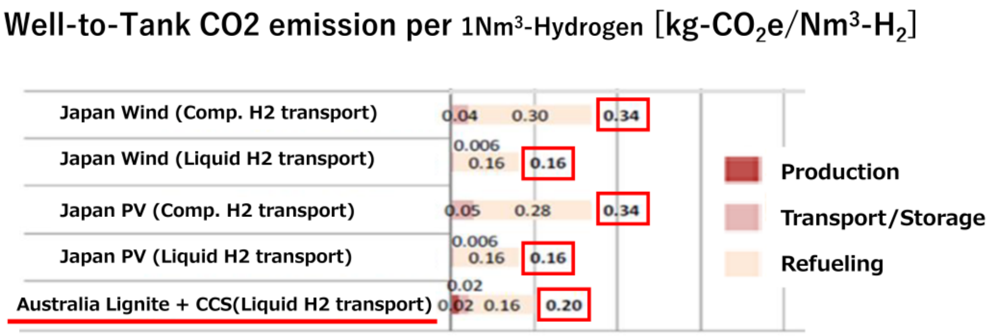
2.3. Life-cycle analysis of liquefied hydrogen supply chain

Figure 4.4 shows the life-cycle analysis (LCA) conducted by the Mizuho Information & Research Institute, Inc.[2] This shows well-to-tank CO_2 emissions in each process of hydrogen production, which uses renewable energy and brown coal (lignite).

CO_2 emissions from liquefied hydrogen produced by brown coal with carbon capture and storage (CCS) are at the same level as the one from renewable energy–derived hydrogen.

Especially when hydrogen is carried by a liquefied hydrogen carrier ship, boiled-off hydrogen gas can be used as a fuel to propel the ship. This technology has already been adapted to the LNG carrier. Therefore, unlike other carriers, the liquefied hydrogen supply chain is a completely CO_2-free supply chain, including the transport process.

Figure 4.4: Life-Cycle Analysis Conducted by Mizuho Information & Research Institute



Source: Mizuho Information & Research Institute, Inc. (2016).

3. Overview of Hydrogen Energy Supply Chain Pilot Project between Australia and Japan

Together with our private and public sector partners, we launched the world's first pilot demonstration project regarding liquefied hydrogen energy supply chain between Australia and Japan. Under this flagship initiative, we will establish an integrated supply chain for CO_2-free hydrogen produced from Australian brown coal to be exported to Japan (Nishimura et al., 2015). The governments of Japan, Australia, and Victoria State have invested in the project alongside a consortium of reputable private sector companies.

In 2020–2021, this pilot project will demonstrate brown coal gasification and hydrogen purification at Latrobe Valley in Australia, hydrogen liquefaction and storage of liquefied hydrogen at Hastings, marine transportation of liquefied hydrogen from Australia to Japan, and unloading of liquefied hydrogen in Japan (Takaoka et al., 2017).

About half of the world's total coal resources is brown coal. However, it is relatively bulky and has low calorie due to its extremely high moisture content. As it runs the risk of igniting spontaneously upon contact with air when it is dried, it is not suitable for transportation and

[2] https://www.mizuho-ir.co.jp/publication/report/2016/pdf/wttghg1612.pdf (in Japanese).

storage in its raw form. Thus, it is limited to local use; there is no international market for brown coal.

We can mass-produce affordable and CO_2-free hydrogen from this unused resource.

Diverting the existing technologies to construct LNG marine carriers for land transport and for the storage of liquefied hydrogen, Kawasaki developed a world's-first cargo containment system for liquefied hydrogen transportation on a marine carrier. The liquefied hydrogen carrier ship cruises around 9,000 km (Takaoka et al., 2019).

This is the first new energy terminal in Japan. The pilot project site is located on a 10,000 m^2 area of land in the northeast section of Kobe Airport Island in the Port of Kobe, where the liquefied hydrogen storage tank and unloading facilities are built. The loading arm system unloads the liquefied hydrogen from the carrier into an on-land liquefied hydrogen storage tank, whilst maintaining a temperature of –253℃.

3.1. Structure of the Australia pilot demonstration

The structure of this pilot demonstration project is shown in Figure 4.5. This pilot project has two portions. One is the portion of the New Energy and Industrial Technology Development Organization (NEDO) (two blue frames) and the other is the Australian portion (orange frame). The NEDO portion covers the gasification in Australia, the hydrogen carrier, and the unloading terminal in Japan.

This portion is supported by NEDO and is performed by HySTRA (CO_2-free Hydrogen Energy Supply-Chain Technology Research Association). HySTRA aims to establish and demonstrate technologies, which are hydrogen production, oversea transport, and unloading. HySTRA comprises the following seven companies: J-Power, Kawasaki, Iwatani, Shell Japan, Marubeni, JXTG Nippon Oil & Energy, and Kawasaki Kisen.

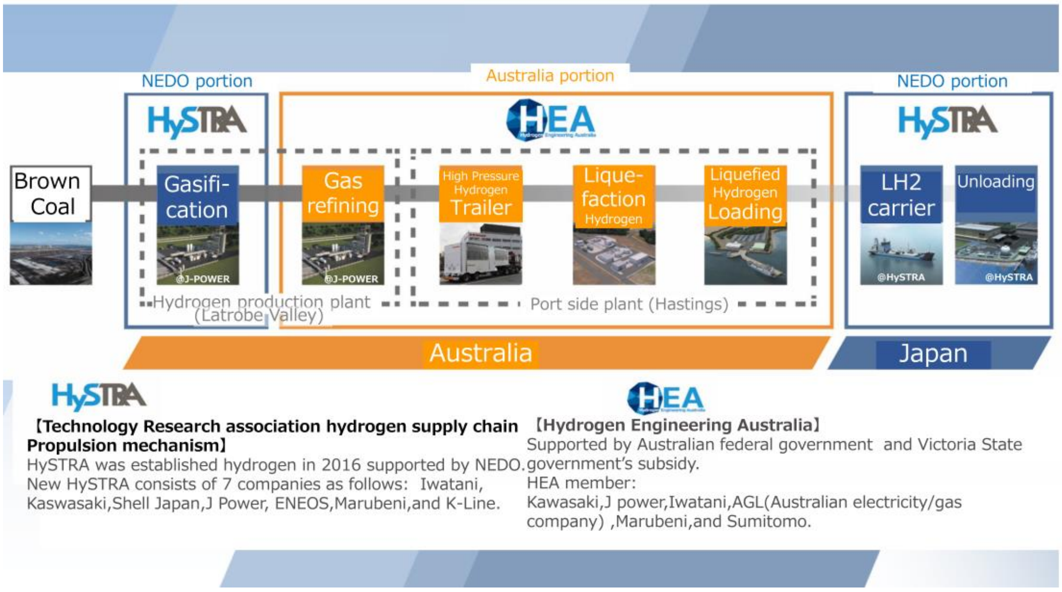
J-Power, which is currently developing an integrated coal gasification combined cycle (IGCC) system, will demonstrate technology for the gasification of brown coal. Kawasaki, Iwatani, and Shell Japan will work together to demonstrate technology for long-range mass transport and cargo handling of liquefied hydrogen.

Kawasaki, which has the cryogenic technology for LNG storage tanks and the receiving terminals as well as equipment for the rocket launch complex on Tanegashima, will build the pilot carrier ship for liquefied hydrogen and construct the unloading terminal. Meanwhile, Iwatani, which is Japan's only producer and supplier of liquefied hydrogen, will operate this loading–unloading terminal for demonstration tests. Shell Japan, a subsidiary of Royal Dutch Shell experienced with LNG supply chains and carrier operation, will operate the liquefied hydrogen carrier ship.

Marubeni and JXTG Nippon Oil & Energy are exploring the commercialisation of CO_2-free hydrogen energy supply chain technology. Kawasaki Kisen assists in the safe transport of liquefied hydrogen.

On the other hand, the scope of the Australian portion is gas purification, hydrogen liquefaction, and the loading terminal for the hydrogen energy supply chain pilot project. Those are being delivered by a consortium of the top energy and infrastructure-related companies of Japan and Australia, with the full support of the Victoria state government and the Australia federal government. Together with Kawasaki and Hydrogen Engineering Australia, the consortium partners include J-Power, JPLV (J-Power Latrobe Valley Pty Ltd), Iwatani, Marubeni, Sumitomo, and AGL.

Figure 4.5: Structure of Technology Pilot Demonstration in Australia

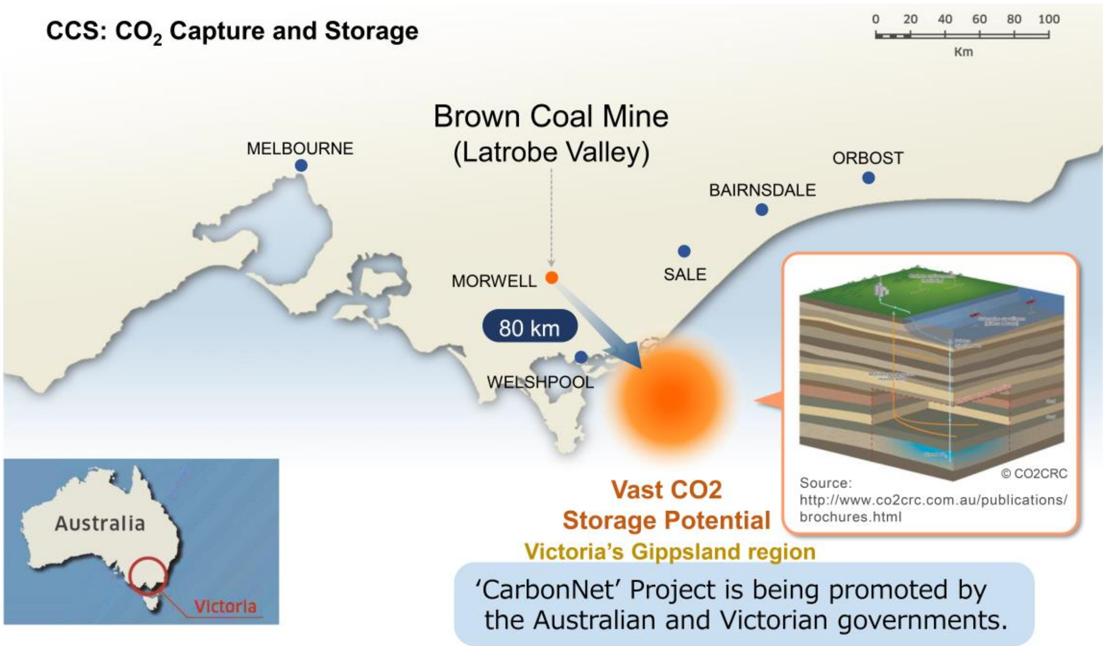


Source: Author.

CCS is an extremely important technology in producing CO_2-free hydrogen. By-produced CO_2 must be captured and sequestered into the aquifer or depleted gas and oil fields under the seafloor. Australia is one of the most advanced countries in terms of CCS (Figure 4.6).

CarbonNet, the famous CCS project, has been promoted jointly by the Australia federal and Victoria state governments. Our project is collaborating with this CarbonNet project.

Figure 4.6: Location of Hydrogen Gas Production Plant and CCS



CCS = carbon dioxide capture and storage.
Source: Author.

3.2. Explanation of each process

3.2.1. Brown Coal (Feed)

Brown coal is an abundant unused resource lying under the earth's surface. However, it contains a large amount of moisture, around 50% water and volatile matter. It easily ignites when dried.

Unlike usual coal, brown coal is difficult to use at a remote place, resulting in its cheaper price; it is also not internationally traded. Additionally, we recognise that hydrogen production using brown coal is one of the most reasonable production methods.

As shown in Figure 4.7, Latrobe Valley, Australia has a huge amount of brown coal. Brown coal layer spreads to the horizon. One-layer thickness is up to 250 metres below the surface. The hydrogen produced from all brown coal in Latrobe Valley is equivalent to Japan's total electrical energy generation for 240 years.

Figure 4.7: Brown Coal Mine

3.2.2. Hydrogen Production Plant for Brown Coal

A. Gasification facility

Brown coal gasification to produce hydrogen will take place at the AGL Loy Yang Complex in the Latrobe Valley. The coal is reacted with oxygen under high pressure and temperature to produce a syngas that consists of carbon monoxide and hydrogen mainly.

During gas purification, the carbon monoxide (CO) is converted to CO_2 using steam, and the hydrogen is separated. In this project, we selected an entrained bed gasification that has a high energy efficiency, has a lot of commercial results, and can easily increase its capacity.

Brown coal has high moisture content and unstable qualities. Therefore, the gasification process needs to resolve various technological hurdles to realise mass production in the future (Figure 4.8).

B.   Gas purification facility

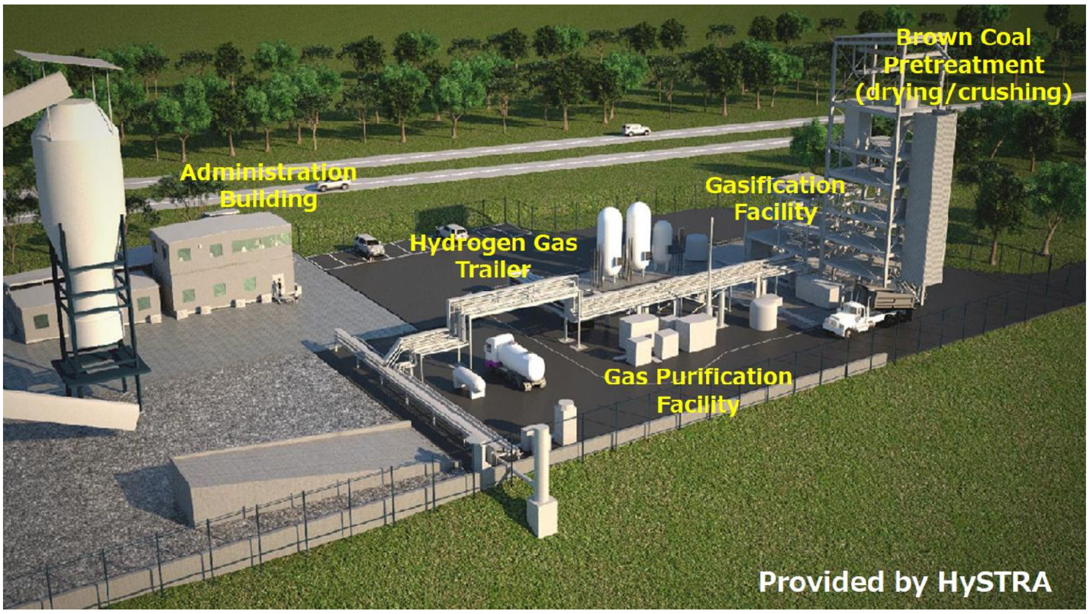
The gas purification facility has two types of treatments on the synthesis gas containing hydrogen, CO, CO_2, and water as the main components, which are produced in the brown coal gasification furnace in the upstream process.

One is a process of increasing the concentration of hydrogen in the synthesis gas by converting CO in the synthesis gas into CO_2 by a water gas shift reaction.

The second is a process in which hydrogen and CO_2 are separated and recovered from the product gas after the shift reaction, and hydrogen is transferred to a hydrogen liquefaction process via a hydrogen pipeline and CO_2 is transferred to a storage process (CarbonNet) via a pipeline.

During extraction of hydrogen from the product gas, it is possible to separate and capture CO_2. This will reduce greenhouse gas (GHG) emissions, despite the energy being derived from fossil fuels.

Figure 4.8: Hydrogen Production Plant for Brown Coal (Latrobe Valley/Image CG Diagram)



3.2.3. Liquefaction/Loading Facility

There are several carriers to efficiently transport the produced hydrogen, such as compressed gas, organic hydride, ammonia, or methane. In this project, we decided that mass transport by liquefied hydrogen has the most potential in decreasing CO_2 emission and, thus, adopt it.

Cooling hydrogen to –253℃ or below turns it from gaseous to liquid state and reduces its volume by 1/800. Such reduction in volume allows for more efficient transport and distribution of more hydrogen.

Kawasaki has already succeeded, and is the first Japanese company, to develop the liquefier in its factory (Figure 4.9).

Kawasaki needs high machinery technology to develop the expansion turbines to keep super high-speed rotation (>100,000 rpm) stable. Kawasaki can diversify this technology from the motorcycle super charger system and the gas turbine system.

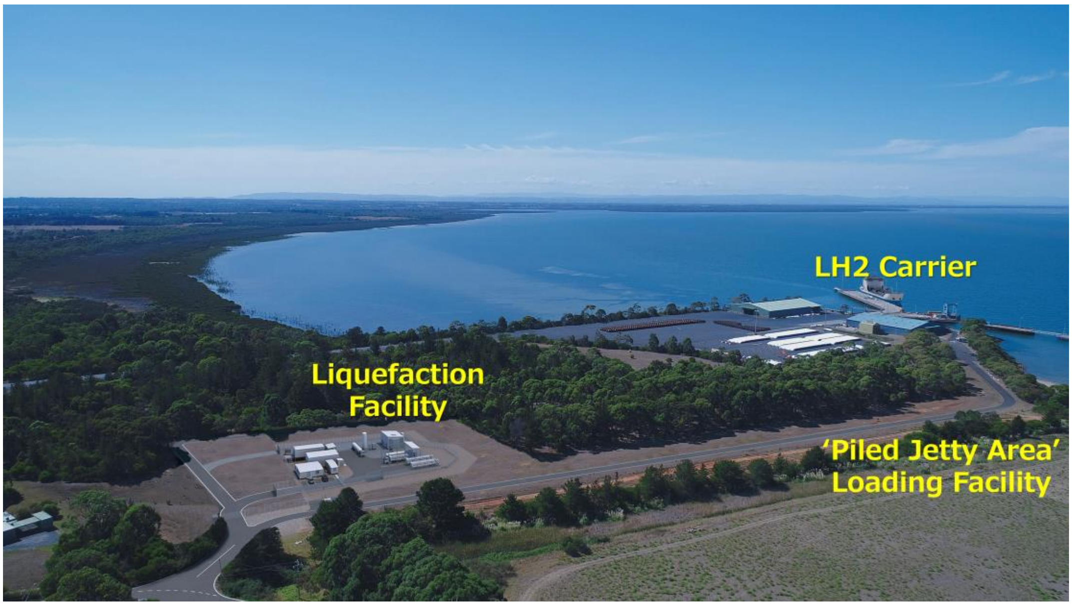
There are many large-scale and high-efficiency facilities in the natural gas liquefaction field. However, the capacity of the hydrogen liquefaction plant is about 5–30 tonnes per day, and the issue is to increase the capacity and improve efficiency.

As shown in Figures 4.10, 4.11, and 4.12, we are constructing a hydrogen liquefaction/loading base in Hastings to be completed in FY2020.

Figure 4.9: Hydrogen Liquefaction Plant in the Harima Factory

Source: Author.

Figure 4.10: Hydrogen Liquefaction/Loading Facility (Hastings/Image CG Diagram)



Source: Author.

Figure 4.11: Overview of Hydrogen Liquefaction/Loading Base Construction (Hastings) in April 2020

Note: The final stage of construction work was aimed to be completed in autumn 2020 and demonstration operation in the second half of FY2020.
Source: Author.

Figure 4.12: Status of Hydrogen Liquefaction/Loading Base Construction (Hastings/Photo) in February 2020

Note: Tree felling and levelling in the main area of the base started on 6 June 2019; underground pipe laying and foundation work are currently under way.
Source: Author.

3.2.4. Liquefied Hydrogen Carrier Ship

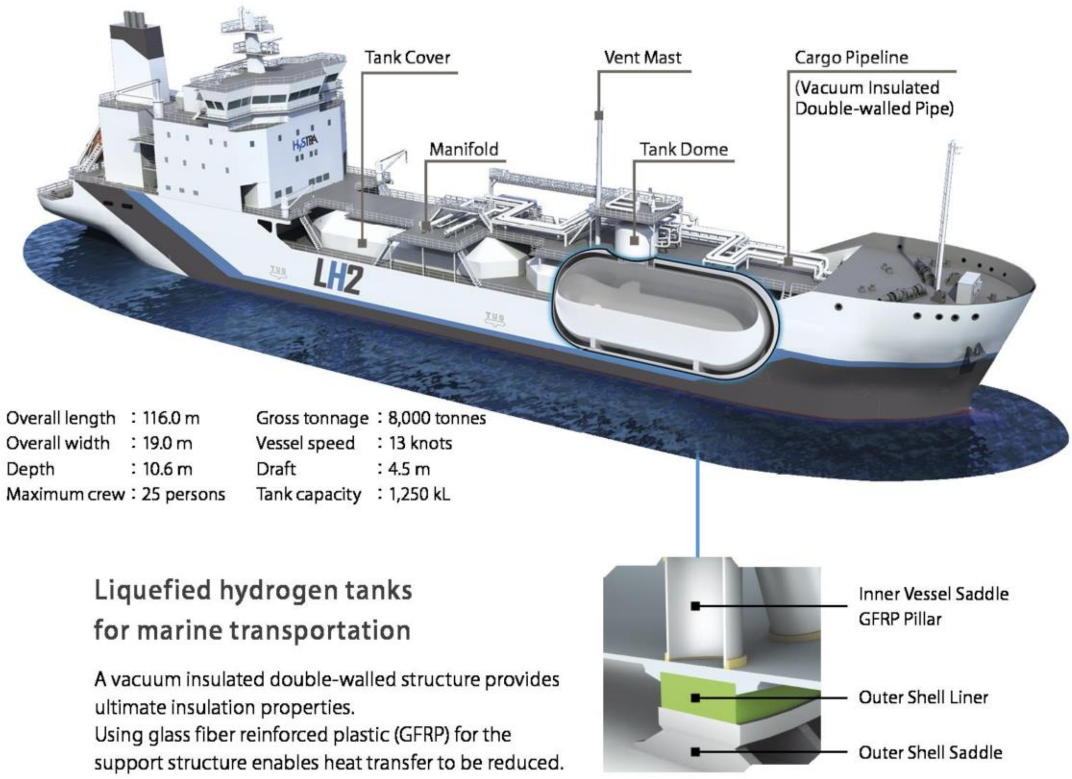
The liquefied hydrogen carrier ship transports produced and liquefied hydrogen by sea from a resource country to Japan, which is a consuming country. Liquefied hydrogen is very convenient for transporting large amounts of hydrogen. Through proven technologies to construct LNG marine carriers, transport by land, and store liquefied hydrogen, Kawasaki developed a new cargo containment system with cryogenic technology to transport liquefied hydrogen in a marine carrier.

