Republic of Indonesia
Ministry of Energy and Mineral Resources (MEMR)
State Electricity Company (Perusahaan Listrik Negara (PLN))

Data Collection Survey on Power Sector in Indonesia for Decarbonization

Final Report

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Japan International Cooperation Agency (JICA)

TEPCO Power Grid, Inc. (TEPCO PG)
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Abbreviations

Abbreviation	Word
AETI	Asia Energy Transition Initiative
AFD	Agence Française de Développement
AGC	Automatic Generation Control
AIIB	Asian Infrastructure Investment Bank
APS	Announced Pledges Scenario
ASEAN	Association of South East Asian Nations
ATR	Autothermal reforming
BAPPENAS	Badan Perencanaan Pembangunan Nasional (Ministry of National Development Planning)
BAU	Business as usual
BECCS	Bio-energy with Carbon Capture and Storage
BESS	Battery Energy Storage System
BOO	Build-Own Operate
BOT	Build, Operate and Transfer
BP	Black Pellet
BPP	Biaya Pokok Penyediaan(Cost of Electricity Supplies)
BPSDM	Badan Pengembangan Sumber Daya Manusia (Human Resources Development Agency)
BUMN	Kementerian Badan Usaha Milik Negara
CAPEX	Capital Expenditure
CCGT (C/C)	Combined Cycle Gas Turbine
CC(U)S	Carbon dioxide Capture, Utilization and Storage
CD-ROM	Compact Disc Read only memory
CEO	Chief Executive Officer
CETP	Clean Energy Transitions Programme
CFR	Cost and Freight
CGR	Center for Geological Resources
CoE	Indonesia Center of Excellence for CCS and CCUS
COP26	The 26th Conference of the Parties to the United Nations Framework Convention on Climate Change
C/P	Counterpart
CPOS	Current Policy Scenario
DACCS	Direct Air Carbon Capture and Storage
DC	Direct Current
DEN	DEWAN Energi. Nasional (National Energy Council)
DJEBTK	Direktorat Jenderal Energi Baru Terbarukan dan Konservasi Energi
DJK	Direktorat Jenderal Ketenagalistrikan
DME	Dimethyl Ether
DMO	Domestic Market Obligation
DNI	Direct Normal Irradiance
DPT	Daftar Penyedia Terseleksi
DSS	Daily Start Stop
EBF	Equity Back Finance
ECBM	Enhanced coal bed methane
EGR	Enhanced Gas Recovery
ELD	Economic Load Dispatching
ENI	Ente Nazionale Idrocarburi
EOR	Enhanced Oil Recovery
EPA	Agreement between Japan and the Republic of Indonesia for an Economic

Abbreviation	Word
	Partnership
EPC	Engineering, Procurement, Construction
ERIA	Economic Research Institute for ASEAN
ETM	Energy Transition Mechanism
ETS	Emissions Trading System
EU	European Union
EV	Electric Vehicle
EVCS	Electric Vehicle Charging Station
EYA	Energy Yield Assessment
FC	Fuel Cell
FFR	Fast Frequency Response
FIRR	Financial Internal Rate of Return
FIT	Feed in Tariff
FOAK	First of a kind
FOLU	Forestry and Other Land Uses
FRU	Floating Regasification Unit
FS	Feasibility Study
FSRU	Floating Storage and Regasification Unit
FSU	Floating Storage Unit
GCCSI	Global CCS Institute
GDP	Gross Domestic Product
GGGI	Global Green Growth Institute
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiation
GIS	Geographic Information System
GT	Gas Turbine
GTCC	Gas Turbine Combined Cycle
HPPS	Hydropower Potentials Study
IAE	Institute of Applied Energy
ICP	Indonesia Crude oil Price
IDD	Indonesian Deepwater Development
IDR	Indonesian rupiah
IEA	International Energy Agency
IEEJ	The Institute of Energy Economics, Japan
IESR	Institute for Essential Services Reform
IFC	International Finance Corporation
IGCC	Integrated coal Gasification Combined Cycle
IHI	IHI
INPEX	INPEX
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
IPPU	Industrial Processes and Product Use
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization
ISO	Independent System Operator
ITB	Institut Teknologi Bandung
IUPTL	Izin Usaha Penyediaan Tenaga Listrik
JANUS	JANUS
JBIC	Japan Bank for International Cooperation
JCM	Joint Crediting Mechanism
JERA	JERA

Abbreviation	Word
JICA	Japan International Cooperation Agency
JJC	Jakarta Japan Club
JOC	Joint Operation Contract
JX	JX
KEN	Kebijakan Energi Nasional
KfW	Kreditanstalt fűr Wiederaufbau
KOICA	Korea International Cooperation Agency
LCCP	Low Carbon Scenario Compatible with Paris Agreement Target
LCOE	Levelized Cost of Electricity
LCOH	Liquid Organic Hydrogen Carrier
LEMIGAS	LEMIGAS
LFC	Load Frequency Control
LFP	Lithium, Ferrum, Phosphorous
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
LPG	Liquefied Petroleum Gas
LT-LEDS	Long-term Low Greenhouse Gas Emission Development Strategy
LTS-LCCR	Long Term Strategy for Low Carbon and Climate Resilience 2050
MCH	Methylcyclohexane
MCFC	Molten Carbonate Fuel Cell
MEMR	Ministry of Energy and Mineral Resources
MOEF	Ministry of the Environment & Forestry
MOF	Ministry of Finance
MoU	Memorandum of Understanding
MPI	Medco Power Indonesia
MSOE	Ministry of State Owned Enterprises
MTPA	Million Tones per annual
NAS	Natrium, Sulfur
NCA	Nickel, Cobalt, Aluminum
NDC	Nationally Determined Contribution
NEDO	New Energy and Industrial Technology Development Organization
NEP	National Energy Policy
NEXI	Nippon Export and Investment Insurance
NGCC	Natural Gas Combined Cycle
NMC	Nickel, Manganese, Cobalt
NOAK	Nth of a kind
NRE	New and renewable energy
NZE	Net Zero Emissions
ODA	Official Development Assistance
OECD	Organisation for Economic Cooperation and Development
O&M	Operation and Maintenance
OPEX	Operating Expense
P2B	Pusat Penfaturan Beban
P3B	Penyalran dan Pusat Penfaturan Beban
PA	Public Acceptance
PAU	Panca Amara Utama
PBB	Pajak Bumi dan Bangunan
PCS	Power Conditioner
PDPAT	Power Development Planning Assist Tool
PEM	Polymer Electrolyte Membrane
PGE	Pertamina Geothermal Energy

Abbreviation	Word
PHV	Plug-in Hybrid Vehicle
PKS	Palm Kernel Shell
PLN	Perusahaan Listrik Negara
PMU	Phasor Measurement Units
POME	Palm Oil Mill Effluent
PPP	Public Private Partnership
PSA	Pressure Swing Adsorption
PSO	Public Service Obligation
PSPP	Pumped Storage Power Plant
PSS/E	Power System Simulator for Engineering
PV	Photovoltaic
RAS	Remedial Action System
RD&D	Research, Development & Demonstration
RF	Redox Flow cell
RITE	Research Institute of Innovative Technology for the Earth
ROE	Return on Equity
ROR	Run-of-River
RPJMN	Rencana Pembangunan Jangka Menengah Nasiona
RTIL	Room Temperature Ionic Liquid
RUEN	Rencana Umum Energi Nasional (National Energy General Plan)
RUPTL	Rencana Usaha Penyediaan Tenaga Listrik (General Plan for the Provision of Electricity)
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SC	Super Critical
SCADA	Supervisory Control and Data Acquisition
SEWGS	Sorbent-Enhanced Water Gas Shift
SKK-MIGAS	Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak Dan Gas Bumi
SMR	Steam methane reforming
SPC	Special Purpose Company
SPE	The Society of Petroleum Engineers
SPS	Special Protection Scheme
SRCCS	Special Report on Carbon Dioxide Capture and Storage
SRMS	Storage Resources Management System
STEPS	Stated Policies Scenario
TRNS	Transition Scenario
TRL	Technology Readiness Level
TSA	Temperature Swing Adsorption
TTL	Tarif Tenaga Listrik (Electricity Tariff)
UIC	Underground Injection Control
UNDP	United Nations Development Programme
UNFCCC	United Nations Framework Convention on Climate Change
USAID	United States Agency for International Development
USC	Ultra Super Critical
VGF	Viability Gap Funding
VLSFO	Very low sulfur fuel oil
VSG	Virtual Synchronous Generator
WEO	World Energy Outlook
WP	White Pellet

Chapter 1. Introduction

1.1 Background to the Survey

Indonesia has maintained a gross domestic product (GDP) growth rate of about 5 - 6% since 2010 and continues its stable economic growth. Reflecting the strong economic growth, the country’s annual sales of electricity (2018: 234 TWh) are expected to increase by approximately 6.4% on average per year to 433 TWh in 2028. The country depends strongly on coal-fired power generation, hence there are concerns about an increase in greenhouse gas emissions as the demand increases in the future. The national energy policy developed by the country in 2014 advocates the development of renewable energy, etc., and an increase in the ratio of renewable energy to the primary energy supply, to 23% or more in 2025 and 31% or more in 2050. Long Term Strategy for Low Carbon and Climate Resilience 2050 (LTS), which was submitted to the UNFCCC (United Nations Framework Convention on Climate Change) by the Indonesian government in July 2021, states that the government will make efforts to achieve carbon neutrality by 2060 or earlier. As the rapid mass introduction of renewable energy can lead to system destabilization, to achieve low carbonization (decarbonization) it is necessary to pay attention to electricity charges and the quality of electricity in formulating and implementing plans. Organizing a roadmap for low carbonization (decarbonization) in the electricity sector, together with JICA support measures, is an urgent matter.

1.2 Purpose of the Survey

The purpose of this survey is to develop a roadmap which indicates concrete energy scenarios and the desired electricity supply, and to organize feasible JICA support measures via schemes based on the roadmap.

1.3 Area in Which to Conduct the Survey

The whole of Indonesia is the target for the survey.

1.4 Conducting Organizations in the Partner Country

- Ministry of Energy and Mineral Resources (MEMR)
- State Electricity Company (Perusahaan Listrik Negara (PLN))

Chapter 2. Energy Policy in Indonesia

2.1 National Policy

In Indonesia, the "National Energy Policy (KEN: Kebijakan Energi Nasional)" provides a comprehensive energy policy for the country based on the Energy Law (Law No.30/2007) which was enacted in 2007. The following is an outline of the Energy Law, the KEN, and the National Energy Plan based on the KEN.

2.1.1 The Energy Law (Law No.30/2007)

The Indonesian energy sector is comprehensively controlled by the Energy Law, which was enacted in 2007. Under the law, energy resources management by the Indonesian government, a stable supply of energy, government subsidies to the poor, promotion of resource development, and the establishment of the National Energy Council (DEN: Dewan Perancang Nasional) to formulate national energy policies are stipulated. (See Table 2-1 for the main contents of the Energy Law.)

Table 2-1 Main Contents of the Energy Law

(1)	The management of energy resources by the Government
(2)	Stable supply of energy (prioritize domestic supply over export)
(3)	Provision of government subsidies to the poor
(4)	Promotion of resource development (expansion of domestic procurement rate)
(5)	Formulation of National Energy Policy
(6)	Establishment of National Energy Council
(7)	Composition of National Energy Plan (composition of national and regional energy plan)
(8)	Government support for the supply and utilization of renewable energy and the implementation of energy conservation

(Source: Japan Electric Power Information Center report)

2.1.2 National Energy Policy (Government Regulation No.79/2014)

The National Energy Policy (KEN) is at the head of the plan in the Indonesian energy sector. The current KEN was approved by the Diet in January 2014 and was signed by then-President Yudhoyono (Government Regulation No. 79/2014) in October 2014. As shown in Table 2-2, KEN sets mid-to-long term numerical targets for promoting the deployment of new and renewable energies and promoting energy conservation, in addition to reducing dependence on fossil fuels.

Table 2-2 The National Energy Policy 2014 target

	2025 target	2050 target
Primary Energy Supply	around 400 MTOE	around 1,000 MTOE
Primary Energy Consumption per capita	around 1.4 TOE	around 3.2 TOE
Power Generation Capacity	around 115GW	around 430GW
Electricity Consumption per capita	around 2,500kWh	around 7,000kWh
Energy Elasticity achievement[1]	less than 1	—
Reduction in Final Energy Intensity	1% per year	—
Percentage of new and renewable energy in primary energy	at least 23%	at least 31%
Percentage of oil in primary energy	less than 25%	less than 20%
Percentage of coal in primary energy	at least 30%	at least 25%
Percentage of natural gas in primary energy	at least 22%	at least 24%

*It also sets Electrification Ratio target of 85% in 2015 and 100% in 2050, and the household gas utilization ratio of 85% in 2015.

(Source: Government Regulation No.79/2014, Article 8 and 9)

2.1.3 National Energy Plan (RUEN)

The "National Energy Plan (RUEN: Rencana Umum Energi Nasional)" describes the measures necessary to achieve the goals set by the KEN. The current RUEN was enacted in 2017 by the Minister of Energy and Mineral Resources with the approval of the National Energy Council (DEN: Dewan Energi Nasional). (See Chapter 3 for Indonesian electricity policy)

2.2 Energy Sector and Power Sector

2.2.1 Government Agencies

Major administrative agencies in the energy sector in Indonesia include the "National Energy Council (DEN)", which formulates and coordinates policy-level plans such as the KEN and the RUEN, "National Development Planning Agency (BAPPENAS)", which formulates and coordinates the National Development Policy, "Ministry of Energy and Mineral Resources (MEMR)", which oversees the entire resource and energy sector, "Ministry of State Owned Enterprises (MSOE)", which owns and manages the state-owned electric power company PLN, and "Ministry of Finance (MOF)", which approves the budget and so on.

2.2.2 Electricity Business-related Corporations

In Indonesia, PLN, the electric power company wholly owned by the government, covers areas from power generation to retail as a vertically integrated company. PLN owns power generation subsidiaries such as "PT Indonesia Power" and "PT Pembangkit Jawa Bali". (See Chapter 3.2.)

In the power generation sector, in addition to the PLN Group (installed capacity share: 72.6%), IPPs have also entered the market. However, the transmission and distribution sector and the retail sector are monopolized by the PLN Group.

[1] Divide energy consumption growth rate by economic growth rate

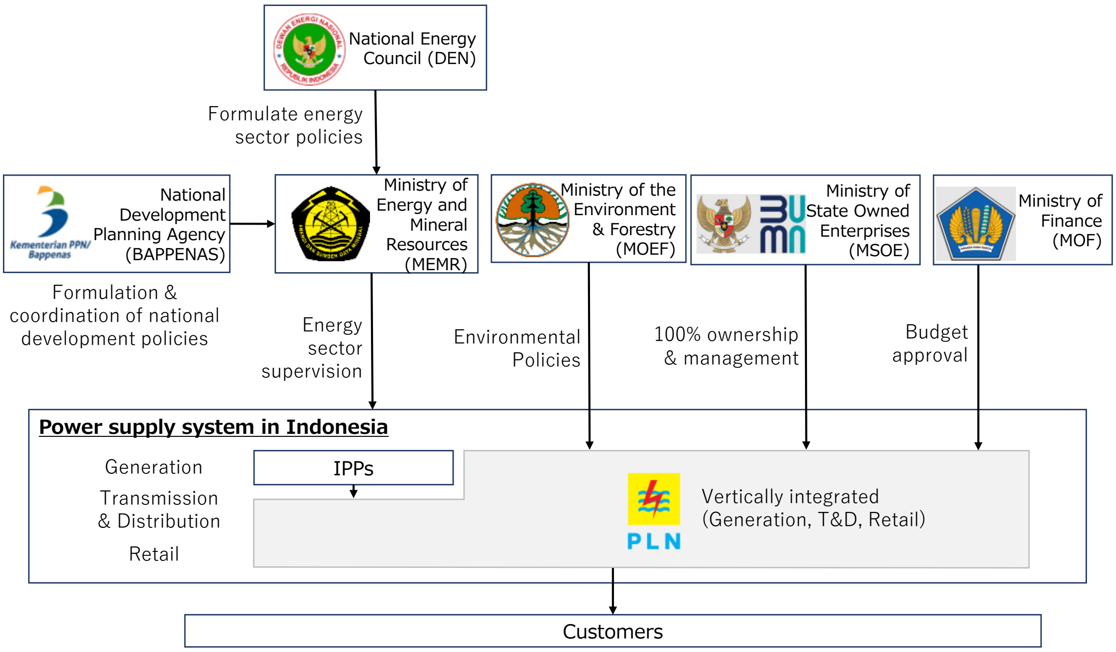
2.3 Role of each Organization in the Power Sector

Table 2-3 summarizes the roles of the main government agencies mentioned in Chapter 2.1. Figure 2-1 shows the organizational relationship in the power sector.

Table 2-3 The role of major government agencies in the energy sector

Name of government agencies	Role
Ministry of Energy and Mineral Resources (MEMR)	In charge of the entire resource and energy sector (See Figure 2-2 for the current organizational structure)
Ministry of Finance (MOF)	Budget approval
Ministry of State Owned Enterprises (MSOE)	100% ownership and management of PLN
Ministry of the Environment & Forestry (MOEF)	Environmental policy formulation such as "Nationally Determined Contribution (NDC) " and " INDONESIA Long-Term Strategy for Low Carbon and Climate Resilience 2050 (LTS-LCCR)"
National Development Planning Agency (BAPPENAS)	Formulation and coordination of national development policies, etc.
National Energy Council (DEN: Dewan Energi Nasional)	Formulate comprehensive energy sector policies Established in 2009 based on the Energy Law enacted in 2007 and chaired by the President

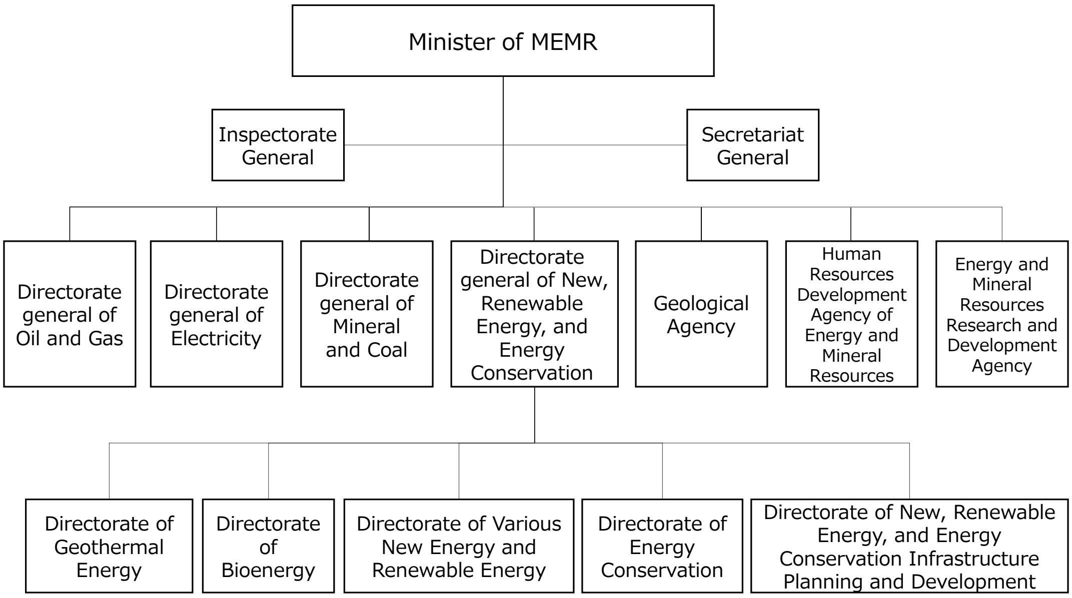
(Source: JICA Survey Team)



(Source: JICA Survey Team)

Figure 2-1 Organizational relationship diagram for the power sector

Figure 2-2 shows the organizational structure of MEMR. Under the Minister of Energy and Mineral Resources, MEMR consists of 4 Directorate Generals (Directorate General of Oil and Gas, Directorate General of Electricity, Directorate General of Minerals and Coal, and Directorate General of New, Renewable Energy, and Energy Conservation) and 3 Agencies (Geological Agency, Human Resources Development Agency of Energy and Mineral Resources, and Energy and Mineral Resources Research and Development Agency).



(Source: MEMR website)

Figure 2-2 Organizational structure of Ministry of Energy and Mineral Resources (MEMR)

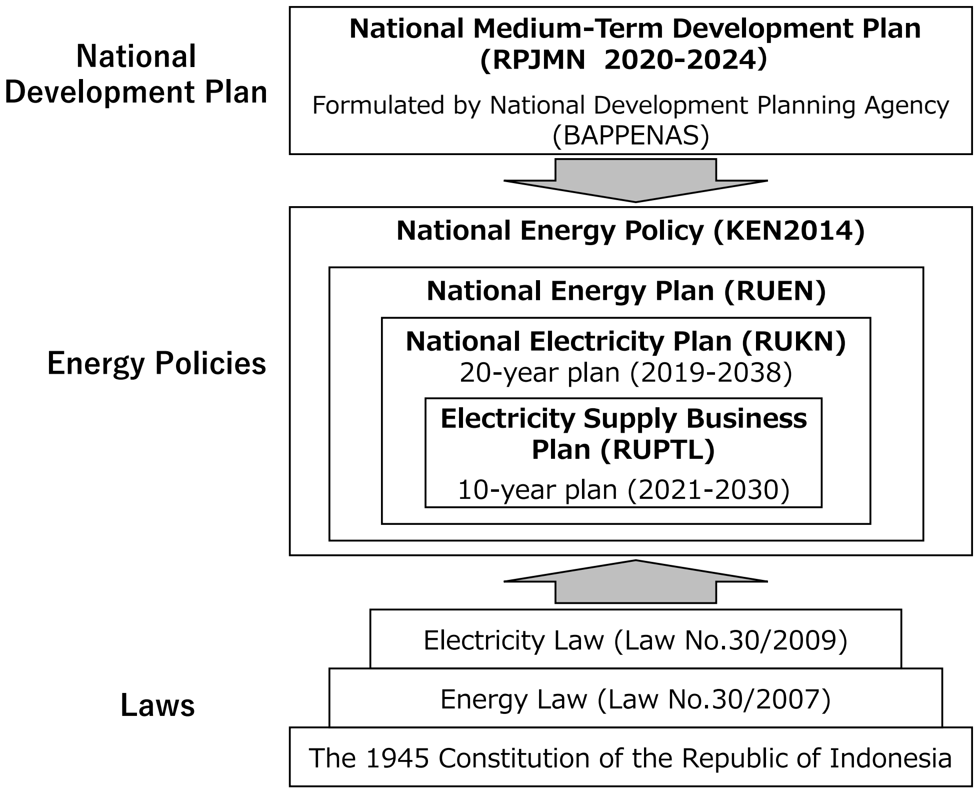
Chapter 3. Current Status of Power Sector

3.1 Related Policies/Laws

3.1.1 Related Policies

Indonesia's electricity policies are examined based on the Electricity Law (Law No. 30/2009), which was enacted in 2009 in addition to the Energy Law. The Direktorat Jenderal Ketenagalistrikan (DJK) under the Ministry of Energy and Mineral Resources (MEMR) formulates the National Electricity Plan (RUKN: Rencana Umum Ketenagalistrikan Nasional) based on the "National Energy Policy" described in Chapter 2. RUKN shows the national power development plan and power development targets for the next 20 years. The current RUKN was published in 2019, covering the plan and targets for between 2019 and 2038.

Based on this RUKN, PLN, the state-owned electric power company, formulates the Electricity Supply Business Plan (RUPTL: Rencana Usaha Penyediaan Tenaga Listrik). RUPTL shows PLN's business plan for the next 10 years and is basically updated annually. The current RUPTL (RUPTL 2021-2030) is a 10-year plan for between 2021 and 2030, which was approved by MEMR on the 28th of September 2021. RUPTL 2021-2030 is more environmentally friendly than the previous plan, RUPTL 2019-2028 (details of RUPTL are explained in Chapter 3.3). Figure 3-1 shows the relationship between various laws, policies and plans, including the energy policy described in Chapter 2.



(Source: Japan Electric Power Information Center report)

Figure 3-1 The Relationship between various Laws, Policies and Plans

3.1.2 Related Laws and Regulations

Table 3-1 shows the relevant laws and regulations for the electric power sector.

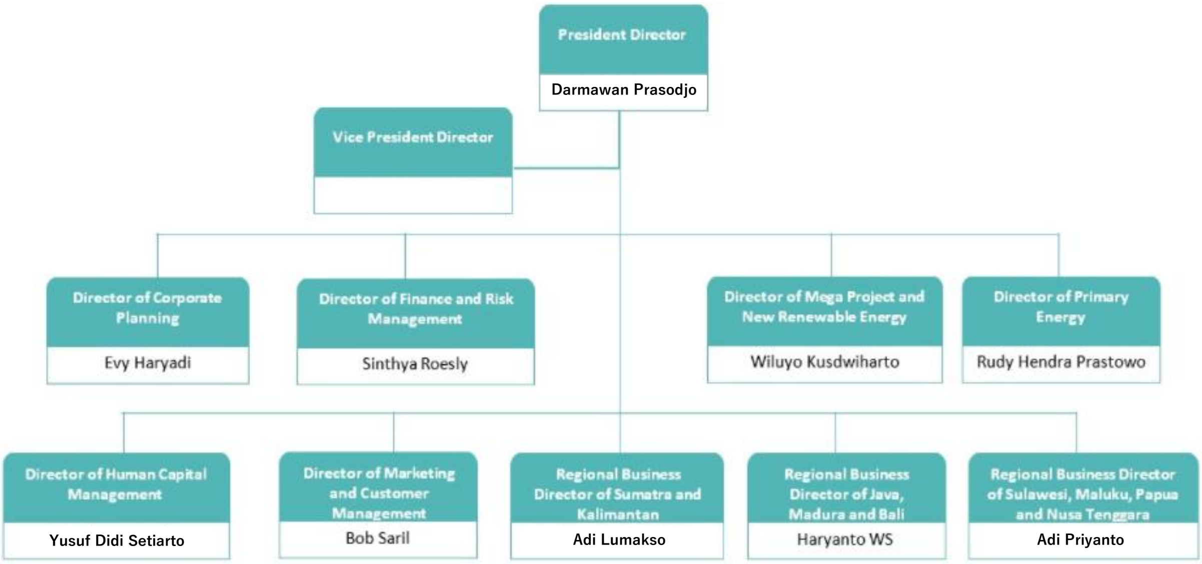
Table 3-1 Key Regulations Governing PLN

Related Laws and Regulations		Overview
Law No. 19/2003	Indonesian State-Owned Enterprises	✓ Regulations on Indonesian state-owned enterprises
Law No. 30/2009	The Electricity Law	✓ Electricity business is controlled by the state through PLN, and PLN is the last resort electricity provider.
Presidential Regulation No. 4/2016 (Amended by No.14/2017)	Acceleration of Electricity Infrastructure Development	✓ Increase the pace of development of electric infrastructure to fulfill Indonesia's demand for electricity and stimulate economic growth.
MEMR Decree No. 188.K/HK.02/MEM.L/2021	RUPTL2021-2030	✓ 10-year nationwide plan for electricity generation, transmission & distribution. ✓ Highlight investment strategies to achieve required capacities, fuel mix, and electrification ratio.
MEMR Regulation No. 28/2016 (Amended by No. 3/2020)	The Electricity Tariff	✓ Tariff is regulated for various end users at different VA. ✓ Variables for tariff adjustment is reviewed quarterly.
MOF Regulation No. 44/2017 (Amended by No. 18/PMK/02/2019)	Electricity Subsidy Mechanism	✓ PLN is eligible to claim subsidy for generated electricity at a 7% PSO margin.
MOF Regulation No. 16/PMK/2021	Compensation Mechanism	✓ PLN is eligible to claim compensation to the government for financially unprofitable assignments.

(Source: PT PLN (Persero), Investor Presentation, June 2021)

3.2 Organizational Structure of PLN

PLN is a vertically integrated electric power company wholly owned by the Indonesian government (Ministry of State-owned Enterprises). As of 2020, PLN Group has 53,385 employees (PLN: 44,299, Subsidiaries: 9,086). PLN supplies electricity in Indonesia under the supervision of MEMR.
The management members of PLN are as shown in Figure 3-2. Former Vice President Darmawan Prasodjo was appointed as the new president at the PLN Shareholders' Meeting held on December 6, 2021.

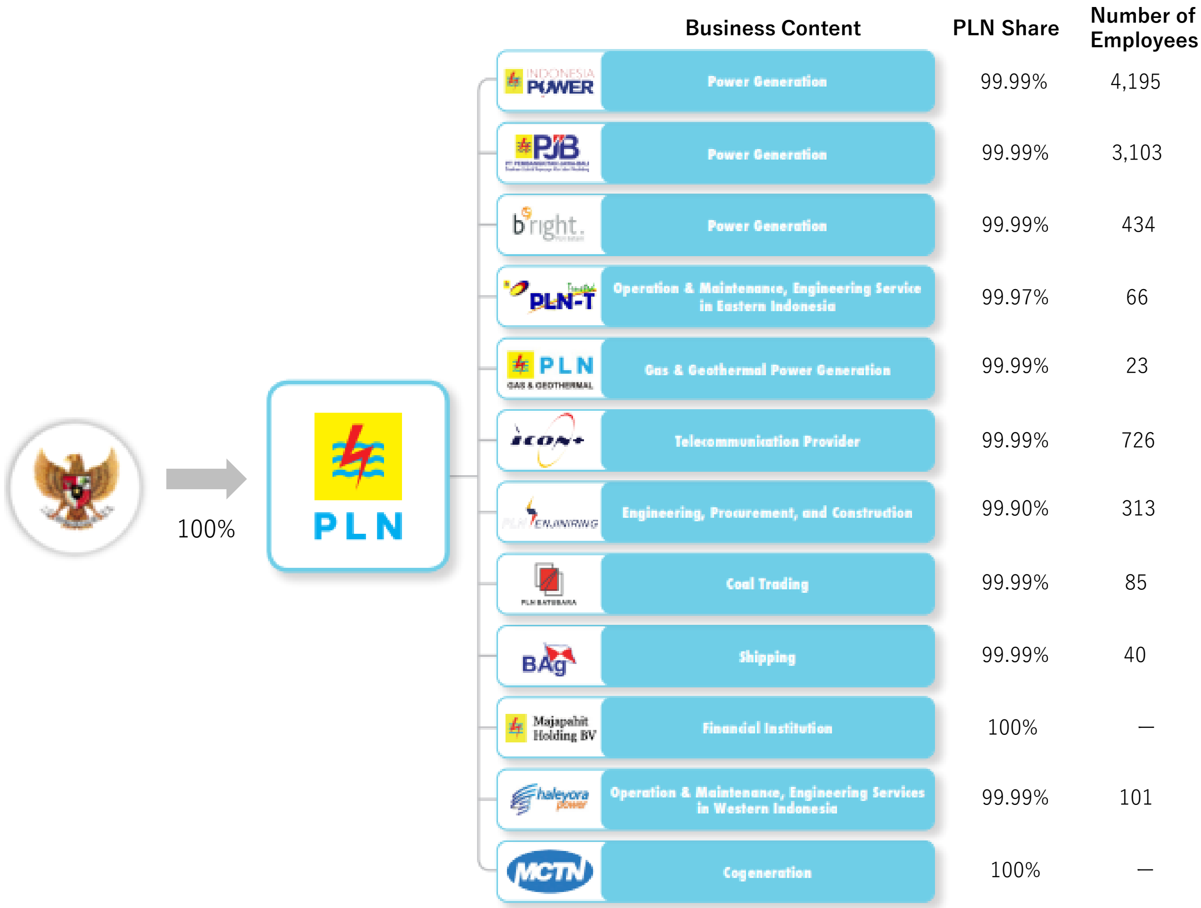


(Source: PLN website)

Figure 3-2 PLN Management members (as of December 2021)

Before September 2015, PLN had a vertically integrated business structure that united the Java-Bali region, Sumatra region and other regions into one. PLN decided to change its structure with the aim of efficiently operating from power generation to retail, and divided its operations into 7 Regional Business areas: Regional Business of Sumatra, Regional Business of West Java, Regional Business of Central Java, Regional Business of East Java and Bali, Regional Business of Kalimantan, Regional Business of Sulawesi and East Nusa Tenggara, and Regional Business of Maluku and Papua. There was one Regional Business Director for each region.
In July 2017, the division of 7 Regional Business areas was slightly changed, to Regional Business of Sumatra, Regional Business of West Java, Regional Business of Central Java, Regional Business of East Java, Bali and Nusa Tenggara, Regional Business of Kalimantan, Regional Business of Sulawesi, and Regional Business of Maluku and Papua.
From May 2020, the number of Regional Business Directors was reduced from 7 to 3. They oversee (1) Sumatra and Kalimantan, (2) Java Madura and Bali, and (3) Sulawesi, Marc, Papua and Nusa Tongara, respectively.

The structure of the PLN Group is as shown in Figure 3-3. PLN has power generation subsidiaries such as “PT Indonesia Power”, “PT Pembangkit Jawa Bali” and “PLN Batam”, which supplies power in a vertically integrated manner in Batam Island. PLN also owns subsidiaries which are engaged in businesses such as telecommunications, engineering, coal trading, shipping, finance, etc.



(Source: PT PLN (Persero), Company Profile 2021, PLN Annual Report 2020)

Figure 3-3 PLN Group structure

3.3 Outline of Power Supply Plan

3.3.1 Demand Forecast

(1) Actual power demand

The actual peak load in 2011-2020 is shown in Table 3-2. The peak load increased at an average annual growth rate of 5.9% in 2011-2019, but decreased to 6.9% (from 41,671 to 38,799 MW) from the previous year in 2020. This is because the power demand suddenly dropped in April 2020 due to the Covid-19 pandemic, the influence of which also continued after that.

Table 3-2 Actual Peak Load in 2011-2020

(Unit: MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Indonesia	26,366	28,559	30,498	32,943	32,959	36,475	38,797	40,243	41,671	38,799
Growth [%]		8.32	6.79	8.02	0.05	10.67	6.37	3.73	3.55	-6.89

(Source: RUPTL 2021-2030 Table 4.30)

The actual electricity sales in 2011-2020 are shown Table 3-3 and Table 3-4. The electricity sales increased at an average annual growth rate of 5.7% in 2011-2019, but due to the influence of the Covid-19 pandemic, decreased 0.8% (from 243,058 to 241,140 GWh) from the previous year in 2020. In particular, industry use (-7.3% year-on-year) and business use (-8.7% year-on-year) decreased significantly, but household use (8.1% year-on-year) increased. The ratio of electricity sales by use in 2020 was: household use 46.1%, industry use 9.6%, business use 17.5%, and public use 6.7%. The ratio for household use was high. The ratio of electricity sales by region in 2020 was: Sumatra 15.7%, Java, Madura and Bali 72.4%, Kalimantan 4.7%, Sulawesi 4.6%, and Maluku, Papua and Nusa Tenggara 2.5%. The ratio of Java, Madura and Bali was quite high. Except for Java, Madura and Bali, the following increased in 2020: Sumatra (3.3%), Kalimantan (5.3%), Sulawesi (3.9%) and Maluku, Papua and Nusa Tenggara (9.5%).

Table 3-3 Actual Electricity Sales by Use in 2011-2020

(Unit: GWh)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Household	64,581	71,554	76,579	83,402	87,972	92,886	93,837	97,143	102,917	111,280
Industry	54,232	59,635	63,774	65,295	63,533	67,586	71,716	76,345	77,142	71,479
Business	27,718	30,084	32,886	35,507	36,108	38,963	40,873	43,244	46,118	42,128
Public	9,758	10,546	11,246	12,215	12,987	14,020	14,641	15,701	16,881	16,254
Total	156,288	171,819	184,484	196,418	200,600	213,455	221,066	232,433	243,058	241,140
Growth [%]		9.94	7.37	6.47	2.13	6.41	3.57	5.14	4.57	-0.79

(Source: RUPTL 2021-2030 Table 4.1)

Table 3-4 Actual Electricity Sales by Region in 2011-2020

(Unit: GWh)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sumatra	21,489	24,203	25,739	27,611	29,167	30,978	32,559	34,612	36,698	37,924
Java, Madura, Bali	120,817	131,700	140,946	149,406	150,898	160,205	165,061	172,788	179,299	174,641
Kalimantan	5,651	6,379	6,988	7,741	8,233	8,779	9,197	9,836	10,703	11,272
Sulawesi	5,637	6,412	7,265	7,721	8,092	8,915	9,410	10,007	10,784	11,200
Maluku and others*	2,693	3,124	3,546	3,939	4,210	4,578	4,839	5,189	5,574	6,102
Total	156,288	171,819	184,484	196,418	200,600	213,455	221,066	232,433	243,058	241,140
Growth [%]		9.94	7.37	6.47	2.13	6.41	3.57	5.14	4.57	-0.79

*Maluku and others: Maluku, Papua and Nusa Tenggara

(Source: RUPTL 2021-2030 Table 4.2-4.6)

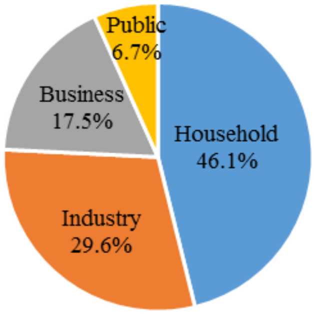


Figure 3-4 Electricity Sales by Use in 2020

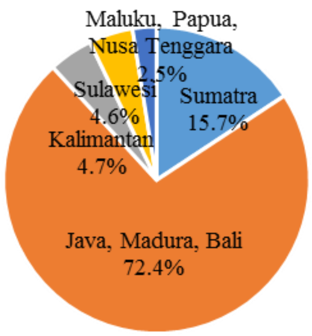


Figure 3-5 Electricity Sales by Region in 2020

(Source: Created from RUPTL 2021-2030)

(2) Demand forecast

Due to the sudden drop in power demand in April 2020 due to the influence of the Covid-19 pandemic, the power demand forecast in 2021-2030 was revised based on two economic growth scenarios (Optimistic Scenario: an average annual economic growth rate of 5.19% in 2021-2030; Moderate Scenario: an average annual economic growth rate of 5.15%). The major difference between the two economic growth scenarios is the timing of economic recovery (Optimistic Scenario: 2021, Moderate Scenario: 2022). Since RUPTL 2021-2030 is based on the Moderate Scenario, which is more realistic, this survey is also based on the Moderate Scenario.

Table 3-5 Economic Growth Forecast for Two Scenarios in 2021-2030

(Unit: %)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Optimistic	5.07	5.10	5.14	5.19	5.22	5.24	5.25	5.24	5.23	5.23
Moderate	4.71	5.10	5.14	5.19	5.22	5.24	5.25	5.24	5.23	5.23

(Source: RUPTL 2021-2030 Figure 5.1)

The peak load forecast in 2021-2030 (Moderate Scenario) is shown in Table 3-6. The peak load will increase at an average annual growth rate of 4.8% in 2021-2030, from 42,575 MW in 2021 to 64,695 MW (+22,120 MW) in 2030. The ratio of peak load by region in 2030 will be: Sumatra 19.6%, Java, Madura and Bali 63.6%, Kalimantan 6.5%, Sulawesi 6.1% and Maluku, Papua and Nusa Tenggara 4.2%.

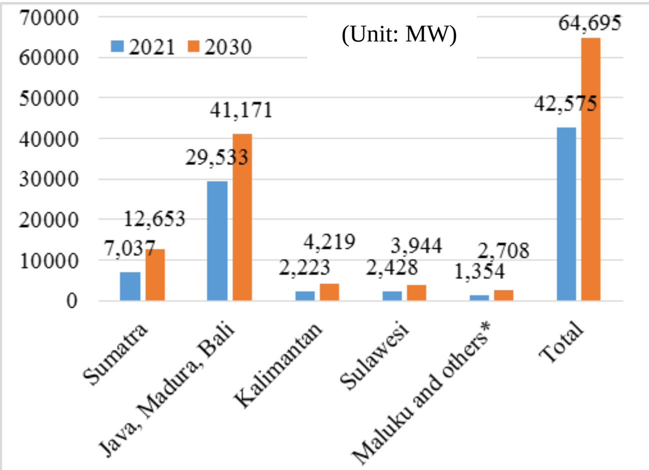
Table 3-6 Peak Load Forecast by Region in 2021-2030 (Moderate Scenario)

(Unit: MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sumatra	7,037	7,648	8,291	8,909	9,540	10,058	10,623	11,203	11,790	12,653
Java, Madura, Bali	29,533	30,543	31,726	33,012	34,398	35,718	37,003	38,339	39,740	41,171
Kalimantan	2,223	2,396	2,602	2,856	3,079	3,346	3,581	3,820	4,027	4,219
Sulawesi	2,428	2,681	2,869	3,020	3,174	3,319	3,466	3,615	3,774	3,944
Maluku and others*	1,354	1,546	1,672	1,838	1,986	2,150	2,279	2,416	2,560	2,708
Total	42,575	44,734	47,160	49,636	52,176	54,591	56,951	59,392	61,892	64,695
Growth [%]		5.07	5.42	5.25	5.12	4.63	4.32	4.29	4.21	4.53

*Maluku and others: Maluku, Papua and Nusa Tenggara

(Source: RUPTL 2021-2030 Table 5.43)



*Maluku and others: Maluku, Papua and Nusa Tenggara

Figure 3-6 Peak Load by Region in 2021-2030 (Moderate Scenario)

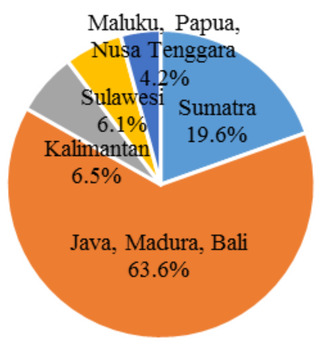


Figure 3-7 Peak Load by Region in 2030 (Moderate Scenario)

(Source: Created from RUPTL 2021-2030)

The electricity sales forecast in 2021-2030 (Moderate Scenario) is shown in Table 3-7 and Table 3-8. Electricity sales will increase at an average annual growth rate of 4.9% in 2021-2030, from 253,134 GWh in 2021 to 389,564 GWh (+136,430 GWh) in 2030. The average annual growth rate of electricity sales by use in 2021-2030 will be: household use 3.8%, industry use 5.5%, business use 6.5%, and public use 5.4%. The growth of business use will be large and that of household use will be small. The ratio of electricity sales by use in 2030 will be: household use 41.9%, industry use 30.5%, business use 20.6%, and public use 6.9%. The average annual growth rate of electricity sales by region in 2021-2030 will be: Sumatra 6.4%, Java, Madura and Bali 4.1%, Kalimantan 7.8%, Sulawesi 6.3%, and Maluku, Papua and Nusa Tenggara 8.2%. The growth of Kalimantan, Maluku, Papua and Nusa Tenggara will be large and that of Java, Madura and Bali will be small. The ratio of electricity sales by region in 2030 will be: Sumatra 18.4%, Java, Madura and Bali 66.4%, Kalimantan 6.1%, Sulawesi of 5.6%, and Maluku, Papua and Nusa Tenggara 3.5%.

Table 3-7 Electricity Sales Forecast by Use in 2021-2030 (Moderate Scenario)

(Unit: GWh)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
House holds	117,194	122,102	127,073	132,118	137,287	142,292	147,428	152,679	157,948	163,417
Industry	73,547	77,735	82,420	88,028	93,983	99,406	104,223	108,965	113,796	118,904
Business	45,675	48,346	51,532	55,313	59,015	62,954	67,022	71,347	75,806	80,392
Public	16,718	17,640	18,631	19,684	20,783	21,925	23,102	24,314	25,556	26,851
Total	253,134	265,824	279,657	295,142	311,068	326,576	341,774	357,304	373,107	389,564
Growth [%]	5.0	5.0	5.2	5.5	5.4	5.0	4.7	4.5	4.4	4.4
Consumption of electric power per capita (kWh/capita)	934	972	1013	1060	1,107	1,153	1,196	1,241	1,286	1,332

(Source: RUPTL 2021-2030 Table 5.32)

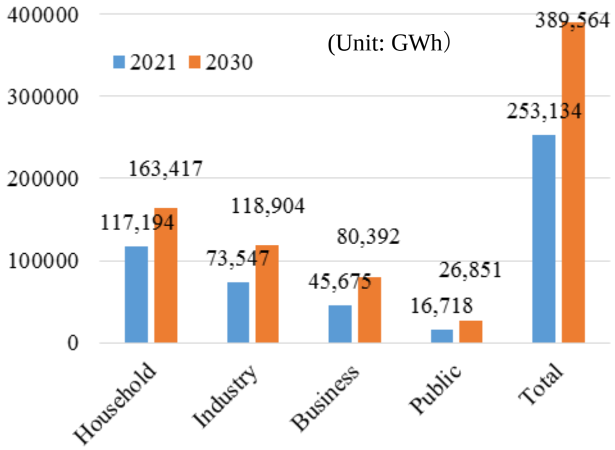


Figure 3-8 Electricity Sales by Use in 2021-2030 (Moderate Scenario)

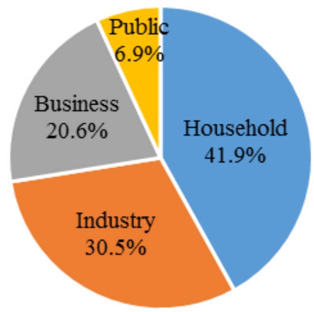


Figure 3-9 Electricity Sales by Use in 2030 (Moderate Scenario)

(Source: Created from RUPTL 2021-2030)

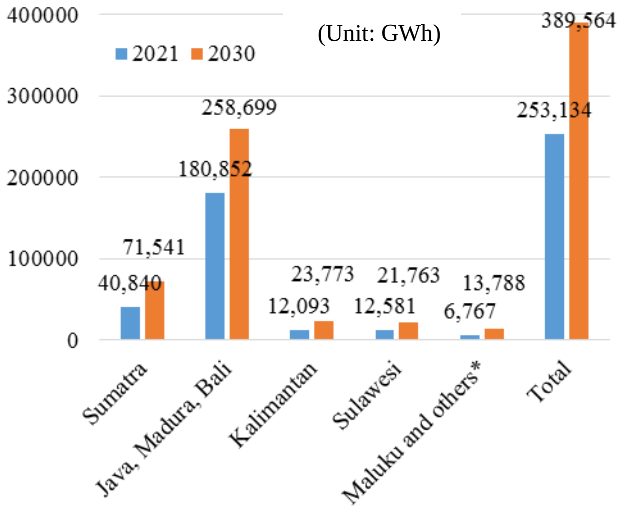
Table 3-8 Electricity Sales Forecast by Region in 2021-2030 (Moderate Scenario)

(Unit: GWh)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sumatra	40,840	43,736	46,725	50,485	54,217	57,454	60,795	64,333	67,874	71,541
Java, Madura, Bali	180,852	187,403	195,358	203,945	213,201	222,072	230,888	239,738	248,959	258,699
Kalimantan	12,093	13,093	14,278	15,741	17,032	18,603	19,990	21,411	22,634	23,773
Sulawesi	12,581	13,885	14,927	15,819	16,722	17,689	18,646	19,626	20,661	21,763
Maluku and others	6,767	7,707	8,368	9,151	9,897	10,758	11,455	12,196	12,979	13,788
Total	253,134	265,824	279,657	295,142	311,068	326,576	341,774	357,304	373,107	389,564

*Maluku and others: Maluku, Papua and Nusa Tenggara

(Source: RUPTL 2021-2030 Table 5.34-5.42)



*Maluku and others: Maluku, Papua and Nusa Tenggara

Figure 3-10 Electricity Sales by Region in 2021-2030 (Moderate Scenario)

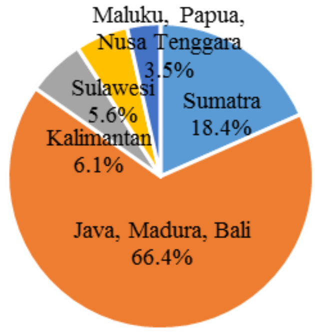


Figure 3-11 Electricity Sales by Region in 2030 (Moderate Scenario)

(Source: Created from RUPTL 2021-2030)

3.3.2 Power Development Plan

(1) Existing power plants

The actual installed capacity of power plants in 2020 is shown in Table 3-9. The installed capacity in 2020 was 62,449.20 MW. The ratio of installed capacity by ownership was: PLN 70.0%, IPP, etc. 27.7%, and rental 2.3%. PLN's ratio was large. The ratio of installed capacity by fuel was: coal thermal power 48.3%, gas/oil/diesel thermal power 39.0%, hydropower 8.3%, geothermal power 3.9%, and other renewable energy 0.5%. The ratio of coal thermal power was large.

Table 3-9 Actual Installed Capacity of Power Plants in 2020

(Unit: MW)

	PLN	Rental	IPP, etc.	Total
Coal	18,615.63	90.00	11,454.50	30,160.13
Gas/Oil/Diesel	20,891.84	1,350.37	2,100.43	24,342.64
Hydro	3,584.07	0.00	1,589.97	5,174.04
Geothermal	579.26	0.00	1,863.42	2,442.68
Other RE	17.68	0.75	311.28	329.71
Total	43,688.48	1,441.12	17,319.60	62,449.20

(Source: RUPTL 2021-2030 Table 4.19)

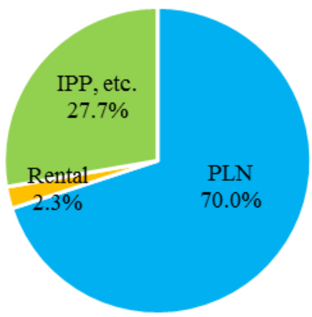


Figure 3-12 Installed Capacity by Ownership in 2020

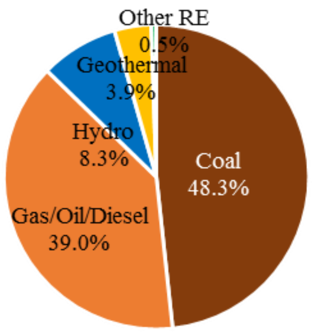


Figure 3-13 Installed Capacity by Fuel in 2020

(Source: Created from RUPTL 2021-2030)

The actual energy production of power plants in 2020 is shown in Table 3-10. The energy production in 2020 was 271,803 GWh. The ratio of energy production by ownership was: PLN 63.4%, IPP, etc. 34.7%, and rental 1.9%. PLN's ratio was large. The ratio of energy production by fuel was: coal thermal power 66.5%, gas/oil/diesel thermal power 19.4%, hydropower 6.6%, geothermal power 5.7%, other renewable energy 1.1%, and import 0.6%. The ratio of coal thermal power was very high.

Table 3-10 Actual Energy Production of Power Plants in 2020

(Unit: GWh)

	PLN	Rental	IPP etc.	Total
Coal	112,922	509	66,772	180,203
Gas/Oil/Diesel	41,739	3,955	6,875	52,569
Hydro	11,949		5,953	17,902
Geothermal	4,186		11,377	15,563
Other RE	1,494	606	907	3,007
Import			1,553	1,553
Total	172,291	5,070	94,442	271,803

(Source: RUPTL 2021-2030 Table 4.22)

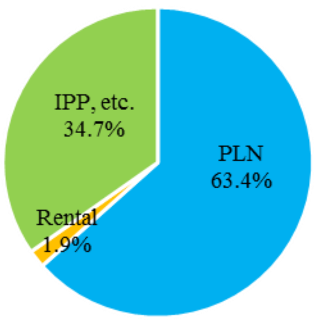


Figure 3-14 Energy Production by Ownership in 2020

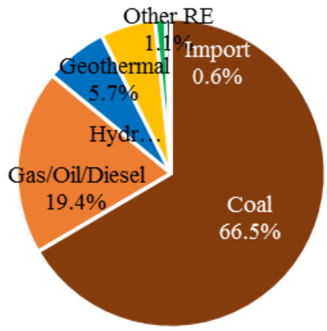


Figure 3-15 Energy Production by Fuel in 2020

(Source: Created from RUPTL 2021-2030)

(2) Outline of power development plan under implementation and in planning (including renewable energy)

The amount of power plant development in 2021-2030 is shown in Table 3-11. Installed capacity of 40.6GW is planned to be developed in 2021-2030. Renewable energy of 20.9GW (51.6%) is to be developed, and the breakdown will be: hydropower 10.4GW (25.6%), geothermal power 3.4GW (8.3%), and other sources 7.2GW (17.7%). Coal thermal power of 13.8GW (34.1%) and gas/oil/diesel thermal power of 5.8GW (14.4%) will be developed mainly in the first five years. Development by IPP etc. will be 22.1GW (64.8%), so development by the private sector will be large.

Table 3-11 Amount of Power Plant Development in 2021-2030

(Unit: MW)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
PLN	Coal	488	306	228	50	231	0	24	0	20	0	1,347
	Gas/Oil/Diesel	610	1,827	316	240	370	140	95	0	10	170	3,778
	Hydro	110	43	132	100	1,333	199	44	1,146	829	1,350	5,286
	Geothermal	0	0	0	5	155	120	25	195	15	0	515
	Other RE	59	128	237	431	928	117	273	250	312	607	3,342
	Total	1,267	2,304	913	826	3,017	576	461	1,591	1,187	2,127	14,269
IPP, etc.	Coal	4,200	2,138	1,314	300	1,660	2,260	600	0	0	0	12,472
	Gas/Oil/Diesel	2,035	0	0	0	0	20	0	0	0	0	2,055
	Hydro	434	164	277	276	1,334	172	412	467	962	606	5,104
	Geothermal	136	108	190	136	715	170	98	255	225	808	2,841
	Other RE	13	205	1,191	721	1,079	200	140	145	140	0	3,834
	Total	6,818	2,615	2,972	1,434	4,788	2,822	1,250	867	1,327	1,413	26,306
Total	Coal	4,688	2,444	1,542	350	1,891	2,260	624	0	20	0	13,819
	Gas/Oil/Diesel	2,645	1,827	316	240	370	160	95	0	10	170	5,833
	Hydro	544	207	409	376	2,667	370	456	1,613	1,791	1,956	10,389
	Geothermal	136	108	190	141	870	290	123	450	240	808	3,356
	Other RE	72	332	1,429	1,152	2,007	317	413	395	452	607	7,176
	Total	8,085	4,919	3,886	2,260	7,805	3,398	1,710	2,458	2,514	3,540	40,575

(Source: RUPTL 2021-2030 Table 5.53)

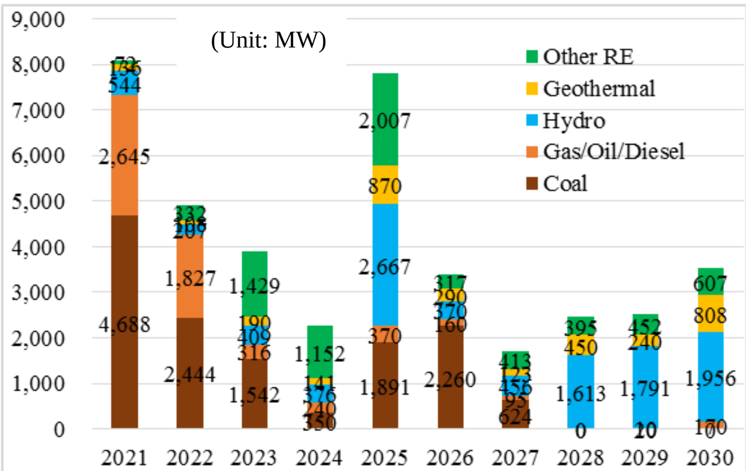


Figure 3-16 Amount of Power Plant Development in 2021-2030

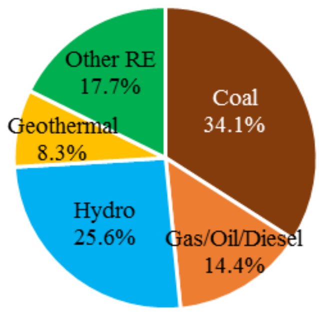


Figure 3-17 Amount of Power Plant Development in 2030

(Source: Created from RUPTL 2021-2030)

(3) Demand and supply balance

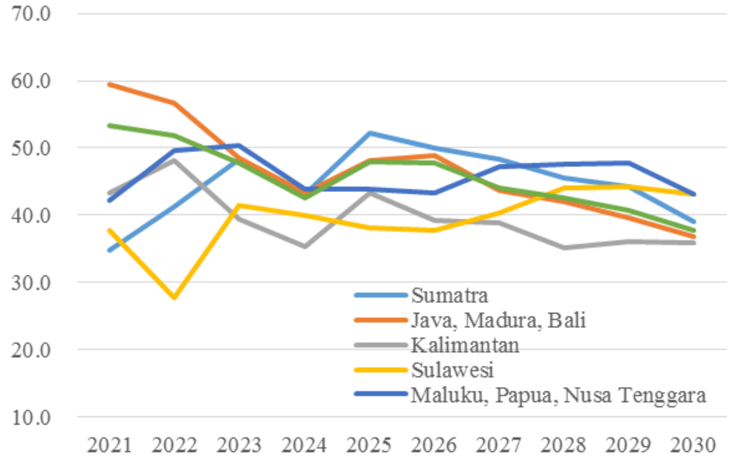
The demand and supply balance in 2021-2030 is shown in Table 3-12. The reserve margin by region will be 35% to 60% in 2021, which is a considerable difference, but it will be 36% to 43% in 2030, which is about 40%.

Table 3-12 Demand and Supply Balance in 2021-2030

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Net Peak Load [MW]	Sumatra	6,330	7,100	7,823	8,428	9,035	9,541	10,061	10,529	11,004	11,661
	Java, Madura, Bali	28,333	29,341	30,524	31,803	33,054	34,204	35,488	36,692	37,924	39,354
	Kalimantan	1,855	2,112	2,467	2,769	2,957	3,213	3,438	3,666	3,865	4,050
	Sulawesi	2,097	2,355	2,616	2,766	2,914	3,055	3,198	3,339	3,495	3,664
	Maluku and others*	640	705	762	818	873	933	1,002	1,067	1,137	1,207
	Total	39,255	41,613	44,192	46,584	48,833	50,946	53,187	55,293	57,425	59,936
Net Power Capacity [MW]	Sumatra	8,534	10,027	11,612	12,062	13,750	14,312	14,922	15,317	15,881	16,221
	Java, Madura, Bali	45,185	45,968	45,358	45,560	48,949	50,936	50,991	52,124	52,959	53,837
	Kalimantan	2,659	3,128	3,439	3,747	4,239	4,472	4,775	4,958	5,261	5,504
	Sulawesi	2,887	3,006	3,699	3,871	4,025	4,208	4,488	4,810	5,042	5,242
	Maluku and others*	909	1,056	1,147	1,177	1,256	1,338	1,475	1,576	1,679	1,729
	Total	60,174	63,185	65,255	66,417	72,219	75,266	76,651	78,785	80,822	82,533
Reserve Margin [MW]	Sumatra	2,204	2,927	3,790	3,634	4,716	4,771	4,861	4,789	4,877	4,561
	Java, Madura, Bali	16,851	16,627	14,834	13,757	15,895	16,732	15,503	15,431	15,035	14,483
	Kalimantan	804	1,015	972	978	1,282	1,259	1,337	1,290	1,395	1,453
	Sulawesi	790	652	1,084	1,105	1,111	1,153	1,290	1,471	1,547	1,578
	Maluku and others*	270	350	384	359	383	404	473	508	542	522
	Total	20,919	21,571	21,064	19,833	23,387	24,319	23,464	23,489	23,396	22,597
Reserve Margin [%]	Sumatra	34.8	41.2	48.4	43.1	52.2	50.0	48.3	45.5	44.3	39.1
	Java, Madura, Bali	59.5	56.7	48.6	43.3	48.1	48.9	43.7	42.1	39.6	36.8
	Kalimantan	43.3	48.1	39.4	35.3	43.4	39.2	38.9	35.2	36.1	35.9
	Sulawesi	37.7	27.7	41.4	39.9	38.1	37.7	40.3	44.1	44.3	43.1
	Maluku and others*	42.2	49.6	50.4	43.9	43.9	43.3	47.2	47.6	47.7	43.2
	Total	53.3	51.8	47.7	42.6	47.9	47.7	44.1	42.5	40.7	37.7

*Maluku and others: Maluku, Papua and Nusa Tenggara

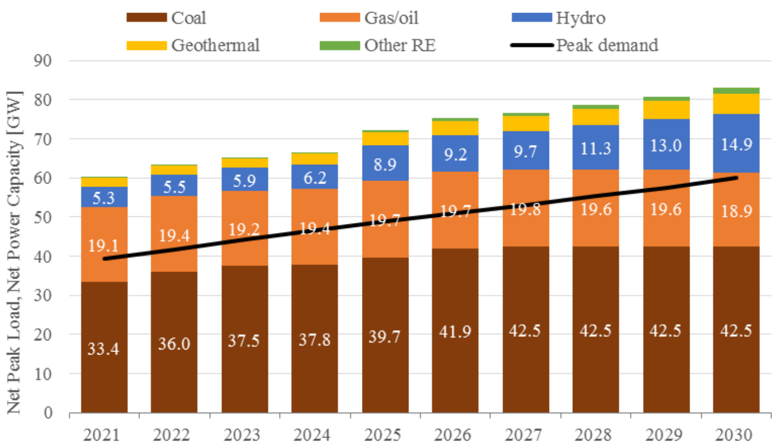
(Source: RUPTL 2021-2030 Table 5.55, 5.56, 5.58, 5.61, 5.62, 5.64, 5.65, 5.68, 5.69, 5.70, 5.71, 5.72, 5.73)



(Source: Created from RUPTL 2021-2030)

Figure 3-18 Reserve Margin by Region in 2021-2030

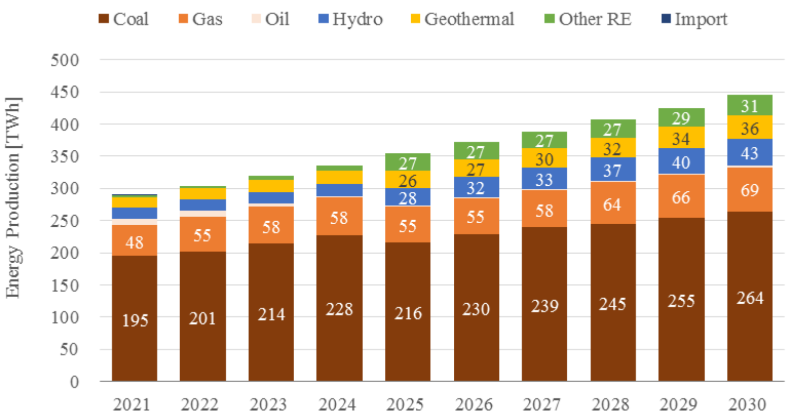
The net power capacity in 2021-2030 is shown in Figure 3-19, and the power production in 2021-2030 is shown in Figure 3-20. In 2021-2030, the ratio of coal thermal power and gas/oil thermal power will decrease, and the ratio of renewable energy, such as hydropower and geothermal power, will increase, but coal thermal power remains the main force in the plan.



	2021		2030
Coal	55%	→	51%
Gas/Oil	32%	→	23%
Renewable	13%	→	26%

(Source: Created from RUPTL 2021-2030)

Figure 3-19　Net Peak Load and Net Power Capacity in 2021-2030



	2021		2030
Coal	67%	→	59%
Gas/Oil	20%	→	16%
Renewable	13%	→	25%

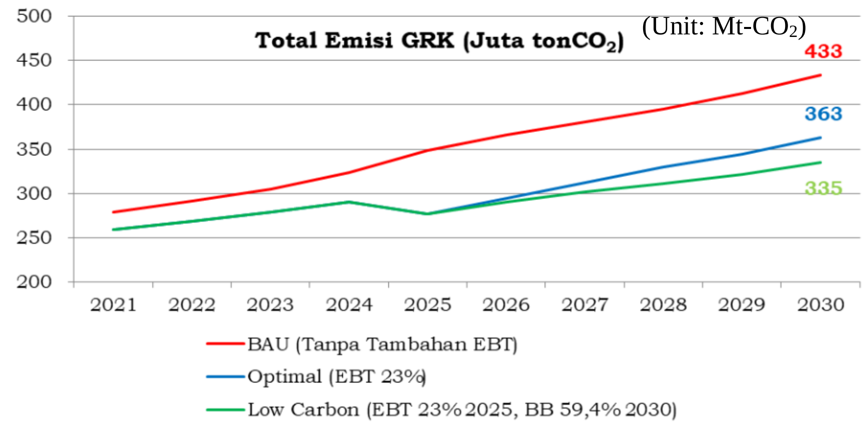
(Source: Created from RUPTL 2021-2030)

Figure 3-20　Power Production in 2021-2030

(4)　Estimation of CO_2 emissions

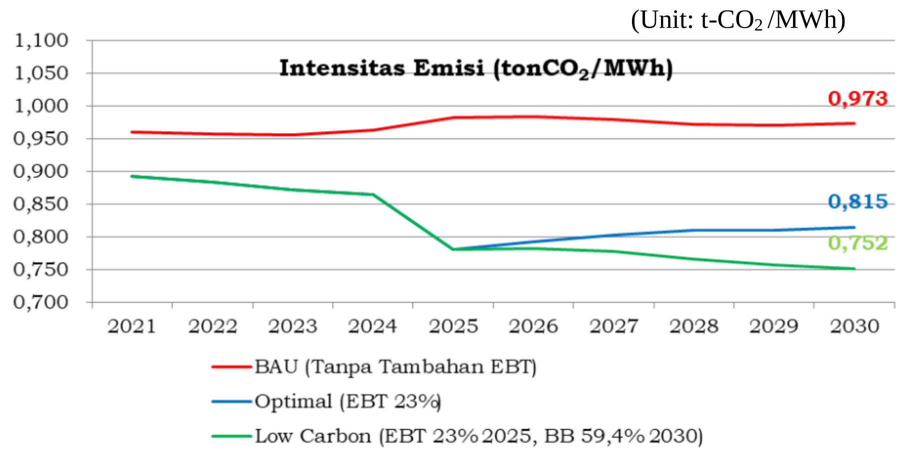
In RUPTL 2021-2030, the Business as Usual (BAU) Scenario, Optimum Scenario and Low Carbon Scenario were studied. Both the Optimum Scenario and Low Carbon Scenario achieve the EBT target of 23% from 2025, but in the Optimum Scenario, the proportion of coal in 2030 is about 64%, or fairly high. On the other hand, in the Low Carbon Scenario, the proportion of coal in 2030 decreases to about 59.4%.

CO_2 emissions in 2030 are: BAU Scenario 433 Mt-CO_2, Optimum Scenario 363 Mt-CO_2 and Low Carbon Scenario 335 Mt-CO_2, with a decrease of 98 Mt-CO_2 (-22.6%) in the Low Carbon Scenario. In 2030, CO_2 emissions per energy production of 1 kWh are: BAU Scenario 0.973 kg-CO_2/kWh, Optimum Scenario 0.815 kg-CO_2/kWh and Low Carbon Scenario 0.752 kg-CO_2/kWh, with a decrease of 0.221 kg-CO_2/kWh (-22.7%) in the Low Carbon Scenario.



(Source: RUPTL 2021-2030 Figure 5.17)

Figure 3-21 CO_2 Emissions for 3 Scenarios in 2021-2030



(Source: RUPTL 2021-2030 Figure 5.16)

Figure 3-22 CO_2 Emissions for 3 Scenarios in 2021-2030

Since the energy production increases significantly (290.5 TWh in 2021 to 445.1 TWh in 2030 by 154.6 TWh, or 53.2%), even in the Low Carbon Scenario, CO_2 emissions increase 259 Mt-CO_2 in 2021 to 335 Mt-CO_2 in 2030, by 76 Mt-CO_2 (29.3%). However, CO_2 emissions per energy production of 1 kWh decrease by 0.221 kg-CO_2/kWh (-22.7%), from 0.89 kg-CO_2/kWh in 2021 to 0.75 kg-CO_2/kWh in 2030.

Table 3-13 CO_2 Emissions in 2021-2030 (Low Carbon Scenario)

(Unit: Mt-CO_2)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gas	27.9	31.1	31.9	30.7	27.9	27.8	28.8	31.2	32.3	34.0
Fuel Oil	9.0	9.3	3.9	2.0	1.4	1.5	1.5	1.6	1.7	1.7
Coal	222.2	228.6	242.7	257.8	247.6	261.4	271.9	278.5	288.1	298.9
Total	259.1	269.0	278.5	290.5	276.9	290.8	302.2	311.3	322.0	334.6

(Source: RUPTL 2021-2030 Table 5.101)

Table 3-14 CO_2 Emissions in 2021-2030 (Low Carbon Scenario)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Production [TWh]	290.5	304.4	319.4	336.1	354.5	372.0	388.4	406.6	425.4	445.1
CO_2 Emission [Mt-CO_2]	259.1	269.0	278.5	290.5	276.9	290.8	302.2	311.3	322.0	334.6
CO_2 Emission [kg-CO_2/kWh]	0.89	0.88	0.87	0.86	0.78	0.78	0.78	0.77	0.76	0.75

(Source: RUPTL 2021-2030 Table 5.76, 5.101)

3.3.3 Transmission and Transformation Facility Expansion Plan

(1) Existing Facilities

According to RUPTL 2021-2030, the total length of PLN's existing transmission lines by voltage and the total capacity of existing transformers by voltage are as shown in Table 3-15 and Table 3-16.

Table 3-15 Total length of existing transmission lines

Voltage	Length (kms) *
500kV	5,250
275kV	3,648
150kV	46,680
70kV	5,656
Total	61,234

*As of Dec 2020

(Source: RUPTL 2021-2030)

Table 3-16 Total capacity of existing transformers

Voltage	Capacity (MVA)
500/275/150kV	37,348
275/150kV	9,998
150/70/20kV	96,683
70/20kV	5,979
Total	150,008

*As of Dec 2020

(Source: RUPTL 2021-2030)

(2) Network expansion plans from 2021 to 2030

(a) Outline of network expansion plans

According to RUPTL 2021-2030, the total length of PLN's transmission line expansion by voltage and the total capacity of transformer increase by voltage are as shown in Table 3-17 and Table 3-18.

Table 3-17 Total length of transmission line expansion

Unit: kms

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
500 kV	2,211	552	440	28	1,537	201	321	1,268	207	720	7,485
500 kV DC	0	0	0	0	0	0	0	0	0	300	300
275 kV	676	236	1,867	275	280	40	1,010	0	0	0	4,384
150 kV	4,520	6,249	7,114	4,152	3,708	1,426	2,102	2,433	1,858	950	34,511
70 kV	284	253	0	0	132	241	10	0	52	70	1,042
Total	7,691	7,290	9,421	4,455	5,656	1,908	3,443	3,701	2,117	2,040	47,723

(Source: RUPTL 2021-2030)

Table 3-18 Total capacity of transformer increase

Unit: MVA

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
500/275 kV	1,500	1,000	0	0	1,500	0	500	0	0	0	4,500
500/150 kV	1,000	4,000	3,500	2,000	5,500	1,500	1,500	7,000	3,000	3,000	32,000
500 kV DC										750	750
275/150 kV	2,250	750	1,750	750	250	0	1,500	0	250	0	7,500
150/230 kV	0	0	0	500	0	0	0	0	0	0	500
150/70 kV	282	180	0	60	100	60	0	0	0	0	682
150/20 kV	4,210	4,700	3,580	2,310	3,200	1,750	2,330	3,660	2,080	1,950	29,770
70/20 kV	200	370	30	0	60	90	30	30	90	60	960
Total	9,442	11,000	8,860	5,620	10,610	3,400	5,860	10,690	5,420	5,760	76,662

(Source: RUPTL 2021-2030)

(b) Interconnections between regional power networks

In Indonesia, Java-Madura-Bali, Sumatra, Kalimantan, and other power networks operate separately. Connecting independent power networks that are operating separately has positive effects, such as improved reliability, optimization of reserve capacity, sharing of surplus power, and a reduction in operating costs. However, in addition to negative technical impacts, the economic advantages and disadvantages must also be considered. The main grid interconnections, planned and under consideration, described in RUPTL 2021-2030 are shown below.

1) Ongoing Interconnection Projects

a) 500 kV Java - Bali Interconnection

It is expected that it will be difficult to build a large coal-fired power plant on Bali Island in accordance with the policy of the state government, and that the 500kV Java-Bali interconnection will be necessary to meet the increasing demand for the Bali system in the future.

Table 3-19 Outline of 500 kV Java – Bali interconnection

Items	Outline
Watudodol substation – Landing point (Banyuwangi, Java system)	500kV double circuit transmission lines: 9.6kms
Landing point (Banyuwangi, Java system) - Gilimanuk substation (Bali system)	500kV double circuit cables: 13kms
Gilimanuk substation - Antosari substation (Bali system)	500kV double circuit transmission lines: 151.2kms
Transmission capacity	2,000MW
Commissioning year	2025

(Source: RUPTL 2021-2030)

b) Interconnections between Sumatra and surrounding islands

The following interconnections between the Sumatra grid system and the island systems are underway, in order to supply cheaper electricity from the Sumatra grid system to the increasing demand in the islands.

Table 3-20 Interconnections between Sumatra grid and island systems

Interconnection	Voltage	Commissioning
Sumatra (South Sumatra pref.) – Bangka island	150kV	2022
Sumatra (Riau pref.) – Bengkalis island	150kV	2022
Sumatra (Riau pref.) – Tebingtinggi island	150kV	2023
Tebingtinggi island – Karimunbesar island	150kV	2025

(Source: RUPTL 2021-2030)

c) Interconnections between Southeast Sulawesi and surrounding islands

In order to reduce the electricity supply costs to Muna Island and Buton Island, Muna Island and Buton Island are to be interconnected first, and then these island networks are to be interconnected with the Southeast Sulawesi network.

Table 3-21 Interconnections between Southeast Sulawesi grid and island systems

Interconnection	Voltage	Commissioning
Muna island – Buton island	150kV	2022
Southeast Sulawesi grid – Muna island	150kV	2026

(Source: RUPTL 2021-2030)

2) Additional interconnections to be studied

a) Interconnection between Sumatra and Java

Per RUPTL 2021-2030, since it has already been confirmed that an HVDC link between Sumatra and Java, for transmitting cheaper electric power generated by Sumatra to the Java grid, will not be cost effective compared to its construction costs, its construction plan is not included in the network expansion plan in RUPTL by 2030.

b) Interconnection between Kalimantan and Java

According to RUPTL 2021-2030, a preparatory survey has been conducted on an interconnection between Kalimantan and Java, and the study was conducted under the following conditions.

Table 3-22 Study conditions for interconnection between Kalimantan and Java

Items	Conditions	Remarks
Voltage	500kV DC	
Length	460kms	
Coal target price	USD 85/ton	Standard scenario
Simulation duration	2020-2040	

(Source: RUPTL 2021-2030)

As a result of the examination, it was concluded that an interconnection between Kalimantan and Java is not feasible.

3.3.4 Status of System Operation

(1) Arrangement of Dispatching Centers

In Sumatra, the system operation department of the Sumatra Transmission and Load Dispatch Center P3B (Penyalran dan Pusat Penfaturan Beban) is responsible for power system operational functions, and in Java Bali, the Java Bali Load Dispatch Center P2B (Pusat Penfaturan Beban) is responsible for this. These load dispatch centers control the generators within the operating networks.

In other areas, it is estimated that there are many independent systems (more than 600), and that the control stations distributed in 9 regional branches are operating generators instead of the load dispatch centers.

(2) Current Impact of Variable Renewable Energy on Power System

As of 2021, the install ratio of solar and wind power generation facilities, which are highly variable generators, is extremely low, at 0.04% and 0.16%, respectively, on a kWh basis. In Sumatra and Java Bali, these are extremely low power generation ratios. Therefore, Variable Renewable Energy (VRE) generators are unlikely to affect grid stability.

However, in the future, as low/de-carbonization generation progresses, the following issues, as occur in other countries, are expected to become apparent.

- Suppression of VRE generator outputs to cope with overload of transmission lines or transformers, or limit reduction of thermal generation output
- Expansions of frequency fluctuation range and variation speed due to decrease in inertial force in the power system
- Ensuring adjustment capabilities (ΔkW and ΔkWh) to absorb fluctuations in the VRE generation output
- Dynamic instability phenomena between regional subsystems caused by sudden changes in VRE generation output

Since island systems other than Sumatra and Java Bali are small-scale independent systems with small capacity and the thermal generators in the systems are notably aged, and the power generation plan and monitoring range are limited, high-quality power system operation may not be achievable. Therefore, when introducing VRE power generation equipment to such a small-scale system, it may be necessary to take measures such as improving the monitoring and control system and introducing a battery storage system, in addition to strengthening the network facilities.

3.4 Distribution Facilities

Electrification ratio, electrical losses, SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) in Indonesia are shown in Table 3-23.

Table 3-23 Indices for Distribution Facilities

	2013	2014	2015	2016	2017	2018	2019	2020	2040
Electrification Ratio of PLN %	80.51	84.34	88.30	91.16 (88.00)	95.53	98.30 (97.5)	98.89 (98.57)	99.20 (99.00)	(100)
Total Network Losses %	9.91 (9.91)	9.71 (9.71)	9.77 (8.45)	9.48 (8.39)	8.75 (8.31)	9.51 (8.24)	9.32 (8.18)	9.15 (9.14)	(8.15)
Network Losses (Transmission) %	2.33	2.37	2.33	2.29	2.39	2.32	2.26	2.08	---
Network Losses (Distribution) %	7.77	7.52	7.64	7.37	6.53	7.37	7.24	7.22	---
SAIDI minutes/customer/year	376 (343)	381 (349)	331 (295)	1,532 (216)	1,160 (155)	958 (113)	1,137 (82)	763 (1,117)	(500)
SAIFI times/customer/year	7.26 (7.3)	5.58 (5.6)	5.97 (5.0)	15.09 (4.0)	12.65 (3.1)	9.90 (2.2)	11.51 (1.4)	9.25 (11.21)	(1.4)

( ): Planned

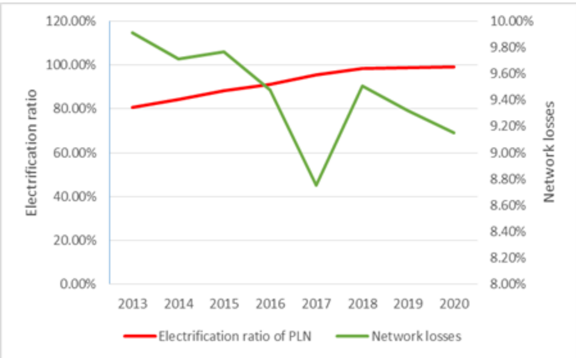


Figure 3-23 Electrification Ratio of PLN and Network Losses

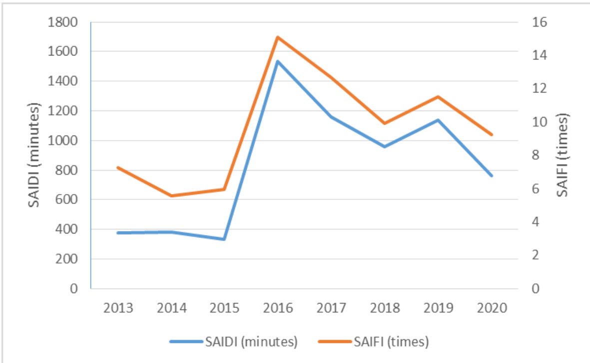


Figure 3-24 SAIFI and SAIDI

(Source: PLN annual report)

Since the GDP in the country and the electricity supply amounts are rapidly increasing, severe shortages of electric power have occurred. Compared with 2015, the supply of electricity has doubled and the demand for electricity has increased by 150%. However, decreases in actual equipment capacity due to degradation are a serious problem. According to the data acquired in 2020, 84% of outages are caused by distribution equipment. The breakdown of this is: 56% accidents, and 30% planned outages.

Amid this situation, the electrification ratio has been increasing year by year and almost all areas of the country were electrified in 2020. The electrification ratio is to reach 100%, with the ratio of NRE (new and renewable energy), such as hydro, geothermal and wind power, increasing versus a decrease in the ratio of thermal power plants using natural gas or coal. To achieve electrification in the whole country, more than 500,000 customers are to be electrified every year, which is not an easy mission.

The term electrification here does not mean that electricity can be used as customers want anytime, like urban areas, but merely a combination of a few solar panels and batteries. Therefore, electricity cannot be distributed to all residents sufficiently, and it will only be used for lights and charging cell phones.

In particular, the eastern area of Indonesia is less developed and many residents suffer a high poverty rate, without electricity. Isolated islands are off the grid because they are out of the electrical grids in the mainland. Electrical grids for these islands have not been developed. Even if electrical grids for isolated islands were developed so that electricity can be distributed from a thermal power plant, operations would be limited because of the costs for fuel and its transportation. Therefore, these problems will be solved by renewable energy (see Chapter 6 for a detailed explanation of practical use for renewable energy).

Network losses have improved year by year. This is thanks to coordinated development of transmission and distribution facilities, with increasing electrical demand correlated with significant economic development. Facilities with high network losses were replaced and/or had substations and transmission/distribution lines newly installed so that load equalization could be carried out. In addition, electrical energy meters installed at consumers were replaced and countermeasures for electrical theft in the middle of distribution lines were carried out. Such work led to decreased network losses.

As the electrification ratio has increased, SAIDI and SAIFI have improved. However, SAIDI and SAIFI deteriorated suddenly in 2016. The reason for this is that the electrical supply was temporarily less than the demand. Since this incident, SAIDI and SAIFI have been decreasing because of new power plants, electrical grid development and system updates for operations.

Increasing network losses in 2018 were due to a change in the calculation method, which excluded minimum electricity customers. The term “minimum electricity customers” here means customers who use electricity for less than 40 hours, such as country villas. Since these customers were excluded from the network losses, the accuracy increased, even though the value was also higher.

Generally, electrical losses go up with the electrical demand. However, constant development and renovation for the electrical facilities based on the improve3ment of the demand in Indonesia. These are not only the installation and replacement of the main facilities like transmission and/or distribution lines, substations and capacitors but also the reconsideration of the electrical grids in accordance with the electrical trends.

Moreover, for the Non-technical Loss, it seems to be around 4-5% compared with the neighboring counties. This estimation is shown calculated on the results in a Japanese electric power company which has 4-5% of Technical Losses within its jurisdiction, and the results of whole network losses in Indonesia is approx. 9-10%. Obviously, even though the quality of both in Japan and Indonesia is different, the estimation is very practical as one of the indexes taking into consideration the development and growth in Indonesia.

3.5 PLN Financial Status

(1) Electricity Tariff (TTL) and Electricity Tariff Adjustments

The main component of PLN's revenue is electricity sales.
An electricity tariff called "TTL" is determined by the government and the House of Representatives (DPR), to be used as the basis for calculating electricity bills for customers.
TTL is reviewed and adjusted periodically. It consists of a number of tariff groups for different customer groups.

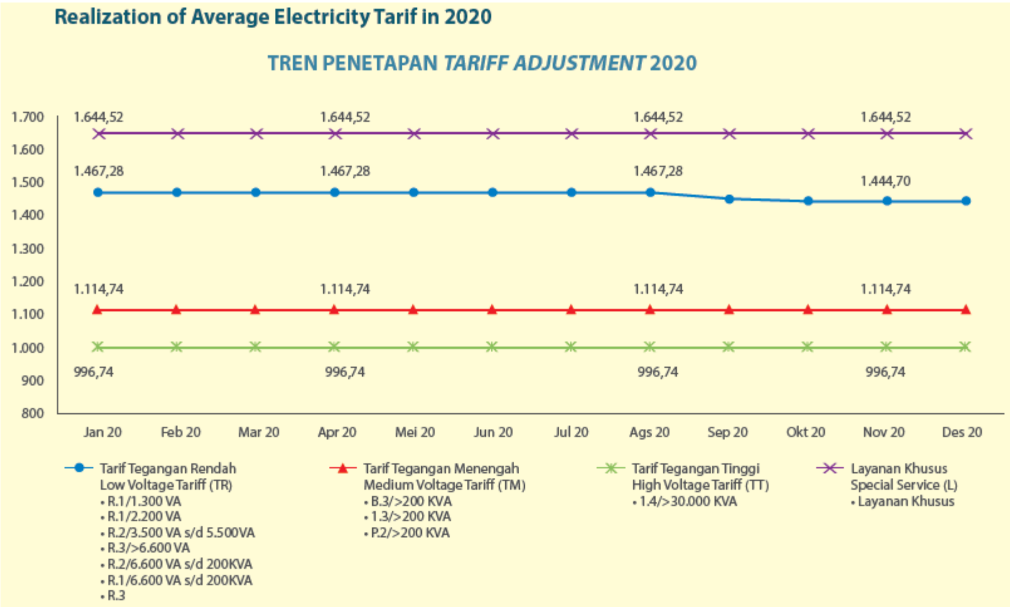
TTL is applied to different groups depending on customer attributes (household, corporate, industrial, etc.), financial situation and voltage.

Electricity tariff adjustments were applied to 13 tariff groups in accordance with the Ministerial Regulation of ESDM 2020, as follows:

1. R-1/TR, 900 VA - RTM (small households)
2. R-1/TR, 1,300 VA (small households)
3. R-1/TR, 2,200 VA (small households)
4. R-2/TR, 3,500 VA - 5,500 VA (medium households)
5. R-3/TR, 6,600 VA and above (big households)
6. B-2/TR, 6,600 VA - 200 kVA (medium enterprises)
7. B-3/TM, above 200 kVA (big enterprises)
8. I-3/TM, above 200 kVA (medium industries)
9. I-4/TT, 30,000 kVA and above (big industries)
10. P-1/TR, 6600 VA – 200 kVA (medium government offices)
11. P-2/TM, above 200 kVA (big government offices)
12. P-3/TR (public street lighting)
13. Special Services (L/TR, TM, TT)

Per the Ministerial Regulation, adjustments to the 13 tariff groups can be carried out every 3 months if there is a change in the USD exchange rate, Indonesian Crude Price (ICP) index, inflation or coal prices. In 2020, the government issued a policy not to impose tariff adjustments on some tariff groups - medium voltage (TM), high voltage (TT), Special Services (L), and low voltage (TR) - starting from October. This was in order to maintain people's purchasing power and to maintain the competitiveness of industry and business players.

The average TTL during 2020 were as follows:

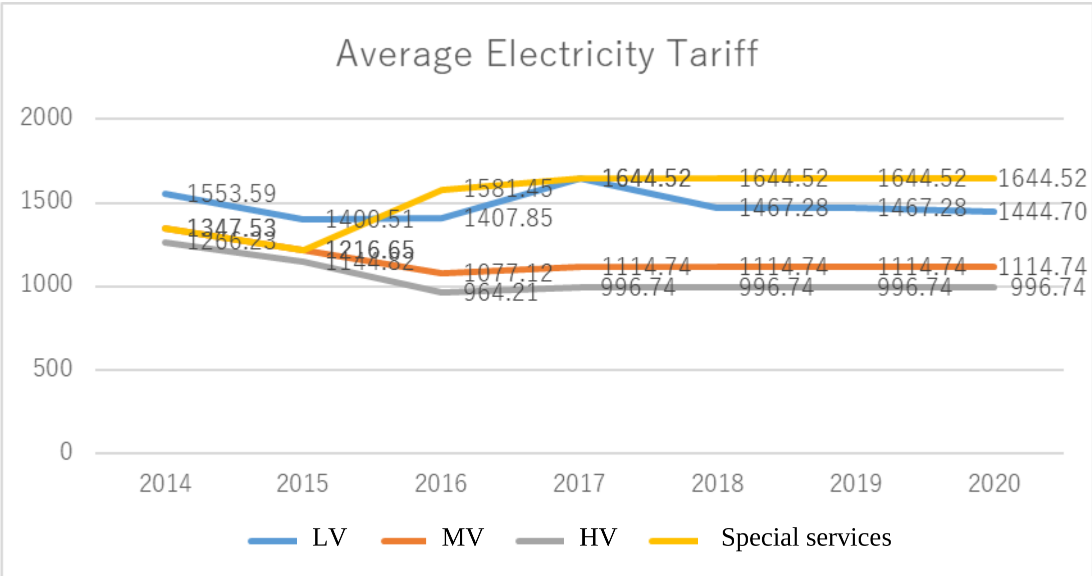


(Source: PLN Annual Report2020 P195 "Realization of Average Electricity Tariff in 2020")

Figure 3-25 Average Electricity Tariffs in 2020

From the above graph, it can be seen that the average electricity rate in 2020 does not change except for the low-voltage electricity rate, and that low-voltage electricity prices fluctuate in September.

Average electricity tariff trends are shown below.



(Source: created by JICA Survey Team based on PLN Annual Report 2014~2020)

Figure 3-26 Average Electricity Tariff

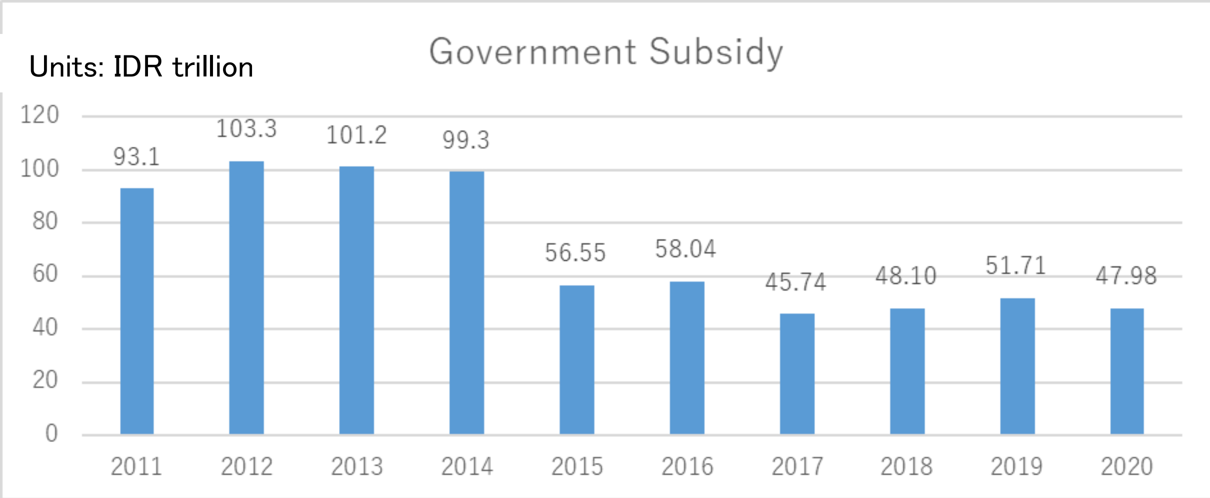
Since the electricity tariff adjustment system started in January 2015 and was applied in 2015 and 2016, there are some fluctuations in electricity rates. Furthermore, from 2017 to 2019, application of the electricity tariff adjustment system was postponed to maintain the purchasing power of citizens and the competitiveness of the industrial and business fields. It is also not in operation at present.

(2) Electricity Subsidies

Electricity subsidies are calculated from the negative difference between the average electricity selling price (Rp/kWh) of each tariff group, minus the BPP of electricity (Rp/kWh) on the voltage in each tariff group, multiplied by the sales volume (kWh) for each tariff group.

The average electricity selling price is still below the average cost of electricity supply, so PLN requires constant subsidies.

Trends in the government's electricity subsidies are shown below.



(Source: created by JICA Survey Team based on PLN Annual Report 2014~2020)

Figure 3-27 Government Subsidies

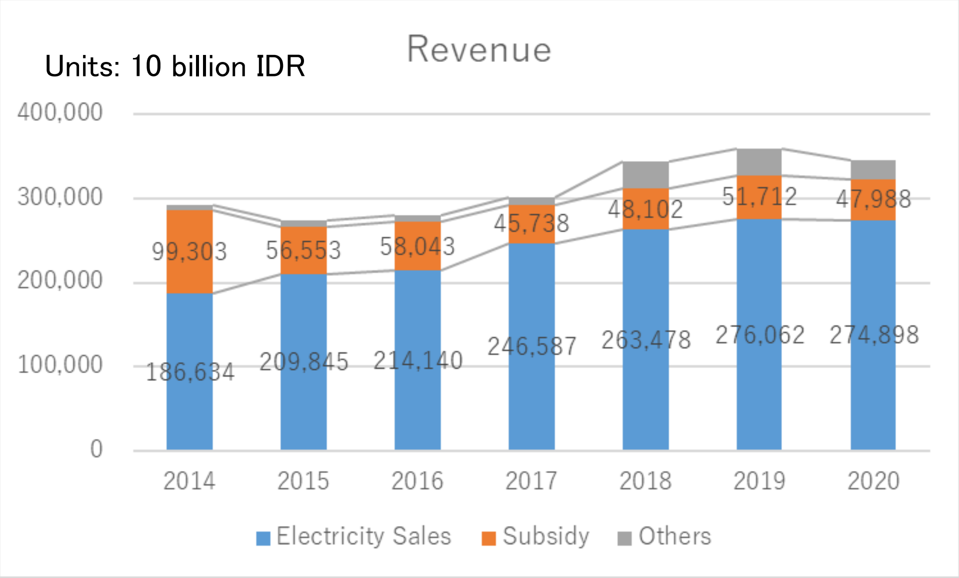
From 2012 to 2014, subsidies of approximately 100 trillion IDR (approximately 790 billion yen, calculated at 1 IDR = 0.0079 JPY) were invested every year, but in recent years this has improved to about 50 trillion IDR. However, the situation of relying on subsidies continues.

Recent fluctuations are due to higher supply costs (BPP), caused by rising energy prices and fluctuations in foreign exchange rates.

(3) PLN Revenue

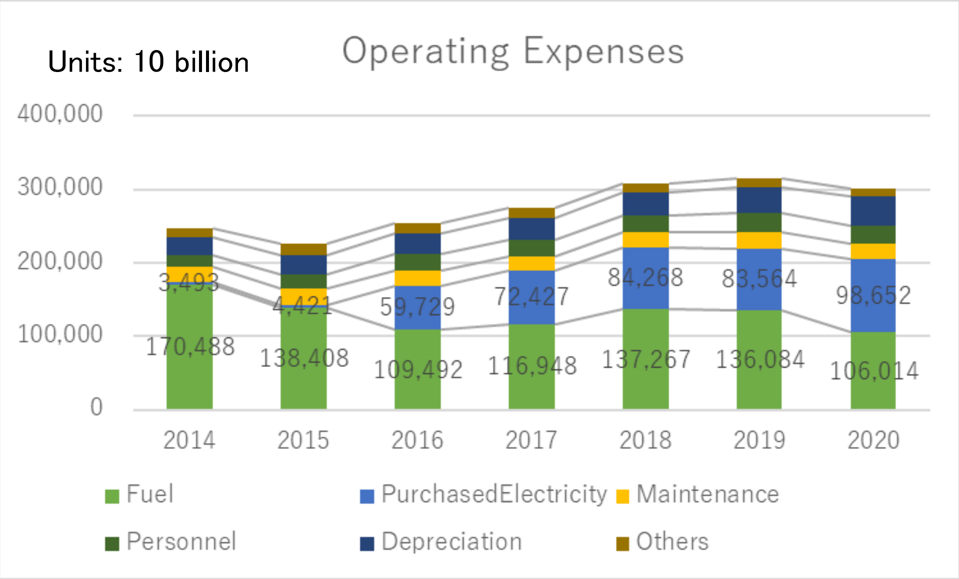
PLN records operating profit by injecting a subsidy equivalent to about 20-40% of the revenue, which is larger than the electricity sales revenue every year. In this way, since the electricity supply costs cannot be recovered only through the electricity sales income, there are concerns that there will be a shortage of funds for future capital investment.

Trends in PLN's revenue status are shown below.



(Source: created by JICA Survey Team based on PLN Annual Report 2014~2020)

Figure 3-28 PLN Revenue



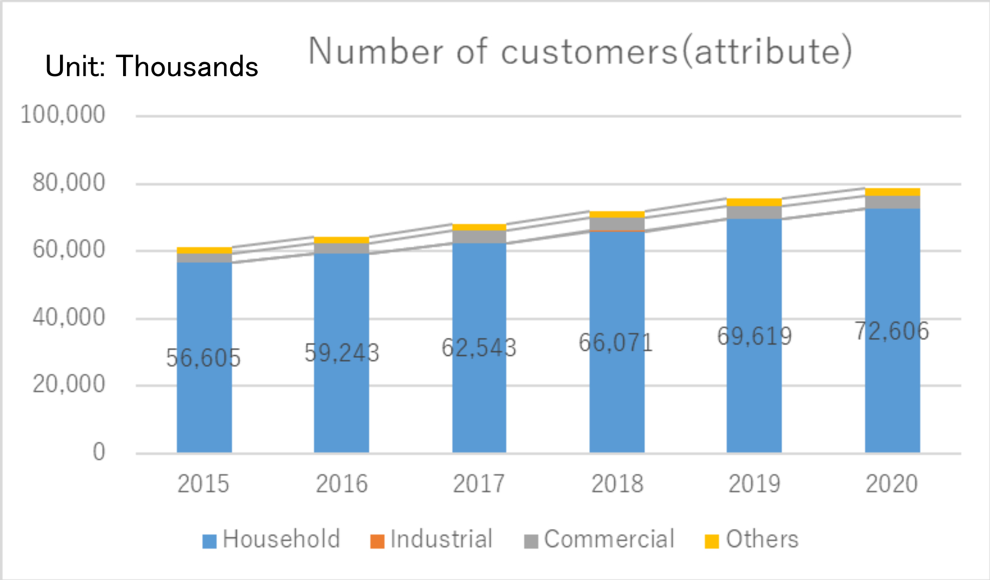
(Source: created by JICA Survey Team based on PLN Annual Report 2014~2020)

Figure 3-29 PLN Operating Expenses

In terms of revenue, electricity sales income is basically increasing every year, but it has not reached the point where it exceeds operating expenses, and the composition relies on the above-mentioned subsidies. In terms of operating expenses, it can be seen that the purchased electricity costs have increased significantly since 2016. This is due to Indonesia Financial Services Authority Regulation No. 6/POJK.04/2017. By applying the accounting practices in Power Purchase Agreement (PPA) transactions ("POJK No. 6") from 2016, purchased power including a lease was treated as the purchased electricity expenses (from PLN Annual Report 2016, P. 591).

(4) Number of customers by attribute, Number of customers by region

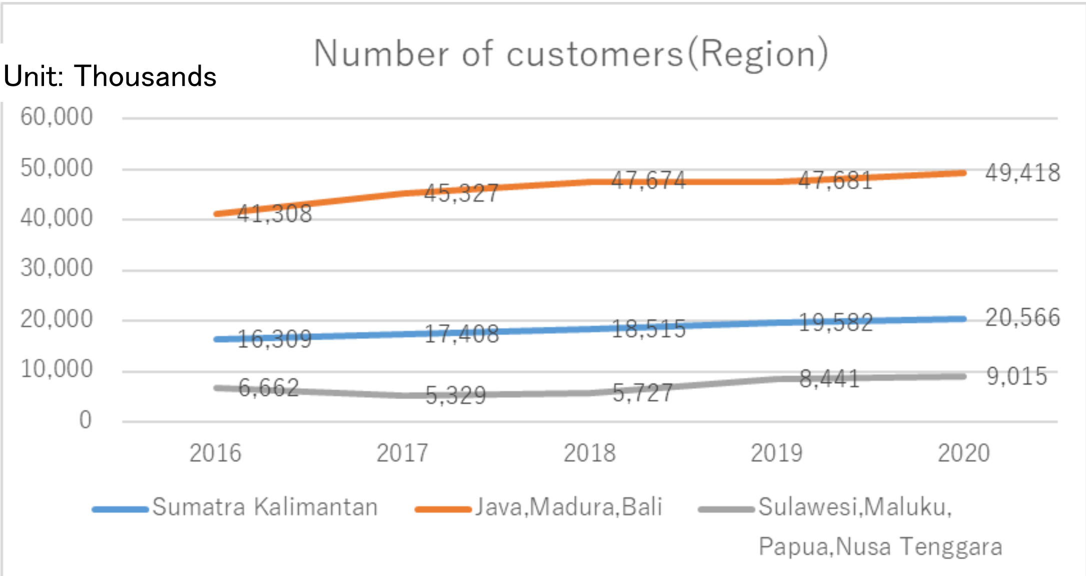
PLN's Number of customers by attribute is shown below.



(Source: created by JICA Survey Team based on PLN Annual Report 2014~2020)

Figure 3-30 Number of customers by attribute

The number of customers is increasing every year in all attributes, including household, industrial and commercial. In particular, for household use, the number of customers has increased by about 16 million when comparing 2020 and 2015.



(Source: created by JICA Survey Team based on PLN Annual Report 2014~2020)

Figure 3-31 Number of customers by region

By region, Java, Madura, and Bali have the largest number of customers. Increases and decreases can be seen in Sulawesi, Maluku, Papua and Nusa Tenggara, but it can be said that the overall trend is increasing due to changes in regional divisions depending on the year.

3.6 Outline of Support by other Donors

Various financial institutions and government agencies are implementing support programs in Indonesia. An example is shown below.

3.6.1 Asian Development Bank (ADB) [2]

Since 1970, ADB has financed more than 50 projects and programs for Indonesia's energy sector. The total lending has reached US $ 5.5 billion. Table 3-24 and Table 3-25 shows the major public and private sector projects that ADB has implemented since 2016.

Table 3-24 ADB Major Public Sector Projects in Indonesia Since 2016

Project Name	Amount ($ million)
Java–Bali Electricity Distribution Performance Improvement Project	50.0
West Kalimantan Power Grid Strengthening Project	49.5
Java–Bali 500-Kilovolt Power Transmission Crossing	224.0
Sustainable and Inclusive Energy Program–Subprogram 1 and 2	1,000.0
Sustainable Energy Access in Eastern Indonesia: Electricity Grid Development Program Results Based Loan	600.0
Electricity Grid Strengthening–Sumatra Program	600.0

(Source: INDONESIA ENERGY SECTOR ASSESSMENT, STRATEGY, AND ROAD MAP, December 2020)

Table 3-25 ADB Major Private Sector Projects in Indonesia Since 2016

Project Name	Location	Capacity (MW)
Riau 275 MW Combined-Cycle Gas-Fired Power Plant	Sumatra	275
Jawa-1 Liquified National Gas-to-Power	West Java	1,760
Eastern Indonesia Renewable Energy Project Phase 1 Tolo Wind	South Sulawesi	72
Eastern Indonesia Renewable Energy Project Phase 2 One 21 MW Solar	Sulawesi	21
Eastern Indonesia Renewable Energy Project Phase 2-three 7 MW Solar	West Nusa Tenggara	21
Rantau Dedap Geothermal	South Sumatra	90

MW = megawatt.

(Source: INDONESIA ENERGY SECTOR ASSESSMENT, STRATEGY, AND ROAD MAP, December 2020)

ADB is also working with other agencies, such as the World Bank, JICA, KfW (Kreditanstalt fűr Wiederaufbau), AFD (Agence Française de Développement) and USAID (United States Agency for International Development), to provide support for the energy sector (see Table 3-26). The governments of Australia, New Zealand, the United Kingdom, Canada, the Netherlands, Norway, and Finland have also been involved.

[2] https://www.adb.org/sites/default/files/institutional-document/666741/indonesia-energy-asr-update.pdf
https://www.adb.org/news/adb-pln-sign-mou-work-indonesia-clean-energy-goals

Table 3-26 Major Development Partners and Programs 2016–2019

Project Name	Year Approved	Amount ($ million)
Asian Development Bank		
Sustainable and Inclusive Energy Program, Subprogram 3	2020 (pending)	400.00
Sustainable Energy Access in Eastern Indonesia: Power Transmission Project	2020 (pending)	300.00
Sustainable Energy Access in Eastern Indonesia: Electricity Grid Development Program (Phase 2) Results-Based Loan	2020 (pending)	600.00
Geothermal Power Generation Project	2020	300.00
Sustainable and Reliable Energy Access Program RBL	2019	300.00
Sustainable Infrastructure Assistance Program Phase 2	2018	30.00
Sustainable and Inclusive Energy Program, Subprogram 2	2017	400.00
Pilot Carbon Capture and Storage Activity in the Natural Gas Processing Sector	2016	1.85
Private Sector Operations Department		
Riau Natural Gas Power Project	2018	167.90
Jawa-1 Liquified Natural Gas-to-Power Project	2018	305.05
Eastern Indonesia Renewable Energy Project Phase 2	2018	40.17
Rantau Dedap Geothermal Power Project (Phase 2)	2018	227.50
Eastern Indonesia Renewable Energy Project Phase 1	2017	120.80
Tangguh Liquefied Natural Gas Expansion Project	2016	400.00
Muara Laboh Geothermal Power Project	2016	109.25
KfW		
Sustainable hydropower 2	2017	€225.00
Sustainable hydropower 1	2017	€85.00
World Bank		
Indonesia Geothermal Resource Risk Mitigation Project	2019	465.00
Indonesia's Infrastructure Finance Development	2017	8.28
Geothermal Energy Upstream Development	2017	104.00
Power Distribution Development Program	2016	1,450.00
Indonesia Energy Sector Development Policy Loan	2016	500.00
Japan International Cooperation Agency		
Hululais Geothermal Power Plant Project	2016	6.00
New Zealand		
New Zealand support for training in Indonesian Geothermal Sector	2018	
New Zealand support for accelerating geothermal development in Indonesia	2017	
United Kingdom		
Indonesia Renewable Energy	2019	€13.50
United States Agency for International Development (USAID)		
Indonesia Clean Energy Development 2	2020	
USAID Sustainable Energy for Indonesia's Advancing Resilience	2020	35.00
Gesellschaft fuer Internationale Zusammenarbeit		
Electrification through Renewable Energy	2017	
1,000 Islands – Renewable Energy for Electrification Program	2017	
Association of Southeast Asian Nations-German Energy Programme	2016	

Source: Asian Development Bank.

(Source: INDONESIA ENERGY SECTOR ASSESSMENT, STRATEGY, AND ROAD MAP, December 2020)

In addition, ADB signed a memorandum of understanding (MoU) with PLN CEO Zulkifli Zaini at COP26 in Glasgow in November 2021 to help Indonesia achieve its clean energy goals. ADB has also announced the launch of the "Energy Transition Mechanism (ETM) Partnership", aimed at early shutdown of coal-fired power plants and investment in new clean energy, together with the Indonesian government and the Philippine government. (The Japanese government announced a $25 million grant for the ETM partnership on November 3.)

ETM will set up a fund in the future to provide and promote financial incentives for the early retirement of coal-fired power plants. The aim of the ETM Partnership is to shorten the life of coal-fired power plants, and to reduce CO_2 emissions by making full use of various technologies in the middle of the process.
Regarding the Energy Policy[3] announced by ADB in September 2021, Article 75 is a provision on coal-fired power plants, which will not be supported unless it can contribute to the early retirement. Article 76 is a clause on gas-fired power plants, which will be supported only when low efficiency plants (diesel etc.) are replaced with high efficiency plants on a one-to-one basis or when CO_2 can be reduced at the grid level. It is possible to support the conversion of coal-fired power to gas-fired power in Indonesia under the Energy Policy, but since Indonesia has a certain track record in geothermal power generation, it is assumed that it will be difficult to give priority to supporting gas-fired power over geothermal power generation. Article 77 is a clause on CCS, and it is not supposed to be able to support CCS for Oil Recovery. Therefore, it is unlikely that CCS can be supported when it is utilized in the blue hydrogen or ammonia production process.

3.6.2 Japan Bank for International Cooperation (JBIC)

JBIC has provided financial support for overseas infrastructure business development by Japanese companies in collaboration with ADB and other international organizations. In Indonesia as well, JBIC is supporting renewable energy generation, especially geothermal energy. So far, JBIC has provided project financing for several geothermal IPP projects such as the Sarulla Geothermal Power Plant Project (concluded a loan agreement in March 2014), the Muara Laboh Geothermal Power Generation Project (loan agreement in January 2017) and the Rantau Dedap Geothermal Power Generation Project (concluded a loan agreement in March 2018) (see Table 3-27). These loans are expected to contribute to economic development through the stable supply of power, which will aid global warming countermeasures in Indonesia.

Table 3-27 Recent Major Overseas Infrastructure Projects in Indonesia

(Loans, equity participations, and guarantees in the last five years, as of the end of March 2020)

Category	Project Name	Area	Financing amount (JBIC portion)	Date of loan agreement
Renewable energy/ environment	Rantau Dedap Geothermal Power Generation Project	South Sumatra	Up to approx. USD188 million	March 2018
	Muara Karang Gas-fired Combined Cycle Power Plant Expansion Project	Jakarta	Up to approx. JPY9.2 billion and USD22 million	March 2017
	Muara Laboh Geothermal Power Generation Project	West Sumatra	Up to approx. USD198 million	January 2017
	Jawa 2 Gas-fired Combined Cycle Power Plant Construction Project	Jakarta	Up to approx. JPY19 billion and USD27 million	October 2016
(Ref.) Power generation	Jawa 1 Gas-to-Power Project	West Java	Up to approx. USD604 million	October 2018
	Cirebon Ultra Super Critical Coal-fired Power Plant Expansion Project	West Java	Up to approx. USD731 million	April 2017

[3] https://www.adb.org/sites/default/files/institutional-document/737086/energy-policy-r-paper.pdf

Category	Project Name	Area	Financing amount (JBIC portion)	Date of loan agreement
	Tanjung Jati B Ultra Super Critical Coal-fired Power Plant Re-expansion	Central Java	Up to approx. USD1,678 million	February 2017
	Central Java Ultra Super Critical Coal-fired Power Plant Construction Project	Central Java	Up to approx. USD2,052 million	June 2016

(Source: JBIC press release, JBIC annual report 2020)

3.6.3 World Bank (WB)

In 2011, the World Bank launched the Partnership for Market Readiness (PMR), with the aim of providing developing countries with capacity building support for institutional design and the introduction of market mechanisms. The World Bank has also supported Indonesia with a total of US $3.56 million between 2017 and 2021, including the development of an online GHG emission reporting system for Indonesia's power generation sector and the development of a market-based policy framework. Furthermore, in February 2021, the Partnership for Market Implementation (PMI) was launched to support developing countries, including Indonesia, in order to implement the carbon pricing system.
In addition, the World Bank has provided support for energy sector decarbonization (see Table 3-28). Most recently, in September 2021, as part of the decarbonization support in Indonesia, the World Bank announced a loan of $380 million for the country's first pumped storage power generation construction project (1,040 MW). AIIB is expected to co-finance this project (see 3.6.4).

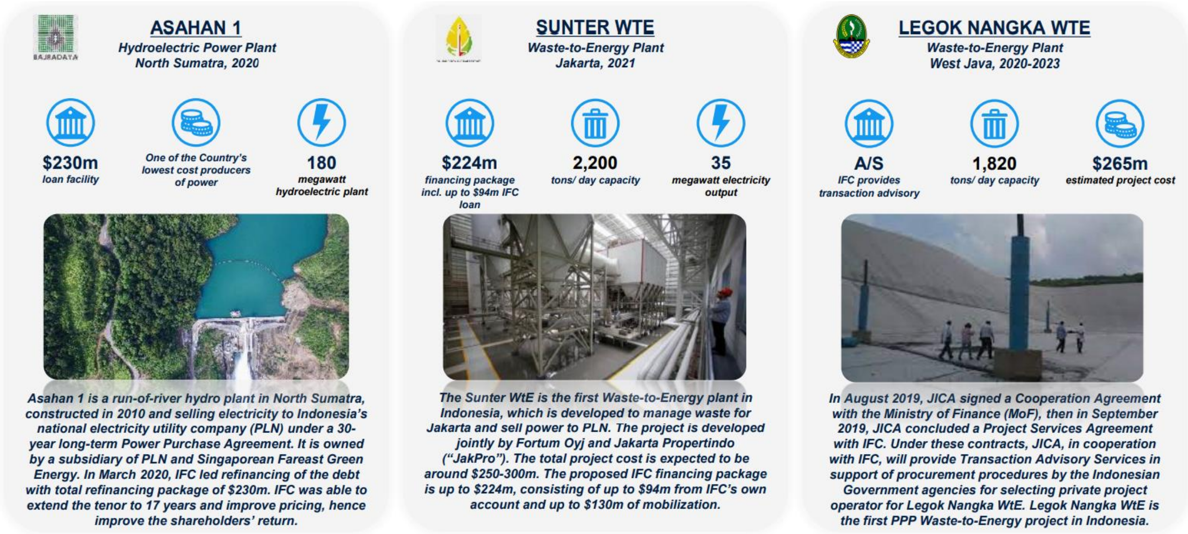
Table 3-28 List of projects that the World Bank is supporting for decarbonization of the Indonesian energy sector

Project Name	Project Development Objective	Implementing Agency	Board Approval Date	Project Closing Date
Development of Pumped Storage Hydropower in Java Bali System Project	To support Indonesia’s energy transition and decarbonization goal by: (i) developing the first large-scale pumped storage hydropower; and (ii) strengthening PLN’s capacity for hydropower development and management.	PT PLN (Persero)	September 2021	September 2027
ID-Geothermal Energy Upstream Development	To facilitate investment in geothermal power generation and reduce greenhouse gas emissions.	PT Sarana Multi Infrastruktur (Persero), PT Geo Dipa Energi	February 2017	December 2025
Indonesia Geothermal Resource Risk Mitigation Project (GREM)	To scale up investment in geothermal energy development and reduce greenhouse gas emissions in Indonesia. The following two items are the main ones to be implemented. (1) Reducing the risk of excavation of geothermal resources by establishing a new loan system (2) Technical support and capacity building	PT Sarana Multi Infrastruktur (Persero)	September 2019	October 2029

Project Name	Project Development Objective	Implementing Agency	Board Approval Date	Project Closing Date
Indonesia Sustainable Least-cost Electrification Technical Assistance (ISLE TA)	To support the Recipient in endorsing a framework approach to electrify the Indonesian Eastern Islands in a sustainable and affordable manner, and in preparing the investments needed to implement the approach in identified Pilot Islands.	PT PLN (Persero)	July 2021	January 2023

(Source: The World Bank website)

In addition, the International Finance Corporation (IFC), a World Bank Group, has supported Jakarta's green building policy for decarbonization in Indonesia, and has also provided loans for hydropower projects in Indonesia.



