Power in Indonesia

Investment and Taxation Guide

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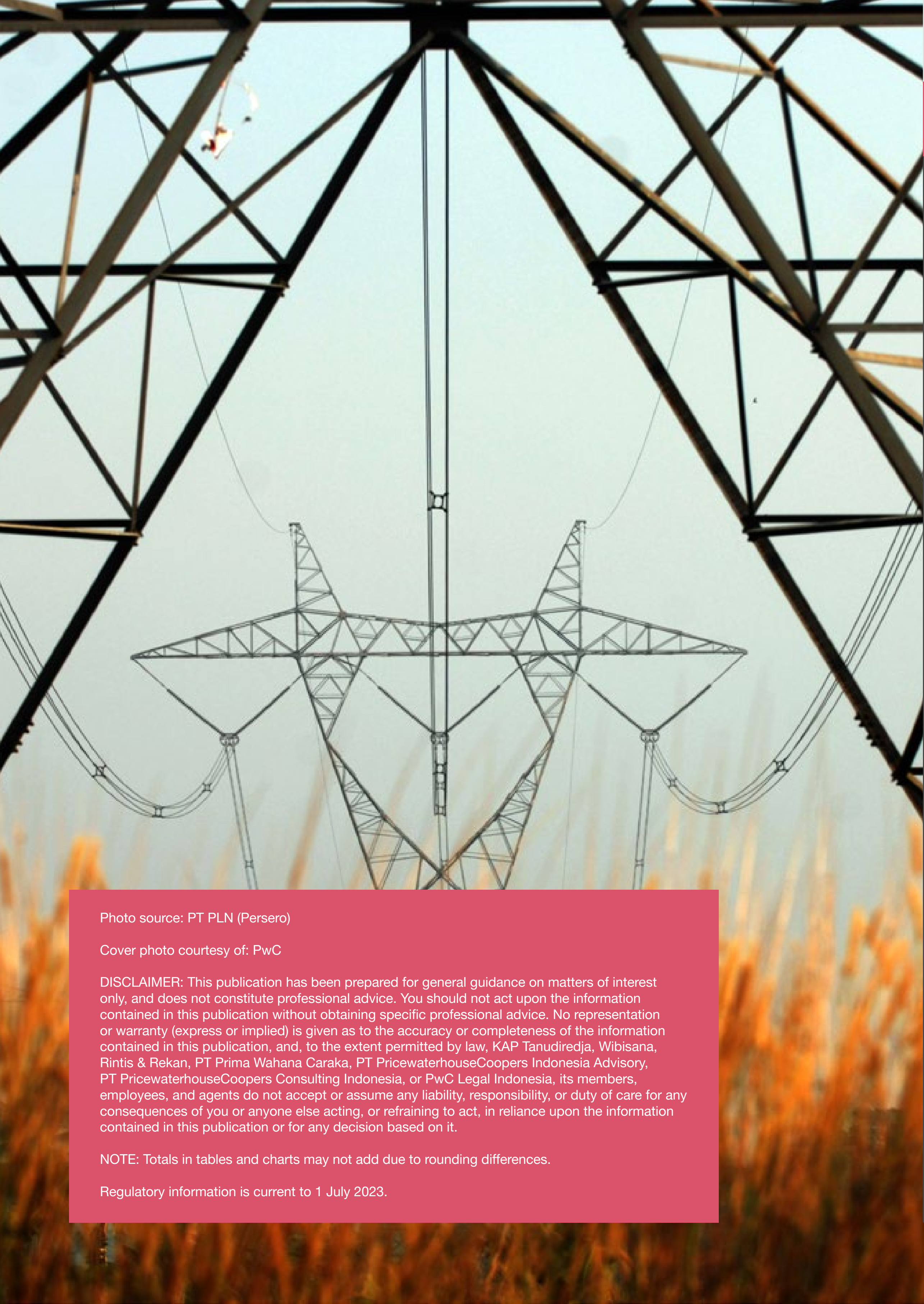

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NOTE: Totals in tables and charts may not add due to rounding differences.

Regulatory information is current to 1 July 2023.

Contents

Glossary

Term	Definition
ADB	Asian Development Bank
AMDAL	Environmental Impact Analysis (*Analisis Mengenai Dampak Lingkungan Hidup*)
APLSI	The Independent Power Producers Association (*Asosiasi Produsen Listrik Swasta Indonesia*)
ASEAN	Association of Southeast Asian Nations
B2B	Business-to-Business
Bappenas	National Development Planning Agency Board (*Badan Perencanaan Pembangunan Nasional*)
BaU	Business as Usual
BBTUD	Billions British Thermal Units per Day
BIK	Benefits in Kind
BKPM	Ministry of Investment (*Badan Koordinasi Penanaman Modal*)
BLU	Public Service Agency (*Badan Layanan Umum)*
BOO	Build Own Operate
BOOT	Build Own Operate Transfer
BOPD	Barrels of Oil Per Day
BOT	Build Operate Transfer
BP	British Petroleum
BPJS	Social Security Agency (*Badan Penyelenggara Jaminan Sosial*)
BPP	Electricity Generation Cost (*Biaya Pokok Pembangkitan*)
BPPT-WHyPGen	Agency for Assessment and Application of Wind and Hybrid Power Generation (*Badan Pengkajian dan Penerapan Teknologi*)
BSCF	Billion Standard Cubic Feet
CFP	Coal Fired Power
CIF	Cost, Insurance and Freight
CIT	Corporate Income Tax
CJPP	Central Java Power Plant
ckt-km	Circuit Kilometre
CMM	Coal Mine-Mouth
CNG	Compressed Natural Gas
COD	Commercial Operation Date
COVID-19	Coronavirus Disease of 2019
C&I	Commercial and Industries
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*)
DPR	House of Representatives (*Dewan Perwakilan Rakyat*)
EBTKE	New and Renewable Energy and Energy Conservation (*Energi Baru, Terbarukan dan Konservasi Energi*)
E&E	Exploration and Evaluation

Term	Definition
EPC	Engineering, Procurement and Construction
ETM	Energy Transition Mechanism
FiT	Feed-in Tariff
FM	*Force Majeure*
FOB	Free On Board
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
GDE	State-owned geothermal company (PT Geo Dipa Energi (Persero))
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GIS	Gas Insulated Switchgear
Government	Government of Indonesia (Central Government)
GR	Government Regulation (*PP* or *Peraturan Pemerintah*)
GSF	Geothermal Support Fund
GW	Gigawatt (1,000 MW)
GWh	Gigawatt Hours
GWp	Gigawatt Peak
HBA	Coal Reference Price (*Harga Batubara Acuan*)
HoA	Heads of Agreement
HPB	Coal Benchmark Price (*Harga Patokan Batubara*)
ICP	Indonesian Crude Price
IDD	Indonesia Deepwater Development
IDR	Indonesian Rupiah
IDX	Indonesian Stock 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”)
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*)
ITO	Indonesian Tax Office
IUJPTL	Electricity Supporting Services Licence (*Izin Usaha Jasa Penunjang Tenaga Listrik*)
IUP	Mining Business Licence (*Izin Usaha Pertambangan*)

Term	Definition
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
JOC	Joint Operation Contract
KBLI	Indonesian Standard Industrial Classifications (*Klasifikasi Baku Lapangan Usaha Indonesia*)
KESDM	Ministry of Energy and Mineral Resources (*Kementerian Energi dan Sumber Daya Mineral Republik Indonesia*)
KPI	Key Performance Indicator
KPPIP	The Committee for the Acceleration of Prioritised Infrastructure Development (*Komite Percepatan Penyediaan Infrastruktur Prioritas*)
km	Kilometre
kW	Kilowatt
kWh	Kilowatt hour
kV	Kilovolt
kVA	Kilovolt Ampere
LKPP	The Government Procurement of Goods and Services Policy Board (*Lembaga Kebijakan Pengadaan Barang dan Jasa Pemerintah)*
LMAN	State Assets Management Agency (*Lembaga Manajemen Aset Negara)*
LNG	Liquefied Natural Gas
LoI	Letters of Intent
MDA	Multilateral Development Agency
METI	Indonesian Renewable Energy Society (*Masyarakat Energi Terbarukan Indonesia*)
MKI	The Indonesian Electrical Power Society (*Masyarakat Ketenagalistrikan Indonesia*)
MMBOE	Million Barrels of Oil Equivalent
MMBtu	Millions of British thermal units
MMSCFD	Millions of Standard Cubic Feet per Day
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*)
MoSOE	Ministry of State-Owned Enterprises (*Kementerian Badan Usaha Milik Negara*)
MoPW	Ministry of Public Works and People's Housing (*Kementerian Pekerjaan Umum dan Perumahan Rakyat*)
MoU	Memorandum of Understanding
MSME	Micro, Small & Medium Enterprises
MSW	Municipal Solid Waste

Term	Definition
MT	Million Tonnes
MTPA	Million Tonnes Per Annum
MTOE	Million Tonnes of Oil Equivalent
MVA	Megavolt Amperes
MW	Megawatts
MWp	Megawatt Peak
NDC	Nationally Determined Contribution
NEP	National Energy Policy
NRE	New and Renewable Energy
NIB	Single Business Number (*Nomor Induk Berusaha*)
O&M	Operations and Maintenance
OJK	The Financial Services Authority of Indonesia (*Otoritas Jasa Keuangan*)
OSS	Online Single Submission
p.a.	per annum
PBG	Building Permit (*Persetujuan Bangun Gedung*)
PB UMKU	Supplementary Business Licenses (*Perizinan Berusaha Untuk Menunjang Kegiatan Usaha*)
PBPL	*Perizinan Berusaha terkait Pemanfaatan Langsung*
Persero	*Perusahaan Perseroan*
PKP2B	Coal Cooperation Agreement (*Perjanjian Karya Pengusahaan Pertambangan Batubara*)
PKUK	Authorised Holder of an Electricity Business Licence under the 1985 Electricity Law (*Pemegang Kuasa Usaha Ketenagalistrikan*)
PLN	The State-owned electricity company (PT Perusahaan Listrik Negara)
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*)
PLTP	Geothermal Power Plant (*Pembangkit Listrik Tenaga Panas Bumi*)
PLTS	Solar Power Plant (*Pembangkit Listrik Tenaga Surya*)
PLTU	Electric Steam Power Plant (*Pembangkit Listrik Tenaga Uap*)
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*)
PSP	Preliminary Geothermal Survey Assignment (*Penugasan Survey Pendahuluan*)

Term	Definition
PSPE	Preliminary Geothermal Survey and Exploration Assignment (*Penugasan Survey Pendahuluan dan Eksplorasi*)
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)
PV	Photovoltaic
PwC	PwC Indonesia, or the PwC global network of firms, as the context requires
RDMP	Refinery Development Master Plan
RE	Renewable Energy
RENSTRA	Strategic Plan (*Rencana Strategis*)
RFP	Request for Proposal
RPJMN	The National Medium-Term Development Plan (*Rencana Pembangunan Jangka Menengah Nasional*)
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*)
RUPTL	Electricity Supply Business Plan (*Rencana Usaha Penyediaan Tenaga Listrik*)
SHP	Small Hydropower
SOE	State-Owned Enterprise
SPC	Special Purpose Corporation
SPPL	Statement of Capability in Environmental Management and Monitoring (*Surat Pernyataan Kesanggupan Pengelolaan dan Pemantauan Lingkungan Hidup*)
SPV	Special Purpose Vehicle
TKDN	Local Content (*Tingkat Komponen Dalam Negeri*)
TOE	Tonnes of Oil Equivalent
TP	Transfer Pricing
TSCF	Trillions of Standard Cubic Feet
TWh	Terawatt hours
UKL-UPL	Environmental Management Efforts and Environmental Monitoring Efforts (*Upaya Pengelolaan Lingkungan Hidup dan Upaya Pemantauan Lingkungan Hidup*)
USD	US Dollar
US GAAP	US Generally Accepted Accounting Principles
VA	Volt Ampere
VAT	Value Added Tax
WHT	Withholding Tax
WKP	Geothermal Working Area (*Wilayah Kerja Panas Bumi*)
WPSPE	Preliminary Survey and Exploration Areas (*Wilayah Penugasan Survey Pendahuluan dan Eksplorasi*)
WtE	Waste to Energy

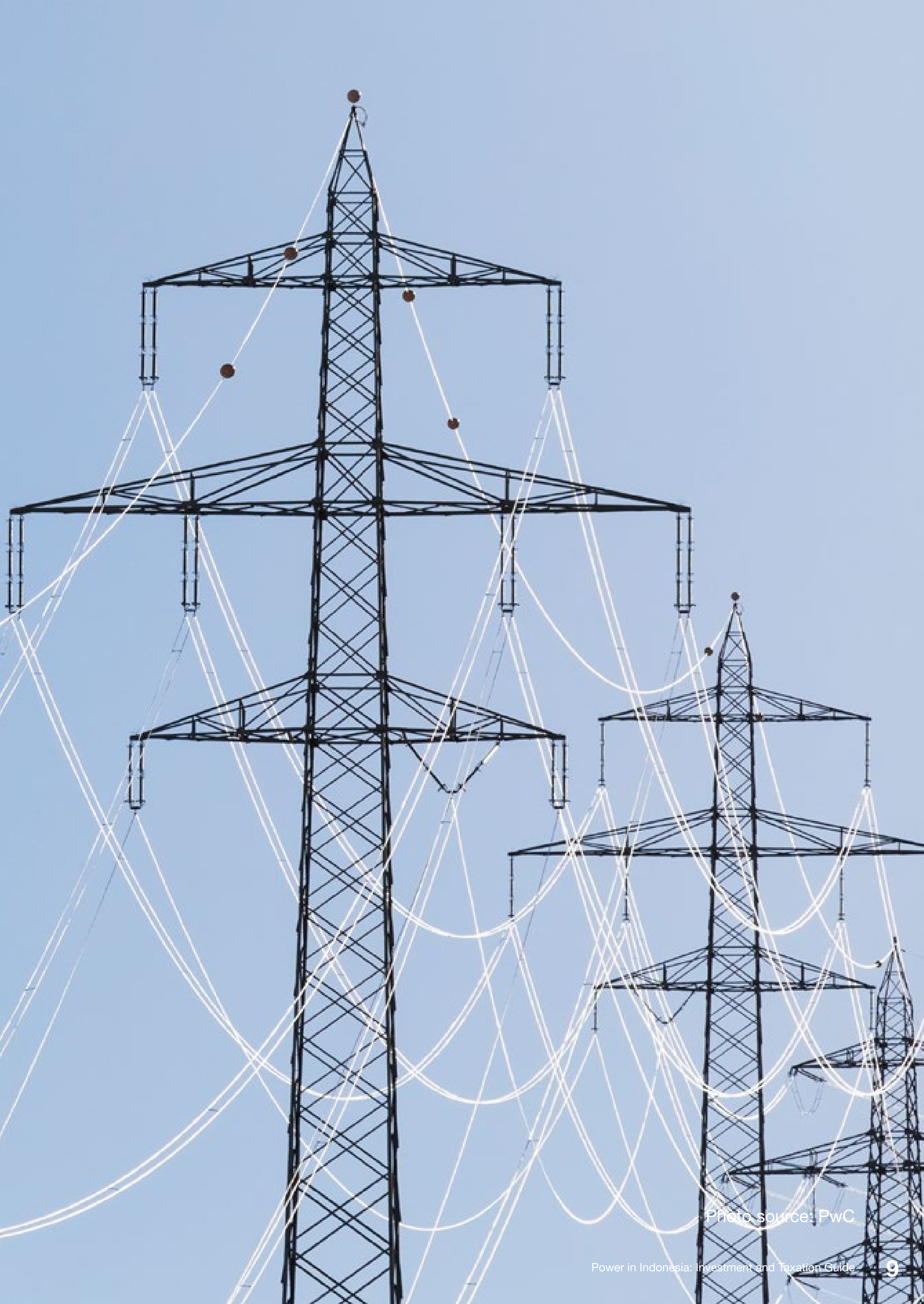


Photo source: PwC

Foreword

Indonesia has had tremendous success in meeting its growing energy demand, and in shifting to modern, commercial energy sources. However, a significant proportion of the expansion in energy supply has been from coal, reflecting domestic resource abundance and national development policy that emphasised exploitation of national resources for economic growth. Together with the expansion in supply from oil and natural gas to meet demand growth from population and economic growth, Indonesia's greenhouse gas ("GHG") emissions from energy use have increased steadily from 318 million tonnes of carbon dioxide equivalent ("mtCO_2e") in 2000 to 639 mtCO_2e in 2019.

Based on the National Energy Policy, Indonesia set a target to achieve a renewable energy ("RE") mix in primary energy supply of 23% by 2025 and at least 31% in 2050. Indonesia also aims to achieve net zero carbon emissions by 2060. However, progress towards achieving the National Energy Policy targets has been slow. In 2021, RE reached only approx. 12.2% of the total primary energy supply, while coal and oil accounted for 37.6% and 33.4% of the primary energy mix. According to Ministry of Energy and Mineral Resources("MoEMR") data in 2021, Indonesia's energy balance was dominated by coal with over 558 million Barrels of Oil Equivalent ("MMBOE"), followed by natural gas and crude oil (324 and 306 MMBOE respectively).

One of the standout stories in the successful expansion of a modern, commercial energy supply for productive uses is that of the power sector, which has progressed remarkably over the last decade. The electrification ratio has increased from 73% in 2011 to over 99% in 2022. The increase in access, economic growth and growing electrification of the economy has resulted in the share of electricity in final energy consumption rising from 6% in 2000 to 19% in 2021, and per capita consumption rising from 328 kWh to over 1,000 kWh today. However, over 85% of generation is from fossil fuel sources, leading to significant GHG emissions from the power sector. As electrification of the economy progresses, this generation mix will have to change.

In its Enhanced Nationally Determined Contribution ("NDC"), Indonesia has committed to an economywide GHG emissions reduction target of 31.89% (unconditional) and 43.20% (conditional) by 2030. This represents a reduction of 914 mtCO_2e (unconditional) and 1,238 mtCO_2e (conditional) from the business-as-usual ("BAU") scenario, where total emissions are projected to reach 2,868 mtCO_2e in 2030. GHG emissions reduction committed from the energy sector comprise 358 mtCO_2e (unconditional) and 446 mtCO_2e (conditional) representing a 21% (unconditional) and 27% (conditional) reduction from energy sector BAU emissions. This Enhanced NDC is aligned with the Long-Term Low Carbon and Climate Resilience strategy ("LTS-LCCR") 2050 with a vision to achieve net-zero emissions by 2060 or sooner.

The power sector is expected to contribute to the achievement by installing almost 21 Gigawatts ("GW") of RE in 2030 and 27.5 GW of clean coal technology and gas power plants. In the Enhanced NDC, Indonesia has committed to achieving a RE mix of 23% in total Primary Energy Supply ("PES") by 2025 and at least 31% in 2050. However, progress on achieving this target has been limited with the proportion of RE in PES reaching only ~12% in 2021. Furthermore, the Indonesia Just Energy Transition Partnership ("I-JETP") requires at least 34% RE in the power generation mix by 2030.

There are several barriers to an accelerated energy transition in Indonesia across governance frameworks, institutional structures, market models, energy pricing and risk sharing models. The market model, which has a single integrated utility company that also serves as a single buyer for electricity and sole supplier of electricity for public interest, overlapping governance responsibilities between ministries, and subsidies that underprice energy supply, are some of the key concerns.

To achieve Indonesia's NDC commitments and effectively leverage I-JETP support, structural changes will be required across governance frameworks, institutional structures, market models, utility cost recovery and energy pricing, and capacity procurement to accelerate the pace of renewable energy integration into electricity supply.

1 Overview of the Indonesian Power Sector

1.1 Demand for and Supply of Power in Indonesia

Indonesia is an archipelago of over 18,000 islands, with a population of 274.9 million as of 2022. This makes it the world's fourth most populous country, and the largest economy in Southeast Asia.[1]

In 2013, the Indonesian economy entered a slowdown period, as global commodity prices fell. This was exacerbated by the slowdown in the Chinese economy. Indonesian Gross Domestic Product ("GDP") growth during 2014–2018 averaged 5% per annum ("p.a."), as compared to average growth of 6% p.a. in 2010-2013. The outlook improved in 2018, however, as the infrastructure spending initiatives of President Joko Widodo's Government began to have an impact, together with regulatory and subsidy reforms and improvements in key commodity prices. The period from 2018 to early 2019 saw the upgrading of Indonesia's sovereign credit rating by Standard and Poor's ("S&P") from BBB- to BBB due to the domestic economy's resilience against external shocks.

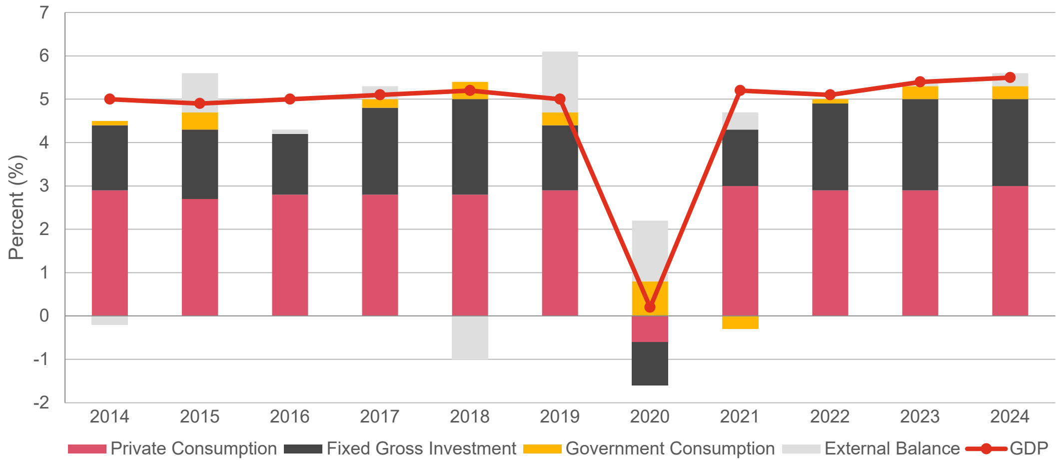
Pre-COVID 19, PwC's World in 2050 report[2] indicated that Indonesia has the potential to become the fifth largest economy in the world by 2030 (based on purchasing power parity), and the fourth largest by 2050. However, coming out of the COVID-19 crisis, this will depend upon significant investments in infrastructure – including power – in order to stimulate demand in the short-term whilst enhancing the economy's supply capacity in the medium to long term, thus driving greater GDP growth. By the end of 2022; comparing Indonesia's economy in the fourth quarter of 2022 against the fourth quarter of 2021, the GDP experienced a growth of around 5% y-o-y.[3]

As of Q4 2022, the main components of the Indonesian GDP were manufacturing (18% of GDP), agriculture and forestry (12%), wholesale and retail (13%), construction (10%) and mining and quarrying (12%).[4] The Ministry of Energy and Mineral Resources ("MoEMR") noted that electricity consumption per capita in Indonesia reached 1,173 kilowatt hours ("kWh") in 2022, an increase of 4.45% over the previous year's 1,123 kWh, in line with GDP growth.

Electricity distribution is uneven, however, and there is greater consumption in more industrialised areas, such as the western part of Java. Similarly, the level of access to the grid is mixed, with electrification rates as high as 100% and as low as 89% in the south eastern part of the country (i.e. East Nusa Tenggara (*Nusa Tenggara Timur* - "NTT")), with the highest being Bali which achieved 100% electrification rate (see Figure 1.3). The national average electrification rate in 2021 was 99.5%, rising from 99.2% in 2020. Based on the Electricity Supply Business Plan (*Rancangan Usaha Penyediaan Listrik* - "RUPTL") 2021-2030, the electrification rate was set to increase to 100% by 2022.[5]

1 Macrotrends, https://www.macrotrends.net/countries/IDN/indonesia/population, accessed 17-Jan-2023
2 PwC, https://www.pwc.com/gx/en/issues/economy/the-world-in-2050.html
3 BPS - Official Statistics News - No. 15/02/Th. XXVI
4 Bank Indonesia, Statistics of Indonesian Economic and Finance - March 2023, www.bi.go.id/seki/tabel/TABEL7_1.pdf
5 RUPTL 2021-2030, p. II-49

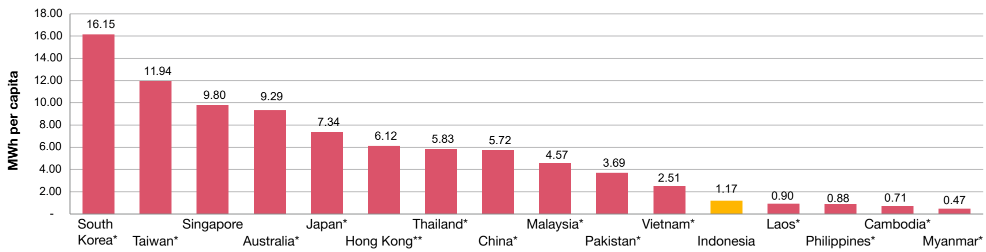
Figure 1.1 – Historical and forecasted GDP growth and contribution by expenditure item (% p.a.)



Source: Bank Indonesia, Statistics of Indonesian Economic and Finance, www.bi.go.id/en/statistik/ metadata/ seki; EIU Forecast

As a consequence of COVID-19, there was surplus electricity available due to demand crashing, leading to more than 3 GW of capacity being idled in 2020. Due to these conditions, in 2021 the Indonesian Government, through the MoEMR, provided an electricity bill relief stimulus for PLN's customers, namely 450 Volt Ampere ("VA") and subsidised 900 VA household customers and 450 VA small business and small industry customers, and provided an exemption from minimum billing and from minimum charge.[6] Cumulatively, throughout the COVID-19 pandemic, the state owned electricity company (*Perusahaan Listrik Negara* - "PLN") distributed up to IDR 24 trillion in electricity stimulus. As Indonesia's recovery from the COVID-19 pandemic continues, the national electricity consumption (January-September 2022) grew by 1.5% when compared to the same period in the previous year. The increase in electricity consumption is supported by the development of electricity infrastructure - the addition of power plants up to the first quarter of 2022 amounted to 1,457.08 Megawatts ("MW").[7]

Figure 1.2 – Electricity consumption per capita 2022 - Indonesia's neighbouring countries



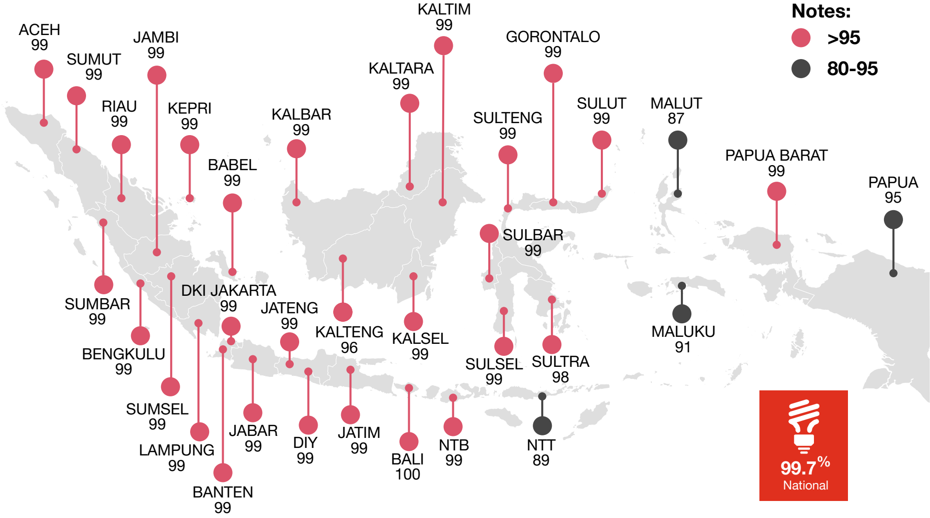
*estimated
**forecasted

Source: Business Monitor International, and MoEMR

6 MoEMR, https://www.esdm.go.id/en/media-center/news-archives/stimulus-keringanan-tagihan-listrik-ringankan-beban-industri-akibat-pandemi-covid-19, accessed 5 October 2020

7 Kontan, https://newssetup.kontan.co.id/news/pln-konsumsi-listrik-tahun-2021-diprediksi-tumbuh-di-atas-475, accessed 12 January 2022

Figure 1.3 – Indonesian electrification ratio by province - 2022



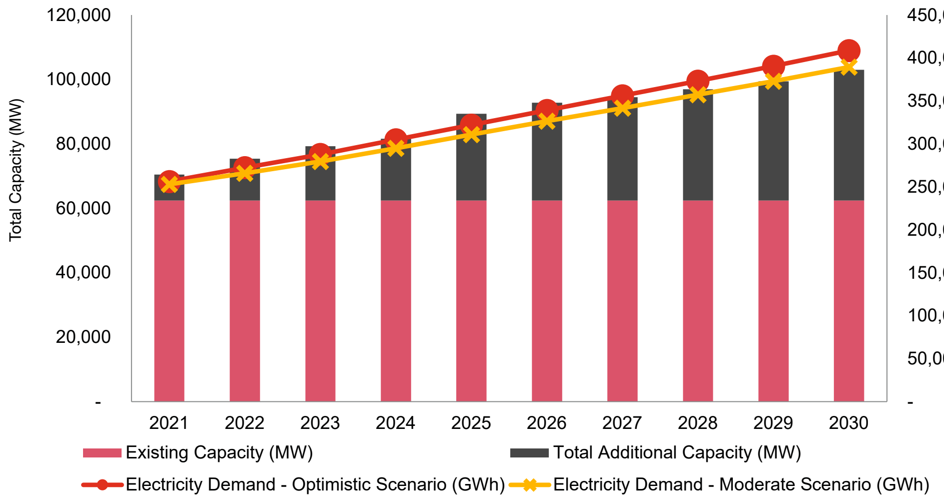
Source: MoEMR

Indonesia's rising income per capita and growing middle class, accompanied by a structurally lower electrification ratio, should have spurred significant growth in electricity demand. However, in light of current events, PLN provides two scenarios (moderate and optimistic) for electricity production based on different economic recovery assumptions. Under both scenarios, PLN has revised its target for electricity downwards; under the RUPTL 2021-2030's moderate scenario, it is revised to 34.5 GW by 2028 from 56.4 GW by 2028 in the 2019 RUPTL. Despite this, renewable power plants will play a major role which is consistent with PLN's Net Zero Ambition of 20.92 GW by 2030.[8] In terms of the electricity demand, PLN has predicted a lower growth rate, around 4.41% (moderate scenario) to 4.67% (optimistic scenario) average per annum by 2030 in the RUPTL 2021-2030 as compared to 6.42% in the 2019 RUPTL, thereby reducing the estimated total electricity demand from 433 Terawatt hours ("TWh") to 357 TWh (a 17.6% decrease) in 2028.[9]

Due to the COVID-19 pandemic, the Government's ongoing 35 GW Programme is facing a series of challenges, due to delays in industrial and electricity projects. In summary, the commercial operation date ("COD") of many new power plants has been delayed or even postponed altogether[10] (see *Section 3.7.2 – The 35 GW Power Development Programme* – for the latest developments and progress). PLN's most recent plan indicates that 17 GW of additional capacity will have been developed by the end of 2023, accumulating up to 40.6 GW by 2030 - with an average increase of around 4 GW per annum until 2030.[11] Although the projection for energy consumption has decreased, there is an increase in the new capacity to be procured from renewable energy, replacing fossil fuels. Improvements in national power generation and electricity access are, however, still a significant part of the Government's wider plan for infrastructure support covering the development of roads, railways, seaports, airports, water supply and treatment, oil refining, supply and distribution of gas, and the rollout of fibre-optic broadband.

8 RUPTL 2021-2030, p. V-54
9 RUPTL 2021-2030, p. V-41
10 Kata Data, https://katadata.co.id/agungjatmiko/berita/5f27924336b36/pengerjaan-7-proyek-pembangkit-listrik-35-ribu-mw-terhambat-pandemi, accessed 01 January 2023
11 RUPTL 2021-2030, p. V-54

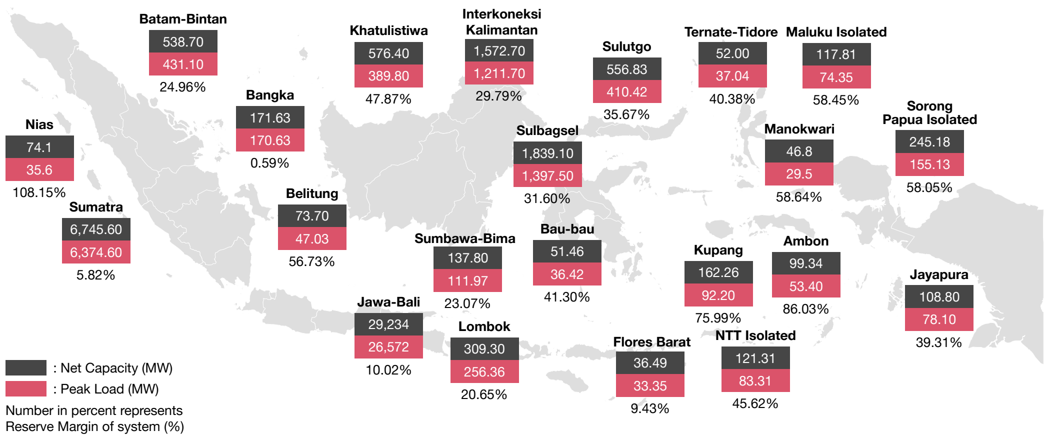
Figure 1.4 – Electricity capacity (MW) and demand (GWh) 2021-2030



Source: RUPTL 2021-2030

By the end of 2022, Indonesia had a reserve margin of around 50% on a national average basis. Based on MoEMR data, at the end of 2022 Indonesia's installed power capacity had amounted to a total of 83.8 GW with the island of Java having 66% share of the total installed capacity.[12]

Figure 1.5 - Condition of national power system - 2022



Source: MoEMR Data 2022

12 PLN Statistics 2022

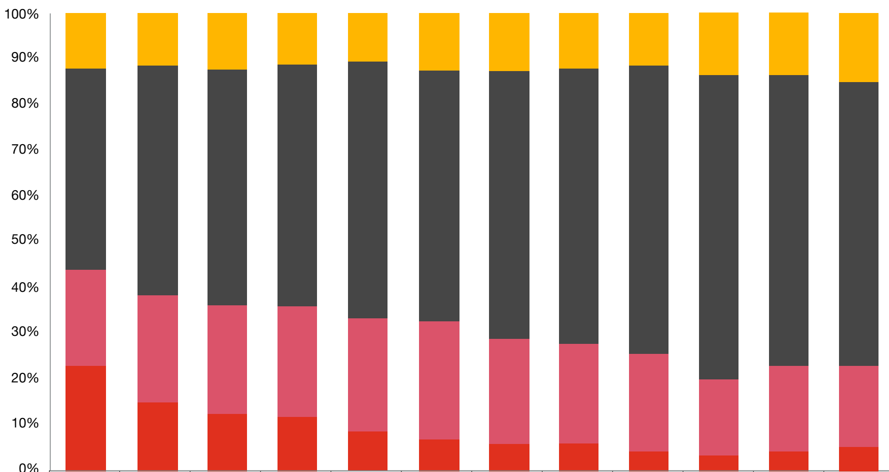
1.2 Sources of Energy

By December 2022, Indonesia had approximately 83.8 GW of installed power plant capacity, including power plants owned by PLN/Independent Power Producers (“IPP”), private power utilities (“PPU”), and plants operating under non-fossil fuel operating licences (*Izin Operasional Non-BBM* - “IO Non-BBM”) (see *Section 2.2.2.1 - Generation* for further details). Indonesian power plants generated 333.5 Gigawatt hours (“GWh”) in December 2022, compared with 309.1 GWh in the previous year.[13] The current power generation fuel mix includes coal, gas, oil and renewables as illustrated in Figure 1.6.[14]

As Indonesia is aiming to achieve its Net Zero target by 2060, PLN has increased the share of renewables to 51.6% of the total 40.6 GW additional capacity by 2030, to reduce the dominance of coal in the power generation fuel mix.

The funding commitment through the Just Energy Transition Programme (“JETP”) reaches USD 20 billion or IDR 300 trillion (assuming an exchange rate of IDR 15,000 per USD). The programme targets Indonesia to reduce 290 million tonnes of carbon emissions in the electricity sector and implement a 34% renewable energy mix by 2030. To achieve the JETP funding target, Indonesia must at least retire up to 8.6 GW of coal-fired power plants. Retiring coal-fired power plants with a capacity of up to 8.6 GW, requires funding of at least USD 5 billion or equivalent to IDR 74.4 trillion.[15]

Figure 1.6 - Energy generation mix

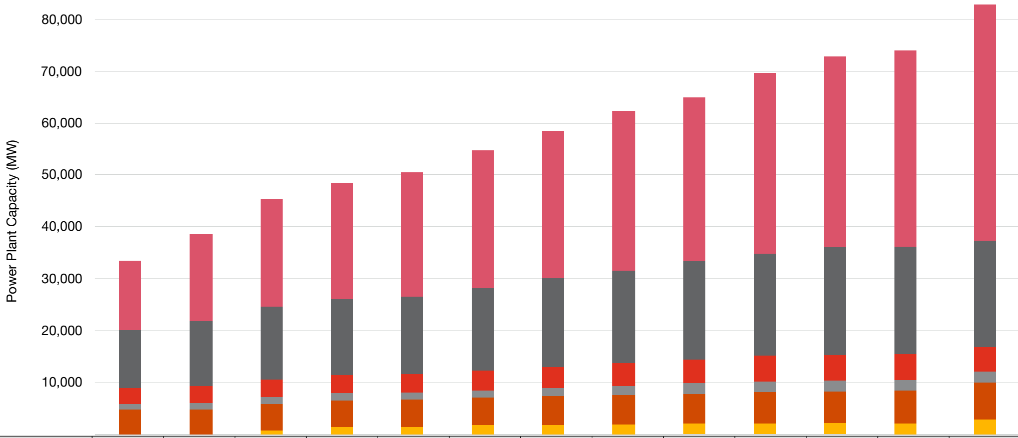


Fuel Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Oil and Biofuel	23.0%	15.0%	12.5%	11.8%	8.6%	7.0%	6.0%	6.0%	4.2%	3.3%	4.2%	6.2%
Gas	21.0%	23.4%	23.6%	24.1%	24.9%	25.9%	22.9%	21.7%	21.4%	16.8%	18.7%	16.8%
Coal	44.1%	50.3%	51.6%	52.9%	56.1%	54.7%	58.4%	60.3%	63.0%	66.3%	63.5%	61.5%
New and Renewable Energy (“NRE”)	12.0%	11.4%	12.3%	11.3%	10.5%	12.5%	12.7%	12.0%	11.4%	13.6%	13.6%	15.5%

Source: HEESI 2020, HEESI 2021, HEESI 2022

13 LAKIN DJK 2020, p. 30
14 DJK Presentation, “Konferensi Pers Perkembangan dan Arah Kebijakan Subsektor Ketenagalistrikan 2021”, p. 4
15 CNBC, https://www.cnbcindonesia.com/news/20230608165055-4-444277/tekan-emisi-karbon-ri-kudu-pensiun-dini-86-gw-pltu, accessed 26 June 2023

Figure 1.7 - Power generation installed capacity



Power Plants (MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Other Renewable Energy	46	69	768	1,385	1,427	1,780	1,831	1,913	2,090	2,195	2,206	2,644	3,566
Hydro(s)	4,672	4,775	5,158	5,211	5,237	5,307	5,651	5,688	5,772	5,976	6,121	6,601	6,689
Geothermal	1,206	1,226	1,336	1,398	1,403	1,438	1,533	1,808	1,948	2,131	2,131	2,286	2,360
Diesel	3,074	3,250	3,362	3,562	3,637	3,824	3,979	4,396	4,631	4,780	4,864	4,986	4,352
Gas	11,019	12,459	14,117	14,552	14,885	15,890	17,070	17,660	18,926	19,860	20,762	20,979	20,831
Coal	13,371	16,751	20,741	22,275	23,858	26,448	28,352	30,768	31,587	34,737	36,668	37,036	46,014
Total	**33,388**	**38,230**	**45,482**	**48,383**	**50,557**	**54,727**	**58,416**	**62,233**	**64,954**	**69,679**	**72,752**	**74,532**	**83,813**

Source: HEESI 2022, RUPTL 2021-2030

The significant role of fossil fuels in the energy mix reflects Indonesia's natural abundance of these resources, as outlined in detail in *Section 4 - Conventional Energy*. The key factors and trends in the three major conventional energy sources include the following:

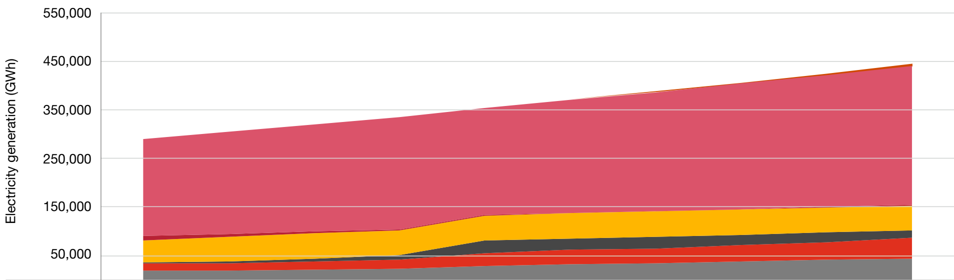
- **Coal**: Coal has historically been, and continues to be, Indonesia's most important source of fuel for generating electricity, and a driver of economic growth. Economic and logistical considerations (as well as the significant amount of available reserves) have led to the ongoing dominance of coal as a low-cost fuel which is easy to extract and transport within the existing infrastructure limitations. By the end of 2022, coal accounted for more than 50% of the total power generation installed capacity. In addition to that, the coal mining industry contributed around 6.6% to the Indonesian GDP in 2022. Based on the RUPTL 2021-2030, production of coal-fired power plants will account for around 59% to 63%, or no notable change in installed capacity by 2030.
- **Natural Gas**: Natural gas is relatively low-carbon (as compared to coal) and it is generally of medium cost. Gas is therefore likely to remain a favoured fuel, at least for the next decade, especially given Indonesia's extensive current gas reserves. However, the electricity generated from natural gas in 2030 is expected to decrease by 4.2% from 2021 in the optimum scenario or rise 0.1% in the low carbon scenario.

In order 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. Since April 2020, the pricing of gas for domestic use in Indonesia has been regulated at USD 6 per million British thermal units ("MMBtu") for seven specific industries which are the: fertiliser, petrochemical, oleochemical, steel, ceramic, glass and rubber glove industries.

- **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 reduce the use of oil in Indonesia's fuel mix for energy generation by a significant amount, from 3.3% in 2020 to around 0.4% by 2030.

Other forms of non-conventional fossil fuel energy such as coalbed methane and coal gasification technologies – also exist, and are being developed 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 our separate Investment Guides.

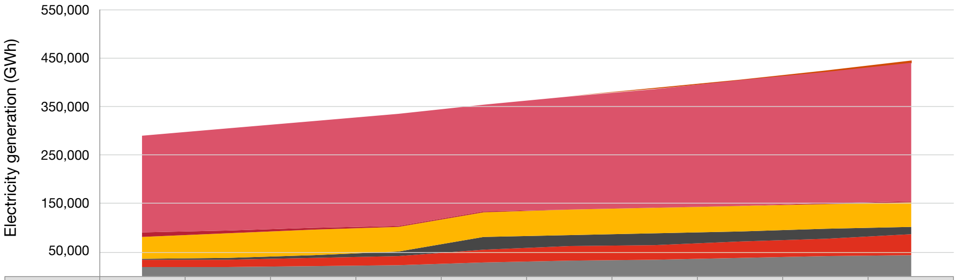
Figure 1.8 - 2021-2030 Indonesian electricity generation optimum scenario



Fuel Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Renewables Potential	-	-	-	-	-	534	1,765	2,545	3,585	5,246
Import	954	-	-	-	-	-	-	-	-	-
Coal	198,103	209,128	219,795	231,446	220,032	233,074	244,352	257,953	27,094	284,637
Oil	9,326	5,622	4,069	1,839	1,417	1,432	1,502	1,606	1,697	1,805
Gas	45,464	50,914	50,953	52,489	51,485	51,956	53,233	53,513	54,945	56,282
Other Renewables	612	271	271	243	74	80	82	88	95	94
Geothermal	15,849	16,571	18,009	18,875	26,785	30,550	31,441	34,380	36,173	43,215
Hydro	18,750	18,629	20,531	22,454	28,291	31,802	33,615	3,735	41,574	44,256

Source: RUPTL 2021-2030, p. V-97

Figure 1.9 - 2021-2030 Indonesian electricity generation low carbon scenario



Fuel Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Renewables Potential	-	-	-	-	-	578	1,831	2,672	3,460	3,960
Import	954	-	-	-	-	-	-	-	-	-
Coal	194,558	201,274	213,835	227,544	216,036	229,525	239,207	245,339	254,516	264,260
Oil	10,222	9,243	4,870	1,729	1,451	1,520	1,575	1,656	1,719	1,798
Gas	48,154	54,811	57,816	58,379	55,446	55,232	57,844	63,987	66,125	68,724
Other Renewables	1,392	1,378	391	283	224	264	270	279	496	1,309
Geothermal	16,954	17,558	18,792	19,700	26,041	27,380	29,801	31,619	33,897	36,485
Hydro	16,867	17,017	17,690	19,658	28,327	31,829	33,444	36,761	40,381	42,516

Source: RUPTL 2021-2030, p. V-99

Indonesia has enormous potential in terms of renewable resources, as outlined in Table 1.1 below. This account of the potential renewable energy resources has been based on a technical assessment conducted by the MoEMR, but this does not necessarily consider the financial or economic viability of individual projects. However, Government Regulation ("GR") No. 79/2014 on the National Energy Policy (the "2014 NEP") requires that developments of renewable energy resources consider their economic viability. Similarly, the potential resource estimates in Table 1.1 do not consider location factors either (i.e. some renewable energy resources are located in areas with a very low electricity demand). As such, some renewable energy projects may not be economically feasible.