Up to now, the operational performance of large liquefied hydrogen transport tanks is unprecedented in the world. For the first time, Kawasaki succeeded in having the International Maritime Organization Maritime Safety Committee approve and recommend the offshore carriage of liquefied hydrogen in bulk.

Figure 4.13 shows a liquefied hydrogen carrier ship now being constructed for pilot demonstration. Installed is a 1,250 m^3 liquefied hydrogen storage tank. Liquefied hydrogen loading weight is 75 tonnes at one time.

This time Kawasaki adapted the proven electric propulsion system using the diesel generator to focus on the demonstration of cargo containment system for liquefied hydrogen. Kawasaki plans to use boil-off gas (BOG) as a propulsion fuel at the start of commercial operation. This utilisation BOG system is adapted to the LNG carrier ship and can contribute to decreased CO_2 emission for marine transport when adapted to the LH2 carrier ship.

Figure 4.13: Outline of Pilot LH2 Carrier Ship



Source: HySTRA.

Kawasaki launched the ship on 11 December 2019 at the Kobe Factory, one of its shipbuilding yards in Japan (Figure 4.14). The ship, called the Suiso Frontier, is owned by CO_2-free Hydrogen Energy Supply-Chain Technology Research Association (HySTRA).

Kawasaki will finish the outfitting of a liquefied hydrogen carrier ship by mid-2020. During commercialisation, Kawasaki is planning to ship 160,000 m^3 liquefied hydrogen, just like an LNG ship, around 10,000 tonnes at a time.

Figure 4.14: Pilot LH2 Carrier, Cargo Containment System Construction Status (Kawasaki Factory)

Source: Author.

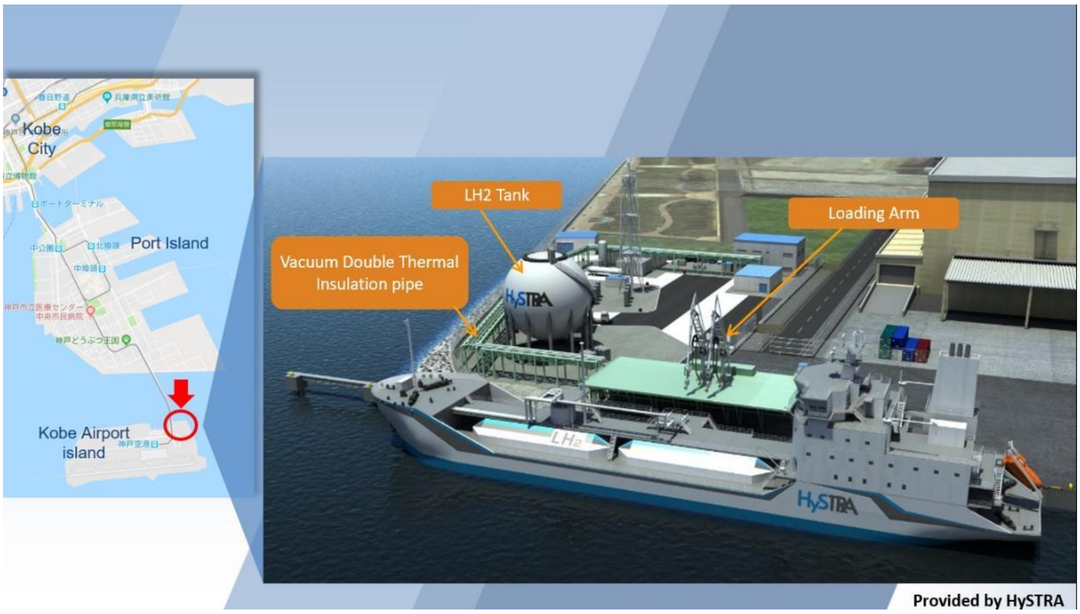
3.2.5. Storage and Unloading Facility

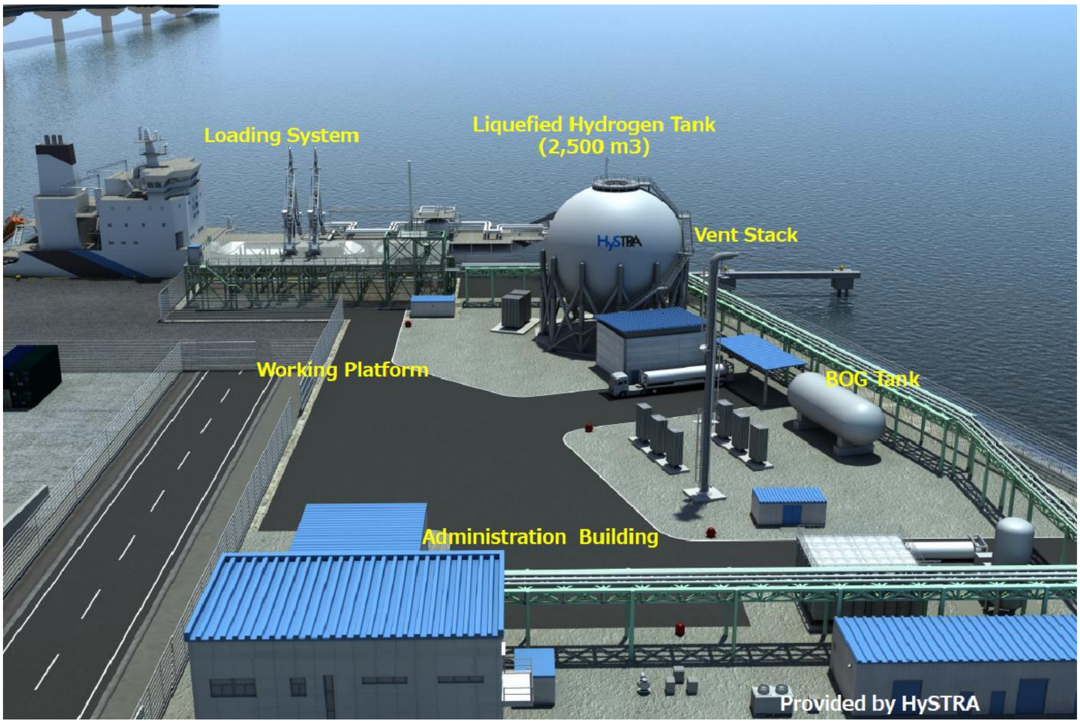
The liquefied hydrogen carrier arrives at the unloading terminal after a journey of around 9,000 km. A loading arm system unloads the hydrogen from the carrier ship into an on-land liquefied hydrogen storage tank, whilst maintaining a temperature of –253℃.

This is the first new energy terminal in Japan. This liquefied hydrogen cargo terminal will be installed in Kobe Airport Island (Figures 4.15 and 4.16).

There, several equipment and facilities such as a liquefied hydrogen tank (2,500 m^3), unloading system for liquefied hydrogen, BOG holder, and others are being constructed. All are cutting-edge facilities and will be completed by 2020.

Figure 4.15: Liquefied Hydrogen Cargo Loading Base in Kobe Airport Island (CG View)





BOG = boil off-gas.

Figure 4.16: Status of Construction of LH2 Cargo Loading Base (Kobe Airport Island) in April 2020

Note: The final stage of construction is targeted to be completed in summer 2020 and demonstration operation in the second half of FY2020.

4. Estimating Hydrogen Cost

This section presents a cost (CIF base) analysis on liquefied hydrogen energy carrier supply chain. This analysis roughly estimates hydrogen cost in the international supply chain from a foreign country (Australia) to Japan by ship. We calculated hydrogen supply cost per 1 normal cubic metre in 2030 and further into the future.

This analysis is not a forecast but just a cost study using data in 2011 because we did not consider future expected data, such as inflation, discount rate, and exchange rate fluctuation.

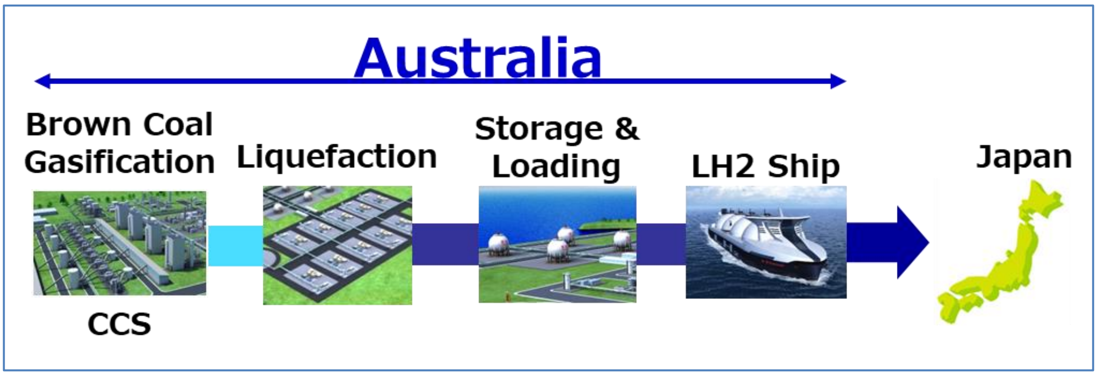
For 2030, the cost, capacity, and efficiency of each facility, which includes technological advancement to 2030, are summed up.

In the case of the further future, the cost, capacity, and efficiency of facilities are assumed with reference to the correlation between demand and cost in the LNG market.

4.1. Scope of the cost study

The target scope of this cost analysis is shown in Figure 4.17. Included in the target scope are the following: (i) brown coal (feed); (ii) hydrogen production facilities (pretreatment, gasification, and purification); (iii) CCS; (iv) transport from the hydrogen gas production site to the liquefied hydrogen base; (v) hydrogen liquefaction facility; (vi) loading terminal; (vii) sea transport; and (viii) storage and unloading facility.

Figure 4.17: Target Scope of the Cost Analysis in Liquefied Hydrogen Supply Chain



Source: Author.

4.2. Specification of each process of the liquefied hydrogen supply chain

Table 4.1 shows the specification of each process due to estimated hydrogen cost.

Table 4.1: Specification of Each Process of the Liquefied Hydrogen Supply Chain

Process	Specification (770 t/d)
Gas production	Fluidised bed gasification type Desulphurisation and decarboxylation: Selexol method Amount of brown coal supply: 540 tonne/h
Gas purification	Pressure swing adsorption (PSA) type Purity 99.999%
Liquefier	Capacity 50 t/(d unit) 20 units Power consumption 6.17 kWh/kg-H2
Loading terminal	200,000 m^3 (50,000 m3/tank, 4 tanks)
LH2 cargo ship transport	160,000 m^3/ship, 2 ships Velocity 16 knots (29.7 km/h)

Source: NEDO (2012), Author.

4.3. Estimation of hydrogen cost in 2030

4.3.1. Precondition for Hydrogen Cost Calculation in 2030

Table 4.2 shows the precondition for hydrogen cost calculation in 2030. These cost estimations were conducted in 2011, and the conditions used for the estimation are as of 2011.

(a)–(g) Setting condition

It is assumed that the year to start a large commercial supply chain will be 2030, and that a large amount of Australian brown coal–derived liquefied hydrogen will be imported to Japan.

<Precondition for sea transportation>

Route: Victoria, Australia to Japan, Cruise distance: Approx. 9,000 km

Ship velocity: 16 knots (29.7 km/h), Annual working days: Approx. 330 days

Loading days: 4 days (total unloading/loading), Annual load: 238,500 t-H2/year.

Annual number of round trips: Approximately 22 times

(h) Project period

The project period is 30 years. However, since the continuation or termination of the business after 30 years has not been decided at this time, dismantling and removal cost will not be included.

(i)–(k) Depreciation years, depreciation methods, tax rates

Since the hydrogen chain model operator will be an Australian corporation, it will be subject to Australian tax laws. A 15-year depreciation and fixed rate depreciation will be adopted, which can reduce the tax cost at the beginning of the year. The tax rate used in Australia is 30%.

(l) Investment and debt ratio

Finance usually involves a sufficient amount of investment to be screened before it is screened. According to information from the Japan Bank for International Corporation (JBIC), a group of Japanese policy-based financial institutions, JBIC's financial debt ratio is mostly 50% which we adapted.

(m) Borrowing rate

Since the US 6-month LIBOR (London Inter-Bank Offered Rate) average over the past 5 years is 2.66%, the JBIC US currency borrowing is estimated to be 0.25 (bank fee) + 2.66 = 2.9%. The economy will be examined at a borrowing interest rate of 3%, considering the accuracy of the economic examination of the commercial chain at present.

(n) Subsidy ratio

The subsidy ratio will be 0% in order to study the economic efficiency of the project.

(o)–(s) Main unit price

Since this study aims at CO_2-free hydrogen production, the cost of CO_2 storage is included in the cost. For electricity used in this project, the unit price of CO_2-free electricity is set based on the use of renewable energy or fossil fuel + CCS.

Table 4.2: Precondition for Hydrogen Cost Calculation in 2030

Items		Description	
(a)	Use technology	Large commercial supply chain	
(b)	Hydrogen production location	Australia (9,000 km)	
(c)	Hydrogen production method	Brown coal gasification hydrogen production	
(d)	Hydrogen production amount	770 tonnes per day	
(e)	CO_2 capture and storage (CCS)	Implemented CCS in collaboration with CarbonNet Project	
(f)	Annual unloading amount in Japan	225,540 tonnes per year	Annual operating rate of H2 production facility is 89%
(g)	Annual number of round trips	22 times	
(h)	Project period	30 years	
(i)	Borrowing period	15 years	
(j)	Years of depreciation*	15 years	
(k)	Tax	30%	
(l)	Investment and debt ratio	50:50	
(m)	Borrowing rate	3% per year	
(n)	Subsidy ratio	0%	
(o)	Brown coal Cost	A$15 per tonne	Shipping fee included
(p)	Electrical	A$70 per MWh	Electricity by renewable energy
(q)	Water	A$2 per tonne	
(r)	CO_2 treatment	A$15 per tonne	CarbonNet storage cost
(s)	Exchange rate	¥81/A$	Average rates from 1991 to 2010
		€0.61/A$	
		US$0.73/A$	

Note: Depreciation costs are calculated using the declining balance method. Hydrogen price is necessary for profit and tax calculation, but here hydrogen cost and hydrogen price are the same.
Source: NEDO (2012), Author.

4.3.2. Capital Expenditure (CAPEX)

As a result of calculating the cost of each facility listed in Table 4.1, CAPEX totalled ¥750 billion.

The cost of each facility includes equipment costs, civil engineering, electricity, machinery, construction/installation costs, land costs equivalent to the total installation area calculated from the layout plan, and site infrastructure costs such as roads and management facility.

Miscellaneous expenses include licences for plant installation, legal compliance, and various expenses related to finance.

The cost of constructing a new power line for a hydrogen liquefaction plant installed at the hydrogen loading terminal is not included in this project, assuming it will be shared with other facilities.

As for port facilities, the equipment required for the hydrogen loading terminal is included in the equipment cost. However, the construction, dredging, and pier construction costs are not included in the equipment cost borne by this project. The hydrogen production facility and hydrogen liquefaction facility accounted for a large proportion of the facility cost.

4.3.3. Operating Expense (OPEX)

The total operating cost for brown coal (raw material), electricity, water/nitrogen, CCS, maintenance, and labour was about A$45 billion. A fluidised bed gasifier with the lowest overhead costs and low CO_2 emissions was adopted.

Electricity accounted for the largest portion of the operating cost, and decreased electricity consumption is the most important factor in reducing hydrogen cost. Particularly for the hydrogen liquefaction facility, the proportion of power consumption is large. To reduce the operating costs, it is important to improve the performance of the hydrogen liquefaction facility and the gas production facility, such as air separation equipment.

4.3.4. Hydrogen Cost Calculation Formula

The hydrogen production cost (hereinafter, hydrogen cost) was calculated from the equipment cost and annual cost.

Hydrogen cost is defined as follows and indicates the average cost during the project period.

$$Hydrogen\,Cost = \frac{\{CAPEX + \sum(Interest + Tax)\} \,/\, ProjectYears + OPEX}{H2\ Annual\ Production}$$

where

Hydrogen Cost	: Hydrogen cost (¥/Nm3)
CAPEX	: Equipment cost (¥)
Σ (Interest + Tax)	: Interest payment and total tax during the project period (¥)
ProjectYears	: Project years (years)
OPEX	: Annual expenses (¥/year)
H2 Annual Production	: Annual hydrogen production (Nm3 CIF/year)

Interest payment will be as follows if the principal repayment is

$$\sum(Interest) = \sum_{i=1}^{DebtYears}\{CAPEX \times Debt\ Ratio - DebtPayment \times (i-1)\} \times ir$$

where

Debt Ratio	: Debt ratio (decimal)
DebtYears	: Debt years (years)
DebtPayment	: Repayment of principal (¥/year)
ir	: Interest rate (decimal)

Taxes can be calculated by multiplying profits by tax rates.

$$Income = H2\ Annual\ Production \times HydrogenPrice - (OPEX + Interest) - Depreciation$$

$$Tax = Income \times Tax\ Rate$$

where,

Income	: (¥/y)
HydrogenPrice	: (¥/Nm3)
Depreciation	: (¥/y)
Tax Rate	: Decimal

Amortisation is calculated using the declining balance method. Hydrogen prices are required for profit and tax calculations. However, here hydrogen costs and hydrogen prices are assumed to be the same.

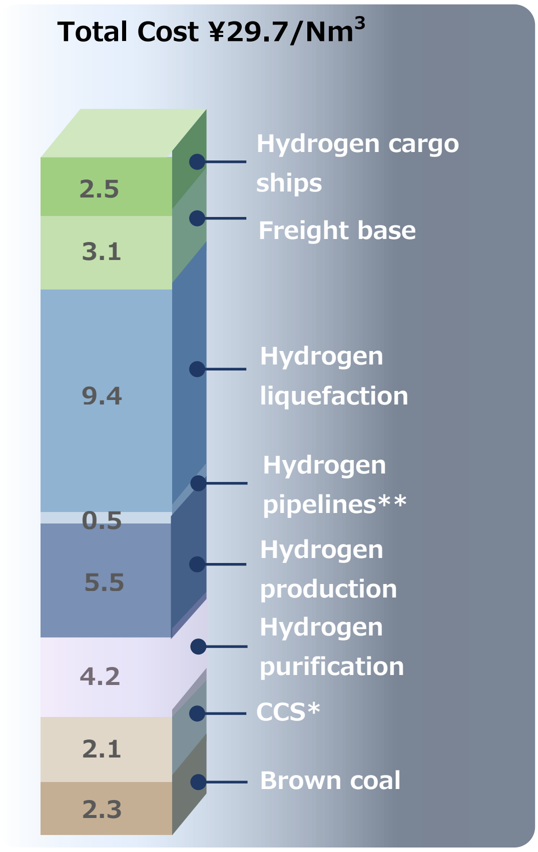
4.3.5. Calculation Result of Hydrogen Cost (¥/Nm^3) in 2030

The calculation result of hydrogen cost (CIF base) is shown in Figure 4.18. The total cost of liquid hydrogen supply chain under the above precondition is ¥29.7 /Nm^3.

Hydrogen liquefaction cost is the highest ratio (¥9.4/Nm^3 (31.6%). Subsequently, hydrogen production cost (¥5.5/Nm^3, 18.5%) and hydrogen purification cost (¥4.2/Nm^3, 14.1%) are high ratios. On the contrary, the ratio of hydrogen cargo ships (¥2.5/Nm^3, 8.4%) and CCS (¥2.1/Nm^3, 7.1%) to the total cost is relatively low.

To reduce the hydrogen cost, it is essential to reduce the costs of the hydrogen production and liquefaction facilities, which account for a large proportion of CAPEX. In OPEX, improvement of liquefaction efficiency is also an important issue. It is also important to reduce costs by increasing the scale-up of facilities.