(Source: IFC presentation slides, April 2021)

Figure 3-32 Examples of energy projects supported or proposed by IFC Indonesia (As of April 2021)

3.6.4 Asian Infrastructure Investment Bank (AIIB)

AIIB's "Sustainable Energy for Asia Strategy" sets out a framework for AIIB to invest in energy projects that will increase access to clean, safe, and reliable electricity for millions of people in Asia. As part of this, AIIB approved a loan of US $ 310 million for the PLN East Java & Bali Power Distribution Strengthening Project in January 2021. The project was the first AIIB loan to Indonesia's energy sector, and negotiations have been held between AIIB and PLN since 2019 to support PLN's RUPTL.

Table 3-29 List of projects AIIB is implementing / considering for the Indonesia energy sector

Status	Financing Type	Project Name	Financing Amount
Proposed	Sovereign	Development of Pumped Storage Hydropower in Java Bali System	Proposed Funding: USD230-250 million
Approved in 2021	Sovereign	PLN East Java & Bali Power Distribution Strengthening Project	Approved Financing: USD310 million

(Source: AIIB website)

3.6.5 International Energy Agency (IEA)[4]

Since Indonesia became an IEA Association country in 2015, the IEA has supported the Indonesian government in terms of fuel, digitization, investment conditions, policies and regulations, and so on. In July 2020, the Indonesian government and IEA announced a new joint project to encourage private investment in renewable power sources, as well as strategies to enhance renewable integration and power system operation in Indonesia. The work will be carried out in partnership with PLN.
With support from the IEA's Clean Energy Transitions Programme (CETP), Indonesia is launching new presidential priorities on renewable power and clean energy technologies, and began to consider a new national energy strategy and roadmap in 2021.
In March 2021, the IEA, together with the Indonesian Minister of Energy and Mineral Resources, Arifin Tasrif, announced the "IEA-Indonesia Energy Transition Alliance" to respond to the gradual changes in the country's energy transition.

3.6.6 International Renewable Energy Agency (IRENA)[5]

The Indonesian Minister of Energy and Mineral Resources, Arifin Tasrif, agreed with IRENA about building more intensive partnerships to develop and implement a decarbonization and emission reduction roadmap at COP26 in Glasgow on November 4, 2021. Under this partnership, IRENA and Indonesia will work closely together to develop a new, ambitious roadmap in line with the Paris Agreement's goal of "realizing a clean global economy by 2050".

3.6.7 United Nations Development Programme (UNDP)

UNDP, which is the United Nations' major development support agency that promotes sustainable development, utilizes the funds of Global Environment Facility[6] (GEF) to support the creation of National Communications (NCs) to be submitted to the United Nations Framework Convention on Climate Change (UNFCCC), and is working on national projects such as MTRE3 (Climate Change Mitigation Actions through The Increase of Renewable Energy Use and Energy Efficiency) to promote countermeasures for climate change through renewable energy and energy efficiency in collaboration with EBTKE.

3.6.8 U.S. Agency for International Development (USAID)

USAID, a U.S. government aid arm, is helping Indonesia's energy sector to lower carbon emissions and electrify facilities. In total since 2015, USAID has mobilized over $1.62 billion of investments in

4 https://www.iea.org/news/the-landmark-iea-indonesia-energy-transition-alliance-will-build-a-path-to-a-sustainable-energy-future
https://www.iea.org/news/indonesia-and-iea-deepen-cooperation-on-electricity-and-renewables-to-advance-energy-transitions
5 https://geothermal.jogmec.go.jp/library/foreign_topics/file/211206.pdf
https://ebtke.esdm.go.id/post/2021/11/04/3000/kementerian.esdm.irena.tingkatkan.kerja.sama.dekarbonisasi.menuju.target.net.zero.emission
6 GEF is the trust fund which is established as the financing mechanism for environment-related treaties. International organizations such as World Bank, UNDP and UNEP utilize this funding to implement projects.

renewable energy with a combined capacity of 571.1MW. In 2020, USAID mobilized $19.8 million of investments in renewable energy for two projects, with a combined total capacity of 11.5 MW.
In addition, USAID assisted PLN in the development of distribution system planning guidelines and renewable energy interconnection assessment guidelines. USAID intends to continue to support the improvement of PLN's capacity for the power grid connection of renewable energy.

3.6.9 Korea International Cooperation Agency (KOICA)

KOICA, which is the government agency in charge of South Korea's grant aid projects, announced the launch of ACCESS (Accelerating Clean Energy Access to Reduce Inequality) Initiative, which is a clean energy project in Indonesia and Timor-Leste, under the framework of the Green New Deal promoted by the Korean government in September 2020.
ACCESS Initiative is also a collaboration with the Ministry of Energy and Mineral Resources of the Republic of Indonesia (MEMR), the Ministry of State Administration of the Republic of Timor-Leste and UNDP, and is spending US $18 million over four years to introduce renewable energy for people who live in remote areas and do not have access to reliable electricity.
In Indonesia, a total of 1,200 kW of off-grid solar power generation systems is expected to be installed in 23 villages in West Sulawesi, Southeast Sulawesi, East Nusa Tenggara, and Central Kalimantan. In March 2021, it was announced that KOICA would provide US $15.5 million in funding for the project.

3.6.10 German Government

Indonesia and Germany signed an agreement for technical cooperation in June 2021. With a total volume of 59.4 million EUR, 16 projects are being financed by the German government for bilateral cooperation projects in the areas of renewable energies, green infrastructure, forests, climate change and so on. The German contributions for these projects will be implemented by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH, in partnership with the relevant Indonesian ministries and subnational institutions.
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3.6.11 Australian Government

The Government of Australia and the Government of Indonesia held a meeting in Rome on the 30th of October 2021 and issued a joint statement on cooperation on the green economy and energy transition. Opportunities to enhance cooperation include green finance mechanisms to support low emissions technology projects that enhance greenhouse gas emissions reduction (including Carbon Capture and Storage/Carbon Capture, Utilization, and Storage (CCS/CCUS)), clean energy (such as clean hydrogen and ammonia) and energy efficiency.

3.6.12 Swiss Government

In December 2020, the Human Resource Development Agency of the Ministry of Energy and Mineral Resources (BPSDM ESDM) signed a new Project Agreement (PA) with the State Secretariat for Economic Affairs of the Swiss Confederation (SECO). The PA includes the development of formal and non-formal training in the new and renewable energy subsector, as well as other activities in the context of knowledge exchange and capacity building.

Chapter 4. Low carbonization/decarbonization Policy

4.1 Indonesia's Low carbonization/decarbonization Targets

Indonesia, which accounts for about half of the Association of Southeast Asian Nations (ASEAN) greenhouse gas (GHG) emissions, held the 13th Conference of the Parties to the United Nations Framework Convention on Climate Change (COP13) in Bali in 2007. Indonesia has been working on its response to the climate change problem from an early stage among the ASEAN countries, such as formulating the "National Action Plan Addressing Climate Change" in 2007.
In January 2016, the Government of Indonesia submitted its "Nationally Determined Contribution (NDC)[7]" to the UNFCCC (United Nations Framework Convention on Climate Change). The government has set an ambitious goal of reducing GHG emissions from 29% (unconditional scenario) to 41% (conditional scenario) compared to the BAU scenario by 2030.
In July 2021, prior to the 26th Conference of the Parties to the United Nations Framework Convention on Climate Change (COP26), which was held in November 2021, the Indonesian government submitted to UNFCCC its "Updated NDC" and the "INDONESIA Long-Term Strategy for Low Carbon and Climate Resilience 2050 (LTS-LCCR)", with the goal of achieving carbon neutrality by 2060 at the latest (an overview of each of these is described below).
In addition, at the COP26 summit meeting, which was held on the 1st of November, 2021, President Joko Widodo made a speech about Indonesia’s support in the face of the ever-deteriorating climate change situation and emphasized its commitment to GHG emissions reduction.

4.1.1 Overview of Updated Nationally Determined Contribution (Updated NDC)

The Updated NDC is not legally binding, but reflects Indonesia's commitment to the realization of the Paris Agreement. Table 4-1 shows the GHG emission targets (in 2030) by sector as shown in the Updated NDC.
The Updated NDC is in line with the policy for the primary energy mix in Indonesia set forth in the National Energy Policy formulated in 2014, which set out the country’s ambition to transform, by 2025 and 2050, the primary energy supply mix with shares as follows:

a) new and renewable energy of at least 23% in 2025 and at least 31% in 2050;
b) oil should be less than 25% in 2025 and less than 20% in 2050;
c) coal should be a minimum of 30% in 2025 and a minimum of 25% in 2050; and
d) gas should be a minimum of 22% in 2025 and a minimum of 24% in 2050.

[7] Countries are obliged to formulate and report NDCs every five years.

Table 4-1 Projected BAU and emission reduction from each sector category

Sector	GHG Emission Level 2010* (MTon CO_2e)	GHG Emission Level 2030 MTon CO_2e			GHG Emission Reduction MTon CO_2e		GHG Emission Reduction % of Total BaU		Annual Average Growth BAU (2010-2030)	Average Growth 2000-2012
		BaU	CM1	CM2	CM1	CM2	CM1	CM2		
1. Energy*	453.2	1,669	1,355	1,223	314	446	11%	15.5%	6.7%	4.50%
2. Waste	88	296	285	256	11	40	0.38%	1.4%	6.3%	4.00%
3. IPPU	36	70	67	66	3	3.25	0.10%	0.11%	3.4%	0.10%
4. Agriculture**	111	120	110	116	9	4	0.32%	0.13%	0.4%	1.30%
5. Forestry and Other Land Uses (FOLU)***	647	714	217	22	497	692	17.2%	24.1%	0.5%	2.70%
TOTAL	**1,334**	**2,869**	**2,034**	**1,683**	**834**	**1,185**	**29%**	**41%**	**3.9%**	**3.20%**

Notes: **CM1**= Counter Measure 1 (unconditional mitigation scenario)
CM2= Counter Measure 2 (conditional mitigation scenario)

*) Including fugitive.
**) Only include rice cultivation and livestock.
***) Including emission from estate crops plantation.

(Source: Updated Nationally Determined Contribution, Republic of Indonesia, July 2021)

For the energy sector, the prerequisites for calculating the emission forecast for each of the BAU scenario, unconditional scenario, and conditional scenario in Table 4-1 are as shown in Table 4-2.

Table 4-2 Assumptions used for projected BAU and emission reduction for Energy sector

SECTOR: ENERGY	BAU	Mitigation Scenario 1 (CM 1)	Mitigation Scenario 2 (CM 2)
1. Efficiency in final energy consumption.	Inefficiency in final energy consumption.	75% *	100% *
2. Implementation of clean coal technology in power plants.	0%		
3. Renewable energy in electricity production.	Coal power plant	19.6% (Committed 7.4 GW based on RUPTL)	Electricity production of 132.74 TWh **
4. Implementation of biofuel in transportation sector	0%	90%	100%
5. Additional gas distribution lines (Gas pipeline for residential and commercial sectors)	0%	100%	100%
6. Compressed Natural Gas consumption (CNG fuelling station).	0%	100%	100%

* The total target to be achieved through clean energy and energy efficiency programmes
**132.74 TWh is equivalent to 21.65 GW

(Source: Updated Nationally Determined Contribution, Republic of Indonesia, July 2021)

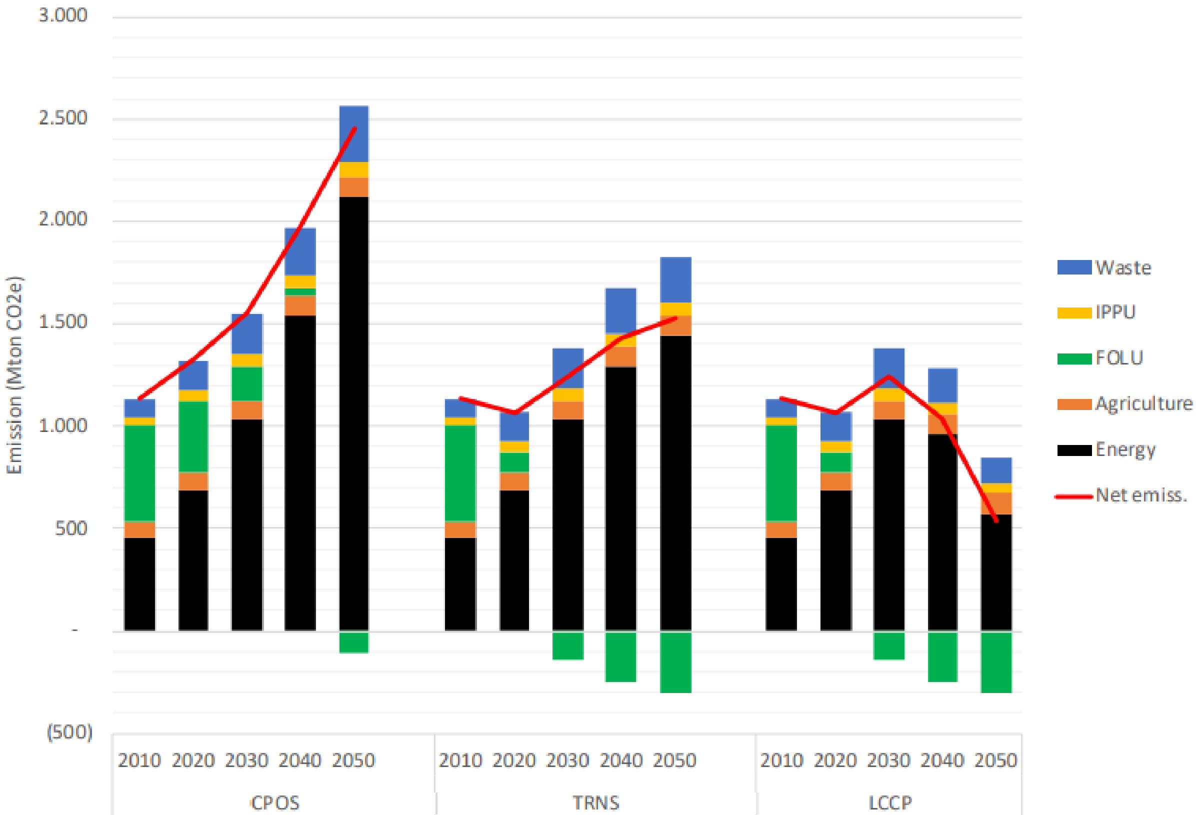
4.1.2 Overview of INDONESIA Long-Term Strategy for Low Carbon and Climate Resilience 2050 (LTS-LCCR)

The Indonesian government has submitted to the UNFCCC the “Long-Term Strategy for Low Carbon and Climate Resilience 2050 (LTS-LCCR)” in conjunction with the Updated NDC. In this long-term strategy, the government has set a goal of achieving carbon neutrality (net-zero carbon emissions) by 2060 at the latest, 10 years ahead of the previous target of 2070.
The following three pathway scenarios were exercised during the development of Indonesia’s LTS-LCCR.

(i) extended unconditional commitment to NDC/current policy scenario (named as CPOS),
(ii) transition scenario (named as TRNS), and
(iii) low carbon scenario compatible with the Paris Agreement target (named as LCCP).

In the CPOS scenario, GHG emissions are expected to continue to increase after 2030. Although the TRNS scenario shows a reduction in GHG emissions compared to the CPOS scenario, emission levels in 2050 are not sufficient to meet the goals of the Paris Agreement. In the LCCP scenario, emissions will decline rapidly after 2030, reaching 540 Mton of CO_2e (1.61 tons of CO_2e per capita) by 2050. The Indonesian government believes that carbon neutrality can be achieved by 2060 at the latest through the LCCP scenario.

The GHG emission forecast by 2050 in each scenario is as shown in Figure 4-1.



(Source: Indonesia Long-Term Strategy for Low Carbon and Climate Resilience 2050 (2021))

Figure 4-1 Projection of emission under the CPOS, TRNS and LCCP

4.1.3 Introduction of carbon pricing regulations

The Indonesian government announced that President Joko Widodo signed the Presidential Regulation No. 98/2021 on the 2nd of November, 2021, during COP26, on the "Carbon Pricing System" to promote emission reductions by pricing carbon.

This system stipulates two carbon pricing determination methods, “trading means” and “non-trading means”. The “trading means” include the Emissions Trading System (ETS) and the carbon offset system (credit mechanism). The “non-trading means” include the carbon tax. Details of the emissions trading system will be stipulated in separate rules, and the Ministry of Finance is preparing to enact related regulations for carbon tax with the aim of enacting it in 2022.

Figure 4-2 shows the introduction schedule for these carbon pricing systems.

1 — 2021:

- Stipulation of Presidential Regulation on economic value of carbon.
- Stipulation of new and renewable energy power plant regulation with one of the provisions is regarding carbon tax.
- Development of technical mechanism of carbon tax and carbon exchange.
- Piloting of carbon trading in the power plant sector by Ministry of Energy and Mineral Resources with average cost of Rp30,000.00 per ton CO2 equivalent.
- Evaluation of the carbon trading pilot execution by Ministry of Energy and Mineral Resources.

2 — 2022:

- Synchronization between cap & trade and cap & tax in the electricity sub-sector.
- Determination of cap for coal-fired power plant sector by the Minister of Energy and Mineral Resources.
- Implementation of carbon tax (cap & tax), limited only to coal-fired power plants with tariff of Rp30,000.00 per ton CO2 equivalent*.
- Preparation of measurement, reporting, verification (MRV) system as a support of carbon trading (by National Registry System or SRN).
- Preparation of technical regulation on carbon trading (by Ministry of Environment and Forestry).

*Carbon tax tariff will be evaluated periodically and determined higher or equivalent to the carbon price in the carbon market.

3 — 2025:

- Implementation of carbon trading fully (to all sectors) through carbon exchange.
- Expansion of cap & trade and cap & tax sector, following the readiness of each sector.

(Source: MOF, December 2021)

Figure 4-2 Carbon Tax Roadmap Planned for a Fair and Sustainable Energy Transition

4.2 Low carbonization/decarbonization Policies of each Country

The low-carbonization/decarbonization policies of Indonesia's neighboring countries will be described herein.

4.2.1 Singapore

(1) Low-carbonization/decarbonization Targets (NDC)

According to the INDC submitted by the Singaporean government to the UNFCCC in 2016, Singapore has set a goal of reducing GHG emissions by 2030 by 36%, compared to 2005.

(2) Long-Term Low-Emissions Development Strategy

In the Long-Term Low-Emissions Development Strategy (LEDS) issued in April 2020, Singapore declares that it will suppress the emissions' peak to 33 $MtCO_2e$ by 2050, with a view to achieving net-zero emissions as soon as viable in the second half of the century.
Energy Market Authority (EMA) says it will harness four supply switches towards the future of a reliable and efficient energy supply.

- 1st Switch: Natural Gas
  - Generate power from natural gas more efficiently to reduce GHG emissions
  - Diversify our natural gas sources to improve energy security

- 2nd Switch: Solar
  - Deploy at least 2 GWp of solar by 2030
  - Deploy at least 200MW of solar energy storage systems beyond 2025

- 3rd Switch: Regional power grid
  - Tap on regional power grids (bilateral power trading arrangements, regional arrangements such as the Lao PDR-Thailand-Malaysia-Singapore Power Integration Project)
  - The longer-term vision: construction of ASEAN Power Grid, unfettered electricity trading between ASEAN members)

- 4th Switch: Emerging low-carbon alternatives
  - R&D for introduction of new technologies, such as CCUS and hydrogen energy utilization and storage

4.2.2 Thailand

(1) Low-carbonization/decarbonization Targets (NDC)

The GHG reduction targets stated in the first INDC (Intended Nationally Determined Contributions) submitted by Thailand to the UNFCCC (United Nations Framework Convention on Climate Change) in 2016 were 20% in the unconditional scenario and up to 25% in the conditional scenario, compared to the BAU scenario, by 2030.
In November 2021, Prime Minister Prayut expressed Thailand's new goal of achieving carbon neutrality by 2050 and net zero emissions by 2065 at the 26th Conference of the Parties to the United Nations Climate Change conference (COP26).
In the Long-term Low Greenhouse Gas Emission Development Strategy (LT-LEDS), Thailand emphasizes the importance of innovation and RD&D, especially in the fields of low carbon power generation, CCS, bioenergy with CCS, and the hydrogen economy, in order to achieve carbon neutrality by 2065.

(2) The Mid-century, Long-term Low Greenhouse Gas Emission Development Strategy

Thailand has set the following goals in the Mid-century, Long-term Low Greenhouse Gas Emission Development Strategy (LT-LEDS) (October 2021):

- Reach peak GHG emissions (approximately 370MtCO_2e) by 2030
- Net GHG emissions to be approximately 200 MtCO_2e by 2050
- Balance between GHG emissions by source and removals by sink as early as possible within the second half of the 21st century

The strategy says the main measures to reduce GHG emissions are in the energy and transportation sectors, including improving energy efficiency, technological transformation by applying renewable energy and CCS, modal shifts and the promotion of new and efficient vehicle fleets. In addition, Thailand is aiming to achieve carbon neutrality by 2065, with the following required conditions:

- Technological and financial support will be provided as soon as possible
- Infrastructure construction: Renewable energy power sources to be at least 50% of the power generation capacity by 2050, and the share of electric vehicles in the market to be at least 69% by 2035
- Energy efficiency improvement
- Adoption of advanced carbon removal technologies such as BECCS, CCS, and CCU
- Transformation of energy systems through decarbonization, digitalization, decentralization, deregulation, and electrification (modernization of grids, energy storage systems, net metering market, EV infrastructure, research and development of hydrogen renewable electricity and CCS, etc.)

4.2.3 Malaysia

(1) Low-carbonization/decarbonization Targets (NDC)

According to the NDC (Nationally Determined Contributions) submitted by the Malaysian government to the UNFCCC in 2015, Malaysia's GHG emission reduction targets were to reduce GHG emissions by 35% in the unconditional scenario and up to 45% in the conditional scenario by 2030, compared to 2005. The 2020 update raised the target for the unconditional scenario to 45%.

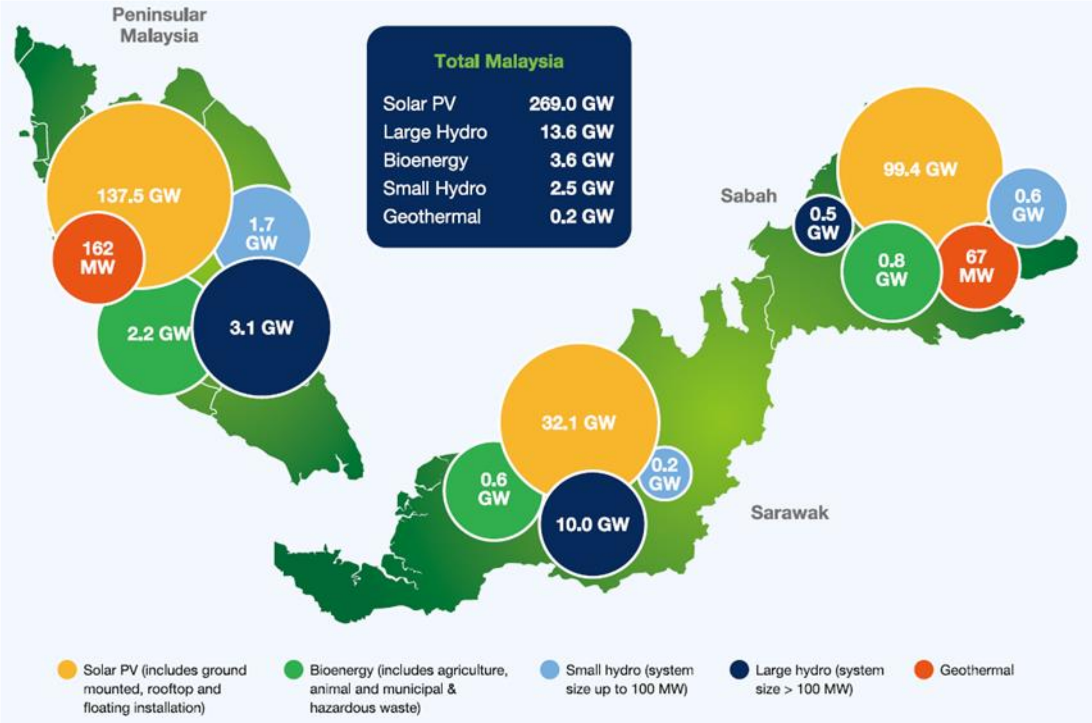
The Malaysian government has set a goal of increasing the share of renewable energy, such as solar, biomass and biogas, in the total power generation capacity to 31% by 2025. To achieve this, in addition to expanding the use of cogeneration, solar heat and fuel cells in the industrial field, Malaysia will promote renewable energy certificates that enable the procurement and trading of renewable energy.

(2) Malaysia Renewable Energy Roadmap (MyRER)

With the aim of achieving the NDC's GHG emission reduction targets, the Malaysian government has set a goal of achieving a renewable energy share of 31% (12.9 GW) by 2025, from 23% (8.45 GW) of national installed capacity in 2020.

As a strategy to achieve this goal, the Sustainable Energy Development Authority (SEDA) has formulated the Malaysia Renewable Energy Roadmap (MyRER).

Malaysia has abundant renewable energy resources, such as year-round solar radiation; agriculture, domestic and industrial waste for bioenergy; and river basins for small hydroelectric power.



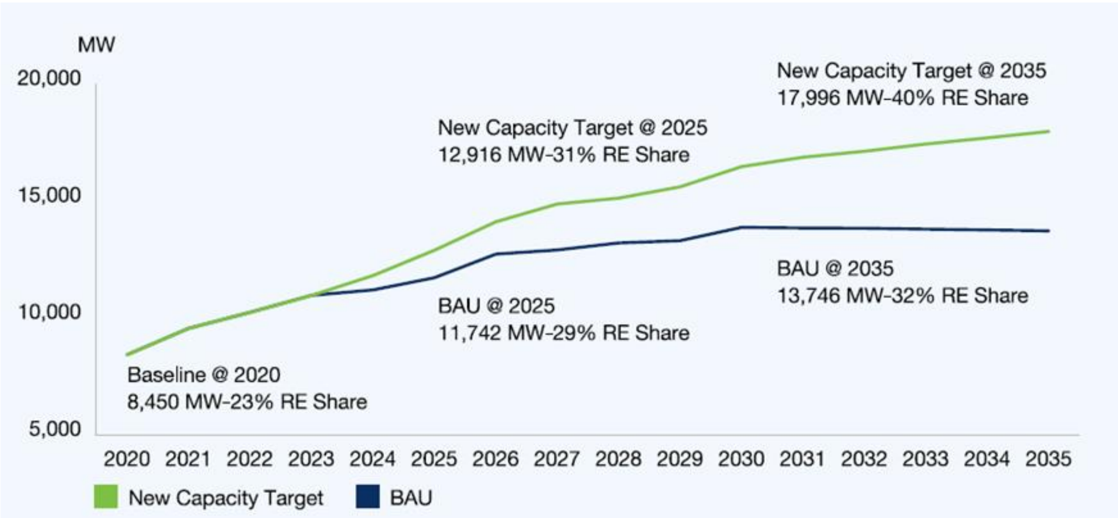
(Source：Malaysia Renewable Energy Roadmap)

Figure 4-3 Renewable energy resources in Malaysia

Based on this potential, MyRER considers the below two scenarios.

- Business as Usual (BAU) scenario: without new measures implemented
- New Capacity Target (NCT) scenario: aiming for higher renewable energy capacity target to align with further decarbonization in the power sector toward 2035 milestone

In the NCT scenario, renewable energy capacity will reach 12,916 MW in 2025 and 17,996 MW in 2035, from 8,450 MW in 2020.



(Source: Malaysia Renewable Energy Roadmap)

Figure 4-4 Renewable energy capacity in each scenario (BAU, NCT)

4.2.4 Vietnam

(1) Low-carbonization/decarbonization Target (NDC)

In the NDC revised in July 2020, Vietnam has set a target of reducing greenhouse gas emissions under the Paris Agreement by 9% in the unconditional scenario and up to 27% in the conditional scenario compared to the BAU scenario by 2030.

In November 2021, Prime Minister Pham Minh Chin announced at COP26 that Vietnam aims for carbon neutrality by 2050.

The revised NDC provides the below GHG emission targets for each sector in 2030.

Table 4-3 GHG reduction contribution by sectors in 2030

Sector	Contribution with domestic resources		Contribution with international support		Total contribution with both domestic resources and international support	
	Compared to BAU scenario (%)	Reduction amount (Mil. tonnes of CO_{2eq})	Compared to BAU scenario (%)	Reduction amount (Mil. tonnes of CO_{2eq})	Compared to BAU scenario (%)	Reduction amount (Mil. tonnes of CO_{2eq})
Energy	5.5	51.5	11.2	104.3	16.7	155.8
Agriculture	0.7	6.8	2.8	25.8	3.5	32.6
LULUCF*	1.0	9.3	1.3	11.9	2.3	21.2
Waste	1.0	9.1	2.6	24.0	3.6	33.1
IP	0.8	7.2	0.1	0.8	0.9	8.0
Total	**9.0**	**83.9**	**18.0**	**166.8**	**27.0**	**250.8**

Note (*): increase in GHGs sequestration

(Source: Updated Nationally Determined Contribution, The Socialist Republic of Vietnam, July 2020)

In November 2021, the government of Vietnam announced at COP26 that the country aims for virtually zero greenhouse gas emissions (carbon neutrality) by 2050.

In October 2021, Vietnam also announced the "National Green Growth Strategy for 2021-2030, vision towards 2050" to achieve green growth. The strategy will contribute to the prevention of global warming by making efforts to realize a green and carbon-neutral economy.

Table 4-4 Targets of National Green Growth Strategy

Items	2030	2050
GHG emissions intensity per unit of GDP	at least 15% reduction compared to 2014	at least 30% reduction compared to 2014
Primary energy consumption per unit of GDP	1.0 - 1.5% reduction on average annually	1.0% reduction annually on average for each 10-year periods
Proportion of renewable energy in the total primary energy supply	15 - 20%	25 – 30%
Digital economy share	30% of GDP	50% of GDP
Forest cover	42% remaining	42 – 43% remaining
Area where advanced and water-saving irrigation methods are applied	at least 30% of the total irrigable dry land crop area	at least 60% of the total irrigable dry land crop area

(Source: Socialist Republic of Viet Nam Government News[8])

(2) Power Development Plan[9]

The Ministry of Industry and Trade of the Socialist Republic of Vietnam (MOIT) is currently preparing to promulgate the Eighth Power Development Plan (PDP8).

It was reported that under the draft PDP8 submitted to the government by the PDP8 Evaluation Committee in October 2021, the total installed capacity of power supplies across the country will be 130,371 to 143,839 MW in 2030, of which coal-fired power will be 28.3-31.2%, gas-fired power (including LNG) will be 21.1-22.3%, large and medium-sized hydroelectric power generation will be 17.73-19.5%, renewable energy (wind and solar power) will be 24.3-25.7% and imported electricity will be 3-4%.

By 2045, the total installed capacity of power sources will reach 261,951 to 329,610 MW, of which coal-fired power will be 15.4-19.4%, gas-fired power (including LNG) will be 20.6-21.2%, large and medium-sized and stored hydropower will be 9.1-11.1%, renewable energy (small hydro, wind, solar, biomass power generation, etc.) will be 26.5 to 28.4%, and imports will be about 3.1%. While Vietnam plans to reduce coal-fired power generation significantly (from 29% in 2020), it intends to develop and expand LNG-fired power generation with low carbon emissions in addition to the introduction of renewable energy.

4.2.5 The Philippines

(1) Low-carbonization/decarbonization Target (NDC)

The NDC, submitted by the Philippine government to the UNFCCC in April 2021, states that the Philippines aims to reduce GHG emissions by 75% by 2030 (2.71% unconditionally, 72.29% conditionally).

(2) Philippine Energy Plan 2020-2040[10]

The Department of Energy (DOE) has set medium- to long-term targets for the transition to low-carbon energy in the Philippine Energy Plan (PEP) 2020-2040. PEP 2020-2040 outlines ambitious plans, policies and goals for renewable energy, natural gas, alternative fuels, and high energy efficiency technologies under its Clean Energy Scenario (CES).

Reference Scenario (REF)

- Present development trends and strategies continue
- 35.0% renewable energy share in the power generation mix by 2040

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8 https://en.baochinhphu.vn/national-green-growth-strategy-for-2021-2030-vision-towards-2050-11142515.htm
9 https://baochinhphu.vn/nhung-diem-nhan-trong-quy-hoach-dien-viii-102302880.htm
10 https://www.doe.gov.ph/pep?withshield=1

- LNG importation starting 2022
- Energy Consumption levels that support an accelerated economic expansion post COVID-19
- Current blending schedule for biofuels (2.0% biodiesel and 10.0% bioethanol) maintained until 2040
- 5.0% penetration rate of electric vehicles for road transport (motorcycles, cars, jeepneys) by 2040
- Current efforts on EEC as a way of life continues until 2040

Clean Energy Scenario (CES)

- 35.0% and 50.0% RE share in the power generation mix by 2030 and 2040
- 5.0% blending for biodiesel starting 2022
- 1.5% increase in aggregated natural gas consumption from the transport and industry sectors between 2020 and 2040
- 10.0% penetration rate of electric vehicles for road transport (motorcycles, cars and jeepneys) by 2040
- 5.0% energy savings on oil products and electricity by 2040
- At least 12.0% reduction in the GHG emissions for the Nationally Determined Contribution (NDC)

Table 4-5 Gross Generation Output (TWh) (2020, 2040)

Source	2020		2040				% Pts Diff in Shares CES vs REF
	Actual		REF		CES		
	Levels	%Shares	Levels	%Shares	Levels	%Shares	
Coal	**58.18**	**57.17**	**89.72**	**24.62**	**80.83**	**23.09**	**-1.53**
Natural Gas	**19.50**	**19.16**	**146.86**	**40.30**	**93.24**	**26.63**	**-13.67**
Oil-based	**2.47**	**2.43**	**0.28**	**0.08**	**0.52**	**0.15**	**0.07**
Renewable	**21.61**	**21.24**	**127.54**	**35.00**	**175.49**	**50.13**	**15.13**
Geothermal	10.76	10.57	16.18	4.44	16.18	4.62	0.18
Hydro	7.19	7.07	51.55	14.15	63.14	18.03	3.89
Wind	1.03	1.01	5.12	1.41	21.77	6.22	4.81
Solar	1.37	1.35	53.06	14.56	72.01	20.57	6.01
Biomass	1.26	1.24	1.63	0.45	2.39	0.68	0.23
Total	**101.76**	**100**	**364.40**	**100**	**350.07**	**100**	**-**

(Source: Philippine Energy Plan 2020-2040)

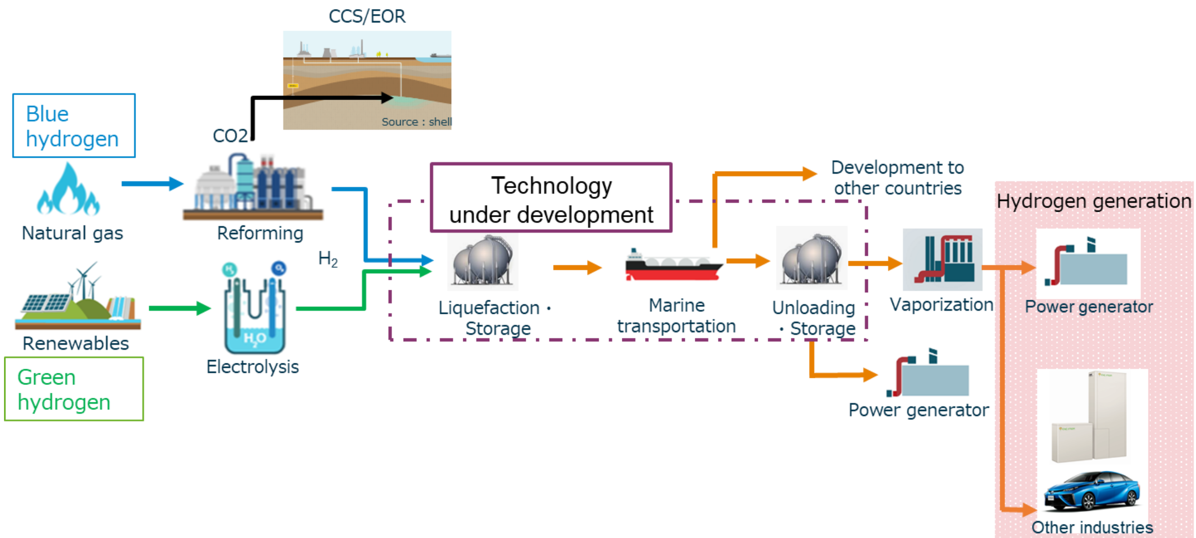
Chapter 5. Low carbonization/decarbonization Technologies for Thermal Power Plants

5.1 Low carbonization/decarbonization Technologies for existing Thermal Power Plants

5.1.1 Technical Issues and Countermeasures related to Thermal Power Generation using Hydrogen as Fuel

(1) Introduction

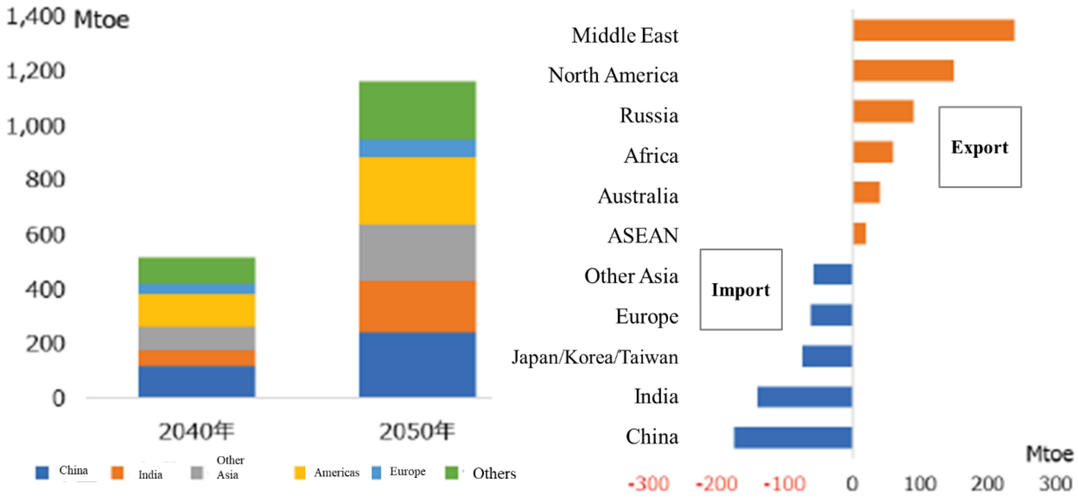
Hydrogen is an essential fuel for low carbonization (decarbonization), which not only directly contributes to low carbonization (decarbonization) in the electric power sector, but also helps maximize the potential of renewable energy sources by converting surplus electricity into hydrogen for storage and use. An example of a hydrogen supply chain is shown below.



(Source: JICA Survey Team)

Figure 5-1 Hydrogen Supply Chain Example

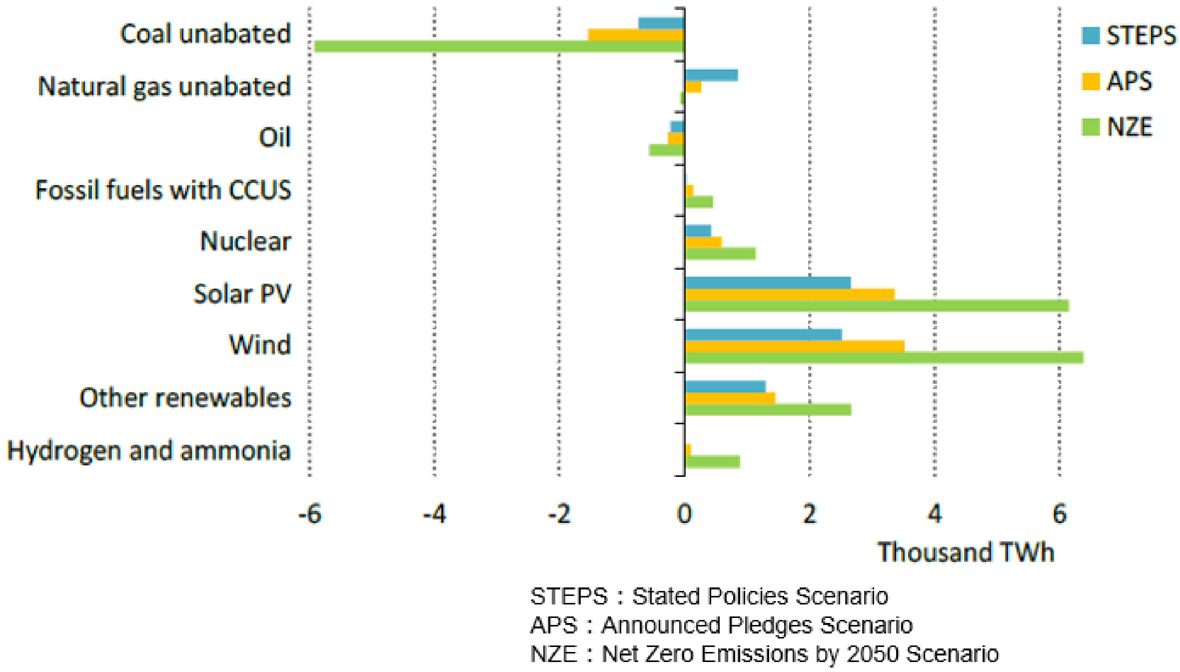
Hydrogen can be produced from a variety of energy sources, but if the supply capacity for domestic demand is not sufficient, it will be necessary to import hydrogen from overseas for the long term to be price competitive. Therefore, from the viewpoint of energy security, it is necessary to diversify procurement sources and to strengthen domestic production capacity. Figure 5-2 shows the global hydrogen demand outlook from The Institute of Energy Economics, Japan (hereinafter IEEJ). According to the IEEJ outlook, global demand for hydrogen will expand in the future, mainly in Asia, and countries that do not have domestic blue hydrogen production capacity will import blue hydrogen from overseas. The main supply sources of blue hydrogen will be the Middle East, North America, Russia etc., which have abundant fossil fuel resources and can conduct CCS.



(Source: IEEJ, "436th Forum on Research Works, 'IEEJ Outlook 2021 – Energy transition in the post corona world'")

Figure 5-2 Global Hydrogen Demand Outlook

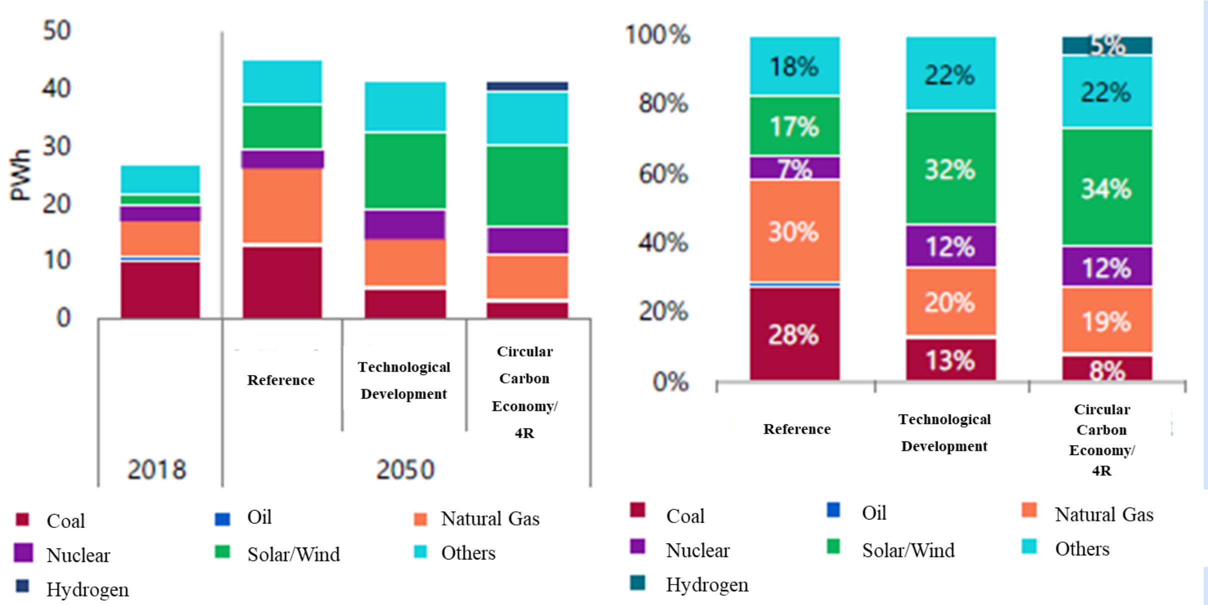
As shown in Figure 5-3, the IEA's World Energy Outlook 2021 shows the changes in the amount of electricity generated for each scenario and type of power generation when comparing 2020 and 2030. According to the Stated Policies Scenario (STEPS), the development amount of hydrogen or ammonia co-firing in CCS and coal-fired and gas-fired thermal power plants will not be very large as of 2030, but a certain amount of development is expected in the Announced Pledges Scenario (APS) and Net 0 Emissions by 2050 Scenario (NZE) even in 2030. In both scenarios, further large-scale development will progress from 2030 to 2050, and hydrogen or ammonia co-firing is positioned to greatly contribute not only to the amount of generated power but also to the stability of the power system due to the flexibility of generation.



Source：IEA World Energy Outlook 2021

Figure 5-3 WEO 2021 Changes in Power Generation by Scenario and Type (2020–2030)

Figure 5-4 shows the assumptions made by the IEEJ for the amount of electricity generated and the composition of power sources for each scenario in the world. In the reference scenario (in which radical energy conservation and low carbon policies are not formulated against the background of existing energy and environmental policies), and in the technology development scenario (in which each country creates strong energy and environmental policies to secure a stable energy supply and strengthen climate change countermeasures, these policies work to the maximum extent, and energy and environmental technologies are introduced to the maximum extent), no remarkable increase in the share of hydrogen power generation will have been recognized by 2050. However, in the carbon cycle economy/4 R scenario, in which several technologies are assumed to be introduced to the maximum extent, taking into consideration the impact of carbon reduction and the stages of technological development, the share of thermal power generation by fossil fuels will decrease to 27% as of 2050 compared with 34% in the technology development scenario. The share of hydrogen power generation will be 5%, and it is assumed that it will replace some fossil fuels. In the carbon cycle economy/4R scenario, the biggest contribution of individual technologies to emission reductions is the conversion of coal-fired power to blue hydrogen power generation, followed by the introduction of blue hydrogen in transport demand.



Source: IEEJ, "436th Forum on Research Works, 'IEEJ Outlook 2021 – Energy transition in the post corona world'"

Figure 5-4 IEEJ's Assumptions on Global Electricity Generation and Composition of Power Sources for Each Scenario

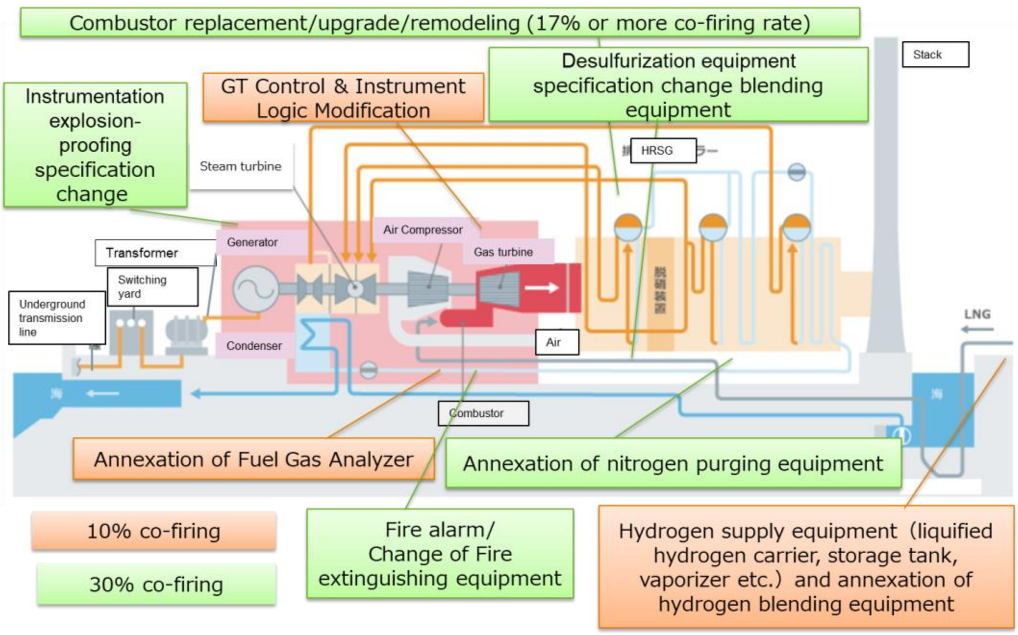
As mentioned above, this chapter describes the status of facility modifications and technological development required for co-firing and future exclusively firing at existing thermal power plants in terms of technological issues and costs for hydrogen-fueled thermal power generation, which is expected to play an important role in low carbonization (decarbonization) over the next several decades.

(2) Outline of hydrogen thermal power generation technology

Since hydrogen has relatively similar combustion characteristics to natural gas, demonstration tests are planned to be conducted preferentially at gas-fired thermal power plants among existing thermal power plants. Compared with natural gas, hydrogen burns faster and has a higher combustion temperature so countermeasures to prevent damage to facilities due to backfire during combustion and to reduce the NOx generated by rapid combustion will be required.

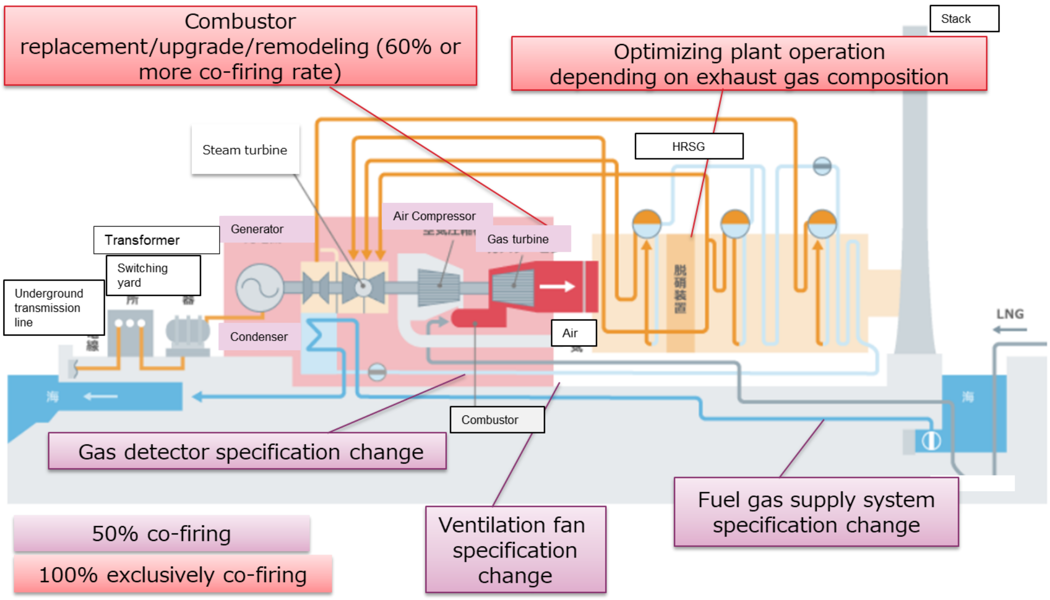
The energy per volume of hydrogen is 10.8MJ/m^3, which is about 1/4 of the 40MJ/m^3 of natural gas. The liquefaction temperature is -253C for hydrogen and -162C for natural gas. The combustion rate of hydrogen is 2.65m/s, the combustion range is 4 to 75%, and the minimum ignition energy is 0.02mJ.

The combustion rate of methane, which is the main component of natural gas, is 0.4m/s, and the combustion range is 5 - 15%. The minimum ignition energy is 0.28mJ.
As for the present status of hydrogen power generation, technology development to supply 30% vol of hydrogen-mixed natural gas to a low NOx combustor for hydrogen co-firing by 2018 at an existing 500 MW class large scale gas-fired thermal power plant has been completed, and technology development for exclusively hydrogen-fired power generation has been in progress since 2020.
In the field of regional thermoelectric power supply, the development of technology that can freely co-fire 0% to 100% of hydrogen into natural gas has been progressing. In 2018, the world's first exclusively hydrogen-fired thermoelectric power supply to an urban area was achieved from a hydrogen-fired power generation facility on Port Island in Kobe, Japan. At this time, 2,800kW of heat was supplied to two facilities and a total of 1,100kW of power was supplied to four facilities. The system operated without any problems.
Existing gas-fired power plants are expected in the future to develop combustors with both stable combustion and NOx reduction, and to enhance their facilities with attention paid to safety when handling hydrogen. Figure 5-5 shows the facility modifications assumed to be necessary for a co-firing rate of approximately 10% to 30% in order to further improve the mixing ratio and to aim for exclusively firing. In addition to these improvements, Figure 5-6 shows the facility modifications that are expected to be necessary for a co-firing rate of approximately 50% to 100%.
In order to implement hydrogen co-firing, additional hydrogen supply facilities such as liquefaction carriers, storage tanks, vaporizers, etc., and facilities for mixing hydrogen and gas are required. For power generation facilities, only minor changes in gas turbine control etc. will be sufficient for co-firing of up to approximately 10%, but for co-firing of up to approximately 30%, it will be necessary to upgrade the combustor to one that is equipped to safely fire hydrogen, which has a high combustion rate, and to modify the facility to deal with NOx generation due to rapid combustion.
When the co-firing ratio exceeds 50%, it is necessary to change the specifications of the fuel gas supply system, ventilation fans, gas detectors, etc. for safety reasons. When aiming for 100% exclusively co-firing, it is necessary to upgrade the combustor due to the larger size and higher pressure of the equipment and to optimize the plant operation according to the exhaust gas composition.



(Source: JICA Survey Team)

Figure 5-5 Facility modification assumed to be necessary for a hydrogen co-firing rate of approximately 10% to 30%



(Source: JICA Survey Team)

Figure 5-6 Facility modification assumed to be necessary for a hydrogen co-firing rate of approximately 50% to 100%

(3) Hydrogen co-firing at gas-fired power plants

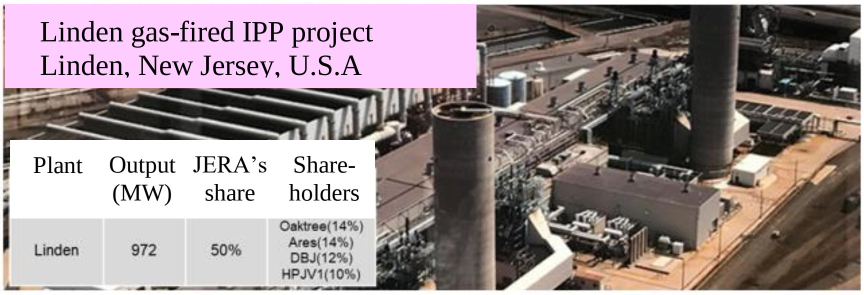
Efforts to conduct hydrogen co-firing at gas-fired power plants have been under way since the late 2010s. Mitsubishi Power Corporation (hereinafter Mitsubishi Power) participated in a project to convert a 1.32 GW-class natural gas-fired GTCC power plant operated by Nuon, a Dutch energy company, into a hydrogen-fired power plant, and conducted a feasibility study to confirm it is possible to convert it to hydrogen combustion. In this project, one of the three M701F gas turbine power generation groups delivered by Mitsubishi Power will be converted to an exclusively hydrogen-fired power plant by around 2027. This will eliminate almost all of the approximately 1.3 million tons of CO_2 emitted by a 440 MW group at the GTCC power generation facility.

Mitsubishi Power has also announced that it will deliver a GTCC power generation facility using two M501JACs groups based on commercialized large gas turbine technology for a hydrogen-based GTCC power generation project planned by the Intermountain Power Agency in Utah, USA. In this project, hydrogen co-firing operation of approximately 30% by volume will be started in 2025, and the goal is to operate the plant with 100% hydrogen firing by 2045.

JERA applied to, and was selected by, the New Energy and Industrial Technology Development Organization (hereinafter NEDO) for the Green Innovation Fund Project/Large-Scale Hydrogen Supply Chain Construction Project to demonstrate actual hydrogen power generation technology at an LNG-fired thermal power plant in 2021. This is a plan to convert a portion of LNG used as fuel in JERA's large-scale LNG-fired power plants in Japan into hydrogen and to evaluate the operational and environmental characteristics with a view to commercializing the use of hydrogen in existing LNG-fired power plants. Based on the results of the feasibility study conducted at the beginning of the project period, JERA will construct a hydrogen supply facility at its LNG-fired power plant and install a combustor capable of firing a mixture of hydrogen and LNG in a gas turbine, aiming to convert approximately 30% of LNG by volume (equivalent to approximately 10% by calorific value) into hydrogen by FY 2025.

Finally, as an approach to hydrogen co-firing in actual power plants, the use of hydrogen in Unit 6 of Linden gas-fired thermal power plant, in which JERA has invested in the United States, will be introduced. The project company that operates Linden gas-fired power plant, in which JERA has a stake through a US subsidiary, entered into an agreement with Phillips 66, a major US oil refiner, in

2021 to receive hydrogen-containing gas produced at the refinery, and is proceeding with modification work for the existing gas turbine so that the hydrogen-containing gas supplied from the adjacent Phillips 66 oil refinery can be co-fired with natural gas. This modification is expected to enable co-firing of up to 40% hydrogen, reducing CO_2 emissions equivalent to up to 10% of the CO_2 emissions from Unit 6. Figure 5-7 shows an outline of the hydrogen co-firing efforts at the Linden gas-fired power plant.



Plant	Output (MW)	JERA's share	Share-holders
Linden	972	50%	Oaktree(14%) Ares(14%) DBJ(12%) HPJV1(10%)

- US EPA has established a rule that the suspension of off-gas combustion will be mandated at oil refineries by the mid-2020s. Phillips 66 (P66) asked the Linden Project Company if it is possible to burn off-gas.
- After evaluating multiple technologies to solve P66's fuel issue, JERA has identified that it is possible to accept high concentrations of hydrogen at existing 7FA gas turbines by introducing PSM's Flame Sheet™ technology.

In May 2021, Project Company approved → To be installed at the 2022 periodical inspection → To start hydrogen co-firing in 2023

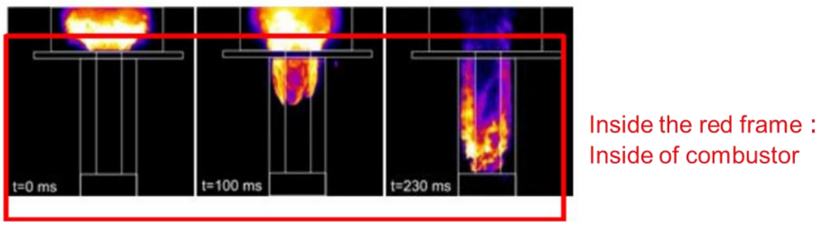
Linden Unit 6, with GE's 7FA gas turbine, started commercial operation in 2002 + Gas turbine combustion system of PSM's Flame Sheet™, which can be installed in existing ⇒ Enable the combustion of off-spec gas with up to 40% hydrogen content

(Source: JERA)

Figure 5-7　Overview of hydrogen co-firing efforts at Linden gas-fired power plant

(4) Technical issues in hydrogen co-firing

When natural gas and hydrogen are co-fired, a change in the fuel component occurs and the properties of the flame change. In order to operate a gas turbine stably, it is necessary to develop technology for hydrogen, which has a higher combustion speed than natural gas. In the case of co-firing hydrogen, the risk of the flashback phenomenon occurring is assumed to be higher than in exclusively natural gas-firing, and the combustor needs to be improved to prevent flashback. Figure 5-8 shows an outline of the flashback phenomenon.



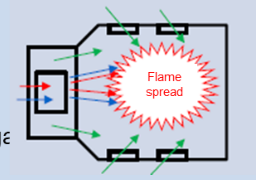
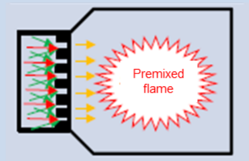
＜Backfire＞

A phenomenon in which a flame travels upward in a fluid when the speed of the flame is higher than the speed of the fluid. If it occurs inside the gas turbine combustor, it can burn out the uncooled parts upstream.

Souce : Prepared by this research team, referring to "Direction of Research & development and Social Implementation of Hydrogen-related projects" at 2nd forum of the Working Group of Energy Structural Transformation Field, Sub-committee of Green Innovation Project, Industrial Structure Council of Agency for Natural Resources and Energy in April 2021

Figure 5-8　Overview of the flashback phenomenon

In the combustor used for the current large gas turbine, the premixed combustion system is often adopted for the purpose of NOx reduction. However, the stable combustion range is narrower than that of the diffusion combustion system, and the backfire phenomenon tends to occur. Figure 5-9 shows the characteristics of different combustion systems. In premixing combustion systems that use a swirling flow to mix the fuel, there is a possibility of backfire in which hydrogen runs up the swirling center. Therefore, the development of a new type of burner for an exclusively hydrogen-fired gas turbine has been promoted, in which the distance from the fuel injection hole to the flame front is shortened by providing several flow passages without swirling mixing, and the resistance to backfire is enhanced by narrowing the region where the flame can spread.

	Diffusion combustion method	Premixing method
Structure	■ Fuel ■ Air ■ Water ■ Mixed ga 	
Features	➢ Simplify the fuel system ➢ Wide range of tolerance for fuel properties ➢ As a countermeasure against NOx, steam or water injection is required, which reduces efficiency.	➢ Capable of reducing NOx while maintaining high efficiency ➢ The fuel system becomes more complex.
Combustion characteristics	➢ Separate injection of fuel and air for combustion ➢ While the flame position is stabilized, there is a possibility of localized high temperature areas.	➢ Fuel and air are pre-mixed and injected. ➢ Localized hot areas are unlikely to occur. ➢ Flame position is unstable, so there is a risk of backfire.

Souce : Prepared by this research team, referring to "Direction of Research & development and Social Implementation of Hydrogen-related projects" at 2nd forum of the Working Group of Energy Structural Transformation Field, Sub-committee of Green Innovation Project, Industrial Structure Council of Agency for Natural Resources and Energy in April 2021

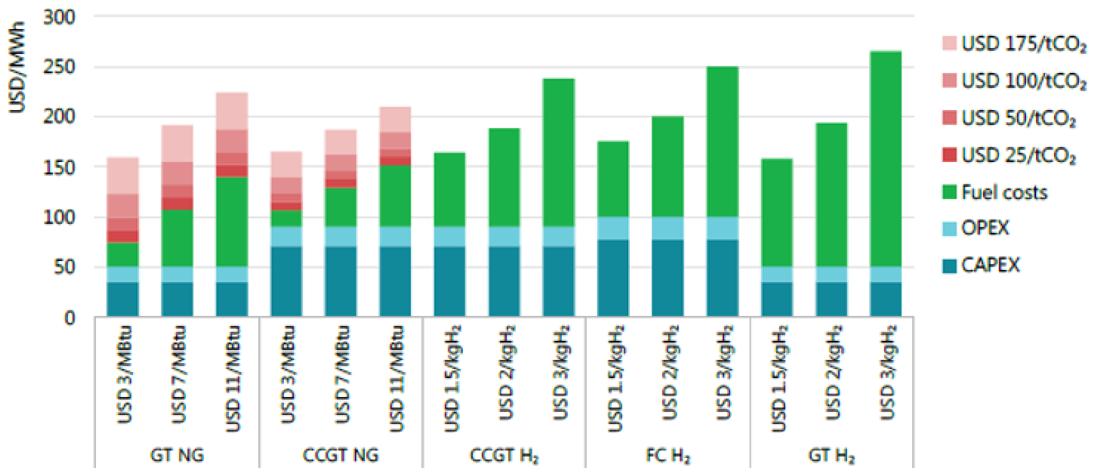
Figure 5-9 Characteristics of Combustion Methods

When hydrogen is introduced in large quantities, there are technical problems in transportation technology. When liquefied hydrogen is used for transportation, it is necessary to increase the size of various facilities in consideration of commercial scale, and to use materials that can withstand severe conditions such as extremely low temperatures and embrittlement, so the technical hurdles are high. In addition, to properly store liquefied hydrogen, tanks must not only be vacuum insulated, but must also utilize heat insulating materials and have a new structure that can withstand its own weight, which requires technological development and demonstration tests. On the other hand, when MCH, which is liquid at normal temperature and pressure, is adopted, there are different problems such as a large amount of necessary storage infrastructure and a need for a heat source for the dehydrogenation reaction. Therefore, it is important to identify a hydrogen carrier that is technically and economically optimal from a long-term perspective. For the characteristics of each carrier, see Section 5.2.2.

(5) Unit price of power generation in hydrogen co-firing

As mentioned earlier, hydrogen power generation facilities can be considered to utilize basically the same equipment as gas-fired power generation facilities. The IEA study also assumes that the operational data, such as capital costs and capacity factors of hydrogen power generation facilities, are equivalent to those of gas-fired power generation facilities, so the various specifications of hydrogen power generation facilities are basically those of gas-fired power generation facilities in this study. However, with regard to fuel prices, since it is necessary to set manufacturing and transportation costs

in consideration of regional characteristics, the price assumptions based on the study team's own survey results were used in the estimation. The details of fuel prices are described in Sections 5.2.2 and 6.2. Figure 5-10 shows the results of the IEA's estimation of power generation costs.
As for the co-firing rate, various co-firing rates are expected to be used in the process of 100% exclusively firing in the future, but in order to avoid complications in the simulation for examining the composition of power sources, the study is divided into only two patterns: 20% vol co-firing and 100% exclusively firing, for which data can be obtained at present.



Notes: GT = gas turbine; CCGT = combined-cycle gas turbine; FC = fuel cell; NG = natural gas. CAPEX = USD 500/kW GT, USD 1 000/kW CCGT without CCS and hydrogen-fired CCGT, USD 1 000/kW FC. Gross efficiencies (LHV) = 42% GT, 61% CCGT without CCS and hydrogen-fired CCGT, 55% FC. Economic lifetime = 25 years for GT and CCGT, 20 years for FC. Capacity factor = 15%. More information on the assumptions is available at www.iea.org/hydrogen2019.

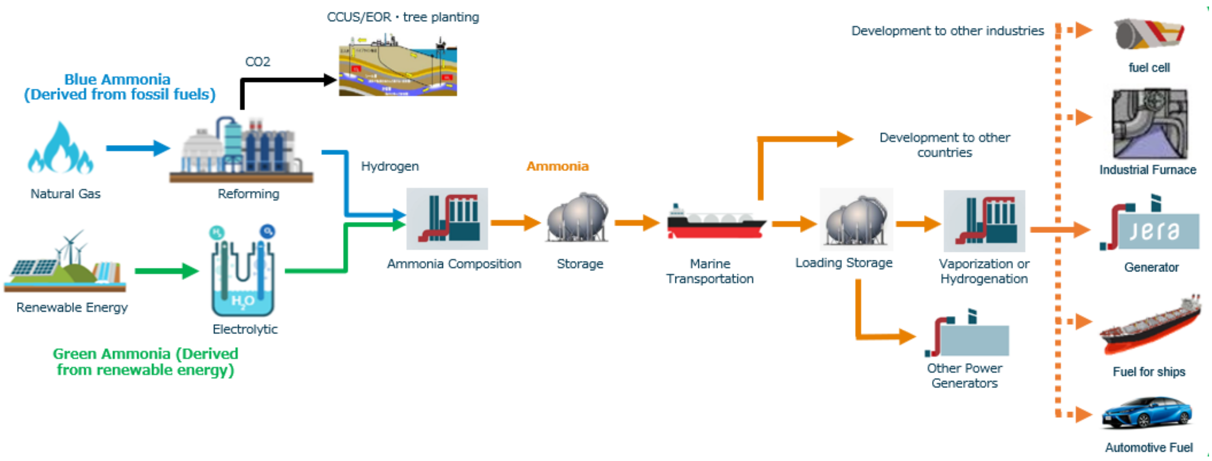
Source: IEA「The Future of Hydrogen 2019/6」

Figure 5-10 IEA's Estimation of Power Generation Costs

5.1.2 Technical Issues and Countermeasures related to Thermal Power Generation using Ammonia as Fuel

(1) Introduction

Ammonia can be produced from natural gas, renewable energy, etc., and is one of the clean fuels that do not generate carbon dioxide when burned. Ammonia is already widely used in industrial processes and as a fertilizer. In addition to being relatively inexpensive to produce by utilizing existing infrastructure equipment, it has high potential as a hydrogen carrier and can be used as a direct fuel even if it is not converted into hydrogen. Therefore, its use is highly anticipated as a decarbonized fuel. An example of an ammonia supply chain is shown below.



(Source: JICA Survey Team)

Figure 5-11 Ammonia Supply Chain Example

Currently, the use of ammonia as a fuel is being considered mainly for co-firing of up to 20% at existing coal-fired power plants. In the future, it will be necessary to study technologies to expand the range of applications, such as high-mix firing and ammonia-firing, and to establish a new supply chain to meet the growing demand. In the processes of ammonia production, transportation, power generation, and other uses, cooperation is required not only with the energy industry, but also with experienced operators and large-scale consumers.

This chapter describes, mainly from the viewpoint of technical issues and costs, the status of equipment modifications and technological developments necessary for ammonia co-firing and future ammonia-firing in existing thermal power plants.

(2) Outline of ammonia thermal power generation technology

Since ammonia has combustion characteristics similar to those of coal, studies on decarbonization are under way through co-firing and ammonia-firing at coal-fired power plants. As of IEA's World Energy Outlook 2019, 70% of global energy demand growth will come from economic growth in the Asia-Pacific region, and as of 2040, coal-fired power plants were expected to account for about 40% of the power mix. In this case, the installed capacity would be 1,800 GW or more, and if ammonia co-firing of about 10% is introduced to these power plants, the annual production of ammonia for raw materials in the world will exceed the current annual production of about 200 million tons only in this area.
Therefore, in order to expand the use of ammonia as a fuel, it is necessary to build a large-scale supply chain by developing technologies to reduce supply costs. In terms of technology, low-concentration co-firing technology for thermal power generation is already being established through demonstration tests in existing businesses, and it will be necessary to develop technology for high-ammonia co-firing of 50% or more in the future.

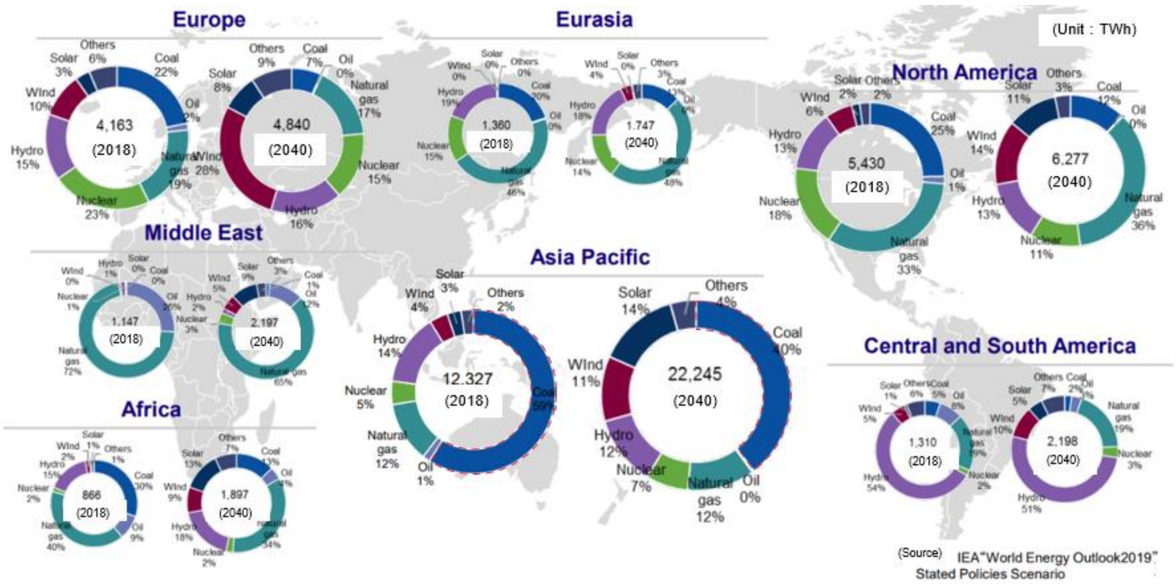


Figure 5-12 Changes in power supply mix in various regions around the world

In addition, according to the latest IEA World Energy Outlook 2021, the Announced Pledges Scenario (APS) estimates that world power demand in 2030 will increase by approximately 30% to 30,300 TWh from 23,300 TWh in 2021. In contrast, CO_2 emissions are expected to decrease by 18% to 10.1 Gt in 2030. Net Zero Emissions in the 2050 Scenario (NZE) estimates that electricity demand in 2030 will be 33,200 TWh, about 10% higher than APS, and that CO_2 emissions will decrease to 5.1 Gt by 2030. The reduction in CO_2 emissions from coal-fired power plants is 18%, as estimated by APS. On the other hand, NZE estimates about 70% CO_2 emission reduction and in order to achieve this. In addition to the retirement of coal-fired power plants, it is necessary to switch to fuels such as ammonia, biomass co-firing, and biomass-firing.

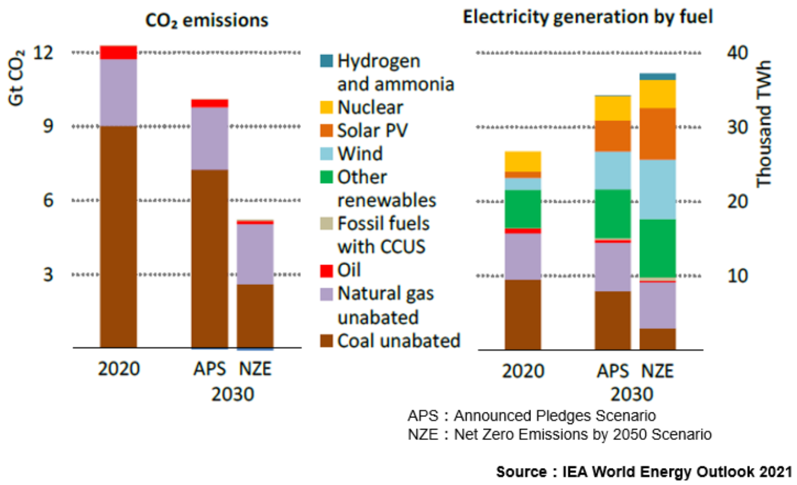
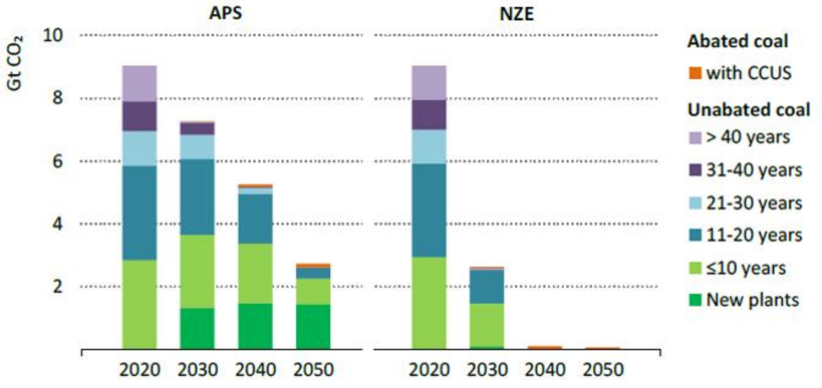


Figure 5-13 CO_2 Emissions and Power Generation in the Global Electricity Sector by Type of Power Generation

In order to reduce CO_2 emissions from coal-fired power plants, a choice must be made between reducing operating hours and achieving flexible operation to complement renewable power generation, or using CCS for CO_2 capture or co-firing fuels such as ammonia and biomass. As shown in Figure 5-14, new coal-fired power plants with shorter operating hours and more efficient power plants are expected to remain to some extent in the 2030s and are candidates for them.



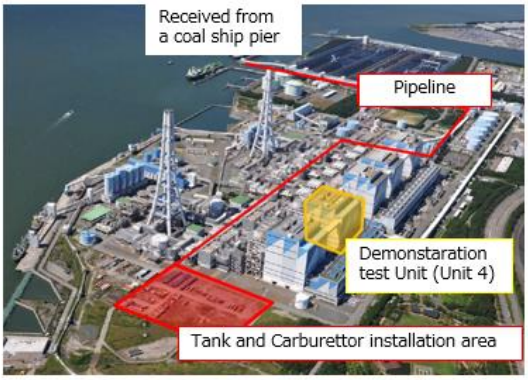
Source : IEA World Energy Outlook 2021

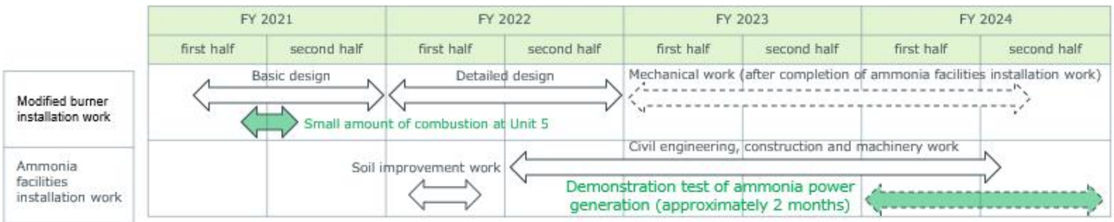
Figure 5-14 CO_2 Emissions from Coal-Fired Power Plants by Years of Operation

(3) Ammonia co-firing technology at coal-fired power plants

As an introduction to ammonia co-firing technology in coal-fired thermal power plants, an outline of the efforts at JERA Hekinan thermal power plant is shown below. This project was jointly commissioned by JERA and IHI Co., Ltd. (IHI) as a project subsidized by the New Energy and Industrial Technology Development Organization (NEDO). In order to reduce environmental impacts in the future, the purpose of this project is to establish ammonia co-firing technology by conducting power generation through the co-firing of coal and ammonia at large commercial coal-fired power plants and evaluating the heat recovery characteristics of boilers, environmental impact characteristics of exhaust gas, etc. The project period is about 4 years, from June 2021 to March 2025, and it is aiming for 20% co-firing of ammonia in Unit 4 by 2024.

Project name	NEDO Development of Technologies for Carbon Recycling and Next-Generation Thermal Power Generation/ Research and development of ammonia co-firing thermal power generation technology and demonstration project
Implementer	**JERA, IHI**
Business Description	Demonstration project to convert 20% of fuel (Calorific value ratio) to ammonia at Hekinan Thermal Power Station Unit 4 (output: 1000MW).
Period	**June 2021 to March 2025**
Ammonia consumption	**30,000 ~ 40,000 tons**
Ammonia acceptance	Received from a coal ship pier



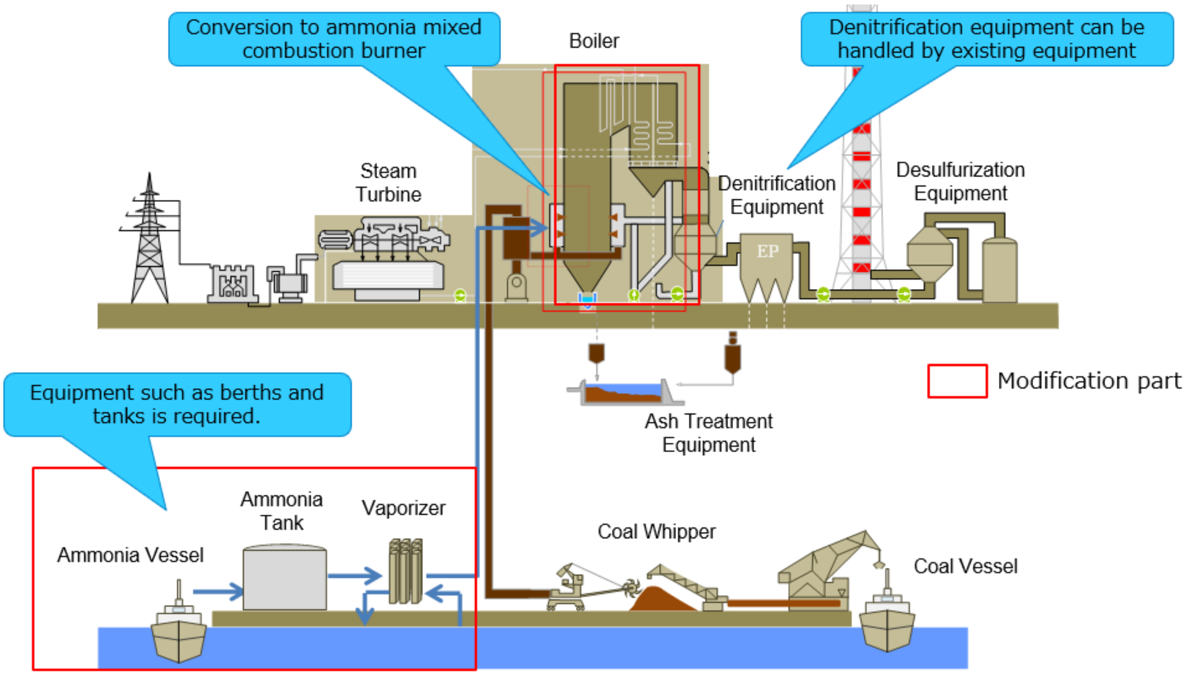


(Source: JERA)

Figure 5-15 Outline and Future Schedule of the Ammonia Combustion Demonstration Test

(a) Outline of facility remodeling

The company plans to use existing facilities to the maximum extent possible, although some facilities will need to be upgraded or remodeled for ammonia co-firing. It is necessary to convert to a burner for ammonia mixed combustion which achieves stable combustion and suppresses generation of NOx, and to install a berth and a tank dedicated to ammonia. However, existing denitration equipment can be used.

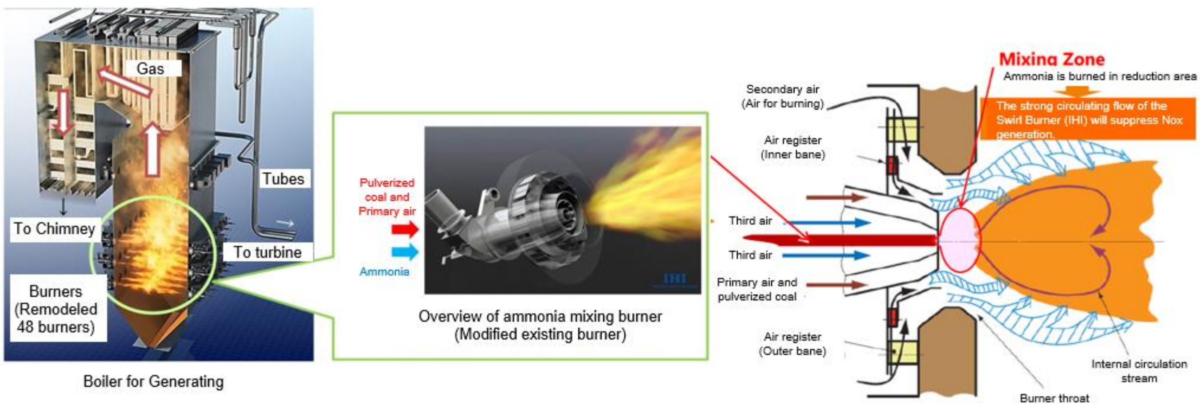


(Source: JICA Survey Team)

Figure 5-16 Outline of facility modification for ammonia co-firing

(b) Remodeling to ammonia mixed combustion burner

NOx generation becomes a problem when ammonia containing much nitrogen is burned as a fuel. In the research by IHI, it was found that the generation of NOx can be suppressed if ammonia is injected into the flame region in the reducing atmosphere in the boiler. For this reason, the Hekinan Thermal Power Station plans to install a dedicated ammonia burner in the center of the existing pulverized coal burner, taking into account the structure of the existing fuel system and flow restrictions. In addition, Mitsubishi Heavy Industries, Ltd. and JERA are planning to develop a burner for the exclusive combustion of ammonia in coal power plants and conduct demonstration tests in the eight years from 2021 to 2028 on a NEDO-subsidized project. Figure 5-17 shows a schematic diagram of an ammonia mixed combustion burner.



Source: "Adoption of Demonstration Project on Ammonia Co-firing in Large Commercial Coal-Fired Power Generators " (IHI, JERA press release)
Strategic Innovation Program (SIP) "Study on ammonia co-firing in existing thermal power plants " (Chubu Electric Power Co., Inc.)

Figure 5-17 Schematic diagram of ammonia mixed combustion burner

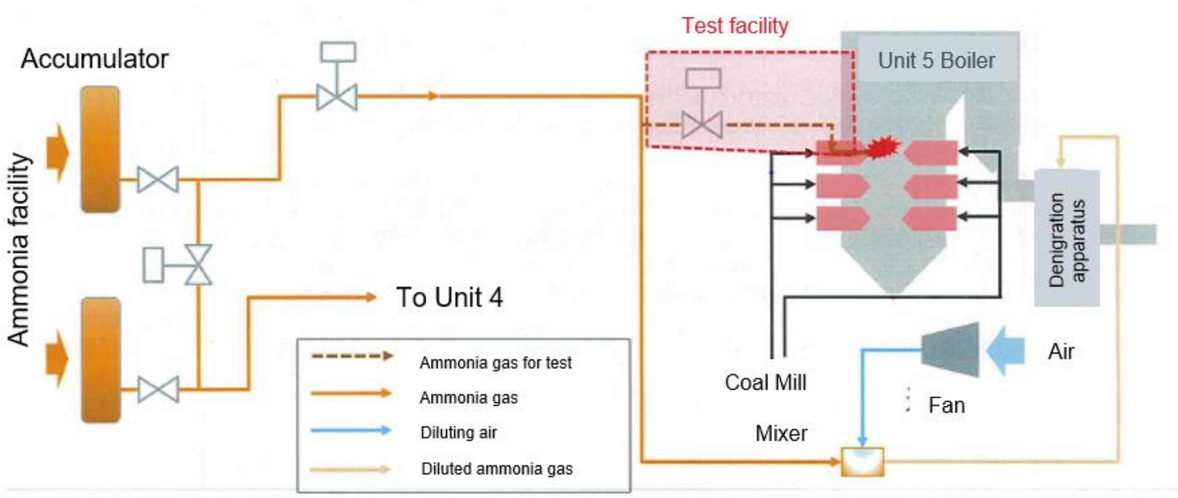
(c) Ammonia small-scale utilization test

At the Hekinan Thermal Power Station Unit 5, a small-scale ammonia utilization test is being carried out with the aim of developing a burner for large-scale co-firing tests at Unit 4. In this test, 2 of the total of 48 burners were converted into test burners, and the effects of different materials and the necessary conditions for the demonstration burners were investigated for about 6 months from October 2021 to March 2022. The amount of ammonia to be used is about 200 tons, and it is planned to supply the test burner of Unit 5 from the ammonia tank for denitration on the power plant site. In October 2021, the first mixed combustion of ammonia was started with a burner made of stainless steel, and a mixed combustion test of about 1,000 hours per burner made from different material is scheduled to be completed by March 2022.

< Test Summary >

① Install test ammonia burner nozzles (0.05 t/h x 2) during periodic inspections.

② The durability (nitriding brittleness) of the metal material used for the ammonia burner will be evaluated in the actual combustion environment of Unit 5 with an ammonia co-firing rate of 0.02 cal%.

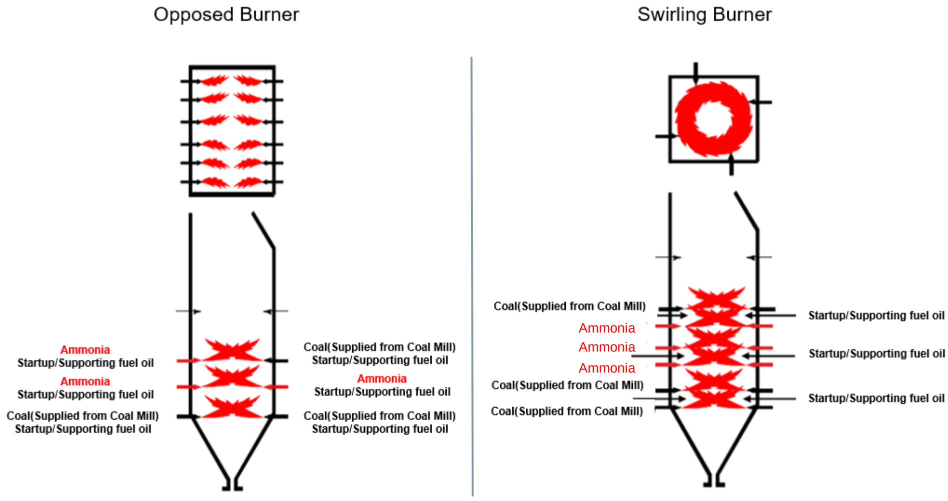


(Source: JERA)

Figure 5-18 Outline of small-scale ammonia utilization test

A comparison of combustion methods at coal-fired power plants is shown in Figure 5-19. An opposed burner is a system in which coal crushed by a coal mill is combusted by burners arranged facing each other in front of and behind the furnace, and a swirling burner is a system in which burners are arranged at four corners in the boiler for combustion and the flame in the furnace is rotated.

Both of these methods are well established methods with a good track record by representative manufacturers. However, since the structure of thermal power generation differs for each method, substitution is impossible. Therefore, in order to promote the wide use of ammonia, it is necessary to develop and manufacture burners for all systems.



Source: Energy Structural Transformation Working Group (5th), Green Innovation Project Subcommittee, Industrial Structure Council
Directions for R&D and social implementation of the "Construction of Fuel Ammonia Supply Chain" project (August 2021, Agency for Natural Resources and Energy)

Figure 5-19 Comparison of combustion methods in coal-fired thermal power plants

(4) Technological Issues in ammonia co-firing

The technical problems of ammonia co-firing in coal-fired power plants can be roughly divided into three: remodeling of burners due to changes in fuel type, NOx control measures to use ammonia with high nitrogen content, and ensuring stable ignition and combustion. Research and development in these technological issues have progressed up to 20% co-firing, and it can be said that countermeasures, including tests on actual machines, are in sight. On the other hand, in the case of high co-firing or ammonia-firing aiming at a co-firing rate of 50% or more, further equipment remodeling and combustion adjustment are required. Therefore, when considering future technological issues, it is necessary to discuss them according to the co-firing rate. Table 5-1 shows the state of achievement regarding current technological issues by the co-firing rate and matters that need to be discussed in the future.

Table 5-1 Comparison of technical issues according to ammonia co-firing rate

	20% Mixed firing	High mixed firing	Ammonia-firing
Burner Design	Demonstration of actual equipment in NEDO budget since 2021. An ammonia input port is added to the pulverized coal mill.	A large amount of ammonia was injected into the coal nozzle of the 20% co-firing burner. Therefore, it is necessary to change the shape of the burner and to develop new materials.	Since the base is a gas burner (without charging coal), it is necessary to develop burners of different shapes from scratch.
NOx Response	We have developed a burner that is as low as coal-fired thermal power. Demonstration of actual equipment will be started in the future.	Since nitrogen content increases, adjustment of ammonia injection position, flow rate, etc. is necessary. At the same time, it is necessary to develop materials that respond to nitriding and corrosion associated with increased nitrogen concentration.	As nitrogen increases, in addition to adjusting the ammonia injection position and flow rate, adjustment of the gas introduction direction and adjustment of the number of nozzles are necessary.
Ignition, fuelic stability	Completed. Demonstration of actual equipment will be started in the future.	Since the flow rate of coal decreases, it is necessary to adjust the combustion method for flame stabilization.	Difficulty in ignition and flame stabilization due to lack of coal
Utilisation Case	A case in which ammonia is to be mixed as soon as possible.	A case in which high co-firing of the entire boiler is desired within the range where switching of the boiler is unnecessary. Especially in Asia, high co-firing is realistic from the viewpoint of utilizing existing assets.	A case in which the entire boiler is to be singulated after switching boilers.

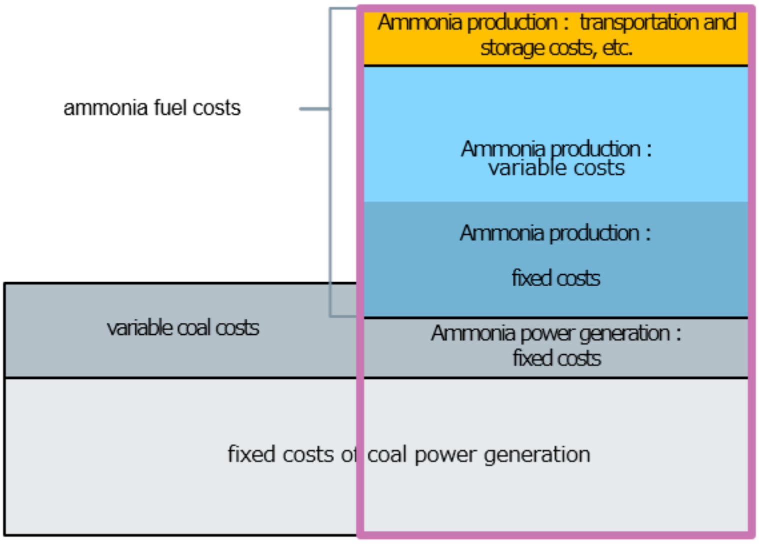
Source: Energy Structural Transformation Working Group (5th), Green Innovation Project Subcommittee, Industrial Structure Council
Directions for R&D and social implementation of the "Construction of Fuel Ammonia Supply Chain" project (August 2021, Agency for Natural Resources and Energy)

(5) Unit price of power generation for mixed combustion of ammonia

When considering the power generation unit costs for ammonia co-firing, we decided to use the specifications of the ultra-supercritical pressure (USC) high-efficiency plant undergoing demonstration tests. Under the assumption that there will not be a huge difference in the operational data even in the case of ammonia co-firing, it was decided to use the capacity factor and O&M costs for existing coal-fired thermal power plants.

As described above, ammonia co-firing requires costs for the remodeling/addition of the loading arm, receiving piping, storage tank, and carburetor on the receiving, storage, and dispensing equipment side, and costs for the remodeling/addition of an ammonia co-firing burner, ammonia supply system, and control equipment on the power generation equipment side. Therefore, we considered these costs as additional costs for ammonia co-firing.

As for fuel prices, it is necessary to consider regional characteristics in manufacturing and transportation costs. Therefore, a price assumption based on the survey team's own survey results was prepared and used in the estimation. Details of fuel prices are given in Sections 5.2.2 and 6.2. Figure 5-20 shows an illustration of the power generation costs for ammonia co-firing.



(Source: JICA Survey Team)

Figure 5-20 Illustration of power generation costs for ammonia co-firing

(6) Other ammonia-fueled thermal power technologies

This section mainly describes ammonia co-firing in coal-fired power plants, but research and development is also progressing on ammonia combustion technology in gas turbines. Table 5-2 compares the combustion technology for ammonia in a coal boiler and that in a gas turbine.

Table 5-2 Comparison of combustion technology in ammonia coal boilers and gas turbines

	Coal fired boiler	Gas turbine
Expected style	Remodeling the burner boiler(high mixed firing case) by utilizing existing coal power plant	Build the ammonia fired plant with new gas turbine
Mindset of ammonia-fired / mixed-fired	As for the 20% mixed firing, aiming early practical utilization. Aiming high mixed firing at the whole of boiler by manufacturing the high mixed/ammonia firing burner in this business.	Aiming ammonia gas-firing. Proceed the expansion of the scale by manufacturing the ammonia gas firing burner in this business
Initial investment	**Middle** (High possibility to utilize the existing facilities)	**High** (On the assumption of new plant building)
Heat efficiency	**Middle** (in case of model plant of coal fire plant, 43.5%)	**High** (in the case of model plant of LNG fire plant, around 55%)
Current development status	This fiscal year, a project commissioned by NEDO began to demonstrate the use of 20% co-firing in actual boilers. Scheduled to run until 2024.	Between FY 2019 and FY 2020, a project commissioned by NEDO implemented 70% ammonia mixture in 2,000 kW class gas turbines.

Source: Energy Structural Transformation Working Group (5th), Green Innovation Project Subcommittee, Industrial Structure Council
Directions for R&D and social implementation of the "Construction of Fuel Ammonia Supply Chain" project (August 2021, Agency for Natural Resources and Energy)

In terms of the power generation technology using ammonia in gas turbines, ammonia decomposition gas turbine combined cycle (which decomposes ammonia using the exhaust heat of a gas turbine and uses it as fuel for the gas turbine) and gas turbine (which burns ammonia directly) are considered. The present development situation is shown in Table 5-3 below.

Table 5-3 Development status of technology for using ammonia in gas turbines

	Overview	Development timing
Ammonia Decomposed GTCC	Ammonia is decomposed by utilizing the exhaust heat of the gas turbine to make fuel for the gas turbine. Suitable for large machines with high exhaust gas temperatures.	The development is expected to be completed in the second half of the 2020s.
Ammonia direct combustion GT	Ammonia is directly combusted by a gas turbine. While the system is simple and does not require a decomposition device, the amount of NOx generated by ammonia combustion is large, requiring the development of a dedicated combustor. Exhaust gas denitrification equipment is also essential.	Development will be completed around 2024, and demonstration tests will be conducted.

Source: Presentation materials of the Institute of Thermal Power Technology, "Development of Decarbonization Technology in Thermal Power Generation"
Prepared by this study group based on "Technology Development of Ammonia-Fired Gas Turbine" by Mitsubishi Heavy Industries, Ltd.

5.1.3 Technical Issues and Countermeasures related to Thermal Power Generation using Biomass as Fuel

(1) Introduction

This chapter describes technical issues and countermeasures for biomass co-firing in existing pulverized coal-fired thermal power plants.

In biomass co-firing in pulverized coal-fired thermal power plants, wood chips and wood pellets are generally used as biomass fuels. In addition, wood pellet fuel can be mixed with coal on the conveyor, or it can be not mixed with coal and use a biomass-dedicated bunker, mill, and burner.

This chapter introduces examples of these three co-firing systems in coal-fired power plants owned by JERA and presents technical issues and countermeasures for these co-firing systems. It also provides an outline of the biomass co-firing situation at major Japanese electric power companies.

When using wood biomass fuel, it is necessary that the raw material wood is supplied in a sustainable manner. When procuring biomass fuel, JERA confirms that it has been certified by a public system, such as FSC certification.

(2) Overview of Biomass Co-firing Technology in Coal-Fired Power Generation

(a) Wood chip

1) Overview

This section describes the efforts at Hekinan Thermal Power Station Unit 1 ~ 5 to conduct co-firing using wood chips in a coal-fired thermal power plant. The plant had been co-firing 1% wood chips since 2010. Wood chips used as fuel are transported by ship from overseas to storage yards near power plants for temporary storage, and are regularly transported by truck from storage yards to power plants. Wood chips entering the Hekinan Thermal Power Station are temporarily stored in a biomass silo by a receiving hopper. The wood chips are then mixed with coal on a coal conveyor. They are pulverized by the existing coal mills and co-fired with coal in the boiler. Since there are two systems of coal conveyors, one for Unit 1 ~ 3 and one for Unit 4 and 5, one unit of biomass equipment for each system is installed. The co-firing period for wood chips was 2009 to 2017, and since 2019, wood pellets have been used.

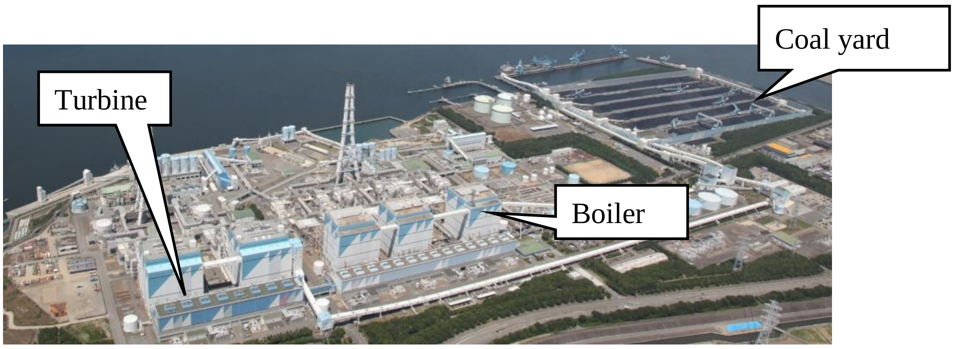


Figure 5-21 JERA Hekinan Thermal Power Station

Table 5-4 Facility Overview

	Output	Start of operation	Start of mixed combustion	Cumulative co-firing	Reduction in coal consumption	CO_2 reduction	Co-firing ratio
Unit 1	700 MW	10/1991	2009.5～Start of mixed combustion test 2010.9～Start of full-scale operation	About 710,000t (2010～2017)	About 50,000t/year	About 130,000 tCO_2/year	1.0cal%
Unit 2	700 MW	6/1992					
Unit 3	700 MW	4/1993					
Unit 4	1000 MW	11/2001					
Unit 5	1000 MW	11/2002					

<Outline of co-firing procedure>

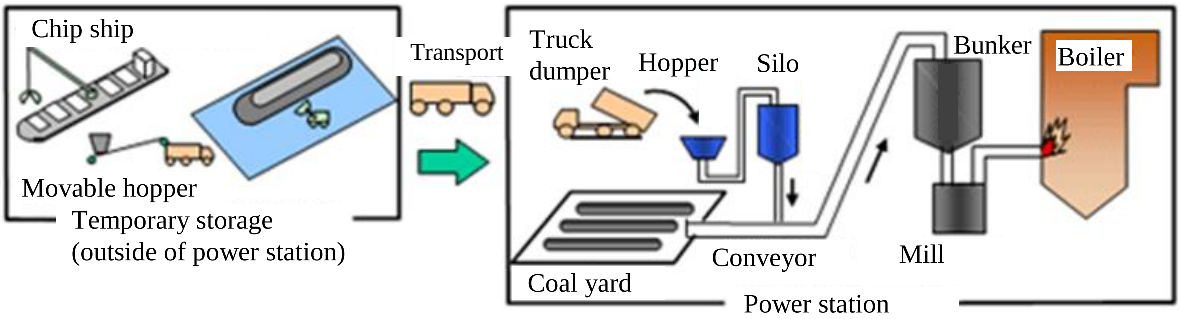
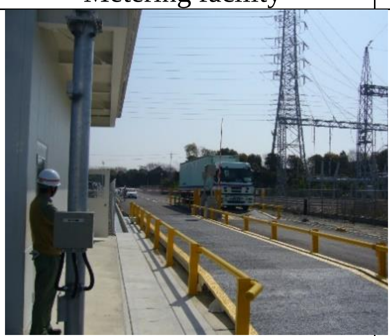


Figure 5-22 Configuration Overview

Table 5-5 Main Facilities

Facility Name		Unit 1 ~ 3	Unit 4 & 5
Daily biomass consumption (3 cal%)		1,280 t/day	1,220 t/day
Number of trailers received		67 units/day	64 units/day
Receiving facility	Truck Scale	1 unit	
	Truck dumper	1 unit	Same as Unit 1 ~ 3
	Receiving hopper	75 m^3 x 1 unit	Same as Unit 1 ~ 3
	Receiving conveyor	230 t/h x 1 unit	Same as Unit 1 ~ 3
Storage facility	Biomass storage silo	2,600 m^3 x 1 unit	Same as Unit 1 ~ 3
Sending facility	Sending conveyor	220 t/h x 1 unit	Same as Unit 1 ~ 3
	Distribution apparatus	110 t/h x 2 units	Same as Unit 1 ~ 3

Metering facility	Receiving building	Truck Dumper
		

2) Major Technical issues and Countermeasures

a) Limitation of co-firing ratio due to increase in moisture content of wood chips

There was a problem in that the co-firing rate of wood chips did not increase due to the problems of moisture content and pulverability. The wood chips received in the storage yard were transported by truck to the power plant for use. However, since the storage yard had no roof and humidity control was not possible, the water content of the wood chips could not be controlled, and the target co-firing ratio of 3 cal% was expected to be only 1 cal%.

Figure 5-23 Storage Yard

Countermeasure

Storage in a covered yard is required for humidity control of wood chips. In order to stabilize the procurement of wood biomass fuel, the use of wood chips was discontinued in 2017, and a covered storage yard was installed on the premises of the power plant. Wood pellets have been used since 2019.

b) Deposition, consolidation and solidification of wood chips

As the wood chips are stored for a long time and the chips consolidate and solidify, there is a possibility that the discharge screw at the lower part of the silo cannot be started or the bridge phenomenon occurs in the silo.

Figure 5-24 Discharge Screw

Figure 5-25 Silo Exit Woody Chip Deposition

Countermeasure

If there is no delivery of wood chips more than once a week, the shaft of the delivery screw at the bottom of the silo is rotated once in the circumferential direction to loosen the wood chips once a day.

(b) Wood Pellet (mixing on the conveyor)

1) Overview

The mixing in the conveyor co-firing system for wood pellets is a system in which wood pellets are transported to an existing coal conveyor. Coal and wood pellets are then mixed on the conveyor, transported to coal bunkers, pulverized by coal mills, and burned by coal burners.

The scope and cost of retrofitting are relatively small, and a moderate co-firing ratio can be realized.

In JERA Hitachinaka Thermal Power Station, both Unit 1 (3 cal%) and Unit 2 (4.5 cal%) are co-firing with wood pellets, and an overview is described below.

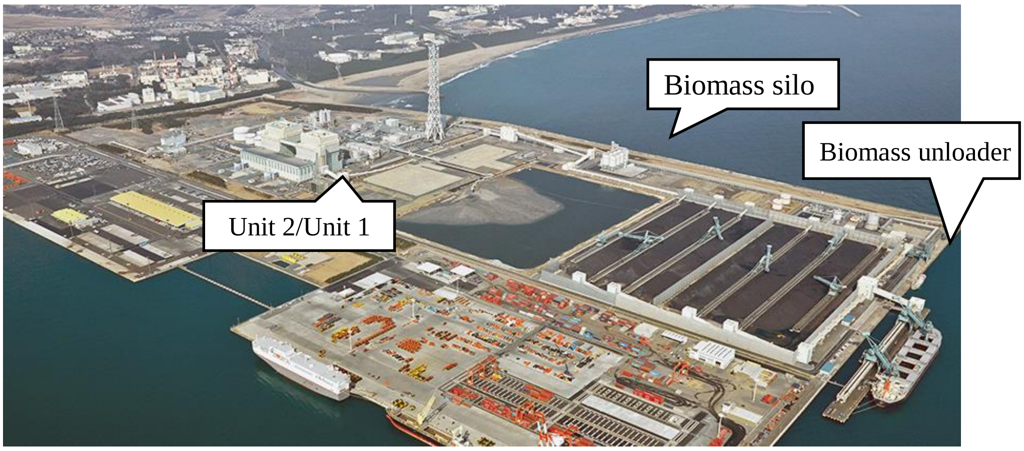
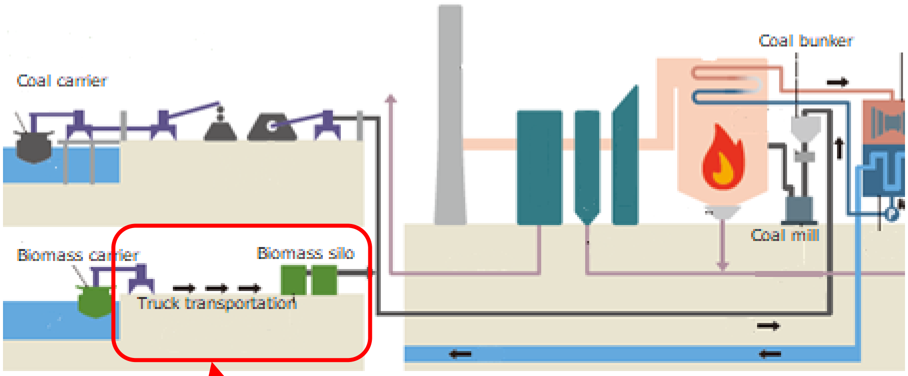


Figure 5-26 JERA Hitachinaka Thermal Power Station

Table 5-6 Facility Overview

	Output	Commercial operation date	Commencement timing of co-firing	Cumulative total amount of wood pellet	Amount of coal reduction	Amount of CO_2 reduction	Co-firing ratio
Unit 1	1,000 MW	12/2003	6/2017	c. 820,000 t (~as of 11/2021)	c. 120,000 t/year	c. 280,000 t/year	3.0 cal%
Unit 2	1,000 MW	12/2013	8/2017				4.5 cal%



Scope of retrofiting

Figure 5-27 System Configuration

Table 5-7 Main Facilities

Facility Name	Type	Capacity
Unloader	Pneumatic	480 t/h
Silo	Cylindrical	3800 m^3 x 8
Receiving conveyor	Chain conveyor	530 t/h
Sending conveyor	Chain conveyor	200 t/h

Unloader

Silo

Conveyor

2) Major Technical issues and Countermeasures

The major technical problems and countermeasures of the mixing on the conveyor co-firing system are described below.

① Limitation of co-firing ratio due to reduction of mill capacity

In the mixing on the conveyor system, coal and wood pellets are simultaneously grinded using existing coal mills. In this grinding method, the wood pellet becomes a buffer material and the grinding capacity of the mill decreases, and the differential pressure inside and outside the mill rises due to the ungrinded fuels in the mill. If a large amount of wood pellets are put in the mill, a large amount of coal may be discharged into the mill pyrite box due to a reduction in the grinding capacity, or the mill may stop due to an increase in the differential pressure. Therefore, the co-firing ratio becomes limited to several percent.

Figure 5-28　Massive coal discharge to the mill pyrite box

Countermeasure
Fundamental measures will require retrofitting of coal mills or primary air fans, but large-scale retrofitting will be necessary. As a temporary measure, there is a method of adjusting the speed of the rotary classifier installed on the upper part of the mill when an increase in mill differential pressure has been confirmed during plant operation. Although this method is very effective, there is a risk of an increase in unburned carbon in the ash and an increase in boiler metal temperature.
In addition, the use of semi-carbonized pellets (Black Pellets) instead of ordinary wood pellets (White Pellets) can improve the pulverability and the co-firing ratio, but the fuel costs are high.
In the absence of major retrofitting or a change in the biomass fuel type, it is important to check the raw materials and test the pulverizability of wood pellets before procuring new wood pellets, and to evaluate in advance whether the required co-firing ratio can be achieved. JERA sets its own standards and conducts preliminary assessments.

② Plant operation troubles due to components and properties of wood pellets
In some cases, wood pellets are made of various tree species, and their components and properties change greatly. Depending on the components of the wood pellets, there is a risk that a large amount of ash will adhere and accumulate (slagging, fouling) inside the boiler, so caution is required.

Countermeasure
To prevent operation trouble at the plant, carry out desktop evaluations, laboratory tests and tests at the actual plant before introducing a new type of wood pellet.
In including the pulverizability test described above, JERA has established these evaluation methods in an operation manual to realize stable plant operation.

Figure 5-29　Wood Pellet Lab Test

③ Contamination of Wood Pellets

Wood pellets contain more foreign matters than coal, which poses a risk to stable plant operation.

Figure 5-30 Plastic Contamination

Figure 5-31 Tool Inclusion

Countermeasure

There are two countermeasures for contamination of wood pellets: confirmation of the quality control system at the supplier and installation of a foreign substance removal device in the receiving equipment at the power plant.

JERA has established a quality control system required of suppliers based on its know-how to procure high-quality wood pellets, and has installed grid and magnet separators in the receiving facilities of power plants to ensure stable operation.

(c) Wood pellets (mixing in the boiler)

1) Overview

The mixing in the boiler co-firing system for wood pellets is a system in which wood pellets are transported to a dedicated bunker, stored, pulverized by a dedicated coal mill and burned with coal in a boiler by a dedicated burner.

JERA Taketoyo Thermal Power Station plans 17 cal% wood pellet co-firing. An overview is described below.

