Power in Indonesia

Investment, taxation and regulatory guide

December 2025, 8th Edition

www.pwc.com/id

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Note: Totals in tables and charts may not add due to rounding differences.

Regulatory information is current to 31 October 2025.

Contents

Glossary

Term	Definition
ADB	Asian Development Bank
AI	Artificial intelligence
AMDAL	Environmental Impact Analysis (*Analisis Mengenai Dampak Lingkungan Hidup*)
APBD	Regional government budget (*Anggaran Pendapatan Belanja Daerah*)
APBN	State budget (*Anggaran Pendapatan Belanja Negara*)
APLSI	The Indonesian Independent Power Producers Association (*Asosiasi Produsen Listrik Swasta Indonesia*)
AP2T	Centralised customer service application (*Aplikasi Pelayanan Pelanggan Terpusat*)
ARED	Accelerated Renewable Energy Development (a scenario under the RUPTL)
ASEAN	Association of Southeast Asian Nations
Bappenas	National Development Planning Agency Board (*Badan Perencanaan Pembangunan Nasional*)
BAU	Business as usual
BBM	Oil fuel (*Bahan bakar minyak*)
BBTUD	Billion British thermal units per day
BESS	Battery energy storage systems
BKPM	Indonesian Investment Coordination Board (*Badan Koordinasi Penanaman Modal*)
BOE	Barrels of oil equivalent
BOO	Build-Own-Operate
BOOT	Build-Own-Operate-Transfer
BOT	Build Own-Transfer
BPJS	Social Security Agency (*Badan Penyelenggara Jaminan Sosial*)
BPP	Electricity generation cost (*Biaya Pokok Pembangkitan*)
CAES	Compressed air energy storage
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CEV	Carbon economic value
CFP	Coal-fired power
CFPP	Coal-fired power plant
CIT	Corporate income tax
CJPP	Central Java Power Plant
ckt-km	Circuit kilometre (*kilometer sirkuit* – kms)
CMM	Coal mine-mouth
CNG	Compressed natural gas
COD	Commercial operation date
COVID-19	Coronavirus Disease of 2019
CO_2e	CO_2 equivalent
COP26	26th meeting of the Conference of the Parties to the UNFCCC

Term	Definition
COP27	27th meeting of the Conference of the Parties to the UNFCCC
COP28	28th meeting of the Conference of the Parties to the UNFCCC
COP29	29th meeting of the Conference of the Parties to the UNFCCC
CWR	The Cash War Room
DEN	*Dewan Energi Nasional*
DER	Debt to equity ratio
DGE/DJK	Directorate General of Electricity (*Direktorat Jenderal Ketenagalistrikan*)
DGNREEC	Directorate General of New and Renewable Energy and Energy Conservation (*Direktorat Jenderal Energi Baru, Terbarukan dan Konservasi Energi*)
DGT	Directorate General of Taxes (*Direktorat Jenderal Pajak*)
DMO	Domestic Market Obligation
DPR	House of Representatives (*Dewan Perwakilan Rakyat*)
EBTKE	New and Renewable Energy and Energy Conservation (*Energi Baru, Terbarukan dan Konservasi Energi*)
EIT	Employee income tax
EJ	Exajoule
E&E	Exploration and evaluation
ENDC	Enhanced Nationally Determined Contribution
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement and Construction
ESG	Environmental, social and governance
ETM	Energy Transition Mechanism
ETP	Energy Transition Programme
ETR	Effective Transition Roadmap
FiT	Feed-in Tariff
FM	Force majeure
FSRU	Floating storage regasification unit
FTA	Free Trade Agreement
FTP I	The fast track programme introduced in 2006, mandating PLN to build 10 GW of coal-fired plants across Indonesia
FTP II	The fast track programme introduced in 2010 for building 10 GW of power plants focusing on renewable energy sources and IPP involvement
G20	The Group of Twenty
GCA	Government Contracting Agency
GDE	PT Geo Dipa Energi (Persero), a state-owned geothermal company
GDP	Gross domestic product
GFPP	Gas-fired power plant
GHG	Greenhouse gas
GoI	Government of Indonesia (Central Government)
GR	Government Regulation (*PP* or *Peraturan Pemerintah*)
GSF	Geothermal Support Fund
Gt	Gigatonne
GW	Gigawatt (1,000 MW)
GWh	Gigawatt hours
HBA	Coal reference price (*Harga Batubara Acuan*)
HEESI	Handbook of Energy & Economic Statistics of Indonesia
HoA	Head of Agreement

Term	Definition
HPB	Coal benchmark price (*Harga Patokan Batubara*)
HSFO	High Speed Fuel Oil
HVDC	High voltage direct current
ICP	Indonesian crude price
IEA	International Energy Agency
IDR	Indonesian rupiah
IDX	Indonesia Stock Exchange
IDX Carbon	Indonesia Carbon Exchange
IFRIC	International Financial Reporting Interpretations Committee
IFRS/IAS	International Financial Reporting Standards/International Accounting Standards
IIGF	Indonesian Infrastructure Guarantee Fund (also known as PT Penjaminan Infrastruktur Indonesia – PTPII)
IIR	Income Inclusion Rule
I-JETP	The Indonesia Just Energy Transition Partnership
IO	Operating licence (*Izin operasional*)
IPB	Geothermal licence under the 2014 Law (*Izin Panas Bumi*)
IPP	independent power producer
IRRs	Internal rates of return
ISAK	Interpretation of Indonesian Financial Accounting Standards (*Interpretasi Standar Akuntansi Keuangan*)
IT	Information technology
ITO	Indonesian Tax Office
IUJPTL	Electricity Supporting Services Licence (*Izin Usaha Jasa Penunjang Tenaga Listrik*)
IUPTL/IUPTLU	Electricity Supply Business Licence (*Izin Usaha Penyediaan Tenaga Listrik*, sometimes referred to as *Izin untuk Melakukan Usaha Penyediaan Tenaga Listrik untuk Kepentingan Umum* – IUKU)
IUPTLS	Temporary Electricity Supply Business Permit (*Izin Usaha Penyediaan Tenaga Listrik Sementara*)
JBIC	Japan Bank for International Cooperation
JETP	Just Energy Transition Partnership
JOC	Joint Operation Contract
Kadin Indonesia	the Indonesia Chamber of Commerce and Industry (*Kamar Dagang dan Industri Indonesia*)
KBLI	Indonesian Standard Industrial Classifications (*Klasifikasi Baku Lapangan Usaha Indonesia*)
KPPIP	The Committee for the Acceleration of Prioritised Infrastructure Development (*Komite Percepatan Penyediaan Infrastruktur Prioritas*)
km	Kilometre
KTT	Large Industrial Customers (*Konsumen Tegangan Tinggi*)
kW	Kilowatt
kWh	Kilowatt-hour
kV	Kilovolt
kVA	Kilovolt ampere
LCR	Local Content Requirement
LKPP	The Government Procurement of Goods and Services Policy Board (*Lembaga Kebijakan Pengadaan Barang dan Jasa Pemerintah*)

Term	Definition
LMAN	State Assets Management Agency (*Lembaga Manajemen Aset Negara*)
LNG	Liquefied natural gas
LoI	Letter of Intent
LTS-LCCR	Indonesia's Long-Term Strategy for Low Carbon and Climate Resilience
MBOPD	Thousand barrels of oil per day
MBOEPD	Thousand barrels of oil equivalent per day
METI	Indonesian Renewable Energy Society (*Masyarakat Energi Terbarukan Indonesia*)
MKI	Indonesian Electrical Power Society (*Masyarakat Ketenagalistrikan Indonesia*)
ML	Machine learning
MMBOE	Million barrels of oil equivalent
MMBtu	Million British thermal units
MMSCFD	Million standard cubic feet per day
MNE	Multinational enterprise
MoEMR	Ministry of Energy and Mineral Resources (*Kementerian Energi dan Sumberdaya Mineral*)
MoEF	Ministry of Environment and Forestry (*Kementerian Lingkungan Hidup dan Kehutanan*)
MoF	Ministry of Finance (*Kementerian Keuangan*)
MoI	Ministry of Industry (*Kementerian Perindustrian*)
MoSOE	Ministry of State-Owned Enterprises (*Kementerian Badan Usaha Milik Negara*)
MoPW	Ministry of Public Works and Housing (*Kementerian Pekerjaan Umum dan Perumahan Rakyat*)
MoU	Memorandum of Understanding
MSW	Municipal solid waste
$MtCO_2e$	Million tonnes of carbon dioxide equivalent
MTPA	Million tonnes per annum
MTOE	Million tonnes of oil equivalent
MVA	Megavolt amperes
MW	Megawatts
MWac	Megawatt alternating current
MWh	Megawatt-hour
MWp	Megawatt peak
NDC	Nationally Determined Contribution
NEP	National Energy Policy (*Kebijakan Energi Nasional*/KEN)
NRE	New and renewable energy
NIB	Single Business Number (*Nomor Induk Berusaha*)
NZE	Net-zero emissions
O&M	Operations and maintenance
OECD	Organisation for Economic Co-operation and Development
OJK	The Financial Services Authority of Indonesia (*Otoritas Jasa Keuangan*)
OSS	Online Single Submission
p.a.	Per annum
PBG	Building Approval (*Persetujuan Bangun Gedung*)
PB UMKU	Business Licensing to Support Business Activities (*Perizinan Berusaha Untuk Menunjang Kegiatan Usaha*)

Term	Definition
Persero	*Perusahaan Perseroan*
PES	Primary energy supply
PGE	PT Pertamina Geothermal Energy, a state-owned geothermal company
PHES	Pumped hydro energy storage
PKUK	Authorised Holder of an Electricity Business Licence under the 1985 Electricity Law (*Pemegang Kuasa Usaha Ketenagalistrikan*)
PLN	PT Perusahaan Listrik Negara (Persero), the state-owned electricity utility
PLTA	Hydroelectric power plant (*Pembangkit Listrik Tenaga Air*)
PLTB	Wind power plant (*Pembangkit Listrik Tenaga Bayu*)
PLTBg	Biogas power plant (*Pembangkit Listrik Tenaga Biogas*)
PLTBm	Biomass power plant (*Pembangkit Listrik Tenaga Biomassa*)
PLTD	Diesel power plant (*Pembangkit Listrik Tenaga Diesel*)
PLTGU	Gas and steam power plant (*Pembangkit Listrik Tenaga Gas dan Uap*)
PLTP	Geothermal power plant (*Pembangkit Listrik Tenaga Panas Bumi*)
PLTS	Solar power plant (*Pembangkit Listrik Tenaga Surya*)
PLTSa	Waste-to-energy power plant (*Pembangkit Listrik Tenaga Sampah*)
POJK	*Peraturan Otoritas Jasa Keuangan*
POME	palm oil mill effluent
PPA	Power Purchase Agreement
PPP	Public-Private Partnership
PPU	private power utility
PR	Presidential Regulation (Perpres or *Peraturan Presiden*)
PSAK	Indonesian Financial Accounting Standards (*Pernyataan Standar Akuntansi Keuangan*)
PSPE	Preliminary Geothermal Survey and Exploration Assignment (*Penugasan Survey Pendahuluan dan Eksplorasi*)
PSN	National strategic project (*Proyek Strategis Nasional*)
PT IIF	PT Indonesia Infrastruktur Financing (a subsidiary of PT SMI)
PT PII	PT Penjaminan Infrastruktur Indonesia (also known as the IIGF)
PT SMI	PT Sarana Multi Infrastruktur (a fund set up to support infrastructure financing in Indonesia)
PT TGRA	PT Terregra Asia Energy Tbk
PV	Photovoltaic
PwC	PwC Indonesia, or the PwC global network of firms, as the context requires
QDMTT	Qualified Domestic Minimum Top-up Tax
RAPBN	Draft state revenue and expenditure budget (*Rancangan Anggaran Pendapatan dan Belanja Negara*)
RDF	Refuse-derived fuel
RE	Renewable energy
RENSTRA	Strategic Plan (*Rencana Strategis*)
RfP	Request for Proposal
RPJPN	Long-term National Development Plan (*Rencana Pembangunan Jangka Panjang Nasional*)
RUED	Regional energy plan (*Rencana Umum Energi Daerah*)
RUEN	National General Energy Plan (*Rencana Umum Energi Nasional*)
RUKD	Regional Electricity General Plan (*Rencana Umum Ketenagalistrikan Daerah*)
RUKN	National Electricity General Plan (*Rencana Umum Ketenagalistrikan Nasional*)

Term	Definition
RUPTL	Electricity Supply Business Plan (*Rencana Usaha Penyediaan Tenaga Listrik*)
SHP	Small-scale hydropower
SLO	Certificate of Operational Eligibility (*Sertifikat Laik Operasi*)
SOE	State-owned enterprise
SPPL	Statement of Capability in Environmental Management and Monitoring (*Surat Pernyataan Kesanggupan Pengelolaan dan Pemantauan Lingkungan Hidup*)
SPV	Special purpose vehicle
SR	Sustainability reporting
SUTET	Extra High Voltage Overhead Transmission Lines
T&D	Transmission and distribution
TES	Total energy supply
TOE	Tonnes of oil equivalent
TP	Transfer pricing
TWh	Terawatt hours
UKL-UPL	Environmental Management Efforts and Environmental Monitoring Efforts (*Upaya Pengelolaan Lingkungan Hidup dan Upaya Pemantauan Lingkungan Hidup*)
UN	United Nations
UNFCCC	United Nations Framework Convention on Climate Change
UNOPS	United Nations Office for Project Services
USD	US dollar
GAAP	Generally Accepted Accounting Principles
VA	Volt ampere
VAT	Value added tax
VRE	Variable renewable energy
WHT	Withholding tax
WKP	Geothermal Working Area (*Wilayah Kerja Panas Bumi*)
WLCAS	World Leaders Climate Action Summit
WPSPE	Preliminary Survey and Exploration Area (*Wilayah Penugasan Survey Pendahuluan dan Eksplorasi*)
WtE	Waste-to-energy
y-o-y	year-on-year

Foreword

Indonesia is at a crucial point in the development of its long-term power generation strategy, which needs to support its ambitious economic growth targets, while considering the trilemma of affordability, availability and sustainability of its electricity supply. The Government through the 2025 energy and electricity planning documents has signalled a significant planned ramp-up in renewable energy development over the next ten years, for which a large component of the significant capital requirement is planned to come from the private sector. This will necessitate improved investment terms to attract the necessary investment. At the same time as supporting the country's long-term economic growth, this will go a long way to helping Indonesia achieve its commitments under international climate change agreements and at the same time support its long-held ambition of energy security.

Indonesia has successfully continued to meet its increasing energy demands. However, this energy fulfillment is still heavily dominated by fossil fuels, such as coal. Alongside coal, both natural gas and petroleum remain important components in meeting domestic energy needs. This reliance has led to a consistent increase in greenhouse gas (GHG) emissions in Indonesia, rising from 264 million tonnes of carbon dioxide equivalent ($MtCO_2e$) in 2000 to an expected 309 $MtCO_2e$ in 2025.

Indonesia has set ambitious targets in the energy sector. According to the National Energy Policy (NEP), renewable energy (RE) is expected to account for 23% of the primary energy supply by 2025 and an even higher target of 31% by 2050. Additionally, Indonesia aims to achieve net-zero carbon emissions by 2060. However, these targets are still far from being met. In 2024, renewable energy only accounted for 14.68% of the total[1], making the 2025 target all but impossible to achieve. Currently, coal and oil still dominate the primary energy supply, contributing approximately two-thirds of the total. According to data from the Ministry of Energy and Mineral Resources (MoEMR), coal and oil account for 40.56% and 28.14% of the total energy mix, respectively.

One of Indonesia's significant achievements in the energy sector is evident in the production of energy for the electricity sector. Over the past ten years, there has been a substantial improvement in electrification rates in Indonesia, rising from 72.95% in 2011 to 99.83%

1 MoEMR., 2024. Handbook Of Energy & Economic Statistics Of Indonesia (HEESI). https://www.esdm.go.id/en/publication/handbook-of-energy-economic-statisticsof-indonesia-heesi

in 2024[2]. This progress has driven economic growth and increased the electrification of the economy. This advancement is reflected in the rising share of electricity in final energy consumption, which grew from 6% in 2000 to 19% in 2021, though it slightly decreased to approximately 16.1% in 2024, indicating a nuanced shift in energy dynamics. Per capita electricity consumption also saw substantial growth, soaring from 328 kilowatt-hour (kWh) in 2000 to over 1,000 kWh by 2022, and continuing to rise to around 1,411 kWh in 2024.

In its enhanced Nationally Determined Contributions (NDCs) under the Paris Agreement, Indonesia has pledged to reduce GHG emissions across the economy by 31.89% unconditionally and 43.20% conditionally (with international support) by 2030. This equates to a reduction of 914 $MtCO_2e$ unconditionally and 1,238 $MtCO_2e$ conditionally from the business-as-usual (BAU) scenario, where total emissions are expected to reach 2,868 $MtCO_2e$ by 2030. The energy sector's contribution to this reduction includes 358 $MtCO_2e$ unconditionally and 446 $MtCO_2e$ conditionally, representing a 21% and 27% reduction from the sector's BAU emissions, respectively. These enhanced NDCs align with Indonesia's Long-Term Strategy for Low Carbon and Climate Resilience (LTS-LCCR) for 2050, which aims to achieve net-zero emissions (NZE) by 2060 or earlier.

The power sector is expected to help achieve these goals. According to PLN's 2025-2034 Electricity Supply Business Plan (*Rencana Usaha Penyediaan Tenaga Listrik*/RUPTL), Indonesia plans to install up to 42.6 gigawatts (GW) of RE capacity by 2034, supported by 10.3 GW of energy storage systems. This includes both utility-scale and distributed renewable energy projects, with a focus on solar, hydro, geothermal and biomass. According to the enhanced NDCs, Indonesia aims to have a 23% RE mix in total primary energy supply (PES) by 2025 and at least 31% by 2050. However, progress has been slow, with the RE proportion in PES reaching only about 14.68%[3] in 2024. Additionally, the Indonesia Just Energy Transition Partnership (JETP) targets at least 34% RE in the power generation mix by 2030.

Indonesia faces several obstacles to accelerating its energy transition, including issues within governance frameworks, institutional structures, market models, energy pricing and risk-sharing models. Key concerns include the market model, which features a single integrated utility company acting as both the sole buyer and supplier of electricity for public interest, overlapping governance responsibilities among ministries and subsidies that result in underpriced energy supply.

To meet Indonesia's NDC targets and effectively utilise JETP support, it will be necessary to implement structural changes in governance frameworks, institutional structures, market models, utility cost recovery, energy pricing and capacity procurement. These changes are essential to speed up the integration of RE into the electricity supply.

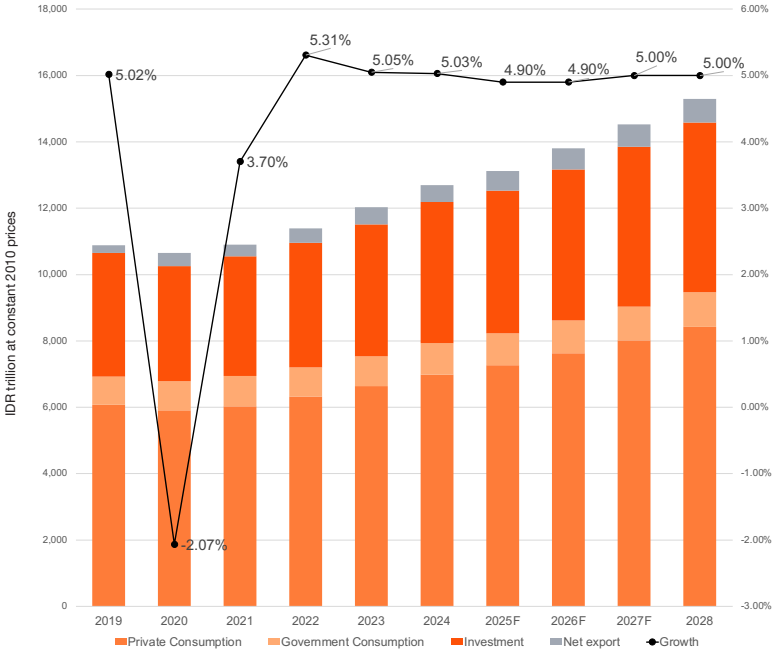
2 PLN, 2025. ESG Performance Report 2024. https://web.pln.co.id/statics/uploads/2025/07/ESG-Performance-Report-2024-1.pdf
3 MoEMR Directorate General of Electricity, 2025. Laporan Kinerja 2024

1 Overview of the Indonesian power sector

Indonesia is an archipelago of over 18,000 islands, with a population of 281.6 million as of 2024. This makes it the world's fourth most populous country, and the largest economy in Southeast Asia[1].

Indonesia's economy in 2024 grew approximately 5% year-on-year (y-o-y)[2]. As of 2024, the main components of the Indonesian gross domestic product (GDP) were manufacturing (18.98% of GDP), wholesale and retail (13.07%), agriculture and forestry (12.61%), construction (10.09%), as well as mining and quarrying (9.15%)[3].

Figure 1.1 – Historical and forecasted GDP growth and contribution by expenditure item (% per annum/p.a.)



Source: Bank Indonesia, Economist Intelligence Unit, Bloomberg

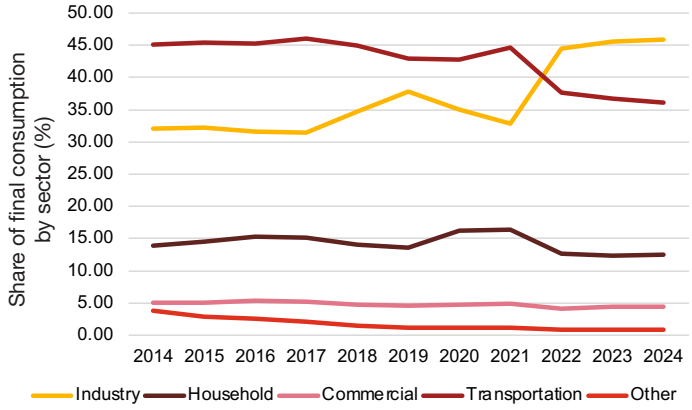
As economic growth continues, energy infrastructure, particularly in the power sector, plays a critical role in enabling industrialisation, urbanisation and improved living standards. Electricity consumption is closely linked to GDP growth, as expanding economic activity drives higher demand across sectors. While the country has achieved near-universal electrification, regional disparities persist, with western Java consuming the most electricity due to its industrial concentration. These imbalances highlight the importance of strategic planning in power generation and distribution to not only meet rising demand but also ensure equitable access.

1.1 Power demand and supply in Indonesia

1.1.1 Demand of the Indonesian power sector

As the Indonesian economy continued to expand in 2024, the country experienced a notable increase in energy consumption, rising by 4.43% to reach the equivalent of 1,292 million barrels of oil equivalent (BOE). Energy use in 2024 marked the highest level recorded in the past decade, with the industrial sector accounting for the largest share of energy demand at 45.94%, followed by transportation at 36.11%, households at 12.58%, commercial activities at 4.47% and other sectors at 0.90%[4]. The industrial sector's dominance in energy consumption was primarily driven by its substantial use of coal and natural gas. Within the sector, coal represented the largest share at 58.45%, followed by gas at 14.65% and electricity at 12.42%[5].

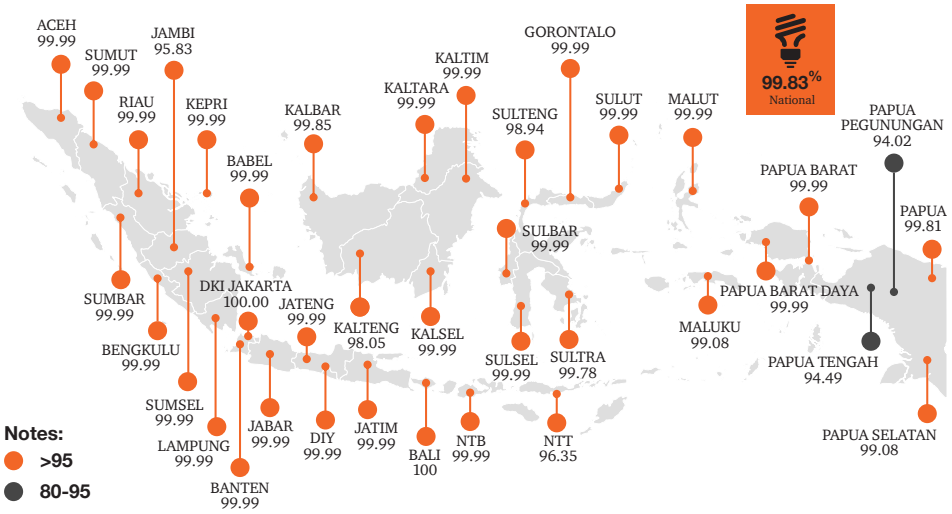
Figure 1.2 – Electricity consumption by sectors



Source: MoEMR, HEESI 2024 (2025), p. 26

Indonesia recorded an electrification ratio of 99.83% in 2024[6], reflecting a marginal increase from 99.79% in 2023 and indicating near-universal access to electricity nationwide. This growth aligns with the overall rise in energy consumption and the substantial share of electricity in the national energy mix. However, despite the high national average, electricity distribution remains uneven across regions. Electricity consumption is significantly higher in more industrialised areas, particularly in western Java. Although Java exhibits the highest electrification rates nationally, access to the electricity grid remains varied across the country. Electrification rates range from 100% in provinces such as Bali and Jakarta to as low as 94.02% in less developed regions, including Papua Pegunungan (refer to Figure 1.3).

Figure 1.3 – Indonesian electrification ratio by province - 2024



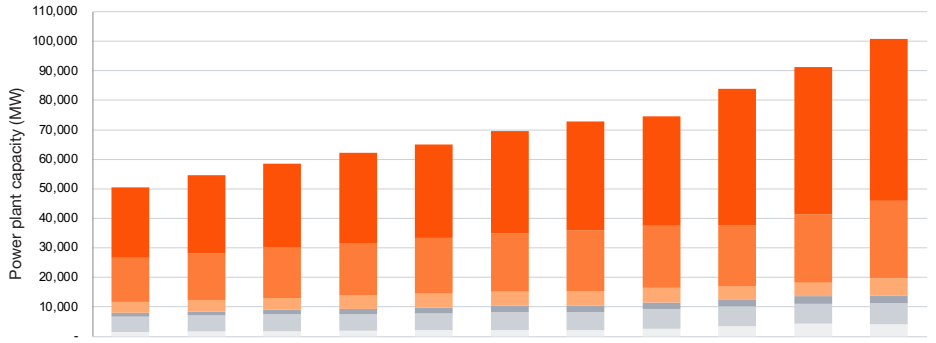
Source: MoEMR, Laporan Kinerja (Lakin) 2024 (2025), p. 179

1.1.2 Supply of the Indonesian power sector

1.1.2.1 Indonesian installed capacity

As a response to rising electricity demand, Indonesia continues to expand and diversify its power supply infrastructure. By December 2024, Indonesia had approximately 100.7 GW of installed power plant capacity[7], including power plants owned by PLN/independent power producers (IPPs), private power utilities (PPU), and plants operating under non-fossil fuel operating licences (*Izin Operasional Non-BBM*/IO Non-BBM). The current power generation fuel mix includes coal, gas, oil and renewables as illustrated in Figure 1.4.

Figure 1.4 Indonesia installed power plant capacity, 2014-2024



Power plants (MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Other renewable energy	1,427	1,780	1,831	1,913	2,090	2,195	2,206	2,644	3,566	4,395	4,218
Hydro(s)	5,237	5,307	5,651	5,688	5,772	5,976	6,121	6,601	6,689	6,570	7,052
Geothermal	1,403	1,438	1,533	1,808	1,948	2,131	2,131	2,286	2,360	2,598	2,639
Diesel	3,637	3,824	3,979	4,396	4,631	4,780	4,864	4,986	4,352	4,638	5,819
Gas	14,885	15,890	17,070	17,660	18,926	19,860	20,762	20,979	20,831	23,208	26,167
Coal	23,858	26,448	28,352	30,768	31,587	34,737	36,668	37,036	46,015	49,756	54,789
Total	**50,447**	**54,687**	**58,416**	**62,233**	**64,954**	**69,679**	**72,752**	**74,532**	**83,813**	**91,165**	**100,684**

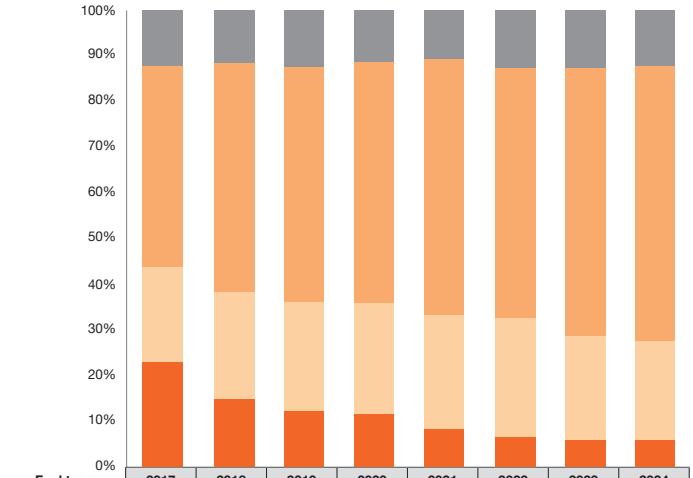
Source: MoEMR, HEESI 2024 (2025), p. 88-89

Power plant capacity in Indonesia has experienced significant growth over the past decade, increasing by approximately 44% from 2019 to 2024. This expansion aligns with rising electricity demand across industrial and residential sectors. Among the various energy sources, coal-fired power plants (CFPPs) have consistently contributed the largest share of installed capacity, reaching approximately 54.8 GW in 2024, which accounts for more than 54% of the total national power generation capacity.

1.1.2.2 Source of energy

Figure 1.5 illustrates the historical Indonesia energy mix from 2017-2024, highlighting a gradual increase in renewables. Coal has increased its share from 30.54% in 2017 to an estimated 40.56% in 2024, reaffirming its dominant position in the national energy landscape[8]. This trend is largely attributable to Indonesia's substantial domestic coal reserves, which offer a reliable and economically viable source of energy. In contrast, the shares of oil and gas have declined steadily over the same period, while new and renewable energy sources have shown encouraging growth, rising from 6.66% in 2017 to an estimated 14.68% in 2024.

Figure 1.5 Indonesia energy generation mix, 2017-2024



Fuel type	2017	2018	2019	2020	2021	2022	2023	2024
Oil and biofuel	41.39%	38.73%	34.98%	32.75%	33.38%	32.40%	29.80%	28.14%
Gas	21.41%	19.67%	18.55%	17.45%	16.82%	16.82%	16.50%	16.62%
Coal	30.54%	32.99%	37.29%	38.53%	37.62%	37.62%	39.65%	40.56%
NRE	6.66%	8.61%	9.18%	11.27%	12.18%	12.16%	14.06%	14.68%

Sources: MoEMR Directorate General of Electricity, Lakin 2023 (2024) & Lakin 2024 (2025)

The significant role of fossil fuels in the energy mix reflects Indonesia's natural abundance of these resources, which continues to shape the country's energy strategy, as outlined in detail in *Chapter 4 - Conventional energy*. There are three major conventional energy resources and each exhibit distinct key factors and trends, as follows:

- **Coal**: Coal has historically been, and continues to be, Indonesia's most important source of fuel for generating electricity, and a driver of economic growth. Economic and logistical considerations (as well as the significant amount of available reserves) have led to the ongoing dominance of coal as a low-cost fuel that is easy to extract and transport within the existing infrastructure limitations. By the end of 2024, coal accounted for 40.56% of the total energy mix[9]. The 2025–2034 RUPTL includes plans for additional coal-fired power plants, targeting 6.3 GW of capacity to be built by 2034 (although the targets for renewables are much higher, as discussed later)[10].
- **Natural gas**: Natural gas has been considered a potential transition fuel while renewables are built out, given the relatively lower carbon emissions compared to coal, and Indonesia's significant gas reserves. However, to enable a strong long-term role for gas in the Indonesian power generation fuel mix, certainty over the upstream oil and gas investment climate, improved physical infrastructure (including pipelines and floating storage regasification units (FSRUs)) and the pricing of gas-for-power arrangements are crucial.
- **Oil**: Crude oil, including imports, has traditionally played a large role in Indonesia's energy supply. However, since Indonesia became a net oil importer almost 20 years ago, increasing oil prices have driven Indonesia's energy mix away from diesel power plants. PLN aims

to continue its commitment to significantly reduce the use of oil in Indonesia's electricity generation fuel mix to only 0.2% by 2034[11]. However, based on the 2025-2034 RUPTL, the Government of Indonesia (GoI) has included an allowance for oil in 2025 and 2026 as a contingency measure to mitigate the current gas supply shortage, in alignment with the Draft State Revenue and Expenditure Budget (*Rancangan Anggaran Pendapatan dan Belanja Negara*/RAPBN)[12].

Other forms of non-conventional fossil fuel energy, such as coalbed methane and coal gasification technologies are being considered for development in Indonesia, but so far their impact has been insignificant. We have not explored these technologies in this guide, due to their limited current usage. For a full overview of the regulatory, tax and investment issues in the mining as well as the oil and gas sectors, please see the latest PwC Indonesia Mining and Oil and Gas Investment Guides (see *More insights* in the Appendices for a list of publications).

Table 1.1 - Potential renewable energy in Indonesia

Source	Potential power generation (GW)
Hydropower	75.0
Mini-micro hydro	19.3
Geothermal	29.5
Bioenergy	32.6
Solar	207.8
Wind	60.6
Ocean	17.9

Source: 2025-2034 RUPTL, p. III-11,12

Renewable energy is nonetheless looking increasingly attractive in Indonesia, not only as a result of the supportive environmental policy around CO_2 emissions and urban air pollution, but also due to its improving cost profile and capacity to be deployed in a decentralised manner. According to the 2025-2034 RUPTL, the key factors and trends in the five major renewable energy sectors include the following:

- **Hydro**: Hydropower is currently the largest source of renewable energy in Indonesia, accounting for 7% of the total installed power generation capacity by the end of 2024[13]. The RUPTL plans for 11.7 GW of additional hydropower plant capacity over the next ten years, which would bring the total capacity to 12.2 GW in 2034. As part of its green energy acceleration efforts, PLN is actively advancing several strategic hydropower projects across Indonesia. In North Kalimantan, PLN is collaborating with PT Kayan Hydropower Nusantara on the development of the Mentarang Induk Hydropower Plant, with a planned capacity of 1,375 MW, and the Kayan Cascade project, which is projected to deliver up to 9,000 MW of renewable electricity to support the Tanah Kuning Green Industrial Park. Meanwhile, on Java Island, PLN is constructing the Upper Cisokan Pumped Storage Hydropower Plant, Indonesia's first pumped storage facility, with a capacity of 1,040 MW[14].

- **Solar photovoltaic (PV)**: According to HEESI 2024, the installed solar power capacity reached 482.4 MW by the end of 2024. The 2025-2034 RUPTL targets 17.1 GW of additional solar power capacity to be built by 2034, bringing total planned capacity to 17.4 GW. As of writing, Cirata Solar Power Plant (*Pembangkit Listrik Tenaga Surya*/PLTS) is Indonesia's first utility-scale floating solar PV and the largest in Southeast Asia, contributing 245 gigawatt hours (GWh)/year of clean energy with a capacity of 145 megawatt alternating current (MWac), equivalent to 192 megawatt peak (MWp)[15]. The GoI's revised MoEMR Regulation No. 2/2024 removes net-metering and capacity limits for rooftop solar, while introducing a quota system to ensure grid stability[16]. Rooftop solar is planned to reach 3.0 gigawatt peak (GWp) by 2034, supported by structured regional quotas. Additionally, PLN is piloting a hybrid solar-battery-hydrogen fuel cell project in Sumba, East Nusa Tenggara (Nusa Tenggara Timur/NTT), aiming to reduce diesel dependency and improve energy access in remote areas[17]. Floating solar PVs are also planned across multiple reservoirs, with a national potential of 13.9 GW identified[18].
- **Geothermal**: Indonesia, which possesses the world's second-largest geothermal reserves, is advancing its clean energy transition through steady geothermal development. By the end of 2024, Indonesia's geothermal installed capacity reached 2,638.7 MW, contributing approximately 3% to the country's total installed capacity. The 2025-2034 RUPTL targets 5.2 GW of additional geothermal capacity to be built by 2034, bringing total planned capacity to 5.24 GW. As a reliable base-load source, geothermal helps address the intermittent challenges faced by solar, wind and small hydro. Despite limited concessions and slow power purchase agreement (PPA) approvals, both private sector and state-owned enterprises continue to play a key role in driving progress. In 2024, PLN Indonesia Power and Pertamina Geothermal Energy formed a consortium to develop binary units at Lahendong (15 MW) and Ulubelu (30 MW), enhancing efficiency through co-generation. Kamojang Geothermal Power Plant (PLTP) became Southeast Asia's first geothermal plant to produce green hydrogen, supporting PLN's "Beyond kWh" strategy[19]. A joint study agreement with China Energy aims to explore large-scale renewable projects in Sulawesi, reinforcing geothermal's strategic role in Indonesia's energy future[20].
- **Bioenergy**: Indonesia's bioenergy market spans several segments, including agricultural and plantation biomass waste, palm oil mill effluent (POME), municipal solid waste (MSW) and biodiesel. Despite the current dominance of small-scale power plants of 10 MW or less, the sector holds significant untapped potential, particularly in agricultural residues and MSW, which are often poorly managed. Unlocking this potential will require regulatory and contractual reforms, especially at the sub-national level, with Presidential Regulation No. 35/2018 remaining the legal basis for MSW-based power purchase agreements. According to the 2025-2034 RUPTL, bioenergy continues to play a strategic role in the energy transition, particularly through biomass co-firing in coal-fired power plants, waste-to-energy (PLTSa) and biogas (PLTBg) initiatives, with a target of an additional 0.9 GW of bioenergy power plant capacity to be built by 2034, bringing total planned capacity to 1.2 GW. As of 2024, Indonesia's installed bioenergy capacity stood

at approximately 3,063 MW, with PLN prioritising small-scale PLTBg and biomass power plant (PLTBm) projects in rural and isolated areas such as Riau, Kalimantan and Papua. In 2024 alone, PLN's co-firing programme generated 16.7 million megawatt hours (MWh) of green electricity across 43 coal plants, significantly reducing coal dependency[21] and projecting an annual biomass demand of 10.7 million tonnes by 2030. PLN is also piloting biogas plants such as the Pasadena PLTBg in Rokan Hulu, Riau, which uses palm oil liquid waste to generate 3 MW of continuous clean power. To support long-term investment in bioenergy and other renewables, PLN signed a strategic memorandum of understanding with China Exim Bank in May 2025, covering financing for biomass, geothermal, waste-to-energy and green transmission infrastructure[22].

- **Wind**: Wind energy has historically played a minor role in Indonesia's energy mix, with only 152.3 MW of installed capacity by the end of 2024[23], primarily from Sidrap Wind Power Plant (PLTB) and Jeneponto PLTB. However, under the 2025–2034 RUPTL, wind power is set for substantial expansion, with new projects planned across several provinces to bring total capacity to a planned 7.3 GW by 2034. PLN has planned several projects across South Sulawesi, South Kalimantan and Java, including large-scale developments such as Tanah Laut (70 MW), Sidrap II (50 MW), Takalar (60 MW) and Bantaeng (84 MW) PLTBs, as well as smaller projects, such as Selayar (5 MW) and Karimunjawa (2.2 MW) PLTBs, with the latter aiming to begin commercial operations in 2026. To address intermittency, PLN will integrate battery energy storage systems, recommending at least 10% of wind capacity for grid stability. In 2024, PLN Nusantara Power partnered with a Chinese company to support technology transfer and local capacity building, reflecting Indonesia's commitment to renewable energy and carbon reduction.

As discussed further in *Chapter 4 - IPP investment in Indonesia,* the 2025-2034 RUPTL plans for a significant portion of the new generation capacity over the next ten years to be constructed by IPPs – 52.76 GW under the RE Base scenario and 69.51 GW under the Accelerated Renewable Energy Development (ARED) scenario. This provides unprecedented opportunity for the private sector to participate in the expansion of renewable energy generation in Indonesia. Further discussions of renewables, including other technologies, such as ocean thermal energy conversion, can be found in *Chapter 6 - Renewable energy*.

1.1.2.3 Transmission and distribution

Given its archipelagic geography, Indonesia's electricity infrastructure is fragmented into more than 600 isolated grids and eight major networks. This decentralised structure presents unique challenges for power transmission and distribution (T&D). Currently, PLN holds a de facto monopoly over T&D asset ownership and operations, although regulations do allow private sector participation. In practice, some IPPs have constructed transmission lines, particularly in remote areas, to connect their power plants to the nearest PLN substations. However, these assets are typically transferred to PLN upon the completion of construction, reinforcing PLN's central role in the national grid.

At the end of 2024, PLN served 92 million customers, an increase of 4.17% from 2023, through a transmission network comprising 90,196 circuit kilometres (kms) of transmission lines and 182,786 megavolt amperes (MVA) of transformation capacity, with 2,700 sub-station transformers. These include 93 units of 500 kilovolt (kV) systems, 50 units of 275 kV systems, 2,247 units of 150 kV systems, 308 units of 70 kV systems and 2 units of systems below 30 kV. Transmission network projects are generally implemented by PLN, while transmission projects specifically related to individual IPPs are conducted by IPP developers, in accordance with PLN's requests for proposal[24].

A summary of the transmission lines for each significant island in Indonesia is as follows (in kms):

Table 1.2 – Transmission lines

Region/island	25-30 kV	70 kV	150 kV	275 kV	500 kV	Total
Java-Bali	96.79	2,996.44	17,238.24	-	2,609.53	22,941.00
Kalimantan	-	2,508.76	15,495.97	162.74	-	18,167.47
Nusa Tenggara	-	1,338.73	1,547.33	-	-	2,886.06
Papua and Maluku	-	400.48	259.95	-	-	660.43
Sulawesi	4.54	1,130.38	16,226.23	7.08	-	17,368.23
Sumatera	-	671.27	17,879.27	4,474.28	884.33	23,909.15
Total	**101.33**	**9,046.06**	**68,646.99**	**4,644.10**	**3,493.86**	**85,932.34**

Source: PLN, PLN Statistics 2024 (2025) p. 55

In 2024, the total length of the distribution network is 1,066,197.2 kilometres (km), consisting of 448,557.61 km of medium voltage networks and 617,639.59 km of low voltage networks[25].

Table 1.3 – Distribution network and transformers by island

Region/island	Low voltage (km)	Medium voltage (km)	Number of transformers (units)	Transformer capacity (MVA)
Java-Bali	**350,526.49**	**194,500.89**	**1,353**	**115,811.10**
Kalimantan	**42,154.18**	**47,114.64**	**350**	**14,442.00**
Nusa Tenggara	**18,125.36**	**17,333.76**	**62**	**2,270.00**
Papua and Maluku	**16,109.72**	**17,080.75**	**53**	**1,756.03**
Sulawesi	**43,768.87**	**45,281.46**	**395**	**13,968.60**
Sumatera	**146,954.97**	**127,246.11**	**487**	**34,539.21**
Total	**617,639.59**	**448,557.61**	**2,700**	**182,786.94**

Source: PLN, PLN Statistics 2024 (2025) p. 56

The power network overall performance is being designed to enable the gradual implementation of smart grid systems across Indonesia, as outlined in the 2025-2034 RUPTL. This framework aims to address the intermittency of variable renewable energy (VRE) sources, such as PLTS and PLTBs, which are affected by weather conditions. At present, PLN has initiated smart grid pilot projects in selected provinces, introducing modern electricity systems that utilise two-way communication and information. These pilots are intended to make the grid more flexible, responsive and capable of optimising energy use, while also serving as a foundation for broader, nationwide deployment in the coming years.

To build a reliable inter-island interconnection system, Indonesia requires the digitalisation of the electricity network and the development of a smart grid integrated with PLTBs, PLTS, battery energy storage systems (BESS), pumped storage, and large-scale high voltage direct current (HVDC) systems. The smart grid implementation can enhance efficiency, stability, and reliability of the electricity supply from VRE power plants, which are planned for extensive development over the next ten years.

1.2 Electricity tariffs

In response to dynamic developments in the energy sector and the imperative to establish a more equitable and efficient electricity pricing framework, the MoEMR has issued Regulation Number 7 of 2024, which supersedes MoEMR Regulation Number 28 of 2016 and its subsequent amendments. Enacted on 6 June 2024, this regulation governs the electricity tariffs administered by PLN, with the objective of enhancing transparency, accountability and operational efficiency within Indonesia's electricity industry. The regulation delineates consumer categories based on usage type including residential, commercial, industrial, social and governmental sectors, as well as installed capacity, ranging from 450 volt ampere (VA) to above 6600 VA. It further introduces two distinct tariff schemes, a regular tariff system for postpaid customers and a prepaid tariff system for token-based users. For customers not receiving subsidies, tariff adjustments shall occur on a quarterly basis, taking into account the key economic indicators such as the rupiah/US dollar exchange rate, Indonesia's crude price (ICP), the national inflation rate and the coal reference price (HBA). Furthermore, any proposed tariff revisions are subject to approval by the House of Representatives (DPR), ensuring rigorous oversight and institutional legitimacy. Collectively, MoEMR Regulation No. 7 of 2024 is formulated to safeguard consumer interests, promote operational efficiency within PLN, and support Indonesia's broader goals of energy transition and economic stability.

Based on the 2025 PLN Statistics report, as shown in Table 1.4 below, PLN's average cost of electricity production in 2024 was IDR1,242.74/kWh (a 13% increase on 2023) and the average tariff or selling price was IDR1,153/kWh, only slightly below the 2013 tariff. This resulted in subsidies from the GoI of IDR77 trillion in 2024, a 12% increase on 2023[26].

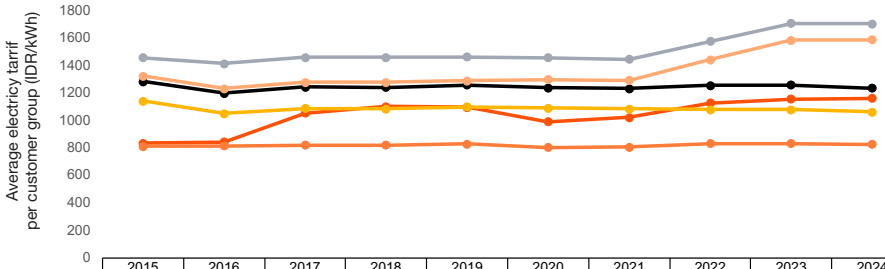
Table 1.4 - Average cost, average tariff and subsidies

Year	Average cost (IDR/kWh)	Average tariff (IDR/kWh)	Subsidies (IDR trillions)	Compensation revenue (IDR trillions)
2015	920.22	1,035.00	56.6	27.88
2016	856.28	991	60.4	28.81
2017	1,087.51	1,105.00	45.7	25.55
2018	1,160.89	1,127.00	48.1	23.17
2019	2,999.73	1,130.00	51.7	22.25
2020	3,097.30	1,071.00	48	17.9
2021	1,391.08	1,083.00	49.7	24.59
2022	1,460.59	1,137.00	58.8	63.64
2023	1,095.19	1,155.00	68.63	73.99
2024	1,242.74	1,153.00	77.04	100.18

Source: PLN Statistics, 2025

Based on the 2025 PLN Statistics report, in 2024 total operating revenue reached IDR545,380,992 million, consisting of electricity sales revenue of IDR353,176,019 million, connection fee revenue of IDR1,746,004 million, government subsidies of IDR77,045,334 million, compensation revenue of IDR100,184,044 million and other income of IDR13,229,589 million.

Figure 1.6 – Average electricity tariff per customer group



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Household	837.01	843.72	1,056.00	1,102.43	1,098.82	991.92	1,024.01	1,128.40	1,156.15	1,164.28
Industry	1,142.72	1,051.82	1,088.80	1,085.30	1,100.69	1,090.89	1,086.22	1,080.66	1,080.32	1,064.21
Business	1,284.17	1,201.16	1,245.62	1,243.99	1,258.34	1,239.34	1,234.68	1,255.56	1,260.65	1,238.09
Social	812.44	815.96	821.34	823.21	830.68	804.11	806.37	833.56	831.98	826.7
Government office building	1,324.51	1,234.72	1,278.54	1,280.11	1,291.45	1,299.22	1,292.84	1445.59	1,587.92	1,590.76
Public street lighting	1,459.06	1,415.31	1,461.49	1,461.64	1,465.09	1,459.94	1,447.08	1,577.94	1,709.18	1,706.26

Source: PLN Stastics 2024, 2025, p. 71

According to the 2025 PLN Statistics Report, Indonesia's electricity sales reached 306,219.42 GWh (306.2 terawatt hours/TWh), a 6.1% increase from the previous year's total of 288.4 TWh. The breakdown of the electricity consumption by consumer groups was as follows:

a. Households: 130,433.10 GWh (42.59%)
b. Industrial sector: 92,195.69 GWh (30.11%)
c. Businesses: 58,771.14 GWh (19.19%)
d. Others (social, government buildings and public street lighting): 21,619.48 GWh (8.11%)[27]

Based on the electricity sales, the number of customers at the end of 2024 reached 92,877,292, representing a 4.17% increase from the end of 2023. The average electricity selling price per kWh, according to the Centralised Customer Service Application (*Aplikasi Pelayanan Pelanggan Terpusat*/AP2T) data for 2024, was IDR1,153.38/kWh, slightly lower than the previous year's rate of IDR1,155.47/kWh.

1.3 Government strategies, policies and plans for the power sector in Indonesia

The Indonesian government has made advancing and reforming the power sector an area of focus as a fundamental part of the nation's broader economic growth and sustainability objectives. Central to this effort are the design of strategies, policies and plans aimed at expanding energy access across the archipelago, modernising and strengthening existing infrastructure and actively promoting the adoption of renewable energy sources. Additionally, a range of regulatory reforms have been undertaken to improve the overall efficiency, reliability, and competitiveness of the power sector, while encouraging greater participation from the private sector. These strategic frameworks collectively provide a roadmap for the power sector's development in the coming years, reflecting Indonesia's firm commitment to building a resilient, sustainable and inclusive energy system. In support of these efforts, several key government strategies and plans have been developed to guide and support these transformative initiatives, promoting alignment with national priorities and international commitments.

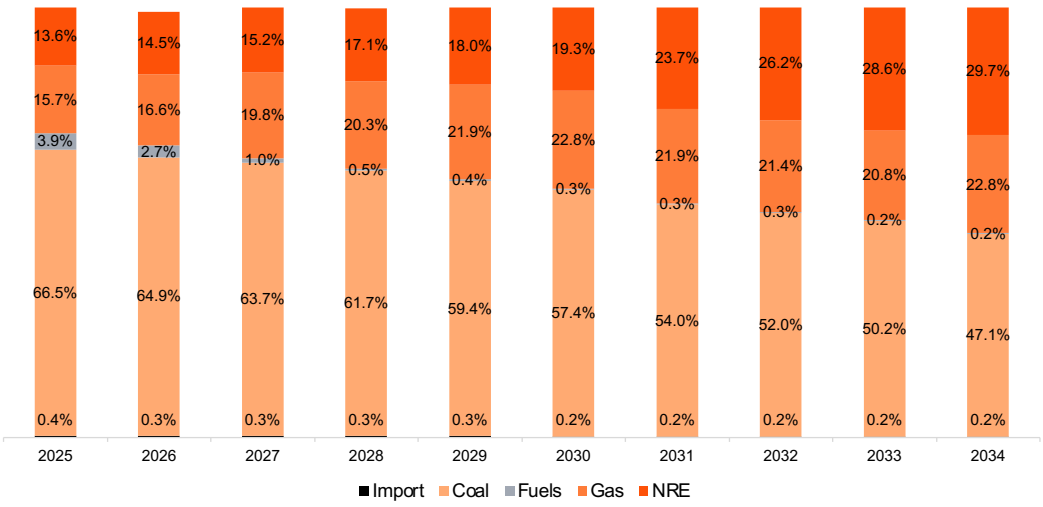
a. 2025-2034 RUPTL

i. Renewable Energy Base (RE Base Scenario)

The RE Base scenario represents an electricity system development pathway based on the project's implementation capacity, aligned with the operational and financial capabilities of PLN and the Government. This scenario does not aim to achieve specific emission reduction or energy mix targets; instead, it optimises the electricity system for cost-efficiency and supply reliability, with a preference for incorporating new power plants based on renewable energy sources[28].

Based on the 2025-2034 RUPTL, the RE Base scenario outlines PLN's plan for a moderate yet steady expansion of generation capacity to meet the anticipated growth in electricity demand. Beginning with an existing capacity of 74,556 MW in 2025, the system is expected to experience cumulative additions of approximately 69,512 MW by 2034. This expansion aims to accommodate a projected increase in electricity demand from 323,044 GWh in 2025 to over 500,000 GWh by 2034, while ensuring system reliability and facilitating the balanced integration of additional renewable energy sources.

Figure 1.7 – 2025-2034 Indonesian electricity generation mix (%) RE Base scenario



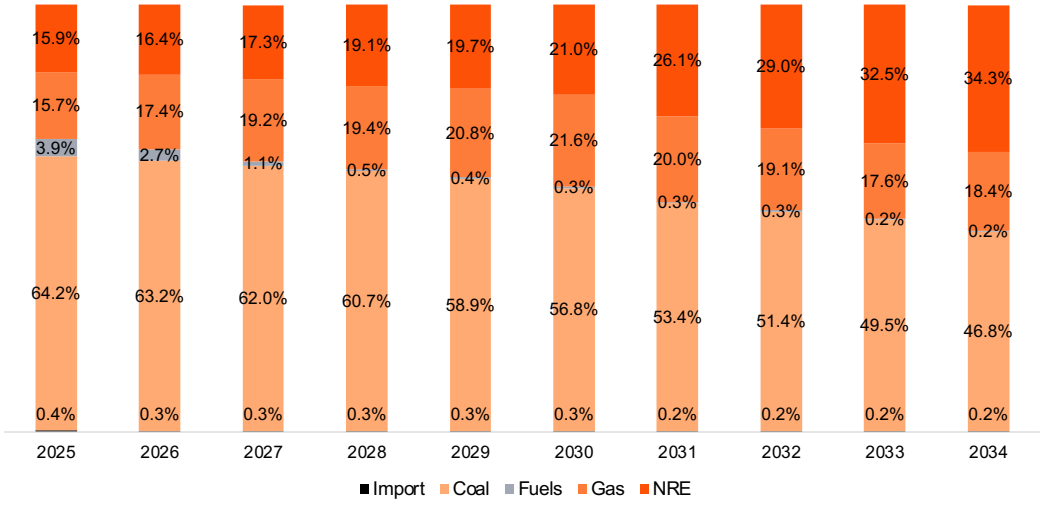
Source: 2025-2034 RUPTL, Page V-235

ii. ARED scenario

The ARED scenario emphasises the development of infrastructure to advance the electricity system, targeting a reduction of GHG emissions by 151 million tonnes of CO_2 by 2030 compared to the BAU scenario. Under this scenario, PLN is committed to completing the Sumatra-Java interconnection to facilitate the transfer of hydroelectric and geothermal power from Sumatra to load centres in Java. Additionally, biomass co-firing is projected to increase to 7.7 million tonnes by 2030, while the VRE scale-up programme is expected to expand to 11.9 GW, including the development of flexible generation that integrates multiple power sources, such as wind and solar. The scenario also incorporates the deployment of energy storage technologies, including BESS and solar-powered hydroelectric plants, reaching a combined capacity of 3.5 GW by 2030. Power plant additions under the ARED scenario prioritise emission reduction targets and the expansion of the renewable energy mix. Renewable energy development within this framework is planned to exceed the 2021-2030 RUPTL previously referred to as the greenest RUPTL[29].

The ARED scenario represents a more ambitious pathway aimed at accelerating the transition to renewable energy. Starting from the same baseline in 2025, this scenario projects a total additional capacity of approximately 77,819 MW by 2034, which is roughly 8,300 MW greater than that of the RE Base scenario. This increase reflects a stronger commitment to deploying renewable energy sources, including solar, wind, hydro and geothermal power, supported by enabling infrastructure such as energy storage systems and smart grids.

Figure 1.8 – 2025 - 2034 Indonesian electricity generation mix (%) ARED Base scenario



Source: 2025-2034 RUPTL, Page V-237

b. The 2025 National Electricity General Plan (*Rencana Umum Ketenagalistrikan Nasional*/RUKN)

The RUKN 2025 is Indonesia's comprehensive national electricity plan aimed at ensuring a reliable, sustainable, and affordable electricity supply to support economic growth and energy transition goals by 2025. The Government's strategy under the RUKN 2025 focuses on diversifying the energy mix by increasing the share of renewable energy sources, such as geothermal, solar and hydropower, while gradually reducing dependence on fossil fuels. Specific electricity strategies include expanding grid infrastructure to improve access in remote areas, promoting energy efficiency, and supporting the integration of distributed generation and smart grid technologies. This approach aligns with Indonesia's commitment to achieving higher electrification rates, reducing greenhouse gas emissions and enhancing energy security as part of its broader national energy policy framework[30].

c. The JETP

The JETP in Indonesia is a strategic collaboration between the Indonesian government, international partner countries, and global financial institutions aimed at accelerating the clean energy transition and significantly reducing carbon emissions. The JETP focuses on providing financial support, technology transfer and capacity building to develop renewable energy sources, improve energy efficiency and reduce dependence on fossil fuels, thereby achieving national climate targets and global commitments. The JETP strategy in Indonesia involves close collaborations with various stakeholders to identify priority clean energy projects, establish a supportive regulatory framework, and encourage private sector investment through fiscal and non-fiscal incentives. Additionally, the programme aims to enhance local technical capacity through training and technology transfer, integrate innovative digital solutions to improve energy efficiency and optimise the use of partnership funds to support renewable energy infrastructure development in regions most vulnerable to climate change. This approach aims to create a sustainable and inclusive energy ecosystem that supports emission reduction goals while fostering environmentally friendly economic growth[31].

d. COP29

COP29 refers to the 29th annual Conference of the Parties (COP) to the United Nations Framework Convention on Climate Change (UNFCCC). This global summit convenes representatives from nearly 200 countries to negotiate and advance international efforts aimed at combating climate change. The conference places significant emphasis on assessing progress towards achieving global climate targets, updating national commitments to reduce greenhouse gas emissions, enhancing adaptation to climate impacts, mobilising climate finance and strengthening international cooperation to accelerate the transition to sustainable, low-carbon economies[32].

At the World Leaders Climate Action Summit (WLCAS), which was held as part of the 29th United Nations (UN) Climate Change Conference (COP29) in Baku, Azerbaijan, Indonesia announced a series of ambitious initiatives to support its clean energy transition. These include the development of a 70,000-kilometre green transmission line to improve energy distribution to the country's most densely populated islands, the establishment of green smart grid infrastructure aimed at doubling wind and solar power capacity and the preparation of 60 gigawatts of electricity generation capacity derived from hydropower, geothermal, solar and wind sources[33].

Indonesia has set a target that by 2040, 75% of its national electricity capacity will be sourced from new and renewable energy. The COP29 summit was attended by 82 heads of state and special envoys, including Indonesia's delegation. Through its participation, Indonesia pursued key diplomatic priorities encompassing the enhancement of both regional and global influence, the promotion of national resilience diplomacy, and the advancement of Pancasila-based economic diplomacy[34].

Indonesia seized the opportunity to consistently articulate and defend the interests of developing countries within the global climate dialogue. The country actively advocated for efforts to limit the global temperature rise to below 1.5°C, while simultaneously promoting the realisation of financial commitments, international cooperation mechanisms and investments in climate management, clean energy and environmental conservation. Through this consistent engagement, Indonesia reinforced its leadership role in advancing equitable and effective global climate action[35].

1.4 Chronological development of the power sector in Indonesia

Indonesia's power sector began under an 1890 Dutch ordinance, regulating electrical installations and power transmission. This ordinance was replaced in 1985 by Law No. 15/1985, which established a centralised system with the state-owned company PLN holding exclusive control over electricity transmission, distribution and sales. Private participation was limited to power generation, allowing IPPs to sell electricity exclusively to PLN under PPAs. PLN became the central driver of the sector's commercial viability, as it was the sole purchaser of electricity output. The first major PPA under this modern framework was signed in 1991 with PT Paiton Energy to develop a large coal-fired power plant, followed by numerous other IPP projects, including geothermal power plants developed under different investment arrangements. Since then, the power sector has continued to evolve, with the latest supporting legislation and regulations introduced between 2022 and 2025 aimed at increasing renewable energy integration and enhancing regulatory frameworks to support Indonesia's energy transition and sustainable development goals.