Figure 4.18: **Result of Cost Analysis (CIF Base) in Liquefied Hydrogen Supply Chain**



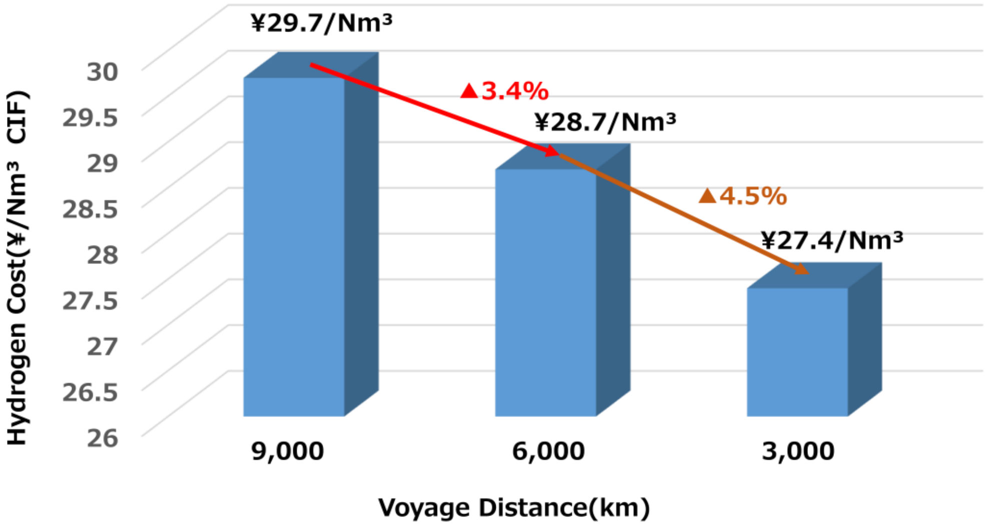
Source: NEDO(2012), Author.
* The CCS cost is the amount presented by the CarbonNet Project.
** Pipeline cost includes expenses related to plant installation licences, legal compliance, and finance.

4.3.6. Analysis on Hydrogen Transport Costs by Voyage Distance

A sensitivity analysis of hydrogen cost by voyage distance was conducted. The set voyage distances are short distance (3,000 km), medium distance (6,000 km), and long distance (9,000 km), and the hydrogen cost is calculated for each voyage distance. The effect of voyage distance on hydrogen cost is shown in Figure 4.19.

The result shows that the hydrogen cost can be reduced by ¥0.3–¥0.4/1,000 km. The reason for the reduction in hydrogen cost is thought to be that the number of voyages increases due to the short distance. If hydrogen production from renewable energy becomes more popular in the future, Southeast Asia and China are expected to be promising manufacturing locations.

Figure 4.19: Effect of Voyage Distance on Hydrogen Cost



Source: Author.

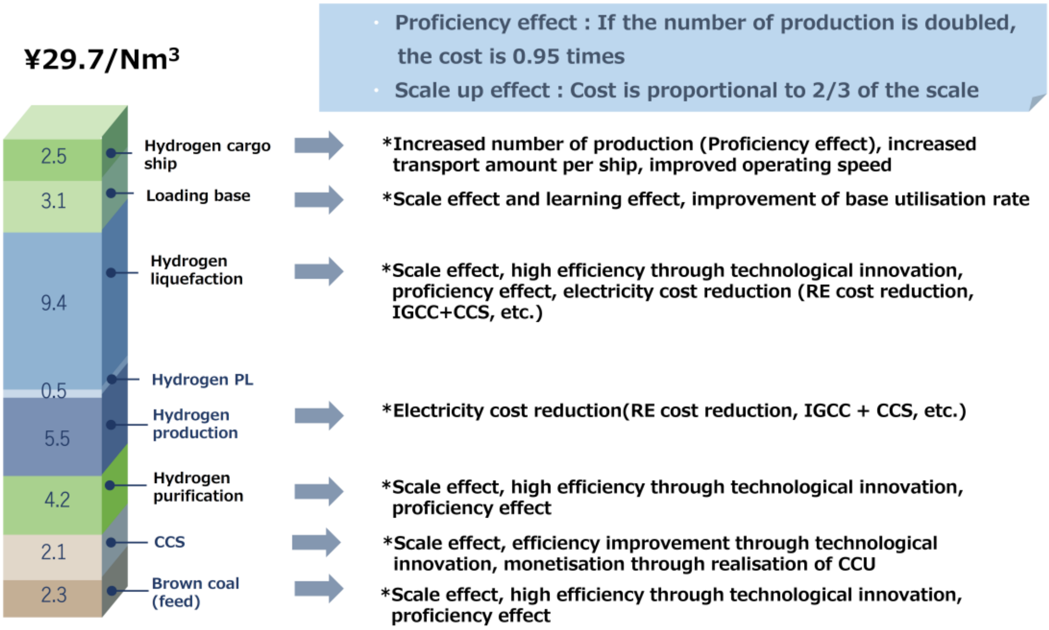
4.4. Estimation of hydrogen cost in the further future

4.4.1. Possibility of Further Hydrogen Cost Reduction in the Future

In the previous calculation, the hydrogen cost in the liquefied hydrogen supply chain is estimated to be ¥29.7/Nm^3 at the early stage of commercialisation in 2030. This section studies the reduction of hydrogen cost due to the possibility of further decreased hydrogen cost in the further future (say, in the 2050s).

Figure 4.20 shows the possibility of further hydrogen cost reduction in each process. Overall, the effect of proficiency in each process and decrease in electricity cost by renewable energy contributes to reduced hydrogen cost. It will also greatly contribute to reduced hydrogen cost. In addition, both the increase in the number of voyages and the improvement in operating rate will contribute to reduced hydrogen cost in CAPEX and OPEX.

Figure 4.20: Possibility of Further Reduction of Hydrogen Cost Co

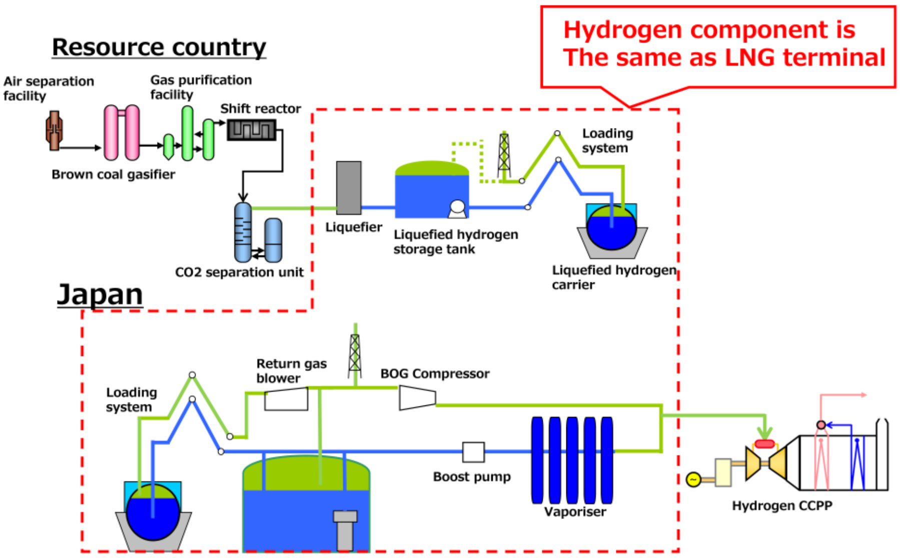


Source: Author.

4.4.2. The History of the LNG Supply Chain Cost

Figure 4.21 shows the similarity of the liquefied hydrogen supply chain process to the LNG process. Thus, we believe that future hydrogen cost will be reduced in the same way as LNG cost. In this section, we researched the past LNG demand and cost changes to consider future hydrogen cost reductions.

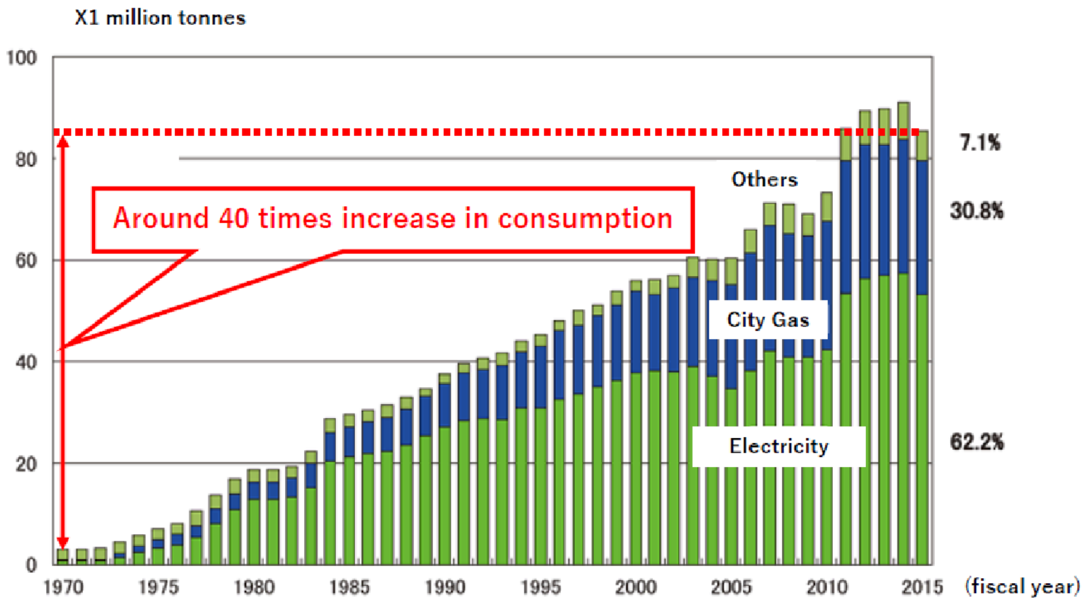
Figure 4.21: Liquefied Hydrogen Supply Chain System Produced from Brown Coal



CCPP = combined cycle power plant, LNG = Liquefied natural gas.
Source: Author.

Figure 4.22 shows the changes in Japan's domestic consumption of natural gas. During the 35 years from 1969 (2,233 tonnes/y) to 2015 (85,553 tonnes/y), the consumption of natural gas has increased about 40 times (METI–ANRE, 2016). Natural gas consumption is increasing rapidly.

Figure 4.22: Changes in Japan's Domestic Consumption of Natural Gas



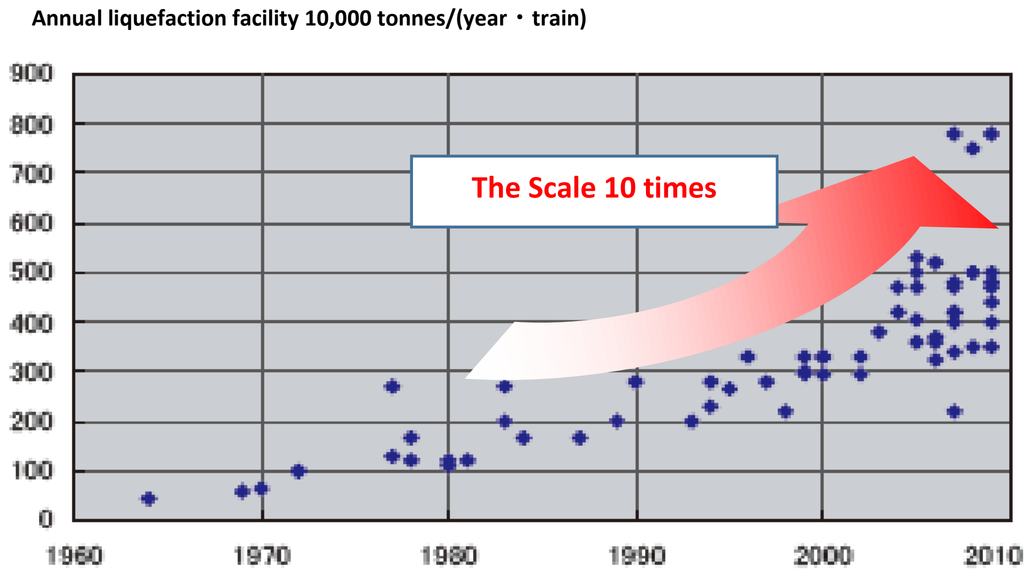
Source: METI–ANRE (2016).

Figure 4.23 shows the capacity and cost changes of an LNG liquefaction facility (Miyazaki, 2005). When Japan first imported LNG in 1960, the liquefaction capacity was around 500,000 tonnes-LNG/year. Forty years later, in the 2000s, the scale expanded about 10 times due to the increase in demand (5–7 million tonnes-LNG/year. Meanwhile, the cost of the LNG liquefaction facility has been halved in about 40 years.

This was when the scale of liquefaction capacity increased 10 times. LNG cost was halved due to technological progress and expansion of LNG-related facility. As mentioned in section 4.4.4.1, cost reduction was the effect of proficiency level and demand for mass transportation, high efficiency of facility, etc.

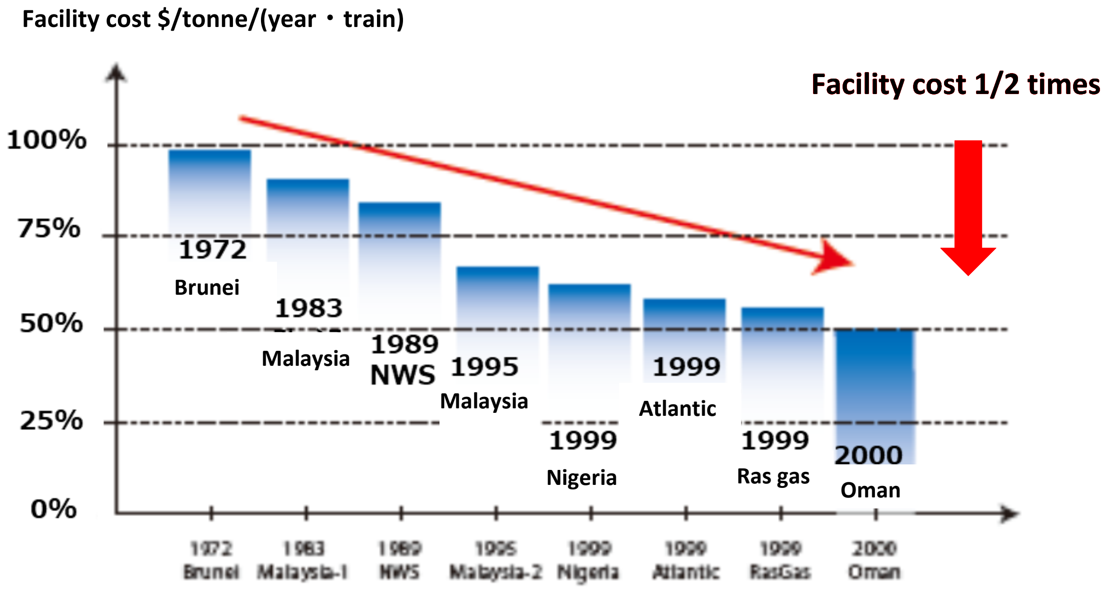
Figure 4.23: Capacity and Cost Changes in LNG Liquefaction Facility

a) Annual change of liquefaction capacity



Source: Miyazaki (2005).

b) Annual change of the cost of liquefaction facility



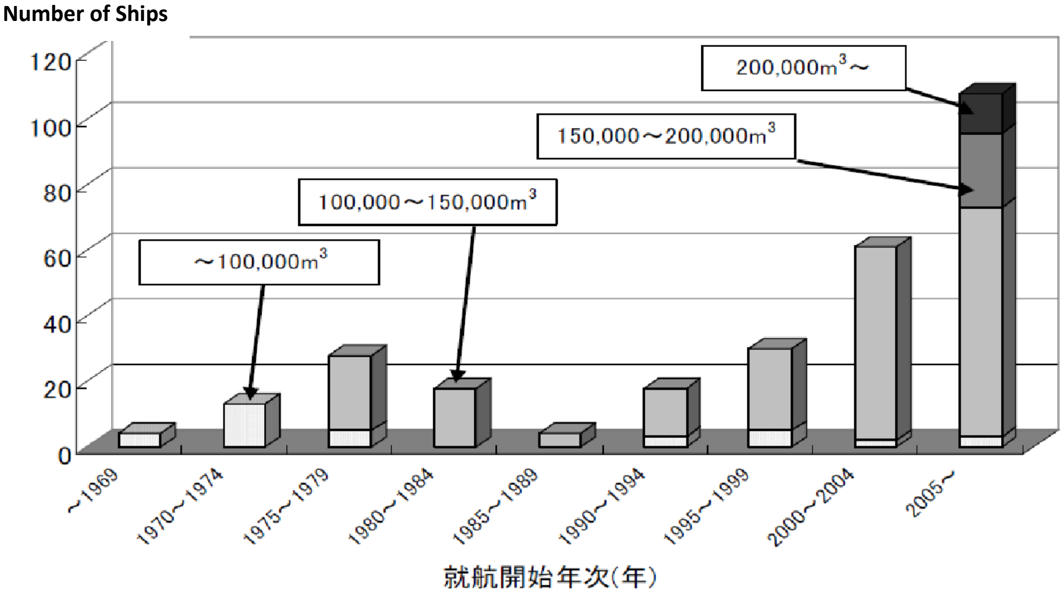
Source: Miyazaki (2005).

Figure 4.24 shows the cost changes of LNG facilities (LNG tankers) (JBIC, 2006). In the 1960s, LNG tankers with a capacity of 100,000 m^3 or less were the mainstream. With the expansion and spread of demand, LNG tankers with a capacity of 150,000 m^3 or more were constructed and have been the mainstream since the 2000s.

On the other hand, the cost of an LNG tanker was US$280 million in the early 1990s. It decreased to US$140 million to US$200 million in the 2000s, resulting in a 30%–50% cost reduction. To reduce facility costs, LNG cost to Japan decreased by 40%. Please also refer to Appendices 1 and 2 on LNG carrier construction history (Itoyama, 2012).

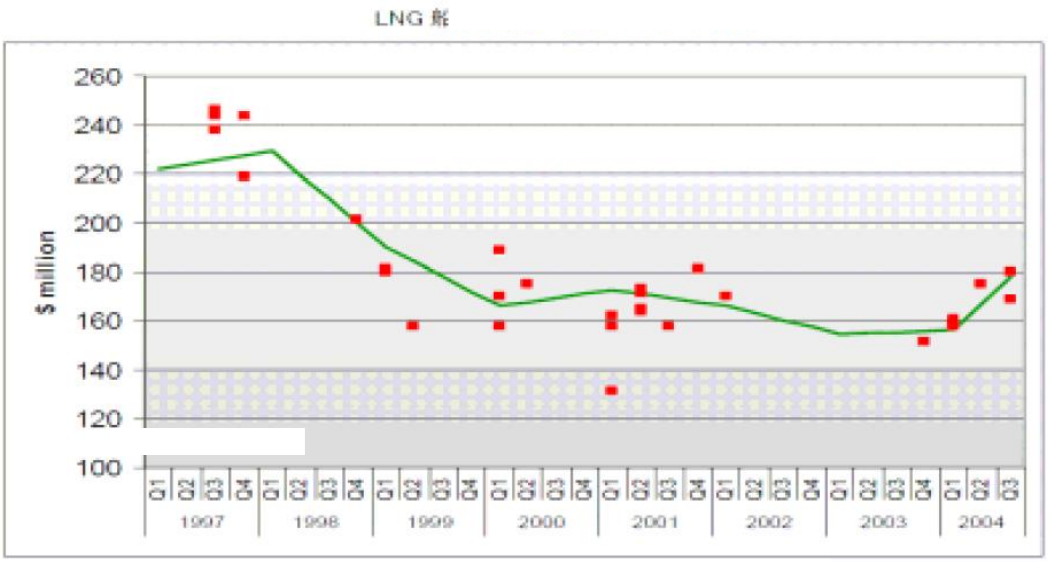
Figure 4.24: Cost Change in LNG Tanker

a) Annual change in the number and capacity of LNG carriers



Source: JBIC (2006).

b) Annual changes in the construction cost of LNG ship (since 1997)



Year of commencement of service

Source: JBIC (2006).

4.4.3. Possibility of Hydrogen Cost Reduction in the Further Future

By applying this relationship between LNG demand and cost reduction, we studied the future reduction of hydrogen cost. As shown in Figure 4.25, if the commercial hydrogen business starts in 2030 and demand increases in the 2050s, hydrogen costs will be reduced by 40% (around ¥18/Nm^3) of the hydrogen cost in 2030 (¥29.7/Nm^3).