Figure 5-32 JERA Taketoyo Thermal Power Station

Table 5-8 Facility Overview

	Output	Scheduled start of operation	Commencement timing of co-firing	Co-firing ratio
Unit 5	1,070 MW	FY 2022	FY 2022	17 cal%

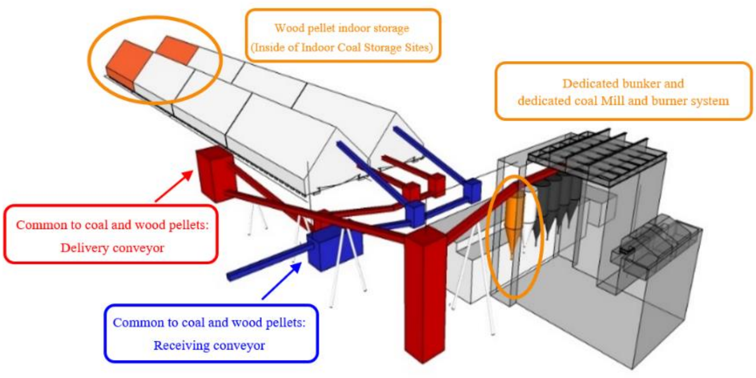


Figure 5-33 System configuration

2) Major Technical Challenges and Countermeasures

The main technical challenges and countermeasures for the mixing in the boiler co-firing system are described below.

① Realization of high co-firing ratio

In the environmental assessment for the construction of Unit 5 of the Taketoyo Thermal Power Station, a biomass co-firing ratio of 17 cal% was announced, and it is necessary to achieve this co-firing ratio.

Countermeasure

In order to achieve a very high co-firing ratio of 17 cal%, a large amount of wood pellets can be co-fired by installing dedicated combustion equipment (from bunker to burner) and ensuring the stable procurement of wood pellets.

The dedicated coal mill for wood pellets has a modified internal structure (reduction of primary air inflow port area and installation of flow reducing member, return prevention cover and double wall) to improve the co-firing ratio. All modifications are intended to improve the dischargeability of pellets from the coal mill (to reduce the differential pressure in the coal mill).

In the case of a burner dedicated to wood pellets, the C/A (ratio of fuel and air) that affects the flame retention at the tip of the burner is reduced in order to increase the amount of primary air for the purpose of improving the discharge efficiency from the coal mill, and since classification in the classifier is not actively conducted for the purpose of improving the discharge efficiency from the coal mill, the wood pellets are burned in the state of coarse grains, which is disadvantageous in terms of flame retention at the tip of the burner in comparison with the combustion of coal. Therefore, as a function for ensuring flame retention, a distributor for concentrating fuel at the tip of the burner is installed.

As for the wood pellet fuel, only Black Pellets were assumed at the beginning of the plan, but by adding White Pellets to the fuel type, the procurement of wood pellets was stabilized, enabling continuous operation at a mixed combustion ratio of 17%.

Black Pellet (BP) and White Pellet (WP)

BP is a semi-carbonized wood pellet (WP) produced in the manufacturing process. Its characteristics (calorific value and friability) are similar to those of coal compared, and it is superior to WP in water resistance, shape stability and easy of handling in power plants.

However, the size of the market is small, and upstream participation need to be considered to realize the large-scale procurement.

On the other hand, WP is inferior to BP in calorific value, water resistance and shape stability. In terms of the handling, facility measures are required in comparison with BP (due to higher pulverization rate than BP), but WP is a biomass fuel that the commercial flow is established and stable procurement is possible.

② Safety measures

Wood pellets have a higher pulverization rate than coal, a higher risk of explosion (rapid combustion), and a lower minimum ignition energy. Therefore, in a wood pellet dedicated firing system, safety measures are required for the bunker and the coal mill, where the dust concentration is above the explosion lower limit concentration.

Countermeasure

Due to the dust generated when wood pellets are dropped into the bunker, the dust concentration in the bunker reaches the lower explosion limit. The necessary ignition energy is only equivalent to static electricity generated by collision between fuels.

Therefore, when the inside of the bunker is in a dry state, static electricity as an ignition source is easily generated. Accordingly, a fine mist is sprayed into the bunker to keep the humidity in the bunker at a constant value or more, and the generation of static electricity as an ignition source of rapid combustion is suppressed.

In addition, since it is assumed that the duct concentration in the coal mill will reach the explosion lower limit concentration, a "rapid combustion suppression device" was installed in the coal mill.

Rapid combustion suppression measures are devices that detect minute pressure changes at the beginning of rapid combustion and quickly supply fire extinguishing media to prevent equipment damage.

③ Ensuring plant operation
The combustion of wood pellets is more responsive to changes in boiler load (temperature and pressure changes) than the combustion of coal, which is a constraint in changing the power generation load.
Countermeasures
At the Taketoyo Thermal Power Station, in order to maintain load change responsiveness even during wood pellet co-firing operation, for operation where load change instructions are received from the Central Power Supply Command Station within a certain range of load bands (called band operation), the power station is equipped with an operation mode in which the amount of wood pellets burned is kept constant and only the amount of coal burned is changed to follow the change in the power generation load (wood pellet supply constant mode), and an operation mode in which the co-firing ratio of wood pellets is kept constant when the operator changes the load to an arbitrary power generation load (co-firing ratio constant mode).

(3) Recommendations on biomass co-firing in coal-fired power plants

Although coal-fired power generation is one of the important power sources in Indonesia, in the short term it may be important to reduce CO_2 emissions from coal-fired power plants while ensuring a stable supply of electricity by using existing plants, given the increasing global headwinds toward coal-fired power generation. Biomass co-firing by retrofitting existing coal-fired power plants is a low-carbon technology that is expected to have an immediate effect, and it must be realized quickly.
In order to realize mixed combustion of biomass in existing coal-fired power plants, it is necessary to comprehensively examine facility retrofitting, fuel procurement, operability, and economic efficiency. The cooperation of manufacturers of existing facilities and power generators with mixed combustion experience is effective for these examinations.
In particular, the latest coal-fired IPP project in Indonesia has adopted a thermally efficient USC boiler, which makes it possible to supply more electricity from limited biomass resources, and makes it easier to recover the cost of retrofitting due to the long remaining life.
It is expected that the promotion of biomass co-firing retrofitting as a new cooperative project by JICA, using the latest high-efficiency coal-fired power plants as pilot plants, will be an effective measure to realize the expansion of biomass co-firing in existing plants.

(Reference information)

(4) Overview of coal-biomass co-firing at Japanese electric power companies

The following is an outline of the co-firing of coal and wood biomass by major electric power companies in Japan.
(Source: Prepared by JICA Survey Team based on press releases from each company and descriptions on its website)

1. Tohoku Electric (wood chip)

	Output	Start of operation	Commencement time for mixing	Amount of Co-firing	Reduction in coal consumption	CO_2 Reduction	Co-firing ratio
Noshiro thermal power plant No1	600MW	5/1993	12/2011	About 30,000 t/year	About 10,000 t/year	About 30,000 tCO_2/year	—
No2	600MW	12/1994					
Haramachi thermal power plant No1	1,000MW	7/1997		About 60,000 t/year	About 20,000 t/year	About 50,000 tCO_2/year	
No2	1,000MW	7/1998					

2. Kyushu Electric (wood chip)

	Output	Start of operation	Commencement time for mixing	Amount of Co- firing	Reduction in coal consumption	CO_2 Reduction	Co-firing ratio
Reihoku thermal power plant No1	700MW	12/1995	FY2010	About 15,000 t/year	—	About 10,000 tCO_2/year	1w%
No2	700MW	6/2003					

3. Shikoku Electric (Wood chip)

	Output	Start of operation	Commencement time for mixing	Amount of Co-firing	Reduction in coal consumption	CO_2 Reduction	Co-firing ratio
Saijyo thermal power plant No1	156 MW	11/1965	7/2005	About 15,000 t/year	About 4,000 t/year	About 11,000 tCO_2/year	Lower than 2%
No2	250 MW	6/1970					Lower than 3%

4. Hokuriku Electric (forest residue etc.)

	Output	Start of operation	Commencement time for mixing	Amount of Co-firing	Reduction in coal consumption	CO_2 Reduction	Co-firing ratio
Nanao Ota thermal power plant No2	700MW	7/1998	9/2010	About 20,000t/year	—	About 14,000 tCO_2/year	—
Tsuruga thermal power plant No2	700MW	9/2000	7/2007	10,000~ 20,000 t/year	—	About 11,000 tCO_2/year	—

5. Okinawa Electric (wood pellet)

	Output	Start of operation	Commencement time for mixing	Amount of Co-firing	Reduction in coal consumption	CO_2 Reduction	Co-firing ratio
Gushikawa thermal power plant No1	156MW	3/1994	3/2010	About 30,000 t/year	—	About 40,000 tCO_2/year	3w%
No2	156MW	3/1995					
Kin thermal power plant No1	220MW	2/2002	3/2021				
No2	220MW	5/2003					

6. Chugoku Electric (t hinned wood)

	Output	Start of operation	Commencement time for mixing	Amount of Co-firing	Reduction in coal consumption	CO_2 Reduction	Co-firing ratio
Shin-onoda Thermal power plant No1	500MW	4/1986	8/2007	About 20,000～30,000 t/year	—	About 30,000～45,000 tCO_2/year	3w% max
No2	500MW	1/1987					

Note: Since the official commencement time for mixing is unknown, the time in the press release is stated.

7. Kansai Electric (wood pellet)

	Output	Start of operation	Commencement time for mixing	Amount of Co-firing	Reduction in coal consumption	CO_2 Reduction	Co-firing ratio
Maizuru Thermal power plant No1	900MW	8/2004	8/2008	About 60,000 t/year	About 40,000 t/year	About 92,000 tCO_2/year	—

Note: Since the official commencing time of mixing is unknown, the time of press release is stated.

8. J power

	Output	Start of operation	Commencement time for mixing	Amount of Co-firing	Reduction in coal consumption	CO_2 Reduction	Co-firing ratio
Takehara Thermal power plant No1 (new)	600MW	6/2020	6/2020	—	—	—	10% Goal

(5) Example of biomass-fired conversion at an existing oil-fired power plant

The following describes Kansai Electric Power Co., Inc. Aioi Power Station, as an example of the conversion of an existing oil-fired power plant to a biomass-fired power plant.

Kansai Electric Power Co., Inc. established a new company, Aioi Bio-Energy Co., Ltd., in April 2017 in cooperation with Mitsubishi Corporation Power Co., Ltd. in order to examine the possibility of switching from heavy oil and crude oil to wood biomass for the fuel used in Unit 2 of the Aioi Power Plant. Aioi Bio-Energy Co., Ltd. is proceeding with remodeling work with the aim of starting commercial operation in January 2023.

Source: KEPCO website

Figure 5-34 KEPCO Aioi Power Station

Table 5-9 Facility overview

	Unit 1	Unit 2	Unit 3
Commercial operation date	9/1982	11/1982 → 1/2023 (planned)	1/1983
Output	375 MW	375 MW → c. 200 MW	375 MW
Fuel	Natural gas, Heavy oil, Crude oil	Heavy oil, Crude oil → Wood pellets	Natural gas, Heavy oil, Crude oil

Source: JICA Survey Team based on KEPCO website

Kansai Electric Power Co., Inc. plans to introduce an electric propulsion ship to transport fuel to the plant, and plans to reduce CO_2 emissions during operation by up to 50% compared to conventional diesel ships.

5.1.4 Measures to ensure Demand-Supply Balancing Power for Gas-fired and Coal-fired Thermal Power

(1) Introduction

In order to realize a low-carbon society, it is expected that the number of renewable energy sources will increase significantly in the future, and that the large thermal power plants that have been providing balancing power will be decommissioned. To maintain the stability of the power grid, a study is under way to make a major shift in the way balancing power should be provided and how it is procured. At present, it is mainly thermal power and hydro power generation that back up and balance natural fluctuations in the power output of renewable energy sources. In thermal power and hydro power generation, even if the supply-demand balance changes rapidly due to the occurrence of an accident, the rotating energy of synchronous generators and turbines has the inertia to counteract the change. The stronger the inertia in the power system, the less likely the frequency of the system will change, and the more it is likely the system will be able to return to a normal state by operating balancing power appropriately in the event of an accident. However, in the United Kingdom, Ireland, and one of the U.S. markets, ERCOT in Texas, where the scale of the grid is currently small, the power demand has changed due to the increase in wind and solar power generation. As a result, if the amount of power generated fluctuates significantly due to factors such as climate, or if a major accident occurs in the grid, there is an increasing possibility that suddenly, the supply-demand balance will be upset and a major power outage will occur. In order to avoid such risks, devices that increase inertia are being deployed and new reserve margin that responds at high speed, FFR (Fast Frequency Response), is being introduced. Measures are also planned to ensure demand-supply balance to help maintain inertia. For example, the faster the response time, the higher the reward offered to balancing power. These measures also include the establishment of a new balancing power procurement option to supply power to the grid with limits such as within a few seconds of a grid incident.

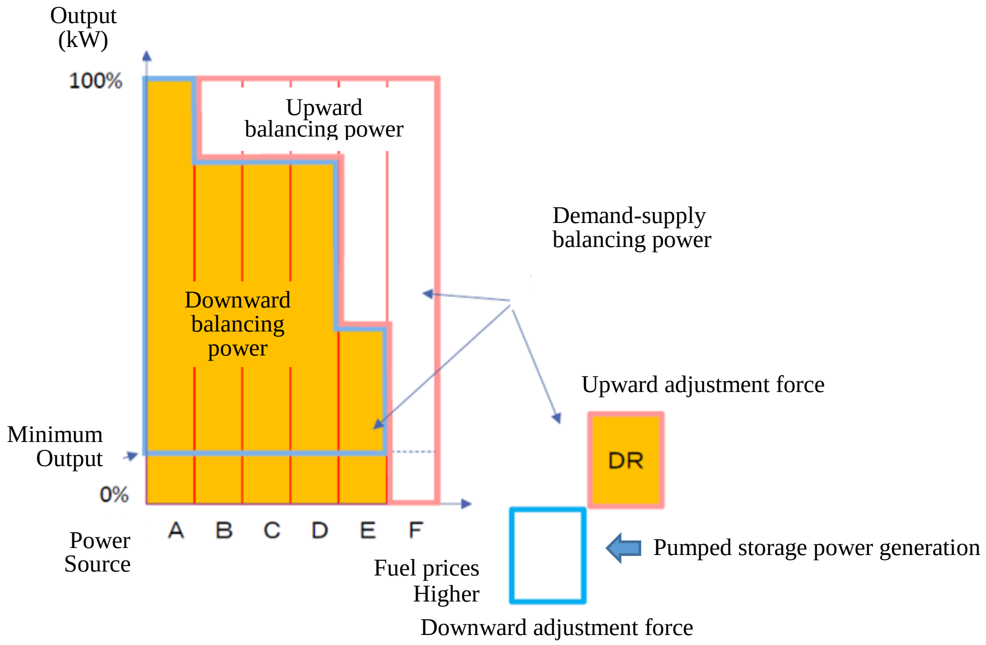
In the northeastern U.S. market, a reserve market system has been established to ensure balancing power, and a system has been built to generate income based on response time, such as 10 or 30 minutes, even for standby power. In this section, we will cover the initiatives that are currently being studied and the technologies that may be introduced in the future, with regard to measures to secure the balancing power that will be an issue in the process of realizing a low carbon (decarbonized) society.

(2) Types of balancing power

(a) Demand-supply balancing

When an imbalance between supply and demand occurs in the grid, it is necessary to match supply and demand through balancing power. It is common for system operators to make adjustments by utilizing the reserve capacity of thermal power generation under partial load, hydroelectric power generation, or standby power reserve from thermal power generation on standby. Since there may be both a surplus and shortage of electricity in the overall area, it is necessary to prepare for both "upward balancing power" and "downward balancing power".

Figure 5-35 shows a breakdown of balancing power. In general, "upward balancing power" is defined as [the remaining generation capacity of power reserve sources connected to the grid] + [supply of non-operational power reserve sources (hydropower, gas turbines)] + [demand response], while "downward balancing power" is defined as [the power output of power reserve sources connected to the grid] – [the minimum power output of power reserve connected to the grid] + [power to pump up for pumped storage power plants].



Source: The Organization for Cross-Regional Coordination of Transmission Operators (OCCTO), Reference 6, "Definition of balancing power and target of ensuring coordination power", The 6th meeting of the Committee on Balancing Power etc.

Figure 5-35 Breakdown of balancing power

(b) Frequency adjustment (Control)

Frequency adjustment (control) refers to an adjustment that maintains the frequency of the grid and does not involve adjustment of the amount of electricity. It is classified into the following types: those that adjust short-period frequency from a few seconds to a few minutes as instantaneous reserve, such as governor-free; those that adjust medium-period frequency from a few minutes to 20 minutes as operating reserve, such as thermal and hydro power during partial load operation, e.g. Load Frequency Control (LFC); and those that adjust daily load variations of 20 minutes to several hours due to economic load dispatching, such as Economic Load Dispatching (ELD).

Figure 5-36 shows the classification of power reserve.

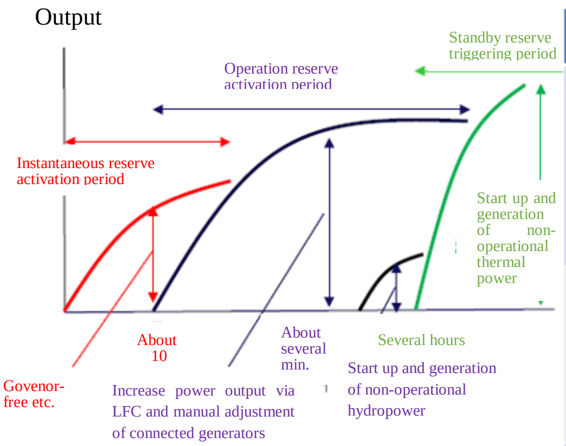


Illustration of increased output due to activation of reserve

Classification	Function	Compatible Facility
Instantaneous reserve	Supply power that begins to respond immediately (within about 10 seconds) to a frequency drop and can continue to generate power automatically at least until an operating reserve other than instantaneous reserve power is activated.	Governor-free responses etc.
Operating reserve	Supply power that can start up within a unit of time (within about 10 minutes) and continue to generate power until the standby reserve power starts up.	➢ Surplus power of thermal power during partial load operation ➢ Non-operational hydropower
Standby power reserve	Supply power that requires several hours from startup to rated output	Non-operational thermal power etc.

Source: The Central Research Institute of Electric Power Industry (CRIEPI), "The role and technology of balancing power of thermal power generators at the time of mass introduction of renewable energy" in the fiscal 2021 lecture in Fukuoka Area, Kyushu Division of Thermal and Nuclear Power Engineering

Figure 5-36 Classification of power reserve

(3) Measures to ensure balancing power in thermal power plants

As mentioned above, thermal power is expected to continue to play an important role in the mass introduction of renewable energy, gradually shifting from its current role as a base load power source to that of a balancing power source. It will be important to supply stable electricity with a good balance of renewable energy and thermal power. Table 5-10 shows a comparison of intermittent renewable energy and thermal power.

Table 5-10 Comparison of intermittent renewable energy and thermal power

Generation type	CO_2 emission	Inertia	Balancing power	Marginal cost
Intermittent Renewable Energy	Good	Bad	Fair	Good
Thermal Power	Bad※	Good	Good	Fair

※ Reduction through the use of biomass and zero-emission fuels is possible.

Figure 5-37 shows possible initiatives to further strengthen the role of thermal power as a required balancing power in the future. On the operational side, in addition to improving the rate of output change and lowering the minimum output, studies are being conducted to expand the time when Daily Start Stop (DSS) is possible, to shorten the start-up time itself, to shorten each hold time in the start-up process, and to make DSS possible for coal-fired power plants. In terms of equipment, the goal is to make the facility more flexible in operation by eliminating restrictions related to the number of gas turbine start-ups and must runs.

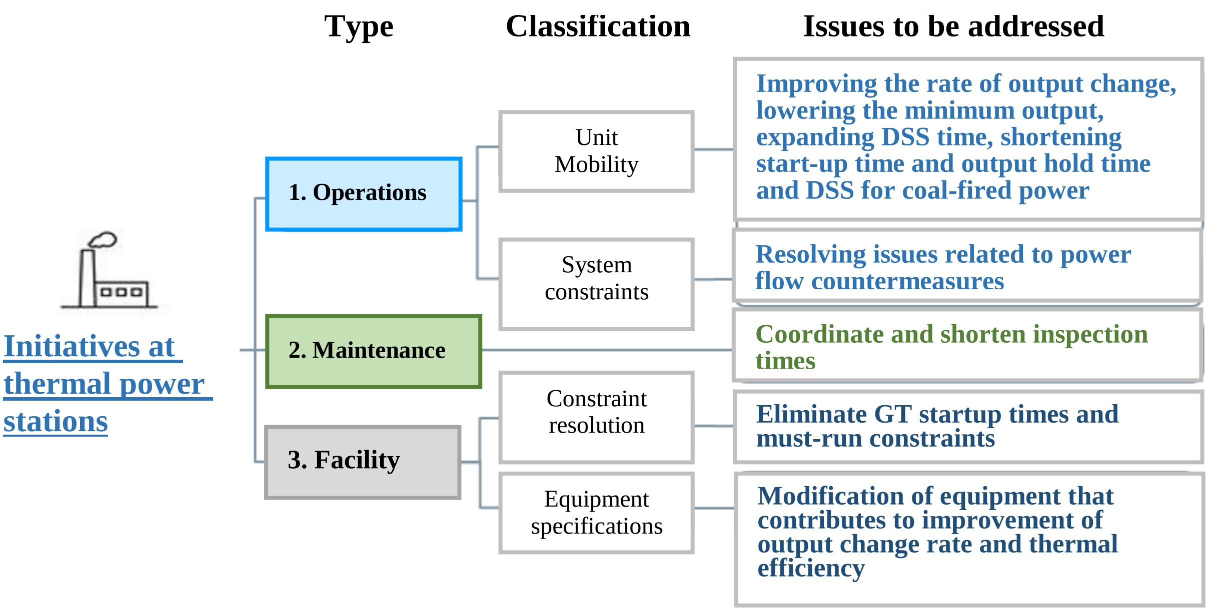
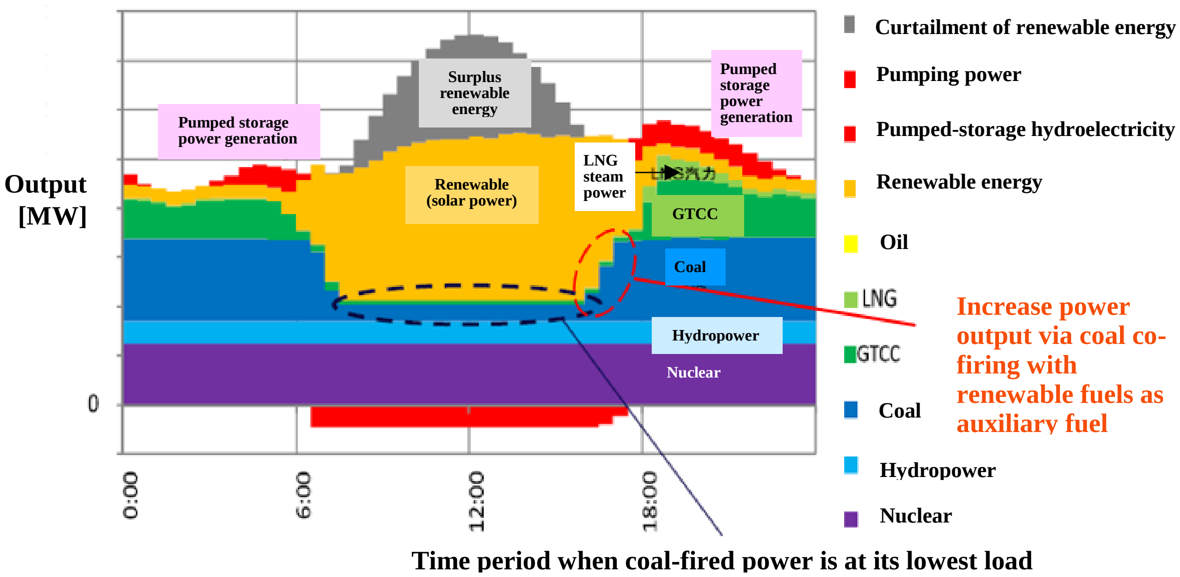


Figure 5-37 Efforts to secure balancing power at thermal power plants

(4) Initiatives at coal-fired power plants

As an example of an actual study, a review of the minimum load operation at a coal-fired power plant will be presented. In the future, when a large amount of renewable energy is introduced, coal-fired thermal power, which is the thermal power with the lowest fuel cost, is expected to be operated at the lowest load during the daytime period when a surplus of electricity is generated. If coal-fired power plants can remain on the grid while reducing their minimum load as much as possible, they can continue to contribute to the stable supply of electricity while maintaining inertia with synchronous generators and ensuring balancing power, such as supplying reactive power. In addition, by reducing their minimum load, it is also possible to reduce the amount of excess renewable energy.

At the 36th Energy Systems, Economics and Environment Conference in 2020, the Central Research Institute of Electric Power Industry (CRIEPI) proposed the use of coal-fired power plants with zero power output at the transmission end for 700 MW class supercritical pressure coal-fired power plants. In this study, during the daytime period, when there is a surplus of electricity from renewable energy sources, boiler operation is stopped (DSS) and the steam turbine is connected to the grid with a generator output of 35 MW (5% load) and a transmission end output of 0 MW using steam generated from surplus renewable energy sources, which are cheaper than coal. The coal-fired generator maintains inertia and supplies reactive power and instantaneous power reserve. After the daytime hours, when the amount of electricity generated by renewable energy sources decreases, boiler operation starts and the output is increased by switching to coal co-firing with renewable fuels, such as biomass and ammonia as auxiliary fuels. Figure 5-38 shows an illustration of the utilization of coal-fired power with zero output at the transmission end.



Source: Prepared by this study team based on The Central Research Institute of Electric Power Industry (CRIEPI), "The role and technology of balancing power of thermal power generators at the time of mass introduction of renewable energy" in the fiscal 2021 lecture in Fukuoka Area, Kyushu Division of Thermal and Nuclear Power Engineering

Figure 5-38 Illustration of the utilization of coal-fired power with zero output at the transmission end

Table 5-11 shows the operating conditions at minimum output.

Table 5-11 Operating conditions at minimum output

Generation Type	Operating conditions	Reference
Generator output	35MW Reference: 700MW during rated operation	Only 5% of the internal load is generated (transmission end output is zero)
High pressure steam temperature/pressure	465.7 degrees Celsius/7.85MPa Reference: 538 degrees Celsius/24.2MPa during rated operation	Apply hot start condition after 8 hours of shutdown
Reheated steam temperature/pressure	455.0 degrees Celsius/49MPa Reference: 566 degrees Celsius/4.1MPa during rated operation	Same as above
Turbine bypass ratio	High pressure: 11% Low pressure: 8%	Set based on literature
Water supply flow rate	96.4t/h Reference: 1,260t/h during rated operation	About 7-8% of rated output

Source: Prepared by this study team based on The Central Research Institute of Electric Power Industry (CRIEPI), "The role and technology of balancing power of thermal power generators at the time of mass introduction of renewable energy" in the fiscal 2021 lecture in Fukuoka Area, Kyushu Division of Thermal and Nuclear Power Engineering

(5) Initiatives at gas-fired power plants

GE, Siemens, and Mitsubishi Power account for the majority of the world's gas turbine combined cycle power plant market share. Each company is developing technologies to improve the mobility of gas turbines. Among gas turbines, light-weight aero-derivative gas turbines have been traditionally superior in terms of rapid start-up characteristics. However, even for large-capacity power generation gas turbines, modifications to the main unit will enable start-up in a short time, comparable to that of an aircraft conversion type. If the output change rate can be improved to a similar level, gas turbines for power generation with a large output change per unit time can make a significant contribution to solving the problem of power system stabilization due to the expansion of renewable energy.

In order to realize a gas turbine capable of rapid start-up, it is necessary to develop technology to make rotors, compressors and turbine blades as light as possible while maintaining strength, to make the materials thinner, and to develop materials with excellent heat resistance and thermal fatigue properties. In addition, for the purpose of reducing CO_2 emissions, the turbine tip clearance control technology has also been improved to minimize the efficiency loss at partial load.

5.1.5 Current Status of LNG in the Indonesian Market and Recommendations for expanding LNG Introduction

(1) LNG production in Indonesia

LNG production in Indonesia started with exports to Japan. It has produced LNG at four locations, the first of which was the Bontang liquefaction plant in Kalimantan. LNG production began in 1977 based on a long-term contract signed with six Japanese buyers (Kansai Electric Power Company, Chubu Electric Power Company, Kyushu Electric Power Company, Osaka Gas Company, Toho Gas Company, and Nippon Steel Corporation). Initially, the plant started with two liquefaction plants, but by 2003, with the addition of several plants, the total number of liquefaction plants had increased to eight, with a total liquefaction capacity of 22.2 MTPA.

The Arun liquefaction plant in Sumatra was the second LNG plant to start production, one year after the Bontang liquefaction plant started production under a long-term contract with two Japanese buyers (Tohoku Electric Power Company and Tokyo Electric Power Company). Arun has been reducing the number of plants in operation as the reserves of the gas fields that supply feed gas to the liquefaction plant decline, and production was terminated in 2014. In response to gas shortages in the North Sumatra region, Arun shifted its position to become an LNG receiving terminal in 2015. Arun's role as a receiving terminal is discussed below.

More than 30 years after the start of production at Arun, Tangguh began production in West Papua in 2009 to supply CNOOC in China, POSCO and SK E&G in Korea, and Sempra's Costa Azul terminal in Mexico under long-term contracts. The plant has two liquefaction units, with a total liquefaction capacity of 7.6 MTPA. Following the signing of long-term contracts with Japan's Kansai Electric Power Company and Indonesia's PLN, Tangguh made a final investment decision in 2016 on the expansion of its third plant, which is currently under construction. In connection with this expansion, Tangguh is planning to increase the production of feed gas by removing CO_2 from the feed gas extracted from the gas field and injecting it into the gas field as CCUS (Carbon dioxide Capture, Utilization and Storage).

Six years after the start of production at Tangguh, the Donggi Senoro liquefaction plant started production in Sulawesi in 2015 based on a long-term contract signed with Chubu Electric Power and Kyushu Electric Power of Japan and KOGAS of Korea, with a liquefaction capacity of 2.3 MTPA.

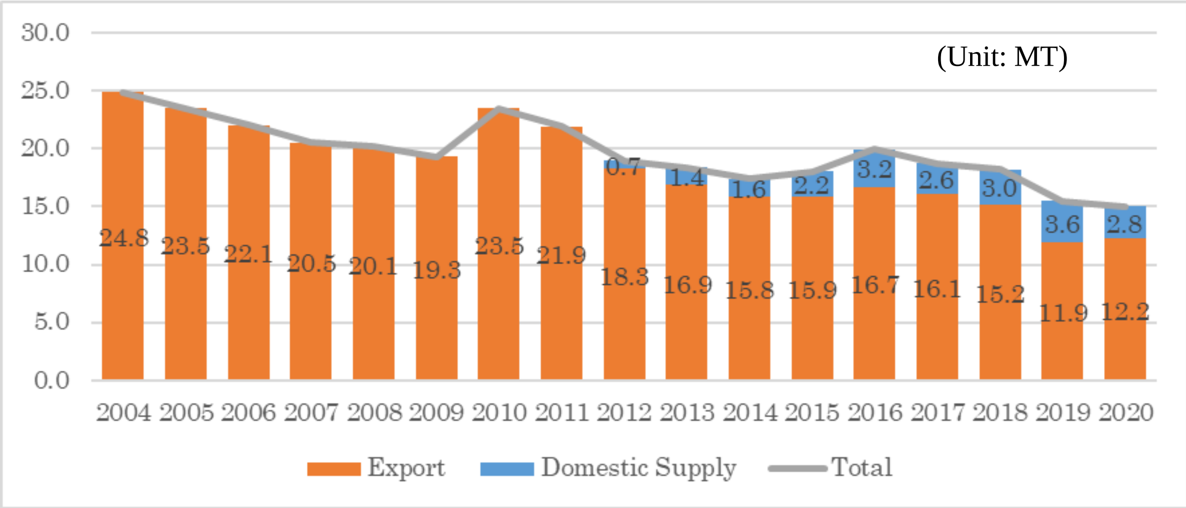
As described above, Indonesia has four liquefaction projects and three are currently producing LNG. The following describes the liquefaction projects under construction and planned.

The liquefaction plant under construction is Sengkang, which is located on the same island of Sulawesi as Donggi Senoro. Unlike the liquefaction plants that have been built in four locations in Indonesia so far, the liquefaction plant has a smaller liquefaction capacity of 0.5 MTPA.

The liquefaction plant planned for construction is Abadi, which is planned to be built in the Tanimbar Islands. Initially, Abadi was planning to install an offshore liquefaction plant, but following opposition from the Indonesian government in March 2016, the plan was changed to install an onshore liquefaction plant. It is planned to have two liquefaction plants, with a liquefaction capacity of 9.5 MTPA. The project is expected to be developed in the future, but in July 2020, Shell, which holds a 35% stake in the Abadi project, announced its intention to withdraw from the project and is currently in the process of selling it. There are concerns that this will delay the start of production at the Abadi liquefaction plant.

(2) LNG production volume in Indonesia

Trends in LNG production in Indonesia are as follows.



(Source: GIIGNL)

Figure 5-39 Trends in LNG production in Indonesia

Indonesia was the world's largest LNG producer until 2005, when it produced 23.5 MT from Bontang and Arun, but in 2006 it ceded this position to Qatar, which increased its production with the start of production from a new liquefaction plant. Indonesia's LNG production volume decreased to 15MT in 2020.

The reason for the decline in LNG production is attributed to Botang and Arun, as evidenced by the fact that Indonesia's LNG production has declined despite the start of production at the Tangguh liquefaction plant in 2009 and at the Donggi Senoro liquefaction plant in 2015.

As mentioned above, Arun ceased production in 2014 due to depletion of its reserves; LNG production at Bontang has been declining due to a reduction in feed gas supply to the liquefaction plant. The number of liquefaction plants in operation has been reduced accordingly, and of the eight liquefaction plants, only three are currently operational. In line with the decrease in the number of operating liquefaction plants, LNG production has been declining, with Bontang's production falling below 0.5 MTPA in 2020.

To stem the decline in LNG production in Bontang, it is necessary to develop new gas fields to supply feed gas to the Bontang liquefaction plant. In this context, ENI started production from the Jangkrik gas field in 2017 and from the Merakes gas field in 2021. In addition, Chevron started production from the first phase of the Indonesian Deepwater Development (IDD) in 2016 and is expected to develop the second phase in the future, but Chevron, which holds a 62% stake in IDD, has announced that it will withdraw from IDD in 2020. It is said that ENI may buy Chevron's stake in the sale, but there are concerns that the sale process may delay the start of production.

Production at Tangguh and Donggi Senoro is roughly in line with liquefaction capacity.

(3) LNG receiving terminal in Indonesia

All LNG produced in Indonesia was exported overseas until 2011, but to meet the increasing demand for gas in Indonesia, Indonesia started receiving LNG in 2012. Currently, five LNG receiving terminals are in operation in Indonesia.

The first LNG was received at the Nusantara Regas terminal in West Java, where PT Nusantara Regas installed an FSRU (Nusantara Regas Satu) with a storage capacity of 125,000 m^3 and a regasification capacity of 3 MTPA in Jakarta Bay, and started operations in May 2012. The FSRU receives 1.5-2mt of LNG from Bontang and Tangguh, and supplies the regasified gas to three power plants (Muara Karang, Tanjung Priok, and Muara Tawar) that were previously oil-fired.

The next terminal to start operations was the Lampung terminal in South Sumatra, where PGN installed an FSRU with a regasification capacity of 1.8 MTPA at Lampung, South Sumatra, which started operations in 2014. This is not an onshore LNG terminal but an FSRU (PGN FSRU Lampung) with a storage capacity of 170,000m^3. The terminal receives LNG from Tangguh, but the receiving volume is only around 0.5 MT at most. Since the Lampung terminal is not connected to the demand area in South Sumatra by a pipeline, most of the regasified gas is supplied to West Java through the South Sumatra-West Java pipeline.

The third terminal, the Arun terminal in North Sumatra, began operations in 2015. As already mentioned, Arun was developed as an LNG liquefaction terminal in 1978, but LNG production was terminated in 2014 due to depletion of reserves, and Pertamina converted it to a receiving terminal in 2015. Unlike Nusantara Regas and Lampung, Arun is an onshore terminal. The Arun terminal has a regasification capacity of 3 MTPA, but has received only 0.5-1 MT so far; LNG is received from Tangguh and regasified gas is transported through the Arun-Belawan pipeline to the PLN power plant in Medan. The Arun terminal is different from other receiving terminals in that it is designed to function as an LNG hub, receiving LNG as well as re-exporting the received LNG. The Arun terminal started re-exporting LNG to China in January 2021.

The Benoa terminal was commissioned in Bali by PT Pelindo Energi Logistik in 2016, a year after the Arun terminal became operational. Unlike the other three LNG terminals, Benoa is a small-scale LNG terminal with a regasification capacity of 0.5 MTPA. Benoa terminal started operations in 2016 with FSU and FRU, but replaced those facilities in 2018 with small scale FSRU (Karunia Dewata) having a storage capacity of 26,000 m^3. LNG is supplied from Bontang, and the gas regasified at the Benoa terminal is sent to PLN's Pesanggaran power plant via pipeline.

In 2020, PT Sulawesi Energi Satu started operation of the Amurang terminal on Sulawesi Island, which, like Benoa, is a small-scale LNG terminal. The FSRU (FSRU Hua Xiang) has a storage capacity of 14,000 m^3 and is used for receiving, storing and regasifying LNG supplied from Bontang, and then supplying it to a power generation vessel (Zeynep Sultan, 125 MW) owned by the Turkish company Karpowership.

In addition to the five operating LNG receiving terminals mentioned above, there are two more receiving terminals scheduled to start operating in 2021.

The first is the Java-1 terminal in West Java. It is part of an integrated development project to install a 170,000m^3 FSRU (FSRU Jawa Satu) with a regasification capacity of 2.4MTPA at Cilamaya, about 100km east of Jakarta, and then supply the regasified gas to a 1,760MW power plant through a pipeline. LNG will be supplied from Tangguh.

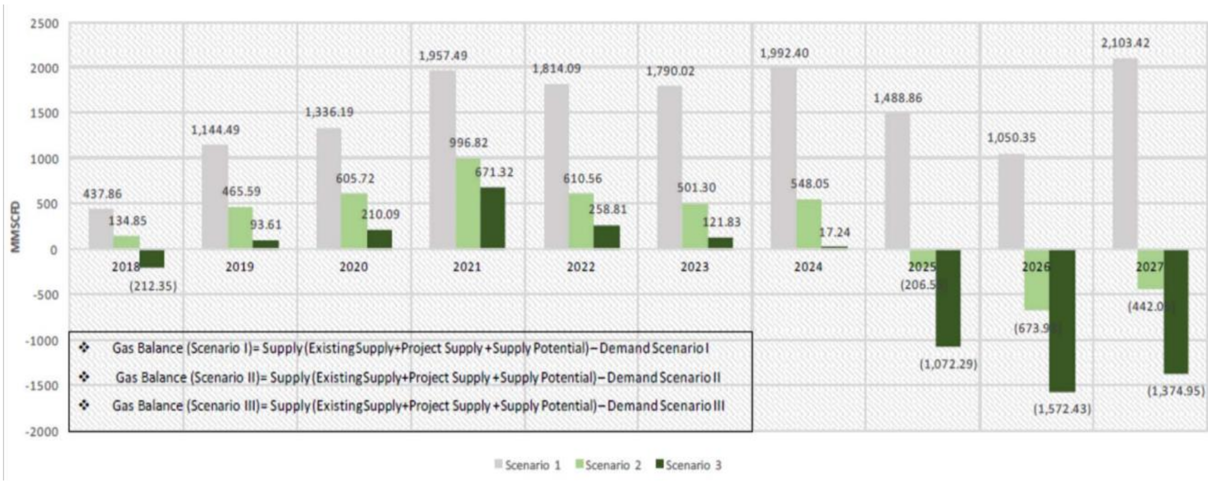
The second is the Teluk Lamong terminal in East Java, which is a small-scale terminal with a regasification capacity of 0.2 MTPA. The development of the base consists of three phases, the first phase is to use the FSRU with a storage capacity of 15,000m^3 and to flow the gas regasified by the FSRU into the existing pipeline. In the second phase, the terminal will be equipped with additional facilities to fill ISO tanks for truck transportation, which will enable gas supply to areas not connected to the pipeline. The final phase of the project is the construction of an onshore terminal which, when completed, will increase the regasification capacity to 1.4 MTPA.

(4) LNG Demand in Indonesia

As mentioned in the previous section, the first LNG consumption in Indonesia started in 2012, when LNG was received at the Nusantara Regas terminal in West Java.

The reason for this is that Indonesia's growing domestic demand for gas cannot be met by domestic natural gas alone via pipeline. Another factor influencing the introduction of LNG in Indonesia is the fact that large-scale gas fields are located far from demand areas such as Java and Sumatra, so gas is liquefied and then transported as LNG.

As the number of LNG receiving terminals increases, the volume of LNG received in Indonesia has been increasing, reaching 3.6 MT in 2019; in 2020, the volume will decrease to 2.8 MT due to the impact of Covid 19, but is expected to increase further with the commencement of operations at the Java-1 and Teluk Lamong terminals.



(Source: Neraca Gas Bumi Indonesia 2018-2027)

Figure 5-40 Indonesian Gas Balance 2018-2027

The Indonesia Gas Balance 2018-2027, published in October 2018, projected that imported LNG would be needed after 2025 in Scenarios 2 and 3 of the three scenarios, while in Scenario 1, the low-demand case, it was assumed that Indonesia's domestic demand could be fully met by 2027 with the current planned domestic gas supply. In addition, as mentioned above, the impact of Covid 19 has resulted in sluggish growth in energy demand. In 2017, the breakdown of gas demand was as follows: power sector demand: 14%, industrial sector demand: 23%, fertilizer sector demand: 10%, other demand: 11%, LNG exports: 30%, and pipeline exports: 12%.

However, entering 2021, the Indonesian government set a goal of carbon neutrality by 2060, and the impact of this on LNG demand growth needs to be assessed. Please see Chapter 7 for simulations considering carbon neutrality.

(5) LNG Procurement in Indonesia

As already mentioned, Indonesia has been receiving LNG since 2012. In line with this, Nusantara Regas has signed an agreement to take 1 MTPA from Bontang for a period of 11 years from 2012 to 2023.

In 2014, PLN signed a contract to take 1.5 MTPA from Tangguh, which was amended in 2016 to approximately 1.3 MTPA for 2017-19 and 2.8 MTPA for 2020-33. Tangguh was requested by the Indonesian Government to supply more than 75% of LNG produced by its third liquefaction plant with a liquefaction capacity of 3.8 MTPA to the domestic market ("Domestic Market Obligation"). In addition to this contract, PLN signed an agreement in 2017 to purchase 1MTPA of Tangguh for Java-1 from 2020-35.

Pertamina has also signed an agreement with ENI to take 1.4 MTPA from Bontang, where feed gas is supplied by Jangkrik, from 2017-24. In addition to this, Pertamina has also signed an agreement with Chevron to take 0.2 MTPA from Bontang, where feed gas is supplied by IDD, from 2016-22.

These are the contracts that have been concluded for the procurement of LNG from Indonesia, but there are also four other LNG procurements from other countries, as described below.

In the previous section, we referred to the "Indonesia Gas Balance 2018-2027" released in October 2018, but prior to that, the "Indonesia Gas Balance 2016-2025" predicted that domestic gas supply would not be able to meet domestic demand and that LNG imports would be required from around 2019.

Prior to this, Pertamina signed contracts with Cheniere in the US in December 2013 and July 2014 to procure LNG from Corpus Christi. The contract is for a period of 20 years, from 2019 to 2039, with a total procurement volume of 1.52 MTPA at 0.76 MTPA each.

Pertamina then signed a contract in February 2016 to procure up to 1.0 MTPA from Total of France for the period 2020-2034, and two months later, in April 2016, it signed a contract to procure up to 1.1

MTPA from Woodside of Australia for the period 2019-2038. These two contracts are portfolio supplies with no identified supply source.

Additionally, in September 2019, the company signed an agreement to procure 1 MTPA from Mozambique LNG for the period 2024-44.

Thus, although LNG procurement contracts were signed to allow LNG imports from 2019, due to the subsequent slump in demand, no LNG imports have been made yet and Indonesia's LNG demand has so far been met by domestic LNG. As for the three contracts that have already been activated, it is believed that LNG is being diverted to other countries.

With regard to future LNG procurement in Indonesia, in addition to the contracts already concluded, the uncontracted portion of LNG produced in Indonesia can be considered as supply capacity for Indonesia.

For Bontang, it is possible that the existing export contract will not be renewed at the end of its contract term and that the gas will be used for domestic supply in Indonesia. For Tangguh, the diverted volume under Sempra's contract for the Costa Azul terminal and uncontracted volume can be expected to be used as supply capacity for Indonesia's domestic market.

In addition to the above, the Domestic Market Obligation requires that at least 50% of Abadi (liquefaction capacity: 9.5 MTPA), which is planned to be newly developed in the future, be supplied to the Indonesian domestic market. Therefore, 4.75 MPTA is expected to be available.

The following graph shows the supply capacity of Indonesian LNG including (1) contracted volume from domestic LNG sources, (2) contracted volume from overseas LNG sources and (3) uncontracted but expected volume from potential domestic LNG sources. Although pipeline gas exports from Indonesia will decline, this will be offset by an increase in domestic demand for gas for non-power sectors. On the other hand, LNG consumption is expected to increase significantly due to the increase in demand for gas for the power sector as a carbon neutrality measure. So after 2030, it will be necessary to import LNG based on the existing LNG contracts, and to conclude new LNG procurement contracts from overseas because the above (1) to (3) will not be enough to meet domestic LNG demand.

(6) Challenges in Expanding LNG Consumption in Indonesia

So far, Indonesia's LNG demand has been served by LNG produced in Indonesia. However, as mentioned in the previous section, it is expected that Indonesia will need to import LNG based on existing contracts and to conclude new LNG procurement contracts after 2030. There are three main issues that need to be addressed in order to significantly increase LNG imports and consumption as a carbon neutrality measure, which are discussed below.

The first is challenges in developing LNG-related facilities. In order to achieve carbon neutrality, Indonesia, like other countries, needs to promote electrification and increase the consumption of LNG-fired power generation in place of coal- and oil-fired power generation. In order to realize the increase in LNG consumption, it is necessary to build new LNG receiving terminals and pipelines between LNG receiving terminals and LNG-fired power plants, and to increase the power generation capacity of LNG-fired power plants by building new LNG-fired power plants and switching fuels from coal- and oil-fired power plants.

The second is the economic issue that arises as a result of solving the above facility problems. The first is the issue of securing funds for investment in LNG receiving terminals, pipelines and new LNG-fired power plants in order to achieve fuel conversion from coal-fired power plants. Securing financing sources for projects using fossil fuels, including not only coal but also even LNG, is becoming increasingly challenging. The second issue is the price competitiveness of LNG-fired power generation, which is less competitive than coal-fired power generation as long as it does not impose high costs for CO_2 emissions. Measures to mitigate the price differences are required to promote further introduction of LNG-fired power generation.

(7) Issues for the development of LNG-related facilities

(a) Financing

As the world accelerates its efforts to decarbonize, multilateral development banks and commercial financial institutions in Europe and the US are increasingly taking a conservative stance on financing the construction of facilities related to fossil fuels, including LNG. The Asian Development Bank

(ADB), for example, announced in its Energy Policy in October 2021 that it would suspend financing for upstream LNG-related facilities and would consider financing downstream LNG facilities only if certain conditions are met. Given these circumstances, it is likely that financing will become an important issue for Indonesia in developing the necessary LNG-related facilities if the country envisages the use of LNG in its roadmap for decarbonization.

In contrast, the Japanese government considers LNG an important fuel and regards it as a transition fuel, with a lower carbon footprint, which can sustain a stable energy supply for the short to mid term until decarbonization is achieved in the long term.

In June 2021, Japan's Ministry of Economy, Trade and Industry (METI) established the Asia Energy Transition Initiative (AETI) to support realistic decarbonization efforts in Asia, and announced the provision of various types of support, including US$10 billion in funding for LNG and renewable energy projects.

In the future, when considering the development of LNG-related facilities in Indonesia, it will become more important to utilize loans provided by Japanese public and private financial institutions, in addition to Japanese public agency support, such as that through JICA. At the same time, it will become more important to involve Japanese private companies in investment or equipment exports for a project, as required for the provision of such loans.

(b) Facility design for transition to hydrogen fuels

LNG as a transition energy is expected to shift to CO_2-free hydrogen fuel in the long term. During the transition to hydrogen fuel, the most economical course of action is considered to be the continued use of existing LNG-related facilities, but the scope of the facilities that can be continued to be used will be determined by what hydrogen carriers prevail in the future.

In terms of hydrogen carriers, "liquid hydrogen", "MCH", "ammonia", "LNG (hydrogen production in the host country)", etc. are being considered, but it is uncertain at present which carrier will become the standard method in the future, and it is necessary to watch trends toward standardization from technical and commercial perspectives. The following are major examples of the current status and issues that should be taken into account in relation to equipment design at present.

1) Transport & Storage

It is difficult to convert existing storage facilities and pipelines to liquid hydrogen, which has a lower temperature than LNG, in terms of brittle strength and cooling capacity. For ammonia, there is a possibility that existing facilities can continue to be used after modification.

2) Gas pipeline

It may be possible to continue to use the gas pipeline system after modification to transport hydrogen in a gaseous state. However, regardless of the hydrogen carrier, the heat value of hydrogen gas is 1/3 of that of natural gas. So, in order to continue to secure the same amount of power generation, it is necessary to increase the gas transmission pressure by three times after reinforcement of facilities, or increase the gas transmission capacity by three times. In both cases, it is necessary to maintain the tightness of hydrogen gas, which is the smallest at the molecular level.

3) Generator

In order to continue to use existing gas turbines, it will be possible to convert to hydrogen fuel mainly by modifying/replacing the combustor, but it will be necessary to take measures to cope with the increase in NOx values and backfiring caused by the faster combustion rate of hydrogen compared to natural gas. In addition, the estimated hydrogen co-firing ratio that can be achieved through modification varies depending on the gas-turbine model, and prior consultation with the manufacturer is necessary when designing a system for continued use.

(8) Policy recommendations for the full-scale introduction of LNG

LNG-fired power plants emit CO_2 during combustion, although less than coal-fired power plants, and cannot be a power source for decarbonization unless CCS is implemented. However, their CO_2 emissions per kWh are less than half those of a coal-fired power plant, and it is necessary to introduce

LNG-fired power plants in place of coal-fired power plants at an early stage as one of the immediate means to reduce CO_2 emissions.
Based on this perspective, we recommend the following items to be implemented for the full-scale introduction of LNG.

(a) **Policy development to promote LNG introduction in Indonesia**
Develop policies that contribute to the promotion of LNG introduction, such as the abolition of preferential acceptance of domestic LNG.

(b) **Development of LNG master plan**
A survey of the optimal locations for the construction of LNG receiving terminals and thermal power plants should be conducted based on the future vision of Indonesia's grid and pipelines, and this should be compiled as a master plan.

(c) **Feasibility study for fuel conversion to hydrogen in existing LNG-fired plants**
Select an existing LNG power plant in Indonesia and conduct a feasibility study on whether the existing infrastructure at the LNG power plant can continue to be used after the transition to hydrogen.

5.2 Possibility of using Hydrogen and Ammonia as Fuel

This section summarizes the potential of hydrogen and ammonia, which are being researched and developed internationally as next-generation clean fuels that do not emit CO_2 during combustion in coal- or gas-fired power plants. It includes an analysis of the current status and potential regarding the hydrogen and ammonia markets; an analysis of the costs of hydrogen and ammonia for production, storage, and transportation; and policy recommendations for the introduction of hydrogen and ammonia. The cost analysis is conducted for the forecast period of 2031 to 2060 for both blue and green hydrogen and ammonia, and is reflected as input data for thermal power plant fuel in the supply-demand operation simulation (PDPAT).

5.2.1 Current Status and Potential Analysis of Hydrogen/Ammonia Market

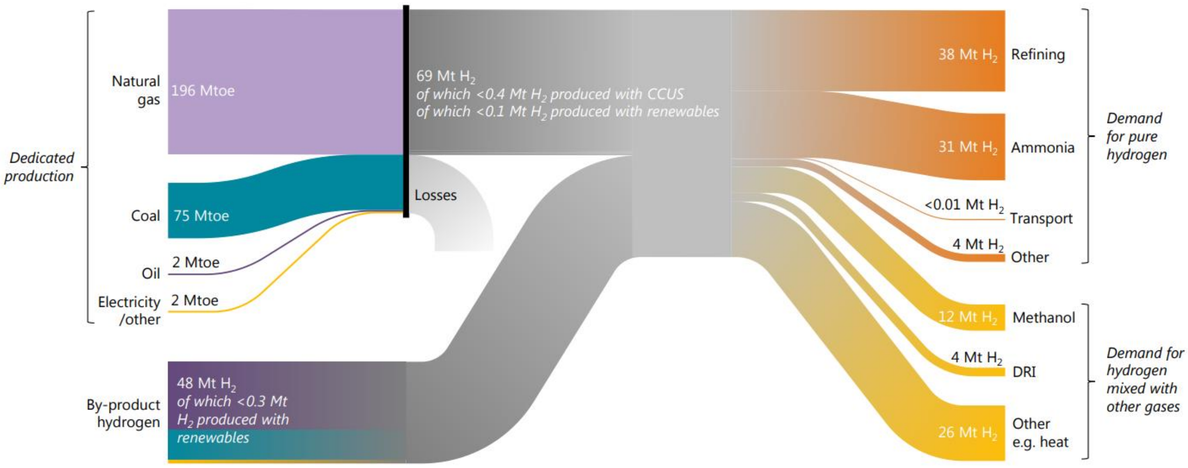
This section summarizes the current status and future potential of the hydrogen and ammonia markets in Indonesia.

(1) Hydrogen Market

In the hydrogen production process, about 60% of the total hydrogen is produced from fossil fuels, such as natural gas and coal, in dedicated hydrogen production facilities, and the remaining 40% is produced as part of the by-product gas generated in industrial processes. The amount of hydrogen produced by water electrolysis is very small (about 0.7%).

Hydrogen is currently used mainly for desulfurization in the oil refining process, as an additive in the steel making process, and as a raw material for ammonia and methanol, most of which is consumed in-house in each industrial plant. As a result, the global production of hydrogen, including by-product gas, is about 115 million tons, but the market volume is very small, at less than 10,000 tons.

An overview of the hydrogen value chain on a global scale is shown below.

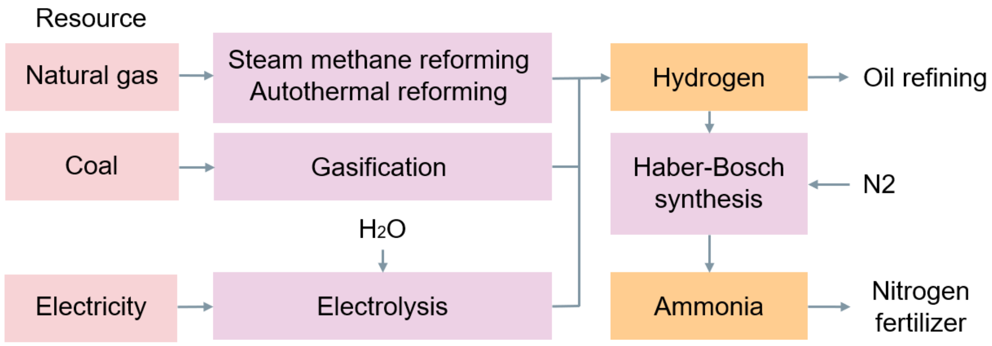


(Source: IEA, The future of Hydrogen - Seizing today's opportunities 2019)

Figure 5-41 Hydrogen value chain

Ammonia is produced by synthesizing hydrogen and nitrogen separated from the air using the Haber-Bosch process. Other than as a by-product gas, hydrogen is produced via three methods: 1) steam methane reforming (SMR) or autothermal reforming (ATR) using natural gas as raw material, 2) partial oxidation via coal gasification, and 3) hydrogen production via water electrolysis. In general, the Haber-Bosch process requires high temperature and high pressure conditions of 400-600°C and 20-100MPa, so ammonia production requires a lot of energy.

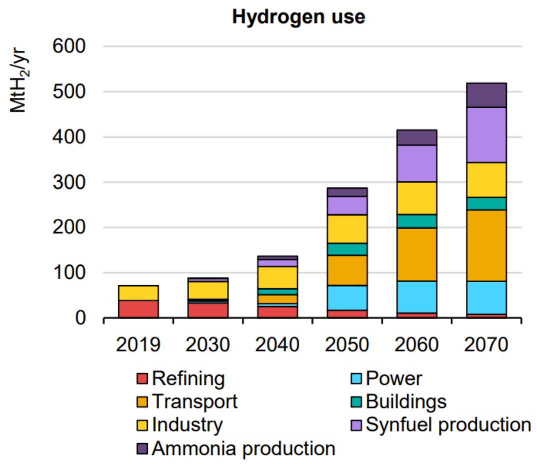
The general production flow for hydrogen and ammonia is shown below.



(Source: JICA Survey Team)

Figure 5-42 Hydrogen/Ammonia production flow

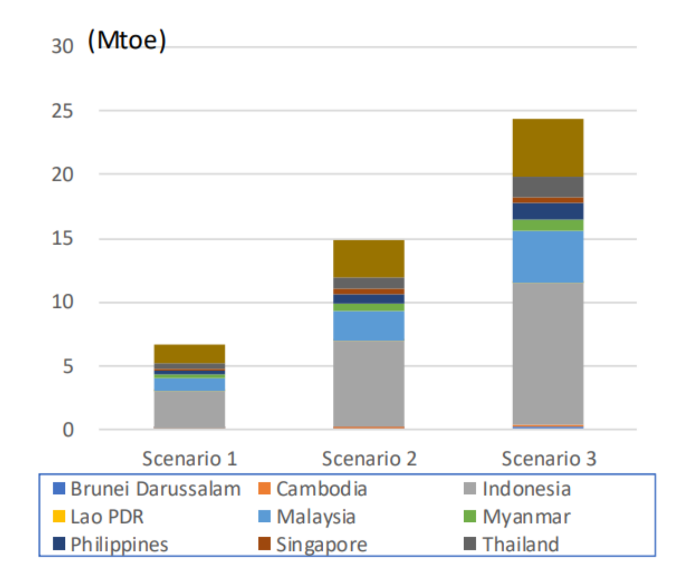
According to the IEA, global demand for hydrogen is expected to expand exponentially over the next 30 years, doubling in 2040 and quadrupling in 2050 compared to 2019, as the world moves toward decarbonization. Hydrogen demand trends are shown below.



(Source: IEA, Energy Technologies Perspectives 2020)

Figure 5-43 Trends in hydrogen and hydrogen-related demand in each sector

The Economic Research Institute for ASEAN (ERIA) has released the results of scenario-based calculations on the potential demand for hydrogen in Southeast Asian ASEAN countries. In Scenario 1, which replaces 10% of electricity demand with hydrogen, the demand potential is about 3 Mtoe (about 1 million tons of hydrogen). In Scenario 3, where 30% of electricity demand is replaced by hydrogen, the demand potential is about 11 Mtoe (about 3.8 million tons of hydrogen).
The following are the results of an estimation of the hydrogen demand potential of ASEAN countries for each scenario in 2040.



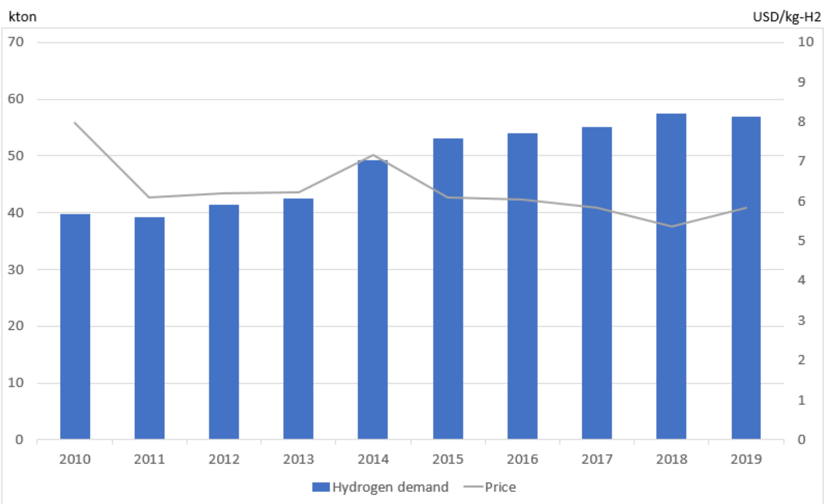
※Mtoe: million tons of oil equivalent

(Source: ERIA, Demand and Supply Potential of Hydrogen Energy, 2018)

Figure 5-44 ASEAN's hydrogen demand potential in 2040

Demand in Indonesia is estimated to be about 60 kilo tons in 2019, with a trading price of about 6 USD/kg-H_2.

The following table shows the evolution of hydrogen demand and transaction prices in Indonesia from 2010 to 2019.

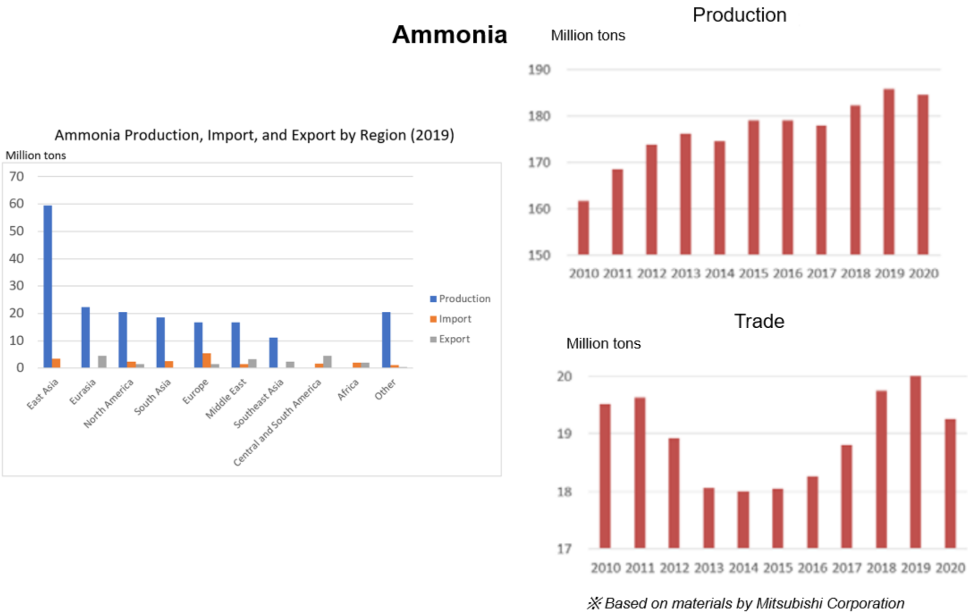


(Source: JICA Survey Team based on INDEXBOX AI Platform)

Figure 5-45 Hydrogen demand and price in Indonesia

(2) Ammonia Market

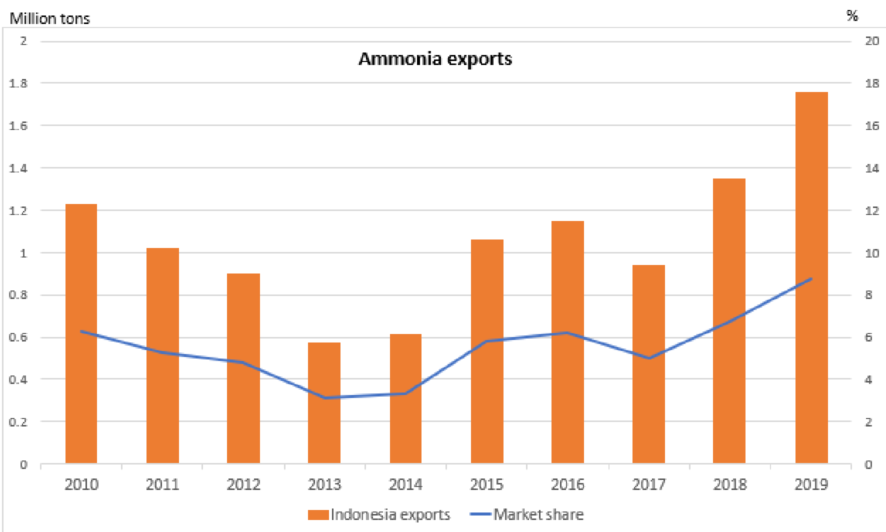
The world's total ammonia production was about 185 million tons per year in 2019, with more than 80% of the total mainly for chemical fertilizers such as urea and ammonium sulfate. Compared to hydrogen, ammonia is already well established as a commercial stream, but most of it is produced and consumed locally, with its volume of distribution in trade being about 11% of the total (about 20 million tons). The following table shows ammonia production and trade volumes by region and their trends.



(Source: JICA Survey Team based on METI, Interim Report of the Public-Private Council on Fuel Ammonia Introduction, 2021)

Figure 5-46 Trends in Ammonia Production and Trade by Region

Indonesia is the world's third-largest exporter of ammonia after Russia and Trinidad and Tobago, and has an ammonia production capacity of about 7 million tons per year, with domestic consumption of about 1.6 million tons per year and exports of about 1.8 million tons per year. This means that the utilization rate of ammonia plant facilities is about 50%. Based on this, it can be inferred that Indonesia's current production capacity is relatively ample.
The following table shows the volume of ammonia exports from Indonesia and Indonesia's share of total world exports.



(Source: JICA Survey Team based on materials by IFA)

Figure 5-47 Trends in ammonia export volume

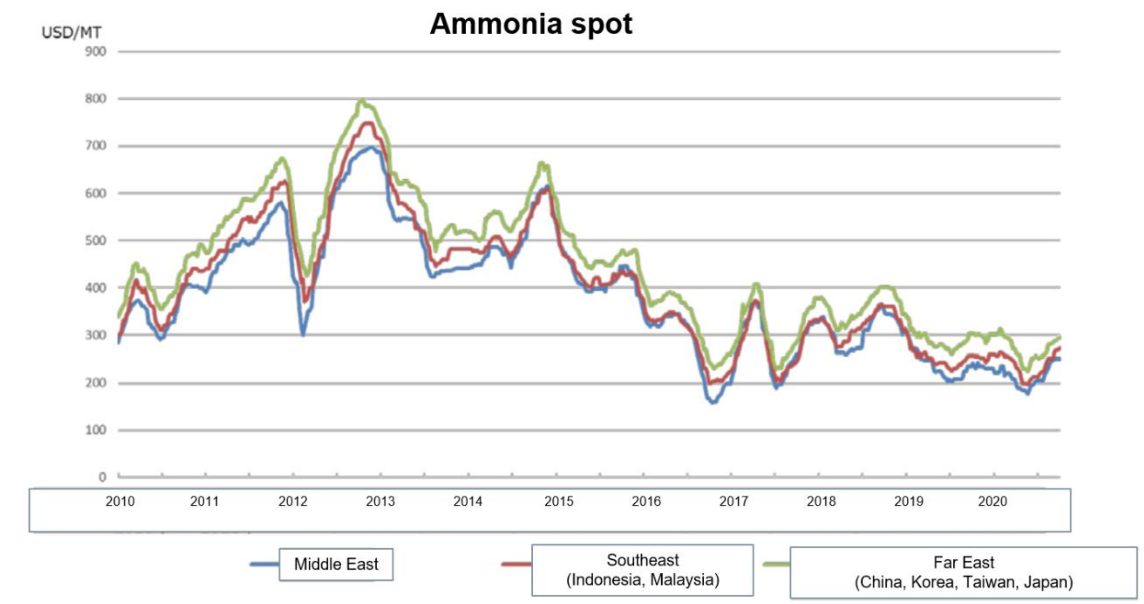
Ammonia market prices can be categorized based on the export port or demand location on the manufacturing country side.

- Export ports: Caribbean (Trinidad and Tobago), Black Sea (Russia), Middle East, Southeast Asia (Indonesia, Malaysia)
- Place of demand: CFR* Europe, CFR US, CFR India, CFR Far East (China, Korea, Taiwan, Japan)

*CFR (Cost and Freight: Condition including freight)

Since raw material costs account for a large portion of ammonia production costs, competitiveness is considered to be determined almost entirely by raw material costs. In addition, ammonia market prices are correlated with crude oil prices and are therefore characterized by a high degree of volatility. The market price of ammonia from Southeast Asia (Indonesia and Malaysia) averaged about 579 USD/ton (about 3.2 USD/kg-H_2 in hydrogen equivalent) from 2011 to 2015 and about 316 USD/ton (about 1.8 USD/kg-H_2 in hydrogen equivalent) from 2016 to 2020.

The following table shows the trend of ammonia market prices.



(Source: METI, Interim Report of the Public-Private Council on Fuel Ammonia Introduction, 2021)

Figure 5-48 Ammonia Market Price Trends

5.2.2 Hydrogen/Ammonia Cost Analysis (Supply, Storage, and Transportation)

In this section, we first clarify the definitions of each of the four types of so-called blue and green hydrogen/ammonia. We also summarize the characteristics of the currently promising hydrogen carriers and select the most suitable carrier for this analysis. In addition, future projections for the procurement costs of blue and green hydrogen and ammonia in Indonesia, assuming that they will be introduced after RUPTL 2021-2030, will be made from 2031 to 2060 under certain assumptions, and will be reflected as input data for thermal power plant fuel in the supply and demand operations simulation (PDPAT).

(1) Blue and Green Hydrogen/Ammonia

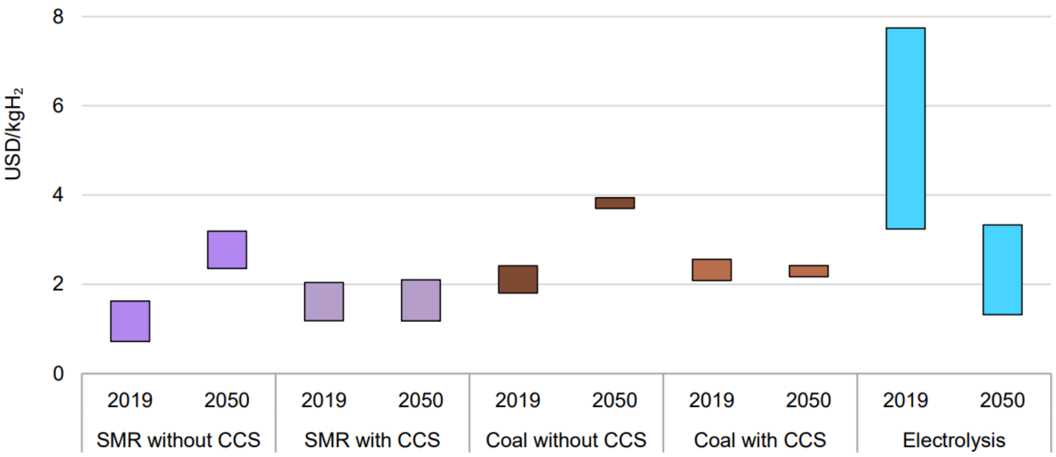
For the purposes of this section, the definitions for blue and green hydrogen, and ammonia shall be as follows. The feedstock for blue hydrogen and ammonia production shall be natural gas. The production process for blue hydrogen and ammonia is steam reforming (SMR, ATR), a technology that has already been established and is widely used in oil refineries. The input power sources for the water electrolysis equipment necessary for green hydrogen and ammonia production will be solar power and onshore wind power, which are expected to become the main power sources in the future as large-scale development is promoted in Indonesia.

Table 5-12 Definition of blue and green hydrogen/ammonia

Blue Hydrogen	・Resource：Natural gas ・Production：SMR or ATR＋Purification ・CO_2 capture rate：90%
Blue Ammonia	・Resource：Natural gas ・Production：SMR or ATR＋Haber-Bosch ・CO_2 capture rate：90%
Green Hydrogen	・Electricity resource：Solar/Onshore wind ・Production：Water electrolysis
Green Ammonia	・Electricity resource：Solar/Onshore wind ・Production：Electrolysis＋Haber-Bosch

(Source: JICA Survey Team)

However, it is estimated that the production costs are about 1.5 times higher, and the CO_2 emissions about 1.7 times higher, than the steam reforming method using natural gas. Therefore, coal gasification via partial oxidation and hydrogen production via CO_2 separation and recovery are not included in this study.
The IEA's comparison of hydrogen production costs by energy source is shown in the figure below.



(Source: IEA, Energy Technologies Perspectives 2020)

Figure 5-49 Comparison of hydrogen production costs by energy source (2019 vs 2050)

(2) Hydrogen Carrier

Hydrogen generates 121 MJ/kg of energy when combusted, but its density under standard conditions (0°C, 0.1 MPa) is 0.089 kg/m^3, which means that the energy per volume is 10.8 MJ/m^3. The issue is that the volumetric energy density is very small: about 25% compared to the 40 MJ/m^3 of natural gas and about 0.03% compared to the 33,000 MJ/m^3 of gasoline.
Therefore, in order to utilize hydrogen energy in the future, research and development of efficient and economical hydrogen carriers, especially for the storage and transportation of hydrogen, is being promoted internationally.

Typical types of hydrogen carriers that are currently considered promising and their characteristics are as follows.

Table 5-13 Typical types of hydrogen carriers and their characteristics

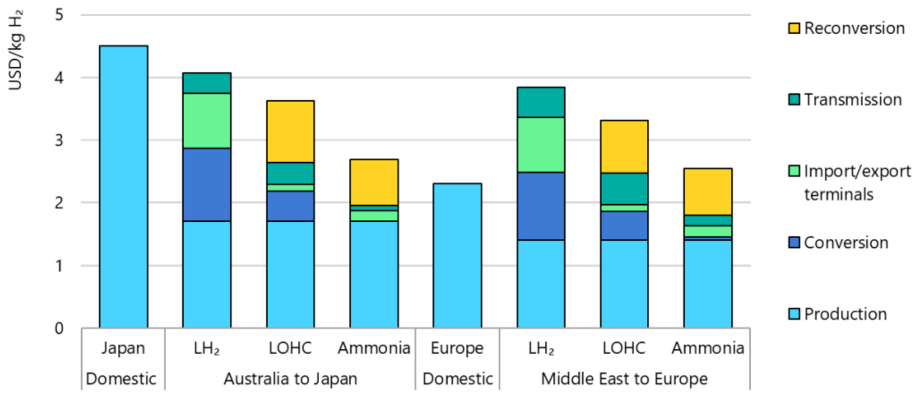
Carrier	Boiling Temp. ℃	Hydrogen Density kg-H_2/m^3	Hydrogen Desorption kJ/mol-H_2	Pros / Cons
Liquefied Hydrogen	-253	70.8	0.90	Pros • High H_2 purity (suitable for FC) Cons • Challenges in BOG process • Not suitable for long-term storage
MCH※1 (LCOH※2)	101	47.0	67.5	Pros • Synergy with existing oil infrastructure • Suitable for long-term storage Cons • Toluene loss occurs
Ammonia	-33.4	121	30.6	Pros • Existing technologies and markets available • Synergy with coal-fired power Cons • Low H_2 purity (not suitable for FC)

※1 MCH : Methylcyclohexane
※2 LCOH : Liquid Organic Hydrogen Carrier

(Source: JICA Survey Team)

Since each hydrogen carrier has its own advantages and disadvantages, it is possible that different types of hydrogen carriers will be used for different purposes, such as for FCs or large-scale thermal power generation. The promising hydrogen carriers are expected to change in the future due to technological progress, such as improved efficiency, and economies of scale as the market volume expands.

The following figure shows a cost comparison by hydrogen carrier in 2030.



(Source: IEA, Global Hydrogen Review, 2021)

Figure 5-50 Cost comparison by hydrogen carrier in 2030

In addition, ammonia is expected to be introduced as an early low-carbon fuel in the power generation sector, since it can be directly combusted into existing coal-fired boilers.

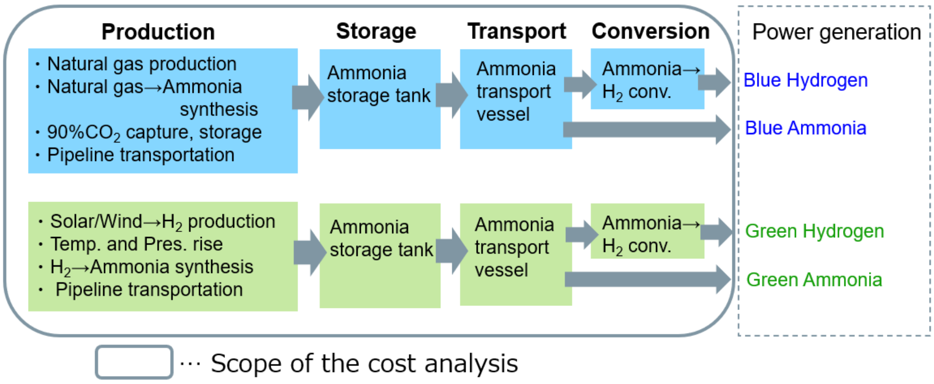
Therefore, in this section, ammonia will be considered as the hydrogen carrier for storage and transportation, unless otherwise specified.
For details on ammonia co-firing technology for coal-fired power plants, please refer to Section 5.1.2.

(3) Hydrogen/Ammonia Procurement Cost Analysis

(a) Scope of the Cost Analysis

The procurement cost analysis method for blue and green hydrogen/ammonia is essentially based on reliable literature, such as studies by IEA, NEDO, Institute of Energy Economics Japan (IEEJ), Institute of Energy Efficiency (IAE), and other government-related organizations. Projections and analysis of the procurement costs in Indonesia from 2031 to 2060 will be conducted by the JICA survey team based on such reliable literature.

The hydrogen and ammonia cost analysis scope is as follows.



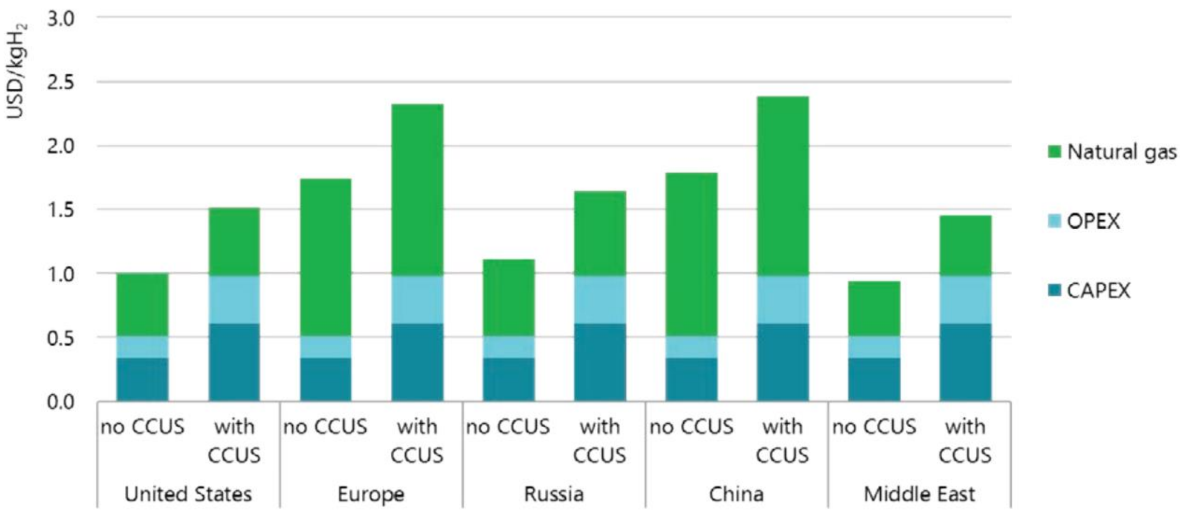
(Source: JICA Survey Team)

Figure 5-51 Scope of hydrogen/ammonia procurement cost analysis

(b) Production Cost Assumptions

The production costs in this section include not only hydrogen production but also ammonia synthesis and pipeline transportation to ammonia storage tanks.

The cost of producing blue hydrogen using natural gas by country/region is shown in the figure below.



(Source: IEA, The future of Hydrogen - Seizing today's opportunities 2019)

Figure 5-52 Cost of producing blue hydrogen using natural gas by country across the world

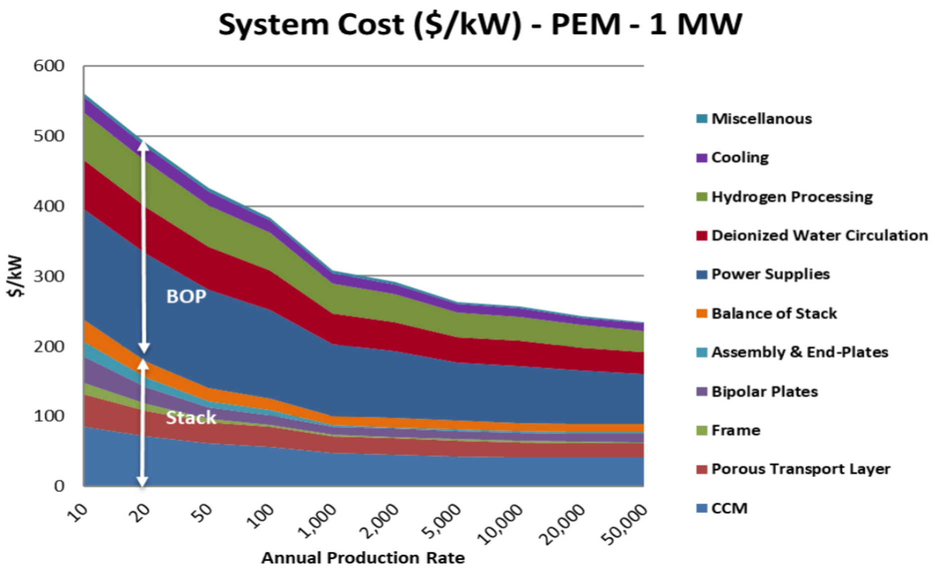
The production cost of blue hydrogen depends largely on the price of natural gas, which is the raw material, and the natural gas cost accounts for 30-60% of the production cost with CCUS. The

production cost of green hydrogen depends largely on the cost of renewable energy generation and the cost of hydrogen production equipment using water electrolysis.
The cost of producing blue and green hydrogen and ammonia is a significant item, accounting for about 60% of the total supply chain cost.
Therefore, in the production cost analysis, corrections for the following items shall be reflected in the cost projections. The inflation rate is not taken into account.

- Blue hydrogen/ammonia: natural gas price
- Green hydrogen/ammonia: renewable energy power generation price, and cost of hydrogen production equipment using water electrolysis

The price of natural gas is assumed to be for gas produced domestically in Indonesia without going through an LNG plant, and will be set by the JICA survey team with reference to RUPTL 2021-2030 and market research information. The same applies to the renewable energy price in Indonesia. The details are described in Chapter 6.

The price of the hydrogen production system using water electrolysis will be set based on the hydrogen introduction potential in Indonesia (Section 5.2.1) and the results of the cost projection for the mass production of 1 MW solid polymer (PEM: Polymer Electrolyte Membrane) shown below.



(Source: NREL, Manufacturing Cost Analysis for Proton Exchange Membrane Water Electrolyzers, 2019)

Figure 5-53 Production cost of a 1MW proton exchange membrane water electrolysis system (PEM)

(c) Storage Cost Assumptions

Storage costs refer to the cost of ammonia storage tanks, ammonia vaporizers, and other auxiliary facilities such as piping. The scale of the project is assumed to be about 1.2 million tons per year (about 225,000 tons of hydrogen equivalent). The plant is assumed to have an ammonia processing capacity of about 5,300 tons per day (about 1,000 tons per day in hydrogen equivalent), and the storage tank is assumed to have a storage capacity of about 60,000 tons of ammonia (about 11,000 tons in hydrogen equivalent) (enough for about 11 days).

(d) Transportation Cost Assumptions

Transportation costs are the cost of the equipment used to transfer ammonia from the storage tanks to the carriers, as well as the cost of chartering and fueling the carriers. The ammonia carriers will use very low sulfur fuel oil (VLSFO) as fuel.

The assumed transport capacity is about 60,000 tons of ammonia (about 11,000 tons of hydrogen equivalent).

(e) Carbon Cost Assumptions

In each process other than the green hydrogen production process, grid electricity and fossil fuels are used as necessary energy. Therefore, as long as the grid power uses fossil fuels, CO_2 will be emitted. The carbon costs are the costs calculated by adding the assumed carbon price imposed on the total amount of CO_2 emitted across the entire supply chain.

(4) Assumptions in Cost Analysis

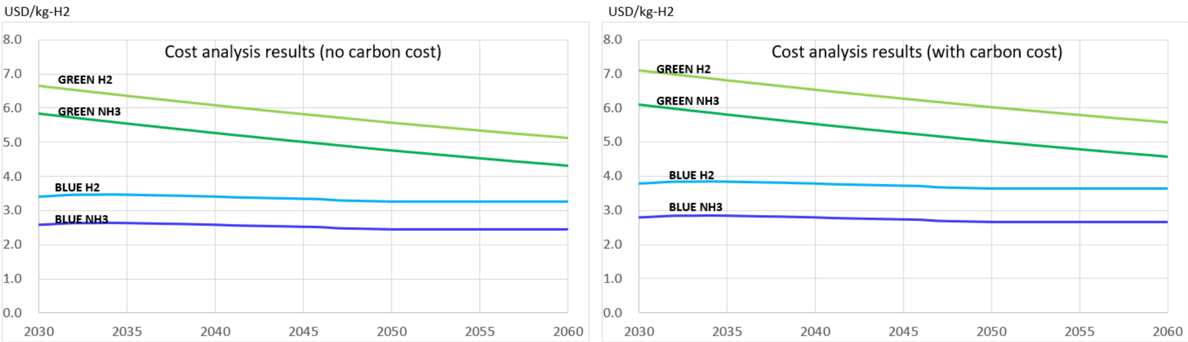
The various assumptions used for the cost analysis in this section are summarized as follows. Other assumptions were made by the JICA survey team after referring to materials published by IEA, NEDO, IEEJ, and IAE.

Table 5-14 Assumptions in cost analysis

Item	Value set	Basis
Natural gas costs	Refer to Chapter 6.	Refer to Chapter 6.
LCOE of solar	Refer to Chapter 6.	Refer to Chapter 6.
LCOE of onshore wind	Refer to Chapter 6.	Refer to Chapter 6.
Ratio of solar and wind power generation to total renewable energy	Solar: 95% Onshore wind: 5%	JICA Survey Team
Cost of water electrolysis equipment	900 USD/kW (2021) 285 USD/kW (2060)	JICA Survey Team based on IEA 2019, and NREL
Carbon costs (Carbon price)	40 USD/t-CO_2	JICA Survey Team
CO_2 emission intensity of grid electricity	0.75 kg-CO_2/kWh (2030)	RUPTL 2021-2030

(5) Results of Cost Analysis

Blue and green hydrogen and ammonia procurement costs are shown below. For comparison, ammonia is also converted on a per-kg-H_2 basis.



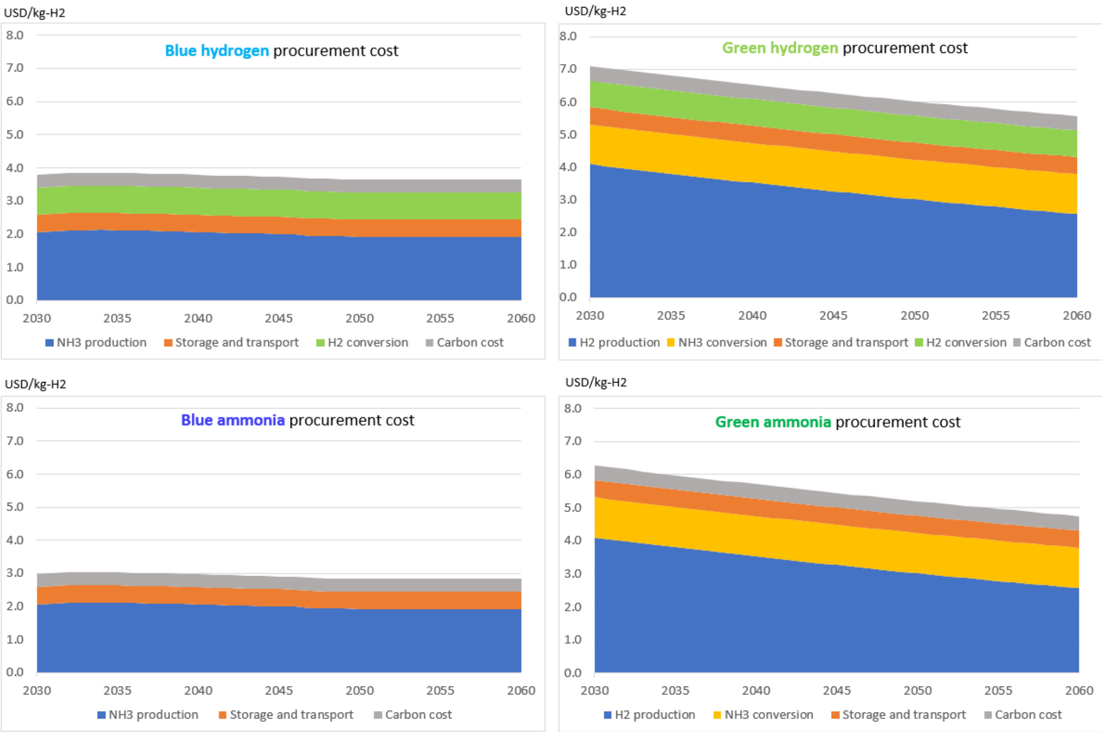
(Source: JICA Survey Team)

Figure 5-54 Procurement costs for blue and green hydrogen and ammonia

Regardless of the presence or absence of carbon costs, the results show that blue is more cost effective than green for both hydrogen and ammonia.

In addition, the procurement cost of hydrogen was about 20-30% higher than that of ammonia due to the conversion process from ammonia to hydrogen required.

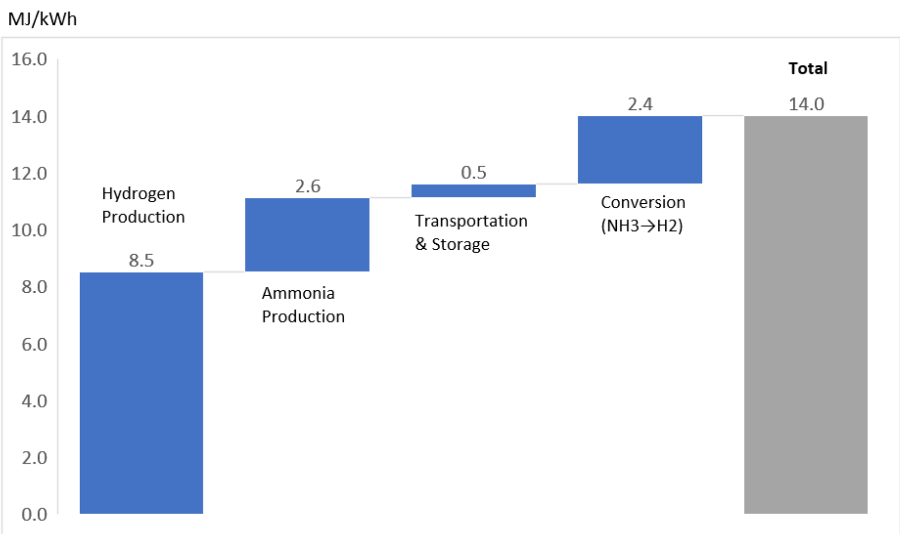
For each procurement cost (with carbon cost), a cost breakdown of production, storage/transportation, hydrogen conversion (end use is hydrogen only), and carbon costs is shown below.



(Source: JICA Survey Team)

Figure 5-55 Breakdown of procurement costs

When considering storage for a certain period of time, as in this study, green hydrogen and green ammonia require a large amount of energy for the conversion of hydrogen to ammonia.
Blue hydrogen and green hydrogen also require a large amount of energy for the conversion of ammonia to hydrogen.
The following figure shows the amount of energy required for blue hydrogen and ammonia production (for 1 kWh of power generation).



(Source: JICA Survey Team based on NEDO, Technology Assessment and Analysis of Energy Carrier Production, Transportation and Storage, and Utilization Overview, 2019)

Figure 5-56 The amount of energy required for fuel production to generate 1 kWh of electricity

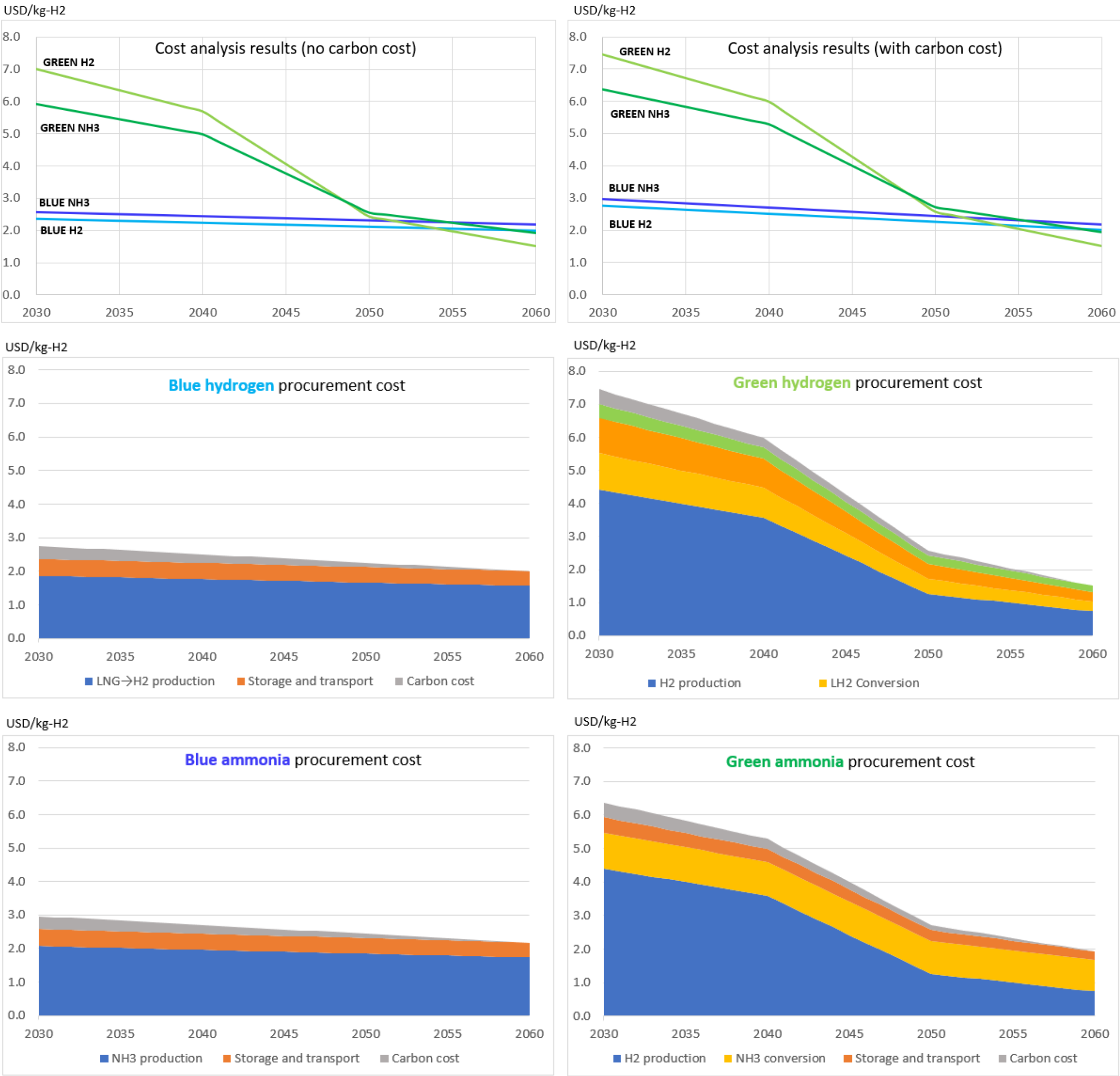
(6) Cost reduction options

There are various views on long-term cost reductions for hydrogen and ammonia, including those published by the IEA, IRENA, and governments of various countries. There is a very high possibility that costs will be significantly reduced in the future. Therefore, the following modified conditions, which take these factors into account to the maximum extent possible, are applied to predict the options for reducing the procurement costs of hydrogen and ammonia.

Table 5-15 Change conditions for cost reduction options

Item	Set value	Basis
Blue Hydrogen Storage	LNG	JICA Survey Team
Green Hydrogen Storage	Liquefied hydrogen	JICA Survey Team
LCOE of solar	Surplus power from 2040, reduced to 10% of current level by 2050	JICA Survey Team
LCOE of wind	Surplus power from 2040, reduced to 10% of current level by 2050	JICA Survey Team
Cost of water electrolysis equipment	2060: 100 USD/kW	JICA Survey Team based on IRENA
Carbon cost (carbon price)	2060: 0 USD/t-CO_2	JICA Survey Team
CAPEX, OPEX for blue fuel	Reduce to 85% or 50% from 2021, depending on the technology readiness level	JICA Survey Team based on IEA and GCCSI
CAPEX, OPEX for green fuel	Reduce to 85% or 40% from 2021, depending on the technology readiness level	JICA Survey Team based on IEA and IRENA

The blue and green hydrogen and ammonia procurement costs for the cost reduction option are shown below.



(Source：JICA Survey Team)

Figure 5-57 Procurement costs for blue / green hydrogen and ammonia (cost reduction option)

Taking maximum future cost reduction options into account, a cost reversal between blue and green is expected to occur after 2050, and the cheapest hydrogen in 2060 will be green hydrogen from surplus renewable energy (about 1.5 USD/kg- H_2).
On the other hand, blue hydrogen and ammonia will be cheaper until 2050, which will contribute to the early establishment of hydrogen and ammonia supply chains.

5.2.3 Proposals for the Introduction of Hydrogen and Ammonia

Proposals for the introduction of hydrogen and ammonia are arranged based on the following objective, facts and assumptions.

- Objective: To achieve carbon neutrality in the Indonesian electricity sector by 2060
- Facts and assumptions:
  - ✓ The price of blue hydrogen/ammonia in Indonesia is high due to the high price of domestic natural gas.

Importing blue hydrogen/ammonia from cheaper countries should be promoted. At the same time,

producing green hydrogen/ammonia using domestic renewable energy should be introduced.

  - ✓ Indonesia is the world's largest exporter of ammonia.
  - ✓ Indonesia is the third largest ammonia exporter in the world.

The full-scale introduction of domestic green hydrogen/ammonia requires a large amount of renewable energy and its surplus electricity to reduce costs.

(1) Support for building the entire ammonia supply chain

The entire ammonia supply chain will need to be established in the future, and support should be provided for the institutional design, upstream development, handling of marine transportation, and other knowledge required to establish the supply chain.

(2) FS and demonstration test for ammonia co-firing at coal-fired power plants

At present, coal-fired power generation is the main power source in Indonesia, but to reduce CO_2 emissions, it will be necessary to decommission aging plants as soon as possible, starting with the least efficient ones. In order to gradually reduce CO_2 emissions while securing a stable supply in the system, it will be effective to retrofit these coal-fired thermal power plants as ammonia mixed combustion and exclusive combustion plants.

In order to realize the mixed combustion of ammonia in existing coal-fired power plants, it is necessary to comprehensively examine facility retrofitting, fuel procurement, operability and economic efficiency. To carry out these studies efficiently, the cooperation of manufacturers of existing facilities and power generation companies with mixed combustion experience is required. Many Japanese companies are involved in the latest USC coal-fired IPP project in Indonesia, and it is easy to obtain cooperation in co-firing and future exclusive firing. Therefore, it would be effective to select a pilot plant from these and provide support for advancing FS and demonstration tests.

(3) Expansion of existing ammonia production in Indonesia

As shown in the previous section, the consumption of ammonia is expected to increase as more facilities implement ammonia co-firing in the future, and it is necessary to expand the ammonia production volume in Indonesia. In order to reduce the cost of ammonia, operational and technical support should be provided, aimed at improving natural gas productivity and manufacturing plant productivity.

(4) Introduction of new hydrogen/ammonia production technologies

For the production of hydrogen and ammonia, it is essential to introduce new production technologies to reduce costs in addition to the current production methods. Support should be provided for the introduction of new synthetic catalysts to be developed in the future that will lead to cost reductions, and other new technologies such as hydrogen production from waste plastics.

(5) Introduction of green hydrogen/ammonia production technologies

The procurement cost of green hydrogen/ammonia depends on the price of electricity from renewable energy sources and the price of water electrolysis equipment. Therefore, it is expected that a certain amount of cost-competitive hydrogen/ammonia will be introduced by utilizing surplus electricity from the future large-scale deployment of renewable energy (solar and wind).

On the other hand, there are many issues that need to be solved before the introduction of the system, such as unstable production volumes due to load fluctuations of renewable energy, improvement of efficiency and durability of water electrolysis equipment, and operational measures including safety during transportation and storage of hydrogen and ammonia. In particular, the instability of the production volume due to the dependence on surplus electricity for hydrogen production will increase the necessity of restraining initial investment, and it will be particularly important to construct a system for local production for local consumption that fully takes into account the climatic conditions of Indonesia.

Therefore, we believe that conducting an FS and demonstration test for the small-scale production of green hydrogen and ammonia using renewable energy in Indonesia at an early stage, while sharing the technical knowledge obtained by Japanese companies through previous projects (including future plans), will enable us to identify specific issues early on, and contribute to the introduction of efficient hydrogen and ammonia utilization systems in the future.

(6) FS and Demonstration Tests for Hydrogen Introduction at GTCC Thermal Power Plants

GTCC thermal power plants are one of the major power sources in Indonesia, in addition to conventional power plants, but from now on, aging and inefficient plants will be retired in order to reduce CO_2 emissions. It will be effective to change these GTCC thermal power plants to hydrogen co-firing and exclusive firing plants in order to gradually reduce CO_2 emissions while securing a stable energy supply in the system.

In order to realize the mixed combustion of hydrogen in existing GTCC thermal power plants, it is necessary to comprehensively examine facility retrofitting, fuel procurement, operability and economic efficiency. To carry out these studies efficiently, the cooperation of manufacturers of existing facilities and power generation companies with mixed combustion experience is required. A gas turbine with a suitable size for the hydrogen co-firing demonstration test and a power plant with a suitable location should be selected from among the GTCC thermal power plants as a pilot plant, and support for the FS and demonstration test should be provided. This will contribute to the decarbonization of Indonesia in the future.

(7) FS and demonstration test for ammonia combustion at GTCC thermal power plants

Ammonia is expected to become cheaper than hydrogen in the future, and when considered as an imported fuel, it is assumed that hydrogen will also be transported in the form of ammonia because of its ease of transport. Therefore, if ammonia can be burned directly in GT, it may be more economical than burning hydrogen. Support for FS and demonstration tests should be provided for ammonia co-firing and ammonia exclusive firing in the existing GTCC power plants.

5.3 CCUS

5.3.1 Current Status of CCUS

(1) Carbon dioxide capture and storage (CCS)

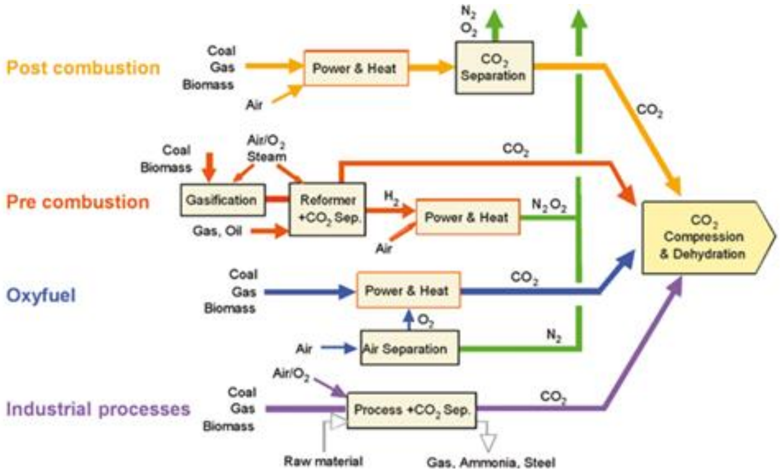
Carbon dioxide capture and storage (CCS) is a technology consisting of capturing CO_2 from sources (e.g. fossil fuel combustion, chemical manufacturing processes), transporting CO_2 to a storage site, and sequestering it from the atmosphere.

Although there are some negative emission technologies (DACCS and BECCS) and CCS for small mobile emission sources such as vehicles and ships, this study mainly focuses on CCS for large-scale emission sources, such as thermal power plants.

(2) CO_2 capture technology

The four main types of CO_2 capture systems are as follows:

- Post-combustion: Capture from the exhaust gas.
- Pre-combustion: The fuel is not directly combusted but is oxidized by oxygen (or air), and then hydrogen is used as fuel through a CO shift reaction ($CO + H_2O \rightarrow H_2 + CO_2$).
- Oxyfuel: Use of oxygen instead of air during combustion (exhaust gas mostly consists of CO_2)
- Capture from industrial processes: Capture processes in natural gas refining, ammonia production, cement production, steel industry, etc. The technology is the same as the above three, but the applicable conditions are different.



Source: IPCC (2005)[11]

Figure 5-58 Main types of CO_2 capture systems

The types and characteristics of the capture technologies applied in the CO_2 capture system are as follows:

- Chemical absorption: CO_2 is separated by a chemical reaction using an absorbing aqueous solution. Amine solvents have a long track record and have been demonstrated on a commercial scale in CCS.
- Physical absorption: A technology that utilizes vapor-liquid equilibrium. The flue gas is brought into contact with a liquid, which physically absorbs CO_2 under high pressure and low temperature. Then the liquid is decompressed or heated to recover the CO_2. This technology has been technically established in wet desulfurization.
- Physical adsorption: CO_2 is adsorbed on a solid adsorbent such as activated carbon or zeolite, and CO_2 is desorbed by decompression or heating. There are a PSA method using pressure swing and TSA method using temperature difference.
- Membrane separation: CO_2 is separated by applying pressure difference to a polymer membrane. This is theoretically the most energy-efficient CO_2 separation process. Research and development

[11] IPCC (2005), IPCC Special Report on Carbon Dioxide Capture and Storage.

are being conducted for membrane materials with excellent selectivity and permeation rate around the world.

- Low-temperature separation process: This is used to separate and recover CO_2 from ammonia and hydrogen production byproduct gases with high CO_2 concentrations. The resulting CO_2 is distributed in the market.
- Oxyfuel combustion: In this process, the gas is combusted with oxygen instead of air so that almost all exhaust gas is recovered as CO_2.
- Chemical loop combustion: In this process, oxidation and reduction of metals are used. Since the oxygen in the air is supplied to the fuel reaction system using metal as a medium, the air and fuel do not mix directly, and the exhaust gas is only CO_2 and H_2O (water vapor).

The advantages and disadvantages of each technology are shown in Table 5-16.

Table 5-16 Advantages and disadvantages of CO_2 capture technologies

Method		Principle	Driving force	Advantages	Disadvantages
Chemical absorption		Chemical reaction	Temperature difference	· Suitable for low partial pressure gases · Low affinity for hydrocarbons · Suitable for large volumes	· Absorbing liquid is expensive · Corrosion, erosion, and foaming · Limited range of applications · Requires a heat source for regeneration
Physical absorption		Physical absorption	Partial pressure difference (Concentration difference)	· Suitable for high partial pressure gas · Wide range of application · Less corrosion, erosion, and foaming · No regenerative heat source is required	· Absorbent is expensive · High affinity for heavy hydrocarbons
Physical adsorption	PSA	Adsorption	Partial pressure difference (Concentration difference)	· High purity purification is possible · Relatively simple equipment · Wide range of applications	· Requires regeneration gas · High affinity for moisture
	TSA	Adsorption	Temperature difference	· High purity purification is possible. · Wide range of applications	· The amount of adsorbent and the equipment is large. · Adsorbent cost is high. · Heat source for regeneration is required
Membrane separation		Permeation	Partial pressure difference (Concentration difference)	· Simple · Low cost · Suitable for small volumes	· Low purity · High operating costs · Not suitable for large volumes · Susceptible to oil and fat-containing gases
Low temperature separation process		Liquefaction Distillation	Phase change	· High purity purification · Suitable for large capacity	· Complex equipment · High construction costs · High cost of operation
Oxyfuel combustion		Air separation	Temperature difference	· High purity purification	· Large air separation equipment · Power required for air separation equipment
Chemical loop combustion		Air separation	Temperature difference	· Low energy consumption	· The durability of the device is an issue.

Source: MOE (2014)[12]

[12] Ministry of Environment (MOE) (2014), Report on FY 2013 Feasibility Study on a Bilateral Credit System Using CCS by Shuttle Ship.

The list of emission sources and their suitable capture technologies are shown in Table 5-17. Suitable methods differ depending on the purity and pressure of the CO_2 emitted.

Table 5-17 Suitable capture technologies for each emission source

	CP	IGCC	Cement	Iron & Steel	Petroleum refining & Chemical industry		Natural Gas
Pressure /CO_2 concentration	AAP/ 10-15%	2.5-4.0MPa/ 40-50%	AAP/ 15-30%	AAP/ 20-30%	AAP/ 5~20%	AAP-4.0MPa/ 10-100%	7.0-10MPa/ 10-70%
Process	Post	Pre	Post	Blast furnace gas, Hot air furnace, Post	Heating furnace, Post	Hydrogen production, Ammonia production, Pre	Natural gas refining, Pre
Suitable capture methods	Cab Sab Pad	Cab Pab Sab Pad M	Cab Sab Pad	Cab Sab Pad	Cab Sab Pad	Cab Pab Sab Pad M	Cab Pab Sab Pad M

*CP=Coal-fired power generation, AAP=Atmospheric air pressure, Post=Post-combustion, Pre=Pre-combustion, Cab=Chemical absorption, Pab=Physical absorption, Sab=Solid absorption, Pad=Physical adsorption, M=Membrane separation

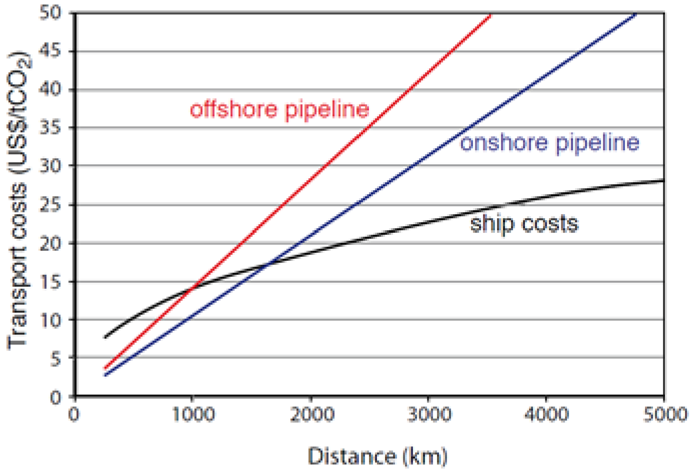
Source: NEDO (2020)[13]

Introducing a CO_2 capture system into a thermal power generation system reduces the power generation efficiency. The main reason for the decrease in efficiency is the energy consumption due to the heat supply and steam required to regenerate the absorption solvent, other pumps and fans, and CO_2 compression.

(3) CO_2 transport technology

Pipelines and ships are the main means of transporting CO_2 to a storage site. Transport by pipelines is a technology that has already been implemented. For example, in the US, long-distance CO_2 pipelines have been laid to over 7,600 km, and CO_2 is being transported[14].
Liquefied petroleum gas (LPG) and various fuel gases are commonly transported by ships, but CO_2 is not transported by ships on a large scale due to the low demand for CO_2. Since the physical properties of LNG are similar to that of CO_2, it is possible to apply existing ship transport technologies to CO_2.
In addition, it is said that ship transport is more cost-effective than pipeline transport for long-distance transport over 1,000 km to 2,000 km. Figure 5-59 shows the relationship between transport distance and costs. The costs include temporary storage facilities, port facility usage fees, fuel costs, loading and unloading operations, and liquefaction costs.

[13] NEDO (2020) Overview of CO_2 Separation and Capture Technology. New Energy and Industrial Technology Development Organization (NEDO) FY2020 Results Briefing.
[14] Global CCS Institute (2016), The Global Status of CCS 2016 Summary Report.