Table 1.1 - Renewable energy resources in Indonesia

Source	Potential Power Generation
Hydropower	75 GW
Geothermal	29 GW
Biomass	33 GW
Solar Photovoltaic ("PV")	208 GWp (4.80 kWh/m^2/day)
Wind Power	61 GW (3 – 6 m/s)
Ocean	18 GW

Source: 2016 EBTKE Statistics

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 RUPTL 2021-2030, the key factors and trends in the five major renewable energy sectors include the following:

- **Hydro**: Hydropower is currently the largest single source of renewable power in Indonesia. By the end of 2022, Hydropower accounted for 7.9% of the total power generation installed capacity. In terms of plant developments; in 2020, a small hydro Power Purchase Agreement ("PPA") has been entered into between PLN and the IPP with capacity of 5 MW, for the *Pembangkit Listrik Tenaga Minihidro* ("PLTM" or Mini Hydro power plant) Bakal Semarak.[16] In 2022, Kayan Hydro Energy established a partnership with Japan's Sumitomo Corporation with the aim of building South East Asia's biggest hydroelectric power plant (*Pembangkit Listrik Tenaga Air* - "PLTA") Kayan with a planned 9,000 MW capacity. This project is expected to be operational by 2025.[17]
- **Solar PV**: The installed solar power capacity reached 272.2 MW by the end of 2022, which grew by about 43% compared to 190.15 in 2021. The majority of IPP projects in the pipeline (585 Megawatt peak ("MWp")) are not expected to be operational until around 2024. The government intends to add 38 GW of renewables installed capacity by 2035, as part of the National Grand Energy Plan (*Grand Strategi Energi Nasional* - "GSEN"). Solar PV is expected to provide for one-third of the increase, with rooftop solar PV accounting for 3.6 Gigawatt peak ("GWp") by 2025. In terms of regulations, in 2021, the government issued MoEMR Regulation No.26/2021 in the hopes of increasing the utilisation of solar energy across the Indonesian population. The net metering multiplier, which is going to be increased from 65% to 100%, is one of the changes being made by this regulation. In terms of projects, Solar Plant (*Pembangkit Listrik Tenaga Surya* - "PLTS") Likupang, which was completed back in 2019, is still Indonesia's biggest solar farm up to date with a capacity of 15 MW. However, in 2022 PLN announced that it is building Indonesia's biggest and South-East Asia's second biggest, floating solar PV farm on the waters of the Cirata dam, located in West Java. This project, called PLTS Cirata, has a planned capacity of 1,008 MW, significantly larger than PLTS Likupang.
- **Geothermal**: With Indonesia possessing the second-largest geothermal resources in the world, the geothermal share of the energy mix is expected to increase to more than 9.3% in 2030. By the end of 2022, geothermal accounted for 2.8% of the total installed power capacity.[18] A key strength of geothermal is its capacity for providing base-load power countering the problem of intermittency associated with solar, wind and small hydro. There are only a limited number of concessions under development, however, with PPA approval being slow and Indonesian state-owned enterprises ("SOEs") playing a dominant role. In terms of recent project developments, in July 2021 Sorik Merapi Geothermal Power succeeded in commissioning its second power plant with a capacity of 45 MW.[19] PT Geo Dipa Energi (Persero) also plans to continue the development of two 55 MW geothermal power plants after securing the financial agreement from the Asian Development Bank ("ADB"), for which the proposed development is expansion of the current 60-MW Geothermal Power Plant (*Pembangkit Listrik Tenaga Panas Bumi* - "PLTP") Dieng and 55-MW PLTP Patuha.[20] In 2020, the MoEMR decided to delay tenders for new geothermal working areas until 2023, to allow the MoEMR Geological Agency and other designated institutions to complete drillings in several geothermal potential areas, so that better information can be provided to investors.[21]

16 Porto News, https://www.portonews.com/2020/laporan-utama/pln-teken-ppa-dengan-3-ipp/, accessed 25 September 2020

17 Detik, https://finance.detik.com/energi/d-5686615/proyek-rampung-2024-plta-kayan-baru-nyetrum-di-2025, accessed 26 January 2023

18 HEESI 2021

19 Bisnis, https://ekonomi.bisnis.com/read/20210728/44/1422898/sempat-terganggu-insiden-pltp-sorik-marapi-unit-ii-akhirnya- resmi-beroperasi, accessed 30 July 2021

20 LAKIN ESDM 2019, p.86

In December 2021, PT Supreme Energy Rantau Dedap ("SERD"), a consortium of PT Supreme Energy, Marubeni Corporation, Tohoku Electric Power Co. Inc. and INPEX, announced that the Rantau Dedap Geothermal Power Plant phase I (located in South Sumatra) began its commercial operations. This project has a capacity of 91.2 MW with a total phase I investment of more than USD 700 million or IDR 10 trillion.[22] In June 2023, the Way Ratai geothermal working area in Lampung, Indonesia, which was awarded to a partnership between PT Pertamina Geothermal Energy ("PGEO") and PT Jasa Daya Chevron (Chevron Geothermal), was one significant tender development.[23]

- **Bioenergy**: The bioenergy market consists of discrete segments, such as agricultural and plantation biomass waste, palm oil mill effluent ("POME"), municipal solid waste ("MSW"), and biodiesel. The market largely consists of power plants with 10 MW or less of capacity. Significant potential remains, therefore, with large amounts of agricultural waste and MSW currently being disposed of improperly but realising this potential will require changes in the regulatory and contracting environment, especially at the sub-National Government level. Presidential Regulation ("PR") No. 35/2018 is the reference point for MSW PPAs. On 2 August 2017, PLN also signed at least four biomass and five biogas PPAs ≤ 10 MW, with tariffs ranging from IDR 890/kWh to IDR 1,555/kWh.

  By the end of 2022, the installed bioenergy capacity reached around 3 GW of the total generating capacity.[24] In early 2020, PLN signed PPAs with IPPs for two biogas power plants located in North Sumatra, which are biogas power plant (*Pembangkit Listrik Tenaga Biogas* - "PLTBg") Kwala Sawit with a capacity of 1 MW and PLTBg Pagar Merbau with a capacity of 0.8 MW. However, the COVID-19 outbreak has caused several delays to CODs mainly due to delays in commissioning since expatriate engineers have been unable to visit Indonesia and the importation of construction components has been delayed.[25] Throughout 2022, PLN also implemented the use of biomass through co-firing technology to replace coal as fuel in 33 electric steam power plants (*Pembangkit Listrik Tenaga Uap* - "PLTU") in various regions.

- **Wind**: Historically, wind has not played an important part in Indonesia's fuel mix. However, significant progress has been observed, with PT UPC Sidrap Bayu Energi's 75 MW wind power plant (*Pembangkit Listrik Tenaga Bayu* - "PLTB") Sidrap in South Sulawesi becoming operational in March 2018 and being officially inaugurated by President Joko Widodo in July 2018.[26] Also PLTB Tolo with capacity of 72 MW in Jeneponto was commissioned in 2019. In November 2022, Adaro Energy announced that it is planning to construct the PLTB Tanah Laut wind power plant in South Kalimantan with co-investor Total Eren. This project is aimed to be completed by 2024.[27] As of November 2022, there are a total of around 154 MW of PLTBs that are operating in Indonesia.

21 CNBC, https://www.cnbcindonesia.com/news/20210115123442-4-216273/waduh-esdm-tak-akan-lelang-wilayah-panas-bumi-sampai-2023, accessed 30 June 2021
22 CNN, https://www.cnnindonesia.com/ekonomi/20220107140206-85-743839/pltp-rantau-dedap-bernilai-rp10-t-mulai-beroperasi, accessed 21 January 2023
23 ThinkGeoEnergy, https://www.thinkgeoenergy.com/way-ratai-indonesia-geothermal-block-awarded-to-pertamina-chevron-consortium, accessed 23 June 2023
24 https://dataindonesia.id/sektor-riil/detail/esdm-kapasitas-terpasang-pembangkit-ebt-capai-target-pada-2022
25 MoEMR, "COVID-19 outbreak impact to development of Indonesia's renewable energy", presentation for video conference of Directorate General of Renewable Energy and Institute of Essential Services Reform on 21 April 2020
26 Katadata, https://katadata.co.id/berita/2018/07/02/diresmikan-jokowi-pltb-sidrap-bisa-alirkan-listrik-ke-70000-rumah, accessed 2 October 2020
27 Kontan, https://industri.kontan.co.id/news/adaro-power-dan-total-eren-bangun-pltb-yang-akan-hasilkan-listrik-murah, accessed 21 January 2023

Many factors support the deployment of renewables, including falling costs, national carbon emissions targets, the high cost of oil-based generation (especially in remote regions), and the regulatory and physical barriers to gas distribution. However, the lack of a bankable PPA has become a major concern. Of the 83 renewable power plant projects signed since 2017, 24 projects had reached COD by July 2020, with 24 projects having yet to reach financial close. Eight projects have been terminated, while the PPAs of 28 other projects have been signed and their construction work started, with PLN regional entities determining the viability of these renewable projects according to their specific locations.[28] However, in March 2020 the Indonesian Government through the MoEMR regulation No. 4/2020 introduced the Build-Own-Operate ("BOO") Scheme to be used by developers who are willing to invest in the power generation processes using renewable energy as the source of power. This action was done mainly to attract more IPPs to make more investments especially in the field of renewables.[29]

On 15 November 2022, during the G20 Leaders' Summit in Bali, the JETP Programme for Indonesia was officially established. With the help of grants, loans with favourable terms, market-rate loans, guarantees, and private investments, the JETP aims to support the decarbonisation of Indonesia's energy sector, with an initial USD 20 billion in public and private funding. It encourages an international course that keeps the 1.5°C global warming goal within reach.

With assistance from its international partners, Indonesia is aiming to develop a comprehensive JETP Investment and Policy Plan by the end of August 2023 to specify approaches to meet new and expedited goals by:[30]

- Peaking total power sector emissions by 2030, shifting the projected emissions peak forward
- Capping power sector emissions at 290 million tonnes of CO_2 in 2030
- Establishing a goal to reach net zero emissions in the power sector by 2050, bringing forward Indonesia's net zero power sector emissions target by ten years; and
- Accelerating the deployment of renewable energy so that renewable energy generation comprises at least 34 percent of all power generation by 2030, roughly doubling total renewables deployment over this decade compared to current plans.

Further discussions of renewables, as well as other technologies, such as ocean thermal energy conversion, can be found in Chapter 5.

1.3 Electricity Tariffs

Under Law No. 30/2009 ("the 2009 Electricity Law"), electricity tariffs no longer need to be uniform throughout Indonesia, and thus they may differ between operating areas or *Wilayah Usaha*. Tariffs are differentiated depending on the end-user group. In general, electricity tariffs are set by taking into account the customer's purchasing power, as well as the installed power capacity of each customer group. The higher the installed power, the higher the tariff imposed. In 2020, the MoEMR through Minister of Energy and Mineral Resources Decree Number 139K/26/MEM/2020 concerning the Stipulation of Discounts for PT PLN (Persero) Consumer Electric Power Rates in the context of Facing the Impact

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28 Ekonomi Bisnis https://ekonomi.bisnis.com/read/20200730/44/1273115/kementerian-esdm-24-pembangkit-listrik-ebt-beroperasi-semester-i-2020, accessed 25 September 2020

29 Katadata, https://katadata.co.id/berita/2019/02/11/4-penyebab-pelaku-usaha-energi-terbarukan-sulit-dapat-pendanaan, accessed 25 September 2020

30 MoEMR Presentation "Energy Transition Financing Through JETP & ETM 2023"

of COVID-19 and Letter of the Director General of Electricity Number 1475/23/DJL. 3/2020 stipulates the provision of a 100% discount for household consumers with 450 VA power (R1 / TR 450 VA), small business consumers with 450 VA power (B1 / TR 450 VA), and small industrial consumers with 450 VA power (I1 / TR 450 VA) and a 50% discount for household consumers with subsidised 900 VA power (R1 / TR 900 VA). There was speculation on whether the MoEMR was going to halt these subsidies after the spread and the intensity of the COVID-19 Pandemic slowed down. However the subsidies have been extended and implemented by the MoEMR throughout 2021 and 2022.

Prior to 2013, PLN's revenue was dictated by regulated electricity prices, with the tariffs being set by the Central Government and ultimately approved by the Parliament. This excluded the electricity prices in Batam, which were approved by the Regional Government. Since price increases required approval from Parliament, PLN's financial position was directly subject to the political process. Should the regulated price of electricity fall below the cost of production (which has generally been the case), then the Ministry of Finance ("MoF") is required to compensate PLN through a subsidy. Since 2013, the electricity subsidy has stabilised, due to the stabilisation of the average cost of the electricity supply, as well as PLN's ability to pass on increases in inflation, the price of oil, and the USD/IDR exchange rate to (non-subsidised) consumers (the "automatic tariff adjustment mechanism"). After being initiated by the first MoEMR Regulation No. 31/2014, the tariff regulation had been revoked by MoEMR Regulation No. 28/2016. This MoEMR Regulation No. 28/2016 had been amended three times, lastly, with MoEMR Regulation No. 19/2019 that takes into account Indonesian Crude Price ("ICP"), reference coal price (*Harga Batubara Acuan* – "HBA"), and IDR-USD exchange rates for electricity tariff adjustment (see Table 1.2). This subsidy includes a public service obligation ("PSO") margin, which was originally set at 5% above the cost of electricity supplied in 2009. The margin increased to 8% for 2010 and 2011, and was then reduced to 7% in 2012.

Table 1.2 - Average cost, average tariff, and subsidies

Year	Average cost (IDR/kWh)	Average tariff (IDR/kWh)	Subsidies (IDR trillions)
2012	1,374	728	103.3
2013	1,399	818	101.2
2014	1,420	940	99.3
2015	1,300	1,035	56.6
2016	1,265	991	60.4
2017	1,318	1,105	45.7
2018	1,406	1,127	48.1
2019	1,385	1,130	51.7
2020	1,348	1,071	48.0
2021	1,333	1,083	49.7
2022	1,473	1,137	58.8

Source: PLN Statistics 2019, 2020, 2021 & 2022

Starting in January 2017, the Government began to revoke the electricity subsidy for 900 VA customers who were classified as high-income households. This follows the previous removal of the subsidies for 1,300–6,600 VA household customers, >200 Kilovolt Ampere ("kVA") business customers, 6,600 VA up to >200 kVA Government Office customers, >200 kVA industrial customers, as well as public street lighting and special services. Therefore, except for 450 VA and some 900 VA customers (who are not classified as high-income households), all customers pay the market price for electricity.

The development of important macroeconomic assumptions, the realisation of electricity consumption, and the adoption of customised electricity subsidy policies for the non-integrated social welfare data (*Data Terpadu Kesejahteraan Sosial* - “DTKS”) family group with 900 VA (R1 / TR 900 VA) all had an influence on the realisation of electricity subsidies, which reached IDR 58.8 trillion at the end of 2022.

1.4 Transmission and Distribution (“T&D”)

Being an archipelago, Indonesia’s electricity is managed through a series of separate T&D grids. There are over 600 isolated grids and eight major networks in total. PLN currently has a de facto monopoly on T&D asset ownership and operations, although the private sector is legally permitted to operate T&D grids (see *Section 2.2.2.2 – Transmission, Distribution and Retailing*). Certain transmission lines have been built by IPPs, particularly for power plants in remote areas, in order to connect these power plants to the closest PLN substations. However, ownership of these transmission lines will typically be transferred to PLN following the completion of the construction.

At the end of 2022, PLN served 79 million customers through a transmission network comprising 68,205 circuit kilometres (“ckt-km”) of transmission lines and 161,366 megavolt amperes (“MVA”) of transformation capacity. Given that close to 0.5% of the population of Indonesia is without access to electricity, with many of those who are connected suffering from frequent supply interruptions, it is unsurprising that the expansion of power generation and T&D networks is both a top priority and a major challenge. According to the RUPTL 2021-2030, PLN has projected that electricity demand will grow at 4.7% p.a. until 2030, reaching a total of 445 TWh of electricity consumed in 2030, compared to 241 TWh in 2020.

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 (“RfP”s).

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

Region/Island	25-30 kV	70 kV	150 kV	275 kV	500 kV	Total
Sumatra	-	671.27	17,027.06	3,661.96	321.18	21,681.47
Java-Bali	96.79	2,996.40	16,628.90	-	6,649.70	26,371.79
Kalimantan	-	123.08	8,009.67	162.74	-	8,295.49
Sulawesi	4.00	595.90	7,947.41	3.41	-	8,546.72
Papua and Maluku	-	246.88	235.31	-	-	482.19
Nusa Tenggara	-	1,276.61	1,547.33	-	-	2,823.94
Total	**100.79**	**5,910.14**	**51,395.68**	**3,828.11**	**6,970.88**	**68,201.60**

Source: PLN Statistics 2022 p.32-34, PwC Internal Analysis

A summary of the sub-station transformer capacity for each significant island in Indonesia is as follows (in MVA):

Region/Island	<30 kV	70 kV	150 kV	275 kV	500 kV	Total
Sumatra	-	880	19,239	10,660	1,000	31,779
Java-Bali	-	3,251	68,341	-	39,849	111,441
Kalimantan	-	148	6,547	498	-	7,193
Sulawesi	30	909	5,818	340	-	7,097
Papua and Maluku	-	336	1,280	-	-	1,616
Nusa Tenggara	-	615	1,595	-	-	2,210
Total	**30**	**6,139**	**102,820**	**11,498**	**40,849**	**161,336**

Source: PLN Statistics 2022 p.32-34, PwC Internal Analysis

Based on the RUPTL 2021-2030, Indonesia will need additional transmission lines of approximately 46,962 kilometres ("km") by 2030 and sub-station transformer capacity of 74,512 MVA.[31] In 2022, PLN set the target to build a further 4,537 ckt-km of transmission lines and 4,930 MVA of transformer capacity.[32]

There are limited cross-border transmission lines connecting Indonesia with other Association of Southeast Asian Nations ("ASEAN") countries, as part of the ASEAN Grid programme. Please refer to *Section 2.2.6 – Cross-Border Sale and Purchase* for a detailed explanation.

In 2022, the existing distribution network consisted of around 430,504 ckt-km of medium voltage cables, 603,152 ckt-km of low voltage cables, and 65,438 MVA of transformation capacity, with 550,852 transformers as follows:

Region/Island	Low voltage (in ckt-km)	Medium voltage (in ckt-km)	Number of transformers (in Unit)	Transformer capacity (in MVA)
Sumatra	144,151	124,398	127,820	13,484
Java-Bali	344,167	188,250	314,852	40,908
Kalimantan	40,290	42,667	39,919	4,362
Sulawesi	42,353	43,549	44,511	4,125
Papua and Maluku	14,909	15,245	11,425	1,277
Nusa Tenggara	17,284	16,395	12,325	1,282
Total	**603,152**	**430,504**	**550,852**	**65,438**

Source: PLN Statistics 2022 p.32-34, PwC Internal Analysis

31 RUPTL 2021-2030, p. V-116 – V117
32 PLN Annual Report 2022, p. 376

The overall performance of the power network has been designed to support the implementation of a smart grid system across Indonesia which will be initiated in the RUPTL 2021-2030 with five locations to be implemented in each year.[33] Efficient energy planning, improved grid reliability and access, and the development of a metering system and the accompanying infrastructure are aspects which have been prioritised in the PLN Smart Grid Roadmap. This has commenced with the following pilot projects:

- The development of a smart grid in the Surya Cipta Sarana Industrial Zone, Karawang;
- The development of a smart grid for renewable energy on Sumba Island (East Nusa Tenggara) and on Nusa Penida Island (Bali);
- The development of a smart grid with advance metering infrastructure technology in a distribution area in Jakarta; and
- The development of a smart grid with automatic generation control in the Jawa-Bali power system.

1.5 Government Strategies, Policies and Plans for the Power Sector in Indonesia

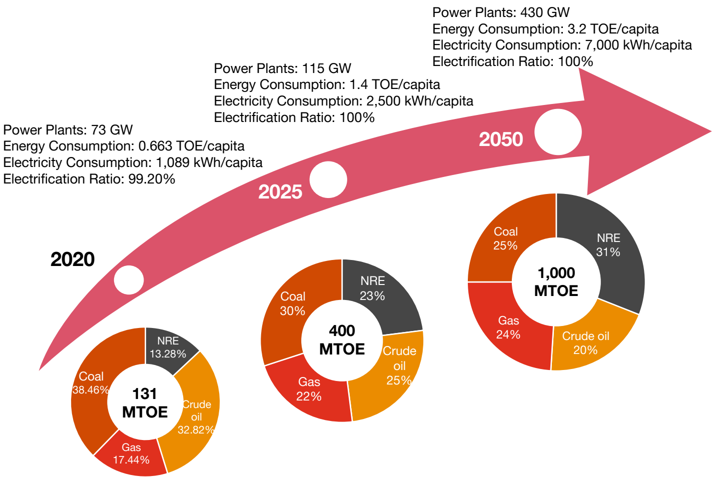
One of Asia's largest power markets, Indonesia's will continue to grow over the coming years. Indonesia had a net installed capacity of 83.8 GW at the end of 2022 and is expected to grow at an average annual rate of 2.8% to reach 98.5 GW in 2032. As Indonesia gradually completes the projects in its pipeline, it is anticipated that conventional thermal power, primarily coal, will continue to account for the majority of capacity gains.

The MoEMR stated at the Conference Of Parties 26 ("COP26") that Indonesia is still committed to reducing greenhouse gas emissions by 29-41% by 2030 and achieving net-zero carbon emissions by 2060. RUPTL 2021-2030, which contains a reinforced aim for adding renewable power capacity, is one strategy supporting efforts to reach this goal. RUPTL 2021-2030 projects an increase in total renewable power capacity of around 20.9 GW between 2021 and 2030, including hydropower. But the government also includes more electricity capacity for coal and gas in the plan, at 13.8 GW and 5.8 GW, respectively, for a total of 19.6 GW.

Renewables have increased in importance in recent years, due to concerns over global warming and other environmental issues. Certain renewable technologies have also become more attractive, as a result of falling costs. These factors have been reflected in the target energy mix for primary energy demand in Indonesia, with the renewable energy portion being increased to 23% based on the 2014 NEP, as compared to 17% based on PR No. 5/2006. In addition, the 2014 NEP aims to achieve an optimal primary energy mix of: (1) New and Renewable Energy ("NRE") of at least 23%, oil of less than 25%, coal of at least 30%, and natural gas of at least 22% by 2025; and (2) NRE of at least 31%, oil of less than 20%, coal of at least 25%, and natural gas of at least 24% by 2050. Furthermore, the 2014 NEP aims for a primary energy supply of 400 Million Tonnes of Oil Equivalent ("MTOE"), and 1,000 MTOE by 2025 and 2050, respectively – or 1.4 Tonnes of Oil Equivalent ("TOE")/capita and 3.2 TOE/capita by 2025 and 2050, respectively. These targets for renewables are likely to become more aggressive in the near term given the COP26 commitments and the aims of the JETP, which should also see retirements of some coal-fired power plants.

33 Bisnis, https://ekonomi.bisnis.com/read/20210221/44/1358991/pengembangan-smart-grid-masuk-ruptl-20212030, accessed March 2021

Figure 1.10 - Indonesia primary energy supply mix target (2020, 2025 & 2050)



Source: 2014 NEP, BP Statistical Review of World Energy 2021, HEESI 2020

The key points in the 2014 NEP that directly relate to the power sector are as follows:

- To reach installed capacity for power generation of 115 GW and 430 GW by 2025 and 2050, respectively;
- To achieve per capita electricity consumption of 2,500 kWh and 7,000 kWh by 2025 and 2050, respectively; and
- To achieve an electrification ratio of close to 100% by 2020.

The strategy for the utilisation of national energy sources by the Government and/or Regional Governments includes the following measures:

- The utilisation of renewable energy from waterflows and waterfalls, geothermal resources, sea waves, tidal and ocean thermal energy conversion, and wind for electricity generation;
- The utilisation of solar for electricity generation and non-electricity energy for industry, households and transportation;
- The utilisation of biomass and waste for electricity generation and transportation;
- The utilisation of natural gas for industry, electricity generation, households and transportation, specifically in cases that offer the highest value added;
- The utilisation of coal for electricity generation and industry;
- The utilisation of new solid and gas energy sources for electricity generation;
- The utilisation of ocean thermal energy conversion as a prototype for early-stage connection to the power grid;
- The utilisation of PV solar cells for transportation, industry, commercial buildings and households; and
- Maximising and making compulsory the utilisation of solar components and solar power plants that are manufactured domestically.

To create a competitive power sector the Government will, among other measures:

a) Determine the prices of certain primary energy sources such as coal, gas, water and geothermal used for power generation;
b) Determine the electricity tariff progressively;
c) Use the Feed-in Tariff ("FiT") mechanism for determining the selling price of renewable energy;
d) Manage geothermal energy resources through risk-sharing between Electricity Supply Business Licence (*Izin Usaha Penyediaan Tenaga Listrik* – "IUPTL") holders and developers;
e) Reduce the electricity subsidy in stages until the population's purchasing power can afford this without subsidy; and
f) Encourage domestic capability in order to execute geothermal exploration and support the power industry.

In order to support the NRE mix, and based on the 2014 NEP, the power generation energy mix should comprise approximately 25% NRE, 50% coal, 24% gas and 1% diesel fuel by 2025.[34] Based on the RUPTL 2021-2030, PLN projects that power generation from renewable sources will amount to a maximum of around 24.1% to 25.3% by 2030.[35] As such, it is likely the target prescribed in the 2014 NEP will not be achieved, unless a new strategy is implemented.

With Law No. 30/2007 on Energy and the 2014 NEP – as targeted in GR No. 79/2014 – in mind, President Joko Widodo issued PR No. 22/2017 on the National General Energy Plan (*Rencana Umum Energi Nasional* – "RUEN") in March 2017. The RUEN is a Central Government policy which consists of a cross-sectoral strategy and implementation plan for achieving the 2014 NEP. The RUEN sets out the results of the energy demand-supply modelling until 2050, and the policies and strategies which will be undertaken to achieve those targets. Under the RUEN, the Government seeks to re-emphasise the purpose of energy use as a driver of the national economy. The RUEN will be reviewed whenever there are changes to the fundamentals of the NEP or the strategic energy policies. Otherwise, the RUEN is to be reviewed every five years.

In terms of regulatory development for renewables, since many large-scale projects are still unbankable, the regulatory framework for other non-hydropower renewables is still in its infancy, and investor interest in them is limited. Despite having potential for the resource and stated renewable energy targets, Indonesia's solar, wind, biomass, and waste sub-sectors expand very slowly. However, given the expanding regulatory support for the sector, it can be anticipated that upside risks are present for Indonesia's non-hydropower renewables growth. A proposed Presidential regulation that will aim for "simpler pricing" for renewable energy, including a feed-in-tariff system for plants up to 5.0MW of capacity and procurement procedures with PLN, is purportedly being finalized by the Indonesian government. Additionally, it will add more incentives and rules to entice private investment, and it will charge 11 state agencies with promoting the economic agenda in their respective regions.

34 The renewables target in the primary energy mix is 23%, which is not to be confused with the renewables target in the power generation fuel mix (25%)

35 RUPTL 2021-2030, p. V-54

1.6 Chronological Development of the Power Sector in Indonesia

Early electricity arrangements in Indonesia were carried out pursuant to the 1890 Dutch Ordinance titled "Installation and Utilisation of Conductors for Electrical Lighting and Transferring Power via Electricity in Indonesia". This ordinance was annulled in 1985, with the introduction of Law No. 15/1985 on Electricity (the "1985 Electricity Law"), which ushered in the modern era of the power sector in Indonesia. The 1985 Electricity Law provided a centralised system, with a state-owned electricity company, PLN, holding exclusive powers over the transmission, distribution, and sale of electricity. Under this law, limited private participation in power generation was permitted for an entity's own use or for sale to PLN. Essentially, the model involved allows private investment in power-generating assets as IPPs. These IPPs were licensed to sell their power solely to PLN, pursuant to PPAs. PLN, being the sole purchaser of power output, became the key driver of the commercial viability of the entire value chain. The first major PPA in this new era was signed with PT Paiton Energy, in order to develop the coal-fired PLTU Paiton in 1991. Several other significant IPP projects followed, including a number relating to geothermal power generation under a slightly different investment framework. Many other IPP projects also made it through the various stages of licensing and commercial approval.

This IPP programme was effectively frozen in the late 1990s when the Asian financial crisis hit. Indonesia was badly affected, with GDP contracting by as much as 13.5%, and the IDR falling from around 2,500 per USD to as low as 16,650 in June 1998. PLN in turn suffered financially, especially as a result of the devaluation of the IDR. A large portion of PLN's costs were denominated in USD, including its PPA offtake prices, but its revenue was IDR-denominated. With the IPP sector being set up as a USD-denominated value chain, the investment economics of the entire sector deteriorated markedly following a fall of 75% in the value of the local currency. Many of the IPPs not yet in production at that time were abandoned. Others could only continue after their PPAs were renegotiated down to much lower offtake prices. Overall, a significant degree of investor confidence in the sector was lost. PLN was also left in the position of being unable to independently fund investment in the country's much-needed additional capacity.

In 2002, the Government introduced reforms through the enactment of Law No. 20/2002 on Electricity (the "2002 Electricity Law"). Under this law, the power business was divided into competitive and non-competitive areas, with the former allowing for private participation in the generation and retail areas of the electricity value chain.[36] The 2002 Electricity Law also allowed for electricity tariffs to be determined by the market, as well as for independent regulation, through the establishment of the Electricity Market Supervisory Agency. In December 2004, however, Indonesia's Constitutional Court ruled that the 2002 Electricity Law was unconstitutional, on the basis that it contravened Article 33 of the Indonesian Constitution. According to the Constitutional Court, electricity is a strategic commodity, and its generation and distribution should remain under the exclusive control of the Government. As a result, the Court effectively re-enacted the previous 1985 Law, and between 1999 and 2004 there was very little private investment of any sort in any new power projects.

36 Article 17(1) and Article 21(3) of the 2002 Electricity Law

The 1985 Electricity Law was implemented through GR No. 10/1989 on the Provision and Utilisation of Electricity, as amended by GR No. 3/2005 and GR No. 26/2006. Based on these regulations, IPPs were permitted to develop and supply power to the Authorised Holder of an Electricity Business Licence (*Pemegang Kuasa Usaha Ketenagalistrikan* – "PKUK") as well as the Holder of Electricity Business Licence for Public Interest (*Pemegang Izin Usaha Ketenagalistrikan untuk Kepentingan Umum*), which were essentially limited to PLN.

Other supporting legislation and regulations since then have included the following:

a) PR No. 67/2005 and MoF Regulation No. 38/2006, which set out rules and procedures for public-private partnership ("PPP") arrangements, including Government support and guarantees;
b) PR No. 42/2005, which outlined the inter-ministerial Committee for the Infrastructure Development Acceleration Programme, with responsibility for coordinating policy relating to the private provision of infrastructure;
c) PR No. 71/2006, which launched the first fast-track programme, and which also allowed the direct selection of coal-fired power plants for the first fast-track programme;
d) MoEMR Regulation No. 1/2006 on Electrical Power Purchasing and/or Rental of Transmission Lines and MoEMR Regulation No. 5/2009 on the Guidelines for Power Purchase by PT PLN (Persero) from Cooperatives or Other Business Entities, which covered the IPP procurement process.

In 2005, the Government began new efforts to attract private investment back to the sector. New PPP legislation was enacted, and a list of IPP projects open for private tender was also made available.

In 2006, the Government announced stage one of a fast-track programme ("FTP I"), which was followed by a second programme ("FTP II") in early 2010. Each programme aimed to accelerate the development of 10 GW generating capacity, with FTP II geared towards IPPs and renewable energy. In 2015, the new Joko Widodo Government announced plans to accelerate the development of 35 GW generating capacity.

In 2009, the Government passed the 2009 Electricity Law in order to strengthen the regulatory framework and provide a greater role for Regional Governments in terms of licensing and determining electricity tariffs. The 2009 Electricity Law replaced the 1985 Electricity Law with effect from 23 September 2009. However, in contrast to the (intervening) 2002 Electricity Law, the 2009 Electricity Law did not eliminate the main role of PLN in the electricity supply business. Under the 2009 Electricity Law, electricity supply is still controlled by the state, but it is conducted by Central and Regional Governments through SOEs. In this case, the Government has given PLN priority rights over the electricity supply business throughout Indonesia. The 2009 Electricity Law also promoted a greater role for private enterprises, cooperatives, and self-reliant community institutions (*Lembaga Swadaya Masyarakat*) in terms of participating in the electricity supply business. Please refer to *Section 2.2 – The 2009 Electricity Law* for more detailed information.

1.7 Environmental, Social and Governance

In Indonesia, the ESG landscape has been gradually evolving since the inception of the International Paris accord 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 Sustainable Finance Roadmap Phase II (2021-2025) guidebook) issued by The Financial Services Authority of Indonesia ("OJK"); the creation of the 2021 – 2040 National Electricity General Plan (*Rencana Umum Ketenagalistrikan Nasional* - "RUKN") (please refer to *Section 2.2.1 - 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. The OJK and the Indonesia Stock Exchange ("IDX") are currently developing the regulations for a carbon trading market.

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. A noteworthy recent development is that the ADB is currently pushing the 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.[37] 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.[38]

In terms of the amount of funding given, USD 20 billion in public and private seed funding over a three to five-year period will be mobilised through the coordination of the JETP Secretariat.[39]

1.8 Messages from B20

As part of the recently concluded G20 Indonesia Presidency, B20 Indonesia hosted by the Indonesian Chamber of Commerce and Industry (*Kamar Dagang dan Industri Indonesia* - "KADIN"), brought together global business and thought leaders to identify the most pressing problems of the day, and compile potential solutions from a business perspective.

37 https://www.climatechangenews.com/2021/06/03/uk-calls-indonesia-set-roadmap-net-zero-emissions/
38 European Commission, https://ec.europa.eu/commission/presscorner/detail/en/ip_22_6926, accessed 21 January 2023
39 Indonesian US Embassy, https://id.usembassy.gov/government-of-indonesia-and-international-partners-launch-just-energy-transition-partnership-secretariat-to-drive-indonesias-energy-transformation, accessed 01 Mar 2023

Three key areas were prioritised in the official communique of the B20 to G20 – accelerating the green transition, promoting inclusive growth and creating equitable access to healthcare.

All three are critically important for different reasons, but ultimately feed into a collective aspiration to accelerate progress on the unfinished development agenda. But even amongst these, accelerating the green transition takes precedence as the continuing reliance on fossil fuels for primary energy supply and associated GHG emissions, primarily CO_2, is causing global warming and climate change. Left unaddressed this will result in catastrophic climate change, which threatens the very existence of life on the planet as we know it.

One of the cornerstones of the policy recommendations of the B20 Energy, Sustainability and Climate Taskforce, for which PwC Indonesia was knowledge partner, is the need for enhanced cooperation on a global scale to ensure broad basing and acceleration of the energy transition in a manner that addresses the energy security and affordability concerns of all countries.

It must, however, be noted that any change to the status quo will result in uneven impacts on different stakeholders. A change on the scale of the energy transition will magnify these distributional impacts, especially in countries that are major producers and suppliers of fossil fuels. Securing the social and political licence for this critically needed transition requires that stakeholder impacts are well considered and addressed through appropriate interventions from Governments and external development partners to ensure a just transition. This is not just the right thing to do, but also the necessary thing to do, as achieving a successful energy transition while increasing inequality, will be unsustainable.

B20 ESC TF policy recommendations

Policy recommendation	Policy action no.	Policy action
Enhance global cooperation on accelerating the transition to sustainable energy use by reducing carbon intensity of energy use through multiple pathways	1.1	Enhance the pace of energy efficiency improvement across the transport, buildings and industrial sectors
	1.2	Progressively reduce the carbon intensity of electricity by reducing emissions from coal fired generation and accelerating renewable energy deployment, according to national circumstances
	1.3	Accelerate the mitigation of carbon emissions from hard-to-abate sectors
	1.4	Progressively enhance the quantum, predictability & ease of financing flows to developing countries
	1.5	Support climate technology innovation by supporting start-ups, and research universities with technology, financing, skilled manpower, knowledge & facilities sharing
Enhance global cooperation on ensuring a just, orderly, and affordable transition to sustainable energy use across developed and developing countries	2.1	Ensure an orderly transition in primary energy sources
	2.2	Ensure Micro, Small & Medium Enterprises ("MSME") participation in energy transition activities with financing and capacity building
	2.3	Assist transition readiness by ensuring human capital ability to accommodate change (e.g., transfer knowledge, upskilling & workshop)
	2.4	Ensure sustainable practices for mining of essential minerals for energy technologies
Enhance global cooperation on enhancing consumer level access and ability to consume clean, modern energy	3.1	Accelerate deployment of integrated electricity access solutions, including off grid with community participation and grid-based electrification to expand energy access and enhance economic prosperity
	3.2	Facilitate adoption of technology by households and MSMEs for efficient, clean, modern energy usage
	3.3	Ensure broad basing of the transition by addressing affordability barriers in developing countries

1.9 Stakeholders

MoEMR

The MoEMR is charged with creating and implementing Indonesia's energy policy, including the RUKN, and regulating the power sector through the DGE and the Directorate General of New and Renewable Energy and Energy Conservation ("DGNREEC"). The MoEMR is also responsible for preparing the implementing regulations that relate to electricity, the NRE, and energy conservation, as well as those endorsing PLN's RUPTL.

House of Representatives (Dewan Perwakilan Rakyat – "DPR")

Commission VII of the DPR is charged with developing regulations in the areas of energy, research and technology, and the environment. Commission VII is also responsible for the approval of energy-related legislation (including for electricity), and the supervision of energy-related Government policy.

PLN

PLN is responsible for the majority of Indonesia's power generation, having exclusive powers over the transmission, distribution and supply of electricity to the public. PLN is regulated and supervised by the MoEMR, the Ministry of State-Owned Enterprises ("MoSOE"), and the MoF.

In 2004, PLN was transformed from a public utility into a state-owned limited liability company (or Persero). The 2009 Electricity Law removed PLN's role as PKUK. PLN is now simply the holder of an IUPTL.

The 2009 Electricity Law also grants the right of first refusal to PLN for the supply of electricity in a particular area, before the Central Government or Regional Governments can offer the opportunity to regionally-owned entities, private entities, cooperatives, or self-reliant community institutions. PLN is also the provider of electricity of last resort. This means that if PLN is not supplying a particular area, and there are no regionally-owned entities, private enterprises, or cooperatives willing to supply that area, then the Government can instruct PLN to ensure the supply of electricity to the area.

Ministry of National Development Planning/National Development Planning Board (*Kementerian PPN/Bappenas* – "Bappenas")

Bappenas is responsible for carrying out governmental duties in the field of national development planning, in accordance with the prevailing laws and regulations. Within Bappenas is the Directorate for PPP (*Direktorat Kerjasama Pemerintah-Swasta dan Rancang Bangun*), which facilitates cooperation on infrastructure projects between the Government and private investors.

Ministry of Investment/Investment Coordinating Board (*Kementrian Investasi/Badan Koordinasi Penanaman Modal* – "BKPM")

From 2010, BKPM started issuing electricity supply business licences. From 2015, BKPM has also acted as a "one-stop" integrated service for business startup and licensing procedures, as well as for facilitating foreign worker permits. BKPM also offers an Investor Relations Unit for providing information to and dealing with enquiries from existing and potential investors. The Government recently introduced an online business licensing platform, via the Online Single Submission ("OSS") System.

Please see the discussions in *Section 2.2.4 – IUPTLU/IUPTLS*, *Section 2.2.5 – OSS System*, and *Section 2.3.6 – Ease of Licensing* for detailed information about the licences issued by BKPM.

Kementerian Badan Usaha Milik Negara – the Ministry of State-Owned Enterprises (the MoSOE)

The MoSOE supervises PLN's management, sets its corporate performance targets, approves its annual budget, and assesses the achievement of those targets.

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

KPPIP is an inter-ministerial coordinating committee chaired by the Coordinating Minister for Economic Affairs together with the Coordinating Minister for Maritime Affairs. Other members of KPPIP include 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 was established with the main objective of coordinating the decision-making process. KPPIP is the main point of contact for "de-bottlenecking" strategically important national and priority projects.

MoF

The MoF approves tax incentives that may be offered by the Government for power projects, as well as 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 reviewing Government support, providing technical guidance, evaluating the financing, and maintaining investor relations. Any approved guarantees are administered by PT Penjaminan Infrastruktur Indonesia ("PT PII") (see below).

The MoF also recommends the maximum level of electricity subsidy to PLN in the national budget, and reviews the loan arrangements entered into by PLN, including the Government's guarantees of PLN's loans.

PT PII or the Indonesian Infrastructure Guarantee Fund ("IIGF")

The IIGF was established on 30 December 2009 to provide guarantees for infrastructure projects under the PPP scheme. The IIGF also acts as a strategic advisor to the Government, and a transaction manager/lead arranger for infrastructure projects. The IIGF is wholly owned by the Government, and a total of IDR 8 trillion in capital was injected at the end of 2018. For further details, please see *Section 3.3.1 – IIGF – for PPPs*.

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

METI was established in 1999 as a forum that focuses on the development of renewable energy in Indonesia. METI is a member of the World Renewable Energy Network, which is based in the UK. The management of METI includes the Heads of the Geothermal, Hydro, Solar, Biofuel, Biomass, Biogas, Wind, Nuclear, and Ocean Energy Associations.

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

MKI was established on 3 September 1998 and it has members from various stakeholders within the power industry. The main objectives of MKI are to provide a forum to discuss matters relating to the industry, and to put forward the views of members to the Government on topics such as technology, the business environment, and regulations.

PT Sarana Multi Infrastruktur ("PT SMI") and PT Indonesia Infrastructure Finance ("PT IIF")

PT SMI was established on 26 February 2009, with IDR 1 trillion (USD 100 million) in capital. The capital had increased to IDR 55.39 trillion by the end of 2017. PT SMI exists to help investors obtain domestic financing for the debt and equity funding of infrastructure development, including power projects, as well as to prepare projects under the Project Development Facilities assigned by the Minister of Finance. PT SMI is backed by multilateral agencies, including the World Bank. The total financing commitment of PT SMI at the end of 2017 was IDR 29 trillion, with 32% being allocated to the power sector.

PT IIF was established on 15 January 2010 and it operates as a private non-bank financial institution, with a focus on infrastructure project finance. Its shareholders are PT SMI, the International Finance Corporation, ADB, Deutsche Investitions-und Entwicklungsgesellschaft GmbH, and Sumitomo Mitsui Banking Corporation.

For further details, please see *Section 3.3.4 - The Infrastructure Financing Fund*.

The Indonesian government and ADB launched the ETM initiative at the COP 26 conference in Glasgow. In addition to that, following technical assessments and discussions with many stakeholders regarding the current conditions of the power & utility industry, the Government has identified 15 GW of coal-fired power plants for early retirement.