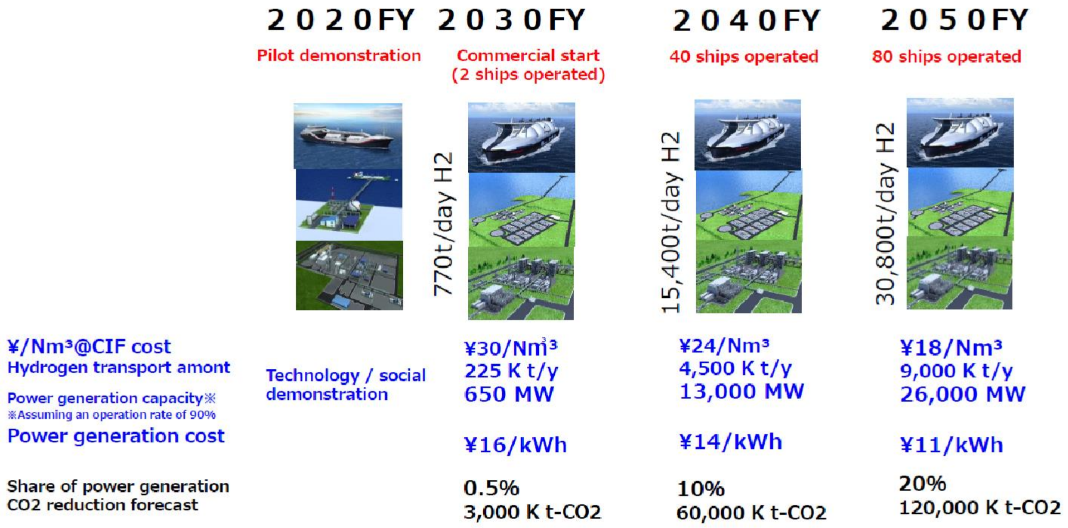
Otherwise, hydrogen transportation can be calculated at 9Mt/y; power generation capacity at 26,000 MW; and power generation unit price at ¥11/kWh). We have not considered carbon pricing or government assistance at this time, so it is highly possible that this cost will be further reduced.

In the 2050s, the prices of other fossil fuels will rise further, resulting in hydrogen production from lignite more competitive. Appropriate overseas bases such as Southeast Asia and China will also produce large amounts of hydrogen using renewable energy.

Hydrogen consumption will also increase. It is highly possible that a full-scale hydrogen society will arrive. If hydrogen will be used to generate commercial power in Japan, it will be more expensive than fossil fuel in 2030. However, the cost of CO_2-free power generation produced by brown coal is expected to be cheaper than the same one produced by renewable energy, such as wind power and solar power.

In the future, when commercialisation will be widely advanced, the cost of hydrogen power generation can be competitive enough with fossil fuel power generation. Regarding CO_2 emission, 120 Mt of CO_2 is also expected to be reduced, greatly contributing to the measures against global warming.

Figure 4.25: Estimation of Hydrogen Costs in Further Future



Source: Author.

5. Conclusion

Chapter 4 reviewed and examined liquefied hydrogen supply chain for decarbonisation, provided an overview of liquefied hydrogen energy supply chain pilot project between Australia and Japan, and forecasted future hydrogen cost. The findings are as follows:

5.1. Liquefied hydrogen supply chain for decarbonisation

- Liquefied hydrogen supply chain is important for the government-proposed basic energy strategy.
- Hydrogen does not emit CO_2 during combustion and is environment friendly.
- The spread of the liquefied hydrogen supply chain is extremely beneficial for environmental measures.
- Liquefied hydrogen is 1/800 of the volume of gaseous state. The transport of liquefied hydrogen can be efficient for large amounts of hydrogen.
- Liquefied hydrogen is non-toxic and can be used simply by evaporating it, without adding extra energy.
- In the life-cycle analysis (LCA), liquid hydrogen supply chain produced from brown coal with CCS is comparable to high-pressure hydrogen supply chain produced from renewable energy.

5.2. Overview of hydrogen energy supply chain pilot project between Australia and Japan

- Brown coal is gasified and refined using an oxygen-blown gas furnace on the coal mine side. The refined hydrogen gas is transported to the port side by pipeline, and then liquefied at the loading terminal on the port side. The process of storing and transporting to Japan by a liquefied hydrogen carrier ship was selected as the optimum process.
- The Australia–Japan Liquefied Hydrogen Supply Chain Pilot Demonstration Project, targeted for FY2020, is under way.
- This project aims to confirm that liquefied hydrogen can be safely and efficiently shipped for over 9,000 km.

5.3. Study of future hydrogen cost

- Aimed to be commercialised in 2030, total hydrogen imports were estimated to be 225,540 tonnes/year.
- The hydrogen cost (CIF [cost, insurance, and freight] price) was calculated in case. Australian brown coal is gasified to produce hydrogen, which is a clean fuel and used in Japan. Sensitivity analysis and examination of diffusion potential of each factor were conducted.
- At the same time, regarding changes in LNG demand and costs in similar supply chains, we assumed hydrogen demand, costs, and CO_2 reductions for the time the commercialisation of hydrogen supply chains will expand after 2030.
- The estimated hydrogen cost (CIF base) in 2030 is ¥29.7/Nm^3.
- Amongst hydrogen costs, the ratio of hydrogen liquefaction（¥9.4/Nm^3, 31.6%） was the highest, followed by hydrogen production（¥5.5/Nm^3, 18.5%）, and hydrogen purification（¥4.2/Nm^3, 14.1%). The cost reduction of these three devices will be essential in the future.
- The factor analysis of cost reduction in the further future revealed that the large size of each equipment, improved performance, and high efficiency are essential.
- According to our study, in the further future, the amount of hydrogen import will be 9 Mt/y; hydrogen CIF cost, ¥18/Nm^3; power generation capacity, 26,000 MW; power generation cost, ¥11/kWh; and amount of CO_2 reduction, 120 Mt/y.

Thus, the result of the analysis confirms that the future proposed energy system on the liquefied hydrogen supply chain model using hydrogen, which is a carbon-free clean fuel, is highly feasible both technically and economically.

With the aim of starting, we will conduct a technical and safety demonstration in the pilot chain, targeting a commercialisation demonstration in 2025, and another in 2030.

Chapter 5
EAS Hydrogen Working Group

1. First East Asia Summit Hydrogen Working Group Meeting

Hydrogen is highlighted in East Asia Summit (EAS) region as one of the clean energies, which are variable renewable energy (vRE) such as solar and wind. Some EAS countries which consist of ASEAN 10 + 8 countries – Australia, China, India, Japan, the Republic of Korea (henceforth Korea), New Zealand, Russia, and the United States (US) – started to set up their hydrogen strategic plans to utilise hydrogen in 2030–2050. Hydrogen has advantages compared to the existing vRE: (i) it is not intermittent; (ii) it has a large capacity factor; (iii) it has a large supply potential; (iv) it is easy to store and transport; (v) it is not affected by seasonal change, etc. However, its supply costs (production and logistic) are currently expensive due to the need for a huge infrastructure investment to support the hydrogen supply chain.

Based on this background, the Economic Research Institute for ASEAN and East Asia (ERIA) organised the First EAS Hydrogen Working Group (WG) Meeting in ERIA in Jakarta on 16 December 2019 to discuss the prospect of hydrogen use in the EAS region. Representatives from EAS countries and industry stakeholders from Japan attended the 1-day workshop. The workshop was divided into four sessions, namely, the introduction of (i) the terms of reference of the working group, (ii) national hydrogen policies, (iii) ERIA's hydrogen potential study – phase 1, and (iv) the Japan-promoted hydrogen pilot projects.

The following sections summarise the presentations and discussions that took place in each session.

1.1. Introduction of the working group's terms of reference

Shigeru Kimura, Special Adviser to the President on Energy Affairs of ERIA, presented the importance of hydrogen (i) as an alternative renewable energy apart from solar PV and wind; (ii) as a potential energy alternative in many sectors, especially transportation, power generation, and industry; and (iii) because it can be produced from various resources and pathways.

However, Mr Kimura explained several issues and challenges that need to be solved for hydrogen to penetrate the market. On the supply side are the high hydrogen production cost, the difficulty to treat CO_2 emissions when hydrogen is produced from fossil fuels, and the high costs of the supply chain. On the demand side are several bottlenecks, such as the high cost of fuel cell in the transport sector and the expensive cost of burner combustion technology to mix natural gas with hydrogen. Finally, the development of hydrogen technology needs government support on both the supply and demand sides through various incentives and subsidies.

Mr Kimura explained four objectives of the working group: (i) to increase the common understanding on hydrogen in the EAS region, (ii) to project the hydrogen potential on the demand and supply sides by 2040, (iii) to investigate the region-wide hydrogen supply chain, and (iv) to study the appropriate hydrogen policies for the Energy Cooperation Task Force (EAS–ECTF) and the Energy Ministers Meeting (EAS–EMM).

According to Mr Kimura, the WG is expected to (i) share information on hydrogen amongst the members; (ii) submit recommendations to ERIA on the content of hydrogen research studies; (iii) review past and ongoing hydrogen research studies performed by ERIA; (iv) organise discussions, seminars, and workshops on hydrogen supply chain; and finally (v) submit policy recommendations on hydrogen to the EAS–ECTF and EAS–EMM.

As a closing, Mr Kimura stated that ERIA shall organise WG meetings per year until 2025 with the ERIA team composed of members from (i) ERIA, (ii) The Institute of Energy Economics, Japan (IEEJ), (iii) Chiyoda Co., and (iv) Kawasaki Heavy Industries Co. WG members are grouped into two topics, namely, hydrogen production and demand potential. The group on hydrogen production potential comprises Alison Reeve (Director, Department of Energy and Environment, Australia); Adelina Haji Mohammad Jaya (Director, Marketing and Trading Department, Petroleum Authority, Brunei Darussalam); Saleh Abdurrahman (Senior Adviser, Ministry of Energy and Mineral Resources, Indonesia); Iman Bin Yussof (Energy Sector, Ministry of Energy, Science, Technology, Environment and Climate Change (MESTECC), Malaysia); and Mark Pickup (Principal Policy Adviser, Ministry of Business, Innovation & Employment, New Zealand). The group of hydrogen demand potential consists of Zheng Lyu (Senior Researcher, Chinese Academy of Sciences, China); Natarjan Rajalakshmi (Senior Scientist, Center for Fuel Cell Technology, International Advanced Research Centre for Power Metallurgy & New Materials, India); Daishu Hara (Director, New Energy and Industrial Technology Development Organization [NEDO], Japan); and Twarath Sutabutr (Inspector General, Ministry of Energy, Thailand).

1.2. Introduction of national hydrogen policies

Hydrogen producers

Three countries' representatives explained their respective hydrogen policies from the point the point of view of hydrogen producers, i.e. Indonesia, Malaysia, and New Zealand.

Indonesia's Hydrogen Policy by Ari Mustaba, Ministry of Energy and Mineral Resources (MEMR), Indonesia

Ari Mustaba explained that Indonesia commits to reduce at least 29% CO_2 emission from BAU (business-as-usual scenario) level by 2030 or by 41% with international support as it has already ratified the Paris Agreement in 2016 by Law 16/2016. Through Government Regulation No. 79 of 2014, the country has set the target of new and renewable energy at 23% shares by 2025. However, it is also aware that the main challenge of applying renewable energy is its intermittency.

One solution to resolve the intermittency issue is by integrating solar power with the energy storage system, which can provide a back-up when solar power is down. A combined solar power and storage system will also give stable power, which is good for the grid.

One example of renewable energy and energy storage system is the application of solar power that is combined with fuel cell and battery. This technology produces stable and reliable power for the whole day. The combined system is also suitable to be implemented in small islands where the grid is very sensitive to intermittency.

Currently, the private sector is the only stakeholder capable of implementing this technology. MEMR Regulation Number 50 of 2017 regulates the mechanism of how the renewable energy business process implemented by Independent Power Producer (IPP) can sell its electricity to the state electricity company (Perusahaan Listrik Negara or PLN). Nevertheless, that regulation has not yet accommodated a system that combines renewable energy with storage from the perspective of both business model and tariff.

For this reason, Indonesia needs to study the implementation of renewable energy and its storage system – especially on small islands, both technically and economically – and the business model that is doable in Indonesia.

Mustaba made three points on Indonesia's situation, as follows:

First, he explained a set of actions that Indonesia is taking to realise the 'Tokyo Statement' since the last hydrogen energy ministerial meeting in 23 September 2018). This statement includes the achievement of the Paris Agreement's objectives, including combating climate change. Hydrogen is expected to have an important role in decarbonising the global energy system. In turn, numerous sectors including transportation, industrial manufacturing, heat, and power generation can use hydrogen. Hydrogen will be an important source of energy, coexisting with current fossil fuels and growing renewable energy, for greater sustainability of our planet. The application of hydrogen technology as energy storage in renewable energy power plants (solar PV and wind power plants) can improve the reliability of the system. Indonesia is planning to pilot a manufacturing hydrogen installation that can be integrated with a renewable energy power plant. PT KAI (Kereta Api Indonesia, the Indonesian Railway Public Corporation) and ALSTOM are collaborating to develop a hydrogen fuel cell train. MEMR, with PT KAI and Alstom, is preparing a memorandum of understanding to develop a hydrogen fuelled train in Indonesia.

Second, on the perspective of hydrogen in Indonesia: hydrogen, as a clean fuel in the energy sector, can be used in transportation, power plant, and energy storage. The deployment of hydrogen fuel cell vehicles is a further step in the electrical vehicle national programme. Hydrogen converted to electric power through fuel cell will be the alternative energy storage technology in addition to using the battery. Hydrogen can be used as storage media. In Eastern Indonesia, hydrogen can be utilised as an energy storage for intermittent generation. Hydrogen source potentials are also available. Indonesia can potentially supply hydrogen from gas and lignite as fossil fuel sources, and solar, hydro, and wind as renewable energy sources. The challenge is how to make hydrogen economically viable, financially attractive, and socially beneficial in the country.

Finally, hydrogen would potentially decrease domestic oil/gas/coal demand for electricity and heat and transport fuel with combination of renewable energy, in addition to the export opportunity.

The Future of Hydrogen in Malaysia by Imran Yussof, Ministry of Energy, Science, Technology, Environment and Climate Change (MESTECC), Malaysia

Energy policy in Malaysia was firstly elaborated by the issuance of the Petroleum Development Act in 1976. Renewable energy matters were first mentioned in 2001 in the Fuel Diversification Policy. The first hydrogen and fuel cell road map, together with solar, was established in 2006 in the Ninth Malaysia Plan (RM9). Now, hydrogen and other renewable energy options are regulated under Renewable Energy Act 2011.

In Malaysia, the Energy Commission takes care of energy matters, in coordination with the Ministry of Economic Affairs (MEA) and MESTECC. At the same time MESTECC also coordinates with the Sustainable Energy Development Agency and Malaysia Power. Other ministries than MEA and MESTECC are the Ministry of Rural Development, the Ministry of Primary Industry, the Ministry of Domestic Trade and Consumer Affairs, and Petronas.

Mr Yussof explained that the transport sector accounted for nearly 25% of energy use in 2016, which made it the highest energy-consuming sector in Malaysia. At the same time, the total final energy consumption is still dominated by petroleum products (53%), followed by natural gas (22%) and electric power (22%). Electric power depends primarily on coal (46%) and gas (nearly 40%) whilst hydropower gets around 13%. Coal and gas make around 74% of total installed power capacity whilst renewables contribute around 22%. with a large share coming from large hydropower (16%). From the demand side, the industry and the commercial sectors in Malaysia make around 78% of total electricity demand. Most of the electricity demand is concentrated in Peninsular Malaysia, i.e. 112,572 GWh which is nearly 80% of the total electricity demand. The total installed capacity in Peninsular Malaysia is around 26,603 MW, which is about 80% of the national total installed capacity (33,095 MW).

Malaysia is targeting to reach 20% of renewable energy installed capacity share by 2025 (around 8,400 MW), a fourfold growth from the Eleventh Malaysia Plan in 2019 of 2,068 MW. With a total production capacity of not more than 20,000 kg/day, hydrogen is produced for industrial purposes as a by-product. Some hydrogen projects have taken place, e.g. the commissioning of the first integrated hydrogen production plant and refuelling stations with the rolling out of three hydrogen-powered buses in Sarawak state (2019). At the same time, hydrogen-related policies in Malaysia principally deal with academic institutions, e.g. around RM40 million in grants have been allocated for research and development (R&D) between 1997 and 2013.

The Hydrogen Policy of New Zealand by Mark Pickup, Principal Policy Advisor, Energy Market Policy, Energy & Resource Markets, Ministry of Business, Innovation & Employment, New Zealand

With the current renewable (geothermal) energy share already reaching 85% in power generation, the New Zealand government aims to achieve 100% renewable electricity by

2035 and net zero–carbon emissions by 2050. Green hydrogen strategy is amongst its main renewable energy strategies to help reduce global emission. The government has partnered with Japan to develop hydrogen technology, and its green hydrogen strategy has been set to contribute to reaching the national target of net zero–carbon emissions in 2050, considering the potential demand growth for power, transport, and the industry sectors as well as for export.

There are currently several main activities in hydrogen strategy in New Zealand, such as studies, demonstration, and pilot projects.

The strategy itself has two parts: (i) the development of a hydrogen vision with a final report to be issued in 2020, and (ii) the development of a hydrogen road map that should be completed in 2020. The road map will consider regulatory and standards gaps, business-as-usual versus an accelerated deployment scenario of hydrogen.

Hydrogen consumers

There were three presentations from China, India, and Thailand from the hydrogen consumers point of view.

Policies and Status of Hydrogen Energy in China by Zheng Lyu, Carbon Data and Carbon Assessment Research Center, Shanghai Advanced Research Institute, Chinese Academy of Sciences, China

Since 2006, China has surpassed the US in becoming the world's largest CO_2 emitter. China's energy consumption will continue to increase with coal and other fossil fuels, accounting for a high proportion of the energy mix, whilst crude oil will still be heavily dependent on imports.

China's nationally determined contributions by 2030 per the Paris Agreement are as follows: (i) to achieve CO_2 to reach its peak around 2030 and to make the best efforts to reach this earlier, (ii) to lower CO_2 emission per unit of GDP by 60% to 65% from the current 2005 level, and (iii) to increase the share of non-fossil fuels in primary energy consumption to around 20%.

China's main national policies on hydrogen energy has been elaborated since 2012 in many development, action, and initiative plans. Amongst the main targets are the development of hydrogen energy and fuel cell vehicles (FCVs) to facilitate energy transition (that includes production, distribution, storage, transportation, standardisation, etc.); realisation of several pilot and demonstration projects; and green industry guidance with hydrogen energy application. In the meantime, in recent years, more than 30 provincial or city governments have released plans or instructions to promote FCVs and the hydrogen energy industry.

To develop hydrogen energy use in transportation, the central government maintains a high subsidy for FCVs – from RMB200,000 to RMB500,000 per car – and the local government provides additional subsidies of around 30% to 100% of this amount. More than RMB4 million of subsidies were also applied to the construction of hydrogen fuelling stations.

Currently, China produces around 21 million tonnes of hydrogen annually with 62% coming from coal, 19% from natural gas, 1% from water electrolysis, and the remaining from industrial by-product. In 2019, 1,527 units of FCVs were sold, mostly buses or trucks, and around 23 tanking stations built.

Finally, China targets hydrogen development after the hydrogen industry road map was documented in the Blue Book of China's Hydrogen Industry Infrastructure Development (China National Institute of Standardization, 2016). Amongst its targets are producing 10,000 FCVs by 2020, 2 million by 2030, and 10 million by 2050, and building more than 100 hydrogen fuelling stations by 2020 and 1,000 by 2030.

In 2019, the China Hydrogen Alliance released the White Book of China's Hydrogen Energy and Fuel Cell Industry with more detailed hydrogen targets not only in the transport sector but also in the industry and power generation sectors until 2050.

The Initiative of the Advanced Research Centre International (ARCI) India on Hydrogen Technology by N. Rajalakshmi, Senior Scientist and Team Leader, Center for Fuel Cell Technology, International Advanced Research Centre for Power Metallurgy & New Materials (ARCI), India

ARCI is an autonomous R&D centre of the Government of India's Department of Science and Technology located in three cities: New Delhi, Hyderabad, and Chennai. Amongst its centres are the Centre for Fuel Cell Technology that deals with research on the Polymer Electrolyte Membrane Fuel Cell system and hydrogen generation and the Centre for Automotive Energy Materials that deals with Li ion battery, magnets for motors, and thermoelectric devices.

Hydrogen and fuel cell activities in India started in the '80s. The number of involved research and industry institutions has grown from only around 10 in the '90s to the current around 100. In 2012, the government approved a significant budget to promote and produce 6 million electric vehicles and hybrid electric vehicles by 2030. At the same time, the finance minister announced a concessional excise duty of 10% for fuel cell and/or hydrogen cell technology. In India, several pathways of hydrogen use in transport are being studied with some demonstration or pilot projects. Amongst the scrutinised pathways are the use of hydrogen as internal combustion engine for two, three, or four wheelers; the use of alkaline fuel cells for three wheelers (*bajaj*); and the use of polymer electrode membrane (PEM) and phosphoric acid fuel cells. Apart from these, many pilot and demonstration projects are also conducted, especially on hydrogen production and hydrogen use in other sectors, such as telecommunication.

India is also actively organising workshops, seminars, and conferences on hydrogen technologies and collaborating with international experts.