- **Presidential Regulation (PR) 112/2022**
  Presidential Regulation No. 112 of 2022 was issued to accelerate the development of renewable energy for electricity supply. It mandates the prioritisation of renewable energy sources, streamlines procurement processes and bans new coal-fired power plants except under specific conditions. The regulation also enables fiscal incentives and requires a roadmap for phasing out existing CFPPs to support the country's energy transition goals.

- **MoEMR Regulation 12/2023**
  Sets out guidelines for the use of biomass fuel as a co-firing component in coal-fired power plants. This regulation aims to accelerate the national renewable energy mix target, reduce greenhouse gas emissions and promote community-based economic development by involving local stakeholders in biomass supply chains. It outlines technical standards, supervision mechanisms and transitional provisions to ensure the effective integration of biomass into existing coal-fired power generation systems, marking a strategic step toward cleaner and more sustainable energy production.

- **National General Energy Plan (*Rencana Umum Energi Nasional*/RUEN) policy (PR No. 73/2023)**
  Presidential Regulation No. 73 of 2023 provides a structured framework for drafting the RUEN and Regional Energy Plans (*Rencana Umum Energi Daerah*/RUEDs) in Indonesia. It establishes clear terminology and procedural guidelines to ensure consistency and alignment with the National Energy Policy (KEN). Both the RUEN and RUEDs are designed as ten-year strategic documents, with mandatory reviews every five years to adapt to evolving energy needs and policy targets. The regulation mandates collaborative governance, requiring provincial governments to coordinate and consult with the National Energy Council (*Dewan Energi Nasional*/DEN) and relevant ministries during the RUED drafting process, in accordance with existing laws and regulations. This approach aims to foster integrated and sustainable energy planning across national and regional levels.

- **MoEMR Regulation No. 2/2024**
  Governs the implementation of rooftop solar power systems connected to the electricity grid operated by licensed public electricity providers. This regulation marks a significant policy shift by removing previous limitations on system capacity, energy export-import mechanisms, capacity charges and encouraging broader adoption of solar energy. It introduces a quota system for rooftop solar development and emphasises environmentally friendly energy utilisation for self-consumption. The regulation also outlines provisions for system management, supervision and transitional arrangements, aiming to streamline solar integration and support Indonesia's transition to more sustainable electricity generation.

- **MoEMR Regulation 10/2025**
  The regulation outlines a comprehensive roadmap for the energy transition within the electricity sector. This regulation serves as a strategic guide to reduce dependence on fossil fuels and achieve national commitments toward sustainable development and net-zero greenhouse gas emissions. The roadmap also supports the integration of smart grid infrastructure and the exploration of green hydrogen and nuclear energy, positioning Indonesia for a cleaner and more resilient energy future.

1.5 Environmental, social and governance (ESG)

In Indonesia, the ESG landscape has been gradually evolving since the inception of the COP agreements in 2016. The Indonesian government's commitment to adopt ESG measures in order to advance national efforts to achieve its updated sustainability target of net-zero emissions by 2060 is apparent in a number of initiatives: the establishment of a coherent roadmap (i.e. the Indonesia Financial Sector Development Report (Q4 2023) issued by the Financial Services Authority of Indonesia (*Otoritas Jasa Keuangan*/OJK); the creation of the 2023 – 2060 RUKN) (please refer to *Section 3.2.1 - RUKN and RUPTL* for details of the RUKN); and the issuance of a standard for "investor-grade" ESG reporting amongst publicly listed companies. Furthermore,

OJK has mandated sustainability reporting starting in 2021 for publicly listed companies through OJK Regulation No. 51/ POJK.03/2017 and additional provisions in OJK Letter No. S-264/D.04/2020. Typical ESG metrics that must be reported follow Global Reporting Initiative standards, and these include GHG emissions, energy consumption, environmental compliance, management of effluents and waste, and procurement practice, among others. In October 2021, the Indonesian government issued Law No. 7/2021 on the Harmonisation of Taxation Regulations, which includes a carbon-tax scheme on energy-intensive sectors. On 26 September 2023, the Indonesia Stock Exchange launched the Indonesia Carbon Exchange (IDX Carbon) to help achieve net-zero emissions by 2060. This follows Presidential Regulation No. 110 of 2025, which established a carbon pricing mechanism. Carbon pricing assigns value to GHG units and is commercialised through carbon trading, result-based payments and carbon taxes[36].

Since achieving net-zero emissions requires transitioning from fossil fuels to renewable energy, international financial institutions are joining forces to formulate a scheme to retire Asia's coal-fired power plants. The Asian Development Bank (ADB) continues to develop its Energy Transition Mechanism (ETM) programme, which is supported by other financial institutions such as Prudential, Citi, HSBC and BlackRock, to acquire coal-fired power plants by means of equity, debt and concessional finance, and retire these power plants within 15 years of acquisition. During the Partnership for Global Infrastructure and Investment (PGII) event, which took place in September 2022, President Joko Widodo, President of the European Commission Ursula von der Leyen on behalf of the European Union (EU) and leaders of the International Partners Group (IPG), co-led by the United States and Japan and including Canada, Denmark, France, Germany, Italy, Norway and the United Kingdom, launched the JETP programme with Indonesia[37]. As much as USD20 billion in public and private seed funding over a three to five-year period will be mobilised through the coordination of the JETP Secretariat[38].

Based on PLN's ESG Performance Report of 2024, PLN is dedicated to conducting socially, financially and environmentally sustainable business activities. Aligned with its vision and mission, PLN has committed to achieving the NDC target by 2030 and net-zero emissions target by 2060. To fulfill this commitment, PLN is undertaking a decarbonisation programme, involving the cancellation of planned CFPPs. These will be replaced with NRE power plants[39].

During COP27 in Sharm El Sheik, Indonesia reaffirmed its commitment to a green economy and energy transition in a session titled "Energy Transition on Achieving Net Zero Emission." Minister Luhut Pandjaitan highlighted Indonesia's efforts, including participation in the G20 Presidency and regulatory steps like Presidential Regulation No. 112 of 2022. Discussions covered collaborations through the JETP's and PLN's commitments to decarbonisation and green financing. Denmark pledged support for Indonesia's transition from coal to renewables, and insights on best practices were shared by companies like Indika Nature and Pertamina Geothermal Energy. Success in energy transition requires concrete commitments from developed countries, adequate financing and strengthening Indonesia's NDC targets[40].

During COP27, Indonesia's Environment and Forestry Minister, Siti Nurbaya, emphasised Indonesia's commitment to achieving its 2030 targets in the Enhanced NDCs under the UNFCCC. Indonesia's latest NDC aims to increase GHG emission reduction targets, with efforts of 31.89% unconditionally and 43.20% conditionally with international support. However, there are concerns regarding certain policy choices in Indonesia's NDC update, particularly regarding reliance on gas infrastructure which still emits greenhouse gases. Indonesia aims to transition to renewable energy, but challenges remain, including slow progress in the renewable energy sector and potential loopholes in the energy policy[41].

After COP28, PLN has signed 14 forms of clean energy agreements with various foreign companies in the development of clean energy in Indonesia. For instance, with Hydrogen de France from France calling for the development of hybrid hydrogen fuel cell power plants in Indonesia. Abu Dhabi National Energy Company (TAQA) to develop transmission network interconnections and a smart grid in Indonesia. PLN and Korean Hydro & Nuclear Power have agreed to explore the feasibility of nuclear power plants in Indonesia using small modular reactor technology. This reflects PLN's and Indonesia's seriousness in transitioning to clean energy post the COP28 event[42].

Following COP28, the Indonesian Chamber of Commerce and Industry (Kadin Indonesia) convened a post-COP28 discussion forum on 15 December 2023, to address commitments made during the summit, notably the USD83.76 billion climate financing secured. This financing aims to accelerate climate change mitigation and adaptation efforts, supporting the development of renewable energy sectors. The forum highlighted Indonesia's strategic positioning in the global green industry competition, emphasising the importance of leveraging clean energy demand aggregation for investment certainty. Furthermore, discussions emphasised collaboration between developed and developing countries to achieve the 2060 net-zero emission target, ensuring climate financing benefits all parties involved. Key figures, such as the Chairman of Kadin Indonesia Energy Transition Task Force, Anthony Utomo, and Vice Chairman Shinta W. Kamdani, emphasised the role of businesses in driving green investments and climate resilience[43].

Indonesian Minister of Environment and Forestry, Siti Nurbaya, met with Razan Al Mubarak, President of the International Union for Conservation of Nature (IUCN) and UN Climate Change High-Level Champion for COP28, to discuss conservation and biodiversity, focusing on the Mangrove Alliance for Climate (MAC). They reviewed the ambitious and inclusive action agenda from the COP28 "UAE Consensus", including Indonesia's commitments in the Forestry and Other Land Use (FOLU) Net Sink 2030. Siti emphasised Indonesia's progress in emission reductions, receiving substantial contributions from international partners. They also discussed carbon governance and Indonesia's emerging carbon trading market. Collaboration on mangrove conservation, particularly with the United Arab Emirates (UAE), Japan and Germany, was highlighted, alongside plans for the World Mangrove Centre in Bali. Al Mubarak praised

Indonesia's systematic approach and social forestry initiatives, emphasising the importance of climate finance and global cooperation. The meeting concluded with plans for further collaboration, including fieldwork in Sumatra and Kalimantan to protect key wildlife species[44].

1.5.1 What is ESG and its objectives

ESG represents principles related to sustainable development that companies are increasingly expected to consider in investment and operational decision-making. The key impacts on environmental, social and governance aspects will inevitably influence investment decisions and strategies[45].

ESG is increasingly influenced by growing sustainability expectations from both regulators and society. It encompasses a diverse array of stakeholders—such as investors, regulatory bodies, customers, employees and the wider community—whose perspectives shape its evolution. As a result, ESG development reflects an eclectic and inclusive approach.

Indonesia is no exception. Based on the 2020 Globescan and Global Reporting Initiative (GRI), Indonesia is one of 27 countries with the highest degree of public trust[46]. This indicates that investors and other stakeholders are starting to reveal ESG performance as a measure of a company's strength. It has become an integral part of sustainable business operations across various sectors including the power sector.

This section aims to share the basic principles of the ESG framework and its applications in the power sector. We offer a practical guide for stakeholders aiming to integrate these principles into their strategies. This document is not a definitive guide but provides a foundational understanding of ESG considerations.

1.5.2 Opportunities and challenges for the development of ESG in the power sector

There are several opportunities for enhancing ESG practices in the power sector. One of the opportunities is to leverage artificial intelligence (AI) which employs IT and engineering implementations. Use of machine learning (ML) algorithms can allow companies to automatically relocate resources and adjust the manufacturing parameters in more cost-effective manners. For example, when determining the optimal operational matrix for a thermal power station, ML algorithms can support decision-making based on carbon footprint mitigation requirements. This holistic approach helps prevent flawed choices that are merely based on cost minimisation and maximum electricity output at the expense of environmental sustainability, particularly when relying on non-sustainable fuel sources[47].

Another promising opportunity lies in the implementation of smart electric grid technologies, which enable dynamic switching between different energy sources based on real-time customer demand. This adaptability can significantly improve the efficiency and reliability of power distribution networks[48]. Additionally, emerging technologies offer predictive maintenance capabilities for critical infrastructure, allowing for pro-active measures that help prevent accidents and service disruptions[49].

However, these opportunities are not without challenges, often also acting as a double-edged sword. On one hand, through the automatisation of certain business and technological processes, AI provides a disruptive technology which may help increase energy efficiency, however, this also comes with the potential for job losses[50]. Further challenges with AI are related to its energy-demanding nature and risk of providing misleading or false information, especially due to the rise of generative AI that has the capability to create fake news based on the prompts given[51].

Challenges can also come from biases of priorities. For instance, the energy sector is one of the highest in terms of ESG disclosures, but mostly focuses on corporate governance which may not have as significant an effect on financial performance as social and environmental aspects.

Photo source: PwC

1.5.3 ESG dimension

Indonesia's power sector is essential for its economic growth, providing energy to a rapidly developing nation. However, the sector faces significant ESG challenges, including environmental pollution, social equity issues and governance concerns. Addressing these challenges necessitates robust governance frameworks and the integration of innovative solutions.

The ESG framework in the power sector encompasses various dimensions, each with specific indices and representative meanings (Table 1.5).

Table 1.5 – Example of application of ESG framework in the power sector[52]

Aspect	Index	Specific content	Classification	Representative meaning
Environment	Energy type	Renewable energy/ traditional energy usage ratio	Less than 25%	The lower the proportion, the lower the utilisation of renewable energy, while the higher the proportion, the less the dependence on traditional energy and the more environmentally friendly.
			25-50%	
			50-75%	
			75% or above	
	Carbon emission	Carbon emissions generated during power generation	Less than 1,000 tonnes	Low carbon emissions mean that enterprises produce less GHG in the process of power generation and have less impact on the climate, while high carbon emissions mean that enterprises may have a greater impact on the climate.
			1,000-5,000 tonnes	
			5,000-10,000 tonnes	
			10,000 tonnes or above	
	Ecosystem impact	Influence of power generation on local ecosystem	No impact	No impact means that enterprise activities have no significant impact on the ecosystem, while significant impact may mean that enterprise activities seriously damaged the ecosystem.
			Slight impact	
			Medium impact	
			Significant impact	
Social	Social reponsibility project	Social reponsibility project and plans implemented	Less than 5 projects	The greater the number of social responsibility projects, the more active enterprises are in fulfilling their social responsibilities and making contributions to the community.
			5-10 projects	
			10-15 projects	
			15 projects or above	
	Employee welfare	The company's welfare treatment and safety measure for	Less than IDR2 million/month	The higher the employee welfare means that enterprises care more about employees and provide better wages and safer working environment.
			IDR2-7 million/ month	
			More than IDR2 million/month	

Aspect	Index	Specific content	Classification	Representative meaning
Governance	Power system governance structure	Structure and decision-making mechanism of power system	Low level Medium level High level	The higher the level, the more transparent and independent the decision-making process of the enterprise, which reduces the possibility of power interference.
	Transparence and compliance	Transparency and compliance of power system operation	Low level Medium level High level	The higher the level of transparency and compliance, the better the enterprise is in terms of information disclosure and compliance with laws and regulations and more responsible to stakeholders.

1.5.4 Sustainability reporting as a means to integrate sustainable practices

Sustainability reporting plays a vital role in embedding ESG principles within the power sector. Sustainability reporting (SR) can become an effective instrument to encourage business actors in the power industry to integrate sustainability into their business. By exposing their performance under the framework of ESG, businesses provide transparency that enables stakeholders to assess their commitment to responsible practices. Ultimately, a good and effective SR can exert subtle yet meaningful pressure on companies to follow through on their sustainability promises.

To achieve a proper SR, companies need to enhance the quality of their sustainability data and disclosures. This involves adopting reporting standards such as the GRI, the Sustainability Accounting Standards Board (SASB), or the International Financial Reporting Standards (IFRS) S1 and S2. Transparent and comprehensive reporting helps stakeholders understand a company's sustainability performance and commitments. In developing their sustainability reports, players in power industry should consider numerous topics, which involves detailing past actions, future plans and annual achievements related to the set targets. Following are some topics which can be included within SR:

i. Decarbonisation

To address emissions at the organisational level, GHG emissions are categorised into three "scopes"[53], as follows:

- Scope 1 emissions are direct GHG emissions that occur from sources that are controlled or owned by an organisation.
- Scope 2 emissions are indirect GHG emissions associated with the purchase of electricity, steam, heat or cooling.
- Scope 3 emissions, also known as value chain emissions, are all indirect emissions that occur in the reporting company's upstream and downstream supply chain.

Carbon dioxide removal (CDR) technologies that could play a vital role in addressing climate change have progressed alongside other technological advancements of the past century. However, recent research led by Professor Gregory Nemet of the University of Wisconsin-Madison highlights that the technologies need to be developed faster to meet the policy targets aimed at limiting global warming[54]. Nonetheless, the widespread adoption of these technologies remains uncertain, largely due to the absence of clear, commercially viable business models.

ii. Investment in renewable energy

Today's investment patterns fall short of the levels required to keep global warming within the 1.5°C threshold above pre-industrial levels and to meet the interim targets set during COP29 in 2024[55]. While the momentum behind renewable energy is encouraging, projections suggest that if current spending trends persist, it will only account for roughly two-thirds of the total investment needed to achieve the goal of tripling renewable capacity by 2030. To fill the gap an extra USD500 billion per year is required in the International Energy Agency (IEA)'s Net Zero Emissions by 2050 Scenario (NZE Scenario). This equates to a doubling of current annual spending on renewable power generation, grids and storage in 2030[56].

Aligned with the goals of decarbonisation, renewable energy is one of the key levers for the power industry to address climate change, together with mainstreaming of sustainable fuels (including various types of biofuels, hydrogen and power-to-gas fuels).

The SR provides power companies with a valuable opportunity to communicate their RE plans.

iii. AI

AI, including generative AI, could help address core challenges in the power industry, such as operational efficiency and customer service. Although under the context of just transition, impact on human labour and local economy must be considered, and how the industry players see and commit to AI should be disclosed clearly in the SR.

iv. Supply chain challenges

The industry faces headwinds from supply chain-related challenges, which affect the cost and availability of clean energy technologies[57]. For example, a shortage of semiconductors has impacted the production of solar panels and wind turbines.

These challenges can slow down the deployment of clean energy technologies, making it harder to meet sustainability goals and transition to a low carbon economy.

Understanding the GHG emissions of suppliers can also be a challenge in reporting scope-3 emissions.

1.5.5 AI-enabled

AI has the potential to revolutionise the power sector by enhancing operational efficiency, reducing costs and promoting sustainability. The application of AI in this sector can be categorised into several key areas.

AI-powered algorithms can anticipate equipment failures before they happen, enabling pro-active maintenance strategies. This approach helps reduce downtime, extend asset lifespans and lower operational expenses. For example, PLN, Indonesia's state-owned electricity provider, has started deploying AI-driven predictive maintenance systems to improve the reliability of its power supply[58]. By leveraging AI, predictive maintenance can significantly enhance system performance while cutting operational costs[59].

AI facilitates smarter energy management by enabling accurate demand forecasting and optimising energy distribution. By processing large volumes of data, AI systems can predict consumption patterns and adjust energy supply in real time, helping to minimise waste and maintain grid stability. In fact, AI-driven energy management systems have the potential to cut energy usage by up to 20%[60].

Integrating renewable energy sources like solar and wind into the power grid poses challenges due to their intermittent nature. AI can play a crucial role in forecasting renewable energy generation and aligning it with demand, thereby improving grid reliability and stability. In Indonesia, AI technologies are being utilised to optimise the integration of renewables energy sources, supporting the nation's target of reaching 23% renewable energy in its energy mix by 2025[61].

AI plays a critical role in smart grid technology, enabling real-time monitoring and dynamic control of the power grid. Smart grids can swiftly detect and respond to fluctuations in electricity demand and supply, thereby enhancing efficiency and reliability. In Indonesia, the GoI has launched several pilot projects to implement smart grid systems nationwide, utilising AI to strengthen grid management. These initiatives are expected to contribute to the development of a more efficient, sustainable and resilient energy infrastructure[62].

1.5.6 Overview of ESG policies in Indonesia

The Indonesian power sector is governed by a range of policies aimed at promoting sustainability and addressing ESG concerns. These policies are designed to align with international standards and drive the sector towards more sustainable practices.

Indonesia has implemented several environmental policies to mitigate the impact of the power sector on the environment. The Environmental Protection and Management Law (Law No. 32/2009) mandates environmental impact assessments (EIAs) for all major projects, including

power plants. Additionally, the government of Indonesia has set targets for reducing GHG emissions, as outlined in the NDCs under the Paris Agreement which has been substantiated in Presidential Regulation No. 110/2025[63].

A "cap and trade" mechanism for coal-fired power plants was introduced in 2024, in anticipation of a broader carbon trading and tax regime. See *Section 7.3.3 Carbon tax* of this Guide for details.

Social sustainability in the power sector involves ensuring fair labour practices, community engagement and social welfare. Ministry of Manpower Regulation No. 35/2021 outlines standards for occupational health and safety in the power sector. Furthermore, power companies are required to engage with local communities and address their concerns, particularly in areas affected by power infrastructure projects[64].

Strong governance policies indicate better corporate performance and sustainability[65]. Indonesia has some anti-corruption laws and/or regulations (i.e. No. 20/2001 on Eradication of Crimes of Corruption, No. 30/2002 on Corruption Eradication Commission, No. 8/2010 on Prevention and Eradication of Money Laundering, No. 54/2018 on National Strategy of Corruption Eradication) whereas the most recent anti-corruption regulation, No. 54/2018, focuses on three priority areas: licensing and commerce, state finance, and law enforcement and bureaucratic reform. Governance policies in Indonesia's power sector itself focus on transparency, accountability and ethical conduct. Fraud-prevention may include implementation of effective internal controls, such as periodic review of performance evaluation systems, utilising internal auditors and fostering anti-fraud awareness through training sessions, workshops and seminars. Further, the Corporate Governance Code issued by the Indonesia Corporate Governance Forum (ICGF) provides guidelines for best practices in corporate governance. These guidelines include recommendations on board composition, risk management and stakeholder engagement[66]. Furthermore, government incentives play a vital role in encouraging investment in sustainable energy projects[67].
The Indonesian government offers various incentives to promote sustainable practices in the power sector, including tax incentives for renewable energy projects, subsidies for energy-efficient technologies, and grants for research and development in sustainable energy solutions[68].

1.6 Stakeholders

a. **MoEMR**

The MoEMR is tasked with formulating and executing Indonesia's energy strategy, which involves developing the RUKN and overseeing the power industry through entities like the Directorate General of Electricity (DGE) and the Directorate General of New and Renewable Energy and Energy Conservation (DGNREEC). Additionally, the MoEMR is responsible for drafting regulations concerning electricity, RE and energy efficiency, as well as approving PLN's RUPTL.

b. **DPR**

The DPR's Commission VII is tasked with formulating legislation pertaining to energy, research, technology and environmental matters. It holds authority over the endorsement of energy-related laws, including those concerning electricity and oversees the implementation of government policies in the energy sector.

c. **PLN**

PLN holds primary responsibility for the majority of Indonesia's electricity generation, including exclusive authority over the transmission, distribution and provision of electricity to the public. Its activities are regulated and overseen by its shareholder Danantara (see below), the MoEMR and the Ministry of Finance (MoF).

In 2004, PLN underwent a transformation from a public utility to a state-owned limited liability company (*Perusahaan Perseroan*/Persero). Following the enactment of the 2009 Electricity Law, PLN's role as the public service obligation provider (*Pemegang Kuasa Usaha Ketenagalistrikan*/PKUK) was abolished and it now operates solely under an electricity supply business licence (*Izin Usaha Penyediaan Tenaga Listrik*/IUPTL).

Furthermore, the 2009 Electricity Law grants PLN a right of first refusal for electricity supply in an area, allowing it to provide electricity before the central or regional governments offer opportunities to regional-owned entities, private enterprises, cooperatives or self-reliant community institutions. PLN also functions as the provider of last resort, meaning that if PLN is not supplying a particular area and no other entities are willing to do so, the Government can instruct PLN to ensure electricity supply.

d. **Ministry of National Development Planning/National Development Planning Board (*Kementerian PPN/Bappenas*)**

Bappenas is entrusted with executing governmental obligations related to national development planning in compliance with existing laws and regulations. Housed within Bappenas is the Directorate for Public-Private Partnership (PPP) - (*Direktorat Kerjasama Pemerintah-Swasta dan Rancang Bangun*) - which facilitates collaboration on infrastructure projects between the Government and private investors.

e. **Ministry of Investment/Investment Coordinating Board (*Kementerian Investasi/ Badan Koordinasi Penanaman Modal* – BKPM)**

Starting from 2010, BKPM commenced the issuance of licences for electricity supply businesses. Since 2015, BKPM has also served as a comprehensive "one-stop" platform for streamlining business startup and licensing procedures, as well as facilitating the acquisition of permits for foreign workers. Additionally, BKPM provides an investor relations unit dedicated to furnishing information to and addressing inquiries from both existing and potential investors. The Government recently introduced an online business licensing platform, the Online Single Submission (OSS) system. For detailed information regarding the licences issued by BKPM, please refer to the discussions in *Section 3.2.4 - IUPTLU/IUPTLS*, *Section 3.2.5 - OSS system* and *Section 3.3.6 - Ease of licensing*.

f. **Daya Anagata Nusantara (Danantara)**

Established in 2025, Danantara serves as the Government's strategic investment arm, dedicated to optimising public investments to drive national economic growth. Danantara focuses on enhancing Indonesia's global competitiveness, particularly in key sectors such as energy. Danantara holds the GoI's equity interest in PLN.

g. **Committee for the Acceleration of Prioritised Infrastructure Development (*Komite Percepatan Penyediaan Infrastruktur Prioritas* – KPPIP)**

KPPIP is an inter-ministerial coordinating committee led by the Coordinating Minister for Economic Affairs alongside the Coordinating Minister for Maritime Affairs. Other members of KPPIP comprise the Minister of Finance, the Minister of National Development Planning/ Bappenas, the Minister of Agrarian and Spatial Planning and the Minister of Environment and Forestry. KPPIP's primary aim is to coordinate the decision-making process and serves as the central hub for resolving bottlenecks in strategically significant national and priority projects.

h. **MoF**

The MoF authorises tax incentives that may be offered by the Government for power projects, along with any government guarantees. The Directorate of Government Support Management and Infrastructure Financing (*Direktorat Pengelolaan Dukungan Pemerintah dan Pembiayaan Infrastruktur*) within the MoF is responsible for evaluating government support, providing technical guidance, assessing financing options and managing investor relations. Any approved guarantees are overseen by PT Penjaminan Infrastruktur Indonesia (PT PII). Furthermore, the MoF advises on the maximum level of electricity subsidy to PLN in the national budget and reviews loan agreements entered into by PLN, including the Government's guarantees of PLN's loans.

i. **PT PII or the Indonesian Infrastructure Guarantee Fund (IIGF)**

The IIGF was founded on 30 December 2009, with the purpose of furnishing guarantees for infrastructure projects operating under the PPP scheme. Additionally, the IIGF serves as a strategic advisor to the Government and assumes the role of a transaction manager/ lead arranger for infrastructure projects. The IIGF is entirely owned by the Government and as of the end of 2018, a total of IDR8 trillion in capital has been injected. For more comprehensive information, please refer to *Section 4.3.1 – IIGF* – for PPPs.

j. **Indonesian Renewable Energy Society (*Masyarakat Energi Terbarukan Indonesia* – METI)**

METI was established in 1999 as a platform dedicated to the advancement of renewable energy in Indonesia. METI is affiliated with the World Renewable Energy Network, headquartered in the UK. The leadership of METI comprises the leaders of various associations representing geothermal, hydro, solar, biofuel, biomass, biogas, wind, nuclear and ocean energy sectors.

k. **Indonesian Electrical Power Society (*Masyarakat Ketenagalistrikan Indonesia* – MKI)**

MKI was founded on 3 September 1998 and comprises representatives from diverse stakeholders within the power sector. The primary goals of MKI are to serve as a platform for discussing industry-related issues and to advocate the perspectives of its members to the Government on matters concerning technology, the business landscape and regulatory frameworks.

l. **PT Sarana Multi Infrastruktur (PT SMI) and PT Indonesia Infrastructure Finance (PT IIF)**

PT SMI was established on 26 February 2009, with an initial capital of IDR1 trillion (equivalent to USD100 million). By the end of 2017, its capital had surged to IDR55.39 trillion. PT SMI's primary mission is to facilitate domestic financing for infrastructure development, including power projects and to prepare projects under the project development facilities designated by the Minister of Finance. Supported by multilateral agencies such as the World Bank, PT SMI's total financing commitment reached IDR29 trillion by the end of 2017, with 32% allocated to the power sector.

On the other hand, PT IIF, established on 15 January 2010, functions as a private non-bank financial institution specialising in infrastructure project finance. Its shareholders include PT SMI, the International Finance Corporation, ADB, Deutsche Investitions-und Entwicklungsgesellschaft GmbH and Sumitomo Mitsui Banking Corporation. For detailed information, please refer to *Section 4.3.4 - The infrastructure financing fund*.

The Indonesian government, in collaboration with ADB, initiated the ETM programme during the COP26 conference in Glasgow. Following thorough technical assessments and consultations with various stakeholders within the power and utility industry, the Government identified 15 GW of CFPPs for early retirement.

PT SMI was appointed as the ETM Country Platform Manager and the national focal point for ETM activities. Collaborating with PLN and international partners, PT SMI aims to mobilise substantial competitive finance capital to facilitate a fair and affordable energy transition. Additionally, PT SMI signed Memorandum of Understanding with 14 international partners to bolster Indonesia's aspirations in energy transition development.

m. **The Indonesian Independent Power Producers Association (*Asosiasi Produsen Listrik Swasta Indonesia* – APLSI)**

APLSI, based in Jakarta, was established on 8 August 2008. Serving as both an organisation and a platform for dialogue, APLSI facilitates communication among IPPs, the Indonesian government and other stakeholders involved in IPP activities. APLSI aspires to be recognised as a proficient and dependable association representing IPPs in Indonesia, with a commitment to advancing the development of Indonesian IPPs on the global stage.

n. **Indonesian Solar Energy Association (*Asosiasi Energi Surya Indonesia* – AESI)**

AESI was established on 9 March 2016, with the objective of establishing a platform for communication and collaboration among stakeholders in the solar energy sector. The organisation endeavours to facilitate dialogue and cooperation among solar energy stakeholders to help achieve the national target for solar energy utilisation and meet sustainable energy requirements.

o. **Indonesian Geothermal Association (*Asosiasi Panasbumi Indonesia*/INAGA)**

INAGA was established in 1991 with the primary goal of serving as a platform for communication and coordination to enhance the capabilities, knowledge, collaboration and accountability of its members concerning the development of geothermal energy in Indonesia.

p. **JETP**

The Just Energy Transition Partnership, commonly abbreviated as JETP, is a global partnership agreed upon by world leaders at the G20 High-Level Conference held in Bali in 2022. Its aim is to accelerate a fair energy transition towards sustainability and reduce the impacts of climate change. This partnership involves leaders from governments, companies, civil society organisations and academic communities worldwide.

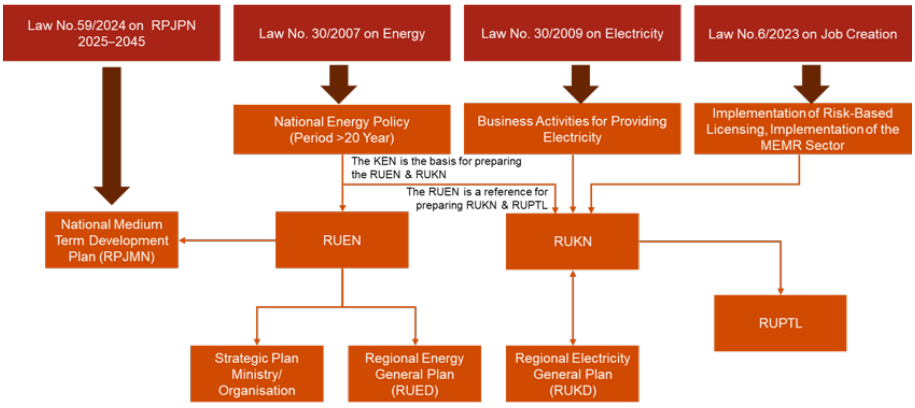
q. **IPPs**

As a key stakeholder in the energy sector, an IPP is a company tasked with generating and selling electricity, typically through power plants, while not owning the transmission infrastructure. IPPs operate independently of national power supply companies, serving either the public power grid or specific end-users. They possess the flexibility to utilise various energy sources, including both conventional (like natural gas) and renewable (such as biogas) options. By integrating IPPs into the energy market, competition is stimulated, energy generation diversifies and investments in renewable technologies may accelerate. This stakeholder's role significantly impacts the energy landscape, promoting sustainability and aligning with global climate change mitigation efforts.

2 Energy transition

Indonesia's energy transition strategy presents a comprehensive approach aimed at shifting from a reliance on fossil fuels to a more sustainable and diversified energy mix. The recent updates on Indonesia's energy transition policy, targets and strategy are in progress to align energy transition policy with climate change ambition toward NZE. There is a number of interconnected plans and policies defining the overall nation level energy transition strategy. Indonesia's long-term energy transition plan is outlined in the RUEN, or the National Energy Plan. RUEN provides a detailed strategy for energy development based on the principles set out in the NEP or National Energy Policy. NEP serves as an umbrella, guiding policy detailing how the energy sector contributes to achieving these long-term goals. Furthermore, RUEN serves as a reference for developing the RUKN, or the National Electricity General Plan, which contains projections for the national electricity sector and RPJPN, or the National Long-Term Development Plan, which outlines the future energy landscape in a broad focus. Additionally, the RUPTL outlines the electricity supply business strategy of PLN, referencing the policies and guidelines established in the RUKN.

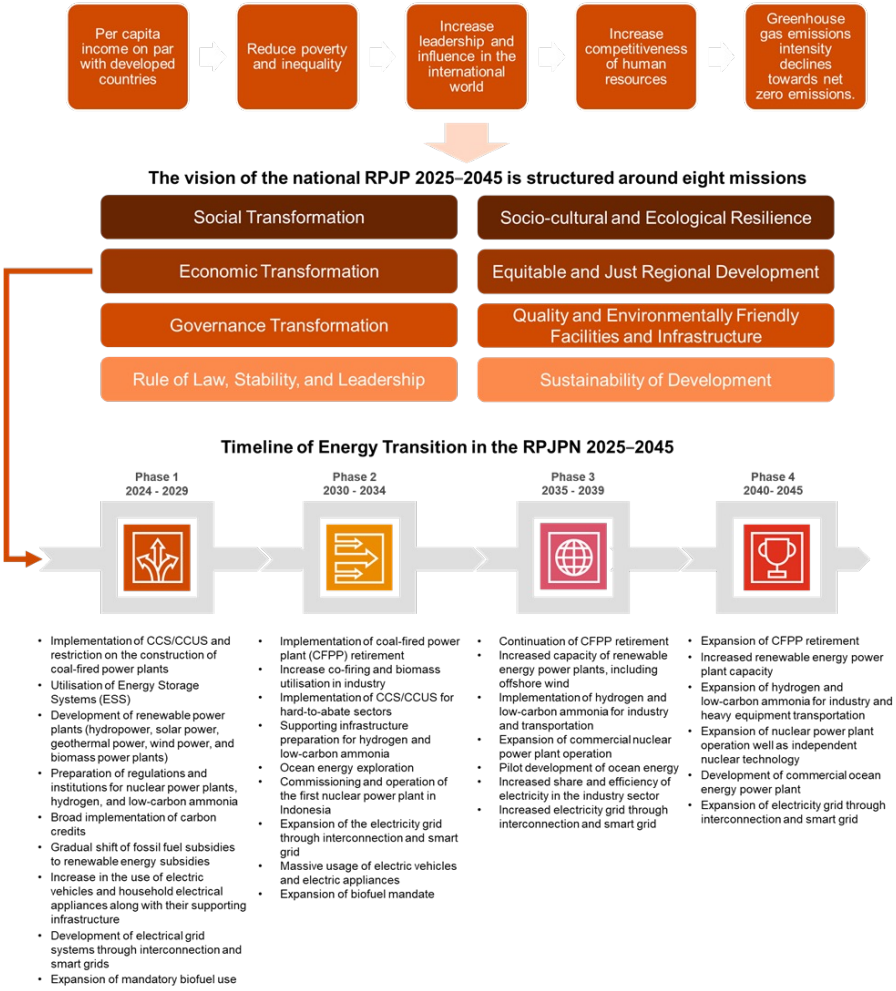
Figure 2.1 – Synchronisation of the NEP, RUEN, RUED, RUKN and RUPTL



2.1 Vision 2045: Unveiling Indonesia's economic transformation towards a golden era

The RPJPN, governed by Law No.59 of 2024, is a strategic framework designed by the GoI to guide the country's development over a 20-year period. The upcoming 2025-2045 RPJPN provides the clear vision and direction for Indonesia's future with five visions which are broken down into eight missions or agenda, as shown in the figure below. The RPJPN has set a goal of reducing GHG emissions by 93.5% to reach net-zero, emphasising that energy transition is a crucial aspect in sustainable economic development. In particular the RPJPN targets the share of renewable energy in the energy mix to increase from an assumed baseline of 20% in 2025 to 70% in 2045. While transitioning to cleaner sources of energy supports sustainable economic growth and energy security and independence, the adoption of a green economy can also become a new source of growth by enhancing job opportunities, green investments and the development of green products.

Figure 2.2 – Vision and mission of the RPJPN and energy transition timeline in the RPJPN



Source: 2025-2045 RPJPN

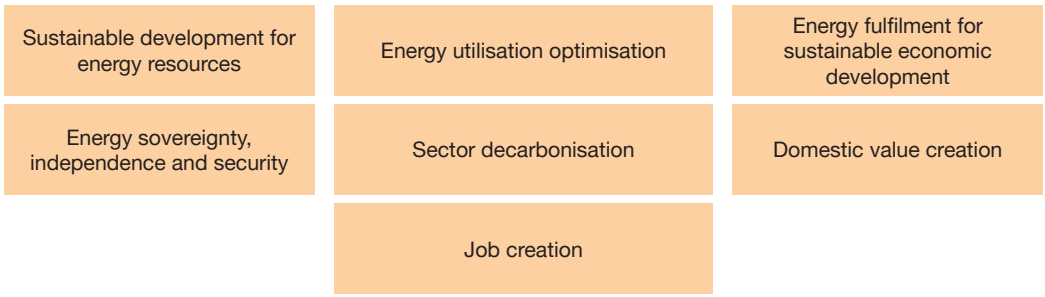
The RPJPN treats energy transition as a part of economic transformation to a green economy. The policy direction for implementing a green economy in Indonesia is based on the execution of low carbon development. Hence, energy transition, as part of economic transformation, is directed towards the utilisation of clean, efficient and renewable energy through the accelerated use of RE sources such as bioenergy, geothermal, hydro, solar, wind, nuclear and hydrogen. This includes the gradual retirement of CFPPs, the development of infrastructure and technology, the increase in quality energy consumption, the completion of rural electrification, the development of electrical grids including island grids and national grids, and the acceleration of the use of transportation vehicles that utilise clean energy, supported by the mass use of energy storage systems throughout Indonesia.

2.2 NEP, RUEN and RUKN updates on energy transition

2.2.1 NEP updates on energy transition

The NEP in Indonesia is updated to address the evolving energy landscape and align with global sustainability goals, based on Government Regulation (GR) No. 40 of 2025 titled National Energy Policy, which serves as the primary guideline for the direction of energy development in Indonesia[1].

Figure 2.3 – The targets of the NEP in energy management



Source: 2025-2060 NEP

Recent changes to the NEP include a revision of the renewable energy targets for 2025. The RE targets for primary energy supply until 2060 are: 368-454 million tonnes of oil equivalent with a renewable energy mix of 19-23% by 2030, 468-596 million tonnes of oil equivalent with a renewable energy mix of 36-40% by 2040, 595-712 million tonnes of oil equivalent with a renewable energy mix of 53-55% by 2050 and 665-775 million tonnes of oil equivalent with a renewable energy mix of 70-72% by 2060. The new targets are designed to be more achievable while still pushing towards a sustainable energy transition.

The table below provides a detailed breakdown of projected energy utilisation across various sectors, including industry, transport, commercial and household, for the years 2030, 2040, 2050 and 2060.

Table 2.1 – Sectoral energy utilisation

Sector	Sectoral energy utilisation (Million tonnes of oil equivalent)			
	2030	2040	2050	2060
Industry	127.9 - 153.4	168.9 - 196.6	215.4 - 252.0	246.7 - 274.0
Transport	87.0 - 95.6	85.8 - 96.8	79.6 - 90.1	64.7 - 80.0
Commercial	11.2 - 15.6	14.8 - 20.9	18.4 - 25.6	20.8 - 27.2
Household	29.0 - 34.3	34.3 - 44.6	41.2 - 46.9	46.3 - 51.7

Displayed here are the projected electricity generation targets in TWh without and with captive power for the years 2030, 2040, 2050 and 2060, illustrating the important role of private power generation for industrial use.

Table 2.2 – Electricity generation

Electricity	Electricity generation (TWh)			
	2030	2040	2050	2060
Without captive power	544 - 806	855 - 1,240	1,240 - 1,593	1,498 - 1,769
With captive power	699 - 983	1,064 - 1,538	1,502 - 2,026	1,813 - 2,349

Outlined below is the planned energy utilisation by technology, including categories such as solar, biomass and natural gas, measured in tonnes of oil equivalent, from 2030 to 2060.

Table 2.3 – Primary energy utilisation

Technology	Primary energy utilisation (Tonnes of oil equivalent/TOE)			
	2030	2040	2050	2060
Solar	1.2 - 1.5 (Million TOE)	1.8 - 1.9 (Million TOE)	4.3 - 4.5 (Million TOE)	11.6 - 12.7 (Million TOE)
Biomass	15.8 - 23.1 (Million TOE)	21.9 - 24.7 (Million TOE)	30.3 - 35.0 (Million TOE)	67.5 - 71.9 (Million TOE)
Biogas	48.4 - 65.1 (Thousand TOE)	87.5 - 118.2 (Thousand TOE)	158.4 - 200.7 (Thousand TOE)	286.7 - 378.3 (Thousand TOE)
Biofuel	18.7 - 22.7 (Million TOE)	21.9 - 25.2 (Million TOE)	18.7 - 22.1 (Million TOE)	13.6 - 19.9 (Million TOE)
Natural gas	18.8 - 20.1 (Million TOE)	24.9 - 27.3 (Million TOE)	40.4 - 47.4 (Million TOE)	56.6 - 71.1 (Million TOE)
Liquefied petroleum gas	11.0 - 11.2 (Million TOE)	2.8 - 3.0 (Million TOE)	1.0 - 1.1 (Million TOE)	0.8 - 0.9 (Million TOE)
Coal	67.2 - 68.7 (Million TOE)	83.3 - 85.3 (Million TOE)	80.3 - 81.8 (Million TOE)	25.3 - 38.6 (Million TOE)
Oil	75.3 - 82.1 (Million TOE)	64.3 - 73.5 (Million TOE)	45.8 - 54.7 (Million TOE)	22.8 - 32.0 (Million TOE)
Hydrogen	0.7 - 1.4 (Thousand TOE)	4.5 - 6.4 (Million TOE)	20.4 - 23.2 (Million TOE)	31.4 - 35.4 (Million TOE)
Ammonia	2.4 - 2.9 (Thousand TOE)	1.0 - 1.2 (Million TOE)	3.5 - 4.3 (Million TOE)	3.5 - 7.5 (Million TOE)
Dimethyl ether	0 - 600 (TOE)	3,000 - 3,600 (TOE)	3,000 - 3,600 (TOE)	3,000 - 3,600 (TOE)

Table 2.4 highlights the projected contribution of various energy technologies to the national energy mix, expressed as percentages, from 2030 to 2060, showcasing strategies for an optimal energy balance.

Table 2.4 – Primary energy utilisation

Technology	Primary energy utilisation (%)			
	2030	2040	2050	2060
Hydro	1.8% - 2.3%	3.6% - 3.8%	4.6% - 4.9%	4.9% - 5.1%
Solar	1.3% - 1.6%	13.1% - 16.0%	23.3% - 25.3%	29.8% - 32.0%
Wind	0.3% - 0.5%	0.9% - 1.1%	1.0% - 1.2%	1.2% - 1.3%
Biomass	7.2% - 9.0%	6.5% - 6.7%	7.4% - 7.6%	12.2% - 13.4%
Geothermal	3.4% - 4.0%	3.8% - 4.4%	4.8% - 5.1%	4.9% - 5.2%
Biogas	0.013% - 0.014%	0.019% - 0.020%	0.027% - 0.028%	0.043% - 0.049%
Biofuel	5.1% - 5.2%	4.2% - 4.7%	3.1% - 3.2%	2.1% - 2.6%
Nuclear	0.4% - 0.5%	2.8% - 3.4%	6.8% - 7.0%	11.7% - 12.1%
Other renewables	0.1% - 0.2%	0.5% - 0.6%	1.2% - 1.5%	1.5% - 1.6%
Oil	22.4% - 26.3%	14.3% - 15.9%	8.7% - 8.8%	3.9% - 4.7%
Coal	40.7% - 41.6%	28.9% - 31.0%	19.1% - 20.9%	7.8% - 11.9%
Natural gas	12.9% - 14.2%	16.7% - 16.8%	17.1% - 17.3%	14.4% - 15.4%

Outlined here are the targets for the reduction of CO_2e emissions in the energy sector in million tonnes, alongside the emissions intensity measured as CO_2e per TOE, spanning from 2030 to 2060.

Table 2.5 – CO_2e emissions and emissions intensity targets

Sector	CO_2e emissions (million tonnes) and emissions intensity (CO_2e per TOE) target			
	2030	2040	2050	2060
Total CO_2e emissions (million tonnes)	1,017 - 1,184	925 - 1,086	676 - 744	Up to 129
Emissions intensity (CO_2e per TOE)	2.61 - 2.76	1.82 - 1.98	1.05 - 1.14	0.17 - 0.19

2.2.2 RUEN updates on energy transition

With the updates on the programme implementation plan (RPP) for the NEP as the reference, the implementation plans for Indonesia's focus on energy is discussed in the RUEN, which was developed by the DEN. In this upcoming RUEN, the GoI's vision for energy aims to fulfil the supply of power generation capacity to about 115 GW by 2025 and 430 GW by 2050 (from approximately 101 GW in 2024), with an electrification ratio of 100% for 2025. The GoI also aims to achieve more efficient energy use, aiming to have energy elasticity of less than 1 by 2025, namely 0.84 by 2025 and targeted to reduce to 0.46 by 2050.

The roadmap for reducing emissions in Indonesia has been outlined with specific targets for the years 2025 through 2060, highlighting notable shifts in energy sourcing and technology adoption. In 2025, emissions are expected to be between 914 and 984 million tonnes of CO_2e, with renewable energy comprising 17-19% of the energy mix. Development of power plants will proceed according to the RUPTL, focusing on increasing renewable sources. By 2030, emissions are projected to rise to a range of 1,074 to 1,223 million tonnes CO_2e, with RE increasing to 19-21%, accompanied by a strategic reduction in fuel and liquefied petroleum gas (LPG) imports. By 2035 emissions are expected to increase slightly to between 1,150 and 1,316 million tonnes of CO_2e, integrating the first phase of CFPP retirements, eliminating diesel power plants and launching nuclear power capabilities with 250 MW planned by 2032, as well as the commencement of carbon capture and storage (CCS)/carbon capture, utilisation and storage (CCUS) for power plants. Progressing to 2040, emissions are planned to reduce to 975-1,085 million tonnes CO_2e, with RE representing 40-42% of the mix, as CFPP retirements continue, biofuel utilisation expands and CCS/CCUS applications extend to industry sectors. By 2050, emissions are expected to halve to 598-579 million tonnes CO_2e and RE jumps to 51-54% of the mix, with significant increases in biofuel implementation. Finally, in 2060, emissions are planned to dramatically reduce to 129 million tonnes CO_2e, achieving an RE share of 70-72%, with full adoption of CCS/CCUS across all fossil fuel power plants, reflecting Indonesia's robust commitment to sustainable energy practices and substantial reductions in carbon intensity.

The figure below illustrates the planned energy transition scenarios across the transportation, household, industrial and commercial sectors.

Figure 2.4 – Energy transition scenarios for energy users

Transportation sector

- Utilisation of biofuel: biodiesel and biogasoline for land transportation, bioavtur for air transportation
- Utilisation for electric vehicles (motorcycles, cars and electric buses) for land transportation
- Hydrogen utilisation (fuel cell) for trucks
- Utilisation of Compressed Natural Gas (CNG) vehicles

Household sector

- Fuel switching from LPG to electrical/induction stoves, DME, gas network and biomass
- Energy Conservation Program (energy management, Minimum Energy Performance Standard (MEPS) and the use of high energy efficient appliances)

Industrial sector

- High-temperature industries:
  - Fuel switching from coal to natural gas and biomass
  - Increasing electrification and energy efficiency
  - Utilisation of CCS/CCUS technologies
- Low-temperature industries
  - Increasing electrification
  - Energy efficiency

Commercial sector

- Fuel switching from LPG to electrical/induction stoves, DME, gas network
- Energy Conservation Program (energy management, Minimum Energy Performance Standard (MEPS) and the use of high energy efficient appliances)

Source: Enerdata, 2014

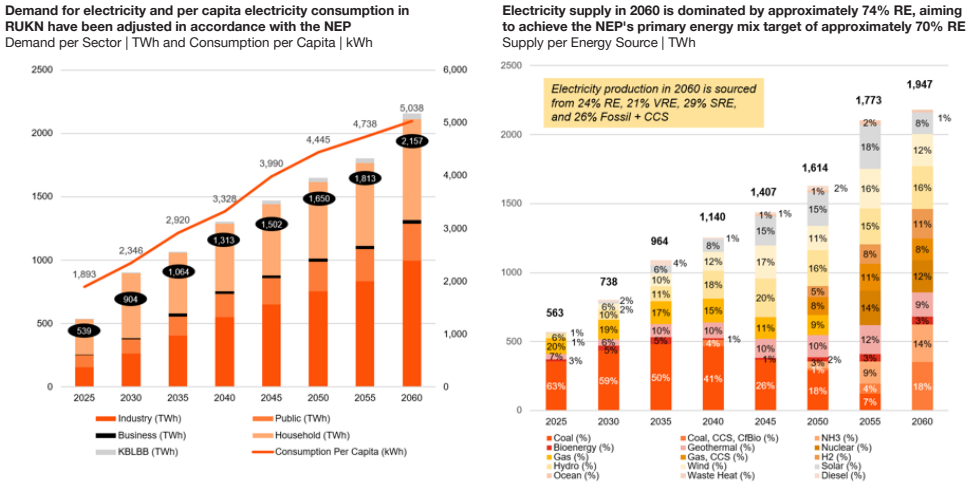
2.2.3 RUKN updates on energy transition

Using the RUEN as a reference, the RUKN contains the policies for national electricity, the conditions of the current electricity supply and the projections of national electricity until 2060 and its system development plans for national electricity supply. The 2025-2060 RUKN is an update to the 2019-2038 RUKN and places a larger emphasis on the policies and plans for electricity supply to support the GoI's emission reduction efforts towards NZE by 2060.

There are three key drivers of the updates incorporated in the 2025-2060 RUKN. First, the plans in the 2020-2024 National Medium-Term Development Plan (*Rencana Pembangunan Jangka Menengah Nasional*/RPJMN) for the development of industrial areas (*Kawasan Industri*/KI), special economic zones (SEZs), smelters, integrated marine and fisheries centres (*Sentra Kelautan dan Perikanan Terpadu*/SKPT), priority tourism areas (*Destinasi Pariwisata Prioritas*/DPP), along with the needs from national strategic projects (*Proyek Strategi Nasional*/PSN), electric vehicles and hydrogen fuel, have driven an increase in national electrical power needs. Second, there is a larger emphasis on environmental protection in the process of reaching sustainability by 2060. Third, the policy to manage the construction of CFPPs has been updated, which are only allowed if they increase the added value of natural resources or if the plant is part of a PSN. The CFPPs must now also reduce GHG emissions by at least 35% within ten years of starting operations and are only allowed to run up to 2050.

Based on the latest RUKN adjustments aligned with the NEP, there are significant developments projected in the electricity demand and supply landscape leading up to 2060. These adjustments consider various key sectors including industrial areas, SEZs, SKPTs and DPPs, supporting a GDP growth target of 8% per annum by 2029. Electricity demand is shown to rise substantially, with per capita consumption projected to reach 5,038 kWh by 2060. This surge is mainly driven by needs across sectors such as industry, business, public services and households, alongside emerging demands from electric vehicles (*Kendaraan Bermotor Listrik Berbasis Baterai*/KBLBB). On the supply side, the 2060 electricity production mix is dominated by approximately 74% renewable energy sources, meeting the NEP's target of 70% RE. This production is fueled by a diverse range of energy sources including solar, wind, ocean currents, bioenergy, geothermal and innovative solutions like green hydrogen. Critically, some coal-fired power production is set to transition with ammonia beginning in 2045 and hydrogen from 2051.

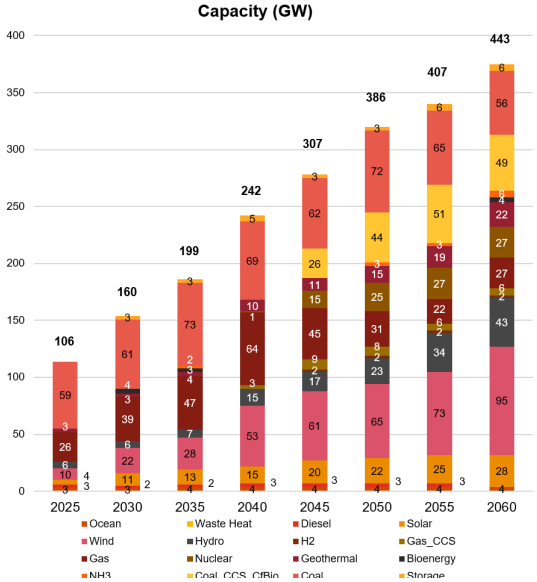
Figure 2.5 – 2025-2060 RUKN demand for electricity and per capita electricity consumption (left-side); electricity supply in 2060 is dominated by approximately 74% RE (right-side)



In the left-hand chart, the projection for demand has taken into account electricity needs for industrial areas, SEZs, smelters and SKPTs, thus allowing for the achievement of 8% GDP growth per annum by 2029. In the right-hand chart, future electricity production will be dominated by RE sources that are diverse, such as solar, wind, ocean currents, bioenergy, geothermal, nuclear, ammonia (NH_3) and green hydrogen (H_2). Furthermore, some coal will be replaced by NH_3 gradually starting from 2045 and will be replaced by H_2 starting from 2051.

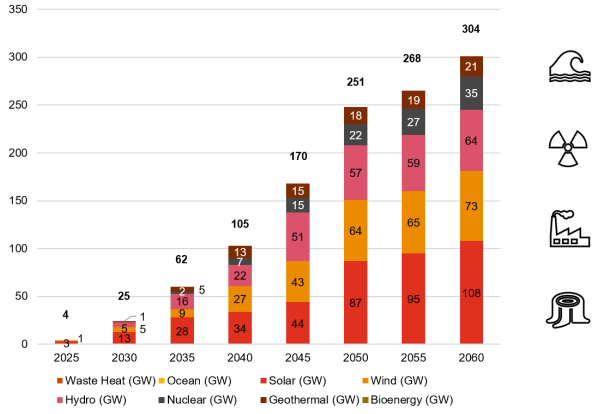
The increased share of new and renewable energy within the energy mix can bolster the Government's commitment to reducing GHG emissions. This commitment is outlined in Indonesia's 2022 ENDC document, where the energy sector is tasked with cutting emissions by 358 million tonnes of CO_2e, representing 12.5% of the national target by 2030 compared to a BAU scenario through domestic efforts, and by 446 million tonnes of CO_2e or 15.5% with international assistance. Moreover, the rising proportion of new and renewable energy can aid the Government's plan to achieve NZE by 2060 or earlier. By 2060, the power generation capacity is projected to reach 443 GW. This will consist of 41.6% VRE, supported by 34 GW of storage solutions, such as BESS planned for deployment by 2025, alongside pumped hydro storage by 2028. The remainder, representing 58.4%, will comprise other renewable energy sources and fossil fuels equipped with CCS, integrated into CFPPs.

Figure 2.6 – 2025-2060 RUKN power generation capacity (GW)



The RUKN features large-scale hydroelectric plants in Sumatra, Kalimantan and Sulawesi, overseen by the Ministry of Public Works. Nuclear power sites are determined based on studies conducted by the National Research Authority (*Badan Riset dan Inovasi Nasional*/BRIN), while geothermal projects focus on areas in Sumatra, Java, Maluku and Nusa Tenggara. Biomass co-firing is utilised to enhance renewable energy output and reduce emissions from coal-fired plants. In this national plan, the Government aims to achieve 105 GW of renewable energy by 2040, with 75 GW developed by PLN and the remainder by the private sector, including under temporary electricity supply business permits (*Izin Usaha Penyediaan Tenaga Listrik Sementara*/IUPTLS).

Figure 2.7 – Cumulative additional renewable energy power plants (GW)

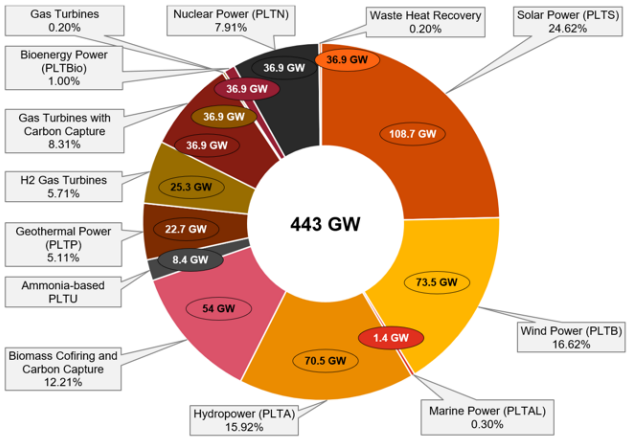


2.2.4 Energy Transition Roadmap (ETR) under MoEMR Regulation No.10/2025

The ETR for the electricity sector, an integral element of Indonesia's comprehensive energy policy framework, details the path for significantly lowering GHG emissions, transitioning to RE sources and ultimately achieving NZE by 2060. The ETR is based on the 2025-2060 RUKN.

To accommodate the rising demand for electricity and to replace existing power plants approaching end of useful life, there is a need for an annual increase in capacity of about 9.6 GW. By 2060, the anticipated total power generation capacity is expected to reach 443 gigawatts. This capacity will comprise approximately 41.5% from variable RE sources, which will include around 34 GW of storage capacity and the remaining 58.5% from dispatchable, non-variable renewable energy sources.

Figure 2.8 – Total power plant capacity mix in 2060



This is supported by a strategic plan for a supergrid that focuses on developing interconnections both within and between islands. As new energy projects connect to the national grid, expanding and upgrading the transmission infrastructure becomes crucial. The supergrid roadmap prioritises intra-island connections among Sumatra, Sulawesi, Kalimantan and Papua, alongside inter-island links planned for specific years: Sumatra-Batam by 2028, Java-Bali by 2029, Sumatra-Java by 2031, Bali-Lombok-Sumbawa by 2035, Kalimantan-Java by 2040, followed by Sumbawa-Flores and Kalimantan-Sulawesi by 2041, and Sumba-Sumbawa-Sulawesi by 2045.

Further reductions in emissions can be realised through the decommissioning of CFPPs that are fully depreciated, have PPAs with IPPs that are coming to the end of term or are naturally retiring. The average annual potential for reducing GHG emissions from CFPPs over various periods is as follows:

Figure 2.9 – CFPP decommissioning and the emission reduction potential (2030-2059)

Period	CFPPs	Average emission reduction potential
2030-2039	13 units	34.5 million tonnes of CO_2 per year
2040-2049	119 units	223.4 million tonnes of CO_2 per year
2050-2059	36 units	48.4 million tonnes of CO_2 per year

Source: MoEMR Regulation No.10/ 2025

In the process of evaluating prospective candidates for expedited cessation of operations of CFPPs, it is essential to adhere to the seven criteria prescribed under Presidential Regulation (PR) No.112/2022, which focuses on the ARED for electricity supply. Paramount among these criteria are the availability of funding support, followed by the reliability of the electricity system, the impact of increased base production costs on electricity tariffs and the implementation of just energy transition principles.

The roadmap includes several stages to ensure a smooth transition. Starting in 2025, MoEMR will enact regulations relevant to the ETR for the electricity sector. Once funding is secured, MoEMR tasks PLN with conducting a comprehensive study and establishing a joint working group. This review process is expected to be completed within six months, utilising studies from independent bodies for additional insights when necessary. Subsequently, a joint working group evaluates the findings of PLN's study, leading to the early retirement of CFPPs. This phase involves PLN initiating the procurement and development of replacement power plants, amending PPAs as required and reinforcing transmission infrastructure to ensure compliance with the closure schedule. Throughout this process, MoEMR may consider increasing funding support or appointing an independent body to conduct further studies if additional financial resources are necessary. The roadmap ultimately targets the early retirement of CFPPs, with alternative power plants becoming operational.