PT SMI was appointed as the ETM Country Platform Manager and national focal point of ETM activities. PT SMI will collaborate with PLN and international partners to mobilise significant competitive finance capital to create a just and affordable energy transition. On this occasion, PT SMI also signed Memorandum of Understanding with 14 international partners that will build the momentum of Indonesia's ambition in the development of energy transition.[40]

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

APLSI is based in Jakarta, and it was incorporated on 8 August 2008. APLSI is an organisation and a forum for communication between IPPs and the Indonesian government, as well as parties connected to the activities of IPPs. APLSI's vision is to become an efficient and trustworthy association of IPPs in Indonesia, and to make a contribution to the development of Indonesian IPPs at the international level.

Indonesian Solar Energy Association (Asosiasi Energi Surya Indonesia – "AESI")

AESI was established on 9 March 2016. The organization aims to build a communication forum and cooperation between solar energy stakeholders, towards reaching the national target of solar energy utilisation in order to fulfil sustainable energy needs.

Indonesian Geothermal Association ("INAGA")

INAGA was established in 1991 as a forum for communication and coordination in order to improve the capabilities, understanding, cooperation, and responsibilities of its member in relation to geothermal energy development in Indonesia.

40 Kemenkeu, https://www.kemenkeu.go.id/informasi-publik/publikasi/berita-utama/ETM-Bentuk-Komitmen-Pemerintah-Transisi-Energi, accessed 21 January 2023


Photo source: PT Pembangkitan Jawa Bali

2 Legal and Regulatory Framework

2.1 Introduction

At the outset, the power sector 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 Government Regulation in Lieu of Law No. 02 of 2022 on Job Creation ("the Omnibus Law")), and several other electricity government regulations namely Government Regulation No. 25 of 2021 on the Organization 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 for Industry, the Minister for Environment and Forestries, and other ministers within their respective roles and responsibilities issued several implementing regulations on technical and standard aspects of the electric sector in Indonesia. In addition, there are other laws and regulations affecting the electric power sector such as Law No. 2/2012 on Land Procurement for Public Interest Developments (as partially amended by the Omnibus Law) and its implementing regulation, PR No. 19/2021 on the Implementation of Land Procurement for Public Interest Developments, which basically provides a legal framework for acquiring land for infrastructure projects. There are also other specific subsector laws and regulations related to electricity generation such as Law No. 21/2014 on Geothermal (as partially amended by the Omnibus Law).

2.2 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).

2.2.1 RUKN and RUPTL

The Central Government is responsible for developing the RUKN. This 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), as stipulated under GR No. 79/2014 and PR No. 22/2017, respectively. The RUKN was formulated in collaboration with the Government and Regional Government during the course of several focus-group discussions ("FGDs"). Pursuant to the Omnibus Law, the MoEMR is no longer obligated to set out guidelines on RUKN, whereas the guidelines of RUKN will be further governed under Government Regulation. The Omnibus Law also repealed the obligation for the Central Government to consult the DPR prior to ratification of the RUKN. The RUKN is reviewed every three years, at least. In contrast with the 2009 Electricity Law (as partially amended by the Omnibus Law), the Regional Electricity Plan (*Rencana Umum Ketenagalistrikan Daerah* - "RUKD") is only applicable for provincial governments as stipulated under the Omnibus Law.

The RUPTL constitutes a ten-year electricity development plan in the operating areas, or *Wilayah Usaha*, of PLN (excluding the *Wilayah Usaha* 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. 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.

2.2.2 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; and/or
    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; or
    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; and
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 *Wilayah Usaha*. Restrictions on *Wilayah Usaha* 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 *Wilayah Usaha* given to private enterprises, cooperatives and self-reliant community institutions involved in the electricity supply business.

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

a) The existing holder(s) of a *Wilayah Usaha* is not able to provide electricity;

b) The existing holder(s) of a *Wilayah Usaha* is not able to provide the required level of quality and reliability;

c) The existing holder(s) of a *Wilayah Usaha* has returned some or all of the area to the MoEMR;

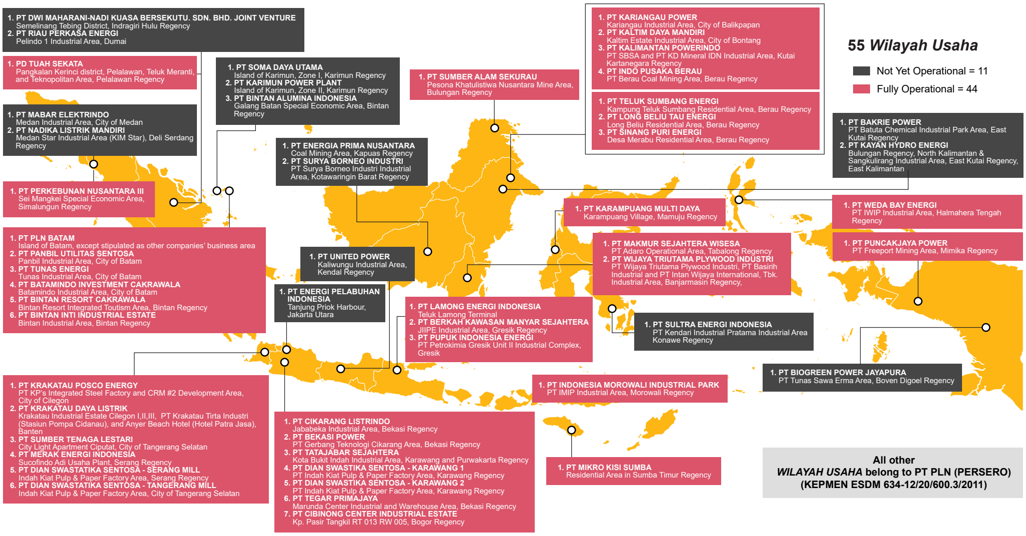
d) The area of the *Wilayah Usaha* proposed by the business actor has not yet been covered by the existing holder(s) of a *Wilayah Usaha*; and/or

e) The area of the *Wilayah Usaha* 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 a *Wilayah Usaha*, 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 *Wilayah Usaha* will be granted.

As of October 2021, the Government has issued 55 *Wilayah Usaha* of PLN, with 44 *Wilayah Usaha* already in operation and 11 *Wilayah Usaha* not yet in operation. The distribution of *Wilayah Usaha* can be seen in Figure 2.1.

Figure 2.1 – The holders of *Wilayah Usaha* as of October 2021



Source: MoEMR

2.2.2.1 Generation

PLN and IPPs

By the end of 2022, according to the MoEMR, the total installed capacity for both on-grid and off-grid power plants reached 83.8 GW. This number increased by 12.5% from 2021 (74.5 GW). This capacity was obtained, in part, due to the completion of new plants by both PLN and IPPs. Of the installed 83.8 GW, fossil fuel power plants (incl. coal, gas, coal-gasification, co-firing and diesel) accounted for 85% (71.2 GW) of the total capacity. Clean and renewable energy accounted for the remaining 15% (12.1 GW).

In terms of generated power (power production), 333.5 GWh worth of power was generated in 2022; an increase of 7.9% from 2021 which stood at 309.1 GWh. The majority of the total power generated came from coal, combined gas-steam and hydro power plants, with each having 61.8%, 11.5% and 8.1% shares of the mix.[41] We note that in January 2023, PLN has spun-off its generation assets into sub-holding entities, including PT Indonesia Power and PT PLN Nusantara Power.

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 PR No. 38/2015 and its implementing regulation the Government Procurement of Goods and Services Policy Board (*Lembaga Kebijakan Pengadaan Barang dan Jasa* - “LKPP”) No. 19/2015, which was partially revoked (from Article 1 to Article 35, only for provisions related to solicited projects) with the issuance of LKPP Regulation No. 29/2018. Later, the Government specialised LKPP No. 19/2015 for unsolicited projects, while solicited projects may refer to No. 29/2018. For a detailed discussion of the IPP and PPP procurement process, please see *Section 3.4 – Procurement Process*.

PPUs

Investors that generate electricity for their own use rather than for sale to PLN are known as private power utilities, or PPUs. Under MoEMR Regulation No. 11/2021, PPUs with a capacity greater than 500 kilowatts (“kW”) must hold an *Izin Usaha Penyediaan Tenaga Listrik Untuk Kepentingan Sendiri* (“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.

GR No. 25/2021 regulates that PPUs with a capacity greater than 500 kW must hold a business licence to operate electricity supplying businesses for their own use. PPUs with a capacity of up to 500 kW must submit one report to the Minister or the Governor prior to operating the electricity supplying business.

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

41 HEESI 2022, p. 94

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 (*Biaya Pokok Pembangkitan* - "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 *Izin Usaha Penyediaan Tenaga Listrik Untuk Kepentingan Umum* ("IUPTLU") holder(s) which has already attained a *Wilayah Usaha*. A parallel operation must consider the power supply capacity of the integrated IUPTLU holder(s) and be conducted in accordance with the grid code.

2.2.2.2 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 transmission and distribution assets, PLN remains the only business entity which is involved in the transmission and distribution 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 transmission and distribution.

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 transmission and distribution 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.

2.2.2.3 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; and
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 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.

2.2.3 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. Minister of Industry Regulation ("MoI Regulation") No. 54/M-IND/PER/3/2012 (as amended by MoI Regulation No. 5/M-IND/ PER/2/2017) stipulates the minimum required percentage of local goods and services (by value) that are to be used for the development of electricity infrastructure for public use. Failure to comply with these local content requirements may result in administrative and financial sanctions.

Imported goods can be used if:
a) The goods have yet to be produced locally;
b) The technical specifications of the local goods do not meet the requirements; or
c) The quantity of the local goods is not sufficient.

The following table summarises the minimum local content requirements for different sources of power generation:

Power Plant	Capacity	Minimum use of local content (TKDN)
Coal-Fired	Up to 15 MW	67.95% for goods; 96.31% for services; and 70.79% for goods and services combined
	>15 to 25 MW	45.36% for goods; 91.99% for services; and 49.09% for goods and services combined
	> 25 to 100 MW	40.85% for goods; 88.07% for services; and 44.14% for goods and services combined
	> 100 to 600 MW	38.00% for goods; 71.33% for services; and 40.00% for goods and services combined
	Above 600 MW	36.10% for goods; 71.33% for services; and 38.21% for goods and services combined
Hydro - Non-Storage Pump	Up to 15 MW	64.20% for goods; 86.06% for services; and 70.76% for goods and services combined
	> 15 to 50 MW	49.84% for goods; 55.54% for services; and 51.60% for goods and services combined
	> 50 to 150 MW	48.11% for goods; 51.10% for services; and 49.00% for goods and services combined
	Above 150 MW	47.82% for goods; 46.98% for services; and 47.60% for goods and services combined

Power Plant	Capacity	Minimum use of local content (TKDN)
Geothermal	Up to 5 MW	31.30% for goods; 89.18% for services; and 42.00% for goods and services combined
	> 5 to 10 MW	21.00% for goods; 82.30% for services; and 40.45% for goods and services combined
	> 10 to 60 MW	15.70% for goods; 74.10% for services; and 33.24% for goods and services combined
	> 60 to 110 MW	16.30% for goods; 60.10% for services; and 29.21% for goods and services combined
	Above 110 MW	16.00% for goods; 58.40% for services; and 28.95% for goods and services combined
Gas-Fired	Up to 100 MW per block	43.69% for goods; 96.31% for services; and 48.96% for goods and services combined
Combined-Cycle	Up to 50 MW per block	40.00% for goods; 71.53% for services; and 47.88% for goods and services combined
	> 50 to 100 MW per block	35.71% for goods; 71.53% for services; and 40.00% for goods and services combined
	> 100 to 300 MW per block	30.67% for goods; 71.53% for services; and 34.76% for goods and services combined
	Above 300 MW per block	25.63% for goods; 71.53% for services; and 30.22% for goods and services combined
Solar Home System (off-grid, stand-alone)	Per unit	39.87% for goods; 100% for services; and 45.90% for goods and services combined
Communal Solar Power System (mini-grid)	Per unit	34.09% for goods; 100% for services; and 40.68% for goods and services combined
On-Grid Solar Power System	Per unit	37.47% for goods; 100% for services; and 43.72% for goods and services combined

The construction of power plants is also regulated as follows:

a) The development of coal-fired power plants up to 135 MW, geothermal power plants up to 60 MW, hydropower plants up to 150 MW, and combined cycle power plants or solar power plants should be undertaken and led by a national Engineering, Procurement and Construction ("EPC") company; and

b) The development of power plants other than those mentioned above can be undertaken by a consortium between a foreign company and a local company.

Based on MoI Regulation No. 5/M-IND/PER/2/2017, the level of domestic components for solar modules had to be at least 50% by 2018, rising to 60% by 2019. This contrasts with the previous regulation, where only 30.14% was required for solar home system modules, and 25.63% for communal solar system modules.

However, based on MoI's letter addressed to the MoEMR in August 2019, the implementation of the minimum local content for solar modules of 60% was suspended until 2021 after inputs were considered from relevant stakeholders. Currently, the minimum local content requirements for solar module products is set at 40%. According to the MoI, the minimum local content for solar modules is expected to be set at 90% in 2025.

The following table summarises the minimum local content requirements for transmission:

Type	kV	TKDN
High-Voltage Aerial Network	70	70.21% for goods; 100% for services; and 76.17% for goods and services combined
	150	70.21% for goods; 100% for services; and 76.17% for goods and services combined
Extra-High-Voltage Aerial Network	275	68.23% for goods; 100% for services; and 74.59% for goods and services combined
	500	68.23% for goods; 100% for services; and 74.59% for goods and services combined
High-Voltage Undersea Cable Network	150	15.00% for goods; 83.00% for services; and 28.60% for goods and services combined
High-Voltage Underground Cable Network	70	45.50% for goods; 100% for services; and 56.40% for goods and services combined
	150	45.50% for goods; 100% for services; and 56.40% for goods and services combined

The following table summarises the minimum local content for main relay stations:

Type	kV	TKDN
High-Voltage Main Relay Station	70	41.91% for goods; 99.98% for services; and 65.14% for goods and services combined
	150	40.66% for goods; 99.98% for services; and 64.39% for goods and services combined
Extra-High-Voltage Main Relay Station	275	22.42% for goods; 74.54% for services; and 43.27% for goods and services combined
	500	21.51% for goods; 74.67% for services; and 42.77% for goods and services combined
High-Voltage Gas Insulated Switchgear ("GIS")	150	14.27% for goods; 26.68% for services; and 19.24% for goods and services combined
Extra-High Voltage GIS	150	11.19% for goods; 26.68% for services; and 17.39% for goods and services combined

The construction of transmission and distribution networks should be undertaken and led by a national EPC company.

The provisions and procedures for the calculation of the local content in goods, services, and the combination of goods and services for power plants, main relay stations, and transmission/distribution networks are regulated by MoI Regulation No. 02/M-IND/PER/1/2014 regarding Guidance for the Use of Domestic Goods in the Procurement of Government Goods/Services and MoI Regulation No. 16/M-IND/PER/2/2011 regarding Provisions and Procedures for the Calculation of Local Content.

2.2.4 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; and
b) An IUPTLS to supply electricity for own use (i.e. for PPUs) with a capacity of more than 500 kW according to MoEMR 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; and
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; or
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 BKPM and is performed via a platform referred to as the OSS system. Please see the following *Section 2.2.5 – Online Single Submission ("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; and
j) Geothermal licences (*Izin Panas Bumi* - "IPB").

2.2.5 Online Single Submission ("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 licences: 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 the Economy to BKPM.

Following the issuance of the Omnibus Law, GR No. 24/2018 was revoked by GR No. 5/2021 on the Organisation of Risk-Based Business Licensing. The implementation of Risk-Based Business Licensing is carried out based on stipulation of 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 an NIB and Standard Certificate, and those undertaking high-risk business activities are required to obtain an NIB and Business Licence. An NIB can be obtained by registering existing and newly established businesses at 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* - “NPWP”); (iv) Business Classification (*Klasifikasi Baku Lapangan Usaha Indonesia* - “KBLI”); and (v) business location.

In addition to the above, it is important to note that since the issuance of GR No. 5/2021 on the Organisation of Risk-Based Business Licensing, there has been a shift in the nomenclature used to represent the licences above and has since been identified simply as “business licence” or “*perizinan berusaha*” the implementation is yet to be finalised and perfected, however, this is the direction the regulation is heading to. Moreover, there are also other supplementary licences that business actors will need to obtain, these supplementary licences are called “*Perizinan Berusaha Untuk Menunjang Kegiatan Usaha*” (“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. 5/2021. Examples of PB UMKU for the electricity sector, include Determination of Electricity Tariffs (*Penetapan Tarif Tenaga Listrik*), Approval on Sales Price and Lease of Electricity Power Network (*Persetujuan Harga Jual dan Sewa Jaringan Tenaga Listrik*), Certificate of Competency of Electricity Engineering Personnel (*Sertifikat Kompetensi Tenaga Teknik Ketenagalistrikan*), etc.

During the registration process, after the completion of data filing to obtain an 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; and
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. 5/2021, 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[42] and/or commercial or operational licence[43] 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) Obtained an Environmental Approval; and
b) Obtained a Building Permit (*Persetujuan Bangun Gedung* - "PBG").

In its mission to make the OSS an integrated licensing platform that can facilitate investment, basic licences such as the Environment Approval and PBG 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, reduce the amount of the licences required for investor in doing business.

2.2.6 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; and
c) The sale will not compromise the quality and reliability of the local power supply.

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42 Under MoEMR Regulation No. 39 of 2018, a business license means a permit issued by the OSS Institution for and on behalf of the minister or governor after the Business Actor has registered and to start a business and/or activity until before commercial or operational implementation by fulfilling the requirements and/or commitments.

43 Under MoEMR Regulation No. 39 of 2018, a commercial/operational business license means a license issued by OSS Institutions for and on behalf of minister or governor after Business Actors have obtained Business Licence and to carry out commercial or operational activities by fulfilling the requirements and/or commitments.

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; and
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. Such purchases increased from 1.26 GWh in 2009 to 892 GWh in 2017, due to a shortage of power in West Kalimantan. Given the lack of power supply to West Kalimantan, the Government permitted the development of a 275 kilovolt ("kV") link between Sarawak, Malaysia and West Kalimantan for importing hydro-generated power under a 20-year agreement between PLN and the Sarawak Energy Supply Corporation. The payments are based on usage for the first five years, while the remainder of the contract will involve a fixed cost, according to the contract. This interconnection went live in January 2016. For the first five years, Indonesia was expected to import around 50 MW during non-peak load times and 230 MW at peak load times, after which time either party could buy or sell the energy from this project. PLN plans to export power on a net basis after the completion of the Kalbar-1 (2 x 50MW), Kalbar-2 (2 x 27.5 MW) and Kalbar-3 (2 x 55 MW) steam power plants.[44]

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.

In addition, a small cross-border transmission line connection has been built from Jayapura to the Papua New Guinea ("PNG") border, in order to supply 2 MW of power (generated from diesel plants in Jayapura) to the Wutung Border Post.[45] PNG Power Ltd ("PPL") is waiting for the approval to invest the estimated PGK 3.5 million (USD 1.1 million) that is required to construct the 42 km, 20 kV transmission line from Vanimo to Wutung.[46]

44 MoEMR, https://www.esdm.go.id/id/media-center/arsip-berita/indonesia-malaysia-kerja-sama-perkuat-kelistrikan-diperbatasan, accessed 9 September 2016
45 The National, https://www.thenational.com.pg/indonesia-set-to-provide-electricity-to-png-border/, accessed 20 July 2018
46 The National, https://www.thenational.com.pg/k1-5m-given-for-villages-to-get-power-from-indonesia/, accessed 20 July 2018

The other planned ASEAN Power Grid projects in which Indonesia will take part are as follows:

Interconnection transmission network	Earliest planned COD
Peninsular Malaysia – Sumatra	2019
Batam – Singapore	2020
East Sabah – East Kalimantan	Post 2020
Singapore – Sumatra	Post 2020

Source: International Energy Agency ("IEA"), "Development Prospects of the ASEAN Power Sector: Toward an Integrated Electricity Market", 2015

As of writing, there is limited progress on the interconnection transmission network, however there has been increased investor interest in development of renewable energy projects for export to Singapore.

2.3 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 Jokowi 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 FTP I for 10 GW of coal-fired power generation in 2006, and FTP II for a further 10 GW – which was largely being sourced from renewable energy projects – in 2010. The realisation of FTP I and II has not been very successful. After 11 years, FTP I is not yet 100% complete. FTP II has also not progressed as expected, with various projects now having been integrated into the 35 GW programme, under President Joko Widodo's administration.[47]

Following the obstacles faced by FTP 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 the 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.

2.3.1 Government Guarantees

Under PR No. 4/2016 (as amended by PR No. 14/2017), an IPP can receive a business viability guarantee from the MoF as a consequence of PLN's obligations under PPAs. In order to obtain such a guarantee, PLN's President Director needs to request the guarantee from the MoF before the start of the procurement process for the power project. PR No. 4/2016 (as amended by PR No. 14/2017) does not provide any criteria for granting a business viability guarantee, or for the granting mechanism of such a guarantee. It is at the discretion of PLN to propose the guarantee. Furthermore, the proposed guarantee may therefore need to be included in the procurement documents.

47 Liputan 6, https://www.liputan6.com/bisnis/read/3877960/baru-8-persen-pembangkit-listrik-program-35-ribu-mw-yang-beroperasi, accessed 31 July 2018.

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.

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.

2.3.2 New and Renewable Energy 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) FiTs for NRE sources;
d) The establishment of a separate business entity to generate energy from new and renewable sources for sale to PLN; and
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 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 greenhouse gas emissions are reduced. The goals for greenhouse gas 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.

PR 112/2022 covers the following:

a) **The electricity development plan**

PR 112/2022 mandates PLN to draw up a RUPTL to replace and serve as the updated version of the existing RUPTL of PLN in order to provide special attention to the development of renewable energy and to meet the targeted energy mix.

b) **The acceleration of the termination of coal-fired power plants operations**

PR 112/2022 mandates PLN to conduct an early termination of its coal-fired power plants or PLTU and/or PLTUs of Independent Power Producers. In order to do this, the MoEMR shall draw up a roadmap by coordinating with the Minister of Finance and Minister of State-Owned Enterprise.

The implementation of acceleration of the termination of privately owned CFPP operation and/or CFPP PPA contract developed by the IPP shall pay attention to at least the following criteria:

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

Moreover, the development of new PLTU power plants is prohibited except for:

- PLTUs that have been determined in the RUPTL prior to the issue of PR No. 112/2022; or
- PLTUs which fulfill the following requirements:
  - Integrated with built-in industries which are oriented towards increasing the added value of natural resources or are included in National Strategic Projects which have a major contribution to the creation of employment opportunities and/or national economic growth;
  - Committed to reducing greenhouse gas emissions by at least 35% (thirty five percent) within a period of 10 (ten) years from the operation of the PLTU compared to the average PLTU emissions in Indonesia in 2021 through the development of technology, carbon offset, and/or renewable energy mix; and
  - Operate until 2050 at the latest.

c) **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.

d) **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 plans and the source of primary energy.

Procurement of Electricity from Renewable Power Plants based on PR 112/2020	
Direct Appointment	Direct Selection
• 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 for the exploitation of geothermal resources and holders of permits for the exploitation of geothermal resources; • Capacity expansion from PLTP, PLTA, PLTS, PLTB, Biomass Power Plant (*Pembangkit Listrik Tenaga Biomassa* - "PLTBm"), or PLTBg; and • Excess power from PLTP, PLTA, PLTBm or PLTBg.	• PLTA; • Photovoltaic 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; and • PLTA which function as peaker plants.

e) **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 year 1-10) and ceiling price shall be considered for the second stage (from year 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.

f) **The payment of electricity purchase**

PR 112/2022 regulates that the payment of electricity purchase shall be in Rupiah using the exchange rate from the Jakarta Interbank Spot Dollar Rate at the time agreed in the PPA.

2.3.3 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 2.2.3 - Local Content.*

2.3.4 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).

2.3.5 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 2.5.4 – 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.

2.3.6 Ease of Licensing

As discussed in *Section 2.2.5 – Online Single Submission (“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 2.2.5 – Online Single Submission (“OSS”) System* for further discussion of the OSS system.

2.3.7 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;[48] and
c) Power infrastructure developments that utilise water, heat and wind, including transmission lines, are permitted in nature reserve areas and nature conservation areas.

2.4 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 Power Purchase Agreements. 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; and
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 new 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.

48 A holding zone is an area for which a change in use has not yet been approved - Kawasan yang Belum Ditetapkan Perubahan Peruntukan Ruangnya

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 (say) 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 COD the PPA may also be extended by the length of time lost to the disaster and repairs.

- **A New 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 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; and
  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.

- **Applying the BOOT Business Scheme**

  The new regulation mandates that the concession period shall be a maximum of 30 years and that all projects must apply the BOOT business scheme. That is, at the end of the contract period, the IPP's facilities shall be transferred to PLN. This implies that contract renewal will no longer be possible for IPPs. This is typically not material for a discounted cash flow analysis longer than 30 years and, in any case, most projects already effectively constitute BOOT arrangements (with the exception of some geothermal and hydro projects that follow the BOO scheme instead). The BOOT scheme could create issues for some projects, such as biomass power plants, where the power assets are sometimes inseparable from the plantation assets including land. Developers are also not clear about the treatment of pre-existing assets under such BOOT arrangements.

In the context of renewable energy resources, MoEMR Regulation No. 50/2017 on the Utilization of Renewable-Energy Resources for the Production of Electricity as amended by MoEMR Regulation No. 4 of 2020, it is stipulated that BOOT arrangements for PPA as regulated under MoEMR Regulation No. 10/2017 do not apply to power plants which utilize renewable energy sources.

- **Other Matters**

  MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation Nos. 49/2017 and 10/2018) provides that:

  a) The PPA has to be in Indonesian Rupiah ("IDR")

  The payment for power must be in Indonesian Rupiah ("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 Jakarta Interbank Spot Dollar Rate ("JISDOR"). This provision reflects BI Regulation 17/3/PBI/2015, which has already been implemented in practice on numerous power projects.

  b) There are Restrictions on the Transfer of the Ownership Rights

  The regulation prohibits the transfer of the ownership rights of the project before reaching COD. Transfers are permitted before COD, if the transfer is to an affiliate where more than 90% of the shares are owned by the Sponsor. Based on MoEMR Regulation No. 48/2017, an affiliate must be a Business Entity one level below the transferor (see also *Section 2.6 - Restrictions on Changes in Shareholders in Business Enterprises in the Energy and Mineral Resources Sector*), and the transfer must be approved by PLN. In the case of post-COD ownership a shareholding transfer is also subject to PLN's approval and it must also be reported to the Minister of Energy and Mineral Resources via the DGE.

2.5 Other Relevant Laws and Regulations

2.5.1 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; and
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 Omnibus Law). A PT PMA can be licensed for both the geothermal (i.e. generation of steam) and power sectors.

Please refer to *Section 2.2.4 – IUPTLU/IUPTLS* and *Section 2.2.5 – Online Single Submission ("OSS") System* for further discussion regarding the OSS system.

2.5.2 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 prescribes a set of 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; and
c) Examination and testing of installations of low-or medium-voltage electrical power utility installations are closed for foreign investment.

2.5.3 The 2009 Environment Law

Pursuant to Law No. 32/2009 (as partially amended by Omnibus Law) and 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 Environmental Impact Analysis (*Analisis Mengenai Dampak Lingkungan Hidup*) before they begin the following operations:
a) Construction of transmission networks > 230 kV;
b) Construction of distribution networks; and
c) Construction of 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*) 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 Environmental Impact Analysis (*Analisis Mengenai Dampak Lingkungan Hidup* or "AMDAL");
b) Environmental Management Efforts and Environmental Monitoring Efforts (*Upaya Pengelolaan Lingkungan Hidup dan Upaya Pemantauan Lingkungan Hidup* or "UKL-

UPL"); or

c) a Statement of Capability in Environmental Management and Monitoring (*Surat Pernyataan Kesanggupan Pengelolaan dan Pemantauan Lingkungan Hidup* or "SPPL").

MoEF Regulation No. 4/2021 stipulates further, in its attachment, the list of business activities that requires AMDAL, UKL-UPL or SPPL. The attachment stipulates the requirement of the environmental license 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; and/or
j) Application of technology that is estimated to have great potential influence to the environment.

2.5.4 Land Acquisition Law

The 2012 Land Acquisition Law (as partially amended by Omnibus Law) and GR No. 19/2021 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, set out a maximum timeframe for the four stages of land acquisition. These stages are planning, preparation, implementation and delivery of result.

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. Furthermore, GR No. 19/2021 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 IDR 16 trillion in order to buy land to support National Strategic Projects. 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.

2.5.5 Bank Indonesia (“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 US Dollar-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 2.4 – Regulation on PPAs* for further details).

2.5.6 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, and their Foreign Loan plan 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 IDR 10 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 amended by Circular Letter No. 17/18/DKEM/2015, 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 USD 100,000 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; and
c) A minimum credit rating of "BB-" or equivalent from a credit ratings agency recognised by BI.

2.6 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 Minister of Energy and Mineral Resources. 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 Minister of Energy and Mineral Resources, via the Director General of Electricity, 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 a Geothermal Licence (i.e. IPB) holder or a geothermal contractor under a Joint Operation Contract ("JOC") through the Indonesian Stock Exchange ("IDX") – presumably meaning via an Initial Public Offering – upon the completion of the exploration must be approved by the Minister of Energy and Mineral Resources. Meanwhile, any transfers of shares not listed on the IDX must only be reported to the Minister of Energy and Mineral Resources.

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 Minister of Energy and Mineral Resources, via the Director General of Electricity or the Director General of New and Renewable Energy, 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: PT UPC Sidrap Bayu Energi

3 IPP Investment in Indonesia

3.1 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 2022, IPPs account for approximately 37% of Indonesia's total installed capacity of 83.8 GW.[49] 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, which contains general guidelines for PPP implementation, and LKPP Regulation Nos. 19/2015 and 29/2018 (as detailed in *Section 2.2.2.1 - Generation*), which contain detailed procurement procedures for PPP projects.

3.2 IPP generations

3.2.1 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 returns (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.

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 3.4 – 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.
For detailed discussions, please see *Section 3.7.2 - The 35 GW Power Development Programme*.

49 HEESI 2022, p. 92

3.2.2 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 support. 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).

3.2.3 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; and
    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; and

    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; and
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. 19/2015 concerning Procedures for the Implementation of Business Entity Procurement in Public Private Partnerships for the Provision of Infrastructure. However, the recently issued LKPP Regulation No. 29/2018 regulates solicited Public Private Partnerships, while LKPP Regulation No. 19/2015 remains in effect for unsolicited PPPs.[50]

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 USD 4.2 billion. The CJPP will operate under a build, own, and transfer ("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. The construction of the power plant is ongoing, and initially it has an expected COD of 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 which approve the plant to be operated for electricity generation.

In the 2019 PPP Book issued by Bappenas, there are no power plant projects in the "ready to offer" or "under preparation" categories, but there are hydro projects in the "prospective prospects" 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 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 have been rolled into the 35 GW programme.

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.

50 LKPP website, http://www.lkpp.go.id/v3/#/read/5487, accessed 30 September 2020

Photo source: PT Jawa Power

The 35 GW Programme

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 was also planned. These projects were awarded through open tender, direct appointment, or direct selection (see *Section 3.4 – 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.
For detailed discussions, please see *Section 3.7.2 - The 35 GW Power Development Programme*.

3.2.4 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 Regulation No. 19/2015; This regulation has been amended with LKPP Regulation No. 29/2018): Guidelines on the Procurement of Infrastructure Delivery Implementing Business Entities Through PPP upon the Initiative of Ministers/Institutional Heads/Regional Heads.	• 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. 1/2006 as amended by MoEMR Regulation No. 4/2007; • GR No. 14/2012 as amended by GR No. 23/2014 on Electricity Business Provision; and • 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 Geothermal power plant, West Sumatra; • Rantau Dadap 2 x 110 MW Geothermal power plant, South Sumatra; • Rajabasa 2 x 110 MW Geothermal power plant, Lampung; and • Wampu 1 x 45 MW hydro power 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. 1/2006 and its revisions under MoEMR Regulations No. 4/2007; • 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 Organization 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. 10/2017 (as amended by MoEMR Regulation No. 49/2017 and MoEMR Regulation No. 10/2018), main Provisions for Power-Purchase Agreements; • 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; and • 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 coal-fired power plant (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)

3.3 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.

3.3.1 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.

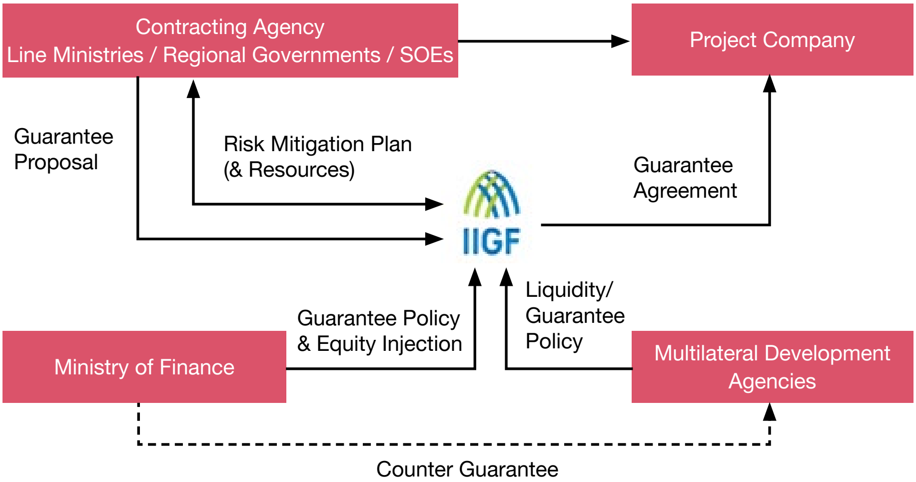
As mentioned above, in October 2011 the USD 4.2 billion CJPP was the first PPP to receive an IIGF guarantee. This took the form of a joint guarantee facility from the IIGF and the MoF. The IIGF will function as a "single window" for all requests for Government guarantees on PPP projects, with the following 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; and
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 Multilateral Development 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 Multilateral Development Agency Guarantee Facility exists only if there is a Co-Guarantee Agreement.

3.3.2 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.

3.3.3 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. Please refer to *Section 2.3.1 – Government Guarantees* for further discussion.

3.3.4 The Infrastructure Financing Fund

The Infrastructure Financing Fund operates through two agencies, PT SMI and PT IIF, and it was established to help investors to 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*.

3.3.5 Energy Transition Mechanism Country Platform

The ETM Country Platform is a transformative regional blended-finance programme that seeks to accelerate the scheduled retirement of existing coal-fired power plants 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 back in the G20 forum in Bali that PLTU Cirebon-1 with a capacity of 660 MW is going to be a part of the Early Retirement program, the first of many to come.

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

3.4 Procurement Process

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

The procurement procedures for the power sale and purchase previously can refer to the MoEMR Regulation No. 1/2006 on Power Sale and Purchase Procedures and/or Lease of Network in Electricity Suppy 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 of power sale and purchase for PLTU. If PLN and/or IPP intend to develop new PLTUs, provided that such PLTUs have complied with the requirement under the PR 112/2022, the procurement process of PLTUs can refer to 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; or
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.

As for the procurement procedures for new and renewable energy power plants can refer to the provisions under PR 112/2022. (*Section 2.3.2 – New and Renewable Energy*).

3.5 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 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;
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; and
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); and
c) Governmental agencies for investment promotion such as JBIC, China Exim Bank, Korean Exim Bank and the Nederlandse Financierings-Maatschappij voor Ontwikkelingslanden NV.

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

3.6 Key Project Contracts

Key project contracts for a power plant development in addition to the PPA typically include:
a) Various shareholders' agreements;
b) EPC contracts;
c) Insurance arrangements;
d) A long-term fuel supply contract;
e) Operations and Maintenance ("O&M") agreements; and
f) Financing documents.

These contracts are further discussed in Table 3.1 below.

Table 3.1 - 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; and • Sponsor Agreements.
Developers'/Sponsors' Agreement	Sponsor and IPP	To provide a developer's fee paid by the IPP entity to the original sponsors

Photo source: PT Pembangkitan Jawa Bali

3.6.1 Power Purchase Agreement ("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);
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; and
r) Purchase options, if any (i.e. for PLN).

3.7 IPP Opportunities and Challenges

3.7.1 IPP Opportunities and Challenges

As discussed in Chapter 1, Indonesia's IPPs will play a greater role in the Indonesian power sector. In addition, PLN will make additional investments of around IDR 87.8 trillion (around USD 6 billion) on average annually until 2030, consistent with additional investment in 2019, in order to cover the construction of substations and transmission and distribution networks, as well as operational costs.[51]

Based on the RUPTL 2021-2030, IPPs may have access to power generation projects, as follows:

Table 3.2 – Accessible IPPs for power generation for 2021–2030 (MW)

	PLN	IPPs	Others	Total
Coal	1,347	8,872	300	10,519
Coal Mine-Mouth	-	3,300	-	3,300
Geothermal	515	2,840	-	3,355
Gas/Combined-Cycle	3,773	2,055	-	5,828
Hydro (including small hydro and pumped storage)	5,286	5,105	-	10,391
Others (including diesel, solar PV, biomass, etc.)	3,348	3,834	-	7,182
Total	**14,269**	**26,006**	**300**	**40,575**

Source: RUPTL 2021-2030, p. V-53

RUPTL 2021-2030 is also focused on achieving the 23% in both scenarios of energy mix from renewables, as dictated by the 2014 NEP. Despite the current low levels of power generation from renewables, renewable power generation in the RUPTL 2021-2030 should be at least around 23% of the fuel mix by 2025. As projected in the RUPTL 2021-2030 (see Table 3.3), renewable power generation in 2025 will only be 23%. According to RUKN 2019-2038, it is targetted that by the year 2038, 28% of primary energy mix would come from renewable energy sources, 25% from gas, 47% from coal and 0.1% from diesel fuel. This indicates that there is a shift towards green energy in the upcoming years.

Table 3.3 – Electricity fuel shares in the RUPTL 2021-2030

Optimum Scenario											
No.	Fuel Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Hydropower	6.5%	6.1%	6.4%	6.7%	8.0%	8.6%	8.7%	9.2%	9.8%	9.9%
2	Geothermal	5.5%	5.4%	5.6%	5.6%	7.6%	8.2%	8.1%	8.5%	8.5%	9.7%
3	Other renewables	0.7%	1.2%	1.9%	2.7%	7.5%	6.1%	5.8%	4.7%	3.9%	2.2%
4	Gas	15.7%	16.7%	16.0%	15.6%	14.5%	14.0%	13.7%	13.2%	13.0%	12.6%
5	Fossil fuels	3.2%	1.9%	1.3%	0.6%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
6	Coal	68.2%	68.7%	68.8%	68.9%	62.1%	62.7%	62.9%	63.4%	63.7%	64.0%
7	Renewables Potential	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.5%	0.6%	0.8%	1.2%
8	Import	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total		**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

51 RUPTL 2021-2030, p. VI-1

Low Carbon Scenario											
No.	Fuel Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Hydropower	5.8%	5.6%	5.5%	5.9%	8.0%	8.6%	8.6%	9.0%	9.5%	9.6%
2	Geothermal	5.8%	5.8%	5.9%	5.9%	7.4%	7.4%	7.7%	7.8%	8.0%	8.2%
3	Other renewables	1.0%	1.5%	2.0%	2.7%	7.7%	7.0%	6.4%	6.0%	6.0%	6.2%
4	Gas	16.6%	18.0%	18.1%	17.4%	15.6%	14.9%	14.9%	15.7%	15.5%	15.4%
5	Fossil fuels	3.5%	3.0%	1.5%	0.5%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
6	Coal	67.0%	66.1%	67.0%	67.7%	61.0%	61.7%	61.6%	60.3%	59.8%	59.4%
7	Renewables Potential	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.5%	0.7%	0.8%	0.9%
8	Import	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total		**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Source: RUPTL 2021-2030

The RUPTL 2021-2030 plans for the installation of additional power capacity of 40.9 GW, as compared to the 56.4 GW in the 2019 RUPTL. The renewable energy capacity installed from 2021 up to 2030 is expected to be at around 51.6% of the total 40.9 GW of capacity to be installed, which accumulates to 20.9 GW. It is proposed that the Government will install 4GW of additional capacity annually, reaching the 40.6 GW mark by 2030.[52] The DGE also notes that 235 MW of new diesel power plant capacity had been installed as per April 2021, from December 2019, which was slightly higher than the 10 MW planned in the 2019 RUPTL,[53] which may indicate a dependency upon diesel in remote areas.

Table 3.4 – Comparison of power generation between 2019 RUPTL and RUPTL 2021-2030 (MW)

Power Source	Allocated to PLN		Allocated to IPPs		Others	
	2019 RUPTL	RUPTL 2021-2030	2019 RUPTL	RUPTL 2021-2030	2019 RUPTL (Unallocated)	RUPTL 2021-2030 (Cooperation between business areas)
Coal	4,704	1,347	20,619	8,872	1,740	300
Coal Mine-Mouth	617	-	3,060	3,300	930	-
Geothermal	7,863	515	4,240	2,840	313	-
Gas - Combined Cycle	2,809	3,773	4,561	2,055	2,173	-
Hydro (including small hydro and pumped storage)	201	5,286	-	5,105	-	-
Others (including solar PV, biomass, etc.)	49	3,348	1,186	3,834	1,330	-
Total	**16,243**	**14,269**	**33,666**	**26,006**	**6,486**	**300**

Source: 2019 RUPTL and RUPTL 2021-2030

52 RUPTL 2021-2030, p. V-54
53 DJK Presentation, "KONFERENSI PERS PERKEMBANGAN DAN ARAH KEBIJAKAN SUBSEKTOR KETENAGALISTRIKAN 2021", p. 4

In the RUPTL 2021-2030, PLN will apply two projected scenarios: optimum and low carbon. These scenarios differentiate the final gas and coal shares in the 2030 energy mix, in which the gas share in 2030 will be slightly higher and the coal share will be around 5% lower in the low carbon scenario compared to the optimum one. Additionally, the RUPTL 2021-2030 projected that a reduction in domestic electricity business including electricity growth, power plant, transmission, and substation development is likely to be occur in the medium term due to the impact of the COVID-19 pandemic.

Coal will continue to play a significant part in the development of power generation in Indonesia over the next ten years, due to its relatively low costs of construction and operation coal mine-mouth ("CMM") power plants remain integral, given that Indonesia's large low-rank coal deposits are often located in remote areas, with minimal infrastructure making transportation of the coal uneconomical. The use of environmentally friendly technology, such as supercritical and ultra-supercritical boilers, is a key priority for both PLN and the Government in the development of large-scale coal-fired power plants, particularly on the highly populated Java Island. PLN Batubara, a subsidiary of PLN, plans to acquire three coal mines in 2019, as PLN Batubara is projected to fulfil 40% of PLN's coal supply by 2022. In 2020, PLN Batubara has acquired several coal mine; in Jambi for PLTU Jambi-1 which is already in production stage, for PLTU Kalselteng which is in the land acquisition stage, a coal mine in South Sumatra which has produced 700,000 million tonnes ("MT") of coal, and for PLTU Meulaboh 2-4, which is in the feasibility study stage. The use of other technology, such as integrated gasification combined cycles or carbon capture and storage, has currently not been planned in the RUPTL 2021-2030 (despite being mentioned), as these forms of technology are not yet commercially viable.

PLN also plans to make extensive use of LNG for gas-fired power plants. However, because of the relatively high cost of LNG (as compared to pipeline gas), as well as the need for regasification, PLN plans to use LNG as a peak-load backup, rather than for base-load power plants. This is particularly the case for the Java-Bali and Sumatra networks, where the power grid has already been established and more affordable power plants cover the base-load generation.

3.7.2 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 MoEMR the progress of the 35 GW power development programme as of December 2022 is as follows:

a) 30% (10.5 GW) of capacity has reached COD;
b) 50% (17.7 GW) of capacity was at the construction stage;
c) 17% (6.1 GW) of capacity had signed PPAs, but not yet commenced construction;
d) 2% (0.8 GW) was at the procurement stage; and
e) 2% (0.7 GW) of capacity was at the planning stage.