Hydrogen – The Missing Link in the Energy Transition: Decarbonising the Energy Sector by Twarath Sutabutr, Inspector General, Ministry of Energy, Thailand

Between 2012 and 2021, in its Alternative Energy Development Plan (AEDP), Thailand targets to reach 30% renewable shares in its total energy consumption by 2036. Included in this target is the objective to reach a 10.1% share of renewable sources or around 3,353 ktoe by 2021 to generate electricity, of which 0.86 ktoe is expected from new energy that includes hydrogen. The AEDP sets out that, by 2036, hydrogen would meet 10 ktoe of energy consumption.

Currently hydrogen production in Thailand comes mainly from natural gas steam reforming. It is used mainly in the refinery to produce petroleum and petrochemical products. Several ongoing development projects that use hydrogen as energy storage, to feed FCEVs, especially heavy-duty vehicles, and to be produced on-site as green hydrogen whilst replacing grey hydrogen produced from fossil fuels.

1.3. Introduction of ERIA's hydrogen potential study – part 1

Mr Kimura introduced the study on hydrogen potential conducted by ERIA.

According to the ERIA outlook, the energy supply in the EAS grew at an annual rate of 1.48% in 2000–2015 and will grow 1.46% in 2015 and 2040. Coal has been taking a major share of the supply during the observed period and, geographically, India and China, being the two biggest countries with the biggest supply. The energy intensity of the regions should decrease by 9% in 2000–2015 and by 38% in 2015–2040. At the same time, in 2040, by going through an 'energy potential' scenario, the region can possibly save its total primary energy supply (TPES) by 13% and its total final energy consumption by 10%. Overall, this means a reduction of 24% of CO_2 emissions in the business-as-usual scenario (BAU).

According to Mr Kimura, hydrogen has three potential benefits to be explored: (i) the potential to be a low or zero carbon-emitting energy, (ii) the possibility to be produced from various sources and pathways, and (iii) the ability to be used as a transportable energy storage.

Mr Kimura explained the current trends of hydrogen development in the world that consist of (i) Japan's policy regarding its basic hydrogen strategy that touches every aspect of hydrogen development, i.e. supply, cost, usage (mobility and power generation), and the development of fuel cells; (ii) the hydrogen ministerial meetings; and (iii) the global hydrogen market, which should be formed as a result of the Paris Agreement.

The study consisted of

- reviewing the climate, renewable energy, and hydrogen policies of ASEAN countries (except Cambodia, the Lao PDR, and Myanmar), Australia, China, India, Japan, Korea, and New Zealand (to be done by IEEJ);
- forecasting hydrogen demand potential in road transport (fuel cell bus [FCB], fuel cell trucks, hydrogen stations, etc.), power generation (hydrogen turbine), and industrial heat (IEEJ);
- forecasting hydrogen supply potential from fossil fuels and renewable sources, including the potential ways of transporting and distributing, with cost as the main parameter (Chiyoda Corporation),
- conducting well-to-wheel analysis of energy use, emissions, and costs (ERIA); and
- surveying several sites (ERIA, Chiyoda, and IEEJ supported by the Mitsubishi Co. and Mitsui & Co.)

Hydrogen Demand Potential by Motokura Mitsuru, Senior Coordinator, Global Energy Group 1, Strategy Research Unit, The Institute of Energy Economics, Japan (IEEJ), Japan

Mr Motokura explained the two study phases on hydrogen demand potential.

Phase one of the study is summarised as follows:

The scenario of hydrogen until 2040 includes three sectors (electricity, industry, and transport). Conventional fossil fuel use will be shifted to hydrogen or a mix of hydrogen and fossil fuels with the introduction of various hydrogen-related technologies in the three sectors. For example, in the transport sector, it is the introduction of fuel cell cars, FCBs, and fuel cell trains.

Basic assumptions consist of the categories of hydrogen technologies that would prevail and be commercialised, carbon content, net calorific value, hydrogen specification (density), thermal efficiency for power generation, and the different conversion factors.

In the electricity generation sector, the scenarios are differentiated by the percentages of hydrogen penetration (10%, 20%, and 30%, respectively) as power generation fuels in 2040 in BAU (0%). These assumptions and different scenarios in the power sector are also applied in the industry sector.

In the transport sector, the scenarios are based on the exogenous assumptions of hydrogen use shares that grow in each of the concerned transport mode, i.e. passenger cars, buses, and trains. These different shares are obtained through assumptions on the number of vehicle stocks, considering the different techno-economic characteristics of the different vehicle types (mileage, fuel economy, etc.)

Some results are obtained in terms of hydrogen demand. First, by 2040, Indonesia would potentially have the highest hydrogen demand in ASEAN whilst China followed by India would have the most demand for hydrogen in the EAS region. Second, electricity would be the sector with the most hydrogen demand, followed by transport and then industry.

CO_2 emissions could be reduced up to 2.7% depending on the scenario compared to the ERIA benchmark outlook. The economic impact is calculated by simply multiplying the CO_2 emission reduction amount and CO_2 price, which is assumed to be US$41/t$CO_2$. Net natural gas demand will increase because 20% of coal-fired electricity generation is assumed to be converted to hydrogen and natural gas mixed fuel.

Phase 2 is the revision of assumptions and scenarios of phase 1 based on consultation with the Mitsubishi Hitachi Power Systems and Toyota Motor Corporation that focused on the transport and power generation sectors. For example, in the power sector, the study assumes that, in an intermediate year (2030), a gas mix of hydrogen and natural gas (30:70) would penetrate the alternative policy scenario. The 2040 situation is divided into two distinct scenarios: one that assumes a 50:50 share of pure natural gas and pure hydrogen whilst the other assumes a 50:50 share of pure natural gas and mix (30:70) of hydrogen and natural gas.

In the transport sector, the study assumes certain shares in the zero-emission vehicle (ZEV) amongst the registered passenger cars in 2040, i.e. 30% in scenario 1 and 50% in scenario 2, with both FCV shares of 20%.

Other improvements to the scenario building is the clustering of countries (regions) into four groups, i.e. combinations resulting from low or high income and low or high hydrogen supply cost. The study also assumes the different hydrogen technologies or facility development rates based on those clusters.

The results of the phase 2 hydrogen demand are then more detailed than those of phase 1 as the hydrogen demand of different countries are analysed based on their cluster characteristics.

Hydrogen Production Potential by Ikeda Osamu, Group Leader, Hydrogen Chain Demo Project Section, Chiyoda Corporation, Japan

Mr Ikeda presented the results of the phase 1 study concentrating on the hydrogen production potential and supply cost forecast.

The study categorised the 16 EAS countries into three groups to identify the positioning for hydrogen trading in 2040 by utilising forecasted data of energy balance between production and demand, including hydrogen. The three groups are exporting (Indonesia, Australia, Brunei Darussalam, New Zealand, Lao PDR); importing (Japan, Korea, Singapore, Cambodia), and trading intra-regionally (China, Thailand, India, the Philippines, Viet Nam, Myanmar, Malaysia, and some parts of Indonesia).

The study estimates hydrogen production cost from various sources, i.e. fossil fuel and renewable resources. In 2040, the production cost would be in the order of gas reforming, water electrolysis (stable power), biomass gasification, lignite gasification, and water electrolysis (fluctuating power).

Hydrogen production cost grows linearly with feedstock price. Hydrogen production from the steam reforming of gas is the most economical, and water electrolysis with a high capacity factor (70%) plus low electricity cost will enhance its cost competitiveness.

Amongst the group of exporting countries, Australia and Indonesia would have the largest potential to produce hydrogen; major sources are solar, wind, and lignite. Amongst the intra-regional trading group, China and India would have the largest potential to produce hydrogen with the largest demand, with solar and biomass as the main sources.

The study suggests that hydrogen can be transported in four modes (rail, ship, truck, and pipeline) through at least four types of carrier (liquid hydrogen [LH2], ammonia [NH3], chemical hybrid [methylcyclohexane, MCH], and compressed hydrogen [CH2-700 Mpa]. Ships transporting liquid and chemical hydrogen are ideal for extremely long distance (global) hydrogen logistics. For small volume compressed gas, the transport by trucks of liquid/chemical hydrogen is suitable for local and short distance whilst high volume compressed gas, liquid/chemical hydrogen via train is ideal for medium and long distance. Pipeline is suitable for transporting compressed gas hydrogen domestically with flexible delivery volume.

To understand the magnitude of local hydrogen supply chain cost and characteristics of each technology, we applied three scenarios utilising three different hydrogen carriers (LH2, NH3, and MCH). We assumed the same centralised hydrogen production with a capacity of 2.5 bio Nm^3-H2/year followed by a centralised carrier synthesis for the three scenarios. The scenarios differ after the carrier synthesis. In the first scenario, we assumed the following sequence: a long-distance ship transportation (600 km), followed by 100 km of truck transportation to deliver to hydrogen pumping stations for hydrogen FCVs. In the second scenario, we assumed a 300-km train delivery followed by 100-km truck delivery to the pumping stations. For the third scenario, hydrogen is transported only by truck for 100 km from the carrier synthesising to the pumping stations.

As a result, the study found that supply chain costs are in the order of MCH, NH3, and LH2 from the lowest in 2020–3030, and NH3 will be the lowest cost carrier in 2040–2050.

The study results are summarised as follows:

- Hydrogen demand and supply in the region is assumed to be well-balanced between the exporting, importing, and intra-regional trading countries in 2040 with enough additional potential.
- In the early stage, the major hydrogen source will come from fossil fuels. In the future, the sources will largely shift to abundant renewable energy as a result of technology development and will expand its network globally and regionally.
- In the early stage (2020–2030), local supply chain and global trading with Japan will start. It is expected to grow into a global hydrogen energy supply chain network in this region in 2040–2050.
- In case of the liquefied natural gas (LNG) business, it has taken 15 years to start the first LNG shipment since the adequate transportation technology was established in 1954 and over 30 years for the LNG business to mature. In the early stage, the LNG price was quite high compared to the oil price. LNG was introduced with government support including tax incentives, subsidy, lending support until crude oil price rose with the oil crisis. LNG production and transportation costs have been reduced by technology development and scaling up of its projects.
- The study proposed two policy approaches – national and regional – towards establishing the global hydrogen market and supply chain in the EAS region: (i) the **national approach** that is based on the national hydrogen strategy and road map, government support and awareness programme; and (ii) the **regional approach** that is based on standardisation, i.e. evaluation or labelling standard development of carbon reduction value of hydrogen, the definition of hydrogen price per volume unit for global trading and statistics and technology or safety standard development in the region.

1.4. Introduction of hydrogen pilot projects promoted by Japan

KHI Hydrogen Road, an Australia Case, by Hasegawa Taku, Hydrogen Energy Use Promotion Section, Project Promotion Department, Hydrogen Project Development Center, Corporate Technology Division, Kawasaki Heavy Industries (KHI), Ltd, Japan

The KHI hydrogen road is a concept being implemented in Australia, which is based on carbon capture and sequestration–equipped hydrogen production from Australian brown coal transported as a liquid carrier. According to a life-cycle analysis (LCA) performed by Mizuho Information & Research Institute, in terms of well-to-tank CO_2 emission, this pathway of production and supply chain emits 0.2 kg CO_2e/Nm^3-H2, which is better than producing hydrogen from Japan's wind farm or solar PV combined with compressed hydrogen gas carrier supply chain which has an emission factor of 0.34 kg CO_2e/Nm^3-H2.

The total hydrogen cost of this pathway is around ¥29.7/Nm^3; around two-thirds of the cost components are contributions from production and liquefaction. This pathway should produce hydrogen at 225,400 tonnes per year, equal to the energy demanded by 3 million fuel cell cars or 1 GW power generator.

The Australian brown coal project is located in Latrobe Valley, Victoria. Brown coal is cheap since it has high moisture content and can potentially feed 240 years of power generation in Japan. The carbon capture and storage (CCS) offshore facility located 80 km from the Latrobe Valley brown coal mine is developed under the CarbonNet Project promoted by the Australia federal and Victoria state governments.

The KHI uses its cryogenic technology to liquify hydrogen, a carrier form to transport a high volume of hydrogen over long distance. The liquid carrier volume is 1/800 of its gas volume, needs no further refinement process, non-toxic, odourless, and free of greenhouse gas (GHG). The KHI is also developing a large-scale liquid hydrogen carrier of 40,000 m x 4 cargo size that is fuelled by evaporated hydrogen gas and has its own tank/storage as well as container to store and transport hydrogen by truck. The KHI is also developing its own hydrogen refuelling stations (HRSs) and gas turbine technologies.

The KHI started its hydrogen project in 2014 that included the development of production, liquefaction, and supply-chain technology and components as well as its Strategy Energy Plan and Strategy Road Map for Fuel Cell and Hydrogen. The KHI aims to do a technology demonstration during the summer Olympics in Tokyo (2020) and targets to start its commercial operation by 2025.

The demonstration project is a cooperation between Japan (NEDO) and Australia. NEDO through HySTRA (CO_2-free Hydrogen Energy Supply-Chain Technology Research Association) is dealing with gasification, carrier and end transportation/storage chains whilst the Australian federal and Victoria state governments through Hydrogen Engineering Australia is dealing with gas refining, transporting to the liquefaction site, the liquefaction process, and the loading of liquefied hydrogen into ships.

Brunei Darussalam Case by keda Osamu, Group Leader, Hydrogen Chain Demo Project Section, Chiyoda Corporation, Japan

Mr Ikeda gave an update of the world's first global hydrogen supply chain demonstration project. He explained that Chiyoda and its partners established the new entity called AHEAD and started the world's first global hydrogen supply chain demonstration project towards 2020. In brief, the project is a creation and operation of hydrogen supply chain produced in Brunei Darussalam, transported in ISO tank container in ships and trucks, and finally used in Kawasaki city as fuel for gas turbine power plants. The total annual maximal volume is 2010 tonnes whilst the demonstration period is between January 2020 and December 2020. The demonstration project is funded by NEDO.

In brief, LNG is produced in the Lumut LNG plant di Brunei Darussalam. The processed gas is transported to Spark hydrogenation plant and liquid hydrogen in the form of MCH is produced. MCH is transported in ISO container in trucks to the container port in Muara and then shipped in container vessels to Kawasaki city. In Kawasaki port, the ISO containers are uploaded in the container yard and transported in trucks to the de-hydrogenation plant in Keihin Industrial Zone. In the plant, MCH is dehydrogenated to become hydrogen gas. The hydrogen gas is then fed to power generation in Kawasaki. In the dehydrogenation plant, the MCH's hydrogen is separated; what is left is toluene that is brought in ISO containers by the trucks back to the container yard. This is then shipped back to Brunei to be used again to bring hydrogen in MCH form back to Japan.

2. Conclusion and Way Forward

Mr Kimura (ERIA) summarised all presentations made during the 1-day meeting. He also presented the plan to organise the second WG meeting to be held in ERIA in March 2020. In said meeting, participants would discuss at least five topics: (i) the hydrogen policies and activities in Australia, Brunei, Indonesia, and Japan; (ii) the standardisation of hydrogen in the EAS region; (iii) the progress of the ERIA phase 2 study; (iv) the proposed content of the phase 3 study; and (v) the policy recommendations to the EAS Energy Ministers Meeting. Unfortunately, due to the COVID-19 pandemic, the second WG meeting has been cancelled and the topics to be discussed during this meeting are transferred to the hydrogen phase 3 study to be implemented in 2020–2021.

Chapter 6
Hydrogen Workshops

The results of the hydrogen potential study phase 1 are relevant, meaningful, and indicate future energy trend. To enable energy policymakers to gain a deeper understanding of hydrogen and confirm the prevailing common understanding on hydrogen, four workshops were planned in Bangkok, Thailand; Brunei Darussalam; New Delhi, India; and Kuching, Malaysia.

However, due to the COVID-19 pandemic, workshops in India and Malaysia were cancelled, so that this chapter introduces the results of only two workshops held in Thailand and Brunei Darussalam.

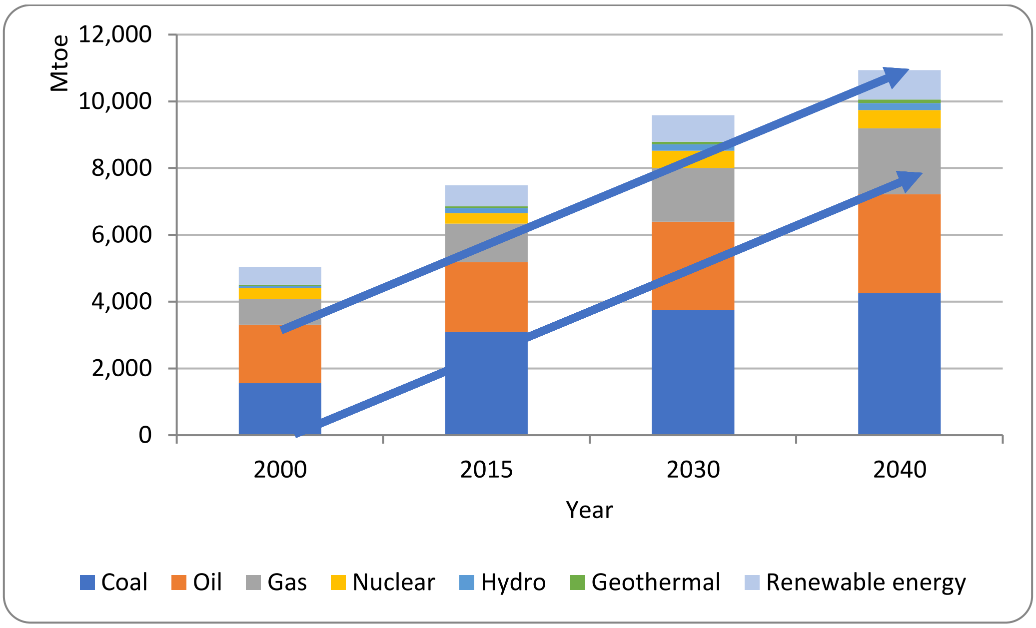
1. Hydrogen: A Potential Energy Source – Supply and Demand Outlook to 2040

ERIA was invited to a public seminar of the Petroleum Institute of Thailand (PTIT), which is organised regularly in Bangkok, to present the major outcomes of its study on the demand and supply sides of hydrogen potential, specifically on phase 1 conducted in 2018–2019. The seminar was held at the PTT Auditorium, PTT Building on 30 May 2019 (13:30–16:00). Kurujit Nakornthap, PTIT Executive Director, delivered the opening remarks, followed by presentations of speakers from ERIA. Around 180 participants from Thailand attended the seminar. After ERIA's presentations, several meaningful questions on electric vehicles vs FCVs, amongst others, were raised. This section summarises ERIA's presentations at the PTIT public seminar.

1.1. Introduction

According to the EAS energy outlook produced by ERIA, the total primary energy supply (TPES) will increase from 7,487 Mtoe in 2015 to 10,931 Mtoe in 2040. The annual growth rate will be 1.5% (1.46 times) and it will be lower than 3.5% of GDP growth rate in the same period. The share of fossil fuels consisting of coal, oil, and gas will be more than 80% in 2040, and it was the same as 2015 (Figure 6.1). In this regard, CO_2 emissions will also increase 1.5% yearly, the same as the TPES.

Figure 6.1: Future Projection of TPES, Mtoe



RE = renewable energy, TPES = total primary energy supply.
Source: ERIA (2019).

Consequently, the most important energy policies in the EAS region are the promotion of energy efficiency and conservation (reducing fossil fuel consumption) and the shift to low carbon energy (reducing CO_2 emissions) such as nuclear power generation and renewable energies. Hydrogen is one of the renewable energies. Currently, it is being highlighted to contribute to the reduction of CO_2 emissions due to the following reasons:

1) Zero CO_2 emissions
   Hydrogen bonds with oxygen to generate electricity/heat, with water being the only by-product.
2) Unlimited supply
   Hydrogen can be extracted from a wide range of substances such as oil, natural gas, biofuels, sewage sludge, and can produce unlimited natural energy through water electrolysis.
3) Storage and transportation
   Hydrogen can be stored for a long period (from summer to winter) because is not depleted and can be transported long distance (from south to north).

In this regard, ERIA conducted a study on hydrogen potential with the following research contents:

1) Introduction of representative hydrogen projects in Japan
2) Forecasting future hydrogen demand potential
3) Forecasting future hydrogen supply potential, including its supply costs
4) Well-to-wheel analysis on the economics and emissions of fuel cell vehicles (FCVs).

1.2. Introduction of representative projects in Japan

Japan depends on overseas fossil fuels for about 94% of its primary energy supply. Therefore, electricity sourced from renewable energy has been gradually increasing and accounted for 15% of Japan's total power generation in FY2016 in consideration of the need to reduce greenhouse gas (GHG) emissions. As a result, Japan's Fifth Basic Energy Plan emphasised the importance of renewable energy to account for 22%–24% of total power generation. The plan also includes a goal to raise Japan's energy self-sufficiency rate to about 24% by 2030.