2.3 RUPTL

The RUPTL is a critical document for Indonesia's energy sector, outlining the country's electricity supply strategy over a ten-year period. Managed by PLN, the RUPTL aims to ensure a reliable and sustainable electricity supply to meet the growing demand. It includes detailed plans for power generation and T&D, emphasising the integration of renewable energy sources and the reduction of reliance on fossil fuels. The latest RUPTL is the 2025-2034 RUPTL, released in June 2025.

Several key factors are driving the update of the RUPTL for 2025-2034. Unlike the previous version, the updated plan is geospatially based and balances the system region by region. To evacuate all potential renewable energy sources, 48,000 km of transmission backbone and island interconnections are planned for construction. The implementation of a smart grid is set to increase the penetration of solar and wind energy. This strategic shift is expected to

stimulate investor interest in renewable energy projects, as market risks related to demand fluctuations are mapped and mitigated individually. The driving factors include fostering national economic growth with multiplier effects, including the development of industrial zones, downstreaming industry, special economic zones, fishing and maritime centres, electric vehicles and super-prioritised tourism spots. Furthermore, there is an incorporation of new technologies into the plan, such as standalone batteries and more hybrid types, including coal with solar PV BESS, solar PV BESS and other renewable energy bases with BESS.

Two scenarios are outlined in this RUPTL: the RE Base scenario and the ARED scenario (as discussed in Chapter 1 of this Guide). The RE Base scenario assumes that the development of the electricity system is based on the ability to complete work according to the capabilities of PLN and the Government, both in terms of project workability and financing. This scenario does not aim to achieve emission reduction and energy mix targets. Instead, it optimises the development of the electricity system for cost and supply reliability. The ARED scenario prioritises emission reduction targets and the renewable energy mix. PLN has declared an intention to pursue the ARED scenario, which includes strategic programmes such as the development of green enabling transmission, smart grid, smart control systems, flexible generation, co-firing, CCU/CCUS, BESS and other emission reduction programmes.

Both the RE Base scenario and the ARED scenario outline a comprehensive strategy that includes a progressive increase in power generation capacity over the years—with the RE Base scenario targeting an increase in power plant capacity of 52.7 GW, while the ARED case targets a 69.5 GW increase. The ARED case marks a major shift towards renewable energy, targeting a 76% share by 2034. Tables 2.6 and 2.7 below segment the total power plant capacity increase into the planned yearly plant capacity increase of each plant technology from 2025 to 2034 under each of the RE Base and ARED scenarios.

In the RE Base case, total capacity addition amounts to 52.8 GW, with non-RE sources accounting for 35% (18.7 GW). In contrast, under the ARED case, non-renewable sources contribute just 24% of the total 69.5 GW, or equivalent to 16.7 GW.

Under the more ambitious ARED scenario, the RE mix is projected to increase 2.5 times from 12% by 2025 to approximately 34.3% by 2034. Renewable sources will contribute 42.1 GW to this increase, including 17.1 GW from solar energy, 15.9 GW from hydropower (including 4.3 GW of pumped hydro storage), 7.2 GW from wind energy, 5.2 GW from geothermal energy and 0.9 GW from bioenergy. Additionally, a contribution of 0.5 GW is planned from nuclear power. Storage solutions are planned to add 10.3 GW, with pumped storage accounting for 4.3 GW (included under hydro in the table) and BESS contributing 6 GW. Non-renewable sources will add 16.7 GW, comprised of 10.4 GW from gas and 6.3 GW from coal.

Table 2.6 – 2025-2034 RUPTL power plant capacity mix per technology (MW), RE Base scenario

RE Base scenario	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total per technology
Fossil	3,596	1,629	3,971	1,235	2,736	2,091	90	1,499	690	1,150	18,687
Geothermal	133	95	305	236	331	529	1,210	663	1,655	0	5,157
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Bioenergy	15	3	13	53	157	177	24	25	13	0	480
Hydro	754	592	439	1,863	588	944	4,181	3,137	2,910	725	16,133
Solar	777	289	964	1,041	471	988	336	286	907	1,085	7,144
Wind	0	350	122	185	103	190	165	272	420	400	2,207
Waste	0	18	0	165	150	101	0	0	19	0	453
BESS Standalone	**50**	**111**	**152**	**100**	**350**	**176**	**0**	**100**	**275**	**1,150**	**2,464**
Ocean	**0**	**0**	**0**	**40**	**0**	**0**	**0**	**0**	**0**	**0**	**40**
Yearly total	**5,325**	**3,087**	**5,966**	**4,918**	**4,886**	**5,196**	**6,006**	**5,982**	**6,889**	**4,510**	**52,765**

Table 2.7 – 2025-2034 RUPTL power plant capacity mix per technology (MW), ARED scenario

ARED scenario	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total per technology
Fossil	3,596	1,629	3,771	1,085	2,586	1,344	90	1,499	937	150	16,687
Geothermal	133	125	275	346	71	564	1,265	573	1,805	0	5,157
Nuclear	0	0	0	0	0	0	0	250	250	0	500
Bioenergy	15	3	13	53	157	177	24	25	13	0	480
Hydro	754	592	439	1,863	588	794	4,331	2,872	2,875	825	15,933
Solar	777	988	1,619	1,468	1,059	1,651	2,284	2,099	3,870	1,247	17,062
Wind	0	350	372	485	293	1,265	930	922	1,570	1,000	7,187
Waste	0	18	0	165	150	101	0	0	19	0	453
BESS standalone	**50**	**311**	**527**	**350**	**650**	**551**	**600**	**900**	**825**	**1,250**	**6,014**
Ocean	**0**	**0**	**0**	**40**	**0**	**0**	**0**	**0**	**0**	**0**	**40**
Yearly total	**5,325**	**4,016**	**7,016**	**5,855**	**5,554**	**6,447**	**9,524**	**9,140**	**12,164**	**4,472**	**69,513**

PLN actively promotes private sector involvement in electricity infrastructure development, allocating 71% of planned new power plant projects for IPPs, with 90% of RE power plants set for private development. The targets for private sector RE development are set at 87% for solar, 90% for hydropower, 89% for biomass and 95% for wind.

Photo source: PwC

In each island, the preferred renewable energy technology varies, reflecting the diverse geographical and climate factors accross the archipelago. In Sumatra, hydropower is the preferred technology, with both the RE Base and ARED scenarios projecting a 4.67 GW increase in hydropower capacity over the 2025-2034 period, followed by geothermal with an expected 2.02 GW of new capacity over the same period. Shifting geographically eastward to Kalimantan, hydropower remains the preferred renewable technology, with projected capacity additions of 1.70 GW under the RE Base scenario and 1.50 GW under the ARED scenario. These account for over 37% and 26%, respectively, of Kalimantan's total capacity additions during the 2025-2034 period.

Hydropower capacity additions are also prioritised in Sulawesi; under both the RE Base and ARED scenarios, 4.18 GW of new hydropower capacity is expected to be added across the island. This represents 49% of the Sulawesi's total capacity addition under the RE Base scenario and 40% under the ARED scenario. Moving on to the island group with the highest planned capacity additions, Java-Madura-Bali, pumped storage hydropower is the most favoured technology, with 3.74 GW of capacity additions projected under both the RE Base and ARED scenarios. This is followed by solar PV, which is expected to contribute 2.56 GW in the RE Base scenario and a significantly higher 10.32 GW under the ARED scenario. Meanwhile, in the NTT/West Nusa Tenggara (NTB)-Maluku-Papua region, the preferred renewable technology is solar PV combined with battery storage, with a planned addition of 1.47 GW under both scenarios—accounting for 31% of the region's total capacity addition target.

Figure 2.10 – 2025-2034 RUPTL additional power plant and storage requirement (GW), mix per region

Indonesia

Technology	RE Base	ARED
Total	**52.76**	**69.51**

Kalimantan

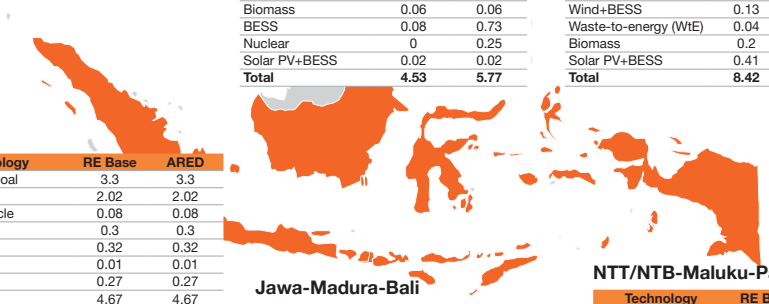
Technology	RE Base	ARED
Coal	0.25	0.25
Mine-mouth coal	0.4	0.4
Combined cycle	0.73	0.58
Gas	0.6	0.3
Gas engine	0.11	0.06
Biogas	0.02	0.02
Microhydro	0.03	0.03
Hydro	1.7	1.5
PLTS	0.47	1.51
Wind	0.07	0.07
Biomass	0.06	0.06
BESS	0.08	0.73
Nuclear	0	0.25
Solar PV+BESS	0.02	0.02
Total	**4.53**	**5.77**

Sulawesi

Technology	RE Base	ARED
Coal	0.21	0.21
Geothermal	0.31	0.31
Combined cycle	2.1	2.1
Gas/Gas engine	0.43	0.43
Microhydro	0.42	0.42
Hydro	4.18	4.18
Wind+BESS	0.13	1.01
Waste-to-energy (WtE)	0.04	0.04
Biomass	0.2	0.2
Solar PV+BESS	0.41	1.53
Total	**8.42**	**10.42**

Sumatra

Technology	RE Base	ARED
Mine-mouth coal	3.3	3.3
Geothermal	2.02	2.02
Combined cycle	0.08	0.08
Gas	0.3	0.3
Gas engine	0.32	0.32
Biogas	0.01	0.01
Microhydro	0.27	0.27
Hydro	4.67	4.67
Pumped storage hydro	0.5	0.5
Solar PV	1.61	1.61
Wind	0.59	0.59
Waste-to-energy (WtE)	0.02	0.02
Biomass	0.05	0.05
BESS	1.08	1.08
Nuclear	0	0.25
Total	**14.81**	**15.06**



Jawa-Madura-Bali

Technology	RE Base	ARED
Coal	2	2
Geothermal	2.5	2.5
Combined cycle	4.65	3.15
Gas	0.6	0.6
Gas engine	0.2	0.2
Microhydro	0.38	0.38
Hydro	0.05	0.05
Pumped storage hydro	3.74	3.74
Solar PV	2.56	10.32
Wind	1.28	5.38
Solar PV+BESS	0.61	0.61
Waste-to-energy (WtE)	0.4	0.4
BESS	1.31	4.21
Total	**20.3**	**33.55**

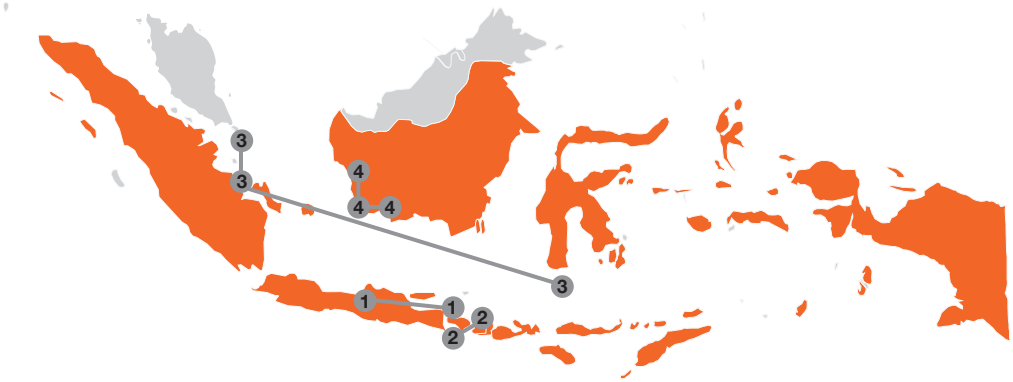
NTT/NTB-Maluku-Papua

Technology	RE Base	ARED
Coal	0.19	0.19
Geothermal	0.33	0.33
Gas	0.35	0.35
Gas engine	1.87	1.87
Microhydro	0.09	0.09
Hydro	0.09	0.09
Wind	0.14	0.14
Biomass	0.14	0.14
Solar PV+BESS	1.47	1.47
Ocean current	0.04	0.04
Diesel	0.01	0.01
Total	**4.71**	**4.71**

The "Green Enabling Super Grid" initiative aims to address the mismatch between supply and demand by evacuating renewable energy sources across Sumatra, Kalimantan, Sulawesi and Nusa Tenggara to major demand centres. Under the 2025–2034 RUPTL, approximately 48,000 km of additional transmission lines are planned, including 11,155 km in Sumatra, 13,889 km in Java-Madura-Bali, 9,812 km in Kalimantan, 9,019 km in Sulawesi and 3,883 km in Maluku, Papua, Nusa Tenggara. Additionally, about 108,000 MVA of new substations are planned, distributed among Sumatra (28,410 MVA), Java-Madura-Bali (59,730 MVA), Kalimantan (8,080 MVA), Sulawesi (9,670 MVA) and Maluku, Papua, Nusa Tenggara (2,060 MVA). Furthermore, the plan for the power system interconnection includes projects such as the following:

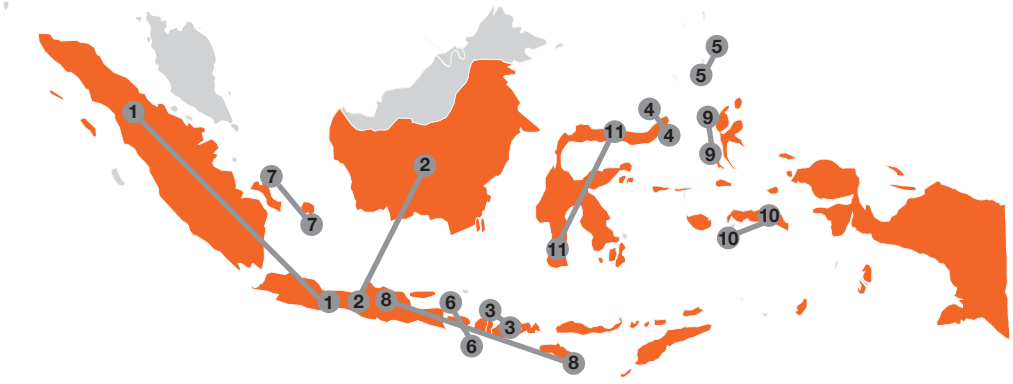
- Ongoing interconnection projects:
    1. 500 kV Java – Bali Interconnection
    2. 20 kV Bali – Nusa Penida Interconnection
    3. 20 kV Dabo Singkep – Selayar – Lingga Interconnection
    4. 150 kV Kendawangan – Sukamara and Sandai – Tayan Interconnection

Figure 2.11 – 2025-2034 RUPTL ongoing interconnection projects



- Interconnection projects requiring further study:
  1. 500 kV Sumatra – Java Interconnection
  2. 500 kV Kalimantan – Java Interconnection
  3. 150 kV Lombok – Sumbawa Interconnection
  4. 20 kV Manado – Bunaken Interconnection
  5. 20 kV Talaud – Lirung Interconnection
  6. 150 kV Bali – Lombok Interconnection
  7. 150 kV Bangka – Belitung Interconnection
  8. 500 kV Sumba – Java Interconnection
  9. 150 kV Ternate – Tidore Interconnection
  10. 150 kV Seram – Ambon Interconnection
  11. 150 kV Sulbagsel – Sulbagut Interconnection

Figure 2.12 – 2025-2034 RUPTL interconnection projects requiring further study



- Inter-Island interconnections:
  1. 150 kV Sumatra – Bengkalis Interconnection
  2. 150 kV Sumatra – Selat Panjang – T. Balai Karimun Interconnection
  3. Sumatra – Batam Interconnection (HVDC/high voltage alternating current/HVAC)
  4. 150 kV Kalimantan – Pulau Tarakan Interconnection
  5. 150 kV Kalimantan – Pulau Nunukan Interconnection
  6. 150 kV Sulbagsel – Baubau-Raha Interconnection

Figure 2.13 – 2025-2034 RUPTL inter-island interconnections

- Inter-country interconnections:
  1. Sumatra – Peninsular (Malaysia) Interconnection
  2. Sumatra – Singapore Interconnection
  3. Kalimantan – Sabah (Malaysia) Interconnection
  4. Kalimantan – Sarawak (Malaysia) Interconnection
  5. NTT – Timor Leste Interconnection
  6. Papua – Papua New Guinea (PNG) Interconnection

Figure 2.14 – 2025-2034 RUPTL inter-country interconnections

This 2025-2034 RUPTL requires a total investment amounting to USD188 billion (IDR2,967 trillion), following the ARED scenario. Through the ARED scenario, PLN is set to contribute to reducing emissions by 151 million tonnes of CO_2 by 2030, a greater amount compared to the RE base scenario, which accounts for a reduction of 145 million tonnes of CO_2 by 2030.

2.4 Local Content Requirement (LCR) reforms opening doors for internationally backed projects

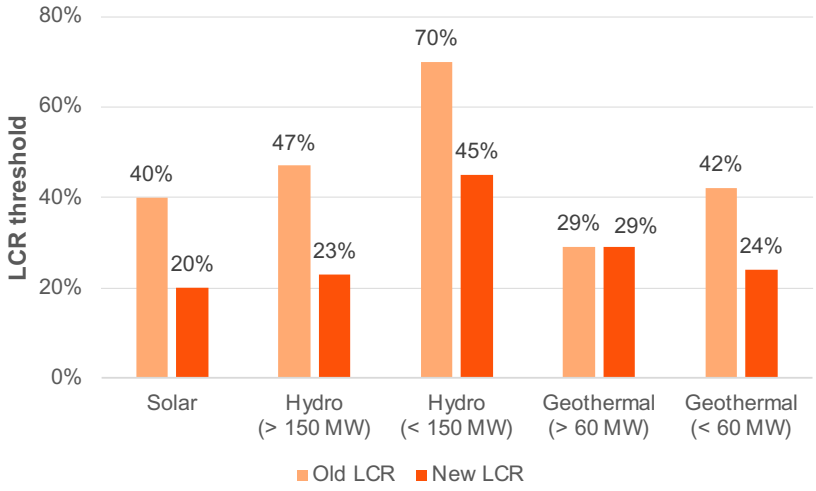
Stringent LCR has been cited as one of the factors hindering RE initiatives. However, from the GoI's perspective, a high LCR is considered vital for economic enhancement. While LCR is advantageous for ensuring local participation, knowledge transfer and stimulating the local supply chain, excessively high LCR, without adequate support from the available local market, suppliers, and production and worker standards, can be counterproductive to the overall RE plan.

Through the newly established JETP and the GoI's commitment to build and incorporate 56.5 GW of renewable energy to the power grid by 2030 and to fulfill PLN's RUPTL, several reforms have been made:

- Filling the gaps and clarifying misunderstandings in the earlier policy (sanction and reward, details on international grants and loans, and details on cross-border electricity trading).
- Broadening the LCR scope for renewable energy plants other than solar such as wind, biomass, biogas and waste-to-energy (WtE).
- Allocating responsibilities for monitoring LCR of power and renewable energy projects to the MoEMR rather than the Ministry of Industry (MoI), while the supporting industrial LCR for the projects remains under MoI's authority.

As part of this reform, the MoI revoked all its LCR regulations in the power sector via MoI Regulation No. 33/2024, and the MoEMR assumed control over the LCR with the implementation of MoEMR Regulation No. 11/2024 and its associated decrees, which set the new lower LCR threshold (MoEMR Decree 191K/2024) and provide calculation guidelines for both renewable energy (DGNREEC Decree 150K/2024) and non-renewable energy projects (DGNREEC Decree 364K).

Figure 2.15 – Comparison of old and new LCR thresholds[2]



The new MoEMR decree significantly lowers the LCR threshold compared to previous levels. This reduction may address financing challenges in renewable energy projects by offering greater flexibility in LCR application for projects with international funding. With these accommodating regulations and the subsequent boost in internationally backed projects, PLN will be able to purchase cheaper electricity from renewable energy power plants through PPAs, benefiting from lower module costs that come with higher performance.

Given this new opportunity in the power sector, financiers should monitor upcoming large-scale procurements by PLN. Power producers will also view this as a golden momentum to accelerate more renewable energy projects within the relaxation timeframe.

2.5 Net-zero targets made achievable through power exporting

Power exporting/importing is the means of transferring generated electricity from one country or region to another through interconnector lines. In terms of international trade, power exporting has played a critical role in fueling economies and fostering energy interconnectivity across the world. Some countries export electricity due to their surplus of energy resources and the opportunity to gain revenue from their neighbouring countries willing to purchase it. For a country like Singapore with limited land and renewable energy resource, green energy imports is a viable strategy to support achievement of net-zero targets.

From the importing side, purchasing power externally does not necessarily signify a country's inability to produce or export power independently. Under certain circumstances, unique to each country, importing power may be beneficial. For instance, the United States imports power from Canada to supply the northern border regions due to its cost-effective nature, rather than distributing it from plants elsewhere in the United States[3]. The United Kingdom, which has interconnector lines with European countries, buys electricity when it is cheaper abroad and sells it when it is more expensive domestically[4]. The same situation applies to Singapore. While Singapore can autonomously produce electricity through gas-fired power plants (GFPPs) (contributing to 95% of the electricity mix) using natural gas imported from Malaysia and Indonesia[5], it must import electricity from renewable energy sources to meet Singapore's National Climate Change Secretariat net-zero target by 2050. This electricity import policy is designed to help Singapore fulfill its electricity demand by 2050 while also aligning with the International Energy Agency (IEA)'s NZE target.

To achieve its NZE target, Singapore aims to reduce its GFPP electricity generation from 53 TWh in 2023 to 26 TWh by 2040. However, electricity demand is expected to reach 128 TWh by 2050. With GFPPs being phased out, Singapore's primary electricity generation is planned to come from solar PV but its limited land area is an issue. Singapore's theoretical solar power potential is only 8.6 GW by 2050, which would generate approximately 15 TWh of electricity, meeting only 12% of the projected demand[6]. With Singapore's low wind speeds, lack of rivers or fast-flowing water systems, inadequate near-surface geothermal resources, and relatively narrow tidal range and calm seas, solar PV is the only feasible renewable energy for power generation. Therefore, the only viable solution is to import renewable electricity from surrounding countries.

For its short-term target, Singapore is aiming to increase solar capacity to 2 GW, from 0.6 GW capacity in 2022, by the end of this decade and import a total of 4 GW of renewable electricity from Association of Southeast Asian Nations (ASEAN) countries by 2035. Currently, Singapore imports 100 MW of hydropower from Lao People's Democratic Republic (LPDR) via Thailand and Malaysia interconnector lines with plans of a potential five-year import agreement extension with an increased hydropower capacity to 300 MW[15]. In addition to the electricity from Lao PDR, Singapore has also granted conditional import approvals (one of the three approvals needed to export electricity to Singapore, as explained below) from:

- Cambodia to import 1 GW of hydropower, solar power and additionally wind power in the future[7]
- Indonesia to import a total of 3.4 GW of solar power with several consortia of IPPs looking to participate[8,9]
- Vietnam to import 1.2 GW of wind power from soon to be developed offshore wind farms in South Vietnam[10]
- Australia-Asia PowerLink (AAPowerLink) project which aims to provide 900 MW to Darwin's green industrial projects in the first stage of deployment with an additional 3 GW of capacity in the second stage available for export to Asia via an undersea HVDC, with Singapore planning to receive 1.75 GW in 2027, accounting for 15% of Singapore's total electricity needs[11]

- a new Singapore-Indonesia interconnector project, involving Singapore Energy Interconnections (SGEI) and Singa Renewables–a joint venture between TotalEnergies and Royal Golden Eagle (RGE). This project is set to import 1 GW of low-carbon electricity from Indonesia's Rangsang Island to Singapore, aiming for commercial operations by 2029[12].

Given its proximity to Singapore, Indonesia has a significant opportunity to increase export of renewable capacity to Singapore via Sumatra, which is projected to hold a substantial number of renewable power plants. North Sumatra, in particular, boasts a planned renewable capacity of 2.8 GW, derived from solar, hydro, wind and geothermal sources[13]. This potential for increased renewable electricity exports to Singapore is further supported by the recently signed Memorandum of Understanding (MoU) between the two countries on cross-border trading projects, including investments for renewable energy manufacturing development in Indonesia.

Additionally, companies have already received approval for five Indonesia-based projects to import a total of 2 GW of low-carbon electricity to Singapore. The Singapore Energy Market Authority (EMA) has granted conditional licences to these five IPPs, which could pave the way for other Indonesian IPPs to engage in this export opportunity while simultaneously contributing to the development of Indonesia's renewable energy in the power sector. The EMA has established clear licensing procedures and requirements. This process involves three major checkpoints: obtaining the conditional approval, which all exporting countries have currently obtained, securing a conditional licence and finally acquiring an importer licence. During the entire licensing process, IPPs or participants must submit a proposal that includes a technical and commercial feasibility study, conduct further studies, engage with relevant countries, obtain necessary regulatory approvals and demonstrate the ability to achieve financial close. Only after these steps are completed can construction, testing and the eventual electricity export to Singapore commence[14].

Another factor spurring the interest of IPPs in electricity export projects is the more competitive electricity tariff. In Indonesia, the tariff structure includes a ceiling price mechanism set by PLN, which limits potential revenue for power producers, including those in the renewable energy sector. In contrast, Singapore employs PPAs with its tariffs determined through a bidding process, potentially resulting in more favourable rates. Moreover, Singapore's electricity market allows IPPs to sell electricity directly to consumers, unlike the Indonesian market, where power must be sold to a single off-taker, PLN. The table below illustrates the differences in electricity tariffs between Singapore[15] and Indonesia[16], highlighting the significant potential benefits for IPPs exporting electricity to Singapore.

3 Legal and regulatory framework

3.1 Introduction

The power sector in Indonesia is monitored and supervised by the MoEMR and its sub-agencies, which include the DGE and the DGNREEC.

The core regulatory framework for the power sector is provided by the 2009 Electricity Law (as partially amended by Law No. 6 of 2023 on Enactment of GR in Lieu of Law No. 02 of 2022 on Job Creation into Law (the Omnibus Law)) and several other electricity GRs namely GR No. 25 of 2021 on the Organisation of the Energy And Mineral Resources Sector (GR No. 25/2021), GR No. 14/2012 (as lastly amended by GR No. 23/2014) on Electricity Business Provision, GR No. 42/2012 on Cross-Border Sales and Purchases, and GR No. 62/2012 on the Electricity Support Business.

In addition to the above, the MoEMR, the MoF, the Minister of Industry, the Minister of Forestry and other ministers have issued several implementing regulations concerning technical and standard aspects of the electricity sector in Indonesia, in line with their respective roles and responsibilities. There are also other laws and regulations from other sectors that impact the electricity sector. For instance, Law No. 2/2012 on Land Procurement for Public Interest Developments (partially amended by the Omnibus Law) and its implementing regulations, including GR No. 19/2021, which was amended by GR No. 39/2023, establish a legal framework for land acquisition for infrastructure projects. Furthermore, there are specific sub-sector laws and regulations related to electricity generation such as Law No. 21/2014 on Geothermal (partially amended by the Omnibus Law).

3.2 The 2009 Electricity Law

Please refer to *Section 1.6 - Chronological development of the power sector in Indonesia* for other information relating to the 2009 Electricity Law (as partially amended by Omnibus Law).

3.2.1 RUKN and RUPTL

The Central Government is responsible for developing the RUKN. This RUKN sets out, among other things, a 20-year projection of electricity demand and supply, investment and funding policies, and the country's approach to the utilisation of NRE resources. The RUKN is developed with reference to the NEP and RUEN (please refer to *Section 1.5 – Government strategies, policies and plans for the power sector in Indonesia* for details of the RUEN).

On 29 November 2024, the Constitutional Court partially granted the petitioners' claim under Case No. 39/PUU-XXI/2023, asserting that the RUKN as stipulated under Article 7 paragraph (1) in Article 42 point 5 of the Appendix of Omnibus Law conflicts with the 1945 Constitution and does not have binding legal effect, insofar as it is not interpreted as "RUKN is formulated according to the national energy policy and established by the Government after obtaining the consideration from DPR".

Prior to this decision, the Omnibus Law amended Article 7 paragraph (1) of the Electricity Law to state "the RUKN is formulated based on the national energy policy and is established by the Central Government." Thereby removing the provision that required involvement from the House of Representatives. The RUKN is reviewed every three years, at least.

The RUPTL constitutes a ten-year electricity development plan in the operating areas, or *Wilayah Usaha*, of PLN (excluding the operating areas of PLN's subsidiaries, such as PT Pelayanan Listrik Nasional Batam). The RUPTL is based on the RUKN and the RUKD. The RUPTL contains demand forecasts, future expansion plans, electricity production forecasts, fuel requirements and projects to be developed by PLN and IPP investors, respectively. The procurement routes for IPPs are also based on the RUPTL.

The latest RUPTL of PLN for the years 2025 - 2034 was approved by MoEMR based on the Decree of the Minister of Energy and Mineral Resources No. 188.K/TL.03/MEM.L/2025 on the Ratification of the RUPTL of PT PLN for the Years 2025 to 2034. As such, the RUPTL is an important document for all investors in the Indonesian power sector. The RUPTL is reviewed annually and whenever changes are required pursuant to the laws and regulations.

3.2.2 Electricity business

The 2009 Electricity Law (as partially amended by the Omnibus Law) in conjunction with GR No. 25/2021 and MoEMR Regulation No. 11/2021 divides the electricity business into two broad categories, which are (i) power supply businesses and (ii) power support businesses. Whereby the power supply businesses are covering the following activities:

a) Activities involved in supplying electrical power for public use:
   i. Power generation
   ii. Power transmission
   iii. Power distribution
   iv. The sale of electrical power.

b) Activities involved in captive power supply or "own use":
   i. Power generation
   ii. Power generation and power distribution
   iii. Power generation, power transmission and power distribution.

Meanwhile, supporting activities for the supply of electrical power covers the following:

i. Activities undertaken by service business, such as consulting, construction and installation, inspection and testing, operation, maintenance, research and development, education and training, equipment and utility testing laboratories, equipment and user certification, certification of electrical engineering competency, certification of power support business entities and other services which are directly related to the power supply.
ii. Activities undertaken by industry businesses, such as the supply of power tools and power equipment.

Electricity supply for public use can only be carried out in an integrated manner by one business entity within one operating area. Restrictions on operating area also apply to the supply of electricity for public use, which only includes power distribution and/or sales of electricity on a standalone basis.

Under the 2009 Electricity Law (as partially amended by Omnibus Law), the Government has given PLN priority rights over the electricity supply business throughout Indonesia. This excludes certain operating area given to private enterprises, cooperatives and self-reliant community institutions involved in the electricity supply business.

Photo source: PwC

The DGE, on behalf of the MoEMR, sets out the operating area for electricity supply businesses. According to MoEMR Regulation No. 11/2021, an operating area can be granted to parties as described above, on the following conditions:

a) The existing holder(s) of an operating area is not able to provide electricity.

b) The existing holder(s) of an operating area is not able to provide the required level of quality and reliability.

c) The existing holder(s) of an operating area has returned some or all of the area to the MoEMR.

d) The area of the operating area proposed by the business actor has not yet been covered by the existing holder(s) of an operating area.

e) The area of the operating area proposed by the business actor is an integrated area that manages energy power in an integrated manner according to the pattern of business electricity needs.

In order to obtain an operating area, state-owned enterprises (SOEs), private enterprises, cooperatives and self-reliant community institutions can make a request to the MoEMR through the DGE. The request should fulfil the requirements set out by the provisions of business licensing in the energy and mineral resources sectors. The DGE may assign a technical team to assess the technical feasibility of the request in order to determine whether the requested operating area will be granted.

As of February 2025, there are 65 operating areas that have been designated as operating areas for the provision of electricity. These include 57 integrated operating areas, one operating area for transmission, and seven operating areas for distribution and sales. The distribution of operating areas can be seen in Figure 3.1.

Figure 3.1 – The holders of operating areas

Source: RUKN MoEMR, 2025

3.2.2.1 Generation

PLN and IPPs

Based on data from the HEESI of the MoEMR, by the end of 2024, the total installed capacity for both on-grid and off-grid power plants in Indonesia reached 100.6 GW. This represents an increase from the previous year, driven by the completion of new power plants by both PLN and IPPs. Of this total capacity, fossil fuel power plants accounted for approximately 86.7 GW (86%), while clean and RE sources contributed around 13.9 GW (14%).

Private sector participation is allowed through IPP or PPP arrangements. IPP appointments are most often granted through competitive tenders; although IPPs can be directly selected or directly appointed in certain circumstances under GR No. 14/2012 (as amended by GR No. 23/2014). A similar situation applies for PPPs under Presidential Regulation (PR) No. 38/2015 and its implementing regulation on the Government Procurement of Goods and Services Policy Board (*Lembaga Kebijakan Pengadaan Barang dan Jasa Pemerintah*/LKPP) No. 1 of 2025. For a detailed discussion of the IPP and PPP procurement process, please see *Section 4.4 – Procurement process*.

PPUs

Investors that generate electricity for their own use rather than for sale to PLN are known as PPUs. Under MoEMR Regulation No. 11/2021, PPUs with a capacity greater than 500 kW must hold an IUPTLS in order to generate electricity for their own use. PPUs with a capacity of up to 500 kW must submit one report to the Minister through the Director General or the Governor, in accordance with the regulations of their authority. The report is to be submitted once for the duration of the electricity for their own use and must conform to the format provided under MoEMR Regulation No. 11/2021.

A PPU may sell excess capacity for public interest subject to the approval of the Central Government or local government in accordance with the norms, standards, procedures and criteria set by the Central government. Sales of excess capacity for public interest may be conducted if the area has not been covered by a business licence for the holder of an electricity supplying business.

MoEMR Regulation No. 19/2017 sets a maximum benchmark price for excess power which is equal to 90% of the regional electricity generation cost (BPP). Under an excess power arrangement, the PPA may last for less than or more than one year, depending on the local power needs. The price will be revisited annually in order to accommodate any changes in the regional BPP. Following the release of MoEMR Regulation No. 11/2021, PPUs may establish a parallel operation through a power plant or electricity interconnection with an integrated Electricity Supply Business Licence (*Izin Usaha Penyediaan Tenaga Listrik untuk Kepetingan Umum*/IUPTLU) holder(s) which has already attained an operating area. A parallel operation must consider the power supply capacity of the integrated IUPTLU holder(s) and be conducted in accordance with the grid code.

3.2.2.2 Transmission, distribution and retailing

The 2009 Electricity Law (as partially amended by the Omnibus Law) provides PLN with priority rights for conducting business throughout Indonesia. As the sole owner of T&D assets, PLN remains the only business entity which is involved in the T&D of electrical power. The 2009 Electricity Law (as partially amended by the Omnibus Law), GR No. 25/2021 and GR No. 14/2012 (as amended by GR No. 23/2014) allow for private participation in the supply of power for public use and for T&D.

However, private sector participation is limited to the power generation sector, following the issuance of MoEMR Regulation No. 19/2017 on the issue of excess power, which aims to allow IPPs and PPUs to use PLN's existing T&D networks. MoEMR Regulation No. 11/2021 also regulates power wheeling as the joint use of the networks to optimise the value of the networks and to speed up the supply of additional generating capacity. However, the implementing regulations regarding the detailed technical procedures and financial charges for T&D network access have yet to be released.


Photo source: PwC

3.2.2.3 Electricity support business

The 2009 Electricity Law (as partially amended by Omnibus Law) classifies electricity support businesses into Electricity Supporting Service Business Licences and Electricity Supporting Industry Business Licences.

Based on GR No. 62/2012, electricity-supporting service businesses cover the following:
a. Consultation on the installation of electricity.
b. Developments and installations for the provision of electricity.
c. Inspection and examination of electricity installations.
d. Operation of electricity installations.
e. Maintenance of electricity installations.
f. Research and development.
g. Education and training.
h. Laboratory testing of electricity equipment and the use of electricity.
i. Certifications of electricity equipment adequacy and the use of electricity.
j. Certifications of electricity engineering competence.
k. Businesses or other services directly related to the provision of electricity.

Subsequently, GR No. 25/2021 also added business-entity certifications for electricity-supporting service businesses to the above list. According to GR No. 62/2012 and GR No. 25/2021, the entities involved in the electricity-supporting service business are required to obtain an Electricity Supporting Services Business Licence (*Izin Usaha Jasa Penunjang Tenaga Listrik*/IUJPTL) and electricity certificate of electricity-supporting service business. In addition, electricity-supporting industry businesses involve the supporting industries for electricity equipment and for electricity utilisation.

3.2.3 Local content

The 2009 Electricity Law (as partially amended by Omnibus Law) requires the holders of an IUPTLU or an IUJPTL to prioritise the use of domestic products and services. The issuance of the MoEMR Regulation No. 11 of 2024, shifting responsibility for overseeing the use of domestic products in electrical infrastructure projects from the MoI to the MoEMR. This change is part of a strategy to prioritise local goods and services in electricity infrastructure, supporting domestic industry growth and accelerating project development. The Minister of Industry, however, retains authority over setting the LCR values for goods and services. The transition aligns with MoI Regulation No. 33 of 2024, which replaced MoI Regulation No. 54/M-IND/PER/3/2012, establishing an LCR target of 60% for solar modules in PLTS by 1 January 2025. Challenges remain in achieving this target due to high costs and limited renewable energy investments, prompting the MoEMR regulation to set revised LCR requirements and a roadmap for both renewable and non-renewable energy projects. The MoEMR regulation introduces incentives to promote domestic products in electricity infrastructure projects. These include price preferences for local products to make them more competitive. Failure to comply with the minimum LCR may lead to sanctions such as warnings, suspensions, fines or licence revocations. Conversely, meeting the LCR requirements can earn rewards like certificates of appreciation, public recognition and other forms of acknowledgment.

One of the key mandates of the MoEMR regulation is the mandatory use of domestic goods and services for electricity infrastructure projects funded by:

a. the state budget or regional budget
b. loans or grants from domestic or foreign sources
c. projects involving SOEs, regionally owned enterprises (BUMDs) or private companies in PPPs.

However, imported goods may only be used if:

a. domestic products are unavailable
b. domestic products do not meet technical specifications
c. domestic products cannot fulfill the required quantity.

Compared to the MoI regulation, the MoEMR regulation introduces new rules for minimum LCR criteria. While the MoI regulation focuses on individual goods and services for industrial components, the MoEMR regulation gives the MoEMR the authority to set the combined LCR for goods and services used in electrical infrastructure projects.

The minimum combined LCR for these projects is detailed in a separate MoEMR decree. In August 2024, MoEMR issued the minimum LCR by virtue of its decree No. 191.K/EK.01/MEM.E.2024. The MoEMR decree sets specific LCR percentages for various types of projects, which are as follows:

Power plant	Minimum use of LCR for goods and services combined
Geothermal	a. Capacity up to 60 MW: 24.00% b. Capacity above 60 MW: 29.00% c. Partial geothermal project: 20.00%
Gas-fired	10.39%
Combined-cycle	21.93%
Gas engine	23.96%
Solar	20.00%
Wind	a. Capacity up to 600 MW: 27.18% b. Capacity above 600 MW: 18.83%
Gas	10.39%
Hydroelectric	a. Capacity up to 10 MW: 45.00% b. Capacity above 10 MW to 50 MW: 35.00% c. Capacity above 50 MW: 23.00%
Biomass	21.00%
Biogas	25.19%

These LCR percentages cover a wide range of infrastructure, from power plants to substations and transmission lines. The MoEMR regulation also sets periodic evaluations of the minimum LCR every three years or as needed.

3.2.4 IUPTLU/IUPTLS

A business licence must be granted before an entity can supply electrical power or run an electrical power-supporting business. Business licences for the supply of electrical power consist of the following:

a. An IUPTLU to supply electricity for public use, which may be issued for a maximum validity period of 30 years and may be extended.

b. An IUPTLS to supply electricity for own use (i.e. for PPUs) with a capacity of more than 500 kW according to MoEMR Regulation No. 11/2021, which may be issued for a maximum validity period of ten years and may be extended.

An IUPTLU can cover any of the following activities:

a. Electricity generation.
b. Electricity transmission.
c. Electricity distribution.
d. Electricity sales.
e. Electricity distribution and sales.
f. Integrated activities from electricity generation to sales.

An IUPTLU may be issued to the following entities:

a. State-owned companies or private companies.
b. Regional government-owned companies.
c. Cooperatives and self-reliant community institutions.

Based on MoEMR Regulation No. 39 of 2018, on Electronically Integrated Business Licensing Services in the Electricity Sector, the authority for issuing power-related licences and certificates has been delegated by MoEMR to the BKPM and is performed via a platform referred to as the Online Single Submission (OSS) system. Please see the following *Section 3.2.5 – OSS system* for an explanation of the OSS system. These licences and certificates include:

a. IUPTLU/IUPTLS
b. the determination of *Wilayah Usaha*
c. IUJPTLs
d. cross-border power sale and purchase licences
e. permits for the utilisation of the power grid for telecommunications, multimedia and informatics
f. certificates of operational worthiness
g. business entity certificates (*sertifikat badan usaha*)
h. certificates of competence for electrical power engineering personnel
i. geothermal preliminary survey assignments
j. geothermal licences (*Izin Panas Bumi*/IPB).

3.2.5 OSS system

In June 2018, the Government issued GR No. 24/2018 on Electronically Integrated Business Licensing Services, which introduced new business licensing procedures via the OSS system. This OSS system was launched on 9 July 2018. The OSS system is an online business licensing platform that is intended to accelerate and simplify the process of obtaining business licence: it can be accessed at any time, from anywhere and by any business in Indonesia. The OSS system was previously operated and managed by a dedicated OSS body, under the supervision of the Coordinating Ministry for Economic Affairs. However, since 2 January 2019, the management and operation of the OSS system has effectively transferred from the Coordinating Ministry for Economic Affairs to BKPM.

In 2025, GR No. 28/2025 on the Organisation of Risk-based Business Licensing was issued. GR No. 28/2025 stipulates that the implementation of risk-based business licensing is carried out based on the stipulation of the risk level based on the results of the risk analysis and scale rating of business activities. The new regulation also mandates that all existing and newly established businesses in Indonesia have to obtain a Single Business Number (*Nomor Induk Berusaha*/NIB). Businesses undertaking low-risk business activities are only required to obtain a NIB, those undertaking medium-risk business activities are required to obtain a NIB and standard certificate and those undertaking high-risk business activities are required to obtain a

NIB and a business licence. A NIB can be obtained by registering existing and newly established businesses on the OSS system through the website https://oss.go.id/oss/. NIB registration requires the following data: (i) profile, (ii) business capital, (iii) Taxpayer Identification Number (*Nomor Pokok Wajib Pajak* or NPWP), (iv) Indonesian Standard Industrial Classifications (*Klasifikasi Baku Lapangan Usaha Indonesia* or KBLI) and (v) business location.

Although GR No. 5/2021 has been revoked by GR No. 28/2025, its substantive provisions remain largely consistent, particularly with respect to the terminology used—now consolidated under the term "business licensing" or *perizinan berusaha*. Moreover, there are also other supplementary licences that business actors will need to obtain referred to as "*Perizinan Berusaha Untuk Menunjang Kegiatan Usaha*" or "Business Licensing to Support Business Activities" (PB UMKU). The list of the PB UMKU in relation to the specific business activities can be referred to in Attachment I of GR No. 28/2025. Examples of PB UMKU for the electricity sector include Determination of Electricity Tariffs or *Penetapan Tarif Tenaga Listrik*, Approval on Sales Price and Lease of Electricity Power Network or *Persetujuan Harga Jual dan Sewa Jaringan Tenaga Listrik*, Certificate of Competency of Electricity Engineering Personnel or *Sertifikat Kompetensi Tenaga Teknik Ketenagalistrikan*, etc.

During the registration process, after the completion of data filing to obtain a NIB, the investor is required to provide certain information to the OSS system to obtain a risk-based business licence by entering the main business activity data for each five digit KBLI code and location. Such data should at least include the following:

a. The type of the products produced.
b. Product capacity.
c. The amount of manpower.
d. The amount of the investment plan.

Following the effective implementation of the OSS system, any corporate actions involving the amendment of the Articles of Association or corporate positions (e.g. mergers, acquisitions, transfers of shares, etc.) that are undertaken by a foreign investment company no longer require prior approval from BKPM. To the extent required by laws and regulations, these actions can only be conducted after obtaining the required approvals from the other relevant government authorities (e.g. the Ministry of Law and Human Rights). However, a business's information on the OSS system must be updated by the relevant company following the due completion of any such matters.

In order to establish a new foreign investment company, or to conduct any corporate actions, care must be taken to ensure that the establishment of such a company and its corporate actions are in line with the prevailing regulations (e.g. the Positive List of Investments). Any violations of the prevailing regulations may result in the risk-based business licence application being rejected by the OSS system.

Pursuant to GR No. 28/2025, risk-based business licensing in the electricity sector covers (i) the supply of electricity for the public interest and (ii) electric power support services. Furthermore, MoEMR Regulation No. 39/2018 provides that a business actor in the electricity sector must obtain the relevant business licence[1] and/or commercial or operational licence[2] from BKPM before it starts the business and proceeds to operate commercially. Such licences will be processed through the OSS system. It must be noted, however, that each business licence and/or commercial or operational licence will be issued by BKPM through the OSS system with certain necessary conditions attached (i.e. administrative and technical requirements that have to be fulfilled). The business actor must fulfil such conditions within a certain time limit. If the business actor fails to fulfil such conditions, then the relevant licences that have been issued will be declared null and void.

For example, an electric power company is generally required to obtain a borrow-to-use permit if the power plant is to be situated in a forest area. This permit will be issued by BKPM through the OSS system. Nevertheless, the borrow-to-use permit will only be effective after the company has fulfilled the following conditions:

a. Conformity of Spatial Utilisation Activities (*Kesesuaian Kegiatan Pemanfaatan Ruang* – KKPR).
b. Environmental Approval (*Persetujuan Lingkungan*).
c. Building Approval (*Persetujuan Bangunan Gedung* – PBG) and Certificate of Feasibility (*Sertifikat Laik Fungsi* – SLF).

In its mission to make the OSS an integrated licensing platform that can facilitate investment, basic licences such as the KKPR, Environmental Approval, PBG and SLF are currently being integrated so that the OSS can issue them online, meaning that applicants will not have to go to the relevant authorities.

On a related note, with regard to Disturbance Permits, the Central Government has issued Minister of Home Affairs Regulation No. 19 of 2017, revoking Disturbance Permits. However, in some areas, Disturbance Permits are still applicable. Hence, a company needs to pay attention to the local and municipal regulations regarding the requirements for obtaining Disturbance Permits. The Government has also enacted the Omnibus Law as a way to, among others: simplify the process of obtaining the licence and reduce the number of licences required for investors in doing business.

3.2.6 Cross-border sale and purchase

GR No. 42/2012 governs the sale and purchase of power across Indonesia's borders, stipulating that a permit is required from the MoEMR.

Power can be sold across the Indonesian border only if:

a. the power needs of the local area and its surroundings have been met
b. the sale prices are not subsidised
c. the sale will not compromise the quality and reliability of the local power supply.

Power can be purchased from outside of Indonesia only if:

a. the purchase is intended to meet local electricity needs or to improve or enhance the quality and reliability of the electricity supply
b. it does not harm national sovereignty, security or economic development
c. the purchase does not ignore the development of the capacity to supply electricity in the country
d. the purchase does not result in dependence upon the procurement of electrical power from other countries.

Cross-border power sale and purchase arrangements are also subject to the prevailing laws and regulations.

Historically, Indonesia has imported electricity from Malaysia. These imports decreased from 1,553.00 GWh in 2020 to 957.51 GWh in 2024. Due to the insufficient power supply in West Kalimantan, PLN has indicated that importing electricity from Malaysia is more cost-effective because Sesco's electricity is primarily generated from hydropower. In contrast, most power plants in West Kalimantan rely on more expensive diesel fuel. Additionally, according to PLN data, there is currently no interconnected electricity grid encompassing all of Kalimantan. PLN is also awaiting the completion of several new power plants under construction. The decline in electricity imports to West Kalimantan began in 2020 following the commencement of operations at the Parit Baru CFPP (2x50 MW) in Bengkayang and the Ketapang IPP CFPP (2x6 MW) in August and July 2019, respectively. Furthermore, PLN plans to connect West Kalimantan's electricity grid to the Kayan Hydroelectric Power Plant, which is under construction in North Kalimantan. The Kayan Cascade Hydropower Plant, which has a capacity of 9,000 MW, is scheduled for completion in 2035[3].

The Sarawak-West Kalimantan link could be viewed as the first Indonesian leg of the ASEAN Power Grid project (connections already exist between a number of ASEAN countries, including Thailand, Laos, Malaysia, Singapore, Vietnam and Cambodia). The rationale for the project is to increase the flexibility of systems operators in terms of matching supply and demand at the lowest possible cost, supporting further intermittent renewable deployments and increasing energy security. This ambitious project, with its large investment outlays,

will require a supportive cross-border regulatory environment, cooperation between national utilities on technical issues and more dynamic pricing in order to better match supply and demand. As of writing, there has been limited progress on the interconnection transmission network. However, investor interest in the development of renewable energy projects for export to Singapore has increased.

For information regarding the interconnection map, please refer to *Chapter 2 - Energy transition*.

3.3 Capacity initiatives – PR No. 4/2016 (as amended by PR No. 14/2017)

A five-year 35 GW power generation programme was announced by President Joko Widodo in late 2014. The introduction of this 35 GW programme was seen as a continuation of the Government's efforts to enhance Indonesia's electricity infrastructure. The Government introduced Fast-track Programme (FTP) I for 10 GW of coal-fired power (CFP) generation in 2006 and FTP II for a further 10 GW – which was largely being sourced from renewable energy projects – in 2010. FTPs I and II were not fully achieved, and some projects were integrated into the 35 GW programme, under President Joko Widodo's administration[4].

Following the obstacles faced by FTPs I and II, PR No. 4/2016 (as amended by PR No. 14/2017) on the Acceleration of Power Infrastructure Development was issued in order to address the various problems affecting the development of power projects in Indonesia. This included a government guarantee for the development of power projects, which covers projects developed by PLN and the projects developed by PLN or its subsidiaries in cooperation with IPPs. The regulation also covers licensing, land acquisition and various other issues.

3.3.1 Government guarantees

PR 4/2016 (as amended by PR No. 14/2017) requires further arrangements related to the procedures for providing government guarantees in the context of accelerating the development of electricity infrastructure carried out by PLN. In order to support the success of this development, the MoF issued the guidelines for providing government guarantees for the development of electricity infrastructure, in order to support the acceleration of electricity infrastructure development carried out through self-management and cooperation with IPPs under the MoF Regulation 130/2016 (as amended by MoF Regulation No. 135/PMK/08/2019).

Government guarantees can take the following forms:

a. **Loan guarantees**: These are intended to ensure the repayment of loans based on agreements made between financial institutions (creditors) and PLN to implement electricity infrastructure development projects managed by PLN through a self-management scheme.

b. **Business feasibility guarantees**: These are designed to ensure PLN's ability to meet its financial obligations, which include purchasing electricity and/or non-purchase of electricity based on PPA signed by PLN and IPP. This cooperation scheme aims to accelerate the development of electricity infrastructure projects using geothermal energy and other forms of renewable energy.

Government guarantees are provided by the MoF and/or infrastructure guarantee business entities. The business entity responsible for this is the IIGF (PT PII), which provides guarantees for infrastructure projects under the PPP scheme and also acts as a strategic advisor to the Government and serves as a transaction manager or lead arranger for these infrastructure projects.

Under PR No. 4/2016 (as amended by PR No.14/2017), any loans obtained by PLN in relation to the development of power infrastructure projects will also be guaranteed by the MoF. In order to obtain such a guarantee, PLN's President Director also needs to request the guarantee from the MoF, which must approve PLN's request within 25 business days from the receipt of the complete submission from PLN. The procedures for obtaining the business viability guarantees for IPPs, as well as the loan guarantees for PLN, are regulated under MoF Regulation No. 130/2016 as amended by MoF Regulation No. 135/PMK/08/2019.

In September 2019, the MoF has issued MoF Regulation No. 135/PMK/08/2019, amending MoF Regulation No. 130/PMK/08/2016 of 2016 on the procedure for implementing government guarantees for the acceleration of electricity infrastructure development. This regulation was issued to provide a full guarantee of the financial obligations of PLN in relation to the development of certain electric power projects. In addition, this regulation also provides more legal certainty for sharia financial institutions in providing loans to PLN for the development of the electric power sector.

3.3.2 NRE projects

The development of electricity infrastructure prioritises NRE in order to achieve the energy mix targeted under the NEP. The Central Government and/or local governments can provide support in the form of

a. fiscal incentives
b. licensing and non-licensing relief
c. feed-in tariffs (FiTs) for NRE sources
d. the establishment of a separate business entity to generate energy from new and renewable sources for sale to PLN
e. specific subsidies for NRE sources.

This support will depend upon the feasibility and the economics of the electricity infrastructure development. As such, PR No. 4/2016 (as amended by PR No. 14/2017) confirms the availability of fiscal incentives for NRE developments.

Based on PR No. 4/2016 (as amended by PR No. 14/2017), it is clear that the Government plans to develop a NRE aggregator to buy the electricity generated by new and renewable sources and sell this on to PLN for specific subsidies. However, it is not clear when this new aggregator will be established, nor whether it will be a part of PLN or an independent SOE.

PR No. 4/2016 (as amended by PR No. 14/2017) clarifies that hydro, geothermal and wind power projects, including transmission lines, can be developed in natural reserve areas and natural conservation areas, in accordance with the prevailing laws and regulations.

To expedite the development of a NRE aggregator, the Central Government issued a new regulation on 13 September 2022, namely PR No. 112/2022 concerning the acceleration of the development of renewable energy for the supply of electrical power. Pursuant to this regulation, the Central Government aims to realise the goals set such that renewable energy comprises 23% of the primary energy mix by 2025 and at least 31% by 2050 and GHG emissions are reduced. The goals for GHG emission reductions are optimistic. As a note, PR No. 112/2022 only applies to PPAs that had not been signed prior to the enactment of this presidential regulation. In addition, the MoF has also issued MoF Regulation No. 103/2023 in relation to funding from the state budget for purposes of early CFPP retirement.

PR No. 112/2022 on Acceleration of Renewable Energy Development for Electricity Supply and the implementation regulations (MoEMR Regulation 10/2025 and MoF Regulation 103/2023)

PR 112/2022 mandates PLN to conduct an early termination of CFPPs. In order to do this, the MoEMR drew up a roadmap by coordinating with the MoF and MoSOE. Furthermore, on 5 March 2025 MoEMR issued a new RUKN under MoEMR Decision No. 85/K/TL.01/MEM.L/2025. In response to this, the MoEMR issued Regulation No. 10 of 2025 on the Roadmap for Energy Transition in the Electricity Sector (MoEMR Regulation 10/2025) as the implementation regulation. MoEMR Regulation 10/2025 among others, covers the following:

a. **Roadmap for accelerating the retirement of CFPPs**

   In MoEMR Regulation 10/2025, the Government outlines its plan to achieve NZE by 2060, emphasising the transition to cleaner energy sources. A central strategy is to retire CFPPs earlier than planned. This move aims to reduce carbon emissions and increase the share of renewable energy in the country's energy mix. Emissions will be measured based on the average emissions each year and plant intensity.

To decide which CFPPs to retire early, MoEMR Regulation 10/2025 builds upon the criteria established in PR 112/2022. The implementation of acceleration of the termination of privately owned CFPP operations and/or CFPP PPAs developed by IPPs shall pay attention to at least the following criteria under the PR No. 112/2022:

- Capacity.
- Generator age.
- Utilisation.
- CFPP GHG emissions.
- Economic added value.
- Availability of domestic and foreign support.
- Availability of domestic and foreign technological support.

MoEMR Regulation 10/2025 introduces three additional criteria, namely electricity system reliability, impact of increased BPP on electricity tariffs and application of just energy transition principle.

b. **PLN assignment**

MoEMR Regulation 10/2025 mandates that PLN conduct feasibility studies for the termination of CFPPs. These studies must adhere to the following requirements:

- Timeline: completed within six months of assignment by MoEMR.
- Content: include technical, legal, commercial and financial aspects, such as funding sources and compliance with good governance and business judgment principles.
- References: utilise studies from independent institutions as supplementary references.

c. **Funding support**

MoEMR will conduct regular evaluations every six months, or as necessary, in collaboration with a joint working team and the funding support provider. These evaluations aim to assess the progress of the CFPP retirement process and identify any additional funding requirements that may arise, such as increased costs. Should the need for extra funding be determined, the MoEMR will commission an independent institution to undertake a detailed study. This study will provide further insights into the procurement process for alternative power plants intended to replace the CFPPs. Upon completion of the study and evaluation, the MoEMR will review the findings to determine the necessity for additional funding. Any decision to proceed with supplementary funding will require written approvals from the MoEMR, the MoF and the MoSOE. Once these approvals are secured, the funding support provider will be responsible for implementing the additional funding.

Moreover, the development of new CFPPs is prohibited except for:

- CFPPs that have been determined in the RUPTL prior to the issuance of PR No. 112/2022
- CFPPs which fulfil the following requirements:
  - Integrated with built-in industries which are oriented towards increasing the added value of natural resources or are included in PSNs which have a major contribution to the creation of employment opportunities and/or national economic growth.
  - Committed to reducing GHG emissions by at least 35% within a period of ten years from the operation of the CFPP compared to the average CFPP emissions in Indonesia in 2021 through the development of technology, carbon offset and/or renewable energy mix.
  - Operate until 2050 at the latest.

d. **The Government support provided to business actors in the form of fiscal and non-fiscal incentives**

PR 112/2022 stipulates that the fiscal incentives include income tax, land and building tax, exemptions from import duties, support for geothermal development, and provision of other facilities and/or guarantees. The non-fiscal incentives are not specified in PR 112/2022.

e. **The procurement method of electricity**

Procurement of electricity may be carried out either by (i) direct appointment or (ii) direct selection. The categorisation of which is based on the type of power plant and the source of primary energy.

Procurement of electricity from renewable power plants based on PR 112/2022	
Direct appointment	**Direct selection**
• Hydroelectric power plants (PLTAs) that utilise hydroelectric power from reservoirs/dams or irrigation canals and the construction of which is defined as multi-purpose state property by the Ministry of Public Works and Housing. • PLTPs organised by holders of geothermal permits, holders of power of attorney for the exploitation of geothermal resources, holders of Joint Operation Contracts (JOCs) for the exploitation of geothermal resources and holders of permits for the exploitation of geothermal resources. • Capacity expansion from PLTP, PLTA, PLTS, PLTB, PLTBm or PLTBg. • Excess power from PLTP, PLTA, PLTBm or PLTBg.	• PLTA. • PV PLTS or PLTB which are either equipped or not equipped with battery facilities or other electrical energy storage facilities and for which the relevant land is provided by the Government or by parties that are utilising their own land. • PLTBm or PLTBg. • PLTA which function as peaker plants.

f. **The purchase price of electricity sourced from renewable energy**

PR 112/2022 regulates that the purchase price is determined by looking into the highest price limit which is calculated by taking into account the capacity of the power plant and the years of operation.

In addition to this, another way of determining purchase price as provided by PR 112/2022 is by taking into account the agreed price. These methods may or may not take into account the location factor. In that regard, Annex II of PR 112/2022 categorises the location factor that ranges from 1.00 up to 1.50 in which the location factor is only applied for the first stage of the power plant (from years one through ten) and ceiling price shall be considered for the second stage (from years 11-30) of the power plant. The categorisation is based on the difficulty level of accessing the areas. The pricing within the first stage is intentionally and strategically made higher to attract foreign investments in the renewable energy sector.

g. **The payment of electricity purchase**

PR 112/2022 regulates that the payment of electricity purchase shall be in IDR using the exchange rate from the Jakarta Interbank Spot USD Rate (JISDOR) at the time agreed in the PPA.

MoF Regulation No. 103/2023

Furthermore, the MoF has also issued a new regulation No. 103/2023 on providing fiscal support through a funding and financing framework to accelerate energy transition in the electricity sector, where the regulation stipulates that the funding regarding the termination or early retirement of CFPPs will be provided through the state budget. This funding and financing framework is called the Energy Transition Platform, which is conducted to accelerate the energy transition in the electricity sector.

The main purpose of the issuance of MoF Regulation No. 103/2023 is to realise the implementation of an equitable and affordable energy transition policy by the Government, through:

- setting up funding and financing mechanisms including blended finance, through the Energy Transition Platform
- providing fiscal support through the Energy Transition Platform
- the arrangement of a coordinated and integrated mechanism necessary for the management of the Energy Transition Platform.