Progress of 35 GW Power Plant as of December 2022

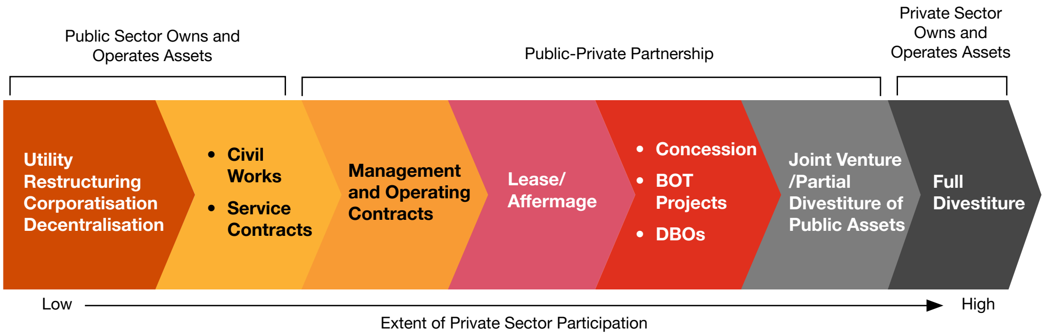
As such, the 35 GW programme has not progressed as planned with only around 10 GW of power plants having commenced operation. The lower than expected demand growth is cited as the main reason for this slow progress. This is reflected even more in the RUPTL 2021-2030 which forecasts around 4.4 to 4.7% annual electricity demand growth instead of 6.4% as in the 2019 RUPTL.

The operating capacity is dominated by IPP or private power plants of 11,897 MW from 189 generating units, the remaining 4,698 MW owned by PLN from 226 generating units.[54]

3.7.3 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:[55]

54 Katadata, https://katadata.co.id/happyfajrian/berita/63d8e233bf1bb/proyek-listrik-35-gw-terus-berjalan-ini-progresnya-hingga-akhir-2022, accessed 21 January 2023
55 World Bank, https://ppp.worldbank.org/public-private-partnership/overview/what-are-public-private-partnerships, accessed 22 May 2016



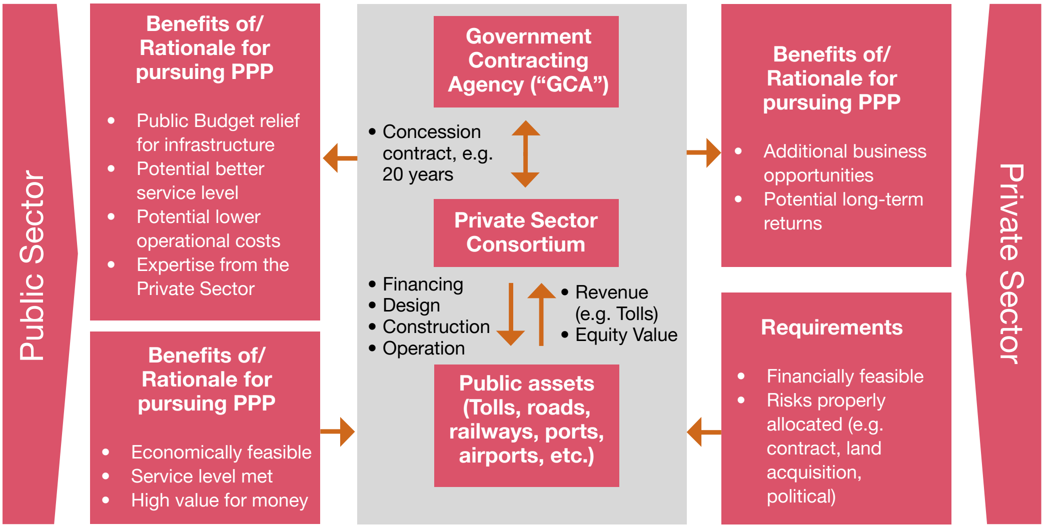
Source: World Bank

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.

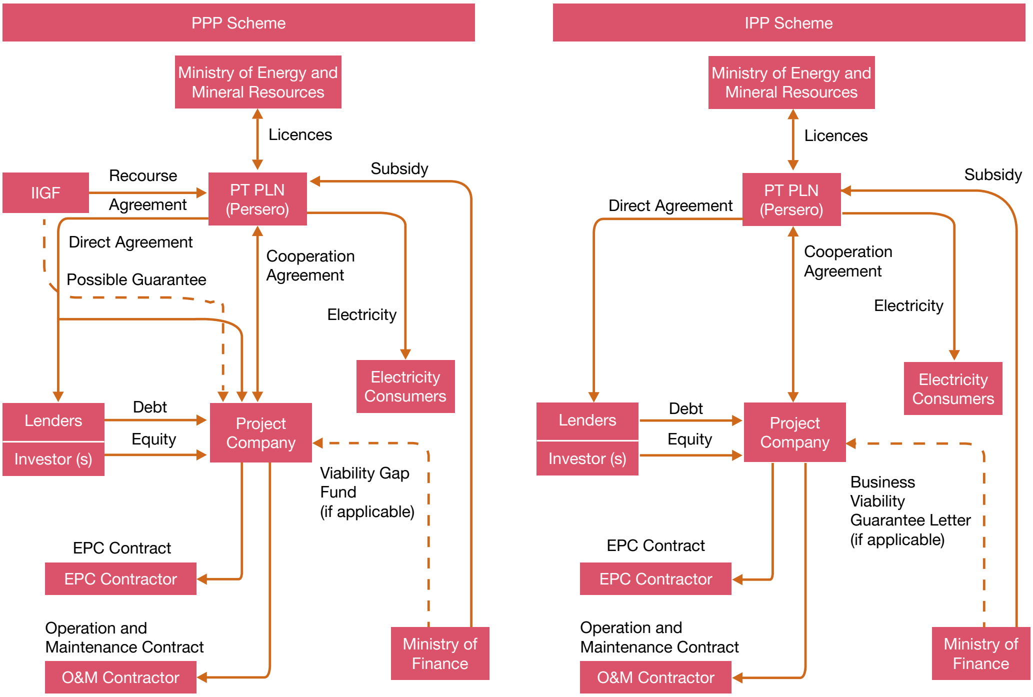
As discussed in Chapter 1 and earlier in this chapter, Indonesia is building a significant amount of infrastructure which requires enormous investments that the Government cannot finance. As such, PPP arrangements represent a possible means of developing Indonesia's infrastructure. However, the meaning 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 2021"), two Waste-to-Energy ("WtE") power projects have been included. The WtE plants, which are located at Banten and West Java, are categorized as "under preparation" projects. While in the "ready to offer" projects there are no power plant projects listed.

LKPP Regulations Nos. 19/2015 and 29/2018 regulate 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.

3.7.4 The Role of the Private Sector in Rural Electrification

In late November 2016, 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 *Wilayah Usaha*.

This regulation is motivated by concern over the 2,510 villages that do not have access to electricity across Indonesia. 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 MoEMR estimated the target probably will be delayed until 2021.[56]

Under MoEMR Regulation No. 38/2016, business entities must optimise the use of new local energy or renewable energy 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 Small-Scale Electricity Supply Businesses (*Usaha Penyediaan Tenaga 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, electricity generation costs, 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 Minister of Energy and Mineral Resources or the Governor, based on their authority, along with the existing laws and regulations.

56 CNN, https://www.cnnindonesia.com/ekonomi/20200730194004-85-530839/esdm-kesulitan-capai-target-rasio-elektrifikasi-karena-corona accessed, 20 September 2020.

4 Conventional Energy

4.1 Introduction

Globally, primary energy demand increased by 1.1% last year, compared to 5.5% in 2021, bringing it to roughly 3% over the 2019 pre-COVID level. In terms of emissions, carbon dioxide emissions from energy use, industrial processes, flaring, and methane reached a new high of 39.3 $GtCO_2e$, an increase of 0.8%, while emissions from energy usage increased by 0.9% to 34.4 $GtCO_2e$. The amount of renewable energy (excluding hydro) rose by 14% to 40.9 Exajoules ("EJ") in 2022. Compared to the prior year, this growth rate was a little lower at 16%. A record 266 GW more wind and solar energy was produced together. Solar contributed 72% (192 GW) of the capacity growth. Hydroelectricity production increased by 1.1%. With an increase of 2.9 million barrels per day to 97.3 million, global oil consumption increased but at a slower rate than between 2020 and 2021. In contrast, the demand for natural gas fell by 3% globally in 2022, falling just short of the 4 Trillion cubic metres ("Tcm") milestone set for the first time in 2021. Its contribution to primary energy dropped slightly to 24% in 2022 (from 25% in 2021). The highest level of coal consumption since 2014 was reached in 2021 with a 0.6% increase to 161 EJ. China (1% increase) and India (4% increase) were the main drivers of the increase in demand. Their combined growth of 1.7 EJ was sufficient to counteract losses of 0.6 EJ in other regions.[57]

Globally, significant price swings in energy commodities, such as coal, gas, and oil, occurred between 2021 and 2022. Due to rising demand from emerging nations, notably those in Asia, and supply interruptions from key producing nations like Australia and China, coal prices increased significantly during this time - reaching a peak of USD 457 per tonne in September 2022. Natural gas prices also had a volatile year, with certain regions seeing prices hit all-time highs also due to supply chain interruptions, severe weather, and growing demand. For oil, the rebound in demand following the pandemic-induced depression and production cutbacks by the Organization of the Petroleum Exporting Countries ("OPEC") also contributed to major shifts in crude oil prices, which reached multi-year highs.

Historically, Indonesia's primary energy supply increased by 37% from 2012 to 2022, from 1,341 million barrels of oil equivalent ("MMBOE") to 1,831 MMBOE. Coal and oil are still the biggest contributors to Indonesia's supply of primary energy, accounting for 41% and 30%, respectively. Natural gas and its derivative products follow with 13%. Biomass accounted for 4% with biofuels and biogas having a similar share of 4%. Hydro accounted for 3%, while geothermal accounted for 2% and the remaining 3% came from other renewable sources including wind and solar PV.[58]

Indonesia's primary energy consumption in 2022 increased by 26%, from 1,268 MMBOE to around 1,596 MMBOE as the country exited the COVID-19 restrictions. Coal, oil and natural gas accounted for 45%, 31% and 14%, respectively. The remaining 11% came from renewable energy.[59] Overall conventional energy (coal, oil and gas) has continued to play a dominant part in Indonesia's energy mix.

57 The Energy Institute, Statistical Review of World Energy 2023
58 HEESI 2022, p.21
59 The Energy Institute, Statistical Review of World Energy 2023, p. 8-9

4.2 Gas

4.2.1 Indonesian Gas Reserves, Consumption and Production

Indonesia has large reserves of natural gas, which stood at approximately 54,830.7 billion standard cubic feet ("BSCF") in Q2 2022 (see Figure 4.1 below for more details).[60] The isles of Maluku, NTT and West Papua have the largest amount of natural gas reserves which accumulate to 27,843 BSCF.[61]

Figure 4.1 – Map of Indonesian gas reserves as of June 2022 (in billion standard cubic feet)

Proven : 36,344.7 BSCF
Potential : 18,485.7 BSCF
Total : 54,830.4 BSCF

Source: MoEMR Oil and Gas Statistics H12022

Despite crude oil traditionally playing a significant part in Indonesia's energy supply and exports, Indonesia has been a net oil importer for several decades. Indonesia's oil and gas production has been dominated by gas over recent years, with the production of natural gas accounting for approximately 65% of total oil and gas production in 2022. This is expected to reach 80% in 2050, should Enhanced Oil Recovery ("EOR") technology not be implemented in any upstream projects. It is expected to be 55% in 2050, even if EOR technology is implemented.[62]

Based on MoEMR data, by the end of 2022 the realisation of Indonesia's oil lifting reached 612 thousand barrels of oil per day ("MBOPD") decreasing from 659 MBOPD in 2021. Then natural gas lifting in 2022 reached 1,148 thousand barrels of oil equivalent per day ("MBOEPD") decreasing from 2021's value of 1,178 MBOEPD.[63]

Upstream oil and gas investment reached USD 12.3 billion, or 93.3% of the 2022 target set by the government. The value of upstream investment is dominated by production (exploitation) activities worth USD 8.1 billion with the largest contributor being Pertamina Hulu Rokan with USD 1.5 billion of the WP&B target of USD 2.3 billion. Major activities such as drilling, seismic surveys and well services have increased after the COVID-19 pandemic.

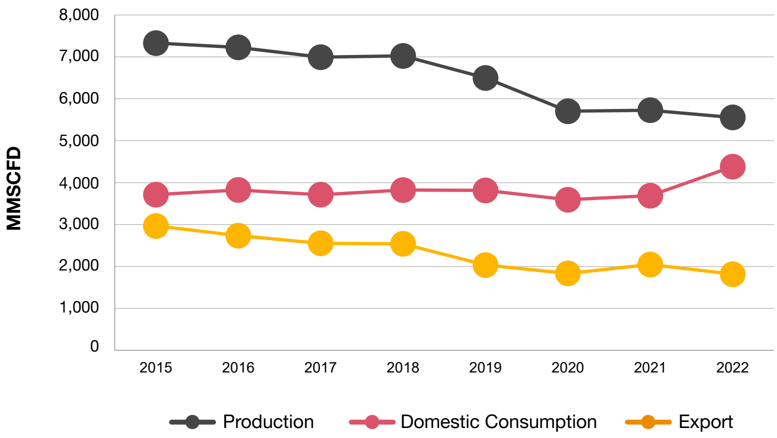
60 ESDM Statistik Migas H12022
61 MoEMR Oil and Gas Statistics H12022
62 Slide of Annual report SKK Migas 2019, p. 8
63 MoEMR Performance Report 2022

Meanwhile, activities on National Strategic Projects after the impact of the Covid-19 pandemic have experienced some delays, such as Tangguh Train-3 which was expected to be onstream in Q1 2023. The achievement of downstream oil and gas investment is still far from the target, only USD 1.6 billion or 41.6% of the government's target.[64]

The low realisation of downstream oil and gas investment in 2022 was due to the cancellation of several projects such as the construction of the East Java LNG Onshore Storage Tank Facility, the construction of the Cilacap LNG Regasification Terminal, the Cilacap LNG Regasification Terminal, and the TPPI LNG Distribution Project. In addition, there was a significant decrease in investment realisation in the RU V Balikpapan RDMP Project due to a change in tax regulations, resulting in unrealised capital investment (realisation of only USD 137 million from the initial target of USD 1.2 billion).

In 2022, domestic gas consumption in Indonesia increased by 18.8% from 3,688 MMSCFD to 4,382 MMSCFD.[65] Indonesia's gas exports in 2022 also saw a decrease of 11.2% from 2,047 MMSCFD to 1,817 MMSCFD. This has resulted in Indonesia becoming the eighth-largest LNG exporter in the world behind Australia, Qatar, the US, Russia, Malaysia, Nigeria and Algeria, despite its pioneering role in LNG decades ago.[66]

Figure 4.2 – Indonesian natural gas used for production, domestic consumption, and exports (in MMSCFD), 2015–2022



**Production obtained from "Net Production"*
Source: HEESI 2021 & 2022

The realisation of gross gas production for 2022 was only 5,554 MMSCFD while the target gas production based on the 2022 State Budget Plan (*Rencana Anggaran dan Belanja Negara* - "RAPBN") was 5,800 MMSCFD.[67] In terms of recent or planned gas project developments, Indonesia has four large-scale strategic projects in the upstream oil and gas sector with a total expected investment of around USD 37.2 billion. These four projects are the Jambaran Tiung Biru project which was completed in September 2022,[68] the Tangguh

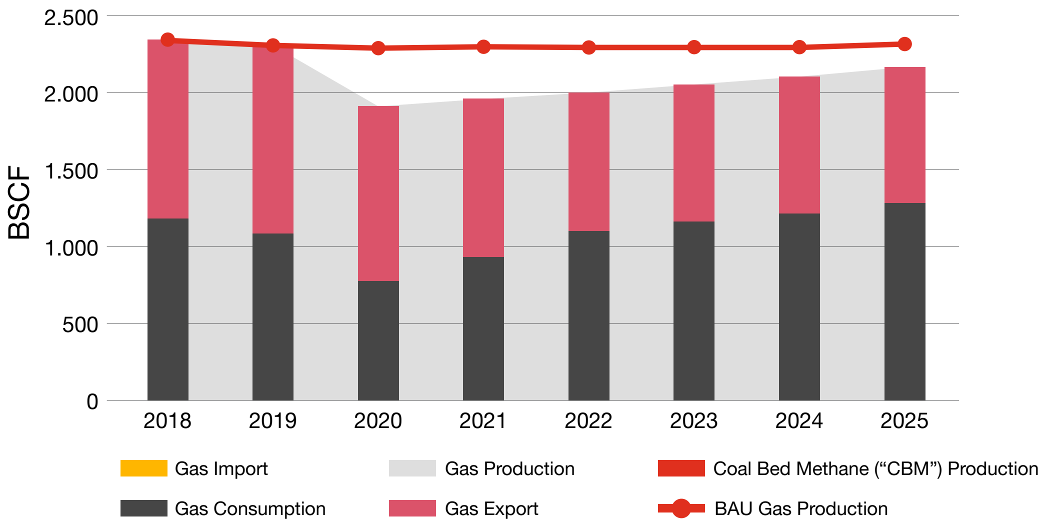
64 MoEMR Performance Report 2022
65 HEESI 2022, p. 85
66 The Energy Institute, Statistical Review of World Energy 2023
67 HEESI 2022, p. 85
68 Dunia-Energi, https://www.dunia-energi.com/pembuktian-jambaran-tiung-biru, accessed 17-Jan-2023

Train 3 Project which is planned to come onstream by the end of 2023,[69] the Indonesian Deepwater Development ("IDD") project previously held by Chevron (and now acquired by ENI) and the Abadi LNG project which is predicted to be completed by 2030.

In December 2022, ENI was officially appointed as the developer of the IDD phase II project located in the Kutai Basin, East Kalimantan.[70] The project is expected to be operational by 2024. According to the RUPTL 2021-2030, the LNG from Tangguh will strengthen the gas supplies for PLN's gas-fired power plants in Sumatra and Java through the Arun LNG terminal, the Nusantara Regas FSRU, and the planned Jawa-1 FSRU.[72]

An increase in domestic gas demand, particularly for power generation, has been projected over the period from 2021 to 2030. This expected increase is similar to the forecast in the RUPTL 2021-2030, since the total gas required (including LNG) is still expected to increase significantly from 364 to 365 Billion British Thermal Units per Day ("BBTUD") in 2021 to 396 to 545 BBTUD in 2030, as a result of the plan for 15.2 GW of additional gas-fired power plants (including combined cycle).[73] This will contribute to the Government's target for domestic gas utilisation (see Figure 4.3 below).

Figure 4.3 - Indonesian natural gas lifting (in MMSCFD) and utilisation targets for 2018 - 2025

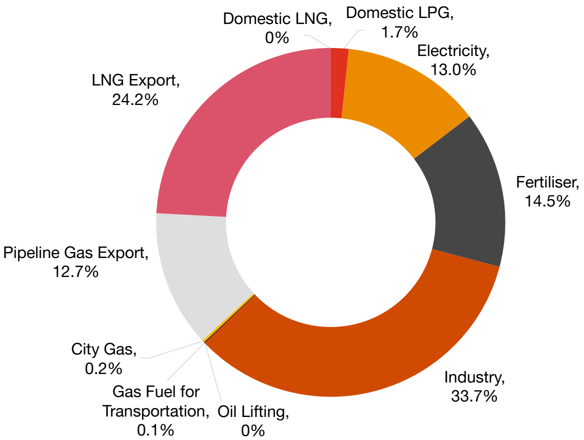


Source: Outlook Energi Indonesia 2020, p. 53, issued by Pusat Pengkajian Industri Proses dan Energi, Badan Pengkajian dan Penerapan Teknologi

69 CNBC, https://www.cnbcindonesia.com/news/20230406110307-4-427828/proyek-kebanggaan-jokowi-di-papua-barat-beroperasi-akhir-2023, accessed 28-Apr-2023
70 Dunia-Energi, https://www.dunia-energi.com/proyek-gas-abadi-masela-molor-hingga-tahun-2030, accessed 17-Jan-2023
71 Katadata, https://katadata.co.id/happyfajrian/berita/639870610f700/esdm-tunjuk-eni-sebagai-pengelola-proyek-migas-idd-jalan-awal-2023, accessed 17-Jan-2023 (sentence deleted)
72 RUPTL 2021-30, p. III-59
73 RUPTL 2021-2030, p. V-54

In 2022, Indonesia's domestic gas consumption was 4,382 MMSCFD. There were five major categories of gas users in 2022 including industrials, LNG export, gas pipeline exports, fertilisers and the power generation sector. The industrial sector accounted for 33.7%, while LNG export, fertilisers, the power sector and gas pipeline exports consumed approximately 24.2%, 14.5%, 13.0% and 12.7%, respectively (see Figure 4.4).

Figure 4.4 - Indonesian natural gas utilisation for 2022

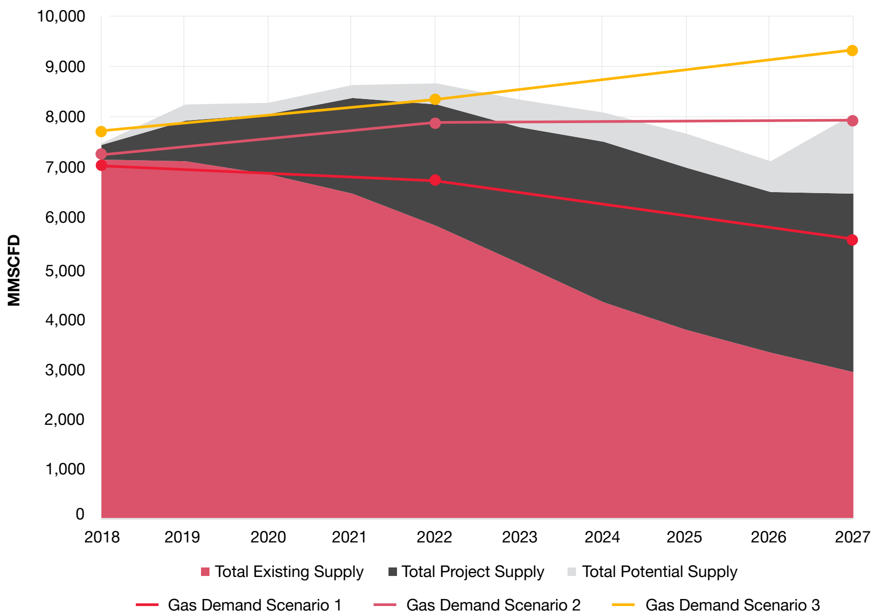


Source: MoEMR Performance Report 2022

Net natural gas production in 2021 decreased by around 3% from 5,726 MMSCFD to 5,554 MMSCFD - 63.1% of this value was used for domestic supply and the remainder was exported.[74] In terms of natural gas infrastructure, Indonesia is building the 260 km Cirebon-Semarang gas pipeline, 360 km Dumai-Sei Mangkei gas pipeline and building mini regasification units and FSRU for Eastern Indonesia.[75] MoEMR Decree No. 1790 K/20/ MEM/2018 also stated that the MoEMR is empowered to allocate some or all of the natural gas previously allocated to the power sector, if it cannot be utilised by PLN or is not followed up with a natural gas purchase agreement within a year. The planned natural gas allocation for the power sector until 2027 is also included in this decree.

74 HEESI 2022, p. 85
75 Kompas.com, https://money.kompas.com/read/2020/09/05/154600126/pandemi-covid-19-tak-hentikan-pgn-tuntaskan-pembangunan-infrastruktur

Figure 4.5 - Natural gas balance for 2018 - 2027 (in MMSCFD)



	2018			2022			2027		
Scenarios	**Scen 1**	**Scen 2**	**Scen 3**	**Scen 1**	**Scen 2**	**Scen 3**	**Scen 1**	**Scen 2**	**Scen 3**
Region 1	198.32	238.20	253.60	205.05	259.42	32.80	14.16	21.70	37.40
Region 2	2,896.47	3,076.74	3,295.53	2,880.86	3,336.2	3,602.14	2,233.91	3,094.15	3,553.56
Region 3	119.45	97.53	100.20	124.92	138.09	141.34	132.28	138.66	348.81
Region 4	635.14	628.65	752.29	659.11	630.60	808.13	691.29	703.91	1,092.16
Region 5	1,662.21	1,682.99	1,682.99	1,229.57	1,270.68	1,359.93	721.49	787.17	984.31
Region 6	1,503.74	1,593.72	1,593.72	1,752.09	2,261.22	2,261.22	1,962.02	3185.32	3,185.32
Total (MMSCF)	**7,015.33**	**7,317.83**	**7,678.33**	**6,851.6**	**7,896.21**	**8,205.56**	**5,755.15**	**7930.91**	**9,201.56**

Source: Indonesia Gas Balance 2018 - 2027, p.114

Table 4.1 Scenarios of natural gas balance for 2018 - 2027

Sector	Scenario 1	Scenario 2	Scenario 3
Oil Lifting	According to Contract	According to Contract	According to Contract
Government Programmes (Gas Network + Gas Station)	5%	5%	5%
Fertiliser + Petrochemical	According to Plan	According to Plan	According to Plan
Electricity	Realisation (n-1) + 1.1%	RUPTL Projection	RUPTL Projection
Retail Industry	Realisation (n-1) + 1.1%	Realisation (n-1) + 5.5%	Contract + 5.5%
Non-Retail Industry	Realisation (n-1) + 1.1%	Contract	Contract + Potential Demand
n = current walking year, baseline year: 2017			

Source: Indonesia Gas Balance 2018 - 2027, p17

After the MoEMR released two different Indonesia Natural Gas Balance reports (2014 – 2030 and 2016 – 2035), in October 2018 the MoEMR published a shorter projection scheme of the nation's natural gas balance for 2018 – 2027 with a different approach. In this projection scheme, the MoEMR through the Directorate General of Oil and Gas ("DGoOC") prepared three different schemes for Indonesia's gas supply and demand and divided the national gas balance areas into six separate regions.

Scenario 1 was drawn up with the following assumptions: if the gas demand for oil lifting is precisely equal to the existing contract; growth of gas demand for Government programmes such as the household gas network and gas stations is constantly growing 5% per year; gas needs for fertiliser and petrochemicals factories are constantly stable according to the plan; and, lastly, the MoEMR assumed the gas needs from electricity, retail, and non-retail industrial sectors are constantly growing at 1.1%. With this optimistic scenario, Indonesia will still have excess gas supply until 2027, since the projection of gas demand refers to 2018 gas utilisation and considering the expired contracts of pipe gas and LNG exports.

In contrast with Scenario 1, the second scenario forecasts whether the national gas stock would still exceed the domestic demand until 2024 and whether it would surpass demand in the period from 2025 to 2027 (without considering supply from new gas fields such as Masela and East Natuna Block). This scheme projects the gas utilisation from existing contracts as 100% realised, gas usage for electricity to match the 2018 – 2027 RUPTL, retail industry demand to grow 5.5%, and the Refinery Development Master Plan ("RDMP") and petrochemicals development to be on schedule.

The last scenario projects that gas production will still surpass the national needs until 2024, while in 2025 – 2027 the MoEMR considers whether there is a possibility domestic supply will not be able to fulfil domestic need (also without considering the possible gas supply from new fields such as in scenario 2). This third scenario assumes retail industries utilise gas at the maximum capacity with rising demand due to the 5.5% economic growth assumption, thus the case of RDMP and factory development is also the same as in scenario 2 (see Table 4.1).

4.2.2 Prices and Regulation

Domestic pipeline gas prices in Indonesia (but not Compressed Natural Gas - "CNG") are negotiated and set out under specific Gas Sales Agreements between the seller and the buyer/end-user. The prices follow a fixed price regime, which is formulated as cost plus an annual escalation (depending on the agreement). This means that the Indonesian gas pricing regime is not directly connected to oil price fluctuations (see Table 4.2). MoEMR Regulation No. 58/2017 with the most recent change to MoEMR Regulation No. 14/2019 stipulates a maximum gas price based on the gas cost, the IRRs for gas infrastructure, and the profit margin for the gas trader. The IRRs for gas infrastructure is limited to 11% (or 12% for a company that develops gas infrastructure in an underdeveloped region), while the profit for gas trading is limited to 7%. It is nevertheless expected that negotiations will still play a major role in determining the gas prices.

The pipeline gas price comprises several components, including the upstream investment and operational costs, the contractor shares, and the transportation costs (i.e. for transmission and distribution, including VAT). Starting from 1 April 2020, industrial natural gas price decreased to USD 6 per MMBtu, in accordance with Presidential Regulation (*Peraturan Presiden* - "Perpres") No. 4/2016, which contains of transmission and distribution costs between USD 1 - 1.5 per MMBtu.[76]

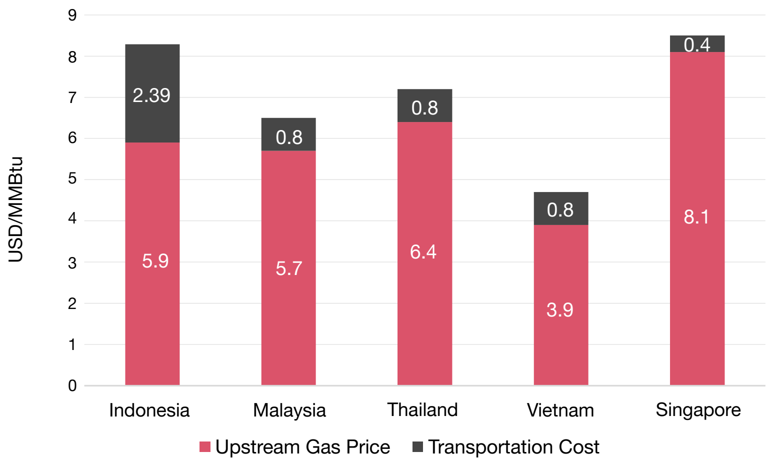
Table 4.2 – Gas price regimes in Asean the region

	Indonesia	Singapore	Malaysia	Thailand	Vietnam
Pricing Regime	Negotiated (fixed price)	Negotiated (oil-linked)	Negotiated (oil-linked)	Pool price	Negotiated (oil-linked)
Formula	Cost-plus annual escalation (depends on agreement and negotiation)	100%-110% of High Speed Fuel Oil (HSFO) price	45%-60% HSFO price	Blended purchase price	45% HSFO price
Gas Sellers	Multiple companies, e.g. Pertamina, PGN, Regional-owned enterprises	Multiple companies, e.g. Pavilion Gas, SembGas, City Gas	Single company i.e. PETRONAS	Single Company	Single company, i.e. PetroVietnam

Source: Arividya Noviyanto (President and General Manager of Total E&P Indonesie), "Upstream Perspective on Managing Indonesia Gas Supply and Demand", 8 February 2017, p. 5; https://www.liputan6.com/bisnis/read/2623349/pemerintah-ingin-ubah-formula-harga-gas-ini-kata-petronas, accessed 6 December 2017

The Indonesian non-LNG upstream gas price is considered to be competitive as compared to neighbouring countries. However, the Indonesian gas market experiences relatively expensive gas transportation (transmission and distribution) costs which have an impact on affordability for the buyer/end-user. Figure 4.6 shows a comparison of domestic pipeline gas prices in Southeast Asia before MoEMR Regulation No. 58/2017 amended by MoEMR Regulation No. 14/2019 was issued.

Figure 4.6 – Comparison of domestic pipeline gas prices in Southeast Asia

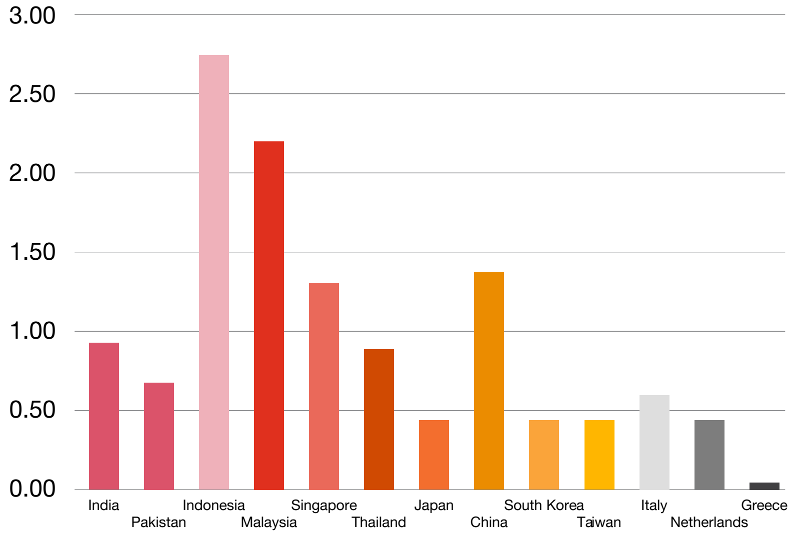


Source: Arividya Noviyanto (President and General Manager of Total E&P Indonesie), "Upstream Perspective on Managing Indonesia Gas Supply and Demand", 8 February 2017, p. 5; PwC Analysis

76 ESDM, https://migas.esdm.go.id/post/read/menteri-arifin-1-april-2020-harga-gas-industri-turun-jadi-us-6-per-mmbtu

With regard to LNG the on-board LNG price is on average USD 6.0 per MMBtu. Shipping and regasification costs are then added - typically around USD 0.6 to USD 2.8 per MMBtu - and then transportation (transmission and distribution) costs. However, although Indonesia is an LNG exporter, it has the highest regasification costs in the world (Figure 4.7). Thus, despite large domestic gas reserves and competitive extraction costs Indonesia faces challenges regarding its end-user gas prices.

Figure 4.7 – Comparison of regasification costs in selected countries as of 2016



Source: SKK Migas, "Policies on Natural Gas Pricing in Indonesia", 3 May 2017, p. 22

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 fertiliser;
d) To support industries that utilise natural gas as a raw material;
e) To provide fuel to be used for electricity production; and
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 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's 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; and
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 providing 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; and
c) They sell at a reasonable price.

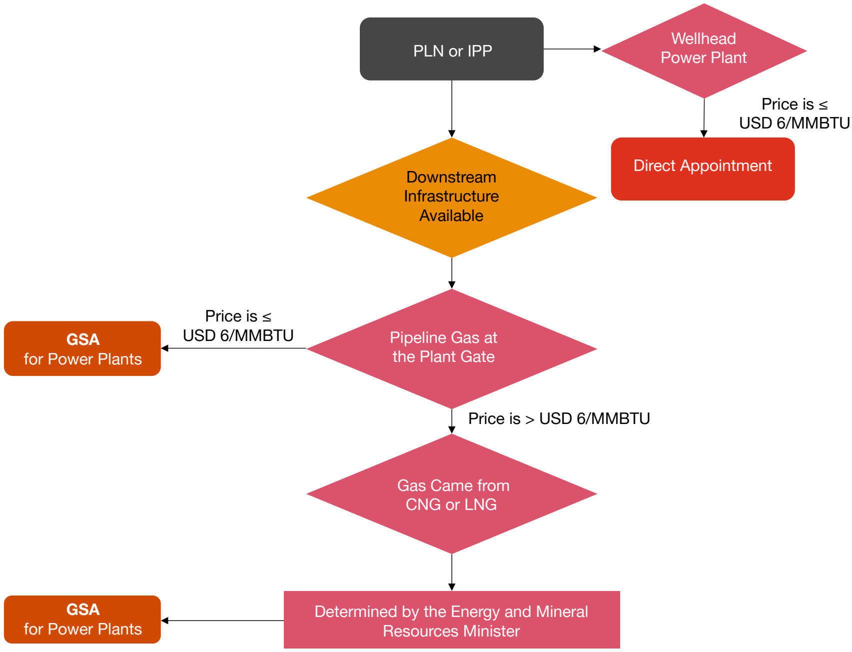
Procedures and regulations for gas allocation and pricing are designed to ensure the efficiency and effectiveness of the availability of natural gas as a fuel, as a raw material, or for other purposes, in order to meet domestic demand optimally. The revision of the decree was due to the Government initiatives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

In May 2016, President Joko Widodo issued PR No. 40/2016 on the Provisions for Natural Gas Prices, which was intended to reduce gas prices to a maximum of USD 6 per MMBtu for certain industries, such as those involving fertilisers, petrochemicals, oleochemicals, steel, ceramics, glass, and rubber gloves. PR No. 40/2016 was implemented by MoEMR Regulation No. 40/2016 on the Prices of Natural Gas for Certain Industries, in November 2016. Under this regulation, the MoEMR established the pipeline gas price at the buyer's plant gates, as well as the gas distribution costs of certain industries, including PT Petrokimia Gresik, PT Krakatau Steel, PT Pupuk Kujang, PT Pupuk Iskandar Muda, and PT Pupuk Kaltim, at USD 6 per MMBtu.[77] Starting from 1 April 2020, industrial natural gas price decreased to USD 6 per MMBtu.[78]

Additionally, and specifically for the power sector, in July 2017 the MoEMR issued MoEMR Regulation No. 45/2017 on the Use of Natural Gas for Power Plants. The key point of MoEMR Regulation No. 45/2017 was 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 to MoEMR Regulation No. 10/2020. The key amendment point is related to changes of the maximum gas price from 14.5% of Indonesia Crude Price ("ICP") to USD 6 per MMBtu effective 7 April 2020. In June 2021 MoEMR released a further decree number 118.K/MG.04/MEM.M/2021 regarding the update of natural gas prices for power plant, which adjusting approximately 56 power plants. Furthermore, the provisions for the importation of LNG are outlined in Figure 4.8, as follows:

77 DGOG, https://migas.esdm.go.id/post/read/pemerintah-putuskan-harga-gas-3-industri-maksimal-us$-6-per-mmbtu, accessed 6 December 2017
78 DGOG, https://migas.esdm.go.id/post/read/pemerintah-putuskan-harga-gas-3-industri-maksimal-us$-6-permmbtu, accessed 6 December 2017

Figure 4.8 – 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 ≤ USD 6 per MMBtu (article 13);
b. If pipeline gas at the buyer's plant gate (power plant) is ≤ USD 6 per MMBtu (article 8), then PLN or an IPP can purchase;
c. If pipeline gas at the buyer's plant gate (power plant) is > USD 6 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.

4.2.3 Current Installed Gas-Fired Power Plant Capacity and Government Plans

Approximately 21 GW of gas-fired power plants (including combined-cycle) have been installed and are currently in operation by PLN, including plants in Belawan, Muara Karang, Priok, Cilegon, Muara Tawar, Tambak Lorok, North Bali, and Gresik. By the end of 2022, power generation from gas-fired power plants accounted for 25% of the total power generation. It is expected, according to the RUPTL 2021-2030, that the share of gas-fired power generation will be approximately 11.5% to 15.8% by 2030. This includes additional gas-fired power plants (including gas only, steam-gas, and diesel-gas power plants) capacity of 7.5 GW, which will increase the gas consumption of power plants by more than 54% over the next ten years.

Generally, PLN prioritises the use of pipeline gas for its gas-fired power plants. This is especially the case for power plants that are "must-run" and 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 looking at the use of CNG.

One of the largest gas-fired power plants to be planned is the Jawa-1 Combined-Cycle (2 x 880 MW). A consortium of Sojitz, Marubeni, and Pertamina was awarded the tender and signed a PPA in January 2017, at a price of USD 5.5 cents/kWh. The Jawa-1 project will be developed in Cilamaya, West Java. Jawa-1 is the first gas-steam combined-cycle power plant in Asia, and it integrates an FSRU with a combined-cycle power plant. With a capacity of 2 x 880 MW, the project will also be the first and the largest gas-steam combined-cycle power plant in Indonesia.[79] The gas for Jawa-1 is to be supplied by LNG Tangguh, as PLN has been reported to have agreed a gas price formula of 11.2% of ICP plus 0.4% for distribution costs.[80] The Jawa-1 Combined-Cycle project reached financial close in December 2018.[81] In February 2022, Pertamina announced that the company has successfully completed the first-fire ignition process of the Jawa-1 combined cycle process. Following the first fire process, the following steps include synchronisation, performance testing, reliability tests, and ultimately COD.[82]

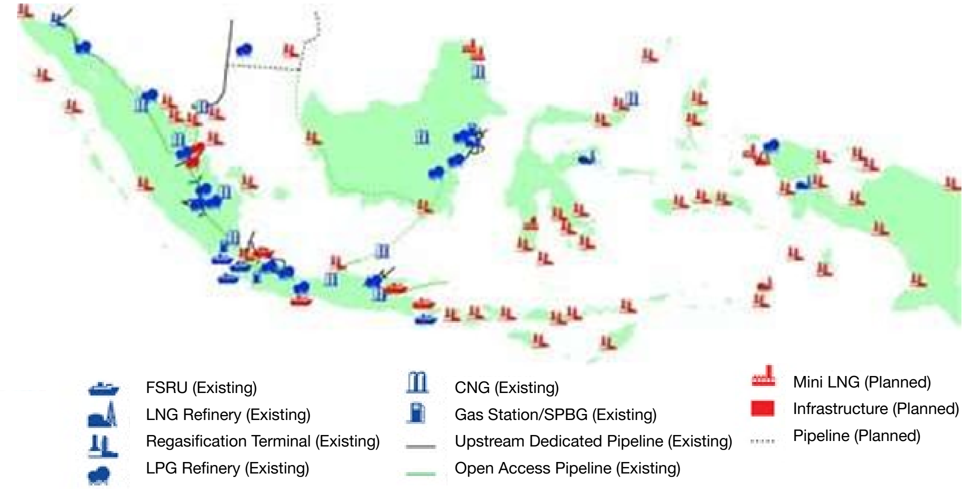
After the issuance of MoEMR Regulation No. 45/2017, PLN plans to build five FSRUs in Indonesia – at Tengah, Bangka Belitung-Pontianak, Krueng Raya-Nias, Maluku-Papua, and Gorontalo[82] – as well as five mini-LNGs, in Ternate, Nabire, Jayapura, Kendari and Flores.[83] This is part of PLN's commitment to secure the gas supply for IPP projects, although the policy remains unclear in terms of smaller gas-fired plant projects (see *Section 4.2.5 - Challenges*).

79 Asian Development Bank, https://www.adb.org/news/adb-finances-largest-combined-cycle-power-plant-indonesia and General Electric, https://www.ge.com/news/reports/7-fakta-menarik-proyek-pltgu-jawa-1
80 Rambu Energy, https://www.rambuenergy.com/2017/05/pln-bp-tangguh-reach-agreement-on-lng-price-for- pltgu-jawa-i-power-plant/, accessed 6 December 2017
81 Pertamina, https://www.pertamina.com/en/news-room/news-release/pertamina-memasuki-tahap-konstruksi-proyek-terintegrasi-fsru-dan-pembangkit-listrik-jawa-1-1760-mw, accessed 9 July 2019
82 Tribunnews, https://www.tribunnews.com/pertamina/2019/05/05/lng-to-power-proyek-ipp-pltgu-jawa-1-1760-mw-fsru-steel-cutting, accessed 9 July 2019
83 Kontan, https://industri.kontan.co.id/news/pln-masih-evaluasi-penawaran-untuk-lima-proyek-fsru, accessed 9 July 2019
84 DGOG, https://migas.esdm.go.id/post/read/negara-kepulauan-indonesia-akan-terus-kembangkan-terminal-mini-lng, accessed 9 July 2019

In terms of project progress, the Senipah Combined-Cycle project reached financial close in October 2017 and after delays the power plant managed to reach COD in 2020.[85] The Jawa-2 Combined-Cycle project reached COD in August 2018.[86] In 2020, there are around seven gas engine power plants that reached COD. These are: Langgur 20 MW, Seram 20 MW, Ambon Peaker 20 MW, Biak 15 MW, Biak-NCB 10 MW, Jayapura Peaker 40 MW and Merauke 20 MW, as well as the Muara Karang 300 MW combined cycle. In 2022, Pertamina announced that it has successfully conducted the first fire operation for *Pembangkit Listrik Tenaga Gas dan Uap* ("PLTGU") Jawa-1. However, by looking at the current progress of the project, it is predicted by the Centre of Energy and Resources Indonesia ("CERI") that the construction of the 1,800 MW power plant would be completed by the end of 2023.[87]

CNG was originally intended to optimise the potential of small-capacity and marginal gas fields, by storing gas in advance for temporary use. Over time, however, PLN has utilised large-scale CNG to supply gas to some power plants, especially those whose status has changed from base-loader to load-follower. CNG has been used for gas-fired power plants in Riau and Southern Sumatra since 2013. Further utilisation of CNG is planned in Sumatra, Central Kalimantan, and Lombok.