Hydrogen can potentially diversify Japan's primary energy supply structure and substantially reduce its use of carbon. To promote the widespread use of hydrogen and enable Japan to become a world-leading hydrogen-based society, the government formulated the Basic Hydrogen Strategy in December 2017. The strategy outlines the vision for the year 2050 and serves as an action plan through the year 2030. On 23 October 2018, the Ministry of Economy, Trade and Industry (METI) and the New Energy and Industrial Technology Development Organization (NEDO) jointly held the Hydrogen Energy Ministerial Meeting in Tokyo. It was the first ministerial meeting to discuss the realisation of a hydrogen-powered society as its main subject. As the latest activity of government policy, on 12 March 2019, the Council for a Strategy for Hydrogen and Fuel Cells renewed the existing Strategic Road Map for Hydrogen and Fuel Cell to achieve the goal set forth in the Basic Hydrogen Strategy and the Fifth Strategic Energy Plan: the realisation of a hydrogen-based society.

Under these circumstances, NEDO, as one of largest public agencies promoting national research and development (R&D) projects, conducts the following projects to realise the shift to a hydrogen society:

Polymer electrolyte fuel cell (PEFC): The main objective of the project is to reduce usage costs for transportation means such as FCVs, since the PEFCs for such use need the highest level of reliability for use in commercial vehicles.

Solid oxide fuel cell (SOFC): The project is being undertaken to reduce cost and improve the durability of SOFCs as well as develop the technology of larger-scale SOFC systems.

Hydrogen refuelling station (HRS): The actual operation of HRS in Japan has provided various hints to resolving issues related to cost reduction of capital expenditure (CAPEX) and/or operating expense (OPEX). A regulatory reform of FCV/HRS is one such approach. Unstaffed operation with remote monitoring is one solution. However, a risk assessment on HRS needs to be considered deeply. Developing low-cost equipment such as polymer materials for dispensers and electrochemical compressors is an important target as well.

Large-scale supply chain: NEDO is focusing on hydrogen power generation that can generate power from hydrogen combustion in a gas turbine to provide electricity and thermal energy in residential areas in Kobe city. To develop a large-scale supply chain, NEDO has embarked on technological development to convert unused energy from overseas into hydrogen and transport this hydrogen long distance to Japan. Therefore, NEDO selected two types of hydrogen carriers: one is liquid hydrogen from Australia, and the other is organic chemical hydrides from Brunei in a large-scale demonstration project.

Power-to-gas (P2G): NEDO conducts several P2G projects. One example is the world's largest-scale P2G demonstration with 10-MW electrolysis in Fukushima Prefecture. Hydrogen generated from renewable energy will be stocked and delivered to other areas for utilisation, such as in the Tokyo Olympic/Paralympic Games in 2020.

1.3. Hydrogen demand potential

The hydrogen supply chain has many uncertainties due to varying promotion policies, utilisation technologies, transportation and distribution logistics, and costs. This study refers to various available resources, the latest hydrogen use and technology trends, and other demand estimation documents. ERIA's energy outlook estimated the hydrogen demand potential in 2040 according to following assumptions and scenarios.

1) Assumptions and Scenarios

a) Basic assumptions

- The national hydrogen pipeline, as well as refuelling stations, will only be partially established in 2040.
- Ammonia is excluded.
- Commercialised H_2 utilisation technologies in 2040:
  - ✔ H_2 and natural gas mixed fuel gas turbine
  - ✔ H_2 and natural gas mixed fuel large-scale boiler
  - ✔ Passenger fuel cell vehicle (PFCV)
  - ✔ Fuel cell bus (FCB)
  - ✔ Fuel cell train (FCT)

b) Assumptions of the electricity generation sector

Twenty percent of new coal-fired and natural gas–fired electricity generation will be converted to natural gas and hydrogen mixed fuel-fired generation. Three scenarios are developed, which consist of hydrogen concentration of mixed fuel, 10%, 20%, and 30%.

c) Assumptions of the industry sector

Twenty percent of natural gas consumption for industrial purposes will be replaced by natural gas and hydrogen mixed fuel. Scenarios are the same as those of electricity generation.

d) Assumptions of the transport sector

Transport fuel demand will be converted to hydrogen. Scenarios consist of the share of hydrogen.

e) Scenarios of PFCV

Gasoline demand will be converted to hydrogen.

Scenario	1	2	3
OECD	2.0%	10%	20%
Non-OECD	1.0%	5%	10%

OECD = Organisation for Economic Co-operation and Development.
Source: Author.

f) Scenarios of FCB

Diesel demand will be converted to hydrogen.

Scenario	1	2	3
Japan	0.05%	0.1%	0.2%
Others	0.025%	0.05%	0.1%

Source: Author.

g) Scenarios of FCT

Diesel consumption for rail transport will be converted to hydrogen.

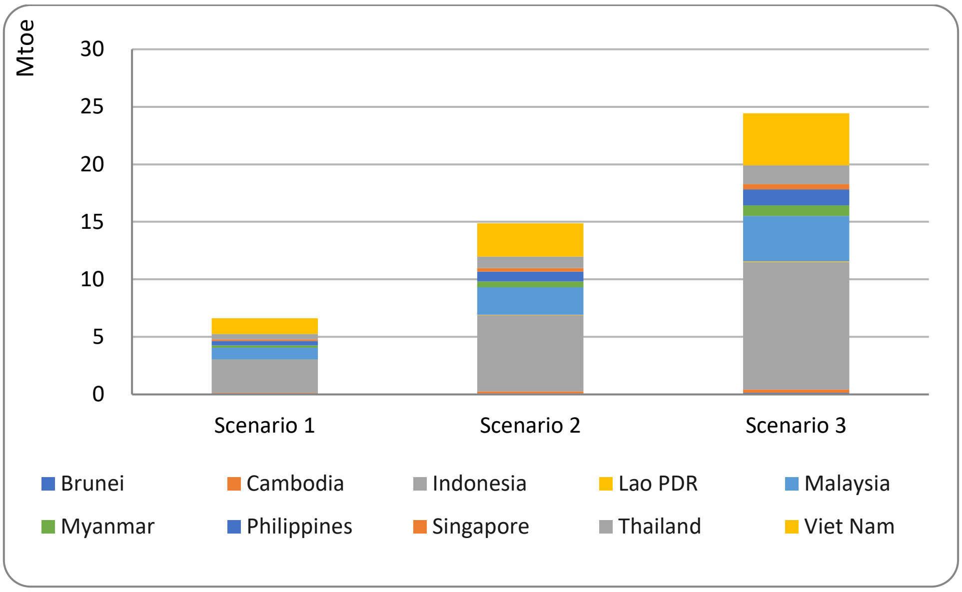
Scenario	1	2	3
ASEAN	5%	10%	20%

Source: Author.

2) Hydrogen Demand Potential in ASEAN

Indonesia has the largest hydrogen demand potential amongst ASEAN member countries, followed by Malaysia and Viet Nam. Thailand has the fourth-largest hydrogen demand potential in ASEAN (Figure 6.2).

Figure 6.2: Forecasted Hydrogen Demand (2040)

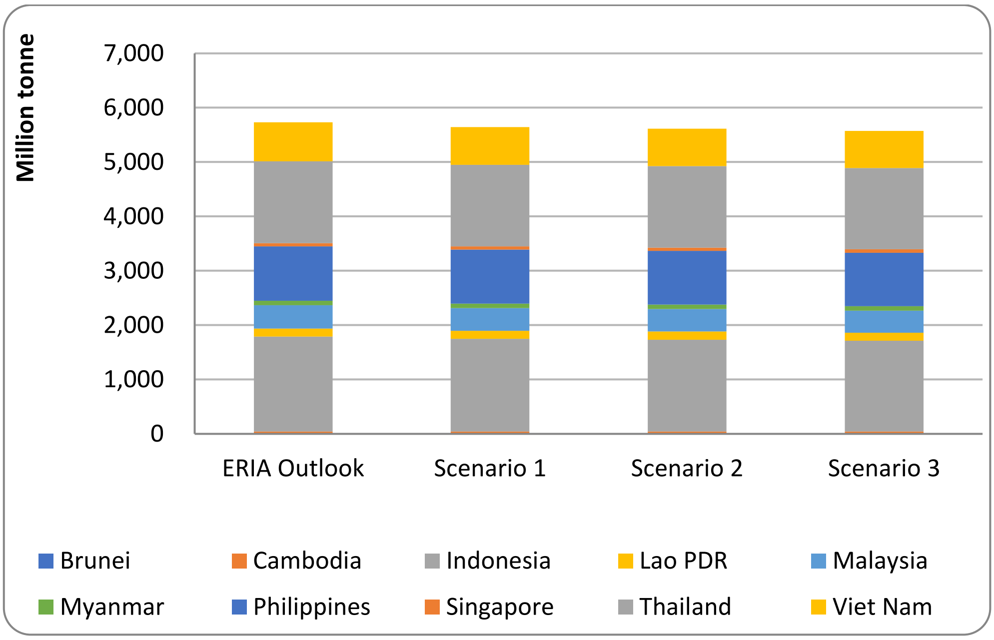


Source: Author.

3) CO_2 Emission Reduction in ASEAN

CO_2 emission can be reduced by up to 2.7% depending on the scenario, compared to the ERIA benchmark outlook. The CO_2 emission reduction rate of Thailand is smaller than the ASEAN average, –0.2%, –0.4%, –0.5% in respective scenarios (Figure 6.3).

Figure 6.3: Forecasted CO_2 Reduction, by Scenario



Source: Author.

1.4. Potential and Costs of Hydrogen Supply

There is enough potential to supply hydrogen to satisfy demand in the EAS region, including trading within the region.

In the early stages, the major hydrogen source will be fossil fuels and stable hydro and geothermal power generation. This will largely shift to abundant renewable energy as a result of technological and market development.

Hydrogen supply chains are assumed to start from supply-intensive countries to Japan, Korea, with some local supply chains in China and India. These will expand their network globally and locally in the EAS region in 2040–2050.

1) Hydrogen Production Method

Hydrogen can be produced from any kind of primary energy, from fossil fuels to renewables.

Three major fossil fuel production methods are by-product hydrogen from petrochemical industry, reformed hydrogen from gas, and gasified hydrogen from coal and petroleum liquid or solid products.

It is important to effectively manage the CO_2 resulting from hydrogen production from fossil fuels. CO_2 can be used for carbon capture utilisation and storage (CCUS) or carbon capture and storage (CCS).

Renewable electricity can be converted to hydrogen through water electrolysis; biomass can also produce hydrogen via gasification.

In the future, new technology, such as biotechnology and photocatalysts, will be expected to diversify and increase the options to produce hydrogen from renewables.

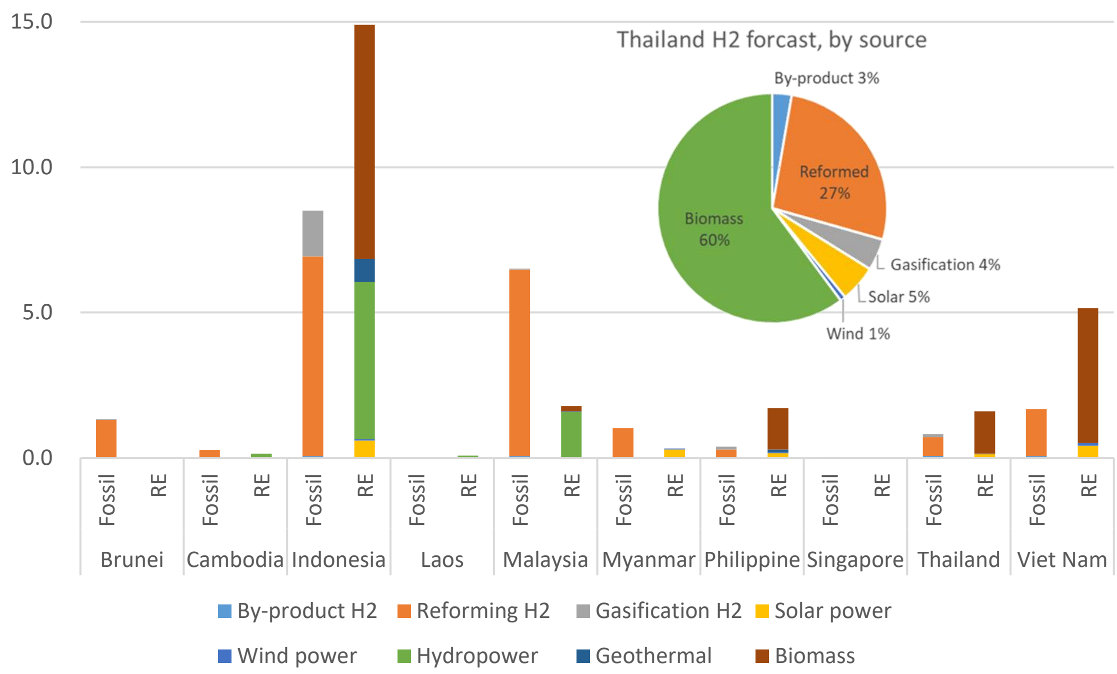
2) Hydrogen Production Forecast in 2040 (ASEAN)

In 2040, the ASEAN region is forecasted to produce 50 Mtoe of hydrogen, with Thailand accounting for 4.8% of the share, the fourth-largest producer in this region.

As a source of hydrogen in Thailand, renewable energy accounts for 66%; biomass gasification takes the largest share at 91%, followed by photovoltaics (PVs) at 8%.

Amongst fossil fuel–derived hydrogen (remaining 34%), reformed hydrogen takes the largest share at 78%, followed by vacuum residue or coke gasification hydrogen at 13%.

Figure 6.4: Hydrogen Production Potential (2040)



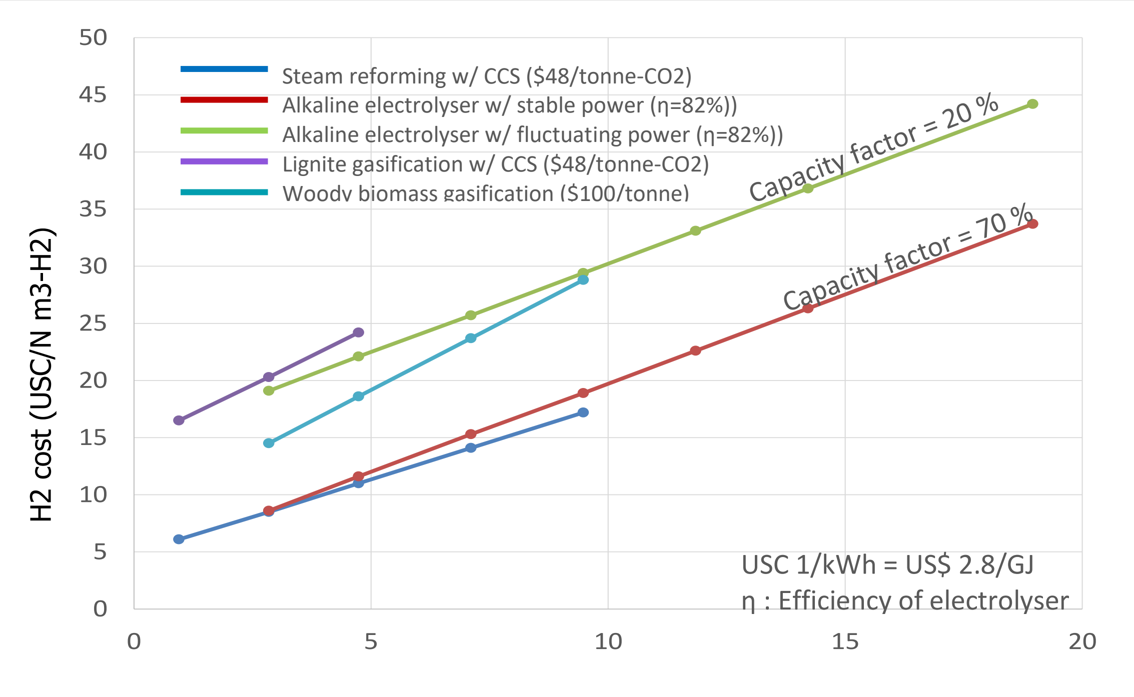
H2 = hydrogen, Lao PDR = Lao People's Democratic Republic, PV = photovoltaics, RE = renewable energy.
Source: Author.

3) Hydrogen Production Cost

Figure 6.5 illustrates the hydrogen production costs by production method. Hydrogen production cost by gas reforming is the most economical method, depending on CCUS availability. Water electrolysis with a high capacity factor plus a low feedstock price will enhance its cost competitiveness.

Lignite gasification with CCS and woody biomass gasification shows the same level of hydrogen production cost; water electrolysis with a low capacity factor shows the highest range.

Figure 6.5: Hydrogen Production Cost (2040), by Feedstock Price



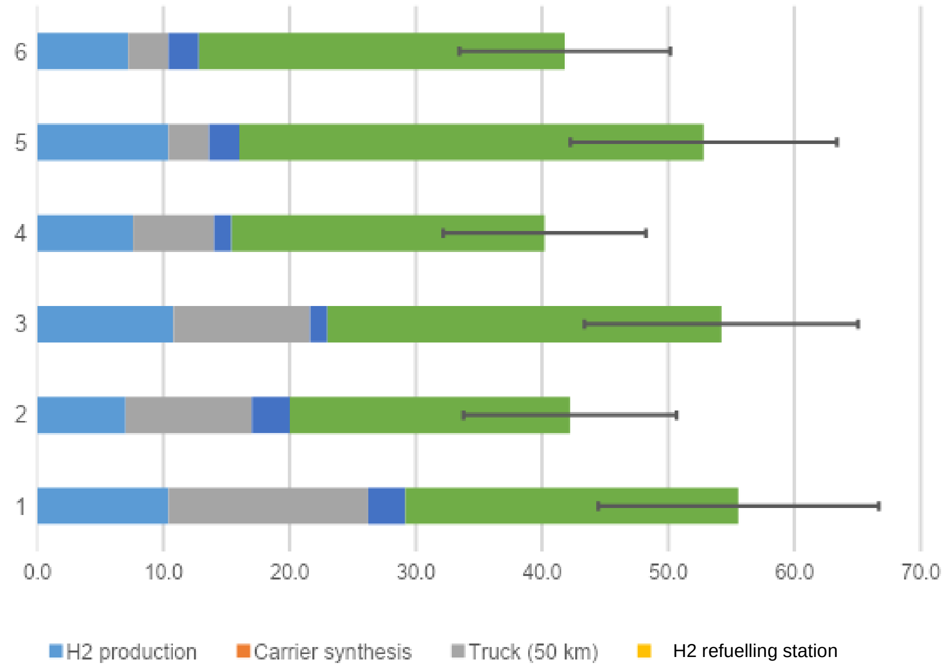
CCS = carbon capture and storage.
Source: Author.

4) Local Hydrogen Supply Chain Cost

Figure 6.6 shows an example of the costs of a local hydrogen supply chain using the selected carriers. The costs include the use of large-scale hydrogen production with carrier synthesis, and smaller scale distribution with truck transport of 50 km to hydrogen refuelling stations (HRSs).

The costs from the lowest in 2020–2030 will be in the order of methylcyclohexane (MCH), ammonia (NH3), and liquified hydrogen (LH2). NH3 will have the lowest cost in 2040–2050.

Figure 6.6: An Example of Local Hydrogen Supply Chain Cost

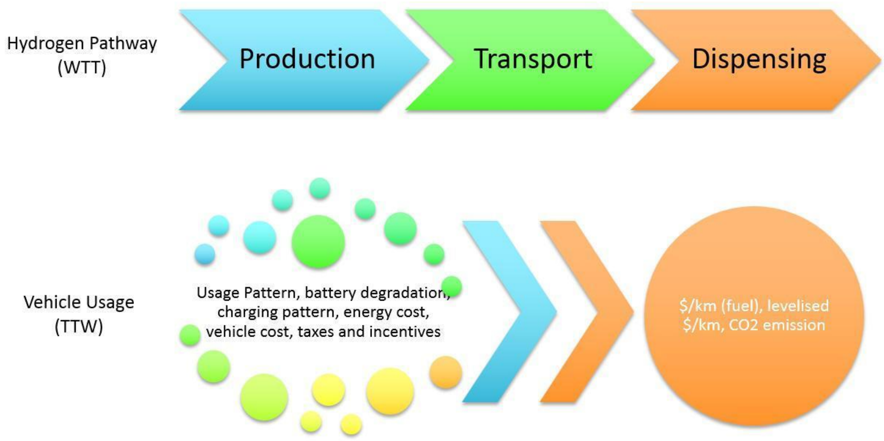


H2 = hydrogen.
Note: The data were customised based on the Institute of Applied Energy (2016).
Source: Author.

1.5. Well-to-wheel (WTW) analysis on the economics and emissions of FCVs

This study builds a WTW model to capture the energy production and consumption process, as well as the costs and emissions involved. Based on the WTW concept, a total cost of ownership (TCO) is further developed to access the cost of owning, as well as driving, a vehicle through its lifetime. The studied vehicle fleets include midsized passenger cars, buses, and heavy-duty trucks.

Figure 6.7: Well-to-Tank, Tank-to-Wheel, and Total Cost of Ownership



TTW = tank-to-wheel, WTT = well-to-tank.
Source: Authors.

Figure 6.7 shows the relationship between the WTW model and the TCO model. Basically, TCO is integrated into the tank-to-wheel part of the WTW.