Source: IPCC (2005)[11]

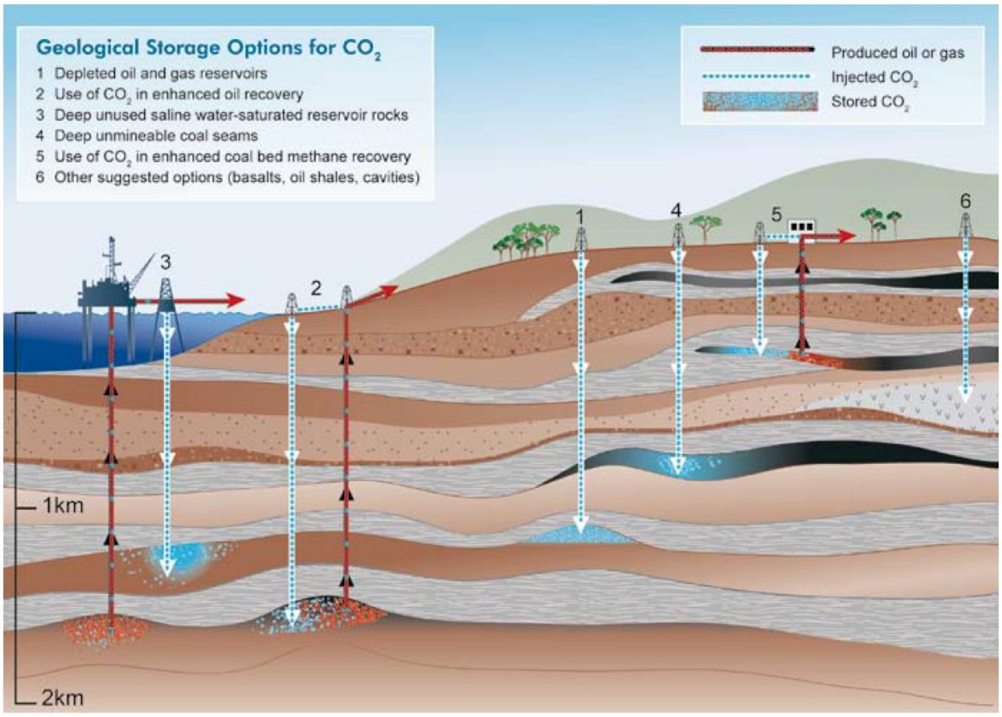
Figure 5-59 Comparison of transport costs

(4) CO_2 storage technology

One method of sequestering CO_2 from the atmosphere is geological storage. In geological storage, CO_2 is pressurized and injected into a geological formation at a depth of 1,000m or more. Reservoirs for storing CO_2 are aquifers and oil and gas fields.

According to the IPCC Special Report on CCS (IPCC SRCCS)[11] published in 2005, it is very likely that more than 99% of the CO_2 in geological storage will be retained for more than 100 years, and it is likely for more than 1,000 years if sites are well selected, designed, operated and appropriately monitored.

The main options for geological storage of CO_2 are as follows.



Source: IPCC (2005)[11]

Figure 5-60 Types of geological storage

- Storage in oil and gas fields (1 and 2 in Figure 5-60)
  There are two patterns to store CO_2 in oil and gas fields: storage in depleted oil and gas fields or storage that occurs in association with CO_2-EOR. The latter is not intended to store CO_2. CO_2-EOR has been implemented in oil production in the US and other countries for more than 50 years. The subsurface structure of oil and gas fields indicates that hydrocarbons have been retained for a long time, and it provides a stable storage site for CO_2.

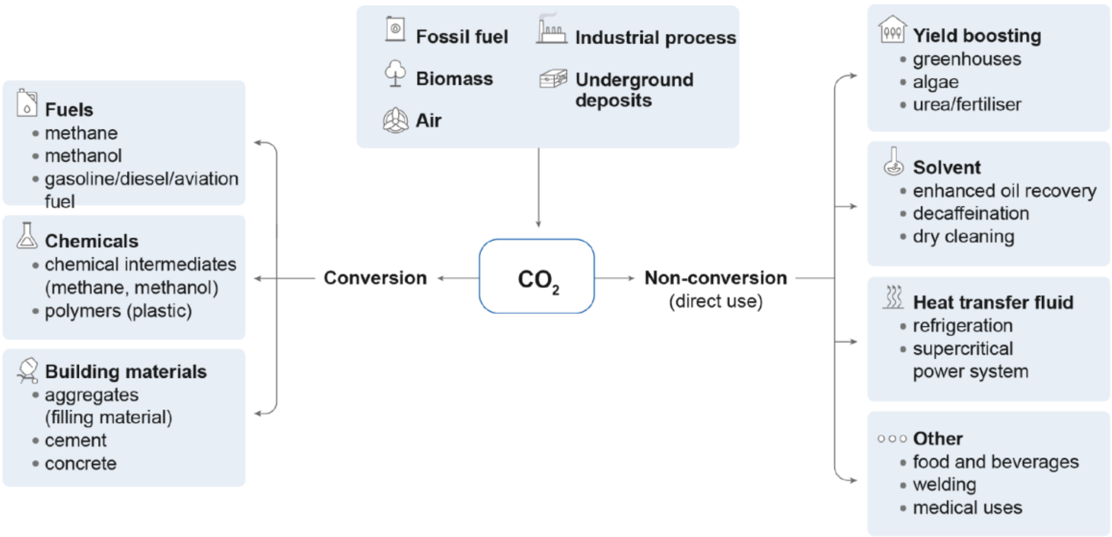
- Storage in aquifers (3 in Figure 5-60)
  CO_2 is also injected and stored in aquifers. Although aquifers are widely distributed, data on location and storage capacity are insufficient compared with that on oil and gas fields.

- Storage in coal seams (4 and 5 in Figure 5-60)
  This is a method to inject CO_2 into depleted shallow coal beds or non-extractable deep coal beds and sequester CO_2 through adsorption reaction with coal beds while recovering methane extracted (ECBM: Enhanced coal bed methane recovery).

(5) CO_2 utilization technology

Carbon dioxide capture and utilization (CCU), also known as carbon recycling, is the use of captured CO_2 as a raw material for various products. In Japan, the Ministry of Economy, Trade and Industry (METI), in its "Green Growth Strategy Through Achieving Carbon Neutrality in 2050,"[15] lists carbon recycling (CCU) as an industry in which Japan can be internationally competitive, like offshore wind power and fuel ammonia.

CO_2 utilization can be broadly classified into direct utilization, in which CO_2 is used, and indirect utilization, in which CO_2 is converted into other materials. Although its applications are limited, the former is already mature, such as in shielding gas for welding, carbonated water in the beverage and food industries, and CO_2-EOR. This section provides an overview of three representative cases of the latter (chemicals, fuels, and mineralization) that are particularly promising.



Source: IEA (2019)[16]

Figure 5-61 CCU Technologies

15 METI (2020) , Green Growth Strategy Through Achieving Carbon Neutrality in 2050, the Committee on the Growth Strategy (6th) material 2, December 25th 2020.
16 IEA (2019), Putting CO_2 to use Creating value from emissions. September 2019.

(a) Chemicals

There are technologies to convert the captured CO_2 into key materials in the chemical industry, polycarbonates, etc. In using CO_2 as materials, there are cases where CO_2 is converted into synthesis gas ($CO + H_2$) via a reverse reaction of the shift reaction (see (2)), and cases where CO_2 is converted into methanol via synthesis using catalysts or organisms. There are also cases where methanol is converted via catalytic or biological synthesis.

Because of the relatively short lifespan of the end products, the use of these chemicals is expected to have little effect on sequestering CO_2 from the atmosphere, and a net reduction in CO_2 emissions can only be achieved by replacing conventional petroleum-based chemical products.[17]

(b) Fuels

Captured CO_2 can be utilized to produce synthetic fuels (such as methane) using hydrogen as a raw material. In particular, the use of hydrogen produced via the electrolysis of water using renewable energy sources can reduce CO_2 emissions in the production process and serve as a substitute for existing fossil fuels, resulting in a reduction in CO_2 emissions. However, it is desirable to use direct atmospheric capture or biomass-derived CO_2 to contribute to CO_2 reductions in the longer term since it will be ultimately combusted, and CO_2 will be released into the atmosphere.

(c) Mineralization

Captured CO_2 can also be used to produce building materials such as concrete and aggregate. Unlike chemicals and fuels, there is no need for energy to convert the CO_2. In other cases, recovered CO_2 may be used to manufacture inorganic products. It is expected that this will fix the CO_2 for a long time compared to other methods.

(d) Outlook

Among the efforts to use captured CO_2 for industrial purposes, except for some direct applications such as welding, most of them are not suitable for practical use due to economic issues, but various R&D and technology demonstrations are being conducted in Japan and overseas. According to the Ministry of Economy, Trade and Industry's roadmap for carbon recycling[18], widespread use of CO_2-based products will begin around 2030, starting with general-purpose products in high demand, to expand the general use and further reduce costs by 2040 and beyond.

Establishing a method to evaluate the emission reduction effects of CO_2 utilization is also an issue. The period of CO_2 fixation from the atmosphere through CCU is only temporary compared to the semi-permanent sequestration from the atmosphere through geological storage. The direct effect of CO_2 fixation is generally considered to be small. The IEA (2020)[19] says that at least the following five points need to be considered when evaluating the decarbonization effects of CCU, and it is desirable to establish and standardize evaluation methods based on these points.

1) Current products/services to be replaced by CO_2-based products/services
2) Period during which CO_2 is retained in the product
3) The source of CO_2
4) The amount and form of energy required to convert CO_2
5) The size of the opportunity to use CO_2

[17] United Nations Economic Commission for Europe (UNECE) (2021), Carbon capture, use and storage. Technology brief.2021.

[18] METI (2021) Roadmap for Carbon Recycling Technologies. Revised June 2021.

[19] IEA (2020), Special Report on Carbon Capture Utilisation and Storage. Energy Technology Perspectives 2020. September 2020.

5.3.2 Technical Issues and Countermeasures related to the Introduction of CCUS

(1) Current status of CCS technology

Technology Readiness Level (TRL) is one of the methods to quantitatively evaluate the maturity level of technology. TRL evaluates the target technology based on its definition and determines the value from 1 to 9 (or a value set by the evaluator), which corresponds to the stage from concept to demonstration and implementation. The Global CCS Institute (GCCSI), an international think-tank, evaluates CCS technology. Table 5-18 shows the definition of TRL, and Table 5-19 and Table 5-20 show the evaluation for each stage of capture, transportation, and storage.

Table 5-18 Definition of TRL

Category	TRL	Description
Deployment	9	Normal commercial service
	8	Commercial demonstration, full-scale deployment in final form
	7	Sub-scale demonstration, fully functional prototype
Development	6	Fully integrated pilot tested in a relevant environment
	5	Sub-system validation in a relevant environment
	4	System validation in a laboratory environment
Research	3	Proof-of-concept tests, component level
	2	Formulation of the application
	1	Basic principles, observed, initial concept

Source: GCCSI (2021) [20]

Table 5-19 TRL evaluation for CO_2 capture technologies

Technology		TRL
Liquid Solvent	Traditional amine solvents	9
	Physical solvent (Selexol, Rectisol)	9
	Benfield process and variants*	9
	Sterically hindered amine	6-9
	Chilled ammonia process*	6-7
	Water-Lean solvent	4-7
	Phase change solvents	5-6
	Amino acid-based solvent*/Precipitating solvents	4-5
	Encapsulated solvents	2-3
	Ionic liquids	2-3
Solid adsorbent	Pressure Swing Adsorption/Vacuum Swing Adsorption	9
	Temperature Swing Adsorption (TSA)	5-7
	Enzyme Catalysed Adsorption	6
	Sorbent-Enhanced Water Gas Shift (SEWGS)	5
	Electrochemically Mediated Adsorption	1
Membrane	Gas separation membranes for natural gas processing	9
	Polymeric Membranes	7
	Electrochemical membrane integrated with MCFCs	7
	Polymeric Membranes/Cryogenic Separation Hybrid	6
	Polymeric Membranes/Solvent Hybrid	4
	Room Temperature Ionic Liquid (RTIL) Membranes	2
Solidlooping	Calcium Looping (CaL)	6-7
	Chemical Looping Combustion	5-6
Inherent CO_2 capture	Allam-Fetvedt Cycle	6-7
	Calix Advanced Calciner*	5-6

Source: GCCSI (2021) [20]

[20] GCCSI (2021), Technology readiness and costs of CCS.

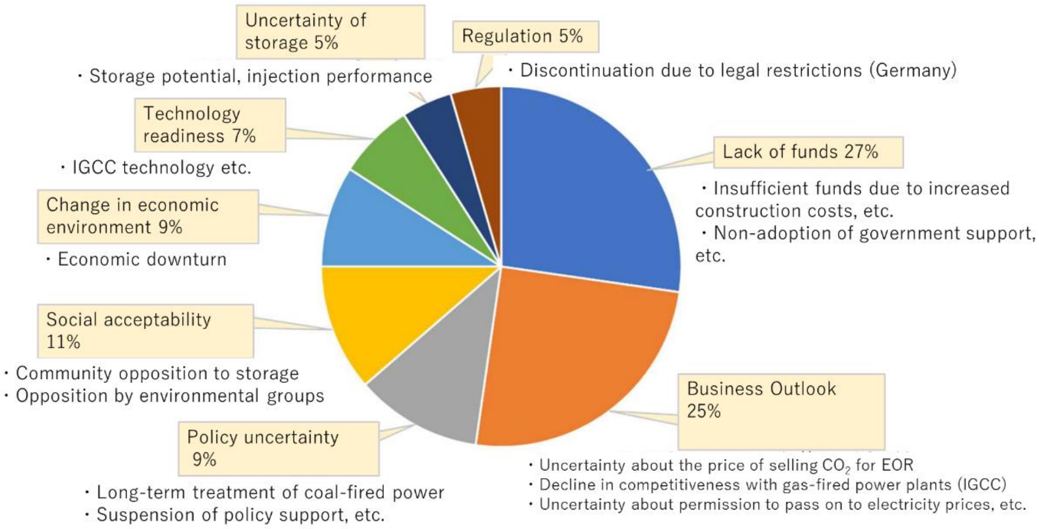
Table 5-20 TRL evaluation for transport and storage technologies

Technology		TRL
Transportation	Compression	8-9
	Pipeline	8-9
	Truck	8-9
	Rail	7-9
	Ship Design	3-9
	Ship infrastructure	2-9
Storage	CO_2-EOR	9
	Aquifer	9
	Depleted oil gas field	5-8
	Basalt/ultrabasic rock	2-6
	ECBM	2-3

Source: GCCSI (2021) [20]

As shown in the results above, it was confirmed that TRLs were generally above TRL 7, except for some advanced CO_2 capture technologies, ship transport, and storage in basic rock and coal seams. Therefore, it can be said that there are few technical issues in the implementation of CCS, especially for conventional CO_2 capture using amine solvents, transportation via pipelines, and storage in aquifers or oil and gas fields.

However, technical feasibility does not always mean that projects are possible. Figure 5-61 shows the results of a survey conducted by the Research Institute of Innovative Technology for the Earth (RITE) on 32 canceled projects in various countries. While only 7% of the projects were canceled due to technical issues, the impact of the business environment is much larger, such as lack of funding and other cost factors, social acceptability (PA), and the legal system.



Source: RITE (2021)[21]

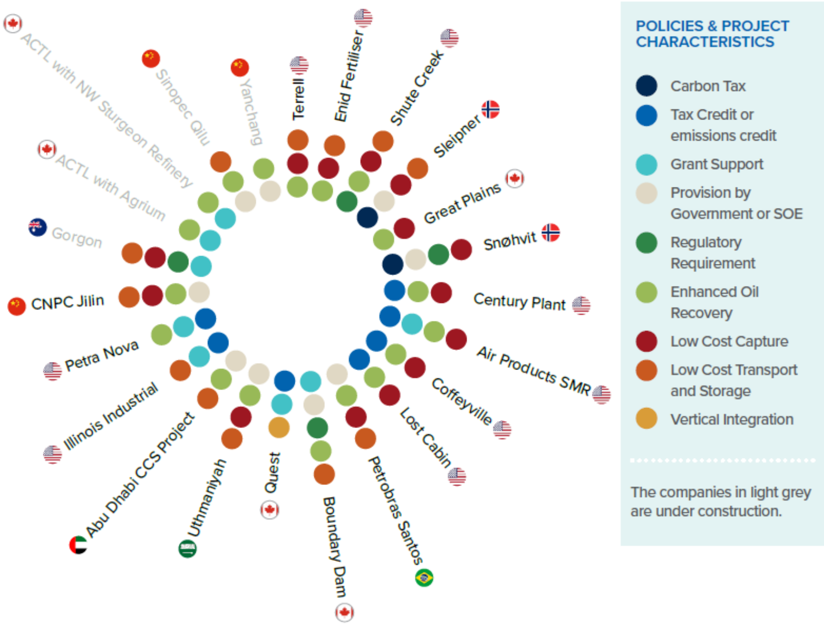
Figure 5-61 Main reasons for the cancellation of 32 projects in each country

(2) Solutions to challenges regarding CCS

Based on the evaluation in (1), CCS can be regarded as technically established, but non-technical factors such as economics and social acceptability are the main barriers to CCS projects. Since CO_2 capture and storage alone is not expected to generate revenue, it is necessary to secure a source of funding for the project.

[21] RITE (2021), Report on FY 2020 Contracted Research Fund for Global Warming and Resource Recycling Measures (Research Project on Institutional Design and Business Environment Improvement for CCS Commercialization in Japan), March 2021.

The incentives for major CCS projects as aggregated by GCCSI are shown in Figure 5-62. In the US and Canada, where many large-scale CCS projects are already in operation, revenue from CO_2-EOR is the main incentive for CCS. In addition to Sleipner and Snohvit in Norway, where the carbon tax encouraged the implementation of the project, tax incentives (Tax Credit), and CO_2 credits in the US have also had success as funding sources. However, many CCS projects are dependent on government funding, such as subsidies and grants.



Source: GCCSI (2019)[22]

Figure 5-62　Incentives for major CCS projects

It can be said that government funding is essential to promote CCS projects in areas where strong incentives such as CO_2-EOR are not anticipated at present. If carbon pricing, including carbon taxes and carbon credits, rises in line with public attention to environmental considerations and decarbonization, it would be possible to implement projects not depending on government support.
In order to achieve social acceptability, it is important to gain understanding and agreement from local residents and the general public through outreach and other activities. The Research Association for Carbon Dioxide Geological Storage Technology (2021)[23] summarized the following lessons learned from the literature review regarding public acceptance.

- The targets/stakeholders of the activities have diverse backgrounds, values, and awareness of issues. A case-by-case approach is necessary, including issues specific to the storage site.
- The activities are also called Public Involvement and Public Communication, and it is important to foster a relationship of trust through the involvement and participation of both parties, rather than unilateral transmission of information from the business to residents and other stakeholders.
- It is advisable to start activities as early as possible, starting from the basic planning stage when concrete plans have not yet been finalized, targeting a wide range of potential stakeholders in the community (educational institutions, media, general residents, related businesses, etc.) who are not directly involved.

[22] GCCSI (2019), Policy priorities to incentivise large scale deployment of CCS.
[23] Carbon Dioxide Geological Storage Technology Research Association (2021), CO_2 Geological Storage Technology Case Studies Phase 01 Basic Plan, October 2021.

5.3.3 Potential Analysis in Indonesia

(1) Potential CO_2 storage capacity in each area

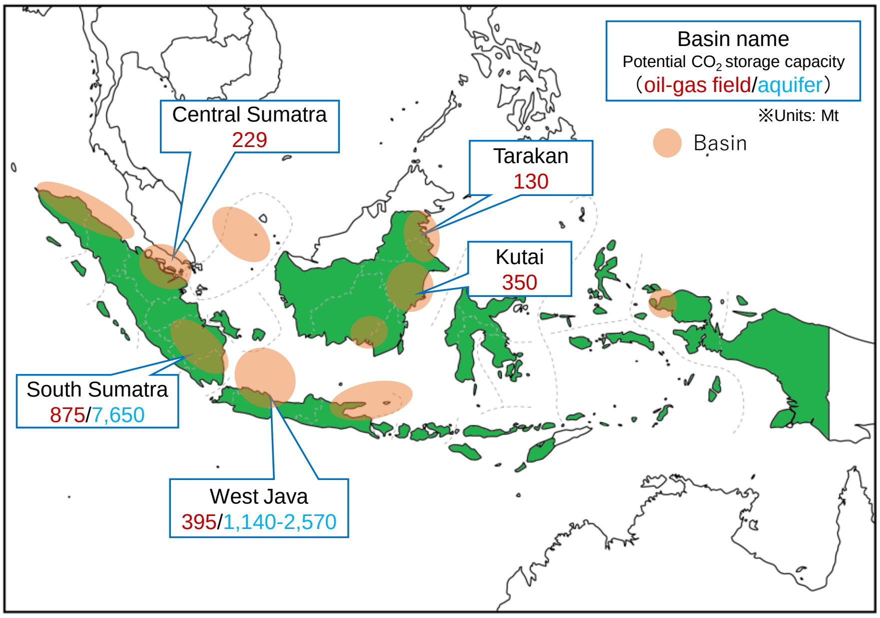
There are many oil and gas fields in Indonesia, and Indonesia is assumed to have a large CO_2 storage capacity. Some studies on potential CO_2 storage capacity based on the data obtained from past seismic surveys have been conducted. Potential CO_2 storage capacity in each Indonesian basin was evaluated based on past studies and prospective areas were identified. The study evaluates potential CO_2 storage capacity based on the Storage Resources Management System (SRMS) proposed by the Society of Petroleum Engineers (SPE).

In principle, the report by Pale Blue Dot (2021)[24] was adopted for the evaluation of the potential CO_2 storage capacity in this study. The report focused on storage sites with more than 10 Mt of storage capacity for large-scale CCS projects. The basins not covered by the report were complemented by other reports such as Hedriana et al. (2017)[25], and Asian Development Bank (2019)[26].

Table 5-21 Potential CO_2 storage capacity in major regions in Indonesia

Basin	Oil field [Mt]	Aquifer [Mt]	References
West Java	395	1,140~2,570	Pale Blue Dot (2021), Hedriana et al. (2017)
Kutai	350	No information	ADB (2019)
Tarakan	130	No information	ADB (2019)
Central Sumatra	229	No information	ADB (2019)
South Sumatra	875	7,650	Pale Blue Dot (2021), Hedriana et al. (2017)
Other areas (East Kalimantan, North Sumatra, etc.)	528	No information	Pale Blue Dot (2021)

24 Pale Blue Dot. (2021), CO_2 Storage Resource Catalogue – Cycle 2, May 2021.
25 Oki Hedriana et al. (2017), "Assessment of CO_2 - EOR and Storage Capacity in South Sumatera and West Java Basins", 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland.
26 ADB (2019), Carbon dioxide-enhanced oil recovery in Indonesia an assessment of its role in a carbon capture and storage pathway, December 2019.



Sources: JANUS

Figure 5-63 Distribution of major CO_2 storage sites in Indonesia

The results show that there is a potential CO_2 storage capacity of more than 2.5 Gt only in oil and gas fields in Indonesia. Total storage capacity is expected to be over 10 Gt only in some major basins. However, it should be noted that there is still uncertainty due to the lack of existing data on aquifers compared to oil and gas fields, where exploration data is abundant.

South Sumatra and Kutai would be promising basins for storage in oil and gas fields. West Java and South Sumatra would be promising basins for storage in aquifers.

While Japan is estimated to have about 150 Gt of CO_2 storage capacity, most storage sites are aquifers in offshore areas that are difficult to access and have not been evaluated through a seismic survey. Indonesia has a lot of storage sites in onshore oil and gas fields that are easy to access, judging by evaluations conducted in the process of exploration.

According to the report by Climate Transparency[27], annual energy-related CO_2 emissions in Indonesia reached a high of 581 Mt in 2019. The industry sector contributes the most, at 37% (215 Mt), followed by the power sector, at 27% (157 Mt). Other energy-related sectors, including CO_2 emissions from extracting and processing fossil fuels, made up 3% (17 Mt). CCS could be applied to these sectors. Generally, a large-scale CCS project is a facility that captures CO_2 with a capacity of 1 Mt per year or greater. It is possible to implement many large-scale CCS projects in Indonesia. Furthermore, considering the easy accessibility of storage sites, the potential for CCS in Indonesia is sufficient.

(2) CCS project status

(a) CCS policy in Indonesia

1) The role of CCS in Indonesian energy policy

According to the Paris Agreement, Indonesia set the following target reduction amounts for domestic GHG emissions: 29% reduction, or 41% reduction with international support, by 2030. As Indonesia has a large potential CO_2 storage capacity, as shown in Section (1), CCS is expected to serve as a climate change measure.

In upstream oil industries, an increase in oil production by applying CO_2-EOR is desirable for coping with the decline in domestic oil production and the rapid growth of domestic oil demand. CO_2-EOR is recognized firstly as a way of increasing oil and, secondly, of reducing GHG emissions. In upstream

[27] The Climate Transparency Report 2020 Indonesia, https://www.climate-transparency.org/wp-content/uploads/2020/11/Indonesia-CT-2020-WEB.pdf

gas industries, more gas production is also expected to cope with the growth of domestic gas demand. The urgent issue is how to develop gas fields with high CO_2 content, so-called CO_2-rich gas fields.

In power generation industries, the importance of CCS has been stressed in recent years. Indonesia is one of the largest countries that produce and export coal, and coal plays an important role in power generation in Indonesia. According to the national electricity plan, the ratio of renewable energy to the overall capacity is increasing over time. However, the electricity demand is expected to increase and coal power plants will be a major source of electricity. As the international pressure on coal-fired power increases, the government refers to the need for CO_2-EOR and CCS.

CCUS has not yet been formally incorporated into Indonesia's national energy plan. However, the potential of CCS to mitigate CO_2 emissions in the long term is recognized. The Ministry of Energy and Mineral Resources (MEMR) established the Indonesia Center of Excellence for CCS and CCUS (CoE) to help facilitate the implementation of CCS in 2017. CoE developed a draft presidential decree on CCS and started a feasibility study on CCS projects under international cooperation, including with Japan. Furthermore, a draft presidential decree on carbon pricing, including an emission trading system, is also under development as a financial incentive for CCS.

In a presentation by MEMR[28], the importance of the combination of fossil fuels and clean technology such as CCUS is stressed. The early stages of CCUS development in Indonesia began by utilizing the existing CO_2 emitted by gas processing plants for CO_2-EOR in oil field candidates which are close to the plant. The success of the use of CO_2 for EOR as CCUS will support the utilization of fossil energy in sustainable low carbon activities, which also include the use of coal power plants.

The government-owned electric power company PLN pledges carbon neutrality by 2060 and will not approve the construction of a new coal power plant after 2022 in principle[29]. PLN presents not only a renewable energy scenario but also a CCUS scenario as scenarios to achieve decarbonization. In the CCUS scenario, coal power plants with CCUS will operate from 2035. However, there is no incentive for CCS despite additional costs for CCS, and processes after CO_2 capture are not within PLN's business. Legal system development and governmental support are necessary to realize the CCUS scenario in the energy sector.

2) CoE (Indonesia Center of Excellence for CCS and CCUS)

MEMR established the Indonesia Center of Excellence for CCS and CCUS (CoE) as a research and development center for CCS and CCUS in 2017. CoE is mainly composed of the Bandung Institute of Technology (ITB) and Research and Development Centre For Oil and Gas Technology (LEMIGAS), and it investigates the application of CCS and CCUS in the energy sector especially. Their objectives are as follows.

- To deliver a coordinated program of CCS research that links government, industry, regulators, and research organizations
- To demonstrate CCS/CCUS pilot projects in Indonesia and identify opportunities for CCS implementation to help Indonesia achieve its target of contributing to global climate change mitigation
- To formulate Policies, Strategy, and Regulations/Standards for the enabling of CCS implementation in Indonesia
- To develop effective communication links and networks with CCS researchers, regulators, policymakers, and other stakeholders in Indonesia
- To provide educational and information materials to partners and the general public to promote public awareness and understanding of CCS as a critical greenhouse gas mitigation measure

CoE focuses on international cooperation in CCS projects, and ITB and LEMIGAS are involved in most of the CCS projects planned in Indonesia.

The steering committee is made up of the heads of the Coordinating Ministry of Economic Affairs, the Coordinating Ministry of Maritime Affairs, MEMR, the Ministry of Environment and Forestry,

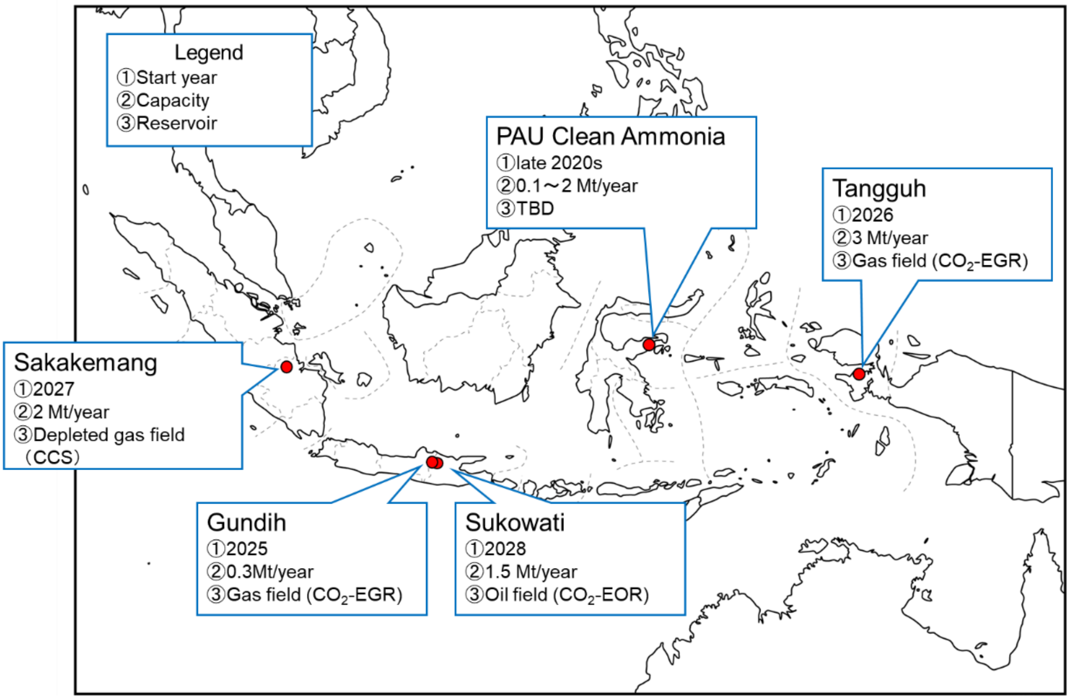
[28] H.E. Mr. Arifin Tasrif (2021), Minister of Energy and Mineral Resources Indonesia, "Paving the Indonesia Pathway to Low Carbon Economy Through Utilization of CCUS", Role of CCUS in Low-Carbon Development in ASEAN, 13th August 2021.

[29] Evy Haryadi (2021), Corporate Planning Director, PT. PLN, "Strategy and Readiness in Entering Energy Transition Era with CCUS", Role of CCUS in Low-Carbon Development in ASEAN, 13th August 2021.

SKK MIGAS (the regulator of the upstream oil and gas sector), and Pertamina (the state-owned oil and natural gas corporation).

(b) CCS projects in Indonesia

According to a report by GCCSI[30] and presentation by MEMR[31], five CCS projects, including CO_2-EOR, are planned in Indonesia. The project overviews are as follows.



Source: JANUS

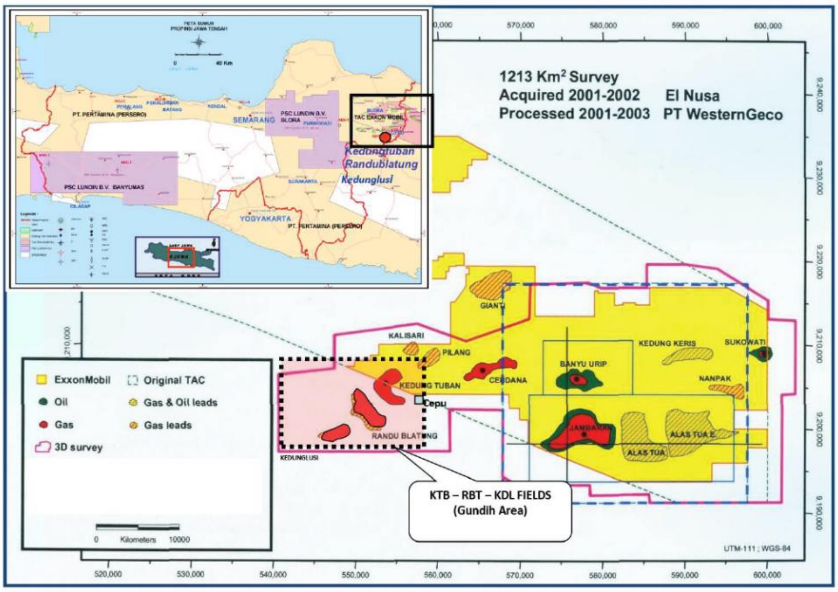
Figure 5-64 Planned CCS projects in Indonesia

[30] GCCSI (2021), Global status of CCS 2021, p33-34.

[31] Dr. Saleh Abdurrahman (2021), Ministry of Energy and Mineral Resources, “CCUS Development in Indonesia: Prospect and Challenges”, 1st ERIA CCUS Forum, 22nd June 2021.

1) Gundih CCUS project

CO_2 source	Natural gas processing	Start year	2025
Location	Central Java	Capacity	300,000 ton/year
Reservoir	Gas field (CO_2-EGR)	Operator	Pertamina (Indonesia)
Status			
・ The JCM feasibility study was started jointly by JGC Global, NUS, and J-Power as a METI project in June 2021. From Indonesia, Pertamina and ITB participate in the project[32].			



Source: MEMR[33]

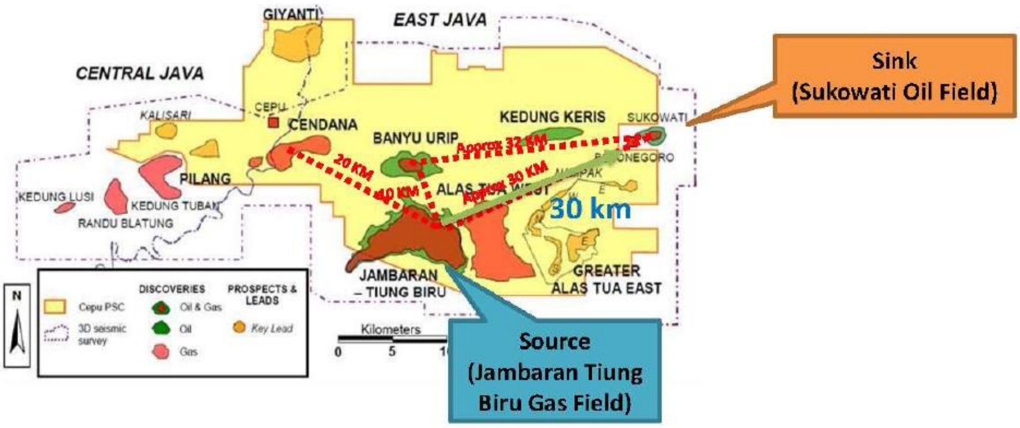
Figure 5-65 Location of Gundih CCS project

[32] JGC holdings News Release (2021.7.19), Commencement of Feasibility Study for the First Southeast Asia CCS Demonstration Project in Gundih Indonesia, https://www.jgc.com/en/news/2021/20210719_02.html

[33] Adhi Wibowod (2020), Director of Oil and Gas Engineering and Environment, Directorate General of Oil and Gas, "CCUS Activities in Indonesia", Japan - Asia CCUS Forum 2020, October 6th, 2020, https://www.japanccs.com/wp/wp-content/uploads/2020/10/CCUS-Activities-in-Indonesia_Dr.-Adhi-Wibowo.pdf

2) Sukowati CO_2-EOR Project

CO_2 source	Natural gas processing	Start year	2028
Location	East Java	Capacity	4,000 ton/day
Reservoir	Oil field (CO_2-EOR)	Operator	Pertamina (Indonesia)
Status			
・ The JCM feasibility study was started by Japan Petroleum Exploration Co. as a project by METI in June 2021. From Indonesia, Pertamina and LEMIGAS participate in the project.[34]			



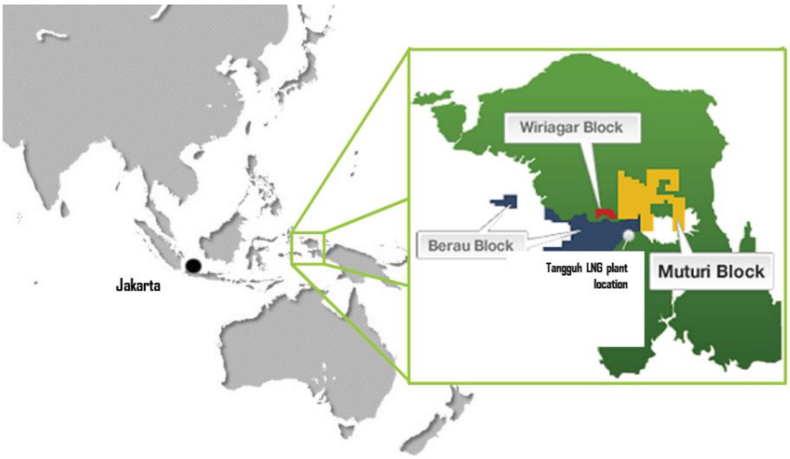
Source: MEMR[33]

Figure 5-66 Location of Sukowati CO_2-EOR project

[34] JAPEX press release (2021.6.22), Agreement for Joint Feasibility Study of CCUS Project Using Joint Crediting Mechanism at Sukowati Oil Field in Indonesia, https://www.japex.co.jp/news/detail/20210622_03/

3) Tangguh CCUS project

CO_2 source	Natural gas processing	Start year	2026
Location	West Papua	Capacity	3,000,000 ton/year
Reservoir	Gas field (CO_2-EGR)	Operator	BP (UK)
Status			
・ SKK-MIGAS approved the plan for development, including the CCUS project, in August 2021. ・ From Japan, Mitsubishi Corporation, INPEX, JX Nippon Oil & Gas Exploration, Mitsui & Co, LNG Japan, Sumitomo Corporation, and Sojitz Corporation have interests in the project.[35]			



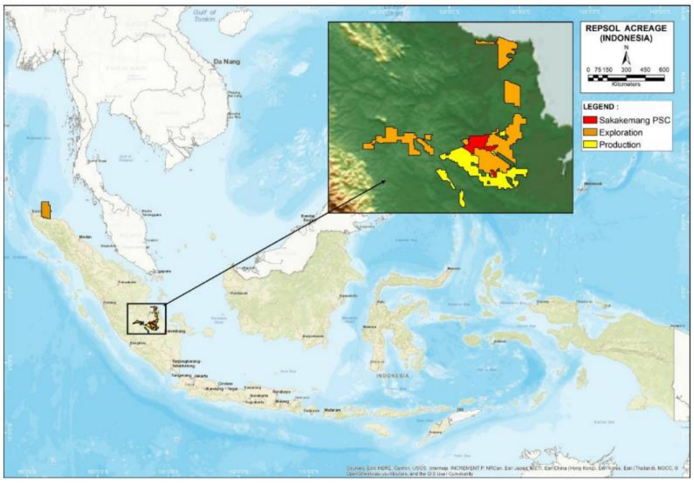
Source: Mitsubishi corporation[35]

Figure 5-67 Location of Tangguh CCUS project

[35] Mitsubishi Corporation press release (2021.8.30), SKK Migas approved Plan of Development for Ubadari Field and Vorwata CCUS at Tangguh LNG Project, https://www.mitsubishicorp.com/jp/en/pr/archive/2021/html/0000047684.html

4) Sakakemang CCS project

CO_2 source	Natural gas processing	Start year	2027
Location	South Sumatra	Capacity	2,000,000 ton/year
Reservoir	Depleted gas field	Operator	Repsol (Spain)
Status			
・ Seal analysis, injection modeling, and risk assessment will be completed by December 2021.[36]			



Source: Repsol[37]

Figure 5-68 Location of Sakakemang gas field

[36] Upstream online (October 13, 2021), "Repsol details Indonesia CCS project linked to giant gas development", https://www.upstreamonline.com/energy-transition/repsol-details-indonesia-ccs-project-linked-to-giant-gas-development/2-1-1081373

[37] Repsol press release (February 19, 2019), Repsol makes largest gas discovery in Indonesia for 18 years, https://www.repsol.com/imagenes/global/en/NP19022019_sakakemang_discovery_eng_tcm14-147758.pdf

5) PAU Central Sulawesi Clean Ammonia project

CO_2 source	Ammonia production	Start year	Late 2020s
Location	Central Sulawesi	Capacity	100,000~2,000,000 ton/year
Reservoir	TBD	Operator	Panca Amara Utama (Indonesia)
Status			
・ Mitsubishi Corporation and JOGMEC agreed with ITB and ammonia producer Panca Amara Utama (PAU) to conduct a joint study on CCUS for clean fuel ammonia production in Central Sulawesi in March 2021.[38]			

Source: Mitsubishi corporation [22]

Figure 5-69 Location of PAU project

[38] Mitsubishi Corporation press release (2021.3.19), Signing of Memorandum of Understanding regarding CCS Joint Study for Clean Fuel Ammonia Production in Indonesia, https://www.mitsubishicorp.com/jp/en/pr/archive/2021/html/0000046720.html

(3) Laws and regulations on CCS

(a) Draft presidential decree on CCS

The draft of a presidential decree on CCS was completed in March 2019 as a new national regulation for CCUS in Indonesia. It is in the process of governmental approval.

The draft was made by a drafting committee, which was hosted by CoE and included the Ministry of Energy and Mineral Resources and the Ministry of Environment and Forestry, with support from ADB[39]. Other agencies and organizations, including Bandung Institute of Technology (ITB), Research & Development Center for Oil & Gas Technology (Lemigas), and Pertamina, participated in drafting committee meetings. The draft of the presidential decree referred to existing foreign regulations and experiences regarding CCS, like the UIC program in the USA[40], CCS directive in EU[41], and offshore petroleum and greenhouse gas storage act 2006 in Australia[42]. The presidential decree includes a general overview of CCS regulations beyond each ministerial jurisdiction. The details of the regulations will be considered by each ministry in the future.

1) Definition of CCS and its regulation

CCS in the presidential decree is defined as the separation of CO_2 from emission sources or the atmosphere, transportation of such CO_2, and injection of CO_2 into a qualifying injection zone for permanent sequestration. The term CCS excludes any form of non-geological sequestration, such as biological carbon sequestration in forests or oceans. CCS includes enhanced oil recovery (CO_2-EOR).

2) Establishment of committees

To coordinate their respective efforts concerning CCS, the “CCS Inter-agency Coordinating Committee” is to be established. The CCS Inter-agency Coordinating Committee consists of ministries and governmental agencies in charge of CCS projects and may include additional members and observers, depending on the content. The Committee is to engage in coordination and knowledge sharing, facilitation of the development of regulations and standards, and project evaluation and supervision.

Additionally, a “CCS Community Engagement Committee” is to be established for each specific CCS project. A CCS Community Engagement Committee consists of relevant national and local stakeholders from local governments, civil society organizations, and local communities, and ensures that public concerns are reflected in the implementation of the project.

3) Required information for permit application

The implementation of a CCS project shall require a permit from the minister. The following information is necessary to apply for a permit.

- Technical and financial qualifications of the applicant;
- Geological assessment data and modeling;
- Project design and construction information;
- Monitoring and emergency remediation response plans;
- Plan for testing the mechanical integrity of wells;
- Operation plan;
- Post-injection monitoring plan;
- Closure plan; and
- Seismic monitoring and risk mitigation plan

[39] ADB (2019), Carbon dioxide-enhanced oil recovery in Indonesia an assessment of its role in a carbon capture and storage pathway, December 2019.
[40] EPA (2011), Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells Final Rule.
[41] EC (2019), Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006.
[42] NOPSEMA (2016), Offshore Petroleum and Greenhouse Gas Storage Act 2006.

A feature of the presidential decree is the consideration of seismic risks due to the many earthquakes in Indonesia. Application requires a comprehensive analysis of the potential impact of earthquakes on the storage complex and surface facilities using empirical data and modeling. Based on this analysis, seismic monitoring and risk mitigation plans are to be designed.

It is necessary to evaluate the possibility of earthquakes in the area around the storage site based on geological information, such as faults in the area and records of past earthquakes. The results of the evaluation must show that the risk is sufficiently small. The plan should include appropriate monitoring (e.g., continuous microseismic monitoring) to assess the risk. Since Japan is also an earthquake-prone country, the Act on Prevention of Marine Pollution and Maritime Disasters, which regulates the storage of CO_2 under the seabed, requires that the storage site is in an area with no significant geological deformation expected in an earthquake.

The Minister is to approve and issue a CCS permit, only upon determining that the proposed CCS project poses no significant risk to health, safety, the environment, and other resources, comprehensively considering the circumstances, technical capabilities, and financial condition of the operator.

4) Post-injection monitoring period

The post-injection monitoring period is determined by the total amount of CO_2 the project will inject. For CO_2 injection volumes of between 150,000 tons and 1,000,000 tons, the post-injection monitoring period is 3 years. In the case where it is larger than 1,000,000 tons, the monitoring period is 10 years. Injection of 150,000 tons or less for research is not subject to CO_2 plume and pressure monitoring. These periods are only default periods, which can be modified by the Minister to a shorter or longer period based on empirical data and the results of modeling.

5) Transfer of long-term liability after site closure

The Inter-Agency Coordination Committee will specifically consider and issue policy recommendations concerning the treatment of long-term liability for injected CO_2.

Within the international community, it is a general opinion that a viable long-term liability regime could involve the state accepting responsibility for the care and maintenance of storage sites once injection has ceased and adequate post-injection monitoring has been completed. Transfer of liability may also be coupled with a collection of fees from the project operator based on the volume of CO_2 injected or similar methodology to defray potential costs for future maintenance.

(4) Challenges and timeline for practical application

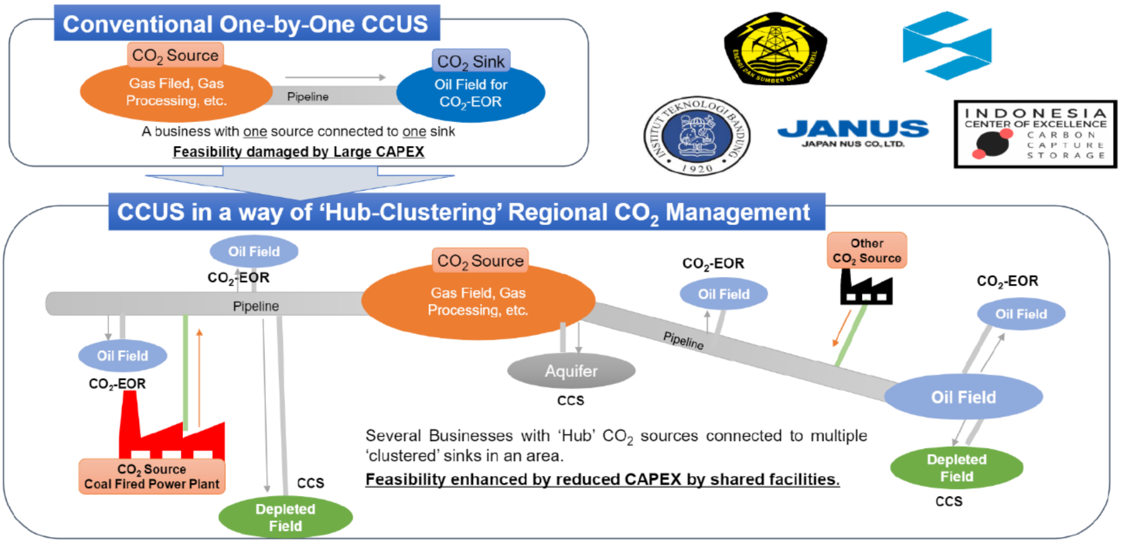
Most of the CCS projects planned in Indonesia are CO_2-EOR or CO_2-EGR projects for enhanced hydrocarbon production using captured CO_2 from natural gas processing. As this background, additional costs are very low because CO_2 capture is part of conventional processes in natural gas production. Moreover, CO_2-EOR and CO_2-EGR projects are expected to be profitable due to profit from an increment of oil and gas production by EOR or EGR. These projects are aiming to start operation in the late 2020s.

CCS projects for thermal power plants have not been planned because CCS is not economically feasible in the current situation. The government-owned electric power company PLN also considers CCS an option for decarbonization but believes that governmental strong support is essential to proceed with it.

To reduce the cost of CCS, CoE is considering Hub and Clustering Regional CO_2 management, which connects multiple CO_2 emission sources and sinks, with JGC and Japan NUS, with support from METI[43]. For a CCS project with a single emission source and a single sink, the initial capital costs for infrastructure development for CO_2 transport and storage will be expensive. In hub and clustering CO_2 management, CCS infrastructure can be shared across multiple projects, reducing initial capital costs. Even in the case of a project which is not viable on its own, the economics would be improved by the

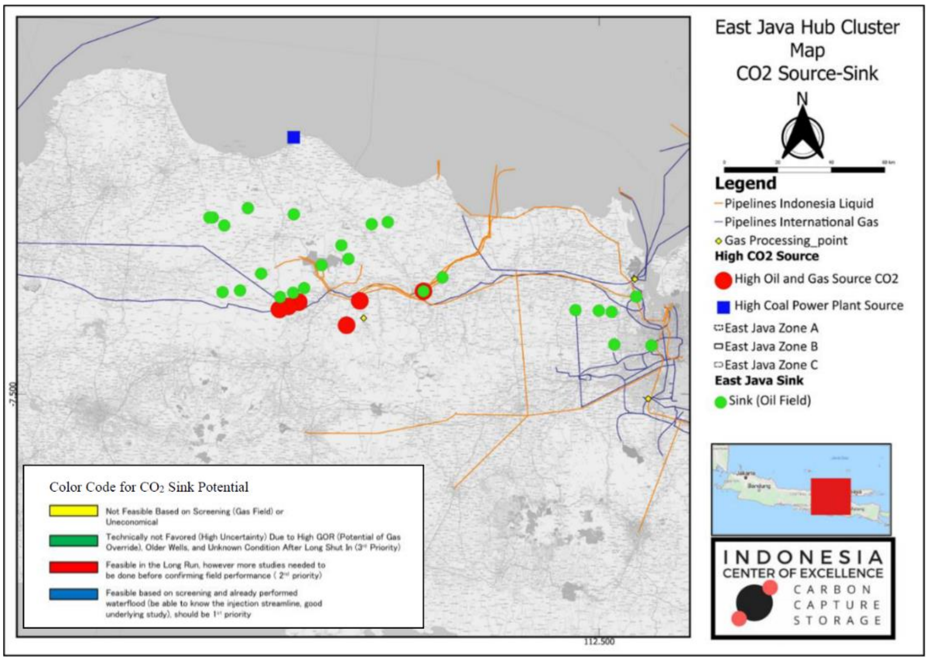
[43] JANUS (2019), Report on the FY 2018 Collaborative program for international organizations against global warming (Collaborative program for international contribution using Japan's CCS technology), https://www.meti.go.jp/meti_lib/report/H30FY/000497.pdf

CO_2 management, and applying CCS to various emission sources, including thermal power plants, would be feasible in the future. CoE has built a GIS database of CO_2 emission sources and sinks for hub and clustering regional CO_2 management.



Source: R. Sule (2021)[44]

Figure 5-70 Hub and Clustering Regional CO_2 management



Source: R. Sule (2021)[45]

Figure 5-71 CO_2 Source and Sink Mapping in East Java

44 R. Sule (2021), Manager of National Center of Excellence for CCS/CCUS, "CO_2-Source-Sink Match GIS System for Indonesia", The First Asia CCUS Network Forum, 22nd-23rd June 2021, https://static1.squarespace.com/static/60b8dd7acb58186e05cb8387/t/60ebf39a085b1c120fb7c522/1626076071824/2021_June_1st-Asia-CCUS-Network-Forum_ITB_Mohammad-Rachmat-Sule.pdf

45 R. Sule (2021), Maximizing the utilization of emitted CO_2 from gas field by implementing CO_2 source and sink clustering, 15th International Conference on Greenhouse Gas Control Technologies GHGT-15, 15th - 18th March 2021, Abu Dhabi, UAE.

The currently planned CCS projects in Indonesia will operate in the late 2020s. Subsequently, if hub and cluster CO_2 management is promoted by large-scale CCS projects in Indonesia, the costs of CCS are expected to be reduced. Furthermore, if regulations and systems are developed to provide incentives for CCS, such as carbon pricing, the application of CCS not only to gas production processes but also to CO_2 from other industrial sources, such as thermal power plants, is expected to start in the 2030s.
However, the challenge is that the business model for CCS has not yet been established. Economic incentives for CCS, including carbon pricing and crediting schemes like JCM, are being considered but have not been introduced yet. Legislation for CCS implementation is also needed. The draft of the presidential decree on CCS was made but has not come into force yet. In particular, long-term liability after injection should be discussed in the CCS Inter-agency Coordinating Committee. Since the timing of the transfer of long-term liability is very important for operators to make investment decisions on CCS, it is necessary to clarify the conditions for it.

5.3.4 Cost Outlook for CCS (Capture, Transportation, and Storage)

(1) Current cost estimates

(a) Rubin et al.

The IPCC SRCCS summarized the existing knowledge on the costs of CCS as of 2005 and provided estimates on the costs required to reduce 1 ton of CO_2 in a new thermal power plant. This is called "avoided cost".

Avoided cost

Avoided cost is the cost of capturing one ton of CO_2 divided by the net amount of CO_2 emissions avoided associated with CCS. It considers the CO_2 emitted from the additional energy input for CCS. In general, the capture, transport, and storage of CO_2 require energy inputs. For a power plant, this means that amount of fuel input (and therefore CO_2 emissions) increases per unit of net power output. As a result, the amount of CO_2 produced per unit of product is greater for the power plant with CCS than the reference plant, as shown in Figure 5-72. To determine the CO_2 reductions one can attribute to CCS, one needs to compare the CO_2 emissions of the plant with capture to those of the reference plant without capture. These are the avoided emissions.

The cost of CO_2 abatement associated with CCS (Avoided cost) is defined as the cost of installing CCS divided by the net CO_2 abatement, as follows.

CO_2 abatement cost (USD/t-CO_2 avoided)

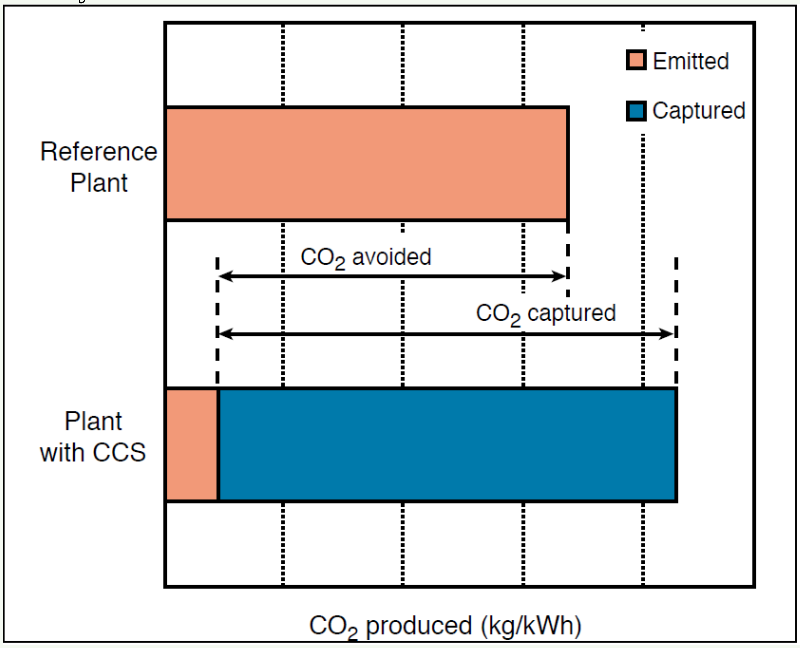
$=[(LCOE)_{capture} – (LCOE)_{ref}] / [(t\text{-}CO_2/kWh)_{ref} – (t\text{-}CO_2/kWh)_{capture}]$

$=[(LCOE)_{capture} – (LCOE)_{ref}] / [(t\text{-}CO_2/kWh)_{avoided}]$

LCOE: Levelized cost of electricity (USD/kWh)

※The subscript "capture" means a plant with CCS. The subscript "ref" means a reference plant without CCS.

Technically, CO_2 abatement costs should be applied to the entire system of capture, transport, and storage. However, CO_2 abatement costs for capture only are also listed, following each publication referred to in this study.



Source: SRCCS[11]

Figure 5-72 The difference between CO_2 captured and CO_2 avoided

In 2015, Rubin et al, one of the leading experts in the field, summarized the progress of CCS cost studies in the 10 years following the publication of IPCC SRCCS[46]. Table 5-22 summarizes the costs of CCS in new thermal power plants based on the results of previous studies since 2011. Capture technologies in the commercialization or demonstration phase as of 2015 were adopted, such as post-combustion capture using amine solvent for SC and NGCC, pre-combustion capture via physical adsorption for IGCC, and oxy-combustion for SC and USC. The transport distance for CO_2 is assumed to be 250 km.

Table 5-22 Costs of CCS in thermal power plants

Process		SC with post-combustion 550 – 1030 (742) MW	NGCC with post-combustion 512 - 910 (661) MW	IGCC with pre-combustion 600 - 748 (645) MW	SC/USC with oxy-combustion 550 -1030 (684) MW
Total CO_2 captured or stored (Mt/year)		3.8 – 5.6 (4.6)	1.1 – 2.3 (1.6)	3.1 – 3.3 (3.2)	3.1 – 5.5 (3.9)
Unit		USD/t-CO_2	USD/t-CO_2	USD/t-CO_2	USD/t-CO_2
Cost of CO_2 captured	Capture	36 - 53 (46)	48 - 111 (74)	28 - 41 (34)	36 - 67 (52)
	Transport	0 – 7			
	Storage	1 – 12			
	EOR	▲40 – ▲15			
Cost of CO_2 avoided	Capture only	45 - 70 (63)	58 - 121 (87)	37 - 58 (46)	45 - 73 (62)
	Total (CCS)	46 - 99	59 - 143	38 - 84	47 - 97
	Total (EOR)	▲5 - 58	10 - 112	▲15 - 46	▲6 - 63

※ All costs are calculated based on USD as of 2013. Figures in brackets mean the average cost in studies referred to.
※ SC: supercritical (coal power plant), USC: ultra-supercritical (coal power plant), NGCC: natural gas combined cycle, IGCC: coal-based integrated gasification combined cycle
※ ▲ means a negative value (in this case, profit).

Source: Rubin (2015)[460]

The cost of capture accounts for more than half of the total CCS costs in all cases. Since only onshore pipeline transportation is to be adopted in this study, the impact of transport costs may be significant in the case of vessel transportation or longer transportation distances.
The abatement cost per ton of CO_2 ranges from 38 to 143 USD in the 2015 study and from 25 to 136 USD in the 2005 IPCC SRCCS. Comparing the results of the two studies on the cost of CCS, the following are the main points of difference between 2005 and 2015.

- The capital costs for power plants and CCS technologies increased significantly. These additional increases are attributed to changes in the power plant and/or CCS system designs, and to market factors that affect technology costs at any point in time.
- The levelized costs of electricity for power plants with and without CCS in recent studies show only small changes compared to the SRCCS costs adjusted for power plant capital and fuel cost escalations.
- The costs of CO_2 avoidance (mitigation cost) for CCS, including pipeline transport and geologic storage, are essentially the same as in the SRCCS.

(b) GCCSI

GCCSI estimated the cost of CCS for power generation and other industrial processes in the US, as shown in Table 5-23 and Table 5-24. The avoided costs were also calculated based on estimates of the cost per unit for power generation or production. The assumptions for the cost estimate are that CO_2 transportation is via onshore 100 km pipelines and the storage site is an onshore aquifer. The transport and storage costs applied are between 7 and 12 US$/t-$CO_2$ for all power generation technologies. A combined 11 US$/t-$CO_2$ is included for the industrial case transport and storage costs.

46 Rubin, E.S. et., al., The cost of CO_2 capture and storage, International Journal of Greenhouse Gas Control vol. 40. 2015, p. 378-400.

Table 5-23 Costs of CCS for power plants in the United States

Emission source	Post-combustion SC	Oxy-combustion SC	Pre-combustion IGCC	Post-combustion NGCC
Levelised cost	USD/MWh	USD/MWh	USD/MWh	USD/MWh
Without CCS (Reference)	75-77	-	95	49
With CCS (FOAK)	124-133	118-129	141	78
With CCS (NOAK)	108	107	102	62
Cost of CO_2 avoided (USD/t-CO_2 avoided)				
FOAK	74-83	66-75	97	89
NOAK	55	52	46	43

※ FOAK (first of a kind): This means that the technology is in the early stages. In an economic evaluation in engineering, the first project is more expensive because it does not benefit from the cost reduction effects associated with the Nth construction of a plant of the same type (NOAK, Nth of a kind).

Source: GCCSI (2017)[47]

Table 5-24 Costs of CCS for other industries in the United States

Emission source	Iron and steel	Cement	Natural gas	Fertilizer	Biomass to ethanol
Unit	USD/t	USD/t	USD/GJ	USD/t	USD/L
Without CCS (Reference)	280-370	101	3.75	400-450	0.40-0.45
With CCS (FOAK)	114	69	0.061	13	0.018
With CCS (NOAK)	95	58	0.058	12	0.017
Cost of CO_2 avoided (USD/t-CO_2 avoided)					
FOAK	77	124	21.5	25.4	21.5
NOAK	65	103	20.4	23.8	20.4

Source: GCCSI (2017)[47]

The costs of CCS in other countries are also estimated, reflecting cost factors like labor costs, land acquisition, etc. in each country. The costs of CCS in Indonesia are shown in Table 5-25.

Table 5-25 Costs of CCS in Indonesia (FOAK, USD/t-CO_2 avoided)

Emission source	Power generation			Other industrial processes				
	Post-combustion SC	Pre-combustion IGCC	Post-combustion NGCC	Iron and steel	Cement	Natural gas	Fertilizer	Biomass to ethanol
Indonesia	74	106	96	76	125	22.8	26.9	22.8
United States (Reference)	74	97	89	77	124	21.5	25.4	21.5

Source: GCCSI (2017)[47]

[47] GCCSI (2017) Global costs of carbon capture and storage 2017 Update, June 2017.

(c) World Bank

The World Bank and PLN, a state-owned power company, estimated the costs of a new coal power plant with CCS in West Java and South Sumatra. The assumptions for the cost estimates are shown in Table 5-26.

Table 5-26 Plant assumptions for the cost estimates

	Case 1	Case 2
Location	West Java	South Sumatra
Installed capacity	1,000MW×2	600MW×1
Technology	Ultra-supercritical	Supercritical
Annual CO_2 emissions	12.13 million tCO_2	4.09 million tCO_2
Transport distance (pipeline)	175 km	15~53.7 km (6 storage sites)
CO_2 capture rate	90%	90%
Plant design life	25 years	25 years

Source: World Bank (2015) [48]

The results of the cost estimates are shown in Table 5-27.

Table 5-27 Costs of CCS in Indonesia

USD/tCO_2	West Java	South Sumatra
Total cost (Captured)	73	71
Capture cost	62.8	65.4
Transport cost	7.9	3.3
Storage cost	2.1	2.1
Total abatement cost (Avoided)	101	102

Source: World Bank (2015) [42]

(d) Tomakomai CCS project

As the first large-scale demonstration CCS project in Japan, the Ministry of Economy, Trade and Industry (METI), the New Energy and Industrial Technology Development Organization (NEDO), and Japan CCS started CO_2 injection underground in Tomakomai, Hokkaido from April 2016. In November 2019, the total amount of injected CO_2 achieved its target of 300,000 tons.

A portion of the PSA (Pressure Swing Adsorption) off-gas, containing approximately 52% CO_2 generated by a hydrogen production unit in the refinery, is transported via a 1.4km pipeline to the adjacent capture facilities, where the CO_2 is captured. The CO_2 is compressed and stored 3-4km offshore in two sub-seabed reservoirs at different depths – the Moebetsu and Takinoue formations – by two independent directional injection wells.

Based on the Tomakomai demonstration data, a cost estimate of 200-thousand tonnes/year scale (scale of Tomakomai project) and practical model that could be applied to CCS for hydrogen production, ammonia production, and IGCC was conducted, as well as a scaled-up 1-million ton/year practical model. Assumptions for estimates are that the storage site is the same as the Tomakomai project (Moebetsu and Takinoue formations) and the operating period is 25 years. Transport costs are not included.

[48] World Bank (2015), Republic of Indonesia: The Indonesia Carbon Capture Storage (CCS) Capacity Building Program CCS for Coal-fired Power Plants in Indonesia, June 2015

Table 5-28 Cost estimates based on Tomakomai CCS project

Yen/t-CO_2	0.2 Mt/year scale	1 Mt/year scale
Total cost (Captured)	11,129	6,186
Capture/Injection	5,572	4,669
Injection wells/Storage	5,557	1,517
Total cost (Avoided)	13,328	7,261

Source: METI (2020)[49]

According to the report, the avoided costs for CCS in the 1 Mt-scale project (commercial scale) are 7,261 yen/t-CO_2. This could reach 6,708 yen/t-CO_2 in the future due to energy consumption reductions in capture technology.

(e) Summary

The cost of CCS in a power plant depends on the power generation system, the scale of the system, and the conditions of transport and storage. Most of the existing studies showed the abatement cost to be between 45 USD and 136 USD per ton of CO_2. However, as Rubin (2015) points out[46], the cost of CCS, including CO_2 transport and storage, has not changed significantly. A CCS cost of 90 USD per ton of CO_2 would be one of the indicators at this point.

CO_2 capture costs account for more than half of the total CCS costs, and research and development of CO_2 capture technology is being promoted around the world. The costs are also greatly influenced by the method of transport, transport distance, and storage site (terrestrial or marine).

The costs shown above assume a large single source and a large single reservoir. Recently, new ideas regarding a business model for cost reduction have also been proposed, such as the hub and clustering concept, which combines multiple, relatively small emission sources and reservoirs.

(2) Future cost estimates

(a) Potential cost reductions

As the introduction of CCS proceeds, further cost reductions are expected due to the "learning by doing" factor, competition between vendors, economies of scale through large-scale introduction, and reductions in business risks[50].

For instance, the capture costs at Petra Nova are 35% lower than at Boundary Dam, which was built just a few years earlier[51], while a detailed feasibility study for retrofitting the Shand coal-fired power station in Canada with CCUS suggests that cost reductions of around 70% for CAPEX and OPEX are possible, relative to the Boundary Dam project[52].

In the Sustainable Development Scenario proposed by IEA, CO_2 capture costs reduction based on learning-by-doing, learning-by-researching, and spillover effects for applications in both power and industrial sectors has been estimated to be around 35% between 2019 and 2070[53].

Furthermore, innovative technologies are also being developed to reduce costs significantly. As shown above, CO_2 capture accounts for a major portion of CCS costs, and low-cost CO_2 capture technologies are under development around the world. In Japan, the targets are shown in the road map for carbon recycling technologies by METI. The costs of CO_2 capture from combustion flue gas are between 4,000 to 6,000 yen/t-CO_2 using current technology, but the target is 2,000 yen/t-CO_2 by 2030.

49 METI, NEDO, Japan CCS (2020), Report by Tomakomai CCS Demonstration Project at 300 thousand tonnes of cumulative injection, May 2020

50 GCCSI (2021), Technology Readiness and costs of CCS

51 GCCSI (2019), The Global Status of CCS 2019

52 IEAGHG (2018), Information Paper 2018-36: Update on the Shand Power Station CCS Feasibility Study by the International CCS Knowledge Centre

53 IEA (2020), Energy Technology Perspectives 2020 - Special Report on Carbon Capture Utilisation and Storage, CCUS in clean energy transitions.

Table 5-29 Development targets for CO_2 capture technology in Japan

Target for 2030	Target from 2040 onwards
For low-pressure gas (CO_2 separation from flue gas, blast furnace gas, etc. at several percent and under normal pressure) JPY 2,000 level/t-CO_2 Chemical absorption, solid absorption, physical absorption, etc.	<Commercialization of CO_2 capture technology> Achieve JPY 1,000/t-CO_2 or lower
For high-pressure gas (CO_2 separation from chemical process/fuel gas, etc. several percent and several MPa) JPY 1,000 level/t-CO_2 Physical adsorption, membrane separation, physical adsorption, etc.	
Overall review of other processes (power generation and chemical synthesis systems with CO_2 separation and capture) JPY 1,000 level/t-CO_2 Closed IGCC/Chemical looping, etc.	

Source: METI (2021)[54]

As for capture technologies, in addition to economies of scale, significant cost reductions are expected through technological innovation. For transport and storage, except for large-scale transport of CO_2 by ships, these technologies are mature, and transport and storage costs are not expected to change significantly in the future. However, Rubin (2015) estimates[46] that the transport cost is 0-7 USD/t-CO_2, and the storage cost is 1-12 USD/t-CO_2. This means that the impact on the total CCS cost (around 100 USD/t-CO_2) is relatively small.

[54] METI (2021), Road map for carbon recycling technologies (July 2021 Revision), https://www.meti.go.jp/english/press/2021/pdf/0726_003a.pdf

5.3.5 Proposals for the Introduction of CCUS

Indonesia has made an international commitment in the Paris Agreement to reduce GHG emissions by 29% by 2030, or by 41% with international support. In consideration of the increasing demand for oil and gas due to future economic development, CO_2-EOR and CO_2-rich gas field developments are required. MEMR is planning to proceed with this. Additionally, coal-fired power plants will continue to be an important energy source for Indonesia, but headwinds against coal-fired power plants are blowing, such as the joint statement to phase out unabated coal-fired power plants at UNFCCC's COP26 in 2021. The application of clean coal technologies, including CCS, is necessary to achieve low-carbon goals while maintaining a stable power supply.
According to the Country Assistance Policy for Indonesia, published by Japan's Ministry of Foreign Affairs, to enhance capacity to address issues in the Asian region and international society, Japan will offer assistance for Indonesia to address global issues, such as environmental conservation and climate change. In a rolling plan for Indonesia, to promote climate change mitigation and adaptation measures, Japan is providing support for the improvement and development of policies and systems, government capacity building, and the introduction and development of low-carbon technologies, while also leveraging Japan's strengths. Providing support related to Japan's CCS technology is consistent with these policies.
No CCS project, including CO_2-EOR projects, has been implemented in Indonesia yet, and it is assumed that Indonesia does not have enough experience or technology in CCS. Japan has implemented the large-scale CCS demonstration project in Tomakomai and other demonstration projects for CO_2 capture from various emission sources, and has sufficient technical knowledge on CCS. Therefore, technical cooperation, such as the dispatching of experts, is possible.
As shown in the concept of hub and clustering CO_2 management, the development of infrastructure is important to reduce costs related to CCS, and loan aid for CCS infrastructure, such as CO_2 pipelines, would be an option. However, the challenge is that there is no entity to operate and manage CCS infrastructure like CO_2 pipelines due to there being no incentives for a CCS project. It is necessary to design a system to address this issue at the same time.

With regard to the concept of hub and clustering CO_2 management, which has already been studied in some regions, it would be useful for JICA to support the establishment of a roadmap for the development of CCS hubs and clustering by conducting detailed studies on suitable CCS sites and estimated CO_2 emissions in regions that are expected to produce a certain level of CO_2 emissions in the future. This would provide a basis for considering the use of CCS not only in the power sector but also in the industrial sector.
CCU is expected to have a variety of applications, such as in chemicals, fuels, and mineralization, and is attracting worldwide interest because of its great potential in realizing a carbon-neutral society. However, most technologies are still in the R&D stage and have yet to be widely adopted due to high costs and other issues. In addition, since some CCU technologies may cause CO_2 to be re-emitted into the air in a short period, methods for evaluating the long-term effects of CO_2 emissions reduction are still being studied. First, it would be essential to proceed with technological demonstration projects in Japan and promote the verification of CO_2 emission reduction effects. Then, while keeping a close eye on global CCU trends, it is expected that the government will promote the deployment of the technology and support the design of the system for CCU in Indonesia and other countries in the future.

With regard to CCUS, the following items should be implemented in the future.

(1) Policy development to promote CCS introduction in Indonesia

The current issue is that there is no economic income from CO_2 capture and storage alone, and no incentive to implement CCS projects. It is important to consider promotion policies and institutions to boost CCS projects in Indonesia.

(2) Development of master plan for the introduction of CCS in Indonesia

In order to promote CCS projects in the future, it is important to establish a master plan for the development of CCS from a long-term perspective, and to proceed with the construction and operation of facilities according to this plan. Specifically, the following studies will be conducted.

- Survey of suitable sites for CO_2 storage in Indonesia
- Wholistic study of CO_2 emission sources, including both thermal power plants and other industrial facilities
  - ✓ Estimation of how much CO_2 will be generated and for how long
- Study on configuration of CO_2 transport pipeline network/shipping scheme
- Select sites for demonstration tests of a combination of thermal power plants and CCS, based on the most feasible CO_2 storage sites and the current status of existing thermal power plants (coal or gas) from the considerations above.

(3) Feasibility study and demonstration tests for CCS projects at specific locations

No CCS project (including CO_2-EOR projects) has been implemented in Indonesia yet, and it is assumed that Indonesia does not have enough experience and technology in CCS. So, with the support of a third country such as Japan, which already has technical expertise, demonstration tests for CCS to store exhaust gas from thermal power plants (coal or gas) should be conducted in Indonesia.

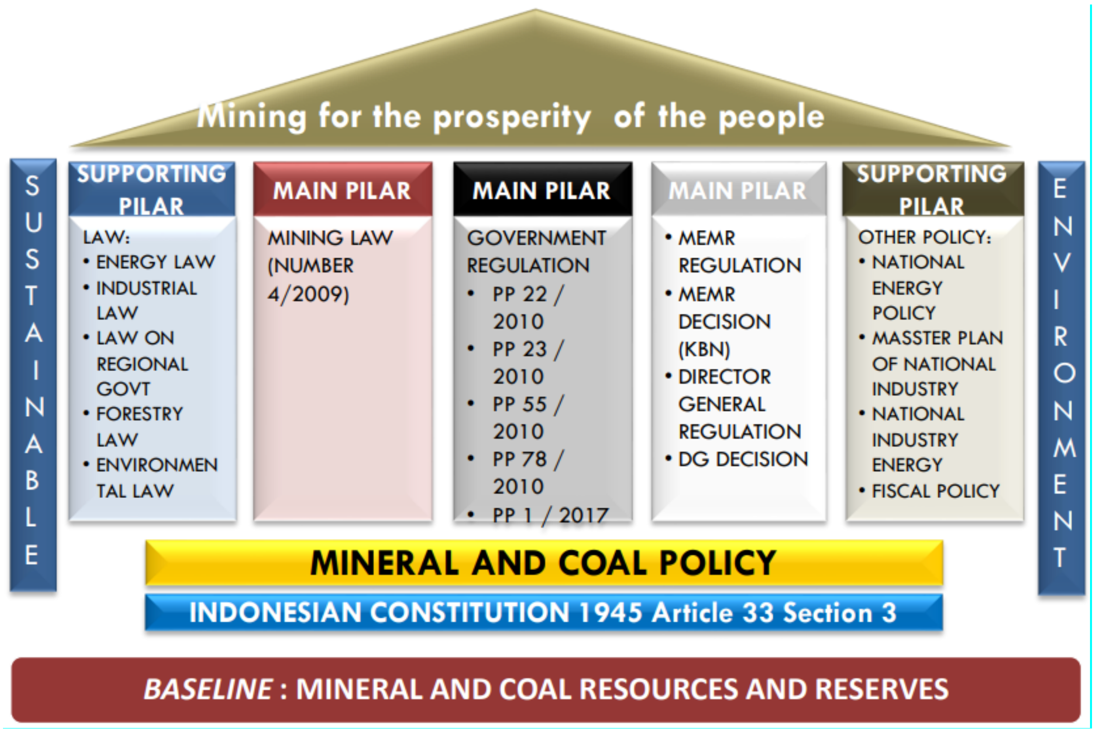
Chapter 6. Primary Energies and Renewable Energies

6.1 Primary Energy Supply and Demand Balance

6.1.1 Legal System for Primary Energies

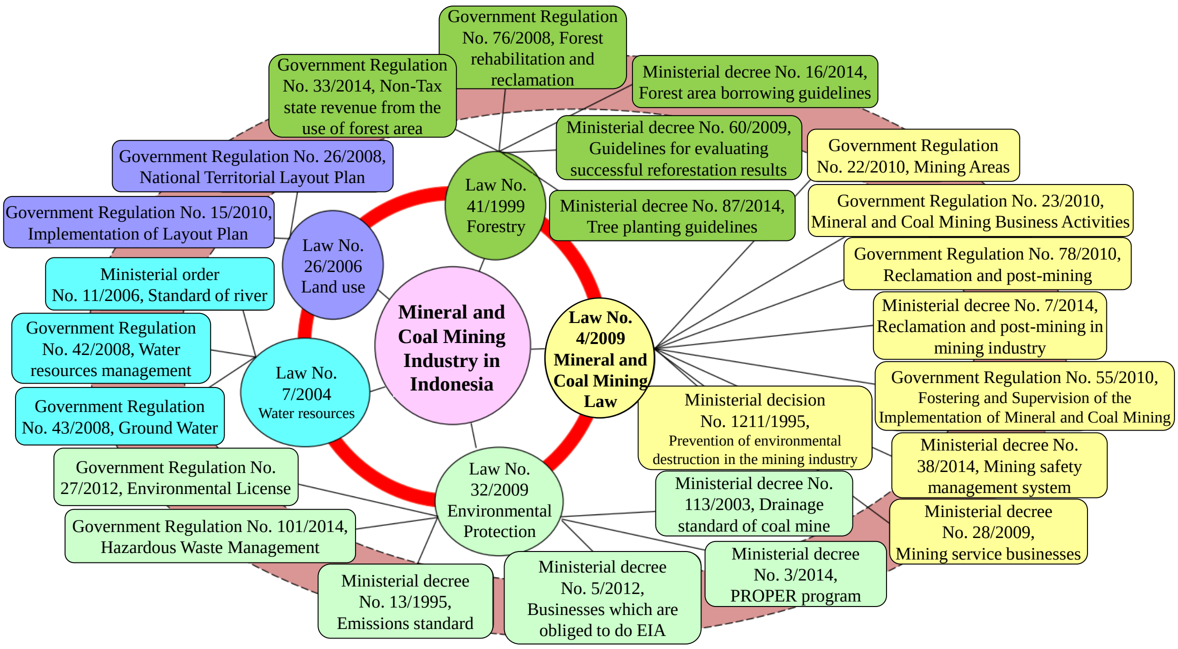
In Indonesia, where natural resources are abundant, Article 33, Paragraph 3 of the "The 1945 Constitution of the Republic of Indonesia" states that “The land, the waters and the natural resources within shall be under the powers of the State and shall be used to the greatest benefit of the people.” and policies have been pursued with the aim of maximizing the benefits to the people. In addition, the Indonesian government attaches great importance to “energy security”, with the aim of securing a stable domestic supply in response to increasing domestic demand, as an energy policy.
Therefore, the "Energy Law (Law No. 30/2007; see Chapter 2.1)" enacted in 2007 stipulates that domestic supply should be prioritized over exports to provide a stable energy supply. For example, with regard to oil and natural gas, the "Oil and Gas Law (Law No. 22/2001)", which was enacted in 2001, imposes a domestic supply obligation on developers of up to 25% of oil and natural gas production. Regarding coal, the government's authority to set annual production and export volumes is stipulated in the “Mineral and Coal Mining Law (Law No. 4/2009)”, which was enacted in 2009, and a Domestic Supply Obligation (DMO) policy for coal mining companies has also been introduced. In addition, the “National Energy Policy (DEN)” was signed by the President in October 2014 to promote the deployment of new and renewable energy and to promote energy conservation while reducing the country’s dependence on fossil energy. In terms of natural resource exports, domestically produced coal and natural gas are expected to gradually reduce in export volume and eventually be stopped completely, considering future domestic demand increase.

Figure 6-1 shows an overview of Indonesia's coal policy.
The law that regulates the country's coal business is the “Mineral and Coal Mining Law”. It was deliberated in parliament for three years and seven months after the bill was drafted in May 2005, and was signed by the President in January 2009. After that, it was promulgated and enforced.
Under the law, the coal mining business license system was unified to a system in which licenses are issued by the national or local government. Also stipulated is an obligation to add value to products (smelting and refining) in Indonesia, and the granting to the Government of authority to control export volumes. As shown in Figure 6-2, amendments to the law and various related regulations are still being launched one after another.
To date, Indonesia has introduced a Domestic Market Obligation (DMO) policy that allocates at least 25% of coal production to domestic markets for domestic coal miners. In December 2020, the Minister of Energy and Mineral Resources promulgated a new ministerial order (No. 255.K/30/MEM/2020) to maintain the DMO policy. According to the ministerial order, coal miners who defaulted on DMO in 2021 will be fined a penalty according to the amount not reached.
In the DMO, coal prices for domestic power plants are limited to 70 USD/ton, while coal prices are soaring. Therefore, there is concern that more companies will choose to export over DMO implementation. In August 2021, the ministry promulgated a new ministry decree stipulating that coal miners who did not meet the DMO quota would be sanctioned in the form of export bans and sanctions.



(Source: MEMR, Directorate General Of Mineral And Coal, January 2020)

Figure 6-1 Overview of Indonesia's coal policy



(Source: JOGMEC report (2016))

Figure 6-2 Indonesian regulations regarding Mineral and Coal Mining

6.1.2 Actual Data on Primary Energy Supply and Demand Balance

(1) Primary energy production and domestic supply (see Table 6-1)

According to MEMR's Handbook of Energy & Economic Statistics of Indonesia 2020, Indonesia's domestic primary energy supply in 2020 was approximately 1,494 million barrels of oil equivalent (BOE).

The total energy production in 2020 was about 3,218 million BOE, of which 73.6% was coal, 11.7% was natural gas and 8.1% was oil, and fossil energy alone accounted for 93.3% of the total energy production.

In terms of energy imports and exports, while coal is net-exported, crude oil, liquefied petroleum gas (LPG), and fuel are net-imported.

For LPG, which relies on imports for 75% of its demand, the Minister of Energy and Mineral Resources announced in January 2021 a policy to achieve zero LPG imports in 2030 and promote the replacement of LPG with dimethyl ether (DME), which uses coal as a raw material.

Table 6-1 Indonesia Primary Energy Supply in 2020 (Thousand BOE)

	Production (a)	Import (b)	Export (c)	Stock Change (d)	Primary Energy Supply (a)+(b)+(c)+(d)
Coal	2,367,659	36,777	-1,701,222	-149,289	553,924
Natural Gas	375,357	0	-33,079	0	342,278
Crude Oil	259,247	79,685	-31,448	907	308,391
Biofuel	55,748	0	-232	0	55,516
Biogas	177	0	0	0	177
LPG	0	54,532	-2	-1,288	53,242
LNG	0	0	-91,135	0	-91,135
Fuel[55]	0	116,743	-3,576	-2,091	111,076
Hydro Power	45,457	0	0	0	45,457
Geothermal	28,909	0	0	0	28,909
Solar	725	0	0	0	725
Wind	1,164	0	0	0	1,164
Other Renewable	30,354	0	0	0	30,354
Biomass	53,365	0	0	0	53,365
Total	3,218,253	287,736	-1,860,694	-151,761	**1,493,534**

(Source: MEMR, Handbook of Energy &Economic Statistics of Indonesia 2020)

[55] Fuel includes Gasoline, Avgas, Avtur, Kerosene etc.

(2) Final Energy Supply (see Table 6-2)

Table 6-2 shows the actual domestic final energy supply in Indonesia in 2020. Coal is used not only for export but also for domestic coal-fired power.

Table 6-2 Indonesia Final Energy Supply in 2020 (Thousand BOE)

	Primary Energy Supply (a)	Power Plant (b)	Other Energy Transformation (c)	Own Use and Losses (d)	Final Energy Supply (a)+(b)+(c)+(d)
Coal/Briquette	553,924	-440,286	-34	0	113,604
Natural Gas	342,278	-71,800	-126,568	-32,538	111,371
Crude Oil	308,391	0	-302,344	-6,047	0
Biofuel	55,516	0	-54,494	0	1,022
Biogas	177	0	0	0	177
LPG	53,242	0	16,381	0	69,623
LNG	-91,135	-22,383	120,833	0	0
Fuel	111,076	-14,153	305,969	-772	402,119
Electricity	0	178,969	0	-21,359	157,610
Hydro Power	45,457	-45,457	0	0	0
Geothermal	28,909	-28,909	0	0	0
Solar	725	-725	0	0	0
Wind	1,164	-1,164	0	0	0
Other Renewable	30,354	-30,354	0	0	0
Biomass	53,365	0	0	0	53,365
Total	**1,493,534**	-476,354	-49,414	-68,032	**908,892**

(Source: MEMR, Handbook of Energy &Economic Statistics of Indonesia 2020)

(3) Final Energy Consumption (see Table 6-3)

Table 6-3 shows the actual domestic final energy consumption in Indonesia in 2020.

Table 6-3 Indonesia Final Energy Consumption in 2020 (Thousand BOE)

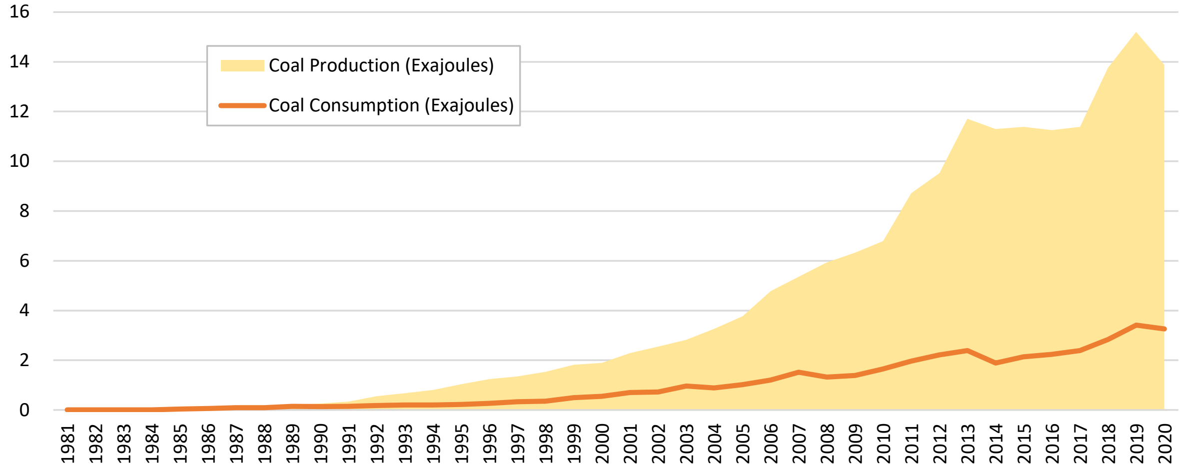
	Final Energy Supply (a)	Statistics Discrepancy (b)	Final Consumption (a)+(b)	Non Energy Use (d)	Final Energy Consumption (a)+(b)-(d)
Coal/Briquette	113,604	0	113,604	0	113,604
Natural Gas	111,371	10,720	122,091	24,616	97,476
Crude Oil	0	0	0	0	
Biofuel	1,022	-1,022	0	0	0
Biogas	177	0	177	0	177
LPG	69,623	0	69,623	0	69,623
LNG	0	0	0	0	0
Fuel	402,119	0	402,119	0	402,119
Electricity	157,610	4,551	162,161	0	162,161
Biomass	53,365	0	53,365	0	53,365
Total	**908,892**	14,249	923,141	24,616	**898,525**

* Hydropower, Geothermal, Solar, Wind, and Other Renewable are deleted because the final energy supply is zero.

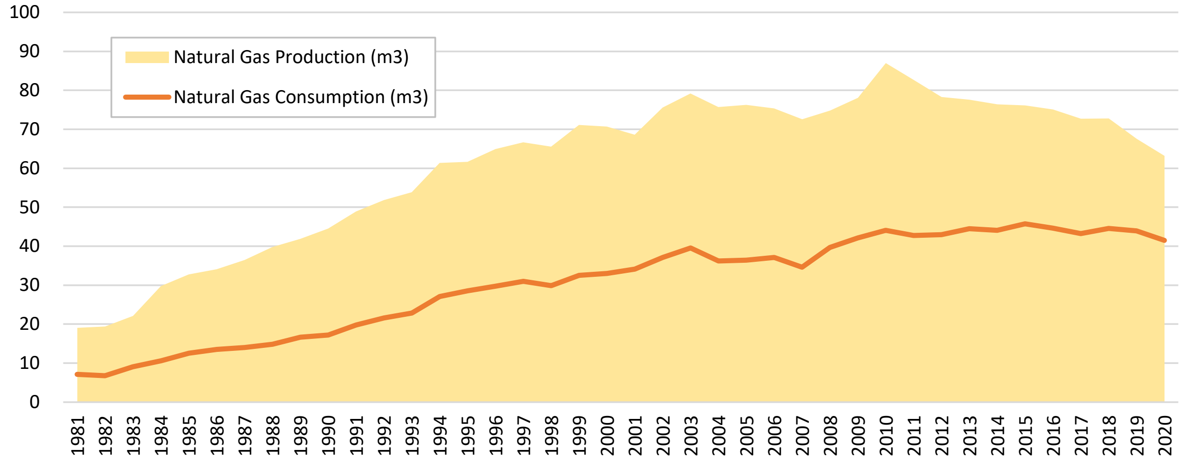
(Source: MEMR, Handbook of Energy &Economic Statistics of Indonesia 2020)

(4) Trends in coal, natural gas, and oil production and consumption (see Figure 6-3)

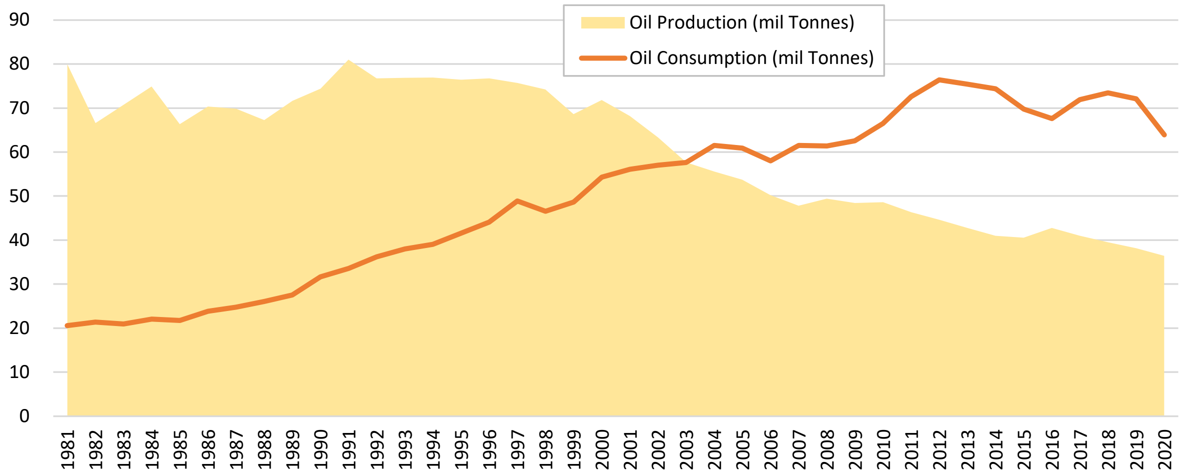
Figure 6-3 shows changes in coal, natural gas, and oil production and consumption from 1981 to 2020. With regard to oil, international majors refrained from exploration investment in response to major political change due to the collapse of the Suharto administration in 1998, and while production has been on a downward trend since 1998, domestic consumption has consistently increased, and consumption exceeded production in 2003. Since then, Indonesia has become a net consumer of oil and withdrew from the Organization of the Petroleum Exporting Countries (OPEC) in 2008.



(a) Coal



(b) Natural Gas



(c) Oil

(Source: BP, Statistical Review of World Energy 2021)

Figure 6-3 Trends in coal, natural gas, and oil production and consumption (1981-2020)

6.1.3 Potential Amounts and Areas for Primary Energies

Indonesia has abundant natural resources, such as oil, natural gas, coal, hydropower and geothermal, and the country exports oil, natural gas and coal. Table 6-4 shows the trends of proved fossil energy reserves. Proved reserves of coal are 34.87 billion tons (anthracite and bituminous: 23.14 billion tons, subbituminous and lignite: 11.73 billion tons), and the world's 7th largest reserve share (3.2%) after the United States (23.2%), Russia (15.1%), Australia (14.0%), China (13.3%), India (10.3%), and Germany (3.3%). As of the end of 2020, the Reserves-to-Production Ratio (R/P ratio) is 9.0 for oil, 19.8 for natural gas, and 62 for coal.

Table 6-4 Trends of proved fossil energy reserves in Indonesia

	2000	2010	2018	2019	2020
Oil (Thousand million barrels)	5.1	4.2	3.2	2.5	2.4
Natural Gas (Trillion cubic metres)	2.7	3.0	2.8	1.4	1.3
Coal (Billion tonnes)	—	—	37.00	39.89	34.87

(Source: BP, Statistical Review of World Energy 2021)

Table 6-5 shows renewable energy potential. Indonesia has great renewable energy potential and its geothermal potential is 23.9 GW, hydropower 94 GW, biomass 32.6 GW, wind 60.6 GW, solar energy 208 GW and ocean energy 17.9 GW. However, the development rates are generally low due to the high production costs of renewable energy.

Table 6-5 Renewable energy potential in Indonesia

Energy Source	Potential	Developed (as of 2020)[56]	Development rate
Geothermal	23.9GW	2,131MW	8.92%
Hydro	94GW	6,141MW	6.53%
Bio PP	32.6GW	1,767MW	5.42%
Wind	60.6GW	1,543MW	2.55%
Solar energy	208GW	1,850MW	0.09%
Ocean energy	17.9GW	—	0.00%

Source: DEN, Indonesia Energy Outlook 2019, and MEMR, Handbook of Energy &Economic Statistics of Indonesia 2020

[56] Total value of On-grid capacity and Off-grid capacity

6.2 Price Forecasts for various Fuels

The survey team has forecasted fuel prices through 2060 using international indicators of fuel prices, and uses them for simulations. If there were discrepancies between the international indicators and the assumed values in Indonesia in recent years, the survey team made corrections. The assumed values in Indonesia refer to Table 5.50 Assumptions of Fuel Prices in RUPTL 2021-2030. Table 6-6 shows the basis for the setting of various fuel prices. All prices shall be real prices in 2020.

Table 6-6 Basis for setting of various fuel prices

Items	Value setting basis
Coal – High Grade	Set by the survey team with reference to IEA World Energy Outlook 2021 and RUPTL 2021-2030
Coal – Mid Grade	Set by the survey team with reference to IEA World Energy Outlook 2021 and RUPTL 2021-2030
Coal – Low Grade	Set by the research team with reference to the market research price and RUPTL 2021-2030
Natural gas	Set by the survey team with reference to IEA World Energy Outlook 2021 and RUPTL 2021-2030
LNG	Set by the survey team with reference to IEA World Energy Outlook 2021 and RUPTL 2021-2030
Oil	Set by the survey team based on the market research price
Hydrogen	Set by the survey team. For details, see Section 5.2.2.
Ammonia	Set by the survey team. For details, see Section 5.2.2.
Biomass	Set by the survey team. USC 2.913/Mcal until 2060. For details, see Section 6.4.5.

Figure 6-4 shows the coal price forecast up to 2060.

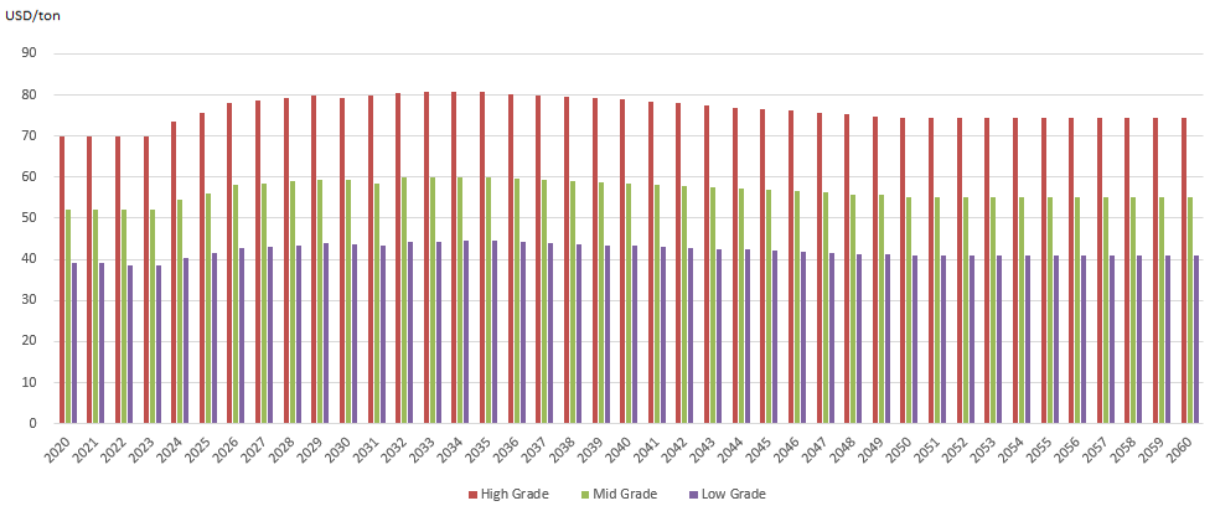


Figure 6-4 Coal price forecast up to 2060

Figure 6-5 shows the gas price forecast up to 2060.

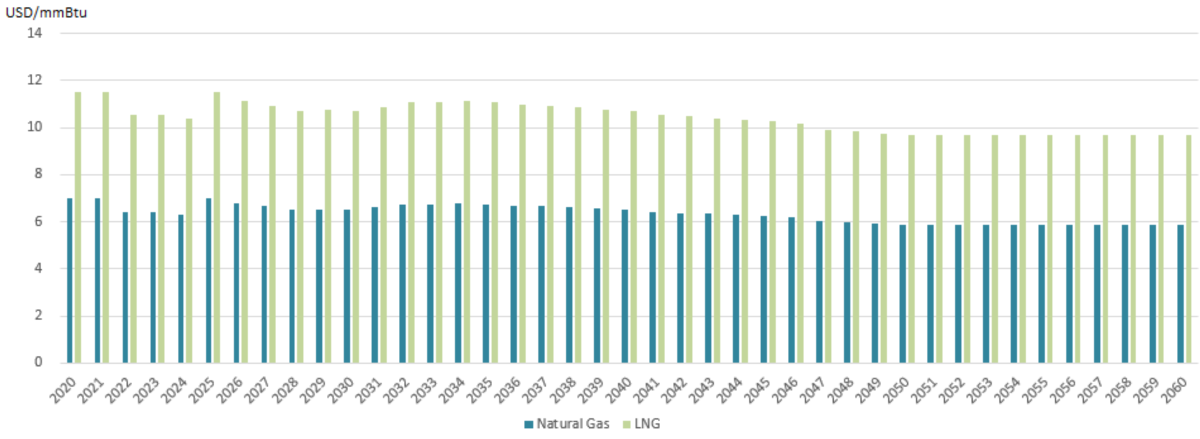


Figure 6-5 Gas price forecast up to 2060

Figure 6-6 shows the oil price forecast up to 2060.

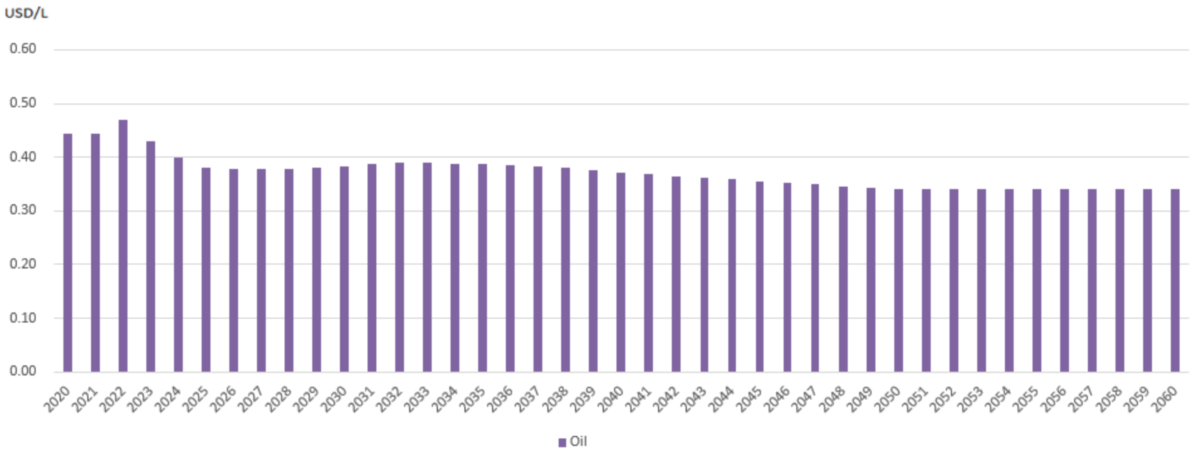
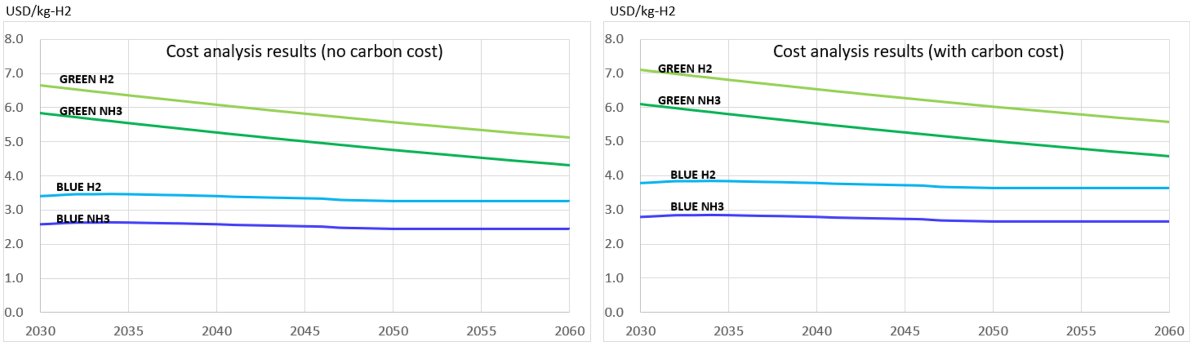


Figure 6-6 Oil price forecast up to 2060

Figure 6-7 shows the blue hydrogen and blue ammonia price forecast up to 2060.

(Base Scenario)



(Cost Reduction Option)

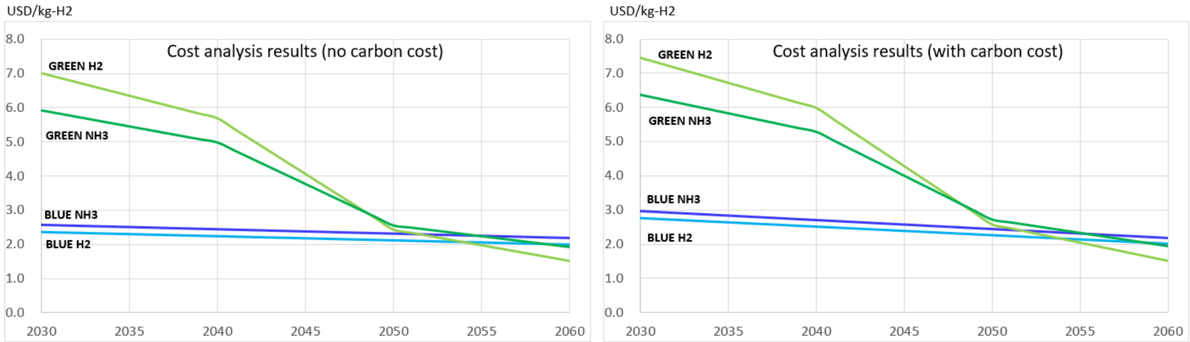
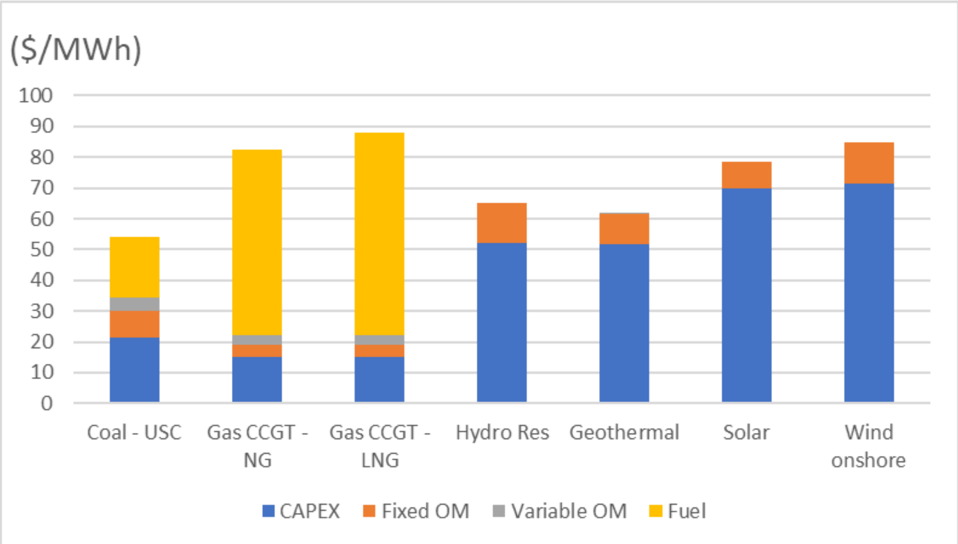


Figure 6-7 Blue hydrogen and blue ammonia price forecast up to 2060

6.3 Renewable Energy Introduction Trends

At the G20 meeting and in the Paris Agreement, Indonesia declared that greenhouse gas emissions should be reduced by 29% from the normal level (Business As Usual) by 2030, and by 41% subject to international assistance.
According to the Power Supply Business Plan (RUPTL 2021-2030), coal and oil (32.0 GW, 50.4% of total installed capacity), natural gas, and diesel (23.4 GW, 37.0%) from fossil fuels accounted for the majority of the installed power capacity in 2020. Despite the Indonesian government's international commitments under the Paris Agreement and other agreements mentioned above, the power generation capacity from renewable energy sources, including hydropower, is still less than 13%. Renewable energy is also largely dependent on hydropower (5.17 GW, 8.17%) and geothermal energy (2.44 GW, 3.86%). The installed capacity of wind power and solar power is about 150 MW each, showing that little progress has been made in the installation of renewable energy.
Indonesia's highest energy sector program, the National Energy Plan (KEN 2014), sets high targets for reducing the dependence on fossil fuels to meet the increasing energy demand, and for renewable and new energy to account for at least 23% of primary energy by 2025, and 31% by 2050.
One of the challenges in improving the adoption of renewable energy in Indonesia is the high levelized cost of electricity (LCOE) by solar and wind power source, and the current feed-in tariff system has created a price war with cheaper power sources such as coal and hydro, in some regions. The LCOE of coal-fired power plants is less than US $50 per MWh, while that of solar PV and onshore wind is about US $80 per MWh (Figure 6-8).



Source: Survey team based on McKinsey GEP and IESR survey e

Figure 6-8 LCOE Comparison by Power Supply

6.3.1 Renewable Energy Policy

As mentioned above, Indonesia aims to supply 23% of its total electricity from new and renewable energy sources by 2025 in its National Energy Policy, which outlines its energy policy up to 2050. New energy sources, however, include technologies such as nuclear, hydrogen, coal bed methane, and coal gasification and liquefaction.
Specifically, the National Energy Policy specifies the following optimal energy mix targets for the share of primary energy sources.

- In the 2025 cross section, new energy and renewable energy will be sources of at least 23% if oil accounts for less than 25%, coal for at least 30%, and natural gas for at least 22% of each share of fossil fuels, assuming economic viability.

- In the 2050 cross section, the target is for new energy and renewable energy sources to be at least 31% of the total supply if oil is less than 20%, coal is 25% or more, and natural gas is 24% or more for each share of fossil fuels, assuming economic viability.

In this context, the National Electricity General Plan (RUKN 2019 -2038) states that the total share of new energy and renewable energy in electricity generation in 2025 could exceed 23% in order to promote targets for the introduction of new and renewable energy. In 2038, the share of new and renewable energy is expected to increase to about 28%.

The most recent Power Supply Plan(RUPTL 2021) targets the addition of 9.2 GW of hydropower, 3.3 GW of geothermal power, 4.6 GW of solar PV, 1.1 GW of small hydro power, and 2.4 GW of other renewable energy from 2021 to 2030. By 2030, renewable energy will account for 20.9 GW of development, or more than half of the 40.6 GW of additional capacity (Table 6-7). Compared with the previous power supply plan (RUPTL 2019), 4.2GW of renewable energy has been added , which is about 25% of the total, while the installed capacity of fossil fuel power generation to be installed has been reduced by about half. The New and Renewable Energy (EBT) -based project is a renewable energy power generation project that will assume the base load as an alternative to the coal-fired power generation project planned by 2025. This will generate base load power by combining it with gas.

Table 6-7 Renewable energy development targets for the next 10 years under the Power Supply Plan 2021

	RE type	Unit	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
1	Geothermal	MW	136	106	190	141	870	290	123	450	240	808	3,355
2	Hydro	MW	400	53	132	87	2,478	327	456	1,611	1,778	1,950	9,272
3	Mini/Micro Hydro	MW	144	154	277	289	189	43		2	3	6	1,118
4	Solar	MW	60	287	1,308	624	1,631	127	148	165	172	157	4,680
5	Wind	MW	-	2	33	337	155	70	-	-	-	-	597
6	Biomass/Waste	MW	12	43	88	191	221	20	-	15	-	-	590
7	EBT base	MW	-	-	-	-	-	100	265	215	280	150	1,010
8	RE peaker	MW	-	-	-	-	-	-	-	-	-	300	300

Source: Compiled based on RUPTL 2021

In terms of power generation, hydro and geothermal power accounted for 44 TWh and 43 TWh, or about 10%, respectively, of the total of 445 TWh generated in 2030, and other renewable energy sources, including solar and wind power, accounted for 9.6 TWh, or about 2.1% (Table 6-8).

Table 6-8 Comparison of Power Generation by Type under Power Supply Plan 2021

	RE Type	Unit	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Hydro	GW h	18,750	18,629	20,531	22,454	28,291	31,802	33,615	37,350	41,574	44,256
2	Geothermal	GW h	15,849	16,571	18,009	18,875	26,785	30,550	31,441	34,380	36,173	43,215
3	other RE(EBT)	GW h	2,031	3,541	6,044	8,958	26,449	22,681	22,516	19,240	16,519	9,655
4	Solar	GW h	106	823	1,241	1,547	2,255	2,339	2,399	2,469	2,551	2,630
5	Wind	GW h	477	477	567	1,880	2,839	2,898	3,088	3,087	3,088	3,087
6	Rubbish	GW h	59	91	91	285	1,615	1,601	1,624	1,605	1,603	1,596
7	Biomass	GW h	777	1,879	3,874	5,003	19,666	15,763	15,323	11,991	9,182	2,248
8	Other	GW h	612	271	271	243	74	80	82	88	95	94

Source: Compiled based on RUPTL 2021

(1) Regulations and Supervisory Entities

Electricity business in Indonesia is regulated by the Electricity Act (Act No. 30 of 2019). In addition to being supervised by the Ministry of Energy and Mineral Resources (MEMR: Ministry of Energy and Mineral Resources), renewable energy power generation is supervised by DJEBTKE (Directorate General of New, Renewable Energy and Energy Conservation: Directorat Jenderal Energi Baru Terbarukan dan Konservasi Energi).

Electricity supply from renewable energy sources is also subject to Regulation No. 50 of the MEMR 2017 (as amended by Regulation No. 4 of the MEMR 2020), which establishes rules related to the Energy Act (DEN, Law No. 30, 2007) and Power Purchase Agreements (PPA), laws governing the energy sector. Furthermore, for geothermal power generation, in addition to the Geothermal Law (Law No. 21 of 2014), the Government Regulation on Indirect Utilization of Geothermal Energy (Government Regulation No. 7 of 2017) and the MEMR Regulation on Geothermal Utilization Areas, Granting of Geothermal Licenses, and Allocation of Geothermal Projects (MEMR Regulation No. 37 of 2018) apply.

Power and renewable energy matters are subject to central or local government authority, depending on their content, but many important matters are subject to central government authority through MEMR and DJEBTKE, as described below (Table 6-9). All important central and local government licenses are essentially available through a system called Online Single Submission.

Table 6-9 Role sharing between central government and local government

Central government	Local government
a. National policies, laws, regulations, guidelines and standards for power sector, as well as RUKN b. Approval of electricity charges for general consumers and IPP's electricity tariff purchased by PLN c. Determination of IPP business license area d. Granting licenses for a power supply business which spans multiple regions e. General supervision	a. Local power business regulations/power plans b. Regional regulations such as environmental regulations and Supervision of license compliance

(Source: Nishimura & Asahi Resource/Energy Newsletter.)

(2) Electricity Supply Business and Foreign Investment Regulations

Electricity supply business is divided into several types according to the purpose (general supply or specific supply (self-use)). Power supply to the general public includes (1) power generation, (2) transmission, (3) distribution and (4) electricity sales.