Figure 4.9 – Indonesian gas infrastructure – current and concept (2016-2035)



Source: Neraca Gas Bumi Nasional 2016-2035

85 RUPTL 2021-2030, p. V-76
86 Metro TV News, http://ekonomi.metrotvnews.com/energi/yKX93Y6N-pltgu-jawa-2-unit-2-siap-pasok-listrik-asian-games, accessed 8 August 2018
87 Okeline, https://www.okeline.com/berita-13252-proyek-pltgu-jawa1-rp-28-t-molor-beroperasi-ceri-sudah-diperingatkan-ada-penyimpangan-ngeyel, accessed 28-Apr-2023

4.2.4 Opportunities

Based on the RUPTL 2021-2030, the Government aims to maintain the proportion of gas in the power generation mix at approximately 11.5% to 15.8% in 2030, which is slightly higher than the 16.7% of 2022. Several IPPs and captive power plants are located near the supporting infrastructure (natural gas plants, ports, etc.). Of the 5.8 GW of planned gas-fired power capacity, 3.7 GW is to be developed by PLN, 2.0 GW by IPPs.[88] These figures highlight the opportunities for the private sector.

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.[89] 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 to MoEMR Regulation No. 10/2020, the gas supply from wellheads will be benchmarked up to USD 6 per MMBtu (see *Section 4.2.2 – Prices and Regulations*).[90] 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. The gas is burned because it cannot be incorporated 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. 32/2017 concerning Flare Gas Utilisation and Pricing in Oil and Gas Upstream Business Activities, the price of flared gas will be set at a base of USD 3.67/MMBtu (minus correcting factors for H_2S and CO_2 content). The floor price for flared gas is USD 0.35/MMBtu, which should enable very cheap power.

4.2.5 Challenges

In order to strengthen its gas business by providing end-to-end solutions for both the domestic and international markets, Pertamina urged its subsidiary PT PGN to develop LNG infrastructures, such as terminals and bunkers, in the middle of 2019. Although it is

88 RUPTL 2021-2030, p. V-50
89 Philip Weems, "FSRUs: Looking back at the Evolution of the FSRU Market", December 2015. https://www.kslaw.com/blog-posts/fsrus-looking-back-at-the-evolution-of-the-fsru-market, accessed 26 June 2018
90 ESDM, https://migas.esdm.go.id/post/read/menteri-arifin-1-april-2020-harga-gas-industri-turun-jadi-us-6-per- mmbtu

presently the case that PT PGN Mainly provides its services to domestic customers, such as households, industries, and PLN, it is keen to expand its LNG business globally in the near future.[91]

Gas, as component C (fuel) in a power plant PPA, is principally a pass-through cost to the IPP. In 2016, PLN announced that it will supply fuel for the gas-fired power plants of IPPs. However, PLN's policy on gas supply frequently changes. In practice, PLN supplies gas only for large-capacity power plant projects, including Jawa-1. For smaller capacity projects, such as the Scattered Riau Gas Machine (180 MW) and the Pontianak Gas Machine (100 MW) plants, PLN is still relying on the private sector to supply gas.[92]

4.3 Coal

4.3.1 Indonesian Resources, Consumption and Production

Coal has historically been – and still remains – Indonesia's most important source of fuel for electricity, with Indonesia's abundance of coal resources favouring investment in coal-fired power plants. The spot price of thermal coal increased during 2021 after declining in 2020. They increased significantly in the second half of 2021 because supply could not keep up with the sharp increase in demand that occurred in the first half, notably in China.

In the long term, world coal production is expected to remain consistent, at between 9 and 10 billion tonnes p.a. from 2015 to 2040, as reduced consumption in China and the US is offset by the growth from India. China's reduction has been linked to the implementation of policies addressing air pollution and climate change.[93] As a share of the energy mix, coal is likely to fall over the long term, as natural gas and renewables increase their presence.[94]

Coal in Indonesia remains one of the most important sources of fuel for electricity generation. Coal mining also plays an important role in the Indonesian economy, contributing around 6.6% to the GDP in 2022. In 2022, according to the Energy Institute ("EI") Statistical Review of World Energy 2023, Indonesia sits in eighth place in terms of proven coal reserves, with a 3.2% share of global coal reserves. Most of Indonesia's coal reserves (about 60 per cent) are in the medium rank category, less than 6,100 kcal/kg of calorific value. Beyond that, the remaining 30 per cent falls into the low rank category, less than 5,700 kcal/kg of calorific value.[95]

The three largest provinces for Indonesian coal resources are South Sumatra, South Kalimantan, and East Kalimantan. There are also smaller coal resources across the rest 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). In 2022, Indonesia had coal resources of 115.6 billion tonnes, which were mainly located in Kalimantan (74.6 billion tonnes) and Sumatra (40.8 billion tonnes).

91 Kontan, https://industri.kontan.co.id/news/perkuat-infrastruktur-lng-pgas-menjaring-pasar-di-bisnis-gas-alam-cair?page=all, accessed 5 December 2019
92 Kontan, http://industri.kontan.co.id/news/pln-diminta-konsisten-soal-suplai-gas-pembangkit, accessed 9 December 2017
93 U.S. Energy Information Administration, International Energy Outlook 2017 Powerpoint slide, slide 63-64
94 PwC, Mine 2017
95 Indonesia Investments, https://www.indonesia-investments.com/business/commodities/coal/item236, accessed 29 Jul 2023

Table 4.3 – Coal resources and reserves by province - in million tonnes, May 2022

Province	Resources					Reserves
	Hypothetic	Inferred	Indicated	Measured	Total	
Banten	5.47	0.00	0.00	0.00	5.47	0.00
Central Java	1.16	0.00	0.00	0.00	1.16	0.00
East Java	0.00	0.00	0.00	0.00	0.00	0.00
Aceh	1.16	275.46	421.87	325.59	1,024.08	539.34
North Sumatra	0.00	10.24	8.48	7.55	26.27	7.12
Riau	3.86	142.10	53.03	301.23	500.22	395.36
West Sumatra	2.26	79.75	72.55	3.15	157.71	64.03
Jambi	140.31	1,402.50	1,183.88	1,987.82	4,714.51	1,831.60
Bengkulu	36.86	140.27	113.69	174.61	465.43	124.69
South Sumatra	4,885.39	11,827.36	8,830.51	8,079.09	33,622.35	9,432.90
Lampung	0.00	149.60	134.20	29.60	313.40	109.40
West Kalimantan	2.26	11.07	53.03	14.57	80.93	0.43
Central Kalimantan	22.54	4,999.99	3,517.60	3,474.01	12,014.14	3,311.52
South Kalimantan	7.83	3,615.36	3,575.78	6,310.57	13,509.54	4,168.40
East Kalimantan	872.99	10,716.07	14,907.98	19,309.23	45,806.27	14,684.99
North Kalimantan	25.79	971.75	996.25	1,246.44	3,240.23	1,597.89
West Sulawesi	11.46	5.42	5.42	3.15	25.45	8.59
South Sulawesi	13.79	3.02	1.84	0.72	19.37	1.77
Southeast Sulawesi	0.64	0.00	0.00	0.00	0.64	0.00
Central Sulawesi	0.52	0.00	0.00	0.00	0.52	0.00
North Maluku	8.22	0.00	0.00	0.00	8.22	0.00
West Papua	93.66	0.00	0.00	0.00	93.66	0.00
Papua	7.20	0.00	0.00	0.00	7.20	0.00
TOTAL	**6,143.37**	**34,349.96**	**33,876.11**	**41,267.33**	**115,636.77**	**36,278.03**

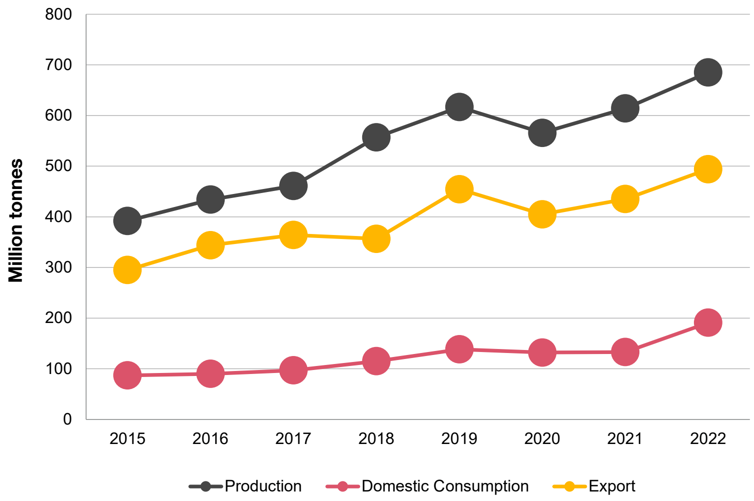
Source: MoEMR "Buku Neraca" May 2022

In addition to being the world's third-largest coal producer, Indonesia is also the world's second largest coal exporter as of 2022.[96]

In 2022, Indonesia was estimated to have exported 494 million tonnes of coal (see Figure 4.10), generating USD 47 billion in export earnings.[97] The main export destinations have historically been China, India, South Korea, Japan and Taiwan.[98] The MoEMR annouced that due to the ongoing Russo-Ukranian war, Indonesia's coal exports to Europe until the end of 2022 set a new record, the largest coal exports in history. Indonesia's coal exports to Europe until December 2022 are expected to reach 6.6 million tonnes. This number even exceeds the highest exports record in 2012 where coal exports to Europe, mainly Spain, reached around 6.2 million tonnes.[99]

96 The Energy Institution, Statistical Review of World Energy 2023
97 Badan Pusat Statistik 2023
98 APBI, http://www.apbi-icma.org/en/indonesian-coal-data, accessed 17-Jan-2023
99 CNBC, https://www.cnbcindonesia.com/news/20221219195820-4-398287/fantastis-ekspor-batu-bara-ri-ke-eropa-di-2022-cetak-sejarah, accessed 20 June 2023

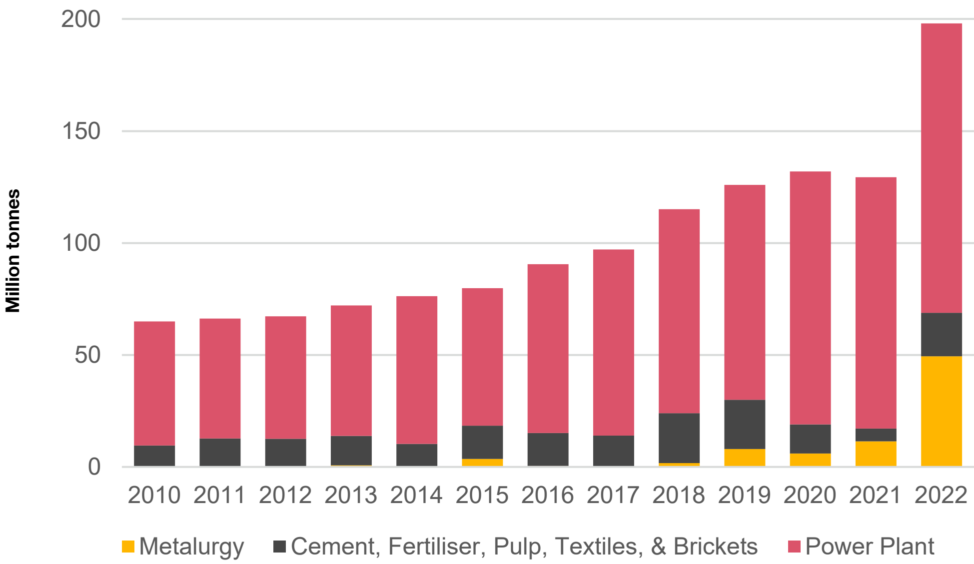
Figure 4.10 – Indonesian coal production and consumption for 2015-2022



Source: APBI Website

Indonesia's domestic coal consumption has continued to increase by 108%, from 87 million tonnes in 2015 to 206 million tonnes in 2022. Based on the RUPTL 2021-2030, coal-fired power plants are expected to consume 153 to 165 million tonnes of coal by 2030. In 2022 domestic coal production reached 685 million tonnes with domestic utilisation of 191 million tonnes, an increase from 2021's 133 million tonnes.

Figure 4.11 – Domestic coal consumption consumer breakdown 2010-2022



Source: MoEMR Data

4.3.2 Prices and Regulations

In March 2017 the MoEMR issued MoEMR Regulation No. 19/2017 on Coal Utilisation for Power Plants and Excess Power Purchases setting a new tariff base for both coal-fired power plants and CMM power plants based on B2B negotiation or subject to benchmarking against the BPP. This regulation replaces MoEMR Regulation No. 3/2015 and the related previous regulations.

MoEMR Regulation No. 9/2016, which was partially amended by MoEMR Regulation No. 24/2016, provides the legal basis for defining mine-mouth power coal supply arrangement as follows:
a) The coal to be used is economically feasible for utilisation in a mine-mouth power project;
b) The availability of the coal supply is guaranteed by the coal mining company throughout the operation of the plant;
c) The power plant is no more than 20 km from the location of the coal mine; and
d) The coal price does not include transportation costs except from the mine location to the power plant's stockpile.

In addition, a mine-mouth coal supplier or an affiliate must have a minimum equity interest of 10% in the IPP and must be the holder of a production mining business licence (*Izin Usaha Pertambangan Operasi Produksi* – "IUP"), a special operation mining business licence (*Izin Usaha Pertambangan Khusus Operasi Produksi* – "IUPK"), or a Coal Cooperation Agreement (*Perjanjian Karya Pengusahaan Pertambangan Batubara* - "PKP2B"). Crucially, the new tariffs may not be as attractive as the previous regime in many cases.

The key features of the regulation are stated in Table 4.4 and Figure 4.12 as follows:

Table 4.4 – Summary of MoEMR Regulation No. 19/2017 - Provisions on Tariffs

<table>
<tr><th rowspan="2">No.</th><th rowspan="2">Type of Power Plant</th><th colspan="2">Maximum Benchmark Price</th><th rowspan="2">Remarks</th></tr>
<tr><th>Regional BPP > National BPP</th><th>Regional BPP < National BPP</th></tr>
<tr><td rowspan="2">1</td><td>Coal-fired >100 MW*</td><td>National BPP</td><td>Regional BPP</td><td rowspan="4">Transmission from power plant to the PLN grid (Component E) is determined by B2B negotiation.</td></tr>
<tr><td>Coal-fired ≤100 MW*</td><td>B2B or Auction</td><td>Regional BPP</td></tr>
<tr><td>2</td><td>CMM</td><td>75% National BPP</td><td>75% Regional BPP</td></tr>
<tr><td>3</td><td>Excess Power</td><td colspan="2">90% Regional BPP</td></tr>
</table>

**Coal price is principally pass-through for non-CMM plants.*

Source: MoEMR Regulation No. 19/2017

The electrical power purchasing price is set under the assumption that the plant has an 80% Capacity Factor and the PPA follows a BOOT scheme.

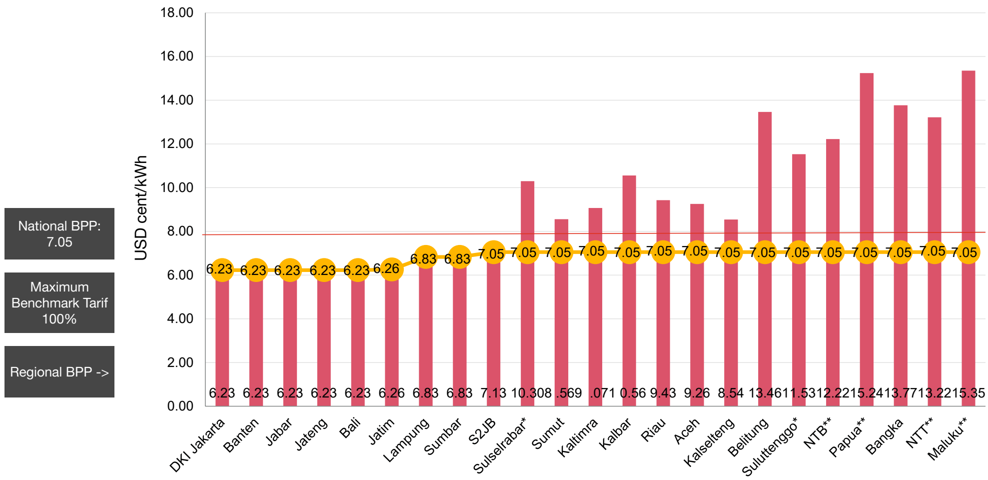
Additionally the regulation specifies the procurement process for power expansion projects as follows:
a) In the event of power purchases resulting from the expansion of a power plant in the same location then the procurement method can follow direct appointment but with a lower benchmark price (as above);
b) In the event of power purchases resulting from the expansion of a power plant in a different location but in the same power system then the procurement method can follow direct selection but with a lower benchmark price (as above).

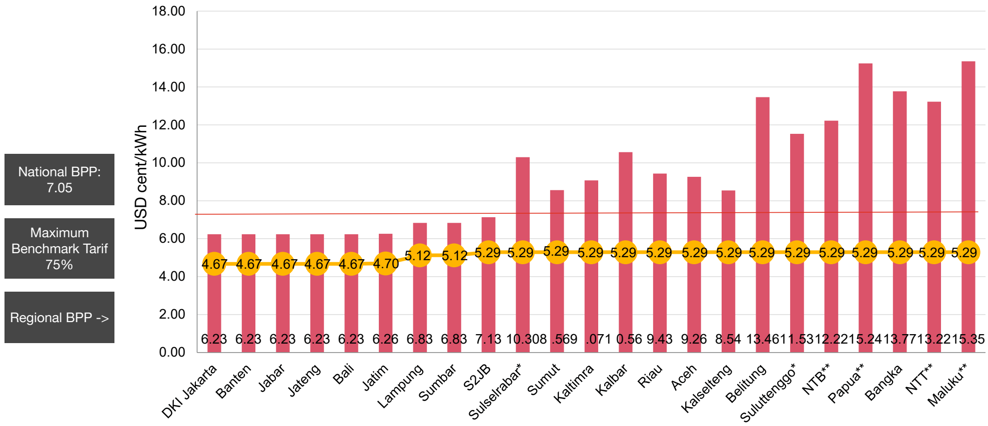
The procurement of CMM power plants can be through direct appointment.

Figure 4.12 outlines the maximum tariffs for coal-fired and CMM power plants in selected regions according to MoEMR Regulation No. 19/2017.

The new maximum benchmark price for coal-fired power plant projects ranges from USD cents 6.23 to 7.05/kWh as stated by the MoEMR Decree no 169.K/HK.02/MEM.M/2021 regarding the 2020 PLN BPP, for any region where the Regional BPP ≤ National BPP, such as in Java, Bali, the Southern part of Sumatra and West Sumatra. The new maximum benchmark price follows the national BPP (USD cents 7.05/kWh) 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 coal-fired power plants with capacity ≤ 100 MW, the tariff is now based on B2B negotiation between PLN and IPPs or an auction.

Figure 4.12 - Tariffs for Coal-fired and CMM Power Plants



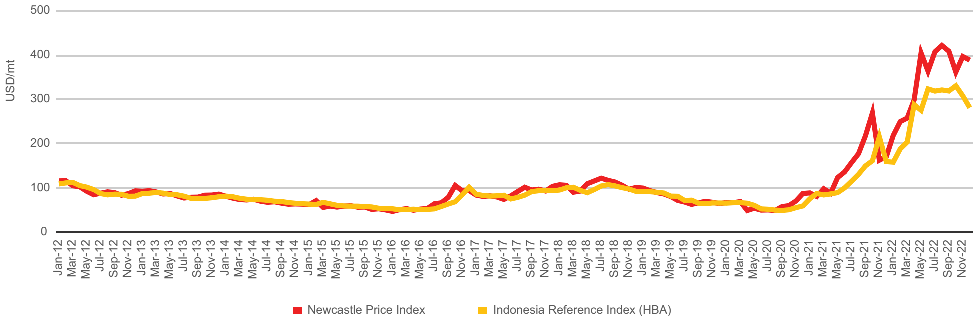


Source: PLN

In addition, the maximum benchmark price for CMM power plant projects follows 75% of the Regional BPP where the Regional BPP ≤ National BPP, or 75% of the National BPP where the Regional BPP is higher than National BPP.

In the end of 2018, the coal price started to fall consistently from USD 120/tonne to below USD 100/tonne. The first quarter of 2019 saw declines in the coal price, due to mild weather, while the restarting of nuclear power stations in Japan has also resulted in weaker demand.[100] The decline has also has been caused by weak demand from the US and Australia, which has been accompanied by a sharp increase in LNG exports. In advanced economies, demand for coal has declined in favour of natural gas, particularly for the purpose of electricity generation. Seaborne coal prices have also been affected by China's decision to curb imports of coal from Australia, its largest supplier. Coal prices were expected to recover partially from their current levels, and the average of USD 94/mt in 2019 – a 12% decline from 2018 – reflects the weakness in natural gas prices, as well as the muted demand.[101] Due to the demand exceeding supply in China, supply interruptions, and increased natural gas costs all around the world, coal prices experienced a hike in 2021. In January 2022, Indonesia imposed an export prohibition, which led to an increase in global prices but a decrease in stability in Chinese pricing because of a thriving domestic market. However, a spike in gas costs following Russia's invasion of Ukraine in late February led to a further increase in coal prices that reached new highs in March and into the summer. The impact of the war and a growing awareness of the possibility of actual energy shortages both contributed to price support. Due to easing supply concerns, prices moderated over the summer. Australian rains over the year made the market even more constrained, resulting in the extraordinary situation of high-quality thermal coal prices exceeding those for high-value coking coal.[102]

Figure 4.13 - Indonesian coal reference price for the periods January 2010 – December 2022



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 Nos. 44/2017 No. 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 reference price of coal (*Harga Patokan Batubara* – "HPB"). This excludes coal for domestic consumption, where the price is determined by the Minister of Energy and Mineral Resources as per 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

100 World Bank, Commodity Market Outlook in Six Charts, https://blogs.worldbank.org/developmenttalk/commodity-markets-outlook-six-charts, accessed 23 April 2019
101 World Bank, Commodity Market Outlook April 2019
102 Bloomberg

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% (fifty percent) of the HBA in the month of contract signing plus 30% (thirty percent) of the HBA one month prior to the contract's signing, plus 20% (twenty percent) 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.[103]

In August 2021, the MoEMR issued Decree No. 139.K/HK.02/MEM.B/2021 on Coal Domestic Market Obligation revoking the previous decree No. 255.K/30/MEM/2020 and its amendment. In general, HBA will remain the reference price for coal sales agreements in the power sector and coal mining companies are also obliged to comply with the minimum coal DMO of 25% of annual production in order to fulfil the domestic needs of electricity and raw material/industrial fuels.

This MoEMR Decree also stipulates that power producers for public use are required to set up a procurement plan prioritising long-term contracts. On coal production, this decree stipulates that the DMO for 2021 is 550 million tonnes; and additional production is 75 million tonnes for the export market, so that the total coal production for 2021 is 625 million.

The MoEMR has also set coal price caps and other pricing schemes as follows:

a) The coal price sales for public-use electricity purpose capped at USD 70/tonne Free On Board ("FOB") vessel with GAR 6,322 kcal/kg, max. TM 8%, S_2 0.8 and ash 15% specifications set as the standard.
b) In the case of different specifications apply with the HBA price equal to or exceeding USD 70/tonne, then adjustment will be governed by a standard formula as set out under this Decree's attachment.
c) If HBA <USD 70/tonne then HBA will be set as the price, but price adjustment also applies for the different specifications and also governed by the standard formula as set out under this Decree's attachment.
d) HBA is also set up as the coal spot price, while specific term price governed by specific formula.

103 Coal Asia, 25 June-25 July 2016, p. 54

4.3.3 Current Installed Coal-Fired Power Plant Capacity and the Government Plans

By December 2022, power generation from coal-fired power plants accounted for more than 50% of total power generation. The share of coal in the energy mix is planned to increase to around 58.5 to 63.9% by 2030, despite the NEP's targeted energy mix in 2030 (see Table 3.3). PLN plans to almost triple the energy production of renewables from 35 GWh in 2020 to around 95 GWh in 2025 (see Figure 1.7).[104]

As discussed in *Section 3.7.1 - 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 their dependency on coal power plants by the issuance of a "greener RUPTL" and also with the early coal power plant retirement plan.[105] Compared with 2019 RUPTL, the PLN allocated coal power plant projects in the RUPTL 2021-2030 only accounted for 30% of the 2019 planned projects. Furthermore, the Government currently working together with ADB to formulate a "buy-to-retire" scheme for Indonesia coal power plants which also called the energy transition mechanism.[106]

4.3.4 Opportunities

Of the additional 16 GW of coal-based power generation planned in the RUPTL 2021-2030, regular additional coal-fired power plants account for 12.49 GW, while CMM power plants account for 3.5 GW. Of the regular coal-fired power plants, about 3.19 GW of coal-fired power plants are planned to be developed by PLN, while another 9 GW are to be developed by the IPPs. The remaining 0.3 GW of projects are projected for the cooperation between business areas. Of the CMM power plants, the entire 3.5 GW of capacity has been allocated to the IPPs.[107] These figures indicate that there are significant opportunities in Indonesia for the private sector.

104 RUPTL 2021-2030, p. V-97
105 The Jakarta Post, https://www.thejakartapost.com/news/2021/08/24/adb-pln-consider-plan-to-retire-indonesian-coal-plants-early.html, accessed 20 October 2021
106 The Jakarta Post, https://www.thejakartapost.com/paper/2021/10/22/plan-for-early-retirement-of-coal-plants-now-in-high-level-talks.html, accessed 23 October 2021
107 RUPTL 2021-2030, p. V-54

RUPTL 2021-2030 noted a significant change on the projection of PLTU and PLTU MT. PLN noted that there are about 2.55 GW of coal-fired power plants that were at the planning stage, including 1.2 GW of unallocated coal-fired power plants and the 1.7 GW power plants at the procurement stage. There were also more than 7.1 GW of plants that on the financing stage.

PLN signed a PPA with the 240 MW Banyuasin and the 300 MW Sumbagsel-1 CMM power plants at the end of May 2018, with the 2019 RUPTL noting that these power plants will come into operation in 2021 and 2023, respectively. These were stalled due to protracted negotiations over power tariffs as well as verification of the mine's "clean and clear" status. By the end of 2018, PLN was reported to be having difficulties in finding partners for 19 CMM power plant projects, and it plans to resolve this issue by 2019.[108] PLN has also started construction of the 100 MW Sulsel Barru-2 coal-fired power plant.[109] On the IPP side, PT Huadian Bukit Asam Power recently signed a USD 1.26 billion loan to help finance the planned Sumsel-8 CMM power plant (2x620 MW), with estimated investment of USD 1.68 billion. The Sumsel-8 CMM power plant has an expected COD of September 2023.[110]

4.3.5 Challenges

Indonesia has large geological reserves of coal. However, the coal transportation infrastructure still contributes significantly to the 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.

Licensing requirements could also hinder the progress of the coal-fired power plant development programme, since many of the concessions for coal mining are expected to expire before the corresponding Coal Supply Agreements (in the early 2020s). The Government may need to signal a commitment to renewing the IUP or PKP2B as part of this.

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.

108 Bisnis.com, https://sumatra.bisnis.com/read/20181204/451/865855/pltu-mulut-tambang-19-proyek-pln-terkendala-mitra, accessed 2 August 2019
109 Coal Asia, 30 June–30 July 2018, pp. 56-57
110 Kontan, https://industri.kontan.co.id/news/pltu-mulut-tambang-sumsel-8-direncanakan-operasi-komersial-pada-september-2023, accessed 20 June 2023

4.4 Oil

In 2022, Indonesia's total crude oil production was around 0.7 million barrels per day or approximately 71% of its 2009 production. Oil and gas output continued to fall in 2022 as a result of a natural drop in reservoir performance and the fact that Indonesia has not yet discovered any new substantial reserves.

In terms of the power sector, oil contributes a relatively insignificant share. PLN generally uses oil to provide electricity in rural or isolated grid areas. In the RUPTL 2021-2030, PLN intends to reduce the use of oil from the estimated 3.2% in 2021 to 0.4% by 2030 (see Table 3.3). This is motivated by efforts to reduce the BPP as well as increase efficiency.

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.[111]

4.5 Carbon Regime and Emissions

One key regulatory basis for Indonesia's efforts to reduce greenhouse gases and meet Indonesia's Nationally Determined Contribution ("NDC") was introduced in October 2021 with the issuance of Presidential Regulation No. 98 of 2021 ("PR 98/2021") concerning the Implementation of Carbon Economic Value for Achieving Nationally Determined Contribution Targets and Control of Greenhouse Gas Emissions in National Development.

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

1. Carbon Trading
2. Results-based Payment
3. Carbon Levy

PR 98/2021 defined the GHG Emission Limit as the maximum GHG emission level for a certain time determined by the relevant minister organising and deciding the GHG emission level in the sub-sectors and enterprises and/or activities. The GHG emission limit is calculated by numerous factors, including (i) the sectoral GHG emission baseline, (ii) the sectoral NDC objective, (iii) the GHG inventory findings, and/or (iv) the time frame for achieving the target. The GHG Emission Limit is utilised in the emission trading system implemented by the MoEF.

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.

111 PwC, Oil and GE Operations Indonesia ("GE"), Private Power Utilities: The Economic Benefits of Captive Power in Industrial Estates in Indonesia, 2016, p. 18

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 socialisation 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 IDR 30.00 per kilogram of carbon dioxide equivalent (CO_2e), or IDR 30,000/ton CO_2e (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 coal fired power ("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.

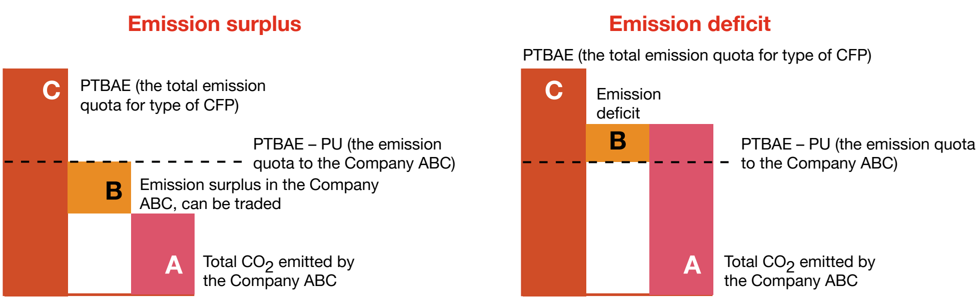
In December 2022, the MoEMR issued MoEMR Regulation No. 16 of 2022 on the Procedures For The Implementation Of Carbon Economic Value In The Power Plant Sub-Sector. The Minister of Energy and Mineral Resources has determined the value of Technical Approval of Emission Limits for Business Entities (*Persetujuan 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 NEK in the power plant subsector, as stipulated in Article 2 of the regulation, includes:

1. Determination of the Technical Approval of the Upper Emission Limits (*Persetujuan Teknis Batas Atas Emisi* - “PTBAE”) of power plants,
2. Preparation of GHG Emission monitoring plan for power plants,
3. Stipulation of PTBAE-PUs,
4. Carbon trading,
5. Preparation of GHG Emission report of power plant, and
6. Evaluation of the implementation of Carbon Trading and PTBAE-PU auction.

MoEMR has specified that the the implementation of carbon trading in the electricity sector will be carried out in 3 phases, as outlined below:

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

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



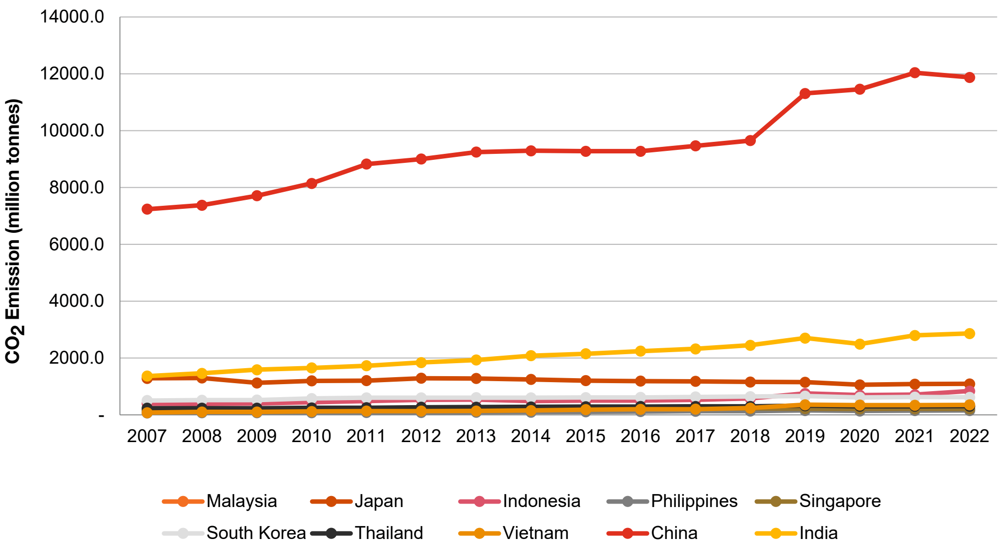
Remarks:
A = PTBAE - PU, the emission quota to the Company ABC
B = Emission surplus/emission deficit
C = PTBAE, the total emission quota for type of CFP

According to the Climate Transparency Report 2022, there was a sharp rebound of carbon dioxide emission, slighly exceeding 2019's level. Economic development explains the large increase in emissions in 2021. Energy usage climbed dramatically as business activity recovered following lockdowns and other COVID-related measures. In 2021, carbon intensity and, to a lesser extent, energy intensity did not improve. BP notes that the noticeable decrease in global carbon emissions in 2020 was just momentary as carbon equivalent emissions from energy sources (including methane), industrial operations, and flaring climbed by 5.7%. Despite MoEMR noting that the CO_2 reduction targets have been fulfilled each year, the Ministry of Forestry and Environment has also noted an increase in the CO_2 emitted by the energy sector. The most recent data shows that in 2019 industrial processes were the largest source of CO_2 emissions, both emitted about 37% of CO_2 in 2019, followed by both power generation and transportation at 27% each.

Since the COP 15 in 2009, Indonesia has made a commitment to combating climate change by pledging in its intended NDC to cut GHG emissions by 26% on its own and by 41% if it obtains international support by 2020. The first NDC document, released in November 2016, reinforced Indonesia's commitment by setting an unconditional objective of 29% and a conditional target of up to 41% compared to the BAU scenario in 2030.

Nonetheless, Indonesian carbon emissions from energy consumption are still considerably higher than those of its fellow ASEAN countries and are equivalent to 1.8% of global emissions. The Energy Institution's Statistical Review of World Energy 2022 notes that Indonesia's carbon emissions in 2022 were estimated to be 80% higher than Thailand's and the rest of the ASEAN region, although they were quite small as compared to Asia Pacific (where 52% of global carbon emissions were from energy use). Aside from Japan, 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.

Figure 4.14 - Carbon emission - neighbouring countries



Source: The Energy Institute, Statistical Review of World Energy 2023

Photo source: PwC

Photo source: PT UPC Sidrap Bayu Energi

5 Renewable Energy

5.1 Overview of Indonesia's Renewable Energy Development

Despite its abundance of renewable energy resources (see Table 1.1), Indonesia has been relatively slow to develop its renewable energy capacity. Fuel subsidies, low electricity tariffs, complex regulations, legal uncertainties, logistical challenges, and extensive cheap coal resources have combined to deter potential investments in renewables. Following years of underinvestment, Indonesia's production of renewable energy remains modest, although utility-scale deployment of wind and solar PV picked up in 2017.

In 2021, the government aimed to bring in USD 33.5 billion in investment in the energy sector for 2022, of which USD 3.9 billion would go toward renewable energy. However, by December 2022, it was announced by the MoEMR that investments into renewables reached only USD 1.6 billion; 41% of the target.

Indonesia's primary objectives when expanding its use of renewable energy are threefold:

a) To improve domestic energy security by diversifying the feedstocks used by PLN and the IPPs to generate power, and to encourage the use of renewable energy as an ancillary source where it is readily available and untapped;
b) To accelerate improvements in the electrification ratio and access to the energy infrastructure, particularly for areas without grid access, such as rural, remote, and border areas, and on islands, with the target of achieving 100% electrification by 2020; and
c) To contribute to GHG emissions reduction targets and encourage the green economy, in line with the Government's desire to cut GHG emissions by 29% by 2030.

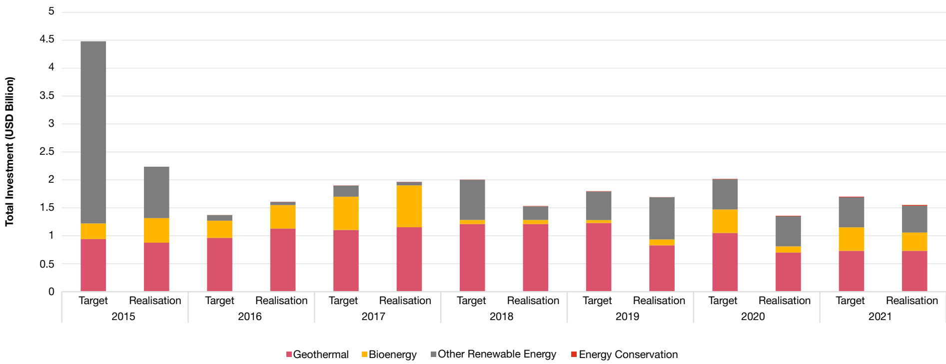
The present utilisation of renewable energy sources for power generation in Indonesia can be broken down into three classes:

a) Energy sources already widely used in commercial operations (e.g. geothermal, hydro, and biomass);
b) Energy sources being developed commercially, but with some residual concerns regarding regulatory and commercial aspects (e.g. solar and wind); and
c) Energy sources at the research stage only (e.g. ocean energy).

The most recent (2014) NEP has set an ambitious goal for NRE sources to constitute 23% of the national energy mix by 2025 and 31% by 2050. Law No. 30/2007 on Energy, defines new energy sources as including liquefied coal, coalbed methane, gasified coal, nuclear energy, and hydrogen, whilst renewable energy sources include geothermal resources, hydropower, bioenergy, solar, wind, and ocean energy.

The National Medium-Term Development Plan (*Rencana Pembangunan Jangka Menengah Nasional* – "RPJMN") for 2020-2024 is the the Indonesia government's planning document for economic development, and provides a basis and key reference points for all other planning documents including the *Rencana Strategis* ("RENSTRA"). The RPJMN set a target for the installed capacity of renewable power plants to reach 19.3 GW in 2024. Hydropower's share in the development plan is expected to be around 51% in 2024 - which stood at around 53% as of 2022. This percentage decrease suggests an ambitious target for the growth of non-hydro renewables in the coming years. Equally ambitious, is the plan to increase the local content of renewable power plants, with the aim of reaching 55.4% by 2024.

Figure 5.1 – Total investment target & realisation in Indonesian renewable energy



Source: RENSTRA 2020-2024, p. 28 & DGNREEC Performance Report 2021, p.72

A range of regulatory and planning issues work to constrain the development of renewable energy ("RE") sector as summarised below.

- *Tariff caps for renewable energy*: The most significant constraint on RE is that power purchase prices are too low to allow developers to recover costs and make reasonable returns,[112] and consider neither the positive externalities of RE nor the negative externalities of carbon-based energy. Moreover, through various policy incentives that support coal and diesel the GOI is bringing down the average cost of carbon-based electricity generation thus putting more pressure on unsubsidised RE producers.
- *Local content requirements*: The local content requirement has constrained development by raising the cost of power generation to a level that, given the 85% of the BPP tariff that is currently available, not attractive.
- *Other subsidies that favour fossil fuels over renewable energy*: A range of other subsidies for fossil fuels effectively work to increase pressure on RE producers. The so-called DMO, where the GOI places a tariff cap on coal sold domestically for coal-fired power plants, can be seen as another subsidy that makes it harder for RE to compete with coal as the lowest cost power generation option.
- *Incentives and Key Performance Indicator ("KPI") for PLN*: PLN's inherent caution, lack of focus on renewables, and understandable desire to protect the integrity of its grid, makes it reluctant to encourage on-grid renewable projects even when the impact could be well-managed.

  Moreover, the current KPIs do not incentivise PLN to consider the longer-term financial benefits of renewable energy compared to the likely increasing costs of fossil fuels. A key PLN KPI is indeed to reduce rather than increase its current BPP, amended KPIs could focus on energy security and resilience as well as on the future reduction of generation costs as fossil fuel costs rise.
- *Lack of regulatory stability and certainty*: Frequent changes to policy, regulatory delays and the patchy implementation of the Indonesian government's policy by PLN combine to undermine investor confidence still further by increasing project development risks and delaying financial close on bankable projects. Of particular concern is MoEMR Regulation 10/2018, which requires key risks to be borne by the IPP including regulatory changes, land acquisition.

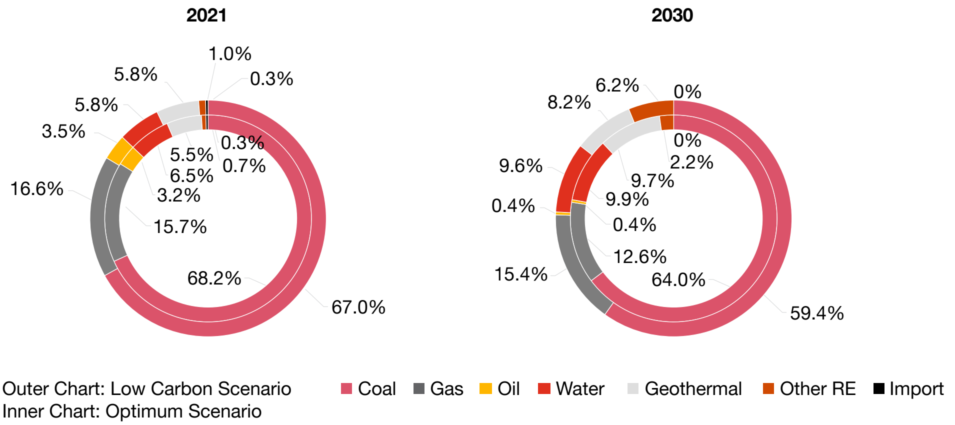
112 This has been especially the case since the implementation of MoEMR Regulation 50/2017 which caps RE power purchase prices at 85% of the local average generation cost (BPP) in eastern Indonesia. The range of BPP in eastern Indonesia is between 14-21 cents/kWh, whilst off-grid electricity is typically priced at around 21 cents/kWh.

As can be seen from the above summary of the regulatory environment, tariffs, subsidies and pricing issues dominate investor concerns. Prior to 2016, the regulations on tariffs were considered to be more investor friendly, but the release of MoEMR Regulation No. 12/2017 (as amended by MoEMR Regulation No. 43/2017) on the Utilisation of Renewable Energy Resources for Electricity reduced the incentives for new investments, especially in low-cost areas such as Java and Sumatra. The release of MoEMR Regulation No. 50/2017 and its amending MoEMR Regulation No. 53/2018 (which revoked MoEMR Regulation No. 12/2017 as amended by MoEMR Regulation No. 43/2017), alleviated concerns regarding tariffs, mainly by increasing some of the tariffs or providing greater flexibility for many provinces, especially those in Java and Sumatra. However, the difficulties in reaching financial close have also been deemed to be the main reason for the lack of investments in other renewables, aside from geothermal, as MoEMR Regulation No. 50/2017 (amended by MoEMR Regulation No. 53/2018 and 4/2020) capped the prices of regional BPP and the BOOT schemes, which are deemed not bankable by investors. Please see *Section 5.9 – New Tariff Stipulations for Renewable Energy* for more information on tariffs and renewable tariffs.

5.2 Renewable Energy in RUPTL

Despite ongoing investor concerns regarding regulatory and pricing issues, both PLN and the MoEMR remain more optimistic about renewable energy development. In the RUPTL 2021-2030, the target for renewable energy deployment in the fuel mix increased from 12.7% in 2021 to 23% in optimum scenario and 24.2% in low carbon scenario by 2030, which is to be supported mostly by hydropower (9.9%) and geothermal energy (9.3% and 9.7%) (see Figure 5.2).