Table 6.1 presents the primary energy consumption per km, carbon emissions per km, TCO per km, as well as fuel cost per km of fuel cell electric vehicles (FCEVs) consuming hydrogen produced from several ways mentioned in section 6.1.4 , compared with those of the vehicles with alternative power trains under the current circumstances. The numbers presented are the outcome of an unweighted average of all ASEAN countries. Detailed results for each country are available upon request.

Table 6.1: Current Energy Consumption, CO_2 Emissions, TCO, and Fuel Cost, by Vehicle Type

		WTW Primary Energy (kWh/km)	WTW CO_2 Emissions (kg/km)	TCO ($/km)	Fuel Cost ($/km)
Passenger Cars	FCEV	0.528	0.109	0.684	0.083
	BEV	0.223	0.093	0.529	0.024
	PHEV	0.415	0.146	0.454	0.050
	ICEV	0.392	0.132	0.326	0.048
Buses	FCEV	1.401	0.290	2.658	0.220
	BEV	1.587	0.662	1.110	0.170
	PHEV	2.537	0.886	1.515	0.305
	ICEV	4.700	1.586	1.289	0.576
Trucks	FCEV	7.076	1.463	2.037	1.109
	BEV	1.521	0.635	0.648	0.163
	PHEV	2.777	0.937	0.688	0.340
	ICEV	3.610	1.219	0.728	0.442

BEV = battery electric vehicle, FCEV = fuel cell electric vehicle, ICEV = internal combustion engine vehicle, PHEV = plug-in hybrid electric vehicle, TCO = total cost of ownership, WTW = well-to-wheel.
Source: Authors.

Table 6.2 presents the results of the future scenario (by 2030) from our model.

Table 6.2: Future Energy Consumption, CO_2 Emissions, TCO, and Fuel Cost in 2030, by Vehicle Type

		WTW Primary Energy (kWh/km)	WTW CO_2 Emissions (kg/km)	TCO ($/km))	Fuel Cost ($/km)
Passenger Cars	FCEV	0.528	0.109	0.376	0.046
	BEV	0.223	0.093	0.531	0.040
	PHEV	0.415	0.146	0.484	0.090
	ICEV	0.392	0.132	0.294	0.090
Buses	FCEV	1.401	0.290	1.426	0.123
	BEV	1.587	0.662	1.184	0.283
	PHEV	2.537	0.886	1.755	0.550
	ICEV	4.700	1.586	1.912	1.208
Trucks	FCEV	7.076	1.463	1.167	0.622
	BEV	1.521	0.635	0.691	0.271
	PHEV	2.777	0.937	0.969	0.621
	ICEV	3.610	1.219	1.114	0.831

BEV = battery electric vehicle, FCEV = fuel cell electric vehicle, ICEV = internal combustion engine vehicle, PHEV = plug-in hybrid electric vehicle, TCO = total cost of ownership, WTW = well-to-wheel.
Source: Authors.

In conclusion, the higher TCO of FCEVs is driven by the very high CAPEX of the vehicles. The adoption of FCEVs must also bear higher costs for the services of fuel transportation and dispensing.

Hydrogen production pathways are not competitive yet, except for those based on natural gas, coal, and biomass, with current level of technologies.

But all these disadvantages are highly likely to be overturned as continuous R&D brings about technological breakthrough, combined with the effects of learning curve and economy of scale, when the hydrogen supply chain, hydrogen transmission and distribution infrastructure, and manufacturing of FCEVs enter commercial operation.

If the GHG emissions benefit of renewable energy–based hydrogen supply chains is considered, the advantages of hydrogen will further boost its competitiveness against other alternative power trains.

1.6. Policy recommendations and way forward

Based on the study results, the following policy recommendations and way forward are extracted:

1) Many EAS countries, especially developing ones, do not have a clear hydrogen policy. Because these countries have many energy choices which are fossil fuel, biomass, renewable energy such as hydropower and new energy, such as solar PV. In this regard, hydrogen is one of their choices and ERIA should pay attention to this. A comparison study on cost and CO_2 emissions between hydrogen and other energy will be implemented for these countries.
2) Hydrogen demand fully depends on its supply costs and prices of FCV and hydrogen power generation system. In this study, ERIA applied the scenario approach for penetration of hydrogen demand. However, it is recommended that, after deeper research on FCV and hydrogen power system, with collaboration of their experts, the scenario will be revised.
3) Hydrogen supply costs at the station are forecasted at US$0.40–0.50/Nm^3 but it is still higher than US$0.30/Nm^3 which is the target of Japan's Basic Hydrogen Strategy. The higher price comes from higher transport cost. Consequently, an in-depth study on hydrogen transportation including technology research will be necessary. Technology to separate hydrogen and chemical products at low cost might be crucial.
4) Places of hydrogen demand are usually different from hydrogen production sites. The study extracted Australia, Brunei, Indonesia, Sarawak of Malaysia, and New Zealand as hydrogen production sites. On the other hand, Japan and Korea have large hydrogen demand. Consequently, to establish overseas hydrogen supply chains, the following studies are needed: (i) standardisation of transport method, (ii) investment to shipping and receiving terminals, and (iii) seeking for large-scale hydrogen production and transportation amounts.
5) In this regard, a working group (WG) to discuss about a common understanding on hydrogen and standardisation of the supply chain will be set up and the WG meeting will be held regularly. WG members comprise EAS countries that have hydrogen production and demand potential.

2. The Role of Hydrogen in ASEAN's Energy Transition

Brunei Darussalam has the potential to develop hydrogen fuel as it is a renewable, secure, and reliable energy source, as mentioned by Minister of Energy Dato Seri Setia Dr Awang Haji Mat Suny bi Haji Mohd Hussein at the opening of a seminar titled 'The Role of Hydrogen in ASEAN's Energy Transition' at Empire Brunei, 20 February 2020.

The first global hydrogen supply chain funded by Japan's New Energy and Industrial Technology Development Organization (NEDO), and operated by Japan's Advance Hydrogen Energy Chain Association for Technology Development's (AHEAD), was started between Brunei Darussalam and Japan. Located in Sungai Liang Industrial Park, the plant was officially launched in November 2019; it aimed to supply 210,000 tonnes of hydrogen to a gas power plant in Kawasaki, Japan. Using Chiyoda Corporation's SPERA hydrogen technology, this hydrogenation (HGN) plant produces hydrogen from by-product gas produced during a liquefaction process from natural gas to liquefied natural gas (LNG), then transported in a conventional commercial shipping in the form of a stable compound, called methylcyclohexane (MCH).

Supporting the ASEAN Plan of Action for Energy Cooperation 2016–2025, the minister also reaffirmed Brunei's support to achieve its goal of 'enhancing energy connectivity and market integration in ASEAN' to establish energy security, accessibility, affordability, and sustainability for all. Also, Brunei will chairthe EAS Energy Ministers Meeting 2021 and will explore further hydrogen energy opportunities.

Utilising hydrogen in the transport sector is one of the main reasons for unlocking the potential of hydrogen demand. Jainatul Halida Jaidin, Acting Director of the Institute of Policy Studies, Universiti Brunei Darussalam, explained that hydrogen will be a power alternative for vehicles and bolster Brunei's effort of decarbonisation. The Ministry of Energy, working closely with the Ministry of Transport and Infocommunications, is conducting intense research on hydrogen fuel cells to fulfil the growing demand for hydrogen vehicles.

This 1-day seminar was hosted by the Brunei National Energy Research Institute , the Institute of Policy Studies and the Centre for Advanced Material and Energy Sciences under Universiti Brunei Darussalam, in collaboration with the Economic Research Institute for ASEAN and East Asia (ERIA). The seminar focused on reviewing the potential of hydrogen as a future energy in the ASEAN region, technology use provided by the Chiyoda Cooperation and Kawasaki Heavy Industries, hydrogen realisation from automotive companies, Japan's hydrogen strategies, and country updates from the ASEAN Committee on Science, Technology and Innovation.

2.1. Hydrogen as Future Energy by Shigeru Kimura, Special Adviser to the President on Energy Affairs, ERIA

Mr Kimura presented the results of the previous ERIA research project on the EAS Energy Outlook Framework 2017. Utilising the energy outlook model and the econometrics analysis of The Institute of Energy Economics, Japan (IEEJ), the study produced an energy outlook in the business-as-usual scenario (BAU) and the alternative policy scenario. It also includes the energy efficiency targets and the energy saving potential report.

Macro assumptions of ASEAN as basis of the study from 2015 to 2040 encompassed (i) economic growth (4.8% per year); (ii) population growth (0.9% per year, or 634 million people in 2015 to increase to 786 million in 2040); (iii) GDP per capita (from US$4.4 thousand per person in 2015 to US$11.6 thousand per person in 2040 (constant 2010 price and US$); and (iv) crude oil price – nominal price (to increase to around US$125 per barrel (2016 constant price) in 2040 due to a tight balance between demand and supply in the future).

Key findings based on the energy modelling analysis are as follows: under BAU, the total final energy consumption will rise around 3.7% per year by 2040, with the oil and electricity sectors as the primary energy source; coal power generation will be utilised around 53% by 2040; and renewable energy will also remarkably increase. For the TPES under BAU, the share of fossil fuels (including coal, oil, and gas) will be around 84% in 2040. Based on the model, renewable energy will significantly increase yet its share will be around 14%, including biomass (about 8%) in 2040. Meanwhile, under the alternative policy scenario, the renewable energy target is 23% in 2040. In addition, ASEAN states are preparing energy saving goals and renewables to contribute to reducing fossil fuel consumption and carbon emissions under BAU. However, the emissions will still increase by 2040.

In response to that, hydrogen is proposed to be an alternative energy source to accelerate the reduction of carbon emissions. Hydrogen supply is unlimited because it can be extracted from a wide range of substances, including coal, oil, natural gas, biofuels, and sewage sludge, and can be generated from water electrolysis.

Additionally, in producing hydrogen, we need to focus on different unused energy sources, which have potential but lack capacity to utilise them. These unused sources are from flared gas, low-ranked coal (such as lignite), renewable energy electricity (i.e. hydropower stations, solar PV), and electricity from nuclear power plants.

Hydrogen in the future is expected to fulfil demand in the following sectors:

1) Road transport: FCVs (hydrogen vehicles)
2) Rail transport: FCTs
3) Power generation: natural gas and hydrogen mixed or 100% hydrogen fuel
4) Industrial heat demand: as substitute for natural gas, diesel oil, and LPG (liquefied petroleum gas)
5) Household or commercial: fixed-type fuel cell facility (cogeneration of electricity and heat)

If hydrogen can replace the oil source in the transport sector as well as coal and gas in the power generation sector, the amount of CO_2 emission will reduce significantly, particularly in the ASEAN region. Hydrogen is predicted to reduce the emission up to 370 Mtoe, which emission is generated by oil consumption in the transport sector in 2040. In the electricity sector, the emission will be reduced up to 360 Mtoe and 180 Mtoe from coal and gas generation, respectively, in 2040.

One advantage of hydrogen is that it can be stored throughout the year regardless of the seasons and can be transported long distance for distribution purposes. The main challenges of hydrogen production are to make hydrogen production and consumption economically viable, financially attractive, and socially beneficial. The main obstacles of expanding hydrogen production lie on the technology costs to utilise, such as liquid hydrogen (LH2), NH3, and chemical hydride (MCH) from fossil fuel and renewable energy as well as the transport costs for distribution.

Two factors should be considered in deciding the transportation options for distributing hydrogen: delivery volume (MJ/year) and distance (km). For domestic use, pipelines, trucks, and trains can be potential modes to distribute compressed gas, liquid or chemical carrier mode. Ships can also be an option for domestic distribution, especially for the archipelagic country. Moreover, for global distribution, a designated ship is suggested to be used to deliver hydrogen in liquid or chemical form.

We can learn from the hydrogen strategy of METI because, since 2017, Japan has been scaling up hydrogen use and allocating it to generate power and for transport. In 2020, Japan is targeting to develop an international hydrogen supply chain, establish hydrogen-derived domestic renewable energy, and fossil fuel–derived hydrogen production technology. Above all, the main goals of Japan's hydrogen production are to generate CO_2-free hydrogen using advanced technology and renewable energy.

2.2. Hydrogen demand and supply potential

This session was divided into two presentations: hydrogen demand potential, presented by the IEEJ representative, and hydrogen supply potential and production infrastructure by Chiyoda Corporation.

Hydrogen Demand Potential, by Mitsuru Motokura, The Institute of Energy Economics, Japan (IEEJ)

IEEJ analysed the hydrogen demand potential of EAS countries under the following basic assumptions:

1) A nationwide hydrogen pipeline will be partially established in 2020 as well as HRSs.
2) Ammonia, as the hydrogen carrier for combustion purposes, is excluded in the analysis as well as hydrogen for generating ammonia and/or methanol.
3) The scheme of commercialised and prevailing hydrogen technologies in 2040 will be:
    - Hydrogen and natural gas mixed fuel gas turbine
    - Hydrogen and natural gas mixed fuel large-scale boiler
    - PFCV

- FCB
- Fuel cell train (FCT)

This study identified the potential demand of hydrogen from major sectors: electricity generation, industry, and transport.

In the electricity generation sector are three scenarios, each of which is differentiated by different percentages of hydrogen concentration (10% under scenario 1, and 20% and 30% under scenarios 2 and 3, respectively). Hydrogen demand will increase by around 20% in 2040 utilising the mixed fuel natural gas and hydrogen methods. These scenarios are also applied to the industry sector.

For the transport sector, three different scenarios are based on assumptions of hydrogen use shares on conventional transport fuels, which are PFCV, FCB, and FCT. In Japan, in 2040, around 2% of gasoline-powered passenger vehicles will be converted to hydrogen-based vehicles. Meanwhile, 0.1% of diesel consumption for the transport sector and 10% for rail transport will be utilised by hydrogen.

Summarising the results of the study, Indonesia has the largest demand potential in the ASEAN region, followed by Malaysia and Viet Nam. Meanwhile, China has the largest demand potential in the EAS region. In Brunei Darussalam, the electricity sector will generate the highest demand for hydrogen, which is estimated at 0.04 Mtoe, 0.09 Mtoe, and 0.14 Mtoe under scenarios 1, 2, and 3, respectively. The next potential demand comes from the transport and the industry sectors.

The study also analysed the competitive price of hydrogen from the demand side perspective by comparing differences in CAPEX and OPEX (except fuel) with conventional energy. For the electricity generation sector, the calculation entails comparing it with fossil fuel import prices. In the industry sector, it is compared only with current natural gas sales price for industry in Japan. Lastly, only a comparison with current gasoline retail rice in Indonesia and Japan is applied to the transport sector. It is important to reduce the hydrogen cost to make it economically feasible and, hence, able to penetrate market.

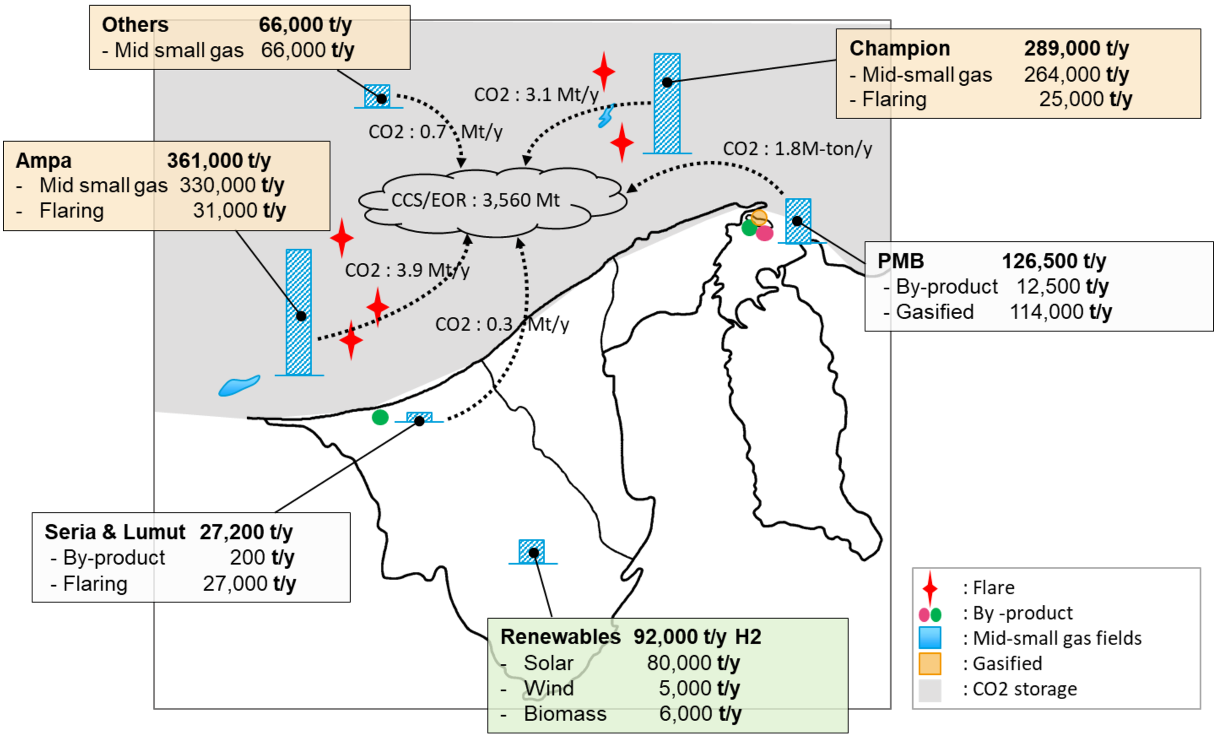
As the impact of hydrogen penetration will reduce CO_2 emission, in Brunei Darussalam, the reduction is estimated to reach 0.3 million tonnes-CO_2 under scenario 1, 1.05 million tonnes-CO_2 in scenario 2, and 0.7 million tonnes-CO_2 in scenario 3. By sector, electricity generation will contribute the most, followed by the transport and the industry sectors. The economic impact of CO_2 emission reduction will reach around US$20 million in 2040 on average.

Hydrogen Supply Potential and Production Infrastructures in ASEAN and Brunei Darussalam, by Osamu Ikeda, Chiyoda Corporation

In the EAS region, there is enough potential to supply hydrogen to meet the demand. Positioning the 16 EAS countries for hydrogen trading in 2040, five + one countries/region will potentially be in hydrogen 'exporting', including Australia, Indonesia (Eastern Region), Malaysia (Borneo), Brunei, New Zealand, and Lao PDR (export by electricity); four countries will be in hydrogen 'importing', including Japan, Korea, Malaysia (Peninsula), and Singapore and the rest of the countries will be as 'intra-regional' group, which are China, India, Indonesia (Java, Sumatera Island), Thailand, Philippines, Viet Nam, Myanmar, and Cambodia. The potential of hydrogen production is enough to fulfil the 2040 demand forecast, and exporting countries are expected to be able to cover the demand from importing countries. Meanwhile, the intra-regional trading countries could satisfy their domestic demand.

Brunei can potentially generate hydrogen mainly from natural gas, residues, and coke for large-scale production. Furthermore, hydrogen production from by-product, solar, and biomass are expected to fulfil the domestic supply. The engineering company, Chiyoda Corporation, had mapped the hydrogen potential resource in Brunei (Figure 6.8).

Figure 6.8: Brunei Hydrogen Resource Map



Source: Chiyoda Corporation presentation (2020).

In the early stage of the development, hydrogen will be generated mainly from fossil fuels or from stable hydro or geothermal and partially from renewable energy, such as solar or wind power, to supply local needs. However, in the future, a shift to abundant renewable energy is expected because of technology advancement and market development.

In 2020–2030, local supply chain and global trading to Japan will start. The global hydrogen energy supply chain network is expected to expand to the EAS region by 2040–2050. Moreover, to establish the global hydrogen market and supply chain in the EAS region, Chiyoda proposed a national and regional policy approach, as follows:

1) National Policy

a) Establish a national hydrogen strategy and road map, aimed at introducing hydrogen into the national energy market from the technical to the market and business perspectives.

b) Enhancing government support, including the introduction of financial support (tax incentives, lending support, etc.) and market mechanisms (carbon trading), especially in the early stages of development.

c) Establishing an awareness programme to enlighten key organisations and the public so that all stakeholders have a common understanding to be part of the hydrogen market.

2) Regional Policy

***Standardisation**:* Labelling the carbon reduction value of hydrogen, price determination, volume unit for global trading and statistic, and technology development as well as its safety standards.

2.3. Hydrogen Utilisation: Perspectives from the Transport and Power Generation Sectors

The following section elaborates the utilisation of hydrogen in the transport sector, as presented by the Toyota Motor Corporation as Japan's representative, and the Kawasaki Heavy Industries as the representative of the power generation sector.

Toyota's Initiatives for the Realisation of a Hydrogen-based Society, by Akihito Hayasaka, Toyota Motor Corporation, Japan

Toyota sets zero CO_2 emissions challenges by 2050 to support the Sustainable Development Goals. The emission challenges urge to target producing zero-CO_2 emission new vehicles to be applied at all Toyota plants worldwide by 2050. Since 2010 when the fuel economy (km/litre) standards have been tightened, Toyota has started increasing the production of electric vehicles to achieve the targets. Besides, it has also improved the operations at its plants by applying the low-CO_2 production technologies and daily kaizen (continuous improvement), as well as utilising renewable energy and hydrogen source.