Sources of funding for the Energy Transition Platform can come from the state budget and/or other legal sources in accordance with the laws and regulations. Sources of funding originating from the state budget are fiscal support in the Energy Transition Platform facility in accordance with laws and regulations and considering the state's financial capacity.

Other legitimate sources are funds obtained by the Platform Manager (the party assigned by the Minister to implement the management of the energy transition platform) based on funding cooperation with international financial institutions and/or other institutions/ agencies, for the energy transition by considering the provisions regarding the fulfillment of criteria to be able to utilise the Energy Transition Platform facilities and/or other cooperation other than the funding cooperation, in order to support the implementation of managing the Energy Transition Platform.

MoEMR Regulation No. 2 of 2024 on PLTS

The MoEMR introduced Regulation No. 2 of 2024 on PLTS (MoEMR Regulation No. 2/2024) connected to electrical power networks. This regulation replaces a previous one from 2021 and aims to enhance governance in utilising solar energy for electricity generation, particularly for personal use. One significant change is the removal of capacity limits, replaced with quotas for PLTS development. These changes are crucial for promoting sustainable energy practices and aligning with national energy policies.

The regulation outlines specific requirements for PLTS, including the necessary equipment, adherence to technical standards, and compliance with national and international regulations. Additionally, it introduces licensing requirements for larger solar-power systems and mandates examinations for certain technical specifications. The development of an electronic application system is planned to streamline processes and improve monitoring and reporting.

Reporting, guidance and supervision mechanisms are also detailed in the regulation, ensuring that IUPTLU holders and customers of PLTS systems comply with the regulations. The Minister has the authority to impose administrative sanctions for violations, emphasising the importance of adherence to the new guidelines for sustainable energy utilisation and effective governance in the sector.

3.3.3 Local content

PR No. 4/2016 (as amended by PR No. 14/2017) also requires the use of domestic products and services for the development of power infrastructure, which is consistent with the 2009 Electricity Law (as partially amended by the Omnibus Law). PLN, a subsidiary of PLN and/or IPPs can cooperate with foreign enterprises working on the development of equipment and the components of electricity equipment, domestic human resources and the transfer of technology which are required for the implementation of power infrastructure development.

For details of the local content requirements please see *Section 3.2.3 - Local content*.

3.3.4 Special provision on PLN's cooperation

PR No. 4/2016 (as amended by PR No. 14/2017) states that where PLN has to work with a foreign business entity, priority will be given to cooperation with foreign business entities owned by the related foreign governments (i.e. foreign SOEs).

3.3.5 Land acquisition

Land acquisition for electricity infrastructure development should be undertaken by PLN, a subsidiary of PLN or IPPs, in accordance with the prevailing laws and regulations on land acquisition for the construction of infrastructure for public use (currently the 2012 Land Acquisition Law (as partially amended by the Omnibus Law) and its implementing regulations). This should also follow the shortest timeframes, with the maximum time currently being set at 330 days (see the further discussion in *Section 3.5.4 – Land Acquisition Law*). For land that has been designated for electricity infrastructure development by the Governor, the land rights cannot be transferred from the landowner to parties other than the National Land Agency.

For the purposes of efficiency and effectiveness, land areas of not more than five hectares can be directly purchased from the holders of land rights by PLN, a subsidiary of PLN, or IPPs in a purchase or exchange or by other means, as agreed by both parties. If the landowner disagrees with the appraisal price, then PLN, the subsidiary of PLN or the IPP can agree to a purchase price higher than the appraisal price, after performing a cost-benefit analysis considering good governance during the process. However, it is not clear how effectively such a cost-benefit analysis can be implemented, since this method is not prescribed in the 2012 Land Acquisition Law (as partially amended by the Omnibus Law).

In the event that the land acquisition for transmission and/or substations cannot be executed, because the landowner disagrees with the price, even when it is higher than the appraisal price, then PLN, the subsidiary of PLN, or the IPP can rent or lease the land, or cooperate with the landowner based on some other agreement.

When acquiring land for electricity infrastructure development that is controlled by people in a forest area, PLN, the subsidiary of PLN or the IPP should ask the National Land Agency to provide information about the land ownership. The National Land Agency will provide the information in coordination with the Minister responsible for the environment and forestry. If the National Land Agency states that the public do not have the rights to the land located in the forest area, then PLN, the subsidiary of PLN or the IPP can request a forest use permit. People who live in a forest area used for electricity infrastructure development will need to settle this with PLN, the subsidiary of PLN or the IPP, together with the other ministries or agencies and the local government. This settlement should take into account the needs of the people and the social impact. All settlements agreed will be regulated by the MoEMR regulation.

The Central Government and/or regional governments can provide support to PLN, the subsidiary of PLN or the IPP in terms of land acquisition, by giving them priority over the required land and also by providing state-owned/regionally-owned land.

As an amendment to PR No. 4/2016, PR No. 14/2017 also includes a provision that PLN must pay rent for the SOE/regionally-owned/entity-owned government assets, although this requirement may be waived with the approval of the Central or regional government.

3.3.6 Ease of licensing

As discussed in *Section 3.2.5 – OSS system*, the Government launched the OSS system in order to simplify the process of obtaining licences. The licensing procedures under PR No. 4/2016 (as amended by PR 14/2017) are no longer relevant. Please see *Section 3.2.5 – OSS system* for further discussion of the OSS system.

3.3.7 Spatial plan (*Tata ruang*)

PR No. 4/2016 (as amended by PR No. 14/2017) introduced the following with regards to spatial planning:

a. In the event that a power infrastructure development is not in accordance with the locations where the power plants are to be built in the spatial plan, the detailed spatial plan for the area, or the zoning plan for coastal areas and small islands, then there can be a change to the spatial plan, the detailed spatial plan for the area, or the zoning plan for coastal areas and small islands.
b. In the event that a change in the spatial plan, the detailed spatial plan for the area, or the zoning plan for coastal areas and small islands cannot be made due to the refusal of the Ministry of Forestry then the matter shall be settled through the use of a holding zone.
c. Power infrastructure developments that utilise water, heat and wind, including transmission lines, are permitted in nature reserve areas and nature conservation areas.

3.4 Regulation on PPAs

In 2017, the MoEMR issued MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulations Nos. 49/2017 and 10/2018) on the principles of PPAs. The regulation outlines the contractual basis for agreements between PLN and IPPs, covering several key areas, including:

a. a new risk sharing and risk allocation concept
b. the implementation of the Build-Own-Operate-Transfer (BOOT) business scheme
c. new penalty mechanisms.

Note that the regulation does not apply to intermittent renewables, small hydro (below 10 MW), biogas or MSW.

MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulations Nos. 49/2017 and 10/2018) raises concerns for investors with the key features being as follows:

- **Risk sharing and risk allocation**

  PLN's previous PPA model was successful in attracting private investment. However, MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulations Nos. 49/2017 and 10/2018) adopts a major change to the risk sharing and risk allocation principles.

  Under the previous regulation, force majeure (FM) risks were generally borne by the party most able to bear them, which generally meant that IPPs were not subject to damages from events beyond their control. The new regulation, however, appears to place both PLN and IPPs in risk sharing positions if an FM event arises from a natural disaster.

  Based on previous regulations and market precedents, PLN bore the FM risk via deemed dispatch payments. PLN was also generally obliged to pay compensation to IPPs by means of termination payments, if an FM event resulted in a long-term interruption.

  However, under MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulations Nos. 49/2017 and 10/2018), where a natural FM event prevents PLN from taking power, PLN is no longer required to make the deemed dispatch payments. As compensation, the PPA may instead be extended by the length of time lost to the disaster and associated repairs. This may of course be problematic to lenders, who require regular debt service payments from project cash flow.

  Where a natural FM event results in a delay in commercial operation date (COD) the PPA may also be extended by the length of time lost to the disaster and repairs.

- **A regime for penalties and incentives**

  Under the previous regulations and market precedents if an IPP failed to meet the plant's availability factor as set out in the PPA, the IPP would be penalised through a revenue deduction aligned with the shortfall in the power supply factor.

  However, the new regulation moves towards a strict "deliver-or-pay" scheme. For example, in the event that an IPP cannot meet its PPA obligations, there is a delay in the COD on account of the IPP, or the IPP fails to meet the availability, capacity or outage factors then the IPP must pay a penalty proportionate to the costs borne by PLN in replacing the necessary supply.

This stricter penalty regime should incentivise performance by IPPs although IPPs will also factor this risk into their bid prices. Other penalties can apply to IPPs which fail to maintain certain technical performance standards, such as:

a. heat rates
b. reactive power rates within the interconnection system
c. frequency and ramp rates.

Similarly, PLN is required to pay a penalty for any failure of a power uptake on account of PLN (except under natural FM events, as mentioned above). Meanwhile, IPPs have the right to incentives if requested by PLN to reach COD ahead of schedule.

Furthermore, in March 2025 the MoEMR issued MoEMR Regulation No. 5/2024 on Guidelines for PPAs from Power Plants Utilising Renewable Energy Sources not to replace issued MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulations Nos. 49/2017 and 10/2018), but addresses the gaps left by MoEMR Regulation 10/2017 and was issued as the implementation regulation under Article 2 paragraph (4) of PR No. 112 of 2022 on the Acceleration of Renewable Energy Development for Power Supply (PR 112/2022), which focuses on accelerating the use of renewable energy for electricity supply.

Photo source: PwC

Key points comparing MoEMR Regulation 5/2025 with MoEMR Regulation 10/2017 are set out below[5]:

Content	Key changes		Note
	MoEMR Regulation 10/2017	MoEMR Regulation 5/2025	
Additional minimum required provisions in PPAs	Under Article 3, there are 14 minimum provisions required that must be stipulated under a PPA.	Under Article 4, there are 18 minimum provisions required that must be stipulated under a PPA.	Under MoEMR Regulation 5/2025, the additional provisions that must be addressed in PPAs related to RE include: i. electrical installation certification ii. use of domestic products iii. environmental attributes or carbon economic value iv. refinancing v. the PPA language.
PPA terms	Under Article 4, a PPA is implemented for a maximum of 30 years from the COD, considering the type of plant used.	Under Article 5, a PPA is initially implemented for a maximum term of 30 years from the COD and can be extended without considering the initial investment costs. PLN determines the duration based on the project's economic feasibility and the type of power plant. If extended, the electricity sale price during the extension will be based on the highest benchmark price after the tenth year, following the applicable laws and regulations.	MoEMR Regulation 5/2025 outlines conditions for extension that were not mentioned in MoEMR Regulation 10/2017.
Development schemes	Applies the BOOT scheme in the PPA.	The development scheme can be the Build-Own-Operate (BOO) scheme or other agreed schemes, considering the power plant type.	The provisions regarding development scheme options may not exhibit significant differences, as the Build-Own-Operate (BOO) scheme has been permitted for renewable project development. This scheme has become the preferred choice for IPPs due to the investments involved in developing renewable power plants.

Content	Key changes		Note
	MoEMR Regulation 10/2017	MoEMR Regulation 5/2025	
Excess energy transaction types and pricing matters	-	Article 16 outlines conditions for PLN when purchasing excess energy beyond Contracted Energy (CE) or Availability Factor (AF): 1. Excess energy is limited to Unit Rate Capacity (URC). 2. Price is capped at 80% of the purchase price under the PPA. 3. Purchase must meet local electricity system demand. For power plants generating beyond URC, PLN may buy electricity for optimisation: 1. at the lowest price 2. limited to 30% of CE or AF 3. to meet local system demand.	It is important to emphasise that the transaction provisions have become more detailed. This provision might imply that a 20% discount for excess energy transactions is applicable. Furthermore, this provision may imply that PLN has the ability to expand supply options among IPPs that have established PPAs with PLN for optimising transactions at the lowest price.
Deemed dispatch	PLN is only obligated to pay deemed dispatch if the electricity network of PLN is disrupted for reasons other than force majeure.	PLN must compensate for undelivered energy due to deemed dispatch. If electricity delivery falls short for reasons other than deemed dispatch, the IPPs must pay a penalty. Furthermore, IPPs are entitled to deemed dispatch in case of curtailment by PLN for inspections, maintenance, repairs or emergencies, unless the IPPs fail to comply with the grid and distribution codes.	The transaction clauses in MoEMR Regulation 5/2025 have become more detailed and aligned with practices where, in the event of curtailment and deemed dispatch, IPPs are eligible for compensation. Additionally, Article 1 of MoEMR Regulation 5/2025 provides flexibility for PLN and IPPs to determine and establish terms and conditions within a PPA concerning deemed dispatch. This provision allowing both parties to tailor agreements that reflect their specific operational and contractual needs.

Content	Key changes		Note
	MoEMR Regulation 10/2017	MoEMR Regulation 5/2025	
Foreign exchange risk	The payment for power must be in IDR except when granted an exemption by the Bank of Indonesia. If the tariff is denominated in USD, then the exchange rate shall refer to the JISDOR.	Payment for electricity purchase transactions is made using the rupiah currency at the JISDOR applicable one day before the payment day.	The exchange rate risk will be primarily borne by IPPs, which ultimately affects the rate of return on capital, considering the trend of the weakening rupiah against the USD. Both MoEMR Regulation No. 10 of 2017 and MoEMR Regulation No. 5 of 2025 address the use of JISDOR. MoEMR Regulation No. 5 of 2025 clarifies that the applicable exchange rate is the JISDOR published one business day before the payment date. By contrast, under Regulation No. 10 of 2017, JISDOR applied unless a Bank Indonesia (BI) exemption was granted. This suggests that PLN is unlikely to apply BI exemptions for electricity payments and that payments should be made in rupiah using the JISDOR rate. Previously, USD payments were sometimes facilitated through tripartite agreements; in light of the new MoEMR regulation, this practice may no longer be available.
Refinancing	-	Article 35 clearly stipulates about the refinancing process. To optimise the operations of electricity supply activities utilising renewable energy sources, IPPs are allowed to engage in refinancing. IPPs must inform PLN about the refinancing process.	MoEMR Regulation 5/2025 explicitly recognises the refinancing activities of IPPs, a provision is not explicitly addressed in MoEMR Regulation 10/2017.

Content	Key changes		Note
	MoEMR Regulation 10/2017	MoEMR Regulation 5/2025	
Project implementation guarantee	-	Under Article 10 of MoEMR Regulation 5/2025, it is stipulated that the project performance guarantee provided by the IPPs to PLN must be a maximum of 10% (ten percent) of the total project cost of the power plant. The project performance guarantee can be divided into three documents, with distribution and disbursement mechanisms defined in the PPA, considering the maximum liquidated damage. All guarantee documents must be submitted by the IPP to PT PLN (Persero) on the PPA effective date.	The requirement to provide a project performance guarantee amounting to 10% of the total project cost upfront, rather than in stages, poses a potential financial burden for IPPs. This provision might offer clarity regarding penalties, which may provide reassurance concerning the implications of non-compliance or delays. However, the provisions seem to imply there are no benefits for achieving an earlier COD, raising questions about whether expedited completion might be discouraged or penalised.
Step-in right	The transfer of ownership rights is applicable for transfers to an affiliate with over 90% ownership by the sponsoring company.	Transfer ownership rights can be made to an affiliate whose shares are more than 90% directly owned by the sponsoring company, or to a lender under step-in rights in case of default, provided this does not affect the sponsoring company's qualifications. The sponsor can be a business entity or consortium, including foreign legal entities, that holds shares or controls the IPP.	MoEMR Regulation 5/2025, marks a significant improvement for lenders by acknowledging the step-in rights, which is a positive development compared to previous limitations under MoEMR Regulation 10/2017. However, the practical implementation of these specific provided step-in rights remains uncertain, as lenders may not take the ownership of shares in the project companies.

Content	Key changes		Note
	MoEMR Regulation 10/2017	MoEMR Regulation 5/2025	
FM	Acknowledges only natural disasters as the true form of FM, excluding any other causes.	Determines FM as follows: a. War (whether declared or not) or civil war. b. Natural disasters, such as volcanic eruptions, fires, floods, earthquakes, pandemics, epidemics, landslides or other uncontrollable events. c. The discovery of dangerous objects or historical artifacts at the power plant site or special facilities. The FM conditions are based on the determination by the relevant authorities. The Minister can designate other FM conditions related to the technical execution of power plant projects, based on an evaluation of requests from affected parties.	MoEMR Regulation 5/2025 restricts the ability to designate additional FM events unless approved by the MoEMR, limiting the parties' autonomy to define such events and involving the Government in private contracts.
The rights of IPPs	IPPs as sellers have the right to: a. receive payments related to the electricity selling price according to the PPA b. receive incentives for the acceleration of COD execution if the acceleration is requested by PLN c. receive deemed dispatch if the PLN network is disrupted not due to FM.	IPPs have the right to: a. receive payments related to the electricity selling price b. receive payments for deemed dispatch based on the electricity selling price, as stated in the PPA.	The incentive for the acceleration execution of a COD as the right of the IPP is not included in MoEMR Regulation 5/2025. However, the incentives related to renewable energy are duly addressed under PR 112/2022.

Content	Key changes		Note
	MoEMR Regulation 10/2017	MoEMR Regulation 5/2025	
Environmental attributes and carbon economic value	-	Power plants utilising renewable energy are entitled to environmental attributes and carbon economic rights, including but not limited to carbon credits, renewable energy certificates, green labels and other tradable rights. The exercise of these rights is subject to applicable laws and regulations. In the absence of specific regulations, ownership and management of these rights shall be determined through mutual agreement between the involved parties.	MoEMR Regulation 5/2025 emphasises the importance of renewable energy power plants' environmental and carbon economic rights. These rights promote sustainable practices and offer financial incentives.
Dispute settlement	Disputes between PLN and the IPP should be resolved through consensus. If consensus fails, an agreed expert will mediate. If the expert's decision is unacceptable, the dispute will be settled by the Indonesian National Arbitration Board (*Badan Arbitrase Nasional Indonesia*/ BANI), the United Nations Commission on International Trade (UNCITRAL) or another designated arbitration body, with their decision being final and binding.	Disputes between PT PLN (Persero) and the business entity should be resolved through consensus within a maximum of 30 calendar days. If an expert is involved, the resolution period extends to a maximum of 150 calendar days. If consensus fails, disputes will be settled through state courts or arbitration, with arbitration procedures and arbitrator appointments mutually agreed upon and included in the contract. The decision from either the court or arbitration is final and binding.	MoEMR Regulation 5/2025 has set a time frame for resolving disputes through consensus deliberation and expert involvement.

3.5 Other relevant laws and regulations

3.5.1 Investment Law

Investment Law No. 25/2007 (as partially amended by Omnibus Law (the 2007 Investment Law)) is intended to provide a one-stop investment framework for investors. This includes key investor guarantees, such as the right to freely repatriate foreign currency, as well as key incentives such as exemptions from import duties and value-added tax (VAT) otherwise due on imports of capital goods and machines and equipment for production needs.

Obligations for power plant investors under the 2007 Investment Law include:

a. prioritising the use of Indonesian manpower
b. ensuring a safe and healthy working environment
c. implementing a corporate and social responsibility programme
d. meeting certain environmental conservation obligations.

BKPM has been given the power to coordinate the implementation of the investment policy including pursuant to the 2007 Investment Law.

Foreign investors wishing to participate in the power sector must first obtain a business licence (such as an IUPTLU) and/or commercial or operational licenses from BKPM, through the OSS system. In order to do this, an entity that is incorporated in Indonesia must be established and licensed as a PT PMA company (under the 2007 Investment Law and Company Law No. 40/2007 (as amended by the Omnibus Law). A PT PMA can be licensed for both the geothermal (i.e. generation of steam) and power sectors.

Please refer to *Section 3.2.4 – IUPTLU/IUPTLS and Section 3.2.5 – OSS system* for further discussion regarding the OSS system.

3.5.2 The Positive List

In order to promote investment, the Government revised the former Negative List to become a Positive List by enacting PR No. 10/2021 on the Capital Investment Business Sector (as amended by PR No. 49/2021). The Positive List sets out business activities that are available to foreign investment with certain requirements and limitations on foreign participation.

The most recent Positive List, as detailed in PR No. 10/2021 (as amended by PR No. 49/2021), prescribes foreign investment limitations in the power sector as follows:

a. Power supply for power plants (<1MW) are closed for foreign investment.
b. Construction and installation of low-or medium-voltage electric power utilisation is closed for foreign investment.

c. Examination and testing of installations of low-or medium-voltage electrical power utility installations are closed for foreign investment.

3.5.3 The 2009 Environment Law

Pursuant to Law No. 32/2009 (as partially amended by Omnibus Law) and Ministry of Environment and Forestry (MoEF) Regulation No. 4/2021 on the List of Business and/or Activities that Must Have an Environmental Impact Analysis, Environmental Management Effort and Environmental Monitoring Effort or Statement on Environmental Management and Monitoring Readiness, IPP investors must comply with environmental practices and secure an Environmental Impact Analysis (*Analisis Mengenai Dampak Lingkungan Hidup* – AMDAL) before they begin the following operations:

a. Construction of transmission networks > 230 kV.
b. Construction of distribution networks.
c. Construction of a power plant ≥ 100 MW in one location.

Businesses and/or activities other than the above should have an environmental management or monitoring effort document (*Upaya Pengelolaan Lingkungan Hidup-Upaya Pemantauan Lingkungan Hidup*/UKL-UPL) or a letter of intent regarding their environmental management/monitoring.

As the implementing regulation of Law No. 32/2009, GR No. 22/2021 stipulates that every business and/or activity plan that has an impact on the environment must have:

a. an AMDAL
b. UKL- UPL
c. a Statement of Capability in Environmental Management and Monitoring (*Surat Pernyataan Kesanggupan Pengelolaan dan Pemantauan Lingkungan Hidup*/SPPL).

MoEF Regulation No. 4/2021 stipulates further, in its attachment, the list of business activities that require AMDAL, UKL-UPL or SPPL. The attachment stipulates the requirement of the environmental licence depending on the specifications of the project.

In addition to this, GR No. 22/2021 also stipulates that the AMDAL must be secured by every business that has significant impact on the environment. The business that is required to secure AMDAL will include (a) the type of business whose size or scale is deemed mandatory in conducting AMDAL and/or (b) type of business whose location is carried out within and/or directly adjacent to a protected area.

Furthermore, Article 8 stipulates the criteria for a business that has a significant impact on the environment and that must therefore secure AMDAL. Such a business will be involved in:

a. land and landscape conversion
b. the exploitation of natural resources, both renewable and non-renewable

c. processes and activities that may potentially cause environmental pollution and/or environmental damage as well as waste and degradation of natural resources in their utilisation
d. processes and activities whose results may affect the natural environment, the artificial environment, as well as the social and cultural environment
e. processes and activities whose results will affect the preservation of natural
f. conservation areas and/or protection of cultural heritage
g. introduction of types of plants, animals and microorganisms
h. manufacture and use of biological and non-biological materials
i. activities that have a high risk and/or affect national defence
j. application of technology that is estimated to have great potential influence to the environment.

3.5.4 Land Acquisition Law

The 2012 Land Acquisition Law (as partially amended by Omnibus Law) and GR No. 19/2021 as amended by GR No. 39/2023 on Land Procurement Procedures for Development and the Public Interest which revoked PR No. 71/2012 and its subsequent amendments, aim to expedite the land acquisition process for certain infrastructure projects, including power plants. The goal is to help overcome the difficulties encountered when performing compulsory acquisitions of land for public purposes. The 2012 Land Acquisition Law (as partially amended by Omnibus Law) and GR No. 19/2021 as amended by GR No. 39/2023 set out a maximum timeframe for the four stages of land acquisition. These stages are planning, preparation, implementation and delivery of results.

Power projects often face land acquisition issues. Before the implementation of this law, Indonesia did not have an established legal procedure regarding the compulsory acquisition of land for public purposes. PR No. 71/2012 and its amendments have also helped to overcome the obstacle of unregistered land, by including holders of "customary land rights" as being potentially eligible for compensation, a provision still upheld in GR No. 19/2021 as amended by GR No. 39/2023. Furthermore, GR No. 19/2021 as amended by GR No. 39/2023 also introduces Land Bank Agency as a rightful party of the land procurement object.

The maximum time period is set at 330 working days from the submission of the land acquisition plan to the issue of the certificate of registration, including any time for objections or appeals. An unwilling landowner can be forced to sell their rights for an amount of compensation, as approved by a court review. Compensation may be in the form of money, replacement land, resettlement, stock ownership or other forms as agreed by the parties.

The State Assets Management Agency (*Lembaga Manajemen Aset Negara*/LMAN) was established in December 2016 in order to optimise the state's asset management. LMAN also aims to optimise the potential state return on assets and non-tax revenue (*Penerimaan Negara Bukan Pajak*) from state assets. So far, the LMAN has received a government capital injection of IDR16 trillion in order to buy land to support PSNs. The first phase of the LMAN is concentrated on toll roads, with the upcoming phases being allocated to ports, railways and dams. So far, no energy-related projects have been included in LMAN's work plans.

3.5.5 BI regulation on the obligation to use rupiah

Law No. 7/2011 regarding Currency was issued in 2011. In March 2011, BI issued BI Regulation No. 17/3/PBI/2015 on the Obligation to Use Rupiah for Transactions in Indonesia. This was effective as of 1 July 2015, with the stated aim of stabilising the rupiah exchange rate.

Of particular interest here is the fact that PLN is still paying invoices denominated in USD. However, for recently signed PPAs with invoices denominated in USD, PLN will in fact pay the invoices in IDR, which will be converted by SOE banks to USD when the payment is transferred to the bank accounts of the IPPs. PLN has signed tripartite agreements with SOE banks and IPPs to ensure that PLN does not violate the regulation requiring the use of IDR, while ensuring at the same time that it does not violate its PPAs.

Notwithstanding this, there is a concern from some IPPs as to whether this arrangement will continue for the entire term of their PPAs, or whether it will only last for the period until the full repayment of the IPP's USD-denominated loans. Since the implementation of MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulations Nos. 49/2017 and 10/2018), payments must now explicitly be made in IDR, unless exempted by BI (see Section 3.4 – Regulation on PPAs for further details).

3.5.6 BI regulation on foreign currency transactions and reporting on foreign exchange trading

BI Regulation No. 16/22/PBI/2014 regarding Reporting on Foreign Exchange Trading and Reporting on the Application of Prudential Principles to Foreign Loan Administration for Non-bank Corporations includes a requirement for companies to report their foreign currency loans to BI on a monthly basis. This regulation was partially revoked by the recently issued BI Regulation No. 21/2/PBI/2019 regarding Reporting on Foreign Exchange Trading, but the prudential principles for foreign loan administration remain in effect. In this new regulation, banking institutions have to report the primary data of their foreign loans and their risk participation agreements, along with the planned and realised withdrawals or payments of their foreign loans and risk participation agreements, as well as their position and any changes in foreign financial liabilities.

Meanwhile, non-banking financial institutions should also report the same data, in addition to every trade between citizens and non-citizens, the position and changes in their foreign financial assets, foreign loan plans and its amendments. The report format is regulated by BI Board of Governor Regulation No. 21/7/PADG/2019, which stipulates that the report must include an explanation and supporting data regarding the transaction, the entity that reports the transaction and/or the other entities involved in the transaction. This is mandatory for any business that is owned by the state, including regionally-owned, private, personal and other enterprises. Furthermore, the fourth quarter's report needs to be verified by an independent public accountant. Failure to comply with the reporting obligations triggers an administrative sanction of IDR10 million.

The prudential principles under BI Regulation No. 16/21/ PBI/2014, as amended by BI Regulation No. 18/4/PBI/2016 and Circular Letter No. 16/24/DKEM/2014, as lastly amended by Circular Letter No. 18/6/DKEM/2016, are as follows:

a. A minimum hedging ratio of 25% of the negative difference between the foreign exchange assets and the foreign exchange liabilities which will be due within three months and which will be due between three and six months from the end of the reporting quarter. Only companies that have a "negative difference" of more than USD100,000 are required to fulfil the minimum hedging ratio.
b. A minimum liquidity ratio of 70%, calculated by comparing the company's foreign exchange assets and foreign exchange liabilities which are due within three months of the end of the reporting quarter.
c. A minimum credit rating of "BB-" or equivalent from a credit ratings agency recognised by BI.

3.6 Restriction on changes in shareholders in business enterprises in the energy and mineral resources sector

On 3 August 2017, the MoEMR issued Regulation No. 48/2017 on the Supervision of Business Enterprises in the Energy and Mineral Resources Sector. The aim of the regulation was to ensure good governance and to improve the supervision of business activities in the energy and mineral resources sector.

This regulation means that all private entities and cooperatives conducting business activities in the field of energy and mineral resources have to report to, or fulfil the requirement for approval from, the MoEMR. With regard to the electricity business, this means that IPPs, which were primarily regulated by their PPA with PLN, will now be subject to greater reporting requirements. The regulation sets out provisions similar to those for geothermal developers. The details are as follows:

Share transfers or changes in shareholders

The transfer of shares in an IUPTLU holder must be reported to the MoEMR, via the DGE, no more than five working days after the most recent amendment of the Articles of Association has been authorised by the Minister of Law and Human Rights.

IUPTLU holders that sell electricity to PLN must not transfer shares until the power plant reaches COD. Transfers can be made prior to the COD, but only to an affiliate where more than 90% of the shares are owned by the sponsor intending to transfer the shares. This is under the condition that such an affiliate must be a business entity one level below the transferor. The transfer must be approved by PLN.

The transfer of shares in an IPB holder or a geothermal contractor under a JOC through the Indonesia Stock Exchange (IDX) – presumably meaning via an IPO – upon the completion of the exploration must be approved by the MoEMR. Meanwhile, any transfers of shares not listed on the IDX must only be reported to the MoEMR.

The scope of this regulation provides an exemption for share transfers prior to COD that applies to sponsors and does not extend to lenders.

Changes in corporate management, including changes in the board of directors and/or commissioners

Changes in the make-up of the board of directors and/or commissioners of an IUPTLU holder or geothermal developer must be reported to the MoEMR, via the DGE or the DGNREEC, no more than five working days after the approval of the latest amendments to the Articles of Association by the Minister of Law and Human Rights. MoEMR Regulation No. 48/2017 also outlines the administrative documents and procedures for conducting both transfers of shares and changes in corporate management.

Photo source: PwC

4 IPP investment in Indonesia

4.1 History of IPPs in Indonesia and the PPP framework

Unlike the oil and gas and mining sectors, power investment has not generally – with the exception of pre-2003 geothermal power – operated pursuant to a stand-alone investment framework. Instead, IPP investment has generally been categorised according to the nature of the relevant off-take arrangements, especially PPAs. IPPs have existed in Indonesia pursuant to PPAs since the early 1990s and they are classified into three broad generations (as outlined below). By the end of 2024, IPPs account for approximately 36.17% of Indonesia's total installed capacity. Certain IPPs, particularly in recent times, have also operated pursuant to a more general set of PPP arrangements.

The key regulatory framework for Indonesian PPPs is PR No. 38/2015, which replaced PR No. 67/2005 (as amended by PR Nos. 13/2010, 56/2011 and 66/2013), Bappenas Minister Regulation No. 4/2015 (as revoked by Bappenas Minister Regulation No. 7/2023), which contains general guidelines for PPP implementation and LKPP Regulation No. 1/2025 (*Section 4.7.3 - PPPs*), which contains detailed procurement procedures for PPP projects.

4.2 IPP generations

4.2.1 First generation (1991 until the Asian financial crisis)

Private participation in Indonesia's power sector started in 1991, with the signing of the PPA with Paiton Energy. Relatively high forecasted internal rates of return (IRRs), often between 20% and 25%, together with the provision of a government guarantee in the form of a letter of support covering PLN's obligations under the PPA, meant that there was initially a high level of investor uptake during the IPP tendering process.

However, when the Asian financial crisis struck in late 1997, PLN became financially troubled, particularly as a result of the fall in the value of the rupiah. PLN had to put many of its IPP projects on hold and ultimately six projects were terminated, six were acquired by the Government, one project ended up in a protracted legal dispute and 14 other projects continued on renegotiated terms. When the renegotiations were completed in 2003, most of the continuing IPP investors agreed to new PPAs, which generally included lower tariffs than had initially been determined.

4.2.2 Second generation (Asian financial crisis to 2009)

The second generation of IPPs commenced during the period from 2005 to 2009. However, this generation was not viewed as being particularly attractive to investors, for the following reasons. First, no government guarantees were provided. Rather than providing direct government support to IPP projects, the MoF entered into an Umbrella Note of Mutual Understanding with the Japan Bank for International Cooperation (JBIC) for the various projects (such as Marubeni's Cirebon Plant, which benefited from JBIC export credit supports). Second, the risk allocation was not viewed as being favourable to investors. Finally, the forecasted returns were lower, with the forecasted IRRs often being between 12% and 14%. Of 126 project proposals, only 18 were awarded. The largest of these projects included the coal-fired plants of Cirebon (660 MW) and the Tanjung Jati expansion (2 x 660 MW).

4.2.3 Third generation (2010 onwards)

The four categories of the third-generation IPP projects are: PPP projects, FTP II projects, 35 GW programme projects and IPP projects under PLN's regular programme. The third-generation IPPs that operate as PPPs are subject to the recent revisions to the PPP framework. These differ from second-generation IPPs, in that the risk allocation mechanism is intended to be clearer and more supportive of investors. The four categories are discussed below.

PPP projects

On 20 March 2015, PR No. 38/2015 on PPPs was issued to replace PR No. 67/2005 and its amendments. PR No. 38/2015 was issued to address a number of concerns surrounding the existing PPP framework. The key enhancements under PR No. 38/2015 were as follows:

a. The sectors covered were wider and included oil and gas infrastructure (e.g. refineries), urban infrastructure, industrial estates and social infrastructure (e.g. healthcare).
b. SOEs or regionally-owned enterprises can act as a Government Contracting Agency (GCA).
c. The "bundling" of two or more PPP projects was permitted (i.e. the projects could be procured together – a power plant and its related infrastructure, for example).
d. Land will be procured by the Government (in accordance with the Land Acquisition Law) before the PPP project is offered.
e. A new type of contract, the "performance-based annuity scheme", was made available.
f. Projects developed through unsolicited bids were encouraged, by providing compensation:
    i. an additional 10% price preference in the bid evaluation
    ii. the right to match a lower priced bid by a competitor
    iii. the purchase of intellectual property rights (e.g. the feasibility study), if the proponent suffers losses.
g. Government support, in the form of a cash contribution towards construction costs, continued to be available via the Viability Gap Fund, as well as any separately available tax incentives.
h. A Government guarantee to cover the GCA's financial obligations was provided.
i. The cost of preparing a project could include a retainer, fixed fees and success fees, while the Government's project preparation costs could be recovered from the winning bidder and could include the following costs:
    i. for the pre-feasibility study
    ii. for managing the transaction
    iii. any compensation to be paid to international organisations or consultants in assisting the project's preparation, when based on a success fee.
j. A standard PPP agreement framework will be provided, including provisions covering change mechanisms and arbitration.
k. The procurement process can be carried out through tender or direct appointment.

The detailed procurement procedures for PPP projects were initially set out in LKPP Regulation No. 1/2025 concerning Procedures for the Implementation of Business Entity Procurement in Public Private Partnerships for the Provision of Infrastructure.

The first PPP in the power sector was the Central Java Power Plant (CJPP), with a capacity of 2 x 1,000 MW and an estimated investment of USD4.2 billion. The CJPP will operate under a BOT structure and the project was awarded to a consortium of the Adaro Energy, J-Power and Itochu groups in 2011. This project also involved the first utilisation of the IIGF guarantee, which was awarded in October 2011.

The land acquisition process for this project was completed in late 2015 and the financial closing of the project was completed in June 2016. COD was expected in 2020, however, the Batang Regional House of Representatives (DPRD) recommended the progress of construction be temporarily stopped due to the COVID-19 outbreak, causing the COD to be delayed to 2021. Finally, in August 2022, both unit 1 and unit 2 of the power plant received permits for electricity generation.

In the 2024 PPP Book issued by Bappenas, there is one hydropower plant project in the "ready to offer" category and one mini hydropower plant project in the "under preparation" category.

FTP II projects

FTP II was launched in January 2010 under PR No. 4/2010 (amended most recently by PR No. 194/2014). The list of projects was set out under MoEMR Regulation No. 15/2010 and lastly amended by MoEMR Regulation No. 40/2014 to 17.4 GW. These focus on the use of IPPs as well as the use of coal and renewable sources of energy, such as geothermal and hydropower. The five-year 35 GW programme announced by President Joko Widodo superseded FTP II and all of the projects planned for completion between 2015 and 2019 were rolled into the 35 GW programme.

The 35 GW programme (2015 - 2019)

A five-year 35 GW programme was announced by President Joko Widodo in late 2014. The goal was to complete 35 GW of power generating projects by the end of his first term. An additional 46,000 km of transmission lines were also planned. These projects were awarded through open tender, direct appointment or direct selection (see *Section 4.4 – Procurement process*). Based on PR No. 4/2016 (as amended by PR No. 14/2017), the projects were also eligible for the MoF's business viability guarantee. Further details regarding the procedures and provisions for the guarantee were regulated by MoF Regulation No. 130/2016 (as amended by MoF Regulation No. 135/2019).

PLN's regular programme

PLN's regular programme includes PLN projects, IPP projects and unallocated projects planned for completion after 2021, which can be found in PLN's RUPTL. IPP projects are subject to the same regulations as the 35 GW programme.

4.2.4 IPP investment framework summary

An outline of the current framework for IPP investment in power generation is as follows:

	Regulations	Guarantees	Examples
PPP	• PR No. 38/2015: Cooperation between the Government and Business Entities for the Provision of Infrastructure. • Bappenas Regulation No. 4/2015 (This regulation has been amended with Bappenas Regulation No. 2/2020): Guidelines for PPP Implementation. • PR No. 78/2010: Infrastructure Guarantees for PPPs Provided through IIGF. • MoF Regulation No. 260/2010 (This regulations has been amended with MoF Regulation No. 8/2016): Implementing Guidelines for Infrastructure Guarantees in PPPs. • LKPP No. 1/2025: Procedures for the Implementation of Business Entity Procurement in Public Private Partnerships for the Provision of Infrastructure.	• A guarantee is provided to the IPP, which covers the contracting agency's/ Government's financial obligations, as stated in the PPA. • The guarantor is the IIGF, sometimes jointly with the Government.	• Central Java 2 x 1,000 MW Coal-fired Power Plant.
FTP II (superseded by 35 GW programme)	• PR No. 4/2010 as amended by PR No. 194/2014, PR No. 48/2011 and PR No. 19/2014 MoEMR Regulation No. 15/2010 as amended by MoEMR Regulations Nos. 1/2012, 21/2013, 32/2014 and 40/2014: The List of Projects to Accelerate the Construction of Renewable Energy, Coal and Gas-fuelled Power Plants. • The bidding process follows MoEMR Regulation No. 10/2022. • GR No. 14/2012 as amended by GR No. 23/2014 on Electricity Business Provision. • MoF Regulation No. 130/2016 as amended by MoF Regulation No. 135/2019: Procedure for the Implementation of Government Guarantee for the Acceleration of Electricity Infrastructure Development.	• A Business Viability Guarantee Letter from the MoF is provided to existing IPP projects, covering PLN's financial viability. According to PR No. 4/2016 (as amended by PR No. 14/2017), a Business Viability Guarantee Letter from the MoF may be extended to the FTP II projects rolled over to the 35 GW programme, as long as the procurement process for the project has not yet commenced.	• Muaralaboh 2 x 110 MW PLTP, West Sumatra. • Rantau Dadap 2 x 110 MW PLTP, South Sumatra. • Rajabasa 2 x 110 MW PLTP, Lampung. • Wampu 1 x 45 MW hydropower plant, North Sumatra.

	Regulations	Guarantees	Examples
35 GW programme	• PR No. 4/2016 (as amended by PR No. 14/2017) was issued to accelerate the development of electricity infrastructure, i.e. the 35 GW programme. • No specific regulation lists the 35 GW Programme projects. Rather, they consist of a combination of the previous FTP II and PLN's regular programme. All are to be completed by 2019. • The bidding process follows MoEMR Regulation No. 10/2022. • GR No. 14/2012 (as amended by GR No. 23/2014) permits the direct selection and direct appointment of an IPP in some circumstances. • GR No. 5/2021: The Organisation of Risk-Based Business Licensing. • MoEMR Regulation No. 35/2014 (as amended by MoEMR Regulation Nos. 14/2017 and 30/2018), BKPM provides a one-stop service for permits and licensing. • MoEMR Regulation No. 5/2025: main Provisions for PPAs. • MoEMR Regulation No. 19/2017: The Use of Coal for Power Plants and Purchase of Excess Power. • MoEMR Regulation No. 45/2017 (as amended by MoEMR Regulation No. 10/2020): The Use of Natural Gas for Power Plants. • MoEMR Regulation No. 50/2017 (as amended by MoEMR Regulation No. 53/2018) and MoEMR Regulation No. 4/2020): The Use of Renewable Energy for Electricity Power Supply. • MoF Regulation No. 130/2016 (as amended by MoF Regulation No. 135/2019): The Procedures for Granting Government Guarantees to Accelerate the Development of Electricity Infrastructure.	• Based on PR No. 4/2016 (as amended by PR No. 14/2017), a Business Viability Guarantee Letter from the MoF may be provided for the 35 GW projects, as long as the procurement process for the project has not yet commenced.	• Riau Kemitraan 2 x 600 MW Coal-fired Power Plant (Sumatra). • Sulut-3 2 x 50 MW CFPP (North Sulawesi). • Jawa-1 2 x 800 MW Combined Cycle Power Plant (West Java).
PLN's regular programme	• Projects planned for completion by 2019 are now covered by the 35 GW programme. Later projects are listed in the RUPTL. • All regulations that apply to the 35 GW programme also apply to the IPP regular programme.	• Based on PR No. 4/2016 (as amended by PR No. 14/2017), a Business Viability Guarantee Letter from the MoF may be provided for 35 GW projects, as long as the procurement process for the project has not yet commenced.	• Lontar Ekspansi 1 x 315 MW coal-fired power plant (Banten).

4.2.5 Investment framework under PR No. 4/2016 (as amended by PR 14/2017)

The development of electricity infrastructure must be conducted in an effective, efficient, transparent, fair and accountable way. To achieve this objective, PR No. 4/2016 welcomes the presence of investors into the acceleration of electricity infrastructure through three different project structures, which are as follows:

Development structure	Applicability	Investment element	Government guarantee
Development of electricity infrastructure by PT PLN	Conducted: • when PT PLN has the financial capacity to provide equity funding and has access to low-cost financing sources • there is low construction risk • there is available fuel supply; • there is a peaking power plant that functions to maintain operational reliability • there is an isolated development system.	PT PLN may engage in a power supply partnership with a power plant developer through a sale and purchase transaction.	Government guarantee for the payment obligations of PT PLN.
Development of electricity infrastructure through partnership between a subsidiary of PT PLN and an enterprise	Conducted when PT PLN's subsidiary (a company where PT PLN has ownership over at least 51% shares) enters into a partnership with a domestic and/or foreign enterprise that is strategically valuable for the development of the electricity infrastructure.	PT PLN partners with a domestic and/or foreign enterprise who provides: • funds that are needed by PT PLN • available energy to be used by PT PLN • technological expertise • enhancement of domestic production capability.	Government guarantee for PT PLN's financial obligations, as derived from a power sale and purchase agreement.
Development of electricity infrastructure through an electrical power supply partnership with a power plant developer	Conducted: • when the project requires large funding • when the construction is of high-risk, especially in new locations that require land acquisition • when the fuel supply is of high-risk • when there is uncertain gas supply and/or infrastructure • when the power plants are using NRE sources • constitutes an expansion of existing power plants owned by power plant developers • when there are several power plant developer that will develop power plants in a particular area.	The developments are conducted in partnership with Power Plant Developers in the form of (1) state-owned enterprises, (2) regional-owned enterprises, corporations and/or (3) private companies.	Government guarantee for PT PLN's financial obligations, as derived from a power sale and purchase agreement.


Photo source: PT Jawa Power

Other than the government guarantees mentioned above, the Central Government and/or regional government are empowered by PR No. 4/2016 to provide support to the development of electricity infrastructure that are prioritising the usage of NRE. This support may be given in the form of: (1) provision of fiscal incentives, (2) ease in obtaining licensing and non-licensing, (3) determination of the electricity purchase price from each NRE source, (4) establishment of a separate business entity that will provide electricity to be sold to PT PLN and/or (5) the provision of subsidies. In considering the many forms of support that may be provided, it may be concluded that the investment framework under PR No. 4/2016 seeks to foster investments in electricity infrastructure development.

Furthermore, PR No. 4/2016 elucidates that the electricity infrastructure development must prioritise the use of domestic goods and services, if available. To facilitate this prioritisation, PR No. 4/2016 allows for PT PLN and/or IPPs to partner with foreign enterprises that are committed to innovations in technology, electrical components, domestic human resources and the transfer technology needed for electricity infrastructure development. In this regard, the foreign contributions shall be facilitated through a partnership with the Government.

4.3 Financial facilities available to IPPs

The Government has established four financial facilities/institutions to support infrastructure projects (including those in the power sector). These are discussed below.

4.3.1 IIGF – for PPPs

The IIGF operates as an infrastructure guarantee fund for PPPs. PR No. 78/2010 and MoF Regulation No. 260/2010 (as amended by MoF Regulation No. 8/2016) are the basis for the IIGF providing guarantees to PPP projects. The aim of the IIGF is to accelerate the development of infrastructure projects, by reducing the risk of financing for infrastructure investors (including IPPs) essentially by providing sovereign "guarantees" or "letters of comfort" for a fee. The IIGF essentially functions as an insurer of any risk exposures to the private sector, for a premium. The IIGF is increasing its guarantee capacity through cooperation with multilateral agencies and bilateral institutions.

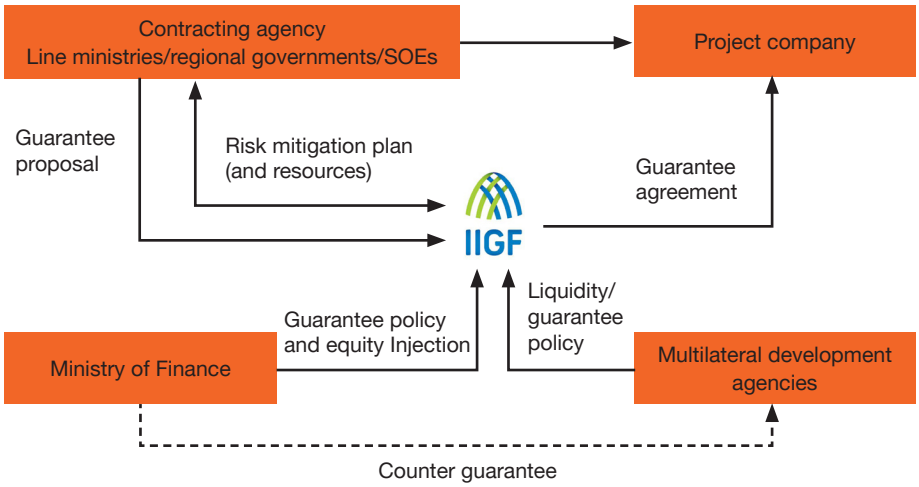
As mentioned above, in October 2011 the USD4.2 billion CJPP (COD 2022) was the first PPP to receive an IIGF guarantee. This took the form of a joint guarantee facility from the IIGF and the MoF. The IIGF will function as a "single window" for all requests for government guarantees on PPP projects, with the following objectives:

a. To improve the quality of PPP projects, by establishing a clear and consistent framework for guarantees.
b. To improve the governance and transparency of guarantees.
c. To facilitate the deal flow for contracting agencies by providing guarantees.
d. To help the Government manage its fiscal risks by ring-fencing government obligations against guarantees.

The issuer of the guarantee agreement is the IIGF; although support from the ministry, department or agency (MDA) or MoF support may also be involved. The guarantee covers the financial obligations of the contracting agency (PLN for electricity) and the addressee is generally the project company (the IPP investors for electricity).

In order to obtain this guarantee, PLN must submit a guarantee support proposal to the IIGF for assessment. If agreed, the IIGF will issue a Letter of Intent at the proposal stage. The IIGF may also cover the risks associated with the project's development, such as those relating to the construction, development and/or operations. The IIGF only provides guarantees for the risks for which PLN is responsible. Project sponsors separately bear or seek cover for the commercial or other risks beyond PLN's control.

The overall guarantee arrangement is outlined in the following diagram:



Source: PTPII's 2017 Company Profile
Note: Counter guarantee for the MDA's guarantee facility exists only if there is a co-guarantee agreement.

4.3.2 Viability Gap Fund – for PPPs

The Government may provide support in the form of licensing, land acquisition, cash payments funding some of the relevant construction costs and/or other forms of support to PPP projects, in accordance with the prevailing laws and regulations (the Viability Gap Fund). This is allocated by the Government through the state budget under MoF Regulation No. 223/2012, as amended MoF Regulation No. 170/2018. The guidelines for application and disbursement are set out in MoF Regulation No. 143/2013, as amended by MoF Regulation No. 170/2015. The MoF may also approve the provision of government support in the form of tax incentives and/or fiscal contributions, based on a proposal by the Minister or Chairman of the governmental institution responsible for certain infrastructure projects (transportation, road, water, irrigation, wastewater, telecommunications, electricity, and oil and gas) or by the head of a region (Governor or Regent). This support is available only if there are no practical means of making a project economically feasible and financially viable.

Examples include toll road construction projects outside Java, or water supply projects with greater social than commercial elements. Power projects are not usually eligible, because most, if not all, are financially viable.

4.3.3 Business viability guarantee letter – for FTP II and 35 GW programme IPPs

The IPPs under FTP II have access to the business viability guarantee from the MoF under MoF Regulation No. 173/2014, which is granted on a case-by-case basis. The MoF business viability guarantee takes the form of a letter to the IPP, affirming the business viability of PLN. This means that, if PLN fails to fulfil its obligations to the IPP, the Government will step in. Termination and buy-out payments are also covered. The guarantee will be terminated if the IPP fails to achieve financial close within 12 months of its issuance (which is extended to 24 months for geothermal projects).

Based on PR No. 4/2016 (as amended by PR No. 14/2017), FTP II programme projects rolled into the 35 GW programme, as well as other 35 GW projects, are also eligible for MoF's business viability guarantee. Further details of the procedures and provisions relating to the guarantee are regulated by MoF Regulation No. 130/2016 (as amended by MoF Regulation No. 135/PMK/08/2019). Please refer to *Section 3.3.1 – Government guarantees* for further discussion.

4.3.4 The infrastructure financing fund

The infrastructure financing fund operates through two agencies, PT SMI and PT IIF, and it was established to help investors obtain domestic finance for the debt and equity funding of infrastructure developments, including power projects.

PT SMI and PT IIF contribute to the acceleration of infrastructure development by providing advisory services, such as project feasibility studies and financing schemes, by providing advice to the Government on forms of incentives, by providing fiscal policy support and regulatory reform, and by socialisation through investor and infrastructure forums.

In addition, PT SMI was assigned by the Government to manage the geothermal fund in 2015. For further details, please refer to *Section 5.3.2 – The 2014 Geothermal Law*.

4.3.5 ETM Country Platform

The ETM Country Platform is a transformative regional blended-finance programme that seeks to accelerate the scheduled retirement of existing CFPPs and replace them with clean generation capacity. ETM is one component of a larger set of domestic and multilateral initiatives aimed at helping Asia and the Pacific mitigate the worst impacts of climate change, such as extreme sea level rise and destructive weather events.

Through the mechanism, it was announced in the G20 forum in Bali in 2022 that Cirebon-1 CFPP with a capacity of 660 MW is going to be a part of the early retirement programme, the first of many to come, although there have been well-publicised delays in finalising the Cirebon agreement.

PT SMI was tasked by the Indonesian government to become its central coordinator to the incoming funds.

4.3.6 Government guarantees

As a mechanism to expedite developments in NRE, PR 112/2022 reaffirms the Government's commitment in the transition to provide renewable energy for the supply of electrical power. Under PR 112/2022, this commitment crystallises through the introduction of both fiscal and non-fiscal incentives to accelerate the development of NRE electricity infrastructure. An example of a regulated fiscal incentive is the issuance of government guarantees.

Under MoF Regulation 5/2025, as the implementing regulation for PR 122/2022, government guarantees are used to cover risks of payment default by (1) PLN to the IPP based on PPA utilising NRE, (2) SOEs to financiers or holders of bonds in the context of NRE utilisation, and (3) a Platform Manager (an SOE who has been assigned to manage the Energy Transition Platform) to energy transition fund providers or holders of energy transition financing bonds. Thus, the government guarantees found in MoF Regulation 5/2025 include loan guarantees and business feasibility guarantees.

In practice, the Government will assign an SOE as an intermediary to provide the government guarantees on behalf of the Government. Regarding this, the Government has assigned PPT PII with the responsibility to provide government guarantees, subjected to approvals from the MoF. The procedure in the provision of government guarantees is regulated more comprehensively in MoF Regulation 5/2025.

4.4 Procurement process

Upon the issuance of PR 112/2022, the development of CFPPs is becoming more limited compared to renewable energy power plants as PR 112/2022 prohibits the new development of CFPPs except for CFPPs that have been determined in the RUPTL prior to the issuance of PR 112/2022 or CFPPs that meet certain requirements.

The procurement procedures for power sale and purchase were previously regulated under MoEMR Regulation No. 1/2006 on Power Sale and Purchase Procedures and/or Lease of Network in Electricity Supply Business for Public Interests and its amendment. However, this regulation has been revoked and is no longer valid as the basis for the procurement process for power sale and purchase for CFPPs. If PLN and/or an IPP intend to develop new CFPPs which meet with the requirements under PR 112/2022, the procurement process is governed by GR 14/2012 (as amended by GR 23/2014), which stipulates that the purchase of electricity is conducted through:

a. open tender

b. direct election, in the event that the purchase of electricity is carried out in the context of energy diversification for power generation to non-fuel oil
c. direct appointment in the event of: (i) the purchase of electricity from renewable energy, marginal gas, coal at the mine mouth and other local energy, (ii) purchase of excess electricity, (iii) local electricity system under emergency crisis conditions or emergency electricity provisions, and/or (iv) the addition of generating capacity at a power plant that has operated in the same location.

Furthermore, PR 4/2016 stipulates that PLN is responsible for electricity infrastructure development in Indonesia. PLN may carry out this development through cooperation between its subsidiary and an IPP. According to the Directors Regulation of PLN No. 0061.P/DIR/2019, which provides guidelines for assigning tasks to subsidiaries to accelerate electricity infrastructure development, the IPP, as a strategic partner of PLN, may hold only up to 49% of the shares in the project. Due to this provision, IPPs may need to limit their share ownership and are likely required to collaborate with a PLN subsidiary as a mandatory partner.

The procurement procedures for new and renewable energy power plants are regulated under PR 112/2022 (*Section 3.3.2 – NRE projects*).

4.5 Project finance

The financial requirements include having sufficient financial capability and a certificate of financial support or reference letter from a bank. The financial capability is to be demonstrated by audited financial statements or a rating result/ranking from a credible financial rating institution.

Project finance is a means of financing projects with significant capital requirements. A key feature is that the financing is typically non-recourse and is solely reliant on the cash flow of the project. Project finance is typically sought for projects in the energy, utilities, natural resources and infrastructure sectors.

The project finance process can include the following steps:
a. The IPP investors conduct a feasibility study to decide whether the project is viable. A financial advisor may be appointed at or near completion of the feasibility study.
b. The financial advisor assists with the preparation of the Request for Proposal (RfP) and choosing the banks to approach.
c. The banks submit expressions of interest, and the financial advisor and investor select the lead arrangers and sign term sheets.
d. The banks undertake financial, accounting, tax and insurance due diligence.
e. The banks take the proposal to their credit committees and, if approved, the credit committees specify the conditions precedent and conditions subsequent.

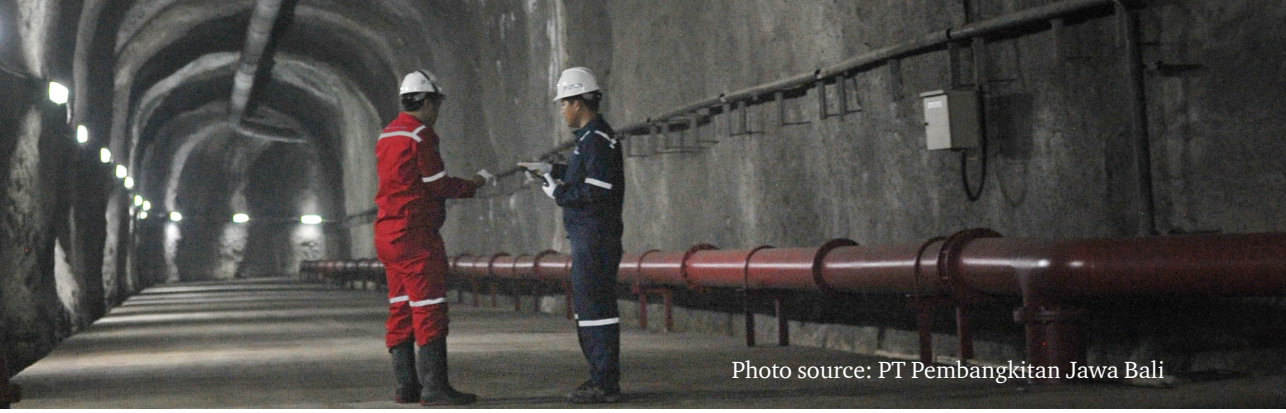


Photo source: PT Pembangkitan Jawa Bali

f. The IPP investors (or an IPP entity if established), the banks, PLN, the MoEMR, and other parties as needed finalise the PPA and other contracts in order to achieve financial close.
g. Once financial close is achieved and conditions precedent have been met then finance is available to be drawn down to fund the construction of the power plant and other related activities.
h. Once the project is completed, the lead arrangers may sell down their debt to other banks and post-completion interest rates apply.
i. The project starts commercial operation generating cash flow to service the debt and generate returns for the investors.

The main sources of project finance for Indonesian IPPs have been the following:

a. International commercial banks.
b. MDAs such as regional multilateral banks (e.g. the ADB and the European Investment Bank) and the World Bank (which includes the International Bank for Reconstruction and Development and the International Finance Corporation).
c. Governmental agencies for investment promotion such as JBIC, China Exim Bank, Korean Exim Bank and the Nederlandse Financierings-Maatschappij voor Ontwikkelingslanden NV.

MDAs and governmental agencies usually provide direct loans with "soft" provisions such as lower-than-market interest rates and longer grace periods.

4.6 Key project contracts

Key project contracts for a power plant development in addition to the PPA typically include:

a. various shareholders' agreements
b. engineering, procurement and construction (EPC) contracts
c. insurance arrangements
d. long-term fuel supply contract
e. operations and maintenance (O&M) agreements
f. financing documents.

These contracts are further discussed in Table 4.1 below.

Table 4.1 - Additional project contract components

Key project contracts	Contracting parties	Purpose of contract
Shareholders' Agreement	Shareholders in the project's special purpose vehicle (SPV) (generally the IPP entity)	Provides for the rights and obligations of shareholders
Shareholders' Loan Agreement	Shareholders in the IPP entity	Covers the terms and conditions for any shareholder loans
PPA	IPP entity and PLN	Sets out the terms and conditions of power generation activity
EPC Agreement – Offshore	IPP entity, third-party contractors and/or affiliates	Sets out the terms and conditions for the supply of offshore design and construction work
EPC Agreement – Onshore	IPP entity, third-party contractors and/or affiliates	Sets out the terms and conditions for the supply of local construction services
EPC Wrap Agreement (also known as Umbrella or Guarantee and Coordination Agreement)	IPP and contractors	Guarantees the performance of both the offshore and onshore contractors
Long-term Fuel Supply Agreement	IPP and third party (generally)	Governs the availability of the long-term fuel supply
O&M Agreement	IPP and O&M contractors	Governs O&M services, associated fees and overheads
Technical Services Agreement	IPP and affiliates/third parties	Governs the provision of technical services to the IPP entity
Project Finance Documents	Financiers and IPP	Covers the key aspects of project financing including: corporate lending • export credit agencies • cash waterfalls • hedging • political risk guarantees • inter-creditor agreements • security documents • sponsor agreements.
Developers'/Sponsors' Agreement	Sponsor and IPP	To provide a developer's fee paid by the IPP entity to the original sponsors

4.6.1 PPA

The PPA is the cornerstone operational contract for IPP investors. Its principal terms and conditions include the following:

a. The objective and scope of the contractual work or service (it is now likely that all PPAs will be a BOOT format - with the exception of renewables and other older PPAs signed prior to the MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulations Nos. 49/2017 and 10/2018)).

b. The period of operation (coal PPAs are generally for 25 years, hydro for 30 years, geothermal for 30 years and gas for 20 years). Since MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation No. 49/2017 and No. 10/2018) the maximum period of power plant operation is 30 years depending on the type of fuel.

c. The implementation guarantees (i.e. the responsibilities of the relevant IPP and PLN).

d. The implementation and construction of the project.

e. Start-up and commissioning issues.

f. The O&M arrangements of the plant.

g. Covenants.

h. Tariffs and payments.

i. Government guarantees (if applicable).

j. Service performance standards.

k. Insurance arrangements.

l. Indemnification and liability arrangements.

m. Natural FM scenarios.

n. Settlements of disputes.

o. Representation and warranty arrangements.

p. Sanctions.

q. Termination events.

r. Purchase options, if any (i.e. for PLN).