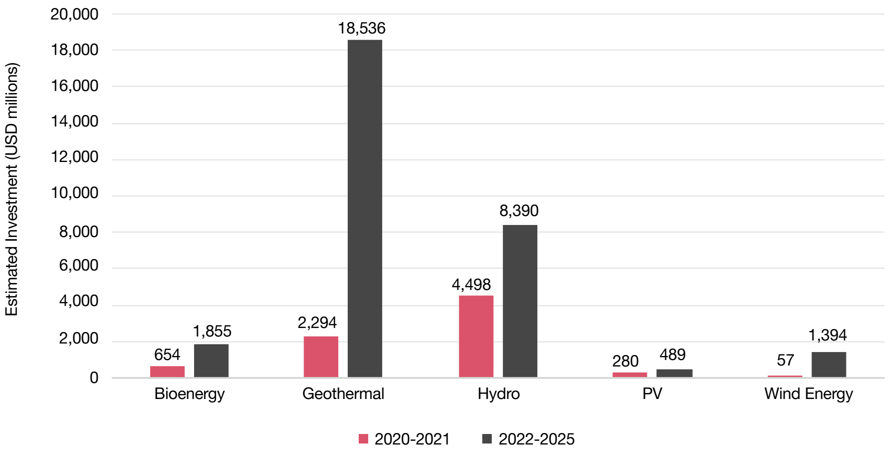
Figure 5.2 – Generation mix projection in the electricity sector as in the RUPTL 2021-2030



Source: RUPTL 2021-2030

Based on the investment projection of power plant projects in the RUPTL 2021-2030, PLN will be dominating the pipeline with annual average of IDR 87.8 trillion of power projects in Indonesia through 2030. PLN investments will not only be counted for power plant development, but also for transmition, substation, distribution, and other electricity business support areas. IPP or private sector will contribute with forecasted annual investment in power plant sector of around IDR 51.7 trillion per year. Despite that, there is no clear projection for the type of power plant source in RUPTL 2021-2030.

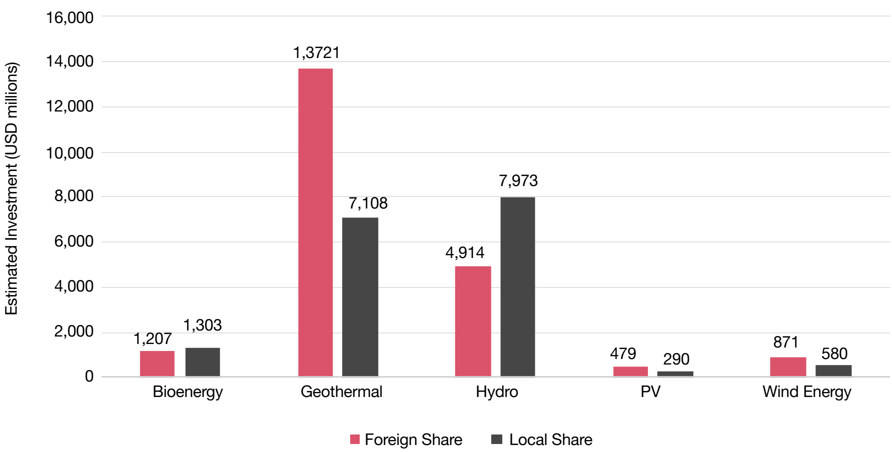
Figure 5.3 – Estimated investment in renewables 2020-2025



Source: Tetra Tech ES Inc., Indonesia Renewable Energy Business Opportunities, presented at the UK Foreign & Commonwealth Office, British Embassy Jakarta

Foreign investment is expected to play a significant role, as USD 21.2 billion or 55% of the investment in renewables is expected to be obtained from foreign investors. Foreign investors are expected to cover more than 60% of the investments in geothermal, PV, and wind energy, while the local investors are expected to be more prominent in hydropower (62%) and bioenergy (52%).

Figure 5.4 – Estimated investment in renewables 2020-2025 based on investors



Source: Tetra Tech ES Inc., Indonesia Renewable Energy Business Opportunities, presented at the UK Foreign & Commonwealth Office, British Embassy Jakarta

5.3 Geothermal Energy

Geothermal power generation relies on the thermal energy of the earth's core to heat water or another fluid. The condensation from the heated fluid is used to turn a turbine and generate electricity. After cooling, the fluid is directed back towards the geothermal resource to repeat the process. Indonesia is geothermal-rich, being situated on the world's most active volcanic fault (the Ring of Fire) and lying between two of the earth's major active tectonic plates (the Pacific and Eurasia) as well as a minor plate (the Philippine plate), which allows geothermal energy from the earth to be transferred to the surface through a fracture system.

Geothermal is regarded as clean energy, emitting up to 1,800 times less carbon dioxide than coal-fired plants and 1,600 times less than oil-fired plants. Being a renewable resource, geothermal energy is unaffected by changes in hydrocarbon prices. It is also the only renewable source with a potential capacity factor of more than 80% worldwide. Some plants have surpassed the capacity factor of 90%, which is higher than fossil fuel resources.[113]

Indonesia's geothermal potential is approximately 23,966 MW (Table 5.1) across 351 locations, and represents the second largest geothermal resource in the world, constituting 28% of the total global resources.[114]

113 International Renewable Energy Agency, Geothermal Power Technology Brief p. 2 and p. 21, 2017 http://www.irena.org/-/ media/Files/IRENA/Agency/Publication/2017/Aug/IRENA_Geothermal_Power_2017.pdf, accessed 8 June 2018
114 RENSTRA KESDM 2020-2024, p. 37

Table 5.1 – Resources, reserves and installed capacity of Indonesian geothermal as of December 2021 (MW)

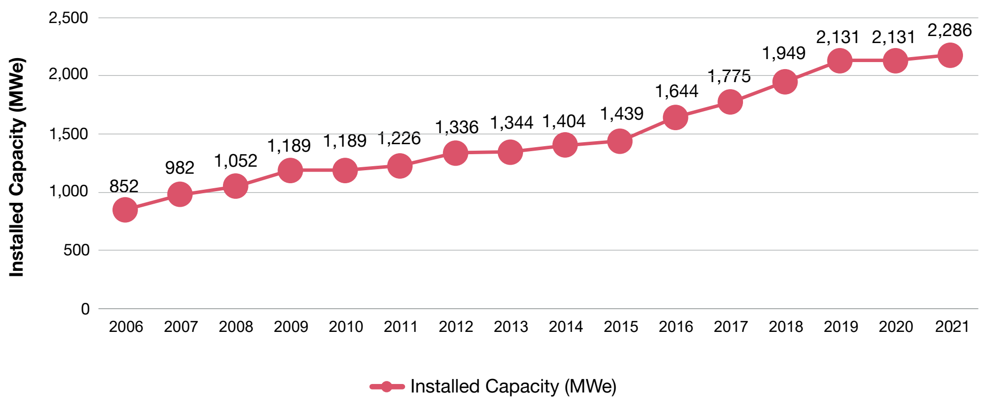
No	Island	No. of Locations	Potential Energy					Total	Installed Capacity
			Resources		Reserves				
			Speculative	Hypothetical	Possible	Probable	Proven		
1	Sumatra	101	2,276	1,551	3,594	976	1,120	9,517	845
2	Java	73	1,259	1,191	3,403	377	1,820	8,050	1,309
3	Bali	6	70	21	104	110	30	335	-
4	Nusa Tenggara	31	225	148	892	121	12.5	1,399	12.5
5	Kalimantan	14	151	18	6	-	-	175	-
6	Sulawesi	90	1,365	343	1,063	180	120	3,071	120
7	Maluku	33	560	91	485	6	2	1,144	-
8	Papua	3	75	-	-	-	-	75	-
	Total	351	5,981	3,363	9,547	1,770	3,105	23,766	2,286

Source: HEESI 2021

The geographical location of geothermal resources across Indonesia means that this power source is well-placed to assist with improving domestic energy security. However, the development of Indonesia's geothermal sector has been slow. The growth of geothermal energy in Indonesia is presented in Figure 5.2.

Recently, there are 14 working areas (or concessions) operating with the addition of the Lumut Balai-I 55 MW and Sorik Merapi-I 45 MW capacity power plants, which came onstream in early 2019 after several delays. Despite abundant geothermal reserves and 75 working areas, currently the total installed capacity has only reached 2,286.1 MW. This is equivalent to around only 9.6% of the total estimated resources.

Figure 5.5 – Installed capacity of geothermal energy in Indonesia (MW)



Source: DGNREEC Performance Report 2021 & Kontan 2021

Table 5.2 – Installed geothermal capacity by licence holder and operator, as of December 2021

No	Geothermal Working Area Location	Licence Holder	Operator	Power Plant	Plant Configuration (MWe)	Plat Capacity
1	West Java	PT Pertamina Geothermal Energy	PGE	PLTP Kamojang	1 x 30 2 x 55 1 x 60 1 x 35	235
2	North Sulawesi	PT Pertamina Geothermal Energy	PGE	PLTP Lahendong	4 x 20 2 x 20	120
3	North Sumatra	PT Pertamina Geothermal Energy	PGE	PLTP Sibayak	1 x 10 2 (Monoblock)	12
4	West Java	PT Pertamina Geothermal Energy	CGS	PLTP Salak	3 x 60 3 x 65.6	376.8
5	West Java	PT Pertamina Geothermal Energy	CGI	PLTP Darajat	1 x 55 1 x 94 1 x 121	270
6	West Java	PT Pertamina Geothermal Energy	SE	PLTP Wayang Windu	1 x 110 1 x 117	227
7	Central Java	PT Geo Dipa Energi (Persero)	GDE	PLTP Dieng	1 x 60	60
8	Lampung	PT Pertamina Geothermal Energy	PGE	PLTP Ulubelu	2 x 55 2 x 55	220
9	NTT	PT PLN (Persero)	PLN	PLTP Ulumbu	4 x 2.5	10
10	NTT	PT PLN (Persero)	PLN	PLTP Mataloko	1 x 2.5	2.5
11	West Java	PT Geo Dipa Energi (Persero)	GDE	PLTP Patuha	1 x 55	55
12	North Sumatra	PT Pertamina Geothermal Energy and Joint Operation Contract Sarulla Operation Limited	SOL	PLTP Sarulla	3 x 110	330
13	West Java	PT Pertamina Geothermal Energy	PGE	PLTP Karaha	1 x 30	30
14	West Java	PT Pertamina Geothermal Energy	PGE	PLTP Lumut Balai	1 x 55	55
15	North Sumatra	PT Sorik Marapi Geothermal Power	SMGP	PLTP Sorik Marapi	1 x 42.4	99.4
16	West Sumatra	PT Supreme Energi Muara Laboh	SEML	PLTP Muara Laboh	1 x 85	85
17	South Sumatra	PT Supreme Energi Rantau Dedap	SERD	PLTP Rantau Dedap	1 x 98.4	98.4
Total Installed Capacity (MW)						**2,286.1**

Source: DGNREEC Performance Report 2021

As of December 2020, 64 Geothermal Working Areas (*Wilayah Kerja Panas Bumi* - "WKP") and 14 Preliminary Survey and Exploration Areas (*Wilayah Penugasan Survei Pendahuluan dan Eksplorasi* - "WPSPE") have been issued by the Government. These comprise 19 existing working areas identified prior to the issuance of Law No. 27/2003 on Geothermal, 45 working areas stipulated after the issuance of Law No. 27/2003, and ten working areas identified after the issuance of Law No. 21/2014 (see Figure 5.6).

Figure 5.6 – The current status of Indonesia geothermal development (2021)

In February 2017, the Government issued a new regulation on geothermal development, GR No. 7/2017 on Geothermal for Indirect Utilisation. In order to expedite the development of geothermal energy in open areas that have not yet been stipulated as working areas, the Government shall either conduct a Preliminary Survey and Exploration by itself or shall offer a Preliminary Geothermal Survey Assignment (*Penugasan Survey Pendahuluan* – "PSP") to a Public Service Agency (*Badan Layanan Umum* – "BLU"),[115] research institute, or university; or shall make a Preliminary Geothermal Survey and Exploration Assignment (*Penugasan Survey Pendahuluan dan Eksplorasi* – "PSPE") to business entities. In addition, in June 2017, the MoEMR released MoEMR Regulation No. 36/2017 on the Procedures for Geothermal Preliminary Survey Assignments ("PSP") as well as PSPE, and MoEMR Regulation No. 37/2017 on Geothermal Working Areas for Indirect Utilisation. Both are implementing regulations of GR No. 7/2017.

115 A BLU is an entity under a Government Agency that also has the role to provide and sell certain products and/or services to citizens. There are several BLUs under MoEMR: LEMIGAS, P3EBTKE, Tekmira, etc.

Photo source: PT Vale Indonesia Tbk

A PSP is assigned by the MoEMR to BLUs, research institutes, or universities. During the implementation stage, a PSP is limited to a preliminary survey, with no well drilling. The period for conducting the PSP is limited to one year, with an option to extend by up to six months.

Alternatively, the MoEMR could issue a PSPE permit to a business entity interested in geothermal development to conduct a survey in an open area. The period of a PSPE is a maximum of three years, which may be extended a maximum of two times, for a period of one year each. In a PSPE, a business entity is required to conduct the preliminary geothermal survey (geological, geochemical, and geophysical). In addition, an assigned PSPE business entity must perform/drill at least one exploration well to obtain an estimate of the geothermal reserves. If two or more business entities are interested in conducting a PSPE, the Minister of Energy and Mineral Resources will choose only one of those business entities, based on an auction mechanism.

A business entity that is assigned to conduct a PSPE will have the right to obtain fiscal facilities, and also have an obligation to make an Exploration Commitment of USD 5 million or USD 10 million (depending on the planned capacity to be developed). It is expected that a 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.[116]

5.3.1 Recent Trends in Geothermal Development in Indonesia

By the end of 2021, Geothermal accounted for 2.3 GW (3%) of the total electricity generation capacity - with the MoEMR setting a 2.4 GW target for 2022. In 2021 the Indonesian government earned IDR 1.9 trillion (USD 99.8 million) in non-tax state earnings from geothermal management through the Energy and Mineral Resources Ministry. This is approximately 34% greater than the IDR 1.4 trillion objective for 2021.[117]

In the previous 2019 RUPTL, PLN planned for Indonesia to have an additional 4,607 MW of installed geothermal capacity by 2028. As a consequence, the total installed capacity will be 6,421 MW by the end of 2028. However, due to several considerations, challenges, and COVID-19 demand adjustment, in the RUPTL 2021-2030 PLN and the Government revised the incoming national geothermal plants to around 2 GW.

116 Under GR No. 7/2017, there is no longer a “right to match” scheme for tenders. All working area tender participants will have to submit a proposal containing analysis and business commitments. The Tender Committee will evaluate all proposals, but a Business Entity that carries out a PSPE will have some privileges in the tender process (see *Section 5.3.2 - The 2014 Geothermal Law*). “Right to match” is still available only for a Business Entity that has been assigned a PSP, subject to the previous regulation (transitional provision – Article 123-126 of GR No. 7/2017)

117 Bahan Ditjen Ketenagalistrikan Capaian Kinerja 2021 Dan Rencana 2022 Sub Sektor Ketenagalistrikan, p.16

Table 5.3 – List of geothermal project development plans for the 2021 - 2030

Geothermal Project Name	Power System Region	Project Developers	Plan of COD and Installed Capacity										
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Remarks
Sorik Marapi	Sumbagut	IPP	45	50	50	50	–	–	–	–	–	–	
Hululais	Sumbagselteng	PLN	–	–	–	–	110	–	–	–	–	–	
Sungai Penuh			–	–	–	–	–	–	–	55	–	–	
Danau Ranau			–	–	–	–	–	–	–	20	–	–	
Kepahiang			–	–	–	–	–	–	–	110	–	–	
Lumut Balai		IPP	–	55	–	–	–	–	–	–	–	–	
Muara Laboh			–	–	–	–	80	–	–	65	–	–	
Rantau Dedap			86	–	–	–	134	–	–	134	–	–	
Rajabasa			–	–	–	–	110	–	–	–	110	–	
Spread geothermal power plants		Unallocated	–	–	–	10	30	–	–	–	–	–	
Tangkuban Perahu-Ciater	Jawa-Bali	PLN	–	–	–	–	–	40	–	–	–	–	
Ungaran			–	–	–	–	–	55	–	–	–	–	
Patuha		IPP	–	–	55	–	–	55	–	–	–	–	
Ijen			–	–	–	55	–	55	–	–	–	–	
Telaga Ngebel			–	–	–	–	–	–	55	–	–	110	
Cibuni			–	–	–	10	–	–	–	–	–	–	
Wayang Windu			–	–	–	–	–	60	–	–	–	–	
Dieng (inc. Binary & Small Scale)			–	–	75	–	110	–	–	–	–	–	
Baturaden/Slamet			–	–	–	–	–	–	–	110	75	35	
Guci			–	–	–	–	–	–	–	–	–	55	
Rawadano			–	–	–	–	30	–	–	80	–	–	
Gunung Salak (inc. small scale binary)			–	–	–	–	70	–	–	–	–	–	
Bedugul			–	–	–	–	10	–	–	–	–	–	
Spread geothermal power plants		Unallocated	–	–	–	–	70	–	–	–	–	485	Additional Plan
Spread geothermal power plant	Sulbagut	IPP	–	–	5	–	–	–	40	–	–	30	Additional Plan
Tulehu	Ambon	PLN	–	–	–	–	10	10	–	–	–	–	
Halmahera	Sofifi	IPP	–	–	–	–	20	–	–	–	–	–	

Source: RUPTL 2021-2030

At the end of July 2021, as planned, PT Sorik Marapi Geothermal Power succeeded in operating Sorik Marapi Unit II after the company reached the COD of Unit I in 2019. The company is also aiming to finish the third plant in 2022.[118] In terms of newly commissioned plants in 2021, Power producer PT Supreme Energy announced that the PLTP Rantau Dedap I in South Sumatra had begun commercial operations. The power plant has been operating since December 2021, with a capacity of 91.2 MW. State electricity company PLN will provide a transmission network to distribute plant electricity to consumers.[119]

Prior to the beginning of 2019, at least five WKPs and five WPSPEs were tendered in 2018. Another five WKPs were directly assigned to SOEs, representing the continuation of a trend beginning in 2016, of geothermal projects being assigned to SOEs. PLN is expected to receive three WKPs, with the other two WKPs assigned to PGE. However, Letter No. 3535/DAN.01.01/DITREGJBTBN/2018 of December 2018 states that PLN was not able to develop WKP Wapsalit, which has an estimated resource potential of 1.21 MW, due to its

118 Bisnis, https://ekonomi.bisnis.com/read/20210728/44/1423020/sukses-operasionalkan-unit-ii-pltp-sorik-marapi-unit-iii-ditargetkan-beroperasi-tahun-depan, Accessed 29 July 2021

119 The Jakarta Post, https://www.thejakartapost.com/business/2022/01/07/geothermal-plant-of-91-mw-begins-operations-in-s-sumatra.html, accessed 17-Jan-2023

non-volcanic geothermal nature. PLN also declined five WKPs that were directly assigned by the MoEMR in June 2019, due to the high costs of these projects, and is still considering the eight other geothermal projects offered. Three PSPEs (Geureudong, Hu'u Daha and Klabat Wineru) were granted to companies through tenders, with five further PSPEs being assigned to business entities that have also been assigned PSPs.

However, despite the ambitious targets and encouraging results, the Government has continued to struggle to attract and accelerate the investment for geothermal exploration. In 2019, the MoEMR failed to arrange geothermal auctions in July 2019, due to difficulties with location and construction permits. Although investment in this sector has increased each year, these increases have been significantly lower than those predicted in the New and Renewable Energy and Energy Conservation Strategic Plan (*Rencana Strategis Energi Baru, Terbarukan dan Konservasi Energi* - "RENSTRA EBTKE") 2015-2019. 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.

Despite the fact that there will be no geothermal working area offerings and tender until 2022/2023, the Government is optimistic about adding 1,027 MW of geothermal capacity within the next five years, according to the DGNREEC 2020 – 2024 strategic plan.

Table 5.4 – MoEMR geothermal target

	2023	2024
Additional Capacity (MW)	300	375
Local Content (%)	30	30
Investment (Billion USD)	1.31	1.56
Geothermal State Revenue (Billion IDR)	1970.42	2181.93

Source: RENSTRA EBTKE 2020-2024, p. 121

5.3.2 The 2014 Geothermal Law

Law No. 27/2003 (the "2003 Geothermal Law") granted the private sector control over geothermal resources and the sale of base load electricity to PLN. The 2003 Geothermal Law replaced the integrated geothermal and power arrangements under the former JOC framework. The 2003 Geothermal Law passed the authority to grant geothermal permits (IUP – Geothermal) to Regional Governments with input from the MoEMR. The permits were granted through competitive tendering.

In the past, there were inconsistencies between the tendering process at the regional level and the subsequent price negotiations with PLN under the PPAs. This may have been because PLN is centrally controlled, while the IUP – Geothermal permits may be granted by Central, Provincial, or Local Governments, depending upon whether the work area crosses provincial or local boundaries. This led to investors effectively negotiating with two parties.

In order to expedite the utilisation of geothermal energy, the Government on 17 September 2014 issued Law No. 21/2014 on Geothermal (the "2014 Geothermal Law") revoking the 2003 Geothermal Law. Under the 2014 Geothermal Law, geothermal operations were classified as being either for "direct use" (e.g. hot springs) or indirect use (i.e. electricity generation). Now, only the Central Government is able to issue a Geothermal Licence or an IPB and to conduct tenders for the geothermal working areas. Direct use licences can be issued by the Central or Regional Governments.

One of the biggest changes in the 2014 Geothermal Law was that geothermal activities were no longer considered mining activities. As a corollary of this law, geothermal activities specifically are now allowed to be conducted in production, protected, and conservation forest areas, where a significant proportion (an estimated 42%) of Indonesia's geothermal resources are found. Previously, as mining activities, these working areas were restricted under the Forestry Law.

The 2014 Geothermal Law requires Geothermal Licence holders to provide a "production bonus" to the Regional Government covering the permit holder's working area. This will be a specified percentage of the gross revenue arising after the COD of the first unit. The amounts and procedures for bonus payments are regulated under GR No. 28/2016.

5.3.3 Working Area Tenders since GR No. 7/2017

The granting of a Geothermal Licence or IPB for a geothermal working area is carried out through a two-stage tender. During the first stage, the tender committee evaluates the qualifications of the business entity, based on its administrative criteria, financial strength, and performance. The second stage evaluates the "geothermal development proposal" and the exploration commitment of the business entity, the results of which are then used by the Minister to choose the tender winner and to grant the IPB. The IPB Licence Holder then has to conduct exploration well drilling to demonstrate the proven reserves. Exploration is followed by exploitation and production activities for a maximum period of 30 years.

For the working areas based on a PSPE, GR No. 7/2017 provides that a business entity which has carried out a PSPE and is interested in proceeding to detailed exploration and development can compete in a two-stage tender process to obtain an IPB for a geothermal working area. In such cases, the MoEMR will open a tender for the assigned business entity and a SOE (as a competitor in the tender) only. A business entity that has performed a PSPE and participated in the assigned working area tender shall be treated as the first-ranked participant (priority) in the tender, while any SOE shall be second-ranked.

In order to determine the winner, the tender committee will assess the geothermal development proposals submitted by the tender participants, which should include:

a) A review of the geothermal data and related information to estimate the feasibility of the Working Area for geothermal operations;
b) The exploration and exploitation implementation strategy, completion targets, and budget plan; and
c) The commitment regarding the COD.

The tender winner is determined by the MoEMR. Within four months of being declared the winner, the relevant business entity has to pay the base price for the working area data, as Non-Tax State Revenue, and put the exploration commitment in place.

The MoEMR reserves the right to conduct direct appointments, even for a private business entity. This is allowable in the event that there is only one participant even after the tender is repeated.

In 2018, the MoEMR issued MoEMR Regulation No. 37/2018 which provided more detail on the tendering process for geothermal working areas (including PSPE working areas), the direct selection process, the granting of the IPB, and the assignment of certain working areas to SOEs with geothermal activities or BLUs.

5.3.4 Omnibus Law and Implementing Regulations in the Geothermal Sector

Following the issuance of the Omnibus Law, several provisions in the 2014 Geothermal Law were amended. Some of the key changes include the authority of the Central Government to stipulate norms, standards, procedures, and criteria for the direct use of geothermal resources. In exercising their authorities, local governments must then follow such requirements including when issuing a Business Licence for the Direct Utilisation of geothermal resources (*Perizinan Berusaha terkait Pemanfaatan Langsung* - "PBPL"). Furthermore, the Omnibus Law also removes the requirement for PBPL holders to pay production fees for direct use of geothermal energy and are only required to pay local taxes and retributions. A separate licence from the Minister of Maritime Affairs and Fisheries for business activities related to the indirect utilisation of geothermal resources in water conservation areas that was previously regulated under the 2014 Geothermal Law was also removed in the Omnibus Law.

The implementing regulation, GR No. 25/2021, regulates the administrative sanctions and penalties on geothermal businesses that: (i) indirectly use geothermal energy without the required licence or in a way that contravenes their licence; (ii) fail to commence activities in their allocated work area within the stipulated timeframe; or (iii) fail to comply with the obligations set out in their licence or the laws and regulations.

IPB holders are prohibited to assign their licenses to a third party. It is also prohibited for IPB holders to transfer their share ownership on the Indonesia Stock Exchange without MoEMR approval prior to the exploration stage. Such violations are subject to a penalty of IDR 100 billion.

5.3.5 Challenges for Geothermal Development

Geothermal investment is characterised by long lead times for commercial operations and project financing, which is only available for the last few years of this process. This means that a typical geothermal project will require significant investor contributions in the form of upfront equity. To assist with this, the Government established the Geothermal Fund in the 2011 State Budget, which allocated IDR 3 trillion (equivalent to USD 250 million) by the end of 2013.

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 *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.[120] The MoF has also stipulated that PT SMI should leverage funds sourced from the private sector or international multilateral agencies.

120 Brahmantio Isdijoso (Directorate of Sovereign Risk Management, Directorate of Budget Financing and Risk Management, MoF), "Government Supports for Geothermal Energy Development", Presentation at Bali Clean Energy Forum, February 2016

In order to expedite the implementation and disbursement of the GSF, the Minister of Finance issued MoF Regulation No. 62/2017 on Fund Management and Infrastructure Financing for Geothermal. Based on the MoF Regulation, the Government, through PT SMI, provides funding for geothermal infrastructure. The funds may be used for:
a) Lending;
b) Equity participation; and/or
c) The supply of geothermal data and information (exploration drilling).

PT SMI will implement lending and equity participation under the corporate business framework of PT SMI. Meanwhile, PT SMI will provide geothermal data and information by acting as the Government's representative, on the basis of a special assignment from the Minister of Finance. For exploration activities, 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. Additionally, PT SMI will apply a revolving fund scheme, as well as conducting exploration drilling in the geothermal working area, by appointing a third party. If the working area has been auctioned, the auction winner shall reimburse any expenses such that the cost may be used to finance drilling in other areas.

The GSF was disbursed for the first time when six geothermal working areas were assigned to PLN in September 2017, three in East Nusa Tenggara and the rest in West Java, Central Sulawesi, and North Maluku.[121] In March 2018, PLN issued a plan to create a new subsidiary in the gas and geothermal sector, stating that the Government would support up to half of the funding using low-interest foreign loans through SMI.[122] PT SMI is also involved in the development of the 10 MW small-scale Dieng Geothermal Power Plant, alongside PT Geo Dipa Energi (Persero), which is predicted to reach COD by 2023. Notably, PT SMI also signed an Memorandum of Understanding ("MoU") with Medco Power in December 2018 regarding their cooperation on the development of Indonesian geothermal exploration, through the funding for the development of geothermal exploration for IPPs in Ijen, East Java. The funding mechanism has not yet been published, as no funding schemes are available yet for IPPs focusing on geothermal at the exploration stage, but the development of the 110 MW Ijen geothermal power-plant is planned in the short term. The 110 MW PLTB Ijen development plan calls for Units 1 and 2 to reach COD in 2024 and 2026, respectively. However, according to the outcomes of exploratory activities and feasibility studies conducted by PT Medco Cahaya Geothermal ("MCG"), the project's developer, Unit 1 would have a capacity of 31.4 MW (nett).

In May 2020, PT Geo Dipa Energi's proposal for geothermal development on Java Island was approved by the ADB, with an amount of up to USD 335 million, consisting of USD 300 million for dedicated geothermal powerplant funds and an additional 35 million allocated from the Clean Technology Fund ("CTF") scheme. This ADB funding will be utilised not only for powerplant development, but also for other social aspects. The primary purpose of the project is to develop and operate geothermal resources - commission an additional 110 MW of geothermal energy producing capacity - 55 MW at the Dieng geothermal field in Central Java and 55 MW at the Patuha geothermal field in West Java. Historically, the ADB is known for funding several Indonesia geothermal projects. Muara Laboh, Rantau Dedap, and Sarula were funded by the ADB to support Indonesia in reaching its energy and

121 Media Indonesia, http://mediaindonesia.com/read/detail/122220-pln-dapat-geothermal-fund-untuk-6-wkp, accessed 28 June 2018
122 Berita Satu, http://id.beritasatu.com/energy/pln-bakal-bentuk-anak-usaha-panas-bumi/173711 accessed 28 June 2018

economic development targets by maximising domestic energy resources while ensuring their environmental sustainability.[123]

Back in 2017, The Geothermal Energy Upstream Development Project ("GEUDP") proposal was approved by the World Bank with a value of USD 55.25 million. This funding scheme has been used to complete five evaluation activities at potential greenfield geothermal areas, consisting of Wae Sano (East Nusa Tenggara), Bonjol (West Sumatra), Jailolo (North Maluku), Bittuang (Gorontalo) and Nage (East Nusa Tenggara). The initial evaluation report was sent to the MoF, which assigned PT SMI to provide Geothermal Data and Information Provision in Wae Sano and Jailolo in 2018. In April 2019, the World Bank indicated that the ground mobilization for Wae Sano and the preparatory studies for Jailolo were expected in the second half of 2019.[124]

A notable ministerial decree No. SK-71/MBU/03/2021 regarding Geothermal Business Development Acceleration Team was released by the MoSOE in July 2021. The decree intended to form an Organizing Committee that will consist of PLN's, PGE's, and GDE's President Directors in order to ensure the establishment of an SOE geothermal holding. The holding is one of the Government's key action to accelerate the expansion of geothermal energy in Indonesia. Furthermore, the Government also claimed the SOE geothermal holding will be one of the largest geothermal companies globally in terms of installed capacity.[125]

Other challenges for investors in the geothermal space include:

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); and
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.

Under the Indonesian model of geothermal development, the developer shoulders 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. Certain countries use 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.

123 Bisnis, https://ekonomi.bisnis.com/read/20200528/9/1245885/adb-siapkan-pinjaman-us300-juta-untuk-proyek- panas-bumi-geo-dipa accessed 6 October 2020

124 World Bank, https://documents1.worldbank.org/curated/en/339201621577956541/pdf/Restructuring-Integrated-Safeguards-Data-Sheet-ID-Geothermal-Energy-Upstream-Development-P155047.pdf, accessed 17 December 2021

125 Kontan, https://industri.kontan.co.id/news/erick-thohir-percepat-pembentukan-holding-bumn-panas-bumi, accessed 29 July 2021

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 the following factors:

a) Geothermal projects have long lead times;
b) BPP values change on an annual basis; and
c) This regulation will lead investors to incur capital expenditure, without knowing whether PLN is committed to purchasing the electricity, or knowing the accompanying tariffs.

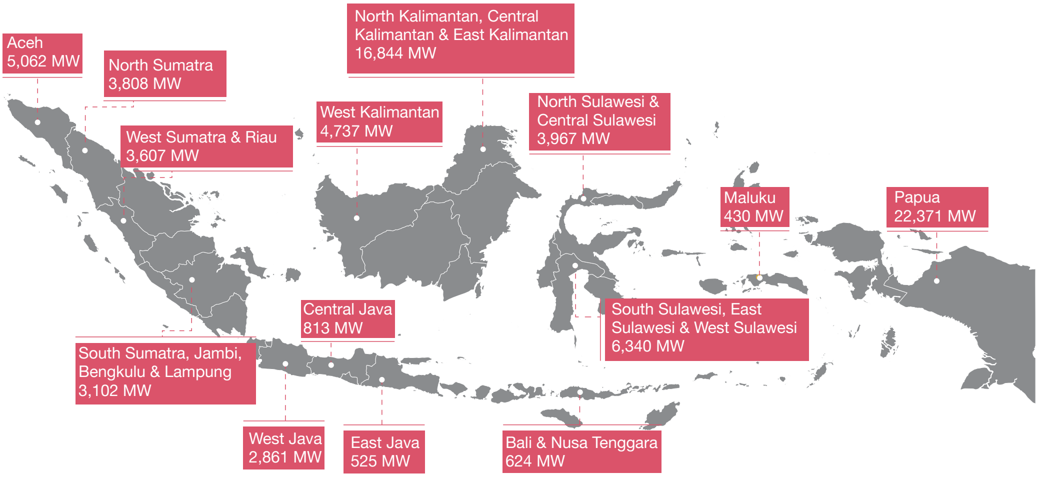
It is likely that investors will be able to negotiate Heads of Agreement ("HoA") with PLN, as a preliminary substitute for a PPA, prior to the exploration process. However, the HoA is not a binding contract, meaning that it may not effectively mitigate the risk profile for geothermal development, especially for greenfield projects.

5.4 Hydropower

Hydropower uses energy from falling or flowing water to turn a water turbine and generate electricity. This 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 robust and mature of the renewable technologies. By the end of 2022, Indonesia had installed 6.7 GW of hydroelectric capacity. However, according to a study done in the year 1983 it was calculated that there is a total potential of 75 GW of Hydroelectricity available in Indonesia (see Figure 5.4). The installation makes it the most utilised source of renewable energy.

Potential hydropower sites are spread across the country, with substantial potential for large-scale projects in the middle and eastern parts of Indonesia, such as Kalimantan and Papua.

Figure 5.7 – Hydropower potential capacity in selected regions of Indonesia



Source: RENSTRA EBTKE 2020-2024, p. 40

Based on the economic, social and environmental considerations, it is realistic to expect that only 8 GW of additional hydropower is likely to be built. The list of prioritised hydropower projects according to RUPTL 2021-2030 is given in Table 5.5, as follows:

Table 5.5 – List of strategic candidate of hydropower projects

No	Province	No. of Power Plants	Total Cap (MW)
1	Kalimantan Utara	9	7,465
2	Sulawesi Tengah	13	3,407
3	Aceh	30	3,154
4	Kalimantan Timur	4	1,442
5	Sulawesi Selatan	9	1,271
6	Sumatra Utara	31	1,178
7	Jawa Barat	6	1,018
8	Sulawesi Barat	6	867
9	Sumatra Barat	13	758
10	Jambi	8	709
11	Kalimantan Selatan	4	559
12	Kalimantan Tengah	2	356
13	Sulawesi Tenggara	3	279
14	Sulawesi Utara	8	248
15	Jawa Tengah	2	237
16	Jawa Timur	2	137
17	Sumatra Selatan	2	117
18	Bengkulu	5	106
19	Maluku	3	88
20	Papua	3	54
21	Lampung	2	54
22	Nusa Tenggara Timur	2	32
23	Nusa Tenggara Barat	1	18
	Grand Total	**168**	**23,554**

Source: RUPTL 2021-2030

Table 5.6 – MoEMR hydropower target

	2023	2024
Additional Capacity (MW)	397	1,951.40
Local Content for Micro Hydro (%)	70	70

Source: RENSTRA EBTKE 2020-2024, p. 121

5.4.1 Large-scale Hydropower

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 reached COD in 2018. In early 2019, the Bank of China evaluated its funding commitment to the PLTA Batang Toru project, due to environmental concerns, although the MoEMR still predicts that this hydropower plant will reach COD in 2022, following the developer's plans to monitor rare orangutan habitats, and to promote orangutan protection and rescue efforts. By the end of 2020, the total capacity of the installed hydropower plants exceeded 6.1 GW. This included the COD of PLTA Poso Peaker with 66 MW capacity in February 2020. PLTA Malea 90 MW which was planned to be COD in 2020 delayed to 2021 due to unforeseen physical conditions in the power plant site.[126] In June 2021, it was announced that PLTA Malea has received its operational permit and is ready to be operational.

The 35 GW programme also lists two PLN hydro projects at the construction stage, which are the 4 x 260 MW Upper Cisokan pumped-storage plant in West Java and the Asahan 3 (2 x 87 MW) project. On 2 May 2017, however, the World Bank cancelled funds worth USD 596 million for the Upper Cisokan pumped-storage plant, after the construction was delayed as a result of needing to agree with the contractor the terms for reconstructing the damaged access road.[127] PLN has stated that the funds required for this USD 800 million project will come from loans and internal funds, with the power plant scheduled to reach its COD by 2024 or 2025.[128] The feasibility stage design study for the Upper Cisokan pumped-storage plant was completed in June 2019, and the focus will then turn to assessing the social and environmental impact, along with planning the land acquisition and resettlement actions.

There are also two construction projects under PLN's regular programme, PLTA Masang 2 (55 MW) and PLTA Jatigede (2 x 55 MW). The investment value of the project reached USD 82.56 million, of which IDR 635 billion comes from APLN and the Export Credit ("ECA") of Sumitomo Mitsui Banking Corporation (China) Limited. Electricity from the plant will be exported through the Sunyaragi (Cirebon) and GI Rancaekek (Bandung) substations.

The Ministry of Public Works and People's Housing ("MoPW") has stated its intention to incentivise the private sector to make use of existing dams for hydropower. This initiative targets 18 dams operated by the MoPW, including those at Jatigede (West Java), Lodoyo (East Java), Berjaya (Riau), and Jatibarang (Central Java). Together with PLN, the MoPW would like to calculate the potential electricity generation from the 18 dams. In May 2017, the MoPW issued MoPW Regulation No. 9/PRT/M/2017 concerning the Procedures for the Cooperation of Business Entities in the Leasing of Dams for the Acceleration of Power Projects (including large- and small-scale hydropower ("SHP") as well as floating Solar PV). This requires hydropower and solar power business entities to follow prequalification and selection processes, should they need to lease infrastructure relating to water resources.

126 DGNREEC Performance Report 2020, p. 41
127 World Bank. World Bank Implementation Status & Results Report on Upper Cisokan PST Project (P112158), 2017
128 The Jakarta Post, http://www.thejakartapost.com/news/2018/06/13/cisokan-hydropower-plant-project-needs-800m-in-investment.html, accessed 1 August 2018

The specific challenges for large-scale hydropower include:
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; and
d. Permits for forest use.

5.4.2 Small-scale Hydropower

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 purchase tariffs (FiT) at a level where SHP plants become attractive renewable energy projects for investors.[129] 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 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 reached COD in June 2021.[130]

In May 2023, PT Terregra Asia Energy Tbk (TGRA) said that it will prepare funds of up to IDR 1 trillion to carry out the construction of 3 PLTMs this year. The three PLTMs to be built are the Sisira PLTM with a capacity of 9.8 MegaWatt (MW), the Batang Toru 3 PLTM with a capacity of 10 MW, and the Batang Toru 4 PLTM with a capacity of 10 MW.[131] However, industry associations are still reporting that financing difficulties have arisen, due to the "unbankability" of the PPAs and associated commercial issues, especially those caused by 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.[132] The MoEMR also noted that unqualified IPPs are facing a number of problems, such as the land to be used is still being under lease, the high values of non-performing loans, or malfunctioning equipment.

The prequalification stages for hydro projects, in accordance with MoEMR Regulation No. 50/2017 amended by MoEMR Regulation No. 53/2018, were held in April 2018, with PLN stating that interested parties must show that they have completed a feasibility study and interested foreign parties must partner with a local developer.[133]

129 DGNREEC, http://ebtke.esdm.go.id/post/2016/01/08/1077/175.permohonan.pembangunan.pltmh.dengan.investasi.rp1094.triliun, accessed 6 December 2017
130 Hutama Karya, https://www.hutamakarya.com/rampung-proyek-epc-hutama-karya-pltm-parmonangan-2-berkapasitas-2-x-5-mw-resmi-beroperasi, accessed 20 July 2021
131 Bisnis, https://market.bisnis.com/read/20230523/192/1658481/terregra-asia-tgra-siapkan-investasi-rp1-triliun-bangun-3-pltm, accessed 20 June 2023
132 Katadata, https://katadata.co.id/berita/2018/04/27/kementerian-esdm-lobi-ojk-fasilitasi-pendanaan-energi-terbarukan, accessed 1 August 2018
133 GBG Indonesia, http://www.gbgindonesia.com/en/main/legal_updates/indonesia_s_pln_invites_hydropower_developers_to_prequalify.php, accessed 2 July 2018

Further challenges to investment in SHPs include the following:

a) A limit on foreign investor equity ownership. As outlined in *Section 2.5.2 – The Positive List*, the most recent negative list detailed in PR No. 44/2016 sets limitations on foreign investments, with micro power plants (<1 MW) being closed to foreign investment and small power plants (1-10 MW) being 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 USD 2.0 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; and
h) Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, resulting in difficult access and logistics at some sites.

5.5 Bioenergy

Bioenergy refers to the energy produced from biomass (direct and cofiring) 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, in order 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 32.6 GW, with 1.88 GW of currently installed capacity (Table 5.7).[134] Most of this capacity is off-grid. To date, the capacity of bioenergy power plants connected to PLN's electricity grid is approximately 250 MW (see Table 5.8). The Government plans further growth in biogas and biomass plants, albeit driven by the private sector. This will help support the development of WtE plants.