In 1997, Toyota became the world's first mass producer of hybrid electric vehicles. This did not stop Toyota from innovating to produce more low-carbon emission vehicles. Using the hybrid technology as basis, Toyota started producing plug-in electric vehicles, battery electric vehicles, and FCEVs Toyota targets to make available the electrified version of all vehicle models at around 2025.

Mr Hayasaka elaborated the advantages of FCEVs apart from its zero emissions. FCEVs have solid performance in cold conditions, which means hydrogen storage will not be an issue during winter. The refuelling time is fast, only around 3–5 minutes. Their cruising distance is long range, around 312 miles. Also, FCEVs can be a power supply of electricity.

Toyota Mirai, established at the end of 2014, was the first FCEV. In its first 5 years, about 10,000 units were sold in Japan, the US, and Europe. Later, the sales volume will increase to more than 30,000 per year by 2020 onwards. To achieve this target, Toyota is currently expanding the fuel cell production facilities to further produce more FCEVs, FCBs, and fuel cell forklifts. Additionally, FCEV diversification will trigger more demand on hydrogen production.

Toyota also dedicated to establishing a low-carbon hydrogen plant, starting from the Toyota's Motomachi plant that produces fuel cell forklifts. The Motomachi plant has a newly established on-site hydrogen station to produce low-carbon hydrogen. This station receives gas and electricity supply from Chita city that generates city gas from biogas and Toyota city that produces electricity from biomass combustion. Throughout these low-carbon processes, the Motomachi plant has iproduced 72 units of fuel cell forklifts.

To enable the hydrogen environment and society, it is crucial to engage all stakeholders from the automotive industry, customers, governments, and academia, such as universities and research institutes, to create hydrogen demand. On the supply side, the reduction of operational costs, as well as the improvement of operation rates and optimisation of transport methods, is needed to make hydrogen supply affordable. Besides, hydrogen demand can be expanded by reducing the fuel cell system costs and expanding fuel cell mobility and hydrogen use at plants. Governments, therefore, must accommodate both sides by accelerating the revisions of regulations that support hydrogen utilisation, enacting related regulations regarding CO_2 reduction in other sectors, and providing incentives and tax benefits. If a society of diverse energy sources has been established, slowly fossil fuel consumption will be reduced, and hydrogen and other renewable energy sources can be maximised.

Development of Hydrogen Supply Chain and Gas Turbine Project, by Ryo Chishiro, Kawasaki Heavy Industry, Ltd., Japan

Based on the Paris Agreement, the power generation sector is required to shift from low carbon to de-carbonisation to address global warming. Japan targets to reduce CO_2 up to 26% by 2030 and 80% by 2050. To achieve the 2030 target, the proportion of zero-CO_2 emission power, such as nuclear and renewable energy, should be 44% or more in the total power generation. As such, power retailers must achieve that composition ratio based on the agreement. In 2018, the low-carbon power (non-fossil fuel) market was created. To increase low-carbon power, gas turbine power generation will play an important role to enhance the stability of the electricity grid by compensating intermittent power from renewable energies.

Fuel change from natural gas to hydrogen can also regulate the fluctuation of renewable energies without CO_2 emissions.

Hydrogen infrastructure technology is divided into three groups: production, transport and storage, and usage. At the production stage are two technologies: brown coal hydrogen production (through drying, pulverising, and other lignite processing technology processes), and hydrogen liquefier (using plant or urbine technology). Moreover, for the transport and storage system, ihydrogen can be employed through ultra-low temperature sealing system technology for loading system, then stored as liquefied hydrogen in the designated tanks. Liquefied hydrogen can later be transported using liquefied hydrogen cargo ships, containers, and trailers. Lastly, the hydrogen is used by gas turbines, which generate stable energy and clean combustion technology. Additionally, the liquified hydrogen has beneficial characteristics to be on large-scale transport because it has an extremely low temperature (–253^0 Celsius), 1/800th the volume of hydrogen gas, highly pure which means there is no need for refinement, and is a sustainable energy carrier because it is non-toxic and has no emissions.

CO_2-free hydrogen chains offer a stable energy supply whilst suppressing CO_2 emissions. The chains ensure low carbon emission from production to utilisation of hydrogen. For example, in Australia, hydrogen is produced at low costs from unused resources (brown coal) and/or abundant recyclable energy. Then the hydrogen is transported or stored in the form of liquefied hydrogen via cargo ships, containers, and storage tanks, and exported to Japan as the utilising country. In Japan, the liquified hydrogen is processed using semiconductors and solar batteries, oil refinement, and desulphurisation. It is also used in the transport sector and in power plants.

The Kawasaki Heavy Industries (KHI) have had hydrogen demonstration projects since 2014. In 2014, the ‘Strategic Energy Plan’ was published and in 2018 the hydrogen gas turbine cogeneration project was launched in Kobe. The pilot project demonstration is expected to be launched in 2020 and the commercial supply chain of hydrogen can be achieved in 2030. This pilot project is a bilateral cooperation between Japan (HySTRA/Technology Research Association Hydrogen Supply Chain Propulsion Mechanism) and Australia (HEA/ Hydrogen Engineering Australia).

2.4. Country Perspectives on Future Hydrogen: Brunei Darussalam and Japan

Brunei Darussalam

Perspectives on Future Hydrogen Energy in Brunei, by a representative from the Petroleum Authority of Brunei Darussalam.

Hydrogen is generated by different energy sources such as gas, coal, renewables, and nuclear, and has multiple applications, including in the transport, industry, and power generation sectors. However, the technical, cost of production, and operational aspects are the main challenges in commercialising its bulk production. Brunei has developed hydrogen and is currently producing about 125,000 Mt per year. The AHEAD Hydrogen Plant can produce 210,000 tonnes per year for export purposes, whilst the Hengyi Refinery and Petrochemical Plant is allocated for domestic use.

Looking at BAU, hydrogen produced in Brunei heavily relies on fossil fuels which generate GHG emissions. The power generation and the transport sectors are also the main contributors to the increase of GHG emissions. Such emissions are expected to further increase in the coming years when the demand for power generation increases due to industrial growth. Therefore, Brunei established the Brunei energy mix to speed up renewable energy to reduce its carbon footprints. Solar power is currently the primary focus of renewable energy. Meanwhile, hydrogen also provides opportunities to further achieve Brunei's commitments to tackle the impacts of climate change. An example of such combination is when hydrogen production is powered by renewable energy.

In promoting the hydrogen society in Brunei, the government developed short- and medium-term plans. In the short term, the plan focuses on making Brunei an initiator of hydrogen application, such as FCEVs in the transport sector. Research and development (R&D) is intensively conducted, for example, by studying the small-scale application of hydrogen produced by AHEAD for 2021/2022. This study will be applied in the small and mid-term plan. Also, the government conducts a comparative study on expansion or commercial scale of AHEAD plant and renewable hydrogen. For the long term, Brunei plans to combine renewable energy and hydrogen production. By then, there will hopefully be cost-competitive technology options for commercial deployment.

There are several challenges in creating hydrogen as an affordable technology. During the production process, limited resources for technology development is one challenge, specifically, in producing CCU-derived fuels for the transport sector as well as combining renewable energy and hydrogen technology for the future. This limitation encompasses funding, availability of raw materials, and proven competitive technologies. In terms of technology application, the challenges lie on creating a competitive life cycle cost, affordable infrastructure, and regulation for safer operation. Brunei aims to incorporate these challenges in its 'National Climate Change' policy.

Japan

Japan's Hydrogen Strategy by Daishu Hara, representative of the New Energy and Industrial Technology Development Organization (NEDO).

Mr Hara elaborated on NEDO's role in Japan's hydrogen development and application.

NEDO was established in 1980 under the Ministry of Economy, Trade and Industry (METI), Japan. This organisation supports the government to enhance technology and innovation development and policy formation. The development of hydrogen is necessary due to the contribution to the 3Es (environment/decarbonisation, energy security/energy independency, and economic/low-cost feedstock), and safety. Also, the government has allocated hydrogen energy as one of Japan's primary energy since 2015. Japan's 2050 vision is to make hydrogen a new energy option following renewable energies, and make it affordable, at US$2 per kg.

To achieve these goals, in 2018 during Hydrogen Energy Ministerial Meeting in Tokyo, the chair highlighted, in his Tokyo statement, four main keys: (i) collaborating on technologies and coordinating on harmonisation of regulation, codes, and standards of hydrogen development; (ii) promoting information sharing and international joint R&D; (iii) evaluating and studying hydrogen's potential across sectors; and (iv) improving communication, education, and outreach.

NEDO also established a strategic road map for hydrogen use in mobility, especially for fuel cells. Approaches to implementing the action plans mainly lie on technical improvement to expand the application of hydrogen, collaboration amongst stakeholders, and regulation of reforms to realise a global hydrogen society.

The current status of fuel cell application in Japan covers many sectors, including residential, commercial/industrial, and automotive. For residential use, 'Ene-Farm', the world's first fuel cell unit for practical home use, usually for water heaters, has set a lower selling price to boost its installation units. Then the SOFC units have been sold for commercial and industrial use since March 2019. This technology aims to increase power and heat generation efficiency. Lastly, until 2019, 3,500 FCVs were sold on-road, including around 100 units of HRSs, throughout Japan following its application on 22 FCBs, several delivery trucks, and forklift vehicles.

Moreover, strong support from the government on hydrogen development for fuel cell expansion resulted in the establishment of the Japan Hydrogen Station Network Joint Company, or Japan H2 Mobility in February 2018. This network was intended to encourage collaboration amongst various stakeholders, including automakers, infrastructure developers, and investors to develop strategic deployment of hydrogen stations, lower the cost of the stations, and improve FCV customers' convenience whilst using the HRS.

NEDO's programmes on R&D are divided into two main steps covering (i) a promotion fuel cell application, and (ii) the development of hydrogen demand and integration with the energy system. In the first step, NEDO's direction is to improve the application of fuel cells for mobility by improving its productivity and focusing on basic research to accelerate material development. The SOFCs were targeted to improve efficiency for stationary use. Meanwhile, NEDO is trying to reduce the CAPEX and/or OPEX, as well as develop low-cost equipment of the HRSs, to address regulatory reform on FCVs and HRSs in Japan. For the second step, to increase hydrogen demand, NEDO has taken several steps, including incorporating hydrogen with gas turbine (H2 gas turbine/H2GT) and improving electrolysis technology to boost power-to-gas systems.

2.5. Country updates from ASEAN's Committee on Science, Technology, and Innovation

A roundtable discussion in the last session was delivered by the ASEAN countries' representatives that are from the Committee on Science, Technology, and Innovation (COSTI), and is led by Romeo Pacudan from the Brunei National Energy Research Institute as moderator. The country updates of the energy policies and strategies related to hydrogen development are summarised in Table 6.3.

Table 6.3: Country Energy Updates by COSTI's Representatives

Country	Policy and Strategy Updates
Malaysia	● The Government of Malaysia has set hydrogen fuel cell production as a priority research since 1997. ● Some universities are also actively contributing to hydrogen research, indicated by the establishment of the Institute of Fuel Cell at the Universiti Kebangsaan Malaysia (UKM), and a Center of Hydrogen Energy at the Universiti of Technology Malaysia (UTM). ● Malaysia also established a showcase of hydrogen economy, called the Malaysian Eco-house, at the UKM. It exhibits the use of renewable energy (solar) to generate electricity and power electronic devices, fuel cells, cooking stoves, etc. ● In 2008, the UTM successfully developed a fuel cell motorcycle run by a 7-kilowatt fuel cell system as the motor to drive the back wheel. ● In 2014, the UKM first launched a body named Malaysian fuel cell indigenous motorcycle vehicle. ● For the policy perspectives, Malaysia has a Hydrogen Road Map 2015–2030 aiming to develop hydrogen as a source of energy and economic competitiveness. According to the road map, Malaysia planned: ➢ To establish the first hydrogen refuelling system (HRS) in 2009; yet, it had no station until 2015. ➢ In 2018, Malaysia set up the Fuel Cell Hydrogen Blueprint; yet, there are no actions, only policy related to hydrogen was established. ➢ To include hydrogen in the 12th Malaysian Plan, which will be announced in 2020. ● The first hydrogen production was launched in 2019 by a private company under the state government of Serawak. It is expected to produce 130 kg of hydrogen and hydrogen buses. Also, Serawak will add six more HRSs.

	● Challenges the governments face, mostly on the technical approaches: ➢ Hydrogen production is still at the pilot skill stage; difficult to scale up for production and efficiency, storage, and transportation ➢ Fuel cell quality and priorities ➢ Proposing more fund from the government to support the research & development (R&D) ➢ Intellectual exchanges with other countries ➢ Difficulties in commercialising hydrogen energy due to its higher cost of production and operation compared to fossil fuel, as well its public acceptance.
Lao PDR	● The main energy sources in the Lao PDR are hydro, solar, and bioenergy. ● The Lao Ministry of Science and Technology has conducted several pilot projects for new energy technology, but hydrogen has not yet been included in the energy projects. The country is focusing more on maximising the current energy sources. Therefore, there are no hydrogen production and stations up to now.
Singapore	● The national energy policy of Singapore focuses on the development of natural gas, solar power, regional power grid, and low-carbon energy, including hydrogen. ● The Office of the Prime Minister is conducting a feasibility study on hydrogen potential. It is looking into the operational, R&D, and hydrogen policy recommendations. The report on this study is planned to be released in July 2020. ● Singapore plans to import hydrogen from other countries.
Thailand	● Thailand has been developing fuel cell technology since 1992, generating hydrogen from the Bangkok Coal Power Plant. However, it is not yet for commercial purposes. ● Thailand has many refinery plants, and each refinery runs a hydrogen production unit. ● For hydrogen from renewable energy source, Thailand is considering using biogas and ethanol. ● Currently, Thailand is looking at hydrogen as a chemical storage to produce fuel cell for electricity and transport mobility. ● In terms of R&D, the Thailand government has many international collaborations with several universities, such as in the United Kingdom and France, as well as with Thai universities.

Myanmar	● Myanmar's main energy sources are hydropower, coal, natural gas, and solar. ● Myanmar has utilised only around 40% of energy development, thus, more collaboration with many stakeholders is needed to maximise its energy sources.
Indonesia	● Indonesia is developing hydrogen energy from fossil fuels and focuses more on hydrogen production than fuel cell. ● The National Research Priority Plan 2020–2040 clearly states that biohydrogen is one of the top priorities. Biohydrogen is produced through biological fermentation and anaerobic process – the so-called biomass source, which is made of fatty acid methyl ester or FAME from crude palm oil, palm oil crown (palm oil industries), cassava (agricultural industries), and molasses from sugar cane industries. ● Indonesia is developing a prototype of biohydrogen reactor. As it is still at the early stage, its capacity is still low. So far, it has been able to produce 720 litres of hydrogen gas per hour with 99% purity, which is expected to reduce the hydrogen price. This reactor is also possible to be installed close to the biomass source that is located on the agricultural industries. ● The researchers are trying to connect the reactor to the existing electricity grids to stabilise electricity generation. ● In 2018, the government collaborated with the National Electricity Agency and Toshiba Japan to develop green hydrogen production, combined with renewable energy sources, mainly solar PV and wind turbine. ● The Science and Technology Research Centre implemented a project called Autonomous Hydrogen System (H2-1), targeted for commercialisation by 2023. ● To develop clean hydrogen energy, the government needs to focus on the infrastructure development of renewable energy. One of the priorities is to increase the capacity of solar PV up to the megawatt scale. The target is for the electricity generated from solar energy to be stored in batteries and be able to produce hydrogen. ● The key challenges in producing hydrogen are as follows: ➢ Technical challenges ➢ Ensuring constant delivery and stable power from hydrogen ➢ Improving the current power system ➢ Implementing the smart battery system ➢ Storing hydrogen effectively when it is combined with the electrolysis system ➢ How to decrease hydrogen operational costs

Viet Nam	● Up to now, Viet Nam has no hydrogen production units at the industry scale, even though many refineries exist in the country. ● In the Viet Nam energy road map, Viet Nam targets 30% of its energy production to be generated from renewable energy, including solar power, hydropower, wind power, and hydrogen by 2040. ● Increasing interests in hydrogen technology research are from the Ministry of Science and Technology and several universities

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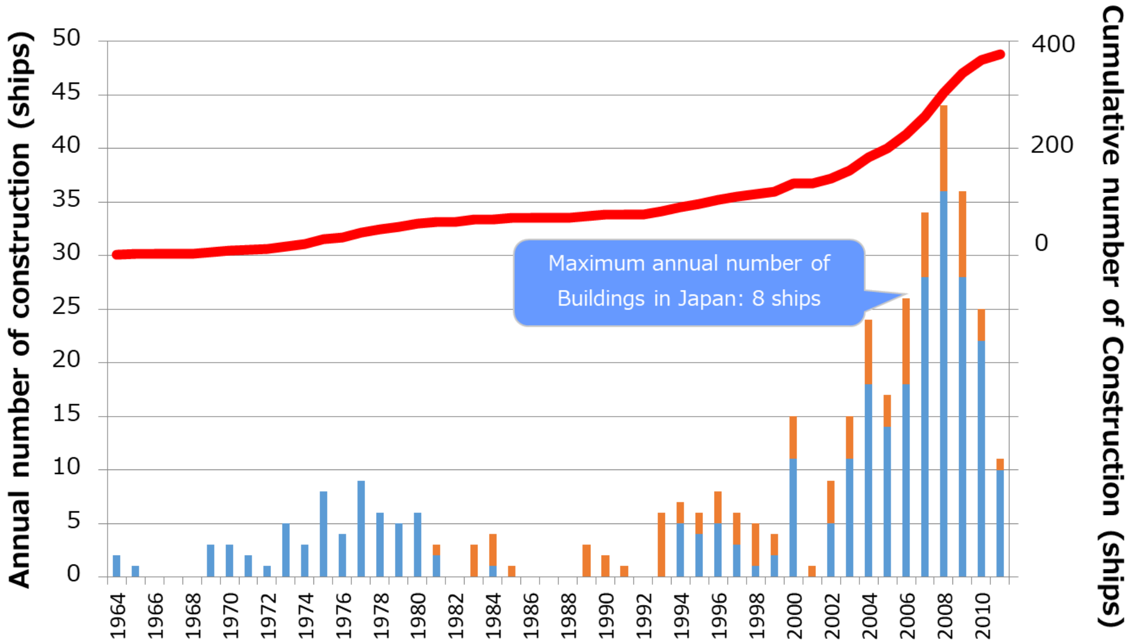
Appendices

Appendix 1. LNG Carrier Construction

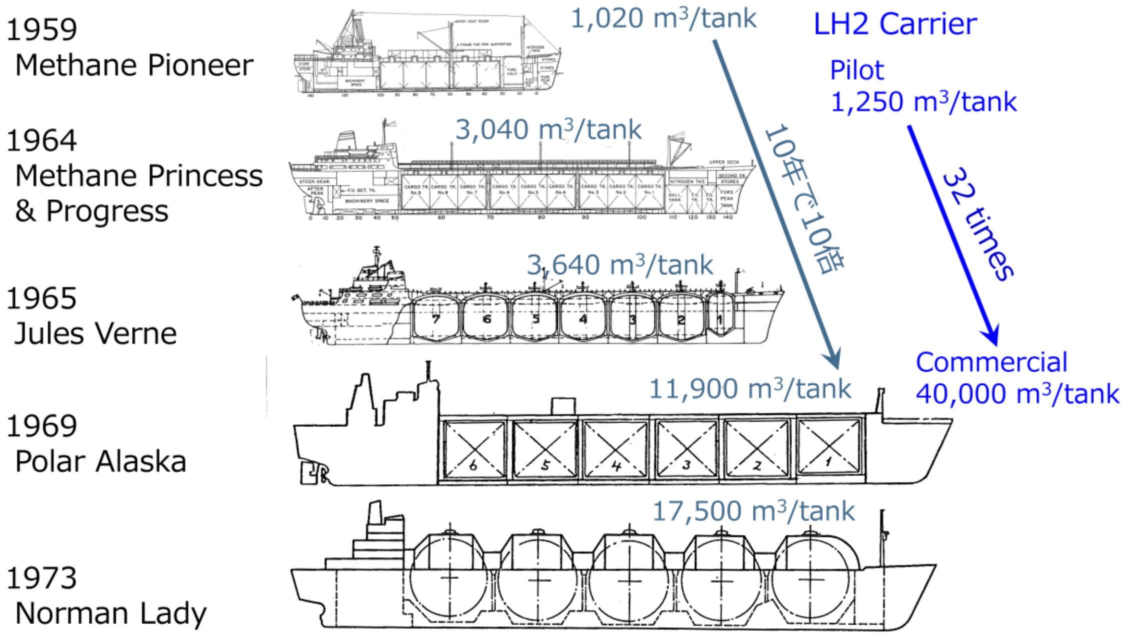


Notes 1: Over 20 years since the commercial start (1964), a cumulative total of more than 70 ships have been built.

2: As of 2016, 439 vessels are in operation (about 120 vessels in Japan).

Source: Itoyama (2012); Estimated by Kawasaki.

Appendix 2: History of Large LNG Carriers



Source: Itoyama (2012).