4.7 IPP opportunities and challenges

4.7.1 IPP opportunities and challenges

As discussed in Chapter 1, Indonesia's IPPs will play a greater role in the Indonesian power sector. PLN is expected to invest around IDR1,214 trillion over the next ten years, averaging IDR121.4 trillion annually. Meanwhile, the total infrastructure investment required from both PLN and private entities during 2025–2034 is projected to reach IDR2,780 trillion. This high investment demand reflects the power plant development needs under the ARED scenario[1].

Based on the 2025-2034 RUPTL, IPPs may have access to power generation projects, as follows:

Table 4.2a – Projects planned for IPPs 2025–2034 (MW) RE Base scenario

	IPPs	PLN	Total
Coal	2,014	629	2,643
Coal mine-mouth	3,700	-	3,700
Gas - combined cycle	4,195	8,144	12,339
Geothermal	4,572	585	5,157
Others (including solar PV/biomass/etc.)	5,955	1,827	7,782
Hydro (including small hydro)	10,791	1,139	11,930
Storage	2,969	6,244	9,213
Total	**31,227**	**12,324**	**52,764**

Source: 2025-2034 RUPTL, p. V-96 & V-97

Table 4.2b – Projects planned for IPPs 2025–2034 (MW) ARED scenario

	IPPs	PLN	Total
Coal	2,014	629	2,643
Coal mine-mouth	3,700	-	3,700
Gas - combined cycle	3,195	7,144	10,339
Geothermal	4,572	585	5,157
Others (including solar PV/biomass/etc.)	20,232	1,826	22,058
Hydro (including small hydro)	10,591	1,139	11,730
Storage	4,793	9,095	13,888
Total	**44,304**	**11,323**	**69,515**

Source: 2025-2034 RUPTL, p. V-97 & V-98

The 2025-2034 RUPTL presents two energy mix scenarios: the RE Base scenario and the ARED scenario. The RE Base scenario is designed to optimise system operations and economic efficiency, while maintaining renewable energy as a key component of the energy supply. The ARED scenario, on the other hand, aims to increase the share of renewable energy by 2030 and stabilise total emissions beyond that point.

By 2034, the RE Base scenario projects an energy mix consisting of 47.1% coal, 22.8% natural gas (including Liquefied Natural Gas (LNG)), 29.7% RE and 0.2% oil[2]. Under the ARED scenario, the projected mix shifts slightly to 46.8% coal, 18.4% natural gas (including LNG), 34.3% RE and 0.2% oil[3] (see Tables 4.3a and 4.3b).

Table 4.3a – Electricity fuel shares in the 2021-2030 RUPTL - RE Base scenario

		RE Base scenario									
No.	**Fuel Type**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
1	Hydropower	6.8%	7.2%	7.5%	8.4%	8.7%	9.1%	11.5%	13.4%	14.5%	14.5%
2	Geothermal	4.7%	4.8%	4.8%	5.2%	5.3%	5.7%	7.4%	8.1%	9.2%	9.9%
3	Other renewables	2.0%	2.5%	2.9%	3.6%	4.0%	4.5%	4.8%	4.8%	4.8%	5.2%
4	Gas	15.7%	17.6%	19.8%	20.3%	21.9%	22.8%	21.9%	21.4%	20.8%	22.8%
5	Fossil fuels	3.9%	2.7%	1.0%	0.5%	0.4%	0.3%	0.3%	0.3%	0.2%	0.2%
6	Coal	66.5%	64.9%	63.7%	61.7%	59.4%	57.4%	54.0%	52.0%	50.2%	47.1%
7	Import	0.4%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%
Total		**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Source: 2025-2034 RUPTL, p. V-234

Table 4.3b – Electricity fuel shares in the 2021-2030 RUPTL - ARED Base scenario

		ARED Base scenario									
No.	**Fuel Type**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
1	Hydropower	6.8%	7.2%	7.5%	8.4%	8.7%	9.0%	11.5%	13.3%	14.2%	14.3%
2	Geothermal	4.7%	4.8%	4.8%	5.2%	5.3%	5.7%	7.3%	7.8%	8.8%	9.6%
3	Other renewables	4.3%	4.5%	5.0%	5.5%	5.6%	6.3%	7.3%	7.9%	9.5%	10.4%
4	Gas	15.7%	17.4%	19.2%	19.4%	20.8%	21.6%	20.0%	19.1%	17.6%	18.4%
5	Fossil fuels	3.9%	2.7%	1.1%	0.5%	0.4%	0.3%	0.3%	0.3%	0.2%	0.2%
6	Coal	64.2%	63.2%	62.0%	60.7%	58.9%	56.8%	53.4%	51.4%	49.5%	46.8%
7	Import	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%
Total		**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Source: 2025-2034 RUPTL, p. V-237

The 2025-2034 RUPTL plans to add a total of 52.8 GW of power generation and storage capacity under the RE Base scenario and 69.5 GW under the ARED scenario. In the RE Base scenario, RE is expected to contribute 27.4 GW, representing 51.9% of the total additions[4]. Under the ARED scenario, the share of RE is projected to increase to 42.6 GW, accounting for 61.2% of the total capacity expansion[5].

In the remote regions of Indonesia, establishing new networks rapidly presents significant challenges. Consequently, diesel power plants (PLTD) were constructed to meet the immediate energy needs. To reduce fuel consumption, the 2025-2034 RUPTL outlines a de-dieselisation programme. This programme is implemented through various strategies, including converting

PLTD to RE generators with hybrid systems incorporating batteries, gasification and the construction of gas generators. Additionally, it involves interconnecting isolated systems to the grid to phase out the operation of PLTD within the system. The DGE notes that the realisation of PLTD capacity has reached 1,180.97 MW in 2024[6].

Table 4.4 – Comparison of power generation between 2021- 2030 RUPTL and 2025-2034 RUPTL (MW)

Power source	Allocated to PLN			Allocated to IPPs			Others		
	2021-2030 RUPTL	2025-2034 RUPTL RE Base	2025-2034 RUPTL ARED Base	2021-2030 RUPTL	2025-2034 RUPTL RE Base	2025-2034 RUPTL ARED Base	2021-2030 RUPTL (Cooperation between business areas)	2025-2034 RUPTL (Cooperation between business areas) RE Base	2025-2034 RUPTL (Cooperation between business areas) ARED Base
Coal	1,347	629	629	8,872	2,014	2,014	300	300	300
CMM	-	-	-	3,300	3,700	3,700	-	-	-
Gas - combined cycle	515	8,145	7,144	2,055	4,195	3,195	-	-	-
Geothermal	3,773	585	585	2,840	4,572	4,572	-	-	-
Hydro (including small hydro and pumped storage)	5,286	4,622	6,224	5,105	11,551	11,351	-	-	-
Others (including solar PV/ biomass/ etc.)	3,348	4,589	2,575	3,834	8,164	23,265	-	-	-
Total	**14,269**	**18,570**	**17,157**	**26,006**	**34,196**	**48,097**	**300**	**300**	**300**

Source: 2021-2030 RUPTL & 2025-2034 RUPTL p. V-96; V-97; V-98

The future power plant development plan focuses on using renewable or non-fossil energy sources. However, several mine-mouth CFPPs are already in the committed phase, with a capacity of 2.3 GW, which will continue as planned. Additionally, there is a proposal for a 1.4 GW hybrid RE and CFPP (solar + BESS) near coal mines in Sumatra and Kalimantan regions, intended to meet additional demand. The COD of the 1.2 GW mine-mouth coal plant in Sumatra will align with the Sumatra-Batam-Bintan interconnection schedule. The choice of a hybrid plant aims to promote domestic energy use, enhance energy security and support national energy self-sufficiency.

The development of this hybrid plant has been discussed between the MoEMR's DGE and PLN. Advances in technology have led to innovations, making CFPP more efficient, flexible and capable of utilising low-calorie coal. In the NZE strategy for 2060, there is potential to modify the mine-mouth plants with the latest technologies:

1. Enhancing efficiency with Ultra Super Critical (USC) technology.
2. Modifying boilers with fast valve or flexible coal technology to increase ramp rates and reduce minimum load.
3. Reducing emissions through co-firing with biomass or ammonia.
4. Implementing CCUS to capture carbon emissions for other uses, such as enhanced oil recovery, or to inject CO_2 back into the earth.

4.7.2 The 35 GW power development programme

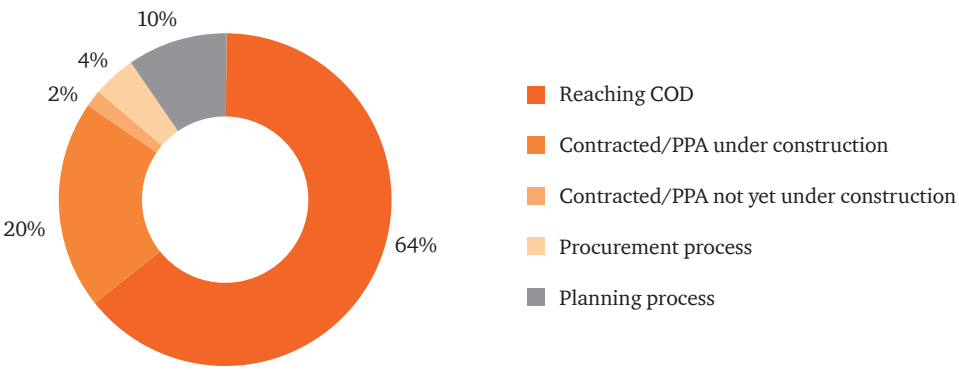
The 35 GW programme was launched in 2015. Since then, the total capacity and its composition have undergone changes in the various versions of the RUPTL. The initial breakdown of the 35 GW programme is outlined in the table below:

Development scheme	Coal (GW)	Gas (GW)	Hydro (GW)	Geothermal (GW)	Other (GW)	Total (GW)
PLN	2.2	7.0	1.2	0.1	0.1	10.6
IPP	18.1	6.6	1.1	–	0.1	25.9
Total (GW)	**20.3**	**13.6**	**2.3**	**0.1**	**0.2**	**36.5**

According to the 2025-2034 RUPTL, the progress of the 35 GW power development programme as of December 2024 is as follows:

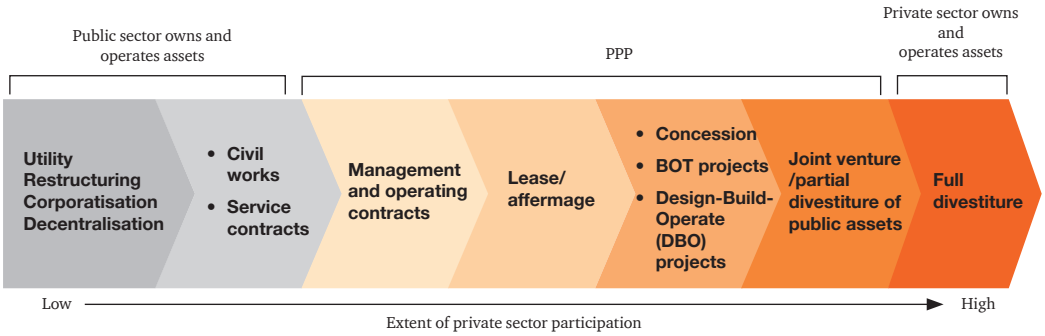
a. 64% (23.1 GW) has reached COD.
b. 20% (7.3 GW) is contracted or under construction.
c. 10% (3.5 GW) is in the planning process.
d. 4% (1.5 GW) is in the procurement stage.
e. 2% (0.6 GW) is not yet contracted or under construction.

Progress of 35 GW power plant as of December 2024



4.7.3 PPPs

There is currently no widely accepted definition of a PPP. The PPP Knowledge Lab defines a PPP as "a long-term contract between a private party and a government entity, for providing a public asset or service, in which the private party bears significant risk and management responsibility and remuneration is linked to performance". PPPs take a wide range of forms and they vary greatly in terms of the involvement of and risks borne by the private party. The terms of a PPP are typically set out in a contract or agreement which outlines the responsibilities of each party and allocates the associated risks. The graph below highlights the spectrum of typical PPP agreements[7]:



Source: World Bank

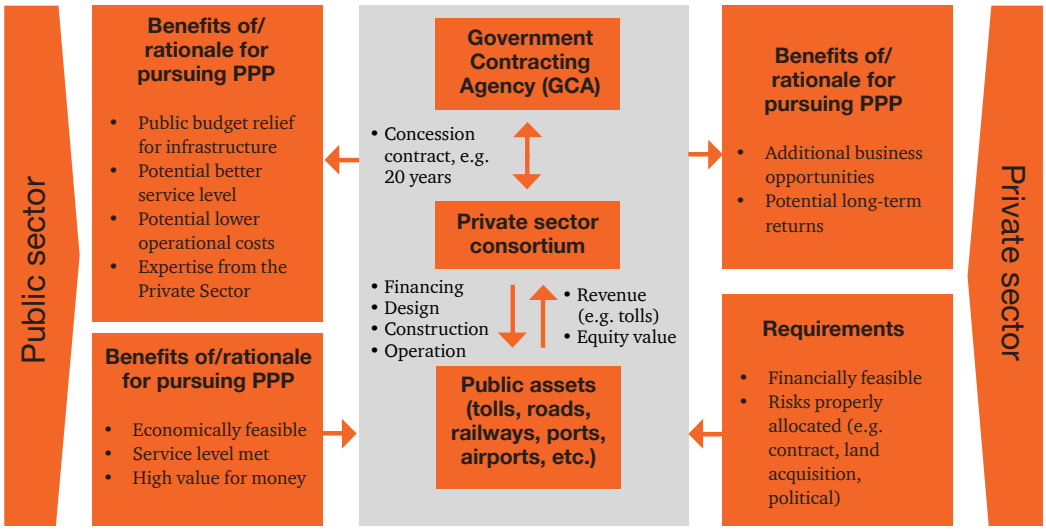
The variety of the arrangements provides a range of options for structuring agreements so that they fit the project, its associated risks and the nature of the investors. Leases and contracts have lower levels of risk, for instance, because they require limited capital outlay. They are often suited to water infrastructure projects, which offer low returns and therefore cannot justify a high-risk investment.

Greenfield projects require a significant commitment from investors and therefore these are often utilised for telecoms and energy projects, which have high potential returns. Greenfield agreements are by far the most utilised form for PPPs worldwide, because they offer the greatest opportunity for governments to divest risk and for investors to earn a significant return. This is especially true for BOO and BOT agreements.

As discussed in Chapter 1 and earlier in this chapter, Indonesia is building a significant amount of infrastructure which requires enormous investments that the Government cannot finance alone. As such, PPP arrangements represent a possible means of developing Indonesia's infrastructure. However, the meaning of a PPP in the Indonesian context is different from that in the global context, according to the definition from the PPP Knowledge Lab.

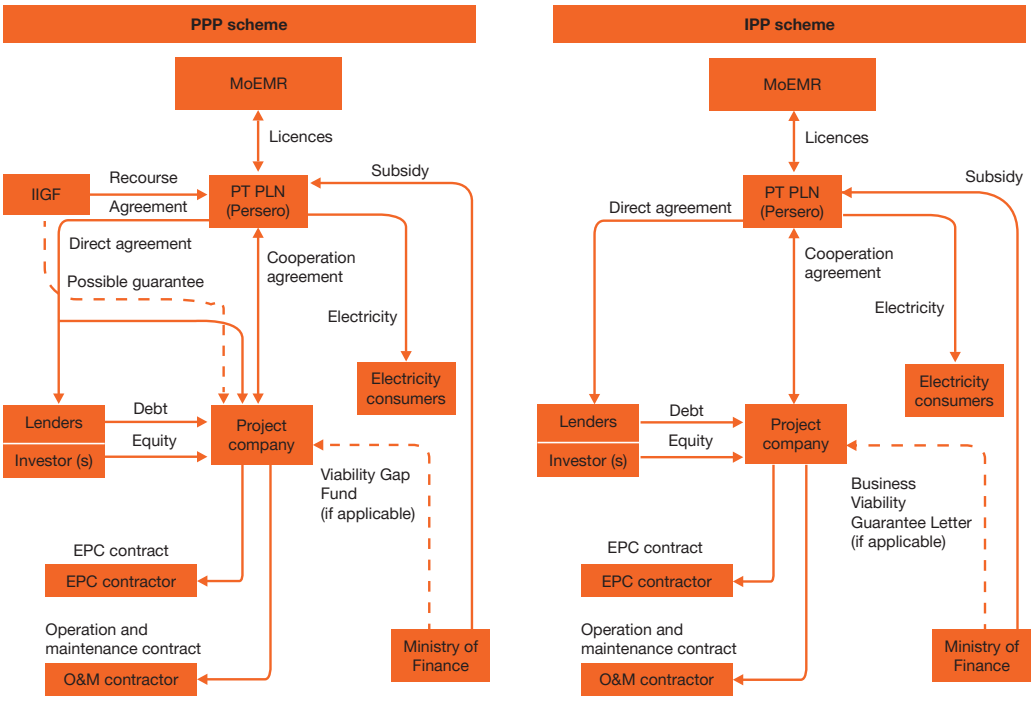
Under the PPP Knowledge Lab's definition, a contract with an IPP would qualify as a PPP. However, an IPP would not officially be labelled as a PPP in Indonesia, because it does not fall under the scope of the PPP regulation (PR No. 38/2015). This is because an IPP does not have any guarantees from the IIGF. All PPP projects are also included in the PPP Handbook issued by Bappenas every year.

A PPP scheme is generally used by the Government to divest its risk and to provide opportunities for investors to earn a significant return by assuming that risk. As such, a PPP scheme will only be successful when the objectives of the Government and the investors have been met. The Government requires that the projects provide the public with a high-quality service. The investors require that the projects be financially feasible and that the risks be manageable, including the contractual, political and land acquisition risks. The interaction between the public sector and the private sector is depicted in the diagram below.



Source: PT SMI (Infrastructure Investment 2014)

Under IPP schemes the role undertaken by the private sector is largely only for generation where PLN acts as the off-taker. Under PPP schemes PLN acts as both the off-taker and contracting agent.



Source: PT SMI (Infrastructure Investment 2014)

In the latest Bappenas "PPP: Infrastructure Projects Planned in Indonesia" report (the PPP Handbook 2023), one hydropower plant and one WtE power project have been included. These projects are categorised as "under preparation" projects. While in the "ready to offer" projects there are no power plant projects listed.

LKPP Regulation No. 1/2025 regulates the Procedures for the Implementation of Business Entity Procurement in Public Private Partnerships for the Provision of Infrastructure. The regulation contains detailed procurement procedures for PPP Projects, noting several key features – i.e. the principles of PPP, the organisation of the procurement, restrictions to prevent conflicts of interest, the provisions of the procurement committee, and the procurement of a business entity that can be conducted via auction or direct appointment, as well as via the direct selection mechanism.


Photo source: PwC

4.7.4 The role of the private sector in rural electrification

In late November 2016, the MoEMR officially launched MoEMR Regulation No. 38/2016 on the Acceleration of Electrification in the Least Developed Rural, Isolated, Border and Populated Small Island Areas through Small-scale Electricity Supply Businesses. Under this regulation, the Government offers opportunities to regionally-owned enterprises, private business entities, and cooperative businesses to become involved in improving electrification in rural and remote areas, by managing an area of business or operating area.

This regulation is motivated by concern over the 2,510 villages that do not have access to electricity across Indonesia. The MoEMR set a target of reaching an electrification ratio of 100% by the end of 2020, with a focus on increasing power accessibility through increased grid coverage areas and solar lamps for off-grid areas, but due to the COVID-19 pandemic the MoEMR estimated the target probably will be delayed until 2021[8].

Under MoEMR Regulation No. 38/2016, business entities must optimise the use of new local energy or RE resources. In doing so, those private investors may be given fiscal incentives, in accordance with the provisions of the laws and regulations.

Business entities that are interested can participate in the procurement selection of Electricity Technical Implementation Unit (*Unit Pelaksana Teknis Listrik*/UPTL). However, in the event that no business entity is interested, the Governor may appoint regionally-owned enterprises to develop small-scale UPTLs.

Meanwhile, the electric power tariff determination can be with or without subsidy funds. In the event that subsidy funds are utilised, the tariff follows the PLN average tariff for the 450 VA household customers. Business entities can propose subsidy funds to the Government, based on certain criteria (i.e. fuel use realisations and plans, operational expenditure, losses, BPP and expansion plans) which will be evaluated and determined by the DGE. On the other hand, where the electricity tariff does not utilise subsidy funds, the tariff is determined by the MoEMR or the Governor, based on their authority, along with the existing laws and regulations.

5 Conventional energy

5.1 Introduction

In the most recent analysis of worldwide energy trends, global energy demand increased by 2.2% in 2024, which was lower than the GDP growth of 3.2%, but significantly higher than the average annual demand rise of 1.3% from 2013 to 2023. More than 80% of the growth in global energy demand in 2024 was attributed to emerging and developing economies. This occurred despite China's slower growth, where energy consumption increased by less than 3%, which is half of its 2023 rate and significantly below its recent annual average. Advanced economies, after several years of decline, experienced renewed growth, with their energy demand rising by nearly 1% overall. The power sector was the primary driver of the accelerated growth in global energy demand in 2024, with global electricity consumption rising by almost 1,100 TWh, or 4.3%. This surge was nearly twice the annual average over the past ten years. Several factors contributed to the sharp increase in global electricity usage last year, including record-high temperatures worldwide that heightened cooling needs in many countries, as well as increased consumption from industry, the electrification of transport, and the expansion of data centres and artificial intelligence[1].

Global oil demand growth significantly decelerated in 2024, with consumption increasing by 0.8% (equivalent to 1.5 exajoules or 830 thousand barrels per day) to reach 193 exajoules (EJ), following a 1.9% rise in 2023. This slowdown was due to the end of the post-pandemic mobility surge, slower industrial growth and the increasing influence of electric vehicles. The 0.8% rise in demand was below the pre-pandemic rate of over 1% during the decade leading up to 2019. For the first time ever, oil's share of total energy demand dropped below 30%, 50 years after its peak at 46%. In 2024, chemical feedstocks and aviation each

contributed to approximately half of the growth in oil demand in energy terms, though in volumetric terms, feedstocks constituted a higher share, around 70%. Following a strong rebound after the lifting of COVID-19 lockdowns in many countries, the growth in oil demand from the road transport sector has notably slowed in recent years[2].

After the supply disruptions in 2022 and 2023, natural gas markets began a gradual rebalancing and resumed structural growth in 2024. Global gas demand hit a new record high, with more than 75% of the growth originating from emerging market and developing economies. Preliminary data suggest that gas demand rose by 2.7%, or 115 billion cubic metres, approximately 4 EJ, in 2024. This increase surpassed the annual average growth rate of about 2% from 2010 to 2019, and was notably higher than the roughly 1% growth rate observed between 2019 and 2023, a period marked by the COVID-19 and global energy crisis. Emerging markets and developing economies in Asia were responsible for around 40% of the additional gas demand in 2024, driven by ongoing economic expansion[3].

In 2024, global CFP generation rose by nearly 1% to reach 10,700 TWh, setting a new record. A significant factor was the record-high temperatures, which increased the electricity demand for cooling, particularly during intense heatwaves in China and India. The impact of higher temperatures on coal demand in 2024 accounts for the entire annual rise in coal usage[4].

Indonesia's energy supply in 2024 increased by 7.3% from the previous year, reaching a value of 2,007 million barrels of oil equivalent (MMBOE), which is the highest in the last ten years. Coal and oil remain the largest contributors to Indonesia's supply of primary energy, accounting for 40% and 29%. Natural gas and its derivative products follow with 16%, while NRE accounts for 14.65%, with biofuel and biomass contributing 5% and 3%[5,6].

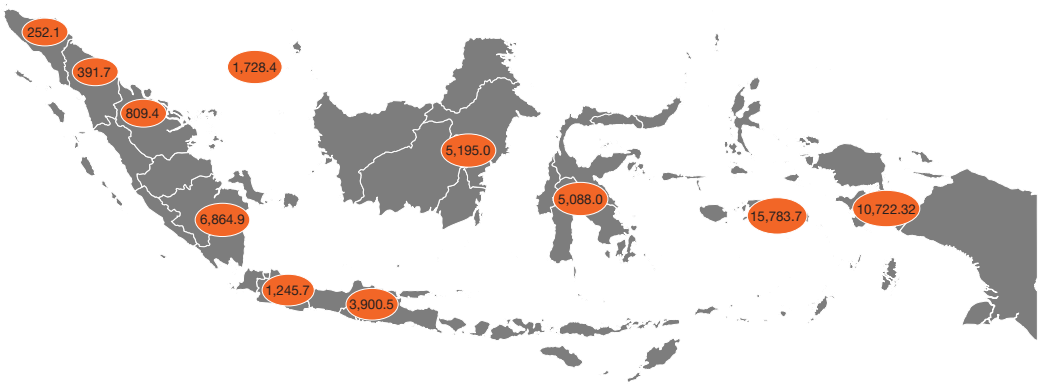
Photo source: PwC

5.2 Gas

5.2.1 Indonesian gas reserves, consumption and production

The MoEMR has recorded a consistent increase in the allocation of natural gas for domestic use, underscoring its strategic role in supporting national energy resilience and industrial development. In 2024, the domestic allocation of natural gas reached 5,785.92 billion British thermal units per day, equivalent to 67.08% of total gas production. Although this figure slightly declined from 69.43% in 2023, it still reflects a strong commitment to prioritising domestic needs over exports[7]. In terms of future production, a target has been established to reach 12 billion standard cubic feet per day by the year 2030 and onwards[8] (refer to figure 5.1 below for more details).

Figure 5.1 – Map of Indonesia gas reserves as of January 2024



Total: 51,981.80 million stock tank barrels (MMSTB)

Source: HEESI, 2025

Indonesia has long relied on crude oil as a cornerstone of its energy supply and export economy. However, for several decades, the country has been a net importer of oil, reflecting a structural decline in domestic oil production. In contrast, natural gas has steadily gained prominence in the national energy mix. By 2022, gas accounted for approximately 65% of total oil and gas production, and this share increased to 68% in 2024, according to the latest data from the MoEMR[9].

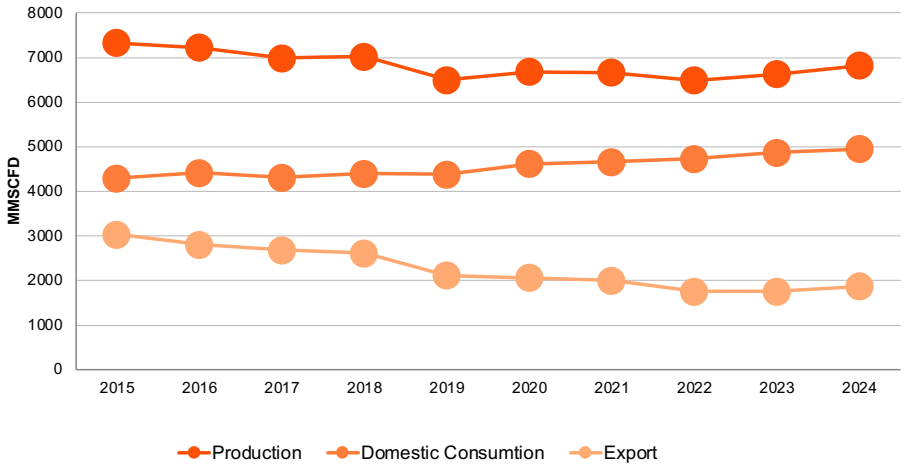
Based on MoEMR data, by the end of 2024 the realisation of Indonesia's oil lifting reached 579.7 thousand barrels of oil per day (MBOPD) decreasing from 605.6 MBOPD in 2024. Meanwhile, for natural gas lifting, the realisation reached 1,026.7 thousand barrels of oil equivalent per day (MBOEPD), increasing by 1.02% from 2023[10].

In 2024, upstream oil and gas investment reached USD15.33 billion, marking a significant increase of 18% compared to 2023 and achieving approximately 89.4% of the Government's target[11]. This growth was primarily driven by intensified production activities, including drilling, seismic surveys and well services, which rebounded strongly following the COVID-19 pandemic. The largest contributor to upstream investment was Pertamina Hulu Rokan, which continued to play a central role in national oil production.

On the downstream side, investment performance also improved, reaching USD2.20 billion, or 115.85% of the target. This increase was largely driven by a surge in oil and gas transportation activities, which reached 300% of the initial forecast for the year. However, downstream investment still faced notable challenges, including land acquisition issues, project schedule integration and the relocation of high voltage transmission line (*Saluran Udara Tegangan Tinggi/* SUTT) towers and access roads particularly affecting the Refinery Development Master Plan (RDMP) and Grass Root Refinery (GRR) projects. Additionally, Perusahaan Gas Negara (PGN)'s gas network expansion encountered permitting delays and Final Investment Decision (FID) constraints, highlighting the need to optimise commercial demand to ensure project viability[12].

In terms of production, oil lifting in 2024 remained below expectations, averaging 580 barrels per day (BPD)–a slight decline from 2023 and still below the national target of of 1 million BPD. Conversely, natural gas production showed resilience, with pipeline deliveries reaching 6,802 million standard cubic feet per day (MMSCFD), reflecting a modest increase and a continued shift toward gas as a transitional energy source[13].

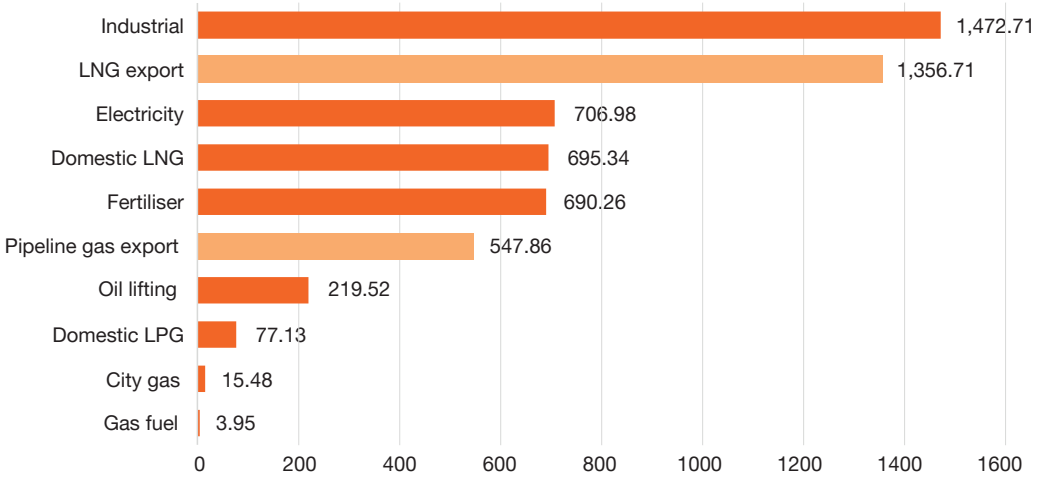
Figure 5.2 – Indonesian natural gas used for production, domestic consumption and exports (in MMSCFD), 2015–2024



Source: MoEMR, HEESI, 2025

In 2024, domestic gas utilisation reached 67.08% with a total distribution of 5,785.92 BBTUD as of December 2024. However, domestic gas absorption showed a decrease compared to 2023, which stood at 69.43% on a year-to-date basis. This sector is divided into five major categories of gas users in 2024, including industrials (1,472.71 BBTUD), LNG export (1,356.71 BBTUD), electricity (706.98 BBTUD), domestic LNG (695.34 BBTUD) and fertiliser sector (690.26 BBTUD)[14].

Figure 5.3 – Indonesian natural gas utilisation for 2024 (in BBUTD)



Source: MoEMR Performance Report 2024 (2025), p. 44

5.2.2 Prices and regulation

In Indonesia, domestic pipeline gas prices (excluding compressed natural gas or CNG) are established through specific Gas Sales Agreements between sellers and buyers/end-users. These prices adhere to a fixed regime, which includes the cost plus an annual escalation, depending on the agreement. Notably, the Indonesian gas pricing system is not directly linked to oil price fluctuations. MoEMR Regulation No. 58/2017, with the most recent update in MoEMR Regulation No. 14/2019, sets a maximum gas price based on factors such as gas cost, IRR for gas infrastructure (limited to 11% or 12% for underdeveloped regions) and a profit margin for gas traders. Despite these regulations, negotiations are still expected to play a significant role in determining actual gas prices. The pipeline gas price consists of various components, such as upfront investment and operational expenses, contractor shares and transportation costs (including VAT). As of 1 April 2020, the industrial natural gas price decreased to USD6 per million British thermal unit (MMBtu), following the guidelines outlined in PR No. 4/2016, which specifically addresses T&D costs ranging from USD1 to USD1.5 per MMBtu.

Photo source: PwC

Further refinements were introduced through MoEMR Decree No. 91.K/MG.01/MEM.M/2023, updated by MoEMR Decree No. 255.K/MG.01/MEM.M/2024 and most recently by MoEMR Decree No. 76.K/MG.01/MEM.M/2025. The 2025 decree introduces a differentiated pricing mechanism under the *Harga Gas Bumi Tertentu* (HGBT) scheme, offering USD7 per MMBtu for gas used as fuel and USD6.5 per MMBtu for gas used as feedstock[15]. This policy targets seven key industrial sectors—fertilisers, petrochemicals, oleochemicals, steel, ceramics, glass and rubber gloves—covering 253 designated users. The new scheme aims to enhance industrial competitiveness, stabilise domestic product prices and improve budget efficiency, while continuing the pricing support beyond 31 December 2024.

The upstream gas price in Indonesia, excluding LNG, is considered competitive compared to neighbouring countries. However, the Indonesian gas market faces relatively high costs for gas transportation (both T&D), which affect affordability for buyers and end-users. In 2024 BPH Migas issued Decree No. 30/TARIF/BPH MIGAS/KOM/2024, updating the methodology for calculating and setting gas transportation tariffs through pipelines. Despite these efforts to improve transparency and efficiency, Indonesia still shows the highest transportation cost component in the region, reinforcing the need for continued infrastructure reform and policy alignment.

The allocation and utilisation of natural gas in Indonesia is regulated by MoEMR Regulation No. 6/2016 on the Provisions and Procedures for the Determination of the Allocation and Utilisation and the Price of Natural Gas. These set priorities as follows:

a) To support the Government's programme by providing gas for transportation, households and small users.
b) To support the national production of oil and gas.
c) To provide raw materials for fertilisers.
d) To support industries that utilise natural gas as a raw material.
e) To provide fuel to be used for electricity production.
f) To provide fuel to be used by other industries.

Another key point in MoEMR Regulation No. 6/2016 (revoked by 32/2017) is that the utilisation of natural gas for power generation, which can be allocated to:

a) an SOE assigned to supply electricity such as PLN and its subsidiaries.
b) regionally-owned enterprises located in oil and gas producing areas which hold IUPTLs.
c) SOE in the oil and gas sector or regionally-owned enterprises located in oil and gas operating areas selling gas to IUPTL-holders.
d) business entities with an IUPTL that own gas-fired power plants.
e) business entities with a marketing permit to sell gas to IUPTL-holders.

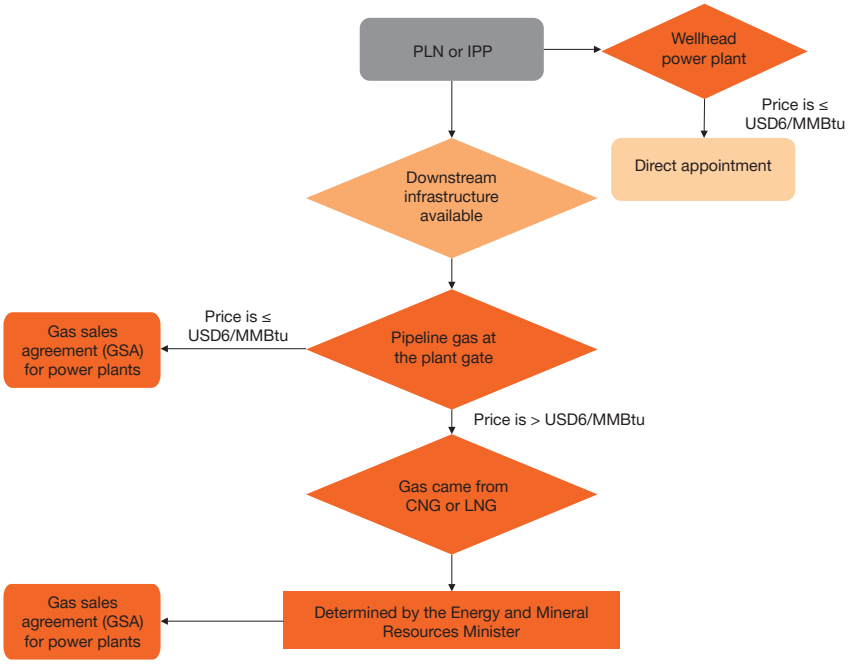
If the entities mentioned in (c) and (e) above are not able to distribute all of their gas to IUPTL-holders, then those entities may sell the excess to other business entities with marketing permits provided that they meet the following requirements:

a) They own or control the gas pipeline infrastructure for distribution to end users.
b) They are selling to end users.
c) They sell at a reasonable price.

Procedures and regulations for gas allocation and pricing are designed to ensure the efficiency and effectiveness of the availability of natural gas as a fuel, as raw material or for other purposes, in order to meet domestic demand optimally. The revision of the decree was due to the government initiatives pushing for the conversion of other power sources to gas, particularly for transportation and household uses. Regulators have also sought to ensure that domestic demand is the first priority. The MoEMR allows imports of natural gas in the event that the domestic demand cannot be met by the domestic supply.

Additionally and specifically for the power sector, the MoEMR issued MoEMR Regulation No. 45/2017 on the Use of Natural Gas for Power Plants in July 2017. The key point of this regulation is the Government allowing PLN or business entities to import LNG for electricity generation, in order to ensure the availability of natural gas at reasonable and competitive prices for the electricity sector. MoEMR Regulation No. 45/2017 has been amended by MoEMR Regulation No. 10/2020. The key amendment point is related to changes of the maximum gas price from 14.5% of ICP to USD6 per MMBtu effective 7 April 2020. In June 2021, the MoEMR released a further decree numbered 118.K/MG.04/MEM.M/2021 regarding the update of natural gas prices for power plants, which adjusted approximately 56 power plants. Furthermore, the provisions for the importation of LNG are outlined in Figure 5.4, as follows:

Figure 5.4 – MoEMR Regulation No. 45/2017 (as amended by MoEMR 10/2020) on the Use of Natural Gas for Power Plants 2020



Source: MoEMR Regulation No. 10/2020

According to MoEMR Regulation No. 10/2020, the gas price for the purpose of power generation is as follows:

a. In the case of the utilisation of wellhead gas, if the price is ≤ USD6 per MMBtu (article 13).
b. If pipeline gas at the buyer's plant gate (power plant) is ≤ USD6 per MMBtu (article 8), then PLN or an IPP can purchase.
c. If pipeline gas at the buyer's plant gate (power plant) is > USD6 per MMBtu or natural gas came from LNG or CNG, the Minister determines the gas price at the plant gate based on calculation of adjusted gas purchase price from the contractor with distribution cost consisting of transmission cost and natural gas midstream cost.

Letter B-2506/TL.04/DJL.3/2023 contains the general evaluation results of certain natural gas prices for each agency. The Ministry of Industry submitted evaluation data on the implementation of the certain natural gas price policy through a letter dated 16 August 2023. However, this submission was not accompanied by evaluation results regarding the multiplier effect for each particular natural gas user industry that has received certain natural gas price policy designation. For example, the fertiliser industry's suboptimal realisation of certain natural gas price volumes is due to several factors, including the limited uptake by most buyers caused by maintenance and factory operational constraints.

5.2.3 Current installed gas-fired power plant capacity and government plans

According to the PLN statistics report in 2024, gas power plants contributed 2,798.65 MW, combined cycle power plants contributed 13,187.80 MW and gas engine power plants contributed 2,071.31 MW to the overall capacity.

Generally, PLN prioritises the use of pipeline gas for its gas-fired power plants. This is especially the case for must-run power plants that bear a high electricity load, such as Muara Karang, Priok and Muara Tawar. However, with the aim of enhancing the security of the gas supply, PLN has started to use LNG as well, due to the depletion of the existing gas fields. Additionally, PLN is exploring the use of CNG.

One of the largest planned gas-fired power plants is the Jawa-1 combined-cycle facility (2 × 880 MW) in Cilamaya, West Java. A consortium of Sojitz, Marubeni and Pertamina was awarded the tender and signed a PPA in January 2017, at a price of USD5.5 cents/kWh. Jawa-1 is the first gas-steam combined-cycle power plant in Asia and it integrates a floating storage regasification unit (FSRU) with a combined-cycle power plant[16]. The gas for Jawa-1 is supplied by LNG Tangguh, as PLN has been reported to have agreed on a gas price formula of 11.2% of ICP plus 0.4% for distribution costs[17]. The Jawa-1 combined-cycle project reached financial close in December 2018[18]. In February 2022, Pertamina announced that the company has successfully completed the first-fire ignition process of the Jawa-1 combined cycle process[19].

In January 2025, President Prabowo Subianto inaugurated the Jawa-1 Gas-Fired Power Plant. With a capacity of 1,760 MW, the largest in Southeast Asia, it is equipped with advanced technology that adds operational, financial and environmental value to support energy security, especially in the Java-Bali region.

5.2.4 Opportunities

Indonesia is grappling with a significant decrease in its natural gas reserves, plummeting by over 50% from 100 trillion cubic feet (tcf) in 2019 to below 52 tcf in 2024. To counter this decline, the Government initiated consecutive rounds of upstream petroleum licensing, offering seven exploration and exploitation areas. Most of these areas are situated in mature basins like South Sumatra, East Java and Kutai, indicating investor interest in low-risk exploration and rapid monetisation opportunities. However, to attract investments in upstream gas exploration and production, the Indonesian government is expected to introduce more blocks in frontier basins and deepwater areas. Exploring untapped and promising regions will be crucial for the country to achieve its gas production targets of 12 billion cubic feet per day by 2030.

The Government also plans to increase the growth of FSRUs across Indonesia. This is partly due to the cost of developing FSRUs, which is significantly lower than for land-based terminals of comparable size and also because FSRUs are generally quicker to develop than onshore regasification terminals. Receiving terminals like these also present a private sector investment opportunity, especially for captive power generation for industrial estates in coastal areas.

Since the revocation of MoEMR Regulation No. 3/2015, the pricing of power from gas-fired power plants has become unclear and will presumably be set by competitive bidding in open tenders for the plants mentioned above. However, in 2017 the MoEMR issued two regulations on gas pricing.

The first regulation deals with untapped gas resources at the gas wellhead. According to MoEMR Regulation No. 45/2017 on the Use of Natural Gas for Power Plants as amended by MoEMR Regulation No. 10/2020, the gas supply from wellheads will be benchmarked up to USD6 per MMBtu. There is some private sector interest in this structure. Recently, ENI, which operates a concession in Muara Bakau (this being the Jangkrik Complex project, which is projected to be one of the largest deep water gas fields in Indonesia), announced that it was considering developing Indonesia's first offshore wellhead gas power plant. The location of the gas power plant would be in the Makassar Strait, with a potential capacity of 400-500 MW.

The second regulation deals with the use of flared gas. Flared gas is gas produced through oil and gas exploration, production or processing activities. This gas is typically burned off because it cannot be integrated into the relevant production or processing facilities. There are at least 175 gas flaring chimneys in Indonesia, spread across Java, Kalimantan and Sumatra, producing 170 MMSCFD.

According to MoEMR Regulation No. 30/2021, the price of flared gas is determined by application to the MoEMR and will be approved or rejected by the MoEMR.

5.2.5 Challenges

Based on the 2025-2034 RUPTL, the Government, through PLN, intends to optimise 4.9 GW of gas power plants by replacing them with NRE facilities, mine-mouth coal-fired power plants, and bio-renewable energy sources such as BESS. As a result, the gas power plant capacity, initially 15.2 GW, is expected to decrease to approximately 10.3 GW by the end of the RUPTL period. Accordingly, the share of gas in the electricity generation mix will not be maintained but rather significantly reduced to accelerate the energy transition towards new and renewable energy.

5.3 Coal

5.3.1 Indonesian resources, consumption and production

Indonesia is undergoing significant transformation within its energy sector, characterised by rising domestic energy demand and increasing global pressure to transition toward cleaner energy sources. This shift is largely driven by the Government's commitment to advancing the energy transition. While coal remains a primary energy source underpinning the country's economic growth, it also performs a vital dual role as a major contributor to foreign exchange earnings through exports. According to data from the MoEMR as of October 2024, coal continues to be a critical component of Indonesia's energy portfolio, particularly in meeting domestic electricity requirements[20]. Currently, coal serves as the fuel source for 67% of Indonesia's power plants, reflecting the nation's ongoing reliance on coal despite the global movement toward renewable energy adoption.

Coal continues to be a key fuel source for electricity generation in Indonesia and plays a significant role in the country's economy. According to the Statistics Indonesia (BPS) report, the coal mining and quarrying sector contributed 8.99% to Indonesia's GDP in the first quarter of 2025. This represents a modest decline compared to the previous quarter, which stood at 9.44% in the fourth quarter of 2024. The sector experienced a year-on-year contraction of 1.23% and a quarter-on-quarter decline of 7.42%[21].

The three largest provinces for Indonesian coal resources are South Sumatra, South Kalimantan and East Kalimantan. There are also smaller coal resources found across other parts of Sumatra and Kalimantan, as well as on the islands of Sulawesi and Papua. The Indonesian coal industry is fragmented, with a few large producers and many small players owning coal mines and concessions (mainly in Sumatra and Kalimantan)[22].

Indonesia has witnessed a steady increase in coal production since 2020. According to the MoEMR press release (No. 30.Pers/04/SJI/2024), coal output from January to June 2025 reached 357.6 million tonnes, representing 48.34% of the annual target of 739.7 million tonnes for 2025[23]. Of this total production, 104.6 million tonnes were designated for domestic consumption under the Domestic Market Obligation (DMO). The DMO plays a crucial role in ensuring supply for domestic CFPPs[24].

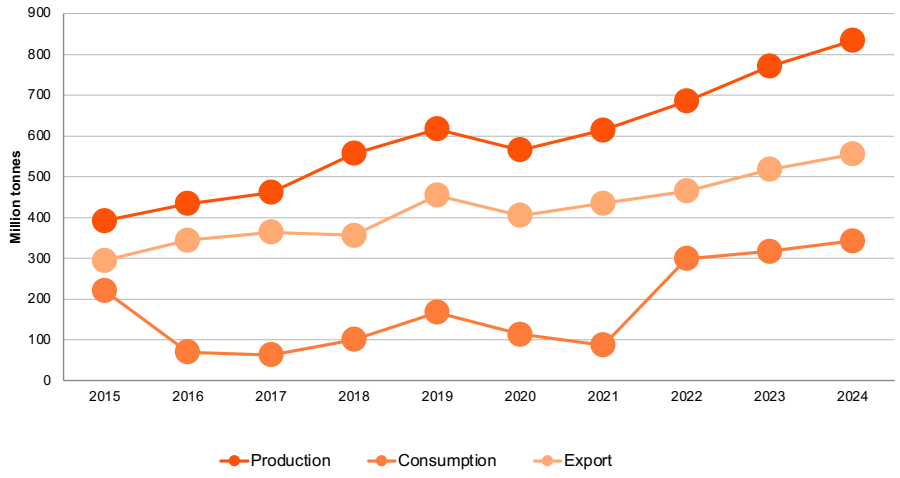
Table 5.1 - Coal resources and reserves by province - in million tonnes

Commodity		Resources				Reserves		
		Inferred	Indicated	Measured	Total	Probable	Proved	Total
Coal	Low calories	17,862.37	23,534.43	25,936.27	67,333.07	11,144.25	12,914.67	24,058.91
	Medium calories	3,338.69	4,215.56	7,972.05	15,526.30	1,638.34	2,901.97	4,540.31
	High calories	4,751.84	4,482.45	5,867.10	15,101.39	1,636.28	1,719.99	3,356.28
Total		**25,952.90**	**32,232.44**	**39,775.43**	**97,960.76**	**14,418.87**	**17,536.63**	**31,955.50**

Source: MoEMR "Buku Neraca" 2025

Indonesia is one of the world's largest coal producers. In 2024, Indonesia exported approximately 555 million tonnes of coal. Historically, the primary export destinations have been China, India, South Korea, Japan and Taiwan. Demand for coal, both for export and domestic consumption, is expected to be relatively stable compared to 2024. Demand is driven by several factors, including from the electricity sector and domestic smelters. Coal production in 2024 achieved a new record of 834 million tonnes, surpassing the 2023 figure of 775 million tonnes.

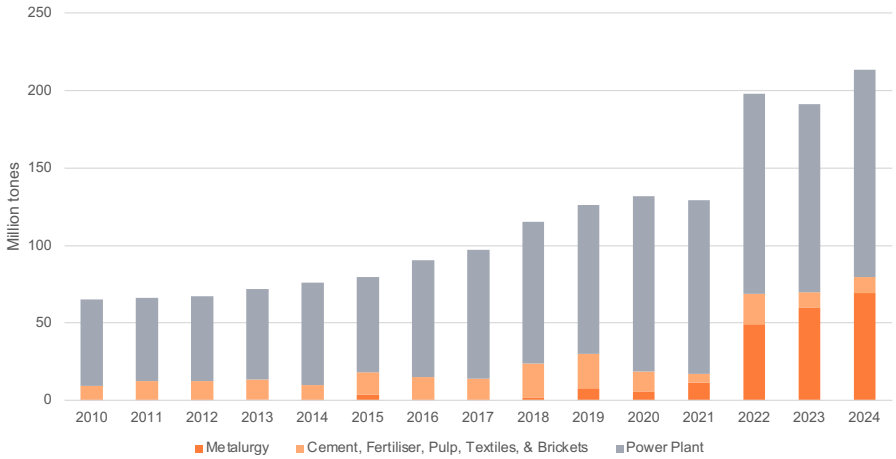
Figure 5.5 – Indonesian coal production and consumption for 2015-2024



Source: MODI application by MoEMR 2025

According to the HEESI report published in 2025, Indonesia's domestic coal consumption has continued to increase from 316 million tonnes in 2023 to 342 million tonnes in 2024. On the demand side, consumption increased by 4.53%, reaching 1,276 million barrels of oil equivalent (BOE), the highest recorded over the past decade.

Figure 5.6 – Domestic coal consumption consumer breakdown 2010-2024



Source: HEESI 2025

5.3.2 Prices and regulations

The maximum benchmark price for CFPP ranges from USD5.54 cents/kWh to USD6.74 cents/kWh, as stated by the MoEMR Decree No. 169.K/HK.02/MEM.M/2021. This applies to regions where the regional BPP ≤ national BPP, such as in Java, Bali, the Southern part of Sumatra and West Sumatra. The maximum benchmark price follows the national BPP (USD6.74 cents) in the case of coal-fired plants with a capacity higher than 100 MW if they are installed in any region where the regional BPP > national BPP. Additionally and specifically for CFPPs with capacity ≤ 100 MW, the tariff is now based on business-to-business negotiation between PLN and IPPs or an auction.

Figure 5.7a - Tariffs for coal-fired and CMM power plants (maximum benchmark tariff 100%)

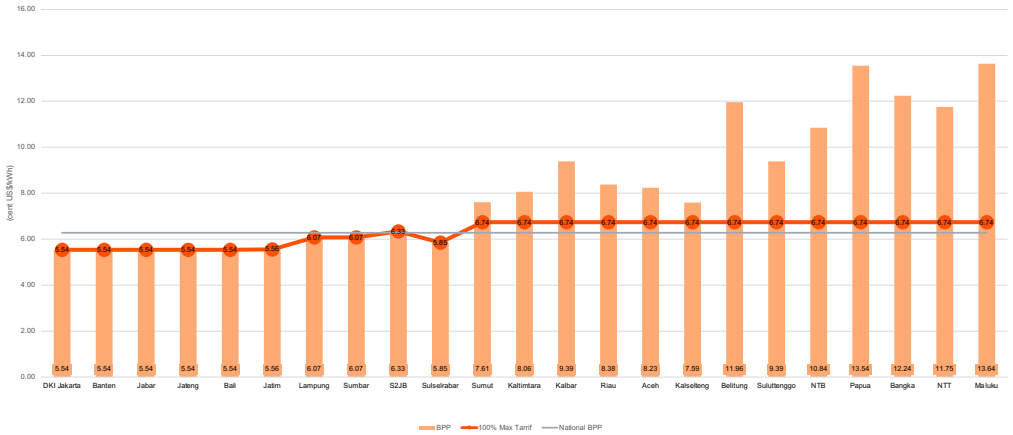
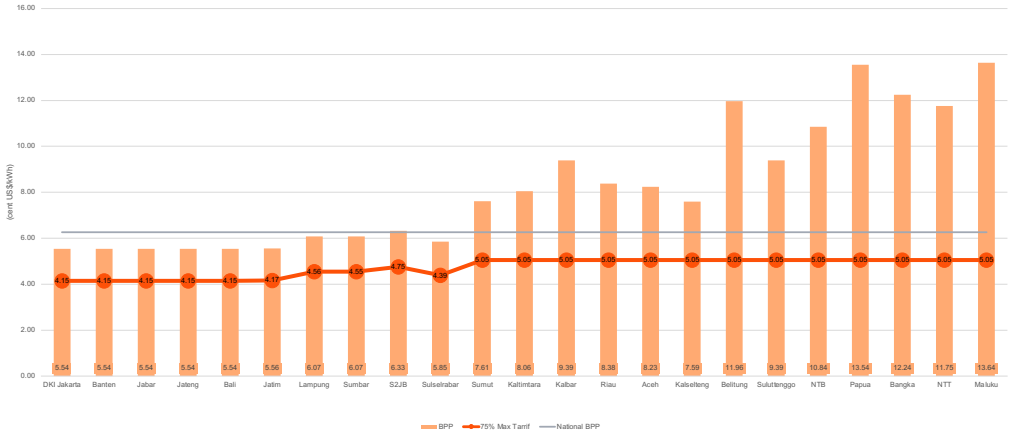


Figure 5.7b - Tariffs for coal-fired and CMM power plants (maximum benchmark tariff 75%)

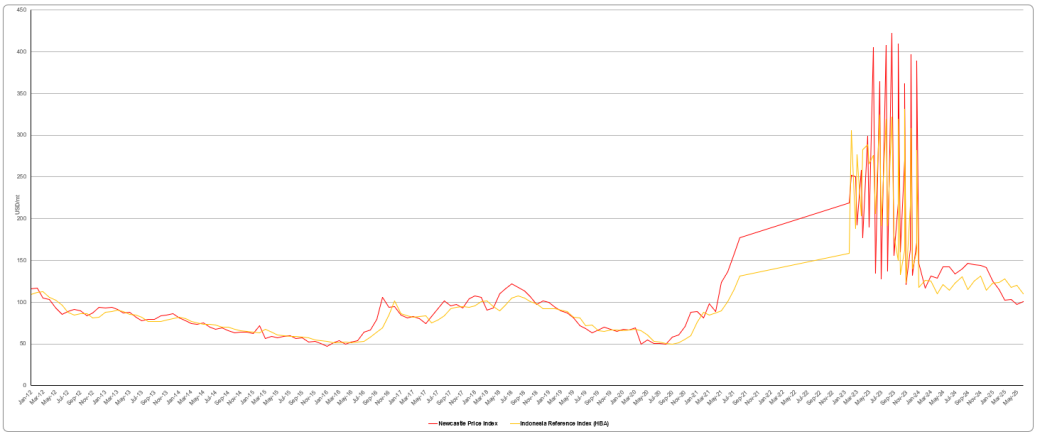


*Calculated using the average middle exchange rate of Bank Indonesia for the year 2025: IDR16,399/USD.
Source: BPP PLN

Additionally, for CMM power plant projects, MoEMR Regulation No. 19/2017 specifies that the maximum benchmark price is set at 75% of the regional BPP if the regional BPP ≤ national BPP, or 75% of the national BPP if the regional BPP > national BPP.

The Indonesian government's HBA for 1 May 2025, increased to USD97.80 per tonne, reflecting a 1.7% rise from April's price of USD96.09. This upward movement, influenced by growing demand for coal in Europe and a depreciation of the rupiah, has generated a mixture of optimism and caution among investors. Although the HBA formula, which is weighted 70% to Newcastle coal prices and 30% to the European Net As-received, provides partial alignment with the global market, its application continues to face significant challenges.

Figure 5.8 - Indonesian coal reference price for the periods January 2012 – May 2025



Source: MoEMR, Bloomberg

The benchmark price for coal sales, specifically steam (thermal) coal, is regulated by MoEMR Regulation No. 7/2017 (as amended by MoEMR Regulations No. 44/2017 Nos. 19/2018 and 11/2020), which revoked MoEMR Regulation No. 17/2010. The regulation states that the sale of coal should be aligned with the benchmark price issued by the Government, which is commonly referred to as the coal benchmark price (HPB). This excludes coal for domestic consumption, where the price is determined by the Minister of Energy and Mineral Resources through MoEMR Regulation No. 19/2018. The HPB is based on a number of factors, including the HBA and the coal's quality characteristics (i.e. calorific value, moisture content, sulphur content and ash content). The HBA is calculated according to the average coal prices set by the local and international market indexes, including the Indonesia Coal Index/Argus Coalindo, Newcastle Export Index, Globalcoal Newcastle Index, Platts Index, Energy Publishing Coking Coal Index and/or IHS Markit Index. The HBA is determined by the MoEMR each month.

The HPB is used as the basis for most IPP contracts. The HPB is also applicable to spot sales and long-term sales. For long-term sales, there are several requirements for mining companies to consider when determining the coal price. In cases where the sale of coal is implemented within a certain period, the HBA used for stipulating the price of coal in a sales contract is based on the formula of 50% of the HBA in the month of contract signing plus 30% of the HBA one month prior to the contract's signing, plus 20% of the HBA two months prior to contract signing. For sales to domestic end users, the HBA used in the contract can be reviewed every three months, at the earliest. While the regulation refers to HBA, the actual reference used in the contract should probably be HPB.

For CMM plants, the approved coal base price is not linked to the HPB, but can instead be escalated using a weighted average of the IDR exchange rate, fuel price, the Consumer Price Index and the regional minimum wage. This is only after the COD of the power plant. The weights are determined on a case-by-case basis. As such, the inflationary risks of the approved coal base price and the COD of the power plant are borne by the coal supplier[25].

5.3.3 Currently installed CFPP capacity and government plans

Based on 2024 MoEMR data, coal remains the primary source of energy in Indonesia, especially for meeting domestic electricity demand. Currently, 67% of power plants in Indonesia still use coal as fuel. There are seven CFPPs operating with supercritical and ultra-supercritical technology, totaling 5,455 MW in capacity, Cirebon (660 MW), Paiton 3 (815 MW), Cilacap 3 (660 MW), Adipala (660 MW), Banten/LBE 1 (660 MW), Jawa 7 Unit 1 (1,000 MW) and Jawa 8 (1,000 MW). Additionally, the Government plans to develop CFPPs using ultra-supercritical boiler technology at nine sites on Java Island, with a combined capacity of 10,130 MW by 2028. This will represent 37.43% of the total planned CFPP capacity[26]. In this context, PLN is targeting an additional power generation capacity of 69.5 GW over the next ten years, with approximately 76% of this capacity expected to come from NRE sources and energy storage technologies. According to the 2025-2034 RUPTL, the objective for the first five years is to construct 27.9 GW of power plants, including 9.2 GW from gas, 12.2 GW from NRE, 3.0 GW from storage systems, and 3.5 GW from CFPPs approaching completion[27].

As discussed in *Section 4.7.1 - IPP opportunities and challenges,* despite coal being likely to continue to play a vital role in the development of power generation in Indonesia over the next ten years, the Government is currently trying to reduce the dependency on coal power plants by the issuance of a "greener RUPTL" and also with the early coal power plant retirement plan. Based on the 2025-2034 RUPTL, the Government plans to resume the construction of CFPPs between 2029 and 2033. No additional CFPP projects are scheduled for the period from 2026 to 2028. By 2033, the total planned additional CFPP capacity is expected to reach 6.3 GW.