134 RENSTRA EBTKE 2020-2024, p. 39

Table 5.7 – 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: RENSTRA EBTKE 2020-2024, p. 39

Table 5.8 – On-grid bioenergy plants - latest data

No.	Company	COD	Type of Contract	Location	Type of Bioenergy	Capacity (MW)
1	Tuing/Gunung Pelawan Lestari	2017	Excess Power	Bangka Belitung	Biogas	1.2
2	Mitra Puding Mas	2017	Excess Power	Bengkulu	Biogas	2.0
3	Agro Muko	2017	Excess Power	Bengkulu	Biogas	1.1
4	PT Bhumi Pandanaran Sejahtera	2020	N/A	Central Java	Biomass	0.8
5	PT Agrokarya Primalestari (Kuayan Mill)	2021	N/A	Central Kalimantan	Biomass	4.8
6	PT Bumitama Gunajaya Abadi (PKS Tonam Raya Mill)	2021	N/A	Central Kalimantan	Biomass	2.0
7	PT Ciptatani Kumai Sejahtera (Engine Room PKS)	2021	N/A	Central Kalimantan	Biomass	2.5
8	PT Sungai Rangi (Engine Room PKS)	2021	N/A	Central Kalimantan	Biomass	3.5
9	PT Tantahan Panduhup	2021	N/A	Central Kalimantan	Biomass	2.0
10	Excess Sampit (PT Unggul Lestari)	2012	Excess Power	Central Kalimantan	Biomass	1.0
11	PT Sumber Organik	2021	N/A	East Java	Biomass	12.0
12	Benowo 1	2015	Excess Power	East Java	Biomass	1.7
13	PT Prima Mitrajaya Mandiri	2020	N/A	East Kalimantan	Biogas	2.0
14	Mangkujenang	2015	Excess Power	East Kalimantan	Biomass	5.0
15	PT Mutiara Sumber Energi	2021	N/A	Jambi	Biogas	2.4
16	Tungkal/Lontar Papyrus	2017	Excess Power	Jambi	Biogas	10.0
17	Taman Raja	2017	Excess Power	Jambi	Biogas	2.2
18	Payo Selinca	2015	Excess Power	Jambi	Biomass	30.0
19	PT Green Energy Hamparan	2020	N/A	Lampung	Biogas	3.0
20	Excess (PT SMI)	2018	Excess Power	Lampung	Biomass	3.0
21	Excess Gunung Batin (PT Gunung Madu Plantations)	2017	Contract Extension as 12 July 2018	Lampung	Biomass	20.0

No.	Company	COD	Type of Contract	Location	Type of Bioenergy	Capacity (MW)
22	PT Merauke Narada Energi	2020	N/A	Merauke	Biomass	3.5
23	PT Karya Mandoge Energi	2021	N/A	North Sumatra	Biogas	2.0
24	PT Pertamina Power Indonesia	2020	N/A	North Sumatra	Biogas	2.4
25	PT PN II PKS HAPESONG	2018	Excess Power	North Sumatra	Biogas	0.6
26	PT United Kingdom Indonesia Plantation	2017	Excess Power	North Sumatra	Biogas	2.0
27	PT Hari Sawit Jaya Negeri Lama-2	2017	Excess Power	North Sumatra	Biogas	1.4
28	PT Saudara Sejati Luhur Gunung Melayu-1	2017	Excess Power	North Sumatra	Biogas	1.4
29	PT Siringo-ringo	2016	Excess Power	North Sumatra	Biogas	1.0
30	PT VAL	2015	Excess Power	North Sumatra	Biomass	6.0
31	PT Harkat Sejahtera	2015	Excess Power	North Sumatra	Biomass	30.0
32	PT Growth Sumatra-1	2013	Excess Power	North Sumatra	Biomass	15.0
33	PT Growth Sumatra-2	2013	Excess Power	North Sumatra	Biomass	15.0
34	PT Growth Asia-2	2012	Excess Power	North Sumatra	Biomass	15.0
35	PT Growth Asia-1	2011	Excess Power	North Sumatra	Biomass	15.0
36	PT Mitra Unggul Pusaka (Segati)	2018	Excess Power	Riau	Biogas	1.2
37	PT Teguh Karsa Wana Lestari	2018	Excess Power	Riau	Biogas	1.0
38	PT BANI	2017	Excess Power	Riau	Biogas	2.1
39	PT PHS	2017	Excess Power	Riau	Biogas	1.0
40	PT IMSB	2017	Excess Power	Riau	Biogas	2.1
41	PT SAR	2017	Excess Power	Riau	Biogas	2.1
42	PT Inti Indo Sawit (Ukul 1)	2017	Excess Power	Riau	Biogas	2.2
43	PT Inti Indo Sawit (Buatan 2)	2017	Excess Power	Riau	Biomass	1.3
44	PT ISK	2017	Excess Power	Riau	Biomass	10.0
45	PT Musim Mas	2016	Excess Power	Riau	Biogas	2.1
46	PT Nagata Bio Energi	2020	N/A	South Kalimantan	Biogas	2.0
47	PT AGROWIRATAMA	2015	Excess Power	West Sumatra	Biogas	1.2
					Total Capacity On-Grid	250.8

Source: DGREEC Performance Report 2019, 2020 & 2021

The Government has set some goals for increasing the on-stream capacity of bioenergy power plants and domestic biofuel utilisation from 2020 - 2024 as follows:

Table 5.9 – MoEMR bioenergy target

	2023	2024
Additional Capacity (MW)	159	252.6
Local Content (%)	40	40
Domestic Biofuel Utilisation (Million KL)	14.55	17.35
Investment (Billion USD)	0.19	0.33

Source: RENSTRA EBTKE 2020-2024, p. 121

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 has a target to reach COD before 2020 but actually 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 biogas power plant which was signed with PT Mitra Puding Mas in May 2017. A 2.2 MW biogas power plant also reached COD in January 2018, with 700 kW being used for self-consumption by PT Inti Indosawit Subur.[135] Another success story is a 700 kW bamboo-based biomass power plant that was inaugurated in September 2019 and is expected to replace the Diesel Power Plant (*Pembangkit Listrik Tenaga Diesel* - "PLTD") and thus light up approximately 1200 households in Mentawai, West Sumatra.[136] Later, the government also claimed success in securing four PPA contracts with total capacity of 10.6 MW of biomass and biogas power plants in 2018 and 2019.[137]

One success story for the year 2021 would be the completion of the PLTBg Pasir Mandoge. In April 2021, the PPA regarding this project was signed between PLN and PT Karya Mandoge Energi.[138] Overall, this particular biogas power plant would help provide electricity supply in Northern Sumatra. Finally, on July 23 2021, the project reached COD and the power plant has been in operation ever since.[139] For developments in 2023, in May 2023 PT Pasadena Biofuels Mandiri has been commercially operating the 3 MW PLTBg Ujung Batu located in Rokan Hulu Regency, Riau.

In addition to biomass and biogass powerplants, the Government also intends to increasing the proportion of co-firing in coal plants. With abundant sources of biomass (see Table 5.6), the Government and PLN claimed the biomass cofiring project 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 cofiring programme.[140] In January 2021, there were at least 32 cofiring power plants with six of them already in the commercial cofiring phase.[141] 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 cofiring programme and more biomass power plants to enter the COD phase, in 2025 the biomass demand is forecasted to increase from 2.7 Million Tonnes per Annum ("MTPA") to around 9 MTPA.[142]

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;

135 Kompas, https://ekonomi.kompas.com/read/2018/01/24/111024626/menteri-esdm-resmikan-pembangkit-listrik- tenaga-biogas-di-tungkal-ulu, accessed 19 July 2018
136 Detik, https://finance.detik.com/energi/d-4710551/warga-mentawai-kini-nikmati-listrik-biomassa-berbasis-bambu, accessed 29 July 2021
137 DGNREEC Performance Report 2020, p. 4
138 https://www.hariansib.com/detail/Berita-Terkini/Tingkatkan-EBT--PLN-UIW-Sumut-Tandatangani-MoU-PLTBg-Pasir-Mandoge-Asahan
139 https://industri.kontan.co.id/news/pltbg-pasir-mandoge-memperkuat-listrik-sumatra-utara
140 Paiton Cofiring Project & Challenge of Biomass Co-Firing in Indonesia Slide 2020, p. 5
141 Liputan6, https://www.liputan6.com/bisnis/read/4464397/hingga-januari-2021-pln-telah-uji-coba-co-firing-biomassa-di-32-plt, accessed 9 December 2021
142 FGB MEBI Slide 2021, pp. 3-6

e) The availability of regional EPC contractors with relevant skills and experience; and
f) The availability of spare parts and after-sales service.

5.5.1 Municipal Waste-to-Energy

Noting the increase in waste, limited waste treatment capacity, and the stresses on most landfill facility areas, "municipal waste-to-energy" 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 5.10.

Table 5.10 – Municipal waste-to-energy potential per province in Indonesia

Province	Municipal Waste Availability (Tonne/Year)	Total Techno-Eco Potential (MW)
DKI Jakarta*	2,737,500	130.0
North Sumatra	664,173	31.4
West Sumatra	143,509	7.1
Riau	122,640	7.7
Riau Islands	240,535	17.2
Jambi	39,858	1.6
Bengkulu	6,114	0.4
South Sumatra	187,976	12.2
Lampung	101,343	5.1
West Kalimantan	109,500	5.0
Central Kalimantan	44,713	1.8
South Kalimantan	73,000	3.5
East Kalimantan	192,082	8.8
Banten	206,681	13.1
West Java	3,508,138	227.6
Central Java	800,755	50.3
DI Yogyakarta	202,657	13.1
Bali	370,752	23.7
NTB	148,543	8.7
East Java	1,237,010	77.7
NTT	15,046	0.9
North Sulawesi	66,704	4.0
Gorontalo	16,973	1.0
South Sulawesi	182,500	11.9
West Papua	10,494	0.6
Total	**11,429,196**	**664.4**

** Based on PwC's Analysis*
Source: 2016 EBTKE Statistics

The Government has continued its efforts to develop municipal waste-to-energy in order to overcome city waste problems as well as to provide clean energy. The Strategic Plan of the MoEMR focuses on the construction of municipal waste-to-energy power plants funded by the Municipal budget or the Central Government.

With this in mind, on 16 April 2018 President Joko Widodo issued PR No. 35/2018 on The Acceleration of Municipal Waste-to-Energy Power Plant Development, revoking the previous PR No. 18/2016. The Government identified 12 cities to host pilot projects for thermal municipal waste-to-energy development: Jakarta, Bandung, Tangerang, Semarang, Surabaya, Solo, Makassar, South Tangerang, Bekasi, Denpasar, Palembang, and Manado. PR No. 35/2018 also regulates the FiT for municipal waste-to-energy power plants, in order to provide certainty on the revenues from the sales of electricity. Where a plant produces less than 20 MW, the project will receive USD 13.35 cent/kWh. Higher capacity waste power plants that are connected to a high or medium voltage grid will receive USD 14.54 cent/kWh, reduced by 0.076 and multiplied by the capacity of the power plant. If a subsidy from the Central Government is required, the subsidy will be capped at IDR 500,000 per tonne of waste. The level of subsidy for the tipping fee from the Central Government must be proposed by the Minister of Environment and Forestry to the Minister of Finance, in accordance with the relevant regulations. Under the new regulation issued by the Ministry of Environment and Forestry (MoEF Regulation No. 24/2019), the support in the form of tipping fee subsidy is upon application by regional government to MoEF. As the subsidy will operate under the Special Allocation Fund (*Dana Alokasi Khusus* – "DAK") mechanism, it can only be applied for the project that are already operating.

In its implementation, the President instructed the Regional Mayors/ Governors to assign regional-owned enterprises, or to appoint private business entities, in order to undertake the project development. This regulation also obliges PLN to sign PPAs for the aforementioned 12 municipal waste-to-energy projects. However, despite six out of 12 municipal waste-to-energy projects already having certainty regarding their project owners, the development of these projects has not progressed rapidly due to challenges including the harmonisation of PPA and PPP Agreement. Although there is an opinion that the FiT under the PR No. 35/2018 is too costly, PLN is obliged to buy the electricity from the WtE Project stated under the PR. The previously issued PR No. 18/2016 was challenged by a number of environmental activists in the Supreme Court in early 2017, leading to the revocation of the regulation. However, the Government continued to develop the municipal waste-to-energy plan, despite the court ruling. The Government believes this is the most effective way to solve the waste problem in large cities in Indonesia.[143] A similar problem can be seen in PR No. 35/2018, with non-governmental organisations highlighting the lack of clear standards relating to environmentally-friendly technology, high capital expenditure, O&M expenditure, and the potential impact on public health and the environment.[144]

143 The Jakarta Post, https://www.thejakartapost.com/news/2017/01/17/govt-sticks-with-incinerator-plan-despite-court-ruling.html, accessed 17 January 2017

144 WALHI, https://walhi.or.id/perpres-no-35-2018-tentang-pltsa-pemaksaan-teknologi-mahal-dan-tidak-berkelanjutan/, accessed 1 August 2018

Table 5.11 – Status of waste-to-energy projects

City	Status	COD Target
Jakarta ITF West Service Area	Feasibility Study	2025
Jakarta ITF East Service Area	Strategic Partner Selection	2025
Jakarta ITF South Service Area	Strategic Partner Selection	2025
Jakarta (ITF Sunter)	Pre-Construction Stage	2025
Tangerang	Negotiation Stage	2025*
South Tangerang	Final Business Case and Transaction Preparation	2026*
Bandung	PPP Procurement Process	2025*
Bekasi	MoU Stage between Local Government and Private Entity	Information not available
Semarang	Transaction Preparation Stage	2025*
Solo	Construction Stage	2023
Surabaya	Operating	2022
Makassar	Pre-Feasibility	2026*
Denpasar	Under Discussion	Information not available
Palembang	Contract Negotiation	2025*
Manado	Pre-Feasibility Study	2025*

** Based on PwC's Analysis*
Source: EBTKE on Pertamina Energi Forum November 2019 'GOVERNMENT REGULATION IN THE DEVELOPMENT OF NRE IN INDONESIA' p.19 & PwC's Analysis

Some of the constraints on and challenges to investment in municipal waste-to-energy include:

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 (PT 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 waste-to-energy plants, due to a lack of experience at the Regional Government level regarding waste-to-energy, 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; and
j) The security or enforceability of contracts signed with sub-national Governments.

However, some of these issues can be addressed by means of a well prepared feasibility study. The recent PR No. 35/2018 also set new tariffs for municipal waste-to-energy projects. Please see *Section 5.9 - New Tariff Stipulations for Renewable Energy* for an explanation of the new tariff stipulations and mechanism.

5.6 Solar PV

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 ("CSP"). In PV technology, the light energy portion of incoming solar radiation is converted to electricity by solar photovoltaic 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.

With average daily insolation of approximately 4.8kWh/m^2,[145] Indonesia is estimated to have around 208 GWp of potential for solar PV based electricity generation.[146] The level of insolation varies across the Indonesian archipelago (see Table 5.12), 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.

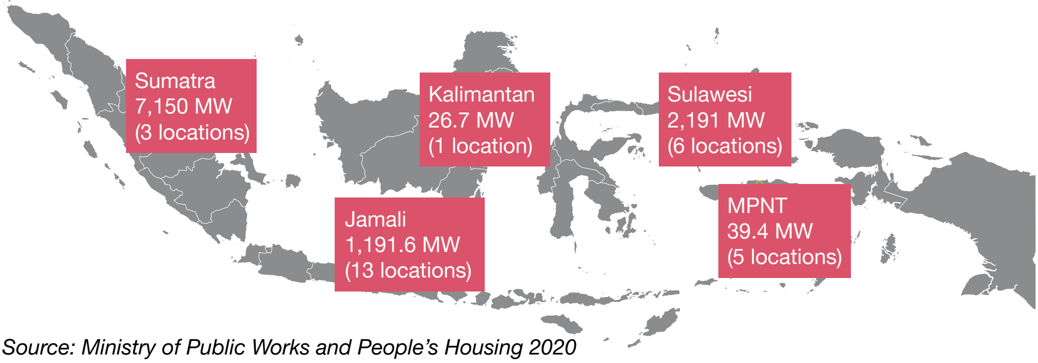
Table 5.12 – Solar energy potential in Indonesia

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
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, Sumba Timur	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

145 2014 EBTKE Statistics, p. 82
146 DGNREEC, "Policy on Development of New and Renewable Energy and Energy Conservation", MoEMR, May 2017

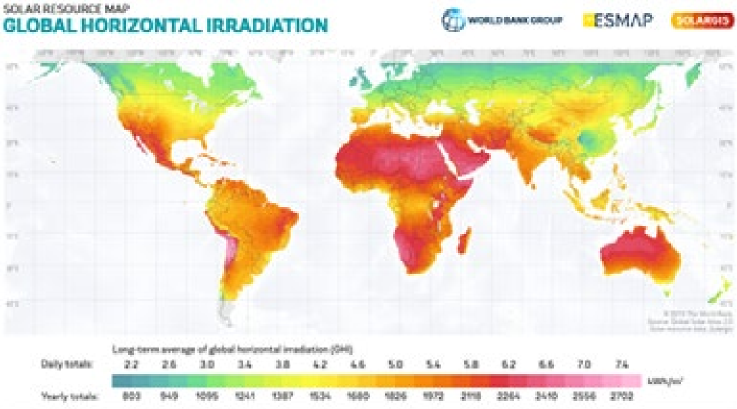
Figure 5.8 – Indonesia floating solar PV potential



Source: Ministry of Public Works and People's Housing 2020

A visual guide to the level of irradiation in Indonesia compared to the rest of the world can be seen in the Figure 5.9 as follows:

Figure 5.9 – Level of global horizontal irradiation map



Source: SolarGIS 2019, World Bank Group, Global Solar Atlas

By the end of 2022, installed solar power capacity reached 272 MW. PLN plans to develop centralized 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.[147] PLN will also begin to utilise the hydropower dams that it has built for PV installation, with the Sumatra region considered as having the most potential capacity areas for floating solar PV with more than 7 GW capacity (see Figure 5.8), while railway and toll roads are also being considered for PV installations. Indonesia had previously planned to increase its installed capacity to 260.3 MW by 2019, with the addition of more than 2 GW over five years, starting in 2020 until 2024, which is a relatively high target.

Table 5.13 – MoEMR solar energy target

	2023	2024
Additional Capacity (MW)	643.2	643.7
Local Content %)	40	40

Source: RENSTRA EBTKE 2020-2024, p. 121

147 2018 RUPTL, p. III-14

In April 2017, President Joko Widodo released PR No. 47/2017 on the Provision of Energy-Saving Solar Lamps for Communities Who Have Not Gained Access to Electricity, which includes guidance on planning, procurement, distribution, installation, and maintenance. PR No. 47/2017 is implemented through MoEMR Regulation No. 33/2017 (as amended by MoEMR Regulation No. 5/2018) on the Guidelines for Energy-Saving Solar Lamp Provisions for Unelectrified Communities. The intended beneficiaries are the communities which are not connected to grid or off-grid electricity supply infrastructure, and which are situated in border, lagging, or isolated areas, and/or outer islands. These programmes also represent a means of allocating funding from the reduction in the electricity subsidy to help ensure equality of energy access across Indonesia.[148]

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 net metering basis with banking charges of 35% and banking period of 3 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 & 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 5 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 26/2021 which became effective on 20 August 2021 has brought in multiple changes that have addressed the unfavourable posture on banking and introduced multiple new aspects that open up possibilities for new business models. Banking charges have been reduced to 0%, and the banking period has been extended from 3 months to 6 months. We feel that this change alone will result in a significant uptick in interest in solar rooftop from consumers, especially in the Commercial and Industry ("C&I") segment. However, as the rooftop solar capacity expands in the C&I segment, the revenue loss to PLN will become a point of concern, and could see reintroduction of a banking charge, albeit at a lower level than 35%. This should be considered in estimating the commercial & financial feasibility of plants. It is to be known that currently there is a proposed regulation in the pipeline which will completely remove banking of electricity using the PLN grid and restrict capacity addition based on cluster quotas determined by PLN.

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 5 days.

148 DGNREEC, http://ebtke.esdm.go.id/post/2017/09/14/1747/gerakan.nasional.sejuta.surya.atap.menuju.gigawatt.fotovoltaik.di.indonesia, accessed 7 August 2018

Keeping in line with the policy stance that rooftop solar plants are meant solely for captive consumption, plant sizing is still limited to contract demand and sale of surplus to other consumers is explicitly barred.

It was also reported that PLN and OJK were currently preparing a funding scheme to facilitate commercial buildings in installing PV rooftop through loans from the bank. As of May 2021, there are 3,781 of registered users that have participated in this movement.

With the development of the PLTS Cirata located in Cirata Dam, for which the kickoff and water breaking ceremony was successfully held at the end of 2020 (a great success, where in fact the project was nearly cancelled by PT PJB in 2019 due to direct selection issues). This also emphasizes the fact that the use of floating technology could potentially solve the issue regarding land use for large-scale utility solar PV. However, regulatory certainty is still needed on the use of a public dam for floating solar PV. Indonesia has more than 200 dams across the country which can be used for developing floating solar plants.

Looking back at it, in 2017, PLN signed two letters of intent ("LoI") to build solar farms in Bali at the end of 2017. There were some initial problems about how the LoI were going to be cancelled and how the projects were being re-rendered with the deadline of August 2019. In August 2020, PLN finally found IPPs that were interested in handling the construction of the two Solar Power Generators by means of auction.[149] As of May 2021, PT Medco Power Indonesia is still negotiating the PPAs with PLN for both solar farms respectively and it is hoped that both solar farms would achieve COD by 2023.[150]

Another success story regarding solar PV development would be the Mangkei Solar PV project. This particular project was completed by the collaboration of Pertamina NRE and PTPN III with 2 MWp capacity also scheduled for COD in 2021. As of July 2021, the Mangkei Solar PV project development reached 89% and finally reached COD on August 2021.[151]

The challenges to the development of solar power plants 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) Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, making access difficult and causing logistical challenges on some sites;
d) Stringent local content requirements (see *Section 2.2.3 – Local Content*); and
e) 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; and
f) Large landbank requirement (±1 Ha/MW).

149 Gapura Bali, https://www.gapurabali.com/news/2018/10/02/pln-build-solar-energy-units-east-and-west-bali/1538469038, accessed 9 December 2021
150 Bisnis.com, https://ekonomi.bisnis.com/read/20210525/44/1397948/medco-power-masih-negosiasi-ppa-plts-bali-barat-dan-timur, accessed 9 December 2021
151 Bisnis.com, https://ekonomi.bisnis.com/read/20211011/44/1452895/plts-sei-mangkei-siap-pasok-listrik-16-gw-per-tahun, accessed 9 December 2021

5.7 Wind Energy

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.

The summary data from the wind resource assessments and the research for 153 sites is presented below (see Table 5.14):

Table 5.14 – Wind site potential in Indonesia

Resource Potential	Wind Speed at 50 m, (m/s)	Wind Power Density, at 50 m, (W/m2)	Number of Sites	Provinces
Lowest	< 3.0	< 45	66	West Sumatra, Bengkulu, Jambi, Central Java, South Kalimantan, West Nusa Tenggara, East Nusa Tenggara, South-East Sulawesi, North Sulawesi and Maluku.
Low (Small-Scale)	3.0 – 4.0	< 75	34	Lampung, Yogyakarta, Bali, East Java, Central Java, West Nusa Tenggara, South Kalimantan, East Nusa Tenggara, South-East Sulawesi, Central Sulawesi, North Sumatra and West Sulawesi.
Medium (Medium-Scale)	4.1 – 5.0	75 – 150	34	Bengkulu, Banten, DKI, Central Java, East Java, East and West Nusa Tenggara, South-east, South and Central Sulawesi and Gorontalo.
High (Large-Scale)	> 5.0	> 150	19	Central Java, Jogyakarta, East and West Nusa Tenggara, South and North Sulawesi.

Source: RENSTRA EBTKE 2015 – 2019

The MoEMR studies indicate that the wind potential in Indonesia could be as high as 61 GW.[152] However, the ADB has wind potential figures for Indonesia that are no higher than 9.5 GW.[153] It should also be noted that the areas in Indonesia with the most wind (i.e. Eastern Indonesia) 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 km resolution wind map is now accessible to the public at indonesia.windprospecting.com.

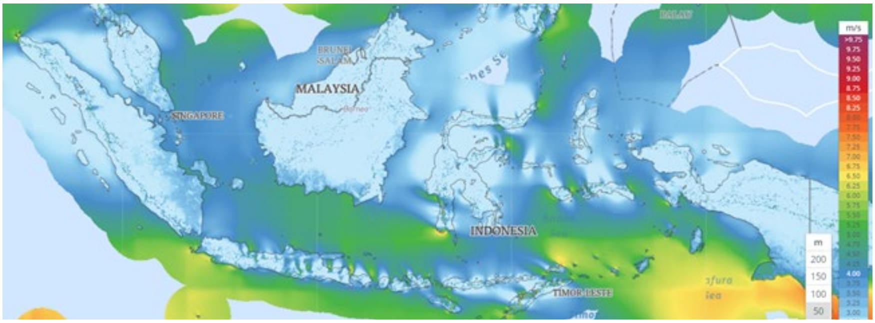
152 Rida Mulyana (Director General of DGNREEC), "Utilisation of Renewable Energy", presentation at the PetroGas Days UI, 16 March 2017

153 Asia Development Bank Paper No. 9, Summary of Indonesian Energy Sector Assessment December 2015. Soeripno Martosaputro and Nila Murti of WHyPGen also cites the MoEMR as assessing the total Indonesian wind capacity at 9.29GW in "Blowing the Wind Energy in Indonesia" presented at the Indonesia Renewable Energy & Energy Conservation Conference and Exhibition [Indonesia EBTKE CONEX 2013] online at Energy Procedia Volume 47, 2014, p. 273–282

Figure 5.10 – Indonesian wind power density at height of 50 metres

Source: Global wind atlas (https://globalwindatlas.info/), accessed 5 October 2020

Figure 5.11 – Indonesia wind speed in height of 50 meters



Source: Global wind atlas (https://globalwindatlas.info/), accessed 5 October 2020

The locations showing the greatest potential for commercial-scale wind energy in Indonesia are as follows:

Table 5.15 – 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 planned development of wind energy by the MoEMR is modest when it is compared to a number of private-sector developments. This is shown by the Government's plan for the on-stream capacity of wind power plants from 2020 to 2024, as follows:

Table 5.16 – MoEMR wind energy target

	2023	2024
Additional Capacity (MW)	279	440
Local Content (%)	40	40

Source: RENSTRA EBTKE 2020-2024, p. 121

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. An initial study by the Agency for Assessment and Application of Wind and Hybrid Power Generation (*Badan Pengkajian dan Penerapan Teknologi* - "BPPT-WHyPGen") in Java and Sulawesi indicated wind energy potential of around 970 MW, distributed across the following locations, including the Jeneponto projects that are currently being developed (see Table 5.17):

Table 5.17 – BPPT-WHyPGen wind energy assessment studies in Java and Sulawesi

No.	Location	Potential Energy
1	Lebak	100.0 MW
2	Sukabumi Selatan	100.0 MW
3	Garut Selatan	150.0 MW
4	Purworejo	67.5 MW
5	Bantul	50.0 MW
6	Gunung Kidul	15.0 MW
7	Sidrap	100.0 MW
8	Jeneponto	62.5 MW + 100.0 MW
9	Oelbubuk	10.0 MW
10	Kupang	50.0 MW (Indicative)
11	Palakahembi	5.0 MW (Indicative)
12	Selayar	10.0 MW
13	Takalar	100.0 MW (Indicative)
14	Bulukumba	50.0 MW (Indicative)

Source: BPPT-WHyPGen

Another wind farm is already being operated by Vena Energy in Jeneponto, South Sulawesi, which reached COD in May 2019. Later, the developer of the PLTB Jeneponto claimed that they intend to develop second phase of the PLTB Jeneponto following the success of their first phase.[154] A consortium of PACE Energy and PT Juvisk Tri Swarna signed an LoI with PLN in December 2017 to develop a 70 MW wind farm in Tanah Laut, South Kalimantan.

154 MoEMR, http://ebtke.esdm.go.id/post/2019/09/09/2330/pltb.tolo.sukses.beroperasi.komersial.tahap.ii.siap.dikembangkan, accessed 28 October 2020

However, this LoI was cancelled and the project was re-tendered, with the project being granted back to the same consortium. Based on the 2019 RUPTL, PLTB Tanah Laut is expected to reach COD in 2021 - however Adaro Power, the project developer of PLTB Tanah Laut has announced that the construction will begin in 2023. At the end 2022, the installed capacity of wind energy was around 154.3 MW of the total 83.8 GW of installed electrical capacity.[155]

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; and
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.

5.8 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.[156]

As an archipelagic state consisting of islands and straits, the potential ocean energy in Indonesia is thought to be 17.9 GW.[157] 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.[158]

155 HEESI 2023, p. 89
156 DGNREEC, http://ebtke.esdm.go.id/post/2016/04/14/1188/potensi.energi.laut.indonesia.menjanjikan, accessed 11 June 2018
157 Rida Mulyana (Director General of DGNREEC), "Utilisation of Renewable Energy", presentation at the PetroGas Days UI, 16 March 2017
158 Agence Française de Développement. Tidal Energy Project in Indonesia., January 2017

In 2015, the MoEMR indicated that Indonesia would encourage the use of the energy potential of the sea as part of the Government's marine development policy.[159] The MoEMR's plan is that 1 MW of ocean energy pilot plants should be ready by 2019,[160] although the 2019 RUPTL notes that the earliest ocean power plant will reach COD in 2021, also pointing out the lack of ocean energy converters with proven reliability to be able to operate commercially for five years.

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. An 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, and is currently valued at USD 380 million. The first stage will see the construction of a 12 MW array by 2021 followed by another 70 MW in the second phase and 150 MW in the final phase. 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.

It was also reported that the Indonesian and Dutch Governments will work together to develop tidal energy in the Larantuka strait, involving an 810-meter Pancasila-Palmerah bridge in East Nusa Tenggara, with sea current turbines being installed under the bridge.[161] An 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.[162] The project was awarded to Tidal Bridge Indonesia – a joint venture between BAM International BV, a Dutch construction engineering company, and PT PJB.

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.[163]

Ocean energy is not only a renewable, but also a source of new energy for Indonesia, and therefore well-maintained cross-sectoral coordination between stakeholders is important for future development. 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; and
c) The need to better understand the economics of ocean energy electricity generation.

159 The Jakarta Post, "Govt looks to ocean wave power plants", 3 June 2015
160 RENSTRA KESDM 2015-2019, p. 137
161 DGNREEC, http://ebtke.esdm.go.id/post/2018/04/02/1924/menteri.esdm.tinjau.lokasi.pembangunan. pembangkit. listrik.arus.laut.di.selat.larantuka, accessed 11 June 2018
162 Rambu Energy,https://www.rambuenergy.com/2018/04/indonesia-to-build-world-first-tidal-bridge-in- larantuka-east-flores/, accessed 29 June 2018
163 Hydro World, https://www.hydroworld.com/articles/2018/01/indonesia-continues-marine-and-hydrokinetic-energy-development-with-10-mw-park-in-bali.html, accessed 22 June 2018

5.9 New Tariff Stipulations for Renewable Energy

The long-awaited Presidential Regulation No. 112 of 2022 on the Acceleration of Renewable Energy Development for Electricity Generation ("PR 112/2022") has finally been released by the government following a protracted discussion process and numerous changes to the proposed drafts that were being circulated in the market.

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; and
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 the PLN's BPP. A 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. The implementation of a single ceiling-price mechanism, which is distinct from the tariff often applied to large-scale existing renewable PPAs, might have a substantial impact on PLN's present procurement procedure and PPAs tariff determination.

Under PR 112/2022, procurement of renewable projects for all capacities are generally conducted through a direct selection, except for:
- hydro power plants that utilise hydropower from reservoirs/dams or irrigation channels (whose construction is multipurpose of state-owned goods by the ministry that carries out government affairs in the field of water resources)
- geothermal power plants
- expansion projects for geothermal, hydro, photovoltaic solar, wind, biomass, or biogas power plants
- excess power from geothermal, hydro, biomass, or biogas power plants, where the procurement may be conducted through 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 system, 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 geothermal power plants, 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 1 through 10), 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. Below are the electricity purchase prices for all power generation types:

Table 5.18 – Purchase price of electricity from hydropower that utilises power from water streams/falls

No.	Capacity	Ceiling price (cent USD/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.*

Table 5.19 – The purchase price of electricity from hydro power plants utilising hydropower from reservoirs/dams or irrigation channels owned by the ministry that manages water resources affairs

No.	Capacity	Ceiling price (cent USD/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.*

Table 5.20 – 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.*

Table 5.21 – Purchase price of electricity from PLTB (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 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.*

Table 5.22 – Purchase price of electricity from PLTBm

No.	Capacity	Ceiling price (cent USD/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.*

Table 5.23 – Purchase price of electricity from PLTBg

No.	Capacity	Ceiling price (cent USD/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.*

Table 5.24 – 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 Grant

No.	Capacity	Ceiling price (cent USD/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.*

Table 5.25 – The purchase price of electricity from photovoltaic 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 (cent USD/kWh)
1	PLTA	3.76
2	Photovoltaic 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.*

5.10 The Application of Smart Grid Technology

The application of smart grid and metering that utilises the latest technology are among efforts of the MoEMR in to meet changing trends in the future development of electrical energy. In addition to the application of smart grids, policy and regulatory reforms to increase the mix of renewable energy power plants are also made by developing additional power plants sourced from renewable energy that can be carried out beyond the details of the RUPTL 2019-2028 and 2021-2030.

Later, based on the Minister of Energy and Mineral Resources Decree No. 188.K/HK.02/MEM.L/2021 concerning the ratification of the RUPTL 2021-2030 of PLN, Chapter 2.4.5 explaining the purpose of implementing the Smart Grid is aiming to answer the challenges of the electricity system in Indonesia, in this case PLN; these challenges are operating efficiency, increasing service reliability, implementing clean energy, and also sustainability.

The mandate for developing a Smart Grid in Indonesia is consistent with Presidential Decree No. 18 of 2020 concerning RPJMN 2020-2024. In RUKN 2019-2038, the policy direction for Smart Grid development should start to be implemented in several areas in Java and Bali in 2020 and gradually implemented on systems outside of Java and Bali to increase the proportion of renewable energy.

The benefits of smart grid development by the Government are as follows:
- The distribution of electricity is more efficient;
- Faster recovery from interruptions;
- Reduced operating and management costs for the utility and ultimately lower electricity rates;
- Better control over peak loads which can help in lowering electricity rates;
- Increased large-scale integration of renewable energy;
- Increased integration of consumer-owned generators including renewable energy into the electric power system; and
- Improved safety of the electric power system.

Table 5.26 – PLN Smart Grid Road Map

Goals	2021-2025	≥ 2026
	Reliability, efficiency, customer experience and grid productivity	**Resilience, customer engagement, sustainability and self healing**
Main Initiative	**Power plant digitization** in order to increase efficiency	**Upgrading SCADA into Wide Area Monitoring System (WAMPAC)** in order to uplift the system resiliency
	Distribution substations and transmission automation selectively in order to improve power quality	**Interconnecting distributed energy resources** (i.e. Rooftop PV, micro gas turbine, etc.)
	Implement distribution grid management to increase reliability, efficiency and faster response	**Integrating energy storage** for VRE integration and system stability
	Developing EV infrastructure and e-mobility for electric vehicle	**Implementing dynamic line rating** in order to upgrade the resiliency and self-healing ability
	Implementing smart micro grid to decrease BPP in remote areas	**Demand response mechanism** which involves large consumers for system efficiency
	Implementing AMI gradually	

Source: PLN slide on the Development of Smart Grid System in Indonesia 2020

Currently, the location for Smart Micro Grid Development outside Java Island are as follow:
- Selayar
- Tahuna
- Medang
- Semau
- Bali Eco Smart Grid – Lora
- Smart Micro Grid – Sumba Green Island[164]

According to PLN, at the end of 2019, there are at least nine pilot projects of smart grid which focus on energy management, power reliability through automation, and the integration of renewable energy.[165]

164 MoEMR, MoEMR Material for PLN International Conference ICT-PEP 2020 on 23 September 2020
165 PLN, PLN Smart Grid Presentation, 2020


Photo source: PT Vale Indonesia Tbk


Photo source: PT Vale Indonesia Tbk

6 Taxation Considerations

6.1 Overview

The chapter provides a general overview of the tax issues relevant to private investors in power generation projects in Indonesia (with the tax issues specific to renewable energy projects being set out in *Section 6.4 – Taxation Issues for Renewable Power Generation)*. These comments focus on the tax regimes which are relevant to equity investors, but also touch upon the taxes which are likely to be encountered by asset constructors, capital equipment suppliers, employees, and financiers.

The taxes relevant to power generation projects in Indonesia fall into the following general categories:
a) Income Tax due on in-country profits;
b) Income Tax withholding ("WHT") obligations generally due on service, royalty, and interest payments;
c) Income Tax due on capital gains, such as those arising from asset sales and following any project divestment;
d) VAT due on the import of, and in-country supply of, most goods and services;
e) Various employment-related taxes, including WHT, on employee cash and non-cash remuneration; and
f) Other taxes including:
   1. Import taxes;
   2. Various regional taxes; and
   3. Taxes due on the ownership of land and buildings.

On 2 November 2020, the Government issued Law No. 11 Year 2020 regarding Job Creation (the "Omnibus Law") which also extends to various taxation matters in Indonesia. The Tax Laws impacted are as follow:
a) The General Tax Provisions and Procedures Law;
b) The Income Tax Law; and
c) The Value Added Tax Law.

Some of the important changes to these laws include the relaxation of sanctions on Taxpayers, exempting certain types of income from tax (including some dividends and offshore income), the introduction of a limited territorial taxation concept for expatriates, the inclusion of coal as a VAT-able product (previously exempted) and several changes to the VAT rules making them more favourable to Taxpayers.

As implementing regulations for the Omnibus Law, the Government issued Government Regulation No. 9 Year 2021 ("GR-9"), which is effective from 2 February 2021, and MoF Regulation No. 18/PMK.03/2021 ("PMK-18") which is effective from 17 February 2021.

On 29 October 2021, the Government issued the new Harmonisation of Tax Regulations Law (the "HPP Law") which includes further tax changes. Some of the most important changes include the introduction of a carbon tax, and an increase in the VAT rate to 11% from 1 April 2022. The new Law also cancels the reduction in the rate of Corporate Income Tax ("CIT") to 20% starting in 2022 (i.e. the rate remains at 22%).

In December 2022, the Government issued several implementing regulations for the HPP Law, as follow:
a) Government Regulation No. 44 Year 2022 dated 2 December 2022 ("GR-44") as the implementing regulation for VAT under the HPP Law. For further details on GR-44 please refer to our December 2022 Tax Flash No. 22.

b) Government Regulation No. 50 Year 2022 dated 12 December 2022 ("GR-50") as the implementing regulation for the General Tax Provisions under the HPP Law. For further details on GR-50 please refer to our December 2022 Tax Flash No. 23.
c) Government Regulation No. 49 Year 2022 dated 12 December 2022 ("GR-49") regarding the exemption and non-collection of VAT and Sales Tax. For further details on GR-49 please refer to our December 2022 Tax Flash No. 24.
d) Government Regulation No. 55 Year 2022 dated 20 December 2022 ("GR-55") as the implementing regulation for Income Tax under the HPP Law. For further details on GR-55 please refer to our December 2022 Tax Flash No. 26.

6.2 Taxes

6.2.1 Income Tax

Indonesian Income Tax is currently levied pursuant to Income Tax Law No. 36/2008 (the "2008 Income Tax Law"). Unlike the regime for the oil and gas and mining sectors, this Income Tax regime is largely the same as that which applies to general business activities. That is, there are very few Income Tax rules which are specific to the power sector, and in particular there are no provisions allowing for tax stability over the life of a power sector investment. As discussed below, this could mean that the tax regime is deficient in a number of key areas, at least from the perspective of an investor in a private power project.

Indonesia's general Income Tax arrangements are broadly conventional from an international perspective, and the tax rates offered are quite competitive even on a regional basis.

The principal features of the Indonesian regime include:
a) CIT due at a flat rate of 22% of taxable profits (see below). This rate moves with the prevailing tax rules (i.e. there is no guarantee of rate stability). IDX-listed entities which satisfy a minimum listing requirement of 40% as well as other conditions may be eligible for a further 3% reduction in this rate, to 19%;
b) A general entitlement to deduct/ depreciate most of the spending connected to income generation;
c) Uncertain restrictions relating to the entitlement to deduct financing costs (see the comments below);
d) An increasing focus on Transfer Pricing ("TP") compliance and thus the potential for TP-related adjustments;
e) An entitlement to five years of tax losses carried forward; and
f) A documentation-intensive tax administration environment, with automatic tax audits before the payment of any tax refunds.

On 31 March 2020, the Government issued Law No. 2 Year 2020 on the establishment of Government Regulation in lieu of Law No. 1 Year 2020 concerning the Financial State Policy and Financial System Stability for Handling the COVID-19 Pandemic ("Law-2"). Law-2 stipulates that the CIT rate will be gradually reduced from 25% to 22% for the fiscal year 2020–2021, and to 20% starting from fiscal year 2022. As explained in the Overview section above, the application of the 20% CIT rate was cancelled by the new HPP Law.

Law-2 further stipulates the CIT rate for Limited Liability Companies with at least 40% of their paid-in shares listed on the Indonesian Stock Exchange and meeting certain liquidity requirements would be reduced by a further 3% (i.e. the CIT rate will become 19%).

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 the *Interpretasi Standar Akuntansi Keuangan* ("ISAK") 16 accounting rules). The regime is single-entity focused, with no ability to calculate tax on a consolidated or group basis or to transfer tax losses between entities.

For more detailed information on Indonesia's general tax rules, please refer to our "Indonesia Pocket Tax Book" publication.

Accounting Rules

As outlined in Chapter 7, the accounting rules relevant to many long-term power projects have, from 1 January 2012, resulted in the respective parties (generally PLN and the IPPs) having to record their arrangements as being either in the nature of a "lease" or (more likely) as a "service concession". This accounting treatment could have a significant impact on the books of an IPP if, for example, under a service concession arrangement, the power asset is reclassified as a financial asset.

No formal guidance on the tax impact of these accounting changes has been issued 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 16 for tax). Developments in this regard should continue to be monitored.

Deductibility Issues

Although there is a general entitlement to deduct all expenditure associated with the generation of income there are a number of categories of specifically non-deductible expenses. These include:

a) *Non-arm's length payments made to related parties*: the general tax rules entitle the tax authorities to adjust the pricing agreed between parties under a "special relationship" where that pricing is not considered arm's length. A special relationship is deemed to exist at a relatively low threshold of 25% common equity ownership. The tax authorities have recently enhanced the documentation requirements to support such pricing, reflecting Indonesia's increasingly aggressive monitoring of TP matters;

b) *Limitations on tax losses carried forward*: the carrying forward of tax losses is generally limited to five years from the year in which a loss was incurred. This expiration period can be an issue in the context of a project with a large upfront capital commitment due to the early generation of significant depreciation/amortisation charges;

c) *Pre-establishment expenses*: although these are not specifically denied, the general tax rules do not easily accommodate any costs incurred prior to the establishment of the taxpayer;

d) *Depreciation/amortisation rules*: Indonesia's Income Tax law effectively requires the capitalisation of all expenditure with an economic life longer than 12 months. The law then allows depreciation, to the extent that the spending relates to tangible assets, and amortisation, to the extent that the spending relates to intangible assets. 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.

   The tax law breaks down depreciation/amortisation on (non-building) tangible and non-tangible assets into four categories and two depreciation methods (the straight-line and the double-declining rates), as follows:

	Effective Life Max. Years	Straight Line Rate (%) p.a.	Declining Balance Rate (years) (%) p.a.
i)	4	25.00	50.00
ii)	8	12.50	25.00
iii)	16	6.25	12.50
iv)	20	5.00	10.00

Under the HPP Law and GR-55, for permanent buildings and intangible assets with a useful life of more than 20 years, the tax depreciation or amortisation may now, at the taxpayer's option, follow either a 20-year useful life or the actual useful life according to the taxpayer's bookkeeping.

Power generation equipment is generally treated as having a useful life of 16 years, and thus attracts a straight-line rate of 6.25% or a declining balance rate of 12.5%. Depreciation generally commences from the date of expenditure. However, where an asset is "constructed" depreciation commences at the time of completion. With the Directorate General of Tax ("DGT") approval commencement can be delayed until operations begin;

e) *Land and buildings*: although "tangible assets" with a useful life of more than one year can be depreciated at the above rates, "buildings" are treated as separate tangible assets and attract a straight-line rate of 5% (except potentially if the useful life is more than 20 years – in which case see above), with no option to use the declining balance rate. Land cannot be depreciated, and this does not usually include buildings. Assets which are attached to the ground and which cannot be moved without being dismantled are generally treated as buildings. Uncertainty can exist regarding the classification of tangible assets connected to land, such as roads, fences, wharves, reservoirs, and pipelines;

f) *(Thin capitalisation) debt: equity requirements*: on 9 September 2015, the Minister of Finance issued Regulation No. 169/2015 ("MoF-169") which introduced a general Debt to Equity Ratio ("DER") limitation of 4:1 for Income Tax purposes. MoF 169 first applied from 1 January 2016. Where debt exceeds equity by a factor of 4 (determined on a monthly basis) the interest attaching to the "excessive debt" is non-deductible. MoF-169 provides an exemption from the DER rules for certain industries, including for those involved in "infrastructure", albeit without an "infrastructure" definition. The formal implementing regulations on the DER were issued in late 2017, but did not clarify which industries were considered as "infrastructure".

The tax authorities nevertheless seem to be of the view that "infrastructure" should follow the definition set out in PR No. 38/2015 pertaining to public-private partnerships. This definition extends to the activities of IPPs. Furthermore, in 2018, the revised "tax holiday" rules (see Section 6.4.4 below) included "economic infrastructure" as an industry that would be eligible for the incentive. A related regulation, issued by the Head of the Investment Coordinating Board, indicated that power infrastructure should be covered by this definition (although this is arguably now limited to renewables - see Section 6.4.5 below).

The HPP Law and GR-55 expand the range of methods which can be used to limit the deductibility of interest, including with reference to a percentage of Earnings Before Interest, Taxes, Depreciation and Amortisation ("EBITDA"). The details of these changes are yet to be provided, but could substantially impact project economics (either positively or negatively). Developments around interest deductibility in particular need to be monitored, although the move away from the current "one-size-fits-all" 4:1 ratio would be generally welcome. It will also be interesting to see how the interest deductibility rules apply to "infrastructure".

g) *Payments of non-cash employment benefits*: see the detailed comments in *Section 6.2.5 – Personal Taxes* below.

Under the HPP Law and GR-55 non-cash employment benefits are deductible to the provider effective from 1 January 2022.

6.2.2 Withholding Tax ("WHT")

In an Indonesian context WHT is an obligation to withhold Income Tax at a set percentage of a relevant payment, and to remit the amount withheld to the Tax Authorities.

Some WHT is "non-final" in that the WHT is creditable against the withheld party's annual Income Tax obligation in Indonesia. Non-final WHT will typically apply to payments made to Indonesian resident service providers, typically at a rate of 2% of the relevant payment. In such cases the service provider will be required to submit an annual Indonesian Income Tax return, to credit the WHT against the annual tax liability, and then be entitled to a refund of any excess.