The Government of Indonesia relaxed restrictions on foreign investment in accordance with Presidential Decree No. 10 of 2021 on Investment Regulation, which allows foreign investment to contribute 100% to (1) power plants with a capacity of more than 1 MW, (2) power transmission and (3) electricity distribution. Foreign investment in transmission, which is also related to national security, may be regulated in the future, but there are no explicit regulations at present. (Foreign investors are not allowed to invest in power plants smaller than 1 MW.) MEMR Regulation No. 48 of 2017 on the Supervision of Natural Resources and Energy Business prohibits IPP investors from transferring their equity interest to a third party before the start of IPP operations, except when transferring the equity interest to an affiliated company, etc., in which they own more than 90% of the equity interest (in this case, the transfer can be made with the approval of PLN). IPPs for geothermal power generation are exempt from this regulation. (Source: Resource/Energy Newsletter 2021, Nishimura & Asahi.)

In addition, foreign investment of up to 100% is allowed in consultation, EPC and OM related to power generation (Table 6-10).

Table 6-10 Overview of foreign capital regulations in the electric power industry

	Power generation		Transmission	Distribution
Business Type	Less than 1 MW	No foreign investment	Up to 100% foreign capital	Up to 100% foreign capital
	1 MW or more	Up to 100% foreign capital		
Consultation	Up to 100% foreign capital			
EPC	Up to 100% foreign capital			
OM	Up to 100% foreign capital			

Source: Prepared based on JETRO regulations on foreign investment in Indonesia

(3) Bidding system and feed-in tariff

In 2017, Indonesia's Ministry of Energy and Mineral Resources announced new rules for the purchase of renewable energy by state-owned utility PLN. These rules apply to solar, wind, biomass, biogas, geothermal, and hydropower tenders.

For power generation other than renewable energy, the purchase of power from IPPs should be conducted through public tendering, and direct selection or direct designation are only allowed under certain exceptional conditions. However, for renewable energy power generation, in order to promote foreign investment, PLN is allowed to purchase electricity from IPPs directly by selection or designation. Direct selection or designation without public bidding is efficient for IPPs and their investors, both in time and cost.

According to the PLN Board of Directors Regulations on the Purchase of Electricity from Renewable Energy Sources (PLN No. 0062.P/DIR 2020) dated August 28, 2020, the procedures for direct selection and appointment are as below.

(a) Direct Selection

The selection procedure should compare proposals from at least two different IPPs and follow the capacity allocation determined by PLN for variable renewable power sources (e.g. solar and wind).

Regulation 50 of 2017 allows all direct selection procedures from qualification, proposal submission and evaluation to the conclusion of a PPA to be carried out within 180 days. However, in practice, it is necessary to assume that a period of more than 180 days may be required depending on the situation.

(b) Direct Appointment

Unlike direct selection, a single IPP is directly designated without requiring multiple IPPs to make proposals. Direct nominations may be made in the following situations:

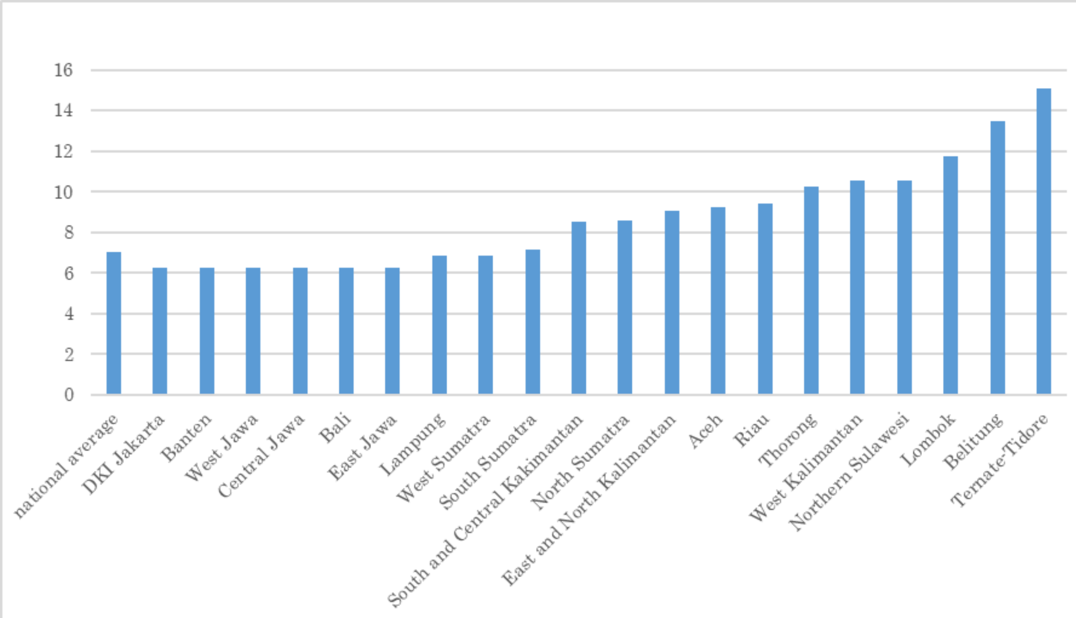
a. When there is only one candidate operator that can implement the work
b. In the event that the Government of Indonesia considers there to be a crisis or emergency situation in the supply of electricity in a specific region
c. In the case where there is a surplus of electricity in a specified area for a private power producer
d. If PLN determines that there is only one IPP capable of increasing the generating capacity of a power plant operating in the region (e.g., expansion of an existing power plant)
e. Specific Indonesian government projects (e.g., specific consignment from MEMR to PLN)

Regulation No. 50 of 2017 allows all procedures for direct designation from qualification, proposal submission and evaluation to the conclusion of a PPA to be implemented within 90 days. However, as with the direct selection procedure, it is necessary to assume that it will take more than 90 days in practice (in practice, it often takes about 6 to 8 months). Since the procurement process is short, there is a risk that price negotiations with PLN will not take much time, and a PPA will be concluded at the price offered by PLN.

For both direct selection and direct appointment, the PLN Board Regulation requires IPPs that generate renewable energy to meet the following conditions:

i) Involvement of EPC operators with experience in the construction of the same type of power plant
ii) Possession of a Project Development Cost Account that accounts for at least 10% of the total project costs (for geothermal power plants, the total project cost less the cost of geothermal exploration).
iii) Compliance with the management requirements for beneficial ownership (including the submission of information on the structure of the IPP beneficial ownership and the highest level holder) and the policy guidelines and standards for the compliance system (Anti-Corruption and Insider Reporting Systems)
iv) Compliance with the technical requirements
v) Sufficient economic capacity (includes financial institution support)

The process for participating in the bidding is not clear, and the template for the power purchase agreements is not clear, so renewable energy projects may not be attractive to developers. PLN will purchase all electricity from renewable projects and pay tariffs based on regional generation costs (BPP, Figure 6-9). The PPA can last up to 30 years, but the build-own operate (BOO) method allows businesses to operate after the PPA expires. Bids must be registered in PLN's DPT (Qualified List). The most recent registration was for solar and bio-power generation, followed by hydropower last year and solar, wind and bio-power generation in 2019.



Source: Baker & McKenzie Indonesia: Government publications, PLN's 2020 BPP figures

Figure 6-9 Comparison of regional generation costs (USc/kWh)

With regard to Feed in Tariff, for solar, wind, biomass, and biogas projects, the maximum tariff paid for each project is limited to 85% of the cost of electricity generation by region if it exceeds the national average. If local generation costs are lower than the national average, the developer and the PLN will negotiate a fee. In this case, direct selection of the project is possible and the capacity is allocated. If the cost of waste, geothermal, and hydropower exceeds the national average cost of generation, 100% of the regional cost of generation is applied. If local generation costs are lower than the national average, rates can be negotiated. In Sumatra, Java, and Bali, however, rates can be negotiated regardless of local generation costs (Table 6-11).

Table 6-11 Fixed Price Basis For Each Type of Renewable Energy

RE type	Threshold	Price
Solar Wind Biomass Biogas Ocean Energy	Regional BPP＞National average BPP	Limited to 85% regional BPP price
	Regional BPP≦National average BPP	Agreed price with PLN
Hydro Waste Geothermal	Regional BPP＞National average BPP	Limited to regional BPP price
	Regional BPP≦National average BPP	Agreed price with PLN
Bio fuel	NA	Agreed price with PLN
Other Hydro		

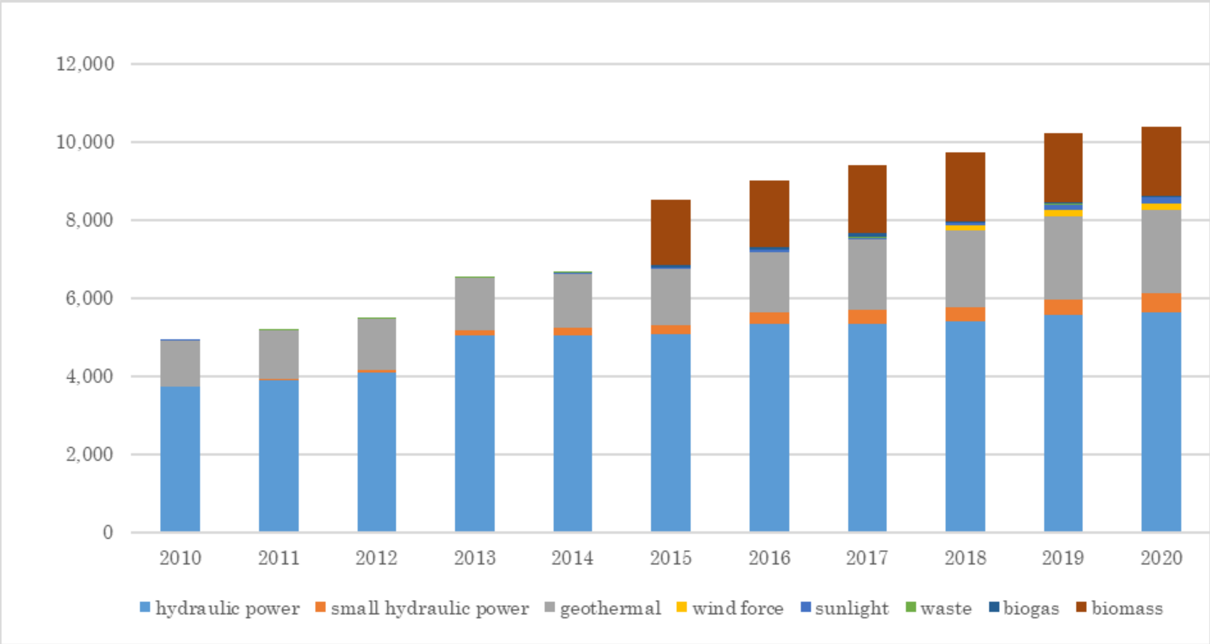
Source: Resource and Energy Newsletter, Nishimura & Asahi

(4) Local Content Requirements

The Electricity Law requires the preferential use of domestic products and services (local content), and the use of foreign products and services is permitted only when domestic products and services are not available. In this regard, the Ministry of Industry Regulation (No. 54/M-IND/PER/3/2012), which sets out guidelines for the use of domestic products and services for the development of electricity infrastructure, sets a minimum percentage of local content to be achieved for each type of renewable energy. For example, more than 60% of photovoltaic power generation needs to be provided by domestic products, and more than 28.95% of geothermal power generation larger than 110 MW needs to be provided by domestic products and services (EPC services, consulting services, etc.).

6.3.2 Renewable Energy Introduction Data and Future Outlook

The Indonesian government needs to expand its use of renewable energy in line with its international commitments to reduce greenhouse gas emissions. As mentioned in the preceding paragraph, the Indonesian government has set targets to increase the use of renewable energy to 23% by 2025, and 31% by 2050, thereby reducing the use of fossil fuels. However, the actual use of renewable energy at the end of 2020 was only about 13%. In terms of installed capacity, the total installed capacity of renewable energy, including large-scale hydropower, was about 10.4 GW (including off-grid) in 2020, accounting for about 14% of the 72 GW of total power supply. However, most of the renewable energy sources are hydro, geothermal, and biomass, with only about 150 MW for each of solar and wind power development (Figure 6-10).



(Source: Compiled based on Handbook-of-energy-and-economic-statistics-of-Indonesia 2020)

Figure 6-10 Trends in renewable power generation capacity over the past 10 years

With regard to renewable energy introduction trends in 2021, the Jakarta Post reported on October 26, 2021 that the Ministry of Energy and Mineral Resources does not expect investment in the new and renewable energy (NRE) sector to meet this year's target and It is assumed that the introduction of renewable energy is not proceeding as planned.

As of October, renewable energy investment totaled $1.12 billion in 2021, only 54% of the $2.04 billion target for the full year, as the pandemic has delayed several renewable energy projects. The

$1.12 billion was accounted for by investments in geothermal energy, other renewable energy projects, and bioenergy, amounting to $540 million, $350 million, and $200 million, respectively.
This year's installed renewable energy capacity, which increased by 386 MW between January and September, is only 44% of this year's target of 855 MW. The additional capacity brings the total installed renewable energy capacity in Indonesia to 10,888 MW.
The additional capacity of 386 MW is accounted for by 130 MW of hydropower, 71.6 MW of small hydropower, and 55 MW of geothermal power plants. Over the past 5 years, renewable generation capacity has increased by 1,469 MW, with an average annual growth rate of 4%, less than half the annual capacity growth required for renewable energy to account for 23% of the national energy mix target by 2025, according to the Institute for Essential Services Reform (IESR). The ministry also plans to meet the target through various initiatives, including the promotion of rooftop solar power generation and the use of biofuels.

6.4 Potential and Cost Outlook for various Renewable Energies

In Indonesia, renewable energy can be developed provided that:
- the balance of supply and demand in the local power system is maintained
- a feasibility study and grid study have been completed
- there are funds available for development
- the price complies with applicable regulations

PLN usually plans its projects in accordance with the demand-led principle, but in certain regions, such as Papua, PLN does not adhere to this principle. For example, PLN is planning to build the Baliem hydropower plant, with a capacity of 50 MW, and to electrify 7 additional provinces in the highlands of the Central Mountains that are not electrified. The project aims to revitalize economic activities in the region.

With regard to solar power in particular, PLN has a policy of developing centralized solar power plants and electrifying many remote areas far from the main power grid, such as undeveloped areas and islands adjacent to neighboring countries. This is driven by PLN's policy of providing remote people with access to electricity quickly.

Fuel consumption is reduced by selecting a site in consideration of technological and economic factors, such as the transportation costs of fuel to a concentrated solar power plant for settlement and the operation of solar power generation via a hybrid system with an existing geothermal power plant. In addition, PLN takes note of the alternative sources of primary and renewable energy available locally and the level of service provided there.

PLN is committed to providing electricity to industrial customers by using PLN-owned renewable power plants or by purchasing electricity from private companies (IPP).

In consideration of the above conditions, RUPTL 2021 estimates the development potential of each renewable energy type to be as follows (Table 6-12).

Table 6-12 Renewable energy developable capacity by type

	Type of renewable energy	Units	Potential	Remarks
1	Geothermal	GW	29.544	
2	Hydraulic power	GW	75.091	
3	Small hydraulic power	GW	19.385	
4	Bioenergy	GW	32.654	
5	Solar	GW	207.898	Sun: 4.80 kWh/m^2/day
6	Wind power	GW	60.647	Average wind speed over 4 m/s

(Source: RUPTL 2021)

6.4.1 Solar Power

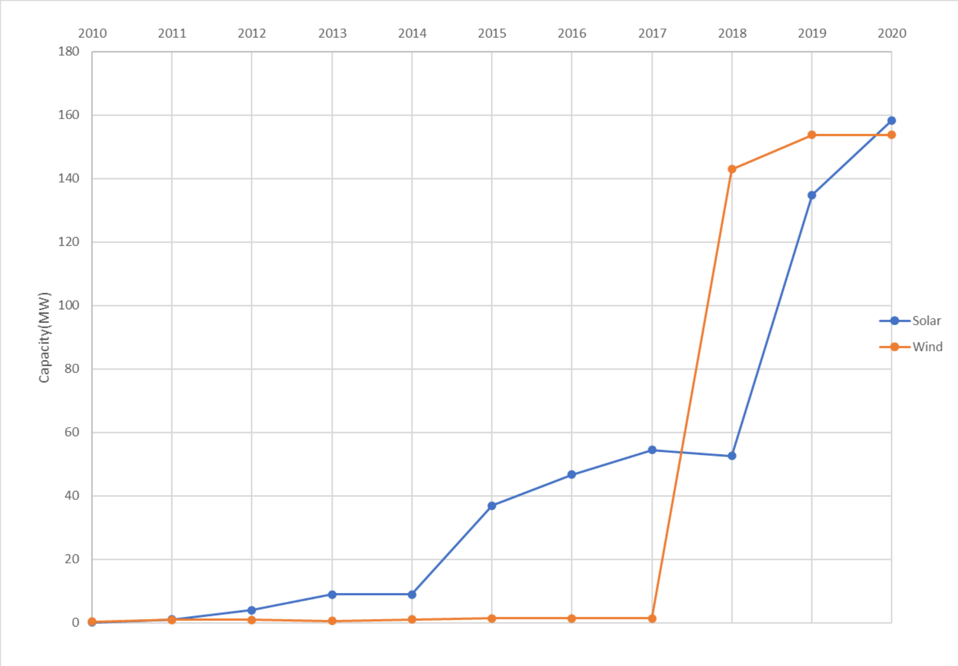
(1) Current Status of Photovoltaic Power Generation

In Indonesia, adoption is slow due to grid constraints and unattractive tariffs for electricity generated from solar power plants. As shown in the table below, solar PV installations have been on an increasing trend since 2018, but the capacity of grid-connected solar PV plants is about 120 MW, of which IPPs account for about 70%. As of the end of 2020, the installed capacity, including off-grid solar PV, was only about 160 MW (Figure 6-11). IPP power plants are listed below (Table 6-13).

Table 6-13 IPP listing of solar power plants

Project Name	Start date of operation	Power Generation Capacity (MWe)	business operator
Quantum Energi Gorontalo PV Plant	2020-01-31	14.5	Quantum Energi PT
Delapan Menit Energi Sambelia PV Plant	2019-12-31	7.25	Delapan Menit Energi PT
Hitachi ABB Power Grids Bontang PV Plant	2019-12-31	3	Hitachi Ltd.
Vena Energy North Sulawesi Rikupang PV Plant	2019-09-30	21	Vena Energy Holdings Ltd/Cayman Islands
Pertamina Persero Arkadaya East Kalimantan Bontang Badak PV Plant Phase II	2019-08-27	3	Pertamina Persero PT
Vena Energy West Nusa Tenggara Lombok Pringgabaya PV Plant	2019-07-31	7	Vena Energy Holdings Ltd/Cayman Islands
Vena Energy West Nusa Tenggara Lombok Selong PV Plant	2019-07-31	7	Vena Energy Holdings Ltd/Cayman Islands
Vena Energy West Nusa Tenggara Lombok Sengkol PV Plant	2019-07-31	7	Vena Energy Holdings Ltd/Cayman Islands
Global Karya Mandiri Atambua PV Plant	2019-07-30	1	Global Karya Mandiri PT
Indo Solusi Ende PV Plant	2019-03-31	1	Number Energi Surya Nusantara PT
Indo Solusi Maumere PV Plant	2019-03-31	1	Number Energi Surya Nusantara PT
Pertamina Persero Central Java Cilacap Rooftop PV Plant	2019-03-05	1.4	Pertamina Persero PT
Pertamina Persero Arkadaya East Kalimantan Bontang Badak PV Plant Phase I	2018-09-14	1	Pertamina Persero PT
SESJ Indonesia South Sumatra Palembang Jakabaring Sports City PV Plant	2018-04-10	1.6	Sharp Energy Solutions Corp.
Buana Energy Sumba Island PV Plant	2017-02-16	1	Number Energi Surya Nusantara PT
Global Karya Mandiri Kotabaru PV Plant	2016-12-31	1	Global Karya Mandiri PT
Sumalata Gorontalo PV Plant	2016-02-19	2	Brantas Abipraya Persero PT
Liberty Solar Laguindingan PV Plant	2016-01-31	1	Liberty Solar Energy Corp.
Len Industries Oelpuah PV Plant	2015-12-08	5	Len Industri Persero PT
Samalewa-Pangkajene Islands PV Plant	2014-04-10	1	N/A
Optimal Power Solutions Indonesia Hybrid PV Portfolio	2012-12-31	1.81	Perusahaan Persero PT Perusahaan Listrik Negara

Source: BloombergNEF



(Source: Compiled based on Handbook-of-energy-and-economic-statistics-of-Indonesia 2020)

Figure 6-11 Changes in installed capacity of wind and solar power

Indonesia does not actively promote mega solar power plants, but aims to develop them in remote areas where regional power generation costs are high. For example, the 1000 Solar Power Plants Program is a PLN solar energy development program in locations/islands with limited power system expansion or transmission access and transportation issues. Power plants are usually located in remote areas or on small islands.

Because photovoltaic power plants generate unstable, intermittent, and variable amounts of electricity, their operation requires backup power to compensate for the periods of time when clouds and night-time conditions reduce the amount of sunlight.

Therefore, in order to evaluate the feasibility of solar mini-grid projects in different regions with different supply-demand characteristics, a separate study is required. The solar power plants developed by PLN will be in the form of a solar power plant (utility scale) with a hybrid mode. The capacity of hybrid solar PV plants is adjusted to the primary energy potential at each site, taking into account population distribution and the difficulty of accessing remote areas.

The development of solar power plants aims to electrify remote areas as quickly as possible (increase the electrification rate), reduce the use of fossil fuels in supply, and reduce regional generation costs in specific areas where fuel transport costs are very high. In an effort to accelerate the development of renewable energy, especially solar energy, PLN has begun using hydroelectric dams as floating solar installations. In addition, it plans to install solar panels along railway tracks and toll roads .

The purchase price for electricity from solar power plants is regulated by Ministry of Energy and Mineral Resources Regulation No. 50 of 2017 on the use of renewable energy sources for the supply of electricity. It is expected that the rising trend of regional power generation costs (BPP) due to renewable energy tariffs will be suppressed.

One of the solar power technologies currently under development is rooftop solar power. Rooftop PV systems are smaller than ground-based PV systems.

The electricity generated from the system is supplied in full to a network (PLN) regulated by a feed-in tariff (FIT) or is used for self-consumption . Through the net metering system, customer generation offsets the power energy from the PLN network system.

Regional differences in power system quality require rules for interconnection between rooftop PV systems and systems for the operation of connected rooftop PV systems (grid codes). These rules are designed to regulate the technical requirements for PV mini-grid connections based on system

characteristics. The rules allow for the optimization of rooftop PV system connections and reduce the probability that the system will be affected by intermittent PV plant output fluctuations.
The use of rooftop solar PV is regulated by Ministry of Energy and Mineral Resources Regulation No. 49 of 2018 (as amended by Ministry of Energy and Mineral Resources Regulation No. 13 of 2019). The issuance of this regulation is expected to help achieve the goal of using approximately 23% NREs by 2025.
Other benefits of rooftop solar PV include:

1. Reduced electricity costs for consumers who purchase electricity from PLN
2. Income from power sales business using rooftop solar
3. Increasing the contribution of distributed power sources and building a society independent of fossil energy

PLN also plans to develop solar power plants in the following locations to achieve the goal of generating 23% of electricity from new and renewable energy by 2025:

1. Closed coal mines

The use of land, including inactive mines and other mines, to develop solar power plants. Based on the identification of available land area, a 435.5 MW solar PV plants are expected to be developed.

A) South Sumatra, 27 MW
B) West Sumatra, 50 MW
C) South Kalimantan, 12.5 MW
D) East Kalimantan, 346 MW

2. Dams and reservoirs (for floating sunlight)

Indonesia also has many reservoirs that can be used to develop floating solar sufficient to meet the targets for the renewable energy mix. One of the reservoirs under construction for floating solar is the 145 MW Cirata reservoir, which Middle Eastern developer Masdar has also signed a PPA for.
Using reservoirs as floating solar power plants can reduce land investment costs and generate more competitive electricity rates. The following reservoirs are planned to be used as construction sites, with a total capacity of 612 MW.

A) Wonogiri Reservoir in Central Java, 100 MW
B) Stami Reservoir, Karankates, East Java, 122 MW
C) Jatiluhur Reservoir, West Java, 100 MW
D) Mica Reservoir in Banjarnugara, Central Java, 60 MW
E) Saguling Reservoir, West Java, 60 MW
F) Wonorejo Reservoir, in Turungagun, East Java, 122 MW
G) Lake Sinkarak, West Sumatra, 48 MW

However, the difficulty of operating and maintaining floating solar power plants when compared to onshore solar power plants should be considered at the time of development.

3. Existing PLN power plants

PLN's existing power plants will use solar power to reduce on-site energy consumption, with a total development potential of 112.5 MW (87.5 MW for Java and 25 MW for non-Java plants).

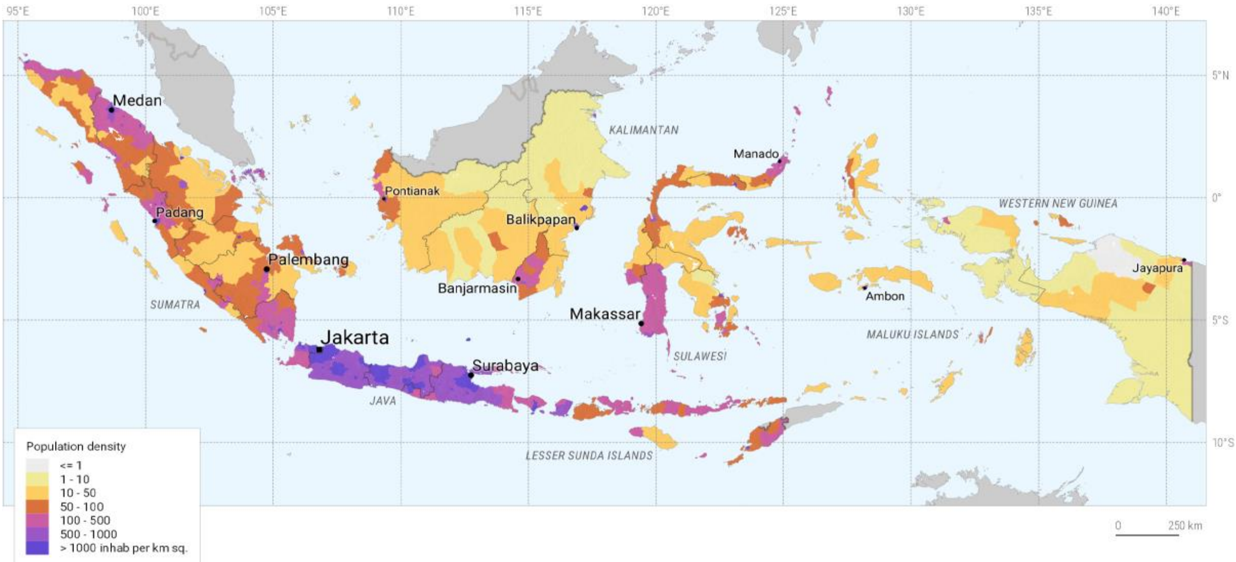
(2) Potential Analysis

Indonesia is located in South Asia, between 6 degrees north latitude and 11 degrees south latitude, and 91 degrees longitude and 145 degrees east longitude across the equator, making it a country with high potential to enjoy the benefits of solar power generation. As mentioned in the previous chapter, RUPTL 2021 is expected to have a development potential of 207 GW. However, in actual development, consideration must be given to the topography of the location where solar panels are installed, the weather conditions at the location, and access to the site.
A World Bank study (Solar Resource and Photovoltaic Patent of Indonesia 2017) examined the potential for developing land-based mega solar. In this study, the following data related to the

development of photovoltaic power plants are collected and considered in the potential calculation. (Rooftop solar is less restrictive and easier to install.)

1. Terrain: physical limitations of development
2. Land type: land available for residential and economic activities; protected areas may affect the size of power plants and associated infrastructure
3. Highway networks: accessing sites
4. Population density
5. Forest fires (air pollution and haze) and volcanic eruptions
6. Rainfall: Impacts on PV module cleaning
7. Temperature: affects PV efficiency

Terrain elevation and slope are limiting factors for large solar installations. High elevations and steep slopes (above about 7 ~ 10 degrees) can make large-scale PV development difficult. Densely populated areas are likely to be flat, roughly in line with the best areas for solar investment (Figure 6-12). Indonesia is also dotted with nature reserves, limiting the deployment of large solar power plants.



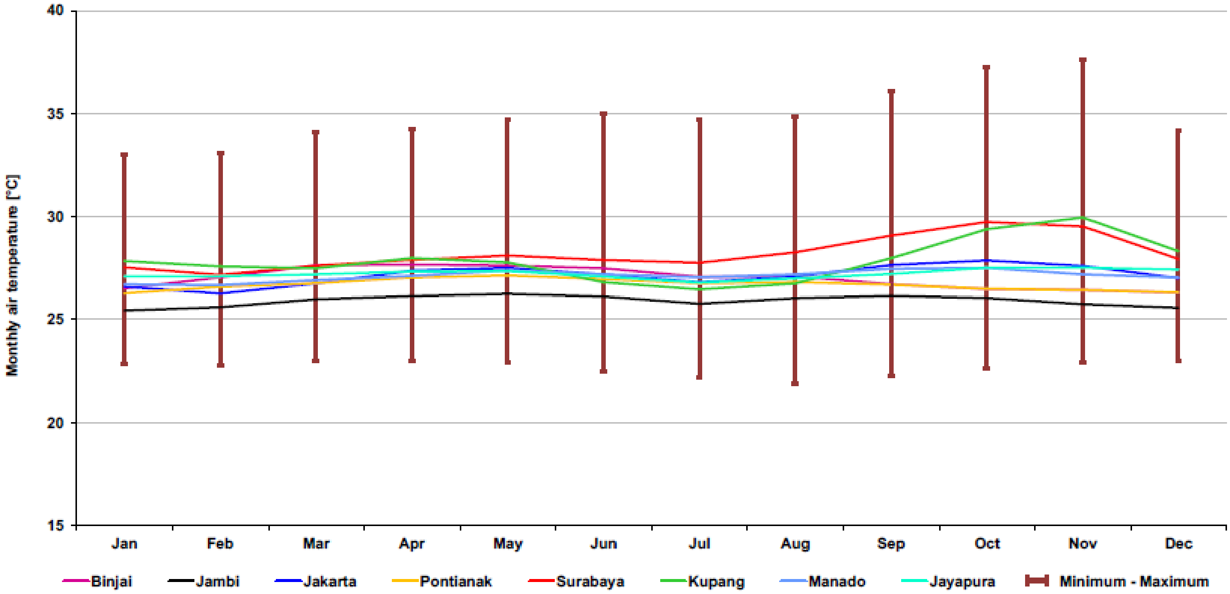
(Source SMAP - Solar Resource and Photovoltaic Potential of Indonesia 2017)

Figure 6-12 Population density distribution

In Indonesia, as agriculture expands, open burning and forest fires often occur. There is a high possibility that fine particles generated by field burning, etc. will interfere with solar irradiance, specifically direct solar radiation (DNI). From 2001 to 2015, hazing was particularly severe in 2015, according to Global Forest Watch bushfire data. Solargis data from Pontianak Airport in West Kalimantan, in particular, reported a 5% decrease in Sunao's solar radiation (DNI) in September 2015 compared to the long-term average for this site.

Indonesia is located on the Pacific Rim orogenic belt and has several active volcanoes in the country. Recent eruptions of active volcanoes include Mount Merapi in 2010, Mount Kelut in 2014, and Mount Soputan in 2011 – 2016. Volcanic ash from these eruptions can accumulate anywhere from a few millimeters to several centimeters, depending on the distance from the source, leading to a reduction in solar panel power generation. Fine particles released from a crater can reach high altitudes and diffuse into the atmosphere, traveling hundreds or 1000 kilometers and reducing solar irradiance.

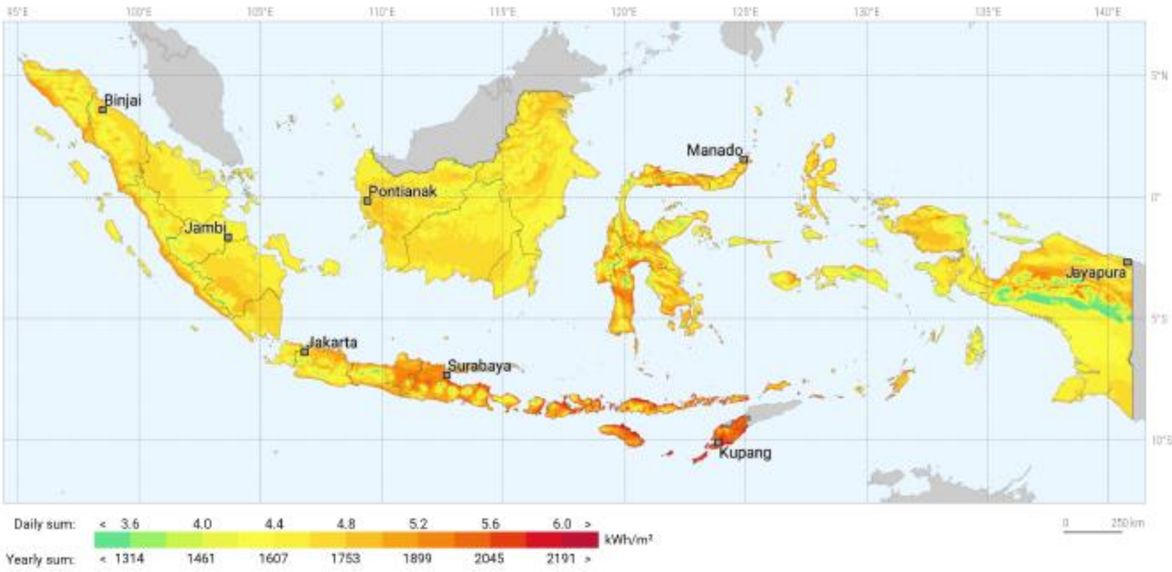
Rainfall is also important for cleaning the surface of PV modules, although it reduces the output of solar panels due to a decrease in the amount of sunlight. Temperature also has a major effect on the power conversion efficiency of PV modules and affects other components (inverters, transformers, etc.). Higher temperatures reduce the power conversion efficiency of solar power plants. In Indonesia, the seasonal variation in temperature and the diurnal and nocturnal temperature variation are not very large, with the average temperature hovering between 25 - 30 °C and the maximum and minimum temperature hovering between 22 and 37 °C throughout the year (Figure 6-13).



(Source SMAP - Solar Resource and Photovoltaic Potential of Indonesia 2017)

Figure 6-13 Changes in annual temperature in 8 cities

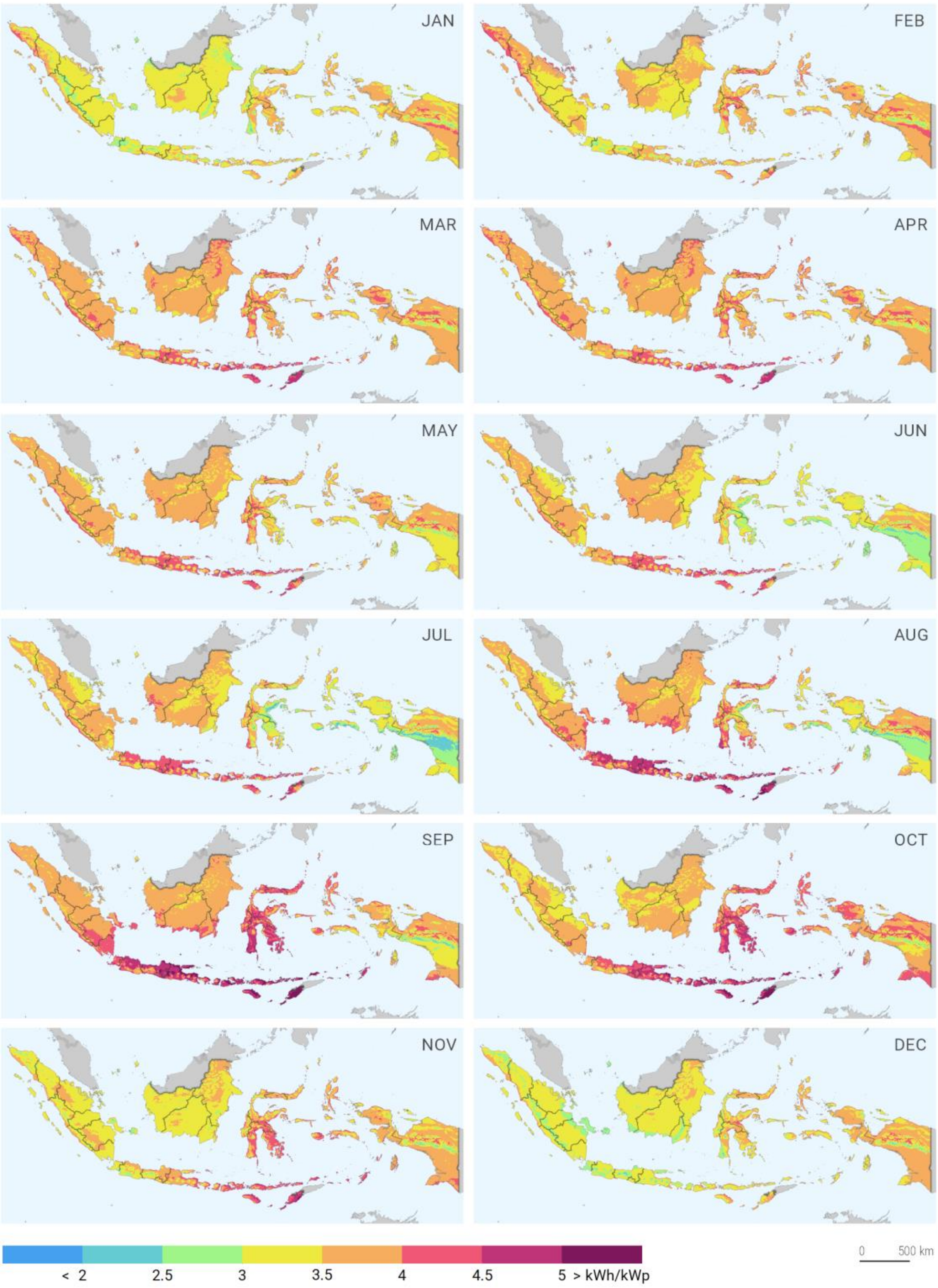
Solar Resource and Photovoltaic Potential of Indonesia 2017 assesses global horizontal radiation (GHI) as an indicator of solar radiation. The highest GHI has been identified in southern islands such as Nusa Tenggara, where the average daily total is more than 5.6 kWh/m^2 (2045 kWh/m^2 per year on average) (Figure 6-14). Further north, the average daily sum of GHI values is assumed to be between 3.8 kWh/m^2 and 4.8 kWh/m^2 (an annual total of between 1400 and 1750 kWh/m^2). The minimum daily GHI value in Japan is less than 3.6 kWh/m^2 (average annual value is less than 1300 kWh/m^2), which is sufficient for small-scale PV for regional use.



(Source SMAP - Solar Resource and Photovoltaic Potential of Indonesia 2017)

Figure 6-14 Annual average global horizontal dose distribution

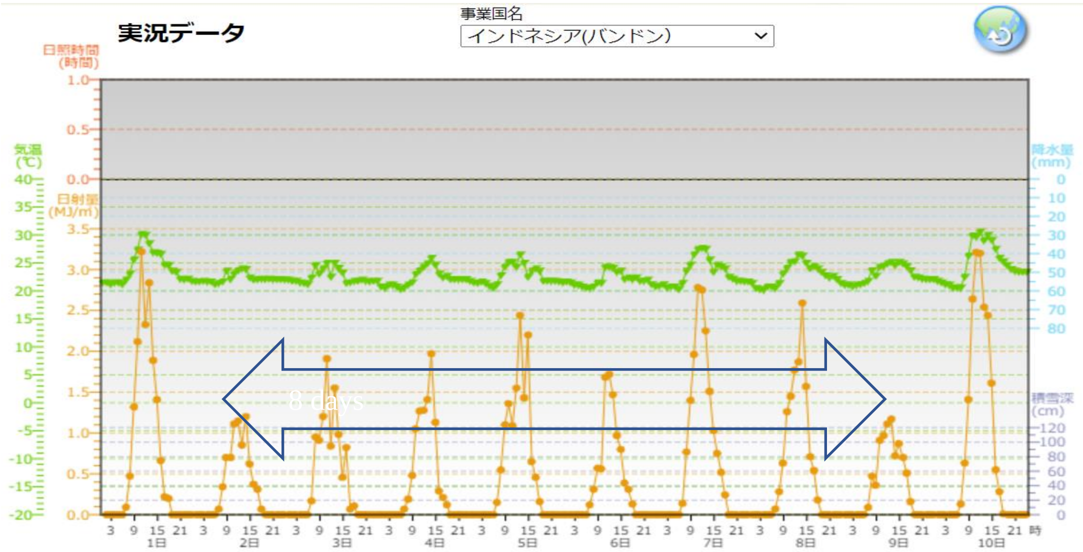
In terms of seasons, the highest amount of sunlight was recorded from August to November during the dry season, and the amount of sunlight decreased from December to February during the rainy season (Figure 6-15).



(Source: SMAP - Solar Resource and Photovoltaic Potential of Indonesia 2017)

Figure 6-15 Monthly global horizontal dose distribution

Looking at the data by day, we checked the data for one year using the design support tool for the NEDO solar power generation system, etc., and found that it was about 30% of that during good weather and cloudy weather, especially during the rainy season when good weather is not common. Since the output is about 40% to 80% and this state may continue for up to 8 days (Figure 6-16), power adjustment, including backup power supply, is required for the introduction of photovoltaic power generation.



(Source: Design Support Tool for NEDO Solar Power Generation System)

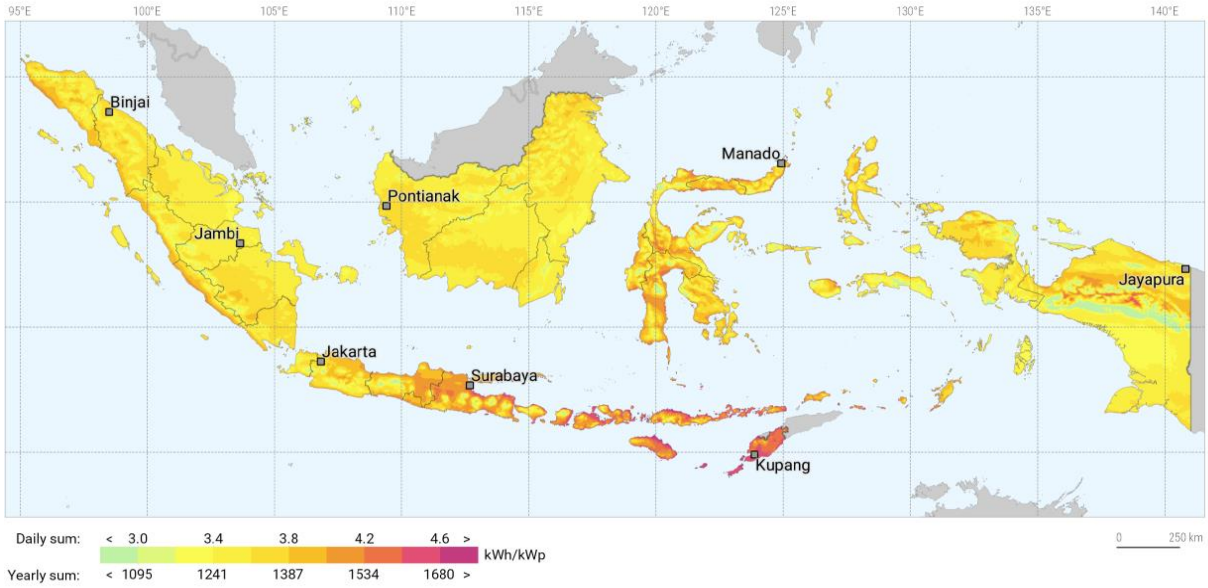
Figure 6-16 Changes in the amount of sunlight by day at Bandung

The Figure 6-14 global horizontal radiation distribution indicates that East Java and the Lesser Sunda Islands have the highest potential for solar power generation. Low values are assumed for Sumatra and Kalimantan because of the high incidence of clouds and the high concentration of fine particles in the atmosphere.

Furthermore, places in Indonesia, especially near the equator, do not benefit much from tilting panels. In general, the main parameter affecting optimal tilt is latitude, and higher latitudes allow panels inclined at optimal tilt angles to acquire more annual solar radiation compared to horizontal installations. It should be noted that it is not recommended to make the inclination angle of the solar panel close to the horizontal position, since it may hinder the self-cleaning of the solar panel due to rain.

A solar panel installed at a very low tilt angle causes dust to accumulate on the panel, causing a decrease in output. In a real project, it is recommended that the module be installed at a slope of at least 10° to enable self-cleaning via rain.

In addition to the above, a potential map for solar power generation in Indonesia is shown (Figure 6-17), taking into account weather conditions such as temperature.



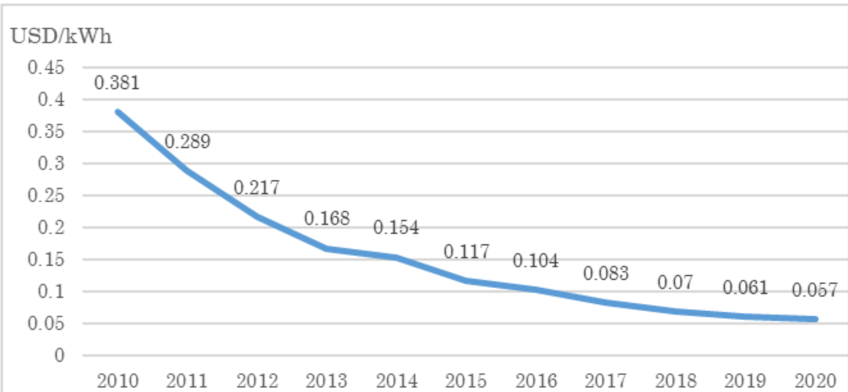
(Source: SMAP - Solar Resource and Photovoltaic Potential of Indonesia 2017)

Figure 6-17 PV Potential Map

The South, with its existing main grid, is suitable for developing medium- to large-scale grid-connected solar PV projects. In grid areas, solar power can be used to improve the electricity balance of the grid and reduce the usage amount of primary energy, such as oil and diesel. In remote areas where power systems are not yet developed, we believe that solar power generation can benefit from the development of local microgrids or compact solar systems as an option for local electrification.

(3) Cost Outlook for Renewable Energy

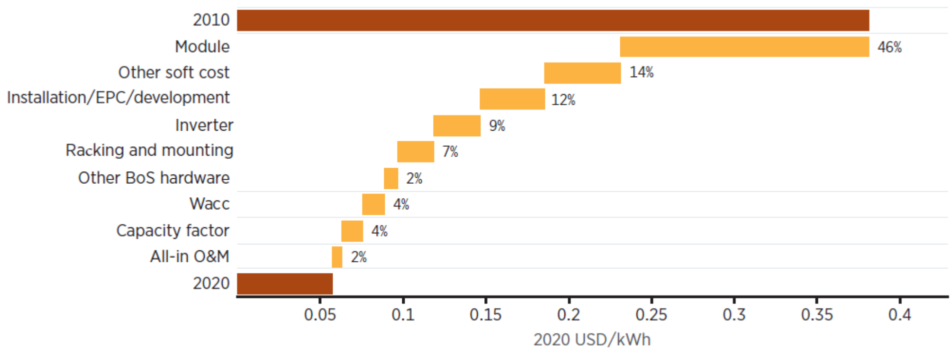
According to IRENA's Renewable Power Generation Cost In 2020, the weighted average equalized cost of electricity generation (LCOE) for utility-scale solar PV worldwide fell 85% between 2010 and 2020. From US $0.381/kWh in 2010, LOCE fell to US $0.057/kWh in 2020, down about 7% from the previous year (Figure 6-18).



(Source: IRENA Renewable Power Generation Cost In 2020)

Figure 6-18 LCOE of utility-scale solar PV over the past 10 years

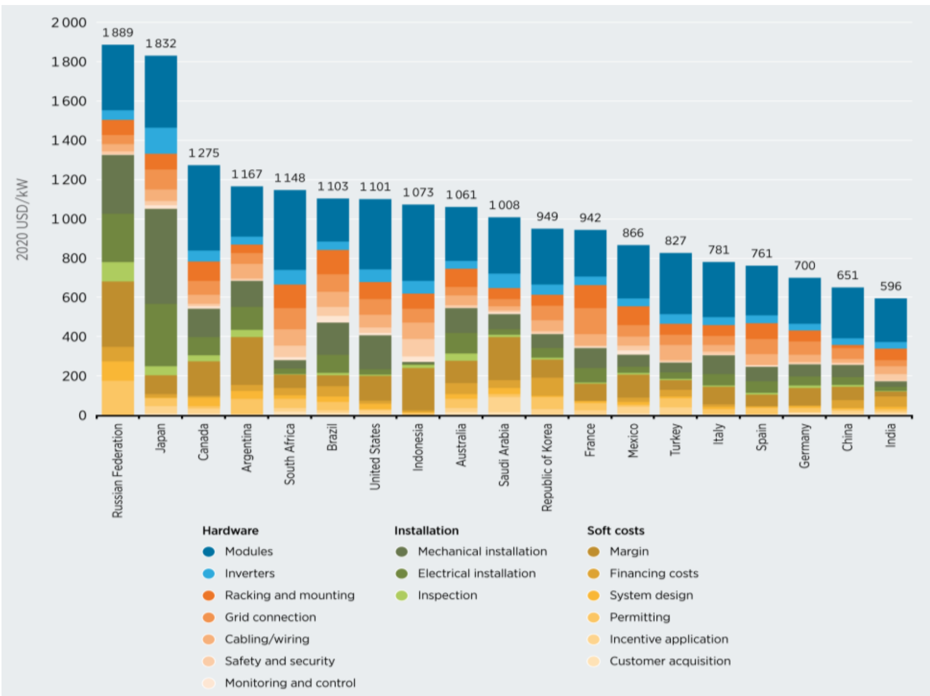
When the main cost reduction factors were broken down, PV module cost reduction contributed the most at 46%, followed by soft costs such as finance costs, installation, EPC, and development costs (Figure 6-19).



(Source: IRENA Renewable Power Generation Cost In 2020)

Figure 6-19 Cost reduction items and contribution rate for the past 10 years

The introduction cost of solar power generation in Indonesia is 1,073 USD/kW, which is about 20% higher than the world average of 883USD/kw. However, the cost ratio of modules and other hardware to the total cost is about 75%, which is the highest level in the world. This may be due to the introduction of solar PV and local content requirements (Figure 6-20).



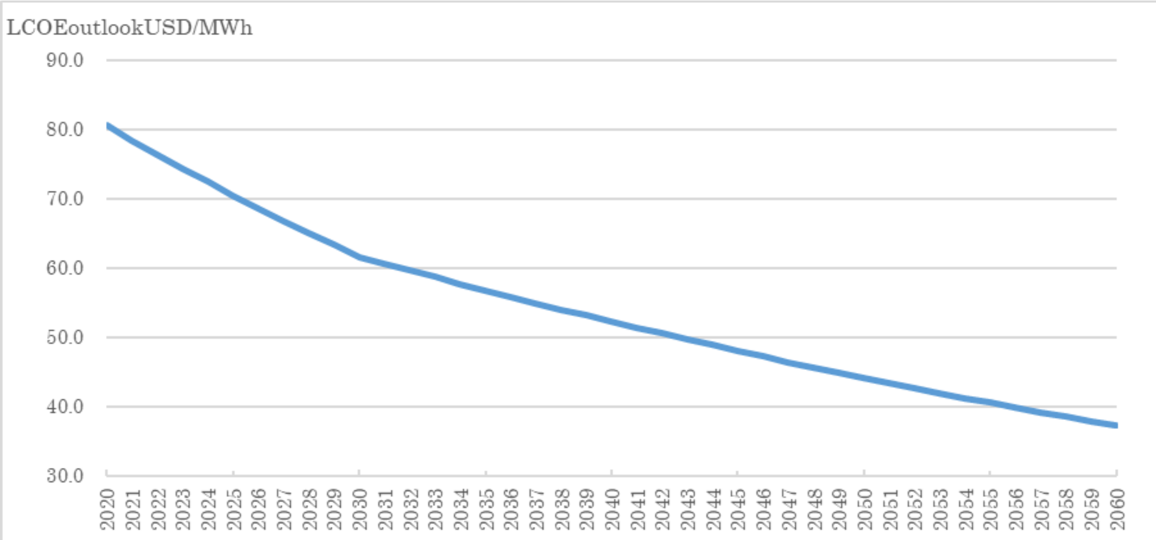
(Source: IRENA Renewable Power Generation Cost In 2020)

Figure 6-20 Comparison of PV installation costs in each country

Based on the McKinsey GEP and IESR data, the LCOE forecast for solar PV up to 2060 in Indonesia is briefly simulated under the following conditions (Table 6-14 and Figure 6-21). The LCOE of the world standard as of 2020 will be achieved around 2035.

Table 6-14 LCOE simulation conditions

Item	Condition	Remarks
WACC	10%	
Project Duration	25 Years	
CAPEX	1100 kUSD/MW	2.5% (up to 2030), 1.3% (since 2031)
O&M Fixed Costs	14.6 kUSD/MW	Decline rate: 1.7 ~ 3.0% per annum
Equipment utilization rate	19.2%	0.22% annual increase



(Source: Survey team based on McKinsey GEP and IESR survey)

Figure 6-21 PV LCOE Outlook

(4) Policy Recommendations for Expanding Renewable Energy

In attempting to accelerate the introduction of solar power, Indonesia's efforts to install floating solar power on rooftops and reservoirs and to install small-scale solar power in remote areas are limited, and it is necessary to attract large investments from foreign investors.

To promote resource efficiency in development, foreign capital wants to develop projects to a certain extent (for example, 10 MW) or more. The development of solar power plants should be promoted in eastern Java, for example, where a power system suitable for the construction of large-scale power plants has been established and the potential has been confirmed.

Under the current system, in Java, the purchase tariff can be determined through negotiations with PLN. However, because of the large capacity of coal power plants, the cost of power generation by region is low, and it is difficult for both solar power developer and off taker PLN to have a satisfactory price. Therefore, the government should propose the design of a fixed price purchase system with incentives, as introduced in Japan and other countries, and an Adder, which adds a certain price to the bid price.

In the case of variable renewable energy, including solar power, it is important to improve the system and the system adjustment capacity (including backup power sources). It is considered worthwhile to propose the preparation of an electric power master plan focusing on system improvement and the development of renewable energy, feeding in lessons learned through previous implementation work in Japan.

The proposal for system improvement is detailed in Chapter 8.

6.4.2 Wind Power

(1) Current Status of Wind Power Generation

As described in the previous chapter, in Indonesia, the purchase tariff for electricity generated from renewable energy is limited by the cost of power generation in each region, and in Java and Sumatra, the main demand areas, the installation of wind power plants is not very advanced because of competition with the cheaper tariffs from thermal power generation, including coal-fired power generation. As shown in the table below, the introduction of wind power plants has not been carried out on a large scale, since only 2 wind power plants started operation in 2018.

Including off-grid systems, the total installed capacity of wind power plants at the end of 2020 was only about 150 MW, consisting of the 72 MW Tolo 1 Wind Farm developed by Vena Energy, and the 78.75 MW Sidrap Wind Farm developed by UPC Renewables (Table 6-15).

In addition, there are currently no specific policies for promoting wind power generation development, and the technical standards for the design of wind power generation facilities and the standards for measurement methods, such as those for wind velocity, have not been clarified. This is one of the barriers for power developers.

Table 6-15 List of wind farms

Project Name	Start date of operation	Total capacity (MWe)	Current Owner
AC Energy UPC Sidrap Wind Farm	2018-03-31	78.75	AC Energy & Infrastructure Corp.; UPC Renewables Indonesia Ltd
Vena Energy Tolo 1 Jeneponto Wind Farm	2019-03-14	72	Vena Energy Holdings Ltd/Cayman Islands

(Source: BloombergNEF)

(2) Potential Analysis

According to RUPTL 2021, Indonesia is believed to have an estimated wind energy potential of about 60 GW, but there would currently be few suitable sites in Indonesia, particularly onshore, with sufficient wind speeds for large-scale wind power generation.

Over the next 10 years, Indonesia plans to install just under 600 MW, but in the future it may be able to increase capacity in some areas with low wind speeds, or offshore, by improving turbine efficiency, including developing technology for low-speed wind turbines, and developing technology for offshore wind.

According to an MEMR presentation (VRE Potential to Support Energy Transition Scenario, Dec 7th 2021), the best onshore wind farms (with an average wind velocity of more than 6 m/s) are located in low-electrification states such as South Sulawesi and East Nusa Tenggara, as well as West Java and South Kalimantan. High potential has also been identified around Papua for offshore wind farms (Figure 6-22).

In terms of seasonal variation, wind conditions are most favorable from June to August, when the wind is affected by the Australian monsoon, and worse from March to May, when the wind shifts from the Asian monsoon to the Australian monsoon.

Figure 6-22 Wind Potential Map

However, in selecting actual sites, wind conditions are affected by short-term and long-term seasonal wind fluctuations, topography, obstacles, etc. Therefore, it is necessary to install metmasts at candidate sites for at least one year in principle, and conduct Energy Yield Assessments (EYA) site by site. Before conducting EYA, the measurement itself needs to be evaluated, mainly on the following points.

- Measurement and site suitability analysis in accordance with international standards such as IEC 61400 and MEASNET
- Review of calibration status of sensors
- Prediction of the long-term average wind speed at the site using multiple data sources (examples: MERRA, NCAR, nearby weather stations, etc.) and correlation check with long-term data, including wind speed distribution and wind distribution diagram
- Evaluation of wind shear (fault of wind) required for hub height proposed by turbine manufacturer
- Estimation of air density at site
- Evaluation of storms and turbulence
- Fluid modeling (typically using simulation software such as WindPro) to predict wind speed variations across the site area at hub height

After the observation data evaluation, the EYA generally consists of the following tasks.

- Annual total power generation of the project (at the generating end) based on the wind distribution diagram, the turbine-generator layout, and the power and turbine-generating characteristic curve for the long-term evaluation
- Calculation of wake loss
- Estimation of wind farm electrical equipment losses
- Estimation of Wind Farm Availability
- Estimation of power generation (P 50, P 75, and P 90 values)

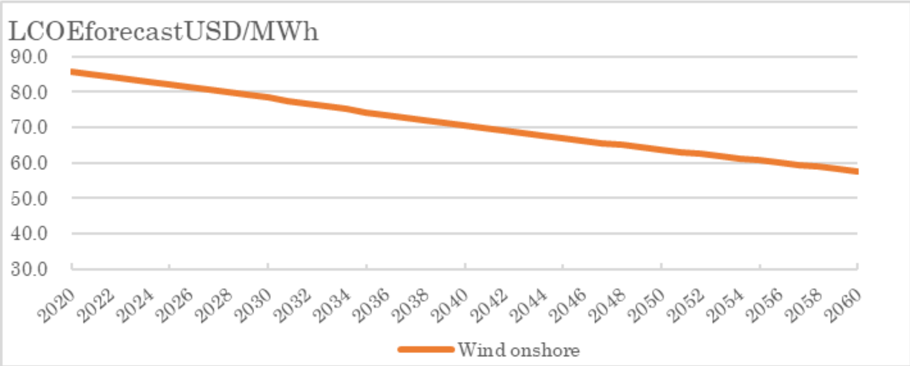
After the implementation of the EYA, the feasibility of the project will be evaluated by taking into account the project period, etc., and the amount of power generation, tariffs, O&M costs, financing costs, etc.

(3) Cost Outlook for Onshore Wind

Global cumulative installed capacity for onshore wind increased almost 4 times over the past 10 years, from 178 GW in 2010 to 699 GW in 2020. LCOE also declined as the installation of power plants progressed, decreasing by 56% from US $0.089/kWh in 2010 to US $0.039/kWh in 2020, and by 13% from the previous year, in 2020. Referring to the McKinsey GEP and IEA World Energy Outlook, the LCOE forecast for onshore wind in Indonesia up to 2060 is simulated simply under the following conditions (Table 6-16 and Figure 6-23).

Table 6-16 LCOE simulation conditions

Item	Condition	Remarks
WACC	10%	
Project Duration	30	
CAPEX	1193 kUSD/MW	0.28% (up to 2030), 0.53% (after 2031)
OM Fixed Costs	24.3 kUSD/MW	Decline rate: 0.3 ~ 1.3% per annum
Equipment utilization rate	20.1%	0.5% annual increase



(Source: Survey team based on McKinsey GEP, IEA Energy Outlook)

Figure 6-23 LCOE outlook for onshore wind

(4) Policy Recommendations for Expanding Renewable Energy

At present, the Indonesian government is not active in the development of wind power generation, so institutional design and detailed potential surveys have not advanced. In addition, power generation costs are inferior to solar power among variable renewable energy, so large-scale introduction may not be possible.

However, cost reductions and technological innovations in wind power generation facilities will continue to progress, and it is necessary to attract foreign investment to accelerate the introduction of wind power generation.

In particular, the development of wind power plants should be promoted in the western part of Java Island, where a power system capable of connecting large-scale power plants, such as those for offshore wind power, has been established and its potential has been confirmed. In addition, as mentioned in the preceding paragraph, detailed EYA and wind conditions data are required to make investment decisions for wind power plants. It is also necessary to collect and create a database of wind conditions data in accordance with international standards at each point where potential has been confirmed, together with detailed potential surveys.

However, under the current system, because of the large capacity of coal power plants on Java Island, the cost of power generation by region is low, and it is difficult for both wind power developer and off-taker (PLN) to have a satisfactory price. Therefore, the government should propose the design of a fixed price purchase system with incentives, as introduced in Japan and other countries, and an Adder with fixed incentives on the winning bid price.

For variable renewable energy, including wind power, it is important to improve the system and the system adjustment capacity (including backup power sources). It is considered worthwhile to propose the preparation of an electric power master plan which focuses on system improvement and the development of renewable energy, feeding in lessons learned through previous implementation work in Japan. The proposal for system improvement is detailed in Chapter 8

6.4.3 Hydropower

(1) Hydropower Potential

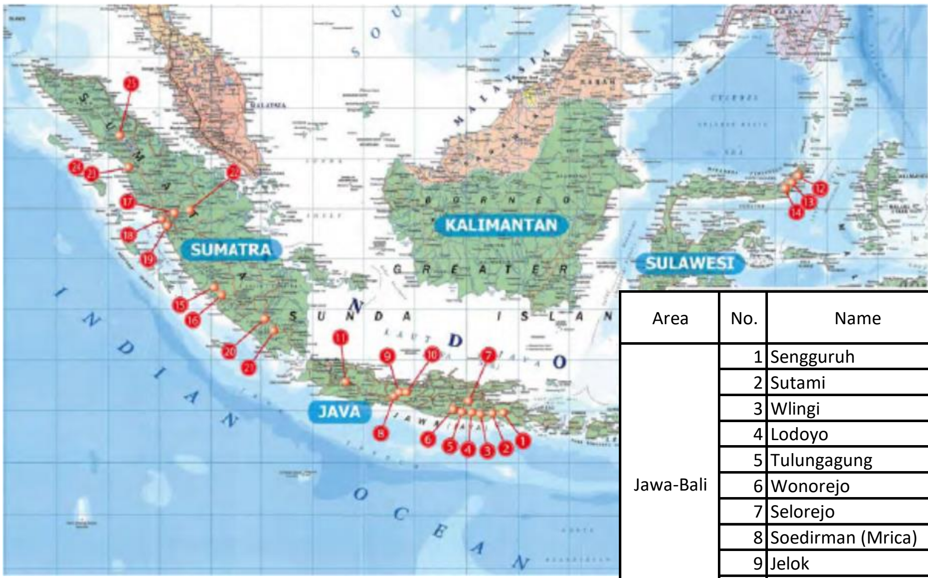
Existing hydropower plants in Indonesia are shown in Table 6-17. The table includes the plants owned by PLN (JICA survey in 2011) and the plants over 50 MW owned by IPP. The small-scale power plants developed in recent years are not counted.

Table 6-17 Existing hydropower plants

Area	Number of Plants	Total Capacity (MW)
Jawa Bali	15	2,406.3
Sulawesi	10	1,057.0
Sumatra	17	1,942.7
Kalimantan	1	30.0
Summation	43	5,436.0

Area	Name	Operator	Capacity (MW)		Energy (GWh)			Catchment Area (km^2)	Discharge (m^3/sec)	Height (m)	Reservoir (10^6m^3)	Pond (10^3m^3)
			Design	in 2010	Planned	Record in 2009	Record in 2020					
Jawa Bali	Sengguruh	PLN	29.0	29.0	99	75						
	Sutami	PLN	105.0	105.0	488	462					253	-
	Wlingi	PLN	54.0	54.0	167	144						
	Lodoyo	PLN	4.5	4.5	37	39						
	Tulungagung	PLN	36.0	36.0	184	121						
	Wonorejo	PLN	6.5	6.5	32	20		126	12.0	63.9	106	-
	Selorejo	PLN	4.5	4.5	20	27						
	Soedirman (Mrica)	PLN	180.9	180.9	580	479		1,070			46	
	Jelok	PLN	20.5	20.5	97	94						
	Tulis	PLN	12.4	6.0	15	10						
	Wonogiri	PLN	12.4	unknown	50	unknown		1,350	75.0	20.4	615	-
	Jatiluhur	PLN	186.0	unknown	unknown	unknown						
	Saguling	PLN	700.0	700.0	2156	2295		2,283	224.0	355.7	609	-
	Rajamandala	IPP	46.6	0.0	181	0			168.0	32.3	-	-
	Cirata	PLN	1008.0	unknown	unknown	unknown			540.0	112.5	796	
Sulawesi	Tonsea Lama	PLN	10.0	10.0	58	44						
	Tanggari I	PLN	18.0	18.0	90	64						
	Tanggari II	PLN	19.0	19.0	92	70						
	Bakaru	PLN	128.0	unknown	970	unknown						
	Bakaru II	PLN	144.0	0.0	unknown	0.0						
	Bili-Bili	PLN	11.0	11.0	70	unknown						
	Larona	IPP	195.0	unknown	unknown	unknown						
	Balambano	IPP	140.0	unknown	unknown	unknown						
	Karebbe	IPP	132.0	unknown	unknown	unknown						
	Pamona 2	IPP	260.0	unknown	unknown	unknown						
Sumatra	Test	PLN	17.6	17.6	87	96						
	Musi	PLN	215.0	215.0	1120	797						
	Batrang Agam	PLN	10.5	10.5	21	35						
	Maninjau	PLN	68.0	68.0	270	205						
	Singkarak	PLN	175.0	175.0	986	704						
	Besai	PLN	90.0	90.0	804	646						
	Batutegi	PLN	28.6	28.6	200	115						
	Kotapanjang	PLN	114.0	114.0	542	489		3,337	348.0	38.1	1,040	-
	Sipansihoporas-1	PLN	33.0	33.0	135	65		196	30.0	128.4	-	914
	Sipansihoporas-2	PLN	17.0	17.0	69	55		210	30.0	67.3	-	-
	Renun	PLN	82.0	82.0	618	566						
	Sigura-gura	IPP	244.0	244.0	unknown	0.0		3,730	126.7	230.0	2,860	752
	Tangga	IPP	269.0	269.0	unknown	0.0		3,820	135.2	237.4	-	713
	Asahan I	IPP	180.0	0.0	unknown	0.0						
	Asahan III (COD2023)	PLN	174.0	0.0	0	0.0						
	Wampu	IPP	45.0	0.0	210	unknown		959	35.6	114.0	-	-
	Kerinci	PLN	180.0	0.0	unknown	unknown						
Kalimantan	Riam Kanan	PLN	30.0	30.0	136	unknown						

※ White : Provided by PLN for JICA reserch in 2010
※ Gray shading : Examined by JICA TEAM(TEPSCO)



Area	No.	Name	COD	Funding source	Capacity (MW)
Jawa-Bali	1	Sengguruh	1988	ADB	29.0
	2	Sutami	1973	JBIC	105.0
	3	Wlingi	1978	JBIC	54.0
	4	Lodoyo	1983	JBIC	4.5
	5	Tulungagung	1993	Austria Loan	36.0
	6	Wonorejo	2003	JBIC	6.5
	7	Selorejo	1973	JBIC	4.5
	8	Soedirman (Mrica)	1988	WB	180.9
	9	Jelok	1937	WB	20.5
	10	Tulis	2003	WB	12.4
	11	Saguling	1985	JBIC	700.0
Sulawesi	12	Tonsea Lama	1950	Own fund	10.0
	13	Tanggari I	1987	ADB	18.0
	14	Tanggari II	1998	ADB	19.0
Sumatra	15	Test	1991	ADB	17.6
	16	Musi	2006	ADB	215.0
	17	Batrang Agam	1983	ADB	10.5
	18	Maninjau	1983	ADB	68.0
	19	Singkarak	1998	ADB	175.0
	20	Besai	2001	WB	90.0
	21	Batutegi	2002	JBIC	28.6
	22	Kotapanjang	1998	JBIC	114.0
	23	Sipansihoporas-1	2005	JBIC	33.0
	24	Sipansihoporas-2	2002	JBIC	17.0
	25	Renun	2005	JBIC	82.0

Figure 6-24 Locations of existing hydropower plants

Hydropower potential in Indonesia has been surveyed. Hydropower potential in Indonesia according to Hydro Power Potential Study (HPPS) in 1983 was 75GW. Hydro Power Potential Study 2 (HPPS2) in 1999 identified 16.8GW (115 projects, excluding 1 project in East Timor) in promising projects for development among a total of 75GW (1,249 projects). In the 115 projects, there were 35 projects with reservoir type power plants, 78 projects with inflow type power plants, and 1 project with an inflow type power plant with low dam.
The 115 promising projects are shown in Table 6-18.

Table 6-18 115 promising projects

(MW)

Area	LHD	LOT	RES	ROR	**Summation**
Jawa-bali	16.7 (1)		86.8 (2)	319.4 (7)	422.9 (10)
Kalimantan		56.2 (1)	5,763.7 (12)	2,452.8 (20)	8,272.7 (33)
Sulawesi			3,882.2 (10)	474.4 (7)	4,356.6 (17)
Sumatra			2,246. (11)	1,519.8 (44)	3,765.8 (55)
Summation	16.7 (1)	56.2 (1)	11,978.7 (35)	4,766.4 (78)	16,818.0 (115)

No.	ID No.	Name	Area	Type	installed Capacity (MW)	Annual Energy (GWh)	FS - Phase in 2011	No.	ID No.	Name	Area	Type	installed Capacity (MW)	Annual Energy (GWh)	FS - Phase in 2011
1	1-190-13	Manlas-2	Sumatra	ROR	51	327.7		59	3-010-01	Kelai-1	Kalimantan	RES	952.8	2106.4	
2	1-192-04	Jaiubo Papetm-3	Sumatra	ROR	25.4	206.1		60	3-004-20	Sesayap-20	Kalimantan	RES	949.2	2633.3	
3	1-204-05	Woyla-2	Sumatra	RES	242.1	664.6		61	3-004-11	Sesavao-11	Kalimantan	RES	624	2035.3	
4	1-190-11	Ketambe-2	Sumatra	ROR	19.4	124.9		62	3-003-03	Sembakung-3	Kalimantan	RES	572.4	1268.3	
5	1-205-09	Teunom-2	Sumatra	RES	230	595.3		63	3-004-15	Sesayap-15	Kalimantan	RES	313.2	956.7	
6	1-192-03	Kluet-1	Sumatra	ROR	40.6	231.9		64	3-014-13	Telen	Kalimantan	RES	193.2	544.4	
7	1-202-06	Meulaboh-5	Sumatra	ROR	43	271.1		65	4-026-03	Poso-2	Sulawesi	ROR	132.8	1125.4	
8	1-192-07	Kluet-3	Sumatra	ROR	23.8	194		66	4-026-02	Poso-1	Sulawesi	ROR	204	1341	
9	1-027-14	Ramasau-1	Sumatra	RES	119	291.9		67	4-106-07	Lariang-7	Sulawesi	RES	618	1489.6	
10	1-192-08	Sibubung-1	Sumatra	ROR	32.4	207.3		68	4-106-06	Lariang-6	Sulawesi	RES	209.4	616.2	
11	1-201-03	Setmangan-3	Sumatra	ROR	31.2	179.3		69	4-003-04	Bone-3	Sulawesi	ROR	20.4	148.3	
12	1-198-05	Teripa-4	Sumatra	RES	184.8	503.6		70	4-030-02	Bongka-2	Sulawesi	RES	187.2	451.3	
13	1-205-10	Teunom-3	Sumatra	RES	102	303.2		71	4-038-01	Solato	Sulawesi	ROR	26.6	176.1	
14	1-202-02	Meulaboh-2	Sumatra	ROR	37	212.5		72	4-106-08	Lariang-8	Sulawesi	ROR	12.8	85.4	
15	1-192-10	Sibubung-3	Sumatra	ROR	22.6	144.9		73	4-100-03	Karama-2	Sulawesi	RES	762.3	1796.1	
16	1-186-01	Sirahar	Sumatra	ROR	35.4	228.3	Pre-Fs	74	4-055-01	Tamboli	Sulawesi	ROR	20.8	150.1	Pre-Fs
17	1-190-33	Ordi-1	Sumatra	ROR	40.8	263		75	4-100-01	Karama-1	Sulawesi	RES	800	2147.1	
18	1-190-40	Simanggo-l	Sumatra	ROR	44.4	285.8		76	4-095-06	Masuni	Sulawesi	RES	400.2	930.2	
19	1-190-21	Remm-3	Sumatra	ROR	19.8	127.8		77	4-073-04	Mong	Sulawesi	RES	255.6	618.9	
20	1-190-32	Kumbil1-3	Sumatra	ROR	41.8	269.6		78	4-093-13	Bonto Batt1	Sulawesi	RES	228.3	560.2	
21	1-190-41	Simanggo-2	Sumatra	ROR	59	366.9	Pre-Fs	79	4-056-01	Wattmohu-1	Sulawesi	ROR	57	309	
22	1-183-01	Raisan-1	Sumatra	ROR	26.2	167.9		80	4-047-01	Lalindu-1	Sulawesi	RES	193.6	544.1	
23	1-190-26	Gunung-2	Sumatra	ROR	22.6	145.3		81	4-057-03	Pongkeru-3	Sulawesi	RES	227.6	556.6	
24	1-178-03	Tom-2	Sumatra	ROR	33.6	237.1		82	14-002-02	Mala-2	Kalimantan	ROR	30.4	209	
25	1-190-24	Renun-6	Sumatra	ROR	22.4	144.8		83	14-002-01	Mala-1	Kalimantan	RES	27.8	65.4	
26	1-184-05	Sibtmdong-4	Sumatra	ROR	31.6	203.6		84	14-012-01	Tala	Kalimantan	RES	51.4	122.7	Pre-Fs
27	1-190-34	Ordi-2	Sumatra	ROR	26.8	172.8		85	13-004-01	Tina	Kalimantan	ROR	22.8	156.7	Pre-Fs
28	1-190-37	Ordi-5	Sumatra	ROR	26.8	173.7		86	5-042-02	Warasai	Kalimantan	ROR	231.9	1314	
29	1-055-02	Bila-2	Sumatra	ROR	42	300.6		87	5-013-06	Jawee-4	Kalimantan	ROR	152.6	1308.6	
30	1-190-35	Ordi-3	Sumatra	ROR	18.4	119.1		88	5-043-07	Derewo-7	Kalimantan	ROR	148.8	1180.5	
31	1-053-01	Silau-1	Sumatra	ROR	52.3	147.9		89	5-013-05	Jawee-3	Kalimantan	ROR	147.2	1163.6	
32	1-190-22	Renun-4	Sumatra	ROR	53.6	134.5		90	5-013-07	Endere-1	Kalimantan	ROR	144.8	1033.5	
33	1-190-38	Siria	Sumatra	ROR	43.9	105.8		91	5-013-08	Endere-2	Kalimantan	ROR	87	727.8	
34	1-178-07	Tom-3	Sumatra	RES	322.7	516.1		92	5-043-06	Derewo-6	Kalimantan	ROR	170	1128.4	
35	1-071-12	Sangir	Sumatra	ROR	41.8	331.7		93	5-013-04	Jawee-2	Kalimantan	ROR	94.2	755.9	
36	1-066-03	sinamar-2	Sumatra	ROR	25.6	217.1		94	5-006-08	Balieru-7	Kalimantan	ROR	97.8	834.7	
37	1-147-03	Air Tuik	Sumatra	ROR	24.8	161.4		95	5-006-06	Baliem-5	Kalimantan	ROR	189.2	1401.4	
38	1-145-01	Sirantih-1	Sumatra	ROR	18.3	153.3		96	5-036-12	Waryori-4	Kalimantan	ROR	94.2	598.8	
39	1-071-11	Batang Hari-4	Sumatra	RES	216	544.9		97	5-042-01	Ulawa	Kalimantan	ROR	34.6	194.6	
40	1-147-01	Taratak Tumpatih-	Sumatra	ROR	29.6	192.6		98	5-037-91	Gita/Ransiki-1	Kalimantan	LOT	56.2	136.2	
41	1-066-02	Sinamar-l	Sumatra	ROR	36.6	254.9		99	5-006-07	Baliem-6	Kalimantan	ROR	88.2	754.2	
42	1-163-02	Masang-2	Sumatra	ROR	39.6	256.1		100	5-032-03	Kladuk-2	Kalimantan	RES	229	567.4	
43	1-071-01	Gumanti-1	Sumatra	ROR	15.8	85.4		101	5-015-05	Titinima-3	Kalimantan	ROR	55.6	402.2	
44	1-155-01	Anai-1	Sumatra	ROR	19.1	109.2		102	5-020-01	Maredrer	Kalimantan	ROR	8.7	62.4	
45	1-163-03	Masang-3	Sumatra	RES	192	473	Pre-Fs	103	5-026-01	Muhm-1	Kalimantan	ROR	458	288.3	
46	1-066-16	Kuantan-2	Sumatra	RES	272.4	734.1		104	5-043-09	Siewa-1	Kalimantan	ROR	58.4	330.5	
47	1-058-08	Rokan Kili-1	Sumatra	RES	183	431.9		105	5-006-09	Baliem-8	Kalimantan	ROR	138.4	1007	
48	1-115-01	Mauna-1	Sumatra	ROR	103	814		106	9-011-01	Parainglala	Jawa-bali	ROR	14.9	85.6	
49	1-136-02	Langkup-2	Sumatra	ROR	82.8	700.5		107		Be Lulic-1	East Timur				
50	1-071-33	Merangin-4	Sumatra	RES	182	491.9		108	9-012-01	Watupanggantu	Jawa-bali	ROR	7.1	40.5	
51	1-113-02	Padang Guci-2	Sumatra	ROR	21	145.1		109	9-001-01	Karendi-1	Jawa-bali	RES	21.4	49.5	
52	1-074-17	Endikat-2	Sumatra	ROR	22	179.8		110	7-015-01	Teldewaia	Jawa-bali	ROR	7	44.2	
53	1-082-07	Semung-3	Sumatra	ROR	20.8	146.9		111	9-005-02	Kambera-2	Jawa-bali	RES	65.4	154	Pre-Fs
54	1-106-02	Memtla-2	Sumatra	ROR	26.8	152.2		112	10-003-02	Wai Ranjang	Jawa-bali	ROR	9.3	53.1	Pre-Fs
55	1-071-17	Tebo-2	Sumatra	ROR	24.4	188.7		113	2-057-17	Kesamben	Jawa-bali	LHD	16.7	99	Pre-Fs
56	3-043-52	Melawi-9	Kalimantan	RES	590.4	1324.8		114	2-050-01	Rowopening	Jawa-bali	ROR	19.6	138.4	
57	3-043-20	Mandai-5	Kalimantan	RES	140.7	351.8		115	2-108-01	Cibareno-1	Jawa-bali	ROR	17.5	117	
58	3-014-06	Boh-2	Kalimantan	RES	1119.6	3299.2		116	2-207-01	Cimandiri-1	Jawa-bali	ROR	244	167.5	

ROR: inflow type power plant、**RES**: reciever type power plant、**LOT** : natural lake、**LHD**: inflow type power plant with low dam、 **NAD**: Ache

※The hydropower potential after screening (In the Master Plan Study for Hydro Power Development in Indonesia in 2011, JICA)

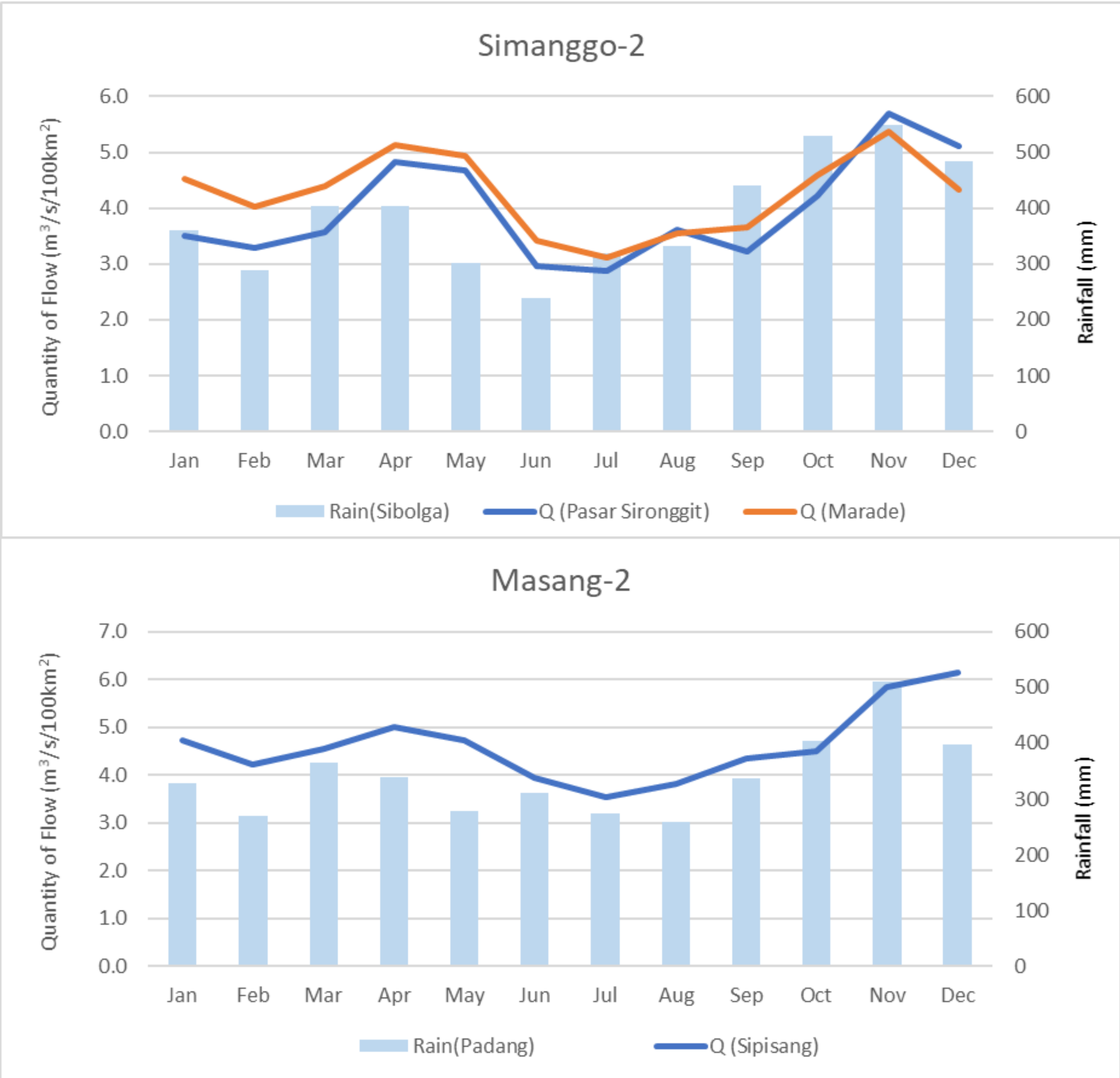
(2) Seasonal capacity

Seasonal capacity is analyzed using Pre-FS documents from 2 projects (Simanggo-2 and Masang-2) among the 115 projects. Table 6-19 shows an overview of the two projects. The capacity is the value in the Pre-FS documents.

Table 6-19 Overview of 2 projects

No.	ID No.	Name	Province	Type	installed Capacity (MW)	Annual Energy (GWh)	Catchment Area (km^2)	Discharge (m^3/sec)	Effective head (m)	Pond (10^3m^3)
21	1-190-41	Simanggo-2	North Sumatra	ROR	90	416	480.6	38.1	260.3	600
42	1-163-02	Masang-2	West Sumatra	ROR	52	240	444.9	32	178.8	322

Figure 6-25 shows rainfall and river flow for the two projects, which are in Sumatra. Both rainfall and river flow increase in Nov-Dec and Mar-Apr.



Rainfall: 1991-2020, Estimated by Japan Meteorological Agency

Figure 6-25 Seasonal river flow and rainfall at 2 sample plants

Figure 6-26 shows seasonal capacity according to the river flow data. Discharge for the river environment was set to $0.2m^3/s/100km^2$.

In HPPS2, the 2 projects are inflow type power plants, but both have an intermediate pond in the Pre-FS documents. The dotted line indicates the maximum output that can last 4 hours using storage in intermediate pond.

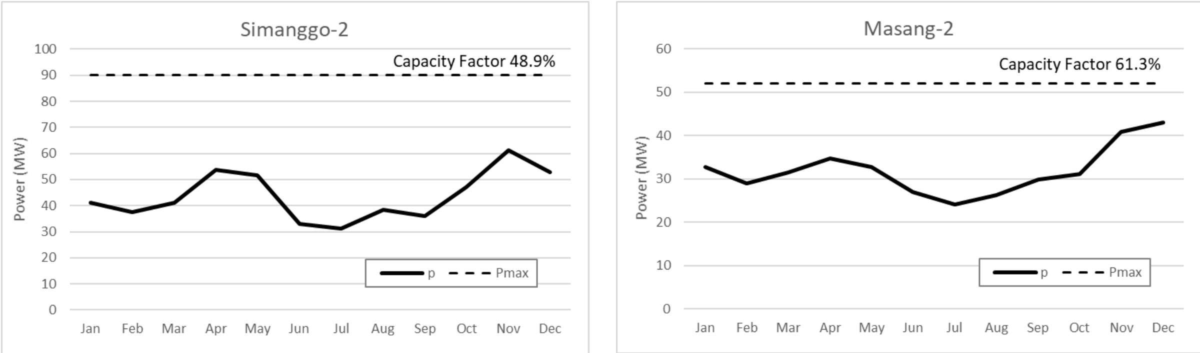
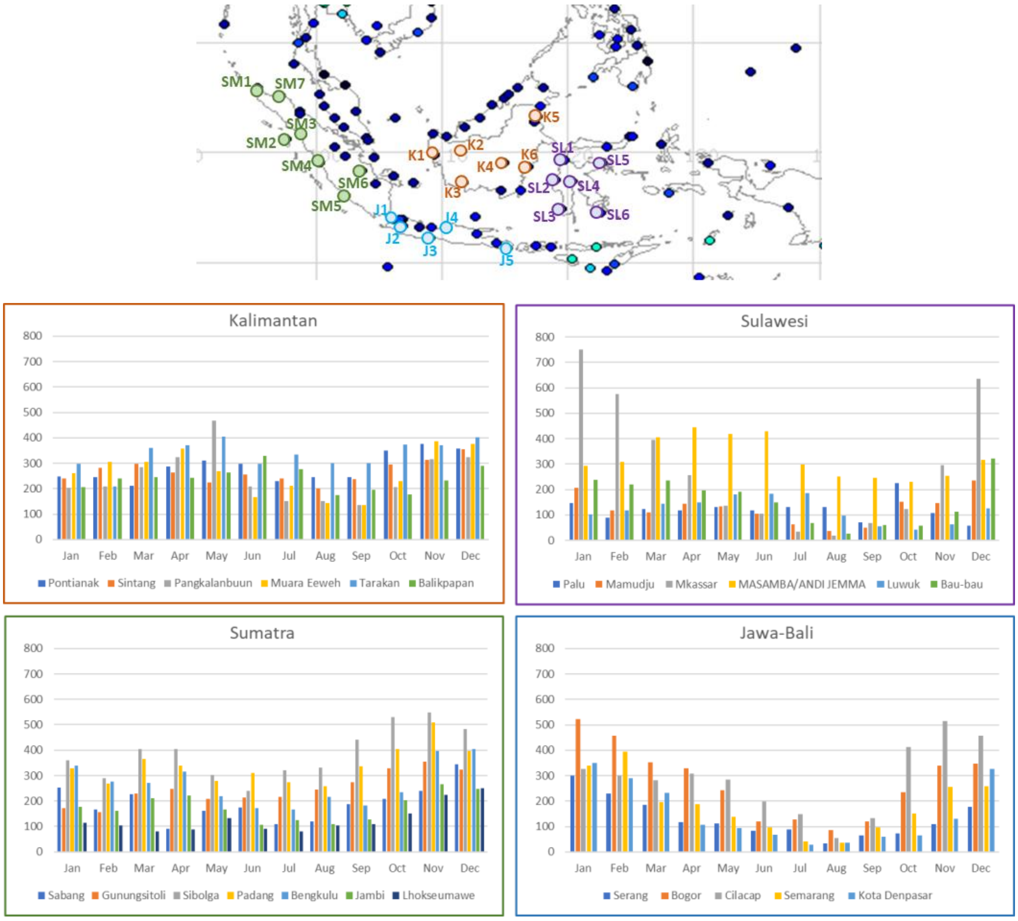


Figure 6-26 Seasonal power output at 2 sample plants

Figure 6-27 shows the seasonal features of rainfall in Indonesia. Rainfall increases in Nov-Dec, and decreases in Jun-Sep in every area. The difference between the rainy season and dry season is large in Java-Bali and Sulawesi. Rainfall varies greatly depending on the measurement point in Sulawesi.



Rainfall: 1991-2020, Estimated by Japan Meteorological Agency

Figure 6-27 Rainfall by area

Since the annual rainfall varies widely from 1,500 to 4,500 mm per year, detailed investigation and analysis are essential at each site.

As a rough examination, seasonal output is estimated from a capacity of 22,254 MW, which includes the existing plants and the 115 projects in HPPS2. It is estimated using the capacity of each plant and average rainfall in area, and the capacity factor is set to 55% (middle value of the two sample projects). Table 6-20 shows the estimation of seasonal output by area.

Table 6-20 Estimation of seasonal output by area (MW)

Area	Existing	Potential	Summation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Sumatra	1,943	3,766	5,709	3,122	2,826	3,111	3,024	2,683	2,398	2,224	2,416	2,949	3,608	4,713	4,588
Jawa-bali	2,406	423	2,829	2,916	2,901	1,927	1,556	1,259	868	636	365	735	1,260	1,948	2,396
Kalimantan	30	8,273	8,303	3,988	4,586	4,682	5,233	5,340	4,441	3,935	3,276	3,497	4,398	5,654	5,787
Sulawesi	1,057	4,357	5,414	4,277	3,798	3,520	3,462	3,244	3,010	2,249	1,564	1,420	2,407	2,585	4,228
Summation	5,436	16,818	22,254	14,303	14,111	13,240	13,275	12,526	10,717	9,044	7,621	8,601	11,673	14,900	16,999

(Reference)
The Master Plan Study by JICA in 2011 indicates 2 scenarios for the development of hydropower plants up to 2027. One is the maximum development scenario, of 19,100MW. The other is a realistic scenario, of 12,378MW. They include existing plants.

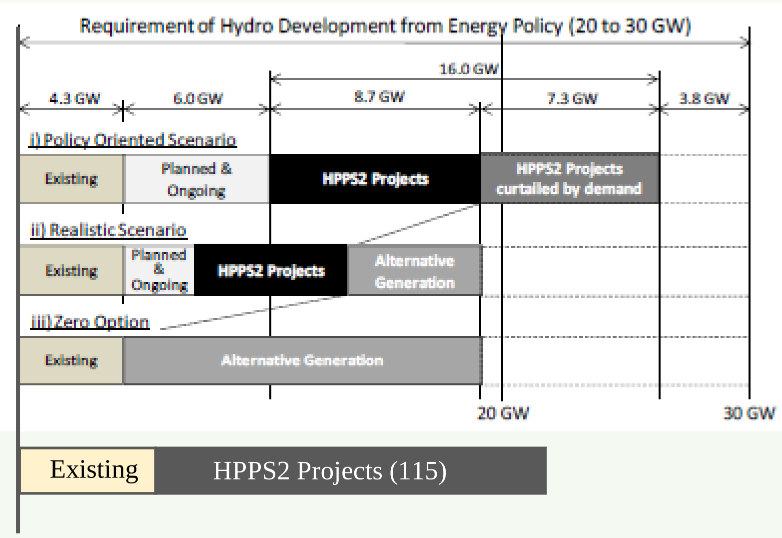


Figure 6-28 Hydropower potential

If hydropower plants have an intermediate pond, maximum output would be expected all season, as with the two sample projects. In the future, if the amount of solar power plants increases, hydropower plants with intermediate ponds will store river flow during the day to reduce output, and increase output during peak evenings.
Furthermore, for reservoir type power plants and cascade type power plants located downstream, seasonal adjustment would be anticipated through reservoir storage. It is possible to store river flow during the rainy season within the capacity of the reservoir, and increase output when the output of solar power generation and wind power generation decreases.

(3) Development costs

The cost of development for the two sample plants is estimated to be 2,300 USD/kW for the Simanggo-2 project, to 3,700USD/kW for the Masang-2 project.
Costs of development vary greatly from site to site. Development costs consist of 50% civil work, 30% generator and turbine costs, and 10% penstock. The cost of the intermediate pond is 20% of the civil work.

The development costs for the Kota Panjang project (114MW capacity with $107m^3$ reservoir) are 2,400USD/kW.
The development of hydroelectric power plants entails a long period and significant costs for pre-works, river flow surveys, geotechnical surveys and so on.

(4) Issues regarding development

It is said that a survey of river flow takes 20 years, to the start of construction. The initial stage is to correctly ascertain the amount of water that can be used at the actual site. Some water is used elsewhere for irrigation, etc. If flow data published by the national government exist near the site, planning would be relatively smooth.
A well-designed and constructed civil engineering structure can be used for a long period of over several decades. As most of the fatal defects in hydroelectric power plants occur at the construction stage, the initial storing stage, and immediately after the start of operation, it is extremely important to reduce the risk by planning and designing the project based on a detailed survey of topography and geology. In constructing a power plant underground, detailed investigation is required before selecting the location.

Larger hydro potential development has many challenges, and needs more time for survey and design than smaller developments.

(5) Development promotion policies, etc.

The Indonesian government has introduced some incentives for IPP development to expand the introduction of renewable energy.

1. Exemption from the use of local currency (rupiah) for national strategic projects.
2. Tax incentives applicable to renewable energy power generation projects.
3. Government Guarantee for Power Plant Projects.

In addition, there were media reports that "the Indonesian government is considering a presidential regulation that includes incentives for renewable energy power generation projects".

For details, refer to “6.4.4 Geothermal Power Generation”.

(6) Contributions of and recommendations regarding Japanese businesses

Projects with an expected high profit would be developed by private investors. Using return on equity (ROE) as an indicator, there is a view that if this exceeds 18%, an Independent Power Producer (IPP) would develop the project, and if it is below this, the project would be developed via PPP or be ODA-based.

Private investors may prefer a short lead time to development, making it easier to select smaller projects with minimal preliminary research. If small development plans are pre-authorized, potential development of large hydropower in the same river may be rejected.

The land and water needed for hydropower is overseen by the local government, and the power business is overseen by MEMR. In order to respect hydropower development proposed through the local governments as much as possible without impairing the large hydropower development, if all hydropower development plans are prepared by PLN in order to optimize hydropower potential, and the plans approved by MEMR are published in RUPTL, private investors and local governments will have a common understanding of hydropower development.

JICA has provided support for the development of many important hydropower plants in Indonesia and created the Hydropower Development Master Plan in 2011.

In Indonesia, various Japanese companies, such as electric power companies, construction companies, design consultants, and heavy electric power equipment manufacturers, have contributed in the development of hydroelectric power generation at each stage of planning, research, design, construction, and operation management.
In recent years, Kansai Electric Power Co., Inc. has participated in the development of the Rajamandala hydropower plant as an IPP, and in 2019, the 47 MW power plant started commercial operation. It is a Build, Operate and Transfer (BOT) business form in which it will be transferred to PLN after 30 years of commercial operation. The company is also involved in O&M operations.

Especially in river basins with high priority, it is desirable for PLN to create a comprehensive plan.
As a first step, existing power plants and all development plans should be confirmed, and the Master Plan reviewed for each river to maximize hydropower development. JICA and Japanese companies could provide support to create rational development plans.

(Appendix) Maintenance of reservoirs and intermediate ponds

As the introduction and expansion of renewable energy that does not have output adjustment capabilities (such as solar power and wind power) progresses, increased effects of output adjustment using reservoirs and intermediate pond would be expected.
As large reservoirs with several hundred million m^3 exist in Indonesia, rationalization of water operation in the entire basin, including for power plants located in downstream areas, is extremely valuable.

JICA confirmed problems caused by sedimentation, which may affect power generation, in multiple reservoirs during a joint survey with PLN in 2010.

+ Sutami dam
Sutami hydropower plant (105MW, from 1973) and Wlingi hydropower plant (54MW, from 1978) were surveyed.
In the basin, there is active sediment production due to volcanic activity, and the effective water storage capacity of 253 million m^3 decreased to 142 million m^3 in 2019.
The Government of Indonesia requested the Government of Japan to cooperate with the Sutami dam sedimentation countermeasure plan among the improvements in water resource management listed in the "Medium-Term National Development Plan 2020-2024".
Construction of a sand removal tunnel, procurement of dredgers, etc. are envisioned as measures to combat sedimentation.

+ Soedirman reservoir
At Soedirman hydropower plant (180.9MW, from 1988), 118.6 million m^3 of sand was deposited until 2014. Small-scale dredging and sediment flushing have been carried out, but they have not been effective enough to solve the problem.

+ Saguling reservoir
At Saguling hydropower plant (700MW, from 1985), as the reservoir has a large capacity of 875 million m^3, decrease in capacity is not an immediate issue. But since Bandon City (population 2.5 million) is located in the upstream area, water quality issues caused by sewage drainage, and domestic waste pollution and large amounts of waste are cited as problems.

+ Wonogiri reservoir
For Wonogiri hydropower plant (12.4MW, from 1981), sediment was 58 million m^3 until 2005 in the effective capacity (615 million m^3), or only 13.4%. But as it reached 49.1% in sediment capacity (114 million m^3), measures for the long term were cited as an issue.

+ Other plants
Issues were confirmed at Sengguruh hydro, Wlingi hydro, Selorejo hydro in Java, Tonsea Lama in Sulawesi, and Renun hydro in Sumatra in the JICA survey in 2010.

In Indonesia, which has a tropical rainforest climate and heavy rainfall, flood damage has repeatedly occurred for many years, and in the latest event in February 2021, flooding caused inundation, including human casualties in the capital, Jakarta. Through the Jakarta Metropolitan Area Flood Mitigation Organization Strengthening Project in 2010, JICA has also contributed to flood risk reduction, in areas such as river maintenance capacity, drainage facility operation capacity, and soft measures that contribute to the evacuation of residents. As in Indonesia, technological knowledge based on water resource development and flood control, learned from facing flood disasters in Japan, can greatly contribute to resilience.

6.4.4 Geothermal Power Generation

(1) Geothermal potential

There are several reports on geothermal potential in Indonesia. According to the energy economic statistics handbook published in 2019 by the Ministry of Energy and Mineral Resources, a relatively new source, the geothermal potential is 23,965 MW (the reserve is 14,626 MW, and resources are 9,339 MW).

Indonesia has large geothermal potential, like the United States and Japan. Table 6-21 to Table 6-23 show the geothermal potential by area.

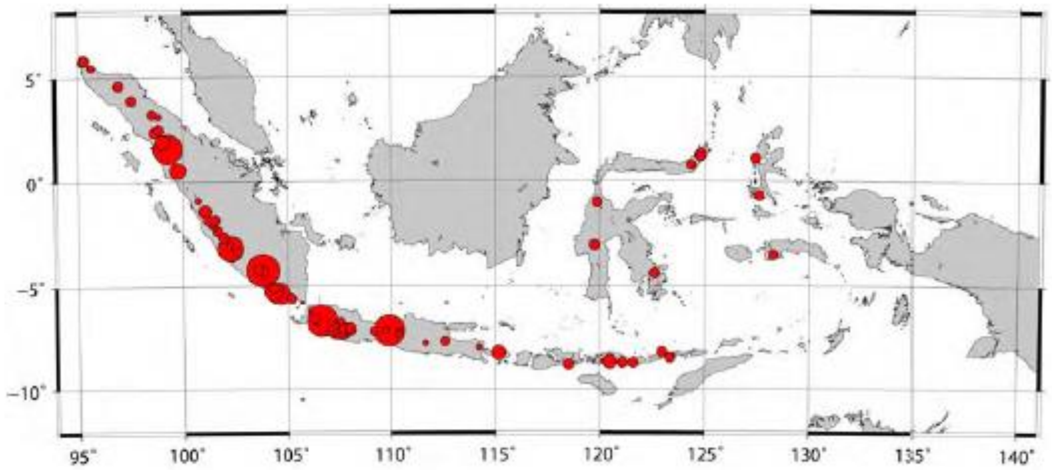
According to RUPTL (2021-2030), the geothermal potential is 9.7 GW for Sumatra and 8.1 GW for Java. According to a TEPSCO survey, the power plants developed total 702 MW for Sumatra and 615 MW for Java.

Although the sources are different, the ratio of already-developed to geothermal potential is 5.8%.

Table 6-21 Geothermal potential location

No.	Island	Potential energy (MW)					Total	(Repeat) Installed capacity
		Power source		Reserves				
		Speculative	Hypothesis	Suspected	Possible	Proved		
1	Sumatra	2,276	1,557	3,735	1,041	1,070	9,679	562
2	Jawa	1,265	1,190	3,414	418	1,820	8,107	1,254
3	Bali	70	21	104	10	30	335	0
4	Nusa	190	148	892	121	12	1,363	13
5	Southeast Kalimantan	151	18	13	0	0	182	0
6	Sulawesi	1,365	362	1,041	180	120	3,068	120
7	Maluku	560	91	497	6	2	1,156	0
8	Papua	75	0	0	0	0	75	0
Total		5,952	3,387	9,696	1,776	3,054	23,965	1,948

(Source: RUPTL (2021-2030))



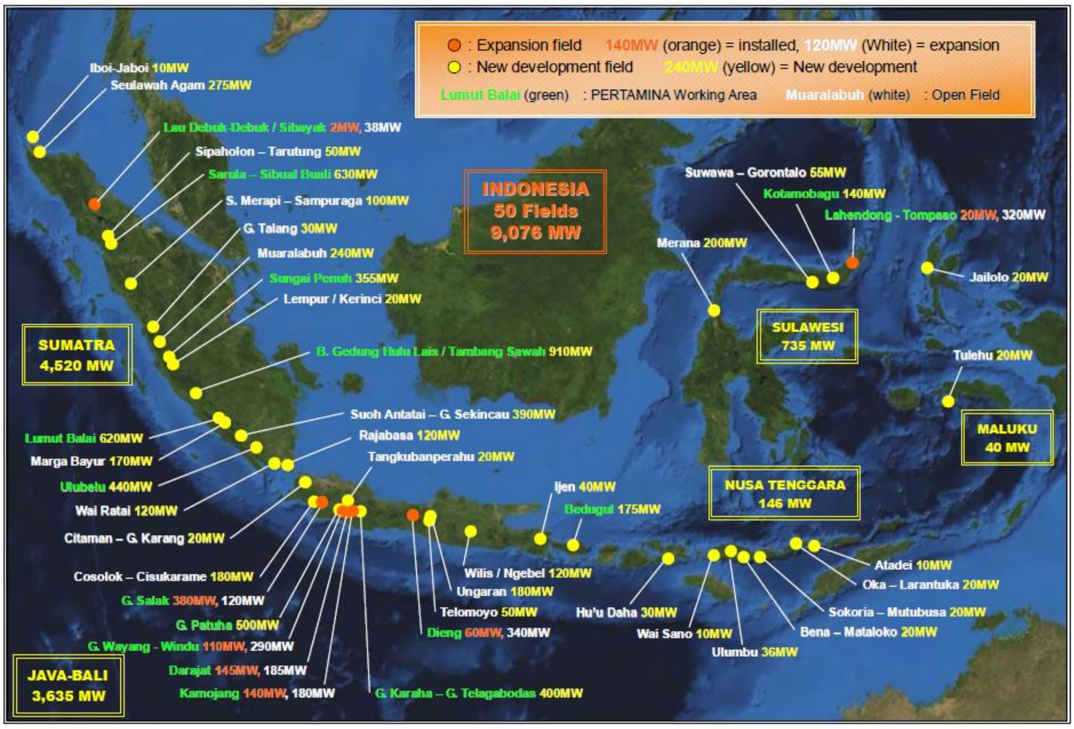
(Source: Major geothermal fields in Indonesia (Muraoka 2005))

Figure 6-29 Major geothermal spots in Indonesia

Table 6-22 Existing and under construction plants

Name	Unit	Capacity (MW)	Location	Operation start time
Kamojang	1	30MW	Jawa	Dec-83
	2 & 3	55MW × 2		Oct-87,Nov-87
	4	60MW		Jan-08
	5	35MW		Jun-15
Sibayak Monoblok	1	2MW	Sumatra	Aug-96
Wayang Windu	1	110MW	Jawa	Jun-00
	2	120MW		Mar-09
Sibayak	1 & 2	5MW×2	Sumatra	Sep-08
Lahendong	1 & 2 & 3 & 4	20MW×2	Sulawesi	Aug-01, Jun-07, Apr-09, Nov-11
	5 & 6	20MW×2		Dec-16
Ulubelu	1 & 2	55MW×2	Sumatra	Sep-12
	3 & 4	55MW×2		Jun-16、Mar-17
Karaha	1	30MW	Jawa	Apr-18
Sarulla	1 & 2 & 3	110MW×3	Sumatra	May-18
Lumut Balai	1	55MW	Sumatra	Sep-19
	2	55MW		Under Construction
Muara Laboh	1	85MW	Sumarta	Dec-19
	2	65MW		Under Construction（conplete in 2024）
Dieng	1	60MW	Jawa	Operating
	2 & 3	55MW × 2		Under Planning
Patuha	1	60MW	Jawa	Operating
	2 & 3	55MW × 2		Under Planning
Hululais	1 & 2	55MW×2	Sumatra	Under Construction
	extension	unknown		investigating
Rajabasa	1 & 2	110MW×2	Sumatra	Under Construction
Rantau Detap	1	98.4MW	Sumatra	Under Construction
Sungai Penuh	1	55MW	Sumatra	Under Construction
Gunung Lawu	unknown	unknown	Jawa	investigating
Kotamobagu	unknown	unknown	Sulawesi	investigating

(Source: Surveyed by TEPSCO)



(Source: Master Plan of geothermal development in Indonesia (2007, JICA))

Figure 6-30 Locations of geothermal plants

Table 6-23 Geothermal potential needing further research

No.	Names	Provinces	Cap. (MW)	No.	Names	Provinces	Cap. (MW)
1	G. Geureudong	Aceh	50	61	Gunung Lawu # l	Jateng	55
2	Gn. Kembar	Aceh	330	62	Gunung Lawu #2	Jateng	55
3	Jaboi (FTP2) #3	Aceh	80	63	Guci #1	Jateng	55
4	Lokop	Aceh	20	64	Guci #2	Jateng	55
5	Seulawah Agam（FI'P2) #I	Aceh	55	65	Mangunan-\Vanayasa	Jateng	40
6	Seulawah Agam (FTP2) #2	Aceh	55	66	Umbul Telumoyo (FTP2)	Jateng	55
7	Sarulla II #2	Sumut	110	67	Arjuno Welirang	Jatim	185
8	Sarulla II #3	Sumut	110	68	Bromo-Tengger	Jatim	20
9	Sarulla II (FTP2) #1	Sumut	40	69	Gunung Pandan	Jatirn	60
10	Sibual Buali	Sumut	590	70	Gunung Wilis #1	Jatim	10
11	Simbolon Samosir (FTP'2)#1	Sumut	50	71	Gunung Wilis #2	Jatim	10
12	Simbolon Samosir (FTP2)#2	Sumut	60	72	Iyang Argopuro（FTP2)	Jatim	55
13	Sipoholon Ria-Ria (FTP2)	Sumut	10	73	Krucil Tiris	Jatim	30
14	Bonjol (FTP2)	Sumbar	60	74	Songgoriti	Jatim	35
15	Cubadak	Sumbar	20	75	Banyu Wedang	Bali	10
16	Gn. Tandikat & Singgalang	Sumbar	20	76	Bedugu]	Bali	110
17	Panti	Sumbar	55	77	On. Batur	Bali	40
18	Simisioh	Sumbar	55	78	Tabanan	Bali	65
19	Sumani	Sumbar	20	79	Pentadio	Gorontalo	10
20	Talamau	Sumbar	20	80	Puhuwato	Gorontalo	10
21	Grabo Nyabu # l	Jambi	50	81	Suwawa	Gorontalo	20
22	Graho Nyabu #2	Jambi	60	82	Klabat Wineru	Sulut	40
23	Sungai Pemlh Semurup	Jambi	30	83	Klabat-\Vineru	Sulut	10
24	Sungai Penuh Small Scale	Jambi	5	84	Kotamobagu I (FTP 2)	Sulut	20
25	Sungai Tenang	Jambi	10	85	Kotamobagu II (FTP 2)	Sulut	20
26	Lumut Balai #3	Sumsel	55	86	Kotamobagu III (FTP 2)	Sulut	20
27	Lumut Balai #4	Sumsel	55	87	Kotamobagu IV (FTP 2)	Sulut	20
28	Lumut Balai Small Scale	Sumsel	5	88	Lahendong #7	Sulut	20
29	Margabayur #l	Sumsel	30	89	Lahendong #8	Sulut	20
30	Margabayur #2	Sumsel	30	90	Lahendong Binary	Sulut	5
31	Tanjung Sakti	Sumsel	55	91	Lahendong Small Scale #2	Sulut	5
32	Bukit Daun #1	Bengkulu	55	92	Lahendong Small Scale #3	Sulut	5
33	Bukit Daun #2	Bengkulu	30	93	Bora Pulu (FTP 2)	Sulteng	40
34	Hululais (FTP2) #3	Bengkulu	55	94	Kadidia	Sulteng	55
35	Hululais (FTP2) #4	Bengkulu	55	95	Marana (FTP 2)	Sulteng	20
36	Hululais Small Scale #1	Bengkulu	10	96	Lainea	Sultra	20
37	Hululais Small Scale #2	Bengkulu	10	97	Bittuang	Sulsel	20
38	Lawang-Malintang	Bengkulu	20	98	Massepe	Sulsel	55
39	Tambang Sawah	Bengkulu	10	99	Pincara	Sulsel	10
40	Gn. Way Panas-Ulubelu	Lampung	110	100	Lilli-Seporaki	Sulbar	10
41	Sekincau (FTP2) #1	Lampung	55	101	BandaBaru	Maluku	10
42	Sekincau (FTP2) #2	Lampung	165	102	Tehoru	Maluku	10
43	Ulubelu Small Scale	Lampung	10	103	Akesahu	Malut	10
44	Gunung Endut (FTP2)	Banten	40	104	Gn. Hamiding #2	Malut	200
45	Cibeureum Parabakti	Jabar	85	105	Gunung Hamiding	Malut	20
46	Cibuni #2	Jabar	20	106	Jailolo (FTP2) #1	Malut	10
47	Cilayu	Jabar	20	107	Jailolo (FTP2) #2	Malut	20
48	Ciseeng	Jabar	20	108	Telaga Ranu	Malut	10
49	Cisolok-Cisukarame	Jabar	50	109	Hu'u (FTP2) #1	NTB	10
50	Gede Pangrango	Jabar	55	110	Hu'u (FTP2) #2	NTB	10
51	Gunung Ciremai (FTP2) #1	Jabar	55	111	Sembalun (FTP2) #1	NTB	10
52	Gunung Ciremai (FTP2) #2	Jabar	55	112	Sembalun (FTP2) #2	NTB	10
53	Gunung Galunggung it I	Jabar	55	113	Gou - Inelika	NTT	10
54	Gunung Galunggung #2	Jabar	55	114	Lesugolo	NTT	10
55	Kamojang-Darajat	Jabar	65	115	Mapos	NTT	20
56	Karaha #2	Jabar	20	116	Nage	NTT	40
57	Masigit #1	Jabar	55	117	Sokoria #7	NTT	30
58	Papandayan	Jabar	40	118	Waisano	NTT	20
59	Tampomas	Jabar	45	119	Wapsalit	NTT	10
60	Wayang Windu(FTP2) #4	Jabar	120	120	WayPesi	NTT	10

Source: RUPTL (2021-2030)

(2) Scheme on geothermal development

Prior to the enactment of the Geothermal Act in 2003, Pertamina was the only government-appointed geothermal mining agency in Indonesia, and in government-selected mining areas Pertamina had the exclusive rights to carry out geothermal business activities independently, or enlist contractors to do so based on the JOC (Joint Operation Contract). An Energy Sales Contract (ESC) was signed between Pertamina as a seller and PLN as a purchaser.