5.3.4 Opportunities

Coal production in Indonesia is primarily concentrated on the islands of Kalimantan and Sumatra. According to the 2025–2034 RUPTL, there are plans to develop several mine-mouth CFPPs in these regions. The construction of CFPPs in Sumatra and Kalimantan follows a resource-based approach, placing power plants closer to energy sources such as South Sumatra, South Kalimantan, Central Kalimantan and East Kalimantan, which boast significant coal reserves. This strategy aims to develop mine-mouth CFPPs that are expected to lower the costs associated with power plant operations. With the NZE programme targeting 2060, the development of mine-mouth CFPPs must align with this sustainability initiative.

In contrast, the construction of CFPPs outside Sumatra and Kalimantan adheres to the regional balance principle, where power plants are situated nearer to the load centres. Due to the lack of sufficient local energy resources to meet electricity generation needs, coal is transported from its sources in Kalimantan or Sumatra, with cost-efficiency being a primary consideration. Consequently, CFPPs constructed outside Sumatra and Kalimantan are non-mine-mouth facilities.

5.3.5 Challenges

Indonesia has large geological reserves of coal. However, the coal transportation infrastructure still contributes significantly to the free on board (FOB) coal prices in many areas. Efficient solutions, such as railways (which have high capital requirements, but generally lower lifetime costs), will need to be accelerated if inland coal is to be accessed in a cost-effective manner.

Compared to the benchmark price stipulated in MoEMR Regulation No. 3/2015, the price for coal-generated power as stated in MoEMR Regulation No. 19/2017 is generally lower. From the Government's standpoint, it is expected that the regional BPPs may be more effective under the new regulation, since this could drive greater competition in terms of electrical power prices. What seemingly drove the MoEMR to implement this regulation was the goal of reducing the cost of electrical power subsidies on the national budget, while also ensuring better accessibility for society as a whole.

The expected outcomes as a result of the revised mechanism are lower electricity supply costs for PLN. However, this may come at a cost in terms of investor interest, particularly if the profitability of the coal-fired and CMM power plants is reduced. A supply issue also threatens the biomass coal co-firing development, as an adequate amount of supply and specific calorific value of biomass are needed to meet the power plant requirements. Also, biomass feedstock price needs to be sufficiently regulated.

Traditional beliefs that CFPPs should operate for many decades are now being questioned due to the pressing need for action on climate change and sustainable development. The justification for the extended lifespan of coal plants was primarily economic, driven by the substantial initial investment required for their construction, which necessitated prolonged operation to ensure profitability.

However, this viewpoint fails to consider the wider environmental, health and social impacts associated with coal power, especially in light of the global climate crisis and public health concerns. When assessing CFPPs, it's essential to account for the "true cost" of coal power, which encompasses the adverse effects on local communities and ecosystems. This approach strengthens the economic argument against CFPP projects, highlighting cleaner alternatives as more justifiable options.

5.4 Oil

Despite several noteworthy discoveries between 2023 and 2024, oil production in Indonesia continued to decline, dropping from 606 MBOPD in 2023 to 580 MBOPD in 2024. This downward trend is primarily attributed to diminishing output from many aging wells and challenges posed by technical factors such as unplanned shutdowns in various oil and gas working areas, posing a significant challenge to efforts aimed at boosting production[28].

In terms of the power sector, oil contributes a relatively insignificant share. Based on the 2025-2034 RUPTL, the use of oil is permitted only for transportation and commercial purposes that cannot be replaced by other energy sources. Meanwhile, biofuels are intended to replace fuel oil, especially for transportation and industry.

PLN generally uses oil to provide electricity in rural or isolated grid areas. However, with regard to captive generation facilities, oil (diesel) is also used by non electrified communities in rural and remote areas, as well as in the industrial sector. For the industrial sector, this has been caused by a surge in demand for electricity greater than capacity growth. As a result, PLN has sometimes been forced to implement blackouts in some provinces. Thus, many industries now operate their own backup diesel generators.

5.5 Carbon regime and emissions

One key regulatory basis for Indonesia's efforts to reduce GHG and meet Indonesia's NDC was introduced in October 2021 with the issuance of PR No. 98 of 2021 (PR 98/2021) concerning the Implementation of Carbon Economic Value for Achieving NDC Targets and Control of GHG Emissions in National Development as recently revised by Presidential Regulation No. 110 of 2025 on The Implementation of Carbon Economic Value Instruments and National Greenhouse Gas Emission Control.

At its core, the implementation of carbon pricing is carried out through mechanisms of:

a. carbon trading
b. results-based payment
c. carbon levy.

PR 110/2025 defined the GHG Emission Upper Limit is the highest amount of GHG emissions permitted and is determined based on the carbon allocation. Carbon allocation is the amount of CO_2e emissions permitted during a certain time period in accordance with national capacity, that is decided based on the periodic data from sectoral GHG emission inventories within certain period, national long-term and medium-term development plans, economic aspects and climate change control.

The Monitoring, Reporting and Verification (MRV) method, which will be applied to carbon trading and result-based payment activities, including those that employ voluntary certification processes, is contained in PR 98/2021. As a result, it is important to better control the voluntary certification-based carbon trading reporting requirement processes.

In terms of carbon tax, the Indonesian government enacted the carbon tax imposition regulation in Law No. 7 of 2021 (the HPP Law) concerning Harmonisation of Tax Regulations. In the kick-off event for the dissemination of the HPP Law conducted by the Minister of Finance on 19 November 2021, it was stated that the carbon tax rate is set higher or equal to

the carbon price in the carbon market with a minimum rate of IDR30.00 per kilogrammes of CO_2e, or IDR30,000/tonnes of carbon dioxide equivalent (tCO_2e). Additionally, the Indonesian government stated that the carbon taxing scheme will be tested initially on the power generation sector, with a focus on CFP facilities as this sector accounts for 38% of Indonesia's overall carbon emissions. However, in October 2022, it was announced that the implementation of the carbon pricing scheme on CFP plants was postponed until 2025.

In December 2022, the MoEMR issued MoEMR Regulation No. 16 of 2022 on the Procedures For The Implementation Of Carbon Economic Value In The Power Plant Sub-Sector. The MoEMR has determined the value of Technical Approval of Emission Limits for Business Entities (*Persetujuan Teknis Batas Atas Emisi Pelaku Usaha* - PTBAE-PU) for 99 units of CFP plants (42 companies) which will become carbon trading participants with a total installed capacity of 33,569 MW. The implementation of carbon economic value (*Nilai Ekonomi Karbon*/ NEK) in the power plant subsector, as stipulated in Article 2 of the regulation, includes:

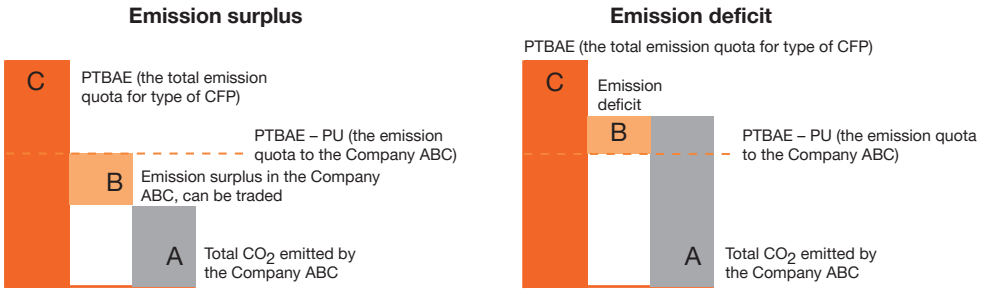
a. determination of the Technical Approval of the Upper Emission Limits (PTBAE) of power plants
b. preparation of GHG emission monitoring plan for power plants
c. stipulation of PTBAE-PUs
d. carbon trading
e. preparation of GHG emission report of power plant
f. evaluation of the implementation of carbon trading and PTBAE-PU auction.

The MoEMR has specified that the implementation of carbon trading in the electricity sector will be carried out in three phases, as outlined below:

a. Phase 1 (2023-2025)
b. Phase 2 (2025-2027)
c. Phase 3 (2027-2030)

The CFP emission trading scheme in Indonesia is illustrated in the diagram below:

Figure 5.9 – Indonesia CFP emission trading scheme



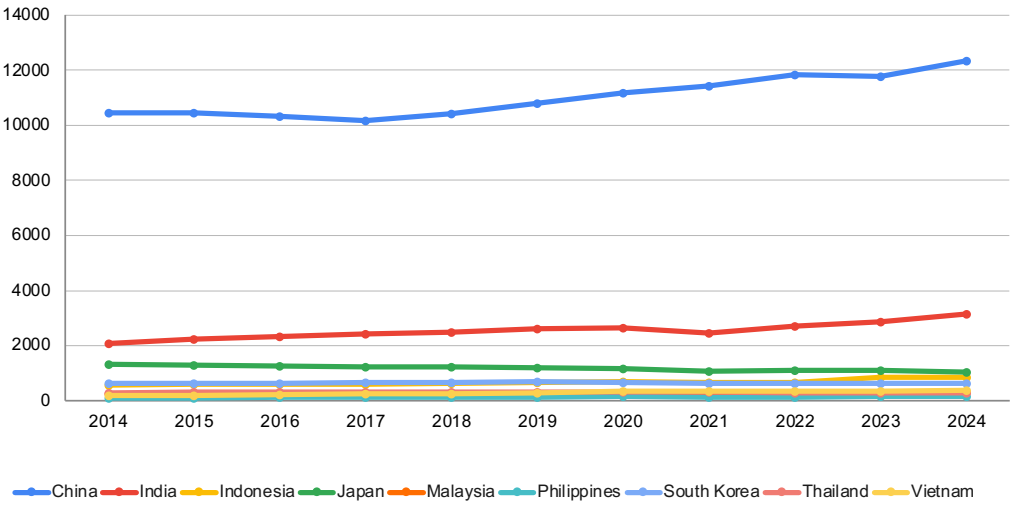
Remarks:
A = PTBAE - PU, the emission quota to the Company ABC
B = Emission surplus/emission deficit
C = PTBAE, the total emission quota for type of CFP

According to the Statistical Review of World Energy 2025, carbon emissions increased by 1% in 2024, surpassing the record level set in the previous year and reaching 40.8 gigatonnes of carbon dioxide ($GtCO_2$). US emissions decreased by 0.7% compared to 2023 levels, which is below its average annual decline rate of 1% over the past ten years. European emissions were nearly 16% lower than they were a decade ago. CO_2 emissions from the combustion of fossil fuels remain the largest source of energy-related greenhouse gas emissions, accounting for 87% of the total[29].

At COP29 in 2024, Indonesia reaffirmed its ambitious climate commitments, emphasising self-reliance and strategic partnerships to combat climate change. The nation outlined its ENDC, targeting a 32% unconditional and 43% conditional reduction in greenhouse gas emissions by 2030. The pathway to net-zero emissions by 2060 includes transitioning from fossil fuels to renewable energy, expanding geothermal and solar power capacity, and constructing 70,000 kilometres of smart transmission lines.

Nonetheless, Indonesian carbon emissions from energy consumption are still considerably higher than those of its fellow ASEAN countries and are equivalent to 2.2% of global emissions. The Energy Institute's Statistical Review of World Energy 2025 notes that Indonesia's carbon emissions in 2024 were the second highest in the ASEAN region, with China ranked first. Aside from Japan and South Korea, the trend in Asian carbon emissions during BAU is generally still increasing, which also implies an increasing challenge in achieving the targets set at the Paris conference[30].

Figure 5.10 – Carbon emission - neighbouring countries



Source: The Energy Institute, Statistical Review of World Energy 2025

6 Renewable energy

6.1 Overview of Indonesia's renewable energy development

Indonesia is on an ambitious path to significantly reduce its GHG emissions, aiming for a 31.89% reduction below BAU levels by 2030, with a more ambitious target of a 43.2% reduction contingent on international support (Government of Indonesia, 2022). Central to this strategy is the accelerated development of renewable energy resources, energy conservation measures and the adoption of clean technologies to achieve NZE by 2060 or sooner[1]. Despite its abundant renewable energy resources, Indonesia currently utilises only a small fraction—specifically, 0.3%—of its total renewables potential. The existing renewable energy mix primarily consists of hydro, bioenergy and geothermal energy. However, the country has a remarkable potential for solar energy, estimated at 3,295 GW[2], highlighting significant opportunities for growth and investment in the renewable energy sector.

In 2021, investments in Indonesia's renewable energy sector reached USD1.49 billion (approximately IDR23.99 trillion), accounting for 1.4% of the total investment of USD106.43 billion (IDR1,714 trillion). A substantial portion of this investment, USD609 million, was directed towards accelerating geothermal and PLTS projects[3]. The portion of renewable energy investment is still at a nascent stage and requires more government attention to attract more investments in this sector. For instance, the procurement of PLN's new business plan and the improvement in regulatory frameworks, e.g. MoEMR Regulation No. 11 of 2024 on the Ease of Domestic Products and Services Requirement in the Development of Electricity Infrastructure, potentially increase the attractiveness of investment in renewable energy.

The present utilisation of RE sources for power generation in Indonesia can be broken down into three classes:

a. Established RE sources: RE sources already widely used in commercial operations (e.g. geothermal, hydro and biomass).

b. Accelerating RE sources: RE sources being developed commercially, but with some residual concerns regarding regulatory and commercial aspects (e.g. solar and wind).

c. Emerging RE sources: RE sources at the research stage only (e.g. ocean energy).

As described in detail in Chapter 2, Indonesia outlines its long-term planning for RE expansion from the RPJPN, NEP and RUKN. The RE in the energy mix is targeted to be 20% by 2025, increasing to 70% by 2045 in an optimistic scenario and reaching NZE by 2060 with RE mix target at 70-72% by 2060[4]. By 2060, the RUKN projects around 135 GW of VRE plants (such as wind and solar energy) with around 34 GW of storage and about 190 GW of dispatchable (non-VRE) power plants e.g. geothermal, dam-based hydropower and biomass. Indonesia net zero would be supported mostly by solar power, hydropower and wind power. In the medium term, the RPJMN for 2025-2029 sets a target for the portion of renewable energy in the primary energy mix to be 23% by 2029[5].

As of 2024, the share of new renewable energy mix reached 14.7%, compared to the 19.5% target set for 2024 as part of the trajectory toward the 23% target by 2025 under the 2014 NEP[6]. This shows the urgent need for Indonesia to catch up and commit to hard-lined targets in order to reach NZE by 2060. In 2019-2024, the additional installed capacity for renewable energy power plants was 4,046 MW, with the cumulative installed capacity breakdown as seen below:

Table 6.1 – New and renewable energy power plants cumulative installed capacity (MW)

NRE power plant	Cumulative installed capacity (MW)						
	2019	2020	2021	2022	2023	2024	Target 2024
Wind	152	152	152	152	152	152	152
Solar	143	171	208	292	600	912	651
Bio energy	2,113	2,252	2,316	3,123	3,393	3,669	3,428
Geothermal	2,434	2,434	2,533	2,539	2,598	2,639	2,646
Hydro	5,540	5,605	6,373	6,465	6,570	7,056	6,762
Total	10,382	10,614	11,581	12.571	13,313	14,428	13,640

Source: MoEMR Performance Achievement 2024

6.2 Tariff for renewable energy

PR No. 112 of 2022 on the Acceleration of Renewable Energy Development for Electricity Generation (PR 112/2022) was released by the Government following a protracted discussion process and numerous changes to the proposed drafts that were being circulated in the market. The regulation addresses two major issues that have long been cited as the primary roadblocks to Indonesia's growth of renewable energy, namely:

a. procurement mechanism for renewable energy power plant projects
b. electricity purchase prices for renewable energy power plant projects.

Regarding the cost of purchasing electricity, earlier regulations stated that the maximum price for renewable energy purchases would be determined by PLN's BPP. A Feed-in Tariff (FiT)approach was suggested in a previous draft that was being disseminated in the market as the purchase price mechanism; however, under PR 112/2022, the purchase price employs a set USD-based ceiling price by taking the location of the projects into account[7]. Moreover, PR 112/2022 also mandates that CFPPs must commit to reducing at least 35% of their GHG emissions within ten years of operation. The implementation of a single ceiling-price mechanism, which is distinct from the tariff often applied to large-scale existing renewable PPAs, coupled with the mandate for CFPPs to reduce their emissions within a predetermined time frame, might have a substantial impact on PLN's present procurement procedure and PPA tariff determination.

Under PR 112/2022, procurement of renewable projects for all capacities are generally conducted through a direct selection, except for:

- hydropower plants that utilise hydropower from reservoirs/dams or irrigation channels (which must be coordinated with the ministry that carries out government affairs in the field of water resources)
- PLTPs
- expansion projects for geothermal, hydro, PV solar, wind, biomass or PLTBg
- excess power from geothermal, hydro, biomass or PLTBg, where the procurement may be conducted through a direct appointment process.

PR 112/2022 specifies that the price for renewable energy electricity purchase will be based on a ceiling price, which will apply to all types of renewable projects regardless of capacity (including solar and wind projects with battery storage systems, expansion projects and excess power) or an agreement, which will only apply to hydro peaker projects. This is in contrast to MoEMR Reg. 4/2020, which mandated that the price for renewable energy electricity purchase must refer to PLN's BPP.

Except for PLTPs, where escalation is permitted, PR 112/2022 states that the ceiling price is a set price without escalation and that it will be regarded as the base tariff prior to escalation. Additionally, it will vary based on the location factor (F), which ranges from 1.00 to 1.50. For the first stage period (years one through ten), locations outside of Java, Madura and Bali will have location factors above 1.00, while the location factor is not taken into account when determining the ceiling price. Additionally, excess electricity for some power plants—such as hydro, biogas and biomass—does not take location factor into account. The electricity purchase prices for all power generation types can be found in Appendix 1.

Recently, the MoEMR announced plans to introduce a new tariff regime that includes hybrid renewable energy systems to accelerate the deployment of various renewable technologies[8]. This updated tariff structure is also aligned with the new RUPTL for 2025-2034, which considers combinations of variable renewable energy sources with storage solutions and fossil-based power plants. The RUPTL outlines several hybrid configurations such as solar PV/wind paired with BESS, solar PV combined with biomass and solar PV integrated with diesel or coal power plants[9].

6.3 Established renewable energy sources

Established renewable energy resources already widely used in commercial operations include geothermal, hydro and biomass. These sources have gained a foothold in Indonesia's energy landscape, contributing significantly to the country's energy mix, partly due to their ease of adoption and the maturity of the technologies involved, which have already been extensively developed and deployed.

6.3.1 Geothermal energy

Indonesia is a country with largest geothermal potential with about 40% of the global reserves, or 24 GW. In Indonesia, geothermal dominates the market for dispatchable renewable technology, with an estimated market potential at around USD21 billion over 2020-2025 and thus has attracted foreign investors to develop some of the world's largest geothermal projects, including the 330 MW Sarulla project in South Sumatra, or the 227 MW Wayang Windu project in West Java[10]. As of 2024, the installed capacity for geothermal energy has reached 2,638 MW, increasing from 2,597 MW in 2023[11]. This is around 11% of the total potential of geothermal energy in Indonesia. Up until 2024, the government has identified 362 potential geothermal locations with a total capacity of 23.6 GW, with 62 geothermal Working Areas (WKPs) and 12 Preliminary Geothermal Survey and Exploration Assignments (PSPEs) that are currently still active, showing commitment and strategic foundations to push further development of geothermal energy in Indonesia[12].

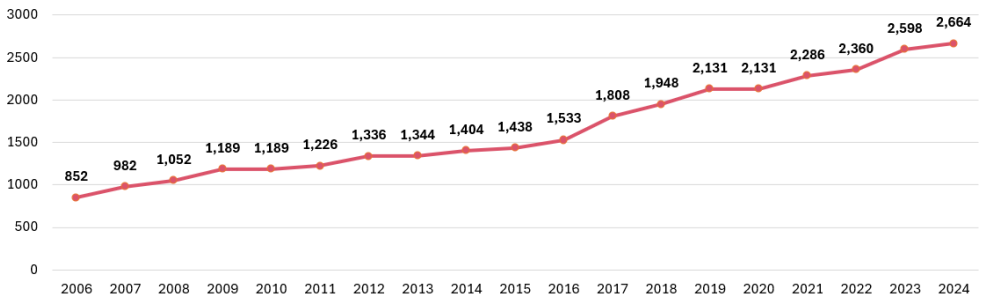
Table 6.2 – Resources, reserves and installed capacity of Indonesian geothermal as of December 2024 (MW)

No	Island	Potential energy					Total
		Resources			Reserves		
		Speculative	Hypothetical	Possible	Probable	Proven	
1	East Nusa Tenggara	213	134	644	138	34	1,163
2	West Kalimantan	65	0	0	0	0	65
3	South Kalimantan	49	1	0	0	0	50
4	East Kalimantan	32	0	0	0	0	32
5	North Kalimantan	20	17	6	0	0	43
6	North Sulawesi	84	51	619	108	150	1,012
7	Central Sulawesi	391	70	227	0	0	688
8	South Sulawesi	259	112	154	0	0	525
9	Southeast Sulawesi	200	36	78	0	0	314
10	Gorontalo	129	11	20	0	0	160
11	West Sulawesi	296	53	32	0	0	381
12	Maluku	325	73	128	36	2	564
13	North Maluku	190	7	379	0	0	576
14	West Papua	25	0	0	0	0	25
15	Southwest Papua	50	0	0	0	0	50
	Total	**5,694**	**3,451**	**9,662**	**1,567**	**3,368**	**23,741**

Source: HEESI 2025

The geographical location of geothermal resources across Indonesia means that this power source is well-placed to assist with improving domestic energy security, as can be seen by the working area locations of PLTPs across Indonesia (see Appendix 2). However, the development of Indonesia's geothermal sector has been slow. The growth of installed capacity for geothermal energy in Indonesia is presented in Figure 6.1.

Figure 6.1 – Installed capacity of geothermal energy in Indonesia (megawatt electrical/ MWe*)



Source: DGNREEC HEESI Report 2024, 2025-2034 RUPTL
(*Note: MWe refers to capacity for the electricity generated from geothermal energy, excluding heating)

In September 2024, the public auction mechanism has resulted in five companies being awarded seven WKPs and Preliminary Survey and Exploration Areas (WPSPEs) with a total geothermal energy capacity of as much as 320 MW, creating 1,401 jobs and up to USD1.82 billion in investment[13]. In detail, the seven awarded geothermal working and exploration areas are: WKP Cisolok-Cisukarame, awarded to PT Daya Anugerah Sejati Utama; WKP Nage, also awarded to PT Daya Anugerah Sejati Utama; WKP Hu'u Daha, awarded to PT Sumbawa Timur Mining; WPSPE Koto Sani, awarded to PT EDC Indonesia; WPSPE Bora Pulu, also awarded to PT EDC Indonesia; WPSPE Samosir, awarded to PT Medco Power Indonesia and WKP Toka Tidung, awarded to PT Ormat Geothermal Indonesia.

In June 2025, PGE successfully conducted the initial synchronisation of the Lumut Balai Unit 2 PLTP in South Sumatra, which will add 55 MW to the national grid and is projected to generate 481 GWh annually[14]. The project is part of PGE's broader goal to reach 1 GW of geothermal capacity by 2027 and 1.7 GW by 2034, backed by a capital expenditure of USD550 million. Moreover, the ADB has approved a USD300 million loan to support Indonesia's geothermal expansion, targeting up to 600 MW of new capacity[15]. Indonesia also secured USD499 million in funding from the Asia Zero Emission Community (AZEC) to accelerate geothermal development[16]. In addition, the MoEMR is drafting a regulation to promote the direct use of geothermal energy, aiming to expand its application beyond electricity generation to sectors such as agriculture, tourism and industrial heating[17].

A business entity that is assigned to conduct a PSPE will have the right to obtain fiscal facilities and have an obligation to make an exploration commitment of USD5 million or USD10 million (depending on the planned capacity to be developed). It is expected that a Preliminary Geothermal Survey Assignment (PSP) or PSPE will be able to convert open areas into working areas that can be developed. A business entity assigned a PSPE will have first rank when entering the tender process for the assigned working area[18].

In the 2011 state budget, the Government created the Geothermal Fund, allocating IDR3 trillion (USD250 million) by 2013 to make geothermal projects financially viable. The fund's aim was to make geothermal projects financially viable, by providing high-quality information to investors about greenfield geothermal sites, as verified by reputable international institutions, during the tendering process for new work areas. Pursuant to the revised 2015 state budget, responsibility for the management of the fund was transferred to PT SMI (see Chapters 1 and 3 for details of PT SMI) from the Government Investment Centre (Pusat Investasi Pemerintah/PIP). Following the transfer, the MoF issued policy directives stating that the so-called Geothermal Support Fund (GSF) should now be able to finance both the exploration and exploitation phases of geothermal projects. The MoF has also stipulated that PT SMI should leverage funds sourced from the private sector or international multilateral agencies[19].

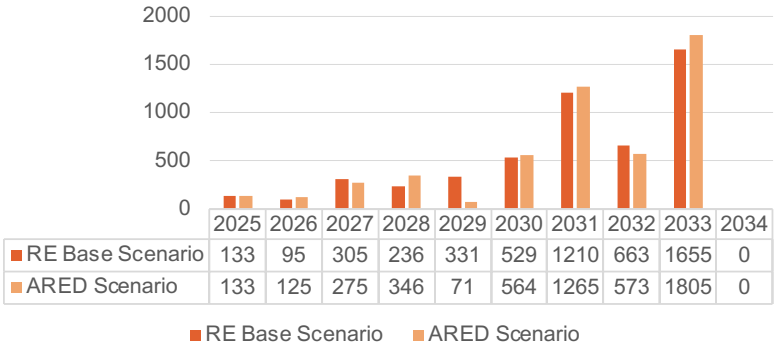
To expedite fund implementation, the MoF issued MoF Regulation No. 62/2017, enabling PT SMI to provide funding for geothermal infrastructure through lending, equity participation and exploration data supply. The provision of funds is expected to significantly reduce the risks for developers, thereby attracting greater participation from developers and banks in the financing and development of geothermal projects. PT SMI will use a revolving fund scheme and conduct exploration drilling via a third party. Auction winners must reimburse exploration costs to fund further drilling.

In 2018, the World Bank (WB) assisted the Government of Indonesia in establishing a geothermal resource risk mitigation (GREM) facility to support exploration drilling by state-owned and private sector developers. PT SMI through the facility will provide geothermal developers with a debt package for exploration drilling, with the possibility of another package for delineation drilling. The availability of a de-risking facility or a risk sharing scheme at which in the event of an exploration failure is offered in a GREM facility, so the developer does not fully bear the risks and costs of exploration. The GREM facility is intended for SOE developers/subsidiaries of SOEs (GREM Public Window) and private developers (GREM Private Window) up to USD30 million for exploration drilling stage[20]. The GSF was disbursed for the first time when six WKPs were assigned to PLN in September 2017, three in East Nusa Tenggara and the rest in West Java, Central Sulawesi and North Maluku[21].

In 2023, the Geothermal Exploration and Energy Development Agreement (GEEDA) was introduced as a shared investment scheme with PLN. This is open for nine WKPs, or working areas, which PLN is developing and offering to investors. The scheme invites collaboration with investors throughout the supply chain, from exploration all the way to electrical production, rather than PLN acting solely as offtakers[22].

Figure 6.2 presents the planned installation capacities for geothermal energy according to PLN's 2025-2034 RUPTL. While the capacity additions for the RE Base case versus the ARED case are slightly different each year, the total geothermal capacity addition from 2025-2034 for both cases is 5,157 MW.

Figure 6.2 – 2025-2034 RUPTL geothermal power capacity buildout (MW)



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
RE Base Scenario	133	95	305	236	331	529	1210	663	1655	0
ARED Scenario	133	125	275	346	71	564	1265	573	1805	0

Source: PwC analysis from PLN's 2025-2034 RUPTL

There are several challenges that accompany geothermal investments in Indonesia. Per GR No. 7/2017 and MoEMR Regulation No. 50/2017 (as amended by MoEMR Regulation No. 53/2018 and 4/2020), the determination and agreement (with PLN) of tariffs for geothermal projects can only be conducted for projects with "proven reserves" following exploration. This obviously raises the risks accompanying geothermal investments, especially since geothermal projects have long lead times. This regulation will lead investors to incur capital expenditure, without knowing whether PLN is committed to purchasing the electricity or knowing the accompanying tariffs. It is likely that investors will be able to negotiate a Head of Agreement (HoA) with PLN, as a preliminary substitute for a PPA, prior to the exploration process. However, an HoA is not a binding contract, meaning that it may not effectively mitigate the risk profile for geothermal development, especially for greenfield projects.

Another challenge is that developers shoulder the exploration risk and therefore also the obligation to fund the exploration phase. While this may be tolerable for larger investors pursuing larger projects, the approach is less likely to lead to the development of smaller fields (below 30 MW), such as those in eastern Indonesia. An alternative approach, used in certain countries, is to assume some of the upfront exploration risk by providing support for this phase of activity through drilling insurance, direct grants, or the use of revolving funds.

Notably, there are also difficulties to arrange geothermal auctions due to issues with location and construction permits. Although investment in this sector has increased each year, these increases have still been lower than those targeted. The DGNREEC notes that the realisation of investment in this sector has been significantly influenced by progress in the geothermal field, as investment in recent years has mostly been dominated by geothermal well drilling and EPC activities.

Other challenges for investors in the geothermal space include the following:

a. Difficulty in obtaining land permits, particularly where the resources are in a forest area.
b. Historical issues with inadequate tariffs, with an imbalance between upstream exploration risks and utility-style economic returns, where the ultimate tariff depends on the level of capacity determined to be commercially feasible after exploration ends.
c. Opposition from local communities.
d. The need to finance significant upfront expenditure (with equity), including preliminary surveys, exploration and test drilling.
e. Poor quality data provided for working areas prior to tender rounds.
f. Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, resulting in difficult access and logistics at some sites and which may require the developer to fund infrastructure (e.g. access roads).
g. Long lead times from exploration to production (generally of seven to eight years).
h. Low electricity demand in geothermal working area.

i. Subsurface uncertainty, including the certainty level of resource and reserve.

j. Poor prequalification standards have allowed unqualified bidders to propose unrealistically low prices, which are impractical.

k. The technical capacity of government tender committees likely needs enhancement.

l. Post-tender negotiations are required for PPAs and their tariff schedules, which govern escalation and indexation.

m. Geothermal resource information often lacks subsurface data, making it difficult for bidders to accurately estimate costs, with incomplete basic geology, geochemistry and geophysics (3G) information.

n. Conflicting objectives of the main government stakeholders such as the MoF, the MoSOE and the MoEMR, which resulted in the difficulty to increase additional geothermal projects[23].

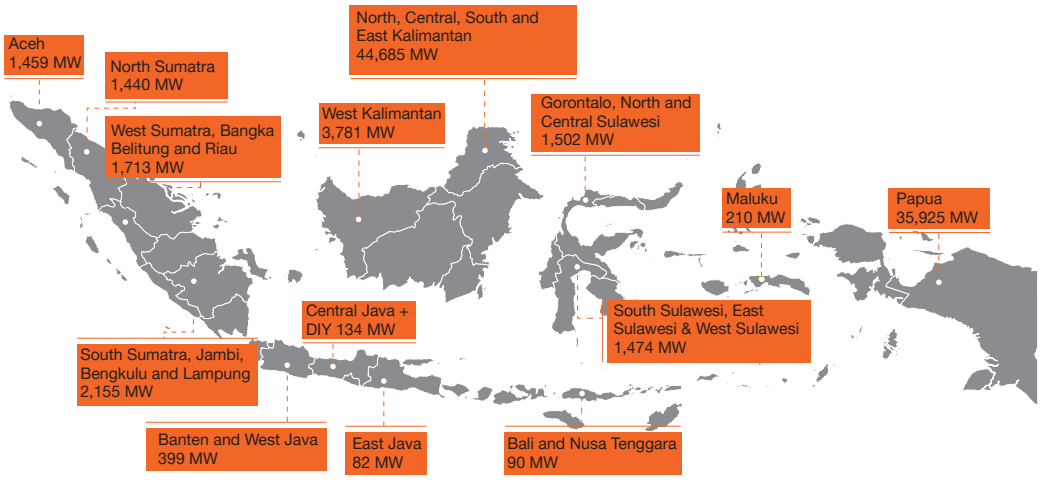
Photo source: PwC

6.3.2 Hydropower

Hydropower can be the natural flow of a river (i.e. “run-of-river” plants) or an artificial flow resulting from a dam/reservoir or an irrigation canal. Hydropower is considered the most mature of the renewable technologies. By the end of 2024, Indonesia had installed 7.07 GW of hydroelectric capacity, making it the most utilised source of renewable energy. However, Indonesia possesses a hydropower potential of approximately 95,049 MW. This includes a run-of-river potential of approximately 94,626 MW, alongside a reservoir or dam potential of roughly 423 MW[24].

Potential hydropower sites are spread across the country, with substantial potential for large-scale projects in the central and eastern parts of Indonesia, such as Kalimantan and Papua (see Figure 6.3). Kalimantan possesses approximately 51% of the country's hydropower potential, whereas Papua accounts for 38% of it.

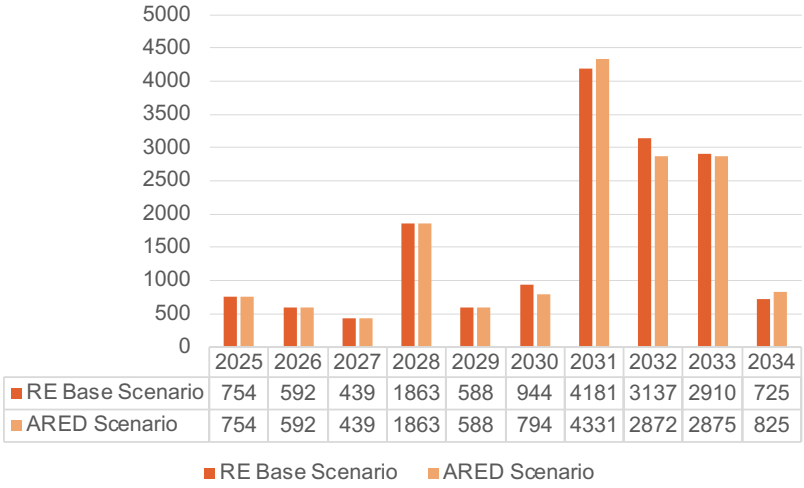
Figure 6.3 – Hydropower potential capacity in selected regions of Indonesia



Source: 2025-2060 RUKN (2024 version), p. 101

Figure 6.4 is the power plant capacity buildout for hydropower energy according to PLN's 2025-2034 RUPTL.

Figure 6.4 – 2025-2034 RUPTL hydroelectric power capacity buildout (MW)



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
RE Base Scenario	754	592	439	1863	588	944	4181	3137	2910	725
ARED Scenario	754	592	439	1863	588	794	4331	2872	2875	825

Source: PwC Analysis from PLN's 2025-2034 RUPTL.

Challenges that hydropower projects face, both large-scale and small-scale hydropower (SHP) projects are as below:

a. Issues faced by unqualified IPPs such as the land to be used is still under lease, the high values of non-performing loans or malfunctioning equipment.

b. Financing difficulties reported by industry associations, due to the "unbankability" of the PPAs and associated commercial issues, especially those related to the BOOT scheme. To help resolve this issue, the MoEMR is reported to be collaborating with OJK to facilitate these PPAs, by means of a green financing programme that requires banking institutions to support the funding of renewable energy[25].

c. Additional prequalification stages for hydro projects. In relation to the amendment of MoEMR Regulation No. 50/2017 by MoEMR Regulation No. 53/2018, PLN was reported to have stated in April 2018 that interested parties must show that they have completed a feasibility study and interested foreign parties must partner with a local developer[26].

Hydropower projects can be divided into two groups: large-scale hydropower and SHP, each with their respective characteristics and challenges.

6.3.2.1 Large-scale hydropower

According to the 2025-2034 RUPTL, PLN is prioritising the development of pumped storage hydroelectric power plants to address the growing energy demands and facilitate integration of renewable energy sources. Key projects include the Cisokan facility with a capacity of 1,040 MW, Matenggeng at 943 MW and Grindulu with 1,000 MW, as well as additional distributed projects in West Java totalling 760 MW and the pumped storage hydroelectric plant in Sumatra with a capacity of 2x250 MW. With other storage facilities (BESS with a capacity of 500 MW), excess power during off-peak conditions can be stored for use during peak load times. These pumped storage systems are vital in decreasing the production cost, particularly during peak load periods. They enhance the load factor and improve the capacity factor of CFPPs, while also providing flexible generation capabilities to counterbalance the intermittency of incoming renewable energy sources. Through the strategic development of pumped storage facilities, PLN is focusing on modernising the energy grid to handle peak loads more effectively. This approach ensures that the power system can adapt to fluctuations in demand and supply, particularly with the increasing penetration of renewable energy sources.

As part of the 35 GW programme and the regular PLN programme, several IPP projects are currently under construction: the Batang Toru (510 MW), Hasang (39 MW), Peusangan 1-2 (86 MW), Semangka (2 x 28 MW) and Malea (2 x 45 MW) IPPs. The Semangka Hydropower Plant commenced commercial operations in 2018. In early 2019, the Bank of China reassessed its funding commitment to the Batang Toru PLTA project, developed by PT North Sumatra Hydro Energy (PT NSHE) and located in South Tapanuli, due to environmental concerns. By the end of 2020, the total capacity of the installed hydropower plants exceeded 6.1 GW. This included the COD of Poso Peaker PLTA with 66 MW capacity in February 2020. Malea PLTA 90 MW which was planned to commence COD in 2020 was delayed to 2021 due to unforeseen physical conditions in the power plant site. In June 2021, it was announced that Malea PLTA has received its operational permit.

Among the projects currently in development is the Kayan Hydropower Plant in North Kalimantan, which is planned to have a total installed capacity of 9,000 MW. Developed by PT Kayan Hydro Energy, the project consists of five cascading dams along the Kayan River and is expected to support the energy needs of the new capital city and industrial zones in Borneo. Despite setbacks, including the withdrawal of key partners such as PowerChina and Sumitomo, the developer remains committed to completing the project independently if necessary[27].

Also in North Kalimantan, the Mentarang Induk Hydroelectric Project (MIHEP) is under development by PT Kayan Hydropower Nusantara. With a planned capacity of 1,375 MW, the project will feature a concrete-faced rockfill dam and is expected to generate around 9 TWh of electricity annually. As of early 2025, the project was 5% complete, with financial closing targeted for Q1 2026 and commercial operation by 2030. The electricity will supply the Kaltara Industrial Park and the project has undergone environmental and social assessments to meet international sustainability standards[28].

There are also two construction projects under PLN's regular programme, Masang 2 PLTA (55 MW) and Jatigede PLTA (2 x 55 MW).

In 2024, the Government of Indonesia, through the Ministry of Finance's PPP scheme, initiated the tender process for the Tiga Dihaji Hydropower Plant in South Sumatra. This 40 MW project is designed to enhance regional electricity supply and promote sustainable energy development. With an estimated investment of IDR1.12 trillion, the project will be implemented under a Design, Build, Finance, Operate, Maintain and Transfer (DBFOMT) model over a 27-year concession period[29].

PLN launched a tender in early 2025 for hydropower projects with a combined capacity of 1 GW across Sumatra (400 MW), Sulawesi (300 MW) and Kalimantan (300 MW). This initiative targets IPPs and reflects PLN's strategic commitment to expanding clean energy infrastructure[30].

Furthermore, PLN completed the construction of the Jatigede Hydropower Plant in Sumedang, West Java. The plant has a total installed capacity of 110 MW (2 × 55 MW) and has successfully passed performance and reliability tests. It received its Certificate of Operational Eligibility (*Sertifikat Laik Operasi*/SLO) ahead of schedule in June 2024 and is now connected to the grid via two 150 kV transmission lines[31].

Complementing these efforts, Kalla Group was named as a national supporting partner at the 2023 World Hydropower Congress, which took place from 31 October 2023 to 2 November 2023 in Bali, Indonesia. Kalla Group announced plans to develop six new hydropower plants with a total planned capacity of 2,060 MW and an investment of IDR30 trillion. Announced in June 2024, these projects include Mamuju Atas PLTA (90 MW), Mamuju Bawah PLTA (360 MW), Poso 3 PLTA (400 MW), Poso 4 PLTA (30 MW), BMS PLTA (225 MW) and Kerinci PLTA (350 MW). The group estimates a potential reduction of 16.7 million tonnes of CO_2 emissions from these plants, which are currently in various stages of planning and awaiting PLN's tender process.

The specific challenges for large-scale hydropower include the following:

a. The need for substantial areas of land, the ownership of which may be unclear or subject to overlapping claims
b. Overlapping permits (for example, where small hydro permits have been issued for a section of a larger watercourse) and lack of data on the historical issuance of water permits by regional/local governments
c. Environmental, resettlement and flora and fauna issues
d. Permits for forest use.

6.3.2.2 SHP

SHP plants have a capacity of less than 10 MW and utilise run-of-river systems. In most cases, SHP plants (especially micro hydropower plants, which have less than 100 kW capacity) are used for off-grid or rural electrification in Indonesia. However, the Government also supports the development of SHPs by regulating the FiTs at a level where SHP plants become attractive renewable energy projects for investors[32]. SHP uses mature technology, as compared to some other small-scale renewables.

In terms of project developments, in June 2021 PT Hutama Karya (Persero) finished the construction of Pamonangan – 2 SHP which is owned by PT Bina Godang Energi in North Sumatra with a total capacity of 2 x 5 MW. Despite the construction phase being during the pandemic, the project reached COD in June 2021[33].

In May 2023, PT Terregra Asia Energy Tbk said that it will prepare funds of up to IDR1 trillion to carry out the construction of 3 SHPs this year. The three SHPs to be built are the Sisira SHP with a capacity of 9.8 MW, the Batang Toru 3 SHP with a capacity of 10 MW[34] and the Batang Toru 4 SHP with a capacity of 10 MW. PT Arkora Hydro Tbk is currently constructing two SHP projects: the 5.4 MW Kukusan II project in Lampung, set to reach COD in the third quarter of 2025, and the 10 MW Tomoni project in East Luwu, expected to reach COD in the third quarter of 2026.

Challenges to investment in SHPs include the following:

a. A limit on foreign investor equity ownership. As outlined in *Section 3.5.2 – The Positive List*, micro power plants (<1 MW) are closed to foreign investment and small power plants (1-10 MW) are open for foreign ownership of up to 49%.
b. The need to invest in transmission lines from the SHP site to the interconnection point, if existing transmission lines are not adequate.
c. The relatively high upfront investment costs, meaning that smaller developers struggle to fulfil their 30% equity requirement – and PPAs for SHPs generally do not include take-or-pay provisions, meaning that the off-take risk is also borne by the investors.
d. Access to finance, with investments of USD2.0 to 2.5 million per MW being required, meaning that the investment size is typically too small for project finance and that it is likely to require substantial collateral from sponsors.
e. The quality of hydrological data.
f. The unclear status of water concessions/permits held by private companies.
g. Long distances from equipment providers.
h. Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, resulting in difficult access and logistics at some sites.

6.3.3 Bioenergy

Bioenergy is one of the renewable energy sources undergoing massive development in Indonesia due to the variety of energy sources and the abundant resources of feed-stock. As of 2024, bioenergy is the second-largest renewable energy source by installed capacity in Indonesia, surpassed only by hydropower[35]. Bioenergy refers to the energy produced from biomass or biogas used to generate electricity and heat, or to produce liquid fuels (e.g. biodiesel or bioethanol) for transport use. Biomass is organic matter derived from recently living plants or animals and includes agricultural products, forestry products, municipal and other waste. Biogas refers to the gases produced from the decomposition of organic matter in the absence of oxygen. For example, biogas can be obtained from animal waste, POME or MSW. Additionally, as Indonesia is the world's second largest palm oil producer, palm plantation waste is another potential source for biomass power generation.

There are essentially two processes for generating bioenergy electricity, biological and thermal. The biological process uses anaerobic digestion technology, where feedstock is decomposed by microorganisms to produce methane (CH_4) gas (biogas) which is combusted for power generation. This process requires feedstock with a high organic content (e.g. POME, vegetables, food or agro-waste). Alternatively, the thermal process mainly uses the technologies of incineration or gasification. Incineration technology requires a high calorific value and low-moisture (dry) content feedstock (e.g. paper, plastics, wood, textiles, etc.), which is commonly shredded or pelletised. The feedstock is combusted to generate heat that flows to a boiler, producing steam which is used to turn the turbine and generate electricity. Meanwhile, gasification feedstock is subject to partial combustion, in the event of a limited supply of oxygen, to produce synthetic natural gas (syngas) that is used to generate electricity.

Based on various estimates, the potential for bioenergy in Indonesia is estimated to be 55.7 GW, with 53.4 GW being the potential for biomass, and 2.3 GW for biogas. If POME is taken into account, the potential for bioenergy at a national level would increase to 57 GW. So far, the region with the highest potential for biomass is Sumatra, which makes up 54% of the national potential[36]. A detailed categorisation of the type of bioenergy and the potential regions can be found in Table 6.3. The Government plans further growth in biogas and biomass plants, albeit driven by the private sector. In 2024, the total installed capacity of biomass is at 3,459.1 MW.

Table 6.3 – Potential bioenergy resources for power generation (in MW)

No.	Type of bioenergy	Sumatra	Kalimantan	Java-Bali-Madura	NTB/NTT	Sulawesi	Maluku	Papua	Total
1	Palm	8,812	3,384	60	-	323	-	75	12,654
2	Cane	399	-	854	-	42	-	-	1,295
3	Rubber	1,918	862	-	-	-	-	-	2,780
4	Coconut	53	10	37	7	38	19	14	178
5	Rice husk	2,255	642	5,353	405	1,111	22	20	9,808
6	Corn	408	30	954	85	251	4	1	1,733
7	Cassava	110	7	120	18	12	2	1	270
8	Wood	1,212	44	14	19	21	4	21	1,335
9	Cow dung	96	16	296	53	65	5	4	535
10	MSW	326	66	1,527	48	74	11	14	2,066
Total		**15,589**	**5,061**	**9,215**	**635**	**1,937**	**67**	**150**	**32,654**

Source: New and Renewable Energy and Energy Conservation Strategic Plan (RENSTRA EBTKE)

Pertamina has indicated that it is working with partners to develop biogas from POME in the Sei Mangkei Special Economic Zone, North Sumatra, which has biogas-to-electricity potential of 1.6 MW, including a tenant as the off-taker. This facility achieved COD in August 2021.

In August 2017, PLN signed four biomass and five biogas PPAs ≤ 10 MW, following 19 MoUs for bioenergy power plants which were signed in March 2017 and a PPA for a 9 MW PLTBg which was signed with PT Mitra Puding Mas in May 2017. A 2.2 MW PLTBg also reached COD in January 2018, with 700 kW being used for self-consumption by PT Inti Indosawit Subur[37]. Another success story is a 700 kW bamboo-based PLTBm that was inaugurated in September 2019 and is expected to replace the PLTD and thus light up approximately 1,200 households in Mentawai, West Sumatra[38]. Later, the Government also claimed success in securing four PPA contracts with total capacity of 10.6 MW of PLTBm and PLTBg in 2018 and 2019[39].

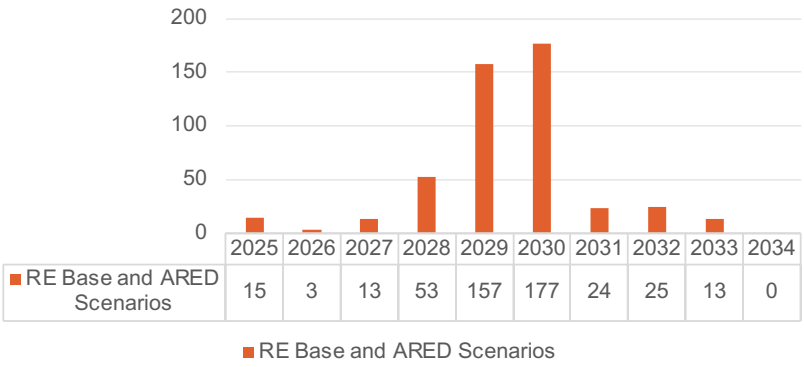
For bio-CNG projects, PT Dharma Satya Nusantara currently has two plants in East Kalimantan, with capacities of 2×600 kW and 6,720 normal cubic metres (Nm^3)/day, as well as 2×850 kW and 12,960 Nm^3/day[40]. The first plant began operating in 2021 and the second in 2023. PT KIS Biofuels Indonesia has operations in Langkat and Labuhanbatu, North Sumatra, focusing on industrial and commercial applications. The first plant is expected to produce 15,500 cubic metres (m^3) of bio-CNG per day by 2024, while the second plant is still under construction, with a planned capacity of 7.23 million m^3 per year, set to be operational by December 2024. The company has plans to establish 25 bio-CNG plants by 2026. PT Sawit Sumbermas Sarana, located in West Kotawaringin, operates a plant with a capacity of 4,800 Nm^3 of bio-CNG per day, which began operations in 2023.

In addition to biomass and biogas powerplants, the Government also intends to increase the proportion of co-firing in coal plants. With abundant sources of biomass, the Government and

PLN have promoted biomass co-firing projects as one of the SOE "green booster" programmes in order to accelerate the national renewable energy growth in the energy mix. Further advantages such as emissions reduction, cost saving and adding competitive alternative fuels for PLN are also expected in the co-firing programme[41]. In August 2024, there were at least 46 co-firing power plants with total biomass usage reaching 1 million tonnes and capable of producing 1.04 TWh of electricity[42].The percentage of biomass that is mixed into coal power plants ranges between 1% to 20%. Due to the Indonesian government targeting the addition of 52 more coal power plants into the co-firing programme and more PLTBm to enter the COD phase, in 2025 the biomass demand is forecast to increase from 2.7 million tonnes per annum (MTPA) to around 9 MTPA[43].

The 2025-2034 RUPTL sets out the following targets for bioenergy capacity:

Figure 6.5 – 2025-2034 RUPTL Bioenergy power capacity buildout (MW)



Source: RENSTRA EBTKE 2020-2024, p. 39

Challenges to investment in bioenergy projects include the following:

a. The lack of continuous, reliable availability of biomass feedstock.
b. The suitability of grid infrastructure or the distance from grid connections.
c. The coordination required between PLN and various authorities (central and regional).
d. Various permit and licensing issues (e.g. land, water, environmental) and a lack of clarity at the regional level regarding the associated fees and processes.
e. The availability of regional EPC contractors with relevant skills and experience.
f. The availability of spare parts and after-sales service.
g. Variability of biomass feedstock availability due to factors such as weather, low season, etc.
h. Inconsistent quality of biomass such (e.g., low calorific value, high moisture content).
i. Risk of insufficient biomass feedstock due to logistical issues, unreliable suppliers, transportation bottlenecks, or competition with other industries.
j. Risk of environmental pollution or contamination due to biomass usage.
k. Technological and operational challenges (e.g., risk of co-firing failure).

6.3.4 Municipal WtE

Noting the increase in waste, limited waste treatment capacity and the stresses on most landfill facility areas, "municipal WtE" is being looked at as a solution for waste management, which remains a significant problem in many cities in Indonesia. Similar to bioenergy, municipal waste is used as a feedstock. In the Indonesian context, however, the application of these technologies is not straightforward. The waste produced in Indonesia is typically mixed and unsorted, with organic and non-organic waste, as well as wet and dry waste, meaning that additional efforts are needed to manage this. Unsorted waste can be fed directly into an incinerator, but the high moisture content reduces the thermal efficiency of the boilers. The potential for using MSW for the production of electricity in selected cities/regencies in Indonesia is set out in Table 6.4.

Table 6.4 – Municipal waste-to-energy potential per province in Indonesia

Province	Total techno-eco potential (MW)	Province	Total techno-eco potential (MW)
Aceh	26.63	DKI Jakarta	82.62
Riau	34.24	D.I. Yogyakarta	19.39
Riau archipelago	11.23	North Maluku	4.19
Bangka Belitung	7.27	Maluku	8.06
West Kalimantan	25.28	South Sulawesi	44.10
Central Kalimantan	13.27	South East Sulawesi	13.34
North Kalimantan	3.48	West Sulawesi	6.21
East Kalimantan	16.13	South Sumatra	42.57
South Kalimantan	21.12	West Java	245.59
Gorontalo	3.50	Central Java	173.10
North Sumatra	73.34	East Java	109.11
West Sumatra	27.45	Bali	21.85
Lampung	42.37	West Nusa Tenggara	25.61
Bengkulu	9.80	East Nusa Tenggara	27.24
Jambi	17.27	West Papua	4.33
Banten	63.60	Papua	16.77

Source: 2025-2034 RUPTL

The potential for municipal WtE across Indonesian provinces according to the RUPTL, as shown in Table 6.4, underscores the opportunity for energy recovery from waste streams. Provinces in Java such as West Java, Central Java, and DKI Jakarta exhibit high potential, reflecting both population density and waste generation volumes. To date, implementation has been limited, with only a few operational facilities such as the Putri Cempo WtE plant in Solo (generating 8 MW electricity) and the Benowo PLTSa in Surabaya (generating 9 MW electricity) serving as early examples. Building on these initial efforts, Indonesia is now accelerating WtE

development through a structured procurement programme led by Danantara, designed to scale up projects nationwide.

In November 2025, Danantara commenced the first tender phase for four cities: Bogor, Bekasi, Denpasar and Yogyakarta[44]. These cities were selected based on their technical and administrative readiness. The first phase of the tender process covers projects in each of the designated regions and involves 24 selected technology providers from a pool of 200 candidates, comprising foreign players collaborating with local consortia that include private sector entities and state-owned enterprises[45]. Tender submissions are scheduled for January 2026, with winners expected to be announced in the first quarter of 2026. Groundbreaking for these projects is targeted for March to April 2026.

Beyond the initial tender programme, Danantara plans to commence construction in seven pilot cities during early 2026. In addition to Bogor, Bekasi, Denpasar and Yogyakarta, the list includes Semarang, Medan and Tangerang Regency. This initiative forms part of a broader national strategy to develop 34 WtE plants by 2029[46]. Table 6.5 offers a snapshot of the scale of planned waste generation across major cities and provinces, highlighting ten of the 33 cities prioritised for WtE development by Danantara. Additional areas include Serang, South Sulawesi, Depok, Pekanbaru, Lampung, Greater Malang, Padang, Samarinda, Balikpapan, Pontianak, Banjarmasin, Jambi, Makassar and South Tangerang. The waste-generation potential of each city is based on data compiled from the Ministry of Environment's National Waste Management System (*Sistem Informasi Pengelolaan Sampah Nasional*/SIPSN) 2024.

The current and previous implementation status of WtE projects prior to Danantara's procurement plan is outlined in Table 6.6, providing visibility into operational facilities, projects under development, and those awaiting financial closure.

Table 6.5 – Waste generation by major cities/provinces

No	City/province	Description	Daily waste (thousand tonnes)	Annual waste (thousand tonnes)
1	Bali	Sixth-largest waste-producing province nationally	3.4	1,254.00
2	Jakarta	Seventh-largest waste-producing province nationally	3.4	1,235.40
3	Bekasi	Second-largest waste-producing city in West Java	1.8 (City), 1.7 (Regency)	645.4 (City), 614.5 (Regency)
4	Tangerang	Largest waste producer in Banten Province	2.2	798.4
5	Medan	Largest waste producer in Sumatera	1.7	632.1
6	Surabaya	Largest waste-producing city in East Java Province	1.8	660.9
7	Bandung	Third-largest waste-producing city in West Java Province	1.3	479

No	City/province	Description	Daily waste (thousand tonnes)	Annual waste (thousand tonnes)
8	Semarang	Largest waste producer in Central Java Province	1.2	434.2
9	Makassar	Largest waste producer in South Sulawesi Province	1.1	388.4
10	Yogyakarta	Produces significant waste despite smaller area	1.9	708.4

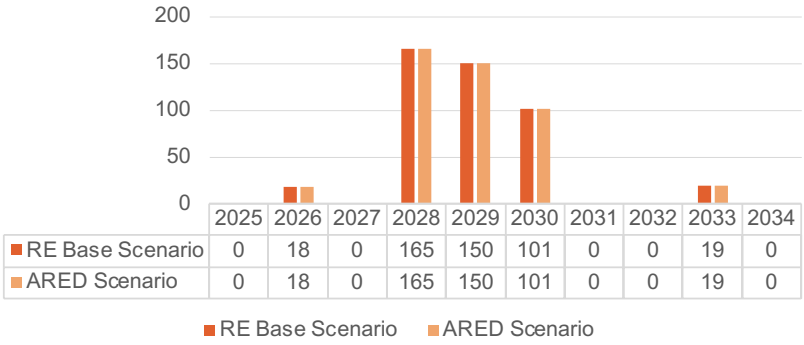
Table 6.6 – Status of WtE projects

City	Status	COD target
Jakarta Intermediate Treatment Facility (ITF) West Service Area	RDF development focus – Off-takers secured (Indocement, SBI)	Information not available
Jakarta ITF East Service Area	Awaiting presidential regulation – Part of four PLTSa plans	Information not available
Jakarta ITF South Service Area	Included in PLTSa plan – Awaiting government support	Information not available
Jakarta (ITF Sunter)	Cancelled due to high tipping fee; shifted to RDF	Cancelled
South Tangerang (Cipeucang)	Under development (construction phase)	2029
Bandung (Sarimukti)	Waste-to-hydrogen project, under development	2027
Bekasi	Tender cancelled, restart needed	Information not available
Semarang (Jatibarang)	PPP preparation phase, incinerator-based WtE	2026
Solo (Putri Cempo)	Operating	Since 2023
Surabaya	Operating	Since 2022
Makassar	Pre-feasibility	2026*
Denpasar	Preparation phase, construction starts 2026	Information not available
Palembang	Under development (construction phase)	2026
Manado	Pre-feasibility study	Information not available
Manado	Pre-feasibility study	2025*

* Based on PwC's analysis
Source: EBTKE on Pertamina Energi Forum November 2019 p.19 & PwC's analysis

The 2025-2034 RUPTL sets out the following targets for WtE capacity:

Figure 6.6 – 2025-2034 RUPTL WtE power capacity buildout (MW)



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
RE Base Scenario	0	18	0	165	150	101	0	0	19	0
ARED Scenario	0	18	0	165	150	101	0	0	19	0

Source: PwC analysis from PLN's 2025-2034 RUPTL

Some of the constraints on and challenges to investment in municipal WtE include the following:

a. Local government fiscal capacity.
b. The difficulty in coordinating the many stakeholders involved in such projects.
c. Land availability.
d. Overlapping regulations between waste and power sector including uncertainty about VAT and other tax issues.
e. Delays in securing the PPA with PLN and off-take arrangements for electricity generated from the processing of MSW.
f. Concerns from regional governments over the management of and responsibility for the implementation of WtE plants, due to a lack of experience at the regional government level regarding WtE, as well as a lack of knowledge of power purchase mechanisms.
g. Negative sentiment from the local community over public health and safety issues.
h. Socio-economic concerns over the livelihoods of waste pickers/scavengers.
i. Concerns of financiers over the use of new or unproven technologies.
j. The security or enforceability of contracts signed with sub-national governments.

6.4 Accelerating renewable energy sources

Following the "Established renewable energy sources" section, this second section, "Accelerating renewable energy sources", will focus on solar and wind energy, as well as the different battery storage technologies, which are being actively developed and deployed despite ongoing regulatory and commercial challenges. This section will delve into the current status, advantages and hurdles faced in scaling up these technologies to meet Indonesia's growing energy demands.

Indonesia is actively exploring the potential of solar and wind energy to meet its energy needs. Despite existing technologies that could facilitate large-scale adoption, challenges remain in industry readiness and infrastructure development. This section will hence discuss the status and the outlook of the accelerating renewable energy technologies in Indonesia.

6.4.1 Solar PV

One of the fastest-growing renewable energy sources being adopted in Indonesia today is solar PV, considering Indonesia's potential and the proven technologies involved. Solar PV systems include utility-scale solar PV, industrial PV large-scale grid connected, rooftop PV grid connected and floating PV large-scale grid connected. Measuring solar potential involves considering the potential land area and radiation intensity filtering, which estimates Indonesia's solar potential to reach 3,315 GW[47].

Power generation through the conversion of solar energy into electricity is carried out using PV technology or thermal technology, as is the case with concentrated solar power. In PV technology, the light energy portion of incoming solar radiation is converted to electricity by solar PV panels. In thermal technology, the heat energy portion of solar radiation is concentrated and used to generate steam, which drives a turbine to generate electricity.