The types of payments subject to creditable/non final WHT include:

a) Payments to residents for the rental of moveable property (a rate of 2%);

b) Payments to residents for consulting, management, or technical services (a rate of 2%);

c) Payments to residents in the nature of royalties (a rate of 15%); and

d) Payments to IUP holding companies for coal purchases (a rate of 1.5%).

From 1 January 2016, PLN began imposing 1.5% "withholding" of (Article 22) Income Tax on payments made to IPP companies (given PLN's status as a SOE). The 1.5% tax is creditable to the IPP company however, so represents a cash flow concern only.

Certain other WHT is also collected on a "final tax" basis. This WHT is still calculated as a percentage of the gross payment, but no additional Income Tax is due from the recipient on such income. There is also no refund entitlement (irrespective of the actual profit derived from the payment).

EPC-related services are subject to this "final tax" regime via a WHT mechanism handled by the relevant IPP. Depending on the structure and on the EPC provider's construction qualifications, the WHT rates vary between 1.75% and 6%.

Other types of payments that are subject to non-creditable/final WHT include:

a) Payments to residents for the rent of certain non-moveable property (at a rate of 10%);

b) Payments to non-residents for most services, as well as interest and royalty payments (at a rate of 20% before any treaty relief). Under the Omnibus Law, the applicable WHT rate for interest paid to non-residents can be lowered by a Government Regulation. 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; and

c) Dividends paid to non-resident investors (at a rate of 20% before any treaty relief).

6.2.3 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 are generally simply treated as income.

An exception is made for sales of assets made by non-residents. In this case, Income Tax 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.

6.2.4 Value-Added Tax ("VAT")

Indonesia imposes broad-based VAT, as currently set out in VAT Law No. 42/2009 (the 2009 VAT Law). The general VAT rate is 10%, although supplies constituting exports of goods or exports of some services attract a 0% VAT rate.

Under the HPP Law, the VAT rate increased from 10% to 11% from 1 April 2022 and will increase to 12% by 1 January 2025.

Indonesia's VAT system is quite conventional as VAT needs to be charged (as output VAT) on the value of most supplies of goods made 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 therefore not generally included in the calculation of Income Tax.

The supply of electricity is technically VAT-able but, because electricity represents a "strategic good", the supply of electricity is effectively VAT-exempt. This is discussed further below in the context of VAT exemptions for strategic goods.

Although under the HPP Law electricity is not included in the statutory list of strategic goods, GR-49 confirms the status of electricity as a VAT-exempt strategic good (except for supplies to households above 6,600 watts).

6.2.5 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. Historically non-cash remuneration or benefits-in-kind ("BIKs") has typically been treated as non-taxable at the hands of the employee, with the cost of the benefit being non-deductible for the employer.

Under the HPP Law and GR-55, the provision of all BIKs is now 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; or

e) Certain other BIKs to be specified under a Minister of Finance Regulation.

Residents are taxed on their worldwide remuneration (including investment income). Non-residents are taxed on their Indonesian-sourced remuneration only.

Foreign nationals (and their dependents) will generally be deemed to be tax residents if they stay in Indonesia for more than 183 days in any year, or if they arrive in Indonesia with the intention to stay for more than 183 days.

PMK-18 elaborates on the definitions of "residing in Indonesia" and "intention to stay in Indonesia" as follow:

a) The definition of "residing in Indonesia" is based on whether the individual:

   1. Lives in a place in Indonesia that is at their disposal or can be accessed at all times, either owned, rented, or available to be used by the individual, and not merely a place of transit;
   2. Has their centre of vital interests in Indonesia; or
   3. Has their habitual abode in Indonesia.

b) An "intention to stay in Indonesia" can be substantiated by documents such as:

   1. A Permanent stay permit (*Kartu Izin Tinggal Tetap* - "KITAP");
   2. A Limited stay visa (*Visa Tinggal Terbatas* - "VITAS");
   3. A Limited stay permit (*Izin Tinggal Terbatas* - "ITAS");
   4. An employment agreement with a period of more than 183 days; or
   5. Other supporting documents (such as a rental agreement of more than 183 days, or documents evidencing the mobilisation of family members to live in Indonesia).

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%

6.2.6 Import Taxes

General

The physical importation of most capital equipment will be subject to the following taxes:

a) Import Duty: this is due at the "harmonised" duty rate which will vary according to the types of goods in question;
b) VAT: this is due at 10% 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.

Pursuant to the Import Duty regulations the Import Duty rates applying to typical 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%

Customs Exemptions – Import Duty

A separate Import Duty concession (currently regulated under MoF Regulation No. 66/2015) may provide an Import Duty exemption on the import of capital goods (being machines, equipment and tools but not spare parts) where these are imported by:

a) PLN;
b) An IUPTL holder in a designated business area;
c) IPPs holding a PPA (or designated Finance Lease Agreement) with PLN; or
d) IPPs holding a PPA with another IUPTL holder in a designated business area.

This exemption should be outlined in the relevant agreement. Historically this concession was sought from the Customs Office but it is now sought from BKPM.

Master List Exemptions – Import Duty

A concession (known as a "master list") is generally available for all BKPM-licensed investments and provides an exemption from Import Duty which is otherwise applicable to imports of "machines, goods, and materials" used for the establishment or development of a facility which is used to produce goods (including electricity) or to provide a limited number of services. The master list is currently regulated under MoF Regulation No. 76/2012 (as amended by MoF Regulation No. 188/2015).

Free Trade Area ("FTA") Agreements – Import Duty

A further Import Duty concession (as an exemption or reduced Import Duty rate) may be available via Indonesia's various FTA Agreements.

Indonesia's FTAs currently include the ASEAN, Australia, New Zealand, Japan, Korea, Pakistan, Chile, India, China, Hong Kong, and Mozambique agreements.


Photo source: PT Gorontalo Listrik Perdana

VAT Exemptions – Strategic Goods

Capital goods (including plant, machines and equipment, but not spare parts) are considered “strategic goods”. Under GR-49, a VAT exemption is available for the importation and local delivery of strategic goods, where these goods are used to produce VAT-able goods.

As indicated above, pursuant to GR-49, the supply of electricity is VAT-able, but is exempt from VAT as a “strategic good” (except for supplies to households above 6,600 watts). Therefore, even though power producers (including PLN) are generally VAT-exempt, a VAT registration requirement exists, and this generally allows access to the VAT exemption for imported capital goods. Furthermore, from 1 January 2016, VAT registration was made mandatory for IPPs, even though electricity supplies remained VAT-exempt.

As a result, IPPs are required to issue VAT invoices on their electricity deliveries, with the VAT invoices being stamped in order to show that the relevant delivery is exempt from VAT.

To obtain a VAT exemption on imports, the IPP needs to submit an application, along with the relevant import/purchase documents, to the DGT.

Article 22 Exemptions - Imports

The tax authorities may allow an Article 22 Income Tax exemption upon application. The requirements include:

a) That the taxpayer is a newly established entity;
b) That the taxpayer has obtained a “master list” facility (see above); and
c) That the taxpayer will not be in an Income Tax underpayment position.

In practice these exemptions can be difficult to obtain. However, in the case of IPPs using renewable energy an automatic Article 22 Exemption may be separately available. For further discussion see *Section 6.4.4 - Incentives for Renewable Power Generation*.

VAT for Operations and Maintenance (“O&M”) Services

The provision of O&M services constitutes an electrical power support business and is subject to VAT. On this basis an O&M company should be a VAT-able firm meaning that its input VAT will be creditable against its output VAT (although the VAT charged on O&M services to the IPP will not be creditable to the IPP).

6.2.7 Regional Taxes

With the passage of the Regional Autonomy Law No. 32/2004 and its amendments (subsequently replaced by Law No. 23/2014 and its amendments) certain taxation powers were transferred exclusively to Indonesia's Provinces and Regions. These arrangements are currently set out in Law No. 28/2009 (as partially replaced by Law No. 23/2014) which provides a list of regional taxes and the maximum rates of each tax. Each tax is subject to local implementation. A summary of the relevant regional tax arrangements 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	
			1% – 2% for the first private vehicle owned	Calculated with reference to sales value and a weight factor (size, fuel, type, etc.). Government tables will be published annually to enable calculation.
			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 street lighting	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.

6.2.8 Stamp Duty

Indonesian Stamp Duty is due on the execution of most documents constituting evidence of transactions. This includes transfers of shares, the conveyance of real estate or other property, and most rental and lease agreements.

In some countries, Stamp Duty is calculated as a percentage of the value of the underlying transaction being evidenced (with a fixed rate for low-value transactions), and can thus be substantial. In Indonesia, however, Stamp Duty is due at nominal values, typically less than USD 1, and is thus rarely a concern.

On 2 November 2020, the Government issued Law No. 10 Year 2020 regarding Stamp Duty that regulates a new tariff for Stamp Duty of IDR 10 thousand, up from IDR 6 thousand, effective from 1 January 2021.

6.2.9 Proposed Carbon Tax

The Carbon Tax is a new tax which was initially to be implemented from 1 April 2022. The Carbon Tax, which follows on from a "voluntary" program which has been place for the last 12 months, is complemented by a Presidential Regulation dated 29 October 2021. The implementation of the Carbon Tax has been deferred based on a longer timeline which has not yet been confirmed by the Government.

A large number of clarifications remain outstanding regarding to the Carbon Tax. However the HPP Law indicates that the key framework will be as follows:

a) *Tax objects*: being those carbon emissions which have a "negative environmental" impact. The criteria for this will be progressively refined according to Indonesia's Carbon Tax "roadmap" which will ultimately cover:
   1. Carbon emissions reduction strategies;
   2. Priority sector targets;
   3. Alignment with new and renewable energy development; and
   4. Alignment between various other policies.

b) *Tax subjects*: being individuals or corporations who:
   1. Buy goods which generate carbon emissions; or
   2. Carry out activities which generate carbon emissions within a specified period. The elucidation of the HPP Law states that the Carbon Tax will be prioritised for corporate taxpayers and, at least initially, will apply only to coal-fired power producers (as was the case during the voluntary trial period). This will however cover both IPP and PLN power generation.

c) *Milestones*: the Carbon Tax program is to be gradually implemented as follows:
   1. For 2021: development of a carbon trading mechanism;
   2. For 2022 – 2024: introduction of a tax mechanism based on emission limits (i.e. following a "cap and tax" formula) to be applied for coal-fired power plants at IDR 30/kg CO_2e (circa USD 2.10/tonnes of CO_2 p.a.);
   3. For 2025 onwards: full implementation of:
      i) A carbon trading mechanism; and
      ii) The expansion of carbon taxation based on the readiness of the relevant sectors by considering economic conditions, the readiness of the players, etc.;

d) *Tariff*: being the higher of:
    1. The tariff set by the domestic carbon market (on a kg CO_2e basis); or
    2. IDR 30/kg CO_2e;

e) *Facility*: taxpayers who participate in carbon trading and the offsetting of emissions (as well as other mechanisms) can be granted:
    1. A Carbon Tax reduction; and/or
    2. Other incentives for the fulfilment of Carbon Tax obligations;

f) *Implementing rules*: these will be in accordance with the roadmap and the allocation of Carbon Tax revenue for greater climate change control. The implementing regulations will stipulate key features including the tax rate, the tax base, the administrative mechanism, and the procedures aimed at reducing Carbon Tax or other means of meeting Carbon Tax obligations.

6.3 Issues for Conventional Power Generation

6.3.1 Income Tax

As indicated, unlike projects in other capital-intensive sectors such as the natural resources sector, the tax arrangements relevant to Indonesia's power generation sector rely heavily on the general tax rules. There is also uncertainty regarding the extent to which tax arrangements in the sector might ultimately be impacted by the application of ISAK 8 or ISAK 16. See the discussion of Accounting Considerations in *Section 7.1 – Accounting for Conventional Power Generation* for further details.

These issues aside, the commercial profile of a power project is generally more analogous to that of a large natural resources project than to (say) an industrial, manufacturing or service investment. For instance, a power generation project will typically involve:

a) A relatively long and expensive period of pre-project feasibility studies, often involving establishing relationships with multiple investing parties, the completion of detailed reviews, the modelling of the project's viability, and extensive liaison with potential project financiers, etc.;

b) A large upfront capital requirement (relative to the overall project cost) often with complex debt to equity requirements driven by third party (including quasi-Governmental) financing requirements;

c) A relatively long but non-volatile payback period with potentially only one customer and pricing pegged only to key operational costs; and

d) A high level of economic sensitivity to the speed at which tax-free cash can be generated for stakeholders, resulting in material relevance of depreciation and amortisation rates, capitalisation policies (including those relating to interest deductibility), and depreciation classifications (i.e. land, buildings, other tangible assets, etc.)

Specific issues relating to these points which might arise under Indonesia's current tax regime include the following (note possible changes to these deductibility rules under the new HPP Law):

a) The lack of certainty around deductions for the founder and other pre-establishment costs;

b) The impact of modelling a long-term project within an investment framework with no tax stability, including any minimum capitalisation requirements (noting that it is not clear whether the DER of 4:1 should apply – see above);

c) The potential for any deductions to be lost due to the five-year limit on tax losses carried forward; and

d) The incremental project costs arising from VAT exemptions on electricity supplies.

6.3.2 VAT

With regard to VAT, as indicated above, the supply of electricity will generally be (effectively) exempt from VAT on the basis of constituting a "strategic good".

Importantly, where a supply is exempt from VAT, the Input VAT incurred by that supplier will not be creditable. As such, for an IPP which only supplies electricity then all of its input VAT will become an outright cost to the project (although the VAT itself should be deductible). This is different in an economic sense to instances where Input VAT is creditable and so represents a cash flow concern only.

In a general sense, therefore, and assuming an Income Tax rate of 22% for FY2020 onwards, the after-tax financial impact of being a VAT-exempt supplier (in a broad-based VAT environment) could potentially be up to 8.6% of project costs (i.e. 11% VAT x (1 - 22% tax rate)), or higher following the increase in the VAT rate to 12% in 2025.

This potential cash impact makes the availability of VAT relief on capital imports and local delivery (such as those highlighted above) critical.

6.4 Taxation Issues for Renewable Power Generation

6.4.1 State Revenues and Taxes – Geothermal Regimes

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 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 then 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 then 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 then 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 buildings taxes which are otherwise due under a general tax regime.

However, Geothermal Law No. 27/2003 (the 2003 Geothermal Law) removed the all-inclusive rate of 34% and, under Geothermal Law No. 21/2014, there are no specific tax regulations for geothermal activities (at least not yet – see below for further details). This means that the prevailing tax laws and regulations should also apply for non-JoC geothermal projects, and thus that most of the Income Tax issues outlined in the earlier sections of this chapter will also apply to all non-JoC geothermal projects (that is, projects which have been licensed since the enactment of the 2003 Geothermal Law).

On this basis, any profits from either geothermal or steam power generation activities (noting that geothermal projects are now licensed on a disaggregated basis) are taxable at the standard rate of 22%.

6.4.2 VAT on Geothermal Projects

Steam generated from geothermal activities is considered a product of mining, excavation, or drilling at source. Under GR-49, the supply of steam is treated as the supply of a strategic good which is VAT-exempt. This means that, under the post-2003 arrangements, input VAT relating to supplies of both steam and electricity is not creditable, irrespective of whether it is related to steam or power generation activities (i.e. the VAT should instead be deductible).

This also contrasts with the JOC arrangements, where VAT is generally reimbursable. The procedures for VAT reimbursement under the "old JOC regime" can be found in MoF Regulation No. 142/2013.

6.4.3 Draft GR on Income Tax for Geothermal Activities

In late December 2009, the DGT circulated a draft GR on the proposed Income Tax arrangements for the (non-JOC) geothermal sector. The key points outlined in the draft GR included the following:

a) That the tax calculation will generally follow the prevailing Income Tax Law. However, there could be an exception in terms of the tax loss carried forward (which could be extended to seven years). Fixed retributions, production retributions and bonuses should also be deductible; and

b) That all geothermal contracts signed prior to Presidential Decree No. 76/2000 (i.e. under the old JOC regime) should be amended within three years in order to comply with the provisions of the GR.

At the time of printing the GR remained in draft.

6.4.4 Incentives for Renewable Power Generation

A number of fiscal incentives exist for renewable power generation projects, including:

a) GR No. 78/2019 (which revokes GR No. 18/2015 as amended by GR No. 9/2016) which provides the following Income Tax incentives:
    1. A 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. An extended tax loss carry forward period of up to ten years;
    3. Accelerated depreciation and amortisation rates; and
    4. A maximum dividend WHT rate of 10% for foreign shareholders.

    GR No. 78/2019 indicates that the Income Tax incentives apply to IPPs involved in "renewable energy";

b) MoF Regulation No. 218/2019 (which revokes MoF Regulation No. 177/2007) which provides an exemption from Import Duty on imports of goods used in "geothermal business activities" including the pre-exploration, exploration, exploitation, utilisation phases. This is available to the following business entities:
    1. JOC contractors;
    2. Geothermal business concession holders;
    3. Geothermal business permit holders;
    4. Geothermal permit holders; or
    5. Pre-exploration business players.

c) MoF Regulation No. 198/2019 (which amends MoF Regulation No. 142/2015) which provides an Import VAT exemption facility for geothermal projects in the pre-exploration, exploration, exploitation, and utilisation phases;

d) MoF Regulation No. 21/2010 which provides an Article 22 exemption for imports by IPPs involved in renewable energy; and

e) MoF Regulation No. 130/2020 ("PMK-130") which provides a "tax holiday" facility – see the following *Section 6.4.5 – Pioneer Industries – Tax Holiday* for further discussion.

6.4.5 Pioneer Industry – Tax Holiday

On 18 September 2020 the MoF issued an updated Tax Holiday policy through Regulation No.130/PMK.010/2020 (PMK-130), revoking MoF Regulation No.150/ PMK.010/2018 (PMK-150).

PMK-130 allows for a reduction of 50% or 100% in the CIT rate for a period of up to 20 years for businesses involved in "Pioneer Industries". PMK-130 includes a number of changes relevant to electricity development. These include business sectors (now) deemed Pioneer Industries (see below). The changes also allow taxpayers engaged in National Strategic Projects (*Proyek Strategis Nasional* – "PSN") to apply for the Tax Holiday.

In tandem with PMK-130 BKPM issued Regulation No.7/2020 ("BKPM-7"). This BKPM regulation provides an updated list of KBLI which fall within the Tax Holiday provisions. For the power sector, these industry classifications are now formally restricted to "renewable" electricity projects.

Separate provisions now however allow any project to apply for Pioneer Industry status (i.e. irrespective of its KBLI), although to our knowledge this alternative gateway remains untested.

The application for the Tax Holiday facility must fulfil the below requirements:

a) Submitted prior to the start of commercial production, and

b) (i) For new taxpayers – made concurrently with a registration to obtain a Single Business Number (*Nomor Induk Berusaha*); or

(ii) For new capital investments (*Izin usaha untuk penanaman modal baru*) – made within one year of the issuance of a business license.

Other developments in PMK-130 include:

a) Reducing the minimum capital investment threshold to IDR 100 billion (approximately USD 7 million); and

b) Requiring the use of the OSS system to process the application. The application procedures also differ according to the business classification of the taxpayer.

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>IDR 100 bn ≤ IDR 500 bn</th><th>≥ IDR 500 bn</th></tr>
<tr><td>CIT Reduction rate</td><td>50%</td><td>100%</td></tr>
<tr><td>Concession period (from the start of commercial production)</td><td>5 years</td><td><table>
<tr><th>No.</th><th>Investment (in IDR)</th><th>Period (in years)</th></tr>
<tr><td>1</td><td>500 bn up to < 1 T</td><td>5</td></tr>
<tr><td>2</td><td>1 T up to < 5 T</td><td>7</td></tr>
<tr><td>3</td><td>5 T up to < 15 T</td><td>10</td></tr>
<tr><td>4</td><td>15 T up to < 30 T</td><td>15</td></tr>
<tr><td>5</td><td>≥ 30 T</td><td>20</td></tr>
</table></td></tr>
<tr><td>Transition</td><td>25% CIT reduction for the next 2 years</td><td>50% CIT reduction for the next 2 years</td></tr>
</table>

The overall application criteria includes that the applicant:

a) Has a business classified as a "Pioneer Industry" which includes:

 "*having broad linkages, giving added value and high externality, introducing new technology, as well as having strategic value for the national economy*."

 As indicated above, taxpayers involved in the "renewable energy" sector will generally be automatically included in the Pioneer Industry definition;

b) Is an Indonesian legal entity;

c) Constitutes a "new" investment where a decision on the granting or refusal of the application for a Tax Holiday has not yet been issued;

d) Has a planned investment of at least IDR 100 billion; and

e) Where financed by debt, the project satisfies [MoF-169, which mandates a general debt to equity ratio ("DER") of 4:1 (with an exception for taxpayers in the "infrastructure" sector) – see Section *6.2.1 - Deductibility Issues* for further discussion].

In general, the new Tax Holiday framework represents a refinement of the prior rules, especially in terms of the restriction to renewable energy projects. This accords with the Government's aim of stimulating investment in infrastructure and other capital-intensive industries more generally, and (presumably) the renewable power generation sector in particular. This is assuming that many renewable energy IPP projects should qualify for at least a partial tax holiday, which should improve their after-tax cash returns.

Enjoyment of the tax holiday facility remains subject to reviews of any of the key qualification criteria pursuant to an Indonesian Tax Office ("ITO") field audit, as approved by the Minister of Finance. If the ITO determines that any of the qualifying requirements have not been satisfied, the Tax Holiday period can be amended or revoked, with any taxes not paid as a result of the non-compliance subsequently becoming payable, plus penalties. This aspect will need to be managed carefully.

Photo source: PT Jawa Power

Photo source: PT Minahasa Cahaya Lestari

7 Accounting Considerations

7.1 Accounting for Conventional Power Generation

Indonesian Financial Accounting Standards ("PSAKs") have been brought substantially into alignment with International Financial Reporting Standards ("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.

7.1.1 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.

The new definition of a lease under PSAK 73 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 73 prescribes that a contract contains a lease when:
a) There is an identified asset; and
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).

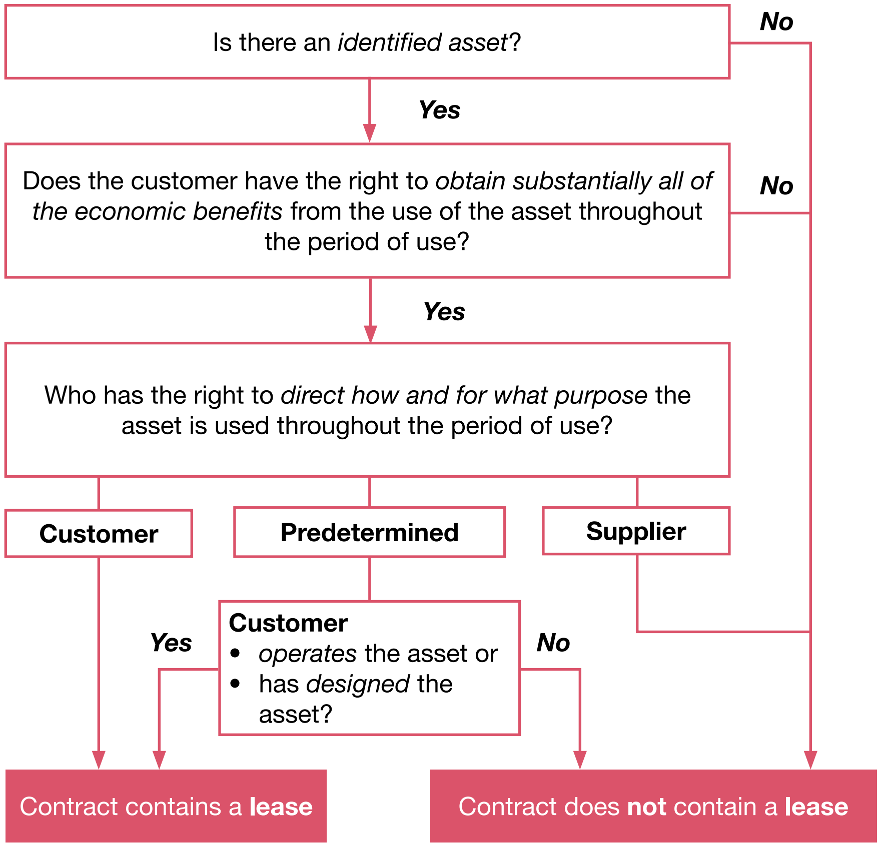
This conceptual change becomes obvious when looking at a contract to purchase substantially all of the output which is produced by an identified asset (for example, a power plant). If the price per unit of output is neither fixed nor equal to the current market price, then the contract would be classified as a lease under International Financial Reporting Interpretations Committee (“IFRIC”) 4. PSAK 76 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.

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 73 gives several examples of relevant decision-making rights:
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; and
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; and
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 73 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.

<table>
<tr><th colspan="3">Background information</th></tr>
<tr><td colspan="3">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.</td></tr>
<tr><th>Customer’s rights</th><th>Supplier’s rights</th><th>Conclusion</th></tr>
<tr><td>Example 1

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.</td><td>

The supplier is responsible for building the power plant to the customer’s specifications, and then operating and maintaining it.</td><td>

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; and
• 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.</td></tr>
</table>

Customer's rights	Supplier's rights	Conclusion
Example 2 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; and • 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 3 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; and • 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 73, 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 the interest rate implicit in the lease. If this rate cannot be readily determined, the lessee should instead use its incremental borrowing rate.

Lease liability

Lease payments made before or at the commencement date

Restoration costs

Initial direct costs

Lease payments

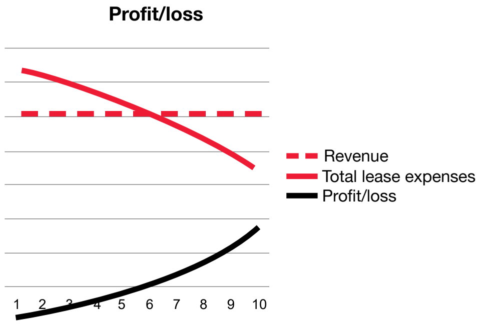
Discount rate

Provision

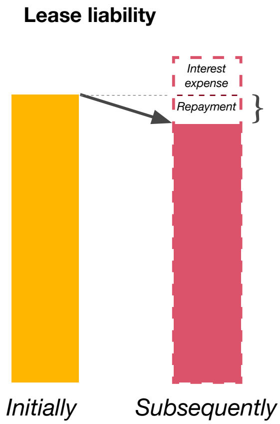
Subsequent Measurement

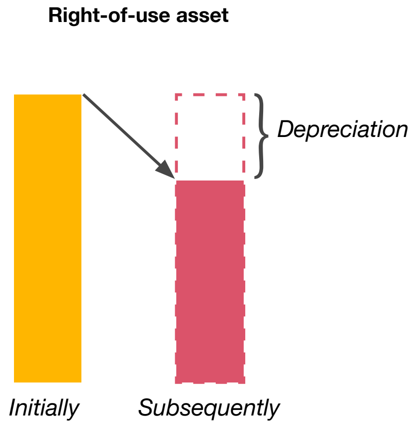
The lease liability is measured in subsequent periods using the effective interest rate method. The right-of-use asset is depreciated in accordance with the requirements of PSAK 16, "Property, Plant and Equipment", which will result in depreciation on a straight-line basis or another systematic basis 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 73
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 73 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 *Peraturan Otoritas Jasa Keuangan* 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 7.1.3 – Accounting Treatment for the Purchase and Sale of Electricity by an Issuer in Indonesia*.

PPAs

PSAK 73 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 73 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 73, 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; and
- the price mechanism used, including whether the amount charged varies per unit.

The determination under PSAK 73 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 73. 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 73 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 73. 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 73
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 plan 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.

7.1.2 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 16 – Service Concession Arrangements (equivalent to IFRIC 12).

Arrangements within the scope of ISAK 16 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 16 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 16, as these have many of the features of a service concession arrangement.

The two accounting models under ISAK 16 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 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 16. If it is within the scope of ISAK 16, 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.

7.1.3 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 7.1.1) and service concession (discussed in 7.1.2) 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.

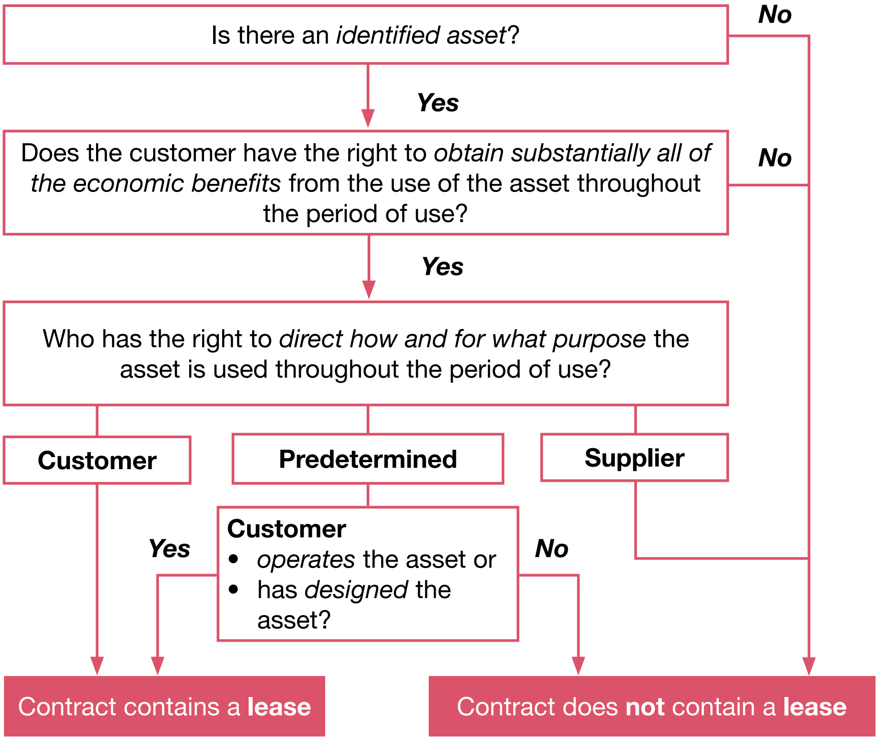
POJK No. 6/2017 has been applied prospectively, starting from 1 January 2017, and it can be adopted for the financial year which began on 1 January 2016. This temporary exemption is only available as long as PR No. 4/2016, subsequently amended by PR No. 14/2017, is in effect. After the temporary exemption 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.

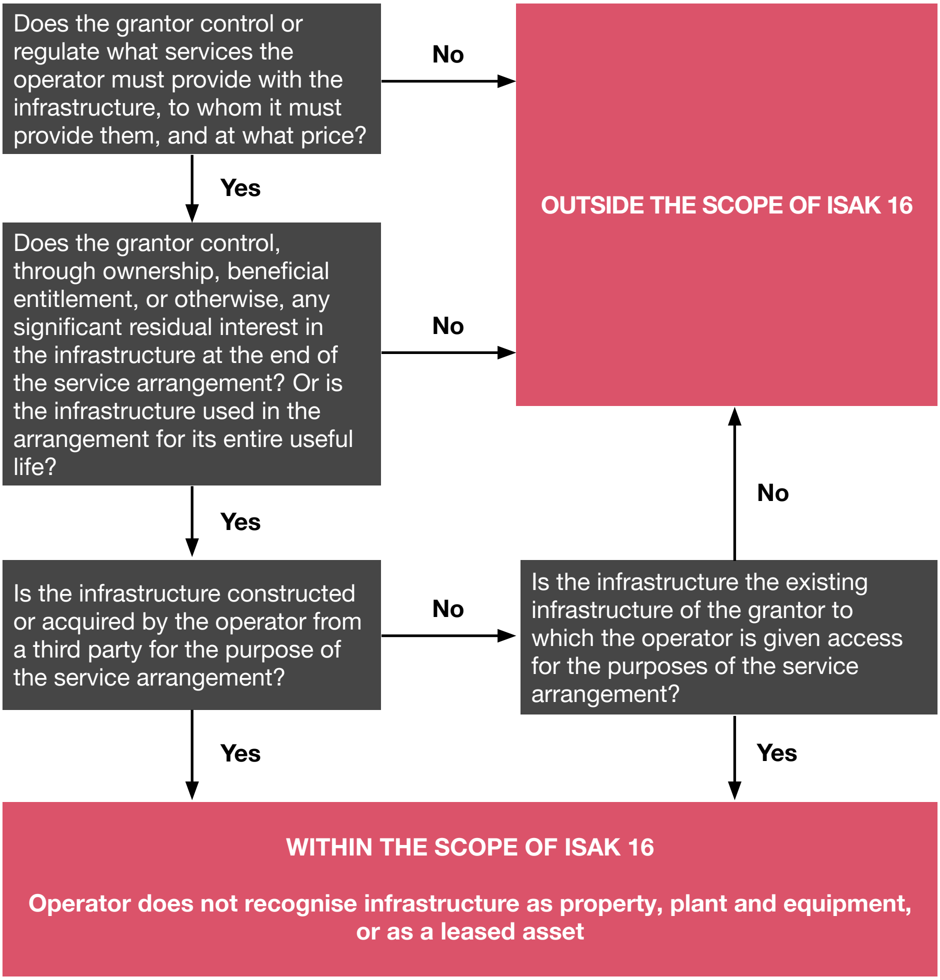
7.1.4 Application of Accounting Standards

The flowchart below summarises the analysis to be made to evaluate whether a contract contains a lease:

PSAK 73 – Identifying a lease



ISAK 16 – 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.

<table>
<tr><th>Category</th><th>Lessee</th><th colspan="3">Service Provider</th><th colspan="2">Owner</th></tr>
<tr><td>Typical arrangement types</td><td>Lease (e.g. Operator leases assets from grantor)</td><td>Service and/or maintenance contract</td><td>Rehabilitate-operate-transfer</td><td>Build-operate-transfer</td><td>Build-own-operate</td><td>100% Divestment/ Privatisation/ Corporation</td></tr>
<tr><td>Asset ownership</td><td colspan="4">Grantor</td><td colspan="2">Operator</td></tr>
<tr><td>Capital investment</td><td colspan="2">Grantor</td><td colspan="4">Operator</td></tr>
<tr><td>Demand risk</td><td>Shared</td><td>Grantor</td><td colspan="2">Operator and/or Grantor</td><td colspan="2">Operator</td></tr>
<tr><td>Typical duration</td><td>8-20 years</td><td>1-5 years</td><td colspan="3">25-30 years</td><td>Indefinite (or may be limited by licence)</td></tr>
<tr><td>Residual interest</td><td colspan="4">Grantor</td><td colspan="2">Operator</td></tr>
<tr><td>Relevant PSAKs</td><td>PSAK 30 - Leases</td><td>PSAK 23 - Revenue</td><td colspan="2">ISAK 16 - Service Concession Arrangements</td><td colspan="2">PSAK 16 - Fixed Assets</td></tr>
</table>

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 7.1.3 – Accounting Treatment for the Purchase and Sale of Electricity by an Issuer in Indonesia* for further details.

7.1.5 Key Accounting Standards under PSAK, US Generally Accepted Accounting Principles ("US 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".

<table>
<tr><th colspan="4">Accounting for Conventional Power Generation</th></tr>
<tr><th colspan="4">A general comparison between Indonesian GAAP, US GAAP and IFRS</th></tr>
<tr><th>Area</th><th>IFRS</th><th>US GAAP</th><th>Indonesian GAAP</th></tr>
<tr><td>Identification and classification of concession arrangements</td><td>PPP service concession arrangements that meet certain conditions must be analysed to determine whether the concession represents a financial asset or an intangible asset.</td><td>Consistent with IFRS in all significant respects.</td><td>Consistent with IFRS in all significant respects, except for Issuers applying POJK No. 6/2017, as explained in Section 7.1.3 - Accounting Treatment for the Purchase and Sale of Electricity by an Issuer in Indonesia.</td></tr>
</table>

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, EITF 01-8 (codified into 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.

7.2 O&M Accounting

No specific accounting standards have been promulgated for power generation O&M businesses. Instead, the generally accepted accounting standards usually apply.

7.3 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 Exploration and Evaluation ("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 64, 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; and
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 64 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 64.

PSAK 64 allows an entity to continue to apply its existing accounting policy under 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".[166] 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".[167]

7.4 PSAK 72 – 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. PSAK 72 has been adapted from IFRS 15, "Revenue from Contracts with Customers". PSAK 72 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 1: Identify the contract with the customer;
Step 2: Identify the separate performance obligations in the contract;
Step 3: Determine the transaction price;
Step 4: Allocate the transaction price to the separate performance obligations; and
Step 5: 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 72. 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 72, and our views may evolve during that process.

166 https://www.pwc.com/id/en/publications/assets/assurance/acs/ifrs-and-indonesia-gaap-ifas-2016-r1.pdf
167 https://www.pwc.com/id/en/publications/assets/utilities-ifrs.pdf

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 73, 'Leases' (see below for further analysis of this standard), PSAK 72 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 72 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 72 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 72.
Contract costs	• There is currently little guidance on how power companies should account for the costs spent in obtaining a PPA. PSAK 72 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 72 treatment may change the pattern of cost recognition, and operating profit, over the contract period.

<table>
<tr><th>Potential scenario</th><th>Potential Impacts on Power Companies</th></tr>
<tr><td>Contract modification</td><td>

Another potential area requiring judgment in the implementation of PSAK 72 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); or
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 2 above. Under PSAK 72, 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.

</td></tr>
</table>

Photo source: PT Paiton Energy

Photo source: PT Jawa Power

Appendices

Tax Incentives: Comparison between Conventional and Renewable Power Plants

Regulation	Incentive	Conventional				Renewable			
		Income Tax	Import Duty	VAT	Article 22	Income Tax	Import Duty	VAT	Article 22
GR No. 78/2019	Investment allowance of 30% (over 6 years), accelerated depreciation and amortisation, and reduced WHT on dividends paid to non-residents.	Potentially yes for micro and mini power plants	–	–	–	Potentially yes for micro and mini power plants	–	–	–
MoF Regulation No. 130/2020	50% CIT reduction for 5 years or 100% CIT reduction for a maximum of 20 years. 25%/50% CIT reduction for the next 2 years after the tax holiday period.	–	–	–	–	Potentially yes	–	–	–
MoF Regulation No. 218/2019	Import Duty exemptions on imports of goods used in "geothermal business activities" (requires a working area, survey licence, or geothermal mining business licence). Goods and materials must either: a) Not be produced in Indonesia; b) Be produced in Indonesia, but not meet the required specifications; or c) Be produced in Indonesia, but in insufficient quantities.	–	–	–	–	–	Yes for geothermal investments	Potentially yes (VAT not collected)	Potentially yes (excluded from Article 22 collection)
MoF Regulation No. 66/2015	Import Duty exemptions for imports of capital goods ("machines, equipment and tools, not spare parts") for PLN and some IPPs. Needs to be outlined in the agreement with PLN.	–	Yes	–	–	–	Yes	–	–

Regulation	Incentive	Conventional				Renewable			
		Income Tax	Import Duty	VAT	Article 22	Income Tax	Import Duty	VAT	Article 22
MoF Regulation No. 176/2009 (as amended by 76/2012 and 188/2015)	Import Duty exemptions on imports of "machines, goods and materials for establishment and development" of facilities to produce goods (including electricity) and limited services.	–	Yes	–	–	–	Yes	–	–
MoF Regulation No. 142/2015	Import VAT exemptions on importations (for which the associated import duty is also exempt).	–	–	–	–	–	–	Yes - for geothermal only and only at the exploration stage	–
GR No. 12/2001 (as amended the latest by GR No. 48/2020)	VAT exemptions on imports of "strategic" capital goods ("plant, machines and equipment, but not spare parts").	–	–	Yes, to VAT-able entrepreneurs (IPPs can qualify).	–	–	–	Yes - to VAT-able entrepreneurs (IPPs qualify).	–
MoF Regulation No. 21/2010	Art. 22 exemptions for imports by IPPs involved in renewable energy.	–	–	–	–	–	–	–	Yes

Commercial and Taxation Issues by Stage of Investment

Stage of Investment	Issues Common to Conventional Power and Renewable Energy	Renewable Energy Issues specifically for Geothermal (Non-JOC post 2003) and Hydro
Bid/Feasibility Stage	• PPA drafting/closing (consider base case fiscal terms); • Preparation of investment model tax and accounting assumptions; • Site and land acquisition (regional land and building taxes); • Forestry borrow and use permits – non-tax state revenue charges; • Consider if there are any Environmental Law issues/levies; and • Spatial Zoning issues.	• Tariffs; • Consider eligibility for tax incentives; and • Post-2012 CDM feasibility for carbon credits/CERs.
Pre-Incorporation SPV	• Cash calls; • Spending pre-incorporation; • Choice of jurisdiction – of holding companies; and • EPC contracting for long lead items.	• Consider KBLI for RE incentives.
SPV Establishment	• USD bookkeeping; • ISAK 8 / ISAK 16 vs. conventional accounting (for tax); • Tax/VAT registrations; • Import Licences; and • Recharging of pre-incorporation spending.	• Licensing clarification based on KBLI.
Ownership of Infrastructure	• Mine-mouth or captive plants; • Transfer of distribution facilities – land and building taxes; and • Ownership of any separate infrastructure.	• Consider use of affiliates; and • Tax treatment of earthworks (specific for hydro).
Key Project Contracts Stage	• Consider the Tax and Commercial issues embedded in: – Shareholder Agreement; – Shareholder Loan; – PPA; – EPC Agreement – Offshore; – EPC Agreement – Onshore; – EPC Wrap Agreement; – Long-Term Fuel Supply Agreement; – Technical Services Agreement; – Project Finance Documents; and – Developer's/Sponsor's Agreement.	• Note that the PPA will be different for geothermal and for hydropower. For hydro also: – Water use agreement; and – Consider water usage fees.

Stage of Investment	Issues Common to Conventional Power and Renewable Energy	Renewable Energy Issues specifically for Geothermal (Non-JOC post 2003) and Hydro
Construction	• Treatment of EPC costs – subject to final construction services tax or not; • PE risk for offshore contractor; and • WHT compliance for onshore project.	For hydro only: • Ownership of waterway diversion facilities.
Importation of Equipment	• Importation issues – special approach to VAT; • Import duty; • Article 22 import tax – 2.5%; and • Treatment of spares or non-capital goods (materials).	• Renewable Energy ("RE") incentives.
Operation	• Input VAT costs; • Regional taxes & levies; • ISAK 8 / ISAK 16 vs. conventional accounting (for tax); • VAT registration & compliance; • WHT on electricity sales – 1.5%; • O&M Fees – transfer pricing if paid to affiliate; • Forestry Licence fees; • Profit repatriation; and • Cash repatriation.	• Article 74 of the Company Law on Corporate Social Environmental Responsibility (CSER). Is spending required, given the use of natural resources?; • Environmental Levies under the Environmental Law; and • Forestry Licence fees. For hydro also: • Regional taxes and water levies.
Overhaul Stage	• Capitalisation of expenditure & amortisation; and • Deductibility of repairs/improvements.	
Handover of Facility Stage	• Taxes on divestment; • Manpower costs – change of control provisions; • Environmental provisions for site rehabilitation; and • Implications for any foundations established for CSR/Pension purposes.	

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- Capital Markets & 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 & 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
- Capital Projects & Infrastructure
- Corporate Finance
- Valuation
- Deal Strategy
- Delivering Deal Value
- Transaction Services
- ESG and Energy Transition Services

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:

- Mergers & Acquisitions 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 2,800 professional staff, including 90 partners and technical advisors, specialised in providing assurance, advisory, tax and legal services to Indonesian and international companies.
- Our Energy, Utilities & Resources ("EU&R") practice in Indonesia comprises over 300 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 21,300 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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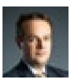
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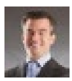
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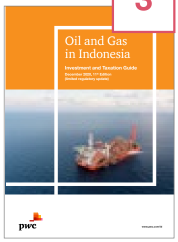

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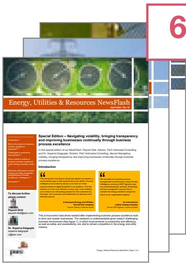

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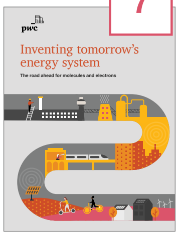

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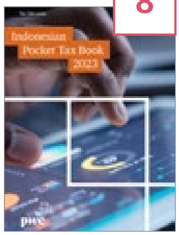

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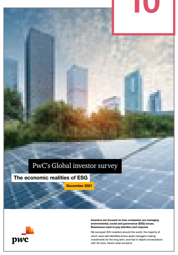

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