The Geothermal Law was enacted in 2003, and through bidding for mining areas, geothermal licenses were issued by the government. "Geothermal Development Road Map (2004-2020)", formulated by the Ministry of Mines and Energy in 2004, aims to develop 6,000 MW by 2020 and 9,500 MW by 2025.

The purchase price for geothermal (high pressure) was set through FIT, introduced in 2012.

The 2014 revision of the Geothermal Law clarifies the distinction between geothermal development and mining, and geothermal development became possible in forest areas even within production forests and protected forest areas, where most of Indonesia's geothermal resources are concentrated, by obtaining permission to "borrow and use".

Currently, IPP will be able to develop geothermal heat by participating in an open bidding process and acquiring the rights to manage and operate the geothermal area. Bidding will be conducted in the following two stages in accordance with Ministerial Ordinance No. 37 of 2018, Ministry of Energy and Mineral Resources.

i) Pre-qualification screening on management, technical and financial standards
ii) Determination of the winning bidder to be granted the rights (license) to manage and operate the geothermal area

(3) Companies in Indonesia

Most of the geothermal power plants in Indonesia have been developed by Pertamina, a state-owned oil company, PLN, a state-owned electric power company, and Pertamina Geothermal Energy (PGE) and PT PLN Gas & Geothermal (PLN GG), their geothermal development subsidiaries.

In 2003, the Indonesian government enacted the Geothermal Law, which stipulated procedures for private companies to participate in geothermal development, and in the same year, Pertamina was converted into a joint-stock company. In 2006, Pertamina established PGE as a subsidiary and transferred the geothermal business.

In 2013, PGE announced plans to build eight geothermal power plants (655 MW):

Ulubelu Unit 3 & 4 (2×55MW)
Lumut Balai Unit 1 & 2 (2×55MW), Unit 3 & 4 (2×55MW)
Lahendong Unit 5 & 6 (2×20MW)
Karaha Unit1 (30MW)
Kamojang Unit 5 (35MW)
Hululais Unit 1 & 2 (2×55MW)
Sungai Pnuh Unit 1 & 2 (2×55MW)

In 2021, the Ministry of State-owned Enterprises of Indonesia (BUMN: Kementerian Badan Usaha Milik Negara) announced that it will establish a state-owned holding company for geothermal power generation business, jointly funded by Pertamina, PLN, and the government.

A new company funded by holding companies, PGE, PLN GG, and PT Geo Dipa Energi, is said to be developing geothermal energy, using its advantages as the largest geothermal company to target each business area: development, drilling, energy supply to users, and financing.

PGE owns seven geothermal power plants with a total output of 672 MW, three additional power plants under development and three exploration areas.
PT Geo Dipa Energi currently operates two geothermal power plants. The Dieng geothermal power plant is 60 MW, and it is planned to add 55 MW for each of Units 2 and 3. The Patuha geothermal power plant is also 60 MW, and is also planned to add 55 MW for each of Units 2 and 3.

PLN GG is said to focus on the operation of geothermal power plants and geothermal development, using steam produced by other companies, and to conduct joint research on development at Lahendong geothermal power plant and Ulubelu geothermal power plant with PGE.

PLN made a list of pre-registered suppliers for renewable energy developers (DPT, Daftar Penyedia Terseleksi). In the latest DPT, 5 geothermal development partners (including JV) appear to be registered.

1. Itochu (Japan)
2. Medco Power Indonesia (Indonesia)
3. Ormat Geothermal Indonesia (United States)
4. KS Orka (Singapore) - Haliburton (United Kingdom) - Adaro (Indonesia)
5. Apexindo (Indonesia) - Schulumberger (France, United States) - EDC (Philippines)

PGE announced in January 2021 that Medco Power Indonesia (MPI) will jointly conduct a six-month survey of seven geothermal development sites (700 MW in total). MPI is a power subsidiary of resource giant Medco Energy International, which operates 18 power plants (over 3,300 MW) in Indonesia.

(4) Development promotion policy, etc.

The Indonesian government has introduced some incentives for IPP development to expand the introduction of renewable energy.

1. Exemption from the use of local currency (rupiah) for power development projects in strategic infrastructure projects
2. Tax incentives applicable to renewable energy power generation projects, per the following.
- Net income tax deduction of 30% from the total capital investment
- 10% (or lower) income tax charged to non-resident taxpayers
- Extension of tax loss carry-forward period (up to 10 years)
- Shortening the depreciation period for tangible/intangible assets
3. 2.5% tariff exemption on imports of capital goods used in power generation projects
4. Government Guarantee for Power Plant Projects
5. Introduction of OSS (Online Single Submission) system to simplify power supply business license (IUPTL) acquisition

In 2020, there were media reports that "the Indonesian government is considering a presidential decree that includes incentives for renewable energy power generation projects".

In media reports, some incentives and preferential provisions have been envisioned for geothermal development compared to other renewable energies, as per the following.

- Application of tax holiday (temporary corporate income tax exemption) and tax allowance (corporate tax incentive)
- Exemption from value-added tax, import duties and prepaid tax (PPH 22) on imported goods
- Reduction of land and building tax (PBB) for geothermal-related business activities
- Support for geothermal surveys and information gathering
- Loans through state-owned enterprises

In addition, the Ministry of Energy and Mineral Resources' New Renewable Energy and Energy Conservation Bureau (hereinafter referred to as EBTKE) conducts geothermal surveys at the expense of the government to reduce the risks on developers. After bidding, the developer who obtained the development rights would pay the survey fee. Surveys are currently ongoing in the Chisorok area in West Java and the Nage area in East Nusa Tenggara.

(5) Issues in promoting geothermal development

In geothermal development, energy is taken out of steam and hot water that exist at depths of about 1,500 to 3,000 m underground, and would be expected to have a capacity factor of 90% as stable power. However, many large risks exist in development.
Long-term surveys and large-scale investment are required, as with the development of oil, natural gas and mineral resources.

Three large issues exist regarding geothermal development.
a. Large initial investment, generation cost usually exceeds selling price.
b. Characteristics of geothermal resource greatly affect profit on projects.
c. Long lead time before development and large initial investment.

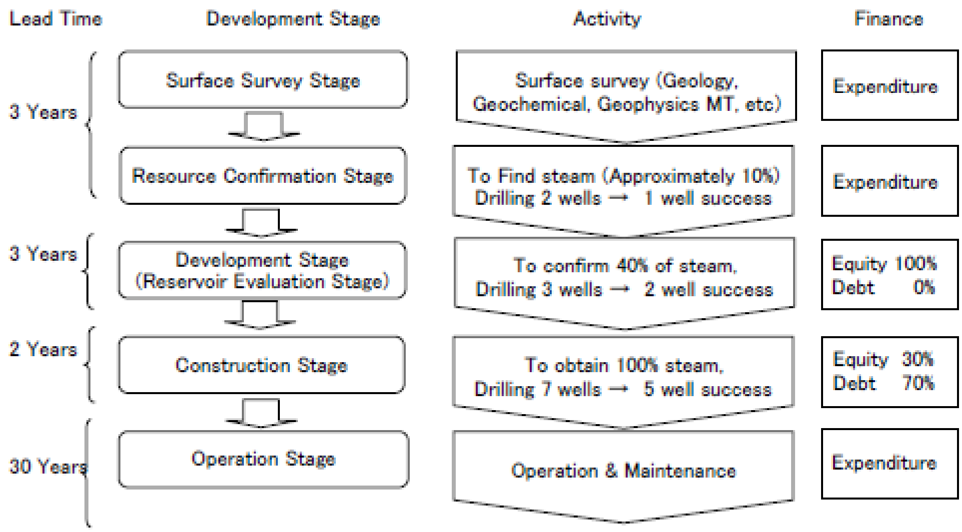
Table 6-24 and Figure 6-31 show the costs and process, as a model case of development for a 55MW geothermal power plant.

Table 6-24 Cost of geothermal development (55MW model case)

Stage	Content	Cost (m$)
1. Surface Survey	Wide-area Surface Survey	2
2. Exploratory	2 Exploratory Wells (success rate 50%) etc.	10
3. Cinfirmation (Development	3 Production Wells (success rate 70%) etc.	10
4. Construction		
4.1 Steam Field	7 Production Wells (success rate 80%), P/L et	42
4.2 Power Plant	Power Plant	65
5. Others		7
Total		136

(Source: Master Plan of geothermal power (in 2007, JICA))

Generation costs of geothermal power plants exceed those of coal-fired power plants, and both are base load generation. Low carbonization might increase the generation costs of coal-fired power plants, and geothermal power plants might become superior.



(Source: Master Plan of geothermal power (in 2007, JICA))

Figure 6-31 Process for geothermal development (55MW model case)

At each stage - survey, development, and operation - important technical risks exist, which may affect the development costs and power output, and be directly linked to profitability.

(a) Survey stage
- Difficulty in constructing access roads, etc.
- Difficulty in surveying due to characteristics of the survey area
- Success rate for survey well drilling

(b) Development stage
- Depth of geothermal potential
- Productivity of geothermal potential
- Properties of geothermal fluid, concentration of non-condensed gas
- Success rate for production well drilling
- Increase in costs for construction and equipment

(c) Operation stage
- Attenuation of steam amount
- Capacity factor decrease

Surveys by EBTKE, to provide geothermal resource data, would contribute to risk reduction in development.

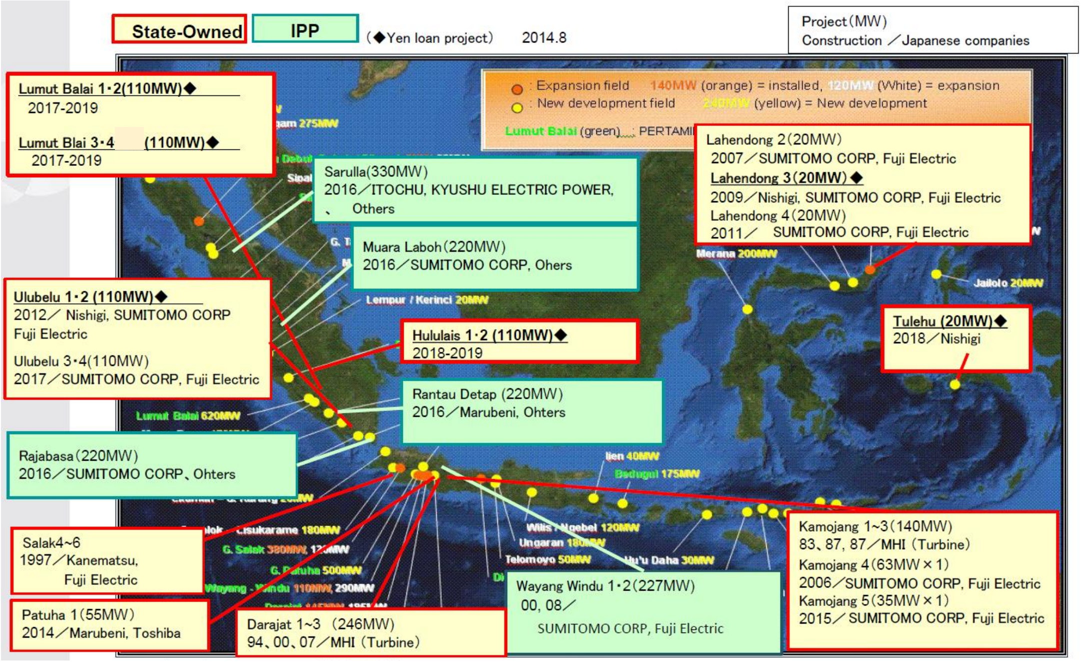
(6) Contribution of Japanese businesses (recommendations)

JICA has contributed in the introduction of geothermal development.
In 2007, it created the Geothermal Development Master Plan.
In 2009, it investigated the introduction of the FIT system and proposed the Effectiveness of FIT, and quoted a target price of 10.9 cent/kWh.
In 2011, it proposed the establishment of a fund by the government for surveys.
In 2010-2013, it helped improve skills in geothermal resource survey at MEMR and the Center for Geological Resources (CGR).

Below are the power plants in which Japanese companies have participated as IPP.

- Wayang Windu power plant (230MW, Java): Mitsubishi Corporation
- Sarulla power plant (330MW, Sumatra): Itochu Corporation, Kyushu Electric Power Company, INPEX
- Muara Laboh power plant (85MW (expanding 65MW), Sumatra): Sumitomo Corporation
- Rajabasa power plant (constructing 220MW, Sumatra): Sumitomo Corporation
- Rantau Detap power plant (constructing 98.4MW, Sumatra): Marubeni, Tohoku Electric Power Company

Figure 6-32 shows projects with orders received by Japanese companies.



(Source: Master Plan of geothermal power (in 2007, JICA))

Figure 6-32 Projects with orders received by Japanese companies

Japan Oil, Gas and Metals National Corporation (JOGMEC), New Energy and Industrial Technology Development Organization (NEDO) etc. are developing technologies related to the development and utilization of geothermal energy in Japan.
These technologies would contribute to geothermal development efforts in Indonesia by reducing risks at each development stage.

Table 6-25 Technologies for geothermal development (JOGMEC, NEDO)

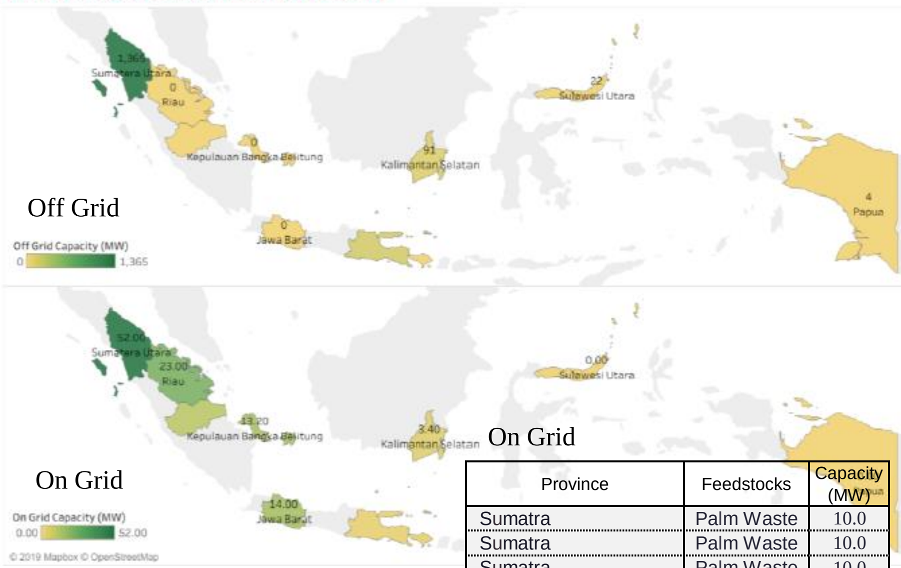
Organization	Title of subject	Project
JOGMEC	Evaluation / management technology of geothermal reservoir	Artificial recharge to geothermal reservoir
		Ground permeabiloty improvement
	Geothermal reservoir exploration	Seismic survey for geothermal reservoir
		Survey by Superconducting Quantum Interface Device
		Survey from existing well
		Survey with directional borehole radar
	Drilling technology for geothermal reservoir	Shortening the survey period by Polycrystalline Diamond Compact Bit
		Shortening the survey period by small and high-power rig
		Mitigating the risk of lost circulation
NEDO	Geothermal power generation system environmentally friendly	Conbined cycle geothermal power plants
	Micro binary power generation system（Utilization on geothermal energy at low-temperature area）	High efficiency binary power generation system using oil-free scroll expander
		Surface modification of steels to suppress calcium carbonate scale adhesion
		small generation system with corrosion and scale adhesion countermeasure
		Binary cycle power generation using hot spring thermal
		New high-performance low-boiling-point fluid for binary-cycle system
		Small binary power generation with water as working medium
	Expansion utilization of geothermal energy	Removal of scale at low temperature
		Hybrid geothermal power plant combined with other thermal energy sources
		Electrolysis scale remover for geothermal power plant
		Physical removing scale technology for geothermal power generation with hot spring heat utilization
		Mechanical Descaling Method for Binary Cycle Power Generation
		Turbine generator for binary power generation
		Turning scale-causing substances in hot water into high-performance material
	Various technology for geothermal energy utilization	Recovery of reinjection capacity of reinjection well
		Utilization of unused geothermal energy
		Advanced management of geothermal powerplant operations
		Alkali injection test into acidic hot water
		Utilization of non-used high-acidic hot water
		Low adhesion technologies for powerplant which utilizes high-acidic hot water
		Wellhead equipment for high-acidic hot water
		Predictive diagnosis of failure, for high operating rate
		Management of hydrogen sulfide at cooling towers
		High-precision monitoring equipment for hydrogen sulfide
		Remote monitoring system of hot spring water quality
		IoT-AI application for small-scale geothermal smart power generation

(Source: Recommendations for promoting the development and utilization of geothermal energy (in 2020, NEF))

6.4.5 Biomass Power Generation

(1) Biomass potential

Figure 6-33 shows biomass power capacity in Indonesia. The off-the-grid power plants are larger than the on-grid power plants, and many of them are located in Sumatra. Many power plants use Palm Waste and POME, which are residues derived from oil palm. Material from paper makes up a large amount of the power output (955MW) in North Sumatra. Sugar cane makes up 219MW of the power output at three plants in Java-Bali and Sumatra. MSW, which is urban waste, makes up 17.6MW of the power output at 4 plants.



Off Grid

Area	Feedstocks	Capacity (MW)
Sumatra	Paper	955.0
Sumatra	Palm Waste	335.0
Sumatra	Sugar Cane	66.0
Sumatra	POME	9.0
Kalimantan	Palm Waste	91.0
Sulawesi	Palm Waste	11.0
Sulawesi	Sugar Cane	11.0
Jawa-Bali	Sugar Cane	142.0
Jawa-Bali	Palm Waste	2.0
Papua	Palm Waste	4.0
TOTAL		1,626.0

On Grid

Province	Feedstocks	Capacity (MW)
Sumatra	Palm Waste	10.0
Sumatra	Palm Waste	10.0
Sumatra	Palm Waste	10.0
Sumatra	Palm Waste	10.0
Sumatra	Palm Waste	10.0
Sumatra	Palm Waste	10.0
Sumatra	Palm Waste	10.0
Sumatra	Palm Waste	9.0
Sumatra	Palm Waste	7.0
Sumatra	Palm Waste	5.0
Sumatra	Palm Waste	3.0
Sumatra	Palm Waste	3.0
Sumatra	POME	1.2
Kalimantan	Palm Waste	0.0
Kalimantan	POME	2.4
Kalimantan	POME	1.0
Kalimantan	Corncob	0.4
Jawa-Bali	MSW	12.0
Jawa-Bali	MSW	2.0
Jawa-Bali	MSW	2.0
Jawa-Bali	MSW	1.6
TOTAL		119.6

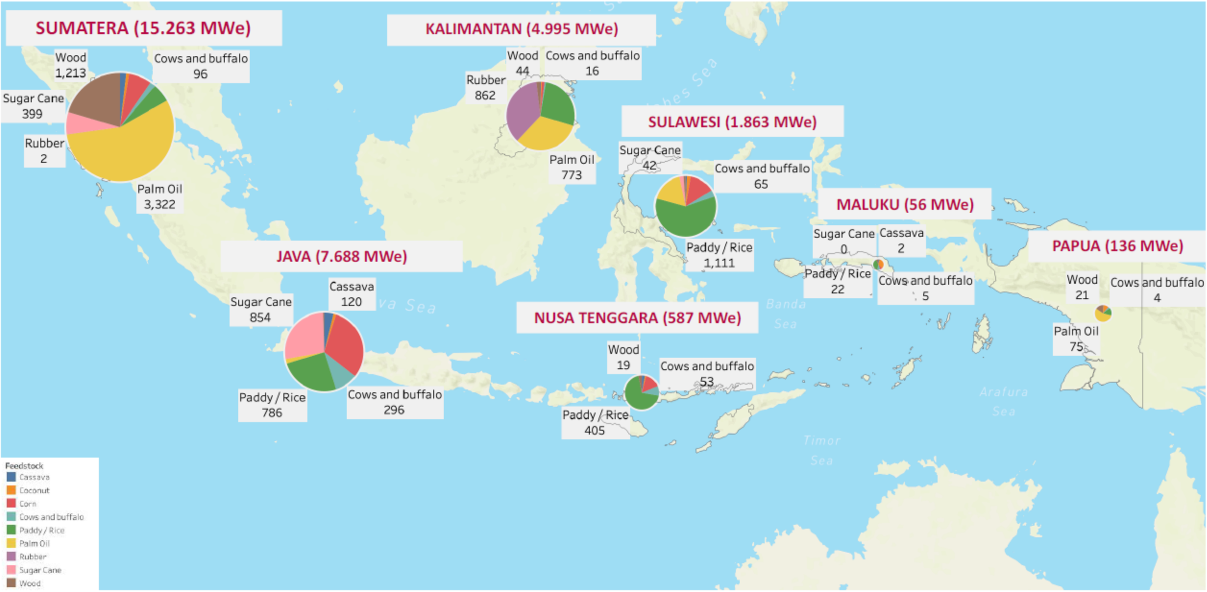
Source: Bioenergy Investment Guidelines, Ministry of Energy and Mineral Resources (2016)

Figure 6-33 Biomass power capacity in Indonesia

The biomass potential shown in RUPTL (2021-2030) is 32,654 MW, most of which is in Sumatra and Java.

Table 6-26 Biomass potential

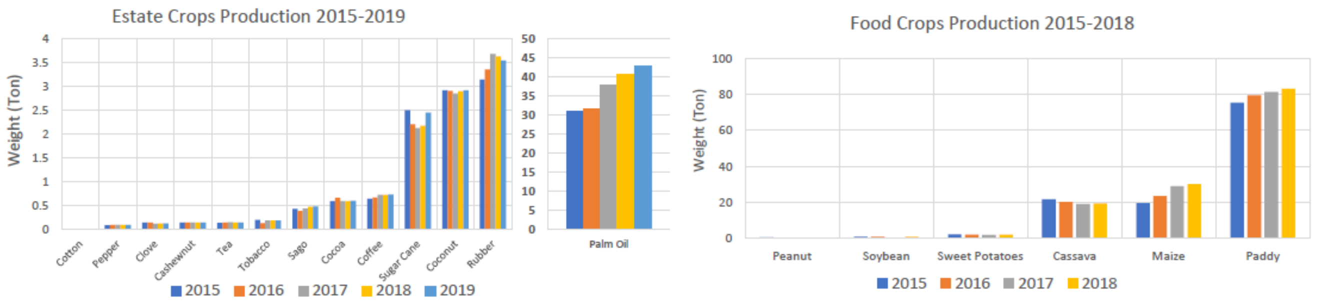
Feedstocks	Sumatra	Kalimantan	Java Bali	Nusa Tenggara	Sulawesi	Maluku	Papua	Total	Ratio
Palm Oil	8,812	3,384	60		323	0	75	12,654	38.8%
Sugarcane	399		854	0	42	0	0	1,295	4.0%
Rubber	1,918	862	0	0	0	0	0	2,780	8.5%
Coconut	53	10	37	7	38	19	14	178	0.5%
Rice Paddy	2,255	642	5,353	405	1,111	22	20	9,808	30.0%
Corn	408	30	954	85	251	4	1	1,733	5.3%
Cassava	110	7	120	18	12	2	1	270	0.8%
Wood	1,212	44	14	19	21	4	21	1,335	4.1%
Livestock	96	16	296	53	65	5	4	535	1.6%
Municipal Waste	326	66	1,527	48	74	11	14	2,066	6.3%
Total	15,589	5,061	9,215	635	1,937	67	150	32,654	100.0%



Source: Bioenergy Investment Guidelines, Ministry of Energy and Mineral Resources (2016)

Figure 6-34 Locations of biomass potential

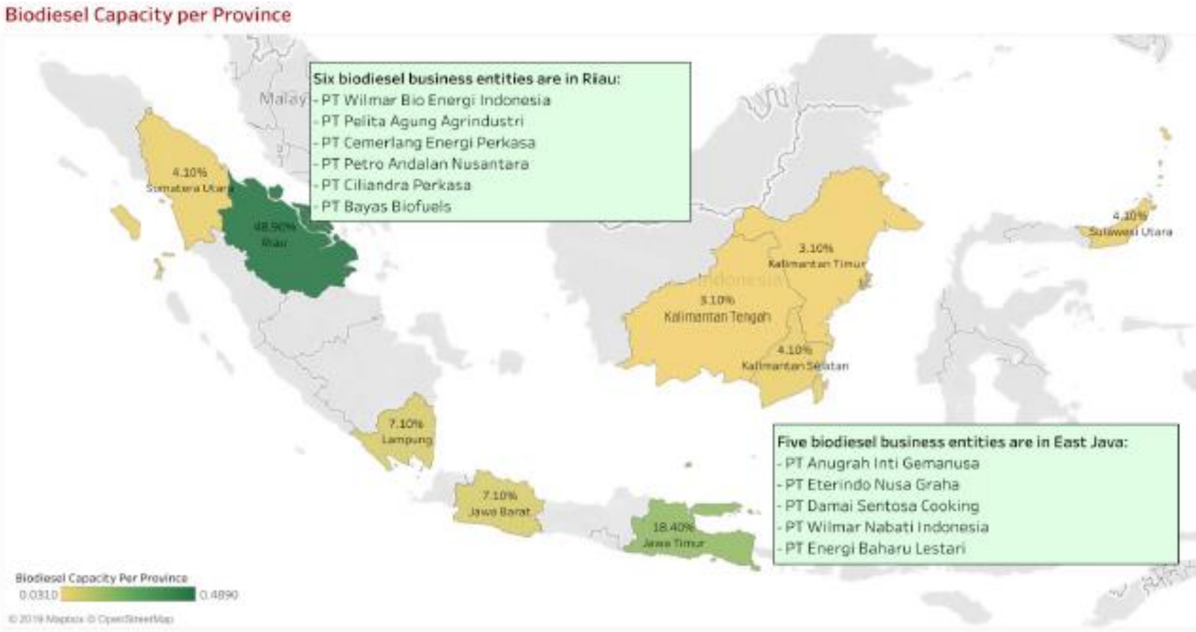
In the field of estate crop production, oil palms are prominent and production continues to increase. In the field of food and crop production, large amounts of rice, corn, and cassava are produced.



Source: BPS – Statistics Indonesia and Ministry of Agriculture (2019)

Figure 6-35 Crop production

Indonesia is the largest producer country, and the largest exporter country, of palm oil. Many biomass plants use palm oil-derived waste after the production of palm oil. There are ongoing efforts to utilize palm oil itself as biodiesel, for which the production capacity is relatively highly concentrated in Sumatra and Java.



Source: Bioenergy Investment Guidelines, Ministry of Energy and Mineral Resources (2016)

Figure 6-36 Biodiesel production capacity

Table 6-27 shows examples of power plants that have started operation in recent years. All biogas is derived from palm oil, and the power output from biogas is small.

Table 6-27 Biomass power plants started in recent years

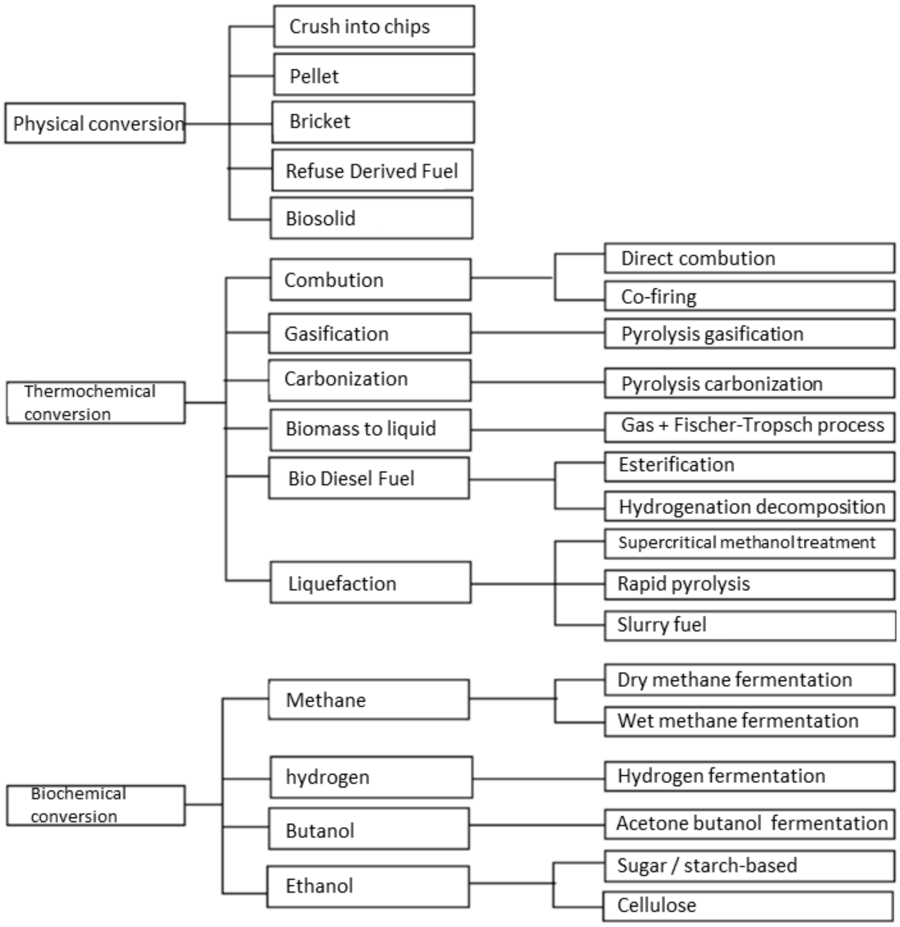
Name	Type	Location	COD	Capacity (MW)	Feedstocks	Capital (Mil US＄)
Siantan	Biomass Power Plant	Kalimantan	2018/4/23	10-15	Palm and wood shells, rice husks, corncobs, bagasse	20.3
BambuSiberut	Biomass Power Plant	Sumatra	2017/3/20	0.7-1.3	Bamboo	12.4
Sofifi	Biomass Power Plant	Maluku	2019/4/2	10	Gamal plant	-
Jangkang	Biogas Power Plant	Belitung	2016.1	1.8	POME	-
Terantam	Biogas Power Plant	Riau	2019/3/4	0.7	POME	1.89
Sei Mangkei	Biogas Power Plant	Sumatra	2019 (Plan)	2.4	Palm	-

（as 1Rp= 0.00007 US＄）

For power plants using waste, not only installation costs but also reduction fees for the collection and treatment of waste affect the economic efficiency of biomass plants.

(2) Issues regarding biomass energy utilization

Biomass resources have various properties, such as calorific value, specific gravity, and water content. Some conversion technologies for biomass energy utilization are in practical use.



Source: Handbook on introducing biomass energy (in 2017, NEDO)

Figure 6-37 Biomass energy utilization technology

Stable collection of biomass material is vital for the commercial use of biomass energy, in addition to conversion technology for biomass energy.
In Indonesia, PKS and POME energy utilization is in practical use together with waste discharge from palm oil. In Indonesia, palm oil is produced on estate farms developed in rainforests. Channels were constructed on large wetlands in rainforests for the development of these estate farms. Since the channels make the peat contained in the soil dry, carbon in the soil is released into the air as carbon dioxide in large-scale fires. Some point out that the carbon dioxide conversion of peat hinders low carbonization.

The amount of biomass power generation depends on the amount of fuel that can be secured. There is a discussion in Indonesia on expanding the use of wood-derived fuels, from which a large amount of fuel can be secured.

There is 920,000 km^2 of forest area in Indonesia (the largest amount of forest area in Southeast Asia), which is 48% of the country’s 1.91 million km^2 land area (FAO/2014). Most of the forests are national forests, of which 45% are classified as protected forests/conservation forests and 55% are classified as production forests.

The amount of tropical logs produced in Indonesia is the largest in the world, accounting for 24% of the world's production of 330 million m^3 (2020). On the other hand, the export volume of wood pellets, which are easy to use in large quantities at biomass power plants and for co-firing of thermal power plants, is much lower than that of neighboring countries such as Vietnam and Malaysia.

In recent years, local companies in West Java and Central Java have established factories as a new local industry, confirming an ambitious move to increase the production of wood pellets. In the future, it is possible that the export volume of wood pellets would increase, and the usage volume in Indonesia would also increase.
The unit price of wood pellets is expected to be determined by competition with neighboring countries. In Japan, which is an importing country for wood pellets, the import volume has increased significantly in recent years, while the fuel unit price has been stable at about 1,200 yen/GJ. Assuming that the unit price of wood pellets in Indonesia, which is an exporting country, is 2/3 of that of Japan, it is estimated to be about 800 yen/GJ.

Using wood as fuel has the potential to generate a significant amount of electricity.
But if it involves large-scale deforestation, there is a discussion on whether biomass generation would be superior to the pre-logging state from the viewpoint of carbon neutrality.

Indonesia has several systems for logging and the management of forests. A system called SVLK (Sistem Verifikasi Legalitas Kayu) was introduced for the purpose of proving the legality of wood. In addition, there are three systems for sustainable forest management certification: FSC (Forest Stewardship Council), IFCC (Indonesian Forestry Certification Cooperation; mutual approval with PEFC (Programme for The Endorsement of Forest Certification)), and LEI (Lembaga Ekolabel Indonesia). As of 2017, each has certified sustainable forest management of 20,000 to 37,000 km^2.

(3) Collaboration with international organizations

Collaboration with the Global Green Growth Institute (GGGI), an international organization, is also being seen in order to promote low carbonization.
To expand the use of energy derived from palm oil, and further reduce environmental pollution and landfilling, bio compressed natural gas (BioCNG), from the utilization of palm oil, livestock manure, and organic municipal waste, has been envisioned in Indonesia.

(4) Contribution of Japanese Businesses (recommendations)

Various Japanese businesses have been engaged in research and demonstration projects by JICA, JETRO, METI, NEDO and MOE, for bio-energy utilization and rationalization of waste treatment in Indonesia.

In the utilization of bioenergy, sustainable efforts are required in each aspect, such as production of raw material crops, conversion to fuel, power generation utilization, and waste disposal. Indonesia, as an exporter of raw materials, and Japanese businesses, as importers, would establish the expanded introduction and effective utilization of bioenergy through international cooperation.

Table 6-28 Projects involving utilization of bioenergy

Organization	report	Project
NEDO	2004	Characteristics of Jatropha curcas and its Planting Trial at the Land after Coal
NEDO	2008	A series of tests to produce ethanol from EFB jointly with Indonesian BPPT
NEDO	2008	latest technology, economy and regulation related to waste and low-calorie coal co-firing
NEDO	2009	Industrial waste and biomass combustion in the Cement Industry
NEDO	2009	Feasibility Study of Model Project for Ethanol Production from Molasses and Bagasse in a Sugar Factory
NEDO	2011	Introduction of CFB (circulating Fluidized Bed) boiler, for EFB(Empty Fruit Bunch) utilization
JETRO	2011	BOT (Build Operate and Transfer) Project on mechanical biological treatment and RDF power generation, etc
JETRO	2011	Waste power generation with infrastructure development
JICA	2012	Preparation Survey of Waste Treatment Facility in West Jawa
JICA	2012	Pilot Project on the Recycle Based Intermediate Waste
NEDO	2012	Study of 12MW biomass project at Sei Mangei industrial estate using EFB
NEDO	2012	Research for a cellulosic bioethanol production plant and its economy and marketability toward business
JICA	2013	Biogasification and composting of organic waste in Bali
NEDO	2013	Model Project of Ethanol Production with Use of Bagasse/Molasses from sugar factory
JICA	2013	Promotion of electrification by small biomass power generation equipment
MOE	2014	Conversion business from palm oil mill effluent to fuel
MOE	2014	Waste power generation business in Bali
NEDO	2016	Energy-saving measures by production and utilization of biofuel such as BDF by using waste biomass in palm oil industry
JICA	2016	Recycling type intermediate treatment of waste, composting in Bali
JICA	2016	Improvement of management of waste in Sumatra
NEDO	2016	Energy saving and heat recovering waste treatment system through effective use of waste as a heat source
JICA	2016	Conversion from Palm Kernel Shell to biomass fuel
MOE	2016	Waste business with sorting and composting in Bali
JICA	2018	Improvement business of general waste treatment in Jawa
JICA	2018	Small incinerators with consideration of Environment in island areas
JICA	2018	Improvement business of general waste treatment in Bali
JICA	2018	Reduction of waste volume by introducing a crusher
MOE	2018	Composting business in Kalimantan
MOE	2018	Recycling business of building waste
JICA	2019	Supply chain of organic waste recycling
MOE	2019	Methane fermentation business from industrial food waste in Jawa
JICA	2020	Waste management support for building a resource-recycling society in Sumatra
JICA	2020	Treatment of general waste without incineration by multi-item sorting and weight reduction
JICA	2020	Pulp and paper manufacturing business from EFB waste

6.5 Storage Battery Introduction Trends

6.5.1 Development Status and Potential Analysis for Storage Battery Technology

(1) Application of storage batteries

Storage batteries are the most popular technology for storing electricity, and they are utilized for various applications. The application of storage batteries can be mainly classified into three areas: consumer use, vehicle use, and stationary use. For consumer use (e.g. portable devices and information terminals), lithium-ion batteries account for the majority of the market. For vehicle use, low-cost lead-acid batteries have traditionally been used as auxiliary power supplies and starting power supplies. However, since electric vehicles and plug-in hybrid vehicles require higher energy density, nickel-metal hydride batteries have been used. At present, lithium-ion batteries are becoming mainstream.

Low cost and highly reliable lead acid batteries (alkaline batteries in a low-temperature environment) have been used as an emergency power source for installation, but with cost reductions and quality improvements in lithium-ion batteries, lithium-ion batteries are now being used and they account for more than 95% of new battery installations worldwide. Battery energy storage systems (BESS), which have been in high demand in recent years, mainly use lithium-ion batteries, which have a high energy density and are capable of supporting a variety of charge-discharge cycles (no memory effect, intermediate charging, and short charging time). Redox flow batteries and NAS batteries (sodium sulfur batteries) are being considered in BESS as well, although the number of projects using them is small.

In this document, “storage battery” or “battery” basically refer to BESS, and the storage battery application purpose is divided into ancillary services for load shifting and system stabilization. The roles expected from users are as shown in Table 6-29 below.

Table 6-29 Battery usage purposes

Function	User	Purpose
Load balancing	- Power System Operator - Transmission & distribution company	- Adjustment of balance between supply and demand - Solving grid congestion (reduce investment for transmission lines)
	- Power generation company	- Solving grid congestion (connect solar/wind power generators to existing transmission lines) - Alternative power sources for peak power plants
	Power market trader and retailer	Businesses that take advantage of market price differences due to supply and demand balance
	Demand side	- Peak demand cut - Reducing electricity costs (time shifting for effective use of the time-of-day rate system)
Ancillary services	Power System Operator	- System stability (voltage and frequency) - Securing reserve capacity - Black start

When storage batteries are used for load balancing, users have different purposes. For transmission and distribution, the purpose is to reduce grid congestion (to reduce investment costs for transmission lines); for power generation companies, to reduce fuel costs by using them as an alternative power source for peak power plants; for power market transactions, to secure profits through arbitrage; and for the demand side, to cut peak demand. When batteries are used for ancillary services, the main purpose is generally system stabilization (voltage and frequency adjustment) by the power system operator.

In countries such as the United States and Australia, where the storage battery business is advanced, there are projects that combine multiple revenue models, including arbitrage and ancillary services. However, in Indonesia at present, the regulations, related markets, and fee mechanisms for storage batteries have not been sufficiently established, and it is assumed that the business model will be greatly influenced by factors to be determined in the future.

Renewable energy sources, such as solar and wind power, vary according to weather and wind conditions. For example, solar power generation varies greatly due to changes in the amount of solar radiation caused by seasons, weather, and cloud shadows, in addition to temporal variations.
Aside from the issue of temporal unevenness, there is also the problem of regional unevenness, in which the place suitable for solar/wind power generation and the place where the electric power demand is do not coincide. Currently, operators can only increase the system capacity to accommodate regional supply and demand mismatch in power generation, but for temporal changes in power generation, there are two possible methods: balancing by installing batteries at the power generation site and stabilizing by installing batteries in the grid system.
Such fluctuations in power generation output, caused by the introduction of a large amount of renewable energy, have had a large impact on both load balancing and ancillary services, and the use of storage batteries is being promoted as a solution.

(a) Power shifting (for Load Balancing)

In a grid system with large-scale solar power generation, the power output of existing thermal power plants is greatly suppressed during the daytime. Figure 6-38 shows the changes in the supply-demand curve of the ISO in California, USA. It can be seen that the output of existing thermal power plants has been suppressed as the introduction of solar power generation has increased. This is commonly called the “Duck Curve” because the curve of the power supply from the output adjustable power source is similar to the shape of a duck.

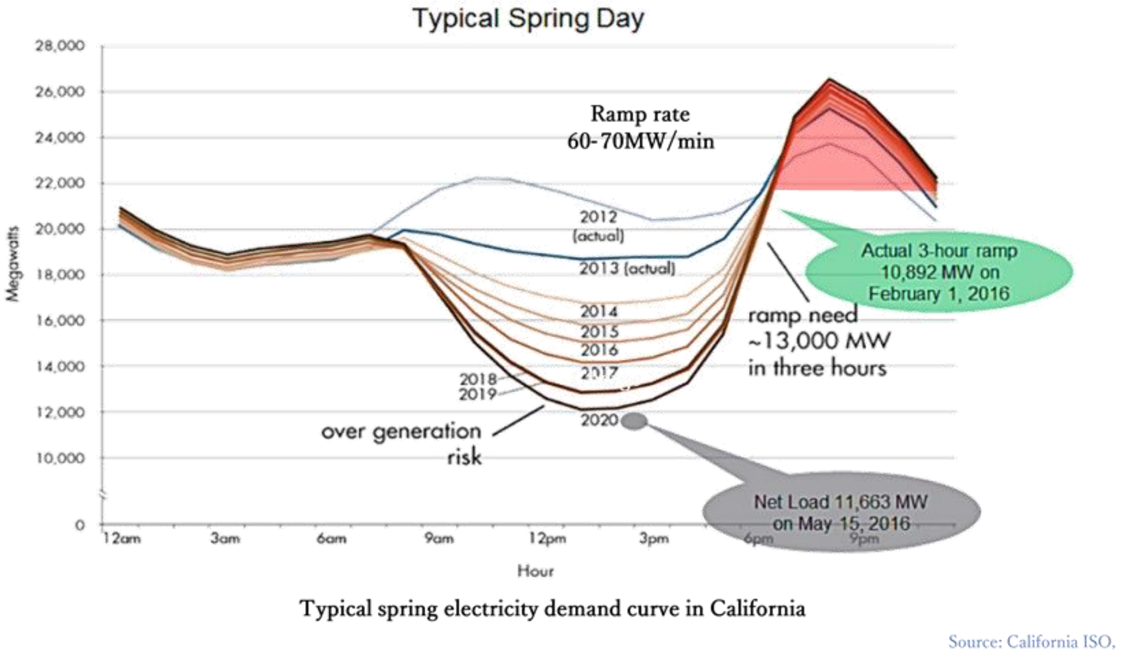


Figure 6-38 “Duck Curve” due to massive introduction of solar power

This has made it difficult for electric power companies to operate power systems and existing thermal power plants because of the need to start and stop thermal power plants for rapid output adjustment every day. In addition, there have been problems such as increased maintenance costs for existing thermal power plants, decreased thermal efficiency due to increased partial load operating time (deterioration in economic efficiency due to increased fuel costs), and decreased facility life.
In order to mitigate this problem, storage batteries are installed in a solar power generation facility or on a grid system, charged around noon when the solar power generation output reaches its peak, and discharged in the evening when the solar power generation output drops rapidly and demand is high, so that the output fluctuation of an existing thermal power plant can be suppressed, the steep

fluctuation in the evening can be slowed down, and the fluctuation amount can be suppressed to within a range by which the thermal power plant can follow the load (Figure 6-39).

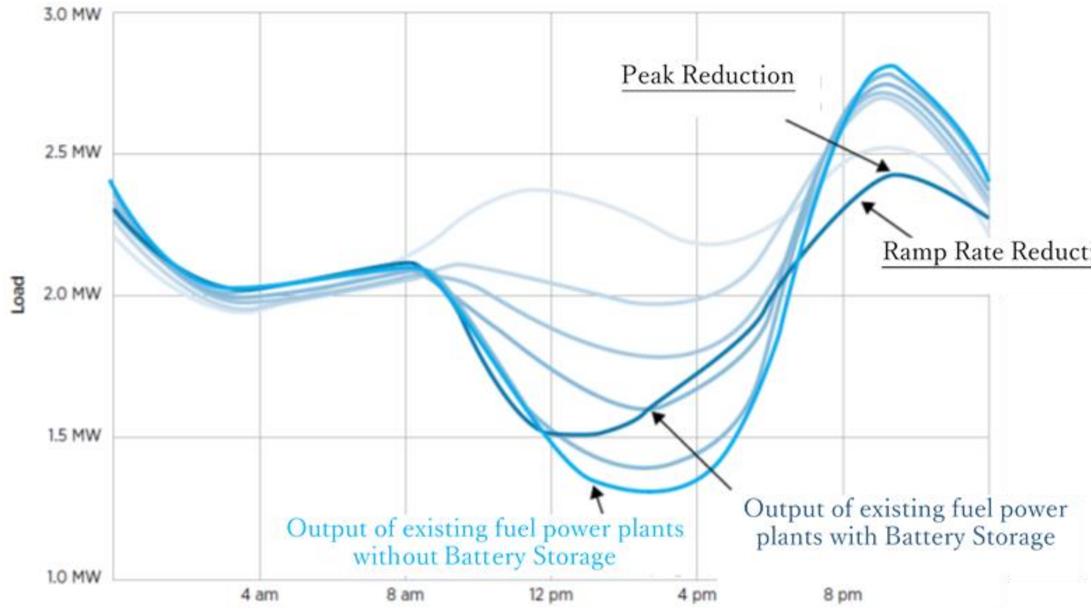


Figure 6-39 Countermeasure for “Duck Curve” with Battery Energy Storage System

(b) Power Fluctuation Control (for Ancillary Services)

Solar power generation output fluctuates due to cloud movements and shape changes, and wind power generation output fluctuates due to wind speed changes in a short period. Conventionally, variations in this time range could be absorbed via the inertial forces of gas turbines and steam turbine generators and governor-free control. However, as the ratio of renewable energy power generation in the system increases, it becomes impossible to absorb them completely, which may lead to a deterioration in power quality. It thus becomes necessary to limit the introduction of solar and wind power in each area. Such variations can be absorbed by installing a storage battery in the grid system and charging and discharging the battery according to variations in the system frequency (Figure 6-40).

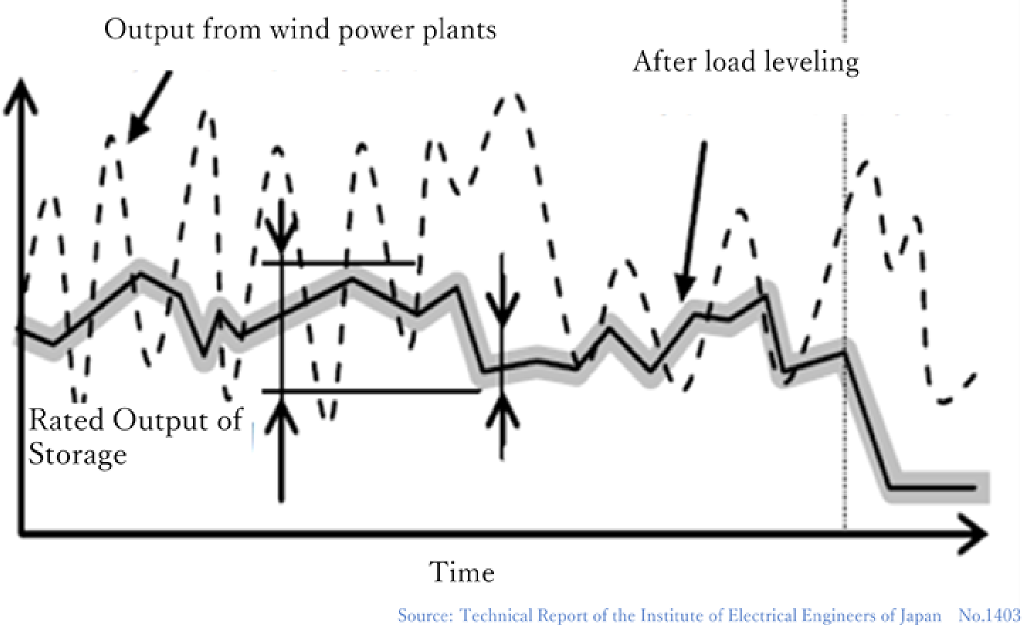
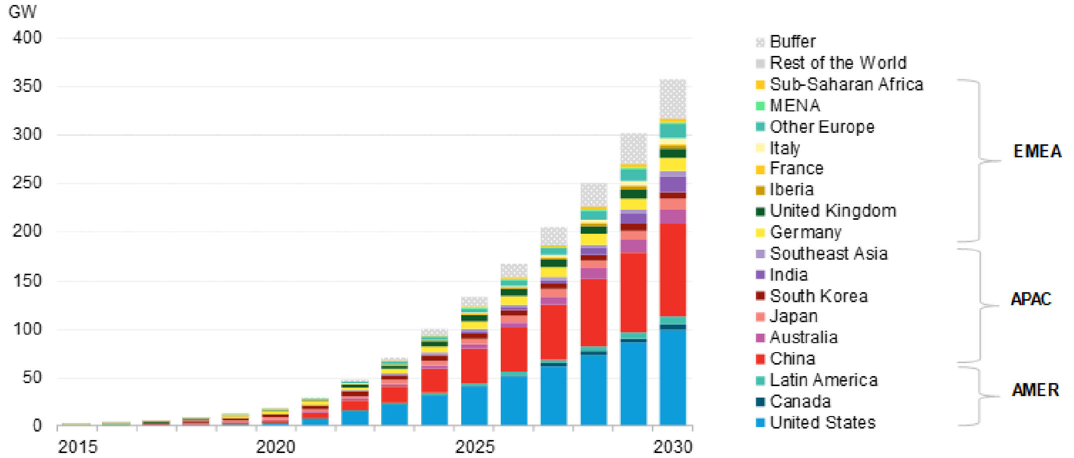


Figure 6-40 Load balancing via storage batteries

(2) Battery installation capacity

With the increase in the amount of renewable energy installed, the capacity of batteries connected to the grid for load balancing and ancillary services is increasing year by year around the world, and the amount of installed capacity is expected to increase at a compound annual growth rate of 33% worldwide by 2030 to reach approximately 350 GW or more. The Asia-Pacific region, including Indonesia, is seeing a marked increase in MW-based capacity, while the United States is expected to see an increase in MWh capacity (Figure 6-41).



Source: BloombergNEF. Note: MENA = Middle East & North Africa. We order countries according to their region group in this chart. Buffer represents markets we lack in visibility and countries that are likely to exceed their current targets.

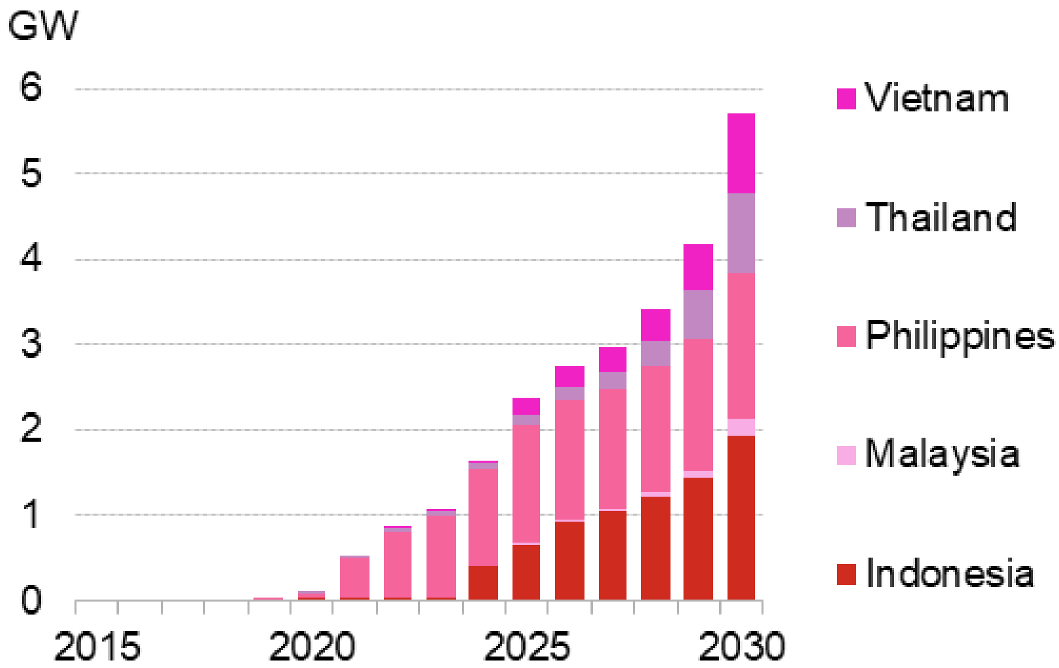
Source: BloombergNEF

Figure 6-41 Prediction of battery installation capacity worldwide

Indonesia and other major Southeast Asian countries such as Vietnam, Thailand, Philippines and Malaysia are expected to install more than 5 GW of batteries in total by 2030, with Indonesia having the potential to install around 2 GW by 2030.

Currently, large storage batteries in Indonesia are 90 MW/85 MWh (total value of multiple sites). These are owned by Tsingshan Holding, a major Chinese materials manufacturer, and started operation in 2019–2020. The batteries are used for ancillary services, including frequency adjustment and black start peak shaving, and are installed in Tsingshan Holding's energy-consuming manufacturing and processing facilities in an industrial park. In Indonesia, many other commercial industrial districts have also introduced batteries for rooftop solar.

Large-scale storage batteries (2.3 GWh) combined with solar power generation systems of about 2.3 GWh are planned to be installed to replace expensive diesel power generation in many islands of Indonesia by 2025 in RUPTL, as newly decided by PLN (Figure 6-42).



Source: BloombergNEF

Figure 6-42 Prediction of battery installation capacity in major Southeast Asian regions

(3) Regulations on storage batteries

The regulations on storage batteries in Indonesia are as shown in Table 6-30. Regulation 20 of 2020 by the Ministry of Energy and Mineral Resources (MEMR) is expected to require the installation of batteries with a minimum capacity of 10% for all variable renewables in the future, but the start timing of the regulation has not been decided. In Government Regulation 25 of 2021, storage batteries are classified as a power generation technology.

Currently, there is no detailed description of the role of batteries in the electric power system, but this is expected to be clarified and presented in the future.

Table 6-30 Regulatory trends and policies for storage batteries in Indonesia

Regulatory trends and policies for storage batteries	Details
MEMR Regulation 20 of 2020	It is a revised version of Indonesia's Grid Code, which will introduce new requirements for renewable energy projects to support power systems, requiring at least 10% capacity batteries for all variable renewable power projects. Frequency and voltage regulation services are provided to PLN and grid system support is assumed, but the timing of enforcement of the regulation is unclear.
Government Regulation 25 of 2021	Battery systems are classified as an electricity generation technology under this regulation. In the past, there was no specific description for batteries, so it is possible to consider a stand-alone battery project in Indonesia. Although there are restrictions imposed by foreign companies on the ownership of power generation projects, foreign companies can also install, operate, and maintain storage batteries.
RUPTL 2021-2030	PLN issued the latest 10 year power development plan in October 2021, and although it is not expected to operate a stand-alone storage battery project in Indonesia until 2029, many solar and wind storage battery projects are planned.

(4) Types and Features of Storage Batteries

Table 6-31 shows the main characteristics of rechargeable batteries applied to battery systems. NAS batteries and redox flow batteries were the first to be used as high-capacity batteries, but in recent years, lithium-ion batteries have been increasing in capacity. In December 2020, the world's largest storage battery (300 MW/1,200 MWh) was installed in California, the United States, by Vistra, and other large-capacity storage battery projects are being planned worldwide.

Lithium-ion batteries have a shorter life than other batteries, but there are many manufacturers, and performance improvements and cost reductions through competition and mass production are advancing year by year, so lithium-ion batteries are becoming economically advantageous even when future replacement is considered.

Table 6-31 Features of various batteries

Type	Lithium-ion battery	Sodium sulfur battery (NAS battery)	Redox Flow Battery
Maximum Output (actual figure)	300 MW	50 MW	15 MW
Maximum Capacity (actual figure)	1,200 MWh	300 MWh	60 MWh
System Efficiency	85-95%	80%	70%
Useful Life	10	15	20
Useful Cycle Number	300 to 10,000 cycles	4,500 cycles	100,000 cycles
Energy Density	70 ~ 260 Wh/kg	87 Wh/kg	10 Wh/kg
Features	● High energy density ● Suitable for high-power use ● Significant usage history ● Battery life depends on operation ● Flexible design for kW/kWh ● Safety considerations are required for the use of hazardous materials ● Operation temperature control is required ● Cost competitiveness	● High energy density ● Suitable for long-duration use ● Significant usage history ● Battery life depends on operation ● Flexibility is slightly inferior because of the fixed system package ● Safety considerations are required for the use of hazardous materials ● Cell must be maintained at a high temperature (300 degC)	● Low energy density ● Suitable for long-term use ● Little usage history ● Long lifespan ● Easy charge state management ● Flexibility is slightly inferior because of the fixed system package ● High safety ● Temperature control is not very difficult ● High operating costs
Expected total system price	300 -900 USD/kWh	450 -650 USD/kWh	700 -1000 USD/kWh
Major manufacturers	Packages: Fluence, TESLA, BYD and many others Cells: Panasonic, Toshiba, Murata, Samsung, LG, CATL and many others	NGK	Sumitomo Electric

<Types of Lithium-ion battery>

A lithium-ion battery is a secondary battery that charges and discharges when lithium ions move between a positive electrode and a negative electrode. The materials of the positive electrode, the negative electrode, and the electrolytic solution differ depending on the application and the manufacturer, but a typical configuration uses a nonaqueous electrolytic solution such as a lithium transition metal composite oxide for the positive electrode, a carbon material for the negative electrode, and an organic solvent for the electrolytic solution. Table 6-32 shows typical types and characteristics of lithium-ion batteries.

Table 6-32 Typical lithium-ion batteries

Battery Type	**Lithium Cobalt Oxide Battery (LCO)**	**Lithium Manganese Oxide Battery (LMO)**	**Lithium Nickel Manganese Cobalt Oxide Battery (NMC)**	**Lithium Nickel Cobalt Aluminum Oxides Battery (NCA)**	**Lithium Iron Phosphate Battery (LFP)**	**Lithium Titanate Battery (LTO)**
Positive Electrode Material	Lithium Cobaltate $LiCoO_2$	Lithium Manganate $LiMn_2O_4$	Nickel, Manganese, Cobalt $LiNiMnCoO_2$	Nickel, Cobalt, Aluminum $LiNiCoAlO_2$	Lithium Iron Phosphate $LiFePO_4$ (Olivin type)	Manganic Acid Lithium $LiMn_2O_4$
Negative Electrode Material	Graphite	Graphite	Graphite	Graphite	Graphite	Lithium Titanate $Li_4Ti_5O_{12}$
Generated Voltage (V)	3.6 ~ 3.7 V	3.7-3.8 V	3.6 ~ 3.7 V	3.6 V	3.2 -3.3 V	2.4 V
Energy Density (Wh/kg)	150-240	100-150	150-220	200-260	90-120	70-80
Charge Rate (C-Rate)*	0.7-1	0.7-3	0.7-1	0.7	1	1-5
Discharge rate (C-Rate)*	1	1-10	1-2	1	1-2	10-30
Cycle Life	1000-1500	600-1000	2500-3500	1000-1500	2500-3500	6000-10000
AC-AC Efficiency (%)	90	90	90	90	85	95
Operating Temperature (degC)	-20~60	-20~50	-20~60	-20~60	-20~60	-30~60
Thermal Runaway Risk	Large	Medium	Medium	Medium	Small	Small
Application as Utility-Scale Storage Battery	-	-	○	△	○	○
Major Manufacturers	Panasonic, Sony, Murata and many others	Vehicle Energy Japan, Lithium Energy Japan, Samsung, LG and many others	Panasonic, Lithium Energy Japan, Samsung, LG	TESLA, Primearth EV Energy	Murata, Sony, Elly Power, CATL, BYD, LISHEN, Narada	Toshiba (SCiB™)

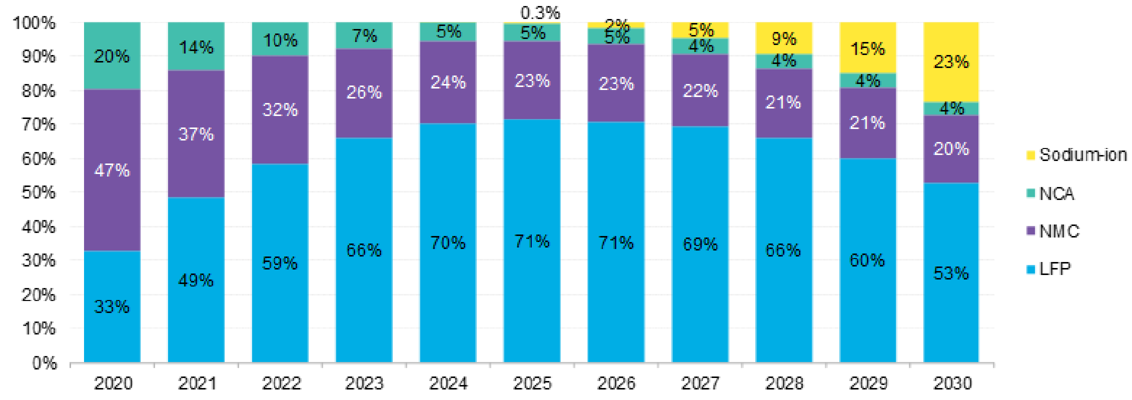
＊ C-Rate is defined as the charge/discharge current divided by the theoretical current draw under which the battery would deliver its nominal rated capacity in one hour. 1C discharge rate would deliver the battery's rated capacity in 1 hour. 2 C rate = 30 minutes for the device to be completely charged/charged.

- Lithium Cobalt Oxide (LCO) batteries were commercialized in 1991 and are still widely used, mainly in mobile devices. Although the energy density is high, the risk of thermal runaway is high, and ignition accidents often occur. Cobalt is a rare metal with high raw material procurement costs and instability.
- Lithium Manganate Oxide (LMO) is used mainly for Electric Vehicles (EV) and is cheaper than LCO because it uses manganese as a positive electrode material, which is advantageous in terms of cost. LMO improves thermal stability, but its energy density and cycle life are slightly inferior to LCO.

- Lithium Nickel Manganese Cobalt Oxide (NMC) batteries were originally developed as an improved version of the LMO, mainly for use in EV. Energy density and cycle life, which were weak points of manganese systems, are improved. Energy density is higher than for other types and they are cost competitive. NMC is used in relatively high power battery storage systems.
- Lithium Nickel Cobalt Aluminum Oxides (NCA) have higher energy density and cost competitiveness compared to NMC, although their cycle life is inferior.
- Lithium Iron Phosphate Batteries (LFP) are said to have the highest potential for cost reduction because they use iron, the cheapest and most common material, as a positive electrode material and do not contain cobalt, a rare metal. Iron phosphate is as safe as titanic acid (LTO) because its molecules are more tightly bound and stable than those of NMC, etc. The voltage and energy density are slightly low. They are not suitable for very high power battery storage systems.
- Lithium Titanate Batteries (LTO) use lithium titanate (Li_4 Ti_5 O_{12}) instead of carbon for the negative electrode, and are the safest because thermal runaway is rare even if an internal short circuit occurs. They have excellent characteristics, such as a long cycle life, and can be used at lower temperatures. The cell voltage and energy density are low and the cost is high.

At present, about half of large-scale lithium-ion batteries use LFP due to their price and safety, and it is expected that LFPs will account for 70% by 2025 according to a Bloomberg New Energy Finance (BNEF) estimate.
In addition, from 2025 onwards, there is a possibility that “sodium-ion” batteries, which use a sodium layered compound as a positive electrode and charge and discharge via the movement of sodium ions between the electrolyte and the positive electrode (the operating principle and cell structure are the same as those for ion batteries), will become widespread. Although the lithium price will inevitably rise considering the current rapid increase in demand, the cost of sodium ion batteries is low because they are based on the abundant, cheap sodium present on the earth. As the manufacturing process is the same as that of lithium ion batteries, it is thought that if a supply chain for manufacturing is established, it will be possible to expand production. However, because of their low energy density, they have not yet been commercialized (Figure 6-43).

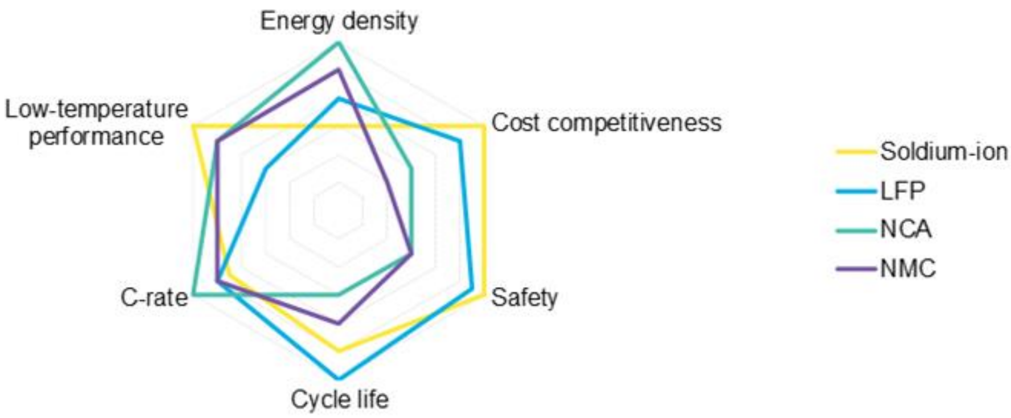
Because advances in battery technology are dynamic, it is necessary to check the latest technological trends and it is important to consider the balance between energy density, cost per capacity, safety, number of charge-discharge cycles, and C rate (speed of charge/discharge). It is also necessary to evaluate which condition is given priority depending on the application and installation environment.



Source: BloombergNEF. Note: LFP, NMC, NCA and Sodium-ion respectively refer to lithium iron phosphate, lithium nickel manganese cobalt oxide, lithium nickel cobalt aluminium oxide and sodium-ion batteries.

Figure 6-43 Prospects for future introduction of lithium-ion and sodium-ion batteries

For example, when comparing typical LFP, NCA, and NMC, it is necessary to select NCAs if they are to be used at high energy density or at a short time rate (such as at a high C rate for frequency adjustment purposes), or select LFPs if safety and cost are to be considered (Figure 6-44).



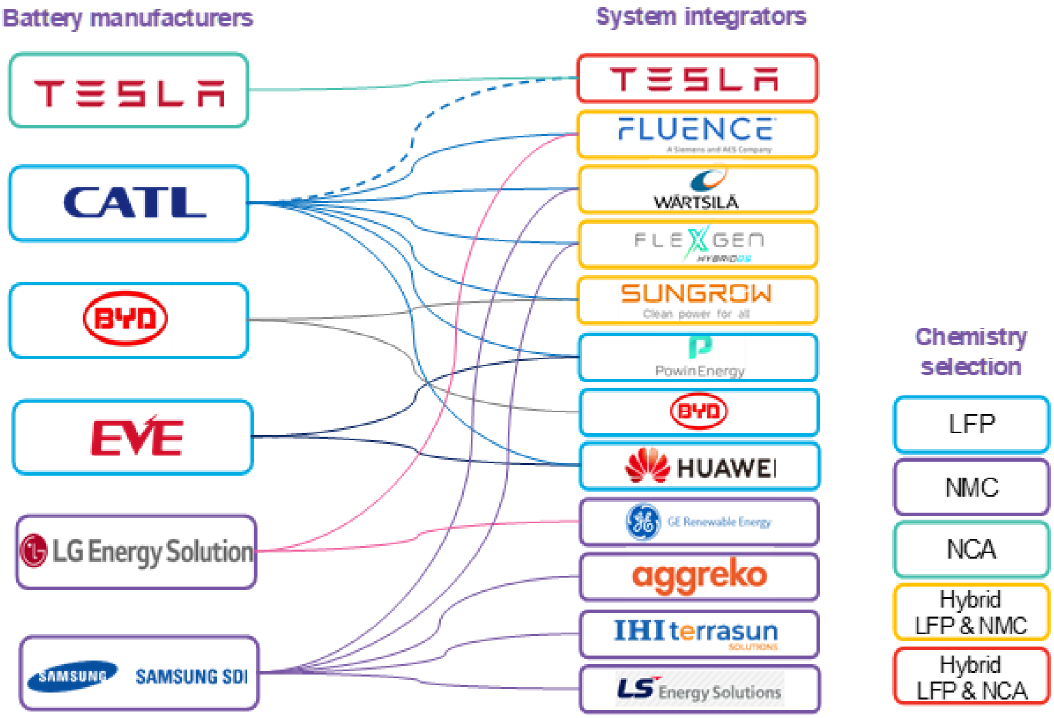
Source: BloombergNEF, Note: Based on the expected performance and cost of sodium-ion batteries when mass produced

Figure 6-44 Performance Comparison of Lithium-Ion and Sodium Ion Batteries

The supply relationships to global battery manufacturers and system integrators are shown in Figure 6-45. Global system integrators such as Tesla, Fluence and Wartisila are now able to offer both LFP and NMC options through multiple battery suppliers, depending on the customer's preference. To reduce the potential cell supply shortage risk, battery system suppliers are now diversifying without relying on one cell manufacturer, or establishing joint ventures with cell manufacturers.

LFP is mainly used for energy shifting, and NMC and NCA are used for ancillary services, and BTM (behind-the-meter).

Basically, Chinese battery manufacturers (CATL, BYD, etc.) focused on LFP, and Korean battery manufacturers (LG, Samsung SDI) initially focused on NMC, but now Korean battery manufacturers are also starting to develop LFP considering potential increased demand in the future.



Source: BloombergNEF

Figure 6-45　Relationship between battery manufacturers and system integrators

6.5.2 Price Outlook for Storage Batteries that are considered promising in the Future

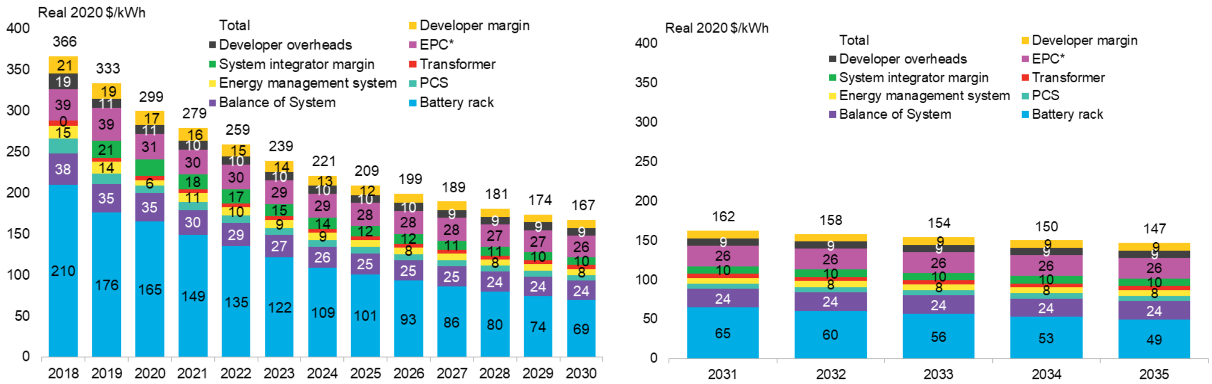
The battery price outlook is shown in Figure 6-46. The data until 2030 are from BNEF and those after that are our original, calculated data based on the assumed price declination rate of battery cells during the period.

The price of energy storage systems has been falling year by year due to the lowering of battery costs, changes in system design, standardization of systems, etc. However, the falling curve has been gradually decreasing compared to the sharp fall rate before 2020 (about 10% per year), and it is assumed that the price will fall by about 4-7% per year over the next 15 years. The price of a large-scale storage battery system, including battery cell (four-hour system), inverters and Balance of Plant (BoP), is 280 USD/kWh (of which storage battery rack prices consist of multiple cells/modules, the BMS, wiring and rack housing, accounting for about half, or approximately 150 USD/kWh), and would be expected to fall to 150 USD/kWh in 2035 (of which storage battery rack prices would account for about one-third, or approximately 50 USD/kWh).

This battery price includes an EPC margin (5%) and excludes warranty costs (which are often paid annually rather than as part of the initial capital expenditure), any taxes, and grid connection costs.

The price of a battery varies greatly depending on the power-to-energy ratio, and also depends on the project. For example, a one-hour system is 10% higher per kWh than a four-hour system in the same capacity (MW). This means that the battery cell cost per kWh is the same for both 1-hour and 4-hour systems, but as the duration becomes shorter, costs other than those for batteries, such as BoP and inverters, increase in proportion to the total system cost. This is because if the charging and discharging time is short, the battery output and current values increase, so it is necessary to increase the capacity of the battery and inverters, interconnection transformers, circuit breakers, and cables. Also, as the amount of heat generated increases through the battery capacity increase, the capacity of the air conditioning system also needs to be increased (Figure 6-46).

The price of residential storage batteries is in the range of 680 USD/kWh to 2,000/kWh in 2020, which is more than 2 times higher than the price of large-scale storage batteries.



Source: BloombergNEF Source: Internal evaluation based on various information

Figure 6-46 Lithium-ion battery price outlook

The LCOE of storage batteries with renewable energy (solar and offshore wind) and thermal power plants (CCGT/Coal) in Indonesia is shown in Figure 6-47. In addition to our estimate, BNEF's data is also shown in the graph.

At present, solar + storage batteries, or onshore wind + storage batteries outperform CCGT/coal-fired thermal power plants on an LCOE basis, but according to our evaluation results, the LCOE of solar + storage batteries is expected to be lower than that of CCGT by around 2030, and lower than that of coal-fired thermal power plants by around 2050. It will take longer for onshore wind + storage batteries to be cost-competitive, and it is assumed that they will fall below the LCOE of CCGT in the late 2060s. The BNEF evaluation shows the results to be slightly ahead of schedule, and it is assumed that the LCOE of solar + storage batteries will be lower than that of CCGT by around the late 2020s, and that it will be lower than that of coal by around 2050. The BNEF calculation results assume that the inflation

rate, cost of equity and debt for coal power projects will rise slowly over the next 10-20 years due to the higher risk associated with these projects.
If decarbonization in Indonesia further accelerates in the future, there is a possibility that the shift from fossil fuels, including from coal to storage batteries with renewable energy, will accelerate even earlier, before storage batteries with renewable energy become competitive on an LCOE basis.

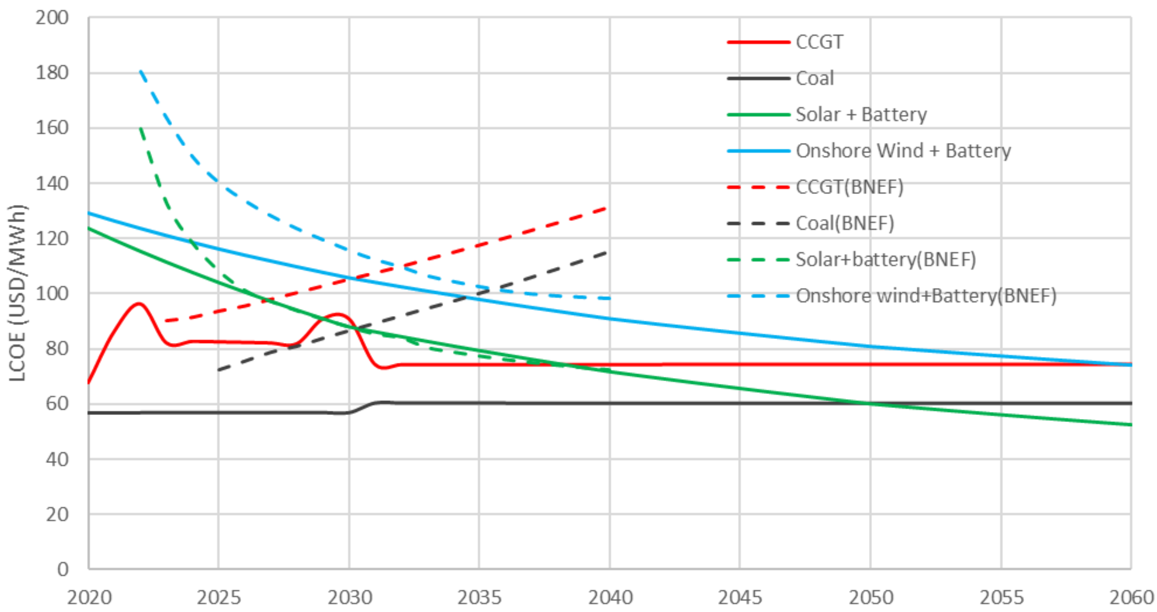


Figure 6-47 Comparison of LCOE between Renewable Energy with Storage Battery and CCGT/Coal-Fired Thermal Power Plant in Indonesia

6.5.3 Proposals for the Introduction of Storage Batteries

In Indonesia, there are currently no incentives or subsidies for introducing batteries, and the cost of batteries is high, making it difficult to expand the scope of battery projects. In Indonesia, it is expected that variable renewable energy, including solar and wind, will expand and renewable energy + storage battery projects will be introduced for load balancing. Although it is assumed that solar + storage batteries will be economically viable on LCOE basis around 2030, there is a possibility that they will be introduced more rapidly in light of the recent decarbonization trend, the early withdrawal of coal-fired thermal power plants and the increase in renewable energy in Indonesia (PLN plans to replace 1.1 GW of coal and gas power with renewable base load power by 2025).
Considering the situation in other countries, such as the United States and Australia, where the deployment of storage batteries is fast progressing, the introduction of government-led incentives and subsidies for storage batteries, long-term fixed contracts, and various storage battery-related tax credits in Indonesia would be expected to popularize the use of storage batteries in the future, which would lead to the further expansion of renewable energy sources. We think it is important to approach and cooperate with the government regarding the future introduction of storage batteries.

6.6 Demand Side Management

6.6.1 Current Status and Future Outlook for Demand Side Management

Electricity management with renewable energy on the customers’ side, especially rooftop solar and EV, is covered in this sub-section.

Renewable energy power plants, such as solar, wind, biomass, geothermal and hydro, have been constructed all over the world. Each country has turned full rudder in the direction of decarbonization. In Europe, large offshore wind power plants are operating mainly in Finland and Denmark. In Asia, many gigawatt solar farms have been developed using domestically produced solar panels in China. For newly-established solar plants, China has been the industry leader for the past eight years.

With moves across the world toward decarbonization, 23% of net electricity generation in Indonesia will be renewable energy by 2035. It will become increasingly difficult to cover the entire electrical demand, given the remarkable economic development, with renewable energy. Furthermore, electrical demand has depended on coal-fired power because the country is a large producer of coal. However, it will become difficult to produce and/or export coal, or construct new coal-fired power plants, because of the negative opinions regarding greenhouse gas generated by such power plants, based on the above mentioned international developments. Therefore, the method of domestic power generation needs to be changed, and rooftop solar and EV will be focused on in this Report.

Solar energy is an unstable electricity supply because the duration and the amount of power generation varies depending on the weather and the climate. As that renewable energy would be connected to the grid, flexible control to maintain the power demand-supply balance with batteries is needed. Furthermore, large, sunny areas are mandatory for the installation of large-scale solar power plants. Indonesia has more than 10,000 large and small islands, and it is difficult to acquire land for plants.

However, solar energy has the advantage of solving problems unique to those islands. Solar panels installed on each island could supply consumers without the need for electrical transmission of power generated in Java and Sumatra, which are metropolitan areas, using transmission lines or submarine cables. Because of this, solar energy is expected to increase the electrification ratio both in isolated islands and rural areas, and PLN is developing solar power plants in coordination with MEMR to achieve a 100% domestic electrification ratio by 2024. Even though the space to install solar panels is limited, installing solar panels on rooftops helps meet the electrical demand of the buildings.

To help control the power demand-supply and battery operation, a combination of rooftop solar and EV is one of the best solutions in terms of cost. In order to generate electricity at home, solar panels will be installed on roofs and the power generated will be used for that demand. Surplus power will be stored in EVs if necessary. EVs are expected not only to provide sustainable energy vehicles but also to serve as batteries.

Currently, transportation is the second largest industry to emit greenhouse gases after electricity generation and being able to use EVs practically to reduce the emissions of greenhouse gases is an urgent issue. Some countries have set the following goals for the future:

Table 6-33 Goal for Practical Use of EVs

Country or Region	Target	Deadline (Year)
United Kingdom	Banning sales of conventional fossil fuel vehicles	2050
Japan	All new car sales eco-friendly[57]	2035
U.S.	More than 50% of new vehicle sales to be all-electric	2030
EU	Reducing emissions gradually: (1)55% (2)100% *Compared with the value in 2021.	(1)2030 (2)2035
China	More than 50% of vehicles to be NEV[58], with 95% or more of them EV. Other than NEV, 50% of conventional fossil fuel vehicles to be HV.	2035
India	More than 50% of new vehicle sales to be all-electric	2030

The EU has the hardest objective in all of the above and all conventional fossil fuel vehicles, including HV, will be banned by 2035 in practical terms.
PLN has also encouraged the installation of EVCS[59] since 2019, looking towards the future for EV. Thanks to these efforts, actions have grown to contribute to their profit in recent years. PLN is planning to install three examples of EVCS in their branch offices, not only for the profits from charging stations but also the benefits of being an installation advisor.

EV sales forecasts in Indonesia are as follows:

Table 6-34 EV Sales Forecasts

Description	2020	2021	2022	2023	2024
Tot. Production	1.500.000	1.600.000	1.700.000	1.800.000	1.900.000
Total Sales	1.250.000	1.338.000	1.426.000	1.514.000	1.602.000
Sales/yr growth	5%	7%	7%	6%	6%
% passenger car (of total sales)	79%	79%	79%	79%	79%
Total Passenger Car	986,124	1.055.547	1.124.971	1.194.394	1.263.817
Energy saving cars 4x2 (KBH2)	310,423	315,938	321,453	326,968	332,483
FCEV, HEV	935	1,338	5,704	10,598	14,418
PHEV, BEV	689	4,014	7,130	10,598	16,020
Total Electric Vehicles	1,624	5,352	12,834	21,196	30,438

Source: Ministry of Finance with data processing by PLN

The values in the table are calculated based on the results of trends for EV from 2011. Furthermore, the expectation includes a demand increase after the COVID-19 pandemic.
The government has already enforced laws for the deployment of rooftop solar by MEMR since 2018 and the amendment in 2021 was the third. The reason for the amendments is a slower pace of usage rate than the expectation. Though a total 3.6GW of solar energy generation is planned by 2024 in the law, only 172MW of solar panels had been installed as of the end of 2020. In 2020, there was only a 17MW increase in solar energy generation.

57 Not only EVs, but also Hybrid Electric Vehicles (HV) and Fuel Cell Vehicles (FCV)
58 New Energy Vehicle (NEV): EVs including Plug-in Hybrid Vehicles (PHV) and FCV
59 Electric Vehicle Charging Station

6.6.2 Proposals for promoting Demand Side Management

The expected future plans for the country are considered in this sub-section, based on the aforementioned information and global trends.

First of all, this consideration is for about 2060. According to the previous estimations, conventional fossil fuel vehicles would be eliminated and all vehicles, including buses and trucks, would be electric. In addition, rooftop solar would be installed in a percentage of the land area and it would generate sustainable electricity. The power demand and supply within a day is considered given this situation.

Surplus power would appear during the daytime due to the electricity generated by rooftop solar. Though this would ideally be stored in EVs, EVs are essentially used for transportation, not as stationary batteries. As of 2021, the rate of occupancy for vehicles is only 5 percent, but vehicles will be used as robotaxis when not used by their owners, through developments in autonomous driving. Therefore, it seems EVs will only be used for batteries during the night.

However, not all EVs would be used for robotaxis or as vehicles, so it is possible to consider using them for batteries via government policy. The EVs to be used as batteries would have the advantage of being able to store electricity generated by rooftop solar during the daytime and supplying home demand in the evening. Or they would be used as vehicles during the night, not only to aid in the area of power demand but also to reduce traffic jams.

Moreover, this estimation includes the demand from charging stations, which are equipment mandatory for the deployment of EVs. Rooftop solar will be installed at the charging stations so that the electricity generated via solar would be used for EV charging. Batteries would be installed at the charging stations to store the surplus power as well.

Based on the above, the deployment of stationary batteries is needed. Currently, the electricity generated by renewable energy can be sold to the electric power company via the FIT policy. However, generation by not only houses but also the electric power company and other parties, including PPS (Power Producer and Supplier), can also be expected. This means that selling the surplus power to the electric power company would be difficult, and supplying oneself would be the most practical course of action. The electricity generated during the daytime would be stored in the batteries and would supply the demand itself during the night.

This is called a Vehicle to Home system and it is currently in the spotlight for future new standards in Western countries. Through it, electricity generated only by the rooftop solar could supply all the demand in the house in some cases. In terms of a preliminary calculation for Japan, if 4kW of solar panels, which generate around 4,000kWh in a year, were installed, approximately 78% of the yearly demand could be supplied. (The average yearly power demand of a general household in Japan is 5,156kWh.) If a 40kWh battery or EV were to be included with the above system, electricity could be secured not only under normal circumstances but also in an electrical grid accident due to an earthquake or typhoon. Natural disasters have become severe due to climate change, so the preparation of self-electricity supply makes sense, as it negates the need to rely on electrical grids.

Vehicle to Home systems with EV and rooftop solar could supply power to the isolated islands. It would be unnecessary to transmit the electricity generated by power plants, and consumers could generate power and use it themselves. This would bring about change to the country because there are lots of isolated islands. It would help to deliver a comfortable life to the people and to encourage tourism development in the islands.

A Vehicle to Home system has the following advantages:

(1) EV and PHV can be employed as batteries in the case of emergency

The first advantage is that they provide a countermeasure for disasters. Electrical outages caused by natural disasters such as typhoons and earthquakes are unavoidable. Indonesia is known as a country with a lot of natural disasters, like Japan, so people are concerned about severe disasters due to climate change. Vehicle to Home systems with large batteries, like EV or PHV, have been receiving attention. In an electrical grid outage, rooftop solar would generate power and supply it to the house. The electricity can also be stored in EV.

Compared with stationary batteries, EV and PHV have a large capacity and can supply power for longer. The duration of supply from EVs is up to 5 days in length. For reference, the performance of Japanese cars is shown in the table below:

Table 6-35 Battery Performance and supply period of Japanese EVs

Manufacturer	Car name	Capacity of the battery (kWh)	Discharge Duration (Hours)
Nissan	Leaf e+	62	111
Nissan	Leaf	40	72
Honda	Honda e	35.5	63
Mitsubishi	Outlander Eclipse cross	13.8	24 *
Toyota	Prius PHV	8.8	15 *

*only the battery is used. The duration can be much longer when its engine is used.

(2) Eco-friendly electricity can be used

The second advantage is environmental friendliness. If a Vehicle to Home system is installed in a house with rooftop solar, not only can its rooftop solar generate power and supply demand, but power stored in the EV can also be used during the night.

As power generated by renewable energy is used, an eco-friendly lifestyle and reduction of greenhouse gas emissions can be achieved. This advantage would be even more apparent after the FIT policy expires.

(3) It can save on electricity bills

Adapting a Vehicle to Home system with EV or PHV can reduce the operational costs for cars, as well as electricity bills.

However, there are challenges in the deployment of EVs.

Governmental or regional support to change the energy infrastructure is necessary. In other words, there are some areas where infrastructure can be easily changed for EVs and some areas that are suitable for conventional fossil fuel vehicles. For example, since there is a great deal of electricity theft on distribution lines in India, the reliability of the electrical grids is not very high and such areas would not be suitable for the deployment of EVs. When an accident occurs due to theft, the outage period may be longer because the electric power company would take time to identify the failure.

Furthermore, it is extremely difficult to foresee the future after the expiration of the FIT policy. However, electricity prices are expected to significantly decrease, meaning that it will not be possible to achieve current profits by selling surplus power after the FIT policy expires. To use surplus power in a house, EVs are essential because the power cannot be stored without charging facilities. According to the data in Japan, the cost for installation of a stationary battery is approx. 200,000 yen (equivalent to 1,750 USD) per kWh, plus construction costs. The equipment for a Vehicle to Home system costs approximately 1 million yen (equivalent to 8,752 USD). Since government subsidies to install these facilities are provided in some countries, like Japan, the Indonesian government could also provide support for this.

Chapter 7. Power Development Plan

7.1 Review of Demand Forecast

(1) Trends in power demand forecast for RUPTL 2021-2030

The correlation coefficient of all approximate straight lines is 0.9 or more for the approximate curve calculated from the power demand forecast from 2021 to 2030, for each state in RUPTL 2021-2030. Since it is generally said that a correlation coefficient of 0.7 or more is a fairly strong correlation, it can be said that there is an extremely strong correlation in linear approximation.

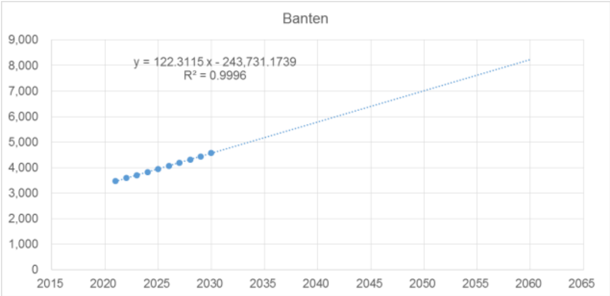


Figure 7-1 An Example of Linear Approximation for Net Peak Load

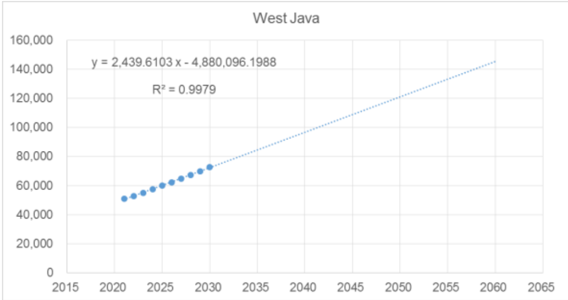


Figure 7-2 An Example of Linear Approximation for Electricity Sales

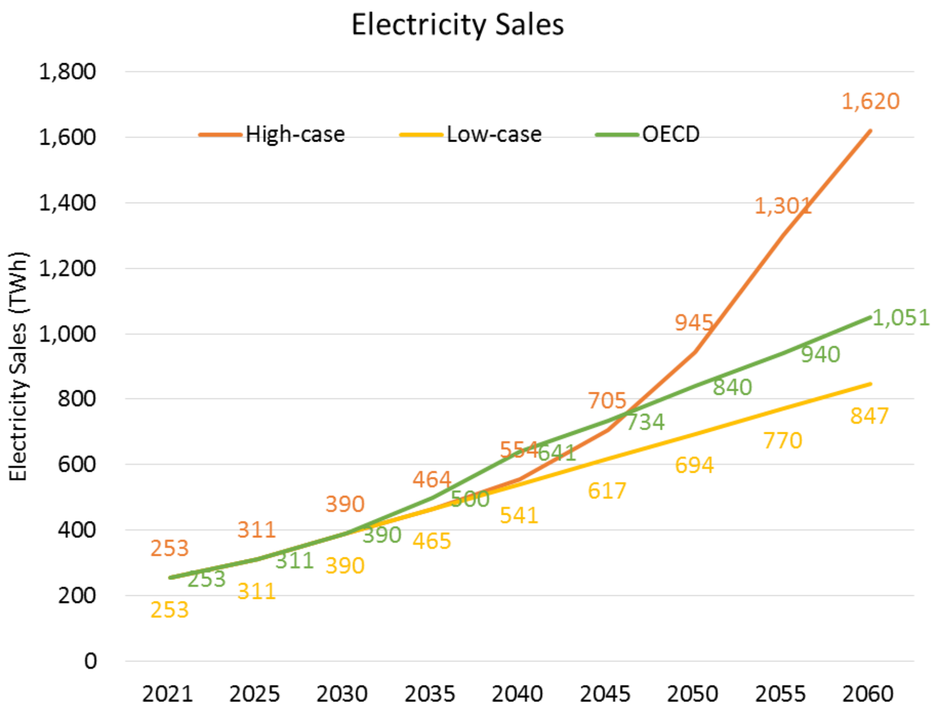
(Source: JICA survey team)

(2) Demand forecast in 2031-2060

Two cases will be studied, the value forecasted by PLN (High-case) and the value forecasted via a linear approximation of the demand forecast in RUPTL 2021-2030 (Low-case).

Since the value forecasted by PLN (High-case) is the production power, the electricity sales will be calculated under the condition that the total loss rate, which is the sum of the power plant rate and the transmission/distribution loss rate, is assumed to be 10%.

According to the OECD Long-term projections, Indonesia's GDP growth rate from 2011 to 2030 will be +148.5%. The electricity sales growth rate in RUPTL 2011-2030 is +189.0%, so the GDP elastic coefficient will be 2.890/2.485 = 1.1631. Figure 7-3 shows the electricity sales forecasted using the GDP growth rate in the OECD Long-term projections up to 2060 and a GDP elastic coefficient of 1.1631. Until 2045, there are no big differences between High-case, Low-case and OECD-case. After 2045, the difference between the two cases (High-case and Low-case) gradually widens, and the OECD-case is between the two cases (High-case and Low-case). That is, even if there are ups and downs in GDP growth rate in the future, future demand is likely to be between the two cases (High-case and Low-case). Therefore, it is appropriate to study the two cases (High-case and Low-case) in consideration of the uncertainty of future demand.



(Source: JICA survey team)

Figure 7-3 Electricity Sales in 2021-2060

Net peak load forecast in 2021-2060 is shown in Table 7-1 and Table 7-2, and electricity sales forecast in 2021-2060 is shown in Table 7-3 and Table 7-4. Net peak load will increase from 40 GW in 2021 to 263 GW in 2060, or by 6.59 times, for the High-case, and to 131 GW in 2060, or by 3.28 times, for the Low-case. Electricity sales will increase from 253 TWh in 2021 to 1,620 TWh in 2060, or by 6.40 times, for the High-case, and to 847 TWh in 2060, or by 3.35 times, for the Low-case. Since the rates of increase in regions other than Java, Madura and Bali are higher than the average rate in Indonesia, demand in regions other than Java, Madura and Bali will see relatively significant increases in the future.

Table 7-1 Net Peak Load Forecast by Region in 2021-2060 (High-case)

(Unit: MW)

	2021	2025	2030	2035	2040	2045	2050	2055	2060
Sumatra	6,330	9,035	11,661	14,840	18,256	23,690	32,282	44,999	56,636
Java, Madura, Bali	28,333	33,054	39,354	46,653	54,708	68,486	90,728	123,625	152,731
Kalimantan	1,855	2,957	4,050	5,516	6,997	9,277	12,846	18,127	23,044
Sulawesi	2,097	2,914	3,664	4,645	5,673	7,323	9,940	13,808	17,335
Maluku and others*	1,307	1,872	2,550	3,327	4,159	5,460	7,503	10,530	13,326
Total	39,922	49,832	61,279	74,981	89,792	114,237	153,300	211,089	263,071

*Maluku and others: Maluku, Papua and Nusa Tenggara

(Source: JICA survey team)

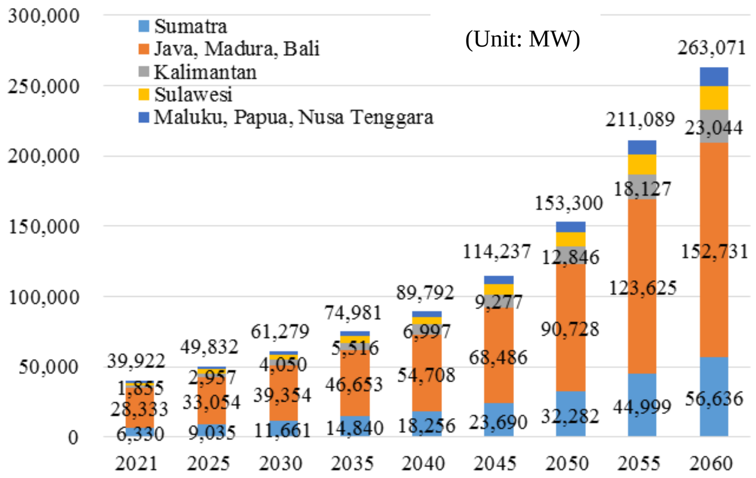


Figure 7-4 Net Peak Load in 2021-2060 (High-case)

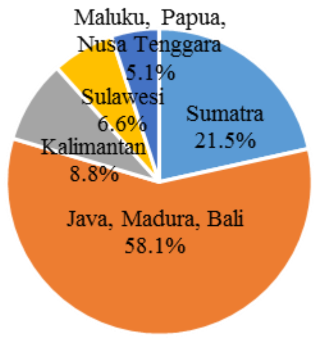


Figure 7-5 Net Peak Load in 2060 (High-case)

(Source: JICA survey team)

Table 7-2 Net Peak Load Forecast by Region in 2021-2060 (Low-case)

(Unit: MW)

	2021	2025	2030	2035	2040	2045	2050	2055	2060
Sumatra	6,330	9,035	11,661	14,416	17,169	19,918	22,670	25,423	28,173
Java, Madura, Bali	28,333	33,054	39,354	45,320	51,451	57,581	63,713	69,844	75,975
Kalimantan	1,855	2,957	4,050	5,358	6,580	7,800	9,021	10,241	11,463
Sulawesi	2,097	2,914	3,664	4,512	5,335	6,157	6,980	7,801	8,623
Maluku and others*	1,307	1,872	2,550	3,232	3,911	4,591	5,269	5,949	6,629
Total	39,922	49,832	61,279	72,838	84,446	96,047	107,653	119,258	130,863

*Maluku and others: Maluku, Papua and Nusa Tenggara

(Source: JICA survey team)

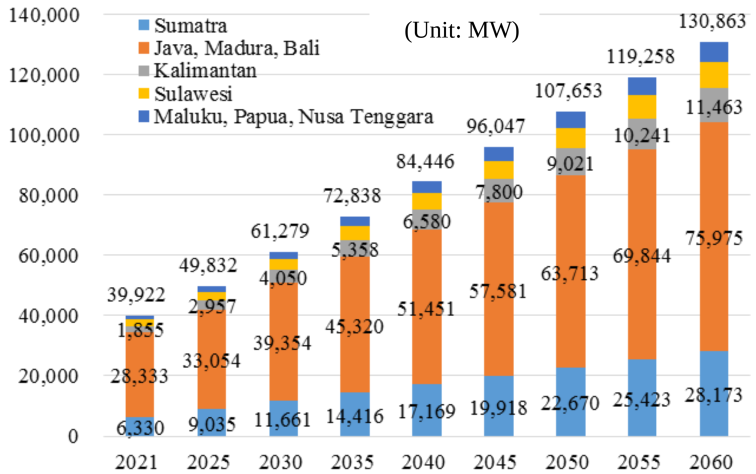


Figure 7-6 Net Peak Load in 2021-2060 (Low-case)

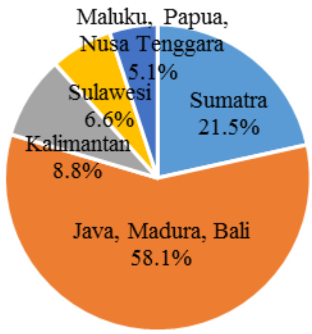


Figure 7-7 Net Peak Load in 2060 (Low-case)

(Source: JICA survey team)

Table 7-3 Electricity Sales Forecast by Region in 2021-2060 (High-case)

(Unit: GWh)

	2021	2025	2030	2035	2040	2045	2050	2055	2060
Sumatra	40,840	54,217	71,541	88,273	108,289	140,234	190,754	265,498	333,770
Java, Madura, Bali	180,852	213,201	258,699	300,519	353,482	443,597	588,888	803,834	994,588
Kalimantan	12,093	17,032	23,773	30,571	38,290	50,318	69,202	97,136	122,940
Sulawesi	12,581	16,722	21,763	26,558	32,339	41,657	56,436	78,294	98,178
Maluku and others*	6,767	9,897	13,788	17,580	22,000	28,894	39,721	55,737	70,524
Total	253,133	311,069	389,564	463,500	554,400	704,700	945,000	1,300,500	1,620,000

*Maluku and others: Maluku, Papua and Nusa Tenggara

(Source: JICA survey team)

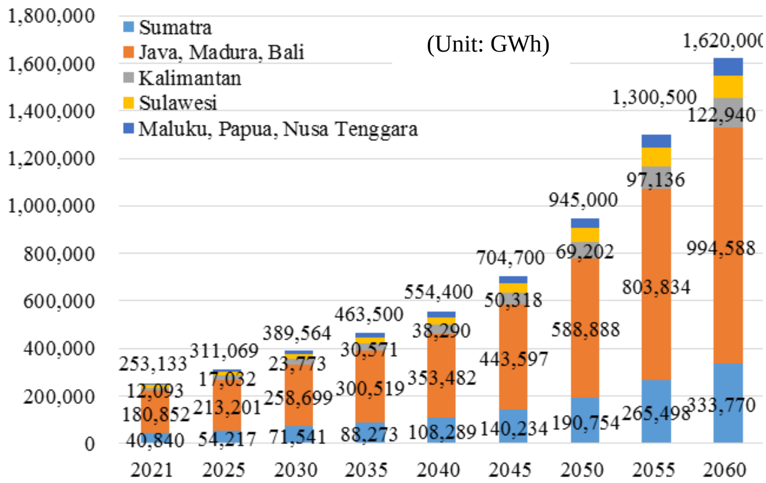


Figure 7-8 Electricity Sales in 2021-2060 (High-case)

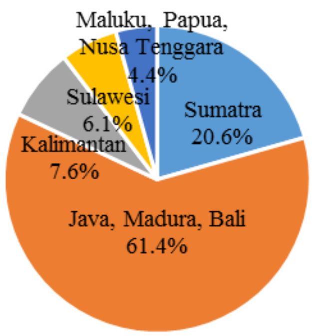


Figure 7-9 Electricity Sales in 2060 (High-case)

(Source: JICA survey team)

Table 7-4 Electricity Sales Forecast by Region in 2021-2060 (Low-case)

(Unit: GWh)

	2021	2025	2030	2035	2040	2045	2050	2055	2060
Sumatra	40,840	54,217	71,541	88,473	105,669	122,867	140,062	157,259	174,456
Java, Madura, Bali	180,852	213,201	258,699	301,201	344,931	388,662	432,393	476,124	519,855
Kalimantan	12,093	17,032	23,773	30,640	37,364	44,087	50,812	57,535	64,259
Sulawesi	12,581	16,722	21,763	26,618	31,557	36,498	41,438	46,375	51,316
Maluku and others*	6,767	9,897	13,788	17,620	21,468	25,316	29,165	33,014	36,862
Total	253,133	311,069	389,564	464,552	540,989	617,430	693,870	770,307	846,748

*Maluku and others: Maluku, Papua and Nusa Tenggara

(Source: JICA survey team)

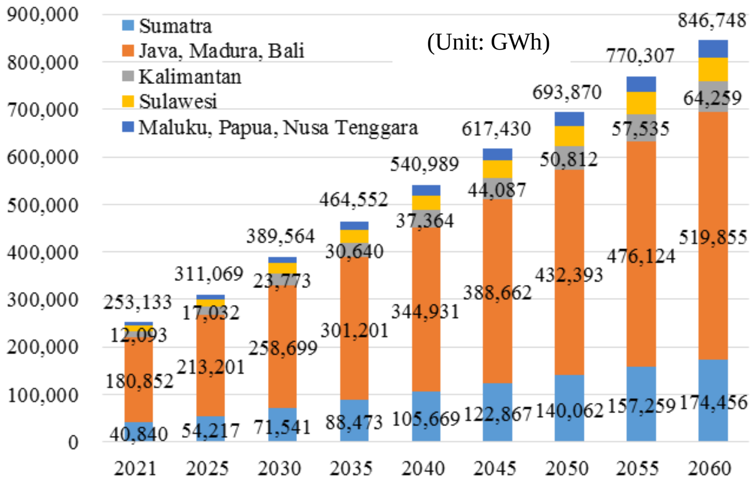


Figure 7-10 Electricity Sales in 2021-2060 (Low-case)

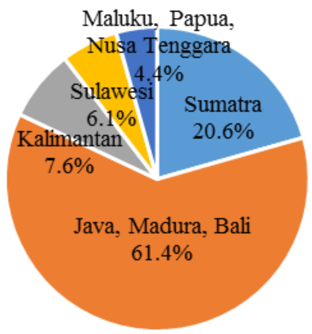


Figure 7-11 Electricity Sales in 2060 (Low-case)

(Source: JICA survey team)

7.2 Review of Current Plan (RUPTL)

As shown in Section 3.3.2, power generation capacity of 40.6GW is planned to be developed in the 10 years from 2021 to 2030. 20.9GW (51.6%) of new and renewable energy will be developed, and the breakdown will be hydropower of 10.4GW (25.6%), geothermal power of 3.4GW (8.3%), and other sources of 7.2GW (17.7%). In addition to new and renewable energy, coal thermal power of 13.8GW (34.1%) and gas/oil/diesel power of 5.8GW (14.4%) will be developed mainly in the first five years.
PLN considers the optimal reserve margin to be 35% for Java, Madura and Bali, and 40% for areas other than Java, Madura and Bali. These are reserve margins that take into account the de-ratings of existing power plants and power used by the power plants, and the probability of delays in PLN and IPP projects in planning, in addition to securing LOLP (Loss of Load Probability) of 0.274% (1 day/year) or less. RUPTL 2021-2030 is based on the reserve margins, and also takes into account additional PLN and IPP delays in specific projects, so it can be said that sufficient supply reliability will be ensured. Due to the development of the above power generation capacity, as shown in Table 3-21, the reserve margin in RUPTL 2021-2030 for 2030 will be 37% for Java, Madura and Bali, and 36-43% for areas other than Java, Madura and Bali. That is, the optimum reserve margin considered by PLN is mostly secured. Therefore, the power development plan for 2021 to 2030 is the same as the power development plan for RUPTL 2021-2030.

Table 7-5 Optimal reserve margin for Java, Madura and Bali

	Items	Reserve margin
	Optimal reserve margin with LOLP of 1day/year or 0.274%	25%
	De-ratings of existing power plants and power used by the power plants	5%
	Probability of delays in PLN and IPP projects in planning	5%
Optimal reserve margin		35%
	Additional PLN and IPP delays in specific projects	4%
RUPTL 2021-2030		39%

(Source: RUPTL 2021-2030)

7.3 Power Development Conceptual Plan (2060)

7.3.1 Prerequisites

(1) Demand forecast

As shown in Section 7.1, two cases of demand forecast for 2031-2060 will be studied, the value forecasted by PLN (High-case) and the value forecasted via a linear approximation of the demand forecast in RUPTL 2021-2030 (Low-case).

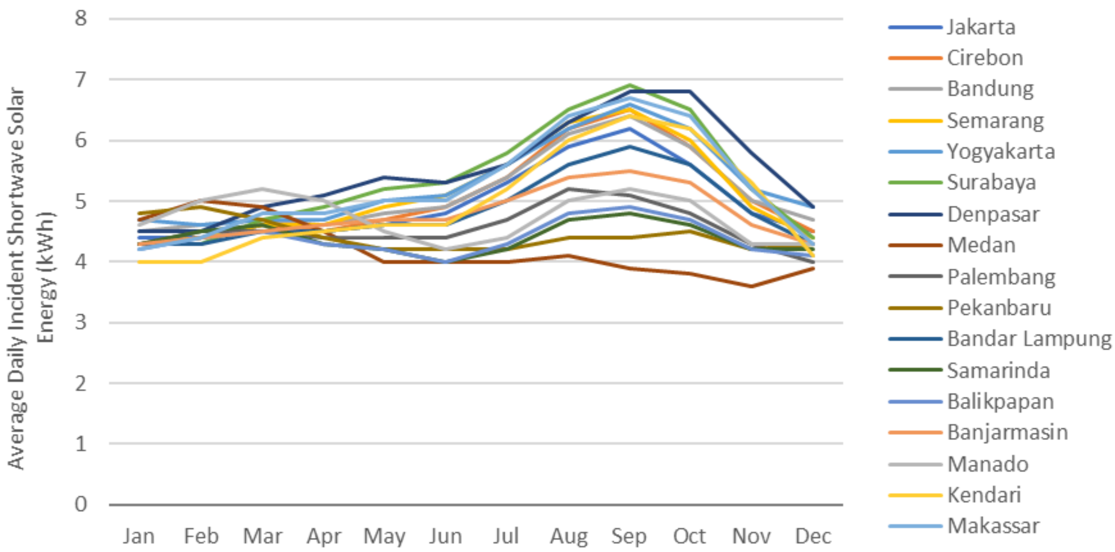
(2) Power development plan

The power development plan up to 2030 will be the same as the existing plan (RUPTL 2021-2030), and the development plan for after 2031 will be studied.

(3) Potential of various renewable energies

(a) Seasonal fluctuations and regional disparities in solar energy and wind power

The average daily solar energy in major cities in Indonesia is shown below.

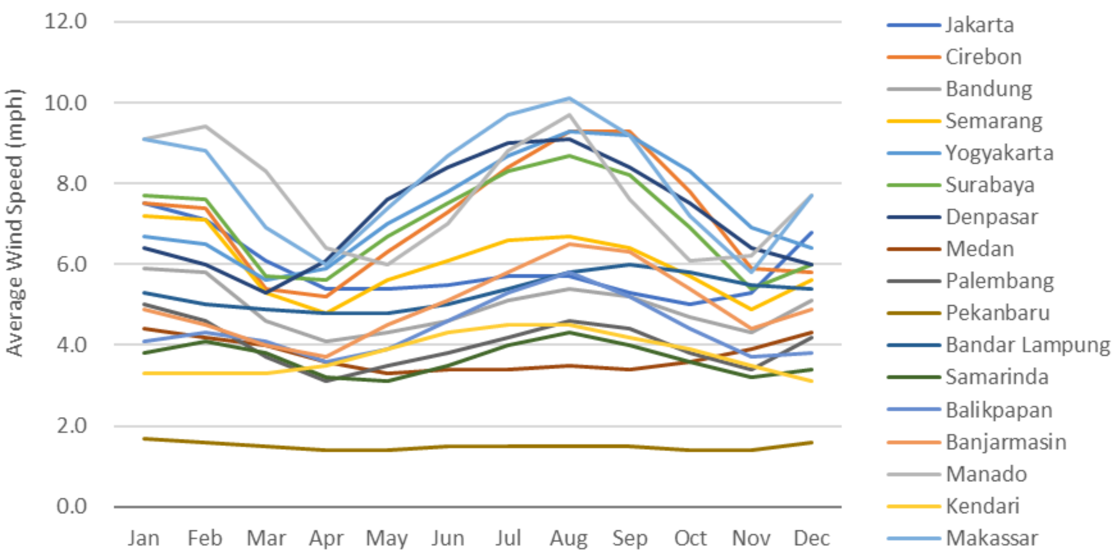


(Source: https://weatherspark.com/countries/ID)

Figure 7-12 Average daily solar energy in major cities

There are no big changes from city to city, and the same level of solar energy can be expected in any city. Seasonally, the energy from August to October is slightly higher.

The average daily wind speeds in major cities in Indonesia are shown below.

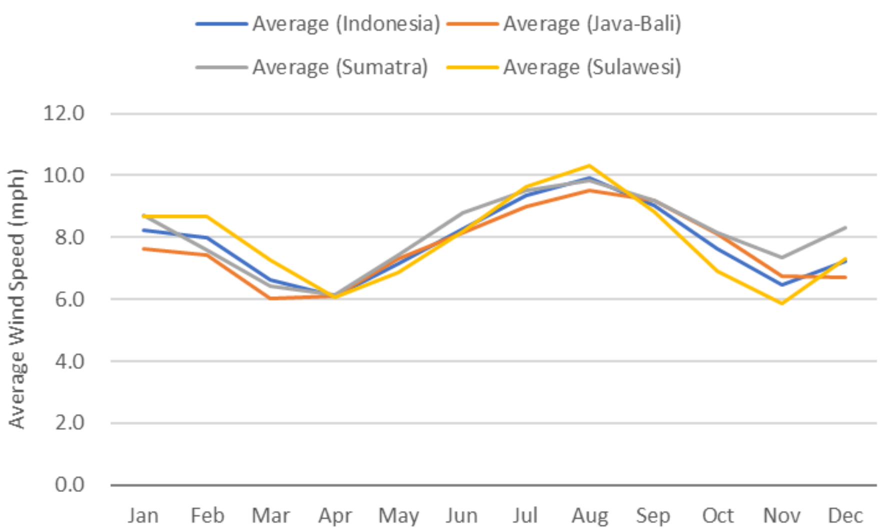


(Source: https://weatherspark.com/countries/ID)

Figure 7-13 Average daily wind speeds in major cities

Unlike solar energy, wind speeds fluctuate greatly from city to city, and suitable locations are unevenly distributed. When viewed seasonally, the wind speeds in January, February, and July-September are relatively high in cities where the average wind speed is high.