The level of insolation varies across the Indonesian archipelago (see Table 6.7) but the country is regarded as having good potential by international standards and solar energy as representing a viable source of power for remote areas or island locations that are off-grid.

Table 6.7 – Solar energy potential in Indonesia

No.	Regency/city location	Province	Geographic position	Average irradiation (kWh/m²/day)
1	Banda Aceh	Nanggroe Aceh Darussalam	4°15'N;96 °52'E	4.10
2	Palembang	South Sumatra	3°10'S;104°42'E	4.95
3	Menggala	Lampung	4°28'S; 105°17'E	5.23
4	Jakarta	DKI Jakarta	6°11'S;106°SE	4.19
5	Bandung	West Java	6°56'S;107°38'E	4.15
6	Lembang	West Java	6°50'S;107°37'E	5.15
7	Citius, Tangerang	West Java	6°07'S;106°30'E	4.32
8	Darmaga, Bogor	West Java	6°30'S;106°39'E	2.56
9	Serpong, Tangerang	West Java	6°11'S;106°30'E	4.45
10	Semarang	Central Java	6°59'S;110°23'E	5.49
11	Surabaya	East Java	7°18'S;112°42'E	4.30
12	Kenteng, Yogyakarta	DI Yogyakarta	7°37'S;110°01'E	4.50
13	Denpasar	Bali	8°40'S;115°13'E	5.26
14	Pontianak	West Kalimantan	4°36'N;9°11'E	4.55
15	Banjarbaru	South Kalimantan	3°27'S;144°50'E	4.80
16	Banjarmasin	South Kalimantan	3°25'S;114°41'E	4.57
17	Samarinda	East Kalimantan	0°32'S;117°52'E	4.17

No.	Regency/city location	Province	Geographic position	Average irradiation (kWh/m²/day)
18	Manado	North Sulawesi	1°32'N;124°55'E	4.91
19	Palu	Central Sulawesi	0°57'S;120°0'E	5.51
20	Kupang	West Nusa Tenggara (NTB)	10°09'S;123°36'E	5.12
21	Waingapu, East Sumba	Central NT	9°37'S;120°16'E	5.75
22	Maumere	East NT	8°37'S;122°12'E	5.72

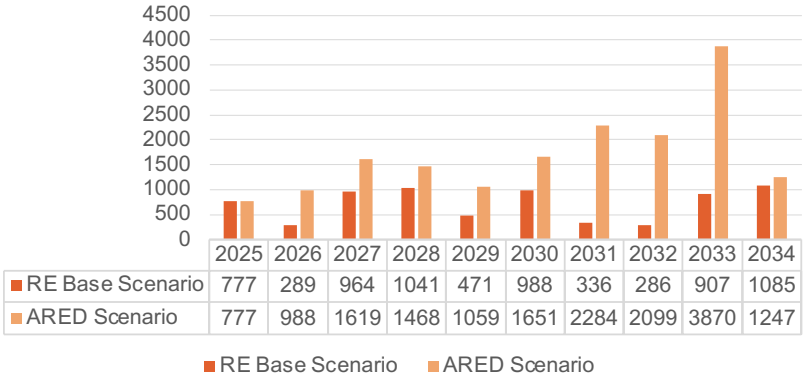
Source: RENSTRA EBTKE 2020-2024, p.43

In 2023, the installed solar power capacity reached around 600 MW[48] and has increased to around 911 MW in 2024[49], exceeding the initial target for the year.

Figure 6.7 below depicts the power plant capacity buildout for solar PV according to PLN's 2025-2034 RUPTL. The solar capacity additions shown above cover both PLTS and PLTS with BESS. In terms of total capacity additions from 2025 to 2034, the RE Base scenario projects a capacity increase of 7,144 MW in solar power capacity, while the ARED scenario targets a significantly higher increase of 17,062 MW, highlighting a substantial expansion in this ARED scenario.

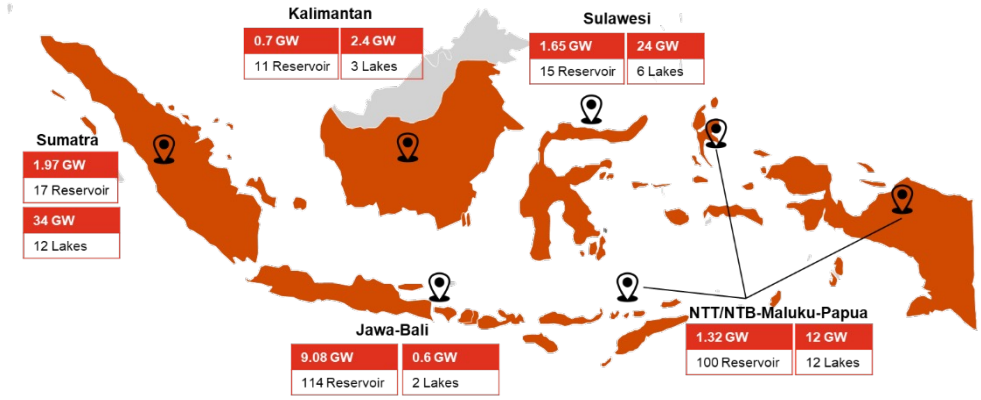
In the RE Base case, PLTS account for 65% of the total capacity increase, while the remaining 35% is attributed to PLTS equipped with BESS. In comparison, the ARED case projects that conventional solar power plants will contribute 78%, while the remaining 22% comes from solar installations integrated with BESS.

Figure 6.7 – 2025-2034 RUPTL solar power capacity buildout (MW)



PLN will also begin to utilise the hydropower dams that it has built for floating solar PV installation, with the Sumatra region considered as having the most potential capacity areas for floating solar PV with more than 89 GW capacity (see Figure 6.8), while railways and toll roads are also being considered for PV installations.

Figure 6.8 - Indonesia's floating solar PV potential



Source: Guideline for Planning of Floating Solar PV Power Plants, MoEMR 2024

In solar rooftop, MoEMR Regulation No. 49/2018, issued in November 2018, addresses various aspects of solar rooftop plants for different consumer categories of PLN. The rooftop solar scheme introduced was on a net metering basis with banking charges of 35% and banking period of three months. Both these aspects were unfavourable, with an estimate showing that the payback period for rooftop solar could be as high as 12 years. Further, industrial consumers with a solar rooftop plant were subject to capacity and energy charges for standby power, if it was operated in on-grid parallel mode. Domestic and commercial consumers were exempt from standby power charges.

Subsequent amendment by MoEMR Regulation No. 13/2019 raised the capacity threshold for requiring an operating licence and operating certificate from 200 kVA to 500 kVA and amendment MoEMR Regulation No. 16/2019 eliminated energy payments for standby power and reduced the capacity charge from 40 to five hours. Both these were favourable changes to the governance framework for solar rooftop plants. However, the commercial structure continued to be unfavourable.

MoEMR Regulation No. 2/2024, which became effective on 31 January 2024, introduced significant updates to the regulatory framework for PLTS in Indonesia. This regulation superseded the previous MoEMR Regulation No. 26/2021, which had been in effect since 20 August 2021. The new regulation aims to enhance rooftop solar development by introducing a quota system, whereby new installations are permitted only within annual capacity limits set by an IUPTLU.

The quota allocations are governed by the Decree of the DGE of the MoEMR Number 279.K/TL.03/DJL.2/2024, which outlines rooftop solar quotas from 2024 to 2028, starting at 825 MW and increasing to 1,400 MW. The majority of the quota—900 MW in 2024—is allocated to Java, Madura and Bali, while provinces like North Kalimantan and West Kalimantan receive only 0.8 MW and 7.1 MW respectively. Despite rising demand, this fixed quota system places a hard cap on annual market growth.

Table 6.8 – Rooftop PTLS system quota (MW)

Province	2024	2025	2026	2027	2028
Sumatra	35	45	60	70	80
West Kalimantan	7	10	16	17	19
South, Central and East Kalimantan	22	34	59	63	68
North Kalimantan	1	1	2	2	2
Java, Madura, Bali	825	900	910	1,010	1,400

To improve administrative efficiency, the regulation mandates automatic approval if the IUPTLU fails to respond within 30 calendar days and removes net-metering and parallel operation charges. However, these incentives are undermined by structural constraints, including limited hosting capacity, unclear grid absorption criteria and the competitive first-come-first-served mechanism, which creates uncertainty and heightens barriers for new entrants.

Another significant favourable change that has been introduced by MoEMR Regulation No. 26/2016 is the eligibility of rooftop solar customers to participate in carbon trading, which will provide an additional revenue stream when carbon trading is operationalised. Other favourable changes introduced are the explicit coverage of consumers connected to the electrical system of an IUPTLU holder, meaning that consumers of IUPTLU holders other than PLN are also explicitly eligible to set up rooftop solar plants and the time for approval by IUPTLU holder of a solar plant has been reduced from 15 days to five days.

Project developments

The Cirata Floating PLTS, located on the Cirata Reservoir in West Java, Indonesia, is a significant milestone in the country's renewable energy journey. This project, a collaboration between PT PLN Nusantara Renewables and Masdar, is the largest floating PLTS in Southeast Asia, with a capacity of 192 MW[50]. Officially inaugurated by President Joko Widodo on 9 November 2023, the plant has been operational since then, producing 158 GWh of green electricity and reducing over 214,000 tonnes of CO_2 emissions annually.

The Tembesi Floating PLTS in Batam, Riau Islands, is being developed by PT Nusantara Tembesi Baru Energi, a subsidiary of PT TBS Energi Utama[51]. The project has secured funding of USD23.3 million from PT SMI and is planned to have a capacity of 46 MWp. It is expected to begin commercial operations by the end of 2025.

The Saguling Floating PLTS, located on the Saguling Reservoir in West Java, is a joint initiative between PLN Indonesia Power and ACWA Power[52]. The project has received USD60 million in financing through the JETP. With a planned capacity of 92 MWp, the plant is projected to reduce carbon emissions by approximately 63,100 tonnes per year. Commercial operation is targeted for mid-2026.

In West Sumatra, the Singkarak Floating PLTS is being developed by PLN Indonesia Power in collaboration with ACWA Power[53]. The project is designed to deliver 76 MWp of solar power and will occupy approximately 49 hectares of Lake Singkarak. It is part of the national renewable energy initiative and is expected to be operational by 2027.

In a bid to further expand its renewable energy portfolio, the Ministry of Public Works and Housing and the MoEMR have announced plans for upcoming tenders for floating solar projects on 259 dams across Indonesia[54]. This initiative aims to harness the potential of these water bodies to generate clean energy, contributing significantly to the country's renewable energy goals.

Further, the dedieselisation programme[55], spearheaded by PLN, is a crucial component of Indonesia's strategy to achieve NZE by 2060. This programme involves converting approximately 5,200 diesel power plants, primarily serving remote areas, to renewable energy sources such as solar power. The initiative is expected to significantly reduce carbon emissions and operational costs associated with diesel power generation. Implemented in multiple phases, phase one of the dedieselisation tender was launched in 2023, utilising diesel-solar PV-BESS hybrid technologies. It serves as an alternative method for decarbonising PLN's last mile grid. By integrating renewable energy solutions into isolated grids, the diesel replacement programme enhances energy security, reduces operational costs and contributes to environmental sustainability.

PLN plans to develop centralised or concentrated solar PV farms using hybrid modes of electricity generation methods, a combination of solar generators and other types of electricity generators with the latter processes being adjusted to the characteristics of specific areas[56].

The challenges to the development of PLTS in Indonesia include the following:

a. The lack of appropriate regulatory support and attractive tariffs.
b. The need for greater government, investor and stakeholder coordination on issues such as obtaining permits, land acquisition and grid conditions – land availability with valid certifications and suitability (e.g. not flood-prone), access to sites and access to a suitable grid should ideally be confirmed prior to a bidding round.
c. Overlapping permitting jurisdictions across multiple ministries, such as the MoEMR, MoEF, ATR/BPN, BKPM and MoHA, often result in inconsistent requirements and local interpretations, which can delay project approvals and PPA negotiations.


Photo source: PwC

d. Lack of clarity and predictability in bid rounds and tender timelines.
e. LCR obligations introduce execution risk, pricing pressure and mandatory LCR thresholds ranging from 20% to 40% that may inflate costs or restrict technology sourcing.
f. Projects must align with RUPTL-defined zones and regional spatial plans, which may be outdated or require local-level harmonisation, resulting in additional administrative burden and potential project delays.
g. IPP developers are required to secure multiple permits including the IUPTL, OSS submission, operating area assignment, Spatial Approval and AMDAL, where delays in any single permit can jeopardise the entire project timeline.
h. Developers may be expected to demonstrate project site readiness (e.g. confirmed land access, valid certification, flood-risk assessments and grid access feasibility) before entering the bidding stage, thereby shifting significant pre-development risk to the private sector.
i. Project permitting may depend on other ministries/local government support, where inconsistent capacity, political will or administrative bottlenecks may delay licensing processes, particularly in remote or underdeveloped regions.
j. Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, making access difficult and causing logistical challenges on some sites.
k. Limited technical experience in PLN's teams in relation to understanding the implications of solar deployment for grid stability and how to manage the accompanying risks.
l. Large landbank requirement (±1 hectare (Ha)/MW).

6.4.2 Wind energy

Wind energy development efforts have been carried out in Indonesia, considering the wind energy potential of 155 GW, which consists of 60.8 GW of onshore wind and 94.2 GW of offshore wind. However, today, Indonesia utilises less than 0.1% of that potential, utilising only 154.3 MW of wind energy for the country's electricity needs[57]. Wind energy has high potential in Indonesia due to the moderate to strong winds that are present due to topographic circumstances, such as the presence of mountain ridges and compressed air flow between and around islands. Regions in Indonesia with the highest potential for utilising wind energy are Maluku, Papua and Nusa Tenggara, holding around 40% of the national potential. This is then followed by the Java region, where the wind potential is around 26% of the national potential[58].

Wind energy relies on the flow of air to turn a wind turbine, converting mechanical energy into electricity by using a generator. Wind energy is regarded as stable from year to year, but it can vary by the hour, day or season. The estimated potential for wind energy in Indonesia has historically been regarded as limited, primarily because the wind velocity in Indonesia is (in general) relatively low. The eastern islands are the exception, where wind velocity can reach levels sufficient to power small-to-medium-scale wind turbines.

Based on an analysis done in 2017 by the Centre for Electricity Survey and Testing of New, Renewable Energy and Energy Conservation, there are four potential locations for the development of wind energy, taking into acount the technical and economic feasibility of exploiting the available resource. The range of wind speeds in Indonesia is between 3 and 7 metres per second (m/s), which is not high compared to other wind-rich countries. Potential locations for wind energy development can be found below:

Table 6.9 – Potential areas to develop wind energy based on wind speeds at an altitude of 30-50 metres (m)

Region	Average wind speed (m/s)
Sukabumi	7
Bantaeng	5
Jayapura	3
Sangihe Island	6

Source: ETP UNOPS 2024

It should be noted that the areas in Indonesia with wind speeds above 5 m/s (i.e. eastern Indonesia, including NTT, NTB, South Sulawesi and Southern Java) are also the least populated and have limited transmission infrastructure.

Previously, in collaboration with the MoEMR, the Danish Embassy in Indonesia through its Environmental Support Programme funded the development of a wind map across Indonesia. The 3-kilometre (km) resolution wind map is now accessible publicly at the website Indonesia. windprospecting.com. Moreover, the MoEMR had also mapped the locations showing the greatest potential for commercial-scale wind energy in Indonesia as follows:

Table 6.10 – Greatest potential for commercial scale wind energy

Locations	Potential energy
Sumatra	7,397 MW
Banten and West Java	8,793 MW
Central, East Java and Bali	15,218 MW
Kalimantan	2,526 MW
Sulawesi	8,380 MW
East Nusa Tenggara	12,793 MW
Maluku and Papua	5,540 MW
Total	**60,647 MW**

Source: RENSTRA EBTKE 2020-2024, p. 45

The continuing advances in wind power technology, including its operational efficiency and its wide and established utilisation in other countries, have nevertheless generated interest in Indonesian wind energy investment. The total wind potential across 34 provinces in Indonesia is also outlined in the RUEN (see Table 6.11):

Table 6.11 – Wind energy potential in 34 provinces in Indonesia at an annual average speed greater than 4 m/s at a height of 50 m based on RUEN

No	Province	Wind energy potential (MW)
1	East Nusa Tenggara	10,188
2	East Java	7,907
3	West Java	7,036
4	Central Java	5,213
5	South Sulawesi	4,193
6	Maluku	3,188
7	West Nusa Tenggara	2,605
8	Bangka Belitung	1,787
9	Banten	1,753
10	Bengkulu	1,513
11	Southeast Sulawesi	1,414
12	Papua	1,411
13	North Sulawesi	1,214
14	Lampung	1,137
15	Yogyakarta	1,079
16	Bali	1,019

No	Province	Wind energy potential (MW)
17	South Kalimantan	1,006
18	Riau island	922
19	Central Sulawesi	908
20	Aceh	894
21	Central Kalimantan	681
22	West Kalimantan	554
23	West Sulawesi	514
24	North Maluku	504
25	West Papua	437
26	West Sumatra	428
27	North Sumatra	356
28	South Sumatra	301
29	East Kalimantan	212
30	Gorontalo	137
31	North Kalimantan	73
32	Jambi	37
33	Riau	22
34	Jakarta	4
Total		**60,647**

Source: ETP UNOPS, 2024

The existing contracted PLTBs are in two provinces, South Sulawesi and Bali (see Table 6.12).

Table 6.12 - Existing wind energy installed capacity in Indonesia

No	Province	Electricity system	Units	Total capacity (kW)	Developer	PPA terms
1	Bali	Tiga Nusa Bali	3	300	PLN	N/A
2	Bali	Tiga Nusa Bali	1	600	IPP	N/A
3	South Sulawesi	Sulselrabar	1	70,000	IPP (PT Barito Wind Energy)	USD11 cents/kWh (30 years)
4	South Sulawesi	Sulselrabar	1	60,000	IPP (Vena Energy)	USD11 cents/kWh (30 years)
	Total			**130,900**		

Source: ETP UNOPS 2024

In South Sulawesi, in the region of Sidenreng Rappang (Sidrap), PT UPC Renewables (UPC) developed what is currently the largest wind farm in Indonesia, with 30 windmills at a height of 80 metres, collectively generating 75 MW[59]. UPC is planning a second Sidrap project of similar scale. Both projects were acquired by PT Barito Wind Energy in 2023 as part of a purchase of a total of three late-stage wind development projects, with a combined potential

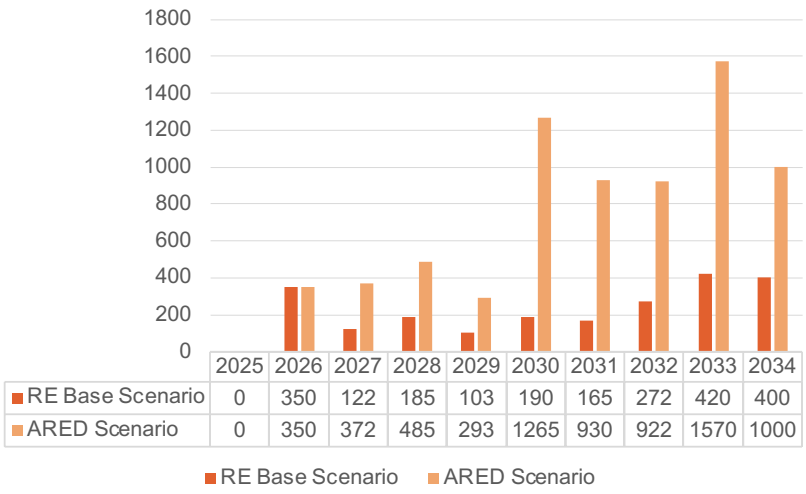
capacity of 320 MW in South Sulawesi, Sukabumi and Lombok[60]. Another wind farm is already being operated by Vena Energy in Jeneponto, South Sulawesi, which reached COD in May 2019. The developer has stated that it intends to develop a second phase of the Jeneponto PLTB following the success of the first phase[61].

Given that Sukabumi has one of the highest wind speeds in Indonesia, PT Barito Wind Energy is considering a 150 MW wind energy development in the area[62]. There is also an ongoing study for a 120 MW wind farm project in Aceh, which is part of a larger assessment for other potential areas including Java and Sumatra[63]. This study was initiated by the MoEMR with the support of the Southeast Asia Energy Transition Partnership under the United Nations Office for Project Services (UNOPS).

Over the ten-year span of the 2025-2034 RUPTL, the RE Base scenario projects a 2,207 MW increase in wind power capacity, while the ARED scenario expects a 7,187 MW capacity increase, more than three times that of the RE Base case.

The most prominent capacity addition is planned for the Java and Bali region, where the wind power capacity addition is expected at 1,277 MW in the RE Base case and 5,377 MW in the ARED case.

Figure 6.9 – 2025-2034 RUPTL wind power capacity buildout (MW)



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
RE Base Scenario	0	350	122	185	103	190	165	272	420	400
ARED Scenario	0	350	372	485	293	1265	930	922	1570	1000

Source: PwC analysis from PLN's 2025-2034 RUPTL

Challenges in developing investments in wind power include the following:

a. The historic lack of an established competitive purchase tariff and an established regulatory framework.
b. Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, leading to difficult access and logistics at some sites.
c. Concerns over the maintenance and the availability of qualified technicians in remote areas with timely access to spare parts.
d. The need for improved wind data resource assessments, with accurate and reliable wind mapping (although projects currently moving ahead appear to have taken responsibility for this).
e. The relatively high upfront investment costs.
f. The need to import equipment manufactured overseas.
g. The need for greater collaboration between all stakeholders, including the Government, PLN and investors.
h. The limited technical experience of PLN's team relating to understanding the implications of wind deployment on on-grid stability and how to manage the risks.
i. The limited skilled local workforce available.
j. Uncertainty and frequent changes in government policies have introduced risks for investors, potentially affecting the financial viability of projects. Additionally, inconsistent implementation of regulations and delays in permitting processes and land acquisition further complicate the investment landscape.
k. Limited research and development (R&D) efforts in the field of wind energy are hindering the growth and establishment of a mature sector in Indonesia.
l. Unclear guidelines for impact analysis and limited access to consistent spatial data for site planning.
m. The absence of standardisation in the development process, such as minimum prerequisite studies and feasibility study guidelines.

6.4.3 Energy storage

Energy storage is the process of containing energy produced at one time for use at a later time. It plays a crucial role in balancing supply and demand, especially for VRE sources, such as solar and wind for a consistent and reliable energy supply. Energy storage technologies can be categorised based on the stored energy form[64]. Table 6.13 shows examples of types of energy storage technology.

Table 6.13 – Energy storage technologies

No.	Technology	Description
Chemical energy storage system		
1.	Fuel cell	Fuel cells work by converting chemical energy into electrical energy through electrochemical reactions between hydrogen and oxygen, producing water as a byproduct. They are efficient and suitable for transport applications due to their quick start-up and rapid load response.
2.	Hydrogen storage	Hydrogen storage involves using an electrolyser to convert electrical energy into hydrogen gas through water electrolysis. The hydrogen is stored and later converted back to electricity using fuel cells.
3.	Ammonia storage	Ammonia is stored in liquid form and can go through a cracking process to produce hydrogen gas when needed.
4.	Biofuels storage	Biofuels are produced from renewable biological sources such as plants. They store energy in chemical form, which can be released through combustion or other chemical processes for transportation and power generation.
5.	Aluminium storage	Aluminium stores energy by reacting with water to produce hydrogen and heat. This process is reversible, allowing the aluminium to be used repeatedly for energy storage.
Mechanical energy storage system		
6.	Flywheel energy storage	Flywheel stores kinetic energy in a rotating mass. Energy is added to the system to increase the speed of the flywheel and it is released by slowing down the flywheel, providing high power density and fast response.
7.	Pumped hydro energy storage (PHES)	Energy is stored by pumping water to a higher elevation during low demand periods. When energy is needed, the water is released to flow downhill through turbines, generating electricity.
8.	Compressed air energy storage (CAES)	CAES uses compressed and pressured air to store energy. Energy is stored by compressing air in an underground chamber. When needed, the compressed air is released, expanded and used to drive turbines to generate electricity.
Electrochemical energy storage system		
9.	Battery	Batteries store energy through chemical reactions within cells. When discharging, chemical energy is converted into electrical energy and the process is reversed during charging.
10.	Flow battery	Flow batteries use liquid electrolytes stored in external tanks. Energy is stored and released through redox reactions as the electrolytes flow through a cell stack.
Electric energy storage system		
11.	Capacitators	Capacitators store energy electrostatically between two metal plates separated by a dielectric material.
12.	Supercapacitators	Supercapacitators store energy using electrostatic and electrochemical processes, offering higher power density and longer life cycles than conventional capacitators.
13.	Superconducting magnetic energy storage (SMES)	SMES stores energy in a magnetic field created by a superconducting coil.
14.	Electric vehicle	Electric vehicles use batteries or hybrid systems to store energy, which powers the vehicle's electric motor.

No.	Technology	Description
Thermal energy storage system		
15.	Sensible heat storage	This system stores energy by increasing the temperature of a material, such as water or rocks. The stored heat is released when the material cools down.
16.	Latent heat storage	Energy is stored during the phase change of a material, such as melting or solidifying, providing higher energy density and stable thermal behaviour.
17.	Thermal chemical energy storage	This involves storing energy through reversible chemical reactions, offering high energy capacity and efficiency for long-term storage with minimal energy losses.

Source: PwC analysis based on various resources for various storage definitions

By storing energy for later use, energy storage systems provide a range of benefits that enhance the efficiency, reliability and sustainability of power grids. Below are some key advantages of energy storage:

1. **Cost savings**: Energy storage can significantly reduce operational costs associated with powering the grid. By storing energy during periods of low demand and releasing it during peak times, utilities can avoid the high costs of generating or purchasing electricity at peak prices.
2. **Backup power**: Energy storage provides a reliable source of backup power during disruptions. In the event of a power outage, stored energy can be used to keep critical systems running, ensuring continuity and reducing downtime.
3. **Supporting VRE integration**: Energy storage can smooth out the delivery of variable or intermittent energy resources such as wind and solar power. By storing excess energy generated during periods of high production and releasing it during low production periods, storage systems help maintain a consistent and reliable energy supply.
4. **Grid stability and flexibility**: Energy storage enhances grid stability and flexibility by providing rapid response capabilities. This allows the grid to quickly adapt to changes in demand and supply, reducing the risk of blackouts and improving overall grid resilience.
5. **Environmental benefits**: By enabling greater integration of renewable energy sources, energy storage helps reduce reliance on fossil fuels, leading to lower GHG emissions and a cleaner environment.

Indonesia has integrated the utilisation of energy storage systems into its RPJPN for 2025-2045. According to the RPJPN, Indonesia plans to begin implementing energy storage systems by 2025.

This first initiative is in the Upper Cisokan PHES Project – which has been under construction since 2022, with completion expected by 2026 and operations commencing in 2027. The project, located in West Java, is Indonesia's first pumped storage power plant with an installed capacity planned at 1,040 MW[65]. The project involves shifting water between two reservoirs to generate electricity during peak demand and store energy during off-peak times. Supported by a significant loan from the World Bank, the project aims to enhance grid stability, reduce transmission losses and facilitate the integration of renewable energy sources into the Java-Bali grid.

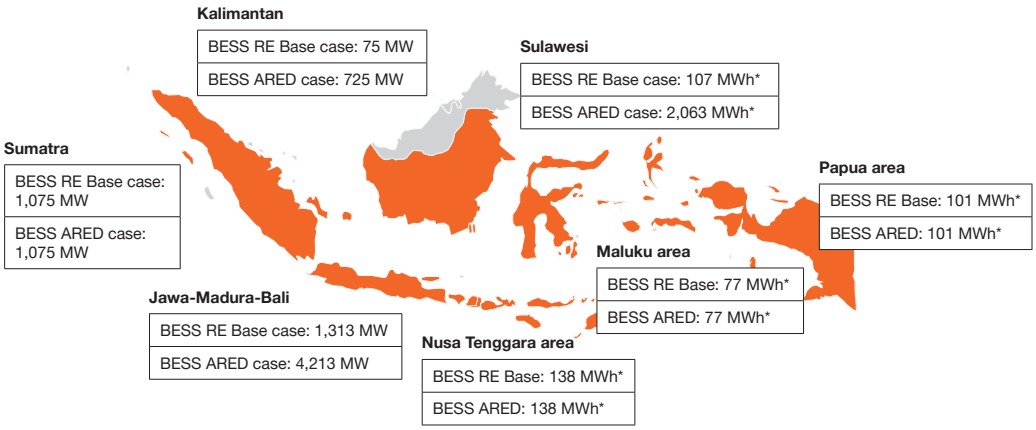
Another example of the use of BESS is the solar power project on Nusa Penida island. PLN, through its subsidiary PT PLN Indonesia Power, has capitalised on the island's potential by constructing a PLTS in Suana village. This plant, built on approximately 4.5 hectares, features hundreds of solar panels designed to absorb optimal sunlight. The energy generated is transformed from direct current (DC) to alternating current (AC) using 18 inverters and eight BESS, ensuring a stable and reliable power supply for the island's residents and businesses. The PLTS, which began operating in November 2022, has a capacity of 4.2 MWp or 3.5 MW and is equipped with a BESS of 1.84 MW[66]. This facility not only supports the growing electricity needs of Nusa Penida, Nusa Lembongan and Nusa Ceningan but also plays a crucial role in reducing carbon emissions. Building on this success, PLN plans to construct a larger PLTS with a BESS of 18 MW capacity starting in 2025. The PLTS is estimated to cut emissions by around 9,000 kilogrammes of CO_2 equivalent per day, or approximately 4,190 tonnes per year.

PLN has also implemented the use of BESS on a small-scale PLTS on Messah Island, located in the West Manggarai Regency of NTT. This PLTS has a capacity of 530 kilowatt peak (kWp) and has been operational since 2019. The facility has around 968 kWh BESS capacity, ensuring a stable power supply for the island's 2,000 residents[67]. The use of BESS is crucial for storing the energy generated by the solar panels, providing continuous electricity even during periods when sunlight is not available.

Further, BESS is also being implemented in the IKN (*Ibu Kota Negara*) Nusantara PLTS, which is a significant renewable energy project aimed at supporting the new capital city of Indonesia. Located in East Kalimantan, the solar power plant has a total planned capacity of 50 MW and is equipped with a BESS[68]. Currently, all 50 MW is already connected to the transmission grid. This initial phase was completed by PLN Nusantara Power, a sub-holding of PLN, which formed a joint venture with Sembcorp, and marks a crucial step towards providing the IKN area with clean, sustainable energy. To date, Indonesia is only using battery storage for power smoothing and power plant services at a site. However, future utilisation for grid services and other commercial applications can be expected, as the RUPTL forecasts the adoption of various standalone batteries in a mature grid.

In the 2025-2034 RUPTL, BESS capacity is reported in either MW or MWh, where MW refers to the battery's power capacity and MWh involves the energy capacity and is more commonly used for off-grid battery storage. The capacities in Sulawesi, Maluku, Papua and Nusa Tenggara are expressed in MWh, while those in Java-Madura-Bali, Sumatra and Kalimantan are measured in MW. BESS capacity addition in the RE Base scenario totals 2,464 MW, while the ARED scenario projects a significantly larger increase of 6,014 MW. Regions such as Sumatra, Maluku, Papua and Nusa Tenggara are expecting similar BESS capacity additions under both scenarios, with increases of 1,075 MWh, 77 MWh, 101 MWh and 138 MWh respectively over the 2025-2034 period. In the Java–Madura–Bali region, the BESS additional capacity jumps to 4,213 MW in the ARED scenario. Sulawesi forecasts to add 2,063 MWh in the ARED scenario and Kalimantan up to 725 MW.

Figure 6.10 – 2025-2034 RUPTL energy storage capacity per region (MW or MWh)



* The capacities in Sulawesi, Maluku, Papua, and Nusa Tenggara are in MWh, as they are off-grid battery storage.
Source: 2025-2034 RUPTL

6.5 Emerging renewable energy sources

This section on "Emerging energy sources" covers those at the research or pilot testing stages. Emerging energy sources, like ocean energy, are still in the research or pilot testing stages, aiming for large-scale application. This section will discuss the potential of ocean energy as a sustainable resource, highlighting the current research efforts and future potential for its large-scale application.

6.5.1 Ocean energy

Ocean energy refers to renewable energy obtained from the sea, either as mechanical energy from the tide and waves or as solar energy from the sun. Wave energy uses the energy of ocean waves or swells to generate electricity. Tidal energy arises from tidal movements, utilising the vertical changes in sea levels or the horizontal movement of the seas and currents to generate

electricity. Ocean Thermal Energy Conversion (OTEC) uses the difference in temperature between the warmer surface or shallow waters and the cooler and deeper waters to generate electricity.

To date, the most common application of ocean energy is the conversion of the kinetic energy of waves into electricity. Some countries that have successfully harnessed this are Scotland, Sweden, France, Norway, England, South Korea and the US. In the Indonesian context, the most significant potential for the utilisation of ocean energy may be in the coastal straits[69]. Indonesia has significant tidal potential due to the thorough flow of marine current from the Pacific Ocean to the Indian Ocean[70].

As an archipelagic state consisting of islands and straits, the potential ocean energy in Indonesia is thought to be 17.9 GW[71]. Based on the 2025-2060 RUKN, Indonesia has a theoretical ocean current potential of approximately 10,741 MW, a technical potential of around 4,296 MW and a practical potential of about 1,504 MW. This potential is located across eight provinces.

The largest practical ocean current potential is found in the NTB Province, accounting for about 53% of the total national practical ocean current potential, distributed across the Lombok Strait and the Alas Strait. The NTT Province also holds a significant practical ocean current potential, constituting approximately 24% of the total national practical ocean current potential. Studies carried out by the MoEMR with foreign donors have identified the areas with the highest potential as being Kelang in Maluku (500 MW), the Alas Strait (9 MW) and the Larantuka Strait (3 MW). However, especially for Kelang, the local demand is very low, meaning that only 3.2 MW could probably be developed[72].

SBS INTL Ltd, a UK-based marine and subsea development engineering and project management consultancy, has also attempted to harvest power from the ocean with its Nautilus tidal-stream project, which started in 2013. The project is centred on the straits around the islands of Bali and Lombok. A MoU with PT Indonesia Power was signed in January 2018, with the feasibility study and report being completed in July 2018. SBS and SIMEC Atlantis Energy, a global sustainable energy company, are currently pursuing the development of this project, which will have a total capacity of 150 MW when completed. In November 2018, SBS has filed a grid expansion feasibility study which is being internally reviewed by PLN exploring the options to expand the grid on Lombok Island to accommodate the Nautilus array output. For the first phase, turbines are expected to be completed in 36 months, supplied by SIMEC Atlantis Energy. The output will be sold to PLN under a 30-year PPA.

In 2024, it was announced that HydroWing, a division of the UK-based Inyanga Marine Energy Group, has signed an agreement with a subholding of PLN to advance plans for a 10 MW tidal current power plant in East Nusa Tenggara as a pilot project[73]. This comes as a follow up to a MoU between the two parties in 2022, which aimed to accelerate tidal energy development

through site selection, resource assessment and initial engineering. HydroWing has experience also in the Philippines, where they were awarded the contract to build a tidal energy plant at Capul.

It was also reported that the Indonesian and Dutch governments will work together to develop tidal energy in the Larantuka Strait, involving an 810-metre Pancasila-Palmerah bridge in NTT, with sea current turbines being installed under the bridge[74]. A MoU with PLN was signed in February 2018, regarding the execution of the feasibility study and the grid impact assessment, which were conducted in April 2018 but were still reported as being ongoing in March 2019. The project will be developed to accommodate 90 to 115 MW of installed capacity for the second phase[75]. The project was awarded to Tidal Bridge Indonesia – a joint venture between BAM International BV, a Dutch construction engineering company and PT PJB, a PLN subsidiary.

Wello Oy, a Finland-based wave energy converter, also announced that it will provide a 10 MW marine and hydrokinetic energy park at Nusa Lembongan, Bali, following a request from Gapura Energi Utama. In March 2019, this project was reported to still be at the design phase, as the company launched a funding campaign[76].

Challenges for ocean energy in Indonesia include the following:

a. The limited domestic availability of technologies and the early stage of the pilot projects and evaluations in the country.
b. The geographical distances involved, including the logistics of the locations and the absence of infrastructure.
c. The need to better understand the economics of ocean energy electricity generation.

Outlined in the 2025-2034 RUPTL, Indonesia anticipates a 40 MW increase in ocean power capacity under both the RE Base and ARED scenarios. The ocean power capacity addition is limited to the Nusa Tenggara region, with the 40 MW planned for 2028. 20 MW each are expected to be installed in East and West Nusa Tenggara, as the first ocean power plant development in Indonesia[77]. Other regions like Java-Madura-Bali, Sumatra and Kalimantan possess ocean energy potential, but are not currently considered in the RUPTL pipeline.

6.5.2. Other advanced renewable energy technologies

In terms of global best practices, the advancement of renewable energy technologies continues to make strides. Innovative technologies are emerging as new breakthroughs, offering more cost-effective, cleaner and higher-performing products. However, these technologies are still in the initial stages of commercial development or pilot testing. Consequently, widespread deployment in emerging markets, such as Indonesia, may experience delays.

Today, energy storage is becoming a crucial option for maintaining grid stability and accommodating greater integration of renewable energy into the grid. Long-duration energy storage is among these breakthroughs and is now being adopted in commercial practices in countries like India, the United States and others. This concept involves the capability for seasonal or long-term discharge. The new technologies undergoing trials for commercial use include the following[78]:

1. Thermal storage cavern (e.g. Finland 90 GWh of thermal energy storage at 140°C).
2. Compressed CO_2 storage (e.g. Energy Dome 200 MWh of compressed CO_2 into an above-ground steel container).
3. Higher density and more charge-discharge cycle solid state batteries.
4. Potassium-ion batteries (at cell development stage).

In solar PV, Perovskite solar modules have reached the piloting stage for commercial-scale production in Australia and the United Kingdom. Solar modules are being developed to be more efficient with bifacial use, as well as being more flexible, lightweight and aesthetically pleasing. With the integration of AI, smart solar PV modules could be developed alongside data analytics and automation, enhancing electricity production and grid compatibility. Cellulosic bioethanol facilities are also being constructed on a large scale in biomass-rich countries like Brazil. The various sea conditions may also advance the floating wind technology in near future. The technology will offer wind turbines designed for any kind of sea condition, higher capacity, stronger and sustainable materials and more aerodynamic as well as bird friendly blades. Chinese manufacturers and developers are now also entering the low wind speed turbines to service countries with lower wind speeds. Data analytics and AI will also boost the wind and solar forecasting and improve operation and maintenance[79]. There is a pipeline of small modular nuclear reactors in PLN's 2025-2034 RUPTL. However, nuclear energy is a new energy source, and this chapter is only intended for renewable energy-based power plants. Nuclear power is considered a new technology in Indonesia; therefore, the adoption of nuclear energy needs to be handled carefully. Supply chain management, safety standards, regulatory frameworks and the capacity of human resources are fundamental elements that the Government must prepare for implementation. If successful, Indonesia would be the first country in Southeast Asia to operate a nuclear power plant in the near future.

Photo source: PwC

7 Taxation considerations

7.1 Overview

The chapter provides a general overview of the tax issues relevant to the operation of power generation in Indonesia, covering conventional and renewable energy. The overview focuses on the tax regimes which are relevant to investors, but also touches upon the taxes which may be encountered by vendors (e.g. asset constructors and service providers) and employees.

For more detailed information on Indonesia's general tax rules, please refer to our "2025 Indonesia Pocket Tax Book" publication available on the PwC Indonesia website at www.pwc.com/id.

Taxes relevant to power generation operation in Indonesia are outlined under the following sections:

a. Income tax due on operation.
b. Income tax on capital gains, such as those arising from asset sales and share sales.
c. Withholding taxes (WHT), such as those applying to services, royalties and interest payments.
d. Employment-related taxes on employee cash and non-cash remuneration.
e. VAT on the import of, and in-country supply of, most goods and services.
f. Import duties and taxes.
g. Other taxation considerations, including regional taxes, stamp duty, carbon tax, geothermal projects under JOC, tax incentives for renewable power generation, and Global Anti-Base Erosion (GloBE) rules.

Regulatory framework

The Indonesian taxation laws mainly consist of the following:

a. Law No. 28 Year 2007 regarding General Tax Provisions and Procedures Law.
b. Law No. 36 Year 2008 regarding Income Tax Law (ITL).
c. Law No. 42 Year 2009 regarding VAT Law.
d. Law No. 12 Year 1994 regarding Land and Building Tax Law.
e. Law No. 10 Year 2020 regarding Stamp Duty Law.
f. Law No. 1 Year 2022 regarding Financial Relations between the Central Government and Regional Governments.
g. Law No. 7 Year 2021 regarding Harmonisation of Tax Regulations (HPP Law).

Certain provisions (as relevant) of most of the laws above are amended by the HPP Law.

Implementing regulations of the laws above include the following:

a. Government Regulation No. 44 Year 2022 for VAT.
b. Government Regulation No. 49 Year 2022 (GR-49) on Exemption and Non-collection of VAT and Luxury Goods Sales Tax.
c. Government Regulation No. 50 Year 2022 for General Tax Provisions.
d. Government Regulation No. 55 Year 2022 (GR-55) for Income Tax.

7.2 Taxes

7.2.1 Income tax

The income tax provisions are in general stipulated under Income Tax Law No. 36/2008 as lastly amended by the HPP Law (the Income Tax Law).

The income tax provisions for geothermal power projects operating under government licence (i.e. licence-based geothermal power projects), which were licensed since the enactment of Geothermal Law No. 27/2003, follow the prevailing Income Tax Law. Profits from the geothermal power project are therefore taxable at the standard rate of 22%. Pursuant to Article 31D of the Income Tax Law, the tax treatment of geothermal business activities will be further regulated under a government regulation (yet to be issued).

Income tax provisions specific to a geothermal power project operating under a JOC are however "*lex specialis*", meaning not following the prevailing Income Tax Law. For details, please refer to Section *7.3.4 - Taxation considerations for geothermal operations under a JOC*.

The principal features of the prevailing income tax rules include:

a. corporate income tax (CIT) due at a flat rate of 22% of taxable profits. IDX-listed entities (subject to satisfying the requirements) are eligible for a further 3% reduction i.e. to 19%
b. entitlement to deduct/depreciate most of the spending connected to income generation
c) entitlement to five years of tax losses carried forward.

Disallowed tax deductions in general include, amongst others:

a. non-business related expenses
b. gifts and aid, except certain religious contributions/alms and certain donations
c. income tax and tax penalties
d. non-arm's length payments made to related parties
e. interest expense on excessive debt to equity ratio (DER) of more than 4:1. MoF Regulation No. 169 Year 2015 however provides an exemption from the DER rules for certain industries, including "infrastructure", which may arguably include the power sector.

The Income Tax Law requires capitalisation of all expenditure with an economic life longer than 12 months. The law allows depreciation and amortisation to be deducted against income by using predetermined categories of useful life and depreciation/amortisation methods.

Depreciable costs include all expenditure incurred in purchasing, installing and constructing an asset. This generally extends to any interest incurred during the construction period, where such interest is construction-related.

Depreciation generally commences from the date of expenditure. However, where an asset is constructed, depreciation commences at the time of completion. With the DGT approval, commencement of depreciation can be delayed until operation begins.

Power generation equipment is generally treated as having a useful life of 16 years and thus attracts a straight-line depreciation rate of 6.25% or a declining balance depreciation rate of 12.5%. Technical constructions which are attached permanently to the ground are generally treated as buildings. Buildings attract a straight-line depreciation rate of 5% (for permanent building) and 10% (for non-permanent building). Uncertainty can exist regarding the classification of tangible assets connected to land, such as boilers as to whether they are considered as non-buildings/equipment or buildings for tax depreciation purposes.

MoF Regulation No.72 Year 2023 (MoF-72) stipulates repair costs that provide future economic benefits should be added to the fiscal Net Book Value (NBV) of the assets (as "adjusted NBV") and expensed through depreciation.

Overall, the taxable income calculation largely follows the "conventional" accounting profit method, with largely conventional adjustments for various timing and permanent differences (although see the below on *Interpretasi Standar Akuntansi Keuangan* (ISAK) 112 accounting rules). The Indonesian tax regime is single entity focused, with no ability to calculate tax on a consolidated or group basis or to transfer tax losses between entities.

Accounting and tax treatment on power assets

As outlined in Chapter 8, the accounting rules relevant to many long-term power projects have, from 1 January 2012, resulted in the respective parties (generally PLN and the IPP) having to record their arrangements as being either in the nature of a "lease" or (more likely) as a "service concession" under ISAK 112 accounting. This accounting treatment could have a significant impact on the books of an IPP if, for example, under a service concession arrangement, the fixed asset is reclassified as a financial asset, there is no depreciation of the power asset.

No formal guidance on the tax impact of these accounting changes has been issued by the Indonesian tax authorities. In a general sense, although the accounting treatment can be persuasive for income tax purposes, this is generally only the case where the income tax treatment is not well regulated. On this basis, the likely result is that the income tax outcome should continue to follow the legal form of the business. This position also appears to have been accepted by the Indonesian tax authorities in practice (although there were a number of early attempts to apply ISAK 112 for tax i.e. no deduction on depreciation expense).

Any prepaid CIT is creditable against the year-end CIT position. For sales of electricity to PLN, PLN is required to impose WHT (under Article 22) at 1.5% of gross payments made to IPP companies (given PLN's status as a state-owned enterprise). As the 1.5% WHT is creditable, it represents a cash flow concern only.

A number of income tax incentives are available to renewable power projects in the forms of tax allowance, tax holiday and specific tax facilities for operation in IKN. Please refer to Section *7.3.5 Tax incentives for renewable power generation* for further details.

If a power project is granted with one of the above facilities, the power producers should consider the impact of Pillar Two GloBE Rules as outlined in Section *7.3.6 GloBE Rules*, as to whether there is a top-up tax that needs to be settled in Indonesia.

7.2.2 Capital gains tax

Indonesia's income tax rules do not focus on the distinction between revenue and capital receipts. Instead, any "profits" from the sale of assets (including shares) are generally simply treated as income.

An exception is made for sales of assets made by non-residents. In this case, income tax imposed is currently limited to sales of shares in non-public Indonesian entities, for which income tax is effectively due at a flat rate of 5% on the transaction proceeds (i.e. irrespective of whether any economic profit has been made).

Furthermore, for sales of shares in Indonesian entities listed on the IDX, Income Tax is due at a flat rate of 0.1% of the transaction proceeds. To be eligible for this rate, any "founder" shareholders must also pay tax at 0.5% of the market prices of their shares upon listing. If this is not paid, the founders are taxed on any gains arising from any subsequent sales under the normal tax rules.

7.2.3 Withholding tax

In an Indonesian context, WHT is generally an obligation of the payee (in this case the power producers) to withhold income tax at a set percentage of a relevant payment (e.g. for services, interest, royalties) and to remit the amount withheld to the tax authorities.

There are basically two categories of WHT from an income recipient perspective: "final" and "non-final". Final WHT constitutes a final CIT for the income recipient where no recalculation of taxable profit and CIT due is required. Non-final WHT is creditable against the income recipient's annual income tax obligation.

Services related to EPC are subject to this "final tax" regime via a WHT mechanism imposed by the relevant IPP. Depending on the type of services and the EPC provider's construction qualifications, the WHT rates vary between 1.75% and 6%.

Another type of payment that is subject to final WHT is payment to residents for rental of non-moveable property (at a rate of 10%).

WHT is also applicable for the following types of payments made to non-residents:

a. Most services, interest and royalty payments (at a rate of 20% before any treaty relief). Under the Income Tax Law, the applicable WHT rate for interest paid to non-residents can be lower than 20%. GR No.9 Year 2021 (GR-9) sets a lower interest WHT rate of 10% (or the applicable tax treaty rate) for interest on bonds paid to non-resident taxpayers.
b. Dividends (at a rate of 20% before any treaty relief).

Non-final WHT will typically apply to payments made to an Indonesian resident. In such cases, the payee is entitled to credit the WHT against its annual tax liability and is entitled to a refund of any excess.

The types of payments subject to non-final WHT include payments made by power producers to:

a. residents for rental of moveable property (a rate of 2%)
b. residents for consulting, management or technical services (a rate of 2%)
c. residents for royalties (a rate of 15%).

Payment made to Mining Business Licence (*Izin Usaha Pertambangan* - IUP) holding companies for coal purchases is also subject to WHT at a rate of 1.5%.

WHT reduction facility on dividends paid to non-resident shareholders is available under the tax allowance facility. Further, the WHT exemption facility is available under the tax holiday facility and tax facilities in IKN. For further details, please refer to *Section 7.3.5 – Tax incentives for renewable power generation*.

7.2.4 Personal taxes

Income tax on remuneration

Employment-related cash remuneration is subject to Indonesian income tax at a (maximum) rate of 35% for resident employees or at a (flat) rate of 20% for non-residents.

Government Regulation No. 58 Year 2023 (GR-58) and Minister of Finance Regulation No. 168 Year 2023 (MoF-168) simplify the monthly employee income tax (EIT) calculation.

The regulations stipulate that the monthly EIT calculation for the months of January to November is to be performed using an effective tax rate with a true-up calculation to be performed in December using the normal progressive income tax rates.

Provision of benefits in kind (BIKs) is taxable in the hands of the employee, except for:

a. food and beverages provided for all employees
b. BIKs provided in certain areas (generally remote areas)
c. BIKs necessary to carry out work
d. BIKs financed by a regional/state revenue budget
e. certain other BIKs as stipulated under MoF Regulation No. 66 Year 2023 (MoF-66).

Residents are taxed on their worldwide income (including employment and non-employment income) regardless of remittance. Non-residents are taxed on their Indonesian-sourced income only. Under HPP Law, foreign nationals who have become domestic tax subjects by reason of becoming tax resident in Indonesia can be taxed only on Indonesian-sourced income (including

income connected with jobs, services or activities in Indonesia in whatever names and forms paid offshore) if they meet certain skill requirements. This will only be available for the first four years they become tax resident.

This territorial taxation system may not be applicable when the foreign nationals receive income from overseas and utilise the applicable tax treaty between Indonesia and the source country.

Foreign nationals (and their dependents) will generally be deemed to be tax residents if they reside in Indonesia, present for more than 183 days in any 12 months period, or if they present in Indonesia with the intention to stay.

Indonesian citizens that are living outside of Indonesia for more than 183 days in 12 months and meet certain requirements can be considered as foreign tax subjects, which the income will be taxable in Indonesia only if sourced from Indonesia.

Certain income tax facilities are available to employees who are located in IKN, receive income from an employer in IKN, and have a Taxpayer Identification Number (*Nomor Pokok Wajib Pajak* – NPWP) registered at a Tax Office within the IKN area. Please refer to *Section 7.3.5 – Tax incentives for renewable power generation* for further details.

Social security contributions

Indonesian employment arrangements require both the employer and the employee to make contributions to a number of schemes as detailed in the table below. These schemes apply to all employees (including expatriates).

The Social Security Agency (*Badan Penyelenggara Jaminan Sosial* – BPJS) scheme replaced the former Jamsostek scheme (which generally did not apply to expatriates) from 1 January and 1 July 2015, for local employees and expatriates.

Insurance component	Agency		Scope	Contribution rate (as a percentage of regular salaries/ wages)	
	Previous	New		Borne by employers	Borne by employees
Worker's social security	• PT Jamsostek • PT ASABRI • PT TASPEN	BPJS for worker's social security (BPJS Ketenagakerjaan)	a) Accident insurance; b) Old age savings; c) Death insurance; d) Pension.	0.24% - 1.74% 3.70% 0.30% 2.00%	 2.00% 1.00%
Health	• PT Jamsostek • PT Askes • Ministry of Health • Ministry of Defence, National Army, Police Department	BPJS for health insurance (BPJS Kesehatan)	Basic health insurance	4.00%	1.00%

7.2.5 VAT

Indonesia imposes broad-based VAT, as currently set out in VAT Law No. 42/2009 as lastly amended by the HPP Law (the VAT Law). The current general statutory VAT rate is 12% (noting however the effective VAT rate is (still) 11% for most goods/services). Whilst any supplies constituting exports of goods attract a 0% VAT rate.

The 12% VAT rate applies only to the import and domestic delivery of luxury taxable goods which are currently subject to the luxury goods sales tax (*Pajak Penjualan Barang Mewah* - PPnBM). These include motor vehicles, luxurious residences, private aircraft, luxurious private cruisers, shotguns, etc.

Indonesia's VAT system requires VAT to be charged (as output VAT) on the value of most supplies of goods sold and services provided within Indonesia, with each person being charged such VAT (as input VAT) being entitled to a credit provided that the person incurs the VAT on their own VAT-able supplies. Input VAT and output VAT are not generally included in the calculation of income tax.

The supply of electricity in principle is VAT-able but, because electricity (except for supplies to households above 6,600 watts) represents "strategic goods", the supply of electricity is exempted from VAT.

For geothermal power projects, the steam generated from geothermal activities is considered a product of mining or drilling at source. The supply of steam is also treated as the supply of "strategic goods", which is VAT-exempt.

Due to the nature of being VAT-exempt, input VAT relating to supplies of (non-exception) electricity and steam is not creditable (whilst the VAT can instead be deductible).

Even though the supply of (non-exception) electricity is VAT-exempt, the power producers and steam producers should register for VAT. They are also required to issue VAT invoices on the sales, with the VAT invoices being stamped in order to show that the relevant sales are exempt from VAT.

The VAT regime for geothermal power projects under a JOC operates differently with the general VAT regime, whereby the input VAT is generally reimbursable. For details, please refer to *Section 7.3.4 – Taxation consideration on geothermal under JOC*.

A number of VAT incentives are available to power producers. Please refer to below under *Section 7.2.6 Import duty and taxes* and *Section 7.3.5 – Tax incentives for renewable power generation* for further details.

7.2.6 Import duty and taxes

Overview

Unless exempted (see further below), the importation of most capital equipment is subject to the following taxes:

a. Import duty: This is due at the "harmonised" duty rate which varies according to the types of goods imported.
   Import duty rates that may be relevant to power-related imports include:

Import item	Duty rate
Turbines	Up to 5%
Steel	Up to 15%
Boiler furnaces	Up to 10%
Transformers	Up to 10%
Electricity transmission cables	Up to 10%

b. VAT: Currently is due at (effectively) 11% of "the import duty-inclusive" Cost, Insurance and Freight (CIF) value of the relevant goods.
c. "Article 22" Income Tax: This is an income tax prepayment and is (generally) due at 2.5% of the "import duty-inclusive" CIF value (for importers with an appropriate import licence) of the relevant goods.

Import duty exemptions

There are several import duty facilities available for importation of certain goods, either specifically for the power sector or for general investment. These facilities are outlined below.

Power projects

A specific import duty exemption (under MoF Regulation No. 66/2015) can be obtained for the import of capital goods (being machines, equipment and tools but not spare parts) by:

a. PLN.
b. an IUPTL holder in a designated business area.
c. IPPs holding a PPA (or designated finance lease agreement) with PLN.
d. IPPs holding a PPA with another IUPTL holder in a designated business area.

This exemption should be outlined in the relevant agreement (for points c and d). Historically, this concession was sought from the Customs Office but it is now sought from the BKPM.

Geothermal power projects

A specific Import Duty exemption is available for geothermal power projects. This is regulated under MoF Regulation No. 172/2022 (which amends MoF Regulation No. 218/2019) where Import Duty on imports of goods by the following entities/institutions used in "geothermal business activities" can be exempted:

1. JOC contractors.
2. Geothermal business concession holders.
3. Geothermal business permit holders.
4. Geothermal permit holders.
5. Pre-exploration business entities.
6. Ministry/institution or regional government.
7. College/university.
8. Research institution.

Master list

A concession known as a "master list" is generally available for all BKPM licensed investments which provides an exemption for import duty for import of machines, goods, and materials which are used to produce goods (including electricity) or to render certain types of services. The master list is currently regulated under MoF Regulation No. 188/2015 (which amends MoF Regulation No. 76/2012).

Free Trade Agreement (FTA)

A further import duty concession (as exemption or reduction of import duty rate) may be available via Indonesia's various FTAs.

Counter parties of Indonesia's FTAs currently include ASEAN, Australia, New Zealand, Japan, Korea, Pakistan, Chile, India, China, Hong Kong, Mozambique, Iceland, Liechtenstein, Norway, Switzerland, Bangladesh, Iran, Malaysia, Egypt, Nigeria, Pakistan, Turkey and United Arab Emirates.

Import VAT exemptions

Capital goods (including plant, machines and equipment, but not spare parts) are considered "strategic goods". Under GR-49, a VAT exemption is available on the import and local delivery of strategic goods, where these goods are used to produce VAT-able goods.

The VAT exemption on imports is subject to pre-approval granted by the Indonesian tax authorities.

MoF Regulation No. 198/2019 (which amends MoF Regulation No. 142/2015) specifically provides an import VAT exemption for geothermal power projects.

Article 22 exemptions

The tax authorities may provide Article 22 Income Tax exemption subject to meeting the following conditions (upon Indonesian tax authorities approval):

a. Taxpayer is in a fiscal loss position (either as a newly established entity, not yet starting commercial production or due to force majeur).
b. Taxpayer has carried forward tax losses.
c. Taxpayer is not in an income tax underpayment position.

Specific to taxpayers in the renewable energy sector, it is entitled for automatic exemption without satisfying any of the above conditions.

A number of import tax incentives are available to certain business activities performed in the IKN. Please refer to *Section 7.3.5 – Tax incentives for renewable power generation* for further details.

Photo source: PwC

7.3 Other taxation considerations

7.3.1 Regional taxes

Regional taxes are regulated under Law No.1/2022 regarding Financial Relationship between the Central Government and the Regional Government (Law 1/2022). Law 1/2022 provides a list of regional taxes and the maximum rates of each tax. Implementation of the respective taxes is subject to local regulation. A summary of the potential relevant regional taxes for the power sector is as follows:

	Type of regional tax	Maximum tariff	Current tariff	Imposition base
A. Provincial Taxes				
1	Taxes on motor vehicles and heavy equipment	10% p.a.	Non-public vehicles	Calculated with reference to sales value and a weight factor (size, fuel, type, etc.). Government tables will be published annually to enable calculation.
			1% – 2% for the first private vehicle owned	
			2% – 10% for the second private vehicle owned and above	
			0.5% – 1% for public vehicles	
			0.1% – 0.2% for heavy equipment vehicles	
2	Title transfer fees on motor vehicles, above-water vessels and heavy equipment	20%	Motor vehicles	
			20% on the first title transfer	
			1% on the second title transfer or above	
			Heavy equipment	
			0.75% on the first title transfer	
			0.075% on any title transfers after the first	
3	Tax on motor vehicle fuel	10%	Public vehicles: at least 50% lower than the tax on non-public vehicle fuel (depending on each region)	Sales price of fuel (gasoline, diesel fuel and gas fuel).
4	Tax on the collection and utilisation of underground water and surface water	10%	Tariff on surface water only	Purchase value of water (determined by applying a number of factors).
B. Regency and municipal taxes				
5	Tax on certain goods and services (*Pajak Barang dan Jasa Tertentu*/PBJT) (including consumption of electric power)	10%	3% utilisation by industry	Sales value of electricity (power bill).
			1.5% personal use	
6	Tax on non-metal minerals and rocks (formerly the C-Category mined substance collection)	25%	Set by region	
7	Tax on groundwater	20%	Set by region	Purchase value.
8	Land and buildings tax	0.3%	Set by region	Only on certain types of land and buildings.
9	Duty on the acquisition of land and building rights	5%	Set by region	Land and buildings sale value.

7.3.2 Stamp duty

The Indonesian stamp duty is due on the execution of documents constituting evidence of transactions. This includes transfer of shares, conveyance of real estate or other property, rental and lease agreements, etc.

Instead of percentage-based stamp duty (as adopted in most countries), pursuant to Law No. 10 Year 2020 (as lastly amended by the HPP Law), the Indonesian stamp duty is due at nominal values, typically IDR10,000 (i.e. less than USD1).

7.3.3 Carbon tax

The Carbon tax is introduced under the HPP Law.

Carbon tax can be imposed on individuals or entities that:
a. carry out activities that emit a certain level of carbon
b. purchase goods containing carbon.

For the implementation of carbon tax, the Government is required to issue roadmaps for carbon tax and the carbon market and relevant implementing regulations. The HPP Law indicates that carbon tax for carbon emission activity is imposed through a "cap and trade" mechanism. This is basically a sale and purchase between entities with carbon emissions below and above a designated cap/allowance. The market facilitating carbon trading under the "cap and trade" mechanism is normally known as a mandatory carbon market (see below). Should the carbon emission cap be exceeded, and the entity has not offset the excess emission through the trading, the excess carbon emission would be subject to carbon tax (currently) at the rate of the lesser of:
a. the carbon credit price in the domestic carbon market per kilogramme (kg) CO_2e.
b. IDR30,000/kg CO_2e.

The MoEMR issued MoEMR Regulation No. 16/2022 (MoEMR-16) to implement the "cap and trade" mechanism specifically for coal-fired power plants (covering both IPP and PLN power generation).

In 2023, the MoEMR set the carbon emission allowances for 99 coal-fired power plants, and in 2024 this was increased to 146 plants.

Carbon emitters are required to record the carbon emission activities, self-remit and report the carbon tax on an annual basis. Up to the time of writing, the relevant implementing regulation has not been issued.

Whilst for carbon tax on purchase, the tax is collected by the seller (appointed carbon tax collector) whereby the seller is required to record the relevant sales, pay and report the carbon tax on a monthly basis. Again, the implementing regulation has not been issued.

Carbon market

On 26 September 2023, the Government set up IDX Carbon to accommodate carbon emission/credits trading. All carbon emission/credits "produced" in Indonesia should be traded on the IDX Carbon. The IDX Carbon is intended to cater to both mandatory market (for emission trading (see above)) and voluntary market (for carbon credits offsetting).

In January 2025, IDX Carbon launched an international carbon trading platform allowing the carbon credits to be sold to foreign buyers.

Mandatory carbon market
The mandatory market should link to carbon tax compliance following the "cap and trade" mechanism. Currently, the mandatory trading which is only applicable for coal-fired power plants is still managed by the MoEMR (instead of IDX Carbon).

Voluntary carbon market
At present, carbon trading on the IDX Carbon is limited to voluntary carbon credits offset. Carbon projects registered on the IDX Carbon currently consist of gas-fired power plants, geothermal power plants and mini-hydro power plants.

Certain tax considerations that project developers should be aware of include tax treatment of expenses related to carbon credit generating assets (as outright deductions or capitalisation), timing difference on revenue recognition (between accounting and tax), and VAT implications on the sale of carbon credits.

Please refer to our publication Accounting and Tax Considerations on Carbon Trading for Voluntary Market, available on the PwC Indonesia website at www.pwc.com/id for further explanations on tax considerations.

7.3.4 Taxation considerations on geothermal operations under a JOC

Government share

The "old" geothermal regime was covered by a JOC framework introduced via Presidential Decree (PD) 45/1991 (as an amendment to the earlier PD No. 22/1981) whereby Pertamina (now PT Pertamina Geothermal Energy Tbk (PGE)) and its contractors could undertake integrated geothermal and power activities.

That is, they could explore and exploit a geothermal source, build power plants and sell the electricity to PLN and other consumers. Pertamina (now PGE) was responsible for managing operations, while the contractor was responsible for producing geothermal energy (i.e. steam), converting the steam into electricity, and delivering the steam and/or electricity to the consumers.

From a tax perspective, a JOC is subject to a "*lex specialis*" arrangement as outlined in the JOC itself. The JOC generally outlines how to calculate the net operating income, which is subject to tax at a rate of 34%. The 34% tax (generally called the "government share") is considered an "all-inclusive" payment, resulting in the contractor taking an "assume to discharge" position in relation to its other tax obligations. These include Income Tax, VAT, import taxes, and any land and building taxes which are otherwise due under a general tax regime.

As mentioned in *Section 7.2.1. Income tax*, geothermal business activities will be further regulated under a government regulation (yet to be issued).

VAT

Under the JOC arrangements, VAT is generally reimbursable. The procedures for VAT reimbursement under the "JOC regime" can be found in MoF Regulation No.142/2013.

7.3.5 Tax incentives for renewable power generation

Tax allowance for renewable power generation

GR No. 78/2019 provides the following income tax incentives for renewable power generation:

1. Reduction in taxable income of up to 30% of the qualifying expenditure on fixed assets (including land). The reduction is prorated at a rate of 5% over six years from the date of commencement of commercial production.
2. Extended tax loss carry forward period of up to ten years (normal period is five years).
3. Accelerated depreciation and amortisation rates (i.e., double up of the normal depreciation/amortisation rate).
4. Dividend WHT rate of 10% or lower according to the applicable tax treaty for foreign shareholders.

Tax holiday for renewable power generation

MoF Regulation No. 69/2024 (MoF-69) (which amends MoF Regulation No. 130 Year 2020) allows for a reduction of 50% or 100% of the CIT rate for a period up to 20 years for businesses involved in "pioneer industries", which includes economic infrastructure.

BKPM issued Regulation No.7/2020 (BKPM-7) which further regulates that the economic infrastructure includes renewable power generation. This means the renewable power sector may be eligible for tax holiday.

Under MoF-69, the tax holiday application should be submitted not exceeding 31 December 2025.

The tax holiday facility can now be summarised as follows:

<table>
<tr><th rowspan="2">Provision</th><th colspan="2">Capital investment plan</th></tr>
<tr><th>IDR100bn ≤ IDR500bn</th><th>≥ IDR500 bn</th></tr>
<tr><td>CIT reduction rate</td><td>50%</td><td colspan="2">100%</td></tr>
<tr><td>Concession period (from the start of commercial production)</td><td>5 years</td><td colspan="2"><table>
<tr><th>No.</th><th>Investment (in IDR)</th><th>Period (in years)</th></tr>
<tr><td>1</td><td>500bn up to < 1tn</td><td>5</td></tr>
<tr><td>2</td><td>1tn up to < 5tn</td><td>7</td></tr>
<tr><td>3</td><td>5tn up to < 15tn</td><td>10</td></tr>
<tr><td>4</td><td>15tn up to < 30tn</td><td>15</td></tr>
<tr><td>5</td><td>≥ 30tn</td><td>20</td></tr>
</table></td></tr>
<tr><td>Transition</td><td>25% CIT reduction for the next two years</td><td colspan="2">50% CIT reduction for the next two years</td></tr>
</table>

The use of the tax holiday facility remains subject to reviews of key qualification criteria pursuant to an Indonesian tax authorities field audit. If the tax authorities determine that any of the qualifying requirements have not been satisfied, the tax holiday period can be amended or the tax holiday facility can be revoked, with liability to pay any unpaid tax plus penalties.

Tax facilities in IKN

Pursuant to Government Regulation No. 12/2023 (GR-12) and MoF Regulation No. 28/2024 (MoF-28), taxpayers located in the IKN areas are eligible for taxation and customs facilities including:

a. tax holiday, by offering a lower investment threshold and extended incentive periods compared to the general tax holiday scheme. The taxpayer who obtains approval for this facility can also be granted WHT exemption
b. super deduction (i.e., additional deduction on top of actual spending) for internships, vocational training, research and development activities, donations and public/social/non-profit facilities
c. final Article 21 Income Tax borne by the Government for employees working in IKN
d. income tax reduction on transfer of land and building (L&B) rights if the L&B is the buyer's first acquisition in IKN
e. VAT not collected for delivery and import of certain strategic goods and services, including for import by and/or delivery to taxpayers producing renewable energy within IKN
f. luxury sales tax (LST) exemption on delivery of luxury residential accommodation for individuals, entities or ministries/institutions with business activities in IKN
g. import duty and Article 22 exemptions and VAT not-collected facilities on the import of capital goods for industrial, construction and development activities in IKN

h. regional tax reductions, relief or exemptions, including zero-rated (0%) duty on L&B acquisition.

IPP projects located in IKN may be entitled to the tax facilities above subject to further assessment of the eligibility.

If a power project is granted with one of the above facilities, the power producers should consider impact of the Pillar Two GloBE Rules as outlined in the *Section 7.3.6 – GloBE Rules*, as to whether there is a top-up tax that needs to be settled in Indonesia.

7.3.6 GloBE Rules

MoF Regulation No. 136 Year 2024 (MoF-136) stipulates how the top-up tax (Pillar Two) mechanism under the GloBE Rules should be implemented in Indonesia. The GloBE Rules are generally effective from 1 January 2025, except for certain top-up tax mechanism (i.e. Under-Taxed Profit Rule or UTPR) which will be effective from 1 January 2026. The MoF-136 is designed to be aligned with the Organisation for Economic Co-operation and Development (OECD) GloBE Rules.

In a nutshell, GloBE Rules are aimed to implement global minimum tax rules that enforce a global tax framework ensuring a minimum taxation of 15% for multinational enterprises (MNEs) operating in low-tax jurisdictions. Certain implications of the MoF-136 for power producers may not be straightforward and therefore a detailed case-by-case analysis may be required.

Photo source: PwC

8 Accounting considerations

8.1 Accounting for conventional power generation

Indonesian Financial Accounting Standards (*Pernyataan Standar Akuntansi Keuangan*/PSAKs) have been brought substantially into alignment with the IFRS for annual reporting periods beginning 1 January 2012. This process of alignment has had an impact on the way many IPPs account for their activities.

8.1.1 Arrangements that may contain a lease

PSAKs require that arrangements conveying the "right to use an asset" in return for a payment or series of payments must be accounted for as a lease. This is the case even if the arrangements do not take the legal form of a lease.

Tolling arrangements may also convey the use of the asset to the party that supplies the fuel, in such a manner as to constitute a lease. Such arrangements have become common in the renewable energy business, in particular where all of the output from wind or solar farms or biomass plants might be contracted to a single party under a PPA.

In 2017, the Indonesian Financial Accounting Standards Board (DSAK-IAI) issued PSAK 73, Leases, which is effective for reporting periods beginning on or after 1 January 2020 and thereby started a new era of lease accounting for lessees. Whereas, under the previous guidance in PSAK 30, Leases, a lessee had to make a distinction between a finance lease (on balance sheet) and an operating lease (off balance sheet), the new model requires the lessee to recognise almost all lease contracts on the balance sheet; the only optional exemptions are for certain short-term leases and leases of low-value assets. Starting 1 January 2024, the PSAK has been recodified and PSAK 73 has changed to PSAK 116.

The new definition of a lease under PSAK 116 will be of particular interest to power companies when assessing their long-term arrangements for the purchase of inputs and the sale of electrical outputs. Once it has been determined that an electrical power supply contract contains a lease, the power purchaser will almost certainly have to account for the right to use the asset (e.g. a power plant) and the associated liability for payments on the balance sheet.

What is a lease?

PSAK 116 prescribes that a contract contains a lease when:

a. there is an identified asset
b. the contract conveys the right to control the use of the identified asset for a period of time in exchange for consideration.

Identified assets

An asset can be identified in a contract implicitly or explicitly. A contract may explicitly define a particular asset (e.g. a specific power plant which will have to be used in a specific location), or it may implicitly define an asset, as when a supplier can only fulfil a contract through the use of a particular asset (e.g. it is practically uneconomical to bring in another power plant from another location in order to fulfil the contract). The right to substitute an asset if it is not operating properly, or if a technical update is required, does not prevent the contract from being dependent upon an identified asset.

The right to control the use of an identified asset

The definition of a lease is now mainly driven by the question of which party to the contract controls the use of the underlying asset for the period of use. A customer no longer needs only to have the right to obtain substantially all of the benefits resulting from the use of an asset (the "benefits" element), but it must also have the ability to direct the use of the asset (the "power" element).

This conceptual change becomes obvious when looking at a contract to purchase substantially all of the output which is produced by an identified asset (for example, a power plant). PSAK 116 requires that the customer not only obtains substantially all of the economic benefits from the use of the asset, but also obtains an additional "power" element: namely, the right of the customer to direct the use of the identified asset (for example, the right to decide the amount and timing of power delivered).

The right to control the use of an identified asset is the key distinguishing factor, because the customer has control over the right to use the identified asset in a lease, whereas the supplier retains control over the use of the particular asset under a simple supply contract.


Photo source: PT Pembangkitan Jawa Bali

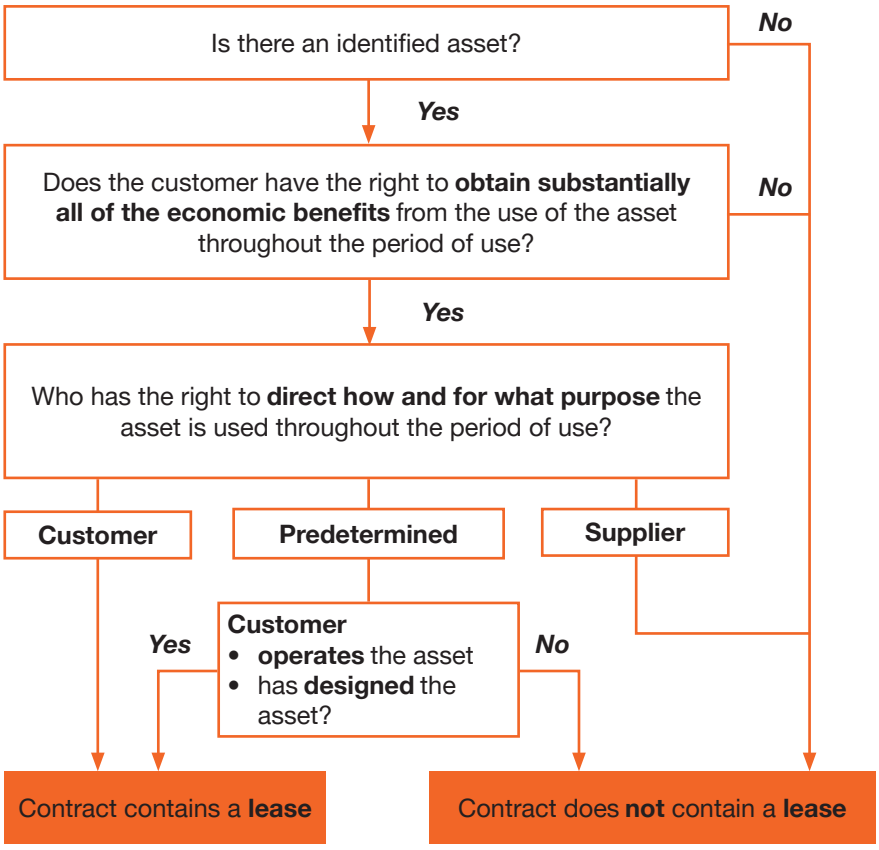
The key question to address, therefore, is which party (that is, the customer or the supplier) has the right to direct how and for what purpose an identified asset is used throughout the contract period. PSAK 116 gives several examples of relevant decision-making rights, namely:

a) the right to change what type of output is produced
b) the right to change when the output is produced
c) the right to change where the output is produced
d) the right to change how much of the output is produced.

The list is not exhaustive and none of the above criteria are independently exclusive, meaning there is no threshold for determining whether any of the criteria are more important than the others. The relevance of each of the decision-making rights depends on the underlying asset being considered. In a typical electrical power supply arrangement, for example, it is important to address which party has the rights to determine:

a) how much power will be delivered and when
b) when to turn the power plant on/off
c) which party has physical access to the power plant
d) whether the customer has the right to manage the power plant operations, even though it may choose not to do so.

The flowchart below summarises the analysis that needs to be made in order to determine whether a contract contains a lease:



Illustrative applications

PSAK 116 includes three illustrative examples of how a contract to purchase electrical power from a solar farm can be assessed in order to determine whether a lease element is embedded in the contract. We have analysed each of the three examples given by the standard and tailored them to illustrate the features which are commonly found in the Indonesian context.

Background information

An industrial complex (customer) enters into a contract with a power company (supplier) to purchase all of the electricity produced by a 10 MW gas-fired power plant for 20 years. The power plant is built next to the industrial complex.

A permanent gas pipeline from a local gas supplier is constructed and connected exclusively for the use of the plant. Due to the quantity of gas needed to fire the power plant, it is uneconomical for the supplier to purchase and transport gas from other locations.

Customer's rights	Supplier's rights	Conclusion
Example one		
The customer designed the power plant before it was constructed. The customer then hires experts to assist in the procurement and engineering of the equipment to be used in the power plant. The customer has access to inspect and monitor the operations of the power plant at any time. There are no decisions to be made about whether, when or how much electricity will be produced because the design of the asset has predetermined those decisions.	The supplier is responsible for building the power plant to the customer's specifications and then operating and maintaining it.	The contract contains a lease for the following reasons: • There is an identified asset and it is uneconomical for the supplier to substitute the plant with another asset from a different location. • The customer has the right to obtain substantially all of the economic benefits from the use of the power plant over the 20-year period. • The customer is deemed to have the rights to direct the use of the power plant, even though the customer does not operate the power plant directly. The design of the power plant has, in effect, programmed into the power plant any relevant decision-making rights about how and for what purpose the power plant is to be used. The customer's substantial involvement in the design of the plant has given it the right to direct the use of the plant.

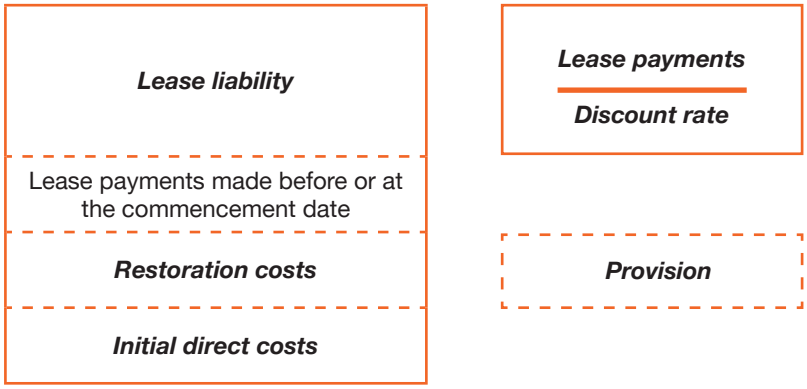
Customer's rights	Supplier's rights	Conclusion
Example two		
The customer has the right to obtain substantially all of the economic benefits from the use of the identified power plant over the 20-year period of use. The contract sets out the quantity and timing of the power that the power plant will produce throughout the period of use, which cannot be changed except in extraordinary circumstances (for example, emergency situations). The customer has no right to access the power plant.	The supplier designed the power plant when it was constructed some years before entering into the contract with the customer; the customer had no involvement in that design. The power plant is owned and operated by the supplier. The supplier operates and maintains the plant on a daily basis in accordance with industry-approved operating practices. The supplier has the right to sell excess capacity to other customers, without being required to obtain the approval of the industrial complex's management.	The contract does not contain a lease for the following reasons: • Even though there is an identified asset, because the power plant is explicitly specified in the contract, the customer does not have the right to control the use of the power plant because the customer does not direct how and for what purpose the plant is used. • How and for what purpose the plant is used (i.e. whether, when and how much power the plant will produce) is predetermined by the contract. • The customer has the same rights in relation to the use of the plant as if it were one of many customers obtaining power from the plant. The supplier can sell excess power to other customers. • The customer has no rights to change how and for what purpose the plant is used. The customer has no other decision-making rights about the use of the power plant (for example, it does not operate the power plant) and it did not design the plant. • The supplier is the only party that can make decisions about the plant by making decisions about how the plant is operated and maintained.
Example three		
The customer has the right to obtain substantially all of the economic benefits from the use of the identified power plant over the 20-year period of use. The customer issues instructions to the supplier about the quantity and timing of the delivery of power. The power plant is not operated in the event that no power is purchased by the customer.	The supplier operates and maintains the plant on a daily basis, in accordance with industry-approved operating practices.	The contract contains a lease for the following reasons: • There is an identified asset. • The customer has exclusive use of the power plant; it has a right to all of the power produced. • The customer has the right to direct the use of the power plant because the customer makes the relevant decisions about how and for what purpose the power plant is used. • Through the regular issuance of instructions, the customer determines whether, when and how much power the plant will produce. • Finally, because the supplier is prevented from using the power plant for another purpose, the customer's decision-making about the timing and quantity of power produced, in effect, determines when and whether, the plant produces output.

Lease accounting for a lessee

Initial recognition

Under PSAK 116, there is no longer a distinction between a finance lease contract and an operating lease: all lessees are required to capitalise a right-of-use asset and a corresponding lease liability for almost all lease contracts. The lease liability is initially capitalised on the date of commencement and measured at an amount equal to the present value of the lease payments that have not yet been paid during the lease term. The value of the right-of-use of the asset is equal to the lease liability at the commencement of the lease, plus any direct costs incurred in obtaining the contract, as well as any contractually obligated restoration costs.

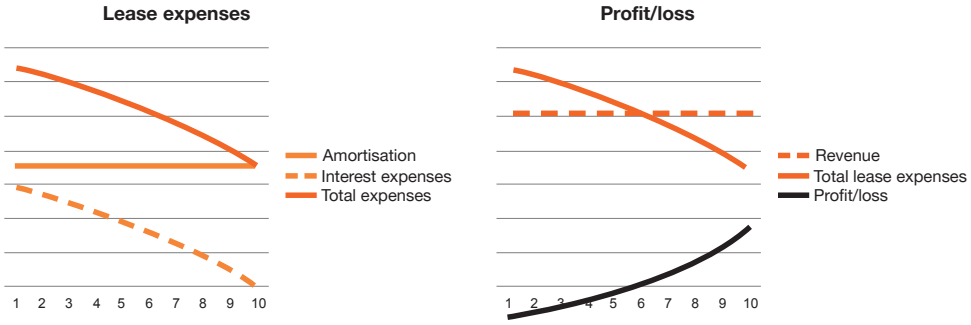
The lessee uses as its discount rate on the interest rate implicit in the lease. If this rate cannot be readily determined, the lessee should instead use its incremental borrowing rate.



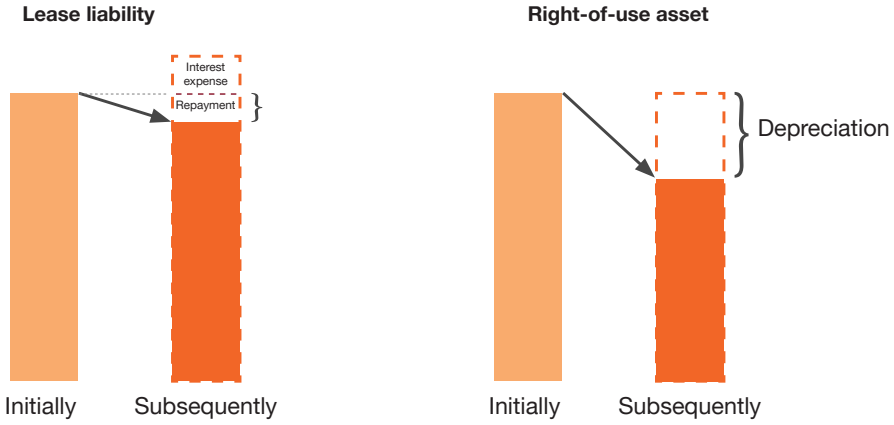
Subsequent measurement

The lease liability is measured in subsequent periods using the effective interest rate method. The right-of-use asset is depreciated in accordance with the requirements of PSAK 216, Property, Plant and Equipment, which will result in depreciation on a straight-line basis or another systematic basis which is more representative of the pattern through which the entity expects to consume the right-of-use asset.

The combination of the straight-line depreciation of the right-of-use asset and the effective interest rate method as applied to the lease liability results in decreasing total lease expenses throughout the term of the lease. This effect is sometimes referred to as frontloading.



The carrying amounts of the right-of-use asset and the lease liability will no longer be equal in subsequent periods. Due to the frontloading effect described above, the carrying amount of the right-of-use asset will, in general, be less than the carrying amount of the lease liability.



Indicator	Impact from PSAK 116
Operating cash flow	This will increase because the operating lease payments that were previously presented as part of operating cash flow are now presented as part of financing cash flow, even though this is offset by higher cash outflows from the finance costs of the lease.
Financing cash flow	This will decrease because the operating lease payments that were previously presented as part of operating cash flow are now presented as part of financing cash flow. The financing cash flow may also be further reduced by the cash outflow relating to the financing cost element of a lease.
Asset turnover sales/total assets	This will be lower because of the additional right-of-use of the leased asset that now has to be capitalised on the balance sheet.

Lease accounting for a lessor

The accounting for a lessor is practically the same under PSAK 116 as it was under PSAK 30. The lessor still has to classify leases as either finance or operating, depending on whether substantially all of the risks and rewards incidental to ownership of the underlying asset have been transferred. For a finance lease, the lessor recognises a receivable at an amount equal to the net investment in the lease, which is the present value of the aggregate of the lease payments receivable by the lessor and any unguaranteed residual value. If the contract is classified as an operating lease, the lessor continues to present the underlying assets.

In March 2017, OJK, the Indonesian Financial Services Authority, issued OJK Regulation No. 6 POJK.04/2017 (POJK No. 6/2017), regulating the accounting treatment for the purchase and sale of electricity by a company with publicly traded debt/equity instruments in Indonesia (the issuer). This matter is further discussed in *Section 8.1.3 – Accounting treatment for the purchase and sale of electricity by an issuer in Indonesia*.

PPAs

PSAK 116 will bring substantial new assets and liabilities onto a lessee's balance sheet for leases of assets. However, the change in definition of a lease will be of particular interest to power and utility companies when assessing long-term arrangements for the purchase of inputs or the sale of output. PSAK 116 supersedes PSAK 30 and ISAK 8 and includes a revised definition of a lease. Previously, the key question was perhaps not whether an arrangement contained a lease, but rather whether it contained a finance lease. This was because the distinction between operating leases and service contracts did not impact the accounting significantly, as both arrangements were effectively "off-balance sheet". Under PSAK 116, following the removal of the "off-balance sheet" operating lease treatment, the determination as to whether an arrangement contains a lease becomes far more important. Currently under ISAK 8, there are three conditions which must be considered in order to determine whether an arrangement includes a lease, being:

- whether the arrangement confers the right to operate one or more assets
- whether the arrangement grants the right to physical access to the assets
- the price mechanism used, including whether the amount charged varies per unit.

The determination under PSAK 116 of whether the contract contains a lease is based on whether the arrangement confers control. Arrangements which confer a right to operate and the right to physical access will typically result in a conclusion of control under both ISAK 8 and PSAK 116. This will lead to the recognition of a right-of-use asset and a lease liability for arrangements which meet these criteria, even if, for example, they do not extend over a significant proportion of the asset's life. However, if meeting the price condition would have been the determining factor under ISAK 8, it is possible that under PSAK 116 no lease would be identified. As an example, if the price for an output contract was a total fixed price to be

paid even if the customer could decide not to take some of the output, this would be viewed as a lease under ISAK 8, but not necessarily under PSAK 116. The standard includes several relevant examples regarding how the above definition should be applied in practice, which are summarised below:

Example	Customer rights	Supplier rights	Other factors	Conclusion under PSAK 116
1 – Solar farm	Contract to purchase all output over 20 year life of plant. Design of plant specified by customer.	Responsible for building and operating plant and operating and maintaining to customer specifications.	Supplier will receive tax credits for the construction.	Contract contains a lease as the customer has the right to direct how and for what purpose the asset is used, as predetermined by the design of the plant.
2 – Solar farm	Purchases all output. Schedule all output is pre-determined. Customer has no right of access to the plant or decision making rights.	Own and operate the plants, cannot substitute the plant. Supplier designed and built the plant with no involvement of the customer.		Contract does not contain a lease since customer rights do not extend beyond those of a customer in a typical supply or service contract.
3 – Solar farm	Purchases all power over a particular period. Customer issues instruction on operating the plant and controls quantity and timing of delivery.	Supplier operates and maintains the plant.		Contract contains a lease as customer is making the decisions about how and for what purpose the asset is being used.
4 – Fibre optic cable	Right to use three physically distinct fibre within fibre optic cable. Customer makes decision about use.	Supplier responsible for repairs and maintenance. Can only substitute for reasons of repair, maintenance or malfunction.		Customer has right of control and contract contains a lease.
5 – Fibre optic cable	Right to use specified amount of capacity within fibre optic cable (cable contains 15 fibres with similar capacities).	Supplier determines which fibres are used.		Contract does not contain a lease as the capacity portion is not physically distinct and hence customer does not control it.

8.1.2 Service concession arrangements

A PPP is an arrangement whereby the Government attracts private sector participation for the provision of infrastructure services. As outlined in earlier chapters, these arrangements include power generation. These types of arrangements are often described as concessions and many fall within the scope of ISAK 112 – Service Concession Arrangements (equivalent to International Financial Reporting Interpretations Committee (IFRIC) 12).

Arrangements within the scope of ISAK 112 are those where a private sector entity constructs the infrastructure (a power generating plant, in this instance), then maintains it and provides the service to the public (via PLN, in the case of power generation). The provider may be paid for its services in different ways. Many concessions require that the related infrastructure assets be returned or transferred to the Government at the end of the concession period.

ISAK 112 applies to arrangements where the grantor (the Government or its agents) controls or regulates which services the operator can provide using the infrastructure, to whom it must provide them and at what price. The grantor also controls any significant residual interest in the infrastructure at the end of the term of the arrangement.

The most common example of such an arrangement will, in this context, be a power plant constructed via a BOOT arrangement with a national utility such as PLN.

Power generation arrangements can fall within the scope of ISAK 112, as these have many of the features of a service concession arrangement.

The two accounting models under ISAK 112 that an operator applies in order to recognise the rights received under a service concession arrangement are the following:

a. Financial assets – an operator with a contractual and unconditional right to receive specified or determinable amounts of cash (or another financial asset) from the grantor which recognises a financial asset rather than a fixed asset (i.e. derecognises the power plant, in this case and replaces it with a financial asset).
b. Intangible assets – an operator with a right to charge the users of the public service recognises an intangible asset. There is no contractual right to receive cash when the payments are contingent on usage.

Arrangements between the Government and service providers are generally complex. A detailed analysis of the specific arrangement is necessary to determine whether the arrangement is within the scope of ISAK 112. If it is within the scope of ISAK 112, then the appropriate accounting model may not always be obvious. Entities should be analysing their arrangements in order to draw conclusions as to whether the arrangement falls under the

financial asset or intangible asset model. Some complex arrangements may have elements of both models for the different phases. It may be appropriate to account separately for each element of the consideration.

8.1.3 Accounting treatment for the purchase and sale of electricity by an issuer in Indonesia

POJK No. 6/2017 should be applied by all issuers (i.e. a company with publicly traded debt/equity in Indonesia) to account for the purchase and sale of electricity in Indonesia. Issuers should account for all purchases and sales of electricity in Indonesia as normal purchase and sales transactions. In practice, OJK is providing a temporary exemption from applying the lease (discussed in 8.1.1) and service concession (discussed in 8.1.2) accounting model for issuers that sell electricity to PLN.

POJK No. 6/2017 was issued to support PR No. 4/2016 (which was later amended by PR No. 14/2017) and to accelerate the development of power generation infrastructure in Indonesia. It is believed that temporarily exempting issuers from the financial implications of lease or service concession accounting will help to advance the development of power generation projects in Indonesia. POJK No. 6/2017 is only applicable to issuers which are under the supervision of OJK. In many cases, however, IPPs which sign PPAs with PLN do not issue publicly traded instruments. Privately-owned project companies are established by a consortium of investors in order to sign PPAs with PLN. These privately-owned IPPs are not issuers which are subject to the Capital Market Laws in Indonesia and consequently they cannot apply the provisions of POJK No. 6/2017, meaning therefore that they must follow the provisions of the PSAKs.

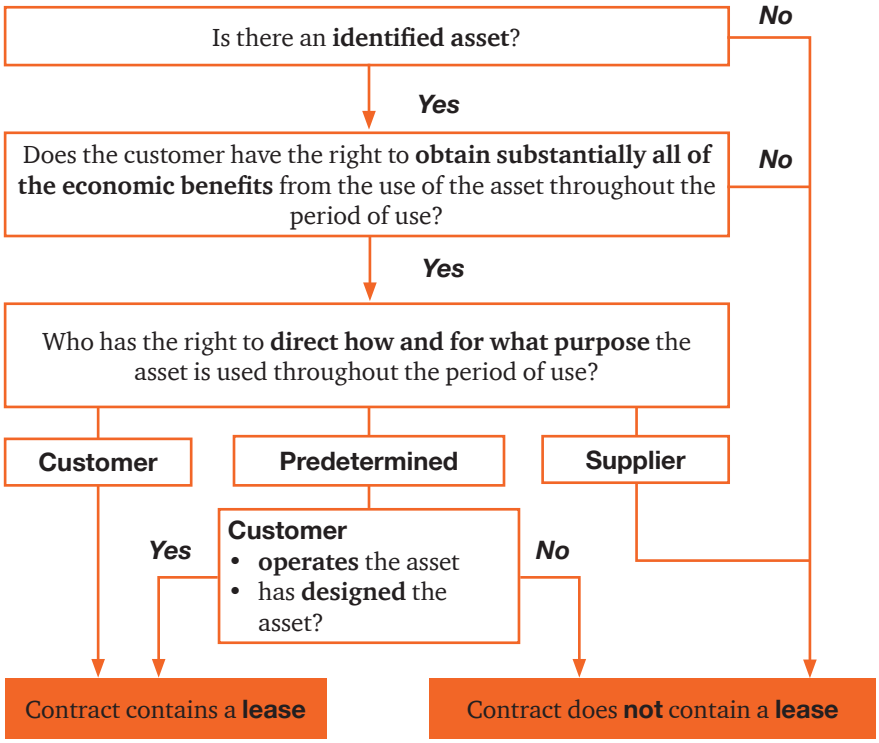
POJK No. 6/2017 has been applied prospectively, starting from 1 January 2017, and it can be adopted for the financial year which began on 1 January 2016. This temporary exemption is only available as long as PR No. 4/2016, subsequently amended by PR No. 14/2017, is in effect. After the temporary exemption period is over, issuers will have to apply all of the provisions of PSAK or IFRS that come into effect in the future.

It is not entirely clear how POJK No. 6/2017 will be applied in a group situation, where a listed parent entity (an issuer) controls a privately-owned IPP that signs a PPA with PLN. As it is currently written, it does not appear that the temporary exemption is applicable to the group, unless the parent issuer sells electricity directly to PLN. This is an issue that requires further elaboration. Therefore, we recommend that you consult with your PwC advisors before applying the temporary exemption of POJK No. 6/2017 in such a situation.

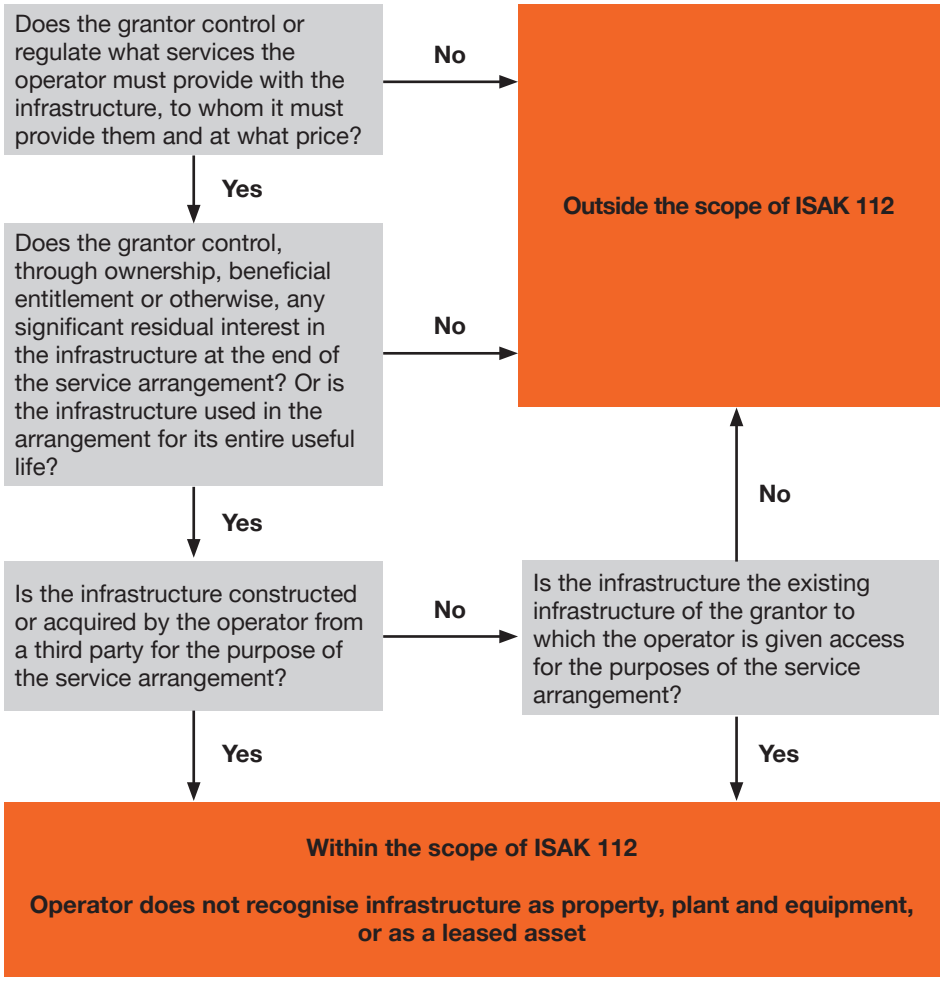
8.1.4 Application of accounting standards

The flowchart below summarises the analysis to be made to evaluate whether a contract contains a lease:

PSAK 116 – Identifying a lease



ISAK 112 – Determining whether a service concession arrangement exists



PSAKs that apply to typical types of PPP arrangements

Excepting issuers which apply the temporary exemption of POJK No. 6/2017, the table below sets out the typical types of arrangement for private sector participation in the provision of public sector services, as well as providing references to the PSAKs which apply to those arrangements. The list of arrangement types is not exhaustive. The purpose of the table is to highlight the continuum of the arrangements. It is not our intention to convey the impression that bright lines exist between the accounting requirements for PPP arrangements.

Category	Lessee	Service provider			Owner	
Typical arrangement types	Lease (e.g. operator leases assets from grantor)	Service and/or maintenance contract	Rehabilitate-operate-transfer	Build-operate-transfer	Build-own-operate	100% divestment/ privatisation/ corporation
Asset ownership	Grantor				Operator	
Capital investment	Grantor		Operator			
Demand risk	Shared	Grantor	Operator and/or grantor		Operator	
Typical duration	8-20 years	1-5 years	25-30 years			Indefinite (or may be limited by licence)
Residual interest	Grantor				Operator	
Relevant PSAKs	PSAK 116 - Leases	PSAK 115 - Revenue from Contract with Customers	ISAK 112- Service Concession Arrangements		PSAK 216- Fixed Assets	

In accordance with POJK No. 6/2017, issuers account for all purchases and sales of electricity as normal purchase and sale transactions, as long as PR No. 14/2017 is in effect. Please see the discussion in *Section 8.1.3 – Accounting treatment for the purchase and sale of electricity by an issuer in Indonesia* for further details.

8.1.5 Key accounting standards under PSAK, US Generally Accepted Accounting Principles (GAAP) and IFRS

The table below summarises the key standards and differences relating to conventional power generation companies under PSAK, US GAAP and IFRS. For details of the key accounting standards, please refer to our publication "IFRS and Indonesian GAAP (PSAK): Similarities and Differences 2015".

Accounting for conventional power generation A general comparison between Indonesian GAAP, US GAAP and IFRS			
Area	**IFRS**	**US GAAP**	**Indonesian GAAP**
Identification and classification of concession arrangements	PPP service concession arrangements that meet certain conditions must be analysed to determine whether the concession represents a financial asset or an intangible asset.	Consistent with IFRS in all significant respects.	Consistent with IFRS in all significant respects, except for Issuers applying POJK No. 6/2017, as explained in *Section 8.1.3 - Accounting treatment for the purchase and sale of electricity by an issuer in Indonesia*.

Accounting for conventional power generation A general comparison between Indonesian GAAP, US GAAP and IFRS			
Area	**IFRS**	**US GAAP**	**Indonesian GAAP**
Arrangements that may contain a lease: retrospective action	Arrangements that convey the right to use an asset in return for a payment or series of payments are required to be accounted for as leases if certain conditions are met. This requirement applies even if the contract does not take the legal form of a lease. The IFRS guidance that requires this analysis, IFRIC 4, requires all existing arrangements to be analysed upon adoption (i.e. no grandfathering of existing arrangements).	Similar to IFRS, except that the US GAAP guidance, Emerging Issues Task Force (EITF) 01-8 (codified into Accounting Standards Codification (ASC) 840), was applicable only to new arrangements entered into (or modifications made to existing arrangements) after the effective date (i.e. grandfathering of existing arrangements was provided).	Consistent with IFRS in all significant respects.

8.2 O&M accounting

No specific accounting standards have been promulgated for power generation O&M businesses. Instead, the generally accepted accounting standards usually apply.

8.3 Accounting for geothermal power generation

The key accounting standards for renewable energy projects are the same as those for conventional power generation.

However, the accounting treatment for geothermal E&E is similar to the accounting treatment for activities in the oil and gas industry, which can be used as guidance for treating the E&E costs.

Exploration, as defined in PSAK 106, exploration and evaluation (E&E) of Mineral Resources (equivalent to IFRS 6), starts when the legal rights to explore have been obtained. Any expenditure incurred before obtaining the legal rights is generally expensed.

Two broadly acknowledged methods have traditionally been used under local GAAP to account for E&E and the subsequent development costs:

a. Successful efforts.
b. Full cost.

Debate continues within the industry on the conceptual merits of both the two methods, although neither is wholly consistent with the PSAK framework. PSAK 106 provides an interim solution for E&E costs, pending the issuance of more comprehensive accounting standards for the extractive industries.

An entity should account for its E&E expenditure by developing an accounting policy which complies with the PSAK framework or which is in accordance with the exemptions permitted by PSAK 106.

PSAK 106 allows an entity to continue to apply its existing accounting policy under the national GAAP for E&E. However, an entity can change its accounting policy for E&E only if the change results in an accounting policy which is closer to the principles of the IFRS framework.

The costs incurred after the probability of economic feasibility has been established are only capitalised if the costs are necessary to bring the resource to the commercial production stage. Subsequent expenditure should not be capitalised after commercial production commences, unless it meets the asset recognition criteria.

For a summary of the key differences between PSAK and IFRS, please refer to our publication "IFRS and Indonesian GAAP (PSAK): Similarities and Differences"[1]. For the major accounting practices adopted by the power industry under IFRS, please refer to our publication "Financial Reporting in the Power and Utilities Industry"[2].

8.4 PSAK 115 – a new model for recognising revenue

Effective from 1 January 2020, all financial statements will have to apply the new PSAK 72, Revenue from Contracts with Customers, in order to determine the timing and amount of revenue which can be recognised for sales of goods and services. Starting 1 January 2024, the PSAK has been recodified and PSAK 72 has changed to PSAK 115. PSAK 115 has been adapted from IFRS 15, Revenue from Contracts with Customers. PSAK 115 introduces a new revenue recognition model which emphasises the satisfaction of the performance obligations identified in contracts with customers for a seller to be able to recognise revenue. Entities will now have to apply a five-step approach in order to determine when and how much revenue can be recognised:

Step one: Identify the contract with the customer.
Step two: Identify the separate performance obligations in the contract.
Step three: Determine the transaction price.
Step four: Allocate the transaction price to the separate performance obligations.
Step five: Recognise revenue when (or as) a particular performance obligation is satisfied.

Entities will need to exercise judgment when considering the terms of the contract and all of the facts and circumstances, including the implied contract terms. The introduction of a new revenue recognition model may change the timing and the amount of the top-line revenue of many power companies.

We have highlighted below a number of potential scenarios which are likely to change the current revenue recognition practices of power companies, following the adoption of PSAK 115. Our analysis has not been written to provide a comprehensive list covering all of the potential cases, as there may be other areas of complexity identified in the different forms of contracts which power companies currently use. We may identify additional issues as more power companies begin to apply PSAK 115 and our views may evolve during that process.

Potential impact on power companies

Potential scenario	Potential impacts on power companies
Take-or-pay arrangement	• Take-or-pay arrangements are often found in PPAs, where a customer agrees to purchase and pay for a minimum amount of electrical power from the supplier over a contracted period. • Where a PPA with a take-or-pay arrangement is not subject to the scope of PSAK 116, Leases (see below for further analysis of this standard), PSAK 115 prescribes specific accounting principles to account for revenue, where a customer does not exercise all of its contractual rights (i.e. breakage). • Breakage is commonly found in cases where a customer has prepaid the minimum guaranteed amount, but does not exercise its rights to take all of the guaranteed electrical output. • The existing accounting literature does not have any specific guidance for breakage, but PSAK 115 allows a power company to estimate the amount of breakage that it expects to benefit from over a contract period (i.e. the amount of unexercised rights by the customer) and to account for the breakage revenue in proportion to the pattern of rights exercised by its customer. • This means that, in some cases, a power company may recognise more revenue upfront if it can reasonably predict the amount of electrical output that is guaranteed but will never be consumed by the customer. Otherwise, breakage is recognised as revenue only when the likelihood of a customer exercising its rights becomes remote.
Contingent consideration	• Contingent consideration is another common feature found in PPAs, where payment for the electrical supply is adjusted for the actual heat rate, performance bonus, step-up prices, etc. • PSAK 115 allows a power company to estimate the amount of variable consideration upfront and include it in the measurement of the total transaction price of a contract. • However, a power company may only recognise revenue from contingent considerations if it is highly probable that the amount of revenue recognised will not be subject to significant future reversals when the uncertainty is resolved. Otherwise, the power company will have to defer the recognition of the revenue from the contingent consideration until the uncertainty has been resolved. • Effectively, power companies need to make decisions using their judgment, based on the facts and circumstances of their arrangements, as the profile of revenue recognition may change as a result of PSAK 115.
Contract costs	• There is currently little guidance on how power companies should account for the costs spent in obtaining a PPA. PSAK 115 allows power companies to capitalise certain costs of obtaining a contract, which may include the commission fees payable to agents for obtaining a PPA. • Once the contract costs have been capitalised, they should be amortised on a systematic basis over the contract period. Consequently, the new PSAK 115 treatment may change the pattern of cost recognition and operating profit, over the contract period.

Potential scenario	Potential impacts on power companies
Contract modification	• Another potential area requiring judgment in the implementation of PSAK 115 is the new guidance on contract modification. For example, a power company may agree to extend the period of a contract and create a blended price for the remaining volume of electrical power to be delivered over the extended contract period. • A power company may account for the blend-and-extend arrangement in one of two ways: – Account for the arrangement prospectively. In this case, the blend-and-extend agreement is treated as a separate contract from the original arrangement, given that the modification results in an additional volume of electrical power to be delivered and the new price reflects the stand-alone selling price of the additional electrical output delivered (e.g. the new blended rate equals the market rate at the time of extension). – Apply the blended rate to all remaining units in cases where the original contract is terminated and a new contract is created. This is the case where the modification results in an additional volume of electrical power to be delivered, but the new price does not represent the stand-alone selling price of the additional output (e.g. the new blended rate is actually higher/lower than the market rate at the time of negotiation). Arguably, there is an economic relationship between the original agreement and the modified contract. • Under the existing accounting literature, many power companies simply apply the new blended rate to all remaining units, similar to option two above. Under PSAK 115, however, the revenue recognition pattern may change depending on the assessment of the new blended rate against the stand-alone selling price of electricity to be delivered at the time of contract extension.

Photo source: PT Paiton Energy

Appendix 1 - Renewable energy pricing

Purchase price of electricity from hydropower that utilises power from water streams/ falls

No.	Capacity	Ceiling price (USD cent/kWh)	
		1st to 10th	Years 11th to 30th
1	Up to 1 MW	(11.23 x F)*	7.02
2	>1 MW to 3 MW	(10.92 x F)*	6.82
3	>3 MW to 5 MW	(9.65 x F)*	6.03
4	>5 MW to 20 MW	(9.09 x F)*	5.68
5	>20 MW to 50 MW	(8.86 x F)*	5.54
6	>50 MW to 100 MW	(7.81 x F)*	4.88
7	>100 MW	(6.74 x F)*	4.21

*The ceiling price is the price after multiplied by factor F.

The purchase price of electricity from hydropower plants utilising hydropower from reservoirs/dams or irrigation channels owned by the ministry that manages water resources affairs

No.	Capacity	Ceiling price (USD cent/kWh)	
		1st to 10th	Years 11th to 30th
1	Up to 1 MW	(11.23 x 0.8 x F)*	7.02 x 0.8
2	>1 MW to 3 MW	(10.92 x 0.8 x F)*	6.82 x 0.8
3	>3 MW to 5 MW	(9.65 x 0.8 x F)*	6.03 x 0.8
4	>5 MW to 20 MW	(9.09 x 0.8 x F)*	5.68 x 0.8
5	>20 MW to 50 MW	(8.86 x 0.8 x F)*	5.54 x 0.8
6	>50 MW to 100 MW	(7.81 x 0.8 x F)*	4.88 x 0.8
7	>100 MW	(6.74 x 0.8 x F)*	4.21 x 0.8

*The ceiling price is the price after multiplied by factor F.

Purchase price of electricity from photovoltaic PLTS (not including battery facilities or other electrical energy storage facilities)

No.	Capacity	Ceiling price (cent USD/kWh)	
		1st to 10th	Years 11th to 30th
1	Up to 1 MW	(11.47x F)*	6.88
2	>1 MW to 3 MW	(9.94x F)*	5.97
3	>3 MW to 5 MW	(8.77x F)*	5.26
4	>5 MW to 10 MW	(8.26x F)*	4.96
5	>10 MW to 20 MW	(7.94x F)*	4.76
6	>20 MW	(6.95x F)*	4.17

*The ceiling price is the price after multiplied by factor F.

Purchase price of electricity from PLTB (not including battery facilities or other electrical energy storage facilities)

No.	Capacity	Ceiling price (USD cent/kWh)	
		1st to 10th	Years 11th to 30th
1	Up to 5 MW	(11.22 x F)*	6.73
2	> 5 MW to 20 MW	(10.26 x F)*	6.15
3	>20 MW	(9.54 x F)*	5.73

*The ceiling price is the price after multiplied by factor F.

Purchase price of electricity from PLTBm

No.	Capacity	Ceiling price (USD cent/kWh)	
		1st to 10th	Years 11th to 25th
1	Up to 1 MW	(11.55 x F)*	9.24
2	>1 MW to 3 MW	(10.73 x F)*	8.59
3	>3 MW to 5 MW	(10.20 x F)*	8.16
4	>5 MW to 10 MW	(9.86 x F)*	7.89
5	>10 MW	(9.29 x F)*	7.43

*The ceiling price is the price after multiplied by factor F.

Purchase price of electricity from PLTBg

No.	Capacity	Ceiling price (USD cent/kWh)	
		1st to 10th	Years 11th to 20th
1	Up to 1 MW	(10.18 x F)*	6.11
2	>1 MW to 3 MW	(9.81 x F)*	5.89
3	>3 MW to 5 MW	(8.99 x F)*	5.39
4	>5 MW to 10 MW	(8.51 x F)*	5.1
5	>10 MW	(7.44 x F)*	4.46

*The ceiling price is the price after multiplied by factor F.

Purchase price of electricity from PLTP wholly built by a business entity and wholly or partially built by the Government or local governments, including those originating from the grants

No.	Capacity	Ceiling price (USD cent/kWh)	
		1st to 10th	Years 11th to 30th
1	Up to 10 MW	(9.76 x F)*	8.3
2	>10 MW to 50 MW	(9.41 x F)*	8
3	>50 MW to 100 MW	(8.64 x F)*	7.35
4	>100 MW	(7.65 x F)*	6.5

*The ceiling price is the price after multiplied by factor F.

The purchase price of electricity from PV PLTS, PLTA, PLTB, PLTBm and PLTBg wholly or partially built by the Government or local governments, including those derived from grants

No.	Type of generation	Ceiling price (USD cent/kWh)
1	PLTA	3.76
2	PV PLTS	5.63
3	PLTB	5.63
4	PLTBm	9.29
5	PLTBg	7.44

*The ceiling price is the price after multiplied by factor F.

Appendix 2 - Geothermal working areas

Installed geothermal capacity by licence holder and operator, as of 2024

No	Working area	Location	IPB owner	Turbine capacity	Operator steam area	Operator PLTP	Total capacity (MW)
1	Sibayak PLTP	North Sumatera	PT Pertamina Geothermal Energy (Persero)	2 x 5.65 MWe, 2 MWe (Monoblock)	PT Pertamina Geothermal Energy (Persero)	Dizamatra Powerindo, PGE	13.30
2	Sarulla PLTP	North Sumatera	PT Pertamina Geothermal Energy (Persero)	1 x 139.205 MWe, 1 x 148.53 MWe, 1 x 130.4 MWe	KKOB Sarulla Operations, Ltd	KKOB SO, Ltd	418.14
3	Sorik Marapi PLTP	North Sumatera	PT Sorik Marapi Geothermal Power	1 x 68.8 MWe, 1 x 66.65 MWe, 1 x 62.8 Mwe, 39.6 MWe, 1 x 41.25 MWe	PT Sorik Marapi Geothermal Power	SMGP	279.10
4	Muaralaboh PLTP	West Sumatera	PT Supreme Energy Muara Laboh	1 x 89.25 MWe	PT Supreme Energy Muara Laboh	SEML	89.25
5	Lumut Balai PLTP	South Sumatera	PT Pertamina Geothermal Energy (Persero)	1 x 59.92 MWe	PT Pertamina Geothermal Energy (Persero)	PGE	59.92
6	Rantau Dedap PLTP	South Sumatera	PT Supreme Energy Rantau Dedap	1 x 98.4 MWe	PT Supreme Energy Rantau Dedap	SERD	98.40
7	Ulubelu PLTP	Lampung	PT Pertamina Geothermal Energy (Persero)	2 x 55 MWe, 2 x 59.5 MWe	PT Pertamina Geothermal Energy (Persero)	PLN, PGE	229.00
8	Kamojang PLTP	West Java	PT Pertamina Geothermal Energy (Persero)	1 x 30 MWe, 2 x 55 MWe, 1 x 64 MWe, 1 x 35 MWe	Indonesia Power	Indonesian Power, PGE	239.00
9	Darajat PLTP	West Java	PT Pertamina Geothermal Energy (Persero)	1 x 55 MWe, 1 x 100.71 MWe, 1 x 137,5 MWe	KKOB Star Energy Geothermal Darajat II, Ltd	Indonesia Power, KKOB SEGD II, Ltd	293.21
10	PLTP Salak	West Java	PT Pertamina Geothermal Energy (Persero)	2 x 60 MWe, 1 x 61 MWe, 3 x 66.99 MWe	Indonesia Power	Indonesia Power, KKOB SEGS, Ltd.	381.97

No	Working area	Location	IPB owner	Turbine capacity	Operator steam area	Operator PLTP	Total capacity (MW)
11	Wayang Windu PLTP	West Java	PT Pertamina Geothermal Energy (Persero)	1 x 110 MWe, 1 x 117 MWe	KKOB Star Energy Geothermal Wayang Windu, Ltd	KKOB SEGWW, Ltd	227.00
12	Patuha PLTP	West Java	PT Geo Dipa Energi (Persero)	1 x 59.88 MWe	PT Geo Dipa Energi (Persero)	GDE	59.88
13	Karaha PLTP	West Java	PT Pertamina Geothermal Energy (Persero)	1 x 30 MWe	PT Pertamina Geothermal Energy (Persero)	PGE	30.00
14	Dieng PLTP	Central Java	PT Geo Dipa Energi (Persero)	1 x 60 MWe, 1 x 12.8 MWe	PT Geo Dipa Energi (Persero)	GDE	72.80
15	Ulumbu PLTP	East Nusa Tenggara	PT PLN (Persero)	4 x 2.5 MWe	PT PLN (Persero)	PLN	10.00
16	Mataloko PLTP	East Nusa Tenggara	PT PLN (Persero)	1 x 2.5 MWe	PT PLN (Persero)	PLN	2.50
17	Sokoria PLTP	East Nusa Tenggara	PT Sokoria Geothermal Indonesia	2 x 3.291 MWe, 1 x 5 MWe	PT Sokoria Geothermal Indonesia	SGI	11.58
18	Lahendong PLTP	North Sulawesi	PT Pertamina Geothermal Energy (Persero)	4 x 20 MWe, 2 x 21.5 MWe, 1 x 0.71 MWe	PT Pertamina Geothermal Energy (Persero)	PLN, PGE	123.71
Total installed capacity (MWe)							2,638,75

Source: HEESI Report, Directorate General of New and Renewable Energy and Energy Conservation 2024

Appendix 3 - About PwC

The firms of the PwC global network (www.pwc.com/id) provide industry-focused assurance, tax, legal, advisory and consulting services for public and private companies. More than 370,000 people in 149 countries connect their thinking, experience and solutions to build trust and enhance value for clients and their stakeholders.

PwC is organised into lines of service, each staffed by highly qualified experienced professionals who are leaders in their fields, providing the following:

Assurance provides assurance over any system, process or controls and over any set of information to the highest PwC quality.

- Financial statement audit
- Risk assurance:
  - Governance, risk and compliance
  - Digital trust solutions
  - Internal audit
- markets and accounting advisory services:
  - Accounting advisory services
  - Capital market services
  - Integrated financial reporting
- ESG reporting and assurance

Tax services optimises tax efficiency and contributes to overall corporate strategy through the formulation of effective tax strategies and innovative tax planning. Some of our value-driven tax services include:

- corporate tax
- international tax
- transfer pricing (TP)
- mergers and acquisitions (M&A)
- VAT
- tax disputes
- international assignments
- customs
- investment and corporate services
- tax technology and strategy
- carbon tax advisory

Deals advisory implements an integrated suite of solutions covering deals and transaction support from deal strategy through to execution and post-deal services:

- Business recovery services
- Sustainable infrastructure advisory
- Economics & policy
- Corporate finance
- Valuation
- Deal strategy
- Delivering deal value
- Transaction services
- Environmental, social and governance (ESG) deal services
- Energy transition advisory
- Forensic investigations
- Financial crime solutions
- Forensic technology solutions
- Human rights impact assessments

Consulting helps organisations to work smarter and grow faster. We consult with our clients in order to build effective organisations, to innovate and grow, to reduce costs, to manage risk and regulations, and to leverage talent. Our aim is to support you in designing, managing and executing lasting beneficial change:

- Digital transformation
- Risk
- Strategy

Legal services provides solutions of the highest quality through the provision of cutting edge legal solutions to support and facilitate legal developments in Indonesia. We work with you to understand your commercial objectives and offer you seamless end-to-end service across the lifecycle of your project. Our core value is providing legal services that put the needs and priorities of our clients first, while continuously improving our approach and continuing to do business ethically. Our legal services include:

- M&A and corporate advisory
- finance and financial regulation
- capital markets
- regulatory

For companies operating in the Indonesian power sector, there are some compelling reasons to choose PwC Indonesia as your professional services firm:

- The PwC network is the leading adviser to the power and utilities industry, both globally and in Indonesia, working with more energy and utilities companies than any other professional services firm. We have operated in Indonesia since 1971 and have over 3,300 professional staff, including over 90 partners and technical advisors, specialised in providing assurance, advisory, tax and legal services to Indonesian and international companies.
- Our energy, utilities and resources (EU&R) practice in Indonesia comprises over 570 dedicated professionals across our lines of service. This body of professionals brings deep local industry knowledge and experience with international industry expertise and provides us with the largest group of industry specialists in the Indonesian professional services market. We also draw on the PwC global EU&R network which includes more than 27,000 people focused on serving energy, power and mining clients.
- Our commitment to the power industry is unmatched and demonstrated by our active participation in industry associations in Indonesia and around the world and our thought leadership on the issues affecting the industry.
- Our client service approach involves learning about your organisation's issues and seeking ways to add value to every task we perform. Detailed power industry and energy transition knowledge and experience ensures that we have the background and understanding of industry issues and can provide sharper, more sophisticated solutions that help clients accomplish their strategic objectives.

Contact us to discuss your plans for investment in the Indonesian power sector.

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Acknowledgements

We would like to convey our sincere thanks to all of the contributors for their efforts in supporting the preparation of this publication.

Photographic contributions

We gratefully acknowledge and thank the following companies that have provided photographs for inclusion in this publication (in alphabetical order):
PT Jawa Power
PT Paiton Energy
PT Pembangkitan Jawa Bali
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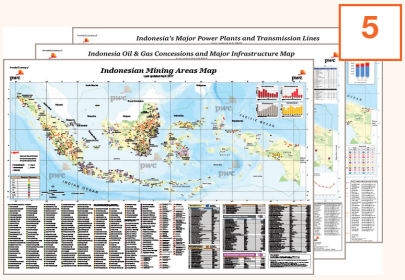

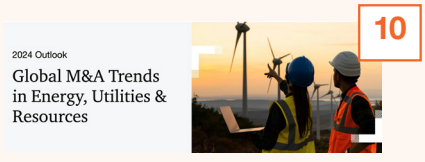

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