The cities where the average wind speed is 6.0 mph or more were extracted and the averaged results are shown below. (Java-Bali - 8 cities, Sumatra - 3 cities, and Sulawesi - 8 cities; there is no city in Kalimantan where the average wind speed is 6.0 mph or more.)



(Source: https://weatherspark.com/countries/ID)

Figure 7-14 Daily average wind speed in cities where the average wind speed is 6.0 mph or higher

There is almost no regional difference, and seasonally, the wind speed is relatively high from December to February and from June to October.

(b) Regional potential of various renewable energies

The potentials of various renewable energies given in RUPTL 2021-2030 are as shown in Table 6-12. Of these renewable energies, solar energy has the highest potential, and as shown in the previous section, suitable sites are widely distributed and there is little seasonal variation, so solar energy is considered to be the most promising renewable energy for achieving carbon neutrality. In this survey, the amount of various renewable energies that can be developed by 2060 is basically limited to the potential shown in Table 6-12, and the upper limit for each region is shown below.

Table 7-6 Regional potential of various renewable energies

	Geothermal	Hydro	Mini-hydro	Biomass	Solar	Wind	Total
Sumatra	12.9	15.6	5.7	15.6	68.7	7.4	126.0
Java, Madura, Bali	10.1	4.8	2.9	9.2	33.1	24.0	84.2
Kalimantan	0.2	21.6	8.1	5.1	52.7	2.5	90.2
Sulawesi	3.2	10.3	1.7	1.9	22.7	8.4	48.2
Other	3.1	22.8	1.0	0.9	30.6	18.3	76.6
Total	29.5	75.1	19.4	32.7	207.9	60.6	425.2

* Other: Maluku, Papua and Nusa Tenggara

(Source: National Energy General Plan (RUEN), 2017)

(4) Specifications for economic evaluation

The numerical values described in Chapters 5 and 6 are used as the specifications for the economic evaluation.

(a) Unit construction costs for various power sources

The unit construction costs for various power sources are shown below.

Table 7-7 Unit construction costs for various power sources

	Unit construction cost (USD/kW)				
	2020	2030	2040	2050	2060
Coal (USC)	1,469	1,469	1,469	1,469	1,469
C/C	944	944	944	944	944
GT	525	525	525	525	525
Oil ST	1,115	1,100	1,100	1,100	1,100
Hydro Res	2,151	2,203	2,203	2,203	2,203
Hydro ROR	3,252	3,305	3,357	3,410	3,410
Geothermal	3,724	3,567	3,462	3,360	3,360
Solar	1,154	896	786	689	604
Wind onshore	1,252	1,217	1,154	1,094	1,038
Wind offshore	5,986	4,420	3,149	2,834	2,452
PSPP (6hr)	800	800	800	800	800
Battery (6hr)	1,593	866	586	457	457

Notes: Real prices in 2020 (excluding escalation).
Interest during construction is excluded because it depends on the funding source.
For power storage equipment, storage batteries and pumped-storage hydropower are considered. Since storage batteries have different power storage durations depending on the type, the construction unit price per kWh is generally used. However, as with pumped-storage hydropower, the cost comparison is carried out assuming the power storage duration is 6 hours.

(Source: JICA Survey Team)

(b) Prices of various fuels

The prices of various fuels are shown below.

Table 7-8 Prices of various fuels

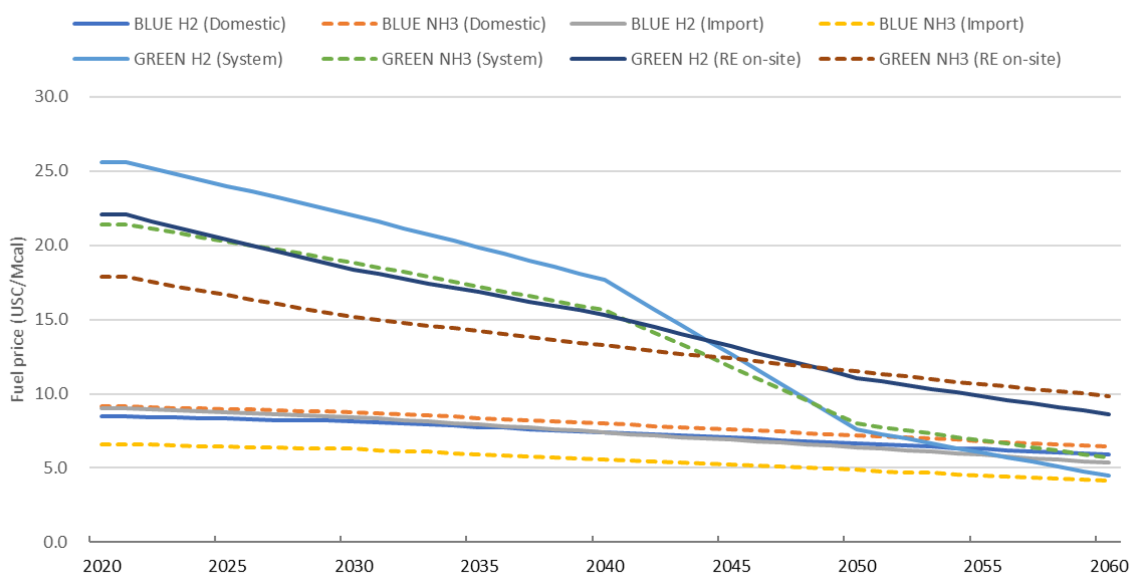
	Converted price (USC/Mcal)				
	2020	2030	2040	2050	2060
Coal	1.106	1.262	1.245	1.176	1.176
Natural gas	2.778	2.584	2.586	2.340	2.340
LNG	4.564	4.245	4.248	3.845	3.845
Oil	4.939	4.263	4.122	3.774	3.774
Hydrogen (Blue)	8.477	8.152	7.414	6.675	5.907
Ammonia (Blue)	9.127	8.772	7.975	7.207	6.439
Hydrogen (Green)	22.064	18.371	15.329	11.076	8.595
Ammonia (Green)	17.869	15.182	13.262	11.490	9.865
Biomass	3.154	3.160	3.155	3.155	3.155

Note: The prices of green ammonia and green hydrogen are calculated on the condition that a dedicated renewable energy power plant will be constructed and manufacture green ammonia and green hydrogen.

(Source: JICA Survey Team)

Fuel prices for hydrogen and ammonia vary greatly depending on the price of raw materials and the manufacturing method. In the future, it is expected that fixed costs for manufacturing equipment will gradually decrease according to the maturity level of the technology.

The price trends of hydrogen and ammonia are shown below.



(Source: JICA Survey Team)

Figure 7-15 Price trends of hydrogen and ammonia

For blue hydrogen, there is no big price difference between domestic and imported products, but for blue ammonia, imported products are slightly cheaper than domestic products. In the future, prices can be expected to decline slightly, but not significantly.

At present, the prices of green hydrogen and green ammonia are much higher than those of blue hydrogen and blue ammonia. But in the future, when a large amount of surplus power is generated in the grid and the surplus power is used for manufacturing, the price will be about the same as that of blue hydrogen and blue ammonia.

(c) O&M costs for various power sources

The O&M costs for various power sources are shown below.

Table 7-9 O&M costs for various power sources

	Fixed (USD/kW/month)	Variable (USC/kWh)
Coal (USC)	4.8	0.47
Gas (C/C)	2.2	0.32
Gas (GT)	1.7	0.39
LNG (C/C)	2.2	0.32
LNG (GT)	1.7	0.39
Oil (ST)	3.8	0.39
Hydro (Res)	1.8	0.00
Hydro (ROR)	2.8	0.00
Geothermal	5.7	0.04
Solar	0.8	0.00
Wind onshore	1.8	0.00
Wind offshore	4.6	0.00
PSPP (6 hours)	0.7	
Battery (6 hours)	0.2	
Ammonia (USC)	4.8	0.47
Hydrogen (C/C)	2.2	0.32

(Source: JICA Survey Team)

(d) Generating costs in 2040

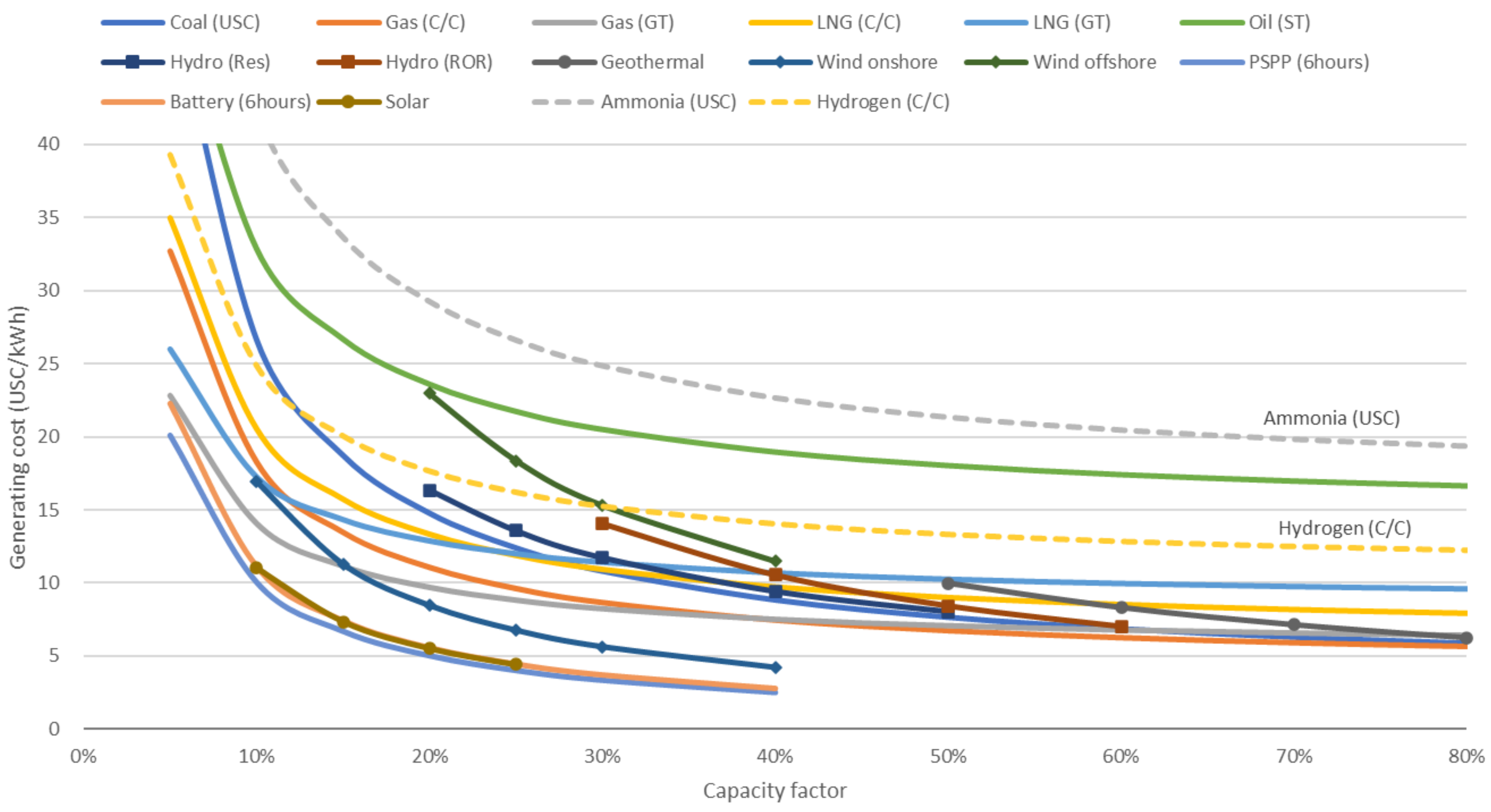
The generating costs for various power sources in 2040 are shown below.

Table 7-10 Generating costs in 2040 (LCOE)

	Construction cost	Life	Fixed O&M	Variable O&M	Fuel price	Efficiency	Capacity factor	Generating cost (LCOE, USC/kWh)				
	USD/kW	Years	USD/kW/month	USC/kWh	USC/Mcal	%	%	CAPEX	Fixed O&M	Variable O&M	Fuel cost	Total
Coal (USC)	1,469	40	4.8	0.47	1.24	44%	75%	2.29	0.88	0.47	2.43	6.07
Gas (C/C)	944	30	2.2	0.32	2.59	63%	70%	1.63	0.43	0.32	3.53	5.91
Gas (GT)	525	30	1.7	0.39	2.59	45%	30%	2.12	0.80	0.39	4.94	8.24
LNG (C/C)	944	30	2.2	0.32	4.25	63%	70%	1.63	0.43	0.32	5.80	8.18
LNG (GT)	525	30	1.7	0.39	4.25	45%	30%	2.12	0.80	0.39	8.12	11.42
Oil (ST)	1,100	30	3.8	0.39	4.12	25%	17%	7.84	3.07	0.39	13.94	25.23
Hydro (Res)	2,203	80	1.8	0.00	0.00	100%	40%	6.29	0.63	0.00	0.00	6.92
Hydro (ROR)	3,357	80	2.8	0.00	0.00	100%	50%	7.67	0.77	0.00	0.00	8.43
Geothermal	3,462	30	5.7	0.04	0.00	100%	80%	5.24	0.97	0.04	0.00	6.26
Solar	786	25	0.8	0.00	0.00	100%	20%	4.92	0.57	0.00	0.00	5.49
Wind onshore	1,154	25	1.8	0.00	0.00	100%	22%	6.54	1.09	0.00	0.00	7.63
Wind offshore	3,149	25	4.6	0.00	0.00	100%	48%	8.25	1.32	0.00	0.00	9.57
PSPP (6 hours)	800	80	0.7		0.00	100%	20%	4.57	0.46	0.00	0.00	5.03
Battery (6 hours)	586	10	0.2		0.00	100%	20%	5.45	0.12	0.00	0.00	5.57
Ammonia (USC)	1,696	40	4.8	0.47	16.47	44%	75%	2.64	0.88	0.47	15.59	19.58
Hydrogen (C/C)	944	30	2.2	0.32	22.37	63%	70%	1.63	0.43	0.32	10.12	12.50

CAPEX is calculated with an interest rate of 10% and a residual rate of 0%.
Pumped-storage hydropower and storage batteries use surplus electricity when storing electricity, so fuel costs are set to zero.
Fuel costs in the LCOE are calculated assuming that the price in 2040 will continue for the useful life.

(Source: JICA Survey Team)



(Source: JICA Survey Team)

Figure 7-16 Generating costs for various power sources

(5) Operating conditions of thermal power plants

The operating conditions of the thermal power plants are shown below.

Table 7-11 Operating conditions of thermal power plants

Fuel		Capacity (MW)	Daily start & stop	Efficiency (%)	Minimum load (%)	Forced outage rate (%)	Scheduled outage (days/year)
Coal	USC	1,000	No	44.0	30	5	20
Ammonia	USC	1,000	No	44.0	60	5	20
Gas, LNG	C/C	493	Yes	63.0	30	2.5	14
	C/C	412	Yes	59.0	30	2.5	14
	GT	314	Yes	45.0	30	2.5	14
	GT	265	Yes	37.8	30	2.5	14
Hydrogen	C/C	493	Yes	63.0	50	2.5	14
	C/C	412	Yes	59.0	50	2.5	14
	GT	314	Yes	45.0	50	2.5	14
	GT	265	Yes	37.8	50	2.5	14
Oil	ST	400	Yes	25.0	35	7.5	20

Note: Capacity is the power generation end, thermal efficiency is lower heating value (LHV)

(Source: JICA Survey Team)

(6) CO_2 emissions and CCS costs

(a) CO_2 emissions

CO_2 emissions are calculated based on the fuel used and the thermal efficiency of the power plants. The CO_2 emissions per kWh at the maximum output of thermal power plants are shown below.

Table 7-12 Comparison of CO_2 emissions per kWh

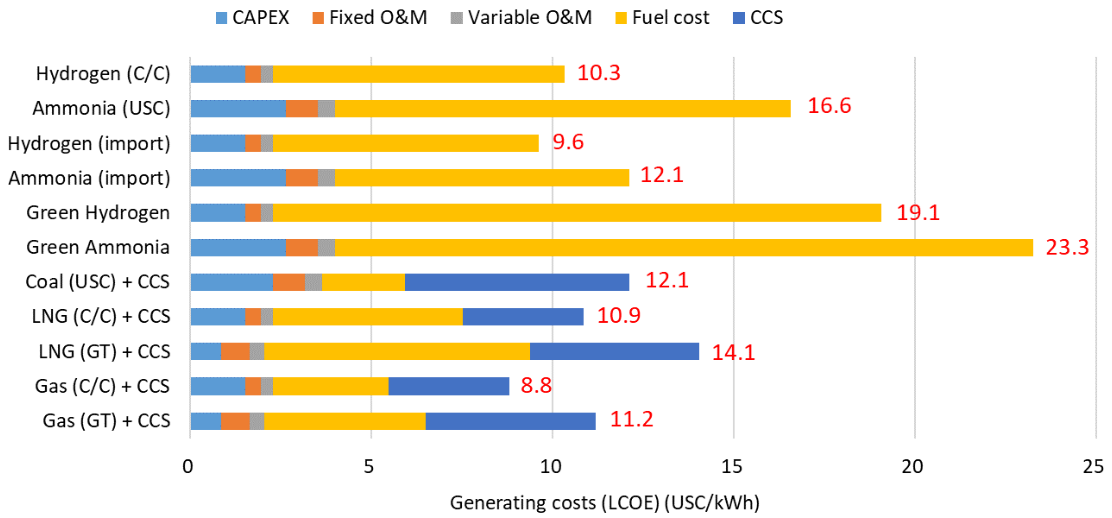
	Fuel			Efficiency	CO_2 Emissions Factor
		g-CO_2/MJ	kg-CO_2/Mcal		kg-CO_2/kWh
Coal (USC)	Coal	93.7	0.3924	44%	0.767
Gas (C/C)	Gas	55.8	0.2338	63%	0.319
Gas (GT)	Gas	55.8	0.2338	45%	0.447
LNG (C/C)	LNG	55.8	0.2338	63%	0.319
LNG (GT)	LNG	55.8	0.2338	45%	0.447
Oil (ST)	Oil	77.6	0.3248	25%	1.098
Coal (USC)	Coal+20%NH_3	75.0	0.3139	44%	0.613
LNG (C/C)	LNG+20%hydrogen	44.7	0.1870	63%	0.255
LNG (GT)	LNG+20%hydrogen	44.7	0.1870	45%	0.357

Note: Electric energy is the power generation end, thermal efficiency is lower heating value (LHV)

(Source: JICA Survey Team)

(b) CCS costs

Considering the CCS costs, the generating costs of the main thermal power aiming at carbon neutrality in 2060 will change as shown below. In particular, the addition of CCS costs will reverse the generating costs of LNG thermal and coal thermal power. The collection efficiency will be 90% when CCS is implemented, and a cost of USD 200/ton will be added as the purchase cost of carbon credits for the 10% that cannot be collected.



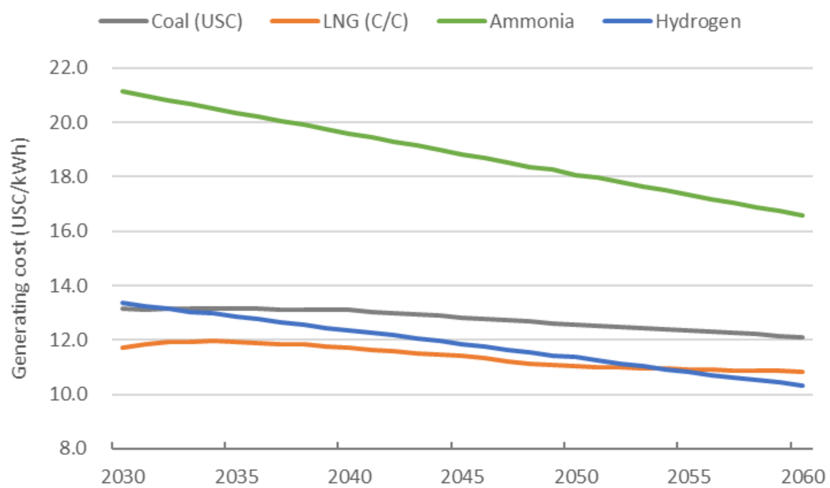
Note: For all thermal power, CAPEX is the value when the capacity factor is 75%.

(Source: JICA Survey Team)

Figure 7-17 Generating costs of thermal power in 2060 (LCOE)

Gas thermal power is the cheapest, but domestic gas is almost exhausted and cannot be expected to provide major supply capacity. Hydrogen thermal power has a high fuel cost, but unlike coal thermal power and LNG thermal power, CCS is not required, and hydrogen thermal power is the cheapest except for gas thermal power. Hydrogen thermal power is assumed to be the most economical thermal power in order to aim for carbon neutrality. Since domestic gas cannot be expected to provide a large amount of hydrogen due to its depletion, it is necessary to consider imports from Australia.

It is expected that the production costs of hydrogen/ammonia and the processing costs for CCS will gradually decrease in line with the future technology readiness level. Based on this, changes in generating costs of various thermal power plants are shown below.



Note: Domestic fuel is used for producing hydrogen and ammonia.

(Source: JICA Survey Team)

Figure 7-18 Changes in generating costs of various thermal power plants (LCOE)

Until around 2055, LNG thermal power + CCS is cheaper, but hydrogen thermal power will decline significantly in the future, and will reverse around 2055, and hydrogen thermal power will be the cheapest in 2060.

As shown in Figure 7-15, the fuel price of ammonia is about the same as that of hydrogen. In particular, the price of imported ammonia is expected to be lower than that of imported hydrogen in the future. However, current technology assumes that ammonia will burn in USC, similar to coal thermal power. The thermal efficiency of USC is about 44%, which is greatly inferior to the thermal efficiency of 63% for combined cycle using the latest GT, so the generating cost in 2060 is about 1.5 times.
Although it is still at an immature stage of technology, research is underway to burn ammonia in GT. If this technology is put into practical use in the future, it is expected that a combined cycle using ammonia as fuel will be feasible and the generating cost will be about the same as that of a combined cycle using hydrogen as fuel.

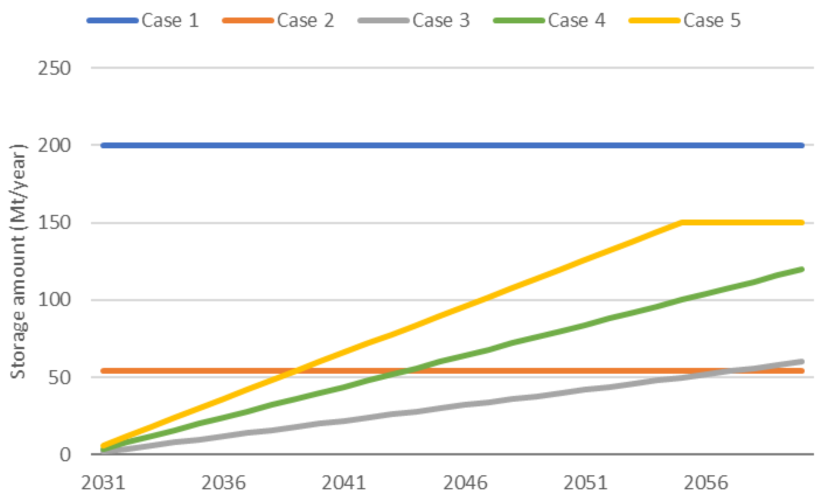
(7) Potential of CCS

The current CO_2 storage potential is estimated to be around 10 billion tons, and the power sector emitted 27% of the total CO_2 emissions in 2019, so the current CO_2 storage potential in the power sector is assumed to be 2.7 billion tons. In terms of the potential of CCS, the following 5 cases are assumed.

Case	Contents	Total of 2031-2060
Case 1	The current CO_2 storage potential (10 billion tons) will be used up in 50 years by the power sector only.	6,000 Mt
Case 2	The current CO_2 storage potential in the power sector (27 billion tons) will be used up in 50 years	1,620 Mt
Case 3	For the development of large-scale CCS (1 million tons/year), it is assumed that about 2 projects will be developed annually from 2030 to 2060.	930 Mt
Case 4	For the development of large-scale CCS (1 million tons/year), it is assumed that about 4 projects will be developed annually from 2030 to 2060.	1,860 Mt
Case 5	For the development of large-scale CCS (1 million tons/year), it is assumed that about 6 projects will be developed annually from 2030 to 2060. (The annual upper limit is fixed at 150 million tons.)	2,700 Mt

(Source: JICA Survey Team)

The CCS treatable amount (storage amount) from 2031 to 2060 in the above five cases is shown below.



(Source: JICA Survey Team)

Figure 7-19 CCS treatable amount from 2031 to 2060

Case 2 is realistic because the total treatable amount up to 2060 is about 2/3 of the power sector allocation storage potential of 2,700 Mt, but CO_2 storage of 54 Mt/year from the first year of CCS introduction seems unrealistic. Similar to Case 2, the total treatable amount up to 2060 for Case 4 is about 2/3 of the power sector allocation storage potential of 2,700 Mt, and the potential of CCS can be retained to some extent after 2060, so it is assumed that this is a valid scenario. In this survey, Case 4 is assumed as the potential for each year. In other words, the maximum CCS treatable amount in 2060 will be around 120 Mt for the entire Indonesian power sector.

7.3.2 Scenario Formulation

The following plans are assumed as scenarios to realize carbon neutrality in 2060.

Table 7-13 Scenarios to realize carbon neutrality in 2060

Scenario name		Content
A 100% renewable energy case	A-1	Carbon neutrality is realized through 100% renewable energy. A large number of storage batteries should be installed to adjust demand and to prevent the loss of power generation due to continuous cloudy or rainy weather. Aim to balance supply and demand within each island as much as possible, but if there are shortages on an island, it will be necessary to establish interconnections with neighboring islands.
	A-2	Carbon neutrality is realized through 100% renewable energy. A large number of power plants using hydrogen (or ammonia) derived from domestic renewable energy will be installed to adjust demand and to prevent the loss of power generation due to continuous cloudy or rainy weather. If there is a shortage on an island, it will be covered by the transportation of hydrogen (or ammonia).
B Renewable energy + hydrogen (ammonia) case	B-1	Carbon neutrality is realized through renewable energy and power plants using hydrogen derived from domestic fossil fuels. CO_2 generated when hydrogen is generated from fossil fuels is treated with CCS.
	B-2	Carbon neutrality is realized through renewable energy and power plants using ammonia derived from domestic fossil fuels. CO_2 generated when ammonia is generated from fossil fuels is treated with CCS.
C Renewable energy + thermal power plants + CCS case	C-1	Carbon neutrality is realized through renewable energy and domestic coal thermal power plants and CCS. CO_2 generated when generating at thermal power plants is treated with CCS.
	C-2	Carbon neutrality is realized through renewable energy and domestic LNG thermal power plants and CCS. CO_2 generated when generating at thermal power plants is treated with CCS.
BAU	BAU	Extend the current RUPTL plan. (Generating costs and CO_2 emissions are calculated and used for comparison.)

Nuclear power, biomass power, geothermal power, hydropower and wind power do not have a large fluctuation range when the potential amount is taken into consideration, so they are the same in all cases.

7.4 Development of Power Resources for Long-range Planning (until 2060)

7.4.1 Sumatra System

(1) Demand Forecast

The two demand forecasts estimated in this survey are shown in the table below:

Table 7-14 Demand Forecast until 2060 (Power Grid in Sumatra)

		2021	2025	2030	2035	2040	2045	2050	2055	2060
High	GW	6.3	9.0	11.7	14.8	18.3	23.7	32.3	45.0	56.6
	TWh	42.1	58.7	75.8	96.5	118.7	154.0	209.8	292.5	368.1
Low	GW	6.3	9.0	11.7	14.4	17.2	19.9	22.7	25.4	28.2
	TWh	42.1	58.7	75.8	93.7	111.6	129.5	147.4	165.2	183.1

(Source: the JICA Survey Team)

Until 2030, the results of both high-case and low-case are identical. However, after that, the gap between them becomes bigger year by year and eventually doubles in 2060.

(2) Development Plan

The composition of power sources in the Sumatra power grid in 2030 according to RUPTL 2021-2030 is shown in the table below. Per the table, the composition contains 43% coal-fired thermal power, 17% gas thermal power (including oil thermal power), and 40% renewable energy.

Table 7-15 Composition of Power Sources in Sumatra Power Grid in 2030

	Capacity (GW)	Ratio
Coal	7.3	42.8%
Gas (& Oil)	2.9	16.8%
Geothermal	1.9	11.1%
Hydro	3.9	23.0%
Solar	0.1	0.7%
Wind	0.1	0.6%
Biomass	0.0	0.3%
Storage	0.8	4.7%
Total	17.1	100.0%

The development plan for renewable energy from 2031 to 2060 is estimated in the table below. The plan for solar will depend on the scenario and the status of supply and demand.

Table 7-16 Development Method for Sumatra Power Grid up to 2060

	Installed Capacity in 2030	Installed Capacity in 2060	Development Method
Hydro	3.6 GW	6.6 GW	Developing by 100MW every year
Geothermal	1.9 GW	4.9 GW	Developing by 100MW every year
Biomass	0.1 GW	1.6 GW	Developing by 50MW every year
Solar	2.9 GW	For adjustment	Depending on the supply and demand
Wind	0.1 GW	3.1 GW	Developing by 100MW every year

(Source: the JICA Survey Team)

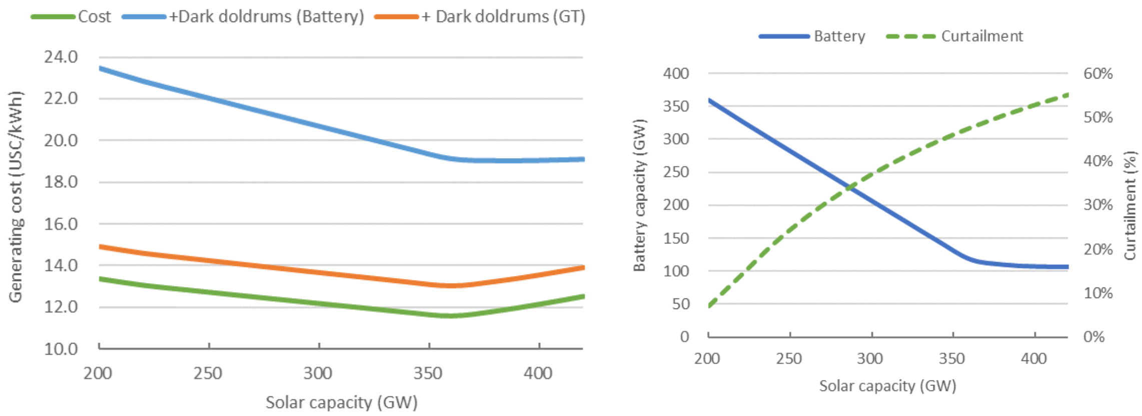
Based on the renewable energy potential described in Table 7-6, the potential amounts for geothermal, hydro, biomass, and wind in Sumatra are 12.9GW, 21.3GW, 15.6GW, and 7.4GW respectively. These are also within each potential amount in 2060.

(3) High-case Estimation

(a) Scenario A (decarbonization through renewable energy only)

1) Scenario A-1

In addition to the installed capacity described in the Table 7-15, the power generating costs which will achieve decarbonization by adjusting solar and battery development are described below. Even though the potential of solar capacity in Sumatra described in the Table 7-6 is 68.7GW, the estimation was carried out to install capacity of more than the potential.



(Source: the JICA Survey Team)

Figure 7-20 Relation between Solar Capacity and Cost (Power Grid in Sumatra, Scenario A, High-case)

When the solar capacity is more than 200GW, required electric supply reliability will be achieved (LOLE = within 24 hours). And if the solar capacity increases, battery capacity can decrease by 150%. Therefore, as a consequence of the rising solar capacity, the overall generating cost will decrease gradually. However, since approximately 100GW of battery capacity is needed for demand during the night, when solar cannot generate electric power, the overall generating cost will rise if the solar capacity is more than 350GW.
Moreover, the generating costs in the above figure include the costs for addressing dark doldrums conditions, described below. If decarbonization is achieved via renewable energy only, a cost increase due to dark doldrums countermeasures (for continued cloudy or rainy weather) will be necessary. When dealing with batteries, the generating cost will increase by approximately 7-10 USC/kWh to 18USC/kWh or more. On the other hand, if hydrogen (green hydrogen), which is manufactured by domestic renewable energy, is used, the rise in the generating cost will be approximately 1.5 USC/kWh. However, if there is not enough renewable energy surplus, it will be difficult to procure hydrogen.

An estimation of the necessary battery capacity in 2060 is given in the following table (for 340GW of solar capacity), including countermeasures for cloudy and rainy weather conditions when electric power cannot be generated (dark doldrums).

Table 7-17 Cost Estimation Addressing Dark Doldrums (with Batteries, High-case)

Item		Remarks
Average of daily electric energy demand	1008.6 GWh	
Average of daily power generation except for solar	206.8 GWh	
Daily power generation by solar	328.0 GWh	Estimated using 20% of average power generation (1639.9 GWh)
Shortage of energy supply	473.8 GWh	
Duration of dark doldrums	5 days	Estimated by the JICA Survey Team
Necessary battery capacity	394.9 GW	6 hour battery
Construction costs for batteries	USD 456.5/kW	6 hour battery
Annual fixed running costs for batteries	USD 73.2/kW	
Annual costs addressing dark doldrums	USD 28,891 million	Equivalent to USC 7.8/kWh of generating costs

(Source: the JICA Survey Team)

If batteries are installed taking into consideration a situation whereby solar can only generate 20% of the average amount of electric power for 5 days of dark doldrums, the generating cost will increase by 7.8/kWh to address this (for 340GW of solar capacity, the generating cost will rise from USC 11.8/kWh to USC 19.6/kWh).

2) Scenario A-2

As a countermeasure for dark doldrums, many power plants use hydrogen (green hydrogen) which is manufactured by domestic renewable energy. Since the plants are not operated constantly, it will be GT, which have low fixed running costs.

A shortage of battery storage during cloudy and rainy weather, depending on the installed battery capacity, would disrupt the power supply in the evening. An estimation of the required GT is given in the table below, including measures for such a situation.

Table 7-18 Cost Estimation Corresponding Dark doldrums (with GT, High-case)

Item		Remarks
Maximum power demand in August	56.0 GW	
Maximum power supply from hydro in August	3.3 GW	Estimated 50% of its capacity due to the dry season
Power supply from geothermal and biomass	5.2 GW	80% of its capacity
Power supply from solar and wind	0 GW	
Shortage of energy supply	47.5 GW	
Necessary capacity of GT	50.0 GW	Estimated 5% of downtime ratio due to an accident
Construction costs for GT	USD 524.6/kW	
Annual fixed running costs for GT	USD 76.3/kW	
Fixed running costs addressing dark doldrums	USD 3,816 million	
Shortage of daily energy supply	473.8 GWh	
Annual duration of required measures	36 days	Equivalent to 3.6% of GT usage rate
Unit price for green hydrogen	USC 8.5/kWh	Estimated 45% of thermal efficiency
Fuel price addressing dark doldrums	USD 1,450 million	
Annual costs addressing dark doldrums	USD 5,266 million	Equivalent to USC 1.4/kWh of generating cost

(Source: the JICA Survey Team)

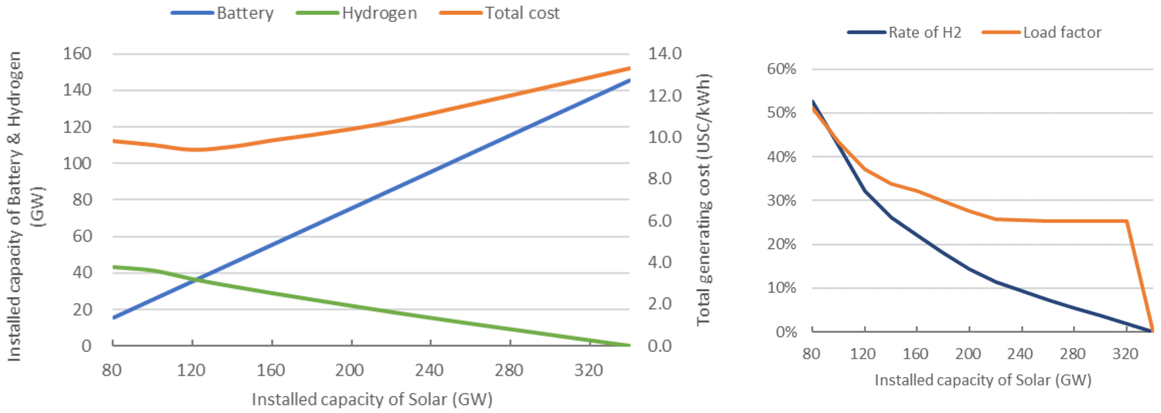
As a dark doldrums countermeasure, the installation of GT using green hydrogen to generate power is much more economical than the installation of batteries. Thus, a comparison is made between these

dark doldrums measures, which will be needed with a high ratio of renewable energy. However, surplus energy from other areas will be included in the mix due to a lack of power supply to generate green hydrogen in Sumatra.
Sufficient fuel capacity is needed if bad weather continues for about 5 days. Hydrogen can be stored as a liquid in high-pressure tanks with low ambient temperatures at present. However, fuel which can be stored at ordinary temperatures and pressures is desirable since it will be used for back-up facilities.

(b) Scenario B

1) Scenario B-1 (Renewable Energy + Hydrogen-fired Power)

Instead of reducing the solar capacity, the following describes a situation of increasing the amount of hydrogen generation power plants using hydrogen manufactured by domestic fossil fuel. The carbon dioxide made by creating hydrogen from fossil fuels will be treated by CCS. The relevant costs for this are included as well.



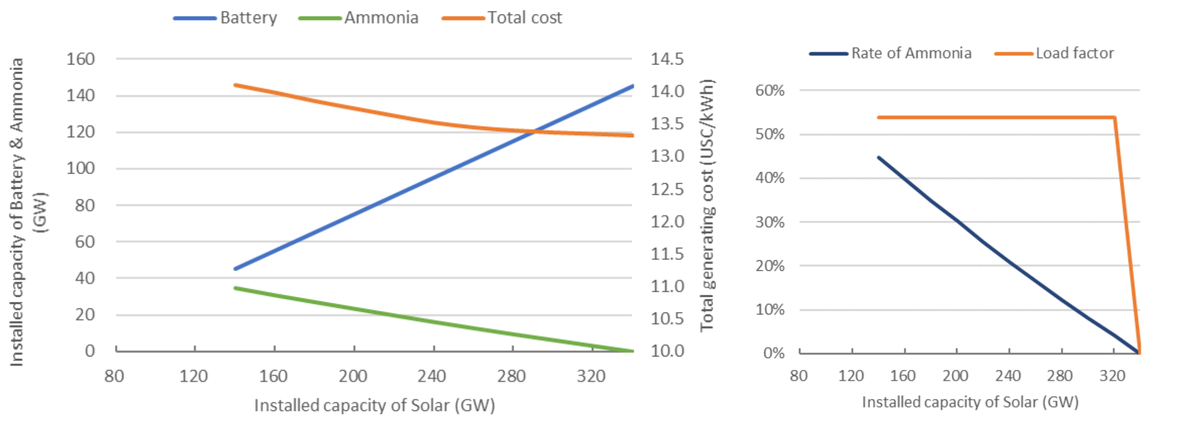
(Source: the JICA Survey Team)

Figure 7-21 Relation between Solar Capacity and Cost (Power Grid in Sumatra, Scenario B-1, High-case)

The generating cost decreases along with the declining solar capacity. The generating cost is most economical when the solar capacity is around 120GW. In this case, the utilization rate of hydropower is approximately 35% (30% of total generated energy).

2) Scenario B-2 (Renewable Energy + Ammonia-fired Power)

Instead of reducing the solar capacity, the following describes a situation of increasing the amount of ammonia generation power plants using ammonia manufactured by domestic fossil fuel. The carbon dioxide made by creating ammonia from fossil fuels will be treated by CCS. The relevant costs for this are included as well.



(Source: the JICA Survey Team)

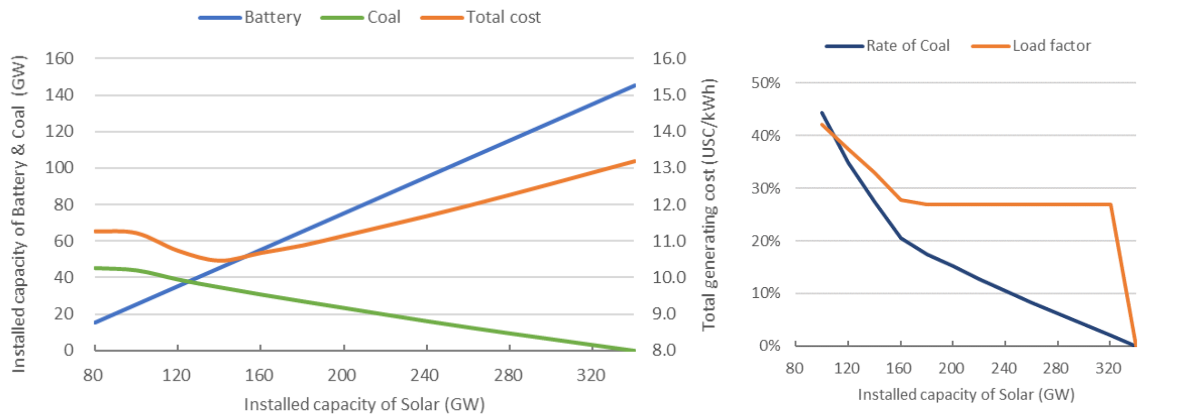
Figure 7-22 Relation between Solar Capacity and Cost (Power Grid in Sumatra, Scenario B-2, High-case)

Ammonia-fired power is difficult to use for start-stop operation with a short duration, or cannot be used for start-stop operation within a day. In addition, since the minimum power output is 60%, its usage rate is more than 50%. The cost of ammonia itself is expensive. The generating cost increases as a consequence of the rise in its usage rate and its capacity.

(c) Scenario C

1) Scenario C-1 (Renewable Energy + Coal-fired power + CCS)

Instead of reducing the solar capacity, the following describes a situation of increasing the amount of coal generation power plants, with the carbon dioxide to be treated by CCS. The recovery efficiency of CCS is 90% in this situation. A cost of USD 200/ton for the uncollectible 10% is added as the cost of carbon credits.[60]



(Source: the JICA Survey Team)

Figure 7-23 Relation between Solar Capacity and Cost (Power Grid in Sumatra, Scenario C-1, High-case)

Instead of reducing the solar capacity, increasing the capacity of coal-fired power makes the generating cost gradually more economical. The generating cost drops to its lowest level (approximately USC 10.5/kWh) when the solar capacity is around 140GW (35GW of the capacity of coal-fired power). The usage of coal-fired power is around 25% and is less than 20% of the total

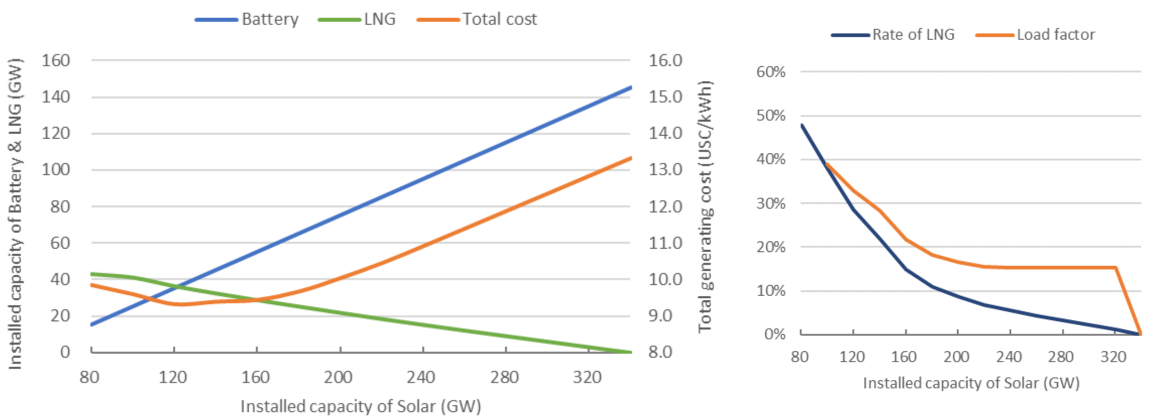
60 To achieve net zero emissions, BECCS (Bio-energy with Carbon Capture and Storage) or DACCS (Direct Air Carbon Capture and Storage) are also considered. But the cost of carbon credits is applied in this survey.

energy supply at the lowest point. When the solar capacity is 140GW or less, the usage of coal-fired power increases drastically and the percentages of total energy supply also increase gradually.

If the coal-fired capacity is around 35GW, its energy supply is 100.7TWh and the amount of treatment by CCS reaches 75.7Mt. The available amount of CCS treatment is estimated to be 120Mt. Taking into consideration approximately 30Mt/year of CCS treatment in the power grid in Sumatra, 16GW of the coal-fired capacity and 90% of renewable energy in the total energy supply is reasonable.

2) Scenario C-2 (Renewable Energy + LNG-fired power(C/C) + CCS)

Instead of declining the solar capacity, the situation of increasing power plants generated by the LNG and The carbon dioxide to be treated by CCS is as follows. The recovery efficiency and the cost for uncollectible is the same as the scenario C-1.



(Source: the JICA Survey Team)

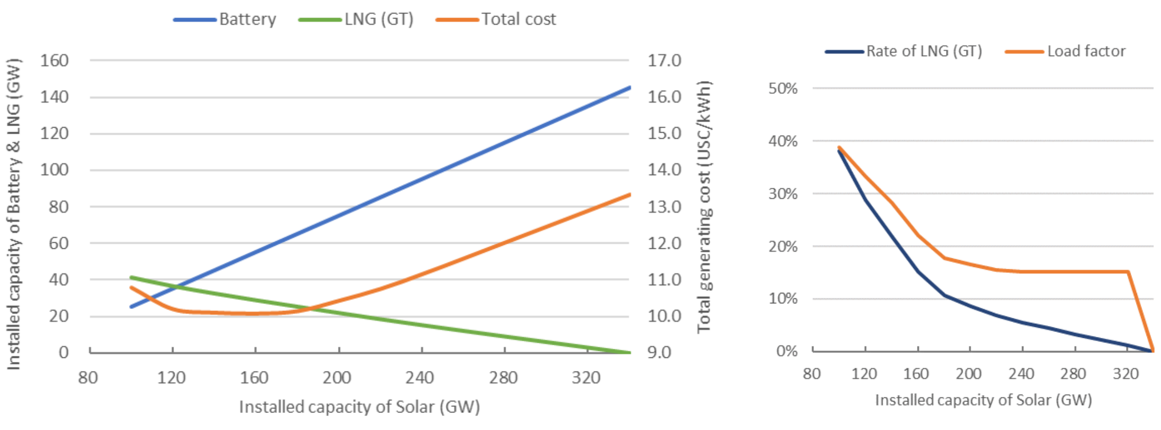
Figure 7-24 Relation between Solar Capacity and Cost (Power Grid in Sumatra, Scenario C-2, High-case)

The generating cost drops to its lowest level (approximately USC 9.1/kWh) when the solar capacity is around 140GW (36GW of the capacity of LNG-fired power). The usage of LNG-fired power is around 30% and is around 30% of the total energy supply at the lowest point. When the LNG-fired power capacity increases, the usage of LNG-fired power increases drastically and percentages of total energy supply also increase gradually.

If the LNG-fired capacity is around 36GW, its energy supply is 105.5TWh and the amount of treatment by CCS reaches 31.5Mt.

3) Scenario C-2' (Renewable Energy + LNG-fired Power (GT) + CCS)

Instead of reducing the solar capacity, the following describes a situation of increasing the amount of LNG (GT) generation power plants, with the carbon dioxide to be treated by CCS. The recovery efficiency and the costs for the uncollectible amount are the same as Scenario C-1.



(Source: the JICA Survey Team)

Figure 7-25 Relation between Solar Capacity and Cost (Power Grid in Sumatra, Scenario C-2', High-case)

The generating cost decreases gradually when reducing the solar capacity and increasing the LNG-fired power capacity. Even though GT have lower fixed running costs than C/C, their efficiency is worse and the fuel costs are higher than for C/C. Therefore, the generating cost for GT is almost the same as that of C/C if the rate of usage is low. As a consequence of increasing the rate of usage, the generating cost is higher and less economically efficient than C/C. The generating cost drops to its lowest level (approximately USC 10.0/kWh) when the solar capacity is around 120GW (36GW of the capacity of LNG-fired power (GT)). When the solar capacity declines and the GT capacity rises, the usage of GT increases drastically and the generating cost increases.

(d) BAU Scenario

The following describes the BAU scenario, with the power source composition in 2060 based on the same rate in 2030. The whole capacity is calculated in the same way as the previous method, which achieves the required electric supply reliability.

Table 7-19 Power Source Composition in 2060 Power Grid in Sumatra, Scenario BAU, High-case)

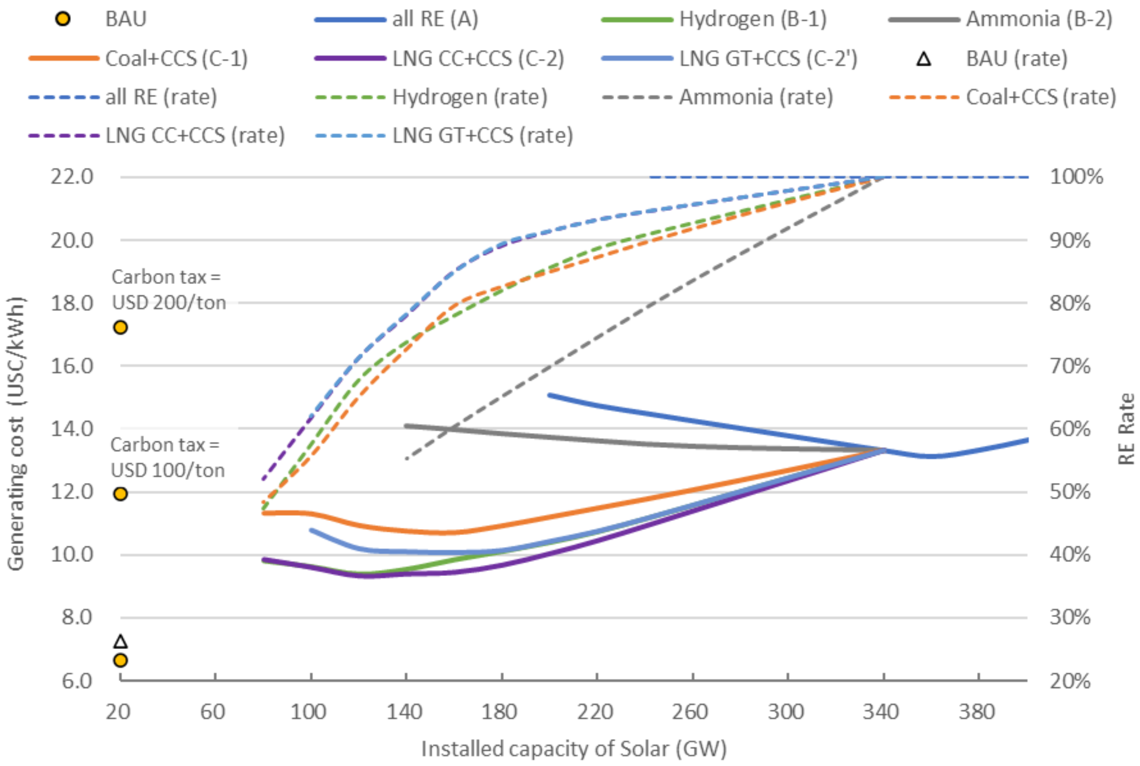
	Capacity (GW)	Ratio	Energy (TWh)	Ratio
Coal	36.5	42.7%	237.1	64.2%
LNG	15.0	17.5%	34.4	9.3%
Geothermal	3.9	4.6%	30.0	8.1%
Hydro	6.1	7.1%	27.4	7.4%
Solar	20.1	23.5%	35.4	9.6%
Wind	2.1	2.5%	4.1	1.1%
Biomass	1.1	1.2%	0.0	0.0%
Storage	0.8	0.9%	0.8	0.2%
Total	85.6	100%	369.2	100%

(Source: the JICA Survey Team)

Based on the results, the generating cost for the BAU scenario is 6.6 USC/kWh and this is the lowest cost among all scenarios. The amount of carbon dioxide emissions is 0.531 kg-CO_2/kWh and 195.3Mt-CO_2 annually. If the unit price of carbon tax is USD 100/ton, the generating cost increases by 5.3 USC/kWh to 11.9 USC/kWh. If the unit price of carbon tax is USD 200/ton, the generating cost increases by 10.6 USC/kWh to 17.2 USC/kWh.

(e) Summary

A summary of the aforementioned cases is described in the figure below:



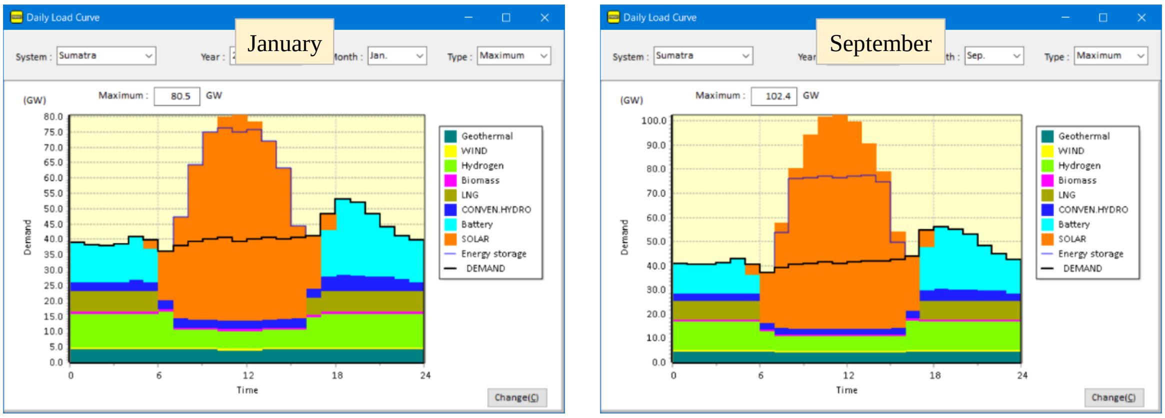
(Source: the JICA Survey Team)

Figure 7-26 Relation between Solar Capacity and Cost (Power Grid in Sumatra, All Scenarios, High-case)

In the BAU Scenario, the generating cost is 6.6 USC/kWh, which is the lowest. However, the amount of carbon dioxide emissions is large. The cost is more expensive than hydrogen-fired power and LNG-fired power + CCS taking into consideration a USD 100/ton carbon tax.

As a power source composition to achieve decarbonization, hydrogen-fired power or LNG-fired power (C/C) + CCS is the most economical when paired with increased renewable energy capacity. Specifically, approximately 120GW of solar, 35GW of batteries, and 36GW of hydrogen-fired power or LNG-fired power capacity is desirable. For the same capacity amount of hydrogen-fired and LNG-fired power, the generating cost is USC 9.4/kWh and the utilization rate of renewable energy is around 69%. Treatment of carbon dioxide by CCS is 11Mt annually. Additional facilities for dark doldrums countermeasures are not necessary because this function is covered by thermal power.

The below figure illustrates the operation status of each power source for the maximum demand day in January and September with the optimized power source composition, which has the same capacity amount for hydrogen-fired and LNG-fired power. Almost all LNG-fired power stops during the day due to the supply from solar power. Surplus power is stored in batteries and is supplied to the electrical grid during the night.

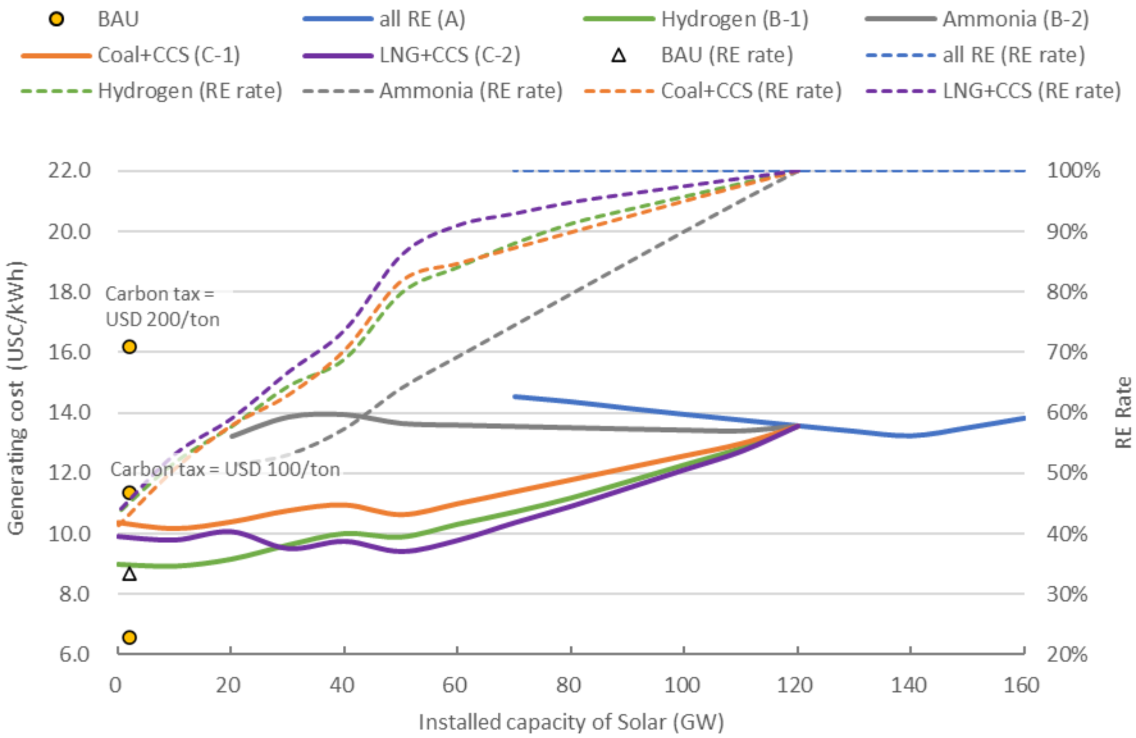


(Source: the JICA Survey Team)

Figure 7-27 Operation Status of Each Power Source after Optimized Power Source Composition (Power Grid in Sumatra, High-case)

(4) Low-case Demand

For low-case demand, the results of an estimation with the same summarization as the high-case are as follows:



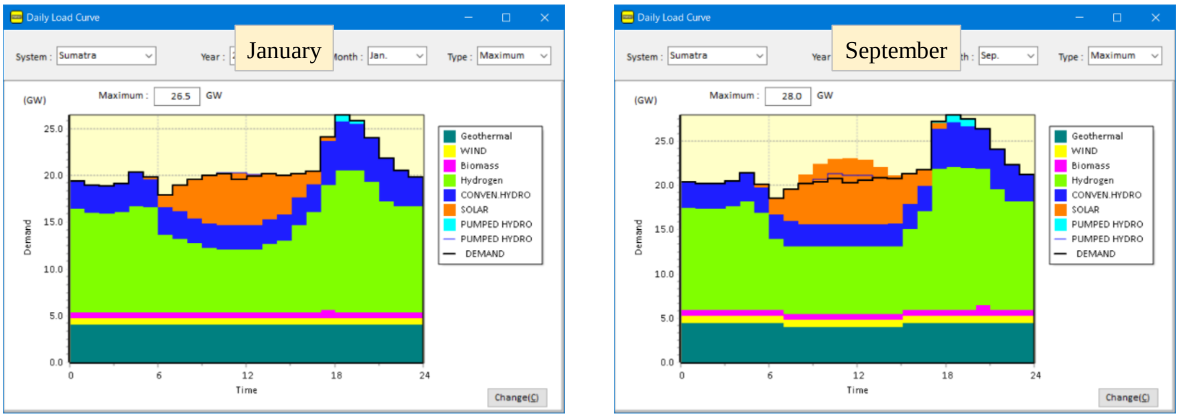
(Source: the JICA Survey Team)

Figure 7-28 Relation between Solar Capacity and Cost (Power Grid in Sumatra, All Scenarios, Low-case)

In the BAU scenario, the generating cost is 6.6 USC/kWh, which is the lowest. However, the cost is higher than hydrogen-fired power and LNG-fired power taking into consideration the carbon tax (which is USD 100/ton) because the amount of carbon dioxide is large.

As a power resource composition to achieve decarbonization, hydrogen-fired power is the most economical, as well as the development of renewable energy. Specifically, around 10GW of solar capacity, no batteries, and 17GW of hydrogen-fired power is desirable. In this case, the rate of renewable energy is 52% and the generating cost is USC 8.9/kWh.

The below figure illustrates the operation status of each power source for the maximum demand day in January and September with the optimized power source composition above. The demand after the application of solar power shows a big difference between the daytime and the evening. The demand and supply balance is secured by adjusting the output of hydrogen-fired power. However, the minimum load for hydrogen-fired power needs to be 50%, which is higher than the LNG-fired power of 30%, so a small amount of surplus power appears.



(Source: the JICA Survey Team)

Figure 7-29 Operation Status of Each Power Source after Optimized Power Source Composition (Power Grid in Sumatra, Low-case)

(5) Summary

In both high and low cases, hydrogen-fired power or LNG-fired power (C/C) + CCS, along with the development of renewable energy, is the most economical as a power source composition for decarbonization. The desirable rate of renewable energy is around 70% in the high-case and 50% in the low-case.

The optimal capacity of solar power is approximately 50GW for the low-case and approximately 120GW for the high-case. Its potential in Sumatra is 68.7GW, as described in Table 7-6. The necessary capacity is within the potential in the low-case, but it is over it in the high-case. For reference, the amount of land necessary to install 120GW of solar power would be around 0.4% of the total land area of Sumatra.[61]

CCS treatment capacity is not necessary in the low-case. The treatment capacity in the high-case is 11.2Mt, which is within the upper limit (30Mt).

[61] Calculated as $60MW/km^2$ ($0.06kW/m^2$)

7.4.2 Java-Bali System

(1) Demand Forecast

Two cases of demand forecast are shown in the table below:

Table 7-20 Demand Forecast until 2060 (Power Grid in Java-Bali)

		2021	2025	2030	2035	2040	2045	2050	2055	2060
High	GW	28.3	33.1	39.4	46.7	54.7	68.5	90.7	123.6	152.7
	TWh	197.3	231.6	279.6	331.4	388.7	486.6	644.6	878.3	1085.1
Low	GW	28.3	33.1	39.4	45.3	51.5	57.6	63.7	69.8	76.0
	TWh	197.3	231.6	279.6	322.0	365.5	409.1	452.6	496.2	539.8

(Source: the JICA Survey Team)

Both results are identical until 2030. However, after that, the difference becomes larger year by year and almost doubles in 2060.

(2) Development Plan

According to RUPTL 2021-2030, power source composition in Java-Bali in 2030 is as follows. Specifically, it contains 52% of coal-fired power, 25% of gas-fired power (including oil-fired power), and 23% of renewable energy.

Table 7-21 Combination of Power Sources in Java-Bali Power Grid in 2030

	Capacity (GW)	Ratio
Coal	30.9	52.1%
Gas (&Oil)	14.8	24.9%
Geothermal	3.1	5.3%
Hydro	3.3	5.6%
Solar	2.9	4.9%
Wind	0.3	0.4%
Biomass	0.3	0.4%
Storage	3.7	6.3%
Total	59.3	100.0%

(Source: the JICA Survey Team)

Development plans from 2031 to 2060 for power sources which do not emit carbon dioxide are described in the table below. Obviously, the capacity of solar power depends on the scenario and power demand.

Table 7-22 Development Method of Power Grid in Java-Bali until 2060

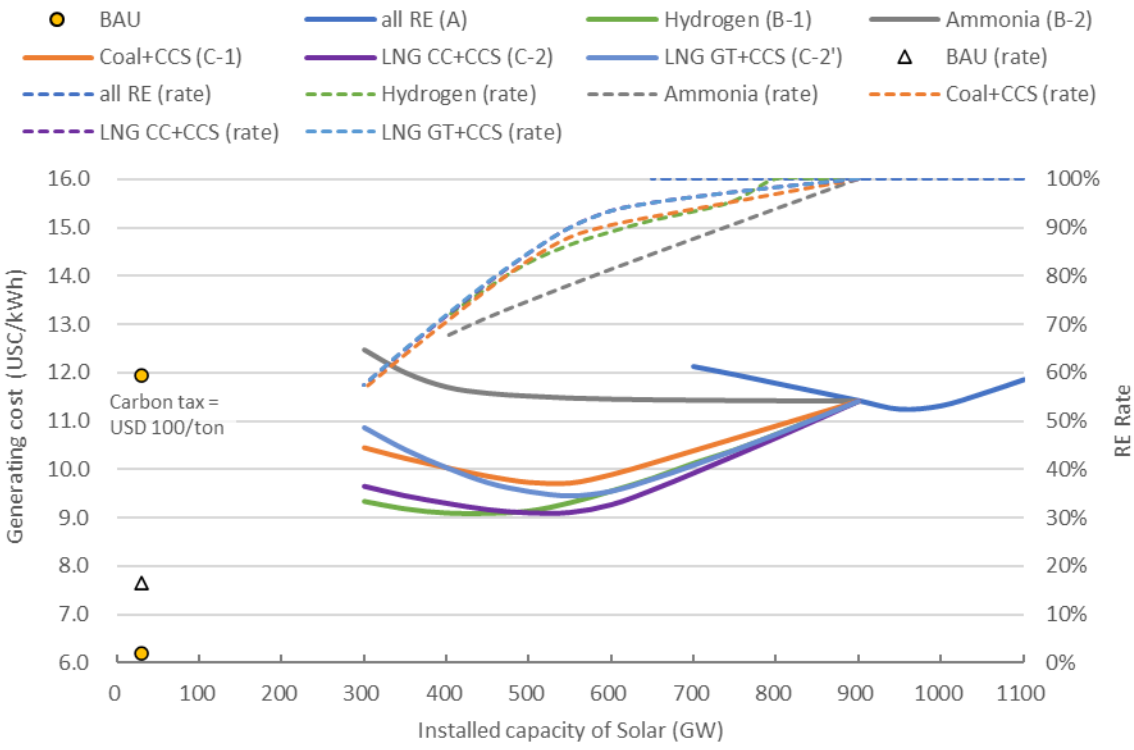
	Installed Capacity in 2030	Installed Capacity in 2060	Development Method
Hydro	3.3 GW	6.3 GW	Developing by 100MW every year
Geothermal	3.1 GW	6.1 GW	Developing by 100MW every year
Biomass	0.3 GW	1.8 GW	Developing by 50MW every year
Solar	2.9 GW	For adjustment	Depending on the supply and demand
Wind	0.3 GW	15.3 GW	Developing by 500MW every year
Nuclear	--	4.0 GW	Developing by 1GW every 5 year after 2045

(Source: the JICA Survey Team)

In accordance with the potential of each type of renewable energy described in Table 7-6, the Java-Bali power grid has 10.1GW of geothermal, 7.7GW of hydro, 9.2GW of biomass, and 24.0GW of wind. These potential amounts can be covered in 2060.

(3) High-case Estimation

The results of an estimation based on the same method as for the power grid in Sumatra are as follows. As described in Table 7-6, the potential of solar power in Java-Bali is 33.1GW. However, the estimation was carried out on the condition of this being over the potential.



(Source: the JICA Survey Team)

Figure 7-30 Relation between Solar Capacity and Cost (Power Grid in Java-Bali, All Scenario, High-case)

In the BAU scenario, the generating cost is 6.2 USC/kWh, which is the most economical, but the amount of carbon dioxide emissions is large. Taking into consideration a USD 100/ton carbon tax, the generating cost is higher than hydrogen-fired power or LNG-fired power + CCS.

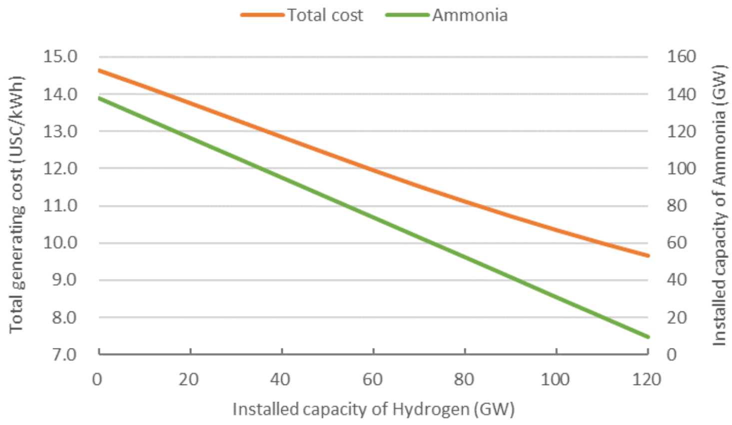
For an ideal power source composition for decarbonization, LNG-fired power + CCS, along with the development of renewable energy, is the most economical. However, the generating cost of hydrogen-fired power is almost the same taking into consideration carbon credits for the surplus which cannot be treated by CCS. Specifically, approximately 500GW of solar power capacity, 230GW of battery capacity, and 56GW of both hydrogen-fired and LNG-fired power (C/C) are desirable. In this case, the rate of renewable energy is around 85%. The amount of carbon dioxide treatment by CCS is around 50Mt annually if only LNG-fired power (C/C) is used.

However, it is not realistic to install solar panels across 6-7% of the total land area in Java-Bali if 500GW of solar capacity is installed in the Java-Bali power grid. Therefore, since decarbonization will not be achieved using only renewable energy, it is necessary to consider the ideal power resource composition with limitations to solar power capacity and compensate for its shortage using decarbonized thermal power.

To meet the maximum energy demand of 152.7GW in the high-case in 2060, taking into consideration the 30GW limitation to solar capacity which is described in RUPTL, it is necessary to develop 130-140GW of decarbonized thermal power for the required supply reliability. For this capacity, the results of a study on the optimal combination are explained in the following sub-section.

(a) Comparison of Hydrogen-fired and Ammonia-fired Power

Hydrogen-fired and ammonia-fired power are compared as decarbonized thermal power sources. Generating cost trends, with the same supply reliability when the capacity of hydrogen-fired power increases instead of decreasing the amount of ammonia-fired power, are illustrated below.



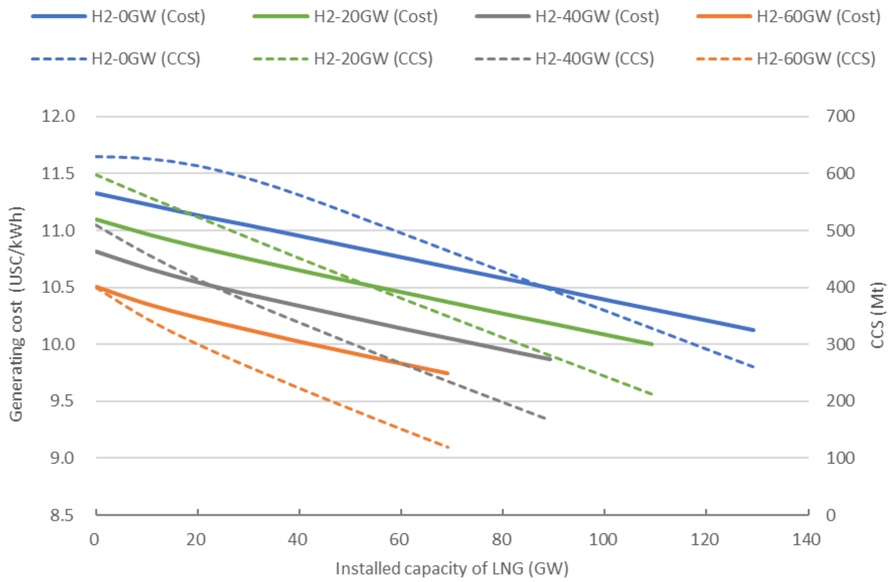
(Source: the JICA Survey Team)

Figure 7-31 Comparison of Hydrogen-fired and Ammonia-fired Power

Since the cost of hydrogen-fired power is a little more economical than ammonia-fired power, the generating cost decreases gradually when hydrogen-fired power increases and ammonia-fired power decreases. Decarbonized thermal power is required if the treatment amount is larger than its capacity, and low cost hydrogen-fired power needs to be added.

(b) Estimation for adopting CCS

An estimation with CCS for LNG-fired and coal-fired power is illustrated below. The figure shows the generating cost trends and the amount of treatment by CCS for the required supply reliability when LNG-fired power increases instead of decreasing the amount of coal-fired power. To define the declining CCS treatment amount, the results of a case when the capacity of hydrogen-fired power changes are also shown in the same figure.



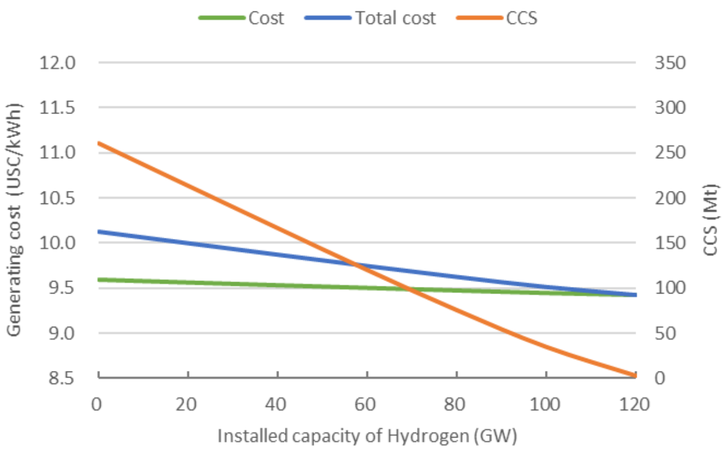
(Source: the JICA Survey Team)

Figure 7-32 Comparison of LNG-fired and Coal-fired Power

Taking into consideration the cost of CCS, the generating cost decreases gradually when LNG-fired power increases instead of decreasing the amount of coal-fired power, because LNG-fired power is a little more economical than coal-fired power. Moreover, the generating cost decreases along with the increasing hydrogen-fired power supply.

(c) Comparison of Hydrogen-fired and LNG-fired Power

A comparison is made with LNG-fired power + CCS and hydrogen-fired power, which is more economical than other thermal power sources. The generating cost and the amount of CCS treatment when the hydrogen-fired power increases are shown in the table below.



(Source: the JICA Survey Team)

Figure 7-33 Relation between Capacity of Hydrogen-fired Power, Generating Cost, and CCS Treatment (High-case)

When the capacity of hydrogen-fired power increases, the generating cost decreases a little. The difference is almost the same as the carbon credit purchase amount for the surplus which cannot be treated by CCS. If the capacity of hydrogen-fired power exceeds 80GW (50GW for LNG-fired power), it falls short of 80Mt, which is the annual limitation of CCS treatment.

(d) Summary

Taking into consideration fuel prices in 2060, a greater capacity of hydrogen-fired power is economical since hydrogen-fired power has more advantages than any thermal power. However, as mentioned in Figure 7-18, LNG-fired power + CCS is economical until around 2055. Taking into consideration the above, LNG-fired power increases at first, and CCS treatment of carbon dioxide starts gradually. When the amount of CCS treatment reaches its limitation, deployment of hydrogen-fired power and fuel conversion from LNG to hydrogen is desirable based on the hydrogen price trends after 2050.

Considering the above conditions, the ideal power resource composition in the high-case in 2060 is as follows.

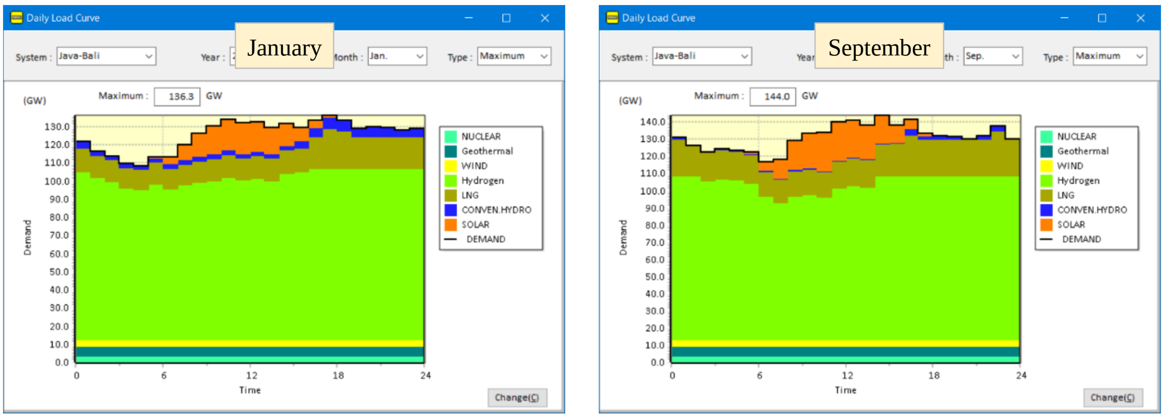
The generating cost of this composition is USC 9.5/kWh and the rate of renewable energy is around 16%. The amount of CCS treatment is approximately 35Mt annually, which is within the capacity. The consumption of fuel is 12.7 million tons for LNG (in the case of 54.5 MJ/kg) and 31.7 million tons for hydrogen (in the case of 141.86 MJ/kg).

Table 7-23 Optimal Power Resource Composition in 2060 (Power Grid in Java-Bali, High-case)

	GW	%	TWh	%	Remarks
Coal	0	0%	0	0%	
LNG	29	15%	120	11%	with CCS
Hydrogen	100	51%	786	72%	
Geothermal	6	3%	47	4%	
Hydro	6	3%	20	2%	
Solar	31	16%	54	5%	
Wind	15	8%	29	3%	
Biomass	2	1%	0	0%	
Nuclear	4	2%	27	3%	
Storage	4	2%	0	0%	including PSPP
Total	197	100%	1085	100%	

(Source: the JICA Survey Team)

In the optimal case above, the operation of each power source composition on the maximum demand days, both in January and August, is as follows:

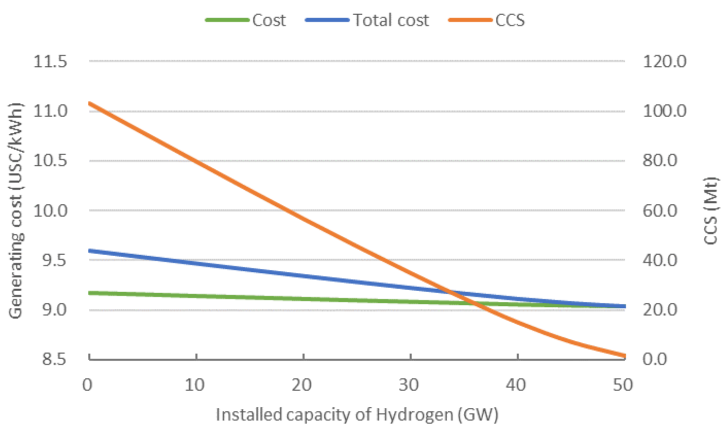


(Source: the JICA Survey Team)

Figure 7-34 Operation Status of Each Power Source after Optimized Power Source Composition (Power Grid in Java-Bali, High-case)

(4) Low-case Estimation

In the low-case, the demand is half of the high-case, but using renewable energy alone cannot achieve decarbonization. The optimal power source composition for a case which compensates for the shortage by using decarbonized thermal power instead of limiting solar capacity is considered.
The maximum demand in the low-case in 2060 is 76.GW. When the capacity of solar is limited to 30GW and the remaining amount is compensated for by decarbonized thermal power, around 60GW of decarbonized thermal power capacity is needed.
As per the high-case, LNG-fired power is compared with hydrogen-fired power, which is more economical than other thermal power sources. The relation between the generating cost and the amount of CCS treatment is given below, when the capacity of hydrogen-fired power increases.



(Source: the JICA Survey Team)

Figure 7-35 Relation between Hydrogen-fired Power, Generating Cost and CCS Treatment (High-case)

As per the high-case, the generating cost decreases a little when the capacity of hydrogen-fired power increases. The difference is almost the same as the carbon credit purchase amount for CCS treatment of the surplus. If the capacity of hydrogen-fired power exceeds 10GW (approximately 44GW for LNG-fired power), the amount of CCS treatment falls short of 80Mt, which is the annual limitation.
As per the high-case, the capacity of LNG-fired power increases at first, and CCS treatment of carbon dioxide starts gradually. When the amount of CCS treatment reaches its limitation, deployment of hydrogen-fired power and fuel conversion from LNG to hydrogen is desirable based on the hydrogen price trends after 2050.
As a result, the optimal power resource composition in the low-case in 2060 is as below. The generating cost of this composition is USC 9.1/kWh and the rate of renewable energy is around 34%. The amount of CCS treatment is approximately 15Mt annually, which is within the capacity. The consumption of LNG is 5.5 million tons (in the case of 54.5 MJ/kg) and that of hydrogen is 12.4 million tons (in the case of 141.86 MJ/kg).

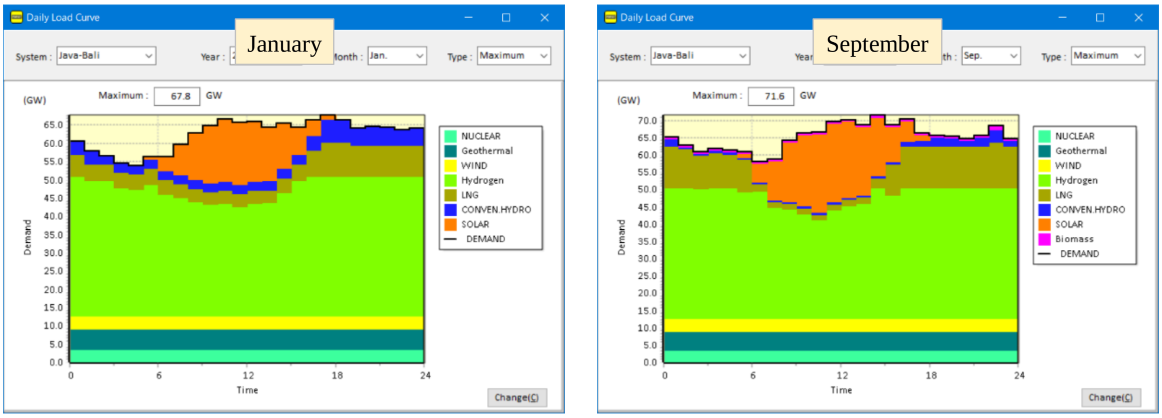
Considering the above conditions, the ideal power resource composition in the low-case in 2060 is as follows.
The generating cost of this composition is USC 9.1/kWh and the rate of renewable energy is around 34%. The amount of CCS treatment is approximately 15Mt annually, which is within the capacity. The consumption of fuel is 5.5 million tons for LNG (in the case of 54.5 MJ/kg) and 12.4 million tons for hydrogen (in the case of 141.86 MJ/kg).

Table 7-24 Power Source Composition in 2060 (Power Grid in Java-Bali, Low-case)

	GW	%	TWh	%	Remarks
Coal	0	0%	0	0%	
LNG	14	12%	52	10%	with CCS
Hydrogen	40	33%	307	57%	
Geothermal	6	5%	47	9%	
Hydro	6	5%	20	4%	
Solar	31	25%	54	10%	
Wind	15	12%	29	5%	
Biomass	2	1%	2	0%	
Nuclear	4	3%	27	5%	
Storage	4	3%	0	0%	including PSPP
Total	122	100%	540	100%	

(Source: the JICA Survey Team)

In the optimal case above, the operation of each power source composition on the maximum demand days, both in January and August, is as follows:



(Source: the JICA Survey Team)

Figure 7-36 Operation Status of Each Power Source after Optimized Power Source Composition (Power Grid in Java-Bali, Low-case)

7.4.3 Kalimantan System

(1) Demand Forecast

Two cases of demand forecast are shown below.

Table 7-25 Demand Forecast until 2060 (Kalimantan System)

		2021	2025	2030	2035	2040	2045	2050	2055	2060
High	GW	1.8	3.0	4.1	5.5	7.4	9.3	12.8	18.1	23.0
	TWh	11.8	18.8	26.1	35.6	45.1	59.8	82.9	116.9	148.6
Low	GW	1.8	3.0	4.1	5.4	6.6	7.8	9.0	10.2	11.5
	TWh	11.8	18.8	26.1	34.6	42.4	50.3	58.2	66.1	73.9

(Source: the JICA Survey Team)

The demands in the two cases are the same until 2030. But after that, the difference becomes larger year by year and almost doubles in 2060.

(2) Development Plan

According to RUPTL 2021-2030, power source composition in Kalimantan in 2030 is as follows. It contains 55% of coal thermal power, 31% of gas thermal power (including oil thermal power), and 14% of renewable energy.

Table 7-26 Power Source Composition in 2030 (Kalimantan System)

	Capacity (GW)	Ratio
Coal	1.9	55%
Gas (&Oil)	1.1	31%
Geothermal	0.0	0%
Hydro	0.2	4%
Solar	0.2	5%
Wind	0.0	0%
Biomass	0.2	5%
Total	3.5	100%

Development plans from 2031 to 2060 for power sources which do not emit CO_2 are shown below. The capacity of solar power changes depending on the scenario and the demand and supply conditions.

Table 7-27 Power Development Method in 2030-2060 (Kalimantan System)

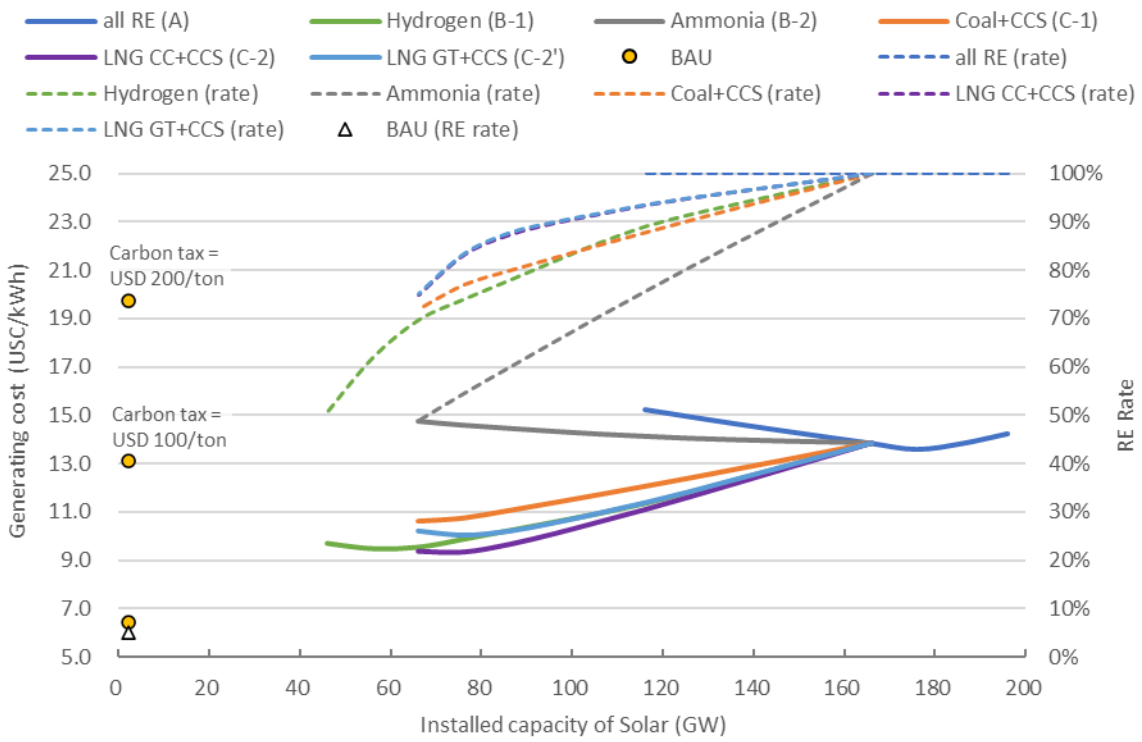
	Installed Capacity in 2030	Installed Capacity in 2060	Power Development Method
Hydro	0.2 GW	0.8 GW	Developing by 20 MW every year
Biomass	0.2 GW	0.8 GW	Developing by 20 MW every year
Solar	0.2 GW	For adjustment	Depending on the demand and supply condition
Wind	0.0 GW	0.3 GW	Developing by 10 MW every year

(Source: the JICA Survey Team)

In accordance with the potential amounts of the various renewable energies shown in Table 7-6, the potential of the Kalimantan system is geothermal power of 0.2 GW, hydropower of 29.7 GW, biomass power of 5.1 GW, and wind power of 2.5 GW. The amount of installed capacity until 2060 is less than the potential.

(3) Study on High-case demand

The results of a study on each scenario are shown below. The potential of solar power in Kalimantan shown in Table 7-6 is 52.7 GW, but the study was conducted on the premise that more solar power can be installed than the potential.



(Source: the JICA Survey Team)

Figure 7-37 Relation between Installed Capacity of Solar Power and Generating Cost (Kalimantan System, All Scenarios, Demand in High-case)

In the BAU scenario, the generating cost is 6.4 USC/kWh, which is the cheapest, but the CO_2 emissions are high, and considering the carbon tax of USD 100/ton, it is higher than the generating cost of hydrogen thermal power or LNG thermal power + CCS.
In addition to the development of renewable energy, LNG thermal power (C/C) + CCS will be the cheapest as a power source composition aiming for carbon neutrality. However, considering the cost of purchasing carbon credits for the uncollectible portion generated in the process of CCS treatment, the generating cost of hydrogen thermal power is almost the same. Specifically, it is desirable that the installed capacity of solar power is about 70 GW, the installed capacity of batteries is about 30 GW, and the total installed capacity of LNG thermal power (C/C) and hydrogen thermal power is about 14 GW.

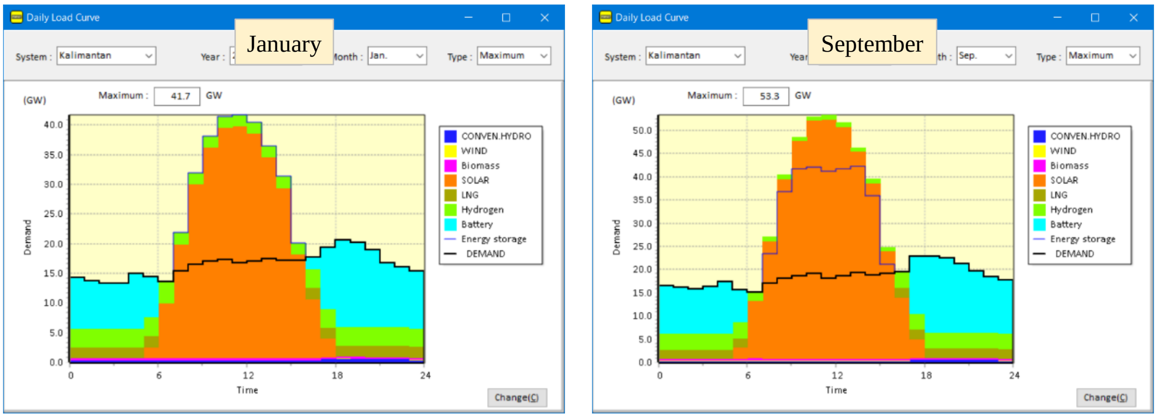
As a result, the optimum power source composition for 2060 with the high-case demand is as below. The generating cost in this composition is USC 9.3/kWh, and the ratio of renewable energy is about 76%. The amount of CO_2 treated by CCS is about 3 Mt per year.

Table 7-28 Optimum Power Source Composition in 2060 (Kalimantan System, Demand in High-case)

	GW	%	TWh	%	Remarks
Coal	0.0	0%	0	0%	
LNG	7.0	6%	10	5%	with CCS
Hydrogen	7.0	6%	26	12%	
Geothermal	0.0	0%	0	0%	
Hydro	0.8	1%	3	2%	
Solar	70.1	60%	123	57%	
Wind	0.3	0%	1	0%	
Biomass	0.8	1%	3	1%	
Storage	30.0	26%	49	23%	
Total	115.9	100%	215	100%	

(Source: the JICA Survey Team)

The operating conditions of various power sources on the maximum demand days in January and September in the optimum power source composition shown above are shown below.

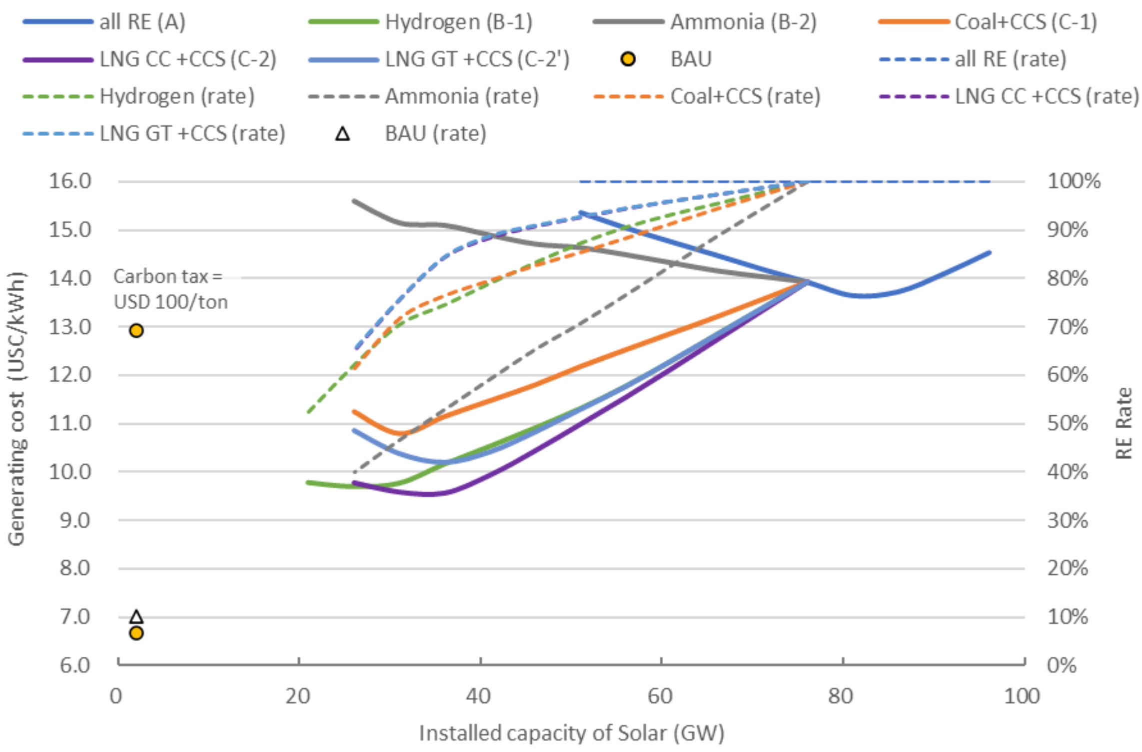


(Source: the JICA Survey Team)

Figure 7-38 Operating Conditions of Various Power Sources in the Optimum Power Source Composition (Kalimantan System, Demand in High-case)

(4) Study on Low-case demand

The results of a study on each scenario are shown below. The potential of solar power in Kalimantan shown in Table 7-6 is 52.7 GW, but the study was conducted on the premise that solar power can be installed to more than the potential.



(Source: the JICA Survey Team)

Figure 7-39 Relation between Installed Capacity of Solar Power and Generating Cost (Kalimantan System, All Scenarios, Demand in Low-case)

In the BAU scenario, the generating cost is 6.7 USC/kWh, which is the cheapest, but the CO_2 emissions are high, and considering the carbon tax of USD 100/ton, it is higher than the generating cost of hydrogen thermal power or LNG thermal power + CCS.

In addition to the development of renewable energy, LNG thermal power (C/C) + CCS will be the cheapest as a power source composition aiming for carbon neutrality. However, considering the cost of purchasing carbon credits for the uncollectible portion generated in the process of CCS treatment, the generating cost of hydrogen thermal power is almost the same. Specifically, it is desirable that the installed capacity of solar power is about 30 GW, the installed capacity of batteries is about 12 GW, and the total installed capacity of LNG thermal power (C/C) and hydrogen thermal power is about 7 GW.

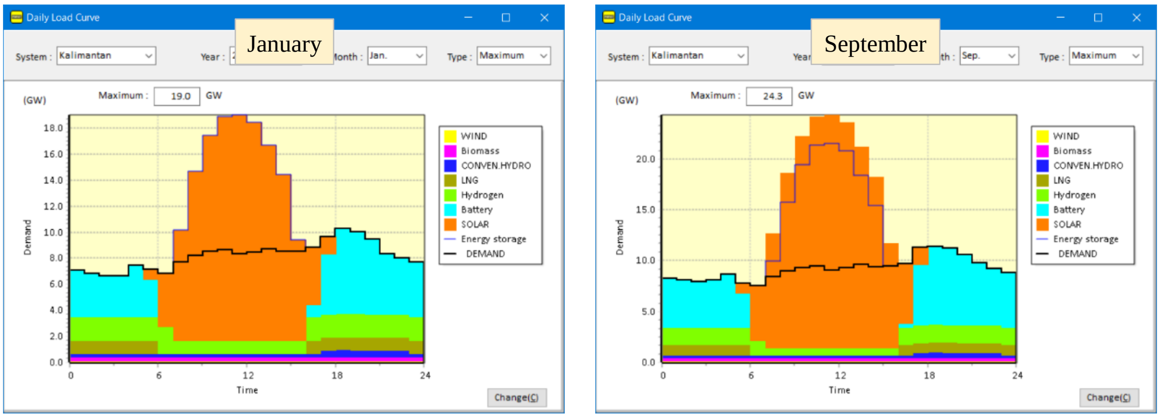
As a result, the optimum power source composition for 2060 with the Low-case demand is as below. The generating cost in this composition is USC 9.6/kWh, and the ratio of renewable energy is about 74%. The amount of CO_2 treated by CCS is about 2 Mt per year.

Table 7-29 Optimum Power Source Composition in 2060 (Kalimantan System, Demand in Low-case)

	GW	%	TWh	%	Remarks
Coal	0.0	0%	0	0%	
LNG	3.5	7%	6	5%	with CCS
Hydrogen	3.6	7%	14	13%	
Geothermal	0.0	0%	0	0%	
Hydro	0.8	1%	3	3%	
Solar	31.1	58%	55	53%	
Wind	0.3	1%	1	1%	
Biomass	0.8	1%	3	3%	
Storage	13.1	25%	22	21%	
Total	53.1	100%	102	100%	

(Source: the JICA Survey Team)

The operating conditions of various power sources on the maximum demand days in January and September in the optimum power source composition described above are shown below.



(Source: the JICA Survey Team)

Figure 7-40 Operating Conditions of Various Power Sources in the Optimum Power Source Composition (Kalimantan System, Demand in Low-case)

(5) Conclusion

For both High-case and Low-case demand, hydrogen thermal power or LNG thermal power (C/C) + CCS will be the cheapest as a power source composition aiming for carbon neutrality, in addition to the development of renewable energy. It is desirable to aim for a renewable energy ratio of about 75% in both demand cases.

The optimum amount of solar power development is about 30 GW with the Low-case demand and about 70 GW with the High-case demand. The potential of solar power in Kalimantan shown in Table 7-6 is 52.7 GW, which is higher than the development amount with the Low-case demand, but is less than the development amount with the High-case demand. In order to install 70 GW of solar power, a site area of about 0.2% of Kalimantan's total land area will be required.

The annual CCS treatment amount is 2 Mt with the Low-case demand and 3 Mt with the High-case demand.

7.4.4 Sulawesi System

(1) Demand Forecast

The two demand forecasts estimated in this survey are shown in the table below:

Table 7-30 Demand Forecast until 2060 (Power Grid in Sulawesi)

		2021	2025	2030	2035	2040	2045	2050	2055	2060
High	GW	2.1	2.9	3.6	4.6	5.7	7.3	9.9	13.8	17.3
	TWh	13.5	18.6	23.6	30.0	36.6	47.2	64.1	89.0	111.8
Low	GW	2.1	2.9	3.6	4.5	5.3	6.2	7.0	7.8	8.6
	TWh	13.5	18.6	23.6	29.1	34.4	39.7	45.0	50.3	55.6

(Source: the JICA Survey Team)

Until 2030, the results of both high-case and low-case are identical. However, after that, the gap between them will become bigger year by year and eventually double in 2060.

(2) Development Plan

The composition of power sources in the Sulawesi power grid in 2030 according to RUPTL 2021-2030 is shown below. Per the table, the composition contains 26% of coal-fired thermal power, 26% of gas thermal power (including oil thermal power), and 48% of renewable energy. Hydropower, which is 34%, is the major power generating resource.

Table 7-31 Composition of Power Sources in Sulawesi Power Grid in 2030

	Capacity (GW)	Ratio
Coal	1.7	26%
Gas (&Oil)	1.7	26%
Geothermal	0.2	3%
Hydro	2.1	34%
Solar	0.4	7%
Wind	0.3	4%
Biomass	0.1	1%
Total	6.4	100%

The development plan for renewable energy from 2031 to 2060 is estimated in the table below. The plan for solar will depend on the scenario and the status of supply and demand.

Table 7-32 Development Method of Power Grid in Sulawesi until 2060

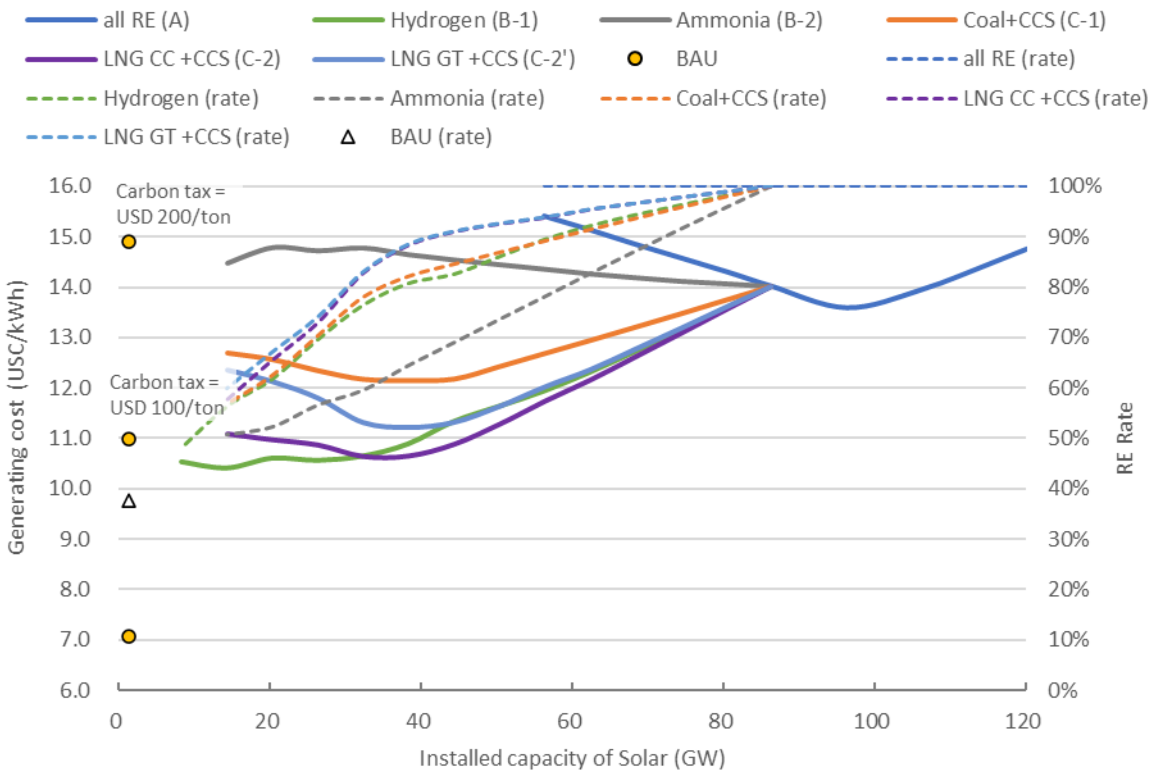
	Installed Capacity in 2030	Installed Capacity in 2060	Development Method
Hydro	2.1 GW	6.2 GW	Developing by 130MW every year
Geothermal	0.2 GW	0.8 GW	Developing by 20MW every year
Biomass	0.1 GW	0.7 GW	Developing by 20MW every year
Solar	0.4 GW	For adjustment	Depending on the supply and demand
Wind	0.3 GW	1.8 GW	Developing by 50MW every year

(Source: the JICA Survey Team)

Based on the renewable energy potential described in Table 7-6, the potential amounts for geothermal, hydro, biomass, and wind in Sulawesi are 3.2GW, 12.0GW, 1.9GW, and 8.4GW respectively. These are also within each potential amount in 2060.

(3) High-case Estimation

The following table describes a summary of the estimations for each scenario. Even though the potential of solar power in Sulawesi is 22.7GW, as mentioned in Table 7-6, the estimation was carried out on the premise that the capacity of solar power can exceed the potential.



(Source: the JICA Survey Team)

Figure 7-41 Relation between Solar Capacity and Cost (Power Grid in Sulawesi, All Scenario, High-case)

Within the BAU scenario, the generating cost is 7.1 USC/kWh, which is the most economical. However, taking into consideration the USD 100/ton carbon taxes, it is a little higher than hydrogen-fired or LNG-fired power + CCS.

As a power resource composition for achieving decarbonization, hydrogen-fired power with renewable energy is the most economical. Specifically, around 15GW of solar power, 5GW of batteries, and 12GW of hydrogen-fired power is desirable.

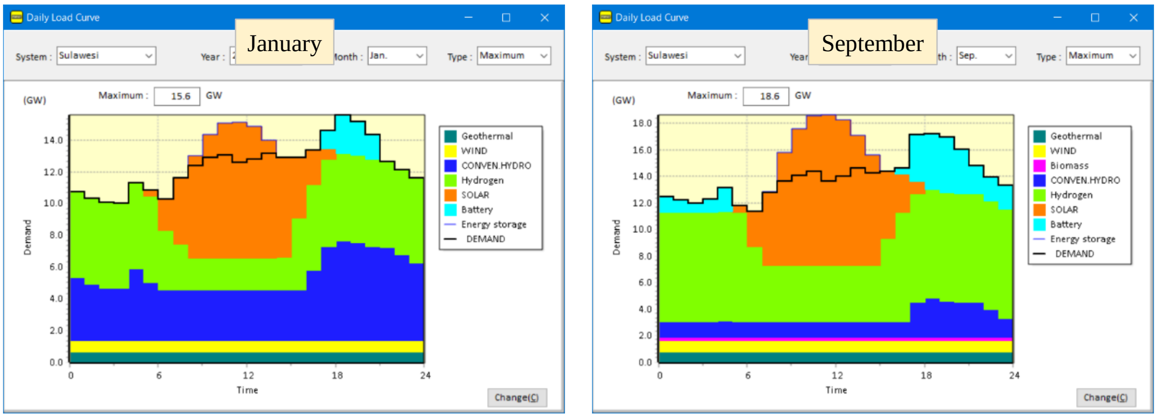
As a consequence, the optimal power resource composition in the High-case in 2060 is as follows. The generating cost in this case is USC 10.0/kWh and the rate of renewable energy is approximately 58%.

Table 7-33 Optimal Power Resource Composition in 2060 (Power Grid in Sulawesi, High-case)

	GW	%	TWh	%	Remarks
Coal	0.0	0%	0	0%	
LNG	0.0	0%	0	0%	
Hydrogen	12.1	28%	47	40%	
Geothermal	0.8	2%	6	5%	
Hydro	6.2	14%	27	23%	
Solar	15.4	35%	27	23%	
Wind	3.3	7%	6	5%	
Biomass	0.7	1%	0	0%	
Storage	5.0	11%	5	4%	
Total	43.5	100%	119	100%	

(Source: the JICA Survey Team)

In the optimal case above, the operation of each power source composition on the maximum demand days, both in January and August, is as follows:

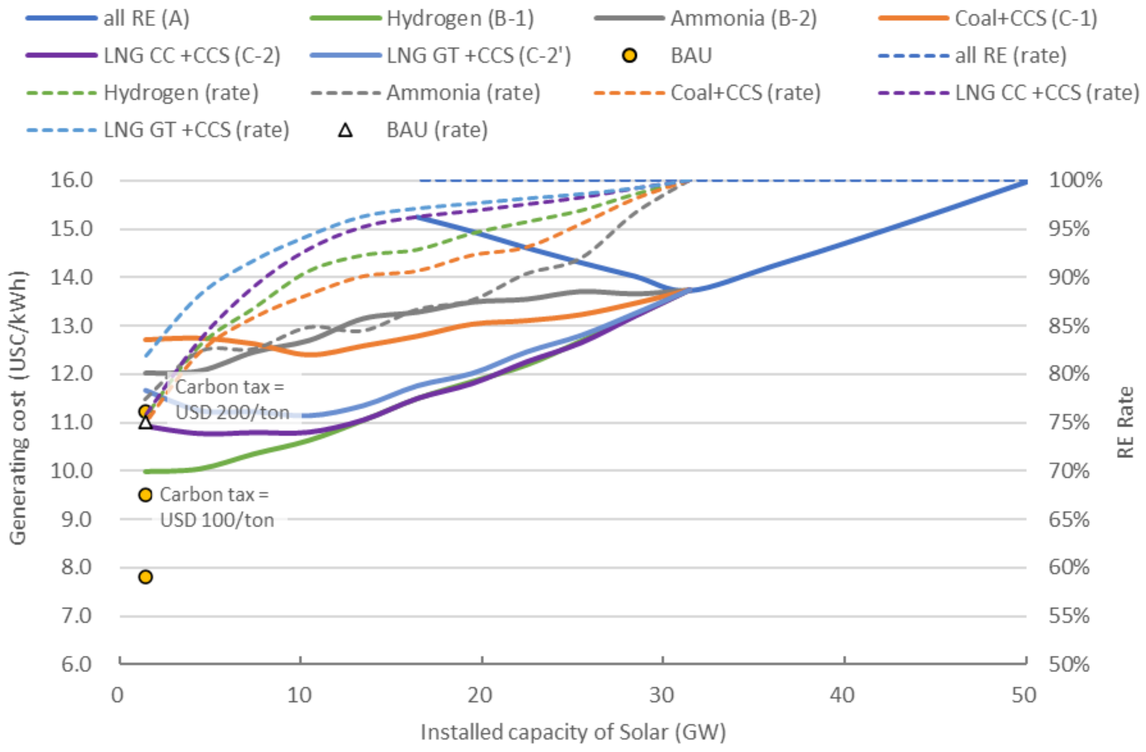


(Source: the JICA Survey Team)

Figure 7-42 Operation Status of Each Power Source after Optimized Power Source Composition (Power Grid in Sulawesi, High-case)

(4) Low-case Estimation

The following table shows a summary of the estimations in each scenario. Even though the potential of solar power in Sulawesi is 22.7GW, as mentioned in Table 7-6, the estimation was carried out on the premise that the solar power capacity can exceed the potential.



(Source: the JICA Survey Team)

Figure 7-43 Relation between Solar Power and Generating Cost (Power Grid in Sulawesi, All Scenarios, High-case)

The generating cost is the most economical in the BAU scenario, at 7.8 USC/kWh. The rate of hydropower in the Sulawesi power grid is high and the composition rate of renewable energy in the BAU scenario is 75%. Taking into consideration the USD 200/ton carbon taxes for the amount of carbon dioxide emission, it is higher than hydrogen-fired power or LNG-fired power + CCS.
As a power source composition for achieving decarbonization, hydrogen-fired power with the development of renewable energy is the most economical. Specifically, around 2GW of solar capacity, no batteries, and 7GW of hydrogen-fired power is desirable.

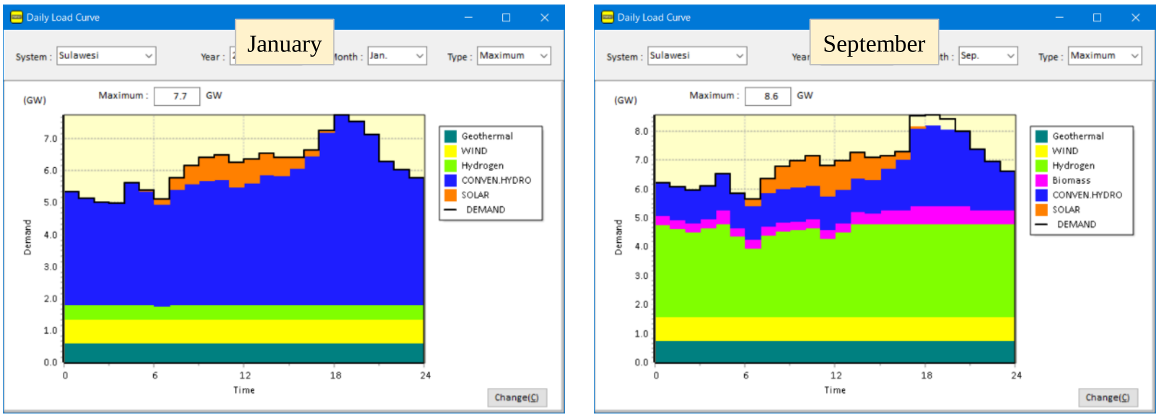
As a consequence, the optimal power resource composition in the low-case in 2060 is as follows. The generating cost in this composition is USC 10.0/kWh and the rate of renewable energy is around 76%.

Table 7-34 Optimal Power Resource Composition in 2060 (Power Grid in Sulawesi, Low-case)

	GW	%	TWh	%	Remarks
Coal	0.0	0%	0	0%	
LNG	0.0	0%	0	0%	
Hydrogen	3.3	21%	14	24%	
Geothermal	0.8	5%	6	11%	
Hydro	6.2	40%	27	48%	
Solar	1.4	9%	3	5%	
Wind	3.3	21%	6	11%	
Biomass	0.7	4%	0	1%	
Storage	0.0	0%	0	0%	
Total	15.7	100%	56	100%	

(Source: the JICA Survey Team)

In the optimal case above, the operation of each power source composition on the maximum demand days both in January and august is as follows:



(Source: the JICA Survey Team)

Figure 7-44 Operation Status of Each Power Source after Optimized Power Source Composition (Power Grid in Sulawesi, Low-case)

(5) Summary

In both high and low cases, as a power resource composition for achieving decarbonization, hydrogen-fired power with the development of renewable energy is the most economical. It is desirable to reach a rate of approximately 75% renewable energy.

The optimal capacity of solar power should be 2GW in the low-case and 15GW in the high-case. The potential of solar power in Sulawesi described in Table 7-6 is 22.7GW, which is within the potential in both cases.

7.4.5 Optimal Power Resource Composition in 2060

A summary of optimal power resource composition for decarbonization in 2060, for each power grid, is as follows:

Table 7-35 Optimal Power Resource Composition for Each Power Grid in 2060

Demand		Sumatra	Java-Bali	Kalimantan	Sulawesi
High	Demand	56.6GW	152.7GW	23.0GW	17.3GW
	Development capacity (2031-2060)	Solar: 120GW BESS: 35GW Hydrogen: 18GW LNG: 18GW	Solar: 31GW BESS: 0GW Hydrogen: 100GW LNG: 29GW	Solar: 70GW BESS: 30GW Hydrogen: 7GW LNG: 7GW	Solar: 15GW BESS: 5GW Hydrogen: 12GW LNG: 0GW
	Generating cost	USC 9.4/kWh	USC 9.5/kWh	USC 9.3/kWh	USC 10.0/kWh
	RE rate	69%	16%	76%	58%
	CCS	11 Mt	35 Mt	3 Mt	0 Mt
Low	Demand	28.2GW	76.0GW	11.5GW	8.6GW
	Development capacity (2031-2060)	Solar: 10GW BESS: 0GW Hydrogen: 17GW LNG: 0GW	Solar: 31GW BESS: 0GW Hydrogen: 40GW LNG: 14GW	Solar: 30GW BESS: 12GW Hydrogen: 4GW LNG: 4GW	Solar: 2GW BESS: 0GW Hydrogen: 7GW LNG: 0GW
	Generating cost	USC 8.9/kWh	USC 9.1/kWh	USC 9.6/kWh	USC 10.0/kWh
	RE rate	52%	34%	74%	76%
	CCS	0 Mt	15 Mt	2 Mt	0 Mt

(Source: the JICA Survey Team)

The demand in the high-case is almost double that of the low-case. The optimal power resource composition in 2060 is considered within this estimation between the high-case and low-case.
Since the potential for renewable energy differs in each power grid, there is a big difference between the grids. Specifically, the dependency rate of renewable energy is very low in Java-Bali because the potential of solar power is limited compared with its electrical demand.
In the newly-developed power, except for solar and relevant battery facilities, hydrogen-fired power is necessary in every grid. LNG-fired power + CCS, which has almost the same economic level, is also necessary taking into consideration the capacity of CCS treatment. However, even if hydrogen-fired power will be needed in 2060, dedicated hydrogen-fired power is still at the development stage. So, LNG-fired power is developed at first and fuel conversion from LNG-fired to hydrogen-fired power is assumed once dedicated hydrogen-fired power is developed.

7.5 Long-term Power Development Plan (2031-2060)

A long-term power development plan from 2031 to 2060 will be formulated with the aim of realizing the optimal scenario extracted via the long-term power development plan (2060).
For the High-case demand in the Java-Bali system, 3 cases (Fast-speed case, Medium-speed case, and Slow-speed case) were set according to the speed toward the realization of the target value, and a comparative evaluation was carried out. The time when decarbonization technology can be introduced in each case is shown below.

Table 7-36 Timing of Introduction for Decarbonization Technology

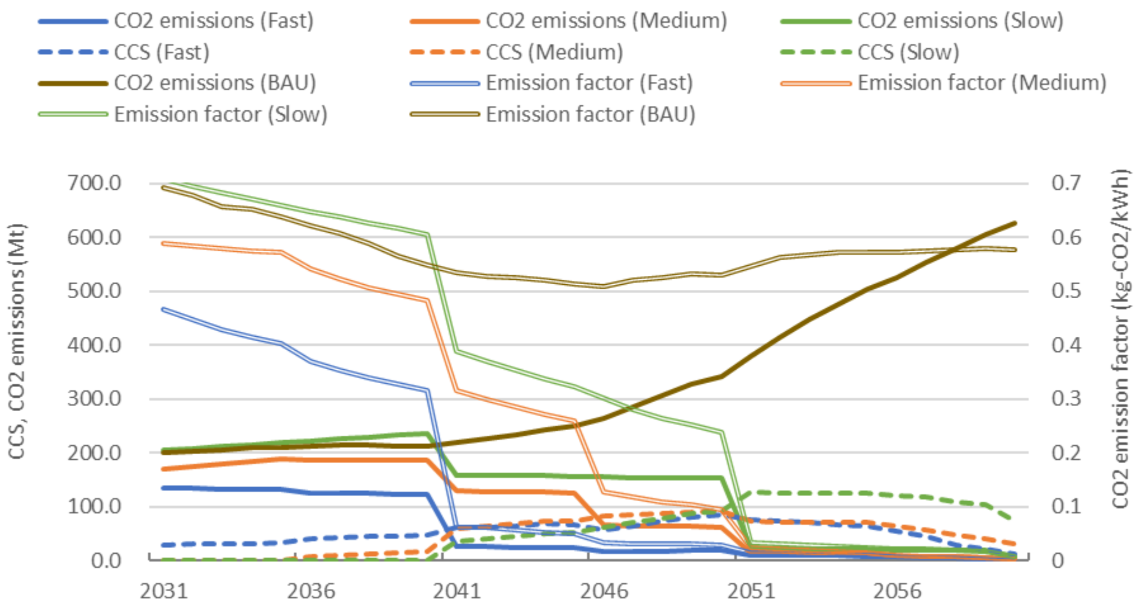
	Fast-speed case (Fast: F)	Medium-speed case (Medium: M)	Slow-speed case (Slow: S)
Abolition of coal thermal power	Abolished by 2050	Abolished by 2055	Extend life as much as possible
	However, the zero emission achievement plant (ammonia exclusive combustion, CCS) will continue to operate until the end of the operable period.		
CCS	Conducted from 2031	Conducted from 2036	Conducted from 2041
Ammonia mixed combustion (20%)	Conducted from 2031	Conducted from 2031	Conducted from 2041
Ammonia-only thermal power	Conducted from 2041	Conducted from 2046	Conducted from 2051
Biomass mixed combustion (20%)	Conducted from 2031	Conducted from 2031	Conducted from 2031
Hydrogen mixed combustion (20%)	Conducted from 2036	Conducted from 2036	Conducted from 2041
Hydrogen-only thermal power	Conducted from 2041	Conducted from 2046	Conducted from 2051
Development of renewable energy	Developed intensively in the previous years	Developed to a certain amount every year	Developed intensively in later years

(Source: JICA Survey Team)

In addition to the three cases shown above, the BAU scenario was also studied for comparison.

(1) CO_2 Emissions

The changes in CO_2 emissions in the four cases (including the BAU scenario) are shown below.



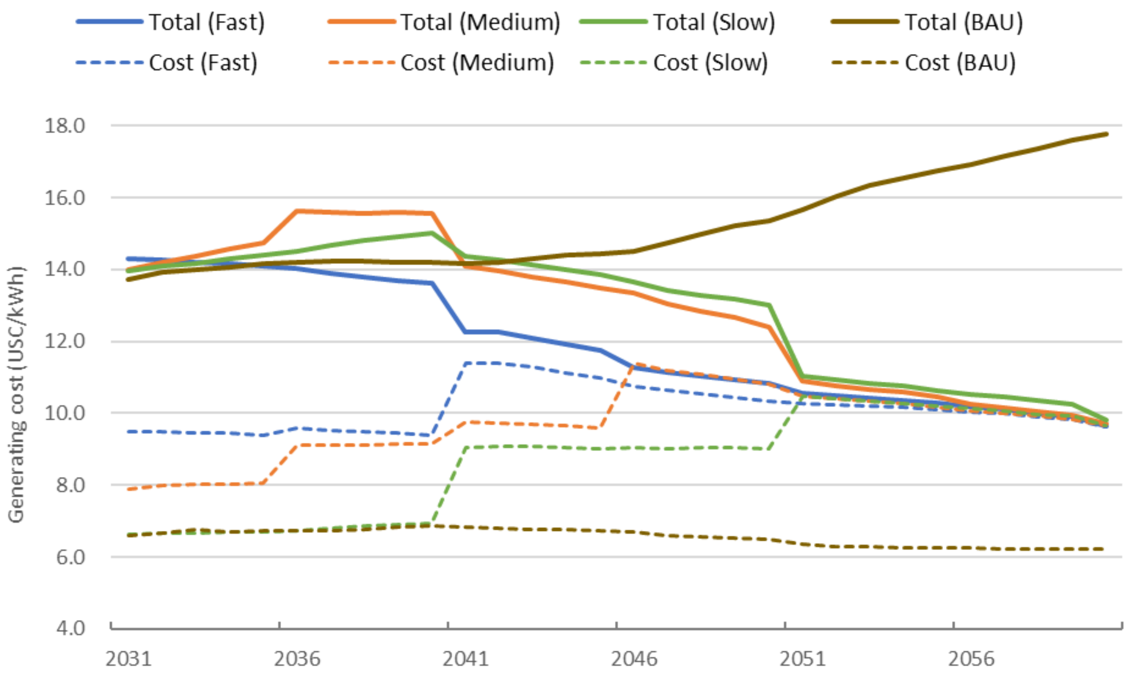
(Source: JICA Survey Team)

Figure 7-45 Changes in CO_2 Emissions

In the BAU scenario, CO_2 emissions will gradually increase, reaching 600 Mt per year in 2060. The emission factor will not change significantly from 2030 and will remain at 0.5-0.6 kg-CO_2/kWh.
In the Fast-speed case, the old coal thermal power plants will be abolished in 2031 and CCS will be conducted, so the CO_2 emissions will be about 70% of the BAU scenario, and the emission factor will gradually decrease. Furthermore, from 2041, CO_2 emissions will significantly decrease because hydrogen-only thermal power will be introduced and existing coal thermal power will be converted to ammonia-only thermal power to carry out ammonia-only firing. Initially, the CCS treatment amount will be about 30 Mt per year, but it will gradually increase to about 90 Mt per year around 2050.
In the Slow-speed case, the introduction of ammonia-only thermal power and hydrogen-only thermal power will start in 2051, and LNG thermal power + CCS will be introduced in large quantities by 2050 as an alternative, so the CCS treatment amount will increase and exceed 100 Mt per year after 2051. After 2051, it is possible to reduce the CCS treatment amount by sequentially converting LNG thermal power with CCS to hydrogen thermal power. However, if fuel conversion is carried out early, CCS will be unnecessary in a situation whereby many unamortized assets remain in the CCS, and there is a concern that economic efficiency will deteriorate.

(2) Generating Costs

The changes in generating costs for the four cases are shown below.



(Source: JICA Survey Team)

Figure 7-46 Changes in Generating Costs

The total costs consider the carbon costs for CO_2 emissions. Carbon costs are calculated under the assumption that the penalty for CO_2 emissions will increase in later years (USD 100/t in 2030, USD 200/t in 2060, and a straight line approximation between them).

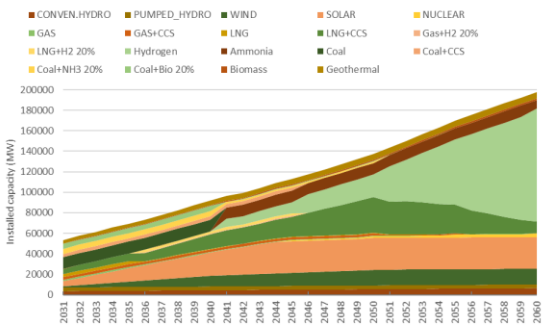
If carbon costs are not taken into account, the BAU scenario will be the cheapest, at USC 6-7/kWh, but considering carbon costs, it will rise to around USC 18/kWh in 2060. If the carbon costs are not taken into account, the Slow-speed case will be the cheapest, but if the carbon costs are taken into account, the Fast-speed case will be the cheapest. After 2051, CO_2 emissions will be very low in all cases, so the generating costs will be about the same.

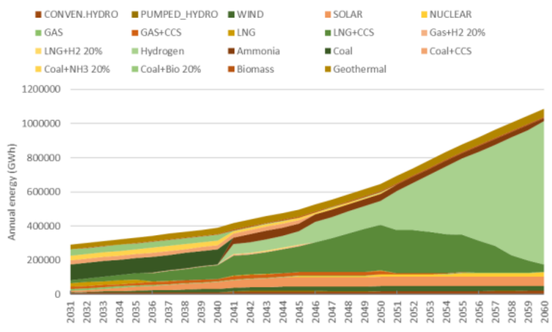
(3) Power Source Composition

The changes in power source composition for the four cases are shown below.

Installed capacity | Annual energy production

F





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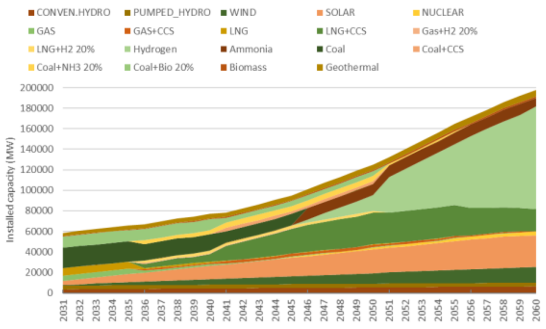

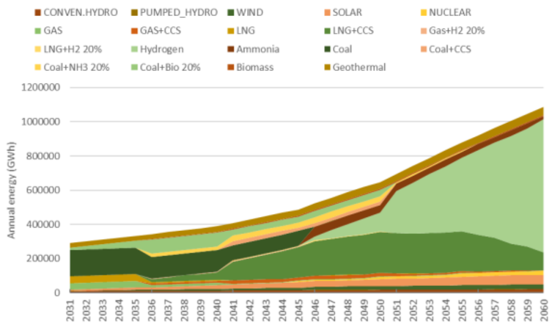

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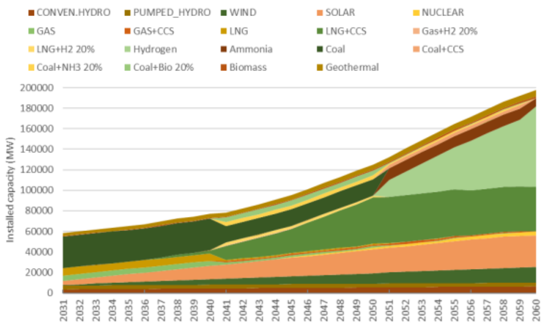

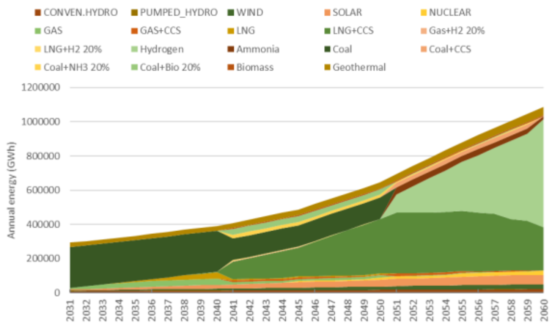

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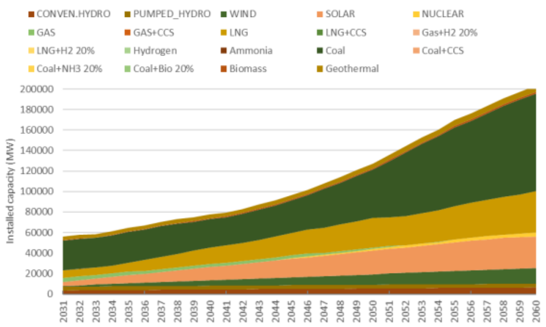
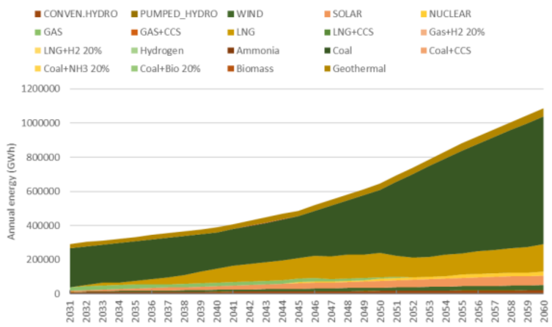




(Source: JICA Survey Team)

Figure 7-47 Changes in Power Source Composition

In the BAU scenario, coal thermal power and LNG thermal power will be the main power sources, while in the decarbonization scenarios, hydrogen-only thermal power will be the main power source. However, in the Slow-speed case, the introduction time for hydrogen-only thermal power and ammonia-only thermal power will be 2051, so a lot of coal thermal power will remain until 2050.

Hydrogen thermal power will account for a large proportion in all decarbonization scenarios after 2051. Considering the current situation where domestic gas is being depleted, it is assumed that it will become increasingly difficult to produce hydrogen domestically, and a large amount of hydrogen generation will have to rely on imports. From the viewpoint of fuel security, excessive reliance on one fuel may cause an extreme power shortage when the supply of that fuel is interrupted. Therefore, it is necessary to diversify the importing countries and consider the introduction of other fuels, even if the costs are slightly higher. In particular, for ammonia, the fuel price can be reduced to the same level as hydrogen, so depending on the progress of technological developments for burning ammonia with GT, it is desirable to position ammonia, hydrogen and LNG (with CCS) as the three main fuels and to compose a portfolio with an appropriate ratio.

7.6 Institutional Reforms, System Confirmations and Proposals for Realizing Electric Power Systems that achieve both Carbon Neutrality and System Stability

(1) Review of renewable energy potential

In this survey, the numerical values described in RUPTL (values based on the National Energy General Plan (RUEN), 2017) were used as the potential amounts for renewable energy. According to this, the potential of solar power in Indonesia is 208 GW, but in discussions with MEMR, it has been reported that there is a potential of 3,200 GW or more.

The potential of solar power is a very important factor in achieving carbon neutrality, and the fact that the information deviates so much has a great influence on the optimum power source composition obtained as a result. In these potential assumptions, the difference in assumption conditions is considered to be a major difference factor, but if the policy is to actively develop renewable energy to achieve carbon neutrality in the future, a detailed potential survey should be conducted under that policy. Specifically, it is necessary to carry out not only a rough desk study using satellite images, but also a confirmation study via a field survey using local consultants.

In terms of the potential of hydropower, in this survey, hydropower in all systems will be developed within the potential. Specifically, we plan to develop about 100 MW every year from 2031 in each system, but since detailed surveys of individual points are required for hydropower development, there is concern that development will not proceed if the survey accuracy is low. For this reason, it is necessary to review existing potential points, re-evaluate development priorities after considering environmental measures, and if necessary, review plans for more economically superior points.

(2) Formulation of LNG Master Plan

One of this study’s conclusions recognized that LNG-fired power plants (including the implementation of CCS) are necessary as part of the power supply mix in 2060 and as a bridge until the goal of carbon neutrality in 2060. LNG has already been introduced in Indonesia, but in addition to the FSRU, which is the main receiving terminal that has been developed so far, it is necessary to consider the introduction of an onshore LNG receiving terminal with excellent scalability and the construction of peripheral infrastructure such as pipelines. Among these facilities, port and storage facilities are very expensive, and it may be more economical to build them as shared facilities rather than for each power plant to build them individually.

Considering these points, when introducing LNG in Indonesia, it is important to formulate a master plan for the development of LNG receiving terminals (importing port facilities and storage facilities) and pipelines, and to proceed with the construction of facilities in accordance with the master plan. Specifically, the following studies will be conducted.

- Selection of candidate sites for LNG receiving terminals (considering the location of existing thermal power plants and future power plant locations)
- Size of LNG receiving terminals (number of berths, capacity and number of storage facilities and vaporizers, etc.)
- Pipeline network concept
- Consideration of utilization for purposes other than power generation

(3) Research and Development for Practical Use of Ammonia GT

The results of this study conclude that ammonia-fueled USC thermal power is not economical because the generating costs are higher than those of other thermal power sources. However, ammonia is expected to be cheaper than hydrogen in the future, and when considered as an imported fuel, it is assumed that hydrogen fuel will also be transported in the form of ammonia due to its ease of transportation. In other words, the imported fuel will first be imported as ammonia, then converted from ammonia to hydrogen in Indonesia, and supplied as fuel for hydrogen thermal power. Therefore, if ammonia can be burned directly in GT, it has the potential to be even more economical than burning hydrogen.

At this stage, the technology for direct combustion of ammonia in GT is immature, but it is necessary to support its technological development for practical use in consideration of future possibilities.

(4) Formulation of Plan based on Restrictions on CCS Treatment Amount

In this survey, the study was carried out with a limit on the CCS treatment amount. The plan does not exceed the set limit in 2060, but if the introduction of zero-emission thermal power that does not require CCS, such as hydrogen-only thermal power and ammonia-only thermal power, is delayed in the process from 2031 to 2060, the CCS treatment amount will increase, and there is a possibility of it exceeding the set limit, so it is necessary to increase the potential CCS treatment amount in the future.

To reduce the CCS treatment amount, it is necessary to proceed with technological development so that zero-emission thermal power that does not require CCS, such as hydrogen-only thermal power and ammonia-only thermal power, can be introduced at an early stage.

(5) Study on Detailed Long-term Vision

In conducting this survey, when matching the study conditions with PLN regarding the demand forecast up to 2060, there was a request from PLN to carry out a demand forecast analysis based on numerical grounds, such as assumptions for economic indicators, because PLN has been asked for a clear numerical basis for an external explanation. PLN understands that it is difficult to deal with demand forecasting based on economic indicator assumptions, etc. in this survey because they are not included in the scope of business, and two demand cases (the High-case currently forecasted by PLN and the Low-case forecasted via linear approximation based on RUPTL's demand forecast) are studied. In addition to the fact that this survey is not based on a formal request from the Indonesian government, the survey implementation period is very short (about 3 months) so the survey is being conducted under conditions whereby it is difficult to obtain the necessary detailed data. It is undeniable that the survey is a rough study based on large assumptions in the details because it is being conducted based on public information on websites, etc. For this reason, it is desirable to study a detailed long-term vision, including the following areas, after thoroughly discussing the needs with the Indonesian side.

- Study on demand forecast (forecasting based on economic indicators and accumulation of major power-using equipment, etc.)
- Study on changes in demand shape based on the introduction trends of EV and rooftop solar
- Study on detailed power source composition based on hourly changes in demand in each system (peak load time, midnight rate, daily load factor, etc.)
- Formulation of a long-term power development plan, with a fuel conversion plan (including co-firing) and abolition plan that takes into account the start-of-operation years of existing power plants
- Study on power source composition using the appropriate potential of solar power, and detailed study on the effects of interconnection between each system based on it

Chapter 8. Power System Expansion Plan

8.1 Transmission Expansion Plan for each System

8.1.1 Sumatra System

Inter-province power flow conditions corresponding to the optimal power generation in 2060 and the necessary transmission equipment expansion plans were confirmed.

(1) Demand Forecast in Sumatra System

Demand in 2060 in each province in the Sumatra System, corresponding to Table 7-1 and Table 7-2, was assumed to be the same proportion as for the year 2030 in RUPTL 2021-2030.

Table 8-1 Demand in 2060 in each province in Sumatra System

PROVINCE	Proportion	Demand in2060	
		High	Low
Ache	7%	4,019	1,999
North Sumatra	26%	14,959	7,441
Riau	14%	7,679	3,820
Riau Islands	2%	1,371	682
Bangka Belitung Islands	3%	1,738	865
WEST SUMATRA	10%	5,788	2,879
Jambi	5%	3,069	1,527
South Sumatra	12%	6,698	3,332
Bengkulu	3%	1,707	849
Lampung	17%	9,610	4,780
Subtotal	100%	56,636	28,173

(JICA Survey Team)

(2) Generation Plan for Sumatra System

Generation plans to meet the demand (high demand and low demand) of the Sumatra grid in 2060 are assumed as noted below on the basis of Figure 7-27 and Figure 7-29.
Since the peak time for the Sumatra system is in the evening, there is almost no solar power generation then and battery systems supply a lot of power.

Table 8-2 Operational Generation Conditions in 2060 for Each Province in Sumatra System (High Demand)

	Capacity (GW)	Output (GW)	Aceh	North Sumatra	Riau	Riau Islands	Bangka Belitung	West Sumatra	Jambi	South Sumatra	Bengkul	Lampung
Hydro	6.6	5.3	0.5 (10%)	1.3 (25%)	0.5 (9%)	0.0 (0%)	0.0 (0%)	0.6 (12%)	0.7 (13%)	0.5 (10%)	0.6 (11%)	0.5 (10%)
Geothermal	4.9	3.9	0.1 (2%)	1.2 (30%)	0.0 (0%)	0.0 (0%)	0.0 (0%)	0.4 (9%)	0.2 (5%)	0.7 (19%)	0.5 (13%)	0.9 (22%)
Biomass	1.6	1.3	0.3 (21%)	0.2 (13%)	0.1 (8%)	0.1 (5%)	0.5 (39%)	0.0 (2%)	0.0 (3%)	0.0 (2%)	0.0 (4%)	0.0 (2%)
Wind	3.1	0.0	0	0	0	0	0	0	0	0	0	0
Battery, PS		26.0	3.1 (12%)	4.4 (15%)	4.6 (18%)	0.4 (2%)	0.9 (3%)	2.2 (9%)	2.7 (10%)	4.9 (19%)	1.1 (4%)	1.8 (7%)
LNG, Hydrogen		20.1	1.7 (9%)	4.6 (23%)	1.9 (9%)	0.2 (1%)	0.5 (2%)	0.7 (3%)	2.7 (14%)	6.8 (34%)	0.1 (0%)	0.9 (4%)
Total		56.6	5.7	11.7	7.1	0.7	1.8	3.9	6.3	13.0	2.2	4.2

(JICA Survey Team)

Table 8-3 Operational Generation Conditions in 2060 for Each Province in Sumatra System (Low Demand)

	Capacity (GW)	Output (GW)	Aceh	North Sumatra	Riau	Riau Islands	Bangka Belitung	West Sumatra	Jambi	South Sumatra	Bengkul	Lampung
Hydro	6.6	5.3	0.5 (10%)	1.3 (25%)	0.5 (9%)	0.0 (0%)	0.0 (0%)	0.6 (12%)	0.7 (13%)	0.5 (10%)	0.6 (11%)	0.5 (10%)
Geothermal	4.9	3.9	0.1 (2%)	1.2 (30%)	0.0 (0%)	0.0 (0%)	0.0 (0%)	0.4 (9%)	0.2 (5%)	0.7 (19%)	0.5 (13%)	0.9 (22%)
Biomass	1.6	1.3	0.3 (21%)	0.2 (13%)	0.1 (8%)	0.1 (5%)	0.5 (39%)	0.0 (2%)	0.0 (3%)	0.0 (2%)	0.0 (4%)	0.0 (2%)
Wind	3.1	0.5	0.3 (50%)	0.3 (50%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)
P. Hydro		1.0	0.1 (12%)	0.6 (15%)	0.1 (18%)	0.0 (2%)	0.0 (3%)	0.0 (9%)	0.1 (10%)	0.1 (19%)	0.0 (4%)	0.0 (7%)
LNG, Hydrogen		16.2	1.4 (9%)	3.7 (23%)	1.5 (9%)	0.2 (1%)	0.4 (2%)	0.5 (3%)	2.2 (14%)	5.5 (34%)	0.0 (0%)	0.7 (4%)
Total		28.2	2.6	7.2	2.2	0.3	0.9	1.6	3.2	6.9	1.2	2.2

(JICA Survey Team)

(3) Transmission Line Capacity

Conductor types and their capacities per circuit for transmission lines between provinces are assumed as follows.

Table 8-4 Transmission Line Conductor Types and Their Capacities per Circuit

Voltage	Conductor Type	Capacity*
500kV	Zebra x 4 bundles	1886 (MW/circuit)
275kV	Zebra x 2 bundles	519 (MW/circuit)
150kV	Hawk x 1 conductor	132 (MW/circuit)

*Product of the typical capacity in MVA and assumed power factor of 0.95

(JICA Survey Team)

Total capacities for inter-province transmission lines of two or more voltage levels were assumed as follows considering N-1 conditions, which means conditions of one transmission line circuit outage.

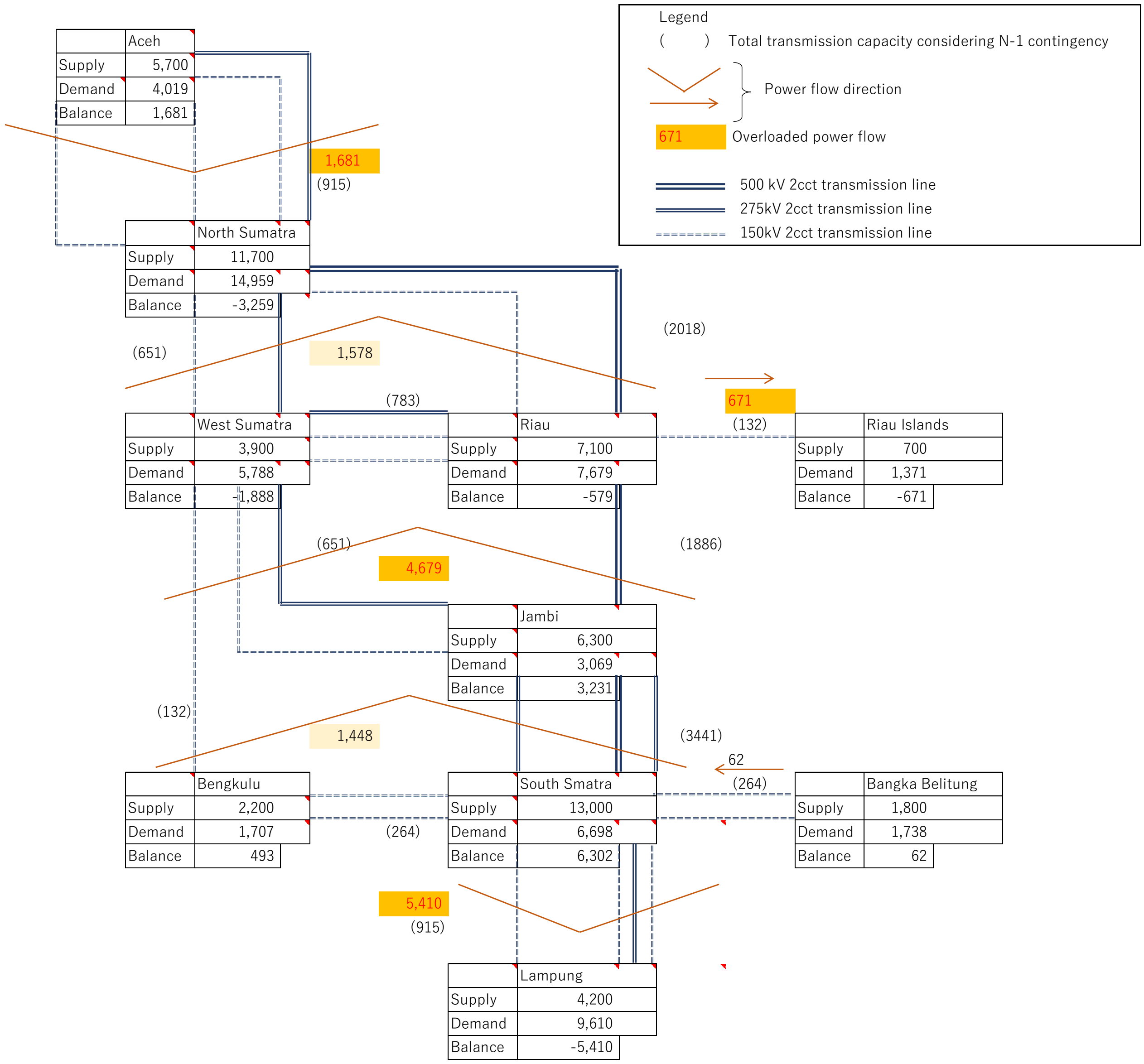
(Total capacity of 500kV transmission lines considering N-1 conditions) + (Total capacity of 275kV transmission lines considering N-1 conditions) + (Total capacity of 150kV transmission lines) / 2

The conceptual difference regarding capacity between 500kV/275kV transmission lines and 150kV transmission lines is that 500kV and 275kV transmission lines have relatively low impedance and the effects of a transmission line outage influence a relatively wide area, but 150kV transmission lines have relatively large impedance and the effects of a transmission line outage remain local.

(4) Power Flow for 2060 in Sumatra System (High Demand)

(a) Power Flow Calculation Results for 2060 in Sumatra System (High Demand)

The figure below shows a power flow diagram for 2060 in the Sumatra System with the said high demand conditions and the operational generation conditions corresponding to the demand.



(JICA Survey Team)

Figure 8-1 Power Flow in 2060 in Sumatra System (High Demand)

Since the power supply amount is large with respect to the demand in Ache province, the power flow from Ache province to North Sumatra province is 1,681 MW, which exceeds the total transmission line capacity of 915 MW.

Besides that, the cases in which power flow exceeds the total capacity of transmission lines are as follows.

- Power flow from Riau province to Riau Islands
- Power flow from Jambi province to the north area
- Power flow from North Sumatra province to Lampung province

(b) Transmission line expansions which are necessary in 2060 (High Demand)

Transmission line expansion plans which are necessary for the said transmission line overloading are listed in the table below.

Table 8-5 Transmission Line Expansion Plans which are Necessary for the Transmission Line Overloading (High Demand)

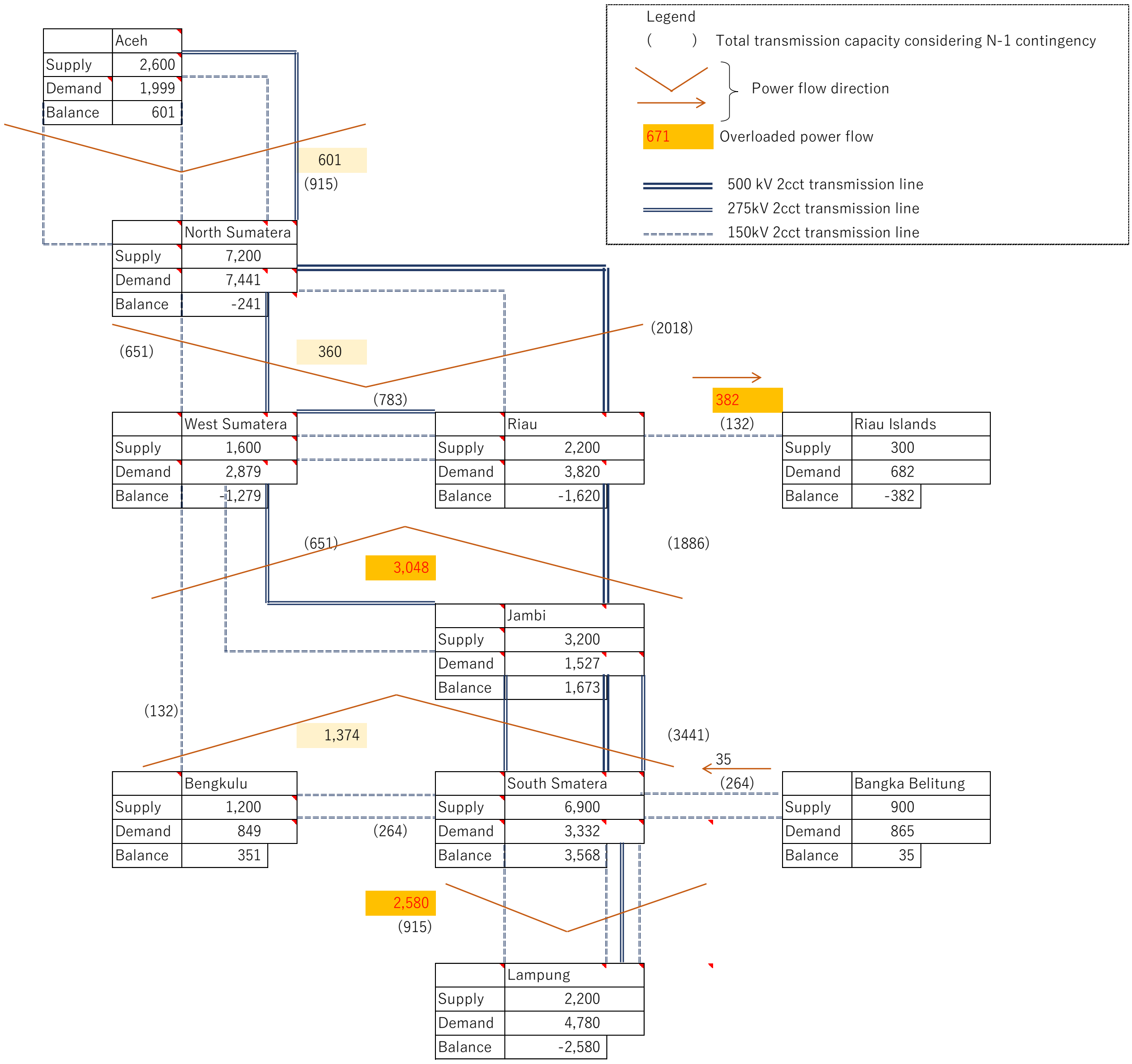
Inter-province Transmission Line	Additional Transmission Lines
Between Ache province and North Sumatra province	275kV Zebra x 2 bundles, 2 circuits
Between Riau province and Riau Islands	275kV Cable x 3, the same capacity as Zebra
Between Riau province and Jambi province	500kV Zebra x 2 bundles, 2 circuits
Between North Sumatra province and Lampung province	500kV Zebra x 2 bundles, 4 circuits

(JICA Survey Team)

(5) Power Flow for 2060 in Sumatra System (Low Demand)

(a) Power Flow Calculation Results for 2060 in Sumatra System (Low Demand)

The figure below shows a power flow diagram for 2060 in the Sumatra System with the said low demand conditions and the operational generation conditions corresponding to the demand.



(JICA Survey Team)

Figure 8-2 Power Flow in 2060 in Sumatra System (Low Demand)

(b) Transmission line expansions which are necessary in 2060 (Low Demand)

Transmission line expansion plans which are necessary for the said transmission line overloading are listed in the table below.

Table 8-6 Transmission Line Expansion Plans which are Necessary for the Transmission Line Overloading (Low Demand)

Inter-province Transmission Line	Additional Transmission Lines
Between Riau province and Riau Islands	275kV Cable x 2, the same capacity as Zebra
Between Riau province and Jambi province	500kV Zebra x 2 bundles, 2 circuits
Between North Sumatra province and Lampung province	500kV Zebra x 2 bundles, 2 circuits

(JICA Survey Team)

8.1.2 Java-Bali System

(1) Demand Forecast in Java-Bali System

Demand in 2060 in each province in the Java-Bali System, corresponding to Table 7-1 and Table 7-2, was assumed to be the same proportion as for the year 2030 in RUPTL 2021-2030. The table below shows demand for each province.

Table 8-7 Demand in 2060 in each province in Java-Bali System

PROVINCE	Proportion	Demand in2060	
		High	Low
DKI Jakarta	18%	27,033	13,447
Banten	12%	17,807	8,858
West Java	28%	42,496	21,140
Central Java and Yogyakarta	18%	26,739	13,301
East Java	21%	32,807	16,320
Bali	4%	5,848	2,909
Subtotal	100%	152,731	75,975

(JICA Survey Team)

(2) Generation Plan for Java-Bali System

Generation plans to meet the demand (high demand and low demand) of the Java-Bali system grid in 2060 are assumed as noted below on the basis of Figure 7-34 and Figure 7-36.

Table 8-8 Operational Generation Conditions in 2060 for Each Province in Java-Bali System (High Demand)

	Capacity (GW)	Output (GW)	DKI Jakarta	Banten	West Java	Central Java and Yogyakarta	East Java	Bali
Hydro	6.0	3.0	0.0 (0%)	0.0 (2%)	2.1 (70%)	0.5 (17%)	0.3 (11%)	0.0 (0%)
Geothermal	6.0	4.8	0.0 (0%)	0.3 (7%)	2.1 (44%)	1.5 (32%)	0.7 (15%)	0.1 (3%)
Biomass	2.0	1.6	0.0 (0%)	0.0 (0%)	1.3 (84%)	0.1 (5%)	0.2 (11%)	0.0 (0%)
Solar	31.0	17.3	0.1 (0%)	1.2 (7%)	4.3 (25%)	5.3 (31%)	5.8 (33%)	0.7 (4%)
Wind	15.0	4.0	0.0 (0%)	3.1 (77%)	0.9 (23%)	0.0 (0%)	0.0 (0%)	0.0 (0%)
Nuclear	4	4.0				4.0		
LNG, Hydrogen	129	114.0	12.8 (11%)	26.3 (23%)	22.6 (20%)	18.2 (16%)	31.6 (28%)	2.5 (2%)
Storage	4	4.0	0.0 (0%)	0.0 (0%)	1.9 (48%)	1.0 (25%)	1.1 (27%)	0.0 (0%)
Total	197.0	152.7	12.8	30.9	35.3	30.6	39.7	3.4

(JICA Survey Team)

Table 8-9 Operational Generation Conditions in 2060 for Each Province in Java-Bali System (Low Demand)

	Capacity (GW)	Output (GW)	DKI Jakarta	Banten	West Java	Central Java and Yogyakarta	East Java	Bali
Hydro	6.0	0.5	0.0 (0%)	0.0 (2%)	0.4 (70%)	0.1 (17%)	0.1 (11%)	0.0 (0%)
Geothermal	6.0	4.8	0.0 (0%)	0.3 (7%)	2.1 (44%)	1.5 (32%)	0.7 (15%)	0.1 (3%)
Biomass	2.0	1.6	0.0 (0%)	0.0 (0%)	1.3 (84%)	0.1 (5%)	0.2 (11%)	0.0 (0%)
Solar	31.0	17.1	0.1 (0%)	1.2 (7%)	4.2 (25%)	5.2 (31%)	5.7 (33%)	0.7 (4%)
Wind	15.0	4.0	0.0 (0%)	3.1 (77%)	0.9 (23%)	0.0 (0%)	0.0 (0%)	0.0 (0%)
Nuclear	4	4.0				4.0		
LNG, Hydrogen	54	40.0	4.5 (11%)	9.2 (23%)	7.9 (20%)	6.4 (16%)	11.1 (28%)	0.9 (2%)
Storage	4	4.0	0.0 (0%)	0.0 (0%)	1.9 (48%)	1.0 (25%)	1.1 (27%)	0.0 (0%)
Total	122.0	76.0	4.6	13.8	18.8	18.3	18.8	1.7

(JICA Survey Team)

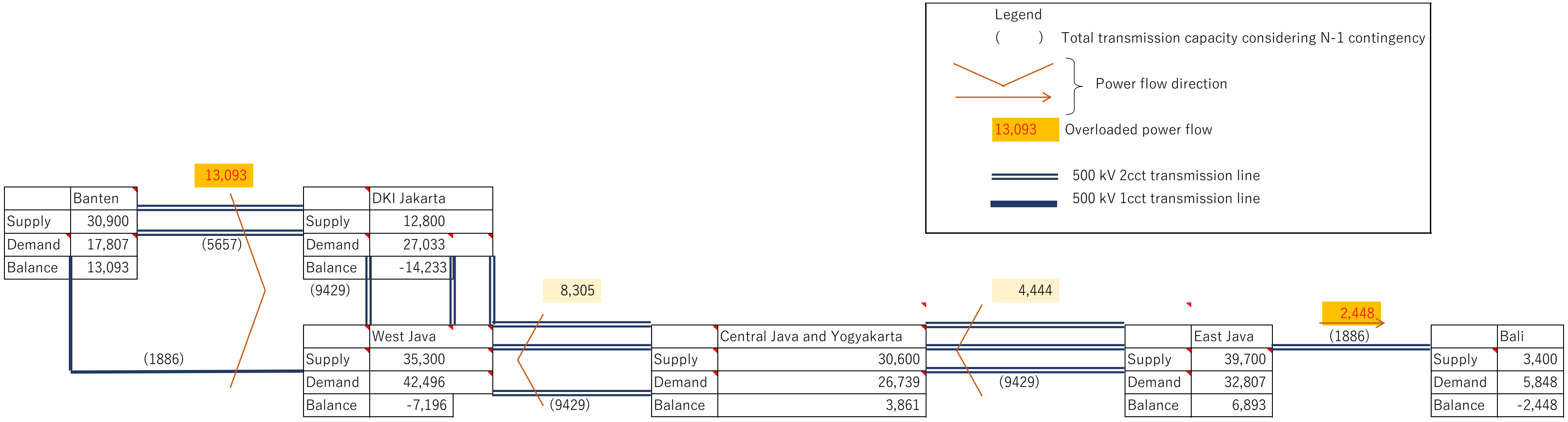
(3) Transmission Line Capacity

Since there are many 500kV transmission lines in the Java-Bali system, 150kV transmission lines with a large capacity difference were ignored. There is no 275kV system in the Java-Bali system.

(4) Power Flow for 2060 in Java-Bali System (High Demand)

(a) Power Flow Calculation Results for 2060 in Java-Bali System (High Demand)

The figure below shows a power flow diagram for 2060 in the Java-Bali System with the said high demand conditions and the operational generation conditions corresponding to the demand.



(JICA Survey Team)

Figure 8-3 Power Flow in 2060 in Java-Bali System(High Demand)

A total of 13,093 MW of power flow from Banten province to the east exceeds the transmission line capacity, and a total of 2,448 MW of power flow from East Java province to Bali province also exceeds the transmission line capacity of 1886 MW.

(b) Transmission line expansions which are necessary in 2060 (High Demand)

Transmission line expansion plans which are necessary for the said transmission line overloading are listed in the table below.

Table 8-10 Transmission Line Expansion Plans which are Necessary for the Transmission Line Overloading (High Demand)

Inter-province Transmission Line	Additional Transmission Lines
Between Banten province and DKI Jakarta	500kV Zebra x 4 bundles, 2 circuits
Between Banten province and West Java province	500kV Zebra x 4 bundles, 2 circuits
Between East Java province and Bali Island	500kV Zebra x 4 bundles, 2 circuits

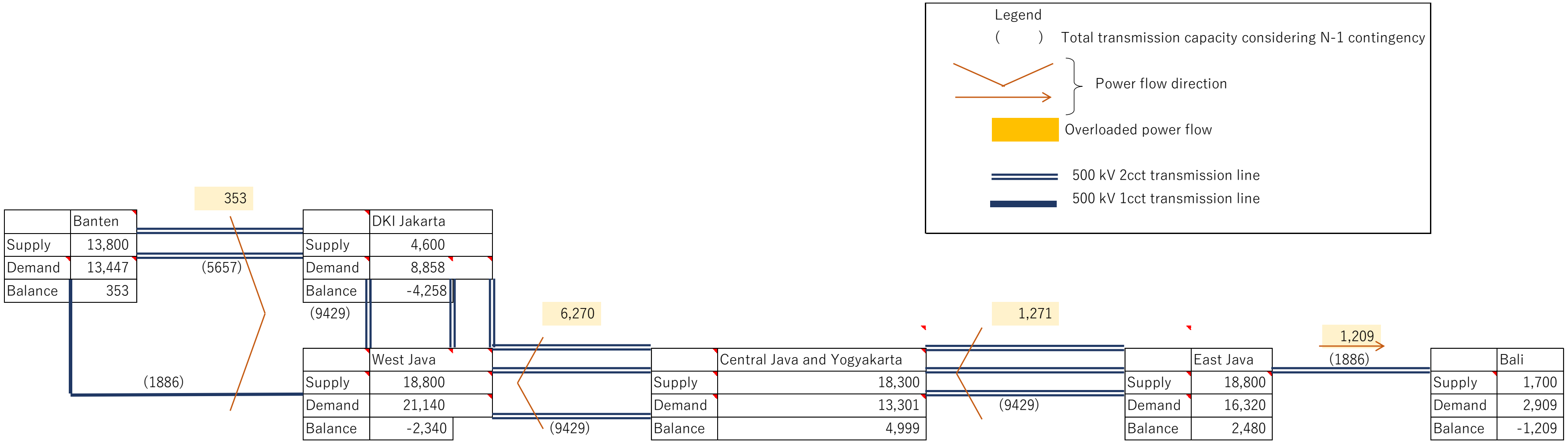
(JICA Survey Team)

(5) Power Flow for 2060 in Java-Bali System (Low Demand)

(a) Power Flow Calculation Results for 2060 in Java-Bali System (Low Demand)

The figure below shows a power flow diagram for 2060 in the Java-Bali System with the said low demand conditions and the operational generation conditions corresponding to the demand.

There are no overloaded transmission lines in terms of inter-province power flow.



(JICA Survey Team)

Figure 8-4 Power Flow in 2060 in Java-Bali System(Low Demand)

8.2 Inter-system (Inter-island) Connection

In order to aim for the optimum mix of energy sources in the Java-Bali system, it is necessary to install a large amount of solar power systems. However, due to the low potential of solar power generation in the Java-Bali system, renewable energy will still account for only 16% in 2060 in the high demand case. On other islands, on the other hand, the optimal composition for solar power is within the potential and this can be constructed to be used for the Java-Bali system. In consideration of this point, economic evaluations were conducted in terms of constructing solar power systems on other islands with abundant solar potential and transmitting it to the Java-Bali system.

(1) Interconnection of Java-Bali System and Sumatra System

The distance between Java island and Sumatra island is relatively short (about 40km), and there was a conceptual plan for a Java system - Sumatra system interconnection previously. According to RUPTL 2012-2021, the outline of the project is as follows.

Table 8-11 Basic Specifications for HVDC Cable

Item		Notes
Voltage	500kV HVDC	
From	Tanjung Pucut	
To	Ketapang (Lampung)	
Conductor	2 pole, HVDC cable	
Length	80km	
Cost	352.8 Million USD	4.4 Million USD/km

(Source: RUPTL 2012-2021)

Table 8-12 Basic Specifications for HVDC OHL (Over-Head Transmission Line)

Item		Notes
Voltage	500kV HVDC	
From	Bogor X	
To	Tanjung Pucut	
Conductor	2 pole, HVDC OHL	Over-Head Transmission Line
Length	220km	
Cost	77 Million USD	0.35 Million USD/km

(Source: RUPTL 2012-2021)

Table 8-13 Basic Specifications for HVDC Converter Station

Item		Notes
Voltage	500kV DC	
Station	Muara Enim 500 kV	
Capacity	3000MVA	
Cost	324 Million USD	Excluding AC equipment

(Source: RUPTL 2012-2021)

The table below shows the latest specifications for the Sumatra-Java HVDC project.

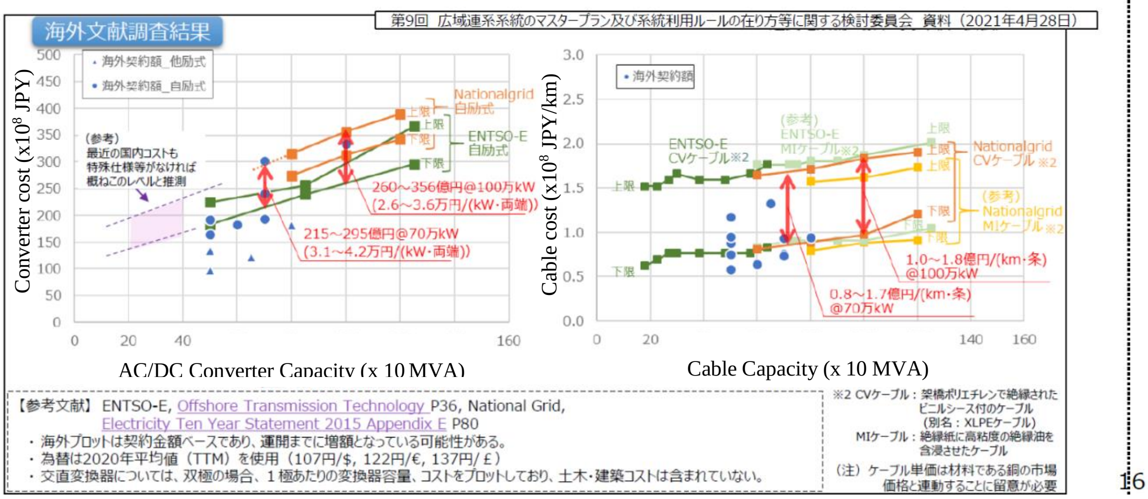
Table 8-14 Latest Specifications for Sumatra-Java HVDC Project

Item		Notes
Voltage	±500kV	
Capacity	3000MVA	
Total Distance [Cable Distance]	503km [38km]	
Number of cables	3	Main: 2, Reserve: 1

(Source: Study for the development of long-distance submarine DC transmission, Interregional interconnection by domestic submarine DC transmission, March 15, 2021, J-POWER Transmission Network Co., Ltd.)

The number of cables is three, including a reserve one.

The material below shows recent price movements.



（Source：FS Survey for Introduction of Submarine DC Power Transmission, Agency for Natural Resources and Energy, July 29, 2021)

Figure 8-5 Recent Costs for AC/DC Converters and Submarine Cables

According to the graph above, the cost of AC/DC converters, including both stations, is between 32 and 44 billion yen at 1500 MVA for single pole, thus the cost of converters would be between 64 and 88 billion yen at 3000 MVA for a bipolar system. The cost of 324 Million USD x 2 in RUPTL 2012-2021 does not differ greatly from the current cost.
However, cable costs depend on specifications such as the HVDC equipment configuration. According to the graph above, the cost of a cable is between 0.1 and 0.220 billion yen/km/cable at 1500 MVA. If the number of cables is two, the cost per unit distance is between 0.2 and 0.44 billion yen/km for 300MVA, and if the number of cables is two plus one, the cost per unit distance is between 0.3 and 0.66 billion yen/km. Comparing the cost per unit distance in RUPTL 2012-2021 (8.8 Million USD/km), the latest cost is much lower. Thus, 50% of the cost in RUPTL 2012-2021, 4.4 Million USD/km, was used for the cost estimation.

Since the supply capacity of Lampung province, in the southern part of Sumatra, is insufficient, it is a good idea to build an AC/DC converter on the Sumatra side in South Sumatra province. Assuming that the length of the HVDC overhead transmission line on the Sumatra side is 500 km, the cost per 3,000 MVA of the Sumatra-Java interconnection is as follows.

Table 8-15 Cost of Interconnection between Sumatra System and Java-Bali System

(Million USD)

DC converter stations	648	Total of Both sides for Sumatra and Java
HVDC cable	167	Distance: 38km
HVDC OHL	326	Distance in Sumatra: 355km Distance in Java: 110km
Total	1,141	Excluding AC equipment

(Source; JICA Survey Team)

If the lifetime of the transmission equipment is 30 years and the interest rate is 10%, the fixed cost (CAPEX) rate is 10.61%, and if the O&M costs are 1% of the construction costs, the annual cost ratio is 11.61%. Therefore, the transmission cost for transmitting 3GW solar power (utilization rate 20%) from the Sumatra system to the Java-Bali system is as follows.
1,141 x 100 x 0.1161/(3GW x 20% x 8760 hours) = USC 2.5/kWh

(2) Interconnection of Java-Bali System and Kalimantan System

The cost for the interconnection between the Java-Bali system and the Kalimantan system was also calculated in the same way as for the interconnection between the Sumatra system and the Java-Bali system.

Table 8-16 Cost of Interconnection between Kalimantan system and Java-Bali system

(Million USD)

DC converter station	648	Assumption: Java-side station located in east of Jakarta and Kalimantan-side station located in West Kalimantan province
HVDC cable	2,200	Assumption: 500km distance
HVDC OHL	245	Assumption: 50km distance in Java and 300km distance in Kalimantan
Total	3,093	Excluding AC equipment

(Source; JICA Survey Team)

Power transmission cost is as follows.
3,093 x 100 x 0.1161/(3GW x 20% x 8760) = USC 6.8/kWh
It will be necessary to upgrade the AC system to collect about 3,000 MW of electricity at the AC/DC converter station in West Kalimantan province. Considering that the capacity of the 275kV transmission line is about 500MW/line, it is desirable to construct new 500kV transmission trunk lines as the backbone system, so the cost will increase further in addition to the above.

(3) Interconnection of Java-Bali System and Sulawesi System

The cost for the interconnection between the Java-Bali system and the Sulawesi system was also calculated.

Table 8-17 Cost of Interconnection between Sulawesi System and Java-Bali System

(Million USD)

DC converter station	648	Assumption: Java-side station located in east of Jakarta and Sulawesi-side station located in South Sulawesi province
HVDC cable	6,160	Assumption: 1,400km
HVDC OHL	245	Assumption: 50km distance in Java and 300km distance in Sulawesi
Total	7,053	Excluding AC equipment

(Source; JICA Survey Team)

Power transmission cost is as follows.
7,053 x 100 x 0.1161/(3GW x 20% x 8760 = USC 15.6/kWh
It will be necessary to upgrade the AC system in addition to the above.

(4) Interconnection of Java-Bali system and Papua System

The cost for the interconnection between the Java-Bali system and the Papua system was also calculated.

Table 8-18 Cost of Interconnection between Papua System and Java-Bali System

(Million USD)

DC converter station	648	Assumption: Java-side station located in east of Jakarta and Papua-side station located in Papua province
HVDC cable	15,400	Assumption: 3,500km
HVDC OHL	42	Assumption: 50km on Java side and 10km on Papua side
Total	16,090	Excluding AC equipment

(Source; JICA Survey Team)

Power transmission cost is about
16,090 x 100 x 0.1161/(3GW x 20% x 8760) = USC 35.5/kWh
It will be necessary to upgrade the AC system in addition to the above.

8.3 Confirmation/Proposals on Constraint Factors and Institutional Reforms to realize Electric Power Systems that achieve both Carbon Neutrality and System Stability

In order to achieve carbon neutrality, it is vital to strengthen frequency adjustment capabilities because the ratio of power sources whose output fluctuates frequently and randomly, such as photovoltaic power generation, has to increase. Since photovoltaic power facilities generate electricity only during the daytime, when a large amount of photovoltaic power is produced, the residual demand in the daytime after applying solar power decreases significantly, as shown in Figure 8-6, and power sources other than solar power have to be applied to this residual demand shape. Since the output of thermal power plants is required to be as low as possible, it is necessary to ensure operational elasticity across the overall system. For this purpose, it is necessary to take measures to significantly reduce the output of the thermal power generation equipment to the minimum possible and to stop it if the amount of suppression is still insufficient. Specifically, coal-fired power plants are required to decrease their output to the minimum operable output, and gas-fired power plants are required to provide agile start and stop operations by shortening the start and stop time.

However, since the thermal power plants need to have a frequency adjustment function, there is a limit to the number of operating units and the amount of output suppression. If the total photovoltaic power generation capacity exceeds the output suppression limit at those thermal power plants, output suppression will probably be required for the photovoltaic power generation equipment.

Therefore, in order to ensure a stable power supply while avoiding the output suppression of photovoltaic power generation systems, it may be necessary to install power storage equipment such as batteries and pumped storage hydropower plants.

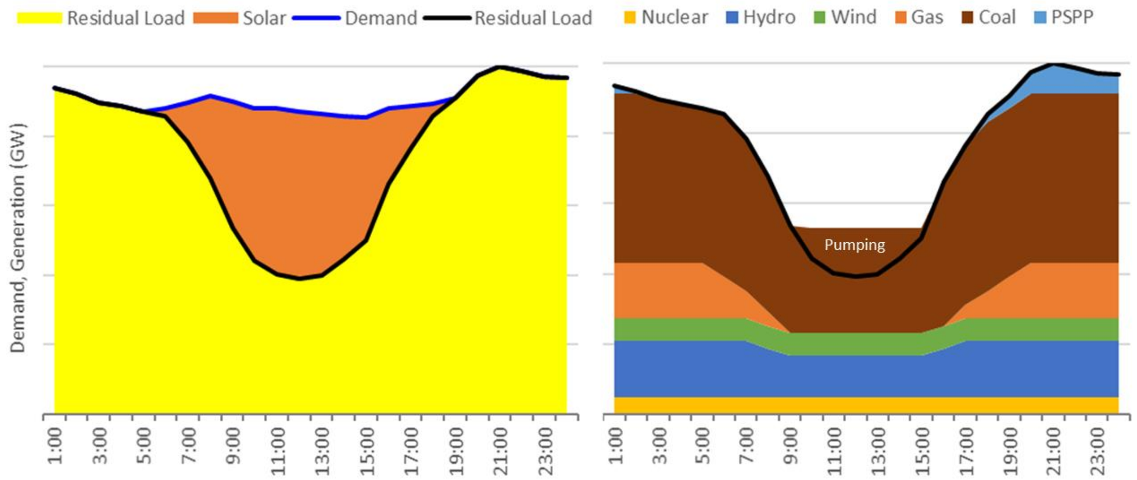


Figure 8-6 Dispatching Generation Sources for Residual Demand with a Large Amount of PV

Necessary system constraints will be estimated based on the supply and demand balance situation and the power supply composition situation in each year, and a consideration will be made as to whether it is possible to handle this with the current regulations and the current power sector structure. New countermeasures will be proposed if necessary.

Based on this situation, the action items that will be required in the future in terms of system operation are organized as follows.

(1) PV power generation curtailment due to insufficient transmission capacity

As of 2060, the amount of PV power generation development is expected to be 10GW to 120GW for the Sumatra grid, about 30GW for the Java-Bali grid, 30GW to 70GW for the Kalimantan grid and 2GW to 15GW for the Sulawesi grid in the scenario that is considered optimal.

Since the power generation capacity of PV depends on weather conditions, there is a high possibility that suitable installation locations will be unevenly distributed, and if PV power generation sites become concentrated in a limited area and transmission facilities are not properly constructed so as to meet the generating capacity, a shortage of transmission capacity may occur, which may lead to an event where power generation output must be curtailed.

Therefore, it is necessary to periodically check the consistency between the generation development plan and the transmission network expansion plan considering both mid-term and long-term outlooks, and it is important to extend the period covered by the master plan, shorten the plan update cycle, and improve the accuracy of the plan.

First of all, we believe that it is necessary to formulate a very long-term master plan for the next 30 to 40 years.

(2) PV Generation curtailment due to Demand and Supply imbalance

Along with the introduction of PV power generation, the introduction of battery storage facilities (including pumped storage hydropower) will also be implemented, and it is assumed that by 2060, 0GW to 35GW of BESS (Battery Energy Storage System) will be installed in the Sumatra grid, 12GW to 30GW in the Kalimantan grid and 0GW to 5GW in the Sulawesi grid.

The BESS will also play a role in avoiding output curtailment caused by demand and supply imbalances in the overall system by charging surplus PV generation during the daytime and discharging the storage power during the night-time peak.

In particular, in the Sumatra grid system, it is assumed that solar power generation will be responsible for almost all of the demand during the daytime, generating more than twice as much power as demand while charging the surplus power in the BES on a constant basis. Despite the large capacity of the BESS, it may be necessary to curtail surplus PV generation depending on the demand.

Therefore, it is necessary to develop a power system operation method, such as a renewable energy generation forecasting method, to reduce the amount of curtailment as much as possible. It is also necessary to consider how to use the surplus generation, such as converting it into green hydrogen or green ammonia for storage.

(3) Forecasting Renewable Energy Generation Output

In Sumatra, the system operation department of the Sumatra Transmission and Load Dispatch Center P3B, and in Java-Bali, the Java Bali Load Dispatch Center P2B, forecast the next day's power demand on the previous day, prepare the operation plan for each power generation facility according to the forecasted demand, and communicate the generation dispatching schedule. Online demand and supply adjustment is carried out via automatic generation control (AGC).

When a demand and supply adjustment plan (Day ahead Generation Plan) is created, as the ratio of renewable energy increases, the accuracy of generation capacity forecasting for renewable energy becomes a big issue. At present, the ratio of renewable energy is low, so accuracy is not an issue, and even if the generation forecast is greatly wrong, it will not have a significant impact on the operational output of other power generation facilities. However, as the ratio of variable renewable energy facilities increases in the future, errors in the generation forecast will lead to changes in the operating output of each power generation facility on the day of the forecast, which may in turn lead to a collapse in economical generation dispatching and an increase in power generation costs.

Therefore, since forecasting of power generation from renewable energies will become important, the introduction of a forecasting method that utilizes weather information is required.

(4) Issues concerning network power flow control

It is assumed that coordination between the construction of the PV power generation facilities and the transmission network enhancement work for transmitting the power generated may not be appropriate, and in that case, there is a concern that the power flow on the transmission lines and transformers may be overloaded.

In order to solve the problem of overloads, it will be necessary to curtail the power generation at the PV power plants. The generation curtailment will be realized by sending curtailment commands from the dispatching center to the PV power plants that are transmitting the power via the transmission lines or transformers in question.

For the generation curtailment, automated controls are desirable, and it is necessary to equip the AGC with a power flow control function through the generation control. In the case of a transmission line that is operated radially, the amount of generation curtailment for each generator can be easily calculated. However, in the case of a loop operation, calculating the distribution of the generation curtailment for each PV generator becomes quite complicated, and care must be taken because the distribution factor for each PV generator will continuously change according to output changes at each PV generator.

In order to curtail renewable energy plants to relieve transmission network congestion, it is necessary to increase the power generation output of hydroelectric and thermal power plants in distant locations to compensate for the decrease in power generation, which changes the power flow distribution of the network system and thus changes the system characteristics. The system operator must take care with power system stability, which may be weakened by network characteristic changes.

(5) Evaluation of impact on system stability (including reduced inertia and synchronization forces)

When a fault occurs in the vicinity of the grid where renewable energy is interconnected, the voltage at the connection point drops significantly, the power conditioner (PCS) is temporarily blocked, and power generation stops. Then, when the fault is removed and the voltage recovers, the PCS is restarted and power generation resumes.

PV generation plants, which account for the majority of renewable energy, are expected to be concentrated in relatively specific areas with good weather conditions. If a fault occurs in the vicinity of a power plant, all the PV generators will shut down at once, and the power flow on the interconnection lines with other areas is expected to fluctuate significantly, which may cause inter-area disturbances.

For this reason, it is vital to verify the effects of simultaneous RE generator trips via simulation, in line with the increase in the renewable energy ratio. If an unstable phenomenon is expected to occur as a result, the design and installation of the following Special Protection Scheme (SPS) may be required.

<Special Protection Scheme (SPS)>

In terms of system problems when a large amount of renewable energy power generation is introduced, it is expected that renewable energy power generators will unnecessarily and simultaneously trip due to a system fault, and the following events will occur:

- Frequency drop due to generation shortage
- Under Voltage due to loss of voltage maintaining generators
- Overloading of transformer and transmission line due to sudden power flow change

Since PV generators have no inertia or synchronism force, the power system will have increased potential for frequency fluctuation and transient instability with the expansion of renewable energy.

In order to prevent a widespread blackout, several kinds of countermeasures are required in response to the phenomena, and the general countermeasures shown in the figure are conducted.

Countermeasures in green are called a Remedial Action System (RAS) and TEPCO has great experience in RAS. Toshiba, Hitachi and Mitsubishi have actual installation experience for several RASs.

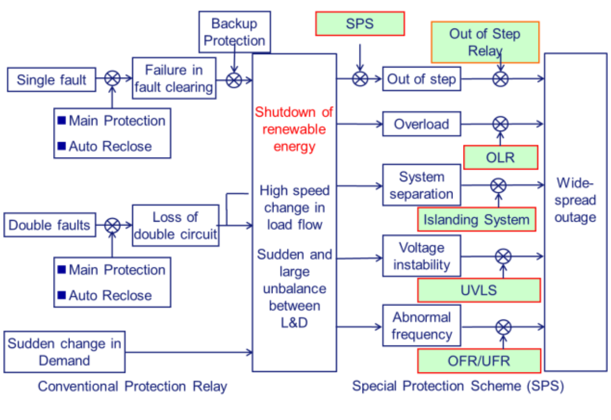


Figure 8-7 Conceptual Diagram of SPS

Recently, Phasor Measurement Units (PMU) that can measure busbar voltage magnitudes and phase angles, as well as transmission line currents with time synchronization via GPS signals, have been installed at substations. Based on these electrical quantity measurement data and network operation statuses captured through the SCADA system, SPS can simulate cascading failure modes in advance. Therefore, the SPS can send predetermined stabilizing control signals to designated control equipment if an expected failure is triggered, thus preventing a cascading failure.

In addition, the Sumatra grid is expected to be operated in such a way that, during the daytime, PV power generation will be responsible for about 80% of the demand, and PV power generation will be used to charge storage batteries with a kW capacity almost equal to the demand, and the ratio of geothermal, hydroelectric, and thermal power generation with inertia is likely to be reduced to about 10% of the generation capacity.

Under these circumstances, if the power generation facilities are shut down, the speed and level of the frequency drop will be extremely large, and there is a possibility that a cascading outage will occur since the PV generator cannot continue to operate under extreme underfrequency conditions. The cascading failure may result in a total blackout of the whole network.

Several countermeasures are currently being considered for these problems, as shown in the table below, and although there are still issues to be overcome in terms of cost-effectiveness and technological development, studies are steadily underway.

Among these measures, the effects of synchronous condensers and MG sets can be estimated using the same approach as for conventional synchronous generators, but VSGs are still being studied by manufacturers and research institutes, and it is necessary to clarify the functions required for VSGs by grid operators.

Table 8-19 Examples of measures to improve inertia and synchronizing force

Measure	Feature	Issues
Synchronous condenser	● Rotates at synchronous speed and provides inertia force ● Steam turbine generator can be the synchronous condenser if the turbine shaft is disconnected	● High maintenance cost due to rotational machine
MG set	● Combining renewable energy and storage batteries with a synchronous motor ● A synchronous generator connected with the motor can output power to the grid, or absorb power from the grid and charge the power in batteries ● Provides inertia force and spinning reserve according to the storage battery capacity	● Relatively high installation costs due to the necessity of many facilities, such as generator, motor, battery, etc.
VSG (Virtual Synchronous Generator)	● Outputs pseudo-synchronization and inertia forces by controlling inverter and storage batteries combined with the inverter power supply (PV, etc.)	● Large-capacity inverters and storage batteries are required to achieve the same characteristics as generators ● If a large amount of VSGs are introduced into the grid, there is a concern that the control system may become unstable

(6) Power System Operation Method

When the renewable energy ratio increases, the grid operation method changes from the current method and becomes more complicated. For this reason, system operators in P2B and P3B need to study the themes that are expected to occur when the renewable energy ratio increases and how to deal with them.

(7) Reflecting information in grid connection code

When connecting renewable energy or a storage battery system to a grid, it is necessary to clearly state the system specifications and grid connection requirements in the grid code from this early stage so that the grid will not be adversely affected after the connection.

In particular, since renewable energy needs to be equipped with an output control function to eliminate transmission line and transformer congestion, the renewable energy should have a function for receiving control signals from the dispatching center and automatically adjusting the power generation output. It is necessary to specify this in the grid code.

(8) Verification of ΔkWh

In order to operate the grid stably and maintain the quality of electric power supply, it is essential to verify the availability for responding to power generation shortage ΔkWh due to errors in demand forecasting, errors in power generation forecasting for renewable energy generators, or generator trouble.

In addition, it is necessary to consider how to secure the ability to adjust demand and supply balance as the ratio of renewable energy increases.

Chapter 9. Economic and Financial Analysis, and Investment Planning

9.1 Economic/Financial Impact Assessment

(1) Determining what to evaluate for Economic/Financial impact

In Indonesia, the introduction of carbon pricing regulations was announced, as mentioned in Chapter 4. Preparations are currently underway for the carbon tax to be applied, and it is scheduled to be applied to coal-fired power plants from April 1, 2022.[62]

As mentioned above in Chapter 5, hydrogen and ammonia are attracting attention as decarbonization technologies. Above all, the existing technology for ammonia has been established, compared to hydrogen, and partial co-firing of ammonia in coal-fired power plants has low technical hurdles and is expected to be feasible in the near future.

Therefore, in this chapter, we decided to examine an economic evaluation for the partial combustion of ammonia in existing coal-fired power plants from the viewpoint of introducing the carbon tax.

(2) Economic / financial impact evaluation conditions

Evaluation conditions are as follows.

- 20% ammonia co-firing at existing coal-fired power plant
- 20 years of operation from 2041 to 2060 after renovation
- Renovation period is one year
- O&M costs are the same after renovation (no change)
- Carbon price is a variable to evaluate financial impact

(3) Specifications for economic evaluation

The numerical values described in Chapter 7 are used as the specifications for the economic evaluation.

Table 9-1 Specifications for economic evaluation

	Construction cost	Efficiency	Capacity factor	Fuel cost
Units	USD/kW	%	%	USC/kWh
Coal (USC)	1,468.74	44	75	2.43
Ammonia (USC)	1,696.01	44	75	15.59

(Source: JICA Survey Team)

In the future, it is expected that the fixed costs for manufacturing equipment for ammonia will gradually decrease according to the maturity level of the technology. The price transition of ammonia will be evaluated below. Blue ammonia is currently cheaper for imports.

At present, the price of green ammonia is much higher than that of blue ammonia, so in this chapter, we decided to use blue ammonia, which has a relatively low cost.

[62] "Indonesia: the introduction of carbon pricing regulations starting from April 2022" (JOGMEC, 2022/1/27) https://mric.jogmec.go.jp/news_flash/20220127/165483/

Table 9-2 Ammonia price

Ammonia Price (USC/Mcal)	BLUE NH_3 (Domestic manufacturing)	BLUE NH_3 (Import from Australia)
2040	7.97	5.58
2041	7.92	5.49
2042	7.83	5.43
2043	7.77	5.38
2044	7.68	5.29
2045	7.59	5.23
2046	7.53	5.14
2047	7.44	5.08
2048	7.35	5.02
2049	7.30	4.93
2050	7.21	4.87
2051	7.15	4.78
2052	7.06	4.73
2053	6.97	4.67
2054	6.91	4.58
2055	6.82	4.52
2056	6.73	4.43
2057	6.68	4.37
2058	6.59	4.28
2059	6.53	4.22
2060	6.44	4.16

(Source: JICA Survey Team)

The CO_2 emissions per kWh at coal-fired power plants are as follows.

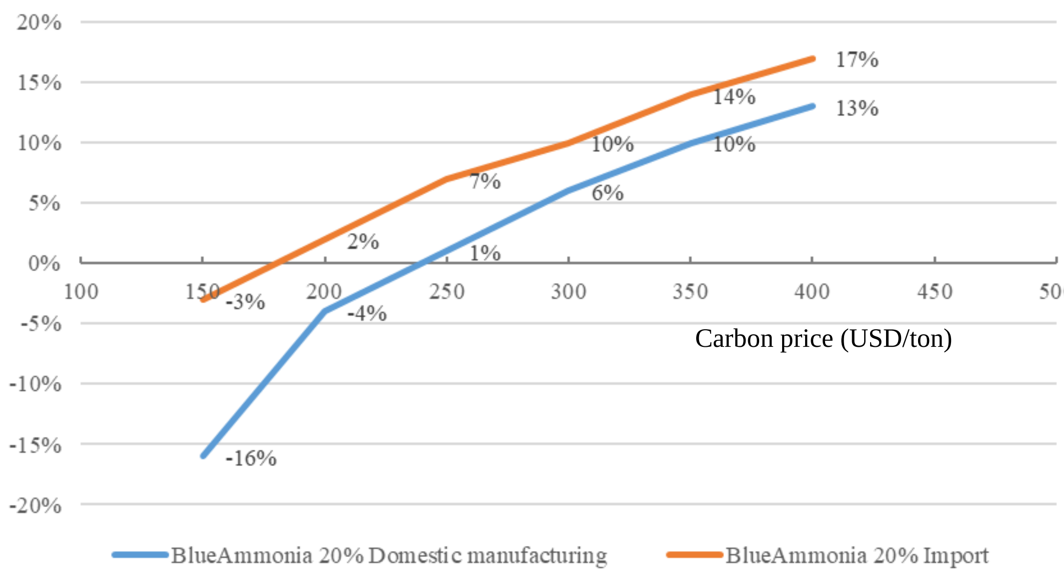
Table 9-3 CO_2 emissions per kWh

	Fuel			Efficiency	CO_2 Emissions Factor
		g-CO_2/MJ	kg-CO_2/Mcal		kg-CO_2/kWh
Coal (USC)	Coal	93.7	0.3924	44%	0.767

(Source: JICA Survey Team)

(4) Results of Economic/financial impact evaluation

In a situation where an existing coal-fired power plant is renovated for 20% ammonia co-firing and operated for 20 years, CAPEX and ammonia fuel cost will be used as cost, and coal fuel reduction and carbon cost reduction contribution due to the 20% ammonia co-firing will be used as income. An FIRR calculation was performed and the results are as follows.



(Source: JICA Survey Team)

Figure 9-1 Changes in FIRR due to carbon price

If the carbon price is 50 USD/ton or 100 USD/ton, it takes a long time to recover the equipment repair costs and fuel costs, so FIRR will be significantly negative (not subject to estimation).
At 200 USD/ton, it will be 2% for imported blue ammonia and -4% for domestically manufactured blue ammonia. A carbon price of 250 USD/ton is required to make a profit for domestically manufactured blue ammonia.
In this way, at present, in order to realize economic efficiency in 20% blue ammonia co-firing, a carbon price of 200 to 250 USD/ton is required. The economic efficiency of green ammonia is more severe.

(5) Economic/financial impact evaluation

In order to realize economic efficiency for the cost of retrofitting an existing coal-fired power plant for 20% ammonia co-firing, from only by reducing the amount of coal fuel and contributing to carbon cost reduction by 20% ammonia co-firing, it is necessary to set a high carbon price.
Currently, even in Sweden, which has one of the highest carbon taxes in the world, it is 119 EUR/tCO_2[63], and it is necessary to set an amount exceeding that value. However, the carbon tax may rise from 2040 to 2060 and it is expected that economic efficiency can be secured due to this factor.
In this chapter, economic efficiency was evaluated only via the reduction of coal fuel and the contribution to carbon cost reduction, but in reality, it is expected that other environmental measures will be implemented and the business environment will change from 2040 to 2060.
In order to promote decarbonization, it can be said that preferential treatment of decarbonized power sources is necessary in terms of areas other than the carbon price.

Specific preferential treatment measures that can be considered include government subsidies, low-interest loans, and adding targets to existing green measures. In Indonesia, the Ministry of Finance is currently introducing green bond issuance and fiscal policies (tax incentives) for the transition to a green economy, but these are targeted for renewable energies such as geothermal power generation, some solar power, and small and medium-sized hydropower. Therefore, they are not applied to co-firing of existing coal-fired power plants.

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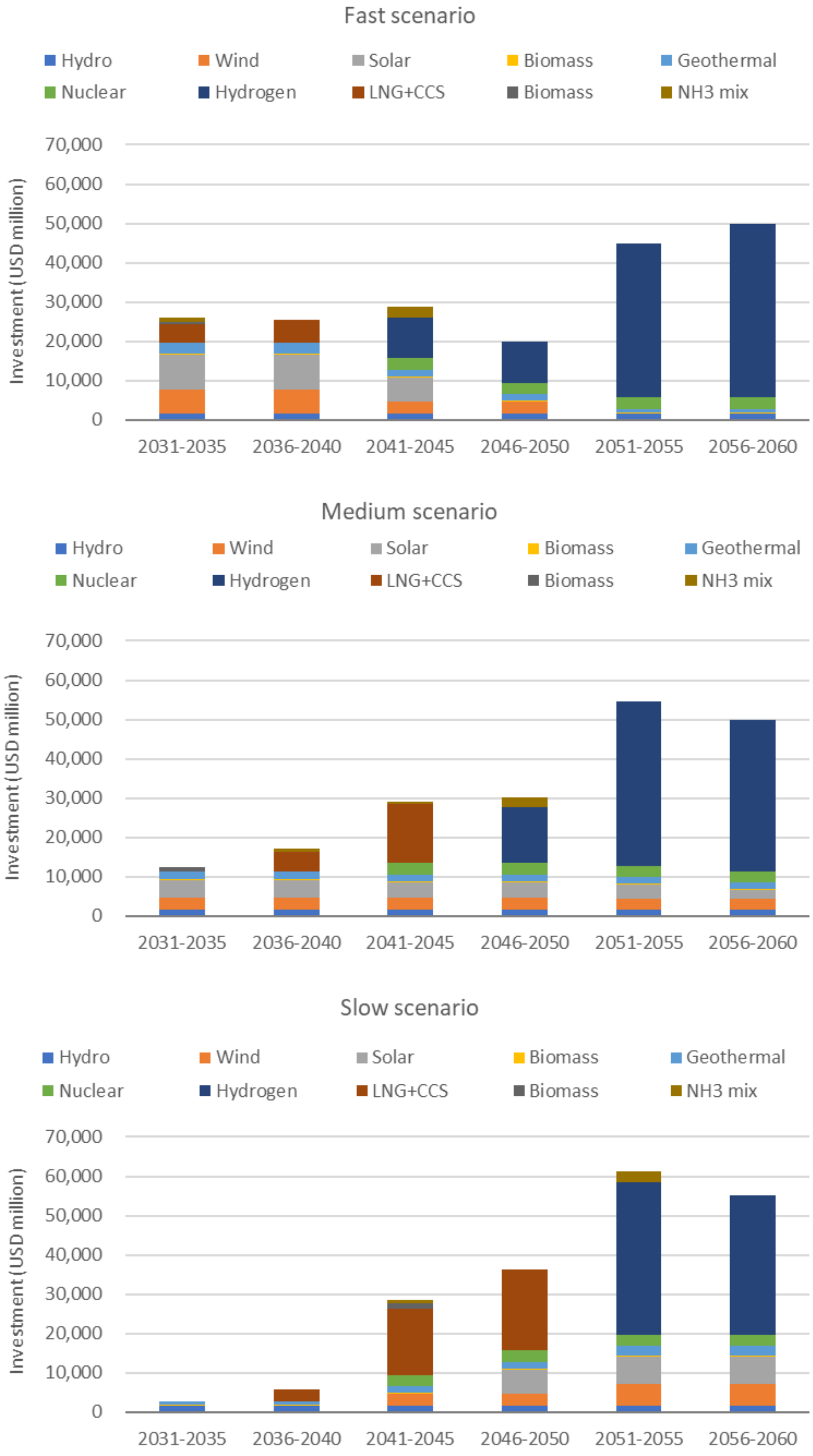
[63] "Introduction status of carbon tax in other countries" (Ministry of Environment, July 2017)
https://www.env.go.jp/policy/tax/misc_jokyo/attach/intro_situation.pdf

In addition, low-interest loans from multilateral development banks are conceivable, but even for projects that contribute to CO_2 emission reduction, support will be difficult to obtain if the project is viewed as leading to life extension measures for existing coal-fired power plants.
From the point of view of the project operators, they are not only anticipating carbon cost reductions, but they are making efforts to reduce CO_2 emissions as much as possible now that headwinds are blowing against coal-fired power. By demonstrating an attitude of making efforts to reduce CO_2 emissions as much as possible, it is assumed that there will be a desire to gain understanding for continuing the operation of coal-fired power plants.

9.2 Investment plan

The transition of the required investment amount for each scenario in the Java-Bali system (high demand) covered in Chapter 7 is shown below.



(Source: JICA Survey Team)

Figure 9-2 Changes in the required investment amount for each scenario

The Fast scenario will require a large investment from 2031 to abolish inefficient coal-fired power that is more than 30 years old at an early stage. In the Slow scenario, the investment amount from 2031 to 2040 is very small because the life of coal-fired power plants built before 2000 is extended by implementing biomass co-firing and ammonia co-firing. However, from 2041, the existing coal-fired power plants will gradually be abolished, so the investment amount in the latter years will increase. In both scenarios, the coal-fired power currently under construction is expected to be converted to ammonia-only combustion power by 2060 and continue to operate after 2061, but the coal-fired power will continue to operate. If this happens, it will emit a lot of CO_2, so there is a high possibility that it will have to be abolished. In such cases, the construction of alternative zero-emission thermal power will be required, further increasing the required investment.

In either scenario, the investment in power generation equipment in the Java-Bali grid will require a total of over USD 200 billion for the 30 years from 2031 to 2060. Most of these investments will be covered by the investment of private funds, but the behavioral principle of private businesses is basically partial optimization to maximize their own profits, and not necessarily to aim for overall optimization of the system. Power source configuration does not factor into their calculations. In terms of grid operations, in order to secure the required supply reliability, a certain amount of development will be required every year according to the growth in demand, but power plants will be developed only with private funds. In this case, since the development decision is left to the private business operator, there is a concern that the development will not always be performed as expected by the grid operator and the required supply reliability cannot be maintained. For this reason, it is necessary to establish an incentive scheme that takes into consideration the securing of supply capacity to satisfy the required supply reliability and guidance on the power supply configuration aiming at the overall optimization of the system. As a concrete idea, a scheme is conceivable in which a capacity market is formed in a few years, the required amount (kW) and the required power source type are presented to private business operators, and the winner is determined by bidding.

Chapter 10. Roadmap for Decarbonization

10.1 Action Plan

In each chapter after Chapter 5, items to be implemented to achieve carbon neutrality by 2060 are proposed. The following is a summary of this information as an action plan.

Table 10-1 Action Plan

Major items	Specific items	Implementing entity
Hydrogen, Ammonia	Formation of the entire ammonia supply chain (master plan)	MEMR
	FS and demonstration test for ammonia co-firing at coal-fired power plants	PLN
	Expansion of existing ammonia production in Indonesia	MEMR
	Introduction of new hydrogen/ammonia production technologies	Manufacturer
	Introduction of green hydrogen/ammonia production technologies	Manufacturer
	FS and demonstration test for hydrogen co-firing at GTCC thermal power plants	PLN
	FS and demonstration test for ammonia firing at GTCC thermal power plants	Manufacturer
Biomass	FS and demonstration test for biomass co-firing at coal-fired power plants	PLN
LNG	Policy development to promote LNG introduction in Indonesia	MEMR
	Formulation of LNG Master Plan	PLN
	Feasibility study for fuel conversion to hydrogen at existing LNG fired plants	PLN
CCUS	Policy development to promote CCS introduction in Indonesia	MEMR
	Development of master plan for the introduction of CCS in Indonesia	MEMR
	Feasibility study and demonstration tests for CCS projects at specific locations	PLN
Wind, Solar	Formation of a power system master plan focused on grid enhancement and renewable energy development	PLN
Hydro	Formulation of a comprehensive development plan for river basins where development is a high priority	PLN
Geothermal	Study on technical risk reduction/avoidance measures in each phase of investigation/development/operation	MEMR, PLN
Batteries	Study on incentives for introducing storage batteries	MEMR
Power development planning	Review of renewable energy potential	MEMR, PLN
	Study on Detailed Long-term Vision	PLN
System planning, System operation	Formulation of a power system master plan that takes into consideration the output curtailment of solar power generation facilities due to insufficient transmission capacity	PLN
	Study on power storage equipment considering the output curtailment of renewable energies due to the balance between supply and demand in the overall system	PLN
	Forecasting Renewable Energy Generation Output	PLN
	Study on issues concerning network power flow control	PLN
	Evaluation of impact on system stability (including reduced inertia and synchronization forces)	PLN
	Training on Power System Operation Methods after introducing large amounts of RE	PLN
	Reflecting information in grid connection code (Review of Grid Code)	MEMR
	Verification of adjustable capacity (ΔkWh)	PLN

(Source: JICA Survey Team)

10.2 Roadmap

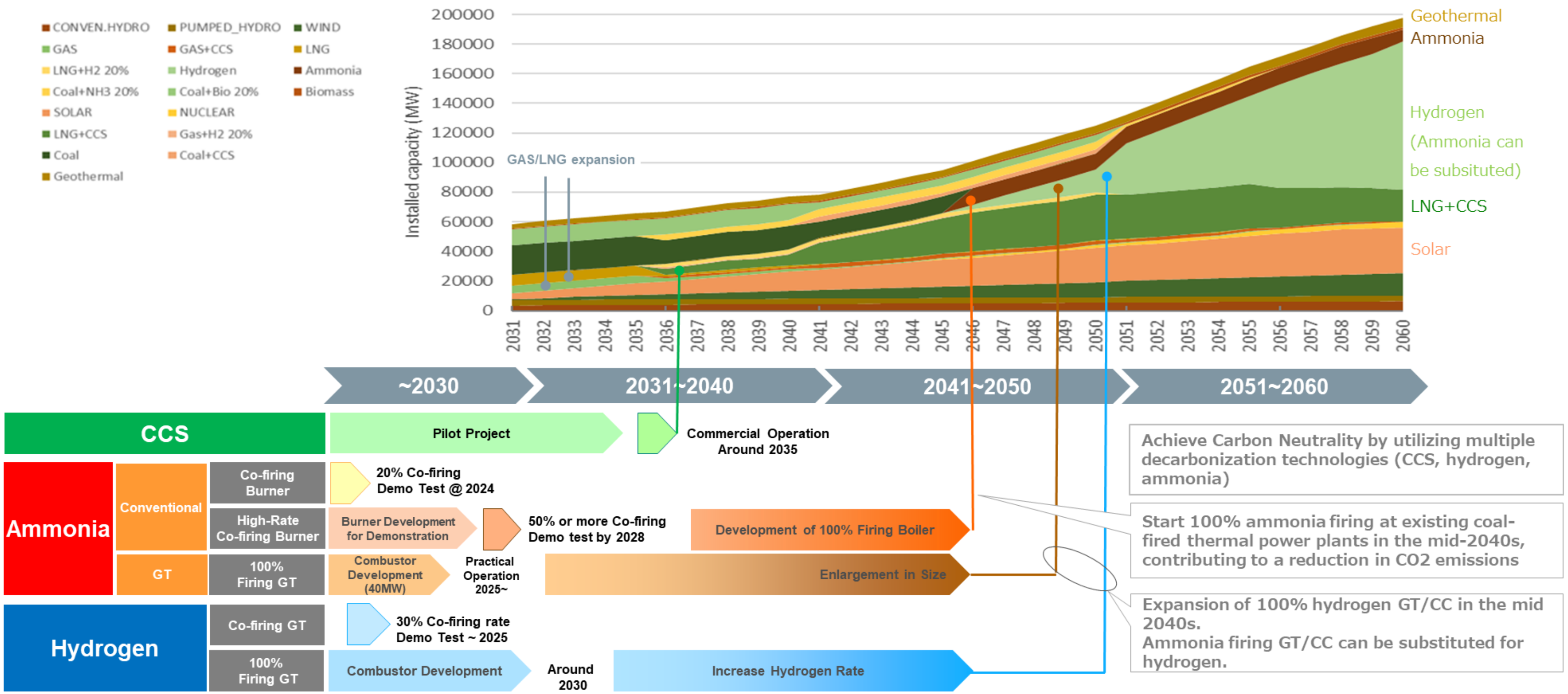
The roadmap, which takes into account the implementation time for the action plan shown in the previous section, is shown below.

Table 10-2 Roadmap

Items	2022	2023	2024	2025	2026	after 2026
Hydrogen, ammonia, biomass						
Formation of the entire ammonia supply chain (master plan)						
FS and demonstration test for ammonia co-firing at coal-fired power plants						
Expansion of existing ammonia production in Indonesia						
Introduction of new hydrogen/ammonia production technologies						
Introduction of green hydrogen/ammonia production technologies						
FS and demonstration test for hydrogen co-firing at GTCC thermal power plants						
FS and demonstration test for ammonia firing at GTCC thermal power plants						
FS and demonstration test for biomass co-firing at coal-fired power plants						
LNG						
Policy development to promote LNG introduction in Indonesia						
Formulation of LNG master plan						
Feasibility study for fuel conversion to hydrogen at existing LNG fired plants						
CCUS						
Policy development to promote CCS introduction in Indonesia						
Development of master plan for the introduction of CCS in Indonesia						
Feasibility study and demonstration tests for CCS projects at specific locations						
Renewable energy, storage batteries						
Formation of a power system master plan focused on RE development						
Formulation of a comprehensive hydropower development plan for river basins						
Study on technical risk reduction/avoidance measures for geothermal						
Study on incentives for introducing storage batteries						
Power development planning						
Review of renewable energy potential						
Study on detailed long-term vision						
System planning, system operation						
Formulation of power system master plan						
Study on power storage equipment considering the output curtailment of RE						
Forecasting renewable energy generation output						
Study on issues concerning network power flow control						
Evaluation of impact on system stability						
Training on system operation methods after introducing large amounts of RE						
Reflecting information in grid connection code (Review of Grid Code)						
Verification of adjustable capacity (ΔkWh)						

(Source: JICA Survey Team)

Figure 10-1 shows the roadmap for thermal decarbonization technology.



(Source: JICA Survey Team)

Figure 10-1 Roadmap for Thermal Decarbonization Technology

Chapter 11. Proposals for JICA Power Sector Cooperation Program

11.1 Prioritization of Action Plan Items

The action plan shown in Chapter 10 basically lists items that should be implemented by the Indonesian side. However, efforts to decarbonize have just begun in Indonesia, and support from other countries is vital. Therefore, the items in this action plan are prioritized based on the indices shown below, taking into account the possibility of support from Japan.

Table 11-1 Indices for evaluating and prioritizing each support measure

	Evaluation item	Weight	Meaning of each index
A	Urgency	5	This index shows the urgency level of support measures that must be dealt with urgently where problems have already occurred and are causing a negative impact.
B	Necessity of support	4	This index measures the necessity of support based on the needs of the Indonesian side. This index identifies infrastructure investment projects which should be developed with public funding because of their cost-effectiveness considering the benefit to the national economy, although the Financial Internal Rate of Return (FIRR) of the project itself is not high and investment by the private sector cannot expected.
C	Consistency with policies of Indonesian government	4	This index measures whether the support measure is consistent with the policies of the Indonesian government.
D	Possibility of applying Japanese technologies and experience	4	This index evaluates the possibility of applying Japanese technologies and experience in an approach.
E	Possibility of collaborating with other donors	1	This index measures whether there is a possibility of involving other donors or not.
F	Environmental impact	2	This index is to evaluate the impact on the surrounding environment and global climate.

(Source: JICA Survey Team)

Table 11-2 shows the evaluation results for each support measure.

Table 11-2 Priority Evaluation Results for each Support Measure

	A	B	C	D	E	F	Total score
Weight	5	4	4	4	1	2	
Formation of the entire ammonia supply chain (master plan)	3	4	4	5	3	5	80
FS and demonstration test for ammonia co-firing at coal-fired power plants	4	5	4	5	4	5	90
Expansion of existing ammonia production in Indonesia	3	4	3	3	3	3	64
Introduction of new hydrogen/ammonia production technologies	2	3	3	3	2	3	54
Introduction of green hydrogen/ammonia production technologies	1	4	2	4	2	5	57
FS and demonstration test for hydrogen co-firing at GTCC thermal power plants	4	4	3	4	3	5	77
FS and demonstration test for ammonia firing at GTCC thermal power plants	2	4	2	5	2	5	66
FS and demonstration test for biomass co-firing at coal-fired power plants	5	4	5	5	3	3	90
Policy development to promote LNG introduction in Indonesia	4	3	4	3	3	3	69
Formulation of LNG Master Plan	5	5	4	4	2	3	85
Feasibility study for fuel conversion to hydrogen at existing LNG fired plants	3	3	3	4	4	5	69
Policy development to promote CCS introduction in Indonesia	4	4	4	3	3	3	73
Development of master plan for the introduction of CCS in Indonesia	5	4	4	4	3	3	82
Feasibility study and demonstration tests for CCS projects at specific locations	4	4	4	4	3	3	77
Formation of a power system master plan focused on grid enhancement and renewable energy development	5	5	3	4	4	4	85
Formulation of a comprehensive development plan for river basins where development is a high priority	4	4	3	4	4	4	76
Study on technical risk reduction/avoidance measures in each phase of investigation/development/operation	5	4	4	5	4	4	89
Study on incentives for introducing storage batteries	3	3	3	3	4	3	61
Review of renewable energy potential	5	4	4	3	4	4	81
Study on Detailed Long-term Vision	5	5	5	4	3	4	92
Formulation of a power system master plan that takes into consideration the output curtailment of solar power generation facilities due to insufficient transmission capacity	4	5	4	4	3	3	81
Study on power storage equipment considering the output curtailment of renewable energies due to the balance between supply and demand in the overall system	3	4	3	4	4	3	69
Forecasting Renewable Energy Generation Output	3	4	3	5	3	3	72
Study on issues concerning network power flow control	3	4	3	4	4	3	69
Evaluation of impact on system stability (including reduced inertia and synchronization forces)	3	4	3	4	4	3	69
Training on Power System Operation Methods after introducing large amounts of RE	4	4	3	4	4	3	74
Reflecting information in grid connection code (Review of Grid Code)	5	5	4	4	3	3	86
Verification of adjustable capacity (ΔkWh)	4	4	4	4	3	3	77

: Support measures that scored 80 points or more

(Source: JICA Survey Team)

Support measures that have obtained 80 points or more (out of 100 points) are considered to be priority measures to be implemented. Details will be described in the next section.

11.2 Proposal of Priority Support Measures

11.2.1 Support for co-firing Implementation at existing Coal-fired Power Plants

The following three projects are proposed as "Support for co-firing Implementation at existing Coal-fired Power Plants" projects.

- FS and demonstration test for ammonia co-firing at coal-fired power plants
- FS and demonstration test for biomass co-firing at coal-fired power plants
- Support for institutional design for promotion of co-firing at coal-fired power plants

The schedule for these three projects is as follows. PLN has announced the implementation of biomass co-firing at 52 existing coal-fired power plants. The conducting of FS and demonstration tests for biomass co-firing at existing coal-fired power plants is in line with PLN's intentions, and it is necessary to start this immediately. If implementation of the demonstration test is included, financial cooperation will be required, and depending on the scale, cooperation through NEDO's international demonstration project etc. can be considered.

Demonstration tests are conducted for the purpose of confirming the effects, the operation/maintenance performance and costs, and the presence or absence of serious adverse effects, in order to promote the diffusion of the immature technologies to be verified. For this reason, in NEDO's international demonstration projects, it is necessary for private companies that own the technology to show that they are contributing some funds.
This would be the first attempt at biomass co-firing at a large-capacity coal-fired power plant in Indonesia, but the technology has been implemented at many power plants in Japan, and it is already past the stage of demonstration tests. If the Indonesian side wishes to carry out co-firing instead of a demonstration test, it will be possible to provide support by applying yen loans and overseas investment loans. However, even for a project that contributes to the reduction of CO_2 emissions, it is expected that support will be difficult to obtain if the lender's logic is that it is a project that will lead to a life extension measure for an existing coal-fired power plant.

Table 11-3 Implementation Schedule for Support for co-firing Implementation at existing Coal-fired Power Plants

Items	2022	2023	2024
Implementation of Feasibility Study and Demonstration Test			
FS and demonstration test for ammonia co-firing at coal-fired power plants			
FS and demonstration test for biomass co-firing at coal-fired power plants			
Support for institutional design for promotion of co-firing at coal-fired PPs			

(Source: JICA Survey Team)

The specific support content is shown below.

(1) FS and demonstration test for ammonia co-firing at coal-fired power plants

At present, coal-fired power generation is the main power source in Indonesia, but to reduce CO_2 emissions, it will be necessary to decommission aging plants as soon as possible, starting with the least efficient ones. In order to gradually reduce CO_2 emissions while securing a stable supply in the system, it will be effective to retrofit these coal-fired thermal power plants as ammonia mixed combustion and exclusive combustion plants.
In order to realize the mixed combustion of ammonia in existing coal-fired power plants, it is necessary to comprehensively examine facility retrofitting, fuel procurement, operability and economic efficiency. To carry out these studies efficiently, the cooperation of manufacturers of existing facilities and power generation companies with mixed combustion experience is required. Many Japanese

companies are involved in the latest USC coal-fired IPP project in Indonesia, and it is easy to obtain cooperation in co-firing and future exclusive firing. Therefore, it would be effective to select a pilot plant from these and provide support for advancing FS and demonstration tests.

(2) FS and demonstration test for biomass co-firing at coal-fired power plants

Although coal-fired power generation is one of the important power sources in Indonesia, in the short term it may be important to reduce CO_2 emissions from coal-fired power plants while ensuring a stable supply of electricity by using existing plants, given the increasing global headwinds toward coal-fired power generation. Biomass co-firing by retrofitting existing coal-fired power plants is a low-carbon technology that is expected to have an immediate effect, and it must be realized quickly.

In order to realize mixed combustion of biomass in existing coal-fired power plants, it is necessary to comprehensively examine facility retrofitting, fuel procurement, operability, and economic efficiency. The cooperation of manufacturers of existing facilities and power generators with mixed combustion experience is effective for these examinations.

In particular, the latest coal-fired IPP project in Indonesia has adopted a thermally efficient USC boiler, which makes it possible to supply more electricity from limited biomass resources, and makes it easier to recover the cost of retrofitting due to the long remaining life.

It is expected that the promotion of biomass co-firing retrofitting as a new cooperative project by JICA, using the latest high-efficiency coal-fired power plants as pilot plants, will be an effective measure to realize the expansion of biomass co-firing in existing plants.

(3) Support for institutional design for promotion of co-firing at coal-fired power plants

When implementing ammonia co-firing or biomass co-firing as a business, the question of how to secure the funds is very important. As mentioned in Chapter 9, if the simple avoidance of carbon costs for CO_2 emissions is considered the benefit, it will not be economical unless the carbon cost unit price is considerably high. For this reason, for business entities that own coal-fired power plants, there is no incentive to implement co-firing with simple economic principles.

On the other hand, the Indonesian government's policy is to realize a low-carbon society, and it is necessary to promote the introduction of co-firing at existing coal-fired power plants as a measure to reduce CO_2 emissions at an early stage. In order to promote such a policy, it is necessary to introduce a preferential system that includes financial support from the government. In addition to promoting the above-mentioned biomass co-firing remodeling as a new JICA cooperation project, by providing support to design and launch such a preferential system in Indonesia, referring to the support system in Japan, it is expected that the implementation of biomass co-firing at the 52 existing coal-fired power plants that PLN is about to carry out will proceed smoothly.

11.2.2 Master Plan Formulation

The master plan is a long-term vision and an important plan that will be incorporated into the national plan that forms the basis of the country’s policy. Basically, formulation will be carried out about once every 10 years, and after the formulation, facilities will be formed according to the plan. In this way, it is necessary to formulate a master plan with a long-term perspective based on the basic national plan, and it is very meaningful to provide support for this formulation.

The projects described in the master plan are basically projects that should be implemented with priority. For this reason, it is very important for companies aiming to implement a project in Indonesia in the future that their project is included in the master plan. From this point of view, providing support for the formulation of the master plan can be expected to have a beneficial effect on companies aiming to implement a project in Indonesia in the future.

The following five projects are proposed as “Master Plan Formulation” projects.

- Formation of the entire ammonia supply chain (master plan)
- Formulation of LNG master plan

- Development of master plan for the introduction of CCS in Indonesia
- Study on detailed long-term vision
- Formulation of power system master plan

The schedule for these five projects is as follows. Of these, the “Formulation of LNG master plan” and the “Study on detailed long-term vision” are urgent support measures and need to be started immediately.

Table 11-4 Implementation Schedule for Master Plan Formulation

Items	2022	2023	2024
Master Plan Formulation			
Formation of the entire ammonia supply chain (master plan)			
Formulation of LNG master plan			
Development of master plan for the introduction of CCS in Indonesia			
Study on detailed long-term vision			
Formulation of power system master plan			

(Source: JICA Survey Team)

The specific support content is shown below.

(1) Formation of the entire ammonia supply chain (master plan)

The entire ammonia supply chain will need to be established in the future, and support should be provided for the institutional design, upstream development, handling of marine transportation, and other knowledge required to establish this supply chain.

(2) Formulation of LNG master plan

One of this study’s conclusions recognized that LNG-fired power plants (including the implementation of CCS) are necessary as part of the power supply mix in 2060 and as a bridge until the goal of carbon neutrality in 2060. LNG has already been introduced in Indonesia, but in addition to the FSRU, which is the main receiving terminal that has been developed so far, it is necessary to consider the introduction of an onshore LNG receiving terminal with excellent scalability and the construction of peripheral infrastructure such as pipelines. Among these facilities, port and storage facilities are very expensive, and it may be more economical to build them as shared facilities rather than for each power plant to build them individually.
Considering these points, when introducing LNG in Indonesia, it is important to formulate a master plan for the development of LNG receiving terminals (importing port facilities and storage facilities) and pipelines, and to proceed with the construction of facilities in accordance with the master plan. Specifically, the following studies will be conducted.

- Selection of candidate sites for LNG receiving terminals (considering the location of existing thermal power plants and future power plant locations)
- Size of LNG receiving terminals (number of berths, capacity and number of storage facilities and vaporizers, etc.)
- Pipeline network concept
- Consideration of utilization for purposes other than power generation

(3) Development of master plan for the introduction of CCS in Indonesia

In order to promote CCS projects in the future, it is important to establish a master plan for the development of CCS from a long-term perspective, and to proceed with the construction and operation of facilities according to this plan. Specifically, the following studies will be conducted.

- Survey of suitable sites for CO_2 storage in Indonesia
- Wholistic study of CO_2 emission sources, including both thermal power plants and other industrial facilities
  - Estimation of how much CO_2 will be generated and for how long
- Study on configuration of CO_2 transport pipeline network/shipping scheme
- Select sites for demonstration tests of a combination of thermal power plants and CCS, based on the most feasible CO_2 storage sites and the current status of existing thermal power plants (coal or gas) from the considerations above.

(4) Study on detailed long-term vision

In conducting this survey, when matching the study conditions with PLN regarding the demand forecast up to 2060, there was a request from PLN to carry out a demand forecast analysis based on numerical grounds, such as assumptions for economic indicators, because PLN has been asked for a clear numerical basis for an external explanation. PLN understands that it is difficult to deal with demand forecasting based on economic indicator assumptions, etc. in this survey because they are not included in the scope of business, and two demand cases (the High-case currently forecasted by PLN and the Low-case forecasted via linear approximation based on RUPTL's demand forecast) are studied. In addition to the fact that this survey is not based on a formal request from the Indonesian government, the survey implementation period is very short (about 3 months) so the survey is being conducted under conditions whereby it is difficult to obtain the necessary detailed data. It is undeniable that the survey is a rough study based on large assumptions in the details because it is being conducted based on public information on websites, etc.

In discussions with PLN, it was requested that electricity demand be estimated based on economic indicators and the accumulation of major power-using equipment, and it is expected that PLN will be highly interested in implementing this project.

For this reason, it is desirable to study a detailed long-term vision after thoroughly discussing the details with PLN. A sample of the study content is indicated below.

- Study on demand forecast (forecasting based on economic indicators and accumulation of major power-using equipment, etc.)
- Study on changes in demand shape based on the introduction trends of EV and rooftop solar
- Study on detailed power source composition based on hourly changes in demand in each system (peak load time, midnight rate, daily load factor, etc.)
- Formulation of a long-term power development plan, with a fuel conversion plan (including co-firing) and abolition plan that takes into account the start-of-operation years of existing power plants
- Study on power source composition using the appropriate potential of solar power, and detailed study on the effects of interconnection between each system based on it

In order to formulate a consistent plan, it is better to implement an integrated master plan study that includes LNG and the power system within the same project. However, if they are carried out separately, it is better to start the formulation of the master plan for LNG and the power system based on the results of this study (at the stage when the conclusions can be seen to some extent), so that it is possible to formulate a consistent plan.

(5) Formulation of power system master plan

Since the power generation capacity of PV depends on weather conditions, there is a high possibility that suitable installation locations will be unevenly distributed, and if PV power generation sites become concentrated in a limited area and transmission facilities are not properly constructed so as to meet the generating capacity, a shortage of transmission capacity may occur, which may lead to an event where power generation output must be curtailed.

Therefore, it is necessary to periodically check the consistency between the generation development plan and the transmission network expansion plan considering both mid-term and long-term outlooks, and it is important to extend the period covered by the master plan, shorten the plan update cycle, and improve the accuracy of the plan.

First of all, we believe that it is necessary to formulate a very long-term master plan for the next 30 to 40 years.

11.2.3 Technical Cooperation Projects

The technical cooperation projects are basically projects to support the capacity development of PLN (or MEMR) staff. The following three projects are proposed as “Technical Cooperation Projects”.

- Study on technical risk reduction/avoidance measures for geothermal development
- Review of renewable energy potential
- Reflecting information in grid connection code (Review of Grid Code)

The schedule for these three projects is as follows. Basically, this is an urgent support measure, and it is necessary to start it immediately.

Table 11-5 Implementation Schedule for Technical Cooperation Projects

Items	2022	2023	2024
Technical Cooperation Projects			
Study on technical risk reduction/avoidance measures for geothermal	■■■■	■	
Review of renewable energy potential	■■■■	■	
Reflecting information in grid connection code (Review of Grid Code)	■■■■	■	

(Source: JICA Survey Team)

The specific support content is shown below.

(1) Study on technical risk reduction/avoidance measures for geothermal development

Japan Oil, Gas and Metals National Corporation (JOGMEC), New Energy and Industrial Technology Development Organization (NEDO) etc. are developing technologies related to the development and utilization of geothermal energy in Japan.

These technologies would contribute to geothermal development efforts in Indonesia by reducing risks at each phase of investigation/development/operation. By sharing information on these technologies with Indonesian engineers and applying the technologies appropriately, it will be possible to promote more geothermal development, and this is expected to contribute to low carbonization efforts.

(2) Review of renewable energy potential

In this survey, the numerical values described in RUPTL (values based on the National Energy General Plan (RUEN), 2017) were used as the potential amounts for renewable energy. According to this, the potential of solar power in Indonesia is 208 GW, but in discussions with MEMR, it has been reported that there is a potential of 3,200 GW or more.

The potential of solar power is a very important factor in achieving carbon neutrality, and the fact that the information deviates so much has a great influence on the optimum power source composition obtained as a result. In these potential assumptions, the difference in assumption conditions is considered to be a major difference factor, but if the policy is to actively develop renewable energy to achieve carbon neutrality in the future, a detailed potential survey should be conducted under that policy. Specifically, it is necessary to carry out not only a rough desk study using satellite images, but also a confirmation study via a field survey using local consultants.

(3) Reflecting information in grid connection code (Review of Grid Code)

When connecting renewable energy or a storage battery system to a grid, it is necessary to clearly state the system specifications and grid connection requirements in the grid code from this early stage so that the grid will not be adversely affected after the connection. In Japan, where the introduction of variable renewable energy such as solar power and wind power is already progressing, events that adversely affect the grid after connection are known, and the provisions for avoiding the adverse effects are reflected in the Grid Code. From this point of view, Japan's support is considered to be very effective.

Chapter 12. Activities to expand the Possibility of Overseas Expansion of Japanese Companies

12.1 Local Seminar

A seminar for Japanese companies in Indonesia was held with the aim of promoting their business to achieve low-carbonization/decarbonization in Indonesia's electric power sector in the future. Due to the COVID-19 situation, the seminar was held online. Dozens of Japanese companies and organizations participated in the seminar, and from the Indonesia side, PLN and MEMR participated as well. An outline of the seminar is as follows.

(1) Outline of the seminar

(a) Date and Time

Date: January 26th, 2022
Time: 10:00 – 13:00 (Jakarta Time)

(b) Venue

Online

(c) Program

1	10:00-10:05	Opening Remarks (JICA)
2	10:05-12:20	Presentations ● Reporting on present status of the survey "Data Collection Survey on Power Sector in Indonesia for Decarbonization" (JICA Survey Team) 1) Low carbonization/decarbonization Technologies for Thermal Power Plants 2) System stabilization technology 3) Prerequisites and Results of Simulation on Supply/Demand Operations 4) Ideas on JICA's Future Support ● Indonesia's efforts toward low-carbonization and de-carbonization (PLN)
3	12:20-12:55	Q&A and Discussion (all attendees and presenters)
4	12:55-13:00	Closing Remarks (JICA)

(d) Language

Indonesian and Japanese (with Consecutive Interpreting)

(e) Participants

Japanese companies that have an interest in low-carbonization/de-carbonization in Indonesia's electric power sector

12.2 Invitation to Japan

An invitation of Indonesian officials to Japan was planned for the purpose of exchanging opinions with Japanese officials on low-carbonization/decarbonization measures and improving their knowledge on low-carbonization/decarbonization technology. However, this was canceled due to the COVID-19 situation.